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RS-26-146

10 CFR 50.71 (e)
10 CFR 54.37(b)

September 18, 2026

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Limerick Generating Station, Units 1 and 2
Renewed Facility Operating License Nos. NPF-39 and NPF-85
NRC Docket Nos. 50-352 and 50-353

Subject: Submittal of Updated Final Safety Analysis Report (UFSAR), Revision 23 and Technical Specification (TS) Bases

Reference: Letter from David P. Heckler (Constellation Energy Generation, LLC- formerly Exelon Generation Company, LLC) to U.S. Nuclear Regulatory Commission – Amended Update to Updated Final Safety Analysis Report (UFSAR), Revision 20, dated April 29, 2021 (ML21138A801)

In accordance with 10 CFR 50.71(e)(4) and 10 CFR 50.4(b)(6), enclosed is Revision 23 of the Updated Final Safety Analysis Report (UFSAR) for Limerick Generating Station (LGS), Units 1 and 2. The enclosed UFSAR Revision 23 is being provided to the NRC in its entirety and constitutes a total replacement copy. In addition, as required by 10 CFR 50.71(e)(2)(ii), Attachment 1 to this letter identifies changes made under the provisions of 10 CFR 50.59, and is included in Revision 23 of the UFSAR, but not previously submitted to the NRC.

10 CFR 50.71(e)(4) stipulates that revisions to the UFSAR must reflect changes made up to a maximum of six months prior to the submittal. As a result, UFSAR Revision 23 reflects changes made up to the LGS, Units 1 and 2, UFSAR at least up to September 1, 2026. Attachment 2 of this document includes UFSAR Chapters 1 thru 17 and Appendix A.

On October 20, 2014, the NRC issued Renewed Facility Operating Licenses NPF-39 and NPF-85 for LGS, Units 1 and 2, respectively. Therefore, pursuant to the requirements of 10 CFR 54.37(b) and the guidance specified in Regulatory Issue Summary 2007-16, Revision 1, "Implementation of the Requirements of 10 CFR 54.37(b) for Holders of Renewed Licenses," the UFSAR update required by 10 CFR 50.71(e) must include any Structures, Systems, or Components (SSCs) newly identified that would have been subject to an aging management review or evaluation of time-limited aging analyses in accordance with 10 CFR 54.21. The UFSAR update must describe how the licensee will manage the effects of aging in order to effectively maintain the intended function(s) of newly-identified SSCs. An evaluation was completed to determine whether any newly-identified SSCs existed in support of submitting UFSAR Revision 23 for LGS, Units 1 and 2. This evaluation involved reviewing pertinent

documentation for the period subsequent to the last LGS biennial UFSAR revision. As a result of this review, there were no newly-identified SSCs for which aging management reviews or time-limited aging analyses would apply.

As noted in the Reference, Appendix 3B of the UFSAR contains proprietary information and will be withheld from public disclosure pursuant to 10 CFR 2.390 in Revision 23 of the LGS UFSAR. The Reference letter provides information regarding the revision history pertaining to Appendix 3B and that earlier legacy correspondence supports the submittal of the Appendix 3B information as proprietary which includes supporting affidavits. Since the Reference letter, there have been no changes to UFSAR Appendix 3B. Therefore, a proprietary version is not included in Revision 23 of the LGS UFSAR update and Appendix 3B is only included by reference.

Additionally, in accordance with the requirement of LGS, Units 1 and 2 Technical Specification (TS) 6.8.4.h.d, Constellation Energy Generation, LLC, hereby submits a complete updated copy of the Unit 1 and Unit 2 TS Bases, which includes changes through the date of this letter.

As required by 10 CFR 50.71(e)(2)(i), I certify that to the best of my knowledge, the information contained in the Attachments to this letter accurately reflects information and analyses submitted to the NRC, or prepared pursuant to the NRC requirements as described above.

If you have any questions or require further information, please contact Lane Oberembt at 267-533-5301.

Respectfully,

Para, Wendi E
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Wendi Para
Sr. Manager - Licensing
Constellation Energy Generation, LLC

Attachments:
1. Summary of UFSAR Changes
2. Compiled Chapters 1-17 and Appendix A
3. LGS Units 1 and 2, Technical Specification Bases

cc: USNRC Region I, Regional Administrator w/ Attachments
USNRC Senior Resident Inspector, LGS "
USNRC Project Manager, LGS "

ATTACHMENT 1

Summary of UFSAR Changes

ATTACHMENT 1

10 CFR 50.71(e)(2)(ii) requires that revisions to the UFSAR include changes made under the provisions of 10 CFR 50.59, but not previously submitted to the NRC. Accordingly, the list below identifies plant changes included in Revision 23 of the Updated Final Safety Analysis Report (UFSAR) that were not previously submitted to the NRC.

Limerick Generating Station, Units 1 and 2
Summary of UFSAR Changes – Revision 23

UFSAR Change Request	Issue Report	Engineering Change Request (ECR) / Engineering Change (EC)	Description
2023-017	4504651-55	EC 640130	FPR Section 9A.6.2, Table 9A-12, and the List of Tables on page 9A.vii are being revised to include new guidance from the NRC in Reg. Guide 1.189 Revision 4. The NRC Staff has reconsidered their position concerning 3-Phase Hot Shorts, and no longer believes they need to be postulated for High/Low Pressure Interfaces. App. 9A Table of Contents change is administrative only. Table 9A-13 was previously deleted but the Table of Contents was not updated.
2024-004	4504651-70	EC 641755	Defeat trip function for Turbine Enclosure Main Steam Isolation Valve Leak Detection System High Temperature. Update Tables 5.2-7, 6.2-17 , 7.3-5 , 7.3-7 and system description in Chapter 7.
2024-005	4504651-71	N/A	Removing reference to abandoned CO2 systems in the plant (Section A.2.1.17). Removal of legacy wording regarding CO2 from Appendix A, Fire Protection AMP that was previously missed during UFSAR Change Package 2022-008 (editorial change).
2025-001	4504651-75	N/A	Update to UFSAR sections for DCWS (Drywell Chilled Water System) and RECW (Reactor Enclosure Cooling Water) to allow outboard RECW to DCWS valves to be operated in OPCONS 1, 2, & 3 as allowed by the PCIV Tech Specs.
2025-003	4504651-78	EC 642350	UFSAR Updates for Limerick Generating Station Unit 2 Cycle 19 Reload Evaluation. The proposed changes are focused on correcting typographical and editorial errors as well clarifying that only Unit 1 is operating with GNF2 fuel. Unit 2 Cycle 19 will be the first cycle operating with a full core of GNF3 fuel.
2025-004	4504651-80	EC 423388	RRP MOTOR 2A REPLACEMENT PROJECT. EC 423388 Rev 3 permanently removes the cabinet and abandons the cables that no longer used. The removed cabinet and abandoned components are no longer in use and are not part of any plant system which has design basis functions. The UFSAR markup is administrative and non-regulatory and remove unnecessary information.
2025-005	4504651-81	N/A	Incorporating changes from previously approved UFSAR Change Packages 2019-

UFSAR Change Request	Issue Report	Engineering Change Request (ECR) / Engineering Change (EC)	Description
			019 and 2023-005 that were inadvertently omitted.
2025-009	4504651-87	EC 644904	Removal of HV-011-132A and HV-011-232A from Table 9A-14 following implementation of EC 644904. EC 644904 evaluated the changes to the Emergency Service Water A/B Loop Outlet valves to prevent stem-disc separation failures.
2026-001	4504651-89	N/A	Buried and Underground Piping and Tanks License Renewal Commitment Clarification. The Buried Piping LR Commitment in the UFSAR has vague wording that led to an inaccurate interpretation of the commitment resulting in the NRC Green NCV. There is no change in the commitment requirements but this is an editorial change to help clarify requirements.
2026-003	4504651-92	EC 644570 & EC 646777	Close and Deactivate Select Post LOCA Hydrogen Recombiner (PLHR) Motor Operated Primary Containment Isolation Valves (HV-057-164 and HV-057-262, -263, -264, -269). Closing and deactivating the valves will render the valves inoperable and maintain the containment isolation requirements of GDC 56 as committed to in the UFSAR.
2026-004	4504651-93	N/A	Reference ANSI/ANS 56.8 - 2002 was adopted in License Amendment Nos. 241 and 204 SER (ML19351E376) to adopt NEI 94-01 Rev 3A. Change the reference to pretest requirements of "ANSI/ANS N56.8 - 1994" to "ANSI/ANS 56.8 - 2002".
2026-005	4504651-94	EC 647146	Unit 1 Recirculation pump discharge valve and suction valve interlock trips will be removed. EC 647146 defeats this vulnerability by disconnecting the interlock contacts and limit switches. Section 15.3.1.1.1 of the UFSAR identifies both either the suction valve or discharge valve trips (not being fully opened) as causes to trip the recirculation pump motor. Removing the aforementioned trios does not adversely affect the design function of the recirculation system as described in the UFSAR.
2026-006	4504651-95	EC 644579	UFSAR Updates for Limerick Generating Station Unit 1 Cycle 22 Reload Evaluation to remove GNF2 information as both LGS units will contain full cores of GNF3 fuel once Cycle 22 commences. Also includes grammatical corrections and editorial updates (word choice & font color), correct Reference titles and dates, remove the use of "latest approved revision" for NF related references and replace this with the correct revision number.
2026-008	4504651-97	N/A	The maximum allowable closure time for PCIVs is detailed in TRM Table 3.6.3-1. This table has the Maximum isolation time for valves associated with penetrations

ATTACHMENT 1

UFSAR Change Request	Issue Report	Engineering Change Request (ECR) / Engineering Change (EC)	Description
			231A & 213B listed as 30 seconds. UFSAR Table 6.2-17 has the isolation times for these valves listed as 20 seconds. The UFSAR should be revised to reflect the information in the TRM.
2026-010	4504651-99	N/A	UFSAR Section 2.3.1, Regional Climatology, states hourly meteorological data from the Pottstown-Limerick Airport is used to review the Site Meteorological Tower data consistency on a daily basis. This UFSAR section is being revised to clarify the current practice of utilizing the meteorological data from the Pottstown – Limerick Airport periodically throughout the month to verify consistency of the Site Meteorological Tower data. If a data discrepancy is identified, further investigation is performed and data comparison is performed more frequently.
2026-011	4974857-01	N/A	This UFSAR change (activity) revises UFSAR Section 5.4.7.1.5 to remove a reactor cavity flooded up restriction to permit bypassing the RHR shutdown cooling (SDC) mode specific automatic isolation functions sooner and for a longer duration during an outage when they are not required by Technical Specifications (TS) and corrects a grammatical error.
2026-012	4974857-02	N/A	UFSAR Chapter 12.3.4.1.3 describes ten portable local area monitors provided in addition to the installed ones. They are located on each of the two refueling bridges, the three turbine enclosure crane cabs, the east and west unit 1 and 2 turbine enclosure deep bed vessel areas, and the health physics and chemistry source storage and calibration room. UFSAR Table 12.3-7 p. 12.3-32 only lists two turbine crane monitors instead of three. All the other portable radiation monitors are correctly listed in both sections.

ATTACHMENT 2

LGS, Units 1 and 2 UFSAR Revision 23

Compiled Chapters 1 – 17 and Appendix A

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CHAPTER 1 - INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 INTRODUCTION

This UFSAR is submitted to fulfill the requirements of 10CFR50.71(e) for Exelon's nuclear power station designated as the Limerick Generating Station, Units 1 and 2. These units hold full power utilization facility (Class 103) licenses, NPF-39 and NPF-85. These licenses were issued in August 1985 and August 1989 respectively.

LGS is located on the east bank of the Schuylkill River in Limerick Township of Montgomery County, Pennsylvania, approximately 4 river miles downriver from Pottstown, 35 river miles upriver from Philadelphia, and 49 river miles above the confluence of the Schuylkill with the Delaware River. The site contains 595 acres (423 acres in Montgomery County and 172 in Chester County).

Each of the LGS units employs a GE BWR originally designed and licensed to operate at a rated core thermal power of 3293 MWt (100% steam flow) with a corresponding gross electrical output of 1092 MWe. Approximately 37 MWe are used for auxiliary power. Subsequent to issuing the original operating licenses, LGS Units 1 and 2 were reevaluated with regard to rerating power to 3458 MWt (Rerate Power). The acceptability of the rerate evaluations stems from the fact that LGS Units 1 and 2 were originally designated for steam flow capabilities at least 5% above its original rating. In addition, improvements in the analytical techniques based on more realistic assumptions, plant performance feedback, and the latest fuel designs resulted in a significant increase in the calculated operational margins related to safety analyses. Subsequently, the core thermal power was uprated from 3458 MWt to 3515 MWt as part of the measurement uncertainty recapture power uprate (MUR PU). The existing analyses assume a 2% uncertainty in feedwater flow, which is reduced to 0.3% using leading edge ultrasonic flow meters. This is acceptable because the analyzed conditions and margins of the safety analyses are not affected by this change in FW flow measurement.

The reactor design power level used in various analyses is discussed in Section 6.3 and Chapter 15.

The containment system, designed by Bechtel Power Corporation, limits the release of radioactive materials to the environs subsequent to the occurrence of a postulated LOCA so that the offsite doses are below the values stated in 10CFR50.67. The design employs the drywell/pressure-suppression features of the BWR/Mark II containment concept. The containment consists of a dual barrier: the primary containment, and the secondary containment. The primary containment is a steel-lined reinforced concrete pressure-suppression system of the over-and-under configuration. The secondary containment is the enclosure that encloses the reactor, and its primary containment, and fuel storage areas.

Condenser cooling is provided by water circulated through natural draft cooling towers.

The LGS PSAR was submitted on February 26, 1970 (AEC Dockets 50-352 and 50-353). The construction permits, CPPR-106 and CPPR-107, were originally issued on June 19, 1974. Environmental impact is discussed in the Applicant's Environmental Report - Construction Permit Stage (Revised) dated May 1972. The Atomic Energy Commission (now Nuclear Regulatory Commission) issued the LGS Final Environmental Statement Construction Stage in November 1973.

The LGS FSAR was originally submitted on March 17, 1981 and docketed on July 27, 1981. The NRC issued its SER in August 1983 and nine supplements to NUREG-0991 through August 1989.

A discussion of environmental impact was also submitted as the EROL, and the NRC issued its LGS Final Environmental Statement Operating License Stage, NUREG-0974, in April 1984.

The LGS Unit 1 low power (5%) operating license (NPF-27) was issued on October 26, 1984 and the full power operating license (NPF-39) was issued on August 8, 1985. The LGS Unit 1 entered commercial operation on February 1, 1986.

The LGS Unit 2 was issued an operating license (NPF-83) to load fuel and conduct testing up to, but not including, initial criticality on June 22, 1989. The low power (5%) operating license (NPF-84) was issued July 10, 1989 and the full power operating license (NPF-85) was issued August 25, 1989. The LGS Unit 2 entered commercial operation on January 8, 1990. The licensee received a license amendment for a 5% increase in rated power to 3458 MWt for LGS Unit 2 on February 16, 1995 and for Unit 1 on January 24, 1996. The licensee received license amendments for an additional 1.65% increase in rated power to 3515 MWt for Unit 1 and Unit 2 on April 8, 2011.

The FSAR was prepared and submitted in accordance with 10CFR50.34(b). Its format and content are in accordance with Regulatory Guide 1.70 (Rev 3), "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants", November, 1978. Following its initial update, the UFSAR will be updated in accordance with 10CFR50.71.

The relationships of other various reports submitted by the licensee are discussed below.

As discussed in Appendix 9A, the Fire Protection Evaluation Report was prepared and submitted in response to a September 30, 1976 NRC request. Since it contains the information suggested by Regulatory Guide 1.70 to be provided in Section 9.5.1.3, the FPER, in its entirety, was incorporated into the UFSAR as Appendix 9A in accordance with 10CFR50.32. The FPER will be updated in accordance with 10CFR50.71.

As discussed in Appendix 3A, the Design Assessment Report was prepared and submitted in response to a generic industry concern of thermohydrodynamic loads resulting from SRV operations and/or discharges during a LOCA. The DAR contains considerable design information and will be updated in accordance with 10CFR50.71. Proprietary DAR information is discussed in Appendix 3B.

The Quality Assurance Program was prepared and submitted in accordance with 10CFR50.34(b). Its format and content were prepared in accordance with Regulatory Guide 1.70 (Rev 3). The Quality Assurance Program is incorporated into the UFSAR as Section 17.2 and will be updated in accordance with 10CFR50.54(a)(3) and 10CFR50.71.

In accordance with 10CFR50.34(b)(6)(v) and Regulatory Guide 1.70, the Emergency Plan, while a separate report, is referenced in Section 13.3 of the UFSAR. The Emergency Plan will be updated in accordance with 10CFR50.54(q) and 10CFR50, Appendix E.

The Security Plan was prepared and submitted in accordance with 10CFR50.34(c). It is identified as a separate report withheld from public disclosure in UFSAR Section 13.6, in accordance with Regulatory Guide 1.70 (Rev 3). The Security Plan will be updated in accordance with 10CFR50.54(p).

The Safeguards Contingency Plan was prepared and submitted in accordance with 10CFR50.34(c), and withheld from public disclosure pursuant to 10CFR2.790(d). No discussion of

this report is provided in the UFSAR, consistent with Regulatory Guide 1.70 (Rev 3). The Safeguards Contingency Plan will be updated in accordance with 10CFR50.54(p).

As discussed in Section 1.0 of the Environmental Qualification Report, the EQR was prepared and submitted in response to a May 1980 Commission Memorandum and Order (CLI 80-21). It has been revised to fulfill the requirements of 10CFR50.49. The EQR is referenced in Section 3.11 of the UFSAR but is considered to be a licensee working document and update submittals are not planned.

The EROL was prepared and submitted in accordance with 10CFR51.21. Its format and content are in accordance with Regulatory Guide 4.2 (Rev 2), "Preparation of Environmental Reports for Nuclear Power Plants", July 1976. Regulatory Guide 4.2, section 7.1, "Station Accidents Involving Radioactivity" was later superseded by the Commission's Interim Position on Accident Consideration Under NEPA (45FR40101).

As discussed in section 1.1 of the Probabilistic Risk Assessment (PRA) and the Severe Accident Risk Assessment (SARA), the PRA and SARA were prepared and submitted in response to an initial May 6, 1980 NRC request. Because they contain the information required by the NRC's Interim Position on Accident Considerations under NEPA (45FR40101), the PRA and SARA were used in the analysis performed for EROL Section 7.1, in accordance with 10CFR50.32. At the request of the NRC Limerick Project Manager, the PRA is acknowledged in UFSAR Section 15.11; it is not referenced therein. The PRA and SARA are considered to be licensee working documents and update submittals are not planned.

1.2 GENERAL PLANT DESCRIPTION

1.2.1 SITE CHARACTERISTICS

A summary of the site characteristics for LGS is provided below. Detailed discussions on the site characteristics are provided in Chapter 2 of the UFSAR.

1.2.1.1 Location

LGS is located in southeastern Pennsylvania on the Schuylkill River about 1.7 miles southeast of the limits of the Borough of Pottstown and about 20.7 miles northwest of the Philadelphia city limits. The Schuylkill River passes through the site and separates the western portion, which is located in East Coventry Township, Chester County, from the eastern portion, which is partly in Limerick Township and partly in Lower Pottsgrove Township, both in Montgomery County, Pennsylvania. All of the major plant structures are located in Limerick Township. The site location map is shown in Figure 2.1-1.

1.2.1.2 Site Environs and Access

The site is located in gently rolling countryside, traversed by numerous valleys containing small creeks or streams that empty into the Schuylkill River. Two parallel streams, Possum Hollow Run and Brooke Evans Creek, cut through the site in wooded valleys, running southwest into the Schuylkill River.

The area surrounding the site can be generally classified as rural and open. A large portion of the land is used for agricultural purposes with the remainder of the area being either vacant or woodland with scattered residences.

The main access to the plant is from U.S. Highway 422 which runs east and west about one mile north of the site. Access to the site and all activities thereon are under the control of the licensee.

1.2.1.3 Geology

The site is situated in the Triassic Lowland section of the Piedmont Physiographic Province. This section is characterized by a gently rolling land surface formed on an eroded low plateau.

The rocks in the region surrounding the site include Precambrian and Lower Paleozoic crystalline rocks and folded sedimentary strata, and essentially unfolded Triassic sedimentary rocks and igneous intrusions. The Triassic rocks belong to the Newark Group which is divided into the basal Stockton Formation and the Brunswick, Lockatong, and Hammer Creek Lithofacies.

Bedrock at the site underlies a thin cover of residual soil. The Brunswick red siltstone, sandstone, and shale is the predominant bedrock formation. Gray shale and argillite of the Lockatong Lithofacies, light gray sandstones and conglomerates of the Hammer Creek Lithofacies, and intruded diabase and associated hornfels are also found in the area. The strata exhibit gentle homoclinal dips to the north and northwest. The thickness of the Newark Group overlying the Paleozoic and Precambrian basement rocks at the site is on the order of 8000 feet.

The dominant structural feature of the region is the Regional Appalachian Orogenic Belt. This belt is marked by the northeast- southwest orientation of the axes and lineation of most of the structural features and stratigraphic contacts.

1.2.1.4 Seismology

The seismicity of the site was evaluated on the basis of historical earthquakes, damage resulting from these shocks, and the regional and local geologic structure. The site lies in a region that has experienced a moderate amount of earthquake activity. Most of the reported earthquakes have occurred in the Piedmont province. Some minor shocks have occurred in a northeast-southwest trend along the Fall Zone, the physiographic boundary between the Piedmont and the Coastal Plain to the southeast. Some scattered activity has occurred in the Coastal Plain. No recent faulting has been mapped in the area of the site.

Based on the seismic history and the geologic structure of the region, no significant earthquake ground motion is expected at the site during the life of the proposed facility. Despite this demonstrative evidence to the contrary, the remote possibility that the geologic structure in the epicentral areas of the significant regional earthquakes could exist in the site area is considered. Thus, a design basis earthquake is hypothesized equivalent to the 1871 Wilmington, Delaware earthquake (Intensity VII) near the site. Such an event is highly improbable and this hypothesis is very conservative.

The plant has the capability for safe shutdown if subjected to a peak horizontal ground acceleration at foundation level of 0.15 g. Seismic Category I structures are founded on the competent siltstone and sandstone bedrock of the Brunswick Lithofacies. Design spectra consistent with the safe shutdown earthquake are used for the dynamic analysis of the seismic Category I structures and equipment.

1.2.1.5 Hydrology

In the site area, Triassic-age siltstone, sandstone, and shale are found at shallow depths beneath a thin cover of residual soils. The residual soils are relatively impermeable. Most groundwater in the area is found in joints, fractures, and other secondary openings in the rock. The groundwater table is found at relatively shallow depths, except in the vicinity of pumping wells. Because of the limited quantities of available groundwater, surface water is the primary source of supply in the region. Groundwater accounts for only about 3% of the total industrial and commercial use in the region. However, numerous domestic wells extract small quantities of water from the Triassic strata.

A number of wells are located in the general site area. However, the geologic, hydrologic, and topographic conditions are such that the possibility of any adverse effect on these wells by operation of LGS is extremely remote.

The flows of the Schuylkill vary widely at different points along the river. This is mainly due to the varying topography and climatological and geohydrologic conditions along its course. The extreme and average daily flows as recorded at Pottstown gauging station (about 5.5 river miles upstream from the site) are:

	Flow (cfs)	Date
Minimum	87	August 13, 1930 (instantaneous)
Average	1793	October 1926-September 1969 (daily)
Maximum	95,900	June 1972 (instantaneous)

The probable maximum flood peak and stage at the plant site are estimated to be 500,000 cfs and el 174' (MSL), respectively.

The principal uses of the Schuylkill River are for municipal and industrial water supply. The river is also used for recreational fishing and boating.

1.2.1.6 Meteorology

The general climate of the site is best described as humid continental. The region is dominated by continental air masses in winter, and by alternating continental and maritime tropical air masses in the summer. The site is near the track of most eastwardly moving low pressure systems that are brought from the interior of the U.S. by the prevailing westerlies. Annual average wind speeds in the region are between 9 and 10 mph and temperatures rarely exceed 100?F or drop below 0?F. The region receives a moderate amount of precipitation which is well distributed over the year.

Five years of meteorological data collected on the site have verified that the general regional conditions do exist at the site and that no unusual meteorological conditions prevail.

1.2.2 PRINCIPAL DESIGN CRITERIA

The principal criteria for design, construction, and testing of LGS are summarized below. Specific criteria, codes, and standards are addressed in Sections 3.1 and 3.2.

1.2.2.1 General Design Criteria

The LGS design conforms to the requirements given in 10CFR50, Appendix A, "General Design Criteria for Nuclear Power Plants." Specific compliance is discussed in Section 3.1.

a. The plant is designed, fabricated, erected, and operated to produce electrical power in a safe and reliable manner.

b. The plant is designed, fabricated, erected, and operated in such a way that the release of radioactive materials to the environment does not exceed the limits and guideline values of applicable government regulations pertaining to the release of radioactive materials for normal operations, and for abnormal transients and accidents. Safety-related systems are designed to permit safe plant operation and to accommodate postulated accidents without endangering the health and safety of the public.

1.2.2.2 System Design Criteria

1.2.2.2.1 Nuclear System Criteria

a. The fuel cladding is designed to retain integrity, so that any failures are within acceptable limits, as a radioactive material barrier for the design power range and for any abnormal transient.

b. Those portions of the nuclear system that form part of the nuclear system process barrier are designed to retain integrity as a radioactive material barrier during normal operation and following abnormal operational transients and accidents.

c. Heat removal systems are provided to remove heat generated in the reactor core for the full range of normal operational conditions from shutdown to design power,

and for any abnormal operational transient. Heat removal systems are provided to remove decay heat generated in the core under remote circumstances where the normal operational heat removal systems become inoperative. The capacity of such systems is adequate to prevent fuel cladding damage.

d. The reactor core and reactivity control systems are designed so that control rod action is capable of bringing the core subcritical and maintaining it so, even with the rod of highest reactivity worth fully withdrawn and unavailable for insertion.

e. Backup reactor shutdown capability is provided independent of normal reactivity control provisions. This backup system has the capability to shut down the reactor from any operating condition, and subsequently to maintain the shutdown condition.

f. The nuclear system is designed so there is no tendency for divergent oscillation of any operating characteristics through hardware and administrative controls, considering the interaction of the nuclear system with other appropriate plant systems.

g. The reactor core is designed so that its nuclear characteristics do not contribute to a divergent power transient through hardware and administrative controls .

1.2.2.2.2 Safety-Related Systems Criteria

1.2.2.2.2.1 General

a. Safety systems act in response to abnormal operational transients so that fuel cladding retains its integrity as a radioactive material barrier to keep any failures within acceptable limits.

b. Safety systems and ESF act to ensure that no damage to the nuclear system process barrier results from internal pressures caused by abnormal operational transients or accidents.

c. Where positive, precise actions are immediately required in response to accidents, these actions are automatic and require no decision or manipulation of controls by operations personnel.

d. Essential safety actions are carried out by equipment of sufficient redundancy and independence so that no single failure of active components prevents the required actions. For systems or components to which IEEE 279 and/or IEEE 308 are applicable, single failures of passive electrical components are considered as well as single failures of active components in recognition of the higher anticipated failure rates of passive electrical components relative to passive mechanical components.

e. Features of the station that are essential to the mitigation of accident consequences are designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed.

f. The design of safety systems and ESF includes allowances for environmental phenomena at the site.

g. Provision is made for control of active components of nuclear safety systems and ESF from the control room.

h. Safety systems and ESF are designed to permit demonstration of their functional performance requirements.

1.2.2.2.2.2 Containment and Isolation Criteria

a. A primary containment is provided to completely enclose the reactor vessel. It is designed to act as a radioactive material barrier during accidents that release radioactive material into the primary containment. It is possible to test the primary containment integrity and leak-tightness at periodic intervals.

b. A secondary containment that completely encloses both the primary containment and fuel storage areas is provided and designed to act as a radioactive material barrier.

c. The primary and secondary containments, in conjunction with other ESF, act to prevent radioactive material released from the containment volumes from exceeding the guideline values of applicable regulations.

d. Provisions are made for the removal of energy from within the primary containment as necessary to maintain the integrity of the containment system following accidents that release energy to the primary containment.

e. Piping that both penetrates the primary containment structure and could serve as a path for the uncontrolled release of radioactive material to the environs is automatically isolated whenever such uncontrolled radioactive material release is threatened. Such isolation is effected in time to prevent radiological effects from exceeding the guideline values of applicable regulations.

1.2.2.2.2.3 Emergency Core Cooling Systems Criteria

a. The ECCS is provided to prevent excessive fuel clad temperature as a result of a LOCA.

b. The ECCS provides for continuity of core cooling over the complete range of postulated break sizes in the nuclear system process barrier.

c. The ECCS is diverse, reliable, and redundant.

d. Operation of the ECCS is initiated automatically when required, regardless of the availability of offsite power supplies and the normal generating system of the plant.

1.2.2.2.3 Process Control Systems Criteria

1.2.2.2.3.1 Nuclear System Process Control Criteria

a. Control equipment is provided for recirculation flow control to allow the operator to respond manually to load changes.

b. It is possible to manually control the reactor power level.

c. Control of the nuclear system is possible from a single location.

d. Nuclear system process controls are arranged to allow the operator to rapidly assess the condition of the nuclear system and to locate process system malfunctions.

e. Interlocks or other automatic equipment are provided as a backup to procedural controls to avoid conditions requiring the actuation of nuclear safety systems or ESF.

f. If the control room is inaccessible, it is possible to bring the reactor from power range operation to a cold shutdown condition by manipulation of controls and equipment that are available outside of the control room.

1.2.2.2.3.2 Power Conversion Systems Process Control and Instrumentation Criteria

a. Controls are provided to maintain temperature and pressure to below design limitations. These systems result in a stable operation and response for all allowable variations.

b. Controls and instrumentation are designed to provide equipment protection, indication, and alarm in the event of power conversion system trouble.

c. Control of the power conversion system is possible from locations accessible during normal operation.

d. Controls are provided to ensure adequate cooling of power conversion system equipment.

e. Controls are provided to ensure adequate condensate purity.

f. Controls are provided to regulate the supply of water so that adequate reactor vessel water level is maintained.

1.2.2.2.3.3 Electrical Power Systems Process Control Criteria

a. Controls are provided to ensure that sufficient electrical power is provided for startup, normal operation, and to attain prompt shutdown and continued maintenance of the station in a safe condition.

b. Control of the electrical power system is possible from locations accessible during normal operation.

1.2.2.2.4 Power Conversion Systems Criteria

a. The power conversion system components are designed to produce electrical power from the steam coming from the reactor, condense the steam into water, and return the water to the reactor as heated feedwater, with a major portion of its gases and particulate impurities removed.

b. The power conversion system components are designed to ensure that fission products or radioactivity associated with the steam and condensate are safely contained inside the system or are released under controlled conditions in accordance with waste disposal procedures and the plant Technical Specifications.

1.2.2.2.5 Electrical Power Systems Criteria

a. The station electrical power systems are designed to efficiently deliver the electrical power generated.

b. Sufficient normal and standby auxiliary sources of electrical power are provided to attain prompt shutdown and continued maintenance of the station in a safe condition. The capacity of the power sources is adequate to accomplish all required ESF under postulated DBA conditions.

1.2.2.2.6 Auxiliary Systems Criteria

a. Fuel handling and storage facilities are designed to prevent criticality and to maintain adequate shielding and cooling for spent fuel.

b. Multiple independent station auxiliary systems are provided for the purpose of cooling and servicing the station, the reactor, and the station containment systems under various normal and abnormal conditions.

c. Auxiliary systems that are not required to effect safe shutdown of the reactor or maintain it in a safe condition are designed so that a failure of these systems does not prevent the essential systems from performing their design functions.

1.2.2.2.7 Radioactive Waste Management Systems Criteria

a. Gaseous, liquid, and solid waste management facilities are designed so that the discharge of radioactive effluents and offsite shipment of radioactive materials are made in accordance with applicable regulations.

b. The waste management systems, design includes means of informing station operations personnel whenever operational limits on the release of radioactive material are exceeded.

1.2.2.2.8 Shielding and Access Control Criteria

a. Radiation shielding is provided, and access control patterns are established, to allow the operating staff to control radiation doses within the limits of applicable regulations in any mode of normal station operation.

b. The control room is shielded against radiation and has suitable environmental control so that occupancy under DBA conditions is possible.

1.2.2.2.9 Fuel Handling and Storage Facilities

Fuel handling and storage facilities are located in the refueling area (Zone III) of the secondary containment and are designed to preclude criticality and to maintain adequate shielding and cooling for spent fuel.

1.2.3 GENERAL ARRANGEMENT OF STRUCTURES AND EQUIPMENT

The principal structures are listed below:

a. Main power block comprised of the following:
    1. Two reactor enclosures with common refueling area
    2. Two turbine enclosures with common operating floor
    3. One control structure with common control room
    4. Two diesel generator enclosures
    5. One radwaste enclosure
    6. One chemistry laboratory expansion
    7. One administration building
    8. One auxiliary boiler enclosure
    9. One warehouse and shop
b. One circulating water pump structure
c. Two cooling towers with two acid/chlorine enclosures and a common valve and meter pit
d. One spray pond and spray pond pump structure
e. One Schuylkill pump structure
f. One Perkiomen pump structure
g. One water treatment enclosure
h. One fuel oil pump structure
i. One sewage treatment plant

The arrangement of structures on the site is shown in drawing C-2. The general arrangements for the major power block structures and the spray pond pump structure are shown in drawings M-110, M-111, M-112, M-113, M-114, M-115, M-116, M-117, M-118, M-119, M-120, M-121,M-122, M-123, M-124, M-125, M-126, M-127, M-128, M-129, M-130, M-131, M-132, M-133, M-134, M-135, M-136, M-137, M-138, M-140, M-141, M-142, M-143, M-144, M-145, M-146, M-388, M-389, and M-390. The layout of piping and equipment within the reactor enclosure and primary containment is shown in drawings M-206, M-207, M-208, M-209, M-210, M-211, M-213, M-215, M-217, M-218, M-219, M-220, M-221, M-222, M-223, M-225, M-226, M-227, M-228, M-229, M-230, M-231, M-232, M-234, M-235, M-236, M-237, M-238, M-239, M-240, M-241, M-242, M-246, M-288, M-289, M-290, M-291, M-292, M-293, M-295, M-296, M-297, M-298, M-299, M-300, M-301, M-302, M-303, M-305, M-306, M-307, M-308, M-309, M-310, M-311, M-312, M-313, M-316, M-317, M-318, M-319, M-320, M-321, M-322, M-323, and M-326.

1.2.4 SYSTEM DESCRIPTION

A summary of the systems provided for LGS is provided below.

1.2.4.1 Nuclear System

The nuclear system includes a single-cycle, forced circulation, GE BWR producing steam for direct use in the steam turbine. A heat balance showing the major parameters of the nuclear system for the rated power condition is shown in Figure 1.2-84.

1.2.4.1.1 Reactor Core and Control Rods

The fuel for the reactor core consists of slightly enriched uranium dioxide pellets contained in sealed Zircaloy-2 fuel rods. These fuel rods are assembled into individual fuel assemblies. Gross control of the core is achieved by movable, bottom-entry control rods. The control rods are of cruciform shape and are dispersed throughout the lattice of fuel assemblies. The rods are controlled by individual hydraulic systems.

1.2.4.1.2 Reactor Vessel and Internals

The reactor vessel contains the core and supporting structure; the steam separators and dryers; the jet pumps; the control rod guide tubes; distribution lines for the feedwater, and core spray; the incore instrumentation; and other components. The main connections to the vessel include the steam lines, the coolant recirculation lines, the feedwater lines, the CRD and nuclear instrumentation housings, and the ECCS lines.

The reactor vessel is designed and fabricated in accordance with applicable codes for a pressure of 1250 psig. The nominal operating pressure is 1060 psia in the steam space above the separators. The vessel is fabricated of carbon steel and is clad internally with stainless steel (except for the top head which is not clad).

The reactor core is cooled by demineralized feedwater that enters the lower portion of the core and is heated as it flows upward around the fuel rods. The steam leaving the core is dried by steam separators and dryers located in the upper portion of the reactor vessel. The steam is then directed to the turbine through four main steam lines. Each steam line is provided with two isolation valves in series, one on each side of the primary containment barrier.

1.2.4.1.3 Reactor Recirculation System

The reactor recirculation system consists of two recirculation pump loops external to the reactor vessel. These loops provide the piping path for the driving flow of water to the reactor vessel jet pumps that provide a continuous internal circulation path for the major portion of the core coolant flow. Each loop has one motor-driven recirculation pump. Recirculation pump speed can be varied to allow some control of reactor power level through the effects of coolant flow rate on moderator void content.

1.2.4.1.4 Residual Heat Removal System

The RHR system consists of pumps, heat exchangers, and piping that fulfill the following functions:

a. Removal of decay and sensible heat during and after plant shutdown

b. Injection of water into the reactor vessel following a LOCA, to reflood the core independent of other core cooling systems. This is discussed Section 1.2.4.2.13.

c. Removal of heat from the primary containment following a LOCA to limit the increase in primary containment pressure. This is accomplished by cooling and

recirculating the suppression pool water (containment cooling) and by spraying the drywell and suppression pool air spaces (containment spray) with suppression pool water.

1.2.4.1.5 Reactor Water Cleanup System

A RWCU system is provided to clean up the reactor cooling water, to reduce the amounts of activated corrosion products in the water, and to remove excess reactor coolant from the nuclear system under controlled conditions.

1.2.4.1.6 Nuclear Leak Detection System

The nuclear leak detection and monitoring system consists of temperature, pressure, flow, and fission product sensors with associated instrumentation and alarms. This system detects and annunciates leakage in the following systems:

a. Main steam lines

b. RWCU system

c. RHR system

d. RCIC system

e. Feedwater system

f. ECCS systems

g. Miscellaneous systems

Small leaks generally are detected by monitoring the temperature, radiation levels, and drain sump fill-up and pump-out rates. Large leaks are also detected by changes in reactor water level and changes in flow rates in process lines.

1.2.4.2 Safety-Related Systems

Safety-related systems provide actions necessary to assure safe shutdown, to protect the integrity of radioactive material barriers, and/or to prevent the release of radioactive material in excess of allowable dose limits. These systems can be components, groups of components, systems, or groups of systems. ESF systems are included in this category. ESF systems function to mitigate the consequences of DBAs.

1.2.4.2.1 Reactor Protection System

The RPS initiates a rapid, automatic shutdown (scram) of the reactor. This action is taken in time to prevent excessive fuel cladding temperatures and any nuclear system process barrier damage following abnormal operational transients. The RPS overrides all operator actions and process controls.

1.2.4.2.2 Neutron Monitoring System

Those portions of the NMS that are part of the RPS are safety-related. The IRM and APRM monitor neutron flux via incore detectors and provide scram logic inputs to the RPS to initiate a scram in time to prevent excessive fuel clad damage as a result of overpower transients (Upscale neutron flux), upscale simulated thermal power, and OPRM upscale are conditions that provide scram logic signals.

1.2.4.2.3 Control Rod Drive System

When a scram is initiated by the RPS, the CRD system inserts the negative reactivity necessary to shut down the reactor. Each control rod is controlled individually by a hydraulic control unit. When a scram signal is received, high pressure water from an accumulator for each rod forces each control rod rapidly into the core.

1.2.4.2.4 Control Rod Velocity Limiter

A control rod velocity limiter is a part of each control rod and limits the velocity at which a control rod can fall out of the core should it become detached from its CRD. The rate of reactivity insertion resulting from a rod-drop accident is limited by this feature. The limiters contain no moving parts.

1.2.4.2.5 Control Rod Drive Housing Supports

CRD housing supports are located underneath the reactor vessel near the control rod housings. The supports limit the travel of a control rod in the event that a control rod housing is ruptured. The supports prevent a nuclear excursion as a result of a housing failure, thus protecting the fuel barrier.

1.2.4.2.6 Nuclear System Pressure Relief System

A pressure relief system, consisting of SRVs mounted on the main steam lines, prevents excessive pressure inside the nuclear system during operational transients or accidents.

1.2.4.2.7 Reactor Core Isolation Cooling System

The RCIC system provides makeup water to the reactor vessel whenever the vessel is isolated from the main condenser and feedwater system. The RCIC system uses a steam-driven turbine-pump unit and operates automatically in time, and with sufficient coolant flow, to maintain adequate reactor vessel water level for events defined in Section 5.4.6.1.

1.2.4.2.8 Primary Containment

A pressure-suppression primary containment houses the reactor vessel, the reactor coolant recirculation loops, and other branch connections of the reactor primary system. The pressure-suppression system consists of a drywell, a pressure-suppression chamber storing a large volume of water, a connecting vent system between the drywell and the water pool, isolation valves, containment cooling systems, and other service equipment. In the event of a process system piping failure within the drywell, reactor water and steam would be released into the drywell air space. The resulting increased drywell pressure would then force a mixture of air, steam, and water through the vents into the pool of water stored in the suppression chamber. The steam would condense rapidly in the suppression pool, resulting in a rapid pressure reduction in the drywell. Air transferred from the drywell to the suppression chamber pressurizes the suppression chamber and is subsequently vented to the drywell to equalize the pressure between the two

chambers. Cooling systems remove heat from the reactor core, the drywell, and from the water in the suppression chamber, thus providing continuous cooling of the primary containment under accident conditions. Appropriate isolation valves are actuated during this period to ensure containment of radioactive materials within the primary containment.

1.2.4.2.9 Primary Containment and Reactor Vessel Isolation Control System

The primary containment and reactor vessel isolation control system automatically initiates closure of isolation valves to close off all process lines that are potential leakage paths for radioactive material to the environs. This action is taken upon indication of a potential breach in the nuclear system process barrier.

1.2.4.2.10 Secondary Containment

Any leakage from the primary containment system is contained within the secondary containment system. This system includes the SGTS and the RERS. The secondary containment system is designed to minimize the release of airborne radioactive materials, and to provide for the controlled, filtered release of the reactor enclosure atmosphere under accident conditions.

1.2.4.2.11 Main Steam Isolation Valves

Although process lines that penetrate the primary containment, and offer a potential release path for radioactive material, are provided with redundant isolation capabilities, the main steam lines, because of their large size and large mass flow rates, are given special isolation consideration. Two automatic isolation valves, each powered by both pneumatic pressure and spring force, are provided in each main steam line. These valves fulfill the following objectives:

a. To prevent excessive damage to the fuel barrier by limiting the loss of reactor coolant from the reactor vessel resulting either from a major leak from the steam piping outside the primary containment, or from a malfunction of the pressure control system, resulting in excessive steam flow from the reactor vessel

b. To limit the release of radioactive materials, by closing the nuclear system process barrier, in case of a gross release of radioactive materials from the fuel to the reactor coolant and steam

c. To limit the release of radioactive materials by closing the primary containment barrier, in case of a major leak from the nuclear system inside the primary containment.

1.2.4.2.12 Main Steam Line Flow Restrictors

A venturi-type flow restrictor is installed in each steam line. These devices limit the loss of coolant from the reactor vessel and prevent uncovering of the core before the MSIVs are closed in case of a main steam line break.

1.2.4.2.13 Emergency Core Cooling Systems

Four independent core standby cooling systems are provided to maintain fuel clad temperatures below the limits of 10CFR50.46 in the event of a breach in the RCPB that results in a loss of reactor coolant. The four core standby cooling systems are as follows:

a. High Pressure Coolant Injection System

The HPCI system provides and maintains an adequate coolant inventory inside the reactor vessel to limit fuel clad temperatures as a result of postulated small breaks in the RCPB. A high pressure system is needed for such breaks because the reactor vessel depressurizes slowly, preventing low pressure systems from injecting coolant. The HPCI system includes a turbine-driven pump powered by reactor steam. The system is designed to accomplish its function on a short-term basis without reliance on plant auxiliary power supplies other than the dc power supply.

b. Automatic Depressurization System

The ADS acts to rapidly reduce reactor vessel pressure in a LOCA situation in which the HPCI system fails to maintain reactor vessel water level. The depressurization provided enables the low pressure ECCS to deliver cooling water to the reactor vessel. The ADS uses some of the relief valves that are part of the nuclear system pressure relief system. The automatic relief valves are arranged to open on conditions indicating that both a break in the nuclear system process barrier has occurred and the HPCI system is not delivering sufficient cooling water to the reactor vessel to maintain the water level above a preselected value. The ADS will not be activated unless either the core spray or the LPCI system is operating.

c. Core Spray System

The CS system consists of two independent pump loops that deliver cooling water to spray spargers over the core. The system is actuated by conditions indicating that a breach exists in the RCPB, but water is delivered to the core only after reactor vessel pressure is reduced. This system provides the capability to cool the fuel by spraying water on the core. Either loop functioning in conjunction with the ADS or HPCI can provide sufficient fuel cladding cooling following a LOCA.

d. Low Pressure Coolant Injection

LPCI is an operating mode of the RHR system. LPCI uses the pump loops of the RHR system to inject cooling water into the reactor system. LPCI is actuated by conditions indicating a breach in the RCPB, but water is delivered to the core only after reactor vessel pressure is reduced. LPCI operation provides the capability of core reflooding following a LOCA in time to maintain the fuel cladding below prescribed temperature limits.

1.2.4.2.14 Residual Heat Removal System (Containment Cooling)

The RHR system for containment cooling is placed in operation to limit the temperature of the water in the suppression pool and of the atmospheres in the drywell and suppression chamber following a design basis LOCA, to control the pool temperature during normal operation and to reduce the pool temperature following an isolation transient. In the containment cooling mode of operation, the RHR system pumps take suction from the suppression pool and deliver the water through the RHR system heat exchangers, where cooling takes place by transferring heat to the RHR service water system. The fluid is then discharged back to the suppression pool, the drywell or suppression chamber spray headers, or to the RPV.

1.2.4.2.15 Control Room Heating, Ventilating and Air Conditioning System

The control room HVAC system provides ventilation, cooling, and control of environmental conditions in the control room areas for the safety and comfort of operating personnel during normal operations and during postulated accident conditions. The system includes air filter units used to remove contaminants that are potentially present in the air following a postulated accident before introducing the air into the control room HVAC system.

1.2.4.2.16 Reactor Enclosure Recirculation System and Standby Gas Treatment System

Both the RERS and the SGTS service the secondary containment. The recirculation system has the capability of recirculating the reactor enclosure air volume prior to its discharge via the SGTS, following a LOCA. The SGTS has the capability of maintaining a negative pressure within the reactor enclosures and the refueling area zones of the secondary containment with respect to the outside atmosphere. The air moving through the SGTS is filtered and discharged through the north exhaust stack.

1.2.4.2.17 Standby AC Power Supply

The standby ac power supply system consists of four diesel generator sets per unit. The diesel generators are sized so that any three diesels can supply all the necessary power requirements for one unit in the DBA condition. The diesel generators are designed to start and be able to accept load within 10 seconds. Four independent 4 kV ESF switchgear assemblies are provided for each reactor unit. Each diesel generator feeds an independent 4 kV bus for each reactor unit.

Each diesel generator starts automatically upon LOOP or detection of a LOCA. The necessary safety-related loads are applied in a preset time sequence. Each generator operates independently and without paralleling during a LOOP or LOCA signal.

1.2.4.2.18 DC Power Supply

Each unit is provided with two independent Class 1E 125/250V, two independent Class 1E 125V, one non-Class 1E 125/250V, and one non-Class 1E 250V DC systems. The systems are provided to supply station DC control power, DC power to diesel generators, their associated switchgear, ESF systems, and DC motor driven pumps and valves.

The Class 1E DC systems are designed to supply power adequate to satisfy the safety-related load requirements of the unit with the postulated LOOP and any concurrent signal failure in the DC system.

1.2.4.2.19 Residual Heat Removal Service Water System

The purpose of the RHRSW system is to provide a reliable supply of cooling water for heat removal from the RHR system during normal shutdown operations and under postaccident conditions. It can also supply a source of water if postaccident flooding of the primary containment is required.

The system consists of two independent loops, each of 100% capacity, supplying one RHR heat exchanger in each unit. During postaccident conditions the system uses the common spray pond as the heat sink. Interconnections are provided to allow use of a cooling tower as a heat sink during normal operations and, if conditions permit, during postaccident operation.

1.2.4.2.20 Emergency Service Water System

The purpose of the ESW system is to provide a reliable supply of cooling water to emergency equipment during LOOP and postaccident conditions.

The system consists of two independent loops. Each loop supplies corresponding safety-related equipment in each unit. The safety- related cooling loads consist of equipment room coolers, control room chillers, and the RHR pump coolers.

ESW for the diesel generators is supplied by either loop. The ESW system uses the common spray pond as a heat sink. Interconnections are provided to allow use of a cooling tower as a heat sink if conditions permit.

1.2.4.2.21 Main Steam Line Radiation Monitoring System

The MSL-RMS consists of four gamma radiation monitors located external to the main steam lines just outside of the primary containment. The monitors are designed to detect a gross release of fission products from the fuel. Upon detection of high radiation, an alarm signal is initiated by the monitors.

1.2.4.2.22 Reactor Enclosure and Refueling Area Ventilation Radiation Monitoring System

The REVE-RMS and RAVE-RMS consists of a number of radiation monitors arranged to monitor the activity level of the ventilation exhaust from the reactor enclosure and refueling area. Upon detection of high radiation, the affected area is automatically isolated and the SGTS and RERS (for reactor enclosure only) are started.

1.2.4.2.23 Remote Shutdown System

A remote shutdown panel and associated procedures are provided for each unit so that the plant can be maintained in a safe shutdown condition in the event that the control room becomes uninhabitable.

1.2.4.2.24 Standby Liquid Control System

Although not intended to provide rapid reactor shutdown, the SLCS provides a redundant, independent, and alternate way to bring the reactor subcritical and to maintain it subcritical as the reactor cools. The system makes possible an orderly and safe shutdown in the event that not enough control rods can be inserted into the reactor core to accomplish normal shutdown. The system is sized to counteract the positive reactivity effect from rated power to the cold shutdown condition. The SLCS also provides pH control for the primary containment water inventory following a LOCA.

1.2.4.2.25 Deleted.

1.2.4.2.26 Redundant Reactivity Control System

The RRCS is designed to provide a redundant and diverse method of shutting down the reactor, in the unlikely event that the RPS does not scram the reactor as a result of an anticipated operating transient. The RRCS logic is initiated when either the high reactor pressure or low reactor water

level setpoints are reached. A signal is then sent to open the ARI valves that vent the CRD scram air header to insert the control rods into the reactor. A signal is also transmitted to the RPT breakers to trip the reactor recirculation pumps to reduce the reactor power. An initiation of the RRCS logic by high reactor pressure will cause the feedwater pumps to automatically runback. If reactor power has not decreased to a predetermined level, within a specified period of time, the RRCS logic will initiate a feedwater runback and the injection of a neutron poison solution into the reactor, via the SLCS, and shut down the reactor.

The system consists of control panels, their associated ATWS detection and actuation logic, and the necessary interface logic to the recirculation system, the feedwater system, the SLCS, the RWCU system and the ARI components of the CRD system required to perform specific functions in response to an ATWS event.

1.2.4.3 Instrumentation and Control Systems

1.2.4.3.1 Nuclear System Process Control and Instrumentation

1.2.4.3.1.1 Reactor Manual Control System

The reactor manual control system provides the means by which control rods are positioned from the control room for power control. The system operates valves in the CRD hydraulic system to control rod position. Only one control rod can be manipulated at a time. The reactor manual control system includes the logic that restricts control rod movement (rod block) under certain conditions as a backup to procedural controls.

1.2.4.3.1.2 Recirculation Flow Control System

The recirculation flow control system controls the speed of the reactor recirculation pumps. Adjusting the pump speed changes the coolant flow rate through the core. This effects changes in core power level. The system is operated manually to match reactor power output to the load demand by adjusting the frequency of the electrical power supply for the reactor recirculation pumps.

1.2.4.3.1.3 Neutron Monitoring System

The NMS is a system of incore neutron detectors and electronic monitoring equipment. The system provides indication of neutron flux that can be correlated to thermal power level for the entire range of flux conditions that may exist in the core. The SRM and IRM provide flux level indications during reactor startup and low power operation. The LPRM and APRM allow assessment of local and overall flux conditions during power range operation. The TIP system provides a means to calibrate the individual LPRMs utilizing a gamma-measuring probe. The NMS provides inputs to the reactor manual control system to initiate rod blocks if preset alarm flux limits are exceeded, and inputs to the RPS to initiate a scram if trip limits are exceeded.

1.2.4.3.1.4 Refueling Interlocks

A system of interlocks, restricting the movements of refueling equipment and control rods when the reactor is in the refueling and startup modes, is provided to prevent an inadvertent criticality during refueling operations. The interlocks back up procedural controls that have the same objective. The interlocks affect the refueling platform, the refueling platform hoists, the fuel grapple, and control rods.

1.2.4.3.1.5 Reactor Vessel Instrumentation

In addition to instrumentation provided for the nuclear safety systems and ESF, instrumentation is provided to monitor and transmit information that can be used to assess conditions existing inside the reactor vessel and the physical condition of the vessel itself. The instrumentation provided monitors reactor vessel pressure, water level, temperature, internal differential pressures and coolant flow rates, and top head flange leakage.

1.2.4.3.1.6 Deleted

1.2.4.3.1.7 Plant Monitoring System

The PMS is a centralized, integrated system which performs the process monitoring and calculation that are necessary for the effective evaluation of normal and emergency power plant operation. The PMS acquires and records process data (e.g., temperatures, pressures, flows, status indicators) to produce displays, logs, and plots of current or historical plant performance which are presented to plant personnel in the plant main control room.

1.2.4.3.1.8 Rod Worth Minimizer

The RWM monitors and enforces adherence to established low power level rod insert and withdraw sequences. This function prevents the operator from establishing control rod patterns that are not consistent with the prescribed sequence by initiating the appropriate rod insert and withdraw block. When RWM is inoperable both insert and withdraw blocks are enforced unless the RWM is bypassed. The RWM enforces control rod sequences designed to limit individual control rod worths to acceptable levels as determined by the rod-drop accident design basis.

1.2.4.3.2 Power Conversion Systems Process Control and Instrumentation

1.2.4.3.2.1 Pressure Regulator and Turbine-Generator Control

The pressure regulator controls the turbine control and turbine bypass valves to maintain the nuclear system pressure essentially constant.

The turbine-generator speed-load control is set above the desired load and grid generator frequency. Load changes are made by the operator by adjusting the reactor recirculation flow control system and control rods.

The turbine-generator speed-load controls initiate rapid closure of the turbine control valves (rapid opening of the turbine bypass valves) to prevent turbine overspeed on loss of the generator electric load.

1.2.4.3.2.2 Feedwater System Control

A three-element control system regulates the feedwater system so that proper water level is maintained in the reactor vessel. Signals used by the control system are main steam flow rate, reactor vessel water level, and feedwater flow rate. The feedwater control signal is used to control the speed of the steam turbine-driven feedwater pumps.

1.2.4.3.2.3 Electrical Power System Control

Controls for the electrical power system are located in the control room to permit safe startup, operation, and shutdown of the plant.

1.2.4.4 Electrical Systems

1.2.4.4.1 Transmission and Generation Systems

Redundant sources of offsite power are provided to each unit by separate transmission lines to ensure that no single failure of any active component can prevent a safe and orderly shutdown. Each unit is provided with an independent substation, which is 220 kV for Unit 1 and 500 kV for Unit 2. The substations are connected by an autotransformer and ultimately feed into the PJM interconnection through the 220 kV and 500 kV transmission systems. Two independent offsite sources provide auxiliary power for startup and for operating the safety-related systems.

The main generator for each unit is an 1800 rpm, 3 phase, 60 Hz synchronous unit rated at 1264.97 MVA. Each generator is connected directly to the turbine shaft and is equipped with an excitation system coupled directly to the generator shaft. Power from the generators is stepped up from 22-220 kV on Unit 1 from 22-500 kV on Unit 2 by the unit main transformers and supplied by overhead lines to the 220 kV and 500 kV switchyards, respectively.

1.2.4.4.2 Electric Power Distribution Systems

The electric power distribution system includes Class 1E and non- Class 1E ac and dc power systems. The Class 1E power system supplies all safety-related equipment, while the non-Class 1E system supplies the balance of plant equipment.

The Class 1E ac system for each unit consists of four independent load groups. Two independent offsite power systems provide the normal electric power to these groups. Each load group includes a 4 kV switchgear, a 440 V load center, 440 V MCCs, and 120 V control and instrument power panels. The vital ac instrumentation and control power supply systems include battery systems and static inverters.

There are four independent diesel generator sets for each unit. Each diesel generator is provided as a standby source of power for one of the four Class 1E ac load groups in each unit. Assuming the total LOOP and failure of one diesel generator, the remaining diesel generators have sufficient capacity to operate all the equipment necessary to prevent undue risk to public health and safety in the event of a DBA on one unit and an emergency shutdown of the second unit.

The non-Class 1E ac system includes 13.2 kV switchgear, 2.3 kV switchgear, 440 V load centers, MCCs, and 120 V control and instrument power panels.

Two independent Class 1E 125 V dc batteries and two independent Class 1E 125/250 V dc batteries and associated battery chargers provide direct current power for the Class 1E dc loads of each unit. Power for non-Class 1E dc loads is supplied from 125/250 V and 250 V non-Class 1E batteries and associated battery chargers.

1.2.4.5 Fuel Handling and Storage Systems

1.2.4.5.1 New and Spent Fuel Storage

The fuel storage racks are designed to prevent load buckling and inadvertent criticality under dry and flooded conditions. Sufficient coolant and shielding are maintained to prevent overheating and excessive personnel exposure, respectively. New and spent fuel will be stored in the spent fuel pool in addition to spent fuel stored in the Independent Spent Fuel Storage Installation.

1.2.4.5.2 Fuel Pool Cooling and Cleanup System

The FPCC system is provided to remove decay heat from spent fuel stored in the fuel pool and to maintain specified water temperature, purity, clarity, and level.

1.2.4.5.3 Fuel Handling Equipment

The major fuel servicing and handling equipment includes the reactor enclosure cranes, refueling service platform, fuel and control rod servicing tools, fuel sipping and inspection devices, and other auxiliary servicing tools.

1.2.4.6 Cooling Water and Auxiliary Systems

1.2.4.6.1 Service Water System

The service water system supplies cooling water to equipment required for normal plant operation.

The system consists of three 50% capacity pumps with associated piping and valves. The cooling water supply to the pumps is taken from the cooling tower basin, while the water being returned from the system is discharged into the cooling tower.

1.2.4.6.2 Reactor Enclosure Cooling Water System

The RECW system is a closed-loop cooling water system that provides cooling water for miscellaneous reactor auxiliary plant equipment. The RECW system consists of two 100% capacity pumps, two 100% capacity heat exchangers, a head tank, chemical addition tank, associated piping, valves, and controls. One RECW pump is normally in service and the other pump is on automatic standby. During normal plant operation, heat is transferred from the RECW system to the service water system.

1.2.4.6.3 Turbine Enclosure Cooling Water System

The TECW system is a closed-loop cooling system that provides cooling water to the auxiliary plant equipment associated with the nuclear and power conversion systems in the turbine enclosure. The TECW system consists of two 100% capacity pumps, two 100% capacity heat exchangers, a head tank, chemical addition tank, and associated piping and valves. During normal plant operation, the TECW heat exchanger transfers heat from the TECW system to the service water system. One TECW pump is normally in service and the other pump is on automatic standby.

1.2.4.6.4 Fire Protection System

A fire protection system supplies fire fighting water to points throughout the plant. An automatic carbon dioxide protection system, in addition to portable fire extinguishers, is provided. An automatic halon fire protection system provides protection in the auxiliary electrical equipment room.

1.2.4.6.5 Plant Heating, Ventilating, and Air Conditioning Systems

The HVAC systems supply and circulate filtered fresh air for personnel comfort and equipment cooling.

1.2.4.6.6 Instrument Air System

The instrument air system supplies compressed air of suitable quality and pressure for power plant operation.

1.2.4.6.7 Clarified and Domestic Water Systems

The clarified and domestic water systems provide filtered, clarified water for plant and personnel use.

1.2.4.6.8 Demineralized Water Makeup System

A demineralized water makeup system is provided to furnish a supply of treated water suitable for use as makeup for the plant.

1.2.4.6.9 Plant Equipment and Floor Drainage System

The plant equipment and floor drainage system handles both radioactive and nonradioactive drains. Drains that can contain radioactive materials are pumped to the radwaste system for cleanup, reuse, or discharge. Nonradioactive drains are processed to remove oil and chemicals and then discharged to the environs.

1.2.4.6.10 Process Sampling System

The process sampling system is provided to monitor the operation of plant equipment and to provide information needed to make operational decisions.

1.2.4.6.11 Plant Communication System

The plant communication system provides communication between various plant structures and locations.

1.2.4.7 Power Conversion Systems

1.2.4.7.1 Turbine-Generator

The turbine-generator consists of the turbine, generator, exciter, controls, and required subsystems designed for a nominally rated MWe 1231.1.

The turbine is an 1800 rpm, tandem-compound, nonreheat steam turbine and an EHC system. The main turbine comprises one double-flow high pressure turbine and three double-flow low pressure turbines. Exhaust steam from the high pressure turbine passes through moisture separators before entering the three low pressure turbines.

The generator is a direct-driven, 3 phase, 60 Hz, 22,000 V, 1800 rpm, synchronous generator rated at 1265 MVA on the basis of guaranteed best turbine efficiency MW rating at an expected 0.973 power factor at 75 psig hydrogen pressure.

1.2.4.7.2 Main Steam System

The main steam system delivers steam from the nuclear boiler system via four 26 inch OD steam lines to the turbine-generator. This system also supplies steam to the SJAE, the RFPT, the main condenser hotwell at startup and low loads, and the steam seal evaporator.

1.2.4.7.3 Main Condenser

The main condenser system condenses and deaerates the exhaust steam from the main turbine and RFPT, and provides a heat sink for the turbine bypass system. The main condenser is a triple-pass, triple-pressure, deaerating-type with a reheating-deaerating hotwell and divided water boxes. The condenser consists of three sections with each section located below one of three low pressure turbines.

1.2.4.7.4 Main Condenser Evacuation System

The main condenser evacuation system removes the noncondensable gases from the main condenser. Two redundant SJAE are provided for air removal during normal operation, and one motor-driven vacuum pump is provided for air removal during startup.

1.2.4.7.5 Steam Seal System

The steam seal system provides clean, nonradioactive steam to the seals of the turbine valve packings and the turbine shaft packings. The sealing steam is supplied by the steam seal evaporator. The auxiliary boiler provides an auxiliary steam supply for startup and can be used as a backup to the steam seal evaporator, when available, during power operation.

1.2.4.7.6 Turbine Bypass and Pressure Control System

The turbine bypass and pressure control system provides control of the reactor pressure for the following operating modes:

a. During reactor heatup to rated pressure

b. While the turbine is being brought up to speed and synchronized

c. During normal power operation and transient power operation when the reactor steam generation exceeds the turbine steam requirements

d. When shutting down the reactor

1.2.4.7.7 Circulating Water System

The circulating water system is a closed-loop system designed to circulate the flow of water required to remove the heat load from the main condenser and auxiliary heat exchanger equipment and discharge it to the atmosphere through natural draft cooling towers.

1.2.4.7.8 Condensate Cleanup System

The function of the condensate cleanup system is to maintain the required purity of the feedwater to the reactor. The system consists of full flow condensate filter/demineralizers and deep bed condensate demineralizers. The condensate filter/demineralizers remove suspended solids from the condensate and feedwater streams. Downstream of and in series with the condensate filter/demineralizers, the deep bed condensate demineralizers use ion exchange resins that remove dissolved impurities from the feedwater. A bypass exists around one of the condensate filter/demineralizers to provide a means to control the iron/transition metal concentration in the reactor recirculation system. The deep bed condensate demineralizers also remove some of the radioactive material produced by corrosion as well as fission product carryover from the reactor.

1.2.4.7.9 Condensate and Feedwater Systems

The condensate and feedwater systems are designed to deliver the required feedwater flow to the reactor vessel during stable and transient operating conditions throughout the entire operating range from startup to full load to shutdown. The system operates using three condensate pumps to pump deaerated condensate from the hotwell of the main condenser through the SJAE condenser, the gland steam packing exhauster condenser, and then to the condensate cleanup system. The demineralized feedwater then flows through three parallel strings of low pressure feedwater heaters to the suction of three reactor feed pumps that deliver the feedwater through one set of three parallel high pressure heaters to the reactor.

1.2.4.7.10 Condensate and Refueling Water Storage Facilities

The condensate and refueling water storage facilities provide storage of condensate water for use in normal plant operations and refueling operations.

1.2.4.8 Radioactive Waste Systems

The radioactive waste systems are designed to confine the release of plant-produced radioactive material to well within the limits specified in 10CFR20 and 10CFR50, Appendix I. Various methods are used to achieve this end (e.g., collection, filtration, holdup for decay, dilution, and concentration). The pre-1994 10CFR20, Appendix B limits were used for the original licensing basis of the plant. Current liquid effluent releases are limited to ten-times the Effluent Concentration Limit (ECL) for each isotope specified in post-1994 10CFR20, Appendix B, Table 2, Column 2. Current gaseous and liquid effluent releases are controlled by the Radioactive Effluent Controls Program defined by the Technical Specifications.

1.2.4.8.1 Liquid Radwaste System

The liquid radwaste system collects, treats, stores, and disposes of radioactive liquid wastes. These wastes are collected in sumps and drain tanks at various locations throughout the plant and then transferred to the appropriate collection tanks in the radwaste enclosure prior to treatment, storage, and disposal. Processed liquid wastes are returned to the condensate system, packaged for offsite shipment, or discharged from the plant.

Equipment is selected, arranged, and shielded to permit operation, inspection, and maintenance within radiation allowances for personnel exposure. For example, tanks and processing equipment that will contain significant radiation sources are shielded and sumps, pumps, instruments, and valves are located in controlled access rooms or spaces. Processing equipment is selected and designed to require a minimum of maintenance.

Valving redundancy, instrumentation for detection, alarms of abnormal conditions, and procedural controls protect against the accidental discharge of liquid radioactive waste.

1.2.4.8.2 Solid Radwaste System

Solid wastes originating from nuclear system equipment are stored for radioactive decay in the fuel storage pool and prepared for reprocessing or offsite storage in approved shipping containers. Examples of these wastes are spent control rods, and incore ion chambers.

Process solid wastes are collected, dewatered, packaged, and stored in shielded compartments prior to offsite shipment. Examples of these solid wastes are filter residue, spent resins, paper, air filters, rags, and used clothing.

1.2.4.8.3 Gaseous Radwaste System

Radioactive gaseous wastes are discharged to the turbine enclosure vent via the gaseous radwaste system. This system provides hydrogen-oxygen recombination, filtration, and holdup of the offgases to ensure a low rate of release from the turbine enclosure vent.

The offgases from the main condenser are the greatest source of gaseous radioactive waste. The treatment of these gases reduces the released activity to well below permissible levels even with some defective fuel elements.

1.2.4.9 Radiation Monitoring and Control

1.2.4.9.1 Process Radiation Monitoring

Radiation monitors are provided on various lines to monitor and control radioactivity in process and effluent streams and to activate appropriate alarms and controls.

1.2.4.9.2 Area Radiation Monitors

Radiation monitors are provided to monitor for abnormal radiation at various locations in the plant. These monitors activate alarms when abnormal radiation levels are detected.

1.2.4.9.3 Site Environs Radiation Monitors

Radiation monitors are provided outside the plant structures to monitor radiation levels. These data are used for determining the contribution of plant operations to onsite and offsite radiation levels.

1.2.4.10 Shielding

Shielding is provided throughout the plant, as required, to reduce radiation levels to operating personnel and to the general public within the applicable limits set forth in 10CFR20, 10CFR50, and 10CFR50.67. It is also designed to protect certain plant components from radiation exposure resulting in unacceptable alterations of material properties or activation.

1.2.5 Control Of Unit 2 Construction Activities During Unit 1 Operation

To meet the requirements of 10CFR50.34(b)(6)(vii), an evaluation was performed which verified that safety-related structures, systems, and components of Unit 1 were protected from potential

hazards resulting from construction activities on Unit 2. This evaluation also identified the plant administrative and managerial controls required to provide assurance that technical specification limiting conditions for operation were not exceeded. Administrative and managerial controls existed in the form of design controls, procedures and training during the construction of Unit 2. The plant Technical Specifications were taken into consideration throughout the development of these controls. The Plant Operations Review Committee was not required to review the Unit 2 construction activity controls or the revisions thereto.

LGS utilizes a unitized design for safety-related structures and systems with only the following common structures and systems as exceptions: the control enclosure and supporting systems, spray pond, spray pond pumphouse and supporting systems, ESW system, RHRSW system, and SGTS. All portions of the Unit 1 systems and those common systems required for the safe operation and shutdown of Unit 1 were completed prior to Unit 1 fuel load. Unit 2 systems and structures required to assure that Unit 1 limiting conditions for operation were not exceeded had also been completed. A PAB that was maintained in accordance with an established separation program served to define the Unit 1 and common operations area. The PAB considered personnel access for both security and ALARA radiation exposure. The LGS security plan covered all aspects of Unit 1 and common security.

Administrative and managerial controls governed the activities associated with Unit 2 construction to prevent the safe operation of Unit 1 from being affected. Design controls, procedures, safety programs, or training sessions existed to ensure that the following areas were addressed during Unit 2 construction:

- Separation of Unit 1 and common safety-related systems and equipment (including those Unit 2 systems, structures, and equipment required for operation of Unit 1) from Unit 2 construction activities.

- Yard activities, such as excavation, blasting, grading, use of heavy equipment, and erection of structures, such that consideration is given to site drainage, protection of underground utilities, and Unit 1 operation.

- Maintenance of construction personnel radiation exposures as low as reasonably achievable.

- Minimizing the probability of the LOOP to Unit 1 due to Unit 2 construction activities.

- The control of the use of hazardous and toxic chemicals which may have been used during Unit 2 construction.

- The control of the use and storage of compressed gas cylinders which may have been used during Unit 2 construction such that Unit 1 was not jeopardized.

- Construction cranes were prevented from damaging Unit 1 and common structures and systems important to safety by governing placement and operation.

- Rigging and the movement of equipment was governed to ensure potential heavy load drops did not affect Unit 1 or common safe shutdown equipment.

- The safe operation of Unit 1 was maintained by considering the fire barrier, missile protection, radiation protection, pressure boundary, flood control, and security aspects of walls, ceilings and floors when construction openings were made.

- Use of safe onsite transportation and traffic practices.

- Fire protection programs were enforced and not affected by construction activities associated with Unit 2.

1.3 COMPARISON TABLES

1.3.1 COMPARISONS WITH SIMILAR FACILITY DESIGNS

This section highlights the principal design features of the plant and compares the major features with those of other BWR facilities. The design of this facility is based on proven technology attained during the development, design, construction, and operation of BWRs of similar types. The data, performance, characteristics, and other information presented here represent the original design, and licensed operating conditions.

The following tables summarize the plant design characteristics for LGS, PBAPS, SSES, and Zimmer Unit 1:

Table No.	System
1.3-1	Nuclear Steam Supply System
1.3-2	Engineered Safety Features and Auxiliary Systems
1.3-3	Power Conversion Systems
1.3-4	Containment
1.3-5	Structural Design
1.3-6	Radioactive Waste Management Systems
1.3-7	Electrical Power Systems

1.3.2 COMPARISON OF FINAL AND PRELIMINARY INFORMATION

Significant changes made in the facility design between the PSAR stage and the FSAR stage are listed in Table 1.3-8. Design changes are only those that have occurred since the last PSAR amendment. Notice of all other design changes has been given through amendments to the PSAR. Each item in Table 1.3-8 is cross-referenced to the appropriate section of the UFSAR which describes the present design.

Table 1.3-1
COMPARISON OF NUCLEAR STEAM SUPPLY SYSTEM DESIGN CHARACTERISTICS

	LGS*	SSES	ZIMMER 1	PBAPS
THERMAL AND HYDRAULIC DESIGN (Section 4.4)				
Rated power, MWt	3293	3293	2436	3293
Design power, MWt	3435	3439	2550	3440
Steam flow rate, lb/hr	14.159×10^6	13.48×10^6	10.477×10^6	13.381×10^6
Core coolant flow rate, lb/hr	100×10^6	100.5×10^6	100.5×10^6	102.5×10^6
Feedwater flow rate, lb/hr	14.127×10^6	13.44×10^6	10.447×10^6	10.447×10^6
Feedwater temperature, °F	420	383	420	376.1
System pressure, nominal in steam dome, psia	1020	1020	1020	1020
Average power density, kW/liter	48.7	48.7	50.51	50.8
Maximum linear heat generation rate, kW/ft	13.4	13.4	13.4	18.35
Average linear heat generation rate, kW/ft	5.3	5.3	5.4	7.049
Maximum heat flux, Btu/hr-ft^2	361,600	361,600	354,255	425,060
Average heat flux, Btu/hr-ft^2	144,100	143,700	144,032	163,230
Maximum uranium dioxide ($U0_2$) temperature, °F	3435	3435	3435	4430
Average volumetric fuel temperature, °F	2130	2130	2130	2780
Average fuel rod surface temperature, °F	566	566	566	560
Minimum critical power ratio (MCPR)	1.22	1.25	1.24	-
Coolant enthalpy at core inlet, Btu/lb	526.1	521.8	527.4	521.2
Core maximum exit voids within assemblies, %	77.1	76.6	75	79
Core average exit quality, % steam	14.1	13.2	13.2	13.2
Design power peaking factor(1)				
Maximum relative assembly power	1.4	1.4	1.4	1.4
Design power peaking factor(1)				
Maximum relative assembly power	1.4	1.4	1.4	1.4
Axial peaking factor	1.4	1.4	1.4	1.5
NUCLEAR DESIGN (FIRST CORE) (Section 4.3)				
Water/UO_2 volume ratio (cold, beginning of cycle [BOC])	2.74	2.80	2.55	2.43
Reactivity with strongest control rod out, k_{eff}	<0.99	<0.99	<0.99	<0.99

Table 1.3-1 (Cont'd)
COMPARISON OF NUCLEAR STEAM SUPPLY SYSTEM DESIGN CHARACTERISTICS

	LGS*	SSES	ZIMMER 1	PBAPS
Dynamic void coefficient (end of cycle 1 [EOC-1])				
a. At core average voids, %	39.7	39.7	40.54	(2)
b. At rated output, ¢/%	-7.48	-7.48	-8.57	(2)
Fuel temperature doppler coefficient (BOC) at rated output (1/k) (dk/dt) (1/°C)	-1.85×10^{-5}	-1.85×10^{-5}	-1.94×10^{-5}	(2)
Initial average U-235 enrichment wt, %	1.88	1.88	1.90	2.19
Initial cycle exposure, Mwd/short ton	9600	9600	9200	(2)
CORE MECHANICAL DESIGN (Sections 4.2 and 4.6)				
Fuel assembly				
Number of fuel assemblies	764	764	560	764
Fuel rod array	8x8	8x8	8x8	7x7
Overall length, in	176	176	176	176
Weight of UO_2 per assembly, lb (pellet type)	456	458	466	490
Weight of fuel assembly, lb	680	665	698	676
Fuel rods				
Number per fuel assembly	62	62	63	63
Outside diameter, in	0.483	0.483	0.493	0.563
Cladding thickness, in	0.032	0.032	0.034	0.032
Diametral gap, pellet to cladding, in	0.009	0.009	0.009	0.011
Length of gas plenum, in	9.48	10	14	16
Cladding material	Zircaloy-2	Zircaloy-2	Zircaloy-2	Zircaloy-2
Cladding process	Freestanding loaded tubes	Freestanding loaded tubes	Freestanding loaded tubes	Freestanding loaded tubes
Fuel pellets				
Material	UO_2	UO_2	UO_2	UO_2
Density, % of theoretical	94	95	95	95
Diameter, in	0.410	0.410	0.416	0.487
Length, in	0.410	0.410	0.420	0.5
Fuel channel				
Overall length, in	166.9	166.9	166.9	166.9

Table 1.3-1 (Cont'd)
COMPARISON OF NUCLEAR STEAM SUPPLY SYSTEM DESIGN CHARACTERISTICS

	LGS*	SSES	ZIMMER 1	PBAPS
Thickness, in	0.100,0.080[3]	0.080	0.100	0.080
Cross section dimensions, in	5.48x5.48	5.48x5.48	5.48x5.48	5.44x5.44
Material	Zircaloy-4	Zircaloy-4	Zircaloy-4	Zircaloy-4
Core assembly				
Fuel weight as UO_2, lb	348,939	349,912	260,551	369,790
Core diameter (equivalent), in	187.1	187.1	160.2	187.1
Core height (active fuel), in	150	150	146	144
Reactor control system				
Method of variation of reactor power	Movable control rods and variable forced coolant flow	Movable control rods and variable forced coolant flow	Movable control rods and variable forced coolant flow	Movable control rods and variable forced coolant flow
Number of movable control rods	185	185	137	185
Shape of movable control rods	Cruciform	Cruciform	Cruciform	Cruciform
Pitch of movable control rods, in	12.0	12.0	12.0	12.0
Control material in movable rods	Boron Carbide (B_4C) granules compacted in stainless steel tubes	B_4C granules compacted in stainless steel tubes	B_4C granules compacted in stainless steel tubes	B_4C granules compacted in stainless steel tubes
Type of control rod drives	Bottom entry locking piston	Bottom entry locking piston	Bottom entry locking piston	Bottom entry locking piston
Type of temporary reactivity control	Burnable poison; gadolinia-urania fuel rods	Burnable poison; gadolinia-urania fuel rods	Burnable poison; gadolinia-urania fuel rods	Burnable poison; gadolinia-urania fuel rods
Incore neutron instrumentation				
Total number of LPRM detectors	172	172	124	172
Number of incore LPRM penetrations	43	43	31	43
Number of LPRM detectors per penetration	4	4	4	4
Number of SRM penetrations	4	4	4	4
Number of IRM penetrations	8	8	8	8
Total nuclear instrument penetrations	55	55	43	55

Table 1.3-1 (Cont'd)
COMPARISON OF NUCLEAR STEAM SUPPLY SYSTEM DESIGN CHARACTERISTICS

	LGS*	SSES	ZIMMER 1	PBAPS
Range (and number) of detectors:				
a. SRM	Shutdown through criticality(4)	Shutdown through criticality(4)	Shutdown through criticality(4)	Shutdown through criticality(4)
b. IRM	Prior to criticality to low power (8)	Prior to criticality to low power (8)	Prior to criticality to low power (8)	Prior to criticality to low power (8)
Power range monitors	1% to 125% power	5% to 125% power	1% to 125% power	1% to 125% power
- LPRM	172	172	124	172
- APRM	6	6	6	6
Number and type of incore neutron sources	7; Sb-Be	7; Sb-Be	5; Sb-Be	7; Sb-Be
REACTOR VESSEL DESIGN (Section 5.3)				
Material	Carbon steel/ stainless clad	Carbon steel/ stainless clad	Carbon steel/ stainless clad	Carbon steel/ stainless clad
Design pressure, psig	1250	1250	1250	1250
Design temperature, °F	575	575	575	575
Inside diameter, ft-in	20-11	20-11	18-2	20-11
Inside height, ft-in	72-1	72-11	69-10	72-11
Minimum base metal thickness (cylindrical section), in	6.187	6.19	5.375	6.3125
Minimum cladding thickness, in	1/8	1/8	1/8	1/8
REACTOR COOLANT RECIRCULATION SYSTEM DESIGN (Section 5.4)				
Number of recirculation loops	2	2	2	2
Design pressure				
a. Inlet leg, psig	1250	1250	1250	1148
b. Outlet leg, psig	1500	1500	1575	1326
Design temperature, °F	575	575	575	562
Pipe diameter, in	28	28	20	28
Pipe material, ANSI	316	304/316	304/316	304/316

Table 1.3-1 (Cont'd)
COMPARISON OF NUCLEAR STEAM SUPPLY SYSTEM DESIGN CHARACTERISTICS

	LGS*	SSES	ZIMMER 1	PBAPS
Recirculation pump flow rate, gpm	45,200	45,200	32,500	45,200
Number of jet pumps in reactor	20	20	20	20
MAIN STEAM LINES (Section 10.3)				
Number of steam lines	4	4	4	4
Design pressure, psig	1115	1250	1250	1115
Design temperature, °F	582	575	575	583
Pipe diameter, in	26	26	24	26
Pipe material	Carbon steel	Carbon steel	Carbon steel	Carbon steel

(1) Local and total peaking factors are not used as input to the thermal/hydraulic codes and are therefore not included here.
(2) Available values for PBAPS first core were developed on a different basis and are not directly comparable to LGS, SSES, or Zimmer 1.
(3) LGS Unit 1 will use 80 mil thick fuel channels beginning with refueling cycle 2.
LGS Unit 2 will use 80 mil thick fuel channels beginning with the initial core.

* Based on the original licensed operating conditions.

Table 1.3-2
COMPARISON OF ENGINEERED SAFETY FEATURES AND AUXILIARY SYSTEMS DESIGN CHARACTERISTICS

	LGS*	SSES	ZIMMER 1	PBAPS
EMERGENCY CORE COOLING SYSTEMS				
(Systems sized on design power)				
(See UFSAR Section 6.3)				
Core spray system				
Number of loops	2	2	1	2
Flow rate, gpm, per pump	6350 at 105 psid	6350 at 105 psid	4725 at 119 psid	6250 at 122 psid
High pressure coolant injection system				
Number of loops	1	1	1	1
Flow rate, gpm	5600 minimum	5000 at 1172-165 psia,	1330 at 1110 psid, 4625 at 200 psid	5000 at 1120-150 psid
Automatic depressurization system				
Number of relief valves	5	6	6	5
Low pressure coolant injection				
Number of loops	4	2	3	2
Number of pumps	4	4	3	4
Flow rate, gpm/pump	10,000 at 20 psid	10,650 at 20 psid	5050 at 20 psid	10,000 at 20 psid
AUXILIARY SYSTEMS				
(See UFSAR Sections 5.4 and 9.2)				
Residual heat removal system				
Reactor shutdown cooling mode:				
Number of pumps	2	2	3	4
Flow rate, gpm/pump	10,000	10,000	5050	10,000
Duty, Btu/hr/heat exchanger	41.6×10^6	44×10^6	30.8×10^6	70.0×10^6
Number of heat exchangers	2	2	3	4
Primary containment cooling mode:				
Flow rate, gpm/heat exchanger	10,000	10,000	5050	10,000
Service water system				
Flow rate, gpm/heat exchanger	12,000	9000	5000	14,000
Number of pumps	3	2	4	3
Reactor core isolation cooling system				
Flow rate, gpm	600 at 1120 psid	600 at 1172-165 psia	400 at 1120 psid	616 at1120 psid
Fuel pool cooling and cleanup system				
Capacity, Btu/hr	11.25×10^6	13.2×10^6	6.9×10^6	11.25×10^6

*Based on the original licensed operating conditions.

Table 1.3-3

COMPARISON OF POWER CONVERSION SYSTEM DESIGN CHARACTERISTICS

	LGS*	SSES	ZIMMER 1	PBAPS
TURBINE-GENERATOR (See UFSAR Section 10.2)				
Design power, MWe (gross)	1092	1085	830	1098
Generator speed, rpm	1800	1800	1800	1800
Design steam flow, lb/hr (maximum guaranteed)	14.14×10^6	13.46×10^6	11.00×10^6	13.36×10^6
Inlet pressure, psig	965	965	950	965
STEAM BYPASS SYSTEM (See UFSAR section 10.4.4)				
Capacity, % design steam flow	25	25	25	25
MAIN CONDENSER (See UFSAR Section 10.4.1)				
Heat removal capacity, Btu/hr	7725×10^6	7890×10^6	7053×10^6	7600×10^6
CIRCULATING WATER SYSTEM (See UFSAR Section 10.4.5)				
Number of pumps	4	4	3	3
Flow rate, gpm/pump	113,000	112,000	150,000	250,000
CONDENSATE AND FEEDWATER SYSTEMS (See UFSAR Section 10.4.7)				
Design flow rate, lb/hr	14.12×10^6	13.44×10^6	10.971×10^6	13.33×10^6
Number of condensate pumps	3	4	3	3
Number of condensate booster pumps	-	-	3	-
Number of feedwater pumps	3	3	2	3
Condensate pump drive	AC power	AC power	AC power	AC power
Booster pump drive	-	-	AC power	-
Feedwater pump drive	Turbine	Turbine	Turbine	Turbine

* Based on the original licensed operating conditions.

Table 1.3-4

COMPARISON OF CONTAINMENT DESIGN CHARACTERISTICS

	LGS*	SSES	ZIMMER 1	PBAPS
PRIMARY CONTAINMENT (See UFSAR Sections 3.8 and 6.2)				
Type	Pressure- Suppression	Pressure-suppression	Pressure-suppression	Pressure-suppression
Construction	Concrete with steel liner	Concrete with steel liner	Concrete with steel liner	Free-Standing Steel
Drywell	Frustum of cone upper portion	Frustum of cone upper portion	Frustum of cone upper portion	Light bulb shape, steel vessel
Suppression chamber	Cylindrical lower portion	Cylindrical lower portion	Cylindrical lower portion	Torus, steel vessel
Suppression chamber internal design pressure, psig	55	53	45	56
Suppression chamber external design pressure, psi	5	5	2	2
Drywell internal design pressure, psig	55	53	45	56
Drywell external design pressure, psi	5	5	2	2
Drywell free volume, ft^3 (low water)	243,580	239,600	180,000	159,000
Suppression chamber free air volume, ft^3	147,670 (high water) 159,540 (low water)	148,590 (high water) 159,130 (low water)	93,000	19,000
Suppression pool water volume, ft^3	134,600(max) 122,120(min)	131,550(max) 122,410(min)	95,762	135,000
Submergence of downcomers below suppression pool surface, ft	12¼ (high water) 10 (low water)	11	10	4

Table 1.3-4 (Cont'd)

	LGS*	SSES	ZIMMER 1	PBAPS
Design temperature of drywell, °F	340	340	340	281
Design temperature of suppression chamber, °F	220	220	275	281
Downcomer vent pressure loss factor	2.23	2.5	2.17	6.21
Break area/total vent area	0.0159	0.016	0.008	0.019
Calculated maximum pressure after blowdown to drywell, psig	44.0	44	40.4	40
Calculated maximum suppression chamber pressure after LOCA blowdown, psig	30.6	29	35.6	25
Initial suppression pool temperature rise during LOCA blowdown, °F	43	40	35	32
Leakage rate, % free volume/day	0.5	0.5	0.635 at 45 psig and 340°F	0.5
SECONDARY CONTAINMENT (See UFSAR Section 3.8)				
Type	Controlled leakage, roof level release	Controlled leakage, elevated release	Controlled leakage, elevated release	Controlled leakage, elevated release
Construction				
Lower levels	Reinforced concrete	Reinforced concrete	Reinforced concrete	Reinforced concrete
Upper levels	Reinforced concrete super-structure and siding	Steel super-structure and siding	Steel super-structure and siding	Steel super-structure and siding
Roof	Reinforced concrete	Steel decking	Steel decking	Steel decking

* Based on the original licensed operating conditions.

Table 1.3-4 (Cont'd)

	LGS*	SSES	ZIMMER 1	PBAPS
Internal design pressure, psig below atmosphere	0.25	0.25	0.25	0.25
Design inleakage rate % free volume/day at 0.25 in wg. Reactor enclosure	200	100	100	100
Refueling area	50	100	100	100

* Based on the original licensed operating conditions.

Table 1.3-5

COMPARISON OF STRUCTURAL DESIGN CHARACTERISTICS

	LGS	SSES	ZIMMER 1	PBAPS
SEISMIC DESIGN (See UFSAR Section 3.7)				
Operating basis earthquake				
- horizontal(g)	0.075	0.05	0.10	0.05
- vertical(g)	0.05	0.033	0.07	0.033
Safe shutdown earthquake				
- horizontal(g)	0.15	0.10	0.20	0.12
- vertical(g)	0.10	0.067	0.14	0.08
WIND DESIGN (See UFSAR Section 3.3)				
Maximum sustained wind speed (mph)	90	80	90	87
TORNADO DESIGN (See UFSAR Section 3.3)				
Translational speed (mph)	60	60	60	-
Rotational speed (mph)	300	300	300	300

Table 1.3-6

RADIOACTIVE WASTE MANAGEMENT SYSTEMS DESIGN CHARACTERISTICS

	LGS	SSES	ZIMMER 1	PBAPS
GASEOUS RADWASTE (See UFSAR Section 11.3				
Design bases, noble gases, Ci/sec	100, 000 at 30 min	100, 000 at 30 min	100, 000 at 30 min	100, 000 at 30 min
Process treatment	Recombiner and ambient charcoal delay	Recombiner and ambient charcoal delay	Chilled charcoal	Recombiner
Design condenser inleakage, cfm	75	30	12.5	54
Release point-height above ground, ft	197	201	172	500
LIQUID RADWASTE (See UFSAR Section 11.2)				
Treatment of:				
Floor drains	F, D, R	F, D, R	F, E, R	F, O
Equipment drains	F, D, R	F, D, R	F, D, R	F, D, R
Chemical drains	F, D, R	E, D concentrates to solid radwaste, distillate R	E, D concentrates to solid radwaste, distillate R	Neutralized radwaste, F, O
Laundry drains	F, O	Diluted and sent to circulating water discharge	Reverse osmosis discharge	F, O

(1) Legend:
D = demineralized
F = filtered
E = evaporator/concentrator
R = recycled, i.e., returned to condensate storage
O = discharged

Table 1.3-7

COMPARISON OF ELECTRICAL POWER SYSTEMS DESIGN CHARACTERISTICS

	LGS	SSES	ZIMMER 1	PBAPS
TRANSMISSION SYSTEM (See UFSAR Section 8.2)				
Outgoing lines, number-rating	3-500 kV 2-230 kV	1-230 kV (Unit 1) 1-500 kV (Unit 2)	3-345 kV	4.500 kV
NORMAL AUXILIARY AC POWER (See UFSAR Sections 8.2 and 8.3)				
Incoming lines, number-rating	3-500 kV 2-230 kV	2.230 kV (common to both units)	1-69 kV 1-345 kV	1-230 kV 13.8 kV
Auxiliary transformers, number	2	1 per unit	1(unit auxiliary)	2
Startup transformers, numbers	2	2 (common to both units)	2	2
Safeguard transformers, numbers	2 + 1 spare	-	-	2
STANDBY AC POWER SUPPLY (See UFSAR Section 8.3)				
Number of diesel generators	8	4 (common to both units)	3	4
Number of 4160 V shutdown buses	8	4 per unit	3	8
Number of 480 V shutdown buses	8	4 load centers and 8 MCCS per unit; 8 MCCs common to both units	8	8

Table 1.3-7 (Cont'd)

	LGS*	SSES	ZIMMER 1	PBAPS
DC POWER SUPPLY (See UFSAR Section 8.3)				
Number of 125 V or 250 V batteries	4-125 V 6-125/250 V 2-250 V	4-125 V per unit 2-250 V per unit	3-125 V 1-250 V	4-125/250 V 2-250 V
Number of 125 V buses	33	4 per unit	3	8
Number of 250 V buses	8 buses and 8 MCCs	2 load centers and 3 MCCs per unit	1	8

Table 1.3-8

SIGNIFICANT DESIGN CHANGES FROM PSAR TO FSAR

ITEM	CHANGE	REASON FOR CHANGE	UFSAR SECTION IN WHICH SUBJECT IS DISCUSSED
Nuclear fuel	The arrangement of fuel rods in each fuel bundle was changed from 7x7 to 8x8.	This change improves fuel performance by increasing safety margins.	4.2
Nuclear pressure relief system	The two safety valves were deleted and the number of relief valves was increased from 11 to 14.	This change improves the pressure suppression capability of the nuclear relief system.	5.2.2
Feedwater sparger	The design of the thermal sleeve connecting the sparger to the reactor vessel has been changed.	This change eliminated the possibility of vibration and leakage.	5.3
Reactor recirculation system	The 4 inch bypass line around the recirculation pump discharge valve has been deleted.	This changed improves the integrity and reliability of the recirculation loop.	5.4
Process sensors	The monitoring devices of process parameters have been changed (e.g., pressure, level, and flow) for the RPS and the ESF systems from process switches to transmitters and trip units.	This change improves testability.	7.2, 7.3
Main condenser low vacuum	The MSIV and main steam drain line isolation valves, rather than the turbine stop valves and turbine bypass valves, are automatically closed if there is loss of vacuum in the main condenser.	This eliminates reliance on the turbine control system for isolation of the main condenser from the main steam supply.	7.2, 7.3

Table 1.3-8 (Cont'd)

ITEM	CHANGE	REASON FOR CHANGE	UFSAR SECTION IN WHICH SUBJECT IS DISCUSSED
Standby ac power system	Bypassing of the following diesel generator trip signals, if there is a LOCA, has been added: a. Phase overcurrent b. Ground neutral overcurrent c. Ant-motoring d. Jacket coolant high temperature/low pressure e. Lube oil high temperature/low pressure	To conform with BTP ICSB 17.	
Control room HVAC system	The capability for total isolation and recirculation of control room atmosphere on toxic chemical detection signal has been added.	For conformance with Regulatory Guides 1.78 and 1.95.	6.4, 9.4.1
Reactor enclosure HVAC isolation	The requirement for complete closure of the isolation valves in the reactor enclosure normal exhaust duct before any contaminated air is released after its detection has been deleted. Isolation valves will trip in normal time on detection of airborne contamination.	The reactor enclosure normal exhaust system serves those areas of the reactor enclosure which have a low release potential. Releases of radioactivity during the short time period required for isolation valve closure would be a very small fraction of 10CFR50.67 guidelines.	9.4.2
Drywell unit coolers	Changed from two-speed to single fan motors of sufficient horsepower for LOCA operation and ILRT operation.	This change was made to obtain motors qualified for 340°F operation.	9.4.5

Table 1.3-8 (Cont'd)

ITEM	CHANGE	REASON FOR CHANGE	UFSAR SECTION IN WHICH SUBJECT IS DISCUSSED
Reactor enclosure and control structure HVAC systems	Added steam flooding isolation dampers	This prevents damage to safeguard equipment and protects personnel from pipe breaks outside containment.	9.4.2
Drywell HVAC duct-work	Added pressure relief valves	This prevents damage to ducts during LOCA pressure surge in drywell.	9.4.5
Mechanical vacuum pump	The pump exhaust was rerouted to the turbine equipment compartment exhaust duct leading to the charcoal filters and vent stack.	The charcoal filters will capture the iodine discharged from the vacuum pumps, as identified by EPRI Report NP-495.	9.4.4
Mechanical vacuum pump compartment	The room air exhaust was changed from nonfiltered to filtered exhaust.	The charcoal filters will capture iodine released to the room per EPRI Report NP-495.	9.444
Liquid Waste Management System	The radwaste evaporator system and associated equipment was not completely installed for plant operation.	Effective processing of chemical waste can be provided by the floor drain subsystem, thereby eliminating operational problems associated with evaporative processing.	11.2
Gaseous waste management system	Change the offgas treatment system from cryogenic distillation type to charcoal adsorption type.	The charcoal adsorption method provides advantages in reliability and maintainability, while limiting offsite doses to levels as low as or lower than can be achieved with the cryogenic distillation method.	11.3

Table 1.3-8 (Cont'd)

ITEM	CHANGE	REASON FOR CHANGE	UFSAR SECTION IN WHICH SUBJECT IS DISCUSSED
Solid radwaste management system	Because the evaporator was not completely installed for plant operation, a system for solidification of evaporator concentrates was also not installed.	Due to the previously described change in the liquid waste management system, the evaporator concentrates will not be produced. Dewatered resin wastes will be packaged in approved high integrity containers consistent with the requirements established by the South Carolina Department of Health and Environmental Control and will meet the intent of BTP ESTB 11-3. The vibrating hoppers were eliminated from system design because of anticipated operational problems and because they are not required for effective functioning of the solid radwaste system.	
Primary containment instrument gas system	A seismic Category I backup gas supply for operation of ADS valves has been added.	To allow for long-term operation of ADS valves to provide an alternate shutdown cooling path for conformance with Regulatory Guide 1.139. Also satisfies NUREG-0694 item.	9.3.1, 5.4.7, 1.13
Bypass leakage barrier design	Added vent lines to potential bypass leakage paths to vent to the secondary containment and added a feedwater fill system to maintain a wate seal on the feedwater lines.	To minimize leakage in order to minimize offsite doses in the event of a LOCA.	6.2.3
Residual heat removal system	Addes intertie piping and valves 'A' and 'B' and between RHR 'C' and 'D' discharge loops.	To allow use of RHR pumps 'B' and 'D' in conjunction with the RHR heat exchanger in the shutdown cooling mode for greater system flexibility during maintenance.	5.4

Table 1.3-8 (Cont'd)

ITEM	CHANGE	REASON FOR CHANGE	UFSAR SECTION IN WHICH SUBJECT IS DISCUSSED
Ultimate heat sink	Added soil-bentonite lining to the spray pond bottom and soil slopes.	To minimize construction delays in event that the potential for greater than expected seepage rates was found.	2.5, 9.2.6
Safeguard piping fill system	Provided a redundant safety-grade piping fill system.	To provide increased assurance that water hammer events will not occur during ECCS system startup.	6.3
Spent fuel pool	Added makeup water connections from the ESW System.	To provide Seismic Category I, safety-grade makeup water supply to the spent fuel pools to provide cooling in the event of loss of the spent fuel pool cooling system in conformance with Regulatory Guide 1.13.	9.1
Reactor recirculation system	Deleted recirculation loops equalizing line.	To improve the integrity and reliability of the recirculation loops.	5.4
Reactor coolant pressure boundary piping	Changed portions of the RHR LPCI, head spray, and shutdown cooling piping to type 316L stainless steel with less than 0.02% carbon. Changed recirculation loop piping to type 316K stainless steel.	To minimize potential for IGSCC.	5.2.3
Battery System	Added a non-Class IE battery to power non-Class IE dc loads.	To provide separation of Class 1E and non-Class 1E loads in conformance with Regulatory Guide 1.75	8.3

Table 1.3-8 (Cont'd)

ITEM	CHANGE	REASON FOR CHANGE	UFSAR SECTION IN WHICH SUBJECT IS DISCUSSED
Reactor enclosure recirculation system	RERS no longer recirculates air from the refueling area which is permanently separated from the reactor enclosure at el 352'. Refueling area now exhausts directly to the SGTS upon isolation.	Separation prevents the temperature and humidity of the refueling area from affecting the reactor enclosure below through RERS mixing, reduces the time for drawdown of the reactor enclosure by eliminating the possibility of mixing airborne activity through reactor enclosure 1, the refueling area, and reactor enclosure 2 following a LOCA.	9.4.2.1
Redundant Reactivity Control System	Added RRCS	To reduce the possibility of an ATWS event and the automatically mitigate the consequences of an ATWS event by independently monitoring the RPV dome pressure and water level and automatically initiating the ARI, RPT, SLCS flow and feedwater runback.	7.6.1.8 & 7.6.2.8
Alternate rod insertion	Added ARI solenoid valves to the scram valve pilot air header.	To provide independent solenoid valves to bleed air from the scram valve pilot air header on low water level or high dome pressure in the RPV when detected by the RRCS to increase the reliability of control rod insertion.	4.6.1.2.5.4
Recirculation Pump Trip	Added redundant trip breakers to the power supply to each reactor recirculation pump motor.	To trip the reactor recirculation pump motors in the event of high dome pressure or low water level in the RPV, and thereby reduce the reactor power level in the event of an ATWS.	7.1 & 7.6

Table 1.3-8 (Cont'd)

ITEM	CHANGE	REASON FOR CHANGE	UFSAR SECTION IN WHICH SUBJECT IS DISCUSSED
HPCI Flow Split	Added a cross connection so that HPCI flow is injected to the RPV through both the core spray and feedwater spargers.	To ensure adequate mixing of SLCS flow injected into the RPV.	6.3.2.2.1
Standby Liquid Control System	Added a third SLCS pump & explosive valve.	To permit increased SLCS maintenance flexibility.	9.3.5
Reactor Building Recirculation System	Added REPS Vent.	This vent is needed to allow simultaneous SGTS operation to the reactor enclosure and refueling area. The SGTS duct is seal welded to ensure RERS prefiltration after the RERS fan starts.	
Standby Gas Treatment System	SGTS filters have 8 inch deep charcoal adsorber with and assigned efficiency of 99.0% for removal of inorganic iodines.	The 8 inch deep SGTS charcoal adsorber provides a residence time 0.68 seconds after drawdown. This is sufficient to meet the filtering efficiency specified in table 2 of Regulatory Guide 1.52 (Rev 2).	6.5.1.1.2
Reactor Recirculation Pump Motor Power Supply	Both of the Unit 1 Recirculation Pump Motors Power Supplies have been changed from a Motor-Generator (MG) Set to an Adjustable Speed Drive (ASD).	The ASD is more reliable and efficient than the MG Set for controlling Reactor Recirculation Pump speed.	Table 1.3-8, 1.10-1, Table 3.2-1, Sect. 3.8.4.1.8, Sect. 4.4.3.3.2, 4.4.3.5, Table 5.2-3, Sect. 5.4.1.3, Table 5.4-1, Sect. 7.1.1.2, Table 7.1-1, Sect. 7.7.1.3.1.1, 7.7.1.3.2, 7.7.1.3.3.2.1, 7.7.1.3.3.3, 7.7.1.3.3.4, 7.7.1.3.3.4.3, 7.7.1.3.3.4.4, 7.7.1.3.3.4.5, 7.7.1.3.3.4.6, 7.7.1.3.3.4.7, 7.7.1.3.3.4.8, 7.7.1.3.3.5, 7.7.1.3.5.1, 7.7.1.3.5.2, 7.7.2.3.1, 7.7.2.3.3, Fig. 7.7-7, Sect. 8.1.6.1.12, Fig. 8.1-4, Table 8.3-28, Table 8.3-29,

Table 1.3-8 (Cont'd)

ITEM	CHANGE	REASON FOR CHANGE	UFSAR SECTION IN WHICH SUBJECT IS DISCUSSED
Reactor Recirculation Pump Motor Power Supply	Recirculation Pump Motor Power Supply has been changed from a Motor-Generator (MG) Set to an Adjustable Speed Drive (ASD) for Unit 2. The Unit 1 MG sets replacement was performed previously.	The ASD is more reliable and efficient to improve system response to perturbations and transients. In addition, the ASD units are designed to be tolerant to single failures	Sect. 9.4.4.1, 9.4.4.2.4, 9.5.1.2.3.2, 9.5.1.2.9, 9.5.1.2.12, Sect. 9A.2.3, 9A.2.12, 9A.5.8.12, Table 9A-1, Fig. 9A-8, Sect. 15.3.1.1.1, 15.3.2.1.1, 15.3.2.2.3, 15.3.2.3.3, 15.4.5.1.1, 15.4.5.2.1, 15.4.5.3.2, 15.9.6.3.3 Table 1.3-8, 1.10-1, Table 3.2-1, Sect. 3.8.4.1.8, Sect. 4.4.3.3.2, 4.4.3.5, Sect. 5.4.1.3, Table 5.4-1, Sect. 7.1.1.2, Table 7.1-1, Sect. 7.7.1.3.1.1, 7.7.1.3.2.1, 7.7.1.3.2.2, 7.7.1.3.3.2.1, 7.7.1.3.3.3.1, 7.7.1.3.3.3.2, 7.7.1.3.3.4.1, 7.7.1.3.3.4.2, 7.7.1.3.3.4.3, 7.7.1.3.3.4.4, 7.7.1.3.3.4.5, 7.7.1.3.3.4.6, 7.7.1.3.3.4.7, 7.7.1.3.3.4.8, 7.7.1.3.3.5, 7.7.1.3.5.1, 7.7.1.3.5.2, 7.7.2.3.1, 7.7.2.3.3, Fig. 7.7-7.1. Fig. 7.7-2.2, Sect. 8.1.6.1.12, Fig. 8.1-4, Table 8.3-28, Table 8.3-29, Sect. 9.4.4.1, 9.4.4.2.4, 9.5.1.2.3.2, 9.5.1.2.9, 9.5.1.2.12, Sect. 9A.2.3, 9A.2.12, 9A.5.8.25, Table 9A-1 Fig. 9A-8, Sect. 15.3.1.1.1, 15.3.2.1.1, 15.3.2.2.3, 15.3.2.3.3, 15.4.5.1.1, 15.4.5.2.1, 15.4.5.3.2, 15.9.6.3.3

1.4 IDENTIFICATION OF AGENTS AND CONTRACTORS

1.4.1 APPLICANT

Exelon Generation Company, LLC (EGC) is the sole applicant for the utilization facility licenses and will operate the plant upon completion. Prime contractors and principal consultants are identified in Sections 1.4.2, through 1.4.5.

The Applicant has been responsible for the design and construction of, and currently operates, eight multi-unit fossil fuel power plants and one 2-unit nuclear power plant. Additionally, two large multi-unit hydroelectric generating plants, one of which is a pumped-storage plant, and several diesel engine and combustion turbine-driven generator installations have also been designed, constructed, and are currently being operated by the Applicant.

The Applicant also has an ownership interest in two operating fossil fuel plants and one operating nuclear power plant. These plants provide capacity and energy to the Applicant's system but are not operated by the Applicant.

These facilities, which had a net capacity of 8,197,600 KWe at the end of 1977, constitute the Applicant's electric generating system.

The Applicant has been active in the development of atomic energy for electric generation for many years. In 1952 it became a charter member of the Dow Chemical-Detroit Edison Nuclear Power Development Project, which subsequently became Atomic Power Development Associates, Inc. This organization designed and developed a fast breeder power reactor for the Atomic Energy Commission's Power Demonstration Program. The Applicant also took part in the formation of Power Reactor Development Company, which was organized to finance, construct, own, and operate the fast breeder reactor designed by Atomic Power Development Associates, Inc., for the Enrico Fermi Atomic Power Station.

The Applicant's engineers have had experience in many phases of nuclear projects including: assignments to Atomic Power Development Associates, Inc. for design and development of core and fuel elements, shielding design, coordination of research at various levels on the metallurgical and chemical aspects of fuel elements; shift supervisor duties and preoperational duties, including preparation of plant operation manuals, at the Enrico Fermi Atomic Power Station; assignment to Power Reactor Development Company for coordination of control instrumentation and electrical features; assignment to the Nautilus nuclear submarine project for field engineering and mechanical operations during startup and initial operation; assignment to the nuclear reactor at Shippingport, Pennsylvania, for training and operational duties; assignment to the Knolls Atomic Power Laboratory for participation in prototype design of a sodium boiler for a submarine reactor; construction, startup, operation, and decommissioning of PBAPS Unit 1, a 40,000 KWe capacity unit employing an HTGR; and construction, startup, operation, and maintenance of PBAPS Units 2 and 3, each unit consisting of a BWR having an original rated core thermal power of 3293 KWt and producing a corresponding net electrical output of 1065 MWe.

1.4.2 ARCHITECT-ENGINEER AND CONSTRUCTOR

The Applicant has retained Bechtel Power Corporation and Bechtel Construction, Inc. to provide architectural, engineering, construction, and startup services for LGS. In addition, Bechtel is responsible for procurement of equipment other than the NSSS, turbine-generators, and certain

other major components that have been purchased by the Applicant. Bechtel has been continuously engaged in engineering and construction activities since 1898. A review of recent tabulations of nuclear units in the continental United States that are planned, under construction, or in operation, indicates that Bechtel is responsible for the engineering design of approximately 60 of these units and, in addition, is charged with responsibility for construction of over 40 units. Bechtel is, therefore, eminently qualified to provide the required services for station design, equipment procurement, construction, and startup.

1.4.3 NUCLEAR STEAM SUPPLY SYSTEM SUPPLIER

GE has the contract to design, fabricate, and deliver the boiling water-type NSSS and nuclear fuel for LGS, as well as to provide technical direction for installation and startup of these systems. GE has been engaged in the development, design, construction, and operation of boiling water reactors since 1955. A review of recent tabulations of nuclear units in the United States that are planned, under construction, or in operation, reveals that approximately 65 of these units employ GE BWRs. Thus, GE has substantial experience, knowledge, and capability to design, manufacture, and furnish technical assistance for the installation and startup of the LGS NSSS.

1.4.4 TURBINE-GENERATOR SUPPLIER

GE was the original contractor to design, fabricate, and deliver the turbine-generators for LGS, as well as to provide technical assistance for installation and startup of this equipment. GE has a long history in the application of turbine-generators to nuclear power stations dating back to 1955. Over 100 of the nuclear units planned, under construction, or in operation in the United States employ GE turbine-generators. GE is, therefore, well qualified to design, fabricate, and deliver the turbine-generators for LGS, and to provide technical assistance for the installation and startup of this equipment. Siemens Power Corporation has the contract to design, fabricate and install the retrofit high pressure and low pressure turbines. Like GE, Siemens is well qualified to perform this work.

1.4.5 CONSULTANTS

The licensee has engaged consultants to provide information and recommendations in a number of specialized fields. Principal consultants include:

a. Gilbert Associates: siting

b. Dames & Moore: geology, seismology, groundwater hydrology

c. Meteorological Evaluation Services, Inc.: meteorology

d. Buchart-Horn: archeology

e. MPR Associates, Inc.: quality assurance

f. C. L. Hosler: cooling tower studies

g. Radiation Management Corporation: aquatic and terrestrial biology, and radioactive releases and their effects

h. Nuclear Associates International Corp: core analysis

i. Kibbe & Associates: nuclear fuel supply

j. Nuclear Energy Services: inservice inspection

k. J. E. Edinger: limnology

l. Hydrocon: Schuylkill River hydrology, radioactive release dispersion analysis

m. Betz-Converse-Murdoch, Inc.: sewage treatment

n. Sanders & Thomas: Schuylkill River soundings, road relocation

o. E. H. Bourquard Associates, Inc: water supply

p. Tippetts-Abbett-McCarthy-Stratton: water supply, hydrology

1.5 REQUIREMENTS FOR FURTHER TECHNICAL INFORMATION

1.5.1 CURRENT DEVELOPMENT PROGRAMS

1.5.1.1 Instrumentation for Vibration of Reactor Intervals

Vibration testing for reactor internals has been performed on virtually all GE BWR plants. At the time of issue of Regulatory Guide 1.20, test programs for compliance were instituted. The first BWR/4 plant of this size, Browns Ferry 1, is considered a prototype design and was instrumented and subjected to both cold and hot, two-phase flow testing to demonstrate that flow-induced vibrations similar to those expected during operation do not cause damage. Subsequent plants that have internals similar to those of the prototypes are tested in compliance with the requirements of Regulatory Guide 1.20 to confirm the adequacy of the design with respect to vibration. Combined with the system for monitoring of vibration within the reactor vessel and its immediate piping, additional equipment is provided to monitor selected rotating machines within the plant in order to provide early warning of excessive machine vibration.

1.5.1.2 Core Spray Distribution

GE has a program underway to study BWR/6 core spray distributions using a combination of single nozzle steam and air tests, single and multiple nozzle analytical models, and full-scale air tests. This methodology was confirmed by a full-scale 30° sector steam test conducted during 1979 and reported in Reference 1.5-1. The NRC has agreed "that the overall empirical/engineering method outlined by GE ... is an acceptable method for verification of the currently assumed core spray distributions which are used to justify conservatisms of the spray cooling heat transfer coefficients in ECCS-LOCA licensing calculations."

For other BWR plants, the NRC believes that "there is a sufficient technical basis to permit continued plant operation and licensing in the interim period while these additional tests and information are being developed. This interim conclusion is based on:

a. The existence of a considerable safety margin between available and required spray flow indicated by preliminary analyses and measurements provided for each size BWR/1 through BWR/5;

b. The relative ease with which ECCS re-analyses could be performed to establish an acceptable power limit in the unlikely event that test results do not support the spray flows currently assumed;

c. The possibility that plants under construction could modify their spray nozzles or aiming pattern to provide a better spray distribution, if future test results indicate the desirability of such changes (particularly applicable to the BWR/6, where the type of preliminary measurements referenced in a. above are not yet available);

d. The existence of counter-current-flow-limiting phenomena in many plants would provide a steam/water layer on top of the core which should force a more even distribution of the core spray;

e. The aforementioned empirical/engineering method is expected to provide timely confirmation of the spray flow margin presently believed to exist."

1.5.1.3 Core Spray and Core Flooding Heat Transfer Effectiveness

Due to the incorporation of an 8x8 fuel rod array with unheated "water rods," tests have been conducted to demonstrate the effectiveness of the ECCS in the new geometry.

These tests are regarded as confirmatory only, since the geometry change is very slight and the "water rods" provide an additional heat sink in the inside of the bundle that improves heat transfer effectiveness.

There are two distinct programs involving the core spray. Testing of the core spray distribution has been accomplished and submitted (Reference 1.5-2). The other program concerns the testing of core spray and core flooding heat transfer effectiveness. The results of testing with stainless steel cladding are reported in Reference 1.5-3. The results of testing using Zircaloy cladding are reported in Reference 1.5-4.

1.5.1.4 Verification of Pressure-Suppression Design

The Mark II pressure-suppression test program was initiated in the fall of 1975 to investigate suppression pool dynamic phenomena. Phase I blowdown tests were completed late in 1975. These tests utilized a single 24 inch diameter (590 mm ID) downcomer that vented into a 7 foot (2.13 meters) inside diameter tank, representative of a single downcomer/pool cell in a typical Mark II suppression pool. The objective of this phase of testing was to quantify pool dynamics phenomena, particularly the effect of wetwell pressurization on pool swell, and the load associated with the low mass flux steam condensation, or chugging. Primary variables were simulated break size, initial vent submergence, and wetwell air space configuration, i.e., vented or closed wetwell. The Phase II tests were generally similar to the Phase I tests, except a 20 inch diameter (489 mm ID) downcomer was used. The Phase I and II tests thus bound the range of vent-to-pool area ratios of all Mark II containments. Although the test objectives were similar during Phases I and II, some changes were made in the Phase II test matrix after review of the Phase I data. For example, since the Phase I test had shown that wetwell configuration was the variable that had the most pronounced effect on pool dynamics, the decision was made to concentrate the testing effort on the closed wetwell configuration, which is characteristic of the Mark II containment.

In place of the open wetwell tests, additional blowdowns were included in the Phase II test matrix in order to investigate the effect of saturated liquid versus saturated steam breaks and the effect of downcomer bracing configuration.

As was the case for the Phase I tests, the primary Phase II variables were simulated break size and initial vent submergence. The Phase III tests investigated the pool temperature sensitivity of pool swell and of the load associated with the chugging phenomenon. Only a single break size and vent submergence were tested, with pool temperature alone being a variable. A significant number of blowdowns were performed to yield a statistically significant data set.

1.5.1.5 Critical Heat Flux Testing

A program for critical heat flux testing was established and was to be similar to that described in Reference 1.5-5. Since that time, however, a new analysis has been performed and the General Electric BWR Thermal Analysis Basis (GETAB) program initiated. The results of that analysis and related testing is described in Reference 1.5-6.

1.5.1.6 Fuel Assembly Structural Testing

Although tests are being conducted to determine the effects of vibration on fuel assembly spacers and to determine the forces to which the assemblies are subjected during shipment, there is no special program at present concentrating on structural testing, and no topical report is anticipated.

1.5.2 REFERENCES

1.5-1 "Core Spray Design Methodology Confirmation Test," NEDO-24712, (August 1979).

1.5-2 "BWR Core Spray Distribution," Licensing Topical Report NEDO-10846, (April 1973).

1.5-3 "Modeling the BWR/6 Loss-of-Coolant Accident: Core Spray and Bottom Flooding Heat Transfer Effectiveness," Licensing Topical Report NEDO-10801, (March 1973).

1.5-4 "Emergency Core Cooling Test of an Internally Pressurized, Zircaloy Clad, 8x8 Simulated BWR Fuel Bundle," Licensing Topical Report NEDO-20231, (December 1973).

1.5-5 "Design Basis for Critical Heat Flux Conditions in Boiling Water Reactors," APED-5286, (September 1966).

1.5-6 "General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation and Design Application," Licensing Topical Report NEDO-10958-A, (January 1977).

1.6 MATERIAL INCORPORATED BY REFERENCE/GENERAL REFERENCE

Table 1.6-1 provides a tabulation of topical reports and other documents incorporated by reference in this UFSAR.

Note: For clarification of the terms “Incorporation by Reference” and “General Reference”, refer to Reg. Guide 1.181, “Content Of The Updated Final Safety Analysis In Accordance With 10 CFR 50.71(e), September, 1999 (endorsement of NEI 98-03, Revision 1, June, 1999).

Table 1.6-1

REFERENCED REPORTS

Report Number			Referenced in UFSAR Section
A.	General Electric Company Reports		
	APED-4827	Maximum Two-Phase Vessel Blowdown from Pipes (1965)	6.2
	APED-5286	Design Basis for Criteria Heat Flux Condition in BWRs (Sept 1966)	1.5
	APED-5458	Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors (March 1968)	5.4
	APED-5460	Design and Performance of General Electric BWR Jet Pumps (July 1968)	3.9
	APED-5555	Impact Testing on Collet Assembly for Control Rod Drive Mechanism (7RDB144A) (Nov 1967)	4.6
	APED-5652	Stability and Dynamic Performance of the General Electric Boiling Reactor	4.1
	APED-5706	In-Core Neutron Monitoring System For General Electric Boiling Water Reactors (Nov 1968, Revised April 1969)	7.2
	APED-5750	Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves (March 1969)	3.9, 5.4
	APED-5756	Analytical Methods for Evaluating the Radiological Aspects of the General Electric Boiling Water Reactor (March 1969)	15.4, 15.7
	GEAP-5620	Failure Behavior in ASTM A 106B Pipes Containing Axial Through-Wall Flows (April 1968)	5.2
	NEDC-32601P-A	Methodology and Uncertainties for Safety Limit MCPR Evaluations (August 1999)	4.1, 15.0

Table 1.6-1 (Cont'd)

Report Number		Referenced in UFSAR Section
NEDE-10813	PDA-Pipe Dynamic Analysis Program for Pipe Rupture Movement (Proprietary Filing)	3.6
NEDE-10958	General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation, and Design Application (November 1973)	15.0
NEDE-20371-02	User Guide and Engineering Description of HEATER Computer Program (March 1974)	4.1
NEDE-20566	Analytical Model for Loss-of Coolant Accident (LOCA) in Accordance with 10CFR50, Appendix K (Nov. 1975)	3.9, 6.3
NEDE-20944-P	BWR/4 and BWR/5 Fuel Design (October 1976) Amendment 1 (January 1977)	1.8, 4.2 4.3
NEDE-21175-3-P	BWR Fuel Assembly Evaluation of Combined Safe Shutdown Earthquake (SSE) and Loss-of-Coolant Accident (LOCA) Loadings (July 1982)	3.9
NEDE-21354-P	BWR Fuel Channel Mechanical Design and Deflection (September 1976)	3.9
NEDE-21821	Boiling Water Reactor Feedwater Nozzle/Sparger Final Report (March 1978)	3.9
NEDE-24011-P-A NEDE-24011-P-A-US	General Electric Standard Application for Reactor Fuel, including the United States Supplement (August 2024)	4.1, 4.2, 9.1 15.0, 15B

Table 1.6-1 (Cont'd)

Report Number		Referenced in UFSAR Section
NEDE-24057-P	Assessment of Reactor Internal Vibration in BWR/4 and BWR/5 Plants (November 1977)	3.9
NEDE-24222	Assessment of BWR Mitigation of ATWS (NUREG-0460 Alternate 3) (Volume 1 May 1979, Volume 2 December 1979)	15.8
NEDO-10173	Current State of Knowledge of High Performance BWR Zircaloy-Clad UO_2 Fuel (May 1970)	11.1
NEDO-10320	The General Electric Pressure Suppression Containment Analytical Model (April 1971) Supplement 1 (May 1971)	6.2
NEDO-10466	Power Generation Control Complex Design Criteria and Safety Evaluation (Revision 2, March 1978)	7.7, 8.1
NEDO-10505	Experience with BWR Fuel Through September 1971 (May 1972)	11.1
NEDO-10527	Rod-Drop Accident Analysis for Large Boiling Water Reactors (March 1972) Supplement 1 (July 1972) Supplement 2 (January 1973)	15.4A
NEDO-10585	Behavior of Iodine in Reactor Water During Plant Shutdown and Startup (August 1972)	5.2, 15.6
NEDO-10602	Testing of Improved Jet Pumps for BWR/6 Nuclear System (June 1972)	3.9
NEDO-10739	Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems (January 1973)	6.3

Table 1.6-1 (Cont'd)

Report Number		Referenced in UFSAR Section
NEDO-10801	Modeling the BWR/6 Loss-of-Coolant Accident: Core Spray and Bottom Flooding Heat Transfer Effectiveness (March 1973)	1.5
NEDO-10802	Analytical methods of Plant Transient Evaluations for General Electric Boiling Water Reactor (February 1973)	5.2, 15.0, 15.1
NEDO-10846	BWR Core Spray Distribution (April 1973)	1.5
NEDO-10871	Technical Derivation of BWR 1971 Design Basis Radioactive Source Terms (March 1975)	11.1
NEDO-10899	Chloride Control in BWR Coolants (June 1973)	5.2
NEDO-10958-A	General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation, and Design Application (January 1977)	1.5
NEDO-10959	General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation, and Design Application (November 1973)	15.0
NEDO-11209-04A	Nuclear Energy Business Group Boiling Water Reactor Quality Assurance Program (February 1980)	1.8
NEDO-12037	Summary of X-Ray and Gamma Ray Energy and Intensity Data (January 1970)	12.3
NEDO-20231	Emergency Core Cooling Tests of an Internally Pressurized, Zircaloy-Clad, 8x8 Simulated BWR Fuel Bundle (December 1973)	1.5
NEDO-20533	The General Electric Mark III Pressure-Suppression Containment System Analytical Model (June 1974) Supplement 1 (September 1975)	6A

Table 1.6-1 (Cont'd)

Report Number		Referenced in UFSAR Section
NEDO-20566	General Electric Company Model for Loss-of-Coolant Accident Analysis in Accordance with 10CFR50, Appendix K (January 1976)	3.9, 6.3
NEDO-20922	Experience with BWR Fuel Through September 1974 (June 1975)	11.1
NEDO-20944-1	BWR/4 and BWR/5 Fuel Design (October 1976) Amendment 1 (January 1977)	4.2, 4.3
NEDO-20953	Three-Dimensional Boiling Water Reactor Core Simulator (May 1976)	15.4
NEDO-21061	Mark II Containment Dynamic Forcing Function Information Report	3.8, 6.2
NEDO-21142	Realistic Accident Analysis The RELAC Code (October 1977)	15.4, 15.6
NEDO-21143	Conservative Radiological Accident Evaluation - The CONAC01 Code (March 1976)	15.4
NEDO-21159	Airborne Release from BWR's for Environmental Impact Evaluation (March 1976)	11.1
NEDO-21231	Banked Position Withdrawal Sequence (January 1977)	15.4
NEDO-21617A	Analog Transmitter/Trip Unit System for Engineered Safe-Guard Sensor Inputs	7.0, 7.2
NEDO-21660	Experience with BWR Fuel through December 1976 (July 1977)	11.1

Table 1.6-1 (Cont'd)

Report Number			Referenced in UFSAR Section
NEDO-21708	Radiation Effects in BWR		5.3
NEDO-21778-A	Transient Pressure Rises Affecting Fracture Toughness Requirements for BWRs (December 1978)		5.3
NEDO-23538	Users Manual for CRPLS01 Program (December 1976)	4.1	
NEDO-24057	Assessment of Reactor Internals Vibration in BWR/4 and BWR/5 Plants (November 1977)		3.9
NEDO-24154	Qualification of the One-Dimensional Core Transient Model for BWRs (October 1978)		5.2, 15.0
NEDO-24708A	Additional Information Required for NRC Staff Generic Report on BWRs, Rev. 1 (Dec. 1980)		1.13, 6.3
NEDO-24712	Core Spray Design Methodology Confirmation Tests (August 1979)		1.5
NEDO-24951	BWR Owners' Group NUREG-0737 Implementation: Analyses and Positions Submitted to the NRC (June 1981)		1.13
NEDO-31897 NEDC-31897P-A	GE Nuclear Energy, "Generic Guidelines For GE Boiling Water Reactor Power Uprate," Class I (Non-proprietary), February 1992; and Class III (Proprietary), May 1992.		6.2, 15.0
NEDO-33484 NEDC-33484P	GE Hitachi Nuclear Energy, "Safety Analysis Report for Limerick Generating Station Units 1 and 2 Thermal Power Optimization," Class I (Non-proprietary), March 2010; and Class III (Proprietary), March 2010.		1.1, 1.2, 1.3, 1.4, 1.10, 3.6, 3.8, 3.9, 4.3, 4.4, 5.2, 5.3, 7.2, 7.7, 8.2, 9.1, 9.2, 10.1, 10.2, 10.4, 15.0, 15.2, 15.6
NEDC-31585P	BWROG Report for increasing MSIV 6.7, Leakage Rate Limits and Elimination of Leakage Control Systems		15.6
NEDM-10320	The GE Pressure Suppression Containment Analytical Model," March 1971		6.2

Table 1.6-1 (Cont'd)

Report Number		Referenced in UFSAR Section
NEDO-20533	The General Electric Mark III Pressure Suppression Containment System Analytical Model," June 1974.	6.2
NEDO-20566A	General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10CFR50 Appendix K - Volume II, January 1976	6.2
NUREG-0800	U.S. Nuclear Regulatory Commission Standard Review Plan, Section 6.2.1.1.C, "Pressure - Suppression Type BWT Containments," Revision 6, August 1984	6.2
NRC Letter	Letter from Ashok Thadani, Director Division of Systems Safety and Analysis, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, to Gary L. Sozzi, Manager Technical Services, General Electric Nuclear Energy, "Use of SHEX Computer Program and ANSI/ANS 5.1-1979 Decay Heat Source Term For Containment Long-Term Pressure and Temperature Analysis," July 13, 1993.	6.2
NEDO-21061	Mark II Containment Dynamic Forcing Functions Information Report, Rev. 4, November 1981	3.8, 6.2
NUREG-0487	U.S. Nuclear Regulatory Commission "Mark II Containment Lead Plant Program Load Evaluation and Acceptance Criteria," October 1978	6.2
NUREG-0808	U.S. Nuclear Regulatory Commission, "Mark II Containment Program Load Evaluation and Acceptance Criteria," August 1981	6.2

Table 1.6-1 (Cont'd)

Report Number			Referenced in UFSAR Section
		U.S. Nuclear Regulatory Commission, "Safety Evaluation Report Related to the Operation of Limerick Generating Station, Units 1 and 2," NUREG-0991, August 1983, and Supplements (Docket Nos. 50-352 and 50-353).	6.2
	NEDO-30832	Elimination of Limit On Local Suppression Pool Temperature For SRV Discharge With Quenchers, Class I, December 1984	6.2
		GE Nuclear Energy, "Generic Evaluations of General Boiling Water Reactor Power Uprate," Licensing Topical Report NEDC-31984P, Class III (Proprietary), July 1991; NEDO-31984, Class I (Non-proprietary), March 1992; and Supplements 1 & 2.	6.2
		D. Gobel, "Thermo-Hydraulic Quencher Design of the Safety Relief System," Revision 1, R14-25/1978, Kraftwerk Union, April 1978	6.2
	NEDC-32170P	Limerick Generating Station Units 1 and 2, SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis, Class III (Proprietary), Revision 1, June 1993	6.2
	NEDC-32225P	Power Rerate Safety Analysis Report for Limerick Generating Station Units 1 & 2 (September 1993)	6.2
B.	Other Reference Reports		
	AI-75-2	Thermal Hydrogen Recombiner System for Water-Cooled Reactors, Rockwell International (Rev.2(P), July 1975)	6.2

Table 1.6-1 (Cont'd)

Report Number			Referenced in UFSAR Section
	AI-77-55	Thermal Hydrogen Recombiner System for Mark I and II Boiling Water Reactors, Rockwell International (Sept 1977)	6.2
	BHR/DER 70-1	Radiological Surveillance Studies at a Boiling Water Nuclear Power Reactor (March 1970)	11.1
	OCF-1	Nuclear Containment Isolation System, Owens-Corning Fiberglass Corporation (Jan 1979)	6.2
	TID-4500	Relap 3 - A Computer Program for Reactor Blowdown Analysis IN-1321 (June 1970)	3.6
C.	Bechtel Power Corporation Reports		
	BC-TOP-1	Containment Building Liner Plant Design (Rev. 1 Dec 1972)	3.8
	BC-TOP-4-A	Seismic Analyses of Structures and Equipment for Nuclear Power Plants (Rev. 3, November 1974)	3.7
	BC-TOP-9A	Design of Structures for Missile Impact (Rev. 2, Sept 1974)	3.3, 3.5
	BN-TOP-2	Design for Pipe Rupture Effects (Rev. 2, May 1974)	3.6
	BN-TOP-4	Subcompartment Pressure Analysis (Nov 1972) Rev. 1 (July 1976)	3.6, 6A
D.	Exelon Reports		
	Limerick Environmental Qualification Report		1.13, 3.11, 7.1, 8.1
	Limerick Probabilistic Risk Assessment Limerick Severe Accident Risk Assessment		15.11
	Limerick Environment Report - Operating License Stage		5.2, 2.3.2

Table 1.6-1 (Cont'd)

Report Number			Referenced in UFSAR Section
E.	Siemens Reports		
	ER 9605	“Missile Probability Methodology for Limerick Generating Station, Units 1 and 2, with Siemens Retrofit Turbines” Siemens Power Corporation Engineering Report, Revision 2, June 18, 1997 - SIEMENS PROPIETARY	3.5, 10.2
	CT-27554	"Missile Analysis Report" Limerick Units 1 and 2 November 29, 2016 (Includes ER-9605, Rev. 2 as Appendix A)	3.5, 10.2

1.7 DRAWINGS AND OTHER DETAILED INFORMATION

Table 1.7-1 provides a listing of electrical drawings used in the plant design.

Table 1.7-2 provides a listing of P&ID drawings, with a reference to their former UFSAR figure number where applicable.

Table 1.7-3 provides a listing of control and instrumentation drawings used in the plant design.

Table 1.7-4 provides a listing of miscellaneous drawings, with a reference to their former UFSAR figure number where applicable.

Note: Refer to the corresponding Limerick design drawings and their associated open change documentation for up to date plant design information.

Table 1.7-1
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
E-1	Sh.1	Single Line Diagram - Station	8.1-1	Sh.1
E-2	Sh.1	Schematic Diagram - Phasing, 220KV, 22KV, 13.2KV, 23KV & 440V Systems Unit 1 and Comm	-	
E-3	Sh.1	Schematic Diagram - Phasing, 500KV, 22KV, 13.2KV, 440V Systems Unit 2	-	
E-4	Sh.1	Schematic Diagram - Phasing 4 kV & 440 V Safeguard Systems - Unit 1	-	
E-5	Sh.1	Schematic Diagram - Phasing 4 kV & 440 V Safeguard Systems - Unit 2	-	
E-6	Sh.1	Single Line Diagram - Synchronizing - Unit 1	-	
E-7	Sh.1	Single Line Diagram - Synchronizing - Unit 2	-	
E-8	Sh.1	Single Line Diagram - Site Services Substation	-	
		SINGLE LINE METER & RELAY DIAGRAMS	-	
E-10	Sh.1	Single Line Meter & Relay Diagram - 1 Generator, 1 Transformer & 11 Auxiliary Transformer - Unit 1	-	
E-11	Sh.1	Single Line Meter & Relay Diagram - 2 Generator, 2 Transformer &211 Auxiliary Transformer - Unit 2	-	
E-12	Sh.1	Single Line Meter & Relay Diagram - 13.2KV Unit Auxiliary Power System - Unit 1	-	
E-12	Sh.1	Single Line Meter & Relay Diagram - 13.2KV Unit Auxiliary Power System - Unit 1	-	
E-13	Sh.1	Single Line Meter & Relay Diagram - 13.2KV Unit Auxiliary Power System - Unit 2	-	
E-13	Sh.2	Single Line Meter & Relay Diagram - 13.2KV Unit Auxiliary Power System - Unit 2	-	
E-14	Sh.1	Single Line Meter & Relay Diagram	-	
E-14	Sh.2	Single Line Meter & Relay Diagram	-	
E-15	Sh.1	Single Line Meter & Relay Diagram - 4 kV Safeguard Power System - Unit 1	8.3-1	Sh.1
E-16	Sh.1	Single Line Meter & Relay Diagram - 4 kV Safeguard Power System - Unit 2	8.3-1	Sh.2
E-17	Sh.1	Single Line Meter & Relay Diagram - 114A & 124A Generator Area L.C. & 114B and 124B Reactor Area L.C., 440V-Unit 1	-	
E-18	Sh.1	Single Line Meter & Relay Diagram - 114C & 124C Turbine Area L.C., 440V - Unit 1	-	
E-19	Sh.1	Single Line Meter & Relay Diagram - 2.3 KV Plant Services Power System - Comm	-	
E-20	Sh.1	Single Line Meter & Relay Diagram - Diesel Generator - Units 1 & 2	-	
E-21	Sh.1	Single Line Meter & Relay Diagram - 214A & 224A Generator Area L.C. and 214B and 224B Reactor Area L.C. - 440V - Unit 2	-	
E-22	Sh.1	Single Line Meter & Relay Diagram - 214C & 224C Turbine Area L.C. - 440V - Unit 2	-	
E-23	Sh.1	Single Line Meter & Relay Diagram - Load Center Load tab, Non-Safeguard Load Center - Unit 1 only		
E-23	Sh.2	Single Line Meter & Relay Diagram - Load Center Load tab, Non-Safeguard Load Center - Unit 2 only	-	
E-23	Sh.3	Single Line Meter & Relay Diagram - Load Center Load tab, Non-Safeguard Load Center - Comm only	-	
E-24	Sh.1	Safeguard LC Load tab - Units 1 & 2	-	
E-25	Sh.1	Single Line Meter & Relay Diagram - 114D, 124D, 134D, 214D, 224D & 234D Plant Serv. & Admin. Complex L.C.-440-Comm	-	
E-25	Sh.2	Single Line Meter & Relay Diagram - 134D, 234D, 144D, 244D Admin. Building & Technical Supp. Center L.C.-440-Comm	-	
E-26	Sh.1	Single Line Diagram - 120 V ac Power Supply HVAC Safeguard Motor-Operated Valves & Dampers - Units 1 & 2 & Comm	-	
E-26	Sh.2	Single Line Diagram - 120 V ac Power Supply HVAC Safeguard Motor-Operated Valves & Dampers - Units 1 & 2 & Comm	-	

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
E-27	Sh.1	Single Line Meter & Relay Diagram MCC Load Tab - D214-R-G1 & D224-R-G1 - Reactor Area Safeguard MCC 440 V - Unit 2	-	
E-28	Sh.1	Single Line Meter & Relay Diagram - D114, D124, D134, D144 Safeguard Load Centers, 440 V - Unit 1	8.3-2	Sh.1
E-29	Sh.1	Single Line Meter & Relay Diagram - D214, D224, D234, D244 Safeguard Load Centers, 440 V - Unit 2	8.3-2	Sh.2
E-30	Sh.1	Single Line Diagram - Instrumentation ac System - Unit 1	-	
E-30	Sh.2	Single Line Diagram - Instrumentation ac System - Unit 1	-	
E-30	Sh.3	Single Line Diagram - Instrumentation ac System - Unit 1	-	
E-31	Sh.1	Single Line Diagram - Instrumentation ac System - Unit 2	-	
E-31	Sh.2	Single Line Diagram - Instrumentation ac System - Unit 2	-	
E-31	Sh.3	Single Line Diagram - Instrumentation ac System - Unit 2	-	
E-32	Sh.1	Single Line Meter & Relay Diagram - Uninterruptible ac System - RPS, UPS and Computer Systems - Units 1 & 2	7.2-16	Sh.1
E-32	Sh.2	Single Line Meter & Relay Diagram - Uninterruptible ac System - RPS, UPS and Computer Systems - Units 1 & 2	-	
E-33	Sh.1	Single Line Meter & Relay Diagram - 125/250 V dc System - Unit 1	8.3-3	Sh.1
E-33	Sh.2	Single Line Meter & Relay Diagram - 125/250 V dc System - Unit 1	8.3-3	Sh.2
E-33	Sh.3	Single Line Meter & Relay Diagram - 125/250 V dc System - Unit 1	8.3-3	Sh.3
E-34	Sh.1	Single Line Meter & Relay Diagram - 125/250 V dc System - Unit 2	8.3-3	Sh.4
E-34	Sh.2	Single Line Meter & Relay Diagram - 125/250 V dc System - Unit 2	8.3-3	Sh.5
E-34	Sh.3	Single Line Meter & Relay Diagram - 125/250 V dc System - Unit 2	8.3-3	Sh.6
E-35	Sh.1	Single Line Meter & Relay Diagram MCC Load Tab - D114-R-G1 & D124-R-G1 - Reactor Area Safeguard MCC 440 V - Unit 1	-	
E-36	Sh.1	Single Line Diagram - Totalizing Demand Metering - Units 1 & 2	-	
E-37	Sh.1	Single Line Meter & Relay Diagram MCC Load Tab - D114-S-L, D124-S-L, D234-S-L & D244-S-L- Spray Pond Area Safeguard MCC 440 V - Comm	-	
E-37	Sh.2	Single Line Meter & Relay Diagram MCC Load Tab - D114-S-L, D124-S-L, D234-S-L & D244-S-L - Spray Pond Area Safeguard MCC 440 V - Comm	-	
E-39	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - D114-G-D & D124-G-D, Generator Area, 440V, Unit 1	-	
E-40	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 114A-G-F & 124A-G-F, Generator Area MCC, 440V, Unit 1	-	
E-40	Sh.2	Single Line Meter & Relay Diagram - MCC Load tab - 114A-G-F & 124A-G-F, Generator Area MCC, 440V, Unit 1	-	
E-41	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 114A-G-D & 124A-G-D, Generator Area MCC, 440V, Unit 1	-	
E-41	Sh.2	Single Line Meter & Relay Diagram - MCC Load tab - 114A-G-D & 124A-G-D, Generator Area MCC, 440V, Unit 1	-	
E-42	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 114B-G-B & 124B-G-B, Generator Area MCC and 124B-R-C Reactor Area MCC, Unit 1	-	
E-42	Sh.2	Single Line Meter & Relay Diagram - MCC Load tab - 114B-G-B & 124B-G-B, Generator Area MCC and 124B-R-C Reactor Area MCC, Unit 2	-	

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
E-43	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 114C-T-F & 124C-T-F, Turbine Area MCC, 440V, Unit 1	-
E-43	Sh.2	Single Line Meter & Relay Diagram - MCC Load tab - 114C-T-F & 124C-T-F, Turbine Area MCC, 440V, Unit 2	-
E-44	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 114C-T-G & 124C-T-G, Turbine Area MCC, 440V, Unit 1	-
E-44	Sh.2	Single Line Meter & Relay Diagram - MCC Load tab - 114C-T-G & 124C-T-G, Turbine Area MCC, 440V, Unit 1	-
E-44A	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 104C-T-G, Turbine Area MCC, 440V, Unit 1	-
E-45	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 114C-R-A & 124C-R-A, Reactor Area MCC, 440V, Unit 1	-
E-46	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 114D-T-B & 214D-T-B, Turbine Area MCC & 114D-V-G & 214D-V-G Water Treatment Enclosure MCC Comm	-
E-47	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 134D-M-F, 234D-M-F & 234D-M-F2 Machine Shop Area MCC 440V - Comm	-
E-47	Sh.2	Single Line Meter & Relay Diagram - MCC Load tab - 134D-M-F, 234D-M-F Mach. Shop Area MCC 440V - Comm	-
E-47	Sh.3	Single Line Meter & Relay Diagram - MCC Load tab - 134D-M-F, 234D-M-F1 & 234D-M-F2 Machine Shop Area MCC 440V - Comm	-
			-
E-48	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 114D-P-G, 214D-P-G Pump House MCC 440V - Comm	-
E-48	Sh.2	Single Line Meter & Relay Diagram - MCC Load tab - 114D-P-G, 214D-P-G Pump House MCC 440V - Comm	-
E-49	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 114B-F-G, 214B-F-G Boiler House Area MCC 440V - Comm	-
E-50	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 114D-T-G, 214D-T-G Turb Area MCC & 124D-W-E &	-
	Sh.1	224D-W-E Radwaste Enclosure 440V - Comm	
E-51	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 124D-W-K, 224D-W-K Radwaste Area MCC 440V - Comm	-
E-52	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 124D-W-J, 224D-W-J Radwaste Enclosure	-
	Sh.1	MCC 440V - Comm	
E-53	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 124D-X-M Sewage Treatment Facility MCC, 124D-Y-N &	-
	Sh.1	224D-Y-N Schukill River Facility MCC 440V - Comm	
E-54	Sh.1	Single Line Meter & Relay Diagram MCC Load tab - D134-C-B & D144-C-B Control Enclosure Safeguard MCC - 440 V	-
	Sh.1	Comm	
E-55	Sh.1	Single Line Meter & Relay Diagram MCC Load tab - D114-R-G & D124-R-G - Reactor Area Safeguard MCC 440 V - Unit 1	-
E-55	Sh.2	Single Line Meter & Relay Diagram MCC Load tab - D114-R-G & D124-R-G - Reactor Area Safeguard MCC 440 V - Unit 1	-
E-56	Sh.1	Single Line Meter & Relay Diagram MCC Load tab - D114-D-G, D124-D-G, D134-D-G & D144-D-G - Diesel Generator Area	-
	Sh.1	Safeguard MCC 440 V - Unit 1	
E-56	Sh.2	Single Line Meter & Relay Diagram MCC Load tab - D114-D-G, D124-D-G, D134-D-G & D144-D-G -	-
		Diesel Generator Area Safeguard MCC 440 V - Unit 1	
E-57	Sh.1	Single Line Meter & Relay Diagram MCC Load Tab - D134-R-H & D144-R-H - Reactor Area Safeguard MCC 440 V - Unit 1	-
E-57	Sh.2	Single Line Meter & Relay Diagram MCC Load Tab - D134-R-H & D144-R-H - Reactor Area Safeguard MCC 440 V - Unit 1	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
E-58	Sh.1	Single Line Meter & Relay Diagram MCC Load Tab - D114-R-C, D124-R-C, D134-R-E & D144-R-E - Reactor Area Safeguard MCC 440 V - Unit 1	-
E-58	Sh.2	Single Line Meter & Relay Diagram MCC Load Tab - D114-R-C, D124-R-C, D134-R-E & D144-R-E - Reactor Area Safeguard MCC 440 V - Unit 1	-
E-58	Sh.3	Single Line Meter & Relay Diagram MCC Load Tab - D114-R-C, D124-R-C, D134-R-E & D144-R-E - Reactor Area Safeguard MCC 440 V - Unit 1	-
E-58	Sh.4	Single Line Meter & Relay Diagram MCC Load tab - D114-R-C, D124-R-C, D134-R-E & D144-R-E - Reactor Area Safeguard MCC 440 V - Unit 1	-
E-59	Sh.1	Single Line Meter & Relay Diagram MCC Load tab - D214-D-G, D224-D-G, D234-D-G & D244-D-G - Diesel Generator Area Safeguard MCC 440 V - Unit 2	-
E-59	Sh.2	Single Line Meter & Relay Diagram MCC Load tab - D214-D-G, D224-D-G, D234-D-G & D244-D-G - Diesel Generator Area Safeguard MCC 440 V - Unit 2	-
E-60	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 214A-G-F & 224A-G-F Generator Area MCC 440V - Unit 2	-
E-60	Sh.2	Single Line Meter & Relay Diagram - MCC Load tab - 214A-G-F & 224A-G-F Generator Area MCC 440V - Unit 2	-
E-61	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 214A-G-D & 224A-G-D Generator Area MCC 440V - Unit 2	-
E-61	Sh.2	Single Line Meter & Relay Diagram - MCC Load tab - 214A-G-D & 224A-G-D Generator Area MCC 440V - Unit 2	-
E-62	Sh.1	Single Line Meter & Relay Diagram - MCC Load tab - 214B-G-B & 224B-G-B Generator Area MCC & 214B-R-C and 224B-R-C Reactor Area MCC -440V - Unit 2	-
E-62	Sh.2	Single Line Meter & Relay Diagram - MCC Load tab - 214B-G-B & 224B-G-B Generator Area MCC & 214B-R-C and 224B-R-C Reactor Area MCC -440V - Unit 2	-
E-63	Sh.1	Single Line Meter & Relay Diagram - MCC Load Tab - 214C-T-F & 224C-T-F Turbine Area MCC - 440V - Unit 2	-
E-63	Sh.2	Single Line Meter & Relay Diagram - MCC Load Tab - 214C-T-F & 224C-T-F Turbine Area MCC - 440V - Unit 2	-
E-64	Sh.1	Single Line Meter & Relay Diagram - MCC Load Tab - 214C-T-G & 224C-T-G Turbine Area MCC - 440V - Unit 2	-
E-64	Sh.2	Single Line Meter & Relay Diagram - MCC Load Tab - 214C-T-G & 224C-T-G Turbine Area MCC - 440V - Unit 2	-
E-64A	Sh.1	Single Line Meter & Relay Diagram - MCC Load Tab - 204C-T-G Turbine Area MCC - 440V - Unit 2	-
E-65	Sh.1	Single Line Meter & Relay Diagram - MCC Load Tab - 214C-R-A & 224C-R-A Reactor Area MCC - 440V - Unit 2	-
E-66	Sh.1	Single Line Meter & Relay Diagram - MCC Load Tab - D214-G-D & D224-G-D Generator Area MCC - 440V - Unit 2	-
E-67	Sh.1	Single Line Meter & Relay Diagram MCC Load Tab - D214-R-G & D224-R-G - Reactor Area Safeguard MCC 440 V - Unit 2	-
E-67	Sh.2	Single Line Meter & Relay Diagram MCC Load Tab - D214-R-G & D224-R-G - Reactor Area Safeguard MCC 440 V - Unit 2	-
E-68	Sh.1	Single Line Meter & Relay Diagram MCC Load Tab - D214-R-A, D224-R-A, D234-R-E & D244-R-E - Reactor Area Safeguard MCC 440 V - Unit 2	-
E-68	Sh.2	Single Line Meter & Relay Diagram MCC Load Tab - D214-R-A, D224-R-A, D234-R-E & D244-R-E - Reactor Area Safeguard MCC 440 V - Unit 2	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
E-69	Sh.1	Single Line Meter & Relay Diagram MCC Load Tab - D234-R-H & D244-R-H - Reactor Area Safeguard MCC 440 V - Unit 2	-
E-69	Sh.2	Single Line Meter & Relay Diagram MCC Load Tab - D234-R-H & D244-R-H - Reactor Area Safeguard MCC 440 V - Unit 2	-
E-70	Sh.1	Schematic Meter & Relay Diagram - 1 Generator, 11 Unit Auxiliary Transformer - Unit 1	-
E-70	Sh.2	Schematic Meter & Relay Diagram - 1 Generator, 11 Unit Auxiliary Transformer - Unit 1	-
E-72	Sh.1	Schematic Meter & Relay Diagram - 2 Generator, 21 Unit Auxiliary Transformer - Unit 2	-
E-72	Sh.2	Schematic Meter & Relay Diagram - 2 Generator, 21 Unit Auxiliary Transformer - Unit 2	-
E-74	Sh.1	Schematic Meter & Relay Diagram - 13.2KV Unit Auxiliary Power System - Unit 1	-
E-75	Sh.1	Schematic Meter & Relay Diagram - 13.2KV Unit Auxiliary Power System - Unit 2	-
E-76	Sh.1	Schematic Meter & Relay Diagram - 13.2KV Station Auxiliary Power System - Unit 1	-
E-77	Sh.1	Schematic Meter & Relay Diagram - 13.2KV Station Auxiliary Power System - Unit 2	-
E-78	Sh.1	Schematic Meter & Relay Diagram - 1 Transformer - Unit 1	-
E-79	Sh.1	Schematic Meter & Relay Diagram - 2 Transformer - Unit 2	-
E-80	Sh.1	Schematic Meter & Relay Diagram - D11 & D12 Safeguard Buses, 4 kV - Unit 1	-
E-81	Sh.1	Schematic Meter & Relay Diagram - D13 & D14 Safeguard Buses, 4 kV - Unit 1	-
E-82	Sh.1	Schematic Meter & Relay Diagram - D21 & D22 Safeguard Buses, 4 kV - Unit 2	-
E-83	Sh.1	Schematic Meter & Relay Diagram - D23 & D24 Safeguard Buses, 4 kV - Unit 2	-
E-84	Sh.1	Schematic Meter & Relay Diagram - 114A, 114B, 114C, 114D, 124A, 124B, 124C, 124D, 214D, 224D, 134D, 234D	-
E-85	Sh.1	Schematic Meter & Relay Diagram - Diesel Generators, 4 kV - Units 1 & 2	-
E-85	Sh.2	Schematic Meter & Relay Diagram - Diesel Generators, 4 kV - Units 1 & 2	-
E-87	Sh.1	Schematic Meter & Relay Diagram - 214A, 214B, 214C, 224A, 224B & 224C Load Centers 440 V - Unit 2	-
E-88	Sh.1	Schematic Meter & Relay Diagram - D114, D214, D314, D414 Safeguard Load Centers 440 V - Unit 1	-
E-89	Sh.1	Schematic Meter & Relay Diagram - D124, D224, D324, D424 Safeguard Load Centers 440 V - Unit 2	-
E-92	Sh.1	Schematic Meter & Relay Diagram - 125/250 V dc System - Units 1 & 2	-
E-92	Sh.2	Schematic Meter & Relay Diagram - 125/250 V dc System - Units 1 & 2	-
E-92	Sh.3	Schematic Meter & Relay Diagram - 125/250 V dc System - Units 1 & 2	-
E-92	Sh.4	Schematic Meter & Relay Diagram - 125V/250V DC System Units 1 & 2	-
E-97	Sh.1	Schematic Meter & Relay Diagram - 2.3 KV Plant Services Power System - Comm	-
		SCHEMATIC BLOCK DIAGRAM - REACTOR SYSTEM	
E-100	Sh.1	Schematic Block Diagram - Steam Leak Detection System - Units 1 & 2	-
E-101	Sh.1	Schematic Block Diagram - Nuclear Steam Supply Shutoff System - Units 1 & 2	-
E-101	Sh.2	Schematic Block Diagram - Nuclear Steam Supply Shutoff System - Units 1 & 2	-
E-101	Sh.3	Schematic Block Diagram - Nuclear Steam Supply Shutoff System - Units 1 & 2	-
E-102	Sh.1	Schematic Block Diagram - RHR System - Units 1 & 2	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
E-102	Sh.2	Schematic Block Diagram - RHR System - Units 1 & 2	-
E-102	Sh.3	Schematic Block Diagram - RHR System - Units 1 & 2	-
E-103	Sh.1	Schematic Block Diagram - Core Spray System - Units 1 & 2	-
E-104	Sh.1	Schematic Block Diagram - HPCI System - Units 1 & 2	-
E-104	Sh.2	Schematic Block Diagram - HPCI System - Units 1 & 2	-
E-105	Sh.1	Schematic Block Diagram - RCIC System - Units 1 & 2	-
E-105	Sh.2	Schematic Block Diagram - RCIC System - Units 1 & 2	-
E-106	Sh.1	Schematic Block Diagram - Process Radiation Monitor System - Units 1 & 2 & Comm	-
E-107	Sh.1	Schematic Block Diagram - Reactor Water Cleanup System - Units 1 & 2	-
E-109	Sh.1	Schematic Block Diagram - Nuclear Boiler Process Instrumentation System - Units 1 & 2	-
E-110	Sh.1	Schematic Block Diagram - Auto-depressurization and Standby Liquid Control Systems - Units 1 & 2	-
E-113	Sh.1	Schematic Block Diagram - MSIV Leakage Control System - Units 1 & 2	-
E-120	Sh.1	Schematic Block Diagram - Power Range Neutron Monitoring System - Units 1 & 2	-
E-120	Sh.2	Schematic Block Diagram - Power Range Neutron Monitoring System - Units 1 & 2	-
E-126	Sh.1	Schematic Block Diagram - Startup Range Neutron Monitoring System - Units 1 & 2	-
E-129	Sh.1	Schematic Block Diagram - Reactor Protection System - Units 1 & 2	-
E-129	Sh.2	Schematic Block Diagram - Reactor Protection System - Units 1 & 2	-
E-129	Sh.3	Schematic Block Diagram - Reactor Protection System - Units 1 & 2	-
		SCHEMATIC DIAGRAMS - AUXILIARY ELECTRICAL SYSTEM	-
E-156	Sh.1	Schematic Diagram - 10 & 20 Auxiliary Buses - 101 & 201 Safeguard Transformer Breakers, 13.2 kV - Units 1 & 2	-
E-159	Sh.1	Schematic Diagram - Load Center Swgr-MCC Feeder Breakers 440 V - 1 and 2 Units	-
E-159	Sh.2	Schematic Diagram - Load Center Swgr-MCC Feeder Breakers 440 V - 1 and 2 Units	-
E-159	Sh.3	Schematic Diagram - Load Center Swgr-MCC Feeder Breakers 440 V - 1 and 2 Units	-
E-160	Sh.1	Schematic Diagram - Safeguard Buses - 101 & 201 Safeguard Bus Feeder Breakers 4 kV - Units 1 & 2	-
E-160	Sh.2	Schematic Diagram - Safeguard Buses - 101 & 201 Safeguard Bus Feeder Breakers 4 kV - Units 1 & 2	-
E-160	Sh.3	Schematic Diagram - Safeguard Buses - 101 & 201 Safeguard Bus Feeder Breakers 4 kV - Units 1 & 2	-
E-160	Sh.4	Schematic Diagram - Safeguard Buses - 101 & 201 Safeguard Bus Feeder Breakers 4 kV - Units 1 & 2	-
E-162	Sh.1	Schematic Diagram - Safeguard Buses - D144 & D244 Safeguard Load Control Transformer Breakers, 4 kV - Units 1 & 2	-
E-163	Sh.1	Schematic Diagram - Safeguard Buses - D114, D124, D134, D214, D224 & D234 Safeguard Load Control Transformer Bkrs, 4kV Units 1 & 2	-
E-164	Sh.1	Schematic Diagram - Safeguard Buses - D11, D12, D13, D14, D21, D22, D23 & D24 Generator Bkrs 4 kV - Units 1 & 2	-
E-164	Sh.2	Schematic Diagram - Safeguard Buses - D11, D12, D13, D14, D21, D22, D23 & D24 Generator Bkrs 4 kV - Units 1 & 2	-
E-164	Sh.3	Schematic Diagram - Safeguard Buses - D11, D12, D13, D14, D21, D22, D23 & D24 Generator Bkrs 4 kV - Units 1 & 2	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
E-164	Sh.4	Schematic Diagram - Safeguard Buses - D11, D12, D13, D14, D21, D22, D23 & D24 Generator Bkrs 4 kV - Units 1 & 2	-
E-168	Sh.1	Schematic Diagram - Safeguard Buses - D11, D12, D13, D14, D21, D22, D23, D24 Protective Relaying 4 kV - Units 1 & 2	-
E-169	Sh.1	Schematic Diagram - Diesel Generator Protective Relaying - 4 kV - Units 1 & 2	-
E-171	Sh.1	Schematic Diagram - 101 & 201 Safeguard Transformer Protective Relaying - Units 1 & 2	-
E-185	Sh.1	Schematic Diagram - MCC Breaker Shunt Trip Coil Circuits & Auxiliary Control - Units 1 & 2 & Comm	-
E-185	Sh.2	Schematic Diagram - MCC Breaker Shunt Trip Coil Circuits & Auxiliary Control - Units 1 & 2 & Comm	-
E-277	Sh.1	Schematic Diagram - Main Steam to RFPT & Radwaste Recombiner Free Heater to Hotwell Steam Spargers & to Steam Seal Evaporators Shutoff MOVs - Units 1 & 2	-
E-321	Sh.1	Schematic Diagram - Emergency Service Water Pumps - Comm	-
E-321	Sh.2	Schematic Diagram - Emergency Service Water Pumps - Comm	-
E-321	Sh.3	Schematic Diagram - Emergency Service Water Pumps - Comm	-
E-321	Sh.4	Schematic Diagram - Emergency Service Water Pumps - Comm	-
E-321	Sh.5	Schematic Diagram - Emergency Service Water Pumps - Comm	-
E-321	Sh.6	Schematic Diagram - Emergency Service Water Pumps - Comm	-
E-322	Sh.1	Schematic Diagram - Diesel Generator ESW Inlet and Outlet MOVs - Units 1 & 2	-
E-322	Sh.2	Schematic Diagram - Diesel Generator ESW Inlet and Outlet MOVs - Units 1 & 2	-
E-323	Sh.1	Schematic Diagram - Turbine Enclosure Cooling Water Heat Exchanger ESW MOVs - Units 1 & 2	-
E-324	Sh.1	Schematic Diagram - ESW Discharge to RHRSW MOVs - Comm	-
E-324	Sh.2	Schematic Diagram - ESW Discharge to RHRSW MOVs - Comm	-
E-324	Sh.3	Schematic Diagram - ESW Discharge to RHRSW MOVs - Comm	-
E-325	Sh.1	Schematic Diagram - Cooling Water Shutoff Valves to Service Water & ESW - Units 1 & 2	-
E-325	Sh.2	Schematic Diagram - Cooling Water Shutoff Valves to Service Water & ESW - Units 1 & 2	-
E-325	Sh.3	Schematic Diagram - Cooling Water Shutoff Valves to Service Water & ESW - Units 1 & 2	-
E-325	Sh.4	Schematic Diagram - Cooling Water Shutoff Valves to Service Water & ESW - Units 1 & 2	-
E-326	Sh.1	Schematic Diagram - ESW Shutoff Valves to Reactor Enclosure Cooling Water Heat Exchangers - Units 1 & 2	-
E-327	Sh.1	Schematic Diagram - Control Room Chiller Cooling Water Shutoff Valves & ESW Valves Auxiliary Ckt - Comm	-
E-327	Sh.2	Schematic Diagram - Control Room Chiller Cooling Water Shutoff Valves & ESW Valves Auxiliary Ckt - Comm	-
E-327	Sh.3	Schematic Diagram - Control Room Chiller Cooling Water Shutoff Valves & ESW Valves Auxiliary Ckt - Comm	-
E-328	Sh.1	Schematic Diagram - Reactor Enclosure Cooling Water Heat Exchangers Shutoff Valves to ESW - Units 1 & 2	-
E-343	Sh.1	Schematic Diagram - Containment Isolation Signal Bypass Permissive - Units 1 & 2	-
E-343	Sh.2	Schematic Diagram - Containment Isolation Signal Bypass Permissive - Units 1 & 2	-
E-350	Sh.1	Schematic Diagram - Core Spray Pumps - Units 1 & 2	-
E-350	Sh.2	Schematic Diagram - Core Spray Pumps - Units 1 & 2	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
E-351	Sh.1	Schematic Diagram - Suppression Pool Water Filter Pump Isolation MOVs - Units 1 & 2	-
E-352	Sh.1	Schematic Diagram - Control Rod Drive Water Pumps 1 & 2 Units	-
E-352	Sh.2	Schematic Diagram - Control Rod Drive Water Pumps 1 & 2 Units	-
E-353	Sh.1	Schematic Diagram - RHR Vacuum Breaker to Suppression Pool Isolation MOVs - Units 1 & 2	-
E-354	Sh.1	Schematic Diagram - Drywell & Suppression Pool Instrument Line Shutoff Valve - Units 1 & 2	-
E-354	Sh.2	Schematic Diagram - Drywell & Suppression Pool Instrument Line Shutoff Valves - Units 1 & 2	-
E-354	Sh.3	Schematic Diagram - Drywell & Suppression Pool Instrument Line Shutoff Valves - Units 1 & 2	-
E-354	Sh.4	Schematic Diagram - Drywell & Suppression Pool Instrument Line Shutoff Valves - Units 1 & 2	-
E-355	Sh.1	Schematic Diagram - BOP Main Steam Line Leak Detection - Units 1 & 2	-
E-357	Sh.1	Schematic Diagram - Instrument Gas Compressor Suction Line Inboard Isolation MOV - Units 1 & 2	-
E-358	Sh.1	Schematic Diagram - Reactor FW Startup Flushing & ECCS Pumps Suct from Cond Storage Tank MOVs - Units 1 & 2	-
E-358	Sh.2	Schematic Diagram - Reactor FW Startup Flushing & ECCS Pumps Suct from Cond Storage Tank MOVs - Units 1 & 2	-
E-359	Sh.1	Schematic Diagram - Spray Pond Makeup Line MOV - Comm	-
E-360	Sh.1	Schematic Diagram - RHR Pumps - Units 1 & 2	-
E-360	Sh.2	Schematic Diagram - RHR Pumps - Units 1 & 2	-
E-360	Sh.3	Schematic Diagram - RHR Pumps - Units 1 & 2	-
E-361	Sh.1	Schematic Diagram - RHR Service Water Pumps - Comm	-
E-361	Sh.2	Schematic Diagram - RHR Service Water Pumps - Comm	-
E-361	Sh.3	Schematic Diagram - RHR Service Water Pumps - Comm	-
E-362	Sh.1	Schematic Diagram - Spray Pond Header Cross-tie & Cooling Water Return Cross-tie MOVs - Comm	-
E-362	Sh.2	Schematic Diagram - Spray Pond Header Cross-tie & Cooling Water Return Cross-tie MOVs - Comm	-
E-363	Sh.1	Schematic Diagram - TBCW Htx Cooling Water Return to RHR Service Water MOVs - 1 & 2 Units	-
E-364	Sh.1	Schematic Diagram - RHR Drain to Radwaste Inboard Isolation Valve - Units 1 & 2	-
E-365	Sh.1	Schematic Diagram - Primary Containment Instrumentation Gas Outboard Isolation Valves - Units 1 & 2	-
E-366	Sh.1	Schematic Diagram - RHR Full Flow Test Line Shutoff & Min Flow Bypass MOVs	-
E-366	Sh.2	Schematic Diagram - RHR Full Flow Test Line Shutoff & Min Flow Bypass MOVs	-
E-371	Sh.1	Schematic Diagram - RHR Heat Exchanger Tube Side Inlet MOVs - Units 1 & 2	-
E-371	Sh.2	Schematic Diagram - RHR Heat Exchanger Tube Side Inlet MOVs - Units 1 & 2	-
E-372	Sh.1	Schematic Diagram - RHR Heat Exchanger Tube Side Outlet MOVs - Units 1 & 2	-
E-372	Sh.2	Schematic Diagram - RHR Heat Exchanger Tube Side Outlet MOVs - Units 1 & 2	-
E-373	Sh.1	Schematic Diagram - RHR SW/ESW to Cooling Tower Shutoff MOVs - Units 1 & 2	-
E-373	Sh.2	Schematic Diagram - RHR SW/ESW to Cooling Tower Shutoff MOVs - Units 1 & 2	-
E-374	Sh.1	Schematic Diagram - Cooling Tower Return to Spray Pond Shutoff MOVs - Units 1 & 2	-
E-374	Sh.2	Schematic Diagram - Cooling Tower Return to Spray Pond Shutoff MOVs - Units 1 & 2	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
E-375	Sh.1	Schematic Diagram - Spray Pond Spray Nozzle Inlet MOVs - Comm	-
E-375	Sh.2	Schematic Diagram - Spray Pond Spray Nozzle Inlet MOVs - Comm	-
E-375	Sh.3	Schematic Diagram - Spray Pond Spray Nozzle Inlet MOVs - Comm	-
E-376	Sh.1	Schematic Diagram - Spray Pond Spray Nozzle Bypass MOVs - Comm	-
E-376	Sh.2	Schematic Diagram - Spray Pond Spray Nozzle Bypass MOVs - Comm	-
E-377	Sh.1	Schematic Diagram - Spray Pond Wetwell Inlet Motor-Operated Gates - Comm	-
E-377	Sh.2	Schematic Diagram - Spray Pond Wetwell Inlet Motor-Operated Gates - Comm	-
E-378	Sh.1	Schematic Diagram - Spray Pond Wetwell Cross-tie Motor-Operated Gate - Comm	-
E-380	Sh.1	Schematic Diagram - HPCI Steam to RHR Heat Exchanger Shutoff Valves Bypass MOVs - Units 1 & 2	-
E-380	Sh.2	Schematic Diagram - HPCI Steam to RHR Heat Exchanger Shutoff Valves Bypass MOVs - Units 1 & 2	-
E-382	Sh.1	Schematic Diagram - Drywell and Suppression Pool Purge Line Outboard Isolation Valves - Units 1 & 2	-
E-382	Sh.2	Schematic Diagram - Drywell and Suppression Pool Purge Line Outboard Isolation Valves - Units 1 & 2	-
E-383	Sh.1	Schematic Diagram - Drywell Nitrogen Makeup Line Isolation Valve - Units 1 & 2	-
E-384	Sh.1	Schematic Diagram - Drywell Nitrogen Purge Line Control Valve and Isolation Valves - Units 1 & 2	-
E-384	Sh.2	Schematic Diagram - Drywell Nitrogen Purge Line Control Valve and Isolation Valves - Units 1 & 2	-
E-385	Sh.1	Schematic Diagram - Containment Atmosphere Sampling System Isolation Valves - Units 1 & 2	-
E-385	Sh.2	Schematic Diagram - Containment Atmosphere Sampling System Isolation Valves - Units 1 & 2	-
E-385	Sh.3	Schematic Diagram - Containment Atmosphere Sampling System Isolation Valves - Units 1 & 2	-
E-386	Sh.1	Schematic Diagram - Hydrogen-Oxygen Analyzer Package Pumps & Sample Select Valves - Units 1 & 2	-
E-386	Sh.2	Schematic Diagram - Hydrogen-Oxygen Analyzer Package Pumps & Sample Select Valves - Units 1 & 2	-
E-388	Sh.1	Schematic Diagram - Drywell & Supp Pool Lines to Containment Hydrogen Recombiner Outboard Isolation Valves - Units 1 & 2	-
E-406	Sh.1	Schematic Diagram - Drywell Floor Drain Sump & Drywell Equipment Drain Sump Drain Isolation Valves - Units 1 & 2	-
		SCHEMATIC DIAGRAMS - HEATING & VENTILATION SYSTEM	
E-453	Sh.1	Schematic Diagram - Turbine Enclosure Equipment Compartment Exhaust Fans - Units 1 & 2	-
E-453	Sh.2	Schematic Diagram - Turbine Enclosure Equipment Compartment Exhaust Fans - Units 1 & 2	-
E-462	Sh.1	Schematic Diagram - Control Room Chilled Water Circulation Pump - Comm	-
E-463	Sh.1	Schematic Diagram - Control Room Chillers, Oil Pumps & Pumpout Compressor - Comm	-
E-463	Sh.2	Schematic Diagram - Control Room Chillers, Oil Pumps & Pumpout Compressor - Comm	-
E-463	Sh.3	Schematic Diagram - Control Room Chillers, Oil Pumps & Pumpout Compressor - Comm	-
E-463	Sh.4	Schematic Diagram - Control Room Chillers, Oil Pumps & Pumpout Compressor - Comm	-
E-464	Sh.1	Schematic Diagram - Drywell Chillers, Oil Pumps & Pumpout Compressors - Units 1 & 2	-
E-464	Sh.2	Schematic Diagram - Drywell Chillers, Oil Pumps & Pumpout Compressors - Units 1 & 2	-
E-464	Sh.3	Schematic Diagram - Drywell Chillers, Oil Pumps & Pumpout Compressors - Units 1 & 2	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
E-465	Sh.1	Schematic Diagram - Drywell Chilled Cooling Water Supply & Return MOVs - Units 1 & 2	-
E-465	Sh.2	Schematic Diagram - Drywell Chilled Cooling Water Supply & Return MOVs - Units 1 & 2	-
E-466	Sh.1	Schematic Diagram - Drywell Cooling Water Supply & Return Isolation MOVs - Units 1 & 2	-
E-466	Sh.2	Schematic Diagram - Drywell Cooling Water Supply & Return Isolation MOVs - Units 1 & 2	-
E-470	Sh.1	Schematic Diagram - Reactor Enclosure Air Recirculation Fan & Auxiliary Control - Units 1 & 2	-
E-470	Sh.2	Schematic Diagram - Reactor Enclosure Air Recirculation Fan & Auxiliary Control - Units 1 & 2	-
E-470	Sh.3	Schematic Diagram - Reactor Enclosure Air Recirculation Fan & Auxiliary Control - Units 1 & 2	-
E-470	Sh.4	Schematic Diagram - Reactor Enclosure Air Recirculation Fan & Auxiliary Control - Units 1 & 2	-
E-471	Sh.1	Schematic Diagram - RCIC, HPCI, RHR and Core Spray Room Unit Coolers - Units 1 & 2	-
E-474	Sh.1	Schematic Diagram - Reactor Enclosure & Refueling Floor Isolation System - Units 1 & 2	-
E-474	Sh.2	Schematic Diagram - Reactor Enclosure & Refueling Floor Isolation System - Units 1 & 2	-
E-476	Sh.1	Schematic Diagram - Drywell Area Unit Coolers - Units 1 & 2	-
E-476	Sh.2	Schematic Diagram - Drywell Area Unit Coolers - Units 1 & 2	-
E-482	Sh.1	Schematic Diagram - Standby Gas Treatment System Charcoal Filter Valves - Comm	-
E-482	Sh.2	Schematic Diagram - Standby Gas Treatment System Charcoal Filter Valves - Comm	-
E-482	Sh.3	Schematic Diagram - Standby Gas Treatment System Charcoal Filter Valves - Comm	-
E-483	Sh.1	Schematic Diagram - Standby Gas Treatment System Exhaust Fans - Comm	-
E-483	Sh.2	Schematic Diagram - Standby Gas Treatment System Exhaust Fans - Comm	-
E-484	Sh.1	Schematic Diagram - Heater - Comm	-
E-485	Sh.1	Schematic Diagram - Standby Gas Treatment System Room Unit Coolers - Comm	-
E-485	Sh.2	Schematic Diagram - Standby Gas Treatment System Room Unit Coolers - Comm	-
E-486	Sh.1	Schematic Diagram - Drywell Purge Exhaust Fans Isolation Valves - Comm	-
E-488	Sh.1	Schematic Diagram - Auxiliary Equipment Room Supply Air Fans, Humidifiers & Cooling Coil Valves - Comm	-
E-488	Sh.2	Schematic Diagram - Auxiliary Equipment Room Supply Air Fans, Humidifiers & Cooling Coil Valves - Comm	-
E-488	Sh.3	Schematic Diagram - Auxiliary Equipment Room Supply Air Fans, Humidifiers & Cooling Coil Valves - Comm	-
E-488	Sh.4	Schematic Diagram - Auxiliary Equipment Room Supply Air Fans, Humidifiers & Cooling Coil Valves - Comm	-
E-489	Sh.1	Schematic Diagram - Control Room & Auxiliary Equipment Room Return Air Fans & Dampers - Units 1 & 2	-
E-489	Sh.2	Schematic Diagram - Control Room & Auxiliary Equipment Room Return Air Fans & Dampers - Units 1 & 2	-
E-489	Sh.3	Schematic Diagram - Control Room & Auxiliary Equipment Room Return Air Fans & Dampers - Units 1 & 2	-
E-490	Sh.1	Schematic Diagram - Diesel Generator Ventilation Air Exhaust Fans & Air Control - Units 1 & 2	-
E-490	Sh.2	Schematic Diagram - Diesel Generator Ventilation Air Exhaust Fans & Air Control - Units 1 & 2	-
E-491	Sh.1	Schematic Diagram - Spray Pond Pump Structure Fan Heater and Auxiliary Control - Comm	-
E-491	Sh.2	Schematic Diagram - Spray Pond Pump Structure Fan Heater and Auxiliary Control - Comm	-
E-491	Sh.3	Schematic Diagram - Spray Pond Pump Structure Fan Heater and Auxiliary Control - Comm	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
E-495	Sh.1	Schematic Diagram - Control Room Emergency Fresh Air Supply Fans and Intake Heaters - Comm	-
E-495	Sh.2	Schematic Diagram - Control Room Emergency Fresh Air Supply Fans and Intake Heaters - Comm	-
E-495	Sh.3	Schematic Diagram - Control Room Emergency Fresh Air Supply Fans and Intake Heaters - Comm	-
E-496	Sh.1	Schematic Diagram - Control Room Isolation System & Valves - Comm	-
E-496	Sh.2	Schematic Diagram - Control Room Isolation System & Valves - Comm	-
E-496	Sh.3	Schematic Diagram - Control Room Isolation System & Valves - Comm	-
E-498	Sh.1	Schematic Diagram - Control Enclosure Purge System - Comm	-
E-508	Sh.1	Schematic Diagram - Reactor Enclosure Steam Flooding Dampers - Units 1 & 2	-
E-508	Sh.2	Schematic Diagram - Reactor Enclosure Steam Flooding Dampers - Units 1 & 2	-
E-508	Sh.3	Schematic Diagram - Reactor Enclosure Steam Flooding Dampers - Units 1 & 2	-
E-509	Sh.1	Schematic Diagram - Control Structure Steam Flooding Dampers - Units 1 & 2	-
E-509	Sh.2	Schematic Diagram - Control Structure Steam Flooding Dampers - Units 1 & 2	-
E-509	Sh.3	Schematic Diagram - Control Structure Steam Flooding Dampers - Units 1 & 2	-
E-509	Sh.4	Schematic Diagram - Control Structure Steam Flooding Dampers - Units 1 & 2	-
E-509	Sh.5	Schematic Diagram - Control Structure Steam Flooding Dampers - 1 7 2 Units	-
E-521	Sh.1	Schematic Diagram - Control Enclosure Emergency Swgr & Battery Rooms Supply Air Fans & Dampers - Comm	-
E-521	Sh.2	Schematic Diagram - Control Enclosure Emergency Swgr & Battery Rooms Supply Air Fans & Dampers - Comm	-
E-522	Sh.1	Schematic Diagram - Control Enclosure - Battery Room Exhaust & Recirculation Dampers - Comm	-
		SCHEMATIC DIAGRAMS MISCELLANEOUS SYSTEMS	
E-560	Sh.1	Schematic Diagram - Diesel Generator Diesel Oil Transfer Pumps - Units 1 & 2	-
E-565	Sh.1	Schematic Diagram - Turbine Enclosure & Reactor Enclosure Cooling Water Pumps - Units 1 & 2	-
E-585	Sh.1	Schematic Diagram - Containment Hydrogen Recombiner System	-
E-585	Sh.2	Schematic Diagram - Containment Hydrogen Recombiner System	-
E-585	Sh.3	Schematic Diagram - Containment Hydrogen Recombiner System	-
E-591	Sh.1	Schematic Diagram - Diesel Generator Control & Auxiliaries - Units 1 & 2	-
E-591	Sh.2	Schematic Diagram - Diesel Generator Control & Auxiliaries - Units 1 & 2	-
E-591	Sh.3	Schematic Diagram - Diesel Generator Control & Auxiliaries - Units 1 & 2	-
E-591	Sh.4	Schematic Diagram - Diesel Generator Control & Auxiliaries - Units 1 & 2	-
E-591	Sh.5	Schematic Diagram - Diesel Generator Control & Auxiliaries - Units 1 & 2	-
E-591	Sh.6	Schematic Diagram - Diesel Generator Control & Auxiliaries - Units 1 & 2	-
E-591	Sh.7	Schematic Diagram - Diesel Generator Control & Auxiliaries - Units 1 & 2	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
E-648	Sh.1	Schematic Diagram - Safety System Bypass/Inop Status Indication Circuits - Units 1 & 2	-
E-648	Sh.2	Schematic Diagram - Safety System Bypass/Inop Status Indication Circuits - Units 1 & 2	-
E-648	Sh.3	Schematic Diagram - Safety System Bypass/Inop Status Indication Circuits - Units 1 & 2	-
E-649	Sh.1	Schematic Diagram - Safety System Annunciator Auxiliary Relay Circuits - Units 1 & 2	-
E-649	Sh.2	Schematic Diagram - Safety System Annunciator Auxiliary Relay Circuits - Units 1 & 2	-
E-649	Sh.3	Schematic Diagram - Safety System Annunciator Auxiliary Relay Circuits - Units 1 & 2	-
E-649	Sh.4	Schematic Diagram - Safety System Annunciator Auxiliary Relay Circuits - Units 1 & 2	-
E-649	Sh.5	Schematic Diagram - Safety System Annunciator Auxiliary Relay Circuits - Units 1 & 2	-
E-649	Sh.6	Schematic Diagram - Safety System Annunciator Auxiliary Relay Circuits - Units 1 & 2	-
E-649	Sh.7	Schematic Diagram - Safety System Annunciator Auxiliary Relay Circuits - Units 1 & 2	-
E-649	Sh.8	Schematic Diagram - Safety System Annunciator Auxiliary Relay Circuits - Units 1 & 2	-
E-649	Sh.9	Schematic Diagram - Safety System Annunciator Auxiliary Relay Circuits - Units 1 & 2	-
E-649	Sh.10	Schematic Diagram - Safety System Annunciator Auxiliary Relay Circuits - Units 1 & 2	-
E-686	Sh.1	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-686	Sh.2	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-686	Sh.3	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-686	Sh.4	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-686	Sh.5	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-686	Sh.6	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-686	Sh.7	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-686	Sh.8	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-686	Sh.9	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-686	Sh.10	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-686	Sh.11	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-686	Sh.12	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-686	Sh.13	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-686	Sh.14	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-686	Sh.15	Schematic Diagram - HVAC Miscellaneous Safeguard Instrumentation - Units 1 & 2 & Comm	-
E-688	Sh.1	Schematic Diagram - Miscellaneous Systems Instrumentation - Units 1 & 2	-
E-688	Sh.2	Schematic Diagram - Miscellaneous Systems Instrumentation - Units 1 & 2	-
		ELECTRICAL LAYOUT DRAWINGS	
E-1001	Sh.1	Electric Duct Layout - Site Plan	-
E-1002	Sh.1	Electrical Duct Layout Profiles, Sections & Details - North Area	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
E-1003	Sh.1	Electrical Duct Layout Profiles, Sections & Details - East Area	-
E-1004	Sh.1	Electrical Duct Layout Profiles, Sections & Details - Southeast Area	-
E-1005	Sh.1	Electrical Duct Layout Profiles, Sections & Details - Southwest Area	-
E-1006	Sh.1	Electrical Duct Layout Profiles, Sections & Details - West Area Control System	-
E-1007	Sh.1	Electrical Duct Layout Profiles, Sections & Details - West Area Startup & Pump Structural Ducts	-
E-1008	Sh.1	Electrical Duct Layout - Spray Pond Area - Plan	-
E-1009	Sh.1	Electrical Duct Layout Profiles, Sections & Details - Spray Pond Area	-
E-1010	Sh.1	Embedded Conduit - Turbine Enclosure Unit 1 - Below el 217'-0"	-
E-1011	Sh.1	Embedded Conduit - Turbine Enclosure Unit 2 - Below el 217'-0"	-
E-1013	Sh.1	Embedded Conduit - Reactor Enclosure Unit 1 - Below el 177'-0"	-
E-1014	Sh.1	Embedded Conduit - Reactor Enclosure Unit 2 - Below el 177'-0"	-
E-1015	Sh.1	Embedded Conduit - Reactor Enclosure Unit 1 - Below el 217'-0"	-
E-1016	Sh.1	Embedded Conduit - Reactor Enclosure Unit 2 - Below el 217'-0"	-
E-1034	Sh.1	Raceway Layout - Spray Pond Pump Structure	-
E-1036	Sh.1	Electrical Details - Spray Pond Pump Structure	-
E-1055	Sh.1	Lighting - Cable Spreading Room - Units 1 & 2 Above el 254'-0"	-
E-1056	Sh.1	Lighting - Cable Spreading Room - Units 1 & 2 Above el 254'-0"	-
E-1056	Sh.2	Lighting - Cable Spreading Room - Units 1 & 2 Above el 254'-0"	-
E-1060	Sh.1	Lighting - Reactor Enclosure - Unit 1 Above el 177'-0"	-
E-1061	Sh.1	Lighting - Reactor Enclosure - Unit 1 Above el 201'-0"	-
E-1062	Sh.1	Lighting - Reactor Enclosure - Unit 1 Above el 217'-0"	-
E-1063	Sh.1	Lighting - Reactor Enclosure - Unit 1 Above el 253'-0"	-
E-1064	Sh.1	Lighting - Reactor Enclosure - Unit 1 Above el 283'-0"	-
E-1065	Sh.1	Lighting - Reactor Enclosure - Unit 1 Above el 313'-0"	-
E-1066	Sh.1	Lighting - Reactor Enclosure - Unit 1 Above el 352'-0"	-
E-1066	Sh.2	Lighting - Reactor Enclosure - Unit 1 Above el 411'-9"	-
E-1067	Sh.1	Lighting - Diesel Generator Enclosure - Unit 1 Above el 217'-0"	-
E-1075	Sh.1	Lighting - Control Room - Above el 269'-0"	-
E-1076	Sh.1	Lighting - Auxiliary Equipment Room - Above el 289'-0"	-
E-1080	Sh.1	Lighting - Reactor Enclosure - Unit 2 Above el 177'-0"	-
E-1081	Sh.1	Lighting - Reactor Enclosure - Unit 2 Above el 201'-0"	-
E-1082	Sh.1	Lighting - Reactor Enclosure - Unit 2 Above el 217'-0"	-
E-1083	Sh.1	Lighting - Reactor Enclosure - Unit 2 Above el 253'-0"	-
E-1084	Sh.1	Lighting - Reactor Enclosure - Unit 2 Above el 283'-0"	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
E-1085	Sh.1	Lighting - Reactor Enclosure - Unit 2 Above el 313'-0" & 331'-0"	-
E-1086	Sh.1	Lighting - Reactor Enclosure - Unit 2 Above el 352'-0"	-
E-1087	Sh.1	Lighting - Diesel Generator Enclosure - Unit 2 Above el 217'-0"	-
E-1112	Sh.1	Raceway Layout - Turbine Enclosure - Unit 1 Columns R-N & 5-12 (Area 1) el 239'-0"	7.2-10 Sh.1
E-1121	Sh.1	Raceway Layout - Turbine Enclosure - Unit 1 Columns R-N & 5-12 (Area 1) el 269'-0"	-
E-1124	Sh.1	Raceway Layout - Turbine Enclosure - Unit 1 Columns N-J & 5-12 (Area 6) el 269'-0"	-
E-1125	Sh.1	Raceway Layout - Turbine Enclosure - Unit 1 Columns N-J & 12-19.2 (Area 7) el 269'-0"	-
E-1141	Sh.1	Raceway Layout - Unit 1 J Wall Elevation Looking North Columns 9-3-23. el 162'-0" to 217'-0"	-
E-1141	Sh.2	Raceway Layout - Unit 1 J Wall Elevation Looking North Columns 9-3-23. el 162'-0" to 217'-0"	-
E-1142	Sh.1	Tray Layout - Turbine Enclosure - Units 1 & 2 Columns N-J & 19.2-26 (Area 8) Auxiliary Equipment Room Sections	-
E-1143	Sh.1	Tray Layout - Turbine Enclosure - Units 1 & 2 Columns N-J & 24.5-26.6 (Area 8) Auxiliary Equipment Room Sections	-
E-1144	Sh.1	Raceway Layout - Turbine Enclosure - Units 1 & 2 Mh Wall Elevation Looking North Columns 19.2-25.5 el 217'-0" to 318'-0"	-
E-1145	Sh.1	Raceway Layout Turbine Enclosure Elevation Mh Wall Looking South Columns 19.2 to 26.8 el 217'-0" to 304'-0"	-
E-1146	Sh.1	Raceway Layout - Turbine Enclosure - Unit 1 Sections and Details	-
E-1147	Sh.1	Raceway Layout Turbine Enclosure - Units 1 & 2 Plans of Mh Wall from el 217'-0" to 300'-0"	-
E-1148	Sh.1	Raceway Layout Turbine Enclosure Sections and Details of Mh Wall	-
E-1149	Sh.1	Raceway Layout - Turbine Enclosure - Unit 1 Section and Plans of 19.4 Wall	-
E-1149	Sh.2	Raceway Layout - Turbine Enclosure - Unit 1 Section and Plans of 19.4 Wall	-
E-1150	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 14.1-18.5 (Area 11) Plan el 177'-0" Slab & Above	-
E-1151	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 18.5-23 (Area 12) Plan el 177'-0" Slab & Above	-
E-1152	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns G.D. & 14.1-18.5 (Area 15) Plan el 177'-0" Slab & Above	-
E-1152	Sh.2	Raceway Layout - Reactor Enclosure - Unit 1 Columns G.D. & 14.1-18.5 (Area 15) Plan el 177'-0" Slab & Above	
E-1153	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns G.D. & 18.5-23 (Area 16) Plan el 177'-0" Slab & Above	-
E-1154	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 14.1-18.5 (Area 11) Plan el 201'-0" Slab & Above	-
E-1155	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 18.5-23 (Area 12) Plan el 201'-0" Slab & Above	-
E-1156	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns G-D & 14.1-18.5 (Area 15) Plan el 201'-0" Slab & Above	-
E-1157	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns G-D & 18.5-23 (Area 16) Plan el 201'-0" Slab & Above	-
E-1158	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 14.1-18.5 (Area 11) Plan el 217'-0" Slab & Above	-
E-1158	Sh.2	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 14.1-18.5 (Area 11) Plan el 217'-0" Slab & Above	-
E-1159	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 18.5-23 (Area 12) Plan el 217'-0" Slab & Above	-
E-1159	Sh.2	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 18.5-23 (Area 12) Plan el 217'-0" Slab & Above	-
E-1160	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns G-D & 14.1-18.5 (Area 15) Plan el 217'-0" Slab & Above	-
E-1160	Sh.2	Raceway Layout - Reactor Enclosure - Unit 1 Columns G-D & 14.1-18.5 (Area 15) Plan el 217'-0" Slab & Above	-
E-1160	Sh.3	Raceway Layout - Reactor Enclosure - Unit 1 Columns G-D & 14.1-18.5 (Area 15) Plan el 217'-0" Slab & Above	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
E-1161	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns G-D & 18.5-23 (Area 16) Plan el 217'-0" Slab & Above	-	
E-1161	Sh.2	Raceway Layout - Reactor Enclosure - Unit 1 Columns G-D & 18.5-23 (Area 16) Plan el 217'-0" Slab & Above	-	
E-1162	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 14.1-18.5 (Area 11) Plan el 253'-0" Slab & Above	-	
E-1162	Sh.2	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 14.1-18.5 (Area 11) Plan el 253'-0" Slab & Above	-	
E-1163	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 18.5-23 (Area 12) Plan el 253'-0" Slab & Above	-	
E-1163	Sh.2	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 18.5-23 (Area 12) Plan el 253'-0" Slab & Above	-	
E-1163	Sh.3	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 18.5-23 (Area 12) Plan el 253'-0" Slab & Above	-	
E-1164	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns G-D & 14.1-18.5 (Area 15) Plan el 253'-0" Slab & Above	7.2-14	Sh.1
E-1164	Sh.2	Raceway Layout - Reactor Enclosure - Unit 1 Hydraulic Control Unit Raceway Plan el 253'-0" Slab & Above	7.2-14	Sh.2
E-1165	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns G-D & 18.5-23 (Area 16) Plan el 253'-0" Slab & Above	7.2-15	Sh.1
E-1166	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 14.1-18.5 (Area 11) Plan el 283'-0" Slab & Above	-	
E-1166	Sh.2	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 14.1-18.5 (Area 11) Plan el 283'-0" Slab & Above	-	
E-1166	Sh.3	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 14.1-18.5 (Area 11) Plan el 283'-0" Slab & Above	-	
E-1167	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 18.5-23 (Area 12) Plan el 283'-0" Slab & Above	-	
E-1167	Sh.2	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 18.5-23 (Area 12) Plan el 283'-0" Slab & Above	-	
E-1167	Sh.3	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 18.5-23 (Area 12) Plan el 283'-0" Slab & Above	-	
E-1168	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns G-D & 14.1-18.5 (Area 15) Plan el 283'-0" Slab & Above	-	
E-1169	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns G-D & 18.5-23 (Area 16) Plan el 283'-0" Slab & Above	-	
E-1169	Sh.2	Raceway Layout - Reactor Enclosure - Unit 1 Columns G-D & 18.5-23 (Area 16) Plan el 283'-0" Slab & Above	-	
E-1170	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 14.1-18.5 (Area 11) Plan el 313'-0" Slab & Above	-	
E-1171	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns J-G & 18.5-23 (Area 12) Plan el 313'-0" Slab & Above	-	
E-1172	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns G-D & 14.1-18.5 (Area 15) Plan el 313'-0" Slab & Above	-	
E-1173	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Columns D-G & 18.5-23 (Area 16) Plan el 313'-0" Slab & Above	-	
E-1174	Sh.1	Conduit and Gutter Layout - Turbine Enclosure - Unit 1 Columns N-J & 19.2-23 (Area 8) Cable Spreading Room - Plan el 254'-0" Slab & Above	-	
E-1174	Sh.2	Conduit Layout - Turbine Enclosure - Unit 1 Columns N-J & 19.2-23 (Area 8) Cable Spreading Room Plan el 254'-0" Slab & Above	-	
E-1175	Sh.1	Conduit and Gutter Layout - Turbine Enclosure - Unit 2 Columns N-J & 23-26.6 (Area 8) Cable Spreading Room Plan El. 234'-0" Slab & Above	-	
E-1175	Sh.2	Conduit Layout - Turbine Encl - Unit 2 Columns N-J & 23-26.6 (Area 8) Cable Spring Room - Plan el 254'-0" Slab & Above	-	
E-1176	Sh.1	Raceway Layout - Reactor Encl - Unit 1 Columns G-D & 14.1-18.5 (Area 15) Plan el 331'-0" Slab & Above	-	
E-1177	Sh.1	Raceway Layout - Reactor Encl - Unit 1 Columns G-D & 18.5-23 (Area 16) Plan el 331'-0" Slab & Above	-	
E-1178	Sh.1	Raceway Layout - Reactor Encl - Unit 1 Columns J-G & 14.1-18.5 (Area 11) Plan el 352'-0" Slab & Above	-	

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
E-1179	Sh.1	Raceway Layout - Reactor Encl - Unit 1 Columns J-G & 18.5-23 (Area 12) Plan el 352'-0" Slab & Above	-
E-1179	Sh.2	Raceway Layout - Reactor Encl - Unit 1 Columns J-G & 18.5-23 (Area 12) Plan el 352'-0" Slab & Above	-
E-1180	Sh.1	Raceway Layout - Reactor Encl - Unit 1 Columns G-D & 14.1-18.5 (Area 15) Plan el 352'-0" Slab & Above	-
E-1181	Sh.1	Raceway Layout - Reactor Encl - Unit 1 Columns G-D & 18.5-23 (Area 16) Plan el 352'-0" Slab & Above	-
E-1182	Sh.1	Panels & Floor Penetration Identification - Turbine Encl - Units 1 & 2 Columns N-J 19.2-26.8 (Area 8) Control Room Plan el 269'-0" Slab & Above	-
E-1183	Sh.1	Conduit and Gutter Layout - Turbine Encl - Units 1 & 2 Columns N-J & 19.2-26.6 (Area 8) Plan el 289'-0" Slab & Above	-
E-1183	Sh.2	Conduit and Gutter Layout - Turbine Encl - Units 1 & 2 Columns N-J & 19.2-26.6 (Area 8) Plan el 289'-0" Slab & Above	-
E-1184	Sh.1	Raceway Layout - Unit 1 D Wall Elevation Looking North Columns 15.5-21.5 el 217'-0" to 313'-0"	-
E-1185	Sh.2	Raceway Layout - Reactor Encl - Units 1 & 2 J Wall Elevation - Looking North Columns 19.4-26.6 el 217'-0" to 332'-0"	-
E-1186	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Drywell Section AZ-0 to AZ-90	-
E-1186	Sh.2	Raceway Layout - Reactor Enclosure - Unit 1 Drywell Section AZ-0 to AZ-90	-
E-1186	Sh.3	Raceway Layout - Reactor Enclosure - Unit 1 Drywell Section AZ-0 to AZ-90	-
E-1186	Sh.4	Raceway Layout - Reactor Enclosure - Unit 1 Drywell Section AZ-0 to AZ-90	-
E-1187	Sh.1	Drywell - Units 1 & 2 Electrical Raceway Supports el 243'-0"	-
E-1187	Sh.2	Drywell - Units 1 & 2 Electrical Raceway Supports el 243'-0"	-
E-1187	Sh.3	Drywell - Units 1 & 2 Electrical Raceway Supports el 243'-0"	-
E-1187	Sh.4	Drywell - Units 1 & 2 Electrical Raceway Supports el 243'-0" to 322'-0" & 6	-
E-1188	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Drywell RPV Instrumentation	-
E-1189	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Drywell Plan Above el 217'-0"	-
E-1190	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Drywell Unit 1 Raceway Supported from Steel at el 253'-0"	-
E-1191	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 CRD & LPRM Inside RPV Pedestal	-
E-1192	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Drywell Miscellaneous Plans & Details	-
E-1193	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Drywell Raceway Supported from Steel at el 272'-9"	-
E-1194	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Drywell Raceway Supported from Steel at el 277'-6"	-
E-1195	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Drywell Raceway Supported from Steel at el 286'-1"	-
E-1196	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Drywell Raceway Supported from Steel at el 295'-11"	-
E-1198	Sh.1	Raceway Layout	-
E-1199	Sh.1	Raceway Layout - Reactor Enclosure - Unit 1 Drywell Tray Section & Details	-
E-1209	Sh.1	Raceway Layout - Turbine Enclosure - Unit 2, Area 5, el 239'-0"	7.2-10 Sh.2
E-1209	Sh.2	Raceway Layout - Turbine Enclosure - Unit 2, Area 5 el 239'-0"	7.2-10 Sh.3
E-1233	Sh.1	Raceway Layout - Turbine Enclosure - Units 1 & 2 Mh Wall Elevation Looking North Columns 19.4-26.6, el 217'-0" to 304'-0"	-
E-1234	Sh.1	Raceway Layout - Turbine Enclosure - Units 1 & 2 J Line Wall Elevation Looking South Columns 19.4-26.6 & el 200'-0" to 289'-0"	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
E-1235	Sh.1	Class I Bus Duct Supports	-	
E-1241	Sh.1	Raceway Layout - Unit 2 J Line Wall Elevation Looking North Columns 23-31.9 el 177'-0" to 217'-0"	-	
E-1241	Sh.2	Raceway Layout - Unit 2 J Line Wall Elevation Looking North Columns 23-31.9 el 177'-0" to 217'-0"	-	
E-1244	Sh.1	Raceway Layout - Turbine Enclosure - Wall Elevation Columns 19.4 and 26.6 J to N el 217'-0" to 332'-0"	-	
E-1250	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 23-27.5 (Area 13) Plan el 177'-0" Slab & Above	-	
E-1250	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 23-27.5 (Area 13) Plan el 177'-0" Slab & Above	-	
E-1251	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 27.5-31.9 (Area 14) Plan el 177'-0" Slab & Above	-	
E-1252	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 23-27.5 (Area 17) Plan el 177'-0" Slab & Above	-	
E-1252	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 23-27.5 (Area 17) Plan el 177'-0" Slab & Above	-	
E-1253	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 27.5-31.9 (Area 18) Plan el 177'-0" Slab & Above	-	
E-1253	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 27.5-31.9 (Area 18) Plan el 177'-0" Slab & Above	-	
E-1254	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns J-G & 23-27.5 (Area 13) Plan el 201'-0" Slab & Above	-	
E-1254	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns J-G & 23-27.5 (Area 13) Plan el 201'-0" Slab & Above	-	
E-1256	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 23-27.5 (Area 17) Plan el 201'-0" Slab & Above	-	
E-1256	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 23-27.5 (Area 17) Plan el 201'-0" Slab & Above	-	
E-1257	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 27.5-31.9 (Area 18) Plan el 201'-0" Slab & Above	-	
E-1257	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 27.5-31.9 (Area 18) Plan el 201'-0" Slab & Above	-	
E-1258	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 23-27.5 (Area 13) Plan el 217'-0" Slab & Above	-	
E-1258	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 23-27.5 (Area 13) Plan el 217'-0" Slab & Above	-	
E-1259	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 27.5-31.9 (Area 14) Plan el 217'-0" Slab & Above	-	
E-1260	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 23-27.5 (Area 17) Plan el 217'-0" Slab & Above	-	
E-1260	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 23-27.5 (Area 17) Plan el 217'-0" Slab & Above	-	
E-1260	Sh.3	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 23-27.5 (Area 17) Plan el 217'-0" Slab & Above	-	
E-1261	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 27.5-31.9 (Area 18) Plan el 217'-0" Slab & Above	-	
E-1261	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 27.5-31.9 (Area 18) Plan el 217'-0" Slab & Above	-	
E-1261	Sh.3	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 27.5-31.9 (Area 18) Plan el 217'-0" Slab & Above	-	
E-1262	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 23-27.5 (Area 13) Plan el 253'-0" Slab & Above	-	
E-1262	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 23-27.5 (Area 13) Plan el 253'-0" Slab & Above	-	
E-1262	Sh.3	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 23-27.5 (Area 13) Plan el 253'-0" Slab & Above	-	
E-1263	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-K & 27.5-31.9 (Area 14) Plan el 253'-0" Slab & Above	-	
E-1263	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-K & 27.5-31.9 (Area 14) Plan el 253'-0" Slab & Above	-	
E-1264	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 23-27.5 (Area 17) Plan el 253'-0" Slab & Above	7.2-14	Sh.3
E-1264	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 23-27.5 (Area 17) Plan el 253'-0" Slab & Above	7.2-14	Sh.4
E-1264	Sh.3	Raceway Layout - Reactor Enclosure - Unit 2, Area 18 el 253'-0"	7.2-14	Sh.5

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
E-1264	Sh.4	Raceway Layout - Reactor Enclosure - Unit 2, Area 18 el 253'-0"	7.2-14	Sh.6
E-1265	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 27.5-31.9 (Area 18) Plan el 253'-0" Slab & Above	7.2-15	Sh.2
E-1265	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 27.5-31.9 (Area 18) Plan el 253'-0" Slab & Above	7.2-15	Sh.3
E-1265	Sh.3	Raceway Layout - Reactor Enclosure - Unit 2, Area 18 el 253'-0"	7.2-15	Sh.4
E-1266	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 23-27.5 (Area 13) Plan el 283'-0" Slab & Above	-	
E-1266	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 23-27.5 (Area 13) Plan el 283'-0" Slab & Above	-	
E-1267	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 27.5-31.9 (Area 14) Plan el 283'-0" Slab & Above	-	
E-1267	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 27.5-31.9 (Area 14) Plan el 283'-0" Slab & Above	-	
E-1268	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 23-27.5 (Area 17) Plan el 283'-0" Slab & Above	-	
E-1268	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 23-27.5 (Area 17) Plan el 283'-0" Slab & Above	-	
E-1269	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 27.5-31.9 (Area 18) Plan el 283'-0" Slab & Above	-	
E-1269	Sh.2	Raceway Layout - Reactor Enclosure - Unit 2 Columns E-H & 14.1-18.5 (Area 14, 17, & 18) Plan el 300'-3" Slab	-	
E-1270	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 23-27.5 (Area 13) Plan el 313'-0" Slab & Above	-	
E-1271	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns G-J & 27.5-31.9 (Area 14) Plan el 313'-0" Slab & Above	-	
E-1272	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 23-27.5 (Area 17) Plan el 313'-0" Slab & Above	-	
E-1273	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Columns D-G & 27.5-31.9 (Area 18) Plan el 313'-0" Slab & Above	-	
E-1276	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 (Area 17) Plan Above el 331'-0"	-	
E-1277	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 (Area 18) Plan Above el 331'-0"	-	
E-1278	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 (Area 13) Plan Above el 352'-0"	-	
E-1279	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 (Area 14) Plan Above el 352'-0"	-	
E-1280	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 (Area 17) Plan Above el 352'-0"	-	
E-1281	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 (Area 18) Plan Above el 352'-0"	-	
E-1284	Sh.1	Raceway Layout - Unit 2 D Wall Elevation Looking North Columns 24.5-30.5 el 217'-0" to 313'-0"	-	
E-1288	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Drywell RPV Instrumentation	-	
E-1289	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Drywell Plan Above el 217'-0"	-	
E-1291	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 CRD & LPRM Inside RPV Pedestal	-	
E-1292	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Drywell Misc. Plans & Details	-	
E-1297	Sh.1	Raceway Layout - Reactor Enclosure - Unit 2 Drywell Raceway Sections - Sheet 1	-	
E-1298	Sh.1	Raceway Layout - Containment - Unit 2 Drywell Tray Layout	-	
E-1299	Sh.1	Raceway Layout - Containment - Unit 2 Drywell Tray Sections	-	
E-1300	Sh.1	Raceway Layout - Radwaste Enclosure Area 20 Plan el 162'-0" Slab & Above	-	
E-1301	Sh.1	Raceway Layout - Radwaste Enclosure Area 22 Plan el 162'-0" Slab & Above	-	
E-1302	Sh.1	Raceway Layout - Radwaste Enclosure Area 23 Plan el 162'-0" Slab & Above	-	

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
E-1303	Sh.1	Raceway Layout - Radwaste Enclosure Area 20 Plan el 191'-0" Slab & Above	-	
E-1304	Sh.1	Raceway Layout - Radwaste Enclosure Area 22 Plan el 191'-0" Slab & Above	-	
E-1305	Sh.1	Raceway Layout - Radwaste Enclosure Area 23 Plan el 191'-0" Slab & Above	-	
E-1306	Sh.1	Raceway Layout - Radwaste Enclosure Area 20 Plan el 217'-0" Slab & Above	-	
E-1307	Sh.1	Raceway Layout - Radwaste Enclosure Area 22 Plan el 217'-0" Slab & Above	-	
E-1308	Sh.1	Raceway Layout - Radwaste Enclosure Area 20 Plan el 237'-0" Slab & Above	-	
E-1309	Sh.1	Raceway Layout - Radwaste Enclosure Area 22 Plan el 237'-0" Slab & Above	-	
E-1310	Sh.1	Raceway Layout - Radwaste Enclosure Area 20 Plan el 257'-0" Slab & Above	-	
E-1311	Sh.1	Raceway Layout - Radwaste Enclosure Area 22 Plan Above el 257'-0"	-	
E-1314	Sh.1	Raceway Layout - Radwaste Enclosure Area 19 Plan el 195'-0" Slab & Above	-	
E-1315	Sh.1	Raceway Layout - Radwaste Enclosure Area 21 Plan el 195'-0" Slab & Above	-	
E-1316	Sh.1	Raceway Layout - Radwaste Enclosure Misc. Plans, Details & Sections	-	
E-1317	Sh.1	Raceway Layout - Radwaste Enclosure Misc. Plans, Details & Sections	-	
E-1318	Sh.1	Raceway Layout - Radwaste Enclosure Area 20 - Partial Plan Below Radwaste Control Room	-	
E-1319	Sh.1	Raceway Layout - Radwaste Enclosure Area 20 Sections Below Radwaste Control Room	-	
E-1328	Sh.1	Raceway Layout - Lube Oil Storage Enclosure	-	
E-1332	Sh.1	Embedded Conduit Layout - Diesel Generator Enclosure - Unit 1	-	
E-1335	Sh.1	Embedded Conduit Layout - Diesel Generator Enclosure - Unit 2	-	
E-1348	Sh.1	Raceway Layout - Diesel Generator Enclosure - Unit 1 Plan el 217'-0"	-	
E-1349	Sh.1	Raceway Layout - Diesel Generator Enclosure - Unit 2 Plan el 217'-0"	-	
E-1360	Sh.1	Riser Diagram - Fire Alarm System - Unit 1	-	
E-1360	Sh.2	Riser Diagram - Fire Alarm System - Unit 1	-	
E-1361	Sh.1	Riser Diagram - Fire Alarm System - Unit 2	-	
E-1362	Sh.1	Riser Diagram - Fire Alarm System (FA) Remote Enclosure - Comm	-	
E-1364	Sh.1	Wiring/Connection Diagram - Evacuation Alarm & River Warning Systems	-	
E-1367	Sh.1	Riser Diagram - Public Address System (PA) Unit 2	9.5-3	Sh.1
E-1368	Sh.1	Riser Diagram - Public Address System (PA) Remote Enclosure - Comm	9.5-4	Sh.1
E-1369	Sh.1	Riser Diagram - Telephone System (PABX) Unit 1	9.5-5	Sh.1
E-1370	Sh.1	Riser Diagram - Telephone System (PABX) Unit 2	9.5-6	Sh.1
E-1366	Sh.1	Riser Diagram - Public Address System (PA) Unit 1	9.5-2	Sh.1
E-1371	Sh.1	Riser Diagram - Telephone System (PABX) Remote Enclosure - Comm	9.5-7	Sh.1
E-1373	Sh.1	Riser Diagram - Lighting, Power & Fire Alarm Panel boards Unit 1 Turbine & Reactor Enclosure	-	
E-1374	Sh.1	Riser Diagram - Lighting, Power, and Fire Alarm Panel boards Unit 2 - Turbine & Reactor Enclosures	-	

Note: See note in Section 1.7 for drawing considerations

Table 1.7-1 (Cont'd)
ELECTRICAL DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
E-1375	Sh.1	Riser Diagram - Lighting, Power, and Fire Alarm Panel boards Remote Enclosure - Comm	-
E-1405	Sh.1	Lighting - Notes, Symbols & Details	-
E-1406	Sh.1	Conduit & Cable Tray Notes, Symbols & Details	-
E-1407	Sh.1	Communication Notes, Symbols & Details	-
E-1408	Sh.1	Fire Alarm System Notes, Symbols & Details	-
E-1412	Sh.1	Wire & Cable - Notes & Details	-
E-1425	Sh.1	Lighting, Power & Fire Alarm Panel Schedules	-
E-1460	Sh.1	Communication and Fire Alarm Layout - Reactor Enclosure - Unit 1 Plan Above el 177'-0"	-
E-1461	Sh.1	Communication & Fire Alarm Layout - Reactor Enclosure - Unit 1 Plan Above el 201'-0"	-
E-1462	Sh.1	Communication & Fire Alarm Layout - Reactor Enclosure - Unit 1 Above el 217'-0"	-
E-1463	Sh.1	Communication & Fire Alarm Layout - Reactor Enclosure - Unit 1 Above el 253'-0"	-
E-1464	Sh.1	Communication & Fire Alarm Layout - Reactor Enclosure - Unit 1 Above el 283'-0"	-
E-1465	Sh.1	Communication & Fire Alarm Layout - Reactor Enclosure - Unit 1 Above el 313'-0"	-
E-1466	Sh.1	Communication & Fire Alarm Layout - Reactor Enclosure - Unit 1 Above el 352'-0"	-
E-1467	Sh.1	Communication & Fire Alarm Layout - Diesel Generator Bids - Unit 1	-
E-1480	Sh.1	Communication & Fire Alarm Layout - Reactor Enclosure - Unit 2 Above el 177'-0"	-
E-1495	Sh.1	Communication & Fire Alarm Layout - Spray Pond Pumphouse Above el 251'-0" & 268'-0"	-
E-1500	Sh.1	Raceway Schedule - Engineered Safeguard System - Unit 1	-
E-1501	Sh.1	Raceway Schedule - Reactor Protection System - Unit 1	-
E-1506	Sh.1	Circuit Schedule - Engineered Safeguard System - Unit 1 & Comm	-
E-1507	Sh.1	Circuit Schedule - Reactor Protection System - Unit 1 & Comm	-
E-1515	Sh.1	Raceway Schedule - Engineered Safeguard Systems - Unit 2	-
E-1516	Sh.1	Raceway Schedule - Reactor Protection System - Unit 2	-
E-1521	Sh.1	Circuit Schedule - Engineered Safeguard System - Unit 2 & Comm	-
E-1522	Sh.1	Circuit Schedule - Reactor Protection System - Unit 2 & Comm	-
E-1675	Sh.1	Communication & Fire Alarm Layout - Main Control Room - Above el 269'-0"	-
E-1676	Sh.1	Communication & Fire Alarm Layout - Auxiliary Equipment Room Above el 289'-0"	-
E-1681	Sh.1	Communication & Fire Alarm Layout - Reactor Enclosure - Unit 2 Above el 201'-0"	-
E-1682	Sh.1	Communication & Fire Alarm Layout - Reactor Enclosure - Unit 2 Above el 217'-0"	-
E-1683	Sh.1	Communication & Fire Alarm Layout - Reactor Enclosure - Unit 2 Above el 253'-0"	-
E-1684	Sh.1	Communication & Fire Alarm Layout - Reactor Enclosure - Unit 2 Above el 283'-0"	-
E-1685	Sh.1	Communication & Fire Alarm Layout - Reactor Enclosure - Unit 2 Plan Above el 313'-0"	-
E-1686	Sh.1	Communication & Fire Alarm Layout - Reactor Enclosure - Unit 2 Plan Above el 352'-0"	-
E-1687	Sh.1	Communication & Fire Alarm Layout - Diesel Generator Enclosure - Unit 2 Above el 217'-0"	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-2
FIGURE INDEX FOR PLANT SYSTEMS

P&ID Number		System	Former UFSAR Figure Number	
M-00	Sh. 1	Legend	1.10-1	Sh.1
M-00	Sh. 2	Legend	1.10-1	Sh.2
M-01	Sh. 1	Main Steam	10.3-1	Sh. 1
M-01	Sh. 2	Main Steam	10.3-1	Sh. 2
M-01	Sh. 3	Main Steam	10.3-1	Sh. 3
M-01	Sh. 4	Main Steam	10.3-1	Sh. 4
M-02	Sh. 1	Extraction Steam	10.2-1	Sh. 1
M-02	Sh. 2	Extraction Steam	10.2-1	Sh. 2
M-02	Sh. 3	Extraction Steam	10.2-1	Sh. 3
M-02	Sh. 4	Extraction Steam	10.2-1	Sh. 4
M-03	Sh. 1	Vents and Drains, Heaters 1 & 2 Drain Cooler 1	10.4-7	Sh.1
M-03	Sh. 2	Vents and Drains, Heaters 1 & 2 Drain Cooler 1	10.4-7	Sh.2
M-04	Sh. 1	Vents and Drains, Heaters 3,4,5 & 6	10.4-8	Sh. 1
M-04	Sh. 2	Vents and Drains, Heaters 3,4,5 & 6	10.4-8	Sh. 2
M-04	Sh. 3	Vents and Drains, Heaters 3,4,5 & 6	10.4-8	Sh. 3
M-04	Sh. 4	Vents and Drains, Heaters 3,4,5 & 6	10.4-8	Sh. 4
M-04	Sh. 5	Vents and Drains, Heaters 3,4,5 & 6	10.4-8	Sh. 5
M-04	Sh. 6	Vents and Drains, Heaters 3,4,5 & 6	10.4-8	Sh. 6
M-05	Sh. 1	Condensate	10.4-4	Sh. 1
M-05	Sh. 2	Condensate	10.4-4	Sh. 2
M-05	Sh. 3	Condensate	10.4-4	Sh. 3
M-05	Sh. 4	Condensate	10.4-4	Sh. 4
M-06	Sh. 1	Feedwater	10.4-5	Sh. 1
M-06	Sh. 2	Feedwater	10.4-5	Sh. 2
M-06	Sh. 3	Feedwater	10.4-5	Sh. 3
M-06	Sh. 4	Feedwater	10.4-5	Sh. 4
M-06	Sh. 5	Feedwater	10.4-5	Sh. 5

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-2 (Cont'd)
FIGURE INDEX FOR PLANT SYSTEMS

P&ID Number		System	Former UFSAR Figure Number	
M-06	Sh. 6	Feedwater	10.4-5	Sh. 6
M-06	Sh. 7	Feedwater	10.4-5	Sh. 7
M-06	Sh. 8	Feedwater	10.4-5	Sh. 8
M-06	Sh. 9	Feedwater	10.4-5	Sh. 9
M-06	Sh.10	Feedwater	10.4-5	Sh.10
M-06	Sh.11	Feedwater	10.4-5	Sh.11
M-07	Sh. 1	Air Removal & Sealing Steam	10.4-1	Sh. 1
M-07	Sh. 2	Air Removal & Sealing Steam	10.4-1	Sh. 2
M-07	Sh. 3	Air Removal & Sealing Steam	10.4-1	Sh. 3
M-07	Sh. 4	Air Removal & Sealing Steam	10.4-1	Sh. 4
M-08	Sh. 1	Condensate and Refueling Water Storage	9.2-24	Sh. 1
M-08	Sh. 2	Condensate and Refueling Water Storage	9.2-24	Sh. 2
M-08	Sh. 3	Condensate and Refueling Water Storage	9.2-24	Sh. 3
M-09	Sh. 1	Circulating Water	10.4-2	Sh. 1
M-09	Sh. 2	Circulating Water	10.4-2	Sh. 2
M-09	Sh. 3	Circulating Water	10.4-2	Sh. 3
M-09	Sh. 4	Circulating Water	10.4-2	Sh. 4
M-09	Sh. 5	Circulating Water	10.4-2	Sh. 5
M-09	Sh. 6	Circulating Water	10.4-2	Sh. 6
M-09	Sh. 7	Circulating Water	10.4-2	Sh. 7
M-09	Sh. 8	Circulating Water	10.4-2	Sh. 8
M-09	Sh. 9	Circulating Water	10.4-2	Sh. 9
M-09	Sh. 10	Circulating Water	-	
M-09	Sh. 11	Circulating Water	-	
M-09	Sh. 12	Circulating Water	-	
M-09	Sh. 13	Circulating Water	-	
M-09	Sh. 14	Circulating Water	-	
M-10	Sh. 1	Service Water	9.2-1	Sh. 1
M-10	Sh. 2	Service Water	9.2-1	Sh. 2

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-2 (Cont'd)
FIGURE INDEX FOR PLANT SYSTEMS

P&ID Number		System	Former UFSAR Figure Number	
M-10	Sh. 3	Service Water	9.2-1	Sh. 3
M-10	Sh. 4	Service Water	9.2-1	Sh. 4
M-10	Sh. 5	Service Water	9.2-1	Sh. 5
M-10	Sh. 6	Service Water	9.2-1	Sh. 6
M-10	Sh. 7	Service Water	9.2-1	Sh. 7
M-10	Sh. 8	Service Water	9.2-1	Sh. 8
M-10	Sh. 9	Service Water	9.2-1	Sh. 9
M-10	Sh.10	Service Water	9.2-1	Sh.10
M-11	Sh. 1	Emergency Service Water	9.2-2	Sh. 1
M-11	Sh. 2	Emergency Service Water	9.2-2	Sh. 2
M-11	Sh. 3	Emergency Service Water	9.2-2	Sh. 3
M-11	Sh. 4	Emergency Service Water	9.2-2	Sh. 4
M-11	Sh. 5	Emergency Service Water	9.2-2	Sh. 5
M-12	Sh. 1	RHR Service Water	9.2-3	Sh. 1
M-12	Sh. 2	RHR Service Water	9.2-3	Sh. 2
M-13	Sh. 1	Reactor Enclosure Cooling Water	9.2-25	Sh. 1
M-13	Sh. 2	Reactor Enclosure Cooling Water	9.2-25	Sh. 2
M-14	Sh. 1	Turbine Enclosure Cooling Water	9.2-26	Sh. 1
M-14	Sh. 2	Turbine Enclosure Cooling Water	9.2-26	Sh. 2
M-15	Sh. 1	Compressed Air	9.3-1	Sh. 1
M-15	Sh. 2	Compressed Air	9.3-1	Sh. 2
M-15	Sh. 3	Compressed Air	9.3-1	Sh. 3
M-15	Sh. 4	Compressed Air	9.3-1	Sh. 4
M-15	Sh. 5	Compressed Air	9.3-1	Sh. 5
M-15	Sh. 6	Compressed Air	9.3-1	Sh. 6
M-15	Sh. 7	Compressed Air	9.3-1	Sh. 7
M-15	Sh. 8	Compressed Air	9.3-1	Sh. 8
M-15	Sh. 9	Compressed Air	9.3-1	Sh. 9

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-2 (Cont'd)
FIGURE INDEX FOR PLANT SYSTEMS

P&ID Number		System	Former UFSAR Figure Number	
M-15	Sh. 10	Compressed Air	9.3-1	Sh. 10
M-15	Sh. 11	Compressed Air	9.3-1	Sh. 11
M-15	Sh. 12	Compressed Air	9.3-1	Sh. 12
M-15	Sh. 13	Compressed Air	9.3-1	Sh. 13
M-15	Sh. 14	Compressed Air	9.3-1	Sh. 14
M-15	Sh. 15	Compressed Air	9.3-1	Sh. 15
M-15	Sh. 16	Compressed Air	9.3-1	Sh. 16
M-15	Sh. 17	Compressed Air	9.3-1	Sh. 17
M-15	Sh. 18	Compressed Air	9.3-1	Sh. 18
M-15	Sh. 19	Compressed Air	9.3-1	Sh. 19
M-15	Sh. 20	Compressed Air	9.3-1	Sh. 20
M-15	Sh. 21	Compressed Air	9.3-1	Sh. 21
M-15	Sh. 22	Compressed Air	9.3-1	Sh. 22
M-15	Sh. 23	Compressed Air	9.3-1	Sh. 23
M-15	Sh. 24	Compressed Air	9.3-1	Sh. 24
M-15	Sh..25	Compressed Air	9.3-1	Sh..25
M-15	Sh..26	Compressed Air	9.3-1	Sh..26
M-15	Sh. 27	Compressed Air	9.3-1	Sh. 27
M-15	Sh. 28	Compressed Air	9.3-1	Sh. 28
M-15	Sh. 29	Compressed Air	9.3-1	Sh. 29
M-15	Sh. 30	Compressed Air	9.3-1	Sh. 30
M-15	Sh. 31	Compressed Air	9.3-1	Sh. 31
M-15	Sh. 32	Compressed Air	9.3-1	Sh. 32
M-15	Sh. 33	Compressed Air	9.3-1	Sh. 33
M-15	Sh. 34	Compressed Air	9.3-1	Sh. 34
M-15	Sh. 35	Compressed Air	9.3-1	Sh. 35
M-15	Sh. 36	Compressed Air	9.3-1	Sh. 36
M-15	Sh. 37	Compressed Air	9.3-1	Sh. 37
M-15	Sh. 38	Compressed Air	9.3-1	Sh. 38
M-15	Sh. 39	Compressed Air	9.3-1	Sh. 39
M-15	Sh. 40	Compressed Air	9.3-1	Sh. 40
M-15	Sh. 41	Compressed Air	9.3-1	Sh. 41
M-15	Sh. 42	Compressed Air	9.3-1	Sh. 42
M-15	Sh. 43	Compressed Air	9.3-1	Sh. 43

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-2 (Cont'd)
FIGURE INDEX FOR PLANT SYSTEMS

P&ID Number		System	Former UFSAR Figure Number	
M-15	Sh. 44	Compressed Air	9.3-1	Sh. 44
M-15	Sh. 45	Compressed Air	9.3-1	Sh. 45
M-16	Sh. 1	Condensate Filter/Demineralizers	10.4-3	Sh. 1
M-16	Sh. 2	Condensate Filter/Demineralizers	10.4-3	Sh. 2
M-16	Sh. 3	Condensate Filter/Demineralizers	10.4-3	Sh. 3
M-16	Sh. 4	Condensate Filter/Demineralizers	10.4-3	Sh. 4
M-16	Sh. 5	Condensate Filter/Demineralizers	10.4-3	Sh. 5
M-16	Sh. 6	Condensate Filter/Demineralizers	10.4-3	Sh. 6
M-17	Sh. 1	Clarified Water	9.2-4	Sh. 1
M-17	Sh. 2	Clarified Water	9.2-4	Sh. 2
M-18	Sh. 1	Makeup Demineralizer	9.2-5	Sh. 1
M-18	Sh. 2	Makeup Demineralizer	9.2-5	Sh. 2
M-18	Sh. 3	Makeup Demineralizer	9.2-5	Sh. 3
M-19	Sh. 1	Lube Oil	-	
M-19	Sh. 2	Lube Oil	-	
M-19	Sh. 3	Lube Oil	-	
M-19	Sh. 4	Lube Oil	-	
M-19	Sh. 5	Lube Oil	-	
M-19	Sh. 6	Lube Oil	-	
M-19	Sh. 7	Lube Oil	-	
M-19	Sh. 8	Lube Oil	-	
M-19	Sh. 9	Lube Oil	-	
M-19	Sh.10	Lube Oil	-	
M-20	Sh. 1	Fuel & Diesel Oil Storage & Transfer	-	
M-20	Sh. 2	Fuel & Diesel Oil Storage & Transfer	-	
M-20	Sh. 3	Fuel & Diesel Oil Storage & Transfer (Fuel oil & Transfer System Unit 1	9.5-8	Sh.1
M-20	Sh. 4	Fuel & Diesel Oil Storage & Transfer (Cooling Water System Unit 1)	9.5-9	Sh.1
M-20	Sh. 5	Fuel & Diesel Oil Storage & Transfer (Cooling Water System Unit 1)	9.5-9	Sh.3
M-20	Sh. 6	Fuel & Diesel Oil Storage & Transfer (Starting Air System Unit 1)	9.5-10	Sh.1

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-2 (Cont'd)
FIGURE INDEX FOR PLANT SYSTEMS

P&ID Number		System	Former UFSAR Figure Number	
M-20	Sh. 7	Fuel & Diesel Oil Storage & Transfer (Lube Oil System Unit 1)	9.5-11	Sh.1
M-20	Sh. 8	Fuel & Diesel Oil Storage & Transfer (Combustion air intake & Exhaust Unit 1)	9.5-12	Sh.1
M-20	Sh. 9	Fuel & Diesel Oil Storage & Transfer (Fuel Oil & Transfer System Unit 2)	9.5-8	Sh.2
M-20	Sh. 10	Fuel & Diesel Oil Storage & Transfer (Cooling Water System Unit 2)	9.5.9	Sh.2
M-20	Sh. 11	Fuel & Diesel Oil Storage & Transfer (Cooling Water System Unit 2)	9.5-9	Sh.4
M-20	Sh. 12	Fuel & Diesel Oil Storage & Transfer (Starting Air System Unit 2)	9.5-10	Sh.2
M-20	Sh. 13	Fuel & Diesel Oil Storage & Transfer (Lube Oil System Unit 2)	9.5-11	Sh.2
M-20	Sh. 14	Fuel & Diesel Oil Storage & Transfer (Combustion air intake & Exhaust Unit 2)	9.5-12	Sh.2
M-21	Sh. 1	Auxiliary Steam	10.4-6	Sh. 1
M-21	Sh. 2	Auxiliary Steam	10.4-6	Sh. 2
M-21	Sh. 3	Auxiliary Steam	10.4-6	Sh. 3
M-21	Sh. 4	Auxiliary Steam	-	
M-22	Sh. 1	Fire Protection	9.5-1	Sh. 1
M-22	Sh. 2	Fire Protection	9.5-1	Sh. 2
M-22	Sh. 3	Fire Protection	9.5-1	Sh. 3
M-22	Sh. 4	Fire Protection	9.5-1	Sh. 4
M-22	Sh. 5	Fire Protection	9.5-1	Sh. 5
M-22	Sh. 6	Fire Protection	9.5-1	Sh. 6
M-22	Sh. 7	Fire Protection	9.5-1	Sh. 7
M-22	Sh. 8	Fire Protection	9.5-1	Sh. 8
M-22	Sh. 9	Fire Protection	9.5-1	Sh. 9
M-22	Sh. 10	Fire Protection	-	
M-23	Sh. 1	Process Sampling	9.3-3	Sh. 1
M-23	Sh. 2	Process Sampling	9.3-3	Sh. 2
M-23	Sh. 3	Process Sampling	9.3-3	Sh. 3
M-23	Sh. 4	Process Sampling	9.3-3	Sh. 4
M-23	Sh. 5	Process Sampling	9.3-3	Sh. 5
M-23	Sh. 6	Process Sampling	9.3-3	Sh. 6
M-23	Sh. 7	Process Sampling	9.3-3	Sh. 7
M-23	Sh. 8	Process Sampling	9.3-3	Sh. 8
M-23	Sh. 9	Process Sampling	9.3-3	Sh. 9

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-2 (Cont'd)
FIGURE INDEX FOR PLANT SYSTEMS

P&ID Number		System	Former UFSAR Figure Number	
M-23	Sh. 10	Process Sampling	9.3-3	Sh. 10
M-23	Sh. 11	Process Sampling	9.3-3	Sh. 11
M-24	Sh. 1	Chlorination	-	
M-24	Sh. 2	Chlorination	-	
M-25	Sh. 1	Plant Leak Detection	5.2-11	Sh. 1
M-25	Sh. 2	Plant Leak Detection	5.2-11	Sh. 2
M-25	Sh. 3	Plant Leak Detection	5.2-11	Sh. 3
M-25	Sh. 4	Plant Leak Detection	5.2-11	Sh. 4
M-26	Sh. 1	Plant Process Radiation Monitoring	11.5-1	Sh. 1
M-26	Sh. 2	Plant Process Radiation Monitoring	11.5-1	Sh. 2
M-26	Sh. 3	Plant Process Radiation Monitoring	11.5-1	Sh. 3
M-26	Sh. 4	Plant Process Radiation Monitoring	11.5-1	Sh. 4
M-26	Sh. 5	Plant Process Radiation Monitoring	11.5-1	Sh. 5
M-26	Sh. 6	Plant Process Radiation Monitoring	11.5-1	Sh. 6
M-26	Sh. 7	Plant Process Radiation Monitoring	11.5-1	Sh. 7
M-26	Sh. 8	Plant Process Radiation Monitoring	11.5-1	Sh. 8
M-26	Sh. 9	Plant Process Radiation Monitoring	11.5-1	Sh.1
M-28	Sh. 1	Generator H2 Cooling and C02 Purge	10.2-2	Sh.1
M-28	Sh. 2	Generator H2 Cooling and C02 Purge	10.2-2	Sh. 2
M-28	Sh. 3	Generator H2 Cooling and C02 Purge	-	
M-28	Sh. 4	Generator H2 Cooling and C02 Purge	-	
M-30	Sh. 1	Postaccident Sample	11.5-2	Sh.1
M-30	Sh. 2	Postaccident Sample	11.5-2	Sh. 2
M-31	Sh. 1	Main Turbine EHC	-	
M-31	Sh. 2	Main Turbine EHC	-	
M-31	Sh. 3	Main Turbine EHC	-	
M-31	Sh. 4	Main Turbine EHC	-	
M-31	Sh. 5	Main Turbine EHC	-	
M-31	Sh. 6	Main Turbine EHC	-	
M-31	Sh. 7	Main Turbine EHC	-	
M-31	Sh. 8	Main Turbine EHC		

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-2 (Cont'd)
FIGURE INDEX FOR PLANT SYSTEMS

P&ID Number		System	Former UFSAR Figure Number	
M-33	Sh. 1	Stator Cooling	-	
M-33	Sh. 2	Stator Cooling	-	
M-41	Sh. 1	Nuclear Boiler	5.1-3	Sh. 1
M-41	Sh. 2	Nuclear Boiler	5.1-3	Sh. 2
M-41	Sh. 3	Nuclear Boiler	5.1-3	Sh. 3
M-41	Sh. 4	Nuclear Boiler	5.1-3	Sh. 4
M-41	Sh. 5	Nuclear Boiler	5.1-3	Sh. 5
M-41	Sh. 6	Nuclear Boiler	5.1-3	Sh. 6
M-42	Sh. 1	Nuclear Boiler Vessel Instrumentation	5.1-4	Sh. 1
M-42	Sh. 2	Nuclear Boiler Vessel Instrumentation	5.1-4	Sh. 2
M-42	Sh. 3	Nuclear Boiler Vessel Instrumentation	5.1-4	Sh. 3
M-42	Sh. 4	Nuclear Boiler Vessel Instrumentation	5.1-4	Sh. 4
M-42	Sh. 5	Nuclear Boiler Vessel Instrumentation	-	
M-42	Sh. 6	Nuclear Boiler Vessel Instrumentation	-	
M-43	Sh. 1	Reactor Recirculation Pump	5.4-2	Sh. 1
M-43	Sh. 2	Reactor Recirculation Pump	5.4-2	Sh. 2
M-43	Sh. 3	Reactor Recirculation Pump	5.4-2	Sh. 3
M-43	Sh. 4	Reactor Recirculation Pump	5.4-2	Sh. 4
M-44	Sh. 1	Reactor Water Cleanup	5.4-16	Sh. 1
M-44	Sh. 2	Reactor Water Cleanup	5.4-16	Sh. 2
M-44	Sh. 3	Reactor Water Cleanup	5.4-16	Sh. 3
M-44	Sh. 4	Reactor Water Cleanup	5.4-16	Sh. 4
M-45	Sh. 1	Cleanup Filter/Demineralizer	5.4-18	Sh.1
M-45	Sh. 2	Cleanup Filter/Demineralizer	5.4-18	Sh. 2
M-46	Sh. 1	Control Rod Drive Hydraulics Part A	4.6-5	Sh.1
M-46	Sh. 2	Control Rod Drive Hydraulics Part A	4.6-5	Sh. 2
M-47	Sh. 1	Control Rod Drive Hydraulics Part B	4.6-6	Sh.1
M-47	Sh 2	Control Rod Drive Hydraulics Part B	4.6-6	Sh. 2

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-2 (Cont'd)
FIGURE INDEX FOR PLANT SYSTEMS

P&ID Number	System	Former UFSAR Figure Number
M-48 Sh. 1	Standby Liquid Control	9.3-5 Sh.1
M-48 Sh. 2	Standby Liquid Control	9.3-5 Sh. 2
M-49 Sh. 1	Reactor Core Isolation Cooling	5.4-8 Sh.1
M-49 Sh. 2	Reactor Core Isolation Cooling	5.4-8 Sh. 2
M-50 Sh. 1	RCIC Pump-Turbine	5.4-9 Sh. 1
M-50 Sh. 2	RCIC Pump-Turbine	5.4-9 Sh. 2
M-50 Sh. 3	RCIC Pump-Turbine	5.4-9 Sh. 3
M-50 Sh. 4	RCIC Pump-Turbine	5.4-9 Sh. 4
M-51 Sh. 1	Residual Heat Removal	5.4-13 Sh. 1
M-51 Sh. 2	Residual Heat Removal	5.4-13 Sh. 2
M-51 Sh. 3	Residual Heat Removal	5.4-13 Sh. 3
M-51 Sh. 4	Residual Heat Removal	5.4-13 Sh. 4
M-51 Sh. 5	Residual Heat Removal	5.4-13 Sh. 5
M-51 Sh. 6	Residual Heat Removal	5.4-13 Sh. 6
M-51 Sh. 7	Residual Heat Removal	5.4-13 Sh. 7
M-51 Sh. 8	Residual Heat Removal	5.4-13 Sh. 8
M-52 Sh. 1	Core Spray	6.3-9 Sh. 1
M-52 Sh. 2	Core Spray	6.3-9 Sh. 2
M-52 Sh. 3	Core Spray	6.3-9 Sh. 3
M-52 Sh. 4	Core Spray	6.3-9 Sh. 4
M-53 Sh. 1	Fuel Pool Cooling	9.1-3 Sh. 1
M-53 Sh. 2	Fuel Pool Cooling	9.1-3 Sh. 2
M-53 Sh. 3	Fuel Pool Cooling	9.1-3 Sh. 3
M-53 Sh. 4	Fuel Pool Cooling	9.1-3 Sh. 4
M-54 Sh. 1	Fuel Pool Filter/Demineralizer	9.1-4 Sh. 1
M-54 Sh. 2	Fuel Pool Filter/Demineralizer	9.1-4 Sh. 2
M-55 Sh. 1	High Pressure Coolant Injection	6.3-7 Sh. 1
M-55 Sh. 2	High Pressure Coolant Injection	6.3-7 Sh. 2

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-2 (Cont'd)
FIGURE INDEX FOR PLANT SYSTEMS

P&ID Number		System	Former UFSAR Figure Number	
M-56	Sh. 1	HPCI Pump-Turbine	6.3-8	Sh. 1
M-56	Sh. 2	HPCI Pump-Turbine	6.3-8	Sh. 2
M-56	Sh. 3	HPCI Pump-Turbine	6.3-8	Sh. 3
M-56	Sh. 4	HPCI Pump-Turbine	6.3-8	Sh. 4
M-57	Sh. 1	Containment Atmospheric Control	9.4-5	Sh. 1
M-57	Sh. 2	Containment Atmospheric Control	9.4-5	Sh. 2
M-57	Sh. 3	Containment Atmospheric Control	9.4-5	Sh. 3
M-57	Sh. 4	Containment Atmospheric Control	9.4-5	Sh. 4
M-57	Sh. 5	Containment Atmospheric Control	9.4-5	Sh. 5
M-57	Sh. 6	Containment Atmospheric Control	9.4-5	Sh. 6
M-57	Sh. 7	Containment Atmospheric Control	9.4-5	Sh. 7
M-57	Sh. 8	Containment Atmospheric Control	-	
M-57	Sh. 9	Containment Atmospheric Control	-	
M-57	Sh.10	Containment Atmospheric Control	-	
M-57	Sh.11	Containment Atmospheric Control	-	
M-58	Sh. 1	Containment Hydrogen Recombiner "A"	6.2-37	Sh. 1
M-58	Sh. 2	Containment Hydrogen Recombiner "B"	6.2-37	Sh. 2
M-58	Sh. 3	Containment Hydrogen Recombiner "A"	6.2-37	Sh. 3
M-58	Sh. 4	Containment Hydrogen Recombiner "B"	6.2-37	Sh. 4
M-59	Sh. 1	Primary Containment Instrument Gas	9.3-2	Sh. 1
M-59	Sh. 2	Primary Containment Instrument Gas	9.3-2	Sh. 2
M-59	Sh. 3	Primary Containment Instrument Gas	9.3-2	Sh. 3
M-59	Sh. 4	Primary Containment Instrument Gas	9.3-2	Sh. 4
M-60	Sh. 1	Primary Containment Leak Testing	6.2-47	Sh. 1
M-60	Sh. 2	Primary Containment Leak Testing	6.2-47	Sh. 2
M-61	Sh. 1	Liquid Radwaste Collection	9.3-4	Sh. 1
M-61	Sh. 2	Liquid Radwaste Collection	9.3-4	Sh. 2
M-61	Sh. 3	Liquid Radwaste Collection	9.3-4	Sh. 3
M-61	Sh. 4	Liquid Radwaste Collection	9.3-4	Sh. 4
M-61	Sh. 5	Liquid Radwaste Collection	9.3-4	Sh. 5

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-2 (Cont'd)
FIGURE INDEX FOR PLANT SYSTEMS

P&ID Number		System	Former UFSAR Figure Number	
M-62	Sh. 1	Liquid Waste Equipment Drain Processing	11.2-1	Sh. 1
M-62	Sh. 2	Liquid Waste Equipment Drain Processing	11.2-1	Sh. 2
M-63	Sh. 1	Liquid Radwaste Floor Drain Processing	11.2-2	Sh. 1
M-63	Sh. 2	Liquid Radwaste Floor Drain Processing	11.2-2	Sh. 2
M-64	Sh. 1	Liquid Radwaste Chemical and Laundry Processing	11.2-3	Sh. 1
M-64	Sh. 2	Liquid Radwaste Chemical and Laundry Processing	11.2-3	Sh. 2
M-66	Sh. 1	Solid Radwaste Collection	11.4-1	Sh. 1
M-66	Sh. 2	Solid Radwaste Collection	11.4-1	Sh. 2
M-67	Sh. 1	Solid Radwaste Collection and Processing	11.4-2	Sh. 1
M-67	Sh. 2	Solid Radwaste Collection and Processing	11.4-2	Sh. 2
M-67	Sh. 3	Solid Radwaste Collection and Processing	11.4-2	Sh. 3
M-67	Sh. 4	Solid Radwaste Collection and Processing	11.4-2	Sh. 4
M-67	Sh. 5	Solid Radwaste Collection and Processing	11.4-2	Sh. 5
M-68	Sh. 1	Plant Waste Water Effluent	-	
M-68	Sh. 2	Plant Waste Water Effluent	-	
M-69	Sh 1	Gaseous Radwaste - Recombination	11.3-2	Sh 1
M-69	Sh. 2	Gaseous Radwaste - Recombination	11.3-2	Sh. 2
M-69	Sh. 3	Gaseous Radwaste - Recombination	11.3-2	Sh. 3
M-69	Sh. 4	Gaseous Radwaste - Recombination	11.3-2	Sh. 4
M-70	Sh. 1	Gaseous Radwaste - Ambient Charcoal Treatment	11.3-3	Sh. 1
M-70	Sh. 2	Gaseous Radwaste - Ambient Charcoal Treatment	11.3-3	Sh. 2
M-70	Sh. 3	Gaseous Radwaste - Ambient Charcoal Treatment	11.3-3	Sh. 3
M-70	Sh. 4	Gaseous Radwaste - Ambient Charcoal Treatment	11.3-3	Sh. 4
M-75	Sh. 1	Turbine Enclosure HVAC	9.4-4	Sh. 1
M-75	Sh. 2	Turbine Enclosure HVAC	9.4-4	Sh. 2
M-75	Sh. 3	Turbine Enclosure HVAC	9.4-4	Sh. 3

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-2 (Cont'd)
FIGURE INDEX FOR PLANT SYSTEMS

P&ID Number		System	Former UFSAR Figure Number	
M-75	Sh. 4	Turbine Enclosure HVAC	9.4-4	Sh. 4
M-75	Sh. 5	Turbine Enclosure HVAC	9.4-4	Sh. 5
M-75	Sh. 6	Turbine Enclosure HVAC	9.4-4	Sh. 6
M-75	Sh. 7	Turbine Enclosure HVAC	9.4-4	Sh. 7
M-75	Sh. 8	Turbine Enclosure HVAC	9.4-4	Sh. 8
M-76	Sh. 1	Reactor Enclosure HVAC	9.4-2	Sh. 1
M-76	Sh. 2	Reactor Enclosure HVAC	9.4-2	Sh. 2
M-76	Sh. 3	Reactor Enclosure HVAC	9.4-2	Sh. 3
M-76	Sh. 4	Reactor Enclosure HVAC	9.4-2	Sh. 4
M-76	Sh. 5	Reactor Enclosure HVAC	9.4-2	Sh. 5
M-76	Sh. 6	Reactor Enclosure HVAC	9.4-2	Sh. 6
M-76	Sh. 7	Reactor Enclosure HVAC	9.4-2	Sh. 7
M-76	Sh. 8	Reactor Enclosure HVAC	9.4-2	Sh. 8
M-76	Sh. 9	Reactor Enclosure HVAC	9.4-2	Sh. 9
M-76	Sh.10	Reactor Enclosure HVAC	9.4-2	Sh.10
M-77	Sh. 1	Drywell Air Cooling	9.4-7	Sh.1
M-77	Sh. 2	Drywell Air Cooling	9.4-7	Sh. 2
M-78	Sh. 1	Control Structure HVAC	9.4-1	Sh. 1
M-78	Sh. 2	Control Structure HVAC	9.4-1	Sh. 2
M-78	Sh. 3	Control Structure HVAC	9.4-1	Sh. 3
M-78	Sh. 4	Control Structure HVAC	9.4-1	Sh. 4
M-79	Sh. 1	Radwaste Enclosure HVAC	9.4-3	Sh. 1
M-79	Sh. 2	Radwaste Enclosure HVAC	9.4-3	Sh. 2
M-79	Sh. 3	Radwaste Enclosure HVAC	9.4-3	Sh. 3
M-80	Sh. 1	Administration Complex, Offices-Shops-HVAC	9.4-11	Sh. 1
M-80	Sh. 2	Administration Complex, Offices-Shops-HVAC	9.4-11	Sh. 2
M-80	Sh. 3	Administration Complex, Offices-Shops-HVAC	9.4-11	Sh. 3
M-80	Sh. 4	Administration Complex, Offices-Shops-HVAC	9.4-11	Sh. 4

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-2 (Cont'd)
FIGURE INDEX FOR PLANT SYSTEMS

P&ID Number		System	Former UFSAR Figure Number
M-81	Sh. 1	Miscellaneous Structures HVAC	9.4-10 Sh. 1
M-81	Sh. 2	Miscellaneous Structures HVAC	9.4-10 Sh. 2
M-81	Sh. 3	Miscellaneous Structures HVAC	9.4-10 Sh. 3
M-82	Sh. 1	Hot Maintenance Shop HVAC	9.4-9 Sh.1
M-82	Sh. 2	Hot Maintenance Shop HVAC	9.4-9 Sh. 2
M-83	Sh. 1	Administration Complex Guard Station HVAC	-
M-87	Sh. 1	Drywell Chilled Water	9.2-27 Sh. 1
M-87	Sh. 2	Drywell Chilled Water	9.2-27 Sh. 2
M-87	Sh. 3	Drywell Chilled Water	9.2-27 Sh. 3
M-87	Sh. 4	Drywell Chilled Water	9.2-27 Sh. 4
M-87	Sh. 5	Drywell Chilled Water	9.2-27 Sh. 5
M-87	Sh. 6	Drywell Chilled Water	9.2-27 Sh. 6
M-87	Sh. 7	Drywell Chilled Water	9.2-27 Sh. 7
M-87	Sh. 8	Drywell Chilled Water	9.2-27 Sh. 8
M-87	Sh. 9	Drywell Chilled Water	9.2-27 Sh. 9
M-87	Sh. 10	Drywell Chilled Water	9.2-27 Sh. 10
M-90	Sh. 1	Control Structure Chilled Water	9.2-28 Sh. 1
M-90	Sh. 2	Control Structure Chilled Water	9.2-28 Sh. 2
M-96	Sh. 1	Plant Heating System	-
M-96	Sh. 2	Plant Heating System	-
M-96	Sh. 3	Plant Heating System	-
M-96	Sh. 4	Plant Heating System	-
M-96	Sh. 5	Plant Heating System	-
M-96	Sh. 6	Plant Heating System	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-3
CONTROL AND INSTRUMENTATION DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
M-01FD	Sh.1	Main Steam	-	
M-02FD	Sh.1	Extraction Steam	-	
M-02FD	Sh.2	Extraction Steam	-	
M-03FD	Sh.1	Vents and Drains Heaters 1 & 2 Drain Cooler 1	-	
M-04FD	Sh.1	Vents and Drains Heaters 3, 4, 5 & 6	-	
M-05FD	Sh.1	Condensate System	-	
M-05FD	Sh.2	Condensate System	-	
M-06FD	Sh.1	Feedwater System	-	
M-06FD	Sh.2	Feedwater System	-	
M-06FD	Sh.3	Feedwater System	-	
M-07FD	Sh.1	Air Removal and Sealing Steam	-	
M-07FD	Sh.2	Air Removal and Sealing Steam	-	
M-07FD	Sh.3	Air Removal and Sealing Steam	-	
M-08FD	Sh.1	Condensate and Refueling Water Storage	-	
M-08FD	Sh.2	Condensate and Refueling Water Storage	-	
M-09FD	Sh.1	Circulating Water	-	
M-09FD	Sh.2	Circulating Water	-	
M-09FD	Sh.3	Circulating Water	-	
M-09FD	Sh.4	Circulating Water	-	
M-09FD	Sh.5	Circulating Water	-	
M-10FD	Sh.1	Service Water	-	
M-10FD	Sh.2	Service Water	-	
M-10FD	Sh.3	Service Water	-	
M-11FD	Sh.1	Emergency Service Water	7.3-21	Sh.1
M-11FD	Sh.2	Emergency Service Water	7.3-21	Sh.2
M-11FD	Sh.3	Emergency Service Water	7.3-21	Sh.3
M-11FD	Sh.4	Emergency Service Water	7.3-21	Sh.4
M-12FD	Sh.1	RHR Service Water	7.3-22	Sh.1
M-12FD	Sh.2	RHR Service Water	7.3-22	Sh.2
M-12FD	Sh.3	RHR Service Water	7.3-22	Sh.3

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-3 (Cont'd)
CONTROL AND INSTRUMENTATION DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
M-12FD	Sh.4	RHR Service Water	7.3-22	Sh.4
M-12FD	Sh.5	RHR Service Water	7.3-22	Sh.5
M-12FD	Sh.6	RHR Service Water	7.3-22	Sh.6
M-13FD	Sh.1	Reactor Building Cooling Water	7.3-17	Sh.1
M-14FD	Sh.1	Turbine Building Cooling Water	-	
M-15FD	Sh.1	Compressed Air	-	
M-16FD	Sh.1	Condensate Filter/Demineralizers	-	
M-17FD	Sh.1	Clarified Water	-	
M-18FD	Sh.1	Make-Up Demineralizer	-	
M-19FD	Sh.1	Lube Oil	-	
M-20FD	Sh.1	Fuel and Diesel Oil Storage and Transfer	-	
M-21FD	Sh.1	Auxiliary Steam	-	
M-26FD	Sh.1	Radiation Monitoring	-	
M-41FD	Sh.1	Nuclear Boiler	-	
M-41FD	Sh.2	Nuclear Boiler	-	
M-42FD	Sh.1	Nuclear Boiler Vessel Instrumentation	-	
M-45FD	Sh.1	Clean-Up Filter Demineralizer	-	
M-46FD	Sh.1	Control Rod Drive Hydraulic Part "A"	-	
M-49FD	Sh.1	Reactor Core Isolation Cooling	-	
M-50FD	Sh.1	Reactor Core Isolation Cooling	-	
M-51FD	Sh.1	Residual Heat Removal	7.3-16	Sh.1
M-51FD	Sh.2	Residual Heat Removal	7.3-16	Sh.2
M-51FD	Sh.3	Residual Heat Removal	7.3-16	Sh.3
M-51FD	Sh.4	Residual Heat Removal	7.3-16	Sh.4
M-52FD	Sh.1	Core Spray	7.3-15	Sh.1
M-53FD	Sh.1	Fuel Pooling Cooling and Cleanup	-	
M-54FD	Sh.1	Fuel Pool Filter Demineralizer	-	
M-55FD	Sh.1	High Pressure Coolant Injection	7.3-14	Sh.1
M-57FD	Sh.1	Containment Atmospheric Control	7.3-18	Sh.1
M-57FD	Sh.2	Containment Atmospheric Control	7.3-18	Sh.2

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-3 (Cont'd)
CONTROL AND INSTRUMENTATION DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
M-57FD	Sh.3	Containment Atmospheric Control	7.3-18	Sh.3
M-57FD	Sh.4	Containment Atmospheric Control	7.3-18	Sh.4
M-57FD	Sh.5	Containment Atmospheric Control	7.3-18	Sh.5
M-59FD	Sh.1	Primary Containment Instrument Gas	7.3-19	Sh.1
M-59FD	Sh.2	Primary Containment Instrument Gas	7.3-19	Sh.2
M-60FD	Sh.1	Primary Containment Leak Testing	-	
M-61FD	Sh.1	Liquid Radwaste Collection	7.3-20	Sh.1
M-61FD	Sh.2	Radwaste Collection	7.3-20	Sh.2
M-62FD	Sh.1	Liquid Radwaste Equipment Drain Processing	-	
M-62FD	Sh.2	Liquid Radwaste Equipment Drain Processing	-	
M-63FD	Sh.1	Liquid Radwaste Floor Drain Processing	-	
M-63FD	Sh.2	Liquid Radwaste Floor Drain Processing	-	
M-64FD	Sh.1	Liquid Radwaste Chemical and Laundry Processing	-	
M-64FD	Sh.2	Liquid Radwaste Chemical and Laundry Processing	-	
M-66FD	Sh.1	Solid Radwaste Collection	-	
M-66FD	Sh.2	Solid Radwaste Collection	-	
M-67FD	Sh.1	Solid Radwaste Collection and Processing	-	
M-67FD	Sh.2	Solid Radwaste Collection and Processing	-	
M-67FD	Sh.3	Solid Radwaste Collection and Processing	-	
M-68FD	Sh.1	Plant Waste Water Treatment	-	
M-68FD	Sh.2	Plant Waste Water Treatment	-	
M-69FD	Sh.1	Gaseous Radwaste Recombination	-	
M-70FD	Sh.1	Gaseous Radwaste, Ambient Charcoal Treatment	-	
M-75FD	Sh.1	Turbine Enclosure - HVAC	-	
M-75FD	Sh.2	Turbine Enclosure - HVAC	-	
M-75FD	Sh.3	Turbine Enclosure - HVAC	-	
M-75FD	Sh.4	Turbine Enclosure - HVAC	-	
M-76FD	Sh.1	Reactor Enclosure - HVAC	7.3-23	Sh.1
M-76FD	Sh.2	Reactor Enclosure - HVAC	7.3-23	Sh.2
M-76FD	Sh.3	Reactor Enclosure - HVAC	7.3-23	Sh.3

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-3 (Cont'd)
CONTROL AND INSTRUMENTATION DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
M-76FD	Sh.4	Reactor Enclosure - HVAC	7.3-23	Sh.4
M-76FD	Sh.5	Reactor Enclosure - HVAC	7.3-23	Sh.5
M-76FD	Sh.6	Reactor Enclosure - HVAC	7.3-23	Sh.6
M-76FD	Sh.7	Reactor Enclosure - HVAC	7.3-23	Sh.7
M-76FD	Sh.8	Reactor Enclosure - HVAC	7.3-23	Sh.8
M-76FD	Sh.9	Reactor Enclosure - HVAC	7.3-23	Sh.9
M-76FD	Sh.10	Reactor Enclosure - HVAC	7.3-23	Sh.10
M-76FD	Sh.11	Reactor Enclosure - HVAC	7.3-23	Sh.11
M-76FD	Sh.12	Reactor Enclosure - HVAC	7.3-23	Sh.12
M-76FD	Sh.13	Reactor Enclosure - HVAC	7.3-23	Sh.13
M-76FD	Sh.14	Reactor Enclosure - HVAC	7.3-23	Sh.14
M-76FD	Sh.15	Reactor Enclosure - HVAC	7.3-23	Sh.15
M-76FD	Sh.16	Reactor Enclosure - HVAC	7.3-23	Sh.16
M-77FD	Sh.1	Drywell - HVAC	7.3-13	Sh.1
M-77FD	Sh.2	Drywell - HVAC	7.3-13	Sh.2
M-78FD	Sh.1	Control Enclosure - HVAC	7.3-24	Sh.1
M-78FD	Sh.2	Control Enclosure - HVAC	7.3-24	Sh.2
M-78FD	Sh.3	Control Enclosure - HVAC	7.3-24	Sh.3
M-78FD	Sh.4	Control Enclosure - HVAC	7.3-24	Sh.4
M-78FD	Sh.5	Control Enclosure - HVAC	7.3-24	Sh.5
M-78FD	Sh.6	Control Enclosure - HVAC	7.3-24	Sh.6
M-78FD	Sh.7	Control Enclosure - HVAC	7.3-24	Sh.7
M-78FD	Sh.8	Control Enclosure - HVAC	7.3-24	Sh.8
M-79FD	Sh.1	Radwaste Enclosure - HVAC	-	
M-79FD	Sh.2	Radwaste Enclosure - HVAC	-	
M-79FD	Sh.3	Radwaste Enclosure - HVAC	-	
M-80FD	Sh.1	Administration Complex, Offices and Shop-HVAC	-	
M-80FD	Sh.2	Administration Complex, Offices and Shop-HVAC	-	
M-80FD	Sh.3	Administration Complex, Offices and Shop-HVAC	-	
M-80FD	Sh.4	Administration Complex, Offices and Shop-HVAC	-	

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-3 (Cont'd)
CONTROL AND INSTRUMENTATION DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
M-80FD	Sh.5	Administration Complex, Offices and Shop-HVAC	-	
M-80FD	Sh.6	Administration Complex, Offices and Shop-HVAC	-	
M-80FD	Sh.7	Administration Complex, Offices and Shop-HVAC	-	
M-80FD	Sh.8	Administration Complex, Offices and Shop-HVAC	-	
M-80FD	Sh.9	Administration Complex, Offices and Shop-HVAC	-	
M-80FD	Sh.10	Administration Complex, Offices and Shop-HVAC	-	
M-80FD	Sh.11	Administration Complex, Offices and Shop-HVAC	-	
M-80FD	Sh.12	Administration Complex, Offices and Shop-HVAC	-	
M-81FD	Sh.1	Miscellaneous Structures-HVAC	7.3-12	Sh.1
M-81FD	Sh.2	Miscellaneous Structures-HVAC	7.3-12	Sh.2
M-81FD	Sh.3	Miscellaneous Structures-HVAC	7.3-12	Sh.3
M-81FD	Sh.4	Miscellaneous Structures-HVAC	7.3-12	Sh.4
M-82FD	Sh.1	Administration Complex, Hot Maintenance Shop	-	
M-82FD	Sh.2	Administration Complex, Hot Maintenance Shop	-	
M-82FD	Sh.3	Administration Complex, Hot Maintenance Shop	-	
M-82FD	Sh.4	Administration Complex, Hot Maintenance Shop	-	
M-82FD	Sh.5	Administration Complex, Hot Maintenance Shop	-	
M-82FD	Sh.6	Administration Complex, Hot Maintenance Shop	-	
M-82FD	Sh.7	Administration Complex, Hot Maintenance Shop	-	
M-82FD	Sh.8	Administration Complex, Hot Maintenance Shop	-	
M-83FD	Sh.1	Administration Complex, Guard Station	-	
M-83FD	Sh.2	Administration Complex, Guard Station	-	
M-83FD	Sh.3	Administration Complex, Guard Station	-	
M-83FD	Sh.4	Administration Complex, Guard Station	-	
M-83FD	Sh.5	Administration Complex, Guard Station	-	
M-83FD	Sh.6	Administration Complex, Guard Station	-	
M-83FD	Sh.7	Administration Complex, Guard Station	-	
M-87FD	Sh.1	Drywell Chilled Water	-	
M-87FD	Sh.2	Drywell Chilled Water	-	
M-87FD	Sh.3	Drywell Chilled Water	-	

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-3 (Cont'd)
CONTROL AND INSTRUMENTATION DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
M-90FD	Sh.1	Control Structure Chilled Water	7.3-25	Sh.1
M-96FD	Sh.1	Plant Heating Steam	-	
M-602	Sh.1	Control Room Arrangement - El. 269'	7.5-1	Sh.1
M-602	Sh.2	Control Room Arrangement - El. 269'	7.5-1	Sh.2
M-603	Sh.1	Auxiliary Equipment Room Arrangement el 289'-0"	7.5-2	Sh.1
M-603	Sh.2	Auxiliary Equipment Room Arrangement el 289'-0"	7.5-2	Sh.2
M-675	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 217'-0" Area 1	-	
M-676	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 239'-0" Area 1	-	
M-677	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 255'-0" Area 1	7.2-11	Sh.1
M-678	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 269'-0" Area 1	-	
M-679	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 189'-0" Area 2	-	
M-680	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 217'-0" Area 2	-	
M-681	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 239'-0" Area 2	-	
M-682	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 255'-0" Area 2	-	
M-683	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 269'-0" Area 2	-	
M-685	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 189'-0" Area 3	-	
M-686	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 217'-0" Area 3	-	
M-687	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 239'-0" Area 3	-	
M-688	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 269'-0" Area 3	-	
M-689	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 200'-0" Area 6	-	
M-690	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 217'-0" Area 6	-	
M-691	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 239'-0" Area 6	-	
M-693	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 269'-0" Area 6	-	
M-695	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 200'-0" Area 7	-	
M-696	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 217'-0" Area 7	-	
M-697	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 239'-0" Area 7	-	
M-699	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 269'-0" Area 7	-	

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-3 (Cont'd)
CONTROL AND INSTRUMENTATION DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
M-700	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 285'-0" Area 7	-
M-701	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 180'-0" Area 8	-
M-701	Sh.2	Unit 1 - Turbine Building Instrument Location Plan el 180'-0" Area 8	-
M-702	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 180'-0" Area 8	-
M-703	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 180'-0" Area 8	-
M-704	Sh.1	Unit 1 - Turbine Building Instrument Location Plan el 200'-0" Area 8	-
M-704	Sh.2	Unit 1 - Turbine Building Instrument Location Plan el 200'-0" Area 8	-
M-705	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 177'-0" Area 11	-
M-706	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 201'-0" Area 11	-
M-707	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 217'-0" Area 11	-
M-708	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 253'-0" Area 11	-
M-709	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 283'-0" Area 11	-
M-710	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 313'-0" Area 11	-
M-711	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 177'-0" Area 12	-
M-712	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 201'-0" Area 12	-
M-713	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 217'-0" Area 12	-
M-714	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 253'-0" Area 12	-
M-715	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 283'-0" Area 12	-
M-716	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 313'-0" Area 12	-
M-717	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 177'-0" Area 15	-
M-718	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 201'-0" Area 15	-
M-719	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 217'-0" Area 15	-
M-720	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 253'-0" Area 15	-
M-721	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 283'-0" Area 15	-
M-722	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 313'-0" Area 15	-
M-723	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 177'-0" Area 16	-
M-724	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 201'-0" Area 16	-
M-725	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 217'-0" Area 16	-
M-726	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 253'-0" Area 16	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-3 (Cont'd)
CONTROL AND INSTRUMENTATION DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
M-727	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 283'-0" Area 16	-
M-728	Sh.1	Unit 1 - Reactor Building Instrument Location Plan el 313'-0" Area 16	-
M-729	Sh.1	Unit 1 - Radwaste Piping Tunnel	-
M-730	Sh.1	Unit 1 - Radwaste Piping Tunnel	-
M-731	Sh.1	Unit 1 - Reactor Building Plan el 352'-0" Area 11	-
M-732	Sh.1	Unit 1 - Reactor Building Plan el 352'-0" Area 12	-
M-733	Sh.1	Unit 1 - Reactor Building Plan el 352'-0" Area 15	-
M-734	Sh.1	Unit 1 - Reactor Building Plan el 352'-0" Area 16	-
M-735	Sh.1	Unit 2 - Radwaste Building Instrument Location Plan el 195'-0" Area 19	-
M-736	Sh.1	Unit 2 - Radwaste Building Instrument Location Plan el 162'-0" Area 20	-
M-737	Sh.1	Unit 2 - Radwaste Building Instrument Location Plan el 191'-0" Area 20	-
M-738	Sh.1	Unit 2 - Radwaste Building Instrument Location Plan el 217'-0" Area 20	-
M-740	Sh.1	Unit 2 - Radwaste Building Instrument Location Plan el 195'-0" Area 21	-
M-741	Sh.1	Unit 2 - Radwaste Building Instrument Location Plan el 162'-0" Area 22	-
M-742	Sh.1	Unit 2 - Radwaste Building Instrument Location Plan el 191'-0" Area 22	-
M-743	Sh.1	Unit 2 - Radwaste Building Instrument Location Plan el 217'-0" Area 22	-
M-744	Sh.1	Unit 2 - Radwaste Building Instrument Location Plan el 257'-0" Area 22	-
M-745	Sh.1	Unit 2 - Radwaste Building Instrument Location Plan el 162'-0" Area 23	-
M-746	Sh.1	Unit 2 - Radwaste Building Instrument Location Plan el 191'-0" Area 23	-
M-747	Sh.1	Unit 2 - Radwaste Building Instrument Location Plan el 237'-0" Area 20	-
M-748	Sh.1	Unit 2 - Radwaste Building Instrument Location Plan el 257'-0" Area 20	-
M-749	Sh.1	Unit 1 - Reactor Building Tunnel el 198'-0" Areas 15 and 16	-
M-750	Sh.1	Unit 1 - Turbine Building el 302'-0" Area 6	-
M-751	Sh.1	Unit 1 - Turbine Building el 302'-0" Area 7	-
M-752	Sh.1	Control Area el 304'-0" Area 8	-
M-753	Sh.1	Control Area el 332'-0" Area 8	-
M-754	Sh.1	Control Area el 350'-0" Area 8	-
M-755	Sh.1	Instrument Location Drawing Radwaste Building Plan el 217'-0" Area 19	-
M-756	Sh.1	Instrument Location Condensate & Refueling Water	-
M-757	Sh.1	Auxiliary Boiler el 217'-0" and 230'-9" Storage Tank, Piping Plan & Section	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-3 (Cont'd)
CONTROL AND INSTRUMENTATION DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
M-758	Sh.1	Fuel Oil Tank, Condensation Storage Tank Number 2 and Pump House	-
M-759	Sh.1	Unit 1 - Instrument Location Plan Circulating Water Pump House	-
M-760	Sh.1	Unit 1 - Instrument Location Plan Service Water Pump	-
M-761	Sh.1	Unit 2 - Instrument Location Plan Circulating Water Pump House	-
M-762	Sh.1	Instrument Installation Detail Circulating Water Pumps	-
M-763	Sh.1	Instrument Location Circulating Water, Chlorination and H2SO4 FD System	-
M-764	Sh.1	Instrument Location Water Treatment Building	-
M-765	Sh.1	Instrument Installation Detail Water Treatment Building	-
	Sh.2	Instrument Installation Detail Water Treatment Building	
M-765	Sh.1	Instrument Installation Detail Water Treatment Building	-
M-766	Sh.1	Instrument Location Drawing Unit 1 - Reactor Building el 331'-0" Area 16	-
M-767	Sh.1	Instrument Location Drawing Spray Pond Pumphouse	-
M-768	Sh.1	Instrument Location Drawing Hydrogen Generating Facility	-
M-769	Sh.1	Yard Work - Partial Area H and J Valve and Meter Pit	-
M-838	Sh.1	Supports for Condenser Water Box Instrument Lines Units 1 and 2	-
M-840	Sh.1	Drywell Plan el 253'-0" Areas 11, 12, 15 and 16	-
M-841	Sh.1	Administration Building, Shop and Warehouse el 217'-0"	-
M-842	Sh.1	Administration Building, Shop and Warehouse el 203'-0", 230'-0" and 269'-0"	-
M-843	Sh.1	Units 1 and 2 Control Area 8 el 269'-0"	-
M-844	Sh.1	Units 1 and 2 Control Area 8 el 289'-0"	-
M-845	Sh.1	Instrument Location Drawing - Yard Work	-
M-846	Sh.1	Instrument Location Drawing - Diesel Oil Storage and Yard el 217'-0"	-
M-847	Sh.1	Unit 1 - Instrument Location Drawing Diesel Generator Enclosure el 217'-0"	-
M-848	Sh.1	Instrument Location Drawing Reactor Roof Units 1 and 2 Plan at el 411'-9"	-
M-849	Sh.1	Instrument Location Radwaste Building Plan at el 237'-0" Area 22	-
M-850	Sh.1	Instrument Location Drawing Suppression Pool Platforms	-
M-883	Sh.1	Containment Leak Detection Radiation Monitor Seismic Modifications	-
M-969	Sh.1	Process Diagram Gaseous Radwaste - Recombiners	-
M-970	Sh.1	Process Diagram Off Gas Charcoal Absorber System	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-3 (Cont'd)
CONTROL AND INSTRUMENTATION DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
M-1500	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 189'-0" Area 4	-
M-1501	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 217'-0" Area 4	-
M-1502	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 239'-0" Area 4	-
M-1503	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 255'-0" Area 4	-
M-1504	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 269'-0" Area 4	-
M-1507	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 217'-0" Area 5	-
M-1508	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 239'-0" Area 5	-
M-1509	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 255'-0" Area 5	-
M-1510	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 269'-0" Area 5	-
M-1511	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 200'-0" Area 9	-
M-1512	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 217'-0" Area 9	-
M-1513	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 239'-0" Area 9	-
M-1515	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 269'-0" Area 9	-
M-1516	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 285'-0" Area 9	-
M-1517	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 302'-0" Area 9	-
M-1520	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 200'-0" Area 10	-
M-1521	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 217'-0" Area 10	-
M-1522	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 236'-0" Area 10	-
M-1524	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 269'-0" Area 10	-
M-1526	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 302'-0" Area 10	-
M-1527	Sh.1	Unit 2 - Turbine Building Instrument Location Plan el 180'-0" Area 8	-
M-1529	Sh.1	Unit 2 - Diesel Generator Instrument Location Plan el 217'-0"	-
M-1530	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 177'-0" Area 13	-
M-1531	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 201'-0" Area 13	-
M-1532	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 217'-0" Area 13	-
M-1533	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 253'-0" Area 13	-
M-1534	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 283'-0" Area 13	-
M-1535	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 313'-0" Area 13	-
M-1536	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 177'-0" Area 14	-
M-1537	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 201'-0" Area 14	-
M-1538	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 217'-0" Area 14	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-3 (Cont'd)
CONTROL AND INSTRUMENTATION DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number
M-1539	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 253'-0" Area 14	-
M-1540	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 283'-0" Area 14	-
M-1541	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 313'-0" Area 14	-
M-1542	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 177'-0" Area 17	-
M-1543	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 201'-0" Area 17	-
M-1544	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 217'-0" Area 17	-
M-1545	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 253'-0" Area 17	-
M-1546	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 283'-0" Area 17	-
M-1547	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 313'-0" Area 1	-
M-1548	Sh.1	Unit 2 - Reactor Building Piping Tunnel Areas 17 and 18	-
M-1550	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 177'-0" Area 18	-
M-1551	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 201'-0" Area 18	-
M-1552	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 217'-0" Area 18	-
M-1553	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 253'-0" Area 18	-
M-1554	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 283'-0" Area 18	-
M-1555	Sh.1	Unit 2 - Reactor Building Instrument Location Plan el 313'-0" Area 18	-
M-1556	Sh.1	Unit 2 - Reactor Building el 352'-0" Area 13	-
M-1557	Sh.1	Unit 2 - Reactor Building el 352'-0" Area 14	-
M-1558	Sh.1	Unit 2 - Reactor Building el 352'-0" Area 17	-
M-1559	Sh.1	Unit 2 - Reactor Building el 352'-0" Area 18	-
M-1560	Sh.1	Unit 2 - Radwaste Tunnel Piping	-
M-1561	Sh.1	Unit 2 - Radwaste Tunnel Piping	-
M-1562	Sh.1	Unit 2 - Radwaste Tunnel Piping	-
M-1563	Sh.1	Unit 2 - Instrument Location Plan Circulating Water and H2SO4	-
M-1564	Sh.1	Reactor Units 1 and 2 Instrument Location Plan (North Stack) el 364'-0" to 410'-0"	-
M-1565	Sh.1	Reactor Units 1 and 2 Instrument Location Plan (South Stack) el 352'-0" to 398'-7"	-
M-1566	Sh.1	Drywell Plan el 253'-0" Areas 13, 14, 17 and 18	-

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-4
FIGURE INDEX FOR MISC. DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
B21-1030-F-001		GE FCD - Nuclear Boiler System	7.3-8	Sh.1
B21-1030-F-002		GE FCD - Nuclear Boiler System	7.3-8	Sh.2
B21-1030-F-002	Sh.2	GE FCD - Nuclear Boiler System	7.3-8	Sh.3
B21-1030-F-003		GE FCD - Nuclear Boiler System	7.3-8	Sh.4
B21-1030-F-004		GE FCD - Nuclear Boiler System	7.3-8	Sh.5
B21-1030-F-005		GE FCD - Nuclear Boiler System	7.3-8	Sh.6
B32-1020-F-002		GE FCD - Reactor Recirculation System	7.7-6	Sh.1
B32-1020-F-003		GE FCD - Reactor Recirculation System	7.7-6	Sh.2
B32-1020-F-004		GE FCD - Reactor Recirculation System	7.7-6	Sh.3
B32-1020-F-005		GE FCD - Reactor Recirculation System	7.7-6	Sh.4
B32-1020-F-006		GE FCD - Reactor Recirculation System	7.7-6	Sh.5
C11-1020-G-004		GE Process Diagram – Control Rod Drive System	4.6-7	Sh.1
C11-1020-G-005		GE Process Diagram – Control Rod Drive System	4.6-7	Sh.2
C11-1020-G-006		GE Process Diagram – Control Rod Drive System	4.6-7	Sh.3
C11-1020-G-007		GE Process Diagram – Control Rod Drive System	4.6-7	Sh.4
C11-1030-F-008		GE FCD - Reactor Recirculation System	7.7-2	Sh.1
C11-1030-F-009		GE FCD - Reactor Recirculation System	7.7-2	Sh.2
C11-1030-F-010		GE FCD - Reactor Recirculation System	7.7-2	Sh.3
C11-1030-F-011		GE FCD - Reactor Recirculation System	7.7-2	Sh.4
C11-1030-F-012		GE FCD - Reactor Recirculation System	7.7-2	Sh.5
C11-1030-F-013		GE FCD - Reactor Recirculation System	7.7-2	Sh.6
C11-1030-F-014		GE FCD - Control Rod Drive System	7.7-2	Sh.7
C32-1010-F-001		GE IED – Feedwater Control System – Turbine Feedpump	7.7-8	Sh.1
C41-1030-F-002		GE FCD – Standby Liquid Control System	7.4-2	Sh.1
C41-1030-F-003		GE FCD – Standby Liquid Control System	7.4-2	Sh.2
C41-1030-F-004		GE FCD – Standby Liquid Control System	7.4-2	Sh.3
C51-1010-F-002		GE FCD - Neutron Monitoring System	7.6-1	Sh.1
C51-1010-F-003		GE FCD - Neutron Monitoring System	7.6-1	Sh.2
C51-1010-F-004	Sh.1	GE FCD - Neutron Monitoring System	7.6-1	Sh.3
C51-1010-F-004	Sh.2	GE FCD - Neutron Monitoring System	7.6-1	Sh.4
C51-1020-F-009		GE FCD - Neutron Monitoring System	7.6-4	Sh.1
C51-1020-F-010		GE FCD - Neutron Monitoring System	7.6-4	Sh.2
C51-1020-F-011		GE FCD - Neutron Monitoring System	7.6-4	Sh.3
C51-1020-F-012		GE FCD - Neutron Monitoring System	7.6-4	Sh.4

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-4 (Cont'd)
FIGURE INDEX FOR MISC. DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
C51-1020-F-013		GE FCD - Neutron Monitoring System	7.6-4	Sh.5
C51-1020-F-014		GE FCD - Neutron Monitoring System	7.6-4	Sh.6
C51-1020-F-015		GE FCD - Neutron Monitoring System	7.6-4	Sh.7
C51-1020-F-016	Sh.1	GE FCD - Neutron Monitoring System	7.6-4	Sh.8
C51-1020-F-016	Sh.2	GE FCD - Neutron Monitoring System	7.6-4	Sh.9
C51-1020-F-016	Sh.3	GE FCD - Neutron Monitoring System	7.6-4	Sh.10
C51-1020-F-016	Sh.4	GE FCD - Neutron Monitoring System	7.6-4	Sh.11
C51-1020-F-016	Sh.5	GE FCD - Neutron Monitoring System	7.6-4	Sh.12
C51-1020-F-016	Sh.6	GE FCD - Neutron Monitoring System	7.6-4	Sh.13
C51-1020-F-016	Sh.7	GE FCD - Neutron Monitoring System	7.6-4	Sh.14
C71-1010-F-002		GE IED - Reactor Protection System	7.2-1	Sh.1
C71-1010-F-003		GE IED - Reactor Protection System	7.2-1	Sh.2
C71-1010-F-004		GE IED - Reactor Protection System	7.2-1	Sh.3
C71-1010-F-005		GE IED - Reactor Protection System	7.2-1	Sh.4
DBA-110-E0001	Sh.1	RPV Head Vent Piping Isometric - Unit 1	3.6-30	Sh.1
DBA-110-J0001	Sh.1	RPV Head Vent Piping Isometric - Unit 1	3.6-30	Sh.1
E11-1020-G002	Sh.1	GE Process Diagram – Residual Heat Removal System	6.3-3	Sh.1
E11-1020-G002	Sh.2	GE Process Diagram – Residual Heat Removal System	6.3-3	Sh.2
E11-1020-G002	Sh.3	GE Process Diagram – Residual Heat Removal System	6.3-3	Sh.3
E11-1030-F-001		GE FCD – Residual Heat Removal System	7.3-10	Sh.1
E11-1030-F-001	Sh.1A	GE FCD – Residual Heat Removal System	7.3-10	Sh.1
E11-1030-F-002		GE FCD – Residual Heat Removal System	7.3-10	Sh.1
E11-1030-F-003		GE FCD – Residual Heat Removal System	7.7-10	Sh.3
E11-1030-F-003	Sh.1A	GE FCD – Residual Heat Removal System	7.3-10	Sh.3
E21-1020-G-001		GE Process Diagram – Core Spray System	6.3-2	Sh.1
E21-1030-F-004		GE FCD - Core Spray System	7.3-9	Sh.1
E21-1030-F-005		GE FCD - Core Spray System	7.3-9	Sh.2
E41-1020-G-002		GE Process Diagram – High Pressure Coolant Injection System	6.3-1	Sh.1
E41-1030-F-004		GE FCD - High Pressure Coolant Injection System	7.3-7	Sh.1
	Sh.2	GE FCD - High Pressure Coolant Injection System	7.3-7	Sh.2
E41-1030-F-005		GE FCD - High Pressure Coolant Injection System	7.3-7	Sh.3
	Sh.2	GE FCD - High Pressure Coolant Injection System	7.3-7	Sh.4
E41-1030-F-006		GE FCD - High Pressure Coolant Injection System	7.3-7	Sh.5
E41-1030-F-007		GE FCD - High Pressure Coolant Injection System	7.3-7	Sh.6

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-4 (Cont'd)
FIGURE INDEX FOR MISC. DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
E41-1030-F-008		GE FCD - High Pressure Coolant Injection System	7.3-7	Sh.7
E41-1030-F-009		GE FCD - High Pressure Coolant Injection System	7.3-7	Sh.8
E51-1020-G-002		GE Process Diagram – Reactor Core Isolation Cooling System	5.4-10	Sh.1
E51-1030-F-004		GE FCD - Reactor Core Isolation Cooling System	7.4-1	Sh.1
E51-1030-F-004	Sh.2	GE FCD - Reactor Core Isolation Cooling System	7.4-1	Sh.2
E51-1030-F-005		GE FCD - Reactor Core Isolation Cooling System	7.4-1	Sh.3
E51-1030-F-006		GE FCD - Reactor Core Isolation Cooling System	7.4-1	Sh.4
E51-1030-F-007		GE FCD - Reactor Core Isolation Cooling System	7.4-1	Sh.5
E51-1030-F-008		GE FCD - Reactor Core Isolation Cooling System	7.4-1	Sh.6
E51-1030-F-009		GE FCD - Reactor Core Isolation Cooling System	7.4-1	Sh.7
G31-1020-F-001		GE FCD - Reactor Water Cleanup System	7.7.11	Sh.1
G31-1030-G-001		GE Process Diagram - Reactor Water Cleanup System	5.4.17	Sh.1
N-00E-246-00193	Sh.1	Heat Balance Diagram-100%	10.1-1	Sh.1
C-2	Sh.1	Yardwork - Plot Plan	1.2-1	Sh.1
C-11	Sh.1	Yardwork - Fire Sytem	9A-3	Sh.1
C-12	Sh.1	Yardwork - Domestic Water System	9.2-29	Sh.1
M-110	Sh.1	Equipment Location - Turbine Enclosure - Unit 1 - Plan at El 200'	1.2-17	Sh.1
M-111	Sh.1	Equipment Location - Turbine Enclosure - Unit 1 - Plan at El 217'	1.2-19	Sh.1
M-112	Sh.1	Equipment Location - Turbine Enclosure - Unit 1 and Control Structure - Plan at El 239'	1.2-21	Sh.1
M-113	Sh.1	Equipment Location - Turbine Enclosure - Unit 1 - Plan at El 269'	1.2-23	Sh.1
M-114	Sh.1	Equipment Location - Turbine Enclosure - Unit 1 - Section A-A	1.2-28	Sh.1
M-115	Sh.1	Equipment Location - Turbine Enclosure - Unit 1 and Control Structure - Plan at El 302' & 304'	1.2-25	Sh.1
M-116	Sh.1	Equipment Location - Reactor Enclosure - Unit 1 - Plan at El 177'	1.2-2	Sh.1
M-117	Sh.1	Equipment Location - Reactor Enclosure - Unit 1 - Plan at El 201'	1.2-4	Sh.1
M-118	Sh.1	Equipment Location - Reactor Enclosure - Unit 1 - Plan at El 217'	1.2-6	Sh.1
M-119	Sh.1	Equipment Location - Reactor Enclosure - Unit 1 - Plan at El 253'	1.2-8	Sh.1
M-120	Sh.1	Equipment Location - Reactor Enclosure - Unit 1 & 2 - Plan at El 283'	1.2-10	Sh.1
M-121	Sh.1	Equipment Location - Reactor Enclosure - Unit 1 - Plan at El 313'	1.2-12	Sh.1
M-122	Sh.1	Equipment Location - Reactor Enclosure Refueling Area - Unit 1 - Plan at El 352'	1.2-14	Sh.1
	Sh.1		9.1-17A	Sh.1
M-123	Sh.1	Equipment Location - Reactor Enclosure - Unit 1 - Section A-A	1.2-16	Sh.1

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-4 (Cont'd)
FIGURE INDEX FOR MISC. DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
M-124	Sh.1	Equipment Location – Control Structure – Plan at El 321', 332', and 350'	1.2-27	Sh.1
M-125	Sh.1	Equipment Location – Turbine Enclosure – Unit 2 – Plan at El 200'	1.2-18	Sh.1
M-126	Sh.1	Equipment Location – Turbine Enclosure – Unit 2 – Plan at El 217'	1.2-20	Sh.1
M-127	Sh.1	Equipment Location – Turbine Enclosure – Unit 2 and Control Structure – Plan at El 239'	1.2-22	Sh.1
M-128	Sh.1	Equipment Location – Turbine Enclosure – Unit 2 – Plan at El 269'	1.2-24	Sh.1
M-129	Sh.1	Equipment Location – Turbine Enclosure – Unit 2 – Section A-A	1.2-29	Sh.1
M-130	Sh.1	Equipment Location – Turbine Enclosure – Unit 2 and Control Structure – Plan at El 302' & 304'	1.2-26	Sh.1
M-131	Sh.1	Equipment Location – Reactor Enclosure – Unit 2 – Plan at El 177'	1.2-3	Sh.1
M-132	Sh.1	Equipment Location – Reactor Enclosure – Unit 2 – Plan at El 201'	1.2-5	Sh.1
M-133	Sh.1	Equipment Location – Turbine Enclosure – Unit 2 – Plan at El 217'	1.2-7	Sh.1
M-134	Sh.1	Equipment Location – Reactor Enclosure – Unit 2 – Plan at El 253'	1.2-9	Sh.1
M-135	Sh.1	Equipment Location – Reactor Enclosure – Unit 2 – Plan at El 283'	1.2-11	Sh.1
M-136	Sh.1	Equipment Location – Reactor Enclosure – Unit 2 – Plan at El 313'	1.2-13	Sh.1
M-137	Sh.1	Equipment Location – Reactor Enclosure Refueling Area – Unit 2 – Plan at El 352'	1.2-15	Sh.1
	Sh.1		9.1-17B	Sh.1
M-138	Sh.1	Equipment Location – Reactor Enclosure – Unit 2 – Section A-A	1.2-16	Sh.2
M-140	Sh.1	Equipment Location – Radwaste Enclosure – Plan at El 162'	1.2-30	Sh.1
M-141	Sh.1	Equipment Location – Radwaste Enclosure – Plan at El 191'	1.2-31	Sh.1
M-142	Sh.1	Equipment Location – Radwaste Enclosure – Plan at El 217'	1.2-32	Sh.1
M-143	Sh.1	Equipment Location – Radwaste Enclosure – Plan at El 237' & 257'	1.2-33	Sh.1
M-144	Sh.1	Equipment Location – Radwaste Enclosure – Sections	1.2-34	Sh.1
M-145	Sh.1	Equipment Location – Diesel Generator Enclosure – Units 1 & 2 – Plan at El 217'	1.2-35	Sh.1
M-146	Sh.1	Equipment Location – Diesel Generator Enclosure – Units 1 & 2 – Sections	1.2-36	Sh.1
M-191	Sh.1	Piping and Mechanical – Turbine Building – Units 1 & 2 – El 180' – Area 8	1.2-75	Sh.1
M-192	Sh.1	Piping and Mechanical – Turbine Building – Units 1 & 2 – El 180' – Area 8	1.2-74	Sh.1
M-195	Sh.1	Piping and Mechanical – Turbine Building – Units 1 & 2 – El 200' – Area 8	1.2-76	Sh.1
M-196	Sh.1	Piping and Mechanical – Turbine Building – Units 1 & 2 – El 217' – Area 8	1.2-77	Sh.1
M-197	Sh.1	Piping and Mechanical – Turbine Building – Units 1 & 2 – El 239' – Area 8	1.2-78	Sh.1
M-198	Sh.1	Piping and Mechanical – Turbine Building – Units 1 & 2 – El 254' – Area 8	1.2-79	Sh.1
M-200	Sh.1	Piping and Mechanical – Turbine Building – Units 1 & 2 – El 269' – Area 8	1.2-80	Sh.1
M-201	Sh.1	Piping and Mechanical – Turbine Building – Units 1 & 2 – El 289' – Area 8	1.2-81	Sh.1
M-202	Sh.1	Piping and Mechanical – Turbine Building – Units 1 & 2 – El 304' – Area 8	1.2-82	Sh.1
M-206	Sh.1	Piping and Equipment Layout – Reactor Enclosure – Unit 1 – Plan at El.177' – Area 11	1.2-40	Sh.1
M-207	Sh.1	Piping and Mechanical – Reactor Bldg – Unit 1 – Plan at El.201'- Area 11	1.2-45	Sh.1

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-4 (Cont'd)
FIGURE INDEX FOR MISC. DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
M-208	Sh.1	Piping and Mechanical - Reactor Enclosure - Unit 1 - Plan at El.217' - Area 11	1.2-49	Sh.1
M-209	Sh.1	Piping and Equipment Layout - Reactor Enclosure - Unit 1 - Plan at El.253' - Area 11	1.2-53	Sh.1
M-210	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.283" - Area 11	1.2-57	Sh.1
M-211	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.313' - Area 11	1.2-61	Sh.1
M-213	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Drywell Plan at El.238' - Area 11, 12, 15, & 16	1.2-65	Sh.1
M-215	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Section B-B - Areas 11, 12, & 16	1.2-71	Sh.1
M-217	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Section D-D - Areas 12, & 16	1.2-72	Sh.1
M-218	Sh.1	Piping and Equipment Layout - Reactor Enclosure - Unit 1 - Plan at El.177' - Area 12	1.2-41	Sh.1
M-219	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.201' - Area 12	1.2-46	Sh.1
M-220	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.217' - Area 12	1.2-50	Sh.1
M-221	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.253' - Area 12	1.2-54	Sh.1
M-222	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.283' - Area 12	1.2-58	Sh.1
M-223	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.313' - Area 12	1.2-62	Sh.1
M-225	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Drywell Plan at El.253' - Area 11, 12, 15, & 16	1.2-66	Sh.1
M-226	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Drywell Plan at El.272'-9" - Area 11, 12, 15, & 16	1.2-67	Sh.1
M-227	Sh.1	Piping and Equipment Layout - Reactor Enclosure - Unit 1 - Plan at El.177' - Area 15	1.2-42	Sh.1
M-228	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.210' - Area 15	1.2-47	Sh.1
M-229	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.217' - Area 15	1.2-51	Sh.1
M-230	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.253' - Area 15	1.2-55	Sh.1
M-231	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.283' - Area 15	1.2-59	Sh.1
M-232	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.313' - Area 15	1.2-63	Sh.1
M-234	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Drywell Plan at El.286' - Area 11, 12, 15, & 16	1.2-68	Sh.1
M-235	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Drywell Plan at El.295' - Area 11, 12, 15, & 16	1.2-69	Sh.1
M-236	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Drywell Plan at El.310' - Area 11, 12, 15, & 16	1.2-70	Sh.1
M-237	Sh.1	Piping and Equipment Layout - Reactor Enclosure - Unit 1 - Plan at El.177' Area 16	1.2-43	Sh.1
M-238	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.210' - Area 16	1.2-48	Sh.1
M-239	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.217' - Area 16	1.2-52	Sh.1
M-240	Sh.1	Piping and Mechanical - Reactor Enclosure - Unit 1 - Plan at El.253' - Area 16	1.2-56	Sh.1
M-241	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.283' - Area 16	1.2-60	Sh.1
M-242	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 1 - Plan at El.313' - Area 16	1.2-64	Sh.1
M-246	Sh.1	Piping and Equipment Layout - Reactor Enclosure - Unit 1 - Plan at El.191' Area 15 & 16	1.2-44	Sh.1
M-312	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.283' - Area 17	1.2-60	Sh.2
M-313	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.313' - Area 17	1.2-64	Sh.2
M-316	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Section B-B - Areas 13, & 14	1.2-71	Sh.2

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-4 (Cont'd)
FIGURE INDEX FOR MISC. DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
M-317	Sh.1	Piping and Equipment Layout - Reactor Enclosure - Unit 2 - Plan at El.191' Area 17 & 18	1.2-44	Sh.2
M-318	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El 177' - Area 18	1.2-42	Sh.2
M-319	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El 201' - Area 18	1.2-47	Sh.2
M-320	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El 217' - Area 18	1.2-51	Sh.2
M-321	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El 253' - Area 18	1.2-55	Sh.2
M-322	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El 283' - Area 18	1.2-59	Sh.2
M-323	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El 313' - Area 18	1.2-63	Sh.2
M-326	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Section D-D - Areas 13, & 17	1.2-72	Sh.2
M-384	Sh.1	Piping Assembly for Spray Network A B C & D	9.2-7	Sh.1
M-388	Sh.1	Equipment Location - Spray Pond Pump Structure -Plans at El 268 and 251	1.2-37	Sh.1
M-389	Sh.1	Piping and Mechanical - Spray Pond Pump Structure, Sections	1.2-39	Sh.1
M-390	Sh.1	Piping and Mechanical - Spray Pond Pump Structure - Plan at El 237'	1.2-38	Sh.1
M-677	Sh.1	Instrument Location - Turbine Bldg - Unit 1 - Plan at El. 255 - Area 1	7.2-11	Sh.1
M-6389	Sh.1	Sewage Treatment Facility – Equipment, Instrumentation & Piping Diagram	9.3-9	Sh.1
M-8320	Sh.1	RHR & Core Spray Strainer Gen. Arrgt.-Plan-Reactor Enclosure Areas 11,12,15	1.2-83	Sh.1
N-110	Sh.1	Shielding and Radiation Zoning Drawing - Turbine Enclosure - Unit 1 - Plan at El. 200'	12.3-8	Sh.1
N-111	Sh.1	Shielding and Radiation Zoning Drawing - Turbine Enclosure - Unit 1 - Plan at El. 217'	12.3-9	Sh.1
N-112	Sh.1	Shielding and Radiation Zoning Drawing - Turbine Enclosure - Unit 1 - Plan at El. 239'	12.3-10	Sh.1
N-113	Sh.1	Shielding and Radiation Zoning Drawing - Turbine Enclosure - Unit 1 - Plan at El. 269'	12.3-11	Sh.1
N-115	Sh.1	Shielding and Radiation Zoning Drawing - Turbine Enclosure - Unit 1 - Plan at El. 302' & 304'	12.3-12	Sh.1
N-116	Sh.1	Shielding and Radiation Zoning Drawing - Reactor Enclosure - Unit 1 - Plan at El. 177'	12.3-13	Sh.1
N-117	Sh.1	Shielding and Radiation Zoning Drawing - Reactor Enclosure - Unit 1 - Plan at El. 201'	12.3-14	Sh.1
N-118	Sh.1	Shielding and Radiation Zoning Drawing - Reactor Enclosure - Unit 1 - Plan at El. 217'	12.3-15	Sh.1
N-119	Sh.1	Shielding and Radiation Zoning Drawing - Reactor Enclosure - Unit 1 - Plan at El. 253'	12.3-16	Sh.1
N-120	Sh.1	Shielding and Radiation Zoning Drawing - Reactor Enclosure - Unit 1 - Plan at El. 283'	12.3-17	Sh.1
N-121	Sh.1	Shielding and Radiation Zoning Drawing - Reactor Enclosure - Unit 1 - Plan at El. 313'	12.3-18	Sh.1
N-122	Sh.1	Shielding and Radiation Zoning Drawing - Reactor Enclosure - Unit 1 - Plan at El. 352'	12.3-19	Sh.1
N-124	Sh.1	Shielding and Radiation Zoning Drawing - Cont Structure - Plans at El. 321', 332', 350', & Sect.	12.3-24	Sh.1
N-125	Sh.1	Shielding and Radiation Zoning Drawing - Turbine Enclosure - Unit 2 - Plan at El. 200'	12.3-8	Sh.2
N-126	Sh.1	Shielding and Radiation Zoning Drawing - Turbine Enclosure - Unit 2 - Plan at El. 217'	12.3-9	Sh.2
N-127	Sh.1	Shielding and Radiation Zoning Drawing - Turbine Enclosure - Unit 2 - Plan at El. 239'	12.3-10	Sh.2
N-128	Sh.1	Shielding and Radiation Zoning Drawing - Turbine Enclosure - Unit 2 - Plan at El. 269'	12.3-11	Sh.2
N-130	Sh.1	Shielding and Radiation Zoning Drawing - Turbine Enclosure - Unit 2 - Plan at El. 302' & 304'	12.3-12	Sh.2
N-131	Sh.1	Shielding and Radiation Zoning Drawing - Reactor Enclosure - Unit 2 - Plan at El. 177'	12.3-13	Sh.2

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-4 (Cont'd)
FIGURE INDEX FOR MISC. DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
M-288	Sh.1	Piping and Equipment Layout - Reactor Enclosure - Unit 2 - Plan at El.177' Area 13	1.2-41	Sh.2
M-289	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.201' - Area 13	1.2-46	Sh.2
M-290	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.217' - Area 13	1.2-50	Sh.2
M-291	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.253' - Area 13	1.2-54	Sh.2
M-292	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.283' - Area 13	1.2-58	Sh.2
M-293	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.313' - Area 13	1.2-62	Sh.2
M-295	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Drywell Plan at El.238' - Area 13, 14, 17, & 18	1.2-65	Sh.2
M-296	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Drywell Plan at El.253' - Area 13, 14, 17, & 18	1.2-66	Sh.2
M-297	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Drywell Plan at El.272'-9" - Area 13, 14, 17, & 18	1.2-67	Sh.2
M-298	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.177' - Area 14	1.2-40	Sh.2
M-299	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.201' - Area 14	1.2-45	Sh.2
M-300	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.217' - Area 14	1.2-49	Sh.2
M-301	Sh.1	Piping and Equipment Layout - Reactor Enclosure - Unit 2 - Plan at El.253' Area 14	1.2-53	Sh.2
M-302	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.283' - Area 14	1.2-57	Sh.2
M-303	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.313' - Area 14	1.2-61	Sh.2
M-305	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Drywell Plan at El.286' - Area 13, 14, 17, & 18	1.2-68	Sh.2
M-306	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Drywell Plan at El.295' - Area 13, 14, 17, & 18	1.2-69	Sh.2
M-307	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Drywell Plan at El.310' - Area 13, 14, 17, & 18	1.2-70	Sh.2
M-308	Sh.1	Piping and Equipment Layout - Reactor Enclosure - Unit 2 - Plan at El.177' Area 17	1.2-43	Sh.2
M-309	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.201' - Area 17	1.2-48	Sh.2
M-310	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.217' - Area 17	1.2-52	Sh.2
M-311	Sh.1	Piping and Mechanical - Reactor Bldg - Unit 2 - Plan at El.253' - Area 17	1.2-56	Sh.2
N-132	Sh.1	Shielding and Radiation Zoning Drawing - Reactor Enclosure - Unit 2 - Plan at El. 201'	12.3-14	Sh.2
N-133	Sh.1	Shielding and Radiation Zoning Drawing - Reactor Enclosure - Unit 2 - Plan at El. 217'	12.3-15	Sh.2
N-134	Sh.1	Shielding and Radiation Zoning Drawing - Reactor Enclosure - Unit 2 - Plan at El. 253'	12.3-16	Sh.2
N-135	Sh.1	Shielding and Radiation Zoning Drawing - Reactor Enclosure - Unit 2 - Plan at El. 283'	12.3-17	Sh.2
N-136	Sh.1	Shielding and Radiation Zoning Drawing - Reactor Enclosure - Unit 2 - Plan at El. 313'	12.3-18	Sh.2
N-137	Sh.1	Shielding and Radiation Zoning Drawing - Reactor Enclosure - Unit 2 - Plan at El. 352'	12.3-19	Sh.2
N-139	Sh.1	Shielding and Radiation Zoning Drawing - Roof Areas of Rx.Enc., RW Encl., & Control Encl.	12.3-25	Sh.1
N-140	Sh.1	Shielding and Radiation Zoning Drawing - RW & Offgas Enclosures - Plan at El. 162' & 187'-6"	12.3-20	Sh.1
N-141	Sh.1	Shielding and Radiation Zoning Drawing - RW & Offgas Enclosures - Plan at El. 191' & 195'	12.3-21	Sh.1
N-142	Sh.1	Shielding and Radiation Zoning Drawing - RW & Offgas Enclosures - Plan at El. 217'	12.3-22	Sh.1
N-143	Sh.1	Shielding and Radiation Zoning Drawing - RW Enclosure - Plan at El. 237' & 257'	12.3-23	Sh.1

Note: See note in Section 1.7 for drawing considerations.

Table 1.7-4 (Cont'd)
FIGURE INDEX FOR MISC. DRAWINGS

Drawing Number		Title	Former UFSAR Figure Number	
105D5584	Sh.1	GE Process Diagram - Control Rod Drive System	4.6-7	Sh.1
	Sh.2	GE Process Diagram - Control Rod Drive System	4.6-7	Sh.2
	Sh.3	GE Process Diagram - Control Rod Drive System	4.6-7	Sh.3
	Sh.4	GE Process Diagram - Control Rod Drive System	4.6-7	Sh.4
731E769AD	Sh.1	GE Process Diagram - Reactor Core Isolation Cooling System	5.4-10	Sh.1
761E292AD	Sh.1	GE Process Diagram - Residual Heat Removal System	5.4-14	Sh.1
	Sh.2	GE Process Diagram - Residual Heat Removal System	5.4-14	Sh.2
	Sh.3	GE Process Diagram - Residual Heat Removal System	5.4-14	Sh.3
761E270AD	Sh.1	GE Process Diagram - High Pressure Coolant Injection System	6.3-1	Sh.1
761E280A	Sh.1	GE Process Diagram - Core Spray System	6.3-2	Sh.1
729E613AD	Sh.1	GE FCD - Core Spray System	7.3-9	Sh.1
	Sh.2	GE FCD - Core Spray System	7.3-9	Sh.2
919D694AD	Sh.1	GE FCD - Standby Liquid Control System	7.4-2	Sh.1
	Sh.2	GE FCD - Standby Liquid Control System	7.4-2	Sh.2
	Sh.3	GE FCD - Standby Liquid Control System	7.4-2	Sh.3
729E618AD	Sh.1	GE FCD - Reactor Recirculation System	7.7-2	Sh.1
	Sh.4	GE FCD - Reactor Recirculation System	7.7-2	Sh.4
	Sh.5	GE FCD - Reactor Recirculation System	7.7-2	Sh.5
	Sh.6	GE FCD - Reactor Recirculation System	7.7-2	Sh.6
729E630AD	Sh.1	GE FCD - Residual Heat Removal System	7.3-10	Sh.1
	Sh.2	GE FCD - Residual Heat Removal System	7.3-10	Sh.2
761E477	Sh.3	GE FCD - Reactor Recirculation System	7.7-6	Sh.3
	Sh.4	GE FCD - Reactor Recirculation System	7.7-6	Sh.4
	Sh.5	GE FCD - Reactor Recirculation System	7.7-6	Sh.5

Note: See note in Section 1.7 for drawing considerations.

1.8 CONFORMANCE TO NRC REGULATORY GUIDES

This section provides a brief description of LGS conformance with the guidelines presented in the regulatory guides and provides reference to the UFSAR sections where the LGS design and details of conformance or alternate approaches are discussed.

The conformance information below applies only to the particular guide being addressed and not necessarily to other guides that may be referenced in that guide.

This section also identifies those guides classified as Category 1,2,3 or 4 per Reference 1.11-2, as discussed in Section 1.11.

REGULATORY GUIDE 1.1 Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps (Safety Guide 1)

Rev 0, November 2 1970

LGS is in conformance with this guide as discussed in Sections 5.4.7 and 6.3.2.

(Category 1)

REGULATORY GUIDE 1.2 Thermal Shock to Reactor Pressure Vessels (Safety Guide 2)
Rev 0, November 2 1970

Although not used as a design basis, LGS is evaluated as being in conformance with this guide. Reactor vessel integrity is discussed in Section 5.3.

(Category 1)

REGULATORY GUIDE 1.3 Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors

Rev 2, June 1974

Regulatory Guide 1.3 was used for the original plant design. Regulatory Guide 1.3 is used for the determination of in-plant doses, shielding design and equipment unless such evaluations are re-performed using Alternate Source Terms. The requirements of Regulatory Guide 1.3, as they apply to the determination of control room and off-site radiological consequences for LOCA, are superseded by the requirements of Regulatory Guide 1.183

(Category 1)

REGULATORY GUIDE 1.4 Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors

Rev 2, June 1974

This guide is for pressurized water reactors and therefore is not applicable to LGS.

REGULATORY GUIDE 1.5 Assumptions Used for Evaluating the Potential Radiological Consequences of a Steam Line Break Accident for Boiling Water Reactors (Safety Guide 5)

Rev 0, March 10 1971

Regulatory Guide 1.5 was used for the original design of LGS. Regulatory Guide 1.5 is used for the determination of in-plant doses, shielding design and equipment unless such evaluations are re-performed using Alternate Source Terms. Regulatory Guide 1.5 steam cloud dispersion methodology is used for the MSLB does assessment for Alternate Source Terms. The requirements of Regulatory Guide 1.5, as they apply to the determination of control room and off-site radiological consequences for a Main Steam Line Break, are superseded by the requirements of Regulatory Guide 1.183.

(Category 1)

REGULATORY GUIDE 1.6	Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems (Safety Guide 6)
Rev 0, March 10 1971	

LGS is in conformance with this guide as discussed in Sections 7.1.2.5, 7.6.2.8.2.1.1 and 8.1.6.1.

(Category 1)

REGULATORY GUIDE 1.7	Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident
Rev 2, November 1978	

LGS is in conformance with this guide. There is a clarification of quality group requirements of paragraph C.3 for the gas analyzer packages, as discussed in Section 6.2.5.4.

(Category 1)

REGULATORY GUIDE 1.8	Personnel Selection and Training
Rev 1-R, May 1977	

LGS is in conformance with this guide to the extent discussed in Section 12.5.3.5.2, 13.1 and 13.2.

(Category 1)

REGULATORY GUIDE 1.9	Selection of Diesel Generator Set Capacity for Standby Power Supplies (Safety Guide 9)
Rev 2, December 1979	

LGS is in conformance with Revision 0 (3/10/71) of this guide as discussed in Section 8.1.6.1. Revision 1 of this guide was for comment only, and Revision 2 is not applicable to LGS (being for plants whose construction permit applications are docketed after December, 1979).

(Category 1)

REGULATORY GUIDE 1.10	Mechanical (Cadweld) Splices in Reinforcing Bars of Category I Concrete Structures
Rev 1, January 2 1973	

LGS is in conformance with this guide except that there are alternate approaches to paragraphs C.4.a, C.4.b, C.5.a, and C.5.b in that some testing procedures differ but are interpreted to be equally or more stringent than those recommended in the regulatory guide. Details are discussed in Section 3.8.6.

(Category 1)

REGULATORY GUIDE 1.11 Instrument Lines Penetrating Primary Reactor Containment (Safety Guide 11)
Rev 0, March 10, 1971

LGS is in conformance with this guide except that position indication of excess flow check valves is provided locally, rather than in the control room as suggested in Paragraph C.1.c. of the guide. Details are discussed in Sections 6.2.4 and 6.2.6. LGS is in conformance with this guide for the TIP system lines to the extent discussed in Section 6.2.4.

(Category 1)

REGULATORY GUIDE 1.12 Instrumentation for Earthquakes
Rev 2, March 1997

The LGS design is in conformance with this guide as discussed in Section 3.7.4.1.

REGULATORY GUIDE 1.13 Spent Fuel Storage Facility Design Basis
Rev 1, December 1975

This guide applies to LGS on a case-by-case basis. LGS is in conformance with this guide as discussed in Sections 9.1.2 and 9.1.4.

(Category 4)

REGULATORY GUIDE 1.14 Reactor Coolant Pump Flywheel Integrity
Rev 1, August 1975

The subject matter does not apply to LGS as reactor coolant recirculation pumps do not have inertia flywheels.

REGULATORY GUIDE 1.15 Testing of Reinforcing Bars for Category 1 Concrete Structures

Rev 1, December 28, 1972

LGS is in conformance with this guide as discussed in Section 3.8.6.2.

(Category 1)

REGULATORY GUIDE 1.16 Reporting of Operating Information - Appendix A Technical Specifications

Rev 4, August 1975

LGS reporting requirements are established in Chapter 16, Technical Specifications, which were based on NUREG-0123, Revision 2, "Standard Technical Specifications for GE Boiling Water Reactors."

REGULATORY GUIDE 1.17 Protection of Nuclear Power Plants Against Industrial Sabotage

Rev 1, June 1973

LGS is in conformance with this guide to the extent discussed in Section 13.6.

(Category 1)

REGULATORY GUIDE 1.18 Structural Acceptance Test for Concrete Primary Reactor Containments

Rev 1, December 28, 1972

LGS is in conformance with paragraphs C.4 through C.8 & C.13. Alternate approaches are employed for portions of paragraphs C.1, C.2, and C.3 regarding pressure tests, measurement locations, and deflection measurement. The test environment of paragraph C.9 is not considered applicable, and LGS has not utilized the test pressure drop procedures of paragraph C.10. Details are discussed in Section 3.8.1.7.

(Category 1)

REGULATORY GUIDE 1.19 Nondestructive Examination of Primary Containment Liner Welds (Safety Guide 19)

Rev 1, August 11 1972

LGS is in conformance with this guide except that alternate approaches are employed for paragraphs C.1.a (radiographic examination increments) and C.7.a and C.7.b (acceptance standards). Conformance to paragraph C.4 (personnel qualification) is subject to an interpretation. Details are discussed in Sections 3.8.1 and 3.8.2.

(Category 1)

REGULATORY GUIDE 1.20 Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing

Rev 2, May 1976

LGS's program is evaluated as being in conformance with this guide and is discussed in Section 3.9.2.4 and 14.2.

(Category 1)

REGULATORY GUIDE 1.21 Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants

Rev 1, June 1974

The LGS process and effluent radiological monitoring and sampling systems are designed to allow conformance to this guide, as discussed in Section 7.7, 11.5 and 12.3. Evaluation and reporting procedures during operation will conform to this guide.

(Category 1)

REGULATORY GUIDE 1.22 Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

Rev 0, February 17 1972

The LGS design is in conformance with this guide as discussed in Sections 7.1.2.5 and 8.1.6.1.

(Category 1)

REGULATORY GUIDE 1.23 Onsite Meteorological Programs (Safety Guide 23)

Rev 0, February 17 1972

The LGS onsite meteorological instrumentation systems met NRC requirements at the time of installation, prior to the issuance of this guide. LGS conforms to the guidelines of Regulatory Guide 1.23, except as discussed in detail in Sections 2.3.2 and 2.3.3.

(Category 1)

REGULATORY GUIDE 1.24 Assumptions Used for Evaluating the Potential Radiological Consequences of a Pressurized Water Reactor Radioactive Gas Storage Tank Failure (Safety Guide 24)

Rev 0, March 23 1972

This guide is for PWRs and therefore does not apply to LGS.

REGULATORY GUIDE 1.25 Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors (Safety Guide 25)

Rev 0, March 23 1972

Regulatory Guide 1.25 was used for the original design. Regulatory Guide 1.25 is used for the determination of in-plant doses, shielding design and equipment unless such evaluations are re-performed using Alternate Source Terms. The requirements of Regulatory Guide 1.25, as they apply to the determination of control room and off-site radiological consequences for a Fuel Handling Accident, are superseded by the requirements of Regulatory Guide 1.183.

(Category 1)

REGULATORY GUIDE 1.26	Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants
Rev 3, February 1976	

LGS is in conformance with this guide except that alternate approaches are used for the CRD hydraulic control units, isolation of certain steam lines, parts of the fuel pool cooling system, diesel generator cooling system, and control structure chilled water system, instrument tubing for "passive" instrumentation, the SLCS storage tanks and accumulator vessels, and the HPCI globe stop-check valves. Details are discussed in Section 3.2.2.

(Category 1)

REGULATORY GUIDE 1.27	Ultimate Heat Sink for Nuclear Power Plants
Rev 2, January 1976	

LGS is in conformance with this guide except that alternate approaches were used to paragraphs C.1, C.1.a, C.1.b, and C.1.c regarding thermal analysis methods and selection of meteorology. The design meteorology is in conformance with Revision 1 of the guide. Details for both Revision 1 and Revision 2 are discussed in Section 9.2.6.6.

(Category 2)

REGULATORY GUIDE 1.28	Quality Assurance Program Requirements (Design and Construction)
Rev 3, August 1985	

At the time of initial licensing, this guide, which endorsed/modified ANSI N45.2 (1977), was not applicable to LGS (being for plants whose construction permit applications are docketed after October 1979); Quality assurance during construction is discussed in the document "LGS Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction." The LGS QA program during operation will be in conformance with this guide, as discussed in the QATR.

Further, as discussed in a letter of approval from the NRC to Exelon, dated December 24, 2002, Regulatory Guide 1.28, Rev 3 endorses NQA-1-1983. The NRC letter approves Exelon's proposal to update its commitment to quality standards by adopting the guidance of NQA-1-1994. Therefore, N45.2.13-1976, superseded by NQA-1-1983 has been superseded by NQA-1-1994.

(Category 1)

REGULATORY GUIDE 1.29	Seismic Design Classification
Rev 3, September 1978	

LGS is in conformance with this guide except that alternate approaches have been taken for the fuel pool cooling system and isolation of certain steam lines. There are clarifications for certain reactor internals and reactivity control systems. Details are discussed in Section 3.2.1.

(Category 1)

REGULATORY GUIDE 1.30 Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

Rev 0, August 11 1972

LGS is constructed in accordance with this guide, which endorses/ modifies ANSI N45.2.4 (1972)/IEEE 336 (1971), although the standard is not specifically a part of construction quality assurance procedures as discussed in Section 8.1.6.1.

The commitments to this Regulatory Guide and ANSI N45.2.4 were deleted since they were superseded by Exelon's commitment to ASME NQA-1 1994 subpart 2.4.

(Category 1)

REGULATORY GUIDE 1.31 Control of Ferrite Content in Stainless Steel Weld Metal

Rev 3, April 1978

Revision 3 of this guide is not applicable to LGS (being for plants whose construction permit applications are docketed after October 1, 1978). For the GE scope of supply, Revision 1 of the guide is used as a design basis for LGS, with certain alternate approaches considered to meet the intent of the guide. Details are discussed in Section 5.2.3.4, along with a comparison of Bechtel procedures with Revision 3 of the guide.

REGULATORY GUIDE 1.32 Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants

Rev 2, February 1977

This guide, which endorses/modifies IEEE 308 (1974), is not applicable to LGS (for plants whose construction permit applications are docketed after April 14, 1977). The LGS design is in conformance as discussed in Section 8.1.6.1.

(Category 1)

REGULATORY GUIDE 1.33 Quality Assurance Program Requirements (Operation)

Rev 2, February 1978

LGS is in conformance with this guide, which endorses/modifies ANSI N18.7 (1976), except for certain alternate approaches to the guide and the ANSI standard, as discussed in the QATR.

(Category 1)

REGULATORY GUIDE 1.34 Control of Electroslag Weld Properties

Rev 0, December 28 1972

Electroslag welding was not used on LGS and therefore this guide is not applicable.

REGULATORY GUIDE 1.35	Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment Structures
Rev 2, January 1976	

LGS does not have a prestressed concrete containment and therefore this guide does not apply.

REGULATORY GUIDE 1.36	Nonmetallic Thermal Insulation for Austenitic Stainless Steel
Rev 0, February 23 1973	

LGS is in conformance with this guide as discussed in Section 5.2.3.2.

(Category 1)

REGULATORY GUIDE 1.37	Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants
Rev 0, March 16 1973	

This guide endorses/modifies ANSI N45.2.1 (1973). While this standard is not specifically applied in Bechtel's scope of work, the procedures in use satisfy the intent of the guide as discussed in Section 5.2.3.4. The GE scope of supply is in conformance with this guide as discussed in Sections 4.5.

The commitments to this Regulatory Guide and ANSI N45.2.1 were deleted since they were superseded by Exelon's commitment to ASME NQA-1 1994 subpart 2.1.

(Category 1)

REGULATORY GUIDE 1.38	Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants
Rev 2, May 1977	

This guide endorses/modifies ANSI N45.2.2 (1972). The guide/ standard is not specifically utilized during construction, although procedures in use for LGS conform with the intent of the guide. Quality assurance during construction is discussed in the document "LGS Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction." The GE scope of supply is in conformance with this guide as discussed in NEDO-11209-04A, "Nuclear Energy Business Group Boiling Water Reactor Quality Assurance Program" February, 1980.

The commitments to this Regulatory Guide and ANSI N45.2.2 were deleted since they were superseded by Exelon's commitment to ASME NQA-1 1994 subpart 2.2.

(Category 1)

REGULATORY GUIDE 1.39	Housekeeping Requirements for Water-Cooled Nuclear Power Plants
Rev 2, September 1977	

LGS is in general conformance with this guide, which endorses/ modifies ANSI N45.2.3 (1973), although the ANSI Standard is not specifically a part of construction quality assurance procedures. Quality assurance during construction is discussed in the document "LGS Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction."

The commitments to this Regulatory Guide and ANSI N45.2.3 were deleted since they were superseded by Exelon's commitment to ASME NQA-1 1994 subpart 2.3.

(Category 1)

REGULATORY GUIDE 1.40 Qualification Tests of Continuous-Duty Motors Installed Inside the Containment of Water-Cooled Nuclear Power Plants

Rev 0, March 16, 1973

Limerick is in conformance with the intent of this guide, which endorses/modifies trial use standard IEEE 334-1971, as discussed in Section 8.1.6.1. The Standard was revised on October 29, 1974, and the method of qualification testing was modified from the trial use version. The in-containment motors at LGS were qualified by testing performed in accordance with the enhanced methods stated in the 1974 version of IEEE Standard 334.

(Category 1)

REGULATORY GUIDE 1.41 Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignments

Rev 0, March 16 1973

LGS is in conformance with this guide as discussed in Sections 8.1.6.1, 8.3.2.2, and 14.2.7.2.

(Category 1)

REGULATORY GUIDE 1.42 Interim Licensing Policy on as Low as Practicable for Gaseous Radioiodine Releases

Withdrawn by the NRC March 22, 1976.

REGULATORY GUIDE 1.43 Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components

Rev 0, May 1973

This guide applies to welding of cladding to low-alloy steels made to coarse grain practice. LGS vessel plate and nozzle forgings are made to fine grain practice and a low heat input process is used. Other components are not clad. Therefore, the guide is not applicable.

(Category 1)

REGULATORY GUIDE 1.44 Control of the Use of Sensitized Stainless Steel

Rev 0, May 1973

For GE scope of supply, this guide is not used as a design basis for LGS and in some instances alternate approaches are used which, however, conform to the intent of this guide. For the Bechtel scope of supply, there is conformance with the guide except for alternate approaches taken for nonsensitization and intergranular corrosion testing. Details are discussed in Section 5.2.3.3.

REGULATORY GUIDE 1.45 Reactor Coolant Pressure Boundary Leakage Detection Systems

Rev 0, May 1973

The LGS design complies with the intent of this regulatory guide. Three diverse methods of detection have been provided. The design bases, limitations, and operation of these systems are discussed in Sections 5.2.5.2.1.3 through 5.2.5.2.1.5. These provisions meet or exceed the recommendations of ANSI/ISA S67.03. Each of the three systems provided for leak detection has readouts and alarms in the main control room in accordance with Regulatory Guide 1.45.

(Category 1)

REGULATORY GUIDE 1.46 Protection Against Pipe Whip Inside Containment

Rev 0, May 1973

For the recirculation system, pipe break locations are selected by alternate criteria which are in accordance with the intent of this guide. For all other systems, the criteria of BTP MEB 3-1 (dated 11/24/75) are used in lieu of the criteria of the regulatory guide. Protection against the effects of postulated pipe ruptures, both inside and outside the primary containment, is discussed in Section 3.6.2.

(Category 1)

REGULATORY GUIDE 1.47 Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

Rev 0, May 1973

LGS is in conformance with this guide as discussed in Sections 7.1.2.5 and 8.1.6.1.

(Category 1)

REGULATORY GUIDE 1.48 Design Limits and Loading Combinations for Seismic Category I Fluid System Components

Rev 0, May 1973

The design limits and loading combinations for non-NSSS seismic Category I fluid systems is in accordance with this guide, as shown in Section 3.9. The NSSS systems were designed prior to the issuance of this guide and therefore the guide was not a design basis requirement, however, there is general agreement with the guide. A comparison between Regulatory Guide 1.48 and the NSSS design is provided in Section 3.9.3.

(Category 1)

REGULATORY GUIDE 1.49	Power Levels of Nuclear Power Plants
Rev 1, December 1973	

LGS is in conformance with this guide as discussed in Section 15.0.4.

(Category 1)

REGULATORY GUIDE 1.50	Control of Preheat Temperature for Welding of Low-Alloy Steel
Rev 0, May 1973	

For GE scope of supply, the guide was not used as a design basis for LGS and in some cases alternate approaches are employed that satisfy the intent of the guide. For Bechtel scope of supply, alternate approaches are employed for portions of the procedure qualifications and maintenance of preheat temperature beyond completion of welding. Details are discussed in Section 5.2.3.3.

(Category 1)

REGULATORY GUIDE 1.51	Inservice Inspection of ASME Code Class 2 and 3 Nuclear Power Plant Components

Withdrawn by the NRC July 15, 1975.

REGULATORY GUIDE 1.52	Design, Testing, and Maintenance Criteria for Post Accident Engineered Safety Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants
Rev 2, March 1978	

The LGS system was designed prior to the original issuance of this guide in 1973, and therefore the guide was not specifically considered in the design. While there is substantial conformance, there are various exceptions and alternate approaches. These, however, are not considered significantly different from the intent of the guide. Details are discussed in Section 6.5.1 and Table 6.5-2. The initial test program will be in conformance except as may be modified by the general statement on regulatory guides in Section 14.2. Testing during operation is discussed in Chapter 16.

(Category 2 for Revision 1)

REGULATORY GUIDE 1.53	Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems
Rev 0, June 1973	

LGS is in conformance with this guide, which endorses/modifies trial use standard IEEE 379 (1972), as discussed in Sections 7.1.2.5 and 8.1.6.1.

(Category 1)

REGULATORY GUIDE 1.54 Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants

Rev 0, June 1973

This guide endorses/modifies ANSI N101.4 (1972). Non-NSSS practice is in conformance with the guide except that, since there are no Class I Service Level coatings in LGS, a quality assurance program was not applied. Most NSSS equipment for LGS was ordered prior to the issuance of the guide and ANSI N101.4 was not used as a design basis. GE procedures are considered to satisfy the intent of the guide. Details are discussed in Section 6.1.2. During operation, LGS will be in conformance with ASTM D3843-93 with an additional clarification, exception, and requirement as discussed in the QATR.

(Category 1)

REGULATORY GUIDE 1.55 Concrete Placement in Category I Structures

Rev 0, June 1973

LGS is in conformance with this guide except that an alternate approach used for paragraphs C.2 and C.3 regarding the division of responsibilities of "designer" and "constructor" within Bechtel. Details are discussed in Section 3.8.6.2. Also, this guide references ACI 301-72 and ACI 305-72 and LGS is in conformance with ACI 301-66 and ACI 605-59.

(Category 1)

REGULATORY GUIDE 1.56 Maintenance of Water Purity in Boiling Water Reactors

Rev 1, July 1978

The LGS design is in conformance with this guide except for alternate approaches to measurement of deep bed condensate demineralizer flow and methods of determining resin exhaustion for the condensate cleanup system. The condensate cleanup system is discussed in Section 10.4.6. The RWCU system is discussed in Section 5.4.8.
Water purity limits are presented in Chapter 16.

(Category 3)

REGULATORY GUIDE 1.57 Design Limits and Loading Combinations for Metal Primary Reactor Containment System Components

Rev 0, June 1973

LGS is in conformance with this guide, which applies to hatches and other metal components on LGS, with the clarification that the Code Addenda in effect at the time of design were used, rather than the later one cited by the guide. Details are discussed in Section 3.8.2.5.

(Category 1)

REGULATORY GUIDE 1.58 Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel

Rev 1, September 1980

This guide endorses/modifies ANSI N45.2.6. QA during construction is discussed in the document "LGS Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction."

During operation, for NDE personnel, the Company and contractor personnel performing NDE are trained, tested, qualified, or certified in accordance with a company procedure that meets applicable requirements of 10 CFR 50.55a and ASME Section XI with specific exceptions and clarifications as discussed in the QATR.

(Category 1)

REGULATORY GUIDE 1.59 Design Basis Floods for Nuclear Power Plants
Rev 2, August 1977

Although this guide does not apply to LGS (being for construction permit applications docketed after the guide's issuance), LGS is in conformance as discussed in Section 2.4.2.2.

(Category 2)

REGULATORY GUIDE 1.60 Design Response Spectra for Seismic Design of Nuclear Power Plants
Rev 1, December 1973

A letter from J.M. Hendrie (NRC) to R.M. Collins (Bechtel) dated Dec. 21, 1973 stated that this guide is applicable only to plants docketed for construction permit review after April 1, 1973. LGS was docketed prior to this date, and therefore the guide is not applicable. The design response spectra were determined prior to the issuance of this guide and LGS has employed alternate approaches. Details are discussed in Section 3.7.1.1.

REGULATORY GUIDE 1.61 Damping Values for Seismic Design of Nuclear Power Plants
Rev 0, October 1973

A letter from J.M. Hendrie (NRC) to R.M. Collins (Bechtel) dated Dec. 21, 1973 stated that this guide is applicable only to plants docketed for construction permit review after April 1, 1973. LGS was docketed prior to this date and therefore the guide is not applicable. The damping values for both the NSSS and non-NSSS scope were determined prior to the issuance of this guide. For the NSSS design, an alternate approach has been employed that is more conservative than the recommendations of the guide. The non-NSSS design uses values equal to or more conservative than the guides except for the SSE value for welded steel structures. Details are discussed in Section 3.7.1.

(Category 1)

REGULATORY GUIDE 1.62 Manual Initiation of Protective Actions
Rev 0, October 1973

LGS is in conformance with this guide as discussed in Sections 7.1.2.5 and 8.1.6.1.

(Category 1)

REGULATORY GUIDE 1.63 Electric Penetration Assemblies in Containment Structures for Light-Water- Cooled Nuclear Power Plants

Rev 2, July 1978

The LGS electric penetration assemblies were purchased when Revision 0 (10/73) of this guide, which endorses/modifies IEEE 317 (1972), was in effect. The LGS assemblies are in full conformance with this revision of the guide. Revision 2 of the guide, which endorses/modifies IEEE 317 (1976), is not applicable to LGS per its implementation section (being for plants whose construction permit applications are docketed after August 31, 1978). There are several exceptions and clarifications to this revision of the guide as discussed in Section 8.1.6.1.

(Category 2)

REGULATORY GUIDE 1.64 Quality Assurance Requirements for the Design of Nuclear Power Plants

Rev 2, June 1976

This guide, which endorses/modifies ANSI N45.2.11, does not apply to LGS (being for construction permits docketed after July 15, 1976). Quality assurance during construction is discussed in the document "LGS Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction." LGS will conform during operation, except for certain alternate approaches to paragraph C.2 of the guide regarding design verification, as discussed in the QATR.

(Category 1)

REGULATORY GUIDE 1.65 Materials and Inspections for Reactor Vessel Closure Studs

Rev 0, October 1973

The reactor vessel closure studs were ordered prior to the issuance of this guide and therefore the guide was not used as a design basis for LGS. The LGS design, is in conformance except that alternate approaches were used for Charpy V impact testing of paragraph C.1.B.(2) of the guide and ultrasonic examination procedures of paragraph C.2.b. Material details and use are discussed in Section 5.3.1.11. The cleanliness recommendations of the guide will be followed during operation.

(Category 1)

REGULATORY GUIDE 1.66 Nondestructive Examination of Tubular Products

Withdrawn by NRC September 1977. Discussion of activities prior to that time is provided in Section 5.2.3.3.

REGULATORY GUIDE 1.67 Installation of Overpressure Protection Devices

Rev 0, October 1973

There are no ASME Section III, Class 1, 2 or 3 relief valves employed in the LGS design, to which Code Case 1569 applies, therefore, the subject matter of this guide is not applicable to LGS.

REGULATORY GUIDE 1.68 Initial Test Program for Water-Cooled Reactor Power Plants
Rev 2, August 1978

LGS will be in conformance with this guide as discussed in Section 14.2.7.2.

(Category 1)

REGULATORY GUIDE 1.68.1 Preoperational and Initial Startup Testing of Feedwater and Condensate Systems for Boiling Water Reactor Power Plants
Rev 1, January 1977

LGS will be in conformance with the guide as discussed in Section 14.2.7.2.

(Category 1)

REGULATORY GUIDE 1.68.2 Initial Startup Test Program to Demonstrate Remote Shutdown Capability for Water-Cooled Nuclear Power Plants
Rev 1, July 1978

LGS will be in conformance with the guide.

(Category 3)

REGULATORY GUIDE 1.68.3 Preoperational Testing of Instrument and Control Air Systems
Rev 0, April 1982

LGS will be in conformance with the applicable portions of this guide.

REGULATORY GUIDE 1.69 Concrete Radiation Shields for Nuclear Power Plants
Rev 0, December 1973

LGS did not directly apply this guide, which endorses/modifies ANSI N101.6 (1972). Certain provisions of the guide, including those pertaining to structural aspects of radiation shield design are met by LGS via conformance to concrete standards. LGS concrete standards are discussed in Section 3.8.

(Category 1)

REGULATORY GUIDE 1.70 Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants
Rev 3, November 1978

The LGS FSAR is in conformance with the format and content requirements of this guide.

(Category 1)

REGULATORY GUIDE 1.71 Welder Qualification for Areas of Limited Accessibility

Rev 0, December 1973

GE does not employ this guide as a design basis for LGS and in some cases employs alternate approaches that are evaluated as satisfying the intent of the guide. Details are discussed in Section 5.2.3.4. Bechtel employs alternate approaches to portions of this guide as in Section 5.2.3.4.

(Category 1)

REGULATORY GUIDE 1.72 Spray Pond Piping Made from Fiberglass-Reinforced Thermosetting Resin

Rev 2, November 1978

The LGS spray pond does not use this type of pipe and therefore the guide does not apply.

(Category 1)

REGULATORY GUIDE 1.73 Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants

Rev 0, January 1974

This Regulatory Guide is applicable to safety-related valve operators. Limerick safety-related valve operators are in conformance with this guide which endorses/modifies IEEE 382-1972 as discussed in Section 8.1.6.1.

(Category 1)

REGULATORY GUIDE 1.74 Quality Assurance Terms and Definitions

Rev 0, February 1974

Quality assurance during construction is discussed in the document "LGS Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction." LGS will be in conformance with this guide, which endorses/modifies ANSI N45.2.10 (1973), during operation as discussed in the QATR.

(Category 1)

REGULATORY GUIDE 1.75 Physical Independence of Electric Systems

Rev 2, September 1978

Although this guide, which endorses/modifies IEEE 384 (1974), does not apply to LGS (being for construction permit applications whose SER's are dated after February 1, 1974), the approach was taken to incorporate as much as possible of the guidelines into the partially completed design. There are various alternate approaches and exceptions to the guide and IEEE 384 as discussed in Sections 7.1.2.5 and 8.1.6.1.

(Category 4 for Revision 1)

REGULATORY GUIDE 1.76 Design Basis Tornado for Nuclear Power Plants

Rev 0, April 1974

LGS is in conformance with this guide except that an alternate equivalent approach to paragraph C.1, regarding design basis tornado characteristics, is used. Details are discussed in Sections 2.3.1.2.4 and 3.3.

(Category 4)

REGULATORY GUIDE 1.77 Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors

Rev 0, May 1974

This guide is for PWRs and therefore is not applicable to LGS.

REGULATORY GUIDE 1.78 Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release

Rev 0, June 1974

LGS complies with the intent of this guide. Details are discussed in Sections 2.2.3 and 6.4.

(Category 1)

REGULATORY GUIDE 1.79 Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors

Rev 1, September 1975

This guide is for PWRs and therefore does not apply to LGS.

REGULATORY GUIDE 1.80 Preoperational Testing of Instrument Air Systems

Rev 0, June 1974

This guide was superseded by Regulatory Guide 1.68.3 in April 1982.

(Category 4)

REGULATORY GUIDE 1.81 Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants

Rev 1, January 1975

LGS is in conformance with this guide as discussed in Section 8.1.6.1.

(Category 1)

REGULATORY GUIDE 1.82 Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident

Rev 2, May 1996

LGS is in conformance with this guide as discussed in Section 6.2.2.2.

REGULATORY GUIDE 1.83 Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes

Rev 1, July 1975

This guide is for PWRs and therefore is not applicable to LGS.

REGULATORY GUIDE 1.84 Code Case Acceptability - ASME Section III Design and Fabrication

The non-NSSS scope of supply is in accordance with this guide with the exception of the spray pond nozzles which used Code Case N-316 for installation. Approval of code cases for Class 3 equipment is not currently required by 10CFR50.55a. The NSSS scope of supply procedure for meeting the regulatory requirements is to obtain NRC approval for code cases applicable to Class I components only. These cases are discussed in Section 5.2.1.2. Approval of code cases for Class 2 and 3 equipment was not required at the time of the design of LGS, and is not currently required by 10CFR50.55a. Therefore, GE believes that this procedure in conjunction with 10CFR50, Appendix B, and other regulatory requirements provide adequate assurance of quality in the design and fabrication of safety-related equipment.

(Category 1)

REGULATORY GUIDE 1.85 Code Case Acceptability - ASME Section III Materials

The non-NSSS scope of supply is in accordance with this guide except that Code Cases 1330-3 and 1481 were used in the manufacture of the offgas system aftercondensers. In addition, Code Case 1481 was applied to the post-LOCA hydrogen recombiners. Code Case 1330-3 was incorporated into the 1974 edition of the ASME B&PV Code, Section III. Code Case 1481 addresses the use of materials used in equipment operating above 800°F, since the present ASME B&PV Code, Section III is limited in applicability to equipment operating below 800°F. In order for the aftercondensers and recombiners to meet the requirements of the ASME B&PV Code, Code Case 1481 must be applied. The NSSS scope of supply procedure for meeting the regulatory requirements is to obtain NRC approval for code cases applicable to Class I components only. These cases are discussed in Section 5.2.1.2. Approval of code cases for Class 2 and 3 equipment was not required at the time of the design of LGS, and is not currently required to 10CFR50.55a. Therefore, GE believes that this procedure in conjunction with 10CFR50, Appendix B and other regulatory requirements provide adequate assurance of quality in the design and fabrication of safety-related equipment.

With regard to Code Case N242 "Materials Certification, Section III, Division 1, Classes 1, 2, 3, MC and CS Construction," Regulatory Guide 1.85 calls for identification in the FSAR of those components and supports requiring the use of Paragraphs 1.0 through 4.0 of the Code Case. Accordingly, Table 1.8-1, is provided.

(Category 1)

REGULATORY GUIDE 1.86 Termination of Operating Licenses for Nuclear Reactors
Rev 0, June 1974

This guide is not applicable at the operating license stage.

REGULATORY GUIDE 1.87 Guidance for Construction of Class 1 Components in Elevated-Temperature Reactors (Supplement to ASME Section III Code Cases 1592, 1593, 1594, 1595, and 1596)

Rev 1, June 1975

This guide is not applicable to LGS.

(Category 1)

REGULATORY GUIDE 1.88 Collection, Storage, and Maintenance of Nuclear Power Plant, Quality Assurance Records

Rev 2, October 1976

This guide, which endorses/modifies ANSI N45.2.9 (1974), is not applicable to LGS (being for construction permit application submittals after October 1976). Quality assurance during construction is discussed in the document "LGS Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction." LGS will be in conformance during operation, except for certain alternate approaches to the ANSI Standard regarding correction to documents and storage, as discussed in the QATR.

(Category 1)

REGULATORY GUIDE 1.89 Qualification of Class 1E Equipment for Nuclear Power Plants

Rev 0, November 1974

Regulatory Guide 1.89, Revision 0, does not apply to LGS. LGS equipment requiring qualification was qualified in accordance with NUREG-0588, Category II as described in Sections 8.1.6.1 and 3.11.

(Category 4)

REGULATORY GUIDE 1.90 Inservice Inspection of Prestressed Concrete Containment Structures with Grouted Tendons

Rev 1, August 1977

LGS does not have a prestressed concrete containment and therefore this guide is not applicable.

REGULATORY GUIDE 1.91 Evaluation of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plants

Rev 1, February 1978

Although this guide does not apply to LGS (being for plants whose construction permits were docketed after February 24, 1978), LGS is in conformance as discussed in Section 2.2.3.

(Category 2)

REGULATORY GUIDE 1.92 Combining Modal Responses and Spatial Components in Seismic Response Analysis

Rev 1, February 1976

This guide does not apply to LGS (being for plants whose instruction permits were docketed after February, 1976). LGS seismic response analysis methods are discussed in Section 3.7 and 3.9. Refer to Section 3.10.

(Category 1)

REGULATORY GUIDE 1.93 Availability of Electric Power Sources
Rev 0, December 1974

The LGS design is in conformance as discussed in Section 8.2. LGS will conform to this guide during operation as discussed in Chapter 16.

(Category 4)

REGULATORY GUIDE 1.94 Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants
Rev 1, April 1976

This guide, which endorses/modifies ANSI N45.25 (1974), is not applicable to LGS (being for plants whose construction permits are docketed after October, 1976). Quality assurance during construction is discussed in the document "LGS Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction."

The commitments to this Regulatory Guide and ANSI N45.2.5 were deleted since they were superseded by Exelon’s commitment to ASME NQA-1 1994 subpart 2.5.

(Category 1)

REGULATORY GUIDE 1.95 Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release
Rev 1, January 1977

This guide is not applicable to LGS (being for plants whose construction permits were docketed after the guide's issuance). The LGS design for protection against accidental chlorine release is discussed in Sections 2.2.3 and 6.4.

(Category 1)

REGULATORY GUIDE 1.96 Design of Main Steam Isolation Valve Leakage Control Systems for Boiling Water Reactor Nuclear Power Plants
Rev 0, May 1975

In 1994, LGS received approval to remove the MSIV-LCS and replace it with the MSIV Leakage Alternate Drain Pathway discussed in Section 6.7

(Category 1)

REGULATORY GUIDE 1.97 Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Rev 2, December 1980

LGS is in conformance with this guide to the extent discussed in Section 7.5.

(Category 3)

REGULATORY GUIDE 1.98 Assumptions Used for Evaluating the Potential Radiological Consequences of a Radioactive Offgas System Failure in a Boiling Water Reactor

Rev 0, March 1976

LGS is in conformance with this guide except that an alternate approach is used for paragraph C.4.b (dose conversion factors) and there is a clarification to paragraph C.4.a regarding surface body dose rates. Details are discussed in Section 15.0.4.

(Category 1)

REGULATORY GUIDE 1.99 Radiation Embrittlement of Reactor Vessel Materials

Rev 2, May 1988

LGS is in conformance with this guide as discussed in Section 5.3.1.4.

(Category 3)

REGULATORY GUIDE 1.100 Seismic Qualification of Electric Equipment for Nuclear Power Plants

Rev 1, August 1977

This guide which endorses/modifies IEEE 344 (1975) does not apply to LGS (being for plants whose construction permits are docketed after the guide's issuance). LGS seismic qualification of electrical components is discussed in Section 3.10.

(Category 1)

REGULATORY GUIDE 1.101 Emergency Planning for Nuclear Power Plants

Rev 2, October 1981

LGS is in conformance with this guide except for certain alternate approaches discussed in the Emergency Plan.

REGULATORY GUIDE 1.102 Flood Protection for Nuclear Power Plants

Rev 1, September 1976

LGS is in conformance with this guide as discussed in Section 3.4.

(Category 2)

REGULATORY GUIDE 1.103 Post-Tensioned Prestressing Systems for Concrete Reactor Vessels and Containments

Rev 1, October 1976

LGS does not have a prestressed concrete containment and therefore this guide is not applicable.

REGULATORY GUIDE 1.104 Overhead Crane Handling Systems for Nuclear Power Plants

Rev 0, February 1976

This guide was withdrawn by the NRC on August 16, 1979. The LGS reactor enclosure crane was designed and procured prior to the issuance of this guide. For explanatory purposes, a comparison with the guide is given in Section 9.1.5.

(Category 4)

REGULATORY GUIDE 1.105 Instrument Setpoints

Rev 1, November 1976

Although this guide does not apply to LGS except for the RRCS (being for plants whose construction permits applications are docketed after Dec. 15, 1976). LGS will be in conformance during operation as discussed in Section 7.1.2.5 and Chapter 16.

(Category 2)

REGULATORY GUIDE 1.106 Thermal Overload Protection for Electric Motors on Motor-Operated Valves

Rev 1, March 1977

This guide is not applicable to LGS (being for plants whose construction permits are docketed after issuance of the guide). The LGS design is discussed in Section 8.1.6.1.

(Category 1)

REGULATORY GUIDE 1.107 Qualifications for Cement Grouting for Prestressing Tendons in Containment Structures

Rev 1, February 1977

LGS does not have a prestressed concrete containment and therefore this guide is not applicable.

REGULATORY GUIDE 1.108 Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants

Rev 1, August 1977

Although this guide does not apply to LGS (being for plants whose construction permits are docketed after issuance of the guide), LGS is in conformance. All diesel generator protective trips which are enforced during a LOOP or emergency operation, are annunciated in a group trouble alarm in the main control room and individually in the diesel generator local annunciator panel. An indication of which of the protective trips is activated first is provided on the local annunciator panel to facilitate diagnosis of trouble. The surveillance feature which would indicate the first diesel generator protective trip, is not necessary for the safe and orderly shutdown and for maintaining the

plant in a safe shutdown condition. Periodic testing of the diesel generators is described in Section 8.1.6.1.20. LGS will be in conformance during operation as discussed and clarified in Chapter 16.

(Category 2)

REGULATORY GUIDE 1.109	Calculations of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10CFR50, Appendix I
Rev 1, October 1977	

LGS is in conformance with this guide as discussed in Section 5.2 of the EROL.

(Category 1)

REGULATORY GUIDE 1.110	Cost-Benefit Analysis for Radwaste Systems for Light-Water-Cooled Nuclear Power Reactors
Rev 0, March 1976	

This guide is not applicable to LGS (being for plants whose construction permit applications are docketed after June 4, 1976). This analysis was not performed for LGS.

(Category 1)

REGULATORY GUIDE 1.111	Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors
Rev 1, July 1977	

LGS is in conformance with this guide except for certain alternate approaches as discussed in Section 2.3.

(Category 1)

REGULATORY GUIDE 1.112	Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light-Water-Cooled Power Reactors
Rev 0-R, May 1977	

LGS is in conformance with this guide as discussed in Section 11.1.

(Category 1)

REGULATORY GUIDE 1.113	Estimating Aquatic Dispersion of Effluents from Accidental and Routine Releases for the Purpose of Implementing Appendix I
Rev 1, April 1977	

LGS is in conformance with this guide as discussed in Section 5.2 of the EROL.

(Category 1)

REGULATORY GUIDE 1.114 Guidance on Being Operator at the Controls of a Nuclear Power Plant

Rev 1, November 1976

LGS will be in conformance with the guide.

(Category 3)

REGULATORY GUIDE 1.115 Protection Against Low-Trajectory Turbine Missiles
Rev 1, July 1977

The LGS analysis does not employ the guidelines of paragraph C.4 regarding damage probabilities assuming turbine failure. However, the total probability, calculated using assumptions acceptable to NRC on other projects, is well within the limits. Details are discussed in Section 3.5.1.3.

(Category 2)

REGULATORY GUIDE 1.116 Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems

Rev 0-R, May 1977

This guide endorses/modifies ANSI N45.2.8 (1975). The ANSI standard is not specifically a part of the construction QA program, however, LGS is in general conformance with the guide. Quality assurance during construction is discussed in the document "LGS Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction."

The commitments to this Regulatory Guide and ANSI N45.2.8 were deleted since they were superseded by Exelon's commitment to ASME NQA-1 1994 subpart 2.8.

(Category 1)

REGULATORY GUIDE 1.117 Tornado Design Classification
Rev 1, April 1978

Although this guide does not apply to LGS (being for plants whose construction permit applications are docketed after May 30, 1978), LGS is in conformance except that an alternate approach is used for protection of the spray pond spray networks. Details are discussed in Section 3.5.1.4.

(Category 2)

REGULATORY GUIDE 1.118 Periodic Testing of Electric Power and Protection Systems
Rev 2, June 1978

This guide, which endorses/modifies IEEE 338 (1977), does not apply to LGS except for the RRCS (being for plants whose construction permit applications are docketed after issuance of the guide). The design for periodic testing of electric power and protection systems is discussed in Sections 8.1.6.1 and 7.1.2.5, respectively.

(Category 1)

REGULATORY GUIDE 1.119 Surveillance Program for New Fuel Assembly Design

Rev 0, June 1976

This guide was withdrawn June 1977.

REGULATORY GUIDE 1.120 Fire Protection Guidelines for Nuclear Power Plants

Rev 1, November 1977

Per the letter transmitting Regulatory Guide 1.120 (Rev 1) LGS will be evaluated against BTP ASB 9.5-1 in lieu of this guide. LGS's conformance to ASB 9.5-1 is discussed in Appendix 9A.

(Category 1)

REGULATORY GUIDE 1.121 Bases for Plugging Degraded PWR Steam Generator Tubes

Rev 0, August 1976

This guide is for PWRs and therefore is not applicable to LGS.

REGULATORY GUIDE 1.122 Development of Floor Design Response Spectra for Seismic Design of Floor-Supported Equipment or Components

Rev 1, February 1978

This guide is not applicable to LGS (being for plants whose construction permit applications are under review after issuance of the guide). LGS floor design response spectra are discussed in Section 3.7.2.3.

(Category 1)

REGULATORY GUIDE 1.123 Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants

Rev 1, July 1977

Historical Information

This guide endorses/modifies ANSI N45.2.13 (1976). Neither the guide nor the ANSI standard are specifically used during construction. Quality assurance during construction is discussed in the document "LGS Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction." LGS will conform during operation, as discussed and clarified in the QATR.

Regulatory Guide 1.123, Rev 1 has been withdrawn and superseded by Regulatory Guide 1.28, Rev 3, August 1985.

Limerick will conform to Regulatory Guide 1.28, Rev.3, August 1985 during operation, as discussed and clarified in the QATR.

(Category 1)

REGULATORY GUIDE 1.124 Service Limits and Loading Combinations for Class 1 Linear-Type Component Supports

Rev 1, January 1978

This guide does not apply to LGS (being for plants whose construction permit applications are docketed after January 10, 1978). This guide has not been used on LGS, and procedures for the subject matter of this guide are discussed in Section 3.9.

(Category 2)

REGULATORY GUIDE 1.125 Physical Models for Design and Operation of Hydraulic Structures and Systems for Nuclear Power Plants

Rev 1, October 1978

This guide is not applicable to LGS (being for plants whose construction permits are under review after issuance of the guide).

(Category 1)

REGULATORY GUIDE 1.126 An Acceptable Model and Related Statistical Methods for the Analysis of Fuel Densification

Rev 1, March 1978

This guide has not been applied. The fuel densification analysis defined in section 4.2.4.4.11 of NEDE-20944-P, "BWR 4/5 Fuel Design", September 1976 has been found acceptable by the NRC and is applicable to LGS.

(Category 1)

REGULATORY GUIDE 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants

Rev 1, March 1978

LGS will be in conformance with this guide during construction of the spray pond. The various investigations and inspections associated with the spray pond are discussed in Sections 2.4 and 2.5. LGS will be in conformance with this guide during operation.

(Category 3)

REGULATORY GUIDE 1.128 Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants

Rev 1, October 1978

This guide is not applicable to LGS (being for plants whose construction permit applications are docketed after December 1, 1977). The LGS design of large lead storage battery facilities is discussed in Section 8.1.6.1 and 8.3.2.

(Category 1)

REGULATORY GUIDE 1.129 Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Nuclear Power Plants

Rev 1, February 2 1978

This guide does not apply to LGS (being for plants whose construction permit applications are docketed after December 1, 1977). However, LGS is in conformance with this guide as described in Section 8.1.6.1. Periodic testing is discussed in Chapter 16 .

(Category 1)

REGULATORY GUIDE 1.130 Design Limits and Loading Combinations for Class 1 Plate-and-Shell-Type Component Supports

Rev 0, July 1977

This guide is not applicable to LGS (being for plants whose construction permit applications are docketed after April 1, 1978). LGS design limits and loading combinations are discussed in Sections 3.9 and 5.4.1.4.

(Category 2)

REGULATORY GUIDE 1.131 Qualification Tests of Electric Cables, Field Splices, and Connections for Light-Water-Cooled Nuclear Power Plants

Rev 0, August 1977

This guide is not applicable to LGS (being for plants whose construction permit applications are docketed after May 1, 1978). LGS qualification tests of electric cables, field splices, and connections are discussed in Section 3.11.

(Category 1)

REGULATORY GUIDE 1.132 Site Investigations for Foundations of Nuclear Power Plants

Rev 1, March 1979

This guide is applicable to LGS only for new investigations conducted after March 30, 1979. No new investigations have been conducted since that time. Site investigations are discussed in Sections 2.4 and 2.5.

(Category 1)

REGULATORY GUIDE 1.133 Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors

Rev 1, May 1981

LGS is no longer in conformance with this guide. The Loose-Part Detection Program has been relaxed as discussed inn BWR Owners' Group Licensing Topical Report NEDC-32975P and associated SER.

REGULATORY GUIDE 1.134 Medical Certification and Monitoring of Personnel Requiring Operator Licenses

Rev 2, April 1987

LGS will be in conformance with this guide, which endorses/ modifies ANSI/ANS 3.4-1983, as discussed in Section 13.1.

(Category 1)

REGULATORY GUIDE 1.135 Normal Water Level and Discharge at Nuclear Power Plants

Rev 0, November 1977

This guide is not applicable to LGS (being for plants whose construction permits are docketed after May 1, 1978). The hydrologic analysis for LGS is discussed in Section 2.4.

(Category 1)

REGULATORY GUIDE 1.136 Material for Concrete Containments

Rev 1, October 1978

This guide is not applicable to LGS (being for plants whose construction permit applications are docketed after November 30, 1978). LGS containment material is discussed in Section 3.8.1.

(Category 1)

REGULATORY GUIDE 1.137 Fuel Oil Systems for Standby Diesel Generators

Rev 1, October 1979

This guide endorses/modifies ANSI N195 (1976) and is limited in its applicability to LGS to paragraph C.2, per the letter transmitting Revision 0 of this guide. LGS will conform to paragraph C.2 during operation, except that the fuel oil surveillance test requirements will be as described in the plant Technical Specifications. The design of fuel oil transfer system is discussed in Section 9.5.4.

(Category 2)

REGULATORY GUIDE 1.138 Laboratory Investigations of Soils for Engineering Analysis and Design of Nuclear Power Plants

Rev 0, April 1978

This guide is applicable to LGS only for new investigations conducted after December 1, 1978. No new investigations have been conducted since that time. Site investigations are discussed in Sections 2.4 and 2.5.

(Category 1)

REGULATORY GUIDE 1.139 Guidance for Residual Heat Removal

Rev 0, May 1978

Although the LGS design was completed prior to the issuance of this guide, LGS is in conformance with the intent, subject to clarifications regarding system protection features and pressure relief discussed in Section 5.4.7. LGS will be in conformance with this guide during operation.

(Category 3)

REGULATORY GUIDE 1.140 Design, Testing, and Maintenance Criteria for Normal Ventilation Exhaust System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants

Rev 1, October 1979

This guide is not applicable to LGS per its implementation section. The LGS design was substantially completed prior to the issuance of this guide. For explanatory purposes, a comparison with Revision 1 of the guide is provided in Table 9.4-18.

(Category 1)

REGULATORY GUIDE 1.141 Containment Isolation Provisions for Fluid Systems

Rev 0, April 1978

The LGS containment isolation system was substantially completed prior to the issuance of this guide which endorses/modifies ANSI N271 (1976). LGS is in conformance with the guide except for certain design features of closed systems inside containment, valve leakage control and leak testing. Details are provided in Section 6.2.4.

(Category 2)

REGULATORY GUIDE 1.142 Safety-Related Concrete Structures for Nuclear Power Plants (Other than Reactor Vessels and Containments)

Rev 0, April 1978

This guide, which endorses/modifies ACI 349-76, is not entirely applicable to LGS (being for plants whose construction permit applications are docketed after December 15, 1978). Practices specified in the UFSAR for design and construction of safety related concrete structures bring LGS into compliance with substantial portions of the guide. LGS safety-related concrete structures are discussed in Section 3.8.

(Category 1)

REGULATORY GUIDE 1.143 Design Guidance for Radioactive Waste Management Systems Structures and Components Installed in Light-Water- Cooled Nuclear Power Plants

Rev 1, October 1979

LGS is in conformance with the intent of the guide, subject to the exceptions and clarifications listed in Table 3.2-1, Note 18. The design codes, standards, and quality assurance for radwaste

system piping and components are presented and discussed in Table 3.2-1; design of the radwaste structure is discussed in Section 3.8; radwaste management systems are discussed in Chapter 11.

(Category 1)

REGULATORY GUIDE 1.144 Auditing of Quality Assurance Programs for Nuclear Power Plants

Rev 1, September 1980

This guide endorses/modifies ANSI N45.2.12 (1977). The guide and the ANSI standard are not specifically utilized during construction. Quality assurance during construction is discussed in the document "LGS Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction."

Regulatory Guide 1.28 superseded commitments to RG 1.144. LGS will comply with Regulatory Guide 1.28 during operation, as described in the QATR.

(Category 1)

REGULATORY GUIDE 1.145 Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants

Rev 1, November 1982

The LGS X/Q values resulting at the EAB and LPZ are calculated using the NRC sponsored computer code PAVAN consistent with the procedures in Regulatory Guide 1.145, as discussed in Section 2.3.

REGULATORY GUIDE 1.146 Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants

Rev 0, August 1980

LGS will comply with this guide, which endorses/modifies ANSI N45.2.23 (1978), as described in the QATR.

Regulatory Guide 1.28 superseded commitments to RG 1.146. LGS will comply with Regulatory Guide 1.28 during operation, as described in the QATR.

REGULATORY GUIDE 1.147 Inservice Inspection Code Case Acceptability ASME Section XI Division 1

Latest Revision

LGS conforms with this guide as specified in the Inservice Inspection Program and Inservice Testing documents .

REGULATORY GUIDE 1.148 Functional Specification for Active Valve Assemblies in Systems Important to Safety in Nuclear Power Plants

Rev 0, March 1981

The program (Section 3.9.3.2b) for the initial procurement of LGS valves was developed prior to the issuance of Regulatory Guide 1.148 and therefore does not include such a functional valves

specification. However, the intent of a functional specification has been met by functional requirements in the existing valve specification.

REGULATORY GUIDE 1.150 Ultrasonic Testing of Reactor Vessel Welds During Preservice and Inservice Examinations

Rev 1, February 1983

LGS will be in conformance with Regulatory Guide 1.150 to the extent practicable. The extent of compliance will be submitted with the RPV PSI Report.

REGULATORY GUIDE 1.155 Station Blackout

Rev. 0, August 1988

LGS is in conformance with this guide by virtue of compliance with NUMARC 87-00, November 1987, except where Regulatory Guide 1.155 takes precedence. Compliance is discussed in Section 8.1.6.1.25.

REGULATORY GUIDE 1.166 Pre-earthquake Planning and Immediate Nuclear Power Plant Operator Post-Earthquake Actions

March 1997

This guide provides guidance acceptable to the NRC staff for a timely evaluation after an earthquake of the recorded instrumentation data and for determining whether plant shutdown is required by 10 CFR Part 50.

REGULATORY GUIDE 1.167 Restart of a Nuclear Power Plant Shut Down by a Seismic Event

March 1997

This guide provides guidance acceptable to the NRC staff for performing inspections and tests of nuclear power plant equipment and structures prior to restart of a plant that has been shut down by a seismic event.

REGULATORY GUIDE 1.181 Content of the Updated Final Safety Analysis Report in accordance with 10 CFR 50.71(e)

Rev 0, September 1999

This Guideline endorses NEI 98-03, Revision 1, “Industry Update Guidelines for Final Safety Analysis Reports.”

REGULATORY GUIDE 1.183 Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors

Rev 0, July 2000

This guideline supersedes Regulatory Guides 1.3, 1.5, and 1.25 for assumptions and methodology for assessing radiological consequences of design basis accidents. Alternative Source Terms (AST) for determination of off-site and control room dose was approved for use at LGS by NRC Safety Evaluation Report dated September 8, 2006. LGS is in conformance with this Regulatory Guide, with exceptions, as discussed in Section 15.0.4.

REGULATORY GUIDE 1.190 Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence

Rev 0, March 2001

This Guideline was not used as a design basis, which is discussed in Section 4.1.4.5, 4.3.2.8 and 5.3.1.6.2. LGS reactor pressure vessel neutron fluence calculations performed after October 2002 will be in conformance with this guide (Reference 5.3-13).

REGULATORY GUIDE 1.194 Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants

Rev 0, July 2003

The LGS X/Q values resulting at the control room intake are calculated using the NRC sponsored computer code ARCON96, consistent with the procedures in Regulatory Guide 1.194, as discussed in Section 2.3.

Table 1.8-1

COMPONENT IDENTIFICATION FOR CODE CASE N242

VALVE OR SYSTEM	PARTS OR COMPONENTS
PSV-44-1F036 -2F036	Screw ring pin, disc, spring steps, compression screw, gag screw, stem, base.
PSV-50-1F018 -2F018	Base, disc, compression screw, spring step, gag screw, stem, guide.
PSV-50-1F033 -2F033	Base, disc, stem, guide, compression screw, spring steps, gag screws.
PSV-51-1F025A,B,C,D -2F025A,B,C,D	Disc, stem, compression screw, spring step, cap, gag screw, base(1), guide.
PSV-51-1F029 -2F029	Base, disc, stem, compression screw, spring step, cap, gag screw, guide.
PSV-51-1F030A,B,C,D -2F030A,B,C,D	Base, disc, stem, compression screw, spring step, cap, gag screw, guide.
PSV-51-1F097 -2F097	Nozzle, disc, disc holder, guide, stem, adjusting ring, compression screw, spring step, screw ring pin, gag screw.
PSV-56-1F018 -2F018	Nozzle, disc, disc holder, guide, stem, gag screw, adjusting ring, compression screw, spring step, screw ring pin.
PSV-56-1F020 -2F020	Base, disc, stem, spring step, compression screw, gag screw, guide.
PSV-51-1F055A,B PSV-51-2F055A,B	Adjusting bolt, disc insert, spindle point.
PSV-56-1F050 -2F050	Base, disc, guide, compression screw, spring steps, gag screw, stem.
PSV-69-145 -245	Stem, compression screw, spring steps, cap, base, disc, guide.
PSV-50-219	Base, stem, gag screw.

Table 1.8-1 (Cont'd)

VALVE OR SYSTEM	PARTS OR COMPONENTS
PSV-56-225	Base, stem, gag screw.
PSV-45-1-61	Guide, compression screw, spring step.
PSV-45-1-62A,B	Compression screw, spring steps, gag screw.
PSV-45-1-63	Guide, compression screw, spring steps.
PSV-45-1-65	Guide, compression screw, spring steps.
PSV-45-1-67	Guide, compression screw, spring steps.
PSV-52-127	Guide, compression screw, spring steps, gag screw.
PSV-52-2F012A,B	Spring step, base, disc, gag screw, guide, compression screw, stem.
Main steam system, Unit 1	Pipe clamp for snubber, Mark: 26 in.-50k-M.S.
Main steam system, Unit 2	Pipe clamp for snubber, Mark: 26 in.-50k-M.S.
Recirculation system, Unit 1	Pipe clamp for snubber, Mark: 22 in.-50k-Recirc.
Recirculation system, Unit 2	Pipe clamp for snubber, Mark 22 in.-50k-Recirc.
Recirculation system, Unit 1	Pipe clamp for snubber, Mark: 28 in.-50k-Recirc. Disc.
Recirculation system, Unit 2	Pipe clamp for snubber, Mark: 28 in.-50k-Recirc. Disc.
Recirculation system, Unit 1	Pipe clamp for snubber, Mark: 28 in.-50k-Recirc. Suct.
Recirculation system, Unit 2	Pipe clamp for snubber, Mark: 28 in.-50k-Recirc. Suct.

Table 1.8-1 (Cont'd)

VALVE OR SYSTEM	PARTS OR COMPONENTS
Diesel generator system	Starting air receiver
Diesel generator system	Starting air system piping and valves
Diesel generator system	Fuel oil day tank
Diesel generator system	Fuel oil system piping and valves
Diesel generator system	Lube oil makeup tank
Diesel generator system	Lube oil system piping and valves
Diesel generator system	Jacket water expansion tank
Diesel generator system	Jacket water intercooler piping and valves

(1) Unit 1 only

1.9 STANDARD DESIGNS

This section is not applicable to LGS as it is not a standard design plant.

1.10 SYMBOLS AND TERMS

1.10.1 TEXT ACRONYMS

Acronyms used throughout the UFSAR are listed in Table 1.10-1.

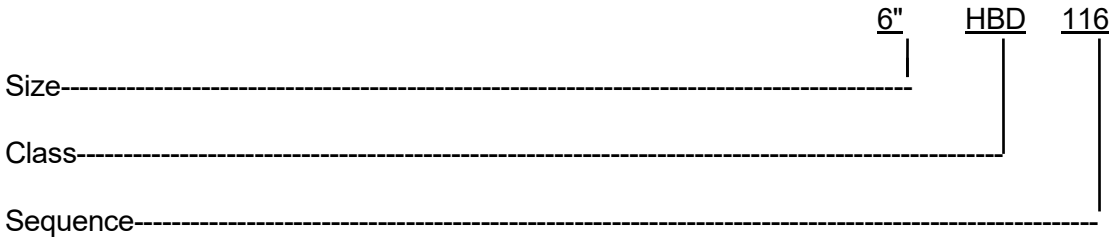
1.10.2 LOGIC SYMBOLS

Logic symbols used on FCDs are shown in Figure 1.10-2.

1.10.3 PIPING IDENTIFICATION

Piping is identified by a three-group identifier where the first group is the nominal pipe size in inches; the second is a three-letter group for the pipe class; and the third is a three-digit group sequentially assigned within a pipe class.

Example:



The three-letter group for the pipe class is described in detail in Table 1.10-2.

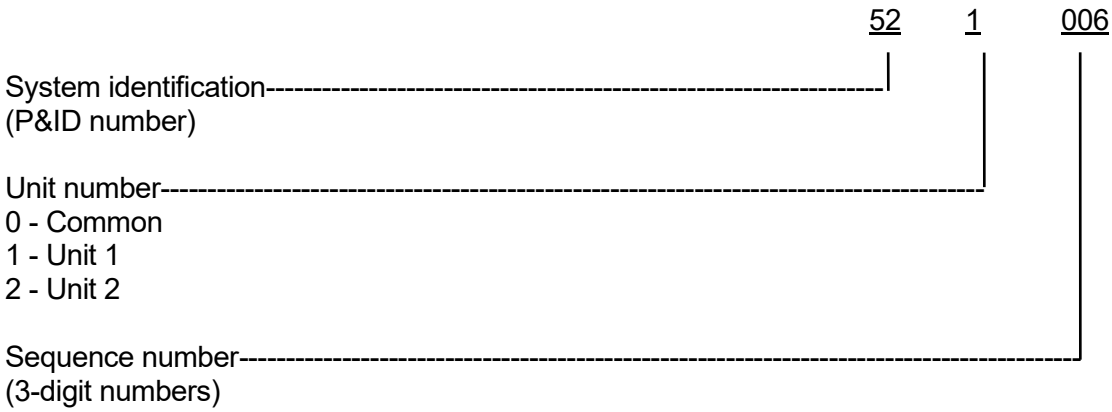
The three-digit sequence number is assigned consecutively to identify specific lines in a pipe class as follows:

Piping common to both units	0-99 and 500-699
Piping for Unit 1	100-199, 300-399, and 700-799
Piping for Unit 2	200-299, 400-499, and 800-899

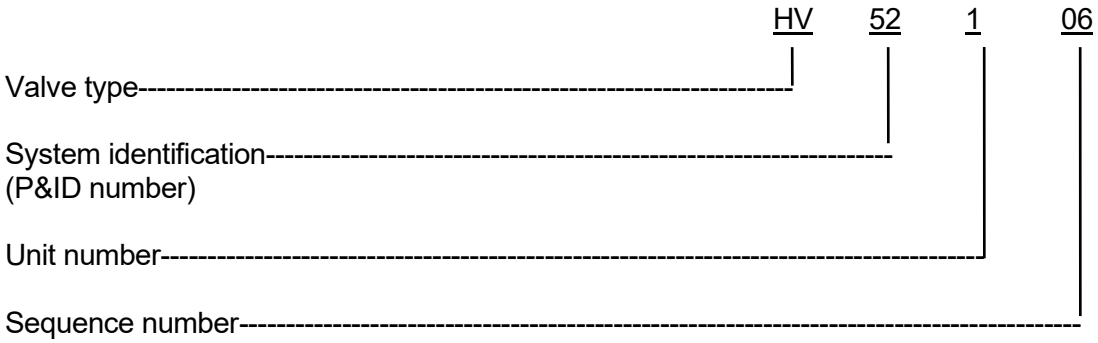
1.10.4 VALVE IDENTIFICATION

All manual and remotely operated valves have unique identification numbers for tracking purposes. Listed below are the numbering systems used for each group of valves.

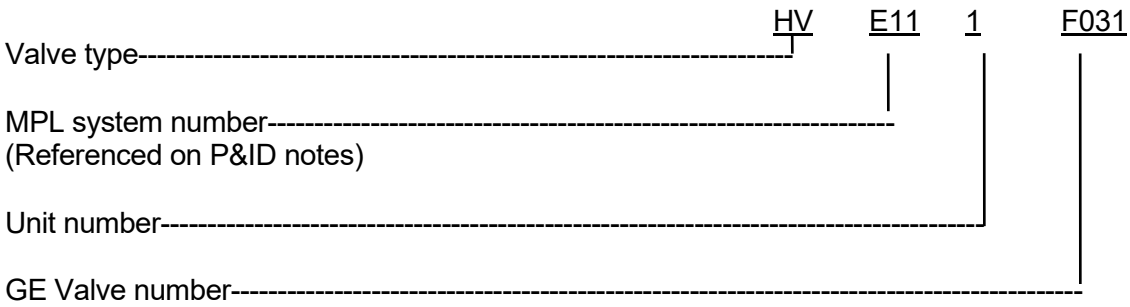
Manual valves, except those which have a GE MPL number and those valves supplied by vendors as part of an equipment package and not installed by Bechtel, are identified by the following method:



Remote-operated valves that do not have a GE MPL number are identified by the operator number as follows:



Those valves in GE's MPL are identified by the GE numbering system as follows:

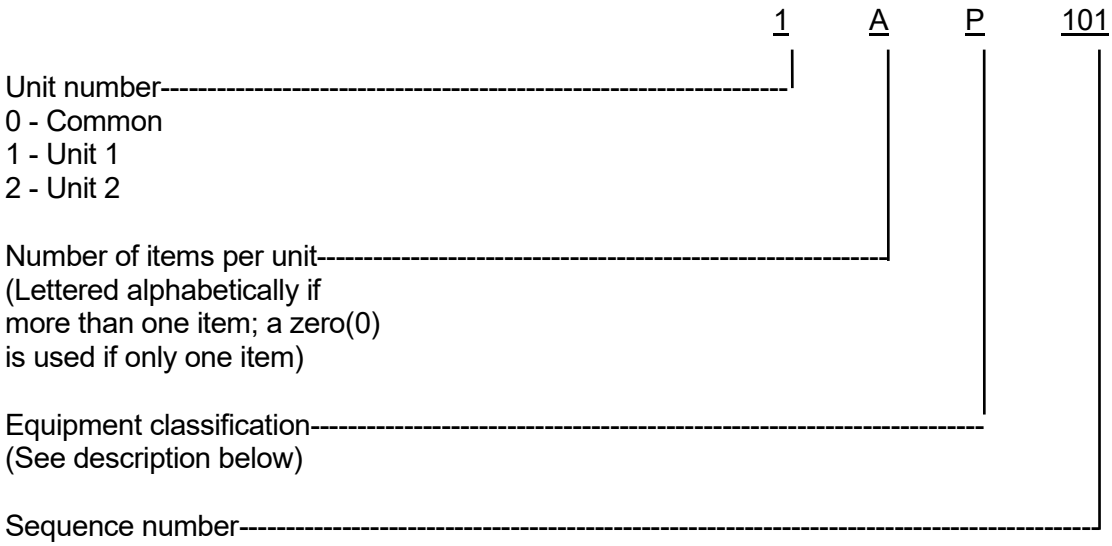


Valve types are indicated in drawing M-00. Valves that are not numbered but are supplied as part of a vendor mounted equipment package are identified in the vendor's operation and maintenance manuals. This is done to avoid duplication in numbering these valves.

1.10.5 EQUIPMENT NUMBERING

Equipment is identified on the P&IDs by a four-group identifier as discussed below.

Example:



Equipment classification is identified by type as follows:

A	13.8, 4.16, and 2.4 kV switchgear
B	440 V load centers and motor control centers
C	Control boards or relay boards
D	Direct current equipment
F	Filters and cleaning equipment
G	Generators (turbine, diesel) and associated equipment
H	Hoists and cranes
K	Air compressors, chiller compressors, process fans, and blowers
L	Lighting, heater, and distribution panels
P	Pumps including drive motors
R	33/220/500 kV switchgear and associated equipment
S	Miscellaneous
T	Tanks and pressure vessels
U	Floor sections
V	Air conditioning units, ventilation fans and exhausters
W	Power receptacles
X	Transformers
Y	Instrument ac equipment
Z	Computer equipment

1.10.6 ELECTRICAL COMPONENT IDENTIFICATION

This section describes the methods used to identify electrical equipment locations and to number electrical schemes, cables, and raceways.

1.10.6.1 Equipment Location Numbers

Each piece of electrical equipment is identified by an equipment number as described in Section 1.10.4. To facilitate cable routing from one equipment location to another, a location number is also assigned to each piece of electrical equipment. Generally, the equipment number and equipment location number for a specific piece of electrical equipment are identical. For large pieces of electrical equipment, such as switchgear, load centers, and MCC, which are compartmentalized, the equipment location number consists of the basic equipment number plus additional suffixed information to identify a location within the equipment itself. The following two examples illustrate equipment location numbers:

Example 1: 10X101
Example 2: 10B22403

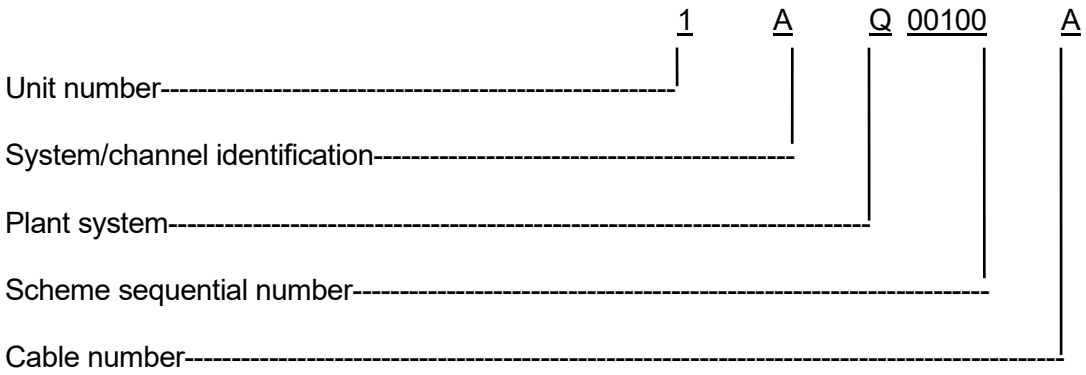
In the first example, the equipment number and equipment location number for transformer 10X101 are identical. In the second example, the basic MCC equipment number 10B224 is suffixed to establish an equipment location number, 10B22403, which identifies a specific cubicle within the MCC.

Equipment location numbers are generally assigned to items listed in the circuit and raceway schedules. Accordingly, most electrical equipment related to systems such as lighting, communications, and cathodic protection is not included.

Electrical equipment that is an integral part of mechanical equipment is assigned the same number as the mechanical equipment.

1.10.6.2 Scheme Cable Numbers

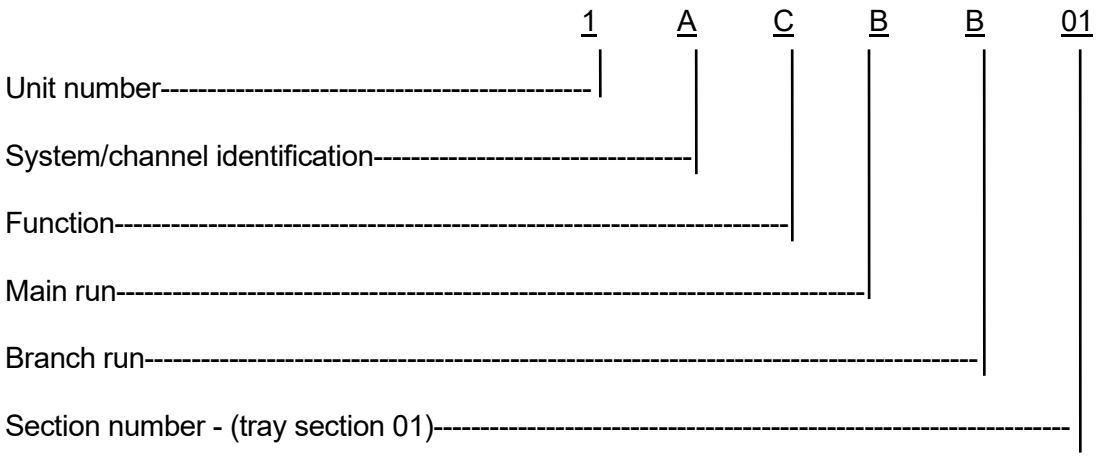
Each electrical scheme is identified by a number with up to nine characters. The first character is numeric and refers to the plant unit number for which the scheme is applicable. The second character is alphabetic or numeric and refers to the separation group to which the cable belongs. The third character is alphabetic and classifies the scheme by major plant system. The next six characters are numeric or alphanumeric, and provide a sequential, but arbitrary, identity for each scheme. (The letter designation at the end of the scheme number is the cable number.) Except for cabling associated with the plant lighting, communications, and cathodic protection systems, each cable in the plant is identified by a scheme cable number. Given below is an example of a typical scheme number including the cable number.



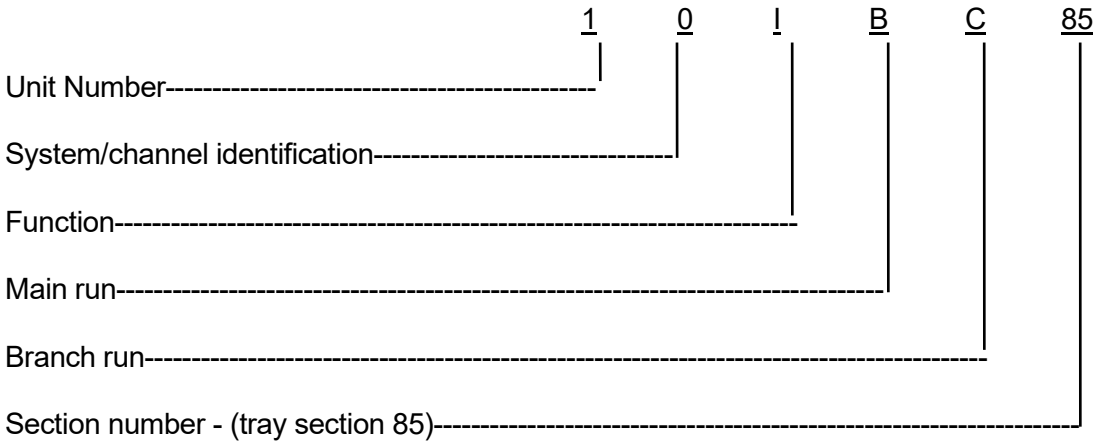
1.10.6.3 Raceway Numbers

All electrical cable trays, ducts, conduits, manholes, conduit sleeves, and junction boxes are identified by six-character raceway numbers. The two examples given below illustrate typical raceway numbers for safety-related and nonsafety-related cable trays, respectively.

Safety-related



Nonsafety-related



The following example illustrates a typical conduit number:

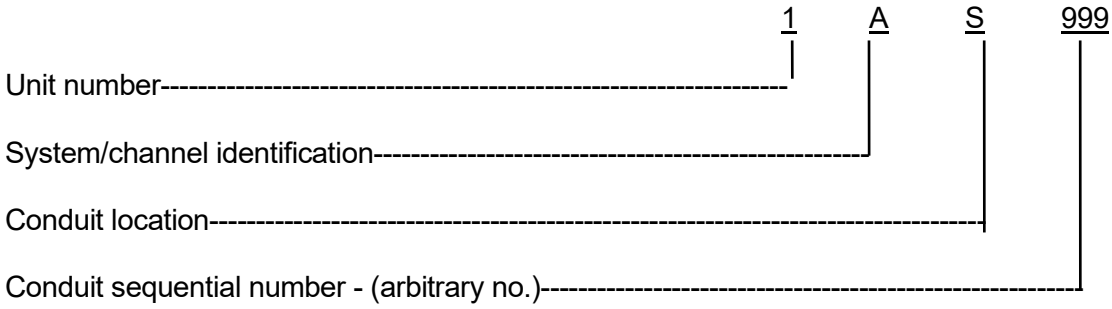


Table 1.10-1

ACRONYMS USED IN UFSAR

AASHTO	American Association of State Highway and Transportation Officials
ABS	absolute summation
AC	alternating current
ACI	American Concrete Association
ACRS	Advisory Committee on Reactor Safeguards
ADS	automatic depressurization system
AE	Architect/Engineer
AEC	Atomic Energy Commission
AEOE-RMS	air ejector offgas effluent radiation monitoring system
AERVS	auxiliary equipment room ventilation system
AGC	automatic gain control
AGL	above ground level
AGMA	American Gear Manufacturer Association
AISC	American Institute of Steel Construction
AISI	American Iron and Steel Institute
ALARA	as low as reasonably achievable
AMCA	Air Moving and Conditioning Association
AMS	American Meteorological Society
ANI	American Nuclear Insurers
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOV	air-operated valve

Table 1.10-1 (Cont'd)

APRM	average power range monitor
ARI	alternate rod insertion
ARMS	area radiation monitoring system
ARS	acceleration response spectra
ASCE	American Society of Civil Engineers
ASHRAE	American Society of Heating, Refrigeration and Air Conditioning Engineers
ASME B&PV Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
ASTM	American Society for Testing and Materials
ATM	analog trip module
ATWS	anticipated transient without scram
ASD	Adjustable Speed Drive
AST	alternative source term
AWS	American Welding Society
AWWA	American Water Works Association
BMI	Battelle Memorial Institute
BNL	Brookhaven National Laboratory
BOC	beginning of cycle
BOP	balance of plant
BPV	bypass valve
BTP	Branch Technical Position
BWR	boiling water reactor
BWROG	Boiling Water Reactor Owners Group
CAC	containment atmospheric control
CAM	continuous air monitor
CAS	central alarm station

Table 1.10-1 (Cont'd)

CCU	condensate cleanup
CECWS	control enclosure chilled water system
CFD	condensate filter/demineralizer
CFR	Code of Federal Regulations
CGCS	combustible gas control system
CIGS	containment instrument gas system
CIGS-ADS	containment instrument gas system - ADS control
CIV	combined intermediate valves
CMAA	Crane Manufacturers Association of America
CMTR	Certified Material Test Reports
CO	condensation oscillation
CO-ADS	condensation oscillation with ADS
CP	collection points
CPR	critical power ratio
CPU	central processing unit
CRD	control rod drive
CRDM	control rod drive mechanism
CRDR	Control Room Design Review
CRGR	Committee to Review Generic Requirements
CREFAS	control room emergency fresh air supply system
CREFA-RMS	control room emergency fresh air radiation monitoring system
CRT	cathode ray tube or equivalent video display interface device
CRV-RMS	control room ventilation radiation monitoring system
CS	core spray (system)
CSCWS	control structure chilled water system
CST	condensate storage tank

Table 1.10-1 (Cont'd)

CTSP-RMS	charcoal treatment system process exhaust radiation monitoring system
CVN	charpy v-notch
DA	drainage area
DAC	distance-amplitude correction
DAR	Design Assessment Report
DAS	data acquisition system
DBA	design basis accident
DBCD	deep bed condensate demineralizer
DBE	design basis earthquake
DBFL	design basis flood level
DC	direct current
DCWS	drywell chilled water system
DDOF	dynamic degrees of freedom
DEMA	Diesel Engine Manufacturers Association
DF	decontamination factor
DFFR	Dynamic Forcing Function Information Report
DG	diesel generator
DGEVS	diesel generator enclosure ventilation system
D-LDS	drywell leak detection system
DLPL	digital loose parts locator
DLV	discharge line volume
DLWL	discharge line water-leg length
DOP	di-octylphthalate
DOR	Division of Operating Reactors (NRC)
DOT	Department of Transportation
DRBC	Delaware River Basin Commission

Table 1.10-1 (Cont'd)

DSLMS	drywell sump level monitoring system
DUC	drywell unit coolers
EAB	exclusion area boundary
ECCS	emergency core cooling systems
ECCS-UC	emergency core cooling systems pump compartment unit coolers
ECL	effluent concentration limit
EFCV	excess flow check valve
EFPY	effective full power years
EGM	electronic governor module
EHC	electrohydraulic control
ELLR	extended lead line region
EMI	electromagnetic interference
EOC	end of cycle
EOF	emergency operations facility
EOL	end of life
EOP	emergency operating procedure
EPA	Environmental Protection Agency
EPG	emergency procedure guidelines/severe accident guidelines
EPRI	Electric Power Research Institute
E/P	electrical-to-pneumatic
EQ	environmental qualification
EQR	Environmental Qualification Report
ERDA	Energy and Research Development Administration
ERFDS	emergency response facility data system
EROL	Environmental Report - Operating License Stage

Table 1.10-1 (Cont'd)

ESBRCS	emergency switchgear and battery rooms cooling system
ESD	emergency shutdown
ESF	engineered safety feature
ESW	emergency service water (system)
FAA	Federal Aviation Administration
FATT	fracture appearance transition temperature
FCD	functional control diagram
FCS	feedwater control system
FM	factory mutual
FMEA	failure modes and effects analysis
FPCC	fuel pool cooling and cleanup
FPER	Fire Protection Evaluation Report
FPSS	fire protection and suppression system
FSAR	Final Safety Analysis Report
FSI	fluid-structure interaction
GDC	General Design Criterion
GE	General Electric Company
GE-NEPD	General Electric - Nuclear Energy Program Division
GKN	Gemeinschaftskernkraftwerk Neckar
GM	Geiger-Mueller
GRS	gaseous radwaste system
HCU	hydraulic control unit
HCRIS	habitability and control room isolation system
HED	human engineering discrepancies

Table 1.10-1 (Cont'd)

HELB	high energy line break
HEPA	high efficiency particulate air
HIC	high integrity container
HMI	human machine interface
HMS-RMS	hot maintenance shop ventilation exhaust radiation monitoring system
HP	high pressure
HPCI	high pressure coolant injection (system)
HPCI-LDS	HPCI leak detection system
HPLPSI	high pressure/low pressure system interlocks
HSA	high specific activity
HTGR	high temperature gas reactor
HX	heat exchanger
H&V	heating and ventilation
HVAC	heating, ventilation, and air conditioning
HWC	hydrogen water chemistry (system)
IBA	intermediate break accident
ICC	inadequate core cooling
ICFR	increased core flow region
IED	instrument and electrical diagram
IEEE	Institute of Electrical and Electronics Engineers
IES	Illuminating Engineering Society
IFR	instrument flight rule
IGSCC	intergranular stress corrosion cracking
ILRT	integrated leak rate test
INPO	Institute of Nuclear Power Operations
I/O	input/output

Table 1.10-1 (Cont'd)

IP	intermediate pressure
IPCEA	Insulated Power Cable Engineers Association
IPE	Individual Plant Examination
IRM	intermediate range monitor
ISI	inservice inspection
IWRC	iron wire rope core
KKB	Kernkraftwerk Brunsbuettel
KKPI	Kernkraftwerk Phillipsburg
KRB	Kernkraftwerk RWE-Bayernwerk
KWU	Kraftwerk Union Atienqesellschaft
LCO	limiting condition of operation
LD	load
LDS	leak detection system
LGS	Limerick Generating Station
LHGR	linear heat generation rate
LLRT	local leak rate test
LO	licensed operators
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
LOR	Licensed Operator Requalification Training Program
LP	low pressure
LPCI	low pressure coolant injection (system)
LPG	liquid propane gas

Table 1.10-1 (Cont'd)

LPRM	local power range monitor
LPZ	low population zone
LRD-RMS	liquid radwaste discharge radiation monitoring system
LRS	liquid radwaste system
LSA	low specific activity
LWR	light water reactor
MAPLHGR	maximum average planar linear heat generation rate
MARSS	multiplex analog recording and switching system
MCC	motor control center
MCM	thousand circular mils
MCPR	minimum critical power ratio
MES	Meteorological Evaluation Services, Inc.
MFLCPR	maximum fraction of limiting critical power ratio
MFLPD	maximum fraction of limiting power density
MG	motor-generator (set)
MLE	mils lateral expansion
MLHGR	minimum linear heat generation rate
MMDRS	meteorological monitoring display and reporting system
MOV	motor-operated valves
MPC	maximum permissible concentration
MPL	master parts list
MSIV	main steam isolation valve
MSIV-LCS	main steam isolation valve leakage control system
MSL-LDS	main steam line leak detection system

Table 1.10-1 (Cont'd)

MSL	mean sea level
MSL-RMS	main steam line radiation monitoring system
MSRV	main steam relief valve
MWL	Maximum working load
MUR PU	Measurement Uncertainty Recapture – Power Uprate
NAI	Nuclear Associates International
NBR	nuclear boiler rated
NBS	National Bureau of Standards
NDE	non-destructive examination
NDT	nil ductility transition
NDTT	nil ductility transition temperature
NEMA	National Electrical Manufacturers Association
NFPA	National Fire Protection Association
NMS	neutron monitoring system
NOAA	National Oceanic and Atmospheric Administration
NPSH	net positive suction head
NRB	Nuclear Review Board
NRC	Nuclear Regulatory Commission
NSE-RMS	north stack effluent radiation monitoring system
NSOA	Nuclear Safety Operational Analysis
NSSS	nuclear steam supply system
NSSSS	nuclear steam supply shutoff system
NTSB	National Transportation and Safety Board
NUMAC	Nuclear Measurement Analysis and Control
NWC	normal water chemistry
NWS	National Weather Service

Table 1.10-1 (Cont'd)

OBE	operating basis earthquake
ODA	Operating Display Assembly
OPEX	Operating Experience
OJT	on-the-job training
OLCPR	operating limit critical power ratio
OLMCPR	operating limit minimum critical power ratio
OPRM	Oscillation Power Range Monitor
OSC	Operations Support Center
OSHA	Occupational Safety and Health Administration
OS&Y	outside screw and yoke
OT	operational transient
PA	public address (system)
PAB	protected area boundary
PABX	private automatic branch system
PASS	postaccident sampling system
PBAPS	Peach Bottom Atomic Power Station
PCIG	primary containment isolation gas (system)
PCLD-RMS	primary containment leak detector radiation monitoring system
PCPL-RMS	primary containment post-LOCA radiation monitoring system
PCRVICS	primary containment and reactor vessel isolation control system
PCT	peak cladding temperature
PCVR	primary containment vacuum relief
PFH	partial feedwater heating
PGCC	power generation control complex
P&ID	piping and instrument diagram

Table 1.10-1 (Cont'd)

PJM	Pennsylvania, New Jersey, Maryland (Interconnection)
PLC	Programmable Logic Controller
PMF	probable maximum flood
PMP	probable maximum precipitation
PMS	plant monitoring system
PORC	Plant Operations Review Committee
PPC	plant process computer (system)
PRA	probabilistic risk assessment
PRNM	power range neutron monitor
PRPM	process radiation plenum monitoring
PRMS	process radiation monitoring system
PRTGS	pressure regulator and turbine-generator system
PSAR	Preliminary Safety Analysis Report
PSAT	saturated steam pressure in the RPV steam dome
PSD	power spectrum density
PSI	preservice inspection
PVC	polyvinyl chloride
PWR	pressurized water reactor
QA	quality assurance
QC	quality control
RAIS	refueling area isolation system
RAVE-RMS	refueling area ventilation exhaust radiation monitoring system
RBI	rod block interlock
RBM	rod block monitor
RCIC	reactor core isolation cooling (system)

RCIC-LDS	RCIC leak detection system
RCIC-UC	RCIC system pump compartment unit coolers
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RECW	reactor enclosure cooling water (system)
RECW-RMS	reactor enclosure cooling water radiation monitoring system
REIS	reactor enclosure isolation system
RERS	reactor enclosure recirculation system
RERV-RMS	radwaste equipment rooms ventilation exhaust radiation monitoring system
REV-RMS	radwaste enclosure ventilation exhaust radiation monitoring system
REVE-RMS	reactor enclosure ventilation exhaust radiation monitoring system
RFCS	recirculation flow control system
RFPT	reactor feed pump turbine
RHR	residual heat removal
RHR-CSM	RHR containment spray mode
RHR-LDS	RHR leakage detection system
RHR-SCM	RHR shutdown cooling mode
RHR-SPCM	RHR suppression pool cooling mode
RHRSW	RHR service water (system)
RHRSW-RMS	RHR service water radiation monitoring system
RHR-UC	RHR system pump compartment unit coolers
RI	refueling interlocks
RIO	Remote Input/Output
RMCS	reactor manual control system
RMDS	radiation monitoring and display system

Table 1.10-1 (Cont'd)

RMS	radiation monitoring system
RMMS	radiation and meteorological monitoring system
RO	Reactor Operator
RPIS	rod position information system
RPS	reactor protection system
RPS-LDS	recirculation pump seal leak detection system
RPT	recirculation pump trip
RPV	reactor pressure vessel
RPVH-LDS	reactor pressure vessel head leak detection system
RRCS	redundant reactivity control system
RRRC	Regulatory Requirements Review Committee
RRHAC-RMS	recombiner rooms and hydrogen analyzer components exhaust radiation monitoring system
RRS	required response spectrum
RSCS	rod sequence control system
RSS	remote shutdown system
RSSV	RSS ventilation system
RTD	resistance temperature detector
RT_{NDT}	reference temperature (nil ductility transition)
RVI	reactor vessel instrumentation
RWCU	reactor water cleanup (system)
RWCU-LDS	reactor water cleanup leak detection system
RWE	rod withdrawal error
RWM	rod worth minimizer
RWP	radiation work permit
SAE	Society of Automotive Engineers

Table 1.10-1 (Cont'd)

SARA	severe accident risk assessment
SAS	secondary alarm station
SAW	submerged arc
SBA	small break accident
SCA	single channel analyzer
SCR	silicon control rectifier
SDIV	scram discharge instrument volume
SDV	scram discharge volume
SEB	Structural Engineering Branch (NRC)
SEDVP-RMS	steam exhauster discharge and vacuum pump exhaust radiation monitoring system
SEP	Systematic Evaluation Program
SEIP	Extra improved plow steel
SER	Safety Evaluation Report
SGTS	standby gas treatment system
SGTS-UC	SGTS filter room and access area unit cooler
SIF	stress intensification factor
SIL	Service Information Letter (General Electric)
SJAE	steam jet air ejector
SLCS	standby liquid control system
SLO	senior licensed operators
SMAW	shielded metal arc
SMUD	Sacramento Municipal Utility District
SOP	System Operating Program
SPDS	safety parameter display system
SPF	standard project flood

Table 1.10-1 (Cont'd)

SPFS	safeguard piping fill system
SPPSVS	spray pond pump structure ventilation system
SS	stainless steel
SPTMS	suppression pool temperature monitoring system
SSPC	Steel Structures Painting Council
SOE	sequence of events
SORV	stuck open relief valve
SQRT	Seismic Qualification Review Team
SRDI	safety-related display instrumentation
SRM	source range monitor
SRO	Senior Reactor Operator
SRP	Standard Review Plan
SRS	solid radwaste system
SRSS	square root of the sum of the squares
SRV	safety/relief valve
SRV-LDS	safety/relief valve leak detection system
SRVPI	safety/relief valve position indication
SSO	safe shutdown
SSE	safe shutdown earthquake
SSER	Supplemental Safety Evaluation Report
SSES	Susquehanna Steam Electric Station
SSE-RMS	south stack effluent radiation monitoring system
STA	Shift Technical Advisor
STP	startup test procedure
SWS	service water system

Table 1.10-1 (Cont'd)

SW-RMS	Service water radiation monitoring system
TAF	top of active fuel
TC	thermocouple
TCV	turbine control valve
TECW	turbine enclosure cooling water (system)
TEMA	Tubular Exchanger Manufacturers Association
TEMR	totally enclosed metallic raceway
TG	turbine-generator
TIP	traversing incore probe
TLD	thermoluminescent dosimeter
TLV	threshold limit valve
TMI	Three Mile Island (Unit 2)
TRA	transient recording and analysis
TRB	Test Review Board
TRS	test response spectrum
TSC	Technical Support Center
TVA	Tennessee Valley Authority
UBC	Uniform Building Code
UC	unit coolers
UFSAR	Updated Final Safety Analysis Report
UHS	ultimate heat sink
UL	Underwriter's Laboratories
UPS	uninterruptible power supply
USAS	United States of America Standards
USGS	United States Geological Survey

Table 1.10-1 (Cont'd)

USI	unresolved safety issue
UT	ultrasonic test
UV	undervoltage
V&V	verification and validation
VBWR	Vallecitos Boiling Water Reactor
VFR	visual flight rules
VOR	very high frequency omni-direction range
ZPA	zero point acceleration

Table 1.10-2

PIPING AND VALVE CLASS IDENTIFICATION

Pipe and valve classes are designated by a three-letter code. The first letter indicates the primary valve and flange pressure rating; the second letter, the type of material; and the third letter, the code to which the piping is designed.

FIRST LETTER - PRIMARY PRESSURE RATING

C - 1500 psi
D - 900 psi
E - 600 psi
F - 400 psi
G - 300 psi
H - 150 psi
I - 250 psi
J - 125 psi
K - 175 psi
L - 75 psi
M - General use as designated on piping class sheets
N - Sanitary drainage
R - Threaded vents and drains
S - Welded vents and drains
X - Special Rating

SECOND LETTER - MATERIAL

A - Alloy steel
B - Carbon steel
C - Austenitic steel
D - Copper
F - Carbon steel - copper bearing
G - Carbon steel - lined
H - Cast iron
J - Alloy steel
K - PVC
L - Carbon steel - impact test as code requires
M - Duriron
N - Carbon steel - galvanized
P - Bronze
Q - Brass

Table 1.10-2 (Cont'd)

THIRD LETTER - DESIGN CODE

A - Nuclear power plant components, ASME B&PV Code, Sect. III, Class 1
B - Nuclear power plant components, ASME B&PV Code, Sect. III, Class 2
C - Nuclear power plant components, ASME B&PV Code, Sect. III, Class 3
D - Power Piping Code ANSI B31.1.0
F - National Fire Protection Code
G - National Plumbing Code

1.11 RRRC CATEGORY 1, 2, 3, AND 4 MATTERS

1.11.1 DISCUSSION OF CATEGORIES

The Regulatory Requirements Review Committee has characterized the backfitting potential of certain regulatory guides and branch technical positions or other proposed modifications to existing staff positions by placing them in one of three categories (Reference 1.11-1):

a. Category 1 - Clearly forward fit only. No further staff consideration of possible backfitting is required.

b. Category 2 - Further staff consideration of the need for backfitting appears to be required for certain identified items of the regulatory position. These individual issues are such that existing plants need to be evaluated to determine their status with regard to these safety issues in order to determine the need for backfitting.

c. Category 3 - Clearly backfit. Existing plants should be evaluated to determine whether identified items of the regulatory position are resolved in accordance with the guide or by some equivalent alternative.

In addition to the above RRRC categories, there also exists an Office of Nuclear Reactor Regulation (NRC) Category 4 list of those matters not yet reviewed by the RRRC, but which have been deemed by the Director, Office of Nuclear Reactor Regulation, to warrant being addressed and considered in ongoing reviews.

The NRC transmitted a list of Category 2, 3, and 4 matters to the licensee (Reference 1.11-2), and requested that the listed items be considered in the LGS FSAR. Reference 1.11-2 defines these categories as follows:

a. Category 1 - Matters are to be applied in accordance with the implementation section of the published guide.

b. Category 2 - This is a new position whose applicability is to be determined on a case-by-case basis.

c. Category 3 - Conformance or an acceptable alternative is required.

d. Category 4 - Matters are to be treated like Category 2 matters until such time as they are reviewed by the RRRC, and a definite implementation program is developed.

Table 1.11-1 identifies the UFSAR sections containing material relevant to the RRRC and to the NRC categorized matters with the exception of Category 1 (those to be implemented in accordance with the implementation section of the published NRC position) which are outside the scope of this appendix.

The categorization of regulatory guides in the RRRC and NRC lists is given in Section 1.8.

1.11.2 REFERENCES

1.11-1 Memorandum, E.G. Case, Chairman, Regulatory Requirements Review Committee to L.V. Gossick, Executive Director for Operations, Regulatory Requirements Review Committee Meeting No. 31, July 11, 1975, (September 24, 1975).

1.11-2 Letter, Roger S. Boyd (NRC) to Edward G. Bauer, Jr. (PECo), (November 20, 1978).

Table 1.11-1

CORRELATION OF LGS UFSAR SECTIONS WITH CATEGORY 2, 3, AND 4 MATTERS[1]

DOCUMENT	REVISION	DATE[2]	TITLE	UFSAR SECTION REFERENCE
A. RRRC CATEGORY 2 MATTERS				
BTP ASB 9.5-1	1	-	Guidelines for Fire Protection for Nuclear Power Plants	9.5.1, Appendix 9A
BTP MTEB 5-7	-	4/77	Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping	5.2.3
B. RRRC CATEGORY 3 MATTERS				
BTP RSB 5-1	1	1/78	Design Requirements of the Residual Heat Removal System	5.4
BTP RSB 5-2 (Draft)	0	3/78	Overpressurization Protection of Pressurized Water Reactors While Operating at Low Temperatures	Not applicable to LGS

Table 1.11-1 (Cont'd)

C. NRR CATEGORY 4 MATTERS

	IMPLEMENTATION DATE	BRANCH	APPLICABLE SRP SECTION	TITLE	UFSAR SECTION REFERENCE
I. Standard Review Plan (SRP) Criteria					
1.	11/24/75	MTEB	5.4.2.1	BTP MTEB 5-3, Monitoring of Secondary Side Water Chemistry in PWR Steam Generators	Not applicable to LGS
2.	11/24/75	CSB	6.2.1	BTP CSB 6-1, Minimum Containment Pressure Model for PWR ECCS Performance Evaluation	Not applicable to LGS
3.	11/24/75	CSB	6.2.5	BTP CSB 6-2, Control of Combustible Gas Concentrations in Containment following a LOCA	6.2.5
4.	11/24/75	CSB	6.2.3	BTP CSB 6-3, Determination of Bypass Leakage Path in Dual Containment Plants	6.2.3
5.	11/24/75	CSB	6.2.4	BTP CSB 6-4, Containment Purging During Normal Plant Operations	6.2.1
6.	11/24/75	ASB	9.1.4	BTP ASB 9.1, Overhead Handling Systems for Nuclear Power Plants	9.1.4
7.	11/24/75	ASB	10.4.9	BTP ASB 10.1, Design Guidelines for Auxiliary Feedwater System Pump Drive and Power Supply Diversity for PWR's	Not applicable to LGS
8.	11/24/75	SEB	3.5.3	Procedures for Composite Section Local Damage Prediction (SRP Section 3.5.3, par. II.1.C)	3.5.3
9.	11/24/75	SEB	3.7.1	Development of Design Time History for Soil-Structure Interaction Analysis (SRP Section 3.7.1, par. II.2)	3.7.1
10.	11/24/75	SEB	3.7.2	Procedures for Seismic System Analysis (SRP Section 3.7.2 par. II)	3.7.2
11.	11/24/75	SEB	3.7.3	Procedures for Seismic Sub-system Analysis (SRP Section 3.7.3, par. II)	3.7.3
12.	11/24/75	SEB	3.8.1	Design and Construction of Concrete Containments (SRP Section 3.8.1, par. II)	3.8.1

Table 1.11-1 (Cont'd)

IMPLEMENTATION DATE	BRANCH	APPLICABLE SRP SECTION	TITLE	UFSAR SECTION REFERENCE
13. 11/24/75	SEB	3.8.2	Design and Construction of Steel Containments (SRP Section 3.8.2, par. II)	Not applicable to LGS
14. 11/24/75	SEB	3.8.3	Structural Design Criteria for Category I Structures Inside Containment (SRP Section 3.8.3, par. II)	3.8.3
15. 11/24/75	SEB	3.8.4	Structural Design Criteria for Other Seismic Category I Structures (SRP Section 3.8.4, par. II)	3.8.4
16. 11/24/75	SEB	3.8.5	Structural Design Criteria for Foundations (SRP Section 3.8.5, par. II)	3.8.5
17. 11/24/75	SEB	3.7, 11.2 11.3, 11.4	Seismic Design Requirements for Radwaste Systems and Their Housing Structures (SRP Section 11.2, BTP ETSB 11-1, par. B.v)	3.2, 3.8.4 11.2, 11.3, 11.4
18. 11/24/75	SEB	3.3.2	Tornado Load Effect Combinations (SRP Section 3.3.2, par. II.2.d)	3.3.2
19. 11/24/75	SEB	3.4.2	Dynamic Effects of Wave Action (SRP Section 3.4.2, par. II)	3.4.2
20. 10/01/75	ASB	10.4.7	Water Hammer for Steam Generators with Preheaters (SRP Section 10.4.7 par. 1.2.b)	Not applicable to LGS
21. 11/24/75	AB	4.4	Thermal-Hydraulic Stability (SRP Section 4.4, par. II.5)	4.4
22. 11/24/75	RSB	5.2.5	Intersystem Leakage Detection (SRP Section 5.2.5 par. II.4) and Regulatory Guide 1.45	5.2.5
II. Other Positions				
1. 12/1/76	SEB	3.5.3	Ductility of Reinforced Concrete and Steel Structural Elements Subjected to Impactive or Impulsive Loads	3.5.3

Table 1.11-1 (Cont'd)

	IMPLEMENTATION DATE	BRANCH	APPLICABLE SRP SECTION	TITLE	UFSAR SECTION REFERENCE
2.	8/01/76	SEB	3.7.	Response Spectra in Vertical Direction	Not applicable to LGS
3.	4/01/76	SEB	3.8.1 & 3.8.2	BWR Mark III Containment Pool Dynamics	Not applicable to LGS
4.	9/01/76	SEB	3.8.4	Air Blast Loads	3.8.4
5.	10/01/76	SEB	3.5.3	Tornado Missile Impact	3.5
6.	6/01/77	RSB	6.3	Passive Failures During Long-Term Cooling Following LOCA	6.3.1
7.	9/01/77	RSB	6.3	Control Room Position Indication of Manual (Handwheel) Valves in ECCS	6.3.2.9 and Table 6.3-7
8.	4/01/77	RSB	15.1.5	Long-Term Recovery from Steam Line Break: Operator Action to Prevent Overpressurization (PWR)	Not applicable to LGS
9.	12/01/77	RSB	5.4.6, 5.4.7 & 6.3	Pump Operability Requirements	5.4
10.	3/28/78	RSB	3.5.1	Gravity Missiles, Vessel Seal-Ring Missiles Inside Containment	3.5
11.	1/01/77	AB	4.4	Core Thermal-Hydraulic Analysis	4.4.4
12.	1/01/78	PSB	8.3	Degraded Grid Voltage Conditions	8.3
13.	6/01/76	CSB	6.2.1.2	Asymmetric Loads on Components Located Within Containment Sub-compartments	1.12.3, 6.2.1.2 Appendix 6A
14.	9/01/77	CSB	6.2.6	Containment Leak Testing Program	6.2.6
15.	1/01/77	CSB	6.2.1.4	Containment Response Due to Main Steam Line Break and Failure of MSLIV to Close	Not applicable to LGS
16.	11/01/77	ASB	3.6.1 & 3.6.2	Main Steam and Feedwater Pipe Failures	3.6
17.	1/01/77	ASB	9.2.2	Design Requirements for Cooling Water to Reactor Coolant Pumps	9.2.2

Table 1.11-1 (Cont'd)

	IMPLEMENTATION DATE	BRANCH	APPLICABLE SRP SECTION	TITLE	UFSAR SECTION REFERENCE
18.	8/01/76	ASB	10.4.7	Design Guidelines for Water Hammer in Steam Generators with Top Feeding Design (BTP ASB 10.2)	Not applicable to LGS
19.	1/01/76	ICSB	3.11	Environmental Control Systems for Safety-Related Equipment	3.11

(1) Regulatory Guides included in the RRRC and NRR lists are addressed in Section 1.8
(2) Version in effect as of the date of Reference 1.11-2

1.12 UNRESOLVED SAFETY ISSUES

1.12.1 INTRODUCTION

The NRC continuously evaluates the safety requirements used in its reviews against new information as it becomes available. Information related to the safety of nuclear power plants comes from a variety of sources including experience from operating reactors; research results; NRC staff and ACRS safety reviews; and vendor, architect-engineer, and utility design reviews. Each time a new concern or safety issue is identified from one or more of these sources, the need for immediate action to ensure safe operation is assessed. This assessment includes consideration of the generic implications of the issue.

In some cases, immediate action is taken to ensure safety, for example, the derating of BWRs as a result of the channel box wear problems in 1975. In other cases, interim measures, such as modifications to operating procedures, may be sufficient to allow further study of the issue before making licensing decisions. In most cases, however, the initial assessment indicates that immediate licensing actions or changes in licensing criteria are not necessary. In any event, further study may be deemed appropriate to make judgments as to whether existing NRC requirements should be modified to address the issue for new plants or if backfitting is appropriate for the long-term operation of plants already under construction or in operation.

These issues are sometimes called generic safety issues because they are related to a particular class or type of nuclear facility rather than to a specific plant. Certain of these issues have been designated as unresolved safety issues (Reference 1.12-1). However, as discussed above, such issues are considered on a generic basis only after the NRC staff has made an initial determination that the safety significance of the issue does not prohibit continued operation or require licensing actions while the longer term generic review is under way.

In 1978, the NRC undertook a review of over 130 generic issues addressed in the NRC program. The review is described in Reference 1.12-2. The report provides the following definition of an unresolved safety issue:

> A USI is a matter affecting a number of nuclear power plants that poses important questions concerning the adequacy of existing safety requirements for which a final resolution has not yet been developed and that involves conditions not likely to be acceptable over the lifetime of the plants it affects.

Furthermore, the report indicates that in applying this definition, matters that pose "important questions concerning the adequacy of existing safety requirements" were judged to be those for which resolution is necessary to (1) compensate for a possible major reduction in the degree of protection of the public health and safety, or (2) provide a potentially significant decrease in the risk to the public health and safety. Quite simply, a USI is potentially significant from a public safety standpoint and its resolution is likely to result in NRC action on the affected plants.

All of the issues addressed in the NRC program were systematically evaluated against this definition as described in Reference 1.12-2. As a result, 17 USIs addressed by 22 tasks in the NRC program were identified. The issues and applicable task numbers are listed below. Progress on these issues was first discussed in the 1978 NRC Annual Report. The number(s) of the generic task(s) (for example, A-1) in the NRC program addressing each issue is indicated in parentheses following the title.

1. Water Hammer (A-1)
2. Asymmetric Blowdown Loads on the Reactor Coolant System (A-2)
3. Pressurized Water Reactor Steam Generator Tube Integrity (A-3, A-4, A-5)
4. BWR Mark I and Mark II Pressure-Suppression Containments (A-6, A-7, A-8, A-39)
5. Anticipated Transients Without Scram (A-9)
6. BWR Nozzle Cracking (A-10)
7. Reactor Vessel Materials Toughness (A-11)
8. Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports (A-12)
9. Systems Interaction in Nuclear Power Plants (A-17)
10. Environmental Qualification of Safety-Related Electrical Equipment (A-24)
11. Reactor Vessel Pressure Transient Protection (A-26)
12. Residual Heat Removal Requirements (A-31)
13. Control of Heavy Loads Near Spent Fuel (A-36)
14. Seismic Design Criteria (A-40)
15. Pipe Cracks at Boiling Water Reactors (A-42)
16. Containment Emergency Sump Reliability (A-43)
17. Station Blackout (A-44)

The NRC has performed an in-depth and systematic review of generic safety concerns identified since January 1979 to determine if any of these issues should be designated as new USIs. The candidate issues originated from concerns identified in Reference 1.12-3, ACRS recommendations, abnormal occurrence reports, and other operating experience. The Commission considered the above information and approved the following four new unresolved safety issues:

1. Shutdown Decay Heat Removal Requirements (A-45)
2. Seismic Qualification of Equipment in Operating Plants (A-46)
3. Safety Implication of Control Systems (A-47)
4. Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment (A-48)

A description of the above process together with a list of the issues considered is presented in Reference 1.12-4. An expanded discussion of each of the new USIs is also contained in Reference 1.12-4.

In addition to the four issues identified above, the Commission approved another issue, A-49, Pressurized Thermal Shock, as a USI in December 1981.

In December, 1987 the NRC issued a compilation of the generic safety issues as NUREG-0933, "A Prioritization of Generic Safety Issues." This compilation includes the USIs and is periodically supplemented to update the status of the safety issues.

1.12.2 APPLICABILITY TO LGS

Seven of the twenty-seven tasks identified with the USIs are not applicable to LGS because they apply to PWRs only. These tasks are A-2, A-3, A-4, A-5, A-12, A-26, and A-49. Also, Tasks A-6 and A-7 only apply to Mark I or Mark III BWR containments. With regard to the remaining eighteen tasks that are applicable to LGS, the NRC staff has issued NUREG reports or rule changes providing its resolution of seventeen of the issues. These issues are listed below.

TASK NUMBER	NUREG REPORT NO. AND TITLE
A-1	NUREG-0927, "Evaluation of Water Hammer in Nuclear Power Plants - Technical Findings Relevant to Unresolved Safety Issue A-1".
	NUREG-0993, "Regulatory Analysis for USI A-1, "Water Hammer".
	NUREG-0800, SRP 3.9.3, 3.9.4, 5.4.6, 5.4.7, 6.3, 9.2.1, 9.2.2, 10.3 and 10.4.7, Various Titles.
A-8	NUREG-0808 "Mark II Containment Pool Dynamic Loads".
	NUREG-0802, "Safety/Relief Valve Quencher Loads: Evaluation for BWR Mark II and III Containments".
	NUREG-0800, SRP 6.2.1.1.c, "Pressure-Suppression Type BWR Containments".
A-9	NUREG-0460, Vol 4, "Anticipated Transients Without Scram for Light-Water Reactors".
	10CFR50.62, Federal Register Notice 49FR2036.
A-10	NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking".
A-11	NUREG-0744, Revision 1, "Resolution of the Task A-11 - Reactor Vessel Materials Toughness Safety Issue".
A-17	NUREG-1174, "Evaluation of Systems Interactions in Nuclear Power Plants". NUREG-1229, "Regulatory Analysis for Resolution of USI A-17".

A-24 NUREG-0588, Revision 1, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment".

NUREG-0800, SRP 3.11, "Environmental Qualification of Mechanical and Electrical Equipment".

10CFR50.49, Federal Register Notice 47FR28363.

A-31 NUREG-0800, SRP 5.4.7 and BTP 5-1, "Residual Heat Removal Systems" (incorporate requirements of USI A-31).

A-36 NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants".

A-39 NUREG-0802, "Safety/Relief Valve-Quencher Loads: Evaluation for BWR Mark II and III Containments".

NUREG-0800, SRP 6.2.1.1.c, "Pressure-Suppression Type BWR Containments".

A-40 NUREG-1233, "Regulatory Analysis for USI A-40".

NUREG-0800, SRP 2.5.2, 3.7.1, 3.7.2 and 3.7.3, Various Titles.

A-42 NUREG-0313, Revision 2, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping" (Note: Revision 1 is applicable prior to issuance of NRC Generic Letter 88-01.)

A-43 NUREG-0869, Revision 1, "USI A-43 Regulatory Analysis".

NUREG-0897, Revision 1, "Containment Emergency Sump Performance".

A-44 NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plants, Technical Findings Related to Unresolved Safety Issue A-44, Draft Report for Comment".

NUREG-1109, "Regulatory Analysis for the Resolution of Unresolved Safety Issue A-44, Station Blackout, Draft Report for Comment".

10CFR50.63, Federal Register Notice 53FR23215.

A-45 NUREG-1289, "Regulatory and Backfit Analysis for the Resolution of USI A-45".

NUREG-1292, "Shutdown Heat Removal Analysis: Plant Case Studies and Special Issues Summary Report".

A-47 NUREG-1217, "Evaluation of Safety Implications of Control Systems in LWR Nuclear Power Plants".

NUREG-1218, "Regulatory Analysis for Resolution of USI A-47".

A-48 10CFR50.44, Federal Register Notice 46FR58484.

NUREG-1370, "Resolution of Unresolved Safety Issue A-48, "Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment".

The remaining issue applicable to LGS is Seismic Qualification of Equipment in Operating Plants (A-46). It is further discussed below.

1.12.3 DISCUSSIONS OF TASKS AS THEY RELATE TO LGS

This section provides an implementation and status summary of LGS for each of the applicable USIs. This includes the NRC requirements summary of each issue as stated in Generic Letter 89-21 (Request for Information Concerning Status of Implementation of Unresolved Safety Issue Requirements).

A-1 Water Hammer

REQUIREMENTS SUMMARY:

On March 15, 1984, the EDO sent the Commissioners a Policy Issue titled, "Resolution of Unresolved Safety Issue A-1, Water Hammer." In this Policy Issue the staff concluded that the frequency and severity of water hammer occurrences had been significantly reduced through (a) incorporation of design features such as keep-full systems, vacuum breakers, J-tubes, void detection systems and improved venting procedures, (b) proper design of feedwater valves and control systems and (c) increased operator awareness and training. Therefore, the resolution of USI A-1 did not involve any hardware or design changes on existing plants. It did involve SRP changes (forward fits) and a comprehensive set of guidelines and criteria to evaluate and upgrade utility training programs (per TMI Item I.A.2.3.). In addition, the assumption was made that for BWRs with isolation condensers a high reactor vessel water level feedwater pump trip was in place or being installed. This was necessary because calculated values had postulated an isolation condenser failure by water hammer that opened a direct pathway to the environment.

Items to certify:

1. A comprehensive set of guidelines and criteria to evaluate and upgrade utility training programs (per TMI Item I.A.2.3) is in place.

2. BWRs with isolation condensers have installed and operated a high reactor vessel water level feedwater pump trip.

IMPLEMENTATION AND STATUS SUMMARY:

1. TMI Item I.A.2.3 implementation was complete at the time of receipt of the operating license. The LGS training program has been upgraded and subsequently INPO accredited.

2. LGS does not have an isolation condenser.

A-8 Mark II Containment Pool Dynamic Loads

REQUIREMENTS SUMMARY:

The requirement is that the 11 BWRs having the Mark II containment shall meet the requirements of GDC 16, "Containment Design."

As stated in NUREG-0808, "Mark II Containment Program Load Evaluation and Acceptance Criteria", the original design of the Mark II containment system considered only those loads normally associated with DBAs that were known at the time. These included pressure and temperature loads associated with a LOCA, seismic loads, dead loads, jet impingement loads, hydrostatic loads due to water in the suppression chamber, overload pressure test loads, and construction loads. However, since the establishment of the original design criteria, additional loading conditions were identified that must be considered for the pressure-suppression containment system design.

In the course of performing large-scale testing of an advanced design pressure-suppression containment (Mark III), and during in-plant testing of Mark I containments, new suppression pool hydrodynamic loads were identified that had not been included explicitly in the original Mark II containment design basis. These additional loads result from dynamic effects of drywell air and steam being rapidly forced into the suppression pool during a postulated LOCA and from suppression pool response to SRV operation, which is generally associated with plant transient operating conditions. Because these new hydrodynamic loads had not been considered, the NRC staff determined that a detailed reevaluation of the Mark II containment system was required.

The issuance of NUREG-0808, NUREG-0802, and NUREG-0487 documented acceptable methods for calculating the hydrodynamic loads associated with plant transient conditions. Specifically, the loads referenced in these NUREGs, as modified by the acceptance criteria, constituted the resolution of USI A-8. SRP 6.2.1 has been modified to reflect the applicability of these NUREGs to Mark II containment evaluations.

Implementation is believed to be complete for all Mark II BWRs. As part of the licensing process, the staff required that the new calculation methodology defined in the referenced NUREGs be utilized by the applicant before issuance of a full power license.

IMPLEMENTATION AND STATUS SUMMARY:

The Mark II containment pool dynamic loads were addressed in the DAR for LGS (Appendix 3A and 3B) during the initial operating license review. The NRC review is documented in SSER-2, Sections 6.2.1.7 and 6.2.1.8.

A-9 Anticipated Transients Without Scram

The USI was resolved on June 26, 1984 with the publication of a final rule (10CFR50.62), to require improvements in plants to reduce the likelihood of failure of the RPS to shut down the reactor following anticipated transients and to mitigate the consequences of an ATWS event. The rule includes the following design-related requirements: 10CFR50.62(C)(l) - Diverse and Independent Auxiliary Feedwater Initiation and Turbine Trip for All PWRs, 10CFR50.62(C)(2) - Diverse Scram Systems for CE and B&W Reactors, 10CFR50.62(C)(3) - ARI for BWRs, 10CFR50.62(C)(4) - SLCS for BWRs, and 10CFR50.62(C)(5) - Automatic RPT Under Conditions Indicative of an ATWS for BWRs. Information requirements and an implementation schedule are also specified.

IMPLEMENTATION AND STATUS SUMMARY:

LGS has completed implementation of ARI, RPT and adequate SLCS capacity. These were installed prior to fuel load and the Technical Specifications included RPT and SLCS. The SLCS

Technical Specification was revised in June 1989 when minor discrepancies were identified in the original Technical Specification.

A-10 BWR Feedwater Nozzle Cracking

REQUIREMENTS SUMMARY:

Inspections of operating BWRs conducted up to April 1978 revealed cracks in the feedwater nozzles of 20 reactor vessels. It was determined that cracking was due to high-cycle fatigue caused by fluctuations in water temperature within the vessel in the nozzle region. This item was originally identified in NUREG-0371 and was later determined to be a USI.

By letter dated November 13, 1980, D.G. Eisenhut (NRC) provided licensees with a copy of NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking." The letter stated that NUREG-0619 provided the resolution of the staffs generic technical activity A-10, a USI, which resulted from the inservice discovery of cracking in feedwater nozzles and CRD return line nozzles. NUREG-0619 describes the technical issues, GE and staff studies and analyses and the staff's positions and requirements. Licensees were required to respond, pursuant to 10CFR50.54(f), that implementation dates indicated in NUREG-0619 would be met.

Generic Letter 81-11 was subsequently issued to provide technical clarification to the November 13, 1980 letter and to clarify that it had been sent to PWR licensees for information only and that no response was required from PWR licensees.

IMPLEMENTATION AND STATUS SUMMARY:

Implementation of NUREG-0619 was reviewed during the initial operating license review. As discussed in the SER, LGS does not have a CRD system return line to the reactor vessel; equalizing valves are installed between the cooling water header and exhaust water header; the flow stabilizer loop is routed to the cooling water header; and both the exhaust header and flow stabilizer loop are stainless steel piping; and are acceptable.

A-11 Reactor Vessel Materials Toughness

Because of the remote possibility of failure of nuclear RPVs designed to the ASME B&PV Code, the design of nuclear facilities does not provide protection against reactor vessel failure. Prevention of reactor vessel failure depends primarily on maintaining the reactor vessel material fracture toughness at levels that will resist brittle fracture during plant operation. At service times and operating conditions typical of current operating plants, reactor vessel fracture roughness properties provide adequate margins of safety against vessel failure; however, as plants accumulate more and more service time, neutron irradiation reduces the material fracture toughness and initial safety margins. This item was originally identified in NUREG-0371 and was later determined to be a USI.

10CFR50, Appendix G required that the charpy upper-shelf energy throughout the life of the vessel be no less than 50 ft-lbs unless it is demonstrated that lower values will provide margins of safety against failure equivalent to those provided by Appendix G of the ASME code. USI A-11 was initiated to address the staff's concern that some vessels were projected to have beltline materials with charpy upper-shelf energy less than 50 ft-lbs.

This USI was resolved in October 1982 with the issuance of NUREG-0744, Revision 1 which was later transmitted to all licensees with Generic Letter 82-26.

NUREG-0744 provides a method for evaluation of reactor vessel materials when their charpy upper-shelf energy are predicted to fall below 50 ft-lbs. Plants will use the prescribed method when analysis of irradiation damage predicts that the charpy upper-shelf energy is below 50 ft-lbs.

IMPLEMENTATION AND STATUS SUMMARY:

Implementation of NUREG-0744 was addressed in the initial operating license review. LGS complies as discussed in SER and SSER-9 Section 5.3.1.2.

A-17 Systems Interaction in Nuclear Power Plants

REQUIREMENTS SUMMARY:

Generic Letter 89-18, dated September 6, 1989, was sent to all power reactor licensees and constitutes the resolution of USI A-17. No licensee actions were required by Generic Letter 89-18.

Generic Letter 89-18 had two enclosures which (1) outlined the bases for the resolution of USI A-17, and (2) provided five general lessons learned from the review of the overall systems interaction issue. It was anticipated that licensees' review of this information would be considered in other programs, such as the "Individual Plant Examination for Severe Accident Vulnerabilities." Specifically, the staff expected that insights concerning water intrusion and flooding from internal sources, provided in the appendix to NUREG-1174, will be considered in the IPE program. Also considered in the USI's resolution was the expectation that licensees would continue to review information on events at operating nuclear power plants in accordance with the requirements of TMI Item I.C.5 of NUREG-0737.

IMPLEMENTATION AND STATUS SUMMARY:

No changes were required for LGS.

I. The IPE for LGS was approved by the NRC by letter dated December 9, 1994.

II. TMI Item I.C.5 of NUREG-0737 is implemented through an Operating Experience Assessment Program as discussed in Section 1.13.

A-24 Qualification of Class 1E Equipment

REQUIREMENTS SUMMARY:

The publishing of NUREG-0588, Revision 1, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment" in July 1981 completed the staff resolution of Generic Technical Activity A-24, "Qualification of Class 1E Safety-Related Equipment." Part I of the report is the original "For Comment" NUREG-0588 which in conjunction with the DOR Guidelines was endorsed by a Commission Memorandum and Order as the interim position on this subject until "final" positions were established in rule making. On January 21, 1983 the Commission amended its regulations, in 10CFR50.49 (the rule), effective February 22, 1983 to codify existing qualification methods in national standards, regulatory guides, and certain NRC publications including NUREG-0588.

The rule is based on the DOR Guidelines and NUREG-0588, which "provide guidance on (1) how to establish environmental service conditions, (2) how to select methods which are considered appropriate for qualifying the equipment in different areas of the plant, and (3) other areas such as margin, aging, and documentation." NUREG-0588 does not address all areas of qualification; it does supplement, in selected areas, the provisions of the 1971 and 1974 versions of IEEE 323. The rule recognizes previous qualification efforts completed as result of Memorandum and Order CLI-80-20 and also reflects different IEEE 323 versions dependent on the date of the construction permit SER. Therefore, plant specific requirements may vary in accordance with the rule.

In summary, the resolution of A-24 is embodied in 10CFR50.49. A measure of whether each licensee has implemented the resolution of A-24 may therefore be found in the determination of compliance with 10CFR50.49. This was addressed by 72 SERs for operating plants shortly after publication of the rule and subsequently in operating license reviews pursuant to SRP 3.11. This was further addressed by the first round EQ inspections conducted by the Office of Inspection and Enforcement, the Regions, and Nuclear Reactor Regulation.

IMPLEMENTATION AND STATUS SUMMARY:

Environmental qualification of electrical equipment was addressed during the initial operating license review. LGS Unit 1 did not complete the necessary documentation until after the operating license was issued. However, the Unit 1 NPF-27 License Condition 2.C(5) was completed and closed in SSER-4. SSER-9 addressed EQ for LGS Unit 2.

A-31 RHR Shutdown Requirements

This USI was resolved in May 1978 and affected PWRs and BWRs. The USI involved establishment of criteria for the design and operation of system necessary to take a power reactor from normal operating conditions to cold shutdown.

The USI was resolved with the issuance of SRP section 5.4.7. The SRP stated (BTP RSB 5-1) that, for purposes of implementation, plants would be divided into three classes: Class 1 would require full compliance with the BTP for construction permit or PDA applications which were docketed before January 1, 1978. Class 2 required a partial implementation of the BTP for all plants for which construction permit or PDA applications were docketed before January 1, 1978, and for which an operating license issuance was expected on or after January 1, 1979. Class 3 affected all operating reactors and all other plants for which issuance of the operating license was expected before January 1, 1979. The extent to which Class 3 plants would require implementation of the BTP was based on the combined inspection and enforcement and DOR review of related plant features. In general, the outcome of these evaluations were that only plants receiving operating licenses after January 1, 1979 were affected by this USI resolution.

IMPLEMENTATION AND STATUS SUMMARY:

The RHR shutdown requirements for LGS were addressed during the initial operating license review as addressed in SER and SSER-2 Section 5.4.7.

A-36 Control of Heavy Loads, Phases I & II

REQUIREMENTS SUMMARY:

The following is abstracted from NUREG-0612: In nuclear power plants heavy loads may be handled in several plant areas. If these loads were to drop in certain locations in the plant, they may impact spent fuel, fuel in the core, or equipment that may be required to achieve safe shutdown and continue decay heat removal. Task A-36 was established to systematically examine staff licensing criteria and the adequacy of measures in effect at operating plants, and to recommend necessary changes to assure the safe handling of heavy loads. The guidelines proposed include definition of safe load paths, use of load handling procedures, training of crane operators, guidelines on slings and special lifting devices, periodic inspection and maintenance for the crane, as well as various alternatives. The report NUREG-0612 completes Task A-36.

The requirements documents are the Generic Letter dated December 22, 1980 "Control of Heavy Loads" transmitting NUREG-0612 and Generic Letter 85-11 dated June 28, 1985 which stated that implementation of Phase I (guidelines noted above) was sufficient and that Phase II could be implemented by licensees as appropriate. Phase II was to have extended the issue beyond the guidelines noted above to include a showing that either single failure proof handling equipment was not needed or that it had been provided.

IMPLEMENTATION AND STATUS SUMMARY:

The requirements for heavy loads, NUREG-0612, were addressed in the initial operating license review. The licensee completed implementation in accordance with an August 13, 1984 submittal and Unit 1 Operating License NPF-27 License Condition 2.C(19).

See LGS UFSAR Section 3.12 for additional information on the control of heavy loads at LGS.

A-39 Determination of SRV Pool Dynamic Loads and Temperature Limits

REQUIREMENTS SUMMARY:

BWR plants are equipped with SRVs to protect the reactor from overpressurization. Plant operational transients, such as turbine trips, will actuate the SRV. Once the SRV opens, the air column within the partially submerged discharge line is compressed by the high pressure steam released from the reactor. The compressed air discharged into the suppression pool produces high pressure bubbles. Oscillatory expansion and contraction of these bubbles create hydrodynamic loads on the containment structures, piping and equipment inside containment.

NUREG-0802 presents the results of the staff's evaluation of SRV loads. The evaluation, however, is limited to the quencher devices used in Mark II and III containments. With respect to Mark I containments, the SRV acceptance criteria are presented in NUREG-0661, and are dealt with as part of USI A-7 (Mark I Long-Term Program).

SRP 6.2.1.1.C, "Pressure-Suppression Type BWR Containments", addresses the applicable review criteria since all Mark II and III containment designs are understood to have completed their operating license reviews subsequent to resolution of this USI and reflection of the resolution in the SRP.

In conjunction with NUREG-0661, NUREG-0763 and NUREG-0783, the issuance of NUREG-0802 concludes USI A-39.

IMPLEMENTATION AND STATUS SUMMARY:

See A-8.

A-40 Seismic Design Criteria - Short-Term Program

REQUIREMENTS SUMMARY:

USI A-40 was originated in 1977. The basic objectives were (1) to study the seismic design criteria, (2) to quantify the conservatism associated with the criteria and (3) to recommend modifications to SRP if changes are justified. Lawrence Livermore National Laboratory completed the study and published their findings in NUREG/CR-1161 dated May 1980. The report recommended specific changes to the SRP. NRC staff reviewed the report and developed some other changes that would reflect the present state of seismic design practices. The resulting SRP changes were issued for public comments in June 1988, and the final SRP changes are to be published in September 1989.

The major SRP changes as a resolution of USI A-40 consist of (1) clarification of development of site specific spectra, (2) use of single synthetic time history, (3) location of input ground motion for Soil-Structure Interaction, and (4) design of flexible vertical tanks. Except for item (4), all other items do not constitute any additional requirements for current licenses and applications, and thus, no backfits are being required for these items. However, the revised provisions could be used for margin studies and reevaluations or IPE for External Events.

The participant utilities in Seismic Qualification Utility Group agreed to implement the changed criteria for flexible vertical tank for their plants. However, there are four plants (six reactors) where this issue has to be resolved on an individual basis. (These plants are: Callaway 1/2, Wolf Creek, Shearon Harris 1, and Watts Bar 1/2.) The 50.54(f) letters have been sent to the affected utilities.

IMPLEMENTATION AND STATUS SUMMARY:

Seismic qualification was addressed during the initial operating license review. The program is discussed in UFSAR Section 3.10 and was accepted as discussed in the SER, SSER-2, SSER-3, and SSER-9, Section 3.10.

A-42 Pipe Cracks in Boiling Water Reactors

Pipe cracking has occurred in the heat-affected zones of welds in primary system piping in BWRs since mid-1960. These cracks have occurred mainly in Type 304 stainless steel which is the type used in most operating BWRs. The major problem is recognized to be IGSCC of austenitic stainless steel components that have been made susceptible to this failure by being "sensitized," either by postweld heat treatment or by sensitization of a narrow heat- affected zone near welds.

"Safe ends" that have been highly sensitized by furnace heat treatment while attached to vessels during fabrication were very early (late 1960s) found to be susceptible to IGSCC. Most of the furnace sensitized safe ends in older plants have been removed or clad with a protective material and there are only a few BWRs that still have furnace sensitized safe ends in use. Most of these, however, are in smaller diameter lines.

Earlier reported cracks (prior to 1975) occurred primarily in 4 inch diameter recirculation loop bypass lines and in 10 inch diameter core spray lines. Cracking is most often detected during ISI using UT techniques. Some piping cracks have been discovered as a result of primary coolant leaks.

This USI was resolved with the issuance of NUREG-0313, Revision 1 which was transmitted to all holders of BWR operating licenses or construction permits in February 1981 via Generic Letter 81-03. MPA B-05 was established for implementation of the resolution at operating plants.

NUREG-0313, Revision 1 provided the NRC staff's revised acceptable methods for reducing the intergranular stress-corrosion cracking susceptibility of BWR code class 1, 2, and 3 pressure boundary piping of sizes identified above and safe ends. In addition, it provided the requirements for augmented inservice inspection of piping with nonconforming materials.

As a result of further IGSCC degradations in large piping, the staff provided licensees with additional requirements in several NRC communications (i.e., Bulletin 82-03, Bulletin 83-2, Bulletin 84-11). The long-term resolution of IGSCC in BWR piping was provided in NUREG-0313, Revision 2 which was transmitted to all holders of BWR operating licenses via Generic Letter 88-01.

IMPLEMENTATION AND STATUS SUMMARY:

IGSCC was most recently addressed by the licensee in its response to Generic Letter 88-01. For LGS, this response consisted of an FSAR revision (Revision 54, dated October 1988), a Technical Specification revision (which was determined not to be necessary and was withdrawn on April 28, 1989) and an ISI program revision which will be completed and implemented at the next refueling outage for each unit.

A-43 Containment Emergency Sump Reliability

REQUIREMENTS SUMMARY:

An issue existed concerning the availability of adequate recirculation cooling water following a LOCA when long-term recirculation of cooling water from the PWR containment sump, or the BWR RHR system suction intake, must be initiated and maintained to prevent core melt.

The technical concerns evaluation under USI A-43 were: (1) post-LOCA adverse conditions resulting from potential vortex formation and air ingestion and subsequent pump failure, (2) blockage of sump screens with LOCA generated insulation debris causing inadequate NPSH on pumps, and (3) RHR and containment spray pumps inoperability due to possible air, debris, or particulate ingestion on pump seal and bearing systems.

NUREG-0897, Revision 1 presents the results of the staff's technical findings. These findings established a need to revise current licensing guidance on these matters. Regulatory Guide 1.82 (Rev 0) and SRP (NUREG-0800) Section 6.2.2, "Containment Heat Removal Systems" were revised to reflect this new guidance.

This revised guidance applies only to future construction permits, preliminary design approvals, final design approvals, standardized designs, and applications of licenses to manufacture. For operating plants, the staff performed a regulatory analysis to determine if this new guidance should be applied. The results of this analysis was reported in NUREG-0869, Revision 1, "USI A-43 Regulatory Analysis." The staff concluded that the regulatory analysis does not support any new generic requirements for current licensees to perform debris assessments. However, an Information Notice was issued recommending (but not requiring) licensees use the revised guidance to conduct a 10CFR50.59 analysis for future insulation modifications or replacements.

IMPLEMENTATION AND STATUS SUMMARY:

Suppression pool strainer blockage is discussed in UFSAR and SER Sections 6.2.2. Additional actions are being taken for LGS in response to NRC Bulletin 96-03.

A-44 Station Blackout

Station blackout means the loss of offsite ac power to the essential and nonessential electrical buses concurrent with turbine trip and the unavailability of the redundant onsite emergency ac power system. WASH-1400 showed that station blackout could be an important risk contributor, and operating experience has indicated that the reliability of ac power systems might be less than originally anticipated. For these reasons station blackout was designated as a USI in 1980. A proposed rule was published for comment on March 21, 1986. A final rule, 10CFR50.63 "Loss of All Alternating Current Power," was published on June 21, 1988 and became effective on July 21, 1988. Regulatory Guide 1.155 was issued at the same time as the rule and references an industry guidance document NUMARC-8700. In order to comply with the A-44 resolution, licensees are required to:

- maintain onsite emergency ac power supply reliability above a minimum level
- develop procedures and training for recovery from a station blackout
- determine the duration of a station blackout that the plant should be able to withstand
- use an alternate qualified ac power source, if available, to cope with a station blackout
- evaluate the plant's actual capability to withstand and recover from a station blackout
- backfit hardware modifications if necessary to improve coping ability

10CFR50.63(c)(1) of the rule required each licensee to submit a response including the results of their coping analysis within 270 days from issuance of an operating license or the effective date of the rule, whichever is later.

IMPLEMENTATION AND STATUS SUMMARY:

The LGS electrical distribution system met the NRC design criteria prior to development of 10CFR50.63. The simultaneous loss of both offsite and onsite power is considered to be a highly unlikely occurrence.

Long-term operation following a loss of all ac power is limited only by suppression pool heatup and ambient heatup of the HPCI and RCIC pump rooms, where compartment cooling requires ac power, and by dc battery capacity.

The LOOP and SBO incidents are programmed as training exercises during the certification program at the LGS Simulator.

The station blackout event has also been incorporated into simulator requalification programs.

The plant staff have written emergency procedures for the station blackout event.

The licensee submitted the LGS program for implementation of the station blackout rule on April 17, 1989.

A-45 Shutdown Decay Heat Removal Requirements

REQUIREMENTS SUMMARY:

USI A-45 was closed out without any new licensing requirements other than the IPE, as described below. Since all of the significant USI A-45 results have been found to be highly plant specific, the Commission decided it was not appropriate to propose a single generic action to be applied uniformly to all plants.

The Commission is currently implementing the Severe Accident Policy (50FR32138) and will require all plants currently operating or under construction to undergo a systematic examination termed the IPE. The reason for this examination is to identify any plant specific vulnerabilities to severe accidents. The IPE analysis intends to examine and understand the plant emergency procedures, design, operations, maintenance, and surveillance to identify vulnerabilities. The analysis will examine both the decay heat removal system and those systems used for other related functions. For CE plants without power-operated relief valves, the need for a rapid depressurization capability will be addressed in the IPE program.

NRC has decided to subsume A-45 into the IPE program as the most effective way of achieving resolution of specific plant concerns associated with A-45.

IMPLEMENTATION AND STATUS SUMMARY:

The IPE for LGS was approved by the NRC by letter dated December 9, 1994.

A-46 Seismic Qualification of Equipment in Operating Plants

As an outgrowth of the Systematic Evaluation Program, the need was identified for reassessment of design criteria and methods for the seismic qualification of mechanical equipment and electrical equipment. The seismic qualification of the equipment in operating plants must, therefore, be reassessed to ensure the ability to bring the plant to a safe shutdown condition when subject to a seismic event. The objective of this issue was to establish an explicit set of guidelines that could be used to judge the adequacy of the seismic qualification of mechanical and electrical equipment at operating plants in lieu of attempting to backfit current design criteria for new plants.

The resolution of USI A-46 was mainly based on work completed by the Seismic Qualification Utility Group and EPRI using the seismic and test experience data approach and reviewed and endorsed by the Senior Seismic Review and Advisory Panel and the NRC staff. The scope of the review was narrowed down to equipment required to bring each affected plant to hot shutdown and maintain it there for a minimum of 72 hours. A walk-through of each plant is required to inspect equipment in the scope. Evaluation of equipment will include: (a) adequacy of equipment anchorage; (b) functional capability of essential relays; (c) outliers and deficiencies (i.e., equipment with nonstandard configurations); and (d) seismic systems interaction.

The staff issued Generic Letter 87-02 on February 19, 1987, with associated guidance, requiring all affected utilities to perform an evaluation of the seismic adequacy of their plants. The specific requirements and approach for implementation are being developed jointly by the Seismic

Qualification Utility Group and the staff on a generic basis prior to individual member utilities proceeding with plant specific implementation (see discussion below).

IMPLEMENTATION AND STATUS SUMMARY:

Generic Letter 87-02 issued on February 19, 1987 and Supplement No. 1 thereto issued May 22, 1992, do not list Limerick as an USI A-46 Plant and therefore does not apply to Limerick, since seismic qualification was addressed during initial operating licensing review. Seismic/dynamic qualification of safety related electrical and mechanical equipment is discussed in LGS UFSAR Section 3.10 and was accepted as discussed in the SER, SSER-2, SSER-3, and SSER-9.

A-47 Safety Implications of Control Systems

USI A-47 is being closed out with the issuance of Generic Letter 89-19 which was issued September 20, 1989. The Generic Letter states, "The staff has concluded that all PWR plants should provide automatic steam generator overfill protection, all BWR plants should provide automatic reactor vessel overfill protection, and that plant procedures and technical specifications for all plants should include provisions to verify periodically the operability of the overfill protection and to assure that automatic overfill protection is available to mitigate main feedwater overfeed events during reactor power operation. Also, the system design and setpoints should be selected with the objective of minimizing inadvertent trips of the main feedwater system during plant startup, normal operation, and protection system surveillance. The Technical Specifications recommendations are consistent with the criteria and the risk considerations of the Commission Interim Policy Statement on Technical Specification Improvement. In addition, the staff recommends that all BWR recipients reassess and modify, if needed, their operating procedures and operator training to assure that the operators can mitigate reactor vessel overfill events that may occur via the condensate booster pumps during reduced system pressure operation."

The Generic Letter provides requirements that licensees provide NRC with their schedule and commitments within 180 days of the Generic Letter date. The implementation schedule for actions on which commitments are made should be prior to startup after the first refueling outage, but no later than the second refueling outage, beginning 9 months after receipt of the Generic Letter.

IMPLEMENTATION AND STATUS SUMMARY:

The licensee’s response to Generic Letter 89-19 was submitted to the NRC on March 20, 1990 and was supplemented on May 4, 1990.

A-48 Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment

REQUIREMENTS SUMMARY:

USI A-48 arose as a result of the large amount of hydrogen generated and burned within containment during the TMI accident. This issue covers hydrogen control measures for recoverable degraded core accidents for all BWRs and those PWRs with ice condenser containments. Extensive research in this area has led to significant revision of the Commission's hydrogen control regulations, given in 10CFR50.44.

The rule in 10CFR50.44 requiring inerting of BWR Mark I and Mark II containments as a method for hydrogen control was published on December 2, 1981. The BWR Mark I and Mark II reactor containments have operated for a number of years with an inerted atmosphere (by addition of an

inert gas, such as nitrogen) which effectively precludes combustion of any hydrogen generated. USI A-48 with respect to BWR Mark I and II containments is not only resolved but understood to be fully implemented in the affected plants.

The rule for BWRs with Mark III containments and PWRs with ice condenser containments was published on January 25, 1985. The rule required that these plants be provided with a means for controlling the quantity of hydrogen produced but did not specify the control method. In addition, the action plan for USI A-48 provided for plant specific reviews of lead-plants for reactors with Mark III and ice condenser containments. Sequoyah was chosen as the lead-plant for ice condenser containments and Grand Gulf for Mark III containments. Both of the lead-plant licensees chose to install igniter-type systems to burn the hydrogen before it reached threatening concentrations within the containment. Final design igniter systems have been installed not only in both lead plants, Sequoyah and Grand Gulf, but in all other ice condenser and Mark III plants as well. Documentation of the staff's safety evaluations of the final analyses required to be submitted by these licensees by the rule are continuing toward completion in 1989.

Large dry PWR containments were excluded from USI A-48 because they have a greater ability to accommodate the large quantities of hydrogen associated with a recoverable degraded core accident than the smaller MARK I, II, III and ice condenser containments. However, this issue has continued to be considered and in 1989, hydrogen control for large dry PWR containments was identified as a high priority Generic Issue 121. (NUREG-0933). The resolution of Generic Issue 121 is being actively pursued in close coordination with more recent research findings.

The NRC staff has concluded that USI A-48 is resolved as stated in SECY 89-122. If interested, the report should be consulted for further details regarding the relationship of A-48 to other ongoing hydrogen activities.

IMPLEMENTATION AND STATUS SUMMARY:

LGS uses an inerted containment as discussed in Section 6.2.5 (see SER and SSER section 6.2.5). Both units received temporary exemptions from inerting during the initial startup testing program. Both units are now in full compliance .

1.12.4 REFERENCES

1.12-1 "NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants," NUREG-0410, (January 1, 1978).

1.12-2 "Identification of Unresolved Safety Issues Relating to Nuclear Power Plants - A Report to Congress," NUREG-0510, (January 1979).

1.12-3 "NRC Action Plan as a Result of the TMI-2 Accident," NUREG-0660.

1.12-4 "Identification of New Unresolved Safety Issues Relating to Nuclear Power Plants, Special Report to Congress," NUREG-0705, (March 1981).

1.13 TMI-2 RELATED REQUIREMENTS FOR NEW OPERATING LICENSES

1.13.1 NUREG-0737, CLARIFICATION OF THE TMI ACTION PLAN REQUIREMENTS

Following the accident at Three Mile Island Unit 2, the NRC developed the TMI Action Plan, NUREG-0660, to provide a comprehensive and integrated plan for improving the safety of power reactors. NUREG-0737 was issued with an October 31, 1980 letter from D.G. Eisenhut (NRC) to licensees of operating power reactors and applicants for operating licenses forwarding specific TMI-related requirements from NUREG-0660 which have been approved by the NRC for implementation at this time. In this NRC report, these specific requirements comprise a single document which includes additional information about implementation schedules, applicability, method of implementation review by the NRC, submittal dates, and clarification of technical positions. It should be noted that the total set of TMI-related actions have been documented in NUREG-0660, but only those items that the NRC has approved for implementation to date are included in NUREG-0737.

Enclosure 2 to NUREG-0737 lists TMI Action Plan requirements for operating license applicants. Section 1.13.2 itemizes these requirements sequentially according to the NUREG-0737 number. Each item is accompanied by a response and/or reference to a section in the UFSAR that further discusses how the licensee or the LGS design complies with the requirement. These responses were revised periodically as ongoing efforts to address each requirement were completed.

1.13.2 TMI ACTION PLAN REQUIREMENTS FOR APPLICANTS FOR AN OPERATING LICENSE (ENCLOSURE 2 TO NUREG-0737)

- I.A.1.1 SHIFT TECHNICAL ADVISOR

Position

Each applicant shall provide an on-shift technical advisor to the shift supervisor. The STA may serve more than one unit at a multiunit site if qualified to perform the advisor function for the various units.

The STA shall have a bachelor's degree or equivalent in a scientific or engineering discipline and have received specific training in the response and analysis of the plant for transients and accidents. The STA shall also receive training in plant design and layout, including the capabilities of instrumentation and controls and the control room. The applicant shall assign normal duties to the STAs that pertain to the engineering aspects of assuring safe operations of the plant, including the review and evaluation of operating experience.

Clarification

(1) Due to the similarity in the requirements for dedication to safety, training, and onsite location and the desire that the accident assessment function be performed by someone whose normal duties involve review of operating experiences, our preferred position is that the same people perform the accident and operating experience assessment function. The performance of these two functions may be split if it can be demonstrated the persons assigned the accident assessment role are aware, on a current basis, of the work being done by those reviewing operating experience.

(2) To provide assurance that the STA will be dedicated to concern for the safety of the plant, our position has been the STAs must have a clear measure of independence from duties associated with the commercial operation of the plant. This would minimize possible distractions from safety judgments by the demands of commercial operations. We have determined that, while desirable, independence from the operations staff of the plant is not necessary to provide this assurance. It is necessary, however, to clearly emphasize the dedication to safety associated with the STA position both in the STA job description and in the personnel filling this position. It is not acceptable to assign a person who is normally the immediate supervisor of the shift supervisor to STA duties as defined herein.

(3) It is our position that the STA should be available within 10 minutes of being summoned and therefore should be onsite. The onsite STA may be in a duty status for periods of time longer than one shift, and therefore asleep at some times, if the 10 minute availability is assured. It is preferable to locate those doing the operating experience assessment onsite. The desired exposure to the operating plant and contact with the STA (if these functions are to be split) may be able to be accomplished by a group, normally stationed offsite, with frequent onsite presence.

We do not intend, at this time, to specify or advocate a minimum time onsite.

Response

See Section 13.1.2.1.1 for discussion of the STA position. Qualification requirements for STA positions are discussed in Section 13.1.3.1.

- I.A.1.2 SHIFT SUPERVISOR RESPONSIBILITIES

Position

Review the administrative duties of the shift supervisor and delegate functions that detract from or are subordinate to the management responsibility for assuring safe operation of the plant to other personnel not on duty in the control room.

Clarification

(1) The highest level of corporate management of each licensee shall issue and periodically reissue a management directive that emphasizes the primary management responsibility of the shift supervisor for safe operation of the plant under all conditions on his shift and that clearly establishes his command duties.

(2) Plant procedures shall be reviewed to assure that the duties, responsibilities, and authority of the shift supervisor and control room operators are properly defined to effect the establishment of a definite line of command and clear delineation of the command decision authority of the shift supervisor in the control room relative to other plant management personnel. Particular emphasis shall be placed on the following:

(a) The responsibility and authority of the shift supervisor shall be to maintain the broadest perspective of operational conditions affecting the safety of the plant as a matter of highest priority at all times when on duty in the control room. The principle shall be reinforced that the shift supervisor should not become totally

involved in any single operation in times of emergency when multiple operations are required in the control room.

(b) The shift supervisor, until properly relieved, shall remain in the control room at all times during accident situations to direct the activities of control room operators. Persons authorized to relieve the shift supervisor shall be specified.

(c) If the shift supervisor is temporarily absent from the control room during routine operations, a lead control room operator shall be designated to assume the control room command function. These temporary duties, responsibilities, and authority shall be clearly specified.

(3) Training programs for shift supervisors shall emphasize and reinforce the responsibility for safe operation and the management function that the shift supervisor is to provide for assuring safety.

(4) The administrative duties of the shift supervisor shall be reviewed by the senior officer of each utility responsible for plant operations. Administrative functions that detract from or are subordinate to the management responsibility for assuring the safe operation of the plant shall be delegated to other operations personnel not on duty in the control room.

Response

In the assignment of functions to the Shift Manager, consideration is given to aspects such as the need to keep the Shift Manager in control of and aware of plant operational, maintenance, and testing activities which may affect safe operation and the need to prevent administrative duties from detracting from the primary responsibility of assuring safe operation.

A letter was written by S.L. Daltroff (PECo) on December 26, 1979, which defines and emphasizes the primary management responsibility of the Shift Superintendent (now the Shift Manager). Similar to PBAPS, this letter will be promulgated to shift supervision in the form of an administrative procedure.

The letter referenced above also defined the duties of control room operators. The nature of the letter was not only to define and emphasize responsibility but to effect the establishment of a definite line of command. This letter will form the basis for an administrative procedure in which the duties of the control room operator will be defined.

In the administrative procedure covering shift operations, a directive will be written which will specify who can relieve the Shift Manager. It will require only that a member of Shift Supervision bearing an active senior license and qualified as an Emergency Director will have such an authority.

Temporary relief of the Shift Manager will normally be accomplished using the Shift Supervisor. Duties and responsibilities, similar to those of the Shift Manager, will be defined in the administrative procedure covering shift operations. He will be a senior licensed individual having worked side-by-side with the Shift Manager, fully knowledgeable of the Shift Manager's responsibilities and the overall plant status at any given time.

The licensee is engaged in a Management Development Program, which includes management training for shift supervisors. All management training courses include training in such topics as style of management, planning, delegation, communications, motivation, personnel and industrial relations and performance review. In addition, all shift supervision has, or will have prior to startup, completed the Genco II Kepner Tregoe Course in Decision Making. In the future, it is planned that shift supervision will have the opportunity to attend some of the subsequent courses associated both with the Management Development Program and the Kepner Tregoe Program.

The administrative responsibilities for all members of shift supervision are defined in an administrative procedure.

The administrative procedure covering shift operations will define shift supervision's administrative responsibilities. Those which will be retained will be those which are defined in that administrative procedure.

The duties and responsibilities of the Shift Manager during accident/transient conditions will be delineated in both the Emergency Plan and the administrative procedures governing shift operations. The procedures developed from the Emergency Plan will contain detailed responsibilities of the Shift Manager during such conditions.

The STA will hold a staff position in the Operations Group. He reports directly to the Shift Manager on his staff. The STA advises the Shift Manager concerning off-normal events and will make appropriate recommendations regarding corrective and precautionary actions.

See Section 13.1.2.1.1 for further discussion.

- I.A.1.3 SHIFT MANNING

Position

Assure that the necessary number and availability of personnel to man the operations shifts have been designated by the licensee. Administrative procedures should be written to govern the movement of key individuals about the plant to assure that qualified individuals are readily available in the event of an abnormal or emergency situation. This should consider the recommendations on overtime in NUREG-0578. Provisions should be made for an aide to the shift supervisor to assure that, over the long-term, the shift supervisor is free of routine administrative duties.

Clarification

At any time a licensed nuclear unit is being operated in Modes 1-4 for a PWR (power operation, startup, hot standby or hot shutdown, respectively) or in Modes 1-3 for a BWR (power operation, startup, or hot shutdown, respectively), the minimum shift crew shall include two licensed senior reactor operators, one of whom shall be designated as the shift supervisor, two licensed reactor operators, and two unlicensed auxiliary operators. For a multiunit station, depending upon the station configuration, shift staffing may be adjusted to allow credit for licensed senior reactor operators and licensed reactor operators to serve as relief operators on more than one unit; however, these individuals must be properly licensed on each such unit. At all other times, for a unit loaded with fuel, the minimum shift crew shall include one shift supervisor who shall be a

licensed senior reactor operator, one licensed reactor operator, and one unlicensed auxiliary operator.

Adjunct requirements to the shift staffing criteria stated above are as follows:

(1) A shift supervisor with a senior reactor operator's license, who is also a member of the station supervisory staff, shall be onsite at all times when at least one unit is loaded with fuel.

(2) A licensed senior reactor operator shall, at all times, be in the control room from which a reactor is being operated. The shift supervisor may from time to time act as relief operator for the licensed senior reactor operator assigned to the control room.

(3) For any station with more than one reactor containing fuel, the number of licensed senior reactor operators onsite shall, at all times, be at least one more than the number of control rooms from which the reactors are being operated.

(4) In addition to the licensed senior reactor operators specified in (1), (2), and (3) above, for each reactor containing fuel, a licensed reactor operator shall be in the control room at all times.

(5) In addition to the operators specified in (1), (2), (3), and (4) above, for each control room from which a reactor is being operated, an additional licensed reactor operator shall be onsite at all times and available to serve as relief operator for that control room. As noted above, this individual may serve as relief operator for each unit being operated from that control room, provided he holds a current license for each unit.

(6) Auxiliary (nonlicensed) operators shall be properly qualified to support the unit to which assigned.

(7) In addition to the staffing requirements stated above, shift crew assignments during periods of core alterations shall include a licensed senior reactor operator to directly supervise the core alterations. This licensed senior reactor operator may have fuel handling duties but shall not have other concurrent operational duties.

Licensees of operating plants and applicants for operating licenses shall include in their administrative procedures provisions governing required shift staffing and movement of key individuals about the plant. These provisions are required to assure that qualified plant personnel to man the operational shifts are readily available in the event of an abnormal or emergency situation.

The following information regarding fatigue management and work hours controls is historical. The current regulatory requirements are provided by the 10CFR26 Fitness for Duty Programs rule, which became effective on April 30, 2008. Implementation of the amended rule was required by October 1, 2009. Limerick administrative procedure LS-AA-119, "Fatigue Management and Work Hour Limits," was revised and issued to implement requirements for managing fatigue and controlling work hours in accordance with 10CFR26, Subpart I, "Managing Fatigue." The procedure defines the scope of workers that are subject to the fatigue management program and the scope of workers subject to work hour controls. The procedure also includes the 10CFR26 work hours limits.

These administrative procedures shall also set forth a policy, the objective of which is to prevent situations where fatigue could reduce the ability of operating personnel to keep the reactor in a safe condition. The controls established should assure that, to the extent practicable, personnel are not assigned to shift duties while in a fatigued condition that could significantly reduce their mental alertness or their decision making ability. The controls shall apply to the plant staff who perform safety-related functions (e.g., senior reactor operators, reactor operators, auxiliary operators, health physicists, and key maintenance personnel).

IE Circular No. 80-02, "Nuclear Power Plant Staff Work Hours," dated February 1, 1980 discusses the concern of overtime work for members of the plant staff who perform safety-related functions. The guidance contained in IE Circular No. 80-02 was amended by the

July 31, 1980 NRC letter. In turn, the overtime guidance of the July 31, 1980 NRC letter was revised in Section I.A.1.3 of NUREG-0737. The NRC was issued a policy statement which further revises the overtime guidance as stated in NUREG-0737. This guidance is as follows:

Enough plant operating personnel should be employed to maintain adequate shift coverage without routine heavy use of overtime. The objective is to have operating personnel work a nominal 8-hour day, 40-hour week while the plant is operating. However, in the event the unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance or major plant modifications, on a temporary basis, the following guidelines shall be followed:

a. An individual should not be permitted to work more than 16 hours straight (excluding shift turnover time).

b. An individual should not be permitted to work more than 16 hours in any 24-hour period, nor more than 24 hours in any 48-hour period, nor more than 72 hours in any seven day period (all excluding shift turnover time).

c. A break of at least eight hours should be allowed between work periods (including shift turnover time).

d. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on shift.

Recognizing that very unusual circumstances may arise requiring deviation from the above guidelines, such deviation shall be authorized by the plant manager or his deputy, or higher levels of management. The paramount consideration in such authorization shall be that significant reductions in the effectiveness of operating personnel would be highly unlikely. Authorized deviations to the working hour guidelines shall be documented and available for NRC review.

In addition, procedures are encouraged that would allow licensed operators at the controls to be periodically relieved and assigned to other duties away from the control board during their tours of duty.

Operating license applicants shall complete these administrative procedures before fuel loading. Development and implementation of the administrative procedures at operating plants will be reviewed by the Office of Inspection and Enforcement beginning October 1, 1982.

Response

See Section 13.1.2 on shift manning.

The shift operations administrative procedure governs the required shift staffing and movement of key individuals about the plant, in particular the location of control operators and shift supervision.

An administrative procedure contains, working hour restrictions, which are in accord with current regulations at the time of writing.

The same administrative procedure that sets forth policies regarding overtime contains procedures which govern the deviation from overtime restrictions and how deviations will be documented.

The operations shift complement required when refueling operations are scheduled, along with the responsibilities of the refueling shift personnel, are defined in administrative procedures.

The licensee maintains a Nuclear Training Division. This organization compiles specific job requirements for operating people within power plants. For this list of job requirements, qualifying tests are generated. These tests are administered to applicants for promotion, with promotion to the applicable job described being contingent upon a passing grade. This applies to all plant operators including the equipment operator.

- I.A.2.1 IMMEDIATE UPGRADING OF OPERATOR AND SENIOR OPERATOR TRAINING AND QUALIFICATION

Position

Applicants for SRO license shall have 4 years of responsible power plant experience, of which at least 2 years shall be nuclear power plant experience (including 6 months at specific plant) and no more than 2 years shall be academic or related technical training. After fuel loading, applicants shall have 1 year of experience as a licensed operator or equivalent.

Certifications that operator license applicants have learned to operate the controls shall be signed by the highest level of corporate management for plant operation.

Applicants must revise training programs to include training in heat transfer, fluid flow, thermodynamics, and plant transients.

Clarification

Applicants for SRO either come through the operations chain (C operator to B operators to A operator, etc.) or are degree-holding staff engineers who obtain licenses for backup purposes.

In the past, many individuals who came through the operator ranks were administered SRO examinations without first being an operator. This was clearly a poor practice and the letter of March 28, 1980 requires reactor operator experience for SRO applicants.

However, NRC does not wish to discourage staff engineers from becoming licensed SROs. The effort is encouraged because it forces engineers to broaden their knowledge about the plant and its operation.

In addition, in order to attract degree-holding engineers to consider the shift supervisor's job as part of their career development, NRC should provide an alternate path to holding an operator's license for 1 year.

The track followed by a high school graduate (a nondegreed individual) to become an SRO would be 4 years as a control room operator, at least one of which would be as a licensed operator, and participation in an SRO training program that includes 3 months on-shift as an extra person.
The track followed by a degree-holding engineer would be, at a minimum, 2 years of responsible nuclear power plant experience as a staff engineer, participation in an SRO training program equivalent to a cold applicant training program, and 3 months on-shift as an extra person in training for an SRO position.

Holding these positions assures that individuals who will direct the license activities of licensed operators have had the necessary combination of education, training, and actual operating experience prior to assuming a supervisory role at the facility.

The staff realizes that the necessary knowledge and experience can be gained in a variety of ways. Consequently, credit for equivalent experience should be given to applicants for SRO licenses.

Applicants for SRO licenses at a facility may obtain their 1 year operating experience in a licensed capacity (operator or senior operator) at another nuclear power plant. In addition, actual operating experience in a position that is equivalent to a licensed operator or senior operator at military propulsion reactors will be acceptable on a one-for-one basis. Individual applicants must document this experience in their individual applications in sufficient detail so that the staff can make a finding regarding equivalency.

Applicants for SRO licenses who possess a degree in engineering or applicable sciences are deemed to meet the above requirements, provided they meet the requirements set forth in sections A.1.a and A.2 in enclosure in the letter from H.R. Denton (NRC) to all power reactor applicants and licensees, dated March 28, 1980, and have participated in a training program equivalent to that of a cold senior operator applicant.

The NRC has not imposed the 1 year experience requirement on cold applicants for SRO licenses. Cold applicants are to work on a facility not yet in operation; their training programs are designed to supply the equivalent of the experience not available to them.

Response

Applicants for SRO license will have at least 4 years of responsible power plant experience, of which at least 2 years will be nuclear plant experience, including 6 months at the plant and no more than 2 years will be academic or related technical training.

The requirements for certification are implemented in administrative procedures.

The training programs for RO and SRO license will include training in heat transfer, fluid flow, thermodynamics, and plant transients. See Section 13.2.1.1 for further discussion.

- I.A.2.3 ADMINISTRATION OF TRAINING PROGRAMS

Position

Pending accreditation of training institutions, training instructors who teach systems, integrated response, transient and simulator courses shall successfully complete a SRO examination prior to fuel loading and instructors shall attend appropriate retraining programs that address, as a minimum, current operating history, problems and changes to procedure and administrative limitations. In the event an instructor is a licensed SRO, his retraining shall be the SRO requalification program.

Clarification

The above position is a short-term position. In the future, accreditation of training institutions will include review of the procedure for certification of instructors. The certification of instructors may, or may not, include successful completion of an SRO examination.

The purpose of the examination is to provide NRC with reasonable assurance during the interim period that instructors are technically competent.

The requirement is directed to permanent members of training staff who teach the subjects listed above, including members of other organizations who routinely conduct training at the facility. There is no intention to require guest lecturers who are experts in particular subjects (reactor theory, instrumentation, thermodynamics, health physics, chemistry, etc.) to successfully complete an SRO examination. Nor is it intended to require a system expert, such as the instrument and control supervisor teaching the control rod drive system, to sit for an SRO examination.

Response

The requirements for training instructors will be implemented in administration of the training program.

- I.A.3.1 REVISE SCOPE AND CRITERIA FOR LICENSING EXAMINATIONS

Position

Applicants for operator licenses will be required to grant permission to the NRC to inform their facility management regarding the results of examinations.

Contents of the licensed operator requalification program shall be modified to include instruction in heat transfer fluid flow, thermodynamics and mitigation of accidents involving a degraded core.

The criteria for requiring a licensed individual to participate in accelerated requalification shall be modified to be consistent with the new passing grade for issuance of a license.

Requalification programs shall be modified to require specific reactivity control manipulations. Normal control manipulations, such as plant or reactor startups, must be performed. Control manipulations during abnormal or emergency operation shall be walked through and evaluated by a member of the training staff.

An appropriate simulator may be used to satisfy the requirements for control manipulations.

Clarification

The clarification does not alter the staff's position regarding simulator examinations.

The clarification does provide additional preparation time for utility companies and NRC to meet examination requirements as stated. A study is under way to consider how similar a nonidentical simulator should be for a valid examination. In addition, present simulators are fully booked months in advance.

Application of this requirement was stated in June 1, 1980 to applicants where a simulator is located at the facility. Starting October 1, 1981, simulator examinations will be conducted for applicants of facilities that do not have simulators at the site.

NRC simulator examinations normally require 2 to 3 hours. Normally, two applicants are examined during this time period by two examiners.

Utility companies should make the necessary arrangements with an appropriate simulator training center to provide time for these examinations. Preferably these examinations should be scheduled consecutively with the balance of the examination. However, they may be scheduled no sooner than 2 weeks prior to and no later than 2 weeks after the balance of the examination.

Response

The requirements for RO and SRO examinations and requalification programs will be implemented.

- I.B.1.2 EVALUATION OF ORGANIZATION AND MANAGEMENT

Position

Corporate management of the utility-owner of a nuclear power plant shall be sufficiently involved in the operational phase activities, including plant modifications, to assure a continual understanding of plant conditions and safety considerations. Corporate management shall establish safety standards for the operation and maintenance of the nuclear power plant. To these ends, each utility-owner shall establish an organization, parts of which shall be located onsite, to: perform independent review and audits of plant activities; provide technical support to the plant staff for maintenance, modifications, operational problems, and operational analysis; and aid in the establishment of programmatic requirements for plant activities.

The licensee shall establish an integrated organizational arrangement to provide for the overall management of nuclear power plant operations. This organization shall provide for clear management control and effective lines of authority and communication between the

organizational units involved in the management, technical support, and operation of the nuclear unit. The key characteristics of a typical organization arrangement are:

(1) Integration of all necessary functional responsibilities under a single responsible head.

(2) The assignment of responsibility for the safe operation of the nuclear power plant(s) to an upper-level executive position.

Utility management shall establish a group, independent of the plant staff, but assigned onsite, to perform independent reviews of plant operational activities. The main functions of this group will be to evaluate the technical adequacy of all procedures and changes important to the safe operation of the facility and to provide continuing evaluation and assessment of the plant's operating experience and performance.

Response

The licensee's corporate and plant staff organizations for routine operations are described in Sections 17.2 and 13.1. The emergency organization is described in the nuclear emergency plan. Independent review activities are described in Section 13.4

- I.C.1 SHORT-TERM ACCIDENT ANALYSIS AND PROCEDURE REVIEW

Position

In our letters of September 13 and 27, October 10 and 30, and November 9, 1979, we required licensees of operating plants, applicants for operating licenses, and licensees of plants under construction to perform analyses of transients and accidents, prepare emergency procedure guidelines, upgrade emergency procedures, and to conduct operator retraining (see also Item I.A.2.1 of this report). Emergency procedures are required to be consistent with the actions necessary to cope with the transients and accidents analyzed. Analyses of transients and accidents were to be completed in early 1980, and implementation of procedures and retraining were to be completed 3 months after emergency procedure guidelines were established; however, some difficulty in completing these requirements has been experienced. Clarification of the scope of the task and appropriate schedule revisions were included in NUREG-0737, Item I.C.1.

Pending staff approval of the revised analysis and guidelines, the staff will continue the pilot monitoring of emergency procedures described in Item I.C.8 (NUREG-0660). The adequacy of the BWR vendor's guidelines will be identified to each near-term operating licensee during the emergency procedure review.

Response

Emergency operating procedures are developed from the BWROG Emergency Procedure and Severe accident Guidelines (EPG/SAGs). Reference UFSAR Section 15.0.6 for a discussion of these guidelines. The development of the EPGs was based on reanalysis of transients and accidents and inadequate core cooling. The licensed operator training program includes training on the emergency operating procedures.

Additional information has been provided in a letter from V.S. Boyer (PECo) to D.G. Eisenhut (NRC) dated April 15, 1983.

- I.C.2 SHIFT RELIEF AND TURNOVER PROCEDURES

Position

The licensee shall review and revise as necessary the plant procedure for shift and relief turnover to assure the following:

(1) A checklist shall be provided for the oncoming and offgoing control room operators and the oncoming shift supervisor to complete and sign. The following items, as a minimum, shall be included in the checklist:

(a) Assurance that critical plant parameters are within allowable limits (parameters and allowable limits shall be listed on the checklist).

(b) Assurance of the availability and proper alignment of all systems essential to the prevention and mitigation of operational transients and accidents by a check of the control console. What to check and criteria for acceptable status shall be included on the checklist.

(c) Identification systems and components that are in a degraded mode of operation permitted by the Technical Specifications. For such systems and components, the length of time in the degraded mode shall be compared with the Technical Specifications action statement.

(2) Checklists or logs shall be provided for completion by the offgoing and oncoming auxiliary operators and technicians. Such checklists or logs shall include any equipment under maintenance or test that by itself could degrade a system critical to the prevention and mitigation of operational transients and accidents or initiate an operational transient (what to check and criteria for acceptable status shall be included on the checklist); and

(3) A system shall be established to evaluate the effectiveness of the shift and relief turnover procedures (for example, periodic independent verification of system alignments).

Response

The requirements stated in this section will be implemented except for the request to establish separate checklists or logs for use by the offgoing and ongoing equipment operators and maintenance technicians.

A variety of shift turnover checklists or logs, situated in various locations of the plant and under the control of many groups would further hinder the transfer of vital information to the operating shift personnel with primary responsibility for plant operations. A limited number of checklists or logs, centralized in the control room and under the supervision of control room personnel, is essential to effective transfer of information.

Maintenance and testing of equipment vital to safe operation of the plant is performed with the knowledge and approval of the appropriate licensed control room operator. The checklists, status boards, or logs will be utilized to identify any equipment under maintenance or test that by themselves could degrade a system critical to the prevention and mitigation of operational

transients and accidents, or initiate an operational transient. Some of this information will be supplied to the control room operators and supervisors, as appropriate, by the equipment operators and technicians for entry into the checklists and logs. Shift personnel meetings under the direction of shift supervision are normally held shortly after shift turnover. Offgoing equipment operators will normally be relieved at their job locations in the plant. Equipment operators will, when job conditions permit, complete and review an applicable shift turnover checkoff list. If plant operations require that equipment operators conduct shift turnover on the job away from their normal turnover location and no turnover checklist is executed, the person making relief will, at the earliest convenience, report to shift supervision to obtain a supplementary briefing. Examples of activities that could preclude normal turnover include filling the main generator with hydrogen and executing a demineralizer regeneration.

Checklists for oncoming and offgoing control room operators and oncoming shift supervisors to be used during shift turnover will be included in administrative procedure for shift operations.

A checklist for shift turnover to be used by equipment operators will be written and will be included in the shift operations administrative procedure.

Included as part of the shift operations administrative procedure, and specifically in the sections relating to shift turnover, instructions will be communicated to the various levels of shift operating personnel directing that, when deficiencies in the turnover process are noticed primarily by the discovery of information which was not surfaced during the turnover, such deficiencies will be brought to the attention of shift supervision, who will in turn initiate a modification to the turnover checkoff list. This mechanism will ensure that, as job responsibilities change, appropriate modifications will be made to the checklist.

- I.C.3 SHIFT SUPERVISOR RESPONSIBILITIES

This item is included with Section I.A.1.2, Shift Supervisor responsibilities.

Response

This requirement will be implemented.

- I.C.4 CONTROL ROOM ACCESS

Position

The licensee shall make provisions for limiting access to the control room to those individuals responsible for the direct operation of the nuclear power plant (e.g., operations supervisor, shift supervisor, and control room operators), to technical advisors who may be requested or required to support operation, and the predesignated NRC personnel. Provisions shall include the following:

(1) Develop and implement an administrative procedure that establishes the authority and responsibility of the person in charge of the control room to limit access.

(2) Develop and implement procedures that establish a clear line of authority and responsibility in the control room in the event of an emergency. The line of succession for the person in charge of the control room shall be established and limited to persons

possessing a current senior reactor operator's license. The plan shall clearly define the lines of communication and authority for plant management personnel not in direct command of operations, including those who report to stations outside the control room.

Response

An administrative procedure for control room access will be written and will define the authority and responsibility of the Shift Manager, or alternate, to exercise control over control room access. This administrative procedure will provide the Shift Manager, or alternate, with authority to order persons out of the control room if they have gained entrance and were not authorized or if conditions in the control room change to an extent which changes the access requirements.

Administrative procedures establish a clear line of authority and responsibility in the control room for emergency conditions. This will include the line of succession for the person in charge of the control room.

During plant emergencies, lines of communications and authority for the subject plant management personnel will be delineated in the Emergency Plan. This will include those persons reporting to the TSC, EOF, and Press Facility.

- I.C.5 FEEDBACK OF OPERATING EXPERIENCE

Position

Each licensee will review its administrative procedures to assure that operating experience from within and outside the organization is continually provided to operators and other operational personnel and is incorporated in training programs.

Response

The Regulatory Assurance Section is supervised by the Manager, Regulatory Assurance, who reports to the Vice President, LGS and is responsible for ensuring review of operating experience reports that may be directed to the plant by various industry groups and regulatory agencies and for disseminating such reports to the appropriate personnel for review for applicability to LGS and determination of required action.

In addition, the External and Internal Operating Experience (OPEX) program ensures that appropriate events that occur within the Exelon fleet and in the industry are evaluated for similar conditions at the station. To ensure consistency between various plants within the Exelon fleet, a corporate OPEX coordinator provides overall coordination and direction to this program. Mechanisms exist for identifying, screening, and investigating OPEX items. The corporate OPEX coordinator screens OPEX issues. Depending on the OPEX item being investigated, appropriate corporate, station or other qualified personnel evaluate the issue. Corporate actions are identified if required and are tracked for completion within the site action tracking program. Appropriate status reporting and monitoring of OPEX are also performed. The site OPEX coordinator function resides within Regulatory Assurance.

- I.C.6 VERIFY CORRECT PERFORMANCE OF OPERATING ACTIVITIES

Position

It is required (from NUREG-0660) that licensees' procedures be reviewed and revised, as necessary, to assure that an effective system of verifying the correct performance of operating activities is provided as a means of reducing human errors and improving the quality of normal operations. This will reduce the frequency of occurrence of situations that could result in or contribute to accidents. Such a verification system may include automatic system status monitoring, human verification of operations, and maintenance activities independent of the people performing the activity (see NUREG-0585, Recommendation 5), or both.

Response

Plant procedures will describe a system for the control of removal and restoration and alignment of safety-related plant systems or equipment. This system will use a combination of control room indicators, operability testing, or independent verification (subject to radiation exposure limitations), to ensure that equipment is in its correct alignment.

- I.C.7 NSSS VENDOR REVIEW OF PROCEDURES

Position

Obtain NSSS vendor review of power ascension and emergency operating procedures to further verify their adequacy.

Response

This requirement will be implemented.

- I.C.8 PILOT MONITORING OF SELECTED EMERGENCY PROCEDURES FOR NEAR-TERM OPERATING LICENSE APPLICANTS

Position

Correct emergency procedures as necessary based on the NRC audit of selected plant emergency operating procedures (e.g., SBA, loss of feedwater, restart of ESF following a loss of ac power and steam line break).

Response

Information on emergency procedures (NUREG-0737, Item I.C.1) was provided to the NRC in a response (Letter from V.S. Boyer to D.G. Eisenhut dated April 15, 1983) to Generic Letter 82-33, Supplement 1 to NUREG-0737. Emergency operating procedures are developed from the current revision of the BWROG Emergency Procedure Guidelines.

- I.D.1 CONTROL ROOM DESIGN REVIEWS

Position

Licensees and applications for operating licenses are required to conduct a detailed control room design review to identify and correct design deficiencies. This detailed control room design review is expected to take about a year. Those applicants for operating licenses who are unable to

complete this review prior to issuance of a license shall make preliminary assessments of their control rooms to identify significant human factors and instrumentation problems and establish a schedule approved by us for correcting deficiencies. These applicants will be required to complete the more detailed control room reviews on the same schedule as licensees with operating plants.

Clarification

Applicants for operating license who will be unable to complete the detailed control room review prior to issuance of a license are required to perform a preliminary control room design assessment to identify significant human factors problems. Applicants will find it of value to refer to the draft document, NUREG/CR-1580, "Human Engineering Guide to Control Room Evaluation," in performing the preliminary assessment. We will evaluate the applicant's preliminary assessments including the performance by us of onsite reviews/audits. Our onsite review/audit will be on a schedule consistent with applicant licensing needs and will emphasize the following aspects of the control room:

(1) The adequacy of information presented to the operator to reflect plant status for normal operation, anticipated operational occurrences, and accident conditions;

(2) The groupings of displays and the layout of panels;

(3) Improvements in the safety monitoring and human factors enhancement of controls and control displays;

(4) The communications from the control room to points outside the control room, such as the onsite technical support center, remote shutdown panel, offsite telephone lines, and to other areas within the plant for normal and emergency operation.

(5) The use of direct rather than derived signals for the presentation of process and safety information to the operator;

(6) The operability of the plant from the control room with multiple failures of nonsafety-grade and nonseismic systems;

(7) The adequacy of operating procedures and operator training with respect to limitations of instrumentation displays in the control room;

(8) The categorization of alarms, with unique definition of safety alarms;

(9) The physical location of the shift supervisor's office either adjacent to or within the control room complex.

Prior to the onsite review/audit, we will require a copy of the applicant's preliminary assessment and additional information which will be used in formulating the details of the onsite review/audit.

Response

The CRDR effort directed by Item I.D.I and required by Supplement 1 to NUREG-0737 began in 1980 with the licensee's participation in the BWROG CRDR Subcommittee. The subcommittee

produced a BWR Owner's Group Generic CRDR Program which addresses Item 5.1.b of Supplement 1. This generic program was submitted to the NRC for review in August 1981. The review and subsequent discussions between the NRC and representatives of the subcommittee have resulted in a supplement to the review program.

A preliminary review of the LGS control room was conducted using the original design review program in October 1981. At that time, the LGS control room was still in the construction phase, and the formal LGS emergency procedures were not available for the walk-through.

The licensee subsequently developed a program to address the assessment, implementation and verification phases of the LGS CRDR Program. This program was submitted in August 1983 and a report was submitted in June 1984 and supplemented in November 1984 and June 1985.

Basic Requirements Completion Dates:

(Numbering refers to corresponding portions of Section 5 of Supplement 1)

5.1.a) As was the case during the initial review phase, a person competent in human factors engineering as well as persons competent in system design and system operation were included in the assessment phase of the Program. This assessment was completed in April 1984.

5.1.b) A detailed review of the control room has been completed as discussed in current status above. Completion of the review to address the supplemental checklist and those items not included in the preliminary review due to construction status was completed in January 1984.

5.1.c) Assessment of the HEDs was completed in June 1985.

5.1.d) Proposed improvements have been reviewed by the multidisciplinary task force described in 5.1.a to ensure that the proposed change addresses the identified HED and does not create additional HEDs. All changes have been integrated with other control room modifications.

5.2.a) The program plan for completing the CRDR was completed and is outlined below:

i. Completed the generic review program including the supplemental review and the emergency procedure walk- through.

ii. Assessed the identified HEDs and generated recommendations for modification to those HEDs that warrant a change.

iii. Each of the proposed modifications were reviewed to verify that it corrected the HED it was intended to correct and did not create any new unacceptable HEDs. The modifications have been coordinated with the balance of the NUREG-0737 Supplement 1 initiatives.

iv. The NRC conducted an in-progress audit in December 1983.

5.2.b) A summary report was prepared and submitted in June 1984 and supplemented in November 1984 and June 1985. These reports included proposed modifications and their Unit 1 schedules. Unit 2 modifications and schedules were provided in October 1988.

- I.D.2 PLANT SAFETY PARAMETER DISPLAY CONSOLE

Position

Each applicant and licensee shall install a SPDS that will display to operating personnel a minimum set of parameters which define the safety status of the plant. This can be attained through continuous indication of direct and derived variables as necessary to assess plant safety status.

Response

The LGS design includes a PMS. This system is based, in part, on the GE emergency response system described in Reference 1.13-7. The SPDS is a part of this PMS. The SPDS is not safety-related, as discussed in Supplement 1 to NUREG-0737. Sensors, isolators, signal conditioners or other components which provide input to the SPDS are Q-listed if they are part of a safety-related system. The SPDS parameters, a subset of the parameters available in the PMS data base, are based on the Regulatory Guide 1.97 (Rev 2) BWR parameter list. All of the critical safety functions defined in Supplement 1 to NUREG-0737, "Clarification of TMI Action Plan Requirements," for a BWR, are addressed by the PMS process variables.

The parameters included in the SPDS display are based on the entry conditions for the LGS EOPs. As changes and improvements are made to the RPV control and containment control procedures, the system can be modified to reflect these changes. The system has been designed in accordance with the guidance provided in NUREG-0696.

A safety analysis describing the basis on which the selected parameters are sufficient to assess the safety status of each identified function for a wide range of events was transmitted by letter from J.S. Kemper (PECo) to A. Schwencer (NRC) dated September 2, 1983.

The software debugging, validation, testing, and acceptance testing will be completed during the Power Ascension Test Program. The SPDS and Regulatory Guide 1.97 parameter displays will be functional within 30 days after the completion of the 100 hour warranty run at 100% power.

- I.G.1 TRAINING DURING LOW POWER TESTING

Position

We require applicants for a new operating license to define and commit to a special low power testing program approved by NRC to be conducted at power levels no greater than 5% for the purposes of providing meaningful technical information beyond that obtained in the normal startup test program and to provide supplemental training.

Clarification

Chapter 14 of the Final Safety Analysis Report describes the applicant's initial test program. The objectives of the initial test program include both training and the acquisition of technical data. This program has been determined by the staff to be acceptable as reported in Section 14 of this report. However, we require the applicant to perform additional testing and training beyond the requirements of the initial test program.

Response

The BWROG program for compliance with NUREG-0737 Requirement I.G.1 was transmitted to the NRC via letter (BWROG-8120) from D.B. Waters (BWROG) to E.G. Eisenhut (NRC). The generic program described in this document is divided into five sections: I-Preoperational Testing; II-Cold Functional Testing; III-Hot Functional Testing; IV-Startup Testing; and V-Additional Training and Testing. The initial test program for LGS as described in Chapter 14 follows the testing described in the first four sections of the BWROG program. During this program, the licensee expects to perform significant plant transients only once, but with a maximum of licensed personnel in attendance. The LGS unit unique simulator provides an excellent mechanism for training people without affecting the real plant. Repetition of startup tests solely for testing purposes will be done on this simulator. Chapter 14 has been changed to describe the additional testing discussed in section V of the BWROG program.

Additional training is to be included in the certification program on the LGS simulator which shall include total loss of offsite and onsite ac power.

- II.B.1 REACTOR COOLANT SYSTEM VENTS

Position

Each applicant and licensee shall install RCS and reactor vessel head high point vents remotely operated from the control room. Although the purpose of the system is to vent noncondensable gases from the RCS which may inhibit core cooling during natural circulation, the vents must not lead to an unacceptable increase in the probability of a LOCA or a challenge to containment integrity. Since these vents form a part of the reactor coolant pressure boundary, the design of the events shall conform to the requirements of 10CFR50, Appendix A, "General Design Criteria." The vent system shall be designed with sufficient redundancy that assures a low probability of inadvertent or irreversible actuation. Each licensee shall provide the following information concerning the design and operation of the high point vent system:

(1) Submit a description of the design, location, size, and power supply for the vent system along with results of analyses for LOCA initiated by a break in the vent pipe. The results of the analyses should demonstrate compliance with the acceptance criteria of 10CFR50.46.

(2) Submit procedures and supporting analysis for operator use of the vents that also include the information available to the operator for initiating or terminating vent usage.

Clarification

A. General

(1) The important safety function enhanced by this venting capability is core cooling. For events beyond the present design basis, this venting capability will substantially increase the plant's ability to deal with large quantities of noncondensable gas which could interfere with core cooling.

(2) Procedures addressing the use of the RCS vents should define the conditions under which the vents should be used as well as the conditions under which the vents should not be used. The procedures should be directed toward achieving a substantial increase in the plant being able to maintain core cooling without loss of containment integrity for events beyond the design basis. The use of vents for accidents within the normal design basis must not result in a violation of the requirements of 10CFR50.44 or 10CFR50.46.

(3) The size of the RCS vents is not a critical issue. The desired venting capability can be achieved with vents in a fairly broad spectrum of sizes. The criteria for sizing a vent can be developed in several ways. One approach, which may be considered, is to specify a volume of noncondensable gas to be vented and in a specific venting time. For containments particularly vulnerable to failure from large hydrogen releases over a short period of time, the necessity and desirability for contained venting outside the containment must be considered (e.g., into a decay gas collection and storage system).

(4) Where practical, the reactor coolant system vents should be kept smaller than the size corresponding to the definition of LOCA (10CFR50, Appendix A). This will minimize the challenges to the ECCS since the inadvertent opening of a vent smaller than the LOCA definition would not require ECCS actuation, although it may result in leakage beyond technical specification limits. On PWRs, the use of new or existing lines whose smallest orifice is larger than the LOCA definition will require a valve in series with a vent valve that can be closed from the control room to terminate the LOCA that would result if an open vent valve could not be reclosed.

(5) A positive indication of valve position should be provided in the control room.

(6) The reactor coolant vent system shall be operable from the control room.

(7) Since the RCS vent will be part of the RCPB, all requirements for the reactor pressure boundary must be met, and, in addition, sufficient redundancy should be incorporated into the design to minimize the probability of an inadvertent actuation of the system. Administrative procedures may be a viable option to meet the single failure criterion. For vents larger than the LOCA definition, an analysis is required to demonstrate compliance with 10CFR50.46.

(8) The probability of a vent path failing to close, once opened, should be minimized; this is a new requirement. Each vent must have its power supplied from an emergency bus. A single failure within the power and control aspects of the reactor coolant vent system should not prevent isolation of the entire vent system when required. On BWRs, block valves are not required in lines with safety valves that are used for venting.

(9) Vent paths from the primary system to within containment should go to those areas that provide good mixing with containment air.

(10) The reactor coolant vent system (i.e., vent valves, block valves, position indication devices, cable terminations, and piping) shall be seismically and environmentally qualified in accordance with IEEE 344 (1975) as supplemented by Regulatory Guide 1.100, Regulatory Guide 1.92 and SEP 3.92, 3.43, and 3.10. Environmental qualifications are in accordance with the May 23, 1980 Commission Order and Memorandum (CLI-80-21).

(11) Provisions to test for operability of the reactor coolant vent system should be a part of the design. Testing should be performed in accordance with subsection IWV of Section XI of the ASME Code for Category B valves.

(12) It is important that the displays and controls added to the control room as a result of this requirement not increase the potential for operator error. A human factor analysis should be performed taking into consideration:

(a) the use of this information by an operator during both normal and abnormal plant conditions,

(b) integration into emergency procedures,

(c) integration into operator training, and

(d) other alarms during emergency and need for prioritization of alarms.

B. BWR Design Considerations

(1) Since the BWROG has suggested that the present BWR designs have an inherent capability to vent, a question relating to the capability of existing systems arises. The ability of these systems to vent the RCS of noncondensable gas generated during an accident must be demonstrated. Because of differences among the head vent systems for BWRs, each licensee or applicant should address the specific design features of this plant and compare them with the generic venting capability proposed by the BWROG. In addition, the ability of these systems to meet the same requirements as the PWR vent system must be documented.

(2) In addition to RCS venting, each BWR licensee should address the ability to vent other systems, such as the isolation condenser which may be required to maintain adequate core cooling. If the production of a large amount of noncondensable gas would cause the loss of function of such a system, remote venting of that system is required. The qualifications of such a venting system should be the same as that required for PWR venting systems.

Response

The BWROG position on NUREG-0737, Item II.B.1 requirements for RCS vents is contained in D.B. Waters (BWROG) letter to D.G. Eisenhut (NRC) dated April 24, 1981, D.B. Waters (BWROG) letter to D.G. Eisenhut (NRC) dated October 8, 1980, and T.D. Keenan (BWROG) letter to D.G. Eisenhut (NRC) dated October 17, 1979. The licensee concurs with the BWROG conclusion that adequate RCS venting capability is provided by the existing plant design. The following is a description of the existing LGS provisions for RCS venting and an assessment of this capability relative to the NUREG-0737 position and clarification.

Position (1)

LGS is provided with five power-operated, safety-grade SRVs (ADS valves PSV-41-F013E, H, K, M, and S) that would be the primary means of venting noncondensable gases from the RPV following a LOCA. The point of connection of the vent lines to the vessel is such that accumulation of gases above this elevation in the vessel will not inhibit natural circulation cooling of the reactor core. These ADS valves are self-actuating at their set relieving pressure to provide system overpressure protection and can also be actuated automatically or manually from the control room to depressurize the reactor. Operation of the ADS valves requires only safety-grade equipment and controls and does not require any source of offsite or ac power. The valves are controlled by dc power from the safeguard batteries and are pneumatically actuated from individual safety-grade accumulators and a safety-grade nitrogen bottle supply for long-term operation. Additional information regarding the design, qualification, power source, etc., of the SRVs is presented in Sections 5.1, 5.2.2, 6.2, 6.3, 7.3, 9.3.1.3, and 15.

Although the power-operated, safety-grade SRVs discussed above satisfy the NUREG-0737 requirements, the following other means of venting noncondensables from the RPV exist:

a) Nine other SRVs (PSV-41-F013 A-D, F, G, J, L, and N) are provided. These valves are identical to those used for ADS except that they are not equipped for automatic actuation or provided with safety-grade air supplies. They may be individually operated from the control room provided that the normal instrument air supply is available. Normally open reactor head vent line 2"- DBA-108 discharges to main steam line "C", which can then be vented to the suppression pool by opening any of the three SRVs on that line.

b) Normally closed reactor vessel head vent valves (2"-HV-41-F001 and F002) are provided. These motor- operated valves are operable from the control room, provided that the normal power supplies are available. The head vent lines discharge to the drywell equipment drain tank.

c) The main steam-driven HPCI and RCIC system turbines exhaust to the suppression pool. These will function automatically to ensure adequate core cooling, as discussed in Sections 6.3 and 5.4 and, in the process, provide continuous venting of noncondensables to the suppression pool during their operation. The effect of noncondensables in the HPCI and RCIC turbine steam has been analyzed and the results are described in the D.B. Waters (BWROG) letter to D.G. Eisenhut (NRC) dated April 24, 1981.

The effects of inadvertent opening of a SRV or both head vent valves would be the same as a small steam line break. A complete steam line break is part of the plant's design basis, and smaller size breaks have been shown to be of lesser severity. A number of reactor system blowdowns due to SORV have confirmed this. Similarly, a break in any of the systems enumerated above would be less severe than a complete steam line break. Because the results of the complete steam line break analysis have demonstrated compliance with the acceptance criteria of 10CFR50.46, no new analyses are required to show conformance with 10CFR50.46 for vent line failures.

Position (2)

In the development of the BWR EPG, this issue was considered. The EPG regarding reactor vessel level control addresses all contingent actions required to maintain RPV level. These actions include venting for all instances when the accumulation of noncondensables may be of concern. Further discussion of this issue is contained in the D.B. Waters (BWROG) letter to D.G. Eisenhut (NRC) dated April 24, 1981.

Clarification A(1)

The automatic and/or manual operation of the RCS vent paths described above provides effective venting capability to deal with large quantities of noncondensable gas. This venting capability will preclude the possibility of noncondensable gas accumulation interfering with core cooling.

Clarification A(2)

The BWR EPG include provisions for RCS venting for all instances when the accumulation of noncondensables may be of concern. This topic is further discussed in the D.B. Waters (BWROG) letter to D.G. Eisenhut (NRC) dated April 24, 1981. As stated in the response to Position (1), the use of these vent paths or their failure will not result in a violation of the requirements of 10CFR50.46.

An analysis demonstrating that the direct venting of noncondensable gases into the primary containment will not result in violation of combustible gas concentration limits is presented in Section 6.2.5. The gas generation rates assumed in this analysis are in accordance with 10CFR50.44 and Regulatory Guide 1.7.

Clarification A(3)

Because the containments are inerted, and postaccident combustible gas control is maintained by oxygen deficiency, the LGS design is insensitive to the rate or extent of metal-water reaction up to the point where containment pressurization is limiting. This point is substantially beyond the present Regulatory Guide 1.7 design basis as demonstrated by the conservative assessment of this margin provided in Sections 6.2.1.3.4 and 6.2.5.

Further consideration will be given to the impact of combustible gas source terms beyond the present design basis in response to the proposed NRC degraded core rulemakings.

Clarification A(4)

As stated in the response to Position (1), a failure of one of the above vents would result in the equivalent of a small steam line break LOCA.

Clarification A(5)

SRV position indication is provided in the control room by the acoustic monitoring system described in Section 7.6.1.5. Direct position indication is provided in the control room for the HPCI, RCIC, and head vent valves.

Clarification A(6)

Each SRV, HPCI, RCIC, and head vent valve may be individually operated from the control room.

Clarification A(7)

All design requirements for the RCPB have been met in the design of appropriate portions of each vent path described above. Because inadvertent operation of a vent path will cause only a minor plant transient as described in the response to Position (1), redundancy is not felt to be necessary. Compliance with 10CFR50.46 is assured for all events as described in the response to Position (1).

Clarification A(8)

Block valves are not provided on the SRV lines in accordance with the clarification. The isolation provisions for the HPCI and RCIC steam lines will withstand a single active failure. Such provisions are not felt to be necessary for the head vent valves for the reasons discussed in the response to clarification A(7).

Clarification A(9)

The point within primary containment to which noncondensables are vented is not of concern because the containment is inerted and effective mixing is assured. Mixing of gases within the primary containment is discussed in Section 6.2.5.2.3.

Clarification A(10)

The equipment, piping, controls, and position indication associated with the ADS SRV and HPCI vent paths described above have been environmentally qualified in accordance with Commission Order and Memorandum CLI-80-21 and seismically analyzed as described in Chapter 3. Portions of the RCIC and the head vent line required for venting are also designed to withstand seismic accelerations. The RCIC valves are environmentally qualified to achieve containment isolation.

Clarification A(11)

The SRVs and the HPCI and RCIC steam valves are tested in accordance with 10CFR50, Appendix J and the intent of subsection IWV of Section XI of the ASME B&PV Code.

Clarification A(12)

This clarification does not apply because no new equipment is being provided to meet the RCS venting requirements.

Clarification B(1)

The information provided above and in the referenced letters demonstrates that the LGS ADS SRVs meet all of the BWROG implementation criteria and NRC requirements for RCS venting.

Clarification B(2)

The following ECCS are available for maintenance of reactor vessel water level at LGS.

a. HPCI

b. RCIC

c. LPCI

d. CS

None of the operating modes of the above systems require venting other than from the reactor vessel.

LGS is not equipped with isolation condensers.

- II.B.2 PLANT SHIELDING

The information in the position and response is historical and represents the original plant design requirements based on source terms consistent with TID-14844. The application of Alternative Source Terms (AST) per Regulatory Guide 1.183 has resulted in the re-assessment of control room and off-site radiological consequences from design basis accidents. Shielding design remains on the TID-14844 source terms; however, Regulatory Guide 1.183 source terms may be used for re-evaluations.

Position

With the assumption of a postaccident release of radioactivity equivalent to that described in Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors," and Regulatory Guide 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors" (i.e., the equivalent of 50% of the core radioiodine, 100% of the core noble gas inventory, and 1% of the core solids are contained in the primary coolant), each licensee shall perform a radiation and shielding design review of the spaces around systems that may, as a result of an accident, contain highly radioactive materials. The design review should identify the location of vital areas and equipment, such as the control room, radwaste control stations, emergency power supplies, MCCs, and instrument areas, in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded by the radiation fields during postaccident operations of these systems.

Each licensee shall provide for adequate access to vital areas of protection of safety equipment by design changes, increased permanent or temporary shielding, or postaccident procedural controls. The design review shall determine which types of corrective actions are needed for vital areas throughout the facility.

Clarification

The purpose of this item is to ensure that licensees examine their plants to determine what actions can be taken over the short-term to reduce radiation levels and increase the capability of operators to control and mitigate the consequences of an accident. The actions should be taken pending conclusions resulting in the long-term degraded core rulemaking, which may result in a need to consider additional sources.

Any area which will or may require occupancy to permit an operator to aid in the mitigation of or recovery from an accident is designated as a vital area. For purposes of this evaluation, vital areas and equipment are not necessarily the same vital areas or equipment defined in 10CFR73.2 for security purposes. The security center is listed as an area to be considered as potentially vital, since access to this area may be necessary to take action to give access to other areas in the plant.

The control room, TSC, sampling station, and sample analysis area must be included among those areas where access is considered vital after an accident. (Refer to section III.A.1.2 of this report for discussion of the TSC and EOF.) The evaluation to determine the necessary vital areas should also include, but not be limited to, consideration of the post-LOCA hydrogen control system, containment isolation reset control area, manual ECCS alignment area (if any), MCCs, instrument panels, emergency power supplies, security center, and radwaste control panels. Dose rate determinations need not be for these areas if they are determined not to be vital.

As a minimum, necessary modification must be sufficient to provide for vital system operation and for occupancy of the control room, TSC, sampling station, and sample analysis area.

In order to assure that personnel can perform necessary postaccident operations in the vital areas, the following guidance is to be used by licensees to evaluate the adequacy of radiation protection to the operators:

(1) Source Term

The minimum radioactive source term should be equivalent to the source terms recommended in Regulatory Guides 1.3, 1.4, 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident," and SRP 15.6.5 with appropriate decay times based on plant design (i.e., assuming the radioactive decay that occurs before fission products can be transported to various systems).

(a) Liquid-Containing Systems: 100% of the core equilibrium noble gas inventory, 50% of the core equilibrium halogen inventory, and 1% of all others are assumed to be mixed in the reactor coolant and liquids recirculated by RHR, HPCI, and LPCI, or the equivalent of these systems. In determining the source term for recirculated, depressurized cooling water, assuming that the water contains no noble gases.

(b) Gas-Containing Systems: 100% of the core equilibrium noble gas inventory and 25% of the core equilibrium halogen activity are assumed to be mixed in the containment atmosphere. For vapor-containing lines connected to the primary system (e.g., BWR steam lines), the concentration of radioactivity shall be determined assuming the activity is contained in the vapor space in the primary coolant system.

(2) Systems Containing the Source

Systems assumed in your analysis to contain high levels of radioactivity in a postaccident situation should include, but not be limited to, containment, RHR system, safety injection systems, chemical and volume control system, containment spray recirculation system, sample lines, gaseous radwaste systems, and SGTS (or equivalent of these systems). If any of these systems or others that could contain high levels of radioactivity were

excluded, you should explain why such systems were excluded. Radiation from leakage of systems located outside of containment need not be considered for this analysis. Leakage measurement and reduction is treated under section III.D.1.1, "Primary Coolant Outside Containment." Liquid waste systems need not be included in this analysis. Modifications to liquid waste systems will be considered after completion of section III.D.1.4, "Radwaste System Design Features To Aid in Accident Recovery and Decontamination."

(3) Dose Rate Criteria

The design dose objectives for personnel in a vital area should be such that the guidelines of GDC 19 will not be exceeded during the course of the accident. GDC 19 requires that adequate radiation protection be provided such that the dose to personnel should not be in excess of 5 rem whole body, or its equivalent to any part of the body for the duration of the accident. When determining the dose to an operator, care must be taken to determine the necessary occupancy times in a specific area. For example, areas requiring continuous occupancy will require much lower dose rates than areas where minimal occupancy is required. Therefore, allowable dose rates will be based upon expected occupancy, as well as the radioactive source terms and shielding. However, in order to provide a general design objective, we are providing the following dose rate criteria with alternatives to be documented on a case-by-case basis. The objectives dose rates are average rates in the area. Local hot spots may exceed the dose rate guidelines. These doses are design objectives and are not to be used to limit access in the event of an accident.

(a) Areas Requiring Continuous Occupancy: <15 mrem/hr (averaged over 30 days). These areas will require full-time occupancy during the course of the accident. The control room and onsite TSC are areas where continuous occupancy will be required. The dose rate for these areas is based on the control room occupancy factors contained in SRP 6.4.

(b) Areas Requiring Infrequent Access: GDC 19. These areas may require access on an irregular basis, not continuous occupancy. Shielding should be provided to allow access at a frequency and duration estimated by the licensee. The plant radiochemical/chemical analysis laboratory, radwaste panel, motor control center, instrumentation locations, and reactor coolant and containment gas sample stations are examples of sites where occupancy may be needed often, but not continuously.

(4) Radiation Qualification of Safety-Related Equipment

The review of safety-related equipment which may be unduly degraded by radiation during postaccident operation of this equipment relates to equipment inside and outside of the primary containment. Radiation source terms calculated to determine environmental qualification of safety-related equipment consider the following:

(a) LOCA events which completely depressurize the primary system should consider releases of the source term (100% noble gases, 50% iodines, and 1% particulates) to the containment atmosphere.

(b) LOCA events in which the primary system may not depressurize should consider the source term (100% noble gases, 50% iodines, and 1% particulates) to remain in the primary coolant. This method is used to determine the qualification doses for equipment in close proximity to recirculating fluid systems inside and outside of containment. Non-LOCA events both inside and outside of containment should use 10% noble gases, 10% iodines, and 0% particulate as a source term. Table 1.13-6 summarizes these considerations.

Response

A. Introduction

The design review of plant radiation and shielding was performed as required by NUREG-0737 Item II.B.2 and is described below. The purpose of the review was to identify potential problem areas and equipment which may require the development of special postaccident procedures, installation of additional permanent or temporary shielding, relocation of components or piping, or requalification of components.

Areas that are vital for postaccident occupancy or operation and all safety-related equipment were evaluated to determine if access and performance of required operator activities or equipment functions might be unduly impaired due to the presence of the postulated radiation source in the selected systems. Systems required or postulated to process highly radioactive fluids or gases outside the containment during postaccident conditions were selected for evaluation. Radiation levels in adjacent plant areas due to contained sources in piping and equipment of these systems were estimated. Airborne sources caused by leakage from the primary containment and systems containing postaccident sources were also included in the evaluation for vital areas as described below.

The identification of vital areas and a summary of the methodology used to determine radiation doses for these areas and to equipment are presented below. Doses to personnel in vital areas and access paths are listed in Tables 1.13-1 and 1.13-2, respectively. The identification of essential equipment, doses to equipment used for qualification purposes, and the results of the review of equipment for the postulated radiation sources are provided in the separate EQR. The results of the shielding design review for vital areas are provided below in Section H.

B. Vital Area Identification

Areas which may require occupancy to permit an operator to aid in the mitigation of or recovery from an accident are designated as vital areas. A review of LGS was made which determined that the following areas should be designated vital areas.

Continuous Occupancy

1) Main Control Room

2) Technical Support Center

3) Operations Support Center

4) Security Center

Infrequent Occupancy

1) Counting Room

2) Radiochemistry laboratory

3) Postaccident sampling station

4) North stack instrument room

5) HVAC panels at el 304'

6) Radwaste control room

7) Diesel generator area

Potential vital areas that are not listed above were excluded for the following reasons. The post-LOCA hydrogen control (recombiner) system and containment isolation valves are all automatic or remotely controlled by the operator in the main control room and require no local access. There is no manual ECCS alignment area at LGS. Instrument panels and MCCs are not included because the control and alignment of essential systems are accomplished from the main control room and require no local action.

Eleven access paths to vital areas were also identified and included in this review.

C. Selection of Systems for Radiation and Shielding Review

A review was made to determine which systems could be required to operate and/or could be expected to contain highly radioactive materials following an accident where substantial core damage has occurred. The results of this review are presented below.

1. CS, HPCI, RCIC, RHR, and Safeguard Piping Fill Systems.

The CS, RHR, HPCI (water side), RCIC (water side), and safeguard piping fill systems would contain suppression pool water being injected to the RCS. Although the HPCI and RCIC systems could also carry condensate, suppression pool water was assumed for this review for conservatism. The steam sides of the HPCI and RCIC systems would operate on reactor steam.

2. RHR System (Shutdown Cooling Mode)

The RHR system recirculates reactor water when it operates in the shutdown cooling mode. Before operation in this mode can be initiated, the reactor must be depressurized to less than 75 psig. This depressurization is expected to remove substantially all of the noble gases released into the reactor water. Following an accident, the HPCI, RCIC, RHR (LPCI mode), and CS systems would inject water into the RCS. This water from the condensate tank and/or the suppression pool

would dilute the reactor water prior to the initiation of shutdown cooling with the RHR system. This review assumed that there are no noble gases in the reactor water in the RHR system for the shutdown cooling mode and that the reactor water is diluted by the suppression pool water volume.

3. CRD System

The operation of the CRD system was reviewed to determine if the scram discharge headers will contain highly radioactive water following an accident. It was determined that they will not. Prior to a scram, the CRD housings contain condensate water delivered by the CRD pumps. When a scram occurs, some of this condensate water from the CRD is discharged to the scram discharge header. After the scram, some condensate and reactor water flows to the scram discharge header until it is completely filled. This takes a matter of seconds. Since the vents and drains in the scram discharge header are isolated by the scram, all discharge flow then stops.

Since it is not reasonable to assume that significant core damage occurs in the first few seconds following a scram, the scram discharge header will contain only a mixture of condensate and preaccident reactor water following this postulated accident.

4. RWCU System

For an accident with resulting core damage, the RWCU system would be isolated and would contain no highly radioactive materials beyond the second isolation valve. On a BWR this system is not needed for RCS venting. It would not be practical to use it for accident recovery after a major accident. It was therefore assumed that this system would not operate with highly contaminated reactor water.

5. Gaseous Radwaste System

For an accident with resulting core damage, it would not be practical to use the gaseous radwaste system for accident recovery. Noble gas isotopes with long lives would cause excessive offsite doses if the gaseous radwaste system was used after a design basis accident. It was therefore assumed that this system would not operate.

6. Postaccident Sampling System

Sampling lines used after an accident would contain primary containment gas, secondary containment gas, reactor coolant (pressurized or depressurized) or suppression pool water, depending on the sampling line take-off location.

7. Containment Atmospheric Control System

The recombiner system and associated H_2-O_2 analyzer lines would recirculate primary containment gas after an accident in order to keep hydrogen and oxygen concentrations at acceptable levels.

8. SGTS and RERS

The SGTS and RERS would collect airborne activity in the secondary containment following an accident. Radioactivity would be collected on the filters and charcoal beds in these systems.

9. Containment

The free volume of the primary containment is assumed to initially contain large amounts of postaccident activity. These sources, as well as those assumed for the suppression pool, are described below. Shine through the drywell and wetwell walls would cause a negligible increase to the secondary containment airborne and piping doses, and therefore was not included in this review.

10. MSIV Leakage Alternate Drain Pathway

Following the accident, the MSIV Leakage Alternate Drain Pathway will be aligned. The sources associated with this pathway are discussed below. Shine through the turbine condenser shield wall is considered negligible and therefore, was not included in this review.

D. Source Release Fractions

The following release fractions were used as a basis for determining the concentrations for the radiation and shielding review:

Source A:	Containment atmosphere:	100% noble gases, 25% halogens
Source B:	Suppression pool liquid:	50% halogens, 1% solids
Source C:	Reactor steam:	100% noble gases, 25% halogens
Source D:	Pressurized reactor coolant:	100% noble gases, 50% halogens, 1% solids

These release fractions were applied to the total curies available for the particular chemical species (i.e., noble gas, halogen, or solid) for an equilibrium fission product inventory for a light-water reactor core.

E. Source Term Models

The assumptions used for release fractions for the radiation and shielding design review are outlined above. These release fractions are, however, only the first step in modeling the source terms for the activity concentrations in the systems under review. The decay time and dilution volume also affect the rationale for the selection of values for these parameters.

1. Decay Time

For conservatism, no decay time credit was taken for the radioactive decay that might occur before fission products would be transported to the various systems.

2. Dilution Volume

The volume used for dilution is important, affecting the calculations of dose rate in a linear fashion. The following dilution volumes were used with the release fractions listed above in Section D to arrive at the final source terms for the shielding reviews.

Source A: Drywell and suppression pool free air volumes.

Source B: The volume of the RCS (based on reactor coolant density at the operating temperature and pressure) plus the suppression pool water volume.

Source C: The total reactor system steam volume.

Source D: The volume of the RCS.

3. Contained Sources and Drywell and Secondary Containment Airborne Sources

In defining the contained sources, accident operating modes were assumed for each system. In defining the limits of the connected piping subject to contamination listed below, normally shut valves were assumed to remain shut.

- CS system - Source B
- HPCI system

  Liquid - Source B

  Steam - Source C (with credit for steam specific activity reduction due to turbine operation).

- RCIC system

  Liquid - Source B
  Steam - Source C (with credit for steam specific activity reduction due to turbine operation).

- RHR system - Source B (all modes)
- Postaccident Sampling Lines

  Gas sample lines - Source A
  Liquid sample lines - Source D

- Containment Atmospheric Control (Recombiner) System - Source A (Drywell free volume only)
- Drywell - Source A
- MSIV Leakage Alternate Drain Pathway – Source C
- SGTS, RERS, and Secondary Containment Activity

The following major assumptions were used to calculate the secondary containment airborne radiation doses and the radiation doses for the SGTS filters and the RERS filters.

a. 100% of the noble gases and 25% of the halogens are available for leakage into the secondary containment.

b. The primary to secondary containment leak rate is 0.5% per day.

c. Airborne activity in the secondary containment is confined to spaces below the refueling floor for normal reactor enclosure/refueling area HVAC alignment. Other alignments have been evaluated to provide additional flexibility during refueling operations.

d. The RERS flow rate is two secondary containment air changes per hour.

e. The SGTS flow rate is one air change per day. (For equipment qualification of equipment in the reactor enclosure, the secondary containment airborne doses and RERS filter doses were conservatively based on an SGTS flow rate of one-half air change per day. This results in a longer holdup time and therefore higher doses. For equipment qualification of the SGTS and equipment in the vicinity, an SGTS flow of one air change per day was used.)

f. The RERS charcoal filter is 95% efficient with respect to halogens.

g. The SGTS charcoal filter is 100% efficient with respect to halogens for filter loading.

h. The activity inventory in the core was based on 1000 days burnup and daughter product formation was not considered. These assumptions, which have off-setting effects, were necessitated by limitations in the computer code used to treat the transport of activity from primary to secondary containment.

i. The capacities of the RERS and SGTS filters are sufficient to sustain cleanup for the duration of the accident.

j. Deleted

4. Airborne Sources for Vital Areas

All the vital areas and access paths are located in the turbine enclosure, radwaste enclosure, control structure, administration building, diesel generator enclosure, TSC, and yard areas. The transport pathway of the airborne sources in these areas consists of leakage from the primary containment to the reactor enclosure, and discharge to the environment via the RERS and the SGTS. The airborne activity discharged then re-enters the buildings through the ventilation intake systems after dilution within the building wake cavity.

The assumptions used in calculating the released airborne activity are the same as those listed in Section 3 above the secondary containment except that an SGTS flow rate of one air change per day and the technical specification minimum filter efficiencies are used to maximize the activity released (i.e. RERS is 95%, and SGTS is 99%, efficient). Also, an assumed 5 gpm systems leakage (at suppression pool activity concentration) to the secondary containment is included in the analysis.

The atmospheric dispersion factors (X/Q), along with their calculation basis, are given in Section 15.10 Section 15.10.2.2 “Control Room Dose Module” includes the main control room, HVAC panels, and the north stack instrument room. The X/Q's for the other vital areas are analyzed using the modified Halitsky X/Q methodology. This methodology is discussed below.

J. Halitsky's efforts summarized in Reference 1.13-1 present the basic equation as follows:

$$X/Q = K/A\bar{u}$$

where:

A = cross-sectional area, M^2 orthogonal to u

$\bar{u}$ = wind speed, m/s

K = isopleth (Concentration coefficient - dimensionless)

It is found in many cases that the above Halitsky equation still provides a reasonable estimate of X/Q. Several correction factors can be applied to this equation to account for situation and plant specific features, such as:

- Stream line flows are used in most wind tunnel tests
- Release points are generally much higher than 10 meters above ground
- Null wind velocity is observed at certain periods of time
- Isothermal temperatures are used in wind tunnel tests
- Buoyancy and jet momentum effects are ignored
- Typical 1 hr field tests account for plume meander effects while 3-5 minute wind tunnel tests do not.

A modified Halitsky X/Q methodology was thus formulated and is presented below.

$$X/Q = \frac{K}{\bar{\bar{u}}} \bullet f_1 \bullet f_2 \bullet f_3 \bullet f_4 \bullet f_5 \bullet f_6 \ (sec/m^3)$$

As a test of the modified Halitsky method, calculated values of X/Q, without using factors f_4 and f_5 due to their uncertainty, were compared to the 1 hour field test X/Q data from Rancho Seco (Reference 1.13-3). Only one X/Q was found to be higher than the calculated value. This was due to an external wake influence caused by wind channeling between the nearby cooling towers. The wind channeling prevented the normal wake turbulence and variation effects over time, which normally spread the plume over a wide area. In most cases the modified Halitsky X/Q was found to be a conservative estimate of the measured X/Q; in some cases it was significantly higher.

The choice of K factors and the suggested modifying factors f_1, f_2, etc, are discussed below.

K factors: The choice of an appropriate K factor from the wind tunnel test data is critical for the X/Q estimate to be valid. Halitsky, in Reference 1.13-1, has several sets of K isopleths for round topped containments (PWRs) and block buildings (BWRs). Multiple building complexes must be simulated by single equivalent structures. The effluent velocity to wind speed ratio of approximately 1 is valid for most power plant systems. Various angles of wind incidence are shown to account for vortexing which could result in worse conditions than a wind normal to the building face. K factors should be estimated for various combinations of wind incidence angle and the appropriate effective building cross-sectional area causing the wake (not just the containment area) to determine the peak value as was done by Walker (Reference 1.13-4).

Wind speed (□): Halitsky's K values are based on wind speeds measured at the top of the containment or building. Therefore, the Reference 1.13-2 five percentile wind speed at a 10 meter height should be adjusted to the actual speed at the top of containment or release point. The five percentile wind speed is adjusted using the formulation presented by Wilson (Reference 1.13-5) as follows:

$$\overline{u}_T = \overline{u}\left(\frac{Z}{Z_{Ref}}\right)$$

where:

$\overline{u}_T$ = wind speed at height Z

Z_{Ref} = 10 meters (five percentile wind speed reference height)

Wind speed change factor (f_1), and Wind direction change factor (f_2): The factor supplied from Reference 1.13-2, shown below, were used.

Time Periods	f_1	f_2
0 - 8 hrs	1	1
8 - 24 hrs	.67	.88

24 - 96 hrs	.50	.75
96 - 720 hrs	.33	.50
720 hrs & on	.25	.33

Wind turbulence effect (f_3): Wilson (Reference 1.13-5) and field tests confirm Halitsky's statement that his K isopleths are a factor of 5 to 10 too conservative due to not accounting for random fluctuations of the wind approaching the building. Therefore, a factor of 0.2 was used for f_3.

Elevated release effect (f_4): Bouwmeester (Reference 1.13-6) indicates that there are up to 10 null wind speed conditions during an hour of data collection. During these periods the effects of jet momentum, plume rise, and buoyancy would result in the radioactive effluent being discharged above the effective wake boundary and thus not entering the wake cavity. A reduction factor of 1 was used.

Time average effects (f_5): Wind speed variations and wind direction meandering effects are not modeled in wind tunnel tests to account for this effect. Reference 1.13-6 indicates the use of the following equation:

$$C_p = C_m \left(\frac{t_p}{t_m}\right)^{-1/2}$$

where:

C_p = prototype concentration

C_m = model concentration

t_p = prototype sampling time

t_m = model equivalent sampling time

Normal wind tunnel data is taken for 3 to 10 minute samples. Thus, for a 1 hour field test, C_p = .22 to .41 C_m and for an 8 hour field test, C_p = .08 to .14 C_m. A value of 0.5 was conservatively assumed for f_5.

Adjustment to top of stack (f_6): To account for wind speed at the top of the stack instead of the Reference 1.13-2 five percentile wind speed at 10 meters height, the factor $f_6 = \bar{u} / \bar{u}_T$ was included. The f_6 value equals 0.66.

The resultant X/Q (sec/m^3) calculated for each of the vital areas except for the main control room, HVAC panels and north stack instrument room (control room X/Q calculated in Section 15.10 was used) are thus shown in Table 1.13-7.

For the MSIV Leakage Alternate Drain Pathway, the F_6 factor is 1.0, since the release point is not an elevated release point.

F. Radiation Dose Calculation

1. Primary and Secondary Containment Doses

The sources described above in Section E were used to estimate doses from the systems included in the radiation and shielding design review. No vital areas are located in the primary or secondary containments, thus the doses described in this section were used for equipment qualification purposes only.

Both gamma and beta post-LOCA doses were calculated for the primary containment. The doses were calculated by assuming that 100% of the core noble gas inventory and 50% of the core halogen inventory are released. These source terms are consistent with those specified in NUREG-0588 and NUREG-0737.

The primary containment airborne dose calculations assumed that 50% of the 50% (i.e. 25%) halogen release from the core plates out instantaneously, as assumed implicitly in Regulatory Guide 1.3 (Rev 2). The airborne doses were calculated assuming source terms diluted by the primary containment (drywell and wetwell) free volume. These assumptions are consistent with those specified in NUREG-0737.

The beta doses and dose rates for qualification of equipment were calculated assuming an infinite cloud geometry. The beta doses and dose rates for qualification of coatings were calculated assuming a semi-infinite cloud geometry.

For components inside primary containment the total integrated gamma doses were calculated by adding the post-LOCA primary containment gamma cloud dose to the 40 year normal operating dose. Dose distance relationships were not used to reduce post-LOCA doses inside primary containment.

Both gamma and beta post-LOCA doses were also calculated for the secondary containment, based on the source terms described above in Section E. For compartments inside the secondary containment, the post-LOCA gamma radiation levels were conservatively determined by adding the maximum piping contact dose in that compartment to the secondary containment gamma cloud dose. The total integrated gamma dose was then determined by adding the post-LOCA integrated dose to the 40 year normal operating integrated dose. The equipment qualification levels for all safety-related electrical components were compared to the applicable calculated dose. For those components initially listed as inadequately qualified, more detailed

calculations were performed, taking into account dose/distance relationships in order to determine more realistic doses. A set of dose/distance curves for each system was developed as part of this effort.

2. Doses in Other Plant Areas for Equipment Qualification

Doses for specified areas outside the secondary containment were also calculated as described below, for equipment qualification purposes. For the SGTS equipment compartment, the post-LOCA gamma dose is the contact dose of the SGTS filters. For the remaining areas, the post-LOCA gamma doses were determined by adding the cloud, filter and piping shine doses from adjacent compartments and the control structure cloud dose, as applicable. These post-LOCA doses were added to the normal operating integrated dose to

determine the total integrated gamma doses. Beta doses outside secondary containment would be negligible for equipment qualification purposes, and therefore they were not calculated.

3. Vital Area and Access Path Doses

Calculations were performed to determine airborne and shine doses from the sources described above in Section E to the vital areas and access paths. These doses were used to determine personnel exposures, using occupancy factors as described below in Section G. For radiation doses due to direct shine, credit was taken for attenuation through the walls and due to distance. For airborne doses, both gamma and beta contributions were included. In the access path airborne dose calculations for the yard area routes, the most conservative X/Q bounding that route was used.

G. Personnel Exposure Limits

The general basis for personnel radiation exposure guidelines was GDC 19. The following additional radiation limit guidelines were used to evaluate occupancy and accessibility of plant vital areas and access paths.

Radiation Exposure Guidelines

Occupancy	Dose Objective
Continuous	≤ Rem for duration
Infrequent	≤ Rem for all activities
Accessway	≤ 10 Rem/hr

These dose objectives are for personnel access only.

Emergency Response Procedures specify the criteria for radiological habitability monitoring to insure the dose objectives are not exceeded. Based on the results of the habitability monitoring personnel in the affected areas may be instructed to don protective devices or limit stay times to maintain the dose objectives.

The dose rate received by personnel in vital areas of continuous occupancy should be <15 mrem/h (average over 30 days). The doses for these areas were determined using the control room occupancy factors contained in SRP 6.4, as discussed in NUREG-0737, i.e., 1.0 for 0-1 day; 0.6 for 1-4 days; and 0.4 for over 4 days.

The dose received by personnel in an infrequent occupancy of vital areas and access paths is determined by taking into account the frequency and duration of the activities anticipated for that area, and is consistent with GDC 19 limits. Average area dose rates are used to determine personnel exposure, although local hot spots may exist.

H. Results of Dose Calculations

1. Environmental Qualification of Equipment

Normal operating radiation doses and conservative post-LOCA gamma and beta doses are provided in the Equipment Qualification Report and its references for all

areas containing safety-related equipment. Equipment was reviewed against these doses or, if necessary, against reduced doses calculated as described above in Section F.1. The results of the review of equipment are provided in the EQR.

2. Personnel Access

The reactor enclosure and refueling floor will be inaccessible after a design basis LOCA. However, this does not present a problem since they do not contain any vital areas requiring operator access. The non-LOCA reactor enclosure will be accessible.

Doses to the vital areas described above in Section B from the sources described above in Section E are provided in Table 1.13-1. The dose objective of Table 1.13-1 are not used to limit access in the event of an accident.

Dose rates for vital area access paths are provided in Table 1.13-2. These access paths are given in Table 1.13-5.

The airborne and direct shine doses must be added together to show the total dose to personnel in the vital areas and access paths.

Peak shine dose rates are provided in Table 1.13-1 along with the integrated doses. The dose rate at any given time for a vital area can be estimated by multiplying the peak dose rate by an appropriate factor which can be determined by using the curves in Figures 1.13-1 and 1.13-2.

Potential problem areas that were identified in the design review of plant shielding are listed in Table 1.13-3, along with the solutions that will be followed for these areas.

I. Conclusion

Areas and safety-related equipment vital for postaccident occupancy or operation were identified, and postaccident doses were calculated in accordance with the requirements of NUREG-0737. Also in Table 1.13-3, potential problem areas were identified, and solutions for these problems were determined. No additional shielding is required as a result of this study.

- II.B.3 POST ACCIDENT SAMPLING

The information in the position and response is historical and represents the original plant design requirements based on source terms consistent with TID-14844. The application of Alternative Source Terms (AST) per Regulatory Guide 1.183 has resulted in the re-assessment of control room and off-site radiological consequences from design basis accidents. See UFSAR Chapter 15 for additional information.

Position

A design and operational review of the reactor coolant and containment atmosphere sampling line systems shall be performed to determine the capability of personnel to promptly obtain (less than 1 hour) a sample under accident conditions without incurring a radiation exposure to any individual in excess of 3 and 18¾ rem to the whole body or extremities, respectively. Accident conditions should assume a Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential

Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors," or Regulatory Guide 1.4 "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactor" release of fission products. If the review indicates that personnel could not promptly and safely obtain samples, additional design features or shielding should be provided to meet the criteria.

A design and operational review of the radiological spectrum analysis facilities shall be performed to determine the capability to promptly quantify (in less than 2 hours) certain radionuclides that are indicators of the degree of core damage. Such radionuclides are noble gases which indicate cladding failure and isotopes which indicate fuel melting. The initial reactor coolant spectrum should correspond to a Regulatory Guide 1.3 or Regulatory Guide 1.4 release. The review should also consider the effects of direct radiation from piping and components in the auxiliary building and possible contamination and direct radiation from airborne effluents. If the review indicates that the analyses required cannot be performed in a prompt manner with existing equipment, then design modifications or equipment procurement shall be undertaken to meet the criteria.

In addition to the radiological analyses, certain chemical analyses are necessary for monitoring reactor conditions. Procedures shall be provided to perform boron and chloride chemical analyses assuming a highly radioactive initial sample (Regulatory Guide 1.3 or Regulatory Guide 1.4 source term). Both analyses shall be capable of being completed promptly (i.e., the boron sample analysis within an hour and the chloride sample analysis within a shift).

Clarification

The following items are clarifications of requirements identified in NUREG-0578, NUREG-0660, or the September 13, 1979, October 30, 1979, September 5, 1980 and October 31, 1980 clarification letters.

(1) The applicant shall have the capability to promptly obtain reactor coolant samples and containment atmosphere samples. The combined time allotted for sampling and analysis should be 3 hours or less from the time a decision is made to take a sample.

(2) The applicant shall establish an onsite radiological and chemical analysis capability to provide, within the 3 hour time frame established above, quantification of the following:

   (a) Certain radionuclides in the reactor coolant and containment atmosphere that may be indicators of the degree of core damage (e.g., noble gases, iodines and cesiums, and nonvolatile isotopes);

   (b) Hydrogen levels in the containment atmosphere;

   (c) Dissolved gases (e.g., hydrogen), chloride (time allotted for analysis subject to discussion below), and boron concentration of liquids; and

   (d) Alternatively, have inline monitoring capabilities to perform all or part of the above analyses.

(3) Reactor coolant and containment atmosphere sampling during postaccident conditions shall not require an isolated auxiliary system (e.g., the letdown system, reactor water cleanup system) to be placed in operation in order to use the sampling system.

(4) Pressurized reactor coolant samples are not required if the applicant can quantify the amount of dissolved gases with unpressurized reactor coolant samples. The measurement of either total dissolved gases or hydrogen gas in reactor coolant samples is considered adequate. Measuring the oxygen concentration is recommended, but is not mandatory.

(5) The time for a chloride analysis to be performed is dependent upon two factors: (a) if the plant's coolant water is seawater or brackish water, and (b) if there is only a single barrier between primary containment systems and the cooling water. Under both of the above conditions, the applicant shall provide for a chloride analysis within 24 hours of the sample being taken. For all other cases, the applicant shall provide for the analysis to be completed within 4 days. The chloride analysis does not have to be done onsite.

(6) The design basis for plant equipment for reactor coolant and containment atmosphere sampling and analysis must assume that it is possible to obtain and analyze a sample without radiation exposures to any individual exceeding GDC 19 (i.e., 5 rem whole body, 75 rem extremities).

(7) If inline monitoring is used for any sampling and analytical capability specified herein, the applicant shall provide backup sampling through grab samples, and shall demonstrate the capability of analyzing the samples. Established planning for analysis at offsite facilities is acceptable. Equipment provided for backup sampling shall be capable of providing at least one sample per day for 7 days following onset of the accident and at least one sample per week until the accident condition no longer exists.

(8) The applicant's radiological and chemical sample analysis capability shall include provisions to:

(a) Identify and quantify the isotopes of the nuclide categories discussed above to levels corresponding to the source terms given in Regulatory Guides 1.3 or Regulatory Guide 1.4 and Regulatory Guide 1.7, "Control of Combustible Gas Concentration in Containment Following a Loss-of-Coolant Accident." Where necessary and practicable, the ability to dilute samples to provide capability for measurement and reduction of personnel exposure should be provided. Sensitivity of onsite liquid sample analysis capability should be such as to permit measurement of nuclide concentration in the range from approximately 1 μCi/g to 10 Ci/g.

(b) Restrict background levels of radiation in the radiological and chemical analysis facility from sources such that the sample analysis will provide results with an acceptably small error (approximately a factor of 2). This can be accomplished through the use of sufficient shielding around samples and outside sources, and by the use of ventilation system design which will control the presence of airborne radioactivity.

(9) Accuracy, range, and sensitivity shall be adequate to provide pertinent data to the operator in order to describe radiological and chemical status of the RCS.

(10) In the design of the postaccident sampling and analysis capability, consideration should be given to the following items:

(a) Provisions for purging sample lines, for reducing plateout in sample lines, for minimizing sample loss or distortion, for preventing blockage of sample lines by loose material in the RCS or containment, for appropriate disposal of the samples, and for flow restrictions to limit reactor coolant loss from a rupture of the sample line. The postaccident reactor coolant and containment atmosphere samples should be representative of the reactor coolant in the core area and the containment atmosphere following a transient or accident. The sample lines should be as short as possible to minimize the volume of fluid to be taken from containment. The residues of sample collection should be returned to containment or to a closed system.

(b) The ventilation exhaust from the sampling station should be filtered with charcoal adsorbers and high efficiency particulate air filters.

(11) If gas chromatography is used for reactor coolant analysis, special provisions (e.g., pressure relief and purging) shall be provided to prevent high pressure argon from entering the reactor coolant.

(12) Applicants should provide a description of the implementation of the position and clarification including pipe and instrumentation drawings, together with either (a) a summary description of procedures for sample collection, sample transfer or transport, and sample analysis, or (b) copies of procedures for sample collection, sample transfer or transport, and sample analysis, in accordance with the proposed review schedule but in no case less than 4 months prior to the issuance of an operating license. A postimplementation review will be performed.

Response

Provisions for postaccident reactor coolant and containment atmosphere sampling and analysis are described in Sections 6.2.5, 7.5.1 and 11.5.5.

Limerick license amendment numbers 166/129 approved the elimination of the requirement to have and maintain the Post Accident Sampling System. The following items were committed to as part of the license amendment numbers 166/129.

1. Limerick has developed contingency plans for obtaining and analyzing highly radioactive samples of reactor coolant, suppression pool, and containment atmosphere. The contingency plans are contained in the Limerick chemistry procedures. Establishment of contingency plans is considered a regulatory commitment.

2. The capability for classifying fuel damage events at the Alert level threshold has been established at a level of core damage associated with radioactivity levels of 300 micro-curies/gm dose equivalent iodine in the primary coolant system. This capability is described in Limerick's emergency plans and emergency plan implementing procedures. The capability for classifying fuel damage is considered a regulatory commitment.

3. Limerick has established the capability to monitor radioactive iodines that have been released offsite to the environs. This capability is described in the emergency plans and emergency plan implementing procedures. The capability to monitor radioactive iodines is considered a regulatory commitment.

The following information contained in the UFSAR regarding the regulatory requirements for post accident sampling is retained for historical purposes.

A grab sample system designed by GE is provided. Radiological spectrum and chemical analysis capabilities have been established to ensure that the appropriate analyses can be performed in a timely manner.

Shielding requirements and source terms used will be consistent with those used for the Design Review of Plant Shielding, discussed under Item no. II.B.2.

- II.B.4 TRAINING FOR MITIGATING CORE DAMAGE

Position

We require that the applicant develop a program to ensure that all operating personnel are trained in the use of installed plant systems to control or mitigate an accident in which the core is severely damaged. They must then implement the training program.

Clarification

STAs and operating personnel from the plant manager through the operations chain to the licensed operators shall receive this training. The training program shall include the following topics:

(1) Incore Instrumentation

(a) Use of fixed or movable incore detectors to determine extent of core damage and geometry changes.

(b) Use of thermocouples in determining peak temperatures; methods for extended range readings; methods for direct readings at terminal junctions.

(2) Excore Nuclear Instrumentation

(a) Use of excore nuclear instrumentation for determination of void formation; void location basis for excore nuclear instrumentation response as a function of core temperatures and density changes.

(3) Vital Instrumentation

(a) Instrumentation response in an accident environment; failure sequence (time to failure, method of failure); indication reliability (actual versus indicated level).

(b) Alternative methods for measuring flows, pressures, levels, and temperatures.

(i) Determination of pressurizer level if all level transmitters fail.

(ii) Determination of letdown flow with a clogged filter (low flow).

(iii) Determination of other RCS parameters if the primary method of measurement has failed.

(4) Primary Chemistry

(a) Expected chemistry results with severe core damage; consequences of transferring small quantities of liquid outside containment; importance of using leak-tight systems.

(b) Expected isotopic breakdown for core damage; for clad damage.

(c) Corrosion effects of extended immersion in primary water; time to failure.

(5) Radiation Monitoring

(a) Response of process and area monitors to severe damage; behavior of detectors when saturated; method for detecting radiation readings by direct measurement at detector output (overranged detector); expected accuracy of detectors at different locations; use of detectors to determine extent of core damage.

(b) Methods of determining dose rate inside containment from measurements taken outside containment.

(6) Gas Generation

(a) Methods of hydrogen generation during an accident; other sources of gas (Xe, Kr); techniques for venting or disposal of noncondensables.

(b) Hydrogen flammability and explosive limit; sources of oxygen in containment or RCS.

Managers and technicians in the instrumentation and control, health physics, and chemistry departments shall receive training commensurate with their responsibilities.

Response

The lesson plan for the training program for mitigating core damage was developed prior to fuel loading, and training completed prior to full power operation. The course outline is presented below.

Core Cooling Mechanics
- Alternate methods of core cooling
- Core spray and core flooding
- Heat removal paths
- Boron precipitation
- Fuel cladding quenching
- Limiting core conditions
- Steam and water cooling

Potentially Damaging Operating Conditions
- Vulnerable plant operating conditions

Core cooling with systems unavailable

Gas/Steam Binding Affecting Core Cooling
- Sources of gas/steam vapor
- Symptoms/effects of gas/steam binding

Recognizing Core Damage
- Data collection, instrumentation, and systems
- Fuel/clad behavior
- Reporting requirements

Core Recriticality
- Reactor Shutdown margin
- Maintaining subcriticality
- SLCS
- Instrumentation response

Hydrogen Hazards During Accidents
- Sources of hydrogen and oxygen
- Hazardous concentrations and reduction
- Gas venting

Monitoring Critical Parameters During Accident Conditions
- Parameter identification
- Instrumentation reliability, accuracy, and failure

Radiation Hazards and Radiation Monitor Response
- Emergency plan implementation
- High radiation areas
- Sampling
- Radiation monitor response and failure

Criteria for Operation and Cooling Mode Selection
- Core cooling procedures
- Core cooling equipment and methods

STAs and operating personnel from the Station Superintendent through the operations chain including the licensed operators receive this training.

Other plant managerial personnel and technicians in the instrumentation and control, health physics, and chemistry groups also receive training commensurate with their responsibilities during accident conditions.

- II.D.1 RELIEF AND SAFETY VALVE TEST REQUIREMENTS

Position

PWR and BWR licensees and applicants shall conduct testing to qualify the RCS relief and safety valves under expected operating conditions for design basis transients and accidents.

Clarification

Licensees and applicants shall determine the expected valve operating conditions through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70 (Rev 2). The single failures applied to these analyses shall be chosen so that the dynamic forces on the safety and relief valves are maximized. Test pressures shall be the highest predicted by conventional safety analysis procedures. RCS relief and safety valve qualification shall include qualification of associated control circuitry, piping, and supports, as well as the valves themselves.

(1) Performance Testing of Relief and Safety Valves - The following information must be provided in report form:

(a) Evidence supported by test of safety and relief valve functionability for expected operating and accident (non-ATWS) conditions must be provided to NRC. The testing should demonstrate that the valves will open and reclose under the expected flow conditions.

(b) Since it is not planned to test all valves on all plants, each licensee must submit to NRC a correlation or other evidence to substantiate that the valves tested in the EPRI or other generic test program demonstrate the functionability of as-installed primary relief and safety valves. This correlation must show that the test conditions used are equivalent to expected operating and accident conditions as prescribed in the FSAR. The effect of as-built relief and safety valve discharge piping on valve operability must be accounted for, if it is different from the generic test loop piping.

(c) Test data including criteria for success and failure of valves tested must be provided for NRC staff review and evaluation. These test data should include data that would permit plant specific evaluation of discharge piping and supports that are not directly tested.

(2) Qualification of PWR block valves - Although not specifically listed as a short-term lessons learned requirement in NUREG-0578, qualification of PWR block valves is required by the NRC Task Action Plan NUREG-0660 under task Item II.D.1. It is the understanding of the NRC that testing of several commonly used block valve designs is already included in the generic EPRI PWR safety and relief valve testing program to be completed by July 1, 1981. By means of this letter, NRC is establishing July 1, 1982 as the date for verification of block valve functionability. By July 1, 1982, each PWR licensee, for plants so equipped, should provide evidence supported by test that the block or isolation valves between the pressurizer and each power-operated relief valve can be operated, closed, and opened for all fluid conditions expected under operating and accident conditions.

(3) ATWS Testing - Although ATWS testing need not be completed by July 1, 1981, the test facility should be designed to accommodate ATWS conditions of approximately 3200 to 3500 (Service Level C pressure limit) pounds per square inch and 700°F with sufficient capacity to enable testing of relief and safety valves of the size and type used on operating PWRs.

Response

The licensee participated in the BWROG program to test SRVs. The test program has been successfully completed and is described in Reference 1.13-8. The applicability of the test results to the LGS valves is described in appendix A of Reference 1.13-8.

An engineering evaluation was done to identify the expected operating conditions for SRVs during design basis transients and accidents. This evaluation identified one event for which testing was appropriate. This event, the alternate shutdown cooling mode, is an anticipated operating condition that has been considered in the design analysis (Section 5.4.7.5).

The test results documented in the topical report verify the adequacy of the LGS valve operation and integrity under the expected discharge conditions. The loads on the valve and piping induced by the liquid discharge were shown to be lower than the high pressure steam discharge loads for which the system is designed. The test results also provide flow capacity information to show that sufficient shutdown cooling flow is provided through one or two valves, dependent on reactor and system conditions. Clarification Items (2) and (3) are not applicable to BWRs.

- II.D.3 RELIEF AND SAFETY VALVE POSITION INDICATION

Position

RCS relief and safety valves shall be provided with a positive indication in the control room derived from a reliable valve position detection device or a reliable indication of flow in the discharge pipe.

Clarification

(1) The basic requirement is to provide the operator with unambiguous indications of valve position (open or closed) so that appropriate operator actions can be taken.

(2) The valve position should be indicated in the control room. An alarm should be provided in conjunction with this indication.

(3) The valve position indication may be safety-grade. If the position indication is not safety-grade, a reliable single channel direct indication, powered from a vital instrument bus, may be provided if backup methods of determining valve position are available and are discussed in the emergency procedures as an aid to operator diagnosis of an action.

(4) The valve position indication should be seismically qualified consistent with the component or system to which it is attached.

(5) The position indication should be qualified for its appropriate environment (any transient or accident which would cause the relief or safety valve to lift) and in accordance with Commission Order of May 23, 1980 (CLI-80-21).

(6) It is important that the displays and controls added to the control room as a result of this requirement not increase the potential for operator error. A human factor analysis should be performed taking into consideration:

    (a) the use of this information by an operator during both normal and abnormal plant conditions,

(b) integration into emergency procedures,

(c) integration into operator training, and

(d) other alarms during emergency and need for prioritization of alarms.

Response

An acoustic monitoring system that meets the requirements of NUREG-0737 and Regulatory Guide 1.97 is provided for LGS (Sections 7.6.1.5 and 7.6.2.5). The system is designed to the following general requirements:

a. A reliable, single channel, direct indication system is provided.

b. The individual valve position (OPEN/CLOSED) is displayed in the control room. In conjunction with this indication, a third indication signifies that the individual valve has been open. These lights are located above each SRV control switch. An alarm is provided in the control room to annunciate when any valve is open.

c. The position indications are powered from a highly reliable non-Class 1E power source (Section 8.3.1.1.1).

A diverse means of valve position indication as specified in the EOPs is provided by the redundant safety-grade suppression pool temperature monitoring system. This is powered from a Class 1E power source.

d) All valve position system components are seismically qualified except for the power supply.

e) All valve position system components located in a potentially harsh environment qualified for a LOCA environment.

f) A human factors analysis was performed to integrate this new information into the control room. The individual OPEN/CLOSED/WAS OPEN indication is located above the SRV control switch.

The WAS OPEN indication was added to aid the operator in determining which valve has opened when a relief valve instantaneously opens on high pressure and closes immediately. This indication is also used to aid the operator in sequencing the relief valves when the reactor is manually depressurized.

Additional human factors aspects were considered during the CRDR required by Item I.D.1.

- II.E.1.1 AUXILIARY FEEDWATER SYSTEM EVALUATION

Response

These requirements are not applicable to BWRs.

- II.E 1.2 AUXILIARY FEEDWATER SYSTEM INITIATION AND FLOW

Response

This requirement is not applicable to BWRs.

- II.E.3.1 EMERGENCY POWER FOR PRESSURIZER HEATERS

Position

Consistent with satisfying the requirements of GDC 10, 14, 15, 17, and 20 for the event of LOOP, the following positions shall be implemented.

(1) The pressurizer heater power supply design shall provide the capability to supply, from either the offsite power source or the emergency power source (when offsite power is not available), a predetermined number of pressurizer heaters and associated controls necessary to establish and maintain natural circulation at hot standby conditions. The required heaters and their controls shall be connected to the emergency buses in a manner that will provide redundant power supply capability.

(2) Procedures and training shall be established to make the operator aware of when and how the required pressurizer heaters shall be connected to the emergency buses. If required, the procedures shall identify under what conditions selected emergency loads can be shed from the emergency power source to provide sufficient capacity for the connection of the pressurizer heaters.

(3) The time required to accomplish the connection of the preselected pressurizer heater to the emergency buses shall be consistent with the timely initiation and maintenance of natural circulation conditions.

(4) Pressurizer heater motive and control power interfaces with the emergency buses shall be accomplished through devices that have been qualified in accordance with safety-grade requirements.

Clarification

(1) Redundant heater capacity must be provided, and each redundant heater or group of heaters should have access to only one Class 1E division power supply.

(2) The number of heaters required to have access to each emergency power source is that number required to maintain natural circulation in the hot standby condition.

(3) The power sources need not necessarily have the capacity to provide power to the heaters concurrently with the loads required for LOCA.

(4) Any changeover of the heaters from normal offsite power to emergency onsite power is to be accomplished manually in the control room.

(5) In establishing procedure to manually load the pressurizer heaters onto the emergency power sources, careful consideration must be given to:

(a) which ESF loads may be appropriately shed for a given situation;

(b) reset of the safety injection actuation signal to permit the operation of the heaters; and

(c) instrumentation and criteria for operator use to prevent overloading a diesel generator.

(6) The Class 1E interfaces for main power and control power are to be protected by safety-grade circuit breakers (see also Regulatory Guide 1.75).

(7) Being non-Class 1E loads, the pressurizer heaters must be automatically shed from the emergency power sources upon the occurrence of a safety injection actuation signal (see item 5.b, above).

Response

This requirement is applicable to PWRs only. Because the BWR operates in all modes with both liquid and steam in the RPV, saturation conditions are always maintained irrespective of system pressure. There is no need for emergency power to maintain natural circulation or to keep the system pressurized.

The LGS power-operated MSRVs can be actuated using emergency power and have no block valves. They are described in Section 5.2.2. They are nitrogen-operated valves, with their normal gas supply coming from the PCIG compressors, which are described in Section 9.3.1.3. Standby ac power is available to the PCIG compressors following a LOOP.

The MSRVs are provided with gas accumulators described in Section 5.2.2.4, for reliable short-term operation without PCIG system operation. A safety-grade gas bottle supply system, described in Section 9.3.1.3, is available for long-term MSRV operation.

Safety-grade reactor vessel level indication is provided in the control room in accordance with Regulatory Guide 1.97 (Rev 2). Additional information is provided in Section 7.5.

- II.E.4.1 DEDICATED HYDROGEN CONTROL PENETRATIONS

Position

Plants using external recombiners or purge systems for postaccident combustible gas control of the containment atmosphere should provide containment penetration systems for external recombiner or purge systems that are dedicated to that service only, that meet the redundancy and single failure requirements of GDC 54 and 56 and that are sized to satisfy the flow requirements of the recombiner or purge system.

The procedures for the use of combustible gas control systems following an accident that results in a degraded core and release of radioactivity to the containment must be reviewed and revised, if necessary.

Clarification

(1) An acceptable alternative to the dedicated penetration is a combined design that is single failure proof for containment isolation purposes and single failure proof for operation of the recombiner or purge system.

(2) The dedicated penetration or the combined single failure proof alternative shall be sized such that the flow requirements for the use of the recombiner or purge system are satisfied. The design shall be based on 10CFR50.44 requirements.

(3) Components furnished to satisfy this requirement shall be safety-grade.

(4) Licensees that rely on purge systems as the primary means for controlling combustible gases following a LOCA should be aware of the positions taken in Reference 1.13-9. This proposed rule, published in the Federal Register on October 2, 1980, would require plants that do not now have recombiners to have the capacity to install external recombiners by January 1, 1982. (Installed internal recombiners are an acceptable alternative to the above.)

(5) Containment atmosphere dilution systems are considered to be purge systems for the purpose of implementing the requirements of this TMI Task Action item.

Response

The containment hydrogen recombiner system, described in Sections 6.2.5 and 9.4.5, is used for postaccident combustible gas control. The recombiners are permanently installed external to the primary containment and are remotely operated from the control room. The design of the containment penetrations associated with the hydrogen recombiner system is single failure proof for containment isolation purposes during system operation and single failure proof for operation of the recombiner system.

LGS complies with each of the points of clarification as described below.

(1) The containment isolation arrangement uses a combined type of design which is single failure proof as permitted by this clarification item. The hydrogen recombiner supply and return lines connect to the high volume purge lines outside the primary containment. Each high volume purge line is provided with redundant, normally closed isolation valves installed in series outboard of the connection point with the hydrogen recombiner lines. This redundancy ensures that isolation of the high volume purge lines remains single failure proof during operation of the recombiners. Each supply and return line for the hydrogen recombiners is provided with two, normally closed containment isolation valves in series. Because two valves in series are provided, the failure of an isolation valve in the open position would not jeopardize containment integrity. The provision of two redundant hydrogen recombiner packages ensures that the recombination function can be performed in the event of a failure of an isolation valve in the closed position.

(2) The recombiner supply and return lines have been sized such that the flow requirements of the recombiners are satisfied for the full range of possible containment pressures that may exist during the time period when the recombiners are required to operate.

(3) As discussed in Section 9.4.5.1.3, the hydrogen recombiner packages, their associated piping, and the containment isolation provisions for the recombiner lines and the containment purge lines are designed as safety-related.

(4) LGS does not rely on a purge system as the primary means for controlling combustible gases following a LOCA.

(5) LGS does not use a containment air dilution system for combustion gas control.

- II.E.4.2 CONTAINMENT ISOLATION DEPENDABILITY

Position

(1) Containment isolation system designs shall comply with the recommendations of SRP Section 6.2.4 (i.e., that there be diversity in the parameters sensed for the initiation of containment isolation).

(2) All plant personnel shall give careful consideration to the definition of essential and nonessential systems, identify each system determined to be essential, identify each system determined to be nonessential, describe the basis for selection of each essential system, modify their containment isolation designs accordingly, and report the results of the reevaluation to the NRC.

(3) All nonessential systems shall be automatically isolated by the containment isolation signal.

(4) The design of control systems for automatic containment isolation valves shall be such that resetting the isolation signal will not result in the automatic reopening of containment isolation valves. Reopening of containment isolation valves shall require deliberate operator action.

(5) The containment setpoint pressure that initiates containment isolation for nonessential penetrations must be reduced to the minimum compatible with normal operating conditions.

(6) Containment purge valves that do not satisfy the operability criteria set forth in BTP CSB 6-4 or the Staff Interim Position of October 23, 1979 must be sealed closed as defined in SRP 6.2.4., item II.3.f during operational conditions 1, 2, 3, and 4. Furthermore, these valves must be verified to be closed at least every 31 days.

(7) Containment purge and vent isolation valves must close on a high radiation signal.

Clarification

(1) The reference to SRP 6.2.4 in position 1 is only to the diversity requirements set forth in that document.

(2) For postaccident situations, each nonessential penetration (except instrument lines) is required to have two isolation barriers in series that meet the requirements of GDC 54, 55, 56, and 57, as clarified by SRP Section 6.2.4. Isolation must be performed automatically

(i.e., no credit can be given for operator action). Manual valves must be sealed closed, as defined by SRP Section 6.2.4, to qualify as an isolation barrier. Each automatic isolation valve in a nonessential penetration must receive the diverse isolation signals.

(3) Regulatory Guide 1.141 (Rev 2) will contain guidance on the classification of essential versus nonessential systems and is due to be issued by June 1981. Requirements for operating plants to review their list of essential and nonessential systems will be issued in conjunction with this guide including an appropriate time schedule for completion.

(4) Administrative provisions to close all isolation valves manually before resetting the isolation signals is not an acceptable method of meeting position 4.

(5) Ganged reopening of containment isolation valves is not acceptable. Reopening of isolation valves must be performed on a valve-by-valve basis, or on a line-by-line basis, provided that electrical independence and other single failure criteria continue to be satisfied.

(6) The containment pressure history during normal operation should be used as a basis for arriving at an appropriate minimum pressure setpoint for initiating containment isolation. The pressure setpoint selected should be far enough above the maximum observed (or expected) pressure inside containment during normal operation so that inadvertent containment isolation does not occur during normal operation from instrument drift or fluctuations due to the accuracy of the pressure sensor. A margin of 1 psi above the maximum expected containment pressure should be adequate to account for instrument error. Any proposed values greater than 1 psi will require detailed justification. Applicants for an operating license and operating plant licensees that have operated less than one year should use pressure history data from similar plants that have operated more than one year, if possible, to arrive at a minimum containment setpoint pressure.

(7) Sealed closed purge isolation valves should be under administrative control to assure that they cannot be inadvertently opened. Administrative control includes mechanical devices to seal or lock the valve closed, or to prevent power from being supplied to the valve operator. Checking the valve position light in the control room is an adequate method for verifying every 24 hours that the purge valves are closed.

Response

A description of compliance with each Position and Clarification is provided below.

Position (1), Clarification (1)

The containment isolation system design has been reviewed for compliance with SRP 6.2.4 regarding diversity in the parameters sensed for the initiation of containment isolation. Section 6.2.4 and Table 6.2-17 identify all containment isolation signals provided. There are eleven valves classified as nonessential that do not receive diverse containment isolation signals.

Two valves on the feedwater lines (HV-109A, HV-109B) are normally closed and will be opened only for startup of the feedwater system before the control rods are withdrawn or when performing hydrostatic testing of the RPVs during unit shutdown.

The RCIC vacuum pump discharge line is provided with a stop-check valve (HV-F002) to prevent flow from the containment. A remote manually actuated motor operator ensures the long-term positive closure of the stop-check valve. This arrangement ensures that the essential RCIC pump-turbine will be ready to operate in the event of a reactor vessel isolation occurrence accompanied by loss of feedwater flow.

The recirculation pump cooling water supply and discharge isolation valves (HV-106, HV-107) and the drywell chilled water isolation valves (HV-122, HV-123, HV-128, HV-129) have provisions for remote manual isolation consistent with GDC 57. Closure of these isolation valves is undesirable unless the cooling water lines have failed.

The HPCI and RCIC steam supply line warmup valves (HV-F100, HV-F076, respectively) are provided with appropriate isolation signals to secure the line when system isolation is required. There is no adverse consequence associated with the valve opening or leaking while these systems are in operation.

The main steam drain line isolation valves (HV-F016, F019) are normally closed during power operation. They provide a path from the steam lines to the main condenser for removal of condensation during shutdown and startup periods and during periods of low load. The six automatic isolation signals provided for these valves are the same as those provided for the MSIVs.

The main steam and recirculation loop sample line isolation valves (HV-F084, F085 and HV-F019, F020, respectively) are typically open less than 1 hour per year during normal plant operations. The two isolation signals which are provided for these valves ensure their automatic closure before any fuel damage would occur for all anticipated periods of sample line use.

The RWCU supply line isolation valves (HV-F001, F004) are provided with the following signals to initiate automatic valve closure:

a. Reactor low water level

b. Line break in RWCU
   high flow
   heat exchanger high temperature
   compartment high temperature

c. SLCS operation

These isolation signals are provided to protect the core in case of a possible break in the RWCU, to protect the ion exchange resin from damage due to high temperature, and to prevent the removal of boron by the ion exchange resin.

The RWCU system is described in Section 5.4.8. Closing times of the RWCU isolation valves have been chosen to prevent the reactor vessel water level from falling below the top of active fuel if a break were to occur in any of the RWCU lines. Diverse isolation signals are supplied to isolate the RWCU in the unlikely event of such a line break. The system is intentionally left in service whenever the above isolation signals are not activated to provide continuous purification of a portion of the recirculation flow.

Position (2), Clarification (3)

All systems penetrating containment have been evaluated and identified as either essential or nonessential. Table 6.2-17 provides the results of this evaluation for each line, and Table 6.2-27 provides the basis for the selection of essential/nonessential systems.

Position (3), Clarification (2)

Systems determined to be nonessential are provided with diverse, automatic isolation signals, except as described in the response to Position (1). Manual valves are sealed closed as discussed in Section 6.2.4.3.

Position (4), Clarifications (4), (5)

The control systems for automatic isolation valves are such that resetting the isolation signal will not result in the automatic reopening of these valves. The HPCI and RCIC steam line isolation valves are exceptions as discussed in Section 7.1.2.11. Ganged reopening of containment isolation valves is performed only where the operation of multiple valves is required for system operation. Sample inlet and return valve controls for the drywell radiation monitors and combustible gas analyzers are ganged as described in Sections 6.2.4.3.1.3.2.8 and 6.2.4.3.1.3.2.1. RECW and drywell chilled water valve controls are ganged as described in Sections 6.2.4.3.1.3.2.10 and 6.2.4.3.1.3.2.11.

Position (5), Clarification (6)

The setpoint for the drywell high pressure isolation signal is set at the minimum compatible with normal operation. Section 7.3.1.1.2.4.6 describes the selection of the drywell high pressure setpoint.

Position (6), Clarification (7)

Containment purge valves comply with BTP CSB 6-4 as discussed below and in Sections 9.4.5.1. Two purge isolation valves have closure times greater than 6 seconds (2"-HV-105 and 2"-HV-111 have closure times of 15 seconds). An analysis of the radiological consequences of a LOCA that occurs during purging was performed to justify the line size and the valve closure time used in the purge system. Using the assumptions of BTP CSB 6-4, the resulting doses were a small fraction of the 10CFR100 limits. For local leak rate tests, the leakage rate of the purge isolation valves, combined with the leakage rate for all other penetrations and valves subject to Type B and C tests will be less than 0.60 La, in accordance with 10CFR50, Appendix J.

Position (7)

The containment purge isolation valves isolate on receipt of any one of the following safety-related isolation signals:

a. high drywell pressure

b. reactor low water level

c. reactor enclosure high radiation

d. refueling floor high radiation

In addition to the safety-related isolation signals listed above, the containment purge and vent isolation valves (HV-114, 115, 104, 112, 123, 124, 135, 147, 121, 131, 109) will isolate on receipt of a nonsafety-related north stack effluent high radiation signal (Sections 6.2.4.3 and 11.5).

The setpoint of the isolation signal (approximately 4 μCi/cc) has been selected to ensure valve closure before offsite doses exceed EPA Protective Action Guide Level 2 limits (1 rem whole body/5 rem thyroid). Containment purging will not be undertaken during periods of power operation when this monitor is out of service unless a temporary replacement of equivalent sensitivity is used. Provisions are included in the Technical Specifications for periodic instrument calibrations and channel checks.

An analysis has been performed to demonstrate that the offsite doses that might result if a LOCA were to occur during purging operations would be less than both 10CFR100 and EPA Protection Action Guide limits. This analysis used the assumptions of SRP Section 6.2.4 and BTP CSB 6-4 and assumes a pre-existing spike that results in coolant activity levels in excess of Technical Specification limits. The analysis methodology was in accordance with Reference 1.13-10.

- II.F.1 ACCIDENT MONITORING INSTRUMENTATION

ATTACHMENT 1, Noble Gas Effluent Monitor

Position

The requirements associated with this recommendation should be considered as advanced implementation of certain requirements to be included in a revision to Regulatory Guide 1.97, "Instrumentation to Follow the Course of an Accident," which has already been initiated, and in other Regulatory Guides, which will be promulgated in the near-term.

Noble gas effluent monitors shall be installed with an extended range designed to function during accident conditions as well as during normal operating conditions. Multiple monitors are considered necessary to cover the ranges of interest.

(1) Noble gas effluent monitors with an upper range capacity of 10^5 μCi/cc (Xe-133) are considered to be practical and should be installed in all operating plants.

(2) Noble gas effluent monitoring shall be provided for the total range of concentration extending from normal condition (ALARA) concentrations to a maximum of 10^5 μ/Ci/cc (Xe-133). Multiple monitors are considered to be necessary to cover the ranges of interest. The range capacity of individual monitors should overlap by a factor of 10.

It is important that the displays and controls added to the control room as a result of this requirement not increase the potential for operator error. A human factor analysis should be performed taking into consideration:

(1) The use of this information by an operator during both normal and abnormal plant conditions;

(2) Integration into emergency procedures;

(3) Integration into operator training; and

(4) Other alarms during emergency and need for prioritization of alarms.

Clarification

NUREG-0578, section 2.1.8b provided the basic requirements for this item. Letters dated September 27, 1979 and November 9, 1979, provided clarification and NUREG-0660, Item II.F.1 provided the action plan for additional accident monitoring instrumentation by noble gas effluent radiological monitor requirements. Additional clarification was provided by letters dated September 5, 1980 and October 31, 1980.

By summary clarification, the following guidelines were established:

(1) Applicants shall provide continuous monitoring of high level postaccident releases of radioactive noble gases from the plant. Gaseous effluent monitors shall meet requirements specified in Table 1.13-8. Typical plant effluent pathways to be monitored are also given in the table.

(2) The monitors shall be capable of functioning both during and following an accident. System designs shall accommodate a design basis release and then be capable of following decreasing concentrations of noble gases.

(3) Offline monitors are not required for the PWR secondary side main steam safety valve and dump valve discharge lines. For this application, externally mounted monitors viewing the main steam line upstream of the valves are acceptable with procedures to correct for the low energy gammas the external monitors would not detect. Isotopic identification is not required.

(4) Instrumentation ranges shall overlap to cover the entire range of effluents from normal (ALARA) through accident conditions. The design description shall include the following:

(a) System description, including:

i. instrumentation to be used, including range or sensitivity, energy dependence or response, calibration frequency and technique, and vendor's model number, if applicable;

ii. monitoring locations (or points of sampling), including description of methods used to assure representative measurements and background correction;

iii. location of instrument readout(s) and method of recording, including description of the method or procedure for transmitting or disseminating the information or data;

iv. assurance of the capability to obtain readings at least every 15 minutes during and following an accident; and

v. the source of power to be used.

(b) Description of procedures or calculational methods to be used for converting instrument readings to release rates per unit time, based on exhaust air flow and considering radionuclide spectrum distribution as a function of time after shutdown.

(5) Applicants should have available for review the final design description of the as-built system, including piping and instrument diagrams together with either (a) a description of procedures for system operation and calibration, or (b) copies of procedures for system operation and calibration. Changes to technical specifications will be required. Applicants will submit the above details in accordance with the proposed review schedule, but in no case less than 4 months prior to the issuance of an operating license. A postimplementation review will be performed.

The design description shall include the information provided in Table 1.13-8.

Until final implementation on January 1, 1982, all operating reactors must provide an interim method for quantifying high level releases which meet the requirements of the Table 1.13-8. This method is to serve only as a provisional fix until the accident monitoring instrumentation is installed, calibrated, tested and approved by January 1, 1982. Methods are to be developed to quantify release rates up to 10,000 Ci/sec for noble gases from all potential release points and any other areas that communicate directly with systems which may contain primary coolant or containment gases. Measurements/analysis capabilities of the effluents at the final release point (e.g., stack) should be such

that measurements of individual sources which contribute to the common release point may not be necessary. For noble gases, an acceptable method of meeting the intent of this requirement is to modify the existing monitoring system, such that portable high range survey instruments set in shielded collimators "see" small sections of the sampling lines. The applicant shall provide the following information on its method to quantify gaseous releases of radioactivity from the plant during an accident.

(a) An interim system/method description for noble gas effluents, including:

i. Instrumentation to be used including range or sensitivity, energy dependence, and calibration frequency and technique;

ii. monitoring/sampling locations, including methods to assure representative measurements and background radiation correction;

iii. a description of method to be employed to facilitate access to radiation readings. For January 1, 1981, control room readout is preferred; however, if impractical, in situ readings by an individual with verbal communication with the control room is acceptable based on (iv), below;

iv. capability to obtain radiation readings at least every 15 minutes during an accident; and

v. source of power to be used. If normal alternating current power is used, an alternate backup power supply should be provided. If direct current power is used, the source should be capable of providing continuous readout for 7 consecutive days.

(b) Procedures for conducting all aspects of the measurement/analysis, including:

i. procedures for minimizing occupational exposures;

ii. calculational methods for converting instrument readings to release rates based on exhaust air flow and taking into consideration radionuclide spectrum distribution as function of time after shutdown;

iii. procedures for dissemination of information; and

iv. procedures for calibration.

Response

All reactor enclosure stack releases following an accident will be through the north stack. The wide range accident monitoring subsystem of the north stack effluent monitoring system provides continuous monitoring of postaccident releases of noble gases in accordance with the requirements of Table 1.13-8. The system is described in Sections 7.6 and 11.5.2.2.1, and its piping and instrumentation diagram is provided in drawing M-26. Control room displays provided for this system meet the requirements of Regulatory Guide 1.97 (Rev 2), and are described in Section 7.5. Table 1.13-9 outlines the requirements for an interim method for quantifying releases to be used by operating reactors and therefore is not applicable to LGS. Human factors aspects of TMI Item II.F.1 are considered part of the CRDR required by Item I.D.1.

ATTACHMENT 2, Sampling and Analysis of Plant Effluents

Position

The requirements associated with this recommendation should be considered as advanced implementation of certain requirements to be included in a revision to Regulatory Guide 1.97, "Instrumentation to Follow the Course of an Accident," which has already been initiated, and in other regulatory guides, which will be promulgated in the near-term.

Because iodine gaseous effluent monitors for the accident condition are not considered to be practical at this time, capability for effluent monitoring of radioiodines for the accident condition shall be provided with sampling conducted by adsorption on charcoal or other media, followed by onsite laboratory analysis.

It is important that the displays and controls added to the control room as a result of this requirement not increase the potential for operator error. A human factor analysis should be performed taking into consideration:

(1) The use of this information by an operator during both normal and abnormal plant conditions;

(2) Integration into emergency procedures;

(3) Integration into operator training; and

(4) Other alarms during emergency and need for prioritization of alarms.

Clarification

NUREG-0578, section 3.1.8b provided the basic requirements for this item. Letters dated September 27, 1979 and November 9, 1979, provided clarification, however, NUREG-0660 inadvertently omitted this requirement on the action plan for additional accident monitoring instrumentation by sampling and analysis of plant effluents. Additional clarification was provided by letters dated September 5, 1980 and October 31, 1980.

By summary clarification, the following guidelines were established:

(1) Applicants shall provide continuous sampling of plant gaseous effluent for postaccident releases of radioactive iodines and particulates to meet the requirements of Table 1.13-10. Applicants shall also provide onsite laboratory capabilities to analyze or measure these samples. This requirement should not be construed to prohibit design and development of radioiodine and particulate monitors to provide online sampling and analysis for the accident condition. If gross gamma radiation measurement techniques are used, then provisions shall be made to minimize noble gas interference.

(2) The shielding design basis is given in Table 1.13-10. The sampling system design shall be such that plant personnel could remove samples, replace sampling media and transport the samples to the onsite analysis facility with radiation exposures that are not in excess of GDC 19 of 5 rem whole body exposure and 75 rem to the extremities during the duration of the accident.

(3) The design of the systems for the sampling of particulates and iodines should provide for sample nozzle entry velocities which are approximately isokinetic (same velocity) with expected induct or instack air velocities. For accident conditions, sampling may be complicated by a reduction in stack or vent effluent velocities to below design levels, making it necessary to substantially reduce sampler intake flow rates to achieve the isokinetic condition. Reductions in air flow may well be beyond the capability of available sampler flow controllers to maintain isokinetic conditions; therefore, the staff will accept flow control devices which have the capability of maintaining isokinetic conditions with variations in stack or duct design flow velocity of ±20%. Further departure from the isokinetic condition need not be considered in design. Corrections for an isokinetic sampling conditions, as provided in Appendix C of ANSI 13.1 (1969) may be considered on an ad hoc basis.

(4) Effluent streams which may contain air with entrained water (e.g., air ejector discharge) shall have provisions to ensure that the adsorber is not degraded while providing a representative sample (e.g., heaters).

(5) License applicants should have available for review the final design description of the as-built system, including P&IDs together with either (a) a description of procedures for system operation and calibration, or (b) copies of procedures for system operation and

calibration. Changes to technical specifications will be required. Applicants will submit the above details in accordance with proposed review schedule, but in no case less than 4 months prior to the issuance of an operating license. A postimplementation review will be performed.

Response

Sampling of plant gaseous effluents for postaccident releases of iodines and particulates is provided as part of the wide range accident monitoring subsystem of the north stack effluent radiation monitoring system described in Sections 7.6 and 11.5.2.2.1. The design of onsite laboratory facilities for analysis of these samples is described in Chapter 12. The design of the sampling media and sampling considerations are in conformance with Table 1.13-10. Human factors aspects of TMI Item II.F.1 are considered part of the CRDR required by Item I.D.1.

ATTACHMENT 3, Containment High Range Radiation Monitor

Position

In containment radiation level monitors with a maximum range of 10^8 rad/hr shall be installed. A minimum of two such monitors that are physically separated shall be provided. Monitors shall be developed and qualified to function in an accident environment.

Clarification

(1) Provide two radiation monitor systems in containment which are documented to meet the requirements of Table 1.13-11.

(2) The specification of 10^8 rad/hr in the above position was based on a calculation of postaccident containment radiation levels that include both particulate (beta) and photon (gamma) radiation. A radiation detector that responds to both beta and gamma radiation cannot be qualified to post-LOCA containment environments but gamma-sensitive instruments can be so qualified. In order to follow the course of an accident, a containment monitor that measures only gamma radiation is adequate. The requirement was revised in the October 30, 1979 letter to provide for a photon-only measurement with an upper range of 10^7 R/hr.

(3) The monitors shall be located in containment(s) in a manner as to provide a reasonable assessment of area radiation conditions inside containment. The monitors shall be widely separated so as to provide independent measurements and shall "view" a large fraction of the containment volume. Monitors should not be placed in areas which are protected by massive shielding and should be reasonably accessible for replacement, maintenance, or calibration. Placement high in a reactor building dome is not recommended because of potential maintenance difficulties.

(4) For BWR Mark III containments, two such monitoring systems should be inside both the primary containment (drywell) and the secondary containment.

(5) The monitors are required to respond to gamma photons with energies as low as 60 keV and to provide an essentially flat response for gamma energies between 100 keV and 3 MeV, as specified in Table 1.13-11. Monitors that use thick shielding to increase the

upper range will underestimate postaccident radiation levels in containment by several orders of magnitude because of their insensitivity to low energy gamma and are not acceptable.

Response

The primary containment post-LOCA radiation monitors described in Sections 7.1, 7.6.1, and 11.5.2.3.1 have a maximum range of 1 rad/hr to 10^8 rad/hr and are physically separated. They are designed and qualified to function in an accident environment.

Section 11.5.2.3.1 describes the degree of conformance with Item II.F.1 Attachment 3 and Table 1.13-11. Additional human factors aspects were considered during CRDR required by Item I.D.1.

ATTACHMENT 4, Containment Pressure Monitor

Position

A continuous indication of containment pressure shall be provided in the control room of each operating reactor. Measurement and indication capability shall include three times the design pressure of the containment for concrete, four times the design pressure for steel, and -5 psig for all containments.

Clarification

(1) Design and qualification criteria are outlined in Appendix B of NUREG-0737.

(2) Measurement and indication capability shall extend to 5 pounds per square inch absolute for subatmospheric containments.

(3) Two or more instruments may be used to meet requirements. However, instruments that need to be switched from one scale to another scale to meet the range requirements are not acceptable.

(4) Continuous display and recording of the containment pressure over the specified range in the control room is required.

(5) The accuracy and response time specifications of the pressure monitor shall be provided and justified to be adequate for their intended function.

Response

The containment pressure instrumentation is described in Section 7.5.1. The design and qualification of the instrumentation meets the guidelines of Regulatory Guide 1.97 (Rev 2) and Appendix B of NUREG-0737. The accuracy and maximum response time for the complete recording and indicating monitors conforms to the requirements of ANS 4.5 (1980) paragraphs 6.3.4 and 6.3.5, which is the referenced document of Regulatory Guide 1.97. Additional human factors aspects were considered during CRDR required by Item I.D.1.

ATTACHMENT 5, Containment Water Level Monitor

Position

A continuous indication of containment water level shall be provided in the control room for all plants. A narrow range instrument shall be provided for PWRs and cover the range from the bottom to the top of the containment sump. A wide range instrument shall also be provided for BWRs and shall cover the range from the bottom of the containment to the elevation equivalent to a 600,000 gallon capacity. For BWRs, a wide range instrument shall be provided and cover the range from the bottom to 5 feet above the normal water level of the suppression pool.

Clarification

(1) The containment wide range water level indication channels shall meet the design and qualification criteria as outlined in Appendices B and C. The narrow range channel shall meet the requirements of Regulatory Guide 1.89.

(2) The measurement capability of 600,000 gallons is based on recent plant designs. For older plants with smaller water capacities, licensees may propose deviations from this requirement based on the available water supply capability at their plant.

(3) Narrow range water level monitors are required for all sizes of sumps but are not required in those plants that do not contain sumps inside the containment.

(4) For BWR pressure-suppression containments, the ECCS suction line inlets may be used as a starting reference point for the narrow range and wide range water level monitors, instead of the bottom of the suppression pool.

(5) The accuracy requirements of the water level monitors shall be provided and justified to be adequate for their intended function.

Response

The existing suppression pool water level instrumentation and the compliance with the above position is described in Section 7.5.1 and meets the requirements of Regulatory Guide 1.97 (Rev 2). Additional human factors aspects were considered during CRDR required by Item I.D.1.

ATTACHMENT 6, Containment Hydrogen Monitor

Position

A continuous indication of hydrogen concentration in the containment atmosphere shall be provided in the control room. Measurement capability shall be provided over the range of 0% to 10% hydrogen concentration under both positive and negative ambient pressure.

Clarification

(1) Design and qualification criteria are outlined in Appendix B.

(2) The continuous indication of hydrogen concentration is not required during normal operation. If an indication is not available at all times, continuous indication and recording shall be functioning within 30 minutes of the initiation of safety injection.

(3) The accuracy and placement of the hydrogen monitors shall be provided and justified to be adequate for their intended function.

Response

The existing hydrogen instrumentation and the compliance with the above position is described in Section 7.5.1 and meets the requirements of Regulatory Guide 1.97 (Rev 2). Additional human factors aspects were considered during CRDR required by Item I.D.1.

For Limerick Generating Station, continuous indication and recording will be functioning within 90 minutes of the initiation of safety injection. The basis for this 60 minute extension, is as follows: (1) information provided by the monitors is not immediately required following LOCA, as referenced in the Limerick Hydrogen and Oxygen Generation Analysis, Section 6.2.5.3 of the UFSAR. (2) it is appropriate to delay actions necessary to initiate hydrogen and oxygen monitoring until the immediate actions required of the operating crew, to assure that safety systems are functioning properly and critical safety functions are being accomplished, are complete. This is due to the relative safety significance of ensuring critical safety functions are being accomplished in the initial stages of the accident.

The hydrogen monitors have been downgraded to non-safety related as described in NRC Letter to Exelon Nuclear, Subject: "Limerick Generating Station, Units 1 and 2 Issuance of Amendment Re: Elimination of Requirements for Hydrogen Recombiners and Hydrogen/Oxygen Monitors (TAC Nos. MC2741 and MC2742)," dated 04/13/05. With the elimination of the Design Basis LOCA hydrogen release, hydrogen monitors are no longer required to mitigate DBAs and, therefore, do not meet the definition of safety related. However, because hydrogen monitors are required to diagnose the course of beyond DBAs, each licensee should verify that it has made a regulatory commitment to maintain a hydrogen monitoring system capable of diagnosing beyond DBAs.

The 0% - 10% hydrogen concentration range is discussed in NUREG-0737, from which the Attachment 6, Position and Clarification was obtained. See NUREG-0737 11.F 1, Attachment 6 for more information.

Measurement capability over the range of 0% to 10% hydrogen concentration is acceptable as the High Hydrogen Alarm setpoint (4%) falls within this range. Figures 6.2-42/43 show that the Drywell Hydrogen concentration will only exceed 10%, at least 8 days after a LOCA, with no hydrogen control. With recombiner operation at 150 scfm or a 150 scfm purge, hydrogen levels in the drywell will not exceed 4%. Figures 6.2-42/43 show that the Suppression Pool Hydrogen concentration will not exceed 4% for at least 30 days after a LOCA.

- II.F.2 INSTRUMENTATION FOR DETECTION OF INADEQUATE CORE COOLING

Position

Licensees shall provide a description of any additional instrumentation or controls (primary or backup) proposed for the plant to supplement existing instrumentation (including primary coolant saturation monitors) in order to provide an unambiguous, easy-to-interpret indication of ICC. A description of the functional design requirements for the system shall also be included. A description of the procedures to be used with the proposed equipment, the analysis used in developing these procedures, and a schedule for installing the equipment shall be provided.

Clarification

(1) Design of new instrumentation should provide an unambiguous indication of ICC. This may require new measurements or a synthesis of existing measurements which meet design criteria (item 7).

(2) The evaluation is to include reactor water level indication.

(3) Licensees and applicants are required to provide the necessary design analysis to support the proposed final instrumentation system for ICC and to evaluate the merits of various instruments to monitor water level and to monitor other parameters indicative of core cooling conditions.

(4) The indication of ICC must be unambiguous in that it should have the following properties:

(a) It must indicate the existence of ICC caused by various phenomena (i.e., high void fraction-pumped flow as well as stagnant boil-off); and

(b) It must not erroneously indicate ICC because of the presence of an unrelated phenomenon.

(5) The indication must give advanced warning of the approach of ICC.

(6) The indication must cover the full range from normal operation to complete core uncovery. For example, water level instrumentation may be chosen to provide advanced warning of two-phase level drop to the top of the core and could be supplemented by other indicators such as incore and core-exit thermocouples provided that the indicated temperatures can be correlated to provide indication of the existence of ICC and to infer the extent of core uncovery. Alternatively, full range level instrumentation to the bottom of the core may be employed in conjunction with other diverse indicators such as core-exit thermocouples to preclude misinterpretation due to any inherent deficiencies or inaccuracies in the measurement system selected.

(7) All instrumentation in the final ICC system must be evaluated for conformance to Appendix B of NUREG-0737, "Clarification of TMI Action Plan Requirements," as clarified or modified by the provisions of items 8 and 9 that follow. This is a new requirement.

(8) If a computer is provided to process liquid level signals for display, seismic qualification is not required for the computer and associated hardware beyond the isolator or input buffer at a location accessible for maintenance following an accident. The single failure criteria of item 2, Appendix B, need not apply to the channel beyond the isolation device if it is designed to provide 99% availability with respect to functional capability for liquid level display. The display and associated hardware beyond the isolation device need not be Class 1E, but should be energized from a high reliability power source which is battery backed. The quality assurance provisions cited in Appendix B, item 5, need not apply to this portion of the instrumentation system. This is a new requirement.

(9) Incore thermocouples located at the core-exit or at discrete axial levels of the ICC monitoring system and which are part of the monitoring system should be evaluated for conformity with Attachment 1, "Design and Qualification Criteria for PWR Incore Thermocouples," which is a new requirement.

(10) The types and locations of displays and alarms should be determined by performing a human factors analysis taking into consideration:

(a) the use of this information by an operator during both normal and abnormal plant conditions,

(b) integration into emergency procedures,

(c) integration into operator training, and

(d) other alarms during emergency and need for prioritization of alarms.

Response

The design of LGS does not include the use of incore thermocouples for detection of ICC. The licensee endorses the position of the BWROG that there is no technical basis for requiring incore thermocouples in addition to the existing reactor water level instrumentation. A justification of the adequacy of the existing instrumentation to detect conditions of ICC is provided in section 2.3 of NEDO-24708A. Reactor water level instrumentation which is used to monitor ICC is described and reviewed for conformance to Regulatory Guide 1.97 (Rev 2) in Section 7.5.

- II.G.1 POWER SUPPLIES FOR PRESSURIZER RELIEF VALVES, BLOCK VALVES AND LEVEL INDICATORS

Position

Consistent with satisfying the requirements of GDC 10, 14, 15, 17, and 20 for the event of LOOP, the following positions shall be implemented:

Power supply for pressurizer relief and block valves and pressurizer level indicators -

(1) Motive and control components of the power-operated relief valves shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.

(2) Motive and control components associated with the power-operated relief and block valves shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.

(3) Motive and control power connections to emergency buses for the power-operated relief valves and their associated block valves shall be through devices that have been qualified in accordance with safety-grade requirements.

(4) The pressurizer level indication instrument channels shall be powered from the vital instrument buses. The buses shall have the capability of being supplied from either the offsite power source or the emergency power source when offsite power is not available.

Clarification

(1) Although the primary concern resulting from lessons learned from the accident at TMI is that the power-operated relief and block valves must be closable, the design should retain, to the extent practical, the capability to also open these valves.

(2) The motive and control power for the block valve should be supplied from an emergency power bus different from the source supplying the power-operated relief valves.

(3) Any changeover of the power-operated relief and block valve motive and control power from the normal offsite power to the emergency onsite power is to be accomplished manually in the control room.

(4) For those designs in which instrument air is needed for operation, the electrical power supply should be required to have the capability to be manually connected to the emergency power sources.

Response

BWRs do not have pressurizer equipment. However, the LGS power-operated MSRVs can be actuated using emergency power and there are no block valves. They are described in Section 5.2.2. The relief valves are nitrogen-operated valves with their normal gas supply coming from the PCIG compressors which are described in Section 9.3.1.3. Standby ac power is available to the PCIG compressors following a LOOP.

The MSRVs are provided with gas accumulators described in Section 5.2.2.4 for reliable short-term operation without PCIG system operation. A safety-grade, gas supply system, described in Section 9.3.1.3, for long-term operation of the MSRVs is used for the ADS.

- II.K.1 IE BULLETINS ON MEASURES TO MITIGATE SMALL BREAK LOCAs AND LOSS OF FEEDWATER ACCIDENTS

- II.K.1.5 ASSURANCE OF PROPER ENGINEERED SAFETY FEATURES FUNCTIONING

Position

Review all safety-related valve positions, positioning requirements, and positive controls to assure that valves remain positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. Also, review related procedures, such as those for maintenance, testing, plant and system startup, and supervisory periodic (e.g., daily/shift checks) surveillance to ensure that such valves are returned to their correct positions following necessary manipulations and are maintained in their proper positions during operational modes.

Response

Valve positioning requirements, positive controls, and test and maintenance procedures associated with ESF systems are addressed in station administrative procedures which have been generated based on the requirements of IE Bulletin 79-08 Item 6. MOVs in safety-related systems are normally maintained in a configuration such as to require the least number of valve automatic movements upon system actuation. The position of manual ECCS valves considered vital to system operability is controlled by the use and documentation of either locks, checklists, or independent verification. Surveillance test procedures for ESF systems include return-to-normal

steps or checklists to ensure that the system is returned to service. Prior to fuel load, all ESF systems were confirmed to be aligned in accordance with approved checklists.

- II.K.1.10 REVIEW AND MODIFY, AS REQUIRED, PROCEDURES FOR REMOVING SAFETY-RELATED SYSTEMS FROM SERVICE (AND RESTORING TO SERVICE) TO ASSURE OPERABILITY STATUS IS KNOWN

Position

Review and modify, as required, procedures for removing safety-related systems from service (and restoring to service) to assure operability status is known.

Response

An administrative procedure addressing the release from service and the return to service of safety-related equipment has been written to address the requirements of IE Bulletin 79-08 Item 8. This procedure, and surveillance test procedures, provide controls to ensure that the status of safety-related system operability is known prior to removal from service and return to service.

- II.K.1.17 TRIP PRESSURIZER LEVEL BISTABLE SO THAT LOW PRESSURE (RATHER THAN PRESSURIZER LOW PRESSURE AND PRESSURIZER LOW LEVEL COINDICENCE) WILL INITIATE SAFETY INJECTION

Position

Trip pressurizer level bistable so that low pressure (rather than pressurizer low pressure and pressurizer low level coincidence) will initiate safety injection.

Response

This requirement is not applicable to LGS which has GE-designed reactors.

- II.K.1.20 PROVIDE PROCEDURES AND TRAINING TO OPERATORS FOR PROMPT MANUAL REACTOR TRIP FOR LOSS OF FEEDWATER, TURBINE TRIP, MAIN STEAM LINE ISOLATION VALVE CLOSURE, LOSS OF OFFSITE POWER, LOSS OF STEAM GENERATOR LEVEL, AND LOW PRESSURIZER LEVEL

Position

Provide procedures and training to operators for prompt manual reactor trip for loss of feedwater, turbine trip, MSIV closure, LOOP, loss of steam generator level, and low pressurizer level.

Response

This requirement is not applicable to LGS.

- II.K.1.21 PROVIDE AUTOMATIC SAFETY-GRADE ANTICIPATORY REACTOR TRIP FOR LOSS OF FEEDWATER, TURBINE TRIP, OR SIGNIFICANT DECREASE IN STEAM GENERATOR LEVEL

Position

Provide automatic safety-grade anticipatory reactor trip for loss of feedwater, turbine trip, or significant decrease in steam generator level.

Response

This requirement is not applicable to LGS.

- II.K.1.22 PROPER FUNCTIONING OF HEAT REMOVAL SYSTEMS

Position

Describe the actions, both automatic and manual, necessary for proper functioning of the auxiliary heat removal systems (e.g., RCIC) that are used when the main feedwater system is not operable. For any manual action necessary, describe in summary form the procedure by which this action is taken in a timely sense.

Response

See Section 5.4.6 and 5.4.7 for discussion of the automatic and manual actions necessary for the proper functioning of heat removal systems when the main feedwater system is not available.

- II.K.1.23 DESCRIBE ALL USES AND TYPES OF REACTOR VESSEL LEVEL INDICATION FOR BOTH AUTOMATIC AND MANUAL INITIATION OF SAFETY SYSTEMS. DESCRIBE OTHER INSTRUMENTATION THAT MIGHT GIVE THE OPERATOR THE SAME INFORMATION ON PLANT STATUS

Position

Describe all uses and types of reactor vessel level indication for both automatic and manual initiation of safety systems. Describe other instrumentation that might give the operator the same information on plant status.

Response

Water level indication and measurement is discussed in Sections 7.2, 7.3, 7.5 and 7.7 and shown in drawing M-42 and Figure 7.7-1.

Automatic initiation of safety systems based on reactor water level is accomplished by the following instrument configurations:

1. RPS - Control rod scram is accomplished by four analog loops arranged in a one-out-of-two-twice logic such that the failure of any one switch or of any one set

of sensing lines will not defeat the safety action. This scheme uses four condensing chamber reference legs and two variable leg sensing lines.

2. PCRVICS - Group I Isolation is accomplished by four analog loops arranged in a one-out-of-two-twice logic such that the failure of any one switch or of any one set of sensing lines will not defeat the safety action. This scheme uses four condensing chamber reference legs and four variable leg sensing lines.

3. ECCS - Initiation of ADS, HPCI, LPCI, Core Spray and diesel generator start is accomplished by four analog loops arranged in a one-out-of-two-twice logic for each of the initiation trip units such that the failure of any one switch or any one set of sensing line will not defeat the safety action. This scheme uses the same sensing lines discussed in the PCRVICS above.

4. ATWS - Initiation of the ATWS functions is accomplished by four analog loops arranged in a one-out-of-two-twice logic such that failure of one switch or set of sensing lines will not defeat the safety action. This scheme uses two condensing chamber reference legs and two variable leg sensing lines. These are different variable lines from those used for the RPS.

   Manual initiation of the safety system based on water level may also be accomplished by use of the following indications: (note: all of the reactor water level instruments in this control room have a common reference zero.)

   a. Three narrow range level indicators and one wide range indicator are installed on the reactor console. The narrow range instruments also feed a signal to a recorder on the reactor console. This scheme employs three condensing chamber reference legs and two variable leg sensing lines. The wide range indicator scheme employs a separate condensing chamber reference leg and variable leg sensing line.

   b. Two postaccident range level indications, in response to Regulatory Guide 1.97, are installed on the ECCS panel. Each indication consist of overlapping wide range and fuel zone indicators. These schemes used two condensing chamber reference legs and four variable leg sensing lines.

   c. This indication is supplemented by the single channel upset range on the reactor panel and shutdown range on the recirculation and RWCU panel. Both of these schemes use the same condensing chamber reference leg and variable leg sensing line.

   d. In addition, all of these indications are fed into the ERFDS (SPDS) computer for display in a temperature compensated reactor water level display.

These instruments are augmented by the other parameters required by Regulatory Guide 1.97 (Rev 2) in the control room. These instruments are addressed in the EOPs to be used by the operator to assess plant conditions. The above water level and supplemental instrumentation was subjected to a human factors review and emergency procedure walk-through prior to fuel load.

- II.K.2 <u>COMMISSION ORDERS ON BABCOCK & WILCOX PLANTS</u>

Response

These requirements are not applicable to LGS.

- II.K.3 FINAL RECOMMENDATIONS OF B&O TASK FORCE

- II.K.3.1 INSTALLATION AND TESTING OF AUTOMATIC PORV ISOLATION SYSTEM

This section is not applicable to LGS.

- II.K.3.2 REPORT ON OVERALL SAFETY EFFECT OF PORV ISOLATION SYSTEM

This section is not applicable to LGS.

- II.K.3.3 FAILURE OF PORV OR SAFETY VALVE TO CLOSE

Position

Assure that any failure of a power-operated relief valve or safety valve to close will be reported to the NRC promptly. All challenges to the power-operated relief valves or safety valves should be documented in the annual report. This requirement is to be met before fuel load.

Response

Procedures for prompt notification of NRC include any failure of a SRV to close as one of the events requiring the shift manager to expeditiously notify the NRC.

- II.K.3.5 AUTOMATIC TRIP OF REACTOR COOLANT PUMPS DURING LOCA

This section is not applicable to LGS.

- II.K.3.7 EVALUATION OF PORV OPENING PROBABILITY DURING OVERPRESSURE TRANSIENT

This section is not applicable to LGS.

- II.K.3.9 PROPORTIONAL INTEGRAL DERIVATIVE CONTROLLER MODIFICATION

This section is not applicable to LGS.

- II.K.3.10 PROPOSED ANTICIPATORY TRIP MODIFICATION

This section is not applicable to LGS.

- II.K.3.11 JUSTIFICATION IN THE USE OF CERTAIN POWER-OPERATED RELIEF VALVES

Response

There are no power-operated relief valves at the LGS. The ADS system employs five SRVs to relieve high pressure in the reactor so that flow from LPCI and/or the CS systems enters the reactor in the event that RCIC and/or the HPCI system cannot maintain the reactor water level. See Sections 5.2.2 and 7.3 for further discussion.

- II.K.3.12 CONFIRM EXISTENCE OF ANTICIPATORY REACTOR TRIP UPON TURBINE TRIP

This section is not applicable to the LGS.

- II.K.3.13 SEPARATION OF HPCI AND RCIC SYSTEM INITIATION LEVELS - ANALYSIS AND IMPLEMENTATION

Position

Currently, the RCIC system and the HPCI system both initiate on the same low water level signal and both isolate on the same high water level signal. The HPCI system will restart on low water level but the RCIC system will not. The RCIC system is a low flow system when compared to the HPCI system. The initiation levels of the HPCI and RCIC system should be separated so that the RCIC system initiates at a higher water level than the HPCI system. Further, the RCIC system initiation logic should be modified so that the RCIC system will restart on low water level. These changes have the potential to reduce the number of challenges to the HPCI system and could result in less stress on the vessel from cold water injection. Analyses should be performed to evaluate these changes. The analyses should be submitted to the NRC staff and changes should be implemented if justified by the analysis.

Response

Analysis performed by the BWROG (NEDO-24951) has concluded that changing the initiation setpoint of HPCI/RCIC is unwarranted. The report recommended a modification to the RCIC circuitry to permit auto-restart of RCIC on low level after a high level trip. Therefore, modifications to the RCIC trip circuitry have been made to delete the high water level turbine trip and to apply this signal to the auto-close circuit of the steam supply valve. This provides automatic operation of the RCIC system to trip at high water level and auto-restart at low water level.

- II.K.3.15 MODIFY BREAK DETECTION LOGIC TO PREVENT SPURIOUS ISOLATION OF HPCI AND RCIC SYSTEMS

Position

The HPCI and RCIC systems use differential pressure sensors on elbow taps in the steam lines to their turbine drives to detect and isolate pipe breaks in the systems. The pipe break detection circuitry has resulted in spurious isolation of the HPCI and RCIC systems due to the pressure spike which accompanies startup of the systems. The pipe break detection circuitry should be modified so that pressure spikes resulting from HPCI and RCIC system initiation will not cause inadvertent system isolation.

Submit sufficient documentation to support a reasonable assurance finding by the NRC that the modifications, as implemented, have resulted in satisfying the concerns expressed in the previous requirements.

Response

The HPCI/RCIC steam line isolation logic has been modified to address the spurious isolation of these systems due to the pressure spike which accompanies startup of them. The modification consists of adding a time delay to the high flow trip logic of HPCI/RCIC. This prevents the instantaneous pressure spike from causing a system isolation.

- II.K.3.16 REDUCTION OF CHALLENGES AND FAILURES OF RELIEF VALVES - FEASIBILITY STUDY AND SYSTEM MODIFICATIONS

Position

The record of relief valve failures to close for all BWRs in the past 3 years of plant operation is approximately 30 in 73 reactor-years (0.41 failures per reactor-year). This has demonstrated that the failure of a relief valve to close would be the most likely cause of a small break LOCA. The high failure rate is the result of a high relief valve challenge rate and a relatively high failure rate per challenge (0.16 failures per challenge). Typically, five valves are challenged in each event. This results in an equivalent failure rate per challenge of 0.03. The challenge and failure rates can be reduced in the following ways:

(1) Additional anticipatory scram on loss of feedwater

(2) Revised relief valve actuation setpoints

(3) Increased ECC flow

(4) Lower operating pressures

(5) Earlier initiation of ECCS

(6) Heat removal through emergency condensers

(7) Offset valve setpoints to open fewer valves per challenge

(8) Installation of additional relief valves with a block or isolation valve feature to eliminate opening of the SRVs, consistent with the ASME Code

(9) Increasing the high steam line flow setpoint for MSIV closure

(10) Lowering the pressure setpoint for MSIV closure

(11) Reducing the testing frequency of the MSIVs

(12) More stringent valve leakage criteria

(13) Early removal of leaking valves.

An investigation of the feasibility and contraindications of reducing challenges to the relief valves by use of the aforementioned methods should be conducted. Other methods should also be included in the feasibility study. Those changes which are shown to reduce relief valve challenges without compromising the performance of the relief valves or other systems should be implemented. Challenges to the relief valves should be reduced substantially (by an order of magnitude).

Clarification

Failure of the power-operated relief valve to reclose during the TMI-2 accident resulted in damage to the reactor core. As a consequence, relief valves in all plants, including BWRs, are being examined with a view toward their possible role in a small break LOCA.

The SRVs are dual-function pilot-operated relief valves that use a spring-actuated pilot for the safety function and an external air diaphragm actuated pilot for the relief function.

The operating history of SRVs has been poor. A new design is used in some plants, but the operational history is too brief to evaluate the effectiveness of the new design. Another way of improving the performance of the valves is to reduce the number of challenges to the valves. This may be done by the methods described above or by other means. The feasibility and contraindications of reducing the number of challenges to the valves by the various methods should be studied. Those changes which are shown to decrease the number of challenges without compromising the performance of the valves or other systems should be implemented.

Response

The licensee endorses the BWROG generic response to Item II.K.3.16 for LGS. This response is described in Reference 1.13-11. The following recommendations from this reference have been implemented at LGS in order to reduce the challenges to relief valves by approximately an order of magnitude:

1) Low water level isolation setpoint (see section 6.3.1.1.1 of Reference 1.13-11). The RPV water level isolation setpoint for MSIV closure is being lowered from Level 2 to Level 1 as part of the ATWS modifications for LGS.

2) Low-low set relief or equivalent manual actions (see section 6.3.1.3.1 of Reference 1.13-11). This recommendation ensures that by following the initial pressurization the pressure will be relieved by one valve alone, and the remaining SRVs will not experience any subsequent actuation. At LGS this will be accomplished manually as directed by the EOPs to manually open SRVs to terminate SRV cycling by reducing RPV pressure to below the lowest SRV safety lift setpoint, in accordance with guidance from the current BWROG EPGs.

3) Reduce MSIV testing frequency (see section 6.3.1.4.4 of Reference 1.13-11). A number of isolation events occur when the MSIV closure tests are being conducted. Reducing the MSIV test frequency would result in a reduction in the number of isolation events. Appropriate reductions have been made to the frequency of testing for the LGS MSIVs.

- II.K.3.17 REPORT ON OUTAGES OF ECCS SYSTEMS LICENSEE REPORT AND PROPOSED TECHNICAL SPECIFICATION CHANGES

Position

Several components of the ECCS are permitted by technical specifications to have substantial outage times (e.g., 72 hours for one diesel generator; 14 days for the HPCI system). In addition, there are no cumulative outage time limitations for ECCS. Licensees should submit a report detailing outage dates and lengths of outages for all ECCS for the last 5 years of operation. The report should also include the causes of the outages (i.e., controller failure, spurious isolation).

Clarification

The present technical specifications contain limits on allowable outage times for ECCS and components. However, there are no cumulative outage time limitations on these same systems. It is possible that ECCS equipment could meet present technical specification requirements but have a high unavailability because of frequent outages within the allowable technical specifications.

The licensees should submit a report detailing outage dates and length of outages for all ECCS for the last 5 years of operation, including causes of the outages. This report will provide the staff with a quantification of historical unreliability due to test and maintenance outages, which will be used to determine if a need exists for cumulative outage requirements in the technical specifications.

Based on the above guidance and clarification, a detailed report should be submitted. The report should contain (1) outage dates and duration of outages; (2) causes of the outage; (3) ECCS or components involved in the outage; and (4) corrective action taken. Tests and maintenance outages should be included in the above listings which are to cover the last 5 years of operation. The licensee should propose changes to improve the availability of ECCS equipment, if needed.

Applicants for an operating license shall establish a plan to meet these requirements.

Response

Starting from the date of commercial operations, for a period of five calendar years for each instance of ECCS unavailability because of component failure, maintenance outage (both forced or planned), or testing, the following information will be collected:

a. Outage date

b. Duration of outage

c. Cause of outage

d. ECCS or component involved

e. Corrective action taken

The above information will be assembled into a report, which will also include a discussion of any changes, proposed or implemented, deemed appropriate, to improve the availability of the ECCS equipment.

- II.K.3.18 MODIFICATION OF ADS LOGIC - FEASIBILITY FOR INCREASED DIVERSITY FOR SOME EVENT SEQUENCES

Position

The ADS actuation logic should be modified to eliminate the need for manual actuation to assure adequate core cooling. A feasibility and risk assessment study is required to determine the optimum approach. One possible scheme that should be considered is ADS actuation on low reactor vessel water level provided no HPCI or high pressure core spray flow exists and a low pressure ECCS is running. This logic would complement, not replace, the existing ADS actuation logic.

Response

Option 4, as outlined in the BWROG Generic Response to NUREG-0737 Item II.K.3.18, has been implemented prior to fuel load. Specifically, modifications were made to add a timer that would bypass the high drywell pressure permissive after a sustained low water level and to add an ADS manual inhibit switch.

- II.K.3.21 RESTART OF CORE SPRAY AND LPCI SYSTEMS

Position

The CS and LPCI system flow may be stopped by the operator. These systems will not restart automatically on loss of water level if an initiation signal is still present. The CS and LPCI system logic should be modified so that these systems will restart if required to assure adequate core cooling. Because this design modification affects several core cooling modes under accident conditions, a preliminary design should be submitted for staff review and approval prior to making the actual modification.

Part a

By January 1, 1981, each licensee shall submit proposed design modifications and supporting analysis which will contain sufficient information to support a reasonable assurance finding by the NRC that the above position is met. The documentation should include as a minimum:

(1) A discussion of the design with respect to the above paragraphs of IEEE 279 (1971);

(2) Support information including system design description, logic diagrams, electrical schematics, piping and instrument diagrams, test procedures and technical specifications

(3) Sufficient documentation to demonstrate that the system, as modified, would not degrade proper system functions.

Part b

Licensee to implement modifications at the next refueling outage following staff approval of the design unless this outage is scheduled within 6 months of the approval date. In this event, modifications will be completed during the following refueling outage.

Response

The licensee endorses the BWROG position for Item II.K.3.21 for LGS. This position was forwarded to the NRC by letter from D.B. Walters (BWROG) to D.G. Eisenhut (NRC) dated December 29, 1980. The conclusion of this position is that automation of the restart of LPCI and CS will result in a net decrease in safety because of the complexity of the logic required. Logic modifications to the LPCI and CS systems are therefore not warranted for LGS.

- II.K.3.22 AUTOMATIC SWITCH-OVER OF RCIC SYSTEM SUCTION - VERIFY PROCEDURES AND MODIFY DESIGN

Position

The RCIC system takes suction from the CST with manual switch-over to the suppression pool when the CST level is low. The switch-over should be made automatically. Until the automatic switch-over is implemented, licensees should verify that clear and cogent procedures exist for the manual switch-over of the RCIC system suction from the CST to the suppression pool.

Response

Modifications have been made to change the RCIC system suction valve logic to automatically switch suction from the CST to the suppression pool on low CST level.

- II.K.3.24 CONFIRM ADEQUACY OF SPACE COOLING FOR HPCI AND RCIC SYSTEMS

Position

Long-term operation of the RCIC and HPCI systems may require space cooling to maintain the pump-room temperatures within allowable limits. Applications should verify the acceptability of the consequences of a complete loss of ac power. The RCIC and HPCI systems should be designed to withstand a complete loss of offsite ac power to their support systems, including coolers, for at least 2 hours.

Response

At LGS, the HPCI and RCIC compartment unit coolers are powered by onsite emergency power and therefore continue to be available during a LOOP. The unit coolers are described in Section 9.4.2.2. The ESW pumps which provide flow to the coolers are also powered from onsite emergency power. Adequate space cooling is therefore assured during a LOOP. There are no other supporting systems that require offsite power such that operation of the HPCI and RCIC systems would be impaired if offsite power should be lost. The current LGS design is therefore acceptable.

- II.K.3.25 EFFECT OF LOSS OF AC POWER ON PUMP SEALS

Position

The licensees should determine, on a plant specific basis, by analysis or experiment, the consequences of a loss of cooling water to the reactor recirculation pump seal coolers. The pump seals should be designed to withstand a complete loss of ac power for at least 2 hours. Adequacy of the seal design should be demonstrated. The results of the evaluation and proposed modifications are due by July 1, 1981. Modifications are to be implemented by January 1, 1982.

Clarification

The intent of this position is to prevent excessive loss of RCS inventory following an anticipated operational occurrence. Loss of ac power for this case is construed to be LOOP. If seal failure is the consequence of loss of cooling water to the reactor coolant pump seal coolers for 2 hours, due to LOOP, one acceptable solution would be to supply emergency power to the component cooling water pump.

Response

At LGS, two systems are available for cooling the recirculation pump seals: the RECW system and the recirculation pump seal purge system. Recirculation pump vendor test data has shown that if either one of these seal cooling systems is operating, seal temperatures will remain within acceptable limits and excessive seal deterioration is not expected to occur.

The primary cooling for the recirculation pump seals is provided by the RECW system which cools the reactor water that flows to the lower seal cavity. After a LOOP, the RECW pumps will be powered by onsite emergency power and will restart automatically. The service water system, which normally provides cooling water to the RECW heat exchangers, will not be available, but cooling water to the heat exchangers can be provided via manual realignment of the ESW system. If the RECW pumps do not restart or are unavailable for some other reason, the ESW can be manually routed directly to the recirculation pump seals for cooling by way of the RECW piping.

Backup cooling is provided by the recirculation pump seal purge system which injects cool water from the CRD system into the lower seal cavity. The CRD pumps are powered from the emergency diesels and can be manually restarted once onsite power is available. Therefore, the CRD pumps provide an alternate method for seal cooling during a LOOP. However, the ability to use CRD may be limited by the requirement to limit the RPV cooldown rate.

Even in the remote case where neither cooling source is reestablished and gross seal degradation occurs, the GE analysis performed under the direction of the BWROG has shown that the maximum coolant loss would be limited to 70 gpm per pump. This loss is small enough to be compensated for by normal or emergency reactor water level controls. It should be noted that since the initial licensing of the LGS Units, an improved seal design, prone to even less leakage in the event of failure, has been installed on the pumps.

Instrumentation for various parameters, including seal cavity pressure, seal staging and drain flows, drywell equipment drain sump pump flow and drywell floor drain sump pump flow is available to the operator to indicate potential seal failure. In addition, gross seal failure may lead to

changes in drywell pressure, temperature, or radioactivity, all of which are monitored and recorded in the control room.

It is therefore concluded that a total loss of recirculation pump seal cooling is not a problem at LGS and modifications are not necessary.

- II.K.3.27 PROVIDE COMMON REFERENCE LEVEL FOR VESSEL LEVEL INSTRUMENTATION

Position

Different reference points of the various reactor vessel water level instruments may cause operator confusion. Therefore, all level instruments should be referenced to the same point. Either the bottom of the vessel or the top of the active fuel are reasonable reference points.

The applicant is to submit documentation by January 1, 1981 and implement action by April 1, 1981.

Response

All reactor vessel water level instruments are referenced to the bottom of the dryer skirt. Section 7.7.1.1.3.1.3 contains additional design information.

- II.K.3.28 VERIFY QUALIFICATION OF ACCUMULATORS ON ADS VALVES

Position

Safety analysis reports claim that air or nitrogen accumulators for the ADS valves are provided with sufficient capacity to cycle the valves open five times at design pressures. GE has also stated that the ECCS are designed to withstand a hostile environment and still perform their function for 100 days following an accident. Licensee and applicant should verify that the accumulators on the ADS valves meet these requirements, even considering normal leakage. If this cannot be demonstrated, the licensee and applicant must show that the accumulator design is still acceptable.

Clarification

The ADS valves, accumulators, and associated equipment and instrumentation must be capable of performing their functions during and following exposure to hostile environments and taking no credit for nonsafety-related equipment or instrumentation. Additionally, air (or nitrogen) leakage through valves must be accounted for in order to assure that enough inventory of compressed air is available to cycle the ADS valves.

Response

The criteria and design basis for short-term ADS valve operation and accumulator capacity is given in Section 5.2.2.4.1. Long-term vessel depressurization capability for the alternate shutdown cooling flow path described in Section 5.4.7.5 is provided by supplying nitrogen to the ADS valves from the safety-grade system described in Section 9.3.1.3.

- II.K.3.30 REVISED SMALL BREAK LOCA METHODS TO SHOW COMPLIANCE WITH 10CFR50, APPENDIX K

Position

The analysis methods used by NSSS vendors and/or fuel suppliers for small break LOCA analysis for compliance with 10CFR50, Appendix K, should be revised, documented, and submitted for NRC approval. The revisions should account for comparisons with experimental data, including data from the LOFT Test and Semiscale Test facilities.

Clarification

As a result of the accident at TMI-2, the Bulletins and Orders Task Force was formed within the Office of Nuclear Reactor Regulation. This task force was charged, in part, to review the analytical predictions of feedwater transients and small break LOCAs for the purpose of assuring the continued safe operation of all operating reactors, including a determination of acceptability of emergency guidelines for operators.

As a result of the task force reviews, a number of concerns were identified regarding the adequacy of certain features of small break LOCA models, particularly the need to confirm specific model features (e.g., condensation heat transfer rates) against applicable experimental data. These concerns, as they applied to each LWR vendor's models, were documented in the task force reports for each LWR vendor. In addition to the modeling concerns identified, the task force also concluded that, in light of the TMI-2 accident, additional systems verification of the small break LOCA model as required by II.4 of 10CFR50, Appendix K, was needed. This included providing predictions of Semiscale Test S-07-10B, LOFT Test (L3-1), and providing experimental verification of the various modes of single-phase and two-phase natural circulation predicted to occur in each vendor's reactor during small break LOCAs.

Based on the cumulative staff requirements for additional small break LOCA model verification, including both integral system and separate effects verification, the staff considered model revision as the appropriate method for reflecting any potential upgrading of the analysis methods.

The purpose of the verification was to provide the necessary assurance that the small break LOCA models were acceptable to calculate the behavior and consequences of small primary system breaks. The staff believes that this assurance can alternatively be provided, as appropriate, by additional justification of the acceptability of present small break LOCA models with regard to specific staff concerns and recent test data. Such justification could supplement or supersede the need for model revision.

The specific staff concerns regarding small break LOCA models are provided in the analysis sections of the Bulletins and Orders Task Force reports for each LWR vendor. These concerns should be reviewed in total by each holder of an approved ECCS model and addressed in the evaluation as appropriate.

The recent tests include the entire Semiscale small break test series and LOFT Test (L3-1) and (L3-2). The staff believes that the present small break LOCA models can be both qualitatively and quantitatively assessed against these tests.

Other separate effects tests (e.g., Oak Ridge National Laboratory core uncovery tests) and future tests, as appropriate, should also be factored into this assessment.

Based on the preceding information, a detailed outline of the proposed program to address this issue should be submitted. In particular, this submittal should identify (1) which areas of the models, if any, the licensee intends to upgrade, (2) which areas the licensee intends to address by further justification of acceptability, (3) test data to be used as part of the overall verification/upgrade effort, and (4) the estimated schedule for performing the necessary work and submitted this information for staff review and approval.

Response

The response to the NRC small break model concerns was provided at a meeting between the NRC and GE on June 18, 1981. Information provided at this meeting showed that, based on the small break test results and sensitivity studies, the existing GE small break LOCA model satisfies the concerns of NUREG-0626 and is in compliance with 10CFR50, Appendix K. Therefore, the GE model is acceptable relative to the concerns of Item II.K.3.30, and no model changes need to be made to satisfy this item.

Documentation of the information provided at the June 18, 1981 meeting was provided via the letter from R.H. Buchholz (GE) to D.G. Eisenhut (NRC), dated June 26, 1981.

- II.K.3.31 PLANT SPECIFIC CALCULATIONS TO SHOW COMPLIANCE WITH 10CFR50.46

Position

Plant specific calculations using NRC approved models for small break LOCAs as described in II.K.3 item 30 to show compliance with 10CFR50.46 should be submitted for NRC approval by all licensees.

Calculations to be submitted by January 1, 1983 or 1 year after staff approval of LOCA analysis models, whichever is later (required only if model changes have been made).

Response

The small break LOCA calculations included in the LGS LOCA analysis are given in Section 6.3.3.7 and Table 6.3-5. The references listed in Section 6.3.6 describe the currently approved 10CFR50, Appendix K methodology used to perform these calculations. Compliance with 10CFR50.46 has previously been established for that methodology. As stated in the June 26, 1981, letter from R.H. Buchholz (GE) to D.G. Eisenhut (NRC), no model changes are needed to satisfy NUREG-0737 Item II.K.3.30; therefore, there is no need to revise the calculations given in Section 6.3.3.7.

The response provided above is historical. The original LOCA analysis has been replaced, and the applicable LOCA analysis is discussed in Section 6.3.3.7.

- II.K.3.44 EVALUATION OF ANTICIPATED TRANSIENTS WITH SINGLE FAILURE TO VERIFY NO FUEL FAILURE

Position

For anticipated transients combined with the worst single failure and assuming proper operator actions, licensees should demonstrate that the core remains covered or provide analysis to show that no significant fuel damage results from core uncovery. Transients which result in a SORV should be included in this category. The results of the evaluation are due January 1, 1981.

Response

The BWROG transmitted a generic response to this requirement by letter dated December 29, 1980, from D.B. Waters (BWROG) to D.G. Eisenhut (NRC). This response contains an evaluation that states the worst case transient with single failure combination for BWR/4 plants is the loss of feedwater event with failure of the HPCI system. A SORV was also considered in addition to the HPCI failure. The results of these studies indicate that the core remains covered during the entire course of the transient either due to RCIC system operation or automatic or manual depressurization permitting low pressure inventory makeup. The operator action assumed in the analysis is to manually depressurize the vessel to permit low pressure injection.

By letter dated November 16, 1981, from J.S. Kemper (PECo) to D.G. Eisenhut (NRC), the licensee verified that the assumptions and initial conditions used in the BWROG generic report are representative of LGS.

- II.K.3.45 EVALUATION OF DEPRESSURIZATION WITH OTHER THAN ADS

Position

Analyses to support depressurization modes other than full actuation of the ADS (e.g., early blowdown with one or two SRVs) should be provided. Slower depressurization would reduce the possibility of exceeding vessel integrity limits by rapid cooldown.

Response

The applicant endorses the BWROG position on Item II.K.3.45 for LGS. This position is presented in Reference 1.13-11 and is summarized below.

An evaluation of alternate modes of depressurization other than full actuation of the ADS was made by the BWROG with regard to the effect of such reduced depressurization rates on core cooling and vessel integrity.

Depressurization by full ADS actuation constitutes a depressurization from about 1050 to 180 psig in approximately 3.3 minutes. The alternate modes of depressurization that were evaluated considered vessel depressurization over the same pressure range (1050 to 180 psig) within two different time periods (6-10 minutes and 15-20 minutes). The cases considered show that no appreciable improvement can be gained by slower depressurization based on core cooling considerations. Because a full ADS blowdown is well within the design basis of the RPV and ADS is properly designed to minimize the threat to core cooling, no change in the depressurization rate is necessary, and no modifications to LGS are needed for this TMI item.

- II.K.3.46 RESPONDING TO MICHELSON CONCERNS

Position

GE should provide a response to the Michelson concerns as they relate to BWRs.

Clarification

GE provided a response to the Michelson concerns as they relate to BWRs by letter dated February 21, 1980. Licensees and applicants should assess applicability and adequacy of this response to their plants.

Response

All of the generic February 21, 1980 GE responses are applicable to LGS Units 1 and 2 and are adequate in terms of a response to the Michelson concerns for LGS.

- III.A.1.1 EMERGENCY PREPAREDNESS, SHORT-TERM

Position

Comply with 10CFR50, Appendix E and Regulatory Guide 1.101, "Emergency Planning for Nuclear Power Plants," and meet the essential elements of NUREG-75/111, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," or have a favorable finding form the Federal Emergency Management Agency.

Response

Emergency planning is discussed in the Emergency Plan.

- III.A.1.2 UPGRADE EMERGENCY SUPPORT FACILITIES

Position

Establish an interim onsite TSC separate from, but close to, the control room for engineering and management support of reactor operations during an accident. The TSC shall be large enough for the necessary utility personnel and five NRC personnel, have direct display or call-up of plant parameters, and dedicated communication with the control room, emergency operations facility, and the NRC. Provide a description of and a completion schedule for establishing a permanent TSC in accordance with the regulatory position of NUREG-0696, "Functional Criteria for Emergency Response" (February 1981).

Establish an onsite OSC, separate from but with communications to the control room for use by operation support personnel during an accident.

Designate a near-site EOF with communications with the plant to provide evaluation of radiological releases and coordination of all onsite and offsite activities during an accident.

These requirements shall be met before fuel loading.

Response

The three types of emergency response facilities required by Section 8 have been provided for LGS.

The TSC meets all of the requirements of section 8.2.1 and is fully functional.

The OSC meets all of the requirements of section 8.3.1 and is fully functional.

The EOF is located approximately 20 miles from the LGS site. The EOF meets all of the technical requirements of section 8.4.1 and is fully functional.

Staffing of the EOF and the TSC is described in the Emergency Plan.

- III.A.2 EMERGENCY PREPAREDNESS

Position

(1) Each nuclear facility shall upgrade its emergency plan to provide reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Specific criteria to meet this requirement is delineated in NUREG-0654 (FEMA-REP-1), "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparation in Support of Nuclear Power Plants."

(2) Perform an emergency response exercise to test the integrated capability and a major portion of the basic elements existing within emergency preparedness plans and organizations.

Response

Emergency planning is discussed in the Emergency Plan.

- III.D.1.1 PRIMARY COOLANT OUTSIDE CONTAINMENT

Position

Applicants shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as-low-as-practical levels. This program shall include the following:

(1) Immediate leak reduction

(a) Implement all practical leak reduction measures for all systems that could carry radioactive fluid outside of containment.

(b) Measure actual leakage rates with system in operation and report them to the NRC.

(2) Continuing Leak Reduction - Establish and implement a program of preventive maintenance to reduce leakage to as-low-as-practical levels. This program shall include periodic integrated leak tests at intervals not to exceed each refueling cycle.

Clarification

Applicants shall provide a summary description, together with initial leak test results, of their program to reduce leakage from systems outside containment that would or could contain primary coolant or other highly radioactive fluids or gases during or following a serious transient or accident.

(1) Systems that should be leak tested are as follows (any other plant system which has similar functions or postaccident characteristics even through not specified herein, should be included):

(a) RHR,

(b) Containment spray recirculation,

(c) HPCI recirculation,

(d) Containment and primary coolant sampling,

(e) RCIC,

(f) Makeup and letdown (pressurized water reactors only), and

(g) Waste gas (includes headers and cover gas system outside of containment in addition to decay or storage system).

Include a list of systems containing radioactive materials which are excluded from program and provide justification for exclusion.

(2) Testing of gaseous systems should include helium leak detection or equivalent testing methods.

(3) Should consider program to reduce leakage potential release paths due to design and operator deficiencies as discussed in our letter to all operating nuclear power plants regarding North Anna and related incidents, dated October 17, 1979.

Response

A review of all systems designed to handle highly radioactive fluids during or after a serious transient or accident has been performed to ensure that appropriate design features to minimize leakage have been included. System isolation provisions have been reviewed in conjunction with this effort (Section 6.2.7). A leak reduction program for these systems will be implemented prior to and after fuel load to measure actual leakage rates and to identify sources of leakage in order that total leakage may be reduced to as-low-as-practical levels. The leakage reduction program is described in Section 6.2.8.

The October 17, 1979, NRC generic letter regarding radioactive releases to North Anna Unit 1 expanded the scope of NUREG-0737 Item III.D.1.1 to include a review of potential radioactive release pathways that would not be related to the handling of highly radioactive fluids during or after a core damage event. This generic letter required "...that release paths exemplified by the

North Anna Unit 1 incident or similar release paths as identified in IE Circular 79-21 should also be considered."

In response to this request per clarification (3), above, a review has been performed to identify all potential unplanned release paths for radioactive fluids during normal plant operation. As shown in Table 1.13-4, it has been determined that existing design provisions and administrative controls are sufficient to prevent unplanned and unmonitored releases of radioactivity.

During review of IE Bulletin 80-10, all interfaces between normally nonradioactive and radioactive systems were identified. It was determined that design provisions adequately maintain boundaries between nonradioactive/radioactive interfaces (Item 4 in Table 1.13-4). These design provisions include one of the following:

a. Two normally closed valves in series

b. One normally closed valve and one check valve in series

c. Two check valves in series

d. Heat exchanger tube sheets (in most cases, the nonradioactive fluid is maintained at a higher pressure than the radioactive fluid).

In the event that leakage or operator errors (e.g., valve mispositionings or incorrect valve lineups) lead to contamination of a nonradioactive system, the process sampling system and numerous grab sampling points for the following normally nonradioactive systems are provided to support a routine contamination monitoring program:

a. Circulating water

b. RECW

c. TECW

d. Clarified water

e. Makeup demineralizers

f. Drywell chilled water

g. Auxiliary steam (both steam and feedwater)

h. Plant waste water effluent

i. Service water

j. Instrument and service air

In addition to the above sampling provisions, the following systems are monitored for radioactive contamination by the process radiation monitoring system:

a. ESW and RHR service water

b. RECW

c. Service water

In the event that a nonradioactive system is found to be contaminated, corrective action will be taken to prevent leakage to the environment and isolate and repair the source of the contamination.

- III.D.3.3 IMPROVED INPLANT IODINE INSTRUMENTATION UNDER ACCIDENT CONDITIONS

Position

(1) Each licensee shall provide equipment and associated training and procedures for accurately determining the airborne iodine concentration in areas within the facility where plant personnel may be present during an accident.

(2) Each applicant for a fuel loading license to be issued prior to January 1, 1981 shall provide the equipment, training, and procedure necessary to accurately determine the presence of airborne radioiodine in areas within the plant where plant personnel may be present during an accident.

Clarification

Effective monitoring of increasing iodine levels in the buildings under accident conditions must include the use of portable instruments using sample media that will collect iodine selectively over xenon (e.g., silver zeolite) for the following reasons:

(1) The physical size of the auxiliary and/or fuel handling building precludes locating stationary monitoring instrumentation at all areas where airborne iodine concentration data might be required.

(2) Unanticipated isolated "hot spots" may occur in locations where no stationary monitoring instrumentation is located.

(3) Unexpectedly high background radiation levels near stationary monitoring instrumentation after an accident may interfere with filter radiation readings.

(4) The time required to retrieve samples after an accident may result in high personnel exposures if these filters are located in high dose rate areas.

After January 1, 1981, each applicant and licensee shall have the capability to remove the sampling cartridge to a low background, low contamination area for further analysis. Normally, counting rooms in auxiliary buildings will not have sufficiently low backgrounds for such analyses following an accident. In the low background area, the sample should first be purged of any entrapped noble gases using nitrogen gas or clean air free of noble gases. The licensee shall have the capability to measure accurately the iodine concentrations present on these samples under accident conditions. There should be sufficient samplers to sample all vital areas.

For applicants with fuel loading dates prior to January 1, 1981, provide by fuel loading (until January 1, 1981) the capability to accurately detect the presence of iodine in the region of interest following an accident. This can be accomplished by using a portable or cart-mounted iodine sampler with attached SCA. The SCA window should be calibrated to the 365 KeV of I-131 using the SCA. This will give an initial conservative estimate of presence of iodine and can be used to determine if respiratory protection is required. Care must be taken to assure that the counting system is not saturated as a result of too much activity collected on the sampling cartridge.

Response

Sampling methods and procedures have been implemented at LGS which will permit the measurement of in-plant iodine concentrations during accident conditions. A description of this method is as follows:

The sampling method uses portable air samplers with a combination particulate filter and iodine sampling cartridge sampling head. The sampling heads use a glass fiber particulate filter and a CESCO style (2.25" diameter by 1.04" thickness) iodine charcoal cartridge. The cartridge normally used is the CESCO-type charcoal cartridge. When long sampling times are required, a larger capacity charcoal cartridge is available. During emergency conditions, with high xenon or krypton concentrations potentially present, either a silver zeolite or a silver impregnated silica gel adsorber canister will be employed.

Iodine activity on the sample cartridge will be determined by gamma isotopic analysis using a computer based multichannel analyzer with high resolution intrinsic germanium detectors located in the LGS counting room. The counting room is located in the radwaste enclosure at el 217'. An assessment of the NUREG-0737 shielding study indicates that the counting room dose rates and airborne radioactivity concentrations are low enough to permit sample analysis during accident conditions.

Isotopic analysis will permit iodine identification in the presence of xenon and krypton. If the analysis of iodine becomes impossible due to interference (high background) from xenon or krypton, then either silver zeolite cartridges will be used or the charcoal cartridge will be purged with clean bottled nitrogen or breathing air to reduce the interference. If the use of silver zeolite does not sufficiently reduce the xenon or krypton interference, the silver zeolite cartridges will also be purged with clean bottled nitrogen or bottled breathing air available onsite.

The Health Physics technical staff have been trained in the implementation of this postaccident procedure.

- III.D.3.4 CONTROL ROOM HABITABILITY

Position

In accordance with Item III.D.3.4 applicants shall assure that control room operators will be adequately protected against the effects of accidental release of toxic and radioactive gases and that the nuclear power plant can be safely operated or shut down under DBA conditions (GDC 19).

Clarification

(1) All applicants must make a submittal to us regardless of whether or not they met the criteria of the referenced SRP sections. The new clarification specifies that applicants that meet the criteria of the SRP should provide the basis for their conclusion that Section 6.4 of the SRP requirements are met. Applicants may establish this basis by referencing past submittals to us and/or providing new or additional information to supplement past submittals.

(2) All applicants with control rooms that meet the criteria of the following sections of the SRP:

2.2.1-2.2.2	Identification of Potential Hazards in Site Vicinity,
2.2.3	Evaluation of Potential Accidents, and
6.4	Habitability Systems

shall report their findings regarding the specific SRP sections as explained below. References 1.13-12, 1.13-13 and 1.13-14 should be used for guidance.

Applicants shall submit the results of their findings as well as the basis for those findings by January 1, 1981. In providing the basis for the habitability finding, applicants may reference their past submittals. Applicants should, however, ensure that these submittals reflect the current facility design and that the information requested in Table 1.13-12 is provided.

(3) All applicants with control rooms that do not meet the criteria of the above listed references, SRPs, regulatory guides, and other references shall perform the necessary evaluations and identify appropriate modifications.

Each applicant submittal shall include the results of the analyses of control room concentrations from postulated accidental release of toxic gases and control room operator radiation exposures from airborne radioactive material and direct radiation resulting from DBAs. The toxic gas accident analysis should be performed for all potential hazardous chemical releases occurring either on the site or within 5 miles of the plant boundary. Regulatory Guide 1.78 lists the chemicals most commonly encountered in the evaluation of the control room habitability but is not all inclusive.

The DBA radiation source term should be for the LOCA containment leakage and ESF leakage contribution outside containment as described in Section 15.6.5, appendices A and B. In addition, BWR facility evaluations should add any leakage from the MSIVs (i.e, valve steam leakage, valve seat leakage, MSIV Leakage Alternate Drain Pathway release) to the containment leakage and ESF leakage following a LOCA. This should not be construed as altering our recommendations in section D of Regulatory Guide 1.95 (Rev 2) regarding MSIV-LCS. Other DBAs should be reviewed to determine whether they might constitute a more severe control room hazard than the LOCA.

In addition to the accident analysis results, which should either identify the possible need for control room modifications or provide assurance that the habitability systems will operate under all postulated conditions to permit the control room operators to remain in the control room to take appropriate actions required by GDC 19, the applicant should submit sufficient information needed

for an independent evaluation of the adequacy of the habitability systems. Table 1.13-12 lists the information that should be provided along with applicant's evaluation.

Response

The information required for control room habitability evaluation as listed in Table 1.13-12 is provided in Sections 1.2, 2.2, 6.4, and 9.4. LGS complies with all criteria of control room habitability in accordance with Item III.D.3.4.

1.13.3 REFERENCES

1.13-1 D. H. Slade, ed., Meteorology and Atomic Energy, TID 24190 (1968).

1.13-2 K. G. Murphy and K. M. Campe, "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Criterion 19", 13th AEC Air Cleaning Conference.

1.13-3 Start, G. E., J. H. Cate, C. R. Dickson, N. R. Ricks, G. H. Ackerman, and J. F. Sagendorf, "Rancho Seco Building Wake Effects on Atmospheric Diffusion", NOAA Technical Memorandum, ERL ARL-69 (1977).

1.13-4 Walker, D. H., R. N. Nassano, M. A. Capo: "Control Room Ventilation Intake Selection for the Floating Nuclear Power Plant", 14th ERDA Air Cleaning Conference (1976).

1.13-5 D. J. Wilson, "Contamination of Air Intakes from Roof Exhaust Vents", ASHRAE Trans. 82, Part 1 pp. 1024-1038 (1976).

1.13-6 R. J. B. Bouwmeester, K. W. Kothari, R. N. Meroney, "An Algorithm to Estimate Field Concentrations Under Nonsteady Meteorological Conditions from Wind Tunnel Experiments", NUREG/CR-1474, NRC, (9/80).

1.13-7.1 General Electric Emergency Response Information System, Licensing Topical Report,

1.13-8 General Electric Licensing Topical Report, NEDE-24988-P and NEDE-24988.

1.13-9 "Proposed Interim Amendments to 10CFR50 Related to Hydrogen Control and Certain Degraded Core Considerations", SECY-80-399, Federal Register, (October 2, 1980).

1.13-10 Letter to D.G. Eisenhut (NRC) from T.J. Dente (BWROG), "Supplement to BWR Owner's Group Evaluation of NUREG-0737, Item II.E.4.2(7)", (June 14, 1982).

1.13-11 "BWR Owners' Group NUREG-0737 Implementation: Analysis and Positions Submitted to the NRC", GE NEDO-24951, (June 1981).

1.13-12 Regulatory Guide 1.78, "Assumptions for Evaluating the Habitability of Regulatory Power Plant Control Room During a Postulated Hazardous Chemical Release".

1.13-13 Regulatory Guide 1.95, "Protection of Nuclear Power Plant Control Room Operators Against an Accident Chlorine Release".

1.13-14 K.G. Murphy and K.M. Campe, "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Design Criterion 19," 13th AEC Air Cleaning Conference, (August 1974).

Table 1.13-1

VITAL AREA RADIATION DOSES[8]

VITAL AREAS(1)	PIPING AND CLOUD SHINE: MAJOR SOURCE	PIPING AND CLOUD SHINE: PEAK DOSE RATE (Rem/hr)	PIPING AND CLOUD SHINE: TOTAL DOSE (Rem)	AIRBORNE WHOLE BODY DOSE (Rem) (2)	SHINE PLUS WHOLE BODY DOSE (Rem)	DOSE OBJECTIVE (Rem)	AIRBORNE ORGAN DOSES (Rem)	DOSE OBJECTIVES (Rem)
Continuous Occupancy								
Main Control Room [8] (SRP 6.4 Occupancy)	ECCS/RHR pipe	1.1	4.2	4.3×10^{-1}	4.6	≤5.0	Thyroid: 6.29×10^{0} [4]	≤30
							Skin : 7.6	≤30
Technical Support Center (SRP 6.4 Occupancy)	RHR Pipe/Reactor Enclosure Cloud	2.7×10^{-3}	1.5×10^{-2}	1.47×10^{-1}	1.62×10^{-1}	≤5.0	Thyroid: 2.3×10^{-1}	≤30
							Skin : 3.6×10^{-1}	≤30
Operational Support Center (SRP 6.4 Occupancy)	RHR Pipe/Reactor Enclosure Cloud	6.6×10^{-3}	6.7×10^{-2}	1.97	2.0	≤5.0	Thyroid: ≤30 [5]	≤30
							Skin : 1.6	≤30
Security Center (SRP 6.4 Occupancy)	RHR Pipe/Reactor Enclosure Cloud	1.7×10^{-1}	7.3×10^{-1}	1.3	2.0	≤5.0	Thyroid: ≤30 [5]	≤30
							Skin : 1.03	≤30
Infrequent Occupancy								
Counting Room(6)	ECCS/RHR Pipe	5.5×10^{-4}	1.3×10^{-3}	1.2×10^{-1}	1.3×10^{-1}	≤5.0	Thyroid: 21.5 Skin : 1.2	≤30 ≤30
Radiochemical Laboratory(6)	ECCS/RHR Pipe	9.3×10^{-3}	3.0×10^{-2}	1.2×10^{-1}	1.6×10^{-1}	≤5.0	Thyroid: 21.6 Skin : 1.2	≤30 ≤30
Postaccident Sampling Station (31 min Occupancy at time = 1 hour) Post-LOCA	H_2 Recombiner/ ECCS Pipe	6.6×10^{-1} [3]	3.4×10^{-1} [3]	2.5×10^{-3}	3.4×10^{-1} [3]	≤5.0	Thyroid: 2.9×10^{-3}	≤30
							Skin : 3.7×10^{-2}	≤30
North Stack Instrument Room (1 hour Occupancy)	North Stack	3.9	3.9	8.7×10^{-1}	4.8 [7]	≤5.0	Thyroid: 1.8×10^{-2}	≤30
							Skin : 4.2×10^{-1}	≤30
HVAC Panels (1 hour Occupancy)	ECCS/RHR Pipe	3.8×10^{-1}	3.8×10^{-1}	8.8×10^{-2}	4.7×10^{-1}	≤5.0	Thyroid: 3.2×10^{-2}	≤30
							Skin : 4.1×10^{-1}	≤30
Radwaste Control Room (6)	ECCS/RHR Pipe	2.1×10^{-2}	6.7×10^{-2}	2.36×10^{-1}	3.0×10^{-1}	≤5.0	Thyroid: ≤30 [5]	≤30
							Skin : 1.2	≤30
Diesel Generator Area (1 hour Occupancy)	ECCS/RHR Pipe/Reactor Enclosure Cloud	8.1×10^{-3}	8.1×10^{-3}	3.0×10^{-2}	4.4×10^{-2}	≤5.0	Thyroid: 5.0×10^{-2}	≤30
							Skin : 2.0×10^{-2}	≤30

(1) Occupancy factors used to calculate doses are listed in parentheses for each vital area. SRP 6.4 occupancy factors are for 30 days. For vital areas with 1 hour occupancy, the doses reflect 1 hour occupancy at the maximum postaccident dose rate unless otherwise specified.

(2) Airborne whole body doses are specified for the listed vital areas.

(3) Doses do not include shine from sample source. See Table 11.5-3 .

(4) MCR Dose was calculated assuming zero inleakage through the MCR Doors. This requires installation of a MCR door seal described in section 6.4 and 15.10.

(5) The calculated Airborne Organ dose was approximately 35 rem over 30 days. Emergency Response Procedures specify the criteria for radiological habitability monitoring to insure the dose objectives are not exceeded. Bi the results of the habitability monitoring personnel in the affected areas maybe instructed to don protective devices or limit stay times to maintain the dose objectives.

(6) The stay times assumed for these areas are half of the stay times specified in SRP 6.4.

(7) Doses to personnel traversing the Refuel Floor on route to and then occupying the North Stack Instrument Room would be 2.86 Rem if a LOCA were to occur while the upper layer of the reactor well shield plugs were removed in OPCON 1, 2 and 3. Doses to personnel traversing the turbine enclosure roof to the reactor enclosure roof on route to and from, and while occupying the North Stack Instrument Room would be 2.9 Rem, if a Unit 2 LOCA were to occur, and 3.957 Rem, if a Unit 1 LOCA were to occur, when both layer of the shield plugs are removed in OPCON 3. These lower doses are a result of a more location specific analysis of the travel routes. The 4.8 Rem value remains the bounding value in all other conditions and areas until specific analysis are performed.

(8) The information in this Table is historical and represents original plant design requirements. The application of Alternative Source Terms per Regulatory Guide 1.183, resulted in the recalculation of control room dose. See Chapter 15 for details.

Table 1.13-2

RADIATION DOSES FOR VITAL AREA ACCESS PATHS[1] [2] [5] [7]

Access Path [2]	Transit Time (min.)	Peak Piping and Cloud Shine Dose (Rem)	Peak Airborne Whole Body Dose (Rem)	Sum of Shine Plus Whole Body Dose (Rem)	Peak Airborne Thyroid Dose (Rem)	Peak Airborne Skin Beta Dose (Rem)
A	4	$6x10^{-3}$	$1x10^{-3}$	$7x10^{-3}$	$1.4x10^{-2}$	$9x10^{-4}$
A' (Alternate)	3	$2x10^{-3}$	$1x10^{-3}$	$3x10^{-3}$	$1x10^{-2}$	$7x10^{-4}$
B	2	$3x10^{-3}$	$5x10^{-4}$	$4x10^{-3}$	$7x10^{-3}$	$5x10^{-4}$
C	0.5	$3x10^{-3}$	$8x10^{-4}$	$4x10^{-3}$	$1x10^{-2}$	$7x10^{-4}$
C' (Alternate)	3	$3x10^{-2}$	$5x10^{-3}$	$4x10^{-2}$	$7x10^{-2}$	$5x10^{-3}$
D	2	$2x10^{-1}$[3]	$5x10^{-4}$	$2x10^{-1}$[3]	$7x10^{-3}$	$5x10^{-4}$
D' (Alternate)	4	$5x10^{-3}$[3]	$1x10^{-3}$	$6x10^{-3}$[3]	$1.4x10^{-2}$	$1x10^{-3}$
E	[4]	[4]	[4]	[4]	[4]	[4]
E' (Alternate)	15	$3x10^{-3}$	$2.4x10^{-2}$	$3x10^{-2}$	$3.3x10^{-1}$	$2x10^{-2}$
E''(Alternate)						
Unit 1 LOCA	15	$7.8x10^{-1}$[6]	$2.4x10^{-2}$	$8.0x10^{-1}$	$3.3x10^{-1}$	$2x10^{-2}$
Unit 2 LOCA	15	$2.5x10^{-1}$	$2.4x10^{-2}$	$2.7x10^{-1}$	$3.3x10^{-1}$	$2x10^{-2}$
F	2	$1x10^{-3}$	$4x10^{-3}$	$5x10^{-3}$	$5.1x10^{-2}$	$4x10^{-3}$
F' (Alternate)	0.5	$6x10^{-3}$	$1x10^{-3}$	$7x10^{-3}$	$1.3x10^{-2}$	$9x10^{-4}$

(1) Dose rates for all parts of access paths are $\leq$10 Rem/hour except as noted in Table 1.13-3.

(2) Access paths are described in Table 1.13-5.

(3) Dose rates will increase slightly at time t = 36 hours when the H_2 recombiner starts operating, but doses will still be below the peak values shown in this table.

(4) Path is not accessible. See Table 1.13-3.

(5) The above doses exclude the impact of the MSIV leakage alternate drain pathway. This source is significant only for paths through the Turbine Enclosure. SCBAs may be required for thyroid protection.

(6) This is an increase of 1.057 Rem (total) above the unit 2 LOCA dose due to the shine from the unit 1 drywell head through the reactor building north wall. These doses are based on the lower layer of reactor well shield plugs being removed on one unit in OPCON 3, and both layers of the other unit being installed or have the unit in OPCON 4 or 5.

(7) The information in this Table is historical and represents original plant design requirements based on source terms consistent with TID-14844. The application of Alternative Source Terms per Regulatory Guide 1.183 may be used to determine vital area radiation doses for subsequent evaluations.

Table 1.13-3

SOLUTIONS TO POTENTIAL VITAL AREA ACCESS PROBLEMS[1][2]

Potential Problem Area	Description	Solution	Remarks
Access Path D	The northeast area of the radwaste enclosure at el 217' near the airlock for the reactor enclosure will have radiation levels of 20 R/hr at time t = 0 hours.	It is preferable to use access path D' instead of access path D until the dose rate falls below 10 Rem/hr in the vicinity of the airlock.	From Figure 1.13-1, it can be seen that the dose rate near the airlock will fall below 10 Rem/hr about 2 hours after a DBA. Access path D would be used for access to the radwaste control room, radiochemical laboratory, or counting area from the control room.If access is required before the dose rate for access path D has fallen to acceptable levels, the operators can use access path D' to enter the radwaste control room. However, it is not necessary to prohibit access in the vicinity of the airlock because the radiation levels decay rapidly and are in a localized area with short transit.
Access Path E	The stairway next to the reactor enclosure exhaust stack will have peak radiation levels of 28 R/hr at time t = 4 hours.	Access path E' should be used until the dose rate falls below 10 R/hr in the stairway. If both the upper and lower reactor well shield plugs are removed, then use path E''	The first sample from the north stack instrument room must be taken within 24 hours. Due to the long time required to pass through the stairway in access path E and the extent of the radiation field, access to the north stack instrument room using this stairway is not possible until after time t = 24 hours.
Access Path E'	If both reactor well shield plugs on either Unit are removed, the refueling floor travel path will have radiation levels of 100 R/hr at t = 0 hours.	Access path E'' should be used until the dose rate falls below 10 R/hr on the refueling floor.	Access to the refueling floor will not drop below 10 R/hr until after time t = 9 hrs.

(1) Access paths are described in Table 1.13-5.

(2) This information had not been updated to reflect the current licensing design basis. The information should be used for historical reference only and not to support the design basis of the plant.

Table 1.13-4

POTENTIAL UNPLANNED RELEASE PATHS

System(s)	Boundary	Potential Release Path	Administrative Control
Air Removal and Sealing Steam	HV-07-142, -143, -144, -145, (Normally Closed)	Airborne contamination release (local) if valves left open after equalizing pressures	Operating procedure requires valve closure
Liquid Radwaste Equipment Drain Processing	62-0021 (Normally Closed)	Airborne contamination release (local) if valve is left open	Operating procedure requires valve closure
Control Rod Drive	XV-47-1F180 XV-47-1F181 XV-47-1F010 XV-47-1F011 (All valves fail closed)	Scram discharge header volume release to DRW or equipment drain collection tank	Operating procedure provides precaution notice
Various Nonradioactive Systems	Valves or heat exchanger tube sheets	Potential cross contamination at radioactive/nonradioactive system interfaces	Routine analysis in chemistry surveillance
Plumbing and Drainage	Open area drains and/or equipment drains	Inappropriate use of segregated drain systems	Precaution notices, drain plugs, curbs and/or color-coded labels around drains to identify
Plumbing and Drainage	Open area and/or equipment drains inside reactor	Open drains are a potential path for air flow from enclosure (air supply fan area and refueling floor)	Controlled opening of plugged drains secondary containment, if the ¼ in. wg. negative pressure is interrupted
Liquid Radwaste Collection	Offsite disposal of sump oil	Sump oil is potentially contaminated	Chemistry sample analysis required prior to disposal
Liquid Radwaste and Waste Water	Release of final radwaste batch to cooling tower blowdown (monitored)	Unauthorized release (inadvertent)	Routine surveillance

Table 1.13-5

ACCESS PATH IDENTIFICATION[1]



Table 1.13-5 (Cont'd)[1]

Access Path	Route Description	Reference (Bechtel) Drawings
D' (Alternate to D)	In main control room, proceed to stairs/elevator near Columns N & 20. Continue downstairs to el 217' and the PASS. Exit control structure and proceed west (corridor 352) to turbine enclosure exit (Columns Jb & 5). Exit building and proceed south to the end of the radwaste enclosure, then turn east. Enter radwaste enclosure near Columns 13 & C. Proceed north to vital areas.	8031-M-104, M-103 and M-102
E (Radwaste Enclosure el 217' to North Stack Instrument Room)	Exit the radwaste enclosure at Columns J & 14. Walk east through Unit 1 turbine enclosure to control structure. Walk up stairs at Columns M & 20 to el 332'. Proceed southeast across room to stairs at Columns J & 21.8 next to the north stack. Climb stairs to el 411', north stack instrument room.	8031-M-102, M-103, M-104, M-105 M-124, and M-139
E' (Alternate to E)	Exit the radwaste area at Columns J & 14. Continue east through turbine enclosure into Unit 2 side After entering Unit 2 side, continue east to the Unit 2 reactor enclosure entrance (Column 32). Enter stairs near Columns J & 32 and continue up the stairs to el 352' (refueling floor). Proceed south on refueling floor to the door on the south wall between the two units (Columns 22 & D). Enter door and proceed up ladder to south stack instrument area (el 411'). Cross roof area to north stack instrument room.	8031-M-102, M-103, M-104, M-105, M-106, and M-139
E'' (Alternate to E & E', if both reactor well shield plugs are removed)	Personnel shall use the most dose-efficient pathway to enter the 217' elevation of the control structure. Continue up stairs at Columns M and 20 to elevation 324'. Proceed out onto turbine enclosure roof Take scaffold stairs at Columns Kg and 17.6 to reactor enclosure roof elevation 411', proceed along farthest north point of travel on roof to north stack instrument room WRAM sample area.	8031-M-102, M-103, M-104, M-105, M-106, and M-139
F (Radwaste Enclosure el 217' to Diesel Generator Bays	Proceed south through radwaste enclosure to exit at Columns C & 13. Enter yard and move towards south) entrance of the emergency diesel generator bays. Enter bay area.	8031-M-102
F' (Alternate to F)	Proceed south through radwaste enclosure and exit into yard. Continue northeast towards reactor enclosure. Enter generator bays through the north entrance.	8031-M-102

(1) This information has not been updated to reflect the current licensing design basis. The information should be used for historical reference only and not support the design basis of the plant.

Table 1.13-6

RADIATION QUALIFICATION OF SAFETY-RELATED EQUIPMENT(1)

Containment	LOCA Source Term (Noble Gas/Iodine/ Particulate)	Non-LOCA HELB Source Term (Noble Gas/Iodine/Particulate)
Outside	Percent (100/50/1) in RCS	Percent (10/10/0) in RCS
Inside	Larger of (100/50/1) or (100/50/1) in RCS	(10/10/0) In RCS in containment

(1) This Table is based on the requirements of Regulatory Guides 1.3, 1.5, and 1.25, consistent with the source terms of TID-14844. Alternative Source Terms, per Regulatory Guide 1.183 requirements may be used for the qualification of safety related equipment.

Table 1.13-7

X/Q VALUES FOR VITAL AREAS[2]

	Time Periods (hours)	Base X/Q (sec/m^3)	Modifying Factors f_1	f_2	f_3	f_4	f_5	f_6	Final X/Q (sec/m^3)	
Technical Support Center	0-8		1.58×10^{-4}	1	1	.2	1	.5	.66[1]	1.04×10^{-5}
	8-24		1.58×10^{-4}	.67	.88	.2	1	.5	.66[1]	6.15×10^{-6}
	24-96		1.58×10^{-4}	.50	.75	.2	1	.5	.66[1]	3.91×10^{-6}
	96-720		1.58×10^{-4}	.33	.50	.2	1	.5	.66[1]	1.72×10^{-6}
	720 & on		1.58×10^{-4}	.25	.33	.2	1	.5	.66[1]	8.6×10^{-7}
Diesel Generator Areas	0-8		2.57×10^{-4}	1	1	.2	1	.5	.66[1]	1.70×10^{-5}
	8-24		2.57×10^{-4}	.67	.88	.2	1	.5	.66[1]	1.00×10^{-5}
	24-96		2.57×10^{-4}	.50	.75	.2	1	.5	.66[1]	6.36×10^{-6}
	96-720		2.57×10^{-4}	.33	.50	.2	1	.5	.66[1]	2.80×10^{-6}
	720 & on		2.57×10^{-4}	.25	.33	.2	1	.5	.66[1]	1.40×10^{-6}
Security Center	0-8		5.16×10^{-4}	1	1	.2	1	.5	.66[1]	3.41×10^{-5}
	8-24		5.16×10^{-4}	.67	.88	.2	1	.5	.66[1]	2.01×10^{-5}
	24-96		5.16×10^{-4}	.50	.75	.2	1	.5	.66[1]	1.28×10^{-5}
	96-720		5.16×10^{-4}	.33	.50	.2	1	.5	.66[1]	5.62×10^{-6}
	720 & on		5.16×10^{-4}	.25	.33	.2	1	.5	.66[1]	2.81×10^{-6}
Turbine Building HVAC Air Intakes - PASS, OSC	0-8		8.25×10^{-4}	1	1	.2	1	.5	.66[1]	5.45×10^{-5}
	8-24		8.25×10^{-4}	.67	.88	.2	1	.5	.66[1]	3.21×10^{-5}
	24-96		8.25×10^{-4}	.50	.75	.2	1	.5	.66[1]	2.04×10^{-5}
	96-720		8.25×10^{-4}	.33	.50	.2	1	.5	.66[1]	8.98×10^{-6}
	720 & on		8.25×10^{-4}	.25	.33	.2	1	.5	.66[1]	4.49×10^{-6}
Radwaste Building HVAC Air Intake - Radiation Chemistry Lab, Counting Room, Radwaste Control Room	0-8		6.19×10^{-4}	1	1	.2	1	.5	.66[1]	4.09×10^{-5}
	8-24		6.19×10^{-4}	.67	.88	.2	1	.5	.66[1]	2.41×10^{-5}
	24-96		6.19×10^{-4}	.50	.75	.2	1	.5	.66[1]	1.53×10^{-5}
	96-720		6.19×10^{-4}	.33	.50	.2	1	.5	.66[1]	6.74×10^{-6}
	720 & on		6.19×10^{-4}	.25	.33	.2	1	.5	.66[1]	3.37×10^{-6}
Main Control Room, HVAC Panels, and North Stack Instrument Room	0-8									3.46×10^{-4}
	8-24									2.04×10^{-4}
	24-96									1.30×10^{-4}
	96-720									5.71×10^{-5}
	720 & on									2.85×10^{-5}

(1) For the MSIV Leakage Alternate Drain Pathway, the F_6 factor is 1.0, since this release point is not an elevated release point.

(2) This Table is historical. The application of Alternative Source Terms per Regulatory Guide 1.183 resulted in the re-evaluation of X/Q values. See UFSAR Section 2.3.

Table 1.13-8

HIGH-RANGE NOBLE GAS EFFLUENT MONITORS (TABLE II.F.1-1)

REQUIREMENT	-	Capability to detect and measure concentrations of noble fission products in plant gaseous effluents during and following an accident. All potential accident release paths shall be monitored.
PURPOSE	-	To provide the plant operator and emergency planning agencies with information on plant releases of noble gases during and following an accident.

DESIGN BASIS MAXIMUM RANGE

Design range values may be expressed in Xe-133 equivalent values for monitors employing gamma radiation detectors or in microcuries per cubic centimeter (μCi/cc) of air at standard temperature and pressure for monitors employing beta radiation detector (Note: 1R/hr @ 1 ft = 6.7 Ci Xe-133 equivalent for point source). Calibrations with a higher energy source are acceptable. The decay of radionuclide noble gases after an accident (i.e., the distribution of noble gas changes) should be taken into account.

10^5 μCi/cc	-	Undiluted containment exhaust gases (e.g., PWR reactor building purge, BWR drywell purge through the SGTS).
	-	Undiluted PWR condenser air removal system exhaust.
10^4 μCi/cc	-	BWR reactor building (secondary containment) exhaust air.
	-	PWR secondary containment exhaust air.
10^3 μCi/cc	-	Buildings with systems containing primary coolant or primary coolant offgases (e.g., PWR auxiliary buildings, BWR turbine buildings).
	-	PWR steam safety valve discharge, atmospheric steam dump valve discharge.
10^2 μCi/cc	-	Other release points (e.g., radwaste buildings, fuel handling/storage buildings).

Table 1.13-8 (Cont'd)

REDUNDANCY	-	Not required; monitoring the final release point of several discharge inputs is acceptable.
SPECIFICATIONS	-	(None) Sampling design criteria per ANSI N13.1.
POWER SUPPLY	-	Vital instrument bus or dependable backup power supply to normal alternating current.
CALIBRATION	-	Calibrate monitors using gamma detectors to Xe-133 equivalent (1R/hr @ 1 ft = 6.7 Ci Xe-133 equivalent for point source). Calibrate monitors using beta detectors to Sr-90 or similar long-lived beta isotope of at least 0.2 MeV.
DISPLAY	-	Continuous and recording as equivalent Xe-133 concentrations or μCi/cc of actual noble gases.
QUALIFICATION	-	The instruments shall provide sufficiently accurate responses to perform the intended function in the environment to which they will be exposed during accidents.
DESIGN CONSIDERATIONS	-	Offline monitoring is acceptable for all ranges of noble gas concentrations.
	-	Inline (induct) sensors are acceptable for 10^2 μCi/cc to 10^5 μCi/cc noble gases. For less than 10^2 μCi/cc, offline monitoring is recommended.
	-	Upstream filtration (prefiltering to remove radioactive iodines and particulates) is not required; however, design should consider all alternatives with respect to capability to monitor effluents following an accident.
	-	For external mounted monitors (e.g., PWR main steam line, the thickness of the pipe should be taken into account in accounting for low-energy gamma radiation.

Table 1.13-9

INTERIM PROCEDURES FOR QUANTIFYING
HIGH-LEVEL ACCIDENTAL RADIOACTIVITY RELEASES (TABLE II.F.1-2)

Applicants are to implement procedures for estimating noble gas and radioiodine release rates if the existing effluent instrumentation goes off-scale.

Examples of major elements of a highly radioactive effluent release special procedures (noble gas).

- Preselected location to measure radiation from the exhaust air, e.g., exhaust duct or sample line.

- Provide shielding to minimize background interference.

- Use of an installed monitor (preferable) or dedicated portable monitoring (acceptable) to measure the radiation.

- Predetermined calculational method to convert the radiation level to radioactive effluent release rate.

Table 1.13-10

SAMPLING AND ANALYSIS OR MEASUREMENT OF
HIGH-RANGE RADIOIODINE AND PARTICULATE EFFLUENTS
IN GASEOUS EFFLUENT STREAMS (TABLE II.F.1-3)

EQUIPMENT	-	Capability to collect and analyze or measure representative samples of radioactive iodines and particulates in plant gaseous effluents during and following an accident. The capability to sample and analyze for radioiodine and particulate effluents is not required for PWR secondary main steam safety valve and dump valve discharge lines.
PURPOSE	-	To determine quantitative release of radioiodines and particulates for dose calculation and assessment.
DESIGN BASIS SHIELDING ENVELOPE	-	10^2 μCi/cc of gaseous radioiodine and particulates, deposited on sampling media; 30 minutes sampling time, average gamma energy (E) of 0.5 MeV.

SAMPLING MEDIA

- Iodine > 90% effective adsorption for all forms of gaseous iodine.
- Particulates > 90% effective retention for 0.3 micron (μ) diameter particles.

SAMPLING CONSIDERATIONS

- Representative sampling per ANSI N13.1 (1969).
- Entrained moisture in effluent stream should not degrade adsorber.
- Continuous collection required whenever exhaust flow occurs.
- Provisions for limiting occupational dose to personnel incorporated in sampling systems, in sample handling and transport, and in analysis of samples.

Table 1.13-10 (Cont'd)

ANALYSIS
- Design of analytical facilities and preparation of analytical procedures shall consider the design basis sample.
- Highly radioactive samples may not be compatible with generally accepted analytical procedures; in such cases, measurement of emissive gamma radiations and the use of shielding and distance factors should be considered in design.

Table 1.13-11

CONTAINMENT HIGH-RANGE RADIATION MONITOR (TABLE II.F.1-4)

REQUIREMENT -	The capability to detect and measure the radiation level within the reactor containment during and the following an accident.
RANGE -	1 rad/hr to 10^8 rads/hr (beta and gamma) or alternatively 1 R/hr to 10^7 R/hr (gamma only).
RESPONSE -	60 keV to 3 MeV photons, with linear energy response (±20%) for photons of 0.1 MeV to 3 MeV. Instruments must be accurate enough to provide usable information.
REDUNDANT -	A minimum of two physically separated monitors (i.e., monitoring widely separated spaces within containment).
DESIGN AND QUALIFICATION -	Category I instruments as described in Appendix A, except as listed below.
SPECIAL CALIBRATION -	In situ calibration by electronic signal substitution is acceptable for all range decades above 10 R/hr. In situ calibration for at least one decade below 10 R/hr shall be by means of calibrated radiation source. The original laboratory calibration is not an acceptable position due to the possible differences after in situ installation. For high-range calibration, no adequate sources exist, so an alternate was provided.
SPECIAL ENVIRONMENTAL QUALIFICATIONS -	Calibrate and type-test representative specimens of detectors at sufficient points to demonstrate linearity through all scales up to 10^6 R/hr. Prior to initial use, certify calibration of each detector at least one point per decade of range between 1 R/hr and 10^3 R/hr.

Table 1.13-12

INFORMATION REQUIRED FOR CONTROL ROOM HABITABILITY EVALUATION
(TABLE III.D.3.4-1)

(1) Control room mode operation, i.e., pressurization and filter recirculation for radiological accident isolation or chlorine release

(2) Control room characteristics:

- (a) air volume control room
- (b) control room emergency zone (control room, critical files, kitchen, washroom, computer room, etc.)
- (c) control room ventilation system schematic with normal and emergency air flow rates
- (d) infiltration leakage rate
- (e) high efficiency particulate air filter and charcoal absorber efficiencies
- (f) closest distance between containment and air intake
- (g) layout of control room, air intakes, containment building, and chlorine, or other chemical storage facility with dimensions
- (h) control room shielding including radiation streaming from penetrations, doors, ducts, stairways, etc.
- (i) automatic isolation capability-damper closing time, damper leakage and area
- (j) chlorine detectors or toxic gas (local or remote)
- (k) self-contained breathing apparatus availability (number)
- (l) bottled air supply (hours supply)
- (m) emergency food and potable water supply (how many days and how many people)
- (n) control room personnel capacity (normal and emergency)
- (o) potassium iodide drug supply

Table 1.13-12 (Cont'd)

(3) Onsite storage of chlorine and other hazardous chemicals:

- (a) total amount and size of container
- (b) closest distance from control room air intake

(4) Offsite manufacturing, storage, or transportation facilities of hazardous chemicals

- (a) identify facilities within a 5 mile radius
- (b) distance from control room
- (c) quantity of hazardous chemicals in one container
- (d) frequency of hazardous chemical transportation traffic (truck, rail, and barge)

(5) Technical specifications (refer to Standard Technical Specifications)

- (a) chlorine detection system
- (b) control room emergency filtration system including the capability to maintain the control room pressurization at $^1/_8$ inch water gauge, verification of isolation by test signals and damper closure times, and filter testing requirements.

Figures 1.2-1 through 1.2-72

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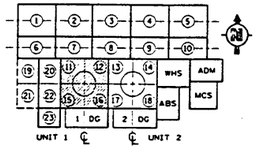
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Figures 1.2-74 through 1.2-82

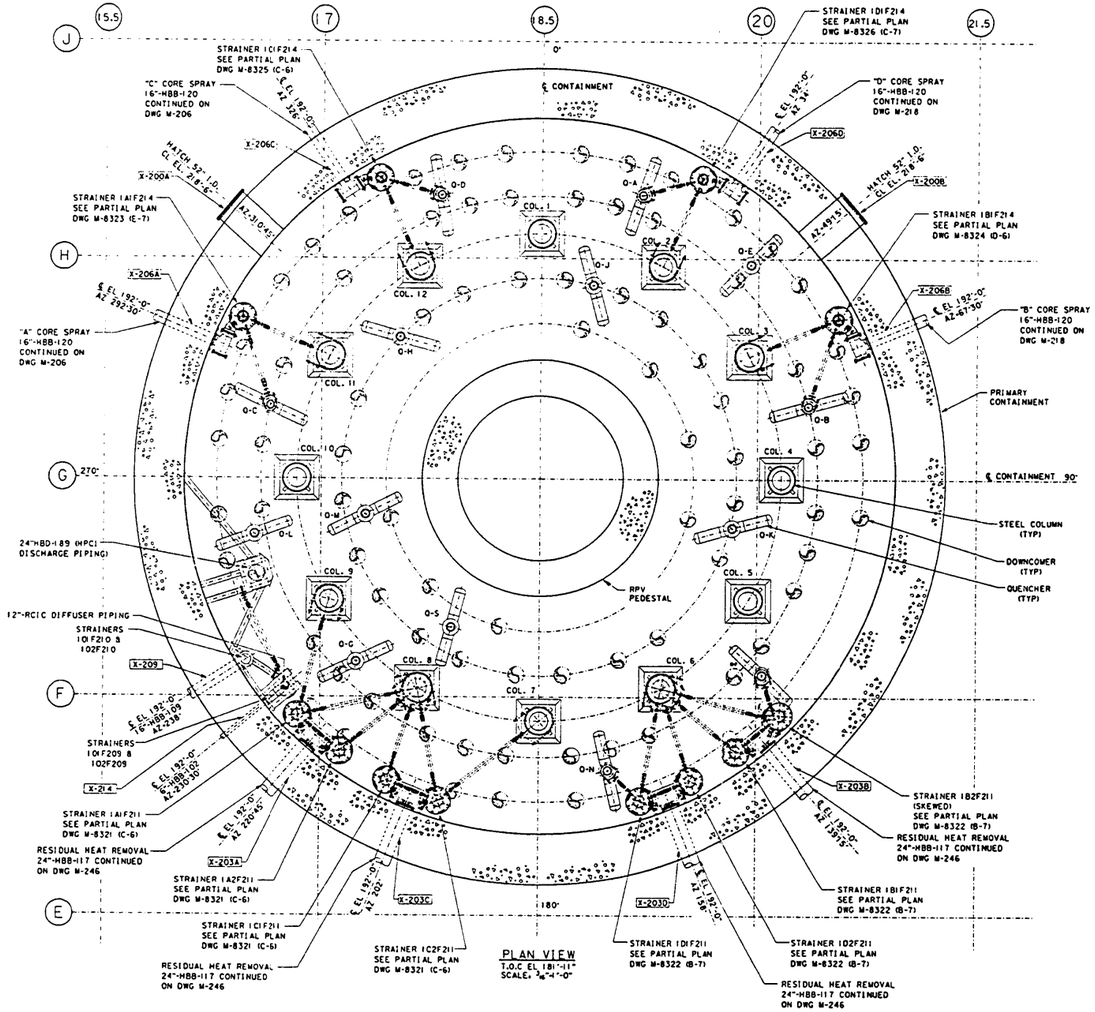
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M-8320

ROUTE



KEY PLAN



PLAN VIEW
T.O.C EL 181'-11"
SCALE: 3/16"=1'-0"

GENERAL NOTES:

1. SCALE, 3/16" = 1'-0"
2. STRAINER ASSEMBLY AND SHOP FABRICATION TO BE IN ACCORDANCE WITH PECO SPECIFICATION NE-265.
3. STRAINER SUPPORTS AND SHOP FABRICATION TO BE IN ACCORDANCE WITH PECO SPECIFICATION NE-269.
4. FABRICATION, INSTALLATION AND INSPECTION OF STRAINERS TO BE IN ACCORDANCE WITH ASME CODE REQUIREMENTS, ASME III, 1986 (UNSTAMPED). THE STRAINERS ARE CLASS NC. THE BOLTING IS CLASS NF.
4. FABRICATION, INSTALLATION AND INSPECTION OF SUPPORTS TO BE IN ACCORDANCE WITH ANSI B31.7 1969 EDITION WITH ADDEDA THROUGT MARCH 1971.

REFERENCE DRAWINGS:

RHR STRAINER 1A1F211, 1A2F211, 1C1F211 & 1C2F211 ARRGT DWG		M-8321
RHR STRAINER 1B1F211, 1B2F211, 1D1F211 & 1D2F211 ARRGT DWG		M-8322
CORE SPRAY STRAINER 1A1F214 ARRANGEMENT DWG		M-8323
CORE SPRAY STRAINER 1B1F214 ARRANGEMENT DWG		M-8324
CORE SPRAY STRAINER 1C1F214 ARRANGEMENT DWG		M-8325
CORE SPRAY STRAINER 1D1F214 ARRANGEMENT DWG		M-8326
RHR & CORE SPRAY SUCTION STRAINER DETAILS DWG		M-8327
P & I D RESIDUAL HEAT REMOVAL DWG	803I-M-51	SHT 1 & 3
P & I D CORE SPRAY DWG	803I-M-52	SHT 1
PIPING AND MECHANICAL MISC. PLAN & SECTIONS DWG	803I-M-206	
PIPING AND MECHANICAL MISC. PLAN & SECTIONS DWG	803I-M-218	
PIPING AND MECHANICAL MISC. PLAN & SECTIONS DWG	803I-M-246	
M.S.R.V. DISCHARGE PIPING PLAN EL 181'-11" DWG	803I-M-453	
PENETRATION SCHEDULE	803I-C-279	
LINER PLATE REQUIREMENTS	803I-C-277 & C-281	
PRIMARY CONTAINMENT DOWNCOMER DETAILS	803I-C-293	
STEEL COLUMN IN SUPPRESSION POOL	803I-C-300	

VENDOR DRAWINGS:

MISC ECCS STRAINER DETAILS.	PECO DOC No. NE-265-25-1
RHR & CORE SPRAY STRAINER DETAILS.	PECO DOC No. NE-265-264-1, 2, 3 & 4
STRAINER NAME PLATE.	PECO DOC No. NE-265-27-1
RHR STRAINER TOP MODULE ASSEMBLY.	PECO DOC No. NE-265-28-1, 2 & 3
RHR STRAINER MODULE GENERAL ARRGT.	PECO DOC No. NE-265-29-1
CORE SPRAY STRAINER TOP MODULE ASSEMBLY.	PECO DOC No. NE-265-30-1, 2 & 3
CORE SPRAY STRAINER MODULE GENERAL ARRGT.	PECO DOC No. NE-265-31-1
CORE SPRAY MOUNTING ELBOW.	PECO DOC No. NE-265-38-1
RHR STRAINER BOTTOM MODULE ASSEMBLY.	PECO DOC No. NE-265-39-1 & 2
CORE SPRAY STRAINER BOTTOM MODULE ASSEMBLY.	PECO DOC No. NE-265-34-1 & 2
RHR & CORE SPRAY PLATE DETAILS.	PECO DOC No. NE-265-36-1
TAPERED DUTCHMAN FLANGE ASSEMBLY	PECO DOC No. NE-265-42-1

TABLE OF ADDITIONS & CHANGES
USE ONLY PRINTS SHOWING LATEST DATE

REV	DATE	DESCRIPTION	DES	DRN	CHK
0	3/28/88	INCORPORATED: MOD P00285-1 LCR'S LG 97-03063 REV. 1, AND LG 97-03064 REV. 1. PREPARED BY SMEC			
1	1/7/98	INCORPORATED: MOD P00285-1 ECR LG 98-00927 REV. 0. PREPARED BY SMEC	MJE	SJS	MJE

MECHANICAL

RHR & CORE SPRAY STRAINER GENERAL ARRANGEMENT PLAN
REACTOR BUILDING AREAS 11, 12, 15 & 16 EL 181'-11"
UNIT 1

LIMERICK GENERATING STATION UNITS 1 & 2
PHILADELPHIA ELECTRIC COMPANY

SCALE	DESIGN	DRAWN	CHECKED	DATE
AS NOTED	WFC	WFC	GAD	1/23/98

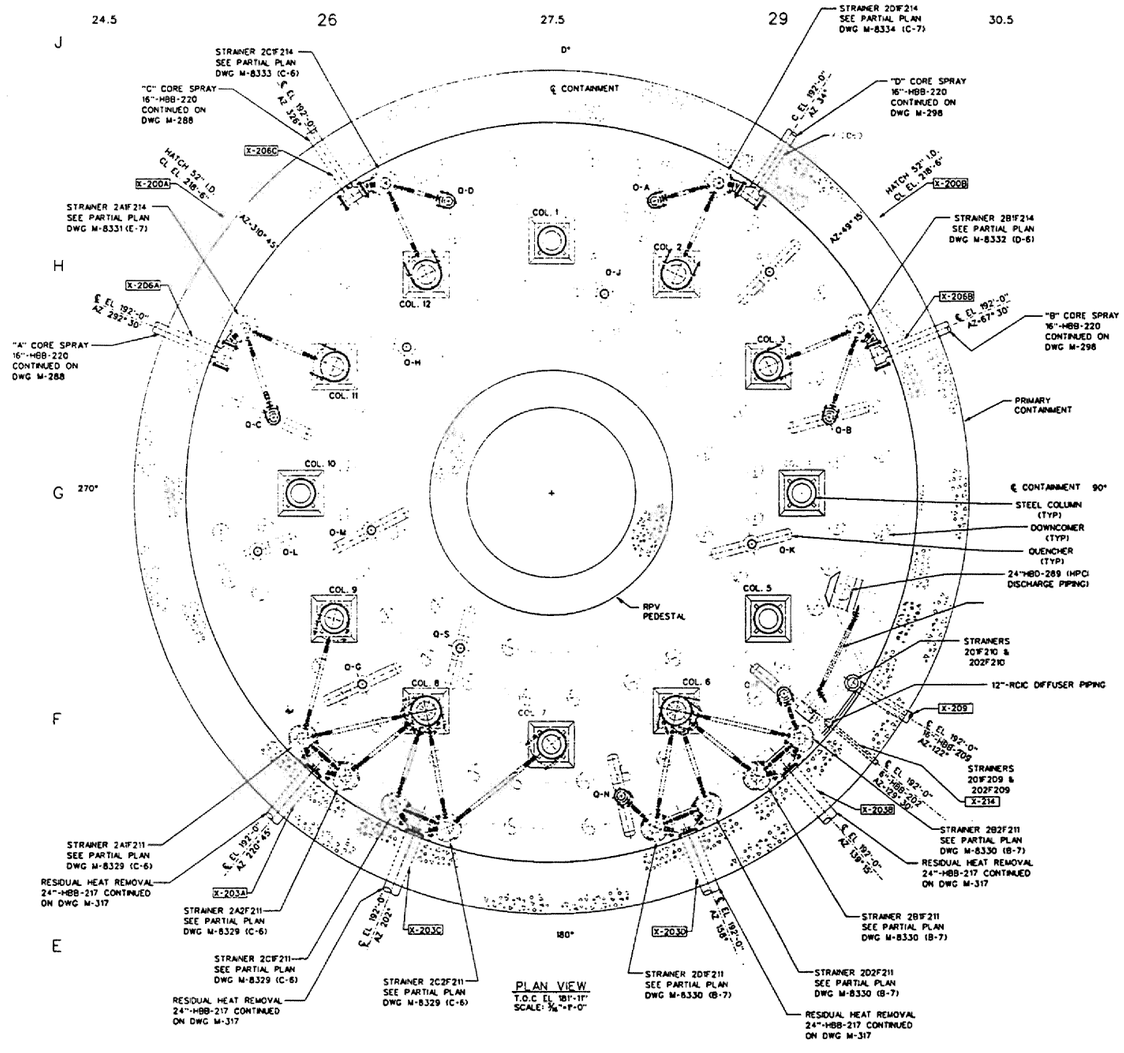
APPROVED _____ SUPT. DWGS (SMEC) APPROVED _____ MGR. NUC. ENGR. FOR G. REID

JOB NO.	DRAWING NUMBER	SHEET NUMBER	REV
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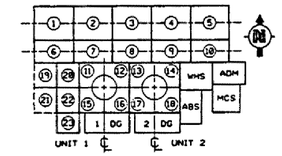
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M-8328

ROUTE



PLAN VIEW
T.O.C EL 181'-11"
SCALE: 3/16"=1'-0"



KEY PLAN

GENERAL NOTES:

1. SCALE: 3/16" = 1'-0"
2. STRAINER ASSEMBLY AND SHOP FABRICATION TO BE IN ACCORDANCE WITH PECO SPECIFICATION ME-265.
3. STRAINER SUPPORTS AND SHOP FABRICATION TO BE IN ACCORDANCE WITH PECO SPECIFICATION ME-269.
4. FABRICATION, INSTALLATION AND INSPECTION OF STRAINERS TO BE IN ACCORDANCE WITH ASME CODE REQUIREMENTS, ASME III, 1986 (UNSTAMPED). THE STRAINERS ARE CLASS NC. THE BOLTING IS CLASS NF.
5. FABRICATION, INSTALLATION AND INSPECTION OF SUPPORTS TO BE IN ACCORDANCE WITH ANSI B31.7 1969 EDITION WITH ADDENDA THROUGH MARCH 1971.

REFERENCE DRAWINGS:

RHR STRAINER 2A1F211, 2A2F211, 2C1F211 & 2C2F211 ARRGT DWG	M-8329
RHR STRAINER 2B1F211, 2B2F211, 2D1F211 & 2D2F211 ARRGT DWG	M-8330
CORE SPRAY STRAINER 2A1F214 ARRANGEMENT DWG	M-8331
CORE SPRAY STRAINER 2B1F214 ARRANGEMENT DWG	M-8332
CORE SPRAY STRAINER 2C1F214 ARRANGEMENT DWG	M-8333
CORE SPRAY STRAINER 2D1F214 ARRANGEMENT DWG	M-8334
RHR & CORE SPRAY SUCTION STRAINER DETAILS DWG	M-8335
P & ID RESIDUAL HEAT REMOVAL DWG	8031-M-51 SHT 7
P & ID CORE SPRAY DWG	8031-M-52 SHT 3
PIPING AND MECHANICAL MISC. PLAN & SECTIONS DWG	8031-M-288
PIPING AND MECHANICAL MISC. PLAN & SECTIONS DWG	8031-M-298
PIPING AND MECHANICAL MISC. PLAN & SECTIONS DWG	8031-M-317
M.S.R.V. DISCHARGE PIPING PLAN EL 185'-11" DWG	8031-M-453
PENETRATION SCHEDULE	8031-C-280
LINER PLATE REQUIREMENTS	8031-C-278 & C-281
PRIMARY CONTAINMENT DOWNCOMER DETAILS	8031-C-293
STEEL COLUMN IN SUPPRESSION POOL	8031-C-300

VENDOR DRAWINGS:

MISC ECCS STRAINER DETAILS,	PECO DOC No. N-DOE-265-25-1
RHR & CORE SPRAY STRAINER DETAILS,	PECO DOC No. N-DOE-265-26-1,2,3 & 4
STRAINER NAME PLATE,	PECO DOC No. N-DOE-265-27-1
RHR STRAINER TOP MODULE ASSEMBLY,	PECO DOC No. N-DOE-265-28-1,2 & 3
RHR STRAINER MODULE GENERAL ARRGT,	PECO DOC No. N-DOE-265-29-1
CORE SPRAY STRAINER TOP MODULE ASSEMBLY,	PECO DOC No. N-DOE-265-30-1,2 & 3
CORE SPRAY STRAINER MODULE GENERAL ARRGT,	PECO DOC No. N-DOE-265-31-1
CORE SPRAY MOUNTING ELBOW,	PECO DOC No. N-DOE-265-38-1
RHR STRAINER BOTTOM MODULE ASSEMBLY,	PECO DOC No. N-DOE-265-39-1 & 2
CORE SPRAY STRAINER BOTTOM MODULE ASSEMBLY,	PECO DOC No. N-DOE-265-34-1 & 2
RHR & CORE SPRAY PLATE DETAILS,	PECO DOC No. N-DOE-265-36-1

TABLE OF ADDITIONS & CHANGES
USE ONLY PRINTS SHOWING LATEST DATE

NO.	DATE	DESCRIPTION	BY	CHKD	APPD
0	9/28/98	INCORPORATED: MOD P00385-2 ECR LC 98-01692 REV. 0 ECR LC 98-01694 REV. 0 ECR LC 98-01695 REV. 0 PREPARED BY SAL			

MECHANICAL

RHR & CORE SPRAY STRAINER GENERAL ARRANGEMENT PLAN REACTOR BUILDING AREAS 13, 14, 17 & 18 EL 185'-11" UNIT 2

LIMERICK GENERATING STATION UNITS 1 & 2
PECO NUCLEAR

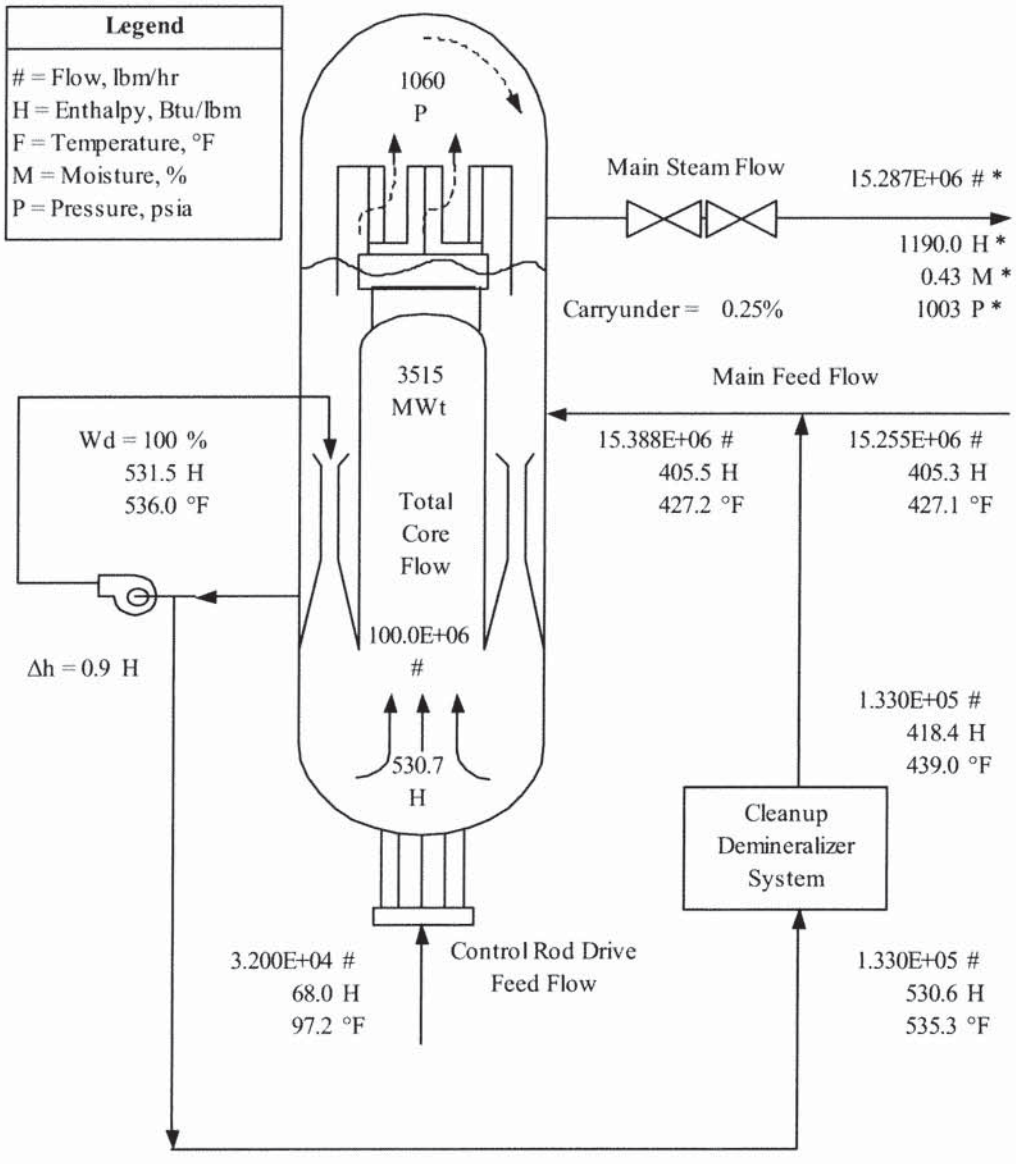
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AS NOTED				9/18/98

APPROVED | APPROVED

JOB NO.	DRAWING NUMBER	SHEET NUMBER	REV.
8031	M-8328	1	0

FILE No. M832851.DGN 09:18:98

UFSAR FIGURE 1.2-83
Sht. 2 of 2 Rev. 09 11/99



*Conditions at upstream side of TSV

Core Thermal Power	3515.0
Pump Heating	9.0
Cleanup Losses	-4.4
Other System Losses	-1.1
Turbine Cycle Use	3518.5 MWt

Note: Wd indicates recirculation drive flow.

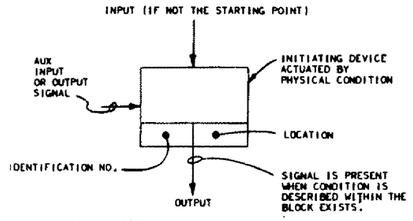
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR SYSTEM HEAT BALANCE

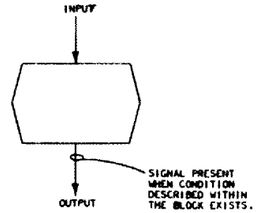
FIGURE 1.2-84 Rev. 16, 09/12

Figures 1.10-1

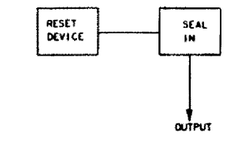
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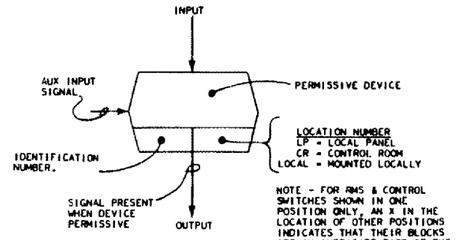
COMMAND BLOCK
THIS BLOCK CAN REPRESENT A SWITCH, VALVE, PROBE, TIMER, OR TRIP CIRCUIT. IT IS NORMALLY THE STARTING POINT OF A FUNCTIONAL SEQUENCE WITH AN OUTPUT ONLY, BUT CAN HAVE INPUT AND AUX. INPUT DEPENDING ON THE TYPE OF DEVICE. THE SAME DEVICE MAY HAVE A NUMBER OF OUTPUTS, BUT EACH FUNCTIONAL SEQUENCE INITIATED SHALL BE SHOWN BY AN INDIVIDUAL BLOCK SHOWING THE SAME IDENTIFICATION NUMBER.



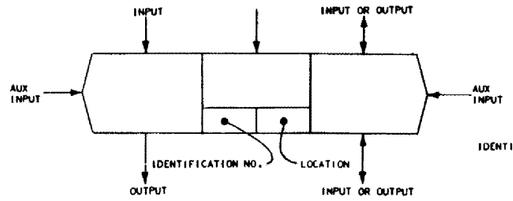
PERMISSIVE CONDITION BLOCK
WHERE THE PERMISSIVE IS A GENERAL CONDITION AND NOT IDENTIFIED WITH A SINGLE DEVICE THE OUTPUTS ENCLOSURE ONLY IS SHOWN



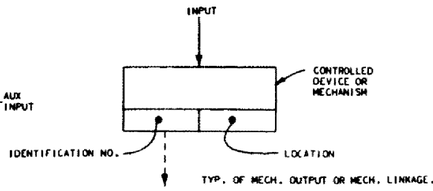
SEAL-IN BLOCK
A SEAL-IN OR LATCHING BLOCK'S FUNCTION IS TO MAINTAIN AN INPUT SIGNAL TO A DEVICE ONCE THE DEVICE HAS BEEN ACTUATED. RESETTING OR INHIBITING A SEAL-IN MAY BE EITHER EXPRESSED OR IMPLIED. IF IMPLIED, THE SEAL-IN WILL BE RESET OR INHIBITED BY INTERRUPTING THE SIGNAL TO THE DEVICE DOWNSTREAM FROM THE POINT WHERE SEAL-IN IS INDICATED. A SEAL-IN SHOWN WITHOUT A RESET DEVICE IMPLIES THAT THE RESET DEVICE IS PART OF, AND LOCATED ON THE NEAREST VALVE OR CONTACTOR. IN ALL OTHER CASES THE RESET DEVICE SHALL BE SHOWN IN CONJUNCTION WITH THE SEAL-IN.



PERMISSIVE DEVICE BLOCK
THIS BLOCK DEFINES A PERMISSIVE FUNCTION WHICH MUST BE SATISFIED TO PERMIT THE SIGNAL FLOW TO PASS TO THE NEXT BLOCK. THIS BLOCK HAS INCOMING, OUTGOING AND MAY HAVE AUXILIARY SIGNALS. THE OUTPUT FROM THIS PERMISSIVE MAY BE SEALED IN.

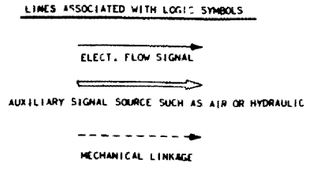


PERMISSIVE OPERATED BY OTHER DEVICES BLOCK
THIS BLOCK IS A PERMISSIVE OPERATED BY DEVICES SUCH AS VALVE OR PUMP SWITCHGEAR DESIGNATED IN THE INNER BLOCK. THIS COND. OR DEVICE EFFECTS THE OPERATION OF THE FINAL DEVICE. IT HAS ELECT. INPUTS, MECH INPUTS, AUX INPUTS (MECH OR ELEC) AND MECH OR ELECT OUTPUTS. THIS DEVICE IS NORMALLY A VALVE. THIS IS ALSO USED FOR OTHER INPUT/OUTPUT POWER SOURCES SUCH AS AIR OR HYDRAULIC. A SOLENOID PILOT VALVE FOR AN AIR OPERATED VALVE IS AN EXAMPLE OF THIS TYPE DEVICE.



FINAL DEVICE BLOCK
THIS BLOCK CAN BE A RELAY, VALVE, ELECTRO-MECH SW. ETC. NORMALLY IT HAS ONLY INPUTS, BUT CAN HAVE MECH OUTPUTS OR POSITION SWITCH OUTPUTS.

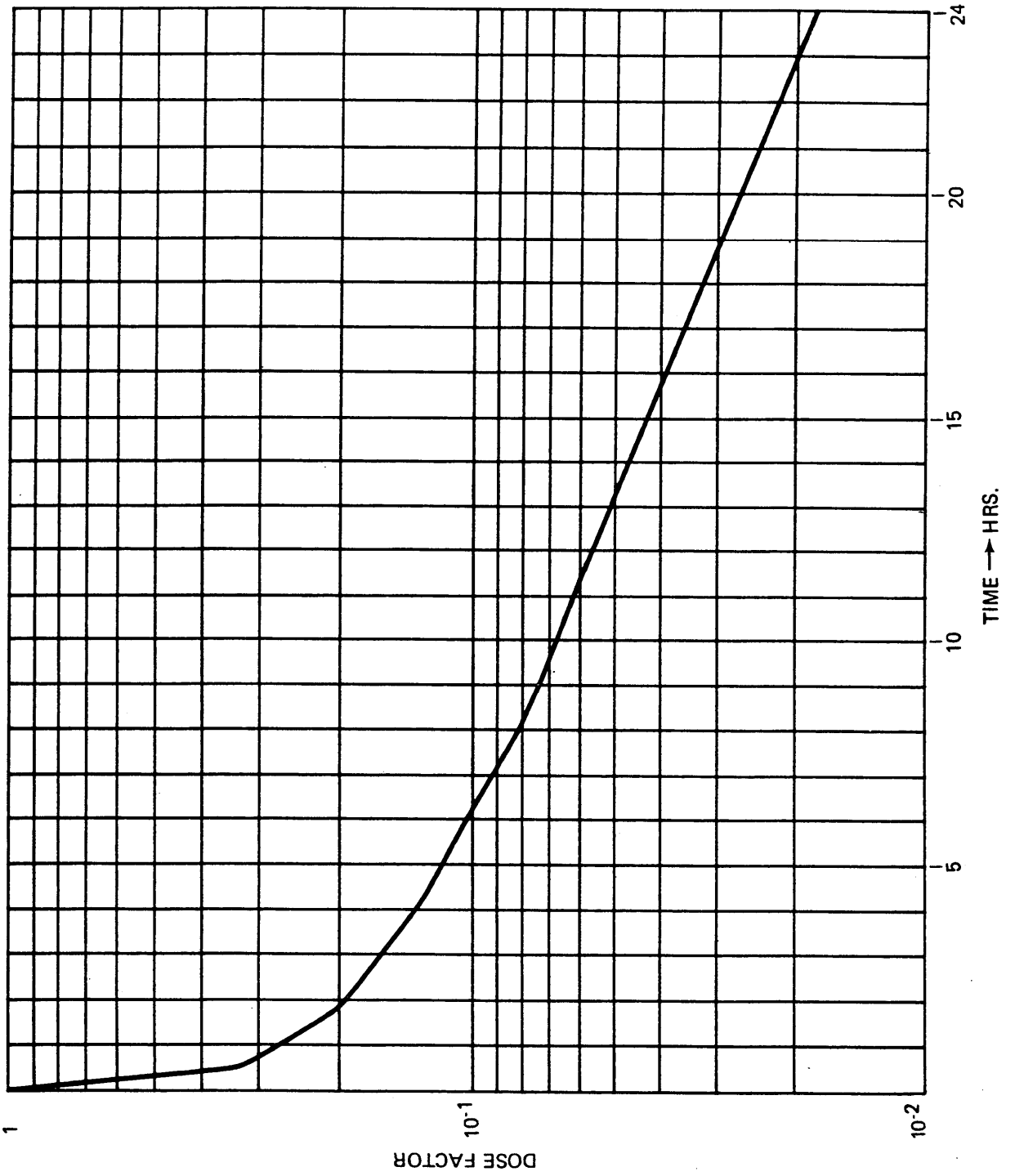
LINES ASSOCIATED WITH LOGIC SYMBOLS



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LOGIC SYMBOLS

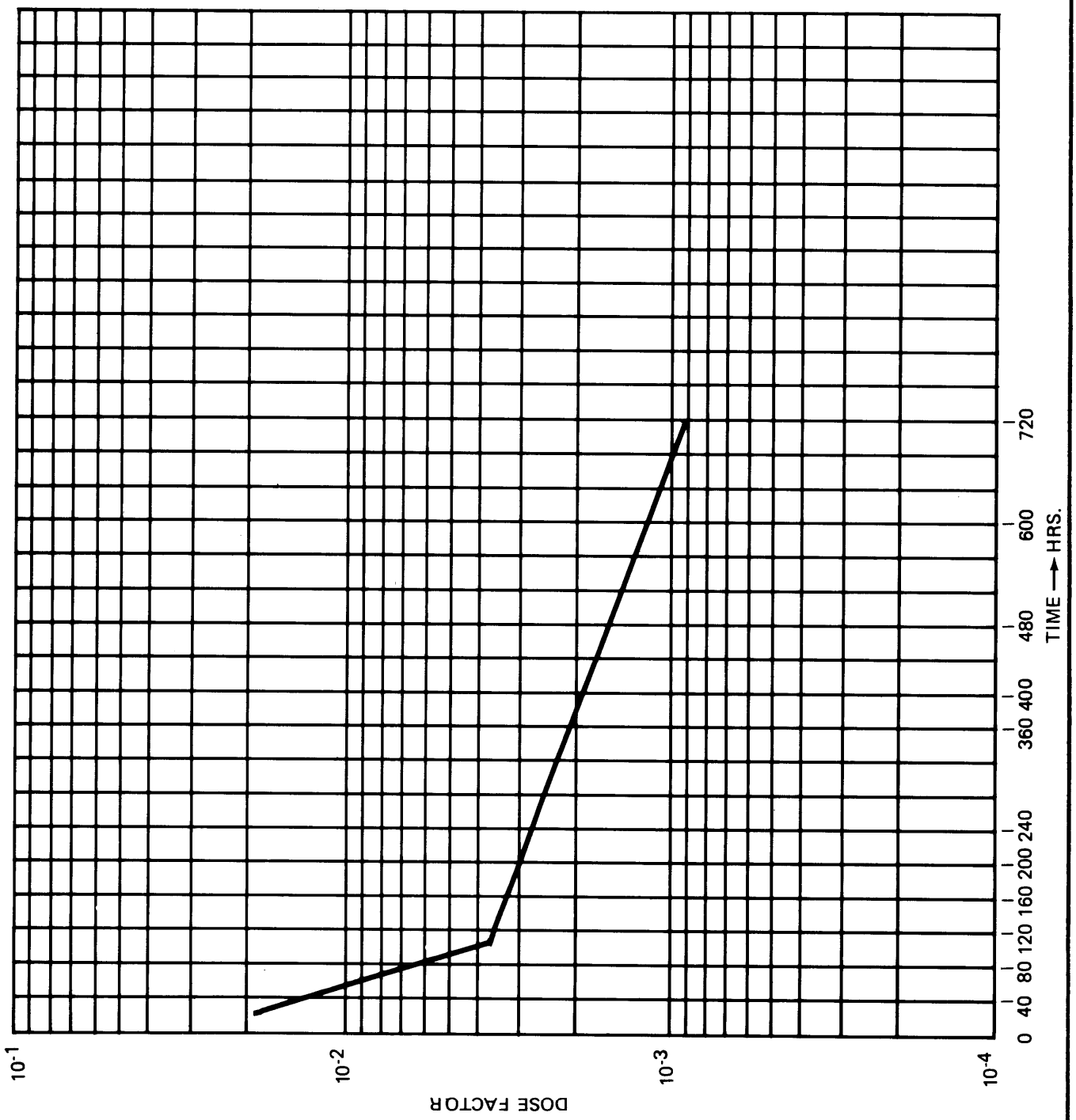
FIGURE 1.10-2



LIMERICK GENERATING STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DOSE RATE REDUCTION FACTORS FOR ECCS/RHR PIPING (0 TO 24 HRS)

FIGURE 1.13-1 Rev. 10 10/00



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DOSE RATE REDUCTION
FACTORS FOR ECCS/RHR PIPING
(24 TO 720 HRS)

FIGURE 1.13-2

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CHAPTER 2 - SITE CHARACTERISTICS

2.1 GEOGRAPHY AND DEMOGRAPHY

2.1.1 SITE LOCATION AND DESCRIPTION

2.1.1.1 Specification of Location

Limerick Generating Station is located in southeastern Pennsylvania on the Schuylkill River, about 1.7 miles southeast of the limits of the Borough of Pottstown and about 20.7 miles northwest of the Philadelphia city limits. The Schuylkill River passes through the site, separating the western portion located in East Coventry Township, Chester County, from the eastern portion located in Limerick Township and Pottsgrove Township, Montgomery County, Pennsylvania. Figure 2.1-1 identifies the general location of the LGS site, and Figure 2.1-2 shows the immediate environs within 5 miles of the site.

The Universal Transverse Mercator coordinates of the LGS Unit 1 reactor are 4,452,582.462 meters north and 449,984.170 meters east, Zone 18T. The corresponding Greenwich coordinates for Unit 1 are 40°13'26.67" north latitude and 75°35'16.27" west longitude. The Unit 2 reactor is located at 4,452,528.462 meters north and 450,033.548 meters east, Zone 18T of the Transverse Mercator Coordinate System with corresponding 40°13'26.64" north latitude and 75°35'14.15" west longitude coordinates.

2.1.1.2 Site Area

The land portion of the site consists of 595 acres, as shown in Figure 2.1-3. The property within the site boundary is owned by the licensee except as noted below. The site boundary is shown in Figure 2.1-3. The licensee owns additional property adjacent to the site on which the nuclear training center is located. This property is not considered part of the site. As shown in Figure 2.1-3, the site is traversed by several public roads, a railroad right-of-way and the Schuylkill River. These areas, including the island in the river, are considered public passageways and not part of the site property.

The site is located in gently rolling countryside, traversed by numerous valleys containing small streams which empty into the Schuylkill River. On the eastern bank of the Schuylkill River the terrain rises from just under el 110' MSL (mean sea level) at the river, to approximately el 300' MSL toward the east, which is the highest ground on the site boundary. Two parallel streams, Possum Hollow Run and Brooke Evans Creek, cut through the site in wooded valleys, running southwest into the Schuylkill River. The grade in the area of the reactor and turbine enclosures is about el 217 feet MSL. On the western bank of the river, the terrain is relatively flat, rising only about 50 feet from the shore to the western edge of the site. One small stream flows southeastward through the site to the Schuylkill River.

The locations of principal station structures are shown in Figure 2.1-4. In addition, the Limerick Energy Information Center is located on the site property. The information center, owned and operated by the licensee, is open to the public during specified hours. Admission to the information center is controlled by the licensee.

A nuclear training center consisting of a simulator, laboratories and classrooms is located on the licensee property adjacent to the site. This facility is operated and controlled by the licensee.

2.1.1.3 Boundaries for Establishing Effluent Release Limits

The boundary line of the restricted area, as defined in pre-1994 10CFR20, is identical to the site boundary line shown in Figure 2.1-3. The land area within the boundary lines is owned by the licensee. Control of public passageways is discussed in Section 2.1.2.1 and 2.1.3.3.

There are no permanent residences within the restricted area.

Station effluent release points are shown in Figure 2.1-4.

2.1.2 Exclusion Area Authority And Control

2.1.2.1 Authority

The exclusion area for LGS, shown in Figure 2.1-3, is defined as the area encompassed by a radius of 2500 feet from the center of each reactor unit. The property within the exclusion area is either owned or controlled by the licensee. Following fuel load, residence within the exclusion area will be prohibited in conformance with 10CFR100.

The Controlled Areas, as defined in the post-1994 10CFR20 Regulation, may be established within the Site Boundary line outside the Restricted Area. LGS has no Controlled Areas because of the Restricted Area boundary extends all the way out to the Site Boundary line.

As shown in Figure 2.1-3, the exclusion area is traversed by several public roads, a Conrail right-of-way, and the Schuylkill River. These areas, including the island in the river, are considered public passageways and not part of the site property. Arrangements for control of public access to these areas in the event of an emergency are discussed in Section 2.1.2.3.

There are no outstanding mineral rights within the exclusion area.

2.1.2.2 Control of Activities Unrelated to Plant Operation

Activities unrelated to plant operation that occur within the exclusion area, aside from transit through the area, are those associated with the Limerick Energy Information Center, located approximately 1500 feet from the plant along Longview Road and Frick's Lock. About 6,000 people are expected to visit the Information Center each year. The number of visitors to the center seldom exceeds 100 at any one time. Evacuation of these people is discussed in the Emergency Plan.

2.1.2.3 Arrangements for Traffic Control on Public Passageways

Arrangements have been made with the Pennsylvania State Police to control public access to the exclusion area in the event of an emergency.

Arrangements have been made with Conrail to control rail traffic through the exclusion area in the event of an emergency.

Letters of agreement between the licensee and the State Police are referenced in the Emergency Plan.

2.1.2.4 Abandonment or Relocation of Roads

Prior to station construction, Longview Road traversed the site in a southerly direction from the juncture of Sanatoga Road and Possum Hollow Road to the railroad right-of-way on the eastern bank of the Schuylkill River. This portion of Longview Road, approximately 6000 feet, was abandoned and relocated to the eastern edge of the LGS site on a portion of roadway formerly known as Lozark Road. New sections of the roadway were constructed to realign Longview Road and Lozark Road between Keen Road and the existing paving on Longview Road South of Brook Evans Creek. Both Longview and Lozark Roads are township roads.

2.1.3 POPULATION DISTRIBUTION

2.1.3.1 Population Within 10 Miles

The population distributions within 10 miles, as a function of distance and direction, for the decades 1970 through 2020 and for the year 1985 are listed in Tables 2.1-1 through 2.1-7. The 1970 and 1980 data are taken from actual census data; the other years are taken from projections (Table 2.1-15). The 1985 projections are considered to be representative of the population near the year of initial station operation, and the 2020 projections represent population near the end of station operation. These projections are based on 1980 census data. The 1980 data shows that population has decreased. A map, keyed to Tables 2.1-1 through 2.1-7, is provided in Figure 2.1-5.

The population distribution within 10 miles is based upon the number of households obtained from a 1980 meter count of PECO Energy Co.'s residential customer billing file, and upon a 1980 meter count of Metropolitan Edison Company's billing file. A factor of 2.88 persons per residential meter in PECo territory and a factor of 2.70 persons per residential meter for the Metropolitan Edison Company territory were used to convert the meter count into population.

Projected populations were determined by using county projection factors obtained from state agencies. Where information was not available to 2020, the licensee extended the available information through that year. Table 2.1-15 lists the sources of population information.

Population for the year 1985 was estimated by the licensee by interpolation of data between 1980 and 1990. Projections for the years 2010 and 2020 were made by increasing projections for the year 2000 at a rate of 20% per 10 year period.

2.1.3.2 Population Between 10 and 50 Miles

Population distribution between 10 and 50 miles for the decades 1970 through 2020 and for the year 1985 are listed in Tables 2.1-8 through 2.1-14. The 1970 and 1980 data are taken from actual census data; the other years are based on projections (Table 2.1-15). A map, keyed to Tables 2.1-8 through 2.1-14, is provided in Figure 2.1-6.

Projected populations were determined by using county projection factors obtained from state agencies. Where information was not available to 2020, the licensee extended the available information through that year. Table 2.1-15 lists the sources of population information.

Population changes for 1950 through 1980 in the counties within 50 miles of the station are indicated in Table 2.1-16.

2.1.3.3 Transient Population

The transient population in the site area is classified as daily or seasonal. The daily transients result from the influx of employees to local business and industrial facilities. Local industries, and their location and employment, are listed in Table 2.1-17. The only industries with a significant daily transient population are Mrs. Smith's Pie Company, Sircom Knitting Company, and Crouse Company.

A 1976 creel survey of people fishing the Schuylkill River within 3.1 miles of the station showed that 96% lived within 6.2 miles of the river and thus do not comprise a transient population. These data also projected 1980 fishing pressure within 3.1 miles of the station at 8800 angler hours for the principal fishing months of May through September. The average time spent fishing was 3.5 hours from shore and 4.7 hours by boat. Less than 20% of the fishing pressure came from boats. Based on these data and data collected in a 1980 creel survey conducted as part of the LGS preoperational program, an average of 1100 boaters per year could be expected to use the Schuylkill River within 10 miles of the station, most of which would occur below Vincent Dam (3.3 miles below the station).

2.1.3.4 Low Population Zone

The LPZ established for LGS, in accordance with 10CFR100, consists of the area within a radius of 1.27 miles (2043 meters). The LPZ and the estimated population within the LPZ are shown in Figure 2.1-7. Population estimates are based on the 1980 meter count.

There are no schools, parks, hospitals, prisons, or public beaches within the LPZ. Industrial facilities within the LPZ include Occidental Chemical Corporation, Amerind-MacKessie, Inc, Mahr Printing, Inc, Structural Foam, Inc, Eastern Warehouse, Inc, and Pottstown Trap Rock Quarries, Inc. The locations of these facilities are shown in Figure 2.2-2, and the number of employees at each location is listed in Table 2.1-17.

Other facilities, located outside of the LPZ, that may require special consideration include the following:

a. Pottstown Memorial Medical Center, with approximately 400 patients and 840 employees. The hospital is located 1.8 miles northwest of the station.

b. Graterford Prison, an 1800 inmate maximum security State Prison. The prison is located approximately 8.3 miles from the station.

c. The Montgomery County Geriatric Center, a 600 patient care facility, is located 5.1 miles from the station.

2.1.3.5 Population Center

The nearest population center, as defined in 10CFR100, is Pottstown Borough, which had a 1980 population of 22,729. The nearest boundary of the borough is 1.7 miles northwest of the station, and is outside the LPZ as defined in Section 2.1.3.4. The transient population in the immediate area does not influence the selection of the population center. The population of the borough is projected to reach 28,195 by 1983, and 46,653 by the year 2020. Based on 1980 census information, these population estimates are probably conservative. The population density in 1970 was estimated to be 5282 persons per square mile, and is expected to grow to 5874 by 1983 and to 9719 by 2020 based on state projections that used 1970 census information. Based on the 1980 census, the population density is estimated to be 4735 persons per square mile in 1980.

2.1.3.6 Population Density

Table 2.1-18 provides a comparison of cumulative population projected for 1985, representative of the initial year of operation, with a cumulative population resulting from a uniform population density of 500 people per square mile in all directions from the plant. Table 2.1-19 provides a comparison of cumulative population projected for 2020, the assumed final year of operation, with a cumulative population resulting from a uniform population density of 1000 people per square mile.

Table 2.1-1

POPULATION DISTRIBUTION 0-10 MILES
(1970)

	DISTANCE (MILES)						
SECTOR	0-1	1-2	2-3	3-4	4-5	5-10	10-MILE TOTAL
N	48	579	423	533	782	6,969	9,334
NNE	110	206	262	360	152	3,121	4,211
NE	21	74	223	322	311	2,982	3,933
ENE	25	71	276	368	180	1,839	2,759
E	18	113	318	474	376	11,995	13,294
ESE	57	131	333	290	328	14,366	15,505
SE	0	417	1,175	4,419	1,235	3,191	10,437
SSE	11	308	1,326	3,612	1,498	25,337	32,092
S	3	390	244	67	337	4,043	5,084
SSW	0	460	290	314	223	2,023	3,310
SW	55	186	163	281	266	3,191	4,142
WSW	42	205	473	397	948	1,120	3,185
W	49	59	1,190	1,192	1,896	304	4,690
WNW	7	76	3,256	11,072	3,323	8,267	26,001
NW	23	466	3,338	8,481	1,987	1,091	15,386
NNW	10	675	1,112	1,093	815	6,234	9,939
TOTAL	479	4,416	14,402	33,275	14,657	96,073	163,302

Table 2.1-2

POPULATION DISTRIBUTION 0-10 MILES
(1980)

	DISTANCE (MILES)						
SECTOR	0-1	1-2	2-3	3-4	4-5	5-10	10-MILE TOTAL
N	58	682	894	397	753	3,158	5,942
NNE	46	1,088	244	478	204	2,428	4,488
NE	46	40	202	334	276	3,732	4,630
ENE	12	58	199	380	228	5,139	6,016
E	20	150	271	389	418	5,120	6,368
ESE	29	179	297	268	579	9,223	10,575
SE	6	369	141	4,844	4,055	6,830	16,245
SSE	0	190	285	2,664	1,587	20,992	25,718
S	3	343	331	164	340	3,864	5,045
SSW	12	611	308	513	268	1,848	3,560
SW	69	181	204	311	300	1,783	2,848
WSW	46	179	533	458	1,596	1,899	4,711
W	35	118	1,754	1,515	1,054	2,239	6,715
WNW	40	320	2,992	11,076	3,545	9,791	27,764
NW	20	288	1,872	6,667	1,309	4,004	14,160
NNW	35	711	1,727	1,237	1,304	6,555	11,569
TOTAL	477	5,507	12,254	31,695	17,816	88,605	156,354

Table 2.1-3

POPULATION DISTRIBUTION 0-10 MILES
(1985)

	DISTANCE (MILES)						
SECTOR	0-1	1-2	2-3	3-4	4-5	5-10	10-MILE TOTAL
N	60	712	933	414	786	3,296	6,201
NNE	48	1,135	254	499	212	2,533	4,681
NE	48	42	210	349	288	3,894	4,831
ENE	12	60	207	397	237	5,359	6,272
E	21	156	282	406	436	5,341	6,642
ESE	30	186	309	279	604	9,620	11,028
SE	6	385	147	5,054	4,230	7,126	16,948
SSE	0	204	306	2,861	1,704	22,544	27,619
S	3	368	356	176	365	4,150	5,418
SSW	12	656	331	551	288	1,986	3,824
SW	74	195	220	334	322	1,913	3,058
WSW	49	192	572	492	1,714	2,041	5,060
W	37	127	1,884	1,627	1,132	2,405	7,212
WNW	42	334	3,122	11,556	3,699	10,215	28,968
NW	21	300	1,953	6,955	1,366	4,176	14,771
NNW	36	742	1,802	1,290	1,361	6,839	12,070
TOTAL	499	5,794	12,888	33,240	18,744	93,438	164,603

Table 2.1-4

POPULATION DISTRIBUTION 0-10 MILES
(1990)

	DISTANCE (MILES)						
SECTOR	0-1	1-2	2-3	3-4	4-5	5-10	10-MILE TOTAL
N	63	741	972	431	818	3,433	6,458
NNE	50	1,182	265	519	221	2,637	4,874
NE	50	44	219	363	300	4,055	5,031
ENE	13	63	216	413	247	5,582	6,534
E	22	163	294	422	454	5,563	6,918
ESE	31	194	322	291	629	10,019	11,486
SE	6	401	153	5,263	4,406	7,423	17,652
SSE	0	218	327	3,058	1,822	24,097	29,522
S	3	393	380	188	390	4,436	5,790
SSW	13	701	354	588	307	2,123	4,086
SW	79	208	235	357	344	2,046	3,269
WSW	53	205	612	526	1,831	2,179	5,406
W	40	136	2,013	1,739	1,210	2,570	7,708
WNW	44	347	3,251	12,035	3,852	10,639	30,168
NW	22	313	2,034	7,244	1,423	4,351	15,387
NNW	38	773	1,876	1,344	1,417	7,123	12,571
TOTAL	527	6,082	13,523	34,781	19,671	98,276	172,860

Table 2.1-5

POPULATION DISTRIBUTION 0-10 MILES
(2000)

	DISTANCE (MILES)						
SECTOR	0-1	1-2	2-3	3-4	4-5	5-10	10-MILE TOTAL
N	64	756	990	440	834	3,499	6,583
NNE	51	1,205	270	529	225	2,690	4,970
NE	51	45	223	370	306	4,134	5,129
ENE	13	64	220	421	252	5,691	6,661
E	22	166	300	431	463	5,672	7,054
ESE	32	198	329	297	641	10,213	11,710
SE	6	408	156	5,365	4,491	7,566	17,992
SSE	0	224	336	3,141	1,871	24,749	30,321
S	3	404	390	194	401	4,557	5,949
SSW	14	720	363	604	316	2,179	4,196
SW	81	214	241	367	353	2,102	3,358
WSW	54	211	628	540	1,881	2,239	5,553
W	41	139	2,068	1,786	1,243	2,640	7,917
WNW	45	354	3,314	12,268	3,927	10,844	30,752
NW	22	319	2,073	7,384	1,450	4,435	15,683
NNW	38	788	1,913	1,370	1,444	7,261	12,814
TOTAL	537	6,215	13,814	35,507	20,098	100,471	176,642

Table 2.1-6

POPULATION DISTRIBUTION 0-10 MILES
(2010)

	DISTANCE (MILES)						
SECTOR	0-1	1-2	2-3	3-4	4-5	5-10	10-MILE TOTAL
N	77	907	1,189	528	1,001	4,199	7,901
NNE	61	1,446	324	635	271	3,227	5,964
NE	61	54	268	444	367	4,960	6,154
ENE	15	77	264	505	302	6,828	7,991
E	27	199	360	517	555	6,806	8,464
ESE	38	237	394	356	769	12,257	14,051
SE	8	490	188	6,438	5,390	9,081	21,595
SSE	0	269	403	3,769	2,245	29,703	36,389
S	4	485	469	232	481	5,468	7,139
SSW	16	864	436	725	379	2,616	5,036
SW	98	257	289	440	424	2,523	4,031
WSW	65	253	754	648	2,258	2,685	6,663
W	49	167	2,482	2,143	1,491	3,168	9,500
WNW	54	425	3,977	14,722	4,712	13,013	36,903
NW	27	383	2,488	8,861	1,740	5,323	18,822
NNW	46	945	2,295	1,644	1,733	8,714	15,377
TOTAL	646	7,458	16,580	42,607	24,118	120,571	211,980

Table 2.1-7

POPULATION DISTRIBUTION 0-10 MILES
(2020)

	DISTANCE (MILES)						
SECTOR	0-1	1-2	2-3	3-4	4-5	5-10	10-MILE TOTAL
N	92	1,088	1,426	633	1,202	5,039	9,480
NNE	73	1,736	389	762	325	3,873	7,158
NE	73	64	322	533	441	5,952	7,385
ENE	18	92	317	606	363	8,195	9,591
E	32	239	432	620	666	8,167	10,156
ESE	46	285	473	427	923	14,708	16,862
SE	9	588	225	7,726	6,468	10,895	25,911
SSE	0	323	484	4,523	2,694	35,640	43,664
S	5	582	562	279	577	6,562	8,567
SSW	20	1,037	523	870	455	3,140	6,045
SW	117	308	347	528	509	3,027	4,836
WSW	78	303	905	777	2,709	3,226	7,998
W	59	200	2,978	2,572	1,790	3,801	11,400
WNW	64	510	4,773	17,667	5,655	15,616	44,285
NW	32	459	2,986	10,634	2,089	6,385	22,585
NNW	55	1,135	2,754	1,972	2,080	10,455	18,451
TOTAL	773	8,949	19,896	51,129	28,946	144,681	254,374

Table 2.1-8

POPULATION DISTRIBUTION 10-50 MILES
(1970)

	DISTANCE (MILES)					
SECTOR	0-10	10-20	20-30	30-40	40-50	50-MILE TOTAL
N	9,334	6,253	40,245	42,944	27,908	126,684
NNE	4,211	19,178	188,605	170,433	35,189	417,616
NE	3,933	21,396	14,868	22,233	38,547	100,977
ENE	2,759	38,121	38,625	17,188	28,712	125,405
E	13,294	52,056	94,689	164,754	338,592	663,385
ESE	15,505	131,917	724,262	610,275	73,658	1,555,617
SE	10,437	90,554	1,255,972	566,597	103,147	2,026,707
SSE	32,092	24,552	250,377	25,563	21,282	353,866
S	5,084	60,017	29,018	332,241	18,248	444,608
SSW	3,310	28,071	23,849	36,668	45,361	137,259
SW	4,142	4,060	34,181	9,976	14,319	66,678
WSW	3,185	7,472	19,717	62,299	126,433	219,106
W	4,690	3,644	15,006	41,717	70,654	135,711
WNW	26,001	123,107	71,310	18,760	26,015	265,193
NW	15,386	7,797	16,911	14,553	61,969	116,616
NNW	9,939	9,816	14,500	5,792	34,883	74,930
TOTAL	163,302	628,011	2,832,135	2,141,993	1,064,917	6,830,358

Table 2.1-9

POPULATION DISTRIBUTION 10-50 MILES
(1980)

	DISTANCE (MILES)					
SECTOR	0-10	10-20	20-30	30-40	40-50	50-MILE TOTAL
N	5,942	7,884	53,061	55,728	24,830	147,445
NNE	4,488	24,323	185,370	175,555	38,751	428,487
NE	4,630	18,810	19,791	25,253	49,483	117,967
ENE	6,016	54,025	52,445	19,874	36,108	168,468
E	6,368	60,790	88,479	178,907	331,487	666,031
ESE	10,575	124,311	654,399	609,017	105,734	1,504,036
SE	16,245	84,571	1,042,915	509,968	182,225	1,835,924
SSE	25,718	24,010	260,063	31,240	22,748	363,779
S	5,045	71,662	37,832	329,479	23,712	467,730
SSW	3,560	41,678	25,473	47,226	48,771	166,708
SW	2,848	7,171	34,583	11,577	18,878	75,057
WSW	4,711	9,298	24,662	72,930	133,537	245,138
W	6,715	4,729	17,437	49,786	74,846	153,513
WNW	27,764	120,554	72,875	25,831	29,043	276,067
NW	14,160	9,026	17,164	17,026	63,480	120,856
NNW	11,569	12,706	16,031	7,502	34,491	82,299
TOTAL	156,354	675,548	2,602,580	2,166,899	1,218,124	6,819,505

Table 2.1-10

POPULATION DISTRIBUTION 10-50 MILES
(1985)

	DISTANCE (MILES)					
SECTOR	0-10	10-20	20-30	30-40	40-50	50-MILE TOTAL
N	6,201	15,786	55,411	58,654	26,896	162,948
NNE	4,681	25,699	193,709	184,827	40,999	449,915
NE	4,831	19,495	21,217	26,719	52,088	124,350
ENE	6,272	54,208	56,225	21,111	39,128	176,944
E	6,642	71,745	94,178	191,806	348,565	712,936
ESE	11,028	136,168	600,174	571,592	108,755	1,427,717
SE	16,948	84,872	948,054	500,820	186,962	1,737,656
SSE	27,619	31,051	257,792	32,345	23,407	372,214
S	5,418	78,282	39,399	343,371	24,571	491,041
SSW	3,824	43,076	27,358	49,699	50,543	174,500
SW	3,058	9,030	37,127	12,403	19,894	81,512
WSW	5,060	9,084	26,382	78,015	142,849	261,390
W	7,212	4,335	18,608	53,247	79,911	163,313
WNW	28,968	129,767	76,716	27,363	30,747	293,561
NW	14,771	4,579	18,068	17,852	66,226	121,498
NNW	12,070	13,491	16,858	7,843	36,416	86,678
TOTAL	164,603	730,668	2,487,276	2,177,667	1,277,957	6,838,171

Table 2.1-11

POPULATION DISTRIBUTION 10-50 MILES
(1990)

	DISTANCE (MILES)					
SECTOR	0-10	10-20	20-30	30-40	40-50	50-MILE TOTAL
N	6,458	16,501	57,759	61,579	28,963	171,260
NNE	4,874	26,941	202,042	193,452	43,149	470,458
NE	5,031	20,676	22,643	28,000	54,138	130,488
ENE	6,534	56,983	60,007	22,529	41,340	187,393
E	6,918	74,718	99,879	204,701	368,386	754,602
ESE	11,486	141,812	545,945	545,422	118,787	1,363,452
SE	17,652	87,619	853,199	509,471	201,709	1,669,650
SSE	29,522	33,077	255,520	35,376	24,065	377,560
S	5,790	83,674	40,942	356,138	25,115	511,659
SSW	4,086	46,044	29,239	52,309	53,205	184,883
SW	3,269	9,652	39,671	13,226	21,149	86,967
WSW	5,406	9,678	28,101	83,101	152,160	278,446
W	7,708	4,486	19,777	56,708	84,972	173,651
WNW	30,168	136,351	80,556	28,896	32,451	308,422
NW	15,387	4,929	18,974	18,681	68,972	126,943
NNW	12,571	14,243	17,682	8,183	38,340	91,019
TOTAL	172,860	767,384	2,371,936	2,217,772	1,356,901	6,886,853

Table 2.1-12

POPULATION DISTRIBUTION 10-50 MILES
(2000)

	DISTANCE (MILES)					
SECTOR	0-10	10-20	20-30	30-40	40-50	50-MILE TOTAL
N	6,583	16,837	58,743	62,871	29,786	174,820
NNE	4,970	27,473	205,566	198,282	44,225	480,516
NE	5,129	21,141	23,177	30,320	59,686	139,453
ENE	6,661	58,184	61,422	24,904	47,162	198,333
E	7,054	76,172	102,127	209,526	389,831	784,710
ESE	11,710	144,573	542,450	572,224	137,627	1,408,584
SE	17,992	89,099	844,309	550,741	224,521	1,726,662
SSE	30,321	33,947	256,615	39,309	25,600	385,792
S	5,949	85,945	42,015	368,752	26,026	528,687
SSW	4,196	47,295	30,036	54,130	55,746	191,403
SW	3,358	9,915	40,738	13,566	21,947	89,524
WSW	5,553	9,931	28,797	85,157	155,924	285,362
W	7,917	4,564	20,260	58,108	87,041	177,890
WNW	30,752	139,379	82,329	29,560	33,205	315,225
NW	15,683	5,078	19,391	19,088	70,460	129,700
NNW	12,814	14,581	18,059	8,347	39,276	93,077
TOTAL	176,642	784,114	2,376,034	2,324,885	1,448,063	7,109,738

Table 2.1-13

POPULATION DISTRIBUTION 10-50 MILES
(2010)

	DISTANCE (MILES)					
SECTOR	0-10	10-20	20-30	30-40	40-50	50-MILE TOTAL
N	7,901	20,203	70,491	75,444	35,745	209,784
NNE	5,964	32,968	246,677	237,938	53,069	576,616
NE	6,154	25,371	27,813	36,384	71,622	167,344
ENE	7,991	69,822	73,705	29,886	56,593	237,997
E	8,464	91,406	122,553	251,430	467,794	941,647
ESE	14,051	173,487	650,942	686,669	165,153	1,690,302
SE	21,595	106,916	1,013,175	660,888	269,426	2,072,000
SSE	36,389	40,734	307,940	47,173	30,722	462,958
S	7,139	103,134	50,417	442,504	31,232	634,426
SSW	5,036	56,752	36,041	64,955	66,896	229,680
SW	4,031	11,895	48,889	16,280	26,336	107,431
WSW	6,663	11,919	34,557	102,185	187,108	342,432
W	9,500	5,478	24,311	69,729	104,447	213,465
WNW	36,903	167,256	98,795	35,473	39,845	378,272
NW	18,822	6,094	23,269	22,906	84,552	155,643
NNW	15,377	17,499	21,671	10,016	47,131	111,694
TOTAL	211,980	940,934	2,851,246	2,789,860	1,737,671	8,531,691

Table 2.1-14

POPULATION DISTRIBUTION 10-50 MILES
(2020)

	DISTANCE (MILES)					
SECTOR	0-10	10-20	20-30	30-40	40-50	50-MILE TOTAL
N	9,480	24,242	84,586	90,526	42,888	251,722
NNE	7,158	39,555	296,007	285,513	63,674	691,907
NE	7,385	30,441	33,371	43,654	85,939	200,790
ENE	9,591	83,778	88,441	35,859	67,908	285,577
E	10,156	109,680	147,060	301,706	561,341	1,129,943
ESE	16,862	208,176	781,112	823,984	198,173	2,028,307
SE	25,911	128,297	1,215,784	793,046	323,302	2,486,340
SSE	43,664	48,875	369,510	56,603	36,862	555,514
S	8,567	123,754	60,496	530,994	37,474	761,285
SSW	6,045	68,095	43,245	77,941	80,271	275,597
SW	4,836	14,273	58,659	19,532	31,599	128,899
WSW	7,998	14,296	41,466	122,616	224,521	410,897
W	11,400	6,573	29,168	83,668	125,325	256,134
WNW	44,285	200,700	118,545	42,560	47,807	453,897
NW	22,585	7,310	27,917	27,482	101,452	186,746
NNW	18,451	20,994	26,002	12,018	56,551	134,016
TOTAL	254,374	1,129,039	3,421,369	3,347,702	2,085,087	10,237,571

Table 2.1-15

SOURCES OF PROJECTED POPULATIONS

State	1970	1980	1985	1990	2000	2010	2020
Delaware	1	7	8	2	2	6	6
Maryland	1	7	8	3	3	6	6
New Jersey	1	7	8	4	4	6	6
Pennsylvania	1	7	8	5	5	6	6

	Year of Estimate
1 U.S. Census	1970
2 Delaware Development Office, Delaware Population Consortium	1982
3. Maryland Department of State Planning	1982
4 New Jersey Department of Labor, Division of Planning and Research, Office of Demographic and Economic Analysis	1983
5 Pennsylvania Department of Environmental Resources	1983
6 PECo	1984
7. U.S. Census	1980
8. PECo, based on projections made by sources 2, 3, 4, and 5	1984

Table 2.1-16

BUREAU OF CENSUS POPULATIONS OF COUNTIES WITHIN
50 MILES OF THE SITE

COUNTY	STATE	1950	1960	1970	1980
New Castle	DE	218,879	307,446	385,856	399,002
Cecil	MD	33,356	48,408	53,291	60,430
Burlington	NJ	135,910	224,499	323,132	362,542
Camden	NJ	300,743	392,035	456,291	471,650
Gloucester	NJ	91,727	134,840	172,681	199,917
Hunterdon	NJ	42,736	54,107	69,718	87,361
Mercer	NJ	229,781	266,392	303,968	307,863
Salem	NJ	49,508	59,711	60,346	64,676
Somerset	NJ	99,052	143,913	198,372	203,129
Warren	NJ	54,374	63,220	73,879	84,429
Berks	PA	255,740	275,414	296,382	312,509
Bucks	PA	144,620	308,567	415,056	479,211
Carbon	PA	57,558	52,889	50,573	52,285
Chester	PA	159,141	210,608	278,311	316,660
Delaware	PA	414,234	553,154	600,035	555,007
Lancaster	PA	234,717	278,359	319,693	362,346
Lebanon	PA	78,905	90,853	99,665	109,829
Lehigh	PA	198,207	227,536	255,304	273,582
Monroe	PA	33,803	39,567	45,422	69,409
Montgomery	PA	353,068	516,682	623,799	643,621
Northampton	PA	185,243	201,412	214,368	225,418
Philadelphia	PA	2,071,605	2,002,517	1,948,609	1,688,210
Schuylkill	PA	200,577	173,027	160,089	160,630
York	PA	202,737	238,336	272,603	312,963

Table 2.1-17

INDUSTRIES WITHIN 5 MILES OF THE SITE

COMPANY	PRODUCT	LOCATION	NUMBER OF EMPLOYEES	TOTAL DISTANCE FROM SITE (MILES)	DIRECTION FROM SITE
Montgomery County					
Mrs. Smith's Pie Co	Frozen Specialties	Charlotte & Water Sts Pottstown	1,700	3.6	WNW
Princess Bakery	Bread and Bakery Products	113 S. Washington St Pottstown	14	3.2	WNW
Lincoln Underwear Co	Knit Underwear Mills	175 S. Evans St Pottstown	240	3.5	WNW
Spring City Knitting Co	Circular Knit Fabric Mills	475 N. Lewis Rd Royersford	129	2.6	ESE
Pottstown Textile Co, Inc	Dresses	420 Apple St Pottstown	36	3.2	WNW
Sunset Manufacturing Inc	Dresses	24 Moser Rd Pottstown	300	2.0	NW
INA-Lin Dress Co	Dresses	119 N. York St Pottstown	40	3.8	WNW
Frederick Bros, Inc	Millwork	Hanover and East Sts Pottstown	14	3.7	NW
Dela Foil, Inc	Aluminum Products	Shoemaker & Robinson Rds	10	4.3	WNW
Rixie Paper Products, Inc	Paperboard Products	Quinter and H Sts Pottstown	40	5.1	WNW
Peerless Publications, Inc	Newspapers	Hanover and King Sts Pottstown	99	3.6	WNW
Mahr Printing	Commercial Printing	R. D. 3 Pottstown	13	1.1	NNW

Table 2.1-17 (Cont'd)

COMPANY	PRODUCT	LOCATION	NUMBER OF EMPLOYEES	TOTAL DISTANCE FROM SITE (MILES)	DIRECTION FROM SITE
Smales Printery	Commercial Printing	785 N. Charlotte St Pottstown	20	3.5	NW
Risson Press, Inc	Commercial Printing	244 King St Pottstown	12	3.5	WNW
S.T.V., Inc	Engineering	Robinson Rd Pottstown	225	4.3	WNW
Polymeric Systems, Inc	Adhesives and Sealants Pottstown	860 Cross St	34	2.6	WNW
Pottstown Roller Mills, Inc	Ball and Roller Bearings	625 Ind Hwy Pottstown	10	2.9	WNW
Stanley Tools, Inc	Miscellaneous Plastics Products	Upper Lewis Rd Limerick Twp	136	2.9	E
Diamond Glass Co	Glass Containers	First Ave Royersford	780	4.0	SE
Keystone Gray Iron Foundry Co	Gray Iron Foundries	Keim and Cross Sts Pottstown	60	2.6	WNW
Albright Paper & Box Co	Cardboard Conversion	Robinson Rd Pottstown	8	4.3	WNW
Reading Crane & Engineering Co	Conveying Equipment	1200 High St Pottstown	30	2.3	NW
Morris Wheeler & Co, Inc Fabricating Works	Fabricated Structural Steel	First Ave Royersford	80	4.1	SE
Pottstown Metal Welding Co, Inc	Fabricated Plate Work	350 W. High St Pottstown	45	4.4	WNW
Sanatoga Metal Co, Inc	Sheet Metal Work	Sanatoga Lower Pottsgrove Twp	15	1.0	WNW
Superior Metal Prod Co, Inc	Sheet Metal Work	Berks St Pottstown	45	5.3	WNW

Table 2.1-17 (Cont'd)

COMPANY	PRODUCT	LOCATION	NUMBER OF EMPLOYEES	TOTAL DISTANCE FROM SITE (MILES)	DIRECTION FROM SITE
Cann and Saul Steel Co	Iron and Steel Forgings	N. 4th Ave Royersford	190	3.6	SE
Mrs. Smith's Foil Co	Metal Stampings, N.E.C.	255 South St Pottstown	75	3.6	WNW
American Metal Finishers, Inc	Electroplating	1346 Farmington Ave Pottstown	30	4.5	NW
Platers, Inc	Electroplating	Keim and Cross Sts Pottstown	12	2.6	WNW
Pottstown Plating Works	Electroplating	Washington & Laural Sts Pottstown	52	3.2	WNW
Rivlin Bros	Scrap Processing	Old Reading Pike Pottstown	10	5.5	WNW
Pottstown Pipe Products, Inc	Valve and Pipe Fittings	412-42 Laurel St Pottstown	44	3.2	WNW
Royersford Spring Co	Wire Springs	Main Street & 1st Ave Royersford	29	3.7	SE
B and S Specialties, Inc	Fabricated Metal Products, N.E.C.	Rt 20 & Levengood Rd Pottstown	23	4.7	NW
Teleflex, Inc Mechanical Division	Internal Combustion Engines, N.E.C.	North Wales Limerick Twp	200	2.5	E
Neapco Products, Inc	Construction Machinery and Equipment	Queen and Bailer Sts Pottstown	400	3.0	WNW
United States Axle Co	Construction Machinery and Equipment	275 Shoemaker Pottstown	40	4.8	WNW
Pottstown Machine Co	Machine Tools	Roland and Reading RR Pottstown	80	2.3	WNW
Brusch Machine and Tool Co	Special Dyes and Tools	342 W. Ridge Pike Limerick Twp	15	3.6	E

Table 2.1-17 (Cont'd)

COMPANY	PRODUCT	LOCATION	NUMBER OF EMPLOYEES	TOTAL DISTANCE FROM SITE (MILES)	DIRECTION FROM SITE
Chop Rite Mfg Co	Food Products Machinery	859 Cross St Pottstown	22	2.7	WNW
American Machine and Tool Co, Inc	Woodworking Machinery	Spring and 4th Sts Royersford	100	3.9	SE
Clover Lamp Co, Inc	Lighting Equipment, N.E.C.	First Ave Royersford	100	3.9	SE
Dana Corp - Spicer Division	Motor Vehicle Parts and Accessories	125 S. Keim St Pottstown	625	2.5	WNW
Tri-Rx Laboratories	Optical Instruments and Lens	701 High St Pottstown	45	2.7	WNW
Power Wash, Inc	Manufacturing Industries, N.E.C.	High and Berks St Pottstown	20	4.7	WNW
Montgomery County					
A & L Handles, Inc	Plastic Products	244 Shoemaker Rd Pottstown	30	4.7	WNW
Amcord, Inc	Redwood Furniture	Adam & Queen Sts Pottstown	106	3.1	WNW
Gudebrod, Inc	Thread, Sewing Kits & Cord	Shoemaker Road Pottstown	250	4.7	WNW
Hooker Chemical Co (PVC Div)	PVC Resins and Fabricated Products	Firestone Boulevard Pottstown	750	1.5	WNW
Pollock Research & Design, Inc	Special Design Machinery & Material Handling Equipment	1200 High St	90	2.3	NW
Pottstown Plating Works, Inc	Electroplating & Finishing – Metals	Washington & Laurel Pottstown	52	3.1	WNW
Bemiss-Jason Corp	Corrugated Paper Displays, Crepe Papers, School Supplies	Railroad Avenue Royersford	20	3.4	SE

Table 2.1-17 (Cont'd)

COMPANY	PRODUCT	LOCATION	NUMBER OF EMPLOYEES	TOTAL DISTANCE FROM SITE (MILES)	DIRECTION FROM SITE
Dow Chemical Co	Plastic Lined Pipe	1st Avenue Royersford	7	4.2	SE
French Creek Products	Plastic Products	1st Avenue Royersford	18	3.4	SE
H. E. Quay Welding	Welding Specialties	Robinson Rd Pottstown	3	4.7	WNW
Snow King Frozen Foods, Inc	Processing of Frozen Foods	980 Glascow St Pottstown	120	4.8	WNW
Pottstown Cement Block Co	Concrete Block & Brick	W. High Street Pottstown	7	5.5	WNW
Crouse Co., Inc	Fabricated Pipe and Industrial Controls	Upper Lewis Rd Royersford	1,300	3.1	E
Gretz Machine Products	Machinery	40 Sacco Rd Linfield, Limerick Twp	13	1.4	SE
Videotek, Inc	Radio - TV Transmitting, & Detectional Equipment	125 N. York St Pottstown	85	3.8	WNW
D - B Construction Co	Wood Kitchen Cabinets	1949 N. Charlotte St Pottstown	41	3.6	NNW
"The Guardian"	Newspaper	40 High St Pottstown	9	3.9	WNW
Sermetal, Inc	Inorganic Chemical Coatings	International Hq 155 S. Limerick Rd Limerick	83	2.8	E
Nelson's Ice Cream Inc	Ice Cream	651 Walnut St Royersford	35	3.8	SE
Bechtel Dairies	Dairy	617 S. Lewis Rd Royersford	52	4.8	ESE

Table 2.1-17 (Cont'd)

COMPANY	PRODUCT	LOCATION	NUMBER OF EMPLOYEES	TOTAL DISTANCE FROM SITE (MILES)	DIRECTION FROM SITE
Columbia Boiler Co of Pottstown	Heating Equipment W. Pottsgrove Twp	Old Reading Pike	89	5.3	WNW
Roll Form, Inc	Roll Forming & Metal Fab.	Rt. 422 Limerick	10	4.1	E
Imperial Specialty, Inc	Screw Machine Products	1153 Sembling Ave Pottstown	20	2.4	WNW
Baker Equipment Engr. Co of Pa	Comm. - Ind. Machinery	Airport Rd Ben Franklin Hwy Limerick	41	2.4	E
Beechwood Co	Plastic	1356 Farmington Ave Pottstown	12	4.5	NW
A. W. Walker	Electrical Construction	826 North Lewis Rd Royersford	30	2.5	E
Jacob Castings Pattern Work, Inc	Industrial Patterns - Alum. & Zinc Molded Castings	Old Reading Pike Pottstown	70	5.4	WNW
Mayer - Pollack Steel Corp	Fabricated Structural Steel	S. Keim St Pottstown	200	2.6	WNW
"The Mercury"	Newspaper	Hanover & King Sts Pottstown	99	3.6	WNW
Interstate Energy	Energy Research	Robinson Road Pottstown	12	4.5	WNW
Pottsgrove Metal Finishers	Electroplating	533 W. High St Pottstown	45	5.5	WNW
Chester County					
Norco Finishing, Inc	Electroplating	238 Root Ave Pottstown	14	3.7	WNW
Bard Mfg. Div. Miller Seal	Precision Parts (Screw Machine Parts)	Elliswood Rd Pottstown	25	1.9	WSW

Table 2.1-17 (Cont'd)

COMPANY	PRODUCT	LOCATION	NUMBER O EMPLOYEES	TOTAL DISTANCE FROM SITE (MILES)	DIRECTION FROM SITE
Pickar Bros	Die Cast & Plastic Molds	876 E. Schuylkill Rd Pottstown	14	2.6	WNW
Meadowbrook Farms, Inc	Fluid Milk	895 S. Keim St Pottstown	53	2.7	W
Sunny Slope Dairies, Inc	Fluid Milk	Bridge St Ext Spring City	88	3.2	S
Sircom Knitting Co, Inc	Male Underwear Spring City	475 N. Lewis St	1,000	2.6	ESE
Valley Forge Flag Co, Inc	Fabricated Textile Prod N.E.C.	Main St Spring City	175	3.6	SSE
Weekly Advisor, Inc c/o The Reporter	Newspapers, Publishing and Printing	225 Schuylkill Rd Spring City	11	3.4	SSE
Tursack Printing, Inc	Commercial Printers, Lithographic	R.D. 1 Spring City	32	5.3	SW
Taylor Industries	Cut Stone and Stone Products	Anderson Rd Parkerford	26	1.4	SSW
Little Lake Industries (U.S. Leisure, Inc)	Wood Household Furniture East Coventry Twp	Sanatoga Rd	105	0.6	W
Mingo Nonferrous Metals, Inc	Nonferrous Foundries	N. Church St Spring City	34	3.4	SSE
Allied Steel Products Corp of PA	Fabricated Plate Work	Rt. 724 & Wells Rd Parkerford	28	1.4	S
Spring City Electric Mfg Co	Cast Metal Housings	Hall and Main Sts Spring City	90	3.9	SSE
Brinser Mfg Co	Screw Machine Products	312 Church St Spring City	10	3.7	SSE
Norco Foundry and Specialty Co, Inc	Valves and Pipe Fittings	216 River Rd Pottstown	25	3.8	WNW

Table 2.1-17 (Cont'd)

COMPANY	PRODUCT	LOCATION	NUMBER OF EMPLOYEES	TOTAL DISTANCE FROM SITE (MILES)	DIRECTION FROM SITE
Amerind-Mackessic, Inc	Garden Tractors and Equipment	Old Schuylkill Rd Parkerford	59	1.3	SSW
Progressive Machine Co, Inc	Special Industrial Machinery, N.E.C.	Pughtown Rd, R.D. 1 Spring City	20	5.2	SSW
Spring City Foundry	Noncurrent - Carrying Wiring Devices	Hall and Main Sts Spring City	100	4.0	SSE
Recticon Corp	Semiconductors and Related Devices	Rt 724 & Wells Rd Parkerford	75	1.4	S
LaSalle Steel Co	Cold Finished Steel Bars	Main & Bridge Sts Spring City	81	3.5	SSE
Micro-Strain, Inc	Electronic Measuring Devices	Stoney Run Rd Spring City	9	3.6	S
Spring City Hoisery Mill, Inc	Women's Hosiery	Pikeland Ave Spring City	12	4.2	SSE

Table 2.1-18

COMPARATIVE CUMULATIVE POPULATIONS FOR 1985

DISTANCE (mi)	1985	500 PEOPLE/sq mi[1]
0-1	499	1,570
0-2	6,293	6,280
0-3	19,181	14,135
0-4	52,421	25,130
0-5	71,165	39,365
0-10	164,603	157,079
0-20	895,271	628,315
0-30	3,382,547	1,413,715

(1) The population that would result if 500 people per square mile were uniformly distributed over the study area.

Table 2.1-19

COMPARATIVE CUMULATIVE POPULATIONS FOR 2020

DISTANCE (mi)	2020	1000 PEOPLE/sq mi[1]
0-1	773	3,140
0-2	9,722	12,560
0-3	29,618	28,270
0-4	80,747	50,260
0-5	109,693	78,530
0-10	254,374	314,159
0-20	1,383,413	1,256,630
0-30	4,804,782	2,827,430

(1) The population that would result if 1000 people per square mile were uniformly distributed over the study area.

2.2 NEARBY INDUSTRIAL, TRANSPORTATION, AND MILITARY FACILITIES

2.2.1 LOCATIONS AND ROUTES

The major transportation routes located within 5 miles of the site include the following:

a. U.S. Route 422, an east-west highway passing approximately 1½ miles north of the site;

b. Pennsylvania Route 100, a north-south highway passing approximately 4 miles west of the site;

c. Pennsylvania Route 724, a southeast-northwest highway passing approximately 1 mile southwest of the site;

d. The Consolidated Rail Corporation (ConRail) line (formerly Reading Company) passing through the site along the east bank of the Schuylkill River. The line is comprised of two tracks, and has a rail spur serving the station; and

e. The ConRail line (formerly Penn Central Railroad) running north-south, and passing along the western boundary of the site.

These transportation routes are shown on Figure 2.2-1.

Oil and natural gas pipelines located within five miles of the site are shown in Figures 2.2-1 and 2.2-4 and Table 2.2-2, and are described in Section 2.2.2.3.

There is one quarry, Pottstown Trap Rock Quarry Inc, located about 0.8 miles from the site. Operations at the quarry consist of blasting, crushing, grading, and storing lightweight rock. The location of the quarry is shown on Figure 2.2-2.

Industries located within 5 miles of the site are listed in Table 2.1-17. A further discussion is provided in Section 2.2.2.1. The locations and description of airports are provided in Section 2.2.2.5.

There are no military installations within 5 miles of the site.

2.2.2 DESCRIPTIONS

2.2.2.1 Description of Facilities

Industries within 5 miles of LGS, with ten or more employees, are listed in Table 2.1-17. The number of employees, products, and locations are listed for each establishment.

The industry nearest the site is the Pottstown Trap Rock Quarry, Inc. Operations at the quarry include the detonation of explosives in the process of quarrying stone. However, the use of explosives is infrequent, and only enough explosives are brought to the quarry for one particular application. There are no explosives stored on the quarry site. The maximum quantity of explosives detonated at the quarry at any time was 11,700 pounds in 20 delays at 585 lb/delay. Explosives are transported to the quarry by the blaster by truck via Route 422, Evergreen Road and Sanatoga Road. Other industries located within 1.3 miles of LGS include Hooker Chemical Company, Mahr Printing, Inc., Eastern Warehouses, Inc., Amerind-MacKissic, Inc., and Structural

Foam, Inc. The location of these industries is shown on Figure 2.2-2. Occidental Chemical Corporation is the only establishment near LGS which has significant quantities of hazardous materials stored onsite.

2.2.2.2 Descriptions of Products and Materials

Hazardous materials stored near LGS consist of those stored by Occidental Chemical Corporation (These are listed in Table 2.2-1). Explosives and hazardous materials may be transported on the highways and railroads. Explosives and hazardous materials are discussed in Sections 2.2.3.1.1 and 2.2.3.1.3, respectively.

2.2.2.3 Pipelines

As shown in Figures 2.2-1 and 2.2-4, there is a natural gas pipeline adjacent to the site, consisting of two separate pipes, operated by the Columbia Gas Transmission Company, and an oil and gasoline pipeline operated by Sunoco within the site area. The closest distances of approach of these lines to the plant safety-related structures are:

	Sunoco (ft)	Columbia Gas(ft)
Reactor Enclosure, Unit 1	1775.0	3650.0
Reactor Enclosure, Unit 2	1625.0	3487.5
Diesel Generator Enclosure, Unit 1	1837.5	3662.5
Diesel Generator Enclosure, Unit 2	1675.0	3510.0
Spray Pond Pump Structure	1962.5	3600.0

Other pipelines within 5 miles of LGS are operated by PECO Energy, Buckeye Partners, Texas Eastern Transmission Corp. Pipe sizes, age, operating pressure, etc., are listed in Table 2.2-2. At the present time, there are no plans to utilize these pipelines to transport products different than those currently transported.

2.2.2.4 Waterways

There is no commercial traffic on the Schuylkill River in the vicinity of the site, due to the presence of downstream dams. Some small pleasure boating does occur in warmer weather. This, however, is relatively minor.

2.2.2.5 Airports

All landing fields within 10 miles of the site are listed in Table 2.2-3. These include 5 public use facilities and 10 private facilities. Four public use airports lie within 5 miles of the LGS site. The aircraft crash probability analysis from operations at airports and airways, including Pottstown Municipal and Pottstown-Limerick Airports, using the procedures of SRP section 3.5.1.6, is provided in Section 3.5.1.6.

Pottstown Municipal Airport lies about 5 miles northwest of the site, and is the only municipal airport within 5 miles. The 1968 National Airport Plan classed it as a general utility airport, one which can handle general aviation craft, except transports and jets. Pottstown Municipal Airport has no scheduled airline service, but serves a charter service, flying school, and privately owned

aircraft. The airport runway is hard-surfaced, 2700 feet long, and has a heading of 250°. A line extending from the runway to the east, along the runway's axis, would pass about 3.3 miles from the site boundary at its point of closest approach. Approximately 53 aircraft are based at the airport, and estimated movements are 16,000 annually.

The New Hanover Airport, about 5 miles north of the site, has a sod runway, 3450 feet long, at a heading of 270°. The airport has no scheduled service, but serves skydiving operations and privately owned aircraft. Skydiving is the primary activity, with peak movements taking place on weekends, weather permitting. Approximately 70% of the aircraft using the airport are single-engine and 30% are twin-engine. The total number of movements is about 2500 annually.

The Sunset Landing Strip, about 5 miles northeast of the site, has a sod runway 1550 feet long, at a heading of 270°. The airport has no scheduled service. Private flights are estimated at 12 per day, weather permitting.

The Pottstown-Limerick Airport, located at Limerick Center, lies about 2 miles northeast of the site. It has a hard-surfaced runway (10-28) 3412 feet long, at a heading of 280° and a sod strip (3-21) 2167 feet long. Currently, there are a total of about 30,000 aircraft movements annually, most involving runway 10-28. There are approximately 60 aircraft based at the airport, of which 40 are single-engine craft, 11 are twin-engine, and 9 are rotary-wing. Ninety-nine percent of the movements involve VFR operations. IFR approaches are presently made from the north, with an FAA-approved approach to Pottstown VOR. The present approach minimums are 649 AGL or 960 MSL. Instructions for a missed approach to runway 21 indicate a left-hand turn to the east away from the site. This facility is owned by Exelon Corporation and leased to the airport operators. The terms of the lease limit fixed-wing aircraft to a maximum weight of 13,500 pounds. The length of the runway precludes any heavier fixed-wing aircraft from using this facility. There are currently no existing terminal navigational facilities.

The Perkiomen Valley Airport is a hard-surfaced landing strip with no scheduled airline service, but supporting a charter service, flying school, and privately owned aircraft. The runway is 3000 feet long, and has a heading of 270°. About 80 aircraft are based at this airport. Movements are estimated to be 7000 for all aircraft annually.

The Pottstown VOR is located 1.3 miles east of the site. This radio range serves as a hub for several VOR airways used for commercial aircraft flights. These airways extend for 4 miles on each side of their center lines. The Pottstown VOR is the main departure route from Philadelphia International Airport for flights going north and northwest, but due to traffic patterns it is not used for arrivals. By the time these departures reach the Pottstown VOR, the flights have reached an altitude of 7000 feet. The Federal airways passing within 10 miles of the site are listed in Table 2.2-4. FAA annual flight estimates include 20,440 flights using the Pottstown VOR 320° radially, no flights along V143, and 8,395 flights along V29/V147.

In addition to the landing fields discussed above, there is a heliport at the LGS site. The landing pad is located east of the Unit 2 cooling tower, 1,250 feet from the nearest safety-related structure. The approach/takeoff flight path has a heading of 350°/170°, and does not pass over any safety-related structures. The approach/takeoff glide angle is no greater than 30° from vertical. The flight frequency is no more than 156 landings and 156 takeoffs per year.

2.2.2.6 Projections of Industrial Growth

Industry within 5 miles of the LGS site is clustered along the Schuylkill River, adjacent to rail lines and along major transportation arteries. The construction of the Schuylkill Expressway extension and planned improvements to the Pennsylvania Route 724 are expected to spur industrial development in these areas. At the intersection of the Schuylkill Expressway with the Collegeville-Trappe Route 422 bypass, a 1000 acre industrial park is planned. This area, when fully developed could employ 16,000 persons, assuming that 80% of the land would be developed at an average employee density of 20 persons per acre. New industrial areas are also planned near Route 724 in Spring City, East Coventry Township, and west of Pottstown Landing.

Pottstown Borough, in light of 1960-1970 population trends, may have reached a point of development saturation. Therefore, no significant increase in industry is anticipated in this area.

2.2.3 EVALUATION OF POTENTIAL ACCIDENTS

This section provides an evaluation of potential accidents in nearby transportation and industrial facilities, to determine what events need to be considered in the plant design. A description of design features to mitigate such events is also provided.

2.2.3.1 Determination of Design Basis Events

2.2.3.1.1 Explosions

Explosions can potentially occur due to accidents on the nearby railway line, highways, or pipelines, as identified in Section 2.2.2. There are no industrial activities involving explosive storage near the site.

The evaluation of potential railway explosions has been performed in conformance with Regulatory Guide 1.91 methodology. The maximum railway explosion is taken as one corresponding to 56 tons of TNT, which is equivalent to the explosion of a boxcar containing a full load of palletized explosives or a tank car containing liquefied petroleum gas.

The frequency of boxcars, derived from a Bechtel study of hazardous materials that passed through the exclusion area during the period from March 1969 through May 1969, amounted to 1800 cars (i.e., 7200 cars per year). There were only 11 cars (i.e., 44 cars per year) that carried explosives.

The explosives are shipped in multiple boxcar shipments per train. However, no more than two carloads of explosives have been shipped at any one time. Normally, only one carload is shipped at any one time.

The safety-related structures of LGS are designed and constructed to withstand the effects of the design basis railroad explosion with no damage, and would be unaffected by any change in explosive shipment frequency.

Selection of a 56 ton maximum TNT explosion model is conservative for the reasons given below. Information on explosives given below have been excerpted from the Bechtel Design Basis Railroad Accident Study. Additional information on the shipment of explosives through 1983 was obtained from ConRail, the American Association of Railroads, and the U.S. Department of Transportation.

Fifty ton box cars have been the most common size car used for shipping high explosives in the past. However, military shippers of high explosives prefer increased usage of 70 ton cars. The use of 100 ton cars has been infrequent and generally limited to items that move in large trainload shipments, such as unfused artillery shells. Such cars are not loaded to capacity due to interior space limitations. In addition, the characteristics of commodities carried further limits the explosive power contained within the cars. For example, artillery shells normally contain only 20% to 30% by weight of explosive.

Thus, an 80 ton load (assuming 20% weight for cases and packing) of shells would contain 24 tons of explosive. Applying a TNT equivalence factor of 1.35 (for composition B) and a 10% muffling factor yields an explosion equivalent to 29 tons of TNT. Thus, 100 ton cars do not provide the limiting case; the LGS explosion magnitude model is adequate and conservative.

Explosive loadings consist of shells, bombs, bulk explosives, demolition blocks, etc. Demolition blocks provide the greatest concentration of explosive power in a car. Shells, bombs, etc, provide smaller concentrations of explosive power due to the heavy weight of casing (50% to 80% of the weight of the munition).

Composition C3 explosive, in the form of M5 demolition blocks, provides the greatest concentration of explosive power in a car. This explosive is more destructive than TNT, having a relative effectiveness factor of 1.34 when compared with TNT. More powerful explosives were eliminated from consideration because they are shipped in less-than-carload lots.

Military and commercial loading practices rather than accident history set the upper limit on the quantity of explosive considered. Car weight and volume capacities limit the maximum load. M5 demolition blocks are placed in boxes, loaded on pallets, and then blocked inside the rail car. Twenty-four blocks are loaded in a box, 24 boxes are loaded on a pallet, and 56 to 68 pallets are loaded into a rail car. An aisle 20 inches wide is down the center of the car, and a 45 inch to 50 inch wide aisle connects the doors. A maximum of 44 tons of composition C3 can be placed in the car.

Forty-four tons of composition C3 is equivalent in explosive power to 59 tons of TNT. Application of a 10% muffling factor (i.e., absorption of explosive power by boxes, air space, and car structure) yields an explosion equivalent to 53 tons of TNT.

The discussion above corroborates the selection of a 56 ton TNT model as an upper limit on the design explosion. Consideration of the history of actual explosions confirms that the model is conservative. There is no evidence that an entire carload of explosives has completely detonated during the study period. There is evidence that the explosives will burn or partially detonate and scatter remaining car contents. At Tobar, Nevada and at Lewis, Indiana, some low and high order explosives occurred in the same car. Experts of the Bureau of Mines and the Army claim that the detonation of a carload is possible, but can only be assured if the explosive is detonated with the aid of blasting caps.

For the above reasons, it is considered that the maximum explosion of a rail car carrying explosives would be equal to or less than the 56 ton model used in the explosion and average reflected overpressure analysis for LGS.

The peak positive reflected pressures for which the critical structural elements of the safety-related structures were analyzed are given in Table 2.2-7. Missile generation from such an explosion is also postulated and is discussed in Section 3.5.

The effects of a release of 64 tons of propane from a ruptured railroad tank car and subsequent detonation of the gaseous cloud which could occur at a distance of 1100 feet from the nearest portion of the Unit 1 reactor enclosure have also been evaluated. Such an explosion could produce a peak reflected overpressure of approximately 9 to 10 psi on the upper two-thirds of the north, west, or south walls of the reactor enclosure. Lower portions of the reactor enclosure and other safety-related structures nearby are protected from the explosion by the geometry of the topography between the river, the railroad grade, and the reactor enclosure. Such an explosion would take place at either railroad grade level or river level, due to the higher density of propane compared to air, especially after the gas has cooled during expansion from the liquid to gas phase. The shock wave of such an explosion exerts an overpressure for a duration of 2 to 10 milliseconds (Reference 2.2-15).

A structural analysis of the upper two-thirds of the reactor enclosure has demonstrated that the enclosure can sustain the load without being damaged. A statistical analysis of the probability of an LPG tank car release and explosion was also performed based on methods described in Regulatory Guide 1.91 (Rev 1). This method utilized specific information on the number of LPG shipments past the LGS site. Credit was also taken for the fact that most LPG incidents occur in industrial installations or rail yards rather than on mainline track. The result of this analysis indicates a probability of approximately $5x10^{-9}$ for an LPG tank car release and explosion within a distance that could impact the LGS facility with an overpressure of 1 psi or greater. In 1981, according to Conrail, there were 1315 movements of LPG tank cars on the rail line that passes by LGS.

Explosions can also occur on nearby highways. However, since the railway is closer to the plant and truck cargo capacity is less than that of rail cars, the effects of a railroad explosion would be more severe than an explosion occurring on the highways.

An evaluation was conducted to determine the acceptability of the transportation route for the delivery of hydrogen gas via tube trailers to the Hydrogen Water Chemistry tube trailer facility located outside the protected area of LGS. The evaluation follows the Regulatory Guide 1.91, which provides guidance for providing safe separation distances between transportation routes, that may carry potentially explosive cargo, and safety related structures. The method for determining acceptable separation distance, determines the level of risk of damage due to the potential explosion of the cargo . Regulatory Guide 1.91 provides guidance for determining an acceptable level of risk. Based on industry data and site specific characteristics, the results of the risk evaluation indicated that the exposure rate is less than the value specified by Regulatory Guide 1.91. The transportation route for hydrogen gas delivery reflects an exposure rate that is of a sufficiently low risk of damage to nearby structures.

The potential also exists for the rupture of one of several nearby pipelines and the subsequent explosion of a gas or vapor cloud. The worst case overpressure due to a pipeline accident would involve the 20 inch Columbia Gas Transmission Company pipeline carrying natural gas.

Previous evaluations (Reference 2.2-2) indicate that natural gas will not detonate in unconfined spaces. However, to evaluate potential impacts, the detonation of a natural gas cloud from a rupture of the larger of the two Columbia gas pipelines gas been postulated. A detonable gas-air mixture approximately 4 times the requirement of Regulatory Guide 1.91 (Rev 1) is conservatively used to develop the explosive pressures for structural assessment. It has the equivalent explosive charge of 347 tons of TNT. Furthermore, the detonation is assumed to occur at an elevation varying from ground to 500 ft above ground to maximize the overpressures on the safety-related structures. In addition, the detonation is also assumed to occur anywhere along a line 2300 feet

downwind of and parallel to the route of the natural gas pipeline. This was done to maximize the explosion overpressures on each of the safety-related structures. The peak positive reflected pressures for which the critical structural elements of the safety-related structures were analyzed are given in Table 2.2-7.

The Sunoco petroleum products pipeline is assumed to carry gasoline, which has the highest volatility and explosive power of the products carried in the line. The gasoline vapor concentration from the pipeline rupture and spill is postulated to reach the explosive limit (Reference 2.2-3) and has a TNT-equivalent energy of 2.6 tons. The centroid of the explosion is assumed to be along the Possum Hollow Run streambed. The distance to a safety-related structure from the point in the streambed which allows maximum exposure is 800 ft measured from the Unit 2 reactor enclosure. The peak positive reflected pressure at the wall is 1.9 psi, and less than this value at the roof. This is the maximum overpressure from the gasoline explosion on the safety-related structures. The methodology used in calculating the overpressures in based on Reference 2.2-1.

As an example, the peak positive reflected pressure at the southwest corner of the Unit 1 diesel generator building at grade level (el 217') is computed as follows:

R_G = Radial distance from charge = 624 ft

W = Charge weight = 56 tons = 112,000 lb
(from page 4-8 of Reference 2.2-1)

Z_G = Scaled ground distance = $R/(W)^{1/3}$

= $624/(112{,}000)^{1/3}$ = 12.95 $ft/lb^{1/3}$

P_{50} = Peak positive incident pressure = 6.0 psi

α = Angle of incidence = 49°20'
(from page 4-5 of Reference 2.2-1)

$C_{r\alpha}$ = Reflected pressure coefficient = 2.8

P_r = Peak positive reflected pressure = $C_{r\alpha}\, P_{50}$

= 2.8 x 6.0 = 16.8 psi

Because different locations of a wall will experience different peak positive reflected pressures, a critical element of a building wall is analyzed for the average of peak positive reflected pressures at the top and bottom of the wall element.

A low rate of leakage from the Sunoco pipeline would likely be detected within one hour by the flow auditing and measurement procedures used at the pump stations along the pipeline. However, if such a leak were to occur and go undetected for a period of several hours, and if the pipeline transported gasoline (the most volatile substance carried), and if the leak were to be located in the vicinity of Possum Hollow Run, it can be anticipated that the gasoline would run into Possum Hollow Run and then flow downstream toward and into the Schuylkill River. Gasoline, with a density of approximately 0.75 compared to water, would form a thin monomolecular layer on the surface of the water flowing in Possum Hollow Run. No large accumulations or pooling would occur.

The worst situation for this type of release would be on a day during which ambient temperatures remain high because the evaporation rate of gasoline is more rapid at higher temperatures. For any gasoline spill, the lighter fraction components, notably butane, evaporate rapidly, while the heavier components such as naphthene evaporate more slowly. A summertime spill of a quantity of gasoline would evaporate completely within about 24 hours, but a wintertime spill could take a week or more to evaporate completely.

If ignition were to occur, the fire would likely spread over the stream surface to all locations where the gasoline had reached, but excluding portions of the gasoline film that had become disconnected from the ignited portions by such means as flows over small waterfalls or by flows through pipes. After ignition, it can be expected that the ensuing fire could be fairly large in surface area along the creek surface, but would be of short duration. Because the gasoline is assumed to be of small initial quantity, continuous evaporation would occur, and there would be only a small amount of gasoline at any given point along the streambed due to the tendency of gasoline to form a thin surface film over water.

A double-ended rupture of the pipeline would be detected within seconds, and pumping would be terminated promptly. In the unlikely event that there was a complete rupture of the pipe and it went undetected for several hours, the severity of such an occurrence would be approximately the same as that described above for a gasoline spill where it was assumed that the contents of the pipeline between two adjacent high points of bank were spilled into Possum Hollow Run. This would amount to approximately 5000 gallons of gasoline distributed along the creek bed, with an ensuing explosion 800 feet from the plant, and a resulting overpressure of 1.9 psi.

The results of an explosion of gasoline vapor from a long-term continuous release of gasoline are assumed to be similar because gasoline released to the creek bed would be carried downstream into the Schuylkill River and would continue away from the plant.

The Sunoco pipeline is an 8 inch line having a pumping capacity of about 1000 barrels per hour. A 1 hour release of gasoline would therefore amount of 42,000 gallons. The standing capacity of the creek bed (the quantity of fluid that would remain in the creek bed in pools if inflow were stopped) between the point where the pipeline crosses and its juncture with the Schuylkill River is small, so that a flow of gasoline at 42,000 gallons per hour, or 700 gallons per minute, would be expected to drain to the river quickly.

In the analysis of a gasoline spill, a point of detonation was used of 800 feet from the closest Category I structure, occurring at a wide point in the streambed where the path to the reactor complex is relatively unimpeded by terrain. The bed of Possum Hollow Run passes closer to Category I structures, as follows:

Unit 2 Diesel generator	512.5 ft
Unit 2 Reactor enclosure	562.5 ft
Turbine-generator building	637.5 ft
Unit 1 Diesel generator	600.0 ft
Unit 1 Reactor enclosure	662.5 ft

Possum Hollow Run, at these closer points, flows through a fairly steep-walled ravine, which would serve to deflect and significantly lessen the effects of an explosion. For this reason, the 800 ft distance selected is conservative.

Missile generation from the Columbia or the Sunoco pipeline explosion would be less severe than from the railroad explosion because such a postulated explosion would take place in a cloud away from the postulated missile sources.

For the overall structural design and assessment of the critical structural elements of a safety-related structure, the highest values of the peak positive reflected pressures for walls and roofs are selected from the railroad, Columbia pipelines, and Sunoco pipeline. The structural adequacy of the critical elements is evaluated against a ductility ratio of 3.0. All such safety-related structures have been determined to be fully capable of withstanding these overpressures with no adverse effects.

2.2.3.1.2 Flammable Vapor Clouds

A pipeline rupture may occur in which the resulting vapor cloud burns rapidly (deflagrates) rather than detonates. Analyses that estimate the effects (radiant heat load) of such an event are discussed below for the Sunoco gasoline pipeline. Other types of fires are discussed later in Section 2.2.3.1.4.

The same Sunoco pipeline rupture discussed previously is assumed here. In this case, the available gasoline vapor is assumed to deflagrate. Worst case meteorological conditions were assumed, using Pasquill 'F' stability and 1 m/s wind speeds. Any other less stable category or higher wind speed would increase dilution of the gas or vapor cloud, and thus decrease the effect on the reactor enclosure. The resulting fire is calculated to produce a radiant heat load of 85 Btu/ft^2-hr (Reference 2.2-5) at the Unit 2 reactor enclosure for a short time. This level would produce a slight warming of the surface concrete. By comparison, a flat surface in the sun at midday receives solar radiation at approximately 50 to 60 Btu/ft^2-hr.

In analyzing deflagration of natural gas released from a rupture of the Columbia Gas Transmission Company pipeline, it is assumed that the larger of the two lines (20") ruptures at the point where the pipeline passes closest to the Unit 2 reactor (approximately 3000 feet). It is further assumed to be a double-ended rupture (complete separation of the pipe at the point of rupture).

A portion of the cloud downwind within flammable limits is assumed to ignite and deflagrate. The radiant heat load at the Unit 2 reactor enclosure is calculated to be about 70 Btu/ft^2-hr (Reference 2.2-5) for a short time. This level would cause a slight warming of the outer layer of concrete.

2.2.3.1.3 Exposure to Hazardous Chemical Releases

Exposure of control room personnel to hazardous chemical vapors could potentially result from an accident involving a chemical spill. Such spills could occur on the rail line, one of several highways close by, nearby industrial facilities, or from onsite chemical storage. A chemical is considered a potential hazard if it is stored or transported nearby in such quantities that its concentration at the control room air intake following a spill could exceed the toxic incapacitation concentration. Acceptable toxic incapacitation levels were based on compliance with the Regulatory Guide 1.78 requirement of 2 minutes for operator protective action NIOSH and OSHA exposure limits, and ACGIH concentration criteria.

Potential chemical hazards were identified by first compiling a list of toxic chemicals that could pose a vapor hazard based on Regulatory Guide 1.78, NUREG-0570, and other sources. Surveys were conducted to determine which of these are actually stored or shipped within 5 miles of the Limerick Generating Station (LGS) site, with what frequency, and in what quantities. For each of the identified hazards, chemical properties, the information in the Superfund Amendments and Reauthorization Act (SARA) Tier II filings, and survey responses are used to screen out the hazard or determine that further analysis is required. Toxic gas detection systems are not credited in this survey.

From R.G. 1.78, chemicals screened out by meeting any of the following criteria:

- First Screen:

  a. Chemical quantity contained in the largest storage container is less than 100 lb.

  b. Chemical is a liquid at l00°F and has a vapor pressure less than or equal to 10 torr (10 mmHg).

  c. Chemical shipment frequency is less than 10 total shipments per year for truck traffic, 30 per year for rail traffic, or 50 per year for barge traffic.

- Second Screen:

  d. Chemical quantity contained in largest storage container is less than that allowed as defined in R.G. 1.78 Table C-2.

Additionally, chemicals screen out if another instance of the same chemical in the survey is bounding both in terms of distance and mass.

For the railroads, Norfolk Southern (NS) and Eastern Berks Gateway (EBG) /Berks County Authority rail lines provided information on which of these are shipped. The EBG railroad did not have any hazardous commodity shipments through all of 2016 and nine months of 2017. The commodities shipped by NS did not provide shipment quantity per railcar. The railcar cargo load of 230,000 lb was used for the screening analysis. Because the nearest approach of the NS line is less than 0.3 mi from LGS, Regulatory Guide 1. 78 directed to evaluate all hazardous chemicals present in weights greater than 100 lb within 0.3 miles ofthe control room in a detailed control room analysis.

Montgomery and Chester County are the only counties that have stationary facilities within

five miles of LGS. Both Montgomery and Chester County provided the SARA Tier II filings for the potentially hazardous chemicals stored within five miles of LGS in the county. In the Montgomery County, the Pottstown Wastewater Treatment Plant was identified with the largest single container capacity for chlorine on site and Dana Driveshaft Products, LLC identified that the largest single container capacity for propane on site. In the Chester County, the North Coventry Municipal Authority and Pennsylvania American Water Shady Lane Plant identified to have water treatment chemicals including chlorine.

The evaluation of chemical hazards transported by truck only considers those chemicals known to be stored or shipped within the five-mile radius of LGS based on the stationary facility surveys. The quantity of a given chemical in a truck shipment is considered to be the highest amount of the chemical listed for the stationary facilities. However, the size of a single truck shipment is limited to 55,000 lb, which is the available payload capability. The transported chemicals are evaluated as being shipped on the major roadway nearest to LGS. U.S. Route 422 is the bounding major roadway within five miles of LGS. The nearest approach of U.S. 422 to LGS is 1.22 miles. Those chemicals which screen out in the first screening analysis also screen out for the roadway evaluation. Those that do not screen out in the first screening are analyzed with the secondary screening methodology for truck transportation in addition to stationary storage out for the roadway evaluation. Those that do not screen out in the first screening are analyzed with the secondary screening methodology for truck transportation in addition to stationary storage for the stationary facilities.

Pipelines carrying potentially hazardous chemicals within five miles of LGS are identified using the National Pipeline Mapping System (NPMS). Pipe sizes, approximate age, operating pressure, etc., are listed in Table 2.2-2 and shown on Figure 2.2-1.

The analysis assumed complete release of the contents of a single container or tank. The control room habitability analyses performed follows methodology for toxic chemical release and atmospheric dispersion as described in Regulatory Guide 1. 78 and NUREG-0570. These methodologies are implemented in the analysis software. The analysis software performs worst case deterministic hazard analysis cases consistent with Regulatory Guide 1. 78 methodology using LGS specific inputs. If the worstcase analysis results are unsatisfactory, the software performs numerous release and dispersion calculations using randomly sampled inputs to determine the conditional probability that a release will result in unacceptable consequences. These Monte Carlo simulation results are used to evaluate the likelihood of unacceptable results for comparison with the Regulatory Guide 1.78 probabilistic acceptance criterion.

The control room concentrations were determined using the following control room parameters:

a. Control room envelope volume of 126,000 ft^3, as defined in Section 6.4.2.1.

b. 2100 cfm of incoming/outgoing air, based on the design outside air flow rate supplied by the normal control room HVAC system, as described in Sections 6.4.3.1 and 9.4 .1.1.

c. [redacted]

d. In leakage rate of 0.25 air changes per hour, during isolation, as discussed in Section 6.4.2 .3. However, the normal mode of operation with 2100 cfm of outside air is modeled throughout the transient.

e. The analysis does not credit any automatic detection of toxic chemicals or isolation of the control room in response to chemical detection. The use of a breathing apparatus within two minutes of nasal detection is credited.

Sodium Hypochlorite is used in water treatment in LGS for chlorination. It is stored in large quantities locations listed on Table 2 2-5. Sodium Hypochlorite was also evaluated in the analysis.

The analysis determined that the concentration of the chemical will not reach Immediately dangerous to life or health (IDLH) levels in the control room, or the operators can effectively detect and isolate the control room in case of the toxic chemical release, or the release events of the chemical has low probability of 10-5 occurrences per reactor year. The automatic chemical detection systems were not credited in the analysis. Although not credited in the analysis, switching the control room air from normal mode to the chlorine/toxic gas isolation mode is recommended upon nasal detection of a chemical to slow the accumulation of hazardous gases in the control room. When the hazard has cleared the area, returning to normal mode will help clear residual chemicals from the control room. The following chemicals are acceptable with credit for nasal detection and operator donning of a self-contained breathing apparatus (SCBA) within two minutes of detection. Operators should be trained in nasal detection and the use of SCBA as described in Regulatory Guide 1.78: R-142b, Acetone, Butane, Butyl Acrylate, Chlorine, Ethyl Acrylate, Heptane, Hydrochloric Acid, Isobutane, Methanol, Propanol, Methyl Methacrylate Monomer, Natural Gas, Nitric Acid, Propane (Odorized), Styrene, Toluene, Tripropylene, Chlorine Dioxide.

To ensure adequate protection of control room personnel, control room operators will be trained and periodically tested on their ability to put on breathing apparatus within 2 minutes after nasal detection of the toxic chemical detection including chlorine or initiation of the toxic chemical alarm. Subsequently, the operators will manually isolate the control room as described in Section 6.4.3.2.3.

If chlorine is detected with the control room HVAC system initially in the radiation isolation mode (as described in Section 6.4.3.2.2), manual action can be taken to realign the system to the chlorine isolation mode. Analysis of this event assumes that the system remains in the radiation isolation mode with 525 cfm of outside air being mixed with recirculated control room air for a total of 3,000 cfm being passed through the charcoal adsorber filter trains, and that the filter has no effect on removal of chlorine. The results of the analysis indicate that, with the control room HVAC system in the radiation isolation mode, the necessity for automatic chlorine isolation is not required to satisfy General Design Criterion (GDC) 19 of 10CFR50 of Appendix A, and that the control room operators would have sufficient time to don breathing apparatus after nasal detection of the chlorine occurs (as shown in Table 2.2-6).

Once it is confirmed that the isolation is not the result of elevated chlorine or toxic gas concentrations, the operators may remove their breathing apparatus. This action is based upon an evaluation of the chlorine and toxic gas accidents with the control room in the chlorine isolation mode prior to the chlorine or toxic gas accident. This evaluation determined that the control room operator would have sufficient time (more than 2 minutes) to don breathing apparatus after odor detection of the toxic substance.

The LGS toxic chemical analysis complies with the intent of Regulatory Guide 1.78.

2.2.3.1.4 Fires

In addition to the flammable vapor clouds discussed earlier, fire hazards may also exist due to a burning tank car on the railroad, a fire subsequent to a ruptured pipeline, or a nearby forest/brush fire. Potential adverse effects of such fires are radiant heat load on plant structures and smoke generation.

To estimate the effects of a railroad fire, an accident is hypothesized in which a railroad tank car derails, ruptures, and releases a cargo of 62 tons of liquified propane. A 62 ton car is typically the largest size used for propane, and from a fire standpoint liquified propane represents one of the most severe materials transported by rail. The site of the hypothetical derailment is the closest point of approach to the Unit 1 reactor enclosure, about 600 feet. The tank car propane is assumed to be released into the drainage ditch alongside the eastern side of the right-of-way, where it pools and is subsequently ignited. The vapor pressure of liquid propane is sufficiently high at ambient conditions that there will be an adequate supply of gaseous propane for ignition, after which the fire is self-propagating. The fire duration is assumed to be 20 minutes, based on experience with this material.

Assuming 19,600 Btu per pound of propane and 62 tons being consumed in 20 minutes, the radiant heat load on the reactor enclosure may be calculated using the relationship (Reference 2.2-5):

$$D = (FQ/12.57K)^{1/2} \qquad \text{(EQ. 2.2-1)}$$

where:

D = distance, feet

F = fraction of heat that is radiant

Q = heat release, Btu/hr

K = radiation load, Btu/ft^2-hr

The result of this calculation indicates a radiant heat load of approximately 500 Btu/ft^2-hr for 20 minutes at the Unit 1 reactor enclosure. This compares to a solar heat load for a flat surface at midday of 50-60 Btu/ft^2-hr. The smoke effects of such a fire would be negligible. This accident represents the worst case radiant heat event. Other possible fires that result in more severe smoke generation are described below.

Rupture of the ARCO pipeline at Possum Hollow Run while carrying diesel fuel or home heating oil, which represents the worst case from a smoke generation standpoint, results in the release of approximately 5000 gallons (120 barrels) distributed over the streambed downstream toward the Schuylkill River. An open burning pool of oil produces 1.5-10 kilograms per second of particulates (smoke) for each 1000 barrels per hour of fuel consumed (Reference 2.2-5). The 5000 gallons is assumed to be completely burned in a short time (about 10 minutes). Assuming an average burn release of about 5 kilograms of particulates per second over the 600 meter length from the

streambed pipeline crossing to the first downstream bridge, concentrations of particulates at the reactor enclosure are approximately 2.60 grams of particulates per cubic meter. The radiant heat effects of such a fire are negligible.

A brush and forest fire in the vicinity of the LGS site releases 210 kilograms of particulates per hectare (Reference 2.2-7). Assuming a normal fire rate of 40 acres per hour along the southeast bank of Possum Hollow Run, the smoke concentration at the reactor enclosure, 800 feet from the fire center, is approximately 0.6 grams per cubic meter.

The design provisions available if smoke reaches the control room ventilation are described in Section 2.2.3.2.

2.2.3.1.5 Collisions with the Intake Structure

The Schuylkill River is not used as a navigable waterway for anything other than small recreational boats. Moreover, the ultimate heat sink is the spray pond, so that damage to the intake structure does not impair safe shutdown capability.

2.2.3.1.6 Liquid Spills

Petroleum floating on the Schuylkill River surface could approach the intake structure due to a spill upstream. The intake is under water, so oil is excluded from entry into the intake line. The severest possible condition occurs at the design low water condition, with the water surface at 104' MSL. The water intake is still submerged 1 foot at this level. As noted above, the intake structure is not safety-related.

2.2.3.2 Effects of Design Basis Events

From the foregoing discussion, the following design basis events are identified, along with their potential effects:

a. Railroad, Columbia natural gas pipeline, and ARCO pipeline explosion - overpressurization and missile generation

b. Toxic chemical spill - hazardous control room concentrations

c. Propane tank car fire - radiant heat load on structures

d. ARCO pipeline fire - smoke in control room

The following design provisions or considerations account for these events:

a. Railroad, Columbia natural gas pipeline, and ARCO pipeline explosion

    1. Blast - safety-related structures are designed to withstand the resulting overpressurization due to an explosion as discussed in Section 2.2.3.1.1.

    2. Missiles - safety-related structures are designed to withstand the impact of blast-generated missiles, as identified and discussed in Section 3.5.

b. Toxic Chemical Spill

1. Control Room - detection and isolation capability is provided for the 6 chemicals identified as constituting a hazard, as discussed in Section 6.4.

2. Diesel Generators - The manufacturer of the emergency diesel generators has determined that the chemicals identified in Tables 2.2-5 and 2.2-6, when present in concentrations and for time spans calculated using the methodology described in Section 2.2.3.1.3, would have no adverse effects on diesel generator operation.

c. Propane tank car fire - the radiant heat load from such a fire is evaluated as having no adverse effect on safety-related structures. The bulk of the heat load would be absorbed by the precast panels on the face of the structures, which do not serve a safety function.

d. ARCO pipeline fire - smoke detectors in the control room intake alarm, and the operator can manually isolate the control room ventilation system, as discussed in Section 9.4.1.

2.2.4 REFERENCES

2.2-1 Department of the Army, Navy, and Air Force, "Structures to Resist the Effects of Accidental Explosions", TM5-1300, (June 1969).

2.2-2 NRC, "Safety Evaluation Report - Hartsville Nuclear Plants", Dockets STN 50-518 through STN 50-521 (April 1976).

2.2-3 N.I. Sax, "Dangerous Properties of Industrial Materials", 4th Ed., Van Nostrand Reinhold, New York (1975).

2.2-4 M.G. Zabetakis, "Safety with Cryogenic Fluids", (March 1967).

2.2-5 American Petroleum Institute, "Guide for Pressure Relief and Depressuring Systems", API RP521, (September 1969).

2.2-6 American Conference of Governmental Industrial Hygienists, "TLV's, Threshold Limit Values for Chemical Substances and Physical Agents in the Workroom Environment with Intended Changes for 1978".

2.2-7 EPA, "Compilation of Emission Factors", AP 42, 3rd Ed., (July 1979).

2.2-8 Deleted.

2.2-9 D.H. Slade, "Meteorology and Atomic Energy 1968, U.S. Atomic Energy Commission", (July 1968).

2.2-10 Deleted.

2.2-11 Deleted.

2.2-12 Deleted.

2.2-13 Deleted.

2.2-14 Deleted.

2.2-15 E.B. Vanta et al, "Detonability of Some Natural Gas - Air Mixtures", Armed Forces Armament laboratory, Air Force Systems Command, TR AFATL-TR-74-80, (April 1974).

Table 2.2-1

HOOKER CHEMICAL COMPANY

CHEMICAL	MAXIMUM QUANTITY	ELEVATION OF TANKS (feet)	RELIEF VALVE CAPACITY (psig)	STORAGE TEMPERATURE AND PRESSURE
Vinyl chloride	3,000,000 lb	12	100	30 psig-ambient
Butadiene	500,000 lb	12	100	20 psig-ambient
Tri-fluro-chloro-enthylene	2,000 lb	Portable cylinder	375	68 psig-ambient
Tri-fluro-chlor-ethylene	1,000 lb	In process	None	Ambient
Formaldehyde	50 Drums	Warehouse	--	Ambient
Methanol	10 Drums	Warehouse	--	Ambient
Nitrogen	139,000 SCF	3	350	-325°F
Tolmene	13,000 gal.	12	(100)	Ambient-vent
Gasoline	52,000 ga.l	Underground	--	Ambient vent
Styrene	50,000 gal.	12	(100)	Ambient-vent
Vinyl acetate	25,000 gal.	12	(100)	Ambient-vent
Tri-chloro-Ethylene	25,000 gal.	12	(100)	Ambient-vent
Vinyl pyridine	10,000 gal.	8	--	40°F

Table 2.2-2

PIPELINES WITHIN 5 MILES OF THE SITE

Pipeline	Columbia Gas Transmission Co No. 1278	Columbia Gas Transmission Co No. 1010	Sunoco	Buckeye Partners	Texas Eastern Transmission Corp	Transcontinental Gas Pipe Line Corp
Size (in)	14	20	8	8	2 lines, each 20 in	6
Operating Pressure (psig)	1000 max[1]	1200 max[1]	1200 max[1]	1440[1]	650[1]	750[1]
Age (years)[4]	46	28	26	48	53	44
Depth of Burial (ft)	3 min	3 min	3 min	2 min	3 min	2 min
Fluid Carried	Natural gas	Natural gas	Refined hydrocarbons	Gasoline and fuel oil	Natural gas	Natural gas
Isolation Valves	1. South of Schuylkill River near Parkerford[2] 2. Each side of Schuylkill River crossing (line divides into two 10 inch lines for river crossing)[4] 3. One mile southeast of Feqleysville at intersection	1. South of Schuylkill River near Parkerford[(6)] 2. One mile southeast of Feqleysville at intersection of Houck Rd and Swamp Pike[2]	1. Each side of Schuylkill River crossing near Royersford[3] 2. Approximately 8 miles north of LGS site[2]	1. Each side of Schuylkill River crossing[2] 2. Limerick Township at Grebe Road, approximately 4-1/2 miles NE of LGS site[2]	1. Each side of Schuylkill River crossing near Royersford[3] 2. Near Eagle, PA, approximately 11 miles SW of LGS site[3] 3. Near Lansdale, PA, approximately 15 miles east of LGS site[3]	1. Pottstown gate station in western Pottstown near Keim St. and Conrail Railroad tracks[4] 2. West Vincent Township near Hollow Rd. approximately 7 miles south of LGS site[2]

[1] Pipeline is not used for storage at pressure higher than that shown.
[2] Valve is manually operated gate valve.
[3] Valve is manually operated ball valve.
[4] The age of the pipeline is approximate.

Table 2.2-3

AIRPORTS WITHIN 10 MILES OF THE SITE [1]

AIRPORT	APPROXIMATE DISTANCE FROM SITE (mi)	TYPE	RUNWAY SURFACE/SERVICE	LONGEST RUNWAY (ft)
Pottstown-Limerick	2	Public use	Hard surface/lights	3412
Pottstown Municipal	5	Public use	Hard surface/lights	2700
New Hanover	5	Public use	Soft surface	3450
Perkiomen Valley	8.5	Public use	Hard surface/lights	2900
Sunset Landing Strip	5	Public use	Soft surface	1550
Godshall	8	Private	Soft surface	2000
Kings	8	Private	Soft surface	1700
Yarrow	9	Private	Soft surface	1800
Kunda	8.5	Private	Soft surface	1300
Malickson	7	Private	Soft surface	1800
Kolb	5	Private	Soft surface	1500
Gingrich	4.5	Private	Soft surface	1600
Emery	2	Private	Soft surface	1300
Dimascio	5.5	Private	Soft surface	1300
Hansen	7.5	Private	Soft surface	1800

[1] Source: VFR Terminal Area Chart for Philadelphia, PA, January 1, 1980

Table 2.2-4

AIRWAYS WITHIN 10 MILES OF THE SITE[1]

DESIGNATION	CENTERLINE DISTANCE FROM SITE	FLIGHT DIRECTION	MAGNETIC RADIAL FROM VOR
V143	Approx. 1 mi to south	East West	095° (Pottstown VOR) 269° (Pottstown VOR)
V29/V147	Approx. 1.3 mi to east	North South	354° (Pottstown VOR) 205° (Pottstown VOR)
V210	Approx. 8 mi to south	West	265° (Yardley VOR)
V276	Approx. 10 mi to northeast	Northwest	294° (Yardley VOR)

(1) Source: VFR Terminal Area Chart for Philadelphia, PA, Jan. 1, 1980

Table 2.2-5

ONSITE CHEMICAL STORAGE

Chemical	Stored Volume (Standard cubic feet)	Number of Tanks	Location
Carbon Dioxide	0	1	Turbine Enclosure el 239' (Common) (Abandoned in Place)
Carbon Dioxide	47,100	2	Turbine Enclosure el 217' (Unit 1 and Unit 2)
Nitrogen	539,150	2	West of Radwaste Enclosure el 218' (Common)
Sulfuric Acid	1,337 (10,000 gallons)	2	Adjacent to Cooling Towers (Unit 1 and Unit 2)
Sulfuric Acid	535 (4,000 gallons)	1	Water Treatment Building (Common)
Sulfuric Acid	889 (6,650 gallons)	2	Adjacent to Cooling Towers (Unit 1 and Unit 2)
Sodium Hypochlorite	94 (700 gal)	1	South East corner H_2O Treatment Bldg
Sodium Hypochlorite	1003 (7500 gal)	2	Adjacent to Cooling Towers (Unit 1 and Unit 2)

LGS UFSAR

Table 2.2-6

(DELETED)

Table 2.2-7

SUMMARY OF PEAK POSITIVE REFLECTED PRESSURES
RESULTING FROM RAILROAD AND NATURAL GAS PIPELINE EXPLOSION

	NATURAL GAS PIPELINE EXPLOSION											
PRESSURE (PSI)	REGULATORY GUIDE 1.19 (REV 1) SURFACE BURST		REGULATORY GUIDE 1.19 (REV 1) AIR BURST		4X REGULATORY GUIDE SURFACE BURST		4X REGULATORY GUIDE AIR BURST		RAILROAD EXPLOSION		PRESSURES USED IN STRUCTURAL ASSESSMENT	
BLDG.	ROOF	EXT. WALL	ROOF	EXT. WALL	ROOF	EXT. WALL	ROOF	EXT. WALL	ROOF	EXT. WALL	ROOF	EXT. WALL
Diesel Generator	1.9	5.8	3.5	8.3	4.0	13.0	2.5	16.0	5.7	16.4	6.7	16.4
Reactor Enclosure	1.2	5.8	2.8	8.3	2.6	13.0	5.2	16.0	5.3	16.1	5.4	16.1
Control Structure	1.6	5.0	2.8	6.9	3.3	11.0	4.7	14.0	3.3	10.0	4.9	14.0
Spray Pond Pumphouse	0.8	2.5	1.2	3.3	1.8	5.0	1.4	6.0	2.1	4.7	3.0	6.0

2.3 METEOROLOGY

2.3.1 REGIONAL CLIMATOLOGY

The regional climatology in the vicinity of the LGS site has been analyzed using long-term data from the nearby NWS stations at the Philadelphia and Allentown, Pennsylvania airports. These data are available in several summarized forms (References 2.3.1-1 through 2.3.1-4) from the National Climatic Center. The LGS site is located about midway between Philadelphia and Allentown with respect to both elevation above MSL and geographic location. Though Reading, Pennsylvania is the NWS station closest to the site, it was removed from service in 1969. Climatic summaries from Philadelphia and Allentown indicate that some extremes of record have occurred since 1969, which would not be included in any Reading summaries.

The Site Meteorological Tower data is reviewed and compared on a periodic basis to the meteorological data from Pottstown - Limerick Airport to verify data consistency.

2.3.1.1 General Climate

2.3.1.1.1 Air Masses and Synoptic Features

The general climate of the LGS site is best described as humid continental. The region is dominated by continental air masses in winter, and by alternating continental and maritime tropical air masses in the summer. The site is near the track of most eastwardly moving low pressure systems which are brought from the interior of the U.S. by the prevailing westerlies. This generally produces a change in the prevailing weather system every three or four days. Coastal storms from the Atlantic Ocean can affect the site, causing heavy rains and severe flooding in the most extreme instances.

2.3.1.1.2 General Airflow

The prevailing winds in the region of the LGS site are from the west. Table 2.3.1-1 compares the long-term annual wind distributions from Philadelphia and Allentown. While there are slight differences, the overall flow patterns are similar. Seasonal variations are evident, with the prevailing wind at both stations shifting to the WSW and SW in the summer months and to the WNW and NW during the winter. Annual average wind speeds are between 9 mph and 10 mph at both stations, but the frequency of measured calms (8%) is much larger at Allentown.

2.3.1.1.3 Temperature

Temperatures in the region of the LGS site rarely exceed 100°F or drop below 0°F. Mean monthly temperatures from Philadelphia and Allentown are given in Table 2.3.1-2. The average temperatures at Allentown are approximately 3°F cooler than Philadelphia, but at times the difference may be as great as 10°F or 15°F. This difference can be attributed almost entirely to local differences at the two NWS stations. Temperatures at Allentown are measured at el 391' MSL, while those at Philadelphia are obtained at el 9' MSL, near the modifying influence of the Delaware Bay. Temperatures in the vicinity of the site should fall somewhere between those at Allentown and Philadelphia.

2.3.1.1.4 Relative Humidity

Mean morning and afternoon values of relative humidity from Philadelphia and Allentown are summarized by month in Table 2.3.1-3. The 7:00 am and 1:00 pm values from each station were selected as being representative of typical morning and afternoon conditions, respectively. As the table indicates, both stations recorded the highest morning values in September and the lowest afternoon values in April. Though Allentown indicates consistently higher values of relative humidity, the differences are small.

2.3.1.1.5 Precipitation

The LGS site receives a moderate amount of precipitation, which is well distributed throughout the year. The precipitation distributions at Philadelphia and Allentown are summarized in Tables 2.3.1-4 and 2.3.1-5, respectively. Both stations indicate slightly more precipitation during the summer months. The only significant difference between the two locations is in the mean annual accumulation of snow and sleet, with Allentown receiving approximately 11 inches more per year. This is not unexpected considering the greater elevation and the inland location of Allentown.

2.3.1.1.6 Relationship Between Synoptic and Local Scale Meteorology

The LGS site is situated in an inland region of rolling terrain where one would expect little local modification of synoptic scale weather systems. There are no large bodies of water near the site, and the Schuylkill River is much too small to significantly affect the local conditions. There is a slight channeling effect at low elevations in the river valley.

2.3.1.2 Regional Meteorological Conditions for Design and Operating Bases

2.3.1.2.1 Seasonal and Annual Frequencies of Severe Weather Phenomenon

2.3.1.2.1.1 Hurricanes

Hurricanes are relatively rare at an inland site such as LGS. These storms usually affect the inland regions of the mid-Atlantic states while moving in a path parallel to the coastline, or after coming ashore in the southern states. In the period from 1901 through 1963, only two hurricanes came ashore in the mid-Atlantic coastal region extending from Virginia to New Jersey. There have been 14 hurricanes and tropical storms that have affected the LGS region between 1963 and 1980 (Reference 2.3.1-22). The primary effect from these storms was increased precipitation that occurred after these storms moved inland and began to dissipate. A summary of the peak winds and precipitation totals in the LGS region from these storms is shown in Table 2.3.1-9. The maximum wind speed resulting from a tropical storm in the region was a fastest mile value of 38 mph recorded at Philadelphia during tropical storm Doria (1971). During the 13 year period from 1955 through 1967, Pautz (Reference 2.3.1-6) reports 69 storms in Pennsylvania where surface winds exceeded 74 mph. There were no wind speeds in the site vicinity in excess of 74 mph between 1967 and 1980. The fastest mile of wind recorded at the regional NWS stations was 57 mph at Philadelphia on June 23, 1969. The highest hourly average wind speed recorded at the LGS site since the beginning of the meteorological monitoring program in 1972 was 50 mph on December 2, 1974 at the 270 foot level on Tower 1. While 74 mph is the wind speed criteria used to designate a hurricane, this total reflects winds resulting from both tropical and extratropical storms.

The potentially heavy rains which can result from a hurricane or a decaying tropical storm as it moves inland are a more serious consideration than strong winds in the LGS area. Doria also produced a 24 hour precipitation total of 4.77 inches. The maximum precipitation measured onsite

during 24 hours from a tropical storm was 5.57 inches during the dissipation stage of Hurricane Agnes (1972). Hurricane Agnes caused severe flooding in June of 1972, leaving 8 inches of rain over most of central and southern Pennsylvania. As much as 19 inches of rain fell during hurricane Agnes in western Schuylkill County, approximately 40 miles northwest of the site.

2.3.1.2.1.2 Tornadoes

Summaries prepared by Pearson (Reference 2.3.1-7) indicate that there were 75 tornadoes within a 50 mile radius of the LGS site in the period 1950 through 1976. This data base has since been updated, indicating that 10 additional tornadoes occurred in the 1° latitude-longitude square surrounding the site in the period 1977-1981. The tornado occurring closest to the LGS site during this period was approximately 13 nautical miles WNW on September 5, 1979. There is also an unconfirmed report (Reference 2.3.1-23) of a small tornado touching down in the immediate Pottstown, Pennsylvania vicinity on May 20, 1982. The most severe occurred on March 22, 1955, 17 miles south of the site. This tornado had a path area of 1.2 square miles, with peak winds estimated to be in excess of 150 mph. The tornado reported closest to the site occurred on June 8, 1961, approximately 6 miles to the east. Peak winds from this storm were estimated to be in excess of 110 mph.

Using the statistical methods of Thom (Reference 2.3.1-8), the tornado probability has been computed for the LGS site. This analysis has been based on 32 years (1950-1981) of data from the National Severe Storms Forecast Center, during which 37 tornadoes were reported in the 1° latitude-longitude square surrounding the site. This produces an annual frequency of 1.16 tornadoes per year.

This data base contains information on all tornadoes that have been reported since 1950, and includes information such as latitude and longitude of the tornado starting and stopping points, path width, path length, and tornado intensity. Of these tornadoes, 32 had measured path lengths and widths, which produce a mean path area of 0.342 square miles. Using Thom's formula, this produces a strike probability for any point within the 1° square of once every 9179 years.

2.3.1.2.1.3 Thunderstorms and Lightning

Thunderstorms are a seasonal phenomenon in the region of the LGS site. Philadelphia and Allentown report 27 and 32 thunderstorm days per year respectively, with 90% of these occurring between the months of April and September. The monthly distribution of thunderstorm days is shown in Table 2.3.1-6. Direct observation of lightning strikes is not a routine function at any of the standard observing stations. However, Uman (Reference 2.3.1-9) has developed a statistic which indicates that the number of lightning flashes (cloud to ground) per square mile per year is equal to between 0.05 and 0.8 times the number of thunderstorm days per year. A conservative estimate of the number of lightning strikes per year in the square mile containing the LGS site is 26.

2.3.1.2.1.4 Hail

Hail storms are a relatively rare phenomenon in the LGS site area. Pautz (Reference 2.3.1-6) reports that there were 57 occurrences of hail in the state of Pennsylvania in the 13 year period from 1955 through 1967. This converts to approximately four hail storms per year. However, hail frequency is not uniform throughout the state. Baldwin (Reference 2.3.1-10) and Changnon (Reference 2.3.1-11) both report an annual frequency of one to two hail storms per year in the eastern region of the state. Changnon indicates that these storms are most likely to occur in the late spring.

Storm data (Reference 2.3.1-12) from the period 1972 through 1976 indicate there were thirteen hail storms in Montgomery and the surrounding counties. An examination of severe weather reports in Reference 2.3.1-24 shows that in the period 1977 through mid-1982 the average number of hail storms has remained at about two storms per year. However, there is a considerable amount of variation from year to year. In 1977, there were six hail storms in the LGS region, while none were reported in 1981. The most severe of these occurred in Schuylkill County on July 29, 1974, where egg-sized hail was reported.

2.3.1.2.1.5 Ice Storms and Freezing Rain

A survey by Bennett (Reference 2.3.1-13) indicates that ice or freezing rain may occur up to three to four times per year in the LGS site region. An analysis of local climatic data from the Philadelphia (Reference 2.3.1-1) and Allentown (Reference 2.3.1-2) NWS stations for a later five year (1977-1981) period shows that freezing rain occurs approximately two days per year in Philadelphia and five days per year at Allentown. Considering the more inland and northerly location of Allentown as compared to Philadelphia, this difference is not unexpected. The fact that the LGS site is also inland and about midway between the two NWS offices in terms of latitude makes the previous estimate of three to four storms per year reasonable. However, glaze accumulations greater than 0.25 inches would be expected only once per year. In the 5 year period from 1972 through 1976, eight cases of freezing rain were reported in the site area.

The NWS stations also make observations of another type of frozen precipitation known as ice pellets. However, unlike freezing rain, ice pellets are frozen before reaching the ground and do not form a glaze, but rather bounce on impact in a way similar to hailstones. The Philadelphia and Allentown NWS stations averaged 7 and 8 days per year respectively when ice pellets were observed during the 5 year (1977-1981) period. However, many of these were isolated observations in conjunction with other types of precipitation and could not categorically be called ice storms.

2.3.1.2.1.6 High Air Pollution Potential

Episodes of limited atmospheric dispersion in the U.S. have been studied by Holzworth (Reference 2.3.1-14) in terms of urban and area source problems. Holzworth has estimated a total of 25 forecast days of high potential for air pollution in a 5 year period in the vicinity of the site. Using a pressure gradient technique to define stagnating conditions, Korshover (Reference 2.3.1-15) found 175 stagnation days in the vicinity of the site during the 40 year period from 1936 through 1975. This converts to 4.4 stagnation days per year, which agrees well with Holzworth's estimate.

Subsequent work by Korshover (Reference 2.3.1-25) has identified 31 additional stagnation days in the period 1976-1981. This also results in an average of 4.4 days per year, which is consistent with Korshover's earlier analysis.

2.3.1.2.2 Maximum Snow Load

The weight on the ground of the 100 year mean recurrence interval snowpack at the LGS site is 25 psf. This value was obtained from estimates by the American National Standards Institute (Reference 2.3.1-16) which are based on the work of Thom (Reference 2.3.1-17). The extreme snow load may be estimated by adding the weight of the 48 hour probable maximum winter precipitation (assumed to occur as snow) to the weight of the 100 year snowpack. From the work of Riedel et al (Reference 2.3.1-18) the 48 hour probable maximum winter precipitation is estimated

to have a water equivalent of 15.0 inches, which has a ground force of 78 psf. Therefore, the extreme snow load on the ground at the LGS site is estimated to be 103 psf.

It should be emphasized that this estimate is unrealistically conservative and is presented only for structure design purposes. The 48 hour probable maximum precipitation is based upon theoretical considerations, not measured values. The assumption that the entire amount falls as snow leads to an estimate of 150 inches of snow in 48 hours, using the standard 10:1 conversion ratio. This is more than double the maximum annual snow accumulation at the Philadelphia, Reading, or Allentown NWS stations in the past 40 years of record. The snowstorm of March 19, 1958 through March 21, 1958, is generally regarded as the worst snowstorm on record for snow load accumulation in the LGS area. This was due to the large snow accumulations and the extremely high water content (20% by volume) of the snow (Reference 2.3.1-19). The maximum water content measured in the site area during this storm was 4.43 inches at Coatesville, Pennsylvania.

2.3.1.2.3 Meteorological Design Basis for the Ultimate Heat Sink

The design basis meteorology for the UHS (spray pond) is discussed in Section 9.2.6.

2.3.1.2.4 Design Basis Tornado

The design basis tornado parameters at the LGS site are presented in Table 2.3.1-7. These parameters were finalized prior to the issuance of Regulatory Guide 1.76 (Reference 2.3.1-20) and are not identical to those listed in the guide for Region I, however they are considered to be equivalently conservative. While the translational speed listed is lower than that of the guide, the rotational speed is higher, and the sum of the two is the same as that of the guide. The lower value of rate of pressure drop is conservative since it implies a longer duration of the pressure load, resulting in a larger dynamic load factor. A value for radius of maximum rotational speed is not specified since it is not required in designing structures to withstand the design basis tornado.

The rotational wind speed of 300 mph used in the analysis of plant design adequacy for tornado resistance (Section 3.3.2.1) was determined from Figure 2.3.1-1. For the LGS reactor enclosure, the design basis tornado (300 mph rotational wind speed plus 60 mph translational velocity) imposes an average wind loading of 220 mph, as determined from the area under the curve of the middle graph of Figure 2.3.1-2. Therefore, 300 mph is taken as a conservative wind speed applied uniformly over the entire structure surface, as shown in Figure 2.3.1-2. Because this rotational wind speed is higher than the value listed in Regulatory Guide 1.76, the analysis is conservative compared to an analysis using the Regulatory Guide 1.76 parameters.

2.3.1.2.5 Fastest Mile of Wind

The 100 year recurrence interval fastest mile of wind to be expected at the LGS site is 82 mph. This value is obtained from the work of Thom (Reference 2.3.1-21), and is valid 30 feet above the ground. Table 2.3.1-8 shows the vertical distribution of the fastest mile of wind, computed using the common power law, in the form:

$$U_z = U_{30}\left(\frac{z}{30}\right)^b \qquad \text{(EQ. 2.3-1)}$$

where:

U_z = wind speed at height z

U_{30} = wind speed at 30 feet

b = stability dependent exponent

Thom indicates that a value for b of 1/7 is appropriate for high wind speeds in rolling rural terrain such as that at LGS.

The design basis wind velocity and associated parameters are discussed in Section 3.3.1.1.

2.3.2 LOCAL METEOROLOGY

Local meteorological data have been collected at the LGS site since January 1972. The analysis of this local meteorology has been based upon five years of site data collected at Weather Station No. 1, from January, 1972 through December, 1976. This is the primary onsite meteorological installation, and is located on high ground (base el 250' MSL) approximately 3000 feet NNW of the reactor-turbine enclosure.

A second meteorological tower, installed at Weather Station No. 2, is located in the Schuylkill River Valley (base el 121' MSL) approximately 3000 feet SSW of Tower 1, to allow comparison of the meteorological conditions in the shallow river valley with those on the adjacent hill. One year of data from April, 1972 through March, 1973 has been selected for this comparison, as it represents the best 1 year cycle of concurrent data recovery between Weather Stations No. 1 and 2.

In addition, two years of data were obtained between January, 1975 and December, 1976 from a light wind sensor on the Satellite Meteorological Tower. This tower is located on the east side of the valley floor in a position to detect any downslope or drainage flow. The exact locations of all weather stations and instruments used in the analyses are shown in Figures 2.3.3-1 and 2.3.3-2. Data recovery from all instruments for each of the time periods summarized in the analyses is shown in Table 2.3.2-1.

2.3.2.1 Normal and Extreme Values of The Meteorological Parameters

(MES was one of the meteorological consultants for licensee during the preoperational phase, 1970-1983. The reference to MES as the meteorological consultant for the licensee is considered historical information.)

2.3.2.1.1 Wind Direction and Speed

The wind measurements at LGS are unique in terms of both the locations and elevations of the sensors. The middle-level and upper-level sensors on Tower 2, at Weather Station No. 2, are located at the same elevations above mean sea level as the lower and middle level sensors on Tower 1, at Weather Station No. 1, though their elevations above grade differ. As can be seen in Figure 2.3.3-2, the 159 foot level on Tower 2 and the 30 foot level on Tower 1 are both located el 280' MSL. For the purposes of this analysis, this MSL height has been designated as "level one". The 304 foot level on Tower 2 and the 175 foot level on Tower 1 are both located el 425' MSL. This elevation has been designated as "level two" in the subsequent analysis.

Distributions of wind speed and direction by atmospheric stability class are listed in Reference 2.3.2-23. Wind directions have been grouped into 22.5° sectors. Atmospheric stability has been classified using both the Brookhaven turbulence classes of Singer and Smith (Reference 2.3.2-1)

and the Pasquill stability classes as defined by the lapse rate criteria in Regulatory Guide 1.23 (Reference 2.3.2-2). Joint frequency distributions of wind speed and direction by atmospheric stability class are provided in Reference 2.3.2-23. Two copies of this report were transmitted to the NRC by letter from E.J. Bradley (PECo) to D.G. Eisenhut (NRC) dated July 27, 1981. An hour-by-hour listing of hourly averaged parameters on magnetic tape was transmitted to the NRC by letter from J.S. Kemper (PECo) to D.G. Eisenhut (NRC), dated August 7, 1981.

2.3.2.1.1.1 Five Year Climatology of Wind Direction and Speed

Annual wind direction distributions from all levels at Tower 1 are summarized for the 5 year period, January 1972 to December 1976 in Table 2.3.2-2. The distribution is essentially the same at all levels, with the WNW and NW sectors being predominant. Wind directions are more or less evenly distributed among the remaining sectors. Seasonal variations at Tower 1 are small, but a slight increase in the frequency of south winds is evident at all levels during the summer months.

Monthly average wind speeds from Tower 1 are summarized in Table 2.3.2-3. The highest monthly average wind speeds occur in early spring, while lower speeds predominate during the summer months. The higher wind speeds measured at Tower 1 usually occur with wind directions from the predominant sectors. The maximum hourly average wind speed measured during the 5 year period was 50 mph on December 2, 1974. This was the result of a low pressure system moving up the Atlantic coast.

MES is the meteorological consultant for the licensee. MES chart reading procedures state that wind speed shall be read as an hourly average. In the case of calm winds, this would be an hourly average of 0 mph.

During the 5 year period (1972-1976) of record, chart reading procedures for wind directions during calm hours changed. Calm hours during the period 1972-1975 were assigned a direction of 777, indicating the trace was uninterpretable. However, examination of the charts from this period indicated that in most cases a direction could be obtained, and that despite the limitations of such a procedure, it was preferable to an arbitrary assignment of direction for a given calm hour. Accordingly, the chart reading procedures were changed, and beginning January 1, 1976, a direction was read for each calm hour.

When calm hours were entered into the joint frequency distributions, those calm hours with uninterpretable directions were distributed uniformly among the directional sectors. Those calm hours with valid directions were put into the sector indicated by that direction. All calm hours were arbitrarily classified as stable and were entered into Class F in the lapse rate distributions.

Tables 2.3.2-27 through 2.3.2-33 contain distributions of calm hours from Tower 1, Tower 2, and the Satellite Tower. In each case the distribution of calm hours which were included in the Class F, 0-3 mph category of each wind rose are compared with the distribution of calms according to the Regulatory Guide 1.111 technique.

Because calm hours were arbitrarily placed in Class F in the earlier wind roses, it was possible for a calm hour with a missing delta temperature to be entered into the distribution. For this reason, the total number of calms in the Regulatory Guide 1.111 type distribution does not match the earlier totals.

Regulatory Guide 1.111 states that calms should be defined as hourly average wind speeds below the starting speed of the vane or anemometer. The starting threshold of the Bendix six-bladed Aerovane is 1.8 mph. However, it is a well-known fact that once a propeller is set in motion, it can

operate at speeds below the starting threshold. Unpublished tests conducted by Brookhaven National Laboratory at the New York University wind tunnel during the 1950s showed that the stopping threshold of the six-bladed Aerovane was roughly 1 ft/sec (0.7 mph) lower than the starting threshold. This indicates that hourly averages of 1 mph are possible.

In addition, MES chart readers are trained to distinguish a calm wind trace from a 1 mph trace based on an analysis of both the speed and direction traces. Figure 2.3.2-6 shows typical light wind speed traces, and an example of the differentiation between calm and 1 mph wind speeds. The hours ending at 6 am and 7 am are calm wind traces, evidenced not only by a 0 mph wind speed, but also by a "boxy" directional trace. However, during the hour ending at 8 am and continuing into the following hour, both the speed and direction traces have become active, with speeds fluctuating between 0 mph and 2 mph. Both of these hours would be read as 1 mph.

The primary reason that calm hours were included in a 0-3 mph wind rose grouping rather than a separate class was to provide compatibility with MES dispersion models. However, it should be noted that Regulatory Guide 1.111 does not specifically say that calms should be assigned "as a separate wind speed class."

2.3.2.1.1.2 The Effect of Terrain on Wind Direction and Wind Speed

In order to assess the influence of the Schuylkill River Valley on the low level wind flow, a 1 year comparison was made between wind measurements at Tower 1, located above the river valley, and Tower 2, located on the valley floor. Wind data from the Satellite Tower were also included in this comparison when appropriate. Though the satellite wind data are from a time period not concurrent with the other towers, these data do provide further insight into the valley circulation and are therefore included.

Annual wind direction distributions from Towers 1 and 2 for the period April, 1972 through March, 1973 are shown in Tables 2.3.2-4 and 2.3.2-5. The 1 year wind direction distribution at Tower 1 is very similar to the 5 year distribution previously presented in Table 2.3.2-2. The wind direction distribution at Tower 2 is somewhat more complex, with the distribution at the 30 foot level showing a preference for those directional sectors parallel to the river valley. Table 2.3.2-6 compares the wind direction distributions from Tower 1 and 2 along the equivalent mean sea level heights, "level one" and "level two." The directional distributions on each of these levels are nearly identical, indicating that winds at the middle and upper levels on Tower 2 are not affected by the underlying valley terrain.

A comparison of the wind direction distributions from the 30 foot sensors on Towers 1 and 2 for the 1 year period is shown in Table 2.3.2-7. The 2 year satellite tower wind distribution is also included for comparison. An increase in the wind directions centered about the NNW and SSE sectors, the orientation of the Schuylkill River Valley, is evident when the 30 foot directional distributions from Tower 2 and the Satellite Tower are compared with the low level directional distribution at Tower 1, situated above the river valley. This effect is most prevalent during low wind speed and stable atmospheric conditions during the summer months.

A comparison of monthly average wind speeds from Tower 1, Tower 2, and the satellite tower is shown in Table 2.3.2-8. Average speeds at Tower 1 are very similar to the 5 year wind speed record summarized in Table 2.3.2-3. Higher average winds occur in the spring, and lower wind speeds predominate in the summer months. A comparison of monthly average wind speeds along level one and level two shows that small differences exist between towers along each level, but they are usually less than 1 mph. It should be noted that there is a preference for lower wind

speeds at the low level sensors located in the river valley. Both Tower 2's 30 foot and the Satellite Tower's 30 foot wind speeds are significantly lower than the 30 foot wind speeds measured above the valley at Tower 1. This is reflected in the comparison of monthly average wind speeds shown in Table 2.3.2-8, as well as in the percentage of calm hours. The Tower 2's 30 foot sensor reported 21.5% calm, comparing well with the more sensitive Satellite Tower anemometer which reported 17.5% calm. In contrast the 30 foot sensor on Tower 1 above the river valley reported only 8.1% calm.

This comparison of low level wind speeds, along with the previously discussed comparison of low level wind directions, clearly indicates that the wind measurements obtained on the satellite tower are similar to those obtained at the 30 foot level on Tower 2, and that the satellite tower is representative of the low level wind flow in the Schuylkill River Valley.

2.3.2.1.1.3 Wind Direction Persistence

Wind direction persistence at the LGS site has been analyzed using a technique which determines the number of consecutive hours the wind direction remains in the same 22.5° sector. This analysis is performed with a sliding technique, using each hour as the starting point in determining persistence. The results, which appear in Reference 2.3.2-23, were derived by tabulating the number of times the wind direction, at each level, remains in the same sector for periods of 6, 12, 24, 36, and 48 hours.

The 5 year annual summary of Tower 1 wind direction persistence indicates that the highest frequency of persistent winds occurs in the predominate (WNW) sector. Examination of the monthly distributions indicates that the most persistent winds occurred during the months of June and August.

Wind direction persistence during the 1 year period of concurrent data from Towers 1 and 2 is also summarized in Reference 2.3.2-23. Comparison of the annual distributions between the two towers shows that wind directions were more persistent at Tower 2 than at Tower 1. The 30 foot distribution at Tower 2 shows the most persistent winds in the NW and NNW sectors, which parallel the river valley.

The monthly summaries for this 1 year period indicate that the most persistent winds occurred during January, not during the summer as one might expect. Examination of hourly meteorological data and synoptic charts indicates that these winds were caused by a strong gradient flow from a slow-moving low pressure system rather than any micrometeorological phenomenon.

2.3.2.1.1.4 Climatological Representativeness of the LGS Wind Data

In order to assess the representativeness of the LGS wind data, the 5 year Tower 1, 270 foot wind distribution has been compared with distributions from the Philadelphia and Allentown NWS stations, and from the PBAPS Meteorological Tower. While the Philadelphia and Allentown data are not derived from the exact same time as the LGS data, they are the most concurrent summaries available from the National Climatic Center.

The distance and directional orientations of these stations from the LGS site are listed below.

Station	Distance and Orientation

	from LGS
Philadelphia	31 miles SE
Allentown	31 miles N
PBAPS	48 miles SW

The annual wind direction distributions from Philadelphia (Reference 2.3.2-3), Allentown (Reference 2.3.2-4), and PBAPS are compared with LGS in Figures 2.3.2-1 through 2.3.2-3. These comparisons indicate that both Philadelphia and Allentown have a larger frequency of winds from the SW direction than LGS. The predominant winds at Philadelphia and Allentown are from the SW and WSW respectively, as compared to a predominant WNW wind at LGS. These distributions are similar in all nonpredominant sectors.

The comparison between the LGS 270 foot and PBAPS 320 foot distributions shows a much closer agreement. This is to be expected since PBAPS is the only station of those compared with a sufficient sensor elevation to be free of local effects.

Due to the large discrepancy in sensor elevation and surface roughness between LGS and the NWS stations, PBAPS is the only site with which meaningful wind speed comparisons can be made. A comparison of these two locations in Table 2.3.2-9 shows that the wind speed frequency distributions are almost identical. The LGS 270 foot sensor has a mean wind speed of 10.4 mph, compared to 10.6 mph at the PBAPS 320 foot sensor.

An evaluation of the climatological representativeness of the time period in which the site data was obtained may be made from a comparison of the concurrent short-term data from the NWS stations with their long-term records. Ten year wind directional distributions from Philadelphia (Reference 2.3.2-5) and Allentown (Reference 2.3.2-6) are compared with the short-term records from each station in Figures 2.3.2-4 and 2.3.2-5. The long-term and short-term records at Allentown are essentially identical. However, some differences are evident in the long-term and short-term Philadelphia comparison.

Several changes in both sensor elevation and location were made at Philadelphia between 1951 and 1960, which could account for some of the differences in the directional distributions.

2.3.2.1.2 Atmospheric Stability

2.3.2.1.2.1 Stability Class Breakdowns

Monthly and annual summaries of atmospheric stability have been incorporated into the wind roses previously discussed in Section 2.3.2.1.1. Annual breakdowns of atmospheric stability classes for the 5 year record at Tower 1, and the 1 year comparison of Towers 1 and 2 are summarized in Tables 2.3.2-12 and 2.3.2-13.

The Brookhaven turbulence classes have been determined using the method of Singer and Smith (Reference 2.3.2-1), which is based upon the short-term fluctuations of the Aerovane wind direction trace. The uppermost Aerovane on each tower, the 270 foot sensor on Tower 1, and the 304 foot sensor on Tower 2 were used to determine the turbulence class. The specific criteria used to define each turbulence class are given in Table 2.3.2-14. The Pasquill stability classes were determined using the temperature lapse rate criteria of Regulatory Guide 1.23 (Reference 2.3.2-2). Lapse rates were measured over the full height interval and between the middle and low levels of each tower.

In the 5 year record at Tower 1, there are distinct differences between the two stability classification systems. The Brookhaven system classifies over 55% of the hours as unstable, compared to approximately 12% unstable, as determined by delta temperature measurements over the full tower height. The lapse rate system predicts approximately 27% more neutral hours and 19% more stable hours than the Brookhaven system. When lapse rates over the lower portion of Tower 1 are used, the number of unstable hours (according to the NRC system) increases slightly, primarily at the expense of neutral hours. The frequency of stable hours as determined by lapse rate criteria remains about the same, regardless of which height interval on the tower is used.

When the stability class breakdowns from Towers 1 and 2 are compared for the April, 1972 through March, 1973 period, the same basic differences between the Brookhaven and NRC systems are evident. There are also significant differences between the two towers within each classification system.

When the Brookhaven stability breakdowns from the two towers are compared in Table 2.3.2-12, Tower 2 reports approximately 10% more unstable hours. This can be attributed primarily to the fact that the 304 foot Aerovane on Tower 2 is located 95 feet lower in reference to surrounding terrain than the 270 foot sensor on Tower 1, and is subject to increased turbulence due to surface friction.

A difference between Towers 1 and 2 is also seen in Table 2.3.2-13 when the Pasquill stability classes are contrasted. Regardless of which height interval is considered, Tower 2 categorizes over 65% of the hours as stable. This is an increase of approximately 15% as compared to Tower 1 for the same time period.

2.3.2.1.2.2 Temperature Inversion Persistence

Monthly and annual summaries of temperature inversion persistence at the LGS site are provided in Reference 2.3.2-23. A temperature lapse rate of greater than 0°C/100m has been used to define inversion conditions. Strong inversions with a lapse rate greater than 1.5°C/100m (Pasquill classes F and G) have also been tabulated.

The most persistent inversion during the five years of measurements at Tower 1 occurred from 2100 August 24, 1974 through 0800 August 26, 1974. This inversion lasted for 36 consecutive hours, and was associated with a large high pressure system which descended from Canada. Winds at the site during this time were variable coming from the SW through NNE direction. The second most persistent inversion lasted 29 hours, and was associated with a Canadian high pressure system which moved through the site area on July 16, 1974 and July 17, 1974.

The most persistent inversions found during the 5 year record usually occurred between the months of August and December.

A comparison of inversion persistence at Towers 1 and 2 for the period April, 1972 through March, 1973 shows that the inversions in the river valley at Tower 2 are more persistent. This comparison also shows that the more persistent inversions occur in the latter half of the year. In 1972 they were confined primarily to the period August through October.

2.3.2.1.2.3 Monthly Mixing Heights

No measurements of mixing height have been made at the LGS site. The nearest NWS upper air station is at Kennedy Airport in New York City. The use of Kennedy data at LGS would be unrealistic. Therefore, in the absence of measurements, the mean seasonal morning and afternoon mixing heights reported by Holzworth (Reference 2.3.2-7) are shown in Table 2.3.2-15. These data have been extracted from the plots in the Holzworth report, and are the best approximations available for mixing heights at LGS.

2.3.2.1.3 Temperature

Ambient dry-bulb temperatures at the LGS site have been summarized in Table 2.3.2-16 and in Reference 2.3.2-23.

The monthly means and extremes of temperature recorded at Weather Station No. 1 are shown in Table 2.3.2-16. The maximum hourly temperature measured at the site was 96.2°F on August 28, 1973. The minimum observed temperature was 0.7°F on January 16, 1972.

2.3.2.1.3.1 Climatological Representativeness of LGS Temperature Data

Monthly mean temperatures from LGS are compared with the concurrent and long-term records from the Philadelphia and Allentown NWS stations in Tables 2.3.2-17 and 2.3.2-18. Both comparisons indicate that 1972 through 1976 was a normal period in terms of temperature. Both NWS stations show little deviation from the long-term record. Temperatures at Allentown are usually slightly cooler than those at Philadelphia, while temperatures at LGS usually fall in between the values from the two NWS stations.

2.3.2.1.4 Precipitation

Precipitation from the LGS site has been summarized in Table 2.3.2-19 and in Reference 2.3.2-23.

As Table 2.3.2-19 indicates, the monthly variation of precipitation at the site is small. The annual mean precipitation measured during the 5 years of record was 59.57 inches. The maximum hourly precipitation (2.25 inches) was recorded during hurricane Agnes in June, 1972. The maximum monthly total (14.23 inches) was in November, 1972, as a result of several moderate rainfalls.

Wind roses, by precipitation rate class, indicate a predominately east to northeasterly flow at the site during precipitation hours. This does not vary seasonally or by precipitation rate class.

Precipitation rate distributions and precipitation intensity versus duration summaries in Reference 2.3.2-23 indicate that the majority of the precipitation at the site has an intensity of $\leq$0.05 in/hr. However, hourly totals exceeding 1 inch were recorded nine times during the 5 year record; and continuous rainfalls of >0.10 in/hr have been observed for up to 12 hours.

2.3.2.1.4.1 Climatological Representativeness of LGS Precipitation Data

Monthly average precipitation values from LGS are compared with the concurrent and long-term records from the Philadelphia and Allentown NWS stations in Tables 2.3.2-20 and 2.3.2-21. These comparisons indicate that even though the 1972 through 1976 period was characterized by abnormally high precipitation amounts, significantly higher precipitation totals were recorded at the site when compared to the NWS stations.

2.3.2.1.5 Humidity

Relative and absolute humidity, dew point temperature, and wet-bulb temperature from Weather Station No. 1 are summarized in Reference 2.3.2-23.

The annual frequency distribution of relative humidity shown in Reference 2.3.2-23 is skewed toward the higher humidities, with the 90% through 100% grouping containing approximately 30% of the total hours. A seasonal trend is evident in the monthly frequency distributions of relative humidity shown in Reference 2.3.2-23, as conditions of high relative humidity (90% through 100%) are more common in the summer and fall months.

The annual frequency distribution of absolute humidity from Weather Station No. 1 is shown in Reference 2.3.2-23. Absolute humidity is expressed in grams of water vapor per cubic meter of air. The maximum frequency is in the 3.01-4.00 g/m^3 category, but the values are quite evenly distributed. There is also a large seasonal variation in absolute humidity as Reference 2.3.2-23 shows. This is expected as the ability of dry air to hold water vapor is temperature-dependent.

The annual frequency distribution of dew point temperatures from the site is shown in Reference 2.3.2-23. The largest frequency of hours occurs in the 60.0°F to 64.9°F category, but the distribution is quite even between 20°F and 65°F. The seasonal trend in dew point temperatures is self-evident.

Cumulative frequency distributions of wet-bulb temperature from the site are given for the annual and monthly cases in Reference 2.3.2-23. Due to the unusually long period of record at the site (5 years), the cumulative frequency distributions of wet-bulb temperature have been computed using onsite data rather than the Philadelphia or Allentown NWS data.

2.3.2.1.5.1 Climatological Representativeness of Humidity Data

Because of its sensitivity to changes in temperature and elevation, relative humidity data from site to site are difficult to compare. Some idea of the climatological representativeness of the LGS data can be seen in Table 2.3.2-22, where mean morning (7 am) and afternoon (1 pm) values of relative humidity from Philadelphia, Allentown, and LGS are compared. As the table shows, in most months the mean values from the three sites are within a few percent of each other. LGS and Allentown are the most similar, with Philadelphia usually a few percent lower, especially in the morning.

Another indication of the climatological representativeness of the LGS relative humidity data can be seen from the summaries of daily average relative humidity given in Section 9.2.6.

In this analysis, two and one-half years (January 1972 through June 1974) of LGS daily average relative humidity data were compared with the concurrent and long-term (34 years) records from Philadelphia. These daily average relative humidity data are summarized in the frequency distribution in Table 2.3.2-23. This table shows that LGS has a higher frequency of days in the 90% through 100% range, and that the concurrent data are representative of long-term conditions at the site. A comparison of frequency distributions of hourly relative humidity values between LGS and Philadelphia is shown in Table 2.3.2-24. This comparison also indicates that LGS has a larger frequency of high relative humidity values.

2.3.2.1.6 Fog

No measurements of natural fog or visibility have been made at the site. However, an approximation of the fog and visibility characteristics of the site can be obtained from the Philadelphia and Allentown National Weather Service data. Table 2.3.2-25 compares the mean

number of days with heavy fog at these two stations. Heavy fog is defined as fog causing visibility to decrease to ¼ mile or less.

This comparison shows surprisingly little difference between the two sites, with Philadelphia averaging 25 days of heavy fog per year, compared to 29 for Allentown. It is reasonable to assume that a similar frequency of heavy fog would be found at LGS.

2.3.2.2 Potential Influence of the Plant and Its Facilities on Local Meteorology

A recent EPRI study by Laurmann (Reference 2.3.2-8) has concluded that although quantitative predictions of the meteorological effects resulting from power plant operation cannot be made, evidence and theory indicate that plants of conventional size (up to 4000 MWe) rarely produce noticeable weather changes. The minor effects on the local meteorology which might occur may be divided into two distinct categories: those attributable to the turbulent wakes associated with the plant structures, and those attributable to the waste heat dissipation system.

2.3.2.2.1 Turbulent Wake Effects From Plant Structures

As part of the technical support for the tall stack regulations in the 1977 Clean Air Act Amendments, the EPA has published a comprehensive review and literature search (Reference 2.3.2-9) on the aerodynamic effects caused by building structures. The consensus of this review is that a structure produces a cavity of increased turbulence on its leeward side, 1.5 building heights deep and persist for approximately five building heights downwind. Based upon these criteria, it is estimated that the turbine-reactor enclosure complex produces a turbulent wake on its leeward side, extending 300 feet vertically and persisting 1000 feet downwind.

Halitsky (Reference 2.3.2-10) has shown through wind tunnel tests that the turbulent effects produced by rounded structures are not as large or severe as those produced by sharp-edged buildings. This is consistent with the results of a combined wind tunnel/field measurement study conducted by Smith and Mirabella (Reference 2.3.2-11) on the cooling tower induced wake at the SMUD Rancho Seco Plant. Their results indicate that the cooling towers produce a turbulent wake only when wind speeds exceed 2 m/sec. They estimate that the wake would be 1.5 structure heights deep, and would persist for 2-3 tower diameters downwind. According to these criteria, the maximum wake produced by two LGS cooling towers would be a turbulent region extending 750 feet vertically and persisting 3400 feet downwind.

2.3.2.2.1.1 Effect of the Turbulent Wake on the Gaseous Reactor Effluent

The primary effect of the structurally induced wakes on the reactor effluent is to bring the effluent plume to the ground more quickly, and to increase the dispersion rate. These factors are accounted for in the diffusion calculations presented in Sections 2.3.4 and 2.3.5.

2.3.2.2.1.2 Effect of the Turbulent Wake on the Meteorological Measurements at Tower 1

The turbulent wake produced by the turbine-reactor enclosure complex is not large enough to affect Tower 1. However, Tower 1 is only 2200 feet from the cooling towers, and is in their turbulent wake during a small percentage of the time. The wake is not expected to have any effect upon mean wind directions or speeds at Tower 1. However, when wind directions are between 135° and 165°, turbulence class readings may be shifted toward a more unstable classification. The 5 year turbulence class wind rose provided in Reference 2.3.2-23 shows that wind speeds >2 m/sec with directions between 135° and 165° occur during 5.3% of the time. However, over half (3.0%) of these hours are already classified as unstable due to natural turbulence. (Note: the 5

year data set represents a period prior to any cooling tower construction). Thus only 2.3% of the total hours might be changed from a stable or neutral to a more unstable classification.

2.3.2.2.2 Potential Effects of the Waste Heat Dissipation System on the Local Meteorology

2.3.2.2.2.1 Natural Draft Cooling Towers

During the early 1970s a large number of publications appeared in open literature speculating upon the atmospheric effects attributable to natural draft cooling towers. As Carson (Reference 2.3.2-12) has pointed out, all too often these studies have predicted atmospheric effects that do not in fact occur. Recently, data from field studies have become available. These studies indicate that while the potential for some minor atmospheric effects resulting from cooling tower operation does exist, the magnitude of these effects is much less than that indicated by earlier theoretical evaluations.

2.3.2.2.2.1.1 Ambient Temperature

Operation of the cooling towers has no effect on the ambient temperatures in the LGS area. Field studies reported by Kramer et al (Reference 2.3.2-13) and Brennan et al (Reference 2.3.2-14) have shown that the cooling tower plumes rise to heights well above the tower tops. Therefore, the cooling towers should have no measurable effects upon the mean surface temperature.

2.3.2.2.2.1.2 Relative Humidity

Observational studies have shown that no changes in the ground level relative humidity should be expected as a result of natural draft cooling tower operation. In a study of a 2000 MW, 8 tower complex in England, Spurr (Reference 2.3.2-15) found no differences in the ground level relative humidity upwind or downwind of the plant.

2.3.2.2.2.1.3 Fog

The cooling tower induced environmental effect most often mentioned is ground level fogging. Observations at natural draft cooling tower installations both in the U.S. (Reference 2.3.2-13) and in Europe (Reference 2.3.2-15) indicate that the visible plume rarely, if ever, intersects the ground surface causing fog. Hosler (Reference 2.3.2-16) reports one observation of the visible cooling tower plume intersecting the ground at the Keystone plant in western Pennsylvania. However, the cooling towers at Keystone are much shorter than those at LGS, making them more susceptible to downwash and subsequent fog problems. The added tower height at LGS, along with a larger exit diameter, should ensure a sufficient rise to prevent downwashing.

2.3.2.2.2.1.4 Solar Radiation

The cooling towers do have the potential to cause slight decreases in the amount of solar radiation received at the site due to plume shadowing. Seeman (Reference 2.3.2-17) has conducted a study at a 1500 MW fossil fuel plant in Europe, and found that a 35% reduction in total radiation (total radiation = solar radiation + whole sky radiation) is possible at the point of maximum shadowing by a visible plume on a clear day. On a cloudy day, the maximum shadowing effect is a 20% reduction in total radiation for short periods of time. Due to the variability in wind direction, the plume moves horizontally and does not remain over any one point for long periods of time, thus giving the same effect as a passing small cumulus cloud. However, Ryznar (Reference 2.3.2-18) has measured increases in solar radiation due to the reflection from the side of the visible plume.

An empirical method for providing climatological estimates of visible plume rise and persistence has been described by Brennen et al (Reference 2.3.2-14). This technique uses one year of Philadelphia International Airport upper air soundings as input and shows that the majority of the long plumes conducive to shadowing occur on days when natural clouds are already present, and (during the winter) when agricultural considerations are minor.

The updraft of heat and water vapor in a natural draft cooling tower can, under the proper conditions, produces cumulus clouds or augments already existing cloud decks. This phenomenon has been documented by both Smith (Reference 2.3.2-19) and Spurr (Reference 2.3.2-15); but it can be expected to occur only when conditions favor natural cloud formation.

2.3.2.2.2.1.5 Precipitation Modification

Observations of precipitation falling from natural draft plumes are very limited. Kramer et al (Reference 2.3.2-20) have documented one observation of light rain falling from a natural draft plume, and several observations of light snowfall. Though it may be possible for a cooling tower to modify the precipitation pattern immediately downwind of the tower, it would not significantly alter the total precipitation in the region, as the water vapor emissions from the towers are small compared to natural fluxes (Reference 2.3.2-12).

During the winter of 1975-1976, Kramer et al (Reference 2.3.2-21) observed light snow from several different cooling towers on ten separate days. This effect was found only during stable atmospheric conditions, with temperatures below 10°F at the height of the plume centerline. In the one year summary of Philadelphia upper air soundings on 22 days, for short periods, the temperature criteria necessary for snowfall were met. This should not be interpreted as a prediction of snowfall frequency. There are several other variables such as atmospheric stability, blowdown water chemistry, drift eliminator condition, and condensation nuclei availability which play a role in snowfall formation. The height to which the plume rises is such that in most cases the snow crystals would sublimate before reaching the ground. There is also a strong likelihood that downslope motion to the east would tend to prevent any depth of cloud development with westerly flow.

Additional precipitation may also come from the cooling tower in the form of drift droplets, though the amounts are very small. Drift deposition at LGS has been evaluated using the model of Hosler, Pena, and Pena (Reference 2.3.2-22). This model indicates that most of the drift deposited from the towers will be in the form of liquid drops, with the amount deposited decreasing with distance from the towers. The annual precipitation increase has been evaluated at the site boundary in each sector. The maximum annual increase in precipitation was 0.253 inches at the ESE site boundary. This is less than 1% of the annual total of natural precipitation reported in Section 2.3.2.1.

2.3.2.2.2.1.6 Atmospheric Stability

In addition to the wake-induced turbulence discussed in Section 2.3.2.2.1, there will also be increased turbulence in the visible cooling tower plume itself directly downwind of an evaporating plume. If the gaseous reactor effluent were entrained into the cooling tower plume, the only effect would be increased rise and dispersion of the effluent, and therefore lower ground level concentrations.

2.3.2.2.2.2 Emergency Spray Pond

The UHS at LGS is a spray pond. During routine operations this pond will not be heated, and water temperatures will fluctuate in response to ambient meteorological conditions in the same manner as any natural pond of the same size. This should produce no adverse impact to the local meteorology.

2.3.2.3 Topography

The topography of the LGS site is described in Section 2.1.1. The topography of the region surrounding the site, out to a distance of 50 miles, is summarized in Table 2.3.2-26 which lists the offsite terrain elevation (in feet above MSL) versus distance from a point midway between the LGS vents. The value listed is the maximum elevation on or outside the site boundary which occurs within each of the sixteen 22.5° sectors at the distance listed.

These terrain elevations were obtained from USGS maps.

2.3.3 ONSITE METEOROLOGICAL MEASUREMENTS PROGRAM

The onsite meteorological measurements program at the LGS site began on December 10, 1970 with preliminary wind measurements taken from a six-bladed Aerovane located 30 feet above grade on a temporary pole. Wind speed and direction data were continuously collected at the temporary pole until December 28, 1971 when it was removed from service. Prior to the sensor removal, the onsite meteorological measurements program was expanded on December 10, 1971 with the installation of Weather Station No. 1 near the temporary pole location. The main tower (Tower 1) extending about 281 feet above grade (el 250' MSL) was erected on high ground, NW of the reactor locations. Wind speed, wind direction, and temperature from three elevations are continuously recorded. Instrument elevations are listed in Table 2.3.3-1. Additional onsite measurements of horizontal and vertical wind direction fluctuations, relative humidity, barometric pressure, and precipitation complete the observation at Weather Station No. 1.

In order to evaluate the effects of the shallow Schuylkill River Valley, the onsite meteorological measurements program was again expanded on December 28, 1971 with the installation of a second weather station. Weather Station No. 2 is located across the Schuylkill River from the main tower and is onsite in an open field having a base elevation close to that of the valley floor. Tower 2 at this location, extends 314 feet above grade (el 121' MSL). Wind speed, wind direction, and temperature from three elevations are continuously recorded. Tower 2 was established to provide supplementary site data on the temperature profile in the valley during the preoperational period. This tower was instrumented at MSL elevations coincident with those of Tower 1 in order to compare meteorological conditions over the valley with those over the adjacent low hills. The locations and relationships between the various wind and temperature instruments are shown in Figures 2.3.3-1 and 2.3.3-2.

The overlapping arrangement of the facilities, which allows a comparison of wind and temperature measurements from each tower at two corresponding levels, produces a complete picture of wind flow and lapse rates from the valley bottom to a point about 270 feet above the higher terrain.

To determine the typical flow over the river and adjacent low terrain, a satellite to Weather Station No. 1 was established and data collection began on November 20, 1974. The sensors are located 32 feet above grade (el 106' MSL) and are capable of continuously measuring wind speed and wind direction.

In 1983, the complete system was upgraded to comply with the criteria of Regulatory Guide 1.23 (Rev 1) and NUREG-0654. Data from each of the meteorological locations is transmitted to the control room where it is logged by a data-logger. The data is also transmitted to the TSC as input to the RMMS (Section 11.5.6).

2.3.3.1 Preoperational Meteorological Measurement System (1970-1983)

This meteorological system was used to obtain measurements as described in Table 2.3.3-1.

2.3.3.1.1 Measurements and Instrumentation

2.3.3.1.1.1 Siting

As shown in Figures 2.3.3-1 and 2.3.3-2, the main meteorological weather tower (Tower 1) located at Weather Station No. 1 is a 280 foot tower situated approximately 3000 feet NW of the LGS structure vents. Tower 1 is also located approximately 2000 feet NNW of the center of the Unit 1 cooling tower location and approximately 2400 feet NW of the center of the Unit 2 cooling tower location. Grade elevation at Weather Station No. 1 is el 250' MSL.

The wind instruments on Tower 1 are mounted on retractable booms extending upwind 10'-0" west of the tower. Each face of the triangular tower is 3'-6" wide. The temperature sensors are located in aspirators and are 2'-0" inches from the tower. Weather Station No. 1 has a base surface made of yardstone. The relative humidity sensor is located in a standard U.S. Weather Bureau-type shelter 5 feet above grade and the surface beneath the instrument shelter is wood.

Meteorological weather tower (Tower 2) located at Weather Station No. 2 is a 310 foot tower situated approximately 2100 feet west of the LGS structure vents. Tower 2 is also located approximately 1950 feet WSW of the center of the Unit 1 cooling tower location, and approximately 2600 feet WSW of the center of the Unit 2 cooling tower location.

The wind instruments on Tower 2 are mounted on retractable booms extending upwind 10'-0" WNW of the tower. Each face of the triangular tower is 3'-6" inches wide. The temperature sensors are located in aspirators and are 2'-0" from the tower. Tower 2 has a base surface made of yardstone.

2.3.3.1.1.2 Instrumentation and Performance Specifications

The instrumentation systems installed on the LGS site were designed to meet the NRC requirements at the time of installation and they generally meet those of Regulatory Guide 1.23. Any deviations from Regulatory Guide 1.23 are described in the following subsections.

The manufacturers' specifications and accuracies for the sensors and associated equipment are given in Table 2.3.3-2. Deviation from paragraph C4 of Regulatory Guide 1.23 regarding the system accuracies is discussed and justified in the following sections on each type of measurement.

2.3.3.1.1.3 Wind speed

The Bendix Aerovane Wind Transmitter, Model 120, measures wind speed by means of a six-bladed rotor coupled to the armature of a tachometer magneto located in the nose of the instrument.

The output voltage is directly proportional to the impeller rotation speed and, therefore, is a function of wind speed. This Aerovane system is used on Towers 1 and 2 at LGS.

As shown on Table 2.3.3-2, some of the instruments do not meet the required starting speeds. This presents no problem because real calm conditions with absolutely no air motion are extremely rare at most sites. Measured calms can be far more frequent, depending on the threshold speed of the instrument used.

At LGS, the number of calm hours recorded on the six-bladed Aerovane is shown in Table 2.3.3-3. All levels of both Towers 1 and 2 are instrumented with these six-bladed sensors. The 175 foot instrument at Tower 1 is at the elevation representative of vent releases. With only 1.7% calm hours, a more sensitive instrument could not produce any significant improvement. The 30 foot level of Tower 2 does have a high percentage of calm hours due to its valley location. With this in mind, light wind instruments meeting the recommendations of Regulatory Guide 1.23 were installed in the valley on the satellite tower. As shown in Table 2.3.3-3, the light wind sensor also produces a large (17.5%) number of calm hours. Experience with both types of instruments indicates that the continued durability and accuracy of the six-bladed Aerovane far outweighs the advantage of the slightly lower threshold speed offered by the light wind instruments. Regulatory Guide 1.23 also specified 90% data recovery, which is considered equally important.

The satellite tower uses a Bendix-Friez 3-cup anemometer, P/N 2416914, to determine wind speed. The 3-cup anemometer has cone-shaped cups formed of 0.010 inch thickness aluminum. The cup wheel is attached to a stainless steel shaft which rotates, via coupling, the tachometer generator. The output voltage is directly proportional to the speed of rotation and, therefore, is a function of wind speed.

2.3.3.1.1.4 Wind Direction

The Bendix Aerovane Wind Transmitter, Model 120, measures wind direction by coupling a streamlined vane to a type 1HG synchro. This synchro electrically transmits the position of the vane and, therefore, the wind direction to the recorder.

The satellite tower uses a Bendix-Friez Wind Vane, P/N 2416970, to determine wind direction. This wind vane is very light and sensitive having a low moment of inertia. Changes in azimuth angle are transmitted, via coupling, to a synchro. The signal output from this synchro is directly proportional to the angular position of the vane and, therefore, wind direction is transmitted to a synchro in the recorder.

2.3.3.1.1.5 Temperature

The ambient temperature-measuring system uses Leeds and Northrup 100 ohm copper thermohm sensors (resistance thermometers). These thermohms are accurate to ±0.2°F across the range of -10°F to 110°F. The detectors use four lead wires, two of which are connected to a constant current source and the other two lead wires are connected, via electronic amplifiers to an analog recorder. Contained in the constant current loop is the copper measuring coil, whose resistance varies with temperature, causing the voltage drop across the coil to change proportionally. This voltage drop is then sensed by the measuring loop of a null balance potentiometer having a scale calibrated in degrees fahrenheit.

2.3.3.1.1.6 Temperature Difference

The temperature difference sensors at the site are identical to the ambient temperature sensors, except for the selection of matched sets. These sets have an accuracy of ±0.1°F across a -12°F to 12°F temperature difference range. The reference thermohm (el 26') is connected (opposite in polarity) to both upper elevation thermohms. The two voltage drops (one from each set) are algebraically added, and the resulting output is equivalent to the temperature difference reading.

Both the ambient temperature and delta temperature sensors are located in a Teledyne/Geotech aspirated thermal radiation shield, Model 327. This is to ensure the measurement of ambient temperature and temperature gradients substantially independent of solar, atmospheric, and terrestrial thermal radiation.

2.3.3.1.1.7 Relative Humidity

The Bendix Hygrothermograph, Model 594, is used at and around the site to determine both relative humidity and ambient air temperature.

The relative humidity portion of the instrument consists of a hair-type humidity-responsive element, a lever system, and a cylindrical chart. The accuracy of the humidity unit is ±5% which includes the temperature effects to which the instrument may be subjected.

The temperature-responsive unit consists of a Bourdon tube, a lever system and a cylindrical chart (same cylinder used for humidity). The accuracy of the hygrothermograph temperature unit is ±1°F.

Regulatory Guide 1.23 suggests that at sites where there may be an increase in atmospheric moisture content (i.e., cooling towers) dew point or humidity should be measured on the tower. The results of published field studies (References 2.3.3-1 through 2.3.3-4) prove conclusively that the only changes in atmospheric moisture characteristics which may be experienced from cooling tower operation would occur at the plume elevation, not at the ground level. The results of approximately 400 flight test observations indicate that the cooling tower plumes would rise clear of the ground and have no effect on the low level moisture characteristics. For dew point or humidity measurements to have any relevance to cooling tower effects, they must be obtained at elevations ranging from approximately 1000 feet to 5000 feet above ground, which is not possible on a continuous basis. Since there is little or no potential for fogging or icing conditions resulting from the cooling towers, there is no need for a dew point measurement at the 10 meter level on the tower.

2.3.3.1.2 Calibration and Maintenance Procedures

2.3.3.1.2.1 Calibration

All sensors and related equipment are calibrated according to written procedures designed to ensure adherence to Regulatory Guide 1.23 guidelines for accuracy. Calibrations occur at least every six months, with component checks and adjustments performed when required.

All meters and other equipment used in calibrations are, in turn, calibrated at scheduled intervals. All instruments used in calibrations are traceable to the NBS.

2.3.3.1.2.2 Maintenance

Inspection and maintenance of all equipment is accomplished in accordance with procedures in the instrument manufacturer's manuals. This inspection occurs at least once a week by qualified technicians capable of performing the maintenance, if required. The results of the inspections and maintenance performed are kept in a log at the site. The information contained in this log is also transmitted to the environmental engineering section and meteorological consultant.

In the event that the required maintenance could effect the instruments calibration, another calibration is performed prior to returning the instrument to service.

2.3.3.1.2.3 Data Output and Recording Systems

All meteorological outputs, at this time, are recorded by analog systems. The charts from these systems are sent on a weekly basis to the meteorological consultant, MES located in Amityville, New York, for inspection to detect discrepancies or evidence of malfunction and data analysis.

The analog recording systems for the weather towers are enclosed in a structure with thermostatically controlled temperature.

2.3.3.1.3 Data Analysis Procedures

2.3.3.1.3.1 Data Quality Control

All data are subject to a quality check by MES. These analog charts are inspected for the following items:

a. Verification of log sheets versus actual charts received

b. Time continuity

c. Instrument malfunction

d. Inking problems

e. Directional switching problems

f. Negative speeds

g. Missing data

An evaluation of system performance is made monthly. The percentage of data recovery for LGS weather station instrumentation is shown from 1972 through 1976 in Section 2.3.2.

2.3.3.1.3.2 Data Reduction

All readings that are taken from the strip-charts represent hourly averages (except where noted).

Data are reduced into the different categories as follows:

Wind

a. Wind speed: hourly average speed. Negative speeds are recorded as read.

b. Wind direction: hourly average direction

c. Span: The span is read from the same portion used to obtain the average direction. Span is defined as the width of the direction trace excluding any abnormal spikes. Maximum span read is 360°.

d. Gustiness: The gustiness is read from the same portion of the chart used to obtain the average direction. Gustiness and its characteristics are described in Reference 2.3.3-5.

Temperature and Humidity

a. Hygrothermographs: All relative humidity and temperature readings taken from a hygrothermograph are instantaneous readings on the hour.

b. Ambient temperature: Recorded on a strip-chart; hourly average temperature manually recorded.

c. Delta temperature: Recorded on a strip-chart; hourly average temperature manually recorded.

2.3.3.1.3.3 Analyses

The hourly data obtained (as described) have been compiled into the series of summary tables described in Section 2.3.2. These data are used as inputs to the computation of the X/Q estimates described in Sections 2.3.4 and 2.3.5.

2.3.3.2 Operational Meteorological Measurement System (1983)

The meteorological measurement system has been upgraded to comply with Regulatory Guide 1.23 (Second Proposed Rev 1). The meteorological monitoring system at LGS complies with the criteria in Regulatory Guides 1.101, 1.97, and 1.21 and NUREG-0654 (Rev 1). The signals from the sensors are digitized and transmitted to the control room and the TSC. Meteorological data can be reviewed at the EOF through the EPDS computer. The satellite tower has been retired from service. Data from this tower was redundant to data already being obtained at the 30' level on Tower 2. The satellite tower is not part of the operational meteorological measurement system. Table 2.3.3-6 is a list of the meteorological measurements made by the system.

2.3.3.2.1 Measurements and Instrumentation

2.3.3.2.1.1 Siting

As shown in Figures 2.3.3-1 and 2.3.3-2, Tower 1 located at Weather Station No. 1 is a 280 foot tower situated approximately 3000 feet NW of the LGS structure vents. Tower 1 is also located approximately 2000 feet NNW of the center of the Unit 1 cooling tower location and approximately 2400 feet NW of the center of the Unit 2 cooling tower location. Grade elevation at Weather Station No. 1 is el 250' MSL.

The wind instruments on Tower 1 are mounted on retractable booms extending upwind 10'-0" west of the tower. Each face of the triangular tower is 3'-6" wide. The temperature sensors are located in aspirators and are 2'-0" from the tower. Weather Station No. 1 has a base surface made of yardstone. A dew point sensor is located on the temperature aspirator at the el 26'.

Tower 2 located at Weather Station No. 2 is a 310 foot tower situated approximately 2100 feet west of the LGS structure vents. Tower 2 is also located approximately 1950 feet WSW of the center of the Unit 1 cooling tower location, and approximately 2600 feet WSW of the center of the Unit 2 cooling tower location.

The wind instruments on Tower 2 are mounted on retractable booms extending upwind 10'-0" WNW of the tower. Each face of the triangular tower is 3'-6" wide. The temperature sensors are located in aspirators and are 2'-0" inches from the tower. The dew point sensor is located on the temperature aspirator at el 26'. Tower 2 has a base surface made of yardstone.

There are two (2) areas were the operational monitoring system does not meet the criteria of Regulatory Guide 1.23. One instance is in the proximity of Tower 1 to the two natural draft cooling towers. The other is the proximity of Tower 2 to multiple transmission poles.

The proposed Revision 1 of Regulatory Guide 1.23 states that the tower:

> "should be located in an area where natural or manmade obstructions....would have little or no influence on the meteorological measurements. The tower should be at least 10 obstruction heights away from the obstruction (Reference 2.3.3-8)."

A review of the Regulatory Guide 1.23 siting criteria shows that they are not applicable to the site for several reasons.

a. The reference quoted as supporting the 10 obstruction heights criteria (Reference 2.3.3-6) did not explicitly specify 10 heights, but rather said that 5 to 10 building heights should separate meteorological sensors and adjacent buildings. Hilficker went on to qualify his criteria as being applicable "most directly to cubicle obstructions", which the natural draft cooling towers clearly are not.

b. Strict application of the 10 obstruction height criteria would mean that, for any plant with a natural draft cooling tower, the meteorological tower would have to be located approximately 1 mile away from the immediate plant vicinity. For the site with local terrain effects (e.g. hills, river valley), this would provide data that would be of questionable representativeness. In addition, placing the tower at this distance would put it beyond the site boundary and control of plant security.

c. It is a well-known fact that the downwind influence of the wake caused by a hyperbolic natural draft cooling towers is a function of the tower diameter, not the tower height. This was shown by Smith and Mirabella (Reference 2.3.2-11) with wind tunnel tests at the SMUD Rancho Seco Plant and field studies at the TVA Paradise Plant. They concluded that, when wind speeds exceeded 2 m/sec, the cooling tower wake could extend to a downwind distance of 2 to 3 tower diameters, with a vertical extent of up to 1.5 tower heights. The 2 to 3 tower diameter criteria has also been confirmed by McLaren (Reference 2.3.3-7).

   Based on these criteria, Section 2.3.2.2.1 states that "the maximum wake produced by two LGS cooling towers would be a turbulent region extending 750 feet vertically and persisting 3400 feet downwind."

   This is a conservative estimate based on the maximum width of a two cooling tower complex rather than the individual tower dimensions.

Because the LGS cooling towers are located less than 2000 feet from Tower 1, there may be times when the meteorological tower is in the cooling tower wake. How often the meteorological tower might be in the cooling tower wake and how this will affect the ability of the plant to meet the objectives of Regulatory Guides 1.101, 1.97, and 1.21 is discussed below.

1. Frequency of Wake Effects

   Tower 1 is in a location that is predominantly upwind of the cooling tower complex. Winds must come from directions between 135° and 165° and be in excess of 2 m/sec for the meteorological tower to experience possible wake effects. At the 30 foot level of Tower 1, this would be 4.56% of the total hours, and at the 175 foot level, 6.64%.

2. Consequences of Wake Effects

   If the meteorological tower is in the cooling tower wake, the only real consequence is that the increased turbulence may cause the atmosphere to appear to be one class more unstable within the wake region. This was found during wind tunnel tests of the AEP Mountaineer Plant (Reference 2.3.3-8) as well as in the Rancho Seco field tests conducted by Start et al. (Reference 2.3.3-9).

   In the Rancho Seco field tests, a meteorological tower was located approximately 660 feet from the cooling tower complex, with wind instruments at heights of 4, 16, and 46 meters. A statistical study was conducted comparing turbulence data (sigma theta) from those hours when the meteorological tower was experiencing uninterrupted flow. The results showed the expected increase in turbulence in the cooling tower wake, but found significant increases only at the 16 meter level. No significant effects were found at the 46 meter level, indicating that the turbulent effect decreases with elevation due to the hyperbolic shape of the cooling towers.

   Of the 4.56% of this time when wake effects were possible at the 30 foot level of Tower 1, 3.23% are already unstable, indicating that a significant shift in stability from stable to neutral or neutral to unstable might be possible only 1.33% of the time. At the 175 foot level, only 2.73% of the hours might undergo such a stability change. However, a change at this level seems less likely based on the Rancho Seco results.

3. Implications for Regulatory Guide 1.101 and 1.97 Objectives

   The primary emphasis of these two guides for meteorology is to provide data for emergency response purposes. The cooling tower wake will have no effect on the average wind direction and speed, and therefore no effect on estimates of the airborne effluent trajectory or speed. The possible shift of stability class may affect the modeled effluent concentrations, but because of the small frequency of occurrence and the uncertainty associated with other model input parameters, this is a minor consideration.

4. Implications for Regulatory Guide 1.21 Objectives

For the routine 10CFR50, Appendix I X/Q calculations required by Regulatory Guide 1.21, the cooling tower wake should have no appreciable effect on the calculated concentrations. These calculations will be based on data from the 175 foot level of Tower 1 and will use the sector average version of the Gaussian plume model with joint frequency distributions of wind and stability data as meteorological input. Because almost no effect is expected from the wake at the 175 foot level, this will not affect the calculated concentrations. However, even if wake effects were present, it is unlikely they would cause noticeable differences in this type of calculation.

d. Two transmission line poles are located approximately 239 feet and 310 feet in proximity to the Tower 2. The transmission line poles are 105 feet in height. To comply with the regulatory guide Tower 2 would need to be 1050 feet away from the poles. An evaluation on the disturbance of meteorological conditions at the effective Tower 2 sensor heights was performed. The evaluation concluded the following:

- Wind speed at the 30 foot elevation would be impacted. An estimated 8% decrease from the -12 to 042 degree sectors and 15% from the 098 to 128 degree sectors. Applying this wind reduction to the ten (10) year speed averages, the reduction would affect the measurements by 4.99% and 2.11 %, respectively. Wind speed data from the 30 foot elevation is not used for Emergency Plan or Offsite Dose Calculations.
- Wind direction at the 30 foot elevation would show an undetermined increase in the turbulence factor. Wind direction data from the 30 foot elevation is not used for Emergency Plan or Offsite Dose Calculations.
- No impact to temperature at the 30, 159, or 304 foot elevations.
- No impact to the wind speed at the 159 or 304 foot elevations.
- Negligible or no impact to wind direction and the wind turbulence factors at the 159 and 304 foot elevations.

The preceding discussions have shown that, while cooling tower wake effects at Tower 1 are possible, the frequency of occurrence is extremely low and should not interfere with the functions and objectives described in Regulatory Guides 1.101, 1.97, and 1.21. The obstruction height question should also be weighed against the other siting criteria of Regulatory Guide 1.23.

Specifically, Regulatory Guide 1.23 also states that the primary meteorological tower should be representative of the meteorological characteristics of the region of effluent release, should not be located in a prevailing downwind direction of the heat dissipation system, and should be at a base elevation close to the finished plant grade.

It is concluded that the present Tower 1 location represents the best possible compromise of the siting criteria. Tower 1 is upwind of the plant, at a location close to plant grade, and representative of dispersion conditions on the plateau on which the plant is built.

In addition, Tower 2's siting with the additional transmission pole obstructions is acceptable, given the fact there is negligible to no impact to the meteorological conditions as observed on the required instrumentation in use by the Emergency Plan
and Offsite Dose Calculation Manual.

2.3.3.2.1.2 Instrumentation and Performance Specifications

The instrumentation systems installed on the LGS site were designed to meet the requirements of Regulatory Guide 1.23 (proposed Rev 1).

The accuracies for the sensors and associated equipment are given in Table 2.3.3-7.

2.3.3.2.1.3 through 2.3.3.2.1.9 DELETED

2.3.3.2.1.10 Data Communication and Display

Data from Tower 1 and from Tower 2 will be logged by a data-logger in the control room and input to the PMS in the TSC. Towers 1 and 2 interface to the control room by means of independent communication lines.

Data from this system will be presented to the control room on a CRT display. Data from this system will be presented to the EOF through the EPDS system. The meteorological data is also used by the Class A model for accident dose assessment.

2.3.3.2.2 Calibration and Maintenance Procedures

Calibration and data collection of the meteorological system are controlled by procedures that are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

2.3.3.2.2.1 Calibration

All sensors and related equipment are calibrated according to written procedures designed to ensure adherence to Regulatory Guide 1.23 (proposed Rev 1) guidelines for accuracy. Calibrations occur according to the requirements of the ODCM, with component checks and adjustments performed when required.

All meters and other equipment used in calibrations are, in turn, calibrated at scheduled intervals. All instruments used in calibrations are traceable to the NIST.

2.3.3.2.2.2 Maintenance

Inspection and maintenance of equipment is accomplished in accordance with station procedures and meteorological vendor procedures. The maintenance of the system is documented in the site work process and vendor reports.

In the event that the required maintenance could effect the instruments calibration, another calibration is performed prior to returning the instrument to service.

2.3.3.2.2.3 Data Output and Recording Systems

All meteorological outputs are recorded by an on site data-logger and the PMS system. The data from the systems are sent on a weekly basis to a meteorological consultant, for inspection to detect discrepancies or evidence of malfunction and data analysis.

The data-logger and PMS Computer systems for the weather towers are enclosed in a structure with thermostatically controlled temperature.

2.3.3.2.3 Data Analysis Procedures

2.3.3.2.3.1 Data Quality Control

The consultant prepares a meteorological data summary, formatted as joint frequency distribution tables of wind speed and wind direction, to satisfy NRC reporting requirements per Regulatory Guide 1.21.

All data are subject to a quality check by the consultant. Digital data is reviewed to detect any malfunctions.

An evaluation of system performance is made monthly to ensure that data recovery is satisfactory.

2.3.3.2.3.2 Data Reduction

Analog chart samples are reduced and compared with the corresponding digital data to ensure both systems are functioning properly.

Temperature and Dew Point (Data Logger)

a. Dew Point: hourly average dew point temperature.

b. Ambient temperature: hourly average temperature.

c. Delta temperature: hourly average temperature.

d. Precipitation: each discrete step represents 0.01 inches of liquid water. The number of steps are added to obtain the total precipitation for the hour.

2.3.3.3 Offsite Meteorological Monitoring Locations

The LGS meteorological data from the preoperational period have been compared with offsite data from the Philadelphia and Allentown, Pennsylvania NWS stations and with the data from PBAPS. Whenever possible LGS parameters were compared with concurrent data from the regional stations to assess their similarity, as well as with the longer term records from the regional stations to assess the climatological representativeness of the time period during which the LGS site data were obtained.

The following are brief descriptions of the offsite measurement locations:

2.3.3.3.1 Philadelphia

The Philadelphia NWS station is presently located at the Philadelphia International Airport, approximately 31 miles SE of the LGS site. The airport is located on the southern edge of the city, bordered on its SE side by the Delaware River. The area is relatively flat, with no appreciable terrain roughness to influence the data.

The Philadelphia NWS meteorological sensors have been moved several times during the period of record used in the long-term comparisons. In 1960, the NWS established standard elevations for all meteorological sensors, and the instrument locations have remained unchanged since that time. A complete history of the sensor locations at the Philadelphia NWS station is shown in Table 2.3.3-4.

2.3.3.3.2 Allentown

The Allentown NWS station is located approximately 31 miles north of the LGS site at the Lehigh Valley International Airport. The station is 5 miles NE of the city of Allentown in the Lehigh River Valley.

The river valley is surrounded by rolling terrain and numerous small streams, but there are also some larger terrain features in the area. Blue Mountain is a ridge located 12 miles north of Allentown, ranging between 1000-1800 feet high. South Mountain, ranging between 500-1000 feet high, is located on the southern edge of Allentown. However, neither of these two mountains is close enough to the Allentown NWS station to have any direct effect on the local meteorology. The Allentown NWS meteorological sensors have been moved between various elevations and locations during the period of record used in the long-term comparisons, but were moved to the standard NWS elevations in 1965, and have remained unchanged since that time. The complete history of the sensor locations and elevations is shown in Table 2.3.3-5.

2.3.3.3.3 Peach Bottom Atomic Power Station

Weather Station No. 2 at the PBAPS is located approximately 48 miles southeast of the LGS site. The PBAPS is located in the Susquehanna River Valley, but Weather Station No. 2 is a 320 foot tower situated on a hill overlooking the valley. The 320 foot wind sensor at Weather Station No. 2 is at an elevation comparable to the upper-level LGS wind sensors, and therefore provides a useful check of the representativeness of the meteorology.

2.3.4 SHORT-TERM (ACCIDENT) DIFFUSION ESTIMATES

2.3.4.1 Objective

Estimates of atmospheric diffusion (X/Q) are made at the exclusion area boundary (731 m) and the outer boundary of the LPZ (2043 m). These estimates are made for periods of 2, 8, and 16 hours, and for 3 and 26 days following a postulated accident. The NRC recommended section-dependent model (PAVAN) in Reference 2.3.4-1 is used.

2.3.4.2 Calculations

2.3.4.2.1 Calculation of X/Q values at the EAB and LPZ

X/*Q* values at the EAB and LPZ were calculated in accordance with Regulatory Guide 1.145. For ground-level releases, calculation for the 2 hours following the accident were based on the following equations:

$$X/Q = \frac{1}{\bar{U}_{10}\,(\pi\sigma_y\sigma_z + A/2)} \qquad (2.3\text{-}2)$$

$$X/Q = \frac{1}{\bar{U}_{10}\,(3\pi\sigma_y\sigma_z)} \qquad (2.3\text{-}3)$$

$$X/Q = \frac{1}{\bar{U}_{10}\,\pi\Sigma_y\sigma_z} \qquad (2.3\text{-}4)$$

where:

X/Q is relative concentration, in sec/m^3.

π is 3.14159.

$\bar{U}_{10}$ is wind speed at 10 meters above plant grade, in m/sec.

σ_y is lateral plume spread, in m, a function of atmospheric stability and distance.

σ_z is vertical plume spread, in m, a function of atmospheric stability and distance.

Σ_y is lateral plume spread with meander and building wake effects (in meters), a function of atmospheric stability, wind speed, and distance [for distances of 800 m or less, $\Sigma_y = M\sigma_y$, where M is determined from Reg. Guide 1.145 Fig. 3; for distances greater then 800 m, $\Sigma_y = (M\text{-}1)\ \sigma_{y\ 800m} + \sigma_y$].

A is the smallest vertical-plane cross-sectional area of the reactor building, in m^2. (Other structures or a directional consideration may be justified when appropriate.)

Plume meander is only considered during neutral (D) or stable (E, F, or G) atmospheric stability conditions. For such, the higher of the values resulting from Equations 2.3-2 and 2.3-3 is compared to the value of Equation 2.3-4 for meander, and the lower value is selected. For all other conditions (stability classes A, B, or C), meander is not considered and the highest *X*/*Q* value of equations 2.3-2 and 2.3-3 is selected.

The *X*/*Q* values calculated at the EAB based on meteorological data representing a 1hour average are assumed to apply for the entire 2-hour period.

2.3.4.2.2 Determination of Max Sector and Overall 5% Site *X*/*Q* Values

2.3.4.2.2.1 Maximum Sector *X*/*Q*

To determine the maximum sector *X*/*Q* value at the EAB, a cumulative frequency probability distribution (probabilities of a given *X*/*Q* value being exceeded in that sector during the total time) is constructed for each of the 16 sectors using the *X*/*Q* values calculated for each hour of data. This probability is then plotted versus the *X*/*Q* values and a smooth curve is drawn to form an upper bound of the computed points. For each of the 16 curves, the *X*/*Q* value that is exceeded 0.5 percent of the total hours is selected and designated as the sector *X*/*Q* value. The highest of the 16 sector *X*/*Q* values is the maximum sector *X*/*Q.*

Determination of the LPZ maximum sector *X*/*Q* is based on a logarithmic interpolation between the 2-hour sector *X*/*Q* and the annual average *X*/*Q* for the same sector. For each time period, the highest of these 16 sector *X*/*Q* values is identified as the maximum sector *X*/*Q* value. The maximum sector *X*/*Q* values will, in most cases, occur in the same sector. If they do not occur in the same sector, all 16 sets of values will be used in dose assessment requiring time-integrated concentration considerations. The set that results in the highest time-integrated dose within a sector is considered the maximum sector *X*/*Q.*

2.3.4.2.2.2 5% Overall Site *X*/*Q*

The 5% overall site *X*/*Q* value for the EAB and LPZ is determined by constructing an

overall cumulative probability distribution for all directions. *X*/*Q* versus the probability of being exceeded is then plotted and an upper bound curve is drawn. From this curve, the 2-hour *X*/*Q* value that is exceeded 5% of the time is found. The 5% overall site *X*/*Q* at the LPZ for intermediate time periods is determined by logarithmic interpolation of the maximum of the 16 annual average *X*/*Q* values and the 5% 2-hour *X*/*Q* values.

2.3.4.2.3 Meteorological Input

Meteorological data from LGS Weather Station No. 1 taken from January, 1996 through December, 2000, is used in the diffusion calculations. Joint stability class and wind occurrence distributions are computed based on using wind speed and direction from the 30 foot level and temperature difference from the 266-26 foot height interval. The lapse rate, wind speed, and wind direction categories are consistent with the recommendations of Regulatory Guide 1.23 (Reference 2.3.4-3).

The meteorological database was prepared for use in PAVAN by transforming the five years (i.e., 1996-2000) of hourly meteorological tower data observations into a joint wind speed-wind direction-stability class occurrence frequency distribution as shown in Table 2.3.4-1. In accordance with Regulatory Guide 1.145 (Reference 2.3.4-2), atmospheric stability class was determined by vertical temperature difference between the release height and the 10-m level, and wind direction was distributed into 16 - 22.5° sectors.

Seven (7) wind speed categories were defined according to Regulatory Guide 1.23 (Reference 2.3.4-3) with the first category identified as "calm. " The higher of the starting speeds of the wind vane and anemometer (i.e., 0.50 mph) was used as the threshold for calm winds, per Regulatory Guide 1.145, Section 1.1. A midpoint was also assumed between each of the Regulatory Guide 1.23 wind speed categories, Nos. 2-6, as to be inclusive of all wind speeds. The wind speed categories have therefore been defined as follows:

Category No.	Regulatory Guide 1.23 Speed Interval (mph)	PAVAN-Assumed Speed Interval (mph)
1 (Calm)	0 to < 1	0 to <0.50
2	1 to 3	>=0.50 to <3.5
3	4 to 7	>=3.5 to <7.5
4	8 to 12	>=7.5 to <12.5
5	13 to 18	>=12.5 to <18.5
6	19 to 24	>=18.5 to <24
7	> 24	>= 24

In the equations shown in Section 2.3.4.2.1, it should be noted that wind speed appears as a factor in the denominator. This causes obvious difficulties in making calculations for periods of calm. The procedures used by PAVAN to assign a direction to each calm period according to the directional distribution for the lowest wind-speed class. This is done separately for the calms in each stability class.

2.3.4.2.4 Building Wake Correction

A building wake correction of 5851 m^2 is equal to the Reactor Enclosure's combined vertical cross sectional area. A correction value of 2500 m^2 is used for one Reactor Enclosure

2.3.4.2.5 Short-Term *X/Q* Modeling Results

Atmospheric diffusion estimates developed for use in evaluating accidents are summarized in Table 2.3.4-4 for the above-mentioned periods following the accident. This table includes estimates for the maximum sector and overall 5% site *X/Q*.

2.3.5 LONG-TERM (ROUTINE) DIFFUSION ESTIMATES

Radionuclides will be routinely emitted to the atmosphere from three locations at LGS. The source vents include the Turbine Enclosure, Unit 1 Reactor Enclosure, and Unit 2 Reactor Enclosure. Diffusion estimates may be based on a single source originating from one point located midway between the three vent locations or based on each individual location independently.

Estimates of annual average X/Q are performed for receptor locations out to 50 miles in each directional sector. These historical values are presented in Table 2.3.5-1.

2.3.5.1 Meteorological Input

Meteorological data taken at Tower No. 1 from January 1972 through December 1976 are used in calculating the long term diffusion estimates.

Routine releases from LGS will be released through the two reactor enclosure vents and the turbine enclosure vent. These vents are all located at an elevation (el 416' MSL) only 9 ft below the 175 ft instrumentation level at Weather Station No. 1. Winds from the 175 ft level were used to calculate the annual X/Q values shown in Table 2.3.5-1. The maximum value of 6.291×10^{-7} is found at the site boundary (762 m) in the ESE sector. The spacing in this portion of the calculational grid is sufficiently dense to assure that the maximum offsite X/Q value has been calculated.

Distributions of wind speed and direction are computed for 22.5° sectors using the wind speed groups suggested in Regulatory Guide 1.23 (Reference 2.3.5-2). The 5 year 175 foot wind distribution used as input for the diffusion calculations is provided in Reference 2.3.2-23.

All calm hours have been distributed equally among the 16 directional sectors. With the exception of the 0-3 mph and 24+ mph groups, the median speed from each wind speed grouping is used. A speed of 1.61 mph (0.72 m/sec) is used as the median for the 0-3 mph group resulting from the guidance in Regulatory Guide 1.111 (Reference 2.3.5-3) that calm hours be assigned a speed of 0.1 m/sec, if the sensor does not conform with the minimum starting speed criteria of Regulatory Guide 1.23. A speed of 27 mph is used to represent the 24+ mph group.

The diffusion model utilized is described in Section 2.3.5.3.

2.3.5.2 Plume Rise

The volumetric flow rate from the LGS reactor enclosure vents will not vary seasonally. However, the volumetric flow rate from the turbine enclosure vent will vary from a summer maximum of 307 m^3/sec to a winter minimum of 147 m^3/sec, with an annual average of 216 m^3/sec. To calculate plume rise, one set of composite vent parameters was derived by appropriately weighing the diameter and exit velocity of each vent according to its volumetric flow rate. The individual vent parameters along with the derived composite vent parameters used in the plume rise calculations are listed in Table 2.3.5-2.

The Briggs (Reference 2.3.5-7) momentum plume rise equations, in the form expressed by Sagendorf and Goll (Reference 2.3.5-8), are used.

2.3.5.3 Diffusion Model

The sector average version of the Gaussian plume equation, as expressed in Regulatory Guide 1.111 is used for all X/Q calculations. The basic equation is as follows:

$$\frac{X}{Q} = \frac{360f}{\phi\pi^{3/2}2^{1/2}xu_e(\sigma_z^2 + \frac{CA}{\pi})^{1/2}} e^{-\left[(h - z_{corr})/\sigma_z\right]^2}$$

(EQ.2.3.-3)

where:

X	=	Concentration at receptor point (curies/meter^3)
Q	=	Emission rate (curies/sec) - assumed to be 1 curie/sec for these calculations
ϕ	=	Sector width - assumed to be 22.5° for these calculations
x	=	Distance of receptor point (meters)
u_e	=	Effective wind speed applicable to stack height, h, (meters/sec)
h	=	Effective stack height from Briggs equations (meters)
σ_z	=	Vertical standard deviation of the plume at distance, x, (meters)
σ_x	=	Lateral standard deviation of the plume at distance, x, (meters)
f	=	Frequency of occurrence of wind speed and stability combination (dimensionless)
Z_{corr}	=	The terrain correction
CA	=	The area of an obstacle (A) times a shape factor to take account of the details of the flow around the obstacle.
360	=	Number of degrees in a circle .
π	=	3.14

2.3.5.3.1 Source Configuration

The entrainment functions of Regulatory Guide 1.111 are used to determine the portion of the effluent plume entrained into the turbine-reactor enclosure wake. However, the effective height of the entrained portion of the plume is never allowed to decrease below 10 meters. Therefore, the building wake term (CA) was set equal to zero, in accordance with the guidance in Regulatory Guide 1.111 that this term be used only when the effective plume height is equal to zero.

2.3.5.3.2 Terrain Corrections

Individual terrain corrections are applied at each receptor. In order to model the LGS vents in the most realistic manner possible, terrain heights relative to the normal elevation of the Schuylkill River (33.5 m MSL) are used, and are allowed to decrease with distance within the first 1000 m. With the exception of those receptor points within the first 1000 m, the terrain correction applied to any particular receptor is the highest terrain between the source and a point up to, but not including, the next downwind receptor. These corrections are subtracted from the calculated effective plume height. A minimum effective height of 10 m is assumed when the terrain elevation exceeds the calculated plume height. The actual terrain elevations in each direction sector are given in Section 2.3.2.

2.3.5.3.3 Atmospheric Stability

Atmospheric stability classes are determined using the Brookhaven Turbulence Class system developed by Singer and Smith (Reference 2.3.5-5). This system, which has been previously defined in Table 2.3.2-14, is based upon the short-term fluctuations of the wind direction trace.

The long-term diffusion estimates for LGS were based upon the Smith-Singer vertical dispersion parameters and the Brookhaven Turbulence Class system because this system is more appropriate for the release and terrain characteristics of the LGS site than the Regulatory Guide 1.111 parameters.

A. Vertical Dispersion Curves

Regulatory Guide 1.111 specifies that the Pasquill-Gifford or P-G dispersion coefficients be used for long-term dispersion estimates. However, there are several sound reasons for using the Brookhaven (Smith-Singer) coefficients instead:

1. Surface Roughness

The P-G dispersion coefficients were developed primarily from the Prairie Grass diffusion experiments at O'Neill, Nebraska. The Prairie Grass data were collected in extremely flat, smooth terrain with a roughness length, z_o, of 3 cm. In contrast, the Brookhaven coefficients were developed in an area of scrub pines and oaks, with a roughness length of 1 meter. The LGS region, characterized by a combination of buildings, open fields and trees, is much more similar to Brookhaven than to O'Neill, Nebraska.

2. Release Elevation

The Prairie Grass experiments consisted of a series of ground level SO_2 releases, with concentrations measured at downwind distances of up to 800 meters. Extrapolation of these curves to distances beyond one kilometer is based on limited observations. The Brookhaven dispersion coefficients, on the other hand, are based on both elevated and low level releases. The standard curves published by Smith (Reference 2.3.5-10) in the ASME Guide were derived from plumes released at 108 meters and tracked for more than 50 km. In addition, a second set of unpublished dispersion coefficients were developed from low level releases, as shown in Section 2.3.5.3.4.

The entrainment coefficients from Regulatory Guide 1.111 specify that the LGS plume will be elevated 84% of the time. In these cases, the standard Brookhaven coefficients were used. For the remaining 16% of the time, the low level coefficients were used.

The 1977 AMS workshop on stability classification schemes and sigma curves (Reference 2.3.5-9) clearly supported the use of the Brookhaven curves in preference to the P-G curves where elevated sources in rolling terrain are involved:

> "For elevated sources, the "Brookhaven" curves (M.E. Smith, 1968) are an appropriate choice when δz is less than the effective source height. These curves are based on average concentration measurements from a passive source at an elevation of 108 m. They differ from the Pasquill-Gifford and Turner curves both because the measurement site was surrounded by a much rougher surface, mostly forests, from which Z_o equals approximately 1 m."

3. Averaging Time

The Prairie Grass project consisted of short duration field experiments, with the P-G horizontal coefficient representing 3 minute averages, and the vertical coefficients 10 minute averages. In contrast, all of the Brookhaven data from which the dispersion curves were derived were hourly averages.

4. Validation

While model validation is a somewhat nebulous and controversial area, attempts have been made to verify the appropriateness of the more commonly used dispersion coefficients with field data. A recent study by Weil (Reference 2.3.5-11) at the coal-fired Dickerson power plant in Maryland found that when using the Gaussian plume model with the Brookhaven dispersion coefficients, predicted concentrations were within a factor of two during 73% of the cases analyzed. Conversely, the P-G coefficients at times resulted in orders of magnitude disagreement between predicted and measured concentrations.

The Dickerson Plant releases a buoyant plume from stacks approximately 400 feet tall, so the analogy with LGS is not clear-cut. However, the results indicate that the Brookhaven curves are preferable.

B. Stability Class Determination

Because the Brookhaven dispersion coefficients are used in the LGS analysis, it is reasonable and consistent to use the Brookhaven stability classification system as well. The two were developed together and are part of a cohesive system.

Furthermore, although the classification system based on delta temperature is recommended by NRC, the ΔT method has been criticized by the scientific community. It seems clear that the system produces an inordinately high percentage of neutral hours, and several recent workshops and publications have recommended that the system be changed. Several of these suggestions are worth reiterating:

1. Weber et al (Reference 2.3.5-12) conducted a regression analysis comparing several stability classification schemes with vertical dispersion data from the Prairie

Grass, Green Glow, and National Reactor Testing Station experiments. The results from this study showed that during unstable conditions, delta temperature did not correlate at all with the measured concentrations. In stable conditions, delta temperature compared favorably with the other stability classification systems, but the authors cautioned that a strict correlation should only be found for delta temperature measured in the surface layer (<10 meters) and that there was no reason to expect correlation at higher levels.

2. AMS Workshop - At the 1977 AMS workshop on stability classification schemes and sigma curves, there were lengthy discussions of the various methods available to classify stability. The workshop recommended that the standard deviation of the horizontal wind direction fluctuations, sigma theta, be used to estimate horizontal diffusion rates, and that dimensionless ratios of temperature lapse rate and wind speed be used to specify vertical turbulence. The workshop also said that there is little physical justification for the current practice of estimating vertical diffusion based on temperature lapse rate data alone.

   It seems contradictory that the NRC has referenced the report from this workshop in the proposed Revision 1 of Regulatory Guide 1.23, yet ignored some of these fundamental recommendations.

3. Gifford (Reference 2.3.5-13), in a memo to the ACRS regarding the proposed Revision 1 of Regulatory Guide 1.23, reiterates his objection to the use of delta temperature. Gifford states:

   > "My main objection (a long-standing one) to the draft is that it continues to recommend the so-called ΔT method (or $\Delta\theta$ method) as the primary means of determining σ_y and σ_z (p 6, lines 12 & 13). The problems involved, and limitations of this methodology are clearly set out in the American Meteorological Society workshop report on the subject, reference 1 in the proposed revision. This reference (Bulletin AMS 58 , p 1306) states "There is little physical justification for the currently widespread practice of approximating S'" (the stability factor) "by - $\Delta\theta$ alone....in stable conditions the effects of topography....may equally invalidate - $\Delta\theta$ and S' as determinants of σ_z". The reference goes on to stress problems of determining σ_z in other types of conditions (i.e. unstable, daytime) and stresses the poor state of our observational knowledge at present. Finally, problems of the $\Delta\theta$ method (p 1309) are discussed in detail, pointing out the desirability of a more physically based indicator such as the bulk Richardson number S'; and also the problem of measuring $\Delta\theta/\Delta Z$ in a meaningfully shallow layer with present requirements for siting the upper temperature sensor (60 m) is pointed out."

   Clearly, the ΔT method is not entirely palatable to the scientific community, and there is little doubt that the Brookhaven system is at least as good an indicator of stability. Particularly for the LGS site and source elevations, the Brookhaven system offers some distinct advantages. The Brookhaven classes are based on the "gustiness" or short-term fluctuations of wind direction trace averaged over an hour and are a physical representation of the horizontal turbulence of the wind flow. In addition, the Brookhaven system determines the atmospheric stability in the region

of the actual effluent release, which was another of the AMS workshop recommendations.

Regulatory Guide 1.111 states that wind speeds representative of the vent release elevation should be used for long-term dispersion estimates. Accordingly, wind data from the 175 ft level of Tower 1 were used for the LGS annual X/Q calculations. This instrument is within 9' MSL of the LGS vent elevation. For the elevation portion of the mixed mode release, wind speeds were not corrected for source elevation. However, for the low level portion of the mixed mode release, speeds were adjusted by standard power law techniques to the 10 meter level.

Figure 2.3.5-1 shows a comparison of the annual X/Q values from Table 2.3.5-1, which were computed using Brookhaven dispersion coefficients. These values represented by the dashed line are from a similar calculation with ΔT stability and the P-G dispersion coefficients of Regulatory Guide 1.111. The comparison shows that the Brookhaven coefficients were more sensitive to terrain elevation because the lower portion of the mixed code release is set at 10 meters in the BNL model, as compared to a ground level release in the Regulatory Guide 1.111 model. Otherwise, the values are quite similar.

2.3.5.3.4 Dispersion Coefficients

Expressions for calculation of the vertical dispersion coefficients, σ_z. for each turbulence class, have been defined by Singer and Smith (Reference 2.3.5-6) and are as follows:

		Very Unstable	Unstable	Neutral	Stable
σ_z	Source Higher Than 50 Meters	$0.40x^{.907}$	$0.33x^{.859}$	$0.22x^{.776}$	$0.06x^{.709}$
σ_z	Source Lower Than 50 Meters	$0.29x^{.907}$	$0.25x^{.859}$	$0.19x^{.776}$	$0.08x^{.709}$

where:

σ_z = Vertical dispersion coefficient, meters

x = Distance downwind, meters

The σ curves were originally derived for the BNL site, where the terrain is slightly flatter than LGS, but the vegetation and small-scale roughness are quite similar. These expressions for the turbulent diffusion parameters are generally accepted, and have been recommended by Hanna et al (Reference 2.3.5-9) as the preferred system for elevated releases. The entrainment coefficients of Regulatory Guide 1.111, combined with the Tower 1, 175 foot wind speed distribution, indicate that the LGS plume is classified as elevated 84% of the time.

2.3.5.3.5 Recirculation Correction Factors

Regulatory Guide 1.111 specifies that the local meteorology be examined to determine the extent of the temporal and spacial variations in the local circulation, and their effect upon the long-term diffusion estimates. Comparisons between Towers 1 and 2 in Section 2.3.2 indicate that there is little variation in the local meteorology surrounding the LGS site. The Schuylkill River Valley is too shallow to have a major effect on the local circulation. The only significant difference between the two towers is that wind speeds are slightly lower near the valley floor.

Previous submittals (References 2.3.5-1 and 2.3.5-4) summarizing wind recirculation effects at PBAPS (located approximately 48 miles SW of LGS) have shown, through a puff-trajectory analysis, that the reactor effluent rarely returns to the site area. Based upon these two studies, it has been concluded that recirculation correction factors are not warranted at LGS.

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Table 2.3.1-1

COMPARISON OF ANNUAL
WIND DIRECTION FREQUENCY DISTRIBUTION (%)

DIRECTION	PHILADELPHIA (1967-1974)	ALLENTOWN (1964-1974)
NNE	2.9	2.0
NE	3.4	4.7
ENE	5.8	2.5
E	6.2	6.3
ESE	3.2	2.8
SE	3.2	2.0
SSE	3.6	1.6
S	7.0	4.9
SSW	5.0	3.6
SW	11.8	7.7
WSW	7.6	10.6
W	10.8	12.3
WNW	8.7	8.5
NW	7.1	7.3
NNW	5.2	5.1
N	8.1	5.1
Calm	.5	8.3
Average Wind Speed (mph)	9.9	9.1

Table 2.3.1-2

MEAN MONTHLY TEMPERATURE COMPARISON (°F)

	PHILADELPHIA (1874-1976)	ALLENTOWN (1944-1976)
JAN	33.0	27.8
FEB	33.8	29.7
MAR	41.7	38.4
APR	52.2	49.6
MAY	63.0	59.7
JUNE	71.9	69.2
JUL	76.6	73.9
AUG	74.7	71.8
SEP	68.4	64.5
OCT	57.5	53.8
NOV	46.2	42.3
DEC	36.1	31.2
ANNUAL	54.6	51.0

TEMPERATURE EXTREMES (°F)

Philadelphia	106	Aug 1908(1)
	-11	Feb 1934(1)
Allentown	105	Jul 1966
	-12	Jan 1961

(1) Extreme value recorded in the local area, but not at the official measurement site

Table 2.3.1-3

COMPARISON OF MEAN MORNING
AND AFTERNOON RELATIVE HUMIDITY (%)

PERIOD OF RECORD: PHILADELPHIA 1960-1976
ALLENTOWN 1951-1976

	MORNING (7 am)		AFTERNOON (1 pm)	
	Philadelphia	Allentown	Philadelphia	Allentown
JAN	74	77	60	62
FEB	71	76	57	59
MAR	71	76	53	55
APR	69	76	48	51
MAY	75	78	53	53
JUN	78	80	55	54
JUL	79	82	54	52
AUG	81	87	54	55
SEP	83	89	56	57
OCT	81	87	53	55
NOV	76	83	55	60
DEC	74	80	60	64
ANNUAL	76	81	55	56

Table 2.3.1-4

DISTRIBUTION OF PRECIPITATION
PHILADELPHIA INTERNATIONAL AIRPORT

PERIOD OF RECORD: 1872-1976 TOTAL PRECIPITATION
1943-1976 SNOWFALL

	TOTAL PRECIPITATION (inches of water)		SNOW AND SLEET (inches)	
	Mean	Maximum	Mean	Maximum
JAN	3.17	6.06	5.4	19.7
FEB	3.10	5.43	6.1	18.4
MAR	3.51	6.27	3.8	13.4
APR	3.28	6.68	0.2	4.3
MAY	3.35	7.41	T(1)	T(1)
JUN	3.65	7.88	0.0	0.0
JUL	4.10	8.33	0.0	0.0
AUG	4.48	9.70	0.0	0.0
SEP	3.40	8.78	0.0	0.0
OCT	2.80	5.21	T(1)	T(1)
NOV	3.07	9.06	0.7	8.8
DEC	3.19	7.23	4.2	18.8
ANNUAL 41.10		-	20.4	-

Greatest Rainfall - Monthly: 12.10, Aug., 1911(2)
24 Hours: 5.89, Aug., 1898(2)

Greatest Snowfall - Monthly: 31.5, Feb., 1899(2)
24 Hours: 21.0, Dec., 1909(2)

(1) T = Trace of precipitation
(2) Extreme value recorded in the local area, but not at the official measurement site

Table 2.3.1-5

DISTRIBUTION OF PRECIPITATION
ALLENTOWN AIRPORT

PERIOD OF RECORD: 1944-1976

	TOTAL PRECIPITATION (inches of water)		SNOW AND SLEET (inches)	
	Mean	Maximum	Mean	Maximum
JAN	3.19	6.16	7.7	24.1
FEB	2.94	5.44	8.6	22.4
MAR	3.66	7.21	6.1	30.5
APR	3.84	10.09	0.4	3.1
MAY	3.86	7.88	T(1)	T(1)
JUN	3.69	8.58	0.0	0.0
JUL	4.30	10.42	0.0	0.0
AUG	4.28	12.10	0.0	0.0
SEP	4.03	7.69	0.0	0.0
OCT	2.74	6.84	T(1)	1.4
NOV	3.66	9.69	1.4	7.8
DEC	3.71	7.89	7.4	28.4
ANNUAL	43.90	-	31.6	-

Greatest Rainfall - Monthly: 12.10, Aug, 1955
24 Hours: 4.79, Aug, 1955

Greatest Snowfall - Monthly: 43.2, Jan, 1925(2)
24 Hours: 17.5, Mar, 1958

(1) T = Trace of precipitation
(2) Extreme value obtained in the local area, but not at the official measurement site

Table 2.3.1-6

MEAN NUMBER OF THUNDERSTORM
DAYS PER YEAR
IN THE LGS VICINITY

PERIOD OF RECORD: PHILADELPHIA 1941-1981
ALLENTOWN 1944-1981

	PHILADELPHIA	ALLENTOWN
JAN	<½	<½
FEB	<½	<½
MAR	1	1
APR	2	2
MAY	4	4
JUN	5	6
JU	6	7
AUG	5	6
SEP	2	3
OCT	1	1
NOV	1	1
DEC	<½	<½
ANNUAL	27	32

Table 2.3.1-7

LGS DESIGN BASIS TORNADO PARAMETERS

Maximum Wind Speed	360 mph
Rotational Speed	300 mph
Translation Speed	60 mph
Pressure Drop	3 psi
Rate of Pressure Drop	1 psi/sec

Table 2.3.1-8

LGS VERTICAL PROFILE OF THE
100 YEAR RECURRENCE INTERVAL FASTEST MILE OF WIND

HEIGHT ABOVE GROUND (feet)	FASTEST MILE (mph)
30	82
100	97
200[1]	108
300	114
400	119
500[2]	123

(1) Approximate height of reactor enclosure
(2) Approximate height of cooling towers

Table 2.3.1-9
SUMMARY OF HURRICANES AND TROPICAL STORMS AFFECTING THE LGS VICINITY
BETWEEN 1963 AND 1981

			Philadelphia NWS		Allentown NWS		LGS Site	
Storm Name	Dates	Status	24 Hour Precip. Total (in)	Fastest Mile of Wind (mph)	24 Hour Precip. Total (in)	Fastest Mile of Wind (mph)	24 Hour Precip. Total (in)	Maximum 10 m Hourly Wind Speed (mph)
Betsy	9/12/65	TD	.08	20	.10	17		
	9/13/65	ET	.37	15	.33	14		
Alma	6/12/66	H	T	24	.00	16		
	6/13/66	TS	T	20	.00	15		
	6/14/66	ET	T	24	.35	17		
Abby	6/10/68	TD	.00	22	T	21	LGS Meteorological Monitoring Program Not Yet Operational	
	6/11/68	TD	T	10	T	10		
	6/12/68	TD	3.05	16	.95	13		
	6/13/68	TD	T	17	.03	16		
Candy	6/25/68	TD	T	12	.09	16		
	6/26/68	ET	.11	24	.16	16		
	6/27/68	-	.38	24	.23	17		
Gerda	9/8/69	H	.29	19	.64	10		
Alma	5/26/70	TD	1.02	17	.36	14		
Doria	8/26/71	TS	.02	15	.07	16		
	8/27/71	TS	4.77	18	3.12	17		
	8/28/71	TS	1.78	38	1.45	25		
Agnes	6/21/72	TS	.92	30	.60	20	2.39	14
	6/22/72	TS	2.35	34	3.23	25	5.57	22
	6/23/72	-	.19	17	.53	21	.41	12
Eloise	9/23/75	H	1.94	12	2.75	17	2.35	7
	9/24/75	ET	2.04	18	1.57	17	MSG	10
Belle	8/9/76	H	.51	22	.83	21	.79	15
	8/10/76	TS	1.17	30	.10	20	.87	16
Claudette	7/29/79	TD	.01	14	1.64	9	.20	7

Table 2.3.1-9 (Cont'd)

Storm Name	Dates	Status	Philadelphia NWS 24 Hour Precip. Total (in)	Philadelphia NWS Fastest Mile of Wind (mph)	Allentown NWS 24 Hour Precip. Total (in)	Allentown NWS Fastest Mile of Wind (mph)	LGS Site 24 Hour Precip. Total (in)	LGS Site Maximum 10 m Hourly Wind Speed (mph)
David	9/5/79	TS	.82	28	.00	9	3.00	19
	9/6/79	TS	1.32	33	.88	20	2.85	23
	9/7/79	ET	.00	16	2.00	28	.02	10
Frederic	9/14/79	TS	.61	27	.49	25	.78	14
Bret	7/1/81	TD	.49	18	.01	17	1.14	14
	7/2/81	-	.03	14	.05	23	.25	14

Legend:
TD = Tropical Depression
TS = Tropical Storm
H = Hurricane
ET = Extratropical Stage
T = Trace of Precipitation
MSG = Missing Data

Table 2.3.2-1

LGS PERCENT DATA RECOVERY
FOR METEOROLOGICAL SENSORS

WEATHER STATION NO. 1	PERCENT DATA RECOVERY		
Instrument	1/72 - 12/76	4/72 - 3/73	1/75 - 12/76
30 ft wind speed	95.3	97.7	-
30 ft wind direction	93.7	97.7	-
175 ft wind speed	93.2	96.6	-
175 ft wind direction	92.6	93.8	-
270 ft wind speed	98.1	98.9	-
270 ft wind direction	98.1	99.2	-
Satellite wind speed	-	-	70.2
Satellite wind direction	-	-	82.5
Bivane azimuth	61.4	-	-
Bivane elevation	53.2	-	-
266-26 ft delta temperature	90.5	99.4	-
171-26 ft delta temperature	90.4	99.4	-
26 ft temperature	90.8	99.4	-
5 ft temperature	91.8	-	-
Hygrothermograph temperature	97.6	-	-
Building temperature	92.0	-	-
Relative humidity	94.6	-	-
Precipitation	91.9	-	-
Barograph	93.5	-	-

WEATHER STATION NO. 2	PERCENT DATA RECOVERY
Instrument	4/72 - 3/73
30 ft wind speed	96.4
159 ft wind direction	97.5
159 ft wind speed	97.1
159 ft wind direction	93.0
304 ft wind speed	97.8
304 ft wind direction	99.0
300 26 ft delta temperature	93.2
171-26 ft delta temperature	44.5
26 ft temperature	69.4

Table 2.3.2-2

LGS COMPARISON OF ANNUAL
WIND DIRECTION FREQUENCY DISTRIBUTIONS (%)
WEATHER STATION NO. 1

PERIOD OF RECORD: JANUARY 1972 - DECEMBER 1976

DIRECTIONAL

SECTOR	30 ft	175 ft	270 ft
NNE	3.5	3.5	3.4
NE	3.7	3.1	3.4
ENE	5.5	4.1	4.2
E	7.6	6.1	5.6
ESE	4.5	3.7	3.6
SE	4.3	3.6	3.6
SSE	4.8	4.6	4.3
S	6.9	7.4	7.2
SSW	6.0	7.0	7.0
SW	4.7	5.0	5.7
WSW	5.1	5.1	5.4
W	8.4	8.3	9.5
WNW	14.8	16.6	16.1
NW	10.7	12.0	11.2
NNW	5.2	5.1	5.2
N	4.4	4.6	4.7

Table 2.3.2-3

LGS MONTHLY AVERAGE WIND SPEEDS (mph)
WEATHER STATION NO. 1

PERIOD OF RECORD: JANUARY 1972 - DECEMBER 1976

	WEATHER STATION NO. 1		
	30 ft	175 ft	270 ft
JAN	6.6	9.4	11.1
FEB	8.0	10.7	12.3
MAR	8.5	11.4	12.9
APR	7.2	11.0	12.3
MAY	6.0	9.0	9.9
JUN	5.1	7.8	9.1
JUL	4.5	7.1	8.0
AUG	4.0	6.8	7.5
SEP	4.6	7.8	9.0
OCT	5.3	8.8	9.9
NOV	6.4	10.3	11.4
DEC	6.3	9.8	11.7
ANNUAL	6.0	9.1	10.4
ANNUAL % CALM	9.9	1.7	1.2

Table 2.3.2-4

LGS COMPARISON OF ANNUAL
WIND DIRECTION FREQUENCY DISTRIBUTIONS (%)
WEATHER STATION NO. 1

PERIOD OF RECORD: APRIL 1972 - MARCH 1973

DIRECTION SECTOR	30 ft	175 ft	270 ft
NNE	4.5	4.9	4.7
NE	3.8	3.3	3.9
ENE	7.0	5.0	5.4
E	8.7	7.4	6.9
ESE	5.1	4.1	4.4
SE	3.5	3.0	3.3
SSE	5.0	4.7	4.4
S	6.8	7.7	8.1
SSW	5.7	6.8	6.6
SW	3.6	4.0	4.7
WSW	4.6	4.7	4.9
W	7.6	6.8	8.1
WNW	13.7	14.3	13.1
NW	8.4	10.3	8.8
NNW	6.4	6.9	6.9
N	5.5	6.1	5.9

Table 2.3.2-5

LGS COMPARISON OF ANNUAL
WIND DIRECTION FREQUENCY DISTRIBUTIONS (%)
WEATHER STATION NO. 2

PERIOD OF RECORD: APRIL 1972 - MARCH 1973

DIRECTIONAL SECTOR	30 ft	159 ft	304 ft
NNE	4.3	4.4	4.5
NE	2.2	2.7	3.1
ENE	4.8	5.0	5.5
E	5.9	7.3	6.1
ESE	5.8	5.4	4.4
SE	4.6	4.8	3.5
SSE	10.3	6.7	5.0
S	7.9	6.7	7.5
SSW	4.3	5.6	6.1
SW	2.1	2.9	4.0
WSW	3.2	4.4	4.7
W	4.8	7.4	6.9
WNW	10.7	10.9	12.7
NW	11.5	11.0	11.6
NNW	11.2	8.8	8.3
N	6.3	6.2	6.1

Table 2.3.2-6

LGS COMPARISON OF ANNUAL
WIND DIRECTION FREQUENCY DISTRIBUTIONS (%)
FROM EQUIVALENT MSL HEIGHTS

PERIOD OF RECORD: APRIL 1972 - MARCH 1973

	Level One (425 ft MSL)		Level Two (520 ft MSL)	
Directional Sector	Tower 1 30 ft	Tower 2 159 ft	Tower 1 175 ft	Tower 2 304 ft
NNE	4.5	4.4	4.9	4.5
NE	3.8	2.7	3.3	3.1
ENE	7.0	5.0	5.0	5.5
E	8.7	7.3	7.4	6.1
ESE	5.1	5.4	4.1	4.4
SE	3.5	4.8	3.0	3.5
SSE	5.0	6.7	4.7	5.0
S	6.8	6.7	7.7	7.5
SSW	5.7	5.6	6.8	6.1
SW	3.6	2.9	4.0	4.0
WSW	4.6	4.4	4.7	4.7
W	7.6	7.4	6.8	6.9
WNW	13.7	10.9	14.3	12.7
NW	8.4	11.0	10.3	11.6
NNW	6.4	8.8	6.9	8.3
N	5.5	6.2	6.1	6.1

Table 2.3.2-7

LGS COMPARISON OF ANNUAL
WIND DIRECTION FREQUENCY DISTRIBUTIONS (%)
LOW LEVEL SENSORS

PERIODS OF RECORD:
TOWER 1 APRIL 1972 - MARCH 1973
TOWER 2 APRIL 1972 - MARCH 1973
SATELLITE JANUARY 1975 - DECEMBER 1976

				Percent Differences	
Directional Sector	Tower 1 30 ft	Tower 2 30 ft	Satellite Tower 32 ft	Tower 2 Tower 1	Satellite Tower 1
NNE	4.5	4.3	1.9	-0.2	-2.6
NE	3.8	2.2	1.7	-1.6	-2.1
ENE	7.0	4.8	2.8	-2.2	-4.2
E	8.7	5.9	8.8	-2.8	+0.1⎤
ESE	5.1	5.8	6.7	+0.7⎤	+1.6 |
SE	3.5	4.6	6.6	+1.1 |	+3.1 |
SSE	5.0	10.3	8.2	+5.3 |	+3.2 |
S	6.8	7.9	7.5	+1.1⎦	+0.7⎦
SSW	5.7	4.3	3.1	-1.4	-2.6
SW	3.6	2.1	2.1	-1.5	-1.5
WSW	4.6	3.2	3.1	-1.4	-1.5
W	7.6	4.8	5.3	-2.8	-2.3
WNW	13.7	10.7	11.6	-3.0	-2.1
NW	8.4	11.5	15.5	+3.1⎤	+7.1⎤
NNW	6.4	11.2	10.0	+4.8 |	+3.6⎦
N	5.5	6.3	5.0	+0.8⎦	-0.5

Bracketed sectors indicate increased flow in the river valley.

Table 2.3.2-8

LGS COMPARISON OF
MONTHLY AVERAGE WIND SPEEDS (mph)

PERIODS OF RECORD:
TOWER 1 APRIL 1972 - MARCH 1973
TOWER 2 APRIL 1972 - MARCH 1973
SATELLITE JANUARY 1975 - DECEMBER 1976

	Tower 1			Tower 2			Satellite Tower
	30 ft	175 ft	270 ft	30 ft	159 ft	304 ft	32 ft
JAN	6.8	10.6	11.5	5.2	7.6	10.9	6.0
FEB	8.8	11.3	13.0	6.0	6.5	9.9	5.1
MAR	7.5	9.8	12.0	6.8	9.1	11.2	6.8
APR	6.7	10.2	11.1	5.3	7.7	10.0	6.8
MAY	5.7	9.0	9.5	4.1	6.0	8.7	4.0
JUN	5.8	9.0	10.0	4.0	6.1	9.0	3.2
JUL	4.4	6.5	7.6	3.0	4.3	6.8	2.6
AUG	4.8	6.8	8.0	3.2	4.6	7.2	3.1
SE	4.6	7.8	8.7	3.4	5.5	7.8	3.5
OCT	5.7	9.0	10.4	4.3	6.8	9.5	3.3
NOV	6.6	9.9	11.5	5.2	7.2	10.3	3.4
DEC	6.0	9.7	11.2	4.3	7.7	9.3	4.7
ANNUAL	6.0	9.1	10.3	4.5	6.5	9.2	4.7
ANNUAL % CALM	8.1	2.0	.9	21.5	9.0	1.9	17.5

Table 2.3.2-9

COMPARISON OF WIND SPEED FREQUENCY DISTRIBUTIONS (%)

Site	Wind Speed Group (mph) 0-3	4-7	8-12	13-18	19-23	24+	Mean Wind Speed (mph)
LGS Tower 1 270 ft level 1/72 - 12/76	9.8	25.6	33.8	21.2	5.8	3.7	10.4
PBAPS Tower 2 320 ft level 1/72 - 12/76	11.0	22.1	33.0	24.3	6.5	3.1	10.6

Table 2.3.2-10

LGS ANNUAL FREQUENCY DISTRIBUTION
OF BROOKHAVEN TURBULENCE CLASSES
WEATHER STATION NO. 1

PERIOD OF RECORD: JANUARY 1972 - DECEMBER 1976

Turbulence Class	Percent Frequency
I	0.0
II	55.4
III	2.6
IV	12.7
V	29.3

Table 2.3.2-11

LGS ANNUAL FREQUENCY DISTRIBUTION OF PASQUILL
STABILITY CLASSES BY NRC LAPSE RATE CRITERIA
WEATHER STATION NO. 1

PERIOD OF RECORD: JANUARY 1972 - DECEMBER 1976

PASQUILL STABILITY CLASS	PERCENT FREQUENCY	
	266-26 ft interval	171-26 ft interval
A	2.2	8.4
B	3.4	4.4
C	6.2	6.0
D	39.6	31.2
E	32.5	30.2
F	12.1	13.4
G	4.0	6.4

Table 2.3.2-12

LGS ANNUAL FREQUENCY DISTRIBUTION
OF BROOKHAVEN TURBULENCE CLASSES

PERIOD OF RECORD: APRIL 1972 - MARCH 1973

	Percent Frequency	
Turbulence Class	Tower 1	Tower 2
I	0.0	0.0
II	44.8	54.0
III	3.3	3.7
IV	14.6	13.6
V	37.3	28.6

Table 2.3.2-13

LGS ANNUAL FREQUENCY DISTRIBUTION
OF PASQUILL STABILITY CLASSES
BY NRC LAPSE RATE CRITERIA

PERIOD OF RECORD: APRIL 1972 - MARCH 1973

Pasquill Stability Class	Percent Frequency			
	266-26 ft interval	171-26 ft interval	300-26 ft interval	155-26 ft interval
A	0.6	4.2	0.2	2.4
B	1.3	3.4	0.2	1.1
C	4.6	6.3	0.7	3.1
D	45.6	34.6	33.6	28.0
E	33.0	33.0	42.6	41.5
F	11.0	12.4	15.4	14.3
G	4.1	6.1	7.2	9.6

Table 2.3.2-14

BROOKHAVEN NATIONAL LABORATORY
TURBULENCE CLASSIFICATION

Turbulence Class	Brookhaven National Laboratory Classification[1]	Description of Wind Trace
I - Extremely Unstable	A	Fluctuations of the wind direction during the course of 1 hour exceed 90 degrees.
II - Unstable	B_1	Fluctuations are confined to a lower limit of 15° and an upper limit of 45°.
III - Very Unstable	B_2	Trace is similar to I and II, but the upper and lower limits are 90 and 45°.
IV - Neutral	C	The lower limit of the fluctuations is 15°, and no upper limit is imposed. The case is distinguished by an unbroken solid core, through which a straight line can be drawn for the entire hour, without touching "open space" on the chart.
V - Stable	D	The trace approximates a line, and short-term fluctuations do not exceed 15°. Direction may vary gradually over a wide angle during the hour.

(1) Reference 2.3.3-5.

Table 2.3.2-15

LGS MEAN MORNING AND AFTERNOON
MIXING HEIGHTS
(meters)

	am	pm
Spring	700	1800
Summer	550	1800
Fall	700	1400
Winter	800	1000
Annual	650	1500

Table 2.3.2-16

LGS TEMPERATURE MEANS AND EXTREMES (°F)
WEATHER STATION NO. 1

PERIOD OF RECORD: JANUARY 1972 - DECEMBER 1976

	MONTHLY MEAN	MONTHLY MAXIMUM	MONTHLY MINIMUM
JAN	31.6	67.9	0.7
FEB	30.2	67.2	3.4
MAR	40.8	75.5	11.6
APR	51.2	91.5	21.4
MAY	60.3	88.0	31.1
JUN	69.0	91.1	40.1
JUL	73.2	90.9	51.0
AUG	72.2	96.2	45.1
SEP	64.5	91.6	36.0
OCT	53.4	85.2	25.0
NOV	44.5	80.3	11.8
DEC	34.5	65.9	5.9
ANNUAL	51.8	96.2	0.7

Table 2.3.2-17

COMPARISON OF MONTHLY MEAN TEMPERATURES (°F)
LGS VERSUS PHILADELPHIA

	LGS[1]	Philadelphia	
	1972-1976	1972-1976	1937-1976
JAN	31.6	34.3	33.0
FEB	30.2	34.9	33.8
MAR	40.8	43.7	41.7
APR	51.2	52.8	52.2
MAY	60.3	63.1	63.0
JUN	69.0	72.2	71.9
JUL	73.2	76.8	76.6
AUG	72.2	76.7	74.7
SEP	64.5	68.4	68.4
OCT	53.4	56.1	57.5
NOV	44.5	46.5	46.2
DEC	34.5	37.0	36.1
ANNUAL	51.8	55.2	54.6

(1) Tower 1 26 foot temperature

Table 2.3.2-18

COMPARISON OF MONTHLY MEAN TEMPERATURES (°F)
LGS VERSUS ALLENTOWN

	LGS[1]	Allentown, Pennsylvania	
	1972-1976	1972-1976	1937-1976
JAN	31.6	29.6	28.7
FEB	30.2	31.0	29.7
MAR	40.8	40.2	38.4
APR	51.2	49.5	49.6
MAY	60.3	59.8	59.7
JUN	69.0	69.3	69.2
JUL	73.2	73.7	73.9
AUG	72.2	72.5	71.8
SEP	64.5	63.6	64.5
OCT	53.4	52.1	53.8
NOV	44.5	43.0	42.3
DEC	34.5	33.0	31.2
ANNUAL	51.8	51.4	51.0

(1) Tower 1 26 foot temperature

Table 2.3.2-19

LGS MONTHLY PRECIPITATION DISTRIBUTION (inches)
WEATHER STATION NO. 1

PERIOD OF RECORD: JANUARY 1972 - DECEMBER 1976

	5 YEAR TOTAL	MAXIMUM MEAN[1]	MONTH	HOUR
JAN	18.09	4.19	6.11	1.22
FEB	15.34	3.07	4.39	.45
MAR	23.45	4.89	6.39	.86
APR	25.75	5.54	8.74	.55
MAY	28.35	5.74	7.63	1.19
JUN	38.13	7.78	12.40	2.25
JUL	16.16	4.01	7.66	1.90
AUG	16.94	3.69	6.29	1.50
SEP	25.09	5.39	6.91	1.17
OCT	18.91	4.26	6.53	.55
NOV	18.93	4.13	14.23	.50
DEC	28.72	6.64	10.10	.65
ANNUAL	273.86	59.57	-	-

(1) Mean values are obtained through a weighting procedure which discounts missing hours.

Table 2.3.2-20

COMPARISON OF MONTHLY MEAN PRECIPITATION (inches)
LGS VERSUS PHILADELPHIA

	LGS	Philadelphia	
	1972-1976	1972-1976	1937-1976
JAN	4.19	3.54	3.17
FEB	3.07	2.95	3.10
MAR	4.89	3.64	3.51
APR	5.54	3.71	3.28
MAY	5.74	4.16	3.35
JUN	7.78	5.82	3.65
JUL	4.01	3.49	4.10
AUG	3.69	2.80	4.48
SEP	5.39	3.77	3.40
OCT	4.26	3.08	2.80
NOV	4.13	2.79	3.07
DEC	6.64	4.02	3.19
ANNUAL	59.57	43.77	41.10

Table 2.3.2-21

COMPARISON OF MONTHLY MEAN PRECIPITATION (inches)
LGS VERSUS ALLENTOWN

	LGS	Allentown, Pennsylvania	
	1972-1976	1972-1976	1937-1976
JAN	4.19	4.05	3.19
FEB	3.07	2.93	2.94
MAR	4.89	3.54	3.66
APR	5.54	3.67	3.84
MAY	5.74	4.59	3.86
JUN	7.78	5.38	3.69
JUL	4.01	3.85	4.30
AUG	3.69	4.67	4.28
SEP	5.39	5.26	4.03
OCT	4.26	3.56	2.74
NOV	4.13	3.45	3.66
DEC	6.64	4.59	3.71
ANNUAL	59.57	49.53	43.90

Table 2.3.2-22

COMPARISON OF MEAN MORNING
AND AFTERNOON RELATIVE HUMIDITY (%)

PERIOD OF RECORD:
LGS 1972-1976
PHILADELPHIA 1960-1976
ALLENTOWN 1951-1976

	Morning (7 AM)			Afternoon (1 PM)		
	LGS	Philadelphia	Allentown	LGS	Philadelphia	Allentown
JAN	79	74	77	63	60	62
FEB	76	71	76	56	57	59
MAR	74	71	76	54	53	55
APR	74	69	76	51	48	51
MAY	80	75	78	56	53	53
JUN	85	78	80	60	55	54
JUL	82	79	82	55	54	52
AUG	84	81	87	54	54	55
SEP	89	83	89	59	56	57
OCT	88	81	87	56	53	55
NOV	82	76	83	56	55	60
DEC	78	74	80	61	60	64
ANNUAL	81	76	81	57	55	56

Table 2.3.2-23

COMPARISON OF FREQUENCY
DISTRIBUTIONS OF DAILY AVERAGE
RELATIVE HUMIDITY VALUES

Relative Humidity (%)	Frequency of Occurrence (%)		
	LGS	Philadelphia	
	(1/72-6/74)	(1/72-6/74)	(1/41-12/74)
90-100	12.3	7.9	6.3
80-89	17.7	17.3	15.7
70-79	29.4	22.9	24.7
60-69	20.1	23.7	26.2
50-59	14.7	17.5	18.5
<50	4.8	10.7	8.6

Table 2.3.2-24

COMPARISON OF
ANNUAL FREQUENCY DISTRIBUTIONS
OF HOURLY RELATIVE HUMIDITY VALUES

Relative Humidity (%)	Frequency of Occurrence (%)	
	LGS Weather Station No.1 (1972-1976)	Philadelphia (1951-1960)
90-100	29.4	16.7
80-89	11.4	15.4
70-79	11.6	14.8
50-69	30.0	31.3
30-49	16.8	19.9
<30	0.7	1.9

Table 2.3.2-25

MEAN NUMBER OF DAYS
WITH HEAVY FOG[1]

	Philadelphia (1940-1976)	Allentown (1943-1976)
JAN	3	3
FEB	3	3
MAR	2	3
APR	1	2
MAY	1	2
JUN	1	1
JUL	1	1
AUG	1	2
SEP	2	3
OCT	4	3
NOV	3	3
DEC	3	3
ANNUAL	25	29

(1) Heavy fog is defined by visibility of ¼ mile or less.

Table 2.3.2-26

OFFSITE ELEVATION VERSUS DISTANCE FROM LGS VENTS

OFFSITE ELEVATION (IN FEET ABOVE MSL) VS DISTANCE (FT) FROM LGS VENTS (PA. COORD. N 331,844,E 2,603,786.5) FOR EACH OF SIXTEEN 22.5 DEGREE SECTORS. MAXIMUM ELEVATION ACROSS EACH SECTOR IS LISTED. THE LAST COLUMN LISTS THE HIGHEST ELEVATION FOR ALL DIRECTIONS.

DISTANCE FROM SOURCE IN FEET	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	ALL	DISTANCE FROM SOURCE IN MILES	DISTANCE FROM SOURCE IN METERS
2500					285	190	150		110	130					150		285	0.473	762.000
2600		270	270	290	290	200	140		110	130				125	150		290	0.492	792.480
2700		265	280	290	290	210	130		110	130				130	150		290	0.511	822.960
2800		260	275	290	290	200	150		110	130		160	155	130	150		290	0.530	853.440
2900	235	260	270	295	290	195	155		120	130	160	170	155	140	150	220	295	0.549	883.920
3000	230	255	270	295	290	190	170		130	130	165	175	160	140	150	250	295	0.568	914.400
3100	230	250	265	300	290	200	180		130	130	165	175	160	150	190	250	300	0.587	944.880
3200	235	250	260	300	240	200	190		130	130	170	180	160	150	200	250	300	0.606	975.360
3300	240	250	255	300	250	200	195	160	130	130	175	180	160	150	200	250	300	0.625	1005.840
3400	240	250	250	300	260	200	210	200	130	130	185	180	160	160	200	250	300	0.644	1036.320
3500	240	250	250	295	270	205	210	205	130	130	185	185	160	170	145	250	295	0.663	1066.800
3600	240	250	250	300	290	210	215	210	130	130	190	190	160	160	145	245	300	0.682	1097.280
3700	240	250	250	305	295	225	220	210	130	130	190	190	165	160	150	240	305	0.701	1127.760
3800	235	250	250	310	290	235	230	210	130	130	190	190	165	160	155	235	310	0.720	1158.240
3900	230	250	255	310	290	240	235	210	130	140	190	185	165	160	160	230	310	0.739	1188.720
4000	215	250	260	310	290	250	230	210	130	145	190	190	170	160	160	215	310	0.758	1219.200
4100	220	250	260	310	290	250	230	205	130	150	195	190	170	160	160	205	310	0.777	1249.680
4200	225	250	260	310	285	250	230	200	130	155	195	190	170	160	170	195	310	0.795	1280.160
4300	230	250	260	310	285	250	230	190	130	160	195	195	170	170	155	180	310	0.814	1310.640
4400	220	250	250	310	260	250	220	190	110	150	180	200	170	170	120	170	310	0.833	1341.120
4600	230	260	260	310	260	250	220	190	110	150	180	200	180	160	110	150	310	0.871	1402.080
4800	230	260	260	300	250	250	210	190	110	150	200	200	180	170	110	180	300	0.909	1463.040
5000	240	260	270	290	260	250	200	200	110	160	210	200	180	170	115	190	290	0.947	1524.000
5200	240	260	270	290	260	250	200	210	110	175	210	200	180	170	120	200	290	0.985	1584.960
5400	240	260	270	280	260	250	200	220	120	200	210	200	190	170	120	210	280	1.023	1645.920
5600	240	270	270	280	265	250	200	220	120	200	220	200	200	170	130	220	280	1.061	1706.880
5800	250	280	270	280	265	250	200	230	130	200	230	200	200	130	135	230	280	1.099	1767.840
6000	250	280	270	280	265	250	200	220	140	200	230	200	200	130	140	250	280	1.136	1828.800
6200	260	290	280	280	270	250	200	190	140	200	240	200	200	130	230	270	290	1.174	1889.760
6400	250	300	300	280	270	250	200	180	130	180	240	200	210	140	230	260	300	1.212	1950.720

Table 2.3.2-26 (Cont'd)

OFFSITE ELEVATION VERSUS DISTANCE FROM LGS VENTS

DISTANCE FROM SOURCE IN FEET	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	ALL	DISTANCE FROM SOURCE IN MILES	DISTANCE FROM SOURCE IN METERS
6600	240	300	300	260	270	240	190	160	140	200	240	200	200	150	235	250	300	1.250	2011.680
6800	240	280	310	250	270	240	160	160	140	220	240	200	200	150	230	230	310	1.288	2072.640
7000	220	270	320	250	270	250	160	160	150	220	250	200	200	150	225	230	320	1.326	2133.600
7200	200	270	320	250	280	250	200	160	150	240	250	250	210	160	190	220	320	1.364	2194.560
7400	230	260	320	260	280	260	200	160	150	240	240	250	210	160	175	240	320	1.402	2255.520
7600	240	260	310	260	280	260	200	160	150	240	240	250	220	170	185	260	310	1.439	2316.480
7800	240	260	310	260	280	260	200	160	150	240	230	250	230	170	200	260	310	1.477	2377.440
8000	250	270	300	280	280	250	200	160	150	240	230	260	230	180	220	260	300	1.515	2438.400
8200	250	279	300	280	280	240	200	170	150	220	230	260	220	190	200	260	300	1.553	2499.360
8400	250	279	300	280	280	240	200	170	150	200	220	260	210	200	190	260	300	1.591	2560.320
8600	250	260	300	290	280	240	200	170	150	175	220	260	220	200	190	260	300	1.629	2621.280
8800	240	260	300	290	280	250	130	170	150	150	220	260	230	210	200	240	300	1.667	2682.240
9000	230	260	300	300	280	250	130	180	150	125	220	260	230	200	200	240	300	1.705	2743.200
9200	230	260	300	300	280	230	140	180	130	150	220	260	230	200	190	240	300	1.742	2804.160
9400	250	255	300	300	280	250	140	180	120	175	210	250	230	180	175	270	300	1.780	2865.120
9600	270	240	300	300	280	250	140	190	120	200	230	250	220	170	165	280	300	1.818	2926.080
9800	270	210	300	300	290	250	140	180	150	240	230	250	150	170	160	280	300	1.856	2987.040
10000	270	200	300	300	290	240	140	180	150	240	230	250	200	160	190	260	300	1.894	3048.000
10200	260	210	300	300	290	240	150	180	150	250	230	240	210	140	210	240	300	1.932	3108.960
10400	260	220	300	300	290	250	160	170	150	260	230	250	230	150	200	260	300	1.970	3169.920
10600	260	225	300	310	290	250	160	170	170	260	240	250	230	140	200	240	310	2.008	3230.880
10800	260	240	300	320	300	260	180	170	190	260	240	250	240	140	200	220	320	2.046	3291.840
11000	260	240	320	320	300	260	180	160	200	260	240	250	250	130	200	240	320	2.083	3352.800
11200	260	250	320	320	300	260	170	150	200	260	240	250	240	150	200	240	320	2.121	3413.760
11400	270	240	320	320	300	260	180	190	200	260	240	250	240	160	200	220	320	2.159	3474.719
11600	270	240	310	320	300	270	200	210	200	260	250	250	240	170	200	240	320	2.197	3535.680
11800	270	240	300	320	300	270	210	230	200	280	270	250	240	180	200	260	320	2.235	3596.640
12000	280	260	300	320	300	270	220	230	210	280	270	250	250	180	200	280	320	2.273	3657.600
12200	290	300	290	320	320	270	210	210	230	280	270	250	250	180	200	280	320	2.311	3718.560
12400	300	310	300	330	320	270	210	230	230	280	260	250	250	180	200	280	330	2.349	3779.520

Table 2.3.2-26 (Cont'd)

OFFSITE ELEVATION VERSUS DISTANCE FROM LGS VENTS

DISTANCE FROM SOURCE IN FEET	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	ALL	DISTANCE FROM SOURCE IN MILES	DISTANCE FROM SOURCE IN METERS
12600	300	320	300	330	320	270	210	250	240	280	260	250	240	180	210	260	330	2.386	3840.479
12800	320	340	290	340	320	260	210	290	250	280	260	260	250	180	220	280	340	2.424	3901.439
13000	320	380	300	340	320	260	210	300	260	280	260	260	250	180	230	260	380	2.462	3962.400
13200	310	400	360	350	320	260	220	320	260	280	280	264	250	200	230	240	400	2.500	4023.360
13400	310	410	380	350	320	260	240	330	250	300	290	250	250	210	240	260	410	2.538	4084.320
13600	310	440	400	360	320	266	230	340	250	300	300	250	260	220	240	260	440	2.576	4145.277
13800	310	480	400	360	320	266	230	340	250	300	300	250	260	220	240	280	480	2.614	4206.238
14000	320	500	400	350	320	266	220	350	260	300	300	250	260	210	235	290	500	2.652	4267.199
14200	330	500	400	350	300	266	210	350	270	300	300	260	270	210	230	290	500	2.689	4328.156
14400	330	490	400	350	300	266	210	330	280	300	300	270	280	210	230	300	490	2.727	4389.117
14600	320	480	400	350	300	250	240	330	300	300	290	260	280	210	230	320	480	2.765	4450.078
14800	340	460	400	350	300	220	240	330	300	300	290	280	280	210	220	340	460	2.803	4511.039
15000	360	440	400	350	300	240	230	310	300	300	290	280	290	210	230	380	440	2.841	4571.996
15200	400	430	400	350	300	240	230	290	300	300	290	300	290	210	230	400	430	2.879	4632.957
15400	420	400	400	350	300	230	230	290	300	300	290	300	290	210	220	420	420	2.917	4693.918
15600	440	390	400	350	300	240	220	290	300	300	290	300	280	210	220	440	440	2.955	4754.879
15800	440	370	400	350	300	250	200	280	300	300	290	300	280	210	225	420	440	2.993	4815.836
16000	460	350	400	350	300	250	200	300	300	320	280	300	270	210	230	420	460	3.030	4876.797
16200	480	370	400	350	320	250	200	300	300	340	270	300	270	220	220	400	480	3.068	4937.758
16400	480	390	400	360	320	250	210	280	300	340	260	300	270	240	230	440	480	3.106	4998.719
16600	500	390	400	360	300	250	210	290	300	340	270	300	270	250	250	480	500	3.144	5059.676
16800	500	400	400	360	300	250	210	290	300	320	280	300	270	250	260	420	500	3.182	5120.637
17000	520	400	400	360	300	250	210	290	300	330	290	320	270	250	280	390	520	3.220	5181.598
17200	540	400	400	360	300	240	210	300	300	330	300	330	270	250	280	420	540	3.258	5242.559
17400	550	400	400	360	300	240	210	300	300	330	300	340	280	240	280	440	550	3.296	5303.520
17600	560	400	380	360	290	230	210	290	300	330	300	360	290	220	280	460	560	3.333	5364.477
17800	560	400	380	360	290	240	210	300	300	320	280	390	310	220	280	460	560	3.371	5425.438
18000	520	400	400	360	290	240	210	310	300	300	290	400	320	200	280	460	520	3.409	5486.398
18200	500	400	400	360	290	230	210	300	290	360	310	424	320	210	260	480	500	3.447	5547.359
18400	500	440	400	360	280	220	210	290	280	350	330	400	320	210	260	480	500	3.485	5608.316
18600	480	460	400	360	290	210	230	280	300	370	340	400	310	220	260	460	480	3.523	5669.277
18800	480	500	400	360	290	240	240	270	300	370	350	390	300	220	260	460	500	3.561	5730.238
19000	480	530	400	360	290	240	240	270	300	370	350	380	290	220	260	480	530	3.599	5791.199
19200	480	540	400	350	290	240	240	270	310	370	350	370	300	210	260	480	540	3.636	5852.156
19400	480	540	400	350	300	240	230	260	320	380	350	360	300	210	280	460	540	3.674	5913.117

Table 2.3.2-26 (Cont'd)

OFFSITE ELEVATION VERSUS DISTANCE FROM LGS VENTS

DISTANCE FROM SOURCE IN FEET	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	ALL	DISTANCE FROM SOURCE IN MILES	DISTANCE FROM SOURCE IN METERS
19600	460	520	420	350	300	230	220	250	320	400	350	350	290	210	300	480	520	3.712	5974.078
19800	460	540	460	350	300	240	240	250	330	420	360	360	290	210	320	460	540	3.750	6035.039
20000	440	560	480	350	290	250	240	250	340	440	360	380	310	210	340	460	560	3.788	6095.996
20200	440	560	500	360	280	250	240	260	350	460	370	396	320	210	360	480	560	3.826	6156.957
20400	420	540	500	360	270	260	240	260	350	480	400	350	310	210	370	480	540	3.864	6217.918
20600	420	510	500	360	260	265	230	250	360	490	430	340	310	210	390	520	520	3.902	6278.879
20800	420	465	480	360	300	270	230	240	360	450	430	330	320	210	400	520	520	3.940	6339.836
21000	400	420	480	400	290	270	230	240	350	440	440	360	340	210	420	540	540	3.977	6400.797
21200	380	400	440	400	290	270	230	250	360	400	440	380	350	210	430	540	540	4.015	6461.758
21400	380	380	440	400	300	270	240	250	360	400	400	400	360	200	440	540	540	4.053	6522.719
21600	360	400	440	400	300	270	230	260	360	380	450	400	370	200	440	520	520	4.091	6583.676
21800	360	400	440	400	300	280	220	270	360	320	440	400	380	190	440	500	500	4.129	6644.637
22000	360	390	420	400	300	280	210	270	350	350	440	400	390	180	460	480	480	4.167	6705.598
22200	360	370	400	400	300	280	200	270	350	340	440	400	430	200	460	470	470	4.205	6766.559
22400	360	350	400	400	300	280	190	270	350	380	440	400	470	200	480	470	480	4.243	6827.516
22600	340	340	380	400	300	280	200	270	350	380	440	400	500	200	480	460	510	4.280	6888.477
22800	360	340	380	400	300	290	170	260	350	400	440	400	515	200	480	440	515	4.318	6949.438
23000	360	340	360	400	300	295	200	260	350	420	450	400	500	200	500	440	500	4.356	7010.398
23200	360	340	360	400	280	300	200	260	340	420	460	400	500	190	500	440	500	4.394	7071.359
23400	360	340	400	400	260	300	200	280	356	440	460	350	490	190	500	470	500	4.432	7132.316
23600	350	340	400	400	280	300	200	290	350	440	460	350	490	180	500	490	500	4.470	7193.277
23800	360	330	400	400	280	300	200	310	350	440	460	350	480	190	520	490	520	4.508	7254.238
24000	360	320	400	400	280	300	210	320	350	440	460	350	460	200	520	510	520	4.546	7315.199
24200	360	340	400	400	300	300	210	330	350	440	490	330	440	200	540	520	540	4.583	7376.156
24400	360	320	400	400	300	300	210	340	350	400	500	330	430	200	540	540	540	4.621	7437.117
24600	340	300	400	400	300	320	210	370	350	380	507	350	430	210	540	540	540	4.659	7498.078
24800	340	300	400	420	300	320	220	380	350	360	490	370	420	210	540	540	540	4.697	7559.039
25000	340	300	400	420	300	340	220	390	350	340	480	390	400	210	540	540	540	4.735	7619.996
25200	340	300	380	420	300	340	220	400	350	340	470	410	380	210	540	540	540	4.773	7680.957
25400	320	300	380	420	300	340	220	390	350	340	470	430	370	210	540	540	540	4.811	7741.918
25600	310	300	360	420	300	340	230	390	350	340	470	460	380	210	540	540	540	4.849	7802.879
25800	300	300	340	420	300	340	240	390	330	330	470	470	390	210	520	530	530	4.887	7863.836
26000	300	280	340	460	320	340	240	390	320	330	480	485	400	210	520	530	530	4.924	7924.797
26200	280	260	340	480	340	340	250	370	300	320	490	500	420	240	500	520	520	4.962	7985.758
26400	280	250	340	500	360	340	260	360	290	310	500	500	430	240	480	510	510	5.000	8046.719

Table 2.3.2-26 (Cont'd)

OFFSITE ELEVATION VERSUS DISTANCE FROM LGS VENTS

DISTANCE FROM SOURCE IN FEET	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	ALL	DISTANCE FROM SOURCE IN MILES	DISTANCE FROM SOURCE IN METERS
26900	300	260	360	500	360	320	260	320	270	300	500	540	430	240	460	470	540	5.095	8199.117
27400	320	300	380	480	360	340	270	300	260	280	480	550	450	240	520	440	550	5.190	8351.516
27900	340	300	400	520	360	320	270	300	260	270	450	620	450	240	400	440	620	5.284	8503.918
28400	320	310	440	540	360	320	270	270	280	280	410	640	470	240	380	440	640	5.379	8656.316
28900	280	310	440	540	280	300	280	260	290	270	440	720	510	240	360	440	720	5.474	8808.719
29400	300	280	400	520	310	300	290	290	290	300	450	750	535	320	320	440	750	5.568	8961.117
29900	300	280	310	520	320	300	290	260	300	400	450	800	520	360	320	440	800	5.663	9113.516
30400	300	280	310	540	310	300	290	260	260	500	450	800	520	380	360	460	800	5.758	9265.918
30900	300	280	310	480	310	300	300	260	290	600	400	750	530	380	360	540	750	5.852	9418.316
31400	300	300	300	380	290	300	290	320	270	600	400	750	530	420	360	580	750	5.947	9570.719
31900	300	300	320	350	280	300	280	290	300	660	530	700	590	440	400	600	700	6.042	9723.117
32400	320	300	300	400	280	290	280	260	350	670	610	700	680	460	420	570	700	6.137	9875.516
32900	320	320	320	380	300	280	280	240	350	680	600	700	710	480	440	530	710	6.231	10027.918
33400	320	340	320	310	280	260	280	230	350	654	650	760	700	480	460	530	764	6.326	10180.316
33900	320	340	300	330	270	260	280	260	350	660	660	740	730	440	480	540	740	6.421	10332.719
34400	320	320	260	330	270	260	300	280	350	670	640	750	780	440	460	560	780	6.515	10485.117
34900	330	340	220	320	260	270	300	260	350	670	620	750	780	440	440	510	780	6.610	10637.516
35400	340	360	260	300	250	250	300	240	350	650	600	750	790	460	360	490	790	6.705	10789.918
35900	340	360	300	280	240	240	300	220	496	640	600	750	790	400	340	510	790	6.799	10942.316
36400	340	360	320	250	270	220	300	220	400	600	606	750	780	400	440	560	780	6.894	11094.719
36900	340	380	360	240	240	200	310	240	350	590	650	700	780	320	520	570	780	6.989	11247.117
37400	330	400	380	220	220	200	320	250	350	580	680	670	770	320	500	580	770	7.084	11399.516
37900	330	420	380	260	200	200	300	240	300	560	660	670	780	320	460	600	780	7.178	11551.918
38400	340	440	360	280	270	200	340	220	350	540	650	700	790	320	460	580	790	7.273	11704.316
38900	340	460	340	300	260	200	360	240	350	560	630	700	790	320	440	510	790	7.368	11856.719
39400	350	460	360	380	270	200	370	250	350	590	640	700	790	320	440	560	790	7.462	12009.117
39900	370	480	380	460	260	200	380	270	400	590	650	700	770	320	380	580	770	7.557	12161.516
40400	390	480	400	500	250	200	380	300	360	600	690	700	760	320	340	580	760	7.652	12313.918
40900	400	500	420	500	260	200	370	370	360	600	700	700	750	320	360	560	750	7.746	12466.316
41400	420	500	440	440	250	190	360	440	380	590	719	750	770	320	380	580	770	7.841	12618.719
41900	500	500	440	420	250	180	370	480	420	580	700	750	810	340	400	640	810	7.936	12771.117
42400	510	560	380	380	250	180	380	480	400	573	680	800	860	360	420	700	860	8.031	12923.516
42900	520	580	380	340	260	190	360	533	533	590	690	800	890	340	480	740	890	8.125	13075.918
43400	560	550	400	340	270	200	360	400	480	580	690	850	910	360	540	820	910	8.220	13228.316
43900	530	410	410	340	260	220	350	320	320	570	690	850	920	340	580	800	920	8.315	13380.719

Table 2.3.2-26 (Cont'd)

OFFSITE ELEVATION VERSUS DISTANCE FROM LGS VENTS

DISTANCE FROM SOURCE IN FEET	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	ALL	DISTANCE FROM SOURCE IN MILES	DISTANCE FROM SOURCE IN METERS
44400	390	380	380	340	290	230	340	310	400	550	650	850	900	340	600	780	900	8.409	13533.117
44900	350	400	300	340	300	240	320	320	400	600	640	850	912	340	660	820	912	8.504	13685.516
45400	350	400	300	340	300	240	270	350	430	620	650	750	890	340	680	690	890	8.599	13837.918
45900	410	400	360	340	300	250	270	370	460	647	640	700	890	340	720	700	890	8.693	13990.316
46400	480	440	360	340	290	250	260	250	440	625	650	700	940	340	820	760	940	8.788	14142.719
46900	560	400	360	360	280	250	230	350	480	590	750	700	990	340	940	900	990	8.883	14295.117
47400	490	460	340	340	300	250	230	380	490	590	760	700	1002	340	1020	1040	1040	8.978	14447.516
47900	460	500	380	340	300	240	230	380	470	550	770	600	990	380	900	980	990	9.072	14599.918
48400	500	600	400	340	300	280	190	420	480	550	810	600	980	420	920	860	980	9.167	14752.316
48900	560	620	440	380	320	360	160	460	490	570	800	600	910	420	1080	840	1080	9.262	14904.715
49400	580	620	440	380	320	400	170	450	527	600	740	600	920	420	1020	760	1020	9.356	15057.117
49900	580	620	440	380	320	400	200	480	520	690	700	600	920	380	900	740	920	9.451	15209.516
50400	620	620	440	360	300	400	210	460	490	740	720	590	900	440	930	700	930	9.546	15361.918
50900	650	620	440	340	320	450	200	500	480	720	750	620	880	440	820	680	880	9.640	15514.316
51400	690	620	440	360	340	450	200	550	470	660	840	633	860	440	720	700	860	9.735	15666.715
51900	720	620	440	340	340	450	200	530	514	620	830	648	840	540	620	720	840	9.830	15819.117
52400	700	640	440	320	340	450	200	500	480	560	800	680	780	600	780	800	800	9.925	15971.516
52800	640	640	440	340	320	450	200	510	480	562	760	720	770	640	780	820	820	10.000	16093.438
79200	650	400	500	300	300	200	400	500	500	500	500	500	600	500	400	700	700	15.000	24140.156
105600	773	500	500	600	464	300	500	250	250	500	500	1000	500	500	1000	600	1000	20.001	32186.875
132000	500	1000	500	500	385	300	300	250	250	500	750	1000	547	500	500	500	1000	25.001	40233.594
158400	500	500	500	500	375	300	50	50	250	500	500	500	500	1000	500	600	1000	30.001	48280.313
184800	500	500	800	500	300	120	50	50	250	450	750	500	900	500	1500	1500	1500	35.001	56327.035
211200	1000	500	900	500	230	50	50	100	50	350	500	500	1000	1500	1000	1000	1500	40.001	64373.754
237600	1000	696	800	300	213	50	150	140	50	350	500	500	900	1300	1000	1500	1500	45.001	72420.438
264000	1591	1500	700	500	108	50	150	100	50	300	500	700	800	1500	1600	1500	1600	50.002	80467.188

Table 2.3.2-27

LGS JOINT FREQUENCY DISTRIBUTION OF CALM HOURS
1972-1976
WEATHER STATION NO. 1
30 FT LEVEL

Directional Sector	Class F	Regulatory Guide 1.111 Technique Stability Class A	B	C	D	E	F	G
NNE	247	0.04	0.19	0.41	13.76	42.01	52.40	32.45
NE	242	0.04	0.19	0.41	16.46	44.96	61.76	45.20
ENE	261	0.05	0.38	0.36	28.69	66.82	82.35	70.70
E	273	0.04	0.14	0.63	29.40	98.51	155.33	93.89
ESE	240	0.03	0.05	0.50	13.41	66.33	86.71	47.52
SE	240	0.01	0.19	0.54	13.76	74.93	77.36	41.73
SSE	244	0.05	0.38	1.04	21.29	71.00	61.76	16.23
S	254	0.10	0.47	1.49	27.52	88.93	79.23	15.07
SSW	241	0.10	0.28	1.13	21.05	62.64	40.55	20.86
SW	265	0.08	0.33	0.99	12.35	57.24	49.91	17.39
WSW	235	0.09	0.66	1.40	14.94	55.27	47.41	32.45
W	242	0.12	0.76	0.99	18.58	82.79	94.82	83.45
WNW	249	0.06	0.38	0.81	17.76	88.19	146.60	125.18
NW	247	0.05	0.24	0.45	12.82	74.44	126.60	88.01
NNW	240	0.05	0.24	0.32	12.82	54.78	54.90	47.52
N	254	0.07	0.14	0.54	15.41	47.17	54.27	38.25
Total	3974	1	5	12	290	1076	1272	816

Source: MES

Table 2.3.2-28

LGS JOINT FREQUENCY DISTRIBUTION OF CALM HOURS
1972-1976
WEATHER STATION NO. 1
175 FT LEVEL

Directional Sector	Class F	Regulatory Guide 1.111 Technique Stability Class A	B	C	D	E	F	G
NNE	39	0.09	0.11	0.24	5.54	7.92	5.81	3.40
NE	40	0.09	0.27	0.15	3.69	8.44	6.37	1.59
ENE	38	0.09	0.16	0.12	7.46	11.19	4.87	2.72
E	43	0.04	0.11	0.15	8.31	17.56	10.11	5.21
ESE	44	0.09	0.00	0.24	4.85	11.02	5.62	2.04
SE	43	0.13	0.16	0.15	3.77	7.75	9.18	8.61
SSE	42	0.17	0.27	0.36	6.62	11.02	10.49	4.08
S	48	0.09	0.32	0.74	10.62	17.73	13.11	8.38
SSW	48	0.57	0.48	0.59	8.15	16.87	10.30	6.80
SW	42	0.30	0.32	0.44	4.54	13.26	9.74	7.93
WSW	41	0.17	0.37	0.41	6.23	11.36	11.24	6.57
W	39	0.43	0.48	0.38	5.77	18.25	20.98	11.56
WNW	43	0.13	0.16	0.47	5.46	18.08	21.73	17.90
NW	40	0.09	0.32	0.18	4.08	17.90	15.92	12.69
NNW	38	0.22	0.05	0.18	4.46	10.50	12.17	3.85
N	45	0.30	0.43	0.21	5.46	10.16	9.37	5.67
Total	673	3	4	5	95	209	177	109

Source: MES

Table 2.3.2-29

LGS JOINT FREQUENCY DISTRIBUTION OF CALM HOURS
1972-1976
WEATHER STATION NO. 1
270 FT LEVEL

Directional Sector	Class F	Regulatory Guide 1.111 Technique Stability Class A	B	C	D	E	F	G
NNE	34	0.16	0.07	0.22	4.06	6.93	7.40	2.89
NE	33	0.05	0.09	0.13	3.04	8.26	3.70	3.37
ENE	28	0.05	0.16	0.16	5.45	8.26	5.88	3.85
E	35	0.07	0.12	0.16	6.40	8.59	8.27	4.58
ESE	26	0.05	0.09	0.19	4.44	6.44	3.70	1.45
SE	35	0.07	0.12	0.22	3.17	5.78	8.05	3.13
SSE	29	0.09	0.05	0.35	4.69	7.59	5.22	2.89
S	28	0.09	0.28	0.62	6.85	11.23	10.44	7.23
SSW	32	0.30	0.16	0.62	5.45	11.56	9.36	7.23
SW	30	0.23	0.14	0.43	4.69	8.75	10.66	6.75
WSW	31	0.16	0.09	0.43	3.93	8.26	11.53	8.19
W	32	0.26	0.21	0.38	4.25	12.55	14.36	5.78
WNW	32	0.12	0.09	0.32	4.56	12.22	12.62	8.91
NW	27	0.14	0.16	0.22	3.99	10.73	11.97	9.15
NNW	31	0.07	0.07	0.24	3.42	6.11	5.66	6.02
N	27	0.09	0.09	0.32	3.61	7.76	7.18	4.58
Total	490	2	2	5	72	141	136	86

Source: MES

Table 2.3.2-30

LGS JOINT FREQUENCY DISTRIBUTION OF CALM HOURS
4/72-3/73
WEATHER STATION NO. 2
30 FT LEVEL

Directional Sector	Class F	Regulatory Guide 1.111 Technique Stability Class A	B	C	D	E	F	G
NNE	113	0.00	0.00	0.00	2.39	18.22	0.00	3.55
NE	113	0.00	0.00	0.00	0.30	5.20	3.56	0.00
ENE	113	0.00	0.00	0.00	2.17	19.70	3.56	0.00
E	113	0.00	0.00	0.00	5.09	29.37	1.78	0.00
ESE	113	0.00	0.00	0.00	3.66	45.73	19.58	10.64
SE	113	0.00	0.00	0.00	1.57	37.55	33.83	39.02
SSE	113	0.00	0.00	0.00	3.96	81.42	215.42	205.72
S	113	0.00	0.00	0.00	4.04	45.36	67.65	31.92
SSW	113	0.00	0.00	0.00	2.69	18.59	24.93	10.64
SW	113	0.00	0.00	0.00	0.37	5.58	3.56	0.00
WSW	113	0.00	0.00	0.00	1.94	12.27	8.90	3.55
W	113	0.00	0.00	0.00	3.89	27.51	30.27	10.64
WNW	113	0.00	0.00	0.00	3.22	45.73	51.63	14.19
NW	112	0.00	0.00	0.00	1.12	30.86	56.97	35.47
NNW	112	0.00	0.00	0.00	3.14	52.05	138.87	78.03
N	112	0.00	0.00	0.00	3.44	30.86	28.49	10.64
Total	1805	0	0	0	43	506	689	454

Source: MES

Table 2.3.2-31

LGS JOINT FREQUENCY DISTRIBUTION OF CALM HOURS
4/72-3/73
WEATHER STATION NO. 2
159 FT LEVEL

Directional Sector	Class F	Regulatory Guide 1.111 Technique Stability Class A	B	C	D	E	F	G
NNE	45	0.00	0.00	0.00	0.82	8.08	7.77	6.01
NE	45	0.00	0.00	0.00	0.44	6.97	4.78	1.72
ENE	45	0.00	0.00	0.00	1.53	9.47	6.57	2.58
E	45	0.00	0.00	0.00	1.64	15.88	7.77	5.15
ESE	45	0.00	0.00	0.00	1.64	22.29	27.49	12.03
SE	45	0.00	0.00	0.00	1.26	16.72	20.92	13.74
SSE	45	0.00	0.00	0.00	1.64	16.16	25.10	27.49
S	45	0.00	0.00	0.00	1.31	13.93	17.93	12.03
SSW	45	0.00	0.00	0.00	1.26	9.20	11.95	12.89
SW	45	0.00	0.00	0.00	0.22	6.69	12.55	5.15
WSW	44	0.00	0.00	0.00	0.87	6.69	14.94	7.73
W	44	0.00	0.00	0.00	1.80	10.87	28.69	13.74
WNW	44	0.00	0.00	0.00	1.04	12.54	22.11	22.33
NW	44	0.00	0.00	0.00	0.49	13.65	21.52	28.35
NNW	44	0.00	0.00	0.00	1.31	13.37	20.92	16.32
N	44	0.00	0.00	0.00	1.75	14.49	8.97	7.73
Total	714	0	0	0	19	197	260	195

Source: MES

Table 2.3.2-32

LGS JOINT FREQUENCY DISTRIBUTION OF CALM HOURS
4/72-3/73
WEATHER STATION NO. 2
304 FT LEVEL

Directional Sector	Class F	Regulatory Guide 1.111 Technique Stability Class A	B	C	D	E	F	G
NNE	11	0.00	0.00	0.00	0.41	3.88	1.15	1.07
NE	11	0.00	0.00	0.00	0.23	2.26	1.73	0.53
ENE	11	0.00	0.00	0.00	0.52	5.17	2.31	1.33
E	11	0.00	0.00	0.00	0.52	4.68	1.15	1.07
ESE	11	0.00	0.00	0.00	0.52	7.11	2.60	0.80
SE	11	0.00	0.00	0.00	0.36	2.75	2.31	1.87
SSE	10	0.00	0.00	0.00	0.67	5.01	6.35	1.33
S	10	0.00	0.00	0.00	0.59	5.65	4.91	3.47
SSW	10	0.00	0.00	0.00	0.23	3.55	2.89	0.80
SW	10	0.00	0.00	0.00	0.10	1.78	2.60	1.33
WSW	10	0.00	0.00	0.00	0.39	1.78	2.02	2.67
W	10	0.00	0.00	0.00	0.62	3.55	4.62	3.73
WNW	10	0.00	0.00	0.00	0.49	5.01	5.48	4.27
NW	10	0.00	0.00	0.00	0.13	3.88	10.10	4.00
NNW	10	0.00	0.00	0.00	0.52	3.72	4.91	1.60
N	10	0.00	0.00	0.00	0.70	3.23	2.89	2.13
Total	161	0	0	0	7	63	58	32

Source: MES

Table 2.3.2-33

LGS JOINT FREQUENCY DISTRIBUTION OF CALM HOURS
1/75-12/76
SATELLITE TOWER
32 FT LEVEL

Directional Sector	Class F	Regulatory Guide 1.111 Technique Stability Class A	B	C	D	E	F	G
NNE	95	0.00	0.00	0.19	4.00	9.07	6.55	7.28
NE	92	0.00	0.00	0.00	3.77	11.08	2.62	4.85
ENE	95	0.00	0.00	0.00	7.30	11.59	7.86	12.13
E	129	0.00	0.00	0.00	16.48	69.52	32.73	14.56
ESE	182	0.00	0.00	0.38	8.00	86.15	70.70	41.26
SE	183	0.00	0.00	0.19	8.47	97.74	75.94	19.42
SSE	149	0.00	0.00	0.95	10.59	86.15	57.94	9.71
S	93	0.00	0.91	2.08	11.06	44.33	57.61	4.85
SSW	78	0.00	0.91	1.32	5.53	13.10	14.14	0.00
SW	78	0.00	0.23	0.00	3.18	9.57	5.24	2.43
WSW	78	0.00	0.69	1.51	4.94	16.63	2.62	2.43
W	80	0.00	1.60	2.46	6.71	39.80	2.62	7.28
WNW	116	0.00	1.14	1.51	6.94	53.91	15.71	19.42
NW	120	0.00	0.91	1.14	7.53	70.03	23.57	24.27
NNW	143	0.00	0.91	1.70	9.42	68.52	61.54	33.98
N	106	0.00	0.69	0.57	7.06	41.82	51.06	12.13
Total	1817	0	8	14	121	729	508	216

Source: MES

Table 2.3.3-1

INSTRUMENT ELEVATIONS
PREOPERATIONAL METEOROLOGICAL MEASUREMENT SYSTEM (1970-1983)

	WEATHER STATION NO. 1	WEATHER STATION NO. 2
	Tower 1	Tower 2
Grade	el 250'	el 121'
Wind speed and wind direction	el 280'(30') el 425'(175')[5] el 520'(270')	el 151'(30') el 280'(159') el 425'(304')[5]
Horizontal and vertical wind fluctuation	el 400'(150')[2]	
Temperature	el 255'(5')[4] el 256'(6') el 276'(26')	el 126'(5')[4] el 147'(26')
Temperature Difference	el 421' - el 276' (171'-26') el 516' - el 276' (266'-26')	el 276' - el 126' (155'-26') el 421' - el 126' (300'-26')
Relative humidity	el 255'(5')	
Rain gauge	el 255'(5')	

	Satellite Tower
Grade	el 106'
Wind speed and wind direction	el 138'(32')[3]

(1) All elevations refer to MSL. The number in parentheses after the elevation above MSL refers to the height of the sensor above grade.
(2) This location is for a bivane used for special studies (removed from service March 7, 1977). All other wind instruments on Tower 1 and Tower 2 are six-blade Aerovanes.
(3) Bendix Wind Vane; 3-cup anemometer and wind vane
(4) Ambient temperature in the control structure
(5) Structure vent release elevation

Table 2.3.3-2

PREOPERATIONAL METEOROLOGICAL MEASUREMENT SYSTEM (1970-1983)
SENSOR AND SYSTEM SPECIFICATIONS AND ACCURACIES

PARAMETER	COMPONENT	MANUFACTURER/ MODEL NO.	COMPONENT ACCURACY	SYSTEM[1] ACCURACY	REGULATORY GUIDE 1.23	COMMENTS/ SPECIFICATIONS
Aerovane wind speed	Impeller	Bendix/120	±0.5 mph(0-10 mph)-	-		Starting speed of 1.8 mph
	Generator	Bendix/141	± 1 mph(>10 mph) -	-		Stopping speed of 0.7 mph
	Recorder	-	[2]			2 element recorder
	Combination of above components			±0.5 mph	±0.5 mph accuracy/ starting speed 1 mph	
Aerovane wind direction	Wind vane and	Bendix/120	+2°			
	Recorder	Bendix/14	[2]			2 element recorder
	Combination of above components		±2°	±5°		
Satellite wind speed	3-cup anemometer	Bendix/2416914	±0.5 mph(0.5-50 mph)			Starting speed <0.5 mph
	Recorder	Bendix/141	[2]	-	-	2 element recorder
	Combination of above components			±0.5 mph	±0.5 mph accuracy/ starting speed <1 mph	
Satellite wind direction	Wind vane	Bendix/2416970	±2°	-	-	
	Recorder	Bendix/141	[2]	-	-	2 element recorder
	Combination of above components			±2°	±5°	

Table 2.3.3-2 (Cont'd)

PARAMETER	COMPONENT	MANUFACTURER/ MODEL NO.	COMPONENT ACCURACY	SYSTEM[1] ACCURACY	REGULATORY GUIDE 1.23	COMMENTS/ SPECIFICATIONS
Temperature (ambient)	Sensor	L&N/8197	±0.2°F	-	-	40°F-120°F, 1 ma ±0.03%
	Constant current power source	L&N/445372	[2]	-	-	6 points, 10 seconds/ point
	Recorder	Speedomax W	±0.36°F	-	-	Dual range recorder
	Combination of above components			±0.41°F	±0.5°C (±0.9°F)	±.0.9°F = ±0.5°C
Temperature (difference)	Sensor	L&N/8197	±0.1°F			Matched pairs ±0.07°F
	Constant current power source	L&N/445372	[2]	-	-	40°F-120°F,1 ma ±.0.03%
	Recorder	L&N/Speedomax	W ±0.072°F	-	-	6 points, 10 seconds/ point
	Combination of above components			±0.12°F (±0.18°F)	±0.1°C	±0.18°F = ±0.1°C
Relative Humidity	Humidity sensor	Bendix/594	3% 20-80% 5% > 80%	3% 20-80% 5% > 80% point	±0.5°C dew	±1.07% RH ±0.5°C dew point @ 21°C
	Temperature sensor	Bendix/594	±1°F	±1°F	-	

[1] Square root of the sum of the squares
[2] Negligible Error

Table 2.3.3-3

LGS PERCENT OF HOURS WITH CALM WINDS

PERIOD OF RECORD	Tower 1	1972-1976	
	Tower 2	1972-1976	
	Satellite	1975-1976	
SENSOR			%
Tower 1		30 ft (el 280' MSL)	9.9
		175 ft (el 425' MSL)	1.7
		270 ft (el 520' MSL)	1.2
Tower 2		30 ft (el 151' MSL)	22.9
		159 ft (el 280' MSL)	6.2
		304 ft (el 425' MSL)	1.9
Satellite		32 ft (el 138' MSL)	17.5

Table 2.3.3-4

STATION LOCATIONS - PHILADELPHIA

Location	Occupied From	Occupied To	Airline Distance and Direction From Previous Location	Latitude North	Longitude North	ELEVATION ABOVE SEA LEVEL: Ground at Temperature Site	ELEVATION ABOVE SEA LEVEL: Wind Instruments	ELEVATION ABOVE GROUND: Extreme Thermometers	ELEVATION ABOVE GROUND: Psychrometer	ELEVATION ABOVE GROUND: Telepsychrometer	ELEVATION ABOVE GROUND: Tipping Bucket Rain Gauge	ELEVATION ABOVE GROUND: Weighing Rain Gauge	ELEVATION ABOVE GROUND: 8" Rain Gauge	ELEVATION ABOVE SEA LEVEL: Hygro-Thermometer	ELEVATION ABOVE SEA LEVEL: Pyrometer	Remarks
CITY																
Philadelphia Board of Trade 505 Chestnut Street	12/23/70	9/21/71	-	39° 57'	75° 09'	-	-	-	-	-	-	-	-	-	-	No record of elevations.
Chamber of Commerce Building, 133 S 2nd St.	9/21/71	2/01/82	0.3 mi E	39° 57'	75° 09'	23	a122	-	b98	-	-	-	c91	-	-	a - About 129 feet to 8/4/75 b - 102 feet to 8/4/75. c - Elev. prior to 8/4/75 unknown.
Mutual Life Ins Building 10th & Chestnut Sts.	2/01/82	4/01/84	0.7 mi W	39° 57'	75° 09'	40	107	-	54	-	-	-	z106	-	-	z - Approximate
Post Office Building 9th & Chestnut Sts.	4/01/84	12/17/34	0.1 mi E	39° 57'	75° 09'	39	175 d184 e190 f182 g341 h367	169 d117 e124	168 d116 e123	-	%114	-	167 d114	-	-	% - Added 1/27/14. d - Effective 2/1/04. e - Effective 1/27/14. f - Effective 7/23/24. g - Moved 1000 feet South to Edison Building 2/2/28 . h - Effective 10/27/28.
New Customhouse 2nd & Chestnut Sts.	12/17/34	12/31/54	0.6 mi E	39° 57'	75° 09'	26	1367 K m148	175	174	-	166 K m132	j166	166	-	-	i - Remained on Edison Building. j - Added 1/1/43. K - Moved to SW Airport 1/1/43. m - Added 0.2 mi. West on Bourse Building 7/1/45.
New Customhouse 2nd & Chestnut Sts.	1/01/55	5/15/59	-	-		26	-	175	-	-	n160	n160	166	-	-	Cooperative Station. n - Added 5/1/55.

Table 2.3.3-4 (Cont'd)

STATION LOCATIONS - PHILADELPHIA

Location	Occupied From	Occupied To	Airline Distance and Direction From Previous Location	Latitude North	Longitude North	ELEVATION ABOVE SEA LEVEL: Ground at Temperature Site	ELEVATION ABOVE SEA LEVEL: Wind Instruments	ELEVATION ABOVE GROUND: Extreme Thermometers	ELEVATION ABOVE GROUND: Psychrometer	ELEVATION ABOVE GROUND: Telepsychrometer	ELEVATION ABOVE GROUND: Tipping Bucket Rain Gauge	ELEVATION ABOVE GROUND: Weighing Rain Gauge	ELEVATION ABOVE GROUND: 8" Rain Gauge	ELEVATION ABOVE SEA LEVEL: Hygro-Thermometer	ELEVATION ABOVE SEA LEVEL: Pyrometer	Remarks
Bourse Building 4th Street below Market	3/01/55	5/01/55	0.2 mi W	39° 57'	75° 09'	-	-	-	-	-	-	133	-	-	-	
PECo Building 10th & Chestnut Sts.	5/15/59	10/19/73	0.7 mi W	39° 57'	75° 10'	35	-	155	-	-	-	-	-	-	-	
Federal Office Building 600 Arch Street	12/03/73	Present	-	39° 57'	75° 09'	35	186	178	-	-	-	178	-	-	-	
AIRPORT																
Administration Building Southwest Airport #	6/20/40	6/22/45	-	39° 53'	75° 14'	13	a58	6	5	-	-	b3	3	-	-	a - 57 feet through 1942. b - Installed 1/1/43. # - Name changed to Internal Airport 4/1/48.
Administration Building N. Philadelphia Airport	6/23/45	11/30/45	18 mi NE	40° 05'	75° 01'	100	51	6	5	-	-	-	4	-	-	
Administration Building	12/01/45	12/22/54	18 mi SW	39° 53'	75° 14'	13	58	6	5	-	-	3	3	-	-	* - Changed to roof exposure 10/4/54. WB design wind equipment installed 5/17/49.
International Airport								*22	*22							
New Terminal Building International Airport	12/23/54	5/09/55	7/8 mi SW	39° 53'	75° 15'	13	120	67	66	-	-	64	64	-	-	
New Terminal Building International Airport	5/09/55	12/31/59	0.2 mi N	39° 53'	75° 15'	13	120	7	66	7	3	4	3	-	-	
New Terminal Building International Airport	1/01/60	Present	-	39° 53'	75° 15'	5	20	d4	d55	-	e64	e64	-	c4	-	c - Commissioned 300 feet South of telepsychrometer site. d - Removed prior to December 1968. e - 4 feet to 7/13/70

Table 2.3.3-5

STATION LOCATIONS - ALLENTOWN

Location	Occupied From	Occupied To	Airline Distance and Direction From Previous Location	Latitude North	Longitude North	ELEVATION ABOVE SEA LEVEL: Ground at Temperature Site	ELEVATION ABOVE SEA LEVEL: Wind Instruments	ELEVATION ABOVE GROUND: Extreme Thermometers	ELEVATION ABOVE GROUND: Psychrometer	ELEVATION ABOVE GROUND: Telepsychrometer	ELEVATION ABOVE GROUND: Tipping Bucket Rain Gauge	ELEVATION ABOVE GROUND: Weighing Rain Gauge	ELEVATION ABOVE GROUND: 8" Rain Gauge	ELEVATION ABOVE SEA LEVEL: Hygro-Thermometer	ELEVATION ABOVE SEA LEVEL: Pyrometer	Remarks
COMPARATIVE																
Allentown-Bethlehem Gas Company 3rd & Union	11/02/11	6/01/65	-	40° 36'	75° 28'	254	-	4	-	-	-	-	-	3	-	Precipitation records
Airport																
Old Administrative Building Allentown-Bethlehem Easton Airport 4.5 miles NNE of Post Office	4/06/38	10/13/50	-	40° 39'	75° 26'	381	57	5	4	-	-	a5	3	-	-	CAA station to 12/13/43, then Weather Bureau. a - Added 12/13/43.
New Administration Building At Allentown-Bethlehem Easton Airport	10/13/50	12/01/65	1300 FT SSW	40° 39'	75° 26'	376	69	6	5	-	-	4	3	-	-	
New Administration Building	12/01/65	Present	(1)	40° 39'	75° 26'	387	b20	c6	c5	-	e5	4 d5	3 d3	b4	-	(1) Office not moved b – 1650 feet previously used sensors. c – Standby status. d – Relocated 5/8/73. e – Added 5/3/77.

Table 2.3.3-6

INSTRUMENT ELEVATIONS[1]
OPERATIONAL METEOROLOGICAL MEASUREMENT SYSTEM (1983)

	WEATHER STATION NO. 1	WEATHER STATION NO. 2
	Tower 1	Tower 2
Grade	el 250'	el 121'
Wind speed, wind direction and sigma theta	el 280'(30') el 425'(175')[2]	el 151'(30') el 280'(159') el 425'(304')[2]
Wind speed and wind direction (Aerovane)	el 520'(270')	
Temperature	el 276'(26')	el 147'(26')
Temperature Difference	el 421' - el 276' (171'-26') el 516' - el 276' (266'-26')	el 276' - el 147' (155'-26') el 421' - el 147' (300'-26')
Dew point	el 276'(26')	el 147' (26')
Rain gauge	el 255'(5')	

(1) All elevations refer to MSL. The number in parentheses after the elevation above MSL refers to the height of the sensor above grade.
(2) Structure vent release elevation

Table 2.3.3-7

OPERATIONAL METEOROLOGICAL MEASUREMENT SYSTEM (1983)
SENSOR AND SYSTEM SPECIFICATIONS AND ACCURACIES

PARAMETER	SYSTEM[1] ACCURACY	REGULATORY GUIDE 1.23 PROPOSED REV. 1	COMMENTS/SPECIFICATIONS
Wind speed			Starting speed of 0.5 mph
	±0.5 mph	±0.5 mph accuracy speed <25 mph	System accuracy valid for speeds < 25 mph
Wind direction	±5°	±5°	
Standard deviation of wind direction (Sigma theta)			Distance constant of 1.5 m Damping ratio of 0.4 15 min of 5 sec sampled data
Temperature (ambient)			100 ohm, platinum RTD -30°F to 120°F
	±0.9°F	±0.5°C ±0.9°F	Data Logger
Temperature (Difference)			100 ohm, platinum RTD -10°F to 20°F
	(±0.27°F) per 50m interval	±0.15°C (±0.27°F) per 50m interval	Data Logger

Table 2.3.3-7 (Cont'd)

OPERATIONAL METEOROLOGICAL MEASUREMENT SYSTEM (1983)
SENSOR AND SYSTEM SPECIFICATIONS AND ACCURACIES

PARAMETER	SYSTEM[1] ACCURACY	REGULATORY GUIDE 1.23 PROPOSED REV. 1	COMMENTS/SPECIFICATIONS
Dew point			Lithium-Chloride
			-30°F to 120°F
	±2.7°F	±1.5°C (±2.7°F)	Data Logger
Precipitation			Tipping bucket, with heater Each tip = .01 inch
	±10% of accumulated catch	±10% of accumulated catch	Data Logger

[1] Square root of the sum of the squares

Table 2.3.4-1
Joint Frequency Distribution
(Number of Observations)
1996 – 2000
30 Ft Level

		Wind Direction Category																	
	Wind Speed Category[1]	N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	Calms	Total
1 (A)	1 (Calm)																	0	0
	2	5	5	7	1	1	1	1	0	0	0	3	14	23	7	8	6		82
	3	85	54	34	16	4	10	8	7	42	94	177	212	214	189	80	56		1282
	4	27	13	4	9	6	9	8	10	71	124	69	125	165	253	190	60		1143
	5	0	0	0	4	8	0	0	0	7	16	6	11	67	139	59	17		334
	6	0	0	0	0	0	0	0	0	2	1	0	0	5	12	8	4		32
	7	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0		1
	Subtotal	**117**	**72**	**45**	**30**	**19**	**20**	**17**	**17**	**122**	**235**	**255**	**362**	**475**	**600**	**345**	**143**	**0**	**2874**
2 (B)	1 (Calm)																	0	0
	2	7	4	8	6	4	2	1	0	3	2	10	12	22	12	5	0		98
	3	50	32	27	29	19	16	6	17	37	76	73	82	93	108	68	40		773
	4	25	11	10	17	24	14	3	6	29	54	20	38	94	124	133	44		646
	5	1	2	0	1	5	2	0	0	6	4	0	2	36	85	50	21		215
	6	0	0	0	0	0	0	0	0	0	1	0	0	7	4	5	4		21
	7	0	0	0	0	0	0	0	0	0	0	0	0	4	0	0	0		4
	Subtotal	**83**	**49**	**45**	**53**	**52**	**34**	**10**	**23**	**75**	**137**	**103**	**134**	**256**	**333**	**261**	**109**	**0**	**1757**
3 (C)	1 (Calm)																	0	0
	2	6	7	13	11	6	4	5	8	8	13	22	26	26	21	11	10		197
	3	52	43	34	60	49	16	34	23	47	82	84	93	124	132	81	35		989
	4	24	9	11	37	47	13	4	9	36	59	23	37	88	168	176	55		796
	5	1	0	0	3	1	1	1	3	12	3	2	1	39	131	124	22		344
	6	0	0	0	0	0	0	0	0	1	1	0	0	8	12	30	3		55
	7	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0		2
	Subtotal	**83**	**59**	**58**	**111**	**103**	**34**	**44**	**43**	**104**	**158**	**131**	**157**	**285**	**465**	**423**	**125**	**0**	**2383**
4 (D)	1 (Calm)																	0	0
	2	204	207	303	243	177	130	119	96	123	146	156	194	195	210	193	154		2850
	3	379	288	508	801	480	280	226	326	443	416	288	315	502	668	582	345		6847
	4	200	116	146	331	362	115	61	171	293	175	53	87	516	1008	820	419		4873
	5	22	2	18	29	82	8	8	18	32	37	5	17	226	526	559	128		1717
	6	0	0	0	2	1	1	0	1	0	1	0	0	24	39	114	12		195
	7	0	0	0	0	1	0	0	0	0	0	0	0	1	1	5	0		8
	Subtotal	**805**	**613**	**975**	**1406**	**1103**	**534**	**414**	**612**	**891**	**775**	**502**	**613**	**1464**	**2452**	**2273**	**1058**	**0**	**16490**
5 (E)	1 (Calm)																	1	1
	2	235	238	265	259	185	146	112	142	193	285	377	402	461	464	352	236		4352
	3	202	183	190	317	234	137	206	250	487	416	295	280	560	846	514	256		5373
	4	44	24	10	31	88	53	31	67	104	88	30	25	133	265	223	83		1299
	5	5	1	2	3	12	9	13	31	8	6	5	3	20	56	54	12		240
	6	0	0	0	0	0	0	3	5	1	0	0	1	1	5	5	0		21
	7	0	0	0	1	0	0	2	0	0	0	0	0	0	0	0	0		3
	Subtotal	**486**	**446**	**467**	**611**	**519**	**345**	**367**	**495**	**793**	**795**	**707**	**711**	**1175**	**1636**	**1148**	**587**	**1**	**11289**
6 (F)	1 (Calm)																	0	0
	2	170	185	179	174	123	91	64	66	73	126	215	294	445	450	353	199		3207
	3	16	36	21	32	38	25	11	19	47	116	71	37	110	192	97	22		890
	4	0	1	0	0	0	1	1	0	2	0	3	0	0	7	0	1		16
	5	1	0	0	0	0	1	1	0	0	0	0	0	0	2	10	0		15
	6	2	3	0	0	0	0	0	0	0	0	0	0	0	0	2	2		9
	7	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0		1
	Subtotal	**189**	**225**	**200**	**206**	**161**	**118**	**77**	**86**	**122**	**242**	**289**	**331**	**555**	**651**	**462**	**224**	**0**	**4138**
7 (G)	1 (Calm)																	1	1
	2	266	208	240	150	115	53	43	39	72	65	133	164	423	512	351	320		3154
	3	4	6	2	17	16	7	12	12	16	13	17	24	65	91	27	9		338
	4	0	0	0	1	6	1	1	7	10	6	4	2	22	14	4	3		81
	5	0	0	0	0	0	0	0	0	1	2	0	0	3	12	0	0		18
	6	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0		1
	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	Subtotal	**270**	**214**	**242**	**168**	**137**	**61**	**56**	**58**	**99**	**86**	**154**	**190**	**513**	**630**	**382**	**332**	**1**	**3593**
	Total	**2033**	**1678**	**2032**	**2585**	**2094**	**1146**	**985**	**1334**	**2206**	**2428**	**2141**	**2498**	**4723**	**6767**	**5294**	**2578**	**2**	**42524**

Notes: (1) Wind Speed Categories defined as follows:

Category	Wind Speed (mph)	Category	Wind Speed (mph)	Category	Wind Speed (mph)	Category	Wind Speed (mph)
1 (Calm)	<0.5	3	>=3.5 to <7.5	5	>=12.5 to <18.5	7	>=24
2	>=0.5 to <3.5	4	>=7.5 to <12.5	6	>=18.5 to <24		

Table 2.3.4-1 (Cont'd)

		Wind Direction Category																	
	Wind Speed Category[1]	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	Calm	Total
1 (A)	1 (Calm)																	0.00	0.00
	2	0.01	0.01	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.05	0.02	0.02	0.01		0.19
	3	0.20	0.13	0.08	0.04	0.01	0.02	0.02	0.02	0.10	0.22	0.42	0.50	0.50	0.44	0.19	0.13		3.01
	4	0.06	0.03	0.01	0.02	0.01	0.02	0.02	0.02	0.17	0.29	0.16	0.29	0.39	0.59	0.45	0.14		2.69
	5	0.00	0.00	0.00	0.01	0.02	0.00	0.00	0.00	0.02	0.04	0.01	0.03	0.16	0.33	0.14	0.04		0.79
	6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.02	0.01		0.08
	7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
	Subtotal	0.28	0.17	0.11	0.07	0.04	0.05	0.04	0.04	0.29	0.55	0.60	0.85	1.12	1.41	0.81	0.34	0.00	6.76
2 (B)	1 (Calm)																	0.00	0.00
	2	0.02	0.01	0.02	0.01	0.01	0.00	0.00	0.00	0.01	0.00	0.02	0.03	0.05	0.03	0.01	0.00		0.23
	3	0.12	0.08	0.06	0.07	0.04	0.04	0.01	0.04	0.09	0.18	0.17	0.19	0.22	0.25	0.16	0.09		1.82
	4	0.06	0.03	0.02	0.04	0.06	0.03	0.01	0.01	0.07	0.13	0.05	0.09	0.22	0.29	0.31	0.10		1.52
	5	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.08	0.20	0.12	0.05		0.51
	6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.01	0.01		0.05
	7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00		0.01
	Subtotal	0.20	0.12	0.11	0.12	0.12	0.08	0.02	0.05	0.18	0.32	0.24	0.32	0.60	0.78	0.61	0.26	0.00	4.13
3 (C)	1 (Calm)																	0.00	0.00
	2	0.01	0.02	0.03	0.03	0.01	0.01	0.01	0.02	0.02	0.03	0.05	0.06	0.06	0.05	0.03	0.02		0.46
	3	0.12	0.10	0.08	0.14	0.12	0.04	0.08	0.05	0.11	0.19	0.20	0.22	0.29	0.31	0.19	0.08		2.33
	4	0.06	0.02	0.03	0.09	0.11	0.03	0.01	0.02	0.08	0.14	0.05	0.09	0.21	0.40	0.41	0.13		1.87
	5	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.01	0.03	0.01	0.00	0.00	0.09	0.31	0.29	0.05		0.81
	6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.07	0.01		0.13
	7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
	Subtotal	0.20	0.14	0.14	0.26	0.24	0.08	0.10	0.10	0.24	0.37	0.31	0.37	0.67	1.09	0.99	0.29	0.00	5.60
4 (D)	1 (Calm)																	0.00	0.00
	2	0.48	0.49	0.71	0.57	0.42	0.31	0.28	0.23	0.29	0.34	0.37	0.46	0.46	0.49	0.45	0.36		6.70
	3	0.89	0.68	1.19	1.88	1.13	0.66	0.53	0.77	1.04	0.98	0.68	0.74	1.18	1.57	1.37	0.81		16.10
	4	0.47	0.27	0.34	0.78	0.85	0.27	0.14	0.40	0.69	0.41	0.12	0.20	1.21	2.37	1.93	0.99		11.46
	5	0.05	0.00	0.04	0.07	0.19	0.02	0.02	0.04	0.08	0.09	0.01	0.04	0.53	1.24	1.31	0.30		4.04
	6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.09	0.27	0.03		0.46
	7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00		0.02
	Subtotal	1.89	1.44	2.29	3.31	2.59	1.26	0.97	1.44	2.10	1.82	1.18	1.44	3.44	5.77	5.35	2.49	0.00	38.78
5 (E)	1 (Calm)																	0.00	0.00
	2	0.55	0.56	0.62	0.61	0.44	0.34	0.26	0.33	0.45	0.67	0.89	0.95	1.08	1.09	0.83	0.55	0.00	10.23
	3	0.48	0.43	0.45	0.75	0.55	0.32	0.48	0.59	1.15	0.98	0.69	0.66	1.32	1.99	1.21	0.60		12.64
	4	0.10	0.06	0.02	0.07	0.21	0.12	0.07	0.16	0.24	0.21	0.07	0.06	0.31	0.62	0.52	0.20		3.05
	5	0.01	0.00	0.00	0.01	0.03	0.02	0.03	0.07	0.02	0.01	0.01	0.01	0.05	0.13	0.13	0.03		0.56
	6	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00		0.05
	7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.01
	Subtotal	1.14	1.05	1.10	1.44	1.22	0.81	0.86	1.16	1.86	1.87	1.66	1.67	2.76	3.85	2.70	1.38	0.00	26.55
6 (F)	1 (Calm)																	0.00	0.00
	2	0.40	0.44	0.42	0.41	0.29	0.21	0.15	0.16	0.17	0.30	0.51	0.69	1.05	1.06	0.83	0.47		7.54
	3	0.04	0.08	0.05	0.08	0.09	0.06	0.03	0.04	0.11	0.27	0.17	0.09	0.26	0.45	0.23	0.05		2.09
	4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.02	0.00	0.00		0.04
	5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00		0.04
	6	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.02
	7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
	Subtotal	0.44	0.53	0.47	0.48	0.38	0.28	0.18	0.20	0.29	0.57	0.68	0.78	1.31	1.53	1.09	0.53	0.00	9.73
7 (G)	1 (Calm)																	0.00	0.00
	2	0.63	0.49	0.56	0.35	0.27	0.12	0.10	0.09	0.17	0.15	0.31	0.39	0.99	1.20	0.83	0.75		7.42
	3	0.01	0.01	0.00	0.04	0.04	0.02	0.03	0.03	0.04	0.03	0.04	0.06	0.15	0.21	0.06	0.02		0.79
	4	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.02	0.02	0.01	0.01	0.00	0.05	0.03	0.01	0.01		0.19
	5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.00	0.00		0.04
	6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
	7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00
	Subtotal	0.63	0.50	0.57	0.40	0.32	0.14	0.13	0.14	0.23	0.20	0.36	0.45	1.21	1.48	0.90	0.78	0.00	8.45
	Total	**4.78**	**3.95**	**4.78**	**6.08**	**4.92**	**2.69**	**2.32**	**3.14**	**5.19**	**5.71**	**5.03**	**5.87**	**11.11**	**15.91**	**12.45**	**6.06**	**0.00**	**100.00**

Notes: (1) Wind Speed Categories defined as follows:

Category	Wind Speed (mph)
1 (Calm)	<0.5
2	>=0.5 to <3.5
3	>=3.5 to <7.5
4	>=7.5 to <12.5
5	>=12.5 to <18.5
6	>=18.5 to <24
7	>=24

Table 2.3.4-2

LAPSE RATE WIND DISTRIBUTIONS[1][2]

SPEED RANGES (mph) LE=1.0

DIRECTION	0-3 SUM	0-3 %	4-7 SUM	4-7 %	8-12 SUM	8-12 %	13-18 SUM	13-18 %	19-23 SUM	19-23 %	24+ SUM	24+ %	ALL SPEEDS SUM	ALL SPEEDS %
22.5	3	0.0	3	0.0	0	0.0	2	0.0	0	0.0	0	0.0	8	0.0
45.0	1	0.0	0	0.0	0	0.0	1	0.0	0	0.0	0	0.0	2	0.0
67.5	1	0.0	3	0.0	0	0.0	0	0.0	0	0.0	0	0.0	4	0.0
90.0	2	0.0	4	0.0	6	0.0	0	0.0	0	0.0	0	0.0	12	0.1
112.5	2	0.0	1	0.0	1	0.0	0	0.0	0	0.0	0	0.0	4	0.0
135.0	0	0.0	2	0.0	4	0.0	0	0.0	0	0.0	0	0.0	6	0.0
157.5	4	0.0	2	0.0	3	0.0	3	0.0	0	0.0	0	0.0	12	0.1
180.0	5	0.0	4	0.0	13	0.1	3	0.0	0	0.0	0	0.0	25	0.1
202.5	5	0.0	9	0.0	16	0.1	2	0.0	0	0.0	0	0.0	32	0.1
225.0	2	0.0	8	0.0	5	0.0	0	0.0	0	0.0	0	0.0	15	0.1
247.5	2	0.0	15	0.1	1	0.0	1	0.0	0	0.0	0	0.0	19	0.1
270.0	3	0.0	12	0.1	17	0.1	6	0.0	1	0.0	0	0.0	39	0.2
292.5	3	0.0	11	0.0	33	0.1	15	0.1	0	0.0	0	0.0	62	0.3
315.0	1	0.0	9	0.0	14	0.1	13	0.1	5	0.0	0	0.0	42	0.2
337.5	1	0.0	3	0.0	9	0.0	10	0.0	0	0.0	0	0.0	23	0.1
360.0	1	0.0	3	0.0	5	0.0	3	0.0	0	0.0	0	0.0	12	0.1
	36/0.0		89/ 0.2		127/0.5		59/ 0.2		6/0.0		0/0.0		317/ 1.5	

Mean wind speed: 9.0

Number of uninterpretable hours: 1

Table 2.3.4-2 (Cont'd)

SPEED RANGES (mph) -1:S/-1.7

DIRECTION	0-3 SUM	0-3 %	4-7 SUM	4-7 %	8-12 SUM	8-12 %	13-18 SUM	13-18 %	19-23 SUM	19-23 %	24+ SUM	24+ %	ALL SPEEDS SUM	ALL SPEEDS %
22.5	0	0.0	7	0.0	5	0.0	1	0.0	0	0.0	0	0.0	13	0.1
45.0	3	0.0	2	0.0	1	0.0	0	0.0	0	0.0	0	0.0	6	0.0
67.5	6	0.0	6	0.0	5	0.0	0	0.0	0	0.0	0	0.0	17	0.1
90.0	2	0.0	6	0.0	5	0.0	2	0.0	0	0.0	0	0.0	15	0.1
112.5	1	0.0	5	0.0	5	0.0	2	0.0	0	0.0	0	0.0	13	0.1
135.0	2	0.0	3	0.0	5	0.0	0	0.0	0	0.0	0	0.0	10	0.0
157.5	5	0.0	14	0.1	13	0.1	0	0.0	0	0.0	0	0.0	32	0.1
180.0	9	0.0	15	0.1	12	0.1	2	0.0	0	0.0	0.	0.0	38	0.2
202.5	1	0.0	15	0.1	12	0.1	4	0.0	0	0.0	0	0.0	32	0.1
225.0	2	0.0	15	0.1	15	0.1	0	0.0	0	0.0	0	0.0	32	0.1
247.5	10	0.0	23	0.1	21	0.1	7	0.0	0	0.0	0	0.0	61	0.3
270.0	11	0.0	31	0.1	34	0.1	9	0.0	2	0.0	0	0.0	87	0.4
292.5	3	0.0	41	0.2	53	0.2	40	0.2	12	0.1	1	0.0	150	0.7
315.0	4	0.0	18	0.1	34	0.1	35	0.2	5	0.0	0	0.0	96	0.4
337.5	3	0.0	7	0.0	15	0.1	14	0.1	1	0.0	0	0.0	40	0.2
360.0	1	0.0	11	0.0	13	0.1	5	0.0	0	0.0	0	0.0	30	0.1
	63/ 0.0		219/0.9		248/ 1.1		121/ 0.5		20/0.1		1/0.0		672/3.0	

Mean wind speed: 9.0

Number of uninterpretable hours: 1

Table 2.3.4-2 (Cont'd)

SPEEDS RANGES (mph)

DIRECTION	0-3 SUM	0-3 %	4-7 SUM	4-7 %	8-12 SUM	8-12 %	13-18 SUM	13-18 %	19-23 SUM	19-23 %	24+ SUM	24+ %	ALL SPEEDS SUM	ALL SPEEDS %
22.5	6	0.0	17	0.1	13	0.1	2	0.0	0	0.0	0	0.0	38	0.1
45.0	5	0.0	17	0.1	3	0.0	1	0.0	0	0.0	0	0.0	26	0.1
67.5	7	0.0	23	0.1	9	0.0	0	0.0	0	0.0	0	0.0	39	0.2
90.0	7	0.0	26	0.1	21	0.1	6	0.0	1	0.0	0	0.0	61	0.3
112.5	8	0.0	16	0.1	10	0.0	0	0.0	0	0.0	0	0.0	34	0.1
135.0	8	0.0	13	0.1	9	0.0	2	0.0	0	0.0	0	0.0	32	0.1
157.5	14	0.1	16	0.1	16	0.1	2	0.0	0	0.0	0	0.0	48	0.2
180.0	20	0.1	50	0.2	39	0.2	1	0.0	0	0.0	0	0.0	110	0.5
202.5	19	0.1	36	0.2	64	0.3	15	0.1	0	0.0	0	0.0	134	0.6
225.0	16	0.1	23	0.1	31	0.1	11	0.0	0	0.0	0	0.0	81	0.4
247.5	22	0.1	36	0.2	37	0.2	7	0.0	0	0.0	0	0.0	102	0.4
270.0	16	0.1	48	0.2	48	0.2	25	0.1	1	0.0	2	0.0	140	0.6
292.5	11	0.0	46	0.2	84	0.4	89	0.4	24	0.1	1	0.0	255	1.1
315.0	8	0.0	30	0.1	53	0.2	74	0.3	16	0.1	0	0.0	181	0.8
337.5	3	0.0	20	0.1	32	0.1	19	0.1	5	0.1	0	0.0	79	0.3
360.0	11	0.0	30	0.1	53	0.2	74	0.3	16	0.1	0	0.0	181	0.8
	181/ 0.8		432/1.9		500/2.2		260/ 1.0		47/ 0.2		3/ 0.0		1423/6.2	

Mean wind speed: 8.8

Number of uninterpretable hours: 2

Table 2.3.4-2 (Cont'd)

SPEED RANGES (mph) -1:S/-0.5

DIRECTION	0-3 SUM	%	4-7 SUM	%	8-12 SUM	%	13-18 SUM	%	19-23 SUM	%	24+ SUM	%	ALL SPEEDS SUM	%
22.5	73	0.3	190	0.8	75	0.3	27	0.1	1	0.0	0	0.0	366	1.6
45.0	84	0.4	187	0.8	93	0.4	6	0.0	2	0.0	0	0.0	372	1.6
67.5	157	0.7	333	1.5	168	0.7	41	0.2	3	0.0	1	0.0	703	3.1
90.0	169	0.7	429	1.9	210	0.9	40	0.2	1	0.0	0	0.0	849	4.7
112.5	77	0.3	192	0.8	106	0.5	9	0.0	1	0.0	0	0.0	385	1.7
135.0	75	0.3	153	0.7	53	0.2	8	0.0	0	0.0	0	0.0	289	1.3
157.5	105	0.5	200	0.9	60	0.3	7	0.0	2	0.0	0	0.0	374	1.6
180.0	147	0.6	256	1.1	130	0.6	15	0.1	3	0.0	0	0.0	551	2.4
202.5	112	0.5	211	0.9	143	0.6	58	0.3	5	0.0	0	0.0	522	2.3
225.0	59	0.3	119	0.5	74	0.3	18	0.1	2	0.0	1	0.0	273	1.2
247.5	85	0.4	164	0.7	119	0.5	39	0.2	4	0.0	1	0.0	412	1.8
270.0	106	0.5	226	1.0	227	1.0	154	0.7	60	0.3	25	0.1	798	3.5
292.5	105	0.5	306	1.3	449	2.0	360	1.6	109	0.5	28	0.1	1357	5.9
315.0	64	0.3	147	0.6	290	1.3	283	1.2	63	0.3	4	0.0	851	3.7
337.5	78	0.3	127	0.6	205	0.9	94	0.4	11	0.0	1	0.0	516	.3
360.0	85	0.4	208	0.9	113	0.5	24	0.1	1	0.0	0	0.0	431	1.9
	1581/7.0		3448/15.0		2515/11.0		1183/ 5.2		268/1.1		61/ 0.2		9056/ 39.6	

Mean wind speed: 7.9

Number of uninterpretable hours: 10

Table 2.3.4-2 (Cont'd)

SPEED RANGES (mph) -0.4/1.5

	0-3		4-7		8-12		13-18		19-23		24+		ALL SPEEDS	
DIRECTION	SUM	%	SUM	%	SUM	%	SUM	%	SUM	%	SUM	%	SUM	%
22.5	105	0.5	90	0.4	14	0.1	4	0.0	0	0.0	0	0.0	213	0.9
45.0	115	0.5	86	0.4	11	0.0	0	0.0	0	0.0	1	0.0	213	0.9
67.5	175	0.8	105	0.5	25	0.1	6	0.0	6	0.0	5	0.0	322	1.4
90.0	260	1.1	196	0.9	50	0.2	15	0.1	0	0.0	0	0.0	521	2.3
112.5	168	0.7	142	0.6	27	0.1	9	0.0	0	0.0	0	0.0	346	1.5
135.0	175	0.8	142	0.6	16	0.1	8	0.0	0	0.0	0	0.0	341	1.5
157.5	179	0.8	159	0.7	22	0.1	7	0.0	3	0.0	0	0.0	370	1.6
180.0	218	1.0	237	1.0	68	0.3	7	0.0	1	0.0	0	0.0	531	2.3
202.5	149	0.7	149	0.7	66	0.3	19	0.1	1	0.0	0	0.0	384	1.7
225.0	133	0.6	119	0.5	44	0.2	19	0.1	2	0.0	0	0.0	317	1.4
247.5	129	0.6	115	0.5	32	0.1	3	0.0	1	0.0	0	0.0	280	1.2
270.0	194	0.9	184	0.8	60	0.3	19	0.1	6	0.0	1	0.0	464	2.0
292.5	251	1.1	419	1.8	200	0.9	48	0.2	21	0.1	0	0.0	939	4.1
315.0	212	0.9	315	1.4	134	0.6	38	0.2	8	0.0	0	0.0	707	3.1
337.5	152	0.7	145	0.6	67	0.3	13	0.1	0	0.0	0	0.0	377	1.7
360.0	126	0.6	140	0.6	40	0.2	3	0.0	0	0.0	0	0.0	309	1.4
	2741/12.3		2743/12.0		876/3.9		218/0.9		49/0.1		7/0.0		6634/29.0	

Mean wind speed: 5.0

Number of uninterpretable hours: 21

Table 2.3.4-2 (Cont'd)

SPEED RANGES (mph) 1:6/4.0

DIRECTION	0-3 SUM	%	4-7 SUM	%	8-12 SUM	%	13-18 SUM	%	19-23 SUM	%	24+ SUM	%	ALL SPEEDS SUM	%
22.5	217	1.0	19	0.1	2	0.0	0	0.0	0	0.0	0	0.0	238	1.0
45.0	217	1.0	18	0.1	0	0.0	0	0.0	0	0.0	0	0.0	235	1.0
67.5	238	1.0	15	0.1	0	0.0	0	0.0	0	0.0	0	0.0	253	1.1
90.0	313	1.4	25	0.1	3	0.0	0	0.0	0	0.0	0	0.0	341	1.5
112.5	245	1.1	27	0.1	1	0.0	0	0.0	0	0.0	0	0.0	273	1.2
135.0	226	1.0	22	0.1	0	0.0	1	0.0	0	0.0	0	0.0	249	1.1
157.5	220	1.0	23	0.1	0	0.0	1	0.0	0	0.0	0	0.0	244	1.1
180.0	233	1.0	11	0.0	5	0.0	0	0.0	0	0.0	0	0.0	249	1.1
202.5	197	0.9	18	0.1	0	0.0	0	0.0	0	0.0	0	0.0	215	0.9
225.0	206	0.9	10	0.0	2	0.0	0	0.0	0	0.0	0	0.0	218	1.0
247.5	209	0.9	12	0.1	1	0.0	0	0.0	0	0.0	0	0.0	222	1.0
270.0	242	1.1	27	0.1	2	0.0	0	0.0	0	0.0	0	0.0	271	1.2
292.5	318	1.4	74	0.3	7	0.0	1	0.0	0	0.0	0	0.0	400	1.8
315.0	286	1.3	69	0.3	1	0.0	0	0.0	0	0.0	0	0.0	356	1.6
337.5	214	0.9	26	0.1	3	0.0	0	0.0	1	0.0	0	0.0	244	1.1
360.0	214	0.9	28	0.1	0	0.0	0	0.0	0	0.0	0	0.0	242	1.1
	3795/16.8		424/ 1.8		27/ 0.0		3/ 0.0		1/ 0.0		0/ 0.0		4250/ 18.8	

Mean wind speed: 1.7

Number of uninterpretable hours: 8

Table 2.3.4-2 (Cont'd)

SPEED RANGES (mph) GT. 4.0

DIRECTION	0-3 SUM	0-3 %	4-7 SUM	4-7 %	8-12 SUM	8-12 %	13-18 SUM	13-18 %	19-23 SUM	19-23 %	24+ SUM	24+ %	ALL SPEEDS SUM	ALL SPEEDS %
22.5	15	0.1	1	0.0	0	0.0	0	0.0	0	0.0	0	0.0	16	0.1
45.0	24	0.1	1	0.0	0	0.0	0	0.0	0	0.0	0	0.0	25	0.1
67.5	40	0.2	4	0.0	0	0.0	0	0.0	0	0.0	0	0.0	44	0.2
90.0	41	0.2	2	0.0	0	0.0	0	0.0	0	0.0	0	0.0	43	0.2
112.5	25	0.1	1	0.0	0	0.0	0	0.0	0	0.0	0	0.0	26	0.1
135.0	23	0.1	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	23	0.1
157.5	11	0.0	1	0.0	0	0.0	0	0.0	0	0.0	0	0.0	12	0.1
188.0	8	0.0	3	0.0	0	0.0	0	0.0	0	0.0	0	0.0	11	0.0
205.5	7	0.0	1	0.0	0	0.0	0	0.0	0	0.0	0	0.0	8	0.0
225.0	8	0.0	1	0.0	0	0.0	0	0.0	0	0.0	0	0.0	9	0.0
247.5	17	0.1	1	0.0	0	0.0	0	0.0	0	0.0	0	0.0	18	0.1
270.0	44	0.2	5	0.0	0	0.0	0	0.0	0	0.0	0	0.0	49	0.2
292.5	65	0.3	10	0.0	3	0.0	0	0.0	0	0.0	0	0.0	78	0.3
315.0	43	0.2	10	0.0	0	0.0	0	0.0	0	0.0	0	0.0	53	0.2
337.5	26	0.1	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	26	0.1
360.0	21	0.1	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	21	0.1
	418/ 1.8		41/ 0.0		3/ 0.0		0/ 0.0		0/ 0.0		0/ 0.0		462/ 1.9	

Mean wind speed: 2.1

Number of uninterpretable hours: 4

Table 2.3.4-2 (Cont'd)

SPEED RANGES (mph) ALL STABILITIES

DIRECTION	0-3 SUM	%	4-7 SUM	%	8-12 SUM	%	13-18 SUM	%	19-23 SUM	%	24+ SUM	%	ALL SPEEDS SUM	%
22.5	419	1.8	327	1.4	109.	0.5	36	0.2	1.	0.0	0	0.0	892	3.9
45.0	449	2.0	311	1.4	108	0.5	8	0.0	2	0.0	1	0.0	879	3.9
67.5	624	2.7	489	2.1	207	0.9	47	0.2	9	0.0	6	0.0	1382	6.1
90.0	794	3.5	688	3.0	295	1.3	63	0.3	2	0.0	0	0.0	1842	8.1
112.5	526	2.3	384	1.7	150	0.7	20	0.1	1	0.0	0	0.0	1081	4.7
135.0	509	2.2	335	1.5	87	0.4	19	0.1	0	0.0	0	0.0	950	4.2
157.5	538	2.4	415	1.8	114	0.5	20	0.1	5	0.0	0	0.0	1092	4.8
180.0	640	2.8	576	2.5	267	1.2	28	0.1	4	0.0	0	0.0	1515	6.6
202.5	490	2.1	439	1.9	301	1.3	98	0.4	6	0.0	0	0.0	1334	6.1
225.0	426	1.9	295	1.3	171	0.7	48	0.2	4	0.0	1	0.0	945	4.1
247.5	474	2.1	366	1.6	211	0.9	57	0.2	5	0.0	1	0.0	1114	4.9
270.0	616	2.7	533	2.3	388	1.7	213	0.9	70	0.3	28	0.1	1848	8.1
292.5	756	3.3	907	4.0	829	3.6	553	2.4	166	0.7	30	0.1	3241	14.1
315.0	618	2.7	598	2.3	526	2.3	443	1.9	97	0.4	4	0.0	2286	10.0
337.5	477	2.1	328	1.4	331	1.5	150	0.7	18	0.1	1	0.0	1305	5.7
360.0	459	2.0	405	1.8	202	0.9	41	0.2	1	0.0	0	0.0	1103	4.9
	8815/38.6		7396/32.3		4296/18.9		1844/ 8.0		391/ 1.5		72/ 0.3		22814/100.2	

Mean wind speed: 5.9

Total number of uninterpretable hours: 47

Total number of calm hours: 2570, Percent: 11.3

Table 2.3.4-2 (Cont'd)

SPEED RANGES (mph) DIRECTION vs. SPEED

DIRECTION	0-3 SUM	%	4-7 SUM	%	8-12 SUM	%	13-18 SUM	%	19-23 SUM	%	24+ SUM	%	ALL SPEEDS SUM	%
22.5	431	1.8	334	1.4	113	0.5	37	0.5	2	0.0	0	0.0	917	3.8
45.0	459	1.9	334	1.4	113	0.5	8	0.0	2	0.0	1	0.0	917	3.8
67.5	642	2.6	507	2.1	211	0.9	47	0.2	9	0.0	6	0.0	1422	5.9
90.0	838	3.5	713	2.9	306	1.3	63	0.3	2	0.0	0	0.0	1922	7.9
112.5	556	2.3	413	1.7	160	0.7	20	0.1	2	0.0	0	0.0	1150	4.7
135.0	547	2.3	370	1.5	94	0.4	19	0.1	0	0.0	0	0.0	1030	4.2
157.5	563	2.3	442	1.8	122	0.5	21	0.1	5	0.0	0	0.0	1153	4.8
180.0	699	2.9	646	2.7	280	1.2	28	0.1	4	0.0	0	0.0	1657	6.8
202.5	549	2.3	490	2.0	326	1.3	98	0.4	6.	0.0	0	0.0	1469	6.1
225.0	481	2.1	346	1.4	182	0.8	49	0.2	5	0.0	1	0.0	1064	4.4
247.5	520	2.1	420	1.7	231	1.0	57	0.2	5	0.0	1	0.1	1234	5.1
270.0	663	2.7	594	2.5	417	1.7	217	0.9	71	0.3	28	0.1	1990	8.2
292.5	813	3.4	968	4.0	851	3.5	564	2.3	171	0.7	31	0.0	3398	14.0
315.0	673	2.8	647	2.7	545	2.2	468	1.9	101	0.4	6	0.0	2440	10.1
337.5	495	2.0	337	1.4	335	1.4	152	0.6	18	0.1	1	0.0	1336	5.5
360.0	471	1.9	415	1.7	206	0.8	42	0.2	1	0.0	0	0.0	1135	4.7
	9400/38.8		7976/32.9		4492/18.7		1890/ 7.8		403/ 1.5		75/ .2		24234/ 87.4	

Table 2.3.4-2 (Cont'd)

Mean wind speed: 5.8

Total number of uninterpretable hours: 55

Total number of calm hours: 2570, Percent: 10.6

Missing speeds: 1364 Percent: 5.6

Missing directions: 1586 Percent: 6.5

(1) Period of data: 1/72 - 12/74, data taken at 30 ft level
(2) The information in this Table is for historical purposes only

Table 2.3.4-3

LGS EFFECTIVE PROBABILITY LEVELS[1][2]

SECTOR	CONSERVATIVE (5%)	REALISTIC (50%)
SSW	8.0	80.0
SW	8.1	81.0
WSW	5.2	52.0
W	3.9	39.0
WNW	6.6	66.0
NW	7.5	75.0
NNW	6.5	65.0
N	4.7	47.0
NNE	5.3	53.0
NE	7.5	75.0
ENE	6.4	64.0
E	3.9	39.0
ESE	2.2	22.0
SE	3.1	31.0
SSE	5.5	55.0
S	6.4	64.0

(1) Calculated using 1972-1974 Tower 1 30 ft lapse rate wind distribution
(2) Information in this Table is for historical purposes only

Table 2.3.4-4

SUMMARY OF THE NORTH AND SOUTH STACKS MAXIMUM SECTOR AND 5% OVERALL SITE LIMIT X/Q VALUES AT THE EAB AND LPZ FOR REGULATORY POST-ACCIENT TIME PERIODS

RELEASE LOCATION	X/Q PARAMETER (sec/m^3)	0-2 hour	2-8 hour	8-24 hour	1-4 day	4-30 day
EAB (731 m)						
North and South Stacks*	**Direction-Specific Max**	**3.18E-04 (ESE)**	**1.76E-04 (ESE)**	**1.31E-04 (ESE)**	**6.89E-05 (ESE)**	**2.74E-05 (ESE)**
	Site Limit	2.79E-04	1.58E-04	1.19E-04	6.39E-05	2.63E-05
LPZ (2043 m)						
North and South Stacks*	**Direction-Specific Max**	**1.15E-04 (ESE)**	**5.79E-05 (ESE)**	**4.10E-05 (ESE)**	**1.95E-05 (ESE)**	**6.68E-06 (ESE)**
	Site Limit	1.01E-04	5.18E-05	3.71E-05	1.81E-05	6.41E-06

* The same PAVAN results apply to the North and South Stacks individually.

TABLE 2.3.4-5

LGS STABILITY AND WIND SPEED DISTRIBUTIONS[1]

Stability	1972-1974		1972-1976	
	Freq. (%)	Mean Speed (mph)	Freq. (%)	Mean Speed (mph)
A	1.4	9.0	2.2	8.3
B	2.9	9.0	3.4	9.1
C	6.2	8.8	6.2	9.0
D	39.7	7.9	38.1	8.0
E	29.1	5.0	29.7	5.1
F	18.6	1.7	18.3	1.7
G	2.0	2.1	2.1	2.0

(1) Information in this Table is for historical purposes only.

Table 2.3.5-1

HISTORICAL ANNUAL X/Q - UNCORRECTED

DISTANCE METERS	SECTOR BEARING (DEGREES) NNE 22.5	NE 45.0	ENE 67.5	E 90.0	ESE 112.5	SE 135.0	SSE 157.5	S 180.0
762.00				3.609×10^{-7}	6.291×10^{-7}	4.214×10^{-7}		1.411×10^{-7}
793.00	3.001×10^{-7}	2.111×10^{-7}	2.220×10^{-7}	3.486×10^{-7}	6.110×10^{-7}	3.979×10^{-7}		1.367×10^{-7}
800.00	2.972×10^{-7}	2.091×10^{-7}	2.197×10^{-7}	3.449×10^{-7}	6.050×10^{-7}	3.941×10^{-7}		1.358×10^{-7}
854.00	2.713×10^{-7}	1.959×10^{-7}	2.035×10^{-7}	3.182×10^{-7}	5.613×10^{-7}	3.708×10^{-7}		1.286×10^{-7}
884.00	2.611×10^{-7}	1.874×10^{-7}	1.963×10^{-7}	3.047×10^{-7}	5.366×10^{-7}	3.593×10^{-7}		1.270×10^{-7}
900.00	2.528×10^{-7}	1.836×10^{-7}	1.920×10^{-7}	2.978×10^{-7}	5.205×10^{-7}	3.578×10^{-7}		1.272×10^{-7}
1000.00	2.226×10^{-7}	1.583×10^{-7}	1.697×10^{-7}	2.442×10^{-7}	4.644×10^{-7}	3.251×10^{-7}		1.149×10^{-7}
1006.00	2.211×10^{-7}	1.572×10^{-7}	1.708×10^{-7}	2.589×10^{-7}	4.884×10^{-7}	3.394×10^{-7}	1.267×10^{-7}	1.142×10^{-7}
1200.00	1.780×10^{-7}	1.276×10^{-7}	1.344×10^{-7}	2.034×10^{-7}	3.914×10^{-7}	2.679×10^{-7}	1.096×10^{-7}	9.466×10^{-8}
1400.00	1.469×10^{-7}	1.050×10^{-7}	1.078×10^{-7}	1.630×10^{-7}	3.153×10^{-7}	2.136×10^{-7}	8.917×10^{-8}	7.913×10^{-8}
1600.00	1.242×10^{-7}	8.692×10^{-8}	8.841×10^{-8}	1.335×10^{-7}	2.594×10^{-7}	1.773×10^{-7}	7.569×10^{-8}	6.704×10^{-8}
1800.00	1.059×10^{-7}	7.457×10^{-8}	7.379×10^{-8}	1.114×10^{-7}	2.173×10^{-7}	1.484×10^{-7}	6.360×10^{-8}	5.802×10^{-8}
2000.00	9.004×10^{-8}	6.419×10^{-8}	6.254×10^{-8}	9.436×10^{-8}	1.847×10^{-7}	1.262×10^{-7}	5.420×10^{-8}	5.063×10^{-8}
2200.00	7.750×10^{-8}	5.531×10^{-8}	5.373×10^{-8}	8.098×10^{-8}	1.599×10^{-7}	1.086×10^{-7}	4.674×10^{-8}	4.417×10^{-8}
2400.00	6.746×10^{-8}	4.832×10^{-8}	4.674×10^{-8}	7.031×10^{-8}	1.391×10^{-7}	9.447×10^{-8}	4.073×10^{-8}	3.886×10^{-8}
2600.00	5.934×10^{-8}	4.278×10^{-8}	4.114×10^{-8}	6.169×10^{-8}	1.221×10^{-7}	8.298×10^{-8}	3.581×10^{-8}	3.444×10^{-8}
2800.00	5.273×10^{-8}	3.839×10^{-8}	3.663×10^{-8}	5.465×10^{-8}	1.082×10^{-7}	7.350×10^{-8}	3.175×10^{-8}	3.073×10^{-8}
3000.00	4.730×10^{-8}	3.491×10^{-8}	3.300×10^{-8}	4.888×10^{-8}	9.659×10^{-8}	6.559×10^{-8}	2.835×10^{-8}	2.760×10^{-8}
3200.00	4.284×10^{-8}	3.217×10^{-8}	3.098×10^{-8}	4.454×10^{-8}	8.689×10^{-8}	5.893×10^{-8}	2.548×10^{-8}	2.551×10^{-8}
3400.00	3.916×10^{-8}	3.002×10^{-8}	2.881×10^{-8}	4.072×10^{-8}	7.935×10^{-8}	5.327×10^{-8}	2.304×10^{-8}	2.311×10^{-8}
3600.00	3.726×10^{-8}	2.836×10^{-8}	2.892×10^{-8}	4.063×10^{-8}	7.255×10^{-8}	4.844×10^{-8}	2.094×10^{-8}	2.133×10^{-8}
3800.00	6.847×10^{-8}	2.709×10^{-8}	3.056×10^{-8}	3.857×10^{-8}	6.682×10^{-8}	4.429×10^{-8}	2.119×10^{-8}	1.991×10^{-8}
4000.00	2.659×10^{-7}	7.774×10^{-8}	3.873×10^{-8}	3.699×10^{-8}	6.200×10^{-8}	4.089×10^{-8}	3.021×10^{-8}	1.838×10^{-8}
4300.00	2.378×10^{-7}	7.581×10^{-8}	3.852×10^{-8}	3.532×10^{-8}	5.617×10^{-8}	3.646×10^{-8}	2.982×10^{-8}	1.889×10^{-8}
4600.00	2.141×10^{-7}	7.371×10^{-8}	3.840×10^{-8}	3.427×10^{-8}	5.169×10^{-8}	3.291×10^{-8}	2.962×10^{-8}	1.788×10^{-8}
4900.00	1.938×10^{-7}	7.149×10^{-8}	3.828×10^{-8}	3.365×10^{-8}	4.826×10^{-8}	3.006×10^{-8}	2.950×10^{-8}	1.718×10^{-8}
5200.00	1.764×10^{-7}	6.919×10^{-8}	3.812×10^{-8}	3.331×10^{-8}	4.565×10^{-8}	2.780×10^{-8}	2.942×10^{-8}	1.671×10^{-8}
5500.00	1.653×10^{-7}	6.685×10^{-8}	3.788×10^{-8}	3.315×10^{-8}	4.368×10^{-8}	2.600×10^{-8}	2.931×10^{-8}	1.642×10^{-8}
5800.00	1.516×10^{-7}	1.244×10^{-7}	3.757×10^{-8}	3.309×10^{-8}	4.219×10^{-8}	2.458×10^{-8}	2.917×10^{-8}	2.574×10^{-8}
6100.00	1.395×10^{-7}	1.228×10^{-7}	3.718×10^{-8}	3.308×10^{-8}	4.107×10^{-8}	2.346×10^{-8}	2.899×10^{-8}	3.282×10^{-8}
6400.00	1.289×10^{-7}	1.136×10^{-7}	5.750×10^{-8}	3.307×10^{-8}	4.372×10^{-8}	2.260×10^{-8}	2.875×10^{-8}	3.239×10^{-8}
6700.00	1.195×10^{-7}	1.055×10^{-7}	5.546×10^{-8}	3.306×10^{-8}	4.738×10^{-8}	2.193×10^{-8}	2.846×10^{-8}	3.190×10^{-8}
7000.00	1.111×10^{-7}	9.824×10^{-8}	5.348×10^{-8}	3.301×10^{-8}	5.183×10^{-8}	2.142×10^{-8}	2.812×10^{-8}	3.138×10^{-8}
7300.00	1.036×10^{-7}	9.173×10^{-8}	6.226×10^{-8}	3.292×10^{-8}	6.287×10^{-8}	2.103×10^{-8}	3.778×10^{-8}	3.081×10^{-8}
7600.00	9.691×10^{-8}	8.588×10^{-8}	5.944×10^{-8}	3.279×10^{-8}	7.550×10^{-8}	2.074×10^{-8}	4.380×10^{-8}	3.022×10^{-8}

Note: Data calculated in Table 2.3.5-1 is based on three sources (Turbine Enclosure vent, Units 1 and 2 Reactor Enclosure vents) treated as a single source originating from one point located midway between the three locations.

Table 2.3.5-1 (Cont'd)

DISTANCE	SECTOR BEARING (DEGREES)							
	NNE	NE	ENE	E	ESE	SE	SSE	S
METERS	22.5	45.0	67.5	90.0	112.5	135.0	157.5	180.0
7900.00	9.085×10^{-8}	8.059×10^{-8}	7.968×10^{-8}	4.906×10^{-8}	7.400×10^{-8}	2.419×10^{-8}	4.223×10^{-8}	2.961×10^{-8}
8200.00	8.537×10^{-8}	7.579×10^{-8}	7.494×10^{-8}	4.803×10^{-8}	7.248×10^{-8}	2.633×10^{-8}	4.071×10^{-8}	2.898×10^{-8}
8500.00	8.039×10^{-8}	7.143×10^{-8}	7.167×10^{-8}	4.698×10^{-8}	7.094×10^{-8}	2.622×10^{-8}	3.925×10^{-8}	2.834×10^{-8}
8800.00	7.585×10^{-8}	6.745×10^{-8}	6.763×10^{-8}	4.593×10^{-8}	6.939×10^{-8}	6.262×10^{-8}	3.785×10^{-8}	5.850×10^{-8}
12073.00	4.454×10^{-8}	3.982×10^{-8}	3.974×10^{-8}	3.512×10^{-8}	8.582×10^{-8}	4.758×10^{-8}	3.519×10^{-8}	3.509×10^{-8}
16098.00	2.734×10^{-8}	2.453×10^{-8}	2.442×10^{-8}	2.542×10^{-8}	5.403×10^{-8}	3.275×10^{-8}	2.162×10^{-8}	2.156×10^{-8}
24146.00	1.370×10^{-8}	1.234×10^{-8}	1.225×10^{-8}	1.477×10^{-8}	2.770×10^{-8}	1.884×10^{-8}	1.085×10^{-8}	1.081×10^{-8}
32195.00	8.381×10^{-9}	7.558×10^{-9}	7.495×10^{-9}	1.080×10^{-8}	1.711×10^{-8}	1.272×10^{-8}	6.639×10^{-9}	6.617×10^{-9}
40244.00	5.720×10^{-9}	5.164×10^{-9}	5.118×10^{-9}	7.409×10^{-9}	1.174×10^{-8}	8.693×10^{-9}	4.534×10^{-9}	4.518×10^{-9}
48293.00	4.186×10^{-9}	3.782×10^{-9}	3.747×10^{-9}	5.439×10^{-9}	8.624×10^{-9}	6.365×10^{-9}	3.319×10^{-9}	3.307×10^{-9}
56342.00	3.214×10^{-9}	2.908×10^{-9}	2.878×10^{-9}	4.185×10^{-9}	6.638×10^{-9}	4.890×10^{-9}	2.549×10^{-9}	2.540×10^{-9}
64390.00	2.557×10^{-9}	2.314×10^{-9}	2.290×10^{-9}	3.334×10^{-9}	5.289×10^{-9}	3.891×10^{-9}	2.028×10^{-9}	2.021×10^{-9}
72439.00	2.089×10^{-9}	1.891×10^{-9}	1.871×10^{-9}	2.728×10^{-9}	4.328×10^{-9}	3.181×10^{-9}	1.658×10^{-9}	1.652×10^{-9}
80488.00	1.744×10^{-9}	1.579×10^{-9}	1.562×10^{-9}	2.279×10^{-9}	3.616×10^{-9}	2.656×10^{-9}	1.384×10^{-9}	1.379×10^{-9}

Table 2.3.5-1 (Cont'd)

DISTANCE METERS	SECTOR BEARING (DEGREES) SSW 202.5	SW 225.0	WSW 247.5	W 270.0	WNW 292.5	NW 315.0	NNW 337.5	N 360.0
762.00	1.125×10^{-7}					1.213×10^{-7}		
793.00	1.090×10^{-7}				1.173×10^{-7}	1.175×10^{-7}		
800.00	1.082×10^{-7}				1.164×10^{-7}	1.166×10^{-7}		
854.00	1.024×10^{-7}		1.259×10^{-7}	1.797×10^{-7}	1.109×10^{-7}	1.103×10^{-7}		
884.00	9.924×10^{-8}	9.285×10^{-8}	1.246×10^{-7}	1.743×10^{-7}	1.092×10^{-7}	1.069×10^{-7}	1.572×10^{-7}	2.680×10^{-9}
900.00	9.762×10^{-8}	9.255×10^{-8}	1.242×10^{-7}	1.726×10^{-7}	1.075×10^{-7}	1.051×10^{-7}	1.628×10^{-7}	2.614×10^{-7}
1000.00	8.815×10^{-8}	8.505×10^{-8}	1.128×10^{-7}	1.564×10^{-7}	9.830×10^{-8}	1.007×10^{-7}	1.447×10^{-7}	2.378×10^{-7}
1006.00	8.904×10^{-8}	8.664×10^{-8}	1.142×10^{-7}	1.575×10^{-7}	1.004×10^{-7}	1.001×10^{-7}	1.437×10^{-7}	2.362×10^{-7}
1200.00	7.555×10^{-8}	7.203×10^{-8}	9.601×10^{-8}	1.326×10^{-7}	8.233×10^{-8}	8.161×10^{-8}	1.162×10^{-7}	1.923×10^{-7}
1400.00	6.391×10^{-8}	6.084×10^{-8}	7.992×10^{-8}	1.139×10^{-7}	6.808×10^{-8}	6.720×10^{-8}	9.513×10^{-8}	1.585×10^{-7}
1600.00	5.497×10^{-8}	5.249×10^{-8}	6.746×10^{-8}	1.004×10^{-7}	5.711×10^{-8}	5.619×10^{-8}	7.920×10^{-8}	1.340×10^{-7}
1800.00	4.661×10^{-8}	4.491×10^{-8}	5.765×10^{-8}	8.764×10^{-8}	4.853×10^{-8}	4.860×10^{-8}	6.797×10^{-8}	1.144×10^{-7}
2000.00	4.140×10^{-8}	3.879×10^{-8}	5.259×10^{-8}	7.606×10^{-8}	4.173×10^{-8}	4.166×10^{-8}	5.803×10^{-8}	9.798×10^{-8}
2200.00	3.577×10^{-8}	3.353×10^{-8}	4.558×10^{-8}	6.833×10^{-8}	3.624×10^{-8}	3.603×10^{-8}	5.011×10^{-8}	8.479×10^{-8}
2400.00	3.122×10^{-8}	2.927×10^{-8}	4.019×10^{-8}	6.013×10^{-8}	3.226×10^{-8}	3.148×10^{-8}	4.372×10^{-8}	7.408×10^{-8}
2600.00	2.748×10^{-8}	2.578×10^{-8}	3.543×10^{-8}	5.332×10^{-8}	2.860×10^{-8}	2.774×10^{-8}	3.849×10^{-8}	6.527×10^{-8}
2800.00	2.439×10^{-8}	2.288×10^{-8}	3.148×10^{-8}	4.760×10^{-8}	2.541×10^{-8}	2.464×10^{-8}	3.438×10^{-8}	5.826×10^{-8}
3000.00	2.201×10^{-8}	2.046×10^{-8}	2.818×10^{-8}	4.276×10^{-8}	2.273×10^{-8}	2.204×10^{-8}	3.080×10^{-8}	5.212×10^{-8}
3200.00	1.980×10^{-8}	1.841×10^{-8}	2.538×10^{-8}	3.917×10^{-8}	2.046×10^{-8}	1.984×10^{-8}	2.782×10^{-8}	4.695×10^{-8}
3400.00	1.825×10^{-8}	1.691×10^{-8}	2.302×10^{-8}	3.557×10^{-8}	1.852×10^{-8}	1.797×10^{-8}	2.534×10^{-8}	4.259×10^{-8}
3600.00	1.673×10^{-8}	1.545×10^{-8}	2.100×10^{-8}	3.247×10^{-8}	1.685×10^{-8}	1.637×10^{-8}	2.328×10^{-8}	4.088×10^{-8}
3800.00	1.545×10^{-8}	1.422×10^{-8}	1.928×10^{-8}	2.981×10^{-8}	1.541×10^{-8}	1.500×10^{-8}	2.156×10^{-8}	4.162×10^{-8}
4000.00	1.546×10^{-8}	1.441×10^{-8}	1.790×10^{-8}	2.785×10^{-8}	1.424×10^{-8}	1.391×10^{-8}	2.082×10^{-8}	3.974×10^{-8}
4300.00	1.445×10^{-8}	1.344×10^{-8}	1.683×10^{-8}	2.732×10^{-8}	1.266×10^{-8}	1.248×10^{-8}	5.400×10^{-8}	5.744×10^{-8}
4600.00	1.644×10^{-8}	1.277×10^{-8}	1.741×10^{-8}	2.554×10^{-8}	1.139×10^{-8}	1.137×10^{-8}	1.250×10^{-7}	1.981×10^{-7}
4900.00	2.085×10^{-8}	1.233×10^{-8}	2.016×10^{-8}	2.424×10^{-8}	1.112×10^{-8}	1.298×10^{-8}	1.574×10^{-7}	2.298×10^{-7}
5200.00	2.091×10^{-8}	1.206×10^{-8}	5.689×10^{-8}	3.050×10^{-8}	1.047×10^{-8}	1.274×10^{-8}	1.443×10^{-7}	2.087×10^{-7}
5500.00	3.165×10^{-8}	2.185×10^{-8}	7.434×10^{-8}	3.019×10^{-8}	9.991×10^{-9}	1.266×10^{-8}	1.328×10^{-9}	1.905×10^{-7}
5800.00	7.095×10^{-8}	2.487×10^{-8}	7.062×10^{-8}	2.998×10^{-8}	9.656×10^{-9}	2.788×10^{-8}	1.226×10^{-7}	1.746×10^{-7}
6100.00	8.894×10^{-8}	5.539×10^{-8}	6.712×10^{-8}	2.983×10^{-8}	9.432×10^{-9}	5.957×10^{-8}	1.239×10^{-7}	1.607×10^{-7}
6400.00	8.250×10^{-8}	6.102×10^{-8}	6.382×10^{-8}	5.895×10^{-8}	9.295×10^{-9}	8.396×10^{-8}	1.145×10^{-7}	1.485×10^{-7}
6700.00	7.675×10^{-8}	5.743×10^{-8}	6.072×10^{-8}	1.320×10^{-7}	9.225×10^{-9}	9.620×10^{-8}	1.062×10^{-7}	1.376×10^{-7}
7000.00	7.161×10^{-8}	5.723×10^{-8}	5.781×10^{-8}	1.227×10^{-7}	9.204×10^{-9}	9.624×10^{-8}	9.875×10^{-8}	1.280×10^{-7}
7300.00	6.698×10^{-8}	6.264×10^{-8}	5.508×10^{-8}	1.145×10^{-7}	9.220×10^{-9}	8.979×10^{-8}	9.212×10^{-8}	1.194×10^{-7}
7600.00	6.281×10^{-8}	5.861×10^{-8}	6.745×10^{-8}	1.071×10^{-7}	9.261×10^{-9}	8.400×10^{-8}	8.616×10^{-8}	1.116×10^{-7}
7900.00	5.903×10^{-8}	5.497×10^{-8}	6.879×10^{-8}	1.004×10^{-7}	9.318×10^{-9}	7.877×10^{-8}	8.079×10^{-8}	1.047×10^{-7}
8200.00	5.559×10^{-8}	5.167×10^{-8}	6.569×10^{-8}	9.434×10^{-8}	9.384×10^{-9}	7.404×10^{-8}	7.593×10^{-8}	9.835×10^{-8}
8500.00	5.245×10^{-8}	4.867×10^{-8}	6.187×10^{-8}	8.885×10^{-8}	9.453×10^{-9}	6.974×10^{-8}	7.151×10^{-8}	9.261×10^{-8}
8800.00	5.135×10^{-8}	4.610×10^{-8}	5.839×10^{-8}	8.386×10^{-8}	5.645×10^{-9}	6.582×10^{-8}	6.749×10^{-8}	8.738×10^{-8}
12073.00	3.019×10^{-8}	2.710×10^{-8}	3.431×10^{-8}	4.927×10^{-8}	3.489×10^{-9}	3.874×10^{-8}	3.968×10^{-8}	5.131×10^{-8}

Table 2.3.5-1 (Cont'd)

DISTANCE METERS	SSW 202.5	SW 225.0	WSW 247.5	W 270.0	WNW 292.5	NW 315.0	NNW 337.5	N 360.0
				SECTOR BEARING (DEGREES)				
16098.00	1.855×10^{-8}	1.665×10^{-8}	2.108×10^{-8}	3.027×10^{-8}	2.145×10^{-9}	2.383×10^{-8}	2.439×10^{-8}	3.150×10^{-8}
24146.00	9.310×10^{-9}	8.355×10^{-9}	1.057×10^{-8}	1.518×10^{-8}	1.077×10^{-9}	1.197×10^{-8}	1.224×10^{-8}	1.579×10^{-8}
32195.00	5.698×10^{-9}	5.114×10^{-9}	6.470×10^{-9}	9.290×10^{-9}	6.596×10^{-9}	7.331×10^{-9}	7.490×10^{-9}	9.654×10^{-9}
40244.00	3.892×10^{-9}	3.492×10^{-9}	4.418×10^{-9}	6.343×10^{-9}	4.506×10^{-9}	5.009×10^{-9}	5.115×10^{-9}	6.589×10^{-9}
48293.00	2.850×10^{-9}	2.557×10^{-9}	3.234×10^{-9}	4.644×10^{-9}	3.300×10^{-9}	3.669×10^{-9}	3.745×10^{-9}	4.822×10^{-9}
56342.00	2.189×10^{-9}	1.964×10^{-9}	2.484×10^{-9}	3.567×10^{-9}	2.536×10^{-9}	2.819×10^{-9}	2.877×10^{-9}	3.703×10^{-9}
64390.00	1.742×10^{-9}	1.563×10^{-9}	1.977×10^{-9}	2.838×10^{-9}	2.018×10^{-9}	2.244×10^{-9}	2.289×10^{-9}	2.945×10^{-9}
72439.00	1.424×10^{-9}	1.277×10^{-9}	1.616×10^{-9}	2.319×10^{-9}	1.650×10^{-9}	1.835×10^{-9}	1.871×10^{-9}	2.407×10^{-9}
80488.00	1.189×10^{-9}	1.066×10^{-9}	1.349×10^{-9}	1.936×10^{-9}	1.378×10^{-9}	1.532×10^{-9}	1.562×10^{-9}	2.009×10^{-9}

Table 2.3.5-2

LGS VENT PARAMETERS

PARAMETER	REACTOR ENCLOSURE VENT	TURBINE ENCLOSURE VENT	COMPOSITE VENT
Vent diameter (m)	3.4	5.3	4.7
Exit velocity (m/sec)	11.9	9.7	10.4
Volumetric flow rate (m^3/sec)	110.5	216.4	181.0

2.4 HYDROLOGIC ENGINEERING

2.4.1 HYDROLOGIC DESCRIPTION

2.4.1.1 Site and Facilities

LGS is located in southeastern Pennsylvania on the Schuylkill River, about 1.7 miles southeast of the limits of the Borough of Pottstown and about 20.7 miles northwest of the Philadelphia city limits. The Schuylkill River passes through the site and separates the western portion, which is located in East Coventry Township, Chester County, from the eastern portion, which is partly in Limerick Township and partly in Lower Pottsgrove Township, both in Montgomery County, Pennsylvania. All of the major plant structures are located in Limerick Township. The location of the site and major plant structures with respect to the surrounding topography is shown in Figure 2.4-1.

The natural ground elevations vary from 110 feet MSL at the Schuylkill River to 280 feet MSL at the highest site elevation. The access elevations of major safety-related structures are listed in Table 2.4-1. Safety-related structures are shown in Figure 3.8-58. Because the topography of the site is such that storm water will flow away from safety-related equipment and structures, site grading is not considered safety-related.

Schuylkill River flooding and flooding that is due to the PMP falling on the plant area are discussed in Sections 2.4.2 and 2.4.3.

2.4.1.2 Hydrosphere

2.4.1.2.1 Hydrologic Characteristics

The plant site is located on the east bank of the Schuylkill River at latitude 40° 13' 3" N, longitude 75° 35' 15" W, approximately 5.5 river miles downstream from Pottstown, Pennsylvania. The drainage area at this point is 1168 square miles, with river bed elevations ranging from about 105 feet MSL at the site to about 1750 feet MSL near the headwaters.

The watershed of the Schuylkill River (Figure 2.4-2) lies entirely in southeastern Pennsylvania. The basin is about 80 miles long by 25 miles wide and encompasses an area of 1909 square miles above its confluence with the Delaware River at Philadelphia. The principal towns and cities along the course of the river are Pottsville, Reading, Pottstown, Phoenixville, Norristown, Conshohocken, and Philadelphia.

To determine the discharge characteristics at the site, it is assumed that the flows at Pottstown and at the site are identical, since the drainage area at the site is less than 2% greater than that at the Pottstown gauging station.

The dominant hydrologic feature in the area is the Schuylkill River, which furnishes part of the project's water requirements and receives its effluents. The principal uses of the Schuylkill River are municipal and industrial water supply. The river is also used for recreational fishing and boating.

In the vicinity of the site, the Schuylkill is a meandering stream of quite gentle slope (2-2½ feet/mile), flanked by floodplains that consist of about 10% built-up areas, 30% thick forest growth, and 60% cultivated or fallow fields.

In about 1947, a massive cleanup project was started on the Schuylkill to remove the silt and debris deposited in the channel by many years of coal mining operations upstream. Physical features (stilling basins, dredged material, impounding basins, and initial channel dredging) were essentially completed by the end of 1950. Maintenance dredging will continue on an as-needed basis whenever the desilting pools become one-half full.

As for future developments along this portion of the river, no additional construction is planned downstream of the plant site, other than the project's own cooling water pumping station. Because of the width of the river at this point, the new pumping station would have no significant effect on the flood levels. Some channel improvement is planned for a 2 mile stretch of the river at Pottstown for small craft navigability and flood crest reduction, but this will have no effect on the flood levels at the plant site.

The extreme instantaneous and average daily flows of record at the Pottstown gauging station are:

	Flow (cfs)	Date
Minimum (instantaneous)	87	August 13, 1930
Average	1,793	October 1926- September 1969
Maximum (instantaneous)	95,900	June 1972

As discussed in Section 2.4.3, the PMF on the Schuylkill River is conservatively estimated at 500,000 cfs, using Appendix B of Regulatory Guide 1.59 (Rev 2). The corresponding stage is estimated at el 174'. If it is also assumed that Ontelaunee Dam would fail under a maximum probable flood condition, the resulting stage would be increased to el 181', without wind.

2.4.1.2.2 Existing and Proposed Water-Control Structures

Figure 2.4-3 shows the location of 23 small dams upstream of LGS. Heights, volumes, and drainage areas are given in Table 2.4-2. None of these dams are close enough and large enough to threaten LGS in event of failure.

There are three significant water-control structures upstream of LGS that are either in existence or in planning at the present time. They are the Ontelaunee, Blue Marsh, and Maiden Creek dams. Their locations are also given in Figure 2.4-3, and their general design characteristics are summarized in Table 2.4-3 and discussed in detail in Section 2.4.4. Ontelaunee Dam is owned by the city of Reading and is used for water supply and recreation. Blue Marsh Dam is a federally owned structure constructed (1979) by the U.S. Army Corps of Engineers. Plans for construction of Maiden Creek Dam, an authorized U.S. Army Corps of Engineers project, have been indefinitely deferred and the project is considered inactive at this time.

In Section 2.4.4, it is shown that a flood wave resulting from the failure of these three dams would result in a maximum transient water level of 201 feet, if the simultaneous crest of the Schuylkill River's SPF is assumed. The 1% wave from a 40 mph wind would have a run-up of less than 6.4 feet, so that the maximum instantaneous water surface from the combined event would theoretically be el 207'. However, conservative approaches used throughout the estimation procedure ensure that, in fact, the actual maximum water surface that is due to such an event would certainly be less

than el 207'. About 3.3 miles downstream of the plant site lies Vincent Dam - an older, free overflow, rock-filled timber crib structure about 12 feet high, with a crest elevation of 103.5 feet. The dam is used now for water supply (1.5 million gallons per day) by Home Water Company and is also used as a sediment trap and recreation pool. Since the thalweg of the Schuylkill is at el 102' to el 104' in the vicinity of the pumping station, there may be a small backwater effect at LGS. However, the Schuylkill River pumping station is not a safety-related facility, so that loss of tail-water due to a failure of Vincent Dam does not impair safety-related water supplies.

2.4.1.2.3 Surface Water Users Whose Intakes Could Be Adversely Affected by the Accidental Release of Contaminants

Figure 2.4-2 shows the location of surface water users on the Schuylkill River between the site and the river mouth in Philadelphia. Domestic users, as classified by the Delaware River Basin Commission (Reference 2.4-1), are listed in Table 2.4-4, together with 1971 actual use and consumptive use details of individual entitlements. Similar information is presented in Table 2.4-5 for industrial users. Groundwater users are discussed in Section 2.4.13.2.

2.4.2 FLOODS

2.4.2.1 Flood History

Flood history is discussed in detail in Section 2.4.3.5.2. Table 2.4-6 shows peak recorded flows at several stations in the Schuylkill Basin. Historically, the greatest recorded flood at Pottstown was due to Hurricane Agnes in 1972; however, according to Philadelphia records, there may have been greater floods before the beginning of the Pottstown record. None of the historic floods on the Schuylkill River (Section 2.4.3.5.2) was caused by ice jams or landslides. Surges, seiches, and tsunamis are not relevant to the LGS site. The consequences of the failures of upstream dams are discussed in Section 2.4.4.

2.4.2.2 Flood Design Considerations

The DBFL with respect to the Schuylkill River is conservatively estimated at el 207'. This stage is derived from an SPF, combined with the wave crests from three simultaneous dam breaks and the 1% wave run-up generated by a 40 mph wind. Without the wave, the maximum level is estimated at el 201'. The three dams are Ontelaunee, Blue Marsh, and Maiden Creek (in the early planning stage). The derivation of this flood is discussed in Section 2.4.4.

The lowest grade level entrance to any safety-related structure is at el 217', which is 10 feet above the DBFL. Therefore, Schuylkill River floods cannot affect any of the safety-related facilities.

The Schuylkill River PMF is conservatively estimated at 500,000 cfs, based on Appendix B of Regulatory Guide 1.59 (Rev 2). When combined with a simultaneous dam break flood wave due to a PMF-induced failure of Ontelaunee Dam, the highest stage obtained at LGS was el 181' (without wind-wave). This is well below the stage obtained from the multiple dam break, as given above. The Schuylkill River PMF is discussed in detail in Section 2.4.3.

The water surface (el 201') resulting from the dam break analysis is transient. It is estimated that the time required for the dam break flood wave at the river cross-section at LGS to rise above and subside back to the SPF elevation (152 feet) is approximately 7.5 hours. The length of time for which the flood wave will be above el 177' and el 195' would be about 4.5 and 2 hours, respectively.

The shortest distance from the el 201' (dam break flood elevation without wave run-up) contour to the nearest safety-related structure inland (diesel oil storage tanks) is about 126 feet. The foundation of these structures is at el 194'. For flood waters to reach these structures, percolation through the embankment would have to occur. An analysis of the percolation was made using the following equation, assuming that Darcy's law is valid and that flow is one-dimensional:

$$\bar{b}\,\frac{\partial^2 b}{\partial x^2} + \frac{\partial z}{\partial x}\cdot\frac{\partial b}{\partial x} = \frac{n}{k}\cdot\frac{\partial b}{\partial t} \qquad \text{(EQ.2.4-1)}$$

where:

$b(x,t)$ = saturated thickness

$\bar{b}$ = average saturated thickness

k = hydraulic conductivity

n = porosity

$z(x)$ = elevation of base of porous medium

Subject to the following conditions:

$b(0,t) = H_o$

$b(x,0) = 0$

where:

H_o = the available head at $x = 0$

It can be shown that the solution to the above equation can be written in the form:

$$b = \frac{H_o}{2}\, e^{-2cx} \cdot \operatorname{erfc}\left[\frac{x}{2\alpha\sqrt{t}} - \frac{c}{\alpha}\sqrt{t}\right] + \operatorname{erfc}\left[\frac{x}{2\alpha\sqrt{t}} + \frac{c}{\alpha}\sqrt{t}\right] \qquad \text{(EQ. 2.4-2)}$$

where:

$$\alpha^2 = \frac{k\bar{b}}{n}$$

$$c = \frac{a}{2\bar{b}}$$

a = slope of the base of the porous medium

The base of the porous medium (base of embankment material) was assumed to rise linearly from el 170' at the toe of the embankment to el 194' at the tanks. The results of the analysis indicate that, if a conservative permeability of $5x10^4$ ft/yr is assumed and if the flood crest remains at el 202' (Section 2.4.3 shows maximum flood elevation of 201 feet) for a duration of two hours, groundwater would not be above el 194' anywhere within 80 feet of the tanks. Therefore the dam break flood wave would not affect hydrostatic pressures on the foundations of safety-related structures.

2.4.2.3 Effects of Local Intense Precipitation

The latest updated estimate (1976) of point (10 square miles) PMP was obtained from the NOAA (Reference 2.4-2). In the updating, which was subsequent to Hurricane Agnes, relatively small increases were made compared to pre-Agnes PMP estimates from Reference 2.4-3. The updated values are given in Table 2.4-7.

As explained later, the impact of the onsite PMP was analyzed by dividing the site area into smaller subareas. For this purpose, the 72 hour PMP was divided into 6 hour increments using the distribution given in Reference 2.4-2. The 6 hour PMP was divided into 1 hour increments using the U.S. Army Corps of Engineers distribution for standard project storms (Reference 2.4-4). These distributions are shown in Table 2.4-7. The 1 hour PMP was further subdivided into 5, 10, and 15 minute increments using the distribution given in Reference 2.4-29.

To estimate the peak run-off from each subarea, the rational formula was conservatively used:

$$Q = CIA \qquad \text{(EQ. 2.4-3)}$$

where:

Q = peak flow rate in cfs

C = run-off coefficient

I = rain fall intensity in inches/hour corresponding to a duration equal to the time of concentration, and

A = area in acres.

The run-off coefficient, C, was conservatively assumed to be 1. Kirpich's formula (Reference 2.4-34) was used to estimate the times of concentration for different subareas.

To obtain conservative results, the following assumptions were used in the analysis:

a. The site drainage system was assumed to be completely blocked.

b. It was assumed that storage due to ponding did not attenuate the outflow rate from any of these subareas.

c. Rating curves for flow over embankments or roadways were developed using the following equation for critical flow, based on the principle of minimum specific energy (Reference 2.4-33):

$$Q = (gA^3/\alpha\, T)^{1/2} \qquad \text{(EQ. 2.4-4)}$$

where:

Q = discharge in cfs

g = gravitational constant; 32.2 ft/sec^2

A = cross-sectional area, ft^2

T = top width of section, ft

α = energy coefficient, conservatively assumed to be 1.38, based on the ratio of broad-crested to sharp-crested weir coefficients

d. For simplicity, the rating curve for CP-1 was developed using the following weir equation (Reference 2.4-33)

$$Q = CLH^{3/2} \qquad \text{(EQ. 2.4-5)}$$

where:

Q = discharge in cfs

L = crest length, 35 feet

H = height of water above crest, ft

C = weir coefficient, conservatively assumed to be 2.63

As shown in Figures 2.4-4 and 2.4-5, the plant site is divided into three main functional areas:

a. The turbine-reactor complex area, at el 217'

b. The cooling tower area, at el 257' to el 265'

c. The spray pond area

The cooling tower area is the highest of the three main functional areas and is located to the north of the turbine-reactor complex area. The spray pond is located north of the cooling tower area but is separated from it by approximately 300 feet. The intervening land rises (Figure 2.4-5) to a hilltop at el 285', about 800 feet east of the north-south plant centerline (E4000). Run-off from this hilltop would be directed partly to the cooling tower area; partly to the spray pond area; partly to Possum Hollow Run; partly to the turbine-reactor complex area; and partly to Sanatoga Creek. Sanatoga Creek is not shown on Figures 2.4-4 or 2.4-5. It is located north of the spray pond area and drains to the Schuylkill River upstream of the plant site. Figure 2.4-11 shows the confluence of Sanatoga Creek with the Schuylkill River near Sanatoga.

Run-off from the three main functional areas drains toward several low points, which in turn drain away from the site. Numerous local drains and small surface ditches have been provided in the site drainage system to facilitate the drainage of normal storm run-off. However, as noted above, for the investigation of onsite PMP, none of these drainage facilities is assumed to function, except for the open-channel portion of a ditch draining the cooling tower area. Otherwise, all flow is assumed to be surface flow, over land or over roadway. All drain pipes and culverts are assumed plugged.

The impact of a PMF in the Possum Hollow Run, which passes along the eastern and southern sides of the site area, is examined in Section 2.4.2.3.5. The impact of a PMF in the Sanatoga Creek is discussed in the following paragraph.

Sanatoga Creek drains an area of less than 10 square miles. With respect to the plant site, the nearest point on the creek is approximately 1400 feet upstream of its confluence with the Schuylkill River. At this location, the thalweg of the creek is approximately at el 127'. As shown in Figure 2.4-4, the spray pond is located mostly within the Sanatoga Creek Basin. The cooling towers are located on a ridge that rises in an ENE direction and separates them from the spray pond area. The same ridge forms the drainage boundary between Sanatoga Creek and Possum Hollow Run and isolates the turbine-reactor area from Sanatoga Creek. The lowest elevation in the vicinity of the spray pond is el 240', and the crest of the spray pond spillway is at el 251'. The SPF elevation of the Schuylkill River near its confluence with the Sanatoga Creek is estimated to be 155 feet. It is inconceivable that the water surface elevation in Sanatoga Creek, with backwater that is due to a concurrent SPF in the Schuylkill River, would rise higher than el 240', which is 113 feet above the creek thalweg and 85 feet above the SPF elevation of Schuylkill River. For reasons given in Section 2.4.3.5, it is considered unlikely that a PMF on the Schuylkill River would coincide with a PMF on the Sanatoga Creek. Therefore, it was concluded that a PMF in Sanatoga Creek would not endanger safety-related structures, and further detailed analysis was not considered necessary.

The following sections describe flow-routing assumptions, drainage areas, and the water surface elevations resulting from a PMP on the site area. Table 2.4-22 summarizes the drainage characteristics, probable maximum rainfall intensity for the critical duration and the resulting peak discharge for each of the subareas.

2.4.2.3.1 Drainage from Cooling Tower Area

As shown in Figure 2.4-5, the cooling tower area and nearby natural topography are divided into three drainage areas, designated as DA-2, DA-3, and DA-4.

Area Designation	Area (Acres)	Peak Discharge (cfs)
DA-2	25.0	620

DA-3	4.5	151
DA-4	20.8	550

2.4.2.3.1.1 Drainage Area DA-2

The run-off from DA-2 collects in part at the road junction at el 258.8', located at the northern central part of the cooling tower area. This point is designated as CP-1 (collection point-1) on detail 3 in Figure 2.4-6. From CP-1, the run-off drains westward along the roadway and the adjacent ditch and picks up run-off from the remainder of DA-2. Finally, the entire run-off from DA-2 passes through a low point in the roadway (CP-2) and enters a ravine that drains to the Schuylkill River (detail 4 in Figure 2.4-6). To the south of CP-2, the access roadway, which partly encircles the Unit 1 cooling tower, rises to a high point that forms the boundary between DA-2 and DA-3.

The most important aspect of drainage from DA-2 is the height to which water is ponded against the roadway fill that spans the distance between the two cooling towers on their south flank. This fill has a nominal top of el 264'. As long as run-off from DA-2 follows the route described and does not overtop this roadway fill, it need not be added to the flows entering the turbine-reactor complex area.

To estimate the maximum water depth against this embankment, it is conservatively assumed that all the run-off from DA-2 collects at CP-1 and passes through critical depth over a conservatively assumed effective flow width of 35 feet. Critical depth must occur at this point, since flow into the ditch downstream is supercritical. This is shown in section E-E' on detail 3 in Figure 2.4-6 which shows the assumed effective width and the discharge rating curve for CP-1. The discharge rating curve was developed using a weir coefficient of 2.63.

The water surface elevations at CP-1 and along the roadway embankment are shown on section A-A' in Figure 2.4-6. The effective width of 35 feet was selected arbitrarily to approximately correspond to the width of the main stream entering the ditch. However, flow would spread to a larger width of approximately 100 feet, as shown in detail 3 and section E-E' of Figure 2.4-6. Consequently, the maximum water surface elevation is less than the estimated value of el 262.7', which is based on an effective flow width of 35 feet. As shown on Section A-A' in Figure 2.4-6 and on Section C-C' in Figure 2.4-6, downstream of CP-1, the flow enters a ditch (supercritical flow with a normal depth of 4.4 feet) and then backs up over the roadway at CP-2 to a depth sufficient to pass the peak flow of 620 cfs.

To compute the resulting water surface elevation at CP-2, a rating curve was prepared for Section D-D' using the method based on the principle of minimum specific energy presented in Section 2.4.2.3. It is shown in Figure 2.4-6. Using the D-D' rating curve, the water surface elevation at CP-2, corresponding to a discharge of 620 cfs, is estimated as el 245.5'. This is well below CP-1 (el 258.8'). Consideration of backwater effects demonstrates that the critical section at CP-1 is not submerged due to the flow depth at CP-2. A high point in the cooling tower access road just west of the Unit 1 cooling tower separates DA-2 from DA-3. The high point in the adjacent drainage ditch is at el 245.0'. Since the maximum water level at CP-2 was found to be el 245.5', some spillover from DA-2 to DA-3 would occur at this point. A rating curve was developed for the ditch section which acts as a control for any possible spill from DA-2 to DA-3. A water surface elevation of 245.5 feet resulted in a spill of less than 5 cfs. For purposes of estimating water levels this was considered to be negligible when compared to the DA-2 flood peak of 620 cfs and DA-3 flood peak of 151 cfs.

2.4.2.3.1.2 Drainage Area DA-3

As shown in Figure 2.4-5, DA-3 comprises the southwest part of the cooling tower area. It drains generally into the western half of the turbine-reactor complex area, both down the roadway and down the south face of the slopes of the access roadway embankment. DA-3 includes natural ground and the roadway to the 220 kV switchyard, but not the switchyard itself, which is sloped generally south to drain toward the Schuylkill River. A peak flow of 151 cfs is generated from DA-3. The disposition of this discharge is discussed in Section 2.4.2.3.3 with the turbine-reactor complex area.

2.4.2.3.1.3 Drainage Area DA-4

Like DA-3, this area also drains directly to the turbine-reactor complex area on the eastern side of the plant centerline. However, it includes a relatively larger proportion of natural catchment, most of which is on the east of the cooling tower excavation area. The handling of the peak discharge from this area, 550 cfs, is discussed in Section 2.4.2.3.3.

2.4.2.3.2 Drainage from Spray Pond Area

The spray pond drainage area, shown as DA-1 in Figure 2.4-5, includes the spray pond itself and the cut slope areas draining toward it, as well as two small pieces of natural topography that drain toward the cut slopes (one on the NW and the other on the SE perimeter). The total drainage area is 17.2 acres. Drainage is to the pond itself, which has a normal operating level of el 251' and a 60 foot wide spillway set at el 252' (shown as CP-5 on Figure 2.4-5). This spillway drains to a natural channel, across a road embankment, and then northward to Sanatoga Creek.

The spray pond spillway is designed to pass a routed PMF (48 hour storm) preceded by an SPF assumed equal to one-half the PMF ordinates. No infiltration is assumed. The pond is assumed to be at normal water surface at the beginning of the storm. A 30 minute routing period is used, with a flood routing computer program adapted from the U. S. Army Corps of Engineers program for hydrograph combining and routing. Precipitation increments for the most critical six hours of the storm are arranged as follows:

Period (30 min)	Precipitation (% of 6 hr)	Period (30 min)	Precipitation (% of 6 hr)
1	5	7	27
2	5	8	8
3	6	9	7
4	7	10	6
5	7	11	6
6	11	12	5

The remainder of the storm is distributed in accordance with Reference 2.4-4.

The pond is filled to a maximum of el 252.5' at the beginning of the 28th hour. The spillway discharges the surcharge above el 252' before the beginning of the second storm. The second flood peaks at a maximum mean inflow of 251 cfs, with a corresponding maximum outflow of 194 cfs and a maximum water surface of el 253'.

Further details for the pond are given in Section 2.4.8.

2.4.2.3.3 Drainage from Power Plant Complex Area

The finished floor elevation of relevant safety-related structures at the power plant complex area (power block) is el 217'. The plant coordinate line (E4000) divides the power block approximately in half, with the divide at el 217'. Drainage is generally away from the structures. The present site drainage condition was determined from the Limerick Site Master Plan, and various walkdowns.

Jersey barriers have been strategically placed along sections of the perimeter fence for security reasons. In the safety evaluation, the jersey barriers are assumed to block the drainage flow, and thus forming boundaries for the drainage areas. Some potential flow outlets along the south-west boundary of the site have been blocked, or partially blocked, by the jersey barriers. In addition, jersey barriers placed between the Technical Support Center and the Warehouse (see Figure 2.4-6) form a portion of the boundary separating the drainage areas DA-5 and DA-6.

The boundary separating drainage areas DA-5 and DA-6 runs along the jersey barriers, from the Technical Support Center to the Warehouse (see Figure 2.4-6). The boundary then runs along the southern edge of the Turbine Building, up to the centerline of the power block. The remaining southern portion of the boundary runs south along the centerline of the power block. For drainage area DA-5, the northern boundary is the plant access road which separates drainage area DA-3 and DA-5; and the western and southern boundaries are along the plant south-west security fence. For drainage area DA-6, the eastern boundary is the outside edge of the plant access road; the northern boundary is the service road which separates drainage areas DA-6 and DA-4; and the southern boundary is the service road adjacent to the southern side of the power plant complex.

The total drainage areas and peak flows from DA-5 and DA-6 were estimated to be as follows:

Area Designation	Area (acres)	Peak Flow (cfs)
DA-5	14.9	369
DA-6	11.6	242

The surface water flow paths around the power block shown on Figure 2.4-6 have been limited in order to provide additional space for lay-down or storage areas. The locations of the critical cross-sections and flow outlets are shown in Figure 2.4-6, while the widths and average bottom elevations for each of the cross-sections and flow outlets are summarized in Table 2.4-23.

Within drainage area DA-5, the important features are the yard and roads, the power plant structures, the refueling water tank dike, and various buildings (especially the ones erected along the security fence right-of-way on the southwest side of DA-5). The yard and road elevations encompassed by the security fence vary from about el 212' to el 217'. The roads entering the power plant structures have crowns set at el 217' or lower. These are sloped to drain away from the structures.

The area assumed for DA-5 includes, conservatively, the roof area of the power block and the area bounded by the condensate storage tank and the resulting water tank dike. The tank dike crest is at el 223', approximately 7 feet above grade. The tank dike, therefore, would contain much more than the 40 inches of rainfall resulting from the 72 hour PMP.

The path of the surface water flow in DA-5 will begin with inflow from DA-3 and a portion of DA-4, through the northern boundary of DA-5. Run-off from DA-5, combined with the inflow, will flow along

the paths shown in Figure 2.4-6, west of the power block, and exit area DA-5 through the outlets along the perimeter fence on the south-west side of the power plant complex. In the safety evaluation, jersey barriers were assumed to block some the outlets along the south-west boundary of DA-5.

Within drainage area DA-6, important features are the yard and roads, and the parking lot around the Site Management Building, shown in Figure 2.4-6.

The surface water flow in DA-6 will begin with inflow from DA-4 along the northern boundary, as shown on Figure 2.4-6. The run-off from DA-6, combined with the inflow, will flow through the parking lot, and exit DA-6 through the outlet on the eastern side of the site, between the Site Management Building and the Warehouse and Procurement Building, as shown in Figure 2.4-6.

The rational formula was used to estimate peak run-off rates at collection points CP-3 and CP-4 (see Figure 2.4-4), which are 446 cfs and 555 cfs, respectively. Flooding calculations were performed assuming critical flow at the outlets, and a Mannings “n” equal to 0.022. These calculations yield maximum water surface elevations of 218.1 feet at CP-3, and 218.1 feet at CP-4. Backwater calculations performed for the flow path located north of the Turbine Building (shown on Figure 2.4-6) yielded a maximum water surface elevation of 218.6 feet along the northern edge of the Turbine Building.

The results of the peak run-off rates and peak water levels for the present condition at the power block are summarized in Table 2.4-8.

An engineering evaluation of the site drainage conditions determined that the only potentially adverse affect is that flood water due to the local intense precipitation (PMP) event or the postulated cooling tower basin failure (PCTBF) could enter the turbine enclosure for a limited period of time. At certain site locations, the PCTBF event results in higher flood levels than the PMP event, but the PMP event is the bounding event due to the longer duration of the event. Consequently, measures are taken to limit the possible flow of flood water from the turbine enclosure into the control enclosure where the safety-related chilled water system is located at el 200’. These measures include controlling openings in the lower portion of the turbine enclosure walls, relying on flood control features within the turbine building, and by limiting the flow of water through the turbine enclosure doors by providing additional curbs and barriers inside the turbine enclosure and by administratively controlling the opening of certain doors. As a result of these measures, flooding into the control enclosure due to the present site drainage condition results in control enclosure flood level below the elevation of the safety-related chilled water system.

Furthermore, administrative controls have been implemented to ensure that future changes in site conditions, affecting flood water run-off, will receive engineering evaluation and approval prior to implementation.

2.4.2.3.4 Roof Loads on Safety-Related Structures That Are Due to PMP Onsite

In the previous analysis of surface drainage, it is assumed that all roof drainage overflows to the ground and then to the various control points. If all roof drains and scuppers are blocked, water could pond on the roofs of some safety-related structures to a depth controlled by the height of the roof parapets. The highest parapet on any safety-related structure is less than the maximum 24 hour PMP of 34.4 inches. Assuming that some accumulation and overflowing occur, the maximum water depth could equal the height of the parapet plus a small amount of head providing flow over the parapet. The design roof load due to PMP for all the safety-related structures (Section 3.2) is equivalent to this maximum water depth.

2.4.2.3.5 PMF in Possum Hollow Run

Possum Hollow Run has a drainage area of 1.3 square miles. It rises approximately 2.5 miles northeast of the site and flows southwesterly, entering the Schuylkill River through a gorge along the south side of LGS.

To assess the flood hazard to the LGS site posed by Possum Hollow Run PMF, the PMF is assumed to occur in Possum Hollow Run at the same time that an SPF is occurring in the Schuylkill River. The Schuylkill River SPF is assumed to be 50% of the PMF, or 250,000 cfs, which results in a Schuylkill River stage of el 152'.

It is unlikely that a PMF on the Schuylkill River would be coincident with the PMF on the Possum Hollow Run. A PMF on the Possum Hollow Run (drainage area = 1.3 square miles) is caused by a local intense thunderstorm, while a PMF on the Schuylkill River (drainage area = 1170 square miles) is due to a basin-wide PMP storm system whose center lies well upstream of LGS. The two storms would have different characteristics, and the joint probability that they produce peak runoffs at LGS at the same time is very low.

Using the slope-area method, a rating curve was developed for the Possum Hollow Run. For this purpose, a typical cross-section is taken at the point where the el 152' contour crosses the stream. The bed slope of the Possum Hollow Run is 0.02. Based on field inspections and comparison with photographs of streams with known (n) values (References 2.4-6 and 2.4-33), a Manning's (n) value of 0.05 is assumed.

A PMF hydrograph was developed for the Possum Hollow Run using the procedure outlined in Reference 2.4-6. The 6 hour PMP (Table 2.4-7) is divided into one-half hour increments, following the distribution used for the spray pond (Section 2.4.2.3.2). The resulting hydrograph peak is 3840 cfs, and the base is 15.5 hours.

Using the rating curve developed for the Possum Hollow Run, the water surface elevation corresponding to a PMF discharge of 3840 cfs is estimated to be 159 ft. The corresponding normal depth, velocity, and Froude number are 7.0 ft, 8.6 ft/sec, and 0.76, respectively.

As stated earlier, the SPF elevation in the Schuylkill River is 152 feet MSL. The bed elevation of the Possum Hollow Run at its confluence with the Schuylkill River is 105 feet MSL. Therefore, at the time of the SPF, the flood water of the Schuylkill River enters the Possum Hollow Run up to a point where its thalweg is at el 152'. This point is about 2400 feet upstream of the confluence of the Possum Hollow Run with the Schuylkill River. The PMF on the Possum Hollow Run is superimposed on the SPF in the Schuylkill River. It is conservatively assumed that in this backwater reach of 2400

feet the cross-sectional area of the Possum Hollow Run below el 152' is ineffective, and the entire PMF flow passes through the remaining cross-sectional area. This results in a water surface elevation of 159 feet at a section 2400 feet upstream of the confluence. This flood level is about 57 feet below the plant bench. Upstream of this section, the Possum Hollow Run is separated from the plant by high ground that is more than 60 feet above the bed of the Possum Hollow Run. It is not credible that the PMF of the Possum Hollow Run (3840 cfs) causes a water depth of 60 feet or more.

Therefore, it is concluded that the PMF in the Possum Hollow Run coincident with the SPF in the Schuylkill River would not flood any safety-related structure at LGS.

2.4.2.3.6 Summary of Results - Local Intense Precipitation

Table 2.4-8 summarizes the results of local intense precipitation investigations at the associated collection points and drainage areas. These investigations show that water levels are either below the access elevations of the safety-related structures or evaluated to be acceptable as shown in Section 2.4.2.3.3.

The Possum Hollow PMF is treated apart from the onsite local intense precipitation. A maximum PMF discharge of 3840 cfs was calculated. An SPF occurring simultaneously in the Schuylkill River produces a backwater effect, but conservative estimates indicate that the water surface elevation would be well below the plant grade el 216.5'.

2.4.3 PROBABLE MAXIMUM FLOOD ON STREAMS AND RIVERS

The PSAR included a PMF developed by the U.S. Army Corps of Engineers for Pottstown, adjusted to the site by the ratio of drainage areas. This PMF was estimated at 356,000 cfs, with a stage at the plant site of 158 feet. After the PSAR was prepared, Hurricane Agnes occurred (1972). In 1975 the PSAR was update to reflect the effect of Hurricane Agnes. At that time there was no reason to change the PMF. But later the NWS revised the values of PMP for the basin. Another significant change occurred with respect to upstream dams. Construction began on Blue Marsh Dam, and Maiden Creek Dam became an authorized project, whereas at the time of the PSAR, construction on Blue Marsh had not started, and Maiden Creek was not expected to be authorized. These changes combined to require a new flood analysis.

Since the LGS PSAR was prepared, Regulatory Guide 1.59 (Rev 1 and Rev 2) were issued, giving the option of using either detailed flood routing studies (Appendix A) or enveloping maps for determining peak PMF flows (Appendix B). The latter method is simpler, but more conservative, giving a value of 500,000 cfs as compared with the PSAR estimate of 356,000 cfs (both before adjustment for a dam break). The Appendix B method was selected for this report because it is conservative and indicates a "dry-site" condition during the PMF, with a large margin of safety.

PMFs were computed for the Schuylkill River at LGS and for Possum Hollow Run. The computations show that the maximum resulting stage in the Schuylkill River is el 181'. The maximum stage that is due to a PMF in Possum Hollow Run was not computed, but was found to be less than el 186' at a point nearly due east of the turbine-reactor area complex. The PMF for the Schuylkill River is covered in this section. The PMF for Possum Hollow Run is discussed in Section 2.4.2.3.5.

2.4.3.1 Probable Maximum Precipitation

This section is not applicable because the PMF is estimated in accordance with Appendix B of Regulatory Guide 1.59.

2.4.3.2 Precipitation Losses

This section is not applicable because the PMF is estimated in accordance with Appendix B of Regulatory Guide 1.59.

2.4.3.3 Run-Off and Stream Course Models

This section is not applicable because the PMF is estimated in accordance with Appendix B of Regulatory Guide 1.59.

2.4.3.4 Probable Maximum Flood Flow

From Appendix B of Regulatory Guide 1.59, the PMF for the Schuylkill River at the LGS site, corresponding to a drainage area of 1170 square miles, is 500,000 cfs.

The design flood for Ontelaunee Dam is 41,000 cfs. The PMF inflow to Maiden Creek Dam (which may be built at the headwater of Lake Ontelaunee) has been estimated by the U.S. Army Corps of Engineers at 118,000 cfs, with a spillway peak outflow at 92,000 cfs.

Blue Marsh Dam was designed by the U.S. Army Corps of Engineers to pass a PMF without failure. Under current authorization plans, the U.S. Army Corps of Engineers plans to design the Maiden Creek Dam spillway for the PMF. Both of these projects attenuate their PMF inflow peaks considerably. For Blue Marsh, the attenuation is from 128,600 to 74,800 cfs, and for Maiden Creek, it is from 118,000 to 92,000 cfs. In the analysis of flooding that is due to a dam break, it is conservatively assumed that no attenuation occurred during the PMF passages through either Blue Marsh or Maiden Creek Dam.

The flood stage at the LGS site for a 500,000 cfs PMF peak is el 174', not accounting for a hypothesized failure of Ontelaunee Dam (Section 2.4.3.5). To assess stages produced by the flood wave caused by the PMF-induced failure of Ontelaunee Dam, the results of a study of dam failure permutations are used. The method of analysis used in this study is the same as described in Section 2.4.4.2 (References 2.4-23 and 2.4-24). One of the permutations in this study postulates the failure of Blue Marsh Dam superimposed on the SPF in the Schuylkill River. This results in a water surface elevation of 177 feet at LGS. The flood wave caused by the failure of Ontelaunee Dam is superimposed on the above condition, resulting in a water surface elevation of 184 feet at LGS. Thus, the rise in water surface elevation that is due to the failure of Ontelaunee Dam is 7 feet.

The assumption is made that a failure of Ontelaunee Dam also produces an incremental increase in stages of 7 feet at LGS. Thus, the water surface elevation for the PMF plus a failure of Ontelaunee, is estimated as el 174' + 7' = 181'. This elevation (el 181') is 19.7 feet lower than the water surface elevation (el 201') caused by the hypothesized seismically induced failure of three major dams upstream of LGS (Section 2.4.4.2).

Therefore, the latter elevation governs plant safety, and a more refined analysis for the water surface elevation caused by the PMF combined with the failure of Ontelaunee Dam is not warranted.

2.4.3.5 Water Level Determinations

A discharge rating curve for the Schuylkill River near the project site (Figure 2.4-7) was developed using observed flood levels, computer backwater studies, and slope-area methods. The procedure that was used is discussed in the following sections.

2.4.3.5.1 Data Availability

Stream flow data are available in USGS publications (References 2.4-7 through 2.4-11). Within the basin and upstream of the plant site, 22 gauging stations have been operated, with 11 presently active. The stations are listed in Table 2.4-9, and their locations are indicated on Figure 2.4-8. Additional data are contained in References 2.4-12, 2.4-13, and 2.4-14. Data on river and flood profiles are available from the Commonwealth of Pennsylvania, U.S. Army Corps of Engineers, and USGS, in addition to a special high-water mark survey commissioned by the licensee in 1972 (Figure 2.4-9).

2.4.3.5.2 Historical Floods

Flood-producing storms in this area are normally associated with tropical disturbances. Although flooding from snowmelt occurs annually, snowmelt run-off usually has not been associated with major historic floods. Peak stages and discharges published by the USGS and the U.S. Army Corps of Engineers for the major historic floods are given in Table 2.4-6 for several stations on the Schuylkill River. At Pottstown, the 1902 flood, with a peak discharge of 53,900 cfs, was the highest known until June, 1972. However, the Reading and Philadelphia data indicate that the 1902 flood was very likely exceeded in 1850 and 1869 and may have been exceeded in 1757 and 1839.

In June, 1972, Hurricane Agnes produced the flood of record on many Pennsylvania streams. The flow at Pottstown has been evaluated as 95,900 cfs by the USGS (Reference 2.4-15). Figure 2.4-10 shows the flood frequency curve for the Schuylkill River at Pottstown. This curve is based on composite regional flood discharge relationships given in Reference 2.4-16. It is not expected that the 1972 flood alters these regional relationships.

2.4.3.5.3 Water Level Determinations up to 356,000 cfs

Table 2.4-10 gives the values from which the rating curve, shown in Figure 2.4-7, was drawn. For flows above 20,000 cfs, bridge clogging is assumed (Section 2.4.3.5.3.5).

After completion of the studies that resulted in the rating curve shown in Figure 2.4-7, Hurricane Agnes produced the flood of record at Pottstown, 95,900 cfs. Some seven hours before the flood's peak, an oil lagoon at Pottstown was overtopped by the flood waters, producing a slick along the river that left oil marks for a considerable distance downstream (Reference 2.4-17).

Figure 2.4-9 shows the results of a special survey commissioned by the licensee in July, 1972 to determine high-water marks between Sanatoga (1.4 miles upstream from the plant) and Cromby (8.6 miles downstream). All readings were taken along the east side of the Schuylkill River and reflect the top of the oil marks where they were visible.

If an upper envelope of that portion of the profile near the site is taken as indicative of the actual high water, it appears that the 1972 flood rose to about el 131'. In addition, there appears to have been almost no clogging of the bridges during this flood.

The rating curve (Figure 2.4-7) indicates a water level at about el 134.3' for a flow of 95,900 cfs. This is 3.3 feet higher than el 131' given by the flood level survey shown in Figure 2.4-9. The assumption of bridge clogging (Section 2.4.3.5.3.5) accounts for about 2 feet of the difference. The rating curve is apparently conservative when used for estimating water level for a given discharge.

2.4.3.5.3.1 Methods of Computation

The geometry of the channel near the site is taken from a survey made in 1969. Normal uniform flows are assumed for the low flows, and an approximate roughness is obtained using the average water surface slope shown in Reference 2.4-18. These low-stage computations were checked by field observations in December, 1969.

The flood levels for flows from 20,000 to 356,000 cfs are obtained using an adaptation of the U.S. Army Corps of Engineers Standard Step Backwater Program (Reference 2.4-19). Flood levels for flows above 356,000 cfs are discussed in Section 2.4.3.5.4. The program employs a computing method similar to method 1 in Reference 2.4-20. Whenever data are insufficient, conservative estimates are made. The computations consider the 14.1 miles of river between Pottstown (5.5 miles upstream from the site) and the village of Cromby (8.6 miles below the site).

2.4.3.5.3.2 Topographic Data

Figure 2.4-11 shows the locations of cross-sections used in the backwater studies. Data are obtained from four sources:

a. Commonwealth of Pennsylvania cross-sections taken in 1967 for the vicinity of Pottstown (river stations 3680+00 through 3810+00)

b. U.S. Army Corps of Engineers cross-sections taken in 1969 in the same reach to supplement the commonwealth sections

c. USGS topographic sheets revised in 1968, Pottstown and Phoenixville 7.5 minute quadrangles (10 foot contours) for the sections downstream of river station 3810+00

d. Specific surveys made for these studies in 1969 and 1970 by the licensee of all bridges between Pottstown and Vincent Dam and of the river bottom close to the site

The only modifications made to existing topographic data consist of assuming that impounding basins along the river are full of dredged material. For the sections taken from the topographic maps, approximate bottom elevations are developed using information contained in the 1950 report to the Commonwealth of Pennsylvania by the Schuylkill River project engineers (Reference 2.4-18). The surveyed cross-sections indicate that the main channel could be represented as having a horizontal bottom two feet above the thalweg elevation. This approximation is extended to the main channel portions of the unsurveyed sections, if they are assumed to be rectangular in section with their base elevations two feet above the thalwegs shown in the 1950 report.

Lengths of reach for both the main and overbank sections are scaled from the USGS topographic maps.

USGS aerial photographs taken in mid-1968 are used to determine floodplain character for roughness evaluation. Floodplain use culture undoubtedly changes from time to time and place to place, but it is assumed that the net effect of such changes is to keep the floodplain roughness approximately constant.

2.4.3.5.3.3 Selection of Observed Flood Profile

Roughness coefficients for a natural stream are best determined by a trial-and-error process of matching observed high-water profiles with those obtained from backwater computations using various roughness coefficients.

Flood profile information is not available for the 53,900 cfs flood of February, 1902.

Several flood marks are available from the USGS and the U.S. Army Corps of Engineers (Reference 2.4-21) for the 50,800 cfs flood of May, 1942 but were collected before the river restoration project was completed in 1950. Changes to the river, the installation of the impounding basins and dredging, have been sufficient to significantly alter the hydraulic characteristics of the river and floodplain.

The largest flood between 1950 and the time that the rating curve was computed occurred in August, 1955, with a peak of 42,300 cfs. The flood level at the USGS gauge on the Hanover Street Bridge in Pottstown was obtained from Reference 2.4-10, and other flood marks from Reference 2.4-21. These data are as follows:

OBSERVED MAXIMUM WATER LEVELS, 1955

Location	Flood Level (ft)
Pottstown Hanover St. Bridge Station	135.84
S. Pottstown Madison (Keim) St. Bridge	133.55
Linfield Highway Bridge	120.03
Spring City Highway Bridge	105.97

See Section 2.4.3.5.3 for a discussion of the 1972 flood.

2.4.3.5.3.4 Derivation of Manning's (n)

In 1969, the Philadelphia District Office, U.S. Army Corps of Engineers, performed backwater studies in connection with a proposed channel improvement project near Pottstown. The following values of Manning's (n) were apparently used by the U.S. Army Corps of Engineering in their 1969 study:

Natural main channel (before improvement)	0.042
Built-up areas	0.062
Fields (cultivated and fallow)	0.062

Wooded areas	0.078

Aerial photographs support the values 0.062 and 0.078 as reasonable for overbank roughness, considering the types of culture along the river. Because of lack of sufficient definition of observed profiles, it was decided to adopt those values for overbank flows and to use main channel roughness coefficients that result in a surface profile matching the observed 1955 flood levels.

Conversation with a witness to the 1955 flood at Pottstown revealed that only small flotsam was involved and that most probably no clogging occurred at any of the bridges. Thus, the bridge openings were considered clear in the calculations performed to evaluate (n). Table 2.4-11 compares the computed and observed values of water levels and gives the (n) values developed for each reach.

The increase in computed roughness going downstream could be caused by actual discharge increases along the 11½ mile reach, or it could reflect the attenuation of the flood wave as it moved downstream. These, however, are probably of minor importance, and the increase in (n) is probably due to an increasing lack of definition of the physical description of the channel.

It should be noted that a weighted mean of the calculated values agrees well with that used by the U.S. Army Corps of Engineers (0.041 versus 0.042). In terms of flood elevations at the site, it is conservative to use large roughness factors downstream of the project site.

Additional conservatism is introduced by assuming the (n) value to be constant for all flow stages.

2.4.3.5.3.5 Bridge Clogging

The following assumptions are made regarding clogging at the various bridges: openings in handrails and trusses are assumed to be fully clogged; bridge openings flanked by woods are assumed 50% clogged; and main channel openings are taken as 20% clogged. In the 1955 flood, as noted above, the bridges did not become clogged with debris. However, in a flood such as the PMF, large debris would be common, and the bridges could be subject to clogging. Because the bridges are over a mile downstream and well submerged during extreme floods, the net effect of clogging is approximately a 2 foot increase in water level at the site.

2.4.3.5.3.6 Selection of Starting Water Surfaces

To obtain proper convergence, it is necessary to extend the computations to Cromby, 8.6 miles downstream of the project site. At this downstream location, the slope-area method is used to obtain an approximate water level. A typical cross-section and the average slope observed during the 1955 flood are used for this. It is assumed that the true water surface at this location falls between the two elevations bounding a 25% and around the computed conveyance ($AR^{2/3}/n$). Table 2.4-12 shows the convergences obtained in the various runs made in this study.

2.4.3.5.3.7 Flood Discharges Studied

The lower portion of the curve in Figure 2.4-7 was developed from several computed water levels. The results in Table 2.4-10 have already been noted, but some discussion of the flood quantities is in order.

a. The average annual flood discharge, 21,000 cfs is based on 42 years of data at the USGS gauge at Pottstown.

b. The average annual flood at Pottstown, 28,000 cfs is computed from regional data presented by the USGS in Water Supply Paper 1672.

c. The second highest flow of record, 53,900 cfs is at Pottstown.

d. The 100 year flood, 99,000 cfs is computed from the regional data in Water Supply Paper 1672.

e. An arbitrary discharge used to obtain 200,000 cfs is better definition of the rating curve.

f. When the PSAR was prepared, 356,000 cfs was the original modified U.S. Army Corps of Engineers estimate of the PMF. In this report, the PMF is estimated at 500,000 cfs, using the more conservative estimating procedure given in Appendix B of Regulatory Guide 1.59. The calculation of levels for the 356,000 cfs flow with the backwater program provided an additional point for graphic extension of the rating curve.

Figure 2.4-12 shows the computed water surface profiles for these floods for the reach between Sanatoga Highway Bridge and Linfield Railroad Bridge. These two points are approximately 4500 feet upstream and 7500 feet downstream from the site, respectively.

2.4.3.5.4 Water Level Determination for Flows Above 356,000 cfs

The discharge rating curve shown in Figure 2.4-7 is extended to above the 356,000 cfs flow (el 158') using the approximate but conservative method described in this section.

The variation of friction slope with discharge in the backwater studies is plotted in Figure 2.4-13. The actual conveyance provided at the depth obtained in the backwater studies is estimated from the formula:

$$K = 1.486\ (AR^{2/3})n^{-1} \qquad \text{(EQ. 2.4-4)}$$

where:

K = conveyance

A = flow area

R = hydraulic mean depth

n^{-1} = coefficient of roughness

The friction slope is computed from the formula:

$$S_f = (Q/K)^2 \qquad \text{EQ. 2.4-5)}$$

where:

S_f = the friction slope

Q = the discharge

K = the conveyance of the river at the LGS site.

This is done for each of the six discharges used to construct the rating curve at and below 356,000 cfs (Table 2.4-10)

In Figure 2.4-13, the points obtained in the backwater study are indicated with circles. As discharge increases from 21,000 to 28,000 cfs, there is essentially no change in friction slope. However, as discharge then changes to 53,000 cfs, there is a sharp decrease in friction slope; this continues to 99,000 cfs, which seems to be at or near a minimum friction slope; as discharge increases beyond 99,000 cfs, the friction slope increases. The minimum slope obtained here, however, is not the same as the minimum slope of uniform flow, critical slope. All the flows considered are well into the subcritical range, being M1-type backwater curves. Differentiating Equation 2.4-5 with respect to (Q), the following equation is obtained:

$$\frac{\Delta s}{\Delta Q} = \frac{2\overline{Q}\Delta K}{K^3}\left[\frac{\overline{K}}{\Delta K} - \frac{\overline{Q}}{\Delta Q}\right] \qquad \text{(EQ. 2.4-6)}$$

This equation shows that if the ratio $Q/\Delta Q$ is larger (smaller) than $K/\Delta K$ in a certain range of depth, there is a corresponding decrease (increase) in slope and an increase in discharge. Thus, the shape of slope-discharge relation (Figure 2.4-13) is a consequence of the backwater starting elevations and the consequent variation of conveyance with depth at LGS.

There appears to be a trend toward an asymptote of S = 0.00038 as (Q) increases beyond 356,000 cfs. However, without additional backwater computations to confirm this trend, its extrapolation would be questionable. To be conservative with respect to depth, a decreasing slope versus discharge relation was chosen instead of the apparent asymptotic value. The relationship chosen is the best straight-line fit-by-eye to the six points in Figure 2.4-13.

At extreme flood stages above el 158' at the LGS site, the left bank (facing downstream) curves away from the river alignment northeasterly, toward Possum Hollow Run. When the stage of the river rises above this level, this side of the cross-section is less effective in carrying discharge, because of local separation of flow in the bend. A conservative extension of the rating curve is made by neglecting a portion of the left side of the stream (looking downstream) in computing cross-sectional area. A plot of the LGS cross-section looking upstream is given in Figure 2.4-14 and shows the area used in computing conveyance above el 158'.

The slope-discharge relation of Figure 2.4-13 is used to determine the required conveyance and associated stages, as given in Table 2.4-13.

The conservative nature of this extension is shown by comparing the conveyances required at 356,000 cfs. The backwater data for 356,000 cfs yield a friction slope of 0.000366, with a required conveyance (K) of 356,000 $(0.000366)^{-½}$ = $18.6x10^6$ cfs. The straight-line relation in Figure 2.4-13 indicates a slope of 0.00028, which gives a conveyance requirement of K = 356,000 $(0.00028)^{-½}$ = $21.3x10^6$ cfs. This is 14% higher than the conveyance actually required, based on the backwater study, and indicates a correspondingly higher stage at LGS. While the stage for 356,000 cfs is based on the backwater study (el 158'), this comparison demonstrates the conservative nature of the straight-line relation shown in Figure 2.4-13 when used in extending Figure 2.4-7 above el 158'.

The required stage given in Table 2.4-13 is determined from a stage conveyance curve, Stage = f(K), in which the conveyance K is determined from Equation 2.4-4.

In this case, a weighted (n) value was computed for a water surface of el 135' based on 0.042 for the channel and 0.07 for the overbank area. The weighted value obtained is n = 0.063, and this value is used for all depths. For computing the area and hydraulic radius above el 158', the cross-section portion noted above on the left bank is omitted.

The final stage relation is shown in Figure 2.4-7. The conservative nature of the extension above el 158' (356,000 cfs) is clearly shown by the change in slope of the curve at that point. If the straight-line stage-discharge relation that prevails below el 158' is extrapolated, it gives a lower stage for the same discharge. The extended stage rating curve should give conservative estimates of stage at LGS for all discharges covered. This rating curve is not applicable to dam break waves. The stage and discharge during the passage of such waves are discussed in Section 2.4.4. The calculations for the above rating curve are based on the assumption that the river channel carries steady, gradually varied flow with the origin of the backwater curve at Cromby.

2.4.3.6 Coincident Wind-Wave Activity

The water surface obtained with the PMF without wind is less than that obtained with the SPF and a multiple dam break, as discussed in Section 2.4.4. Since that case is more critical, the discussion of wind-wave activity is omitted here (see Section 2.4.4.3 for a discussion of wind-wave activity under the more adverse dam break case).

2.4.4 POTENTIAL DAM FAILURES, SEISMICALLY INDUCED

The reservoirs in the Schuylkill Basin upstream of LGS can be classified as being either minor or major with respect to a seismically induced failure.

Table 2.4-2 is a list of minor dams that are either too small or too remote to cause significant flooding at LGS in the event of their seismic failure. The table indicates that these are all less than 100 feet high and less than 4000 acre-feet in volume. Except for three Schuylkill River dams, their drainage areas are all less than 16 square miles. Their locations are shown in Figure 2.4-3.

Table 2.4-3 lists three major dams whose seismic failure could, under certain circumstances, generate significant waves in the LGS reach of the Schuylkill River. These structures are discussed further, and their various failure permutations are considered here in detail.

Ontelaunee Dam has a storage volume of 11,900 acre-feet and a height of 52 feet. It is principally of concern because it is located immediately below the site of another and larger dam that is authorized for future construction by the U.S. Army Corps of Engineers - Maiden Creek Dam. Maiden Creek

Dam will be situated 5 miles upstream of Ontelaunee Dam and will have a volume of 114,000 acre-feet, of which 38,000 acre-feet will be dedicated to flood control storage; the maximum height will be 110 feet.

Blue Marsh Dam, completed in 1979, is about 35 miles upstream of LGS on Tulpehocken Creek. This U.S. Army Corps of Engineers' project has a total storage of 50,000 acre-feet, of which a minimum of 22,900 acre-feet is dedicated for flood storage; the maximum height is 96 feet.

Figure 2.4-14 presents a location map and a schematic profile relating Ontelaunee, Maiden Creek, and Blue Marsh dams in elevation to LGS. All three dams have, or will have, uncontrolled open spillways.

Felix Dam is a recreation dam on the Schuylkill River in the city of Reading, which is downstream of the Maiden Creek confluence. The pool has a volume of 1470 acre-feet, and the dam is a 24 foot high rock-filled timber crib overflow structure, with a spillway el 237.5' MSL. This dam will be drowned out (or will be previously destroyed) by the SPF, and the flood wave resulting from its failure therefore need not be added to the flood waves from the failure of the Ontelaunee and Maiden Creek dams upstream.

Appendix A of Regulatory Guide 1.59 suggests that an acceptable combination of run-off floods and seismic events would be the SSE with a 25 year flood and the OBE with a standard project flood. The OBE has a design acceleration of 0.075 g horizontal and 0.050 g vertical. The SSE has a design acceleration of 0.15 g horizontal and 0.10 g vertical.

On Blue Marsh Dam, the U.S. Army Corps of Engineers provides for horizontal design accelerations of 0.05 g for concrete structures and 0.10 g for the embankment; no provision is made for a vertical acceleration component. Plans for completing final design and for construction of Maiden Creek Dam, also a U.S. Army Corps of Engineers project, has been indefinitely deferred; the U.S. Army Corps of Engineers presumably would apply its Blue Marsh seismic design values to Maiden Creek Dam.

There is no indication that Ontelaunee Dam, an earth-fill and masonry spillway structure complete in 1934 and now owned by the City of Reading, has any specific design provision for seismic loadings.

The U.S. Army Corps of Engineers design accelerations do not clearly fall into either the OBE or the SSE design category. On the one hand, the embankment horizontal design acceleration exceeds the OBE horizontal design value, but on the other hand the concrete structure horizontal design value is less than the OBE. In addition, no provision is included for vertical design acceleration. While the U.S. Army Corps of Engineers dam designs embody a considerable resistance to seismic failure, the amount of damage accompanying either an OBE or SSE is difficult to assess without a detailed seismic analysis of those structures. Therefore, for the purpose of this report, the two U.S. Army Corps of Engineers dams and the Ontelaunee Dam are all considered as nonseismic Category I structures. Their total instantaneous failure is considered simultaneously with the LGS SPF, which thus corresponds to an OBE design failure condition. This simplification negates the need for study of the SSE combined with a 25 year flood, since that case is simply the same total seismic failure, but with a lesser coexisting flood.

2.4.4.1 Dam Failure Permutations

If a major seismic failure occurred at the future Maiden Creek Dam, a domino-type failure would be likely at Ontelaunee because of the limited spillway capacity. Moreover, these two dams will be approximately 5 miles apart, and Blue Marsh Dam on Tulpehocken Creek is only 6.7 miles from Ontelaunee; thus a seismic event severe enough to cause failure in any one of these could cause severe damage to the other two. Therefore, a multiple failure analysis is considered in which all three structures are considered to fail in such a way that their peaks arrive at LGS simultaneously.

The failure, seismic or otherwise, of any of the six Schuylkill River navigation dams downstream of LGS would not affect safety-related water supplies, since safety-related water supplies do not rely on the Schuylkill River.

Regulatory Guide 1.59 (Rev 2) specifies that the appropriate SPF at the dam should be coincident with the dam failure in the OBE case and that the flood control pool should be filled. This specification is equalled or exceeded in the analysis at all reservoirs, as indicated in Table 2.4-3. The SPF peak flow for LGS of 250,000 cfs is estimated at 50% of the PMF, using the conservative criteria in Appendix B of Regulatory Guide 1.59 (Rev 2) for determining the PMF.

Landslides induced by seismic action could block the river, causing dam break type waves downstream when water pressure builds up and breaches the slide material. However, topographic considerations alone appear to preclude any hazard to the plant from landslide-induced waves. The Allegheny Mountains lie over 40 miles upstream from the site. Any landslides across the river in that area might temporarily back up water that could later breach the slide; however, by the time the flood wave appeared at LGS, it would be greatly attenuated. Below the Allegheny Mountains, in the Great Valley above Reading and the Triassic Lowland below Reading, the river's meander floodplain is typically 3000-5000 feet wide. Blockage of this wide channel by a landslide is not conceivable. The topography on both sides of the floodplain is generally gentle, but with some steeper hills occurring, particularly on the south side of the floodplain, between the site and Reading; however, a study of the USGS 1:24,000 maps indicates that, except at Reading, none of these appear to have the volume required to block the river.

At Reading, there are several steep hills on both sides of the river. Of these, the closest to the river and the steepest is Neversink Mountain, on the north side (Figure 2.4-14). The river is 200 feet wide and has no floodplain at this point. If Neversink Mountain were to collapse and block the river, with the slide subsequently breached by the river, water could back up to el 255' before spillage occurs over Poplar Neck, a long ridge on the south bank. The river bottom here is at about el 170'; therefore, the maximum depth of the water backup would be 85 feet, after which it would spill over Poplar Neck. The resulting wave could not produce a water surface elevation at LGS that would endanger the plant. The joint occurrence of a wave at LGS from a Neversink Mountain slide and a failure of one or more upstream dams is an event much less likely than is required by Regulatory Guide 1.59. The peak flow rate that is due to simultaneous failure of the three dams, Maiden Creek, Ontelaunee, and Blue Marsh, is conservatively estimated at 762,000 cfs. When superimposed on the SPF flow of 250,000 cfs, the combined event results in a total flow rate of 1,012,000 cfs.

2.4.4.2 Unsteady Flow Analysis of Potential Dam Failures

The dam break problem has been discussed in the literature for various idealized cases. The most generalized and convenient approach developed to date is by Sakkas (Reference 2.4-23) as most recently described by Sakkas and Strelkoff (Reference 2.4-24). With this method, cognizance is

given to channel friction and volume of the flood wave. However, it was derived by dry-bed conditions and requires consideration of a uniform prismatic channel downstream.

In Reference 2.4-23, dimensionless graphs are given that are determined by numerical integration of the equations for unsteady flow, using the method of characteristics. A wide variety of combinations of dam height, channel slope, and cross-sections is analyzed so that the various graphs permit an analysis of many practical dam failure situations. Channel geometry is assumed as prismatic, and procedures are given in Reference 2.4-23 for deriving the constants characterizing the channel cross-section, yielding a relation between the cross-section width B and the depth Y. This relation is given by:

$$\overline{B} = \overline{CY^m} \qquad \text{(EQ. 2.4-7)}$$

where:

$\overline{B}$ = the width at depth $\overline{Y}$

$\overline{C}$ and m = constants derived from the cross-section properties.

To determine the constants C and m, it is necessary to have the values of two pairs of B's and Y's (say B_o, Y_o, and B_1,Y_1) of this representative cross-section. Thus paired B's and Y's were obtained by taking the geometric mean of paired b's and y's at three actual river cross-sections using:

$$B_\circ = \left(\pi_{i=1}^{3}\ b_{\circ_i}\right)^{1/3}$$

$$Y_\circ = \left(\pi^{3}_{i=1}\ y_{\circ_i}\right)^{1/3}$$

and

$$B_1 = \left(\pi_{i=1}^{3}\ b_{1_i}\right)^{1/3}$$

$$Y_1 = \left(\pi_{i=1}^{3}\ y_{1_i}\right)^{1/3}$$

in which (i) denotes the individual of the three river cross-sections, at the hypothetical dam, the LGS site, and near Birdsboro, respectively. Because these paired b's and y's determine the (C) and (m) values and thus characterize the shape of the representative cross-section, they are called "paired characteristic breadth and depth dimensions".

Reference 2.4-23 gives dimensionless curves of the time of arrival of the wave front, the flood depth, and its time of arrival as a function of the distance downstream, empirical cross-section constants (C) and (m), and the initial Froude number (F) at the dam:

$$C = \overline{C}\ \overline{Y}_{\circ}^{(m-1)}, \quad F = \frac{\overline{V}_{\circ}}{\left(\overline{gY_{\circ}}\right)^{1/2}}$$

where:

$$\overline{V}_{\circ} = 1.486 \left(\frac{\overline{R}_{\circ}^{2/3} S^{1/2}}{n} \right)$$

$\overline{R}_{\circ}$ = The hydraulic radius at the instant of failure

$\overline{Y}_{\circ}$ = the initial depth at the dam

$\overline{g}$ = acceleration of gravity

S = channel slope

$\overline{n}$ = Manning's friction coefficient for channel downstream

Symbols with bars over the top are dimensioned variables, and symbols without the bar are dimensionless, following Sakkas' notation.

For the assumptions specified, the results of the Sakkas procedure are considered reasonably accurate. However, adapting the general model to a particular situation and then superposing multiple dam failures requires careful consideration and interpretation to obtain conservative estimates of incremental and total flood depth. A set of simplified surrogate regimes is assumed whose cumulative effect on flood depth certainly is greater than the depth in the actual hydraulic regime that would prevail in such an event. This conservatism is justified only because of the LGS location high above the Schuylkill River.

To incorporate the prismatic channel assumption, it is necessary to adopt a single representative channel cross-section between the failed dam and the site. The river section at a dam is typically narrow, whereas the river floodplain below tends to be wider. In the Schuylkill River and its tributaries, the basic valley is U-shaped or V-shaped; i.e., there are no relatively wide floodplains in the reaches between the dams and LGS, and the main stream channel does not vary greatly in basic geometry, particularly under the initial condition of the SPF. Under these conditions an approximation of a constant prismatic section is considered realistic.

A single representative cross-section is defined by taking the geometric mean of two, paired characteristic breadth and depth dimensions at three cross-sections: one at the hypothetical dam described later; one at LGS; and one at a section of the Schuylkill River located about 1 mile upstream of the town of Birdsboro, or about 15 miles upstream of LGS. These three cross-sections are presented in Figures 2.4-21, 2.4-22 and 2.4-23 respectively. Figure 2.4-24 is the defined representative cross-section. The geometric mean section is then used for estimating the effect of a particular dam break.

The results given by the Sakkas procedure apply to a flood wave progressing down an initially dry-bed. To approximate this condition in the analysis, the channel slope and the geometry of the two downstream sections are set before a mean section is determined. They allow for the existence of the SPF and any stage increments from previous dam breaks. In effect, the peak of the SPF is "frozen" at 250,000 cfs at LGS for the time that the peak of a dam break flood wave is enroute to LGS. Conservatism is embedded in this approach, since an earthquake of multiple dam break failure

magnitude is more likely to be a single massive event dispensing flood waves from each dam at the same time, rather than timed so that their peaks would be additive at LGS, simultaneously with the crest of the SPF.

Since Maiden Creek and Ontelaunee dams are located on the same stream within 5 miles of each other, the SPF peak at Ontelaunee is estimated from that at Maiden Creek, using the ratio of drainage areas. This gives the SPF peak at Ontelaunee as 58,400 cfs. If it is conservatively assumed that there is no attenuation that is due to the storage in Ontelaunee reservoir above the spillway crest (el 294'), the SPF peak of 58,400 cfs discharges at a reservoir elevation of 304.2 feet. It is estimated that, at this elevation, the volume of water impounded behind Ontelaunee Dam would be 29,000 acre-feet.

Based on the information available from the U.S. Army Corps of Engineers, the volumes of water stored in Maiden Creek and Blue Marsh reservoirs under SPF conditions are estimated as 130,000 and 76,700 acre-feet, respectively. Thus, the total storage of the three dams combined together is 235,700 acre-feet.

To obtain a conservative water surface elevation that is due to simultaneous failure of the three dams, it is assumed that the total volume of water (235,700 acre-feet) would be stored upstream of a hypothetical dam located near Reading, approximately 30 miles upstream of LGS and 5 miles downstream of Blue Marsh Dam. As the hypothetical dam is downstream of the three real dams, the channel storage assumed available for attenuation of a flood wave released from the hypothetical dam would be smaller than actual. This results in a higher, and therefore conservative, estimate of the water surface elevation at LGS.

The area-capacity characteristics of the hypothetical dam are assumed to be the same as at Blue Marsh Dam, which is the nearest upstream dam. Actually, the channel section at the location of the hypothetical dam would be wider than that at Blue Marsh, and so the above assumption provides conservative estimates of the water surface elevation corresponding to a given storage. By this assumption, the water surface elevation in the hypothetical reservoir for the combined storage of 235,700 acre-feet is estimated to be 333.5 feet. The river bed elevation at this location is 213 feet. Thus the depth of impoundment of the hypothetical dam at the instant of the postulated failure was 120.5 feet.

Using a slope-area method and assuming uniform flow conditions, the water surface elevations corresponding to the SPF at Birdsboro and LGS are estimated to be 188 feet and 152 feet, respectively. To simulate pre-existing SPF conditions in the river, cross-sections at Birdsboro and LGS are assumed to be represented by the portions of the flow sections above the SPF elevations. For the cross-section just downstream of the hypothetical dam, dry channel conditions are assumed. With the Sakkas method, it is conservative to ignore any water in the channel immediately downstream of a failing dam because a deeper than actual reservoir storage results. As stated earlier, to use Sakkas' dimensionless charts, a representative prismatic section for the routing reach from the hypothetical dam to LGS is obtained by taking the geometric mean of the characteristic breadth and depth of the river sections at the hypothetical dam (above dry-bed), at Birdsboro (above SPF elevation), and at LGS (above SPF elevation).

To be conservative, the channel slope between the hypothetical dam and LGS is computed using the dry-bed elevation at the hypothetical dam site and the SPF elevation at LGS. The actual channel slope during SPF conditions is steeper than that used.

To obtain a representative value of the coefficient of roughness, (n), for the river reach between the hypothetical dam and LGS, weighted average values are computed for the sections at Birdsboro and LGS using the equation (Reference 2.4-33):

$$n = \left[\frac{AR^{2/3}}{\sum_{i=1}^{2} \left(\frac{A_i R_i^{2/3}}{n_i} \right)} \right] \qquad \text{(EQ. 2.4-8)}$$

where:

A	=	total flow area
R	=	hydraulic mean depth for the entire section
A_1, R_1	=	flow area and hydraulic mean depth for the channel section
A_2, R_2	=	flow area and hydraulic mean depth for overbank flow
n_1, n_2	=	coefficients of roughness for the channel and overbank sections

For the section at the hypothetical dam site, where dry-bed conditions are assumed, a value of n = 0.062 is used for the entire section. This value is recommended for floodplains with light-to-medium brush and trees (Reference 2.4-33) and conservatively represents the conditions at the hypothetical dam section. For the sections at Birdsboro and LGS, where the dam break flood wave is superimposed on the SPF, a value of 0.062 is used for the overbanks, and a conservative value of 0.03 is used for the interface between the water surface at SPF and the dam break flood wave. The arithmetic average of the (n) values for the three sections was assumed to be applicable for the entire reach.

Using Sakkas' curves (Reference 2.4-23), the maximum flood depth that is due to the dam break is determined at the downstream section at LGS. The calculated depth thus determined is a depth in the derived geometric mean cross-section. To relate the computed depth to the actual section, conveyance relations are used. Using the derived properties of the geometric section (C and m), the area is given by:

$$A = (CY^{m+1})(m+1)^{-1} \qquad \text{(EQ. 2.4-9)}$$

From this, the conveyance (Equation 2.4-4) required in both the geometric section and the natural section can be calculated. Using the stage conveyance characteristics of the natural river section above the SPF elevation at LGS, the water surface elevation that gives incremental conveyance (above SPF elevation) equal to that corresponding to the calculated depth in the geometric mean cross-section is computed. This results in a water surface elevation of 201 feet at LGS.

2.4.4.3 Water Level at Plant Site

2.4.4.3.1 Maximum Computed Water Surface and Wave Effects

This section describes the effect of wind-waves on the maximum water surface (el 201') estimated at LGS that is due to the dam break condition described in the previous section.

The dam break waves are transients and do not contain enough volume to cover the entire Schuylkill Valley above LGS to the computed maximum depth at LGS. However, for an approximate wind-wave analysis, the following conditions are assumed; the water surface at LGS is el 201', and wind velocity is 40 mph.

Fetch is based on a map study of a level pool upstream at el 201' At this water surface elevation, the ridges and the two bends between Pottstown and the site are submerged. This permits a roughly rectangular fetch of 31,000 feet average length and a width of 4,500 feet, on a bearing of about N 72° W. The centerline of the rectangle intersects a ridge about a mile west of the village of Stowe. It is conservative to assume a rectangular fetch area, which according to Reference 2.4-25 gives a fetch effectiveness ratio of 0.18 and an effective fetch of 2.65 miles. Using Reference 2.4-25, these parameters yield a significant wave H_sV (33% frequency) of 3.8 feet, with a period of 3.9 seconds and a length of 78 feet. The maximum wave (1% frequency) is estimated as $1.67H_s = (1.67)(3.8) = 6.4$ feet.

At the LGS site bench, the maximum water surface without wind action, el 201', intersects a sloped-fill surface to the windward (west) side of the plant (Figure 2.4-4). The fill surface has an average slope of 1 vertical to 2 horizontal. The toe of the slope varies between el 170' and el 200'. The top of the fill varies from el 213' at the northwest end (adjacent to the switchyard bench), to el 216' on the south side of the plant, where the top of the fill curves toward the east. From the top of this fill, the ground rises gently on a long flat slope to the roadway at el 215' to el 217', which encircles the west side of the turbine-reactor area complex. The roadway's low part (el 215') is 90-350 feet from the top of the slope. The fill material is broken rock and fines, with sizes up to 24-30 inches. For computing wave run-up, this material can be considered as graded riprap. To compute run-up, curves given in figures 7-19 of Reference 2.4-25 are used, which are for a 1:2 slope. However, the wave from the maximum fetch direction is not perpendicular to the 1:2 slope surface, but intersects it at an angle of about 64° from normal. This results in an effective slope normal to the wave of about 1:4.5, so that actual run-up is less than computed.

Run-up (R) from the significant (33%) wave and the maximum wave (1%) is calculated from Reference 2.4-25 as follows:

Wave	H_o=Height (ft)	H_o/gT^2	R/H_o	R (ft)	Max el Run-up (ft)
Significant	3.8	0.0078	1.3	4.9	206
Maximum	6.4	0.013	1.0	6.4	207

Thus, the highest water surface elevation at LGS that is due to the most severe dam break permutation coincident with wave activity induced by a 40 mph wind would be 207 feet. This is 10 feet below the plant grade (el 217') and 8 feet below the roadway (el 215') .

2.4.4.3.2 Recapitulation of Conservative Steps in Dam Break Analysis

The computed water surface elevations (with and without waves) resulting from the dam break analysis are the result of a compounding of conservative assumptions.

The series of conservative steps used to compute the water surface are listed below.

a. The SPF is estimated at 50% of PMF, as determined from Appendix B of Regulatory Guide 1.59 (Rev 2). The PMF, as estimated by this procedure, has a peak of 500,000 cfs (unadjusted for dam breaks), whereas the peak PMF computed by conventional methods in the PSAR was 356,000 cfs, approximately 30% less. The SPF peak at 50% of the Appendix B PMF, or 250,000 cfs, is thus also conservative. Conservatism is further confirmed by a published U.S. Army Corps of Engineers estimate (Reference 2.4-26) of 128,000 cfs for the SPF at Pottstown; adjusted to the site, this would be 131,000 cfs, 52% of the SPF given by Appendix B of Regulatory Guide 1.59 (Rev 2).

b. The effective cross-sectional area used at LGS omitted part of the left overbank area (looking downstream) to conservatively allow for local flow separation produced by the river bend.

c. The earth-fill dams should not fail instantaneously as is assumed.

d. A dry channel is assumed downstream of the hypothetical dam, resulting by a larger effective reservoir depth by using Reference 2.4-23.

e. The concept of the hypothetical dam implies seismic failures of the three real dams generated at different times, corresponding to three different travel times to LGS. This is an improbable series of selectively destructive tremors. It is more likely that a single catastrophic tremor would be involved in a multiple dam failure, with the resulting flood waves arriving at LGS at different times.

f. The actual channel slope in the river reach from the hypothetical dam to LGS is steeper than the slope used in the analysis. This results in a higher water surface elevation at LGS, computed by Sakkas' procedure.

Since all of these assumptions are conservative, it is concluded that the maximum stages computed with and without waves are well above the stages that a precise analysis would indicate. It is finally concluded that the most severe seismic dam break permutation of the three dams, Blue Marsh, Ontelaunee, and Maiden Creek, would not endanger safety-related structures. The simplified analysis is justifiable because the plant area is high above the Schuylkill River.

2.4.5 PROBABLE MAXIMUM SURGE AND SEICHE FLOODING

This section is not applicable to LGS.

2.4.6 PROBABLE MAXIMUM TSUNAMI FLOODING

This section is not applicable to LGS.

2.4.7 ICE EFFECTS

This section is not applicable to LGS. Spray pond icing is discussed in Section 9.2.6.

2.4.8 COOLING WATER CANALS AND RESERVOIRS

In this section, only the hydrologic engineering aspects of the spray pond components of the UHS are covered. There are no canals in the cooling water system. The spray pond serves as the UHS for the RHRSW system and the ESW system after a possible accident. The pumps of the two systems take water from the spray pond, and circulate it through coolers and heat exchangers. The warm water is returned to the spray pond through a network of spray nozzles. A complete description of the spray pond system is given in Section 9.2.6.

2.4.8.1 General Description of the Spray Pond

The spray pond is located about 500 feet north of the cooling towers. The bottom of the pond is at el 241' and is composed of a 600x400 foot rectangular midsection, with a semicircle (radius = 200 feet) on each side. The spray pond system is common to both Units 1 and 2. The system consists of a spray pond, uncontrolled emergency spillway, pump structure complex, and associated piping and valves.

As shown in Figure 2.4-5, the spray pond is constructed by excavation only. The slopes of the excavation are 1:1 in rock and 4:1 in soils. Around most of the spray pond, random compacted fill about 3 feet deep overlies the original natural ground, with a bench at the soil-rock interface. The water surface area of the pond at el 251' is approximately 9.9 acres. An additional 7.3 acres of the surrounding area, including roads, cut surfaces, and natural terrain, drains towards the pond. Run-off onto the cut face is normally intercepted by a drainage ditch along the outside edge of a peripheral service road at el 255' and is directed to culverts that discharge to the pond. Along the north edge of the pond, the finished roadway is constructed to el 252' for a distance of 60 feet, with 9% slopes upward at either end to el 255'; this low portion of the roadway is designed to function as the crest of an uncontrolled emergency spillway. Spill is directed to a draw that drains northward into Sanatoga Creek.

2.4.8.2 Hydrologic Design Bases

Derivation of the PMF that forms the basis for the hydrologic design of the spray pond and emergency spillway is discussed in Section 2.4.2.3.2. The emergency spillway is sized so that the design flood will be evacuated safely. The elevation of the roadway around the pond and the slope protection of the pond are dictated by anticipated wave action.

2.4.8.2.1 Design Basis Flood Level

To arrive at a conservative elevation that is due to severe floods, with coincident wind-wave activity in the spray pond, the following cases were analyzed for waves, freeboard, and slope protection, using the procedures given in Reference 2.4-25.

Case	Flood	Still Pond Max Water Surface el (ft)	Maximum Wind (mph)
1	PMF	253.0	40
2	½ PMF (SPF)	252.5	90

Results are as follows:

Case	Significant (33-1/3%) Wave Height (ft)	Maximum (1%) Wave Height (ft)	Maximum Wave Run-up ft	Maximum Wave Run-up el
1	0.8	1.3	1.1	254.1
2	2.0	3.3	2.4	254.9

Based on the above, the DBFL is set at el 253.9'. The roadway surface has been set at el 254', or 0.1 foot higher than the DBFL.

Using criteria in Reference 2.4-25, the minimum riprap stone requirements are: a minimum weight of 7 pounds, a 50 percentile weight of 30 pounds, and a maximum weight of 108 pounds (assuming a stone density of 165 lb/ft^3). The gradation and design of the riprap for the spray pond soil slopes are discussed in Section 2.5.5. The riprap is capable of resisting the wave action and therefore protects the soil slopes. No protection is necessary for rock-cut slopes.

2.4.8.2.2 Safe Shutdown and Operating Basis Earthquakes

According to Regulatory Guide 1.59, the higher of the following two alternative combinations of events is considered to be an adequate design basis for floods that are due to seismic failure of dams:

a. Alternative 1 - 25 year flood coincident with SSE and 2 year extreme wind speed from the critical direction and length of effective fetch

b. Alternative 2 - one-half PMF, coincident with OBE, and 2 year extreme wind speed from the critical direction and length of effective fetch

When routed through the spray pond, the SPF yields a maximum water surface el 252.5'. The 25 year flood yields a maximum water surface el 251.8'. The starting water surface elevation in the spray pond for both these cases is assumed to be the normal operating water surface elevation (el 251'). In the latter case, the entire volume of the 25 year, 24 hour precipitation, without any losses over the contributing drainage area of 17.2 acres, is superimposed on the normal pond el 251'. Because the flood is contained below the spillway crest (el 252'), flood routing computations are not required for this case.

To estimate the height of waves due to earthquakes, the following equation, developed for determining the height of waves generated by a piston-type wave generator (Reference 2.4-31) is used:

$$H = 2s \left[\frac{2 \sinh^2 \frac{(2\pi d)}{L}}{\frac{(2\pi d)}{L} + \left[\sinh \frac{(2\pi d)}{L} \cosh \frac{(2\pi d)}{L} \right]} \right]$$

(EQ. 2.4-10)

where:

H = wave height vertical distance between the wave crest and trough (feet)

s = design displacement (amplitude) caused by the earthquake (feet)

d = initial depth of water (feet)

L = wave length; a function of the period of the design basis earthquake (feet)

From the response spectra of the SSE and OBE, the design displacement (amplitude) and period are estimated to be 6.5 inches and 2.0 seconds for the SSE and 3.0 inches and 2.0 seconds for the OBE, respectively. Conservatively, assuming that a negative wave is generated at the opposite boundary of the spray pond and that the amplitudes of the positive and negative waves are in phase and additive, the maximum possible wave height would be 2H. This results in a maximum water surface elevation H above the still water. The computed values of H and the resulting water surface elevations are tabulated below:

Earthquake	Concurrent Flood	Earthquake Wave (ft) H	Earthquake Wave (ft) 2H	2 Yr Wind Effect (ft)	Max Water Surface el (ft)
OBE	SPF	1.0	2.0	0.25	253.8
SSE	25 year	2.1	4.2	0.25	254.2

Because the spillway crest is at el 252', there would be some splash over the spillway for a short duration. However, water loss due to such splashes would be negligible compared to the total capacity of the spray pond and would not impair the safety-related water supply functions of the pond.

For the design of riprap protection, the wind-generated waves described in Section 2.4.8.2.1 are more critical than the short duration earthquake-induced waves.

For the spray-head pipe supports and the pump structure, hydrodynamic forces due to the OBE and SSE are computed. The forces on the pipe supports are computed using the virtual mass formula, $F = C_m V_\rho a$ (Reference 2.4-30), in which (F) is the hydrodynamic force on a body of submerged volume (V) that is due to an acceleration (a), in a fluid of mass density (ρ). Based on information available in Reference 2.4-30, a value of 1.5 is used for the coefficient (C_m). The resulting forces on the spray-

head pipe supports are 431 lbs and 890 lbs for the OBE and SSE, respectively; the forces are assumed to be applied at mid-depth, el 247.3' and el 247.5', respectively.

For the pump structure, hydrodynamic forces are computed both in the N-S and E-W directions. For the N-S direction, the TVA method (Reference 2.4-31) is used. For the E-W direction, where only part of the structure is exposed to water, the method given by Sarpkaya (Reference 2.4-32) is used. The resulting forces and their points of application are given below:

Earthquake	Direction	Max Force (kips)	Point of Application (ft)
SSE	N-S	144.0	246.2
	E-W	70.0	247.5
OBE	N-S	67.0	246.0
	E-W	34.0	247.5

These hydrodynamic forces on the pipe supports and the pump structure do not include the hydrostatic forces that are due to normal water depth, flood surcharge, or earth pressures, nor do they include dynamic forces that are due to waves.

2.4.8.3 Low Level Outlet Facilities

Evacuation of the normal storage of the spray pond, if needed, is accomplished by using the ESW system and/or RHRSW system pumps to pump water to the cooling tower basins via the cooling tower spray pond intertie line down to the minimum operation level of the pumps, and by other means below that level.

2.4.9 CHANNEL DIVERSIONS

This section is not applicable to LGS.

2.4.10 FLOODING PROTECTION REQUIREMENTS

As discussed in Section 2.4.2.2, the safety-related structures and facilities are secure from flooding. Hence, flooding protection requirements are not necessary.

2.4.11 LOW WATER CONSIDERATIONS

Extreme low flow in streams does not affect the ability of any safety-related facilities to perform adequately, including the UHS, as discussed in Section 9.2.6.

Availability of nonsafety-related water supplies is governed by the Delaware River Basin Commission (DRBC) Docket Decision D-69-210CP. The DRBC also has exclusive jurisdiction over the necessity for and approval of compensating water storage capacity for the LGS. LGS shall operate its nonsafety-related water supply systems in accordance with the terms and conditions imposed by the DRBC.

2.4.12 DISPERSION, DILUTION, AND TRAVEL TIMES OF ACCIDENTAL RELEASES OF LIQUID EFFLUENTS IN SURFACE WATERS

There are no credible accidents that can occur that result in an accidental liquid release of radioactive effluents to surface waters.

The term maximum permissible concentration (MPC) is used in various sections of the UFSAR. The term MPC is reflective of pre-1994 10CFR20, Apprendix B, Table II limits. These limits were used for the original licensing basis of the plant. Current liquid effluent releases are limited to ten-times the Effluent Concentration Limit (ECL) for each isotope specified in post-1994 10CFR20, Appendix B, Table 2, Column 2 (See Radioactive Effluent Release Controls Program required by the Technical Specifications).

The radwaste and reactor enclosures are seismic Category I structures. Each structure has a floor drain collection system to collect any potential liquid spills that may occur and to transfer the liquid to radwaste tanks. The radwaste tanks are located at the lowest elevation in the radwaste enclosure, which has a leak-tight membrane from the floor to el 174' MSL (grade is el 217' MSL). Consequently, any effluents accidentally spilled inside these enclosures are contained and remain isolated from the surface water environment.

In addition, the release of radioactive liquids by the failure of an outside storage tank is not considered credible since the tanks are enclosed by retaining dikes (Section 9.2.7). These dikes are constructed of compacted fill. The dikes and the area between the tanks and the dikes are covered with asphalt pavement. The outside tanks that contain radioactive liquid are the Unit 1 and 2 CSTs, each having a capacity of 200,000 gallons, and the refueling water storage tank, with a capacity of 500,000 gallons.

The Unit 1 CST and the refueling water storage tank are surrounded by a retaining dike. The Unit 2 CST is also surrounded by a retaining dike (Section 9.2.7). These dikes are designed to contain 110% of the contents of the largest tank that they enclose. Therefore, even if the entire contents of the largest of these tanks is spilled, the effluents are contained within the diked area, and do not reach any source of surface water.

The retaining dikes surrounding the outside CSTs are designed in accordance with seismic Category IIA requirements (Section 3.2.1). However, an analysis to determine the potential for contamination of nearby surface waters assuming that both tanks and dikes fail is not necessary for the following reasons:

SRP 15.7.3 indicates that the technical specifications shall limit the contents of outside storage tanks to those levels that will not exceed 10CFR20 concentrations at the nearest potable water supply unless dikes are provided to limit the water released by a tank or associated component failure or overflow. LGS has provided a dike to limit these water releases.

Based on section C.1.p of Regulatory Guide 1.29, the CSTs and surrounding dikes have been classified as seismic Category II and IIA respectively because the airborne doses from a failure of these structures would not exceed 0.5 rem whole body or its equivalent to any part of the body (1.5 rem thyroid in this case). Thyroid doses of 2.1×10^{-3} rem have been calculated at the EAB, based on a 350,000 μCi/sec offgas release rate resulting in the tank inventories of Table 12.2-87, an iodine dose factor of 10, and a 5 percentile X/Q of 2.9×10^{-4}.

Although the retaining dikes are not seismic Category I, they will retain their structural integrity during an SSE event as discussed in Section 2.5.5. In view of this, failure of both tanks and dikes need not

be assumed in determining the potential for contamination of nearby surface waters. An analysis is provided in Section 2.4.13 which assumes a radwaste tank failure only. The analysis indicates that significant periods of decay (over 600 years) will occur before any radioactivity is released via the groundwater pathway if the contents should be absorbed by the ground. Because the primary contributors to the normally expected CST activity are the iodines and several shorter-lived isotopes with half-lives of less than 1 day, and all other isotopes have expected concentrations less than the MPC levels for water in unrestricted areas, doses via any food or drinking water pathways will be well below 10CFR20 limits.

Accidental release of radioactive effluents into the groundwater environment is discussed in Section 2.4.13.3.

In view of the above, detailed analyses regarding the ability of the surface water environment to disperse, dilute, or concentrate accidentally released radioactive effluents are not required.

2.4.13 GROUNDWATER

Investigation of regional and local groundwater conditions indicates that the construction and operation of the LGS has no adverse effects on the groundwater resources in the region and the site.

2.4.13.1 Description and Onsite Use

The site is located in the Triassic Lowland Section of the Piedmont Physiographic Province. The region is characterized by rolling hills and long low ridges and is well drained by numerous tributaries to the Schuylkill River. Precipitation averages about 44 inches per year, and run-off averages about 21 inches per year. The balance represents mainly evaporation and transpiration losses, with minor infiltration.

Groundwater occurs in sedimentary rocks of Triassic-age. The Brunswick lithofacies, the aquifer underlying the LGS site, yield small-to-moderate quantities of water to wells.

The water supply for LGS plant operation is obtained from surface water, and no groundwater use is planned.

2.4.13.1.1 Groundwater Aquifer

Groundwater in the region occurs in sedimentary rocks. The region is underlain by the Newark group of Triassic-age, which includes the Stockton Formation and the overlying Lockatong, Hammer Creek, and Brunswick lithofacies.

The strata are intruded by diabase dikes and sills. Although the other units provide some groundwater in the region, the Brunswick lithofacies are the only aquifer of significance at the LGS site.

The Stockton Formation, which crops out about five miles south of the site, is composed of interbedded sandstone, conglomerate, red shale, and red siltstone and is at too great a depth at the LGS site to be of hydraulic importance. The Hammer Creek conglomerates and sandstones stratigraphically overlie the Stockton in the region but are not present in the site area. The nearest occurrence of the Hammer Creek is a few miles west of the site, in Berks County. The Stockton is overlain south of the site by the Lockatong, a dark gray argillite. The areal distribution of these formations and lithofacies is shown in Figure 2.5-2.

The Brunswick, the aquifer at the site, is composed of red shale, sandstone, and siltstone. Within the Triassic Lowland, as well as in the site region, the Brunswick is the most widespread source of groundwater. The Brunswick is interbedded with thin tongues of Lockatong, and changes in lithology are common.
The dip of the Brunswick and Lockatong strata is to the north and northwest at about 10° to 20°. Several broad synclines and anticlines trending about N 60° W are superimposed on the regional structure. The strata have been cut by many faults, most of which are relatively small. Joint systems are well developed and strike N 20° E to N 50° E and about N 50° W to N 90° W. The joints are mostly vertical, and in some strata are closely spaced.

The Brunswick is composed of very fine-grained rocks. The pore spaces within the rock matrix are very small and offer great resistance to the flow of groundwater. Therefore, permeability that is due to the primary porosity of the Brunswick is small.

Most of the groundwater movement within these rocks follows secondary openings that developed following the deposition of the beds. Some of these openings are fractures that parallel the bedding-planes. They are usually narrow and probably contribute little to the permeability. The most important openings are nearly vertical joint planes; they cross each other at various angles throughout the beds. These joints, where present, provide an interconnected series of channels through which groundwater can flow, giving the material a low to moderate permeability (Reference 2.4-36).

The number and width of secondary openings vary; consequently, the permeability differs from one bed to another. In a series of beds 100 feet thick, there may be only a few beds in which the secondary openings are well developed. These beds range in thickness from a few inches to a few feet; the average thickness is about 2 feet (Reference 2.4-36).

In the Brunswick, the water table is found at shallow depths. Wells that penetrate deep strata in the Brunswick may encounter water under confined conditions. The water table slopes from the topographic divides to discharge areas along streams and rivers. The Brunswick is generally a reliable source of small-to-moderate quantities of groundwater but, yields from wells that penetrate it vary widely because of lateral and vertical variations in lithology, the occurrence of lens-shaped beds, uneven spacing of joints and locally complex structure. Fault zones in the Triassic rocks have been found to be barriers to the flow of groundwater, and wells located near them generally have very low yields. The median yield of drilled municipal and industrial wells is about 110 gpm. Yields in excess of 300 gpm are rare and are obtained from wells that intersect a larger number of water-bearing zones. The median transmissivity of the Brunswick is 1100 gpd/ft (Reference 2.4-36).

Most groundwater in the Brunswick aquifer is a calcium bicarbonate-type, but some of the groundwater, with a total dissolved solids content in excess of 500 ppm, is a calcium sulfate-type (Reference 2.4-36). Water quality data for the Brunswick Lithofacies are presented in Table 2.4-14.

Most water from the aquifer is suitable for domestic and other purposes.

2.4.13.1.2 Aquifer Recharge and Discharge

Recharge to the Brunswick occurs through the soil cover as precipitation percolates down to the water table. The water table generally follows the surface of the land, and groundwater flows from high to low topographic areas.

Poor water quality and low yields in wells deeper than 600 feet indicate little groundwater movement below that depth. Most groundwater movement is prevalent only in the upper portion of the Brunswick, where the fracture density is greatest.

At the site, groundwater moves from the topographic high northeast of the plant structures down gradient to the north and the southwest, where it eventually discharges into the Schuylkill River and Possum Hollow Run (Figure 2.4-15).

2.4.13.1.3 Onsite Use of Groundwater

Water for plant operation is supplied by surface water and is discussed in Section 2.4.

Three wells were developed : Well No. 1 is 310 feet deep, 6 inches in diameter, and yields 50 gpm; Well No. 3 is 585 feet deep, 7-7/8 inches in diameter, and yields 65 gpm; and Well No. 4 is 198 feet deep, 6 inches in diameter, and yields 65 gpm. Note that well No. 4 was decommissioned and is no longer in service for domestic water.

These wells will be utilized as permanent water sources as follows:

- Site well 1, source of chlorinated drinking water.

- Site well 3, water to batch plant water tank and 500,000 gallon backup fire water storage tank.

The operation of the wells has no permanent impact on the groundwater resources of the site area.

2.4.13.2 Sources

Within 20 miles of the site, surface water sources supply most of the public and commercial demand. The Schuylkill River and its tributaries are widely used. However, a number of municipalities and industries, together with many domestic users, utilize groundwater.

2.4.13.2.1 Regional Use of Groundwater

The locations of public water supply systems within 20 miles that use groundwater are shown in Figure 2.4-16. An inventory of the supply systems is presented in Table 2.4-15. Public water systems supply more than 80% of the population in the region (Reference 2.4-37). Groundwater contributes less than 40% of the total amount of public water supplied.

Individual, private wells supply groundwater to slightly less than 20% of the population in the region and generally account for less than 10% of the total water usage (Reference 2.4-37).

2.4.13.2.2 Use of Groundwater in the Vicinity of the Site

An inventory of local groundwater users is presented in Table 2.4-16. Locations of groundwater users within 1 mile of the site are shown on Figure 2.4-17.

Groundwater supplies several homes, farms, and commercial interests in the vicinity of the site. Most of the wells are less than 200 feet deep and yield less than 100 gpm. The largest groundwater user, Publicker Industries, is 1½ miles south of the site and uses 150,000 gpd from three wells in the Brunswick.

Water wells in the site vicinity are either not in the same groundwater basin as the plant (hydrologically separate) or are hydraulically up-gradient of the plant. No wells to which groundwater beneath the plant discharges are present in the area.

2.4.13.2.3 Projected Future Use of Groundwater

Population growth and relocation will create a corresponding need for larger supplies of water in the site region. Much of the increase in water usage will take place in Limerick Township and neighboring townships as suburban development creates new demands for groundwater (Reference 2.4-37). Based on the assumption that the usage in the region reflects the national average, water usage is expected to increase by approximately 1 gcd (gallon per capita per day) each year. By the year 1990, a 12% gcd increase, combined with more than a 30% increase in people served by public water systems, will increase the total amount of water use by approximately 50% (Reference 2.4-37). The increase in the demand for water will be met mostly by public water supply systems, which are developing additional wells to meet part of the demand.

The number of domestic and private wells is not expected to increase significantly, because most new water users will purchase water from water supply companies. By 1990, more than 90% of the population in the region will be supplied by public water suppliers.

Large increases in the use of groundwater in the site area are precluded by the low permeability and limited area of the water-bearing units there.

LGS will have no effect on the future use of groundwater in the region. The plant uses groundwater from site wells 1, 3 and 4 for drinking water and for filling the 500,000 gallon backup fire water storage tank.. The site is hydrologically isolated from all public groundwater supplies and areas of extensive groundwater development.

2.4.13.2.4 Water Levels and Groundwater Movement

Groundwater levels were measured in borings (observation wells) at various locations near the spray pond and power block areas. The observation wells were monitored at regular intervals from June 1973 through August 1975, and from November 1978 through May 1979, to determine the direction of groundwater movement and the elevation of the water table, and to establish structural design criteria for groundwater effects. These wells were subsequently monitored throughout the remaining plant construction period to determine the effect of plant construction on the groundwater movement and levels, and to verify/assure the adequacy of the design criteria used in the design of safety-related plant structures. Figure 2.4-18 shows hydrographs of the observation wells.

2.4.13.2.4.1 Observation Wells

A network of 22 groundwater observation wells were installed at the site at various construction stages to determine the depth to water, and to measure groundwater level fluctuations. The locations of these wells are shown in Figure 2.4-15. The construction data (depth of hole, interval screened, etc.) are presented in Table 2.4-17.

Five observation wells were installed in the planned spray pond area in June 1973, and monthly water level readings commenced. In June 1974, four more wells were installed in the spray pond area and incorporated in the monitoring program. Monitoring was temporarily discontinued between August 1975 and November 1978 because of construction of the spray pond. Observation wells P2, SP20, and SP21 were destroyed by this construction.

In November 1978, water level monitoring was resumed in the remaining six wells near the spray pond area. Furthermore, 10 more observation wells were installed in January 1979, and three more wells were installed in June 1981. Six of the 13 wells are located near the power block area, and the remaining seven wells are located near the spray pond area. Observation wells P1 and P4 were destroyed in 1981 by ongoing construction activities and grading. In addition, observation wells P9, P13, and P15 were abandoned in April 1988, June 1984, and December 1987, respectively.

The recorded water levels in the observation wells between early 1979 and early 1988 are shown on the hydrographs in Figure 2.4-18.

2.4.13.2.4.2 Groundwater Levels

The depth to water in observation wells has ranged from 13-96 feet below ground surface. Recharge to the groundwater beneath the site is primarily from infiltration of precipitation on the ground surface. During the period 1973 through 1975, precipitation was average for the region. Thus, groundwater levels during that period were probably near average.

The potentiometric surface determined from levels measured in May 1979, prior to spray pond construction, is shown in Figure 2.4-15. This indicates the water table east of the planned spray pond was at el 250' and decreased in elevation to less than 130 feet southwest of the power block. Postconstruction water levels reveal the same general configuration, with localized variations probably due to site grading/surface and drainage installation.

Hydrographs of observation wells (Figure 2.4-18) indicate that water levels fluctuate seasonally, with the lowest levels occurring in the fall and early winter, and the highest levels occurring in the spring. In the spray pond area, these records indicate a 17 foot maximum seasonal fluctuation (wells P5 and P6), with most well levels fluctuating less than 12 feet.

Neither average water levels nor water level fluctuations were significantly affected by the filling of the spray pond during October 1982 and November 1982. The only exception to this is the water level in well P17, which currently averages about 10 feet higher than it did prior to pond filling. However, the water level fluctuation in well P17 remains as large as or larger than that recorded prior to pond filling, suggesting there is no hydraulic connection between well P17 and the water in the spray pond which is maintained at a constant level. In any event, measured seepage loss from the entire spray pond was calculated to be only 4.7 gpm (Reference 2.4-43).

Hydrographs of observation wells in the power block area (Figure 2.4-18) exhibit larger water level fluctuations than those in the spray pond area. These fluctuations were closely related to precipitation, as illustrated in Figure 2.4-19. Wells P12 and P15 do not show large fluctuations because the water table is below the screened intervals during low periods. When the water table drops below the screen, the level measured in the well is of the water remaining in the sump, a 5 foot length of casing below the screen. Thus, only the highest water levels reflect the water table (fluctuation peaks) at wells P12 and P15.

During construction, the observation wells in the power block area were adjacent to open trenches or to plant excavations backfilled with relatively permeable materials. Precipitation that collected in the open trenches or that infiltrated the permeable backfill provided abnormal amounts of recharge to the water table. When the open trenches were filled and asphalt or other relatively impermeable layer was placed over these backfilled areas, the water table fluctuation was reduced because of the reduction of infiltration of precipitation (Figure 2.4-18). The surfacing also resulted in large reductions

of average water levels in wells P13 and 14. Figure 2.4-15 shows potentiometric contours of the water table as of May 31, 1988.

2.4.13.2.4.3 Direction of Groundwater Flow

Groundwater in the shale and siltstone strata immediately underlying the site flows in fractures and joints. Exploration at the site suggests the fractures are tight below a depth of 140 feet, indicating little or no movement of groundwater in these units below this depth.

The direction of flow is from topographically high areas to topographically low areas (Figure 2.4-15). Groundwater beneath the plant flows southwesterly toward the Schuylkill River, eventually discharging to the river. North of the plant, a groundwater divide is present beneath the topographic ridge. Groundwater north of the divide flows northward, discharging to tributaries of the Schuylkill River. Because of the low permeability and poor hydraulic connection between beds in the bedrock, the influence of groundwater at the site on the regional hydrology is negligible.

Below the shale and siltstone strata described above, some discontinuous beds of sandstone yielded water to the wells used during construction. Pumping tests using these wells and closely spaced observation wells in the sandstone and the overlying siltstone-shale beds measured the hydraulic interconnection between these units. The results indicate that the connection ranges from very slight to negligible.

2.4.13.2.5 Aquifer Parameters

A pumping test and other permeability tests were performed to evaluate the groundwater hydrology of the site.

For the pumping test, a 6 inch diameter test well, located near the center of the construction area, was installed to a depth of 185 feet. Changes in water level as a result of pumping were measured in 6 observation wells located at various distances (20 feet to 700 feet) from the test well. Using the time-drawdown data from the pumping test, and the Theis nonequilibrium formula, bedrock transmissivity (T) is computed to be 2250 gpd/ft. This value corresponds to an average permeability (K) of 11 gpd/ft^2 (550 ft/yr).

Forty constant head tests were performed in auger holes and boreholes to estimate the permeability at the spray pond. Calculated permeabilities range from 4 ft/yr to 1247 ft/yr and are listed in Table 2.4-18. The average permeabilities for the overburden, the contact zone between the overburden and bedrock, and the bedrock are 3.5 ft/yr, 14 ft/yr, and 214 ft/yr, respectively. The tests indicate that the permeability of the overburden is lower than the bedrock's permeability. The greatest range of permeability values was determined from test data in bedrock. Because of the fractured nature of the bedrock, the permeability depends on the number of fractures the boring intercepts. More than 84% of the permeabilities measured in bedrock are less than 390 ft/yr.

2.4.13.2.6 Reversibility of Groundwater Flow

Seepage from the spray pond may cause a groundwater mound beneath the pond, with minor, local reversals of flow direction. This would increase the groundwater flow to the north and to the Schuylkill River, but the general direction of flow would remain the same. Because the pond will be lined, these changes will be minor.

2.4.13.2.7 Water Quality

Chemical analyses of groundwater are available from wells that penetrate the Brunswick lithofacies in Montgomery County (Table 2.4-14). The median dissolved solids content of samples from these wells is 302 ppm, and the median hardness (as $CaCO_3$) is 218 ppm. Groundwater from the Brunswick is largely of the calcium bicarbonate-type, although water samples having concentrations of dissolved solids greater than 500 ppm are of the calcium sulfate-type. Groundwater from the Brunswick is of good quality for most domestic and municipal uses, although it may need to be treated for hardness.

Water quality information is available from Well Nos. 1, 3, and 4 at the LGS site (Table 2.4-19). Samples were taken from holding tanks rather than from open discharge at the wells, but are considered indicative of the water quality. The water is a calcium sulfate-type, with pH ranging from 7.5 to 8. The water is moderately hard, ranging from 134 ppm to 618 ppm as $CaCO_3$, and contains total dissolved solids ranging from 199 ppm to 1052 ppm.

2.4.13.3 Accident Effects

An accidental spill of radioactive effluents from the radwaste enclosure is hypothesized, and the effect of a spill is analyzed with regard to the nearest offsite source of potable water, the Schuylkill River, 800 feet from the radwaste enclosure. Potentiometric contours shown on Figure 2.4-15 indicate that, in the radwaste enclosure area, groundwater flows southwest toward the Schuylkill River. It is assumed that radionuclides from a spill would percolate directly to the water table in the rock and then move with the groundwater laterally toward the river. The radioactive effluents that would constitute a spill are assumed to originate from the waste sludge tank, which contains the largest source of radioactivity in the enclosure. For conservatism, radioactive effluents are postulated to immediately enter the water table below the radwaste enclosure, and concentrations of radionuclides at that point are assumed to be the same as those in the radwaste tanks. No credit is taken for ion exchange, dispersion, or radioactive decay during percolation to the water table.

In addition to the accidental spill of radioactive effluents from the radwaste enclosure hypothesized as the worst case spill, a feed water line break between the main condensers and the condensate filter demineralizer in the Unit 2 turbine enclosure could contaminate the groundwater supply to site well 4. Site well 4 is utilized as a source of chlorinated water at the site. Site well 4 is on the same side of the groundwater divide as the east side of the Unit 2 turbine enclosure therefore a radioactive spill in the Unit 2 turbine building could enter the ground directly beneath the building. This spill would then enter the groundwater and flow southeast of the groundwater divide approximately 600 feet to site well 4.

2.4.13.3.1 Groundwater Movement

The rate at which the contaminants migrate is no greater than that of the groundwater in which it is carried. Groundwater travel time and direction of flow is controlled by permeability and effective porosity of the bedrock and by the hydraulic gradient of the water table. The average groundwater velocity and the travel time to the river may be calculated using a form of Darcy's Law:

$$\mu = \frac{ki}{n} \qquad \text{(EQ. 2.4-11)}$$

$$t_{gw} = \frac{xn}{ki} \qquad \text{(EQ. 2.4-12)}$$

where:

μ	=	average groundwater velocity (ft/yr)
k	=	permeability (ft/yr)
i	=	hydraulic gradient (ratio)
n	=	effective porosity (ratio)
t_{gw}	=	travel time (yr)
x	=	distance (ft)

A permeability of 390 ft/yr is selected as a conservative estimate of the effective permeability of the underlying materials, based on the 84th percentile of the permeability tests described in Section 2.4.13.2.5. No porosity measurements of site bedrock were performed, but the low permeability indicates that interconnected void spaces are few, resulting in a low effective porosity. An effective porosity of 5% is estimated for the bedrock.

The hydraulic gradient between the radwaste enclosure and the river is calculated as 0.031, based on the hydraulic head difference between the 130 foot elevation potentiometric contour just southwest of the radwaste enclosure (Figure 2.4-15) and the elevation of the river, 105 feet, divided by the distance between the river and the radwaste enclosure, 800 feet, which is assumed to be the flow path.

Using these values for the parameters in the above equations, the computed travel time for groundwater, traveling at an average velocity of 243 ft/yr, to flow from the radwaste enclosure to the river is 3.28 years.

2.4.13.3.2 Analytical Model for Radionuclide Migration

The concentration of contaminants would be reduced during migration in the groundwater by the processes of ion exchange, dispersion, and radioactive decay. The total effect of these processes on the concentrations of the contaminants at the point where they would enter the Schuylkill River was determined by use of an analytical model (Reference 2.4-38). The model accounts for adsorption, one-dimensional longitudinal dispersion, and radioactive decay:

$$C/C_o = \tfrac{1}{2} \exp(-\lambda t) \left[\operatorname{erf}\left(\frac{x - u_i t'}{2\sqrt{D_m t'}} \right) - \operatorname{erf}\left(\frac{x - u_i t}{2\sqrt{D_m t}} \right) \right] \qquad \text{(EQ. 2.4-13)}$$

where:

C	=	final concentration
C_o	=	initial concentration
λ	=	radioactive decay constant = 0.693/radioactive half-life
t	=	time
t'	=	(t-Δt) where Δt is the time necessary for the fluid to flow one pulse width (the length of spill volume)
x	=	distance
u_i	=	average velocity of ion
D_m	=	longitudinal dispersion constant
erf	=	error function: $\text{erf}(x) = \frac{2}{\sqrt{\pi}} \int_0^{x - t^2} e dt$

The waste sludge tank is assumed to be 80% full at the time of the spill. Thus, 10,240 gallons of radioactive effluent is assumed to be released. The spill is considered to enter directly into the groundwater. The volume of bedrock containing the effluent is assumed to be a cube. The length of one side of the cube would be 30 feet, based on an effective porosity of 5%. Of the radionuclides present in the waste sludge tank (Table 11.4-9), Sr-90 and Cs-137 are the most hazardous because of their long half-lives (29 years and 33 years, respectively) and their relatively high concentrations (2.2×10^{-3} μc/ml). Because the concentration of Sr-90 is equal to Cs-137 and Sr-90 is adsorbed less than Cs-137, the movement of Sr-90 is analyzed as the worst case.

2.4.13.3.3 Radionuclide Ion Velocity and Travel Time

The average velocity of Sr-90 in groundwater (U_{ion}) is determined by the relationship (Reference 2.4-39):

$$U_i = \frac{U_w}{1 + \left(\frac{P_b K_d}{n}\right)} \qquad \text{(EQ. 2.4-14)}$$

where:

U_i = average velocity of ion in groundwater (ft/yr)
U_w = average velocity of groundwater (ft/yr)

K_d = distribution coefficient (ion exchange factor)

$$= K_{Ca}^{Sr} \frac{E_x}{C_{Ca}}$$

K_{Ca}^{Sr} = equilibrium constant (ratio)

E_x = cation exchange capacity (mg/gm)

C_{Ca} = calcium (or Ca + Mg) ion concentration in ambient groundwater (meq/ml)

P_b = bulk density of the bedrock (g/ml)

n = porosity (ratio)

Cation exchange capacities were measured for three bedrock samples from the site. The samples were ground into two different size fractions, and cation exchange capacities were determined for the two size fractions according to the Agriculture Handbook No. 60 Method (Reference 2.4-39). Cation exchange capacities for samples including particle sizes ranging from 0.001 mm to 1.39 mm averaged 0.5 meq/g. Samples of particle sizes ranging from 4.01 mm to 38 mm have an average cation exchange capacity of 0.05 meq/g.

A cation exchange capacity of 0.05 meq/g was selected as representative of the materials through which the groundwater moves. The cation exchange capacity of a ground rock sample is inversely related to the particle size. Although no fine particle sizes are included in the 4 mm to 38 mm size fraction, bedrock fractures at the site are partially filled with particle sizes less than 4 mm. Thus, it is probable that exchange capacities are higher than 0.05 meq/g at the site, making the value conservative.

A bulk density of 2.65 g/ml, obtained from the literature (Reference 2.4-40), was selected as representative of the rock at the site.

The equilibrium constant (K_{Ca}^{Sr}) for strontium-calcium systems reported in the literature, ranges between 1.0 and 1.6, depending on the percentage of Sr and Ca of the total cation concentration in solution and the principal clay minerals (Reference 2.4-41). Because reduction in concentration is inversely proportional to the selectivity coefficient, a conservative value of 1.0 was chosen.

Concentrations of dissolved solids in ambient groundwater are given in Table 2.4-19. The highest concentration of Ca in the groundwater samples tested is 178 ppm as $CaC0_3$. This sample has a total hardness of 618 ppm as $CaC0_3$. The concentration of Mg as $CaCo_3$ is equal to the total hardness minus Ca hardness as $CaC0_3$, or 440 ppm. These concentrations are equivalent, as divalent ions, to 0.004 meq/ml Ca^{++} and 0.009 meq/ml Mg^{++}, which is a total of 0.013 meq/ml to compete with Sr-90 for exchange sites.

Using these values for the parameters, and the above described relationships, a distribution coefficient (K_d) of 3.84 ml/gm is determined. According to the calculated velocity of the Sr-90 in groundwater, the ion travels at 1.2 ft/yr and takes 666.6 yrs to travel the 800 feet to the river.

2.4.13.3.4 Dispersivity (Dispersion Constant)

The dispersivity (D_m) can be expressed as a characteristic length. Attempts by researchers have been made to relate the median grain-size (d_{50}) to dispersivity in porous media (Reference 2.4-42).

The jointed and fractured bedrock beneath the site approximates a porous medium over a large representative elementary volume. Thus, the distance between fractures, which in some places is on the order of meters, is a reasonable estimate of dispersivity. However, for conservatism in this analysis, a dispersivity of 4 mm (0.013 ft) was chosen, the grain-size fraction from which the cation exchange capacity was determined.

2.4.13.3.5 Results of Analysis

All of the parameters used for the analysis were selected with a very high degree of conservatism. The parameters are presented in Table 2.4-20. The solution, which accounts for ion adsorption, radioactive decay, and one-dimensional longitudinal dispersion, was obtained for the Sr-90 ion. As discussed previously, the movement of strontium in groundwater is faster than the movement of cesium. Thus, actual cesium concentrations at the river would be much less than those calculated for Sr-90. Other radionuclides in the radwaste tank have short half-lives in comparison to groundwater travel times, and they will decay below MPC levels before reaching the Schuylkill River.

As discussed at the beginning of this section, accidental releases are assumed to spill from the waste sludge tank at the radwaste enclosure directly into the groundwater and flow toward the Schuylkill River. Radionuclides in the contaminated groundwater are considered to be at the same concentration as in the waste sludge tank (Table 11.4-9). The travel time of groundwater from the radwaste enclosure to the river is 3.28 years. Considering the adsorption of the Sr-90 ion, the travel time is 666.6 years. The maximum concentration of Sr-90 and Cs-137 that will arrive at the river is less than 1.34×10^{-10} μCi/ml. This is 10^3 times below MPC concentrations for both Sr-90 and Cs-137. Because of the conservative nature of the input parameters, actual concentrations would probably be lower.

From the analysis, it is evident that should a spill of radioactive effluents from the radwaste enclosure reach the groundwater beneath the LGS site, it would not constitute a health hazard to the potable sources of water in the vicinity. Radionuclides in such a spill would decay sufficiently below MPC concentrations before leaving the site.

For the radioactive spill in the Unit 2 turbine building entering the groundwater, based on a conservative analysis, the only isotope above the 10CFR20 maximum permissible concentration (mpc) released from a feedwater line break is tritium (^3H). The mpc value for tritium (^3H) is 3×10^{-3} μCi/gm. NUREG-0016 indicates that the expected Tritium concentration in the feedwater is 1×10^{-2} uCi/gm. Tritium would not be retarded by absorption into the groundwater and since it has a long half life, radioactive decay would not have an appreciable effect. The equilibrium concentration of tritium at well 4 will be 1.5×10^{-3} μCi/gm (below the 10CFR20 mpc level) one year after the accidental spill.

Using the conservative assumption of a continuous source to model the feedwater line break, concentrations at site well 4 are below the 10CFR20 mpc levels. Ample time exists between the accident and the time that concentrations reach the maximum levels. Therefore, site well 4 can be used following an accident. Furthermore, routine monitoring tests of the wells utilized for drinking

water assures that the continued use of site wells does not compromise the safety of the public or plant employees.

2.4.13.4 Monitoring and Safeguard Requirements

Groundwater levels were measured in borings (observation wells) at various locations (Table 2.4-17) near the spray pond and power block areas. The observation wells were monitored at regular intervals from June 1973 through August 1975, and November 1978 through May 1979 to determine the direction of groundwater movement and the elevation of the water table, and to establish structural design criteria for groundwater effects (Sections 2.4.13.2.4 and 2.4.13.5). These wells were subsequently monitored throughout the remaining plant construction period to determine the effect of plant construction on groundwater movement and level, and to verify/assure the adequacy of the design criteria used for design of safety-related plant structures. The recorded water levels in the wells are shown in the hydrographs in Figure 2.4-18.

Figure 2.4-20 shows the corresponding monthly precipitation, and Table 2.4-21 lists the monthly highest water levels measured at the wells of Figure 2.4-15 during the 36 months of monitoring. Also listed in the table are the estimated maximum water levels and highest levels of record at each well, and the corresponding precipitation during the month of highest level. During the 36 month observation period, the highest observed water level was 4.8 feet below the estimated maximum water level at well P11, and the average difference between the estimated maximum water level and the observed maximum water level is 12 feet.

Water levels continued to be measured monthly in the observation wells between September 1979 and February 1982. Three additional wells were constructed in 1981 (wells P17, P18 and P19) and are shown on Figure 2.4-15. Wells P1 and P4 were destroyed during construction of the spray pond. Monitoring of the wells, up to February 1982, covered a period of 66 months, beginning in June 1973.

The extended monitoring of the observation wells demonstrated that May is an annual period of high water levels. During the period of monitoring the water levels did not exceed the estimated maximum water levels except in well SP22. This occurred in May, 1981 when the water level reached el 247.4' which is 0.1 foot higher than the estimated maximum. This well is located between the cooling towers and the spray pond. A review of the hydrograph of well SP22 (Figure 2.4-18) shows a steady increase in water level beginning in June 1974, when it was installed, to about April 1980. Since April 1980 the level has fluctuated in a manner similar to that of other wells. None of the other observation wells experienced this steady increase in level. They have tended to maintain a steady level, or to slightly decline since installation.

The steady increase in water level at SP22 is attributed to the buildup of a localized groundwater mound that was caused by infiltration of water from construction activities within this area. As construction activities decrease and the surface drains in the area are lined, this localized groundwater mound is expected to slowly dissipate.

This water level monitoring has indicated no changes in the groundwater flow direction. The changes in potentiometric surface throughout major plant construction and site grading/surfacing are within the plant design criteria established in Section 2.4.13.5.

The groundwater monitoring program will be discontinued one year after all major site grading/surfacing is completed because further significant changes in the potentiometric surface are not expected. The network of groundwater observation wells will then be abandoned and sealed.

2.4.13.5 Design Bases for Subsurface Hydrostatic Loading

During the operating life of the plant, the underlying groundwater table is expected to be at approximately the same elevations as shown in Figure 2.4-15. As discussed in Section 2.4.13.2.4.2, fluctuations of the measured levels in most observation wells during the 36 months of monitoring have been less than 12 feet, and the maximum has been 17 feet. The levels indicated on Figure 2.4-15 are near the seasonally high levels of those fluctuations.

Although the period of monitoring covers only 36 months, it is sufficient to establish typical seasonal fluctuations and provide a basis for estimating what may be expected during the operating life of the plant. Thus, the maximum expected groundwater levels are conservatively estimated to be 15 feet above the levels shown in Figure 2.4-15 (these levels were measured in May, when levels are near their maximum). In applying this to the design bases for subsurface hydrostatic loading, a single groundwater level is not applicable to all structures, nor even to individual structures, because of the relatively steep gradient of the water table. It can be seen in Figure 2.4-15 that, from the northeast corner of the turbine building to the southwest corner of the radwaste enclosure, the water table drops relatively uniformly more than 50 feet in elevation. Therefore, for the design bases, two maximum expected water levels are provided for each principal structure: the highest (beneath the northeast corner) and the lowest (beneath the southwest corner).

The maximum expected water levels are:

	Maximum expected water table el (ft)	
Structure	Northeast corner	Southwest corner
Turbine enclosure	205	175
Reactor enclosure	195	175
Radwaste enclosure	180	160

Groundwater contours prepared from water levels measured on May 31, 1988 indicate that the above water levels are conservative. These contours are shown in Figure 2.4-15.

2.4.14 TECHNICAL SPECIFICATION AND EMERGENCY OPERATION REQUIREMENTS

The possibility of adverse hydrologically related events at the LGS site is precluded by the configuration of the site topography.

Consequently, there are no emergency protective measures designed to minimize the water associated impact of adverse hydrologically related events on safety-related facilities. In addition, there is no need for technical specifications for plant shutdown required by accidents resulting from these events. Further discussion is in Sections 2.4.1.1 and 2.4.2.2.

The UHS, as described in Sections 2.4.8 and 9.2.6, has been designed with appropriate consideration to adverse hydrologically related events.

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Table 2.4-1

ACCESS OPENINGS IN SAFETY-RELATED STRUCTURES

STRUCTURE	ACCESS OPENING	NUMBER OF OPENINGS	FLOOR ELEVATION (ft)
Reactor enclosure	Personnel door to service water pipe tunnel	1 per unit	201
	Personnel door to outside	1 per unit	217
	Personnel door to radwaste enclosure or turbine enclosure	1 per unit	217
	Equipment airlock	1 per unit	217
	Railroad car airlock	1 common	217
	Personnel door to turbine enclosure	1 per unit	269
Control structure	Double doors to turbine enclosure	3	200
	Double doors to turbine enclosure	3	217
	Personnel doors to turbine enclosure	9	239
	Personnel door to turbine enclosure	1	254
	Personnel doors to turbine enclosure	3	269
	Personnel door to turbine enclosure	1	290
	Personnel doors to turbine enclosure	2	304
	Double doors to turbine enclosure		304

Table 2.4-1 (Cont'd)

STRUCTURE	ACCESS OPENING	NUMBER OF OPENINGS	FLOOR ELEVATION (ft)
Diesel generator enclosure	Personnel doors to outside cell	2 per DG	217
Spray pond pump structure	Personnel doors to outside	2	268
	Roll-up doors to outside	2	268

Table 2.4-2

MINOR DAMS UPSTREAM OF LGS SITE[1]

NAME	STREAM	HEIGHT (ft)	VOLUME (acre-ft)	DRAINAGE AREA (mi^2)
Still Creek	L. Schuylkill - Trib.	48	767	8.5
PA-422	L. Schuylkill - Trib.	87	3,850	15.6
PA-422A	L. Schuylkill - Trib.	55	925	3.1
PA-424	L. Schuylkill - Trib.	35	459	2.2
PA-423	L. Schuylkill - Trib.	98	1,965	13.1
Tamaqua – 1	L.Schuylkill - Trib.	28	123	2.7
Tamaqua – 2	L. Schuylkill - Trib.	38	954	1.7
PA-425	L. Schuylkill - Trib.	21	229	1.1
Minersville – 1	Schuylkill - Trib.	24	55	4.4
Minersville – 2	Schuylkill - Trib.	33	196	2.6
Crystal	Schuylkill - Trib.	40	200	5.1
Indian Run	Schuylkill - Trib.	14	15	2.4
Silver Creek	Schuylkill - Trib.	47	712	1.1
Auburn	Schuylkill River	16	1,900	157.0
Dear Lake	Schuylkill - Trib.	9	55	13.6
Kernsville	Schuylkill River	17	583	340.0
PA-476	Schuylkill - Trib.	38	63	0.5
PA-477	Schuylkill - Trib.	47	206	1.59
PA-478	Schuylkill - Trib.	51	664	1.39
Felix	Schuylkill River	24	1,470	647.0
Bernhart	Schuylkill - Trib.	30	129	2.6
Antietam	Schuylkill - Trib.	60	310	5.4
Green Hills	Schuylkill - Trib.	17	187	15.3

(1) These data were compiled from Reference 2.4-12 and from a tabulation furnished by the Dam Safety Section, Division of Dams and Encroachments, Department of Environmental Resources, Commonwealth of Pennsylvania, P.O. Box 2063, Harrisburg, PA 17120, dated March 1, 1977.

Table 2.4-3

DAM FAILURE INVESTIGATION:
CHARACTERISTICS OF MAJOR UPSTREAM DAMS

CHARACTERISTICS	ONTELAUNEE	MAIDEN CREEK	BLUE MARSH
Date constructed	1926-34	Authorized[2]	1979
Distance upstream LGS (mi)	37	42	35
Stream name	Maiden Creek	Maiden Creek	Tulpehocken
el at base (ft)	253	302	236
el spillway crest (ft)	294	394	307
el top dam (ft)	305	412	332
PMF - peak inflow (cfs)	No Est.	118,000	128,600
PMF - peak outflow (cfs)	No Est.	92,000	74,800
SPF - peak inflow (cfs)	No Est.	49,000	54,300
SPF - peak outflow (cfs)	No Est.	17,500	30,300
SPF - max water surface (ft)	No Est.	397.5	317.5
Volume below spillway (acre-ft)	11,900	114,000	50,000
Spillway capacity (cfs)	41,000	92,000	74,000
Type of dam	Earth fill and masonry gravity spillway	Earth and rock fill	Random fill with impervious core
Assumed water surface elevation at time of failure[1] (ft)	304.2	397.5	317.5
Volume at time of failure (acre-ft)	29,000	130,000	76,700

(1) Used in failure study. Equivalent to water surface required to pass floods greater than or equal to the standard project flood

(2) Construction indefinitely deferred

Table 2.4-4

DOMESTIC WATER USERS ON SCHUYLKILL RIVER

DOWNSTREAM OF LGS SITE

No.	Water User[1]	1971[2] Use	ENTITLEMENT				
			Total	Non-Comsumptive	Comsumptive	Consumptive as a Percentage of Total	Approximate Location (River mi.)[3]
1.	Philadelphia Water Dept., Belmont Water Treatment Plant	5,145.250	7,843.200	7,451.040	392.160	5	10.21 (Belmont)
2.	Philadelphia Water Dept., Queen Lane Water Treatment Plant	(4)	(4)	(4)	(4)	4)	12.61 (Queen Lane)
3.	Keystone Water Co., Norristown Dist.	258.333	510.720	459.648	51.072	10	24.30
4.	Philadelphia Suburban Water Co.	11.650	608.000	528.960	79.040	13	34.40
5.	Phoenixville Borough	144.827	212.800	191.520	21.280	10	35.50
6.	Citizens Utility Home Water Co.	35.649	60.800	54.720	6.080	10	45.70

(1) See Figure 2.4-2 for locations of water users.
(2) Water use is given in 10^6 gallons per month (1 month = 30.4 days).
(3) Measured from the confluence of the Schuylkill River with the Delaware River. Source: DRBC, Trenton N.J., and EPA Region III, Philadelphia, PA.
(4) Data included with Belmont Water Treatment Plant.

Table 2.4-5

INDUSTRIAL WATER USERS ON SCHUYLKILL RIVER
DOWNSTREAM OF LGS SITE[4]

No.	Water User[1]	1971[2] Use	ENTITLEMENT Total	Non-Comsumptive	Comsumptive	Consumptive as a Percentage of Total	River Distance From Station (mi.)[3]
7.	Connelly Containers Inc., Philadelphia Plant	1.160	1.751	1.576	0.175	10	34.4
8.	Container Corp. of America, Philadelphia Plant, Mill Div.	247.333	328.320	321.754	6.566	2	33.0
9.	Nicolet Industries Inc., Norristown Plant	1.700	13.133	12.520	0.613	4.67	30.0
10.	PECo, W. Conshohocken Gas Plant	26.250	55.750	55.192	0.558	1	27.2
11.	National Gypsum Co. (Allentown Portland-Cement Co.) W. Conshohocken Plant	66.666	66.666	65.999	0.667	1	27.05
12.	Lukens Steel Co.[5]		54.602	52.107	2.495	4.6	25.70
13.	PECo, Barbadoes Generating Station	Station Closed in 1996					
14.	Synthane-Taylor Corp.	24.417	39.398	39.004	0.394	1	17.4
15.	Phoenix Steel Corp. (Phoenixville Plant)	250.000	509.490	407.592	101.898	20	12.4
16.	PECo, Cromby Generating Station	Station Closed in 2011					
17.	Keystone Coke Co.[5]		65.362	49.506	15.856	24.3	26.10

(1) These serial numbers are a continuation of those in Table 2.4-4.
(2) See Figure 2.4-2 for locations of water users.
(3) Water use is given in 10^6 gallons per month (1 month = 30.4 days).
(4) Source: DRBC, Trenton N.J., and EPA Region III, Philadelphia, PA.
(5) No entitlement, rather a fee is paid for water withdrawn from the river.

Table 2.4-6

MAJOR FLOODS AT SELECTED STATIONS ON SCHUYLKILL RIVER[1]

		BERNE DA = 335 sq mi		READING DA = 880 sq mi		POTTSTOWN DA = 1147 sq mi		PHILADELPHIA DA = 1893 sq mi	
YEAR	DATE	Gauge Ht (ft)	Peak Q (cfs)	Gauge Ht (ft)	Peak Q (cfs)	Gauge Ht (ft)	Peak Q (cfs)	Gauge Ht (ft)	Peak Q (cfs)
1972[2]	22-23 June	19.00	42,800	-	-	29.97	95,900	14.65	103,000
1955	19 Aug	15.73	29,400	-	-	17.98	42,300	14.32	90,100
1950	26 Nov	14.52	23,300	-	-	17.90	42,000	14.32	89,800
1942	23 May	15.00	26,900	21.6[3]	-	20.15	50,800	12.44	61,400
1933	24 Aug	-	-	-	-	19.20	47,800	14.70	98,200
1902	28 Feb	-	-	21.5	70,600	21.00	53,900	14.80	98,000
1869	4 Oct	-	-	21.6	71,200	-	-	17.00	135,000
1850	2 Sept	-	-	23.0	80,000	-	-	16.42	125,000
1839	26 Jan	-	-	13.9	33,300	-	-	15.80	114,000
1757	15 July	-	-	15.0	37,200	-	-		

(1) From References 2.4-21 and 2.4-22
(2) From Reference 2.4-15
(3) Estimated

Table 2.4-7

PROBABLE MAXIMUM PRECIPITATION AT LGS SITE

INITIAL 6 HOUR PMP DISTRIBUTION[1]

Time (hrs)	Incremental Depth (in)	Fraction of Hour Total Depth (%)
0-1	2.7	10
1-2	3.2	12
2-3	4.0	15
3-4	10.2	38
4-5	3.8	14
5-6	2.9	11

72 HOUR PMP DISTRIBUTION[2]

Time (hrs)	Accumulated PMP Depth (in)
6	26.8
12	31.1
24	34.4
48	38.0
72	39.7

(1) 6 hour PMP distribution taken from Reference 2.4-4
(2) PMP estimates taken from Reference 2.4-2

Table 2.4-8

SUMMARY OF RUN-OFF FROM LOCAL INTENSE PRECIPITATION

RUN-OFF BY DRAINAGE AREA

Drainage Area[1]	Area (acres)	Peak Discharge (cfs)	Routed to Collection Point[1]
DA-1	17.2	251[2]	CP-5
DA-2	25.0	620	CP-1 and CP-2
DA-3	4.5	151	CP-3
DA-4	20.8	550	CP-3 and CP-4
DA-5	14.9	369	CP-3
DA-6	11.6	242	CP-4

RUN-OFF BY COLLECTION POINTS

Collection Point[1]	Areas Drained[1]	Maximum Discharge at CP (cfs)	Maximum Energy Grade-Line at CP
CP-1	DA-2	530	262.7
CP-2	DA-2	620	245.5
CP-3	DA-3, 4,and 5	446	218.1
CP-4	DA-4 and 6	555	218.1
CP-5	DA-1	194	252.0

(1) See Figures 2.4-4, 2.4-5, and 2.4-6 for locations of drainage areas and collection points.
(2) Corresponds to maximum 30 minute mean inflow to the spray pond.

Table 2.4-9

SURFACE WATER GAUGING STATIONS UPSTREAM FROM LGS SITE

LOCATION NO.	STATION NAME	STATION NO.	RAINAGE AREA (sq mi)	PERIODS OF RECORD		
				Daily or Monthly (Calendar Year)	Annual Peak (Water Years)	Low Flow Measurements (Water Years)
1	Schuylkill River at Pottsville, Pa.	4675	53.4	1943-	-	-
2	West Branch Schuylkill River at Cressona, Pa.	4679.5	52.5	1964-1965	-	-
3	Schuylkill River at Landingville, Pa.	4685	133	1947-1953; 1963-1965	-	-
4	Schuylkill River at Auburn, Pa.	4690	160	1947-1951	-	-
5	Still Creek Reservoir near Hometown, Pa.	4692	8.5	1933-	-	-
6	Little Schuylkill River at Tamaqua, Pa.	4695	42.9	1916-1919; 1919-	-	-
7	Little Schuylkill River at Drehersville, Pa.	4700	122	1947-1951; 1963-1965	-	-
8	Schuylkill River at Berne, Pa.	4705	355	1947-	-	-
9	Maiden Creek near Lenhartsville, Pa.	4707	75.5	-	-	1943; 1946-57
10	Maiden Creek Tributary at Lenhartsville, Pa.	4707.2	7.46	1965-	1962-1965	-
11	Sacony Creek at Virginville, Pa.	4707.5	55.5	-	-	1958 -
12	Mill Creek near Bernville, Pa.	4707.8	11.9	-	-	-

Table 2.4-9 (Cont'd)

LOCATION NO.	STATION NAME	STATION NO.	RAINAGE AREA (sq mi)	PERIODS OF RECORD		
				Daily or Monthly (Calendar Year)	Annual Peak (Water Years)	Low Flow Measurements (Water Years)
13	Tulpehocken Creek at Bernville, Pa.	4708	84.8	-	-	1943; 1946-57
14	Northmill Creek at Bernville, Pa.	4709	42.0	-	-	1943; 1946-57
15	Tulpehocken Creek at Blue Marsh Dam site near Reading, Pa.	4709.6	175	1965-	-	-
16	Tulpehocken Creek near Reading, Pa.	4710	211	1950-	-	-
17	Schuylkill River at Reading, Pa.	4715	880	1914-1915; 1915-1919; 1919-1930	-	-
18	Allegheny Creek at Beckersville, Pa.	4716	11.3	-	-	1946-1957
19	Monocacy Creek at Limekiln, Pa.	4717	6.68	-	-	1946-1957
20	Pine Creek near Manatawny, Pa.	4718	15.6	-	1961-	-
21	Manatawny Creek at Earlville, Pa.	4719	60.0	-	-	1946-1957
22	Schuylkill River at Pottstown, Pa.	4720	1147	1926-	-	-

(1) The locations are shown on Figure 2.4-8.

Table 2.4-10

OBSERVED AND ESTIMATED WATER SURFACE ELEVATIONS OF SCHUYLKILL RIVER AT LGS SITE

OCCURRENCE	DISCHARGE (cfs)	WATER SURFACE ELEVATION AT SITE (ft)
Observed 12/5/69	566	105.3
Observed 12/18/69	1,610	106.5
Computed Floods		
Average Annual (Pottstown Records)	21,000	117.4
Average Annual (WSP 1672)	28,000	119.5
Maximum Observed Before 1972	53,900	125.7
100 Year (WSP 1672)	99,000	134.8
Additional Discharge for Rating Curve	200,000	145.0
Additional Discharge for Rating Curve	356,000	158.0

Table 2.4-11

DERIVED VALUES OF MANNING'S (n) FOR SCHUYLKILL RIVER MAIN CHANNEL

LOCATION	WATER LEVEL		MANNING'S (n)	APPROXIMATE REACH LENGTHS (mi)
	Observed	Computed		
Pottstown Hanover St. Bridge	135.84	135.8	0.028	1
S. Pottstown Madison St. Bridge	133.55	133.6	0.036	6
Linfield Highway Bridge	120.03	120.0	0.048	4.7
Spring City Highway Bridge	105.97	106.0[1]	-	-

[1] Assigned starting elevation for computations

Table 2.4-12

COMPUTATION OF CONVERGENCE IN BACKWATER STUDY

DISCHARGE (cfs)	STARTING WATER SURFACE -12½%	STARTING WATER SURFACE +12½%[1]	COMPUTED WATER SURFACE AT SITE -12½%	COMPUTED WATER SURFACE AT SITE +12½%	DIFF (ft)
21,000	95.8	97.6	117.4	117.4	-
28,000	97.8	100.0	119.5	119.5	-
53,900	103.9	106.8	125.7	125.7	-
99,000	111.4	115.3	134.7	134.9	0.2
200,000	123.7	128.9	144.8	145.7	0.9
356,000	137.8	144.5	157.3	159.2	1.9

[1] +12½% refers to assumed channel conveyance $\Sigma\left(\frac{AR^{2/3}}{n}\right)$ compared with the computed requirement at the downstream end of study reach.

Table 2.4-13

CONVEYANCE, SLOPE, AND STAGE FOR SELECTED DISCHARGES
ABOVE 356,000 cfs AT LGS SITE

DISCHARGE Q (cfs)	FRICTION SLOPE S_f	REQUIRED CONVEYANCE K (10^6 cfs)	REQUIRED STAGE el=f(K) (ft)
450,000	0.00025	28.2	171
600,000	0.00023	39.9	183
750,000	0.00021	51.3	197
900,000	0.00020	63.6	207
1,100,000	0.00019	80.4	217

Table 2.4-14

CHEMICAL ANALYSIS OF GROUNDWATER IN THE BRUNSWICK LITHOFACIES IN MONTGOMERY COUNTY, PENNSYLVANIA[1]

DATE OF COLLECTION	DEPTH OF WELL (ft)	SILICA (SiO)	TOTAL IRON (Fe)	TOTAL MANGANESE (Mn)	CALCIUM (Ca)	MAGNESIUM (Mg)	SODIUM (Na)	POTASSIUM (K)	BICARBONATE (HCO_3)
9-25-25	350	18	0.06	-	47	17	9.4	2.1	194
9-28-25	388	32	0.05	-	36	15	11	1.8	173
2-21-52	387	21	0.01	-	24	20	6	1.0	150
5-10-62	219	30	0.37	0.00	57	18	13	0.7	171
4-07-53	205	13	0.26	-	57	28	13	1.0	242
2-07-62	373	17	0.07	0.00	45	5.4	12	1.0	134
2-08-62	202	22	0.04	0.00	55	23	14	1.0	256
4-09-62	600	20	0.44	0.02	116	51	22	0.8	163
3-02-61	300	22	0.05	0.00	39	8.3	10	1.0	120
3-01-61	450	19	0.26	0.01	47	9.0	14	1.0	179
4-09-62	210	24	0.00	0.17	49	12	12	0.8	128
3-02-61	916	28	3.9	0.04	180	32	27	1.0	180
4-21-49	100	20	0.17	-	52	13	11	1.4	198
2-28-61	500	16	0.38	0.03	30	8.2	45	0.5	173
3-01-62	312	28	0.02	0.03	90	36	19	1.8	162
2-27-61	300	17	0.21	0.06	71	30	30	1.5	217
3-01-61	300	24	0.06	0.04	39	14	8.3	1.0	178
3-01-61	500	28	0.70	0.38	59	17	15	1.0	252
3-01-61	300	32	0.02	0.05	126	28	19	2.5	158
2-05-62	123	23	0.14	0.00	70	21	12	1.5	236
2-08-62	80	23	0.05	0.00	44	34	12	1.0	298
2-08-62	100	22	0.20	0.00	55	20	14	2.2	202
2-08-62	81	33	0.07	0.00	36	17	11	3.0	152
2-05-62	157	21	1.6	0.00	54	36	17	1.5	268
4-09-62	133	19	3.0	0.12	53	15	15	1.5	211
9-30-25	111	23	4.9	-	45	11	12	3.0	183
9-30-25	110	25	0.15	-	48	24	12	1.2	234

Table 2.4-14 (Cont'd)

DATE OF COLLECTION	SULFATE (SO_4)	CHLORIDE (Cl)	FLUORIDE (F)	NITRATE (NO_3)	DISSOLVED SOLIDS (residue at 180°C)	HARDNESS AS $CaCO_3$ CALCIUM, MAGNESIUM	HARDNESS AS $CaCO_3$ NON-CARBONATE	SPECIFIC CONDUCTANCE (microhms/cm at 25°C)	pH
9-25-25	23	13	-	7.5	232	187	28	-	-
9-28-25	15	8	-	2.5	201	152	10	-	-
2-21-52	22	5	-	0.4	-	142	19	321	6.4
5-10-62	69	16	0.1	4.9	317	216	76	457	6.6
4-07-53	58	18	0.0	9.9	327	257	59	555	7.3
2-07-62	26	10	0.1	13.0	200	135	25	313	7.5
2-08-62	19	17	0.1	7.7	285	232	22	480	7.6
4-09-62	370	11	0.1	11	732	500	366	959	7.3
3-02-61	24	7.4	0.1	20	192	132	33	295	7.7
3-01-61	12	9.3	0.0	18	214	155	8	351	7.8
4-09-62	69	5.8	0.1	13	252	172	67	378	6.8
3-02-61	420	18	0.2	2.8	805	581	433	1090	7.4
4-21-49	23	7.0	0.0	12	242	183	21	392	7.5
2-28-61	48	3.5	0.0	3.7	239	109	0	378	8.0
3-01-62	248	6.0	0.2	2.7	534	373	240	747	7.7
2-27-61	84	68	0.1	5.6	426	301	123	695	7.9
3-01-61	17	4.2	0.0	8.0	204	155	9	322	7.7
3-01-61	37	4.2	0.1	0.2	283	217	11	447	7.5
3-01-61	300	16	0.6	0.5	620	430	300	838	7.6
2-05-62	32	20	0.1	36	344	261	68	536	7.6
2-08-62	9.7	5.1	0.1	20	302	250	6	490	8.2
2-08-62	40	18	0.2	19	307	219	54	478	7.4
2-08-62	29	13	0.2	8.8	236	160	36	359	7.7
2-05-62	83	6.4	0.1	3.1	360	283	63	565	7.6
4-09-62	27	13	0.0	4.0	255	194	21	429	6.9
9-30-25	13	12	-	0.88	209	158	8	-	-
9-30-25	6.4	19	-	14	252	218	26	-	-

(1) Results are in parts per million except as indicated.

Table 2.4-15

PUBLIC GROUNDWATER SUPPLIES

WATER COMPANY	AREA SERVED	SOURCE PRIMARY (1), SECONDARY (2) STREAMS	WELLS	SPRINGS	SOURCES	AV PLANT OUTPUT (mgd)	ESTIMATED POPULATION SERVED	NUMBER OF SERVICES
Ambler Borough Water Department (B)	Ambler Borough; part of Upper Dublin, Whitpain Lower Gwynedd, and Whitemarsh Townships	-	1	2	1 spring 6 wells	1.82	15,310	4,410
Audubon Water Company (B)	Lower Providence Township	-	1	-	10 wells	.39	5,600	1,156
Borough of Boyertown Water Department (A)	Borough of Boyertown; part of Douglass and Colebrookdale Townships	2	-	1	Several springs, Trout River, unnamed tributary to Ironstone Creek, Ironstone Creek	.46	4,400	1,423
Citizens Utilities Home Water Company (B)	Royersford and Spring City Boroughs, part of Limerick and Upper Providence Townships	-	2	-	Schuylkill River 2 wells	1.46	7,830	3,059
Collegeville-Trappe Joint Water Works (B)	Collegeville and Trappe Boroughs	-	1	-	6 wells	.26	4,870	977
Douglasville Water Company (A)	Amity Township	-	1	-	2 wells	.02	450	100
Dublin Water Company (B)	Upper Dublin Township	-	1	-	3 wells	.60	3,650	1,170
Borough of East Greenville Water Department (B)	East Greenville Borough	1	2	-	Perkiomen Creek 1 well	.19	2,100	1,170

Table 2.4-15 (Cont'd)

WATER COMPANY	AREA SERVED	SOURCE PRIMARY (1), SECONDARY (2) STREAMS	WELLS	SPRINGS	SOURCES	AV PLANT OUTPUT (mgd)	ESTIMATED POPULATION SERVED	NUMBER OF SERVICES
Evansburg Water Company (B)	Evansburg Borough; part of Lower Providence Township	-	1	-	1 well	.02	120	38
Graterford State Correctional Institution (B)	Graterford	-	1	-	8 wells	.67	1,700	--
Hatfield Water Department (B)	Hatfield Borough; part of Hatfield Township	-	1	-	7 wells	.50	6,790	1,142
Horsham Water Authority (B)	Horsham Township	-	1	-	11 wells	.74	7,850	2,497
Lionville Water Co (A)	Uwchland Township	-	1	-	2 wells	.01	150	45
Lyons Water Co (A)	Lyons Borough	-	1	2	2 wells, 2 springs	.03	590	143
Malvern (Water Dept.) (A)	Malvern Borough	-	1	2	3 wells, 2 springs	.15	725	180
Mount Penn Municipal Water Authority (A)	Mount Penn Borough, Lower Alsace and St. Lawrence Townships	3	1	2	3 wells, springs, stream	.60	12,000	2,797
Norristown State Hospital (B)	Norristown	-	1	-	6 wells	.36	1,600	--
North Penn Water Authority (B)	Lansdale and Souderton Boroughs, Franconia,Hatfield and Towamencin Townships; part of Worcester Township	-	1	-	36 wells Bulk purchase from North Wales	3.40	38,000	9,495

Table 2.4-15 (Cont'd)

WATER COMPANY	AREA SERVED	SOURCE PRIMARY (1) SECONDARY (2) STREAMS	WELLS	SPRINGS	SOURCES	AV PLANT OUTPUT (mgd)	ESTIMATED POPULATION SERVED	NUMBER OF SERVICES
North Wales Water Authority (B)	North Wales Borough; Upper & Lower Gwynedd Townships and Montgomery Township; bulk water to Lansdale Borough	-	1	-	19 wells	2.97	22,710	6,192
Pennhurst State School (A) Township	East Vincent	-	1	-	6 wells	.40	3,900	--
Pennsburg Water Co (A)	Part of Upper Hanover and Hereford Townships	-	1	2	2 wells	.35	2,400	700
Perkasie Borough Authority (A)	Perkasie Borough	-	1	2	4 wells, springs	.25	5,500	1,350
Philadelphia Suburban Water Company (B)	Conshohocken, Narberth and West Conshohocken Boroughs; Abington, Cheltenham, Lower Merion, Plymouth, Spring Field, Upper Dublin, Upper Merion, Upper Moreland, Lower Moreland, Whitemarsh, Eastown, East Whiteland, Tredyffrin, Chester, Willistown and Radnor Townships	1 ,	2	-	Schuylkill River, Pickering Creek Perkiomen Creek, 17 wells	77.6	311,170	219,796

Table 2.4-15 (Cont'd)

WATER COMPANY	AREA SERVED	SOURCE PRIMARY (1), SECONDARY (2) STREAMS	WELLS	SPRINGS	SOURCES	AV PLANT OUTPUT (mgd)	ESTIMATED POPULATION SERVED	NUMBER OF SERVICES
Red Hill Water Authority (B)	Red Hill Borough	-	-	1	spring	.12	1,550	496
Saint Gabriel's Hall (B)	Lower Providence Township	-	1	-	2 wells	.02	--	--
Schwenksville Borough Water Department (B)	Schwenksville Borough; part of Lower Frederick and Perkiomen Townships	-	1	-	3 wells	.13	1,985	336
Sellersville Water Department (B)	Sellersville	-	2	1	Springs, 4 wells	.20	2,500	650
Skippack Water Company	Skippack Township	-	1	-	8 wells	.002	225	72
Telford Water Authority (B)	Telford and part of Souderton Boroughs, part of Franconia Township	-	1	-	4 wells	.02	-	-
Trumbauersville Water Department (A)	Trumbauersville	-	1	-	2 wells	.03	400	94

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(A)Biesecker et al., 1968
(B)Hammer, 1976

Table 2.4-16

PRIVATE GROUNDWATER USERS IN THE VICINITY OF THE SITE[1]

OWNER'S NAME	TOTAL DEPTH (ft)	DIAM (in)	CASING LENGTH (ft)	STATIC WATER LEVEL (ft)	YIELD (gpm)	REMARKS
Leroy Shaner	226	6	40±	-	-	Pump Capacity 30 gpm Serves 104 trailer houses and apartments
Leroy Shaner	300	6	40±	50±	-	Pump Capacity 18 gpm
Tom & Mike Volpe	193	6	-	-	-	Serves bar and grill
Saratoga Inn	120	6	-	-	-	Serves hotel bar and restaurant
Mike Bar	138	6	-	-	-	Single dwelling
Pottstown Trap Rock Quarry	130	6	20±	40±	100	Pumped at 50 gpm 10 hr/day
James Florig	260	6	20	80±	-	
Cliff Groff	20	-	-	-	-	Dug well
George Kirlin	110	6	45	40±	-	Single dwelling and livestock
Leonard Miller	109	6	20	50	6	Single dwelling
William Soditus	87	-	-	-	-	Single dwelling
Parker Ford Esso	38	-	-	-	-	Gasoline service station
Sailors Groceries	100±	-	-	-	-	Grocery store and single dwelling
Eastern Warehouses, Inc	80	4	-	-	40	
" " "	140	6	60±	-	120	Business (Warehouse and trucking)
" " "	100±	4	-	-	-	
" " "	100±	4	-	-	-	-
Wilmer Godshall	160	6	60	100±	60	Single dwelling
Ray Miller	90	-	-	15±	-	Single dwelling
East Coventry Elem School	202	6	69	72	25	500 elementary students and staff-two wells
E. Pennypacker	-	-	-	-	-	Spring in basement, supplied 30 head dairy cattle and dwelling. Never dry in 50 years.
R. Elliot	90	6	30±	5±	-	Supplies 80 head dairy cattle and dwelling
Swanson Service Co	Shallow	-	-	13±	-	10 employees
N. J. Hedrick	125	6	-	75±	-	Single dwelling
Publicker Industries	200	6	100±	50±	300	150,000 gpd average use from three wells in warehousing and bottling of distilled spirits
" "	160	6	100±	50±	200	
" "	160	6	100±	50±	120	
" "	-	-	-	-	-	
" "	-	-	-	-	-	Four wells similar to above in same area are inactive or abandoned.
" "	-	-	-	-	-	
" "	-	-	-	-	-	

[1] Inventory of wells performed by Dames and Moore, 1970

Table 2.4-17

OBSERVATION WELL CONSTRUCTION DATA

OBS. WELL	MONTH CONSTRUCTED	ELEVATION (ft) Ground Surface	ELEVATION (ft) Reference Point	DEPTH OF HOLE (ft)	INTERVAL SCREENED BELOW GROUND SURFACE (ft)
P1	6/73	268.31	268.59	120.0	105.0 - 115
P2	6/73	264.93	266.03	63.0	47 - 57
P3	6/73	244.65	245.38	65.0	50 - 60
P4	6/73	256.45	257.03	75.0	60 - 70
P5	6/73	249.03	247.60	71.0	56 - 66
P6	1/79	275.6	278.0	70.0	55 - 65
P7	1/79	267.8	269.6	72.5	57.5 - 67.5
P8	1/79	253.9	255.9	65.0	50 - 60
P9	1/79	257.6	260.2	65.0	50 - 60
P11	1/79	215.7	218.8	60.0	45 - 55
P12	1/79	215.5	218.3	100.0	65 - 75 85 - 95
P13	1/79	216.8	219.7	100.0	65 - 75 85 - 95
P14	1/79	216.4	217.3	80.0	65 - 75
P15	1/79	216.1	218.5	90.0	75 - 85
P16	1/79	216.7	219.2	80.0	65 - 75
P17	6/81	262.56	262.52	115.0	98 - 108
P18	6/81	266.0	267.8	120.0	100 - 110
P19	6/81	253.22	255.64	99.0	61 - 71
SP20	6/74	244.52	245.24	65.0	50 - 60
SP21	6/74	244.63	247.90	60.0	45 - 55
SP22	6/74	263.85	265.73	62.2	47.2 - 57.2
SP23	6/74	274.67	276.03	63.5	48.5 - 58.5

Table 2.4-18

PERMEABILITY DATA

Hole No.	Type of Test	Depth Interval Tested (ft.)	Zone Tested	Permeability (ft/yr)
PT1	Well Permeameter	4.38 - 7.55	Soil	<1
PT2	"	7.75 - 12.17	Soil	3
PT3	"	16.67 - 22.67	Soil	3
PT4	"	12.00 - 16.16	Soil	9
PT5	"	21.52 - 26.94	Rock	<1
PT6	"	19.37 - 23.25	Rock	<1
PT7	"	6.37 - 12.67	Soil	<1
SP17	"	20.97 - 21.77	Contact	21
SP18	"	19.10 - 21.10	Contact	17
SP19	"	14.70 - 16.45	Contact	3
P1	Packer	10 - 20	Rock	38
	"	20 - 30	Rock	41
	"	30 - 40	Rock	176
	"	40 - 50	Rock	266
	"	50 - 60	Rock	18
	"	50 - 60	Rock	7
	"	60 - 70	Rock	71
	"	70 - 80	Rock	1
	"	80 - 90	Rock	287
	"	90 - 100	Rock	<1
	"	100 - 110	Rock	28
	"	110 - 120	Rock	5
P2	"	14 - 22	Rock	<1
	"	22 - 32	Rock	41
	"	32 - 42	Rock	86
	"	42 - 52	Rock	119
	"	52 - 62	Rock	50
P3	"	15 - 25	Rock	1081
	"	25 - 35	Rock	476
	"	35 - 45	Rock	459
	"	45 - 55	Rock	371
	"	55 - 65	Rock	191
P4	"	25 - 35	Rock	329
	"	35 - 45	Rock	58
	"	45 - 55	Rock	525
	"	55 - 65	Rock	127
	"	65 - 75	Rock	361
P5	"	21 - 31	Rock	1247
	"	41 - 51	Rock	66
	"	51 - 61	Rock	314
	"	61 - 71	Rock	200

Table 2.4-19

CHEMICAL ANALYSIS OF GROUNDWATER FROM WELLS IN THE BRUNSWICK LITHOFACIES AT THE LGS SITE
(Results in ppm except as indicated)

Well No.	DATE COLLECTED	DEPTH OF WELL (ft)	CALCUIM AS $CaCO_3$	CHLORIDE	SULFATE	NITRATE AS (N)	AMMONIA AS (N)	IRON (TOTAL)	TOTAL ALKALINITY	TOTAL HARDNESS EDTSA	DISSOLVED SOLIDS	pH
1	12/10/70	307	16.0	4.5	422	0.26	1.36	.0	120	540	988	7.7
3	12/10/70	508	177.9	6.0	461	0.38	2.24	.0	148	618	1052	7.9
4	08/12/71	198	32.0	3.0	77	1.0	----	.04	116	134	202	8.0

Table 2.4-20

ACCIDENTAL SPILL ANALYSIS PARAMETERS

PARAMETERS	SYMBOL	VALUE
Hydraulic Conductivity	k	390 ft/yr
Hydraulic Gradient	I	0.031
Effective Porosity	n	0.05
Average Groundwater Velocity	U	243 ft/yr
Distance	x	800 ft
Travel Time of Groundwater	t	3.28 yr
Volume of spill		10,240 gal
Width of spill		30 ft
Initial Concentration Sr-90	C_o	2.2×10^{-3} Ci/ml
Ion Exchange Capacity	E_x	0.05 mea/g
Concentration of Divalent Ions	Ca	0.013 mea/ml
Equilibrium Constant	K	1
Median Grain-Size	d_{50}	4 mm (0.013 ft)
Dispersivity (Dispersion constant)	D	0.013 ft
Distribution Coefficient	K_d	3.84 ml/g
Bulk Density	P_b	2.65 gm/ml

Table 2.4-21

SUMMARY OF GROUNDWATER LEVEL MEASUREMENTS USED TO ESTABLISH DESIGN BASES FOR HYDROSTATIC LOADING

	Water Level Elevation (ft)				
Observation Well	Estimated maximum level[a]	Highest level of record[b]	Highest level of 36 months [c]	Month of highest level of 36 months [c]	Precipitation during month of highest level of 36 months [c] (inches)
P1[d]	239.2	228.4	226.4	3/79	2.91
P2[e]	-	229.2	229.2	6/75	7.91
P3[i]	242.4	229.6	229.6	2/75	3.96
P4[d]	243.3	230.1	230.1	2/75	3.96
P5[i]	239.1	229.6	229.6	2/75	3.96
P6[f]	255.2	241.4	240.2	5/79	6.98
P7[i]	237.3	222.3	222.3	5/79	6.98
P8[i]	245.9	232.3	230.9	5/79	6.98
P9[h]	257.2	242.8	242.5	3/79	2.91
P11[i]	206.5	203.3	201.7	3/79	2.91
P12[i]	138.3	127.6	127.6	2/79	6.27
P13[f]	177.0	167.2	162.3	1/79	13.18
P14[i]	193.0	178.0	178.0	5/79	6.98
P15[g]	151.0	138.8	138.8	1/79	13.18
P16[i]	169.2	161.1	161.8	3/79	2.91
P17[i]	---	283.3	---	---	---
P18[i]	---	226.5	---	---	---
P19[f]	---	224.5	---	---	---
SP20[e]	---	230.5	230.5	2/75	3.96
SP21[e]	---	222.4	222.4	7/74	1.93
SP22[i]	247.3	247.4	240.6	1/79	13.18
SP23[i]	266.9	255.0	255.0	10/74	2.51

[a] Determined by adding 15 feet to May 1979 measured level.
[b] Measurements as of February 1982.
[c] June 1973 to August 1975, November 1978, January 1979 to August 1979.
[d] Well destroyed.
[e] Destroyed prior to May 1979.
[f] Abandoned in June 1984.
[g] Abandoned in December 1987.
[h] Abandoned in April 1988.
[i] Monitoring to be discontinued one year after completion of all major site grading/surfacing.

Table 2.4-22

PARAMETERS USED IN RATIONAL FORMULA AND KIRPICH'S FORMULA

SUBAREA	Area A (acres)	Slope S	Length L (ft)	Time of Concentration Tc		Rainfall Intensity I (in/hr)	Peak Flow Rate Q (cfs)
				Calculated (min)	Adopted (min)		
DA-1	17.2	*	*	*	*	*	251
DA-2	25.0	0.00133	600	13.8	10	24.78	620
DA-3	4.5	0.0398	830	4.8	5	32.16	151
DA-4	20.8	0.019	1200	8.4	8.4	26.37	550
DA-5	14.9	0.0033	900	13.3	10	24.78	369
DA-6	11.6	0.00222	900	15.4	15	20.88	242
CP-1	20.0	0.00133	320	8.4	8.4	26.37	530
CP-2	25.0	0.00133	600	13.8	10	24.78	620
CP-3	12.8	0.0033	900	13.3	10	24.78	446
CP-4	35.6	0.0024	1250	19.2	20.0	18.27	555
CP-5	17.2	**	**	**	**	**	194

Rational Formula Q = CIA

Kirpich's Formula Tc = 0.0078 (L/S) ^ 0.77

* Rational method was not used for subarea DA-1.

** Rational method was not used for collection point CP-5, flow is maximum 30 minute mean inflow to spray pond.

Table 2.4-23

DRAINAGE FLOW PATH CROSS-SECTIONAL DATA

CROSS-SECTION	OUTLET NUMBER	WIDTH (ft)	AVERAGE BOTTOM ELEVATION (ft)
A	7	37	215.00
B		40	215.40
C	6	17.5	215.00
E		60	216.40
F	5	29	215.00
G		22.75	215.00
H		50	216.65
I		62	215.80
II	4	41	215.00
K	3	52	215.00
L		28	215.80
M	2	15	214.90
N		13	216.40
O	1	12	216.20
P		11	216.40
Q		72	216.40
R		104	216.10
S		150	215.20
TT		200	216.20
V		45	215.50
Z	8	166	216.60

2.5 GEOLOGY AND SEISMOLOGY

In accordance with the criteria provided in 10CFR100 Appendix A, "Seismic and Geologic Siting Criteria for Nuclear Power Plants", and Regulatory Guide 1.70 (Rev 3), this section describes and evaluates the geologic and seismologic conditions for the region around LGS. Foundation conditions are evaluated, and the foundation design is described. The seismic history of the region is examined, and the earthquake design criteria are described.

This section presents the results of the evaluation of the regional and site geology and demonstrates that the evaluation is in sufficient detail to ensure the safe design and operation of the nuclear power facility. Results of the literature study, field studies, foundation exploration, and laboratory test programs are presented. Static and dynamic properties of the foundation materials are described, and design criteria are outlined. Groundwater factors affecting plant construction and operation are discussed. (Groundwater conditions are presented in detail in Section 2.4.13).

Investigations were performed to define the site foundation conditions, and regional and site geologic, geohydrologic, and seismological conditions. These investigations determined the characteristics of the foundation materials and their suitability for supporting the structures, the depth and configuration of the groundwater table, and the characteristic effects of the soil and rock materials on the migration of radioactive solutions, should such solutions come in contact with them. Investigations were also performed to evaluate tectonics, faulting, and seismicity of the area, so that appropriate parameters for seismic design could be selected. Results of fault investigations are discussed in Section 2.5.3 and are presented in detail in a report prepared by Dames and Moore in 1974 (Reference 2.5-1). Site exploration is discussed in detail in Section 2.5.4.

LGS is approximately 3 miles southeast of Pottstown, Pennsylvania, adjacent to the Schuylkill River. It is in the Triassic Lowland section of the Piedmont physiographic province. The area is within the Newark-Gettysburg Basin, which is underlain by red sandstones, shales and siltstones of the Triassic Newark Group. These sedimentary basin deposits are gently tilted and warped, and are cut by diabase dikes and sills and by minor faulting.

Faulting has occurred in association with the major episodes of deformation in the region, and some faulting of the Triassic sediments occurred during Triassic and Jurassic time, over 140 million years ago. Some minor Jura-Triassic faults occur near the site; detailed studies carried out by the licensee show that they are not significant to the construction and operation of the plant.

Earthquake activity in historic time within 200 miles of the site has been moderate. Zones of major earthquakes in the eastern United States are far away, and have not had an appreciable effect at the site. Evaluation of tectonic structures and the historical seismic record indicate a design intensity of VII (Modified Mercalli Scale) is adequately conservative for the site. Intensity VII corresponds to a peak ground acceleration of 0.13 g; for additional conservatism, 0.15 g has been adopted for the SSE.

The principal plant structures are founded on competent bedrock, about 100 feet above the river. Bedrock at the site, which consists of Triassic siltstone, sandstone, and shale, is moderately to closely jointed, and joints are generally vertical to nearly vertical. Two major joint systems are prevalent, striking N 20° to 50° E, and N 50° to 60° W. The bedding strikes approximately east-west and dips 8° to 20° to the north. P-wave velocities in rock in the area of the major plant structures average about 12,000 ft/sec.

Minor faults, inactive since mid-Mesozoic time, occur west and south of the construction area. Fracture zones with a few inches of offset have been encountered in the excavation; however, they can be attributed to Mesozoic events and are not significant to plant structures. Minor clay seams, which occur locally along bedding, and the fracture zones are treated as required where encountered in the foundation excavations.

Soils at the site, predominantly clayey silts, are residual and range in thickness from zero to approximately 40 feet.

The natural groundwater at the site occurs in joints and along bedding. The emergency spray pond, excavated partly in soil and partly in rock, is lined to preclude excess seepage. The pond will not significantly affect groundwater levels beneath the plant structure.

2.5.1 BASIC GEOLOGIC AND SEISMIC DATA

2.5.1.1 Regional Geology

2.5.1.1.1 Regional Physiography and Geomorphology

The site is located in the Triassic Lowland section of the Piedmont physiographic province, as shown on Figure 2.5-1. The Piedmont is bounded on the southeast by the Coastal Plain and on the northwest by a projection of the New England Upland (the Reading Prong) and by the Valley and Ridge province (References 2.5-2 and 2.5-3).

The Valley and Ridge province is characterized by folded Paleozoic sedimentary rocks, which form a series of generally northeast-southwest trending parallel ridges. The Reading Prong of the New England Upland is underlain by Precambrian crystalline rocks. The Coastal Plain is underlain by sedimentary formations of Cretaceous and Tertiary ages.

The northeast-southwest trending Piedmont province is an eroded plateau of low relief and rolling topography. The surface of the plateau slopes gently to the southeast. The Piedmont is divided into an upland and a lowland section. The upland section is underlain by metamorphosed sedimentary and crystalline rocks of Paleozoic and Precambrian age (Reference 2.5-4). The rocks are relatively resistant to erosion, and they support an irregular, hilly surface. The higher hills are capped by Cambrian quartzites and Precambrian crystalline rocks, while broad valleys characterize areas underlain by limestone and calcareous shales. The less rugged lowland section, in which LGS is located, is north and west of the Piedmont uplands and is formed largely on shales and sandstones of Triassic-age. Ridges in the Triassic Lowland trend northeast-southwest along the strike of the more resistant bedrock formations. Higher and more rugged terrain exists where these formations have been intruded by diabase dikes and sills (Reference 2.5-4).

2.5.1.1.2 Regional Stratigraphy

In the region surrounding the site, the rocks exposed at the surface form lithologic belts that correspond to the physiographic provinces and sections. These rocks include crystalline igneous materials, metamorphic sequences, and sedimentary formations. The distribution of the geologic units of the region surrounding the site is shown on Figure 2.5-2. The stratigraphic relationships and thickness of the various formations are shown on Figures 2.5-3 and 2.5-4.

The oldest rocks of the region are of Precambrian age. They occur to the northwest of the site in the Reading Prong, and to the south and southwest in the upland section of the Piedmont and the Blue Ridge. These rocks are highly metamorphosed and faulted and have been intruded by a wide range of igneous materials. The Precambrian rocks, as shown on Figure 2.5-2, have been grouped into a single unit. The principal formations within this unit include the Baltimore and Pickering gneiss, and the Franklin limestone and marble. Other Precambrian rocks include granite gneiss and hornblende gneiss which underlie large areas of the Reading Prong. Gabbroic gneiss and gabbro in the upland section of the Piedmont are also of Precambrian age.

The Glenarm Series is a group of metamorphosed sedimentary rocks. In the region around the site, the Glenarm Series is represented primarily by the Wissahickon Formation which consists of schist and gneiss. In early geologic publications the Glenarm Series was identified as Precambrian because of the high degree of metamorphism of these rocks and their intrusion by igneous materials unknown in recognized Paleozoic formations. However, more recent studies (Reference 2.5-5) which include radiometric age determinations, show the Glenarm Series must be younger than 1100 million years (age of the basement gneiss) and older than 550 million years, the age of intrusives that cut the Wissahickon Formation. The Glenarm Series is therefore either late Precambrian or early Cambrian.

Paleozoic sedimentary rocks are exposed in the Piedmont upland, the Reading Prong, the Valley and Ridge, and the Appalachian Plateau provinces within the region. The occurrence of Paleozoic rocks is shown on Figure 2.5-2. Rocks of early Cambrian age consist primarily of quartzites, while the higher Cambrian and Ordovician formations are characterized by shales, limestones, and dolomites. The quartzites are prominent ridge formers in the Piedmont Upland and occur as outliers on the Precambrian rocks of the Reading Prong. The Upper Cambrian and Ordovician calcareous formations constitute what is known as the valley limestones and occur mainly in the lower-lying areas.

Sandstone, conglomerate, and shale with some limestone begin the Silurian sequence, giving way to carbonate formations in the upper units. The Devonian consists of shale and sandstone, with some limestone in the Middle and Lower Devonian.

The Mississippian rocks are divided into the Pocono Group, which is predominantly conglomerate and sandstone with some shale, and the Mauch Chunk Formation, typically consisting of red shales, but also consisting of sandstone and some limestone.

Sandstone and conglomerate are the predominant rock types of the Pottsville Group, oldest of the Pennsylvanian units in the region. Some coal is present in the Pottsville group, but most of the minable coal in the region occurs in the overlying units, which consist of cyclic deposits of shale, clay, coal, limestone, and sandstone. Similar deposits extend through the Permian; in some areas the deposition was continuous, with no clearly defined boundary between Pennsylvanian and Permian time.

Rocks of Triassic-age are contained in basins that parallel the northeast-southwest structural trend of the region. The Triassic basins of eastern North America occur from Canada to the Carolinas. The site is located in one of these Triassic basins, the Newark-Gettysburg Basin, which extends from the Hudson River across north-central New Jersey, through a portion of southeastern Pennsylvania, and into Maryland (Figure 2.5-38). The basin reaches a maximum width of 32 miles in Bucks County, Pennsylvania, near the Delaware River.

The Triassic rocks characteristically occur as red shales and sandstones, which are locally interbedded with basalt flows and intruded by diabase dikes and sills. The rocks of the Triassic basins have been designated by various authors as the Newark Group.

In the northern (Newark) portion of the Newark-Gettysburg Basin, where the site is located, the Newark Group is divided from oldest to youngest into the Stockton arkosic sandstone, the Lockatong gray shale and argillite, and the Brunswick red shale and sandstone. Of these three units, the Stockton is the only unit that can be classified as a true stratigraphic formation (Reference 2.5-6). The other sedimentary units of this group were deposited more or less contemporaneously, and they interfinger with each other. Since no definite three-dimensional boundaries can be placed on the Lockatong and Brunswick, they have been designated as lithofacies related to the Hammer Creek lithofacies which occurs west of the Schuylkill River.

The outcrop of the Stock Formation is found in a 4 mile wide belt along the southeastern border of the Newark Basin. The outcrop of the formation narrows, and ultimately pinches out to the west, in southern Berks County, Pennsylvania. Another body of the Stock Formation occurs between Center Bridge and Lumberville, along the Delaware River, having been brought to the surface by the Furlong and Flemington faults. The formation extends along the strike about 12 miles southwest of the river, where it is cut off by the Chalfont fault. The rocks of the Stock Formation consist of beds of coarse conglomerate at the bottom, and they range from coarse-to-fine arkosic sandstones to fine-grained sandstones and shales. The source of the sediments of the Stock Formation lay to the south of its present outcrop area. The formation is estimated to be at least 3000 feet thick (Figure 2.5-4). It unconformably overlies Precambrian and Paleozoic rocks to the south, at the margin of the basin. The formation is overlain conformably from east to west successively by the Lockatong, the Brunswick, and, west of the Schuylkill River, the Hammer Creek lithofacies.

The remaining sedimentary rocks of the Newark Group fill the basin from the upper contact of the Stockton Formation to the northern border of the basin. A great alluvial fan, formed by a large Triassic-age river that flowed from the north into the basin, provided the source of these sediments. The sediments of this alluvial fan were distributed to the northeast into the Newark Basin, and to the southwest into the Gettysburg Basin. The Hammer Creek conglomerates and sandstones in southern Berks County and in the northern portions of Lancaster and Chester Counties are the remnants of the main body of this great alluvial fan. The stratigraphic thickness of the Hammer Creek lithofacies is about 15,000 feet (Reference 2.5-6). This thickness is about the same as, or greater than, the combined thickness of the Lockatong and Brunswick lithofacies that occur in the site area.

The main body of the Lockatong lithofacies overlies the Stockton Formation in a belt with a maximum width of four miles. About 15 miles east of the site, this belt has been offset by the Chalfont fault. The Lockatong thins to the west. It passes about five miles to the south of the site, where the outcrop is only one-half mile wide. North of the main body of the Lockatong, tongues of this unit are interbedded with strata of the Brunswick lithofacies. The uppermost continuous member of the Lockatong pinches out approximately three miles east of the site. The next lower, the Sanatoga member, passes just north of the site and becomes discontinuous.

The Lockatong lithofacies consist of gray shales and massive mudstone; it has been classified as an argillite although it is not a low rank metamorphic facies. The rock may be calcareous, may contain carbonaceous horizons, and often contains mud cracks. The Lockatong was deposited in a

shallow lake environment. The maximum stratigraphic thickness of this formation is about 3800 feet (Reference 2.5-6).

The Brunswick lithofacies are more closely related to the Hammer Creek, which occurs west of the Schuylkill River, than to the Lockatong. The Brunswick represents the depositional extension of a great alluvial fan. Thus, the western margins of this formation contain more sand members, whereas to the south and east the strata are typically more shaly. The main body of the Brunswick lithofacies extends from the northern border of the basin to its interfingering contact with the Lockatong to the south. To the west of the Schuylkill River, the Brunswick interfingers with the conglomerates and sandstones of the Hammer Creek. The site is located about five miles east of the interfingering contact of the Brunswick and Hammer Creek.

The Brunswick consists of relatively soft red shales, siltstones, and sandstones. The cementing agent is largely iron oxide derived from the hematite contained in the sediments. In areas where the Brunswick approaches the tongues or the main body of the Lockatong, it is sandier and harder. The stratigraphic thickness of the Brunswick strata is about 7000 feet (Reference 2.5-6).

Along the north border of the basin, the upper Brunswick strata locally consists of coarse fanglomerates derived from minor streams pouring into the basin from the north. As shown on Figure 2.5-2 these broader fanglomerates, as well as the basal conglomerate of the Stockton Formation, appear under the same lithologic symbol as the Hammer Creek.

Two types of igneous rocks occur within the Newark Basin. The majority of these are diabase dikes and sills, which have intruded into the sedimentary sequence. A minor basalt flow has been mapped in the area southwest of Reading, Pennsylvania. Both the basalt flow and the intrusives are of Triassic-age. A large sill to the west of the site was intruded along bedding-plane surfaces in the sedimentary rocks, and locally has "baked" the sediments in a zone up to 500 feet wide. Numerous dikes of Triassic-age cut the basin rocks, as well as the Precambrian and Paleozoic rocks surrounding the basin. The most prominent of these dikes, the Downington Dike, extends from 11 miles southwest of Downingtown, Pennsylvania, through Sanatoga Station, just north of the site, and continues about three miles to the northeast. It occupies a fracture zone, and in places it enters zones of weakness provided by pre-existing faults. The major mineral constituents of the Triassic diabase are augite and labradorite. The diabase intrusions postdate Triassic sedimentation and tectonics, as discussed in the following sections on structural geology and geologic history. Radiometric ages obtained during geologic investigations for LGS (see section 3.2.3 and 3.7.1 of Reference 2.5-1) indicate some of the diabase dikes near the site are probably of Jurassic-age.

Cretaceous sedimentary deposits occur in the Coastal Plain province. These sediments consist of clays and sands, which are moderately to poorly consolidated.

Deposits of Cenozoic age consist of Tertiary sediments and terrace deposits, Quaternary gravels, sandy gravels, glacial drift, and Recent alluvium. Tertiary and Quaternary deposits occur in the Coastal Plain province.

Glacial deposits of Pleistocene age cover large areas of the bedrock surface north of the site, but do not extend into the area adjacent to the site.

2.5.1.1.3 Regional Geologic Structure

The dominant structural feature in the region surrounding the site is the Appalachian Orogenic Belt. This belt is marked by northeast-southwest orientation of the axes and alignment of most of the structural features and stratigraphic contacts. The major structural features of the region are shown on Figure 2.5-5. Figure 2.5-38 is a compilation from the recent literature (References 2.5-10, 2.5-60, 2.5-17, 2.5-112, and 2.5-119) showing faults mapped within and in the vicinity of the Newark-Gettysburg Basin. Major faults and structures within 5 miles of the site are shown in more detail on Figure 2.5-6. A Bouguer gravity anomaly map of the region is shown on Figure 2.5-7, and aeromagnetic intensities for the Limerick-Pottstown area are shown on Figure 2.5-8.

The Paleozoic and Precambrian rocks of the Piedmont Uplands to the south and west of the site, and of the Reading Prong and the Great Valley section to the north, are structurally complex. These strata are intensely folded and faulted. The axes of foliation, and of the major folds involving these rocks, generally strike to the northeast. Precambrian and Lower Paleozoic rocks south of the site are strongly metamorphosed, and they exhibit tightly folded structures superimposed on broader synclinoria and anticlinoria. The Paleozoics to the west, and in particular those to the north of the site, exhibit recumbent folds, with basal truncation or decollement by thrust faults.

The majority of the faults that displace Precambrian and Paleozoic strata are thrust faults. The thrust sheets are relatively thin, and they generally exhibit movement to the northwest. The north-south trending faults at their flanks are tear faults. These faults do not involve Mesozoic or Cenozoic strata. To the west of the site, in the Piedmont Uplands, some of the major thrust faults are transected by Triassic-age diabase dikes that show no displacement. Similar relationships of Triassic dikes crossing Paleozoic faults are found in the Readin Prong area, north of the site. The last movement along these faults probably occurred over 200 million years ago, and certainly no later than 140 million years ago, based on the absence of displacement of the Triassic diabase dikes.

A major postulated fault system of Paleozoic age in the region is the Martic Line of thrust faulting. The Martic Line was introduced in earlier geologic publications (Reference 2.5-7), primarily to account for the fact that the Glenarm Series (thought to be of Precambrian age) overlies sedimentary rocks of known lower Paleozoic age in southern Lancaster County, Pennsylvania. The fault was subsequently drawn for hundreds of miles along the Appalachians as the boundary of the inner and outer Piedmont. Cloos and Hietanen (Reference 2.5-8) prove imbricate thrusting in the type area. Wise (Reference 2.5-9) concluded that the Martic Line is a "complex polygenetic feature made up of distinct segments...." He indicates that the Martic Line is a Paleozoic feature, which may be largely a facies boundary marking the edge of a deeply subsided basin to the southeast. Along this basin margin there has been imbricate thrusting, regional metamorphism, brittle movement of large basement blocks, widespread development of kink bands and joints, and local intense folding. Wise states: "The final event was the injection of basaltic dikes of probable Triassic-age with north to northeast trend across the region."

The geologic map of Pennsylvania (References 2.5-10 and 2.5-60) and the tectonic map of the central and southern Appalachians (References 2.5-11) show Triassic dikes crossing the Martic Line without offset, indicating that no movement has occurred in this zone for at least 140 million years.

The major recognized Paleozoic faults in the region occur to the south and west in the Piedmont Uplands, and to the north in the Reading Prong and Great Valley sections. The Huntington

Valley-Cream Valley and Rosemont faults occur in the Piedmont Uplands, 15 miles south of the site. The major structural features in the Piedmont Uplands west of the site are, from south to north, the Mine Ridge anticline, Brandywine Manor fault, Welch Mountain anticline, and the Elverson thrust fault (Reference 2.5-12). Of these features, the nearest to the site is the Brandywine Manor fault, which lies nine miles to the southwest. None of the major Paleozoic faults has a mapped extension to the east of the Triassic border or into the Newark-Gettysburg Basin.

To the north in the Reading Prong and Great Valley sections, nappe structures exhibited by the strata greatly complicate their interpretation. An interpretation presented for the Valley and Ridge province to the northwest (Reference 2.5-13) is that the Paleozoic rocks have been transported westward along nonoutcropping, low angle, detachment thrust faults. The group of rocks observed in any one locality represents an allochthon, entirely unrelated stratigraphically to the surrounding rocks. This hypothesis is supported by deep bore hole and geophysical data, which indicate that the basement below the relatively thin skin of folded and faulted Paleozoic sedimentary rocks does not reflect connected or similar structures (References 2.5-60, 2.5-30, 2.5-87, and 2.5-89).

Over the past several years additional deep seismic reflection studies have suggested that these various thrust faults conveying the allochthonous slices westward are splays of a deeper, regionally extensive detachment surface or decollement which may be a fundamental tectonic structure of the central and southern Appalachians, extending eastward beneath the Piedmont province and possibly continuing beneath the Coastal Plain and Atlantic shelf (References 2.5-60, 2.5-75, 2.5-76, 2.5-77, 2.5-78, 2.5-88, 2.5-97, 2.5-64, 2.5-94, 2.5-68, 2.5-69, 2.5-121, 2.5-122, and 2.5-82). The seismic profiles from Pennsylvania, Virginia, eastern Tennessee, South Carolina, and Georgia show laterally continuous subhorizontal reflectors ranging in depth from less than 6 km in the Valley and Ridge to more than 11 km beneath the Coastal Plain. Cook (Reference 2.5-79) and Harris and Bayer (Reference 2.5-88) interpret these subsurface reflectors to be elements of a regionally extensive decollement underlain by relatively undeformed, unmetamorphosed, layered Paleozoic sedimentary rocks. The subhorizontal east-sloping decollement presumably accommodated crustal foreshortening associated with continental plate convergence in late Paleozoic time when metamorphic Precambrian and early Paleozoic rocks of the Blue Ridge and Piedmont were thrust to the west and northwest over relatively unmetamorphosed sedimentary rocks of the Valley and Ridge.

The eastern extent of the decollement is still poorly known. The seismic reflection profiles confirm the presence of a decollement from the Valley and Ridge to at least as far as the inner (western) Piedmont where the subsurface reflectors thicken, become discontinuous, and dip steeply to the southeast (References 2.5-75, 2.5-76, 2.5-77, and 2.5-78). In one interpretation, the steeply dipping reflectors mark the root zone of the decollement beneath the outer Piedmont (References 2.5-92, 2.5-93, and 2.5-94). Reflections from the coastal plain and continental shelf, however, suggest that the decollement may extend southeastward to the coast (References 2.5-78, 2.5-88, 2.5-68, 2.5-69, and 2.5-122). In the second interpretation, the steeply dipping reflectors are interpreted as sedimentary deltaic deposits accumulating on the shelf of an autochthonous proto-North American continental margin (Reference 2.5-78). Cook et al (Reference 2.5-78) suggest that the decollement may be rooted offshore where a complex structural configuration is evident on the seismic profiles.

A recent reinterpretation (Reference 2.5-97) of these seismic reflection profiles supports the interpretation by Hatcher and his coworkers (References 2.5-90, 2.5-91, 2.5-92, 2.5-93, and 2.5-94). Based on palinspastic restorations of the crust, they suggest that the decollement is probably rooted beneath the Kings Mountain belt of the Piedmont province. Subhorizontal reflectors farther to the southeast described by Cook et al (Reference 2.5-78) as a decollement

probably represent subhorizontal ultramylonites or layered intrusions related to the internal structure of an accreted island arc (Reference 2.5-97).

Age constraints for displacement on the decollement are not well established. Many investigators believe that the principal displacement occurred during the Alleghenian orogeny and that it is responsible for the thin-skinned fold and thrust deformation of the Valley and Ridge Province, emplacement of the crystalline Blue Ridge and Piedmont rocks as thin, allochthonous sheets, and the extensive metamorphism and plutonism along the eastern margin of the Appalachians (References 2.5-92, 2.5-94, 2.5-64, and 2.5-93). Although principal displacement probably did occur during the Alleghenian, Harris and Bayer (Reference 2.5-88) suggest that the decollement is also long-lived and may have grown intermittently from the late Precambrian to the late Paleozoic. Based on radiometric age dates, paleomagnetic data and geologic field relations, however, Ellwood et al (Reference 2.5-81) believe that a 350 million year old intrusive complex was emplaced through the decollement after major thrusting. The 350 million year old age for the intrusion would thus provide a minimum age for thrusting.

A second conspicuous feature indicated by both deep and shallow seismic reflection profiles across the Appalachian orogen is the presence of upwardly concave reflectors beneath the Piedmont and Coastal Plain. Most of the reflectors are listric into the suspected decollement and may represent late Paleozoic thrust faults, Mesozoic listric normal faults, or both (Reference 2.5-78). In this interpretation, the Brevard zone is a splay off the main decollement (Reference 2.5-77). There is some uncertainty as to whether, and to what extent, late Mesozoic crustal rifting was accommodated by reactivation of these listric faults as normal basin faults. It seems reasonable to presume that at least some Mesozoic basin faults are deep-seated, as evidenced by basaltic magmatic activity, in which case they would displace and disrupt the Paleozoic decollement surface.

A postulated major east-west fault zone, named the Cornwall-Kelvin wrench fault, has been inferred by Drake and Woodward (Reference 2.5-14) on the basis of subsea topography and geophysical surveys and has been postulated to extend through the Triassic Lowland of southeastern Pennsylvania. However, there is neither geological nor geophysical evidence of a westward continuation of this fault into the continent, either at the surface or at depth (Reference 2.5-15).

The strata of the Newark Group, unlike those of the older Paleozoic rocks, are only locally and gently folded. In general, the rocks dip between 5° and 20° to the north and northwest. The Brunswick lithofacies and the upper tongues of the Lockatong are involved in broad cross-folded structures north and east of the site. The Triassic strata are characteristically faulted by normal strike and transverse faults, some of which show considerable lateral displacement. Unlike most of the Paleozoic thrusts, the Triassic faults are high angle gravity faults, with the downthrown side usually to the south.

The faults of Triassic-age have generally not displaced the younger Cretaceous and Cenozoic strata in the Coastal Plain to the southeast. According to a recent compilation (Reference 2.5-134, plate 1; Reference 2.5-135, figure 3), the only instance of a fault which offsets coastal plain strata overlying Triassic sediments within 200 miles of the site is the inferred Brandywine fault zone located 9 miles southeast of Washington, D.C., about 140 miles from the site. Evidence for both the faulting and the presence of Triassic sediments at depth is entirely from subsurface data, including seismic reflection, drill holes and geophysical logging, as reported by Jacobeen (Reference 2.5-98). These data indicate that two northeast striking, southeast dipping en echelon reverse faults offset the top of the Lower Cretaceous Arundel Formation a maximum of about 250 feet. The relation of this faulting to Triassic basin structure, however, is uncertain because both

Triassic sediments and granitic rocks were penetrated by deep drill holes on both sides of the fault zone. (It should be noted that Jacobeen (Reference 2.5-98) states he believes the faults to be unrelated to Mesozoic structures.) Up section, the drill hole data confirm that the Paleocene-Eocene Aquia Formation is monoclinally folded without being offset by faulting. This folding occurred prior to Oligocene erosion and only minor flexuring is displayed in overlying Miocene strata (Reference 2.5-98). Jacobeen concludes that there is no evidence for post-Miocene movement on the Brandywine fault zone.

Mixon and Newell (References 2.5-105, 2.5-106, and 2.5-107) suggest that the Brandywine fault zone may be an extension of faults bordering the Richmond Triassic basin in Virginia, 60 miles farther to the southwest, based on the alignment of both fault zones with a linear gravity anomaly that extends between the two locations. However, evidence to associate the Richmond basin faults with Cretaceous or younger faulting apparently could not be found because neither Mixon and Newell (References 2.5-105, 2.5-106, and 2.5-107) nor Wentworth and Mergner-Keefer (References 2.5-134 and 2.5-135) indicate any offset of coastal plain strata where these strata overlap the Richmond basin faults.

Offshore, reported instances of significant Cenozoic displacements within 200 miles of the site are rare. Hutchinson and Grow (Reference 2.5-96) report offset of the basement-Cretaceous contact of up to 280 feet on a 20 mile long, north-northeast trending fault (New York Bight fault) off the northern New Jersey coast, about 100 miles east of the site. However, evidence for post-Cretaceous offset on the fault is highly ambiguous, due to poor seismic resolution in the shallow section, lack of stratigraphic control, and the upward-decreasing amount of possible offset. Hutchinson and Grow (Reference 2.5-96) state that their data are not sufficient to determine the dip of the fault or whether it is reverse or normal. They conclude the data show "potential offset" in the Tertiary and possible "warpage" of strata they infer to be Quaternary in age.

Another fault zone about 15 miles west of, and parallel to, the Brandywine has been named the Stafford fault zone (References 2.5-105, 2.5-106, and 2.5-107). Surface exposures of the Stafford fault zone show that coastal plain strata are offset along high angle basement faults. Although the Stafford fault zone is not associated with Triassic sediments and has no demonstrable relation to any Triassic basin structure, the relative proximity, similar trend, and presence of reverse sense of displacement in both the Brandywine and the Stafford fault zones suggest they may be structurally related.

The Stafford fault zone consists of four subparallel, en echelon basement faults which offset coastal plain strata. Each fault has a maximum throw of about 150 feet. Two of the faults display reverse throw on high angle, west dipping planes (down-to-coast movement).

On one of these faults (the Fall Hill fault) an exposure near the Stafford-Spotsylvania county line shows a high angle fault contact between basement gneiss and Cretaceous coastal plain sediments. The gneiss projects about 14 inches upward into overlying Plio-Pleistocene fluvial gravels, consistent with reactivated reverse displacement along the fault-plane (Reference 2.5-107, figure 7). On the other hand, such relationships are also consistent with features produced by normal stream erosion, particularly in view of the great contrast in erodability between the gneiss and the Cretaceous sands.

A detailed investigation of the Stafford fault zone, including an extensive drilling and trenching program, was conducted by Dames and Moore for Potomac Electric Power Company (Reference 2.5-113). Tertiary strata were identified above the faulted Cretaceous strata in trenches across one of the four faults (Hazel Run fault). The trenches show that this fault truncates Paleocene-Eocene

strata (Aquia Formation) and is overlain by unfaulted Miocene strata (Calvert Formation) which exhibit only minor flexure not necessarily caused by fault movement. Significantly, all three trenches excavated to the base of the alluvial gravels across the trace of the Fall Hill fault disclosed that the gravels are not offset by the fault, strongly suggesting that the feature described by Mixon and Newell is erosional. Therefore, no unequivocal evidence was found for post-Miocene movement on any of the faults; latest movement could be as early as Paleocene or early Eocene.

A discussion of surface faulting is presented in Section 2.5.3 and was presented in detail in a report by Dames and Moore in 1974 (Reference 2.5-1).

2.5.1.1.4 Geologic History

The geologic history of the region can be traced from the Precambrian; the sediments that were deposited to form the Baltimore and Pickering Gneisses and the Franklin Limestone were subjected to magmatic intrusion, metamorphism, and erosion before the onset of Cambrian time.

In late Precambrian, Cambrian, and early Ordovician time, a thick sequence of sediments accumulated. They were derived from a highland that lay southeast of the region and were deposited in a broad inland sea. During Cambrian and early Ordovician time, thick sequences of sand and calcareous and dolomitic ooze accumulated. In the latter part of Ordovician time, the region was subjected to folding and uplift as a result of the Taconic orogeny. Farther to the northwest, sediments were deposited throughout the remainder of the Paleozoic Era.

The major tectonic events during the Paleozoic era began with the Taconic orogeny during the Middle Ordovician, continued with the Acadian orogeny in late Devonian, and culminated in the Appalachian orogeny at the end of the era. Major folding of the strata occurred predominantly during the Appalachian orogeny. The less competent units in the Middle Cambrian, Upper Ordovician, and Upper Silurian became thrust zones (Reference 2.5-16). Thrusting is discussed in Sections 2.5.1.1.3 and 2.5.1.1.4.1.

From the close of the Paleozoic to the present, the region has remained above sea level, and most of the area has undergone erosion. During the late Triassic, a series of down-warped or down-faulted basins developed in the central portion of the Appalachian Highlands. Streams from the higher areas adjacent to these basins filled them with the alluvial deposits that make up the Triassic sedimentary rocks of the region. After sedimentation ceased in the Newark Basin, the Triassic strata were tilted to the northwest along a synclinal hinge line near the north border of the basin. The faulting and broad folding of the strata occurred during or after the tilting.

The igneous activity in the Triassic occurred in three stages. The first stage was the extrusion of basaltic lava, which occurred during Triassic sedimentation. The second stage was the intrusion of diabase sills. The sills are cut by later Triassic faulting, and therefore they predate the development of the major fracture system of the surrounding rock. The final stage was the intrusion of diabase dikes along the major fractures. Most of the dikes in the region are not faulted and represent the final activity affecting the Triassic strata. Paleomagnetic age dating of these Triassic dikes indicates that they were emplaced between 180 and 140 million years ago. Radiometric dates obtained during geologic investigations for the site are in good agreement, ranging from 151 to 198 million years (see Reference 2.5-1, section 3.7).

During Jurassic and early Cretaceous time, the region underwent a prolonged period of erosion. The ancestral patterns of the present day drainage system of the region probably began during the late Triassic or Jurassic. Early in the Cretaceous, the ocean encroached on the Coastal Plain to

the southeast, and alluvium and marine sands, marls, and clays were deposited. These deposits constitute the unconsolidated Cretaceous and Tertiary sedimentary formations of the Coastal Plain.

There is no record in the eastern United States of any major tectonic event in the interval between Cretaceous time and the present. The region was subjected to broad, gentle periodic warping of the crust.

During the Pleistocene epoch, the maximum advance of the continental glaciers reached as far as the northern portion of the Reading Prong, about 20 miles to the northeast of the site. During periods of glacial melting, the major rivers of the region were choked with great quantities of glacial outwash. These materials were deposited along the valleys of the major streams and remain today as terrace deposits. The glaciated region was north of the Schuylkill River headwaters, and the river was little affected by continental glaciation.

2.5.1.1.4.1 Appalachian Plate-Tectonic History

The geologic history of the region summarized above can be stated in terms of lithospheric plate-tectonic interactions based on the considerable geologic research reported in the current technical literature on Appalachian tectonics (References 2.5-26, 2.5-30, 2.5-75, 2.5-76, 2.5-77, 2.5-78, 2.5-88, 2.5-92, 2.5-93, 2.5-94, 2.5-64, 2.5-97, and 2.5-138).

In the late Precambrian (approximately 820 million years ago) extensional tectonics rifted proto-North America from proto-Africa, proto-Europe and proto-South America (References 2.5-116 and 2.5-117). Various continental fragments were distributed in the expanding proto-Atlantic or "Iapetus" Ocean as the major continents separated (References 2.5-116, 2.5-76, 2.5-77 and 2.5-92). Some major continental fragments include the Avalon and Inner Piedmont-Blue Ridge provinces. During the ensuring plate convergence or contraction of the Iapetus Ocean, several island arcs developed offshore of the continental margin. The Carolina slate belt, for example, is believed to be one of these island arcs subsequently accreted to the margin of North America.

In the southern and central Appalachians, closure of the oceanic basin between North America and the Inner Piedmont-Blue Ridge fragment and subsequent collision of the land masses during the Cambrian and Ordovician is recorded by the Taconic orogeny (480-450 million years ago). The Inner Piedmont-Blue Ridge fragment was accreted to North America by overthrusting (References 2.5-117, 2.5-91, and 2.5-76). Extreme deformation, metamorphism and plutonism in the Inner Piedmont accompanied the orogeny. Six hundred to 500 million year old volcanics on the offshore Carolina slate belt suggest that eastward subduction and development of a volcanic arc on the slate belt accompanied closure of the basin (Reference 2.5-91). In western New England, the Taconic orogeny produced extensive thrust and fold deformation, low grade regional metamorphism, gravity-slide nappe structures, and extensive granodioritic and ultramafic intrusions (References 2.5-26, 2.5-30, and 2.5-133).

Continued closure of the Iapetus Ocean by eastward subduction resulted in the collision of the Carolina slate belt with the Inner Piedmont-Blue Ridge terrain of the southern and central Appalachians during the Acadian orogeny (400-300 million years ago) (Reference 2.5-92). Rocks of the Kings Mountain-Charlotte belt probably represent allochthonous portions of the intervening oceanic crust caught in the collision and obducted onto the margin of North America by overthrusting. The orogeny resulted in additional extensive metamorphism and deformation. The allochthonous Inner Piedmont-Blue Ridge fragment was thrust further westward over the old

continental margin. In the northern Appalachians, extensive high grade regional metamorphism and granitic intrusions accompanied the orogeny.

The last phase of plate convergence along the margin of North America culminated in the continental collision between proto- North America and proto-Africa during the Alleghenian orogeny (300-250 million years ago). Most of the prominent southern and central Appalachian structures and provinces assumed their present configuration in this orogeny. Extensive igneous activity in the eastern Piedmont accompanied the orogeny and large-scale overthrusting deformed the sedimentary rocks in the Valley and Ridge Province (References 2.5-76 and 2.5-78). Thrusting of the Piedmont over the Blue Ridge also created the Brevard zone at this time. In the northern Appalachians, the Alleghenian orogeny is manifest primarily in southeastern New England by folding, low and medium grade local metamorphism and granitic intrusions.

In the Triassic, following the Alleghenian orogeny, extensional tectonics again dismembered a megacontinent (Pangaea). Rifting separated North America from Africa, Europe and South America, forming the present Atlantic Ocean in its wake. Extensional Triassic-Jurassic basins bordered by normal faults (such as the Newark-Gettysburg Basin) were superimposed on the Paleozoic compressional structures. As rifting continued, Cretaceous and Tertiary sediments of the Coastal Plain province accumulated on the trailing eastern margin of North America. The composition of these sediments and their gentle dip away from the Appalachian Mountains implies that the Appalachians have stood as an eroding structural high for over 200 million years (Reference 2.5-84). Although many of the Triassic-Jurassic basins are exposed at the surface in the Piedmont Province, most are buried beneath the Coastal Plain sediments and have been tentatively located on the basis of drill holes (Reference 2.5-98), aeromagnetic and gravity anomalies (Reference 2.5-100), and seismic reflection and refraction profiles (Reference 2.5-81).

In summary, the Appalachians evolved principally by a sequence of plate rifts and collisions during the late Precambrian and Paleozoic eras. Subsequent rifting in late Triassic and early Jurassic time initiated the latest cycle of Atlantic sea floor spreading and produced the present configuration of the continental margin.

2.5.1.2 Site Geology

2.5.1.2.1 General

The site is located approximately 3 miles southeast of Pottstown, Pennsylvania, adjacent to the Schuylkill River, as shown on Figure 2.5-6. The principal plant structures are located on a broad ridge, approximately 100 feet above the river. Bedrock, encountered at shallow depths, consists predominantly of red siltstone, sandstone, and shale of late Triassic-age. The soils are residual, derived from the weathering of the underlying bedrock. Minor Triassic-age faults, inactive since Middle Mesozoic time, occur to the west and south of the construction area (see Sections 2.5.1.1.3 and 2.5.3). Fracture zones with a few inches of offset were encountered in the excavation. However, they are not significant to the plant structures.

2.5.1.2.2 Physiography

The topography of the site area is characterized by broad, gently rolling ridges that are dissected by the entrenched courses of the Schuylkill River and its tributaries. Elevations in the area range from a high of 200-300 feet above sea level on the ridge tops to a low of 100 feet along the Schuylkill River. Higher elevations occur in the more rugged terrain to the north and west of the site.

Topography and drainage of the area are controlled to a large degree by the lithologic and structural characteristics of the bedrock. The ridges generally trend east-west along the strike of the bedrock. The prominent ridge tops are capped by the more resistant rocks: sandstone, argillite, and diabase. Higher order drainage courses trend along the major joint directions. Tributary streams in the area (Sanatoga Creek, Possum Hollow Run, and Brooke Evans Creek) flow along the strike of the bedding or along major joints and fracture zones.

2.5.1.2.3 Stratigraphy

Bedrock at the site includes both the Brunswick and Lockatong lithofacies. Bedding dips toward the north at 8° to 20°. In the power block area, the dip is approximately 10° to 18° to the north. Contours on top of rock are shown on Figure 2.5-9.

Strata of the Brunswick lithofacies underlie most of the area. This rock unit is several thousand feet thick and is basically a reddish-brown siltstone, which grades locally to a shale. Calcite commonly fills joints and bedding-planes in the rock. Sandstone beds interfinger with the siltstones and range from reddish-brown, very fine-grained, silty sandstone to light gray, and medium-to-coarse-grained sandstone. Lateral gradation between sandstones and siltstones is common throughout the area. Geologic sections through the site area are shown on Figures 2.5-10 and 2.5-11. The stratigraphic column at the site is shown on Figure 2.5-12.

The Lockatong lithofacies, represented by the Sanatoga Member, interfinger with the Brunswick in the northern part of the site area. The Sanatoga Member of the Lockatong lithofacies consists of bluish-gray, calcareous argillite, with two distinct beds of black carbonaceous shale. The Sanatoga member occurs in the spray pond area, but does not occur beneath the cooling towers or the main plant structures.

Diabase has been intruded into the sedimentary rocks along major fractures, trending about N 20° to 30° E. The most extensive of these intrusives is the Downingtown Dike, about 1300 feet west of the site. The rocks at the borders of the dikes have been baked to a tough gray hornfels.

For the most part, soils consist of red sandy and clayey silts, with numerous rock fragments derived from the underlying bedrock. Soil thickness ranges from 0-40 feet with an average of 10-15 feet. A typical soil section consists of the following:

0-5 feet	-	Reddish-brown clayey silt
5-10 feet	-	Reddish-brown clayey silt with numerous rock fragments
10-20 feet	-	Highly weathered and fractured rock with some silts and clays

Residual soils overlying the diabase and hornfels are usually thicker and contain fewer rock fragments than the section described above.

Typical flood plain deposits occur along the Schuylkill River. They consist of silt, sand, and gravel that have been transported from upstream areas.

2.5.1.2.4 Structure

The principal structural features and relationships in the site area are shown on Figures 2.5-6 and 2.5-13. The bedrock strata dip to the north at between 8° to 20°. Two major joint directions are

prevalent in the area. Both are nearly vertical; they strike approximately N 20° to 50° E and N 50° to 60° W. Several fracture zones with minor offsets of Jura-Triassic age were encountered in foundation excavations and are described in Section 2.5.1.2.5.

As previously indicated, the site lies within a down-warped Triassic basin. Subsequent to the deposition and consolidation of the basin sediments, the region was uplifted, and the brittle basin materials were broken by numerous small faults and fractures.

Three faults, the Sanatoga, the Brooke Evans, and the Linfield, occur within 2 miles of the site. These faults are shown on Figure 2.5-6 and discussed in Section 2.5.3. The nearest approach of the Sanatoga fault to the reactor enclosure area is 1300 feet to the west. Vertical displacement on the fault is approximately 290 feet, with the downthrown side to the east. The fault-plane is intruded by Triassic diabase, which is part of the Downingtown Dike.

The Brooke Evans Fault passes within 2800 feet to the south of the plant area and trends approximately N 50° E. The apparent vertical displacement is about 350 feet, with the downthrown side to the south.

The Linfield fault is located east of the town of Linfield, about 2 miles southeast of the site. Field investigations in 1974 (Reference 2.5-1) identified five vertical or nearly vertical faults, trending N 40° to 55° E, with apparent vertical offsets of from 1-20 feet.

All three of these faults, the Sanatoga, the Brooke Evans, and the Linfield, are associated with the Jura-Triassic events that occurred 140-200 million years ago (Section 2.5.3.2).

2.5.1.2.5 Fracture Zones in the Site Area

Three fracture zones were encountered during excavation of the main power block. Figure 2.5-13 shows their locations, widths, and attitudes at final foundation grades. None of the zones presents a hazard to the structures. The zones have relatively lower strength than the rock adjacent to them; consequently, they were treated to preclude any unacceptable differential settlement across them. Treatment of these zones is discussed in Section 2.5.4.12.

A fracture zone (Zone A), consisting of discrete fractures about 20 feet apart with hard, relatively unfractured rock between them, was encountered in the Unit 1 foundation excavation, at the south edge of the reactor enclosure. To the northeast, these fractures converge and intersect other fractures, resulting in a zone of closely fractured, partly weathered rock varying in width from 2-7 feet. This zone extends across the northern part of the reactor enclosure foundation and the entire control structure and turbine enclosure foundations (Figure 2.5-13). No offset was observed along this zone. At the south wall of the control structure, most of the fractures in this zone, and essentially all of the weathering, terminated at a bedding-plane (clay seam 1 described later in this section) at about el 158. At this wall, the fracture zone was removed down to the bedding-plane. To the northeast, it was treated, where necessary, by dental excavation, as described in Section 2.5.4.12. Treatment of the zone was not required at the south wall of the Unit 1 reactor enclosure, since the "zone" consists only of narrow, widely spaced fractures with hard unweathered rock between them.

Another fracture zone (Zone B) occurs at the southeast corner of Unit 2 reactor enclosure (Figure 2.5-13). It strikes about N 30° E, is essentially vertical, and contains highly fractured, partly weathered rock in a zone about one foot wide. This zone has about 8-10 inches of apparent

vertical offset, down on the southeast side. Since this fracture zone is vertical and narrow, dental treatment was probably not needed, but was done as a conservative measure, as described in Section 2.5.4.12.

A third zone (Zone C) in the foundation of the Unit 2 turbine enclosure was mapped as a minor fracture zone. Dames and Moore indicate that the zone is similar in character to fracture Zone B, with apparent vertical offsets of up to two feet (Reference 2.5-1, section 2.3.4.3). This zone contains from ¼-4 inches of clay and decomposed rock. Treatment of this zone was not necessary.

Two clay seams were encountered in the plant excavation. They occur along bedding, striking generally northeast-southwest and dipping 10° to 18° northwest. The first seam is near the top of rock south of Unit 1, where it is about 10 inches thick in the south slope of the excavation. The thickness of this zone decreases rapidly down-dip, toward Unit 1, and is generally less than 1½ inches thick under Unit 1; in places it is barely discernible. Clay, where present in the seam, contains numerous hard rock particles of small gravel size. Some shearing is evident along this seam.

The second clay seam is stratigraphically lower than seam 1 and intersects foundation grade in part of Unit 2. This seam occurs along shaly beds, which are relatively softer than the adjacent siltstone. The soft material in seam 2 is usually only about ¼-½ inch thick where exposed in foundations or excavated slopes, and it consists of plastic clay with shaly, sheared rock fragments. Only minor local treatment of these seams was required. The method of treatment is described in Section 2.5.4.12.

Geologic mapping in the spray pond excavation (Figures 2.5-42 and 2.5-43) disclosed only few minor instances of offset along near-vertical joints and fractures. The maximum apparent displacement observed does not exceed 3 inches. These minor offsets observed in the spray pond excavation are consistent with the late Triassic or Jura-Triassic deformational features found elsewhere at the site and in the region around the site. Extensive geologic investigations conducted by Dames and Moore (Reference 2.5-1) have confirmed the noncapability of these deformational features (Section 2.5.3).

Near the western end of the spray pond excavation, a vertical joint trending N 20° E displayed about 1 inch of offset (east side down); the joint was traced a distance of about 100 feet A narrow (2-6 inches wide) east-west zone of closely spaced jointing and fracturing, locally accompanied by more widely spaced jointing, was exposed in the southern part of the pond. It was traced from the western edge of the excavation eastward for a distance of about 600 feet. The maximum observed offset on this feature is no more than 2 inches (south side down); slickensides were not generally apparent but were noted in a few places. These features were examined by an NRC geologist and a geotechnical engineer during their site visit on September 10, 1981. Locally altered and weathered rock within the zone was excavated to sound rock following procedures employed in the main power block excavation (Section 2.5.4.12).

In the rock slope at the eastern end of the spray pond excavation, an east-west fracture zone was exposed that displayed between 2 and 3 inches of total apparent lateral displacement (left-lateral sense) as measured by offsets between matching joints on either side of the fracture. No slickensides were visible along this fracture. The fracture terminated downward at a bed of hard, calcareous siltstone. No trace of the fracture was present on the exposed bedding-plane surface of this underlying siltstone, thus demonstrating the superficial nature of the fracture. Several other

narrow east-west zones of closely spaced fractures were also mapped in the spray pond excavation, none of which showed evidence of offset.

There is little evidence of shearing in the excavation, despite the proximity of the Sanatoga fault to the western end of the spray pond. As investigated and mapped by Dames and Moore (Reference 2.5-1), the Sanatoga fault - Downington dike passes within about 250 feet of the western end of the spray pond. The N 20° E joint with about 1 inch offset noted above strikes parallel to the trend of the Sanatoga fault. The structural investigations conducted by Dames and Moore recognize east-west fracturing and shearing as a secondary but persistent occurrence accompanying the dominant northeast and northwest structural trends. East-west shearing was mapped at the site in a trench excavated across the trace of the Sanatoga fault. Similar shears were also recorded in exposures of the Downington dike south of the site and in road-cuts about 3 miles northeast of the site.

Dames and Moore concluded that lateral shears occur as a numerically minor east-west regional fracture trend which includes both extension fractures and shears. In several cases these joints appear to have resulted from simple shear along northeast-trending fractures (Reference 2.5-1).

2.5.1.2.6 Site Geologic History

The geologic history of the region is discussed in Section 2.5.1.1.4. The Newark-Gettysburg basin, in which the site is located, was formed in two phases (Reference 2.5-17). The first phase consisted of formation of the sedimentary basin, probably by down-warping rather than faulting. The bulk of the intrusives were emplaced late in basin development, but before the end of deposition. The second phase consisted of a deformational period. Faill (Reference 2.5-17) states: "All the deformation appears to have been postdepositional, with the monocline, the folds, and the faults developing contemporaneously.... With few exceptions, faults are not intruded with diabase - in general, the faults offset diabase plutons. This indicates that most of the faulting occurred after the diabase intrusions."

Studies by Dames and Moore (Reference 2.5-1), which include radiometric age dating of the diabase dikes in the vicinity of the site, indicate that the age of the diabase in the site area is 191 ±10 million years. The age of the faulting is uncertain but is considered by the Geology Review Board, a group of authorities on Appalachian geology, to be associated with the Jura-Triassic development of the Newark Basin 140-200 million years ago (Reference 2.5-1).

Reported instances of Triassic basin faults that also offset Cretaceous and Tertiary deposits are quite rare along the Atlantic coastal plain. These rare occurrences are characterized by relatively small displacements compared to those present in known Triassic basins. All such displacements investigated have been found to be at least 500,000 years old, and no proof has been found for post-Miocene movement. These occurrences are considered to be unrelated to the capability of Triassic faults in the site region.

According to a recent compilation (References 2.5-135, plate 1, and 2.5-134, figure 3), the only instance within 200 miles of the site of a fault that offsets coastal plain strata overlying Triassic sediments is the inferred Brandywine fault zone located 9 miles southeast of Washington, D.C., about 140 miles from the site. Evidence for both the faulting and the presence of Triassic sediments at depth is entirely from subsurface data, including seismic reflection, drill holes and geophysical logging, as reported by Jacobeen (Reference 2.5-61). These data indicate that two northeast striking, southeast dipping en echelon reverse faults offset the top of the Lower Cretaceous Arundel Formation a maximum of about 250 feet. The relation of this faulting to

Triassic basin structure, however, is uncertain because both Triassic sediments and granitic rocks were penetrated by deep drill holes on both sides of the fault zone. Jacobeen (Reference 2.5-61) states he believes the faults to be unrelated to mesozoic structure. Up section, the drill hole data confirm that the Paleocene-Eocene Aquia Formation is monoclinally folded without being offset by faulting. This folding occurred prior to Oligocene erosion, and only minor flexuring is displayed in overlying Miocene strata (Reference 2.5-61). Jacobeen concludes that there is no evidence for post-Miocene movement on the Brandywine fault zone.

Mixon and Newell (References 2.5-105, 2.5-106 and 2.5-107) suggest that the Brandywine fault zone may be an extension of faults bordering the Richmond Triassic basin in Virginia, 60 miles to the southwest, based on the alignment of both fault zones with a linear gravity anomaly that extends between the two locations. However, evidence to associate the Richmond basin faults with Cretaceous or younger faulting apparently could not be found because neither Mixon and Newel nor Wentworth and Mergner-Keefer (References 2.5-135 and 2.5-134) indicate any offset of coastal plain strata where these strata overlap the Richmond basin faults.

Another fault zone about 15 miles west of, and parallel to, the Brandywine has been named the Stafford fault zone (References 2.5-105, 2.5-106, 2.5-107 and 2.5-151). Surface exposures of the Stafford fault zone show that coastal plain strata are offset along high angle basement faults.

However, the Stafford fault zone is not associated with Triassic sediments and has no demonstrable relation to any Triassic basin structure at this location. Nevertheless, the relative proximity and similar trend of the Brandywine and the Stafford fault zones suggest they may be structurally interrelated.

The Stafford fault zone consists of four subparallel, en echelon basement faults that offset coastal plain strata. Each fault has a maximum throw of about 150 feet. Two of the faults display reverse throw on high angle, west dipping planes (down-to-coast movement).

On one of these faults (the Fall Hill fault), an exposure near the Stafford-Spotsylvania county line shows a high angle fault contact between basement gneiss and Cretaceous coastal plain sediments. The gneiss projects about 14 inches upward into overlying Plio-Pleistocene fluvial gravels, consistent with reactivated reverse displacement along the fault-plane (Reference 2.5-107). Such relationships are also consistent with features produced by normal stream erosion, particularly in view of the great contrast in erodability between the gneiss and the Cretaceous sands.

A detailed investigation of the Stafford fault zone, including an extensive drilling and trenching program, was conducted by Dames and Moore for Potomac Electric Power Company (Reference 2.5-113). Tertiary strata were identified above the faulted Cretaceous strata in trenches across one of the four faults (Hazel Run fault). The trenches show that this fault truncates Paleocene-Eocene strata (Aquia Formation) and is overlain by unfaulted Miocene strata (Calvert Formation) which exhibit only minor flexure not necessarily caused by fault movement. The Aquia and Calvert Formations were not present in trenches across the remaining faults; instead, these faults are directly overlain by undisturbed Quaternary materials (generally Plio-Pleistocene upland gravels). Along the Fall Hill fault, three trenches were excavated to expose the basal contact of the upland gravels crossing the fault. In all three cases, the upland gravels were not disturbed by faulting. The investigation concluded (Reference 2.5-113) that the minimum age of fault displacement on the Stafford fault zone is at least 500,000 years. Moreover, no unequivocal evidence was found for post-Miocene movement on any of the faults. Absence of post-Miocene movement is also

supported by an investigation by Mixon (Reference 2.5-150), who maps a late Miocene erosional scarp trending across the Stafford fault zone without observable offset.

It is concluded that the indication of Cretaceous and early to middle Tertiary offset above possible Triassic basin faults is a highly exceptional occurrence within the site region and does not warrant the presumption of similar movement on Triassic basin faults in general. Furthermore, detailed investigations of these known exceptional occurrences within the site region have established that their age of latest movement is at least 500,000 years, and is probably Miocene or older. Therefore, these occurrences are considered to be unrelated to the capability of Triassic faults in the site region.

Since late Mesozoic time, the area around the site has been a land mass subject to erosion. Continental glaciation that occurred during the Pleistocene did not extend to the site area. Bedrock at the site is overlain by up to 40 feet of residual soil derived from the bedrock by weathering. These residual soils, which overlie the Sanatoga fault and the Downington Dike without offset, have been dated in studies by Dames and Moore as being of Yarmouthian age, or 500,000-850,000 years before present (Reference 2.5-1, p. 4-17).

Additional discussion related to post-Mesozoic faulting in the site region is provided in Section 2.5.2.3.1.2.

2.5.1.2.7 Engineering Geology Evaluation

Site subsurface exploration is described and discussed in Section 2.5.4.3. Laboratory tests of foundation materials and in situ geophysical tests of the foundation materials are discussed in Sections 2.5.4.2 and 2.5.4.4, respectively. Geologic mapping of the foundation excavations is described in Sections 2.5.1.2.5 and 2.5.4.3. It is concluded from these studies and evaluations that the site geologic and foundation conditions are entirely suitable for plant construction and operation.

2.5.1.2.7.1 Geologic Conditions Under Category I Structures

All seismic Category I plant facilities are founded on bedrock, except part of the spray pond, portions of the underground piping, and electrical ducts, diesel oil tanks, and valve pits, which are founded on weathered rock, natural soil or fills. For more detail, refer to Section 2.5.4.5. The locations of the major Category I facilities are shown on Figure 3.8-58.

The foundation rock at the site consists of reddish-brown siltstone, interbedded and lensing with shale and sandstone. These rocks are part of the Brunswick and Lockatong lithofacies of Triassic-age (Section 2.5.1.2.3). The bedrock strata dip to the north at angles of from 8° to 20°. Several fracture zones with minor offsets were encountered during site excavation; these zones and their treatment are described in Sections 2.5.1.2.5 and 2.5.4.12. All the Category I rock foundations were excavated to unweathered bedrock. Geologic maps and sections of the Category I excavations at the main power block are shown in Figures 2.5-10, 2.5-11, and 2.5-13. Engineering properties of the foundation rock are described in Section 2.5.4.

The natural soils at the site consist of materials derived from the in situ weathering of siltstone, sandstone, and shale. Soil from 0 feet to about 40 feet thick was encountered in the borings at the site. In some parts of the area, the bedrock has not completely broken down into soil, and the soil materials are mixed with weathered, decomposed rock fragments. Weathering decreases with

depth, and grades gradually to fresh rock. The evaluation of the stability of the natural soils at the site is presented in Section 2.5.4.

2.5.1.2.7.2 Landslide Potential

There are no steep or unstable natural rock slopes in the construction area. No old landslides, rock slips, or landslide scars have been noted near plant structures. The natural rock slopes present no hazards to plant structures. Stability of soil slopes is discussed in Section 2.5.5.

2.5.1.2.7.3 Areas of Potential Subsidence, Collapse, or Uplift

Rocks in the area around the site are primarily well-indurated siltstones, sandstones and shales to a depth of several thousand feet. No cavernous or karstic terrain exists in the area. There is no mining or significant fluid withdrawal in the area.

Analyses of precise leveling surveys indicate that some broad crustal warping may be occurring in the area (Reference 2.5-18). If so, it is of a broad, regional nature and does not significantly affect plant structures. Measurements of residual stresses (Reference 2.5-1) using overcoring methods indicate very low stress in the area near the site. It is concluded that available data indicate that uplift or subsidence, either from man's activities or natural geologic conditions, does not have any significant effect on the safe operation of the LGS.

2.5.1.2.7.4 Behavior of Site During Prior Earthquakes

There is no evidence at the site of any effects, such as landslides, fissuring, or subsidence, that could be attributed to prior earthquakes.

Within historical time, the maximum intensity of earthquakes that have occurred near the site was probably V or less. Ground motion at this intensity has no significant effect on the dense soil and well-indurated rock at the site. For additional information on historical seismicity, see Section 2.5.2.1.

2.5.1.2.7.5 Zones of Deformation or Structural Weakness

As reported in the PSAR, the preconstruction investigation defined major joint and fracture systems, minor faults in the area around the site, and indicated the possibility of fracture zones with small offsets within the site area.

During the foundation excavation some fracture zones with small displacements were encountered and were treated as required. Descriptions of the fracture zones are presented in Section 2.5.1.2.5, and their treatment is discussed in Section 2.5.4.12. Figure 2.5-13 shows their locations at final foundation grades, their widths, and their attitudes. None of the zones presents a hazard to plant structures.

2.5.1.2.7.6 Zones of Alteration or Irregular Weathering

Bedrock at the site is overlain by from 0-40 feet of residual soil, developed in situ by the gradual decomposition of the parent rock.

The soil horizon has developed over a long period of time, probably in excess of 500,000 years (Reference 2.5-1, section 4.0). The soil grades gradually into fresh, unweathered rock; no clearly defined boundary between soil and rock exists. Weathering appears to be a function of lithology and fracture spacing. Where the rock is closely jointed or shaly, weathering has progressed more rapidly, and a thicker soil horizon is present. In the fracture zones, weathering extends below the general level of the fresh rock surface. These zones are generally narrow, such as the fracture zones described in Section 2.5.1.2.5, and were treated locally when encountered in foundation excavations.

Within the site area, the narrow zones of irregular, relatively deeper weathering that were encountered in the foundation excavations were treated by standard methods, as described in Section 2.5.4.12, and pose no hazard to the construction and operation of the LGS plant.

2.5.1.2.7.7 Potential for Unstable or Hazardous Rock or Soil Conditions

The bedrock at the site contains no unstable minerals, and the soils derived from this rock are also composed of stable minerals. There are no potentially unstable or hazardous conditions present in the site foundation materials.

2.5.1.2.7.8 Unrelieved Residual Stress In Bedrock

Geologic investigations by Dames and Moore in 1974 (Reference 2.5-1) include several measurements of residual stress in rock, made using overcoring methods. These tests were made in closely jointed rock near the Sanatoga fault and in a boring in Possum Hollow Run southeast of the major plant structures. Of the 15 tests made, only two indicate valid results. Dames and Moore state: "Only the results of test FTa-1 and test ET-1 are considered valid (Reference 2.5-1, page 5-4). They show relatively low stresses: major principal stresses of 450 psi and 950 psi, respectively; and minor principal stresses of 175 psi and 650 psi, respectively. The orientation of the major stresses in the two tests is almost identical; N 75° W and N 85° W, respectively."

The report of the geologic evaluation committee, consisting of Dr. Donald U. Wise, Dr. Carlyle Gray, and Dr. Paul B. Myers (Reference 2.5-1), evaluates the residual stress-field as follows: "The present WNW orientation of compressive stresses in the residual stress measurement differs markedly from the NNE compression which produced the Jura-Triassic faults at the site and nearby folds. The effect is to increase normal stresses across the faults, increasing fractional resistance to movement, and decreasing available space for additional graben displacement."

Calcite is present in vein form along joints and fractures in the site area. Despite the fact that calcite twins easily at low stress levels, calcite twins are rare in the latter stages of the mineralization in the site area. The low stress levels indicated by the calcite correspond well with values measured in situ.

It is concluded that the stress regime at the site is low and stable, and residual stress is not a factor in the safe operation of LGS.

2.5.1.2.7.9 Conclusions and Summary

Consideration of all the engineering geologic factors at the LGS site leads to the conclusion that the site is suitable for constructing and operating the plant. The bedrock in the construction area is competent and provides satisfactory foundation support for all major plant structures.

2.5.1.2.8 Site Groundwater Conditions

This section provides a summary of groundwater conditions at the site. Reference for more detailed information on this subject may be made to Sections 2.4.13 and 2.5.4.6.

LGS will have no effect on the future use of groundwater in the region. The site is hydrologically isolated from public groundwater supplies and areas of extensive groundwater development.

Groundwater at the site occurs in sedimentary rocks of Triassic-age. The Brunswick lithofacies, the formation underlying the plant site, is consolidated rock consisting of bedded sandstone, siltstone and shale. It yields small-to-moderate quantities of water to wells. Most of the groundwater movement within the Brunswick follows secondary openings, the most important of which are nearly vertical joint planes that cross each other at various angles throughout the beds, giving the rock a low to moderate permeability. About 85% of the permeabilities measured in bedrock are less than 390 ft/yr.

Recharge to the Brunswick occurs through the relatively impervious soil cover as precipitation percolates down to the water table. The water table approximately parallels the topographic surface, groundwater flows from high to low topographic areas. Groundwater beneath the plant flows toward the Schuylkill River in a southwesterly direction, eventually discharging to the river. North of the plant, a groundwater divide is present beneath the topographic high that occurs there. Groundwater north of the divide flows northward, discharging to tributaries of the Schuylkill River.

A map of the potentiometric surface at the site determined from levels measured in May, 1979, is shown in Figure 2.4-15. This indicates the groundwater level is at el 250' east of the spray pond, decreasing through the area of the principal plant facilities to about el 120' southwest of the power block enclosure. Fluctuation of water levels in observation wells are illustrated by the hydrographs in Figure 2.4-18, and discussed in Section 2.4.13.

The emergency spray pond, excavated partly in soil and partly in rock, was lined to preclude excess seepage. The pond will not significantly affect groundwater levels beneath the plant (refer to Section 2.5.4.6 for a discussion of groundwater conditions beneath the spray pond).

2.5.2 VIBRATORY GROUND MOTION

This section presents the evaluation of the geologic and seismic conditions in the site region as they affect design for vibratory ground motion. The investigation undertaken for the PSAR includes the following:

a. A study of geologic structure and tectonic history of the site region

b. A review of seismicity of the region, primarily based on a literature search and supplemented by a review of contemporary newspaper accounts

c. An evaluation of seismicity of the region that considers the relationship of historic earthquakes to geologic and tectonic features

d. Field geophysical measurements to determine physical properties of the bedrock at the site

e. Selection of appropriate OBE and SSE

f. Estimation of maximum level of ground motion to be expected at the site due to the occurrence of the OBE and SSE

g. Characterization of seismic design criteria in the form of response spectra and recommended time histories

Detailed descriptions and the results of the geologic and geophysical investigations that provide background information for some of the results discussed in this section are presented in Sections 2.5.1, 2.5.3, and 2.5.4. Information gained after the submittal of the PSAR has been considered and added, and discussion of this information is provided where appropriate in this report.

2.5.2.1 Seismicity

The site is located in a region that has experienced a moderate amount of historic earthquake activity. The record of earthquake occurrence in southeastern Pennsylvania and the surrounding area dates back to the early 1700s. Since this region has had a relatively large and well distributed population since this time, it is probable that any major earthquake activity (defined in this context as intensity greater than or equal to VIII on the Modified Mercalli Scale, Table 2.5-1), would have been reported in local newspapers, private journals, or diaries. No evidence in documentation of this type has been found.

As indicated in the PSAR, zones of major earthquakes in the eastern United States, such as the St. Lawrence River region and the New Madrid, Missouri region, are too far removed from the site, both tectonically and geographically, to have an appreciable effect on the seismic evaluation. Maximum historic intensities at the site from earthquakes in these two active regions are estimated to be about IV or less on the Modified Mercalli Scale. Earthquakes near Charleston, South Carolina in 1886 are the only major earthquakes recorded in the Coastal Plain physiographic province of the eastern United States. These shocks, which had a maximum intensity of about IX, were centered about 550 miles SSW of the site. It is estimated that these shocks were felt in the site area, with an intensity of about III. The more modest local and regional seismicity of the site area is more important to the seismic evaluation of the site area than effects from events in the distant zones of major earthquakes; thus, only seismicity within 200 miles of the site is considered in the discussion below. For the purposes of this discussion the site region is defined as that area within a 200 mile radius.

2.5.2.1.1 Regional Seismicity

The epicenters of earthquakes of maximum intensity IV-V or greater within approximately 200 miles of the site are shown in Figure 2.5-14 and listed in Table 2.5-2. This data set covers the interval from the first historical account in the beginning of the 18th century through January 1982. A total of 131 events are shown and listed. Sixteen of these earthquakes (3 of intensity VI, 10 of intensity V, and 3 of intensity VI-V) occurred after 1967 and thus are an update of the PSAR compilation. A number of additional small pre-1968 earthquakes were found (2 of intensity V-VI, 9 of intensity V, and 18 of intensity IV-V), predominantly from two recent catalogs by Winkler (References 2.5-53 and 2.5-54). Data on post-1967 events have been taken from various publications of the USGS (References 2.5-19, 2.5-20, 2.5-21, and 2.5-55), Bulletins of the Northeastern U.S. Seismic Network (Reference 2.5-56), Bulletins of the Southeastern U.S. Seismic Network (Reference 2.5-57), and supplementary data from a National Geophysical and Solar

Terrestrial Data Center earthquake list (Reference 2.5-58). The new earthquakes do not alter the seismic characterization of the site region implied by pre-1968 seismic history.

The parameters of the Moodus, Connecticut, event of May 16, 1791 have been altered from the data in the PSAR. Although two events are listed in the PSAR, one on May 16th and another on May 18th, no single account describes two large events, two days apart. Rather, two very similar descriptions of a single earthquake, quoted as occurring on these two different dates, are the source of the two events in the PSAR. It is probably confusion over the date of occurrence of this shock that has led to duplication in the original listing. More importantly, the maximum intensity at East Haddam, Connecticut, is anomalous with respect to reports from nearby localities. This observation led Linehan (Reference 2.5-22) to reevaluate the intensity of this earthquake, which he assessed as V-VI. Seismologists from the NOAA, U.S. Department of Commerce, have recommended that the 1791 earthquake be reclassified as intensity VII. This value is conservatively adopted in this report.

Although no modification of the maximum intensity associated with the 1929 Attica, New York earthquake is exercised here, it may be noted in passing that, in a recent study of this event (Reference 2.5-23), a revised intensity of VII has been suggested.

As Table 2.5-2 shows, 59 earthquakes with maximum intensities of IV-V or greater have been reported within 100 miles of the site since the first historical account, at the beginning of the 18th century. Of these shocks, 5 were of intensity VII, 10 were of intensity VI, 40 were of intensity IV-V or V, and 4 were of uncertain intensity. Of the intensity VII earthquakes, the closest to the site was a shock near Wilmington, Delaware in 1871, approximately 30-40 miles from the site. Smaller earthquakes have occurred closer to the site. A series of shocks occurred in the Reading-Sinking Spring area in 1954 and 1955, about 20-25 miles to the west of the site. The largest of these had a maximum intensity of VI. Such smaller shocks are discussed in detail in the section on local seismicity below.

A discussion of the most significant earthquakes in the region follows:

a. Wilmington earthquake of October 9, 1871:

This shock is the largest earthquake originating in or near the Piedmont, and close enough to the site to be of significance in the current report. Little information about this earthquake is available, and it is therefore difficult to accurately locate its epicenter or estimate its maximum intensity. It is believed that the epicenter was located somewhat to the south of Wilmington, Delaware, where the shock was felt with intensity VII. The shock was felt from Chester, Pennsylvania, to the north, to Middletown, Delaware, to the south; and from Salem, New Jersey, to the east, to Oxford, Pennsylvania, to the west. The initial shock was followed by a much smaller aftershock just after midnight on October 10th. A contemporary newspaper account indicates that the shock was felt at Wilmington, "with great distinctness." Buildings were shaken severely, and a number of chimneys in various parts of the city were shaken down. Windows and glass were broken. The shock also was felt strongly and resulted in broken chimneys in the surrounding towns of Oxford, Pennsylvania, and New Castle and Newport, Delaware.

An interesting aspect of this earthquake is the fact that it was accompanied by a very loud sound, as of an explosion. This loud noise, in fact, led to the belief that

the shock was caused by an explosion, probably at the powder mill of the E.I. Dupont deNemours Company, near Wilmington. This possibility was carefully investigated at the time, however, and it was concluded that the shock was due to an earthquake.

b. Wilkes-Barre earthquake of February 21, 1954:

This earthquake and a strong aftershock two days later were probably not of tectonic origin. The shock occurred in an area in Wilkes-Barre, Pennsylvania, which is underlain by coal mines extending to a depth of 400 feet below the ground surface. Wilkes-Barre is about 65 miles north of the site. The affected area was confined to the east side of the Susquehanna River, in a five-block residential area. The effects of this disturbance were locally severe. Occupants fled to the streets. Sidewalks pushed upward with a heaving motion and then collapsed. Hundreds of homes were damaged, ceilings and cellar walls split, and backyard fences were pushed over. Gas and water mains snapped. Methane gas rising from cracks in the earth presented a temporary emergency. The estimated property damage was $1,000,000; however, this figure may be somewhat high.

The second shock, two days later, occurred in the same area. Again, hundreds fled to the streets. Cracks appeared in ceiling, and walls of apartment buildings. Curbs pulled away from sidewalks; street pavements buckled from curb to curb. Additional water and gas mains were broken.

The small affected area of these shocks suggests a very shallow focus and a source mechanism of limited lateral extent. Detailed investigations of the event shortly after it occurred lead to these conclusions: it was closely related to slip along a zone of weakness that exists in the strata (in which coal mining was taking place) along the south side of the affected area, and, whatever the cause-and-effect relationship was between this slip and roughly concurrent failure of coal pillars and partial mine collapse, this event would not have occurred without the previous existence of the coal mine excavations.

c. Earthquake of March 8, 1889:

This shock had its epicenter in southeastern Pennsylvania, probably near York, about 60 miles southwest of the site, where the shock was felt most strongly.

The maximum intensity of the shock was VI. The shock was felt throughout northeastern Maryland, northern Delaware, and southeastern Pennsylvania. The area in which it was felt was roughly elliptical in a NE-SW direction from Trenton, New Jersey, to Hagerstown, Maryland. The shock lasted about ten seconds.

No serious damage was reported. The greatest damage occurred at York, where some chimneys were knocked over and people were badly frightened. A man was thrown from a sofa, and articles were thrown from shelves. The shock was accompanied by a loud rumbling noise. It is interesting to note that there were reports of a "ball of fire" passing over the area at the same time as the shock.

2.5.2.1.2 Local Seismicity

Some minor earthquake activity has occurred in the site vicinity. Seventy-two events within approximately 50 miles of the site are listed in Table 2.5-8 and plotted in Figure 2.5-15. Forty-five of these events have been of less than intensity IV-V (or unassigned) and therefore do not appear in the regional catalog above. Data on the additional events have been taken from various publications of the USGS (References 2.5-19, 2.5-20, 2.5-21, and 2.5-55), Bulletins of the Northeastern U.S. Seismic Network (Reference 2.5-56), Bulletins of the Southeastern U.S. Seismic Network (Reference 2.5-57), Winkler (References 2.5-53 and 2.5-54), and supplementary data from a National Geophysical and Solar Terrestrial Data Center earthquake list (Reference 2.5-58).

The completeness and accuracy of earthquake reporting in the site area is not uniform over the entire period of record. Before instrumental epicenters were reported in the northeastern and southeastern U.S. Seismic Network Bulletins, most earthquake locations were based on sensory and damage reports from area surveys following the earthquake, from newspaper articles, historical journals and publications, and private diaries. No formal location accuracy estimate is attempted for earthquakes occurring before 1975. However, it is believed reasonable to assume that these events are generally located to an accuracy of better than ten to several tens of kilometers. The instrumental locations of earthquakes occurring after 1975 are generally better constrained. The degree of uncertainty in the locations of the small site area events that have occurred after 1975 is about one-half the degree of uncertainty associated with pre-1975 event locations. In addition, the disproportionate number of post-1975 earthquakes indicates an increased earthquake detection capability in the site area. Location uncertainties, and the nonuniformity of location accuracy and event detection capability over the total time period of record, should be recognized in considering the seismicity of the vents listed below and of those shown in Table 2.5-8 and Figure 2.5-15.

Descriptions of the historical seismicity for the Reading-Sinking Spring, Allentown and Philadelphia areas follow. A "detected" event as used in this discussion indicates that the event was felt, heard, or noticed in some way.

a. Reading-Sinking Spring Area Earthquakes: (about 20-25 miles west of the site)

1. May 28 and 29, 1906 - A small shock of reported intensity III was felt on May 28 over an area within about 2-3 miles of Geigerstown. On May 29 a water tank collapsed in New York City, tentatively associated with a IV-V shock in Reading. The occurrence of this latter event is suspect.

2. June 8, 1937 - This shock was very slight, with a possible maximum intensity of III. The epicenter was in the vicinity of Reading. Little information is available.

3. January 7, 1954 - This shock and a series of aftershocks originated in the Sinking Spring area west of Reading. The shock had a maximum intensity of VI. Damage in Sinking Spring consisted of plaster ripped from walls, dishes and bottles tumbled from tables, upset furniture, and slight damage to brick and frame buildings. People were thrown out of bed. In the surrounding communities, many people felt the tremor, homes rocked, furniture toppled, and dishes and lamps rattled. The main shock was followed by many minor aftershocks over a period of a few weeks.

4. January 23, 1954 - An aftershock of maximum intensity III shook a 10 mile square area surrounding Sinking Spring.

5. August 10, 1954 - About 12 tremors, four of "good size," maximum intensity IV, were felt in the Sinking Spring area within a 10 minute period.

6. September 24, 1954 - A series of minor tremors, maximum intensity III, were felt in the Sinking Spring area.

7. January 19, 1955 - A shock of maximum intensity IV occurred in the Sinking Spring Area. The shock was felt from West Reading west to Wernersville; houses vibrated, windows and dishes rattled, and a lamp tumbled to the floor. A noise accompanied the shock. Many felt the shock and were alarmed.

b. Allentown Area Earthquakes:

1. May 31, 1884 - This shock had a maximum intensity of about V. The shock was felt in a small area at Allentown. No damage was reported other than dishes thrown from tables.

2. May 31, 1908 - This shock had a maximum intensity of VI. This shock was felt in all parts of Allentown, in a total area of about 50 square miles, but not in the surrounding communities. The shock lasted about one or two seconds and was accompanied by a low rumbling sound followed by a loud report, as of an explosion. Many people were frightened by the shock. Some were thrown to the ground. Damage consisted of a few fallen chimneys, broken windows, dishes, etc, and other minor building damage.

3. November 23, 1951 - An extremely local shock was reported in the northwest section of Allentown. The maximum intensity of the shock was IV. Many were awakened. It was reported that a bed was moved 6-7 inches. A vase was knocked off a shelf and a pump was put out of order. Reports indicated that the water level in a well used for 25-30 years dropped 60 feet. The shock was accompanied by a low rumbling noise.

4. September 14, 1961 - This shock was centered in the Lehigh Valley, about 5 miles east of Allentown. The maximum intensity of the shock was V. It was felt in a larger area than the foregoing earthquakes; however, no damage was reported. The earthquake was strongest in Allentown, Bethlehem, and surrounding communities where the shock was felt by nearly all and where many were alarmed and awakened. Many were shaken from their beds. Loose bricks fell from a chimney. Buildings shook, loose objects rattled, and thunderous sounds were heard.

c. Philadelphia Area Earthquakes:

1. November 26, 1755 - Detected at Philadelphia.

2. November 22, 1963 - Detected at Delaware County, Pennsylvania.

3. October 13, 1763 - Detected at Philadelphia.

4. October 30, 1763 - Intensity IV-V at New Jersey; IV at Philadelphia; detected at Bensalem, Pennsylvania.

5. November 22, 1777 - Detected at Philadelphia.

6. November 23, 1777 - Detected at Delaware County, Pennsylvania.

7. November 29 and 30, 1783 - For November 29 event at 22:15: intensity IV-V at Philadelphia; IV at New York City and New Haven, Conn.; detected at Hartford, Conn., Boston, Mass., N.H., N.J., and R.I.; shocks also felt at 21:00 and 01:00-02:00 the next morning (November 30) at Philadelphia and New York City.

8. March 17, 1799 - Detected at Philadelphia.

9. March 17, 1800 - Severely felt at Philadelphia.

10. November 29, 1800 - Severely felt at Philadelphia.

11. November 12, 1801 - Detected at Philadelphia.

12. December 8, 1811 - Intensity III at parts of Pennsylvania and Delaware (including Wilmington, DE).

13. November 11 and 14, 1840 - Both had intensity IV at Philadelphia; great and unusual swell on the Delaware River was noted.

14. October 12, 1870 - Intensity III near Wilmington, Delaware.

15. October 9, 1871 - Intensity VII at Wilmington, Delaware. A press report stated chimneys toppled and windows broke. Damage also was reported at New Castle and Oxford. Event was felt in New Jersey (IV-V at Haddonfield; IV at Salem) and Pennsylvania (IV at Philadelphia).

16. August 10, 1877 - Intensity III near Trenton, N.J.

17. September 10, 1877 - Intensity IV-V in the Delaware Valley. Felt from Trenton, N.J. to Philadelphia, over an area 20 miles wide with center near Burlington, N.J.

18. March 25, 1879 - Intensity IV-V in the Delaware Valley, near Dover, Delaware and below Philadelphia. Felt from Chester, Pennsylvania to Salem, N.J., a distance of 30 miles. Felt most strongly on the east side of the Delaware River.

19. October 10, 1892 - Intensity III near Wilmington, Delaware.

20. November 20, 1895 - Intensity IV at Claymont, Delaware and Chester, Pennsylvania; felt at Wilmington, Delaware and Linwood, Pennsylvania.

21. March 17, 1900 - Intensity III near Philadelphia.

22. April 28, 1900 - Intensity III near Philadelphia. Felt at Camden, N.J., southern N.J., and Philadelphia.

23. November 29, 1900 - Intensity III near Philadelphia.

24. February 6, 1909 - Intensity III near Trenton, N.J.

25. January 26, 1921 - Intensity V at Moorestown, N.J. Rumbling noise reported. Felt in Philadelphia. Fissure reported in Burlington.

26. January 24, 1933 - Intensity V near Trenton, N.J. A Sharply felt shock. Pictures thrown from wall at Lakehurst.

27. August 22, 1938 - Intensity V in central New Jersey. Felt throughout central New Jersey, southeastern Pennsylvania, and northern Delaware. Slight damage at Gloucester City and Highstown, N.J., and Ardmore, PA. Four smaller shocks occurred on the 23rd and one on the 27th.

28. November 14, 1939 - Intensity V in Salem County, N.J. Reported felt from Trenton, N.J. to Baltimore, MD., and from Cape May, N.J., to Philadelphia, PA and its adjoining counties. About 6000 square miles were affected. Little or no damage resulted. Intensity V at Deep Water, N.J. where small objects overturned.

29. January 8, 1944 - Felt from Wilmington, Delaware to the southwestern outskirts of Philadelphia. Windows rattled and houses shook.

30. December 27, 1961 - Intensity V near Pennsylvania-New Jersey border. At Bristol and in the northeast portion and suburbs of Philadelphia, buildings shook, dishes rattled, and disturbed objects were observed by many. Police and newspaper offices were swamped with calls from alarmed citizens inquiring about the loud rumbling sounds. Felt by many at Levittown and Langhorne, Pennsylvania and Bordertown and Trenton, New Jersey, where houses shook and creaked, windows and dishes rattled. Felt by several at Burlington.

31. February 28, 1973 - Felt in all or parts of Connecticut, Delaware, Maryland, New Jersey, Pennsylvania, and Virginia. Observers reported cracked plaster at North East and Perryville, MD, and Laurel Springs and Penns Grove, N.J. At Harrisonville, N.J., cinder block basements reportedly cracked. An observer at Palmyra, N.J. reported damage (not described) and that a driveway "dropped 3 inches." At New London, PA, patio, walls, and plaster cracked. "Silent cracks where concrete meets house," loosened rain spouts and cracked plaster were observed by Norristown, PA, residents. At Thornton, PA, pipe connections to a well broke. Two mirrors fell from a wall and shattered at Wallingford, PA. Small objects shifted and fell in several towns in Delaware, New Jersey, and Pennsylvania. Magnitude 3.8.

32. March 2 to May 2, 1980 - Sequence of small earthquakes in the vicinity of Abington, PA. The largest events were on March 5 (magnitude 3.5) and March 11 (magnitude 3.7); both were felt with maximum intensities of IV to V. A small magnitude 3.1 aftershock 13 minutes after the March 5 event was also felt in the Abington area. Bischke (1980) reports that both of the March 5 and 11 events were felt and heard by many people as explosive or low distant rumbling sound. "In one case a plant overturned; in several cases small objects vibrated and shifted slightly on their foundations, plaster cracked and pictures tilted on the walls. In general, windows and dishes rattled, and over half of the people reporting the March 11 event at 1 in the morning were awakened by the earthquake."

33. August 30, 1980 - Event near Medford, N.J.; magnitude 3.0.

The descriptions above discuss all known seismic activity in the Reading-Sinking Spring, Allentown, and Philadelphia areas. As discussed below, none of these seismic activities are associated with any known structures within the context of 10CFR100, Appendix A.

Six events with maximum intensities ranging from II to VI have been tabulated near Reading-Sinking Spring. These occurred between 1906 and 1955 and were located only by sensory reports.

Four shocks of intensities from IV to VI are reported to have occurred in the Allentown area between 1884 and 1961. Only sensory report information constrains the locations of these events.

Estimates of location accuracy for these earthquakes indicate an uncertainty of several miles or more. In addition, small events of this type could easily occur on small dislocations in the earth's crust with no surface representation. Because of their small size and uncertain locations, none of these events are associated with known structures in the context of 10CFR100, Appendix A.

As discussed in Section 2.5.2.3, a number of earthquakes in the site region appear to parallel the NE-SW geologic structural trend in a relatively narrow belt along the axis of the Fall Zone. This belt passes through the Philadelphia area about 30 miles southeast of the site. A total of 33 events and event sequences are noted in this area. These range in size from indeterminate intensity to intensity VII and occurred from 1755 to 1980. For all events before 1973, only sensory report locations are available. For the sequences beginning February 28, 1973 and March 2, 1980, instrumental and intensity report data exist. For a single earthquake on August 30, 1980, only instrumental data was found.

The Philadelphia area earthquakes occurring before the availability of instrumental data are, as with the Allentown and Reading-Sinking Spring events, too poorly located and too small to suggest association with specific known structures in the context of 10CFR100, Appendix A. A similar conclusion is reached for the August 30, 1980 event.

Sbar et al. (Reference 2.5-148) investigated the February 28, 1973 earthquake sequence and speculated that this sequence may have occurred on a northeast continuation of a graben described by Spoljaric (Reference 2.5-149). This continuation coincides with the Fall Zone in the Wilmington, Delaware area. Sbar et al. noted that more accurate locations of earthquakes and extensive mapping of faults are necessary to verify their hypothesis.

Bischke (Reference 2.5-146) investigated the association of the March 2, 1980 sequence with the Huntingdon Valley fault and concluded that the fault should be considered active on the basis of meizoseismal epicenters for several earthquakes of this sequence. Instrumental epicenters lie from several to over ten miles from the Huntingdon Valley fault. Bischke attributes these locations to inadequate instrumental coverage and possible errors in local crustal model velocities. Bischke concludes further that additional study of this fault is warranted.

Although both the 1973 and 1980 sequences have been speculated to occur on specific structures near the Fall Zone in the Philadelphia area, all events of these sequences have been small (less than magnitude 4.0), therefore they are not associated with large source structures. Both sequences have had disparate sensory and instrumental epicenter locations indicating some real uncertainty in the epicenters of these events. Each sequence has been an isolated instance of a cluster of events near a known or postulate structure. For these reasons; it is believed that these earthquakes should not be associated with known structures in the context of 10CFR100, Appendix A. Rather they are seen as part of the historic series of earthquakes near the Fall Zone in the Philadelphia area as noted above.

As discussed below, the April 1982 and March 1980 earthquakes are not correlated with the same structure.

A magnitude of 2.9 earthquake occurred on April 12, 1982 near Burlington, New Jersey. The epicenter was at 40°3.5' N, 74°48.9' W, according to an instrumental location by Lamont-Doherty Geological Observatory. Bischke (Reference 2.5-147) located this event about 6 miles to the west of the instrumental location based on sensory reports. The earthquake was both felt and heard, and many people detected the trembling motion for 5-10 seconds. An intensity of III to IV has been proposed for this event, although intensity V effects were felt locally (Reference 2.5-147).

Bischke (Reference 2.5-147) associates the April 12, 1982 earthquake with the Fall Zone beneath the Delaware River and attributes the failure of the instrumental epicenters to agree with the intensity data to instrumental location errors. This event should not be associated with a particular structure in the context of 10CFR100, Appendix A. Because the March 2, 1980 sequence and the April 12, 1982 event are associated with separate features, it is concluded that they are not correlated.

2.5.2.2 Geologic Structures and Tectonic Activity

2.5.2.2.1 Regional Geologic Setting

The site is located in the Triassic Lowland section of the Piedmont physiographic province of the Appalachian Highlands. The Piedmont is bounded on the southeast by the Atlantic Coastal Plain physiographic province. The Fall Zone, which trends NE-SW approaching within about 30 miles southeast of the site, marks the topographic boundary between the Piedmont and Coastal Plain provinces.

Bedrock in the Piedmont is generally at shallow depth, covered only by a thin veneer of residual soil. In some places, bedrock is exposed. Crystalline Precambrian rocks outcrop to the north and northeast of the site (the Reading Prong) and in a narrow belt parallel to the Fall Zone southeast of the site. The site is located in a down-warped or down-faulted Triassic basin, the Newark Basin, which contains sedimentary rocks, predominantly sandstones and shales. The geologic history of the Piedmont is complex. Major tectonic activity has occurred in the ancient part and many zones of faulting have been identified. Many intrusions are known; for example, the rocks of the Newark

Basin are crossed by numerous dikes and sills, which in some instances have intruded pre-existing faults.

Coastward, the bedrock surface is down-warped to the south and east, with the line of flexure generally within the Fall Zone. In the Coastal Plain, the bedrock is covered by unconsolidated sediments consisting of interbedded silt, sand, and gravel. These sediments form a wedge-shaped mass that thickens toward the southeast. These sediments range in age from Cretaceous to Recent. The down-warping of the bedrock surface of the Coastal Plain has occurred under the weight of accumulating sediments.

There are indications that some down-warp of the coastal plain relative to the Appalachian chain may be occurring today, although no significant crustal warping during Pliocene and Quaternary time is evident in the record of offshore sedimentation (References 2.5-24 and 2.5-25).

North of the site, the Triassic Lowland rocks abut Precambrian crystalline rocks of the Reading Prong, a narrow highland belt separating the Piedmont rocks from the intensely folded Lower Paleozoic rocks of the Great Valley sequence farther north. Westward, Triassic rocks of the Gettysburg Basin lie directly upon recumbent folds and nappes of the Valley and Ridge province.

2.5.2.2.2 Regional Tectonic Provinces

The site lies in a Triassic Lowland section (Newark Basin) of the Appalachian Piedmont tectonic province (Figure 2.5-16). This part of the Appalachian Piedmont in Pennsylvania, New Jersey, and Maryland is typified by the presence of several triassic basins (Culpeper, Gettysburg, and Newark) that have been postorogenically down-warped in the contorted metamorphic and igneous rocks exposed elsewhere in the Piedmont (Figure 2.5-16). Southwest of Reading, Triassic basin sediments of the Piedmont province rest directly on tightly folded and overturned beds of the Northern Valley and Ridge province.

A few miles north of the site, a belt of metamorphosed Precambrian (Grenville) crystalline rock, capped by patches of resistant basal Cambrian quartzite and dolomite, intervenes between the Triassic basin sediments and the slightly metamorphosed, but tightly folded, strata of the Great Valley section of the Northern Valley and Ridge province, here occupied by the Lehigh Valley. This intervening strip of Precambrian rock is the Reading Prong, the southwestern most extension of a distinctive belt of Grenville rocks that forms a series of highlands that can be traced northeastward into western Vermont. Traditionally, the Reading Prong has been viewed as a physiographic and lithologic extension of the crystalline rocks of the New England Appalachians.

Precambrian rocks also occur along South Mountain, southwest of Harrisburg. Here they form the northeastern arm of the Blue Ridge tectonic province, an anticlinorium of late Precambrian metavolcanics (greenstones) and associated Grenville age rocks, enclosing the southwestern flank of the Gettysburg Basin. Grenville rocks may possibly persist in a continuous zone from the Blue Ridge province to the Reading Prong-Hudson Highlands-Green Mountain belt, but if so, the relationships are obscured beneath the Triassic sediments of the Newark and Gettysburg Basins.

Proceeding northwestward from the site, across the folds of the Northern Valley and Ridge province, the folds are at first appressed and complexly faulted in the Great Valley belt but become more open farther northwest, where they assume their classic cylindrical forms. Beyond the Allegheny front (Figure 2.5-16), the folding at once becomes open and subdued, with the strata descending into a broad, gently folded basin or synclinorium. Classically this region of broad, gentle folding is part of the Appalachian Plateaus, though truly undeformed Paleozoic strata lie as much as 100 miles further beyond the Allegheny front.

Southeast of the site, the wedge overlap of Coastal Plain strata on the Piedmont crystalline rocks is about 30 miles distant; beyond, undeformed Lower Cretaceous through Recent sediments of the Atlantic Coastal Plain province thicken uniformly seaward.

The New England part of the Appalachian orogenic belt is an extensive terrain composed predominantly of metamorphic rocks, with lesser amounts of igneous and sedimentary rocks included. Like the rest of the Appalachian orogen, the New England Appalachians (Figure 2.5-16) are characterized by elongated structural systems and tectonic belts; however, the dominant orientation of these features, at least in the southern and western parts of the New England Appalachians, is more nearly north-south than NE-SW, as it is in most of the Appalachians. Recent application of plate-tectonic concepts to New England geology has led to a recognition of several fundamentally distinct crustal units within the New England Appalachians (References 2.5-26, 2.5-27, and 2.5-28). Several investigators have used findings to subdivide the New England Appalachians into tectonic provinces (for example, see Reference 2.5-29. The provinces are not discussed in this report since, for the reasons explained in Section 2.5.2.3, the detailed subdivision of the New England Appalachians is not significant to the LGS site.

2.5.2.2.3 Regional Tectonic Structures

Faulting of Precambrian age undoubtedly exists in the Piedmont, but the rocks of the Piedmont have been so metamorphosed since that time that no significant Precambrian faults are recognizable. Paleozoic faults generally are characterized by thrusting toward the northwest, a reflection of compressional forces imposed during the late Paleozoic (Alleghenian) orogeny, as well as during earlier tectonic events.

These thrusts are especially well displayed in the Northern Valley and Ridge province, just northwest of the Blue Ridge-Reading Prong anticlinoria, where the compressive forces in the sedimentary pile were at a maximum. In the Valley and Ridge provinces, thrusting is believed not to have involved basement rocks; rather, the foreshortening necessitated by the great Valley and Ridge folds is thought to have been taken up by buried ramp thrusts riding over incompetent shale lying on top of the basement rocks (References 2.5-13 and 2.5-30). Highly complex fault patterns are also displayed in the Precambrian rocks of the Blue Ridge and Reading Prong anticlinoria; their appearance attests to the fact that basement rocks were very much involved with thrusting southeast of the Great Valley. Southeastward, in the Appalachian Piedmont, the crystalline rocks have been subjected to multiple deformational and metamorphic episodes the Paleozoic, and many zones of pre-Triassic faulting have been identified.

Recent studies using COCORP (Consortium for Continental Reflection Profiling) seismic reflection data suggest that the entire Blue Ridge and at least part of the Piedmont of the southern and central Appalachians are allochthonous, underlain at several kilometers depth by a regional decollement which was active during the Alleghenian orogeny. This same decollement would extend westward beneath the Valley and Ridge province, where upward-splaying ramp thrusts, listric into the decollement, absorbed the westward translation and crustal foreshortening achieved along the decollement, thereby producing the well-known thrust fault and fold pattern of the Valley and Ridge province.

The closest major mapped fault of Paleozoic age is the Brandywine Manor fault, which approaches within about 9 miles to the southwest of the site. The Huntington Valley-Cream Valley fault (and the related Rosemont fault) approach within about 15 miles to the south of the site. None of the major Paleozoic faults has a mapped extension eastward into the Triassic Newark Basin. These

faults have been completely healed and are inactive. Some major thrust faults are transected by subsequently intruded Triassic-age dikes that show no displacement.

Faults of Triassic-age occur within the Newark Basin (Figures 2.5-2 and 2.5-38). The most significant of these to the east of the site. The Chalfont fault is the closest of these, approaching within about 9 miles to the northeast of the site. Some minor Triassic faults exist closer to the site (Figure 2.5-6). Some of these faults have developed along the major joint systems in the Triassic rocks. In some instances, Triassic-age dikes have intruded along some of these fracture zones, thus indicating their lack of activity since the Triassic (more than 140 million years ago). These minor faults are discussed in Section 2.5.1.2.3.

Faulting younger than Jura-Triassic is reported in a few places in the Coastal Plain. Reported displacements are steeply dipping; reverse motion on northeast-trending planes has occurred in some instances. All such displacements are minor compared to older faulting. Within 200 miles of the site, these faults include the Brandywine fault (140 miles southwest of the site), the Stafford fault system (150 miles southwest of the site), and the New York Bight fault (off the New Jersey coast, about 100 miles east of the site). On none of these is there unequivocal evidence for latest movement younger than Miocene, or possibly no younger than Paleocene or early Eocene (Section 2.5.1.1.3).

A postulated major east-west fault zone, named the Cornwall-Kelvin wrench fault, has been suggested to extend through the Triassic Lowland of southeastern Pennsylvania. The postulation of this fault zone is based on subsea topographic and geophysical surveys. However, there are neither geological nor geophysical bases for projecting this postulated fault zone into the continent.

Two small faults occur in the Newark Basin near the site: the Sanatoga fault, in the northwest portion of the site; and the Brooke-Evans fault, in the southeast portion of the site. The maximum displacement along these faults is about 350 feet. The Sanatoga fault has been intruded by the Triassic-age Downingtown Dike. These faults were investigated by Dames and Moore (Reference 2.5-1) and evaluated by an independent review committee consisting of experts in Appalachian geology. The review committee concluded that these faults are closely related to the well-dated Jura-Triassic dikes injected along them.

Geologic structure is discussed further in Sections 2.5.1.1.3 and 2.5.3.

2.5.2.3 Correlation of Earthquake Activity with Geologic Structures or Tectonic Provinces

As shown in Figure 2.5-14, the trend of epicenters in the site region is generally NE-SW, parallel to the trend of geologic structure in the Appalachian Mountains. As a particular example, within 100 miles of the site there appears to be a pattern of seismicity paralleling geologic structure in a relatively narrow belt, roughly along the axis of the Fall Zone. At distances greater than 100 miles northeast of the site, the seismicity becomes more diffuse and scattered throughout that part of the New England Appalachians within 200 miles of the site. To the southwest of the site, at distances greater than 100 miles, the seismicity is again more diffuse and, moreover, there are fewer events until the Virginia Piedmont is reached just beyond the 200 mile radius. A modest clustering of historic earthquakes occurs here, in the general area of Richmond, Virginia. Finally, both to the southeast and northwest of the Fall Zone, there is scattered earthquake activity within the Coastal Plain and Appalachian physiographic provinces, respectively.

The earthquake activity in northeastern Massachusetts, although well in excess of 200 miles from the site, has been considered. In November 1755, an intensity VIII earthquake occurred offshore

near Cape Ann, at least 300 miles from the site. This is the largest historic earthquake known to have occurred in the New England region. It has been associated variously with the Southeastern or Avalon Platform tectonic province, a Cape Ann-New Hampshire tectonic province (each more than 200 miles from the site) (Reference 2.5-29), an east-west zone of intense thrust and strike-slip faulting (Reference 2.5-31), a northwest trending seismic and plutonic zone (Reference 2.5-32), and a specific plutonic structure (Reference 2.5-33). None of the above alternatives would relate the event to provinces or structures that are closer than 200 miles from the site; therefore, the 1755 Cape Ann event is not significant to the site.

2.5.2.3.1 Tectonic Models Relating Seismicity to Geologic Structure

A number of widely divergent hypotheses have recently been advanced relating seismicity in the Appalachian region to specific geologic structures. Direct field evidence, such as surface faulting or fault-generated topographic features, has not been found. This wide divergence of opinion results because of the limited data base available and because the hypotheses are constructed largely from permissive rather than compelling evidence. These hypotheses have been summarized and evaluated previously by others (Reference 2.5-79).

The hypotheses that have been advanced can be grouped into one of four general mechanisms: (1) reactivation of steep basement faults, (2) decollement reactivation, (3) stress amplification at the margins of mafic and ultramafic intrusions, and (4) subsidence of the continental margin. The following discussion reviews and assesses these hypotheses.

2.5.2.3.1.1 Reactivation of Steep Basement Faults

Steeply dipping, northeast-trending faults exhibiting Cretaceous and Cenozic displacement are present in the Atlantic Coastal Plain. Several authors suggest that the faults are a reactivation of former basement structures and relate historic seismicity to recurrent movement on these faults.

Cretaceous and Cenozoic displacement is indicated from geologic and seismic reflection data for a number of faults, including the Stafford fault zone (References 2.5-110, 2.5-106, and 2.5-107), the Brandywine fault zone (Reference 2.5-98), and the New York Bight fault (Reference 2.5-96) within 200 miles of the site; and south of the 200 mile radius, the Belair fault zone (in Georgia) (References 2.5-114, 2.5-111, and 2.5-115) and the Cooke and Helena Banks faults (onshore and offshore South Carolina, respectively) (References 2.5-68 and 2.5-69). The faults displace strata as young as Eocene or Miocene in age and, in possibly two cases (New York Bight and Stafford faults), as young as Pliocene or early Pleistocene in age. (The interpretation of Plio-Pleistocene movement on the Stafford fault zone discussed in Reference 2.5-107 seems questionable in view of several trenches across the same fault which show no such offset (Section 2.5.1.1.3).) Wentworth and Mergner-Keefer assume these faults have experienced recurrent movement, based on the indication of smaller displacements on them in younger strata.

Zoback and Zoback (Reference 2.5-140) suggest that if these faults are zones of weakness, they may localize stress and cause brittle failure (earthquakes) in the upper crust. Wentworth and Mergner-Keefer (References 2.5-134 and 2.5-135) further suggest that a domain of northeast-trending, specifically reverse faults exists along the east coast, in keeping with the inference by Zoback and Zoback of persistent NW-SE regional compression. They point out that northeast-trending reverse faults in the basement must have been reactivated by compressive stresses. They propose that the reactivated basement structures are most likely to be normal faults associated with Triassic and possibly Precambrian rifting. (It should be noted, however, that evidence for reverse displacement on the Helena Banks fault is quite tenuous, and there is no

indication that the New York Bight fault is reverse. Furthermore, there is no convincing proof of post-Miocene offset on any of the investigated reverse faults.) Mergner-Keefer (References 2.5-134 and 2.5-135) propose that historic seismicity in the eastern U.S., including the 1886 Charleston event, is related to continued reactivation of these reverse faults but that long periods of quiescence and small cumulative offsets make it difficult to recognize surface rupture and to document historic fault activity.

In support of their reactivation hypothesis, Wentworth and Mergner-Keefer infer the existence of a persistent, northwest directed regional compressive stress-field by reference to focal mechanism solutions, and to orientation and sense of displacement of Cretaceous and Cenozoic faults. In particular, they refer to focal mechanism solutions in the Giles County, Virginia seismogenic zone (Reference 2.5-70) and the Newark Basin area (References 2.5-63 and 2.5-119), and selected solutions from the Charleston, South Carolina area (Reference 2.5-131), and conclude that reverse faulting on northeast-trending high angle or subhorizontal faults is the predominant mode of contemporary fault movement.

However, the evidence is not fully supportive of such a regional stress regime. As Stephenson and Pratt (Reference 2.5-127) and Talwani (Reference 2.5-129) note, fault-plane solutions in the southeast imply considerable local variations in stress; for example, the data from Monticello Reservoir in central South Carolina and from Lake Jocassee in northwest South Carolina imply northeast directed compression, as does hydrofacturing and overcoring data at Bad Creek (Reference 2.5-130). At Charleston itself, focal mechanism solutions strongly favor northwest-oriented fault-planes (northeast compression). Tarr et al (Reference 2.5-131) consider that all except three of 16 solutions define relatively well constrained, northwest-oriented faulting, whereas but two solutions, defining a nearly vertical plane loosely constrained between a northwest and an E-NE strike, merely permit inference of northeast-trending faulting. Tarr et al (Reference 2.5-131, p. 1895) in this latter case select the northeast, rather than northwest trend on the basis of evidence (geophysical) unrelated to focal mechanism solutions. The favored indication of northwest-trending structure is corroborated by recent detailed focal plane studies by Talwani (Reference 2.5-129) which imply shallow northwest-oriented, steeply dipping reverse faulting and deep-seated, northeast-oriented strike-slip (but not reverse) faulting.

In summary, the hypothesis of Wentworth and Mergner-Keefer that contemporaneous northwest directed crustal compression causes large eastern U.S. earthquakes by reverse reactivation along steep basement faults has a number of inconsistencies. Among these are:

a. Even with a long recurrence interval of 500,000 to 1 million years and a displacement rate of 0.35-0.5 m per million years on the reactivated faults (Reference 2.5-134), many late Cenozoic displacements should be evident. However, there is little convincing evidence for post-Miocene offset on any of the recognized Cenozoic reverse faults. Consequently, there is little basis for extrapolating continued movement from Miocene to the present time on reverse faults presumed to be present throughout the eastern U.S. Therefore, there is little justification for associating present day seismicity with these faults.

b. Implicit in the model is regional NW-SE directed compression. However, several authors describe either random and weak regional compression (Reference 2.5-83) or NE-SW directed compression (References 2.5-127, 2.5-129, and 2.5-132).

c. To the extent that NW-SE compression in the central and southern Appalachians is postulated to exist based on the premise of indicated northeast-trending

Cretaceous and Cenozoic reverse faults (Reference 2.5-140), this inferred compressive stress direction cannot then serve as evidence to justify postulating the existence of additional, as yet undiscovered reverse faulting (References 2.5-134 and 2.5-135).

d. NW-SE regional compression, required by the model, is not consistent with subsidence known to be occurring in regions along the Atlantic Coast. Subsidence implies a tensional horizontal stress regime with associated normal faults.

e. Composite focal mechanism solutions by Talwani (Reference 2.5-129) suggest that northeast-trending reverse faults are not active in the Charleston area. Instead two clusters of seismicity are present: a shallow cluster (4-8 km) which defines a northwest-trending reverse fault, and a deep cluster (9-13 km) which defines a northeast-trending strike-slip fault. Either the Charleston area is unique or the reactivation model is not regionally applicable. Furthermore, composite fault-plane solutions by Tarr et al (Reference 2.5-131) show two relatively well constrained vertical nodal plane striking northwest. Even if Wentworth and Mergner-Keefer's hypothesis were correct, it does not appear to be applicable to the Charleston area.

f. The present day Charleston seismogenic zone trends northwest (Reference 2.5-131), rather than northeast, and composite focal mechanism solutions suggest that the seismic activity is associated with a northwest-trending structure (References 2.5-129 and 2.5-131). In addition, the extended meizoseismal area of the 1886 earthquake trends northwest (References 2.5-123, 2.5-65, and 2.5-124). Thus, although seismic reflection data show structures trending both northwest and northeast, there is little evidence associating either the 1886 earthquake or recent seismicity to a northeast-trending structure.

One of the few, and certainly one of the best documented, instances of possible relation of seismic activity to tectonic structure involves the Ramapo fault in northern New Jersey (Figure 2.5-38). This activity, detected by seismic network monitoring for microearthquakes (Nuttli magnitude less than 3) appears to be concentrated near the trace of the Ramapo fault and its northern splays east of the Hudson River (Reference 2.5-119). Hypocentral locations of microearthquakes near the fault appear to fall approximately on the downward projection of mapped dips on the Ramapo and associated Paleozoic shear zones (Reference 2.5-119, figure 4). Nodal plane solutions for three microearthquakes positioned close to the fault indicate reverse-slip (Reference 2.5-137, figure 14).

In contrast, macroseismicity shows no obvious tendency to cluster near the Ramapo zone. Historical earthquakes with epicentral locations within at least 25 kilometers of the Ramapo do not exceed intensity VI (Reference 2.5-82, figures 1 and 2). Considering the complete record, many of the microearthquakes recorded by the seismic network (including those with reverse-slip fault-plane solutions) are located at considerable distance from the Ramapo fault system. Further, there have been some earthquakes located close to the Ramapo that have fault-plane solutions indicating reverse-slip on northwest trending, southeast dipping planes (Reference 2.5-82). Thus, the record shows a diffuse scattering of historical epicenters in the region, with a clustering of some, but by no means all, of the detected small earthquakes along the Ramapo.

It is interesting to examine the geologic evidence for offset along the Ramapo. Detailed mapping of the area in the vicinity of the Ramapo, including trenching and examination of drill cores across the Ramapo fault, have revealed no evidence of reactivation along the Ramapo fault surface. In drill hole cores which penetrated the actual fault contact (cataclastic Triassic fanglomerate over

gouge over phyllonitized basement rock), the last recorded displacement is normal; no evidence of reverse reactivation is seen (Reference 2.5-119, figure 7). No instance has been discovered of offset glacially polished surfaces or of offset surficial deposits in natural exposures or in trenches across the trace of the Ramapo fault (Reference 2.5-119, p. 282). Ratcliffe (Reference 2.5-119, p. 281) concludes, "my present feeling is that we have not yet demonstrated either from experiment, theory or empirical observation that the premise restricting seismic activity to surface brittle fracture zones (e.g., Ramapo fault) is at all valid."

2.5.2.3.1.2 Decollement

Recent seismic reflection profiles reveal the presence of a low angle detachment surface or decollement beneath much of the southern and central Appalachians (References 2.5-88, 2.5-76, 2.5-77, 2.5-78, and 2.5-75). The decollement was active primarily during the Alleghenian orogeny when rocks of the Valley and Ridge, Blue Ridge and Piedmont were thrust tens of mile to the west and northwest (Reference 2.5-92). Harris and Bayer (Reference 2.5-88) and Cook and others (Reference 2.5-77) suggest that the decollement may extend from beneath the Valley and Ridge to the continental margin. Recent seismic profiles from the Coastal Plain and continental shelf, although not conclusive (Reference 2.5-97), appear to substantiate this eastward extent (References 2.5-78, 2.5-67, 2.5-68, 2.5-69, 2.5-121, and 2.5-122). The postulated depth of the decollement based on those profiles beneath Charleston, S.C., also agrees well with a seismic velocity discontinuity at about 10 km depth observed by Talwani (Reference 2.5-129).

Several authors suggest that seismicity in the eastern U.S. is caused by reactivation of the decollement (References 2.5-68, 2.5-69, and 2.5-123). The decollement is a fundamental mechanical discontinuity in the crust and if it has not been disrupted by subsequent Mesozoic extensional faults or intrusive complexes, it may be a zone of crustal weakness susceptible to reactivation by properly oriented intraplate stresses. Reactivation would be in either a forward (thrust) sense in response to NW-SE regional compression (Reference 2.5-68) or in a gravity-driven backward sense (References 2.5-123, 2.5-65, and 2.5-124). Large earthquakes such as the Charleston 1886 event would represent displacement or slippage on the decollement.

The decollement reactivation hypothesis as thus proposed may not be incompatible with the reactivation of steep basement faults. Seismic reflection profiles suggest that many high angle faults are listric into the decollement (Reference 2.5-78). Movement on the high angle faults would thus be viewed as second order displacements (but capable of producing earthquakes) accommodating horizontal movement on the decollement (Reference 2.5-68, pp. 121-122). Noting that at least one listric fault appears to project to a Triassic basin border fault, Cook et al (Reference 2.5-78, p. 742), speculate that perhaps the listric thrust (reverse) faults were reactivated during Mesozoic rifting as listric normal faults to produce the Triassic basins.

The following geologic and seismic data are cited as evidence supporting decollement reactivation: (1) the decollement is the most likely fault that could achieve significant differential offset without producing surface displacement. (2) Common to all the focal mechanism solutions supporting displacement on high angle northeast-trending reverse faults (References 2.5-132, 2.5-70, and 2.5-63) is one subhorizontal nodal plane which supports displacement on the decollement. (3) Seismic reflection profiles indicate the structural disruptions and other geometric impediments to reactivation are not present across the decollement (References 2.5-78, 2.5-123, and 2.5-140). (4) Releveling data by Citron and Brown (1979) indicate that vertical crustal movements as far west as the Blue Ridge front may be related to gravity-induced back-slip along the decollement (Reference 2.5-123). The maximum primary stress orientation may be different above and below the decollement supporting a decoupled upper sheet (Reference 2.5-123).

On the other hand, active movement along a decollement appears unlikely for the following reasons:

a. Continuation of the decollement beneath the coastal plain is not certain. The subhorizontal seismic reflectors representing the decollement (Reference 2.5-78) widen, become discontinuous and dip steeply southeastward beneath the outer Piedmont where magnetic and gravity data have been interpreted to suggest a root zone (References 2.5-102, 2.5-92, and 2.5-93). Recent palinspastic restorations of the crust by Iverson and Smithson (Reference 2.5-97) indicate that the decollement is rooted to the east beneath the outer Piedmont and does not extend to the east beneath the Coastal Plain.

b. Although Cook et al (Reference 2.5-78) and Seeber and Armbruster (Reference 2.5-123) suggest that no offsets of the decollement or other geometric impediments to reactivation exist, figure 7 of Reference 2.5-78 seems to show a series of normal faults within the inner Piedmont which displace basement Precambrian Grenville rocks as well as overlying Precambrian and Paleozoic sedimentary rocks beneath of the decollement. If these extensional faults are related to Mesozoic rifting, which they appear to be because they displace Paleozoic strata, then they must also displace the overlying decollement. Ellwood et al (Reference 2.5-81) also cite paleomagnetic data, radiometric age data and geologic relationships indicating that a major, relatively undisplaced intrusive complex has been emplaced through the decollement. Mafic dikes and aulocogens related to Mesozoic rifting (Reference 2.5-117) would also have to be truncated after rifting. It is not probable that gravitational back-slip could overcome these impediments to reactivation, and it is difficult to account for a source of relatively shallow crustal compression of a passive, presumably subsiding continental plate margin.

c. Seismic data from the Giles County, Virginia seismogenic zone are not consistent with decollement reactivation. Hypocentral depths range from 5 km to 25 km (Reference 2.5-70) which places it beneath the decollement in the crystalline basement under the deformed Paleozoic sediments of the Valley and Ridge province.

d. Seeber and Armbruster (Reference 2.5-123) speculate that the stress-field above and below the decollement may differ. Composite focal plane solutions from the Charleston area, however, indicate a consistent orientation of maximum stress across the postulated depth of the decollement suggesting that there is no decoupling of the stress-field (Reference 2.5-129).

e. If gravitational backsliding is responsible for seismicity, then extensional stresses resulting in normal faulting should be evident in the overthrust plate. However, many focal mechanism solutions indicate reverse displacements in the overthrust plates, and geologic and geophysical evidence suggest that some Cenozoic faults in the overthrust plate have reverse displacements (References 2.5-134 and 2.5-135).

f. It does not seem likely that the gravitational force resolved parallel to the postulated, extremely low angle decollement is sufficient to overcome normal frictional shear resistance of rock materials within the decollement.

Deep seismic reflection data (COCORP and other lines) suggest that the central and southern Appalachian system, including at least the Blue Ridge and inner Piedmont provinces, are underlain at depth by a low angle regional thrust, or decollement, resting on relatively unmetamorphosed sedimentary rocks, extending westward beneath the Valley and Ridge province. This decollement was presumably active during the Alleghenian orogeny at the end of the Paleozoic Era; ramp-like displacements branching upward from the decollement produced the well-known thrust sheets of the southern Appalachian Valley and Ridge and were taken up as faulted anticlinal folds in the central Appalachians. The eastern extent, or "root zone", of the decollement is a matter currently in dispute (Section 2.5.1.1.3). The inclination of the decollement plane is flat; profiles (Reference 2.5-78, figure 7, and Reference 2.5-88, figure 5) show it to be a horizontal to subhorizontal surface, broken perhaps by local offsets or minor ramps, but not exceeding about 2½° overall, sloping gradually downward to the east.

This new evidence of a decollement east of the Blue Ridge helps to explain the mechanics of the Alleghenian orogeny. Heretofore it has been difficult to explain the large-scale westward thrusting that produced the Valley and Ridge structures in late Permian or early Triassic time, in the face of so little surface evidence for such thrust faulting, or for a source of compression, in the metamorphosed rocks to the east, which show abundant evidence of only earlier Paleozoic orogenies. On the other hand, its relevance, if any, to current seismicity is unclear. Speculations that gravity-induced backsliding may be occurring on the decollement and thereby causing earthquakes, in particular the Charleston event of 1886 (References 2.5-123 and 2.5-124) seem implausible in view of the extremely low coefficient of friction that would be necessary for gravitational slippage to occur on a subhorizontal plane, even discounting structural and lithologic impediments that would be expected to exist along the decollement surface. Similarly, the inverse hypothesis of a compressional reactivation of the decollement proposed in Reference 2.5-68 to account for events such as Charleston seems improbable. The source of such compression at the edge of a passive, presumably subsiding continental margin acting on a relatively shallow crustal feature is difficult to envision.

The possibility of a continuation of the Alleghenian decollement into the New England Appalachians is not in accordance with recent studies (Reference 2.5-133). Such decollements as may occur there relate to the Taconic orogeny (Reference 2.5-26); these are found along the western and northern margin of New England (References 2.5-133 and 2.5-136), east of Logan's line. Subsequent Acadian orogeny and metamorphism (Reference 2.5-26) have obliterated the regional mechanical significance of such decollements, and there is no evidence of extensive regional Alleghenian thrusting in New England. As pointed out in Reference 2.5-28 and by others since 1975, strike-slip rather than thrust faulting appears to have characterized at least the latter part of late Paleozoic deformation in New England. This deformation is best developed as displayed in eastern New England and as inferred in the Gulf of Maine.

The idea of reverse reactivation of pre-existing NE-SW striking faults generated by inferred, present day NW-SE oriented regional crustal compression has gained popularity with some investigators (References 2.5-140, 2.5-134, and 2.5-135). Early Mesozoic (i.e., Jura-Triassic) faults having this orientation are attractive candidates because they presumably had a deep-seated origin related to continental rifting, but other smaller faults seaward of the edge of the Coastal Plain showing evidence of reverse offset of Cretaceous and younger strata are also considered, provided they have the appropriate NE-SW strike.

It seems somewhat presumptuous to define by inference a regional stress-field on the basis of fault orientation, or even of focal plane mechanism solutions, in the Appalachians. The reason is that

the occurrence of strain release of modern stress would be expected to be constrained by the existing structural planes of rock weakness, regardless of the "real" stress orientation, provided the stress levels are moderate, as seems appropriate for a passive continental margin. Because the structural grain of the Appalachians, which was imposed during Paleozoic orogenies, has a very pronounced and persistent NE-SW orientation, often almost to the exclusion of other trends, earthquakes in the Appalachians occur mostly on NE-SW trending planes. The same problem exists when the argument is turned around to infer the orientation of modern stresses from the trend and sense of displacement of existing faults (for example, faulting of coastal plain strata) because presumably these faults are simply new expressions of old basement faults that have been reactivated. If the faults do not extend to basement, they are of no significance.

Here there is an additional critical problem; namely, the justification for assuming that displacements for which there is no proof of movement over the past several million to several tens of millions of years have any meaningful relationship to modern stresses or seismicity.

In References 2.5-134 and 2.5-135, it states that a northeast- trending reverse fault may have been responsible for the Charleston event of 1886 and cites the inference of existing northwest directed compressive stress in the eastern U.S. from focal plane and fault orientation studies (Reference 2.5-140). They review the evidence indicating Cretaceous and Cenozoic reverse offsets on NE-SW trending faults in the eastern U.S. and propose that such faults should be viewed as potential sources of large earthquakes, such as the Charleston event of 1886. Their conclusion is based on dating different measured displacements on the same or different faults and deriving rate curves, extrapolating continued episodic movement to the present from the most recent documented movement on any of the faults (Reference 2.5-134, figure 5). These rate curves are assumed to represent a hypothetical family of both known and as yet undiscovered NE-SW reverse faults, an assumption Wentworth and Mergner-Keefer consider reasonable in view of the limited area for which such documentation can be obtained.

Critical to the presumption (References 2.5-134 and 2.5-135) of significant potential for present day movement on these hypothetical faults is the age and amount of the most recent offset plotted in their data set because the older and smaller an offset is, the less justification there is in presuming continued activity to the present. They (Reference 2.5-134, figure 5) present only one data point younger than Eocene: namely, an offset measured at an exposure of the Stafford fault system in Virginia. This particular exposure, which occurs along the Fall Hill fault of the Stafford fault system, is diagrammed in a field trip guide by Mixon and Newell (Reference 2.5-107, figure 7). It shows a sharp, 14 inch projection of metamorphic rock (gneiss) upward into overlying upland gravels (late Pliocene to early Pleistocene in age), consistent with the gneiss having moved upward in a reverse sense on a steep, west dipping plane. Below this, the metamorphic rock has been reverse-faulted against Cretaceous alluvial deposits (Potomac Group) with obvious deformation and significant offset. However, the above described offset in the overlying fluvial gravels apparently is accompanied by little or no deformation, in that no shear planes are shown in Reference 2.5-107 extending upward into the gravel along the plane of the fault, and the gravels in the sketch appear structureless or vaguely "draped" across the offset. Thus, it would seem that an equally plausible

explanation for the origin of the "offset" in the gravels is that it is an erosional feature, particularly when one considers the contrast in erodability between the Cretaceous sands and the metamorphic rock, the relatively high energy depositional environment of the gravels, and the presence of angular metamorphic boulders in the gravel (Reference 2.5-107, figure 7).

This alternative explanation is reinforced by the trenching across the Fall Hill fault that was performed by Dames and Moore (Reference 2.5-113). In the three trenches that exposed the base of the Plio-Pleistocene alluvial gravels resting on the trace of the Fall Hill fault, the gravels were plainly not offset across the trace of the fault.

The above evidence calls into question the validity of the single data point younger than Eocene (40 million years) of Wentworth and Mergner-Keefer's rate curve (Reference 2.5-134, figure 4) for reverse fault movement. Therefore, there is no solid evidence for movement younger than Eocene on any of the NW-SE trending faults used by Wentworth and Mergner-Keefer in their analysis. Such faults should not be considered to be capable within the content of the siting criteria.

The basis for presuming that the Charleston seismicity is associated with a northeast-trending structure is also questionable. Although Wentworth and Mergner-Keefer cite the data of Tarr et al (Reference 2.5-131) in support of a northeast structure, Tarr et al include only three of a total of 16 focal mechanism solutions from the Middleton Place-Summerville (i.e., Charleston) area in such a trend; moreover, Tarr et al choose this trend not so much from focal mechanism solutions but from gravity anomalies and inferred fault trends (Reference 2.5-131, p. 1892, 1898). Specifically, Tarr et al state that the three focal mechanism solutions are "consistent with early vertical faulting on a plane striking northwest to E-NE, with one inconsistency... A nearly vertical E-NE striking plane was chosen because of independent geophysical evidence..." (Reference 2.5-131, p. 1892). The other 13 focal mechanism solutions which Tarr et al studied define two alternate, relatively well constrained nodal planes that strike northwest, thus implying a stronger likelihood of northwest-faulting at Charleston, and suggesting the presence of unique structure. This is further corroborated by recent detailed focal plane studies by Talwani (Reference 2.5-129), with no evidence found for northeast-trending reverse faulting. It does define reverse motion along a relatively shallow, steeply dipping northwest-oriented plane and strike-slip motion along a deeper, northeast-trending plane. Therefore the Charleston area, rather than being structurally and tectonically typical for the Coastal Plain and surrounding region, seems more likely to be just the opposite, based on current data and analysis.

2.5.2.3.1.3 Stress Amplification at the Margins of Mafic Plutons

The presence of mafic plutons in certain areas of historical or current seismic activity, such as in the New Madrid area and at certain locations in New England, has been pointed out by a number of observers; whether these plutons have the capacity to localize earthquakes is a matter of considerable conjecture. Investigators have suggested that stress is mechanically concentrated in or near the plutons because of contrasts in elastic moduli with the surrounding country rock (References 2.5-103, 2.5-104, and 2.5-99). They theorize that the stress concentrations may be sufficiently high to result in earthquakes.

According to these stress modeling studies, stress can be concentrated in or near mafic plutons by one of three methods: (1) The instructions are "softer" or less rigid than surrounding rocks because of serpentinization, and deform by creep rather than fracture. Stress is thus concentrated in the more rigid country rock surrounding the intrusion (Reference 2.5-99). (2) The intrusions are "stiffer" or more rigid than the surrounding rocks and stress is concentrated within the intrusion (References 2.5-104). (3) The intrusions are weakened by pervasive fracturing and high pore pressure caused by residual volatiles associated with their origin and emplacement. Stress is therefore concentrated in the more rigid country rock.

McKeown (References 2.5-103 and 2.5-104) studied the association between mafic plutons and seismicity primarily in the New Madrid and Charleston area on the basis of geologic, gravity, aeromagnetic and seismic data. He noted that the trend of nodal planes of many fault-plane solutions coincides with the trend of many mafic dikes. He suggests that earthquakes are controlled by the presence of mafic intrusions and that ancient rift zones may have been the primary control for the location of the intrusions.

References 2.5-132, 2.5-118, 2.5-62, 2.5-128, 2.5-101, 2.5-102, and 2.5-140 also report an empirical spatial association of seismicity and mafic plutons interpreted from surface exposures and shallow source gravity and magnetic anomalies. Tarr and Rhea (Reference 2.5-132) further note that in the broad areas of flat or negative anomalies, seismicity is lacking. They indicate that, although earthquakes in the Piedmont tend to be scattered, those in the Coastal Plain tend to Cluster. They interpret the clustering to result from localized stresses on or near intersecting faults and mafic plutons.

Kane (Reference 2.5-99) speculated that the mafic bodies at Charleston are serpentinized. Analytical modeling by Campbell (Reference 2.5-73) supports Kane's hypothesis as an explanation for the Charleston earthquake. Kane suggests that the lack of seismicity at other geophysically inferred mafic and ultramafic plutons is due to the lack of serpentinization, an insufficiently large or randomly changing stress-field, or inappropriate geometric relations between the intrusive body and stress-field direction.

The stress amplification hypotheses are beset with a number of uncertainties and unknowns due chiefly to insufficient information. Some of the major problems and uncertainties are:

a. In most cases where earthquakes are clearly related to geologic structures, the earthquakes occur along planes or zones of weakness (i.e., faults) rather than in areas of concentrated stress in the neighborhood of relatively rigid bodies.

b. Although some intrusions are spatially associated with seismicity, there are many large and small intrusions (such as the Cortlandt Complex near the Ramapo fault, Reference 2.5-120) which are either not associated with seismicity or have no effect on localizing seismicity.

c. Presently it does not appear feasible to obtain field data in sufficient to test the proposed models.

d. Mafic/ultramafic intrusions are common in zones of crustal rifting. If seismicity is caused by the reactivation of basement structures such as triassic association of seismicity with mafic/ultramafic plutons may be simply a secondary coincidence.

e. The inferred mafic/ultramafic bodies are not necessarily localized intrusions. The mafic body beneath Charleston penetrated by core holes in a Jurassic basalt flow. The flow is laterally continuous beyond the limits of concentrated historic seismicity (References 2.5-78, 2.5-122, and 2.5-68).

2.5.2.3.1.4 Subsidence

Several workers have noted that east coast seismicity may be spatially associated with subsiding embayments on the Cretaceous continental margin and Triassic basin border faults inland from the

continental margin. They suggest that the seismic activity may represent minor adjustments in the crust associated with continued opening of the Atlantic Ocean.

Barosh (Reference 2.5-66) empirically observed the relationship between seismicity and structural depressions. He hypothesizes that current seismicity along the Atlantic seaboard is caused by small-scale vertical movements within pre-existing fracture zones and subsiding embayments. The seismicity, for example, is concentrated along the northeastern margin of the subsiding Southeastern Georgia Embayment.

Following the Triassic-Jurassic extension that resulted in the development of Triassic basins and the Atlantic Ocean, the trailing continental margin has sagged and accumulated a mantling wedge of Cretaceous and Tertiary sediment. Subsidence of the margin may be due to sediment loading (Reference 2.5-126), thermal contraction (Reference 2.5-125), thermally induced phase changes (Reference 2.5-109), or oceanward creep of lower continental crust due to gravity (Reference 2.5-71). Barosh (Reference 2.5-66) suggests that seismicity is localized in those areas along the coast where the lowlands are subsiding over the ancestral margin of the continent.

Subsidence in areas along the Atlantic coast is known to be occurring (Reference 2.5-95). Subsidence as a cause for seismicity, however, is not consistent with several facts and observations:

a. Many focal mechanism solutions indicate reverse displacement on either high angle or low angle faults. Reverse displacement is not consistent with a tensional, subsiding stress regime.

b. Many observed Cenozoic faults in the Coastal Plain have reverse and not normal displacement.

c. The nearly aseismic nature of the offshore region (continental shelf) where subsidence has been greatest argues against subsidence as a primary cause of seismicity.

2.5.2.3.1.5 Conclusion

Although the recent geologic and geophysical data summarized above demonstrate the significant role of compressional and extensional deformation in the evolution of eastern North America, they do not provide consistent evidence that these older deformational structures have been regionally reactivated and pose a widespread, significant potential for damaging earthquakes.

Correlation of Charleston seismicity and the Charleston 1886 earthquake with a steep reverse northeast-trending basement fault is extremely tenuous. Composite fault-plane solutions, hypocentral location patterns and the inferred and measured orientation of the principal maximum stress direction implies a coherent pattern of deformation unique to the Charleston area. Fault planes trend northwest with reverse displacement in the upper crust and trend northeast with strike-slip displacement in the lower crust. The vertical maximum principal stress axis near the surface (Reference 2.5-127) and the deeper northeast-trending maximum principal stress axis (Reference 2.5-129) are not consistent with the northwest- oriented stress axis required by the hypotheses for reactivation of steep basement faults (References 2.5-134 and 2.5-135) or thrust reactivation of the decollement (Reference 2.5-68).

Apparent association of small earthquakes with the Ramapo fault is not reflected by any obvious concentration or association of historical macroseismicity in its vicinity; the widely scattered historical epicenters within at least 25 kilometers of the Ramapo fault do not exceed an intensity of VI (Reference 2.5-82). The Ramapo fault has been intensively studied by drilling, trenching and detailed mapping. No evidence for reactivation of the fault surface has been found, and no instance of surficial offset along the fault, either in natural exposures or in numerous trenches, has been discovered (Reference 2.5-119).

It is concluded that the lack of recent faulting and the modest size of even the largest historic earthquakes within 200 miles of the site and the general scatter and infrequency of reported earthquakes argue against the meaningful association of regional macroseismicity with specific faults.

2.5.2.4 Maximum Earthquake Potential

No earthquake within the 200 mile radius site region has exceeded intensity VII during the historic record for this area, which began in the early 18th century. There have been 6 intensity VII shocks during this period in the site region. Of these, 2 occurred near New York City, in 1737 and 1884, at the edge of the Newark Basin, near the junction of the Piedmont, New England, and Coastal Plain provinces; one occurred near Wilmington, Delaware in 1871, about 35 miles south of the site, near the Piedmont-Coastal Plain boundary; one occurred along the New Jersey coast in 1927, about 80 miles northeast of the site in the Coastal Plain; one occurred near Moodus, Connecticut in 1791, about 180 miles northeast of the site in the New England Upland section of the New England Province;

and one occurred in Wilkes-Barre, Pennsylvania in 1954 in the Folded Appalachians to the N-NW of the site and was almost certainly not related to either tectonic strain accumulation or release, as these terms are normally understood. One additional intensity VII event, which was slightly more than 200 miles from the site, occurred near Richmond, Virginia in 1875, close to the Piedmont-Coastal Plain province boundary. Thus, most of the intensity VII events recorded, and particularly those south of the New England Appalachian-Piedmont Coastal Plain physiographic province junction, have occurred near the Fall Zone. An apparent NE-SW trend of smaller earthquakes occurs along the same zone, although intensity VI and smaller events are scattered throughout the site region.

Considering the historic seismicity of the site region alone, a reasonable interpretation of maximum potential earthquake might be either an intensity VII event along the Fall Zone at its closest approach to the site or an intensity VI event very near the site. Because of the uncertainties involved in associating regional activity with specific structures, however, the maximum potential earthquake is specified as being equivalent to the I_o = VII 1871 Wilmington, Delaware earthquake occurring near the site. This is equivalent to translating the largest historical earthquake that has occurred anywhere within 200 miles of the site.

2.5.2.5 Seismic Wave Transmission Characteristic of the Site

Detailed descriptive data on the foundation material properties appear in Section 2.5.4. All Category I structures are founded on competent bedrock, except some buried structures including portions of underground piping and electrical ducts, diesel oil tanks, and buried valve pits. An analysis was performed to determine the response of the soil column and the effects of the properties used in the analysis are given in Section 2.5.4.2.2, and the results of the analyses are given in Section 2.5.4.7.1.

The seismic wave velocity of the in situ soils and the fill materials, on which the buried structures are founded, are not available. However, because of the shallow foundation soil depth to the competent bedrock and the smooth transition from rock to soil foundation (Figure 2.5-37), LGS Category I underground piping is designed in accordance with the procedure identified in Section 3.7.3.12 for seismic load, assuming the seismic shear-wave velocity of the foundation soil is the same as the competent bedrock. The application of the bedrock seismic wave velocity to the foundation soil material in buried piping analysis is shown in Reference 2.5-53.

The LGS design response spectra, discussed in Section 3.7.1 and Figures 3.7-1 and 3.7-2, are based on data developed from records of previous earthquake activities representing an envelope of motion expected at a sound rock site.

2.5.2.6 Safe Shutdown Earthquake

The SSE is defined in terms of a peak ground acceleration and a design response spectrum. As indicated in Section 2.5.2.4, the site design intensity is VII on the Modified Mercalli Scale. This intensity may be associated with a peak ground acceleration of approximately 0.13 g (References 2.5-34 and 2.5-35). For additional conservatism, a peak acceleration of 0.15 g the design response spectrum shown in Figure 3.7-2 for critical damping values of 0.0%, 0.5%, 2.0%, 5.0%, and 10.0%.

2.5.2.7 Operating Basis Earthquake

The OBE is defined as one-half the peak ground acceleration associated with the SSE, 0.075 g. The design response spectrum is identical in shape to that specified for the SSE. This value (0.075 g) is the high frequency asymptote of the OBE design response spectrum shown in Figure 3.7-1. Curves for the same percent critical damping values appearing in the SSE design response spectrum are shown.

2.5.3 SURFACE FAULTING

2.5.3.1 Geologic Conditions of the Site

LGS is located approximately 3 miles southeast of Pottstown, Pennsylvania, adjacent to the Schuylkill River. It is situated within the western portion of the Newark Basin, which is part of the Triassic Lowland subdivision of the Piedmont physiographic province (Section 2.5.1.1). The Triassic Lowlands represent sedimentary basins that form outcrop patterns broadly parallel to the sinuous, folded Appalachians and extend from Maine to South Carolina. The basins contain rocks of relatively similar gross lithologic types, usually occurring in the same stratigraphic sequence (Reference 2.5-6).

The Newark Basin, together with the contiguous Gettysburg Basin further west, forms the largest of the Triassic basins. This basin extends in a W-SW direction from the Hudson Palisades, near the New Jersey-New York boundary to the Catoctin Mountains, near Frederick, Maryland (Figure 2.5-38). The basin varies in width from 3 miles in its narrowest section to almost 35 miles at its greatest width. The Newark-Gettysburg Basin represents a series of some 18,000-20,000 feet of nonmarine sedimentary rocks with associated basaltic flows, and diabase dikes, sills, and stocks (Figure 2.5-6). For detailed descriptions of the regional geology, see Section 2.5.1.1. Site geologic conditions are described in Section 2.5.1.2.

Several faults of apparently large displacement occur within the Newark Basin. These are the Chalfont and Furlong faults in Pennsylvania, and the Flemington and Hopewell faults in New Jersey. These faults, which are of Triassic-age, result in Paleozoic age rocks being exposed at the surface, indicating at least 10,000 feet of displacement. The orientation and direction of movement of these faults are not known. Although generally considered to be steeply south dipping normal faults (Reference 2.5-36), Sanders (Reference 2.5-37) suggests predominant strike-slip movement, and Faill (Reference 2.5-17) indicates these faults may be high angle reverse faults resulting from intersection of two different axes of monoclinal folding within the basin.

Smaller Triassic faults cross the basin margins and extend well into the surrounding rocks. They usually show less than 3000 feet of displacement. Associated with these faults are local concentrations of smaller faults.

The major fault closest to the site is the Chalfont fault, which passes 9 miles to the northeast (Figure 2.5-2). The maximum throw on this fault is 6500 feet, in Bucks County, Pennsylvania, near Bennetts Corner (Reference 2.5-38). The throw decreases to about 3000 feet at the Montgomery County line and eventually dies out to the northeast of the site. The northeastward branch of the Chalfont fault (at Bennetts Corner) is called the Furlong fault. The fault crosses the Delaware River near Center Bridge, Pennsylvania and continues through New Jersey (where it is called the Flemington fault) to just beyond the north border of the Triassic basin. The maximum throw on the Furlong-Flemington fault is 10,000 feet, with an undetermined amount of right-lateral, strike-slip displacement (Reference 2.5-37). The displacement along the Furlong fault in eastern Pennsylvania is sufficient to offset the entire thickness of the Newark Group and expose the Cambrian rocks on the floor of the basin. Five and one-half miles southeast of the Furlong fault, the east-west trending Buckmanville fault crosses the river and becomes the Hopewell fault of New Jersey. A throw of 15,000 feet has been measured on the Hopewell, with a right-lateral, strike-slip displacement of 12 miles (Reference 2.5-37). Other faults associated with the Furlong-Buckmanville complex and their eastward extensions into New Jersey are, the Holmquist School, Bridge Valley, Pidcock Creek, and Danborough faults. These faults are all normal, with the downthrown side to the south. Some show lateral displacement, and all are strike faults.

Many of the minor faults in the Newark Basin of southeastern Pennsylvania are transverse normal faults. These have developed along the major joint system exhibited by the Triassic strata, and they trend approximately N 30° E. Some of the Triassic dikes have intruded along these fracture zones subsequent to movement along them. The Downingtown Dike is an example of this type of intrusion.

In this report the minor faults that occur in the site area have been named the Sanatoga fault, the Brooke-Evans fault, and the Linfield fault, as shown on Figure 2.5-6. The Sanatoga fault passes within 1300 feet to the west of the reactor location, the Brooke-Evans fault is 2800 feet to the south, and the Linfield fault is 2 miles to the southeast.

Detailed field investigations of faults in the site area were performed by Dames and Moore in 1974 (Reference 2.5-1).

2.5.3.2 Evidence of Fault Offset

As previously indicated, the site lies within a down-warped basin of Triassic-age. Subsequent to the deposition and consolidation of the basin sediments, the region was uplifted, and numerous small faults and fractures were formed.

The Sanatoga fault, shown on Figure 2.5-6, trends approximately N 25° E, becoming discontinuous approximately 2 miles to the north and 1 mile south of the site area. The nearest approach of the fault trace to the reactor area is 1300 feet to the west. Detailed studies by Dames and Moore in 1974 (Reference 2.5-1) indicate vertical displacement on the fault is approximately 290 feet, with the downthrown side to the east. The fault-plane is occupied by a Triassic diabase intrusive, which is part of the Downingtown Dike.

The Brooke-Evans fault passes within 2800 feet to the south of the plant area and trends approximately N 50° E. Slickensides on the fault-plane indicate some lateral movement. Field evidence based on the offset of marker beds indicates that the movement was probably both right-lateral and vertical. The apparent vertical displacement is about 350 feet, with the downthrown side to the south. West of the Schuylkill River, magmatic material from the Downingtown Dike occupies the fault for a short distance. A high concentration of calcium carbonate filling occurs in the fracture zone associated with fault.

A third fault, the Linfield fault, is located east of the town of Linfield about 2 miles southeast of the site. This fault trends N 20° E, with the downthrown side to the west. Displacement on this fault is approximately 130 feet. Field evidence based on slickensides in the fault-plane indicates an undetermined amount of lateral movement. This fault is associated with a diabase dike that occupies a parallel fault approximately 700 feet to the east.

Detailed inspection of rock cores and nearby outcrops disclosed the existence of other very small displacements (maximum less than 2 feet), especially in those areas close to the faults described above. On the basis of detailed stratigraphic correlation in the site area done for the PSAR, it was concluded that the strata between the Brooke-Evans fault to the south and the Sanatoga fault to the north have not been offset by faulting. The rock at the site is moderately-to-well jointed. A statistical analysis of joints by Dames and Moore in the rock cores revealed a higher joint frequency along the northeast trend through the southeastern portion of the construction area, an the PSAR noted that the presence of these abundant joints may be related to an undetected fracture zone. Fracture zones with minor offsets were encountered in the excavation. These are described in Section 2.5.3.2.1.

As noted in the PSAR, the presence of minor faults within the Newark Basin in general, and near the site area in particular, is not surprising, nor is it hazardous to the operation of the plant. As previously discussed, such minor faulting is common throughout the basin. Regional crustal stresses during Mesozoic time resulted in numerous small-scale readjustments and fracturing of the brittle, flat-lying Triassic strata. Small-scale insignificant displacements are likely to be found in any major rock exposure within the basin.

Evidence that confirms the regional inactivity of the Triassic faults includes the following:

a. The regional uplifting forces that induced the basin faulting no longer exist.

b. There is no evidence that faulting has displaced overlying Coastal Plain sediments.

c. Many faults are known to be healed by secondary mineralization.

d. Within the same Triassic rock-type, no fault exhibits surface expression in the form of fault scarps.

These faults were discussed in the PSAR (section 2.5.2.3.4) and were described as inactive for at least the last 140 million years. The PSAR stated: "Perhaps the most conclusive proof of tectonic inactivity near the site is the presence of unfaulted, intact diabase, at least 140 million years old, along the nearby fault planes. The faults near the site have not moved in at least 140 million years and will not move during the life of the proposed facility."

Subsequently, some evidence for possible offset of the diabase was observed, and an extensive geologic study was made by Dames and Moore (Reference 2.5-1) in an attempt to date as closely as possible the age of the faulting in the area.

A committee consisting of Dr. D.U. Wise, University of Massachusetts (Amherst); Dr. C. Gray, Franklin and Marshall College, Lancaster, Pennsylvania; and Dr. P.B. Myers, Lehigh University, Bethlehem, Pennsylvania, was selected to evaluate the study. In evaluating the faults in the area around the site, they state: "The fault and fold patterns are indicative of a Jura-Triassic (150-200 million years) stress system with maximum compression oriented NNE... The present WNW orientation of compressive stresses in the residual stress measurements differs markedly from the NNE compression which produced the Jura-Triassic faults at the site and nearby folds. The effect is to increase normal stresses across the faults, increasing fractional resistance to movement, and decreasing available space for additional graben displacement."

2.5.3.2.1 Geologic Structures in the LGS Site Excavation

The site stratigraphy consists of a sedimentary sequence of red shale, siltstone, and sandstone (Figure 2.5-12). Structural mapping of the excavation at the LGS site shown on Figure 2.5-13, confirms the existence of three fracture zones with small displacements (LGS PSAR, supplement 4, question 2.29).

All three zones are characterized by the following:

a. Two vertical, or subvertical, northeast-trending fractures, in addition to numerous closely spaced smaller fractures

b. Observable vertical stratigraphic offsets (1 inch to 4 feet), which vary along the length of a given shear zone

c. Mineralization of the shear zone or adjacent fractures by calcite, quartz, or fibrous clay (Reference 2.5-1, section 3.4)

d. Subvertical and subhorizontal slickensides, indicating both strike-slip and subsequent dip-slip offsets

A detailed discussion of these shear zones is presented in a 1974 Geologic Report by Dames and Moore (Reference 2.5-1).

The minor faulting and shearing encountered within the site excavation are not unique to the area, and they have the same geometry as and similar mineralization to adjacent larger faults. These larger faults in turn are part of the pervasive fault-fold pattern that reflects an initial northeast-trending regional compressive stress. Extension features (small grabens and dikes) for the most part strike parallel to the compression axis, and dikes sometimes display an en echelon geometry.

As one would expect, the fold axes, together with thrust shear joints in nearby areas, strike normal to the compression.

Upon completion of their 1974 study (Reference 2.5-1), Dames and Moore concluded:

> "The results of this comprehensive investigation indicate that shears exposed in the excavation are not capable by AEC (NRC) definition. It is concluded that movement along the shears could not have occurred later than 500,000 years ago and in all probability, have been inactive since Jura-Triassic time some 150-200 million years ago."

The review committee (Dr. Wise, Dr. Gray, and Dr. Myers) concluded:

> "We believe the small faults discovered in the LGS containment excavation have been thoroughly tied to regional 150-200 million year structural events of this area. The ancient stress-field orientations which caused the faults have been superseded by the present stress-field orientations which tend to lock the faults against further motion. The faults have undeformed or little deformed delicate minerals in them indicating the absence of strong shearing stresses in the containment area since cessation of mineralization, most likely in the same 150-200 million year range. There is no evidence of displacement of any feature as young as the undisturbed upland terrace surface which has a minimum age on the order of a half million years.
>
> We conclude that a very strong circumstantial case has been made on structural ground for the containment faults being on the order of 150-200 million years old. An equally strong geomorphic case has been made precluding any movements in the last half million years.
>
> The committee sees abundant evidence suggesting geologic antiquity of the faults. We have yet to see the first piece of evidence suggesting recent movements. Based on our collective local experience, none of us has seen anything about the faults onsite to indicate they are other than typical small movement features associated with the 150-200 million year old events in the area."

It is concluded that these small faults are not significant to the operation of the power plant.

2.5.3.3 Earthquakes Associated with Capable Faults

There are no capable faults within 5 miles of the site. There have been no earthquakes in historic time with epicentral locations within 10 miles of the site. For correlation of epicenters and geologic structure, see Sections 2.5.2.2 and 2.5.2.3.

2.5.3.4 Investigation of Capable Faults

There are no capable faults within 5 miles of the site. Shear zones encountered in foundation excavations have been mapped in detail (Section 2.5.1.2.5 and Figure 2.5-13). The geologic investigations demonstrate that the small fracture zones encountered during foundation excavation and the faults in the vicinity of the site are associated with the 150-200 million year old events in the area.

2.5.3.5 Correlation of Epicenters with Capable Faults

There are no capable faults within 5 miles of the site. No earthquakes with epicentral locations within 10 miles of the site have occurred in historic time. For regional correlation of epicenters with geologic structures, see Sections 2.5.2.2 and 2.5.2.3.

2.5.3.6 Descriptions of Capable Faults

There are no capable faults in the region around the site extending to within 5 miles of the site. For a description of faults within 5 miles of the site, see Section 2.5.3.2.

2.5.3.7 Zone Requiring Detailed Fault Investigation

As discussed in Section 2.5.1.2, some shear zones with small offsets were encountered during foundation excavation at the site. Structures of this type are not unusual in the region; however, these zones were mapped in detail and photographed as part of the site geologic record (Figure 2.5-13). The detailed geologic investigation included mapping of an area approximately 5 miles in diameter. A review committee was established (Section 2.5.3.2.1), and the results of all investigations were included in a report issued in July 1974 (Reference 2.5-1). The review committee concluded that the shear zones in the foundation excavation at the site and the faults within the area mapped are typical of features associated with 150-200 million year old events in the area (Section 2.5.3.2.1).

2.5.3.8 Results of Faulting Investigation

See Sections 2.5.1.2 and 2.5.3.7; there are no capable faults within 5 miles of LGS.

2.5.4 STABILITY OF SUBSURFACE MATERIALS AND FOUNDATIONS

2.5.4.1 Geologic Features

Bedrock at the site consists of well-indurated Triassic sandstones, siltstones, and shales that extend to a depth of several thousand feet. Bedding dips toward the north at 8° to 20°. Site stratigraphy is presented in Section 2.5.1.2.3. Geologic structure in the site area is presented in Section 2.5.1.2.4. Bedrock is overlain by from 0-40 feet of residual soil, developed in situ by weathering and decomposition of the parent rock. The soil grades into weathered rock, then into fresh, unweathered rock; no clearly defined boundary exists between soil and rock.

During foundation excavation, some fracture zones with small displacements were encountered and were treated locally as required. Descriptions of the fracture zones are presented in section 2.5.1.2.5; their locations at final foundation grades are shown on Figure 2.5-13. Treatment of these fracture zones is discussed in Section 2.5.4.12.

Engineering evaluation of the site geology is discussed in Section 2.5.1.2.7. The bedrock at the site contains no unstable minerals or hazardous conditions. The stress regime within the bedrock materials is low and stable. There are no mines in the site area and no significant fluid withdrawal. The bedrock in the construction area is competent and provides satisfactory foundation support for plant structures.

2.5.4.2 Properties of Subsurface Materials

The principal plant structures are founded on bedrock. The spray pond is excavated partly in soil and partly in rock. All or portions of other facilities not founded on bedrock are founded on natural soil or manmade fills. The locations of the major plant structures are shown on Figure 2.1-3. Results of laboratory tests for foundation and construction materials are presented in References 2.5-39 and 2.5-51, and in Sections 2.5.4.1.2, 2.5.4.2, and 2.5.4.10.

2.5.4.2.1 Properties of Foundation Rocks

The seismic Category 1 reactor and diesel generator enclosures, as well as the turbine and radwaste enclosures, are founded on hard, competent bedrock. The bedrock consists of siltstone, sandstone, and shale of Brunswick lithofacies of Triassic-age. The Brunswick is described in Section 2.5.1.2. The Lockatong lithofacies, represented by the Sanatoga Members, interfinger with the Brunswick in the northern part of the site area. The Sanatoga Member consists of blue-gray calcareous argillite with two distinct beds of black carbonaceous shale. The spray pond is underlain by both the Lockatong and Brunswick lithofacies.

Bedding and jointing patterns are well developed in the foundation rocks. Bedding-plane spacing varies from a few inches to several feet. Bedding-planes strike generally east to west and dip to the north at 8° to 20°. Two major joint systems are prevalent in the area. Both are vertical or nearly vertical; they strike approximately N 20° to 50° E and N 50° to 60° W. Three fracture zones and two minor clay seams along bedding were encountered in the main power block foundation excavations; they are described in Section 2.5.1.2.5. Treatment of these zones is described in Section 2.5.4.12.

Rock quality designation values were measured in a total of 81 boreholes, which include the 200-, 300- and M-series borings completed in 1970, and borings 400 and 401 completed in February 1971 (Figure 2.5-22). In general, rock quality designation values measured on the first core run (5-10 ft) in rock were very low, usually zero; with some exceptions, minimum rock quality designation values increased to approximately 50% or greater after the first 10-30 feet of rock cored. The lower rock quality designation values in the upper 10-30 feet of rock reflect poorer rock quality caused by rock weathering; this weathered material was removed during foundation excavation. The data and analyses discussed below demonstrate that the higher rock quality designation values are associated with the sound, unweathered bedrock that supports the foundations for the principal plant structures.

Because of the gradational nature of the upward transition from sound rock to soil, engineering properties in the zone of rock weathering can be expected to vary from soil-like properties near the top of the zone to properties approaching those of sound rock near the base of the zone. Properties of sound, unweathered foundation rock were determined as follows.

Laboratory tests on 16 core samples, using substantially the same procedure as specified in the subsequently adopted ASTM D2938-71, indicate unconfined compressive strengths ranging from 6370-24, 540 psi with an average of 15,820 psi. Results of these tests are shown in Table 2.5-3. Laboratory sonic tests on intact cores (ASTM D2845-69) (Table 2.5-13) from four borings yield an average compressional velocity of 12,060 fps.

Seismic refraction surveys were performed to determine P-wave and S-wave velocities for site foundation materials. P-wave velocities in rock range from about 7700 fps to 20,000 fps, with an average of about 12,500 fps; locations of refraction lines are shown in Figure 2.5-21. Shear-wave

velocities were determined to be about 6100 fps in a line perpendicular to the strike of the bedding (north-south). A line run approximately parallel to the east-west strike of the bedding measured a shear-wave velocity of 5800 fps. Poisson's ratio is calculated to be about 0.3. The dynamic modulus of elasticity calculated from the seismic data is $3x10^6$ psi. Representative engineering properties of foundation rock are summarized in Table 2.5-11.

Because geophysical test methods were used to establish dynamic design rock properties, it is appropriate to consider a range of dynamic moduli. Accordingly, all LGS available geotechnical data have been evaluated to establish the most appropriate range of dynamic moduli to be considered. This approach is presented below. It was concluded from this evaluation that an appropriate LGS dynamic rock modulus range would be between $2.7x10^6$ and $4.0x10^6$ psi, a range of ±20%. The seismic analysis of the containment structure and reactor control enclosures included the SSE effect as discussed in Section 3.7. These analyses use a Young's dynamic modulus for rock equal to $3.0x10^6$ psi. Additional soil-structure interaction studies were performed for the containment structure and reactor and control enclosures to assess the sensitivity of the structural response to variations in the design basis rock modulus. Modal analyses have demonstrated that for a ±50% range (of the design elastic modulus), variations in structural frequency do not exceed 10% for predominant modes. These results indicate that a reduction in rock modulus to $1.5x10^6$ psi will not produce significant effects on structural response. It is thus concluded that the average dynamic elastic modulus value of $3.0x10^6$ psi is adequate for design.

Examination of the LGS Design Basis Dynamic Rock Modulus

The following actions have been taken to establish an appropriate range of dynamic elastic rock moduli: (1) re-examination of the data on seismic velocities and dynamic moduli of the rock at the site, as given in the Dames and Moore reports and in the PSAR and the FSAR, (2) study of relevant technical literature including the WASH-1301 report (Reference 2.5-155), and (3) discussions with Dr. A.J. Hendron, a recognized authority on rock foundation engineering.

(1) Seismic velocity data and in situ dynamic moduli at the LGS site.

Young's modulus (dynamic) is calculated from either P-wave or shear-wave velocities. Ambraseys and Hendron (Reference 2.5-153) state, "for fairly competent rock masses (V_P greater than 10,000 fps) the compressional wave velocity and an assumed value of Poisson's ratio ranging from 0.27 to 0.35 may be used to evaluate a dynamic Young's modulus for engineering purposes". The average compressional wave velocity in rock at the site is approximately 12,000 fps; therefore, it is appropriate to consider P-wave velocities in computing the dynamic modulus. Accordingly, the dynamic modulus value of $3.0x10^6$ psi for the site has been re-examined considering both P-wave and S-wave velocity data from refraction surveys, and considering up-hole velocities measured in one hole at the site. Also, results of laboratory tests have been re-evaluated to determine sonic velocities of rock cores, at the recommendation of Dr. A.J. Hendron.

Shear-wave velocities were measured along two refraction lines in the power block area (Figure 2.5-21); Dames and Moore (Reference 2.5-154) reported V_s of 6100 fps along strike and 5800 fps parallel to dip direction, for an average of 5950 fps, as described in Table 2.5-11. Poisson's ratio calculated from the average P-wave and S-wave velocities is 0.33. Young's modulus calculated from the average shear-wave velocity and this Poisson's ratio is $3.1x10^6$ psi.

Upper layer P-wave velocities measured across the entire site have approximately the same average value (12,020 fps) as those measured only in the power block area (11,880

fps) but, as expected, the former data set has significantly higher scatter (standard deviation 2,660 fps vs. 930 fps). A test (F-test) for equivalence of variance shows conclusively that the scatter of the P-wave values for the whole site is unrepresentative of the data for the power block area only. Therefore, P-wave data primarily from the power block area have been considered for evaluation and analysis.

Within the power block area, Dames and Moore (Reference 2.5-154) measured P-wave velocities on lines 3E, 4 and 6 (Figure 2.5-21). In addition, seismic P-wave velocities east of the Unit 1 turbine building were recorded along line 3F. Neglecting the higher velocities detected from the more deeply buried rock strata, eight refraction velocities (PSAR figure 2.5.5) yield an average P-wave velocity of 11,880 fps with an unbiased 1 sigma range of 10,950 fps to 12,810 fps. Using the lower end of the range (10,950 fps), and a Poisson's ratio of 0.30 as recommended by Dame and Moore, (E) is calculated to be 2.9×10^6 psi; the upper end of the range corresponds to (E) of 4.0×10^6 psi. With a Poisson's ratio of 0.33 (as indicated by the ratio between average P-wave and S-wave velocities), the range for (E) is 2.7×10^6 to 3.7×10^6 psi.

From the up-hole survey (Dames and Moore, Reference 2.5-154) and PSAR figure 2.5.6, the weighted mean P-wave velocity (weighted by relating velocity of each layer to the relative thickness of that layer) is 11,650 fps, which is in agreement with the profile data. The corresponding (E), with a Poisson's ratio of 0.3, is calculated to be 3.3×10^6 psi.

Sonic tests on cores taken at the site (nine determinations) (Table 2.5-13) have an average P-wave velocity of 12,060 fps. The ratio of average field measured P-wave velocity to laboratory measured P-wave velocity (11,880-12,060 fps) is 0.98. This ratio provides support for the statement provided below in this section that: "The agreement between laboratory and field velocity measurements suggests that the seismic refraction results are representative of sound foundation rock, for otherwise the field measurements would be significantly less than measurements on intact core. Therefore the field seismic velocity data should provide a reasonable quantitative index of the general character of the in situ foundation rock".

(2) Reduction of dynamic modulus for higher strain levels during SSE event

The rigidity of soil decreases significantly with strain; however, this should not be translated directly to rock, particularly to hard rock. For example, the relative reduction of shear modulus for sands ranges from 15% to 35%, depending primarily on void ratio or relative density, as the strain level increases from 10^{-4}% to 10^{-2}% (Figure 2.5-47). The corresponding reduction in rock moduli for a similar increase in strain level would be expected to be significantly less.

A brief search of the literature was made for data on the effect of strain on the rigidity of rock. Also, the maximum strain that would occur in the foundation rock at LGS during the SSE event was computed.

A simple estimate of strain in rock during a seismic event can be obtained by assuming sinusoidal, plane, vertically propagating SH-waves in an elastic, homogeneous whole space. Under these assumptions, maximum shear strain is equal to the maximum SH-wave particle velocity divided by the propagation velocity of the medium. For rock, a peak particle velocity to peak acceleration ratio of 36 inches/second/g has been recommended

(Newmark and Hall, Reference 2.5-155). Using this ratio and the 0.15g SSE for the site, and estimate of about 5.4 in/sec is derived for the SSE ground motion at the site. The site near surface SH-wave propagation velocity is about 6000 ft/sec, so that:

$$\text{STRAIN} = \frac{5.4 \text{ in/sec}}{72{,}000 \text{ in/sec}} = 7.5\times10^{-5} = 7.5\times10^{-3}\%$$

Actual strain at or near ground surface would not be this high because this calculation ignores the zero stress-free and strain-free surface boundary condition.

Strain levels associated with seismic profiling pulses are presumed to be on the order of 10^{-4}%, depending on the shot charge and line spread (e.g., Silver and Seed, Reference 2.5-159). There is little published information quantifying to what extent typical rock materials deviate from linear-elastic behavior at these small strain levels. Raphael and Goodman (Reference 2.5-157), drawing upon rock mechanics studies conducted in France, state that the modulus computed from seismic profiling should be greater than the rock modulus which would pertain during earthquakes, but they provide little information on the specific ratio of E (earthquake) to E (seismic test) to be adopted for varying circumstances.

Schnable et al (Reference 2.5-158) plot shear modulus as a function of strain for rock (Figure 2.5-46). In this context, "rock" is generally considered to be a material with an S-wave propagation velocity of about 2500-3000 ft/sec or higher (Schnable et al, 1971, Reference 2.5-158 and Algermissen and Perkins, 1976, Reference 2.5-152). These authors indicate that the shear modulus should decrease by less than 10% as the shear strain increases from 10^{-4}% to 7.5×10^{-3}%.

A.J. Hendron (personal communication, 1983) stated that a reduction in dynamic modulus - from E (seismic test) to E (earthquake) - is appropriate for rock because strain levels experienced during earthquakes are higher than the strains which are associated with the measurement of seismic velocities. For the site, Hendron favors tying such a reduction to the square of the ratio of field measured seismic velocities to laboratory measured velocities on core samples. Dr. Hendron has developed such a curve from his studies at the Nevada Test Site and other localities; that curve would plot well above the curve shown on Figure 2.5-45. He stated that the amount of reduction for higher strain during a seismic event is significantly less for dynamic conditions than it is for reducing dynamic E to static E, which is the purpose of Figure 2.5-45. On Hendron's revised graph, for example, he stated that the square of the ratio of field-to-laboratory P-wave velocities $(V_F/V_L)^2$ of 0.87 correlates with a reduction in dynamic modulus E_d of about 22% at a strain level of 10^{-3} in/in (Hendron, personal communication, January 1983). Subsequently, Hendron prepared a brief report describing his additional data on variation of propagation velocity with strain and commenting on dynamic Young's Modulus for the site under SSE conditions. Based on the data on rock quality provided to him, it is his judgment that the reduction factor at LGS should be about 0.75 to 0.85.

The following is a summary of the measured seismic velocities at the site and the corresponding values of the dynamic modulus of elasticity computed from them.

P-Wave (from In Situ Field Surveys)

Average velocity - 11,880 fps
Range of velocities (mean ±1 S.D.) = 10,950-12,810 fps

E (Assuming Poisson's ratio = 0.30)
Average - 3.5×10^6 psi
Range - 3.0×10^6 psi to 4.0×10^6 psi
E (Assuming Poisson's ratio = 0.33)
Average - 3.3×10^6 psi
Range - 2.6×10^6 psi to 3.7×10^6 psi

S-Wave (From In Situ Field Surveys)

Average velocity	-	5950 fps
Range	-	5800-6100 fps
E (Average)	-	3.1×10^6 psi (Poisson's ratio of 0.33)
E (Range)	-	3.0×10^6 psi to 3.3×10^6 psi

Sonic Velocity Tests (On Intact Cores in Laboratory)

Average - 12,060 fps
Ratio of field velocity to lab velocity V_F/V_L
= 11,880/12,060 = 0.98

Up-Hole Survey Measurements

Weighted average velocity - 11,680 fps
E (with Poisson's ratio = 0.33) - 3.0×10^6 psi
E (with Poisson's ratio = 0.30) - 3.3×10^6 psi

Maximum Range of E - 2.6×10^6 psi to 4.0×10^6 psi (Range with ±1 S.D. of P-wave and S-wave velocities, and up-hole velocities, using Poisson's ratio of 0.30 and 0.33)

E used for design - 3.0×10^6 psi

(lower 28 percentile of the maximum range).

The seismic velocity data of the foundation rock at the site indicates that the dynamic (E) value used for design (3×10^6 psi) represents the lower portion of the data range. The available data do not justify a range of dynamic moduli of ±50% of the design basis value. Data from Schnable et al (Reference 2.5-158), for example, indicate that a reduction of less than 10%, for rock of undefined quality, is appropriate. Considering the rock quality at the LGS site is indicated by a velocity ratio squared of about 0.87, Hendron recommends a reduction of about 20%. (Actually, the velocity ratio squared of the rock at is about 0.96, based on the few lab velocities measured.)

It is therefore concluded that 3×10^6 psi is an appropriate value for the average dynamic modulus of elasticity of the foundation rock at the site. The range of moduli to be taken into consideration for design should be 2.7×10^6 psi to 4.0×10^6 psi. Additional discussion of seismic refraction survey techniques is given in Section 2.5.4.4; plate bearing tests and static moduli are described in Section 2.5.4.10.

The agreement between laboratory and field velocity measurements suggests that the seismic refraction results are representative of sound foundation rock, for otherwise the field measurements would be significantly less than measurements on intact core. Therefore, the field

seismic velocities should provide a reasonable quantitative index of the general character of the in situ foundation rock. Weathering reduces rock quality typically in the upper 10-30 feet of rock as indicated by reduced rock quality designation values in this zone. The weathered rock grades upward with no well defined contact into residual soil. Therefore, the properties of weathered rock are similar to those of sound rock at the base of the weathered zone and approach those of soil at the top of the zone. Because foundations for the main plant structures including the power block, radwaste, and pumphouse enclosures are carried to unweathered rock, rock weathering is not significant to foundation design for these facilities. Seismic Category I structures founded on weathered rock are buried structures including diesel oil tanks and portions of buried piping and electrical duct banks. In the foundation design of these structures, the bearing pressure allowable for dense natural soil (6,000 psf) is conservatively used, as discussed in Section 2.5.4.10.2.

Nevertheless it was recognized that occasional localized features such as fracture zones or clay seams encountered in the foundation rock would require evaluation as they became exposed. Accordingly, foundation rock was mapped and evaluated for such features by experienced engineering geologists during the course of construction. Measures to improve foundation conditions were carried out at certain areas where potential rock weakness was encountered. Detailed discussion of these measures is provided in Section 2.5.4.12.

2.5.4.2.2 Properties of Foundation Soils

The in situ soils are residual in nature, derived from weathering of siltstone, sandstone, and shale. The properties of these soils were determined by laboratory testing. Testing of the in situ soils at the spray pond was conducted by Geotechnical Engineers, Inc. The complete laboratory test report is given in Reference 2.5-39. The properties of the soils are given in Sections 2.5.4.2.2.1 through 2.5.4.2.2.3 and are summarized in Table 2.5-4.

The properties of the in situ soils other than spray pond were determined by Dames and Moore. The complete laboratory test results are included in Reference 2.5-51. The laboratory testing procedures are given in Reference 2.5-141. The properties of these soils are described in Section 2.5.4.2.2.4 and are summarized in Table 2.5-4.

A compaction test was performed on a sample of the overburden soil to obtain soil compaction characteristics. Sieve tests were performed on representative soil samples to evaluate grain-size distribution. In addition, Atterberg limits were performed on the bulk soil sample used for the compaction test and on other soil samples to evaluate the plasticity characteristics. The locations of borings at the site are shown in Figure 2.5-20.

Seismic Category I structures not founded on competent bedrock include the spray pond and buried structures described below. The manner and conservatism in which soil data were used in the design of the spray pond is discussed in Section 2.5.5. Seismic Category I buried structures include portions of underground piping and electrical duct banks, valve pits, and diesel oil tanks. These buried structures are founded above the high groundwater table and have bearing weight less than the replaced in situ soil. The static stability of the buried structures is discussed in Section 2.5.4.10.1. The seismic inertia effect of buried structures are negligible and the propagating seismic wave effects on buried piping are considered as described in Section 3.7.3.12.

2.5.4.2.2.1 Index Properties of Soils at Spray Pond

The index properties include the following:

a. Visual and laboratory classification of samples - ASTM D2488

b. Mechanical analysis - ASTM D422

c. In situ moisture content and unit weight - ASTM D2216

d. Atterberg limits - ASTM D423 and ASTM D424

e. Specific gravity tests - ASTM D854

The in situ soil of the spray pond includes clayey silt, sandy silt, and silty fine sand, with varying amounts of gravel-sized rock fragments. The predominant soil is clayey silt, classified as ML and CL. The in situ moisture ranges from 11.9 to 38.7%, and averages 21.7%. The specific gravity ranges from 2.70 to 2.80, with an average value of 2.76.

Sieve and hydrometer analyses were performed to determine grain-size distribution according to ASTM D422. The mean grain-size (D_{50}) was found to be in the range of 0.006 mm to 4.4 mm, with an average value of 0.32 mm.

The Atterberg Limits were obtained according to ASTM D423 and ASTM D424. The liquid limit ranges from 27 to 51, with an average value of 37. The plasticity index ranges from 2 to 27, with an average value of 15 (Figure 2.5-17).

2.5.4.2.2.2 Static Shear Strength of In Situ Soils at Spray Pond

Consolidated-undrained triaxial tests were made in which undisturbed specimens were placed in the triaxial chamber and saturated by the back pressure method. After saturation the samples were consolidated isotropically to a consolidation pressure of 1 ksf. Plots are made of deviator stress vs axial strain, induced pore pressure vs axial strain, and stress paths for each test. These plots are included in appendix J of the PSAR. The failure stresses of samples are shown on Figure 2.5-18. From this drawing, the effective friction angle is determined to be 33.5°.

Points plotted on Figure 2.5-18 represent conditions at failure. In general, the failure condition was chosen when the sample reached 20% strain if the shear stress continues to increase. However, if the peak was reached at a lower strain level, the (p-q) point shown on Figure 2.5-18 would represent the stresses at the peak. The point, p = 10.2 and q = 5.2, represents the Test R14 which reached its peak shear stress at 15% strain. The points are plotted in conformance with this criteria.

The undrained shear strength of the material is calculated from the effective stress friction angle and pore pressure parameter (A) at failure using the following relationship (from Reference 2.5-40):

$$g_f = \frac{\bar{P}_\circ \sin \bar{\phi}}{1 + (2A_f - 1) \sin \bar{\phi}} \qquad \text{(EQ. 2.5-1)}$$

where:

g_f = undrained shear strength

$\bar{\phi}$ = effective stress friction angle

A_f = pore pressure parameter (A) at failure

$\bar{P}_o$ = initial mean effective principal stress

For the samples tested, A_f varies from -0.04 to -0.38. Using the conservative assumption of $A_f = 0$ and $\bar{\phi} = 33.5°$, the undrained shear strength is calculated to be 1.2 $\bar{P}_O$.

2.5.4.2.2.3 Dynamic Shear Strength of In Situ Soils at Spray Pond

Stress controlled cyclic triaxial tests were made in which the undisturbed samples were placed in a chamber and saturated using the back pressure method. When saturated, the samples were consolidated isotropically to an effective confining pressure of 2 ksf. After consolidation, the drainage valves were closed, and a symmetrical cyclic deviator stress was applied. The axial deformation, axial load, and pore pressure were measured continuously during the cyclic loading. The cyclic stress ratio plotted against the number of cycles required to cause 5% double amplitude strain is shown on Figure 2.5-19.

The dynamic shear strength of the soil is determined by multiplying the cyclic stress ratio by the effective overburden pressure. The cyclic stress ratio required to cause 5% double amplitude strain in five cycles is determined to be 0.61 (Figure 2.5-19). The selection of 5 cycles simulates the SSE of 0.15 g at the site, based on correlations of equivalent uniform stress cycles and time histories by Seed, et al (Reference 2.5-41).

2.5.4.2.2.4 Properties of In Situ Soils Other Than Spray Pond Area

The properties of soils at the site, other than those discussed in Sections 2.5.4.2.2.1 through 2.5.4.2.2.3, are discussed in the Dames & Moore report (Reference 2.5-51). The results of the tests are described below and are summarized in Table 2.5-4.

The predominant soils at the site consist of red sandy and clayey silts with numerous rock fragments. They are classified as ML. The in situ moisture content measured in accordance with ASTM D2216-61 ranges from 8.3% to 21.3%, and averages 13.4%. The average grain-size distribution, based on the results of sieve analyses, in accordance with ASTM D422-63, were found to be 14% in gravel-size, 27% in sand-size, and 59% silt and clay. The average liquid limit and plasticity index in accordance with ASTM D422-63, based on three tests, were found to be 25 and 8, respectively. The plasticity index was calculated using the results of the liquid limit test in accordance with ASTM D423-66 and plastic limit test in accordance with ASTM D424-59.

A limited number of compression tests were performed to determine the shear strength of the in situ soil. The total shear strength parameters, based on two unconfined compression in accordance with ASTM D2166-66 and two unconsolidated undrained triaxial compression tests in accordance with ASTM D2850-70, were found to be c = 3.0 ksf, and Ø = 18°. The effective shear strength, based on four consolidated drained triaxial compression tests, were found to be $\bar{c} = 0$, and $\bar{\emptyset} = 26.5°$. Procedures given in Reference 2.5-141 were followed in conducting the consolidated drained triaxial compression tests.

No laboratory tests were made to determine the dynamic shear strength of the soil.

2.5.4.2.2.5 Properties of Type I Fill

A description of Type I fill and methods of placement are given in Section 2.5.4.5.4. The static or dynamic properties of this material have not been measured.

A total unit weight of 140 pcf and an at rest coefficient of lateral earth pressure of 0.7 have been assumed for Type I fill. The Type I fill is expected to have properties similar to dense sand and gravel and to have a maximum shear-wave modulus determined by the following expression (Reference 2.5-144):

$$G = 1000\ K_2\ \sigma_m^{1/2}$$

where:

G = maximum shear modulus, psf, at a strain of 10^{-6} in/in

K_2 = 140

σ_m = average stress, psf, and is equal to $\frac{(\sigma_1 + 2\sigma_3)}{3}$

σ_1 = ν H

σ_3 = 0.7 ν H

ν = Unit weight, 140 pcf

H = depth, ft

2.5.4.3 Exploration

The locations of all field explorations are shown in Figures 2.5-20 and 2.5-21. Summary logs of borings are shown in Figure 2.5-22. Soils are classified in accordance with the Unified Soil Classification System. Rock coring was performed with double-tube, NX equipment.

Site drilling began in September and October, 1969 and continued in the spring of 1970 (Borings 1 through 301). Geophysical surveys (Section 2.5.4.4) were performed in the plant area at this time. In the spring of 1971, additional drilling was performed in the area of the Perkiomen Creek pump station. In late 1971 and early 1972, additional drilling was performed in the Schuylkill River pump station area. In 1973 auger holes were drilled in the area of the emergency spray pond, and in 1974 detailed spray pond investigations were completed. The cooling tower foundation exploration was also completed at this time. Most of the main plant foundation was exposed at this time, and some fracture zones were noted (Sections 2.5.1.2.5 and 2.5.4.12). Between April and July, 1974, an extensive geologic study of these zones and the area around the site was completed by Dames and Moore. This study consists of geologic mapping, with some drilling and test trenching near the Sanatoga, Brooke-Evans, and Linfield faults. Site exploration was completed in the fall of 1974. A total of 366 borings and four test pits was completed in the site area for geologic, groundwater, and foundation investigations. In March, 1977, 13 additional test pits were excavated to depths of from 5-11.5 feet, to investigate soils for use in construction of the soil-bentonite liner for the emergency spray pond.

Static water levels were measured in some of the borings drilled on the site. Perforated plastic pipes were installed in some borings to allow future collection of water level data. These borings are denoted on the plot plan (Figure 2.5-20).

A geologic map of the main power block foundations is presented in Figure 2.5-13. Contours on top of rock in the site area are shown on Figure 2.5-9. Geologic profiles are shown on Figures 2.5-10 and 2.5-11.

2.5.4.4 Geophysical Surveys

2.5.4.4.1 Seismic Refraction Survey

Seismic refraction surveys were conducted at the site. A continuous series of seismic lines closely followed the continuous line of borings drilled across the site (Figure 2.5-21). These lines ranged in length from about 400-700 feet, with some overlapping coverage. Two 550 foot refraction lines were performed perpendicular to the major line that traversed the site.

The results of the seismic refraction surveys were used to develop dynamic properties of the foundation materials. Permanent records of the compressional waves generated from the survey were obtained using an Electro-Technical Labs ER75012 seismic timer, which is a 12-trace refraction seismograph. Geophone spacings of 25 feet and 50 feet were used in performing the surveys. Compressional wave velocities (V_p) in rock measured during these studies range from about 7000 fps to 20,000 fps, with an average of approximately 12,500 fps.

2.5.4.4.2 Shear-Wave Velocity Survey

A shear-wave velocity survey was performed to further evaluate dynamic bedrock characteristics. Shear-wave velocities were computed from the records obtained using two Sprengnether 3-component engineering seismographs. Observations were made at distances of between 500 feet and 1000 feet from the shot point, at the locations indicated on Figure 2.5-21. An apparent shear-wave velocity (V_s) of 6100 ft/sec was derived from the line run perpendicular to the rock strike, roughly in a north-south direction. In the second line, which parallels the approximate east-west strike of the bedding-plane, an apparent shear-wave velocity of 5800 ft/sec was measured. Using elastic theory, a Poisson's ratio of about 0.3 can be calculated using these shear-wave velocities and average compressional wave data across the site. Shear-wave data are included in Table 2.5-11.

2.5.4.4.3 Up-Hole Velocity Survey

An up-hole velocity survey was performed in the pump test well at the location shown on Figure 2.5-21. Measurements were obtained using a Porta-Seis refraction seismograph, with small explosive charges as energy sources, and an in-hole cable with 25 foot geophone spacings. Repeated shots were made and the cable was withdrawn in 5 foot increments.

The up-hole velocity survey was made to determine variations in the vertical compressional wave velocity of the underlying rock. Compressional wave velocities (V_p) measured were 7700 fps from depth 110-140 feet, and 12,600 fps from depths 37-110 feet and from 140-187 feet.

2.5.4.4.4 Micromotion Measurements

Measurements of the ambient background motion of the site and its response to natural motion generators, such as wind and tides, give an index of the dynamic properties of the materials

underlying the site. An attempt was made to measure these motions in the proposed plant area using the Dames and Moore microtremor equipment. This equipment is a highly sensitive, electronic, vibration recording device capable of magnification up to 150,000 times, and it is accurate over a frequency range of about 0.4-30 cycles per second. The 3 component micromotion observation was made on the existing ground surface (prior to construction), near the test well used for the up-hole velocity survey, as shown on Figure 2.5-21.

The microtremor records indicate that ambient motions caused by natural background excitations at the site are negligible. There is a suggestion of motion at a period of 0.7-0.8 second, but no apparent predominant ground period; this is a condition common at sites where competent materials are exposed at the surface.

2.5.4.5 Excavations and Backfill

The location, limits of excavation, and type of fills associated with seismic Category I facilities are presented in Figure 2.5-37. Detailed descriptive data concerning these backfills and excavations are discussed below. Procedural controls, such as inspections and tests, exercised during the preparation of foundations for seismic Category I structures are described below and in Section 2.5.5.

The properties of foundation rock at the site (Section 2.5.4.1 and Tables 2.5-3 and 2.5-11) indicate that the rock has adequate strength to resist significant heave at the depths excavated. Further, the moderately well to well developed conjugate sets of vertical joints present at the site, together with subhorizontal bedding-planes, would presumably have provided for prior release of any excessively high in situ stresses, minimizing the potential for rock rebound.

Seismic Category I facilities on soil, such as pipelines and electrical ducts, are largely buried and backfilled facilities, such that the accompanying loads approximate the original in situ conditions. The diesel oil storage tank facility, which is founded on weathered rock, is also a buried and backfilled facility. At the spray pond, the pump house, overflow structure and all pipe supports are to be founded on rock; as discussed in Section 2.5.5.2, factors of safety on the seismic Category I soil slopes are considerably in excess of the minimum acceptable requirements.

In view of these circumstances, specific measures for monitoring foundation rebound and heave were considered but are not considered to be necessary. No instances of foundation rebound or heave were noted during excavation or construction of the facilities.

2.5.4.5.1 Main Power Block and Cooling Tower Excavation

All seismic Category I rock foundations at the main power block are carried to, or well below, unweathered bedrock. These include the reactor enclosures and control room structure. Rock foundations for the turbine and radwaste enclosures, although they are not seismic Category I structures, are prepared according to the same general procedures and criteria used in preparing the seismic Category I rock foundations.

The excavation of rock proceeded by initial ripping of any weathered surficial rock material, followed where necessary by line blasting and presplitting in holes drilled to provide stable slopes. Essentially vertical slopes in unweathered rock proved stable throughout the duration of construction, and no special protective measures were required.

The surface of the excavated foundation rock is scaled to remove loose debris and jetted with water or air to remove loose fragments and to prepare the surface for concrete. Before placement of structural concrete or concrete backfill to design elevation, all seismic Category I foundations for the main power block are inspected by an engineering geologist to verify the suitability of the rock and its proper surface preparation to receive concrete. Geologic mapping of foundation rock in the main power block area is presented in Figure 2.5-13.

Foundations for each of the cooling towers (nonseismic Category I structures) consist of 40 individual pedestals supporting the columns and extending to bedrock. Excavation proceeded by cutting a ring trench and preparing a suitable surface for each pedestal in unweathered or partly weathered bedrock by ripping or blasting as necessary, followed by scaling and jetting.

2.5.4.5.2 Diesel Generator Enclosure Excavation

The plans and sections of the diesel generator enclosure foundations are shown in Figure 3.8-61. The diesel generator enclosures are founded on bedrock; the geological inspection and preparation of the foundation rock are the same as for the main power block.

The spray pond pump structure and spray network pipe supports are seismic Category I and are founded on bedrock. Geological inspection and preparation of the foundation rock for these structures are the same as that for the main power block.

2.5.4.5.3 Spray Pond Excavation, Slope Protection and Liner Construction

The plans and sections of the spray pond showing excavation, slopes, and normal pond level are given in Figures 3.8-56 and 3.8-57. As shown, the spray pond is constructed primarily by excavation. A soil-bentonite liner and a protective soil cover are placed over the entire bottom of the pond and on the soil slopes. The soil cover on the slopes in turn is protected by riprap and riprap bedding. The rock slopes are treated by shotcrete for protection against weathering. Due to a sloping bedrock surface, the bottom of the pond below the soil-bentonite liner is underlain partially by soil and partially by rock. Slopes in soil are excavated at 4 horizontal to 1 vertical; rock slopes are excavated at 1 horizontal to 1 vertical (Section 2.5.5), except for a short transition zone in weathered rock, which is excavated at 2:1.

The soil-bentonite liner, soil cover, riprap bedding and foundation preparation of the spray pond are discussed in detail in Section 2.5.5.

2.5.4.5.4 Fills - General

All fills placed at the site, which are associated with seismic Category I structures (except spray pond), include random fill, select granular backfill, cementitious backfill, and concrete.

Two types of random fill, identified as Type I and Type II, were used for general site grading.

Type I fill was placed in the areas adjacent to the main power block and as backfill over part of the RHR and ESW piping. Type II fill was used for finished grading in the outlying areas, including backfill over part of the safety-related duct banks.

The division line between cut and fill and the limits of Type I and Type II fill within the main power block complex are shown in Figure 2.5-37.

Type I fill consisted of broken rocks and fines obtained from the site excavations and was graded from fine to coarse material with no rock fragments larger than 8 inches in diameter. It was placed in uniform layers of loose lifts with a maximum thickness of 12 inches and was compacted and tested as described below.

Type I fill placed before July 1971 was compacted to 90% of the maximum dry density in accordance with AASHO T180-61, Method D, and was tested in accordance with AASHO T147-54. Type I fill placed thereafter was compacted to 90% of the maximum dry density in accordance with AASHO T180-70, Method D, and was tested in accordance with AASHO T191-61.

Type I fill was compacted by the following approved types of equipment:

a. Sheep-foot roller with minimum weight of 4000 pound per linear foot of drum, operated at a speed of approximately 3 mph.

b. Rubber tire rollers with minimum of 4 pneumatic tire wheels maintaining tire pressure on the ground of between 80-100 psi. The load per wheel may vary from 18,000-25,000 pounds.

c. Vibratory roller with minimum weight of 21,000 pounds, drum diameter approximately 70 inches and length of 78 inches, and minimum centrifugal force of 40,000 pounds, and frequency 1000-1400 vibrations per minute.

d. In confined areas, hand operated equipment was used with a maximum lift of 8 inches.

e. A total of 379 compaction tests were performed before the end of 1982. The minimum frequency for testing Type I fill for compaction was not less than once for each 500 cubic yards placed. Fills failing to meet the compaction requirements were removed, recompacted, and retested.

Type II fill consisted of broken rocks and fines obtained from the site excavations. It was placed uniformly in unconsolidated lifts not exceeding 24 inches in thickness, producing a reasonably well graded mass with a minimum of stratification of fine or coarse materials. The material was uniformly spread over the entire area by bulldozer prior to compaction. The material was moisture-conditioned to attain satisfactory compaction. Type II fill was compacted by the equipment described for Type I fill under general supervision without testing requirements. Granular Type II fill was also compacted by use of a track-type tractor weighing not less than 60,000 pounds and making a minimum of four passes overlapping one-fourth the width of the track on each pass.

Select granular backfill consisted of imported aggregate or screenings. The maximum particle size was ¾ inch, with no more than 10% by weight passing the No. 200 sieve. Select granular backfill was placed in loose lifts with a maximum thickness of 6 inches and was compacted to 95% of the maximum dry density in accordance with AASHO T180-70, Method D. As an alternative to the above material, when cohesionless select backfill was used, it was compacted to 90% of the maximum dry density in accordance with ASTM D2049-69 by the use of both dry and wet methods. In-place select granular backfill was tested in accordance with AASHO T191-61.

The cementitious backfill consisted of a mixture of portland- cement, aggregate, and water. The minimum compressive strength at 28 days was 80 psi. Testing for compressive strength of cementitious backfill using sand as aggregate was in accordance with ASTM C109, ASTM C31, and ASTM C39. Testing for compressive strength of the backfill using coarse aggregate was in accordance with ASTM C31 and ASTM C39.

Slump tests were performed in accordance with ASTM C143. The cementitious backfill was consolidated by use of mechanical vibrating equipment for proper placement.

The concrete backfill consisted of a mixture of portland-cement, aggregates, admixtures, and water. The minimum 28 day compressive strength was 2,000 psi. The standards and specifications that governed the concrete backfill are stated in the following sections:

a.	Section 3.8.6.1.2.2	Mix proportioning
b.	Section 3.8.6.1.4.2	Mixing and delivery
c.	Section 3.8.6.1.4.3	Placing
d.	Section 3.8.6.1.4.4	Consolidation
e.	Section 3.8.6.1.5	Construction testing

Field tests of Type I random fill, select granular backfill, cementitious backfill and concrete backfill used in conjunction with seismic Category I structures, electrical duct banks, manholes, pipelines and valve pits were performed by Quality Control. The test data are available at the site for inspection and review.

2.5.4.5.5 Miscellaneous Category I Facilities - Excavation and Backfill

Seismic Category I facilities not founded on unweathered bedrock include part of the spray pond, portions of the underground piping and electrical ducts, oil tanks, and valve pits. The spray pond is discussed separately in Section 2.5.4.5.3. Portions of these Category I facilities are founded on weathered rock, natural soil, or fills. The fills are discussed in Section 2.5.4.5.4.

Underground piping was installed in trenches excavated to a minimum of 6 inches below the pipe. Soft spots and unsuitable material found at the bottom of the trenches were removed and replaced with select granular backfill, cementitious backfill, or concrete. Select granular backfill, cementitious backfill, or concrete was placed at least 6 inches below and on each side of the pipe to a minimum of 12 inches above the pipe. The remainder of the trench was backfilled with Type I fill, select granular backfill, cementitious backfill, or concrete. All Category I piping was buried with adequate cover for missile protection.

The plans, profiles, and sections showing the detailed relationship of the Category I piping to subsurface soil, fill, and rock materials are shown on Figure 2.5-37.

The diesel oil tanks and Category I electrical ducts were buried with adequate cover for missile protection. The Category I valve pits were buried, except the roof slabs, which are missile and tornado resistent and are exposed above ground. Soft spots and unsuitable material found at the bottom of the excavations for these structures were removed and replaced with cementitious

backfill or concrete. Where overexcavation occurred below these structures, the select granular, cementitious or concrete backfilling materials were used. Cementitious backfill was placed at least 2 feet below and on each side of the diesel oil tanks, to a minimum of 12 inches above the tanks. The remaining backfill to finish grade was placed using select granular backfill. The sides of the valve pits were backfilled with cementitious backfill or Type I fills. The electrical duct banks were completely encased in concrete with a minimum of 3 inches of concrete cover on all four sides. The remaining trench excavation was backfilled to finish grade with Type I or Type II fills. Section 3.8.4.1.6 contains additional discussions on these miscellaneous structures. The plans, profiles, and sections showing the detailed relationship of the Category I electrical duct banks to subsurface soil, fill, and rock materials are shown on Figure 2.5-37.

2.5.4.6 Groundwater Conditions

A detailed groundwater study of the site is presented in Section 2.4.13. Groundwater occurs at the site in the Brunswick lithofacies which consist of bedded siltstone, sandstone, and shale. Groundwater flows primarily through joints, fractures, and other secondary openings in the consolidated rock. The water table is 15-95 feet below land surface at the site. A map of the potentiometric surface, determined from water levels measured in May, 1979, indicate the groundwater levels range from el 250' east of the spray pond to el 120' southwest of the radwaste enclosure. Fluctuation of water levels in observation wells are indicated by the hydrographs in Figure 2.4-18.

Groundwater studies conducted for the spray pond include installation of permanent observation wells and the performance of 41 permeability tests. Permeability values obtained from the field tests at the spray pond are given in Table 2.4-18. The average permeabilities for various materials are as follows:

Material	Permeability (ft/yr)
Overburden	3.5
Contact Zone	14.0
Rock	214

2.5.4.6.1 Spray Pond Seepage Analysis

The spray pond makeup system has sufficient capacity to replace estimated seepage losses during normal operation. Moreover, the total volume of water in the pond itself is sufficient to accommodate estimated seepage during the 30 day transient period throughout which no makeup to the pond is assumed to be available.

Seepage losses from the pond migrate toward the Schuylkill River and to the north, as shown on Figure 2.5-23. As detailed below, estimated seepage losses from an unlined spray pond indicate that seepage from the pond would not adversely affect the safety and performance of the ultimate heat sink, nor significantly effect groundwater levels beneath the site. Nevertheless, a liner is provided.

Estimated seepage losses from an unlined pond were calculated by subtracting the natural, preconstruction groundwater underflow from the total underflow expected after the spray pond is constructed. Flows toward two discharge areas were analyzed separately because of the difference in differential heads. Two methods were used to calculate total underflow using Darcy's

Law: construction and analysis of a flow net, and computation of underflow through a peripheral cross-section.

In the first analysis, a flow net method was used in which a plan flow net was constructed as shown on Figure 2.5-23. Total flow was calculated using the equation (from Reference 2.5-42):

$$Q = \frac{n_s}{n_d} KDH \qquad \text{(EQ. 2.5-2)}$$

where:

- Q = quantity of underflow, ft^3/yr
- n_s = number of stream tubes
- n_d = number of equipotential drops
- K = permeability, ft/yr
- H = differential head, ft
- D = aquifer thickness, ft

The differential head between the spray pond surface and the Schuylkill River is 141 feet. The differential head between the spray pond surface and the northern discharge area at el 200' is 51 feet. An effective aquifer thickness of 140 feet is used because of the decrease in number and size of fractures at that approximate depth as observed in the core holes. A permeability of 200 ft/yr is used as an effective value for the residual soils and bedrock materials (Section 2.4.13.2.5).

Underflows were determined to be 5.3×10^6 ft^3/yr towards the Schuylkill River, and 1.6×10^6 ft^3/yr toward the north, giving a total underflow of 6.9×10^6 ft^3/yr.

The second method of analysis, a cross-sectional area method, uses the following form of Darcy's Law:

$$Q = KIA \qquad \text{(EQ. 2.5-3)}$$

where:

- Q = quantity of underflow, ft^3/yr
- K = permeability, ft/yr
- I = hydraulic gradient (ratio)
- A = cross-sectional area of underflow, ft^2

Using an aquifer thickness of 140 feet, the cross-sectional area through which both natural underflow and seepage from the pond is flowing toward the Schuylkill River is approximately 224,000 ft^2; the cross-sectional area through which water is flowing toward the north is approximately 168,000 ft^2. The hydraulic gradient is approximately 0.1 toward the Schuylkill River

and 0.05 toward the north. The permeability is 200 ft/yr. The rates of underflow determined by this method are 4.5×10^6 ft^3/yr toward the Schuylkill River and 1.7×10^6 ft^3/yr toward the north, giving a total underflow of 6.2×10^6 ft^3/yr.

Preconstruction natural underflow was calculated using equation 2.5-3. The hydraulic gradient (I) was determined from equipotential contours of the groundwater table measured on June 24, 1974, shown on Figure 2.5-23. The hydraulic gradient is 0.08 for flow toward the Schuylkill River, and 0.02 for flow toward the northern discharge area. The cross-sectional areas of natural underflow (A) are based on a saturated aquifer thickness of 110 feet. The permeability (K) is 200 ft/yr, as described above. Based on these parameters, natural underflow beneath the pond is estimated to be 2.74×10^6 ft^3/yr toward the Schuylkill River and 0.54×10^6 ft^3/yr toward the north. Total preconstruction (natural) underflow, then, is estimated to be 3.3×10^6 ft^3/yr, the sum of these flows.

Therefore, the estimated spray pond seepage loss from an unlined pond is:

$(6.9 \times 10^6) - (3.3 \times 10^6) = 3.6 \times 10^6$ ft^3/yr (Flow net method)

or

$(6.2 \times 10^6) - (3.3 \times 10^6) = 2.9 \times 10^6$ ft^3/yr (Cross-sectional area method)

These calculated losses would cause a decline of 0.6-0.7 feet per month in the water level of an unlined spray pond.

In both methods of analysis, the average permeability is assumed to be approximately that of rock (200 ft/yr). Because only 60% of the pond bottom is exposed to rock, and the balance is exposed to residual soils of markedly lower permeabilities, these estimates of total seepage loss from an unlined pond are probably high.

The permeability of the materials exposed within the pond is an important parameter in the seepage analysis. Bedrock, the most permeable material underlying the pond, underlies approximately 60% of the pond. Most of this rock is now covered with concrete which provides foundation and support for the spray pond piping network.

The balance of pond is underlain by overburden and the bedrock-overburden contact zone. As presented in Table 2.4-18, the 33 measured permeabilities of the bedrock (Brunswick Formation) range from 1 ft/yr to 1247 ft/yr, of which the arithmetic mean is 214 ft/yr. The location of wells where tests were performed is shown on Figure 2.4-15. The median value is 71 ft/yr, and fully 90% of the measured permeabilities in rock are less than 500 ft/yr. Only two of the measured permeabilities are more than 1000 ft/yr. The measured permeabilities from eight tests in the overburden and contact zone range from less than 1 ft/yr to 21 ft/yr (Table 2.4-18). The mean value is 7.5 ft/yr and the median is 3 ft/yr.

Section 2.4.13.1.1 points out that most groundwater flow occurs through secondary openings in the rock (fractures and joint), and the higher permeability measurements are attributed to test performed in relatively more fractured zones that are of limited extent. The 200 ft/yr used in the seepage analysis is quite conservative because: 1) it is approximately equal to the arithmetic mean of all rock permeability measurements even though this average is biased by the inclusion of the abnormally high (greater than 1000 ft/yr) permeability measurements; 2) almost half (40%) of the spray pond area is underlain by overburden or contact zone material that has a significantly lower permeability than the bedrock (average value of 7.5 ft/yr). More realistic, although still

conservative, estimates of the average effective permeability of the spray pond area might be 132 ft/yr (60% at 214 ft/yr and 40% at 7.5 ft/yr), or 173 ft/yr (the average of all permeability tests).

The spray pond includes a soil-bentonite liner on the bottom and on soil slopes, and shotcrete on rock slopes. The soil-bentonite liner is one foot thick and has a permeability of less than one ft/yr (Figure 2.5-24 and Section 2.5.5.4). The seepage loss for the lined pond is calculated to be 1.83×10^6 gal/month or 2.94×10^6 ft^3/yr (Section 9.2.6.4). The liner ensures that the actual seepage loss is acceptable by preventing higher rates of seepage through localized fracture zones in the event such conditions were found to exist.

A seepage test was performed to ensure that the design basis seepage rate assumptions were not exceeded. The test results show that, based on weekly measurements of seepage losses over a 23 week period, the average seepage loss for the entire period is between 11% and 21% of the allowable design value, depending on how evaporation losses are measured. This is equivalent to a seepage rate of about 5-9 gpm for the whole pond. Considering possible error contributions from all measurements, the upper limit of this seepage loss is estimated to be approximately 40% of allowable design value, whereas the lower limit is effectively zero. Therefore, the actual seepage loss from the spray pond is well below the allowable design value. Additional information is contained in Section 2.5.5.4.3 and Reference 2.5-145.

2.5.4.6.2 Dewatering During Construction

Groundwater presented no problem during excavation and construction in the main power block area. The water table was below most of the excavation during construction. The rock around the power block has low permeability and did not transmit significant quantities of water into the excavation. Only small amounts of seepage occurred along the walls of the radwaste enclosure excavation during construction.

This same low permeability of foundation rock caused surface run-off to collect in the foundation excavations, especially during periods of construction inactivity. For example, the rock in the excavation was more or less continuously covered with water from early 1972 to late August. In March 1972, water was standing in the excavation to about el 170', inundating the radwaste foundation area and lower parts of the reactor foundations. On July 6, 1972, rain from Hurricane Agnes raised the water level in the excavations to about el 175'; 22 days later, the water level had not noticeably declined. The run-off water was pumped out of the excavation following resumption of construction activities. These conditions further indicate the low permeability of the foundation rock.

A subdrainage system was installed for dewatering of the main power block region during construction. This system will remain permanent following construction to minimize water table height, thereby minimizing hydrostatic loading on subsurface walls. Any lowering of groundwater elevation by the subdrainage system has not been taken into consideration for design of subsurface portions of power block structures. The maximum expected water table elevations, defined in Section 2.4.13.5, were used for design.

2.5.4.6.3 Groundwater Monitoring

The water level in observation wells at the spray pond and power block area were monitored as discussed in Sections 2.4.13.2.4 and 2.4.13.4. The data obtained were used in establishing the potentiometric surface and the direction of groundwater flow. This water level monitoring,

throughout plant construction and site grading/surfacing, has indicated no changes in the groundwater flow direction. Changes in the potentiometric surface are within the plant design criteria for hydrostatic loading. Hence, the hydrologic condition is expected to remain within the design criteria during the operating life of the plant.

2.5.4.7 Response of Soil and Rock to Dynamic Loading

The responses of soil and rock to dynamic and seismic loading conditions are discussed in Section 2.5.2. Further discussion of response characteristics of soil at the spray pond site is contained in Sections 2.5.4.8 and 2.5.5.2. Soil-structure interaction considerations are discussed in Sections 3.7.1.4 and 3.7.2.4.

2.5.4.7.1 Response of Soil Along Pipelines

A soil response study was performed to determine the characteristics of ground motion induced by the SSE. This ground motion is required to evaluate the response of buried seismic Category I piping.

The stratigraphic profile along seismic Category I piping is shown on Figure 2.5-37. The pipe support conditions vary from rock to in situ soil to as much as 24 ft of Type I fill beneath the pipe.

The soil stratigraphy and properties used in the analyses are shown in Table 2.5-10. The assumed properties for Type I fill are given in Section 2.5.4.2.2.5. The shear modulus of the rock is presented in Table 2.5-11.

Soil response studies were performed using the computer program SHAKE, Reference 2.5-143. The design SSE time history with a peak acceleration of 0.159 (Section 3.7.1.2) was input at the surface of the rock. The shear modulus and damping factors were varied with strain as shown on Figures 2.5-40 and 2.5-41, in general accordance with Reference 2.5-144. The results of the analyses along with solutions for higher and lower moduli for Type I fill are given in Table 2.5-10. The results presented include peak acceleration at the level of the pipe, peak particle velocity at the level of the pipe, and natural frequency of the soil column.

2.5.4.8 Liquefaction Potential

The soil at the seismic Category I spray pond was analyzed for liquefaction potential. The soils at other seismic Category I facilities were not analyzed since these soils are not saturated and the potential for becoming saturated is negligible.

The liquefaction potential of soil in the spray pond site was analyzed for a maximum ground acceleration of 0.15 g. Because of the shallow depth of soil, the maximum induced shear stress was calculated assuming that the soil mass behaves as a rigid body, and the average equivalent shear stress was taken as 65% of the maximum induced shear stress (Reference 2.5-43).

The dynamic strength of soil was determined from the cyclic triaxial test results included in appendix J of the PSAR and is shown graphically in Figure 2.5-19. The equivalent number of uniform stress cycles is taken as five.

The soil profile below the pond bottom used in the analysis represents the most critical section. The soil profile includes a 12 inch layer of protective soil cover and a 12 inch layer of soil-bentonite

liner on top of 9 feet of in situ soil. The pond bottom and the bedrock are at el 241' and el 230', respectively.

The average induced shear stress was calculated as follows:

$$\tau_{ave} = 0.65 \frac{\gamma h}{g} a_{max} r_d \qquad \text{(EQ. 2.5-4)}$$

where:

τ_{ave} = average induced shear stress

γ = saturated unit weight of the material. The values used in the analysis were 123.8 pcf, 119.0 pcf, and 126.4 pcf for the soil cover, soil-bentonite liner, and the in situ soil respectively (Table 2.5-5)

h = depth where the induced stress is to be computed

$\frac{a_{max}}{g}$ = 0.15

r_d = correction factor (0.98 to 0.99 for shallow soil profile)

The shear strength was calculated based on the results of cyclic triaxial shear tests and equals $0.37\sigma_o$, which was obtained by multiplying the design cyclic stress ratio of 0.61 (Figure 2.5-19), the effective overburden pressure σ_o, and a correction factor of 0.60 (Reference 2.5-43).

The factor of safety was obtained by dividing the shear strength by the average induced shear stress. Since both the shear strength of the soils and the induced shear stresses are dependent on depth below ground surface, determinations of the factor of safety against liquefaction were made at various depths. The results of this analysis are summarized in Figure 2.5-25. The minimum factor of safety was computed to be 1.9.

2.5.4.9 Earthquake Design Basis

Derivation of the OBE and SSE are discussed in Section 2.5.2. The liquefaction potential and slope stability of the spray pond are analyzed for the SSE event.

2.5.4.10 Static Stability

The reactor enclosures, control structure, diesel generator enclosure, spray pond pump house, spray networks, turbine enclosures, and radwaste enclosure are founded on sound, unweathered bedrock. Seismic Category I facilities not founded completely on unweathered bedrock include the spray pond, underground piping, diesel oil tanks, valve pits and electrical ducts. Portions of these facilities not founded on rock are founded on natural soil and/or manmade fills.

The strength of the unweathered bedrock amply accommodates the loads of the plant, providing highly stable foundation conditions. As measured by seismic refraction surveys in the area of the principal plant structures, compressional wave velocities range from 7000-20,000 fps, averaging about 12,500 fps; shear-wave velocities range between 5800 fps and 6100 fps. An up-hole survey

(Figure 2.5-21) measured a compressional wave velocity of 12,600 fps in the siltstone beneath the site. Unconfined compression test results on rock core samples (Table 2.5-3) range from 460-1760 tons/ft^2, with an average of about 1140 tons/ft^2. Poisson's ratio is calculated to be about 0.3 (Table 2.5-11). Static moduli derived from additional compression tests on rock cores range from 1.2x10^6 psi to 8.3x10^6 psi, averaging 4.1x10^6 psi; compressive strengths range from about 580-2370 tons/ft^2, averaging 1230 tons/ft^2 (Table 2.5-12). Unconfined compressive strength and elastic modulus determinations substantially followed ASTM D2938-71 and ASTM D3148-72, respectively, which were adopted after these tests were completed.

Plate bearing tests (ASTM D1194-57) were run by Dames and Moore at the site (Reference 2.5-50); the results are quite variable. Values of the Secant Modulus of Deformation at first loading, which includes plastic and elastic deformation and also reflects the closing of joints and fractures, ranges from 30,000 psi to 200,000 psi, with an average of 85,000 psi. The Secant Modulus of Elasticity at second loading is much higher, with an average value of 356,667 psi.

A bearing capacity of 30 tons/ft^2 (60 ksf) for static and frequently applied live loads on sound rock is used for design, following recommendations by Dames and Moore (Reference 2.5-51). Actual loads induced by the plant structures founded on bedrock are much less than the allowable bearing pressure of the foundation rock, and they are far below the ultimate bearing capacity. The structural loads produce no significant total or differential settlement of the foundations.

The design lateral earth pressure acting on subsurface walls of seismic Category I structures was computed assuming granular backfill having the properties stated in Section 2.5.4.5.4. The coefficient of earth pressure "at-rest" was used. In addition, the walls were designed for surcharge loadings and dynamic soil pressures as appropriate. The typical pressure diagrams and combinations are shown on Figure 2.5-39.

2.5.4.10.1 Static Stability of Safety-Related Structures on Rock

The following sections contain information regarding static and dynamic lateral earth pressures and groundwater loads on the reactor enclosure, control structure, diesel generator enclosure including pipe tunnel, and spray pond pumphouse, which are all founded on bedrock. Table 2.5-9 includes safety-related structures, dimensions of foundations, approximate bearing elevation, design bearing pressure, and hydrostatic pressure. Seismic Category I structures not founded on rock are discussed in Section 2.5.4.10.2.

2.5.4.10.1.1 Diesel Generator Enclosure Including Pipe Tunnel

The exterior and interior foundation walls of the diesel generator enclosure are founded on bedrock (Figure 3.8-61). The interior walls support the base slab at el 217'. The space between the bedrock and the bottom of the base slab is backfilled with fillcrete. Concrete backfill surrounds all subsurface walls and extends to the rock profile such that there will be no transmissibility of lateral pressures to the walls.

The pipe tunnel is a concrete box section with the base slab founded on bedrock. The north wall lies parallel to the adjacent reactor enclosure wall and is separated by a 1 inch seismic gap. The west and east tunnel walls are separated by 1 inch seismic gaps from the adjacent radwaste enclosure and auxiliary boiler enclosure. The south tunnel wall was designed as a restrained retaining wall to resist the lateral earth pressure due to backfill which has a saturated unit weight of

140 pcf, an at rest earth pressure coefficient of 0.7, a surcharge of 250 psf due to AASHO H-20 truck loading, and a dynamic lateral force due to seismic loading as shown on Figure 2.5-39.

The box section was also designed for the lateral earth pressure resulting from the Cooper E-72 railroad loading, the live load on the roof, and the seismic load.

Because the high-water table elevation is below that of the foundation in the power block region, there are no groundwater loads acting on the foundations of the diesel generator enclosure.

2.5.4.10.1.2 Reactor Enclosure and Control Structure

The reactor enclosure and control structure are separated from the surrounding Type I fill by adjacent structures or pipe tunnels.

The reactor enclosure and control structure are bounded to the north and west by two nonseismic Category I structures (the turbine enclosure and the radwaste enclosure). The south and east sides of the reactor enclosure and control structure are bounded by pipe tunnels. The adjacent structures and pipe tunnels, founded on competent bedrock, extend up to or above plant grade el ±217'. Those subsurface exterior walls of the reactor enclosure and control structure, lower than the foundation grade of adjacent structures, are placed adjacent to excavated rock slope with Class A concrete or fillcrete backfilled between the face of the wall and the face of the rock slope. Because of the conditions described above, lateral earth pressure is not considered in the design of the exterior walls.

The walls of the control structure and reactor enclosure have been designed for a hydrostatic pressure up to el 195', which is the expected maximum water table elevation in this region.

2.5.4.10.1.3 Spray Pond Pumphouse

The foundation mat and walls of the spray pond pumphouse are founded on bedrock (Figure 3.8-62). Exterior walls along the east, west, and south sides are placed adjacent to excavated rock slopes with Class A concrete or fillcrete backfilled between the face of the wall and the face of the rock slope. The exterior wall along the north side extends to the bottom of the spray pond with no embedment. Because of the conditions discussed above, lateral earth pressure is not considered in the design of the exterior walls.

The north wall of the water pit area has been designed to resist hydrostatic pressure (from el 236' to el 267') and lateral seismic loads. The foundation mat has been designed for the same hydrostatic pressure as the north wall in combination with other concurrent loads.

2.5.4.10.1.4 Diesel Oil Tanks

These tanks are located on a base slab founded on weathered rock or cementitious backfill bearing on weathered rock as shown in Figure 2.5-37. The associated valve pits located on top of the tanks are founded on cementitious backfill, which also acts as backfill around the tanks. The cementitious backfill has a minimum compressive strength of 80 psi. The remaining portion is backfilled with select granular fill placed and compacted as discussed in Section 2.5.4.5.4.

Railroad tracks were located on top of select granular fill. The base slab bearing pressure is 5410 psf, which includes all dead and live loads and the Cooper E-80 railroad loading. The bearing

pressure on the foundation of the valve pits, including dead loads and AASHO H-20 truck loading, is 2830 psf. The allowable bearing capacities of the rock and cementitious backfill are not exceeded by these pressures.

The walls of the valve pits are designed to resist lateral loads due to backfill having a saturated unit weight of 140 pcf and an at rest earth pressure coefficient of 0.7, AASHO H-20 truck surcharge, and dynamic lateral loading due to a seismic event. The roofs of the valve pits are adequately designed to resist AASHO H-20 truck loading and tornado depressurization or missile impact. Because the tanks are founded on bedrock or dense natural soil, the amount of settlement is considered to be insignificant.

As an additional protection against flotation, the tanks are adequately tied to the base slab by holddown straps. For this purpose, the tanks are assumed to be submerged completely in water.

2.5.4.10.2 Static Stability of Safety-Related Structures on Soil

The following sections discuss seismic Category I facilities not founded completely on unweathered bedrock. There are no groundwater loads acting on the foundations of the spray pond, underground piping, diesel oil tanks, valve pits, or electrical ducts because the high water table elevation is below these foundations. Table 2.5-9 includes safety-related structures, dimensions of foundations, approximate bearing elevation, design bearing pressure, and hydrostatic pressure.

2.5.4.10.2.1 Spray Pond

The sustained load from the spray pond is less than the weight of overburden removed; therefore, there is an adequate factor of safety against overstressing the underlying soil (Figures 3.8-55, 3.8-56, and 3.8-57). Soil rebound during excavation for the spray pond is insignificant. Section 2.5.5 contains a discussion of slope stability under static and seismic conditions, including the design parameters and test results of soil exploration.

2.5.4.10.2.2 Underground Piping

The method used for installation of underground piping is discussed in Section 2.5.4.5.5. The placement of backfill is discussed in Section 2.5.4.5.4. All buried pipes satisfy the diameter-to-thickness ratio (<300) requirement in accordance with Reference 2.5-52. Therefore, piping deflection due to earth load will not exceed the allowable. In addition, in accordance with table 1 of Reference 2.5-52, deflections due to AASHO HS-20 loading with the minimum required cover of 4 ft are less than the allowable deflections. Process piping located under railroad tracks that are not encased in concrete are approximately 12 ft below-grade. Therefore, the deflection due to Cooper E-80 railroad loading will not exceed the allowable. The more conservative E-80 loading was used in design for required railroad loadings outside of safety-related structures.

2.5.4.10.2.3 Valve Pits

The valve pits for the RHR and ESW piping (Figure 3.8-64), which are not founded directly on bedrock, fall into the following categories:

a. Valve pits founded on concrete backfill with a minimum compressive strength of 2000 psi, which bears on bedrock

b. Valve pits for diesel oil storage tanks shown on Figure 2.5-37 are founded on cementitious backfill with a minimum compressive strength of 80 psi, which bears on weathered rock.

c. One valve pit (located near RHR and ESW piping for Unit 2 as shown in Figure 2.5-37, coordinates N5819.5, E4205.0) is supported on cementitious backfill which bears on natural soil, with minimum bearing capacity of 6000 psf.

The valve pits are designed for AASHO HS-20 truck loading. The maximum calculated pressure under the base slabs is 2440 psf.

The walls of the valve pits are designed to resist lateral loads due to backfill having a saturated unit weight of 140 pcf and an at rest earth pressure coefficient of 0.7, and a surcharge of 250 psf due to AASHO HS-20 truck loading and lateral force increment due to seismic loading as shown on Figure 2.5-39. The roofs of the valve pits are adequately designed to resist AASHO HS-20 truck loading, tornado depressurization or missile impact. Because the valve pits are founded on concrete or cementitious backfill, the amount of settlement is considered to be insignificant.

2.5.4.10.2.4 Electrical Ducts

Electrical ducts are encased in Class A concrete having a minimum design strength of 2000 psi. The ducts are buried a minimum of 4 ft below finished grade with Type I or II fill placed on top and compacted as described in Section 2.5.4.5.4. The duct banks are founded on either bedrock, weathered rock, dense natural soil or compacted Type I fill. Where the bottom of the trenches were overexcavated, they were backfilled under the ducts with a minimum of 6 inches of either select granular, cementitious, or concrete backfill.

Select granular, cementitious, and concrete backfill are described in Section 2.5.4.5.4.

All Class I electrical ducts have a minimum 4 ft of backfill on top, which has been found adequate for Cooper E-80 loading without causing significant settlement or loading of ducts or foundation.

2.5.4.11 Design Criteria

2.5.4.11.1 Design Criteria For Safety-Related Structures on Rock

The plant structures founded on rock are designed for a maximum acceleration of 0.15 g from an occurrence of the SSE event. From consideration of its engineering properties, it is evident that the foundation rock would not be measurably affected by seismic loadings, and negligible additional foundation settlement would accompany these maximum potential dynamic loads. The maximum contemplated total static and dynamic loads are only a fraction of the bearing capacity of the rock, thus ensuring an ample margin of safety.

2.5.4.11.2 Design Criteria For Safety-Related Structures on Soil

The design criteria and methods of design concerning the liquefaction potential of soil at the spray pond are discussed in Section 2.5.4.8. The design criteria and stability analyses of the spray pond slopes are discussed in Section 2.5.5.2.

2.5.4.12 Techniques to Improve Subsurface Conditions

2.5.4.12.1 Treatment of Fracture Zones and Clay Seams - Main Power Block Area

During excavation of the main power block area, three fracture zones and two clay seams were encountered in the foundation rock. The locations of these zones are shown on Figure 2.5-13. The zones are described in Section 2.5.1.2. Treatment of these zones during construction is described below.

2.5.4.12.1.1 Criteria for Treatment of Fracture Zones and Clay Seams

As outlined in the PSAR, the criteria for treatment of the steeply dipping fracture zones are to: excavate soft or excessively fractured material in the zones under footings to a depth below foundation grade that is at least equal to the width of the undesirable material at foundation grade; slope the sides of these excavations so that they become narrower downward; extend this excavation beyond the edges of footings crossing the fracture zones; and replace the excavated material with concrete. This dental treatment is designed to replace the compressible material under footings with a wedge of concrete that transfers vertical loads laterally to the adjacent sound rock on each side of the zone, to confine this adjacent rock, and to reduce unit loads by extending the bearing area beyond the edges of walls and columns.

The criteria for treatment of a clay seam, except under column footings, are to determine the thickness of soft, compressible material in the seam at its intersection with foundation grade and to treat the seam only if the compressive material is ¾ inch or more thick. Under wall footings, treatment consisted of removing the compressible material in the seam and the rock above it, to provide a minimum of 3 feet of sound rock between the bottom of the footing and the seam. The material removed was replaced with concrete. Isolated column footings do not span the intersection of the clay seam with foundation grade; where this situation could occur, the clay seam and all rock above it were removed under the column footing and replaced with concrete so that all of the footing is founded on rock below the seam. Where the clay seam was not treated, compressible material in the seam is thin (¾ inch or less). This material commonly contains hard rock fragments; thus, the total consolidation resulting from it is very slight. Also, the consolidation occurs rapidly after loading and is completed before the structures are finished.

2.5.4.12.1.2 Treatment of Fracture Zone A

The location, attitude, and width of Zone A at final foundation grade are shown on Figure 2.5-13. The zone is described in detail in Section 2.5.1.2. Fracture Zone A trends generally N 40° to 45° E and dips from 70° to vertical.

Zone A is locally over 10 feet wide at ground surface, but narrows rapidly with depth. Weathering along the zone decreases with depth, and the fractures often converge with depth. At foundation grade, weathered, soft material between fracture surfaces is usually thin, or absent entirely. As a result, Zone A usually is minor in extent at foundation grade, and does not normally require treatment under thick, stiff, reinforced footings, since such footings could span over a narrow, steeply dipping zone. It was treated under wall footings of Category I structures, however,in accordance with the criteria presented in the PSAR.

Photo 1 (figure 13A) of Figure 2.5-13 shows a typical section of Fracture Zone A at foundation grade. Photo 2 (figure 13B) of Figure 2.5-13 shows the type of excavation performed for dental concrete placement. Photo 3 (figure 13C) of Figure 2.5-13 shows placement of dental concrete at "Mh" and "N" lines.

2.5.4.12.1.3 Treatment of Fracture Zone B

Fracture Zone B occurs at the southeast corner of Unit 2 reactor enclosure, as shown on Figure 2.5-13. The zone trends N 30° E and is nearly vertical. It contains from 2-10 inches of crushed, weathered rock and plastic clay. The rock on the southeast side of the zone shows an apparent displacement of 8-10 inches downward relative to that on the northwest side. Zone B is treated in the same manner as Zone A. Dental excavation for Zone B at "D" line is shown on Photo 4 (figure 13D) of Figure 2.5-13. Photos 5 and 6 (figures 13E and 13F) of Figure 2.5-13 show Zone B before and after dental excavation for the column footing at the intersection of lines F and 31.9.

Treatment excavation is performed using picks, shovels, and a backhoe with a hydraulic breaker. The excavation is deeper and wider than the actual fracture zone in order to obtain a wedge effect into the zone. This wedge was created as shown on the photographs of Figure 2.5-13. The excavation continues past the column footing in order to increase the bearing area under the footing.

2.5.4.12.1.4 Other Fracture Zones

Another less significant fracture zone was exposed in the excavation between Zones A and B and north of "J" line. Its location and description are shown on Figure 2.5-13. This zone contains from less than 1 inch to a maximum of about 4 inches of soft material, and they are nearly vertical; consequently, they required no special foundation treatment. The adjacent rock is hard and strong, although sometimes closely jointed, and can easily support the loads imposed by the structures. As noted on Figure 2.5-13, this zone shows slight offsets of several inches.

2.5.4.12.1.5 Treatment of Clay Seams

The clay seam in Unit 1, described in Section 2.5.1.2, is hereafter referred to as Seam 1. A second clay seam, hereafter referred to as Seam 2, is stratigraphically lower than Seam 1 and intersects foundation grade in part of Unit 2. These seams occur along shaly beds that are relatively softer than the adjacent hard siltstone. As mentioned in Section 2.5.1.2, there has apparently been some shearing along these seams, since they show slickensides and some crushing.

Seam 1 has a maximum thickness of about 10 inches near the top of rock south of Unit 1, but its thickness decreases rapidly downdip, so that under Unit 1, it is generally less than about 1½ inches thick, and in places, it is barely discernible, Where the seam contains clay, it also usually contains rock fragments.

As described in the PSAR, three large diameter core holes were drilled downdip from the seam's exposure on excavated rock surfaces to verify that the seam continues to become thinner downdip. These holes show the seam to be no more than ¾ inch thick.

Figure 2.5-13 shows the approximate trace of Seam 1 on the excavated rock surface in the radwaste building and in Unit 1. Normal excavation extends below this seam in Unit 2, as the rock tends to break naturally to the seam, and cleanup and foundation preparation removed the seam northward to the "J" line. Thus the trace of the seam is at the toe of the excavated slope near the "J" line.

Under the mat for Unit 1, clay in Seam 1 has a maximum, thickness of less than ½ inch. Where this seam intersects grade, the thin silver of rock above the seam tends to break naturally to the

seam and was removed during the normal foundation preparation. Special treatment for Seam 1 was done in only one area, under the footing for column F-15.5. Here, all the rock above the seam was removed under that footing. Elsewhere, Seam 1 is so thin that no treatment was required.

The second clay seam, Seam 2, occurs along a relatively soft, thin shaly bed that is stratigraphically lower than Seam 1.

Soft material in Seam 2 is usually only about ¼-½ inch thick where exposed in foundations or excavated slopes, and it consists of plastic clay with shaly, sheared rock fragments. Seam 2 was removed under several column footings in Unit 2. At columns F-31.9, H-31.9, F-30.5, and H-30.5, all the rock above Seam 2 was removed (the footings rest on rock below the seam).

2.5.4.12.1.6 Summary and Conclusions on Treatment of Fracture Zones and Clay Seams

The fracture zones, although narrow and steeply dipping, have been conservatively treated to preclude the occurrence of any significant settlements due to these zones. They pose no threat to the stability of slopes after the structures are completed. The stresses that caused the fracture zones, and the other fractures and joints in the foundation rock, no longer exist and have not existed for millions of years. The faults near the site have been inactive for millions of years, as documented in the PSAR and the geologic report prepared by Dames and Moore in 1974 (Reference 2.5-1).

The two thin clayey seams along bedding were carefully evaluated in the foundation rock and they were treated under some column footings. Settlement due to consolidation of clay in untreated seams is negligible, since the clay is so thin. Any consolidation of the clay will have occurred before the structures are completed.

2.5.4.12.2 Treatment of Fracture Zones and Clay Seams - Spray Pond and Other Areas

No special treatment of foundation rock was required at the spray pond. The foundations for the spray pond pumphouse, overflow structure, and spray network pipe supports were excavated to unweathered bedrock.

Two bedding-plane clay seams, generally not exceeding 1 inch in thickness, were encountered one of which trends across the bottom of pond excavation (Figure 2.5-42). Where exposed in the excavations for the spray networks, the seam was excavated below foundation grade whenever it was overlain by less than one or two feet of firm rock. At the eastern spray network (network "B") the seam was slightly thicker and additional overlying rock was removed beneath the pipe support footings (Figure 2.5-42). At the spray pond pumphouse excavation, this seam was not exposed on bearing rock except in the western abutment trench, in which case all rock overlying the seam was removed.

A considerable amount of soil and soft, weathered rock was overexcavated at the western spray network (network "C"), and replaced by up to 14 feet of backfill concrete (section A-2 of Figure 2.5-43). Small amounts of broken or weathered rock were also removed as locally required along minor east-west trending fracture zones (Figure 2.5-42).

The entire bottom of the spray pond whether underlain by soil or rock, and the soil slopes below the elevation of the perimeter service road, are covered with a soil-bentonite liner (Section 2.5.5.4). The spray pond rock-cut slopes are covered with shotcrete. The shotcrete extends below the soil-

bentonite liner to provide a suitable transition zone. A plan and typical sections are shown on Figure 3.8-57.

2.5.4.13 Subsurface Instrumentation

Subsurface instrumentation is not required at the site. Load- bearing safety-related structures are founded on competent bedrock. The properties of the bedrock are presented in Section 2.5.4.2.1. Instrumentation for surveillance of rock foundations was not installed for the reasons described in Section 2.5.4.5.

2.5.5 STABILITY OF SLOPES

Natural slopes at the site are shown on the Site Plan, Figure 2.1-3.

There are no steep or unstable natural rock slopes within the plant boundaries that would have nay adverse effect on the safety-related operation of the LGS plant. Although excavated rock slopes could be cut vertically, the rock would eventually weather and ravel to a flatter slope with time. Therefore, all permanent excavated rock slopes are either cut on a gradient no steeper than 1 horizontal to 1 vertical, or they have engineered backfill placed against them to provide additional stability. The only permanent exposed rock slopes that could affect safety-related structures are those in the spray pond excavation.

The soil slopes considered are the excavated soil slopes in the spray pond. In addition, the dikes surrounding storage tanks are discussed in Section 2.5.5.5.

2.5.5.1 Slope Characteristics

The spray pond was constructed primarily by excavation. The spray pond is designed for the water level to be at el 251' and for the bottom of the pond to be at el 241'. Because of the sloping bedrock surface, the bottom of the pond is located in both soil and rock. The top of the rock is shown on Figure 2.5-9. Cut slopes are 4 horizontal to 1 vertical in soil and generally 1 horizontal to 1 vertical in rock, with a bench at the soil-rock interface. A short section of weathered rock is excavated at 2 horizontal to 1 vertical.

The bottom of the spray pond, excavated in both soil and rock, and soil slopes below the perimeter service road (at el 255') are covered with a 12 inch thick liner of a soil-bentonite mixture (Figure 2.5-24). The liner is protected by a 12 inch thick soil cover to reduce the possibility of the liner drying and cracking and to prevent damage from equipment during construction and maintenance. The design and construction of the soil-bentonite liner and soil cover are discussed in Section 2.5.5.4.1. In order to prevent erosion due to wave action, the liner and soil cover at the soil slopes are protected by a 12 inch thick layer of riprap bedding and an 18 inch thick layer of riprap. The gradation and placement of the riprap and riprap bedding are discussed in Section 2.5.5.4.2. Rock slopes are covered by shotcrete, which extends below the soil-bentonite liner in the bottom of the pond. A plan and typical sections of the slopes are shown on Figures 2.5-48 and 2.5-49.

2.5.5.1.1 Geologic Conditions

Rock at the site consists of well-indurated, gently dipping sandstone, shale, and siltstone of Triassic-age. Bedding dips 8° to 20° to the north, with only minor local variations. Two major joint systems are prevalent in the area. Both are vertical or nearly vertical; they strike approximately N

20° to 50° E and N 50° to 60° W. Three fracture zones and two clay seams were encountered in foundation excavations in the main power block area; they are described in Section 2.5.1.2.5.

Bedrock is overlain by from 0 feet to about 40 feet of residual soil, developed in situ by the gradual decomposition of the parent rock. No clearly defined boundary between soil and rock exists, as the soil grades into fresh, unweathered rock.

The spray pond is underlain mostly by Lockatong lithofacies beds, except at the southeastern and northwestern margins of the pond (Figure 2.5-42). The Lockatong rocks are characterized by black shale and associated fine-grained, variably calcareous beds deposited in a lacustrine or swampy environment, in contrast to the sandier, typically red beds of the Brunswick Formation. Two prominent black shale or claystone beds, neither exceeding about 4 feet in thickness, were exposed and mapped in the spray pond excavation (Figure 2.5-42). These same beds had been recognized and logged from rock cores during the initial 1969-1970 site exploration by Dames and Moore (see log for Boring 150, Figure 2.5-22).

Joints exposed at the spray pond trend northeast and northwest, the former being dominant. A third prominent joint set trending approximately east-west in the Brunswick sandstone beds tends to be more widely spaced and shows irregular fracturing in the Lockatong (Figure 2.5-42). Major north-south jointing is locally prominent near the middle of the excavation (spray network "D"). Generally, any particular joint was found to be confined vertically to a single bed or series of lithologically similar beds.

Only a few minor offsets were noted in the excavation, along near-vertical joints and fractures. They are described in detail in Section 2.5.1.2.5.

Slickensides are locally abundant in the spray pond excavation. They occur almost without exception as dip-slip striations on curved, gently-to-moderately dipping joint surfaces, in beds that overlie claystone or shale units in the Lockatong. Where observable in profile at vertical cuts within the excavation, these curved joint planes wee seen to terminate downward at the contact with the underlying shale. It is therefore concluded that the slickensides arise from slight differential movement related to compaction of the shales during diagenesis and have no tectonic significance. Figure 2.5-42 shows typical occurrences of these slickensides.

2.5.5.1.2 Exploration - Emergency Spray Pond

The exploration for the site is presented in Section 2.5.4.3. Exploration for the emergency spray pond is discussed detail in this section.

2.5.5.1.2.1 General

The exploration for the emergency spray pond was conducted in three phases. The first phase, conducted during May and June, 1973, consisted of 5 NX core holes and 43 auger holes to define the bedrock surface. The second phase, carried out in April and May, 1974, consisted of 25 borings and 4 test pits to obtain undisturbed soil samples in the spray pond area. The third phase, conducted in March, 1977, consisted of 13 test pits to investigate the soils for use in constructing the soil-bentonite liner.

2.5.5.1.2.2 Phase 1 Exploration

Borings in the first phase were made by American Drilling Company of East Providence, Rhode Island. In order to define the bedrock surface, 43 auger holes were drilled in the spray pond area.

The contours of the top of the bedrock are shown on Figure 2.5-9. Five NX core holes were drilled to determine the bedrock lithology, structure, and foundation conditions at the intake structure.

2.5.5.1.2.3 Phase 2 Exploration

The Phase 2 exploratory borings were also made by American Drilling Company. Block samples from test pits were taken by Geotechnical Engineers, Inc. of Winchester, Massachusetts.

Twenty-five borings were made around the perimeter of the spray pond. The locations of these borings are shown on Figure 2.5-26. Both disturbed and undisturbed samples were obtained in all holes. Disturbed samples were obtained using a standard split spoon sampler (ASTM D1486). Undisturbed samples were obtained using Shelby tubes and a Denison sampler equipped with a 3-7/8 inch ID, 24 inch long brass tube liner. Four test pits were dug to obtain undisturbed block samples. Their locations are shown on Figure 2.5-26.

Laboratory testing of soil samples was carried out by Geotechnical Engineers, Inc. All test results are given in a soil testing report from Geotechnical Engineers, Inc (Reference 2.5-39) and they are briefly discussed in Section 2.5.4.2.2.

Figures 2.5-27 through 2.5-29 show typical subsurface cross-sections through the spray pond.

2.5.5.1.2.4 Phase 3 Exploration

Thirteen test pits were excavated at the spray pond site in March, 1977 to investigate the soils for use in constructing the soil-bentonite liner,. The locations of the test pits and the generalized soil profiles are shown on Figure 2.5-30. Bulk samples of soils suitable for constructing the soil-bentonite liner were taken from each of the test pits, except for one pit where suitable soil material was not encountered. A more detailed discussion on exploration and sampling is given in Section 2.5.5.4.1.1.

Laboratory testing of soil samples and soil-bentonite mixtures was carried out by Geotechnical Engineers, Inc. All test results are given in a July, 1977 report on soil-bentonite mixtures that was prepared by Geotechnical Engineers, Inc. (Reference 2.5-44).

2.5.5.1.3 Laboratory Testing of Soils

The results of laboratory testing of undisturbed samples of soil from the spray pond site are presented in Section 2.5.4.2. The results of laboratory testing of soil-bentonite mixtures for the pond lining are presented in Section 2.5.5.4.

2.5.5.2 Design Criteria and Analyses

The design analyses for the spray pond include seepage analyses, liquefaction potential evaluation of the soils in the pond, and stability of the side slopes. The seepage and the liquefaction evaluation are presented in Sections 2.5.4.6 and 2.5.5.8, respectively. The analysis of the stability of the pond side slopes is provided in this section.

2.5.5.2.1 Stability of Rock Slope

Rock slopes at the spray pond are cut no steeper than 1 to 1. The slope in partly weathered rock west of the spray pond pumphouse is at 2H to 1V. Weathered bedrock elsewhere is cut at the

same slope as the soil, 4H to 1V. The height of the 1:1 rock slope varies from zero to about 20 feet. The bench at the top of the 2:1 rock slope is about 13 feet above bottom of pond excavation (11 feet above the top of the soil liner). The location of rock slopes at the spray pond are shown on Figure 2.5-48; Figure 2.5-49 shows representative rock slope profiles.

Stability of rock slopes is influenced primarily by the orientation of bedding attitudes with respect to that of the slope. Bedding dips quite uniformly at about 10° (range 8° to 13°) to the northwest (N 20° W; strike N 70° E). Major joint trends are nearly east-west and NE-SW. Minor or locally prominent joints trend northwest and north-south. The great majority of these joints are nearly vertical.

Major consideration was given to stability of slopes on the south side of the pond, where beds dip uniformly out of the slope at about 10° to 11°. Because the strike of beds is nearly parallel to the slope, potential failure would occur as a sliding block; prominent east-west joints, together with additional joint sets described above, would provide cohesionless release surfaces for the slide. Simple single-plane, two-dimensional static analysis is therefore appropriate. Seismic loading is conservatively represented as the design SSE acceleration (0.15 g) applied to the entire mass of the assumed failure block, parallel to the maximum dip direction. Such a representative overestimates actual earthquake loading of the slopes and is therefore conservative.

1 to 1 Slope East of Spray Pond Pumphouse. Rock along the slope east of the spray pond pumphouse consists of highly competent, indurated (Calcareous) siltstone and fine-grained sandstone (section E of Figure 2.5-49). The entire slope required excavation by blasting; the in situ rock here resisted attempts at removal by heavy, single-toothed ripping equipment. It is likely that its strength exceeds typical values of unweathered foundation rock (Table 2.5-11). Prominent but widely spaced east-west joints, together with relatively thick bedding, resulted in a steplike slope profile; the average width of the steps which form due to breaking along bedding-planes is more than 1 foot. The rock, thoroughly examined for evidence of clayey or shaly interbeds or partings, displays no evidence of these features.

An assessment of the stability of this slope was made by calculating the angle of internal friction required along bedding-planes to achieve stability, assuming no cohesion on these planes. Although the water table, presently well below the bottom of the pond, is not expected to be significantly affected by any seepage from the pond during operation of the plant, the slope behind the pond was conservatively assumed to be saturated (water table at el 251') for purpose of calculation (actually the weight of water in the pond would enhance the stability of the unsaturated slope). During rapid drawdown under static conditions, the water level behind the slope is assumed to remain at that elevation, and the toe is assumed to be undrained. Under assumed maximum seismic loading, a friction angle of only 25° or less would be sufficient to maintain stability at a safety factor of 1.25 if cohesion is assumed to be zero. This value is much lower than any reasonable coefficient of friction to be expected for the strength of bedding in this rock. In addition, significant cohesive strength is present, for otherwise beds could have been excavated by ripping. Based on the above analysis, the slope east of the spray pond pumphouse is considered to be highly stable.

2 to 1 Slope West of the Spray Pond Pumphouse. The rock in the 2 to 1 slope west of the spray pond pumphouse (section F of Figure 2.5-49) is slightly to moderately weathered, most generally in the upper part of the slope. Jointing is generally well developed, parallel to the slope and in NW-SE and NE-SW orientations. At two intervals of strata exposed in the slope, bedding-planes with brown, thin clayey films or partings about one millimeter thick on them occur. (X-ray analysis of

similar brown clay from partings in rock exposed in the spray bank area indicate that kaolin constitutes most of the clay mineral content.) Bedding-planes are not perfectly planar but undulate on the order of several millimeters to several centimeters. The amplitude of these asperities with respect to the thickness of the clay film should impart a relatively high initial coefficient of friction against sliding, but it is difficult to quantify this effect. For stability calculations, initial friction angle was conservatively estimated to be 20° along the bedding-planes; for additional conservatism, the planes were assumed to be cohesionless although some cohesion occurs along the bedding (all detached blocks of rock were removed during cleaning of the slopes). Maximum weight of the sliding mass is calculated by assuming failure at the toe of the slope (el 239', below pond liner), the failure plane extending back under the 4:1 slope in soil above the rock. Factors of safety were computed for the following conditions:

	CONDITION	POND	SLOPE	LOADING
a.	rapid drawdown	empty	saturated	static
b.	operation	full	saturated	seismic
c.	operation	full	drained	seismic

Water table levels and hydrostatic pressures are assumed to be the same as described above for the 1:1 slope. The calculations indicate that if rock bolts were not installed and shotcrete was not applied, a portion of the 2:1 slope would be unstable under rapid drawdown conditions and under seismic loading, provided that all of the numerous conservative assumptions are correct. In general, the weak bedding-planes described are exposed in the middle or upper part of the slope, whereas stability calculations assumed that the weak plane occurs at the toe of the slope.

Two lines of rock bolts were installed in the 2:1 rock slope to stabilize the two bedding-planes prior to placing shotcrete. Bolts were tensioned to 25 kips and spaced an average of 5 feet apart on the slope. A total of 38 rock bolts, 10 feet long, were installed.

The shotcrete on the rock has a significant stabilizing effect against sliding failure on weak bedding-planes because of its bond strength to rock and its shear strength. Slope failure would initiate along a bedding-plane where the plane forms a bench in the overall slope (Figure 2.5-49). The shotcrete will be thickest at this location of the potential site of movement, at the intersection of a vertical rock face and a bench (a leveling course of shotcrete was applied to fill in rock re-entrants and overhangs). It is calculated that about 45 kips force per linear foot of slope would be required to shear the 3000 psi shotcrete, minimum 4 inches thick, assuming shear strength at 600 psi.

Shotcrete bond strength to rock of at least 100 psi or 14 kips per linear foot of slope is calculated to be resisting slope failure where there is a bench width of 1 foot in front of the failure plane; this is somewhat less than the average width measured in the field. It is important to note that the weakest and most prominent bedding-planes consistently form the widest benches in the slope, as would be expected. Good rock-to-shotcrete bond was assured during preparation of the slope for shotcreting by air-water jetting to remove loose and clayey material from the rock surface.

Table 2.5-7 shows the factors of safety against sliding under various conditions, considering the effect of rock bolts, and of rock bolts and shotcrete; the latter is the present condition of the pond. The minimum factor of safety computed for the conservative assumptions made for the stability

analyses is 4.5. If cohesion of only 5 psi is assumed along the failure plane, the minimum factor of safety is increased to over 10.

The weakest bedding-plane in the excavation is at the eastern end of the 2:1 slope. A soft, black seam of clay about 1 inch thick was barely exposed (no more than 2 inches above bottom of pond) at the extreme northwestern corner of the spray pond pumphouse excavation; the plane dips below bottom of the excavation slope in a westward direction along the toe of the slope. Rock surfaces are exceptionally smooth and planar on each side of the seam. The clay fraction is mostly smectite (expandable clay) as determined by x-ray analysis.

Potential slope instability at this location is effectively eliminated by the buttressing provided by the header pipe footing (section G of Figure 2.5-49). The excavation for the footing, approximately 15x15 feet, was extended to hard, competent rock below the soft clay seam. The surface was thoroughly jetted with water and cleaned prior to placement of Class A concrete backfill. The footing and backfill concrete along with the rock below the bottom of the pond act as a buttress against possible sliding by virtue of the bond strength between concrete and competent rock and the passive resistance of the rock against which the Class A concrete was placed. Typical bond strength between concrete and the rock underlying the footing is more than 200 psi. Assuming a bond strength of only 100 psi, the footing affords a resistance of over 3,000 kips against slope failure, not including the frictional effect of load on the footing or the passive resistance of the rock at the north edge of the footing. Furthermore, substantial resistance against sliding is provided by Class A concrete backfill between the edge of the pumphouse excavation and the pumphouse wall (Figure 2.5-48). This concrete backfill, placed against the irregular edge of rock above the clay seam, helps to lock the rock mass in place.

A calculation was made of the force required to stabilize the slope against sliding on the soft clay seam at the extreme eastern end of the 2:1 slope, neglecting the stabilizing effects of the footing and concrete backfills. Assumptions are the same as described above, except that the angle of friction of the clay seam is assumed to be 8°, with cohesion being zero. The section of slope considered is about 35 feet long, the portion where there is less than 2 feet of competent rock covering the plane at the toe of the slope (the shear strength of this rock is not considered in the calculation). Maximum force required to achieve stability is about 12 kips per foot, or a total of approximately 430 kips, compared to the resisting strength of the header pipe footing of over 3000 kips.

On the north side of the spray pond, beds dip into the slope producing an inherently stable slope configuration. The east slope of the pond bedding has a shallow apparent dip out of the slope only in the southeast segment where the competent rock, which required blasting, is exposed. Thus, slope instability along bedding is not a concern in these areas.

Consideration was given to toppling failure of portions of the slopes where vertical joints isolate columns of rock. The shallow angle of the excavated slopes is not conducive to such failure, and the continuous layer of shotcrete and wire mesh ties the rock together and eliminates any concern for failure due to toppling.

2.5.5.2.2 Design Criteria for Soil Slopes

The soil slopes of the spray pond must be stable against sliding under normal conditions and also during and following an SSE event. The minimum acceptable factors of safety are:

End of construction	1.3
Long-term static condition	1.5
Long-term seismic condition	1.1
Rapid drawdown	1.25

The design value used for the maximum horizontal ground acceleration during the SSE is 0.15 g (Section 2.5.2.6).

2.5.5.2.3 Methods of Slope Stability Analyses

The stability of the soil slopes was analyzed by the Simplified Bishop Method (Reference 2.5-45) using the computer program SLOPE (Reference 2.5-46) and by the wedge method of analysis described in the U.S. Navy Design Manual DM-7 (Reference 2.5-47) and in the U.S. Army Corps of Engineers Manual (Reference 2.5-48).

The wedge analysis was used to determine the sliding stability along the interface of the soil-bentonite liner and the in situ soil underneath. The Simplified Bishop method was used to determine the critical arc through the in situ soil and the corresponding factor of safety.

The wedge analysis considers the stability of the mass of soil above the bottom of the soil-bentonite layer, as shown on Figure 2.5-31. The tendency for this mass to move downslope is resisted by the passive earth pressure at the toe of the slope and the total shear strength developed along the bottom of the wedge. The sum of these resisting forces must be greater than the gravitational force that tends to cause downward movement. The factor of safety against sliding is equal to the ratio between the sum of the resisting forces and the gravitational driving force.

The Simplified Bishop method for evaluating the stability of a slope assumes a trial failure arc; the mass above the arc is broken up into a series of vertical slices, and the equilibrium of each of these slices is considered. It is assumed that the forces acting on the sides of any slice have zero resultant in the vertical direction (Reference 2.5-49). A factor of safety is obtained for the assumed trial failure arc by determining the ratio of the resisting forces to the driving forces. These procedures are repeated for various locations of the center of arc and different lengths of radius until a minimum factor of safety is obtained.

The cross-section used in all circular arc analyses is based on the subsurface conditions at the northwest end of the spray pond (Figures 2.5-27 and 2.5-28). This profile was selected because the depth to rock is the greatest and it, therefore, represents the most critical conditions encountered.

2.5.5.2.4 Design Parameters

Design parameters required for the slope stability analysis include those for the in situ soils, compacted soil-bentonite mixture, compacted soils, riprap, and riprap bedding. Detailed discussions of the engineering properties of these materials are presented in various sections: Section 2.5.4.2 for in situ soils; Section 2.5.5.4.1 for compacted soil-bentonite mixture and

compacted soil; and Section 2.5.5.2.4.2 for riprap and riprap bedding. Design parameters are summarized in Table 2.5-5 and given in the subsequent sections under the headings of various types of materials.

2.5.5.2.4.1 In Situ Soil

a. Unit Weight

The total and saturated unit weights of in situ soils were determined in the laboratory; the average values chosen for design analyses are 122 lb/ft^3 and 126.4 lb/ft^3, respectively.

b. Static Shear Strength

Effective shear strength parameters based on the results of consolidated-undrained triaxial tests are $\bar{\phi}$ = 33.5°, and $\bar{c}$ = 0. The undrained shear strength of the material is 1.2 $\bar{P}_o$, where $\bar{P}_o$ is the initial mean effective principal stress (Section 2.5.4.2).

c. Dynamic Shear Strength

The dynamic shear strength of the soil is determined by multiplying the cyclic stress ratio required to cause 5% double amplitude strain in 5 cycles by the average effective confining pressure. This results in a design dynamic shear strength of $0.61\sigma_o$ where σ_o is the effective overburden pressure (Section 2.5.4.2.2.3).

2.5.5.2.4.2 Soil-Bentonite Mixture

a. Unit Weight

The total and saturated unit weights of the soil-bentonite mixture (selected from laboratory test results) are 113 lb/ft^3 and 119 lb/ft^3, respectively. The mixture is compacted at optimum moisture content to 95% of maximum dry density as determined in ASTM D698.

b. Static Shear Strength

The static effective shear strength parameters of the soil-bentonite mixture are based on the results of consolidated-undrained triaxial tests with pore pressure measurements (R). The design values of $\bar{\phi}$ = 29° and $\bar{c}$ = 0 are chosen from the test results shown on Figure 2.5-32, based on the U.S. Army Corps of Engineers recommendation that two-thirds of the test values should exceed the design value (Reference 2.5-48). The undrained shear strength of the mixture is 0.95 $\bar{P}_o$, where $\bar{P}_o$ is the initial mean effective principal stress (Section 2.5.5.4.1.2.3).

c. Dynamic Shear Strength

The dynamic shear strength of the soil-bentonite mixture is based on test results of undrained triaxial tests after cyclic loading ($C\bar{R}$ - $\bar{R}$). The test is described in Section 2.5.5.4.1.2.3, and the results are shown on Figure 2.5-33. The total shear

strength design parameter values $\overline{\phi}$ = 20° and $\overline{c}$ = 225 lb/ft^2 are based on the U.S. Army Corps of Engineers recommendation that two-thirds of the test values should exceed the design value (Reference 2.5-48).

2.5.5.2.4.3 Compacted Soil

The total and saturated unit weights determined from laboratory test results are 120.5 lb/ft^3 and 123.8 lb/ft^3, respectively. The values were determined at 95% of maximum dry density as determined in ASTM D698. The shear strength of compacted soil is assumed to be equal to the shear strength of the in situ soil.

2.5.5.2.4.4 Riprap and Riprap Bedding

A unit weight of 130 lb/ft^3 assumed for both the riprap and the riprap bedding material. The effective angle of internal friction is assumed to be 45° for the riprap and 40° for the riprap bedding.

2.5.5.2.5 End of Construction Under Static Conditions

The stability of the slope at the end of construction was analyzed using a total stress analysis. The in situ soil is divided into sublayers, and the shear strength assigned to each layer determined from the undrained shear strength relationship of q = 1.2 $\overline{P}_o$ (Section 2.5.5.2.4.1), where $\overline{P}_o$ is the effective average stress at the mid-depth of each sublayer. The minimum factor of safety of a circle is found to be 3.8, and the factor of safety of a wedge with a potential sliding surface along the bottom of the liner is found to be 5.7. Both factors of safety are considerably higher than the minimum value of 1.3 required by the design criteria. Figure 2.5-31 shows the sections analyzed and the critical arcs.

2.5.5.2.6 Rapid Drawdown Under Static Conditions

Drawdown is assumed to be instantaneous from the normal pool level (el 251') to the bottom of the pond (el 241'). The stability of effective stress analysis, with $\overline{\phi}$ = 29° and $\overline{c}$ = 0 for the soil-bentonite liner, and $\overline{c}$ = 0 and $\overline{\phi}$ = 33.5° for the in situ soil and compacted soil. The minimum factor of safety of a sliding wedge is found to be 1.7, and the minimum factor of safety for the critical deep-seated circle is found to be 2.1. All factors of safety are higher than the minimum values required by the design criteria. The results are shown on Figure 2.5-31.

2.5.5.2.7 Long-Term Stability Under Static Conditions

The long-term stability of the spray pond slope is calculated using an effective stress analyses. The water level is assumed to have risen to its normal level of el 251' in the pond. The minimum factor of safety is determined using the infinite slope procedure and using effective shear strength parameters of the material. Under static conditions, the factor of safety is given by:

$$F.S. = \frac{\tan \overline{\phi}}{\tan \alpha} \qquad \text{(EQ. 2.5-5)}$$

where:

$\overline{\phi}$ = effective friction angle

α = angle of inclination of the slope

For α = 14° (4 horizontal to 1 vertical), the minimum factor of safety is 2.2 for a potential sliding along the soil-bentonite liner with a $\overline{\phi}$ = 29°. The factor of safety of a wedge with a potential sliding surface through the interface between the soil-bentonite liner and the soil underneath is 2.6, and the minimum factor of safety for a critical circle is 2.4. Both the minimum factors of safety resulting from the infinite slope analyses, and that determined by the sliding wedge and circular arc analysis, are higher than the minimum values required by the design criteria. The results of these analyses are shown on Figure 2.5-31.

2.5.5.2.8 Long-Term Stability Under Seismic Conditions

Two analyses were made for the stability of soil slopes under seismic conditions. A pseudostatic analysis using effective shear strength evaluated the stability of the slope during an earthquake, and a total stress analysis evaluated the stability of the slope immediately after the earthquake.

The pseudostatic method of analysis involves the computation of the minimum factor of safety against sliding either along a circular arc or along a plane surface or series of plane surfaces for a sliding wedge. A horizontal force is added to account for seismic forces. The entire analysis is handled as a static effective stress analysis. The added horizontal force is equal to the total weight of the sliding mass times the seismic coefficient. The total weight of the sliding mass is calculated using the moist unit weight of the soil above the phreatic surface and the saturated unit weight of the soil below the phreatic surface. For this analysis, it is conservatively assumed that the seismic coefficient used equals the design maximum ground acceleration (0.15g).

In the pseudostatic analysis, the strength used for the soil-bentonite mixture is $\overline{\phi}$ = 29° and $\overline{c}$ = 0 (Section 2.5.5.2.4.2), and ϕ = 33.5°, $\overline{c}$ = 0 for the in situ soil (Section 2.5.5.2.4.1). The minimum safety factor obtained is 1.1 for both the circular arc and a sliding wedge through the soil-bentonite lining. All computed safety factors meet the minimum values required by the design criteria. The results are summarized on Figure 2.5-31.

Immediately after an earthquake, the pore pressures built up in the soil and soil-bentonite mixture during the earthquake reach their maximum values. Laboratory tests evaluated the undrained shear strength of both the soil-bentonite mixture and the in situ soil, without permitting any dissipation of pore pressure built up during cyclic stress loading. The total shear strength parameters representing the total strength of the soil-bentonite mixture and the in situ soil at the end of 5 uniform stress cycles are $\overline{\phi}$ = 20°, $\overline{c}$ = 225 lb/ft^2, and $\overline{c}$ = 0.61σ_o respectively (Section 2.5.5.2.4.2 and Section 2.5.5.2.4.1). The minimum factor of safety for the critical circle and for the sliding wedge procedure are 2.3 and 4.3, respectively. Both values are higher than the minimum value of 1.1 required by the design criteria.

2.5.5.3 Logs of Borings

The logs of borings and test pits from the spray pond exploration are presented in Figure 2.5-22. Drilling and sampling procedures are discussed in Sections 2.5.4.3 and 2.5.5.1.2.

2.5.5.4 Compacted Fill

The spray pond is primarily constructed by excavation (Figures 3.8-56 and 3.8-57). However, a soil-bentonite liner is placed on all soil slopes, as well as the pond bottom. The liner in turn is covered by a layer of compacted soil, riprap, and riprap bedding. The development of design and construction procedures for the development of a design mix for the compacted soil-bentonite mixture and the requirements for the compacted soils are covered in Section 2.5.5.4.1. The riprap and riprap bedding are discussed in Section 2.5.5.4.2.

2.5.5.4.1 Soil-Bentonite Liner and Soil Cover

The following sections present the results of the investigations and studies made in designing a soil-bentonite liner for the emergency spray pond. These consist of a soil investigation of the spray pond site, laboratory testing and design of a suitable soil-bentonite mixture, slope stability analyses, and liner design. The following sections also briefly describe the construction procedures for the soil-bentonite liner and soil cover.

The design criteria for the soil-bentonite liner are:

a. The permeability of the soil-bentonite liner is less than 1 ft/yr ($1x10^{-6}$ cm/sec).

b. The liner is protected to prevent drying and cracking, erosion from wave action, damage from equipment during construction and maintenance.

c. The slope of the pond with a liner is stable against sliding under static condition and during an SSE event. The minimum acceptable factors of safety against sliding are given in Section 2.5.5.2.2.

2.5.5.4.1.1 Soil Investigation and Sampling

The purpose of the field exploration program was to investigate the soils to determine their suitability for use in constructing the soil-bentonite liner. Because the pond is constructed by removing more than 10 feet of material, the primary interest was to investigate whether there is sufficient suitable soil for soil-bentonite mixture within the limits of the pond excavation.

Thirteen test pits were made at the site in March 1977. These test pits were dug to depths ranging from 5 feet to 11.5 feet. A layer of sandy, clayey silt, which is suitable for a soil-bentonite liner, was found to be consistently located between the topsoil and the weathered siltstone/shale bedrock in all test pits. The thickness of this layer varies from less than 2 feet at the southeast end of the pond to more than 6 feet near the northwest end. At the northwest corner, the bedrock was not encountered in Test Pits 1 and 13, because the soils are thicker there. It was determined that suitable soil for the soil-bentonite mixture is available in amounts estimated to be about three times the quantity required for the liner.

At the time of the investigation, the site had been covered with approximately 3 feet of shot rock-fill. The area was being used as a lay-down area for plant construction. The locations of the test pits and soil profiles are shown on Figure 2.5-30. Logs of test pits are included in Figure 2.5-22.

Bulk samples of soils suitable for the soil-bentonite liner were taken from each of the test pits except TP-8, where suitable soil material was not encountered. In addition to the bulk samples, jar samples were taken at each test pit to determine the natural moisture content.

2.5.5.4.1.2 Laboratory Testing and Soil-Bentonite Mix Design

All laboratory testing was performed in the laboratory of Geotechnical Engineers, Inc. of Winchester, Massachusetts. Soil samples obtained during the field investigation, along with the bentonite to be used in the tests, were shipped to the laboratory.

The laboratory testing proceeded in three stages. In the first stage, the onsite soils were classified. In the second stage, moisture-density relationships were established for soil-bentonite mixtures, and the bentonite content to meet permeability requirements was determined. In the final stage, the static and dynamic engineering properties were determined for the soil-bentonite mixture at the bentonite content established in the second stage.

The first stage was performed to obtain the index properties of the soil specifically used in testing for the soil-bentonite mix design, rather then using the properties previously obtained at the spray pond site (Section 2.5.4.2.2.1). As can be seen below, the results are similar.

The laboratory test procedures and the results of all tests are summarized in the July, 1977 report prepared by Geotechnical Engineers, Inc. (Reference 2.5-44).

2.5.5.4.1.2.1 Classification of Onsite Soils

Soil samples were classified visually in the laboratory as well as by testing to determine grain-size distribution, natural moisture content, and Atterberg Limits. The test results are summarized in Table 2.5-6.

a. Grain-Size Distribution

Grain-size determinations were made on all bulk samples according to ASTM D422, except that the sample preparation avoided air-drying of fines. During sieving of the moist soil through the ¾ inch sieve and during washing through the No. 200 sieve, only finger pressure was applied to break clay lumps and weak particles. These procedures prevent breakdown of soil particles.

The range of grain-size curves is shown on Figure 2.5-34. The median grain-size (D_{50}) of the soils varies between 0.006 mm and 2.38 mm, with an average of 0.20 mm. The percent by weight passing the No. 200 sieve varies from 41% to 88%, with an average of 71%.

b. In Situ Moisture Content

Moisture contents of all jar and bulk samples were determined in accordance with ASTM D2216. The moisture contents, determined from the samples kept in water-tight jars, are believed to be representative of in situ moisture contents, and are included in Table 2.5-6. The range of in situ moisture contents for the soils varies between 15.0% and 30.7%, with an average of 23.6%.

c. Atterberg Limits

Atterberg Limits were determined for the 12 bulk samples in accordance with ASTM D423 and ASTM D424, except that the soil was not air-dried before testing, and the grooving tool used was of the Casagrande-type. The results are summarized in Table 2.5-6 and are plotted on Figure 2.5-35.

2.5.5.4.1.2.2 Soil-Bentonite Mix Design

Three soils, which represent the entire range of grain-size distribution for onsite soils were selected for the soil-bentonite mixture design. These soils were designated as Soils A, B, and C, and each was obtained by combining two bulk samples. Their grain-size distributions are shown on Figure 2.5-34. Soils A and C represent the finest and the coarsest soils, respectively, in the spray pond area, and Soil B is typical of the soils in the middle of the range. The bentonite used in the tests was a high swelling Wyoming-type bentonite. The bentonite was in granular form before mixing with soil and water (Reference 2.5-44).

a. Compaction Tests

Compaction tests were made on Soils A, B, and C in accordance with ASTM D698. For each soil, the amount of bentonite mixed with the soils varied from 0% to 20% by weight.

The bentonite used in the test was in granular form, with the size of granules ranging from 0.1 mm to 1.0 mm. Mixtures of soil and bentonite before compaction had the appearance of granular soil. No difficulty was experienced during mixing and compacting of soil-bentonite mixtures as the percentage of bentonite was increased, because the moisture was kept at optimum.

Results of the compaction tests are shown on figures 6, 7, and 8 of Reference 2.5-44. As shown on these figures, the maximum dry density decreases as the bentonite content increases, with the maximum dry density dropping about 10% when the bentonite content increases from 0% to 20%. However, the optimum moisture content did not vary significantly (less than 2%) when the bentonite content was varied from 0% to 20%.

b. Permeability Tests

Permeability tests on Soils A, B, and C mixed with 0% to 20% bentonite were performed on compacted specimens in triaxial cells. The specimens had a diameter of approximately 2.8 inches and were about 1.0 inch high. The specimens were prepared at optimum moisture content and compacted to approximately 95% of the maximum dry density determined by ASTM D698. A Harvard Miniature compaction device was used to compact the specimens.

After compaction, each specimen was placed in a triaxial cell and consolidated under an effective confining. All specimens were allowed to saturate and swell before being tested for permeability. Saturation was checked by determining the value of Skempton's "B" parameter (Reference 2.5-40). All specimens were saturated to a "B" parameter of 0.95 or higher. The swelling of the specimens was roughly proportional to the bentonite content. Specimens with 0% to 5% bentonite showed little swelling, while specimens with 20% bentonite swelled as much as 10%.

The results of the permeability tests are shown on Figure 2.5-36. The permeability decreases from greater than 10^{-5} cm/sec to less than 10^{-7} cm/sec when the bentonite content increases from 0% to 20%.

The details of the permeability tests are given in Reference 2.5-44.

c. Selecting Design Mix of Soil and Bentonite Based on the results of permeability tests, a soil-bentonite mixture with 7.5% bentonite content by weight in terms of soil-bentonite mixture is selected for design, i.e., a mix with 7.5% bentonite and 92.5% soil by dry weight. When mixed with water at the optimum moisture content and compacted to 95% of maximum dry density as determined in ASTM D698, the compacted mixture has a permeability of less than 10^{-6} cm/sec (1 ft/yr) (Figure 2.5-36).

2.5.5.4.1.2.3 Engineering Properties Tests

Static and dynamic triaxial tests were conducted to determine the strength characteristics of the design soil-bentonite mixture (Section 2.5.5.4.1.2.2).

Soils A and C, which envelop the range of the grain-size distribution of the onsite soils sample (Figure 2.5-34), were used in making the soil-bentonite specimens for the strength tests. The test specimens were approximately 6.1 inches high and approximately 2.8 inches in diameter.

a. Consolidated-Undrained Triaxial Tests with Pore Pressure Measurements ($\overline{R}$)

Six consolidated-undrained triaxial tests ($\overline{R}$) were performed. Three specimens were mixed with Soil A, and another three with Soil C.

The specimens were consolidated isotropically at effective consolidation pressures of approximately 0.15 tons/ft^2, 0.30 tons/ft^2, and 0.60 tons/ft^2. These consolidation pressures simulate actual field conditions. Specimens were saturated using a back pressure of 10 tons/ft^2 to achieve a "B" parameter of 0.95 or higher (Reference 2.5-44). After saturation, the test specimens were axially loaded in compression, and pore pressures were monitored.

The results of the six $\overline{R}$ tests are summarized on Figure 2.5-32, which shows maximum shear stress at failure versus the mean effective principal stress at failure. From this drawing, the effective friction angle obtained is 29°. Detailed test data and results are presented in table 4 and figures 14 and 15 of Reference 2.5-44.

The undrained shear strength of the soil-bentonite mixture is calculated from the effective stress friction angle and pore pressure parameter A_f at failure, using the same procedure as for the in situ soil (Section 2.5.4.2.2.2). For the samples tested, A_f varies from 0 to -0.25. Using the conservative values of $A_f = 0$ and $\overline{\phi} = 29°$, the undrained shear strength is calculated to be 0.95 $\overline{P}_o$, where $\overline{P}_o$ is the initial mean effective principal stress.

b. Cyclic Loading Followed by Undrained Triaxial Compression with Pore Pressure Measurements ($C\overline{R}$ - $\overline{R}$) Seven $C\overline{R}$-$\overline{R}$ tests were made in which the specimens

were first subjected to cyclic loading, followed by static axial loading under undrained condition. The purpose of this test was to evaluate any reduction of the shear strength of the soil-bentonite mixtures following a seismic event. Three specimens were prepared with Soil A, and four with Soil C.

The consolidation and saturation of the $C\overline{R}\text{-}\overline{R}$ specimens were similar to that described for $\overline{R}$ testing. After saturation, the specimens were subjected to five cycles of sinusoidal cyclic loading, with deviator stresses of approximately 0.015 tons/ft^2, 0.03 tons/ft^2, and 0.06 tons/ft^2. Drainage was not permitted. The selection of five uniform stress cycles simulates the SSE of 0.15 g at the site, based on correlations of equivalent uniform stress cycles and earthquake time histories by Seed, et al (Reference 2.5-41).

The deviator stress during cyclic loading was chosen to be approximately equal to the average shear stress induced during an earthquake, which is approximately equal to one-tenth of the total overburden pressure when the maximum ground acceleration is 0.15 g, that is:

Deviator Stress = average induced shear stress

$$= 0.65 \frac{\nu H_a}{g} \qquad \text{(EQ. 2.5-6)}$$

$$= 0.65 (\nu h)\ 0.15$$

$$= 0.1 (\nu h)$$

Axial deformations and pore pressures were monitored. A typical test record is presented on figure 16 in Reference 2.5-44.

Upon completion of the cycling, time was permitted for pore pressure to equalize throughout the specimens; however, drainage was not permitted. The specimens were then subjected to undrained axial compressive loading. Pore pressures were monitored.

The results of the seven $C\overline{R}\text{-}\overline{R}$ tests are summarized on Figure 2.5-33, which shows maximum shear stress versus the mean principal stress at the end of 5 uniform stress cycles. From this drawing the total dynamic shear strength parameters are calculated to be $\phi = 20°$ and $\overline{c} = 225$ lbs/ft^2. Detailed test data and results are presented in table 5 and on figures 16, 17, and 18 of Reference 2.5-44.

2.5.5.4.1.3 Design Section

Based on the design criteria given in the previous section and the results of seepage and stability analyses (Sections 2.5.4.6 and 2.5.5.2, respectively), a 12 inch soil-bentonite liner with soil and rock protection was adopted as a precaution (Section 2.5.4.6). The section is shown on Figure 2.5-24 and will conform to these additional requirements:

a. The liner is placed on a 4 horizontal to 1 vertical slope.

b. The liner on the slope is protected by soil, riprap and riprap bedding to prevent erosion from wave action, drying and cracking. Design details of riprap and its bedding are given in Section 2.5.5.4.2.

c. Soil cover on the liner on the bottom of the pond is designed to protect the liner from damage by equipment during construction and maintenance.

2.5.5.4.2 Riprap and Riprap Bedding

The riprap and bedding are 18 and 12 inches thick, respectively. The gradation of the riprap and bedding is as follows:

Riprap

Particle Weight (pounds)	Fraction of Total Mix (% by weight)
>500	0
300 – 500	≥25
10 – 300	45 - 75
<10	0 - 25

Riprap Bedding

Sieve Size (U.S. Standard Sieves)	Fraction Passing (% by weight)
2 inch	100
3/4 inch	52 - 100
3/8 inch	36 - 70
No. 4	24 - 50
No. 16	10 - 30
No. 200	0 - 10

The riprap is placed in a manner to insure that the larger rock fragments are uniformly distributed. The smaller rock fragments serve to fill the spaces between the larger rock fragments, resulting in a well-keyed, densely placed, uniform layer of riprap.

Control of riprap placement consists of visual observation of the operation and of the completed product to assure that a dense, rough-surfaced layer of well-keyed and graded rock fragments of the required thickness is provided.

The riprap bedding material is handled and placed in such a manner as to prevent segregation. The moisture content of the material during placement is controlled as required to minimize segregation. A uniform layer of bedding is formed by spreading with a bulldozer.

2.5.5.4.3 Construction

Brief descriptions of materials, foundation preparation, and construction for the soil-bentonite liner and soil cover are given in this section.

The in situ soils from the excavation within the limits of the spray pond are used for the liner and soil cover. The gradation of soils is checked before mixing with bentonite to make sure they are within the range shown on Figure 2.5-34 and that sizes larger than 2 inches are removed. The bentonite is high swelling, Wyoming-type bentonite.

Water used for adjusting the moisture content of the soil-bentonite mixture is clean and free from deleterious substances.

Before placement of the liner, all underlying soil surfaces are prepared by scarifying, moisture conditioning, and compacting as necessary to meet the required density.

The pond bottom is underlain with soil and rock. Where the pond bottom is overexcavated, it is backfilled to the bottom level of the soil-bentonite liner. The soil backfill, as well as soft spots in the in situ soil, underlying the liner will be compacted to 95% of the maximum dry density determined by ASTM D698.

The soil-bentonite mixture is mixed in a central plant to ensure uniformity of the mixture. The mixture is then transported from the mixing plant to the construction site in clean equipment. The soil-bentonite mixture and the soil cover are placed and compacted to 95% of the maximum dry density determined by ASTM D698.

The individual components of the soil-bentonite mixture are tested for conformance with the specification before mixing. The proportions of the mixture are inspected at the mixing plant for conformance to specified proportions. The plant includes metering and feeding equipment that can be calibrated to the required accuracy. During compaction, the density of the liner and soil cover is checked to confirm that the requirements of the specification are met.

2.5.5.4.4 Seepage Test

Upon completion of construction of the spray pond, a seepage test was conducted to verify that the design basis seepage rate of 1.83×10^6 gallons per month would not be exceeded.

Filling of the spray pond began on October 11, 1982, and was completed on November 22, 1982, when the water surface reached el 251.0'. A seepage loss test was conducted for a period of 23 weeks from December 13, 1982 to May 21, 1983. Measurements of seepage loss were determined for each weekly interval. Depending upon the evaporation rate factor considered, the average seepage loss from the pond during this test was calculated to be between 2.1×10^5 gallons per month and 3.8×10^5 gallons per month, or between about 5 gpm and 9 gpm for the entire pond. This is 11% to 21% of the design basis rate. An error factor was developed which considers the accuracy of measurements of pond water level, of flows into and out of the pond, and of precipitation. The maximum error contribution was estimated to be approximately ±22% of the design basis rate. With error contribution, the upper bound of the average seepage loss is approximately 40% of the design value, and the lower bound is close to zero. Therefore, the test demonstrates that actual seepage will not exceed the design basis rate. Details of the seepage test and data analysis are contained in Reference 2.5-145.

2.5.5.5 Dikes

The dikes surrounding the storage tanks as shown on Figure 3.8-58 are not seismic Category I, but are designed in accordance with seismic Category IIA requirements as discussed in Section 2.4.12 and 2.5.4. However, the dikes will be stable under both static and dynamic conditions as discussed below.

a. A cross-section of the dikes is shown in Figure 2.5-44. The dikes are designed to be 4 feet wide at the crest and minimum 6.5 feet high, with side slopes of 2.25

horizontal to 1 vertical. The dikes are supported by Type I (Unit 1) or II (Unit 2) fill, which varies in thickness from a few feet to more than 30 feet. Between the plant fill and bedrock is natural soil with a thickness varying from a few feet to more than 10 feet. Bedrock is therefore at a depth varying from about 10 feet to more than 40 feet below the dikes. The subsurface conditions described above are based on the logs of boring No. 12 at the tank located southwest of Unit 1 and at borings Nos. 4 and 5 at the tank south of Unit 2. Figure 2.5-20 shows the locations of these borings. The logs of the borings are shown on Figure 2.5-22.

The dikes will be compacted to 95% of the maximum density determined by ASTM D698 (Standard Proctor). Shear strengths for the compacted soil in the dikes and the fill supporting the dikes are assumed to be similar to the shear strength for compacted soil at the spray pond (Section 2.5.5.2.4.3); the angle of internal friction is 33.5°. The natural soil below the fill is dense to very dense sandy and clayey silt with rock fragments. Properties of the natural soil have been added to Table 2.5-4 and Section 2.5.4.2.2.4.

The crest and the inside slopes of the dikes will be protected by a bituminous surface.

b. For design, the groundwater level at the tanks is conservatively considered to be 15 feet above the water table contours shown on Figure 2.5-15. This means that it will be at el 145' at the location of the CST southwest of Unit 1 and at el 175' at the location of the CST south of Unit 2. Based on the logs of borings 4, 5, and 12, the design groundwater level will be in the dense natural soil below the bottom of the fill and just above bedrock. Therefore, there will be no water table within the retaining dikes and the fill supporting them so that the fill and dike cannot liquefy.

Because the groundwater level is below the dikes, the infinite slope analysis and the yield acceleration analysis by Seed and Goodman (Reference 2.5-160) are considered appropriate for evaluating the stability of the slopes.

For static conditions, the infinite slope analysis was used to determine the factor of safety of soil slopes:

$$F.S. = \frac{\tan \phi}{\tan i} \qquad \text{(EQ. 2.5-7)}$$

where:

ϕ = friction angle

i = inclination of slope

Therefore, for $\phi = 33.5°$ and $i = \tan^{-1}(1/2.25) = 24°$, the factor of safety under static conditions is found to be 1.5.

For dynamic conditions, the yield acceleration analysis was used. The yield acceleration is defined as the acceleration at which sliding will begin to occur. The yield acceleration coefficient (k_y) is defined as:

$$k_y g = \sin(\phi - i) g$$

where ϕ and i were defined in the previous paragraph. For $\phi = 33.5°$ and $i = 24°$, (k_y) is found to be 0.165. Compared to the SSE of 0.15 g, the factor of safety for the dynamic condition would be

$$F.S. = \frac{0.165}{0.15} = 1.1$$

These stability values are equal to the minimum values required by the design criteria given in Section 2.5.5.2.2.

Therefore, the dike slopes will be stable under both static and dynamic conditions.

The slope of the fill is 2 horizontal to 1 vertical. With an angle of internal friction of 33.5°, the yield acceleration for such a slope is 0.12 g. During an SSE event, the fill slope may revel back to a slope of 2.15 horizontal to 1 vertical. A probable failure surface is shown in Figure 2.5-44. This would mean a loss of about 4.0 feet at the top of a 25 foot high slope. The ravelling will not influence the stability of the retaining dikes because the minimum space between the toe of the dike and the top of the slope of the fill is more than 20 feet (at the southeast corner of Unit 2 dike).

c. Other than the logs of three borings (Nos. 4, 5, and 12) at the locations of the CST, no separate field borings and laboratory test programs were conducted for the evaluation of stability of the dikes. The shear strength ($\phi = 33.5°$) used in the stability analysis mentioned above was assumed, based on data for similar soils from the spray pond compacted to the same degree (Table 2.5-4).

d. The construction procedure for the earth part of the dikes will be similar to that used for the spray pond construction. The main requirements will be as follows:

1. Soil gradation

Sieve Size	% Passing (by weight)
2 inch	100
¾ inch	75 - 100
No. 4	50 - 95
No. 50	35 - 90
No. 200	30 - 85

2. Loose lift thickness

-For machine compaction 8 inches maximum
-For hand compaction 6 inches maximum

3. Compaction

Minimum 95% of the maximum density as determined by ASTM D698, method D.

4. Testing

In-place density tests will be performed and documented with a minimum of one on each lift or 300 cubic yards of soil placed, whichever is the more frequent.

5. Quality Control

The quality control program will contain requirements for surveillance, audits, inspection, testing, and corrective action for nonconforming conditions.

6. Inservice Inspection

The dikes surrounding the storage tanks are passive water-retaining barriers for short-term water retention. The inspection requirements will conform with appropriate portions of Regulatory Guide 1.127 to assure short-term water retention when needed.

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Table 2.5-1

MODIFIED MERCALLI INTENSITY SCALE OF 1931

[Abridged]

I.	Not felt, except by a very few under especially favorable circumstances. (I Rossi-Forel scale.)
II.	Felt only by a few persons at rest, especially on upper floors of buildings. Delicately suspended objects may swing. (I to II Rossi-Forel scale.)
III.	Felt quite noticeably indoors, especially on upper floors of buildings, but many people do not recognize it as an earthquake. Standing motor cars may rock slightly. Vibration like passing of truck. Duration estimated. (III Rossi-Forel scale.)
IV.	During the day felt indoors by many, outdoors by few. At night some awakened. Dishes, windows, doors disturbed; walls make cracking sound. Sensation like heavy truck striking building. Standing motor cars rock noticeably. (IV to V Rossi-Forel scale.)
V.	Felt by nearly everyone; many awakened. Some dishes, windows, etc., broken; a few instances of cracked plaster; unstable objects overturned. Disturbance of trees, poles, and other tall objects sometimes noticed. Pendulum clocks may stop. (V to VI Rossi-Forel scale.)
VI.	Felt by all; many frightened and run outdoors. Some heavy furniture moved; a few instances of fallen plaster or damaged chimneys. Damage slight. (VI to VII Rossi-Forel scale.)
VII.	Everybody runs outdoors. Damage negligible in buildings of good design and construction; slight to moderate in well-built ordinary structures; considerable in poorly built or badly designed structures; some chimneys broken. Noticed by persons driving motor cars. (VIII Rossi-Forel scale.)
VIII.	Damage slight in specially designed structures; considerable in ordinary substantial buildings, with partial collapse; great in poorly built structures. Panel walls thrown out of frame structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned. Sand and mud ejected in small amounts. Changes in well water. Disturbs persons driving motor cars. (VIII+ to IX Rossi-Forel scale.)

Table 2.5-1 (Cont'd)

IX.	Damage considerable in specially designed structures; well-designed frame structures thrown out of plumb; great in substantial buildings, with partial collapse. Buildings shifted off foundations. Ground cracked conspicuously. Underground pipes broken. (IX+ Rossi-Forel scale.)
X.	Some well-built wooden structures destroyed; most masonry and frame structures destroyed with foundations; ground badly cracked. Rails bent. Landslides considerable from river banks and steep slopes. Shifted sand and mud. Water splashed (slopped) over banks. (X Rossi-Forel scale.)
XI.	Few, if any, (masonry) structures remain standing. Bridges destroyed. Broad fissures in ground. Underground pipe lines completely out of service. Earth slumps and land slips in soft ground. Rails bent greatly.
XII.	Damage total. Waves seen on ground surfaces. Lines of sight and level distorted. Objects thrown upward into the air.

Table 2.5-2

EARTHQUAKES WITH EPICENTERS WITHIN APPROXIMATELY 200 MILES OF THE SITE[1]

YEAR	DAY	LOCAL TIME	INTENSITY[2]	LOCATION	N. LAT.	W. LONG.	DISTANCE FROM SITE[3] (mi.)
1737	Dec. 18	2230-2300	VII	Near New York City	40.5	74	85
1758	Apr. 24	2130	-	Annapolis, Md.	39	76.5	98
1763	Oct. 30	1625	IV-V	New Jersey	-	-	-
1773	Oct. 27	0000-0100	IV-V	New York City	-	-	-
1774	Feb. 21	1400	VI	Eastern Va.	37.5	77.5	214
1774	Feb. 22	PM	V-VI	Eastern Va.	37.5	77.5	214
1775	July 6	1555	V	Jessopborough, N.Y.	-	-	-[4]
1775	July 12	1555	VI-VII	S. of Lake George, N.Y.	43.25	73.75	229
1783	Nov. 29	2215	IV-V	Philadelphia, Pa.	-	-	-
1783	Nov. 29	2250	VI	W. of New York City	41	74.5	78
1791	May 16	0800	VII	Moodus, Conn.	41.5	72.5	183
1792	Aug. 28	2200	IV-V	Near E. Haddam, Conn.	41.5	72.5	183
1793	Jan. 11	0800	IV-V	Near E. Haddam, Conn.	41.5	72.5	183
1794	Mar. 6	1400	IV-V	Near E. Haddam, Conn.	41.5	72.5	183
1796	Dec. 24	1300	V-VI	New London, Conn.	41.5	72	207
1800	Mar. 17	-	-	Philadelphia, Penn.	39.75	75.25	37
1800	Nov. 29	-	-	Philadelphia, Penn.	39.75	75.25	37
1802	Aug. 23	0500	V	Charlotte, Va.	37.6	77.4	206
1805	Aug. 11	1900	IV-V	Near E. Haddam, Conn.	41.5	72.5	183
1827	Aug. 23	-	IV-V	Near New London, Conn.	41.5	72.25	195

Table 2.5-2 (Cont'd)

YEAR	DAY	LOCAL TIME	INTENSITY[2]	LOCATION	N. LAT.	W. LONG.	DISTANCE FROM SITE[3] (mi.)
1833	Aug. 27	0600	V-VI	Eastern Va.	37.75	78	214
1837	Apr. 12	-	V	Hartford, Conn.	41.75	72.75	181
1840	Jan. 16	2000	V-VI	Near Utica, N.Y.	43	75	194
1840	Aug. 9	1530	V	Conn. River Valley	41.5	72.75	172
1840	Nov. 11	-	-	Philadelphia, Penn.	39.75	75.25	37
1845	Oct. 26	-	V-VI	W. Hudson River Valley, N.Y.	42.5	73.75	183
1847	Sep. 2	-	V	Probably near N.Y. City	40.5	74	85
1847	Sep. 29	-	V	New York City	-	-	-
1848	Sep. 9	2200	V	Probably near N.Y. City	40.5	74	85
1852	Nov. 2	1835	VI	Eastern Va.	37.75	78	214
1855	Feb. 6	2330	V-VI	Hudson River Valley, N.Y.	42	74	148
1858	June 30	2245	IV-V	Near New Haven, Conn.	41.25	73	152
1861	Mar. 5	1200	IV-V	Bloomfield, N.J.	40.8	74.2	82
1871	Oct. 9	0940	VII	Wilmington, Del.	39.75	75.5	33
1872	July 11	0525	IV-V	Westchester Co., N.Y.	41	73.75	110
1874	Dec. 10	2225	V-VI	Westchester Co., N.Y.	41	73.75	110
1875	July 28	0410	V	NW Conn.	41.75	73.25	161
1875	Dec. 22	2345	VII	Near Richmond, Va.	37.5	77.5	214
1877	Jan. 3	2300	IV-V	Emmittsburg, MD.	39.5	77.3	104
1877	Aug. 31	0959	IV-V	Laurel, MD.	39.2	77.2	112
1877	Sep. 10	0959	IV-V	Delaware Valley	40.1	74.9	37

Table 2.5-2 (Cont'd)

YEAR	DAY	LOCAL TIME	INTENSITY[2]	LOCATION	N. LAT.	W. LONG.	DISTANCE FROM SITE[3] (mi.)
1878	Feb. 5	1120	V	New York City	40.5	74	85
1878	Oct. 4	0230	V	Hudson River Valley, N.Y.	41.5	74	85
1879	Mar. 25	1930	IV-V	Delaware Valley	39.75	75.5	33
1881	Feb. 4	0430	IV-V	Marlborough, N.Y.	41.6	74.0	125
1881	Apr. 21	1130	V-VI	Port Jefferson, N.Y.	40.9	73.1	138
1882	Apr. 2	evening	V	New Market, Va.	38.7	78.7	197
1883	Mar. 11	1857	IV-V	Harford County, Md.	39.5	76.4	66
1883	Mar. 12	0000-0100	IV-V	Harford County, Md.	39.5	76.4	66
1884	May 31	-	V	Allentown, Penn.	40.6	75.5	20
1884	Aug. 10	1407	VII	Near New York City	40.5	74	85
1885	Jan. 2	2116	V	Md. and Va.	39.2	77.5	124
1885	Mar. 8	-	IV-V	Lancaster, Pa.	40.0	76.3	41
1886	Jun. 12	0005	IV-V	Asbury Park, N.J.	40.5	74	85
1887	Jan. 2	2330	V	Baltimore, MD.	39.8	77.0	81
1887	Mar. 2	1613	IV-V	Seaford, De.	40.6	73.3	123
1889	Mar. 8	1840	VI	SE Penn.	40	76.75	63
1893	Mar. 9	0030	V	Near New York City	40.5	74	85
1893	Mar. 14	1505	V	Brooklyn, N.Y.	40.7	73.9	94
1894	Jan. 25	2040	IV-V	Annapolis, MD.	39.0	76.5	98
1895	Sep. 1	0609	VI	Near High Bridge, N.J.	40.7	74.8	53
1897	Nov. 27	1556	V	Ashland, Va.	37.7	77.5	202

Table 2.5-2 (Cont'd)

YEAR	DAY	LOCAL TIME	INTENSITY[2]	LOCATION	N. LAT.	W. LONG.	DISTANCE FROM SITE[3] (mi.)
1897	Dec. 18	1845	V	Near Ashland, Va.	37.7	77.5	202
1899	May 16	2015	V	Conn. River Valley	41.5	72.5	183
1900	Apr. 28	1907	IV-V	Camden, N.J.	39.9	75.1	34
1906	May 8	1241	V	Seaford, Del.	38.7	75.7	105
1906	May 11	-	IV-V	Rockaway, N.Y.	40.6	73.8	97
1906	May 29	evening	IV-V	Reading, Pa.	40.3	75.9	18
1907	Jan. 24	0630	IV-V	Near Schenectady, N.Y.	42.75	74	192
1907	Feb. 11	0822	VI	Near Arvonia, Va.	37.7	78.3	227
1908	Feb. 5	0320	IV-V	Housatonic Valley, Conn.	41.5	73.25	150
1908	May 31	1242	VI	Allentown, Penn.	40.6	75.5	26
1908	Aug. 23	0430	V	Near Powhatan, Va.	37.5	77.9	225
1909	Apr. 2	0225	V-VI	Near border of Va.	39.4	78.0	140
1910	Apr. 23	0408	IV-V	Atlantic City, N.J.	39.3	74.4	90
1912	Nov. 6	1530	V	Atlantic City, N.J.	39.2	74.4	95
1914	Mar. 6	evening	IV-V	Newark, N.J.	40.8	74.1	87
1914	Mar. 25	0200	IV-V	Five Mile Beach, N.J.	39.2	74.2	102
1916	Feb. 2	2326	V	Mohawk Valley, N.Y.	43	74	208
1916	June 8	1615	IV-V	Westchester Co., N.Y.	41	73.75	110
1918	Apr. 9	2109	V	Near Luray, Va.	38.75	78.5	186
1919	Sep. 5	2146	VI	Near Front Royal, Va.	38.75	78.25	175
1920	Jul. 25	early morn	IV-V	Lauray, Va.	38.7	78.4	184

Table 2.5-2 (Cont'd)

YEAR	DAY	LOCAL TIME	INTENSITY[2]	LOCATION	N. LAT.	W. LONG.	DISTANCE FROM SITE[3] (mi.)
1921	Jan. 26	1840	V	Moorestown, N.J.	40.0	75.0	34
1925	Jul. 14	0400	IV-V	Richmond, Va.	37.6	77.4	206
1925	Nov. 14	0804	VI	Near Moodus, Conn.	41.5	72.5	183
1926	May 11	2230	V	New Rochelle, N.Y.	40.9	73.9	100
1927	June 1	0720	VII	New Jersey Coast	40.3	74.0	83
1928	Jan. 13	1450	IV-V	Block Island, R.I.	41	71.5	220
1929	Aug. 12	0625	VIII	Near Attica, N.Y.	42.9	78.3	232
1929	Dec. 26	2156	VI	Near Charlottesville, Va.	38	78.5	219
1933	Jan. 24	2100	V	Central N.J.	40.1	74.5	58
1938	July 15	1745	VI	S. Blair Co., Penn.	40.4	78.2	138
1938	Aug. 22	2236	V	Central N.J.	40.1	74.5	58
1939	Nov. 14	2154	V	Salem Co., N.J.	39.6	75.2	48
1940	Mar. 25	2228	IV-V	Near Woodstock, Va.	38.9	78.6	185
1947	Jan. 4	1351	V	Near Greenwich, Conn.	41	73.5	121
1949	May 8	0601	IV-V	Near Powhatan, Va.	37.5	78	228
1951	Sep. 3	2026	V	Rockland Co., N.Y.	41.2	74.1	103
1952	Aug. 24	1907	V	Mohawk Valley, N.Y.	43.0	74.5	199
1952	Oct. 8	1640	V	Poughkeepsie, N.Y.	41.7	74.0	131
1953	Mar. 27	0350	V	Stamford, Conn.	41.1	73.5	125
1954	Jan. 7	0225	VI	Sinking Spring, Penn.	40.3	76.0	23
1954	Feb. 21	1500	VII	Wilkes-Barre, Penn.	41.2	75.9	69

Table 2.5-2 (Cont'd)

YEAR	DAY	LOCAL TIME	INTENSITY[2]	LOCATION	N. LAT.	W. LONG.	DISTANCE FROM SITE[3] (mi.)
1954	Feb. 23	2255	VI	Wilkes-Barre, Penn.	41.2	75.9	69
1955	Jan. 21	0304	V	Malta, N.Y.	43.0	73.8	212
1957	Mar. 23	1403	VI	West-Central N.J.	40.6	74.8	49
1961	Sep. 14	2117	V	Lehigh Valley, Penn.	40.6	75.4	28
1961	Dec. 27	1206	V	Penn.-N.J. border	40.1	74.8	42
1964	May 12	0445	VI	Near Cornwall, Penn.	40.2	76.5	48
1964	Nov. 17	1208	V	Westchester Co., N.Y.	41.2	73.7	119
1966	Jan. 1	0824	VI	Near Attica, N.Y.	42.8	78.2	223
1966	May 31	0119	IV-V	Eastern Va.	37.6	78.0	223
1967	June 13	1409	VI	Near Attica, N.Y.	42.9	78.2	229
1967	Nov. 22	1710	V	Westchester Co., N.Y.	41.1	73.8	111
1968	Nov. 3	0334	V	S. Conn.	41.3	72.5	177
1968	Dec. 10	0413	V	N.J.	39.7	74.6	63
1971	Sep. 11	1907	V	Va.	38.1	77.4	176
1972	Sep. 5	1100	V	Richmond, Va.	37.6	77.7	214
1973	Feb. 28	0322	V	N.J.	39.7	75.4	34
1974	June 7	1446	VI	Wappingers Falls, N.Y.	41.6	73.9	129
1976	Mar. 11	1607	VI	Northeastern N.J.	40.84	74.05	91
1977	Feb. 27	1506	V	Va.	37.9	78.6	229
1978	Jun. 30	1513	IV-V	between Mahwah & Oakland, N.J.	41.08	74.20	93
1978	Jul. 16	0139	V	Lancaster, Pa.	39.90	76.22	41

Table 2.5-2 (Cont'd)

YEAR	DAY	LOCAL TIME	INTENSITY[2]	LOCATION	N. LAT.	W. LONG.	DISTANCE FROM SITE[3] (mi.)
1978	Oct. 6	1425	VI	Lancaster, Pa.	40.05	76.09	30
1979	Jan. 30	1130	V	Cheesequake, N.J.	40.321	74.264	70
1979	Mar. 9	2349	V	Bernardsville, N.J.	40.721	74.504	66
1979	Dec. 30	0915	V	Mt. Kisco, N.J.	41.140	73.690	117
1980	Mar. 5	1206	IV-V	Abington, Pa.	40.17	75.07	27
1980	Mar. 11	0100	IV-V	Abington, Pa.	40.15	75.09	26

(1) Only earthquakes with intensities greater than IV on the Modified Mercalli Intensity Scale are included in this table.
(2) Intensity based on Modified Mercalli Intensity Scale of 1931.
(3) Calculated using site coordinates of 40.23 N. latitude, 75.58 W. longitude.
(4) This event may not have occurred within 200 miles of the site. Jessopborough may correspond to Jessup Falls in Warren Co., formerly Washington Co. in the 1700s.

Table 2.5-3

UNCONFINED COMPRESSION TESTS ON ROCK SAMPLES

BORING NO.	ELEVATION (feet)	UNCONFINED COMPRESSIVE STRENGTH (psi)	DENSITY (lbs/ft^3)
2	139.0	17,490	151
2	91.5	15,000	149
2	88.0	17,850	144
9	148.0	6,370	140
9	106.5	14,520	153
20	175.0	19,630	159
22	190.5	20,110	162
22	179.0	14,570	155
25A	204.5	16,560	155
25A	201.5	13,670	150
120	124.0	19,290	153
120	122.5	22,140	161
120	118.0	24,540	162
120	76.0	10,950	144
121	97.0	12,100	145
122	109.5	8,340	150

Table 2.5-4

SUMMARY OF ENGINEERING PROPERTIES
OF IN SITU SOIL

PROPERTIES	AT SPRAY POND RANGE	AVERAGE
In situ moisture content (%)	11.9 - 38.7	21.7
In situ total unit weight (lb/ft^3)	98.6 - 137.2	122.0
Grain-size distribution:		
Medium grain-size, D_{50} (mm)	0.006 - 4.4	0.32
Percent by weight passing No. 200 sieve	15 - 100	72
Atterberg limits:		
Liquid limit	27 - 51	37
Plasticity index	2 - 27	15
Effective consolidated-undrained shear strength:		
$\bar{C}$ (psf)	-	0
$\bar{\phi}$ (deg)	-	33.5
Undrained shear strength, s (psf)	-	1.2 $\bar{P}_o$ (1)
Dynamic shear strength	-	$0.61\sigma_o$ (2)
Cyclic stress ratio	-	0.61
Standard penetration resistance (blows/ft)	7 - 86	36
Specific gravity	2.70 - 2.80	2.76

Table 2.5-4 (Cont'd)

OTHER THAN AT SPRAY POND SITE

PROPERTIES	RANGE	AVERAGE
In situ Moisture Content (%)	8.3 - 21.3	13.4
In situ Total Unit Weight (pcf)	126.0-140.6	132.8
Grain-Size Distribution		
Gravel (retain on No. 4 sieve)	4.0 - 25.0	14.0
Sand (passing No. 4 and retain on No. 200)	12.0 - 54.0	27.0
Silt/Clay (passing No. 200 sieve)	26.0 - 82.0	59.0
Atterberg Limits		
Liquid Limit	18.0 - 37.0	25.0
Plasticity Index	3.0 - 17.0	8.0
Standard Penetration Resistance (blows/ft)	2 -.98	.42
Total Undrained Shear Strength	c = 3.0 ksf,	$\phi = 18^o$
Effective Shear Strength	$\bar{c} = 0$,	$\bar{\phi} = 26.5^o$

(1) $\bar{P}_o$ = mean effective principal stress, $(\bar{\sigma}_1 + \bar{\sigma}_3)/2$

(2) σ_o = effective overburden pressure

Table 2.5-5

SUMMARY OF DESIGN PARAMETERS OF SOILS
AND SOIL-BENTONITE MIXTURES

PARAMETER	IN SITU SOIL	SOIL COVER[1]	SOIL-BENTONITE LINER[1]
Unit weight (lb/ft^3)			
Total	122.0	120.5	113.0
Saturated	126.4	123.8	119.0
Effective shear strength parameters			
$\overline{c}$ (psf)	0	0	0
$\overline{\phi}$ (deg.)	33.5	33.5	29.0
Undrained shear strength (psf)[2]	1.2 $\overline{P}_o$	1.2 $\overline{P}_o$	0.95 $\overline{P}_o$
Dynamic shear strength[3]	0.61 σ_o	0.61 σ_o	$\phi = 20^o$
			$c = 225\ lb/ft^2$
Permeability (ft/yr)	-	-	1.0

(1) Both soil cover and soil-bentonite liner are compacted to 95% of maximum dry density determined in accordance with ASTM D698.

(2) $\overline{P}_o$ = mean effective principal stress, $(\overline{\sigma}_1 + \overline{\sigma}_3)/2$

(3) σ_o= effective overburden pressure

Table 2.5-6

SOIL TEST RESULTS SUMMARY
(SPRAY POND TEST PITS)

			MECHANICAL ANALYSIS			ATTERBERG LIMITS			NATURAL MOISTURE
TEST PIT NO.	DEPTH (FEET)	LABORATORY CLASS.	GRAVEL (%)	SANDS (%)	FINES (%)	LL	PL	PI	CONTENT (%)
TP-1	8.0	CL	11	13	76	32	20	12	20.1
TP-2	5.0	CL	12	24	64	34	21	13	20.9
TP-3	5.0	CL	20	19	61	37	21	16	21.1
TP-4	5.0	CL	5	7	88	39	21	18	21.9
TP-5	5.0	SC	31	22	47	48	25	23	29.5
TP-6	4.0	CL	10	25	65	44	25	19	25.1
TP-7	5.0	CL	6	13	81	40	22	18	21.8
TP-8	4.5	GC	-	-	-	-	-	-	24.8
TP-9	6.0	CL	5	12	83	41	23	18	26.7
TP-10	4.0	CL	3	9	88	40	21	19	20.7
TP-11	7.0	ML	13	14	73	45	28	17	30.7
TP-12	9.0	SC	45	14	41	35	20	15	15.0
TP-13	7.0	ML	5	11	84	41	27	14	28.5

Table 2.5-7

RESULTS OF STABILITY ANALYSIS
(2H:1V ROCK SLOPE - SPRAY POND)[2]

Water level in Pond	el of Water Table in Slope	Factor of Safety[1] Loading	Minimum Factor of Safety[1] without shotcrete	Minimum with shotcrete
Empty – rapid drawdown	251	static	1.5	5.7
Full - el 251'	251 (saturated slope)	static	>10	>10
Full - el 251'	251 (saturated slope)	SSE	1.5	4.5
Full - el 251'	241 (drained slope)	static	>10	>10
Full - el 251'	241 (drained slope)	SSE	6.0	>10

[1] These minimum factors of safety against sliding include the effect of the rock bolts. Also, the factors apply only to the least stable bedding-planes of the 2:1 rock slope, where failure of such planes would occur at the toe of the slope. The other portions of the 2:1 slope as well as all other rock slopes have factors of safety exceeding the above values.

[2] The applicable slope is shown in profile as section F, Figure 2.5-49.

DESIGN PROPERTIES USED IN ANALYSIS

Unit weight of soi	122 pcf (Table 2.5-5)
Unit weight of roc	152 pcf (Table 2.5-11)
DIP of failure plane	11°
Friction angle □ (along failure plane)	20°
Cohesion C (along failure plane)	0 psi
SSE loading (parallel to failure plane)	15% of total static weight above failure plane

Table 2.5-8

EARTHQUAKES WITH EPICENTERS WITHIN APPROXIMATELY
50 MILES OF THE SITE

YEAR	DAY	LOCAL TIME	INTENSITY[1]	LOCATION	N. LAT.	W. LONG.	DISTANCE FROM SITE[2] (mi.)
1755	Nov 26	2000	-	Philadelphia, Pa.	-	-	-
1763	Mar 22	-	-	Delaware Co., Pa.	-	-	-
1763	Oct 13	-	-	Philadelphia, Pa.	-	-	-
1763	Oct 30	1625	IV-V	New Jersey	-	-	-[3]
1772	Apr 25	0800-0900	IV	Cohantle, N.J.	-	-	-[3][4]
1777	Nov 22	-	-	Philadelphia, Pa.	-	-	-
1777	Nov 23	0700	-	Delaware Co., Pa.	-	-	-
1783	Nov 29	2215	IV-V	Philadelphia, Pa.	-	-	-
1783	Nov 30	0100-0200?	IV	Pennsylvania	40.0	75.1	30
1799	Mar 17	-	-	Philadelphia, Pa.	-	-	-
1800	Mar 17	-	-	Philadelphia, Pa.	39.75	75.25	37
1800	Nov 29	-	IV	Philadelphia, Pa.	39.75	75.25	37
1801	Nov 12	-	-	Philadelphia, Pa.	-	-	-
1811	Dec 08	2000	III	Pennsylvania	39.8	75.5	30
1840	Nov 11	-	IV	Philadelphia, Pa.	39.75	75.25	37
1840	Nov 14	-	IV	Philadelphia, Pa.	39.7	75.2	36
1870	Oct 12	-	III	Wilmington, De.	39.8	75.5	30
1871	Oct 09	0940	VII	Wilmington, De.	39.75	75.5	33
1877	Aug 10	-	III	near Trenton, N.J.	40.1	74.8	42
1877	Sep 10	0959	IV-V	Delaware Valley	40.1	74.9	37
1879	Mar 25	1930	IV-V	Delaware Valley	39.75	75.5	33
1884	May 31	-	V	Allentown, Pa.	40.6	75.5	26
1885	Jan 15	0410	III	Pennsylvania	40.3	76.3	38
1885	Mar 08	-	IV-V	Lancaster, Pa.	40.0	76.3	41
1889	Mar 08	1840	V	Pennsylvania	40	76	27
1889	Mar 09	0500	-	Pennsylvania	40	76	27
1892	Oct 10	-	III	Wilmington, De.	39.8	75.5	30
1893	Apr 26	morning	III	Lancaster, Pa.	40.1	76.2	34
1895	Sep 01	0609	VI	near High Bridge, N.J.	40.7	74.8	53
1895	Nov 20	0300	IV	Claymont, De.	39.8	75.6	30
1900	Mar 17	-	III	Philadelphia, Pa.	39.9	75.2	30
1900	Apr 28	1907	IV-V	Camden, N.J.	39.9	75.1	34
1900	Nov 29	-	III	Philadelphia, Pa.	39.9	75.2	30
1906	May 28	1730	III	Pennsylvania	40.2	75.8	12
1906	May 29	evening	IV-V	Reading, Pa.	40.3	75.9	18
1908	May 31	1242	VI	Allentown, Pa.	40.6	75.5	26
1909	Feb 06	early morning	III	Trenton, N.J.	40.2	74.7	46
1921	Jan 26	1840	V	Moorestown, N.J.	40.0	75.0	34
1933	Jan 24	2100	V	central New Jersey	40.1	74.5	58

Table 2.5-8 (Cont'd)

YEAR	DAY	LOCAL TIME	INTENSITY[1]	LOCATION	N. LAT.	W. LONG.	DISTANCE FROM SITE[2] (mi.)
1937	Jun 08	1904	-	Reading, Pa.	40.3	75.9	18
1938	Aug 22	2236	V	central New Jersey	40.1	74.5	58
1939	Apr 01	2200	-	Lancaster, Pa.	40.0	76.3	41
1939	Nov 14	2154	V	Salem Co., N.J.	39 6	75.2	48
1944	Jan 08	-	-	Wilmington, De.	39.8	75.5	30
1949	Oct 16	1833	-	Massena, N.Y.	40.4	74.8	43
1951	Nov 23	0145	-	Allentown, Pa.	40.7	75.5	33
1954	Jan 07	0225	VI	Sinking Spring, Pa.	40.3	76.0	23
1954	Jan 23	2230	-	Sinking Spring, Pa.	40.3	76.0	23
1954	Aug 10	2240	-	Sinking Spring, Pa.	40.3	76.0	23
1955	Jan 19	2200	IV	Berks Co., Pa.	40.9	75.9	49
1957	Mar 23	1403	VI	west-central N.J.	40.6	74.8	49
1961	Sep 14	2117	V	Lehigh Valley, Pa.	40.6	75.4	28
1961	Dec 27	1206	V	Pa. - N.J. border	40.1	74.8	42
1964	May 12	0145	VI(4.5)	near Cornwall, Pa.	40.2	76.5	48
1972	Dec 07	2200	IV-V	Pennsylvania	40.1	76.2	34
1973	Feb 28	0322	V-VI	New Jersey	39.7	75.4	34
1974	Apr 27	0945	(3.0)	Pennsylvania	41.00	75.96	57
1977	Jun 10	0748	(1.1)	near High Bridge, N.J.	40.70	74.89	49
1977	Jul 02	0613	(2.3)	Hampton, N.J.	40.70	74.93	47
1978	Jul 16	0139	V(3.3)	Lancaster, Pa.	39.90	76.22	41
1978	Oct 06	1425	VI(3.0)	Lancaster, Pa.	40.05	76.09	30
1979	Feb 23	0523	IV	New Jersey	40.80	74.81	56
1980	Mar 02	0654	(2.8)	Abington, Pa.	40.21	75.08	26
1980	Mar 05	1206	IV-V(3.5)	Abington, Pa.	40.17	75.07	27
1980	Mar 05	1220	(3.1)	Abington, Pa.	40.18	75.07	27
1980	Mar 11	0100	IV-V(3.7)	Abington, Pa.	40.15	75.09	26
1980	Mar 11	1116	(2.8)	Abington, Pa.	40.25	74.99	31
1980	Apr 10	1210	(2.8)	Middleton (Abington), Pa.	40.2	75.0	31
1980	Apr 16	1317	(3.2)	Newtown (Abington), Pa.	40.3	75.0	31
1980	May 02	1023	(2.8)	Langhorne (Abington), Pa.	40.16	74.99	32
1980	May 02	1402	(3.0)	Jamison (Abington), Pa.	40.24	75.03	29
1980	Aug 30	0419	(3.0)	Medford, N.J.	39.84	74.86	47

(1) Intensity based on Modified Mercalli Intensity Scale of 1931. Values in parentheses are body wave or code length type magnitudes given for earthquake size comparison.
(2) Calculated using site coordinates of 40.23 N. latitude, 75.58 W. longitude.
(3) This event may not have occurred within 50 miles of the site.
(4) Cohantle may be a misspelling of Cohansey, formerly either Bridgeton or Greenwich, N.J., approximately 60 miles from the site.

Table 2.5-9

DESIGN PARAMETERS OF SAFETY-RELATED STRUCTURES[1][2]

Safety-Related Structure	Basement Dimension	Approx. Bearing Elev.	Static Design Bearing Pressure	Maximum Hydro-static Pressure	Discussion in UFSAR Section
Containment	100'-4" dia.	174'	8.3 ksf	N/A	2.5.4.10.1.2
Reactor Enclosure	326'x137' (Units 1 & 2)	174'	31.4 ksf	1123 psf	2.5.4.10.1.2
Control Structure	132'x62'	178'	31.4 ksf	936 psf	2.5.4.10.1.2
Spray Pond Pumphouse	83'x22'-9" 151'x22'-9"	257'-6" 235'	14.1 ksf	1810 psf	2.5.4.10.1.3
Diesel Generator Enclosure	273'x86' (Units 1 or 2)	190'	22.1 ksf	Above ground-water level	2.5.4.10.1.1
Valve Pit (on soil)	7'x8' (on fill)	198'	2.7 ksf	Above ground-water level	2.5.4.10.2.3
Electrical Duct Bank (portions on soil	± 4' width x variable length	6' Below Grade	2.7 ksf	Above ground-water level	2.5.4.10.2.4
Diesel Oil Storage Tank Foundation	59'x123' (For all tanks)	189'-9"	5.4 ksf	Not req'd for a slab w/no walls	2.5.4.10.1.4

(1) Bearing capacities of rock material = 60 ksf (Table 2.5-11)
(2) Bearing capacities of soil material = 6 ksf (Section 2.5.4.10.2.4)

Table 2.5-10

SOIL-RESPONSE STUDY
SUMMARY OF PARAMETERS AND RESULTS

DESCRIPTPION OF PARAMETERS	CASE A	CASE B	CASE C
STRATIGRAPHY			
Type 1 Fill			
Depth, ft	40	40	40
K_2	140	100	180
Strain level, in/in	10^{-6}	10^{-6}	10^{-6}
Total unit wt, pcf	140	140	140
At rest earth pressure coefficient	0.7	0.7	0.7
Depth, Centerline Pipe, ft	13	13	13
Rock			
Shear modulus, psf	$1700x10^5$	$1700x10^5$	$1700x10^5$
RESPONSE			
Response at Centerline Pipe			
Peak acceleration, g	0.36	0.32	0.36
Peak particle velocity, ft/sec	0.87	0.76	0.83
Frequency of soil column, Hz	5.9	4.8	7.1

Table 2.5-11

REPRESENTATIVE ENGINEERING PROPERTIES
OF SOUND FOUNDATION ROCK[1]

PROPERTY	APPROXIMATE AVERAGE VALUE	RANGE	REFERENCE
Unconfined compressive strength	15,820 psi	6,370 - 24,540 psi	Table 2.5-3
Allowable bearing pressure			
Normal load	420 psi	-	[2]
Normal plus dynamic load	625 psi	-	[2]
Density	152 lbs/ft^3	140 - 162 lbs/ft^3	Table 2.5-3
Compressional wave velocity (refraction)	12,500 fps	7,000 - 20,000 fps	Section 2.5.4.4.1
Shear-wave velocity (refraction)	5,950 fps	5,800 - 6,100 fps	Section 2.5.4.4.2
Poisson's ratio (measured)	0.30	-	[2]
Modulus of elasticity[3] (dynamic)	3.0x10^6 psi	-	-
Modulus of elasticity[2] (static)	6.9x10^5 psi	-	-
Shear modulus[3]	1.2x10^6 psi	-	-

(1) From measurements on unweathered rock in power block area.
(2) Dames and Moore, Foundation Report dated October 5, 1970, and letter from Dames and Moore to PECo dated August 19, 1971.
(3) Calculated from average shear-wave velocity and Poission's ratio given above.

Table 2.5-12

STATIC MODULI OF FOUNDATION ROCK[1]

BORING NUMBER	ELEVATION (ft)	PEAK COMPRESSIVE STRESS (psi)	YOUNG'S MODULUS (E) (psix10^6)
232	193.0	24,810	5.17
271	157.0	8,000	6.67
272	191.0	18,800	4.0
274	180.0	10,950	3.33
275	190.5	16,670	3.22
276	198.5	18,630	3.2
279	209.0	14,950	2.7
285	148.6	10,900	1.8
285	145.1	9,260	1.2
286	131.8	16,970	3.4
286	121.8	19,440	5.6
287	137.0	28,180	8.3
287	117.5	32,870	7.8
288	150.8	15,450	3.3
288	142.3	9,100	1.8

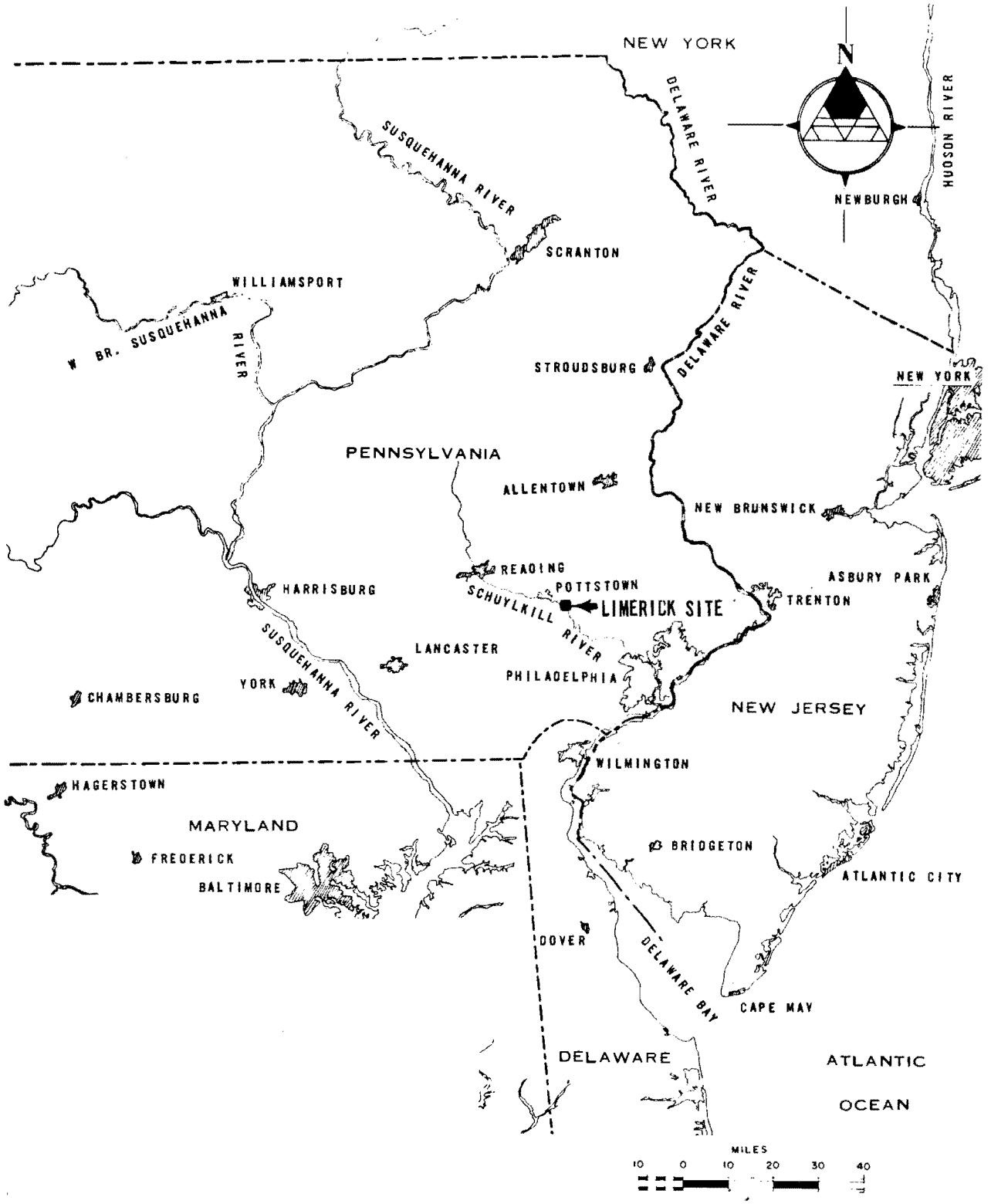
(1) Source: From appendix, table II of Dames and Moore Foundation Report dated October 5, 1970.

Table 2.5-13

SONIC TESTS ON INTACT CORES[1]

Boring No.	Depth (ft)	Compressional Wave Velocity (fps)
120	31.9	12,200
120	32.7	16,100
120	37.9	13,900
120	79.5	12,300
121	27.8	10,400
121	31.6	11,000
121	22.8	10,400
232	41	11,110
272	43	11,160

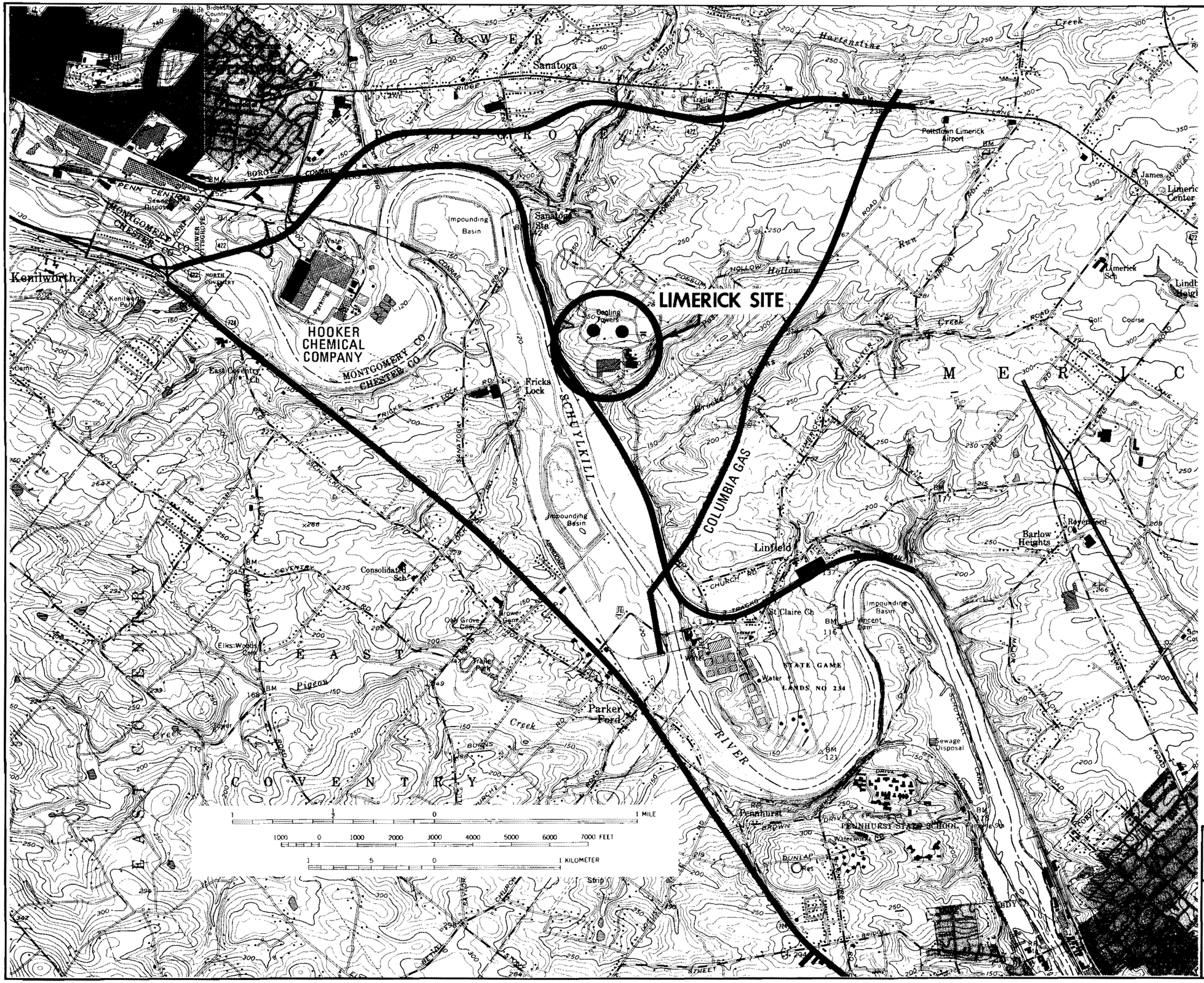
(1) Source: From table 2.5-2 of Dames and Moore Site Environmental Studies dated July 31, 1970, and appendix, table 1 of Dames and Moore Foundation Report dated October 5, 1970.



LIMERICK GENERATING STATION
UNITS 1 AND 2
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SITE LOCATION MAP

FIGURE 2.1-1

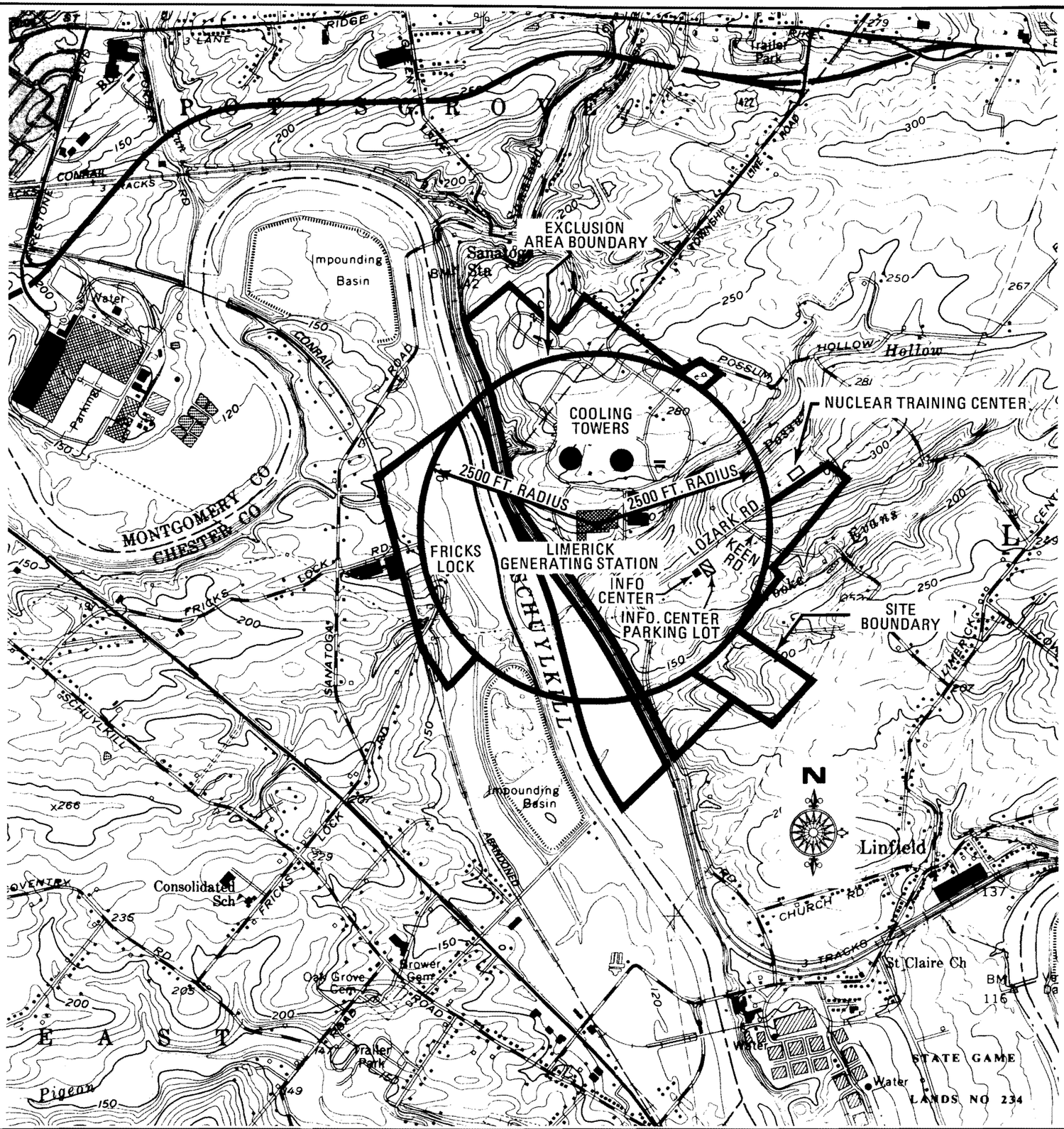


NOTE: THIS FIGURE IS BASED ON THE U.S. GEOLOGICAL SURVEY MAPS OF POTTSTOWN, PA. (PHOTO REVISED 1973), AND PHOENIXVILLE, PA. (PHOTO REVISED 1983).

LIMERICK GENERATING STATION
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GENERAL SITE AREA MAP

FIGURE 2.1-2 REV. 52, 06/88



NOTE: THIS FIGURE IS BASED ON THE U.S. GEOLOGICAL SURVEY MAP OF PHOENIXVILLE, PA. (PHOTO REVISED 1983).

LIMERICK GENERATING STATION
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SITE PLAN

FIGURE 2.1-3 REV. 52, 06/88

NORMAL RELEASE POINTS

PA STATE COORDINATES,
SOUTH ZONE (IN FEET).
ELEVATIONS (FEET MSL)

① TURBINE ENCLOSURE VENT (NORTH STACK)
N 331,932
E 2,603,786.5
ELEVATION 416

② TWO HVAC VENTS FOR REACTOR ENCLOSURES
N 331,782
E 2,603,786.5
ELEVATION 416

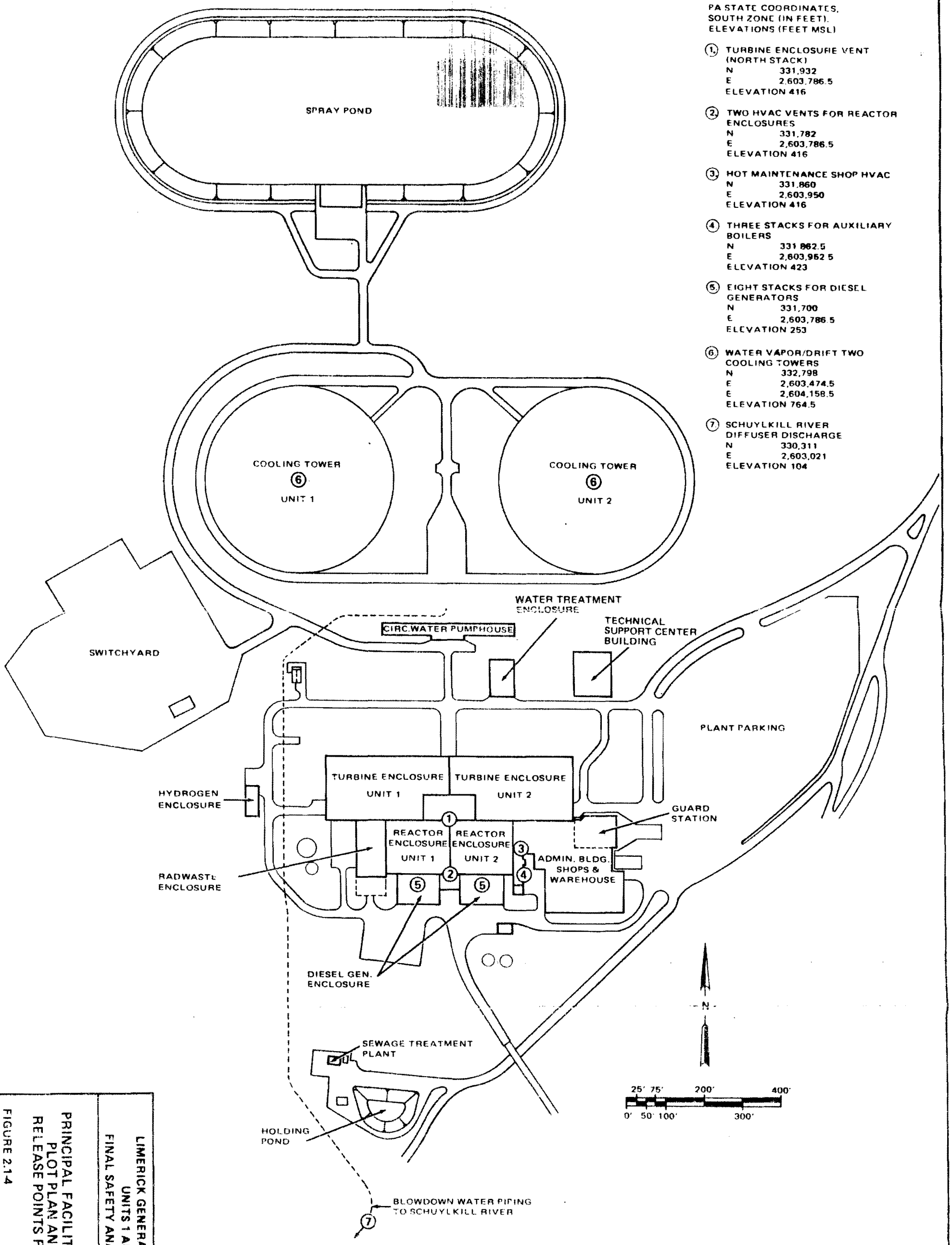
③ HOT MAINTENANCE SHOP HVAC
N 331,860
E 2,603,950
ELEVATION 416

④ THREE STACKS FOR AUXILIARY BOILERS
N 331 862.5
E 2,603,952 5
ELEVATION 423

⑤ EIGHT STACKS FOR DIESEL GENERATORS
N 331,700
E 2,603,786.5
ELEVATION 253

⑥ WATER VAPOR/DRIFT TWO COOLING TOWERS
N 332,798
E 2,603,474.5
E 2,604,158.5
ELEVATION 764.5

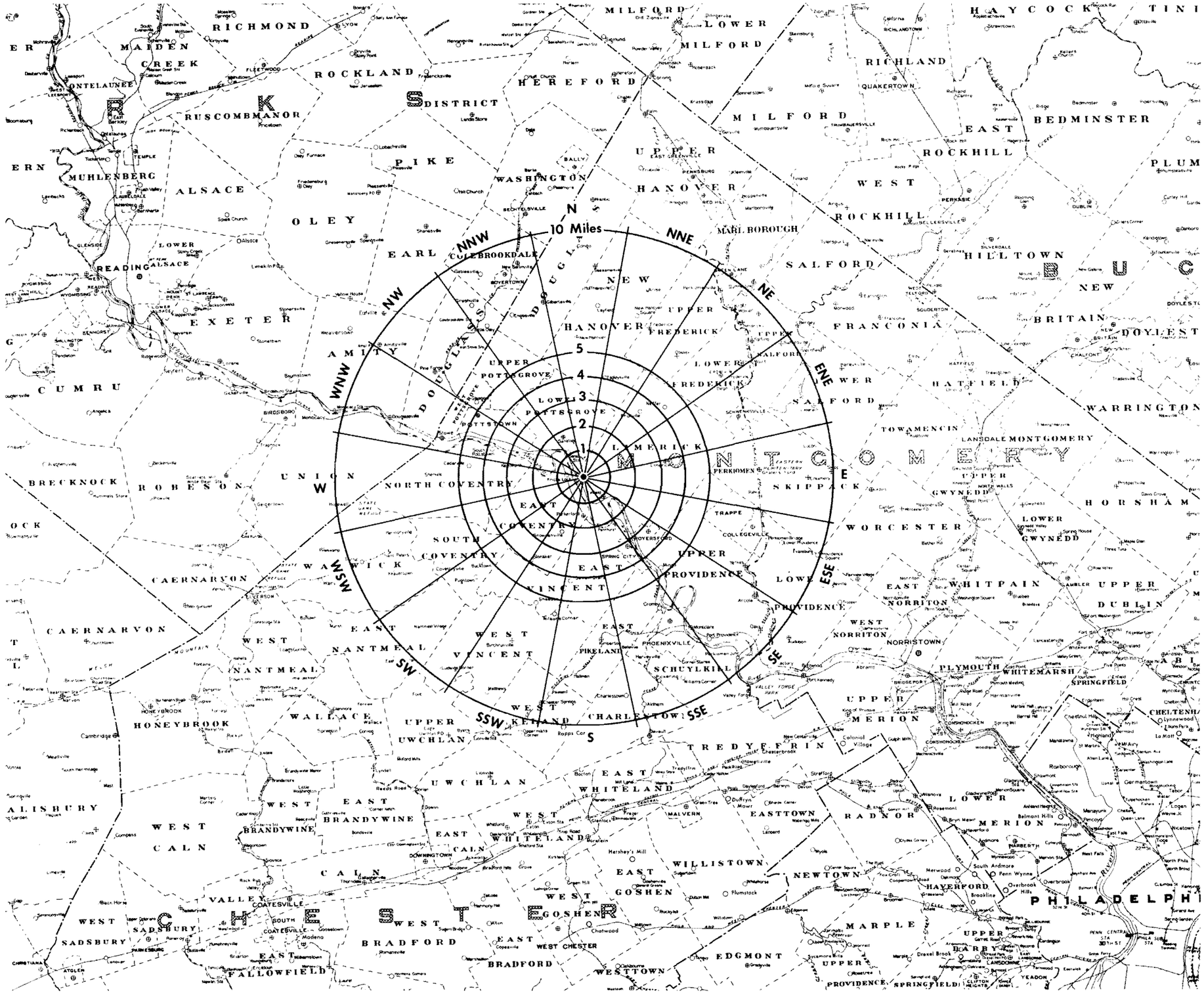
⑦ SCHUYLKILL RIVER DIFFUSER DISCHARGE
N 330,311
E 2,603,021
ELEVATION 104



LIMERICK GENERATING STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

PRINCIPAL FACILITY STRUCTURES
PLOT PLAN AND NORMAL
RELEASE POINTS FOR EFFLUENTS

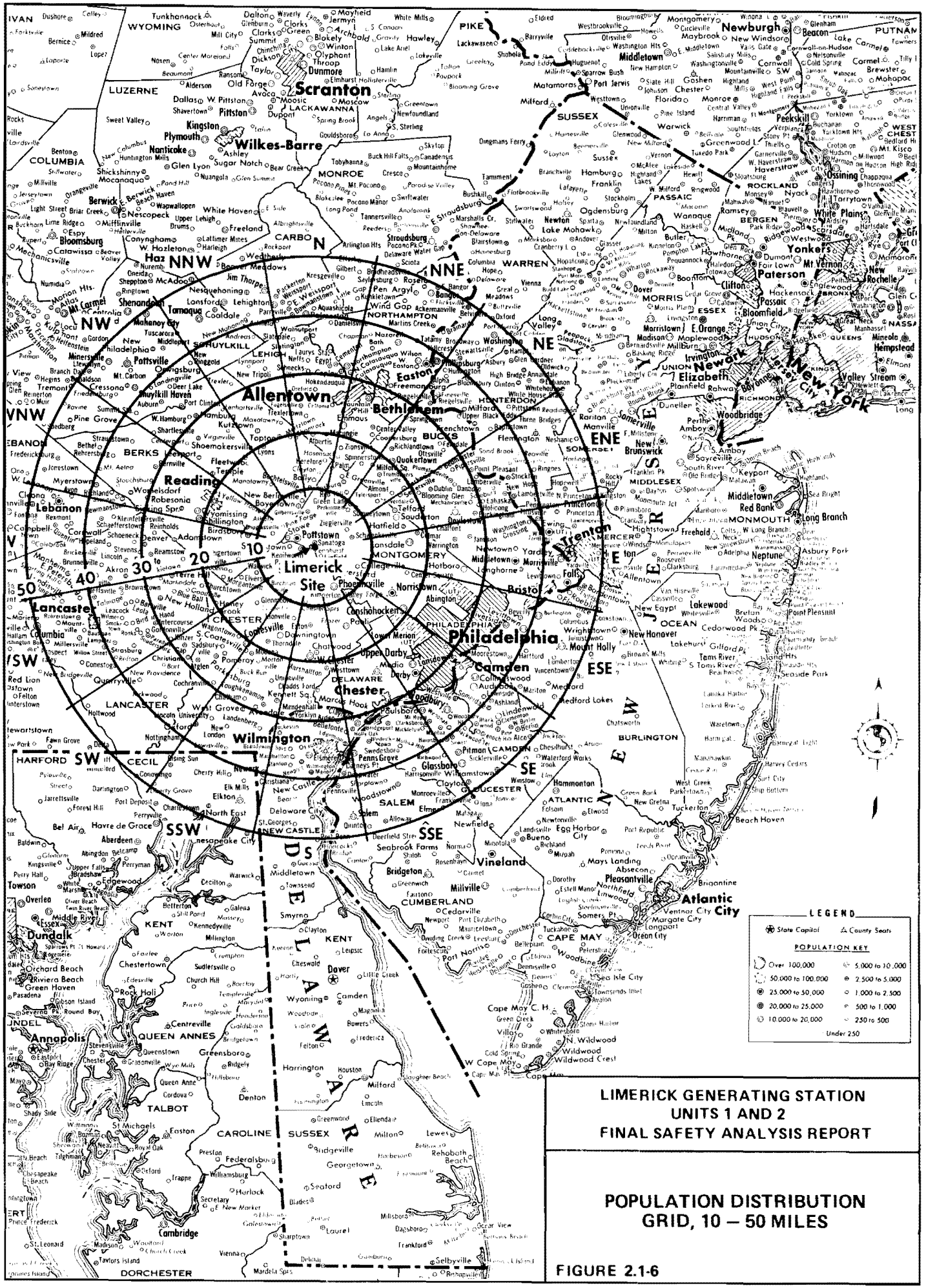
FIGURE 2.1-4 REV. 8, 07/82



LIMERICK GENERATING STATION
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POPULATION DISTRIBUTION GRID, 0 – 10 MILES

FIGURE 2.1-5

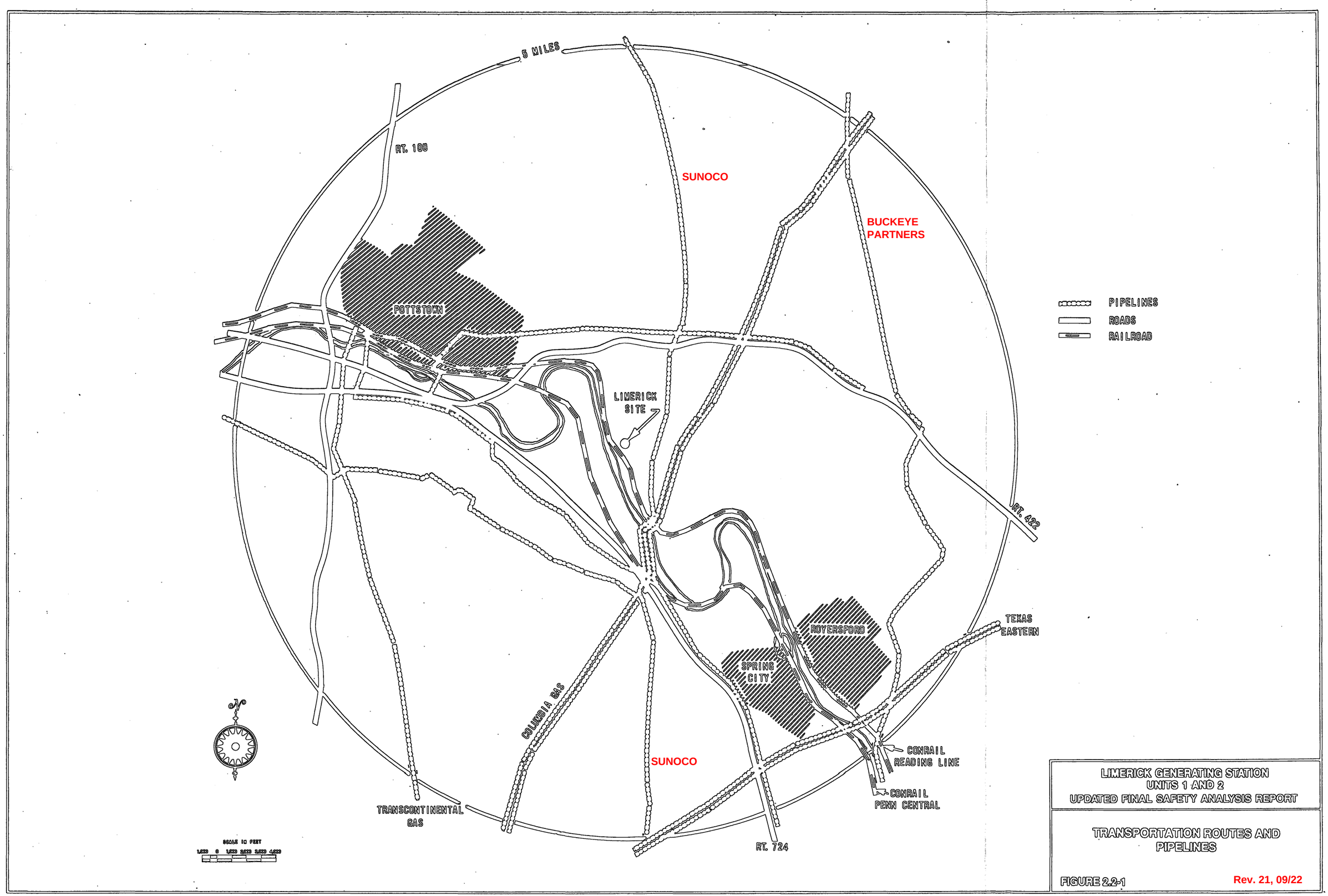

Scranton
Wilkes-Barre
Allentown
Bethlehem
Easton
Reading
Pottsville
Lebanon
Lancaster
Limerick Site
Philadelphia
Camden
Chester
Wilmington
Trenton
Atlantic City
Vineland
Millville
Dover
Annapolis
Cambridge
Salisbury
Newark
Elizabeth
Paterson
Yonkers
New York
Peekskill
Newburgh
Middletown
Poughkeepsie
Hazleton
Sunbury
Harrisburg
Chambersburg
Hagerstown
Frederick
Baltimore
Towson
Dundalk
Glen Burnie
Aberdeen
Havre de Grace
Elkton
Newark
Georgetown
Seaford
Milford
Laurel
Delmar
Ocean City
Cape May
Wildwood
Pleasantville
Egg Harbor City
Hammonton
Millville
Bridgeton
Salem
Penns Grove
Glassboro
Woodbury
Mount Holly
Burlington
Trenton
Princeton
New Brunswick
Perth Amboy
Toms River
Lakewood
Asbury Park
Long Branch
Red Bank
Freehold
Morristown
Dover
Boonton
Hackensack
Passaic
Clifton
Jersey City
Hoboken
Weehawken
Union City
Bayonne
Staten Island
Long Island
Valley Stream
Hempstead
Mineola
Nassau
Queens
Brooklyn
Manhattan
Bronx
Westchester
Rockland
Orange
Sussex
Warren
Pike
Monroe
Carbon
Schuylkill
Northumberland
Snyder
Union
Lycoming
Clinton
Centre
Blair
Cambria
Somerset
Fayette
Greene
Washington
Allegheny
Beaver
Lawrence
Mercer
Crawford
Erie
Warren
McKean
Potter
Tioga
Bradford
Susquehanna
Wayne
Pike
Lackawanna
Luzerne
Columbia
Montour
Northumberland
Dauphin
Lebanon
Lancaster
York
Adams
Franklin
Fulton
Huntingdon
Bedford
Blair
Cambria
Somerset
Fayette
Greene
Washington
Allegheny
Beaver
Lawrence
Mercer
Crawford
Erie
Warren
McKean
Potter
Tioga
Bradford
Susquehanna
Wayne



LIMERICK GENERATING STATION
UNITS 1 AND 2
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LOW POPULATION ZONE

FIGURE 2.1-7 **REV. 11, 10/82**

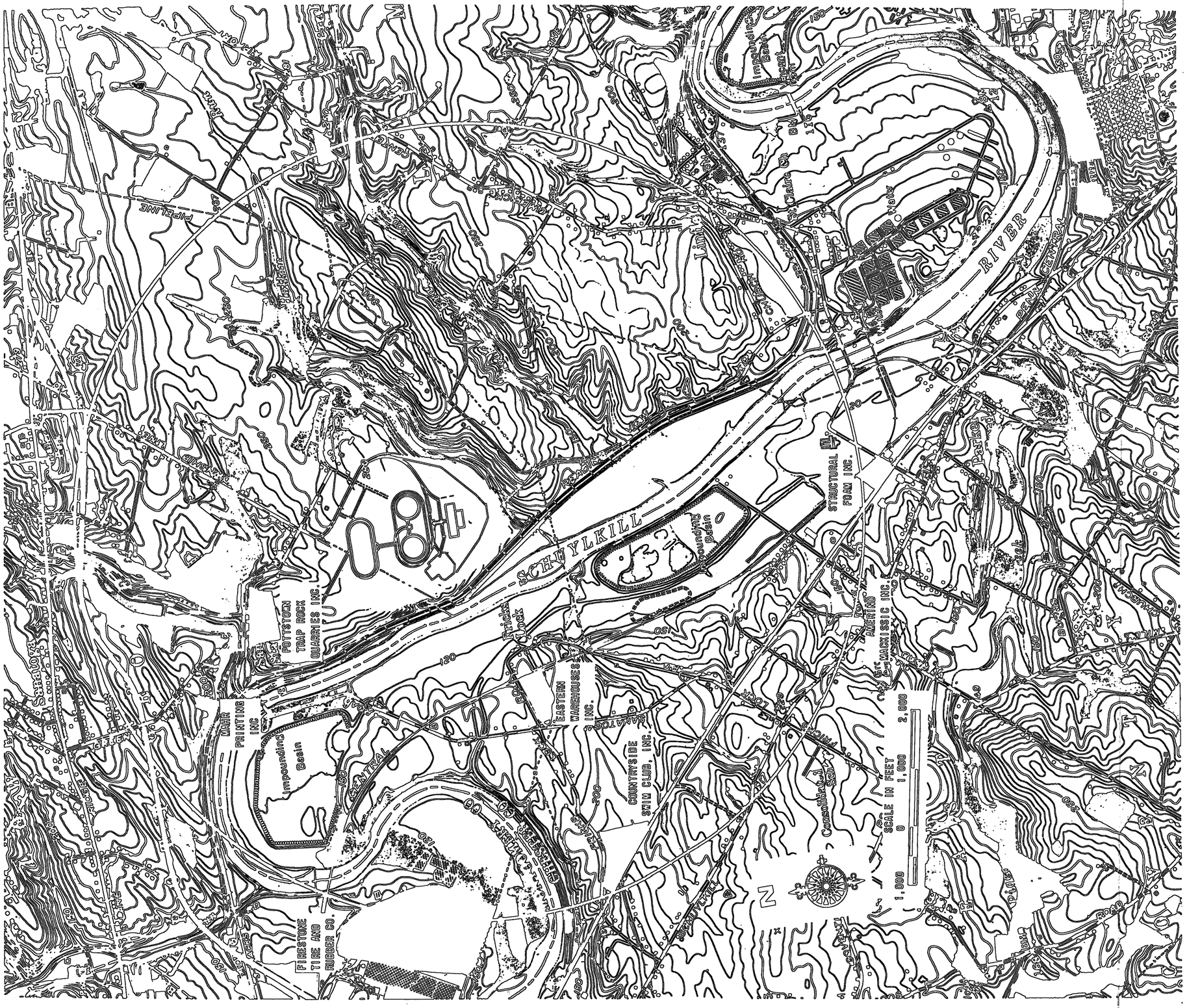


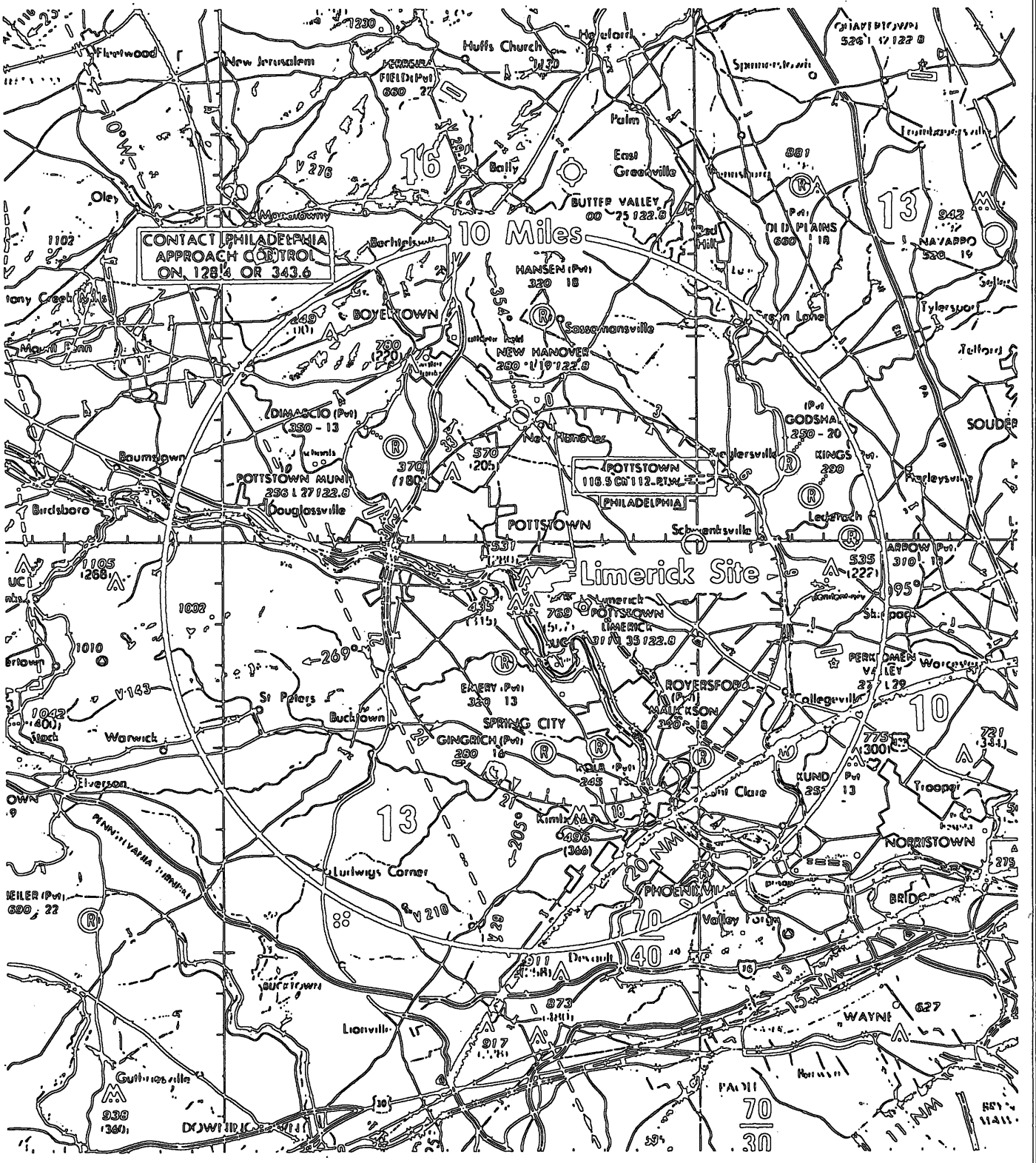
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TRANSPORTATION ROUTES AND PIPELINES

FIGURE 2.2-1

Rev. 21, 09/22

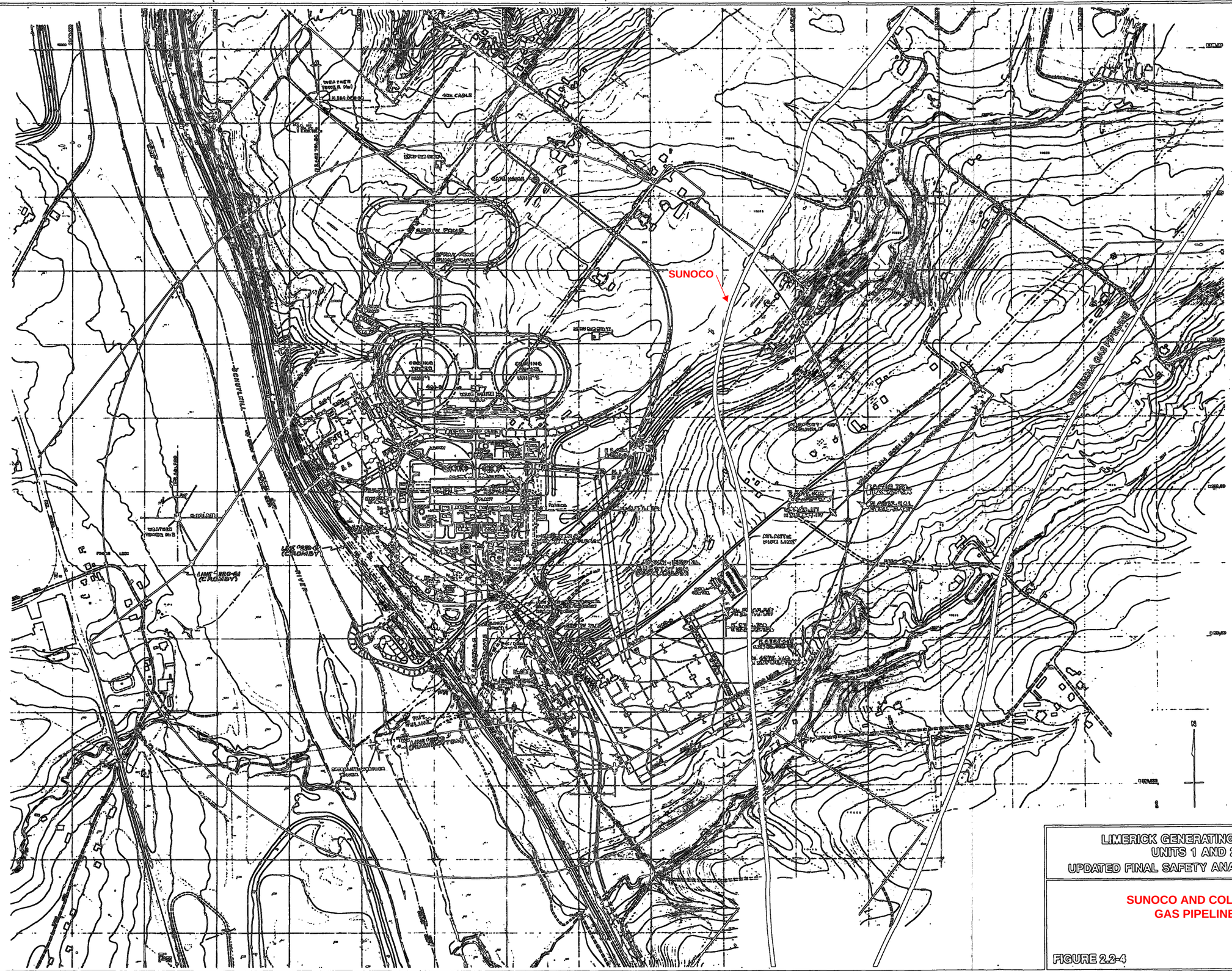

RIVER
SCHUYLKILL
Impounding Basin
Impounding Basin
Limerick Generating Station
Limerick Generating Station
Limerick Generating Station



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

AIRPORTS AND
AIRWAY ROUTES

FIGURE 2.2-3

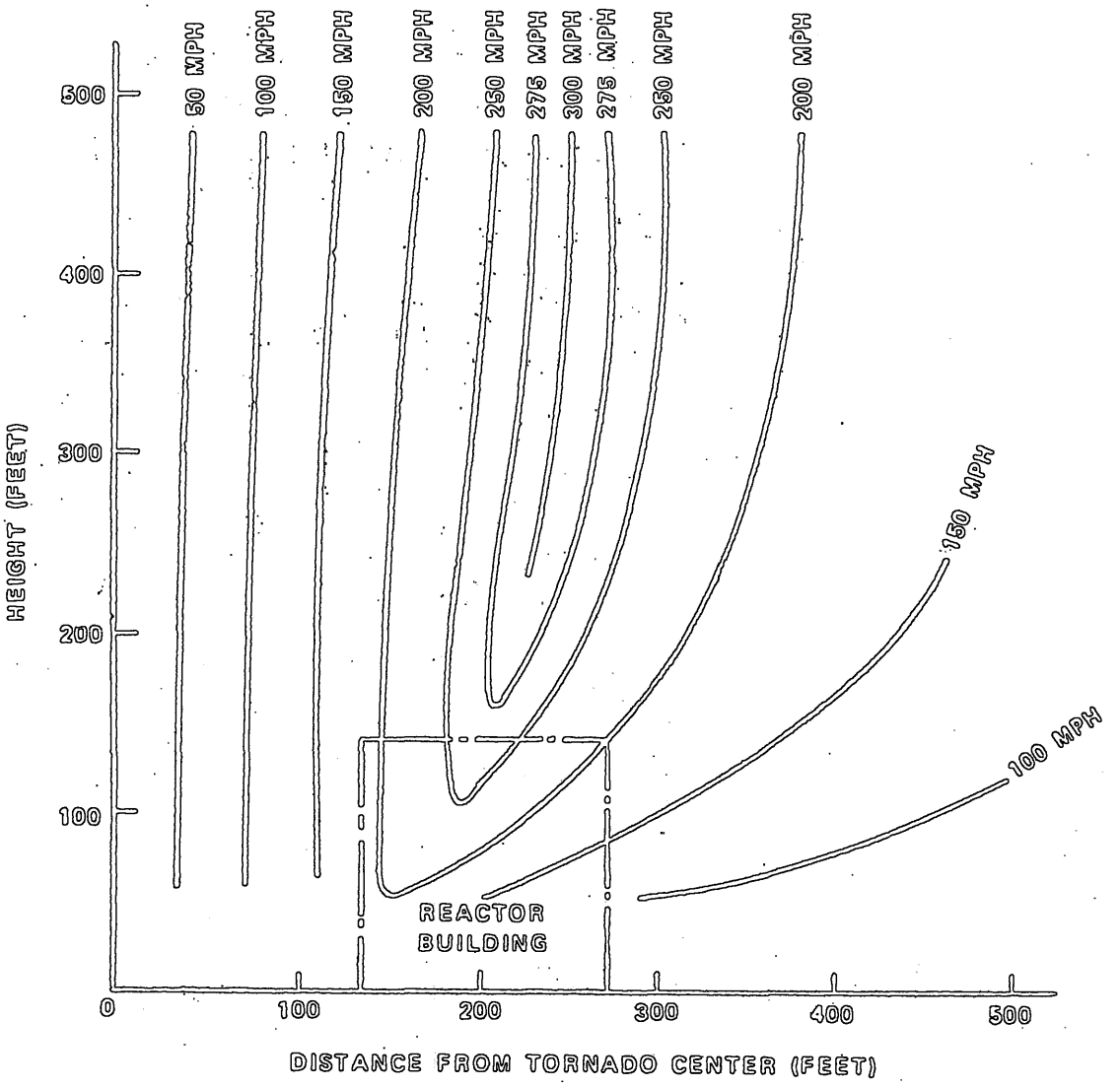


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUNOCO AND COLUMBIA
GAS PIPELINES

Rev. 21, 09/22

FIGURE 2.2-4

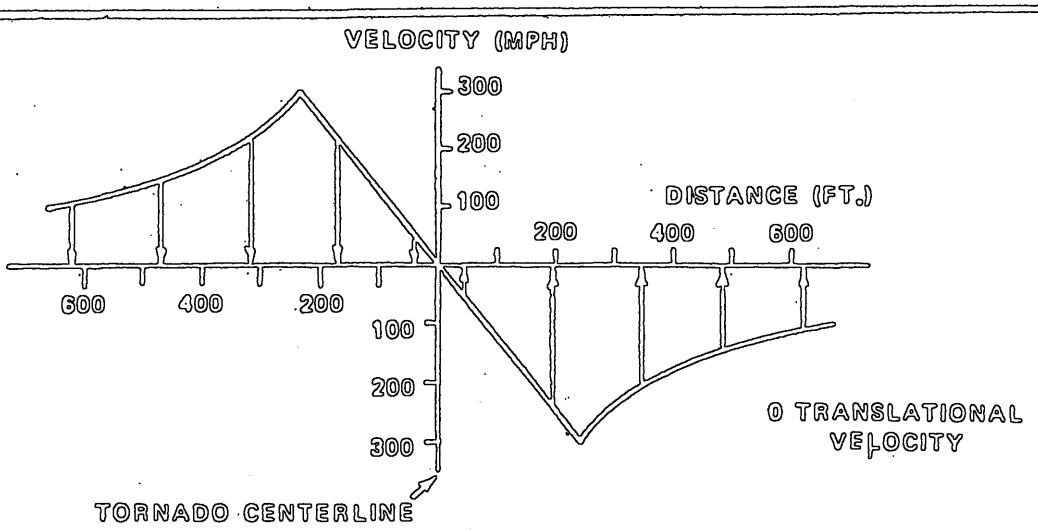


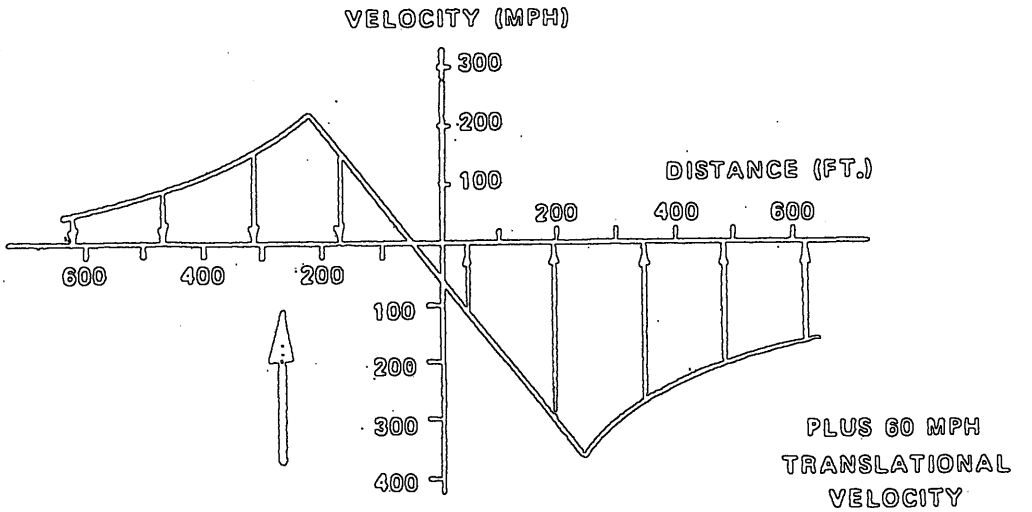
NOTE: DATA EXTRAPOLATED FROM W. H. HOECKER "WIND SPEED AND AIR FLOW IN THE DALLAS TORNADO OF APRIL 2, 1957" MONTHLY WEATHER REVIEW 83, 5, 167, 1960

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

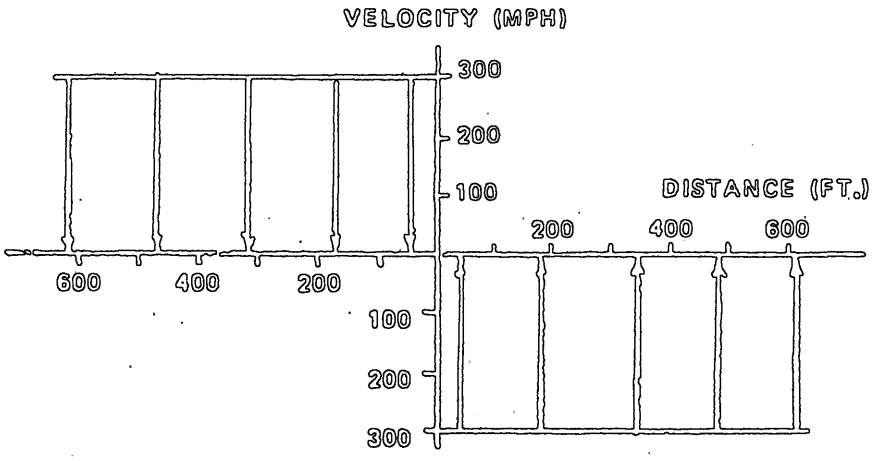
TANGENTIAL VELOCITY DISTRIBUTION

FIGURE 2.3.1-1





Design Tornado Tangential Velocity



Tornado Wind Velocity Design Criteria

NOTE: DATA EXTRAPOLATED FROM W. H. HOECKER "WIND, SPEED, AND AIR FLOW IN THE DALLAS TORNADO OF APRIL 2, 1937" MONTHLY WEATHER REVIEW 88, 5, 167, 1939

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UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

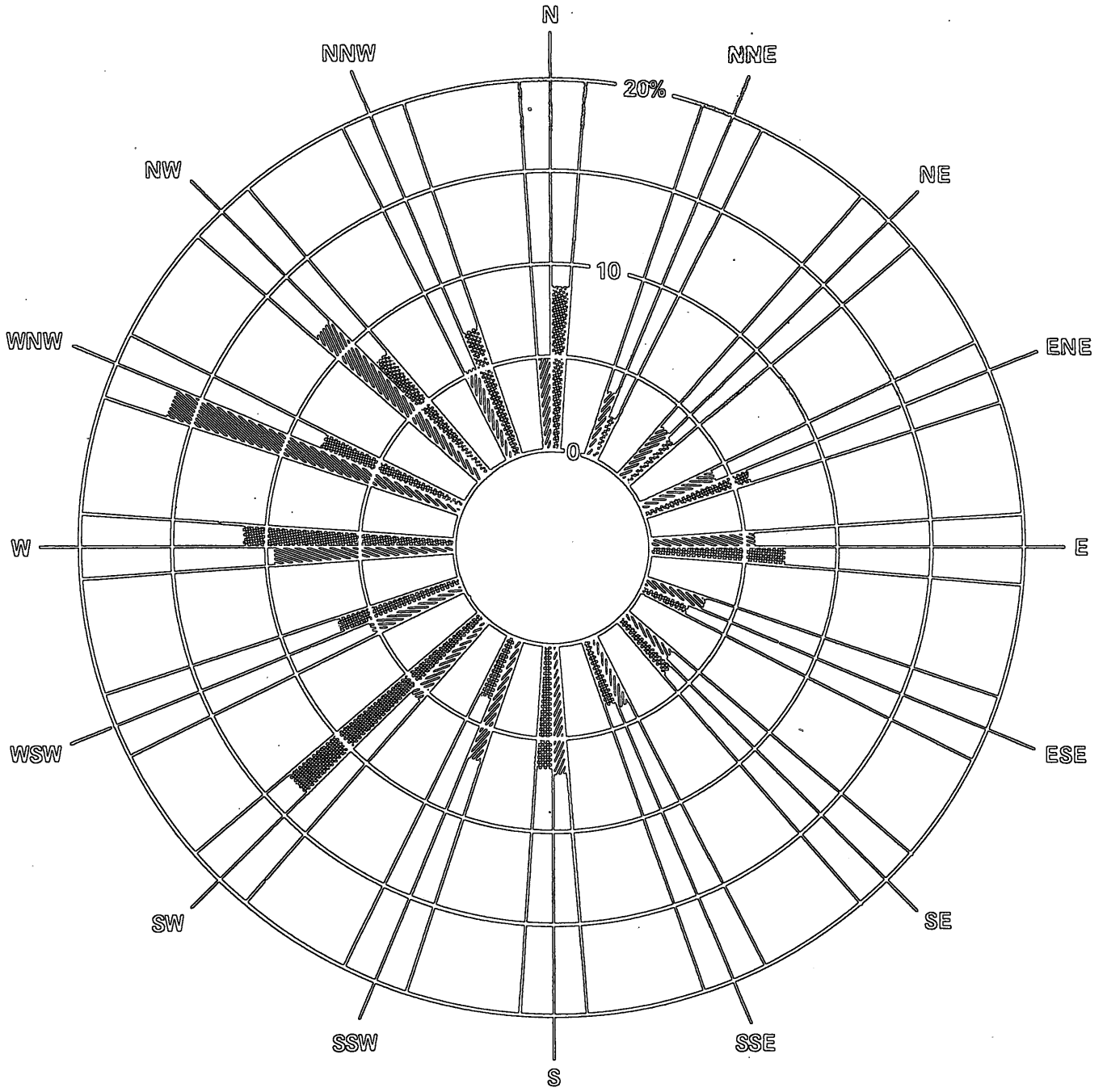
DERIVATION OF DESIGN TORNADO WIND VELOCITY

FIGURE 2.3.1-2

LIMERICK
1/72-12/76
HEIGHT 270 FT.

VS

PHILADELPHIA
1/71-12/75
HEIGHT 20 FT.



PHILADELPHIA — 1.0% CALM

LIMERICK — 1.2% CALM

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

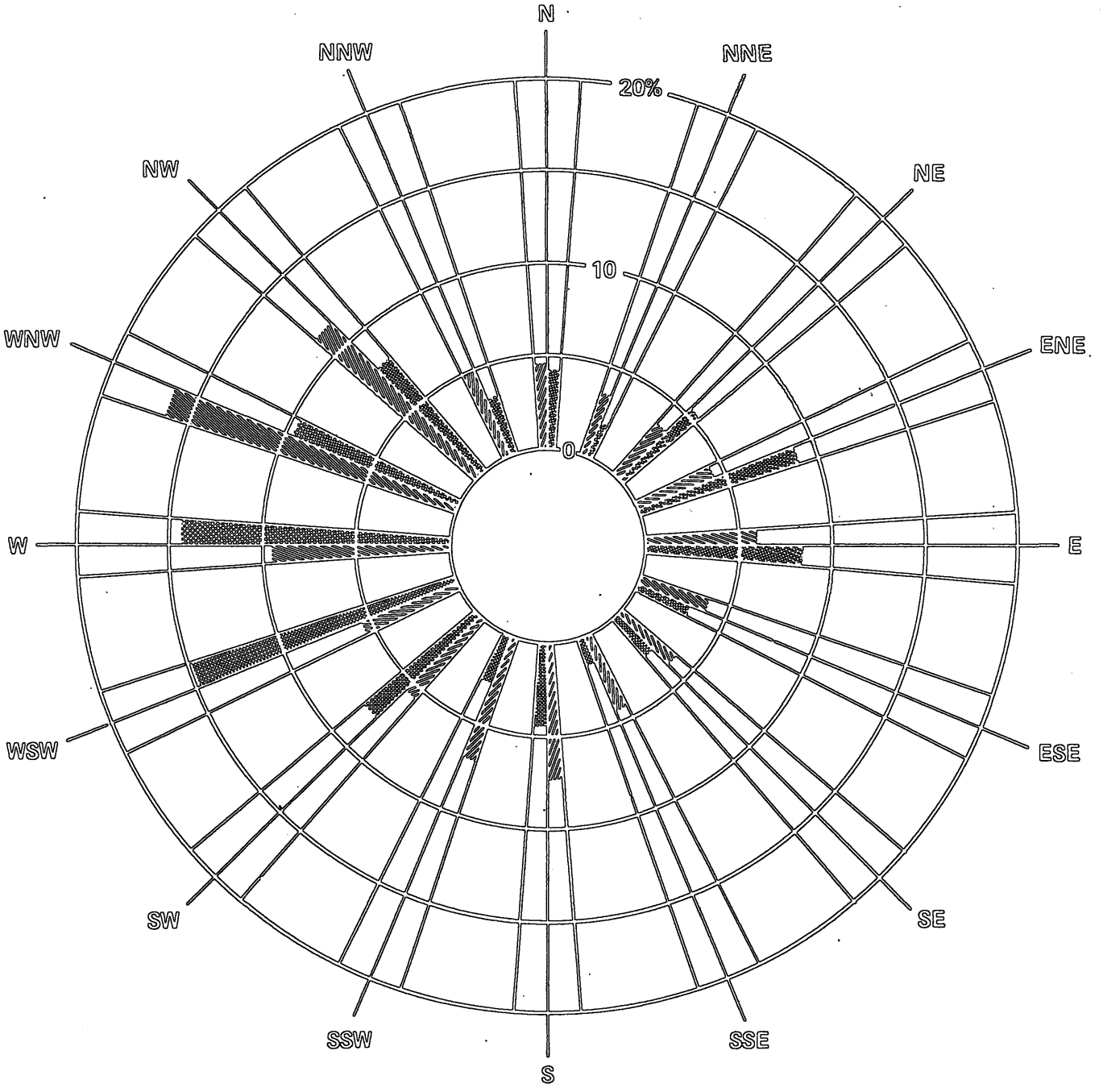
LIMERICK VS. PHILADELPHIA
WIND DIRECTION PERCENTAGE

FIGURE 2.3.2-1

LIMERICK
1/72-12/76
HEIGHT 270 FT.

VS

ALLENTOWN
1/73-12/73
HEIGHT 20 FT.



LIMERICK — 1.2% CALM

ALLENTOWN — 9.9% CALM

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

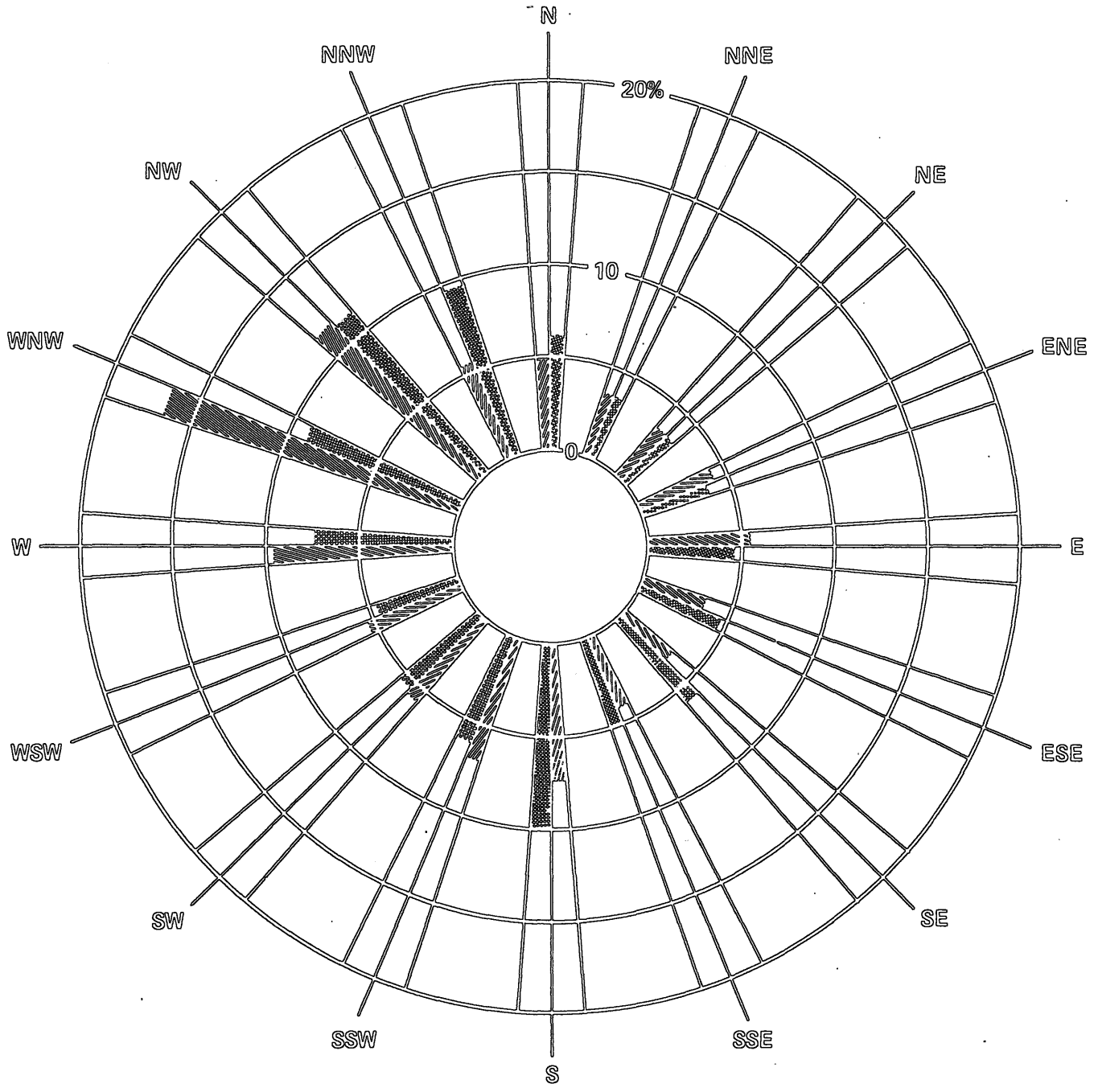
LIMERICK VS. ALLENTOWN
WIND DIRECTION PERCENTAGE

FIGURE 2.3.2-2

LIMERICK
1/72-12/76
HEIGHT 270 FT.

VS

PEACH BOTTOM
1/72-12/76
HEIGHT 320 FT.



LIMERICK — 1.2% CALM

PEACH BOTTOM — 2.0% CALM

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LIMERICK VS. PEACH BOTTOM WIND DIRECTION PERCENTAGE

FIGURE 2.3.2-3

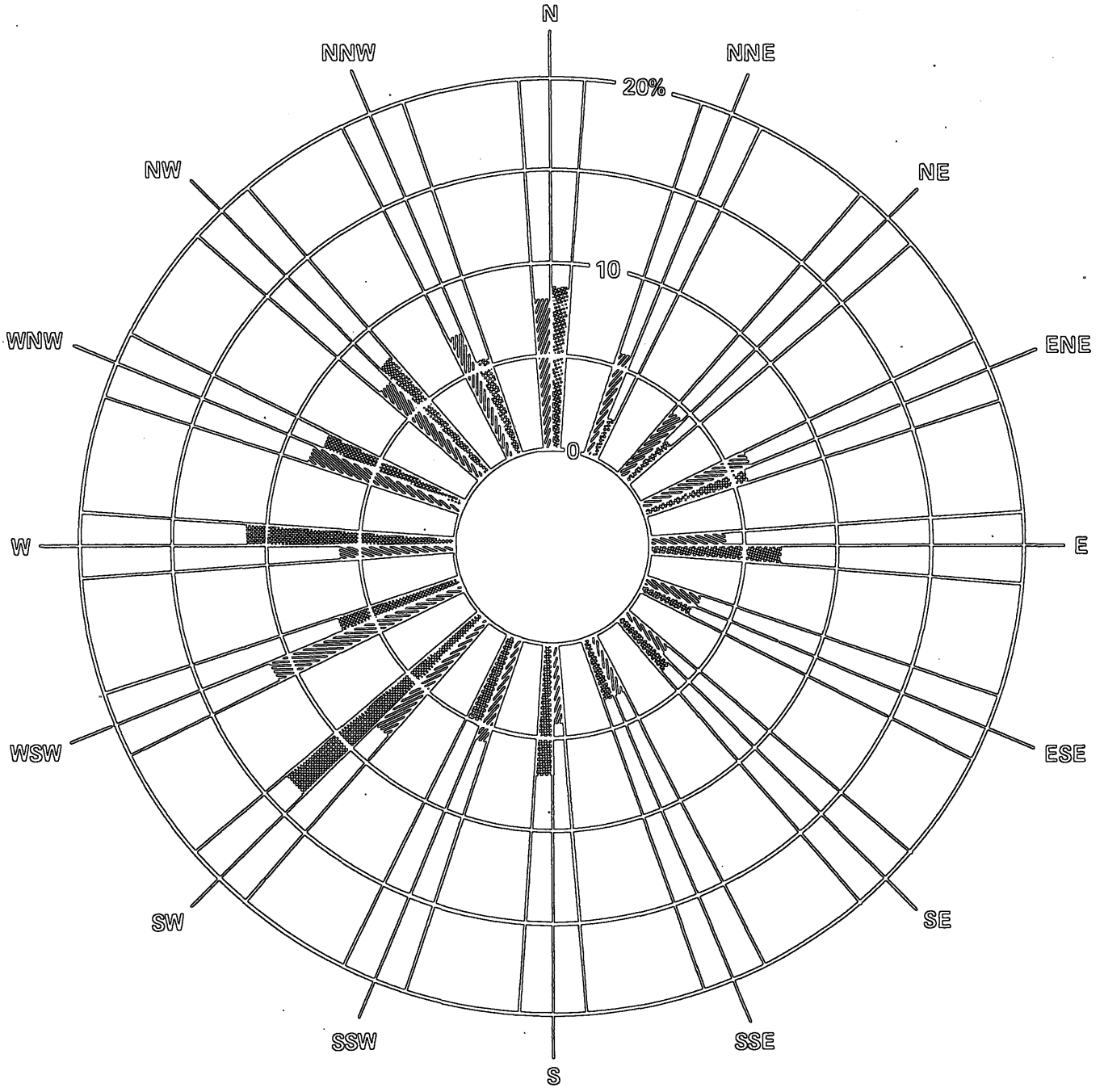
PHILADELPHIA
1/51 - 12/60

HEIGHT - 58 FT. TO 12/22/54
120 FT. 12/23/54 - 12/31/59
20 FT. THEREAFTER

VS.

PHILADELPHIA
1/72 - 12/75

HEIGHT - 20 FT.



1/51 - 12/60 — 7.0 % CALM

1/71 - 12/75 — 1.0 % CALM

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PHILADELPHIA WIND
DIRECTION PRECENTAGE

FIGURE 2.3.2-4

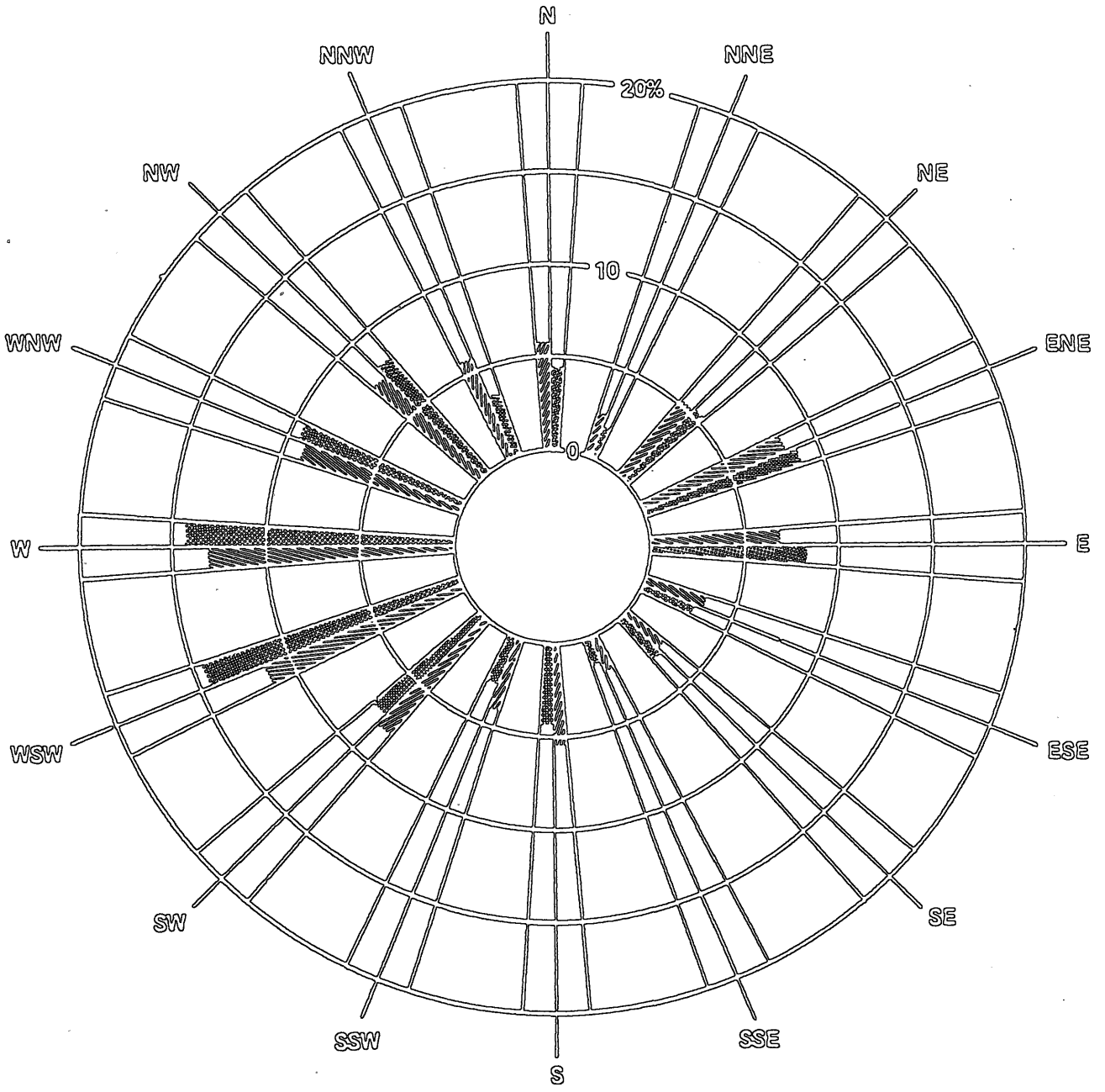
ALLENTOWN
1/64 - 12/73

HEIGHT - 69 FT. TO 12/1/65
20 FT. THEREAFTER

VS

ALLENTOWN
1/73 - 12/73

HEIGHT - 20FT.



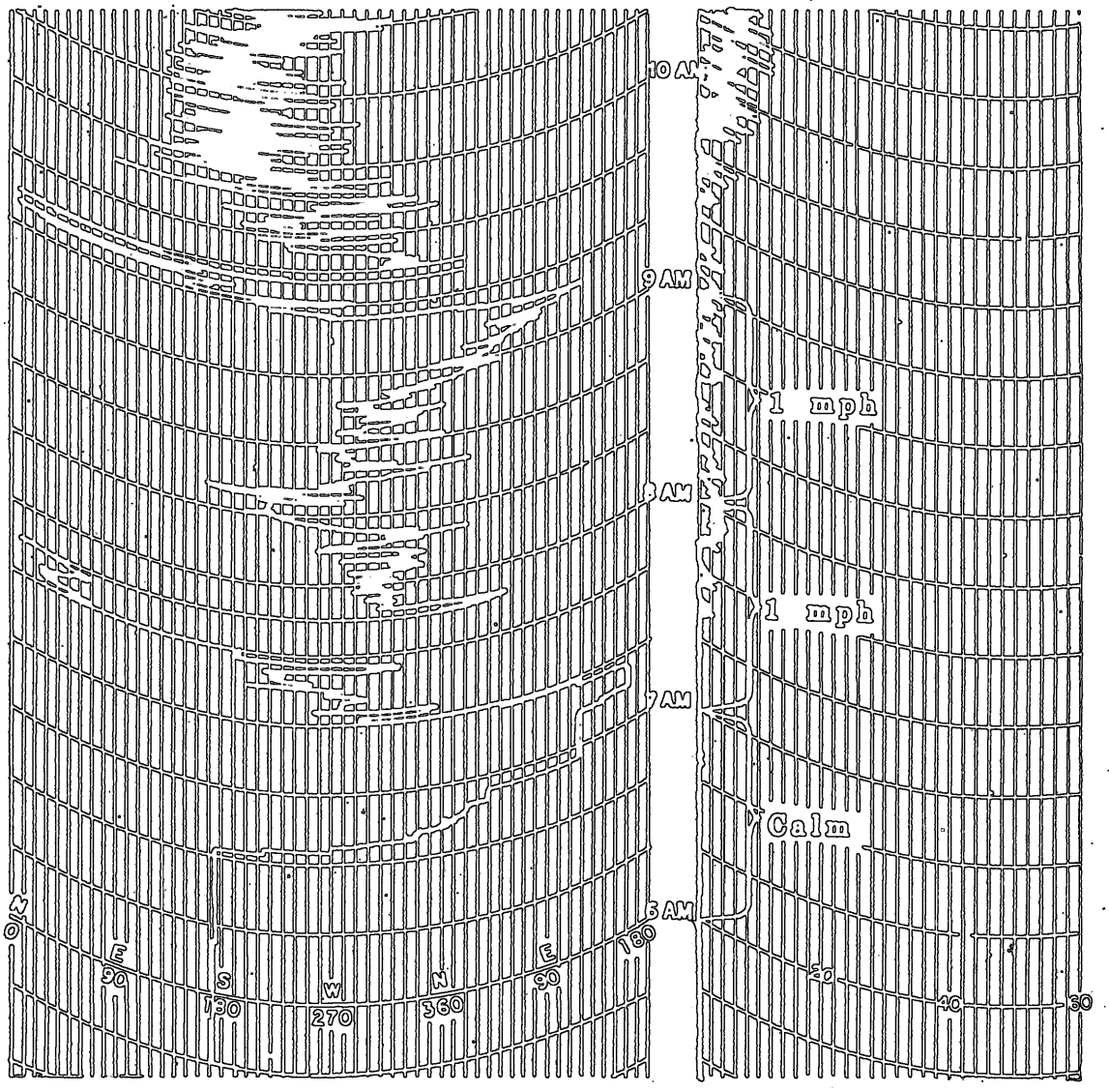
1/64 - 12/73 — 8.1 % CALM

1/73 - 12/73 — 9.9 % CALM

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

ALLENTOWN VS. ALLENTOWN
WIND DIRECTION PERCENTAGE
AT 20 AND 270 FEET

FIGURE 2.3.2-5



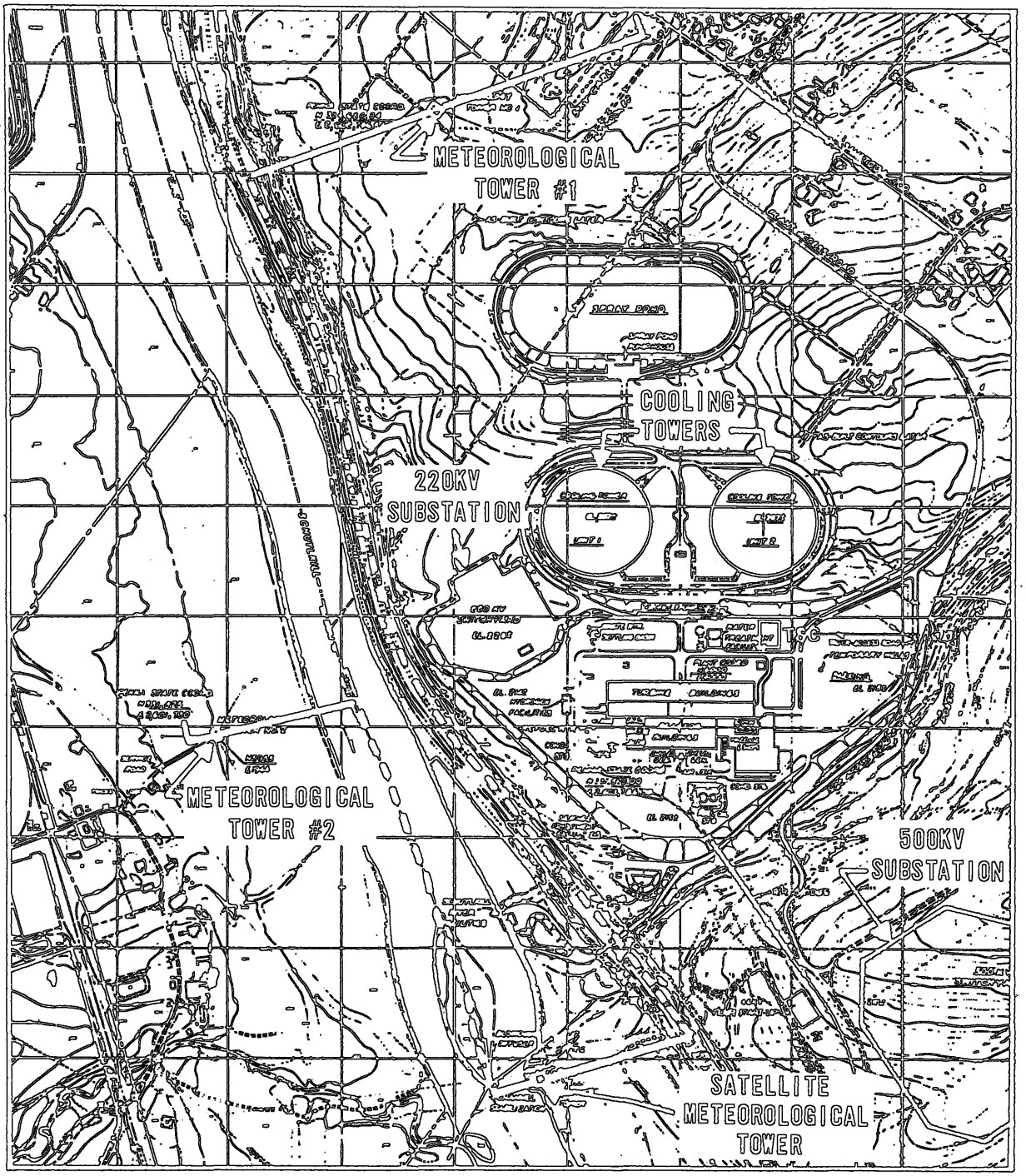
WIND DIRECTION

WIND SPEED

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL LIGHT WIND TRACES

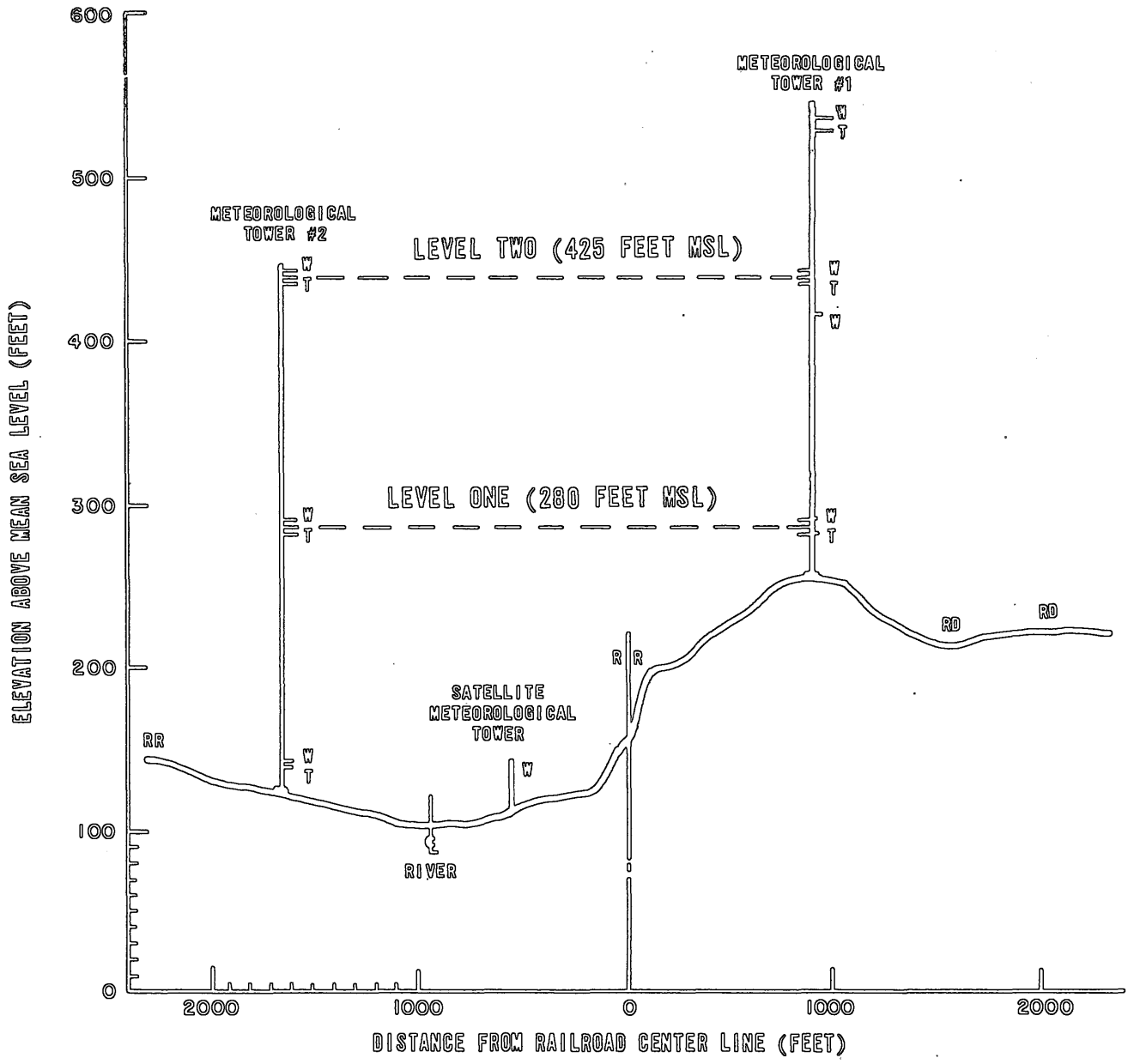
FIGURE 2.3.2-6



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LOCATION OF METEOROLOGICAL INSTRUMENTS

FIGURE 2.3.3-1



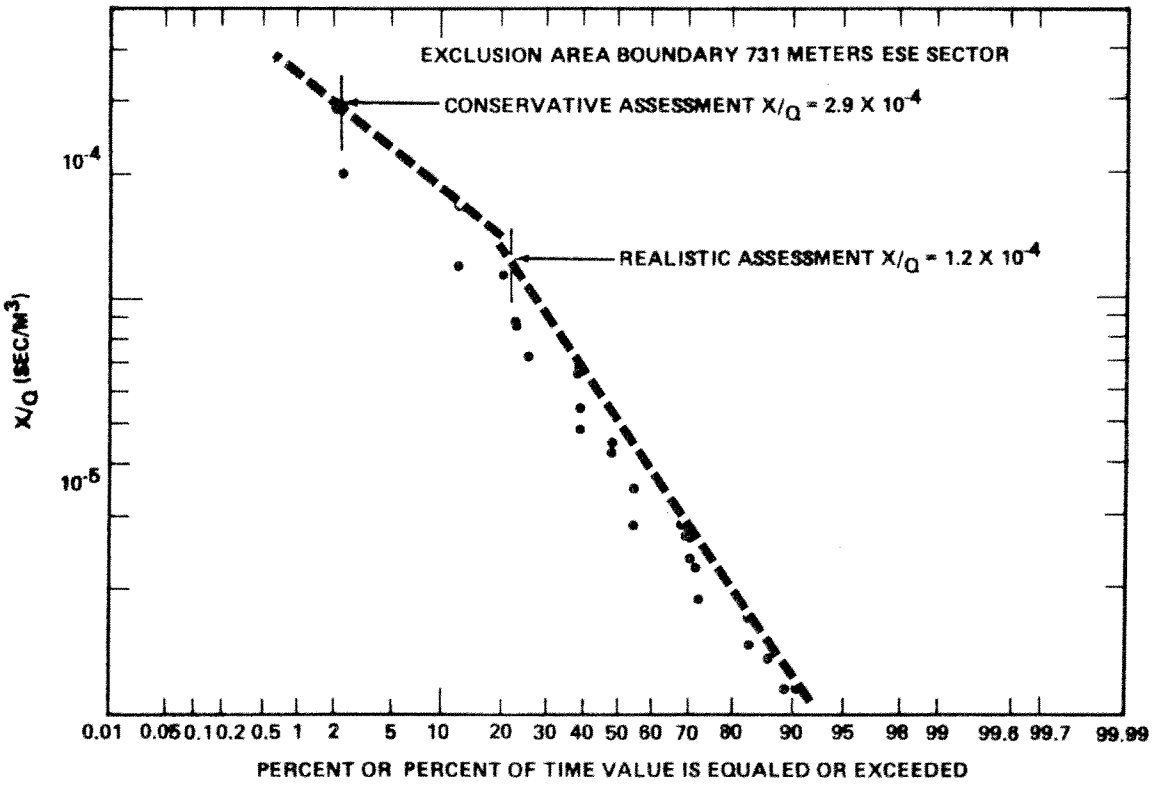
SECTION A–A

W WIND SENSOR
T TEMPERATURE SENSOR

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

ELEVATIONS OF METEOROLOGICAL INSTRUMENTS AT LIMERICK SITE

FIGURE 2.3.3-2

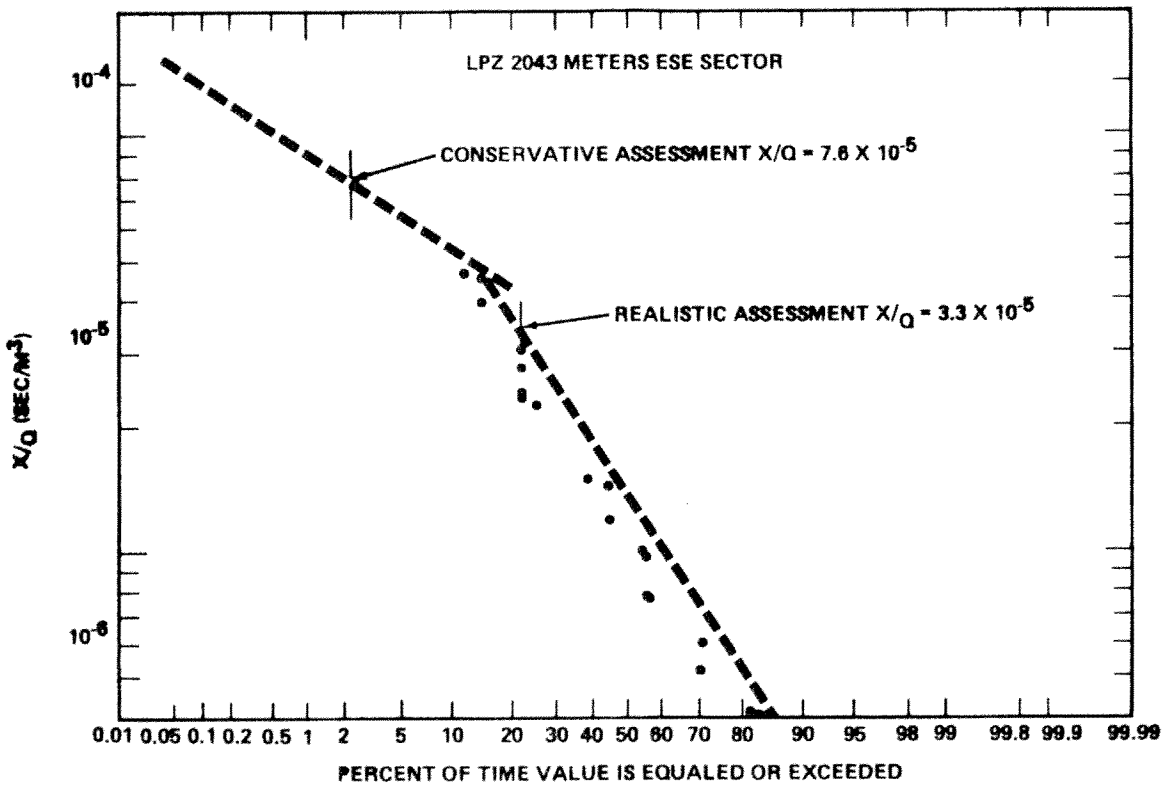


NOTE: Information in this figure is for historical purposes only.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CUMULATIVE PROBABILITY DISTRIBUTION OF X/Q FOR THE EXCLUSION BOUNDARY

FIGURE 2.3.4-1 REV. 14, 09/08

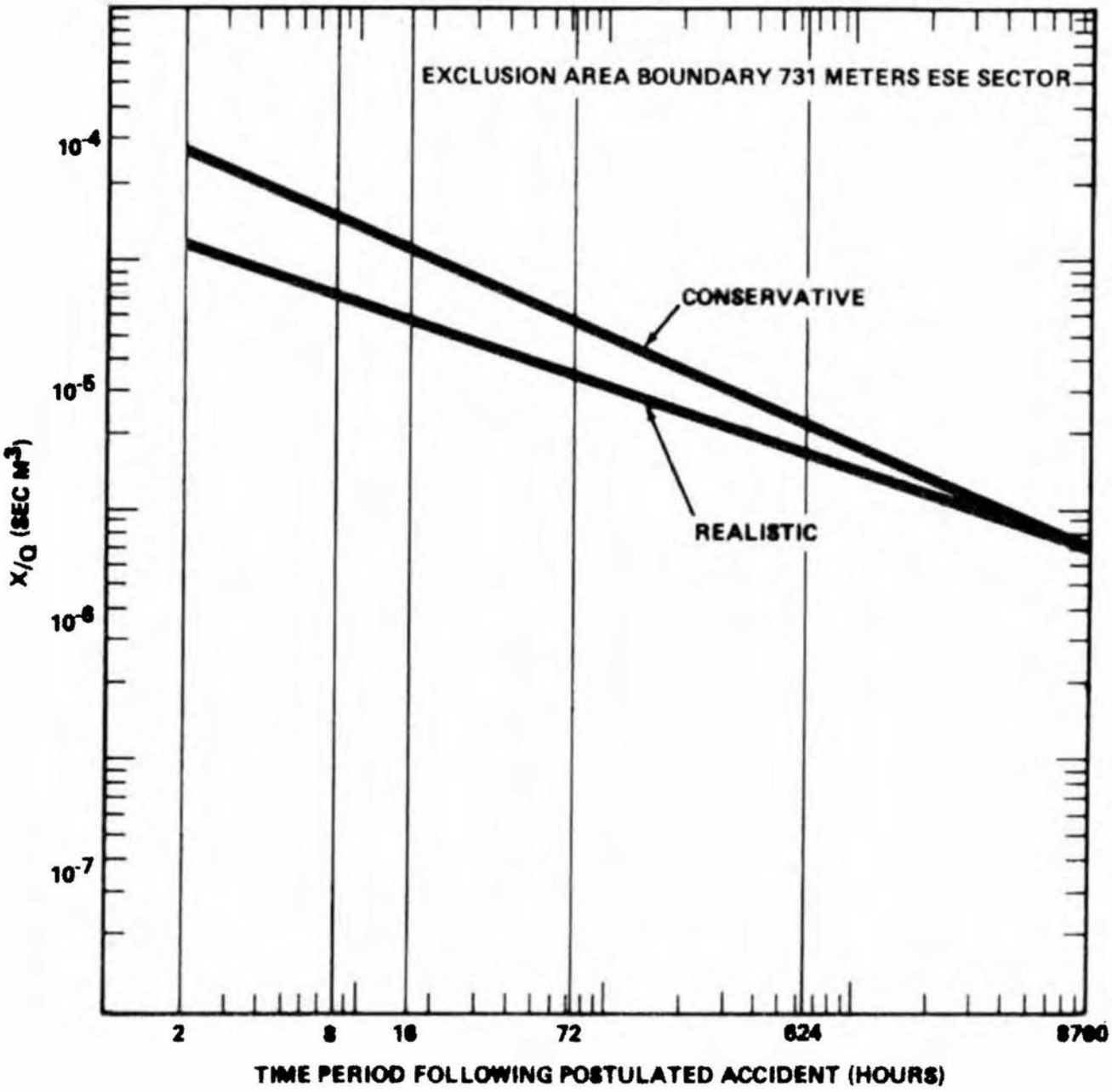


NOTE: Information in this figure is for historical purposes.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CUMULATVE PROBABILITY
DISTRIBUTION OF X/Q FOR THE
LPZ BOUNDARY

FIGURE 2.3.4-2 REV. 14, 09/08

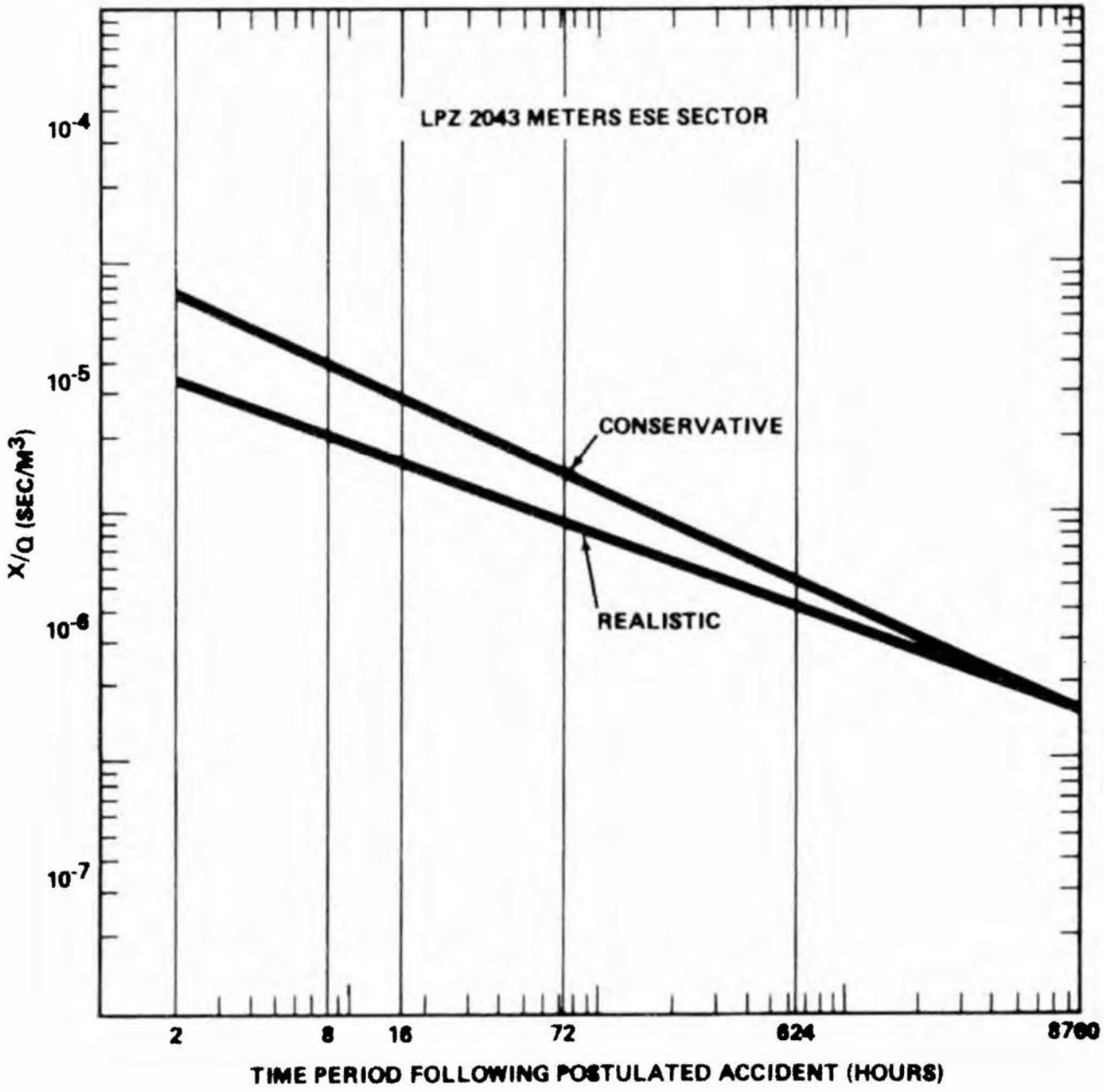


NOTE: Information in this figure is for historical purposes only.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

ACCIDENT X/Q VALUE FOR RELEASE PERIODS GREATER THAN 2 HOURS AT THE EXCLUSION AREA BOUNDARY

FIGURE 2.3.4-3 REV. 14, 09/08

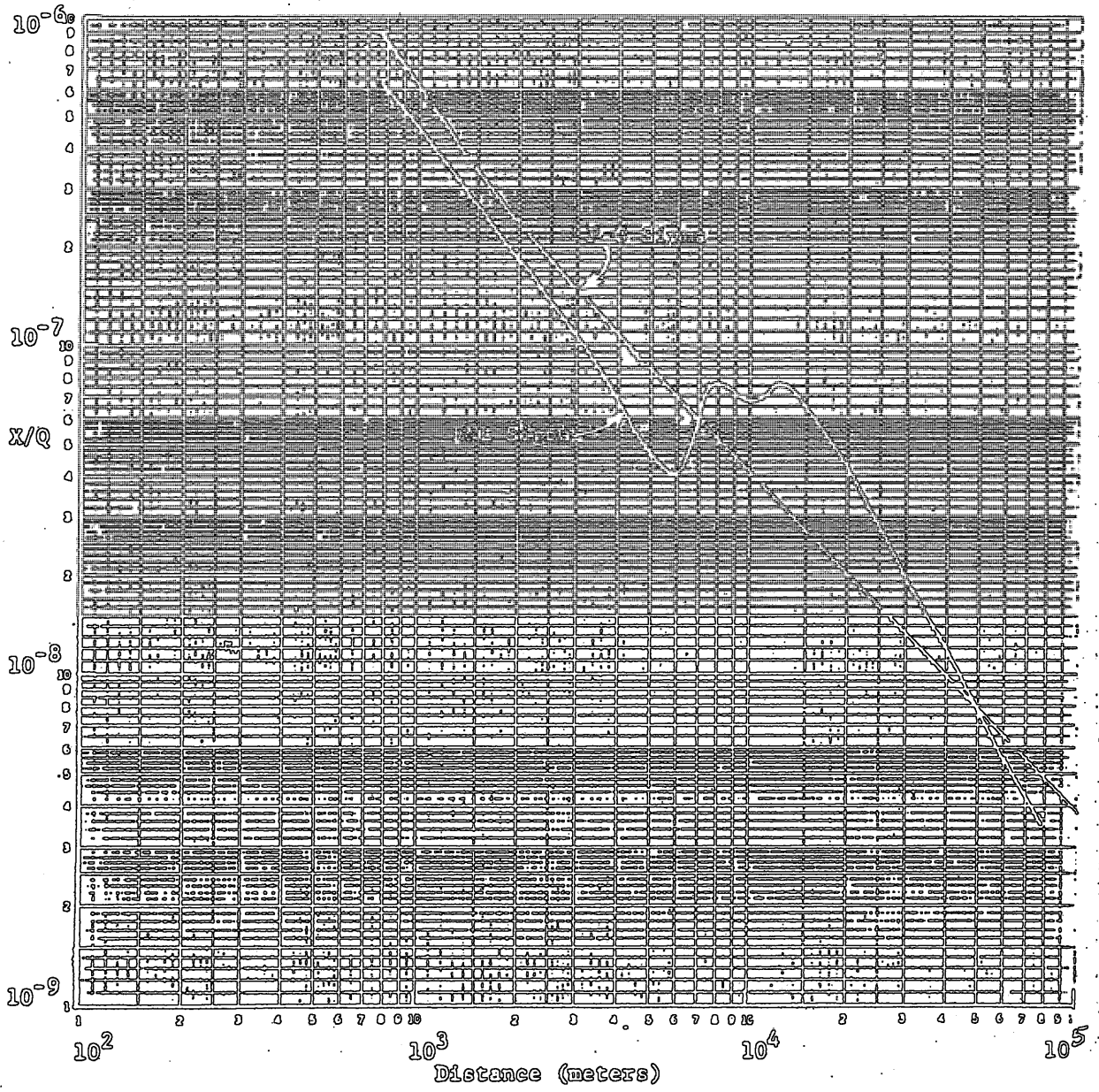


NOTE: Information is this figure is for historical purposes only.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

ACCIDENT X/Q VALUE FOR RELEASE PERIODS GREATER THAN 2 HOURS AT THE LPZ BOUNDARY

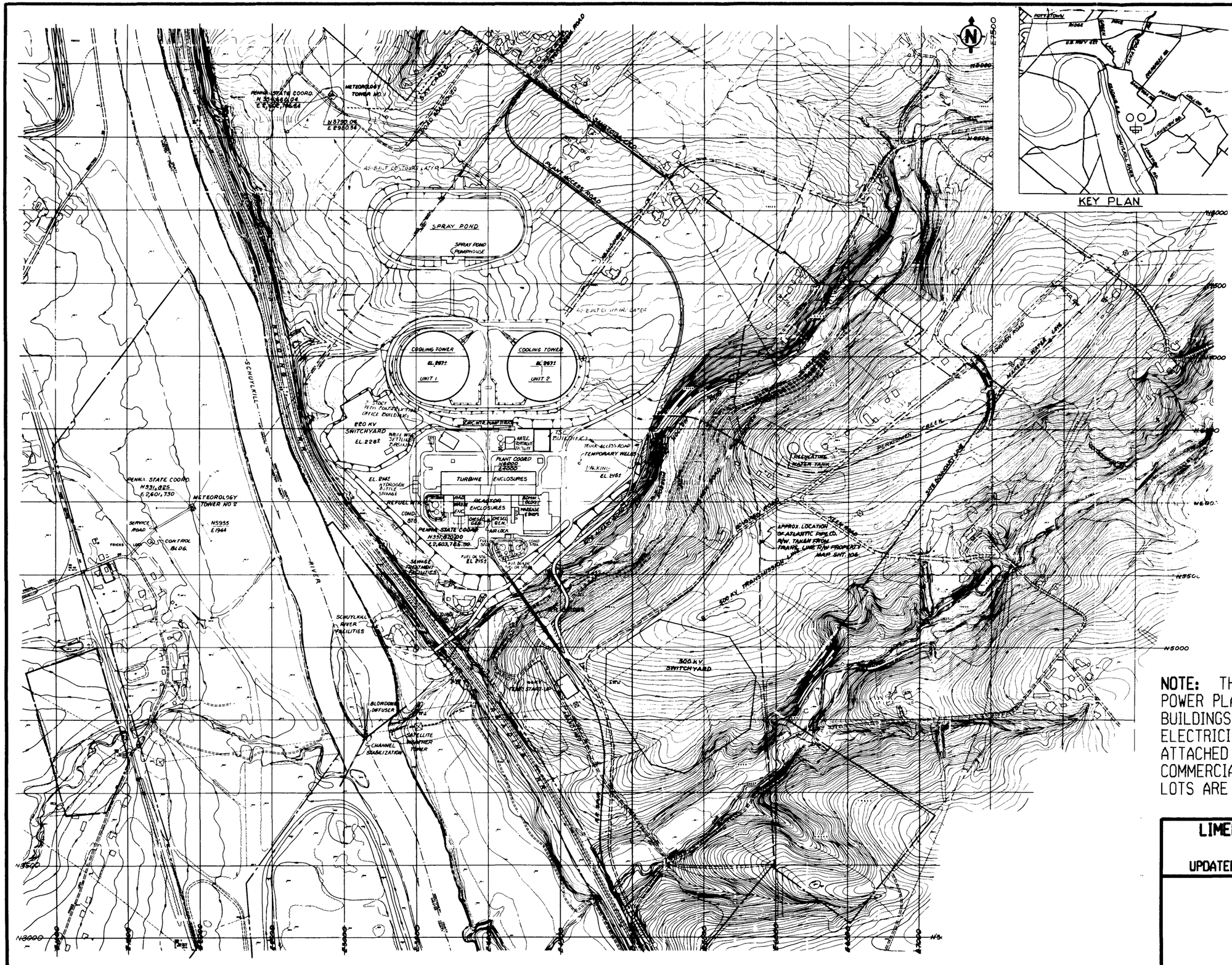
FIGURE 2.3.4-4 **REV. 14, 09/08**



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

COMPARISON OF ANNUAL X/Q VALUES USING 175' LEVEL WITH ESE SECTOR WIND

FIGURE 2.3.5-1

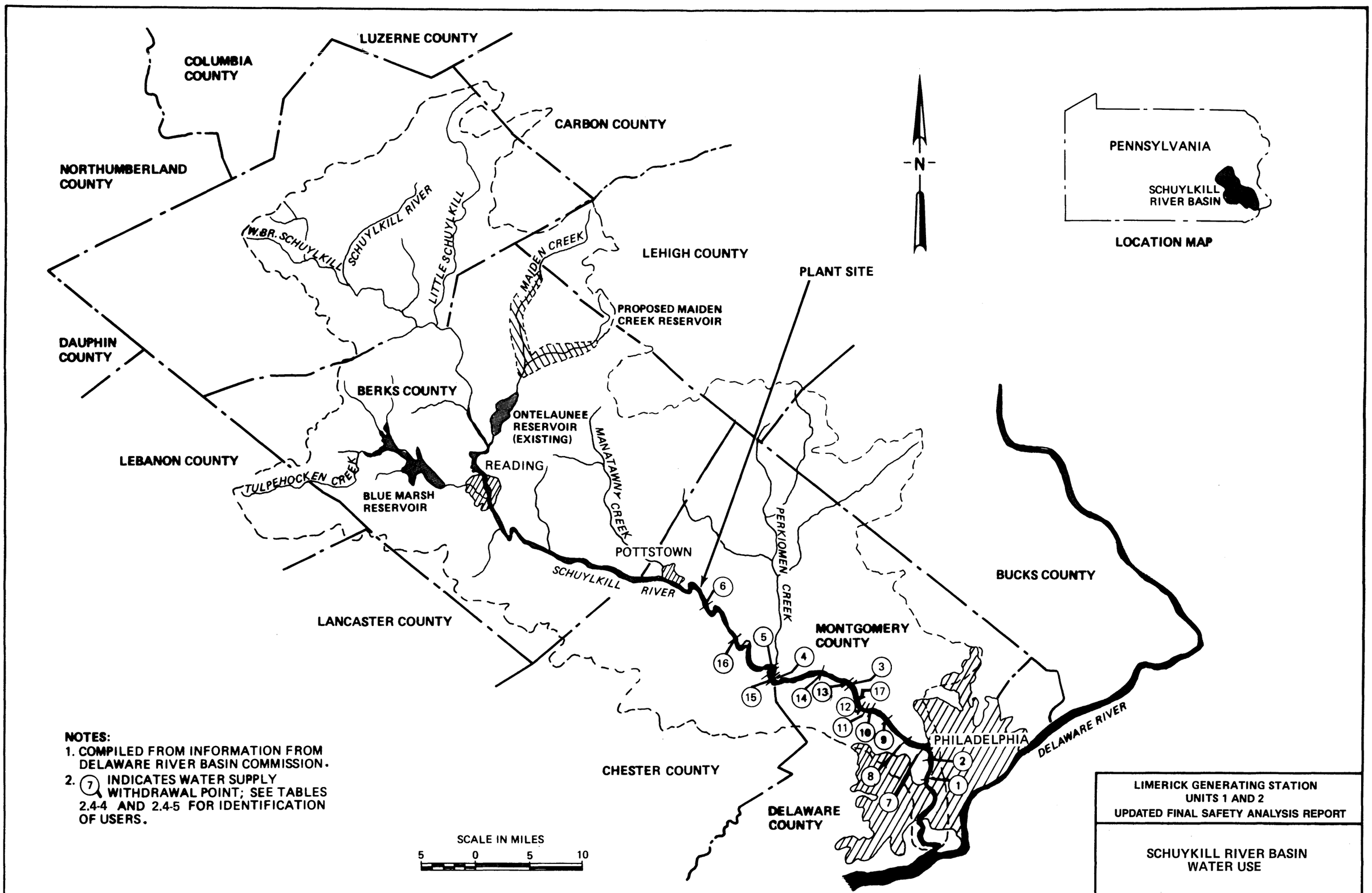


NOTE: THIS DRAWING ONLY SHOWS POWER PLANT BUILDINGS, AUXILIARY BUILDINGS NEEDED TO GENERATE ELECTRICITY, AND SUPPORT BUILDINGS ATTACHED TO THE POWER PLANT. COMMERCIAL OFFICES AND PARKING LOTS ARE NOT SHOWN.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SITE PLAN

FIGURE 2.4-1 Rev. 2 July/92



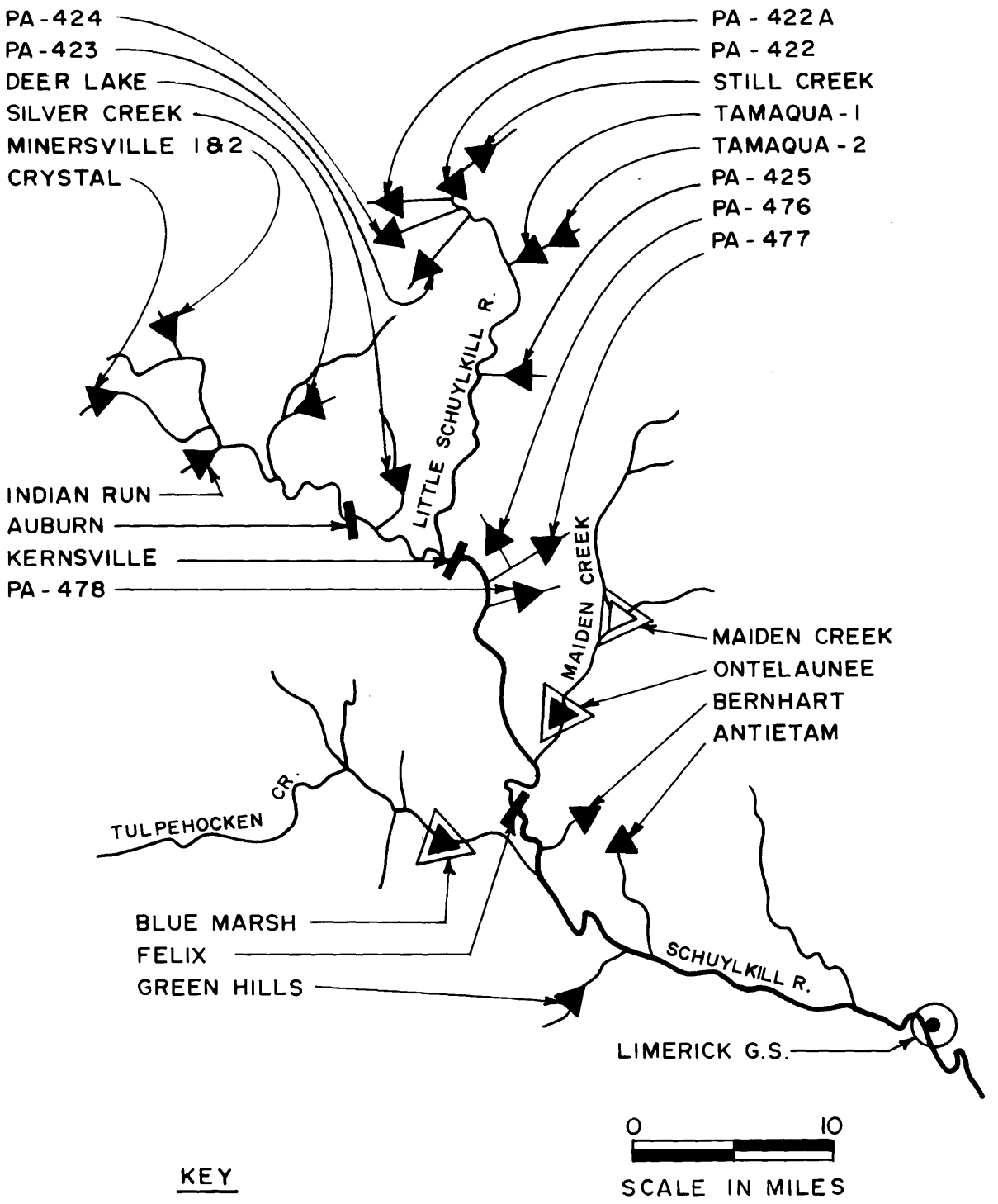
NOTES:

1. COMPILED FROM INFORMATION FROM DELAWARE RIVER BASIN COMMISSION.
2. (7) INDICATES WATER SUPPLY WITHDRAWAL POINT; SEE TABLES 2.4-4 AND 2.4-5 FOR IDENTIFICATION OF USERS.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SCHUYKILL RIVER BASIN
WATER USE

FIGURE 2.4-2



KEY

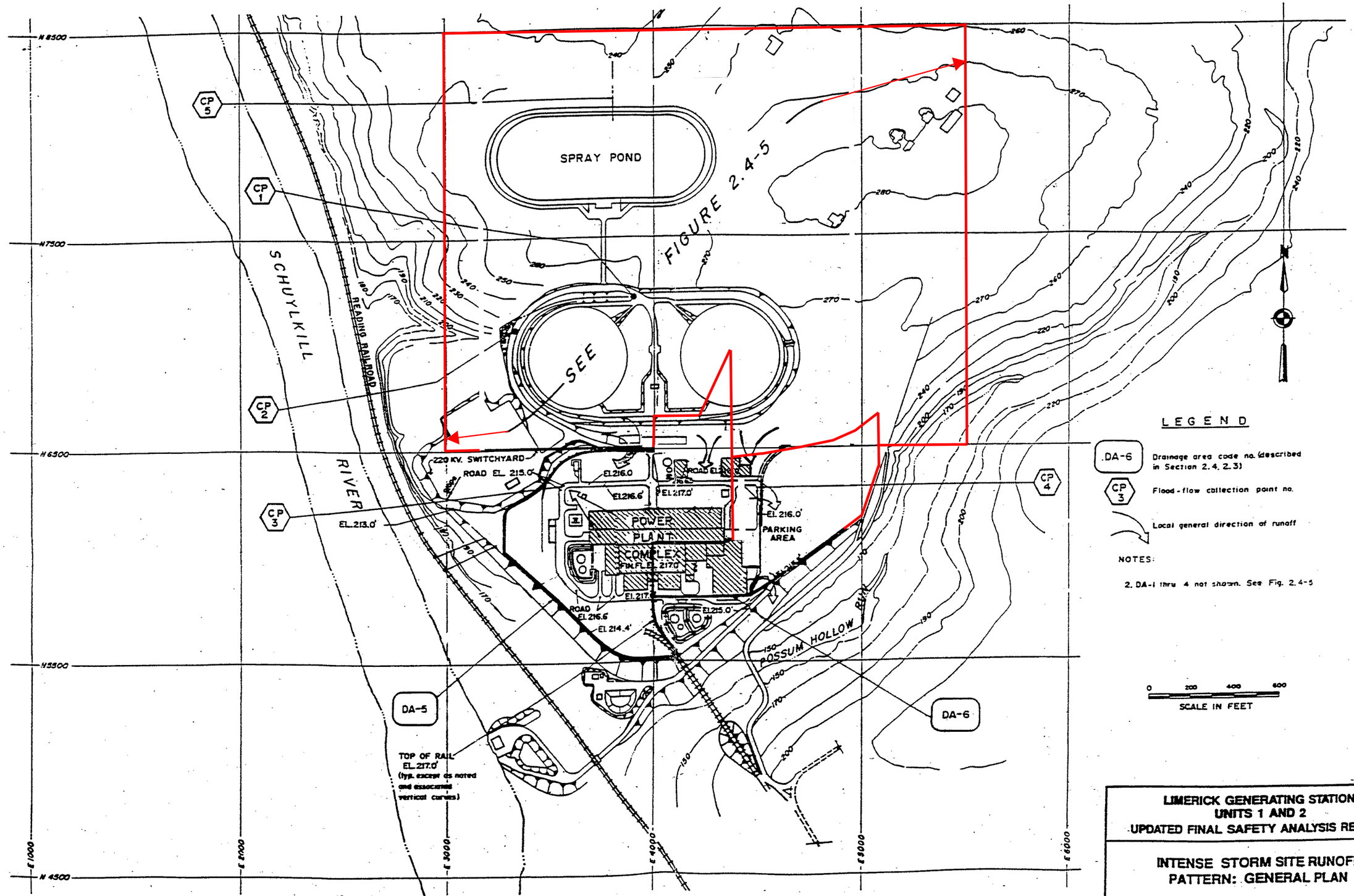
- ▲ Storage dam
- ▬ Run-of-river dam
- ▼ Dam considered in seismic study
- ▽ Future dam

Adopted from Bull. 4, Dpt. of Forest & Waters (Dpt. of Environmental Resources) Commonwealth of PA.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SCHUYLKILL RIVER DAMS UPSTREAM FROM LIMERICK SITE

FIGURE 2.4-3

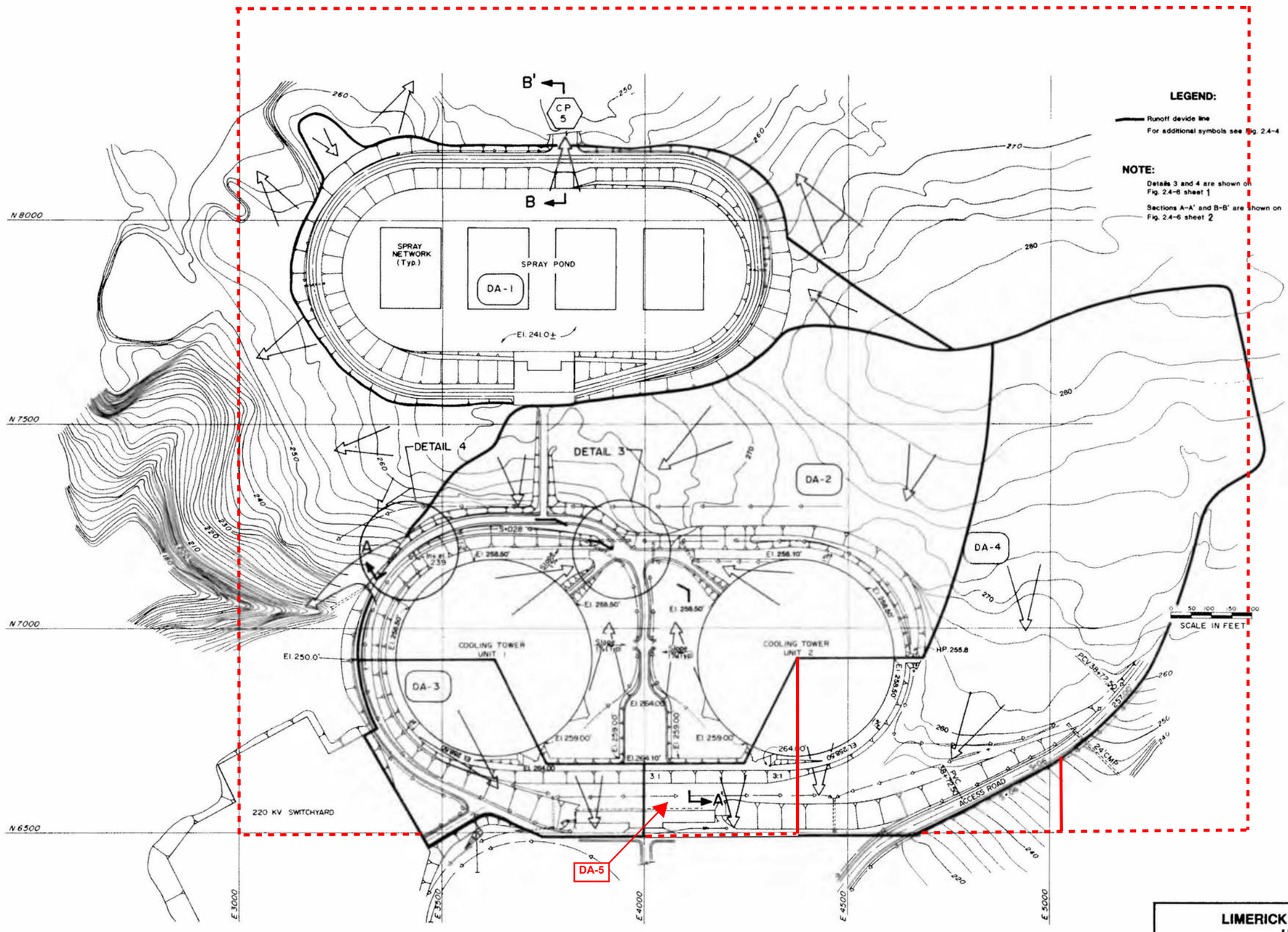


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

INTENSE STORM SITE RUNOFF
PATTERN: GENERAL PLAN

FIGURE 2.4-4

Rev. 15, 09/10

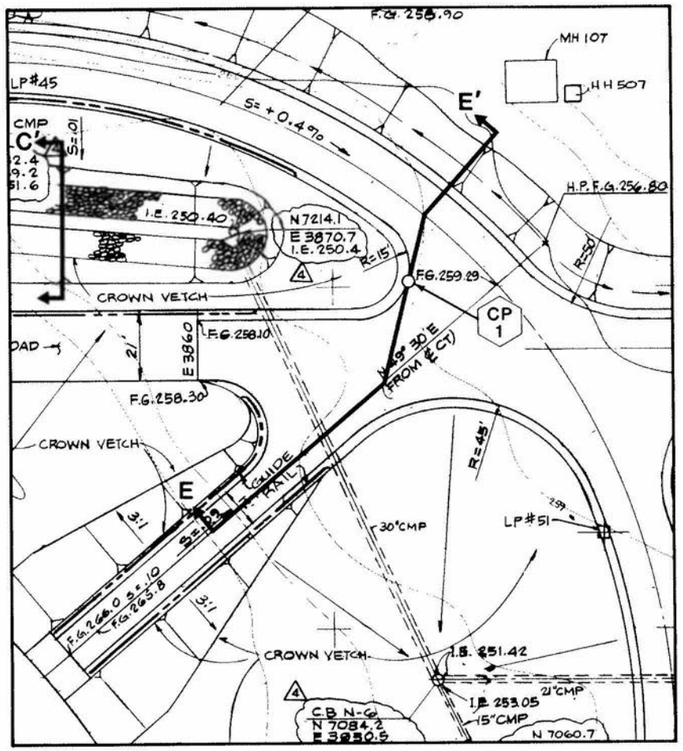


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

INTENSE STORM SITE RUNOFF PATTERN: SPRAY POND AND COOLING TOWER AREAS

FIGURE 2.4-5

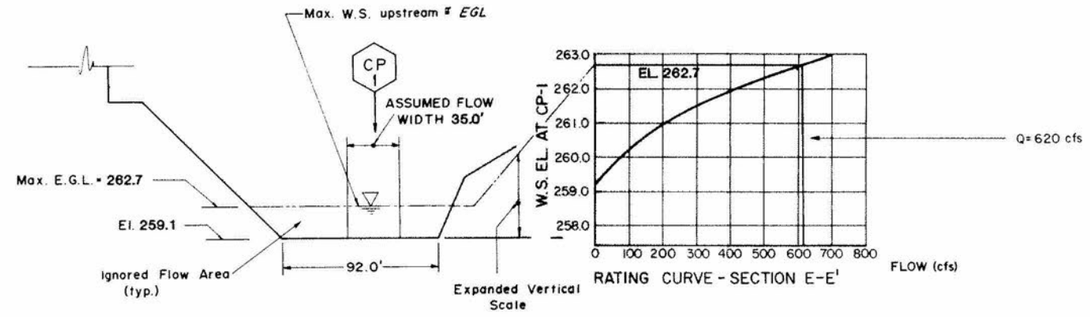
Rev. 15, 09/10



DETAIL 3

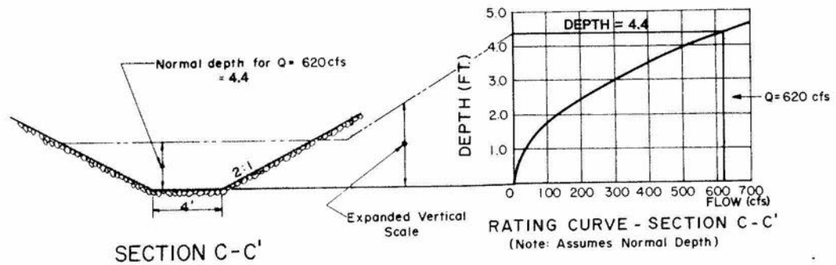
Collection Point CP-1 & Vicinity

SCALE IN FEET



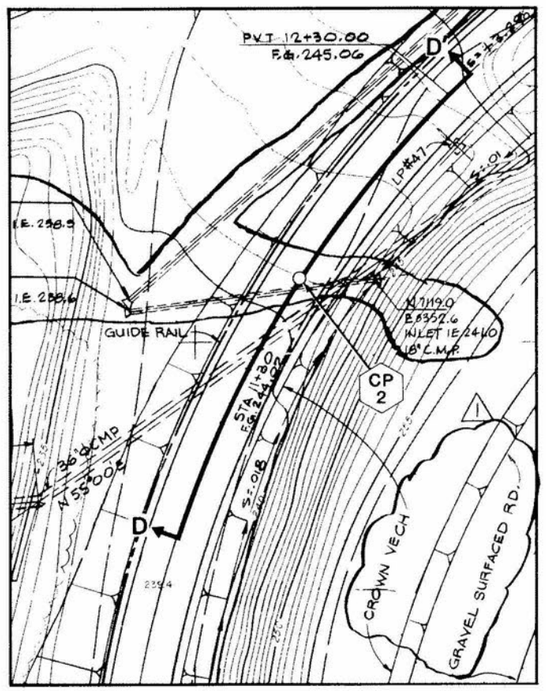
SECTION E-E'

HORIZONTAL SCALE IN FEET
DISTORTED SCALE V = 10H



SECTION C-C'

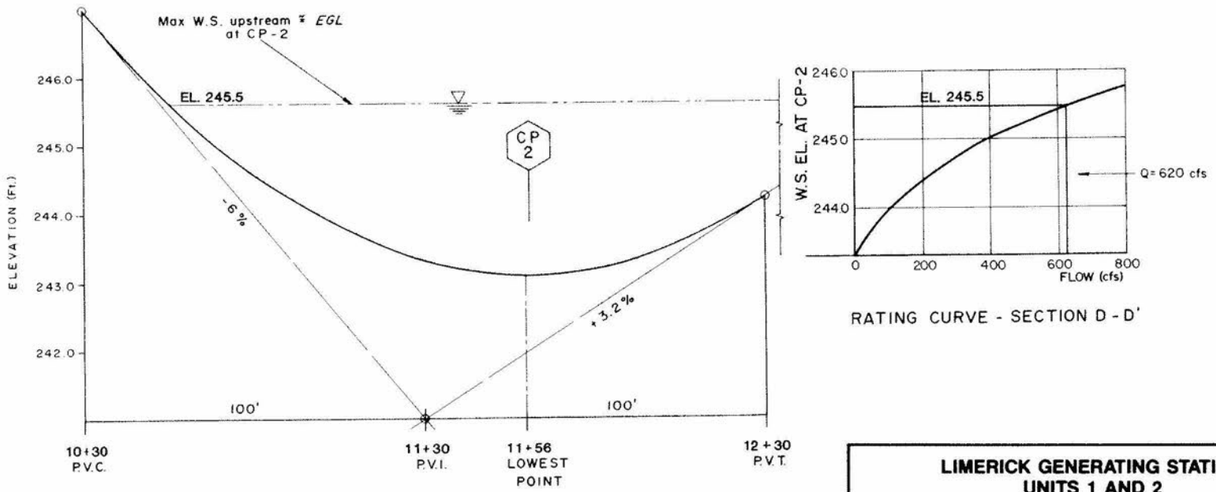
SCALE IN FEET



DETAIL 4

Collection Point CP-2 & Vicinity

SCALE IN FEET



SECTION D-D'

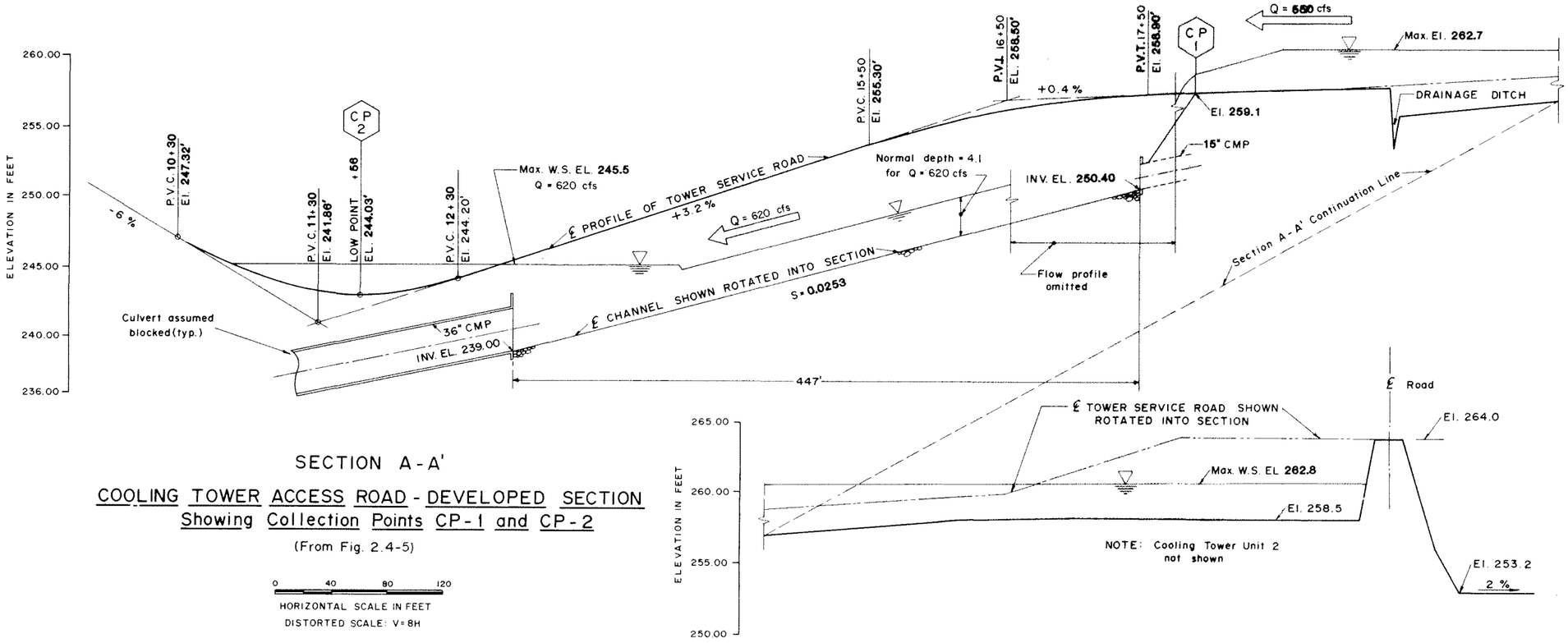
HORIZONTAL SCALE IN FEET
DISTORTED SCALE V=20H

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

INTENSE STORM SITE RUNOFF PATTERN: SECTIONS AND DETAILS (SHEET 1 OF 4)

FIGURE 2.4-6

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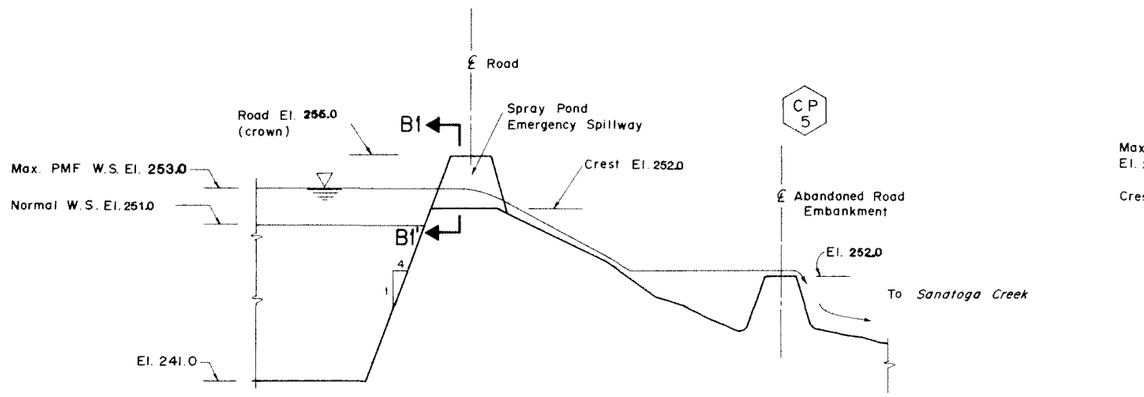


SECTION A-A'

COOLING TOWER ACCESS ROAD - DEVELOPED SECTION
Showing Collection Points CP-1 and CP-2

(From Fig. 2.4-5)

0 40 80 120
HORIZONTAL SCALE IN FEET
DISTORTED SCALE: V=8H

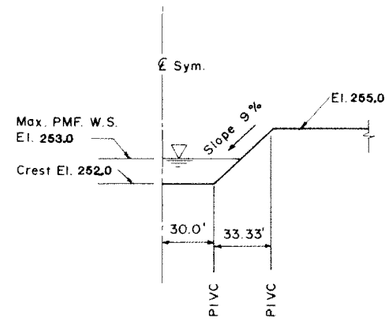


SECTION B-B'

SPRAY POND EMERGENCY SPILLWAY

(From Fig. 2.4-5)

0 40 80 120
HORIZONTAL SCALE IN FEET
DISTORTED SCALE: V=10H



SECTION B1 - B1'

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

INTENSE STORM SITE RUNOFF PATTERN: SECTIONS AND DETAILS (SHEET 2 OF 4)

FIGURE 2.4-6

Rev. 15, 09/10

SK-C-378 SHT.3

U/1 COOLING TOWER

U/2 COOLING TOWER

N

SEE NOTE 1

N6600

N6400

N6200

N6000

N5800

N5600

E3200

E3400

E3600

E3800

E4000

E4200

E4400

E4600

E4800

E5000

E5200

CIRC WATER PUMP STRUCT.

JSK

WWSB

WATER TREATMENT BUILDING

TSC

SIMULATOR

LLC

CONTROL ROOM

220 YARD

U/1 TURBINE BLDG

U/2 TURBINE BLDG

HP MUSTER AREA

CANOPY

LGS WAREHOUSE BUILDING

APPROXIMATE RAMP LOCATION

CHEM LAB

RADWASTE BLDG

U/1 REACTOR BLDG

U/2 REACTOR BLDG

AUX BOILER

GML BLDG

OUTLETS 1 & 2

SITE LAB

CIVIL/STAFF BUILDING

OUTLET

U/1 DIESEL BLDG

U/2 DIESEL BLDG

OUTLET 3

HHT

FUEL OIL PUMP HOUSE

OUTLET

OUTLET 4B

SSB

MMF

FUEL GENERATOR STORAGE BUILDING

OUTLET 5

NOTES:
1. THESE BLOCKS EXTEND FURTHER TOWARD NORTHEAST, BUT NOT SHOWN ON THIS DRAWING.

REPRESENTS AREAS OF FLOW PATH FOR SURFACE WATER DRAINAGE.

REPRESENTS STRUCTURES AND FACILITIES WHICH SHALL NOT BE REMOVED WITHOUT PRIOR ENGINEERING APPROVAL.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

INTENSE STORM SITE RUNOFF PATTERN: SECTIONS AND DETAILS (SHEET 3 OF 4)

FIGURE 2.4-6

Rev. 20 09/20

SK-C-378 SHT.4

U/1 COOLING TOWER

U/2 COOLING TOWER

N

SEE NOTE 1

CIRC WATER PUMP STRUCT.

JSK

WWSB

WATER TREATMENT BUILDING

TSC

SIMULATOR

LLC

CONTROL ROOM

220 YARD

U/1 TURBINE BLDG

U/2 TURBINE BLDG

HP MUSTER AREA

CANOPY

LGS WAREHOUSE BUILDING

APPROXIMATE RAMP LOCATION

CHEM LAB

RADWASTE BLDG

U/1 REACTOR BLDG

U/2 REACTOR BLDG

AUX BOILER

GML BLDG

U/1 DIESEL BLDG

U/2 DIESEL BLDG

CIVIL/STAFF BUILDING

HHT

SSB

MMF

FUEL OIL PUMP HOUSE

FLEX GENERATOR STORAGE BUILDING

N6600

N6400

N6200

N6000

N5800

N5600

E3200

E3400

E3600

E3800

E4000

E4200

E4400

E4600

E4800

E5000

E5200

NOTES:
1. THESE BLOKS EXTEND FURTHER TOWARD NORTHEAST, BUT NOT SHOWN ON THIS DRAWING.

TABLE OF ADDITIONS & CHANGES
USE ONLY PRINTS SHOWING LATEST DATE

NO.	DATE	DESCRIPTION	DRAWN	CHECKED	APPD
3	06 25 14	INCORP. EC 625915 REV.1, ADDED BLOCKS AND NOTE 1 PER EC. ID-M.1-31	DJS	AZ	AK
2	05 21 14	INCORP. ECR LG 13-00417 REV.1, REVISED FLOOD BARRIER AT EASTERN EDGE OF ISFSI PAD.	DJS	AZ	AK
1	04 15 14	INCORP. ECR LG 14-00052 REV.3, REMOVED TOOL STORAGE BUILDING AND ADDED FLEX GENERATOR STORAGE BLDG.	DJS	AZ	AK

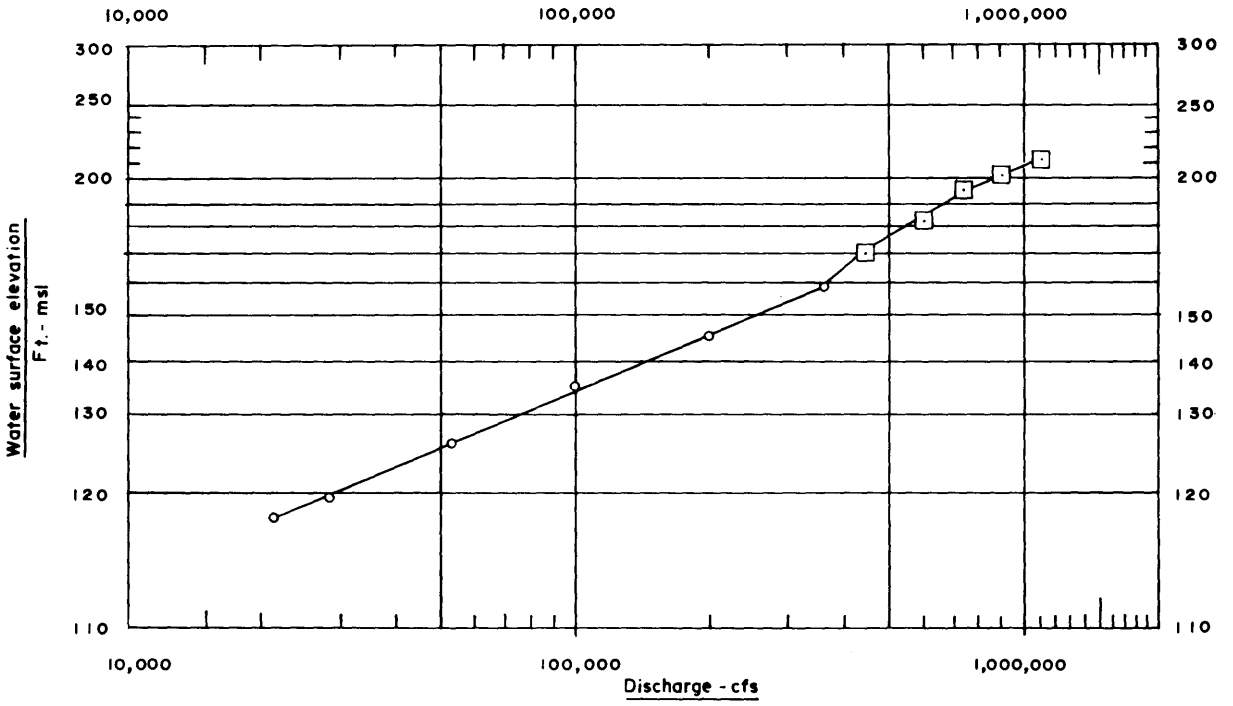
SITE PLAN
FLOODING CONTROL AREAS

LIMERICK GENERATING STATION
EXELON NUCLEAR

SCALE	DESIGN	DRAWN	CHECKED	DATE
				/ /

APPROVED _____ APPROVED _____

DRAWING NUMBER	SHEET NUMBER	REV
SK-C-378	SHT.4	3



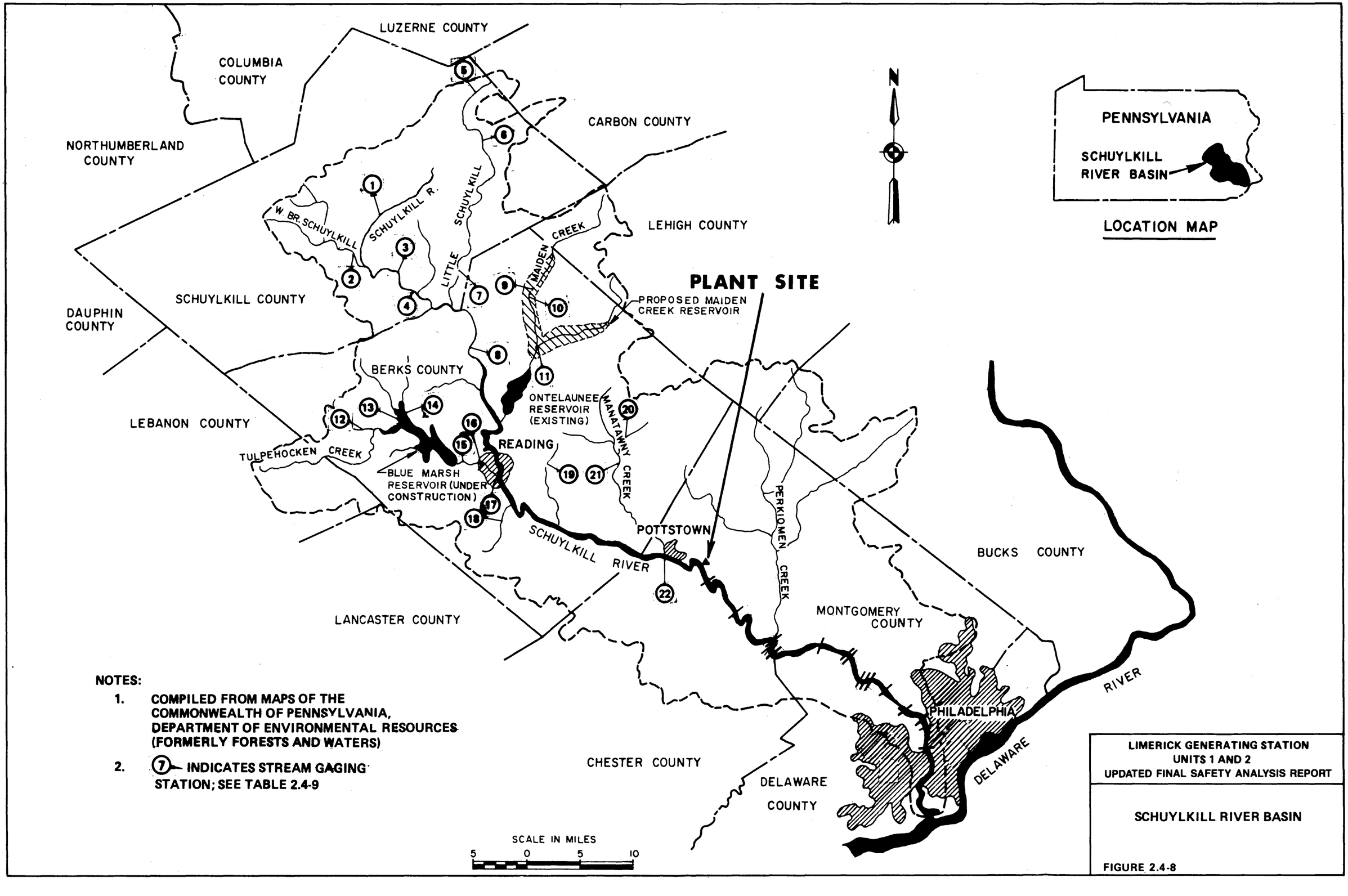
o From backwater study

□ From friction - slope - discharge relation (Fig. 2.4-13)

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SCHUYLKILL RIVER DISCHARGE RATING CURVE AT LIMERICK SITE

FIGURE 2.4-7



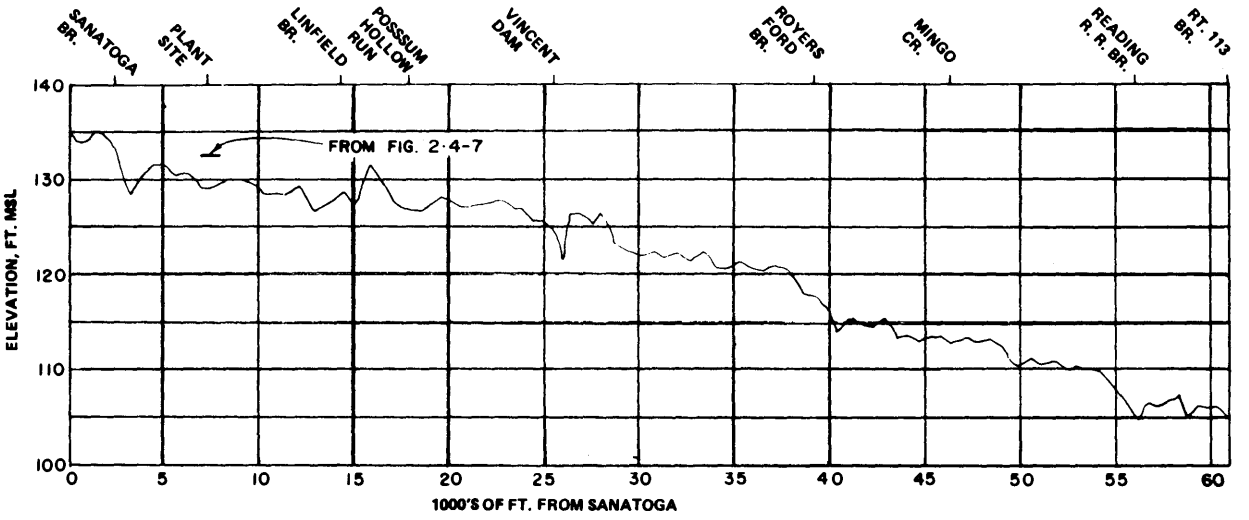
NOTES:

1. **COMPILED FROM MAPS OF THE COMMONWEALTH OF PENNSYLVANIA, DEPARTMENT OF ENVIRONMENTAL RESOURCES (FORMERLY FORESTS AND WATERS)**
2. **(7) INDICATES STREAM GAGING STATION; SEE TABLE 2.4-9**

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SCHUYLKILL RIVER BASIN

FIGURE 2.4-8



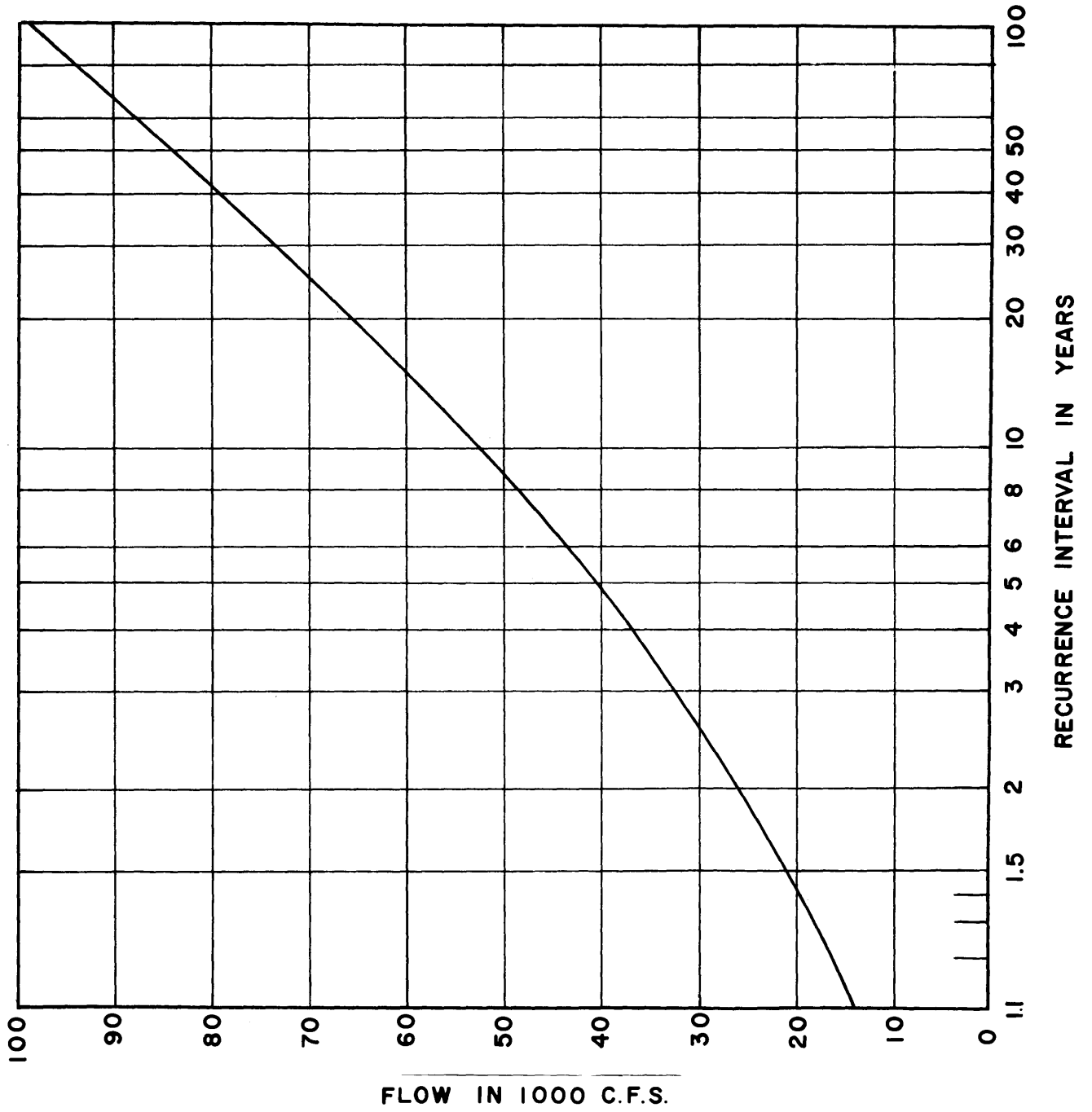
NOTES:

1. PROFILE FROM SURVEY DATA TAKEN BY SANDERS AND THOMAS, INC, THEIR DRAWING 1 OF 1 DATED 7/17/72, PROJECT NUMBER 3208.
2. ALL READINGS TAKEN ON EAST SIDE OF SCHUYLKILL RIVER.
3. ALL RAW DATA SHOWN. NO ATTEMPT MADE TO ADJUST FOR POSSIBLE HUMAN ERROR IN LOCATING HIGH WATER MARKS. (TOP OF OIL DEPOSIT WHERE VISIBLE)

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SCHUYLKILL RIVER HIGH WATER PROFILE FLOOD OF JUNE 22, 1972

FIGURE 2.4-9



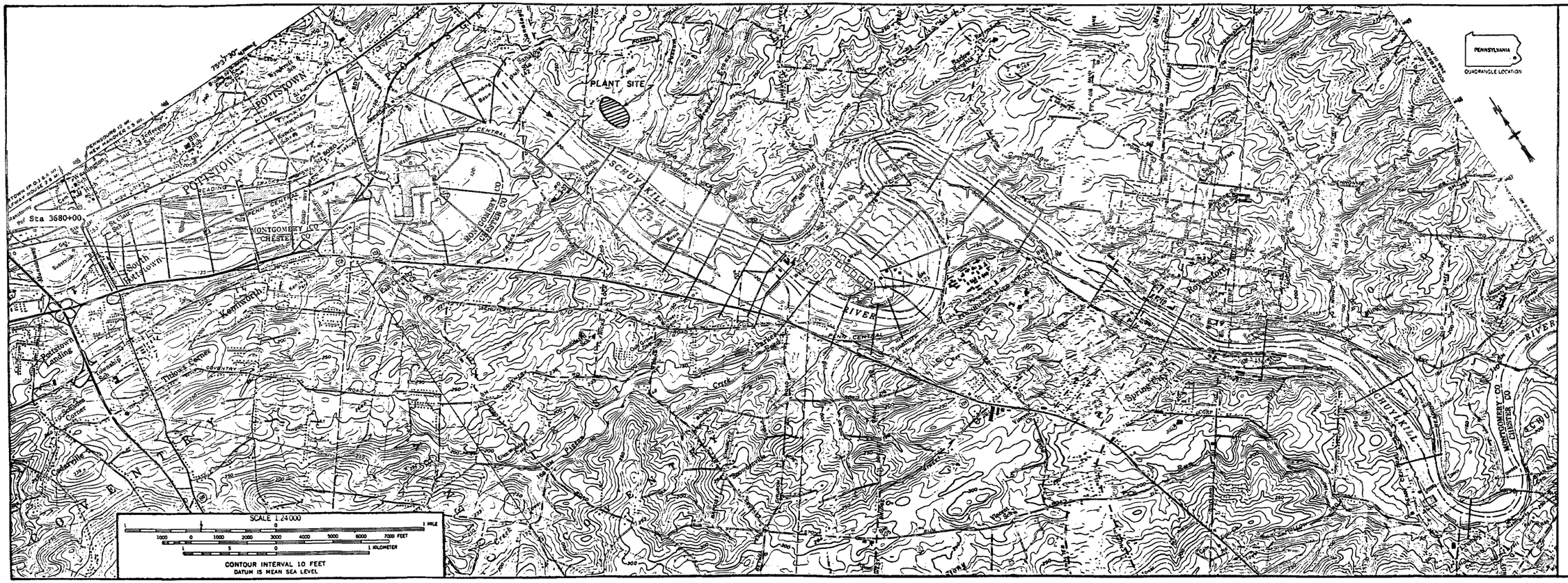
NOTES:

BASED ON REGIONAL FLOOD — FREQUENCY ANALYSIS PRESENTED IN USGS WATER SUPPLY PAPER 1672. DRAINAGE AREA EQUALS 1147 SQUARE MILES.

LIMERICK GENERATING STATION
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SCHUYLKILL RIVER FLOOD FREQUENCY AT POTTSTOWN, PA

FIGURE 2.4-10



NOTE:
THIS DRAWING IS COMPOSED OF PORTIONS OF U.S.G.S TOPOGRAPHIC MAPS, 7.5 MINUTE SERIES, PENNSYLVANIA:
PHOENIXVILLE 1955 (REV. 1968)
POTTSTOWN 1956 (REV. 1968)

LIMERICK GENERATING STATION
UNITS 1 AND 2
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SCHUYLKILL RIVER BELOW POTTSTOWN, PA. BACKWATER SECTION LOCATION

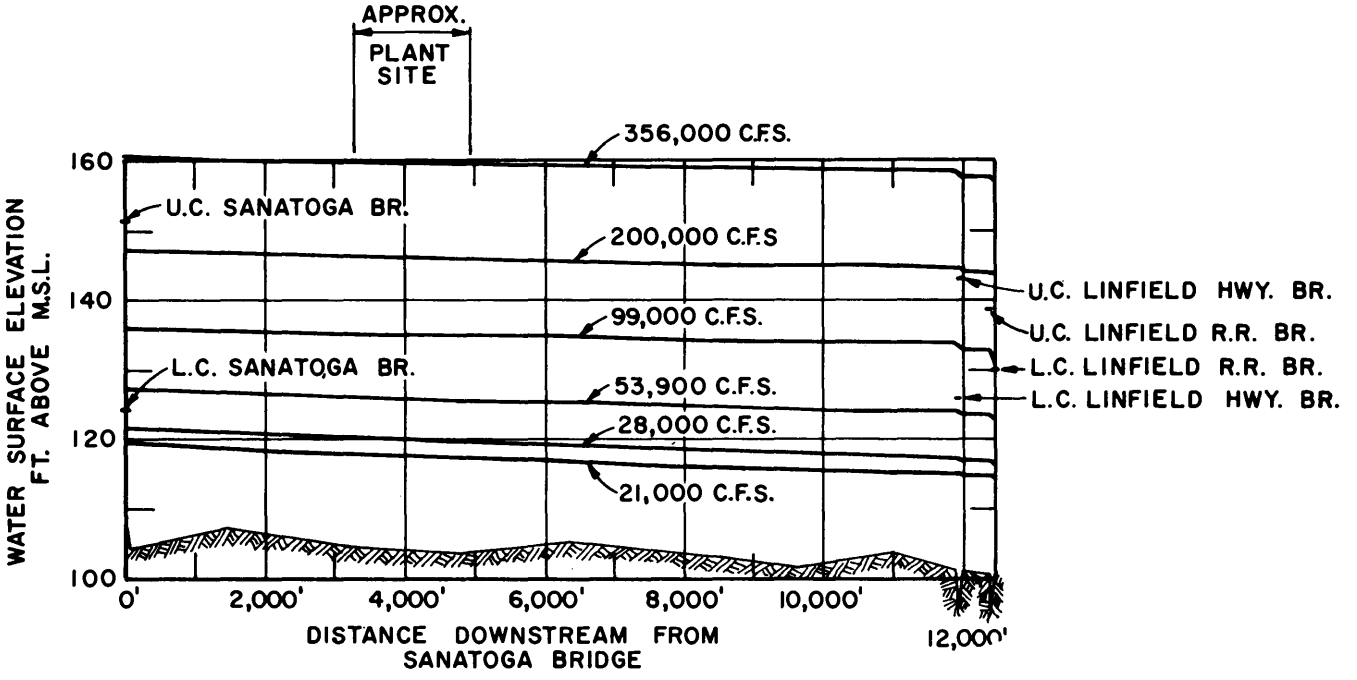
FIGURE 2.4-11

NOTES:

1. BOTTOM SHOWN IS ASSUMED ELEV. OF EQUIVALENT RECTANGULAR MAIN CHANNEL SECTION (SEE TEXT).
2. WATER SURFACE ELEVATIONS SHOWN ARE FOR HIGH ASSUMED STARTING WATER SURFACE (SEE TEXT).

LEGEND:

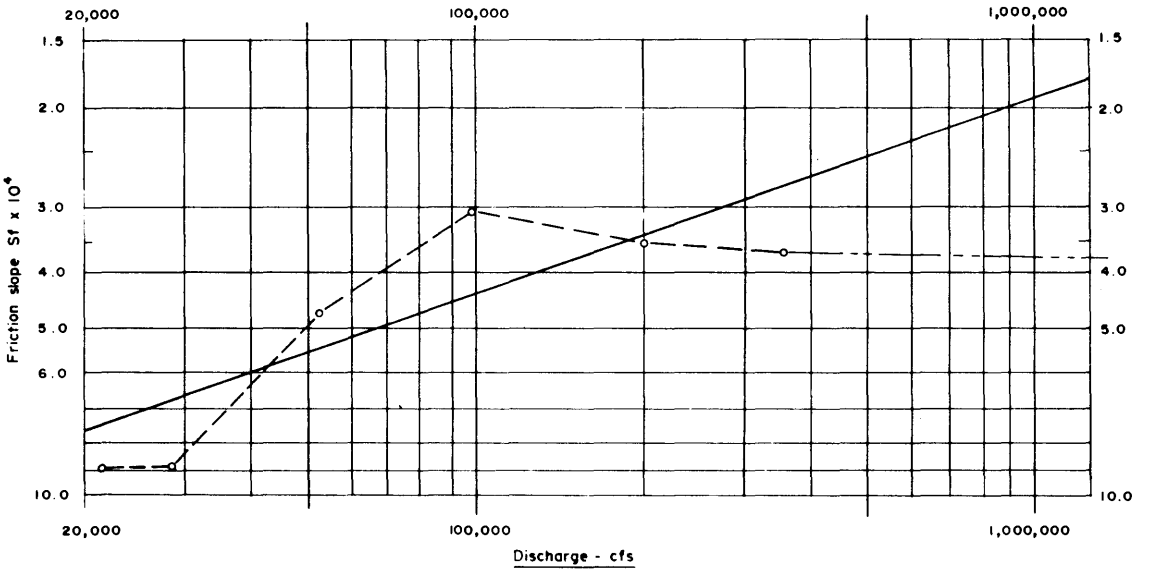
U.C. DENOTES UPPER CHORD
L.C. DENOTES LOWER CHORD
"UPPER AND LOWER CHORDS" REFER RESPECTIVELY TO THE TOP AND BOTTOM OF THE FLOW OBSTRUCTION PRESENTED BY THE BRIDGE SUPERSTRUCTURE.



LIMERICK GENERATING STATION
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COMPUTED WATER SURFACE PROFILE AT LIMERICK SITE

FIGURE 2.4-12



o From backwater studies

— — — Connecting line between points

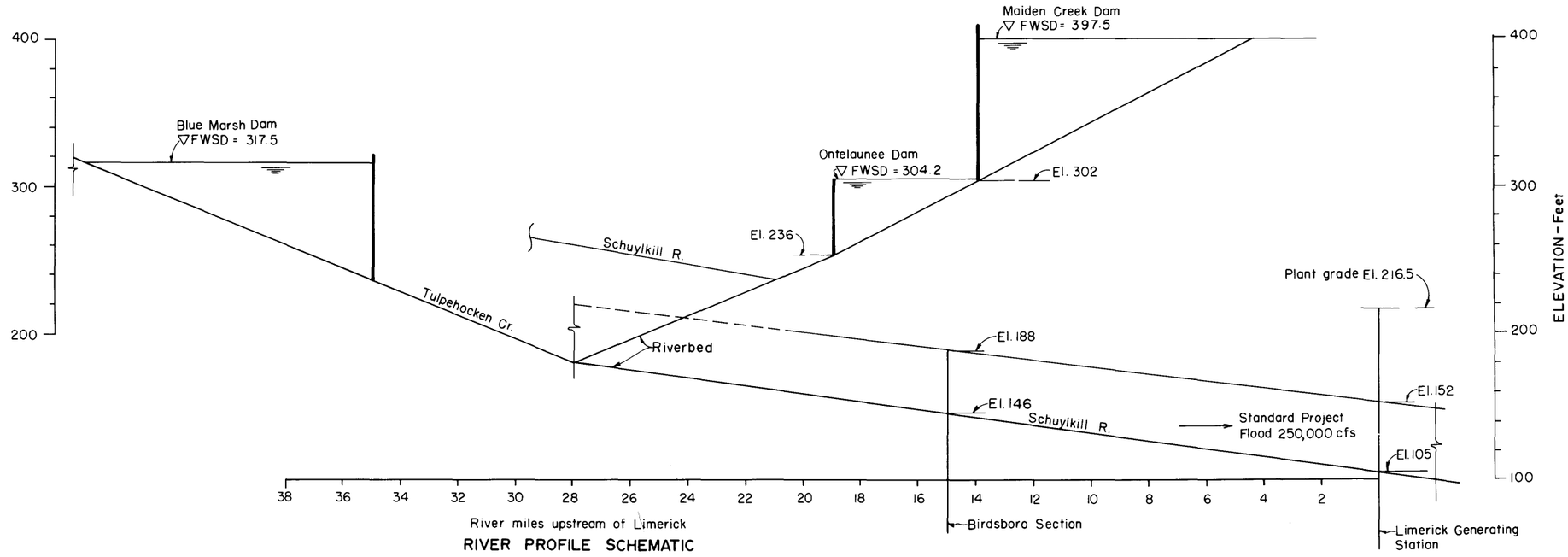
———— Apparent Asymptote (S=.00038)

———— Best - Fit by eye trend (Used)

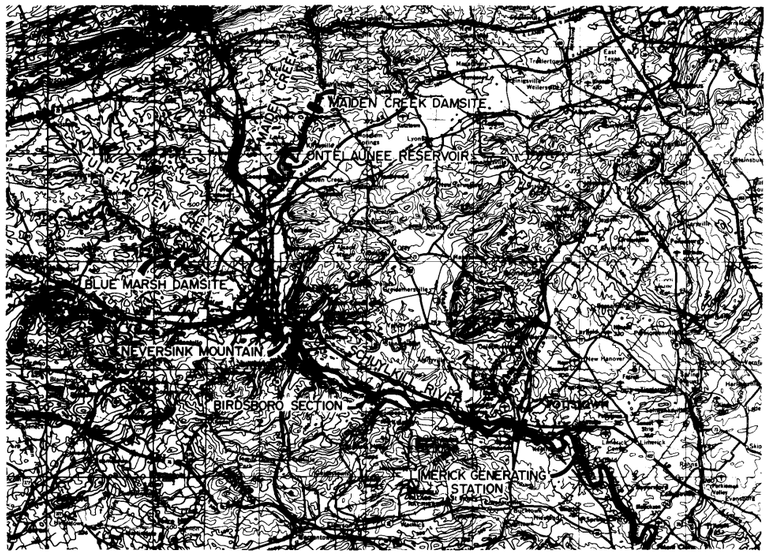
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RELATION BETWEEN FRICTION SLOPE AND DISCHARE OF SCHUYLKILL RIVER AT LIMERICK SITE

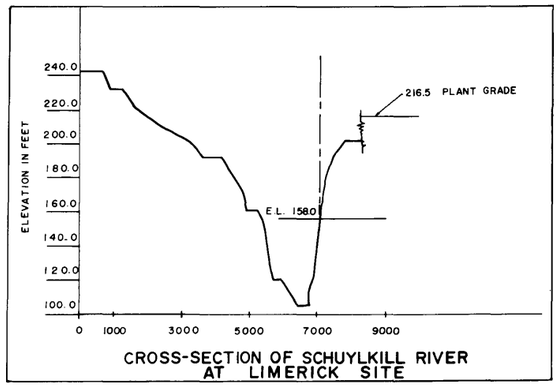
FIGURE 2.4-13



RIVER PROFILE SCHEMATIC



LOCATION MAP-FEATURES OF DAM FAILURE STUDY



CROSS-SECTION OF SCHUYLKILL RIVER AT LIMERICK SITE

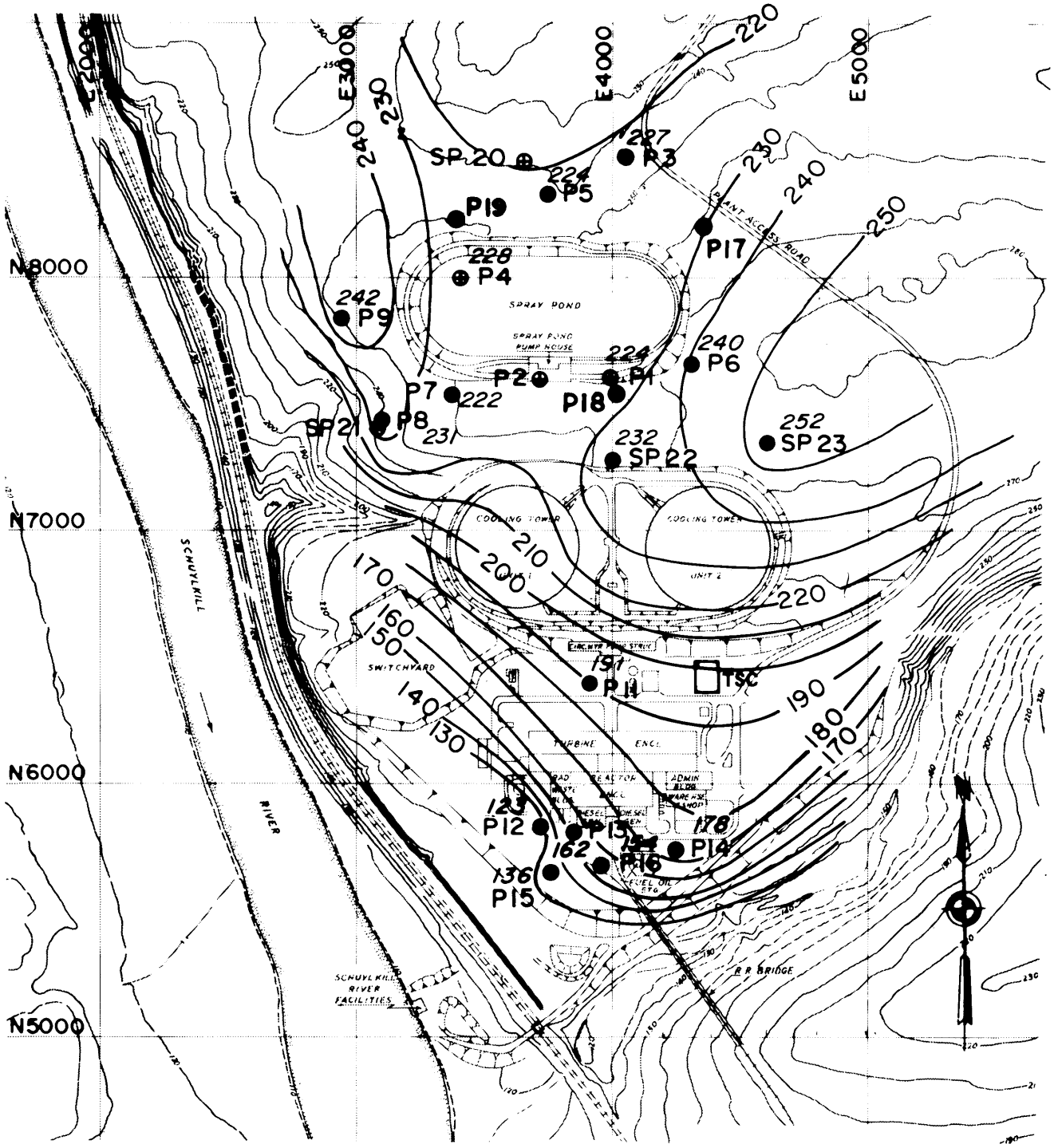
EXPLANATION:

▽FWSD = Water surface elevation at time of failure.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FLOODS DUE TO DAM FAILURE
RIVER PROFILE AND DAM
LOCATION MAP

FIGURE 2.4-14



EXPLANATION

214
● P6 OBSERVATION WELL WITH ELEVATION OF WATER LEVEL IN FEET.

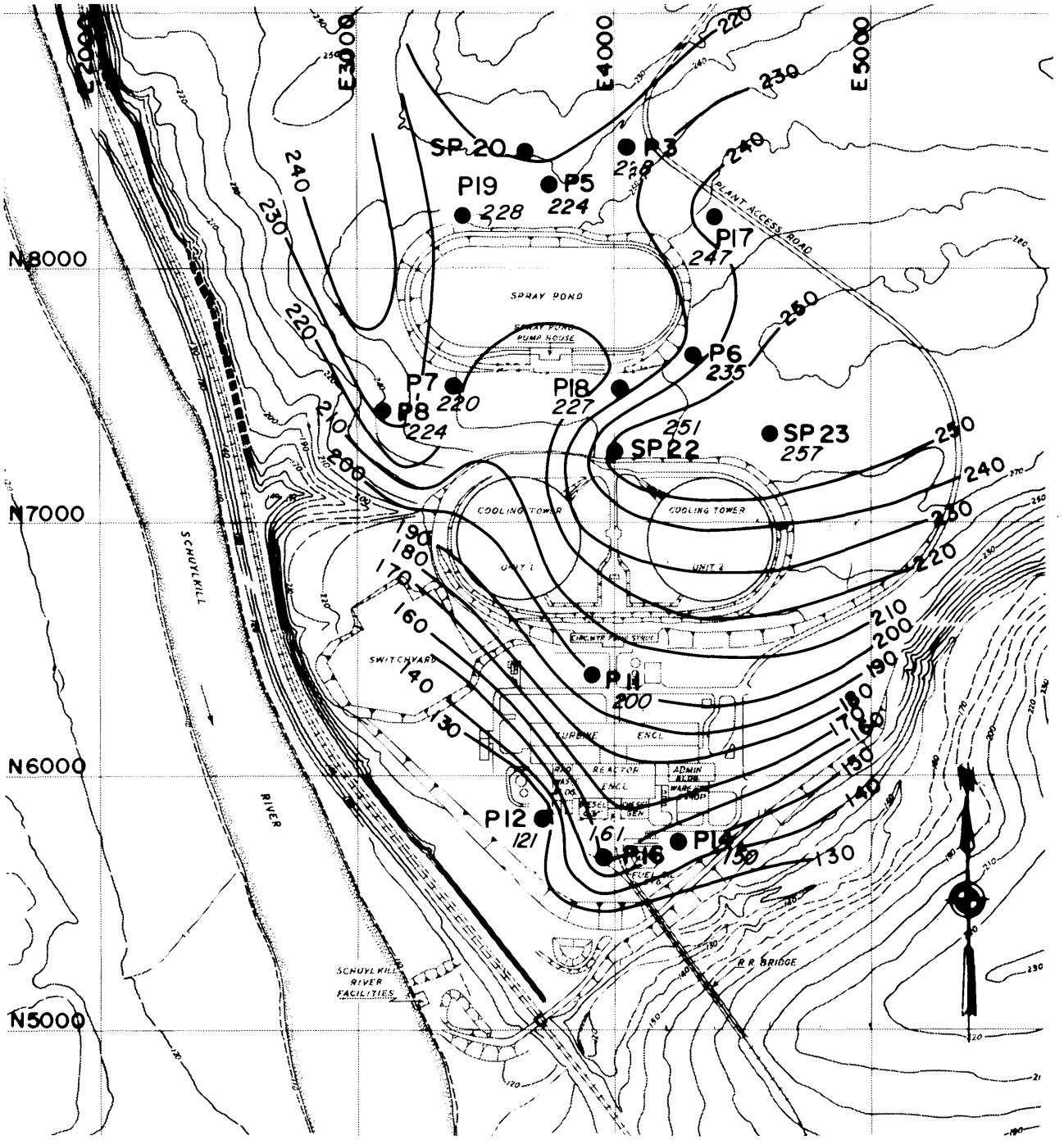
250 POTENTIOMETRIC CONTOURS IN FEET.

NOTE:
WELLS ABANDONED OR DESTROYED DURING CONSTRUCTION, SEE UFSAR TABLE 2.4-21

LIMERICK GENERATING STATION
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OBSERVATION WELLS AND POTENTIOMETRIC CONTOURS OF WATER TABLE, MAY 25, 1979
(SHEET 1 OF 2)

FIGURE 2.4-15



EXPLANATION

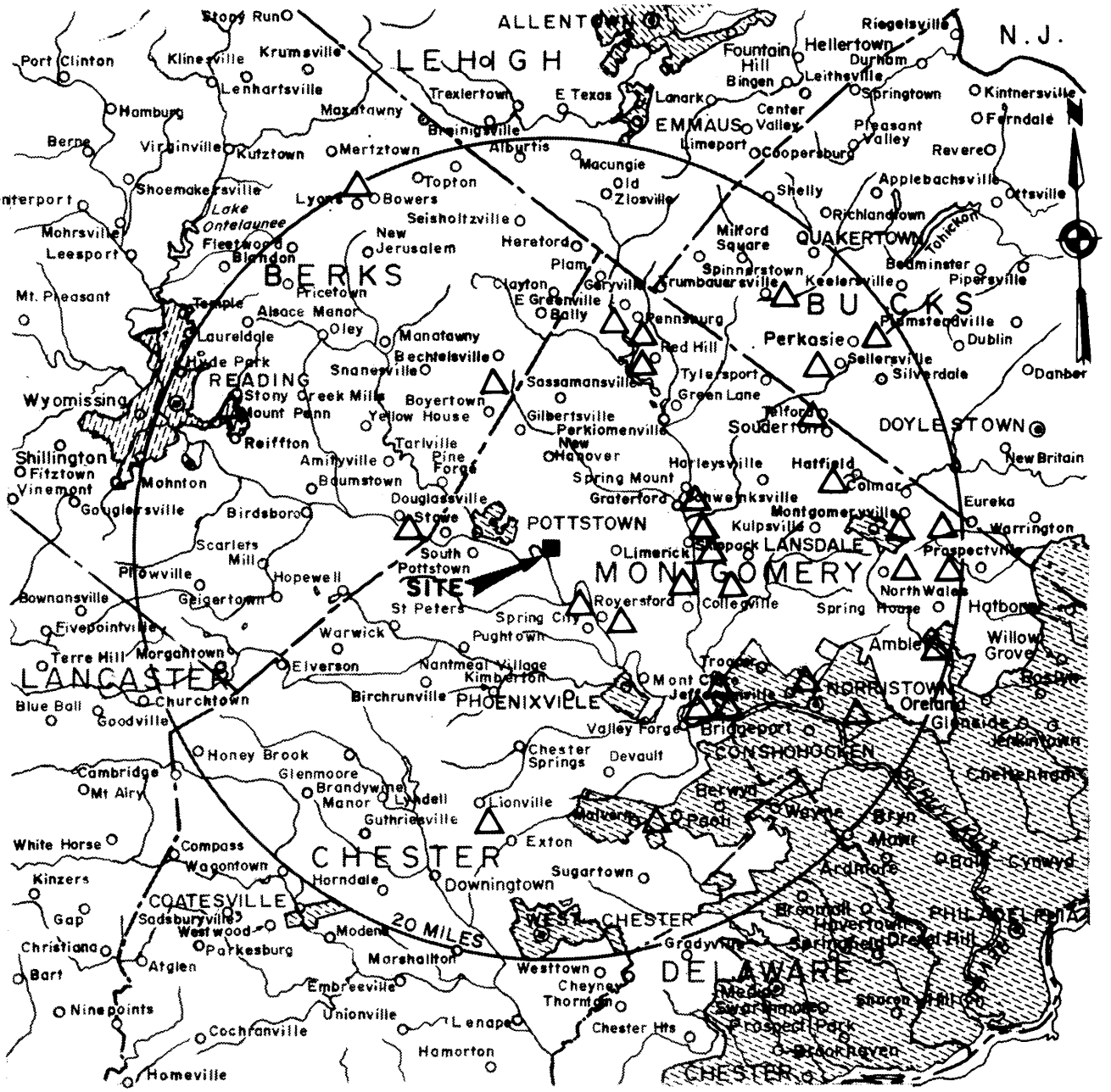
● P6 — OBSERVATION WELL WITH ELEVATION OF WATER LEVEL IN FEET

250 — POTENTIOMETRIC CONTOURS IN FEET

LIMERICK GENERATING STATION
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OBSERVATION WELLS AND POTENTIOMETRIC CONTOURS OF WATER TABLE -- MAY 31, 1988
(SHEET 2 OF 2)

FIGURE 2.4-15



EXPLANATION

△ Public Ground Water Supplier

References:

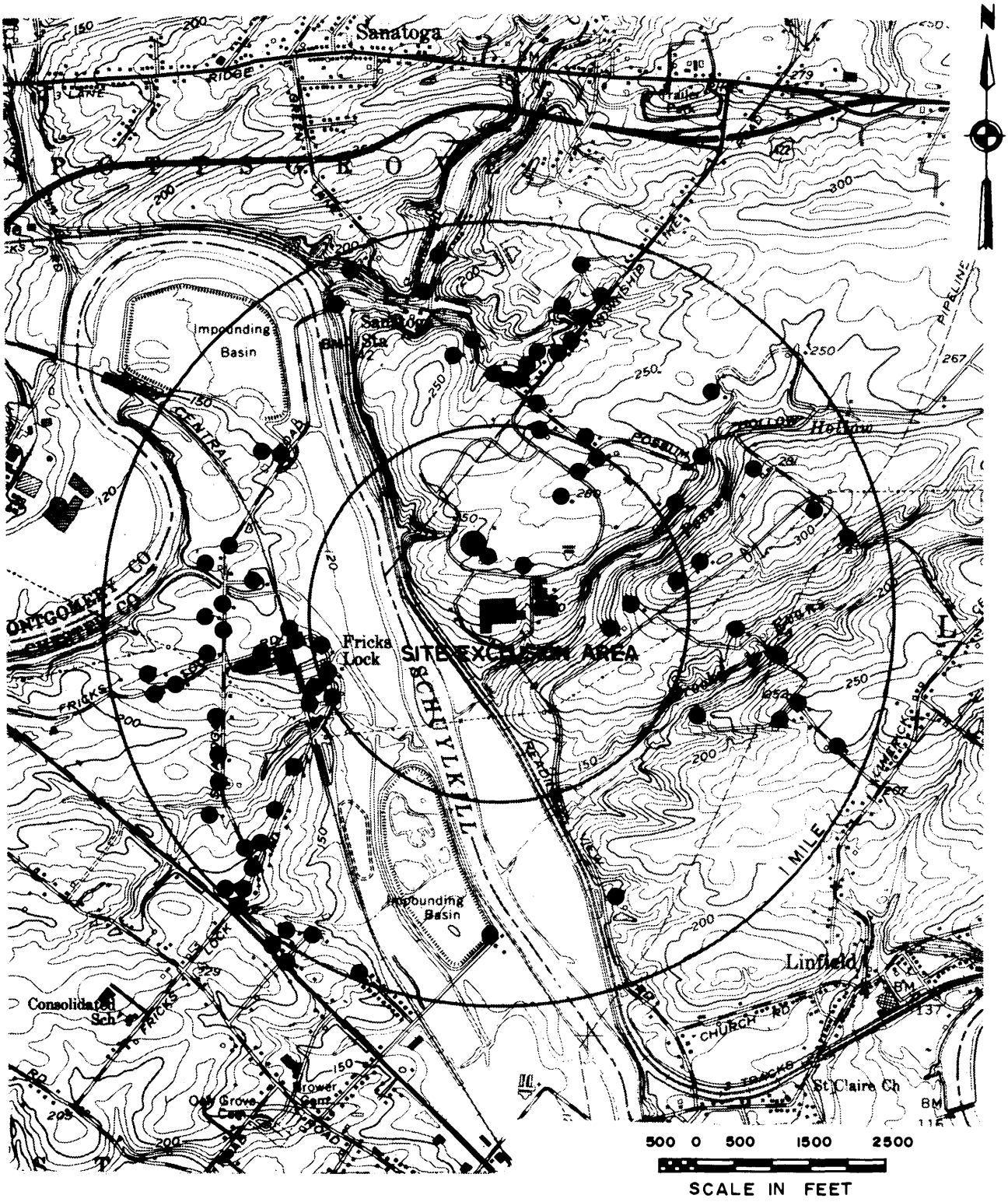
Biesecker, J.E. Lescinsky, J.B. and Wood, C.R., 1968 "Water Resources of the Schuylkill River Basin", Water Resources Bulletin No. 3, Department of Forest and Waters, Harrisburg, Pennsylvania.

Hammer, P., 1976, "Water Service Plan", Montgomery County Planning Commission, Court House, Morristown, PA.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PUBLIC GROUND WATER SUPPLIERS WITHIN 20 MILES OF THE SITE

FIGURE 2.4-16



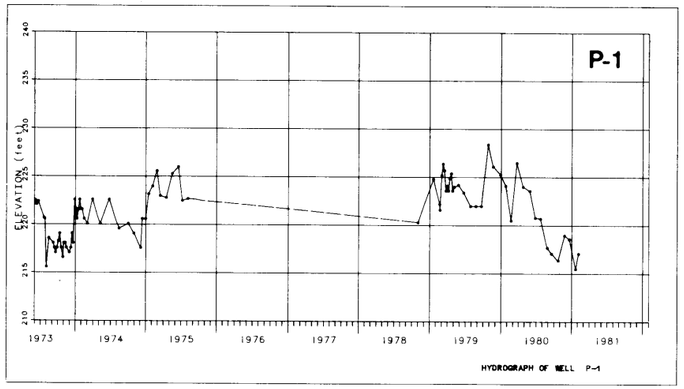
Reference:

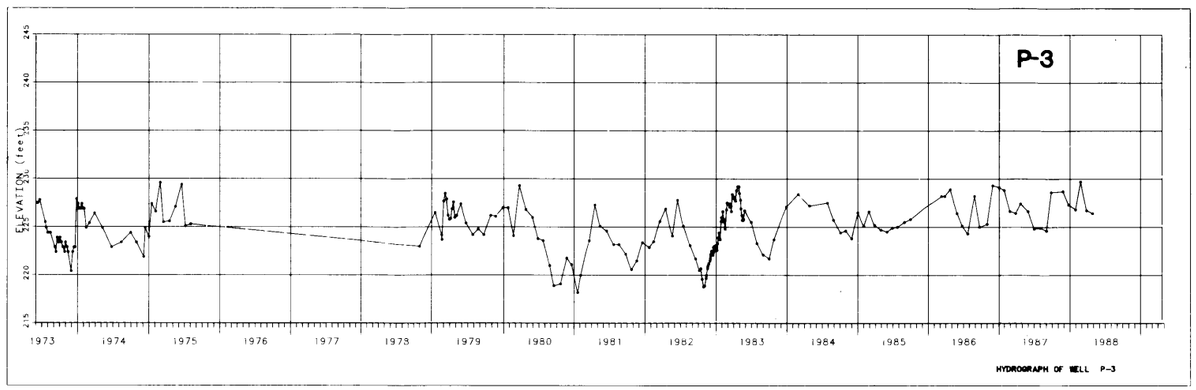
LGS PSAR Figure 2.4.2

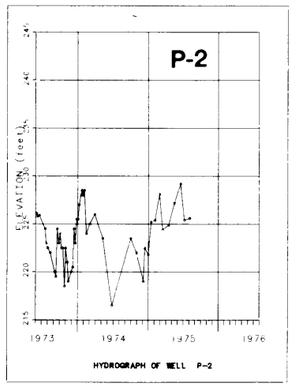
LIMERICK GENERATING STATION
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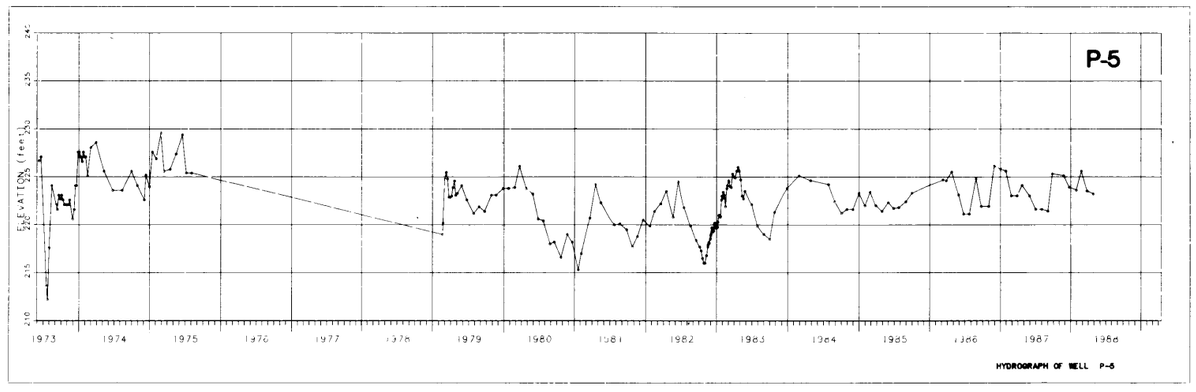
GROUND WATER USERS WITHIN ONE MILE OF THE SITE

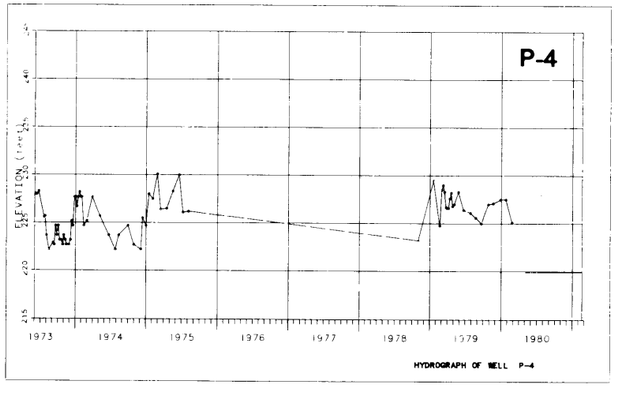
FIGURE 2.4-17

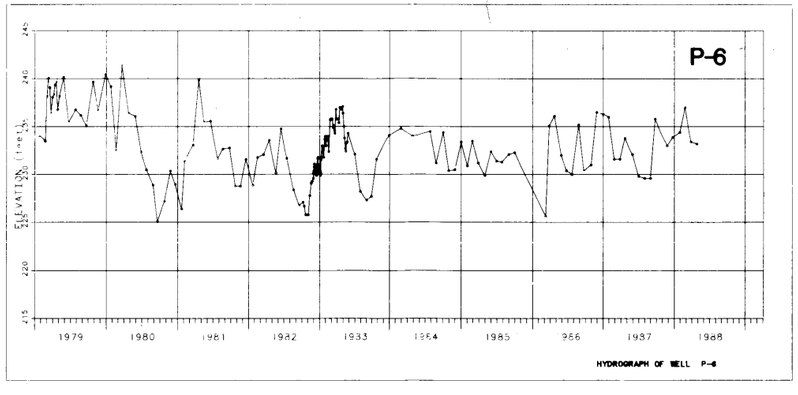












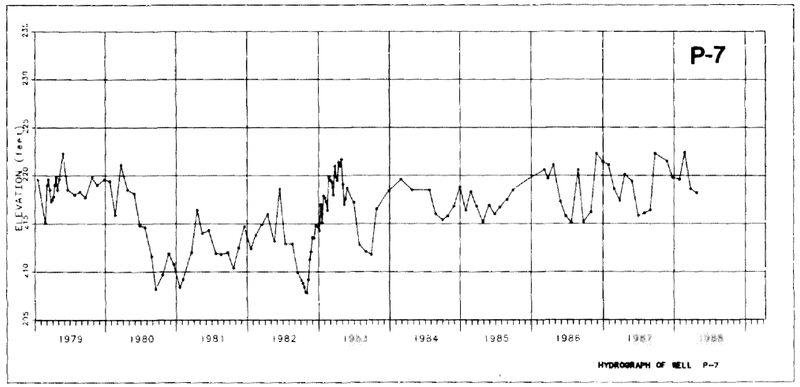
NOTES:

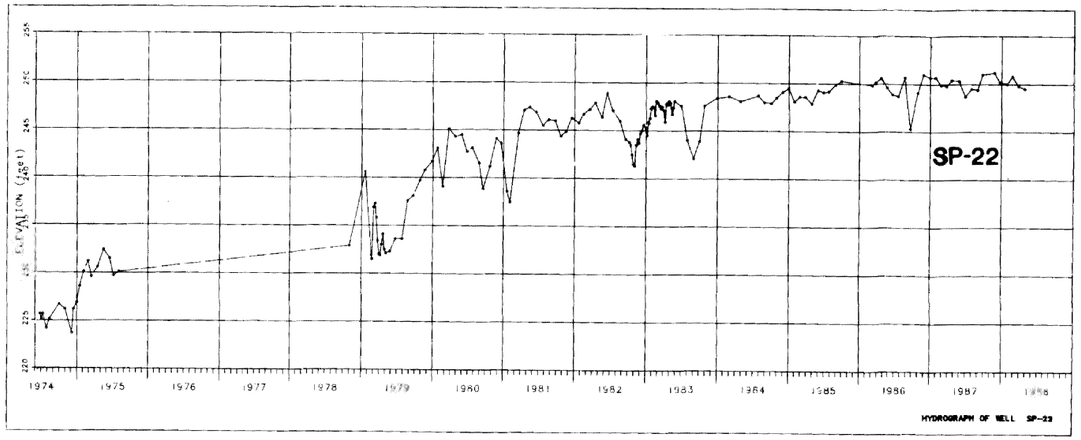
1. For locations of observation wells, see "Figure 2.4-16"
2. Temporary wells P1, P2 and P4 were destroyed during construction.

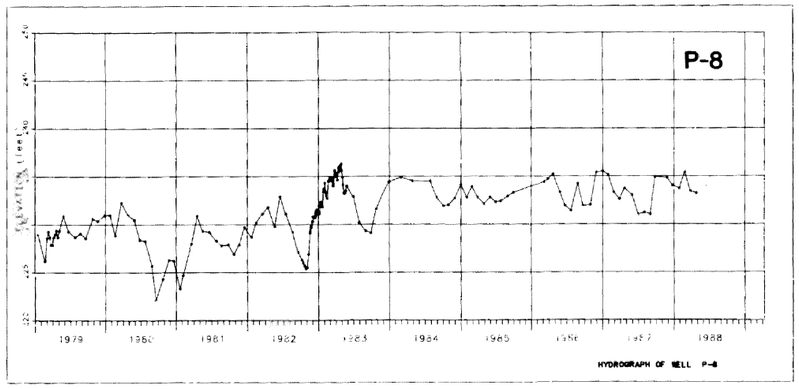
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

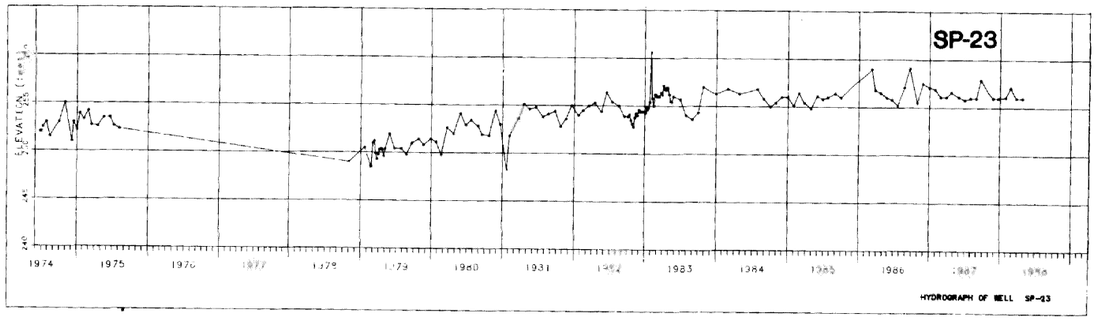
HYDROGRAPHS OF OBSERVATION WELLS (SPRAY POND AREA)
(SHEET 1 OF 3)

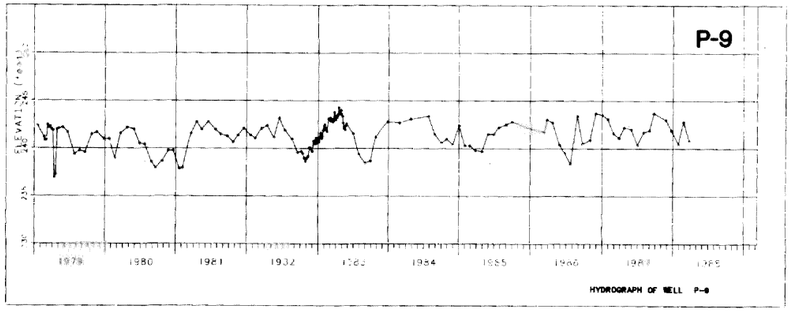
FIGURE 2.4-18

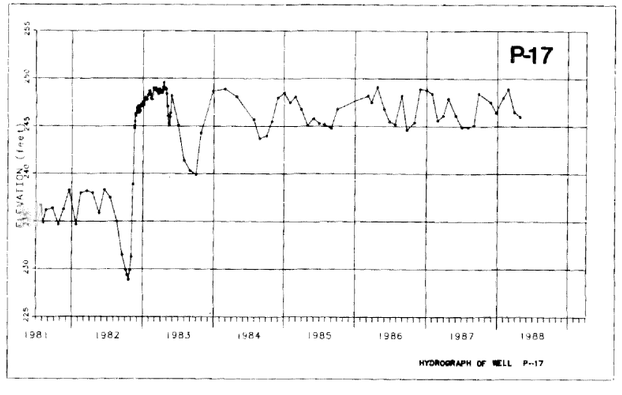


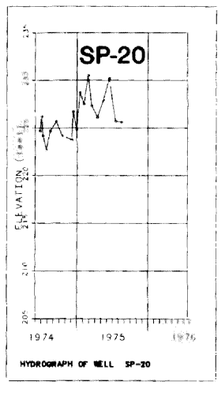


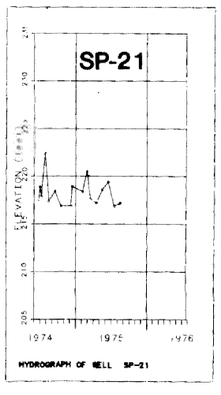


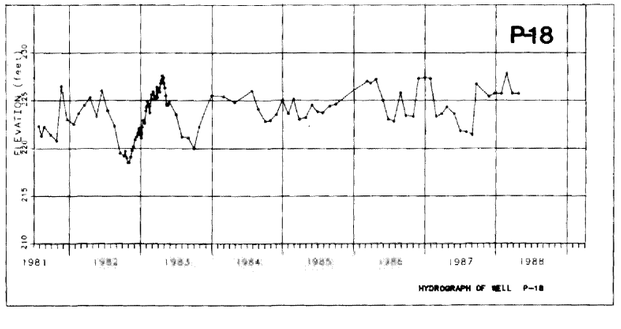


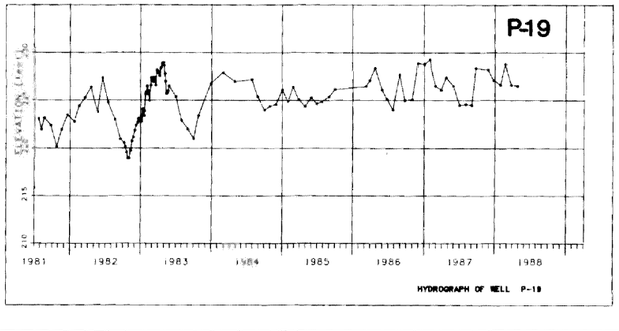












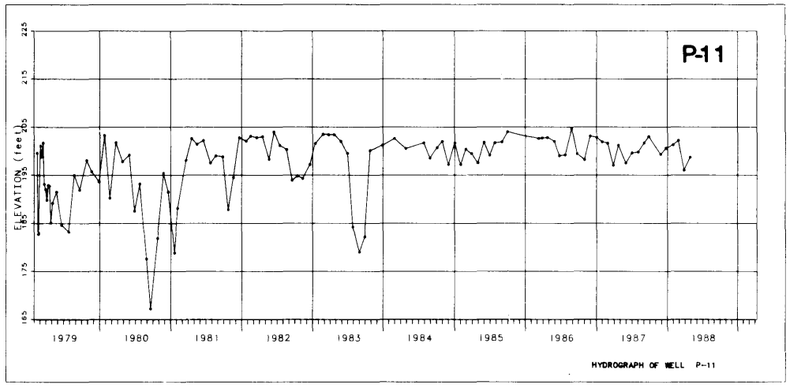
NOTES:

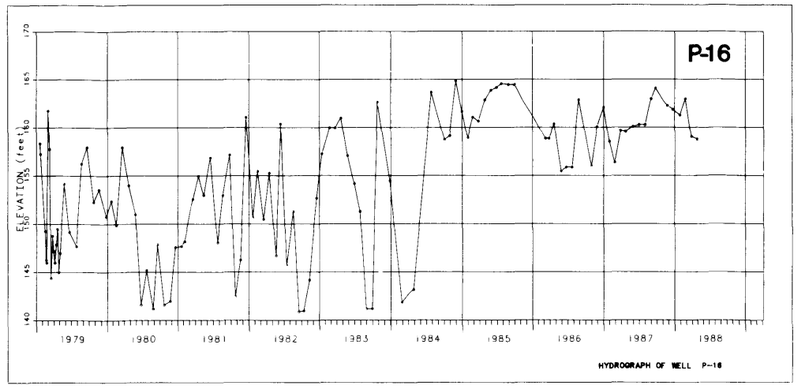
1. For locations of observation wells, see "Figure 2.4-15"
2. Observation wells SP-20 and SP-21 destroyed during construction; SP-21 replaced by P8
3. OBSERVATION WELL P9 WAS ABANDONED.

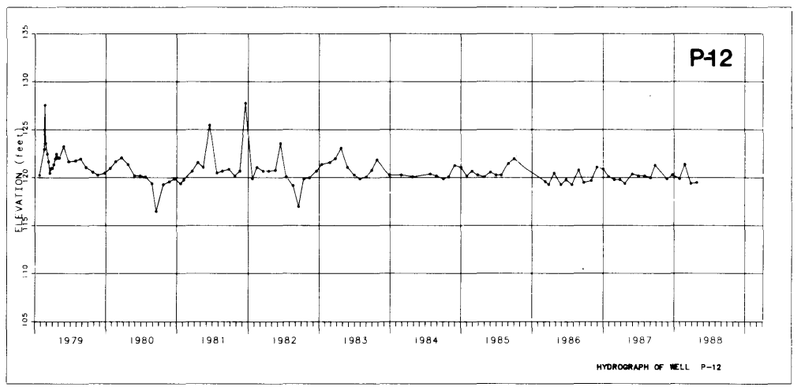
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

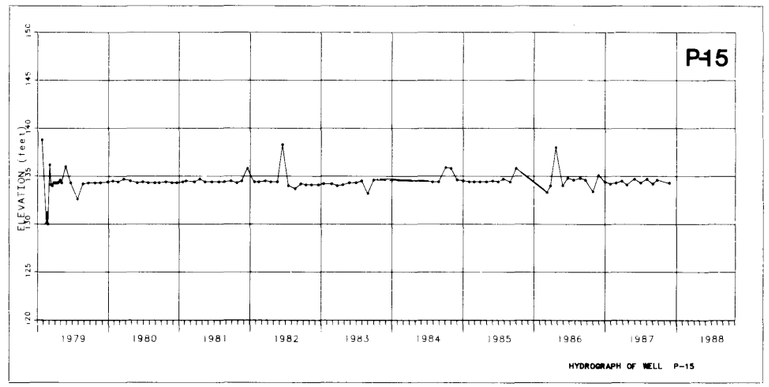
HYDROGRAPHS OF OBSERVATION WELLS (SPRAY POND AREA)
(SHEET 2 OF 3)

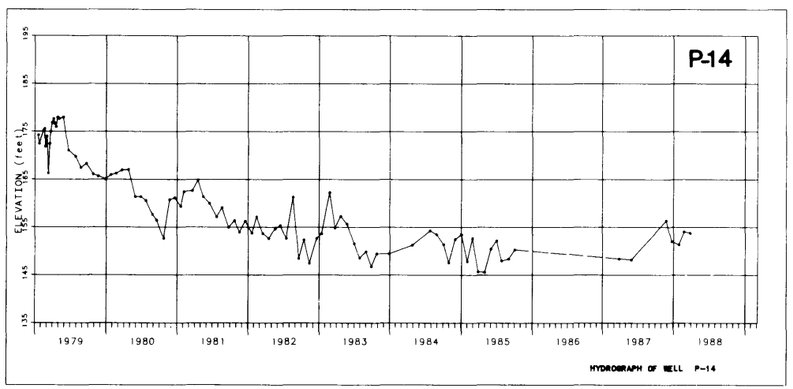
FIGURE 2.4-18

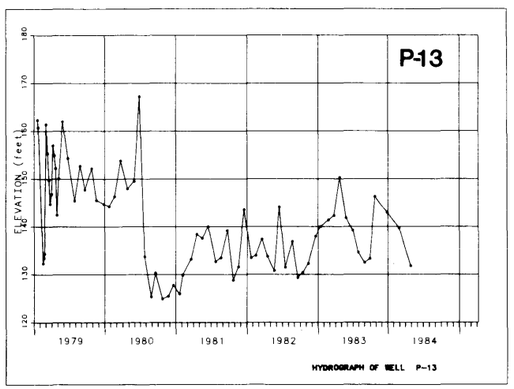










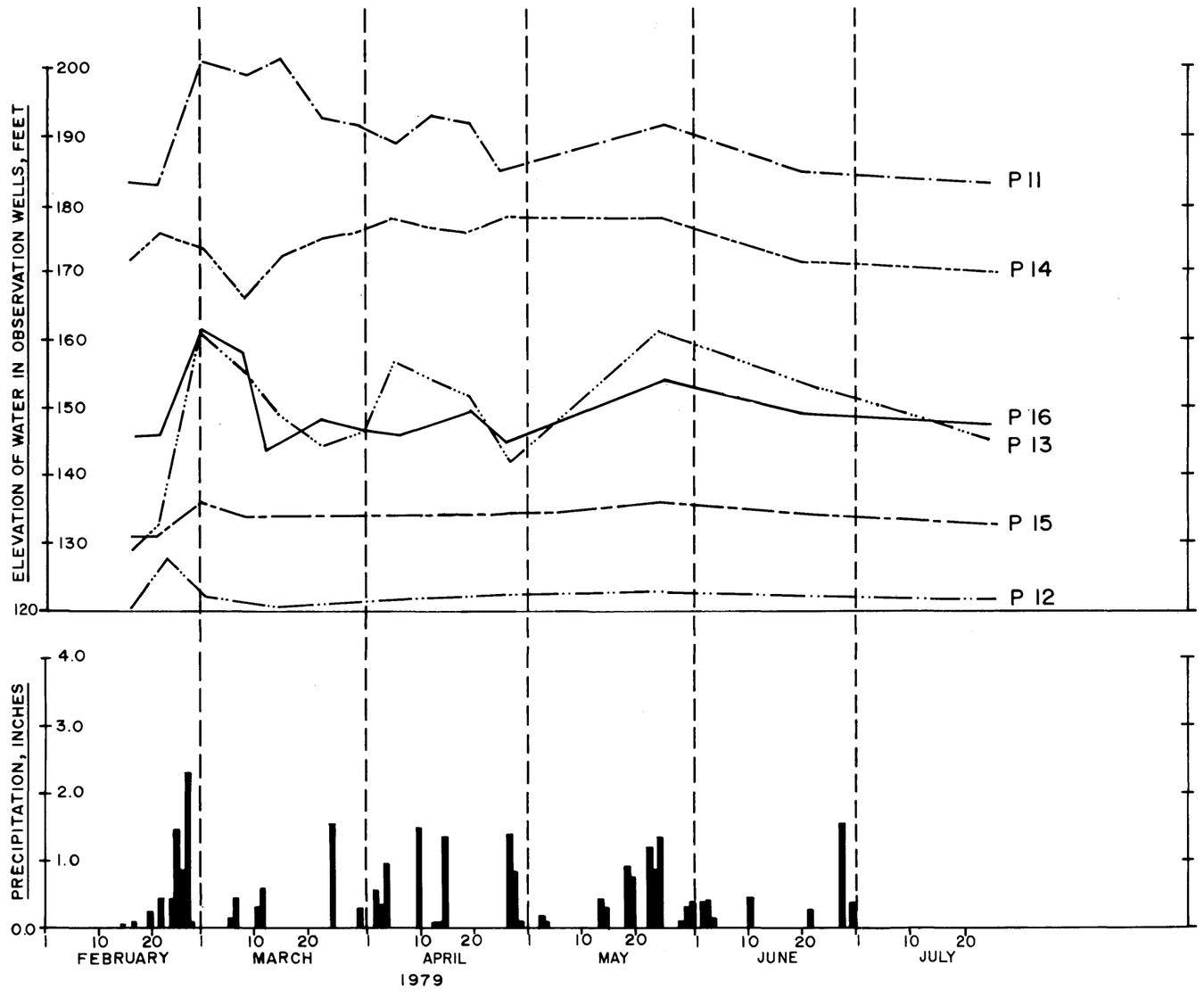


NOTES:

1. For locations of wells, see Figure 2.4-15
2. Note compressed vertical scale of hydrographs of P11, P13 and P14.
3. Wells P13 and P15 damaged during on-going construction and abandoned.

LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

HYDROGRAPHS OF OBSERVATION WELLS (POWER BLOCK AREA)
(SHEET 3 OF 3)
FIGURE 2.4-18



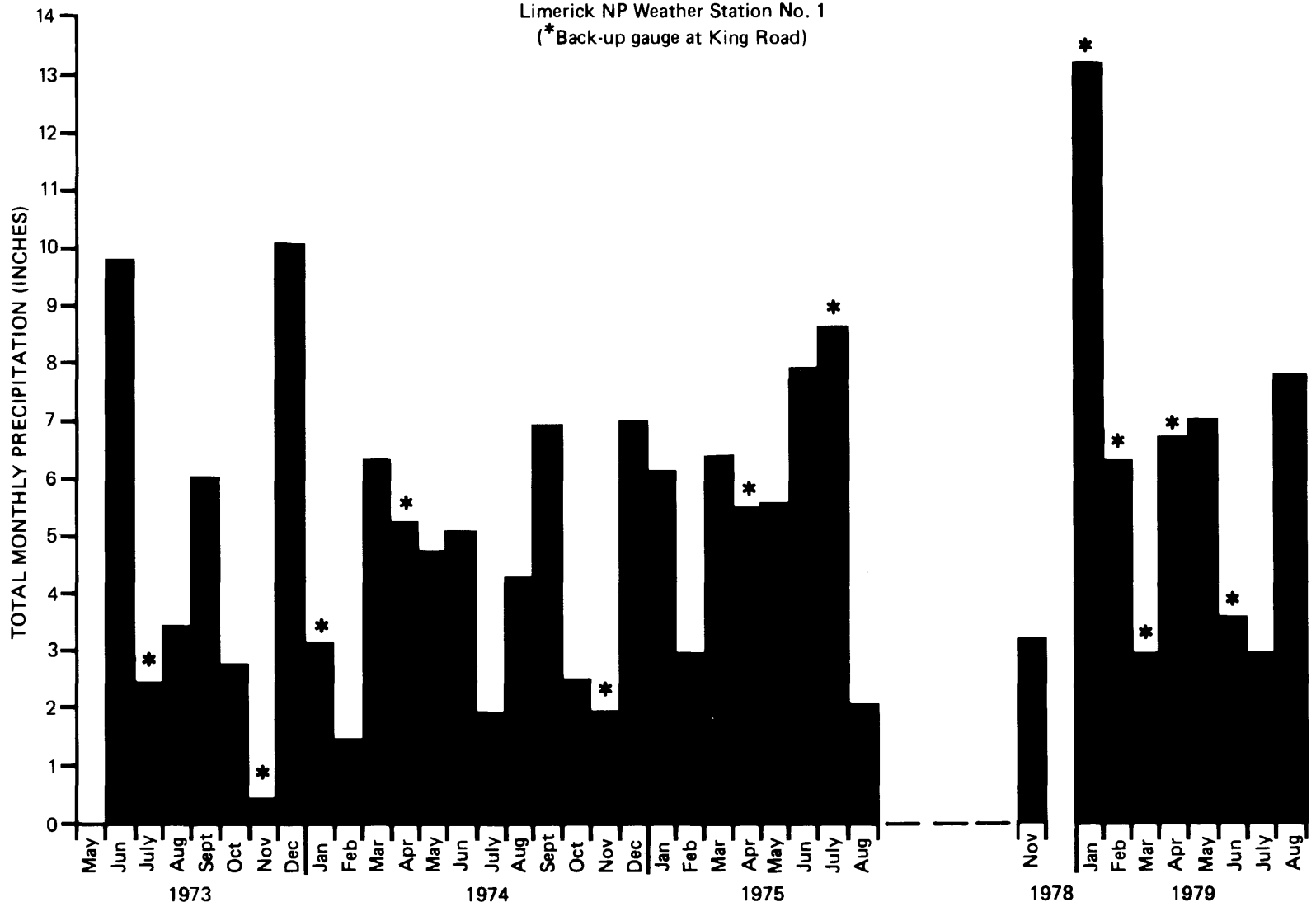
NOTES:

1. For locations of observation wells see Figure 2.4-15.
2. Precipitation data from on site metorological station.

LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

DAILY PRECIPITATION & ELEVATION OF WATER IN OBSERVATION WELLS POWER BLOCK AREA

FIGURE 2.4-19

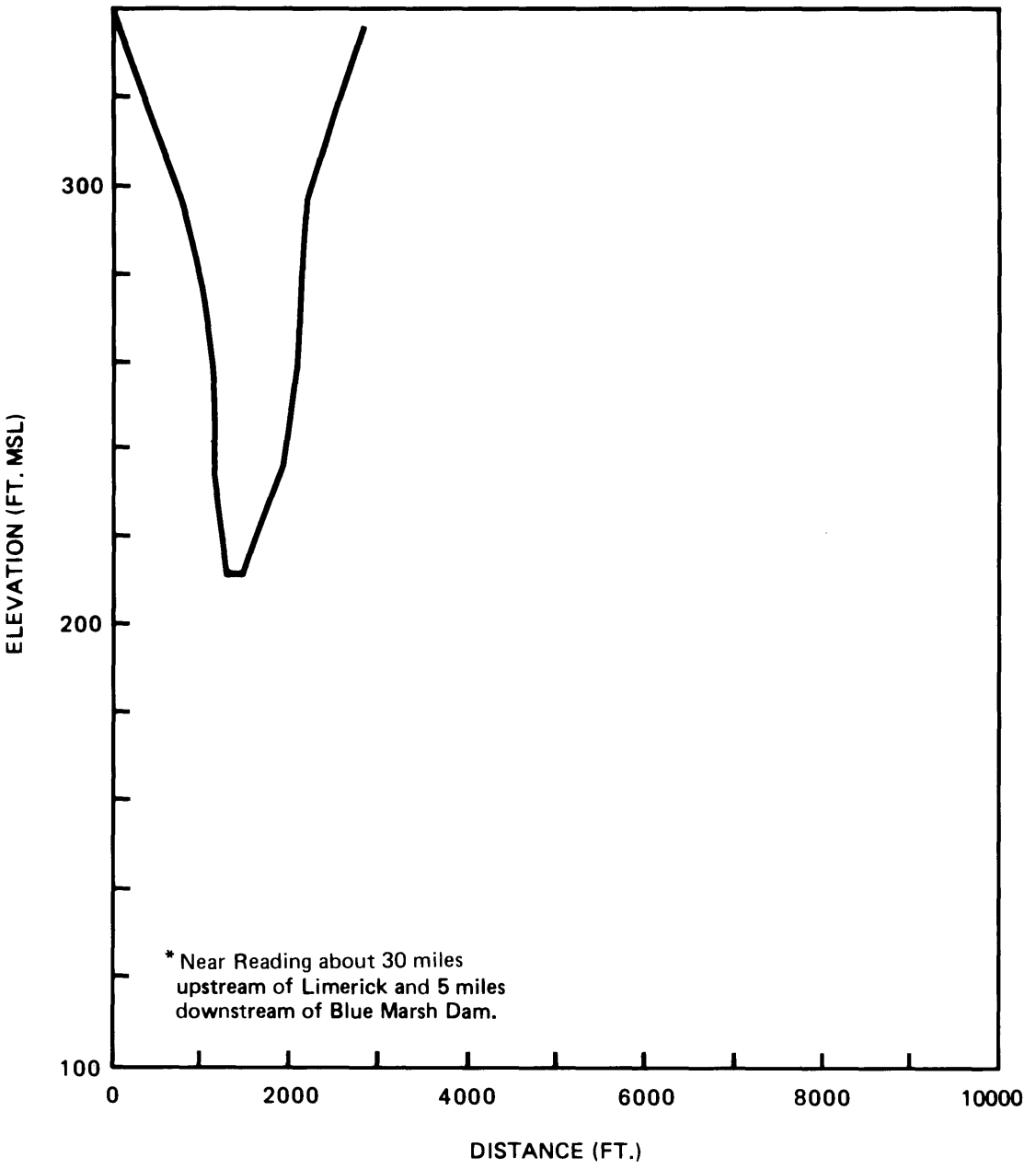


LIMERICK GENERATING STATION
UNITS 1 AND 2

UPDATED FINAL SAFETY ANALYSIS REPORT

TOTAL MONTHLY PRECIPITATION
36 MONTH MONITORING PERIOD

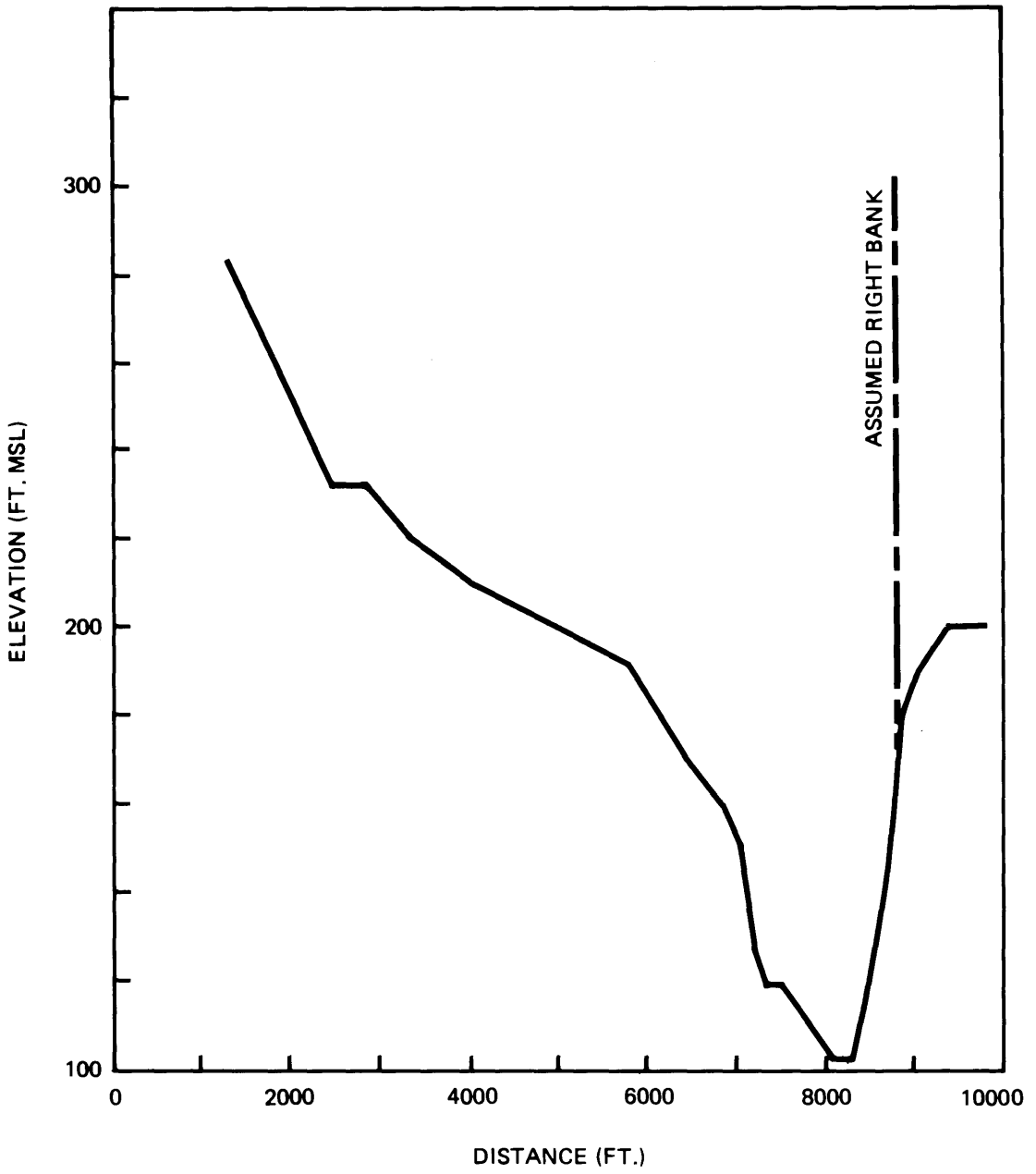
FIGURE 2.4-20



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CROSS-SECTION OF SCHUYLKILL RIVER AT HYPOTHETICAL DAM SITE * (LOOKING UPSTREAM)

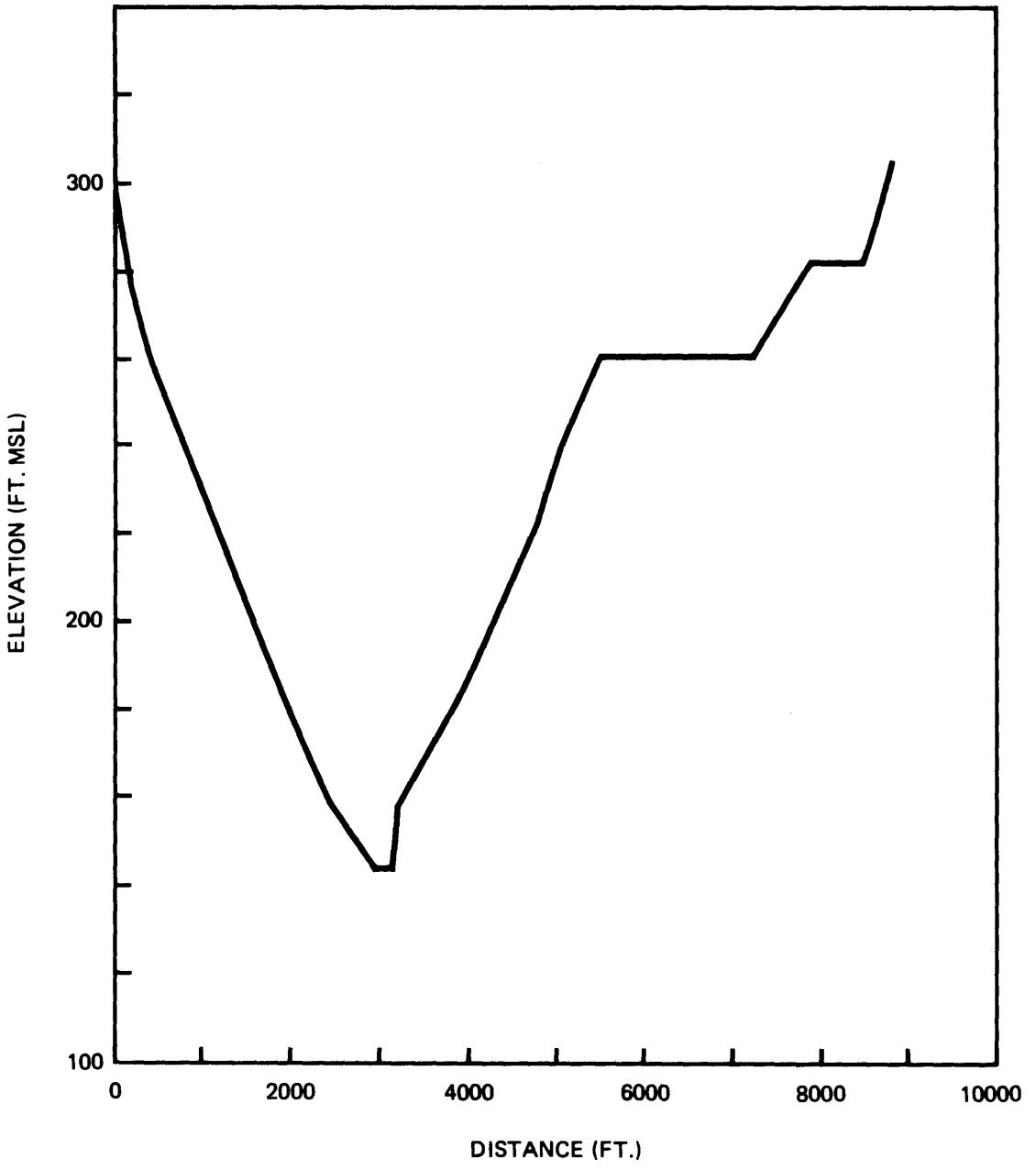
FIGURE 2.4-21



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CROSS-SECTION OF SCHUYLKILL RIVER
AT LIMERICK
(LOOKING UPSTREAM)

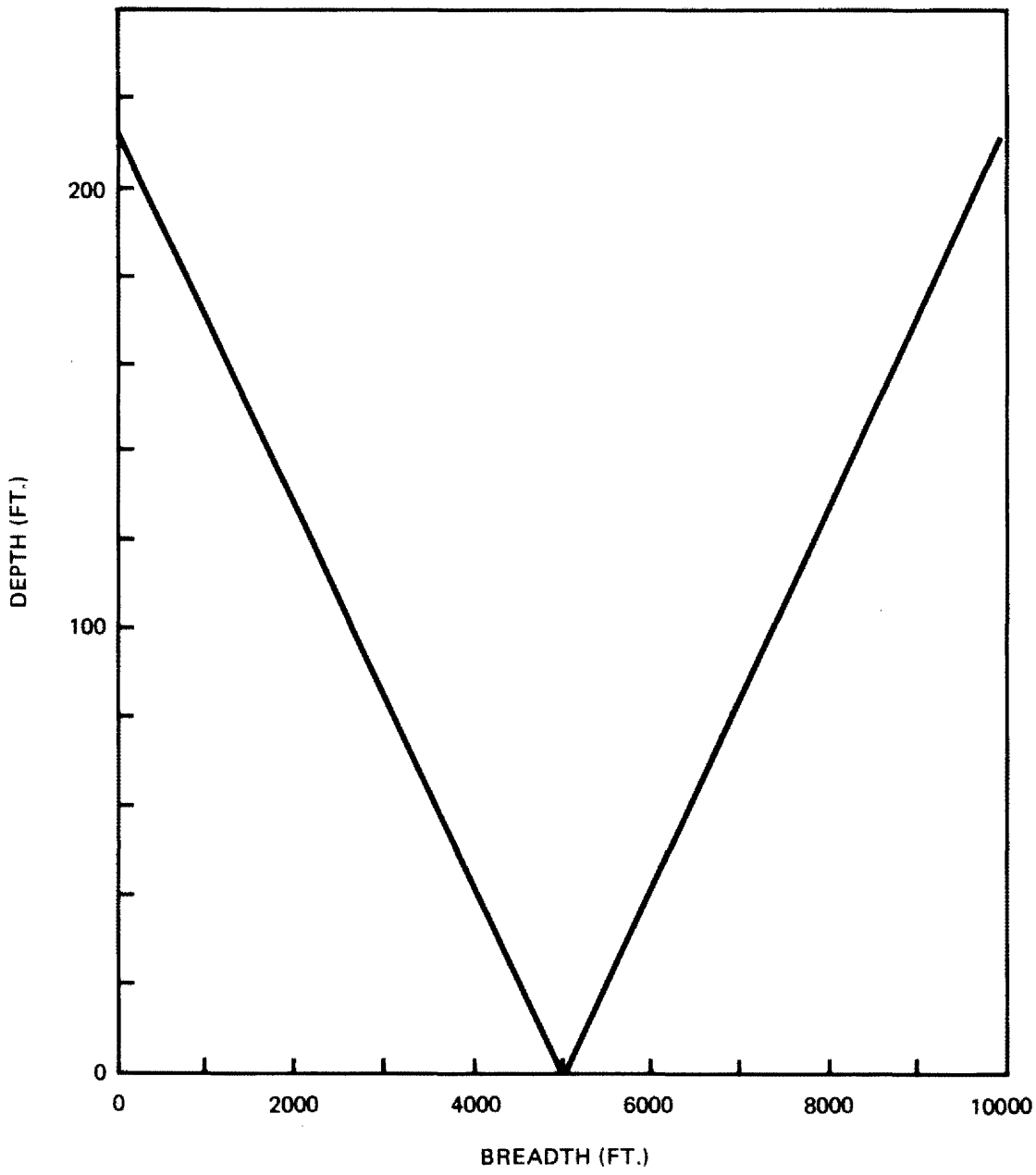
FIGURE 2.4-22



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CROSS-SECTION OF SCHUYLKILL RIVER
NEAR BIRDSBORO
(LOOKING UPSTREAM)

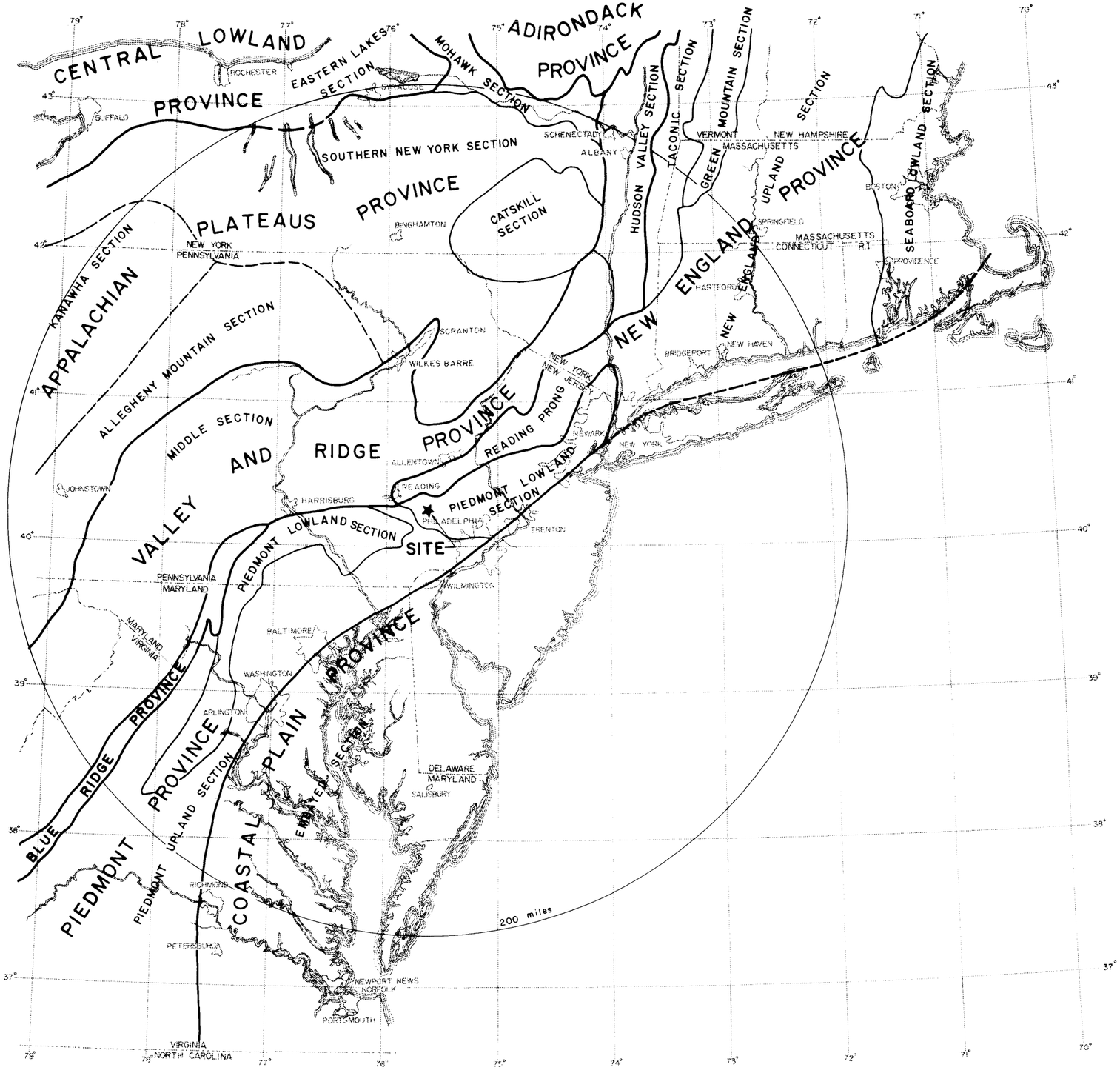
FIGURE 2.4-23

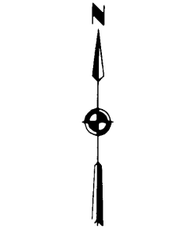


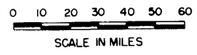
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CROSS-SECTION OF
REPRESENTATIVE PRISMATIC CHANNEL

FIGURE 2.4-24







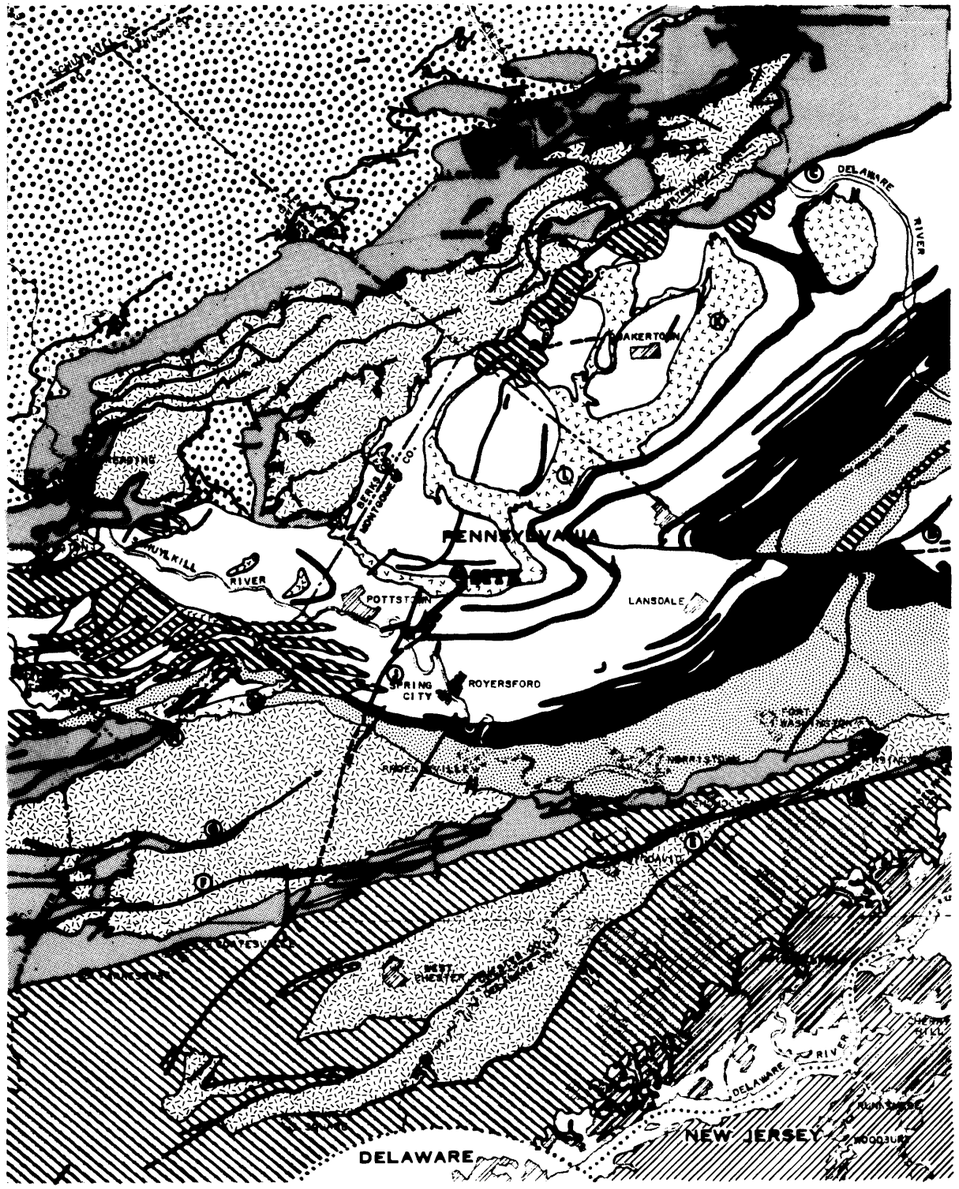
REFERENCE:

Fenneman, N. M., and Johnson, D.W., 1946 Physiographic Divisions of the United States; U.S. Geological Survey, Washington, D.C. Scale 1: 7,000,000

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PHYSIOGRAPHIC DIVISIONS

FIGURE 2.5-1



N

EXPLANATION

SYMBOL	DESCRIPTION
	CRETACEOUS: UNCONSOLIDATED SANDS AND CLAYS
	TRIASSIC: DIABASE SILLS AND DIKES
	TRIASSIC: LOCKATONG LITHOFACIES; ARGILLITE AND SHALE
	TRIASSIC: HAMMER CREEK LITHOFACIES AND BORDER CONGLOMERATES
	TRIASSIC: BRUNSWICK LITHOFACIES; SILTSTONE, SHALE AND SANDSTONES
	TRIASSIC: STOCKTON FORMATION; SANDSTONES AND SHALE
	ORDOVICIAN: LIMESTONES, DOLOMITES, SHALES
	CAMBRIAN: QUARTZITES, PHYLLITES AND CARBONATES
	PROBABLE LOWER PALEOZOIC: SCHISTS, GNEISS AND GRANITE
	PRECAMBRIAN: GRANITE GNEISS, DRANODIORITE QUARTZ MONZONITE AND GABBROIC ROCKS

KEY :

FAULTS

- (A) CHALFONT
- (B) FURLONG (FLEMINGTON)
- (C) NORTH BORDER
- (D) HUNTINGDON VALLEY–CREAM VALLEY
- (E) ROSEMONT
- (F) LIMEVILLE
- (G) BRANDYWINE MANOR
- (M) ELVERSON

DIKES & SILLS

- (J) DOWNINGTOWN DIKE
- (K) HAYCOCK SILL
- (L) ROCK HILL SILL
- (ZI) ZIEGLER SILL
- (M) ST. PETERS SILL

5 0 5 10 15

STATUE MILES

REFERENCE:

THIS MAP WAS PREPARED FROM PORTIONS OF THE FOLLOWING U.S.G.S. TOPOGRAPHIC MAPS: WILMINGTON, DEL.-N.J.-PA.-MD., 1956, AND NEWARK 1964.

GEOLOGY ADAPTED IN PART FROM THE PENN. GEOL. SURVEY GEOLOGICAL MAP OF PENN, 1960.

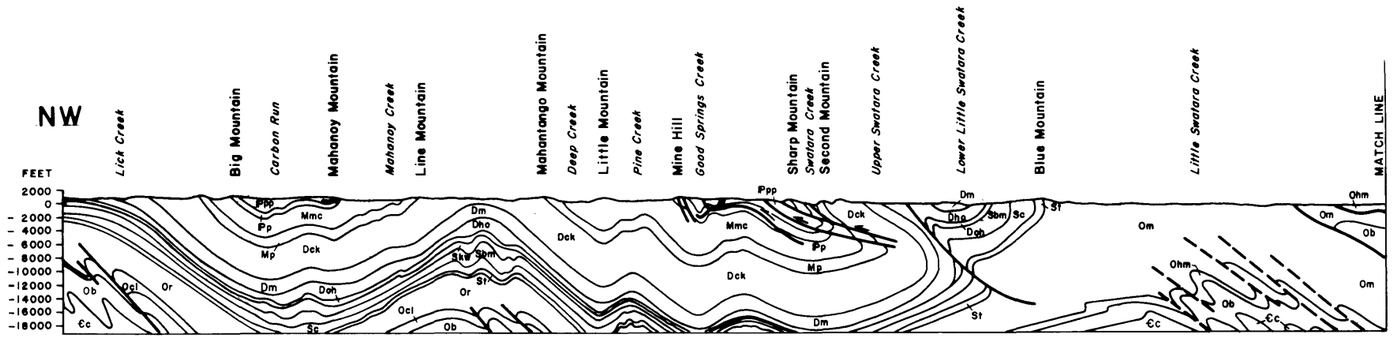
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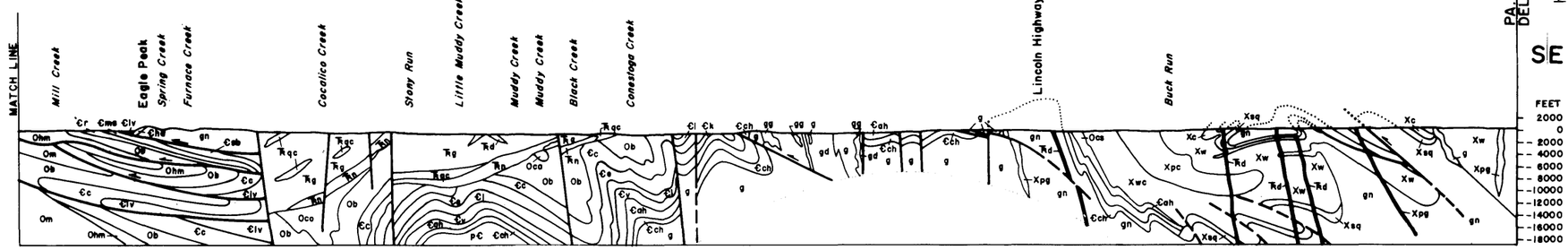
PRESENTED IN PSAR AS FIGURE 2.5.8; PREPARED BY DAMES AND MOORE.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REGIONAL GEOLOGY

FIGURE 2.5-2





EXPLANATION

MESOZOIC — TRIASSIC: Trd diabase dikes and sills, Trg Gettysburg formation (Brunswick equivalent), Trqc quartz pebble conglomerate, Trn New Oxford formation (Stockton equivalent).

PENNSYLVANIAN: IPpp post-Pottsville formations; IPp Pottsville group - sandstone and conglomerate with coal.

MISSISSIPPIAN: Mmc Mauch Chunck formation - shale and sandstone; Mp Pocono group - conglomerate and sandstone.

DEVONIAN: Dck Catskill formation, red sandstones and shales; Dm Marine gray to brown shales, graywackes, and sandstones; Dho Hamilton group, undifferentiated; Doh Oriskany and Helderberg formations, undifferentiated.

SILURIAN: Skw Keyser, Tonoloway and Wills Creek formations, undifferentiated; Sbm Bloomsburg and McKenzie formations, undifferentiated; Sc Clinton group; St Tuscarora formation.

ORDOVICIAN: Central Pennsylvania - Or Reedsville formation, Ocl Curtin formation, Ob Beekmantown group; Great Valley - Om Martinsburg formation, Ohm Hershey and Myerstown formations; Piedmont - Oco Cocalico formation, Oca Conestoga formation.

CAMBRIAN: Cc Conococheague group, undifferentiated; Cr Richland formation, Cms Millbach and Schaeffers-town formations, Cab Snitz Creek and Buffalo Springs formations; Ce Elbrook formation; Clv Leitnsville formation, undifferentiated; Cl Ledger formation, Ck Kinzers formation, Cv Vintage formation, Cah Antietam and Harpers formations; Cch Chickies formation.

PROBABLY LOWER PALEOZOIC: Xpg pegmatite; Xpc Peters Creek schist; Xwc Wissahickon formation, albite-chlorite schist; Xw Wissahickon formation, oligoclase-mica schist; Xc Cockeysville marble; Xsq Setters formation.

PRECAMBRIAN — PRECAMBRIAN: pC undifferentiated; g gabbroic gneiss and gabbro; gd granodiorite; gg graphitic gneiss, gn granite gneiss.

FAULT, arrow indicates relative movement

GEOLOGIC CONTACT

DIKES, pegmatite or diabase, as indicated

SCALE IN MILES 0 1 2 3

REGIONAL GEOLOGIC SECTION – ANTHRACITE REGION TO SOUTHEASTERN PIEDMONT

No vertical exaggeration

NOTES:

1. Redrafted from the Geologic Map of Pennsylvania, 1960.
2. Section extends from approximately Sunbury, Pennsylvania to about 11 miles Southwest of West Chester, Pennsylvania, passing within 22 miles of the Limerick site through geologically similar terrain.

LIMERICK GENERATING STATION
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REGIONAL GEOLOGIC SECTION

FIGURE 2.5-3

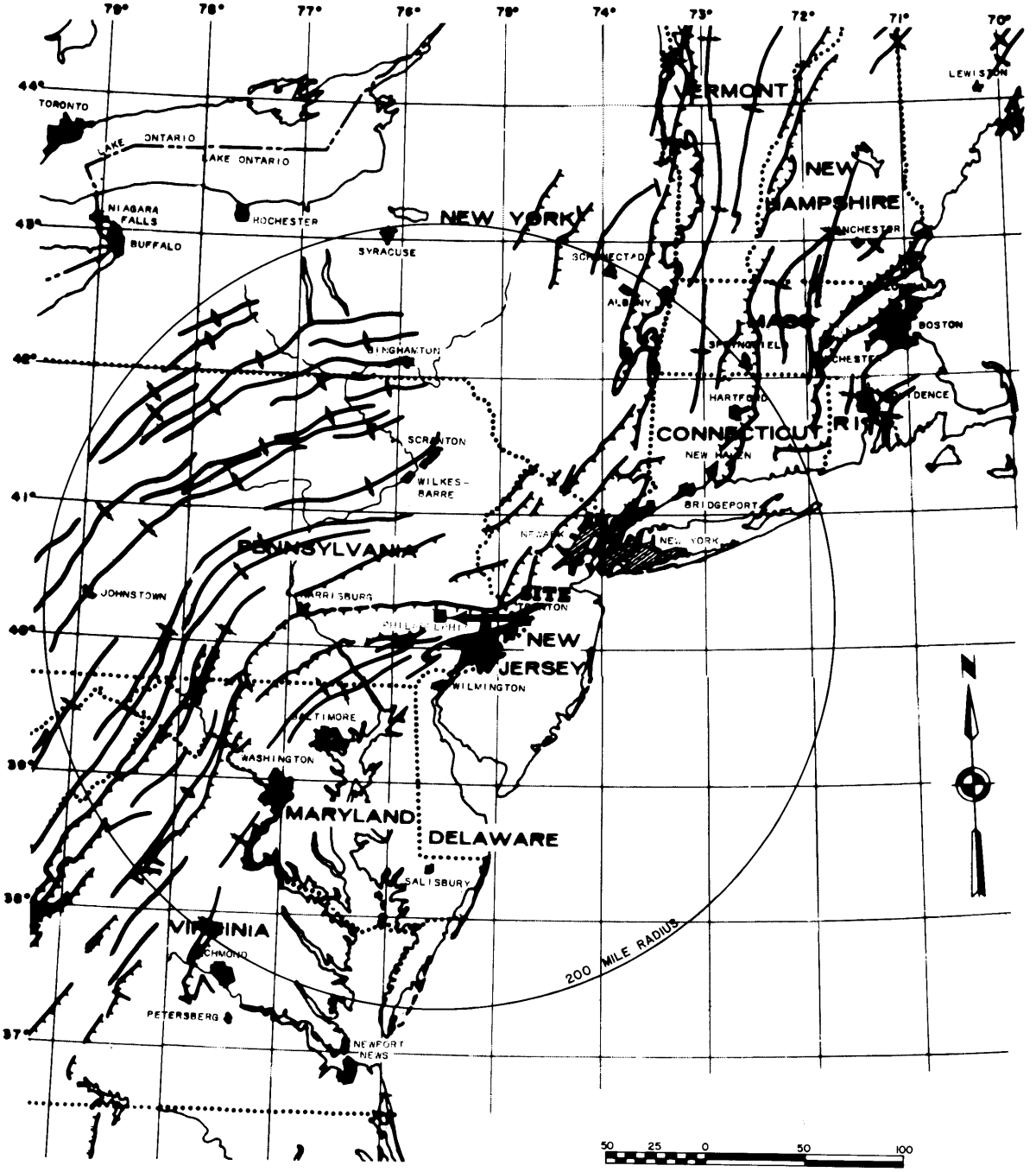
ERA	PERIOD	FORMATION/ROCK TYPE	THICKNESS IN FEET	OUTCROP LOCATION
CENOZOIC	RECENT AND QUATERNARY	RIVER ALLUVIUM AND TERRACE DEPOSITS	0-20	ALL AREAS
MESOZOIC	CRETACEOUS	SAND, SILT AND CLAY	0 TO OVER 1000	COASTAL PLAIN
MESOZOIC	TRIASSIC	DIABASE DIKES AND SILLS	5000-15,000	TRIASSIC LOWLANDS
MESOZOIC	TRIASSIC	BRUNSWICK LITHOFACIES; LOCKATONG LITHOFACIES; HAMMER CREEK LITHOFACIES	5000-15,000	TRIASSIC LOWLANDS
MESOZOIC	TRIASSIC	STOCKTON FORMATION	3000	TRIASSIC LOWLANDS
PALEOZOIC	PERMIAN	CYCLIC DEPOSITS OF SHALE, CLAY, COAL LIMESTONE & SANDSTONE	NOT PRESENT WITHIN 25 MILES OF SITE	VALLEY AND RIDGE
PALEOZOIC	PENNSYLVANIAN	CYCLIC DEPOSITS OF SHALE, CLAY, COAL LIMESTONE & SANDSTONE	NOT PRESENT WITHIN 25 MILES OF SITE	VALLEY AND RIDGE
PALEOZOIC	PENNSYLVANIAN	POTTSVILLE GROUP SANDSTONE & CONGLOMERATE	NOT PRESENT WITHIN 25 MILES OF SITE	VALLEY AND RIDGE
PALEOZOIC	MISSISSIPPIAN	CONGLOMERATE, SHALE, SANDSTONE AND SOME LIMESTONE	NOT PRESENT WITHIN 25 MILES OF SITE	VALLEY AND RIDGE
PALEOZOIC	DEVONIAN	SHALE AND SANDSTONE WITH SOME LIMESTONE	NOT PRESENT WITHIN 25 MILES OF SITE	VALLEY AND RIDGE
PALEOZOIC	SILURIAN	DOLOMITE, LIMESTONE SANDSTONE, SHALE AND CONGLOMERATE	NOT PRESENT WITHIN 25 MILES OF SITE	VALLEY AND RIDGE
PALEOZOIC	ORDOVICIAN	CONESTOGA AND BEEKMANTOWN LIMESTONE	3000	PIEDMONT UPLAND AND GREAT VALLEY
PALEOZOIC	CAMBRIAN UPPER	CONOCOHEAGUE AND ELLBROOK LIMESTONE	1400	GREAT VALLEY AND PIEDMONT UPLAND
PALEOZOIC	CAMBRIAN LOWER	QUARTZITE, PHYLLITE AND DOLOMITE	1900 TO 4100	PIEDMONT UPLAND READING PRONG
PALEOZOIC	CAMBRIAN LOWER	GLENARM SERIES; WISSAHICKON SCHIST & GNEISS	GREATER THAN 9000	PIEDMONT UPLAND
PRE-CAMBRIAN		BALTMORE GNEISS PICKERING GNEISS FRANKLIN MARBLE	UNKNOWN	READING PRONG AND PIEDMONT UPLAND

NOTE:
Modified from Figure 2.5.14 of the Limerick Generating Station PSAR, using data from the Geologic Map of Pennsylvania, 1960 edition.

LIMERICK GENERATING STATION UNITS 1 AND 2
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REGIONAL STRATIGRAPHIC COLUMN

FIGURE 2.5-4



REFERENCE:

THIS MAP WAS PREPARED FROM A PORTION OF THE U.S.G.S. "IFR WALL PLANNING CHART, EAST AND WEST, 1968."

MAJOR TECTONIC FEATURES WERE TAKEN FROM A PORTION OF THE "TECTONIC MAP OF THE UNITED STATES" BY U.S. U.S. AND A.A.P.G.,

MAP PREPARED BY DAMES AND MOORE AS FIGURE 2.5.9 OF THE PSAR.

LIMERICK GENERATING STATION
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REGIONAL TECTONIC MAP

FIGURE 2.5-5



GEOLOGIC MAP OF THE LIMERICK-POTTSTOWN AREA

0 2000 6000 10,000

SCALE IN FEET

KEY:

TRIASSIC(?)

- TRACE OF FAULT, DASHED WHERE INFERRED
- STRIKE AND DIP OF BEDDING
- DIKE; DASHED WHERE INFERRED FROM FIELD EVIDENCE
- DIKE; INFERRED FROM MAGNETIC SURVEY
- Tmb DIABASE
- Tmm BRUNSWICK FACIES
- Tml LOCKATONG FACIES
- Tms STOCKTON FACIES
- SYNCLINAL AXIS (APPROXIMATE)
- ANTICLINAL AXIS (APPROXIMATE)

REFERENCES:

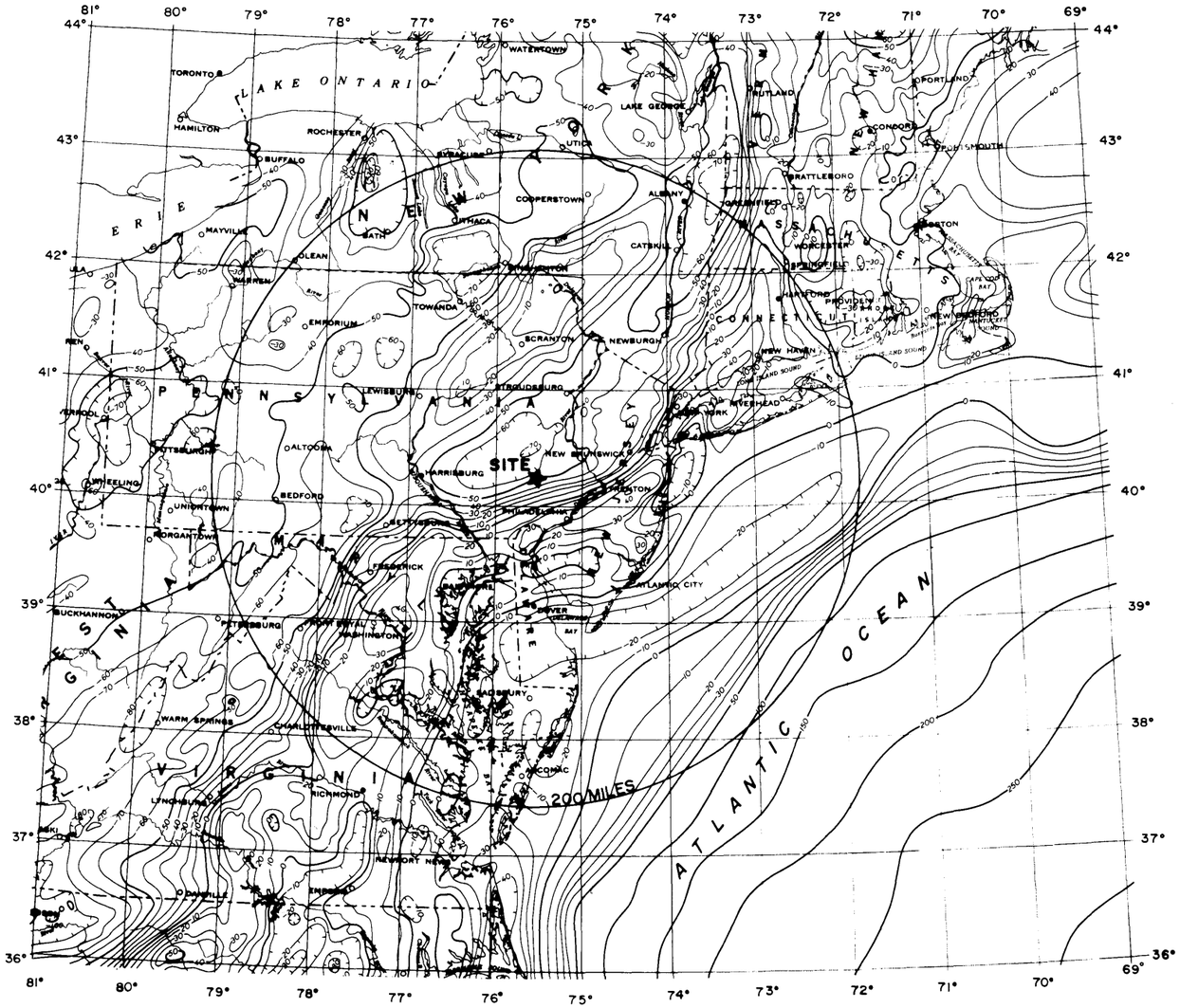
THIS MAP WAS PREPARED FROM PORTIONS OF U.S.G.S. QUADRANGLES; BOYERTOWN, PA., DATED 1968; POTTSTOWN, PA., DATED 1968; SASSAMANSVILLE, PA., DATED 1968, AND PHOENIXVILLE, PA., DATED 1968.,
CHESTER COUNTY PLANNING COMMISSION, 1973, CHESTER COUNTY GEOLOGY, CHESTER COUNTY PRINTING DEPARTMENT 95P.
LONGWILL, S. AND WOOD, M., 1965, GROUNDWATER RESOURCES BERKS COUNTY PENNSYLVANIA, PA.
COMMONWEALTH OF PENNSYLVANIA DEPT. OF INTERNAL AFFAIRS; GROUND WATER REPORT W22, 59P.

NOTE:
THIS MAP PREPARED BY DAMES AND MOORE AS PLATE 2.2-1 IN THE 1974 LIMERICK GENERATING STATION GEOLOGIC REPORT.

LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

GEOLOGY OF THE LIMERICK-POTTSTOWN AREA

FIGURE 2.5-6



REFERENCE:

American Geophysical Union, 1964, Bouguer Gravity Anomaly Map of the United States, U.S. Geological Survey, Washington, D.C. Scale 1:2,500,000.

0 50 100 150

SCALE IN MILES

CONTOUR INTERVAL 10 MILLIGALS

LIMERICK GENERATING STATION
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BOUGUER GRAVITY ANOMALY MAP

FIGURE 2.5-7



AEROMAGNETIC INTENSITY OF THE LIMERICK - POTTSTOWN REGION

TOTAL MAGNETIC INTENSITY CONTOUR = 10 GAMMA INTERVAL

KEY:

- SILLS
- DIKES FIELD CHECKED
- DIKES (INFERRED FROM FIELD EVIDENCE)
- FAULTS (BASED ON PENNA. GEOLOGY MAP 1966 OR FIELD EVIDENCE)
- DIKES (INFERRED FROM AEROMAGNETIC DATA)
- FAULTS (INFERRED FROM AEROMAGNETIC DATA)
- AEROMAGNETIC ANOMALY CONTOUR LINE

REFERENCE:

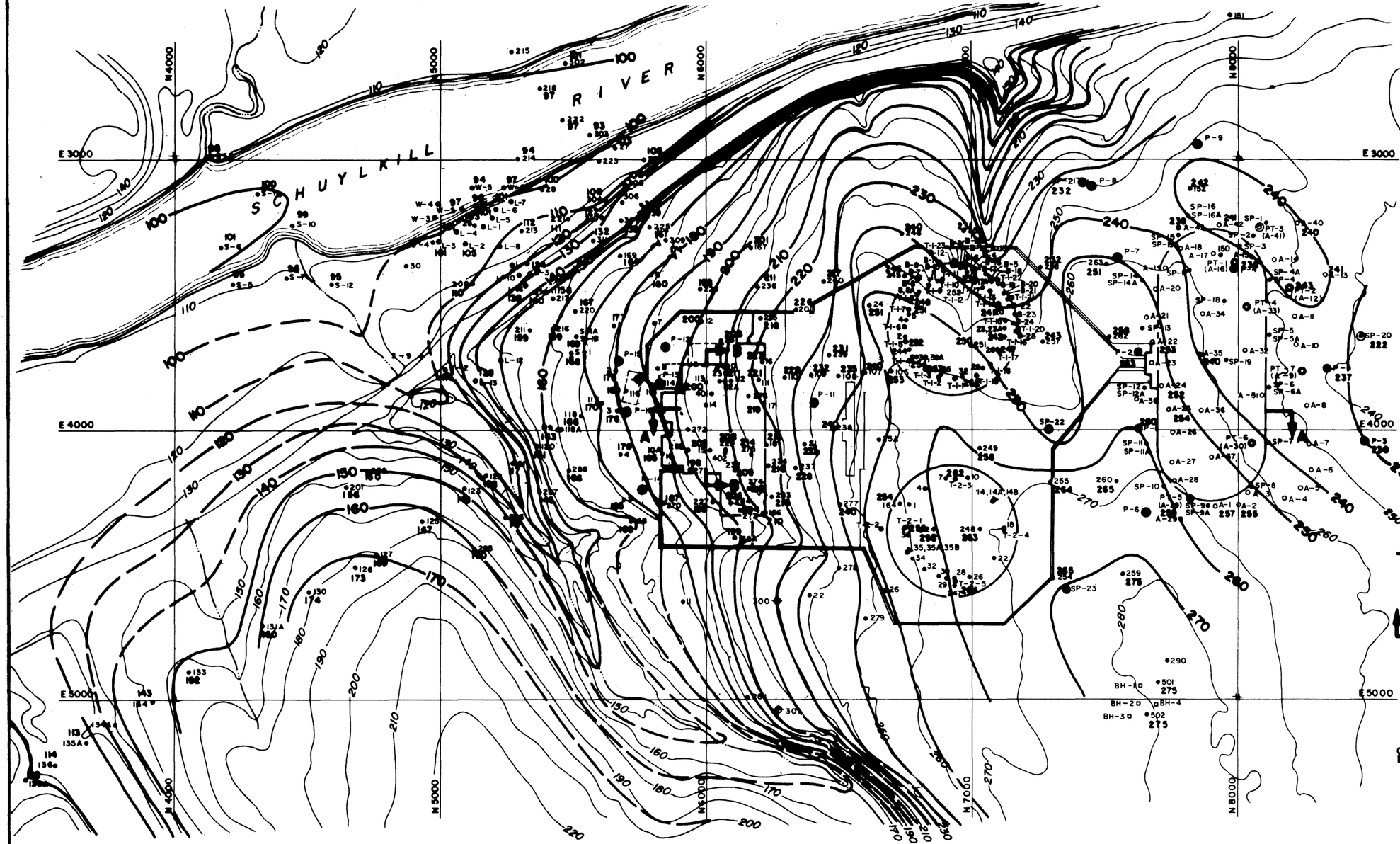
THIS MAP WAS PREPARED FROM PORTIONS OF THE FOLLOWING: BASE MAP U.S.G.S. 7.5 SERIES, BOYERTOWN, SASSAMANVILLE, POTTSTOWN AND PHOENIXVILLE QUADRANGLES (1966 CULTURAL REVISION). AEROMAGNETIC MAP COMPILED BY LKB RESOURCES INC. FLOWN 1974 BY GRUMMAN ECOSYSTEMS, CORP.

NOTE:
THIS MAP PREPARED BY DAMES AND MOORE AS PLATE 6.2-1 IN THE 1974 LIMERICK GENERATING STATION GEOLOGIC REPORT.

LIMERICK GENERATING STATION
UNITS 1 AND 2
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AEROMAGNETIC INTENSITY OF THE LIMERICK-POTTSTOWN REGION

FIGURE 2.5-8



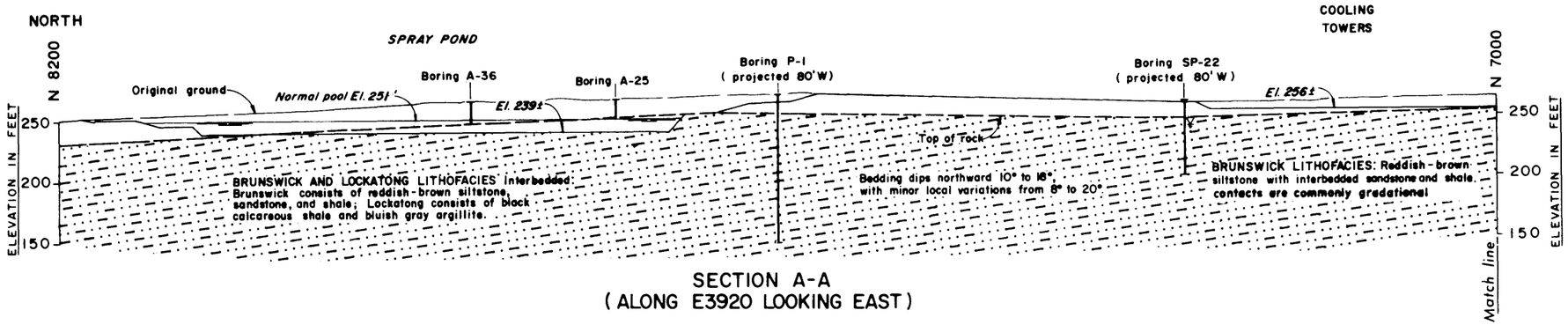
NOTES:

1. For location of geophysical surveys see Figure 2.5 -21.
2. For graphic logs of borings, see Figure 2.5-22 .
3. Geologic sections A-A and B-B are shown on Figures 2.5-10 2.5-11.

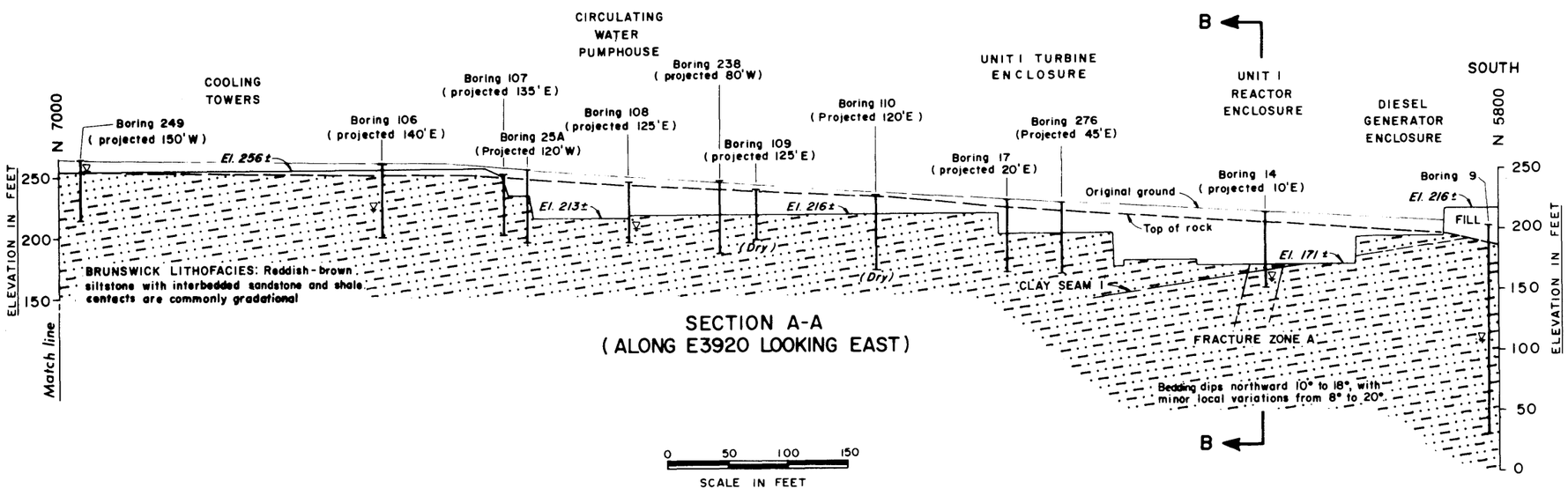
LIMERICK GENERATING STATION
UNITS 1 AND 2
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TOP OF ROCK CONTOURS

FIGURE 2.5-9



SECTION A-A
(ALONG E3920 LOOKING EAST)



SECTION A-A
(ALONG E3920 LOOKING EAST)

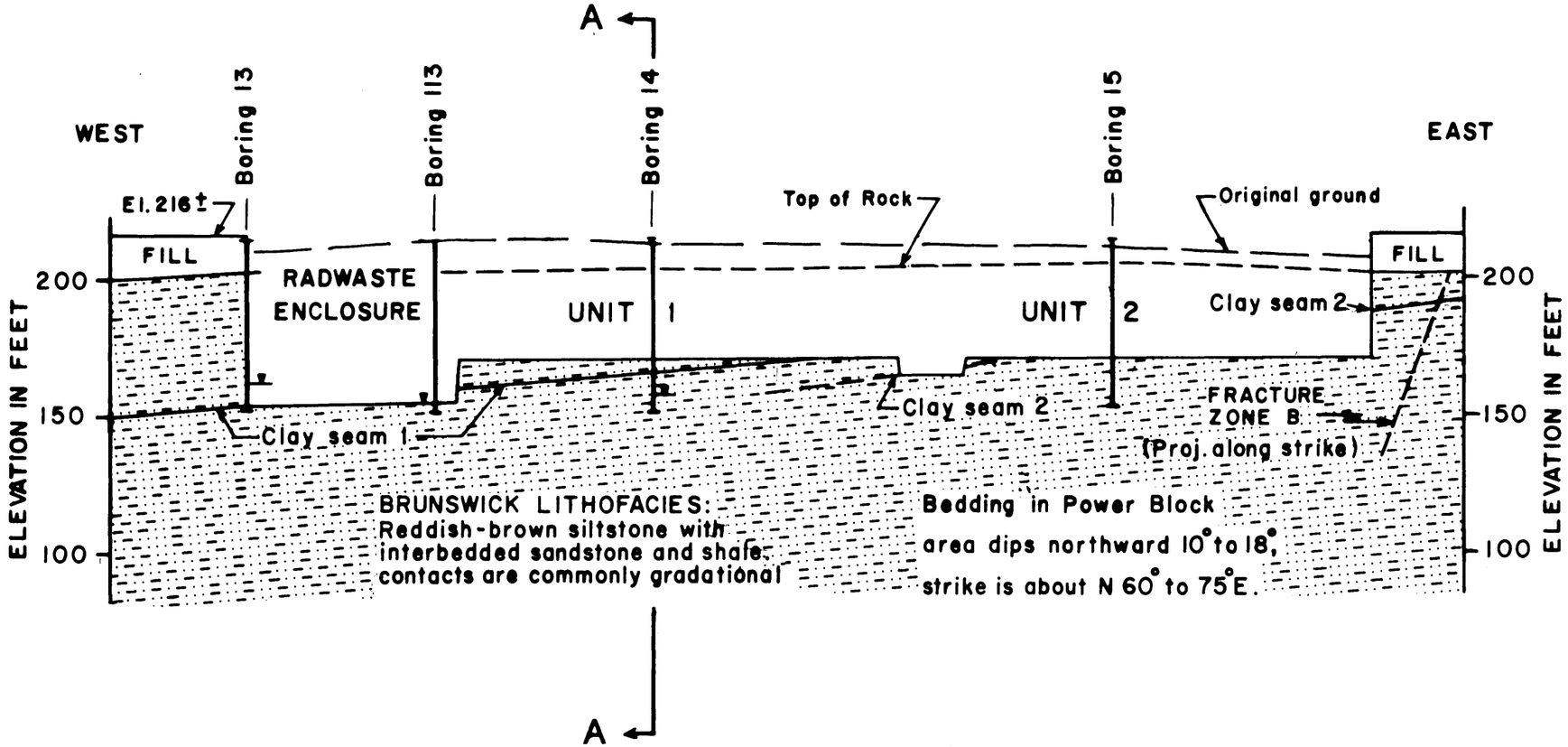
NOTES:

1. For location of Section, see Figures 2.5-9 and 2.5-13.
2. For Logs of Borings, see Figure 2.5-22
3. Section B-B is shown on Figure 2.5-11.
4. Boring locations projected to section along strike of bedding (N 75° E).

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GEOLOGIC SECTION

FIGURE 2.5-10



SECTION B-B

(Along N6000 Looking North)

NOTES:

1. For location of sections see Figure 2.5-13.
2. For logs of borings, see Figure 2.5-22.
3. Section A-A is shown on Figure 2.5-10.

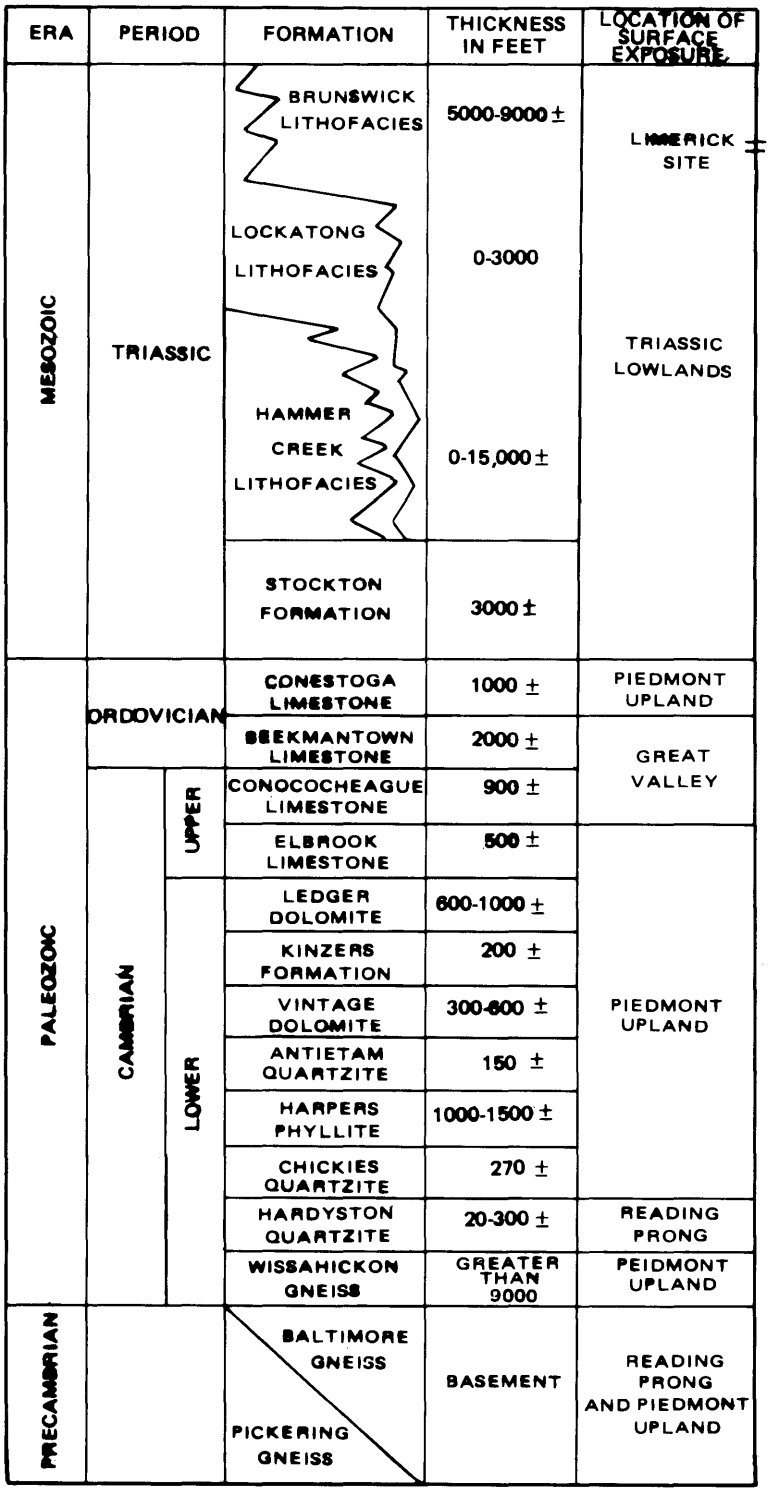
0 50 100

SCALE IN FEET

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GEOLOGIC SECTION

FIGURE 2.5-11

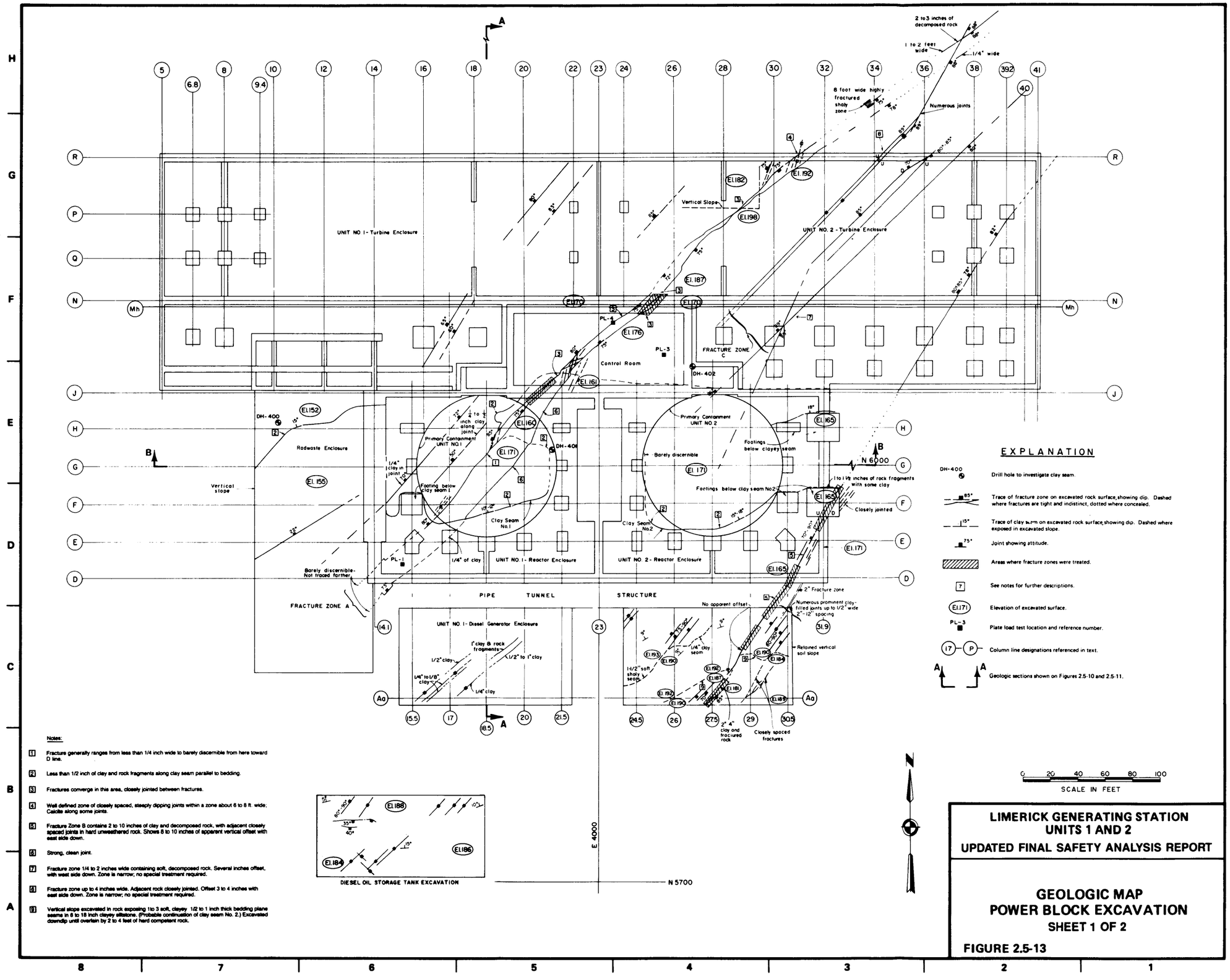


From PSAR Figure 2.5.14

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STRATIGRAPHIC SECTION SITE AND VICINITY

FIGURE 2.5-12



EXPLANATION

- DH-400 — Drill hole to investigate clay seam.
- 85° — Trace of fracture zone on excavated rock surface, showing dip. Dashed where fractures are tight and indistinct, dotted where concealed.
- 15° — Trace of clay seam on excavated rock surface, showing dip. Dashed where exposed in excavated slope.
- 75° — Joint showing attitude.
- Areas where fracture zones were treated.
- [7] — See notes for further descriptions.
- EL.171 — Elevation of excavated surface.
- PL-3 — Plate load test location and reference number.
- 17 — P — Column line designations referenced in text.
- A — A — Geologic sections shown on Figures 2.5-10 and 2.5-11.

Notes:

1. Fracture generally ranges from less than 1/4 inch wide to barely discernible from here toward D line.
2. Less than 1/2 inch of clay and rock fragments along clay seam parallel to bedding.
3. Fractures converge in this area, closely jointed between fractures.
4. Well defined zone of closely spaced, steeply dipping joints within a zone about 6 to 8 ft. wide; Calcite along some joints.
5. Fracture Zone B contains 2 to 10 inches of clay and decomposed rock, with adjacent closely spaced joints in hard unweathered rock. Shows 8 to 10 inches of apparent vertical offset with east side down.
6. Strong, clean joint.
7. Fracture zone 1/4 to 2 inches wide containing soft, decomposed rock. Several inches offset, with west side down. Zone is narrow; no special treatment required.
8. Fracture zone up to 4 inches wide. Adjacent rock closely jointed. Offset 3 to 4 inches with east side down. Zone is narrow; no special treatment required.
9. Vertical slope excavated in rock exposing 1 to 3 soft, clayey 1/2 to 1 inch thick bedding plane seams in 8 to 18 inch clayey siltstone. (Probable continuation of clay seam No. 2.) Excavated downdip until overlain by 2 to 4 feet of hard competent rock.

0 20 40 60 80 100
SCALE IN FEET

LIMERICK GENERATING STATION UNITS 1 AND 2

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GEOLOGIC MAP POWER BLOCK EXCAVATION

SHEET 1 OF 2

FIGURE 2.5-13



FIGURE 13A - Fracture Zone A at Mh and N lines
Looking down on the zone. SW is to the left of the photo. The paint outlines the area to be excavated for dental treatment. Note the numerous through-going joints at an acute angle to the fracture zone.



FIGURE 13C - Fracture Zone A at Mh and N lines
Looking SW along strike as dental concrete is being placed in the zone.



FIGURE 13E - Fracture Zone B at Column line 31.9
Looking SW at zone. Clay and decomposed rock are about 10 inches wide here. The paint in the center of the photo marks column line 31.9.

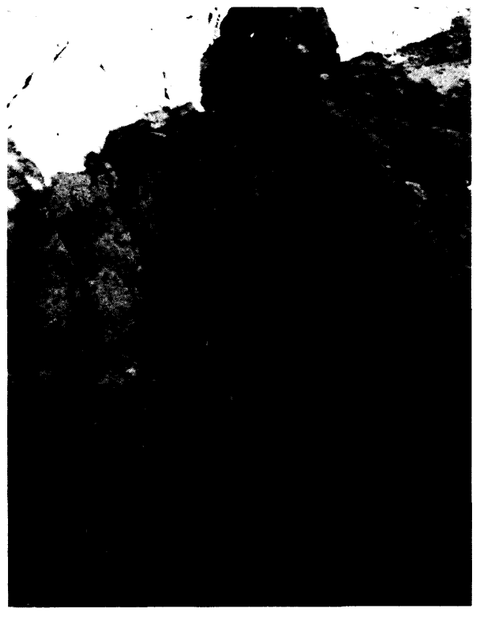


FIGURE 13B - Fracture Zone A at Mh and N lines
Looking NE into the dental excavation, immediately prior placing concrete in it.



FIGURE 13D - Fracture Zone B at D line
Looking SW along the zone after dental excavation into it. Paint in upper left corner of photo mark the "D" line. The scale in the zone is 6 inches long. Note the numerous joints parallel to the zone. The zone here contained a maximum of 2 inches of clayey material and decomposed rock.

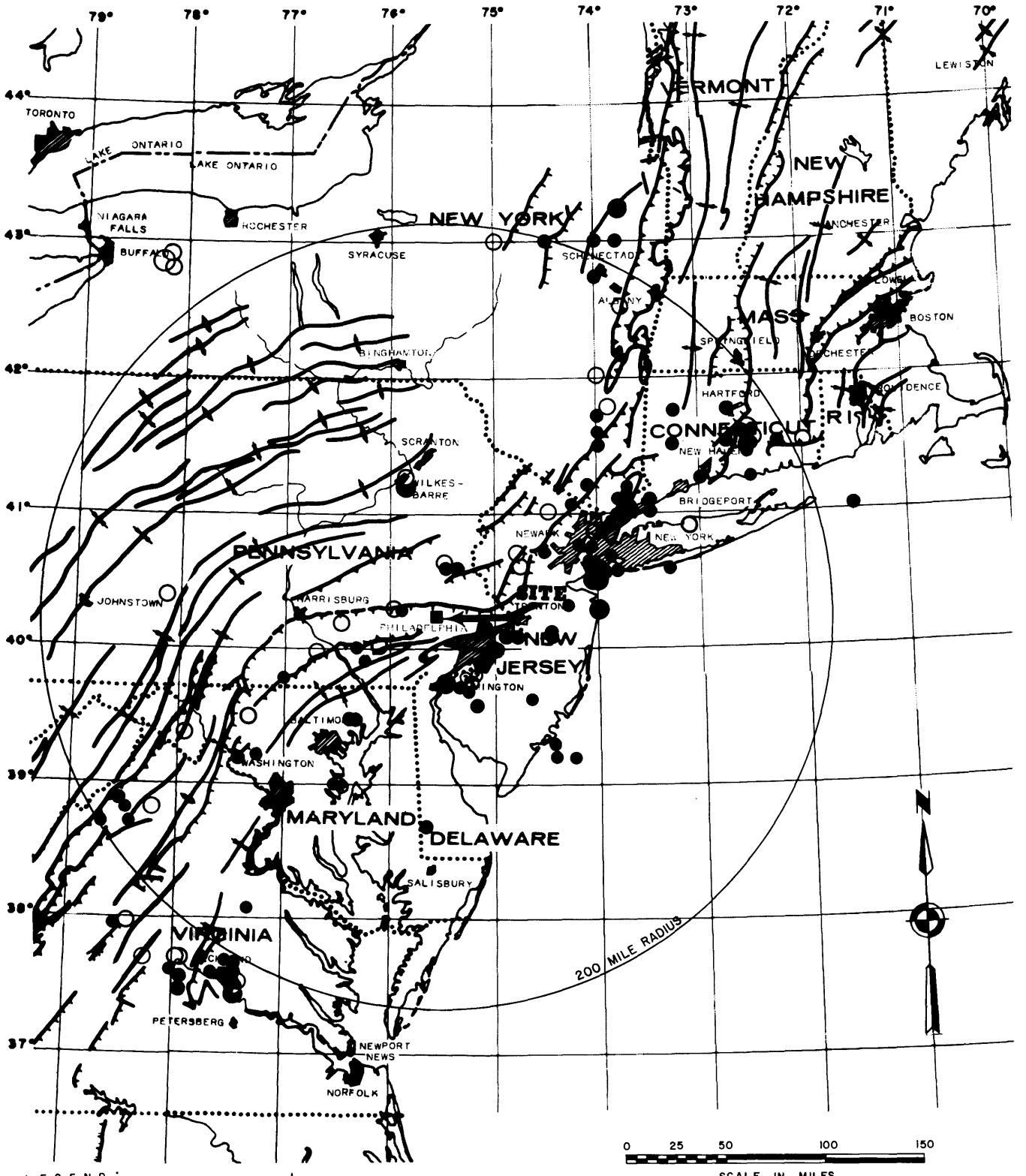


FIGURE 13F - Fracture Zone B at Column Footing F-31.9
Looking SW along the strike of the zone. This area was covered with concrete before it was treated, thus dental excavation was carried through the concrete and into the zone below it. The fracture zone here contained up to 10 inches of clay and soft weathered rock. Scale in the bottom of the excavation is 6 inches long.

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SUPPLEMENTAL PHOTOGRAPHS A THRU F, GEOLOGIC MAP OF POWER BLOCK EXCAVATION
SHEET 2 OF 2

FIGURE 2.5-13



LEGEND:

- INTENSITY UNCERTAIN
- INTENSITY V
- INTENSITY VI
- INTENSITY VII
- INTENSITY VIII
- SYNCLINAL AXIS
- ANTICLINAL AXIS
- NORMAL FAULT
- THRUST FAULT
- UNDIFFERENTIATED FAULT

REFERENCE:

THIS MAP WAS PREPARED FROM A PORTION OF THE U.S.G.S. "IFR WALL PLANNING CHART, EAST AND WEST, 1968."

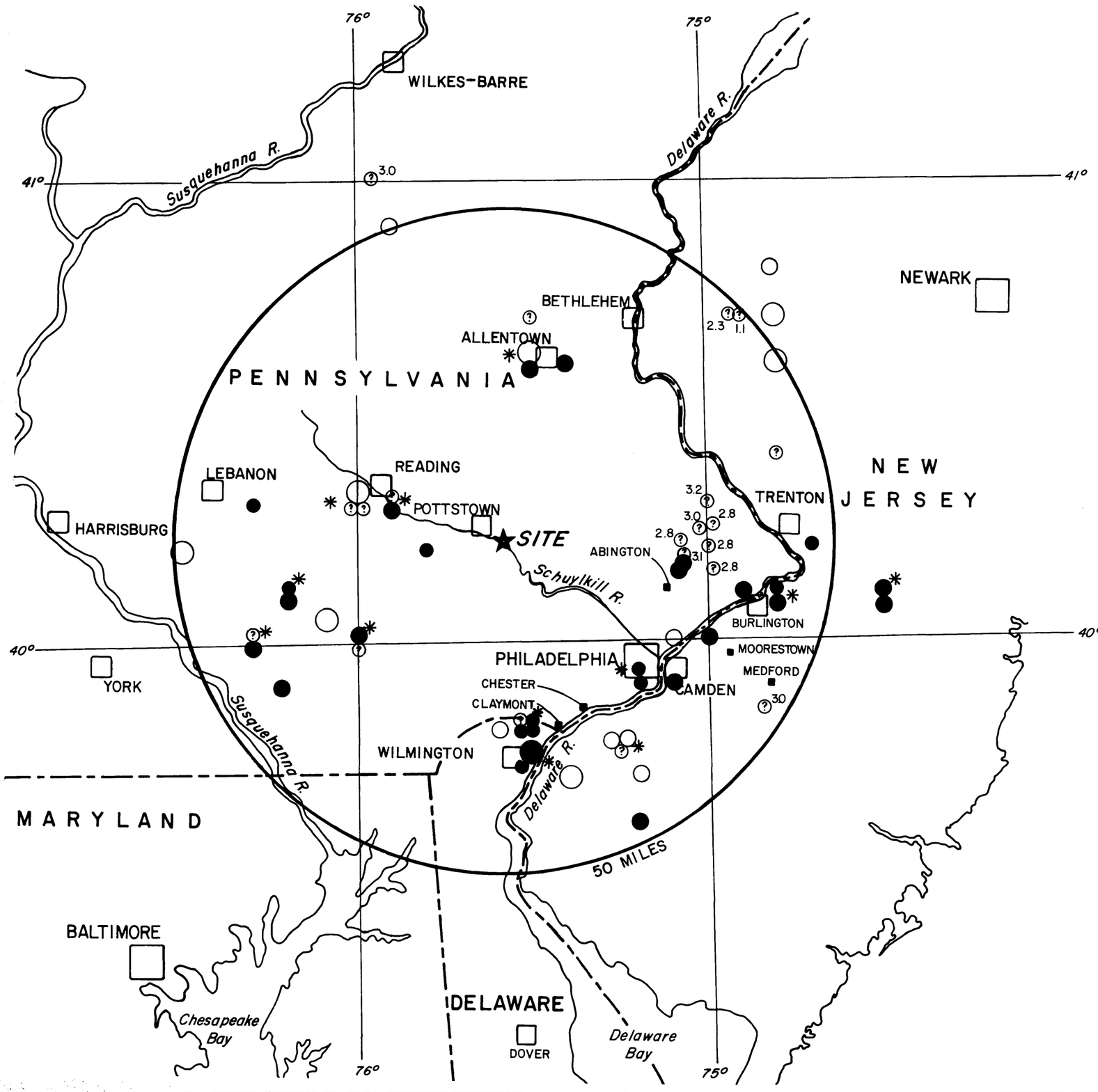
MAJOR TECTONIC FEATURES WERE TAKEN FROM A PORTION OF THE "TECTONIC MAP OF THE UNITED STATES" BY U.S.G.S. AND A.A.P.G.,

MAP PREPARED AS FIGURE 2.5.15 OF THE PSAR BY DAMES AND MOORE; UPDATED FOR THE FSAR.

LIMERICK GENERATING STATION
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SIGNIFICANT EARTHQUAKE EPICENTERS (1737 THROUGH JANUARY 1982) AND REGIONAL TECTONIC MAP

FIGURE 2.5-14



EXPLANATION

- (?)2.1 Intensity uncertain. Number, if given, represents magnitude
- ● Intensity III
- ○ Intensity IV
- ● Intensity V
- ○ Intensity VI
- ● Intensity VII

NOTE:

An asterisk (*) by a cluster of epicenters indicates that one or more have been displaced slightly for drafting convenience. Formal locations are reported for all earthquakes in Table 2.5-8.

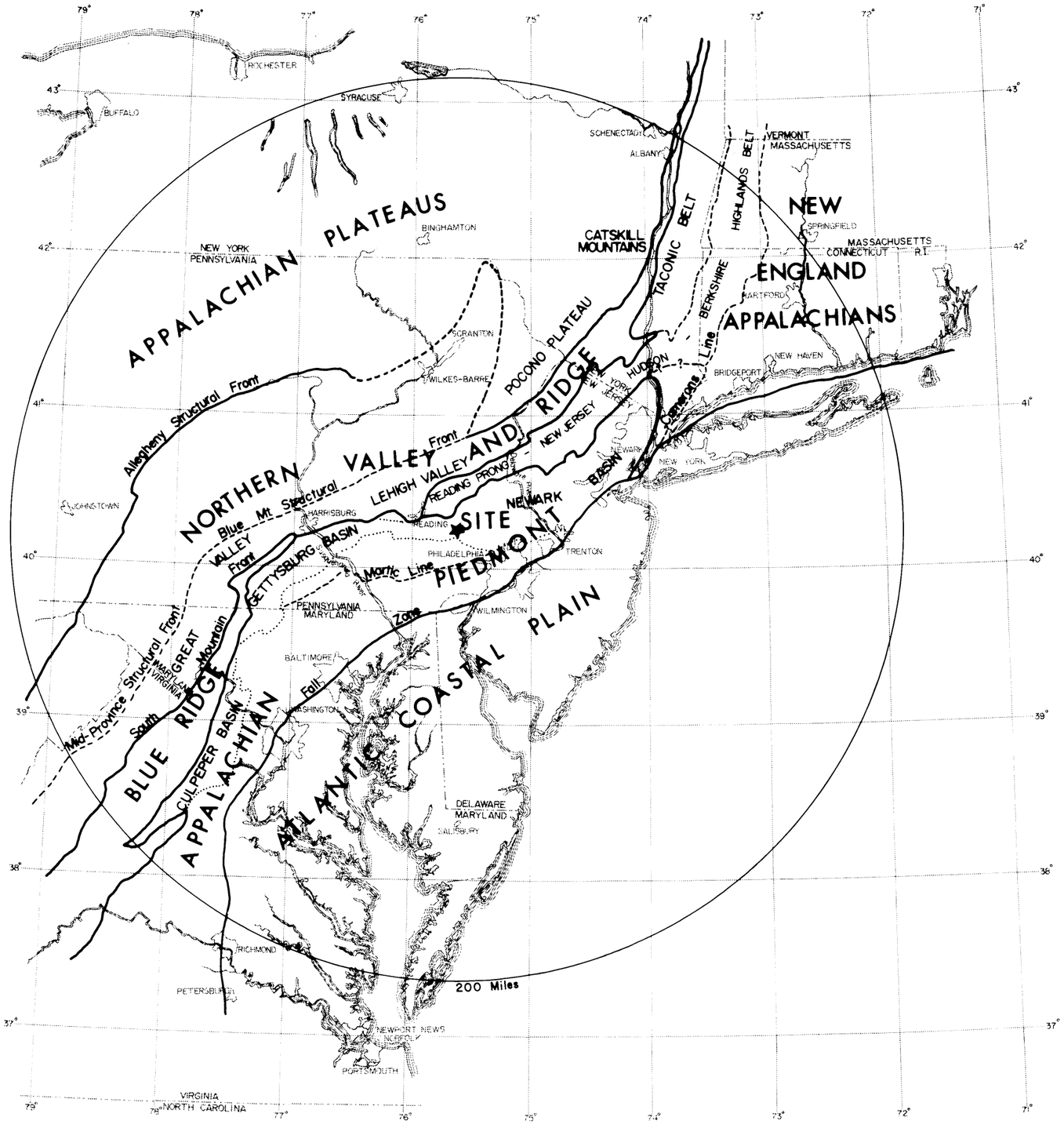
N

0 25 Miles

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EARTHQUAKE EPICENTERS WITHIN 50 MILES OF SITE

FIGURE 2.5-15



EXPLANATION

Tectonic province boundary (dashed where approximate or indefinite)

Outline of tectonic belt or tectonic front

Contact of basin sediments in metamorphic terrane

REFERENCES:

Bennison, A.P. 1978, Geological Highway Map of the Northeastern Region: A.A.P.G., U.S. Geological Highway Map Series, No. 10.

Cohee, G.Y. (chairman), 1982, Tectonic Map of the United States: U.S.G.S./A.A.P.G.

Eardley, A.J., 1962, Structural Geology of North America, 2nd Ed: Harper and Row (figure 7.1)

Hadley, J.B. and Devine J.F., 1974, Seismotectonic Map of the Eastern United States: U.S.G.S. Map MF-620

King, P.B. and Beikman, H.M. (compilers), 1974, Geological Map of the United States: U.S.G.S.

Rodgers, John, 1968, The Eastern Edge of the North American Continent during the Cambrian and Early Ordovician: in Zen, et al, Studies of Appalachian Geology: Northern and Maritime; Interscience Publishers, figure 10-3.

Rodgers, John, 1970, The Tectonics of the Appalachians: Wiley-Interscience, plate I.

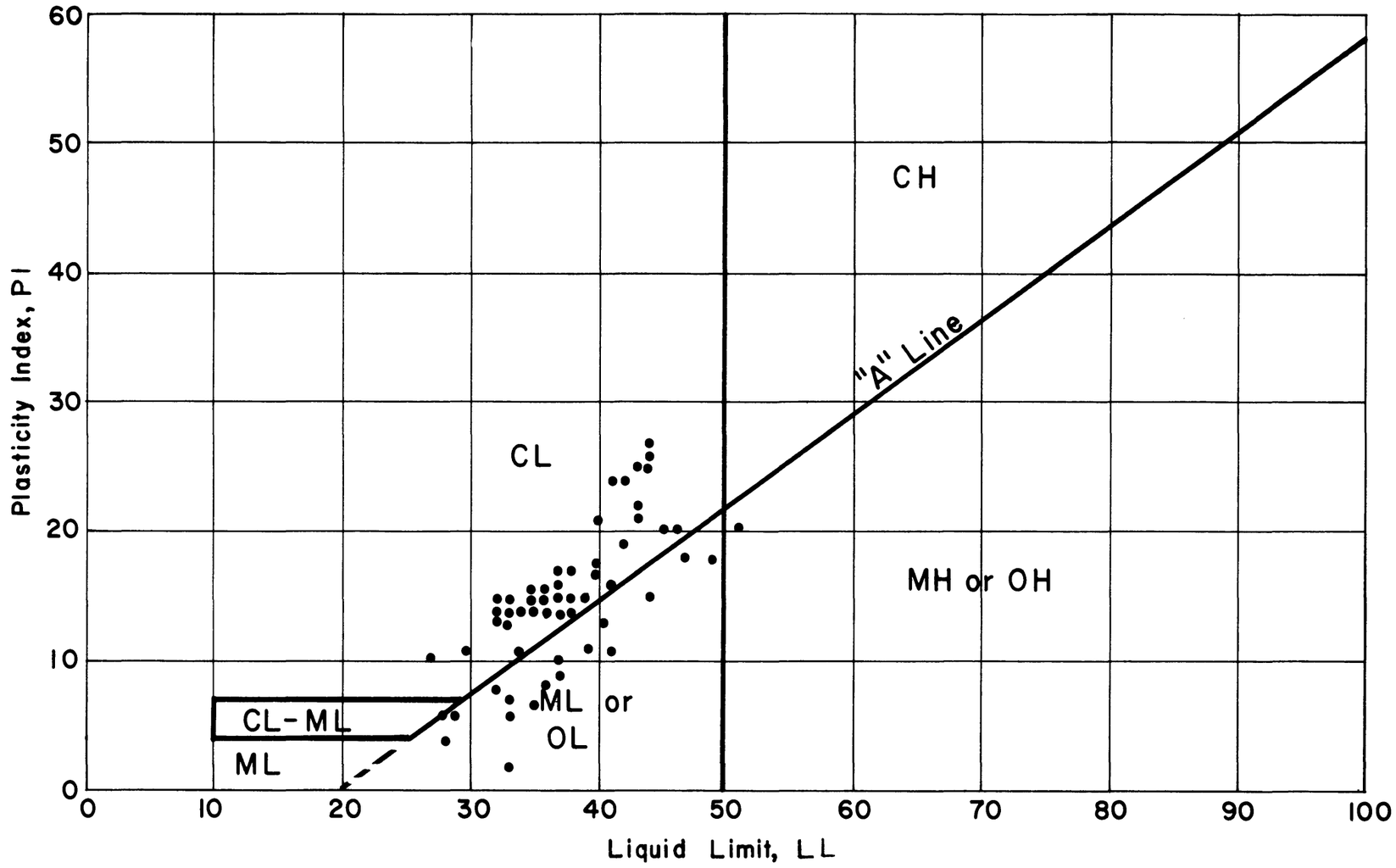
N

0 10 20 30 40 50 60
SCALE IN MILES

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TECTONIC PROVINCES

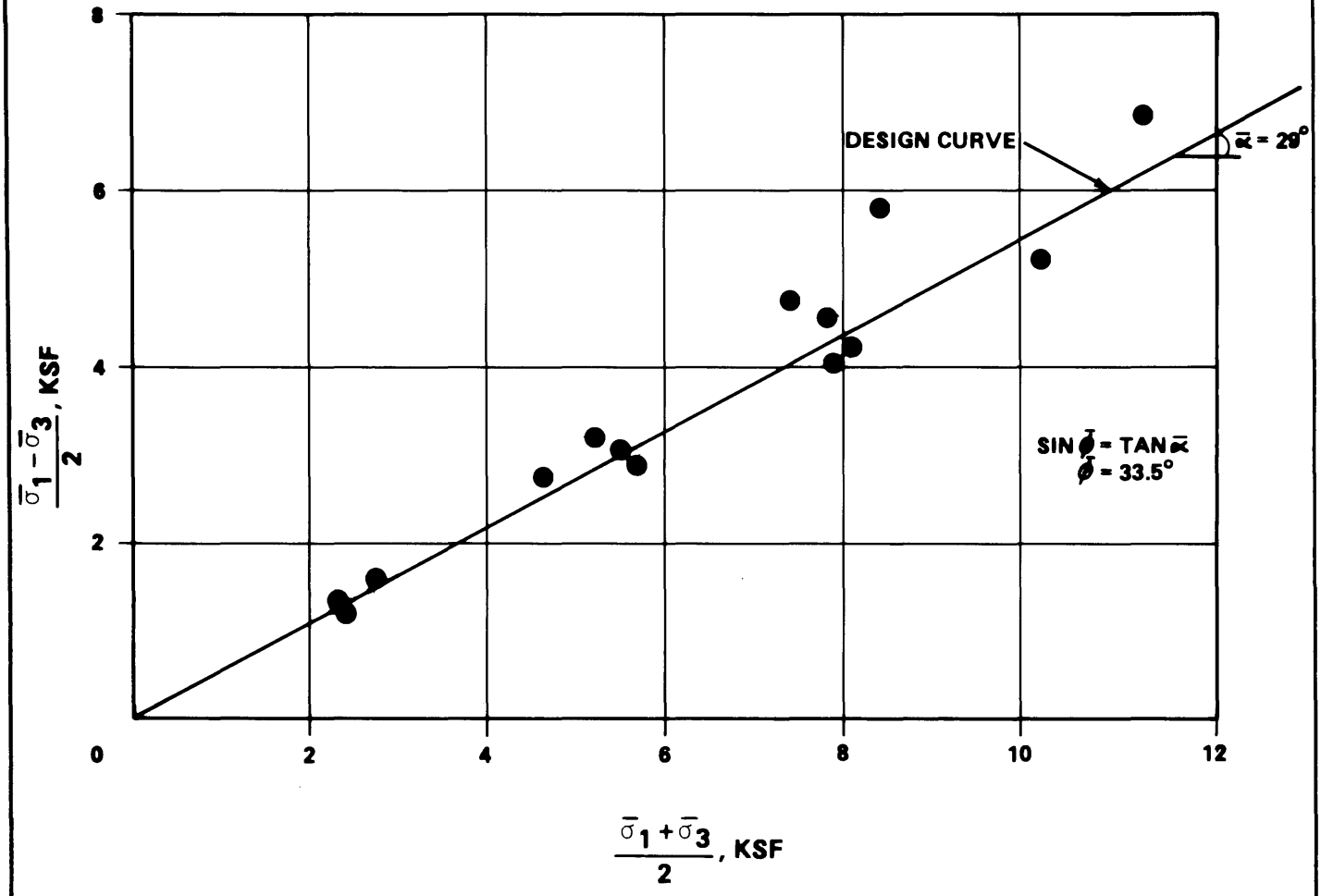
FIGURE 2.5-16



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UNITS 1 AND 2
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PLASTICITY CHART OF IN-SITU SOIL
SPRAY POND AREA

FIGURE 2.5-17



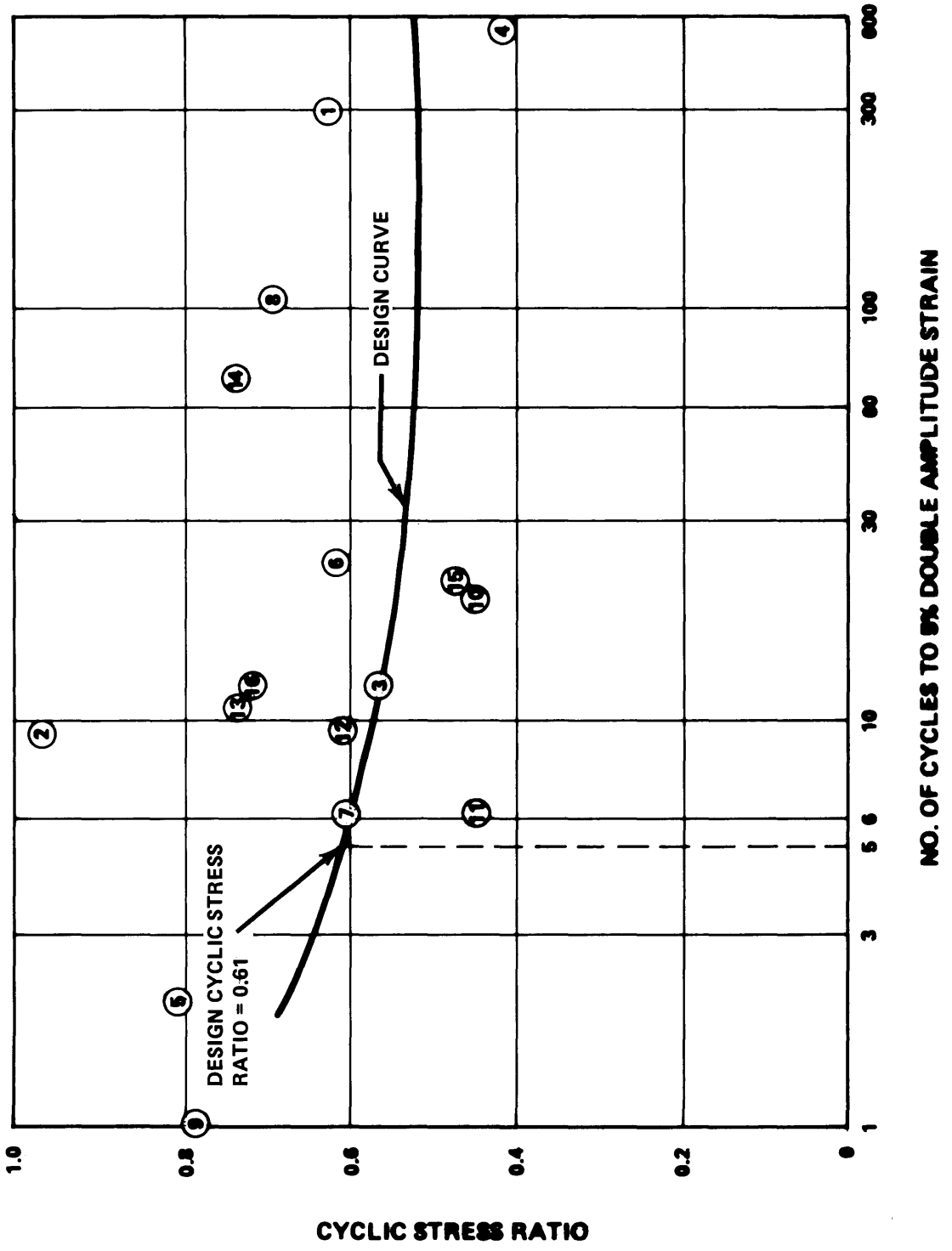
NOTES

1. ALL SAMPLES CONSOLIDATED ISOTROPICALLY TO AN EFFECTIVE CONSOLIDATION PRESSURE OF 1 KSF.
2. POINTS PLOTTED REPRESENT CONDITIONS AT FAILURE.
3. DESIGN CURVE WAS CHOSEN BASED ON THE CORPS OF ENGINEERS' RECOMMENDATION THAT TWO-THIRDS OF THE TEST VALUES EXCEED THE DESIGN VALUE.

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SUMMARY OF CONSOLIDATED UNDRAINED TRIAXIAL TEST RESULTS OF IN-SITU SOIL

FIGURE 2.5-18



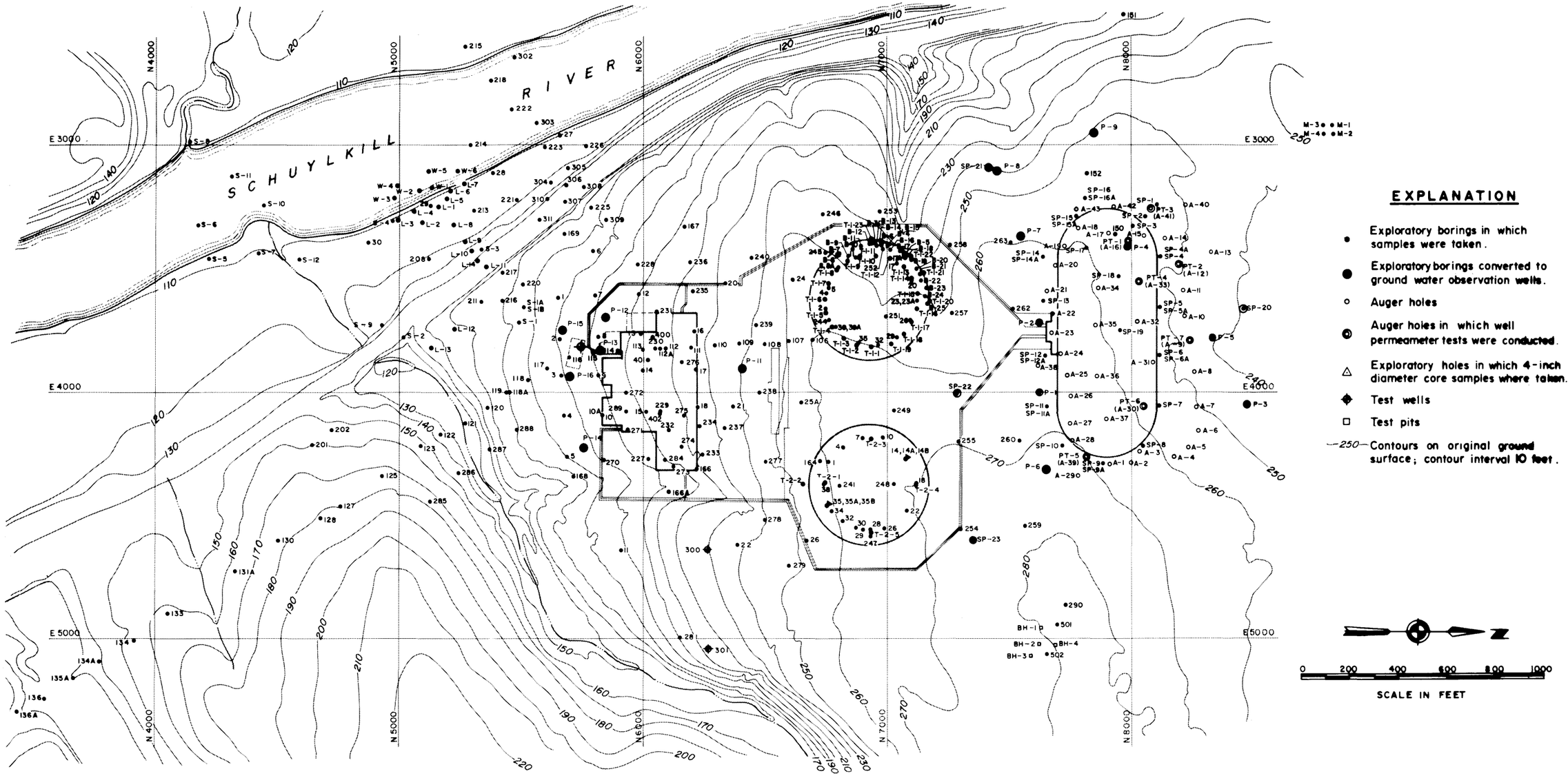
NOTE

1. ALL SAMPLES CONSOLIDATED ISOTROPICALLY TO AN EFFECTIVE CONSOLIDATION PRESSURE OF 2 KSF.
2. NUMBERS INDICATE TEST NUMBER DESIGNATED BY GEOTECHNICAL ENGINEERS, INC.

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SUMMARY OF CYCLIC TRIAXIAL TEST RESULTS

FIGURE 2.5-19



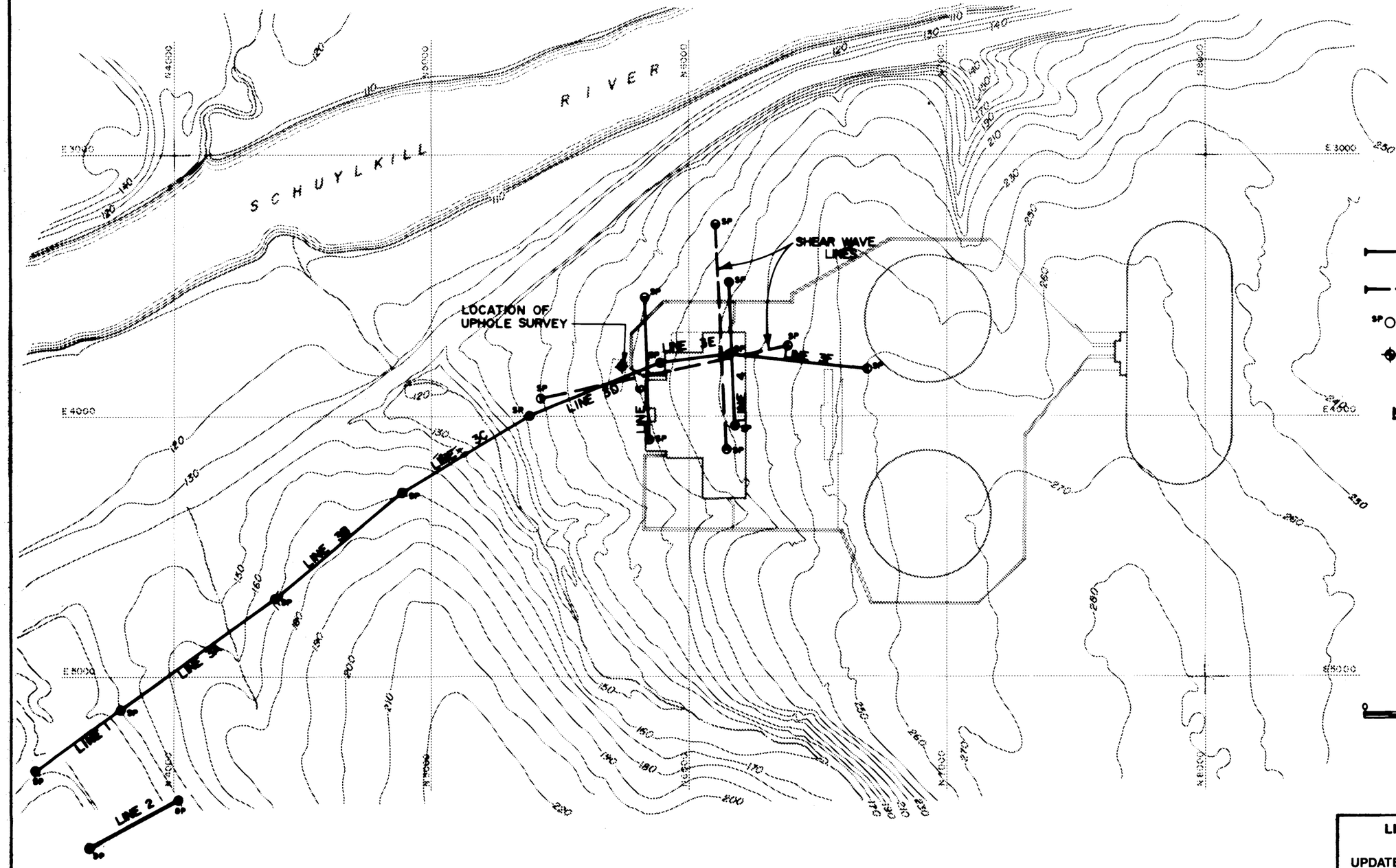
NOTES:

1. For location of geophysical surveys, see Figure 2.5-21.
2. For graphic logs of borings, see Figure 2.5-22.

LIMERICK GENERATING STATION
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SITE EXPLORATION

FIGURE 2.5-20



EXPLANATION

- Seismic line for determination of compressional wave (Vp) velocities.
- Seismic line for shear wave (Vs) velocity determinations.
- SP ○ Shot point
- Test well used for uphole velocity measurements.

NOTE:

Geophysical surveys performed under technical direction and supervision of Dames and Moore.

N

0 200 400 600 800 1000

SCALE IN FEET

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GEOPHYSICAL SURVEYS

FIGURE 2.5-21

BORING 1

SURFACE ELEVATION +187.4'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	103		ML	REDDISH-BROWN, SANDY AND CLAYEY SILT
	19			
10	88%			BRUNSWICK SHALE-INTERBEDDED REDDISH-BROWN TO GRAY SILTSTONE AND FINE GRAINED REDDISH-BROWN SANDSTONE
	100%			SANDY SILTSTONE (MODERATELY HARD)
20	100%			REDDISH-BROWN SILTY SANDSTONE (MODERATELY HARD)
30	100%			REDDISH-BROWN SILTSTONE (HARD) (MASSIVE)
	100%			
	100%			BROWN TO REDDISH-BROWN FINE GRAINED TO MEDIUM GRAINED SANDSTONE
40				REDDISH SILTSTONE
	96%			GRAYISH-BROWN FINE GRAINED TO MEDIUM GRAINED SANDSTONE
				REDDISH-BROWN VERY FINE GRAINED SANDY SILTSTONE (MODERATELY HARD)
50	98%			
	100%			GRAYISH-BROWN VERY FINE TO FINE GRAINED SANDSTONE
60	100%			

BORING COMPLETED ON 10-8-69
CASING TO A DEPTH OF 10'
300-LB. HAMMER @ 18" FALL
WATER LEVEL @ 5½' ON 10-24-69

BORING 2

SURFACE ELEVATION +191.5'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	71		SM	REDDISH-BROWN FINE GRAINED SANDY SILT (FIRM)
	44			FEW THIN SANDY SILTSTONE LAYERS
10	50/2"			
				BRUNSWICK SHALE-REDDISH-BROWN SANDY SHALE WITH SOME SILTSTONE (HARD) WEATHERED IN PART
20	88%			REDDISH-BROWN SILTY FINE GRAINED SANDSTONE INTERBEDDED WITH SHALEY SANDY SILTSTONE (HARD)
				REDDISH-GRAY FINE GRAINED SANDSTONE (HARD) FRIABLE IN PART
30	92%			FEW THIN SHALE SEAMS
				LIGHT GREEN FINE GRAINED SANDY SHALE (MEDIUM HARD)
				REDDISH-BROWN FINE GRAINED SANDY SILTSTONE (MEDIUM HARD TO HARD)
40	94%			REDDISH-BROWN FINE TO MEDIUM GRAINED SANDSTONE (VERY HARD) FRIABLE
	100%			REDDISH-BROWN SLIGHTLY SANDY SILTSTONE
50				REDDISH-BROWN FINE GRAINED SANDSTONE
	100%			RED SANDY SILTSTONE-SHALEY (VERY HARD)
60	100%			GRADING REDDISH-GRAY AND VERY SANDY
70	100%			GRADING SILTY AND SHALEY
80	100%			GRADING LESS SILTY
				GRADING SILTY
90	100%			BROWN MEDIUM GRAINED SANDSTONE (VERY HARD) LIMONITE STAINING, FRACTURED
				GRADING GREENISH-GRAY
100	100%			COAL LAMINAE
				GRADING BLUEISH-GRAY
110	100%			GRADING REDDISH-BROWN
				REDDISH-BROWN SILTSTONE (HARD TO VERY HARD)
120	100%			SHALEY ZONE
	91%			BROWNISH-GRAY FINE GRAINED SANDSTONE (HARD)
130	100%			REDDISH-GRAY FINE GRAINED VERY SANDY SILTSTONE, MASSIVE (VERY HARD)
	100%			GRADING SHALEY IN PART
140	99%			MULTI-COLORED GREEN TO GRAYISH-PURPLE FINE GRAINED SANDSTONE (HARD TO VERY HARD)
	100%			REDDISH-BROWN SILTSTONE (VERY HARD)
150	100%			BROWNISH-GRAY SILTY VERY FINE GRAINED SANDSTONE (HARD)
				REDDISH-GRAY SILTSTONE (HARD)
160	100%			GRAY VERY FINE GRAINED SANDSTONE MASSIVE (VERY HARD)
				GRADING LIGHT BLUEISH-GRAY WITH FEW THIN SHALE PARTINGS
				CLAY SEAM; GRADING SILTY AND GRAY IN COLOR
				FINE TO MEDIUM GRAINED
				REDDISH-BROWN SLIGHTLY SANDY SILTSTONE (HARD)

BORING COMPLETED ON 10-13-69
CASING TO A DEPTH OF 15'
140-LB. HAMMER @ 30" FALL
WATER LEVEL @ 87½' ON 10-24-69

BORING 4

SURFACE ELEVATION +186.0'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	64		ML	REDDISH-BROWN SANDY AND CLAYEY SILT
	13			
10	66%			BRUNSWICK SHALE-BRICK RED SILTSTONE - MODERATELY FRACTURED
20	96%			
	96%			GRADING SANDY
30	98%			REDDISH-BROWN FINE GRAINED SANDSTONE
	98%			REDDISH-BROWN FINE GRAINED SANDY SILTSTONE
40	98%			
	100%			REDDISH-BROWN FINE GRAINED SILTY SANDSTONE (HARD)
50	96%			REDDISH-BROWN SHALEY SILTSTONE (HARD)
	98%			
60	96%			

BORING COMPLETED ON 10-9-69
CASING TO A DEPTH OF 10'
140-LB. HAMMER @ 30" FALL
WATER LEVEL @ 30½' ON 10-24-69

BORING 6

SURFACE ELEVATION +185.4'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	82			RED WEATHERED SHALE
	100/5"			BRUNSWICK SHALE-RED SILTSTONE (MODERATELY HARD)
10	100%			RED FINE GRAINED SANDSTONE
				RED SILTSTONE
	88%			SHALEY
20				GRADING SANDY
	100%			REDDISH-GRAY TO GRAY FINE GRAINED SANDSTONE
30	100%			GRADING COARSER
				REDDISH-GRAY SILTSTONE (HARD)
				GRAY, VERY FINE GRAINED SANDSTONE
				REDDISH-GRAY SILTSTONE
				GRAY MASSIVE FINE GRAINED SANDSTONE
40	100%			GRADING MEDIUM TO COARSE GRAINED
				FRIABLE AND POROUS
	100%			RED SANDY SILTSTONE WITH SHALE PARTINGS (HARD)
50	100%			

BORING COMPLETED ON 10-13-69
CASING TO A DEPTH OF 5'
140-LB. HAMMER @ 30" FALL
WATER LEVEL @ 50' ON 10-24-69

BORING 3

SURFACE ELEVATION +190.0'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	56/5"		ML	RED SANDY SILT WITH ROCK FRAGMENTS
	66			
10	51			BRUNSWICK SHALE-REDDISH-BROWN SANDY SILTSTONE WITH SHALE PARTINGS
				REDDISH-BROWN FINE TO MEDIUM GRAINED SANDSTONE
20	78%			RED SHALEY SILTSTONE (MEDIUM HARD)
				PURPLISH-GRAY FINE GRAINED SANDY SILTSTONE (HARD)
30	100%			REDDISH-BROWN TO GRAY, FINE GRAINED SANDSTONE
				GRADING BLUISH-GRAY
40	100%			
				RED FINE GRAINED SANDY SILTSTONE (HARD)
50	100%			
	100%			
60				
70				

BORING COMPLETED ON 10-9-69
CASING TO A DEPTH OF 15'
140-LB. HAMMER @ 30" FALL
NO WATER IN BORING ON 10-24-69

BORING 5

SURFACE ELEVATION +179.8'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	57		ML	REDDISH-BROWN SANDY AND CLAYEY SILT
	51			BRICK RED (DECOMPOSED) SILTY SHALE (HARD)
10	78			GRADING WITH ROCK FRAGMENTS
				GRADING FINE SAND
	90%			BRUNSWICK SHALE-REDDISH-BROWN SILTY SANDSTONE (HARD)
20				REDDISH-BROWN SILTY SHALEY SILTSTONE
	97%			
30				REDDISH-BROWN FINE GRAINED SILTY SANDSTONE
				REDDISH-BROWN SHALEY SILTSTONE
	100%			
40				
				REDDISH-BROWN GRAINED SILTY SANDSTONE
	100%			
50				REDDISH-BROWN SHALEY SILTSTONE (HARD)
	97%			
60				REDDISH-BROWN VERY FINE GRAINED SANDY SANDSTONE
	100%			

BORING COMPLETED ON 10-9-69
CASING TO A DEPTH OF 11'
300-LB. HAMMER @ 18" FALL
WATER LEVEL @ 90½' ON 10-24-69

NOTES:

THE FIGURES IN THE COLUMN LABELLED "BLOW COUNT" INDICATE THE NUMBER OF BLOWS REQUIRED TO ADVANCE EITHER THE DAMES & MOORE SAMPLER OR A STANDARD SPLIT SPOON SAMPLER A DISTANCE OF ONE FOOT INTO THE UNDISTURBED SOIL.

THE DAMES & MOORE SAMPLER IS 3¼" O.D. AND 2½" I.D. THE STANDARD SPLIT SPOON SAMPLER IS 2" O.D. AND 1 3/8" I.D.

DATA RELATIVE TO THE ENERGY USED TO ADVANCE EITHER SAMPLER ARE INDICATED AT THE BOTTOM OF ALL BORINGS DRILLED TO INVESTIGATE THE ENGINEERING PROPERTIES OF THE SOIL. SOIL SAMPLES WERE OBTAINED IN ALL BORINGS NUMBERED 10C AND HIGHER USING A STANDARD SPLIT SPOON SAMPLER ADVANCED BY A 140-LB. HAMMER FALLING 30".

WHEN ROCK WAS CORED, THE FIGURES IN THE COLUMN LABELLED "BLOW COUNT" INDICATE THE PERCENTAGE OF ROCK RECOVERED IN THE CORING RUN, INDICATED TO THE RIGHT OF THESE FIGURES BY HEAVY BLACK LINE.

ELEVATIONS REFER TO U.S.G.S. DATUM.

FOR LOCATIONS, SEE FIGURE 2.5-20.

LOGS PREPARED BY DAMES AND MOORE.

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GRAPHIC LOGS
SHEET 1 OF 37

FIGURE 2.5-22

BORING 7

SURFACE ELEVATION +198.9'

DEPTH IN FEET	SAMPLES	BLOW COUNT	SYMBOLS	DESCRIPTIONS
0		52/6"	ML	REDDISH-BROWN CLAYEY AND SANDY SILT WITH ROCK FRAGMENTS
				BRUNSWICK SHALE-RED SILTSTONE HIGHLY WEATHERED
10		80%		RED VERY FINE GRAINED SANDSTONE, (MASSIVE)
				RED FINE GRAINED SANDY SILTSTONE
		100%		RED VERY FINE GRAINED SANDSTONE
				RED SHALEY SILTSTONE
20		100%		RED VERY FINE GRAINED SANDSTONE (HARD) GRADING GRAY
		94%		GRADING TO MEDIUM GRAINED
30		100%		GRADING TO FINE GRAINED
				REDDISH-BROWN SILTSTONE (HARD)
40		93%		GRAY REDDISH-BROWN SILTY VERY FINE GRAINED SANDSTONE
				GRADING TO GRAYISH-BROWN
				GRADING MEDIUM TO COARSE GRAINED
50		100% 100%		REDDISH-BROWN SILTSTONE (HARD)
		91%		

BORING COMPLETED ON 10-10-69
CASING TO A DEPTH OF 10'
140-LB. HAMMER @ 30" FALL
WATER LEVEL @ 45' ON 10-24-69

BORING 8

SURFACE ELEVATION +201.6'

DEPTH IN FEET	SAMPLES	BLOW COUNT	SYMBOLS	DESCRIPTIONS
0		43	ML	RED SHALEY SILT (STIFF)
		52%		BRUNSWICK SHALE-RED SHALEY SILTSTONE HIGHLY BROKEN
10		90%		BROWN TO GRAY FINE GRAINED SANDSTONE (HARD)
				GRADING COARSER REDDISH-GRAY SANDY SILTSTONE GRAY TO BROWN MEDIUM GRAINED SANDSTONE
20		100%		INTERBEDDED VERY SANDY SILTSTONE AND RED SHALEY SILTSTONE
30		100%		GRAY FINE TO MEDIUM GRAINED SANDSTONE
40		100%		GRADING TO GRAYISH-BROWN FRIABLE
50		100%		RED SANDY SILTSTONE (VERY HARD)
60				

BORING COMPLETED ON 10-14-69
CASING TO A DEPTH OF 10'
140-LB. HAMMER @ 30" FALL
WATER LEVEL @ 50½' ON 10-24-69

BORING 9

SURFACE ELEVATION +201.1'

DEPTH IN FEET	SAMPLES	BLOW COUNT	SYMBOLS	DESCRIPTIONS
0		75	ML	REDDISH-BROWN SANDY SILT (TOPSOIL)
		58	ML	REDDISH-BROWN SANDY AND CLAYEY SILT WITH INTERBEDDED ROCK LAYERS
10		50/5"		BRUNSWICK SHALE-REDDISH-GRAY MEDIUM GRAINED SANDSTONE (HARD TO VERY HARD)
		87%		REDDISH-BROWN VERY SANDY SILTSTONE INTERBEDDED WITH FINE GRAINED SANDSTONE (VERY HARD) GRADING SHALEY
20		100%		GRAY MEDIUM GRAINED SANDSTONE (VERY HARD) HIGHLY WEATHERED AND POROUS FROM 25.5'-26.4'
				REDDISH-BROWN SHALE
30		100%		REDDISH-GRAY FINE GRAINED SANDSTONE
				REDDISH-BROWN SHALE
40		99%		REDDISH-BROWN SILTSTONE (VERY HARD) GRADING SANDY
50		100%		REDDISH-BROWN TO GRAY FINE GRAINED SANDSTONE (VERY HARD)
				REDDISH-BROWN SILTY SHALE AND SILTSTONE (INTERBEDDED) GRADING SANDY
60		100%		REDDISH-BROWN FINE SANDY SILTSTONE (VERY HARD)
				REDDISH-GRAY VERY FINE TO FINE GRAINED SANDSTONE (HARD TO VERY HARD)
70		97%		INTERBEDDED REDDISH-GRAY VERY FINE GRAINED TO FINE GRAINED SANDSTONE AND REDDISH-GRAY SANDY SILTSTONE (VERY HARD)
		94%		REDDISH-GRAY VERY FINE TO FINE GRAINED SANDSTONE (VERY HARD)
80		100%		REDDISH-BROWN SLIGHTLY SANDY SILTSTONE SHALEY IN PART (VERY HARD) GRADING SANDY
90		100%		REDDISH-GRAY MEDIUM GRAINED SANDSTONE REDDISH-GRAY TO BROWN SANDY SILTSTONE
100		100%		
110		100%		BROWN MEDIUM GRAINED SANDSTONE, FRIABLE REDDISH-BROWN SILTSTONE (VERY HARD)
120		96%		INTERBEDDED REDDISH-GRAY SILTSTONE AND FINE TO MEDIUM GRAINED SANDSTONE (VERY HARD) GRADING SHALEY
130		98% 84%		REDDISH-BROWN SANDSTONE-SLIGHTLY FRIABLE REDDISH-BROWN SILTSTONE (VERY HARD)
140		100%		SHALEY GRAY FINE GRAINED SANDSTONE (VERY HARD) REDDISH-BROWN SHALEY SILTSTONE (HARD)
150		55%		GRAY FINE GRAINED SANDSTONE (VERY HARD) REDDISH-GRAY SANDY SILTSTONE (HARD TO VERY HARD) GRAY FINE GRAINED SANDSTONE (VERY HARD) GRADING MEDIUM TO COARSE GRAINED
160		96% 51%		HIGHLY FRACTURED GRADING REDDISH-GRAY
170		100%		REDDISH-BROWN SANDY SILTSTONE (VERY HARD)

BORING COMPLETED ON 10-8-69
CASING TO A DEPTH OF 10'
140-LB. HAMMER @ 30" FALL
WATER LEVEL @ 94½' ON 10-24-69

BORING 10

SURFACE ELEVATION +196.7'

DEPTH IN FEET	SAMPLES	BLOW COUNT	SYMBOLS	DESCRIPTIONS
0		22	ML	BROWN FINE GRAINED SANDY SILT, TOPSOIL (MEDIUM STIFF)
		23		BRUNSWICK SHALE-BRICK RED FINE SANDY SILTSTONE, BADLY WEATHERED
10		18		BROWNISH-GRAY FINE GRAINED SANDSTONE (HARD)
		62%		BRICK RED CLAYEY SILTSTONE (MEDIUM HARD)
20		50%		GRADING VERY HARD
		88%		
30		50%		CLAYEY SEAM
		70%		HIGHLY FRACTURED AND JOINTED FROM [illegible]
40		78% 80%		
50		68%		BORING COMPLETED ON 10-16-69 CASING TO A DEPTH OF 15' 140-LB. HAMMER @ 30" FALL WATER LEVEL @ 12½' ON 10-24-69

BORING 10A

SURFACE ELEVATION +195.7'

DEPTH IN FEET	SAMPLES	BLOW COUNT	SYMBOLS	DESCRIPTIONS
0		36	ML	REDDISH-BROWN CLAYEY SILT WITH SOME GRAVEL AND SAND (DENSE)
		57		
10		57	SM-GM	DARK BROWN TO BROWN SILTY GRAVELLY SAND
				REDDISH & SHALEY LIGHT GRAY MEDIUM TO COARSE GRAINED SANDSTONE (HARD)
20		95%		REDDISH-BROWN SILTSTONE (HARD) SHALEY IN PART CALCITE STRINGERS AND INCLUSIONS TRACE OF SAND SHALEY ZONE
30		100%		REDDISH-BROWN SILTY VERY FINE GRAINED SANDSTONE LAYER
		100%		REDDISH-BROWN SILTSTONE (HARD) FEW CALCITE INCLUSIONS AND STRINGERS
40				REDDISH-BROWN FINE GRAINED SANDSTONE (HARD) PEBBLE ZONE
				REDDISH-BROWN VERY FINE TO FINE GRAINED SANDY SILTSTONE (HARD)
50		100%		REDDISH-BROWN TO GRAY SILTY VERY FINE GRAINED SANDSTONE (HARD) PEBBLE ZONE
		93%		REDDISH-BROWN SILTSTONE (HARD) FEW CALCITE INCLUSIONS TRACE OF SAND
60		100%		

BORING COMPLETED ON 10-19-69
CASING TO A DEPTH OF 15'
300-LBS. HAMMER @ 18" FALL
WATER LEVEL NOT RECORDED

BORING 11

SURFACE ELEVATION +186.6'

DEPTH IN FEET	SAMPLES	BLOW COUNT	SYMBOLS	DESCRIPTIONS
0		55	ML	RED CLAYEY SILT WITH SHALE FRAGMENTS
		32		
10		52/6"		BRUNSWICK SHALE-RED SILTSTONE (HARD) SHALEY WITH CLAY FILLINGS
				GRADING SANDY
20		95%		HIGHLY JOINTED ZONE 24.3' TO 28.5'
30		100%		GRADING SHALEY
				VERY SANDY
40		100%		DARK BROWN FINE GRAINED SANDSTONE (HARD)
				RED SANDY SILTSTONE (HARD)
50		99%		SHALEY
				GRADING VERY SANDY
60		100%		DARK BROWN FINE GRAINED SANDSTONE RED VERY SANDY SILTSTONE

BORING COMPLETED ON 10-16-69
CASING TO A DEPTH OF 11'
300-LB. HAMMER @ 18" FALL
WATER LEVEL @ 51½' ON 10-24-69

NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

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GRAPHIC LOGS
SHEET 2 OF 37

FIGURE 2.5-22

BORING 12

SURFACE ELEVATION +209.7'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	76		ML	REDDISH-BROWN SANDY AND CLAYEY SILT
	67			GRADING WITH WEATHERED ROCK FRAGMENTS
10				BRUNSWICK SHALE-REDDISH-BROWN SHALEY SILTSTONE (HARD)
	100%			
20				GRADING MASSIVE
	100%			SHALE PARTINGS
30				MASSIVE
	100%			SHALE PARTINGS
40				GRADING VERY SANDY
	100%			
50	100			
	98%			RED VERY FINE GRAINED SANDSTONE (VERY HARD)
60				

BORING COMPLETED ON 10-11-69
CASING TO A DEPTH OF 11'
300-LB. HAMMER @ 18" FALL
WATER LEVEL @ 47½' ON 10-24-69

BORING 14

SURFACE ELEVATION +214.1'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	93		ML	RED CLAYEY SILT (STIFF)
	33			
10	84%			BRUNSWICK SHALE-HIGHLY BROKEN RED SILTSTONE
	100%			RED SILTSTONE (HARD)
20				GRADING SANDY
				SHALEY
30	100%			GRADING VERY SANDY
				FRACTURED AND BROKEN FROM 36.5' TO 37.5'
40	100%			
	100%			REDDISH-GRAY TO BROWN FINE TO MEDIUM GRAINED SANDSTONE PARTLY FRIABLE.
50	97%			
60	97%			GRADING COARSER
				RED SANDY SILTSTONE

BORING COMPLETED ON 10-13-69
CASING TO A DEPTH OF 10'
140-LB. HAMMER @ 18" FALL
WATER LEVEL @ 56' ON 10-24-69

BORING 16

SURFACE ELEVATION +226.8'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	63		SM-ML	REDDISH-BROWN SILTY FINE GRAINED SAND
	88%			BRUNSWICK SHALE-GRAYISH-BROWN SILTY FINE TO MEDIUM GRAINED SANDSTONE (HARD)
10				SOME INTERBEDDED SILTSTONE LAYERS
	96%			REDDISH-BROWN SILTSTONE (HARD)
				FEW CALCITE STRINGERS AND INCLUSIONS
20	94%			SHALEY ZONE
				SHALEY ZONE
				SHALEY ZONE
30	100%			
	100%			SHALEY ZONE
40				REDDISH-BROWN SILTY FINE GRAINED SANDSTONE (HARD)
	100%			REDDISH-BROWN SILTSTONE (HARD)
				FEW CALCITE STRINGERS
50	100%			LIGHT GRAY MEDIUM GRAINED SANDSTONE (HARD)
				SILTY ZONE WITH CALCITE STRINGERS
				REDDISH-BROWN SILTSTONE INTERBEDDED WITH FINE TO MEDIUM GRAINED SANDSTONE; FEW CALCITE STRINGERS
60	100%			

BORING COMPLETED ON 10-17-69
CASING TO A DEPTH OF 5'
300-LB. HAMMER @ 30" FALL
WATER LEVEL @ 42½' ON 10-24-69

BORING 18

SURFACE ELEVATION +225.4'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	105		ML	REDDISH-BROWN SANDY AND CLAYEY SILT
	121			
10				BRUNSWICK SHALE-REDDISH-BROWN SILTSTONE (HARD)
				REDDISH-BROWN SILTY SANDSTONE
	100%			REDDISH-BROWN TO BROWN MICACEOUS SILTSTONE
20				SOME VERY FINE GRAINED SAND (HARD)
				GRADING SANDIER
	100%			GRAY-REDDISH-BROWN VERY FINE GRAINED SILTY SANDSTONE (HARD)
30				
	100%			REDDISH-BROWN SILTSTONE (HARD)
40				SHALEY
	100%			GRADING SANDY
				SHALEY
50	100%			GRADING VERY SANDY
60	100%			

BORING COMPLETED ON 10-11-69
CASING TO A DEPTH OF 7'
300-LB. HAMMER @ 18" FALL
WATER LEVEL NOT RECORDED

BORING 13

SURFACE ELEVATION +213.8'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	62		ML	RED CLAYEY SILT WITH SHALE ROCK FRAGMENTS
				BRUNSWICK SHALE-REDDISH-BROWN SANDY TO VERY SANDY SILTSTONE
	40%			
10	100%			
20	100%			2" SANDSTONE LAYER
	100%			
30				
	97%			
40	96%			BROWN TO REDDISH-BROWN MEDIUM GRAINED SANDSTONE (HARD)
				REDDISH-BROWN SILTSTONE (HARD)
				SHALEY
50	100%			REDDISH-BROWN TO BROWN MEDIUM GRAINED SANDSTONE
				REDDISH-BROWN SILTSTONE (HARD)
				SHALEY
	100%			REDDISH-BROWN TO GRAY SILTY VERY FINE GRAINED SANDSTONE
60				REDDISH-BROWN SILTSTONE
				REDDISH-BROWN TO GRAY VERY FINE GRAINED SANDSTONE

BORING COMPLETED ON 10-15-69
CASING TO A DEPTH OF 5'
300-LB. HAMMER @ 18" FALL
WATER LEVEL @ 52' ON 10-24-69

BORING 15

SURFACE ELEVATION +212.7'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	98		ML	REDDISH-BROWN SANDY AND CLAYEY SILT
	86			
10				BRUNSWICK SHALE-REDDISH-BROWN VERY FINE GRAINED SANDY SILTSTONE
	90%			
20				
	100%			
30				GRAYISH-BROWN FINE GRAINED SANDSTONE (HARD)
	100%			
40				
	100%			INTERBEDDED REDDISH-BROWN SILTSTONES AND REDDISH-BROWN FINE GRAINED SANDSTONES (VERY HARD)
50				
	100%			
60				

BORING COMPLETED ON 10-10-69
CASING TO A DEPTH OF 10'
140-LB. HAMMER @ 30" FALL
WATER LEVEL @ 10' ON 10-24-69

BORING 17

SURFACE ELEVATION +227.2'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	25		ML	REDDISH-BROWN TO BROWN CLAYEY SILT WITH GRAVEL FRAGMENTS (MEDIUM STIFF)
	36			
10				REDDISH-BROWN SHALEY SILTSTONE (HARD)
	100%			
20	94%			SHALEY
	100%			SHALEY
30				
	100%			REDDISH-BROWN TO GRAY SILTY VERY FINE GRAINED SANDSTONE (HARD)
40	100%			GRADING COARSER GRAINED
50	99%			SANDY
60	100%			

BORING COMPLETED ON 10-15-69
CASING TO A DEPTH OF 10'
300-LB. HAMMER @ 30" FALL
WATER LEVEL NOT RECORDED

NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

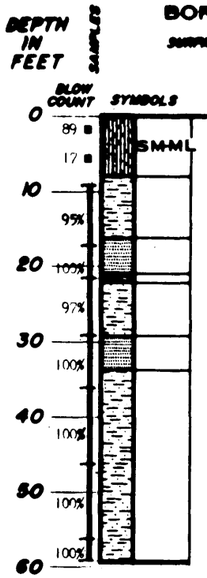
LIMERICK GENERATING STATION
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GRAPHIC LOGS
SHEET 3 OF 37

FIGURE 2.5-22

BORING 20

SURFACE ELEVATION +232.0'



DESCRIPTIONS

REDDISH-BROWN FINE SANDY SILT (VERY STIFF)
GRADING WITH FRAGMENTS OF SILTSTONE

BRUNSWICK SHALE-REDDISH-GRAY FINE GRAINED SANDY SILTSTONE (MEDIUM HARD), FEW SHALE PARTINGS

GRAY FINE GRAINED SANDSTONE (HARD TO VERY HARD) WITH LIMONITE INCLUSIONS
GRADING DARK BROWN, MEDIUM GRAINED
RED SHALE, FISSILE, CALCITE STRINGERS (SOFT TO MEDIUM HARD)
INTERBEDDED REDDISH-GRAY SANDSTONES AND SILTSTONES (HARD TO VERY HARD)

GRAY FINE GRAINED SANDSTONE, MASSIVE AND CROSS-BEDDED (HARD)

REDDISH-GRAY FINE SANDY SILTSTONE, FEW CALCAREOUS INCLUSIONS (VERY HARD)
GRADING PURPLISH-GRAY IN COLOR
GRADING RED IN COLOR-LESS SAND

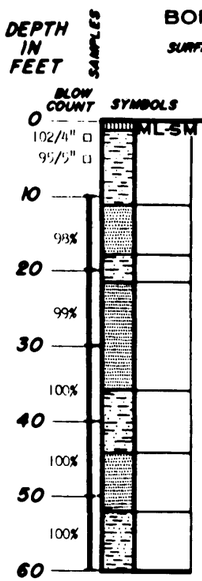
GRADING REDDISH-GRAY AND SANDY

GRADING RED, LESS SANDY, WITH CALCITE STRINGERS
GRADING SANDY

BORING COMPLETED ON 10-16-69
CASING TO A DEPTH OF 9.0'
300-LB. HAMMER @ 30" FALL
WATER LEVEL @ 48' ON 10-24-69

BORING 22

SURFACE ELEVATION +238.4'



DESCRIPTIONS

REDDISH-BROWN SILT-TOPSOIL (STIFF)
BRUNSWICK SHALE-REDDISH-BROWN SILTSTONE INTERBEDDED WITH SHALE (SOFT TO HARD)
GRADING MASSIVE
GRADING SANDY

GRAY FINE GRAINED SANDSTONE WITH OCCASIONAL SILTSTONE LAYER (HARD TO VERY HARD)
PEBBLE ZONE
REDDISH-GRAY FINE GRAINED SANDY SILTSTONE WITH FEW BUFF INCLUSIONS
GRAY FINE GRAINED SANDSTONE MASSIVE (VERY HARD)

SHALEY ZONE

REDDISH-GRAY VERY SANDY SILTSTONE WITH CALCITE STRINGERS (VERY HARD)

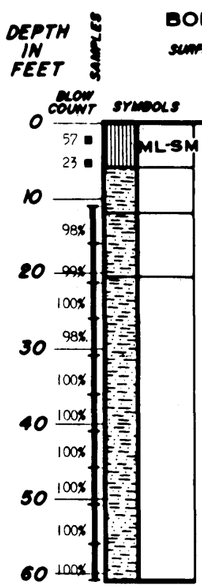
GRAY FINE TO MEDIUM GRAINED SANDSTONE (VERY HARD)

REDDISH-GRAY VERY SANDY SILTSTONE WITH CALCITE STRINGERS (VERY HARD)
FEW SHALE PARTINGS-MASSIVE

BORING COMPLETED ON 10-15-69
CASING TO A DEPTH OF 10'
300-LB. HAMMER @ 30" FALL
WATER LEVEL @ 27½' ON 10-24-69

BORING 25A

SURFACE ELEVATION +254.4'



DESCRIPTIONS

REDDISH-BROWN CLAYEY SILT (STIFF)

BRUNSWICK SHALE-INTERBEDDED REDDISH-GRAY VERY SANDY SILTSTONE AND VERY FINE GRAINED SANDSTONE

GRAY FINE GRAINED SILTSTONE, MASSIVE

RED SILTSTONE, MASSIVE (HARD)

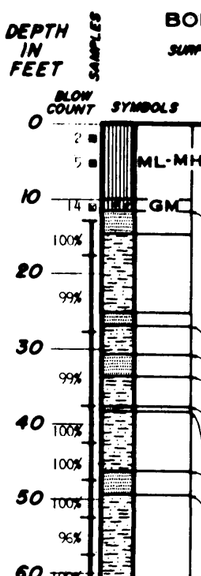
SANDY

SANDY

BORING COMPLETED ON 10-17-69
CASING TO A DEPTH OF 11'
300-LB. HAMMER @ 30"
WATER LEVEL NOT RECORDED

BORING 27

SURFACE ELEVATION +115.0'



DESCRIPTIONS

DARK GRAY TO BLACK SILT (SOFT)
CARBONACEOUS SAND - MICACEOUS
SOME REDDISH-BROWN SILT
GRADING WITH SOME CLAY

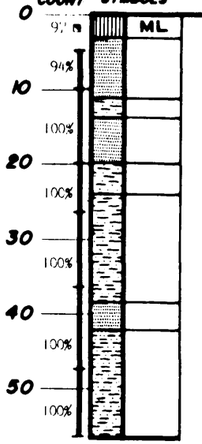
REDDISH-BROWN SILTY FINE TO MEDIUM SANDY GRAVEL (MEDIUM DENSE)
BRUNSWICK SHALE - REDDISH-BROWN FINE GRAINED SANDSTONE (HARD)
REDDISH-BROWN SHALEY SILTSTONE (HARD)
FEW CALCITE STRINGERS
GRADING VERY SANDY

REDDISH-BROWN VERY FINE GRAINED TO FINE GRAINED SANDSTONE-CROSS-BEDDED
REDDISH-BROWN SILTSTONE (HARD)
FEW CALCITE STRINGERS AND INCLUSIONS
REDDISH-BROWN FINE GRAINED SANDSTONE INTERBEDDED WITH SILTSTONE (HARD)
REDDISH-BROWN SILTSTONE (HARD)
FEW CALCITE STRINGERS AND INCLUSIONS
REDDISH-BROWN SILTY VERY FINE TO FINE GRAINED SANDSTONE (HARD)
REDDISH-BROWN SILTSTONE (HARD)
FEW CALCITE INCLUSIONS AND STRINGERS
GRADING VERY SANDY
LIGHT BROWN FINE GRAINED SANDSTONE (HARD)
SOME SILTSTONE
REDDISH-BROWN SILTSTONE (HARD)
FEW CALCITE STRINGERS AND INCLUSIONS
GRADING SOME FINE GRAINED SANDSTONE

BORING COMPLETED ON 10-24-69
CASING TO A DEPTH OF 13'
300-LB. HAMMER @ 18" FALL
WATER LEVEL NOT RECORDED

BORING 21

SURFACE ELEVATION +236.6'



DESCRIPTIONS

REDDISH-BROWN SANDY SILT (STIFF)
GRADING SOME SANDSTONE LAYERS (HARD)
BROWN MEDIUM GRAINED SANDSTONE SLIGHTLY WEATHERED (HARD)

REDDISH-BROWN SILTSTONE (HARD)

REDDISH-BROWN TO GRAY SILTY VERY FINE GRAINED SANDSTONE, FEW CALCITE INCLUSIONS
INTERBEDDED REDDISH-BROWN SILTSTONE AND SILTY FINE GRAINED SANDSTONE (HARD TO VERY HARD)
REDDISH-BROWN SILTSTONE (HARD)

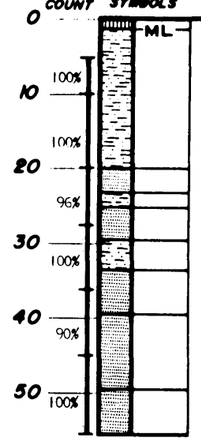
LIGHT REDDISH-BROWN, GRAY, SILTY FINE GRAINED SANDSTONE (HARD)
FEW CALCITE INCLUSIONS
REDDISH-BROWN SILTSTONE, FEW CALCITE BED STRINGERS (HARD)
SHALEY ZONE

CALCITE BEDDING STRINGERS

BORING COMPLETED ON 10-13-69
CASING TO A DEPTH OF 5'
140-LB. HAMMER @ 30" FALL
WATER LEVEL @ 26' ON 10-24-69

BORING 24

SURFACE ELEVATION +254.6'



DESCRIPTIONS

REDDISH-BROWN CLAYEY SILT (STIFF)
BRUNSWICK SHALE-REDDISH-BROWN SHALEY SILTSTONE (MEDIUM HARD TO HARD)
SHALEY IN PART

FEW CALCITE STRINGERS AND INCLUSIONS

REDDISH-BROWN GRAY VERY FINE GRAINED SANDSTONE (HARD)
REDDISH-BROWN SHALEY SILTSTONE
REDDISH-BROWN TO LIGHT GRAY SILTY VERY FINE GRAINED SANDSTONE (HARD)
REDDISH-BROWN INTERBEDDED SILTSTONE AND SANDSTONE
REDDISH-BROWN FINE TO MEDIUM GRAINED SANDSTONE

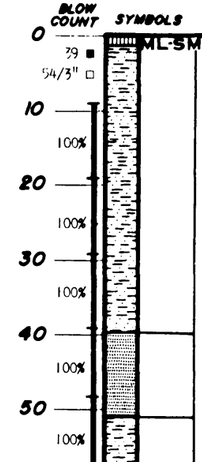
INTERBEDDED SILTSTONE AND SANDSTONES GRADING MEDIUM TO COARSE GRAINED

LIGHT GRAY MEDIUM GRAINED SANDSTONE (HARD)
FEW THIN SHALE PARTINGS

BORING COMPLETED ON 10-17-69
CASING TO A DEPTH OF 5'
WATER LEVEL @ 40' ON 10-24-69

BORING 26

SURFACE ELEVATION +252.9'



DESCRIPTIONS

REDDISH-BROWN FINE SANDY SILT (STIFF)
BRUNSWICK SHALE-REDDISH-BROWN SANDY SILTSTONE WITH SHALE (SOFT TO MEDIUM HARD)
GRADING REDDISH-GRAY WITH CALCITE STRINGERS
SHALEY
GRADING SANDY

MASSIVE

GRAY FINE GRAINED SANDSTONE WITH FEW SHALE PARTINGS (HARD)
MASSIVE-SILTY IN PART

REDDISH-BROWN SILTSTONE WITH FEW CALCITE STRINGERS AND INCLUSIONS (HARD TO VERY HARD)

BORING COMPLETED ON 10-17-69
CASING TO A DEPTH OF 9'
300-LB. HAMMER @ 18" FALL
WATER LEVEL NOT RECORDED

NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

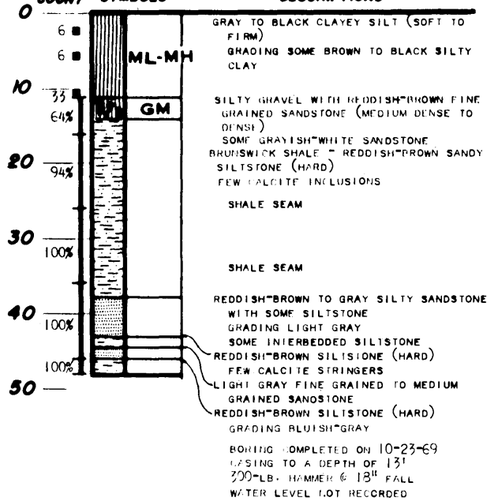
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 4 OF 37

FIGURE 2.5-22

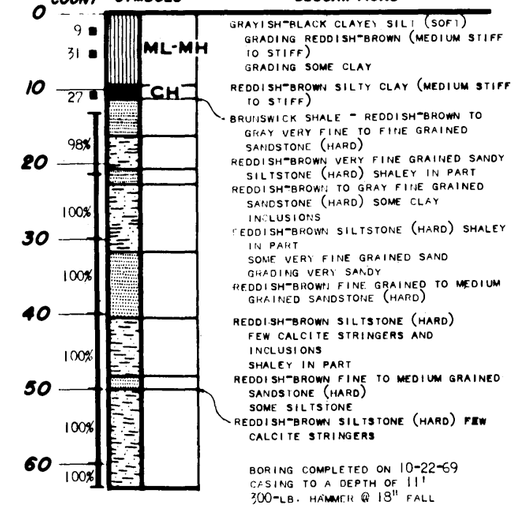
BORING 28

SURFACE ELEVATION +114.1'



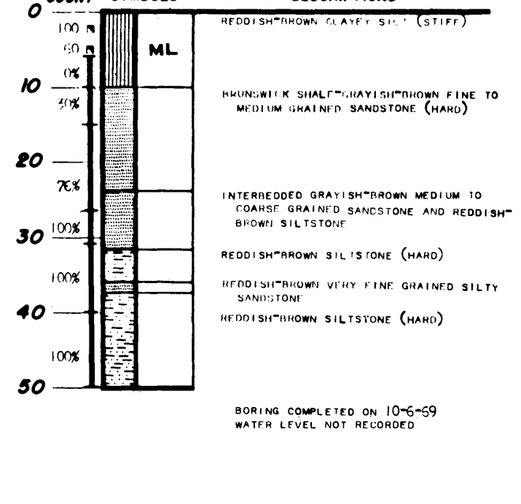
BORING 30

SURFACE ELEVATION +115.0'



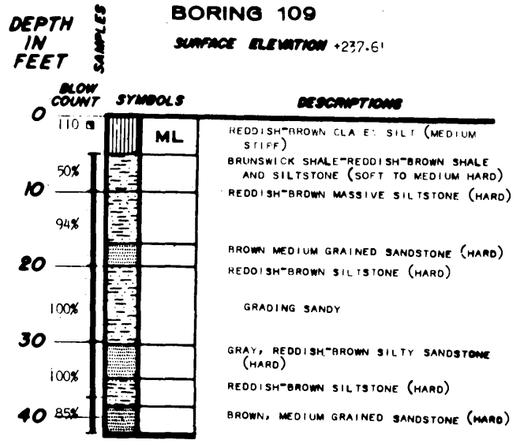
BORING 107

SURFACE ELEVATION +250.4'



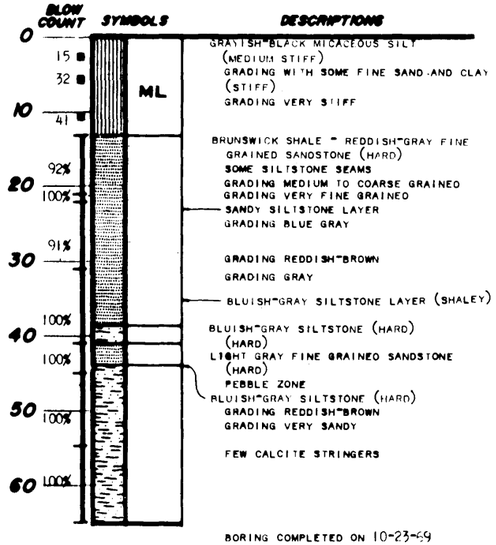
BORING 109

SURFACE ELEVATION +237.6'



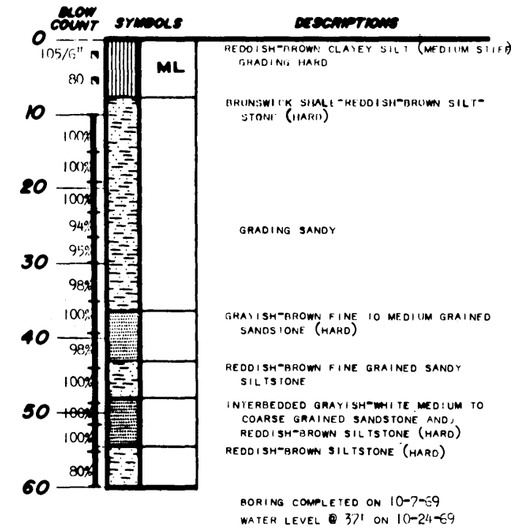
BORING 29

SURFACE ELEVATION +115.3'



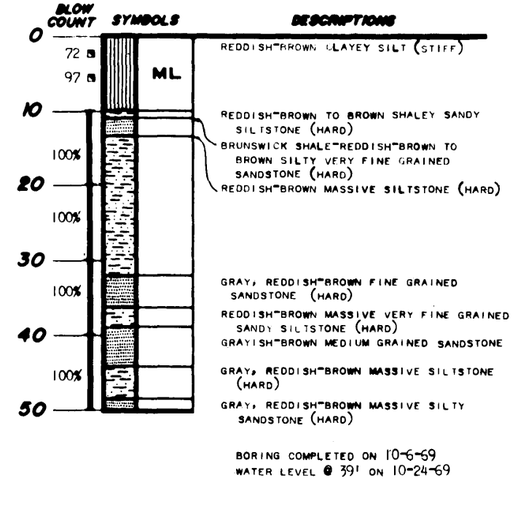
BORING 106

SURFACE ELEVATION +260.0'



BORING 108

SURFACE ELEVATION +243.1'



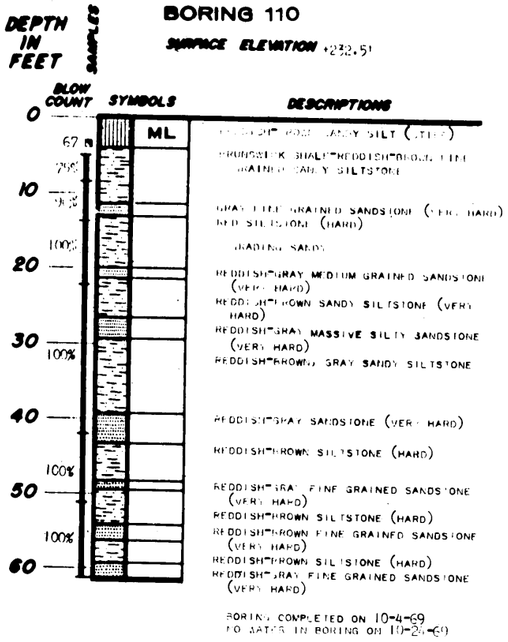
NOTES:

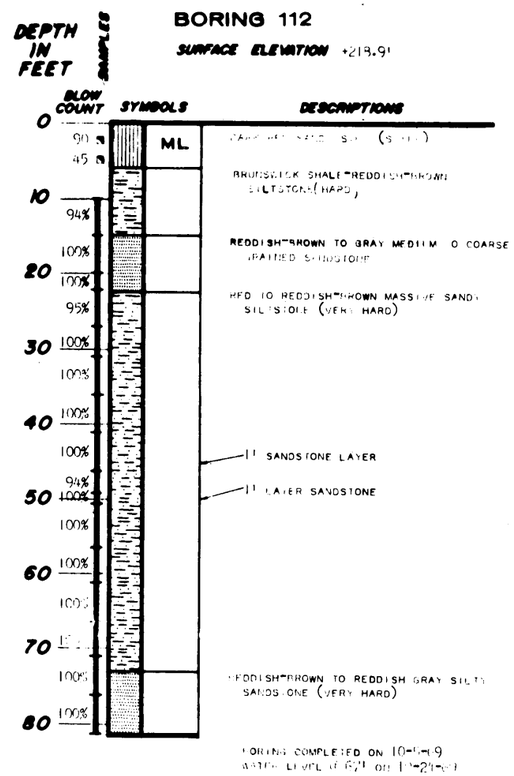
1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

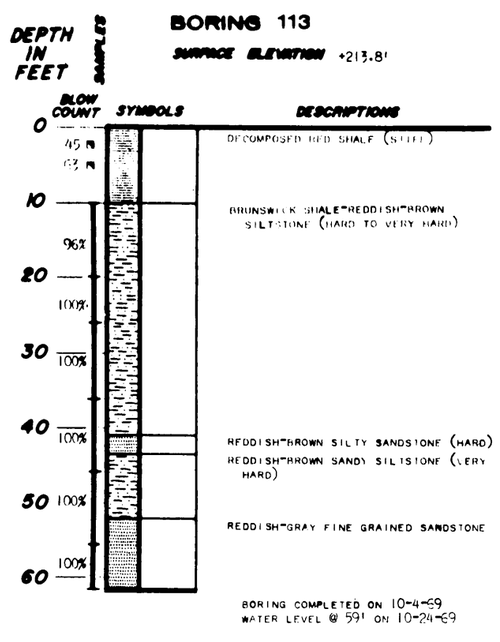
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

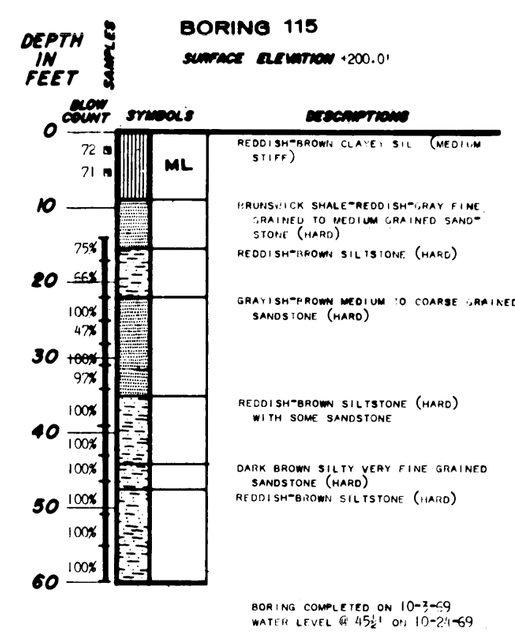
GRAPHIC LOGS
SHEET 5 OF 37

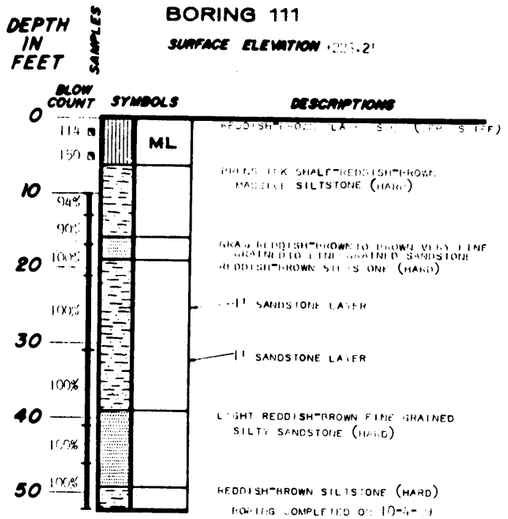
FIGURE 2.5-22

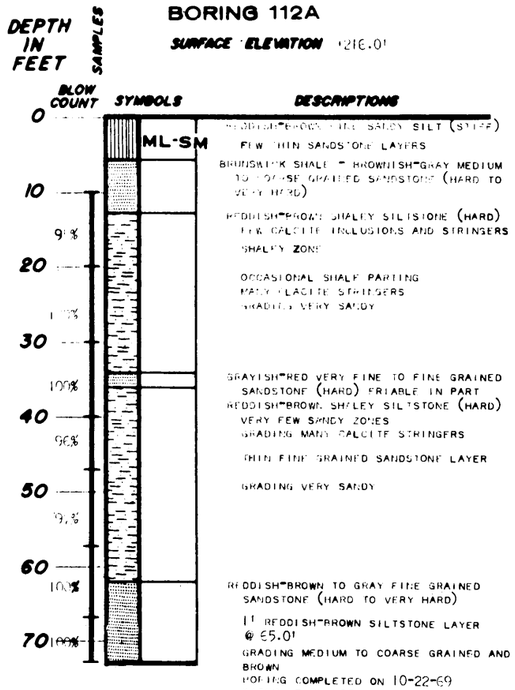


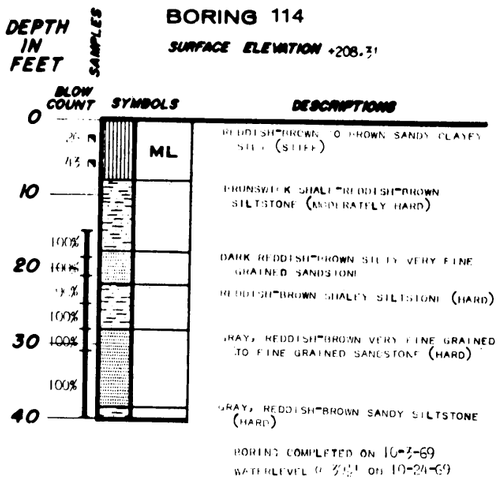












NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

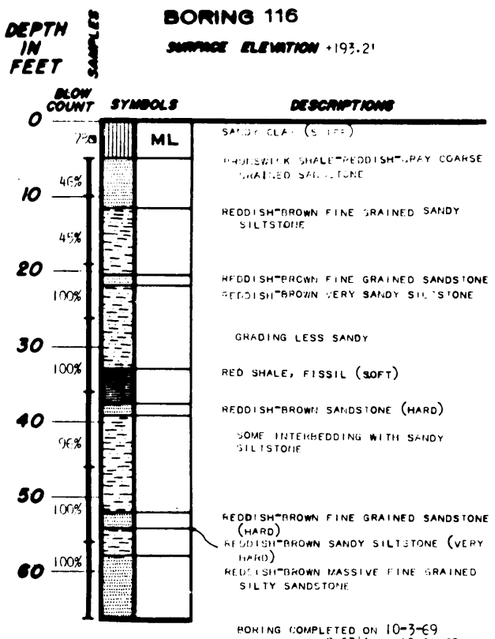
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 6 OF 37

FIGURE 2.5-22

BORING 116

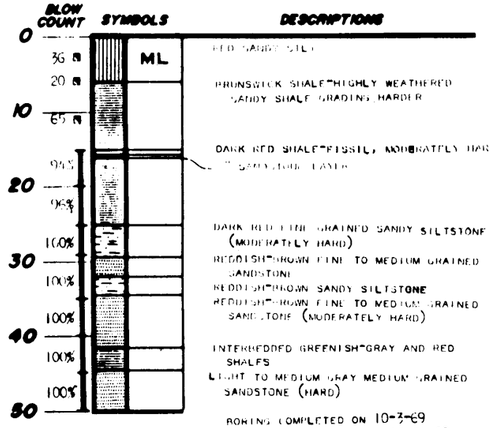
SURFACE ELEVATION +193.2'



BORING COMPLETED ON 10-3-69
WATER LEVEL @ 63½' ON 10-24-69

BORING 117

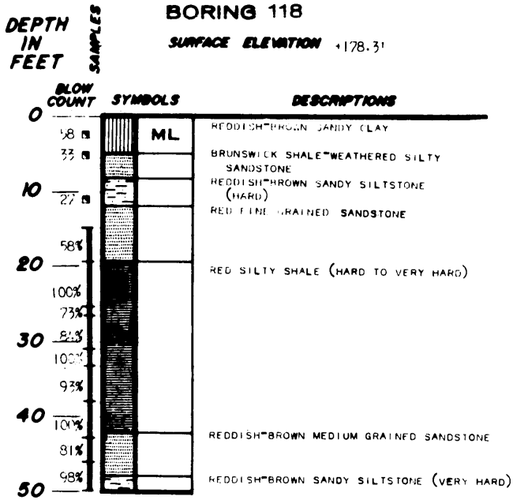
SURFACE ELEVATION +185.7'



BORING COMPLETED ON 10-24-69
WATER LEVEL NOT RECORDED

BORING 118

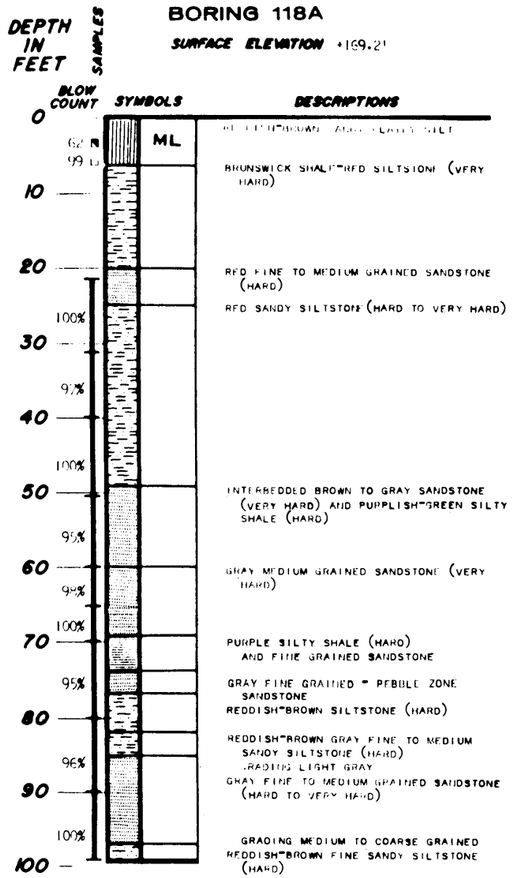
SURFACE ELEVATION +178.3'



BORING COMPLETED ON 10-2-69
WATER LEVEL @ 39' ON 10-24-69

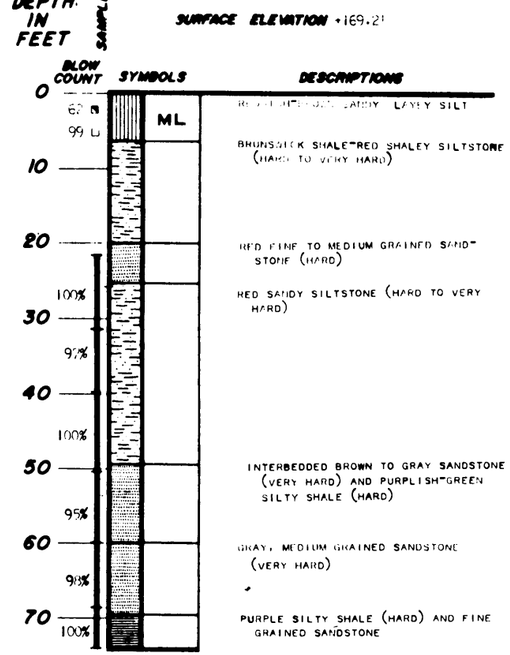
BORING 118A

SURFACE ELEVATION +169.2'



BORING 119

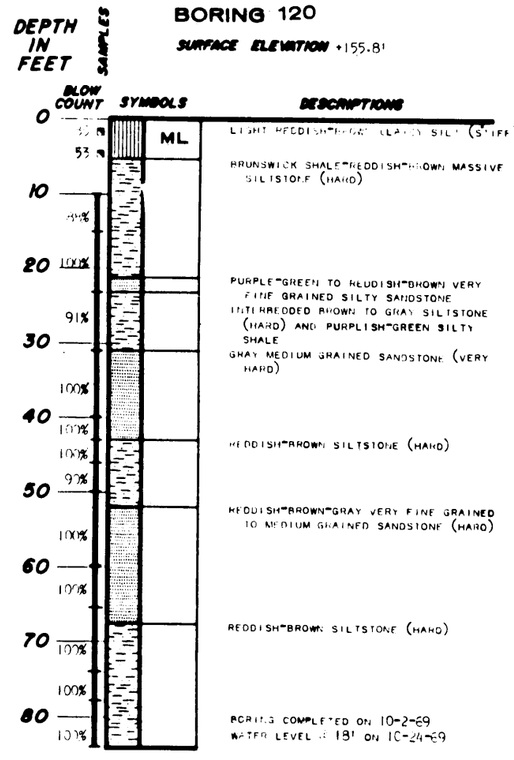
SURFACE ELEVATION +169.2'



BORING COMPLETED ON 10-2-69
WATER LEVEL NOT RECORDED

BORING 120

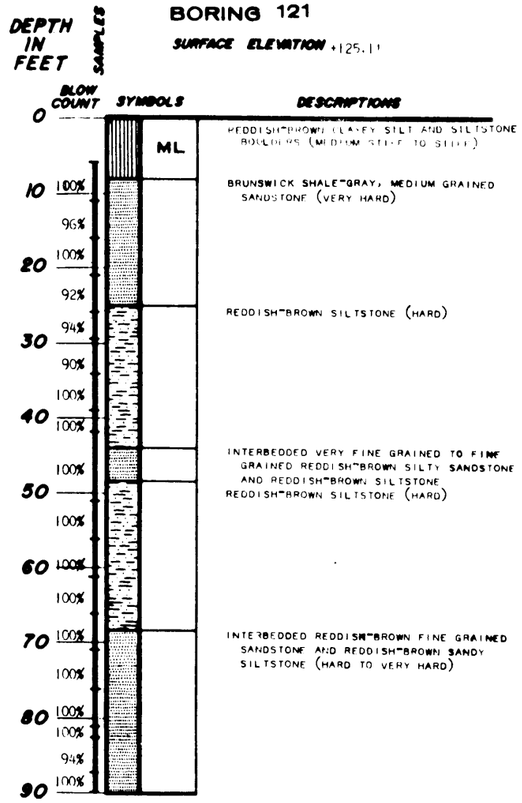
SURFACE ELEVATION +155.8'



BORING COMPLETED ON 10-2-69
WATER LEVEL @ 18' ON 10-24-69

BORING 121

SURFACE ELEVATION +125.1'



BORING COMPLETED ON 10-2-69
WATER LEVEL @ 33' ON 10-24-69

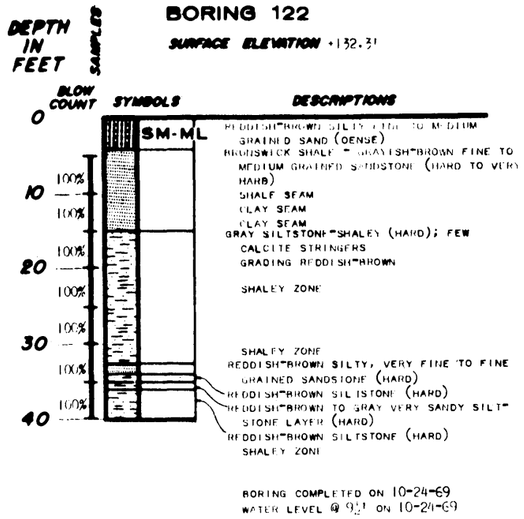
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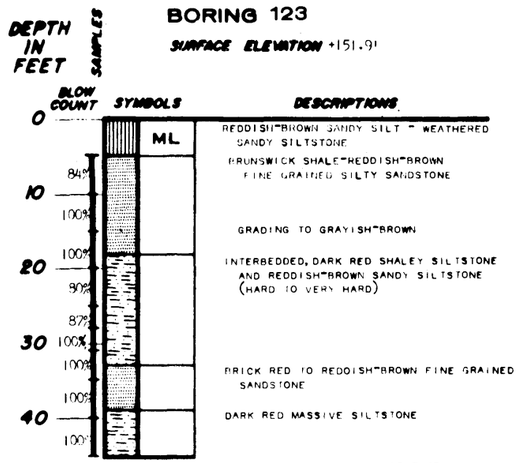
1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

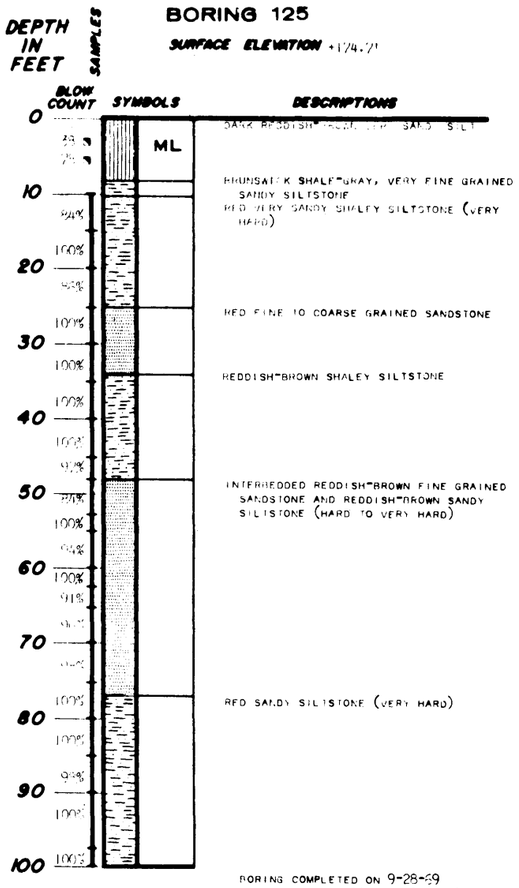
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

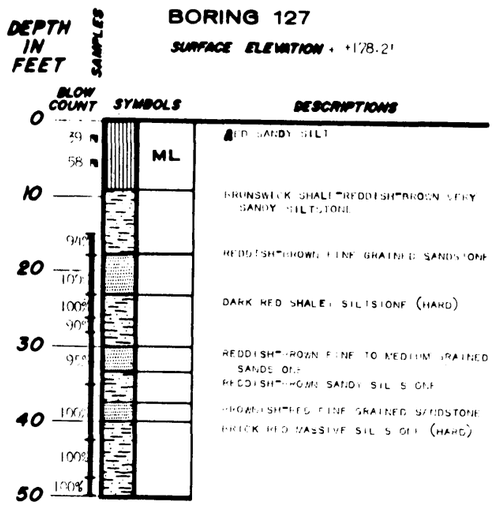
GRAPHIC LOGS
SHEET 7 OF 37

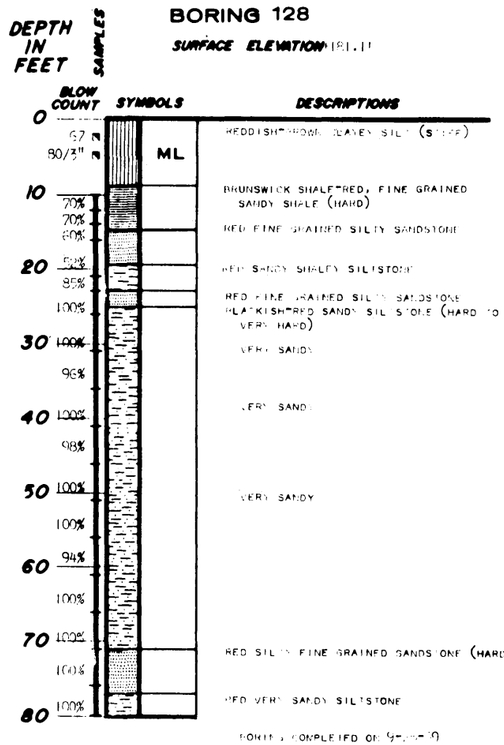
FIGURE 2.5-22

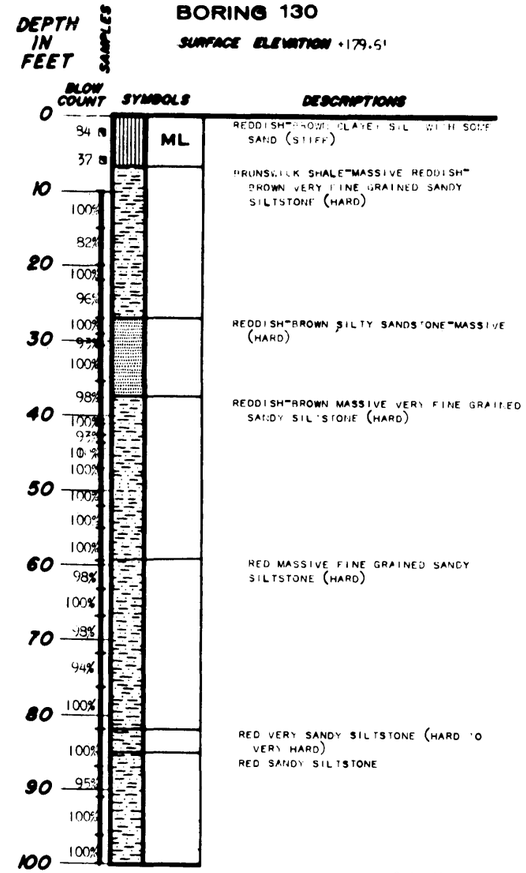












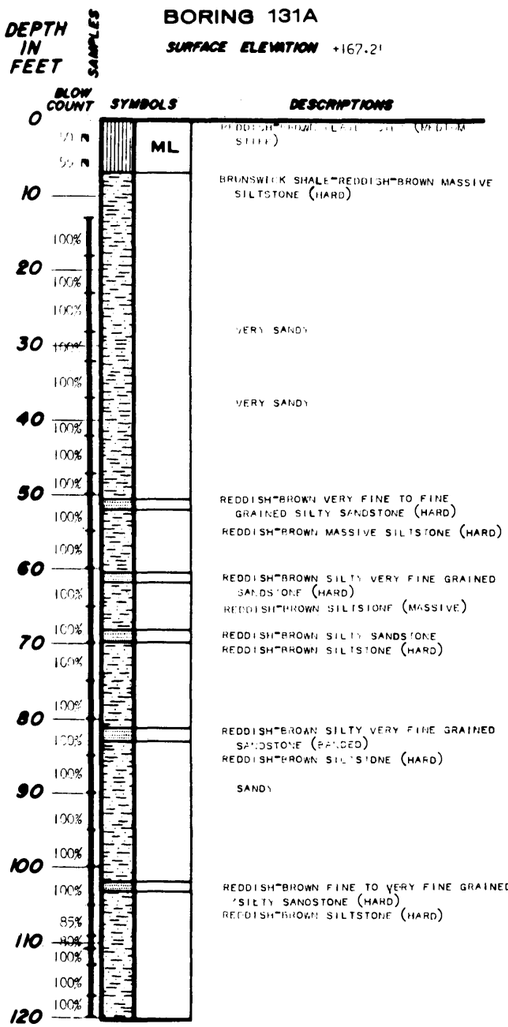
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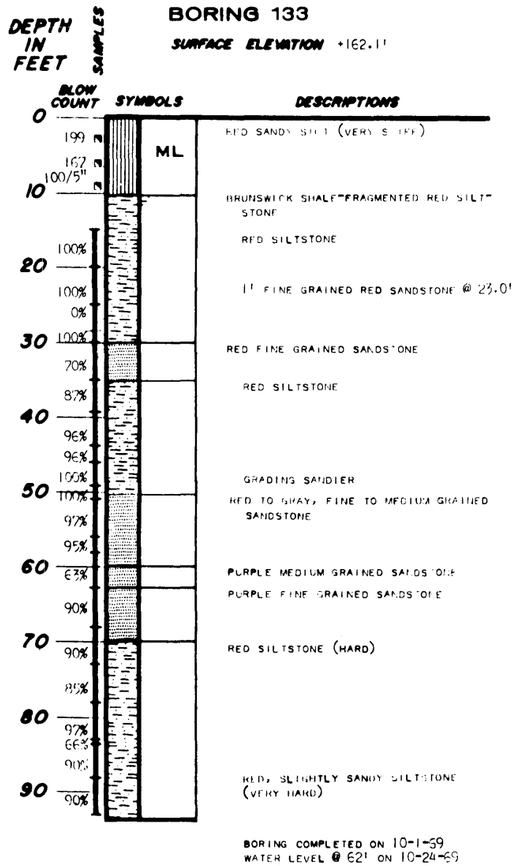
1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

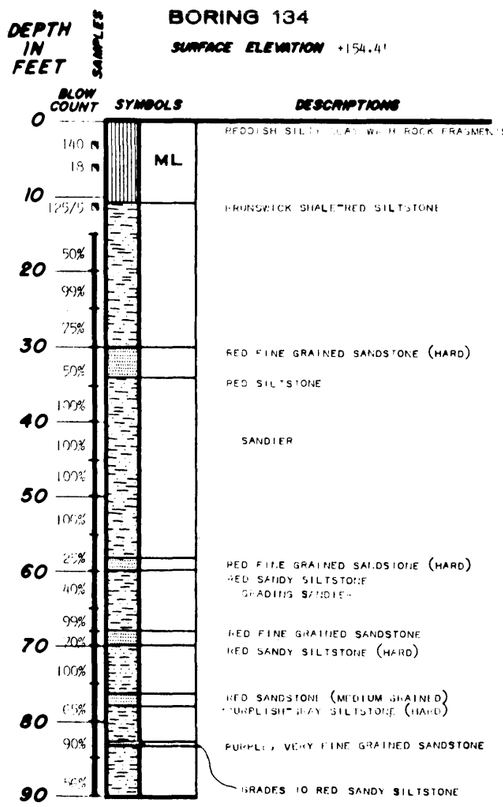
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

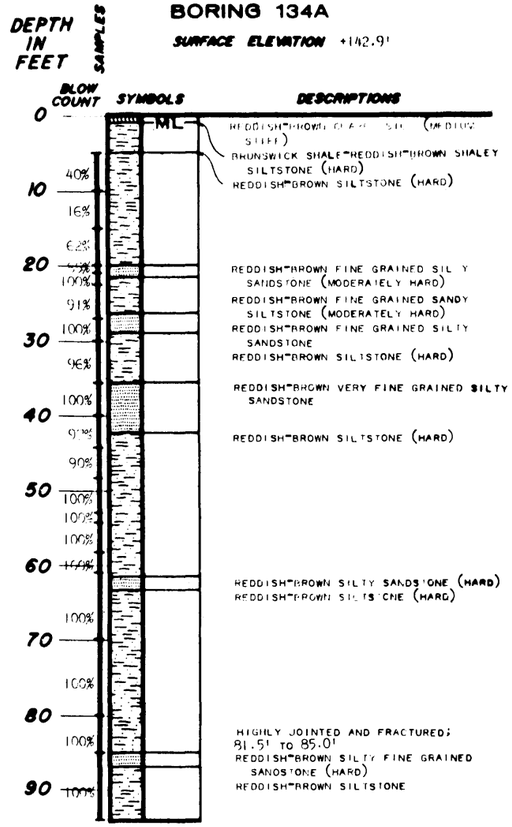
GRAPHIC LOGS
SHEET 8 OF 37

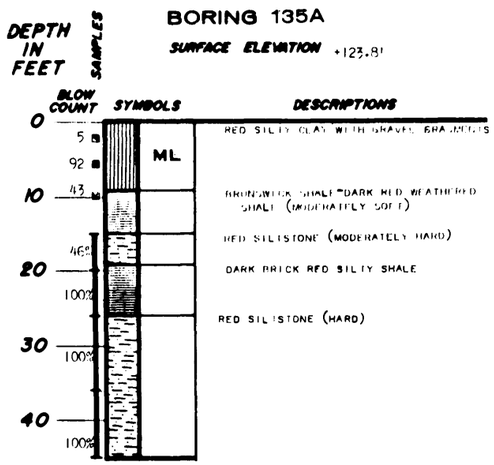
FIGURE 2.5-22

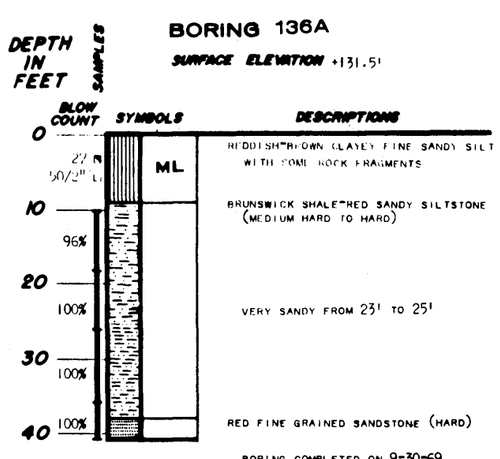










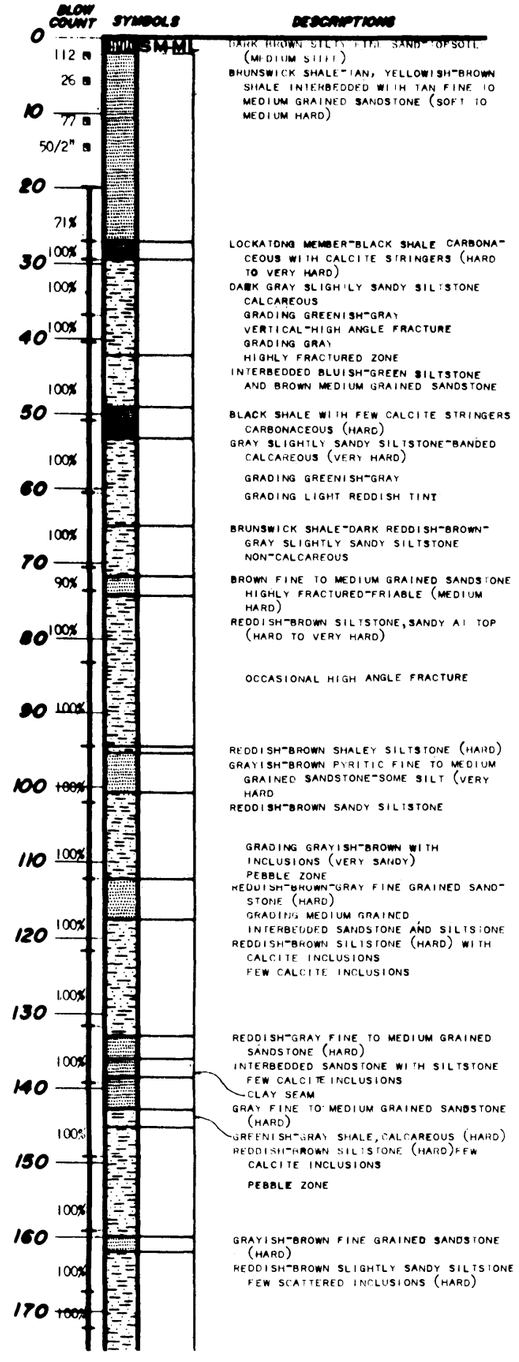


NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

BORING 150

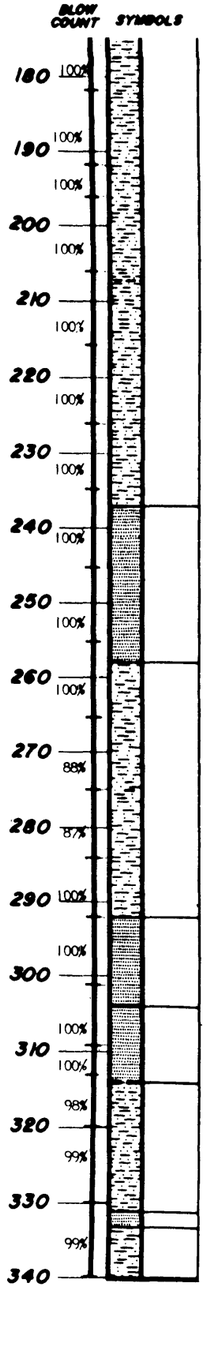
SURFACE ELEVATION +260.1'



DESCRIPTIONS

- DARK BROWN SILTY FINE SAND "TOPSOIL (MEDIUM STIFF)
- BRUNSWICK SHALE "TAN, YELLOWISH"BROWN SHALE INTERBEDDED WITH TAN FINE TO MEDIUM GRAINED SANDSTONE (SOFT TO MEDIUM HARD)
- LOCKATONG MEMBER "BLACK SHALE CARBONACEOUS WITH CALCITE STRINGERS (HARD TO VERY HARD)
- DARK GRAY SLIGHTLY SANDY SILTSTONE CALCAREOUS
- GRADING GREENISH"GRAY
- VERTICAL "HIGH ANGLE FRACTURE
- GRADING GRAY
- HIGHLY FRACTURED ZONE
- INTERBEDDED BLUISH"GREEN SILTSTONE AND BROWN MEDIUM GRAINED SANDSTONE
- BLACK SHALE WITH FEW CALCITE STRINGERS CARBONACEOUS (HARD)
- GRAY SLIGHTLY SANDY SILTSTONE "BANDED CALCAREOUS (VERY HARD)
- GRADING GREENISH"GRAY
- GRADING LIGHT REDDISH TINT
- BRUNSWICK SHALE "DARK REDDISH"BROWN" GRAY SLIGHTLY SANDY SILTSTONE NON"CALCAREOUS
- BROWN FINE TO MEDIUM GRAINED SANDSTONE HIGHLY FRACTURED "FRIABLE (MEDIUM HARD)
- REDDISH"BROWN SILTSTONE, SANDY AT TOP (HARD TO VERY HARD)
- OCCASIONAL HIGH ANGLE FRACTURE
- REDDISH"BROWN SHALEY SILTSTONE (HARD)
- GRAYISH"BROWN PYRITIC FINE TO MEDIUM GRAINED SANDSTONE "SOME SILT (VERY HARD
- REDDISH"BROWN SANDY SILTSTONE
- GRADING GRAYISH"BROWN WITH INCLUSIONS (VERY SANDY)
- PEBBLE ZONE
- REDDISH"BROWN "GRAY FINE GRAINED SANDSTONE (HARD)
- GRADING MEDIUM GRAINED INTERBEDDED SANDSTONE AND SILTSTONE
- REDDISH"BROWN SILTSTONE (HARD) WITH CALCITE INCLUSIONS
- FEW CALCITE INCLUSIONS
- REDDISH"GRAY FINE TO MEDIUM GRAINED SANDSTONE (HARD)
- INTERBEDDED SANDSTONE WITH SILTSTONE
- FEW CALCITE INCLUSIONS
- CLAY SEAM
- GRAY FINE TO MEDIUM GRAINED SANDSTONE (HARD)
- GREENISH"GRAY SHALE, CALCAREOUS (HARD)
- REDDISH"BROWN SILTSTONE (HARD) FEW CALCITE INCLUSIONS
- PEBBLE ZONE
- GRAYISH"BROWN FINE GRAINED SANDSTONE (HARD)
- REDDISH"BROWN SLIGHTLY SANDY SILTSTONE
- FEW SCATTERED INCLUSIONS (HARD)

BORING 150



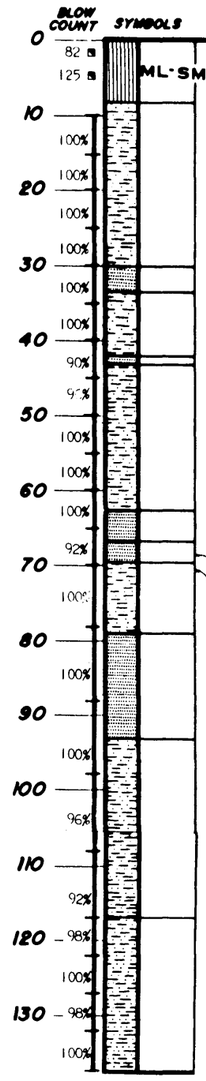
DESCRIPTIONS

- SHALEY ZONE
- GRADING SANDY WITH CLAY INCLUSIONS
- GRADING SANDY
- LESS SANDY, FEW CALCITE INCLUSIONS
- FEW CALCITE INCLUSIONS
- REDDISH"BROWN TO GRAY SILTY VERY FINE TO FINE GRAINED SANDSTONE (HARD)
- SILTSTONE LAYERS
- GRADING MEDIUM TO COARSE GRAINED
- REDDISH"BROWN SILTSTONE (HARD) FEW CALCITE STRINGER AND INCLUSIONS
- GRADING SANDY
- GRADING REDDISH"GRAY, "VERY SANDY
- PEBBLE ZONE
- PEBBLE ZONE
- LIGHT GRAY FINE TO MEDIUM GRAINED SANDSTONE (HARD)
- SILTY ZONE
- FEW JOINTS WITH STAINING
- REDDISH"BROWN SILTSTONE INTERBEDDED WITH REDDISH"BROWN VERY FINE TO FINE GRAINED SANDSTONE (HARD TO VERY HARD)
- SOME CROSS BEDDING
- REDDISH"BROWN SILTSTONE (HARD) FEW CALCITE INCLUSIONS
- GRADING LESS CALCITE INCLUSIONS
- GRADING SOME FINE GRAINED SAND" STONE
- LIGHT GRAY FINE TO MEDIUM GRAINED SANDSTONE (HARD)
- REDDISH"BROWN SILTSTONE (HARD)
- FEW CALCITE INCLUSIONS
- GRADING SOME SANDSTONE

BORING COMPLETED ON 10-22-69
WATER LEVEL NOT RECORDED

BORING 151

SURFACE ELEVATION



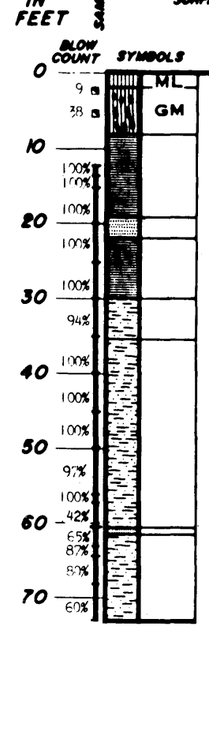
DESCRIPTIONS

- REDDISH"BROWN FINE TO MEDIUM GRAINED SANDY SILT (MEDIUM STIFF TO STIFF)
- BRUNSWICK SHALE " REDDISH"BROWN FINE TO MEDIUM GRAINED SANDY SILTSTONE (HARD)
- SHALEY ZONE
- GRADING SANDY
- FEW CALCITE STRINGERS
- GRADING VERY SANDY
- REDDISH"GRAY SILTY VERY FINE TO FINE GRAINED SANDSTONE "MASSIVE (HARD)
- REDDISH"GRAY SANDY SILTSTONE (HARD)
- FEW CALCITE STRINGERS
- GRADING VERY SANDY
- GRAY VERY FINE TO FINE SANDSTONE LAYER
- REDDISH"GRAY FINE SANDY SILTSTONE
- SHALE PARTING
- VERY SANDY ZONE
- GRADING VERY SANDY WITH SOME SAND" STONE
- GRAY VERY FINE TO FINE GRAINED SAND" STONE (HARD)
- SOME SIL STONE
- GRADING REDDISH
- GRAY VERY FINE TO FINE SANDSTONE WITH SOME RED SANDY SILTSTONE LAYERS
- REDDISH"BROWN SHALEY SILTSTONE (HARD)
- GRADING VERY SANDY AND GRAY
- GRAY FINE GRAINED SANDSTONE MASSIVE (HARD TO VERY HARD)
- WELL CEMENTED
- GRADING DARK BROWN"FRIABLE
- PEBBLE ZONE
- GREENISH"GRAY FINE SANDY SILTSTONE
- PEBBLE ZONE
- GRADING VERY SANDY"GRAY
- FEW SHALE PARTINGS
- PEBBLE ZONE
- BLUISH"GRAY SILTSTONE LAYER
- REDDISH"BROWN TO GRAY SILTY VERY FINE "TO FINE GRAINED SANDSTONE LAYER
- REDDISH"BROWN SILTSTONE (HARD)
- GRADING SANDY IN PART
- FEW CALCITE INCLUSIONS AND STRINGERS
- FEW SANDY ZONES
- CALCITE INCLUSIONS
- CALCITE INCLUSIONS
- GRADING SANDY

BORING COMPLETED ON 10-22-69
WATER LEVEL NOT RECRODED

BORING 136

SURFACE ELEVATION +122.4'



DESCRIPTIONS

- RED SANDY CLAY (SOFT)
- RED SILTY GRAVEL
- HIGHLY FRACTURED
- BRUNSWICK SHALE " DARK RED SILTY SHALE
- REDDISH"GRAY, HIGHLY FRACTURED, FINE GRAINED SANDSTONE
- DARK RED SILTY SHALE (HARD)
- BRICK RED, FINE GRAINED SANDY SILTSTONE (HARD)
- BRICK RED, FRACTURED, SILTSTONE (HARD)
- RED FINE GRAINED SILTY SANDSTONE
- DARK RED, HIGHLY FRACTURED, SILTSTONE (HARD)

BORING COMPLETED ON 10-1-69
WATER LEVEL @ 3½' ON 10-24-69

NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

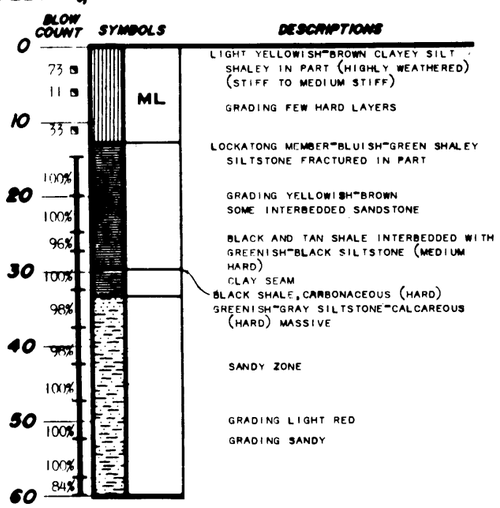
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 10 OF 37

FIGURE 2.5-22

BORING 152

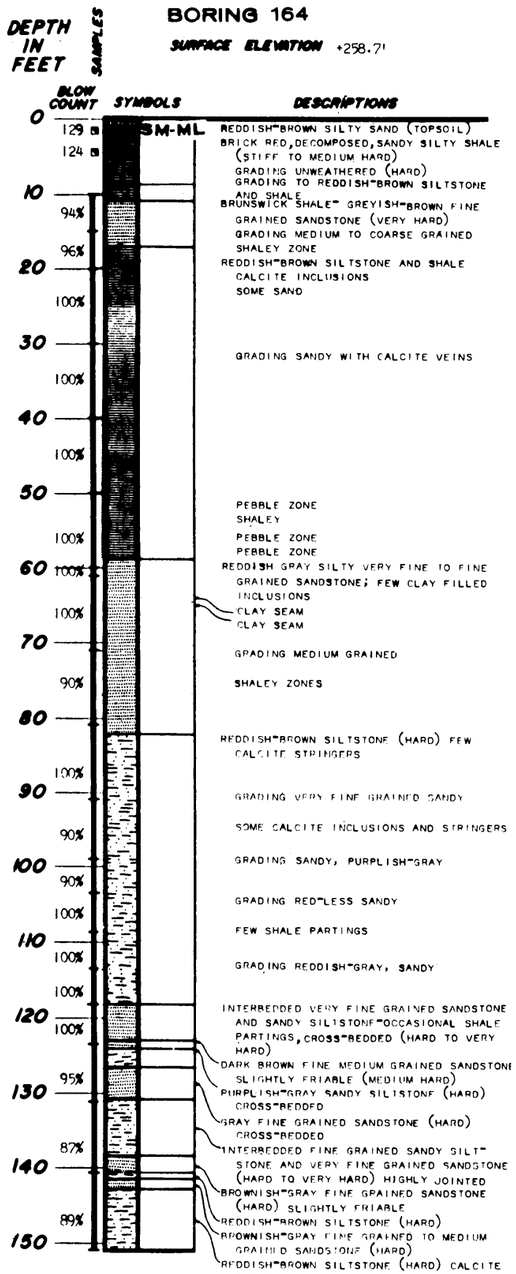
SURFACE ELEVATION +254.9'



BORING COMPLETED ON 10-20-69
WATER LEVEL @ 21' ON 10-24-69

BORING 164

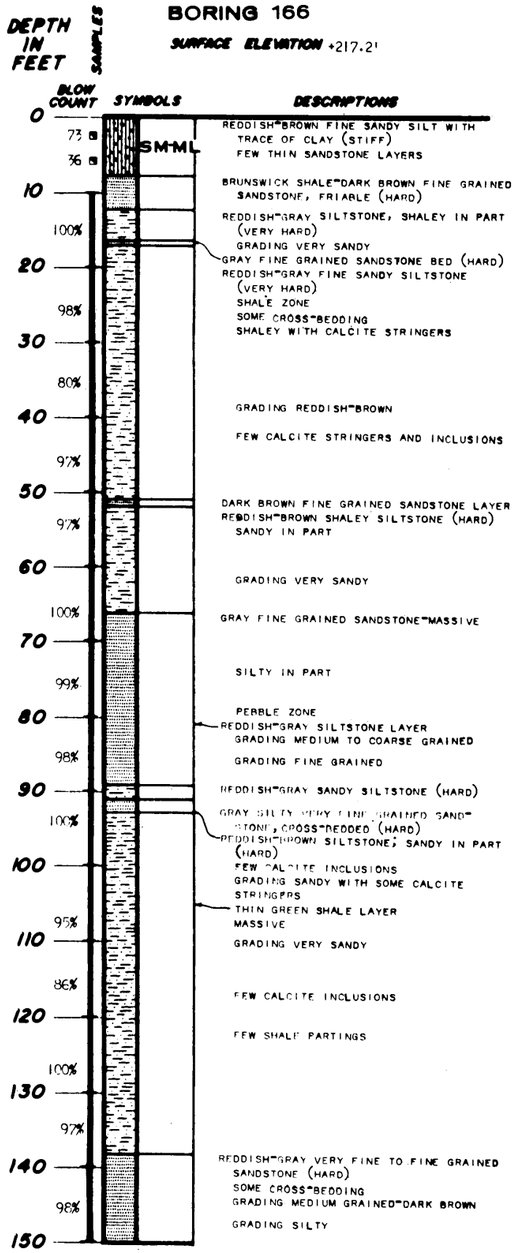
SURFACE ELEVATION +258.7'



BORING COMPLETED ON 10-16-69
WATER LEVEL @ 109.1' ON 10-24-69

BORING 166

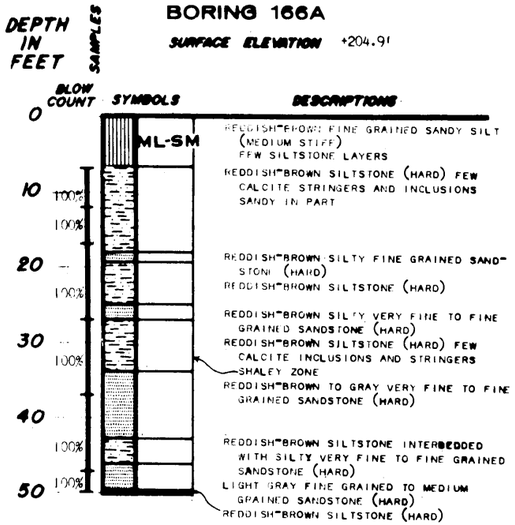
SURFACE ELEVATION +217.2'



BORING COMPLETED ON 10-21-69
WATER LEVEL @ 90' ON 10-24-69

BORING 166A

SURFACE ELEVATION +204.9'



BORING COMPLETED ON 10-23-69
WATER LEVEL NOT RECORDED

NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 11 OF 37

FIGURE 2.5-22

BORING 167

SURFACE ELEVATION +211.4'

DEPTH IN FEET | SAMPLES | BLOW COUNT | SYMBOLS | DESCRIPTIONS

0
40
24
CL
SC
BROWN SANDY CLAY, TOPSOIL
REDDISH-BROWN FINE TO MEDIUM SANDY CLAY-ROCKY
10
24%
100%
BROWNISH-GRAY SHALE-REDDISH-BROWN SILTSTONE ALTERNATELY SANDY (VERY HARD)
20
100%
100%
REDDISH-BROWN FINE GRAINED SILTY SANDSTONE
DARK REDDISH-BROWN SANDY SILTSTONE (HARD)
30
100%
DARK BROWN VERY SANDY SILTSTONE (LIMONITE)
REDDISH-BROWN TO BRICK RED SILTSTONE MASSIVE
100%
40
REDDISH-BROWN FINE GRAINED VERY SANDY SILTSTONE (VERY HARD)
97%
50
100%
60
DARK BROWN COARSE GRAINED SANDSTONE SLIGHTLY WEATHERED (HARD TO VERY HARD)
REDDISH-BROWN SILTSTONE-MASSIVE WITH THIN ALKLITE SEAMS
95%
70
REDDISH-BROWN FINE GRAINED SANDSTONE FRIABLE (HARD)
DARK RED SHALEY SILTSTONE
REDDISH-BROWN VERY SANDY SILTSTONE (VERY HARD) MASSIVE
DARK REDDISH-BROWN FINE GRAINED SANDSTONE (VERY HARD)
80
98%
REDDISH-BROWN VERY SANDY SILTSTONE (VERY HARD) MASSIVE
RED FINE SANDY SILTSTONE MASSIVE (HARD TO VERY HARD)
GRADING VERY SANDY
100%
90
REDDISH-BROWN SILTY SANDSTONE (VERY HARD)
RED SILTSTONE (HARD)
REDDISH-BROWN SILTY SANDSTONE (VERY HARD)
100%
100
BROWN TO GRAY MEDIUM GRAINED SANDSTONE (HARD)
REDDISH-BROWN SILTSTONE (HARD)
100%
110
GRADING SANDY
GRAY-REDDISH-BROWN SILTY FINE GRAINED SANDSTONE (HARD)
96%
GRADING MEDIUM GRAINED
120
REDDISH-BROWN SILTSTONE (HARD)
BROWNISH-GRAY FINE GRAINED TO MEDIUM GRAINED SANDSTONE
100%
130
GRAY-REDDISH-BROWN SILTY VERY FINE GRAINED SANDSTONE INTERBEDDED WITH REDDISH-BROWN SILTSTONE (HARD TO VERY HARD)
94%
140
REDDISH-BROWN SILTSTONE (HARD)
100%
150

BORING COMPLETED ON 10-10-69
WATER LEVEL @ 90.1' ON 10-24-69

BORING 168

SURFACE ELEVATION +169.3'

DEPTH IN FEET | SAMPLES | BLOW COUNT | SYMBOLS | DESCRIPTIONS

0
3
4
SM
SM
REDDISH-BROWN SANDY SILT (SOFT)
OR OMPOSED REDDISH-BROWN VERY SANDY SILTSTONE
10
BRUNSWICK SHALE-REDDISH-BROWN MEDIUM GRAINED SANDSTONE (HARD)
BRICK RED SILTSTONE (MEDIUM HARD)
REDDISH-BROWN SILTY FINE GRAINED SANDSTONE (HARD)
20
100%
REDDISH-BROWN FINE SANDY SILTSTONE, VERY MASSIVE (VERY HARD)
REDDISH-BROWN SILTY FINE GRAINED SANDSTONE (VERY HARD)
100%
REDDISH-BROWN SANDY SILTSTONE
BRICK RED THINLY BEDDED FISSIL SHALE (SOFT TO MODERATELY HARD)
97%
30
BROWNISH-RED SANDY SILTSTONE (VERY HARD) SHALEY
100%
DARK REDDISH-BROWN FINE GRAINED SANDY SILTSTONE (VERY HARD)
40
REDDISH-BROWN SILTY FINE GRAINED SANDSTONE-SLIGHTLY FRIABLE (HARD)
100%
LIGHT BROWNISH-GRAY VERY SANDY SILT-STONE (HARD)
96%
50
REDDISH-BROWN SILTSTONE SOME BANDING
LIGHT BROWNISH-GRAY FINE GRAINED VERY SANDY SILTSTONE (HARD)
100%
GRADING LIGHT GRAYISH-BROWN SILTY FINE TO COARSE GRAINED SANDSTONE (VERY HARD)
96%
60
BRICK RED SANDY SILTSTONE GRADING SHALEY
100%
GRADING MASSIVE
100%
70
GRADING PURPLISH-RED
REDDISH-GRAY SILTY FINE GRAINED SANDSTONE (VERY HARD)
100%
GRADING MEDIUM TO COARSE GRAINED
GRADING FINE GRAINED
80
GRADING MEDIUM TO COARSE GRAINED SOME CLAY FILLED VUGS
96%
GRADING BLUISH-GRAY FINE TO MEDIUM GRAINED SANDSTONE (HARD)
GRADING MEDIUM TO COARSE GRAINED SLIGHTLY WEATHERED
96%
90
GRADING FINE GRAINED
100%
REDDISH-BROWN FINE GRAINED SANDY SILTSTONE (VERY HARD)
100%
100
GRADING BROWN SILTY FINE GRAINED SANDSTONE (VERY HARD)
100%
110
REDDISH-BROWN FINE GRAINED SANDY SILTSTONE WITH SOME SILTY FINE GRAINED SANDSTONE (HARD)
100%
120

BORING COMPLETED ON 10-10-69
WATER LEVEL NOT RECORDED

BORING 169

SURFACE ELEVATION +174.4'

DEPTH IN FEET | SAMPLES | BLOW COUNT | SYMBOLS | DESCRIPTIONS

0
95
70
ML
REDDISH-BROWN CLAYEY SILT (HARD)
BRUNSWICK SHALE-REDDISH-BROWN SILT WITH SHALE FRAGMENTS
10
0%
80%
GRAYISH-BROWN, WEATHERED, MEDIUM GRAINED SANDSTONE (MODERATELY HARD)
REDDISH-BROWN SILTSTONE (HARD)
20
81%
GRAYISH-BROWN VERY FINE GRAINED TO FINE GRAINED SANDSTONE (HARD)
GRADES GRAYER
GRADES TO VERY FINE GRAINED SILTY SANDSTONE
98%
30
REDDISH-BROWN SILTSTONE (HARD)
REDDISH-BROWN TO BROWN FINE GRAINED SANDSTONE (HARD)
98%
REDDISH-BROWN SILTSTONE (HARD)
40
100%
GRAYISH-BROWN FINE GRAINED MICACEOUS SANDSTONE (MODERATELY HARD)
50
100%
REDDISH-BROWN SILTSTONE (HARD)
100%
REDDISH-BROWN FINE GRAINED SANDSTONE (HARD)
60
95%
REDDISH-BROWN MASSIVE SILTSTONE (HARD)
70
100%
GRAY REDDISH-BROWN VERY FINE GRAINED SILTY SANDSTONE
REDDISH-BROWN SILTSTONE INTERBEDDED AT TOP
REDDISH-BROWN SILTSTONE (HARD)
80
100%
GRAYISH-BROWN FINE GRAINED SANDSTONE (HARD)
90
99%
REDDISH-BROWN SILTSTONE (HARD)
100
99%
GRAY, REDDISH-BROWN VERY FINE GRAINED SILTY SANDSTONE (HARD)
100%
REDDISH-BROWN SILTSTONE (HARD)
110
100%
GRAY, REDDISH BROWN SILTY SANDSTONE (HARD)
REDDISH-BROWN SILTSTONE (HARD)
GRAY, REDDISH-BROWN SILTY VERY FINE GRAINED SANDSTONE (HARD)
120
100%
REDDISH-BROWN SILTSTONE (HARD)
80%
GRADING SANDY
130
70%
LOST WATER
GRAY FINE GRAINED SANDSTONE (HARD)
140
95%
GRADING TO MEDIUM GRAINED
150
95%

BORING COMPLETED ON 10-14-69
WATER LEVEL NOT RECORDED

BORING 201

SURFACE ELEVATION +160.5'

DEPTH IN FEET | SAMPLES | BLOW COUNT | SYMBOLS | DESCRIPTIONS

0
16
40
OL
ML
TOPSOIL - REDDISH-BROWN CLAYEY SILT WITH ORGANIC MATTER AND ROCK FRAGMENTS
REDDISH-BROWN CLAYEY SILT WITH A FEW ROCK FRAGMENTS
66%-16%
10
GRADING WITH MORE ROCK FRAGMENTS
TOP OF ROCK @ 6½'
BRUNSWICH SHALE
100%-60%
REDDISH-BROWN SANDY SILTSTONE (MEDIUM HARD) WEATHERED TO 10'
20
SILTSTONE BECOMING HARD AND UNWEATHERED
100%-69%
WEATHERED AND SLIGHTLY DECOMPOSED IN 3" ZONE @ 16'
SOME HAIRLINE CALCITE FILLED BEDDING JOINTS
30
SLIGHTLY WEATHERED
100%-71%
LAYER OF VERY FINE-GRAINED SANDSTONE FROM 28'-29'
GRADING LESS SANDY
40
SLIGHTLY WEATHERED @ 34'
100%-61%
GRADING WITH SOME FINE SAND
GRADING WITH LESS SAND
50
100%-76%
60
GRADING TO REDDISH-BROWN SILTSTONE WITH CALCITE FILLED BEDDING PLANES

LENGTH OF CORE RUN, PERCENT RECOVERY AND R.Q.D.

BORING COMPLETED ON 3-6-70
CASING TO 60'
WATER LEVEL NOT TAKEN
300-LB. HAMMER DROPPED 24"

NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

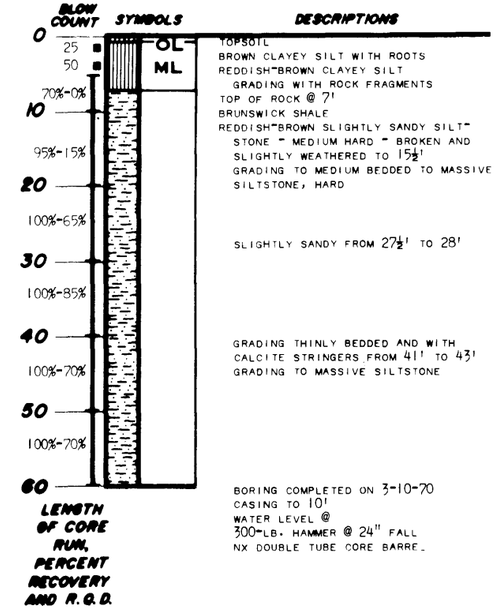
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 12 OF 37

FIGURE 2.5-22

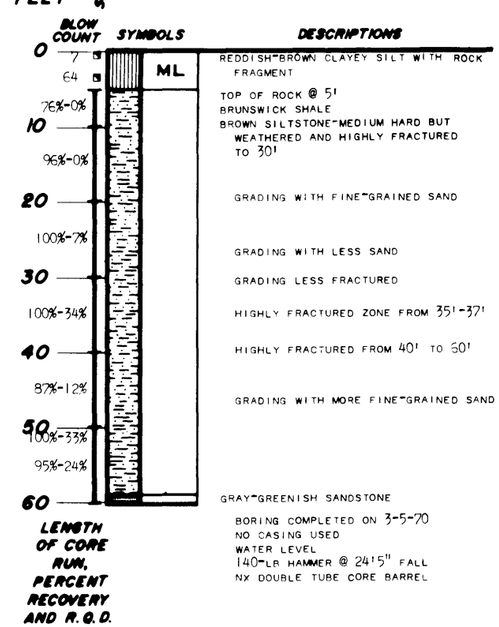
BORING 202

SURFACE ELEVATION +157.2'



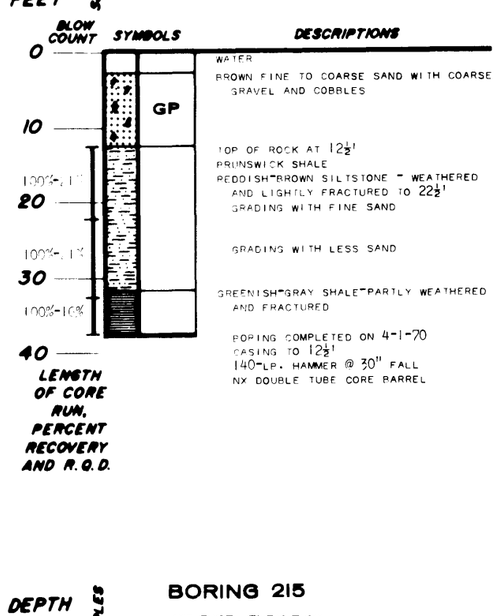
BORING 211

SURFACE ELEVATION +164'



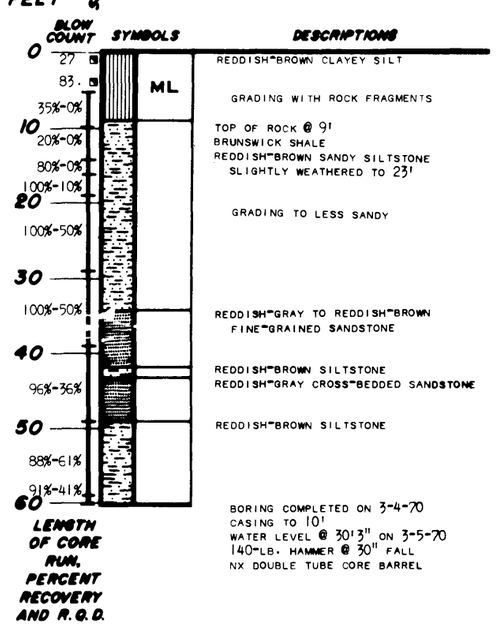
BORING 214

SURFACE ELEVATION +106½'



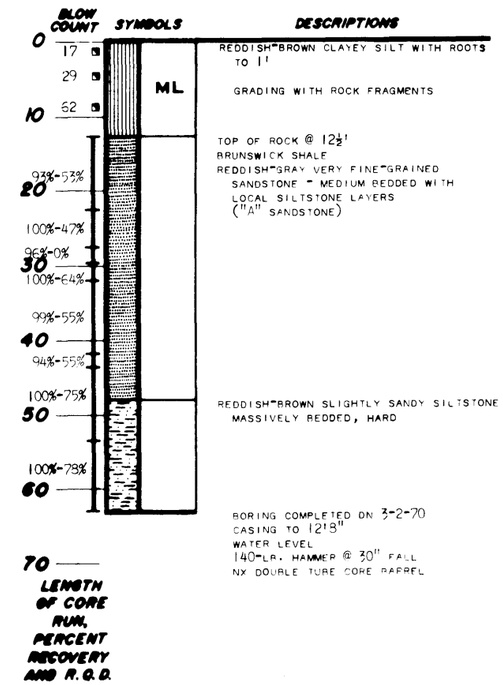
BORING 216

SURFACE ELEVATION +169'



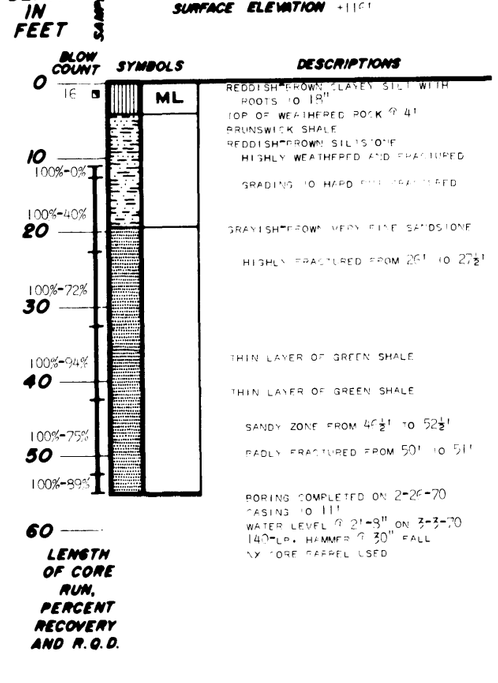
BORING 208

SURFACE ELEVATION +122'



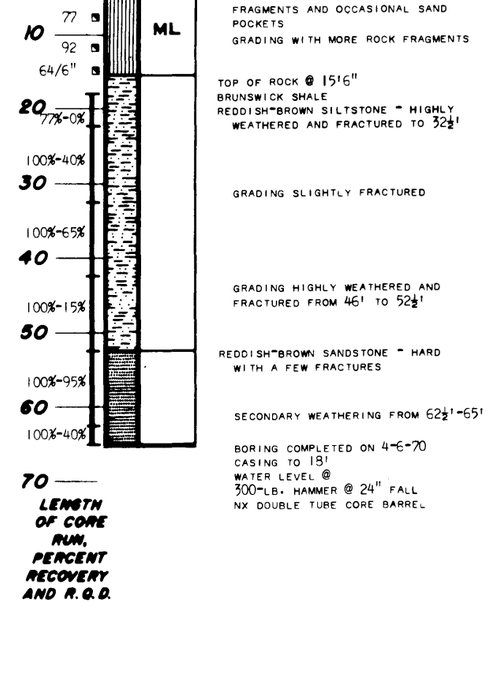
BORING 213

SURFACE ELEVATION +116'



BORING 215

SURFACE ELEVATION



NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

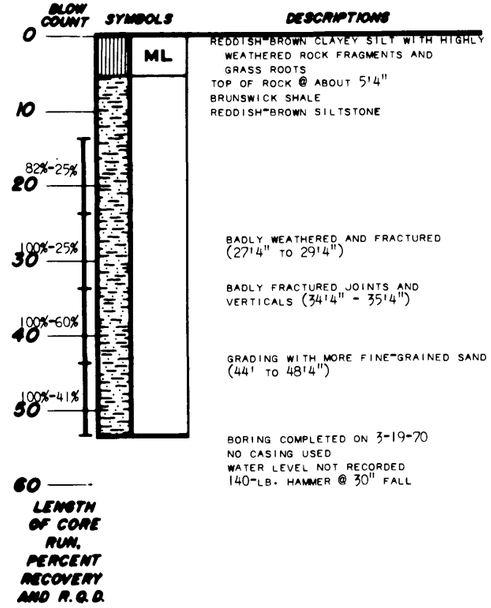
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 13 OF 37

FIGURE 2.5-22

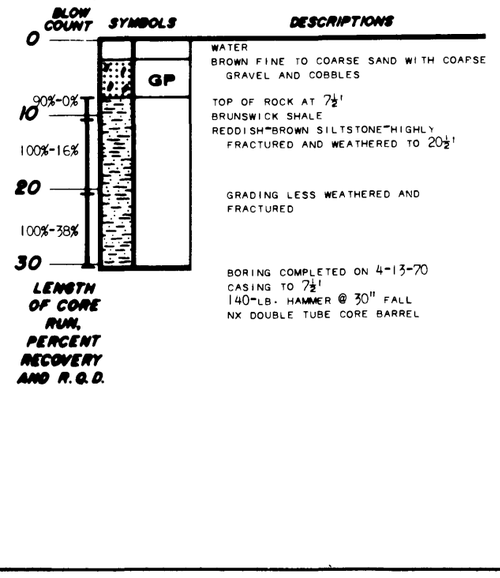
BORING 217

SURFACE ELEVATION +163'



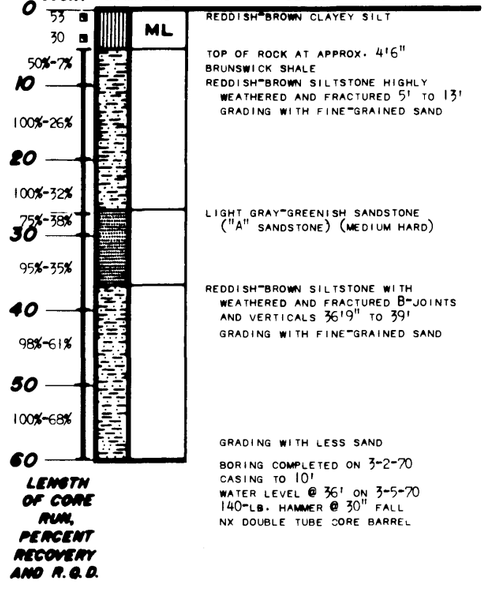
BORING 218

SURFACE ELEVATION +105½'



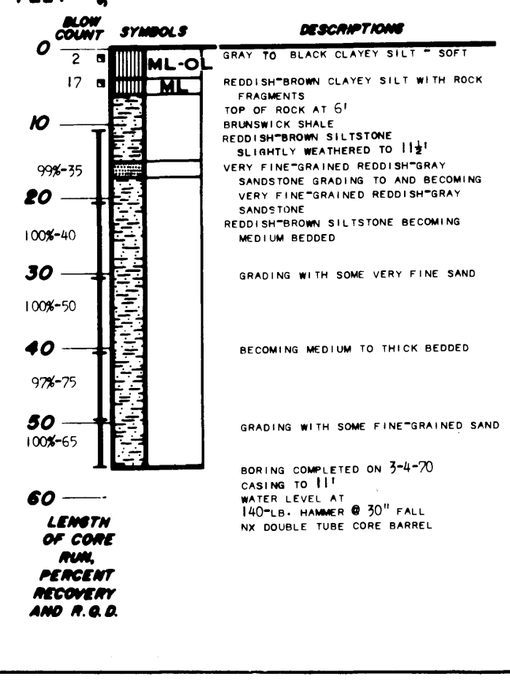
BORING 220

SURFACE ELEVATION +172'



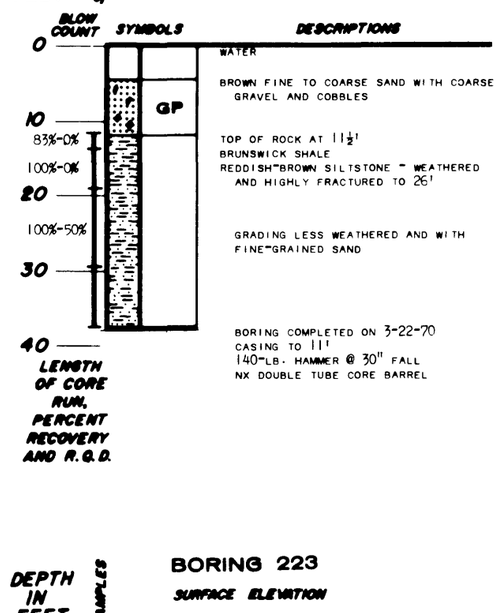
BORING 221

SURFACE ELEVATION +116.7'



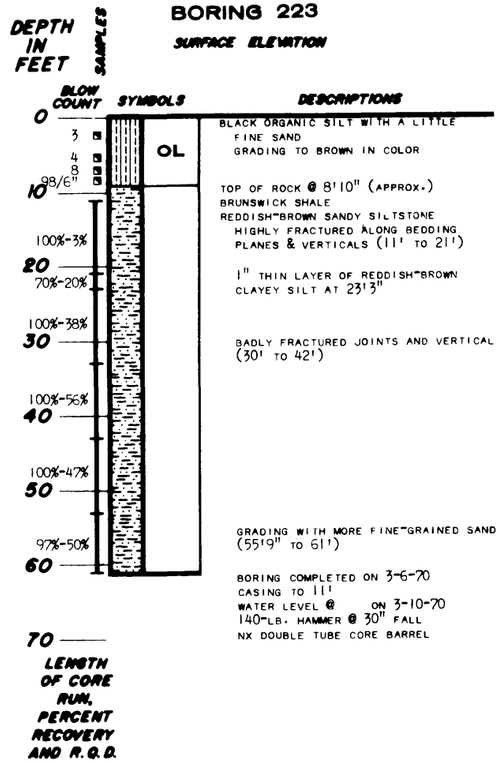
BORING 222

SURFACE ELEVATION +108½'



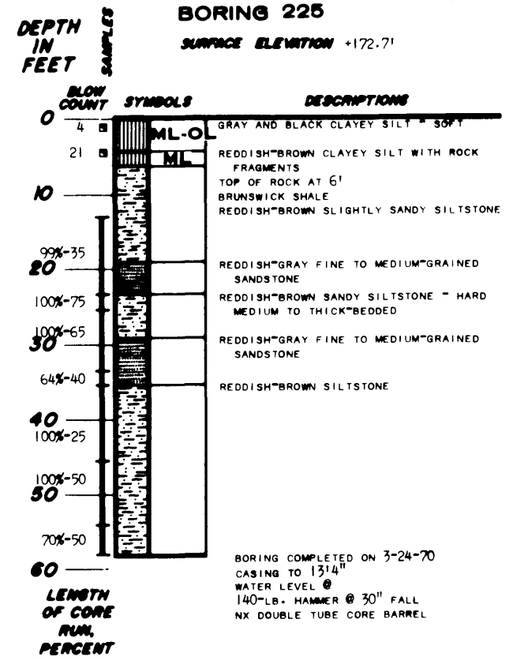
BORING 223

SURFACE ELEVATION



BORING 225

SURFACE ELEVATION +172.7'



NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

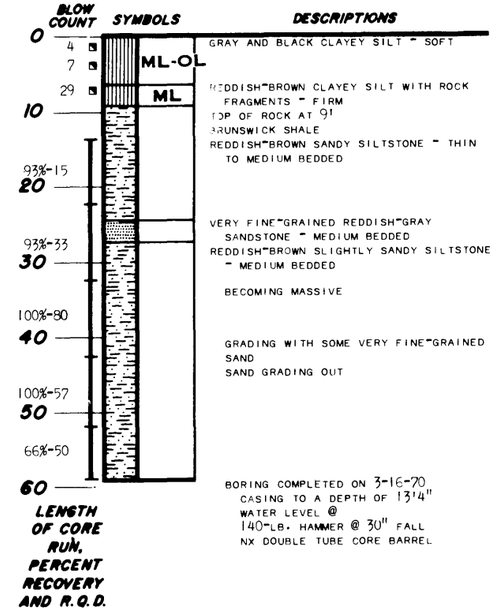
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 14 OF 37

FIGURE 2.5-22

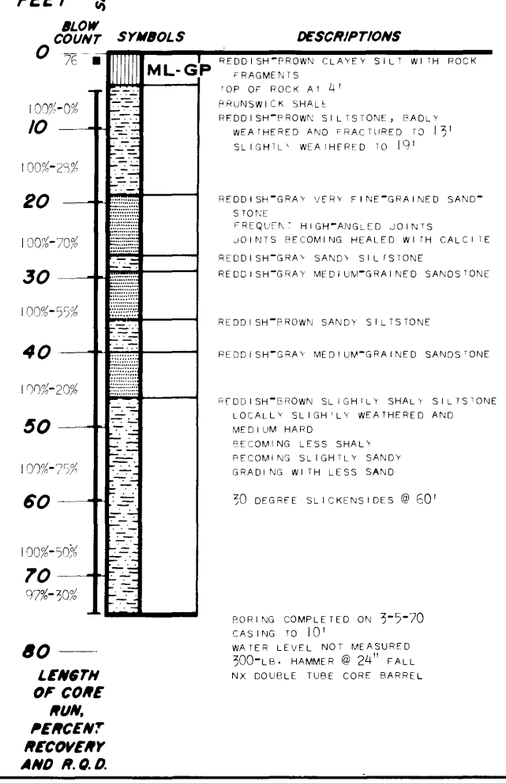
BORING 226

SURFACE ELEVATION +117.0'



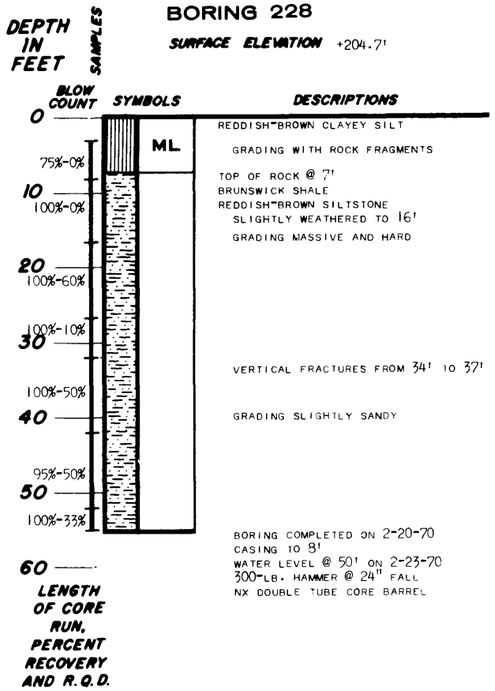
BORING 227

SURFACE ELEVATION +202'



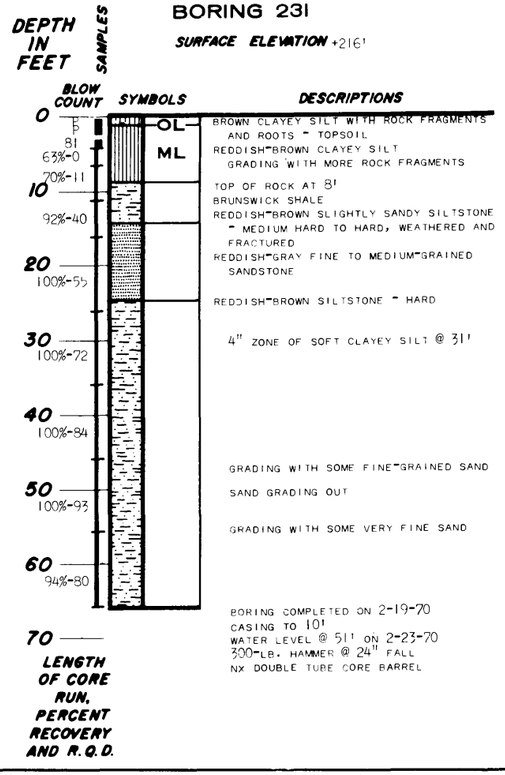
BORING 228

SURFACE ELEVATION +204.7'



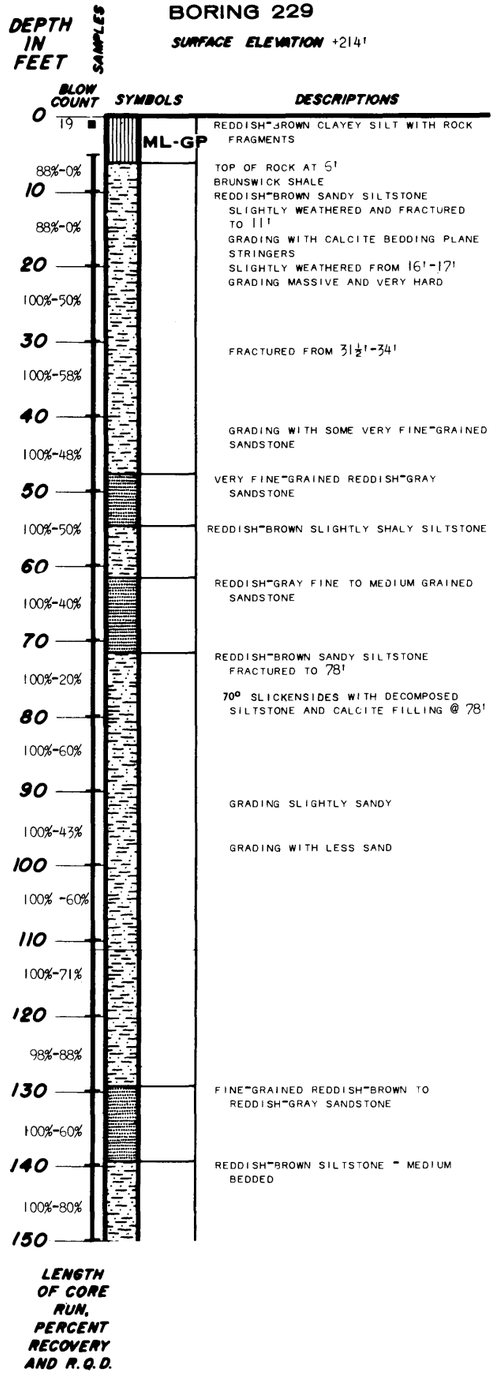
BORING 231

SURFACE ELEVATION +216'

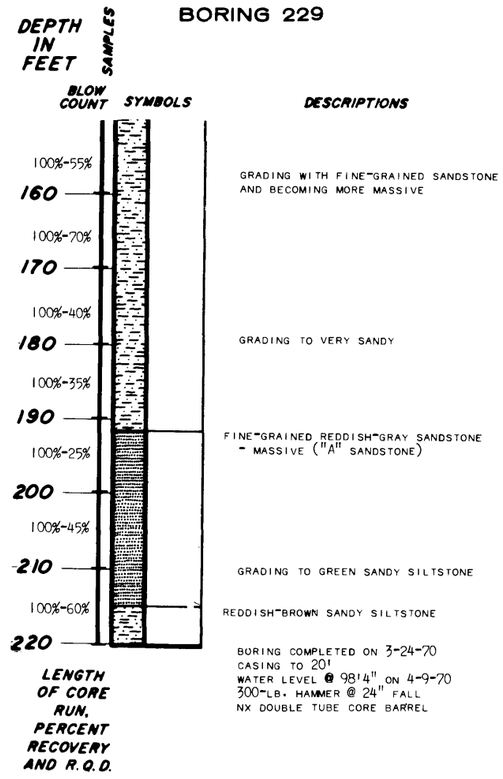


BORING 229

SURFACE ELEVATION +214'



BORING 229



NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

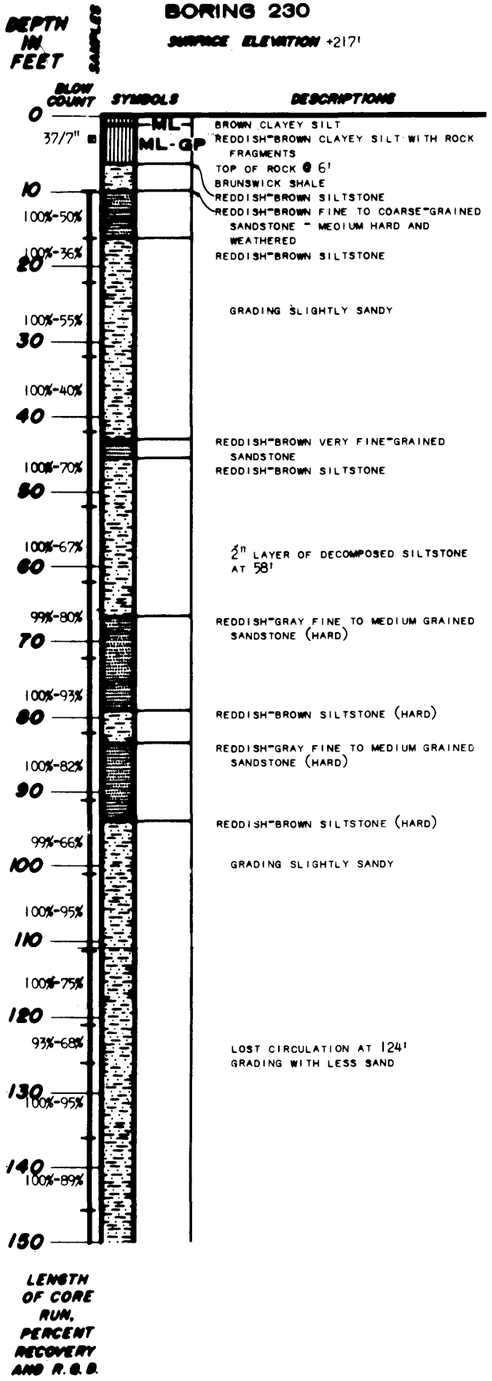
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 15 OF 37

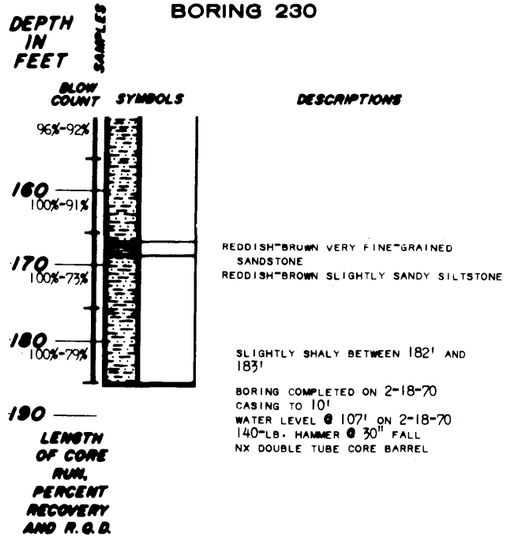
FIGURE 2.5-22

BORING 230

SURFACE ELEVATION +217'

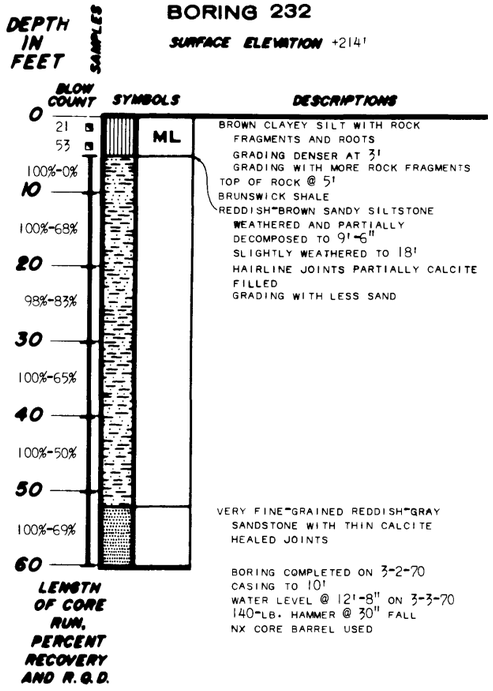


BORING 230



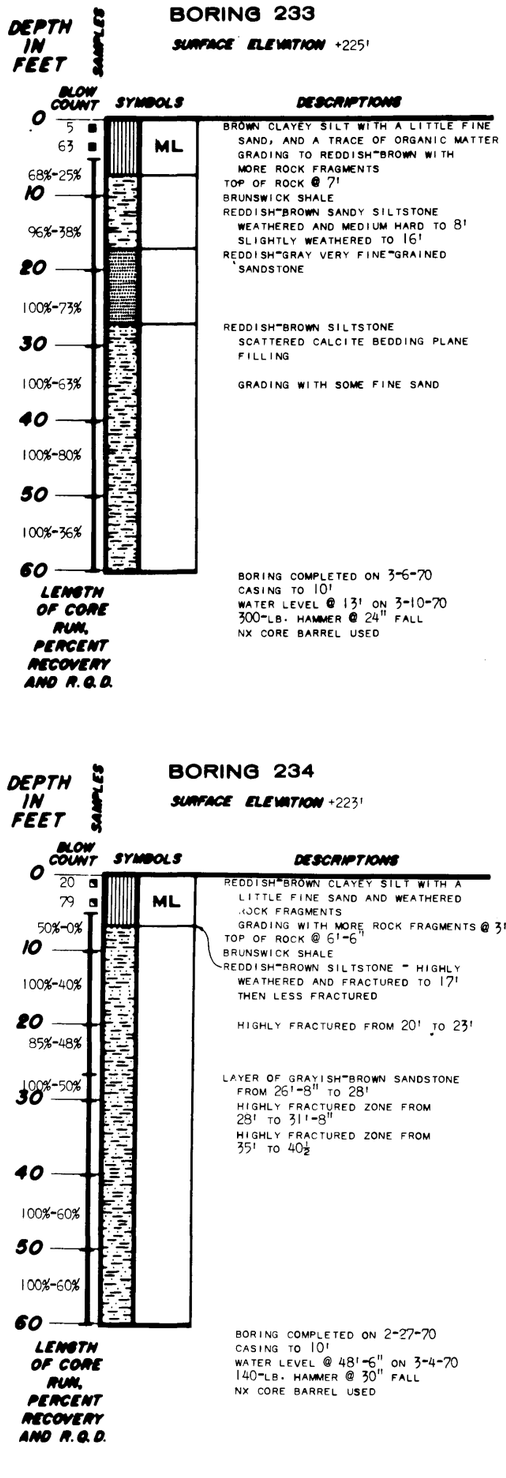
BORING 232

SURFACE ELEVATION +214'



BORING 233

SURFACE ELEVATION +225'

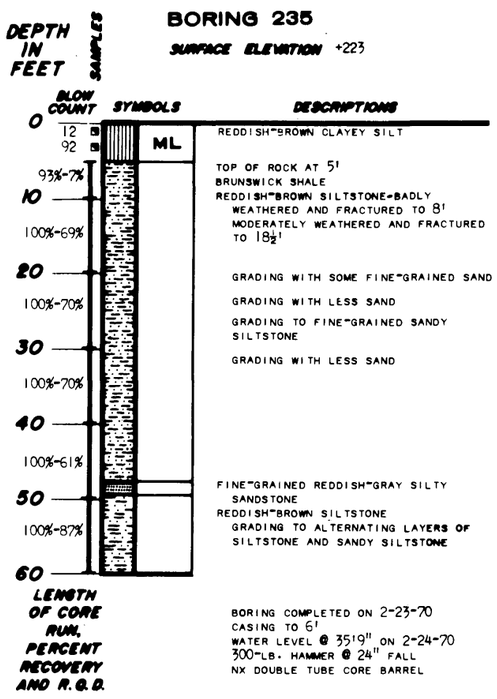


BORING 234

SURFACE ELEVATION +223'

BORING 235

SURFACE ELEVATION +223



NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

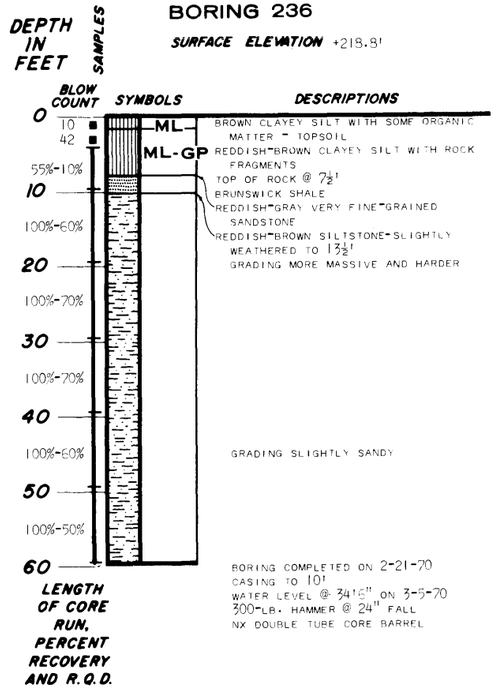
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 16 OF 37

FIGURE 2.5-22

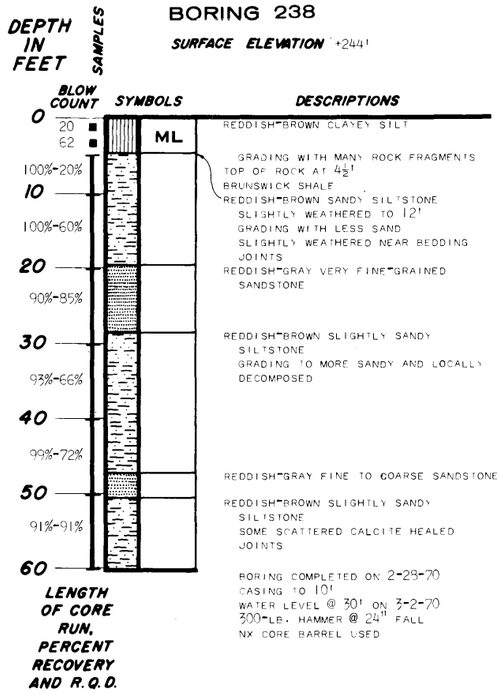
BORING 236

SURFACE ELEVATION +218.8'



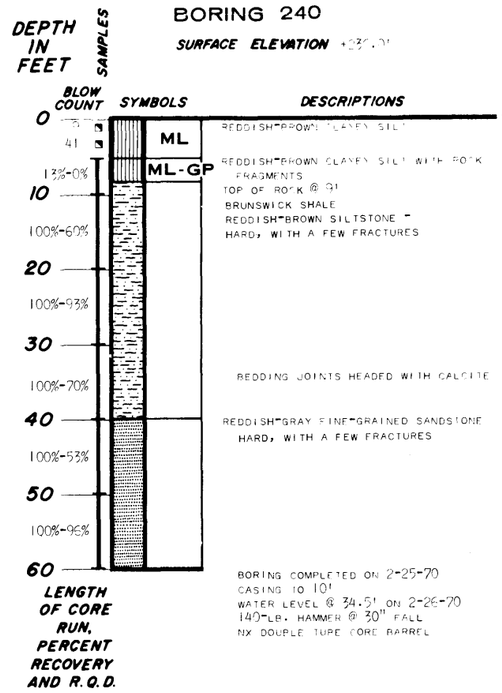
BORING 238

SURFACE ELEVATION +244'



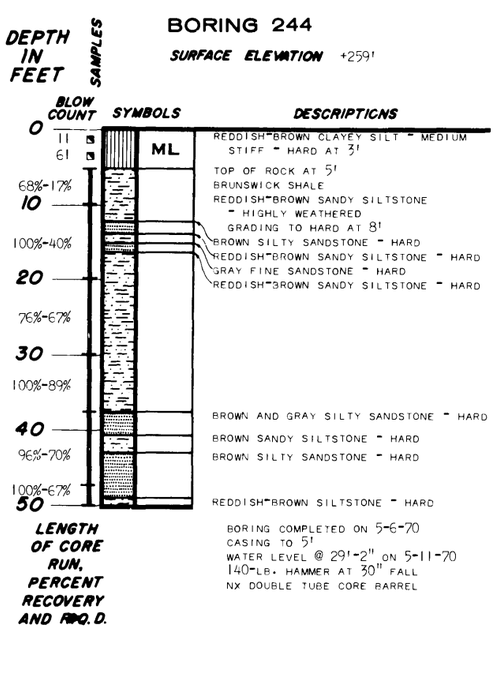
BORING 240

SURFACE ELEVATION +23[illegible].0'



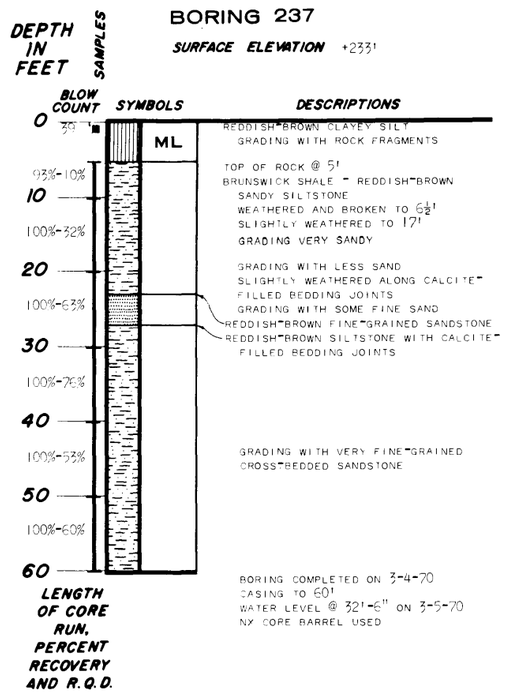
BORING 244

SURFACE ELEVATION +259'



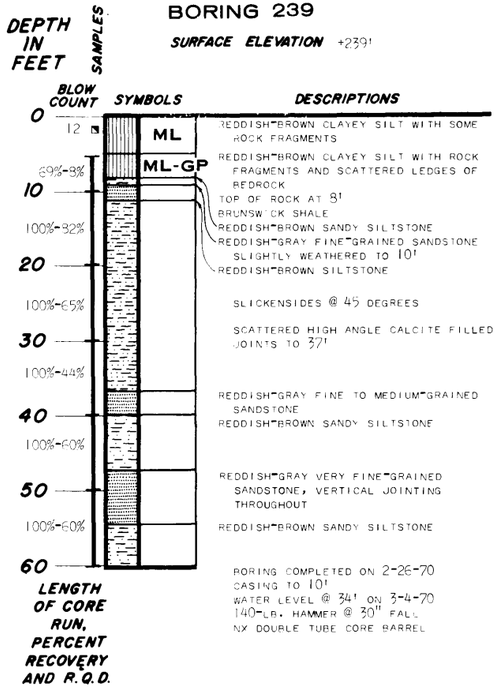
BORING 237

SURFACE ELEVATION +233'



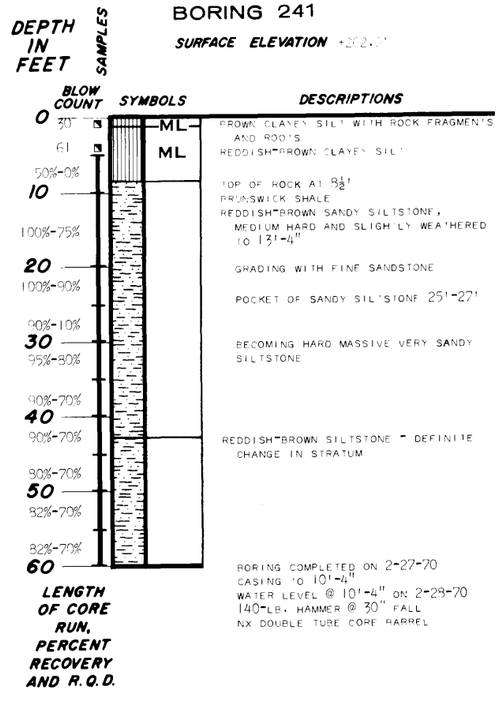
BORING 239

SURFACE ELEVATION +239'



BORING 241

SURFACE ELEVATION +252.3'



NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

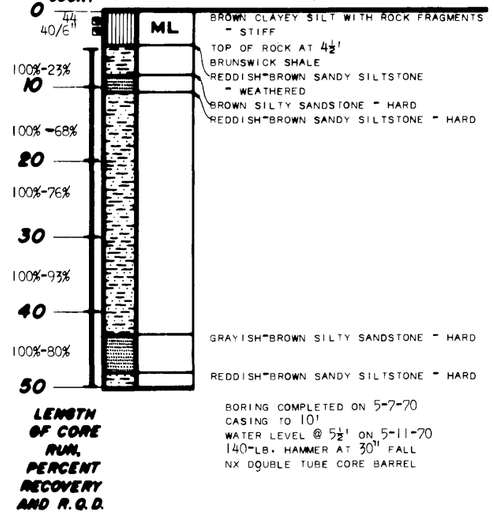
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 17 OF 37

FIGURE 2.5-22

BORING 245

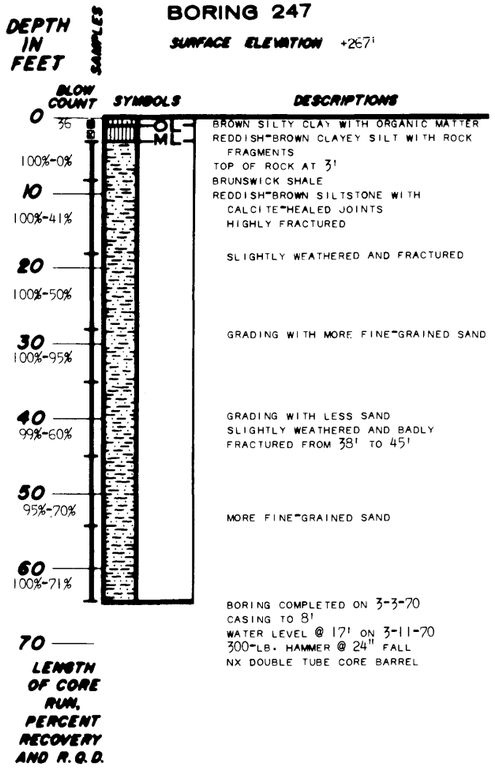
SURFACE ELEVATION +251'±



BORING COMPLETED ON 5-7-70
CASING TO 10'
WATER LEVEL @ 5½' ON 5-11-70
140-LB. HAMMER AT 30" FALL
NX DOUBLE TUBE CORE BARREL

BORING 247

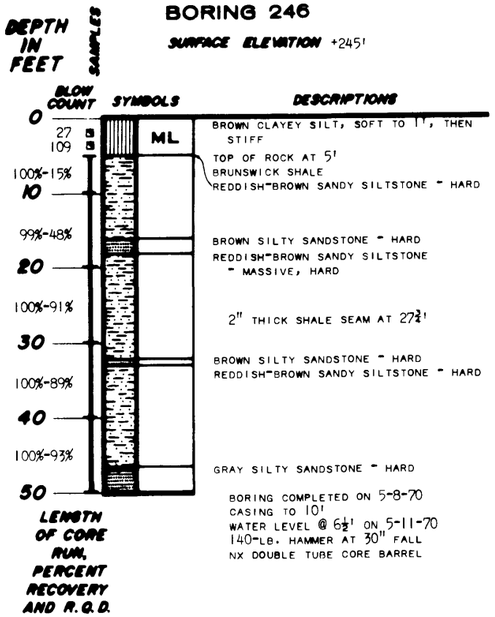
SURFACE ELEVATION +267'



BORING COMPLETED ON 3-3-70
CASING TO 8'
WATER LEVEL @ 17' ON 3-11-70
300-LB. HAMMER @ 24" FALL
NX DOUBLE TUBE CORE BARREL

BORING 246

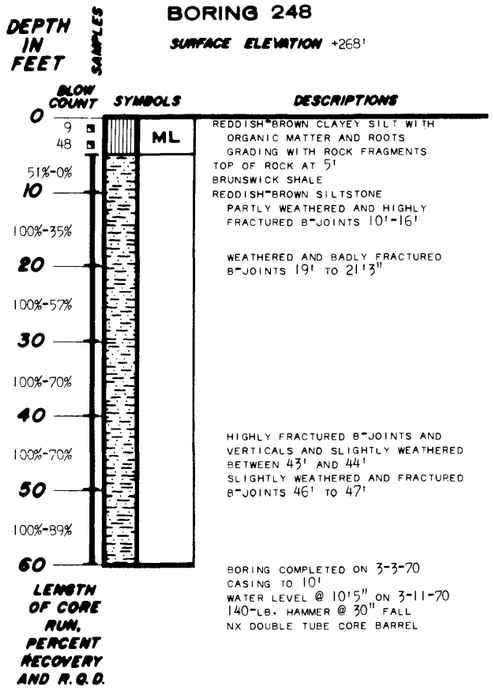
SURFACE ELEVATION +245'



BORING COMPLETED ON 5-8-70
CASING TO 10'
WATER LEVEL @ 6½' ON 5-11-70
140-LB. HAMMER AT 30" FALL
NX DOUBLE TUBE CORE BARREL

BORING 248

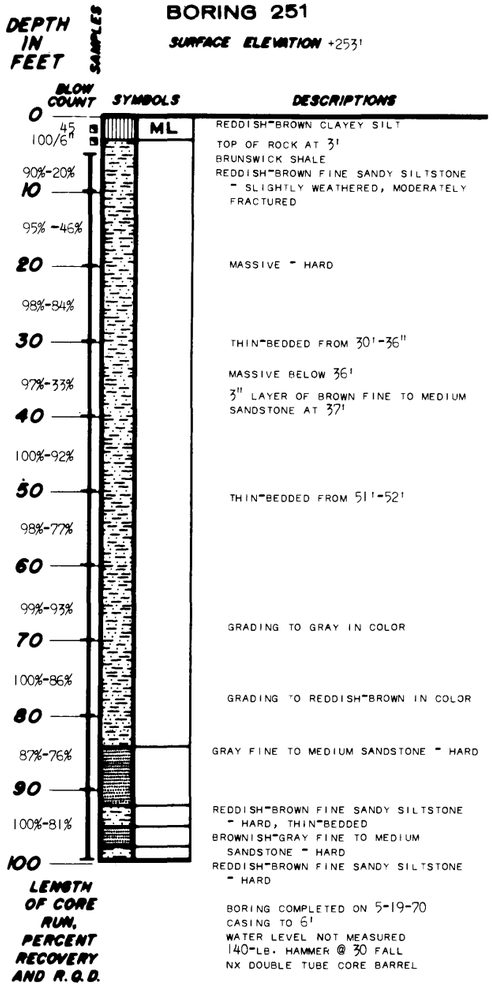
SURFACE ELEVATION +268'



BORING COMPLETED ON 3-3-70
CASING TO 10'
WATER LEVEL @ 10'5" ON 3-11-70
140-LB. HAMMER @ 30" FALL
NX DOUBLE TUBE CORE BARREL

BORING 251

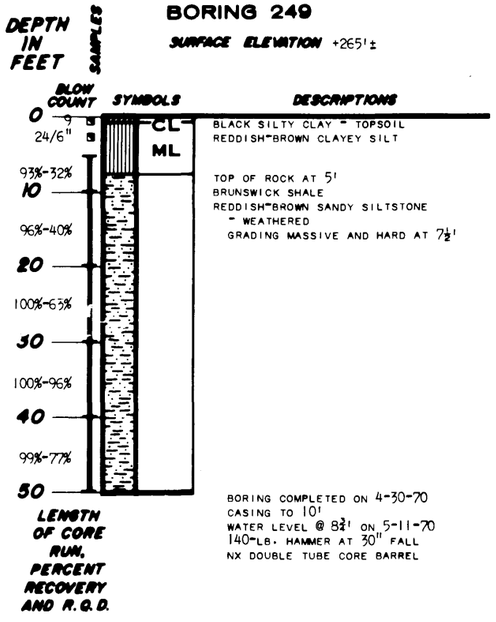
SURFACE ELEVATION +253'



BORING COMPLETED ON 5-19-70
CASING TO 6'
WATER LEVEL NOT MEASURED
140-LB. HAMMER @ 30 FALL
NX DOUBLE TUBE CORE BARREL

BORING 249

SURFACE ELEVATION +265'±



BORING COMPLETED ON 4-30-70
CASING TO 10'
WATER LEVEL @ 8½' ON 5-11-70
140-LB. HAMMER AT 30" FALL
NX DOUBLE TUBE CORE BARREL

NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

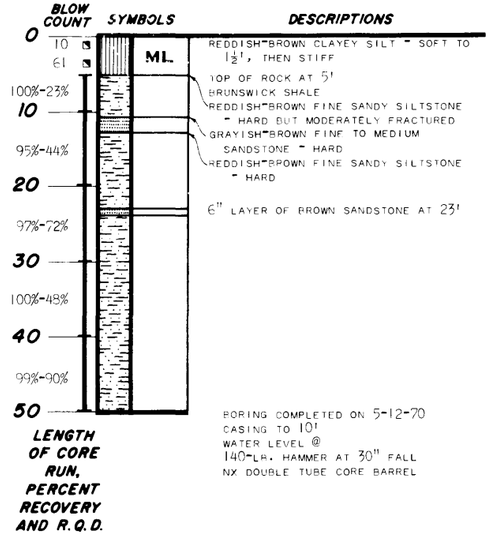
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 18 OF 37

FIGURE 2.5-22

BORING 252

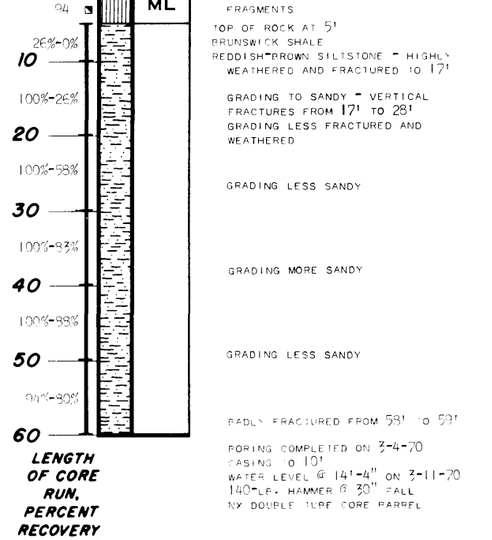
SURFACE ELEVATION +243'



BORING COMPLETED ON 5-12-70
CASING TO 10'
WATER LEVEL @
140-LB. HAMMER AT 30" FALL
NX DOUBLE TUBE CORE BARREL

BORING 254

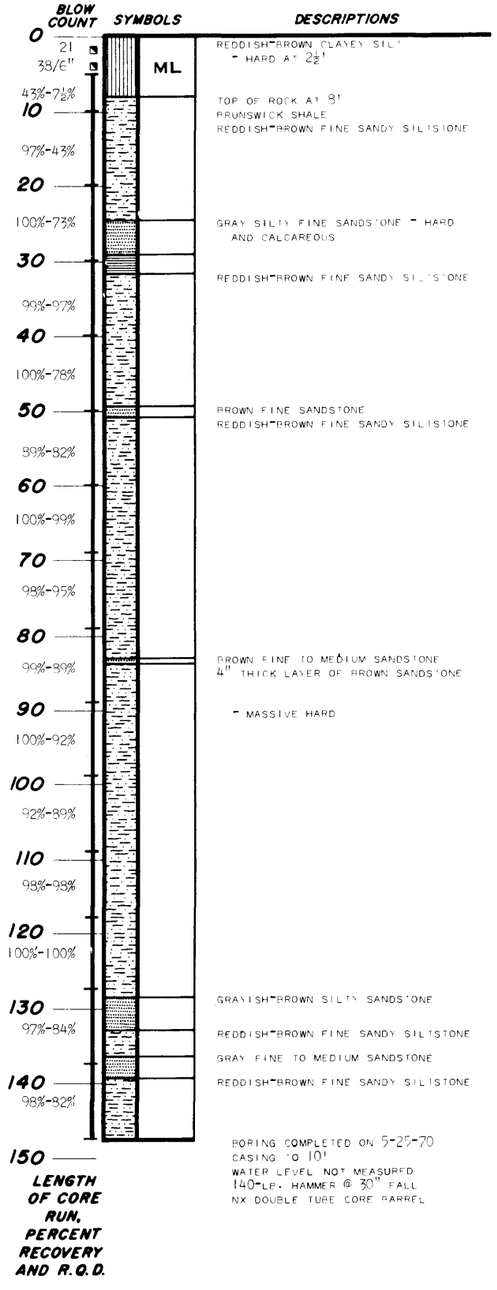
SURFACE ELEVATION +270'±



BORING COMPLETED ON 3-4-70
CASING TO 10'
WATER LEVEL @ 14'-4" ON 3-11-70
140-LB. HAMMER @ 30" FALL
NX DOUBLE TUBE CORE BARREL

BORING 257

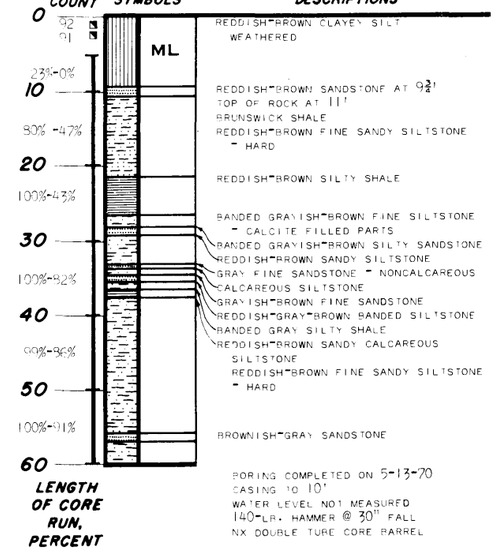
SURFACE ELEVATION +251'



BORING COMPLETED ON 5-25-70
CASING TO 10'
WATER LEVEL NOT MEASURED
140-LB. HAMMER @ 30" FALL
NX DOUBLE TUBE CORE BARREL

BORING 258

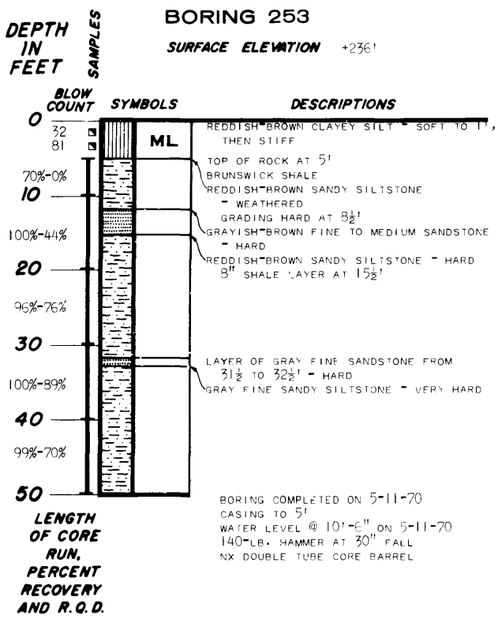
SURFACE ELEVATION +243'



BORING COMPLETED ON 5-13-70
CASING TO 10'
WATER LEVEL NOT MEASURED
140-LB. HAMMER @ 30" FALL
NX DOUBLE TUBE CORE BARREL

BORING 253

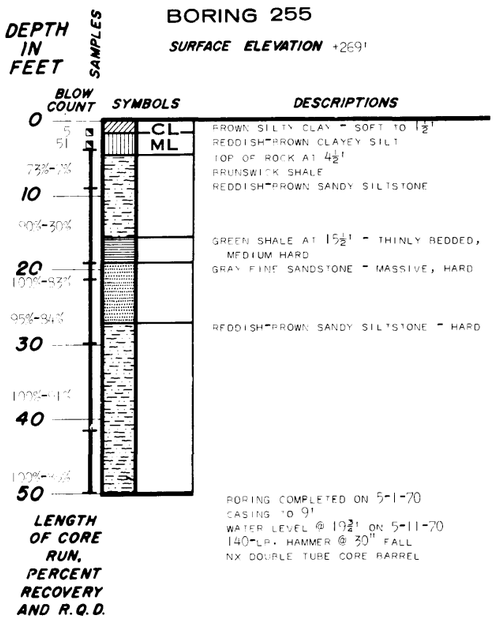
SURFACE ELEVATION +236'



BORING COMPLETED ON 5-11-70
CASING TO 5'
WATER LEVEL @ 10'-6" ON 5-11-70
140-LB. HAMMER AT 30" FALL
NX DOUBLE TUBE CORE BARREL

BORING 255

SURFACE ELEVATION +269'



BORING COMPLETED ON 5-1-70
CASING TO 9'
WATER LEVEL @ 19½' ON 5-11-70
140-LB. HAMMER @ 30" FALL
NX DOUBLE TUBE CORE BARREL

NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

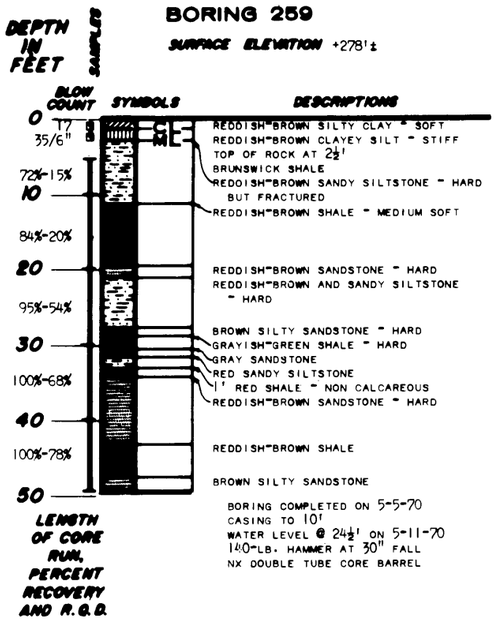
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 19 OF 37

FIGURE 2.5-22

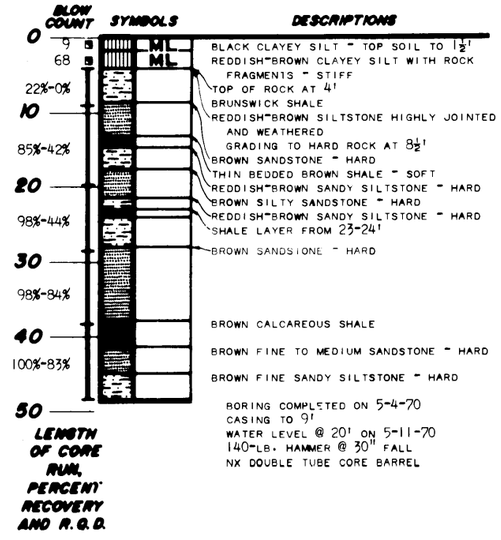
BORING 259

SURFACE ELEVATION +278'±



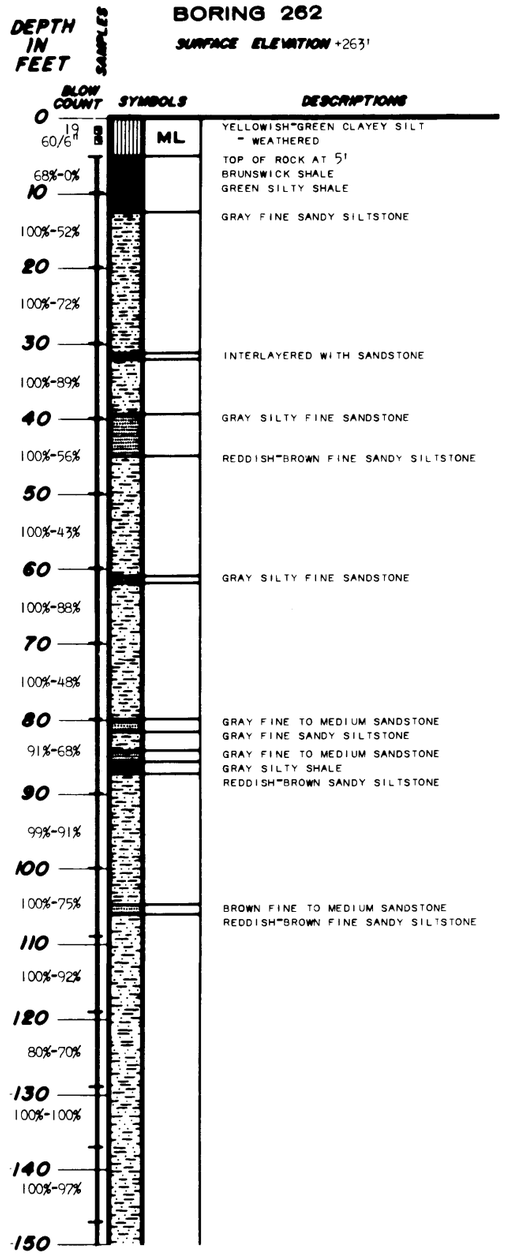
BORING 260

SURFACE ELEVATION +269'



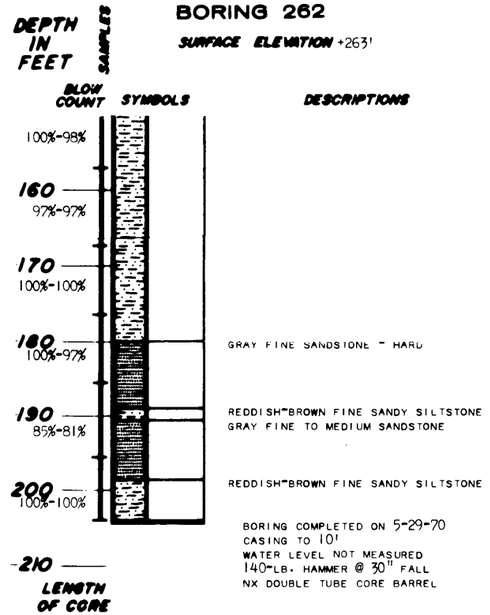
BORING 262

SURFACE ELEVATION +263'



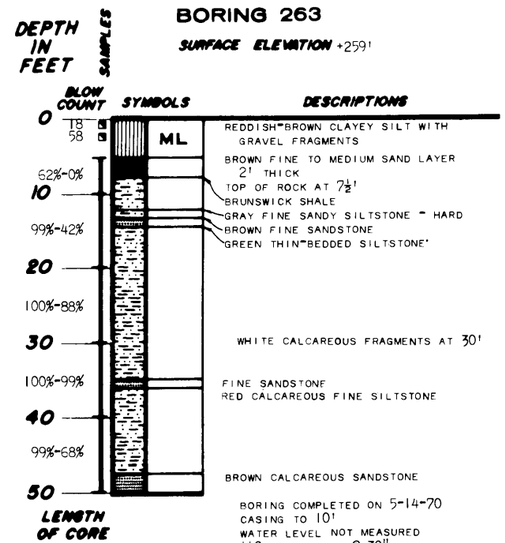
BORING 262

SURFACE ELEVATION +263'



BORING 263

SURFACE ELEVATION +259'



NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

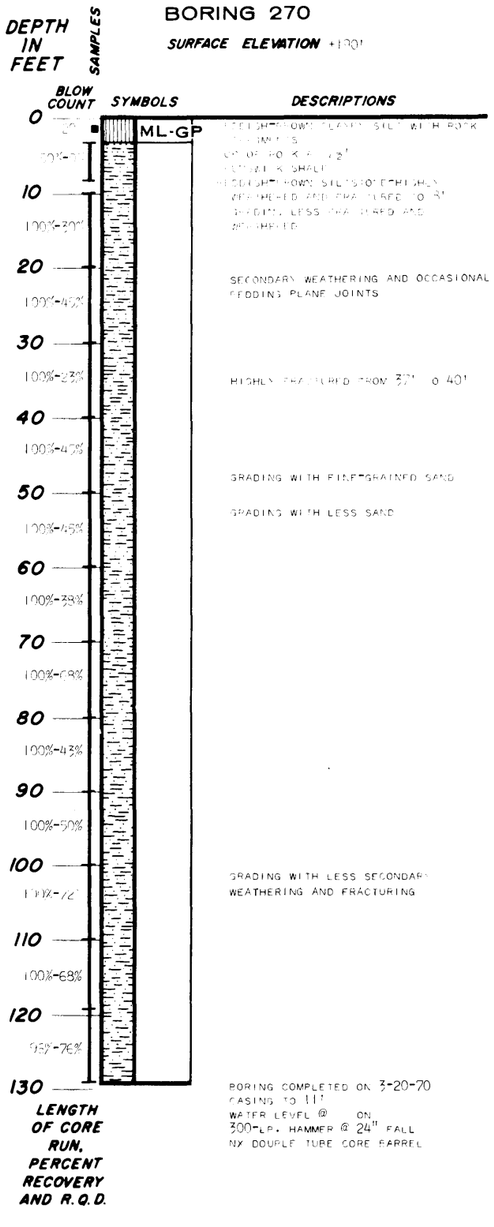
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 20 OF 37

FIGURE 2.5-22

BORING 270

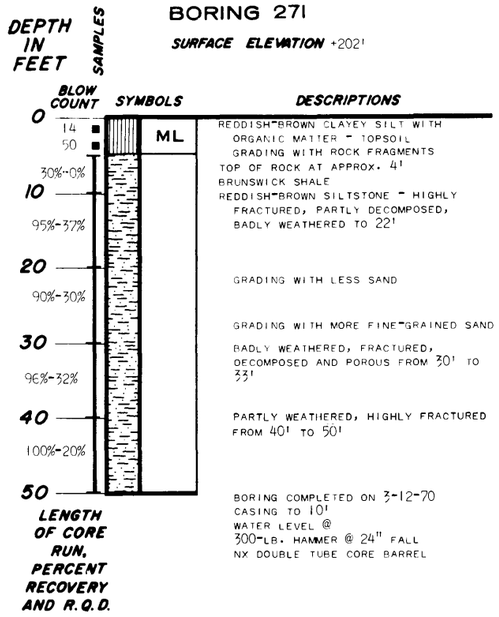
SURFACE ELEVATION +130'



BORING COMPLETED ON 3-20-70
CASING TO 11'
WATER LEVEL @ ON
300-LB. HAMMER @ 24" FALL
NX DOUBLE TUBE CORE BARREL

BORING 271

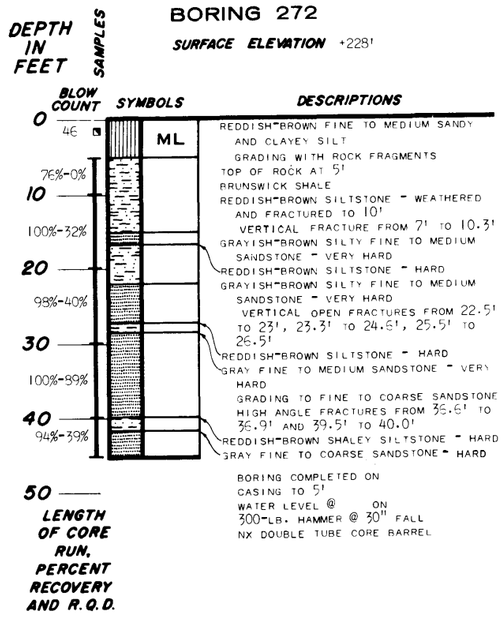
SURFACE ELEVATION +202'



BORING COMPLETED ON 3-12-70
CASING TO 10'
WATER LEVEL @
300-LB. HAMMER @ 24" FALL
NX DOUBLE TUBE CORE BARREL

BORING 272

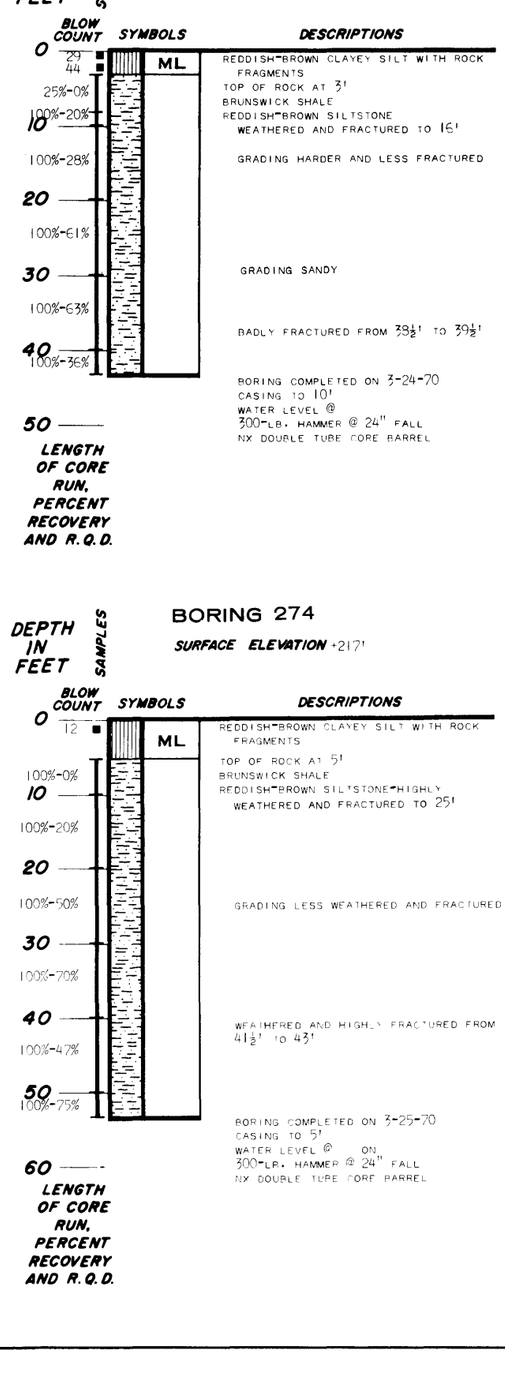
SURFACE ELEVATION +228'



BORING COMPLETED ON
CASING TO 5'
WATER LEVEL @ ON
300-LB. HAMMER @ 30" FALL
NX DOUBLE TUBE CORE BARREL

BORING 273

SURFACE ELEVATION +207'



BORING COMPLETED ON 3-24-70
CASING TO 10'
WATER LEVEL @
300-LB. HAMMER @ 24" FALL
NX DOUBLE TUBE CORE BARREL

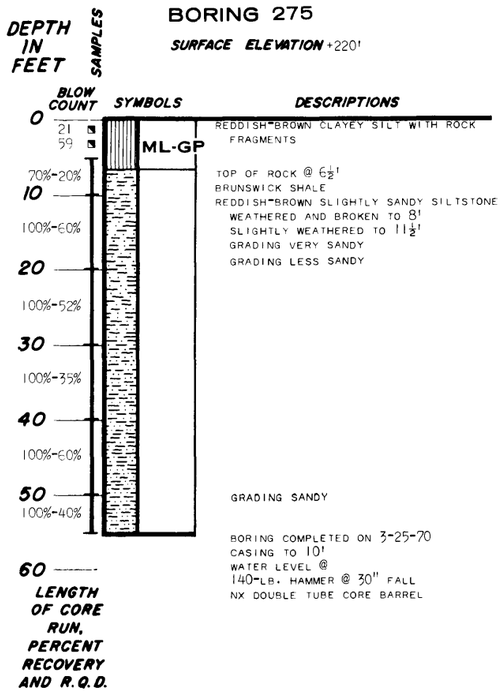
BORING 274

SURFACE ELEVATION +217'

BORING COMPLETED ON 3-25-70
CASING TO 5'
WATER LEVEL @ ON
300-LB. HAMMER @ 24" FALL
NX DOUBLE TUBE CORE BARREL

BORING 275

SURFACE ELEVATION +220'



BORING COMPLETED ON 3-25-70
CASING TO 10'
WATER LEVEL @
140-LB. HAMMER @ 30" FALL
NX DOUBLE TUBE CORE BARREL

NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

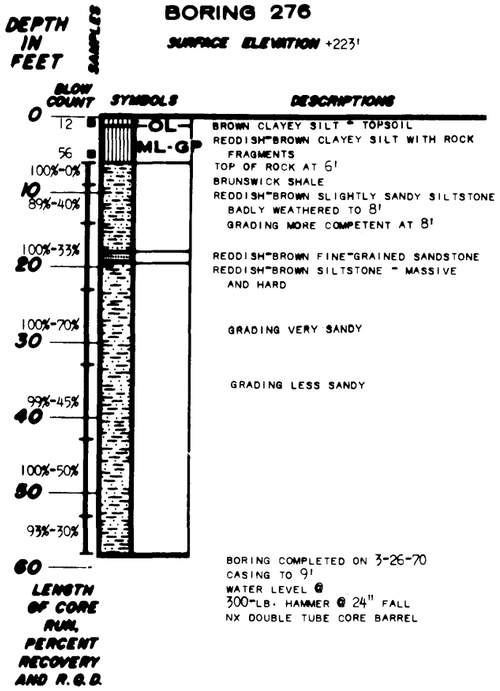
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 21 OF 37

FIGURE 2.5-22

BORING 276

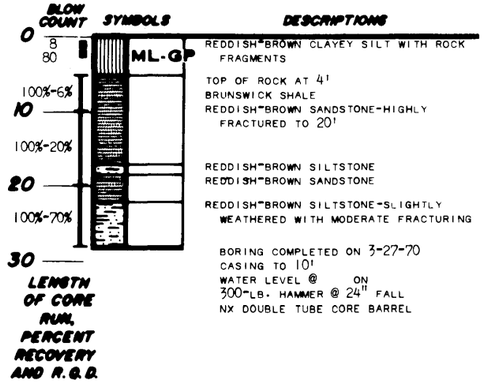
SURFACE ELEVATION +223'



BORING COMPLETED ON 3-26-70
CASING TO 9'
WATER LEVEL @
300-LB. HAMMER @ 24" FALL
NX DOUBLE TUBE CORE BARREL

BORING 277

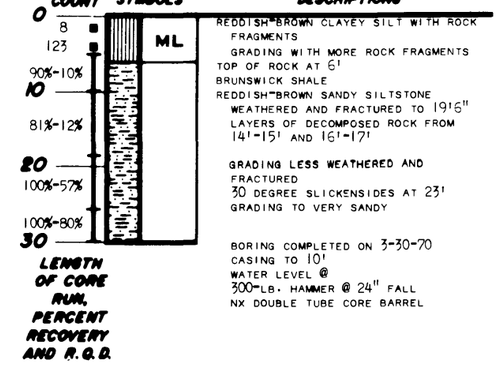
SURFACE ELEVATION +244'



BORING COMPLETED ON 3-27-70
CASING TO 10'
WATER LEVEL @ ON
300-LB. HAMMER @ 24" FALL
NX DOUBLE TUBE CORE BARREL

BORING 278

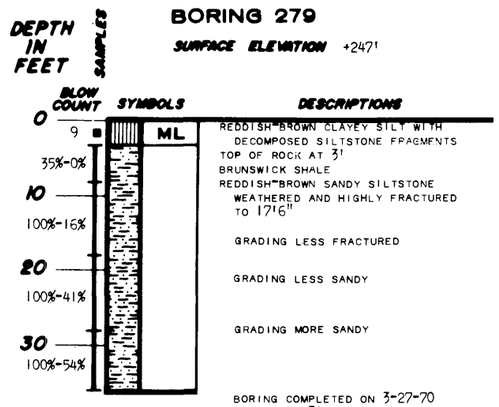
SURFACE ELEVATION +240'



BORING COMPLETED ON 3-30-70
CASING TO 10'
WATER LEVEL @
300-LB. HAMMER @ 24" FALL
NX DOUBLE TUBE CORE BARREL

BORING 279

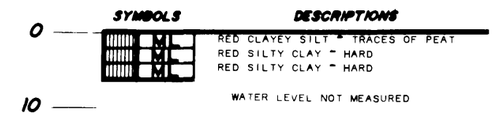
SURFACE ELEVATION +247'



BORING COMPLETED ON 3-27-70
CASING TO 3'
WATER LEVEL @ ON
300-LB. HAMMER @ 24" FALL
NX DOUBLE TUBE CORE BARREL

BORING 281

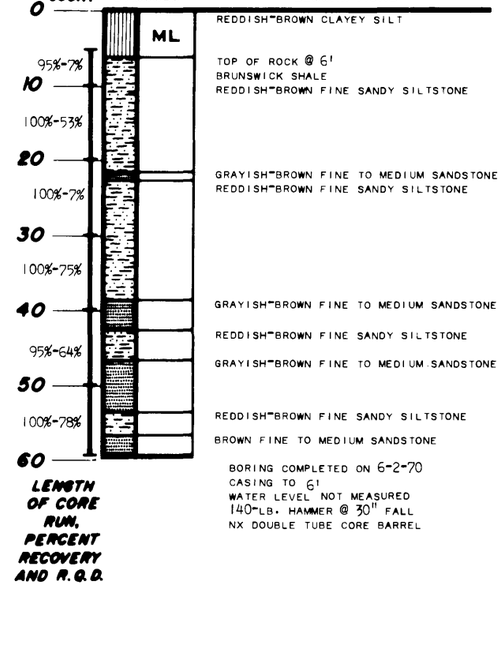
SURFACE ELEVATION +200'



WATER LEVEL NOT MEASURED

BORING 284

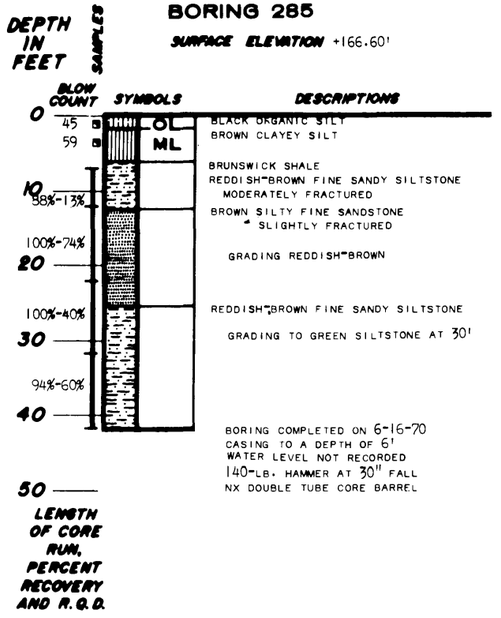
SURFACE ELEVATION +210'



BORING COMPLETED ON 6-2-70
CASING TO 6'
WATER LEVEL NOT MEASURED
140-LB. HAMMER @ 30" FALL
NX DOUBLE TUBE CORE BARREL

BORING 285

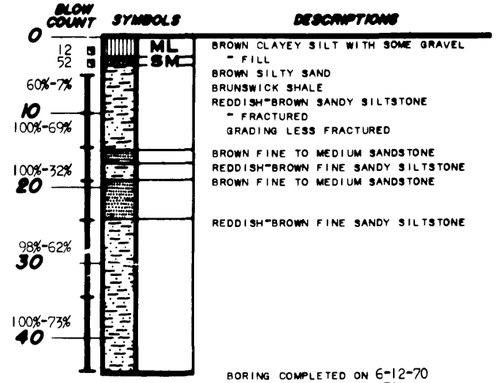
SURFACE ELEVATION +166.60'



BORING COMPLETED ON 6-16-70
CASING TO A DEPTH OF 6'
WATER LEVEL NOT RECORDED
140-LB. HAMMER AT 30" FALL
NX DOUBLE TUBE CORE BARREL

BORING 286

SURFACE ELEVATION +145.8'



BORING COMPLETED ON 6-12-70
CASING TO A DEPTH OF 3'
WATER LEVEL NOT RECORDED
140-LB. HAMMER @ 30" FALL
NX DOUBLE TUBE CORE BARREL

NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

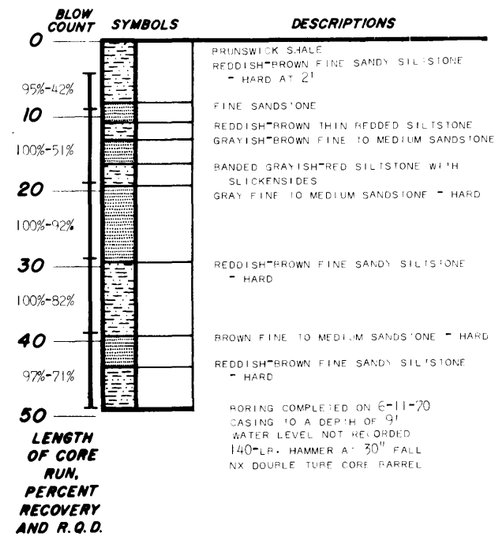
LIMERICK GENERATING STATION
UNITS 1 AND 2
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GRAPHIC LOGS
SHEET 22 OF 37

FIGURE 2.5-22

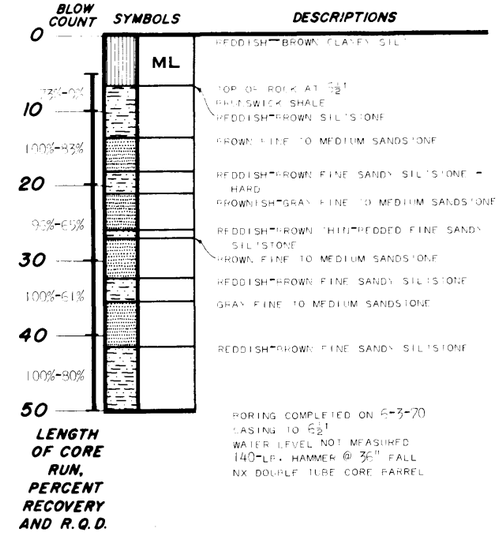
BORING 287

SURFACE ELEVATION +146.46'



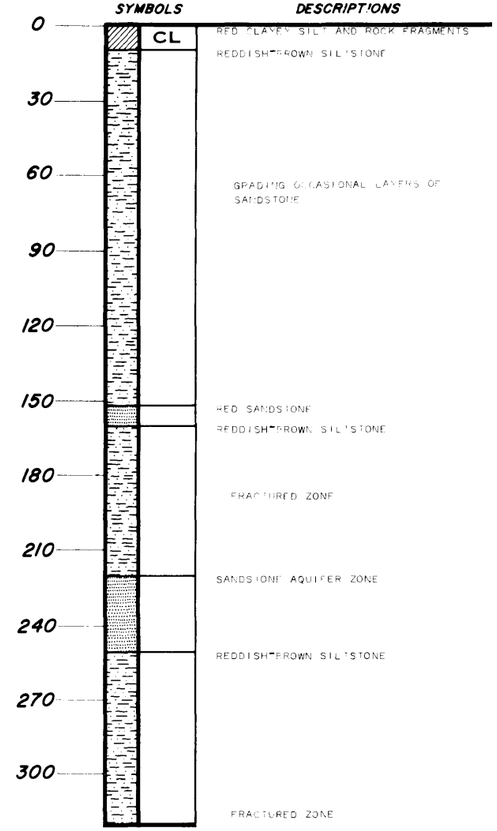
BORING 289

SURFACE ELEVATION +203'



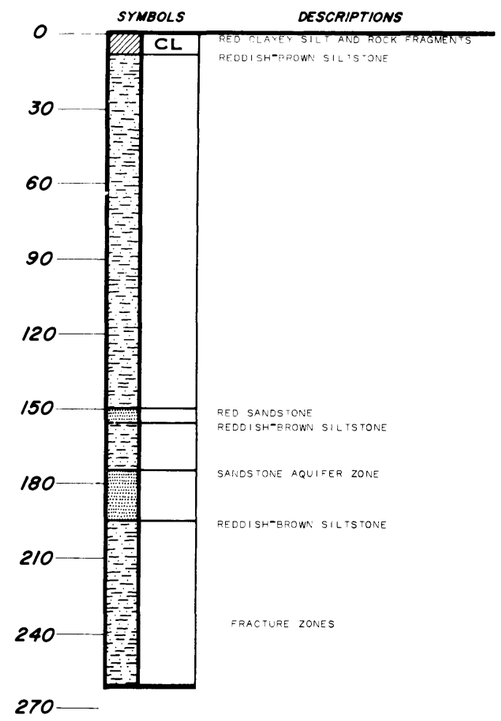
BORING 300 - LOG OF TEST WELL

SURFACE ELEVATION +230'±



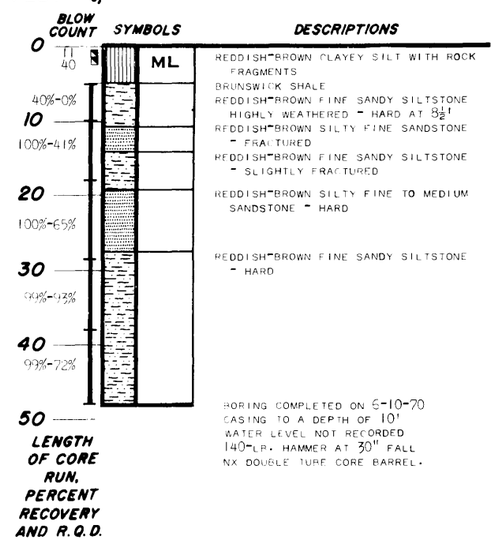
BORING 301 - LOG OF TEST WELL

SURFACE ELEVATION +214'±



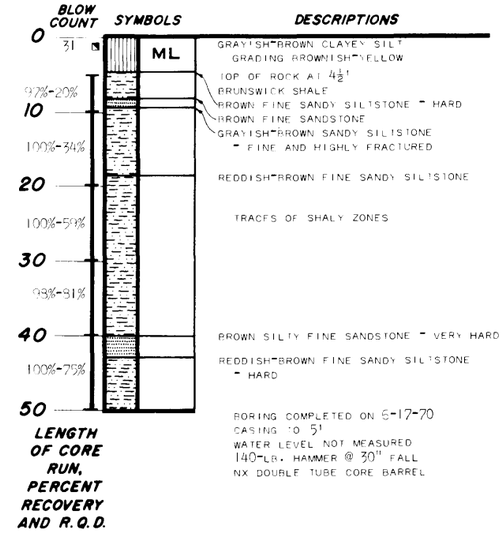
BORING 288

SURFACE ELEVATION +171.29'



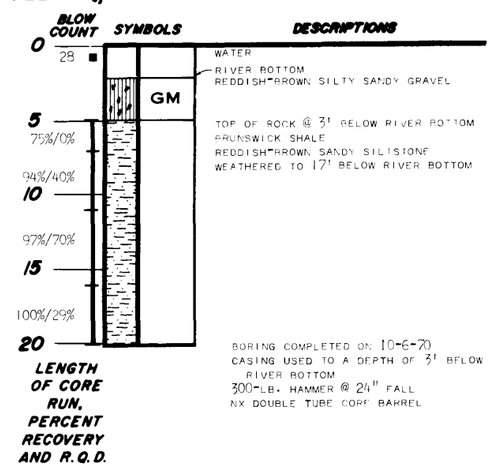
BORING 290

SURFACE ELEVATION +231'



BORING 302

SURFACE ELEVATION RIVER BOTTOM - +105.8'±



NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

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GRAPHIC LOGS
SHEET 23 OF 37

FIGURE 2.5-22

BORING 303

SURFACE ELEVATION RIVER BOTTOM = +105.3'±

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	11			WATER
				RIVER BOTTOM REDDISH-BROWN MEDIUM TO COARSE SILTY SAND WITH GRAVEL
5	47		SM	
	53/9"			
10	100%/0%			TOP OF ROCK @ 7'9" BELOW RIVER BOTTOM BRUNSWICK SHALE REDDISH-BROWN SILTSTONE WEATHERED AND FRACTURED TO 12½' BELOW RIVER BOTTOM
	100%/0%			
15	100%/66%			GRADING GRAYISH-BROWN @ 15' BELOW RIVER BOTTOM AND MORE SANDY
20	100%/69%			
25	100%/85%			BORING COMPLETED ON 10-5-70 CASING USED TO A DEPTH OF 9' BELOW RIVER BOTTOM 300-LB. HAMMER @ 24" FALL
30				

LENGTH OF CORE RUN, PERCENT RECOVERY AND R.Q.D.

BORING 304

SURFACE ELEVATION +23.9'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	34			REDDISH-BROWN SANDY SILT
5	14		ML	
10	23			
15	42/10"			TOP OF ROCK @ 16'3" BRUNSWICK SHALE REDDISH-BROWN SANDY SILTSTONE WEATHERED TO 22'
	100%/0%			
20	100%/33%			
	100%/47%			
25	100%/32%			BORING COMPLETED ON 9-22-70 CASING TO 16'3" WATER LEVEL @ 4'4" ON 9-22-70 300-LB. HAMMER @ 24" FALL NX DOUBLE TUBE CORE BARREL
30				

LENGTH OF CORE RUN, PERCENT RECOVERY AND R.Q.D.

BORING 305

SURFACE ELEVATION +121.5'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	31			TOPSOIL REDDISH-BROWN SANDY SILT WITH ROCK FRAGMENTS LARGE FRAGMENT OF ROCK @ 2' TO 5'
	50%/0%			
	37%/0%			
5	13		ML	
10	21			
15	22			TOP OF ROCK @ 15'11" BRUNSWICK SHALE REDDISH-BROWN SANDY SILTSTONE WEATHERED TO 19½' GRADING WITH LESS SAND @ 19½' BECOMING REDDISH-BROWN SILTSTONE WITH CALCAREOUS INCLUSIONS AND HAIRLINE CALCITE BEDDING FILLINGS. BECOMING SLIGHTLY SANDY @ 21½' BECOMING LESS SANDY @ 25'
	94%/0%			
20	100%/50%			
25	100%/66%			BORING COMPLETED ON 9-21-70 CASING USED TO A DEPTH OF 16' WATER LEVEL @ 6' ON 9-22-70 300-LB. HAMMER @ 24" FALL NX DOUBLE TUBE CORE BARREL

BORING 306

SURFACE ELEVATION +140.1'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	7			FILL - CINDERS WITH SOME SANDY SILT
5	24		ML	REDDISH-BROWN SANDY SILT TOP OF ROCK @ 5' BRUNSWICK SHALE REDDISH-BROWN FINE GRAINED SANDSTONE WITH SANDY SILTSTONE WEATHERED TO 27'
	67%/0%			
	73%/0%			
10	53%/3%			SANDSTONE GRADING MORE COARSE, SLIGHTLY PITTED, MORE WEATHERED
	67%/0%			
15	35%/18%			
	33%/0%			WEATHERED, BROKEN AND DECOMPOSED 19' TO 27'
20	50%/18%			
25	88%/14%			REDDISH-BROWN SANDY SILTSTONE
30	81%/0%			
	100%/75%			BECOMING HARD @ 35'
35	100%/75%			
	100%/90%			
40	89%/60%			GRADING WITH MORE SAND @ 45'
	100%/60%			
45	100%/0%			GRADING WITH LESS SAND @ 49½'
	100%/61%			
50				BORING COMPLETED ON 9-25-70 CASING USED TO A DEPTH OF 5½' WATER LEVEL NOT RECORDED 300-LB. HAMMER @ 24" FALL NX DOUBLE TUBE CORE BARREL

LENGTH OF CORE RUN, PERCENT RECOVERY AND R.Q.D.

BORING 307

SURFACE ELEVATION +141.9'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	34		ML	FILL - CINDERS AND SILTY SAND REDDISH-BROWN SANDY SILT TOP OF ROCK @ 2½' BRUNSWICK SHALE REDDISH-BROWN SANDY SILTSTONE WEATHERED TO 5½', VERY FRACTURED TO 4½'
5	100%/29%			
	100%/70%			
10	100%/60%			
15	100%/70%			
20	100%/80%			VERY FRACTURED @ 21' TO 22'
25	100%/80%			
30	100%/80%			VUGGY AND WEATHERED @ 29' TO 29½'
35	100%/95%			
40	100%/90%			
45	93%/90%			GRADING WITH LESS SAND
50	98%/90%			BORING COMPLETED ON 10-1-70 CASING USED TO A DEPTH OF 5½' WATER LEVEL @ 12'4" ON 10-1-70 300-LB. HAMMER @ 24" FALL NX DOUBLE TUBE CORE BARREL

LENGTH OF CORE RUN, PERCENT RECOVERY AND R.Q.D.

BORING 308

SURFACE ELEVATION +141.7'

DEPTH IN FEET	BLOW COUNT	SAMPLES	SYMBOLS	DESCRIPTIONS
0	10		ML	FILL - CINDERS REDDISH-BROWN SANDY SILT TOP OF ROCK @ 2'3" BRUNSWICK SHALE LIGHT GRAY FINE GRAINED SANDSTONE
	95%/35%			WEATHERED TO 8'
5	89%/59%			
10	88%/60%			GRADING TO REDDISH-BROWN SANDY SILTSTONE @ 10'
15	100%/50%			SAND GRADING OUT @ 17'
20	100%/91%			
25	100%/100%			
30	93%/80%			
35	100%/100%			
40	100%/70%			VERY FRACTURED @ 40½' TO 41½' VERY SANDY @ 43½' TO 44'
45	100%/90%			
50	81%/64%			BORING COMPLETED ON 10-2-70 CASING USED TO A DEPTH OF 2'3" WATER LEVEL @ 26'7" ON 10-5-70 300-LB. HAMMER @ 24" FALL NX DOUBLE TUBE CORE BARREL

NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

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GRAPHIC LOGS
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FIGURE 2.5-22

BORING 309

SURFACE ELEVATION +184.2'

DEPTH IN FEET	BLOW COUNT / SAMPLES	SYMBOLS	DESCRIPTIONS
0	37	ML	REDDISH-BROWN SANDY SILT
			GRADING WITH ROCK FRAGMENTS
5	86		
10	100%/0%		TOP OF ROCK @ 10' BRUNSWICK SHALE REDDISH-BROWN SANDY SILTSTONE WEATHERED TO 24'-6"
15	100%/80%		
20	94%/33%		
25	100%/80%		
30	100%/60%		
35	100%/95%		GRADING TO REDDISH-GRAY FINE-GRAINED SANDSTONE @ 35½'
40	100%/70%		GRADING GRAYISH-BROWN @ 39'
45	100%/16%		GRADING TO DARK REDDISH-BROWN @ 42'
50	100%/85%		GRADING TO REDDISH-BROWN SILTSTONE @ 47'
55	100%/67%		GRADING WITH SOME FINE SAND @ 55'
60	100%/70%		GRAYISH-BROWN SANDSTONE FROM 60'-66'
65	100%/46%		GRADING TO REDDISH-BROWN SILTSTONE @ 66' BECOMING SANDY SILTSTONE @ 68½'
70	100%/90%		
75	100%/100%		
80	100%/40%		
85	100%/57%		
90	100%/95%		
	100%/85%		

BORING COMPLETED ON 10-8-70
CASING USED TO A DEPTH OF 14'
WATER LEVEL NOT RECORDED
300-LB. HAMMER @ 24" FALL
NX DOUBLE TUBE CORE BARREL

LENGTH OF CORE RUN, PERCENT RECOVERY AND R.Q.D.

BORING 310

SURFACE ELEVATION +140.4'

DEPTH IN FEET	BLOW COUNT / SAMPLES	SYMBOLS	DESCRIPTIONS
0	8	FILL	FILL - CINDERS
			GRADES TO SANDY SILT WITH ROCK FRAGMENTS AND OCCASIONAL CINDERS
5	13		
10	7	ML	
	7		REDDISH-BROWN SANDY SILT WITH ROCK FRAGMENTS
15	14		
20	100%/0%		TOP OF ROCK @ 18½' BRUNSWICK SHALE REDDISH-BROWN SANDY SILTSTONE SLIGHTLY WEATHERED TO 22'. VERY FRACTURED TO 21'
	100%/0%		
	100%/60%		
25	100%/68%		
30	100%/45%		VUGGY @ 31' TO 31½', WEATHERED CALCACEOUS INCLUSIONS
35	100%/75%		
	100%/90%		
40	100%/35%		GRADING BLUISH-GRAY AND MORE SANDY @ 42'
45	100%/80%		
	79%/0%		VERY FRACTURED @ 47½' TO 49½'
50			BORING COMPLETED ON 9-29-70 CASING USED TO A DEPTH OF 18½' WATER LEVEL @ 12½' ON 9-30-70 300-LB HAMMER @ 24" FALL

LENGTH OF CORE RUN, PERCENT RECOVERY AND R.Q.D.

BORING 311

SURFACE ELEVATION +141.7'

DEPTH IN FEET	BLOW COUNT / SAMPLES	SYMBOLS	DESCRIPTIONS
0	100/4"	GM	FILL - CINDERS REDDISH-BROWN SILTY GRAVEL
	100/3"		
5			
10	96%/35%		TOP OF ROCK @ 9½' BRUNSWICK SHALE FRACTURED, 10' TO 15' REDDISH-BROWN SANDY SILTSTONE WEATHERED TO 17' VERY FRACTURED, 10' TO 15'
15	100%/40%		
20	94%/26%		
25	96%/30%		GRADING MORE MASSIVE
30	95%/50%		FINE-GRAINED SANDSTONE AT 32' TO 37'
35	88%/70%		BADLY PITTED AND WEATHERED @ 36'-37' REDDISH-BROWN SILTSTONE WITH SOME FINE-GRAINED SANDSTONE @ 39'
40	93%/30%		GRADING TO REDDISH-BROWN FINE-GRAINED SANDSTONE @ 42'
45	*73%/30%		GRADING TO REDDISH-BROWN SILTSTONE WITH CALCITE STRINGERS @ 46'
50	*75%/50%		BORING COMPLETED ON 10-6-70 CASING USED TO A DEPTH OF 9' WATER LEVEL @ 5½' ON 10-6-70 300-LB. HAMMER @ 24" FALL NX DOUBLE TUBE CORE BARREL *CORE LOSS DUE TO GRINDING OF ROCK

LENGTH OF CORE RUN, PERCENT RECOVERY AND R.Q.D.

BORING M-3

SURFACE ELEVATION +251.0'

DEPTH IN FEET	BLOW COUNT / SAMPLES	SYMBOLS	DESCRIPTIONS
0	3	CL	BROWN SILTY CLAY WITH SOME GRAVEL SOFT TO 2'
	79	ML	REDDISH-BROWN CLAYEY SILT WITH ROCK FRAGMENTS - STIFF TOP OF ROCK @ 4' BRUNSWICK SHALE REDDISH-BROWN SILTSTONE - HIGHLY WEATHERED GRADING HARDER AT 6½' BUT HIGHLY FRACTURED GRADING LESS FRACTURED
5	64%-12%		
10	100%-22%		
15			BORING COMPLETED ON 4-28-70 CASING TO 4' WATER LEVEL NOT ENCOUNTERED 140-LB. HAMMER @ 30" FALL

BORING M-4

SURFACE ELEVATION +250.8'

DEPTH IN FEET	BLOW COUNT / SAMPLES	SYMBOLS	DESCRIPTIONS
0	21	CL	BLACK SILTY CLAY WITH ROOTS - TOPSOIL (SOFT)
	45/5"	ML	REDDISH-BROWN CLAYEY SILT WITH ROCK FRAGMENTS - FIRM TO STIFF TOP OF ROCK @ 2' BRUNSWICK SHALE REDDISH-BROWN SANDY SILTSTONE SLIGHTLY WEATHERED AND HIGHLY FRACTURED GRADING LESS FRACTURED TO HARD SILTSTONE
5	70%-30%		
10	100%-57%		
15			BORING COMPLETED ON 4-29-70 CASING TO 2' WATER LEVEL NOT ENCOUNTERED 140-LB. HAMMER @ 30" FALL

BORING M-1

SURFACE ELEVATION +249.8'

DEPTH IN FEET	BLOW COUNT / SAMPLES	SYMBOLS	DESCRIPTIONS
0	20	CL	BLACK SILTY CLAY WITH FINE TO COARSE GRAVEL - TOPSOIL
	35	CL	REDDISH-BROWN SILTY CLAY - FIRM
5		ML	REDDISH-BROWN CLAYEY SILT WITH ROCK FRAGMENTS - VERY FIRM TOP OF HIGHLY WEATHERED ROCK AT 5' BRUNSWICK SHALE REDDISH-BROWN SILTSTONE - HIGHLY WEATHERED TOP OF HARD ROCK AT 8½' MODERATELY FRACTURED
10	75%-40%		
15	100%-57%		BORING COMPLETED ON 4-28-70 CASING TO 5' WATER LEVEL NOT ENCOUNTERED 140-LB. HAMMER @ 30" FALL

LENGTH OF CORE RUN, PERCENT RECOVERY AND R.Q.D.

BORING M-2

SURFACE ELEVATION +249.8'

DEPTH IN FEET	BLOW COUNT / SAMPLES	SYMBOLS	DESCRIPTIONS
0	8	CL	BLACK CLAYEY SILT - SOFT
	60	ML	REDDISH-BROWN CLAYEY SILT WITH ROCK FRAGMENTS - FIRM TOP OF ROCK @ 4' BRUNSWICK SHALE REDDISH-BROWN SANDY SILTSTONE - HARD - INFREQUENT HEALED FRACTURES
5	95%-53%		
10	100%-72%		
15			BORING COMPLETED ON 4-29-70 CASING TO 4' WATER LEVEL NOT ENCOUNTERED 140-LB. HAMMER @ 30" FALL

LENGTH OF CORE RUN, PERCENT RECOVERY AND R.Q.D.

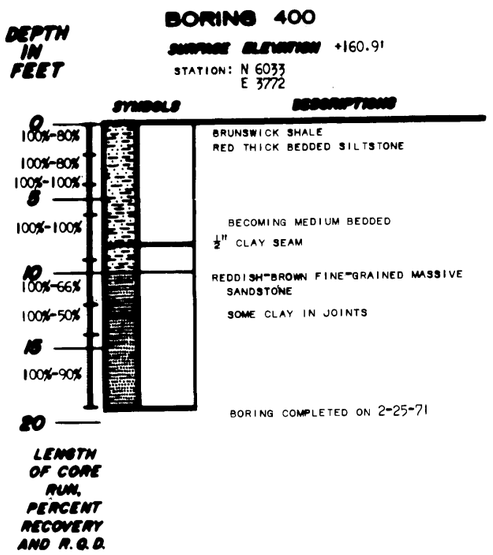
NOTES:

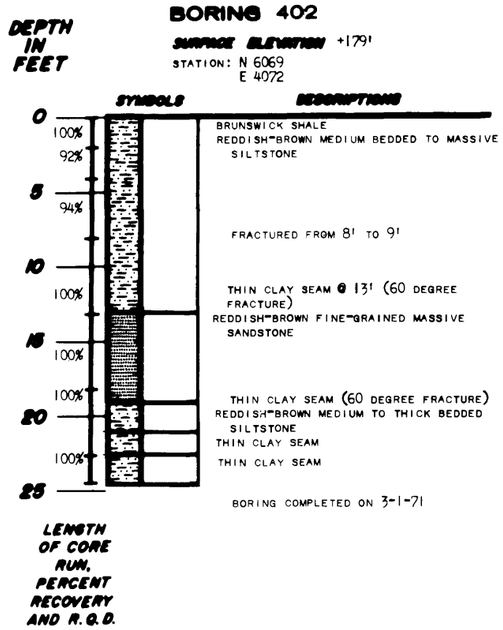
1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

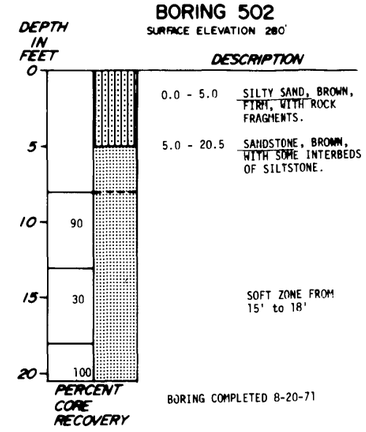
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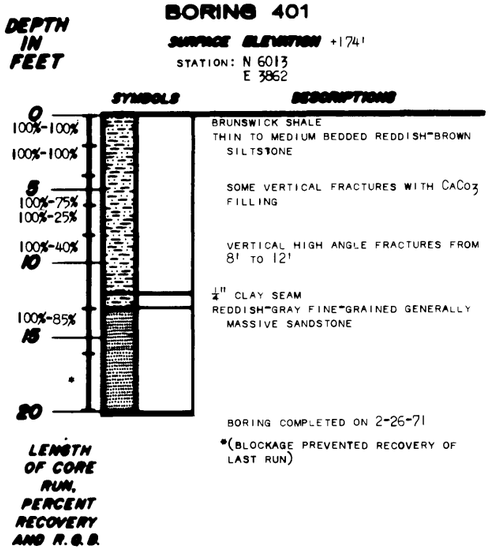
GRAPHIC LOGS
SHEET 25 OF 37

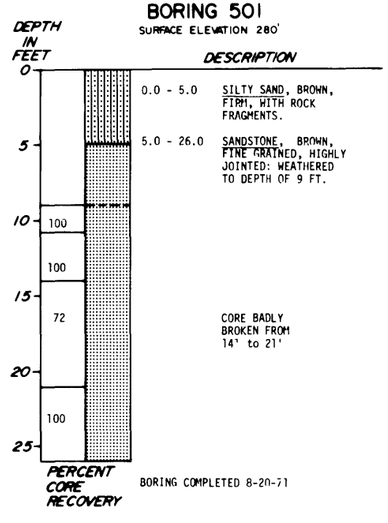
FIGURE 2.5-22











NOTES:

1. See notes on Figure 2.5-22, Sheet 1 for additional explanation of logs.
2. For locations of borings, see Figure 2.5-20.
3. Logs prepared by Dames and Moore.

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GRAPHIC LOGS
SHEET 26 OF 37

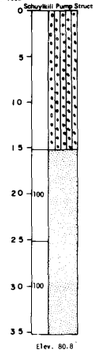
FIGURE 2.5-22

L-1

Elev. 116

C.R. = 100%

Schuylkill Pump Structure



Elev. 80.8

0.0' - 12.0' SANDY SILT: BROWN, CLAYEY.

12.0' - 15.2' GRADES TO SANDSTONE; WEATHERED.

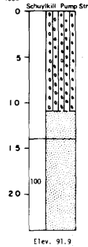
15.2' - 35.2' SANDSTONE: RED, VERY FINE-GRAINED WITH THIN SHALE PARTINGS. MODERATELY FRACTURED PARALLEL TO GENTLY DIPPING BEDDING. OCCASIONAL VERTICAL JOINTS. AVERAGE CORE LENGTH 8 INCHES.

L-2

Elev. 115.9

C.R. = 100%

Schuylkill Pump Structure



Elev. 91.9

0.0' - 11.0' SANDY SILT: CLAYEY.

11.0' - 14.0' GRADES TO SANDSTONE, WEATHERED.

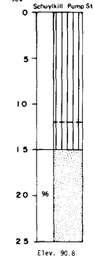
14.0' - 24.0' SANDSTONE: RED, VERY FINE-GRAINED, HARD, WITH SHALE PARTINGS. MODERATELY FRACTURED PARALLEL TO BEDDING. ONE VERTICAL JOINT.

L-3

Elev. 115.8

C.R. = 96%

Schuylkill Pump Structure



Elev. 90.8

0.0' - 12.0' CLAYEY SILT

12.0' - 15.0' GRADES TO SHALE AND SILTSTONE: WEATHERED.

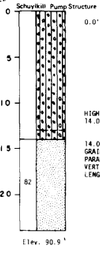
15.0' - 25.0' SANDSTONE: VERY FINE-GRAINED, HARD WITH SHALE PARTINGS. MODERATELY JOINTED. AVERAGE CORE LENGTH IS ABOUT 2 INCHES.

L-4

Elev. 114.9

C.R. = 82%

Schuylkill Pump Structure



Elev. 90.9

0.0' - 13.0' SANDY SILT: CLAYEY.

HIGHLY WEATHERED ROCK @ 13.0' - 14.0'.

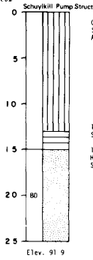
14.0' - 24.0' SANDSTONE: FINE-GRAINED, HARD, MODERATELY FRACTURED PARALLEL TO BEDDING, OCCASIONAL VERTICAL JOINTS. AVERAGE CORE LENGTH IS ABOUT 4 INCHES.

L-5

Elev. 116.9

C.R. = 80%

Schuylkill Pump Structure



Elev. 91.9

0.0' - 12.5' SILT: CLAYEY AND SANDY WITH SOME GRAVELS STARTING AT 9'.

12.5' - 15.0' SHALE: WEATHERED, SOFT.

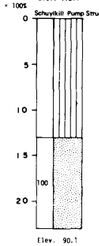
15.0' - 25.0' SANDSTONE: GRAY BROWN, HIGHLY FRACTURED PARALLEL TO BEDDING. SHALE PARTINGS.

L-6

Elev. 113.1

C.R. = 100%

Schuylkill Pump Structure



Elev. 90.1

0.0' - 11.0' CLAYEY SILT

GRADES TO WEATHERED ROCK @ 11.0'.

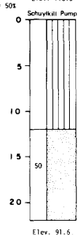
13.0' - 23.0' SANDSTONE: RED, VERY FINE-GRAINED, HARD, MODERATELY JOINTED. GRADES TO GRAY, MEDIUM GRAINED AT 17'.

L-7

Elev. 113.6

C.R. = 50%

Schuylkill Pump



Elev. 91.6

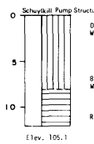
0.0' - 12.0' SILT: CLAYEY AND SANDY WITH GRAVEL BELOW 8'

12.0' - 22.0' SANDSTONE: RED HIGHLY WEATHERED, WITH 50% SHALE PARTINGS.

L-8

Elev. 117.1

Schuylkill Pump Structure



Elev. 105.1

0.0' - 8.0' SILT: CLAYEY AND SANDY WITH TRACE OF GRAVEL.

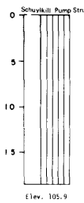
8.0' - 12.0' SHALE: HIGHLY WEATHERED.

REFUSAL AT 12.0' AUGER HOLE

L-9

Elev. 124.4

Schuylkill Pump Structure



Elev. 105.9

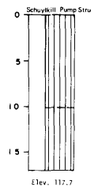
0.0' - 18.5' SILT: SANDY AND CLAYEY WITH OCCASIONAL GRAVEL BELOW 11.0'.

REFUSAL @ 18.5' (AUGER HOLE, NO SAMPLES)

L-10

Elev. 134.7

Schuylkill Pump Structure



Elev. 117.7

0.0' - 10.0' SILT: CLAYEY AND SANDY.

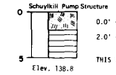
GRADES TO WEATHERED BEDROCK @ 10.0'.

(AUGER HOLE, NO SAMPLES) REFUSAL AT 17.0'.

L-11

Elev. 143.8

Schuylkill Pump Structure



Elev. 138.8

0.0' - 2.0' RAILROAD BALLAST

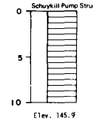
2.0' - 5.0' SHALE: RED

THIS IS A HAND-DUG PIT.

L-12

Elev. 155.9

Schuylkill Pump Structure



Elev. 145.9

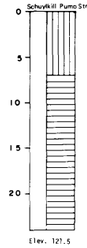
0.0' - 10.0' SHALE: BROWN, HIGHLY WEATHERED.

REFUSAL @ 10.0'. (AUGER HOLE, NO SAMPLES)

L-13

Elev. 145.5

Schuylkill Pump Structure



Elev. 127.5

0.0' - 7.0' CLAYEY SILT

7.0' - 24.0' SHALE: HIGHLY WEATHERED

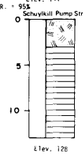
(AUGER HOLE, NO SAMPLES)

L-14

Elev. 141

C.R. = 95%

Schuylkill Pump Structure



Elev. 128

0.0' - 3.0 RAILROAD BALLAST

3.0' - 13.0' SHALE: RED, HARD, WITH FINE-GRAINED SANDSTONE PARTINGS.

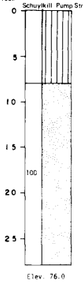
(AUGER HOLE, NO SAMPLES)

W-1

Elev. 104

C.R. = 100%

Schuylkill Pump Structure



Elev. 76.0

0.0' - 8.0' SILT: DENSE, SANDY WITH OCCASIONAL SMALL GRAVEL.

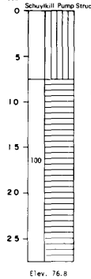
8.0' - 28.0' SANDSTONE: RED, VERY FINE-GRAINED GRADING TO SLIGHTLY COARSER AND GRAY AT 13 FEET; HARD, MODERATELY JOINTED.

W-2

Elev. 104.4

C.R. = 100%

Schuylkill Pump Structure



Elev. 76.8

0.0' - 7.6' SILT: SANDY, DENSE WITH OCCASIONAL SMALL GRAVEL.

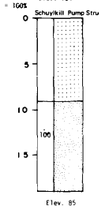
7.6' - 27.6' SHALE: RED, THINLY BEDDED, MODERATELY FRACTURED PARALLEL TO NEAR-HORIZONTAL BEDDING.

W-3

Elev. 104

C.R. = 100%

Schuylkill Pump Structure



Elev. 85

0.0' - 9.0' SAND: SILTY, DENSE, RANDOM GRAVEL.

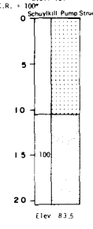
9.0' - 19.0' SANDSTONE: GRAY TO RED, VERY FINE GRAINED WITH SHALE PARTINGS. HARD, MODERATELY FRACTURED.

W-4

Elev. 104

C.R. = 100%

Schuylkill Pump Structure



Elev. 83.5

0.0' - 10.5' SAND: SILTY, SOME SMALL GRAVEL.

10.5' - 20.5' SANDSTONE: GRAY, HARD WITH RED SHALE PARTINGS. MODERATELY FRACTURED.

W-5

Elev. 104.4

C.R. = 100%

Schuylkill Pump Structure



Elev. 83.9

0.0' - 10.5' SAND: SILTY AND GRAVELLY.

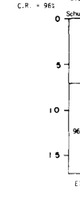
10.5' - 20.5' SANDSTONE: RED, FINE-GRAINED, WITH ZONES OF SHALE; HARD.

W-6

Elev. 104

C.R. = 96%

Schuylkill Pump Structure



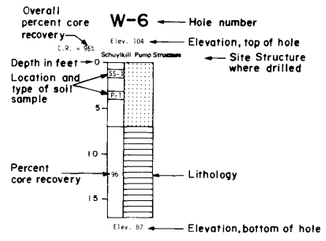
Elev. 87

0.0' - 7.0' SAND: SILTY WITH RANDOM SMALL GRAVEL

7.0' - 17.0' SHALE: RED TO GRAY, HARD.

EXPLANATION

- Fill.
- Overburden, undifferentiated.
- Sand.
- Silt; clayey silt (ML).
- Sandy silt (SM).
- Sandy gravel (GM).
- Silt with siltstone fragments or boulders.
- Clay (CL).
- Silty clay, sand and gravel; clayey sand (SC).
- Siltstone.
- Siltstone and soil; siltstone and sandstone.
- Sandstone.
- Shale.



NOTE:

For location of borings, see Figure 2.5-20

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GRAPHIC LOGS
SHEET 27 OF 37

FIGURE 2.5-22

S-1

Elev. 174
C.R. = 990
Schuylkill Pump Structure

0.0' - 6.0' SANDY CLAY.

6.0' - 25.0' SILTSTONE: RED, OCCASIONAL SANDSTONE PARTINGS HIGHLY BROKEN PARALLEL TO BEDDING, MAINLY AT 45 DEGREES.

25.0' - 30.0' SANDSTONE: GRAY, VERY FINE-GRAINED, CORE LENGTHS AVERAGE 4 INCHES.

30.0' - 33.0' BROWN, MEDIUM-GRAINED

36.0' - 66.0' SILTSTONE: RED, HARD, CLOSELY JOINTED PARALLEL TO BEDDING TO 43 FEET, THEN MASSIVE.

66.0' - 82.0' SANDSTONE: GRAY AND RED, HARD, THINLY SHALES TO SILTSTONE, CORE LENGTHS AVERAGE 8 - 12 INCHES.

82.0' - 106.0' SILTSTONE: RED, HARD, SANDSTONE IN PART. CORE LENGTHS TO 20 INCHES.

106.0' - 119.0' SANDSTONE: GRAY, HARD, FINE-GRAINED WITH PARTINGS AND IRREGULAR POCKETS OF SILTSTONE.

Elev. 55

S-1A

Elev. 176
C.R. = 930
Schuylkill Pump Structure

0.0' - 7.0' CLAYEY SILT AND SAND WITH ROCK FRAGMENTS

7.0' - 30.0' SILTSTONE: RED, HARD WITH OCCASIONAL SHALE PARTINGS. JOINTS PARALLEL TO POORLY DEFINED BEDDING CORE LENGTHS AVERAGE 3 INCHES.

19.0' - 19.3' SOFT ZONE

30.0' - 47.5' SANDSTONE: GRAY, GRADING TO RED, HARD, VERY FINE-GRAINED. CORE LOSS FROM 42' - 45'

47.5' - 73.0' SILTSTONE: RED WITH WHITE STREAKS, MASSIVE, HARD; CORE LENGTHS AVERAGE 8 - 11 INCHES.

73.0' - 86.0' SANDSTONE: RED WITH OCCASIONAL WHITE STREAKS. FINE-GRAINED, POORLY DEFINED BEDDING CORE LENGTHS AVERAGE 12 INCHES.

86.0' - 101.0' SILTSTONE: RED, HARD, JOINTS PARALLEL TO POORLY DEFINED BEDDING. CORE LENGTHS AVERAGE 8 INCHES.

Elev. 75

S-1B

Elev. 176
C.R. = 975
Schuylkill Pump Structure

0.0' - 7.0' CLAYEY SILT

7.0' - 34.5' SILTSTONE: RED, MODERATELY HARD, JOINTS PARALLEL TO POORLY DEFINED BEDDING. - SOME SMALL VUGS, CLAYEY ALONG BEDDING. CORE LENGTHS AVERAGE 3 INCHES.

34.0' - 34.3' SOFT ZONE

34.5' - 39.0' SANDSTONE: GRAY, VERY FINE-GRAINED, GRADING TO BROWN MEDIUM GRAINED. SOFT CLAY FROM 38.0' - 39.0'?

39.0' - 64.0' SILTSTONE: RED, IMMEDIATELY HARD. JOINTS PARALLEL TO POORLY DEFINED BEDDING. AVERAGE CORE LENGTH IS 6 INCHES. CORE MARKEDLY IMPROVED BELOW 55 FEET.

47.0' - 49.0' FISSILE SHALE

50.0' - 51.0' FISSILE SHALE

60.0' 2 INCH SOFT ZONE

64.0' - 78.0' SANDSTONE: GRAY, HARD, FINE-GRAINED, FEW JOINTS.

78.0' - 96.0' SILTSTONE: RED, HARD, GRADING INTO SANDSTONE IN PLACES. CORE LENGTHS AVERAGE 8 INCHES.

96.0' - 121.0' SANDSTONE: RED TO REDDISH GRAY, LOCAL TURBID BEDDING.

106.0' - 109.0' FISSILE SHALE, BLUE GREEN, WHITE AND YELLOW WITH SLIPPERY BEDDING PLANES.

111.6' - 112.0' FISSILE SHALE, SOFT.

121.0' - 126.0' SILTSTONE: RED, HARD SANDSTONE IN PART. CORE LENGTHS AVERAGE 10 INCHES.

126.0' - 138.0' SANDSTONE: GRAY, VERY FINE TO MEDIUM GRAINED. CORE LENGTHS FROM 3 TO 20 INCHES.

Elev. 38

S-2

Elev. 130
C.R. = 894
Schuylkill Pump Structure

0.0' - 23.0' FILL: EMBANKMENT FILL, SILTY CLAY, SOFT WITH SMALL ROCK FRAGMENTS.

23.0' - 32.0' SILTSTONE: RED, HARD, BROKEN ALONG POORLY DEFINED BEDDING.

32.0' - 38.0' SANDSTONE: RED, HARD, LOCALLY VERY FINE-GRAINED; SOME SILTSTONE.

Elev.101

S-3

Elev. 133
C.R. = 986
Schuylkill Pump Structure

0.0' - 9.0' FILL AND CLAYEY SAND WITH GRAVEL

9.0' - 24.0' SILTSTONE: RED, HARD. PREDOMINATELY JOINTED PARALLEL TO NEAR HORIZONTAL BEDDING, OCCASIONAL VERTICAL JOINT. 3 INCH AVERAGE CORE LENGTH.

24.0' - 52.0' SANDSTONE: RED, HARD, FINE-GRAINED WITH SILTSTONE PARTINGS TO 28 FEET, THEN GRAY. CORE LENGTHS AVERAGE 10 INCHES.

34.0' CORE WERE BROKEN. 34.5' - 37.0' OPEN VERTICAL JOINT. LOST 50S WATER AT 34.5 FEET.

43.5' SANDSTONE HAS SPECKLE APPEARANCE.

52.0' - 55.9' SILTSTONE: RED, HARD, SHALE IN PART.

Elev. 72.3

S-4

Elev. 115
C.R. = 975
Schuylkill Pump Structure

0.0' - 12.5' SILTY SAND AND GRAVEL: rich BROWN

12.5' - 40.0' SILTSTONE: RED, WEATHERED TO 15 FEET. LOCALLY SHALEY AND SANDY. 2 INCH AVERAGE CORE LENGTH TO DEPTH 18 FEET: BELOW 18.0 AVERAGE 15 6 INCHES.

Elev. 75

S-5

Elev. 108
C.R. = 804
Schuylkill Pump Structure

0.0' - 13.0' SILTY SAND, GRAVEL AND BOULDERS: BOULDERS BELOW 5 FEET.

13.0' - 29.0' SILTSTONE: RED, HARD, JOINTS PARALLEL TO POORLY DEFINED BEDDING. CORE LENGTH ABOUT 3 INCHES THROUGHOUT.

Elev. 79

S-8

Elev. 116
C.R. = 1004
Schuylkill Pump Structure

0.0' - 18.0' CLAYEY SILT: RED.

18.0' - 33.0' SILTSTONE: RED, AVERAGE CORE LENGTH OF 4 INCHES.

Elev. 83

S-9

Elev. 123
C.R. = 1005
Schuylkill Pump Structure

0.0' - 9.0' CLAYEY SILT AND SMALL GRAVEL

9.0' - 24.0' SILTSTONE, SANDSTONE IN PART, RED, BROKEN IN 2 INCH PIECES TO 18 FEET, THEN GOOD CORE.

Elev. 99

S-10

Elev. 106
C.R. = 1004
Schuylkill Pump Structure

0.0' - 2.5' WATER

2.5' - 7.0' SILTY SAND AND GRAVEL

7.0' - 23.0' SILTSTONE: RED, HARD, BEDDING POORLY DEFINED. AVERAGE CORE LENGTH 4 INCHES.

Elev. 83

S-6

Elev. 105
C.R. = 1096
Schuylkill Pump Structure

0.0' - 2.1' WATER

2.1' - 3.9' SILTY SAND AND GRAVEL

3.9' - 22.0' SILTSTONE: RED, BEDDING POORLY DEFINED. OCCASIONAL VERTICAL JOINTS. BROKEN TO 11 FEET: THEN CORE LENGTHS AVERAGE 6 - 10 INCHES.

Elev. 83

S-7

Elev. 111
C.R. = 1086
Schuylkill Pump Structure

0.0' - 15.0' SILTY SAND AND GRAVEL: REDDISH BROWN.

15.0' - 31.0' SILTSTONE: RED, SANDY IN PART, JOINTS PARALLEL TO POORLY DEFINED BEDDING. OCCASIONAL VERTICAL JOINTS. AVERAGE CORE LENGTH 3 INCHES TO DEPTH 23 FEET, 6 - 10 INCHES BELOW 23 FEET.

Elev. 80

S-11

Elev. 105
C.R. = 1005
Schuylkill Pump Structure

0.0' - 2.0' WATER

2.0' - 5.0' SAND AND GRAVEL

5.0' - 11.0' SANDSTONE: RED, FINE-GRAINED, BROKEN INTO 2-3 INCH PIECES.

11.0' - 15.0' SILTSTONE: RED, SHALEY IN PART, CORE LENGTH AVERAGE 4 INCHES.

Elev. 90

S-12

Elev. 109
C.R. = 935
Schuylkill Pump Structure

0.0' -14.0 SILTY SAND AND GRAVEL

14.0' - 21.5' SHALE: RED, HARD, SILTSTONE IN PART. CORE LENGTHS AVERAGE 6 INCHES.

21.5' - 30.0' SANDSTONE: PALE RED, HARD, FINE-GRAINED WITH POORLY DEFINED BEDDING. AVERAGE CORE LENGTH IS 8 INCHES.

Elev. 79

NOTES:

1. For explanation of symbols, see sheet 27, Figure 2.5-22.
2. For location of borings, see Figure 2.5-20.

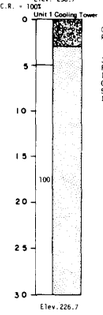
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FIGURE 2.5-22

T-1-1

Elev. 256.7



0.0' - 3.0' OVERBURDEN: WEATHERED ROCK AND ROCK FRAGMENTS WITH CLAY.

3.0' - 30.0' SANDSTONE: RED, HARD, FINE-GRAINED GRADING TO SILTSTONE IN PART. OCCASIONAL VERTICAL JOINTS. CORE LENGTHS AVERAGE 1 INCH FROM DEPTH 5-9.5 FEET, THEN AVERAGE 10-15 INCHES.

T-1-2

Elev. 257.4

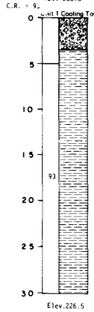


0.0' - 3.5' SILTSTONE AND SANDSTONE: WEATHERED, CLAYEY.

3.5' - 5.0' BIT RESISTANCE AT 3.5 FEET, HARD AT 5 FEET.

T-1-3

Elev. 256.5

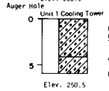


0.0' - 3.5' OVERBURDEN: ROCK FRAGMENTS IN CLAY.

3.5' - 30.0' SILTSTONE: RED, HARD, SANDSTONE IN PART. OCCASIONAL VERTICAL JOINTS. CORE LENGTHS AVERAGE 8-10 INCHES.

T-1-4

Elev. 256.5



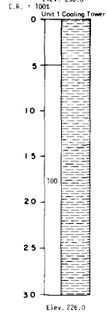
0.0' - 4.0' ROCK FRAGMENTS AND CLAY.

4.0' - 6.0' BECOMES HARD AT 4 FEET

REFUSAL AT 6.0 FEET.

T-1-5

Elev. 256.0



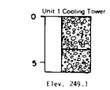
0.0' - 4.0' SILTSTONE: WEATHERED, CLAYEY.

4.0' - 30.0' SILTSTONE: RED, HARD, SANDSTONE IN PART. AVERAGE CORE LENGTH 2 INCHES. BELOW 6 FEET AVERAGE INCREASES TO 10 INCHES.

15.0' - 19.0' BED WITH WHITE STREAKS.

T-1-6

Elev. 255.1

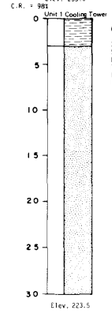


0.0' - 3.5' OVERBURDEN

3.5' - 6.0' BECOMES HARD AT 4 FEET.

T-1-7

Elev. 253.5

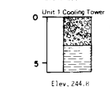


0.0' - 3.0' SILTSTONE: WEATHERED

3.0' - 30.0' SANDSTONE: RED, HARD, SANDY SILTSTONE IN PART. PROMINENT BEDDING. CORE LENGTHS AVERAGE 2 INCHES TO DEPTH 7', AVERAGE 6 INCHES FROM 7' TO 14', AND AVERAGE 10 INCHES BELOW 14'.

T-1-8

Elev. 250.8

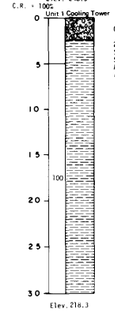


0.0' - 3.0' OVERBURDEN

3.0' - 6.0' SILTSTONE: HARD

T-1-9

Elev. 248.3

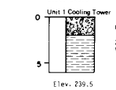


0.0' - 2.5' OVERBURDEN

2.5' - 30.0' SILTSTONE: RED, HARD, SANDY, SANDSTONE IN PART. OCCASIONAL STEEPLY DIPPING JOINTS. CORE LENGTHS AVERAGE 2 INCHES TO 8', BELOW 8' AVERAGE 15 TO 18INCHES.

T-1-10

Elev. 245.5

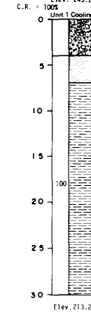


0.0' - 2.0' OVERBURDEN: CLAYEY

2.0' - 6.0' SILTSTONE: BECOMES VERY HARD AT 5 FEET.

T-1-11

Elev. 243.2



0.0' - 4.0' OVERBURDEN

4.0' - 7.0' SANDSTONE: GRAY-RED, MODERATELY HARD WITH CLOSE HORIZONTAL JOINTING, MOIST.

7.0' - 30.0' SILTSTONE: WEATHERED, SOFT TO 13 FEET. SANDSTONE IN PART. JOINTS ARE PRIMARILY ALONG BEDDING WITH AN OCCASIONAL NEAR VERTICAL JOINT. AVERAGE CORE LENGTHS BELOW 13 FEET IS 6 INCHES.

T-1-12

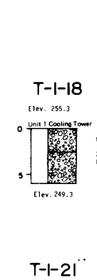
Elev. 241.9



0.0' - 6.0' SILTSTONE: WEATHERED GRADING TO HARD AT 6 FEET.

T-1-13

Elev. 244.0

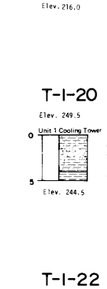


0.0' - 3.0' OVERBURDEN: RED CLAY AND ROCK FRAGMENTS.

3.0' - 30.0' SILTSTONE: SOFT ZONES TO 9 FEET. PRIMARILY JOINTED PARALLEL TO BEDDING WITH AN OCCASIONAL NEAR VERTICAL JOINT. SANDSTONE IN PART. CORE LENGTHS AVERAGE LESS THAN 1 INCH TO 9 FEET, 4 INCHES TO 20 FEET, THEN 12 INCHES.

T-1-14

Elev. 246.0



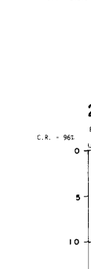
0.0' - 3.0' OVERBURDEN: ROCK FRAGMENTS AND CLAY.

3.0' - 5.5' SHALE: YELLOW, DECOMPOSED, CLAYEY.

5.5' - 30.0' SANDSTONE: GRAY, HARD, GRADING TO SANDY SILTSTONE. CORE LENGTHS AVERAGE 4 INCHES TO DEPTH 11.0', AVERAGE 6-10 INCHES BELOW 11.0'.

T-1-15

Elev. 248.9



0.0' - 3.0' SILTY CLAY: RED WITH ROCK FRAGMENTS.

3.0' - 8.5' SHALE: YELLOWISH, WEATHERED, SOFT AND CLAYEY, OVERLAIN BY THIN BED OF DARK GRAY, MEDIUM-GRAINED SANDSTONE.

8.5' - 30.0' SANDSTONE: GRAY, VERY HARD, FINE-GRAINED, BRITTLE. SILTSTONE IN PART.

T-1-16

Elev. 251.5



0.0' - 30.0' OVERBURDEN

3.0' - 30.0' SANDSTONE: DARK GRAY WITH WEATHERED, YELLOW CLAYEY SHALE, MEDIUM TO FINE-GRAINED. CORE LENGTHS AVERAGE 2 INCHES TO DEPTH 9.8 FEET, AVERAGE 8 INCHES BELOW 9.8'.

8.0' - 9.5' SOFT ZONE

9.5' - 30.0' GRAY, HARD, BRITTLE GRADES IN PART TO SILTSTONE.

T-1-17

Elev. 253.9



0.0' - 3.0' OVERBURDEN

3.0' - 7.0' SHALE, YELLOW SOFT, CAPPED BY THIN, DARK RED SANDSTONE.

7.0' - 30.0' SANDSTONE: GRAY, HARD, GRADING TO RED SANDY SILTSTONE IN PART.

T-1-19

Elev. 256.5



0.0' - 4.0' OVERBURDEN: CLAYEY SILT AND ROCK FRAGMENTS.

4.0' - 30.0' SILTSTONE: RED, HARD, SANDY, SANDSTONE IN PART. CORE LENGTHS AVERAGED 3 INCHES TO DEPTH OF 12 FEET, THEN 10-15 INCHES. OCCASIONAL NEAR VERTICAL JOINTS.

T-1-18

Elev. 255.3

0.0' - 2.5' OVERBURDEN

2.5' - 6.0' EASY DRILLING TO 4 FEET, BECOMING HARD AT 5 FEET.

T-1-20

Elev. 249.5

0.0' - 4.0' SILTSTONE: WEATHERED AND SOIL.

4.0' - 5.0' SILTSTONE

T-1-21**

Elev. 241



0.0' - 3.5' (APPROX.) SILTSTONE: WEATHERED, SOME FILL

3.5' - 5.0' (APPROX.) SILTSTONE:

T-1-22

Elev. 240



0.0' - 4.0' FILL: CLAYEY SILT AND ROCK FRAGMENTS.

4.0' - 5.0' SILTSTONE:

T-1-23

Elev. 240.6



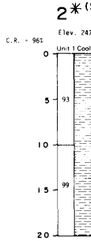
0.0' - 2.0' SILTSTONE: WEATHERED, GRADES TO

2.0' - 5.0' SILTSTONE: RELATIVELY UNWEATHERED.

REFUSAL AT 5.0 FEET

2* (SEE NOTE 3)

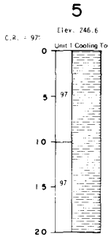
Elev. 247.3



0.0' - 20.0' SILTSTONE: RED-BROWN, MEDIUM HARD, SCATTERED STEEPLY DIPPING CALCITE-FILLED JOINTS AND CALCITE GRAINS.

5

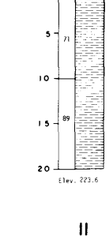
Elev. 246.6



0.0' - 20.0' SILTSTONE: RED-BROWN, MEDIUM HARD, SCATTERED CALCITE-FILLED,STEEPLY DIPPING JOINTS. BROKEN ALONG NEAR-VERTICAL JOINTS @ 2.1' AND 2.8', 3/4" HORIZONTAL CLAY SEAM @ 2.9'. BROKEN INTO 1/2" - 1-1/2" PIECES @ 3.4' - 4.8'.

8

Elev. 243.8



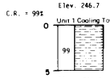
0.0' - 20.0' SILTSTONE: RED-BROWN, MEDIUM HARD, SCATTERED CALCITE GRAINS. BROKEN FROM 0.5' - 0.7' AND 2.0' - 2.5'.

NEAR VERTICAL JOINTS @ 12.4' - 12.8' AND 13.2' - 13.4'.

NEAR VERTICAL, IRON-STAINED FRACTURE @ 19.5'.

4

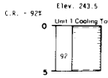
Elev. 246.7



0.0' - 5.0' SILTSTONE: RED-BROWN, MEDIUM HARD, UNWEATHERED. BROKEN INTO 1/2" - 1" PIECES FROM 1.0' - 1.6'.

8-A

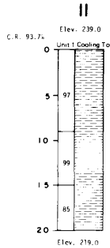
Elev. 243.5



0.0' - 5.0' SILTSTONE: RED-BROWN, MEDIUM HARD, BROKEN WITH TRACE OF CLAY @ 1.8'. BROKEN INTO 1/2" - 1-1/2" PIECES FROM 0.0' - 2.3'.

11

Elev. 239.0



0.0' - 20.0' SILTSTONE: RED-BROWN, MEDIUM HARD, UNWEATHERED, SCATTERED STEEPLY DIPPING CALCITE-FILLED JOINTS.

BROKEN @ 7.1' - 7.5' AND 7.7' - 7.8'.

SANDY @ 10.0'.

NOTES:

1. For explanation of symbols, see sheet 27, Figure 2.5-22.
2. For location of borings, see Figure 2.5-20.
3. Holes 2 through 39A are numbered to indicate plinth foundation for the Unit 1 cooling tower where hole was drilled.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

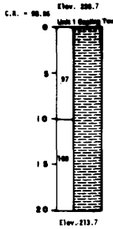
GRAPHIC LOGS
SHEET 29 OF 37

FIGURE 2.5-22

17 # (SEE NOTE 3)

Elev. 226.7

C.R. = 98.5%



0.0' - 20.0' SILTSTONE: RED-BROWN TO GRAY, HARD, UNWEATHERED STEEPLY DIPPING CALCITE-FILLED JOINTS.

1" SANDSTONE LAYER @ 6.1'.

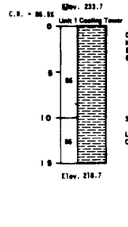
MOTTLED APPEARANCE FROM 11.0' - 11.8'.

1/4" CLAY LAYERS @ 13.8' AND 13.9'. APPEAR TO BE HORIZONTAL.

17A

Elev. 233.7

C.R. = 86.5%



0.0' - 15.0' SILTSTONE: RED-BROWN, HARD
BROKEN ALONG STEEPLY DIPPING FRACTURES @ 2.5' - 3.8' AND 10.0' - 10.6'.

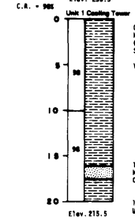
SANDSTONE @ 10.7' - 11.3'.

LESS THAN 1/8" CLAY/ROCK FRAGMENT COATING ON FRACTURE @ 13.9'.

20

Elev. 236.5

C.R. = 90%



0.0' - 16.0' SILTSTONE: RED-BROWN, HARD, SCATTERED STEEPLY DIPPING CALCITE-COATED JOINTS.
SANDY @ 0.0' - 3.0'

VERTICAL JOINTS @ 3.8' - 4.3'.

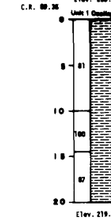
16.0' - 17.5' SANDSTONE: GRAY-BROWN, HARD, UNWEATHERED WITH SCATTERED CALCITE GRAINS.

17.5' - 20.0' SILTSTONE: RED-BROWN, UNWEATHERED.

23

Elev. 230.1

C.R. = 89.3%



0.0' - 20.0' SILTSTONE: GRAY-BROWN, MEDIUM HARD, UNWEATHERED, SCATTERED CALCITE AND CALCITE-FILLED JOINTS.
SANDY @ 0.0' - 3.0'.

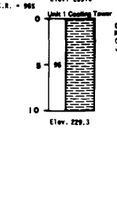
BROKEN @ 5.3' - 5.4'

BROKEN @ 15.6' - 15.7'.

23A

Elev. 239.3

C.R. = 96%

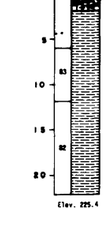


0.0' - 10.0' SILTSTONE: GRAY-BROWN, MEDIUM HARD, UNWEATHERED, SCATTERED CALCITE VEINING AND STEEPLY DIPPING JOINTS.

26

Elev. 248.5

C.R. = 98%



0.0' - 20.0' SILTSTONE: RED-BROWN, MEDIUM HARD, UNWEATHERED, SCATTERED CALCITE-FILLED, STEEPLY DIPPING JOINTS.

BROKEN INTO 1/2" - 1" PIECES @ 3.2' - 4.0'

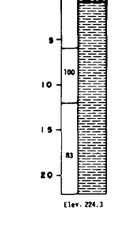
LEACHED CALCITE ALONG STEEPLY DIPPING JOINT @ 12.0' - 12.8'

BROKEN INTO 1/2" - 1" PIECES @ 18.2' - 18.8'.

32

Elev. 248.6

C.R. = 91%



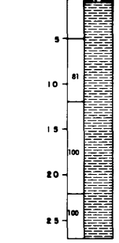
0.0' - 20.0' SILTSTONE: RED-BROWN, HARD, SCATTERED CALCITE GRAINS. BROKEN FROM 3.8' - 3.9' AND 8.4' - 8.5'.
CORE BREAKS COMMONLY AT NEAR-HORIZONTAL PLANES.

MINOR CALCITE LEACHING @ 0.5' - 2.5' AND 10.1' - 12.1'.

35

Elev. 250.5

C.R. = 88.4%



0.0' - 20.0' SILTSTONE: RED-BROWN MEDIUM HARD, UNWEATHERED, BROKEN INTO 1/2" - 3/4" PIECES @ 1.5' - 3.2'.

CALCITE LAMINAE AND FILLED JOINTS

SANDY @ 10.9' - 11.4'.

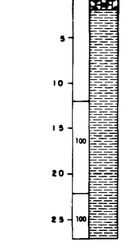
BROKEN @ 13.1' - 13.2' BUT UNWEATHERED.

LOW ANGLE CALCITE COATED FRACTURE @ 16.5'.

39

Elev. 248.4

C.R. = 96.5%



0.0' - 20.0' SILTSTONE: RED-BROWN, MEDIUM HARD, UNWEATHERED, SCATTERED STEEPLY DIPPING CALCITE-FILLED JOINTS.

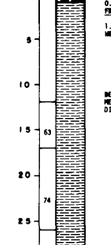
BROKEN ALONG NEAR-VERTICAL JOINTS @ 2.5' - 3.7'; 8.2' - 8.5'; 9.1' - 9.2' and 13.0' - 16.0'.

MOTTLED, WITH CALCITE @ 16.6' - 17.0'.

39A

Elev. 248.1

C.R. = 100%



0.0' - 5.0' SILTSTONE: RED-BROWN MEDIUM HARD, UNWEATHERED. VERTICAL FRACTURE @ 1.8' - 2.0'. STEEPLY DIPPING CALCITE-FILLED JOINT @ 2.6'.

B-3

Elev. 242.5

C.R. = 96%

0.0' - 3.0' SILT WITH SILTSTONE FRAGMENTS

3.0' - 10.0' SILTSTONE: HIGHLY WEATHERED TO 9.5', THEN BECOMES MEDIUM HARD EXCEPT SOFT, WEATHERED AT 6.9' - 7.1' and 8.6' - 8.9'.

10.0' - 11.5' SANDSTONE:

11.5' - 29.5' SILTSTONE: BROKEN, HIGHLY WEATHERED AT 11.7' - 12.3'; 13.0' - 13.5' AND 14.5' - 15.3'.

SLIGHTLY WEATHERED, HARD BELOW 17.9'.

B-4

Elev. 243.3

C.R. = 88%

0.0' - 2.0' SILT WITH SILTSTONE FRAGMENTS

2.0' - 31.0' SILTSTONE: RED-BROWN, HIGHLY WEATHERED WITH NUMEROUS SILT/CLAY TO ZONES TO 9.5', THEN BECOMES MEDIUM HARD, SLIGHTLY WEATHERED EXCEPT WHERE NOTED.
1/8" - 1/4" SOFT LAYERS @ 11.6' - 12.5'.

BROKEN ALONG STEEPLY DIPPING JOINTS @ 13.9' - 16.5'.

BROKEN ALONG STEEPLY DIPPING JOINTS @ 21.8' - 23.0'.

B-5

Elev. 244.6

C.R. = 92%

0.0' - 2.0' SILT WITH SILTSTONE FRAGMENTS

2.0' - 30.0' SILTSTONE: RED-BROWN SILTSTONE/SHALE FRAGMENTS IN A SILT/CLAY MATRIX TO 6.5'.

HIGHLY WEATHERED FROM 6.5' - 17.1'. BELOW, CORE BECOMES MEDIUM HARD SLIGHTLY WEATHERED WITH SCATTERED CALCITE GRAINS.

BROKEN SOME IRON-STAINING @ 20.0' - 21.0'. TRACE SILT/ROCK FRAGMENTS ALONG NEAR-HORIZONTAL PLANE @ 21.0'.

SANDY @ 29.5' - 30.0'.

B-6

Elev. 243.8

C.R. = 94%

0.0' - 2.0' SILT WITH SILTSTONE FRAGMENTS: BREAKS INTO DECOMPOSED ROCK.

2.0' - 23.0' SILTSTONE: HIGHLY WEATHERED/DECOMPOSED TO 10.0'.

AT 10.0' BECOMES RED-BROWN; MEDIUM HARD WITH SCATTERED CALCITE GRAINS AND LAMINAE. STEEPLY DIPPING FRACTURES @ 10.0' - 12.0'.

BROKEN @ 13.0' - 14.0'.
1/4" NEAR-HORIZONTAL LAYER OF DECOMPOSED ROCK @ 14.0'.
BROKEN @ 18.0' - 18.8'

BROKEN @ 20.3' - 20.6'.

BROKEN @ 21.1' - 21.3' WITH SOFTER LAYER @ 21.2'.

B-7

Elev. 247.2

C.R. = 94%

0.0' - 2.0' SILT WITH SILTSTONE FRAGMENTS:

2.0' - 8.0' SILTSTONE/SHALE: RED-BROWN, HIGHLY WEATHERED/DECOMPOSED TO 4.0'. BECOMES HARDER @ 4.0' BUT HIGHLY FRACTURED AND CONTAINS SOFT SEAMS TO 8.0'.

8.0' - 18.0' SILTSTONE: RED-BROWN, MEDIUM HARD, FRIABLE AND CONTAINS SHALE LAYERS. NUMEROUS CALCITE LAMINAE.

STEEPLY DIPPING FRACTURES @ 8.0' - 8.8'; 13.0' - 14.0' and 15.8' - 18.0'. TRACE OF CLAY ALONG ALL

B-8

Elev. 247.4

C.R. = 83%

0.0' - 2.0' SILT WITH SILTSTONE FRAGMENTS

2.0' - 22.0' SILTSTONE: RED-BROWN, SOFT, WEATHERED TO 8.0'. THEN BECOMES MEDIUM HARD, UNWEATHERED EXCEPT WHERE NOTED. SCATTERED CALCITE GRAINS.

CLAY ALONG STEEPLY DIPPING JOINTS @ 6.1' - 6.6'.

BROKEN ALONG STEEPLY DIPPING JOINTS @ 6.1' - 7.5'; 12.0' - 12.5'; 17.7' - 18.4'; 18.9' - 20.0'.

LEACHED CALCITE ALONG JOINT @ 17.0' - 17.6'.

B-9

Elev. 246.3

C.R. = 89%

0.0' - 1.0' SILT WITH SILTSTONE FRAGMENTS:

1.0' - 22.0' SILTSTONE: SOFT, HIGHLY WEATHERED TO 8.0'. BELOW 6.0, CORE IS RED-BROWN, MEDIUM HARD WITH SCATTERED CALCITE GRAINS.

BROKEN FROM 6.0' - 7.8'.

SANDY @ 11.8' - 12.5'.

LESS THAN 1/8" THICK SOFTER, NEAR-HORIZONTAL LAYER @ 16.4'.

BROKEN FROM 17.5' - 19.0'.

B-10

Elev. 245.1

C.R. = 94%

0.0' - 1.0' SILT WITH SILTSTONE FRAGMENTS

1.0' - 27.0' SILTSTONE: SOFT, WEATHERED TO 5.0', THEN BECOMES RED-BROWN TO GRAY, MEDIUM HARD, UNWEATHERED EXCEPT AS NOTED. SCATTERED CALCITE GRAINS.

BROKEN FROM 5.0' - 5.5' AND 6.8' - 7.1'. 1/2" HORIZONTAL CLAYEY SILT SEAM @ 7.0'.

NEAR HORIZONTAL CALCITE LAMINAE @ 17.0' - 22.0'.

BROKEN ALONG VERTICAL JOINT @ 25.3' - 25.9'.

B-11

Elev. 244.0

C.R. = 100%

0.0' - 2.0' SILT WITH SILTSTONE FRAGMENTS:

2.0' - 27.0' SILTSTONE: SOFT, WEATHERED TO 12.0'.

BELOW 12.0', RED-BROWN, MEDIUM HARD UNWEATHERED WITH SCATTERED STEEPLY DIPPING CALCITE-FILLED JOINTS.

BROKEN ALONG FRACTURE @ 22.0' - 22.6'.

B-12

Elev. 243.4

C.R. = 79%

0.0' - 1.0' SILT WITH SILTSTONE FRAGMENTS:

1.0' - 32.5' SILTSTONE: SOFT, HIGHLY WEATHERED TO 12.0'.

BELOW 12.0', RED-BROWN TO GRAY, MEDIUM HARD WITH SEVERAL STEEPLY DIPPING CALCITE-FILLED JOINTS.

NOTES:

1. For explanation of symbols, see sheet 27, Figure 2.5-22.
2. For location of borings, see Figure 2.5-20.
3. Holes 2 through 39A are numbered to indicate plinth foundation for the Unit 1 cooling tower where hole was drilled.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

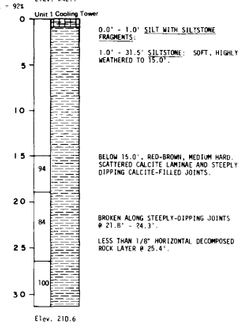
GRAPHIC LOGS
SHEET 30 OF 37

FIGURE 2.5-22

B-13

Elev. 242.1

C.R. = 92%



0.0' - 1.0' SILT WITH SILTSTONE FRAGMENTS:

1.0' - 31.5' SILTSTONE: SOFT, HIGHLY WEATHERED TO 15.0'.

BELOW 15.0', RED-BROWN, MEDIUM HARD, SCATTERED CALCITE LAMINAE AND STEEPLY DIPPING CALCITE-FILLED JOINTS.

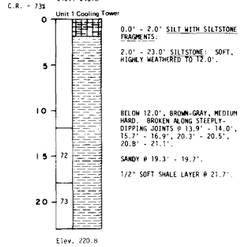
BROKEN ALONG STEEPLY-DIPPING JOINTS @ 21.8' - 24.3'.

LESS THAN 1/8" HORIZONTAL DECOMPOSED ROCK LAYER @ 25.4'.

B-14

Elev. 243.8

C.R. = 73%



0.0' - 2.0' SILT WITH SILTSTONE FRAGMENTS:

2.0' - 23.0' SILTSTONE: SOFT, HIGHLY WEATHERED TO 12.0'.

BELOW 12.0', BROWN-GRAY, MEDIUM HARD, BROKEN ALONG STEEPLY-DIPPING JOINTS @ 13.9' - 14.0', 15.7' - 16.9', 20.3' - 20.5', 20.8' - 21.1'.

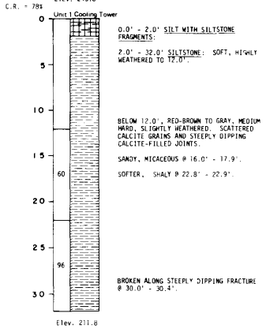
SANDY @ 19.3' - 19.7'.

1/2" SOFT SHALE LAYER @ 21.7'.

B-15

Elev. 243.8

C.R. = 78%



0.0' - 2.0' SILT WITH SILTSTONE FRAGMENTS:

2.0' - 32.0' SILTSTONE: SOFT, HIGHLY WEATHERED TO 12.0'.

BELOW 12.0', RED-BROWN TO GRAY, MEDIUM HARD, SLIGHTLY WEATHERED. SCATTERED CALCITE GRAINS AND STEEPLY DIPPING CALCITE-FILLED JOINTS.

SANDY, MICACEOUS @ 16.0' - 17.9'.

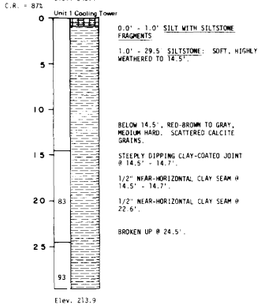
SOFTER, SHALY @ 22.8' - 22.9'.

BROKEN ALONG STEEPLY DIPPING FRACTURE @ 30.0' - 30.4'.

B-16

Elev. 243.4

C.R. = 87%



0.0' - 1.0' SILT WITH SILTSTONE FRAGMENTS

1.0' - 29.5' SILTSTONE: SOFT, HIGHLY WEATHERED TO 14.5'.

BELOW 14.5', RED-BROWN TO GRAY, MEDIUM HARD, SCATTERED CALCITE GRAINS.

STEEPLY DIPPING CLAY-COATED JOINT @ 14.5' - 14.7'.

1/2" NEAR-HORIZONTAL CLAY SEAM @ 14.5' - 14.7'.

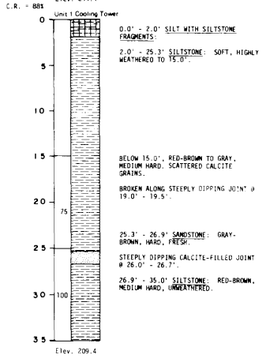
1/2" NEAR-HORIZONTAL CLAY SEAM @ 22.6'.

BROKEN UP @ 24.5'.

B-17

Elev. 244.4

C.R. = 88%



0.0' - 2.0' SILT WITH SILTSTONE FRAGMENTS:

2.0' - 25.3' SILTSTONE: SOFT, HIGHLY WEATHERED TO 15.0'.

BELOW 15.0', RED-BROWN TO GRAY, MEDIUM HARD, SCATTERED CALCITE GRAINS.

BROKEN ALONG STEEPLY DIPPING JOINT @ 19.0' - 19.5'.

25.3' - 26.9' SANDSTONE: GRAY-BROWN, HARD, FRESH.

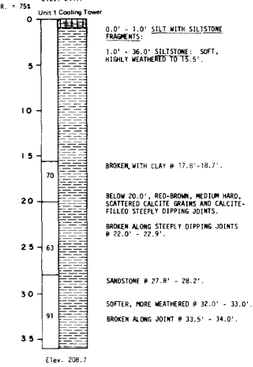
STEEPLY DIPPING CALCITE-FILLED JOINT @ 26.0' - 26.7'.

26.9' - 35.0' SILTSTONE: RED-BROWN, MEDIUM HARD, UNWEATHERED.

B-18

Elev. 244.7

C.R. = 75%



0.0' - 1.0' SILT WITH SILTSTONE FRAGMENTS:

1.0' - 36.0' SILTSTONE: SOFT, HIGHLY WEATHERED TO 15.5'.

BROKEN WITH CLAY @ 17.8'-18.7'.

BELOW 20.0', RED-BROWN, MEDIUM HARD, SCATTERED CALCITE GRAINS AND CALCITE-FILLED STEEPLY DIPPING JOINTS.

BROKEN ALONG STEEPLY DIPPING JOINTS @ 22.0' - 22.9'.

SANDSTONE @ 27.8' - 28.2'.

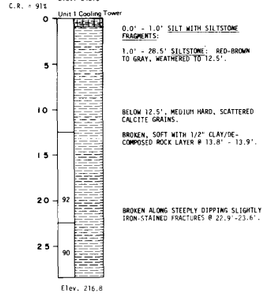
SOFTER, MORE WEATHERED @ 32.0' - 33.0'.

BROKEN ALONG JOINT @ 33.5' - 34.0'.

B-19

Elev. 245.3

C.R. = 91%



0.0' - 1.0' SILT WITH SILTSTONE FRAGMENTS:

1.0' - 28.5' SILTSTONE: RED-BROWN TO GRAY, WEATHERED TO 12.5'.

BELOW 12.5', MEDIUM HARD, SCATTERED CALCITE GRAINS.

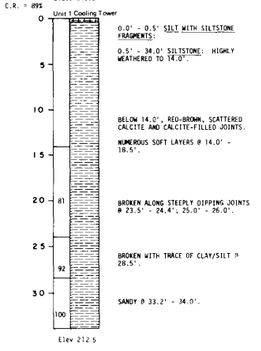
BROKEN, SOFT WITH 1/2" CLAY/DE-COMPOSED ROCK LAYER @ 13.8' - 13.9'.

BROKEN ALONG STEEPLY DIPPING SLIGHTLY IRON-STAINED FRACTURES @ 22.9'-23.6'.

B-20

Elev. 246.5

C.R. = 89%



0.0' - 0.5' SILT WITH SILTSTONE FRAGMENTS:

0.5' - 34.0' SILTSTONE: HIGHLY WEATHERED TO 14.0'.

BELOW 14.0', RED-BROWN, SCATTERED CALCITE AND CALCITE-FILLED JOINTS.

NUMEROUS SOFT LAYERS @ 14.0' - 18.5'.

BROKEN ALONG STEEPLY DIPPING JOINTS @ 23.5' - 24.4', 25.0' - 26.0'.

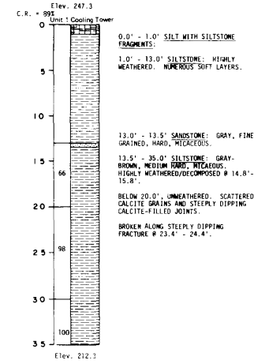
BROKEN WITH TRACE OF CLAY/SILT @ 28.5'.

SANDY @ 33.2' - 34.0'.

B-21

Elev. 247.3

C.R. = 89%



0.0' - 1.0' SILT WITH SILTSTONE FRAGMENTS:

1.0' - 13.0' SILTSTONE: HIGHLY WEATHERED. NUMEROUS SOFT LAYERS.

13.0' - 13.5' SANDSTONE: GRAY, FINE GRAINED, HARD, MICACEOUS.

13.5' - 35.0' SILTSTONE: GRAY-BROWN, MEDIUM HARD, MICACEOUS. HIGHLY WEATHERED/DECOMPOSED @ 14.8'-15.8'.

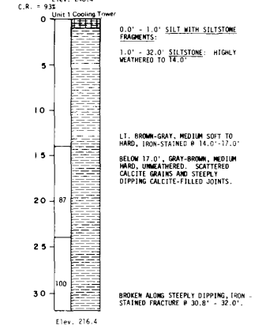
BELOW 20.0', UNWEATHERED. SCATTERED CALCITE GRAINS AND STEEPLY DIPPING CALCITE-FILLED JOINTS.

BROKEN ALONG STEEPLY DIPPING FRACTURE @ 23.4' - 24.4'.

B-22

Elev. 248.4

C.R. = 93%



0.0' - 1.0' SILT WITH SILTSTONE FRAGMENTS:

1.0' - 32.0' SILTSTONE: HIGHLY WEATHERED TO 14.0'.

LT. BROWN-GRAY, MEDIUM SOFT TO HARD, IRON-STAINED @ 14.0'-17.0'.

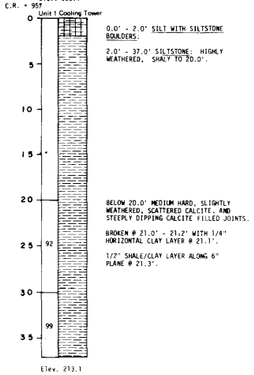
BELOW 17.0', GRAY-BROWN, MEDIUM HARD, UNWEATHERED. SCATTERED CALCITE GRAINS AND STEEPLY DIPPING CALCITE-FILLED JOINTS.

BROKEN ALONG STEEPLY DIPPING, IRON-STAINED FRACTURE @ 30.8' - 32.0'.

B-23

Elev. 250.1

C.R. = 95%



0.0' - 2.0' SILT WITH SILTSTONE BOULDERS:

2.0' - 37.0' SILTSTONE: HIGHLY WEATHERED, SHALY TO 20.0'.

BELOW 20.0' MEDIUM HARD, SLIGHTLY WEATHERED, SCATTERED CALCITE, AND STEEPLY DIPPING CALCITE FILLED JOINTS.

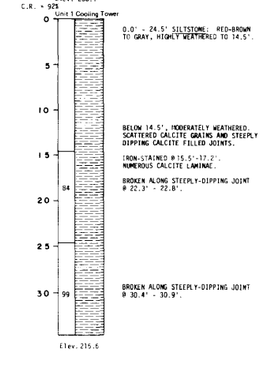
BROKEN @ 21.0' - 21.2' WITH 1/4" HORIZONTAL CLAY LAYER @ 21.1'.

1/2" SHALE/CLAY LAYER ALONG 6° PLANE @ 21.3'.

B-24

Elev. 250.1

C.R. = 92%



0.0' - 24.5' SILTSTONE: RED-BROWN TO GRAY, HIGHLY WEATHERED TO 14.5'.

BELOW 14.5', MODERATELY WEATHERED, SCATTERED CALCITE GRAINS AND STEEPLY DIPPING CALCITE FILLED JOINTS.

IRON-STAINED @ 15.5'-17.2'. NUMEROUS CALCITE LAMINAE.

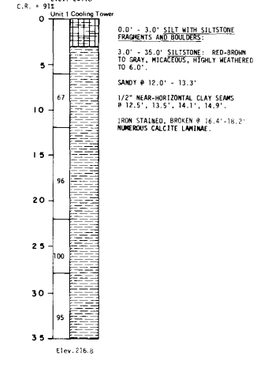
BROKEN ALONG STEEPLY-DIPPING JOINT @ 22.3' - 22.8'.

BROKEN ALONG STEEPLY-DIPPING JOINT @ 30.4' - 30.9'.

B-25

Elev. 251.8

C.R. = 91%



0.0' - 3.0' SILT WITH SILTSTONE FRAGMENTS AND BOULDERS:

3.0' - 36.0' SILTSTONE: RED-BROWN TO GRAY, MICACEOUS, HIGHLY WEATHERED TO 6.0'.

SANDY @ 12.0' - 13.3'

1/2" NEAR-HORIZONTAL CLAY SEAMS @ 12.5', 13.5', 14.1', 14.9'.

IRON STAINED, BROKEN @ 16.4'-16.2' NUMEROUS CALCITE LAMINAE.

NOTES:

1. For explanation of symbols, see sheet 27, Figure 2.5-22.
2. For location of borings, see Figure 2.5-20.

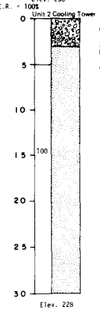
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 31 OF 37

FIGURE 2.5-22

T-2-1

Elev. 258
C.R. = 100%
Unit 2 Cooling Tower

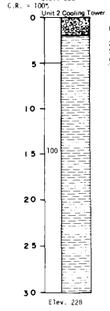


0.0' - 3.0' OVERBURDEN

3.0' - 30.0' SANDSTONE: GRAY, HARD, GRADING TO RED, SILTSTONE IN PART, CORE LENGTHS AVERAGE 4 INCHES, BELOW 13' AVERAGE 10-15 INCH CORE LENGTHS.

T-2-2

Elev. 258
C.R. = 100%
Unit 2 Cooling Tower

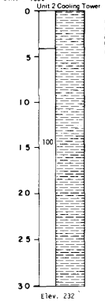


0.0' - 2.0' OVERBURDEN

2.0' - 30.0' SILTSTONE: RED, HARD, SANDSTONE IN PART, CORE LENGTHS AVERAGE 2 INCHES TO DEPTH 10'. BELOW 10' AVERAGE IS 12-16 INCHES.

T-2-3

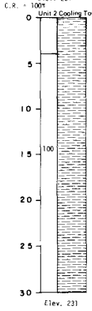
Elev. 262
C.R. = 100%
Unit 2 Cooling Tower



0.0' - 30.0' SILTSTONE: RED, HARD, GRAY SANDSTONE IN PART. PROMINENT NEAR HORIZONTAL BEDDING FRACTURES WITH OCCASIONAL NEAR VERTICAL JOINTS. CORE LENGTHS AVERAGE 10 INCHES.

T-2-4

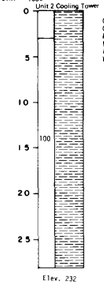
Elev. 261
C.R. = 100%
Unit 2 Cooling Tower



0.0' - 30.0' SILTSTONE: RED, HARD, SANDY IN PART AND GRADES TO SANDSTONE TO DEPTH OF 12 FEET. BELOW 12 FEET, ROCK IS PRIMARILY SILTSTONE. CORE LENGTHS AVERAGE 3 INCHES TO 12'. BELOW DEPTH OF 12' AVERAGE IS OVER 10 INCHES. MOST CORE BREAKS ALONG NEARLY HORIZONTAL BEDDING.

T-2-5

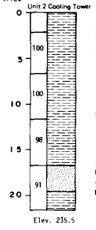
Elev. 260
C.R. = 100%
Unit 2 Cooling Tower



0.0' - 28.0' SANDSTONE: RED TO GRAY, VERY HARD, SILTSTONE IN PART. SCATTERED JOINTING PRIMARILY PARALLEL TO BEDDING. CORE LENGTHS AVERAGE 6-10 INCHES, INCREASING WITH DEPTH.

I* (see note 3)

Elev. 257
C.R. = 97.2%
Unit 2 Cooling Tower



0.0' - 16.5' SILTSTONE: RED-BROWN, HIGHLY WEATHERED TO 2.5', UNWEATHERED BELOW EXCEPT FOR SEVERAL LOCAL CLAY SEAMS UP TO 3/4" WIDE AND SCATTERED JOINTING.

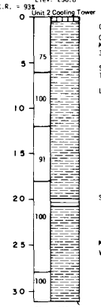
SHALE LAYERS @ 13.1' AND 13.7'.

16.5' - 19.5' SANDSTONE: GRAY-BROWN, FINE GRAINED, HARD.

19.5' - 21.5' SILTSTONE: RED-BROWN, MEDIUM HARD, UNWEATHERED.

4

Elev. 256.8
C.R. = 93%
Unit 2 Cooling Tower



0.0' - 0.5' SILT

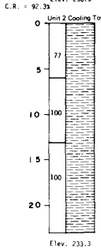
0.5' - 31.0' SILTSTONE: RED-BROWN, MEDIUM HARD, MODERATELY WEATHERED 3/4" NEAR-HORIZONTAL CLAY/DECOMPOSED ROCK SEAM @ 2.9'.
STEEPLY-DIPPING JOINTS @ 8.9'-9.8'.
1/4" CLAY/DECOMPOSED ROCK SEAM ALONG 45° JOINT @ 9.8'.
LESS THAN 1/4" SHALE LAYER @ 11'.

SHALE @ 20.0' - 20.8'.

MICACEOUS @ 28.0' - 30.0'.
VERY MICACEOUS @ 30.0' - 31.0'.

7

Elev. 256.3'
C.R. = 92.3%
Unit 2 Cooling Tower

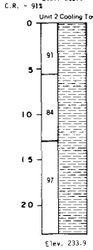


0.0' - 23.0' SILTSTONE: RED-BROWN, MEDIUM-HARD UNWEATHERED, CALCITE GRAINS SCATTERED THROUGHOUT, CORE BROKEN UP 0.0' - 0.5'.
STEEPLY-DIPPING CALCITE-COATED JOINTS @ 1.0'-2.5' AND 3.4'-4.1'.

STEEPLY-DIPPING JOINT @ 14.7' - 16.7'.

10

Elev. 256.9
C.R. = 91%
Unit 2 Cooling Tower



0.0' - 23.0' SILTSTONE: RED-BROWN, MEDIUM HARD, UNWEATHERED EXCEPT FOR SLIGHT WEATHERING 0.0'-3.0'.

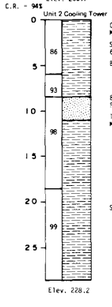
CALCITE LAMINAE AND JOINTING @ 0.5'-3.2'.
SPACING OF 1/8" TO 1/4".

JOINT DIPPING 75° WITH 1/16" CLAY COATING @ 10.3' - 11.1'.

STEEPLY DIPPING JOINTS @ 13.0' - 14.3'.

14

Elev. 256.7
C.R. = 94%
Unit 2 Cooling Tower



0.0' - 8.5' SILTSTONE: RED-BROWN, MEDIUM HARD, UNWEATHERED.

STEEPLY DIPPING JOINTS @ 1/2'-2' AND 6' - 8'.

BROKEN FROM 8' - 8.5'.

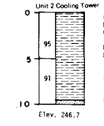
8.5' - 11.0' SANDSTONE: GRAY-BROWN, FINE GRAINED, HARD.

11.0' - 28.5' SILTSTONE: RED-BROWN, MEDIUM HARD, UNWEATHERED.

STEEPLY DIPPING JOINT @ 23.8' - 24.4'.

14-A

Elev. 256.7
C.R. = 96%
Unit 2 Cooling Tower



0.0' - 9.6' SILTSTONE: RED-BROWN, MEDIUM HARD, UNWEATHERED, BREAKS COMMONLY ALONG 12" PLANES.

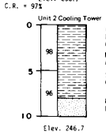
BROKEN @ 5.0' - 5.2' AND 8.0' - 8.6'.

1/8" - 1/4" CLAY/SILT LAYER WITH ROCK FRAGMENTS @ 8.6'.

9.6' - 10.0' SANDSTONE: GRAY-BROWN, FINE GRAINED, HARD.

14-B

Elev. 256.7
C.R. = 97%
Unit 2 Cooling Tower



0.0' - 8.0' SILTSTONE: RED-BROWN, MEDIUM HARD; SCATTERED CALCITE GRAINS, BROKEN UP @ 0.0'-0.5'.

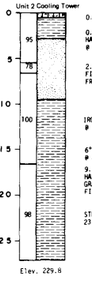
NEAR VERTICAL JOINTS @ 2.1' - 2.8' AND 7.7' - 10.0'.

SHALEY, BROKEN WITH LESS THAN 1/16" CLAY ALONG 6° PLANE @ 7.7'.

8.0'-10.0' SANDSTONE: BROWN-GRAY, FINE GRAINED, HARD.

18

Elev. 256.8'
C.R. = 92.7%
Unit 2 Cooling Tower



0.0' - 0.5' SILT AND DECOMPOSED ROCK.

0.5' - 2.8' SILTSTONE: RED-BROWN, HARD, STEEPLY DIPPING FRACTURES @ 0.5' - 2.4'.

2.8' - 9.5' SANDSTONE: GRAY-BROWN; FINE GRAINED, HARD; STEEPLY DIPPING FRACTURES @ 3.2'-4.8'.

IRON STAINED CLAY-COATED FRACTURE @ 5.5' - 8.0'.

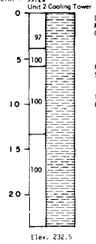
6° PLANE WITH THIN CLAY COATING @ 8.0'.

9.5'-27.0' SILTSTONE: RED-BROWN, HARD, UNWEATHERED; SCATTERED CALCITE GRAINS AND STEEPLY DIPPING CALCITE FILLED JOINTS.

STEEPLY DIPPING FRACTURES @ 22.8'-23.1' AND 25.0'-26.0'.

22

Elev. 256.0'
C.R. = 99.2%
Unit 2 Cooling Tower



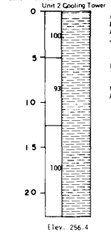
0.0' - 23.5' SILTSTONE: RED-BROWN, MEDIUM HARD, SCATTERED CALCITE GRAINS AND CALCITE FILLED JOINTS.

NEAR-HORIZONTAL 1" DECOMPOSED ROCK/SILT SEAM @ 2.5'.

1/2" NEAR-HORIZONTAL DECOMPOSED ROCK SEAM @ 2.7'.

26

Elev. 256.4
C.R. = 97.6%
Unit 2 Cooling Tower



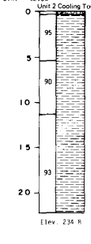
0.0' - 22.5' SILTSTONE: RED-BROWN, MEDIUM HARD, SCATTERED CALCITE GRAINS AND CALCITE FILLED STEEPLY DIPPING JOINTS.

BROKEN FROM 0.0' - 0.3' AND 1.0' - 1.2'.

NEAR-VERTICAL JOINTS @ 10.0' - 10.5' AND 17.5' - 19.3'.

28

Elev. 256.78
C.R. = 92.6%
Unit 2 Cooling Tower



0.0' - 0.5' OVERBURDEN:

0.5' - 22.0' SILTSTONE: RED-BROWN, MEDIUM HARD;CONTAINS CALCITE LAMINAE AND CALCITE-FILLED JOINTS.

STEEPLY-DIPPING JOINTS @ 1.4' - 3.3' AND 16.0' - 16.3'.

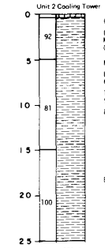
THIN CLAY COATING ON JOINT @ 1.4' - 2.0'.

BROKEN INTO 1/4" PIECES @ 18.1' - 18.3'.

1-1/2" SHALY LAYER @ 18.3'.

29

Elev. 256.9
C.R. = 91%
Unit 2 Cooling Tower



0.0' - 0.5' SILT AND ROCK FRAGMENTS:

0.5' - 25.0' SILTSTONE: RED-BROWN, MEDIUM HARD, SCATTERED CALCITE AND CALCITE FILLED JOINTS.

NEAR-VERTICAL FRACTURE @ 3.5' - 4.0'.

BROKEN @ 2.9'-3.0'; 5.4'-5.6', 6.5'-6.8'; 7.6'-8.0'.

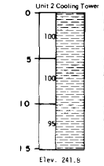
1/2" NEAR HORIZONTAL CLAY SEAM @ 9.1'.

BROKEN WITH SOFT ROCK @ 12.6'-12.8'.

BECOMES GRAY, MICACEOUS @ 21.0'.

30

Elev. 256.78
C.R. = 98.3%
Unit 2 Cooling Tower



0.0'-15.0' SILTSTONE: RED-BROWN, MEDIUM HARD; SCATTERED CALCITE AND NEAR-VERTICAL CALCITE FILLED JOINTS.

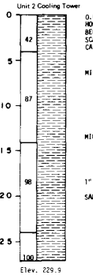
BROKEN INTO 1/8"-3/4" PIECES @ 1.0'-1.4', 1.8'-2.2' AND 7.4' - 8.0'.

SHALY , SOFTER @ 7.4'-8.0'.

STEEPLY DIPPING FRACTURES WITH 1/4"-1/2" CLAY @ 4.3'-5.0', CLEAN FRACTURES @ 2.9'-3.9' AND 5.9'-6.8'.

32

Elev. 256.9
C.R. = 81.7%
Unit 2 Cooling Tower



0.0'-27.0' SILTSTONE: RED-BROWN, HORIZONTAL CLAY SEAMS TO 4.0', BECOMES MEDIUM HARD BELOW; SCATTERED CALCITE GRAINS AND CALCITE FILLED JOINTS.

MICACEOUS @ 7.0'-10.8'

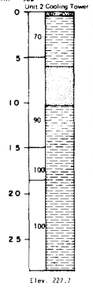
MICACEOUS @ 14.0'-17.0'.

1" SHALE LAYER @ 20.0'.

SANDY @ 20.3'-21.0'.

34

Elev. 256.2
C.R. = 90%
Unit 2 Cooling Tower



0.0'-0.5' OVERBURDEN:

0.5'-6.0' SILTSTONE: RED-BROWN, NUMEROUS NEAR-HORIZONTAL CLAY SEAMS 1"-1-1/2" WIDE FROM 0.0' - 3.0'.; MODERATELY WEATHERED BELOW.

6.0'-10.6' SANDSTONE: GRAY-BROWN, FINE GRAINED, MICACEOUS, 1" MODERATELY SOFT SHALE LAYER @ 10.5'.

1-1/2" MODERATELY SOFT SHALE LAYER @ 11.9'.

10.6'-28.5' SILTSTONE: RED-BROWN, MEDIUM HARD, CONTAINS SEVERAL STEEPLY-DIPPING CALCITE FILLED JOINTS.

MICACEOUS, SANDY AT 12.5'-14.0'. SHALE LAYER @ 22.8'.

35

Elev. 256.7'
C.R. = 76.5%
Unit 2 Cooling Tower



0.0' - 1.0' SILT WITH ROCK FRAGMENTS

1.0' - 6.5' SILTSTONE: RED-BROWN, HIGHLY WEATHERED; NUMEROUS CLAY SEAMS ALONG 10°-12° BEDDING.

6.5' - 9.0' SANDSTONE: GRAY-BROWN HARD; 1/2" SOFT HORIZONTAL SEAMS @ 6.8' AND 8.7'

9.0' - 33.0' SILTSTONE: RED-BROWN, TO GRAY, MEDIUM HARD; CONTAINS SCATTERED CALCITE GRAINS.

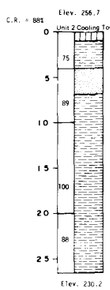
GRAY, MICACEOUS @ 16.9' - 18.9' WITH SOME SHALE LAYERS.

2" CLAY SEAM ALONG 8° PLANE @ 24.3'

1/2" NEAR VERTICAL LAYER OF SOFT DECOMPOSED ROCK @ 31.9'.

35 A

Elev. 256.7
C.R. = 88%
Unit 2 Cooling Tower



0.0' - 1.0' SILT WITH ROCK FRAGMENTS

1.0' - 4.0' SILTSTONE: RED-BROWN, CONTAINS NUMEROUS CLAY SEAMS UP TO 3-1/2" WIDE.

4.0' - 7.0' SANDSTONE: GRAY-BROWN, FINE GRAINED HARD.

7.0' - 26.5' SILTSTONE: RED-BROWN, MEDIUM HARD, UNWEATHERED EXCEPT WHERE NOTED.

1-1/2" SHALE LAYER @ 6.5'.

2" SOFT SHALE LAYER @ 7.4'.

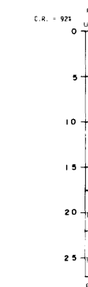
SANDY @ 10.0' - 10.6'.

1/8" - 1/4" SHALE LAYERS @ 8.2' - 9.1'; 10.5' - 19.3' and 20.0'.

STEEPLY DIPPING JOINTS WITH SOME CLAY COATING @ 22.8 - 23.2 and 25.0' - 25.5'.

35B

Elev. 256.7
C.R. = 92%
Unit 2 Cooling Tower



0.0' - 2.0' SILT WITH ROCK FRAGMENTS:

2.0' - 3.0' SILTSTONE: RED-BROWN, HIGH-Y WEATHERED.

3.0' - 5.0' SANDSTONE: GRAY, MEDIUM-HARD, 1/2" CLAY SEAM @ 4.0'; LEACHED FROM 5.3' - 5.5'.

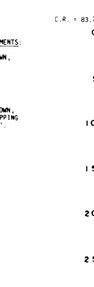
5.8' - 27.0' SILTSTONE: RED-BROWN, LOCALLY BROKEN ALONG STEEPLY DIPPING JOINTS. BROKEN FROM 5.8' - 6.2'.

3/4" CLAY SEAM @ 8.7'.

SANDSTONE @ 10.4' - 10.9'.

38

Elev. 256.7
C.R. = 83.7%
Unit 2 Cooling Tower



0.0' - 5.0' SILTSTONE: RED-BROWN, MEDIUM HARD; NUMEROUS CLAY AND DECOMPOSED ROCK SEAMS UP TO 1" THICK.

5.0' - 8.0' SANDSTONE: GRAY TO RED-BROWN, FINE TO MEDIUM GRAINED HARD, GRADES TO SILTY @ 7.0'.

8.0' - 25.0' SILTSTONE: RED-BROWN, HARD, WITH SCATTERED CALCITE COATED JOINTS BROKEN @ 8.4' - 9.4'.

NEAR HORIZONTAL SILT-COATED JOINT @ 12.5'.

75° JOINT @ 12.8' - 13.1'.

NEAR HORIZONTAL JOINT WITH TRACE OF CLAY @ 17.5'.

STEEPLY DIPPING JOINTS @ 7.5' - 18.5'.

BROKEN INTO 1/2" - 1" PIECES @ 21.5' - 22.2'.

NOTES:

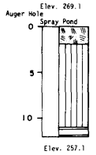
1. For explanation of symbols, see sheet 27, Figure 2.5-22.
2. For location of borings, see Figure 2.5-20
3. Holes I through 38 are numbered to indicate plinth foundation for the Unit 2 cooling tower where hole was drilled.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GRAPHIC LOGS
SHEET 32 OF 37

FIGURE 2.5-22

A-1

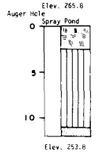


0.0' - 2.0' FILL

2.0' - 11.0' SILT (ML): YELLOW BROWN, SANDY

11.0' - 12.0' SHALE: YELLOW-GRAY, HIGHLY WEATHERED.

A-2

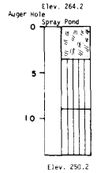


0.0' - 2.5' FILL

2.5' - 11.0' SILT: YELLOW BROWN, CLAYEY, BECOMES MORE CLAYEY WITH DEPTH. SCATTERED SANDSTONE FRAGMENTS, TO 5.5 FEET.

11.0' - 12.0' SANDSTONE: SOFT, WEATHERED.

A-3

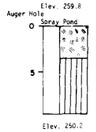


0.0' - 3.5' FILL

3.5' - 9.0' SILT (ML): YELLOW-BROWN

9.0' - 14.0' CLAYEY SILT (ML): LIGHT BROWN WITH NUMEROUS SHALE FRAGMENTS LESS THAN 1/8 INCH DIAMETER. BECOMES YELLOW-BROWN CLAYEY, FINE SILTY-SAND AT 12.5 FEET.

A-4

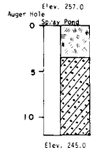


0.0' - 3.5' FILL

3.5' - 9.6' SILTY SAND: YELLOW-BROWN TO RED-BROWN, VERY CLAYEY.

REFUSAL AT 9.6 FEET.

A-5

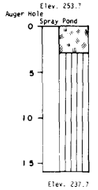


0.0' - 3.5' FILL

3.5' - 17.0' CLAYEY SAND (SC): BROWN, FINE; SILTY. BECOMING RED TO RED BROWN AT 7.0 FEET. INCREASING CLAY CONTENT WITH DEPTH.

REFUSAL AT 12.0 FEET

A-6

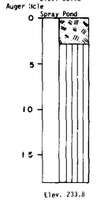


0.0' - 3.0' FILL

3.0' - 16.0' SILT: RED BROWN, CLAYEY. SCATTERED SHALE FRAGMENTS FROM 7.0 - 13.0 FEET.

REFUSAL AT 16.0 FEET

A-7

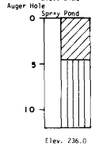


0.0' - 3.0' FILL

3.0' - 18.0' SILT (ML): LIGHT BROWN TO YELLOW BROWN, CLAYEY. BECOMES REDDISH BROWN TO RED AT 8.0 FEET.

REFUSAL AT 18.0 FEET.

A-8

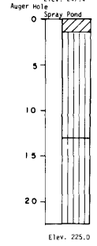


0.0' - 4.6' SILTY CLAY: YELLOW BROWN.

4.6' - 12.0' SILTY SAND: RED-BROWN, VERY FINE. TRACES OF MEDIUM TO COARSE SAND.

REFUSAL AT 12.0 FEET.

A-9



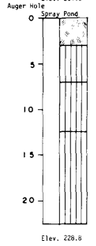
0.0' - 1.5' CLAY (CL): BROWN, SILTY, SOFT, CONTAINS MUCH ORGANIC MATERIAL AND MICA.

1.5' - 13.0' SILT (ML): RED-BROWN WITH SCATTERED PIECES OF ORGANIC MATERIAL

13.0' - 22.4' SILT (ML): RED-BROWN WITH THIN LAYERS OF HIGHLY WEATHERED SHALE.

REFUSAL AT 22.4 FEET

A-10



0.0' - 3.0' FILL

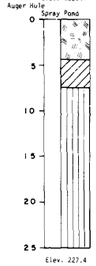
3.0' - 7.0' CLAY (CL): DARK BROWN

7.0' - 12.5' SILT (ML): LIGHT BROWN, SLIGHTLY CLAYEY

12.5' - 22.5' CLAYEY SILT: RED-BROWN TO RED, BECOMING LESS CLAYEY AT 17.0 FEET. SCATTERED SHALE FRAGMENTS, LESS THAN 0.25 INCHES DIAMETER BELOW 17.0 FEET.

REFUSAL AT 22.5 FEET

A-11



0.0 - 4.5' FILL

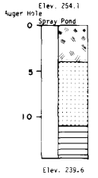
4.5' - 7.5' CLAY: BROWN, SILTY, VERY SOFT, WET

7.5' - 25.0' SILT: BROWN, VERY SOFT, WET

18.0' - 20.0' TRACES OR MEDIUM-GRAINED SAND. GRADES INTO SOFT, RED SHALE

REFUSAL AT 25.0 FEET

A-12



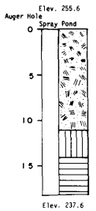
0.0' - 4.0' FILL

4.0' - 11.0' SAND: BLACK TO BROWN VERY SILTY, CLAYEY, FINE TO MEDIUM GRAINED. BECOMES REDDISH BROWN WITH SHALE FRAGMENTS AT 7.0 FEET.

11.0' - 14.5' SHALE: RED, HIGHLY WEATHERED.

REFUSAL AT 14.5 FEET.

A-13



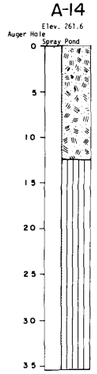
0.0' - 11.0' FILL

11.0' - 14.0' SILT: RED-BROWN WITH SHALE FRAGMENTS.

14.0' - 18.0' SHALE: RED, HIGHLY WEATHERED.

REFUSAL AT 18.0 FEET

A-14



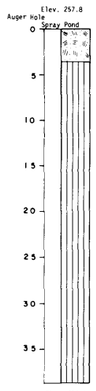
0.0' - 12.5' FILL

12.5' - 35.5' SILT, BROWNISH-RED, CLAYEY.

LESS CLAYEY BELOW 17.5.

REFUSAL AT 35.5 FEET

A-15

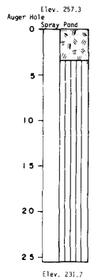


0.0' - 3.5' FILL

3.5' - 39.0' SILT: BROWN, CLAYEY, TO 5.0 FEET. RED-BROWN BELOW 5.0 FEET.

REFUSAL AT 39.0 FEET

A-16

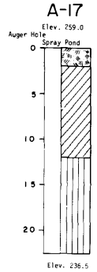


0.0' - 3.5' FILL

3.5' - 25.6' SILT: LIGHT BROWN TO REDDISH BROWN, VERY CLAYEY. BECOMES LESS CLAYEY AT 4.5 FEET.

REFUSAL AT 25.6 FEET

A-17



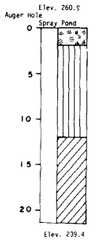
0.0' - 2.0' FILL

2.0' - 12.0' SILTY CLAY: DARK BROWN, SANDY. FINE TO MEDIUM GRAINED.

12.0' - 22.5' SILT LIGHT BROWN.

REFUSAL AT 22.5 FEET.

A-18



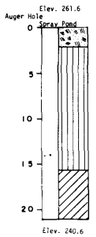
0.0' - 2.0' FILL

2.0' - 12.0' SILT (ML): YELLOW BROWN, SLIGHTLY CLAYEY.

12.0' - 21.5' CLAY (CL): YELLOW-BROWN, SILTY, TRACES OF MEDIUM SAND. BECOMES SANDY CLAY AT 18.0 FEET.

REFUSAL AT 21.5 FEET.

A-19



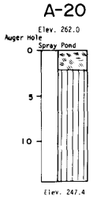
0.0' - 2.0' FILL

2.0' - 15.6' SILT (ML): YELLOW, BROWN

15.6' - 21.0' SILTY CLAY (CL): DARK BROWN WITH SCATTERED GRAVEL. BECOMES BLACK AT 19.6 FEET.

REFUSAL AT 21.0 FEET.

A-20

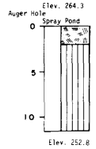


0.0' - 2.0' FILL

2.0' - 14.6' SILT (ML): LIGHT TO MEDIUM BROWN, CLAYEY

REFUSAL AT 14.6 FEET

A-21

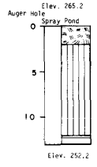


0.0' - 2.0' FILL

2.0' - 11.5' SILT (ML): YELLOW TO GREENISH BROWN, SCATTERED GREEN-GRAY SHALE FRAGMENTS LESS THAN 1/8 INCH IN DIAMETER.

REFUSAL AT 11.5 FEET.

A-22



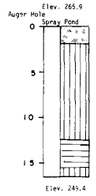
0.0' - 2.0' FILL

2.0' - 12.0' SILT (ML): YELLOW-BROWN, SLIGHTLY CLAYEY.

12.0' - 13.0' SHALE: HIGHLY WEATHERED.

REFUSAL AT 13.0 FEET

A-23



0.0' - 2.0' FILL

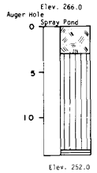
2.0' - 12.5' SILT (ML): YELLOW-BROWN, BECOMES LIGHT BROWN WITH TRACES OF CLAY AT 11.0 FEET.

12.5' - 15.5' SHALE: GREEN-YELLOW, MODERATELY HARD.

15.5' - 16.5' SILT (ML): DARK BROWN.

REFUSAL AT 16.5 FEET.

A-24



0.0' - 3.0' FILL

3.0' - 13.5' CLAYEY SILT (ML): YELLOW BROWN.

13.5' - 14.0' SHALE: HIGHLY WEATHERED

REFUSAL AT 14.0 FEET.

NOTES:

1. For explanation of symbols, see sheet 27, Figure 2.5-22.
2. For location of borings, see Figure 2.5-20.

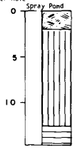
LIMERICK GENERATING STATION
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GRAPHIC LOGS
SHEET 33 OF 37

FIGURE 2.5-22

A-25

Auger Hole
Elev. 266.7
Spray Pond



Elev. 252.1

0.0' - 2.0' FILL

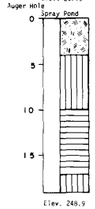
2.0' - 12.4' CLAYEY SILT (ML): YELLOW-BROWN.

12.6' - 14.6' SHALE: GREEN, HIGHLY WEATHERED.

REFUSAL AT 14.6 FEET.

A-26

Auger Hole
Elev. 267.9
Spray Pond



Elev. 248.9

0.0' - 4.0' FILL

4.0' - 10.0' SILT (ML): YELLOW-BROWN.

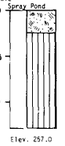
10.0' - 17.0' SHALE: YELLOW-GREEN, HIGHLY WEATHERED, VERY HARD FROM 12.0-13.0 FEET.

17.0' - 19.0' SILT (ML): DARK BROWN, SANDY.

REFUSAL AT 19.0 FEET.

A-27

Auger Hole
Elev. 270.0
Spray Pond



Elev. 257.0

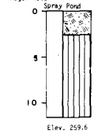
0.0' - 2.5' FILL

2.5' - 13.0' SILT (ML): YELLOW-BROWN WITH SCATTERED MEDIUM TO SMALL GRAVEL AND COARSE SAND; DISTINCT COLOR CHANGE AT 12.0 FEET TO BLACK WITH FRAGMENTS OF WEATHERED SHALE. DRILLING MORE DIFFICULT AT 12.0 FEET

REFUSAL AT 13.0 FEET

A-28

Auger Hole
Elev. 271.7
Spray Pond



Elev. 259.6

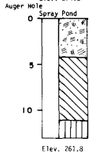
0.0' - 2.5' FILL

2.5' - 11.6' SILT (ML): YELLOW-BROWN, CLAYEY WITH TRACES OF FINE SAND. BECOMES DARK BROWN TO BLACK AT 9.0 FEET WITH MANY SHALE FRAGMENTS TO 1/4 INCH IN DIAMETER. DRILLING DIFFICULT AT 10.5 FEET.

REFUSAL AT 11.6 FEET.

A-29

Auger Hole
Elev. 274.8
Spray Pond



Elev. 261.8

0.0' - 4.0' FILL

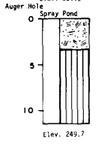
4.0' - 11.0' CLAY (CL): YELLOW-GRAY WITH SCATTERED SHALE FRAGMENTS.

11.0' - 13.0' SILT (ML): DARK BROWN, SANDY WITH SHALE FRAGMENTS.

REFUSAL AT 13.0 FEET.

A-30

Auger Hole
Elev. 261.2
Spray Pond



Elev. 249.7

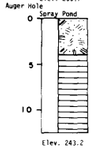
0.0' - 3.5' FILL

3.5' - 11.5' SILT (ML): DARK TO MEDIUM BROWN, CLAYEY.

REFUSAL AT 11.5 FEET.

A-31

Auger Hole
Elev. 255.7
Spray Pond



Elev. 243.2

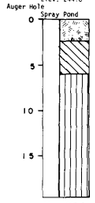
0.0' - 4.0' FILL

4.0' - 12.5' SHALE: GREEN-YELLOW, HIGHLY WEATHERED.

REFUSAL AT 12.5 FEET.

A-32

Auger Hole
Elev. 244.8
Spray Pond



Elev. 225.3

0.0' - 2.5' FILL

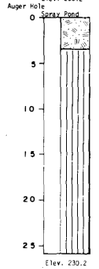
2.5' - 6.0' CLAY (CL)

6.0' - 19.5' SILT (ML): YELLOW-BROWN, TRACES OF CLAY.

REFUSAL AT 19.5 FEET

A-33

Auger Hole
Elev. 256.2
Spray Pond



Elev. 230.2

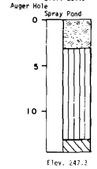
0.0' - 3.5' FILL

3.5' - 26.0' SILT (ML): MEDIUM TO DARK BROWN, BECOMES LIGHT BROWNISH YELLOW AT 12.0 FEET.

REFUSAL AT 26.0 FEET

A-34

Auger Hole
Elev. 261.8
Spray Pond



Elev. 247.3

0.0' - 3.0' FILL

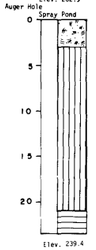
3.0' - 13.0' SILT (ML): MEDIUM BROWN, CLAYEY.

13.0' - 14.5' CLAY (CL): MEDIUM BROWN, SILTY.

REFUSAL AT 14.5 FEET.

A-35

Auger Hole
Elev. 262.9
Spray Pond



Elev. 239.4

0.0' - 3.0' FILL

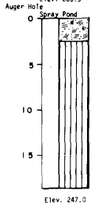
3.0' - 21.0' SILT (ML): LIGHT YELLOW TO YELLOW BROWN WITH FRAGMENTS OF HIGHLY WEATHERED SHALE.

21.0' - 23.5' SHALE: GREENISH YELLOW BECOMES GRAY TO BLACK AT 23.0 FEET.

REFUSAL AT 23.5 FEET.

A-36

Auger Hole
Elev. 265.5
Spray Pond



Elev. 247.0

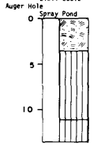
0.0' - 2.5' FILL

2.5' - 18.5' SILT (ML): YELLOW-BROWN, SLIGHTLY CLAYEY. BECOMES MORE CLAYEY BELOW 10 FEET.

REFUSAL AT 18.5 FEET.

A-37

Auger Hole
Elev. 266.2
Spray Pond



Elev. 252.7

0.0' - 3.5' FILL

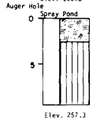
3.5' - 11.0' SILT (ML): YELLOW-BROWN, SLIGHTLY CLAYEY.

11.0' - 13.5' SILT (ML): DARK BROWN, CLAYEY WITH SHALE FRAGMENTS.

REFUSAL AT 13.5 FEET.

A-38

Auger Hole
Elev. 266.8
Spray Pond



Elev. 257.3

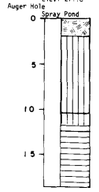
0.0' - 2.5' FILL

2.5' - 9.5' SILT (ML): YELLOW-BROWN.

REFUSAL AT 9.5 FEET.

A-39

Auger Hole
Elev. 271.8
Spray Pond



Elev. 253.3

0.0' - 2.0' FILL

2.0' - 10.5' SILT (ML): YELLOW-BROWN BECOMING DARK BROWN AT 9.0 FEET.

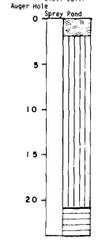
10.5' - 12.5' SILT (ML): BLACK

12.5' - 18.5' SHALE: YELLOW-GREEN, HIGHLY WEATHERED.

REFUSAL AT 18.5 FEET.

A-40

Auger Hole
Elev. 261.1
Spray Pond



Elev. 237.1

0.0' - 2.0' FILL

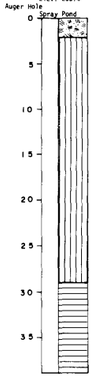
2.0' - 21.0' SILT: DARK BROWN, CLAYEY. BECOMES RED-BROWN AT 9.0 FEET.

21.0' - 24.0' SHALE, RED-BROWN, HIGHLY WEATHERED.

REFUSAL AT 24.0 FEET.

A-41

Auger Hole
Elev. 263.4
Spray Pond



Elev. 224.4

0.0' - 2.0' FILL

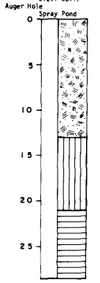
2.0' - 29.0' SILT: REDDISH, CLAYEY.

29.0' - 39.0' SHALE: HIGHLY WEATHERED, CLAYEY.

REFUSAL AT 39.0 FEET.

A-42

Auger Hole
Elev. 261.7
Spray Pond



Elev. 233.2

0.0' - 13.0' FILL

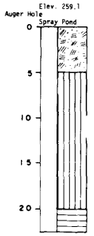
13.0' - 21.0' SILT: RED BROWN, CLAYEY.

21.0' - 28.5' SHALE: WEATHERED.

REFUSAL AT 28.5 FEET.

A-43

Auger Hole
Elev. 259.1
Spray Pond



Elev. 236.6

0.0' - 5.0' FILL

5.0' - 20.0' SILT

20.0' - 22.5' SHALE

REFUSAL AT 22.5 FEET.

NOTES:

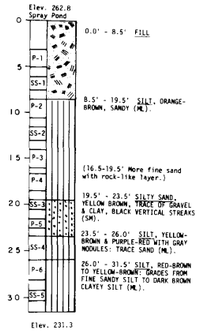
1. For explanation of symbols, see sheet 27, Figure 2.5-22.
2. For location of borings, see Figure 2.5-20.

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GRAPHIC LOGS
SHEET 34 OF 37

FIGURE 2.5-22

SP-1



0.0' - 8.5' FILL

8.5' - 19.5' SILT, ORANGE-BROWN, SANDY (ML).

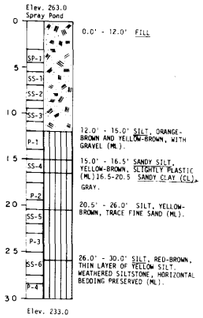
(16.5-19.5' More fine sand with rock-like layer.)

19.5' - 23.5' SILTY SAND, YELLOW BROWN, TRACE OF GRAVEL & CLAY, BLACK VERTICAL STREAKS (SM).

23.5' - 26.0' SILT, YELLOW-BROWN & PURPLE-RED WITH GRAY NODULES: TRACE SAND (ML).

26.0' - 31.5' SILT, RED-BROWN TO YELLOW-BROWN, TRACES FROM FINE SANDY SILT TO DARK BROWN CLAYEY SILT (ML).

SP-2



0.0' - 12.0' FILL

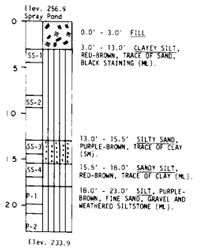
12.0' - 15.0' SILT, ORANGE-BROWN AND YELLOW-BROWN, WITH GRAVEL (ML).

15.0' - 16.5' SANDY SILT, YELLOW-BROWN, SLIGHTLY PLASTIC (ML)16.5-20.5 SANDY CLAY (CL), GRAY.

20.5' - 26.0' SILT, YELLOW-BROWN, TRACE FINE SAND (ML).

26.0' - 30.0' SILT, RED-BROWN, THIN LAYER OF YELLOW SILT. WEATHERED SILTSTONE, HORIZONTAL BEDDING PRESERVED (ML).

SP-3



0.0' - 3.0' FILL

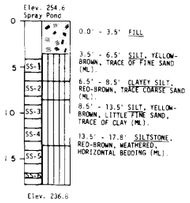
3.0' - 13.0' CLAYEY SILT, RED-BROWN, TRACE OF SAND, BLACK STAINING (ML).

13.0' - 15.5' SILTY SAND, PURPLE-BROWN, TRACE OF CLAY (SM).

15.5' - 18.0' SANDY SILT, RED-BROWN, TRACE OF CLAY (ML).

18.0' - 23.0' SILT, PURPLE-BROWN, FINE SAND, GRAVEL AND WEATHERED SILTSTONE (ML).

SP-4



0.0' - 3.5' FILL

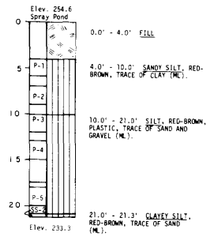
3.5' - 6.5' SILT, YELLOW-BROWN, TRACE OF FINE SAND (ML).

6.5' - 8.5' CLAYEY SILT, RED-BROWN, TRACE COARSE SAND (ML).

8.5' - 13.5' SILT, YELLOW-BROWN, LITTLE FINE SAND, TRACE OF CLAY (ML).

13.5' - 17.8' SILTSTONE, RED-BROWN, WEATHERED, HORIZONTAL BEDDING (ML).

SP-4A



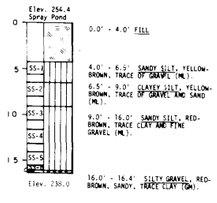
0.0' - 4.0' FILL

4.0' - 10.2' SANDY SILT, RED-BROWN, TRACE OF CLAY (ML).

10.0' - 21.0' SILT, RED-BROWN, PLASTIC, TRACE OF SAND AND GRAVEL (ML).

21.0' - 21.3' CLAYEY SILT, RED-BROWN, TRACE OF SAND (ML).

SP-5



0.0' - 4.0' FILL

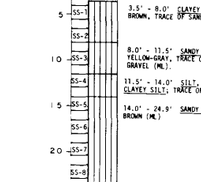
4.0' - 6.3' SANDY SILT, YELLOW-BROWN, TRACE OF GRAVEL (ML).

6.5' - 9.0' CLAYEY SILT, YELLOW-BROWN, TRACE OF GRAVEL AND SAND (ML).

9.0' - 16.0' SANDY SILT, RED-BROWN, TRACE CLAY AND FINE GRAVEL (ML).

16.0' - 16.4' SILTY GRAVEL, RED-BROWN, SANDY, TRACE CLAY (GM).

SP-5A



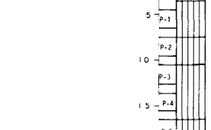
0.0' - 3.5' FILL

3.5' - 7.0' SANDY SILT, YELLOW-BROWN, MOTTLED, PLASTIC, TRACE GRAVEL (ML).

7.0' - 10.0' CLAYEY SILT, YELLOW-BROWN, MOTTLED, TRACE OF SAND AND GRAVEL (ML).

10.0' - 15.0' SANDY SILT, RED-BROWN, TRACE OF GRAVEL (ML).

SP-6

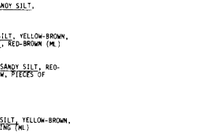


0.0' - 2.5' FILL

2.5' - 5.5' CLAYEY SILT, YELLOW-BROWN, TRACE OF SAND AND GRAVEL (ML).

5.5' - 9.0' SANDY SILT, BROWN, SLIGHTLY PLASTIC, SOME GRAVEL (ML).

SP-6A



0.0' - 2.5' FILL

2.5' - 5.0' SANDY SILT, YELLOW-BROWN, WITH SILTSTONE LAYERS (ML).

SP-7

0.0' - 3.0' FILL

3.0' - 5.5' SANDY SILT, RED-BROWN PLASTIC, TRACE OF CLAY AND GRAVEL (ML).

5.5 - 6.6 SILTY GRAVEL, RED-BROWN, SANDY, TRACE OF CLAY (GM).

SP-8

0.0' - 1.5' FILL

1.5' - 6.9' SANDY SILT, TAN, SOME GRAVEL-SIZED ROCK FRAGMENTS (ML).

SP-9

0.0' - 2.5' FILL

2.5' - 5.3' CLAYEY SILT, YELLOW-BROWN, TRACE OF SAND (ML).

5.3' - 8.9' SANDY SILT, YELLOW-BROWN, TRACE OF WEATHERED GRAVEL (ML).

SP-9A

0.0' - 2.5' FILL

2.5' - 5.5' NO RECOVERY

5.5' - 7.5' SILT, YELLOW-BROWN, PLASTIC, SOME GRAVEL (ML)

SP-10

0.0' - 2.5' FILL

2.5' - 6.4' SANDY SILT, YELLOW-BROWN, PLASTIC, TRACE OF GRAVEL (ML).

SP-11

0.0' - 2.5' FILL

2.5' - 6.0' CLAYEY SILT, YELLOW-BROWN, TRACE OF SAND (ML).

6.0' - 8.5' SILTSTONE, GREEN-BROWN, PARTIALLY WEATHERED (ML).

8.5' - 9.0' SILTY SAND, YELLOW-BROWN, SOME GRAVEL (SM).

SP-11A

0.0' - 2.5' FILL

2.5' - 5.0' CLAYEY SILT, RED-BROWN, TRACE OF GRAVEL (ML).

NO RECOVERY 5.5' - 7.5'

SP-12

0.0' - 2.5' FILL

2.5' - 5.5' SILTY CLAY, YELLOW-BROWN, MOTTLED, TRACE OF SAND, GRAVEL (CL).

5.5' - 11.0' SANDY SILT, YELLOW-BROWN, PLASTIC POCKETS OF NON-PLASTIC SILT AND CLAYEY SILT, TRACE OF GRAVEL (ML).

11.0' - 12.0' SILTSTONE, DARK BROWN TO BLACK, WEATHERED (ML).

SP-12A

0.0' - 2.5' FILL

2.5' - 7.0' CLAYEY SILT, YELLOW-BROWN, TRACE OF SAND, ROCK FRAGMENTS (ML).

7.0' - 7.8' SILT AND GRAVEL; PARTIALLY WEATHERED SILTSTONE (ML-GM)

SP-13

0.0' - 2.5' FILL

2.5' - 7.0' SANDY SILT, YELLOW-BROWN, CLAYEY, VERTICAL GRAY SILT ZONES; SILTSTONE PIECES (ML).

SP-14

0.0' - 2.5' FILL

2.5' - 5.5' CLAYEY SILT, MOTTLED BROWN, TRACE OF FINE SAND (ML)

5.5' - 8.0' NO RECOVERY

8.0' - 8.5' SHALE, DARK GRAY-GREEN

SP-14A

0.0' - 2.5' FILL

2.5' - 6.0' SILT, MOTTLED YELLOW

6.0' - 8.0' SILTY GRAVEL, YELLOW-BROWN (GM).

SP-15

0.0' - 3.5' FILL

NO RECOVERY 3.5' - 6.5'

6.5' - 22.5' SANDY SILT, TAN, WITH FINE GRAVEL (ML)

SP-15A

0.0' - 3.5' FILL

3.5' - 10.0' SANDY SILT, MOTTLED GRAY-BROWN, PLASTIC, TRACE OF GRAVEL (ML).

7.0' - 10.0' YELLOW-BROWN, WITH POCKETS OF CLAYEY SILT.

10.0' - 13.0' SILTY SAND, BROWN, FINE, TRACE OF GRAVEL; LAYERS OF SANDY CLAY (SM).

13.0' - 19.0' SILT, YELLOW-BROWN, PLASTIC, TRACE OF FINE SAND, SILTSTONE FRAGMENTS (ML).

19.0' - 21.0' SILTY GRAVEL, YELLOW-BROWN, WITH SAND

SP-16

0.0' - 3.5' FILL

3.5' - 8.0' CLAYEY SILT, RED-BROWN, TRACE OF SAND (ML).

8.0' - 11.5' SANDY SILT, MOTTLED YELLOW-GRAY, TRACE OF FINE GRAVEL (ML).

11.5' - 14.0' SILT, YELLOW-BROWN, AND CLAYEY SILT; TRACE OF SAND (ML).

14.0' - 24.9' SANDY SILT, YELLOW-BROWN (ML)

24.0' - 24.9' TRACE OF ROCK FRAGMENTS

SP-16A

0.0' - 3.5' FILL

3.5' - 7.5' SANDY SILT, RED-BROWN (ML)

7.5' - 10.5' SILT, YELLOW-BROWN, AND CLAYEY SILT, RED-BROWN (ML)

10.5' - 16.5' SANDY SILT, RED-BROWN AND YELLOW, PIECES OF GRAVEL (ML)

16.5' - 22.5' SILT, YELLOW-BROWN, HORIZONTAL BEDDING (ML)

HARDER, ROCK-LIKE FROM 20.5' - 22.5'

NOTES:

1. For explanation of symbols, see sheet 27 Figure 2.5-22.
2. For location of borings, see Figure 2.5-20.

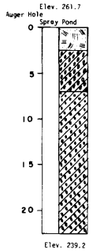
LIMERICK GENERATING STATION
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GRAPHIC LOGS
SHEET 35 OF 37

FIGURE 2.5-22

SP-17

Elev. 261.7



0.0' - 2.5' FILL

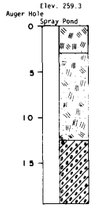
2.5' - 7.0' SILTY CLAY: BROWN, MOIST, SOME PEBBLES.

7.0' - 22.5' SILTY CLAY: PURPLE-BROWN, SLIGHTLY MOIST, SOME SAND AND PEBBLES.

Elev. 239.2

SP-18

Elev. 259.3



0.0' - 2.5' FILL

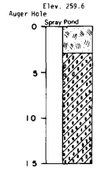
2.5' - 12.5' SILTY CLAY: DARK BROWN, DRY, MODERATELY PLASTIC, SOME PEBBLES.

12.5' - 19.5' SILTY CLAY: LIGHT BROWN, SOME PEBBLES.

Elev. 239.8

SP-19

Elev. 259.6



0.0' - 3.0' FILL

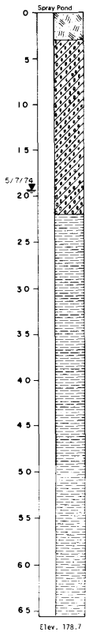
3.0' - 12.5' SILTY CLAY: BROWN, MOIST, SOME PEBBLES.

12.5' - 15.0' CLAY: DARK BROWN, WET WITH A SMALL AMOUNT OF SAND, SOME PEBBLES.

Elev. 244.6

SP-20

Elev. 244.1



0.0' - 3.0' FILL

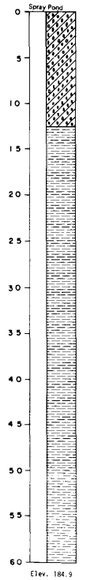
3.0' - 22.0' SILTY CLAY: PURPLE-BROWN, SLIGHTLY MOIST, SOME FINE SAND.

22.0' - 65.4' SILTSTONE: PURPLE-BROWN WITH SOME CLAY AND SAND.

Elev. 178.7

SP-21

Elev. 244.9



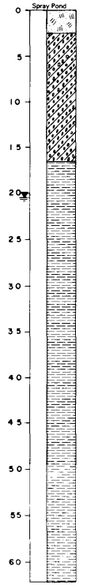
0.0' - 12.5' SILTY CLAY: BROWN, DRY, SOME PEBBLES.

12.5' - 60.0' SILTSTONE: PURPLE-BROWN, SOME CLAY AND SAND PRESENT.

Elev. 184.9

SP-22

Elev. 263.8



0.0' - 2.5' FILL

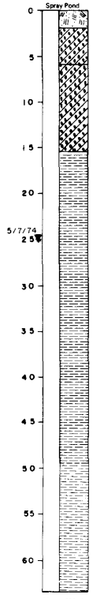
2.5' - 16.5' SILTY CLAY: BROWN, DRY, SOME PEBBLES.

16.5' - 62.2' SILTSTONE: PURPLE BROWN, SOME CLAY AND SAND PRESENT

Elev. 201.6

SP-23

Elev. 274.7



0.0' - 2.0' FILL

2.0' - 6.0' SILTY CLAY: PURPLE-BROWN, DRY, SOME PEBBLES.

6.0' - 15.5' SILTY CLAY: BROWN, DRY, SOME PEBBLES.

15.5' - 63.5' SILTSTONE: PURPLE-BROWN, SOME CLAY PRESENT.

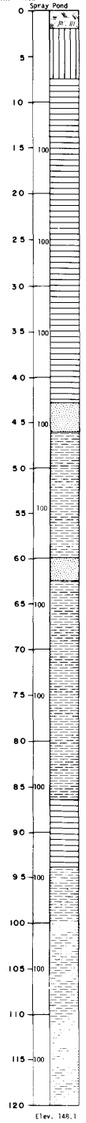
25.0' - 30.0' GRAY SAND LAYERS

Elev. 211.2

P-1

Elev. 268.1

C.R. = 100%



0.0' - 2.0' FILL

2.0' - 7.5' SILT: BROWN TO YELLOW WITH 10-15 PERCENT FINE TO MEDIUM SAND. SCATTERED TRACES OF ORGANIC MATERIAL RED, RED-BROWN BELOW.

7.5' - 43.0' SHALE: GREENISH YELLOW GRADING TO BROWN BELOW 12.5 FEET. HIGHLY WEATHERED, FISSILE, HIGHLY FRACTURED ALONG BEDDING PLANES, SOME FRACTURES ARE CALCITE FILLED. NUMEROUS CALCITE STRINGERS AND CLAY FILLINGS. CORE LENGTHS RANGE FROM LESS THAN 1 INCH TO 10 INCHES, AVERAGING 2-4 INCHES.

43.0' - 46.0' SANDSTONE: REDDISH GRAY, FINE-GRAINED, MICACEOUS, WELL CEMENTED, HARD.

46.0' - 60.0' SILTSTONE-CLAYSTONE: RED TO RED-BROWN SEQUENCE OF CLYSTONE AND SILTSTONE.

60.0' - 62.5' SANDSTONE: GRAY, WEATHERS TO BRICK RED, FINE-MEDIUM GRAINED, WELL CEMENTED.

62.5' - 86.5' SILTSTONE-CLAYSTONE AS ABOVE AT 46.0' - 60.0'

86.5' - 94.0' SHALE: RED TO GRAY GRADING TO DARK BLACK. GRADES TO SILTSTONE. SOFT FROM 87.0' - 88.5'.

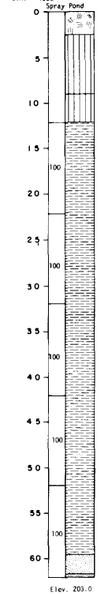
94.0' - 120.0' SILTSTONE-CLAYSTONE REDDISH, MICACEOUS, AS ABOVE

Elev. 148.1

P-2

Elev. 265.0

C.R. = 100%



0.0' - 2.5' FILL

2.5' - 9.0' SILT: YELLOW-BROWN, CLAYEY WITH SCATTERED SHALE FRAGMENTS.

9.0' - 12.0' SILT-SHALE: GRAY-BROWN SILT GRADING INTO HIGHLY WEATHERED SHALE.

12.0' - 59.5' SILTSTONE: GRAY-GREEN GRADING TO GRAY-RED; HIGHLY WEATHERED. MANY CALCITE STRINGERS.

46.2' - 46.8' VERTICAL FRACTURE FILLED WITH CALCITE.

59.5' - 62.0' HIGHLY FRACTURED.

59.5' - 61.5' SANDSTONE: REDDISH, FINE-MEDIUM GRAINED, HIGHLY FRACTURED.

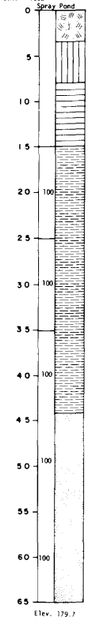
61.5' - 62.0' SILTSTONE: AS ABOVE

Elev. 203.0

P-3

Elev. 244.7

C.R. = 100%



0.0' - 3.5' FILL

3.5' - 8.0' SILT: RED-BROWN, SLIGHTLY CLAYEY.

8.0' - 15.0' SHALE: RED-BROWN, HIGHLY WEATHERED TO 15 FEET.

15.0' - 44.0' SILTSTONE: RED-BROWN WITH SCATTERED VERTICAL FRACTURES AND SOME CALCITE STRINGERS.

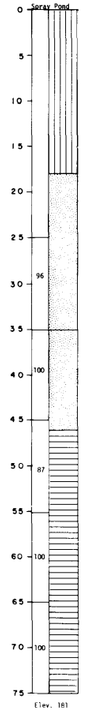
44.0' - 65.0' SANDSTONE: GRAY, FINE TO MEDIUM-GRAINED.

Elev. 179.7

P-4

Elev. 256

C.R. = 96%



0.0' - 18' CLAYEY SILT: RED WITH ANGULAR SHALE AND SANDSTONE PARTICLES.

18' - 35.0' SANDSTONE: WEATHERED

35.0' - 46.0' SANDSTONE: BROWN, SILTY, FINE-GRAINED. CORE LENGTHS AVERAGE 4 INCHES.

42' - 43' SOFT ZONE

46.0' - 75.0' SHALE: GRAY TO WHITE AND VARI-COLORED TO BLACK. OCCASIONAL FINE-GRAINED SANDSTONE LENSES. FEW JOINTS. JOINTS IRON-STAINED TO 57 FEET.

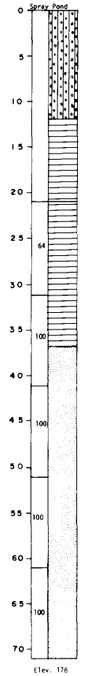
57' - 61' BLACK

Elev. 181

P-5

Elev. 249

C.R. = 92%



0.0' - 12' SANDY SILT: RED WITH OCCASIONAL ROCK PARTICLES.

12' - 21.0' SHALE: HIGHLY WEATHERED.

21.0' - 37.0' SHALE: RED, HIGHLY JOINTED TO 35 FEET. SOME ZONES OF FINE-GRAINED SANDSTONE; CORE LOSS IN SANDSTONE.

37.0' - 71.0' SANDSTONE: GRAY, FINE-GRAINED, MODERATELY JOINTED. PROMINENT NEAR VERTICAL JOINTS. IRON-STAINING TO 54 FEET. CORE LENGTHS AVERAGE 6 INCHES.

46' - 49' BLACK.

60' - 64' VARI-COLORED, GRAY AND WHITE.

Elev. 178

NOTES:

1. For explanation of symbols, see sheet 27, Figure 2.5-22.
2. For location of borings, see Figure 2.5-20

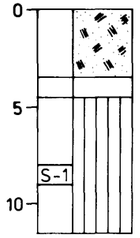
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FIGURE 2.5-22

TP-1

ELEV. 257.5
SPRAY POND

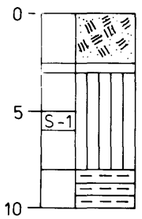


0.0 - 3.5 FILL
3.5 - 4.5 TOPSOIL
4.5 - 11.5 SANDY CLAYEY SILT, WITH GRAVELS. (CL)

ELEV. 246.0

TP-2

ELEV. 259.6
SPRAY POND

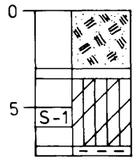


0.0 - 2.5 FILL
2.5 - 3.0 TOPSOIL
3.0 - 8.0 SANDY CLAYEY SILT, WITH GRAVELS. (CL)
8.0 - 10.0 SILTSTONE / SHALE

ELEV. 249.6

TP-3

ELEV. 258.0
SPRAY POND

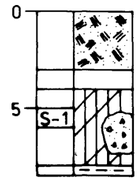


0.0 - 3.0 FILL
3.0 - 3.5 TOPSOIL
3.5 - 7.0 SANDY SILT/CLAY, TRACE GRAVEL (CL)
7.0 - 7.5 SILTSTONE/SHALE

ELEV. 250.5

TP-4

ELEV. 265.1
SPRAY POND

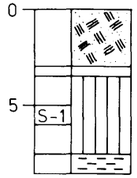


0.0 - 3.0 FILL
3.0 - 4.0 TOPSOIL
4.0 - 8.0 CLAYEY SILT (CL)
6.0 - 8.0 SAND AND GRAVEL POCKET
8.0 - 8.5 SILTSTONE

ELEV. 256.6

TP-5

ELEV. 261.5
SPRAY POND

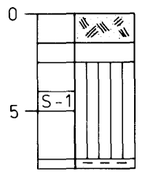


0.0 - 3.0 FILL
3.0 - 3.5 TOPSOIL
3.5 - 7.5 SANDY CLAYEY SILT, WITH GRAVELS (SC)
7.5 - 8.5 SILTSTONE

ELEV. 253.0

TP-6

ELEV. 262.2
SPRAY POND

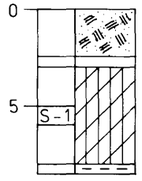


0.0 - 1.5 FILL
1.5 - 2.5 TOPSOIL
2.5 - 7.5 SANDY SILT WITH GRAVELS (CL)
7.5 - 8.0 SILTSTONE / SHALE

ELEV. 254.2

TP-7

ELEV. 264.5
SPRAY POND

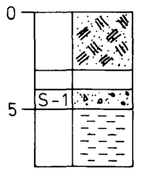


0.0 - 2.5 FILL
2.5 - 3.0 TOPSOIL
3.0 - 8.0 SANDY SILT/CLAY (CL)
8.0 - 8.5 SILTSTONE

ELEV. 256.0

TP-8

ELEV. 269.9
SPRAY POND

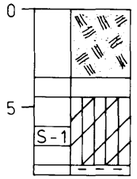


0.0 - 3.0 FILL
3.0 - 4.0 TOPSOIL
4.0 - 5.0 CLAYEY SAND AND GRAVEL (GC)
5.0 - 8.0 SILTSTONE

ELEV. 261.9

TP-9

ELEV. 266.2
SPRAY POND

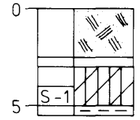


0.0 - 3.5 FILL
3.5 - 4.5 TOPSOIL
4.5 - 8.0 SANDY SILT/CLAY (CL)
8.0 - 8.5 SILTSTONE

ELEV. 257.7

TP-10

ELEV. 257.4
SPRAY POND

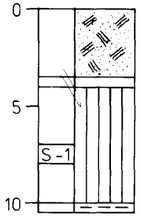


0.0 - 2.5 FILL
2.5 - 3.0 TOPSOIL
3.0 - 5.0 SANDY CLAYEY SILT (CL)
5.0 - 5.5 SILTSTONE / SHALE

ELEV. 251.9

TP-11

ELEV. 268.3
SPRAY POND

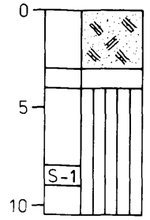


0.0 - 3.5 FILL
3.5 - 4.0 TOPSOIL
4.0 - 10.0 SANDY SILT (ML)
10.0 - 10.5 SILTSTONE

ELEV. 257.8

TP-12

ELEV. 255.8
SPRAY POND

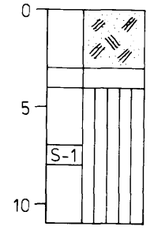


0.0 - 3.0 FILL
3.0 - 4.0 TOPSOIL
4.0 - 10.5 SANDY SILT (SC)

ELEV. 245.3

TP-13

ELEV. 259.3
SPRAY POND



0.0 - 3.0 FILL
3.0 - 4.0 TOPSOIL
4.0 - 11.0 SANDY SILT (ML)

ELEV. 248.3

NOTES:

1. FOR LOCATION OF TEST PITS, SEE FIGURE 2.5-30.
2. TEST PITS IN THIS SERIES WERE MADE TO INVESTIGATE THE SOILS IN CONSTRUCTING THE SOIL-BENTONITE LINER.

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GRAPHIC LOGS
SHEET 37 OF 37

FIGURE 2.5-22



EXPLANATION

- EQUIPOTENTIAL LINES
- FLOW LINES
- WATER LEVEL ELEVATION CONTOUR (6/24/74)

N

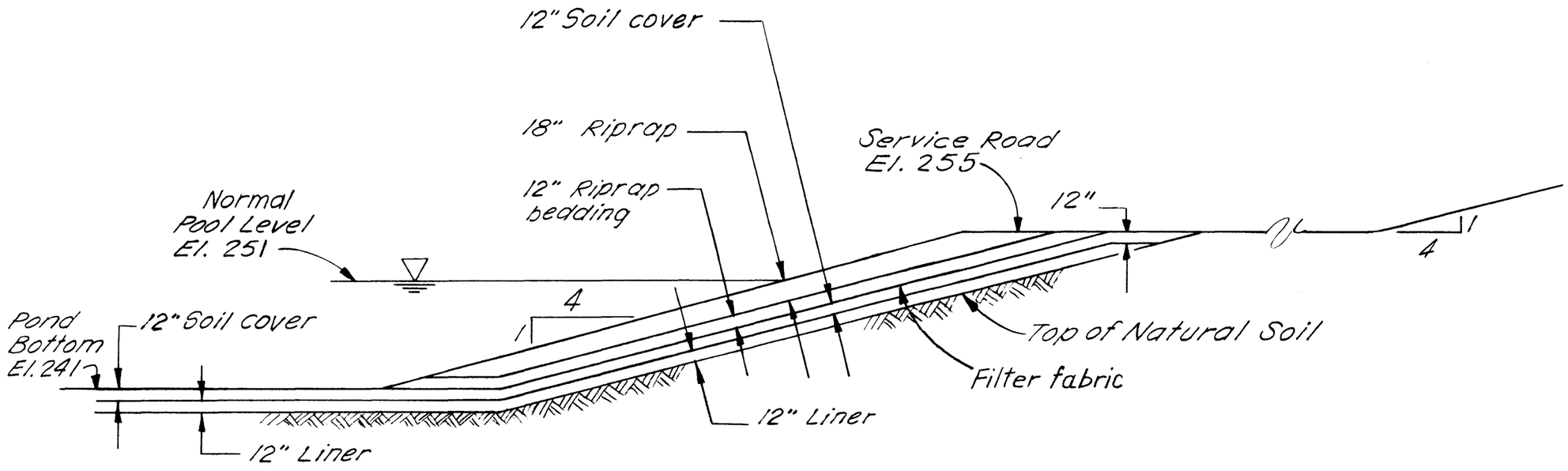
0 100 200 300 400 500

SCALE IN FEET

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UNLINED SPRAY POND
ESTIMATED FLOW NET

FIGURE 2.5-23



TYPICAL SECTION

OF SPRAY POND SLOPE

Graphic Scale in Feet

0 10 20 30

1" = 10'

NOTES:

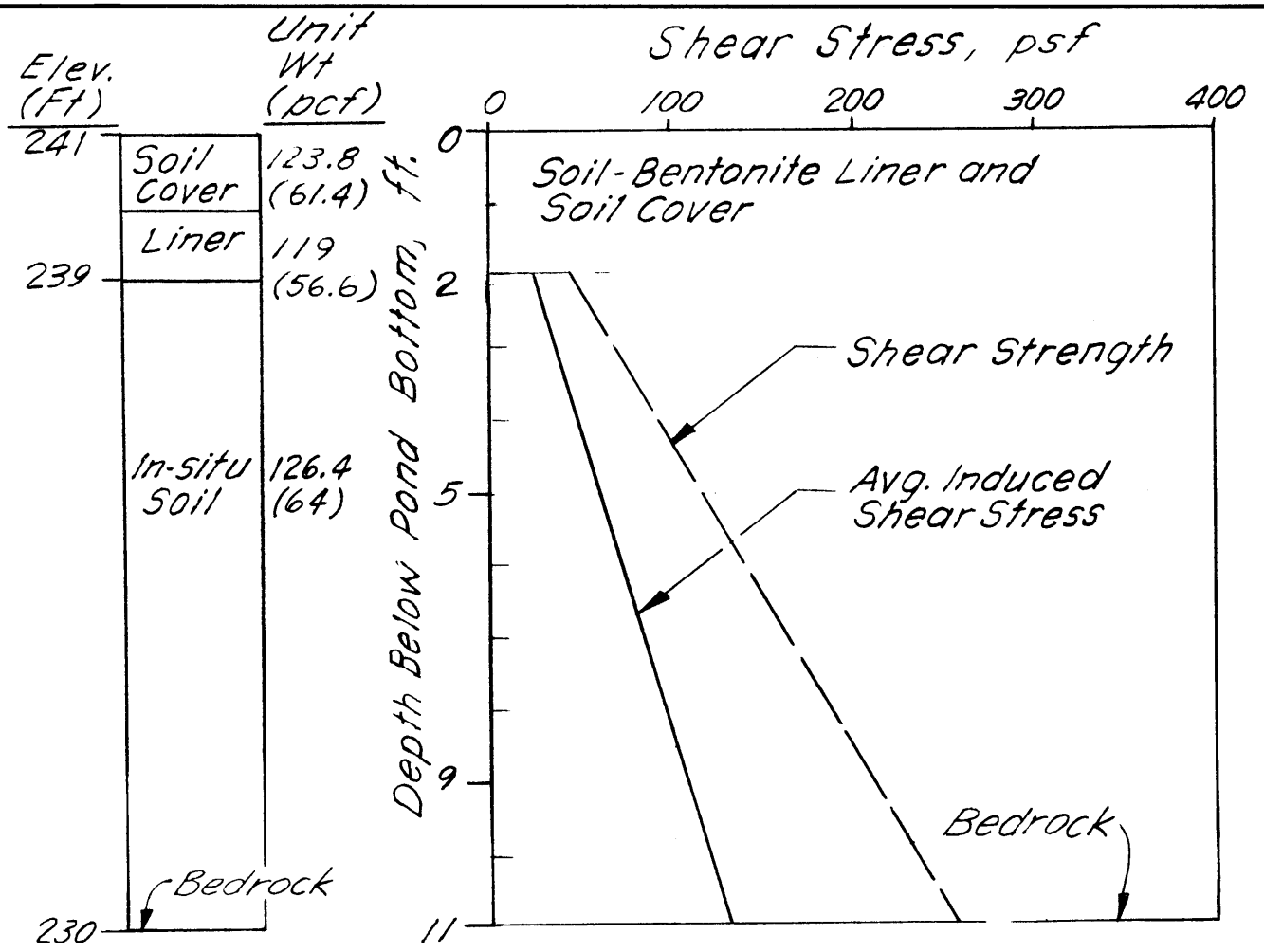
1. The soil-bentonite mixture for the liner will consist of 7.5 % bentonite and 92.5 % on-site soil.

2. Both the soil-bentonite liner and the soil cover were compacted to 95 % of maximum dry density determined in accordance with ASTM D 698.

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TYPICAL SECTION OF SPRAY POND SLOPE

FIGURE 2.5-24



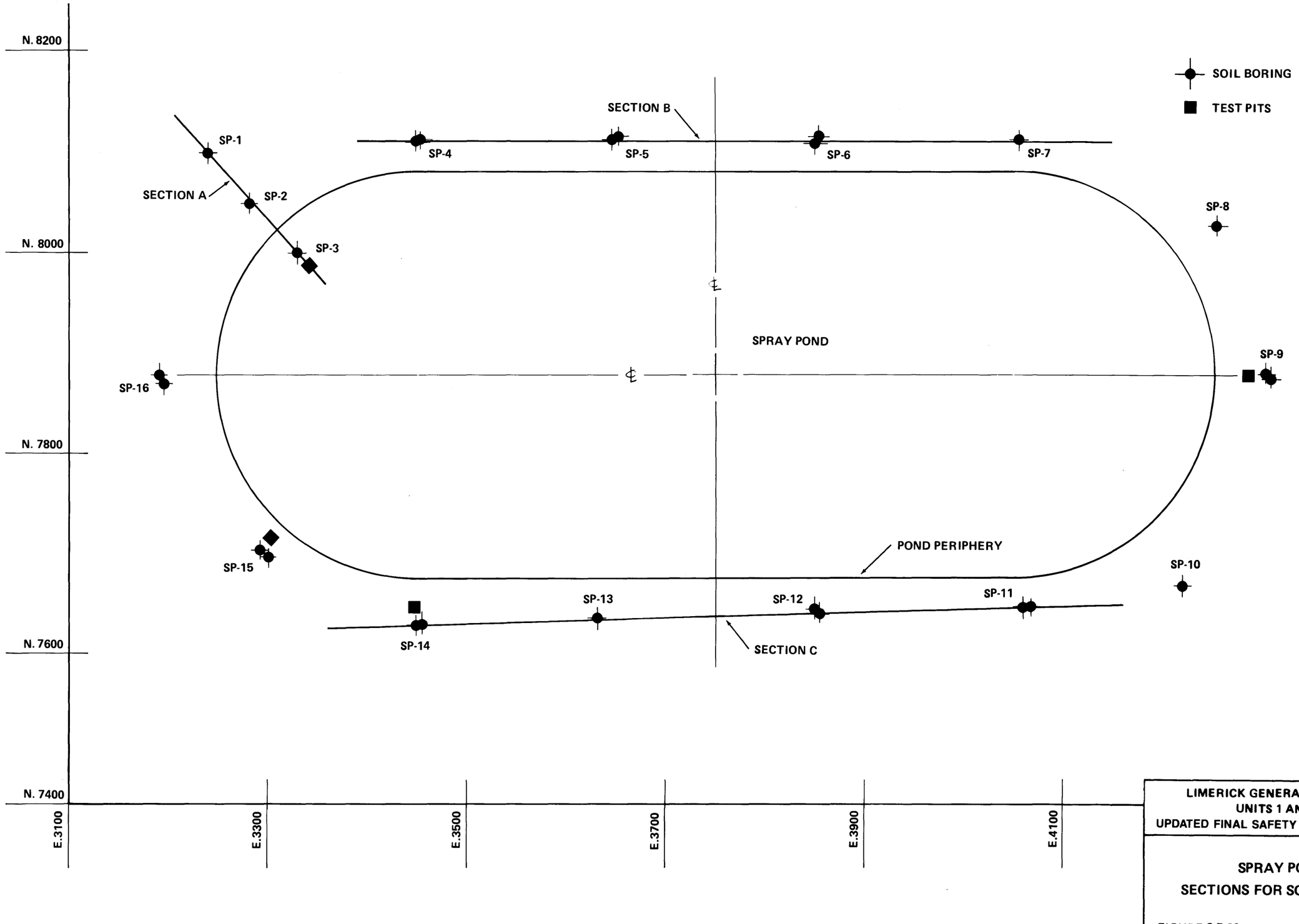
SUMMARY OF LIQUEFACTION ANALYSES

DEPTH BELOW POND BOTTOM FT.	SHEAR STRENGTH PSF	AVE. INDUCED SHEAR STRESS PSF	FACTOR OF SAFETY
2	44	23	1.9
3	67	36	1.9
4	91	48	1.9
5	115	60	1.9
6	138	72	1.9
7	162	84	1.9
8	186	96	1.9
9	209	108	1.9
10	233	120	1.9
11	257	132	1.9

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUMMARY OF LIQUEFACTION ANALYSES

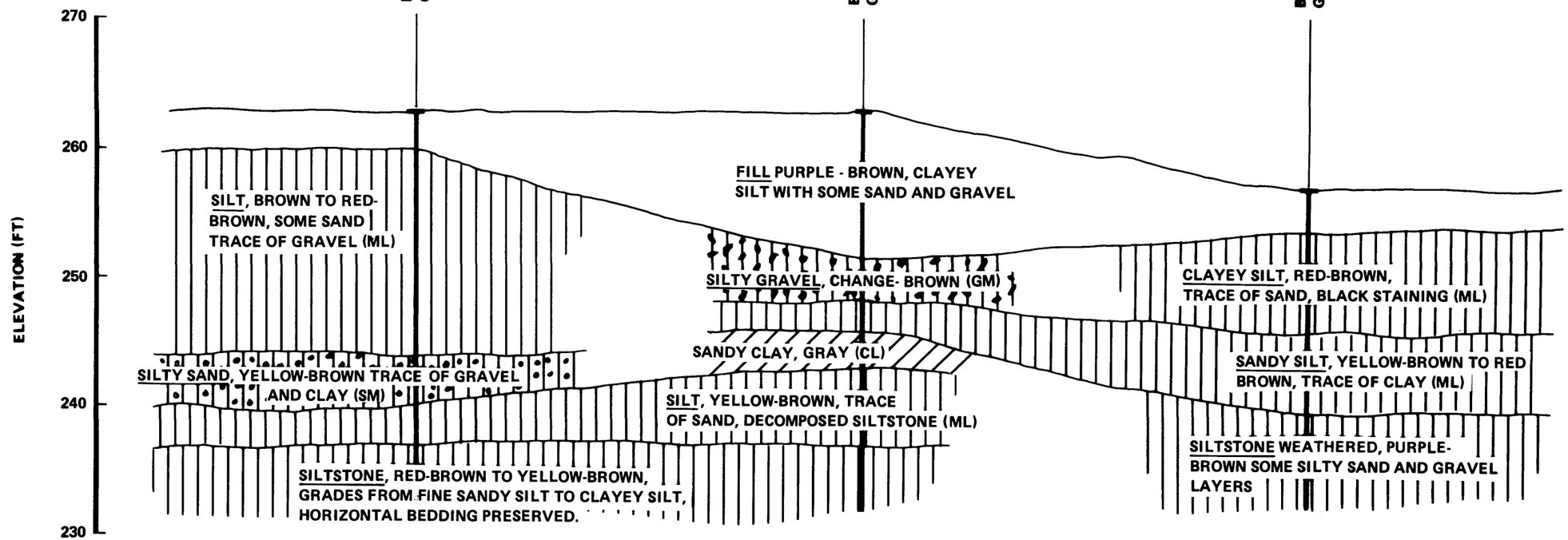
FIGURE 2.5-25



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SPRAY POND
SECTIONS FOR SOIL PROFILE

FIGURE 2.5-26



PROFILE A

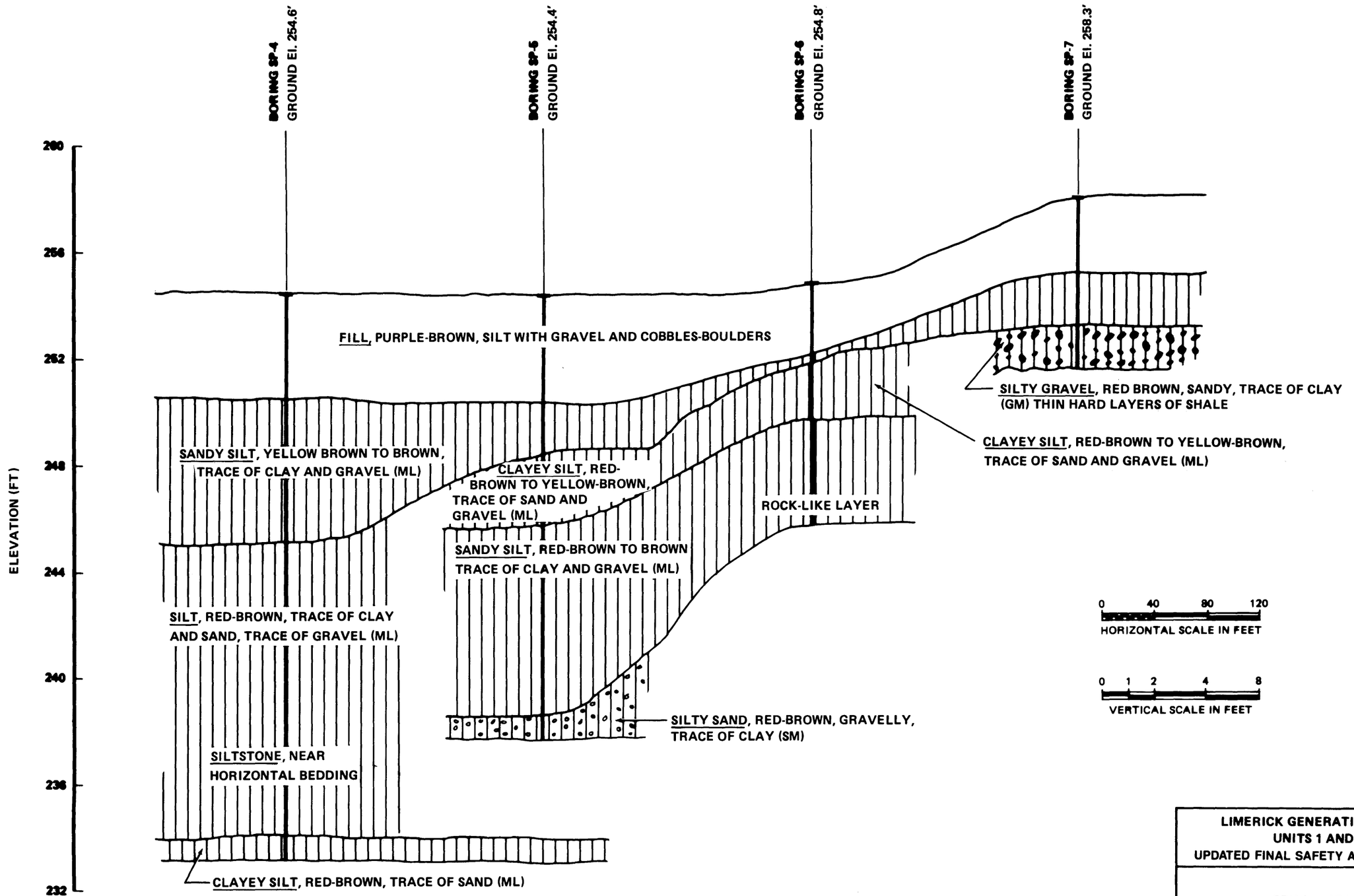
0 5 10 15
VERTICAL SCALE

0 10 20 30
HORIZONTAL SCALE

LIMERICK GENERATING STATION
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SPRAY POND
SOIL PROFILE A

FIGURE 2.5-27

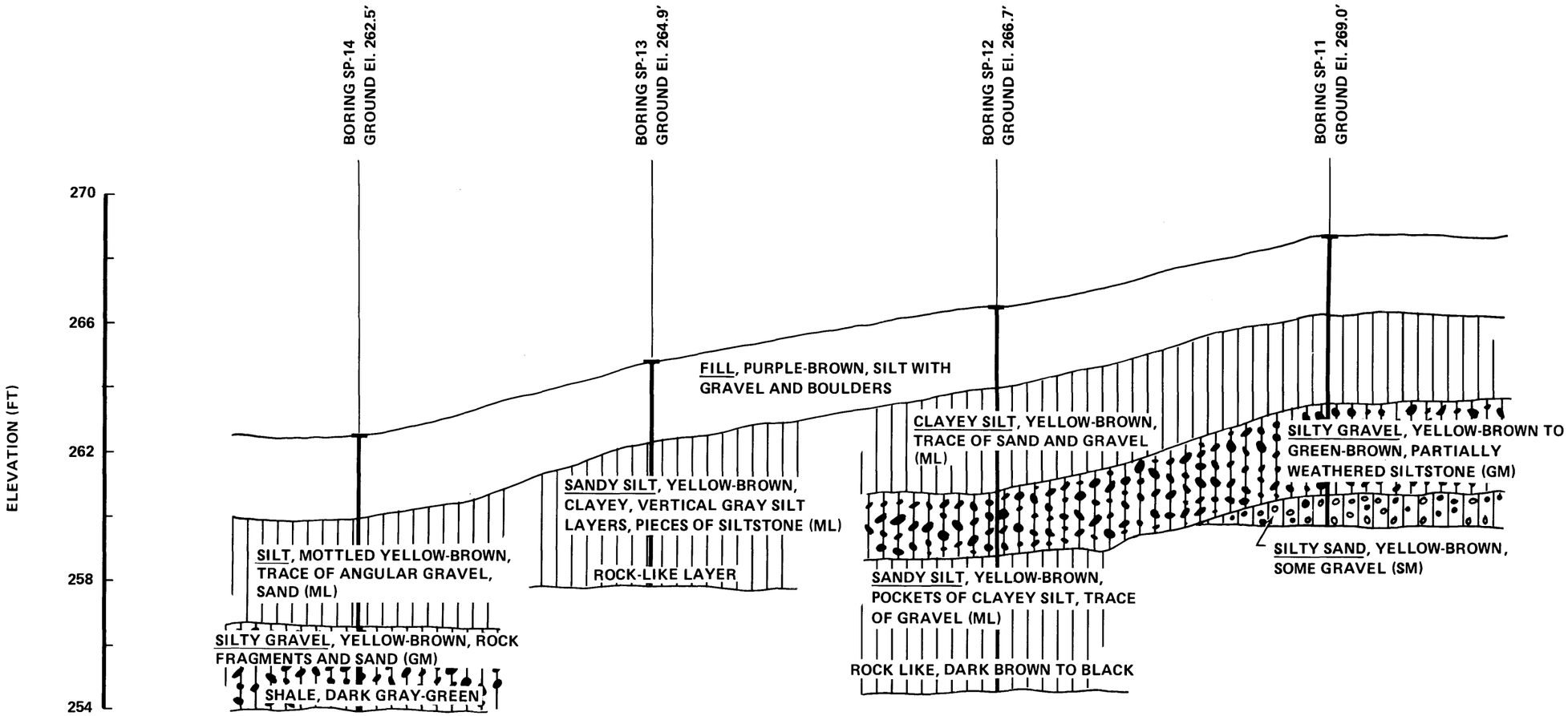


PROFILE B

LIMERICK GENERATING STATION
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SPRAY POND
PROFILE B

FIGURE 2.5-28



PROFILE C

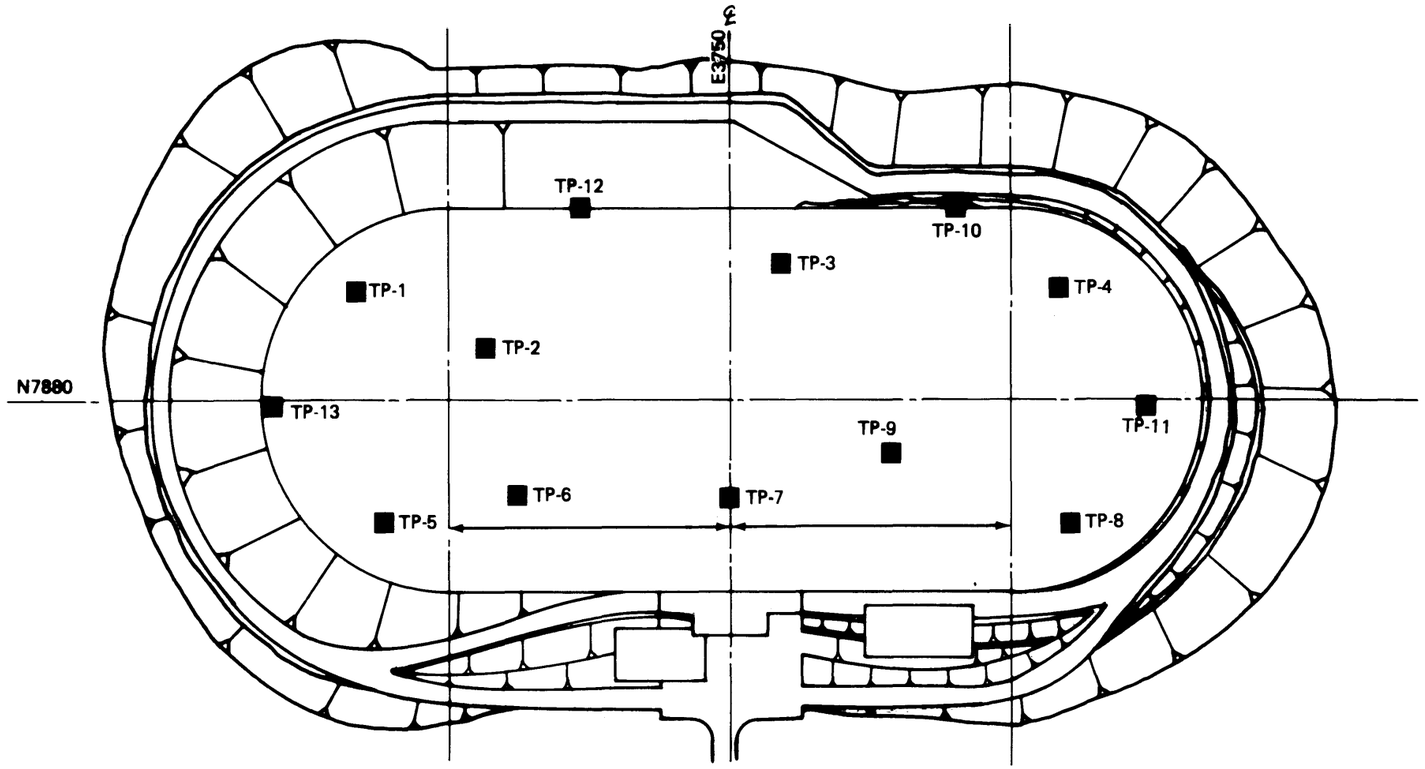
0 40 80 120
HORIZONTAL SCALE IN FEET

0 1 2 4 8
VERTICAL SCALE IN FEET

LIMERICK GENERATING STATION
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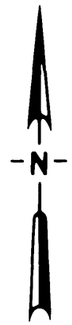
SPRAY POND
PROFILE C

FIGURE 2.5-29



TEST PIT LOCATIONS

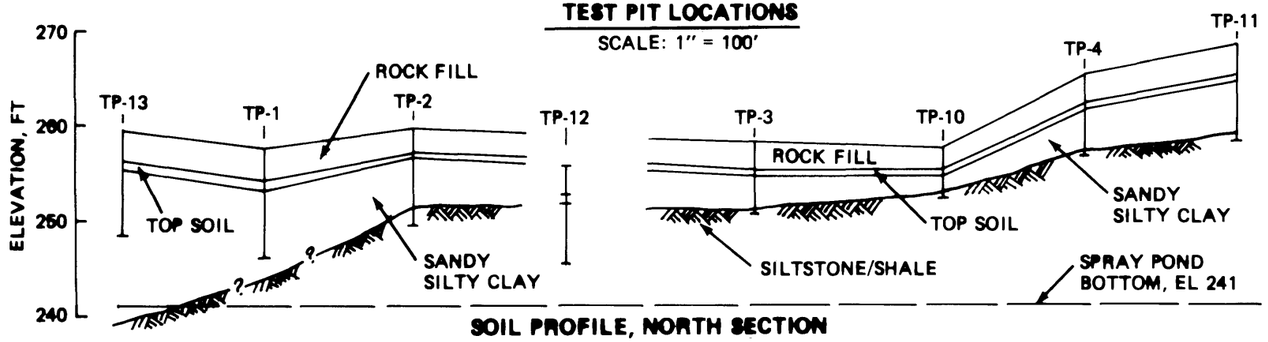
SCALE: 1" = 100'



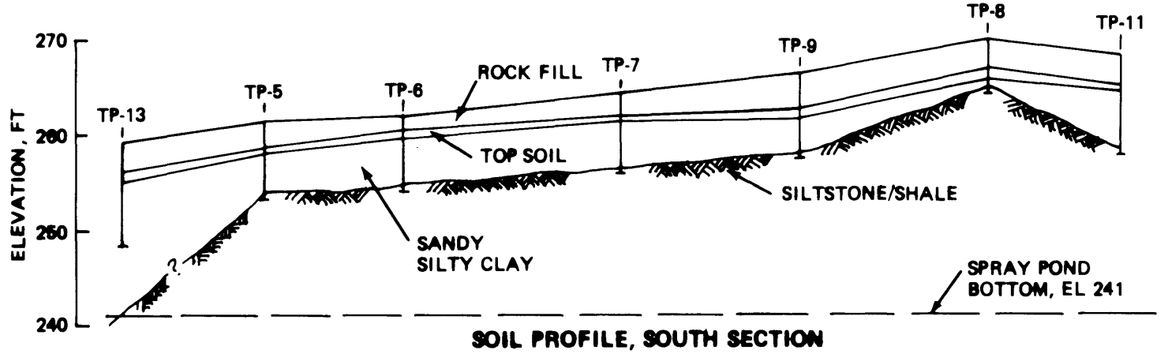
LEGEND

■ TEST PITS

NOTE:
THE TEST PITS SHOWN ON THIS DRAWING WERE MADE FOR THE INVESTIGATION OF SOILS FOR THE SOIL-BENTONITE MIXTURE ONLY. THE EXPLORATION OF THE ENTIRE SPRAY POND AREA IS REFERRED TO IN FIGURE 2.5-26



SOIL PROFILE, NORTH SECTION



SOIL PROFILE, SOUTH SECTION

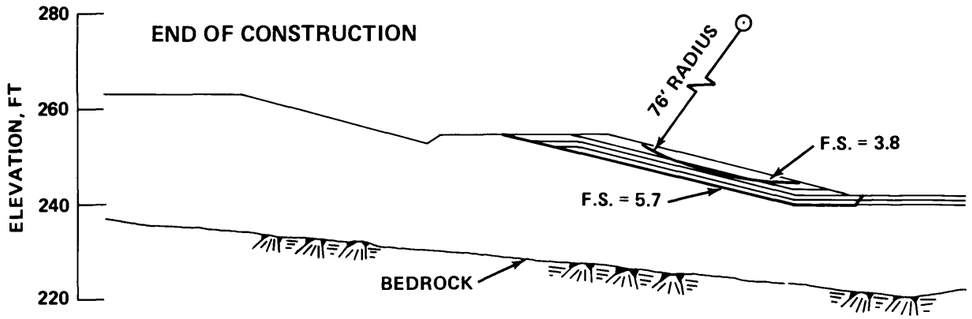
GRAPHIC SCALE IN FEET

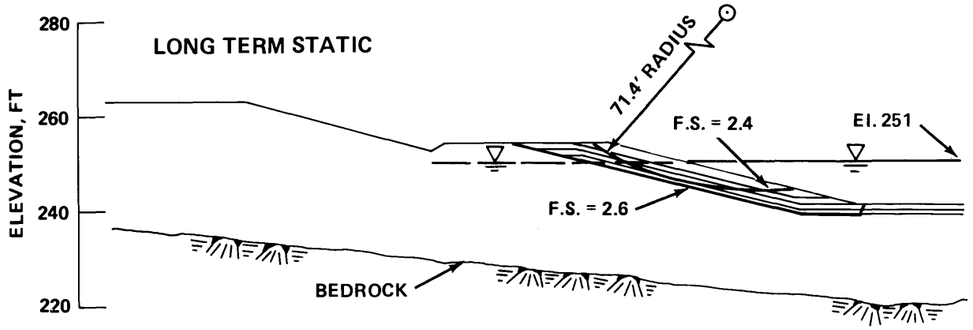
0 100 200 300

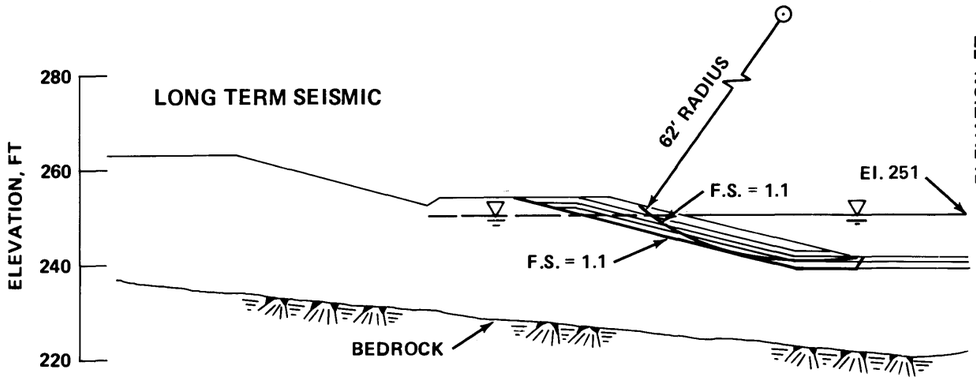
LIMERICK GENERATING STATION
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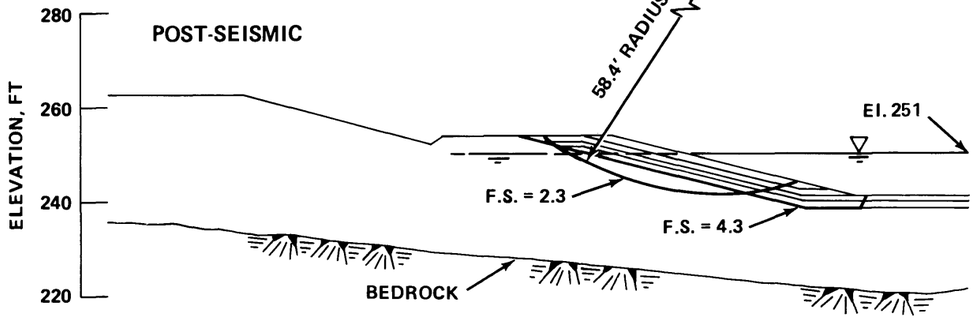
TEST PIT LOCATIONS AND GENERALIZED SOIL PROFILES

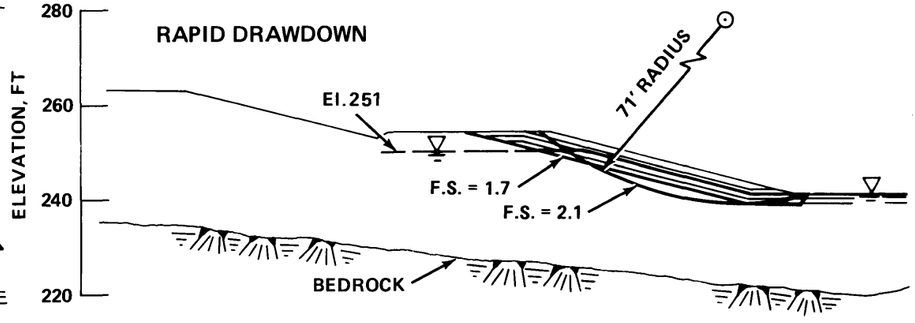
FIGURE 2.5-30











SUMMARY OF DESIGN PARAMETERS

	UNIT WT. (pcf)		SHEAR STRENGTH PARAMETERS (C IN psf, ϕ IN DEGREES)					
			UNDRAINED		EFFECTIVE		SEISMIC	
	TOTAL	SAT.	C	ϕ	C′	ϕ'	C	ϕ
IN-SITU SOIL	122.0	126.4	$1.2\bar{p}_c$	0	0	33.5	$0.61\sigma_o'$	0
SOIL-BENTONITE LINER	113.0	119.0	$0.95\bar{p}_o$	0	0	29.0	225	20
COMPACTED SOIL COVER	120.5	123.8	$1.2\bar{p}_o$	0	0	33.5	$0.61\sigma_o'$	0
RIPRAP BEDDING	130.0	130.0	0	40	0	40.0	0	40
RIPRAP	130.0	130.0	0	45	0	45.0	0	45

NOTES: 1. $\bar{p}_o$ = MEAN EFFECTIVE PRINCIPAL STRESS, $\frac{\bar{\sigma}_1 + \bar{\sigma}_3}{2}$

2. σ_o' = EFFECTIVE OVERBURDEN PRESSURE.

SUMMARY OF RESULTS

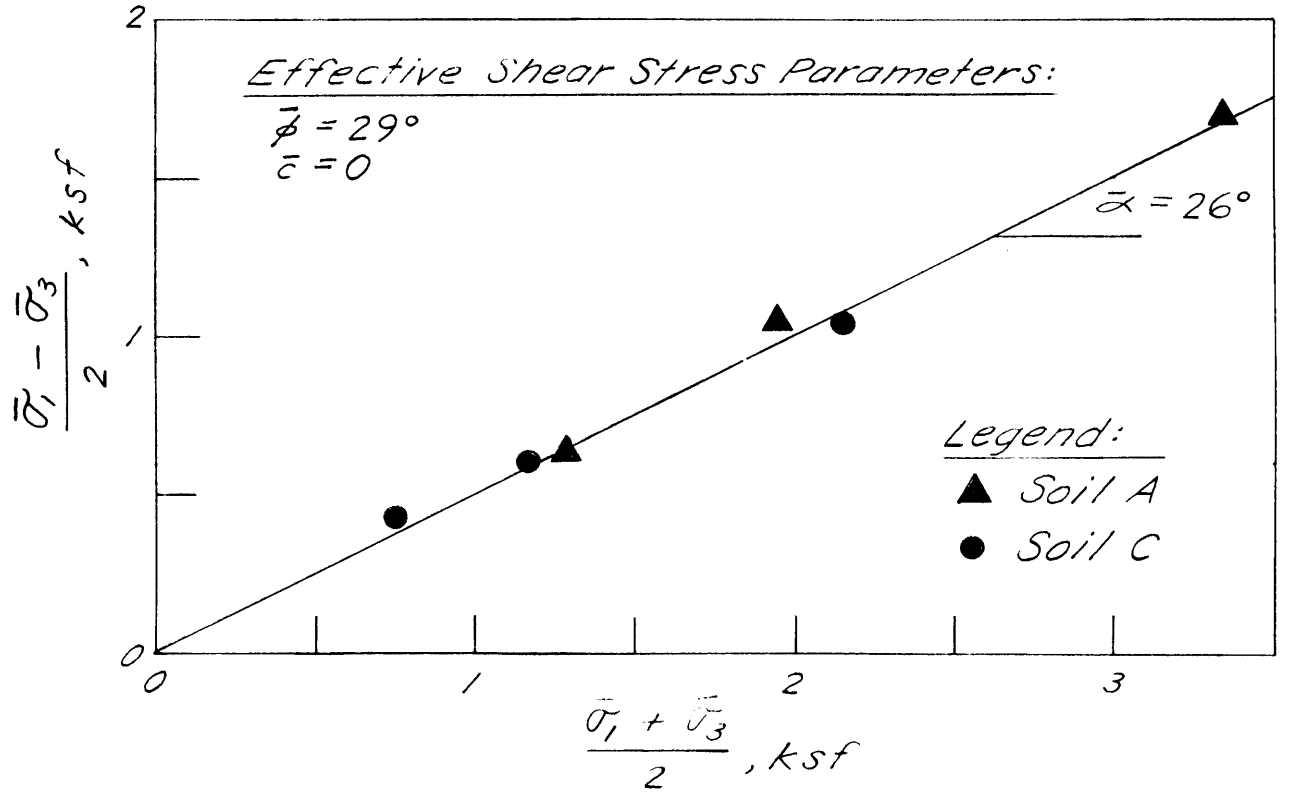
CONDITION	REQUIRED F.S.	COMPUTED MIN. F.S.	
		CIRCULAR ARC	WEDGE
END OF CONSTRUCTION	1.30	3.8	5.7
LONG TERM STATIC	1.50	2.4	2.6
LONG TERM SEISMIC	1.10	1.1	1.1
POST SEISMIC	1.10	2.3	4.3
RAPID DRAWDOWN	1.25	2.1	1.7

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SUMMARY OF SLOPE STABILITY ANALYSES

FIGURE 2.5-31

SUMMARY OF CONSOLIDATED UNDRAINED TRIAXIAL TEST ($\bar{R}$) RESULTS OF SOIL-BENTONITE MIXTURES



Notes:

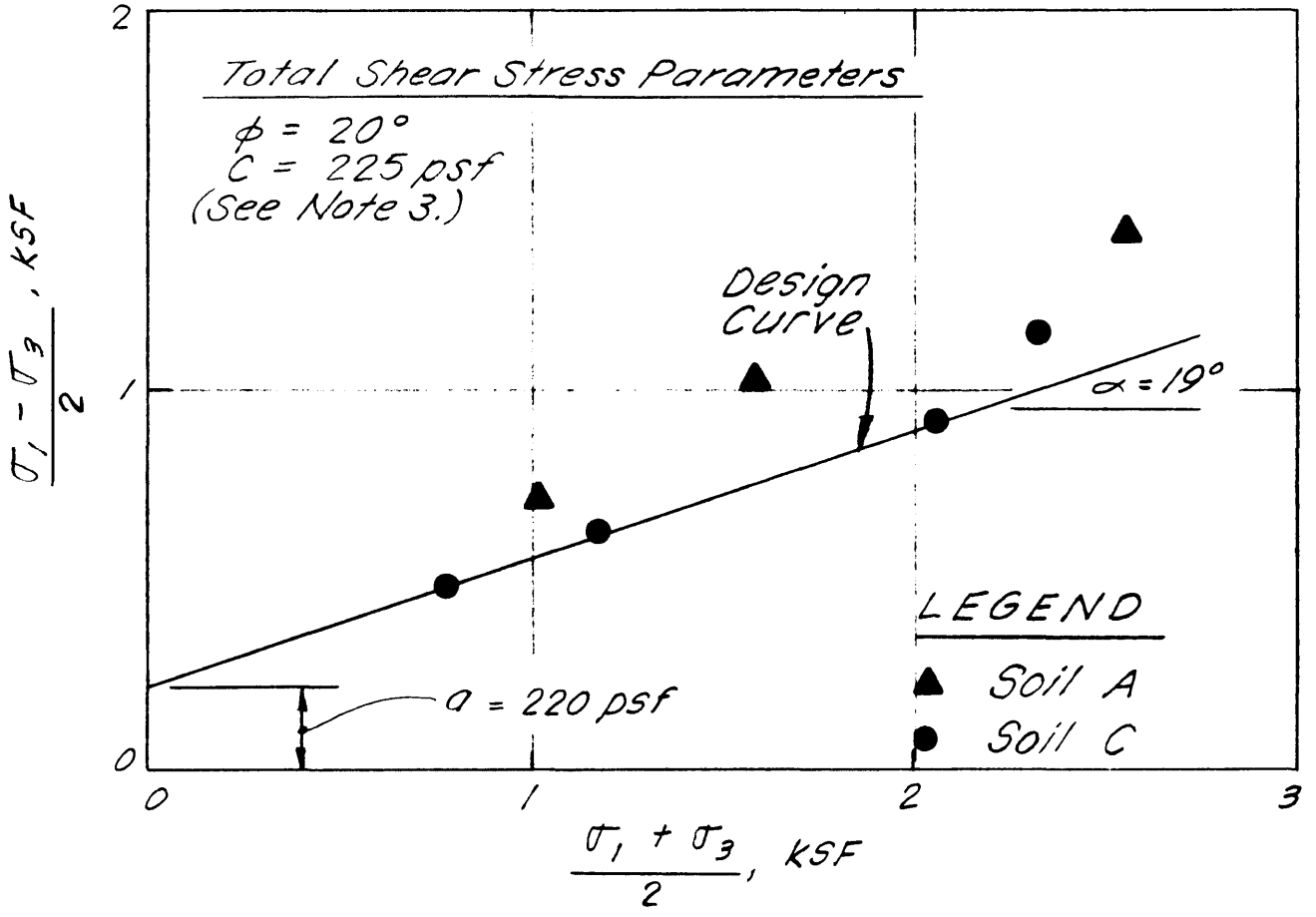
1. All Soil-Bentonite specimens were allowed to saturate and swell before testing.
2. Points plotted represent conditions at failure.
3. $\sin \bar{\phi} = \tan \bar{\alpha}$, $\bar{c} = \bar{a} / \cos \bar{\phi}$.

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SUMMARY OF $\bar{R}$ TEST RESULTS OF SOIL-BENTONITE MIXTURES

FIGURE 2.5-32

SUMMARY OF CONSOLIDATED- UNDRAINED TRIAXIAL TESTS AFTER CYCLIC LOADING ($C\bar{R}$-$\bar{R}$) OF SOIL-BENTONITE MIXTURES



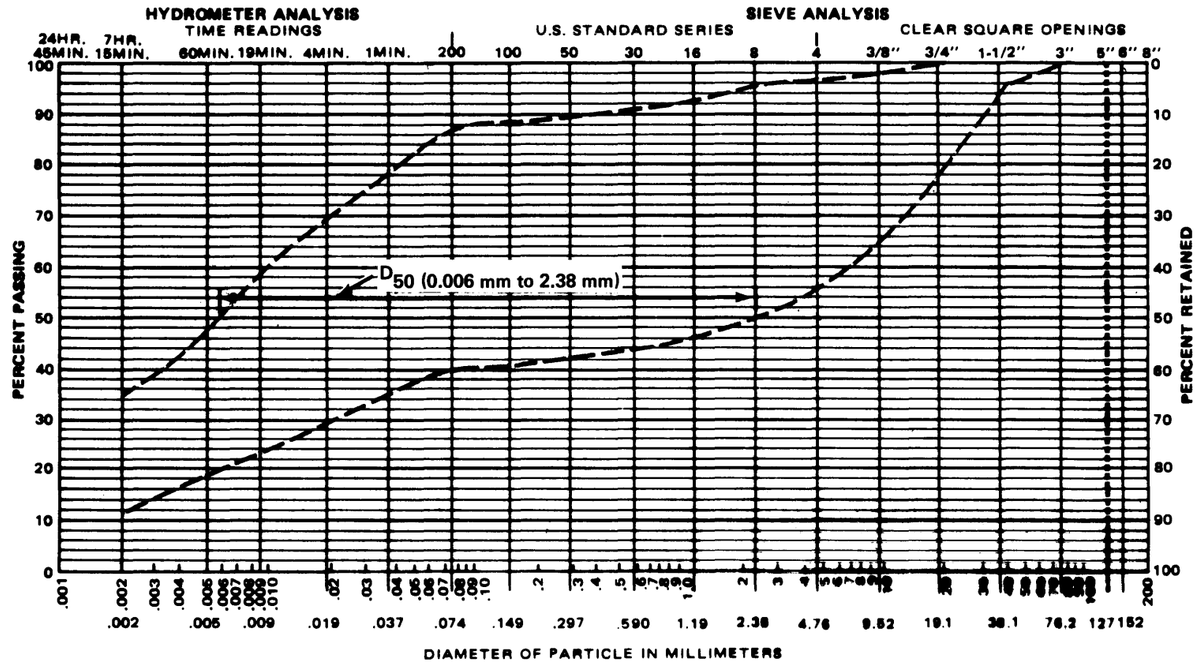
NOTES:

1. All Soil-Bentonite specimens were allowed to saturate and swell before testing.
2. Points plotted represent conditions at the end of (5) uniform stress cycles.
3. $\sin\phi = \tan\alpha$, $C = a/\cos\phi$

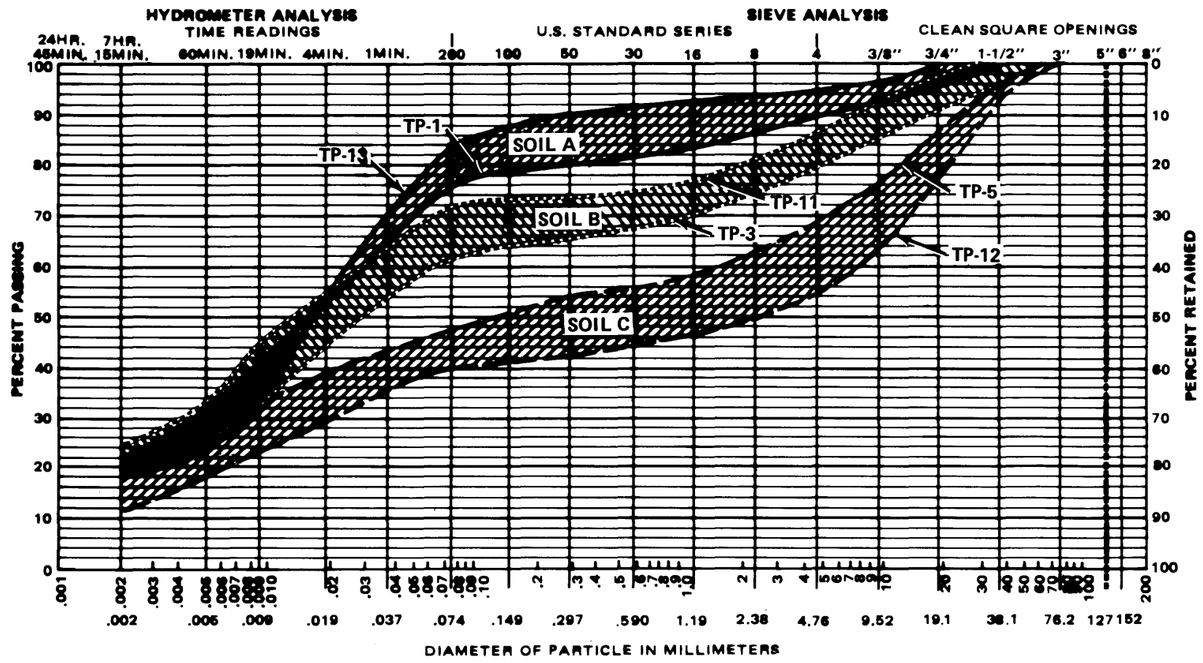
LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

SUMMARY OF $C\bar{R}$-$\bar{R}$ TEST RESULTS OF SOIL-BENTONITE MIXTURES

FIGURE 2.5-33



RANGE OF SOIL GRAIN SIZE FOR SOIL-BENTONITE MIXTURES



SOILS USED IN SOIL-BENTONITE MIXTURE DESIGN TESTING

SUMMARY OF SOILS FOR SOIL-BENTONITE MIXTURES

SAMPLE SOURCE	SOIL A		SOIL B		SOIL C	
	TP-1	TP-13	TP-3	TP-11	TP-5	TP-12
LL	32	41	37	45	48	35
PL	20	27	21	28	25	20
PI	12	14	16	17	23	15
NAT. W/C	20	28	21	31	30	15
CLASSIFI-CATION	CL	CL	CL	ML	SC	SC

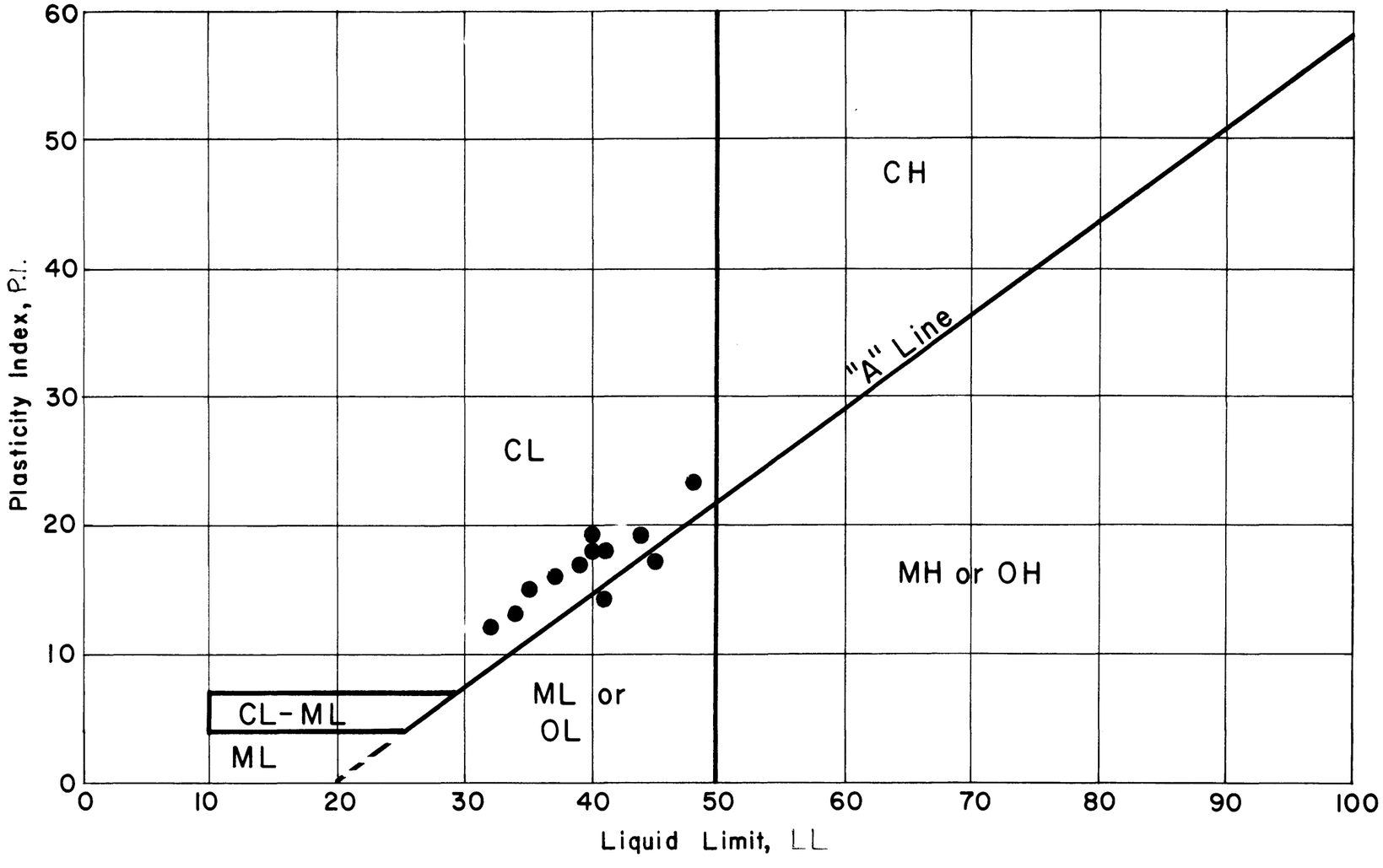
NOTES:

1. ON-SITE SOIL FROM SPRAY POND EXCAVATION WILL BE USED IN SOIL-BENTONITE MIXTURE.
2. SOILS A AND C REPRESENT THE FINEST AND THE COARSEST SOILS RESPECTIVELY IN THE SPRAY POND AREA.

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SOIL USED IN SOIL-BENTONITE MIXTURE DESIGN

FIGURE 2.5-34

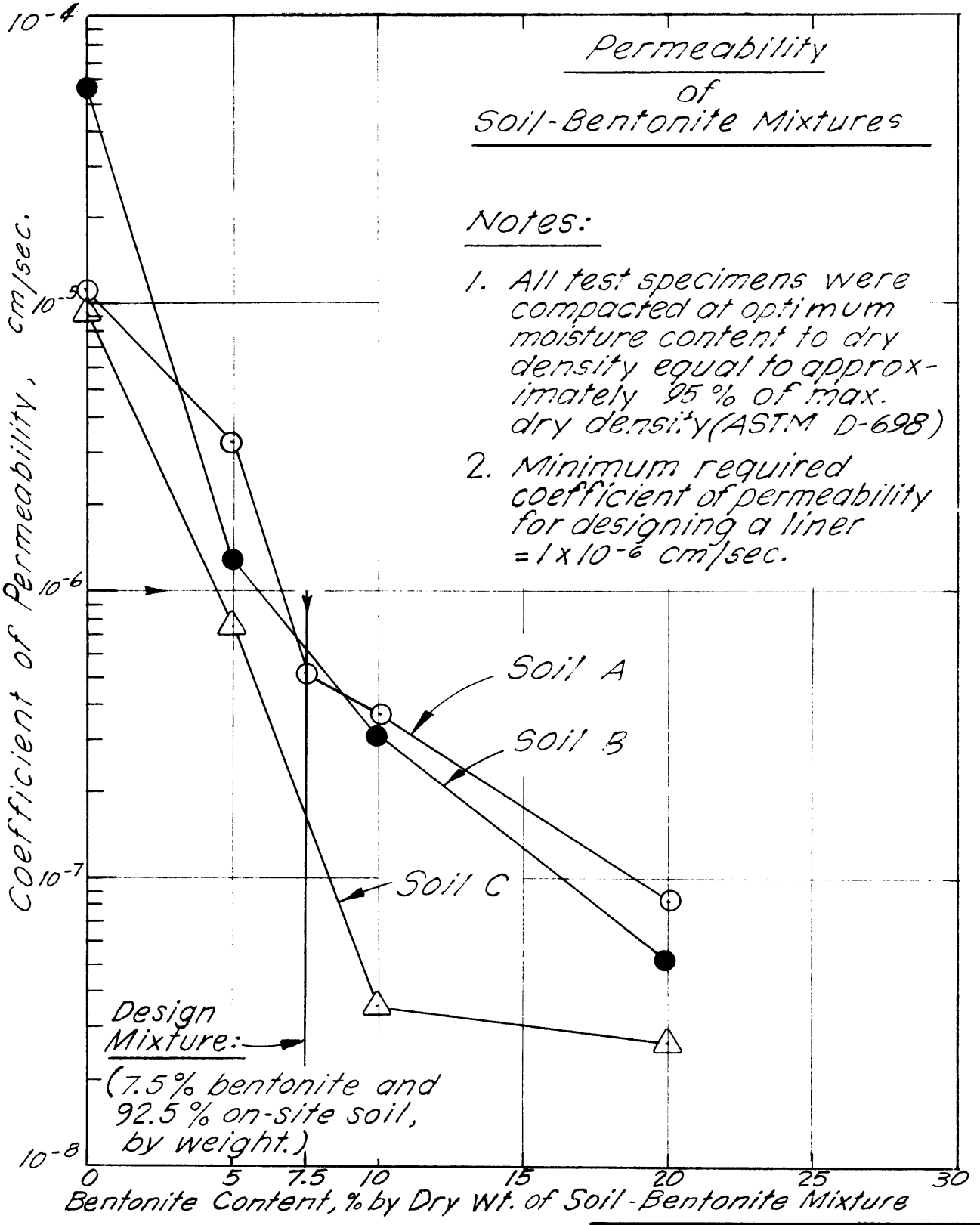


Note:
The plasticity of soils shown are for the soils used for soil-bentonite mixtures. The plasticity chart for the soil in general in the spray pond area is shown on Figure 2.5-17.

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PLASTICITY CHART OF SOILS IN SOIL-BENTONITE MIXTURE DESIGN

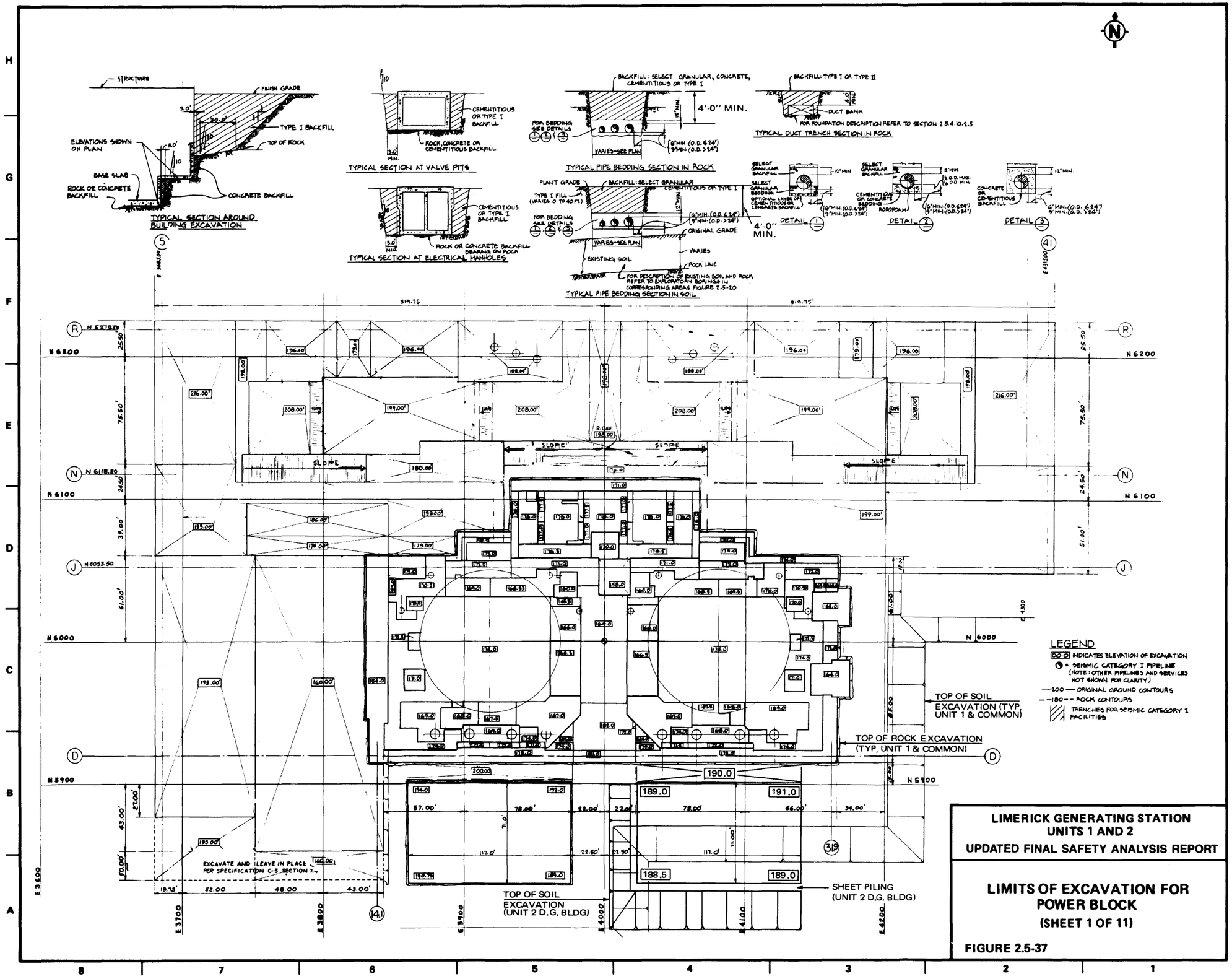
FIGURE 2.5-35



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PERMEABILITY OF SOIL-BENTONITE MIXTURES

FIGURE 2.5-36

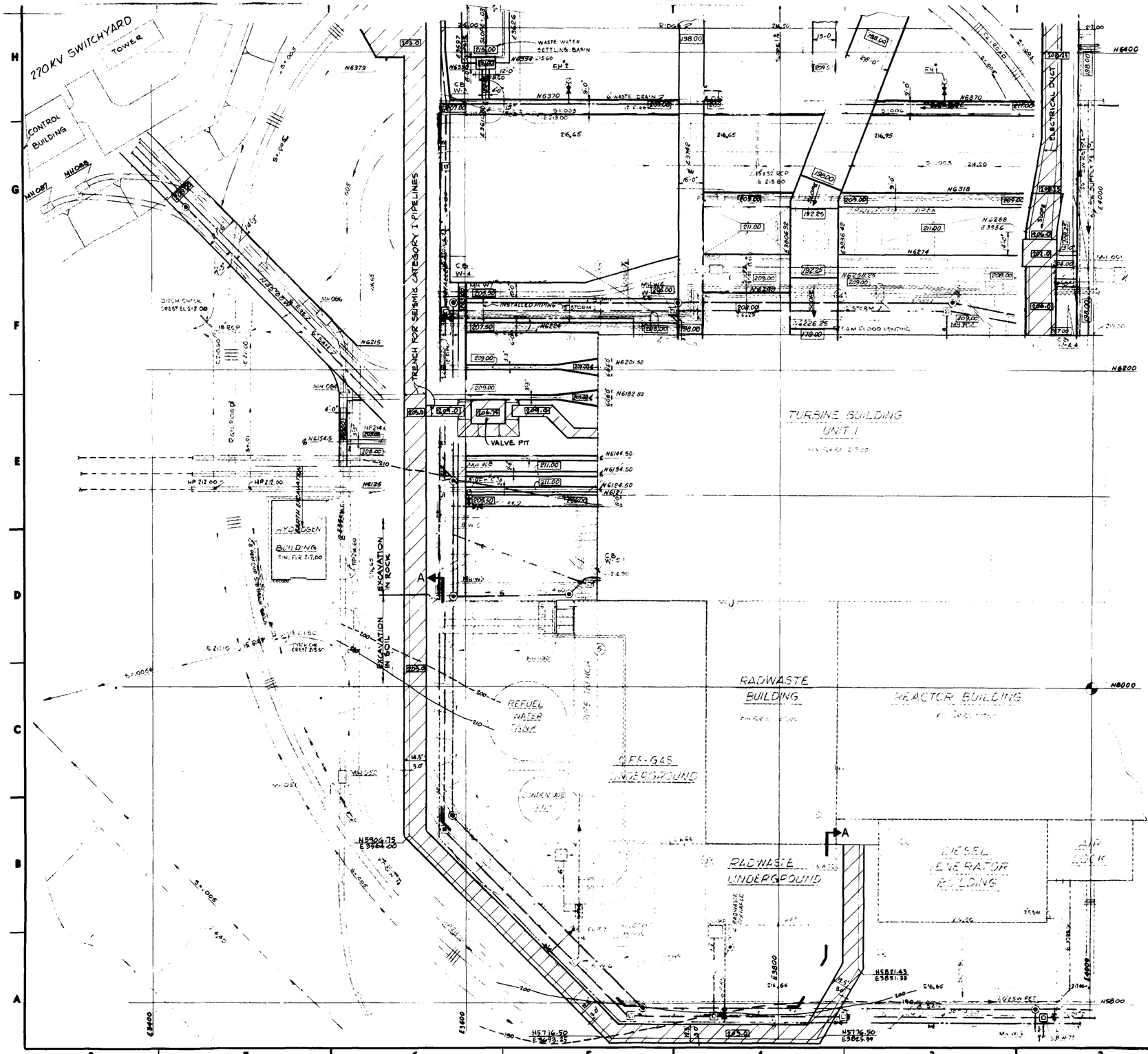


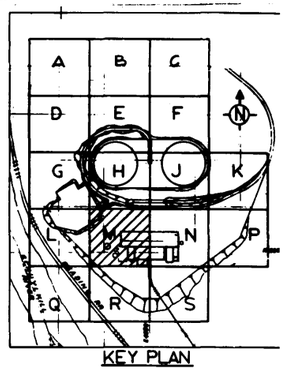
LIMERICK GENERATING STATION
UNITS 1 AND 2
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LIMITS OF EXCAVATION FOR POWER BLOCK

(SHEET 1 OF 11)

FIGURE 2.5-37

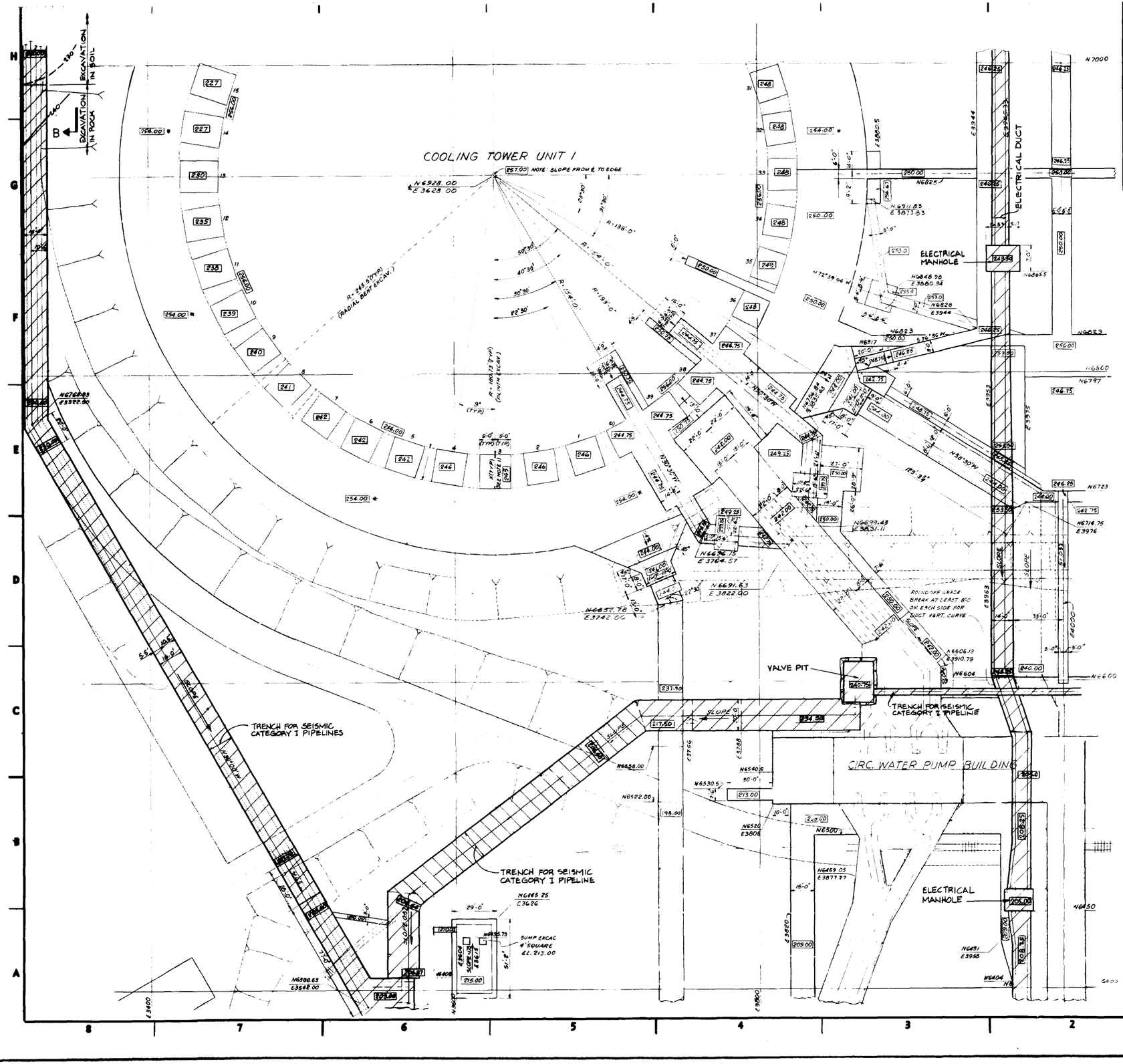


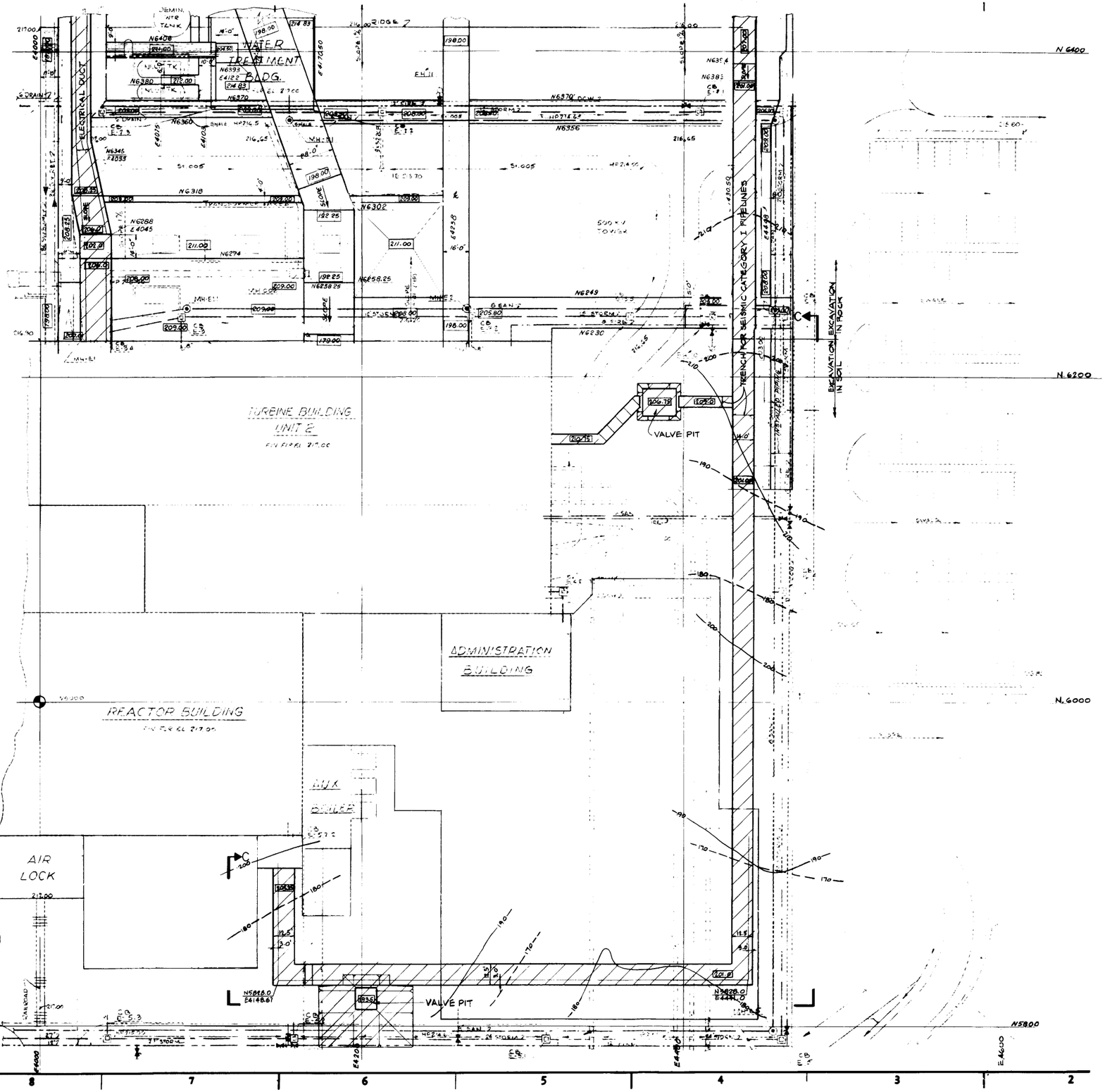


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LIMITS OF EXCAVATION FOR SEISMIC CATEGORY I PIPELINES & ELECTRICAL DUCTS
SHEET 2 OF 11

FIGURE 2.5-37

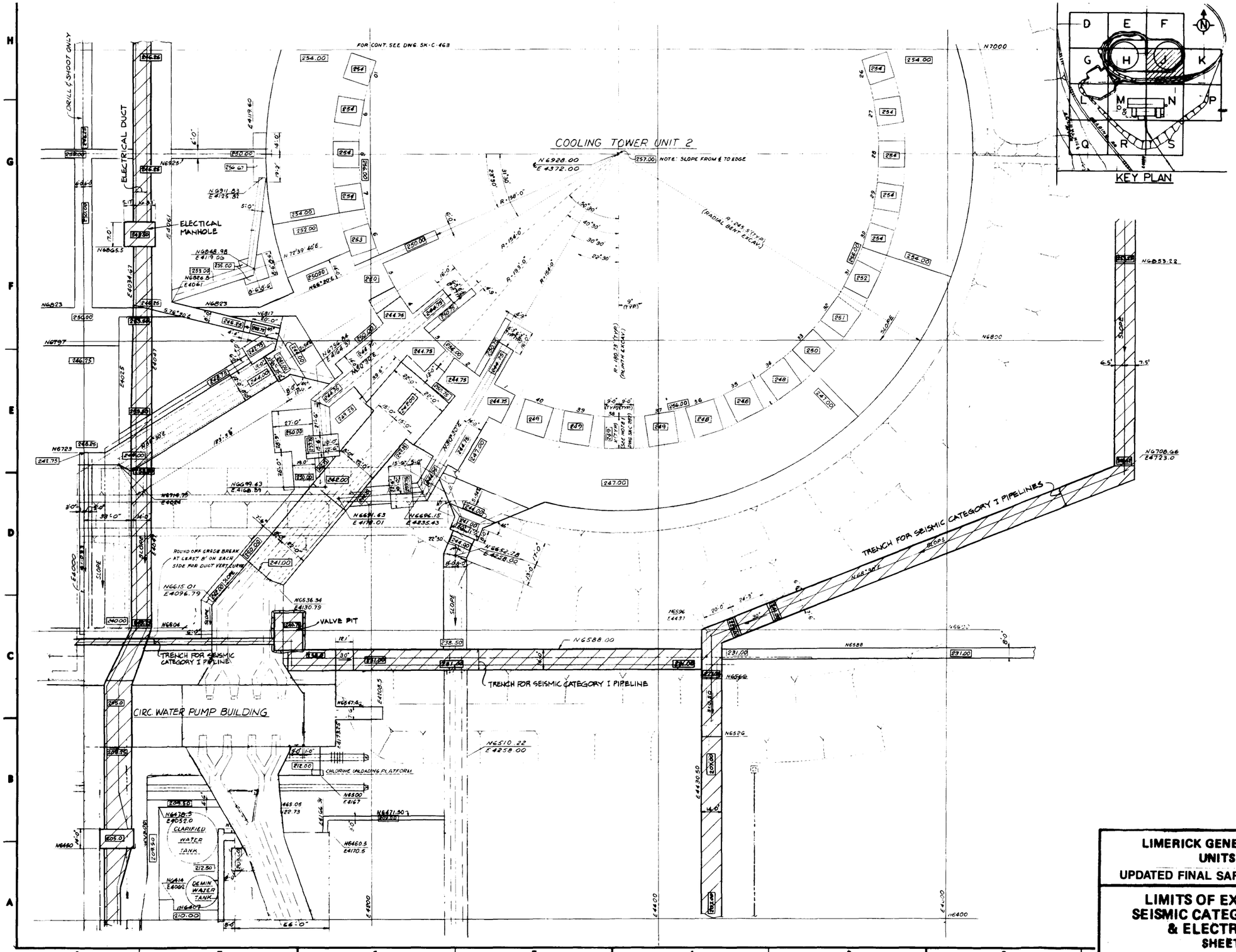

COOLING TOWER UNIT 1
N6928.00
E3628.00
NOTE: SLOPE FROM ℄ TO EDGE
R: 245.5' (TYP) (RADIAL BENT EXCAV.)
R: 193'-0"
R: 154'-0"
R: 193'-0"
R: 154'-0"
R: 193.33' (TYP) (ALIGN EXCAV.)
9° (TYP)
50°30"
40°30"
30°30"
82°30"
N76769.89
E3992.80
EXCAVATION IN SOIL
EXCAVATION IN ROCK
B
TRENCH FOR SEISMIC CATEGORY I PIPELINES
TRENCH FOR SEISMIC CATEGORY I PIPELINE
TRENCH FOR SEISMIC CATEGORY I PIPELINE
ELECTRICAL DUCT
ELECTRICAL MANHOLE
ELECTRICAL MANHOLE
VALVE PIT
CIRC. WATER PUMP BUILDING
SLOPE
SLOPE
SLOPE
SUMP EXCAC 4' SQUARE EL. 213.00
N6398.63
E3368.00
N6685.25
E3626
N6695.75
N6691.63
E3822.90
N6636.75
E3764.57
N6632.78
E3742.00
N6639.43
E3831.11
N6606.13
E3910.79
N6540.15
N6530.5
E3808
N6469.05
E3877.27
N6716.75
E3976
N6723
N6650
N6797
N6823
N6825
N6828
E3944
N6848.98
E3880.94
N6911.83
E3873.83
N7000
N6817
N6655
N6660
N6604
N6500
E3400
E3800
E3820
E3975
E3953
E3944
E3933
E3956
E3768
E3756
E3805
E3933
E3933
E3933



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LIMITS OF EXCAVATION FOR SEISMIC CATEGORY I PIPELINES & ELECTRICAL DUCTS
SHEET 4 OF 11

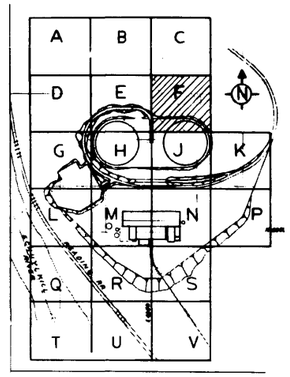
FIGURE 2.5-37



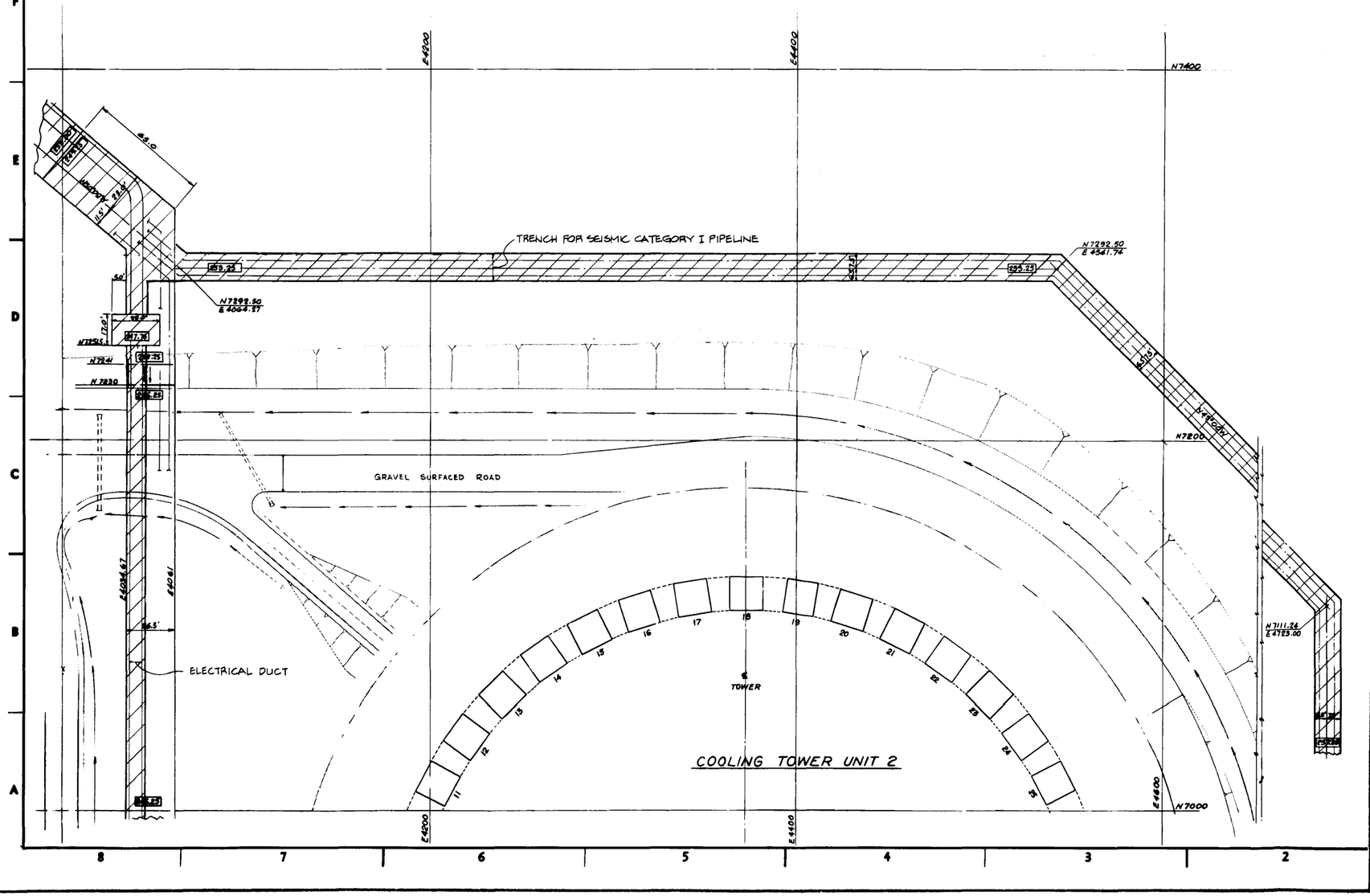
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UNITS 1 AND 2
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LIMITS OF EXCAVATION FOR SEISMIC CATEGORY I PIPELINES & ELECTRICAL DUCTS
SHEET 5 OF 11

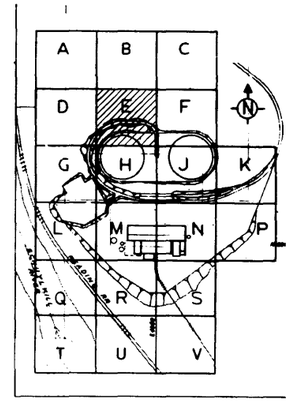
FIGURE 2.5-37


A
B
C
D
E
F
G
H
J
K
L
M
N
P
Q
R
S
T
U
V
N
SCHUYLKILL RIVER
SCHUYLKILL RIVER

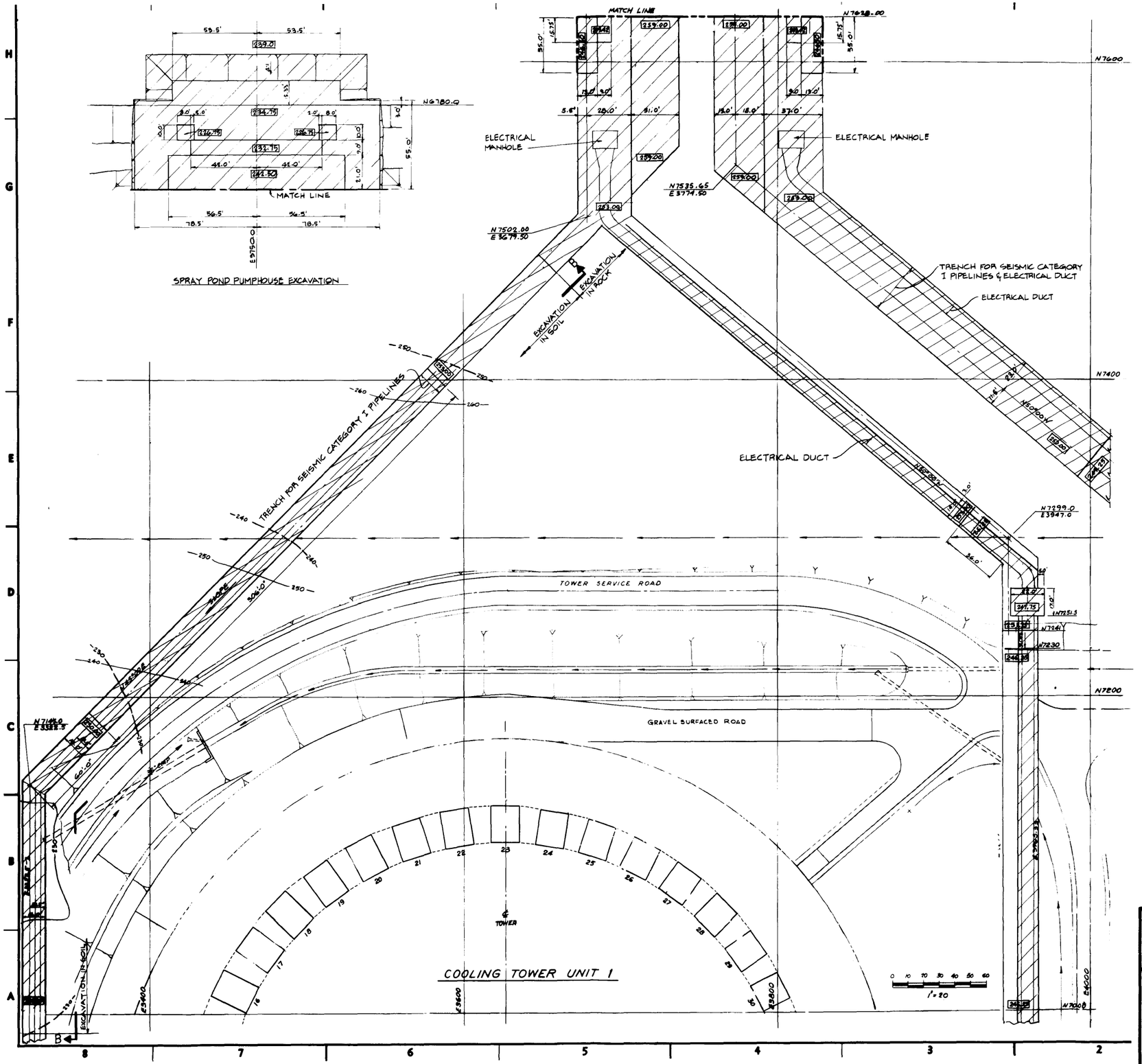
KEY PLAN


H
G
F
E
D
C
B
A
8
7
6
5
4
3
2
E4000
E4400
N7400
N7000
N7200
E4800
E4100
TRENCH FOR SEISMIC CATEGORY I PIPELINE
N7292.50
E 4541.74
N7292.50
E 4064.87
GRAVEL SURFACED ROAD
ELECTRICAL DUCT
COOLING TOWER UNIT 2
TOWER
N7111.24
E 4123.00
N7241
N7230
N7315
E4084.87
E4091
46.5'
50'
98.2'
95.5'
93.25
95.25
97.25
99.25
101.25
103.25
105.25
107.25
109.25
111.25
113.25
115.25
117.25
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147.25
149.25
151.25
153.25
155.25
157.25
159.25
161.25
163.25
165.25
167.25
169.25
171.25

SPRAY POND PUMPHOUSE EXCAVATION



KEY PLAN



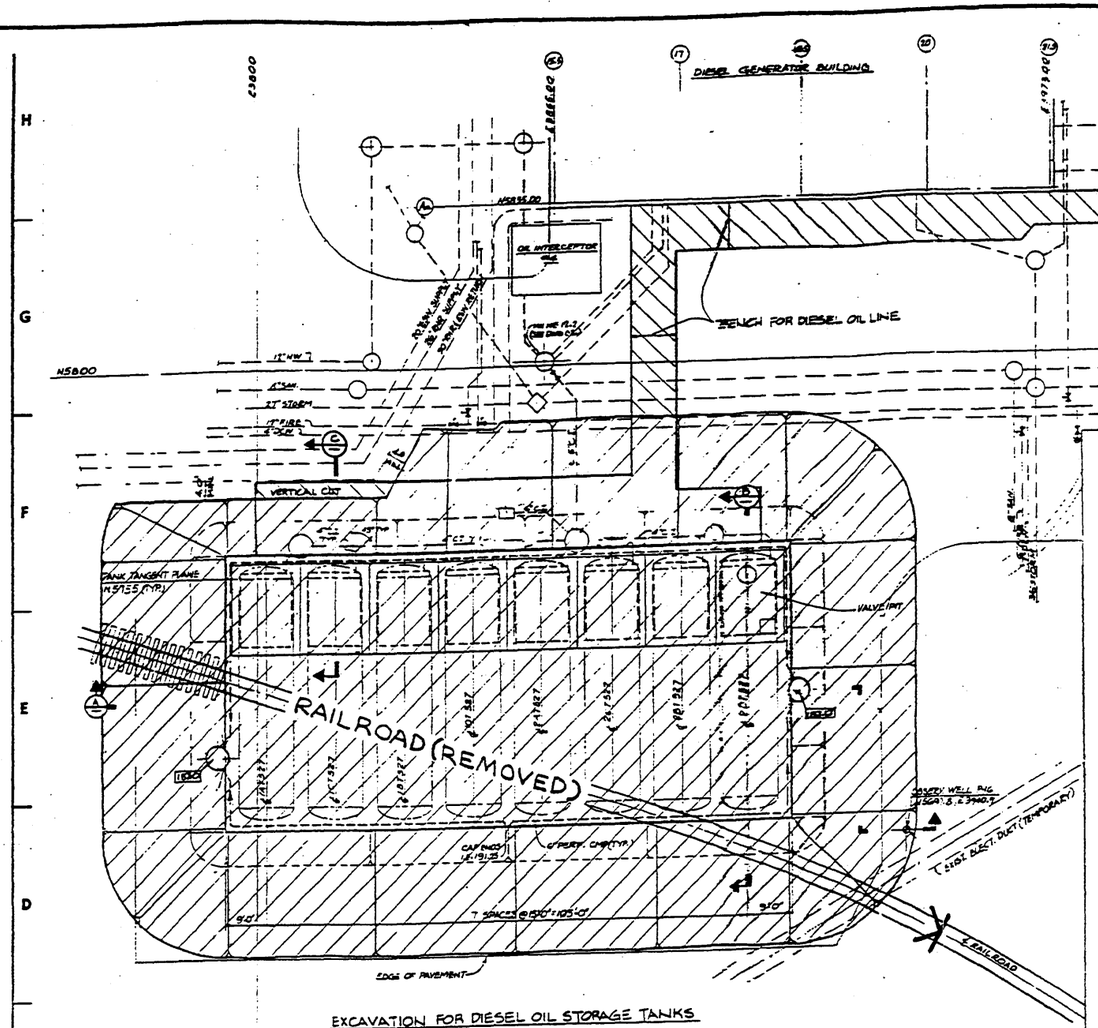
LIMERICK GENERATING STATION
UNITS 1 AND 2

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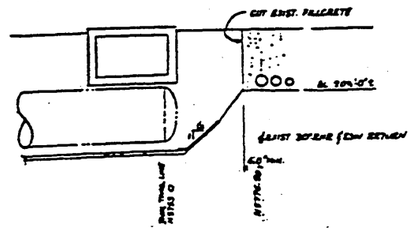
LIMITS OF EXCAVATION FOR SEISMIC CATEGORY I PIPELINES, ELECTRICAL DUCTS & SPRAY POND PUMPHOUSE

SHEET 7 OF 11

FIGURE 2.5-37

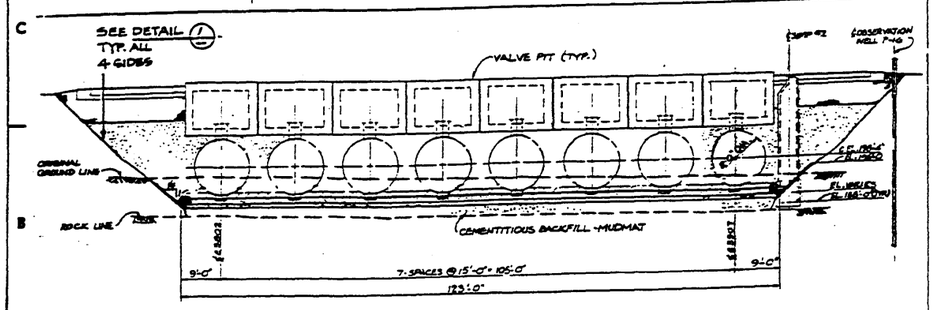


EXCAVATION FOR DIESEL OIL STORAGE TANKS

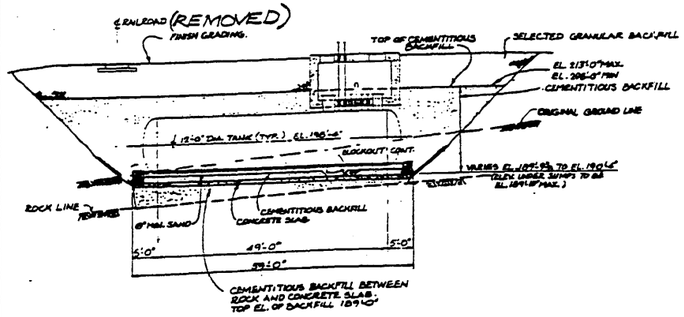


DETAIL (1)

SECTION (C)



SECTION (A)



SECTION (B)

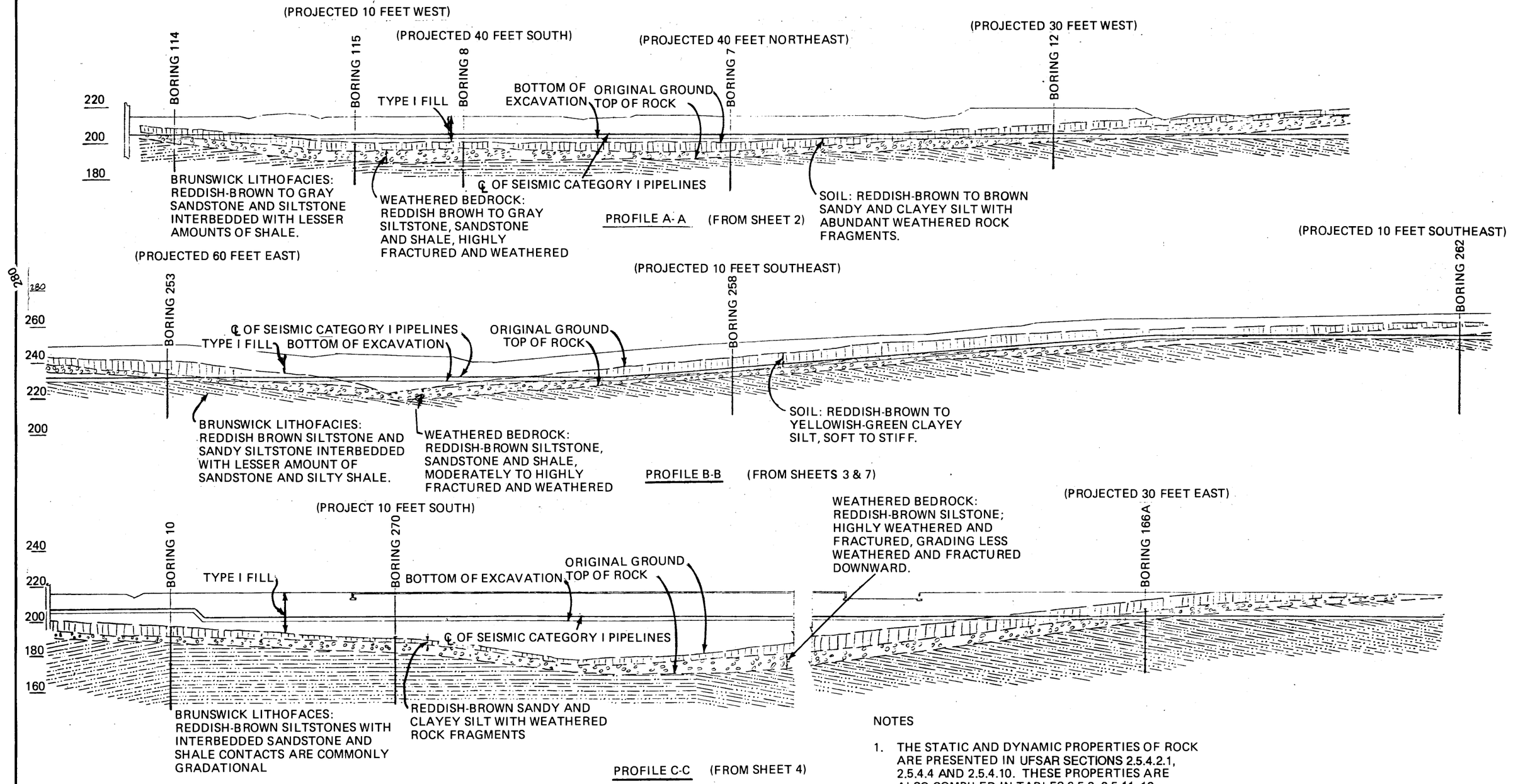
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LIMITS OF EXCAVATION FOR DIESEL OIL STORAGE TANKS & DIESEL OIL LINES

SHEET 8 OF 11

FIGURE 2.5-37

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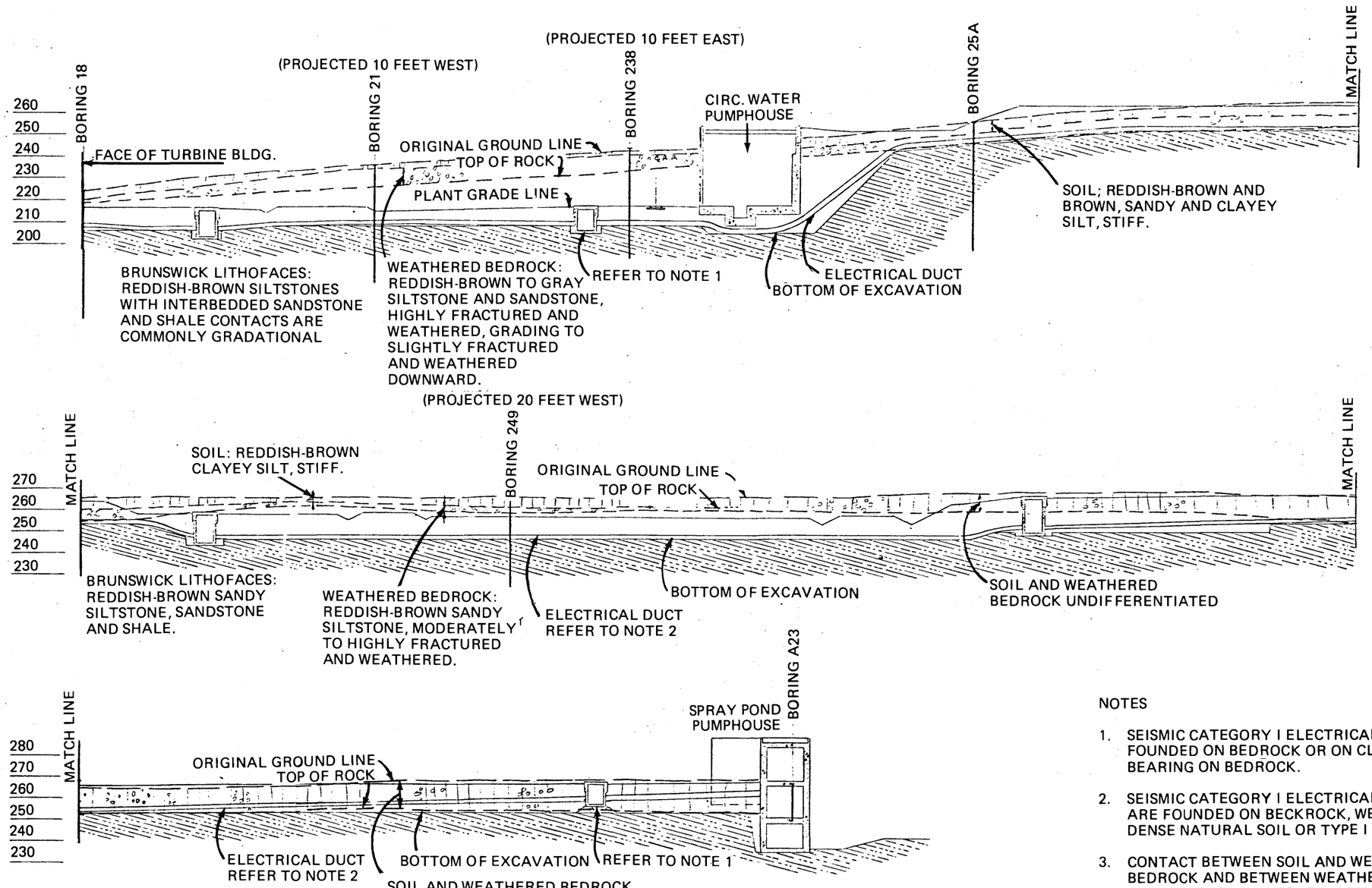
NOTES

1. THE STATIC AND DYNAMIC PROPERTIES OF ROCK ARE PRESENTED IN UFSAR SECTIONS 2.5.4.2.1, 2.5.4.4 AND 2.5.4.10. THESE PROPERTIES ARE ALSO COMPILED IN TABLES 2.5-3, 2.5-11, 12 AND 13.
2. THE SOIL PROPERTIES ARE PRESENTED IN UFSAR SECTION 2.5.4.2.2.1 THROUGH 2.5.4.2.2.4.
3. FILLS ARE PRESENTED IN UFSAR SECTION 2.5.4.5.4.
4. SEE FIGURE 2.5-22 FOR LITHOLOGIC LOG OF BORINGS.
5. CONTACT BETWEEN WEATHERED ROCK AND ROCK IS GENERALLY GRADATIONAL OVER 2 TO 5 FEET.

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LIMITS OF EXCAVATION FOR SEISMIC CATEGORY I PIPELINES
SHEET 9 OF 11

FIGURE 2.5-37



PROFILE OF ELECTRICAL DUCT

PROFILE SHOWN IS FOR UNIT 2
PROFILE FOR UNIT 1 IS SIMILAR

NOTES

1. SEISMIC CATEGORY I ELECTRICAL MANHOLES ARE FOUNDED ON BEDROCK OR ON CLASS A CONCRETE BEARING ON BEDROCK.
2. SEISMIC CATEGORY I ELECTRICAL DUCT BANKS ARE FOUNDED ON BECKROCK, WEATHERED ROCK, DENSE NATURAL SOIL OR TYPE I FILL.
3. CONTACT BETWEEN SOIL AND WEATHERED BEDROCK AND BETWEEN WEATHERED BEDROCK AND BEDROCK ARE GENERALLY GRADATIONAL OVER 2 TO 4 FEET.
4. SEE FIGURE 2.5-22 FOR LITHOLOGIC DESCRIPTION OF BORINGS.

0 20 40 60 80 100

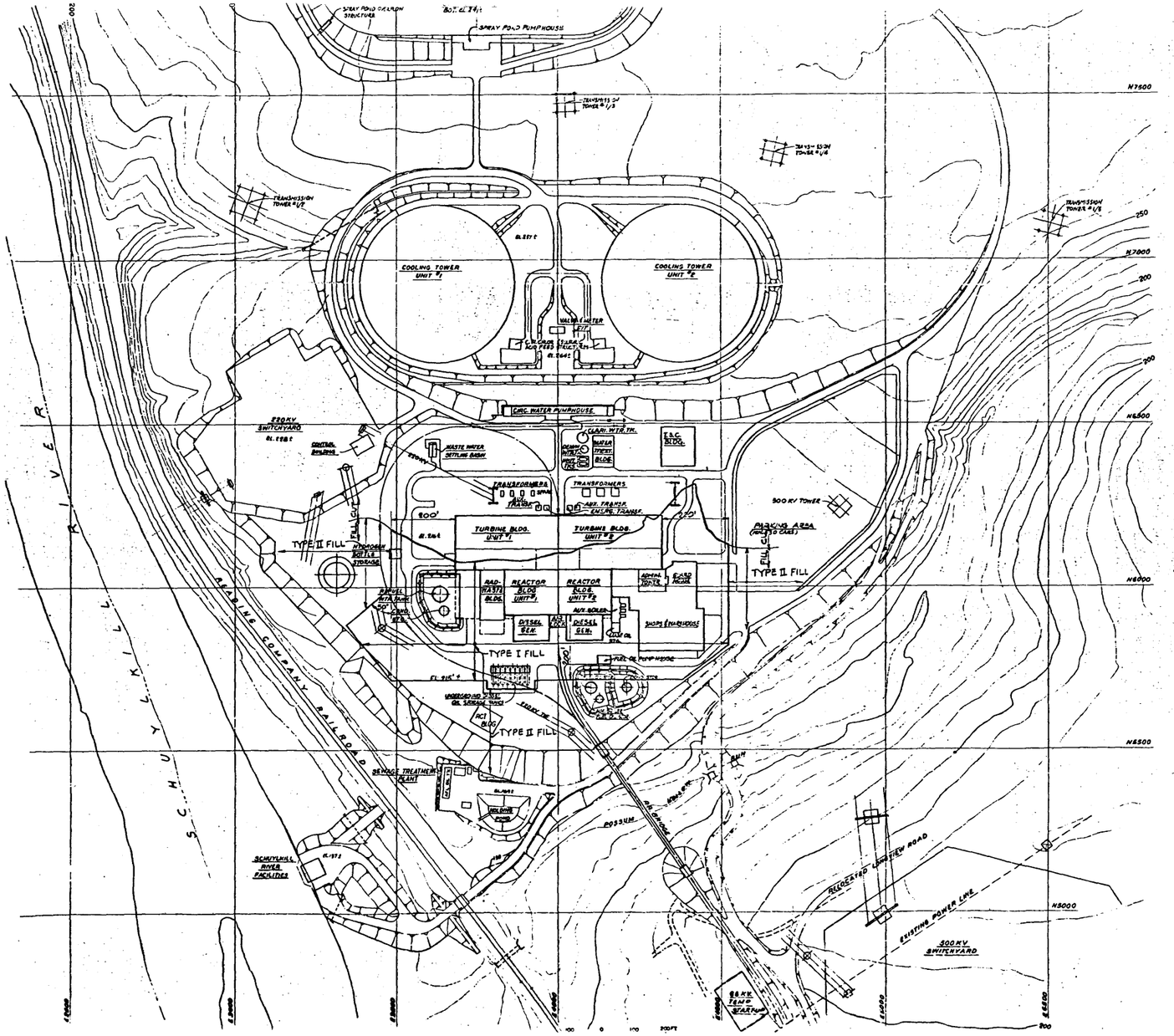
SCALE: 1" = 20'

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LIMITS OF EXCAVATION FOR SEISMIC CATEGORY I ELECTRICAL DUCT BANKS

SHEET 10 OF 11

FIGURE 2.5-37

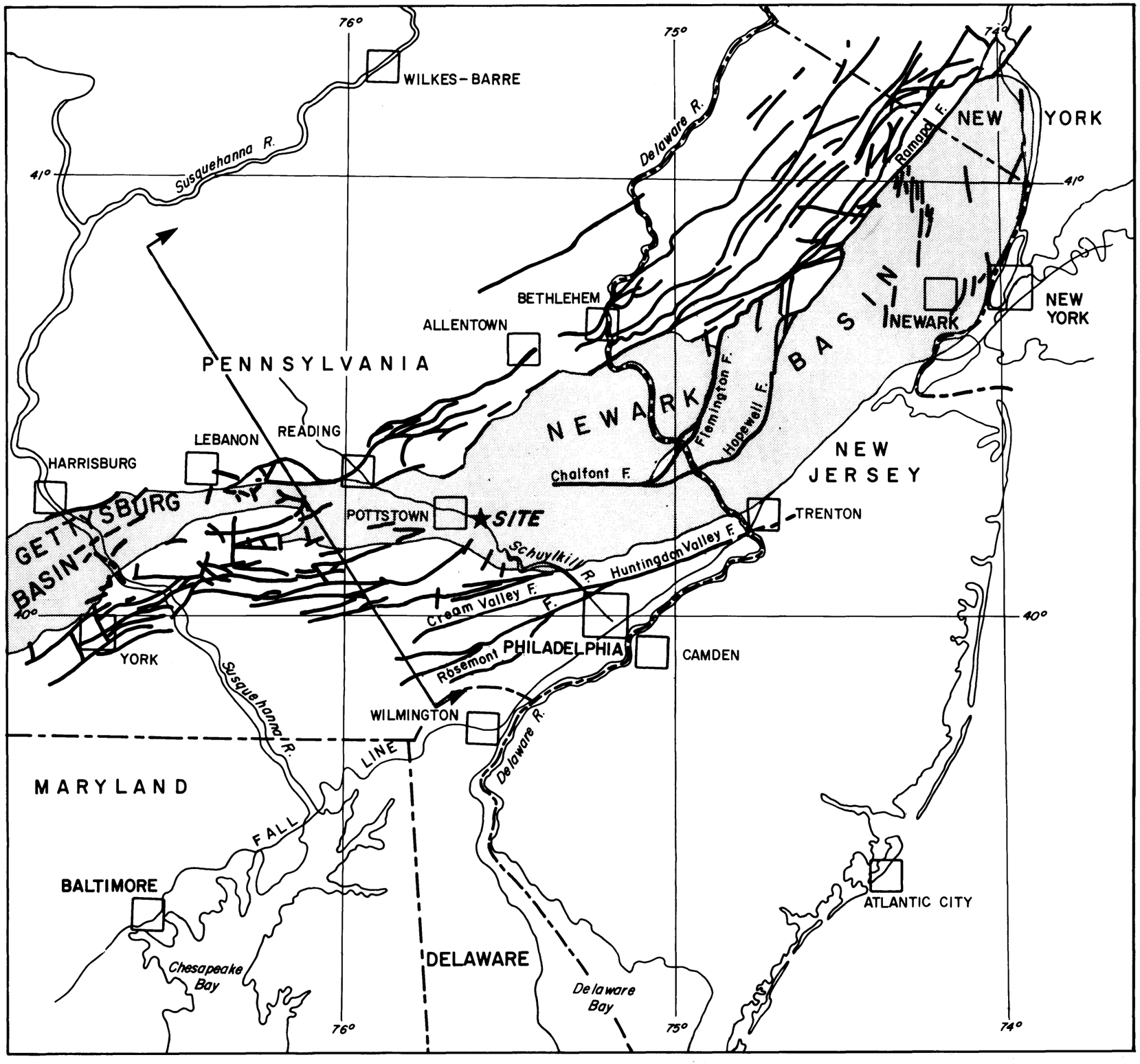


LIMERICK GENERATING STATION
UNITS 1 AND 2
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LIMITS OF EXCAVATION FOR TYPE I AND TYPE II FILL

SHEET 11 OF 11

FIGURE 2.5-37



EXPLANATION

Area underlain by Triassic rocks of Newark-Gettysburg Basin.

Mapped Faults (type unspecified).

Boundary of Coastal Plain sediments

Location of geologic section shown in Figure 2.5-3.

Data Sources: Triassic basin and associated faults from Faill(1973) in Pennsylvania and from Olsen(1980) and Ratcliffe(1980) in New Jersey. Other faults in Pennsylvania from Penna. Geol.Survey state geologic map (Map No. 1; 1975, 1980)

N

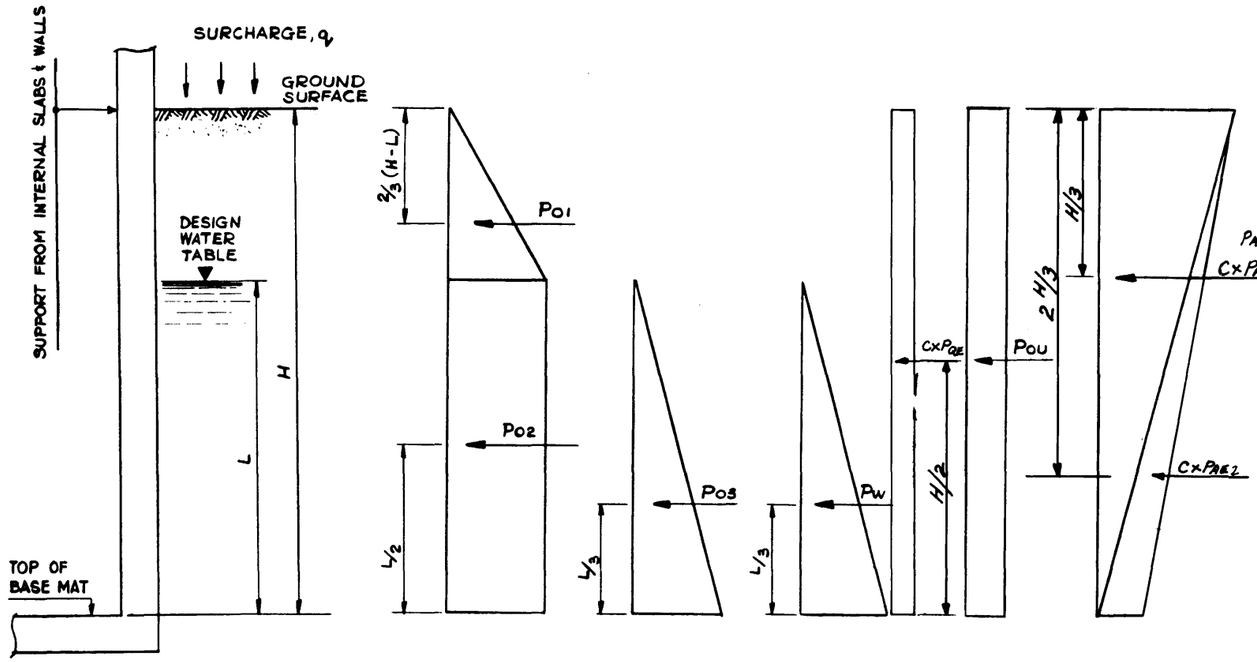
0 25 Miles

LIMERICK GENERATING STATION UNITS 1 AND 2

UPDATED FINAL SAFETY ANALYSIS REPORT

GEOLOGIC STRUCTURE, VICINITY OF NEWARK – GETTYSBURG BASIN

FIGURE 2.5-38



SECTION THROUGH EXTERNAL WALL

SOIL AND WATER PRESSURE DIAGRAMS

NOTES:

Po1, Po2, Po3 = THRUST RESULTING FROM SOIL IN THE "AT REST" STATE
Pw = THRUST RESULTING FROM HYDROSTATIC PRESSURE
Pou = THRUST RESULTING FROM SURCHARGE PRESSURE
P_{AE1}, P_{AE2} = THRUST RESULTING FROM DYNAMIC ACTION OF SOIL & WATER (SEED-WHITMAN FORMULA, 1970)

$P_{o1} = \frac{1}{2} K_o \gamma_b (H-L)^2$
$P_{o2} = K_o \gamma_b (H-L) L$
$P_{o3} = \frac{1}{2} K_o \gamma' L^2$
$P_w = \frac{1}{2} \gamma_w L^2$
$P_{ou} = K_o q H$
$P_{AE} = \frac{3}{8} \gamma_s H^2 K_h$
$P_{AE1} = 0.3 (1+K_v) K_h \gamma_s H^2$
$P_{AE2} = \frac{1}{2} K_v K_A \gamma_s H^2$
$P_{AE} = gH(1+K_v)0.6K_h + gHK_v$

* Restrained retaining wall assumption used

WHERE:

K_A = STATIC LATERAL ACTIVE EARTH PRESSURE COEFFICIENT
*K_o = COEFFICIENT OF EARTH PRESSURE "AT REST" = 0.70
γ_b = BULK UNIT WEIGHT = 135 p.c.f.
γ' = BUOYANT UNIT WEIGHT = 77.5 p.c.f.
γ_s = SATURATED UNIT WEIGHT = 140 p.c.f.
γ_w = DENSITY OF WATER = 62.5 p.c.f.
q = SURCHARGE PRESSURE = 250 p.c.f.
K_h = HORIZONTAL ACCELERATION/g
0.075 FOR OBE
0.15 FOR SSE

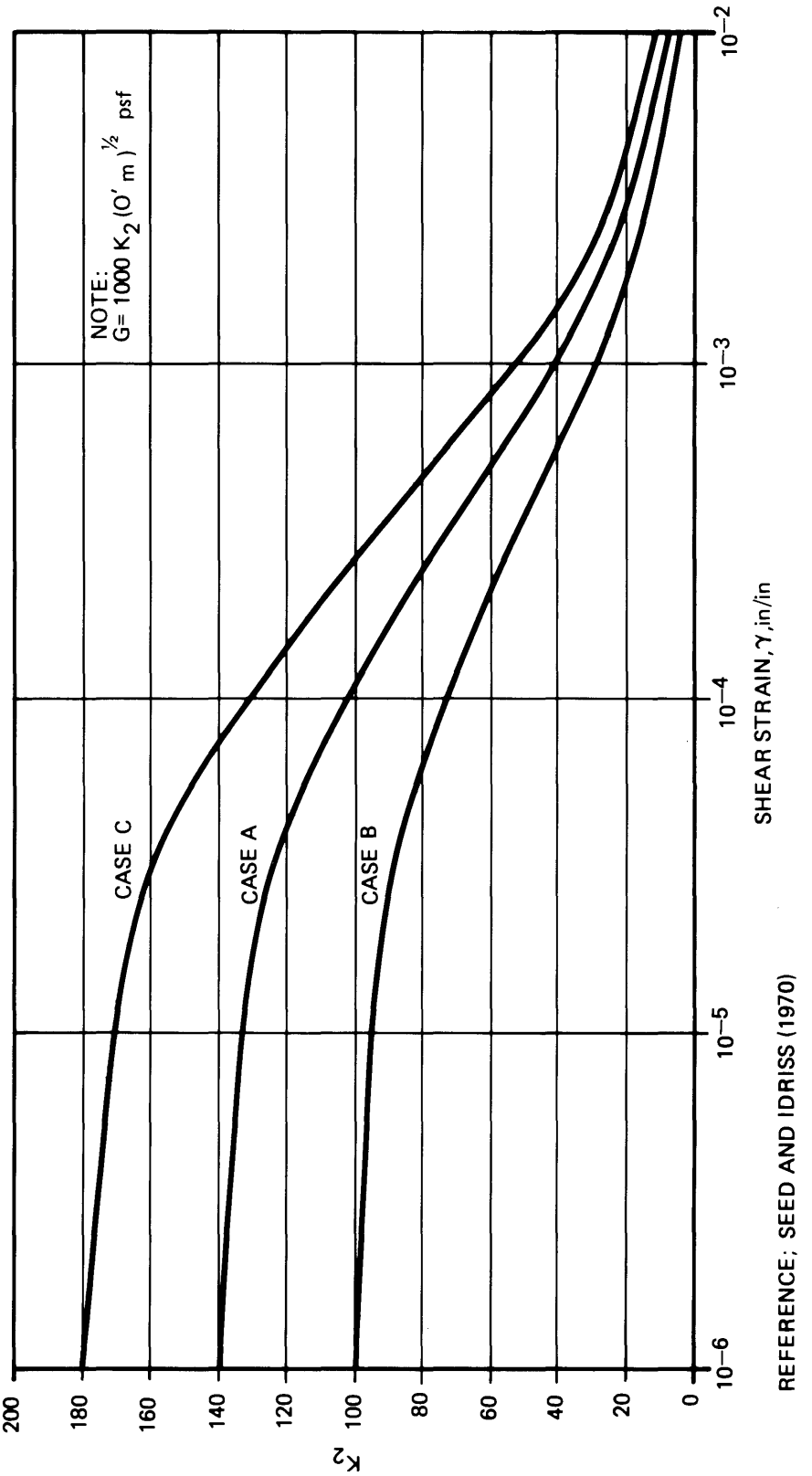
C = COEFFICIENT = 2.0 FOR RIGID WALLS

K_v = VERTICAL ACCELERATION / g
$= \frac{2}{3} K_h$

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LATERAL SOIL PRESSURE DIAGRAMS

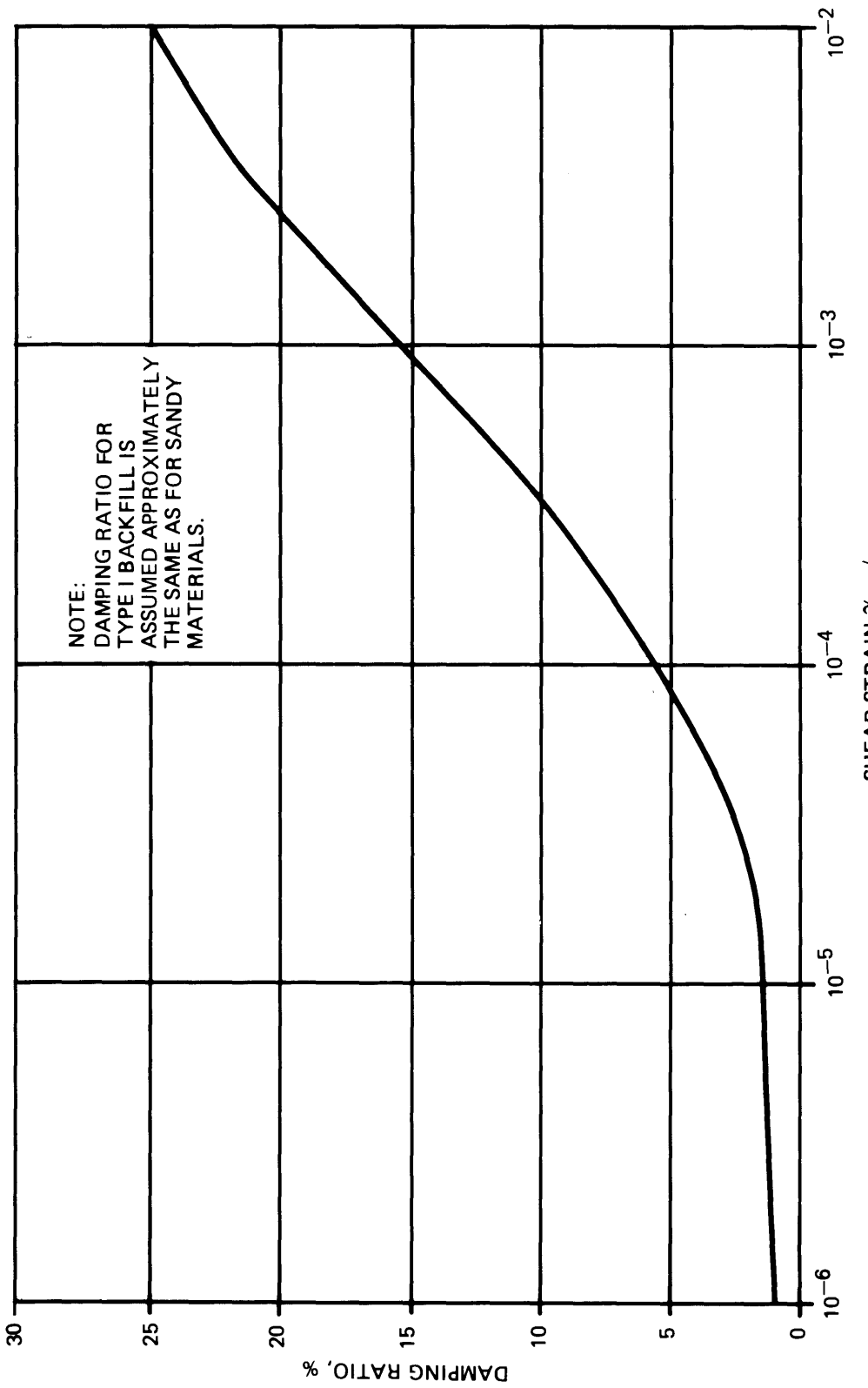
FIGURE 2.5-39



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SHEAR MODULUS PARAMETER, K2, VS. STRAIN PROPERTY TYPE I BACKFILL MATERIAL

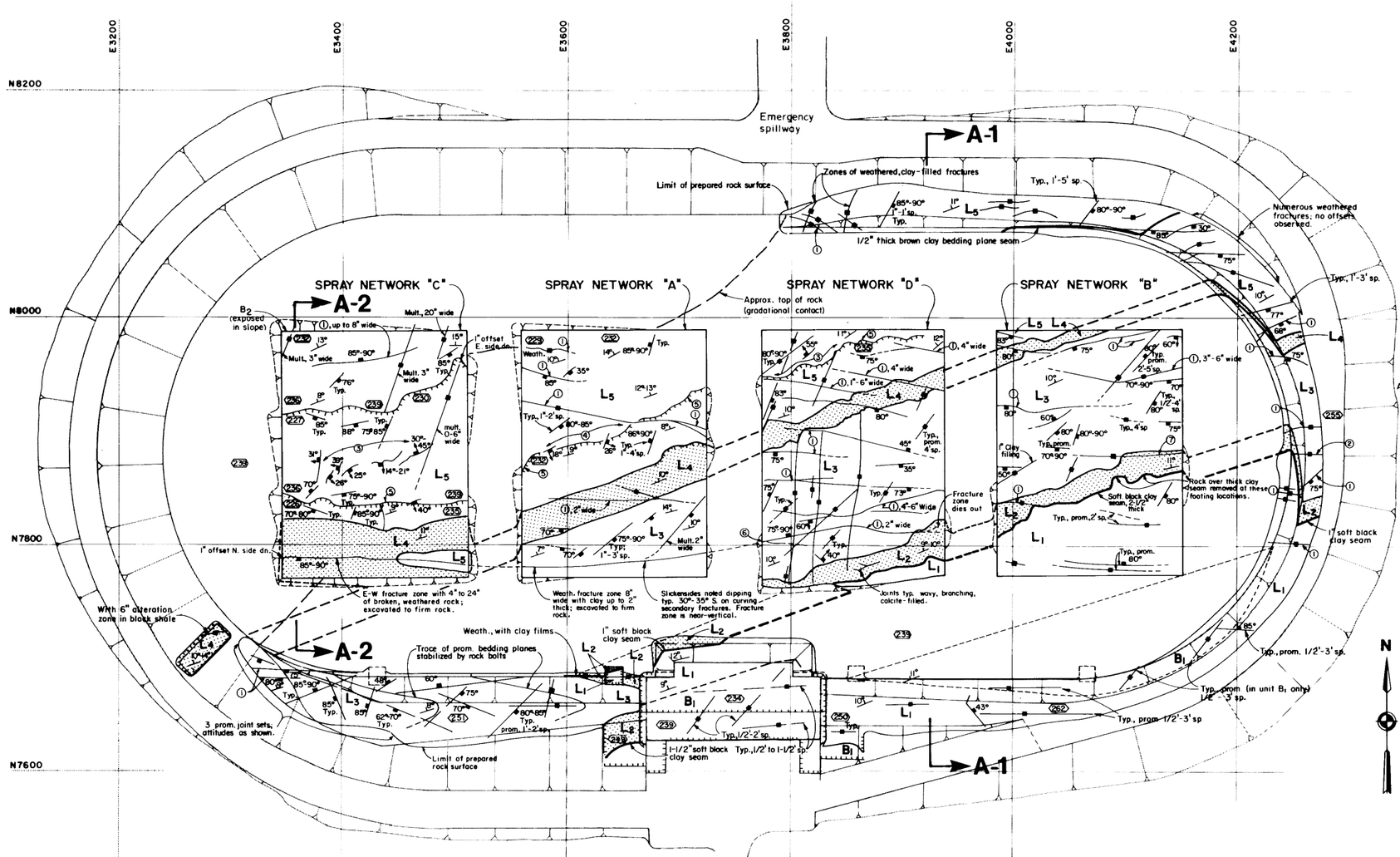
FIGURE 2.5-40



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DAMPING RATIO VS. STRAIN PROPERTY TYPE I BACKFILL MATERIAL

FIGURE 2.5-41



EXPLANATION

SYMBOLS

- 10° — Strike and dip of bedding.
- 85° — Joints and fractures, showing dip; vertical joint (right); dashed where indistinct.
- 40° / 40° — Dip of slickensided joint plane, showing dip of slickensides. (Note: dip-slip lineation shown.)
- Typ. 70°-90° 1/2'-3' sp. — Representative joint, showing range of dip and joint spacing. (See abbreviations below.)
- Lithologic contact, dashed where indistinct.
- Prominent bedding-plane clay seam.
- Vertical or near-vertical slope in excavation; hachures toward lower side.
- (239) — Denotes elevation of excavated surface at location shown.
- B_1, L_3 — Lithologic units recognized in mapping. (See description at right.)
- Exposure of black shale members of Lockatong Formation.
- A-2 A-2 — Location of Geologic Section (Shown on Figure 2.5-43)

LITHOLOGIC DESCRIPTION

B – Brunswick Formation – Red to brown sandstone, siltstone, minor shale; noncalcareous

B_1 – Brunswick strata below Lockatong units

B_2 – Brunswick strata above Lockatong units

L – Lockatong Formation – Black shale or claystone with associated gray to tan or brown calcareous units

L_1 – Light to medium gray, very hard, fine-grained calcareous sandstone with minor silty limestone; medium bedded. Locally exhibits impressions of dinosaur footprints

L_2 – Black to dark gray, hard, shaly-weathering mudstone or claystone; massive

L_3 – Yellow to brown, variably calcareous fine- to very fine-grained silty sandstone, siltstone, minor shale; some greenish weathering members. Mostly thin-bedded

L_4 – Black, highly carbonaceous claystone; in part shaly

L_5 – Lithologically similar to L_3 unit

NOTES:

1. Irregular joints or fractures; generally weathered and oxide-stained, some with clay films. Width is shown where close-spaced fractures form narrow zone.
2. Fracture zone 1/2" to 24" wide; up to 2-1/2" apparent right lateral offset observed; zone terminates downward at L_1-L_2 contact.
3. Numerous curving, gently dipping slickensided joints. Striations show pure dip-slip adjustments.
4. Low-angle joints with slickensides exposed in slope.
5. Prominent shale bed exposed at base of slope (1' to 1-1/2' thick).
6. 2" offset, N. side dn. Fracture zone 2-24" wide, weathered, iron-stained, clay-coated; excavated to firm rock.
7. Fracture zone; fractures dip 70°N to 70°S within zone 6" wide; iron-stained and weathered. No offsets. All soft material excavated to firm rock.
8. Base plan and elevations show excavation configuration prior to placing lining or backfill.

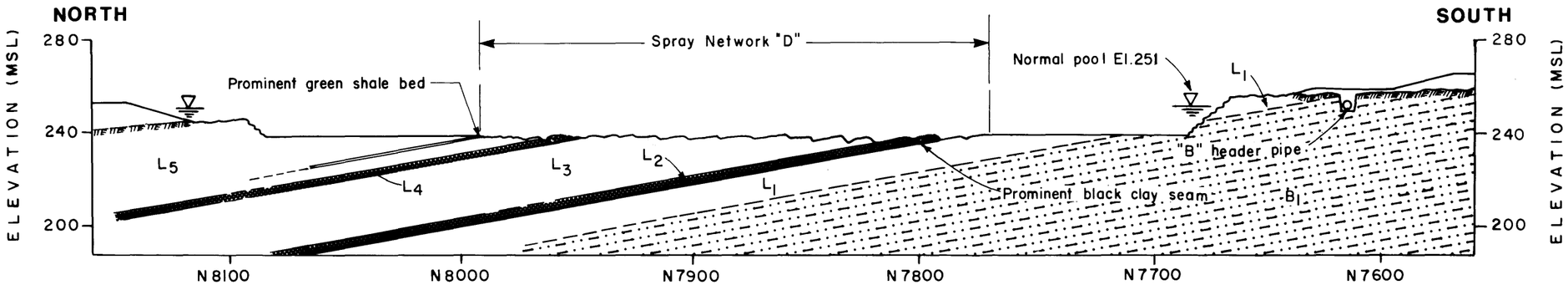
ABBREVIATIONS USED:

typ.: typical or typically; used to indicate joint symbol shown represents a set of numerous repetitive joints
prom.: prominent
sp.: spacing
mult.: multiple; refers to very close-spaced parallel joints observed at western end of pond
weath.: weathered

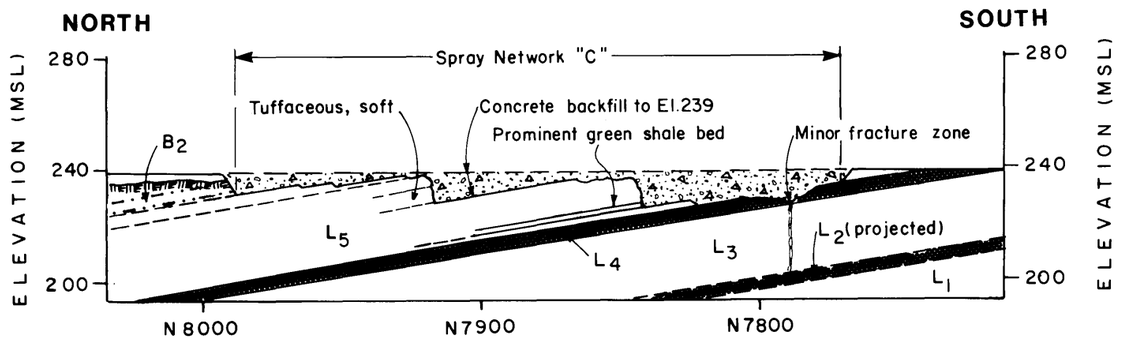
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GEOLOGIC MAP OF SPRAY POND

FIGURE 2.5-42



SECTION A-1



SECTION A-2

EXPLANATION

Brunswick Formation

Lockatong Formation (Black claystone or shale members shown in dark stipple)

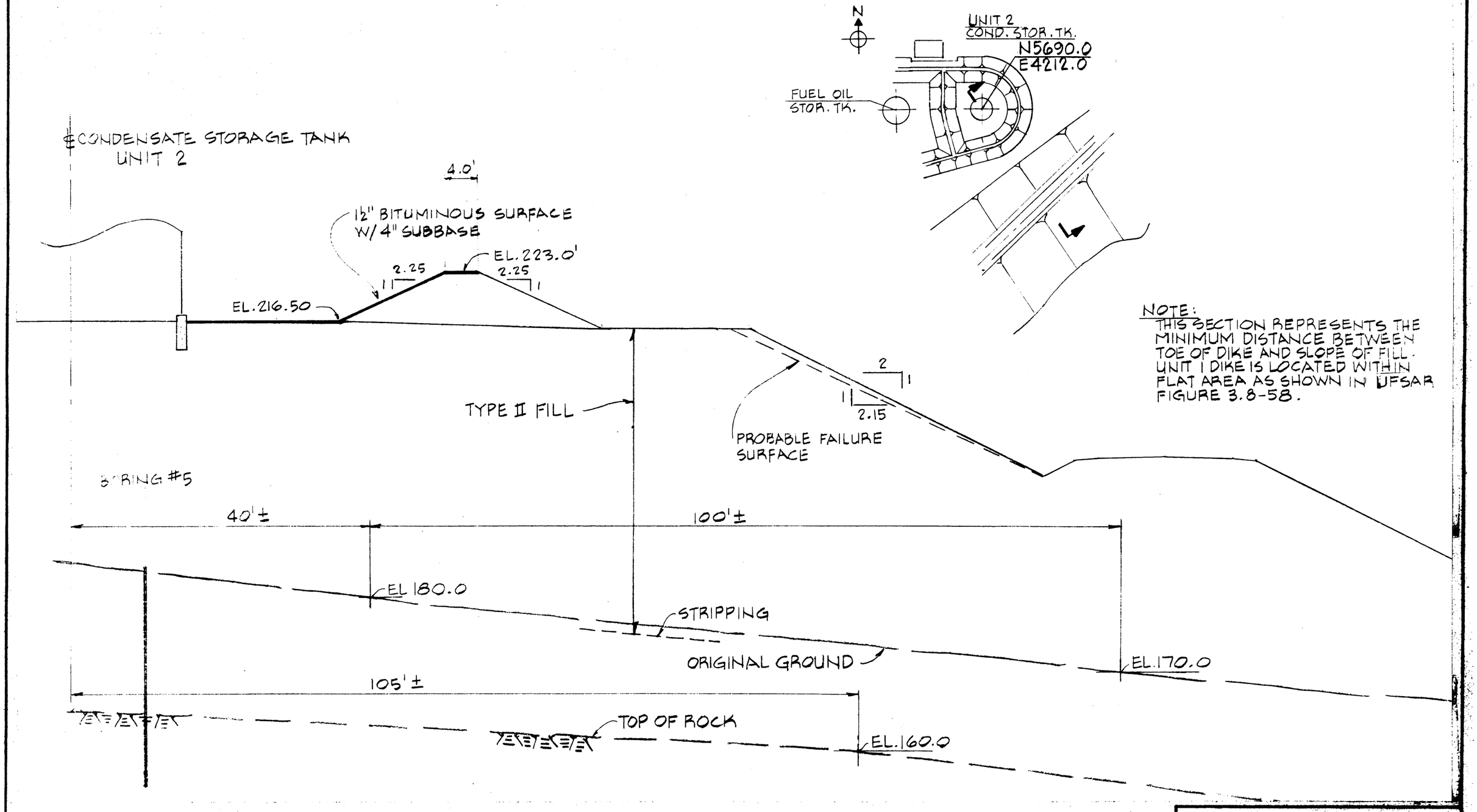
NOTES:

1. Southern continuation of Section A-1 is shown in Figure 2.5-9.
2. For lithologic descriptions see Figure 2.5-42.
3. Rock surface at spray pond networks was backfilled with concrete to elevation 239 (see Section A-2).
4. Location of sections is shown on Figure 2.5-42.

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SPRAY POND GEOLOGIC SECTIONS

FIGURE 2.5-43

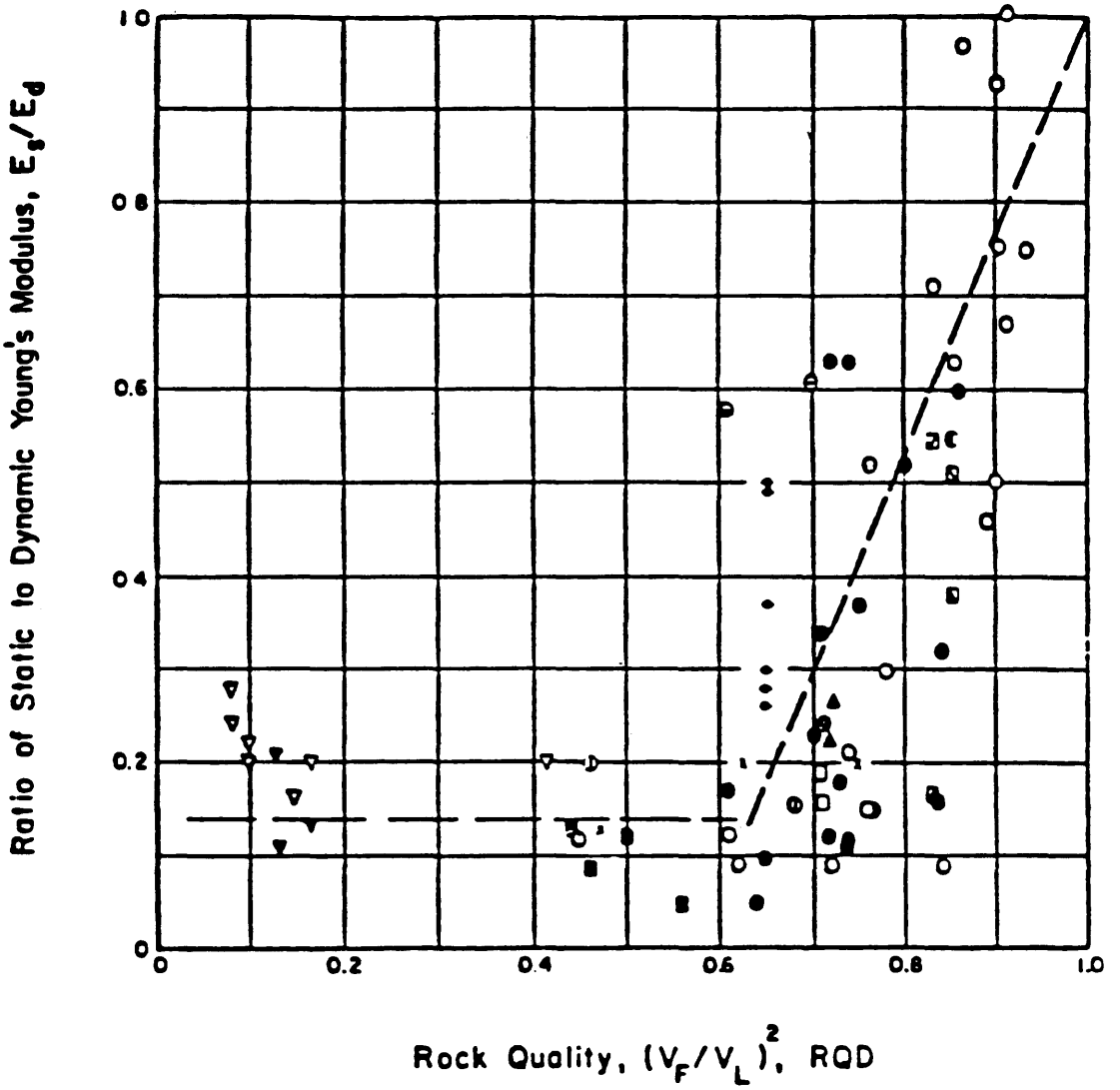


NOTE:
THIS SECTION REPRESENTS THE MINIMUM DISTANCE BETWEEN TOE OF DIKE AND SLOPE OF FILL. UNIT 1 DIKE IS LOCATED WITHIN FLAT AREA AS SHOWN IN UFSAR FIGURE 3.8-58.

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CROSS SECTION OF CONDENSATE TANK DIKES

FIGURE 2.5-44

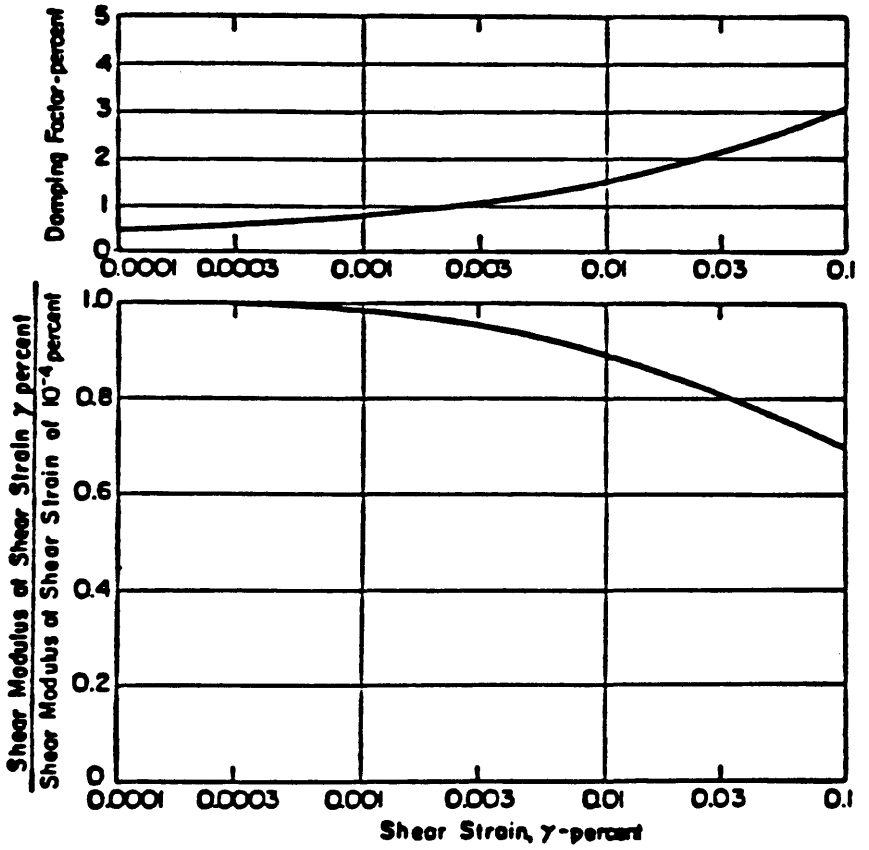


REFERENCE: WASH 1301 REPORT (1974)

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VARIATION OF THE RATIO OF STATIC TO DYNAMIC YOUNG'S MODULUS WITH ROCK QUALITY FOR ROCK MASSES

FIGURE 2.5-45

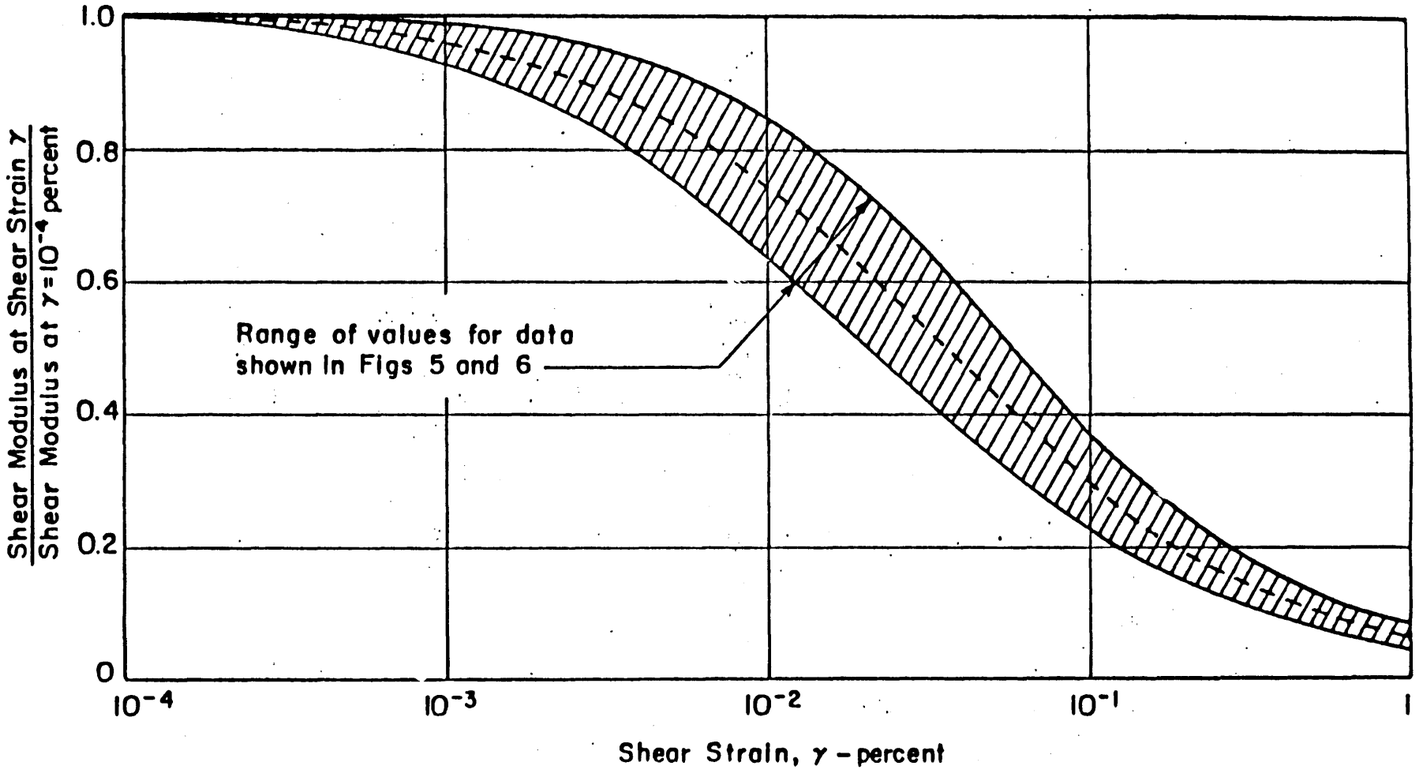


REFERENCE: SCHNABEL, ET AL (1971)

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SHEAR MODULI AND DAMPING CHARACTERISTICS FOR ROCK

FIGURE 2.5-46

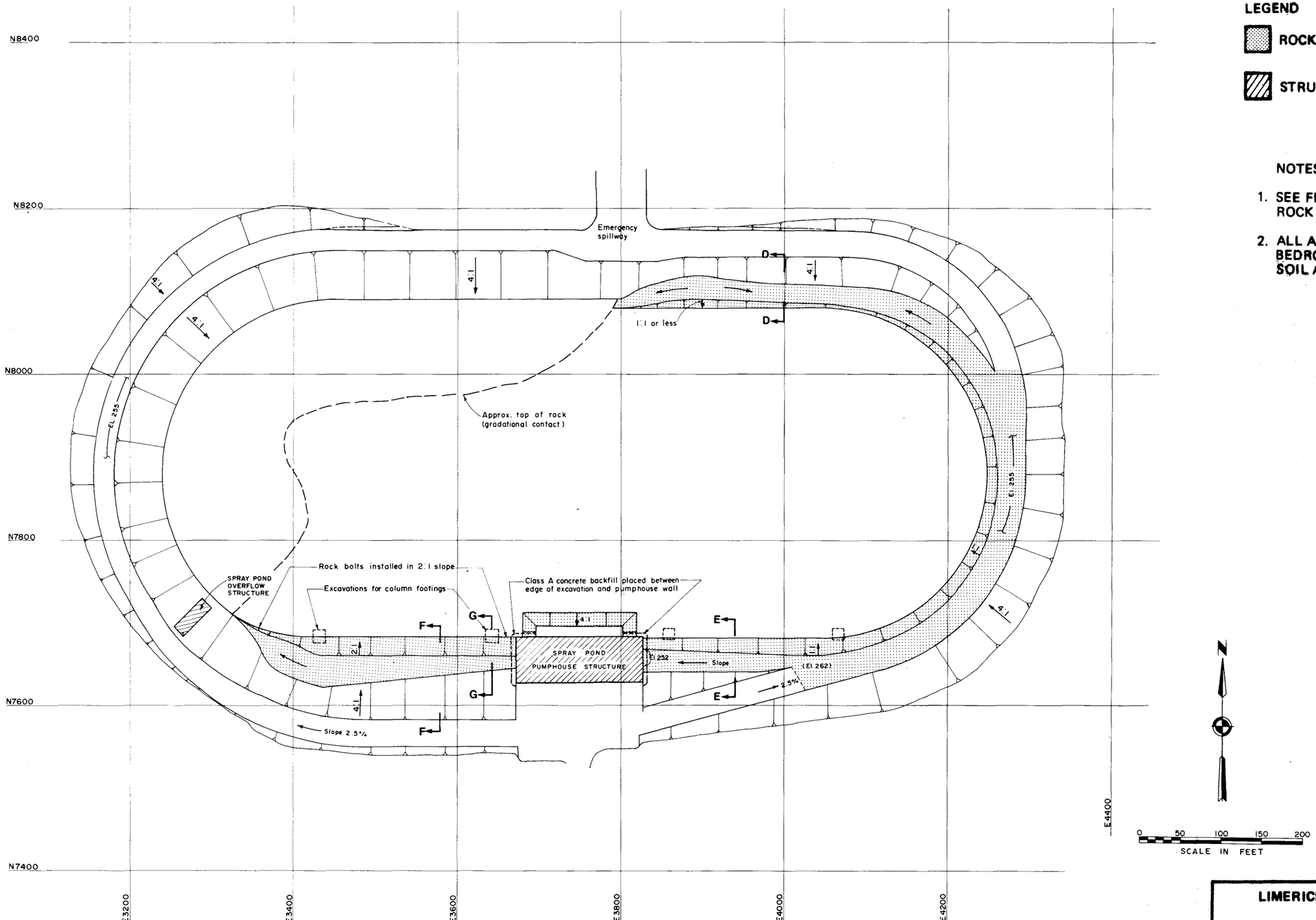


REFERENCE: SEED AND IDRISS (1970)

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VARIATION OF SHEAR MODULUS WITH SHEAR STRAIN FOR SANDS

FIGURE 2.5-47



LEGEND

ROCK SLOPES

STRUCTURAL EXCAVATION

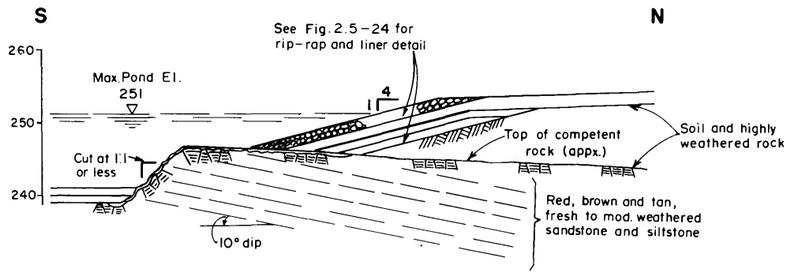
NOTES:

1. SEE FIGURE 2.5-49 FOR ROCK SLOPE PROFILES.
2. ALL AREAS OF WEATHERED BEDROCK WERE EXCAVATED AS SOIL AND CUT AT 4 TO 1.

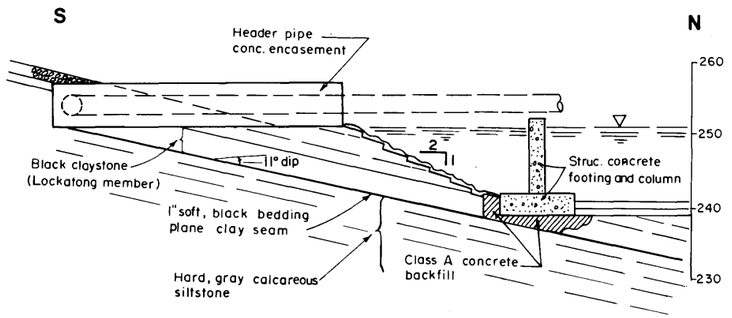
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LOCATION OF SPRAY POND ROCK SLOPES

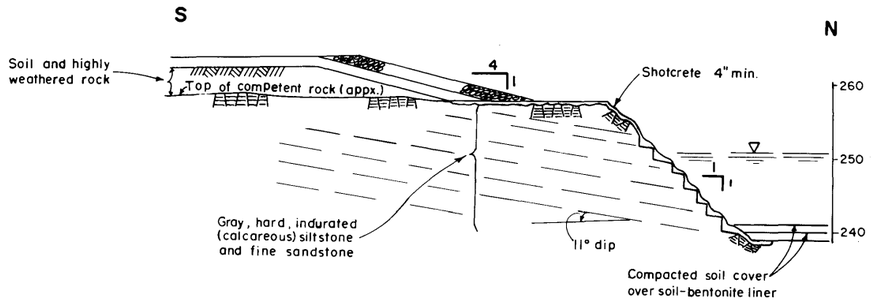
FIGURE 2.5-48



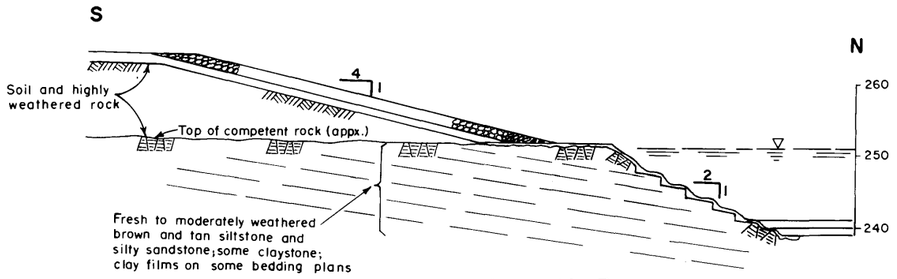
SECTION **D**



SECTION **G**



SECTION **E**



SECTION **F**

NOTE:

FOR LOCATION OF SECTIONS, SEE FIGURE 2.5-48

0 5 10 20 30 40

SCALE IN FEET

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SPRAY POND
ROCK SLOPE PROFILES

FIGURE 2.5-49

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CHAPTER 3 - DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.1 CONFORMANCE WITH NRC GENERAL DESIGN CRITERIA

This section discusses the extent to which the design criteria for the plant structures, systems, and components important to safety meet the General Design Criteria for Nuclear Power Plants specified in 10CFR50, Appendix A. For each criterion, a summary is provided to show how the principal design features meet the criterion. The discussion of each criterion also gives the section of the UFSAR where more detailed information is presented to demonstrate compliance with the criterion.

GDC 1 - Quality Standards and Records

> Structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection, and testing of structures, systems, and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

Design Evaluation

Structures, systems, and components important to safety are designed, fabricated, erected, tested, and operated under a QA program that satisfies the requirements of 10CFR50, Appendix B. Chapter 17.2 of the UFSAR discusses the QA program during operation, which is designed and implemented to ensure that LGS is tested and operated in conformance with the regulatory requirements and design bases outlined in the license application.

Design requirements and other information regarding implementation of the QA program are described in various sections of the UFSAR. Codes and standards that apply to safety-related, pressure-retaining piping and equipment are discussed in Section 3.2. Building codes and standards are discussed in Section 3.8. Detailed seismic design is outlined in Section 3.7.

Structures, systems, and components are classified with regard to location, service, and relationship to the safety function to be performed. Recognized codes and standards are applied to the equipment in keeping with the appropriate classification. Where codes are not available or where the existing code must be modified, justification is provided in the UFSAR.

Documents and records are available to show objective evidence that the requirements of the QA program have been satisfied. The documentation shows that the required codes, standards, and specifications were observed; specified materials were used; correct procedures were used; qualified personnel performed the work; and inspections and tests verified that finished parts and components meet the applicable specifications. Appropriate records are maintained during the operational life of the plant.

The QA program developed by the licensee and it's contractors satisfies the requirements of GDC 1.

GDC 2 - Design Bases for Protection Against Natural Phenomena

> Structures, systems, and components important to safety shall be designed to withstand the effect of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions. The design bases for these structures, systems, and components shall reflect: 1) appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time in which the historical data have been accumulated, 2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena, and 3) the importance of the safety functions to be performed.

Design Evaluation

The design basis for protection against natural phenomena is in accordance with GDC 2. Structures, systems, and components important to safety are designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, and floods without loss of the capability to perform required safety functions, with appropriate margin to account for uncertainties in the historical data. The natural phenomena postulated in the design are presented in Sections 2.3, 2.4, and 2.5. The design criteria for the structures, systems, and components affected by each natural phenomenon are presented in Sections 3.2, 3.3, 3.4, 3.5, 3.7, and 3.8. Those combinations of natural phenomena and plant originated accidents that are considered in the design are identified in Sections 3.8, 3.9, 3.10, and 3.11.

GDC 3 - Fire Protection

> Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat-resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and control room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. Fire fighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.

Design Evaluation

Structures, systems, and components important to safety are designed to minimize the probability and effect of fires and explosions. Noncombustible and heat-resistant materials are used wherever practicable throughout the plant, particularly in the containment, control room, and areas containing engineered safeguards.

Appropriate equipment and facilities for fire protection, including the detection, alarm, and extinguishing of fires, are provided to protect plant equipment and personnel from fire, explosions, and the resultant release of toxic vapors. Automatic and manual types of fire protection equipment are provided.

The fire protection system provides an adequate supply of water to the deluge systems, sprinkler systems, and hose stations located throughout the plant. Two separate Halon extinguishing systems

are provided for the raised flooring in the auxiliary equipment room. Portable fire extinguishers are provided throughout the plant. A detailed description of the fire protection system and its design bases is provided in Section 9.5.1.

Early warning of incipient fires is provided by a fire detection system utilizing smoke detectors and/or heat-responsive devices located in areas of the plant where significant fire potential exists.

The fire protection system is designed, fabricated, and installed in accordance with the requirements of the NFPA, ANI, OSHA, and applicable local codes and regulations as listed in Section 9.5.1.

The fire protection system was inspected and functionally tested prior to plant operation in order to ensure its proper operation. The fire suppression systems are provided with test valves and facilities for periodic testing. All equipment is accessible for periodic inspection.

Although it can be postulated that failure or inadvertent operation of the fire suppression system may incapacitate some safety-related systems or components, such failure or inadvertent operation will not prevent safe shutdown from being achieved through the use of redundant safety-related systems.

Structures, systems, and components important to safety are designed to meet the requirements of GDC 3. Fire protection systems meeting the requirements of GDC 3 are provided.

GDC 4 - Environmental and Missile Design Bases

> Structures, systems, and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including LOCAs. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit.

Design Evaluation

Structures, systems, and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including the design basis LOCA. These structures, systems, and components are appropriately protected against dynamic effects and discharging fluids that may result from equipment failures. Normal and postulated accident effects and load combinations are given in Sections 3.6, 3.8, 3.9, 3.10, and 3.11.

Special attention has been directed to the effects of pipe movement, jet forces, and missiles within the primary containment. Pipe whip restraints have been provided to the extent practicable (Section 3.6). Primary containment integrity protection is discussed in Section 6.2.1. The structures, systems, and components important to safety are protected from dynamic effects by separating redundant counterparts so that no single event can prevent a required safety action, and by routing and locating these components, to the extent practicable, to avoid potentially hazardous areas. The means used to preserve the independence of redundant counterparts of safety-related systems are discussed in Chapter 6.

Dynamic effects external to the plant, induced by natural phenomena (e.g., tornado-produced missiles), are discussed in Section 3.5. Section 3.11 contains a discussion of design environmental conditions.

Environmental and missile design bases are in accordance with GDC 4.

GDC 5 - Sharing of Structures, Systems, and Components

> Structures, systems, and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

Design Evaluation

Although LGS Units 1 and 2 share certain structures, systems, and components, sharing them does not significantly impair the performance of their safety functions.

The following safety-related structures are shared between both units:

a. Control enclosure and support subsystems

b. Spray pond pumphouse and support subsystems

c. Spray pond

The safety-related structures are designed to remain functional during and following the most severe natural phenomena. Therefore, sharing these structures does not impair their ability to perform their safety functions.

Seismic Category I structures that house safety-related systems and equipment are discussed in Section 3.8.

The below listed safety systems and subsystems are shared by both units. Refer to the section listed by each system or subsystem for discussion of design criteria for instrumentation. The instrumentation for these systems is available on common panels in the control room and therefore is available to the operators of both units.

SHARED SAFETY SYSTEMS	SECTION
ESW system	7.3.2.11
RHRSW system	7.3.2.12
RHRSW-RMS	7.6.1.1
Control structure support systems	
Habitability, control room isolation subsystem	7.3.2.10
Emergency switchgear and battery room cooling subsystem	7.3.2.15
CECWS	7.3.2.13
AERVS	7.3.2.15
CRV-RMS	7.6.1.1
CREFA-RMS	7.6.1.1
SGTS	7.3.2.7
SGTS-UC	7.3.2.15
RAVE-RMS and REVE-RMS	7.6.1.1
North stack radiation monitoring system	7.6.1.1
Spray pond pumphouse support system	7.3.2.15

The shared systems that are important to safety are discussed below. A more detailed discussion may be found in these referenced sections.

Emergency Service Water System

The ESW system is designed to supply cooling water to safety- related components, including the diesel generators, room coolers and chillers, and the RHR pumps during LOOP and accident conditions. Certain nonessential components can be cooled by the ESW system also, at the operator's option.

The ESW pumps are located in the spray pond pumphouse with the RHRSW pumps. The spray pond pumphouse is designed as seismic Category I. The ESW system consists of two redundant loops, each capable of simultaneously providing 100% of the cooling water required by both Units 1 and 2. The system is designed so that no single active or passive electrical or control component failure or active mechanical component failure can prevent it from achieving its safety-related objective.

For additional discussion, see Section 9.2.2.

RHR Service Water System

The RHRSW system is designed to supply cooling water to the RHR heat exchangers during normal shutdown cooling operations as well as during LOOP and accident conditions.

The RHRSW pumps are located in the spray pond pumphouse with the ESW pumps. The spray pond pumphouse is designed as seismic Category I. The RHRSW system consists of two redundant loops, each supplying one RHR heat exchanger in each unit and capable of simultaneously providing 100% of the cooling water required by both Units 1 and 2. The system is designed so that no single active or passive component failure can prevent it from achieving its safety-related objective.

For additional discussion, see Section 9.2.3.

Ultimate Heat Sink (Spray Pond)

The spray pond provides the water for both the ESW and the RHRSW systems. It is the UHS for both Units 1 and 2. The return lines from the ESW and the RHRSW system are combined, and the total quantity of water from both these systems is discharged through spray networks, which dissipate the heat. There are two redundant return loops. Either one is capable of handling the full flow from the ESW and RHRSW systems when shutting down two units simultaneously.

Each return loop supplies two spray networks. Two of the four networks provide sufficient cooling for the design basis conditions.

The spray pond contains sufficient water to meet the requirements for shutting down one unit if there is an accident and to permit the safe shutdown of the second unit for a period of 30 days without makeup.

For additional discussion, see Section 9.2.6.

Standby Gas Treatment System

The SGTS is designed to maintain both reactor enclosures and refueling area at the required negative pressure when any of these areas are isolated.

The SGTS filter train and fans are located in the control enclosure. The control enclosure is a seismic Category I structure. The SGTS consists of two 100% capacity redundant filter trains and two 100% capacity fans. The system is designed so that no single failure can prevent it from achieving its safety-related objective.

Additional discussion is given in Section 6.5.1.1.

Control Room and Control Structure HVAC Systems

The control room and control structure HVAC systems are designed to maintain the space temperature and pressure in the various areas within the common control structure at their design conditions.

Each system consists of two 100% capacity redundant HVAC units and the system is designed so that a single failure will not prevent the system from achieving its safety-related objective.

Additional discussion is given in Section 9.4.1.

Control Structure Chilled Water System

The CSCWS provides chilled water to maintain stipulated ambient air temperature in various areas inside the common control structure.

The system consists of two 100% capacity redundant chillers and pumps and is designed so that a single failure will not prevent the system from achieving its safety-related objective.

Additional discussion is given in Section 9.2.10.2.

GDC 10 - Reactor Design

> The reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

Design Evaluation

The reactor core components consist of fuel assemblies, control rods, incore ion chambers, neutron sources, and related items. The mechanical design is based on a conservative application of stress limits, operating experience, and experimental test results.

The core has sufficient heat transfer area and coolant flow to ensure that there is no fuel damage under normal conditions or anticipated operational occurrences. The RPS is designed to monitor certain reactor parameters, sense abnormalities, and shut down the reactor, thereby preventing fuel damage when trip setpoints are exceeded. Trip setpoints are selected according to operating experience and the design bases. There is no case in which the scram-trip setpoints allow the core to exceed the thermal-hydraulic safety limits. Power for the RPS is provided by dc-ac static inverters. Alternate electrical power is available to the RPS buses. The RPS is fail-safe, i.e., scram is initiated on loss of power.

An analysis and evaluation have been made of the effects on core fuel following adverse plant operating conditions. The results of abnormal operational transients are presented in Chapter 15 and show that the MCPR does not fall below the specified limit, thereby satisfying the transient design basis. The conditions assumed in the analysis and the control systems used to accommodate these transients are identified in Chapter 15.

The reactor core and associated coolant, control, and protection systems are designed to ensure that the specified fuel design limits are not exceeded during conditions of normal or abnormal operation and therefore meet the requirements of GDC 10.

Referenced sections are as follows:

a.	Fuel system design	Section 4.2
b.	Nuclear design	Section 4.3
c.	Thermal and hydraulic design	Section 4.4
d.	Component and subsystem design	Section 5.4
e.	RPS	Section 7.2
f.	All other instrumentation systems required for safety	Section 7.6
g.	Control systems not required for safety	Section 7.7
h.	Accident analyses	Chapter 15

GDC 11 - Reactor Inherent Protection

> The reactor core and associated coolant systems shall be designed so that, in the power operating range, the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity.

Design Evaluation

The reactor core is designed to have a reactivity response that regulates or damps changes in power level and spatial distributions of power production to a level consistent with safe and efficient operation.

The inherent dynamic behavior of the core is characterized in terms of:

a. Fuel temperature or Doppler coefficient

b. Moderator void coefficient

c. Moderator temperature coefficient

The combined effect of these coefficients in the power range is termed the power coefficient.

Doppler reactivity feedback occurs simultaneously with a change in fuel temperature and opposes the power change that caused it. Thus, it contributes to system stability. Since the Doppler reactivity opposes load changes, it is desirable to maintain a large ratio of moderator void coefficient to Doppler coefficient for optimum load-following capability. The BWR has an inherently large moderator-to-Doppler coefficient ratio that permits the use of coolant flow rate for load-following.

In a BWR, the moderator void coefficient is of primary importance during operation at power. Nuclear design is based on the void coefficient inside the fuel channel being negative. The negative void reactivity coefficient provides an inherent negative feedback during power transients. Because of the large negative moderator coefficients of reactivity, the BWR has a number of inherent advantages, such as:

a. Use of coolant flow as opposed to control rods for load-following

b. Inherent self-flattening of the radial power distribution

c. Ease of control

d. Spatial xenon stability

The reactor is designed so that the moderator temperature coefficient is small and positive in the cold condition; however, the overall power reactivity coefficient is negative.

The reactor core and associated coolant system are designed so that, in the power operating range, prompt inherent dynamic behavior tends to compensate for any rapid increase in reactivity in accordance with GDC 11. Referenced sections are as follows:

a.	Nuclear design	Section 4.3
b.	Thermal and hydraulic design	Section 4.4

GDC 12 - Suppression of Reactor Power Oscillations

> The reactor core and associated coolant, control, and protection systems shall be designed to ensure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed.

Design Evaluation

The reactor core is designed to ensure that no power oscillation can cause fuel design limits to be exceeded. The power reactivity coefficient is the composite simultaneous effect of the fuel temperature or Doppler coefficient, moderator void coefficient, and moderator temperature coefficient to the change in power level. It is negative and well within the range required for adequate damping of power and spatial xenon disturbances. Operating experience has shown large BWRs to be inherently stable against xenon-induced power instability.

The RPS design and the recirculation pump trip system provide protection from excessive fuel cladding temperatures and protect the nuclear system process barrier from excessive pressures that threaten the integrity of the system. Local abnormalities are sensed, and, if protection system limits are reached, corrective action is initiated through an automatic scram and recirculation pump trip. High reliability of the RPS is achieved through the combination of logic arrangement, trip channel redundancy, power supply redundancy, and physical separation.

The reactor core and associated coolant, control, and protection systems are designed to suppress any power oscillations that could result in exceeding the fuel design limits. These systems ensure that GDC 12 is met. Referenced sections are as follows:

a.	Fuel system design	Section 4.2
b.	Nuclear design	Section 4.3
c.	Thermal and hydraulic design	Section 4.4
d.	Integrity of RCPB	Section 5.2
e.	RPS	Section 7.2
f.	All other instrumentation systems required for safety	Section 7.6
g.	Accident analyses	Chapter 15

GDC 13 - Instrumentation and Control

Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operations, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the RCPB, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

Design Evaluation

Instrumentation is provided to monitor variables and systems over their anticipated ranges for normal operations, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety. Appropriate controls are provided to maintain these variables and systems within prescribed operating ranges. A summary description for each instrumentation and control system is provided in Section 7.1. The instrumentation and controls provided meet the requirements of GDC 13. Referenced sections are as follows:

a.	Reactor Trip System (Reactor Protection System) – Instrumentation And Controls	Section 7.2
b.	ESF Systems	Section 7.3
c.	Systems Required For Safe Shutdown	Section 7.4
d.	Information Systems Important To Safety	Section 7.5
e.	All Other Instrumentation Systems Important To Safety	Section 7.6
f.	Control Systems Not Required For Safety	Section 7.7

GDC 14 - Reactor Coolant Pressure Boundary

The RCPB shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

Design Evaluation

The piping and equipment pressure parts within the RCPB through the outer isolation valves are designed, fabricated, erected, and tested to provide a high degree of integrity throughout the plant lifetime. Section 3.2 classifies the systems and components within the RCPB. The design requirements and codes and standards applied to the quality group ensure a quality product in keeping with the safety functions to be performed.

To minimize the possibility of brittle fracture within the RCPB, the fracture or notch properties and the operating temperature of ferritic materials are controlled to ensure adequate toughness when the system is pressurized to more than 20% of the design pressure. Section 5.2 describes the methods used to control toughness properties. Materials to be impact-tested are tested by the Charpy

V-notch method in accordance with ASME B&PV Code, Section III. The service temperature of these materials is maintained above the NDTT. The fracture toughness temperature requirements of the RCPB materials also apply for the RCPB piping that penetrates the containment.

Piping and equipment pressure parts of the RCPB are assembled and erected by welding unless applicable codes permit flanged or screwed joints. Assembly is according to ANSI B31.7 and ASME Section III. Erection is according to ASME Section III. Welding procedures are employed that produce welds of complete penetration, complete fusion, and freedom from unacceptable defects. All welding procedures, welders, and welding machine operators are qualified in accordance with the requirements of ASME B&PV Code, Section IX for the materials to be welded.

Section 5.2 contains the detailed material and examination requirements for the piping and equipment of the RCPB before and after its assembly and erection. Leakage testing and surveillance is accomplished as described in the evaluation against GDC 30.

The design, fabrication, erection, and testing of the RCPB ensure an extremely low probability of failure or abnormal leakage, thus satisfying the requirements of GDC 14. Referenced sections are as follows:

a.	Design of structures, components, equipment, and systems	Chapter 3
b.	Integrity of RCPB	Section 5.2
c.	Reactor vessel and appurtenances	Section 5.3
d.	Component and subsystem design	Section 5.4
e.	Accident analyses	Chapter 15
f.	QA	Chapter 17

GDC 15 - Reactor Coolant System Design

The RCS and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

Design Evaluation

The RCS consists of the reactor vessel and appurtenances, the reactor recirculation system, the pressure relief system, and the main steam and feedwater lines. This system is designed, fabricated, erected, and tested to stringent requirements and appropriate codes and standards that ensure high integrity of the RCPB throughout the plant lifetime. The RCS is designed and fabricated to meet the requirements of the ASME B&PV Code, Section III.

The auxiliary, control, and protection systems associated with the RCS provide sufficient margin to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including anticipated operational occurrences. As described in the evaluation of GDC 13, instrumentation is provided to monitor essential variables to ensure that they are within prescribed operating limits. If the monitored variables exceed their predetermined settings, the auxiliary, control, and protection systems automatically respond to maintain the variables and systems within allowable design limits.

An example of the integrated protective action scheme that provides sufficient margin to ensure that the design conditions of the RCPB are not exceeded is the automatic initiation of the pressure relief system on receipt of an overpressure signal. To accomplish overpressure protection, a number of pressure-operated relief valves are provided that can discharge steam from the nuclear system to the pressure-suppression pool. The pressure relief system also provides for automatic depressurization of the nuclear system if there is a LOCA in which the vessel is not depressurized by the accident. The depressurization of the nuclear system in this situation allows operation of the low pressure ECCS to supply enough cooling water to adequately cool the core. In a similar manner, other auxiliary, control, and protection systems provide assurance that the design conditions of the RCPB are not exceeded during any conditions of normal operation, including anticipated operational occurrences.

The application of appropriate codes, standards, and high quality requirements to the RCS and the design features of its associated auxiliary, control, and protection systems ensure that the requirements of GDC 15 are satisfied.
Referenced sections are as follows:

a.	Integrity of RCPB	Section 5.2
b.	Reactor vessel and appurtenances	Section 5.3
c.	Component and subsystem design	Section 5.4
d.	ECCS	Section 6.3
e.	ESF systems	Section 7.3
f.	Control systems not required for safety	Section 7.7
g.	Accident analyses	Chapter 15

GDC 16 - Containment Design

Reactor containment and associated systems shall be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

Design Evaluation

The primary containment system, which includes the drywell and suppression chamber, is designed, fabricated, and erected to accommodate, without failure, the pressures and temperatures resulting from the double-ended rupture or equivalent failure of any coolant pipe within the primary containment. The reactor enclosure encompassing the primary containment provides secondary containment. To provide protection against the consequences of accidents involving the release of radioactive materials from the fuel and nuclear system process barrier, the PCRVICS initiates automatic isolation of appropriate pipelines that penetrate the primary containment whenever monitored variables exceed preselected operational limits. The two containment systems and their associated safety systems are designed and maintained so that offsite doses, which could result from postulated design basis accidents, remain below the values stated in 10CFR50.67 when calculated by the methods of Regulatory Guide 1.183. The referenced sections provide detailed information that demonstrates compliance with GDC 16. Referenced sections are as follows:

a.	Containment systems	Section 6.2
b.	MSIV Leakage Alternate Drain Pathway	Section 6.7
c.	Primary containment ventilation system	Section 9.4.5
d.	Accident analysis	Chapter 15

GDC 17 - Electric Power Systems

An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that 1) specified acceptable fuel design limits and design conditions of the RCPB are not exceeded as a result of anticipated operational occurrences and 2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies (including the batteries) and the onsite electric distribution system shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time, following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a LOCA to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

Design Evaluation

Two separate offsite power systems that are common to both units and four physically independent, onsite, standby diesel generators per unit, with associated battery systems, are provided to supply adequate power to all the functions important to safety. Either of the two offsite power systems or any three of the four onsite standby diesel generator systems in each unit have sufficient capability to operate safety-related equipment so that specified acceptable fuel design limits and design conditions of the RCPB are not exceeded as a result of anticipated operational occurrences and to cool the reactor core and maintain primary containment integrity and other vital functions if there are postulated accidents. For a further and more detailed discussion on safety-related load distribution on diesel generators, including safety-related equipment common to both units, see Chapter 8.

The two independent offsite power systems supply electric power to the onsite power distribution system via the 220 kV and 500 kV switchyards. The two switchyards are approximately 1.7 miles apart. These two power systems are physically independent and are designed to minimize the possibility of their simultaneous failure under operating and postulated accident and environmental conditions. Each offsite source is capable of supplying all safety-related loads during a LOCA in one unit with a simultaneous safe shutdown of the other unit while maintaining proper voltage regulation.

Each offsite power source can supply all engineered safeguard buses through its associated transformer. Power is available to the safeguard buses from their preferred offsite power source during normal operation and from the alternate offsite power source if the preferred power is unavailable. Each of the offsite power sources is available immediately following a loss of all onsite alternating current power supplies and the other offsite electric power circuit to ensure that fuel design limits and design conditions of the RCPB are not exceeded. The loss of both offsite power sources to a safeguard bus results in the automatic starting and connection of the associated diesel generator. Loads are progressively and sequentially added to prevent generator instabilities. The sequential loading is such that core cooling, containment integrity, and other vital safety functions are maintained.

In addition to the two offsite sources described above, a third offsite source is available from the 33 kV distribution system to supply power to the engineered safeguard loads. This source can be connected to the safeguard buses within 72 hours if there is a loss of one of the two offsite sources or of one of the safeguard transformers.

The onsite safeguard power supplies, including the safeguard batteries and onsite safeguard electric distribution systems, are independent, redundant, and testable, thus ensuring their operability and ability to perform their safety functions, assuming that there is a single failure. For a further and detailed discussion of electric power systems, see Chapter 8.

Onsite and offsite electric power systems are provided in accordance with GDC 17. Provisions are included in the design of the electric power system to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

GDC 18 - Inspection and Testing of Electric Power Systems

> Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to test periodically 1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses, and 2) the operability of the systems as a whole and, under conditions as close to design as practical, the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system, and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system.

Design Evaluation

Transmission line protective relaying will be tested on a routine basis. This can be accomplished without removing the transmission lines from service.

The onsite power systems, consisting of the standby diesel generators with their associated switchgear assemblies (supplying power to safety-related equipment) and the associated battery systems, are designed and arranged for periodic testing of each system independently.

Full load testing of each standby diesel generator can be performed while the plant is at power by manually starting each standby generator and by manual synchronization to the normal power

supply. These tests prove the operability of the electric power systems under conditions as close to design as practicable to assess the continuity of these systems and the condition of the components. The inspection and testing of electric power systems, described in Chapters 8 and 16, conform to GDC 18.

GDC 19 - Control Room

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including LOCAs. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

Equipment at appropriate locations outside the control room shall be provided 1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown and 2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

Note: The application of Alternative Source Terms in accordance with 10CFR50.67 modified the GDC 19 dose limit from 5 Rem whole body to 5 Rem TEDE.

Design Evaluation

A control room is provided in which appropriate controls and instrumentation are located to permit personnel to operate the unit safely under normal conditions or maintain it in a safe condition under accident conditions. The control room and associated postaccident ventilation systems are designed in accordance with seismic Category I requirements.

The design of the control room permits access and occupancy during a LOCA. Sufficient shielding and ventilation are provided to permit occupancy of the control room for a period of 30 days following the LOCA, without receiving more than a 5 Rem total effective dose equivalent (TEDE). An analysis of exposures within the control room for each of the postulated accidents is presented in Chapter 15.

The capability for prompt hot shutdown of the reactor and the capability for subsequent cold shutdown through suitable procedures from locations outside the control room is provided by the remote shutdown system, if the control room becomes inaccessible. The remote shutdown system has the capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown, and subsequent cold shutdown of the reactor. The remote shutdown system panel contains controls for the following equipment:

a. RHR system - The controls for one loop of the RHR system and associated RHRSW system are provided on the remote shutdown panel. The suppression pool cooling and shutdown cooling modes of RHR system operation can be controlled from the remote shutdown panel.

b. RCIC system - All basic RCIC equipment can be controlled from the remote shutdown panel.

c. Reactor recirculation system - The suction valve of one recirculation pump can be controlled from the remote shutdown panel.

d. MSRVs - Three MSRVs can be operated from the remote shutdown panel.

e. Ac power supplies for the above systems can be controlled from the remote shutdown panel.

See Section 7.4 for a further detailed discussion of remote shutdown capabilities. The control room and the remote shutdown panels conform to GDC 19.

GDC 20 - Protection System Functions

> The protection system shall be designed 1) to initiate automatically the operation of appropriate systems, including the reactivity control system, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and 2) to sense accident conditions and to initiate the operation of systems and components important to safety.

Design Evaluation

The RPS is designed to provide timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and nuclear system process barrier. Fuel damage is prevented by initiation of an automatic reactor shutdown if monitored nuclear system variables exceed pre-established limits of anticipated operational occurrences. Trip settings are selected and verified to be far enough above or below operating levels to provide proper protection but not be subject to spurious actuation. The RPS includes the sensors, relays, bypass circuitry, and switches that signal the control rod system to shut down the reactor. The shutdowns initiated by neutron monitoring system variables, nuclear system high pressure, turbine stop valve closure, TCV fast closure, and reactor vessel low water level prevent fuel damage following abnormal operational transients. Specifically, these process parameters initiate a shutdown in time to prevent the core from exceeding thermal-hydraulic safety limits during abnormal operational transients. Response by the RPS is prompt, and the total shutdown time is short.

A fully withdrawn control rod (withdrawn to 144 inches) traverses 90% of its full stroke at Technical Specification insertion rates which is sufficient to ensure that acceptable fuel design limits are not exceeded.

In addition to the RPS, which provides for automatic shutdown of the reactor to prevent fuel damage, other portions of the protection systems are provided to sense accident conditions and automatically initiate the operation of other systems and components important to safety. The ECCS and the primary containment and reactor containment isolation control system are initiated automatically following a LOCA to limit the extent of fuel damage and prevent the release of significant amounts of radioactive materials from the fuel and the nuclear system process barrier. The control and instrumentation for the ECCS and the isolation systems are initiated automatically when monitored variables exceed preselected operational limits.

The design of the protection system satisfies the functional requirements as specified in GDC 20. Referenced sections are as follows:

a. Fuel System Design — Section 4.2

b.	ECCS	Section 6.3
c.	Reactor Trip System (Reactor Protection System) – Instrumentation And Controls	Section 7.2
d.	ESF systems	Section 7.3
e.	All Other Instrumentation Systems Important To Safety	Section 7.6
f.	Accident analyses	Chapter 15

GDC 21 - Protection System Reliability and Testability

> The protection system shall be designed for high functional reliability and inservice testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that 1) no single failure results in loss of the protection function and 2) removal from service of any component or channel does not result in loss of the required minimum redundancy unless the acceptable reliability of operation of the protection system can be otherwise demonstrated. The protection system shall be designed to permit periodic testing of its functioning when the reactor is in operation, including capability to test channels independently to determine failures and losses of redundancy that may have occurred.

Design Evaluation

The protection system is designed for high functional reliability and inservice testability. The protection system design fulfills the single failure criterion by providing redundant channels. No single component failure, intentional bypass, maintenance operation, calibration operation, or test to verify operational availability can impair the ability of the system to perform its intended safety functions. The system design ensures that when a trip setpoint is exceeded there is a high probability of successful completion of the required safety functions. There is sufficient electrical and physical separation between channels and between trip logics monitoring the same variable to prevent environmental factors, electrical transients, and physical events from impairing the ability of the system to respond correctly.

The protection system includes design features that permit inservice testing. This ensures the functional reliability of the system if the monitored variables exceed the corrective action setpoint.

The RPS initiates an automatic reactor shutdown if the monitored plant variables exceed pre-established limits. The RPS consists of two independent trip systems. Each trip system has two trip logics arranged in a one-out-of-two-twice logic, to produce an automatic trip signal.

Both the manual and automatic portions of each trip logic of the RPS can be tested independently during reactor operation. The test verifies the ability to de-energize the scram pilot valve solenoids. Indicating lights verify that the actuator contacts have opened. This capability for a thorough testing program determines if failures or losses of redundancy have occurred. CRD operability can be tested during normal reactor operation. CRD position indicators and the incore neutron detectors are used to verify control rod movement. Each control rod can be withdrawn one notch and then reinserted to the original position without significantly disturbing the reactor system. One control rod is tested

at a time. The control rod mechanism overdrive demonstrates rod-to-drive coupling integrity. Hydraulic supply subsystem pressures can be observed on control room instrumentation. The HCU scram accumulator pressure is monitored and the scram discharge volume level is continuously monitored.

The ESFs are designed to be operable for test purposes during normal operation of the nuclear system. The high functional reliability, redundancy, independence, and inservice testability of the protection system satisfy the requirements specified in GDC 21. Referenced sections are as follows:

a.	Component and subsystem design	Section 5.4
b.	Containment systems	Section 6.2
c.	ECCS	Section 6.3
d.	RPS	Section 7.2
e.	ESF systems	Section 7.3
f.	All other instrumentation systems required for safety	Section 7.6
g.	Accident analyses	Chapter 15

GDC 22 - Protection System Independence

> The protection system shall be designed to assure that the effects of natural phenomena and of normal operating, maintenance, testing, and postulated accident conditions on redundant channels do not result in loss of the protection function, or shall be demonstrated to be acceptable on some other defined basis. Design techniques, such as functional diversity or diversity in component design and principles of operation, shall be used to the extent practical to prevent loss of the protection function.

Design Evaluation

The components of protection systems are designed so that the mechanical and thermal environment resulting from any potential accident condition in which the components are required to function does not interfere with that function. The wiring for the protection system outside the control room is run in rigid metallic conduit or enclosed raceways segregated from all other wiring.

Only one trip actuator logic circuit from each trip system may be run in the same wireway.
The system sensors are electrically and physically separated. In general, redundant sensors have separate process taps. Where common process taps are used, analysis shows that failure of the common process tap will not interfere with the protection function. The wires from duplicate sensors on a common process tap are run in separate wireways.

The RPS is designed to permit maintenance and diagnostic work while the reactor is operating without restricting the plant operation or hindering any safety functions.

The design uses multiple trip logics so that an intentional bypass, maintenance operation, calibration operation, or test will not prevent completion of a protection function when required.

The protection system meets the design requirements for functional and physical independence as specified in GDC 22. Referenced sections are as follows:

a.	Component and subsystem design	Section 5.4
b.	ECCS	Section 6.3
c.	RPS	Section 7.2
d.	ESF system	Section 7.3
e.	All other instrumentation systems required for safety	Section 7.6
f.	Accident analyses	Chapter 15

GDC 23 - Protection System Failure Modes

The protection system shall be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air), or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.

Design Evaluation

The RPS and the normally energized portion of the PCRVICS are designed to fail in a safe state on disconnection or loss of energy supply. The rest of the ESFs will not initiate a protection function on disconnection or loss of energy supply. This is acceptable since these systems are designed with more than one independent trip logic, each with its own independent power supply. Disconnection of one of the trip logics or loss of one of the power supplies will not prevent accomplishing a protection function when required. The environmental conditions in which the instrumentation and equipment of the protection system must operate were considered in establishing the component specifications. Instrumentation specifications are based on the worst expected ambient conditions in which the instruments must operate.

The failure modes of the protection system are such that it fails in an acceptable state as required by GDC 23. Referenced sections are as follows:

a.	Environmental design of mechanical and electrical equipment	Section 3.11
b.	RPS	Section 7.2
c.	ESF systems	Section 7.3
d.	All other instrumentation systems required for safety	Section 7.6

GDC 24 - Separation of Protection and Control Systems

The protection system shall be separated from control systems to the extent that failure of any single control system component or channel or failure or removal from service of any single protection system component or channel which is common to the control and protection systems leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems shall be limited to assure that safety is not significantly impaired.

Design Evaluation

There is separation between the protection system and the control systems. Outputs from the control system components and channels are not used as protection system inputs. The sensors, trip channels, and trip logics of the protection system are not used for automatic control of process systems. Therefore, failure in the controls and instrumentation of process systems cannot induce failure of any portion of the protection system.

For additional details of evaluation of the reactivity control system, see the evaluation for GDC 25.

The protection system is separated from control systems as required in GDC 24. Referenced sections are as follows:

a.	RPS	Section 7.2
b.	ESF systems	Section 7.3
c.	All other instrumentation systems required for safety	Section 7.6

GDC 25 - Protection System Requirements for Reactivity Control Malfunctions

The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods.

Design Evaluation

The RPS provides protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier and the nuclear system process barrier. Any monitored variable that exceeds the scram setpoint initiates an automatic scram and does not prevent the remaining variables from being monitored, and if one channel fails, the remaining portions of the RPS can function.

The reactor manual control system is designed so that no single failure can negate the effectiveness of a reactor scram. The circuitry for the reactor manual control system is completely independent of the circuitry controlling the scram valves. This separation of the scram and normal rod control functions prevents failures in the reactor manual control circuitry from affecting the scram circuitry. Because each control rod is controlled as an individual unit, a failure that results in energizing any of the insert or withdraw solenoid valves can affect only one control rod. The effectiveness of a reactor scram is not impaired by the malfunctioning of any one control rod.

The most serious rod withdrawal errors occur when an out-of-sequence rod is continuously withdrawn while the reactor is just subcritical. The RWM normally prevents the withdrawal of out-of-sequence control rods. If such a continuous rod withdrawal were to occur, the increase in fuel temperature subsequent to scram would not be sufficient to exceed acceptable fuel design limits.

The design of the protection system ensures that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems as specified in GDC 25. Referenced sections are as follows:

a.	Fuel mechanical design	Section 4.2
b.	Nuclear design	Section 4.3
c.	Thermal and hydraulic design	Section 4.4
d.	RPS	Section 7.2
e.	All other instrument systems required for safety	Section 7.6
f.	Control systems not required for safety	Section 7.7
g.	Accident analyses	Chapter 15

GDC 26 - Reactivity Control System Redundancy and Capability

> Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure that acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Design Evaluation

Two independent reactivity control systems using different design principles are provided. The normal method of reactivity control employs control rod assemblies that contain a neutron absorbing material as described in Section 4.2. Control of reactivity is operationally provided by a combination of these movable control rods, burnable poisons, and reactor coolant recirculation system flow. These systems accommodate fuel burnup, load changes, and long-term reactivity changes.

Reactor shutdown by the CRD system is sufficiently rapid to prevent the exceeding of acceptable fuel design limits for normal operation and all abnormal operational transients. The circuitry for manual insertion or withdrawal of control rods is completely independent of the circuitry for reactor scram. Two sources of scram energy (accumulator pressure and reactor vessel pressure) provide the needed scram performance over the entire range of reactor pressure (i.e., from operating conditions to cold shutdown).

The design of the control rod system includes appropriate margin for malfunctions, such as stuck rods, in the highly unlikely event that they do occur. Control rod withdrawal sequences and patterns are selected before operation to achieve optimum core performance and, simultaneously, low individual rod worths. The operating procedures for accomplishing such patterns are supplemented by the RWM, which prevents rod withdrawals yielding a rod worth greater than permitted by the preselected rod withdrawal pattern. An additional design basis of the control rod system requires that the core in its maximum reactivity condition be subcritical with the control rod of the highest worth fully withdrawn and all other rods fully inserted. Because of the carefully planned and regulated rod withdrawal sequence, prompt shutdown of the reactor can be achieved with the insertion of a small number of the many independent control rods. If a reactor scram is necessary, the unlikely occurrence of a limited number of stuck rods does not impair the capability of the control rod system to render the core subcritical.

A SLCS containing a neutron-absorbing sodium pentaborate solution is the independent backup system. This system has the capability to shut the reactor down from full power and maintain it in a subcritical condition at any time during the core life. The reactivity control provided to reduce reactor power from rated power to a shutdown condition with the control rods withdrawn in the power pattern accounts for the reactivity effects of xenon decay, elimination of steam voids, change in water density due to the reduction in water temperature, Doppler effect in uranium, change in neutron leakage from boiling to cold, and change in rod worth as boron affects the neutron migration length.

The redundancy and capabilities of the reactivity control systems satisfy the requirements of GDC 26. Referenced sections are as follows:

a.	Fuel mechanical design	Section 4.2
b.	Reactor trip system	Section 7.2
c.	Systems required for safe shutdown	Section 7.4
d.	Control systems not required for safety	Section 7.7

GDC 27 - Combined Reactivity Control Systems Capability

> The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes to assure that, under postulated accident conditions and with appropriate margin for stuck rods, the capability to cool the core is maintained.

Design Evaluation

There is no credible event applicable to the BWR that requires combined capability of the control rod system and poison additions by SLCS. The primary reactivity control system for the BWR during postulated accident conditions is the control rod system. Abnormalities are sensed, and, if protection system limits are reached, corrective action is initiated through an automatic scram. High integrity of the protection system is achieved through the combination of logic arrangement, trip channel redundancy, power supply redundancy, and physical separation. High reliability of reactor scram is further achieved by separation of scram and manual control circuitry, individual control units for each control rod, and fail-safe design features built into the CRD system. Response by the RPS is prompt, and the total scram time is short.

In operating the reactor, there is a spectrum of possible control rod worths, depending on the reactor state and on the control rod pattern chosen for operation. Control rod withdrawal sequences and patterns are selected to achieve optimum core performance and low individual rod worths. The RWM prevents rod withdrawal other than by a preselected rod withdrawal pattern. This function provides the operator with an effective backup control rod monitoring routine that enforces adherence to established startup, shutdown, and low power level operations. As a result of this carefully planned procedure, prompt shutdown of the reactor can be achieved with scram insertion of fewer than half of the many independent control rods. If accident conditions require a reactor scram, this can be accomplished rapidly with appropriate margin for the unlikely occurrence of malfunctions such as stuck rods.

The reactor core design assists in maintaining the stability of the core under accident conditions as well as during power operation. Reactivity coefficients in the power range that contribute to system stability are: the fuel temperature or Doppler coefficient, moderator void coefficient, and moderator temperature coefficient. The overall power reactivity coefficient is negative and provides a strong negative reactivity feedback under severe power transient conditions.

The design of the reactivity control system ensures reliable control of reactivity under postulated accident conditions with appropriate margin for stuck rods. The capability to cool the core is maintained under all postulated accident conditions. Thus, GDC 27 is satisfied. Referenced sections are as follows:

a.	Fuel mechanical design	Section 4.2
b.	Nuclear design	Section 4.3
c.	Thermal and hydraulic design	Section 4.4
d.	RPS	Section 7.2
e.	All other instrumentation systems required for safety	Section 7.6
f.	Control systems not required for safety	Section 7.7
g.	Accident analyses	Chapter 15

GDC 28 - Reactivity Limits

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effect of postulated reactivity accidents can neither 1) result in damage to the RCPB greater than limited local yielding nor 2) sufficiently disturb the core, its support structures, or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

Design Evaluation

The control rod system design incorporates appropriate limits on the potential amount and rate of reactivity increase. Control rod withdrawal sequences and patterns are selected to achieve optimum core performance and low individual rod worths. The RWM prevents withdrawal other than by the preselected rod withdrawal pattern. This function provides the operator with an effective backup control rod monitoring routine that enforces adherence to established startup, shutdown, and low power level operations control rod procedures.

The control rod mechanical design incorporates a hydraulic velocity limiter in the control rod that prevents rapid rod ejection. This engineered safeguard protects against a high reactivity insertion rate by limiting the control rod velocity to less than 5 ft/sec. Normal rod movement is limited to 6 inch increments, and the rod withdrawal rate is limited through the hydraulic valve to 3 in/sec.

The accident analyses in Chapter 15 evaluate in detail postulated reactivity accidents as well as the abnormal operational transients. Analyses are included for rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition. The initial conditions, assumptions, calculational models, sequences of events, and anticipated results of each postulated occurrence are covered in detail. The results of these analyses indicate that none of the postulated reactivity transients or accidents results in damage to the RCPB. In addition, the integrity of the core, its support structures, or other RPV internals is maintained so that the capability to cool the core is not impaired for any of the postulated reactivity accidents described in Chapter 15.

The design features of the reactivity control system, which limit the potential amount and rate of reactivity increase, ensure that GDC 28 is satisfied for all postulated reactivity accidents.
Referenced sections are as follows:

a.	Design of structures, components, equipment, and systems	Chapter 3
b.	Fuel mechanical design	Section 4.2
c.	Nuclear design	Section 4.3
d.	Nuclear design	Section 4.5
e.	Integrity of RCPB	Section 5.2
f.	Reactor vessel and appurtenances	Section 5.3
g.	Component and subsystem design	Section 5.4
h.	Reactor trip system	Section 7.2
i.	All other instrumentation systems required for safety	Section 7.6
j.	Accident analyses	Chapter 15

GDC 29 - Protection Against Anticipated Operational Occurrences

The protection and reactivity control systems shall be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences.

Design Evaluation

The high functional reliability of the protection and reactivity control systems is achieved through the combination of logic arrangement, redundancy, physical and electrical independence, functional separation, fail-safe design, and inservice testability. These design features are discussed in GDC 21, 22, 23, 24, 25, and 26.

An extremely high probability of correct protection and reactivity control systems response to anticipated operational occurrences is maintained by a thorough program of inservice testing and surveillance. Active components can be tested or removed from service for maintenance during reactor operation without compromising the protection or reactivity control functions. Components important to safety such as CRDs, MSIVs, RHR pumps, etc, are tested during normal reactor operation. Functional testing and calibration schedules are developed using available failure rate data, reliability analyses, and operating experience. These schedules represent an optimization of protection and reactivity control system reliability by considering the reliability effects during individual component testing on the portion of the system not undergoing testing. The capability for inservice testing ensures the high functional reliability of protection and reactivity control systems if a reactor variable exceeds the corrective action setpoint.

The capabilities of the protection and reactivity control systems to perform their safety functions if there are anticipated operational occurrences satisfy the requirements of GDC 29. Referenced sections are as follows:

a.	Fuel mechanical design	Section 4.2
b.	Component and subsystem design	Section 5.4
c.	Containment systems	Section 6.2
d.	ECCS	Section 6.3
e.	RPS	Section 7.2
f.	ESF system	Section 7.3
g.	All other instrumentation systems required for safety	Section 7.6
h.	Accident analyses	Chapter 15

GDC 30 - Quality of Reactor Coolant Pressure Boundary

Components which are part of the RCPB shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage.

Design Evaluation

By using conservative design practices and detailed quality control procedures, the pressure-retaining components of the RCPB are designed and fabricated to retain their integrity during normal and postulated accident conditions. Accordingly, components that comprise the RCPB are designed, fabricated, erected, and tested in accordance with recognized industry codes and standards listed in Chapter 5. Further product and process quality planning is provided as discussed in the evaluation of GDC 1 to ensure conformance with the applicable codes and standards and to retain appropriate documented evidence verifying compliance. Because the subject matter of this criterion deals with the aspects of the RCPB, further discussion of this subject appears in the response to GDC 14.

Means are provided for detecting reactor coolant leakage. The leak detection system consists of sensors and instruments to detect, annunciate, and, in some cases, isolate the RCPB from potential hazardous leaks before predetermined limits are exceeded. As described in Section 5.2.5, small leaks are detected by temperature and pressure changes, increased frequency of sump pump operation, and measurement of airborne radioactivity in the primary containment atmosphere. In addition to these means of detection, large leaks are detected by flow rates in process lines and changes in reactor water level. The allowable leakage rates are based on the predicted and experimentally determined behavior of cracks in pipes, the ability to make up coolant system leakage, the normally expected background leakage due to equipment design, and the detection capability of the various sensors and instruments. The total leakage rate limit is established so that, in the absence of normal ac power concurrent with a loss of feedwater supply, makeup capabilities are provided by the RCIC system. While the leak detection system provides protection from small leaks, the ECCS network provides protection for the complete range of discharges from ruptured pipes. Thus, protection is provided for the full spectrum of possible discharges. The RCPB and the leak detection system are designed to meet the requirements of GDC 30. Referenced sections are as follows:

a.	Design of structures, components, equipment, and systems	Chapter 3
b.	Integrity of RCPB	Section 5.2
c.	Reactor vessel and appurtenances	Section 5.3
d.	Component and subsystem design	Section 5.4
e.	All other instrumentation systems required for safety	Section 7.6
f.	Accident analyses	Chapter 15

GDC 31 - Fracture Prevention of Reactor Coolant Pressure Boundary

The RCPB shall be designed with sufficient margin to assure that, when stressed under operating, maintenance, testing, and postulated accident conditions, 1) the boundary behaves in a nonbrittle manner and 2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining 1) material properties, 2) the effects

of irradiation on material properties, 3) residual, steady-state, and transient stresses, and 4) size of flaws.

Design Evaluation

Brittle fracture control of pressure-retaining ferritic materials is provided to ensure protection against nonductile fracture. To minimize the possibility of brittle fracture failure of the RPV, it is designed to meet the requirements of the ASME B&PV Code, Section III.

The NDTT is defined as the temperature below which ferritic steel breaks in a brittle rather than ductile manner. The NDTT increases as a function of neutron exposure at integrated neutron exposures greater than about $1x10^{17}$ nvt with neutrons of energies in excess of 1 MeV. Since the material NDTT dictates the minimum operating temperature at which the reactor vessel can be pressurized, it is desirable to keep the NDTT as low as possible.

The reactor assembly design provides an annular space from the outermost fuel assemblies to the inner surface of the reactor vessel that serves to attenuate the fast neutron flux incident on the reactor vessel wall. This annular volume contains the core shroud, jet pump assemblies, and reactor coolant. Assuming that plant operation is at rated power and the plant has an availability of 100% for the plant lifetime, the neutron fluence at the inner surface of the vessel is not sufficient to appreciably shift the transition temperature. Expected shifts in transition temperature during design life as a result of environmental conditions, such as neutron flux, are considered in the design. Operational limitations assume that NDTT shifts are accounted for in the reactor operation.

The RCPB is designed, maintained, and tested so that adequate assurance is provided that the boundary will behave in a nonbrittle manner throughout the life of the plant. Therefore, the RCPB is in conformance with GDC 31. Referenced sections are as follows:

a.	Design of structures, components, equipment, and systems	Chapter 3
b.	Integrity of RCPB	Section 5.2
c.	Reactor vessel and appurtenances	Section 5.3

GDC 32 - Inspection of Reactor Coolant Pressure Boundary

Components which are part of the RCPB shall be designed to permit 1) periodic inspection and testing of important areas and features to assess their structural and leak-tight integrity and 2) an appropriate material surveillance program for the RPV.

Design Evaluation

The LGS design conforms to GDC 32. The RCPB design meets the requirements of the ASME B&PV Code, Section XI, including Summer 1971 Addenda, which requires access for all mandatory inspections. The design also permits the conduct of a material surveillance program for the RPV. Additional details of these features are in Section 5.2.4.

The reactor recirculation piping and main steam piping are hydrostatically tested with the RPV at a test pressure that is in accordance with ASME Section III.

Vessel material surveillance samples are located within the RPV to enable periodic monitoring of material properties with exposure. The program includes specimens of the base metal, the heat-affected zone within the base metal, and weld metal.

The plant testing and inspection programs ensure that the requirements of GDC 32 are met. Referenced sections are as follows:

a.	Design of structures, components, equipment, and systems	Chapter 3
b.	RCPB	Section 5.2
c.	Reactor vessel and appurtenances	Section 5.3
d.	Component and subsystem design	Section 5.4

GDC 33 - Reactor Coolant Makeup

A system to supply reactor coolant makeup for protection against small breaks in the RCPB shall be provided. The system safety function shall be to assure that specified acceptable fuel design limits are not exceeded as a result of reactor coolant loss due to leakage from the RCPB and rupture of small piping or other small components which are part of the boundary. The system shall be designed to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished using the piping, pumps, and valves used to maintain coolant inventory during normal reactor operation.

Design Evaluation

Means are provided for detecting reactor coolant leakage. The leak detection system consists of sensors and instruments to detect, annunciate, and in some cases isolate the RCPB from potential hazardous leaks before predetermined limits are exceeded. As described in Section 5.2.5, small leaks are detected by temperature and pressure changes, increased frequency of sump pump operation, and the measurement of airborne radioactivity. The allowable leakage rates are based on predicted and experimentally determined behavior of cracks in pipes, the ability to make up coolant system leakage, the normal expected background leakage due to equipment design, and the detection capability of the various sensors and instruments. The total leakage rate limit is established so that,

in the absence of normal ac power concurrent with a loss of feedwater supply, makeup capabilities are provided by the RCIC systems. Thus, protection is provided to ensure that fuel clad temperature limits are not exceeded.

The plant is designed to provide ample reactor coolant makeup for protection against small leaks in the RCPB. The design of these systems meets the requirements of GDC 33. Referenced sections are as follows:

a.	Integrity of RCPB	Section 5.2
b.	ECCS	Section 6.3

c. ESF Systems Section 7.3

GDC 34 - Residual Heat Removal

A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the RCPB are not exceeded.

Suitable redundancy in components and features and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Design Evaluation

The RHR system provides the means to:

a. Remove decay heat and residual heat from the nuclear system so that refueling and nuclear system servicing can be performed.

b. Deleted

The major equipment of the RHR system consists of two heat exchangers, four main system pumps, and two service water pumps. The equipment is connected by associated valves and piping, and the controls and instrumentation are provided for proper system operation.

One loop consists of a heat exchanger, two main system pumps, and associated piping, and is located in one area of the reactor enclosure. A redundant loop is located in another area of the reactor enclosure to minimize the possibility of a single physical event causing the loss of the entire system.

Each heat exhanger is alignable to one of two RHR pumps. During cold shutdown and refueling operations, this results in availability of four subsystems of shutdown cooling.

As described in the evaluation for GDC 44, the RHRSW system is used to remove heat from the RHR heat exchanger.

Both RHR loops take suction from a common line coming from the reactor. A failure of either containment isolation valve in this common suction line would therefore prevent use of this flow path. In the event of such a failure, a flow path can be established through the ADS valves (Section 15.2.9).

During cold shutdown and refueling operation conditions when two subsystems of shutdown cooling may be aligned to a common passive heat exchanger and discharge piping, a failure of the associated shutdown cooling discharge valve or check valve will require manual actions to repair the valve to restore flow, or if unsuccessful, may require cooling water flow to be returned through the LPCI injection line.

The systems used for residual heat removal are powered from the safeguard buses. The design of the safeguard buses, as described in the evaluation for GDC 17, assures that residual heat can be removed, assuming a single failure, when onsite electric power is available (assuming offsite power is not available) and when offsite electric power is available (assuming onsite power is not available).

The RHR system is adequate to remove residual heat from the reactor core to ensure that fuel and RCPB design limits are not exceeded. Redundant offsite and onsite electric power systems are provided. The design of the systems used to remove residual heat, including their power supplies, meets the requirements of GDC 34. Referenced sections are as follows:

a.	Component and subsystem design	Section 5.4
b.	ECCS	Section 6.3
c.	ESF systems	Section 7.3
d.	Systems required for safe shutdown	Section 7.4
e.	Onsite power systems	Section 8.3
f.	Water systems	Section 9.2
g.	Accident analyses	Chapter 15

GDC 35 - Emergency Core Cooling

A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that 1) fuel and clad damage that could interfere with continued effective core cooling is prevented and 2) clad metal-water reaction is limited to negligible amounts.

Suitable redundancy in components and features and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Design Evaluation

The ECCS consists of the following: HPCI system; ADS; CS system; and LPCI system (an operating mode of the RHR system). The ECCS is designed to limit fuel cladding temperature over the complete spectrum of possible break sizes in the nuclear system process barrier, including a complete and sudden circumferential rupture of the largest pipe connected to the reactor vessel.

The HPCI system consists of a steam turbine, a constant flow pump, system piping, valves, controls, and instrumentation. The HPCI system is provided to ensure that the reactor core is adequately cooled to prevent excessive fuel clad temperatures for breaks in the nuclear system that do not result in rapid depressurization of the reactor vessel. The HPCI system continues to operate until the reactor vessel pressure is below the pressure at which LPCI operation or CS system operation maintains core cooling. Two sources of water are available, the CST and the suppression pool.

In case the capability of the feedwater pumps, CRD water pumps, and RCIC and HPCI systems is not sufficient to maintain the reactor water level, the ADS functions to reduce the reactor pressure so that flow from the LPCI and the CS systems enters the reactor vessel in time to cool the core and prevent excessive fuel clad temperature. The ADS uses several of the nuclear system pressure relief valves to relieve the high pressure steam to the suppression pool.

Two independent loops are provided as a part of the CS system. Each loop consists of two centrifugal water pumps driven by electric motors, a spray sparger in the reactor vessel above the core, piping and valves to convey water from the suppression pool to the sparger, and the associated controls and instrumentation. In case of low water level in the reactor vessel or high pressure in the drywell, the CS system automatically sprays water onto the top of the fuel assemblies in time and at a sufficient flow rate to cool the core and prevent excessive fuel temperature. The LPCI system starts from the same signals that initiate the CS system and operates independently to achieve the same objective by flooding the reactor vessel.

LPCI and CS operation provide protection to the core if there is a large break in the nuclear system when the feedwater pumps, CRD, RCIC, and the HPCI systems are unable to maintain reactor vessel water level. Protection provided by LPCI and CS also extends to a small break for which the ADS has operated to lower the reactor vessel pressure so that these systems start to provide core cooling.

The results of ECCS performance for the entire spectrum of liquid line breaks are discussed in Section 6.3.

The RHR and CS systems are powered from the safeguard buses. The design of the safeguard buses, as described in the evaluation for GDC 17, assures that emergency core cooling can be provided, assuming a single failure, when onsite electric power is available (assuming offsite power is not available) and when offsite electric power is available (assuming onsite power is not available).

The ECCS provided is adequate to prevent fuel and clad damage that could interfere with effective core cooling and to limit clad metal-water reaction to a negligible amount. Redundant offsite and onsite electric power systems are provided. The design of the ECCS, including its power supplies, meets the requirements of GDC 35. Referenced sections are as follows:

a.	Component and subsystem design	Section 5.4
b.	ECCS	Section 6.3
c.	ESF systems	Section 7.3
d.	Onsite power systems	Section 8.3
e.	Water systems	Section 9.2
f.	Accident analyses	Chapter 15

GDC 36 - Inspection of Emergency Core Cooling System

The ECCS shall be designed to permit appropriate periodic inspection of important components, such as spray rings in the reactor pressure vessel, water injection nozzles, and piping, to assure the integrity and capability of the system.

Design Evaluation

The ECCS discussion in GDC 35 includes inservice inspection considerations.

The CS spargers within the reactor vessel are accessible for remote visual inspection during refueling outages. Removable plugs in the sacrificial shield and/or panels in the insulation provide access for the examination of nozzles from the outside of the vessel. Removable insulation is provided on the ECCS piping out to and including the first isolation valve outside containment. Inspection of the ECCS is in accordance with Section XI of the ASME B&PV Code, or 10 CFR 50.69 Alternative Treatment, when applicable. Refer to Section 6.6.1 for further information.

During plant operations, the pumps, valves, piping, instrumentation, wiring, and other components outside the primary containment can be visually inspected at any time. Components inside the primary containment can be inspected when the drywell is open for access. When the reactor vessel is open for refueling or other purposes, the spargers and other internals can be inspected. Portions of the ECCS that are part of the RCPB are designed to specifications for inservice inspection to detect defects that might affect the cooling performance. The design of the reactor vessel and internals for inservice inspection and the plant testing and inspection program ensures that the requirements of GDC 36 are met. See Section 5.2.4 for further discussion of ECCS inservice inspection.

GDC 37 - Testing of Emergency Core Cooling System

> The ECCS shall be designed to permit appropriate periodic pressure and functional testing to assure 1) the structural and leak-tight integrity of its components, 2) the operability and performance of the active components of the system, and 3) the operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

Design Evaluation

The ECCS consists of the HPCI system, ADS, LPCI mode of the RHR system, and CS system. Each of these systems is provided with sufficient test connections and isolation valves to permit appropriate periodic pressure testing to ensure the structural and leak-tight integrity of its components.

The HPCI, ADS, LPCI, and CS systems are designed to permit periodic testing to ensure the operability and performance of the active components of each system.

The pumps and valves of these systems are capable of being tested periodically to verify operability. Flow rate tests can be conducted on the CS, LPCI, and HPCI systems.

Each system of the ECCS is capable of being tested under conditions as close to design as practicable to verify the performance of the full operational sequence that brings each system into operation, including the transfer between normal and emergency power sources. The operation of the associated cooling water system is discussed in the evaluation of GDC 46 design conformance. It is concluded that the requirements of GDC 37 are met. Referenced sections are as follows:

a.	Overpressurization protection	Section 5.2
b.	ECCS inspection and testing	Section 6.3
c.	ECCS instrumentation and controls	Section 7.3

d. Standby ac power system Section 8.3

GDC 38 - Containment Heat Removal

A system to remove heat from the reactor containment shall be provided. The system safety function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any LOCA and to maintain them at acceptably low levels.

Suitable redundancy in components and features and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Design Evaluation

If there is a LOCA, the pressure-suppression system rapidly condenses the steam to prevent containment overpressure. The containment feature of pressure-suppression employs two separate compartmented sections of the primary containment: the drywell that houses the nuclear system and the suppression chamber containing a large volume of water. Any increase in pressure in the drywell from a leak in the nuclear system is relieved below the surface of the suppression chamber water pool by connecting vent lines. The pressure buildup in the suppression chamber is equalized with the drywell by a vent line and vacuum breaker arrangement. Cooling systems remove heat from the reactor core, the drywell, and from the water in the suppression chamber during an accident condition; thus, continuous cooling of the primary containment is provided.

Sufficient water is provided in the suppression pool to accommodate the initial energy that can be transiently released into the drywell from a postulated pipe failure.

The suppression chamber is sized to contain this water plus the water displaced from the reactor primary system, together with the free air initially contained in the drywell.

The containment heat removal function is accomplished by the containment cooling mode of the RHR system. This mode consists of the suppression pool cooling subsystem and the containment spray subsystem.

Either or both RHR heat exchangers can be manually activated to remove energy from the containment. The redundancy and capability of the offsite and onsite electrical power systems for the RHR system, discussed in the evaluation against GDC 34, ensure that the system safety function can be accomplished, assuming there is a single failure, for onsite electric power system operation (assuming that offsite power is not available) and for offsite electric power system operation (assuming that onsite power is not available).

The pressure-suppression system is capable of rapid containment pressure and temperature reduction following a LOCA to ensure that the design limits are not exceeded. Redundant offsite and onsite electrical power systems are provided. The design of the containment heat removal system meets the requirements of GDC 38. Referenced sections are as follows:

a. Component and subsystem design Section 5.4

b.	Containment systems	Section 6.2
c.	ECCS	Section 6.3
d.	ESF systems	Section 7.3
e.	Electric power systems	Chapter 8
f.	Auxiliary systems	Chapter 9
g.	Accident analyses	Chapter 15

GDC 39 - Inspection of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic inspection of important components, such as torus, sumps, spray nozzles, and piping, to assure the integrity and capability of the system.

Design Evaluation

Provisions are made to facilitate periodic inspections of active components and other important equipment of the containment pressure-reducing systems. During plant operations, the pumps, valves, piping, instrumentation, wiring, and other components outside the primary containment can be periodically visually inspected. Components inside the primary containment can be inspected when the drywell is open for access. The testing frequencies of most components are correlated with the component inspection.

The pressure-suppression chamber is designed to permit appropriate periodic inspection. Space is provided inside the chamber for inspection and maintenance. There are two hatches that permit access to the suppression chamber for inspection.

The containment heat removal system is designed to permit periodic inspection of major components both outside and within the primary containment. This design meets the requirements of GDC 39. Referenced sections are as follows:

a.	Component and subsystem design	Section 5.4
b.	Containment systems	Section 6.2
c.	ECCS	Section 6.3
d.	Water systems	Section 9.2

GDC 40 - Testing of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic pressure and functional testing to assure 1) the structural and leak-tight integrity of its components, 2) the operability and performance of the active components of the system, and 3) the operability of the system as a whole and, under conditions as close to the design as practical, the performance of the full operational sequence that brings the system into

operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

Design Evaluation

The containment heat removal function is accomplished by the containment cooling mode of the RHR system. This mode consists of the suppression pool cooling subsystem and containment spray subsystem.

The RHR system is provided with sufficient test connections and isolation valves to permit periodic pressure and flow rate testing.

The pumps and valves of the RHR system can be operated periodically to verify operability. The containment cooling mode is not automatically initiated, but operation of the components can be periodically verified. The operation of associated cooling water systems is discussed in the conformance to GDC 46. It is concluded that the requirements of GDC 40 are met.

GDC 41 - Containment Atmosphere Cleanup

Systems to control fission products, hydrogen, oxygen, and other substances which may be released into the reactor containment shall be provided as necessary to reduce, consistent with the functioning of other associated systems, the concentration and quantity of fission products released to the environment following postulated accidents and to control the concentration of hydrogen or oxygen and other substances in the containment atmosphere following postulated accidents to assure that containment integrity is maintained. Each system shall have suitable redundancy in components and features and suitable interconnections, leak detection, isolation, and containment capabilities to assure that, for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available), its safety function can be accomplished, assuming a single failure.

Design Evaluation

Fission products released into the secondary containment following postulated accidents are automatically processed by the RERS and/or the SGTS. Initiation of the SGTS and RERS follows high radiation signals from monitors located in the reactor enclosure exhaust ducts, a high drywell pressure signal, or a low reactor level signal. Initiation of the SGTS follows a high radiation signal from monitors in the refueling area exhaust ducts.

The ability of these systems to remove radioactivity from the process stream is discussed in Section 6.5. The SGTS and RERS are each composed of two trains that are separated physically and electrically so that a single failure does not prevent their function, except as described in Table 6.5-2. The redundancy of these systems is also discussed in Section 6.5.3.

A combustible gas control system consisting of redundant hydrogen recombiners maintains hydrogen and oxygen concentrations below flammable limits following a postulated LOCA. The system continuously processes the primary containment atmosphere following manual initiation. As a backup to the combustible gas control system, the containment atmosphere can be purged through the SGTS filters to the turbine enclosure north vent stack. A detailed description is provided in Section 6.2.5.

The SGTS, RERS, and the combustible gas control system meet the requirements of GDC 41 except as described above.

The containment atmospheric cleanup systems are connected to the safeguard buses. The design of the safeguard buses, as described in the evaluation for GDC 17, ensures that the containment atmospheric cleanup function can be provided, assuming a single failure, when onsite electric power is available (assuming that offsite power is not available) and when offsite electric power is available (assuming that onsite power is not available).

GDC 42 - Inspection of Containment Atmosphere Cleanup Systems

> The containment atmosphere cleanup systems shall be designed to permit appropriate periodic inspection of important components, such as filter frames, ducts, and piping, to assure the integrity and capability of the systems.

Design Evaluation

Inspection of the internal structure of the SGTS and RERS filter banks is facilitated by access doors installed in each unit to allow entry to the unit for visual inspection of structural members and filter faces.

The charcoal beds are provided with removable canisters for taking charcoal samples.

For a further discussion of the SGTS and RERS inspection features, see Section 6.5.

All active components of the combustible gas control system are located externally to the primary containment and are accessible for inspection during normal operation of the plant. For a discussion of inspection, see Section 6.5.

The design of the containment atmosphere cleanup systems meets the requirements of GDC 42.

GDC 43 - Testing of Containment Atmosphere Cleanup Systems

> The containment atmosphere cleanup systems shall be designed to permit appropriate periodic pressure and functional testing to assure 1) the structural and leak-tight integrity of its components, 2) the operability and performance of the active components of the systems such as fans, filters, dampers, and valves, and 3) the operability of the systems as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of associated systems.

Design Evaluation

Each unit of the SGTS and the RERS is operated periodically to ascertain the operability and performance of the major active components, such as fans, filters, motors, pumps, and valves, as well as the structural integrity of the unit. This test verifies the operability of the system as a whole and the operability of all associated subsystems. See Section 8.3.1 for a discussion of the testing of the auxiliary power system.

The leak-tightness of the HEPA filters is measured by the DOP test. A halogenated hydrocarbon refrigerant system is provided to test the activated charcoal filters. For a further discussion of testing, see Section 6.5. Each loop of the combustible gas control system is designed for periodic pressure and operability testing. For a further discussion of testing, see Section 6.5.

The design of the containment atmosphere cleanup systems meets the requirements of GDC 43.

GDC 44 - Cooling Water

> A system to transfer heat from structures, systems, and components important to safety to an UHS shall be provided. The system safety function shall be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions. Suitable redundancy in components and features and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Design Evaluation

The ESW system and the RHRSW system provide cooling water for the removal of excess heat from all structures, systems, and components that are necessary to maintain safety during all abnormal and accident conditions. These include the standby diesel generators, the RHR motor oil coolers and pump compartment unit coolers, the control room chillers, the CS pump compartment unit coolers, the RCIC pump compartment unit coolers, the HPCI pump compartment unit coolers, and the RHR heat exchangers.

The ESW system and the RHRSW system are designed to seismic Category I requirements. Redundant safety-related components served by the systems are supplied through redundant supply headers and returned through redundant discharge or return lines. Electric power for operation of redundant safety-related components of these systems is supplied from separate independent offsite and redundant onsite standby power sources. No single failure renders these systems incapable of performing their safety functions.

The ESW system and RHRSW system meet the requirements of GDC 44. Referenced sections are as follows:

a.	AC power systems	Section 8.3
b.	Service water system	Section 9.2.1
c.	ESW system	Section 9.2.2
d.	RHRSW system	Section 9.2.3
e.	UHS	Section 9.2.6

GDC 45 - Inspection of Cooling Water System

The cooling water system shall be designed to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system.

Design Evaluation

The ESW system and RHRSW system are designed to permit appropriate periodic inspection to ensure the integrity of system components, thus meeting the requirements of GDC 45. Referenced sections are as follows:

a.	ESW system	Section 9.2.2
b.	RHRSW system	Section 9.2.3

GDC 46 - Testing of Cooling Water System

The cooling water system shall be designed to permit appropriate periodic pressure and functional testing to assure 1) the structural and leak-tight integrity of its components, 2) the operability and the performance of the active components of the system, and 3) the operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation for reactor shutdown and for LOCAs, including operation of applicable portions of the protection system and the transfer between normal and emergency power sources.

Design Evaluation

The RHRSW system described in GDC 44 is in operation during all plant shutdowns. The ESW system is periodically tested when the diesel generators are tested. This testing includes transfer between the normal offsite power supply and the emergency onsite power system. These systems are designed to the extent practicable to permit demonstration of operability of the systems as required for operation during a LOCA or a LOOP. Thus, the ESW and RHRSW systems meet the requirements of GDC 46. Referenced sections are as follows:

a.	ESW system	Section 9.2.2
b.	RHRSW system	Section 9.2.3

GDC 50 - Containment Design Basis

The reactor containment structure, including access openings, penetrations, and the containment heat removal system, shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and, with sufficient margin, the calculated pressure and temperature conditions resulting from any LOCA. This margin shall reflect consideration of 1) the effects of potential energy sources which have not been included in the determination of the peak conditions, such as energy in steam generators and energy from metal-water and other chemical reactions that may result from degraded emergency core cooling functioning, 2) the limited experience and experimental data available for defining accident phenomena and containment responses, and 3) the conservatism of the calculational model and input parameters.

Design Evaluation

The primary containment structure, access openings, penetrations, heat removal system, and internal compartments are designed with sufficient margin to meet the requirements of GDC 50. Containment design is described in Section 6.2.

GDC 51 - Fracture Prevention of Containment Pressure Boundary

> The reactor containment boundary shall be designed with sufficient margin to assure that under operating, maintenance, testing, and postulated accident conditions 1) its ferritic materials behave in a nonbrittle manner and 2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the containment boundary material during operation, maintenance, testing, and postulated accident conditions, and the uncertainties in determining 1) material properties, 2) residual, steady-state, and transient stresses, and 3) size of flaws.

Design Evaluation

The primary containment boundary is designed to the load combination shown in Section 3.8, which covers the operational, testing, and postulated accident conditions. Each condition results in a stress level that is related to its corresponding temperature and is the basis for comparison with the allowable limits.

The ferritic steel used for the primary containment boundary is specified so that the toughness of the material meets the above established conditions.

The weld procedure qualification ensures that the toughness of the weld metal and heat-affected zones follow the same criteria as for the base metal.

Since the primary containment is located within the reactor enclosure, the possibility of brittle fracture of ferritic material under low temperature is considerably reduced.

The lowest design service temperature is conservatively taken as 30ºF. The actual service temperature is calculated to be approximately 135ºF. Thus sufficient margin is inherent in the design to account for the various uncertainties involved in design and fabrication. The design of the reactor containment boundary meets the requirements of GDC 51. Actual service conditions above 135°F do not adversely affect this conclusion.

Records for the materials of the flued head fittings, main steam piping, and MSIVs are available for inspection. Additional information is provided in Section 5.2.3.3.

GDC 52 - Capability for Containment Leakage Rate Testing

> The reactor containment and other equipment which may be subjected to containment test conditions shall be designed so that periodic integrated leakage rate testing can be conducted at containment design pressure.

Design Evaluation

The primary containment liner plate and all other equipment that may be subjected to containment test conditions are designed to permit Type A, integrated leak rate testing as described in 10CFR50,

Appendix J. The design of the primary containment thus meets the requirements of GDC 52. A more complete discussion is in Section 6.2.6 and Chapter 16.

GDC 53 - Provisions for Containment Testing and Inspection

> The reactor containment shall be designed to permit 1) appropriate periodic inspection of all important areas, such as penetrations, 2) an appropriate surveillance program, and 3) periodic testing at containment design pressure of the leak-tightness of penetrations which have resilient seals and expansion bellows.

Design Evaluation

The primary containment is designed to optimize the accessibility of important areas to permit required inspection and surveillance.

All penetrations with resilient seals are designed to permit local leak rate testing as described in 10CFR50, Appendix J. This is discussed further in Section 6.2.6.

Expansion bellows are not used on containment penetrations.

The reactor containment meets the requirements of GDC 53.

GDC 54 - Piping Systems Penetrating Containment

> Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

Design Evaluation

Piping systems that penetrate the primary containment have been accorded special design considerations to reflect their importance in accomplishing safety-related functions and in achieving isolation, if required. The penetrations are discussed in Section 6.2.4. Both the isolation valves and the system that initiates isolation use components whose quality maximizes reliability. Sufficient independence and redundancy is provided to ensure effective isolation. Containment isolation is discussed in Section 6.2.4.

Piping systems penetrating the primary containment are designed to permit Type C local leak rate testing as described in Section 6.2.6. The operability of the isolation valves and associated equipment can be verified during the leak rate testing program. Containment leakage testing is further discussed in Section 6.2.6.

Piping systems penetrating primary reactor containment meet GDC 54.

GDC 55 - Reactor Coolant Pressure Boundary Penetrating Containment

> Each line that is part of the RCPB and that penetrates the primary reactor containment shall be provided with containment isolation valves as follows unless it can be demonstrated that

the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

a. One locked closed isolation valve inside and one locked closed isolation valve outside containment, or

b. One automatic isolation valve inside and one locked closed isolation valve outside containment, or

c. One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

d. One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to the containment as practical and upon loss of actuating power automatic isolation valves shall be designed to take the position that provides greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided as necessary to assure adequate safety. Determination of the appropriateness of these requirements (such as higher quality in design, fabrication, and testing, additional provisions for inservice inspection, protection against more severe natural phenomena, and additional isolation valves and containment) shall include consideration of the population density, use characteristics, and physical characteristics of the site environs.

Design Evaluation

The piping systems that are part of the RCPB and penetrate primary containment conform to the requirements of GDC 55 as described in Section 6.2.4. Similarly, for lines that do not penetrate the primary containment but form a portion of the RCPB, the design ensures that isolation from the RCPB can be achieved.

GDC 56 - Primary Containment Isolation

Each line that connects directly to the containment atmosphere and penetrates the primary reactor containment shall be provided with containment isolation valves, as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

a. One locked closed isolation valve inside and one locked closed isolation valve outside containment, or

b. One automatic isolation valve inside and one locked closed isolation valve outside containment, or

c. One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

d. One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to the containment as practical and, upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Design Evaluation

The piping systems penetrating primary containment conform to the requirements of GDC 56 as described in Section 6.2.4.

GDC 57 - Closed System Isolation Valves

Each line that penetrates the primary reactor containment and is neither part of the RCPB nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, locked closed, or capable of remote manual operation. This valve shall be outside the containment and located as close to the containment as practical. A simple check valve may not be used as the automatic isolation valve.

Design Evaluation

The piping systems penetrating primary containment conform to the requirements of GDC 57 as described in Section 6.2.4.

GDC 60 - Control of Releases of Radioactive Materials to the Environment

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

Design Evaluation

In all cases, the design for radioactivity control is on the basis of the requirements of 10CFR20, 10CFR50, and applicable regulations for normal operations and for any transient situation that might reasonably be anticipated to occur, and is on the basis of 10CFR50.67 dose limits for potential accidents of exceedingly low probability of occurrence. The activity level of waste gas effluents is substantially reduced by holdup of noble gases from the offgas system in charcoal decay beds and subsequent release at the plant exhaust duct.

Control of liquid waste effluents is maintained by batch processing of all liquids, sampling before discharge, and controlled rate of release. Radioactive liquid waste system tankage and external processing capacity is sufficient to handle any expected transient in the processing of liquid waste volume.

Solid wastes are shipped offsite for disposal in shielded and reinforced containers that meet applicable NRC and DOT requirements (Section 11.4).

The liquid, gaseous, and solid waste systems meet the requirements of GDC 60. Referenced sections are as follows:

a.	Liquid waste system	Section 11.2
b.	Gaseous waste system	Section 11.3
c.	Solid waste system	Section 11.4
d.	Process and effluent radiological monitoring system	Section 11.5
e.	Accident analyses	Chapter 15
f.	Technical Specifications	Chapter 16

GDC 61 - Fuel Storage and Handling and Radioactivity Control

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed 1) with a capability to permit appropriate periodic inspection and testing of components important to safety, 2) with suitable shielding for radiation protection, 3) with appropriate containment, confinement, and filtering systems, 4) with a residual heat removal capability having reliability and testability that reflects the importance to safety of decay heat and other residual heat removal, and 5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

Design Evaluation

a. New fuel storage

New fuel is stored in the spent fuel storage pool.

b. Spent fuel handling and storage

Irradiated fuel is stored submerged in the spent fuel storage pool located in the reactor enclosure. Fuel pool water is circulated through the FPCC system to maintain fuel pool water temperature, purity, water clarity, and water level. Storage racks preclude accidental criticality (GDC 62 design evaluation).

Reliable decay heat removal is provided by the FPCC system. The pool water is circulated through the system with suction taken from the pool and is discharged through diffusers at the bottom of the fuel pool. Pool water temperature will not

exceed 143°F during removal of the maximum normal heat load from the pool with the service water temperature at its maximum. The RHR system with its substantially larger heat removal capacity can be used as a backup for fuel pool cooling.

If there is a complete loss of capability to remove heat from the spent fuel pool using heat exchangers, heat can be removed by allowing the pool to boil and adding makeup water from the UHS (spray pond), by either of two seismic Category I flow paths, to maintain the pool water level.

High and low level switches indicate pool water level changes in the control room. Fission product concentration in the pool water is minimized by the fuel pool filter/demineralizer. This minimizes the radioactivity release from the pool to the reactor enclosure.

The reactor enclosure ventilation system and secondary containment are designed to limit the release of radioactive materials to the environment and ensure that offsite doses are lower than the limiting values specified in 10CFR50.67 during operation and all accident conditions.

No special tests are required, because at least one pump and one heat exchanger are continuously in operation while fuel is stored in the pool. Other cooling trains are operated periodically to handle high heat loads or to replace a unit for servicing. Routine visual inspection of the system components, instrumentation, and trouble alarms is adequate to verify system operability.

c. Radioactive waste systems

The radioactive waste systems provide all equipment necessary to collect, process, and prepare for disposal all radioactive liquids, gases, and solid waste produced as a result of reactor operation.

Liquid radwastes are classified, contained, and treated as high or low conductivity, chemical, detergent or sludge wastes. Processing includes filtration, ion exchange, analysis, and dilution. Wet solid wastes are dewatered and packaged in steel containers. Dry solid wastes are compressed and packaged in steel drums. Gaseous radwastes are monitored, processed, recorded, and released so that radiation doses to persons outside the controlled area are below those allowed by applicable regulations.

Accessible portions of the spent fuel pool area and radwaste enclosure have sufficient shielding to maintain dose rates within the limits set forth in 10CFR20 and 10CFR50. The radwaste enclosure is designed to preclude an accidental release of radioactive materials to the environment that exceeds the limits allowed by the applicable regulations.

The radwaste systems are used on a routine basis and do not require specific testing to ensure operability. Performance is monitored by radiation monitors during operation.

The fuel storage and handling and the radioactive waste systems are designed to ensure adequate safety under normal and postulated accident conditions. The design of these systems meets the requirements of GDC 61.

Referenced sections are as follows:

a.	RHR system	Section 5.4
b.	Containment systems	Section 6.2
c.	New fuel storage	Section 9.1
d.	Spent fuel storage	Section 9.1
e.	FPCC system	Section 9.1
f.	HVAC systems	Section 9.4
g.	Radioactive waste management	Chapter 11
h.	Radiation protection	Chapter 12

GDC 62 - Prevention of Criticality in Fuel Storage and Handling

Criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations.

Design Evaluation

Appropriate plant fuel handling and storage facilities are provided to preclude accidental criticality for new and spent fuel. Criticality in new and spent fuel storage is prevented by the geometrically safe configuration of the storage rack. There is sufficient spacing between the assemblies to ensure that the array, when fully loaded, is substantially subcritical. Fuel elements are limited by rack design to only top loading and fuel assembly positions. The new and spent fuel storage racks are designed to seismic Category I requirements.

New fuel storage is discussed in Section 9.1.1. New fuel is stored in the spent fuel pool.

Spent fuel is stored underwater in the spent fuel pool. The racks in which spent fuel assemblies are placed are designed and arranged to ensure subcriticality in the storage pool. Spent fuel storage is discussed in Section 9.1.2.

Refueling interlocks include circuitry that senses conditions of the refueling equipment and control rods. These interlocks reinforce operational procedures that prohibit making the reactor critical. The fuel handling system is designed to provide a safe, effective means of transporting and handling fuel and is designed to minimize the possibility of mishandling or misoperation.

The use of geometrically safe configurations for new and spent fuel storage and the design of fuel handling systems precludes accidental criticality in accordance with GDC 62. Referenced section is as follows:

a.	Fuel storage and handling	Section 9.1

GDC 63 - Monitoring Fuel and Waste Storage

> Appropriate systems shall be provided in fuel storage and radioactive waste systems and associated handling areas 1) to detect conditions that may result in loss of residual heat removal capability and excessive radiation levels and 2) to initiate appropriate safety actions.

Design Evaluation

Appropriate systems are provided to meet the requirements of GDC 63. A malfunction of the FPCC system that could result in a loss of residual heat removal capability and excessive radiation levels is alarmed in the control room. Alarmed conditions include low fuel pool cooling water pump discharge pressure, high and low levels in the fuel storage pool and skimmer surge tanks, and flow in the drain lines between the fuel pool gates between fuel pool and reactor well. System temperature is also continuously monitored and alarmed in the control room. Spent fuel storage is discussed in Section 9.1.2, and fuel pool cooling and cleanup are discussed in Section 9.1.3.

The reactor enclosure and refueling floor ventilation radiation monitoring systems detect abnormal amounts of radioactivity and initiate appropriate action to control the release of radioactive material to the environment. These systems are discussed in Sections 9.4 and 11.5.

Area radiation and tank and sump levels are monitored and alarmed to indicate conditions that may result in excessive radiation levels in radioactive waste system areas. Area radiation monitoring is discussed in Section 12.3.

GDC 64 - Monitoring Radioactivity Releases

> Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of LOCA fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

Design Evaluation

Appropriate means are provided for monitoring radioactivity releases to meet the requirements of GDC 64.

A fission products monitoring system is provided to sample the containment (both drywell and suppression pool) atmosphere for radioactive particulates, noble gases, and iodine during normal operation. A hydrogen-oxygen analyzer system is provided to monitor the hydrogen-oxygen concentration in the containment during normal operation and following an accident.

Means are provided to monitor radioactive effluent discharge paths and the site environment for radioactivity releases. Referenced sections are as follows:

a.	RCPB leakage detection system	Section 5.2
b.	ESF systems	Section 7.3
c.	All other systems required for safety	Section 7.6

d.	Control systems not required for safety	Section 7.7
e.	Radioactive waste management	Chapter 11
f.	Airborne radioactivity monitoring	Section 12.3

3.2 CLASSIFICATION OF STRUCTURES, COMPONENTS, AND SYSTEMS

Certain structures, components, and systems of the nuclear plant are considered important to safety because they perform safety actions required to avoid, or to mitigate the consequences of abnormal operational transients or accidents. The purpose of this section is to classify structures, components, and systems according to the importance of the safety functions they perform. In addition, design requirements are specified to ensure the proper performance of safety actions when required.

3.2.1 SEISMIC CLASSIFICATION

GDC 2 and 10CFR100, Appendix A require that nuclear power plant structures, systems, and components important to safety be designed to withstand the effect of earthquakes. Regulatory Guide 1.29 (Rev 3) provides additional guidance, and defines seismic Category I structures, components, and systems and those necessary to ensure:

a. The integrity of the RCPB,

b. The capability to shut down the reactor and maintain it in a safe shutdown condition,

c. The capability to prevent, or mitigate the consequences of accidents which could result in potential offsite exposures in excess of the dose limits of 10CFR50.67.

Plant structures, systems, and components, including their foundations and supports, that are designed to remain functional if there is a SSE are designated as seismic Category I, as indicated in Table 3.2-1. Class 1E electric equipment is seismic Category I equipment. Seismic classification of systems instrumentation is discussed in Chapter 7.

All seismic Category I structures, systems, and components are analyzed under the loading conditions of the SSE and OBE. Since the two earthquakes vary in intensity, the design of seismic Category I structures, components, equipment, and systems to resist each earthquake and other loads is based on levels of material stress, or load factors, whichever is applicable, and yields margins of safety appropriate for each earthquake. The margins of safety provided for safety-related structures, components, equipment, and systems for the SSE are sufficiently large to ensure that their design functions are not jeopardized.

Seismic Category I structures are sufficiently isolated, or protected, from other structures to ensure that their integrity is maintained at all times.

Components and their supporting structures that are not seismic Category I, but are located in the vicinity of seismic Category I items, are listed as seismic Category IIA in Table 3.2-1. Those components listed as seismic Category IIA are either designed to seismic Category I criteria or are reviewed to identify those whose failure could result in loss of required function of seismic Category I structures, equipment, or systems required after an SSE. Components identified by this review are considered safety-impact items and are either analytically checked to confirm their integrity against collapse when subjected to seismic loading from the SSE or are separated from seismic Category I equipment by a barrier.

Structures, systems, and components that are not required to maintain their structural integrity or function during or after, the SSE are classified nonseismic (seismic Category II). The boundaries of each seismic category portion of the systems are shown on the piping and instrument diagrams in appropriate sections of this document. A cross reference of system to former UFSAR figure number is provided in Section 1.7.

Clarifications and alternate approaches to the guidelines of Regulatory Guide 1.29, as applied to LGS, are the following:

a. Regarding the seismic design of the reactor core and internals of paragraph C.1.b, reactor internals that are not required for safe shutdown of the plant are designed to maintain their relative positions following an SSE, but may not remain functional.

These internals are listed below:

1. Feedwater spargers
2. Initial startup neutron sources
3. Surveillance sample holders
4. Incore instrument housings
5. Steam dryer
6. Shroud head and separator assembly
7. Guide rods

Generic evaluation has demonstrated that the failure of these structures will not jeopardize the safety function of other safety-related internals during a seismic event.

b. The spent fuel pool cooling system, and the associated service water supply, discussed in paragraph C.1.d and C.1.g of the guide, are seismic Category IIA rather than seismic Category I systems. However, two alternate seismic Category I cooling sources are provided via connections from the RHR system and the ESW system, as discussed in Section 9.1.3. The portions of the spent fuel pool cooling system necessary for use of these alternate cooling sources are seismic Category I. This arrangement meets the intent of the guide.

c. The seismic Category I boundary of the main steam system and connected piping outside primary containment may not always be at a valve that is normally closed, or capable of automatic isolation, as discussed in paragraph C.1.e of the guide. In these cases, the boundary is at a valve that is capable of remote manual closure to avoid unnecessary complication in lines that normally would not be provided with automatically closing valves. The remote manual valves are the following (shown in drawing M-01):

1. Main steam to air ejectors isolation valve, HV-150 and HV-250
2. Main steam to steam seal evaporator isolation valve, HV-111 and HV-211
3. Main steam to reactor feed pump-turbine high pressure steam supply valve, HV-108 and HV-208.

The use of remotely operated manual valves in lieu of normally closed or automatic valves is justifiable for the following reasons:

Those portions of the steam system extending from the outermost containment isolation valve up to but not including the turbine stop valves, and connected piping of 2½ inches nominal pipe size or larger up to and including the remotely operated manual valves are classified seismic Category I. In addition, these valves are Class 1E powered, and the controls are installed on seismic Category I panels located in the control room for ready operator access to remotely close the valves when required.

During normal plant operation, in case of a pipe break downstream of any one of the remotely operated manual valves, radiation monitors in the turbine enclosure exhaust will detect radiation and alert the operator in the control room. Temperature elements will also show an increase in temperature.

Each of the three remotely operated manual valves in question is downstream of the MSIVs which automatically close in the event of a large pipe break in the main steam line.

Following a Design Basis Large Break LOCA, the operator can manually align the MSIV Leakage Alternate Drain Pathway, as described in section 6.7. This alignment includes the shutting of each three remotely operated manual valves in question.

Even assuming the unlikely event of a pipe break downstream of any one of these remotely operated manual valves coincident with a LOCA, during the time period before the MSIV Leakage Alternate Drain Pathway is aligned, the radiation doses are well below the values of 10CFR50.67. The activity levels in the residual steam would be comparable to normal operation activity levels. Core activity would not be transported past the already closed MSIVs due to the transport delay time of the residual steam and water.

Consistent with Regulatory Guide 1.26, the turbine bypass valve chest is designed to Quality Group D. In accordance with the Regulatory Guide 1.29 for the turbine stop valve, the turbine bypass valve chest is not designed to seismic Category I requirements.

d. Paragraph C.3 of Regulatory Guide 1.29 recommends seismic Category I design requirements be extended "to the first seismic restraint beyond the defined boundaries." Since seismic analysis of a piping system required division of the system into discrete segments terminated by fixed points, this means that the seismic design cannot be terminated at a seismic restraint, but is extended to the first point in the system which can be treated as an anchor to the plant structure. In addition, paragraph C.4 of Regulatory Guide 1.29 states that the pertinent quality assurance requirement of 10CFR50, Appendix B, should be applied to the safety requirements of such items. Both these guidelines are considered to be met adequately by applying the following practices to such items:

1. Design and design control for such items are carried out in the same manner as that for items directly important to safety. This includes the performance of appropriate design reviews.

2. Field audits are performed by representatives of the originating design group to ensure that the final installation of such items is in accordance with documents that formed the basis for the seismic analysis of the items.

3. Such items are not included in the Q-List.

3.2.2 SYSTEM QUALITY GROUP CLASSIFICATIONS

GDC 1 of 10CFR50, Appendix A, requires that structures, systems and components important to safety be designed, fabricated, erected, and tested to quality standards commensurate with their importance to safety. Components of the RCPB meet the requirements of Class 1 components of the ASME B&PV Code, Section III, or equivalent quality standards, as required by 10CFR50.55a. Regulatory Guide 1.26 (Rev 3), describes a quality classification system that may be used to determine applicable standards for other components in nuclear power plants. Quality group classifications are assigned to systems and components in accordance with the reliance placed on these systems to:

a. Prevent, or mitigate the consequences of, accidents and malfunctions originating within the RCPB

b. Permit shutdown or the reactor, and maintain it in the safe shutdown condition

c. Contain radioactive material

A tabulation of quality group classification for each component so defined is shown in Table 3.2-1 under the heading "Quality Group Classification." The applicable codes and standards of each quality group, as described by Regulatory Guide 1.26, are given in Tables 3.2-2 and 3.2-3. The locations of these components, and the quality group classification of the piping, valves, and interfaces between components of different classifications, are indicated on the system piping and instrumentation diagrams in the pertinent section of the UFSAR. A cross reference of system to former UFSAR figure number is provided in Section 1.7.

System quality group classifications, and design and fabrication requirements as indicated in Table 3.2-1, meet the guidelines of Regulatory Guide 1.26, except as noted below.

The LGS design is based on quality group commitments made before Regulatory Guide 1.26 was issued, as shown in Table 3.2-3, and in some cases alternate approaches to the guide have been used, as follows:

a. Regarding systems important for reactor shutdown, as discussed in paragraph C.1.b (Quality Group B) of the guide, the CRD system HCUs are classified as "special equipment" by GE because the codes and standard of a quality group are not strictly applicable to the HCUs. A detailed discussion is given in the notes of Table 3.2-1.

b. The Quality Group B classification may terminate on some steam system connected piping at the first valve capable of remote manual closure, rather than at a normally, or automatically, closed valve. Additionally, Quality Group B is applied only to piping 2½ inches in diameter and larger, similar to the guidelines of Regulatory Guide 1.29 for application of seismic Category I classification.

c. Certain components in the normal spent fuel pool cooling system were designed , fabricated, procured, installed, and tested to the requirements of ASME Section III, Class 3, prior to May 1978. After May 1978, system design, fabrication, materials, procurement, installation, and testing are, at a minimum, in accordance with Quality Group D and the intent of Regulatory Guide 1.143 (Rev 1). However, as discussed in Section 3.2.1, backup cooling and makeup sources are provided. These sources are at least Quality Group C, as are the connecting portions of the normal cooling system.

d. The standby diesel generator piping is designed as shown in drawing M-20. Supplementary material certification, design, and examination requirements have been applied to the Seismic Category I off-skid portions of the emergency diesel auxiliary systems to ensure that their quality is essentially equivalent to ASME Section III, Class 3. The technical differences between ANSI B31.1 and ASME Section III, Class 3 are few. The major differences were addressed by supplemental requirements and are listed in Table 3.2-4.

The on-skid piping and components in the diesel generator auxiliary systems were provided in accordance with ASME Section III, Class 3 or manufacturer's standards, as shown in the vendor manual and also drawing M-20. Auxiliary system components were supplied to ASME Section III, Class 3 to the greatest extend practicable at the time of procurement. The referenced drawing indicate that this encompasses most of the equipment within the main process loop of each skid-mounted auxiliary system.

All skid-mounted components, regardless of design code, have been designed to withstand seismic accelerations (Seismic Category I) as well as normal diesel operating loads. Portions of the Air Start System, which do not have a safety related function, have been downgraded to Seismic Category IIA as shown on drawing M-20. Motors Associated with stand-by components such as the Oil Pre-Lube Pump, The Oil Circulating Pump and the Jacket Water Keep Warm Pump, have been reclassified as non-safety related. The associated pumps are considered safety related (passive) since they are required for pressure boundary integrity only. These non-safety related components will have mountings that are calssified as seismic Category IIA. Each assembled diesel generator skid was subjected to a series of operating tests including load acceptance and rejection, air start capacity, variable load, overspeed, 300 hr rating, normal operating, and contract acceptance tests. In addition, to the operating tests, the following specific component tests were conducted:

1. Fuel Oil Injectors - These were functionally tested and calibrated to deliver a metered amount of fuel to the combustion chamber. Each injector has a unique serial number which permits traceability to its shop test and calibration records.

2. Flexible Hose Assemblies and Pipe Coupling Connectors - These components (drawing M-20) are manufacturer unique designs used to ensure flexibility in the piping systems and are not supplied to ASME Section III, Class 3. However, these components were fabricated in

accordance with engineering specifications, and each component was hydrotested to in excess of 1.25 times design pressure.

3. ASME Section III, Class 3 and non-ASME Section III, Class 3 Piping - All piping systems were hydrostatically tested to 1.5 times the design pressure regardless of design code, except for the on-skid starting air system piping which was pneumatically tested to 1.25 times the design pressure. These tests are documented in the shop test records.

All diesel components were supplied or manufactured in accordance with the following vendor's quality control standards:

1. Subsupplied Components - Design and procurement controls were used in the procurement of all subsupplied components. These components were purchased to detailed engineering specifications and drawings. Upon receipt, all components (or a representative sample) were inspected against the specification, drawings, and purchase order requirements, and affixed with appropriate tags to be removed at the point of use in the manufacturing cycle. Periodic reviews of subsupplier performance and audits or vendor records were conducted to ensure that the quality of the items provided remained acceptable.

   Typical examples of subsupplied items procured under this program are as follows:

   - Air start solenoid valves, filters, strainers, and compressors
   - Inlet and exhaust expansion joints and the exhaust silencer
   - Motor-driven fuel oil, jacket water, and lube oil pumps
   - Combustion air coolers, lube oil and jacket water standby heaters
   - Fuel and lube oil strainers
   - Jacket water, air cooler coolant, and lube oil thermostatic bypass valves
   - Electrical and pneumatic instrumentation and controls.

2. Supplier Manufactured Components - Equipment and components designed and manufactured by the diesel generator vendor were designed in accordance with written procedures for design control which required appropriate reviews and approvals of all detail drawings, specifications, procedures, and instructions. During the manufacturing process, visual inspection, dimensional checks, final inspections, and customer hold and witness points were used. Also, procedures were developed and implemented for rejection of components, recall of materials, and internal audits. Typical examples of supplier manufactured components incorporating the above standards include the following:

- Air admission check valves, pilot valves, and air start distributors
- Engine-mounted intake and exhaust air piping, scavenger air receivers, evacuation system components
- Fuel injectors, dirty fuel drip tank, fuel and oil drip pan
- Governor control linkage.

The above standards are fully documented in the diesel generator suppliers' Quality Assurance Plan, which addresses the 18 criteria contained with 10CFR50, Appendix B. It is invoked upon all diesel generators supplied by this manufacturer for use in nuclear plants and has received the approval of the appropriate operating utilities and the NRC.

The above described controls were invoked on all piping and components supplied by the manufacturer. In addition to these requirements, the applicant invoked supplemental quality assurance requirements on the following selected diesel generator and auxiliary system components:

1. Subsupplier Items:
   - Generators, generator controls, and static exciters
   - Starting air receivers and inlet valves
   - Jacket water, lube oil, and air cooler coolant heat exchangers
   - Lube oil strainers and filters
   - Governors
   - Inlet air filters
   - Turbochargers
   - Fuel oil day tank
   - Lube oil storage tank
   - Jacket water expansion tank.
2. Diesel Generator Supplier Manufactured Items:
   - Engine blocks
   - Subbase oil pan
   - Cylinder liners
   - Exhaust belts

- Pistons and piston inserts
- Crankshafts and connecting rods
- Vertical drive assembly
- Scavenging air blower gears, housings, impellers
- Engine driven lube oil, jacket water, and air cooler coolant pumps
- Jacket liners
- Skid-mounted piping and valves provided to ASME Section III, Class 3.

The additional quality assurance requirements invoked by the applicant include: (1) periodic documented subsupplier audits (including plant visits), (2) review and approval of subsupplier QA programs and manuals, (3) test and inspection audits, (4) calibration of test gauges before and after use, and (5) control of calibration records and acceptance devices.
With the imposition of the above design, manufacturing, and testing controls, the on-skid and off-skid piping and components have been made to be equivalent to Quality Group C.

e. The chilled water piping system for the control structure chilled water system is designed to ANSI B31.1 with supplementary material certification and design requirements to ensure that the quality is essentially equivalent to ASME Section III, Class 3. The technical differences between ANSI B31.1 and ASME Section III, Class 3 are few. The major differences were addressed by supplemental requirements and are listed in Table 3.2-5.

f. Instrument tubing downstream of the containment isolation valve of instrument lines connected to the RCPB is Quality Group D for instruments that are "passive": (i.e., do not actuate safety systems), rather than Quality Group B or C as discussed in paragraphs 1.e and 2.c of the regulatory guide. This is based on considerations given in Regulatory Guide 1.11 for instrument lines penetrating containment and having two restriction devices.

g. The piping between the two containment isolation valves, and the outboard isolation valves, on the drywell chilled water system are the equivalent of Quality Group B although they were originally designed and constructed as ANSI B31.1. Equivalency has been assured through the imposition of supplemental design, fabrication, and testing requirements:

- Piping material properties are essentially equivalent to the requirements of ASME Section III, Class 2
- Seismic and hydrodynamic accelerations were considered in design and analysis

- Design temperatures and pressures are greater than design values for the primary containment
- Documented quality control inspections were performed (by trained and qualified inspectors) on piping installation, welds, valves, and hangers
- The installation is of fully welded construction except for the outboard isolation valves, which are flanged
- A hydrostatic test was performed at a pressure 3 times greater than containment design pressure

These provisions meet or exceed the commitments made in PSAR Appendix A and PSAR Figure A.2.1.

h. The water chillers in the control room HVAC system are designed and fabricated in accordance with ASME Section VIII, Division I requirements, with the exception of the ASME Section III, Class 3 condenser. The condenser is connected to the ESW system. Supplementary material certification and design requirements have been applied to the ASME Section VIII portions of the chillers to ensure that their quality is essentially equivalent to ASME Section III, Class 3 at the time of purchase. The chillers were designed to seismic Category I requirements and fabricated under an approved quality assurance program. The major similarities and differences are listed in Table 3.2-6 along with the supplementary requirements.

i. The control structure chilled water pumps are designed and fabricated in accordance with the manufacturer's standards with supplementary requirements applied. The pumps are designed to seismic Category I requirements and fabricated under an approved quality assurance program used for ASME Section III, Class 3 pumps. The pressure-retaining materials used are approved for use in ASME Section III, Class 3 pumps and were supplied with CMTRs. The pumps were hydrotested at a pressure greater than that required by the code. The electrical components were environmentally qualified. Therefore, the quality of the pumps is essentially equivalent to ASME Section III, Class 3.

j. The seismic Category I control structure chilled water cooling coils in safety-related air handling units are fabricated from ASME Section III, Class 3 approved materials, with CMTRs, for the pressure-retaining parts. The coils are fabricated in accordance with the same quality assurance program using equivalent processes, are tested to the same procedures, and are of the same design as the ASME Section III, Class 3 ECCS unit cooler cooling coils, but are not N-stamped.

k. The seismic Category I SLCS tank was designed to API-650 standards and supplementary ASME Section III, Class C testing and examination requirements. The tank meets key later requirements of NC-3800, ASME Section III, Class 2, and is judged to be of equivalent quality.

l. All three of the Unit 1 and one of the Unit 2 SLCS pump discharge accumulator vessels were designed to ASME Section VIII, Division 1 requirements. These

weldless vessels, except for stamping, meet the code requirements of ASME Section III, Class C cited in Table 3.2-3.

m. The HPCI turbine exhaust line globe stop-check valves meet the material, design, fabrication, inspection, and testing requirements of the 1968 Draft ASME Code for Pumps and Valves indicated in Table 3.2-3 and the nondestructive inspection requirements of ASME Section III. They are, therefore, equivalent to Quality Group B. These valves were manufactured, however, to ANSI B31.1 (1967), ANSI B16.5 and MSS-SP-66 requirements.

n. The CRD system piping between the HCUs and the containment isolation boundary valves was originally designed and constructed according to ANSI B31.1. This piping has been reanalyzed and reevaluated as part of the modification which provided new isolation valves. This piping is now considered to be equivalent to ASME Section III, Class 2. The Upgrade Program included the following:

- The design requirements of the piping and the applicable stress calculations have been reviewed and found adequate to meet the requirements of ASME III, Class 2 and Seismic Category I.
- The installation rules and processes have been reviewed and found adequate to meet the intent of ASME III, Class 2.
- The inspection and testing procedures and acceptance criteria have been reviewed and found adequate to meet the requirements of ASME III, Class 2.
- The documentation required by the specifications and programs satisfies the intent of ASME III, Class 2 to provide written evidence of an acceptable level of quality. Engineering review of the documents has been found to be satisfactory.

o. The Unit 1 Corrosion Monitoring Piping and Components for the RHR Heat Exchanger IBE205 (RHR HX "B") connected to the RHRSW system was installed using ANSI B31.1 materials. This piping and components are considered to be equivalent to ASME Section III, Class 3. This consideration is based on the following:

- The design requirements of the piping and the applicable stress calculations have been performed in accordance with the requirements of ASME III, Class 3 and Seismic Category I.
- This equipment and piping was installed in accordance with the requirements of ASME III, Class 3.
- The inspection and testing procedures and acceptance criteria have been done in accordance with the requirements of ASME III, Class 3.
- The documentation required by the specifications and programs satisfies the intent of ASME III, Class 3 to provide written evidence of an acceptable level of quality. Engineering review of the documents has been found to be satisfactory.

3.2.3 QUALITY ASSURANCE

Those structures, components, and systems necessary to ensure:

a. the integrity of the RCPB,

b. the capability to shut down the reactor and maintain it in a safe shutdown condition,

c. the capability to prevent, or mitigate the consequences of, accidents that could result in potential offsite exposures in excess of the values of 10CFR50.67.

are classified as Q-listed, require conformance to the applicable quality assurance requirements of 10CFR50, Appendix B and are summarized in Table 3.2-1 under the heading, "Q-List". Table 3.2-1 (LGS Design Criteria Summary) is intended, in part, to provide identification of safety-related structures, systems, and components. The LGS Q-List is not part of the UFSAR; it is a controlled QA program document that serves to identify structures, systems and components requiring compliance with 10CFR50, Appendix B.

Quality assurance during construction is discussed in the document "Limerick Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction," referenced in Section 17.1. The Quality Assurance Program during the Operational Phase is described in Section 17.2.

The Q-listed boundaries for piping systems terminate at the outermost containment or system isolation valve. The piping downstream of this boundary is not required to ensure items a, b, or c above and is therefore not required to be Q-listed. However, in order that failure of the non Q-listed piping not affect the Q-listed piping or the isolation valves, the non Q-listed piping is designed to seismic Category I requirements up to and including the first point in the system that can be treated as an anchor to the plant structure except as indicated in part c of the discussion on Regulatory Guide 1.29 in Section 3.2.1. Stress analysis, support design, and design control for this non Q-listed piping, classified as seismic Category IIA, is carried out in the same manner as it is for Q-listed, seismic Category I items.

The pertinent quality assurance requirements of 10CFR50, Appendix B, are considered to be adequately met for the seismic Category IIA piping as indicated in Section 3.2.1, part d.

The design control and construction control practices that were used during the design and construction phase are also applied during the operations phase to ensure that the same stringent requirements are maintained for any changes to seismic Category IIA piping. In addition, seismic Category IIA piping and supports which are included in seismic Category I stress calculations will be included as part of the ISI program, to the extent that repairs and replacements to the IIA supports are performed in accordance with the ASME Section XI Repair and Replacement Program. The ISI program is included in the operations phase of the Nuclear Quality Assurance Plan.

Table 3.2-1

LGS DESIGN CRITERIA SUMMARY

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCATION[2]	QUALITY GROUP CLASSIFICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
I NSSS								
A. Reactor System	4,5							
1. Reactor vessel		GE	C	A	III-1	I	Y	(7)
2. Reactor vessel support skirt		GE	C	-	III-1	I	Y	(49)
3. Reactor vessel appurtenances, pressure-retaining portions		GE	C	A	III-1	I	Y	
4. CRD housing supports		GE	C	-	MF STD	I	Y	(50)
5. Reactor internals, ESFs		GE	C	-	MF STD	I	Y	
6. Reactor internals, other,		GE	C	-	MF STD	II	Y/N	(8)(62)
7. Control rods		GE	C	-	MF STD	I	Y	
8. Core support structure		GE	C	-	MF STD	I	Y	(72)
9. Power range detector hardware		GE	C	A	III-1	I	Y	
10. Fuel assembles		GE	C	-	MF STD	I	Y	
B. Nuclear Boiler System	4,5							(87)
1. Vessels, level instrumentation condensing chambers		GE	C	A	III-1	I	Y	(9)
2. Vessels, air accumulators (except in item 8 below)		P	C	C	III-3	I	Y	
3. Piping, relief valve discharge		P	C	C	III-3	I	Y	(48)
4. Piping and valves, RCPB		GE/P	C,R	A	III-1	I	Y	(7)(9)(48)
5. Mechanical components, instrumentation with safety function		GE	C	B	MF STD	I	Y	(11)
6. Electrical modules, with safety function		GE	C,R,CS	-	IEEE 323, 344	I	Y	(11),(12)
7. Quenchers and quencher supports		P	C	C	III-3/III-NF	I	Y	
8. Air accumulators on non-ADS SRVs		P	C	D	B31.1	IIA	N	
C. Control Rod Drive Hydraulic System	4.6.1							Class 1
1. CRDs		GE	C	-	III-1	I	Y	Appurtenance
2. HCU including scram accumulators		GE	R	-	MF STD	I	Y	(14)
3. Piping and valves, insert and withdraw lines, and scram discharge volume lines		P/GE	R,C	B	III-2	I	Y	(15)
4. Piping and valves, other		P	R	D	B31.1	I/II/IIA	Y/N	(67)
5. Pumps		GE	T	D	VIII-1	II	N	
6. Electrical modules, with safety function		GE	C,R,CS	-	IEEE 323, 344	I	Y	(11)(12)

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCA-TION[2]	QUALITY GROUP CLASSI-FICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
D. Recirculation System	5							
1. Piping		GE	C	A	III-1	I	Y	(7)(9)(48)
2. Valves		GE	C	A	III-1	I	Y	(7)(9)
3. Pumps		GE	C	A	III-1	I	Y	(7)
4. Motors, pump		GE	C	-	NEMA MG-1	I	N	
5. Electrical modules, with safety function		P/GE	C,R,CS	-	IEEE 323, 344	I	Y	(11)(12)
6. ASD Piping & Valves		P	T	D	ANSI B31.1	II	N	
7. ASD Heat Exchangers		P	T	D	VIII-1	II	N	
E. Reactor Water Cleanup System	5.4.8							(86)
1. Filter/demineralizer vessels		GE	R	C	III-3	II	N	
2. Heat exchangers		GE	R	C	III-C/ TEMA R	IIA	N	(71)
3. Piping and valves, RCPB		P	R	A	III-1	I	Y	(7)(9)(16)(48)
4. Piping and valves, connections to RCIC, and feedwater		P	R	B	III-2	I	Y	(48)(16)
4A. Piping and valves, connection to pump suction outboard containment isolation valve		P	R	B	III-2	IIA	N	(16)
5. Piping and valves, other		P	R	C	III-3	II/IIA	N	(16)
6. Pumps								
A pump		P	R	C	III-3	IIA	N	
B & C pumps		GE	R	C	III-3	II	N	
7. Mechanical components		P	R	-	MF STD	II	N	(11)
F. Traversing Incore Probe System	7.7.1							
1. Drive mechanism, chamber shield		GE	R	-	MF STD	II	N	
2. Indexing mechanism		GE	C	-	MF STD	II	N	
3. Tubing, TIP drive		GE	C,R	B	MF STD	IIA	N	
4. Valves and tubing, TIP drive isolation		GE	R	B	MF STD	I	Y	
5. Purge equipment		GE	R	-	MF STD	II	N	
6. Piping, TIP purge		P	C,R	D	B31.1	IIA	N	
7. Valves and piping, TIP purge isolation		P	C,R	B	III-2	I	Y	

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCATION[2]	QUALITY GROUP CLASSIFICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
II ENGINEERED SAFETY FEATURES								(61)
A. Reactor Core Isolation Cooling System	5.4.6							(86)
1. RCIC turbine		GE	R	-	MF STD	I	Y	(17)
2. RCIC barometric condenser		GE	R	D	B31.1	II	N	
3. Piping and valves, RCPB		P	C	A	III-1	I	Y	(7)(9)(48)
4. Piping within outermost containment isolation valves, discharges to suppression pool		P	C	D	B31.1	I	Y	(48)
5. Piping and valves, other safety-related		P	R	B	III-2	I	Y	(9)(48)
6. Portion of piping for RCIC turbine drains		P	R	D	B31.1	I	Y	(55)
7. Pumps, RCIC condensate and condenser vacuum		GE	R	D	MF STD	II	N	
8. Pump, RCIC		GE	R	B	III-2	I	Y	
9. Electrical modules, with safety function		GE	R,CS	-	IEEE 323, 344, 279	I	Y	(11)(12)
10. Out of service piping connected to RHR		P	R	-	B31.1	IIA	N	(84)
B. Residual Heat Removal System	5.4.7							(86)
1. Heat exchangers, primary (process) side		GE	R	B	III-2/TEMA C	I	Y	
2. Heat exchangers, secondary (service water) side		GE	R	C	VIII-1/ TEMA C	I	Y	
3. Piping, RCPB		P	C	A	III-1	I	Y	(7)(9)(48)
4. Piping, containment spray line (inside containment)		P	C	B	III-3	I	Y	(48)(58)
5. Piping and valves, other safety-related		P	R	B	III-2	I	Y	(48)
6. Valves, isolation		GE/P	C,R	A,B	III-1,2	I	Y	(7)
7. Pumps		GE	R	B	III-2	I	Y	
8. Motors, pump		GE	R	-	NEMA MG-1	I	Y	
9. Mechanical components		GE	R	B	MF STD	I	Y	(11)
10. Electrical modules, with safety function		P/GE	R,CS	-	IEEE 323, 344, 279	I	Y	(11)(12)
11. Containment spray nozzles		P	C	-	MF STD	I	Y	(59)
12. Out of service piping connected to RCIC		P	R	-	B31.1	IIA	N	(84)

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCATION[2]	QUALITY GROUP CLASSIFICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
C. Core Spray System	6.3							(86)
1. Piping and valves, RCPB		P/GE	C	A	III-1	I	Y	(7)(9)(48)
2. Piping and valves, other safety-related		P	R	B	III-2	I	Y	(9)(48)
3. Pumps		GE	R	B	III-2	I	Y	
4. Motors, pump		GE	R	-	NEMA MG-1	I	Y	
5. Electrical modules, with safety function	GE	R,CS	-	IEEE 323	I	Y 344, 279	(11)(12)	
D. High Pressure Coolant Injection System	6.3							(86)
1. HPCI turbine		GE	R	-	MF STD	I	Y	(17)
2. Piping and valves, RCPB		P	C	A	III-1	I	Y	(7)(9)(48)
3. Piping and valves, other safety-related		P/GE	R	B	III-2	I	Y	(9)(48)(70)
4. Piping, return test line to CST beyond second isolation valve		P	R,AB, RW,O	B	III-2	IIA/II	N	
5. Piping, remainder		P	AB, RW,O	D	B31.1	II	N	
6. Pumps, HPCI and booster		GE	R	B	III-2	I	Y	
7. Electrical modules, with safety function		GE	R,CS	-	IEEE 323, 344, 279	I	Y	(11)(12)
8. HPCI barometric condenser		GE	R	D	MF STD	II	N	
9. Pumps, HPCI condensate and condenser vacuum		GE	R	D	MF STD	II	N	
10. Piping within outermost containment isolation valves, discharges to suppression pool		P	C	D	B31.1	I	Y	(48)
11. Portion of piping for HPCI turbine drains		P	R	D	B31.1	I	Y	(55)
E. Standby Liquid Control System	9.3.5							(86)
1. SLCS tank		GE	R	B	API 650	I	Y	(68)
2. Test tank		P	R	D	API 650	IIA	N	
3. Piping and valves, RCPB		P	C	A	III-1	I	Y	(7)(48)
4. Piping and valves, other safety-related		P	R	B	III-2	I	Y	(9)(48)(69)
5. Piping, service and drain		P	R	D	B31.1	I/IIA	N	
6. Pumps		GE,P	R	B	III-2	I	Y	
7. Motors, pump		GE,P	R	-	NEMA MG-1	I	Y	
8. Electrical modules, with safety function		GE	C,R,CS	-	IEEE 323, 344, 279	I	Y	(11)(12)

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCA-TION[2]	QUALITY GROUP CLASSI-FICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
F. Section Deleted								
III FUEL STORAGE AND HANDLING; REACTOR VESSEL SERVICING								
A. Storage Equipment	9.1.1, 9.1.2							
1. Spent fuel storage racks (also used for new fuel)		P	R	-	MF STD	I	Y	
2. Channel storage racks		GE	R	-	MF STD	II	N	
3. In-vessel racks		GE	R	-	MF STD	I	Y	
4. Defective fuel storage containers		GE	R	-	MF STD	I	Y	
B. Fuel Pool Cooling and Cleanup System	9.1.3							
1. Heat exchangers		P	R	C	III-3/TEMA C	IIA	N	(18)
2. Skimmer surge tanks		P	R	C	AWWA D-100	I	Y	
3. Filter/demineralizer vessels		P	RW	C	III-3	II	N	(18)
4. Resin and precoat tanks		P	RW	D	MF STD	II	N	(18)
5. Piping and valves, cooling loop		P	R	C	B31.1	IIA	N	(8)(18)(19)(52)
6. Piping and valves, RHR intertie		P	R	B	III-2	I	Y	(48)
7. Piping and valves, ESW makeup		P	R,CS	C	III-3	I	Y	(48)
8. Piping and valves, other		P	R	D	B31.1	II	N	(18)
9. Pumps		P	R	C	III-3	IIA	N	(18)
C. Fuel Servicing Equipment	9.1.4							
1. Fuel preparation machine		GE	R	-	MF STD	I	Y	
2. New fuel inspection stand		GE	R	-	MF STD	II	N	
3. General purpose grapple		GE	R	-	MF STD	I	Y	
4. Jib cranes		GE	R	-	B30.11/ B30.16	I	Y	
D. Refueling Equipment	9.1.4							
1. Refueling platforms		GE	R	-	MF STD	I	Y	(20)
2. Fuel grapples		GE	R	-	MF STD	I	Y	(20)
3. Fuel grapples (Main Hoist)		PaR	R	-	MF STD	IIA	N	(20)
4. Refueling Mast		GE	R	-	MF STD	IIA	N	(20)

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCATION[2]	QUALITY GROUP CLASSIFICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
E. Under Reactor Vessel Service Equipment	9.1.4							
1. Equipment handling platform		GE	C	-	MF STD	II	N	
2. CRD handling equipment		GE	C	-	MF STD	II	N	
F. Reactor Vessel Servicing Equipment	9.1.4, 9.1.5							
1. Steam line plugs		GE, PE	R	-	MF STD	I	Y	
2. Dryer and separator sling		GE	R	-	MF STD	I	Y	
3. RPV head strong-back		GE	R	-	MF STD	I	Y	(85)
4. Deleted								
5. Control rod grapple		GE	R	-	MF STD	I	Y	
6. Reactor enclosure crane		P	R	-	CMAA 70	I	Y	(20)
7. Combined Grapple, CRB/FSP		P	R	-	MF STD	I	Y	
8. Service Pole Caddy		GE	R		MF STD	IIA	N	
9. Fuel Floor Auxiliary Platform		P	R	-	CMAA 70	IIA	N	
10. Reactor Cavity Work Platform Assembly		P	R	-	AISC	IIA	N	
IV RADIOACTIVE WASTE MANAGEMENT	11							
A. Liquid Waste Management Systems	11.2							(86)
1. Atmospheric tanks		P	RW	D	API 650	II	N	(18)
2. Filter vessels		P	RW	D	III-3	II	N	(18)
3. Demineralizer vessels		P	RW	D	III-3	II	N	(18)
4. Evaporator, complete system (abandoned)		P	RW	D	III-3	II	N	(18)
5. Laundry drain filter		P	RW	D	III-3	II	N	(18)
6. Piping and valves		P	RW	D	III-3/ B31.1	II	N	(18)
7. Pumps, centrifugal		P	RW	D	III-3	II	N	(18)
B. Gaseous Waste Management System	11.3							
1. Heat exchanger		P	RW	D	VIII-1	II	N	(18)
2. Pressure vessels		P	RW	D	VIII-1	II	N	(18)
3. Atmospheric tanks		P	RW	D	API 650	II	N	(18)
4. 0-15 psig tanks		P	RW	D	API 620	II	N	(18)
5. Recombiner		P	CS	D	III-3	II	N	(18)
6. Preheater		P	CS	D	III-3	II	N	(18)
7. Aftercondenser		P	CS	D	VIII-1	II	N	(18)
8. Refrigeration equipment, piping		P	RW	D	B9.1/B31.5	II	N	(18)
9. Refrigeration equipment, other		P	RW	D	VIII-1/ TEMA C	II	N	(18)
10. Piping and valves		P	RW	D	III-3/ B31.1	II	N	(18)
11. Pumps/compressors		P	RW	D	MF STD	II	N	(18)

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCA-TION[2]	QUALITY GROUP CLASSI-FICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
C. Solid Waste Management System	11.4							
1. Tanks, atmospheric		P	RW,T	D	API 650	II	N	(18)
2. Phase separators		P	RW	D	API 650	II	N	(18)
3. Waste containers		P	RW	-	MF STD	II	N	(18)
4. Centrifuges		P	RW	-	MF STD	II	N	(18)
5. Piping and valves		P	RW	D	III-3/ B31.1	II	N	(18)
6. Pumps		P	RW	D	III-3	II	N	(18)
V WATER SYSTEMS								
A. Service Water System	9.2.1							(87)
1. Heat exchangers		P	R,T	D	VIII-1/TEMA C	II	N	
2. Piping and valves		P	R,CW,T	D	B31.1	II/IIA	N	
3. Pumps		P	R,CW	D	MF STD	II	N	
B. Emergency Service Water System	9.2.2							(86)
1. Piping and valves		P	R,T, O,S	C/D	III-3/ B31.1	I/IIA	Y/N	(48)-seismic Category I only
2. Pumps		P	S	C	III-3	I	Y	
3. Motors, pump		P	S	-	IEEE 323, 344	I	Y	(12)
4. Electrical modules, with safety function		P	O,S, CS,R	-	IEEE 323, 344, 279	I	Y	(11)(12)
C. RHR Service Water System	9.2.3							(86)
1. Piping and valves		P	R,S,O	C/D	III-3/ B31.1	I/IIA/II	Y/N	(48)-seismic Category I only
2. Pumps		P	S	C	III-3	I	Y	
3. Motors, pump		P	S	-	IEEE 323, 344	I	Y	(12)
4. Electrical modules, with safety function		P	O,S, CS,R	-	IEEE 323, 344, 279	I	Y	(11)(12)

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCATION[2]	QUALITY GROUP CLASSIFICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
D. Reactor Enclosure Cooling Water System	9.2.8							(87)
1. Tanks, pressure		P	R	D	VIII-1	IIA	N	
2. Tanks, atmospheric		P	R	D	API 650	IIA	N	
3. Cooler, reactor enclosure equipment drain sump		P	R	D	B31.1	IIA	N	
4. Heat exchangers, other		P	R	D	VIII-1/ TEMA C	II	N	
5. Piping and valves forming part of containment boundary		P	R,C	B	III-2	I	Y	(48)
6. Piping to recirculation pumps (Unit 1)		P	R	C	III-3	IIA	N	
(Unit 2)		P	R	D	B31.1	IIA	N	
7. Piping and valves, other		P	R	D	B31.1	IIA	N	
8. Pumps		P	R	D	MF STD	IIA	N	
E. Turbine Enclosure Cooling Water System	9.2.9							
1. Heat exchangers		P	T	D	VIII-1/ TEMA C	II	N	
2. Tanks, atmospheric		P	T	D	API 650	II	N	
3. Piping and valves		P	T	D	B31.1	II	N	
4. Pumps		P	T	D	MF STD	II	N	
F. Circulating Water System	10.4.5							
1. Condenser		P	T	D	HEI	II	N	
2. Cooling tower		P	O	-	MF STD	II	N	
3. Piping		P	O,CW,T, SP, PP	D	B31.1	II	N	
4. Valves		P	CW,SP, PP,T	D	B31.1	II	N	
5. Pumps		P	CW,SP, PP	D	MF STD/ HYDI	II	N	

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCA-TION[2]	QUALITY GROUP CLASSI-FICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
VI DIESEL GENERATOR SYSTEM	9.5.4,9.5.5, 9.5.6, 9.5.7							(86)
1. Diesel generators		P	G	C	IEEE 387	I	Y	(47)
2. Fuel oil storage and transfer		P	G,O	C	III-3 B31.1, MF STDS	I	Y	(47)(22)
3. Lubrication system		P	G	C	III-3 IV, VIII B31.1, MF STD	I	Y	(47)(83)
4. Air start system		P	G	C	III-3 VIII B31.1 MF STD	I	Y	(47)(81)
5. Cooling water systems		P	G	C	III-3 B31.1 MF STD	I	Y	(47)(83)
6. Air intake and exhaust system		P	G	C	III-3 B31.1 MF STD	I	Y	(47)(44)(83)
7. Electrical modules, with safety function		P	G,CS	C	IEEE 323, 344, 279	I	Y	(11)(12)
VII HEATING, VENTILATING, AND AIR CONDITIONING SYSTEMS								
A. Control Structure								
1. Control Room HVAC System	9.4.1.1							(74)(86)
a. Water chillers (except condenser)		P	CS	C	VIII-1/ IEEE 323, 344	I	Y	(54)
b. Water chiller condensers		P	CS	C	III-3	I	Y	
c. Chilled water pumps		P	CS	C	MF STD IEEE 323, 344	I	Y	(56)
d. Chilled water piping and valves		P	CS	C	B31.1/IEEE 323	I	Y	(19)(48)(53)
e. Fans		P	CS	-	AMCA	I	Y	
f. Motors, fan		P	CS	-	NEMA MG-1/ IEEE 323, 344	I	Y	
g. Coils, cooling		P	CS	C	ARI	I	Y	(57)
h. Coils, electric heating		P	CS	-	NEC	IIA	N	
i. Duct-work and registers		P	CS	-	AISI/AWS	I	Y	(23)
j. Dampers, isolation and control		P	CS	-	AMCA	I	Y	(25)

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCA-TION[2]	QUALITY GROUP CLASSI-FICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
2. Auxiliary Equipment Room HVAC System	9.4.1.2							(74)(86)
a. Chilled water system		P	CS	C	See Item VII .A.1.a/d	I	Y	(19)(53)
b. Fans		P	CS	-	AMCA	I	Y	
c. Motors, fans		P	CS	-	NEMA MG-1/ IEEE 323, 344	I	Y	
d. Coils, cooling		P	CS	C	ARI	I	Y	(57)
e. Coils, electric heating		P	CS	-	NEC	IIA	N	
f. Duct-work and registers		P	CS	-	AISI/AWS	I	Y	(23)
g. Dampers, isolation and control		P	CS	-	AMCA	I	Y	(25)
3. Emergency Fresh Air Supply System	9.4.1.3							(74)(86)
a. Fans		P	CS	-	AMCA	I	Y	
b. Motors, fans		P	CS	-	NEMA MG-1/ IEEE 323, 344	I	Y	
c. Coils, electric heating		P	CS	-	NEC	I	Y	
d. Duct-work		P	CS	-	AISI/AWS	I	Y	(23)
e. Dampers, isolation and control		P	CS	-	AMCA	I	Y	(25)
f. Prefilters		P	CS	-	ANSI N509	I	Y	(24)
g. HEPA filters		P	CS	-	ANSI N509	I	Y	(24)
h. Charcoal adsorbers		P	CS	-	ANSI N509	I	Y	(24)
4. Cable Spreading/Auxiliary Switchgear Room HVAC	9.4.1.4							
a. Chilled water and steam heating systems		P	T	D	MF STD/ B31.1	II	N	
b. Fans		P	T	-	AMCA	II	N	
c. Coils, cooling		P	T	-	ARI	II	N	
d. Coils, steam heating		P	T	-	MF STD	II	N	
e. Duct-work and registers		P	CS	-	AISI/AWS	IIA	N	(23)
f. Dampers, fire		P	CS	-	UL	IIA	N	(25)

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCA-TION[2]	QUALITY GROUP CLASSI-FICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
5. SGTS Equipment Compartment HVAC System	9.4.1.5							(74)(86)
a. Chilled water system		P	CS	C/D	See Item VII .A.1.a/d	I	Y	(19)
b. Air supply system		P	CS	-	See Item VII .A.2.b/f	I	Y	
c. Unit coolers		P	CS	-	AMCA/ IEEE 323, 344	I	Y	
d. Unit heaters, electric		P	CS	-	NEC	IIA	N	
e. Exhaust duct-work and registers		P	CS	-	AISI/AWS	IIA/II	N	(23)
f. Exhaust fans		P	CS	-	AMCA	II	N	
g. Prefilters, exhaust		P	CS	-	ANSI N509	II	N	
h. HEPA filters, exhaust		P	CS	-	ANSI N509	II	N	
i. Charcoal adsorbers, exhaust		P	CS	-	ANSI N509	II	N	
6. Emergency Switchgear, Battery and Inverter Rooms HVAC System	9.4.1.6							(74)(86)
a. Chilled water system		P	CS	C/D	See Item VII .A.1.a/d	I	Y	(19)
b. Recirculation fans		P	CS	-	AMCA/IEEE 323, 344	I	Y	
c. Coils, cooling		P	CS	-	ARI	I	Y	
d. Recirculating duct-work and registers		P	CS	-	AISI/AWS	I	Y	
e. Dampers, isolation		P	CS	-	AMCA	I	Y	(25)
f. Battery rooms normal exhaust fans		P	CS	-	AMCA	II	N	
g. Battery rooms normal exhaust duct-work		P	CS	-	AISI/AWS	IIA/II	N	(23)
B. Reactor Enclosure and Refueling Area								(86)
1. Reactor Enclosure HVAC System (Normal Operation)	9.4.2.1							
a. Chilled water and steam heat equipment		P	R,AB	D	MF STD	II	N	
b. Piping		P	R	D	B31.1	IIA/II	N	
c. Valves, isolation, chilled water to primary containment		P	R	B	III-2	I	Y	
d. Valves, remainder		P	R	D	B31.1	II	N	
e. Fans		P	R	-	AMCA	II	N	
f. Coils, cooling		P	R	-	ARI	II	N	
g. Coils, heating		P	R	-	MF STD	II	N	

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCA-TION[2]	QUALITY GROUP CLASSI-FICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
h. Duct-work and registers		P	R	-	AISI/AWS	I/II	Y/N	(23)(26)
i. Dampers, isolation and control		P	R	-	AMCA	I/II	Y/N	(25)(26)
j. Prefilters, exhaust		P	R	-	ANSI N509	II	N	
k. HEPA Filters, exhaust		P	R	-	ANSI N509	II	N	
l. Charcoal adsorbers, exhaust		P	R	-	ANSI N509	II	N	
2. Refueling Floor HVAC System (Normal Operation)	9.4.2.1							
a. Chilled water and steam heating equipment		P	R	D	MF STD	II	N	
b. Piping and valves		P	R	D	B31.1	II	N	
c. Fans		P	R	-	AMCA	II	N	
d. Coils, cooling		P	R	-	ARI	II	N	
e. Coils, heating		P	R	-	MF STD	II	N	
f. Duct-work and registers		P	R	-	AISI/AWS	I/II	Y/N	(23)(26)
g. Dampers, isolation and control		P	R	-	AMCA	I/II	Y/N	(25)(26)
3. Reactor Enclosure Air Recirculation System	6.5.1							(74)
a. Fans		P	R	-	AMCA	I	Y	
b. Motors, fans		P	R	-	NEMA MG-1/ IEEE 323, 344	I	Y	
c. Duct-work		P	R	-	AISI/AWS	I	Y	(23)
d. Dampers, isolation and control		P	R	-	AMCA/IEEE 323, 344	I	Y	(25)
e. Prefilters		P	R	-	ANSI N509	I	Y	(24)
f. HEPA filters		P	R	-	ANSI N509	I	Y	(24)
g. Charcoal adsorbers		P	R	-	ANSI N509	I	Y	(24)
4. Standby Gas Treatment System	6.5.1							(74)
a. Exhaust fans		P	CS	-	AMCA	I	Y	
b. Motors		P	CS	-	NEMA MG-1/ IEEE 323, 344	I	Y	
c. Coils, electric heating		P	CS	-	NEC	I	Y	
d. Duct-work		P	R/CS	-	AISI/AWS	I	Y	(23)
e. Dampers, isolation and control		P	R/CS	-	AMCA	I	Y	(25)
f. HEPA filters		P	CS	-	ANSI N509	I	Y	(24)
g. Charcoal adsorbers		P	CS	-	ANSI N509	I	Y	(24)
h. Prefilters		P	R	-	ANSI N509	I	Y	(65)(24)

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCA-TION[2]	QUALITY GROUP CLASSI-FICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
5. RHR, HPCI, RCIC and CS Rooms HVAC	9.4.2.2							(74)
a. Piping and valves		P	R	C	III-3	I	Y	(48)
b. Fans, unit coolers		P	R	-	AMCA	I	Y	
c. Motors, fans		P	R	-	NEMA MG-1/ IEEE 323, 344	I	Y	
d. Coils, cooling		P	R	C	III-3	I	Y	
e. Duct-work and registers		P	R	-	AISI/AWS	I	Y	(23)
C. Primary Containment								
1. Drywell Cooling System	9.2.10, 9.4.5							(86)
a. Piping and valves		P	T,R	D	B31.1	II,IIA	N	
b. Motors, fan		P	C	-	NEMA MG-1/ IEEE 323, 334, 344	I	Y	
c. Fans (operate after LOCA mixing)		P	C	-	AMCA	I	Y	
d. Fans (other)		P	C	-	AMCA	IIA	N	
e. Coils, cooling		P	C	-	ARI	IIA	N	
f. Duct-work (operate after LOCA mixing)		P	C	-	AISI/AWS	I	Y	
g. Duct-work (other)		P	C	-	AISI/AWS	IIA	N	
h. Dampers (operate after LOCA mixing)		P	C	-	AMCA	I	Y	
i. Dampers (other)		P	C	-	AMCA	IIA	N	
j. Chilled water equipment		P	R	D	MF STD	II	N	
k. Chilled water isolation valves at primary containment		P	R	B	III-2	I	Y	
l. Piping associated with isolation valves at primary containment penetration		P	C	B	B31.1	I	Y	(21)(48)
2. Purge System								
a. Piping and valves		P	R	B	III-2	I	Y	(48)
b. Piping and valves, beyond outermost containment isolation valves (smaller than 18 inch nominal diameter)		P	R	D	B31.1	IIA	N	

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCATION[2]	QUALITY GROUP CLASSIFICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
3. Hydrogen recombiner								(86)
a. Piping and valves		P	R	B	III-2	I	Y	(48)(27)
b. Reaction chamber		P	R	B	III-2	I	Y	
c. Blower		P	R	B	III-2	I	Y	
4. Vacuum relief system								
a. Valves		P	C	B	III-2	I	Y	
b. Tees supporting valves		P	C	B	ASTM/B31.1	I	Y	(66)
D. Radwaste and Offgas Enclosure	9.4.3							
1. Fans		P	RW	-	AMCA	II	N	
2. Coils, cooling		P	RW	-	ARI	II	N	
3. Heating coil, steam		P	RW	-	MF STD	II	N	
4. Duct-work		P	RW,T,CS	-	SMACNA	II	N	
5. Dampers		P	RW	-	AMCA	II	N	
6. Prefilters, exhaust		P	RW	-	ANSI N509	II	N	
7. HEPA filters, exhaust		P	RW	-	ANSI N509	II	N	
8. Chilled water, direct expansion and steam equipment		P	R,RW AB	D	MF STD	II	N	
9. Charcoal adsorbers, exhaust		P	RW	-	ANSI N509	II	N	
10. Piping, chilled water		P	RW	D	B31.1	II	N	
E. Turbine Enclosure	9.4.4							(86)
1. Piping, chilled water		P	T	D	B31.1	II	N	
2. Fans		P	T	-	AMCA	II	N	
3. Coils, cooling		P	T	-	ARI	II	N	
4. Coils, heating, steam		P	T	-	MF STD	II	N	
5. Duct-work		P	T,CS	-	SMACNA	II	N	
6. Dampers		P	T	-	AMCA	II	N	
7. Prefilters, exhaust		P	T	-	ANSI N509	II	N	
8. HEPA filters, exhaust		P	T	-	ANSI N509	II	N	
9. Charcoal adsorbers, exhaust		P	T	-	ANSI N509	II	N	
10. Chilled water and steam heat equipment		P	R,AB	D	MF STD	II	N	

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCA-TION[2]	QUALITY GROUP CLASSI-FICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
F. Diesel Generator Enclosure	9.4.6							(86)
1. Motors, fan		P	G	-	IEEE 323, 344/ NEMA, MG-1	I	Y	
2. Fans		P	G	-	AMCA	I	Y	
3. Duct-work		P	G	-	MF STD	I	Y	(23)
4. Dampers		P	G	-	AMCA/IEEE 323	I	Y	(25)
5. Unit heaters, steam		P	G	-	MF STD	IIA	N	
G. Spray Pond Pump Structure	9.4.7							(86)
1. Motors, fan		P	S	-	IEEE 323, 344/NEMA MG-1	I	Y	
2. Fans		P	S	-	AMCA	I	Y	
3. Dampers		P	S	-	AMCA	I	Y	(25)
4. Coils, electric heating		P	S	-	NEC	IIA	N	
H. Miscellaneous Pump Structures Schuylkill, Perkiomen, Circulating Water)	9.4.9							
1. Fans		P	SP,PP, CW	-	AMCA	II	N	
2. Dampers		P	SP,PP, CW	-	AMCA	II	N	
I. Miscellaneous Enclosures (Auxiliary Boiler, Fuel Oil Transfer, Water Treatment, Sewage Treatment)	9.4.9							
1. Fans		P	AB,F, W,ST	-	AMCA	II	N	
2. Dampers		P	AB,F, W,ST	-	AMCA	II	N	
J. Administration Building	9.4.9							
1. Fans		P	A	-	AMCA	II	N	
2. Coils, cooling		P	A	-	ARI	II	N	
3. Coils, heating		P	A	-	MF STD	II	N	
4. Duct-work		P	A	-	SMACNA	II	N	
5. Dampers		P	A	-	AMCA	II	N	
6. Chilled hot water, and direct expansion systems		P	A	-	MF STD	II	N	

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCATION[2]	QUALITY GROUP CLASSIFICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
K. Hot Maintenance Shop	9.4.8							
1. Direct expansion and hot water equipment		P	HS,A	-	MF STD	II	N	
2. Fans		P	HS	-	AMCA	II	N	
3. Coils, cool and heat		P	HS	-	ARI/MF STD	II	N	
4. Duct-work		P	HS	-	SMACNA	II	N	
5. Dampers		P	HS	-	AMCA	II	N	
6. Dust collectors		P	HS	-	MF STD	II	N	
7. HEPA Filters, exhaust		P	HS	-	ANSI N509	II	N	
8. Prefilters, exhaust		P	HS	-	ANSI N509	II	N	
VIII MAIN STEAM AND POWER CONVERSION SYSTEM								
A. Condensate Storage and Transfer System	9.2.7							
1. Tanks		P	O	D	AWWA D100	II	N	
2. Piping and valves		P	T,O	D	B31.1	II	N	
3. Pumps		P	T	D	HYD I/MF STD	II	N	
4. Dikes		P	O	-	-	IIA	N	
B. Main Steam System	10							(86)
1. Piping, main steam to turbine stop valves and branch line		P	R,T	B	III-2	I	Y	(8)(19)(28)(48)
2. Piping, main steam from, and including, the turbine stop valve to turbine casing and branch line up to, and including, first valve		P	T	D	B31.1	II	N	(29)(30)(31)
3. Piping and valves, other, steam		P	T	D	B31.1	II	N	
C. Main Condenser Evacuation System	10.4.2							
1. Condensers		P	T	D	VIII-1	II	N	
2. Air ejectors		P	T	D	B31.1	II	N	
3. Pumps, mechanical vacuum, and accessories		P	T	D	MF STD	II	N	
4. Piping and valves		P	T,RW	D	B31.1	II	N	
D. Turbine Gland Sealing System	10.4.3							
1. Steam seal evaporator		P	T	D	VIII-1	II	N	
2. Gland steam condenser		P	T	D	VIII-1	II	N	
3. Piping and valves		P	T	D	B31.1	II	N	

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCATION[2]	QUALITY GROUP CLASSIFICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
E. Condensate Cleanup System	10.4.6							
1. Pressure vessels (filter and deep bed/demineralizers)		P	T	D	VIII-1	II	N	
2. Piping and valves		P	T	D	B31.1	II	N	
3. Atmospheric tanks (spent resin)		P	T	D	API 650	II	N	(18)
4. Piping and valves (spent resin)		P	T	D	B31.1	II	N	(18)
F. Condensate and Feedwater System	10.4.7							
1. Heat exchangers		P	T	D	VIII-1	II	N	
2. Piping and valves, reactor feedwater, RPV to outermost isolation valve		P	C,R	A	III-1	I	Y	(32)(48)
3. Piping and valves, reactor feedwater, other		P	R,T	B,D	III-2/ B31.1	I,II	Y,N	(48)-seismic Category I only
4. Piping, steam, to feedwater pump-turbine		P	T	D	B31.1	II	N	
5. Piping, crossover (low pressure)		P	T	D	B31.1	II	N	
6. Piping, bypass (high pressure) downstream of first isolation valve		P	T	B	III-2	I	Y	(48)
7. Piping and valves, condensate		P	T	D	B31.1	II	N	
8. Pumps, feedwater and condensate		P	T	D	B31.1/ HYD I	II	N	
G. Auxiliary Steam System	10.4.10							
1. Auxiliary boilers		P	AB	-	VIII-1	II	N	
2. Piping and valves		P	AB,T	-	B31.1	II	N	
H. Main Chlorination System	9.2.4							
1. Piping and valves		P	CW	-	B31.1	II	N	
I. Lube Oil System								
1. Lube oil storage tank		P	T	-	API 650	II	N	
2. Reservoirs		P	T	-	MF STD	II	N	
3. Centrifuges		P	T	-	MF STD	II	N	
4. Heat exchangers		P	T	-	VIII-1/ TEMA C	II	N	
5. Piping and valves		P	T	-	B31.1	II	N	
6. Pumps		P	T	-	B31.1/ HYD I	II	N	
IX INSTRUMENTATION AND CONTROL SYSTEMS								(10)
A. Reactor Protection (Trip) System	7.2	GE	C,R	-	IEEE 279	I	Y	(45)(87)

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCATION[2]	QUALITY GROUP CLASSIFICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
B. Engineered Safety Features Systems	7.3							
1. ECCS: HPCI, ADS, CS, LPCI (RHR)		GE	C,R	-	IEEE 279	I	Y	(45)(87)
2. Primary containment and reactor vessel isolation control system		GE	C,R	-	IEEE 279	I	Y	(45)
3. Class 1E power system		P	G	-	IEEE 279	I	Y	(45)
4. RHR containment spray mode		GE	C,R	-	IEEE 279	I	Y	(45)(87)
5. Service water systems: RHRSW, ESW		P	C,R	-	IEEE 279	I	Y	(45)(87)
6. Containment atmospheric control systems:								(86)
CGCS		P	C	-	IEEE 279	I	Y	(45)
Combustible Gas monitoring system		P	C	-	IEEE 279	I	Y	(45)(27)
Primary containment vacuum relief system		P	C	-	MF STD	II	N	
7. Deleted								
8. RHR suppression pool cooling system		GE	C,R	-	IEEE 279	I	Y	(45)(87)
9. RERS		P	R	-	IEEE 279	I	Y	(45)(87)
10. Reactor enclosure isolation system		P	R	-	IEEE 279	I	Y	(45)(87)
11. Habitability and control room isolation		P	CS	-	IEEE 279	I	Y	(45)
12. SGTS filter room and access area unit coolers		P	CS	-	IEEE 279	I	Y	(45)
13. Diesel generator enclosure ventilation system		P	G	-	IEEE 279	I	Y	(45)(87)
14. Spray pond pump structure ventilation system		P	S	-	IEEE 279	I	Y	(45)
15. ESF switchgear and battery rooms cooling system		P	CS	-	IEEE 279	I	Y	(45)
16. ECCS pump compartment unit coolers		P	R	-	IEEE 279	I	Y	(45)
17. Drywell unit coolers		P	R	-	IEEE 279	I	Y	(45)(86)
18. CECWS		P	CS	-	IEEE 279	I	Y	(45)
19. Auxiliary equipment room ventilation system		P	CS	-	IEEE 279	I	Y	(45)
20. SGTS		P	CS	-	IEEE 279	I	Y	(45)
C. Safety-Related Display Instrumentation	7.5	P/GE	CS	-	IEEE 279	I	Y	(45)(27)
D. Systems Required for Safe Shutdown	7.4							
1. RCIC system		GE	C,R	-	IEEE 279	I	Y	(45)
2. SLCS		GE	C,R	-	MF STD	I	Y	(45)
3. Reactor shutdown cooling mode of the RHR System		GE	R	-	IEEE 279	I	Y	(45)(87)
4. Remote shutdown system		GE	CS	-	MF STD	I	Y	(45)(87)

Table 3.2-1 (cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCATION[2]	QUALITY GROUP CLASSIFICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
E. All Other Instrumentation Systems Required for Safety	7.6							
1. Process radiation monitoring system		P/GE	C,R,CS	-	MF STD	I	Y	(45)(86)
2. NMS-IRM, APRM, LPRM		GE	R	-	IEEE 279	I	Y	(45)
3. SRV position indication		P	C,CS	-	-	IIA	N	(51)(27)
4. Leak detection systems Main steam line leak detection RCIC system leak detection RWCU system leak detection HPCI system leak detection		P	C,R	-	-	I	Y	(45)(86)
5. CIGS-ADS control		P	R	-	IEEE 279	I	Y	(45)
6. High pressure/low pressure systems interlocks		GE	R	-	IEEE 279	I	Y	(45)
7. Safeguard piping fill system		P	R	-	IEEE 279	I	Y	(45)
F. Control Systems Not Required for Safety	7.7							
1. RPV instrumentation		GE	C	-	MF STD	I	Y	(45)
2. RMCS		GE	C,R	-	MF STD	II	N	
3. Recirculation flow control system		GE	C,R,T	-	MF STD	I,IIA,II	Y/N	-
3A. Recirc Motor Adjustable Speed Drive Set		P	T	-	NEMA MG-1	II	N	
4. Feedwater control system		P/GE/W	T	-	MF STD	I/II	Y/N	(45)
5. Pressure regulator and turbine generator system		P	T	-	MF STD	II	N	
6. NMS-TIP, RBM, SRM		GE	R	-	MF STD	II	N	
7. RWCU system		GE	R	-	MF STD	I/IIA	Y/N	(45)
8. FPCC		P	R,RW	-	MF STD	II	N	(45)
9. Radwaste system - Gaseous radwaste system Liquid radwaste system Solid radwaste system		P	RW	-	MF STD	II/IIA	N	
10. ARMS		P/GE	C,R,T, CS,RW,HS	-	MF STD	II	N	(87)
11. Plant Monitoring System (PMS)		RTP	CS	-	MF STD	II	N	
12. CIGS		GE	C,R	-	MF STD	I/II	Y/N	(45)
13. Refueling interlocks		GE	C	-	MF STD	I	Y	
14. Leak detection system		P	C,R	-	MF STD	II	N	
15. Fire protection and suppression system		GE	CS	-	MF STD	II	N	
16. Nonsafety-related equipment area cooling ventilation systems		P	R,T,RW	-	MF STD	II	N	
17. Process radiation monitoring systems		P/GE	R,T,RW, HS	-	MF STD	II	N	(86)

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCATION[2]	QUALITY GROUP CLASSIFICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
X ELECTRIC SYSTEMS								
A. Engineered Safety Features AC Equipment	8.3							
1. 4 kV switchgear, including safeguard bus feeder breakers, protective relays, control panels		P	G	- 323, 344	IEEE 308,	I	Y	(43)(45)
2. 440 V load centers, including 4160/440 V transformers, protective relays, control panels		P	R	-	IEEE 308, 323, 344	I	Y	(43)(45)
3. 440 V motor control centers		P	R	-	IEEE 308, 323, 344	I	Y	(43)(45)
B. Engineered Safety Features DC Equipment	8.3							
1. 125 V and 125/250 V station batteries and racks, battery chargers		P	CS	-	IEEE 308, 323, 344	I	Y	(45)
2. MCC and distribution panels, including protective relays		P	CS,R, G	-	IEEE 308, 323, 344	I	Y	(43)(45)
C. 120 V Vital AC System Equipment	8.3							
1. 120 V distribution panels		P	CS	-	IEEE 308,323,344	I	Y	(43)(45)
D. Electric Cables for Safety-related Equipment	8.3							
1. 5 kV power cables		P	ALL	-	IEEE 279 308, 323, 383	-	Y	(12)(45)
2. 600 V power cables, including all dc power cables		P	ALL	-	IEEE 279, 308, 323, 383	-	Y	(12)(45)
3. Control and instrumentation cables		P/GE	ALL	-	IEEE 279, 308, 323, 383	-	Y	(12)(45)
E. Miscellaneous Electrical	8.3, 9.5							
1. Primary containment enclosure electrical penetration assemblies		P	C	-	IEEE 317, 344, 383/III-MC	I	Y	(45)
2. Raceway systems, safety-related		P	ALL	-	IEEE 344	I	Y	(41)(45)
3. Emergency lighting batteries		P	ALL	-	MF STD	II	N	
4. Emergency lighting systems		P	ALL	-	MF STD	II	N	(63)
5. Emergency communications systems		P	ALL	-	MF STD	II	N	
6. Motors, nonsafety-related		P	ALL	-	NEMA MG-I	II	N	
7. Inverters		P	ALL	-	MF STD	II	N	(42)
8. Valve operators		-	-	-	-	-	-	(40)
9. Raceway systems, nonsafety-related		P	ALL	-	NEC	II/IIA	N	

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCA-TION[2]	QUALITY GROUP CLASSI-FICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
F. Offsite Power Systems	8.2	P	-	-	MF STD	II	N	
XI AUXILIARY SYSTEMS								
A. Safeguard Piping Fill System, Including Feedwater Fill System	6.3							
1. Piping and valves, from and including isolation valves, to feedwater lines		P	R	A	III-1	I	Y	(48)
2. Piping and valves, other		P	R	B	III-2	I	Y	(48)
3. Pumps		P	R	B	III-2	I	Y	
B. Suppression Pool Cleanup System	P&ID M-52							
1. Piping and valves, to second isolation valve		P	R	B	III-2	I	Y	(48)
2. Piping and valves, after second isolation valve		P	R	D	B31.1	IIA	N	
3. Pumps		P	R	D	MF STD	IIA	N	
C. Demineralized Water Makeup System	9.2.5							
1. Tanks		P	W	D	API 650/ AWWA D100	II	N	
2. Piping and valves		P	ALL	D	B31.1	II	N	
3. Pumps		P	W	D	B31.1/HYD I	II	N	
4. Filter vessels		P	W	D	VIII-1	II	N	
5. Demineralizer vessels		P	W	D	VIII-1	II	N	
D. Drywell Chilled Water System	9.2.10							(86)
1. Chillers		P	T	D	VIII-1	II	N	
2. Cooling coils		P	T	-	ARI	II,IIA	N	
3. Piping and valves, other		P	T,R	D	B31.1	II,IIA	N	
4. Valves, isolation to primary containment		P	R	B	III-2	I	Y	
5. Pumps		P	T	D	HYD I/B31.1	II	N	
6. Piping associated with isolation valves at primary containment penetration		P	C	B	B31.1	I	Y	(21)(48)

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCATION[2]	QUALITY GROUP CLASSIFICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
E. Control Structure Chilled Water System	9.2.10							(86)
1. Piping		P	CS	C	B31.1	I	Y	(48)(53)
2. Valves		P	CS	C	B31.1	I	Y	(53)
3. Pumps		P	CS	C	III-3	I	Y	(56)
4. Motors, pump		P	CS	-	IEEE 323, 344	I	Y	
5. Chillers (except condensers)		P	CS	C	VIII-1/IEEE 323	I	Y	(54)
6. Chiller condensers		P	CS	C	III-3	I	Y	
F. Compressed Air and Instrument Gas System	9.3.1							(86)
1. Compressors		P	T	D	MF STD	II	N	
2. Instrument gas bottles (ADS – Long Term)		P	T	-	MF STD	I	Y	(13)
3. Air and gas receivers		P	T	D	VIII-1	II	N	
4. Piping and valves forming part of containment boundary		P	C,R	B	III-2	I	Y	(48)
5. Piping and valves, safety-related (except as in item 7 below)		P	C,R, CS,G	C	III-3	I	Y	(48)
6. Piping and valves, other		P	ALL	D	B31.1	II/IIA	N	(82)
7. Piping and components to Unit I & 2 inflatable seals 1,2,3,4,7 & 10		P	R	D	B31.1	I	Y	(80)
G. Sampling System	9.3.2							
1. Sample coolers		P	C,R, T,RW	D	MF STD	II	N	(73)
2. Piping and valves on III-1 system		P	C	A	III-1	I	Y	(9)(48)
3. Piping and valves on III-2 system (includes containment penetration isolation)		P	R	B	III-2	I	Y	(9)(48)
4. Piping and valves on III-3 system		P	R	B	III-2	I	Y	(9)(48)
5. Piping and valves, other systems		P	R,T,RW	D	B31.1	II	N	(9)
H. Equipment and Floor Drains	9.3.3							(87)
1. Piping, radioactive		P	C,R, T,RW	D	B31.1	II/IIA	N	
2. Piping, nonradioactive		P	ALL	D	B31.1	II	N	
3. Piping and valves primary containment isolation boundary		P	C	B	III-2	I	Y	(48)
I. Fire Protection System	9.5.1							
1. Pumps, piping and water system components		P	ALL	-	NFPA/ANI	II/IIA	N	
2. Gas system components (CO_2 and Halon 1301)		P	CS	-	NFPA/ANI	II/IIA	N	
3. Fire and smoke detection and alarm system		P	ALL	-	NFPA/ANI	II/IIA	N	

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCA-TION[2]	QUALITY GROUP CLASSI-FICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
J. Nitrogen System and Generator External Hydrogen System								
1. Vessels (nitrogen only)		P	H,O	D	VIII-1	II	N	
2. Piping		P	H,T,R, O,RW	D	B31.1	II	N	
3. Valves		P R,O	H,T,	D	B31.1	II	N	
K. Postaccident Sampling System	11.5.5							(79)(27)
1. Sample coolers		GE	R	D	VIII-1	IIA	N	
2. Sample line root valves		P	R	B	III-2	I	Y	(46)
3. System piping		P,GE	R,CS	D	B31.1	IIA/II	N	
4. System tubing and other valves		P,GE	R,CS	-	MF STD	IIA/II	N	
L. Zinc Injection System								
1. Tanks		GE	T	D	B31.1	II	N	
2. Pipes		P,GE	T	D	B31.1	II	N	
3. Valves		P,GE	T	D	B31.1	II	N	
XII ENCLOSURES								(33)
A. Reactor Enclosure and Refueling Area	3.8.4	P	R	B	ACI/AISC	I	Y	(75)
1. Roof scuppers and parapet openings		P	R	-	UBC	II	N	
2. Pressure resisting doors		P	R	-	MF STD	I	Y	
3. Missile barriers for safety-related equipment		P	R	-	ACI/AISC	I	Y	
4. Spent fuel pool liner		P	R	-	AISC	I	Y	
5. Safety-related masonry walls		P	R	-	ACI/UBC	I	Y	(75)
6. Fabricated supports for safety-related systems and components	3.7.3/ 3.10.3	P	R	-	AISC/AISI	I	Y	
7. Inflatable Seals (Unit 1 & 2, seals 1,2,3,4,7 & 10 only)	9.3.1	P	R	-	MF STD	I	Y	
B. Primary Containment	3.8.1	P	C	B	ACI/AISC/III	I	Y	(64)
1. Access hatches/locks/doors		P	C	B	III-2	I	Y	(64)
2. Liner plate ?¼"		P	C	B	VIII-1	I	Y	(64)
3. Penetration assemblies and liner plate >¼"		P	C	B	III-2	I	Y	(39)(64)(27)
4. Vacuum relief valves		P	C	B	III-2	I	Y	(66)
5. Downcomers		P	C	B	III-2	I	Y	(64)(66)
6. Downcomer bracing		P	C	-	AISC	I	Y	
7. Biological (primary) shield		P	C	-	ACI/AISC	I	Y	
8. Fabricated supports for safety-related systems and components	3.7.3/ 3.10.3	P	C	-	AISC/AISI	I	Y	

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]	UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCATION[2]	QUALITY GROUP CLASSIFICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
C. Turbine Enclosure	3.8.4.1	P	T	-	ACI/AISC	II	N	
D. Control Structure	3.8.4.1	P	CS	-	ACI/AISC	I	Y	(75)
1. Roof scuppers and parapet openings		P	CS	-	UBC	II	N	
2. Pressure resisting doors		P	CS	-	MF STD	I	Y	
3. Missile barriers for safety-related equipment		P	CS	-	ACI/AISC	I	Y	
4. Safety-related masonry walls		P	CS	-	ACI/UBC	I	Y	
5. Fabricated supports for safety-related systems and components	3.7.3/ 3.10.3	P	CS	-	AISC/AISI	I	Y	(75)
E. Radwaste and Offgas Enclosure	3.8.4.1	P	RW	-	ACI/AISC	IIA	N	(18)
F. Diesel Generator Enclosure	3.8.4.1	P	G	-	ACI/AISC	I	Y	
1. Roof scuppers and parapet openings		P	G	-	UBC	II	N	
2. Missile barriers for safety-related equipment		P	G	-	ACI/AISC	I	Y	
3. Safety-related masonry walls		P	G	-	ACI/UBC	I	Y	
4. Fabricated supports for safety-related systems and components	3.7.3/ 3.10.3	P	G	-	AISC/AISI	I	Y	
G. Spray Pond Pump Structure	3.8.4.1	P	S	-	ACI/AISC	I	Y	
1. Roof scuppers and parapet openings		P	S	-	UBC	II	N	
2. Fabricated supports for safety-related systems and components	3.7.3/ 3.10.3	P	S	-	AISC/AISI	I	Y	
H. Schuylkill Pump Structure		P	SP	-	ACI/AISC	II	N	
I. Perkiomen Pump Structure		P	PP	-	ACI/AISC	II	N	
J. Circulating Water Pump Structure		P	CW	-	ACI/AISC	II	N	
K. Auxiliary Boiler Enclosure		P	AB	-	ACI/AISC	II	N	
L. Fuel Oil Pump Structure		P	F	-	ACI/AISC	II	N	
M. Water Treatment Enclosure		P	W	-	ACI/AISC	II	N	
N. Sewage Treatment Enclosure		P	ST	-	ACI/AISC	II	N	
O. Administration Building		P	A	-	ACI/AISC	II	N	
P. 5-Line Outage Support Facility		P	T	-	ACI/AISC	II	N	
Q. Chemistry Lab Expanion		p	CL	-	UBC B OCA/UBS	II	N	

Table 3.2-1 (Cont'd)

SYSTEM/COMPONENT[40]		UFSAR SECTION	SOURCE OF SUPPLY[1]	LOCA-TION[2]	QUALITY GROUP CLASSI-FICATION[3]	PRINCIPAL CODES AND STANDARDS[4]	SEISMIC CATEGORY[5]	Q-LIST[6]	COMMENTS
XIII	SPRAY POND								
A.	Pond	3.8	P	S	-	-	I	Y	(34)(35)
B.	Support Columns	3.8	P	S	-	ACI/AISC	I	Y	(36)
C.	Overflow Structure	3.8	P	S	-	ACI/AISC	I	Y	
D.	Spray-Network Piping	9.2	P	S	C	III-3	I	Y	(38)(60)
E.	Soil-Bentonite Lining and Soil Cover	2.5	P	S	-	-	-	N	
F.	Unreinforced Concrete (excluding foundations) Concrete Backfill, Exploration, Trench Backfill, and Soil Cover		P	S	-	-	-	N	
G.	Riprap and Riprap Bedding	2.5	P	S	-	-	-	N	
H.	Shotcrete 2.5		P	S	-	-	-	N	
I.	Rock Bolts	2.5	P	S	-	-	-	N	
J.	Roadwork-		P	S	-	-	-	N	
K.	Emergency Spillway	3.8	P	S	-	-	II	Y	(37)

Table 3.2-1 (Cont'd)

NOTES ON
LGS DESIGN CRITERIA SUMMARY

(1) GE - General Electric

W - Westinghouse Nuclear Automation

P - PECO Energy

PE - Preferred Engineering

(2) Location

R - Reactor Enclosure

C - Containment

T - Turbine Enclosure

CS - Control Structure

RW - Radwaste and Offgas Enclosure

G - Diesel Generator Enclosure

AB - Auxiliary Boiler Enclosure

F - Fuel Oil Pump Structure

W - Water Treatment Enclosure

ST - Sewage Treatment Enclosure

A - Administration Building

S - Spray Pond Pump Structure

SP - Schuylkill Pump Structure

PP - Perkiomen Pump Structure

CW - Circulating Water Pump Structure

O - Outdoors, Onsite

HS - Hot Maintenance Shop

CL - Chemistry Laboratory Expansion

(3) A,B,C,D - Quality group classification as defined in Regulatory Guide 1.26, see also Tables 3.2-2 and 3.2-3.
- = Not applicable to quality group classification

Table 3.2-1 (Cont'd)

(4) Notations for principal construction codes:

AA	-	Aluminum Association
ACI	-	American Concrete Institute
AFBMA	-	Anti Friction Bearing Manufacturers Association
AISC	-	American Institute of Steel Construction
AISI	-	American Iron and Steel Institute
AMCA	-	Air Moving and Conditioning Association
AMCA 210	-	"Test Codes for Air Moving Devices"
AMCA 211A	-	"AMCA Certified Ratings Program for Air Performance"
ANI	-	American Nuclear Institute
ANSI	-	American National Standards Institute
ANSI B9.1	-	"Safety Code for Mechanical Refrigeration"
ANSI B30.11	-	"Monorail Systems and Underhung Cranes"
ANSI B30.16	-	"Overhead Hoists"
ANSI B31.1	-	"Code for Pressure Piping"
ANSI B31.5	-	"Refrigeration Piping"
ANSI N509	-	"Nuclear Power Plant Air Cleaning Units and Components" (1976, 1980)
API	-	American Petroleum Institute
API 620	-	"Recommended Rules for Design and Construction of Large, Welded, Low Pressure Storage Tanks"
API 650	-	"Welded Steel Tanks for Oil Storage"
ARI	-	Air Conditioning and Refrigeration Institute
AWS	-	American Welding Society
BOCA	-	National Building Code

Table 3.2-1 (Cont'd)

CMAA 70	-	Crane Manufacturers Association of America, Specification Number 70, "Electric Overhead Traveling Cranes"
HEI	-	Heat Exchange Institute
HYD I	-	Hydraulic Institute
IEEE	-	Institute of Electrical and Electronics Engineers
IEEE 279	-	"Criteria for Protection Systems for Nuclear Power Generating Stations" (1971)
IEEE 308	-	"Standard Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations" (1971)
IEEE 317	-	"Standard for Electrical Penetration Assemblies in Containment Structures for Nuclear Fueled Power Generating Stations" (April 1971)
IEEE 323	-	"General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations" (1971, 1974)
IEEE 334	-	"Trial Use Guide for Type Test of Continuous-Duty Class 1 Motors Installed Inside the Containment of Nuclear Power Generating Stations (ANSI N41.9)" (1971)
IEEE 344	-	"Guide for Seismic Qualification of Class 1E Electric Equipment for Nuclear Power Generating Stations" (1971, 1975)
IEEE 383	-	"Type Test of Class 1E Electrical Cables, Field Splices, and Connections for Nuclear Power Generating Stations" (1974)
IEEE 387	-	"Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations" (1972)
MF STD	-	Manufacturer's Standard
NEC	-	National Electric Code
NEMA MG-1	-	National Electrical Manufacturers' Association, "Motors and Generators" (1971)
NFPA	-	National Fire Protection Association
RDT-M-16-1T-		Reactor Research and Development Gas Phase Adsorbents for Trapping Radioactive Iodine and Iodine Compounds
SMACNA	-	Sheet Metal and Air Conditioning Contractors National Association Inc.
TEMA C	-	Tubular Exchanger Manufacturers Association, Class C

Table 3.2-1 (Cont'd)

	UBC	-	Uniform Building Code
	UL	-	Underwriters Laboratories Standard
	III	-	"1, 2, 3, MC" - ASME B&PV Code, Section III, Class 1,2,3, MC (Certain NSSS mechanical components ordered prior to July 1, 1971, were built to the older code categories. Refer to Table 3.2-3 for the appropriate code)
	VIII-1	-	ASME B&PV Code, Section VIII, Division 1
(5)	I	-	The equipment is constructed in accordance with the seismic requirements for the SSE.
	IIA	-	The equipment of this category is designed so that it cannot adversely affect plant safety features during and after SSE.
	II	-	The equipment of this category is not designed for the SSE.
(6)	Y	-	Requires compliance with the requirements of 10CFR50, Appendix B
	N	-	Not within the scope of 10CFR50, Appendix B

(7) PECo's request to use alternative codes to those required in 10CFR50.55a for primary pressure boundary components was sent to the NRC on July 15, 1975. The applicable codes, code dates, and addenda are listed in the request letter for the following components which are still included in the LGS design:

A. RPV

B. Main steam SRVs

C. Main steam piping (26") from RPV to 2nd isolation valve

D. Main steam line suspension

E. Recirculation pump

F. Recirculation gate valves (motor-operated):
28" suction
28" discharge

G. Recirculation loop piping (28")

H. Recirculation loop suspension

Table 3.2-1 (Cont'd)

I. RHR valves
20" gate valve

J. Core spray valves
12" check valve (air-operated)

K. Nuclear Class I piping (all except main steam and recirculation)

NRC approval of the request was given on November 18, 1975 in a letter from R.C. De Young (NRC) to E.G. Bauer (PECo).

The applicable code for design, fabrication, and testing of the MSIVs is the ASME Standard Code for Pumps and Valves for Nuclear Power - 1968 Draft including March 1970 Addenda.

(8) See Section 3.2.1 for discussion of conformance to Regulatory Guide 1.29.

(9) Instrument and sampling lines Quality Group, seismic category, and quality assurance requirements are as follows:

A. Instrument Lines

1. From the process boundary through the process root valve (including restriction orifice adapter), or, for lines penetrating primary containment, through the containment isolation valve or excess flow check valve, whichever applies: same Quality Group, seismic category, and QA requirements as the process line

2. Downstream of the boundary defined in 1, above:

   a. Lines penetrating primary containment and whose associated instruments are required to function to perform a safety function (Q-active) are Quality Group B, seismic Category I, and are Q-listed.

   b. Lines penetrating primary containment and whose associated instruments are only required to maintain their pressure boundary integrity (Q-passive) are Quality Group D, seismic Category I, and are Q-listed.

   c. Lines not penetrating primary containment whose associated instruments are Q-active are Quality Group B, seismic Category I, and Q-listed.

   d. Lines not penetrating primary containment whose associated instruments are Q-passive are Quality Group D, seismic Category I, and Q-listed.

   e. Other lines are Quality Group D, nonseismic Category I, and not Q-listed.

   f. Certain adapters in nonsafety-related, non Q-listed instrument lines are not manufactured per ANSI B31.1.

Table 3.2-1 (Cont'd)

B. Sampling Lines

1. From process line to root valve: Same quality group, seismic category, and quality assurance as process line.

2. From root valve through sample rack isolation valve:

   a. Sampling lines from Q-listed Quality Group A, B, and C process lines are Quality Group B, seismic Category I, and Q-listed.

   b. Sampling lines from non Q-listed Quality Group C process lines are Quality Group B or D, nonseismic Category I, and not Q-listed

   c. Sampling lines from Quality Group D process lines are Quality Group D, nonseismic Category I, and non Q-listed.

3. Downstream of sample rack isolation valve: Quality Group D, nonseismic Category I, and non Q-listed

(10) Accident monitoring instrumentation was designed using the guidance provided in Regulatory Guide 1.97 Revision 2. Regulatory Guide 1.97 Category I and most of Category II instrumentation is Q-listed. For additional design criteria information, see Section 7.5.

(11) Components include any assembly of interconnected parts that constitutes an identifiable device or piece of equipment. For example, electrical components include sensors, power supplies, and signal processors; and mechanical components include turbines, strainers, and orifices.

(12) Refer to Section 7.1 for descriptions of conformance with IEEE 279, IEEE 308, IEEE 323, and IEEE 344.

(13) These bottles are not available as seismic Category I items. However, the piping from the bottles is seismic Category I and Q-listed. DOT specifications were used for the bottles.

(14) The HCU is a GE factory assembled, engineered module of valves, tubing, piping, and stored water that controls a single CRD by the application of precisely times sequences of pressures and flows to accomplish slow insertion, or withdrawal, of the control rods for power control, while providing rapid insertion for reactor scram.

Although the HCU is field installed and connected to process piping, many of its internal parts differ markedly from process piping components because of the more complex functions they must provide. Thus, although the codes and standards invoked by the Group A, B, C, and D pressure integrity quality levels clearly apply at all levels to the interfaces between the HCU and the connecting conventional piping components (e.g., pipe nipples, fittings, simple hand valves, etc), it is considered that they do not apply to the specialty parts (e.g., solenoid valves, pneumatic components, and instruments).

Table 3.2-1 (Cont'd)

The design and construction specifications for the HCU do invoke such codes and standards as can be reasonably applied to individual parts in developing required quality levels, but these codes and standards are supplemented by additional requirements for these parts, and for the remaining parts and details. For example, all welds are liquid penetrant inspected; all socket welds are inspected for gap between pipe and socket bottom; all welding is performed by qualified welders; and all work is done by written procedures.

The following examples are typical of the problems associated with codes designed to control field assembled components when applied to the design and production of factory fabricated specialty components:

A. The HCU nitrogen gas bottle is a punch forging that is mechanically joined to the accumulator. It stores the energy required to scram a drive at low vessel pressures. It has been code stamped since its introduction in 1966, although its size exempts it from mandatory stamping. It is constructed of a material listed by ASME B&PV Code Section VII that was selected for this strength and formability.

B. The scram accumulator is joined to the HCU by a split flange joint chosen for its compact design to facilitate both assembly and maintenance. Both the design and construction conform to ANSI B31.1, Power Piping Code, This joint, which requires a design pressure of 1750 psig, has been proof tested to 10,000 psi.

C. The accumulator nitrogen shutoff valve is a 6000 psi cartridge valve whose copper alloy material is listed by ASME Section VIII. The valve was chosen for this service partly because it is qualified by the U.S. Navy for submarine service.

D. The directional control valves are solenoid pilot-operated valves that are subplate mounted on the HCU. The valve has a body specially designed for the HCU, but the operating parts are identical to a commercial valve with a proven history of satisfactory service. The pressure-containing parts are stainless steel alloys chosen for service, fabrication and magnetic properties. The manufacturer cannot substitute a code material for that used for the solenoid core tube.

The foregoing examples are not meant to justify one pressure integrity quality level or another, but to demonstrate that the codes and standards invoked by those quality levels are not strictly applicable to special equipment and part designs. Group D Classification is generally applicable, supplemented by the QC techniques described above. Thus, the HCU is classified as "Special Equipment".

(15) Quality Group B on the CRD insert and withdraw lines and scram discharge lines extends from the drive flange up to, and including, the first valve on the HCU.

(16) The RWCU pump suction piping from its tap off the recirculation loop up to and including the first valve outside primary containment (HV-44-F004) is classified Group A. The piping between valve HV-44-F004 up to and including the second valve (HV-44-F040) is classified Group B. The remainder of the pump suction piping is classified Group C.

Table 3.2-1 (Cont'd)

The RWCU system discharges into the feedwater lines and the RCIC line. There are three RWCU discharge paths: a tap into the RCIC line outside containment, a tap to feedwater loop A outside containment, and a tap to feedwater loop A inside containment. The RWCU piping upstream of the feedwater outboard containment isolation valve (HV-44-F039) is classified Group C. Valve HV-44-F039 and piping up to the feedwater and RCIC line taps (outside primary containment) is classified Group B. The RWCU tap into the feedwater line inside primary containment is classified Group B up to the outboard containment isolation valve (41-1016). Valve 41-1016 and piping up to the tap into the feedwater line is classified Group A.

(17) The HPCI and RCIC turbine do not fall within the applicable design codes. To ensure that the turbine is fabricated to the standards commensurate with their safety and performance requirements, GE has established specific design requirements for this component in their specification.

(18) Certain major liquid, solid, and gaseous radwaste system components were designed, fabricated, procured, installed, and tested to the requirements of ASME Section III, Class 3, prior to May 1978. After May 1978, radwaste and deep bed spent resin system design, fabrication, materials, procurement, installation, and testing are at a minimum, in accordance with quality group D and the intent of Regulatory Guide 1.143 (Rev 1), subject to the following clarifications and exceptions:

A. Certain atmospheric tanks are welded to API/AWS standards in lieu of ASME Section IX.

B. Curbs or elevated thresholds are not provided for indoor tanks because of the watertight integrity of the surrounding structure.

C. Hydrotest pressure is held for 10 minutes, in accordance with ASME Section III, rather than 30 minutes. When in-place pressure testing is not practical, the tie-in welds will be examined via NDE per ANSI B31.1.

D. The radwaste enclosure is designed in accordance with seismic Category I criteria (Section 3.8.4). LGS does not use Regulatory Guide 1.60, as stated in Section 1.8. Alternate methods are discussed in Sections 3.7 and 3.8.

E. LGS's quality program during construction did not require audits of activities associated with radwaste systems, and items of nonconformance and their regulation are not always documented. Beginning February 14, 1983, auditing or monitoring is required for activities associated with radwaste systems, and items of nonconformance and their regulation shall be documented.

F. Cleaning and welding of piping is conducted in accordance with the specified piping quality group.

Table 3.2-1 (Cont'd)

G. Inspection of all Q-listed instrument installation is performed by Bechtel QC personnel. Inspection of BOP instrumentation installations is performed by Bechtel field engineering personnel. In addition, final inspection of instrumentation up to the first root valve is performed by PECo QC personnel. Calibration and functional testing of all instrumentation is performed by PECo personnel.

Decontamination equipment and facilities are associated with the liquid radwaste system and are not safety-related.

(19) See Section 3.2.2 for discussion of conformance to Regulatory Guide 1.26.

(20) These components and associated supporting structures must be designed to retain structural integrity during, and after, the SSE, but do not have to retain operability for protection of public safety. The basic requirement is prevention of structural collapse, and damage to equipment and structures required for protection of the public safety and health.

(21) The basis for classification of non-ASME Section III equipment as Quality Group B is given in Section 3.2.2.g.

(22) Diesel fuel oil storage tanks and transfer pumps were designed to ASME Section III, Class 3 but were not stamped.

(23) The structural design of seismic Category I and IIA HVAC ducts was verified by testing duct specimens as permitted by the AISI Code, to substantiate the duct width to duct sheet thickness ratio (w/t) and cut height to duct sheet thickness ratio (h/t) of up to 1500. Seismic Category II ducts were designed and constructed in accordance with SMACNA.

(24) Regulatory Guide 1.52 (July 1976) suggests various industry standards and codes for this equipment. These references were used for system design, with exceptions as noted in Section 6.5.

(25) Dampers with electro-hydraulic operators were designed to IEEE 323. Fire dampers are labeled by UL.

(26) Portions of ducts and dampers in the reactor enclosure and refueling floor HVAC system are seismic Category II non Q-listed, and the remainder are seismic Category I, Q-listed.

(27) For discussion of design criteria related to TMI Action Plan requirements, see Section 1.13.2.

(28) The main steam system from its outer isolation valve up to, but not including, the turbine stop valve and bypass valve chest, and all branch lines 2½ inches in diameter and larger up to, and including, the first valve (including their restraints), will be designed by the use of an appropriate dynamic seismic-system analysis to withstand the OBE and SSE design loads in combination with other appropriate loads, within the limits specified for Class 2 pipe in the ASME Section III Code. The mathematical model for the dynamic seismic analyses of the main steam system and branch line piping includes the turbine stop valves and the piping from the stop valves to the turbine casing. The dynamic input loads for design of the

Table 3.2-1 (Cont'd)

main steam system are derived from a history model analysis (or an equivalent method) of the reactor and applicable portions of the turbine building. An elastic multi-degree-of-freedom system analysis is used to determine the input to the main steam system. The allowable stress and associated deformation limits for piping are in accordance with the ASME Section III Class 2 requirements for the OBE loading combinations. The main steam system supporting structures (those portions of the turbine enclosure) are such that the main steam system and its supports can maintain their integrity.

(29) The following qualification has been met with respect to the certification requirements:

A. The manufacturer of the turbine stop valves, turbine control valves, turbine bypass valves, and main steam leads from turbine control valve to turbine casing has used quality control procedures equivalent to those defined in GE Publication GEZ-4982A, "General Electric Large Steam Turbine-Generator Quality Control Program".

B. The manufacturer of these valves and steam leads has certified that the quality control program so defined has been accomplished.

(30) This section of steam piping was seismically analyzed to ensure that it will not fail under loadings normally associated with an SSE.

(31) The main steam loads from the turbine control valve to the turbine casing meet all of the requirements of Group D, plus the addition of the following requirements:

A. All longitudinal and circumferential butt weld joints are radiographed (or ultrasonically tested to equivalent standards). Where size or configuration does not permit effective volumetric examination, magnetic particle or liquid penetrant examination may be substituted. Examination procedures and acceptance standards are at least equivalent to those specified in appropriate sections of ANSI B31.1.

B. All fillet and socket welds are examined by either magnetic particle or liquid penetrant methods. All structural attachment welds to pressure-retaining materials are examined by either magnetic particle or liquid penetrant methods. Examination procedures and acceptance standards are at least equivalent to those specified in appropriate sections of ANSI B31.1.

C. All inspection records are maintained for the life of the plant. These records include data pertaining to qualification of inspection personnel, examination procedures, and examination results.

(32) The classification of the feedwater line from the reactor vessel through the second isolation valve is Group A. The classification of the feedwater line from the second isolation valve through the third valve is Group B. Beyond the third valve the classification is Group D.

(33) The listed design criteria apply to the external and internal structure of each enclosure. Refer to Sections 3.7 and 3.8 for discussion of seismic design and Category I structure design, respectively.

Table 3.2-1 (Cont'd)

(34) The following construction activities are conducted under the quality assurance program to ensure that the pond will perform its safety function:

A. Inspection and treatment of the rock surface at the pond bottom and sides to ensure that permeability requirements are met.

B. Final survey and measurement of the as-built pond to ensure that the water volume and side slopes satisfy design requirements.

C. Performance of a seepage test to ensure that the design basis seepage rate assumptions are not exceeded.

In addition, material used for treatment of fracture zones and capping observation wells is Q-listed.

(35) The pond is built completely by excavation. Ability to meet seismic Category I criteria is verified by measurement of as-built side slope areas (see Note 34.b) to ensure that design requirements are met.

(36) Includes unreinforced concrete used for support column foundations.

(37) The final survey and measurement of the as-built emergency spillway are conducted under the applicable portions of the QA program to ensure that the geometry satisfies design requirements.

(38) A complete description of the codes and standards, seismic category, and Q-list status of piping and instrumentation within the spray pond is shown on drawing M-12.

(39) Containment isolation barriers listed in Table 6.2-17 are Q-listed. Containment isolation valves are also included in the entries for each applicable system in this table.

(40) Specific components that comprise parts of major components with the same design criteria are generally not listed. For example, transformers are a part of load centers or switchgear, and valves operators are a part of motor-operated valves. Class 1E valve operators are in compliance with IEEE 323 and IEEE 344.

(41) Raceway systems include conduit, cable trays, and their supports. Raceway fire stops and seals are not Q-listed. However, quality control provisions commensurate with BTP CMEB 9.5-1 are applied to the raceway fire stops and seals.

(42) Inverters do not supply power to safety-related loads. The Class 1E battery loads are discussed in Section 8.3.2.1.1.4.

(43) Primary, backup and fault current protection devices are subcomponents of switchgear, load centers, MCC and distribution panels, which are Q-listed as shown in items X.A, X.B and X.C.

(44) Exhaust piping beyond the roof penetration is not Q-listed.

Table 3.2-1 (Cont'd)

(45) Equipment is qualified in accordance with the conformance statements made in Section 7.2, 7.3, 7.4, 7.5, and 7.6 in reference to IEEE 279 paragraph 4.4 and IEEE 323.

(46) Primary containment gas sample lines from the sample taps to and including the outboard containment isolation valves are seismic Category I. Liquid sample lines from the RHR system are seismic Category I up to and including the second system isolation valves. The sample line from the jet pump instrument system is seismic Category I to the PASS isolation valves.

(47) Delineation of applicable codes or standards and seismic category is shown in applicable piping specification for line class as indicated in drawing M-20 and in vendor manual for on-skid piping. The basis for classification of non-ASME Section III equipment as Quality Group C is given in Section 3.2.2.d.

(48) Supports associated with this piping are constructed in accordance with quality assurance and seismic Category I requirements.

The parts of the ESW system that are seismic Category IIA are indicated on drawing M-11. Nonseismic Category I drain and vent lines and capped ends extending from seismic Category I piping are seismic Category IIA downstream of the last isolation valve.

The operator may also elect to provide ESW to the following nonseismic Category I equipment:

A. RECW heat exchanger

B. TECW heat exchanger

C. Reactor recirculation pump seal and motor oil coolers.

ESW flow to and from these components is controlled by redundant key-locked remote manual valves for RECW and TECW and locked closed manual valves for the recirculation pump.

(49) The reactor vessel support skirt is designed to ASME Section III, Class I, subsection NF criteria.

(50) CRD housing supports are designed in accordance with the AISC code.

(51) Equipment is qualified in accordance with the conformance statements made in Section 7.6.

(52) The original design was to ASME Section III. The actual requirements are that of ANSI B31.1. The cleaning and welding of piping is conducted in accordance with the specified piping quality group.

(53) The basis of classification of non-ASME Section III equipment as Quality Group C is given in Section 3.2.2.e.

Table 3.2-1 (Cont'd)

(54) The basis for classification of non-ASME Section III equipment as Quality Group C is given in Section 3.2.2.h.

(55) Short welded sections of ANSI B31.1 piping in the turbine stop valve seat drains, stop valve leak-offs, governing valve leak-offs, casing drains, ring drains, chest drains, and turbine shaft seal leak-offs that cannot be hydrotested will be inservice tested to ANSI B31.1 requirements and the welds will be surface examined.

(56) The basis for classification of non-ASME Section III equipment as Quality Group C is provided in Section 3.2.2.i.

(57) The basis for classification of non-ASME Section III equipment as Quality Group C is provided in Section 3.2.2.j.

(58) This piping was purchased and constructed to Quality Group C requirements and was subsequently upgraded to Quality Group B by volumetrically examining all circumferential welds over two inches using radiography. Visual examination will be performed inservice in accordance with the Inservice Inspection Program.

(59) The containment spray nozzles are fabricated to manufacturer's standards. Inservice inspection requirements will be consistent with Quality Group B requirements.

(60) Spray pond nozzles and junction boxes were designed and built to ASME III, Class 3 requirements, except that they were not N-stamped by the manufacturer. No manufacturer had an N-stamp at that time.

(61) ESF also include those systems in Chapter 6 and Table 6.1-1. Although RCIC is not an ESF, it is listed in this subsection because, although not required to mitigate the consequences of an accident, it may be used.

(62) The reactor internal structures, other, include the steam dryer, shroud head and steam separator assembly, incore guide tubes and incore guide tube stabilizers, differential pressure and liquid control lines inside the RPV, fuel orifices, and feedwater spargers. These structures are neither required for safe shutdown of the plant nor will their failure jeopardize the safety function of other safety-related reactor internals. Differential pressure and liquid control lines inside the RPV that form part of the RCPB are Q-listed. With the exception of these lines, the aforementioned components are not safety-related, are not Q-listed, and are not under 10CFR50, Appendix B. However, they are inspected as part of the inservice inspection program which is included in the operations phase of the QA Plan.

(63) Control room emergency lighting meets seismic Category I requirements as described in Section 9.5.3.2.2.

(64) The metal components for the primary containment (including hatches, liner plate, penetration sleeves, and downcomers) are designed and fabricated in accordance with the principal codes and standards noted in this table and Sections 3.8.1 and 3.8.2, but are not N-stamped except the personnel airlock.

Table 3.2-1 (Cont'd)

(65) Prefilters for the refueling area to SGTS alignment are installed in the refueling area duct-work. Prefiltering for the reactor enclosure to SGTS alignment is provided by the RERS.

(66) The tees supporting the vacuum relief valves are fabricated from ASTM material and welded into the downcomers. All welds have been radiographed.

(67) Exceptions: Valves HV-046-127, 128, 227, and 228 are seismic Class I and Q-listed. Isolation signals must close these block valves to prevent bypass leakage. Valves HV-046-125, 126, 225, and 226 are also seismic Class I and Q-listed. The piping and valves from the HCUs to and including the Containment Isolation Valves 46-1101, 46-1102, 46-1108, 46-1109, 46-1115, 46-1116, 46-1122, 46-1123, 46-2101, 46-2102, 46-2108, 46-2109, 46-2115, 46-2116, 46-2122, and 46-2123 are equivalent to ASME Section III, Class 2, seismic Class I and are Q-listed.

(68) The SLCS storage tanks were purchased before Article NC-3800 on atmospheric storage tanks was included in the ASME Section III, Class 2 code, and were hence designed and fabricated to API 650 and supplemental requirements at the time of purchase as discussed in Section 3.2.2(k).

(69) All three of the Unit 1 and one of the Unit 2 SLCS pump discharge accumulator vessels were purchased to ASME Section VIII, Division 1. These weldless vessels, except for the code stamping, also meet the ASME Section III, Class C requirements. Per Table 3.2-3, vessels purchased prior to July 1, 1971, are purchased to ASME Section III, Class C rather than Class 2.

(70) The HPCI turbine exhaust line globe stop-check valves were manufactured to ANSI B31.1 (1967), ANSI B16.5, and MSS-SP-66. They have been shown to meet the requirements of 1968 Draft ASME Code for Pumps and Valves and the nondestructive inspection requirements of ASME Section III.

(71) The shell side of the nonregenerative heat exchangers is constructed to ASME Section VIII, Division 1 and TEMA R.

(72) The core support structure was designed and procured prior to the issuance of subsection NG of ASME Section III. However, an earlier draft of the ASME Code was used as a guide in developing the design criteria in lieu of subsection NG.

Subsequent to the issuance of subsection NG, NG-3000 has been used, for evaluation purposes, in the core support structure evaluation. A detailed comparison between the original design basis and Appendix F (referenced by NG-3000) shows that the two sets of limits have no significant differences.

(73) The sample coolers were manufactured to the equivalent of ASME VIII, Division 1, but not code stamped. It was not customary at the time of manufacture to code stamp these coolers.

Table 3.2-1 (Cont'd)

(74) The safety-related portions of the HVAC systems are designed, fabricated, erected, and tested to quality standards commensurate with the safety function to be performed. Fans, filters, plenums, dampers, and duct-work in these systems are not classified as piping or pressure vessels and, as such, do not fall under the jurisdiction of ASME Section III. All of the equipment in these systems performing safety-related functions is Q-listed and seismic Category I, and all electrical components performing safety-related functions are environmentally qualified in accordance with Regulatory Guide 1.89. In addition, these systems provide substantial conformance with Regulatory Guide 1.52 as discussed in Sections 1.8 and 6.5.1 and Table 6.5-2.

(75) Includes shield walls identified by the plant shielding study (Section 1.13.2, Item II.B.2).

(76) Deleted

(77) Deleted

(78) Deleted

(79) The PASS does not function to mitigate the consequences of an accident. Therefore, with the exception of its interfaces with Q-listed systems, the PASS is not Q-listed. The PASS design is consistent with the guidance of Regulatory Guide 1.97 for the monitoring of Type E variables. While not a mitigating system, PASS is an integral part of the plant's capability to obtain and analyze samples and is therefore administratively controlled based on the guidance in Generic Letter 83-36, enclosure I.

(80) Select valves per QAD-M-15, to Unit 1 & 2 inflatable seals 1, 2, 3, 4, 7 and 10 are leak tested under the ASME section XI IST program but are not required to be installed to meet ASME class codes, but rather to ANSI B31.1 codes. These valves have been upgraded to meet seismic category I requirements and are Q-listed.

(81) Portions of the Air Start System have been downgraded to Seismic Category IIA as shown on drawing M-20. These portions were designed and installed to Seismic Category I standards, however, they do not perform a safety related function.

(82) Portion of external pneumatic connection beyond 59-*137 is seismic category IIA. The remainder of Item F.6 is seismic category II.

(83) The Emergency Diesel Generator Air Cooler Coolant, Jacket Water, and Lube Oil Cooler Heat Exchangers, sub-assembly parts purchased after 11/2000 have been procured in accordance with US NRC Generic Letter 89-09 and ASME Section III, Class 3 equivalent requirements.

(84) A portion of the piping connecting the Unit 2 RCIC Pump suction to the RHR heat exchangers has been downgraded to ANSI/ASME B31.1 Power Piping and Seismic Category IIA because it no longer serves a safety-related function.

(85) The original RPV strongback was replaced in 1994 with a RPV strongback carousel by GE that was designed and fabricated to ANSI N14.6-1978. GE later identified that the hook

Table 3.2-1 (Cont'd)

pins, clevis pins, and clevis rods did not meet the material testing as required by paragraph 3.2.6 of ANSI N14.6-1978. Because the new RPV strongback carousel was proof tested and is periodically inspected and load tested, its design function to provide a single-failure proof device to lift the RPV head during refueling is not impacted although it is not completely compliant to ANSI N14.6-1978.

(86) This system has been categorized under 10 CFR 50.69. See Section 13.5.5 for further information.

(87) Components within this system have been categorized under the 10 CFR 50.69 process. This is based on the 10 CFR 50.69 system boundaries as defined in the associated System Categorization Document. See Section 13.5.5 for further information.

Table 3.2-2

CLASSIFICATION AND CODE COMPLIANCE REQUIREMENTS FOR NON-NSSS MECHANICAL COMPONENTS

	CODE CLASSIFICATIONS			
COMPONENT	GROUP A	GROUP B	GROUP C	GROUP D[1]
Pressure Vessels	ASME B&PV Code, Section III, Nuclear Power Plant Components-CLASS 1	ASME B&PV Code, Section III, Nuclear Power Plant Components-CLASS 2	ASME B&PV Code, Section III, Nuclear Power Plant Components-CLASS 3[5]	ASME B&PV Code, Section VIII, Division 1
Piping Systems [4] (including pipe supports)	As above [3]	As above [3]	As above [3]	ANSI B 31.1 Power Piping
Pumps	As above	As above	As above	Manufacturer's Standards
Valves	As above	As above	As above	ANSI B 31.1
0-15 psig Storage Tanks	-	As above	As above	API 620, or ASME B&PV Code Section VIII, Division 1
Atmospheric Storage Tanks	-	As above	As above [2]	API 650, AWWA D 100, ANSI B 96.1, or ASME B&PV Code Section VIII, Div. 1

[1] Certain portions of the radwaste systems meet the additional requirements of Quality Group D (Augmented), as defined in BTP ETSB 11-1, Parts B.4 and B.5.

[2] Atmospheric storage tanks fabricated to Group C requirements may be used in a Group D or Group D (Augmented) system.

[3] ASME Section III piping systems (including pipe supports) are constructed in accordance with ASME Section III, 1971 Edition with Addenda through Winter 1971, except:

a. Piping material conforms to ASME Section III, 1971 Edition with Addenda through Winter 1971, ASME Section II, Part D 1999 Addenda of the 1998 Edition, or to later editions or addenda approved by the AE.

b. Field fabrication, installation, examination, and testing are in accordance with ASME Section III, 1974 Edition with Addenda through Winter 1974.

c. Paragraphs NC-4436 and ND-4436 of ASME Section III, 1980 Edition with Addenda through Winter 1981, is used for installation of attachments to Class 2 and 3 piping systems after testing.

Table 3.2-2 (Cont'd)

d. Pipe supports are constructed and installed in accordance with the 1969 Edition of ANSI B31.7 with Addenda approved March 10, 1971. Snubbers supplied through the architect-engineer are manufactured in accordance with ASME Section III, 1977 Edition with Addenda through Winter 1977, and installed in accordance with the 1969 Edition of ANSI B31.7 with Addenda approved March 10, 1971.

e. Stress analysis is in accordance with ASME Section III, 1971 Edition with Addenda through Winter 1972, except:

1. Class 1 piping systems stress analysis is in accordance with the 1977 Edition with Addenda through Summer 1979.

2. Class 2 and 3 flange stress analysis is in accordance with the 1977 Edition with Addenda through Summer 1979.

3. Unit 2 only. The SIF values for nuclear class 2 and 3 weldolets, sockolets and half coupling branch connections are in accordance with the 1974 Edition of the code.

f. Containment penetration flued heads are manufactured in accordance with ASME Section III with Addenda through Summer 1974, and installed in accordance with item b above. Diaphragm penetration flued heads are manufactured in accordance with ASME Section III, 1980 Edition with Addenda through Winter 1981, and installed in accordance with item b above.

g. Group B and C instrument sensing lines that are attached to Group A instrument sensing lines are hydrotested in accordance with ASME Section III, 1974 Edition with Addenda through Winter 1975.

h. Orifice plates (which are clamped between flanges and used in flow measuring service) that do not exceed ½ inch nominal thickness are not considered to be an ASME piping subassembly, part, appurtenance, component, or material in accordance with Paragraph NCA-1273 of ASME Section III, 1980 Edition with Addenda through Summer 1980.

i. For installation of instrument lines supplied through the architect-engineer, the minimum fillet weld size is in accordance with figure NB/NC/ND-4427-1 of ASME Section III 1980 Edition with Addenda through Summer 1980.

j. The NSSS piping systems supplied by GE and installed by the architect-engineer are installed in accordance with ASME Section III, 1974 Edition with Addenda through Winter 1974. Supports are manufactured and installed and snubbers are installed for the GE-supplied systems in accordance with ANSI B31.7, 1969 Edition with Addenda approved March 10, 1971. Snubbers are manufactured in accordance with ASME Section III, 1977 Edition with Addenda through Winter 1977.

k. Paragraph NB-4436 of ASME Section III, 1977 Edition, is used for installation of attachments to Class 1 piping systems after testing.

l. Subparagraph N(X)-4453.1 of ASME Section III, 1983 Edition with Addenda through Summer 1983, is used for making repairs to welds in Class 1, 2, and 3 piping systems.

m. Unit 2 only. Nameplate removal/replacement of N-stamped items shall be in accordance with the 1983 Edition through the Winter of 1984 Addenda, Paragraph NCA-8240.

n. Unit 2 only. Venting prior to hydrostatic test shall be in accordance with the 1980 Edition through the Summer 1981 Addenda, Paragraph NB/NC/ND-6211.

(4) CRD and TIP piping systems are constructed in accordance with ASME Section III, 1974 Edition with Addenda through Summer 1976. For evaluation of CRD insert/withdrawal piping interference with the CRD housing, Paragraph NC-3600 of the 1974 Edition with Addenda through Winter 1976 is used.

(5) The Emergency Diesel Generator Air Cooler Coolant, Jacket Water, and Lube Oil Cooler Heat Exchangers, sub-assembly parts purchased after 11/2000 have been procured in accordance with US NRC Generic Letter 89-09 and ASME Section III, Class 3 equivalent requirements.

Table 3.2-3

CLASSIFICATION AND CODE COMPLIANCE REQUIREMENTS FORNSSS MECHANICAL COMPONENTS

Group Classification	ASME III Code Classes 1968 Ed.	1971 Ed.	Components Ordered on or after January 1, 1970 to July 1, 1971	Components Ordered on or after July 1, 1971
A	A	1	ASME I ASME III, A ASME IX ANSI B16.5 ANSI B16.11 ANSI B31.1 ANSI B31.7, I NP&VC, I TEMA C (2)	ASME I ASME III, 1 ASME IX ANSI B16.5 ANSI B31.7 NA&NB Subsections TEMA C (2) (5)
B	B(1),C	2, MC(1)	ASME III, B(1),C(7) ANSI B31.7, II NP&VC, II(8) TEMA C TANKS	ASME III,2 & MC(1) NA&NC Subsections NA&NE Subsections TEMA C TANKS(6) (5)
C	-	3	ASME VIII, Div. 1 ANSI B31.7, III NP&VC, III TEMA C TANKS (5)	ASME III, 3 NA&ND Subsections TEMA C TANKS (5)
D	-	-	ASME VIII, Div. 1 ANSI B31.1.0 TEMA C TANKS(3) (4)	ASME VIII, Division 1 ANSI B31.1 TEMA C TANKS(3) (4)

Table 3.2-3 (Cont'd)

(1) Metal containment vessel (as applicable) and extensions of containment only.

(2) PECo's request to use alternative codes to those required in 10CFR50.55a for primary pressure boundary components was sent to the NRC on July 15, 1975. The applicable codes, code dates, and addenda are listed in the request letter for the following components that are still included in the LGS design:

a. PRV
b. Main steam SRVs
c. Main steam piping (26 inches) from RPV to second isolation valve
d. Main steam line suspension
e. Recirculation pump
f. Recirculation gate valves (motor-operated):
   28 inch suction
   28 inch discharge
g. Recirculation loop piping (28 inches)
h. Recirculation loop suspension
i. RHR valves
   20 inch gate valve
j. Core spray valves
   12 inch check valve (air operated)
k. Nuclear Class 1 piping (all except main steam and recirculation)

NRC approval of the request was given on November 18, 1975 in a letter from R.C. De Young (NRC) to E.G. Bauer (PECo).

The applicable code for design, fabrication, and testing of the MSIVs is the ASME Standard Code for Pumps and Valves for Nuclear Power - 1968 Draft including March 1970 Addenda.

Paragraphs NB-4433 and NB-3123.2 of the 1980 Edition of the ASME Section III are applicable for the design of hanger lugs welded to the main steam piping pressure boundary.

(3) Class D tanks shall be designed, constructed, and tested to meet the intent of API 620/650, AWWA D100, or ANSI B96.1

(4) For pumps classified Group D and operating above 150 psi or 212°F, ASME Section VIII, Division 1 shall be used as a guide in calculating the wall thickness for pressure- retaining parts and in sizing the cover bolting. For pumps operating below 150 psi and 212°F, manufacturer's standard pump for service intended may be used.

Table 3.2-3 (Cont'd)

(5) For pumps classified A, B, or C, applicable Subsections NB, NC, or ND respectively in ASME Section III shall be used as a guide in calculating the thickness of pressure-retaining portions of the pump and in sizing cover bolting.

(6) The SLCS storage tanks were designed and constructed to API 650; ASME Section III, Class 2 did not contain Article NC-3800 on atmospheric storage tanks at the time these tanks were purchased.

(7) All three of the Unit 1 and one of the Unit 2 SLCS accumulator vessels are ASME Section VIII, Division 1. The ASME Section III, Class C code requires only that these weldless vessels meet the ASME Section VIII, Division 1 standards, and hence, except for the code stamping, they meet all ASME Section III, Class C requirements.

(8) The HPCI turbine exhaust line globe stop-check valves meet the requirements of the cited code but were manufactured to ANSI B31.1 (1967), ANSI B16.5, and MSS-SP-66 requirements.

Table 3.2-4

OFF-SKID PORTIONS OF THE EMERGENCY DIESEL GENERATOR AUXILIARY SYSTEMS

ASME Section III Class 3	ANSI B31.1	LGS Supplementary Requirements
Requires ASME materials and CMTRs for all piping larger than ¾ inch nominal pipe size. Certificates of compliance may be substituted for CMTRs for piping less than ¾ inch.	Requires materials that conform to either ASME or ASTM specification.	ASTM and ASME materials were procured and CMTRs were supplied for all piping larger than ¾ inch nominal pipe size. Certificates of compliance may be substituted for CMTRs for piping less than ¾ inch.
Requires seismic design in addition to the B31.1 requirements.	Requires design for pressure, temperature, and normal operating loads.	Piping is designed to seismic Category I with minimum wall thicknesses in conformance with ASME Section III, Class 3.
Requires liquid penetrant, magnetic particle, or radiographic examination for circumferential welds greater than 2 inches nominal pipe size.	Requires only visual inspection of welds at the design pressure and temperature of the auxiliary systems.	Same as ANSI B31.1.
Requires pneumatic testing at 1.2x design pressure.	Requires pneumatic test at 1.2x design pressure with initial service leak test as an alternative.	All piping is pneumatically tested to 1.2x design pressure except for piping with design pressure at or below 0 psig.

Table 3.2-5

CHILLED WATER PIPING SYSTEM FOR THE CONTROL STRUCTURE CHILLED WATER SYSTEM

ASME Section III Class 3	ANSI B31.1	LGS Supplementary Requirements
Requires ASME materials and CMTRs for all piping larger than ¾ inch nominal pipe size. Certificates of compliance may be substituted for CMTRs for piping less than ¾ inch.	Requires materials that conform to either ASME or ASTM specification.	ASTM and ASME materials were procured and CMTRs were supplied for all piping larger than ¾ inch nominal pipe size. Certificates of compliance may be substituted for CMTRs for piping less than ¾ inch.
Requires seismic design in addition to the ANSI B31.1 requirements.	Requires design for pressure, temperature, and normal operating loads.	Piping is designed to seismic Category I with minimum wall thicknesses in conformance with ASME Section III, Class 3.
Requires liquid penetrant, magnetic particle, or radiographic examination for circumferential welds greater than 2 inches nominal pipe size.	Requires only visual inspection of welds at the design pressure and temperature of the chilled water system.	Same as ANSI B31.1.
Requires hydrostatic testing at 1.25x design pressure.	Requires hydrostatic test at 1.5x design pressure.	Same as ANSI B31.1.

Table 3.2-6

CONTROL ROOM HVAC CHILLERS

ASME Section III Class 3	ASME Section VIII Division 1	LGS Supplementary Requirements
Requires use of ASME materials that are listed in the stress tables or in ASME Section VIII for nonferrous materials.	Requires use of ASME materials that are listed in the stress tables.	Materials used in the vessels are permitted by ASME Section III, with the exception of SA306, Grade 60 bar used for the vessel water box flange. Use of this material is permitted by ASME Section VIII.
Requires CMTRs.	CMTRs or certificates of compliance not required.	CMTRS were provided for the pressure retaining material, with the exception of some vessel nozzles.
Requires examination of materials in accordance with the ASME material specification for the product forms involved.	Requires examination of materials in accordance with the ASME material specification.	
Requires the vessel design to be in accordance with ASME Section VIII, Division 1.	Provides rules for vessel design.	Requires vessel to be designed to seismic Category I requirements.
Requires the vessel fabrication to be in accordance with ASME Section VIII, Division 1.	Provides rules for vessel fabrication.	
Requires the vessel weld examination to be in accordance with ASME Section VIII, Division 1.	Provides rules for vessel weld examination.	
Requires hydrostatic testing at 1.5x design pressure.	Requires hydrostatic testing at 1.5x design pressure.	

Table 3.2-6 (Cont'd)

ASME Section III Class 3	ASME Section VIII Division 1	LGS Supplementary Requirements
Requires the manufacturer to implement a quality control system.	Requires the manufacturer to implement a quality control system.	
Requires authorized inspector and Code Data Report.	Requires authorized inspector and Code Data Report.	
Requires the material manufacturer to document and maintain a QA program.	No requirement.	Requires the material manufacturer to document and maintain a QA program.

Table 3.2-7

RHR Heat Exchanger "B"
Corrosion Monitoring Components
Connected to RHRSW System Pressure Boundary

ASME Section III, Class 3	ANSI B31.1	LGS Supplementary Requirements
Requirements ASME materials and CMTRs for all piping larger than 3/4 inch nominal pipe size. Certificates of compliance may be substituted for CMTRs for piping less than 3/4 inch.	Requires materials that conform to either ASME or ASTM specification.	ASTM and ASME materials were procured and CMTRs were supplied for all ASME piping larger than 3/4 inch nominal pipe size. Certificates of compliance may be substituted for CMTRs for ASME piping less than 3/4 inch.
Requires seismic design in addition to the ANSI B31.1 requirements	Requires design for pressure, temperature, and normal operating loads.	Piping is designed to seismic Category I with minimum wall thicknesses in conformance with ASME Section III, Class 3.
Requires liquid penetrant, magnetic particle, or radiographic examination for circumferential welds greater than 2 inches nominal pipe size.	Requires only visual inspection of welds at the design pressure and temperature of the chilled water system.	Same as ASME
Requires hydrostatic testing at 1.25X design pressure.	Requires hydrostatic test at 1.5X design pressure.	Same as ANSI B31.1, for HBD components. Same as ASME for GBC and GBD components.
Requires use of ASME materials that are listed in the stress tables or in ASME Section VIII for nonferrous materials.	Requires use of ASME materials that are listed in the stress tables.	Materials used in the vessels are permitted by ASME Section III.
Requires CMTRs.	CMTRs or certificates of compliance not required.	CMTRs were provided for the pressure retaining material.

Table 3.2-7 (Cont'd)

RHR Heat Exchanger "B"
Corrosion Monitoring Components
Connected to RHRSW System Pressure Boundary

ASME Section III, Class 3	ANSI B31.1	LGS Supplementary Requirements
Requires examination of materials in accordance with the ASME material specification for the produce forms involved.	Requires examination of materials in accordance with the ASME material specification.	
Requires the vessel design to be in accordance with ASME Section VIII, Division 1.	Provides rules for vessel design.	Requires vessel to be designed to seismic Category I requirements.
Requires vessel fabrication to be in accordance with ASME Section VIII, Division 1.	Provides rules for vessel fabrication.	
Requires the vessel weld examination to be in accordance with ASME Section VIII, Division 1	Provides rules for vessel weld examination.	
Requires hydrostatic testing at 1.5X design pressure.	Requires hydrostatic testing at 1.5X design pressure.	
Requires the manufacturer to implement a quality control system.	Requires the manufacturer to implement a quality control system.	
Requires authorized inspector and Code Data Report.	Requires authorized inspector and Code Data Report.	
Requires the material manufacturer to document and maintain a QA program.	No requirement.	Requires the material manufacturer to document and maintain a QA program.

3.3 WIND AND TORNADO LOADINGS

3.3.1 WIND LOADINGS

Design wind loads for all exposed structures are based on Reference 3.3-1 and Reference 3.3-2.

3.3.1.1 Design Wind Velocity

Exposed structures are designed to withstand a basic wind velocity of 90 mph at 30 feet above ground. The recurrence interval of this wind velocity is estimated to be at least 100 years (Reference 3.3-1). A gust factor of 1.1 is used in conjunction with this basic wind velocity. The variation of wind velocity with height is given in Table 3.3-1.

3.3.1.2 Determination of Applied Forces

The dynamic pressures on the exposed structural surfaces due to the design wind are computed in accordance with the requirements of Reference 3.3-1, which are summarized as follows:

$$q = 0.002558V^2$$

where:

q = dynamic pressure (psf)

V = design wind velocity, mph

$$V = G\,(v)$$

where:

G = gust factor

v = basic wind velocity

The total design pressure for a structure is the product of dynamic pressure and shape coefficient. A shape coefficient of 1.3 is applied with all wind loads. This total design pressure is distributed among different exposed surfaces of the structure, on the basis of location with respect to the wind direction. Pressures and suction developed by using the above procedure and used in the design of plant structures are given in Table 3.3-1.

Table 3.3-4 provides a comparison between the maximum expected external pressure and the external design pressures. This table shows that an adequate margin of safety for wind loadings exists for the secondary containment structure.

3.3.2 TORNADO LOADINGS

Structures that directly affect the ultimate safe shutdown of the plant are designed to resist applicable design basis tornado forces. Table 3.3-2 lists the systems and components that are protected against tornados and the enclosures that provide this protection. The radwaste enclosure is tornado-resistant only to the extent of protecting the gaseous radwaste treatment system and retaining approximately 500,000 gallons of solid and liquid radwaste within the confines of the enclosure.

3.3.2.1 Applicable Design Parameters

Structures required to be tornado-resistant are designed for the following effects of a design basis tornado:

a. Dynamic wind loadings - These are the external pressure or suction forces on a structure due to the passage of a tornado funnel. The design basis tornado has a rotational speed of 300 mph and a translational speed of 60 mph. Conservatively, this is taken as a 300 mph wind applied uniformly over an entire structure.

b. Differential pressures - When the low pressure within a tornado funnel engulfs a structure, a rapid depressurization occurs and produces differential pressures between the inside and outside of the structure and between the compartments inside the structure depending on the available vent paths. The pressure transient caused by the design basis tornado is a 3 psi pressure drop at the rate of 1 psi/sec, followed by a 2 second calm and then a repressurization to the original pressure at a rate of 1 psi/sec.

c. Tornado missiles - The types of missiles postulated to be generated by a tornado are discussed in Section 3.5.1.4.

Regulatory Guide 1.76, "Design Basis Tornado for Nuclear Power Plants", calls for a pressure drop of 3 psi at the rate of 2 psi/sec, however, the increased depressurization rate of 2 psi/sec in Regulatory Guide 1.76 would have no significant effect on the external structural elements of tornado-resistant structures. These structures are designed for the maximum pressure differential due to a tornado of 3 psi regardless of the rate of depressurization.

The increased depressurization rate would increase the maximum differential pressure for internal structural elements. These elements were checked for the maximum differential pressure caused by the following design basis tornado pressurization profile: a 1 psi/sec pressure decrease for 3 seconds; a 2 second calm; a 1 psi/sec pressure increase for 3 seconds. An analysis to determine the effects of the increased maximum differential pressures on the internal structural elements has not been performed because the 1 psi/sec depressurization rate is considered to be conservative. The design basis tornado pressurization profile used was committed to in the LGS PSAR, Appendix C, Section C.2.4, prior to the issuance of Regulatory Guide 1.76. This pressurization profile was based on Reference 3.3-4. Previous documents used as the design basis for tornado effects were References 3.3-5 and 3.3-6. Actual tornado parameters were developed by studies of the tornado damage, eyewitness accounts of the maximum tornado depressurization on barometric instruments, and analysis of films of actual tornadoes. The depressurization effects defined in References 3.3-4, 3.3-5, and 3.3-6 substantiate the conservatism of the 1 psi/sec depressurization rate because they exceed the observed effects of actual tornadoes.

To further demonstrate the conservatism of the 1 psi/sec depressurization rate, site specific tornado parameters have been determined for LGS using the methodology of Reference 3.3-7. This reference is the basis document for Regulatory Guide 1.76.

In accordance with Regulatory Guide 1.76, LGS is in zone I, a region which encompasses a wide variation of tornado risks, from high tornado risk areas such as the Midwest to low risk areas such as New England. For the following analysis, a site specific tornado risk data base is used to determine the design basis tornado parameters.

Tornado data was obtained from the National Severe Storms Forecast Center for the years 1950 through 1981 for an area 125 nautical miles in radius centered on Pottstown, Pennsylvania. During this period, these were 322 tornadoes, or 10.1 tornadoes per year.

The probability that a tornado will strike a particular area is given by Reference 3.3-7 as:

$$P_s = \bar{n}\ (a/A)$$

where:

P_s = tornado strike probability

$\bar{n}$ = average number of tornadoes per year

a = average individual tornado area

A = land area within 125 nm of Pottstown (1 square nautical mile = 1.32 square miles)

From the tornado data, tornado areas were calculated for 307 tornadoes (data was not available for 15 tornadoes). The average area was 0.24 square miles. The land area within 125 nm of Pottstown is approximately 53,500 square miles (the total area is 64,900 square miles), of which 82% is land area. Therefore, the average probability of a tornado strike is:

$$P_s = \frac{10.1(0.24)}{53{,}500} = 4.6\times10^{-5} \text{ per year}$$

In accordance with Reference 3.3-7, the probability of occurrence of a tornado that exceeds the design basis tornado should be on the order of 10^{-7} per year to adequately protect public health and safety. Therefore:

$$P_s \cdot P_i \leq 10^{-7}$$

where:

P_i = acceptable intensity probability

Thus,

$$P_i = 10^{-7}/4.6\times10^{-5} = 2.2\times10^{-3} \text{ per year} = 0.22\%$$

Each tornado in the tornado data base has been classified according to a wind speed scale (the Fujita parameters). The distribution of tornadoes with respect to wind speed is given in Table 3.3-3. The cumulative distribution from Table 3.3-3 is plotted in Figure 3.3-1. Using Figure 3.3-1, the maximum wind speed corresponding to a probability P_i of 0.22% is 280 mph.

To determine the rotational and translational components of the maximum wind speed, the values obtained from table 4 of Reference 3.3-7 are used for interpolation. The values thus obtained are translational wind speed of 56.5 mph and rotational wind speed of 223.5 mph.

The depressurization rate is calculated by Reference 3.3-7 as follows:

$$\frac{dp}{dt} = \frac{T}{r_m} \rho V_m^2$$

where:

p = pressure

t = time

T = translational wind speed

V_m = rotational wind speed

ρ = density of air

r_m = radius of maximum rotational wind speed

From table 4 and table 5 of Reference 3.3-7, the parameters for a Region I design basis tornado are:

T = 70 mph

V_m = 290 mph

$\frac{dp}{dt}$ = 2 psi/sec

Therefore, by ratio

$$\frac{dp_2}{dt} = \frac{dp_1}{dt} \frac{T_2 V_{m2}^2}{T_1 V_{m1}^2} = \frac{2.0 \cdot 56.5 \cdot (223.5)^2}{70 \cdot (290)^2}$$

= 0.96 psi/sec

These site specific tornado parameters are less limiting than the values used for the design basis tornado in Section 2.3.1.

3.3.2.2 Determination of Forces on Structures

The procedures used to transform the tornado loadings into effective loads on structures are described below under separate headings for each parameter described in Section 3.3.2.1.

a. Dynamic wind loadings - The procedure used to transform the tornado wind velocity into an effective pressure is the same as described in Section 3.3.1.2, with the following exceptions: velocity and velocity pressure are not assumed to vary with height, and a gust factor of 1.0 is used. The resulting pressure loadings are as follows:

1. Pressure on windward side (0.8q) 185 psf

2. Suction on leeward side (0.5q) 115 psf

3. Total pressure on structure (1.3q) 300 psf

4. Uplift on roof (0.6q) 140 psf

b. Differential pressures - The maximum differential pressure between the inside and outside of fully enclosed areas is taken as 3.0 psi. Blowout panels are provided where necessary to lower the design differential pressures. For vented compartments, a flow analysis of all interconnecting air volumes is performed and the maximum transient pressure differentials across walls, floors, and roofs are calculated. All structural components in the vented and nonvented compartments are then checked to confirm that they can withstand the maximum calculated transient differential pressure.

c. Tornado missiles - The procedures and methods outlined in Reference 3.3-3 are used to transform the dynamic loads into effective loads and to determine the structural response of the elements subjected to missile impingement.

All of the above design basis tornado loadings are considered as loadings that act simultaneously.

Analytical techniques were used for estimating the values of tornado parameters for purposes of design with an adequate level of conservatism. Although the tornado parameters used in the LGS external design pressure analyses differ slightly from those defined in Regulatory Guide 1.76, the LGS analyses are either equivalent or conservative compared to analyses using the Regulatory Guide 1.76 parameters (Section 2.3.1.2.4). The use of these parameters for calculating the external design pressure ensures an adequate margin above the maximum expected external pressure.

3.3.2.3 Effect Of Failure Of Structures Or Components Not Designed For Tornado Loadings

Structures such as the turbine enclosure and outdoor storage tanks, which are not designed for tornado loads, are investigated and checked to ensure that they cannot produce missiles that have more severe effects than those listed in Section 3.5.1.4. The modes of failure of these structures are analyzed to verify that their failure due to tornado loading cannot prevent structures or components needed for safe shutdown from performing their intended functions.

3.3.3 REFERENCES

3.3-1 "Wind Forces on Structures", Transactions, Volume 126, Part II, ASCE paper No. 3269, (1961).

3.3-2 H.C. Thom, "New Distributions of Extreme Winds in the United States", Journal of the Structural Division, ASCE, (1969).

3.3-3 "Design of Structures For Missile Impact", BC-TOP-9-A, Rev. 2, Bechtel Power Corporation, (September 1974).

3.3-4 J.A. Dunlop and K. Wiedner, "Nuclear Power Plant Tornado Design Considerations", Journal of the Power Division, Proceedings of the ASCE, (March 1971).

3.3-5 "Design Criteria for Nuclear Power Plants Against Tornadoes", Bechtel Power Corporation, B-TOP-3, (March 12, 1970).

3.3-6 "Tornado Criteria for Nuclear Plants", Bechtel Power Corporation, (July 1969).

3.3-7 "Technical Basis for Interim Regional Tornado Criteria", AEC, WASH-1300, (May 1974).

Table 3.3-1

DESIGN WIND LOADS ON STRUCTURES

HEIGHT ZONE (ft)	BASIC WIND VELOCITY v (mph)	DYNAMIC PRESSURE, q[1] (psf)	WALL LOAD[2] Total Design Pressure, 1.3 q (psf)	WALL LOAD[2] Windward Pressure, 0.8 q (psf)	WALL LOAD[2] Leeward Suction, 0.5 q (psf)	WALL LOAD[2] Roof Load Suction, 0.6 q (psf)
0-50	90	25	33	20	13	15
50-150	105	34	44	27	17	20
150-400	125	48	63	39	24	29
>400	135	56	73	45	28	34

(1) Includes gust factor of 1.1

(2) The wall loadings presented in this table are adjusted by the following multiplication factors when applied to structure design:

Square or rectangular structures - 1.00

Round or elliptical structures - 0.60

Table 3.3-2

TORNADO PROTECTED SYSTEMS AND TORNADO-RESISTANT ENCLOSURES

PROTECTED SYSTEM OR COMPONENT ENCLOSURE	TORNADO-RESISTANT
RCPB	Reactor enclosure
ECCS	Reactor enclosure
RHR system	Reactor enclosure
RHRSW system	Reactor enclosure and spray pond pumphouse
ESW system	Reactor enclosure, diesel generator enclosure, control structure, and spray pond pumphouse
RECW system	Reactor enclosure
Fuel pool cooling system	Reactor enclosure
Fuel pool	Reactor enclosure
CRD hydraulic system	Reactor enclosure
SLCS	Reactor enclosure
Standby diesel generators	Diesel generator enclosure
Gaseous radwaste system	Radwaste enclosure
Control room	Control structure
CSCWS	Control structure
Various electrical, instrumentation, and control equipment required for safe shutdown	Reactor enclosure, diesel generator enclosure, control structure, and spray pond pumphouse
SGTS *	Reactor enclosure
RERS *	Reactor enclosure

Table 3.3-2 (Cont'd)

NOTE * The SGTS and the RERS are provided to reduce airborne radiation concentrations in the secondary containment prior to release to the environment for low probability events such as a LOCA. They are not required to achieve safe shutdown. In accordance with Regulatory Guide 1.117, such systems are not required to be protected against tornadoes. However, they are totally enclosed in the reactor enclosure and control structure, which are tornado-resistant enclosures.

Table 3.3-3

WIND SPEED AND CUMULATIVE WIND SPEED DISTRIBUTION FOR TORNADOES WITHIN 125 nm OF POTTSTOWN, PA

Wind Speed Classification	No. of Tornadoes	Percent of Total	Cumulative Percentage
F5 (261 - 308 mph)	0	0.0	0.0
F4 (207 - 260 mph)	0	0.0	0.0
F3 (158 - 206 mph)	15	4.9	4.9
F2 (113 - 157 mph)	93	30.2	35.2
F1 (73 - 112 mph)	154	50.2	85.3
F0 (40 - 72 mph)	43	14.0	99.3
F-1 (<40 mph)	2	0.7	100.0

Table 3.3-4

CALCULATION OF MARGIN BETWEEN DESIGN
AND MAXIMUM EXPECTED WIND LOADINGS

Height Above Ground (Feet)	Fastest Mile[1] (mph)	Max. Expected Wind Pressure on Wall[2] (psf)	Basic Wind Velocity[3] (mph)	Total Design Pressure on Wall[3] (psf)	Margin[4]
30	82	27	90	33	1.22
100	97	38	105	44	1.16
200 (Reactor Enclosure Roof)	108	47	125	63	1.34
300	114	52	125	63	1.21

(1) The fastest mile values of wind are taken from Table 2.3.1-8.

(2) The maximum expected wind pressure on the wall included a gust factor of 1.1 and a shape factor of 1.3 corresponding to its respective fastest mile velocity. The approach described in Section 3.3.1.2 can be used to calculate the maximum expected wind pressure, i.e., $0.002558 (\text{fastest mile } V \cdot 1.1)^2 \cdot 1.3$ or $0.004024V^2$.

(3) Data are taken from Table 3.3-1.

(4) The horizontal and vertical components of the wind pressure are based on the height above ground. Therefore, the margin associated with roof pressure (suction) will be the same as that due to the horizontal pressure on the walls (i.e. 34%).

3.4 WATER LEVEL (FLOOD) DESIGN

3.4.1 FLOOD PROTECTION

3.4.1.1 Flood Protection Measures for Seismic Category I Structures

Seismic Category I structures and the safety-related systems and components housed within them are listed in Table 3.4-1. As discussed in Section 2.4.2.2, the design basis flood level of the Schuylkill River at the site is 207 feet, including wave activity. The shortest horizontal distance from the contour at el 207' to the nearest safety-related structure is approximately 200 feet. Grade level is no lower than el 215' at any of the safety-related structures, and none of the safety-related structures has exterior openings below el 217'. Therefore, the safety-related structures are secure from Schuylkill River flooding and no special provisions for flood protection are necessary. Flooding from internal events is discussed in Section 3.6.1. The impact of local intense precipitation is discussed in Section 2.4.2.3.

Table 2.4-1 lists the access openings in safety-related structures. Two of these doors are below the design basis flood (el 207' MSL) but do not represent a flooding concern. The doors between the reactor enclosure and water pipe tunnel room 202 at el 201' are watertight. The doors between the control structure and the turbine enclosure at el 200' are watertight because the turbine enclosure is not watertight against the PMP as discussed in Section 2.4.2.3.

The failure of nonseismic Category I and nontornado protected tanks, vessels, and major pipes located outside buildings (Table 3.4-2) has also been evaluated and determined to not adversely affect safety-related structures, systems, and components as discussed below.

Tank Failure

The location of tanks in the yard area is shown in Figure 3.8-58. Failure of the tanks on the west and south sides of the power plant complex (Table 3.4-2, items 1 through 5) will not cause potential flooding of safety-related structures, systems, and components. Any flooding due to a failure of these tanks will be contained within seismic Category IIA earth dikes, which will remain stable under both static and dynamic conditions. The design of the earth dikes is discussed in Sections 2.4.12 and 2.5.5.5.

The tanks on the north side of the power plant complex (Table 3.4-2, items 6 through 9) do not have seismically designed containments around them. Failure of these tanks could cause local flooding. This flooding would not adversely affect safety-related facilities for the following reasons:

a. Surface drainage in this area will drain water towards the Schuylkill River and Possum Hollow Run before it can reach the power plant complex.

b. Seismic Category I electrical cable and duct banks located in the vicinity of these tanks are adequate, as discussed below.

Even if the above dikes were to fail, there would be no impact on other safety-related structures, systems, or components due to site drainage.

Failure of Cooling Tower Basin Wall

The failure of the cooling tower basin wall (Table 3.4-2, items 10 & 11) would not adversely affect safety-related structures, systems, and components as discussed below.

The runoff pattern of water from the cooling tower basin wall failure would be similar to that caused by intense storm precipitation as discussed in Section 2.4.2.3 and shown in Figures 2.4-4, 2.4-5 and 2.4-6. Most of the flood water from the cooling tower basin would run away from the power plant complex. The worst case flood conditions for the power plant complex would be created by a failure of the south side of the Unit 1 cooling tower basin wall. For this case, a portion of the cooling tower basin water would flow towards the turbine enclosure. Although some limited turbine enclosure flooding may occur, there would be no impact on safety-related components.

The seismic Category I electrical cable and duct banks and valve pits located in the flow path of the water from the failed cooling tower basin are adequately protected as discussed below.

Failure of Circulating Water Conduit

Failure of the conduit within the yard area between the cooling tower basin and the turbine enclosure (Table 3.4-2, item 12) will cause flooding of this area. Water from the damaged conduit will erode the soil cover and flood the yard.

The runoff pattern will be similar to that shown in Figure 2.4-4. The seismic Category I electrical cable and duct banks and valve pits, located in this area are adequate, as discussed below.

In the most severe case, all the water from the cooling tower basin could drain through the damaged conduit into the yard area between the cooling water pumphouse and turbine enclosure and cause flooding of the condenser pit. However, safety-related systems and components would not be damaged, as discussed in Section 10.4.1.3.3.

Failure of Major Yard Piping

Failure of any of the pipes identified in Table 3.4-2, items 13 through 17, may cause local flooding. However, the intensity and volume of water discharge from any of the pipes is less than that of the cooling water conduit failure discussed above and would not cause damage to any safety-related facilities. Soil erosion caused by failure of these pipes is discussed in Section 3.8.4.1.6.

Safety-related structures, systems, and components, including underground cables, will not be adversely affected by flooding or wetting caused by (1) design basis flood, (2) design basis precipitation or (3) failure of an outdoor tank or tank truck.

The safety-related structures, systems, and components located within the yard area are shown in Figure 3.8-58. Excavation for seismic Category I structures, pipelines, electrical duct banks, manholes, and underground diesel oil storage tanks are shown in Figure 2.5-37.

The design basis flood is not applicable to structures and yard facilities. The design basis flood level with respect to the Schuylkill River is 207 ft (Section 2.4.2.2), which is 10 feet lower than the lowest grade level entrance to any of the safety-related facilities.

The protection of safety-related structures, systems, and components with respect to flooding caused by the design basis precipitation is discussed in Section 2.4.2.3. The runoff patterns for flood water caused by precipitation are shown in Figures 2.4-4 and 2.4-5. Below-grade parts of structures are protected from water intrusion as stated in Table 3.4-1.

The following seismic Category I yard facilities may be susceptible to flooding:

a. 5 Valve pits for RHRSW and ESW piping

b. 8 Valve pits for diesel generator fuel oil storage tanks

The valve pits may be temporarily covered with water during an intense storm or major failure of an outdoor tank. However, the following protective features have been provided to resist resultant flooding of these facilities:

a. They are built as reinforced concrete boxes and are equipped with solid steel manhole covers with gaskets.

b. The tops of slabs of these facilities are elevated 3 to 12 inches above grade.

c. The RHRSW/ESW valve pits are equipped with drain pipes leading seepage water into normal waste drainage system.

d. The diesel generator fuel oil storage tank valve pits' drain lines have been sealed off from the normal waste drainage system to minimize the potential for back flow from the downstream drainage pipe. Administrative controls shall assure that:

- These pits are periodically inspected (at least quarterly) at a frequency sufficient to assure that seepage water does not accumulate to a level at which it would enter the fuel oil tank or jeopardize safety related components in the pits.

- Accumulated seepage water is pumped out of the pits and out of the collection sumps of the concrete base surrounding the fuel oil storage tanks, as necessary.

- The pits are periodically inspected for material conditions adverse to pit flood resistance.

All electrical cables are designed to operate under water. Water absorption characteristics for all cables have been reviewed to confirm that even under flooded conditions, electrical cabling in manholes and duct banks will continue to operate properly. In addition, all electrical conduits that travel to electrical manholes outside the structures are sealed to prevent water from entering the structures through the electrical duct banks (Table 3.4-1).

The design features described above will also protect seismic Category I structures and yard facilities against internal flooding in case of failure of an outdoor tank or tank truck.

3.4.1.2 Permanent Dewatering System

All safety-related structures founded below the design basis groundwater levels can withstand the resulting hydrostatic loading. Safety-related systems and components not located within structures are founded above the maximum groundwater levels. Furthermore, the groundwater levels by safety-related structures, systems, and components are located below the top of rock. Therefore, a permanent dewatering system to protect safety-related structures, systems, and components is not required.

Groundwater does not affect the yard facilities because the design groundwater elevation (Section 2.4.13.5) is generally below yard facilities.

Rubberized flat dumbbell-type water stops have been provided at construction joints below the maximum expected groundwater level listed in Section 2.4.13.5 for all safety-related enclosures.

3.4.2 ANALYTICAL AND TEST PROCEDURES

The safety-related structures listed in Table 3.4-1 are built of reinforced concrete with below-grade exterior walls that are a minimum of 1 foot thick for yard structures and 2 feet thick for the remaining listed structures. The roofs and parapets of all safety-related structures have been analyzed to verify their ability to withstand the static loading resulting from any water confined on the top of the structures due to local intense precipitation (discussed in Section 2.4.2.3).

The safety-related structures founded below the design basis groundwater levels (see Section 2.4.13.5) have been analyzed to verify their ability to withstand the resulting hydrostatic loading.

The spray pond pump structure and other safety-related structures at the spray pond have been designed to withstand the maximum water level in the spray pond.

Table 3.4-1

FLOOD LEVELS AT SAFETY-RELATED STRUCTURES

	STRUCTURE	SAFETY-RELATED SYSTEM OR COMPONENTS HOUSED IN STRUCTURE	ELEVATION OF LOWEST EXTERIOR ACCESS OPENING[1]	DESIGN FLOOD ELEVATION
1.	Reactor Enclosure	Primary containment, ECCS, miscellaneous safety-related systems and components	217'-0"	207.0'
2.	Diesel Generator Enclosure	Diesel generator	217'-0"	207.0'
3.	Spray Pond and Spray Pond Pump Structure	ESW system and RHRSW system	268'-0"	254.9'[2]
4.	Miscellaneous Yard Structures	See Figure 3.8-58	See Figure 3.8-58	207.0'

(1) Penetrations below the lowest exterior access openings typically include underground electrical and piping penetrations. These penetrations are sealed water-tight.

(2) The design basis flood level for the spray pond pumphouse in based on the design basis flood level of the spray pond (Section 2.4.8.2.1).

Table 3.4-2

YARD TANKS AND MAJOR PIPING (NONSEISMIC)

ITEM NO.	TANK OR PIPE DESCRIPTION	CAPACITY OR FLOWS	LOCATION	TYPE OF CONTAINMENT	TORNADO PROTECTION
1	Unit 1 CST tank	200,000 gal.	West of power plant complex	Earth dikes	None
2	Refueling Water	550,000 gal.	West of power plant complex	Earth dikes	None
3	Unit 2 CST tank	200,000 gal.	South of power plant complex	Earth dikes	None
4	Fuel oil storage tank	200,000 gal.	South of power plant complex	Earth dikes	None
5	Deleted				
6	Deleted				
7	Deleted				
8	Clarified water tank	200,000 gal.	Water treatment plant north of power plant complex	None	None
9	Demineralized water tank	50,000 gal.	Water treatment plant north of power plant complex	None	None
10	Cooling tower Basin 1	$7x10^6$ gal.	North of power plant complex	Reinforced concrete walls	None
11	Cooling tower Basin 2	$7x10^6$ gal.	North of power plant complex	Reinforced concrete walls	None
12	Cooling water pipes 8.0 ft diam. 4 pressure pipe each unit	450,000 gpm per unit	Between cooling tower and turbine enclosure	Underground	Soil cover
13	36" ϕ makeup water pressure pipe	30,000 gpm	From Schuylkill River to cooling tower	Underground	Soil cover
14	36" ϕ blowdown gravity pipe	18,000 gpm	From cooling tower to Schuylkill River	Underground	Soil cover

Table 3.4-2 (Cont'd)

15	36" ϕ makeup water pressure pipe	30,000 gpm	From Perkiomen Creek to cooling tower	Underground	Soil cover
16	36" ϕ service water pressure pipe	35,000 gpm	From cooling tower to turbine enclosure	Underground	Soil cover
17	12" ϕ fire loop pressure pipe	2,500 gpm	Around plant complex	Underground	Soil cover

3.5 MISSILE PROTECTION

Where possible, the seismic Category I and safety-related structures, equipment, and systems are protected from missiles through basic station component arrangement so that the missile does not cause the failure of these structures, equipment, or systems. Where it is impossible to provide protection through plant layout, suitable physical barriers are provided to isolate the missile or to shield the critical system or component. Also, redundant seismic Category I components are suitably protected so that a single missile cannot simultaneously damage a critical system component and its backup system. Missile protection provides for either safe operation or shutdown during all operating conditions, operational transients, and postulated accident conditions. Table 3.2-1 provides a tabulation of safety-related structures, systems, and components, along with their applicable seismic category and quality group classification.

3.5.1 MISSILE SELECTION AND DESCRIPTION

3.5.1.1 Internally Generated Missiles (Outside Primary Containment)

There are three general sources of postulated missiles outside the primary containment:

a. Rotating component failure missiles

b. Pressurized component failure missiles

c. Gravitationally generated missiles

3.5.1.1.1 Rotating Component Failure Missiles

The systems located outside the primary containment have been examined to identify and classify potential missiles. Redundant equipment is normally located in different areas of the plant or separated by walls so that a single missile from a rotating mass does not damage both redundant systems.

Catastrophic failure of rotating equipment such as pumps, fans, and compressors leading to the generation of missiles is not considered credible. Massive and rapid failure of these components is unlikely because of the conservative design, material characteristics, inspections, quality control during fabrication and erection, and prudent operation as applied to the particular component.

Additionally, the bases for considering it unlikely for rotating components, other than those identified in this section, to break through their casings and adversely impact safety-related equipment are the following:

A review of event reports on file at the Nuclear Safety Information Center, Oak Ridge National Laboratory, concerning failures of fans and missile generation indicated that a few fan failures have resulted in generation of missiles in safety-related areas of a nuclear facility. Small pump failures resulting in generation of missiles are considered more improbable than fan failures resulting in generation of missiles because pump casings are generally thicker than fan casings and pump speeds are generally lower than fan speeds. Even in the unlikely event that a rotating component does break through its casing, much of the component's kinetic energy would be dissipated in moving through the casing, thereby decreasing the probability of the component adversely

damaging a safety-related component. Therefore, generation of secondary missiles from the internally generated missiles described above is not considered credible. It is an even lower probability that a rotating component would adversely affect redundant safety-related systems because redundant equipment is generally located in different areas or separated by barriers.

Large pumps, such as the RHR and CS pumps, are installed so that the impeller section is surrounded by concrete; additionally, these pumps are located in separate compartments. Therefore, they are not considered a missile hazard to other systems.

Missiles from HPCI or RCIC turbines would be contained by the walls of their compartments that form suitable barriers so that no other systems can be affected by a HPCI or RCIC turbine failure.

Other rotating equipment is not considered to constitute missile hazards because of its small size and/or the unlikelihood that it could move its rotating components through its housing. A review of the analyses of internally generated missiles performed for Palo Verde and San Onofre verified that postulated missiles from pumps and fans (e.g., a pump impeller or fan blade) typically do not have sufficient energy to penetrate the component casings. Because LGS uses pumps and fans that are generally designed and constructed in accordance with the same recognized industry codes and standards as those installed at Palo Verde and San Onofre, the results of the rigorous structural analyses conducted for those plants are indicative of the integrity of LGS equipment.

It was further verified that no internally generated missiles will cause loss of function of any system required for safe shutdown. The plant arrangement was reviewed to ensure that all essential systems or components are either remote from or separated by adequate barriers from potential missile sources.

In any case where a direct path exists between a potential missile source and equipment required for safe shutdown, potential missiles cannot impact more than a single component; therefore redundant equipment will be available to effect safe shutdown.

All HVAC fans located in safety-related enclosures are listed in Table 3.5-6, along with the reason why they are not credible missiles that could adversely affect redundant equipment needed for safe shutdown. For many fans, there are barriers that separate the potential fan blade missiles from essential systems. These barriers consist of walls, floors, and ceilings that totally enclose the potential missile and are sufficiently thick to prevent spalling. All redundant fans needed for safe shutdown are separated by adequate barriers. Class I seismic duct-work of a thickness substantially greater than normal duct-work is utilized in safety-related areas that have duct-work, which should preclude escape of a potential missile from connecting duct-work.

A review was also made of the fan installation drawings to ensure no inlet conditions to fans existed that could result in operating conditions that would impose cyclical fatigue on fan blades resulting in blade cracks. No such conditions exist.

The only fan blades that have the potential for damaging redundant components needed for safe shutdown, if they escape through their casing, are the drywell area unit cooler fans. A study was performed for these fans which demonstrated that the fan blades do not have sufficient kinetic energy to penetrate their casings. In addition, a complete physical inspection of all drywell unit cooler fan blades for blade angle, verification of proper torque on blade retaining bolts, and lock

wiring of the bolts by the manufacturer's representative was conducted to ensure that no blades would loosen during operation. This inspection is documented in the quality records.

3.5.1.1.2 Pressurized Component Failure Missiles

The following are potential internal missiles from pressurized equipment:

a. Valve bonnets

b. Valve stems

c. Temperature detectors

d. Nuts and bolts

Pressurized components in systems where service pressure exceeds 275 psig are evaluated as to their potential for becoming missiles.

Most valves of ANSI 900 psig rating and above and most valves of 600 psig rating, constructed in accordance with ASME Section III, are pressure seal bonnet type valves. For pressure seal bonnet valves, valve bonnets are prevented from becoming missiles by the retaining ring, which would have to fail in shear, and by the yoke, which would capture the bonnet or reduce bonnet energy. Because of the highly conservative design of the retaining ring of these valves, bonnet ejection is highly improbable and hence the bonnets are not considered credible missiles.

The remaining valves of ANSI rating 900 psig and below are valves with bolted bonnets. Valve bonnets are prevented from becoming missiles by limiting stresses in the bonnet-to-body bolting material by requirements set forth in the ASME Section III and by designing flanges in accordance with applicable code requirements. Even if bolt failure were to occur, the likelihood of all bolts experiencing simultaneous complete severance failure is remote. The widespread use of valves with bolted bonnets and the low historical incidence of complete severance failure of bonnets confirm that bolted valve bonnets need not be considered as credible missiles.

Valve stems are not considered potential missiles if at least one feature in addition to the stem threads is included in their design to prevent ejection. Valves with back-seats are prevented from becoming missiles by this feature. In addition, air or motor-operated valve stems are effectively restrained by the valve operators.

Temperature or other detectors installed on piping or in wells are considered highly improbable missiles, since a complete and sudden failure of a circumferential weld is needed for a detector to become a missile.

Nuts, bolts, nut and bolt combinations, and nut and stud combinations have little stored energy and thus are of no concern as potential missiles.

In addition, high pressure gas cylinders and accumulators are not considered credible internally generated missiles impacting on redundant safety-related equipment for the following reasons:

a. All accumulators located in areas that contain safety-related equipment are listed in Table 3.5-3, along with the maximum pressure and temperature at which they operate. These accumulators have low stresses and operate in the "moderate energy" range. Therefore, any failures would not be of concern for missile generation.

b. Safety-related gas cylinders and accumulators are seismically supported, which ensures that they will not become gravity-generated missiles during design basis conditions. Nonsafety-related cylinders and accumulators are seismically restrained if they are located in the vicinity of safety-related components.

c. High pressure gas (H_2, O_2, N_2, Kr) cylinders meet the manufacturing and test requirements of the DOT standards, 49CFR178.37, Specification 3AA and ICC standards. Vessel wall thickness requirements of both standards are comparable to ASME Section III, Class 3 requirements. Because of this highly conservative design, any failure of these cylinders that would cause them to become missiles is highly improbable.

d. Halon gas cylinders used in the fire protection system are located in the turbine enclosure and are isolated from safety-related equipment.

3.5.1.1.3 Gravitationally Generated Missiles

Installed equipment and components in safety-related plant areas outside containment are designed and installed so that they would not present gravitational missile hazards to safety-related structures, systems, or components during or after an SSE. This is achieved for safety-related equipment by seismic Category I design and installation (in accordance with Regulatory Guide 1.29 criteria) and for nonsafety-related equipment by seismic Category IIA design and installation (Section 3.2). Nonpermanently installed equipment is either removed from the safety-related areas, adequately separated from safety-related components, or secured in place before reactor operation to ensure that it would not present a missile hazard.

The information requested in the generic letter dated December 22, 1980 regarding conformance to the criteria contained in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants" is provided in Reference 9.1-1.

3.5.1.2 Internally Generated Missiles (Inside Containment)

There are three general sources of postulated missiles inside the primary containment:

a. Rotating component failure missiles

b. Pressurized component failure missiles

c. Gravitationally generated missiles

3.5.1.2.1 Rotating Component Failure Missiles

The most substantial piece of NSSS rotating equipment is the recirculation pump and motor. This potential missile source is covered in detail in Reference 3.5-1.

It is concluded in Reference 3.5-1 that destructive pump overspeed can result in certain types of missiles. A careful examination of shaft and coupling failures shows that the fragments do not result in damage to the containment or to vital equipment.

a. Low energy missiles (kinetic energy less than 1,000 ft-lbs):

   Low energy level missiles may be created at motor speeds of 300% of rated through failure of the end structure of the rotor. The structure consists of the retaining ring, the end ring, and the fans. Missiles potentially generated in this manner would strike the overhanging ends of the stator coils, the stator coil bracing, support structures, and two walls of ½ inch thick steel plate. Due to the ability of these structures to absorb energy, it is concluded that missiles would not escape this structure. It is at this point that frictional forces would tend to bring the overspeed sequence to a stop.

b. Medium energy missiles (kinetic energy less than 20,000 ft-lbs):

   In the postulated event that the body of the rotor bursts, medium energy missiles could be created. The likelihood that these missiles would escape the motor is considered less than the likelihood of escape for the low energy missiles described above, due to the additional amount of material constraining missile escape, such as the stator coils and stator frame directly adjacent to the rotor.

c. The motor as a potential missile:

   Since bolting is capable of carrying greater torque loads than the pump shaft, pump bolt failure is precluded. Since pump shaft failure decouples the rotor for the overspeed driving blowdown force, only those cases with peak torques less than that required to fail the pump shaft (five times rated) have the capability to drive the motor to overspeed. When missile generation probabilities are considered along with a discussion of the actual load-bearing capabilities of the system, it is evident that these considerations support the conclusion that it is unrealistic that the motor would become a missile.

It is concluded that the other rotating components inside the containment, such as fans, do not have sufficient energy to move the masses of their rotating parts through the housings in which they are contained and therefore are not considered missile hazards. Additional evaluation and discussion of the potential for rotating equipment generated missiles to impact safety-related equipment is provided in Section 3.5.1.1.1 above.

3.5.1.2.2 Pressurized Component Failure Missiles

It is concluded that potential internal missiles inside the containment from pressurized components are not considered credible for the same reasons listed in Section 3.5.1.1.2.

3.5.1.2.3 Gravitationally Generated Missiles

Installed equipment and components in the containment are designed so that they would not present gravitational missile hazards to safety-related structures, systems, or components during or

after an SSE. This is achieved for safety-related equipment by seismic Category I design and for nonsafety-related equipment by seismic Category IIA design, as discussed in Section 3.2. Nonpermanently installed equipment is either removed from the containment or secured in place before reactor operation to ensure that it does not become dislodged and present a missile hazard.

3.5.1.3 Turbine Missiles

The turbine inspection program which is being implemented in Section 10.2.3.6 uses a probabilistic approach for scheduling the inspection and replacement of the low pressure turbine rotors with shrunk-on discs. This turbine inspection program is based upon the missile probability analysis methodology in Reference 3.5-15 and the probabilistic approach established in NUREG 1048 (Reference 3.5-14). The approach in Reference 3.5-14 was found acceptable by the NRC for use in establishing maintenance and inspection schedules for specific turbine systems including the original Main Turbines installed at Limerick Generating Station. As a result of the replacement of the original Main Turbines, the missile probability analysis methodology in Reference 3.5-15 has been adopted to maintain the probabilistic approach to determine the inspection program for the installed turbine system. The overspeed protection system and turbine valve test interval was determined by References 3.5-16 and 3.5-17 in accordance with the missile probability analysis methodology in Reference 3.5-15.

The intent of the program is to ensure that the probability of a turbine generating a missile is maintained less than $1x10^{-5}$ per year. The program takes into account specific turbine wheel operating conditions, material properties, results of periodic in service inspections, and other factors. The program's determination of missile probability is based on the probabilities of individual parameters which may lead to the generation of the turbine missile. As a result, the program can facilitate evaluations of the effects of changes in any parameter. Table 3.5-9, Turbine System Reliability Criteria, has been extracted from table U.1 of Reference 3.5-14, for use with an unfavorably oriented turbine. The probability of unacceptable damage from turbine missile will be maintained at less than or equal to $1x10^{-7}$ per year.

Schedules for future inspection and replacement of low pressure turbine rotors with shrunk-on discs will be based on the probabilistic approach.

3.5.1.4 Missiles Generated by Natural Phenomena

Only tornado-generated missiles have been considered. Missiles used in the design and assessment of structures and openings are listed in Table 3.5-4. All safety-related structures, systems, and components listed in Table 3.2-1 were reviewed for adequacy against tornado-generated missiles listed in Table 3.5-4. These safety-related structures, systems, and components are designed either to resist tornado missiles in accordance with Reference 3.5-6 or are protected by these tornado-resistant enclosures. The structures designed for these tornado missiles and the systems protected are listed in Table 3.3-2. Table 3.5-8 provides information on the characteristics of these barriers. Additionally, ESW and RHRSW systems yard piping is protected by burial and separation of redundant loops.

The exterior walls and roof thicknesses have been evaluated for the tornado-resistant enclosures listed in Table 3.3-2 and are capable of withstanding all of the missiles listed in Table 3.5-4. The 4000 psi strength concrete walls and roofs have minimum thicknesses of 24 inches and 18 inches, respectively (Table 3.5-8). This exceeds the minimum acceptable missile barrier thickness requirements specified in table 1 of SRP (NUREG-0800, July 1981) section 3.5.3.

Where necessary to protect safety-related components, the doors in these enclosures have been designed to withstand the 1 inch steel rod, the utility pole, the 6 inch steel pipe, and the 12 inch pipe in addition to the original three design basis missiles. This design is in accordance with the SRP (NUREG-0800, July 1981).

The probability of any of the above tornado missiles penetrating any of the openings and structures (not specifically designed to be resistant to the above missiles) and adversely impacting safety-related components, such that safe shutdown is prevented, is considered low for the following reasons:

a. The total area of the nontornado-resistant features that have safety-related components located behind them is extremely small compared to the total area of the tornado-resistant portions of the enclosures.

b. To penetrate a nontornado-resistant feature and travel a sufficient distance to impact a safety-related component, a missile would need to strike the feature at a perpendicular angle.

c. Much of the missile's kinetic energy would be dissipated in breaking through the nontornado-resistant feature, which reduces the possibility of the missile adversely damaging a safety-related component even if it strikes one.

d. Redundant safety-related components are normally located in different areas of the plant or yard or are separated by walls so that a single tornado missile would not damage both redundant systems.

Evaluations have been carried out considering all seven tornado missiles listed in Table 3.5-4 and their penetration/impact on the openings and nontornado designed structures of the plant including manhole covers and valve pit roofs. Even though some singular safety-related components may be affected, damage would not occur to all redundant systems, and safe shutdown could be achieved even when assuming an additional single active failure.

LGS is in conformance with Regulatory Guide 1.117 regarding systems to be protected from tornado missiles except as discussed below where unacceptable damage to unprotected spray networks is not considered credible.

As described in Section 9.2.6, the ultimate heat sink at LGS is an excavated spray pond with a surface area of 9.9 acres. Four spray networks, each having 50% capacity for shutdown of two units, are provided.

Details of the spray pond excavation and finished grading are shown in Figures 3.8-55, 3.8-56, and 3.8-57. The general arrangement of the spray pond, spray networks, and spray pond pump structure is shown in Figure 9.2-6. The layout of the spray networks is shown in M-384.

As discussed in Section 3.5.1.4, all essential structures, systems, and components related to the ESW system, RHRSW system, and the UHS are protected from the effects of tornadoes and tornado missiles. Protection of the spray networks from tornado missiles is provided by location of

the network piping and sprays below the surrounding grade and by physical separation of the networks:

a. In all but the spillway area, the surrounding grade is in excess of el 260' while the top of the sprays are at el 258' and the spray network piping is between el 253'-5" and el 256'-8".

b. The closest branches of adjacent spray networks are separated by 65 ft.

c. The supply piping to adjacent networks is separated by 215 ft.

d. The networks are located at a minimum distance of 72 ft from the edge of the pond.

The use of elevational differences and physical separation to provide protection of the spray pond networks from tornado missiles is justified by the following considerations:

a. Only two spray networks are required for the safe shutdown of both units.

b. The only active failure that can compromise the operability of a spray network is failure of its supply valve (HV-012-032A, B, C or D). These valves may be manually operated to isolate damaged networks or to initiate the use of undamaged networks if their controls or motors are inoperable.

c. The physical arrangement of the spray networks precludes the possibility that large missiles can damage more than one spray network due to trajectory considerations. Multiple missiles of sufficient energy and distribution to substantially damage multiple networks are unlikely. Network piping varies in size from the 30 inch diameter supply headers to the 2 inch diameter piping at the extreme ends of the distribution branches. Network piping wall thickness varies from 0.337-0.500 inch.

d. The loss of some sprays in a network does not result in substantial loss of heat removal capability for the entire network (each network contains 240 spray nozzles).

e. The design thermal performance of the spray pond is based on conservative design values of initial pond temperature and meteorology as described in Section 9.2.6.4. For all expected conditions, the margin in thermal performance would be considerably greater than the 10% margin demonstrated under design conditions. In fact, for average meteorological conditions, a single spray network is sufficient for the removal of the heat rejected from both units for at least a 24 hour period.

f. Interconnections are provided that allow the use of the cooling towers as a heat sink for ESW and RHRSW systems. Such operation may be initiated from the control room or locally by manual operation.

It is unlikely that tornado winds would compromise the heat removal capability of the spray pond networks, or the cooling towers, to the extent that safe shutdown of the units would be affected. The spray networks have been designed to withstand design basis tornado winds. While not specifically designed to withstand design

basis tornado winds, the cooling tower shell and supporting structure have been designed to withstand the following wind loading when either operating or dry:

Elevation Above Grade (ft)	Wind Velocity (mph)
30	90
150	113
200	118
300	125
400	130
500	135

The cooling towers are expected to provide sufficient heat removal capability for the safe shutdown of the units even in the event that the tower fill is extensively damaged.

g. The loss of more than two spray networks and the coincident loss of the cooling towers due to tornado missiles is unlikely due to physical separation of the cooling towers and the spray pond. The cooling towers are located approximately 600 feet from the nearest portion of a spray network.

The likelihood of tornado winds and/or missiles affecting the safe shutdown capability of the cooling towers and spray networks at the same time is quite remote when the above described design factors are considered together with the variation in tornado intensity along its path length and width (Reference 3.5-2).

h. Tornado missiles are an insignificant contributor to plant risk because of the low frequency of occurrence of tornadoes in this region (EROL section 2.3.1.2.2) and the low likelihood of damaging missiles if one were to occur.

Even if the safe shutdown capability of the cooling towers and spray networks were compromised by tornado effects, use of the cooling tower basins and/or UHS in a "cooling pond type" mode would allow substantial time for spray network repair. A plant procedure governs such repair activities. This procedure will contain, at a minimum, the following elements:

1. Repair work on damaged spray networks will begin immediately, using materials, equipment, and personnel that have been verified to be available. Procedure verification will be made each year.

2. On current loss of all UHS spray headers and all cooling tower cooling capacity, the spray pond will be operated as a closed cycle cooling pond until the temperature of the water reaches the design limit of 95°F. In this mode, water will be returned to the pond via the winter bypass line to promote thermal mixing and minimize the likelihood or recirculation.

   Under design basis conditions of initial pond temperature and meteorology, it would take approximately 6 hours for the pond to reach the 95°F limit.

Under average conditions, it would take approximately 10 hours to reach this limit. Both numbers are for two-unit, full power operation. For single-unit operation, these times would be approximately 12 hours and 20 hours, respectively. The heat rejection rate can be further reduced by depressurizing the reactor at a slower rate than 100°F/hr assumed in the design basis analysis.

3. When the pond reaches the design temperature limit, the sluice gates between the spray pond pumphouse wet wells and the spray pond will be closed. Water will be released from the cooling tower basins into the wet wells and pumped through the plant to service the required heat loads. The water will be returned to the spray pond and allowed to discharge over the blowdown weir and storm spillway.

   The two cooling tower basins contain a total of 14 million gallons. If it is conservatively assumed that only one-half of this volume of water is available, there is sufficient water to provide makeup for the ESW and RHRSW pumps, operating in a once-through mode, for an additional 4 hours. In the unlikely event that the cooling tower basin walls have failed due to tornado missiles, the additional time of 4 hours would not be available. However, the spray pond PRA demonstrates that it is extremely improbable that the four spray pond networks would not be available.

4. Sufficient makeup water can be supplied to the cooling tower basins to sustain continuous operation in this mode for a number of sources as described in Item i.

i. The Schuylkill River makeup pumphouse is located approximately 1500 ft from the nearest cooling tower, making it unlikely that the pumphouse would be damaged by a tornado that would also compromise the spray pond networks and the cooling towers. The pumphouse is powered from the 2300 V plant services switchgear. The switchgear can be fed using offsite power from either of the two plant substation via underground lines. The two substations are approximately 2000 ft apart, making it highly unlikely that both substation would be disabled by a tornado that would also compromise the spray pond networks and the cooling towers.

   While an additional source of water is available from the pump station to provide the Perkiomen makeup supply located approximately 8 miles from the plant site, no reliance is being placed on this intake for the purpose of safety analysis nor the safety licensing basis for the facility.

   If existing sources of makeup cannot be made available in a timely manner, makeup will be provided using available portable pumps of required size and capacity to pump water from the Schuylkill River to the spray pond pumphouse wet wells. The water would be pumped via a tie-in to the existing underground water pipeline from the Schuylkill River intake pumphouse to the cooling tower basins. It would flow via gravity to the pump pits. If a tie-in to the existing pipeline is not possible, the water would be pumped directly to the wetwell through temporary

lines. The portable pumps that would be used are either licensee owned or rental pumps. The required pumps will be verified to be available on an annual basis.

j. Plant EOPs address the various contingency actions available to the operators to deal with degraded UHS conditions. As indicated in the above discussions, substantial time is available for corrective operator actions. If UHS capability should be lost for such a period of time that conditions degraded considerably, the EOPs would direct the use of equipment that would achieve a safe stable state regardless of UHS capability.

3.5.1.5 Missiles Generated by Events Near the Site

The safety-related structures, systems, and components were reviewed for adequacy against missiles externally generated by railroad explosions. The safety-related facilities are either designed to resist the externally generated missiles in accordance with Reference 3.5-6 or are protected by these missile-resistant barriers. The barriers designed to resist externally generated missiles and the corresponding systems and components protected by these missile barriers are listed in Table 3.5-7.

The nearest possible train explosion accident and its consequent missiles are considered to be the most severe missile-generating event that could occur near the site. The postulated missiles resulting from such an accident considered in the design of structures protecting safety-related systems are listed in Table 3.5-5. Missiles resulting from truck, industrial, and pipeline explosions would be less severe and therefore are not considered. As demonstrated in Section 2.2, there is no potential for missiles from ship or barge explosions or military installations. Descriptions of the railroad, its location relative to the plant, the railroad explosion, and explosions from other sources are given in Section 2.2.

3.5.1.6 Aircraft Hazards

The safety-related structures, systems, and components were reviewed for adequacy against missiles externally generated by aircraft accidents. The safety-related facilities are either designed to resist the externally generated missiles in accordance with Reference 3.5-6 or are protected by these missile-resistant barriers. The barriers designed to resist externally generated missiles and the corresponding systems and components protected by these missile barriers are listed in Table 3.5-7.

Airports and aircraft activity in the vicinity of the site are discussed in Section 2.2.2. Based on the airport and aircraft information provided in Section 2.2.2, an analysis has been performed using the methodology of SRP section 3.5.1.6 to demonstrate that the probability of an aircraft accident causing damage to safety-related equipment or structures sufficient to result in radiological consequences that are a significant fraction of 10CFR50.67 exposure guidelines is lower than the acceptance criteria of SRP section 3.5.1.6.

3.5.1.6.1 Design of Safety-Related Structures

Aircraft operating or capable of operating out of nearby airports are listed in Table 3.5-1. Based on the estimated maximum kinetic energy at impact and corresponding local damage to concrete elements, the Learjet is determined as the design aircraft for the design of safety-related structures.

The characteristics of the Learjet are presented in Table 3.5-2, and the associated load curve acting on structures due to the impact is shown in Figure 3.5-1. The design aircraft is assumed to impact perpendicularly to the vertical surface of the buildings or to impact at a glide angle of 15° from horizontal on the roof of buildings. The reactor enclosure, control structure, and spray pond pump structure are designed to withstand the impact of the design aircraft without loss of structural integrity. Safety-related equipment and systems located therein are designed to remain functional. The diesel generator enclosures are not designed to withstand aircraft impact.

3.5.1.6.2 Analysis Method

The probability of damage to structures containing safety-related equipment (P) is calculated from the formula:

$$P = \sum_{i=1}^{L} \sum_{j=1}^{M} N_{ij} C_{ij} A_{ij} \qquad \text{(EQ. 3.5-1)}$$

where:

L	=	number of different flight paths that affect the site
M	=	number of different types of aircraft that may constitute a hazard
N_{ij}	=	number of movements per year by aircraft j operating in flight path i
C_{ij}	=	probability of a crash per square mile per aircraft movement for aircraft j operating in flight path i
A_{ij}	=	effective plant area (square miles) for aircraft j operating in flight path i

Values for the above parameters and related assumptions are discussed in the following sections.

3.5.1.6.2.1 Aircraft Movements (N_{ij})

In addition to the movements, type of aircraft, and other particulars of aircraft operation described in Section 2.2.2, the following considerations for each of the sources of aircraft movement apply.

Pottstown-Limerick Airport - The analysis assumes that 90% of the takeoffs (45% of the movements) are towards the west, in the direction of the site, and that 10% of the landings (5% of the movements) are from the west, in the direction of the site. This is based on the VFR and IFR information provided in Section 2.2.2. The flight restrictions discussed in Section 2.2.2 are accounted for in the analysis.

Based on the approach pattern for Pottstown-Limerick Airport, the holding area is at least 3.8 miles northeast of the runway, which would locate the holding area more than 5 miles northeast from the site. Due to the distance and direction, no additional movements involved with the holding pattern were considered in calculating the aircraft crash probability.

Pottstown Municipal Airport - The proportions of single-engine and twin-engine aircraft using the airport are assumed to be 70% and 30%, respectively. Based on the information provided in Section 2.2.2, it is assumed that 50% of the takeoffs involve eastbound passes over the site, with the remainder to be north and west away from the site. Similarly, it is assumed that 50% of the landings involve northbound flight patterns over the site.
New Hanover Airport, Sunset Landing Strip and Perkiomen Valley Airport - The projected annual number of operations for these facilities located between 5 and 10 miles from the site is less than 500 D^2. In accordance with SRP section 3.5.1.6, their contributions to the total probability are extremely small and are not considered in the analysis.

Federal Airways - The traffic data presented in Section 2.2.2 are employed in the analysis. It is conservatively assumed that the Boeing 727 is representative of traffic in these airways.

LGS Plant Site Heliport - The analysis is based on 156 landings and 156 takeoffs per year. The helicopter parameters used are given in Table 3.5-1. These parameters are bounded by those of the Learjet, which was the design basis aircraft for impact.

3.5.1.6.2.2 Aircraft Crash Probability (C_{ij})

Pottstown-Limerick and Pottstown Municipal Airports

Aircraft crash probabilities from the SRP section 3.5.1.6, are used in this analysis. The SRP specifies the crash probability per square mile in an annular sector 60° on each side of the extended runway centerline as a function of the distance from the end of the runway.

Accordingly, the crash probability for U.S. general aviation at a distance of 1-2 miles of 1.5×10^{-7} per square mile per aircraft movement is used for Pottstown-Limerick Airport. This probability is also applied to the rotary-wing operations at that airport. For Pottstown Municipal Airport, the U.S. general aviation probability for 4-5 miles, 1.2×10^{-8} per square mile per aircraft movement, is used. The use of this value for Pottstown Municipal Airport is conservative because LGS lies outside the 60° sector of the extended runway centerline.

LGS Plant Site Heliport

The crash probability for the helicopter traffic using the plant site heliport is based on NTSB and FAA nationwide statistics on the estimated number of helicopter flight hours for 1979 and the number of fatal helicopter crashes during takeoff and landing during that same year, and is equal to 4.88×10^{-7} per takeoff or landing.

Federal Airways

For commercial aircraft in the Federal airways, a model for the probability that an aircraft crash will result at a distance (x) normal to its flight path is employed, which was developed by Solomon (References 3.5-7 and 3.5-8) using a negative exponential distribution. Solomon's model requires estimation of the deviation, which was determined by a 20° angle from the flight path. A deviation is estimated here by referencing Solomon's angle at 14,000 feet, and adding one mile for deviation in the airway. This gives the probability:

$$f(x) = \frac{1}{3.94} e^{-x/1.97} \qquad \text{(EQ. 3.5-2)}$$

Where:

x = distance in miles

The probability that an enroute crash will occur is about 0.45×10^{-9} per flight path mile, based upon U.S. commercial aviation performance in the period 1970-75 (Reference 3.5-9). Thus, the crash probability at the site per passage in each of the Federal airways can be estimated by the product of these two probabilities.

The resulting probabilities are as follows:

Airway	x (miles)	Probability (per square mile)
V29/147	1.3	5.9×10^{-11}
Pottstown VOR 320° radial	1.3	5.9×10^{-11}
V210	8.0	2.2×10^{-12}
V276	10.0	7.1×10^{-13}

3.5.1.6.2.3 Critical Target Areas (A_{ij})

The aircraft crash probability estimates the chance that a given aircraft maneuver (passage, takeoff, or landing) would result in striking the ground within a specific unit area, without regard to the obstruction of surrounding objects. If the assumed flight ray of the aircraft in crashing should pass through an obstructing object, then the probability of crash into that obstructing object is the same as for the associated unit ground area.

The determination of target areas are based on the following considerations:

a. The skid area, associated with a ground strike ahead of a wall, followed by sliding into the wall. The controlling parameters for the target area of this mode are the width of the wall normal to the skid path (augmented by the wingspan of the striking aircraft), and the distance the aircraft will slide.

b. The roof or plan area (augmented by the wingspan of the striking aircraft), which may be projected to an equal ground area regardless of the angle of flight path slope.

c. The wall shadow area, (Bh) cot (A), which is the ground area projected by a wall of vertical dimension (h), width (B) normal to the flight path (and augmented by the

wingspan of the striking aircraft), with aircraft glide path making an angle (A) with the ground.

d. Shadowing of target structures by other structures.

Skid lengths are calculated from the equation provided in Reference 3.5-5:

$$L_s = \frac{6.3 \times 10^{-6}}{k} V^2 \qquad \text{(EQ. 3.5-3)}$$

where:

L_s = skid length (miles)

k = roughness factor (set equal to 2.5)

V = velocity (mph)

The glide angle is assumed to be 15° for fixed-wing aircraft. For rotary-wing aircraft, it is assumed to be 0° because of the poor aerodynamic characteristics of such aircraft. The skid length for rotary-wing aircraft is therefore considered to be zero feet.

The impact velocity for single-engine and twin-engine general aviation aircraft is estimated to be 110 mph. Therefore, from Equation 3.5-3, the skid length is 0.0305 miles or 161 feet. The impact velocity of a Boeing 727, assumed to be the average aircraft in the Federal airways, as discussed in Section 3.5.1.6.2.1, is taken as 290 mph, yielding a skid length of 0.212 miles or 1120 feet.

The analysis assumes that single-engine aircraft have a wingspan of 32 feet, twin-engine aircraft have a wingspan of 50 feet, and the wingspan of a Boeing 727 is 110 feet.

Pottstown-Limerick and Pottstown Municipal Airports

As discussed in Section 3.5.1.6.1, the reactor enclosure, control structure, and spray pond pump structure are designed to withstand the impact of the largest aircraft capable of operating out of the nearby airports, the design basis Learjet, and are therefore not considered in the calculation of critical target areas.

The spray pond itself is not susceptible to aircraft damage because it is constructed completely in excavation, as discussed in Section 2.5. Aircraft damage to the spray pond spray network is not considered because the design provides for separation and redundancy so that the loss of a network would not affect the systems safety function.

The diesel generator enclosures for Units 1 and 2 each have an east-west dimension of 108 feet, a north-south dimension of 84.5 feet, and a height of 29 feet. The two structures are separated by 54 feet in the east-west direction.

Flight paths of concern for the diesel generator enclosures are those in the east, west, and northbound directions. There are no intervening structures for northbound aircraft. The critical

target area for single-engine aircraft is 3.51×10^{-3} square miles and 4.01×10^{-3} square miles for twin-engine aircraft.

For westbound traffic, the reactor enclosures and the administration building provide shadowing to the diesel generator enclosures. The reactor enclosures, located north of the diesel generator enclosures, reduce the effective target area for westbound aircraft to 84.5 feet plus one-half the aircraft's wingspan. The warehouse and shop area, located to the east of the diesel generator enclosures, effectively eliminates the skid area. The resultant critical target areas for single-engine aircraft is 1.36×10^{-3} square miles, and 1.49×10^{-3} square miles for twin-engine aircraft.

For eastbound traffic, shadowing to the diesel generator enclosures is provided by the reactor enclosures and the radwaste enclosures. The resultant critical target areas are 1.68×10^{-3} square miles for single-engine aircraft and 1.86×10^{-3} square miles for twin-engine aircraft.

For southbound traffic, the critical target area for diesel generators is zero due to the shadowing afforded by the reactor enclosure.

For rotary-wing aircraft, the critical target area of the diesel generator enclosure is 6.55×10^{-4} square miles.

LGS Plant Site Heliport

The probability of a crashing helicopter impacting the diesel generator building is determined based on the known flight path of the helicopter traffic using the heliport, the closest distance this flight path comes to the diesel generator building, and the deviation from the flight path.

The possible deviation from the bounding traffic pattern for landing or takeoff path is represented by an exponential density function of the form:

$$f(x;\lambda) = \lambda e^{-\lambda x} \qquad \text{(EQ. 3.5-4)}$$

where:

$f(x;\lambda)dx=$ the probability that the deviation is in the range (x, x+dx);

x = the perpendicular distance (deviation) from the flight path;

λ = the exponential distribution parameter.

The exponential distribution parameter, λ, is the inverse of the expected value of x. The expected value of x, *x* has been chosen as the mean distance which the helicopter can travel from an altitude (h). Therefore, *x* is given by:

$$x = h \tan(\phi)$$

The angle ϕ is conservatively assumed to be the helicopter glide angle due to loss of a rotor. The expected altitude (h) of the helicopter on an approach or departure from the helipad is given by:

$$h = a \tan(\theta)$$

The angle θ, the approach angle, is conservatively assumed to be 15°, and (a) is the distance from the helipad.

Using the above information, λ is given by:

$$\lambda = \frac{1}{a \tan(\phi) \tan(\theta)}$$

The probability of impacting at a distance greater than (d) perpendicular to the flight path on one side of the flight path, is then given by the cumulative distribution function:

$$P(>d) = 0.5\, e^{-\lambda|d|}$$

The probability of impact on the diesel generator enclosure is greatest when the helicopter is on the approach path 675 feet from the helipad and 1,100 feet laterally from the diesel generator enclosure. The average conditional probability of impacting the diesel generator enclosure from a crash for all three types of helicopters given in Table 3.5-1 is 7.66×10^{-4}.

Federal Airways

The reactor enclosure, control structure, and diesel generator enclosures are considered in the calculation of critical target areas. The spray pond pump structure represents only about 5% of the total target areas of safety-related structures, and its contribution to the overall probability is considered negligible.

The spray pond is not susceptible to aircraft damage because it is constructed completely in excavation, as discussed in Section 2.5. Aircraft damage to the spray pond spray network is not considered because the design provides for separation and redundancy so that the loss of a network would not affect the systems safety function.

Because the majority of airway traffic is northbound, the analysis considers the south faces of the diesel generator enclosures and the reactor enclosures as the target area. The calculated critical target area is 3.33×10^{-2} square miles.

3.5.1.6.3 Crash Probabilities

Based on the given data and assumptions regarding the number of aircraft movements (N_{ij}), aircraft crash probability (C_{ij}), and critical target areas for the plant (A_{ij}), the probability of an aircraft striking to safety-related structures has been calculated.

For operations out of the Pottstown Municipal Airport, the probability of an aircraft striking the diesel generator enclosures is given by:

$$P = 1.2 \times 10^{-8} \bullet [1.73N_e + 1.40N_w + 3.66N_n] \times 10^{-3}\ yr^{-1} \quad \text{(EQ. 3.5-5)}$$

where:

N_e = number of eastbound movements over the site

N_w = number of westbound movements over the site

N_n = number of northbound movements over the site

and the target areas have been weighted to reflect the proportion of single and twin-engine traffic.

For

$N_e = N_n = 4000; N_w = 0,$

this yields a crash probability of 2.59×10^{-7} per year.

Similarly, for operations out of the Pottstown-Limerick Airport, the probability is given by:

$$P = 1.5 \times 10^{-7} \cdot [1.73N_e + 1.40N_w + 3.66N_n + 0.655N_r] \times 10^{-3} \text{ yr}^{-1}$$

(EQ. 3.5-6)

where:

N_r = number of rotary-wing operations over the site from the Pottstown-Limerick Airport.

For

$N_e = 1500, N_w = 13500, N_n = 0; N_r = 0,$

this yields a crash probability of 3.2×10^{-6} per year.

For operations out of the LGS plant site heliport, the probability of a helicopter striking the diesel generator enclosure is the product of the number of takeoffs and landings per year, the probability of the helicopter crashing during takeoff or landing, and the probability that the crashing helicopter will impact the diesel generator building:

$$P = 312 \cdot 4.88 \times 10^{-7} \cdot 7.66 \times 10^{-4}$$

$$= 1.17 \times 10^{-7} \text{ per year}$$

The probability of an aircraft in one of the airways near the site striking the diesel generator enclosures, or the reactor enclosures is given by:

$$P = [(8395 + 20240)(590) + (46355)(22) + (4745)(7.1)] \times 10^{-13} \cdot 0.0333$$

$$= 5.98 \times 10^{-8} \text{ yr}^{-1} \quad \text{(EQ. 3.5-7)}$$

3.5.1.6.4 Probability of Aircraft Strike Resulting in Unacceptable Consequences

Given the aircraft impact resistant design of all safety-related structures except the diesel generator enclosures, an aircraft strike could jeopardize safe shutdown capability or have potential offsite dose consequences only under the following scenarios:

(1) The impacting aircraft is larger in size than the design basis aircraft described in Section 3.5.1.6.1, and the impact causes structural failure and/or damage to systems required to achieve or maintain safe shutdown, resulting in the possibility of offsite consequences in excess of 10CFR50.67 guidelines.

(2) The impacting aircraft strikes a diesel generator enclosure, damaging more than 2 diesel generators, thereby leaving that unit dependent on offsite power for achieving and maintaining shutdown. During the period required to return at least 2 diesel generators to service, a complete loss of offsite power occurs, which leaves the affected unit dependent on its Class 1E battery system to achieve and/or maintain safe shutdown. If offsite power is not restored before the batteries are exhausted, inadequate core cooling and offsite radiological consequences in excess of 10CFR50.67 guidelines could result.

The probabilities of scenarios (1) and (2) occurring are calculated as follows:

Scenario 1: Impact By Aircraft Larger Than Design Basis Aircraft

This scenario is credible only for aircraft in Federal airways. It is conservatively assumed for this analysis that the impact of any aircraft using the Federal airways causes damage such that offsite radiological consequences in excess of 10CFR50.67 occur. The probability of such an impact causing unacceptable radiological consequences is therefore equal to the crash probability of an aircraft in one of the airways near the site, shown in Section 3.5.1.6.3 to be 5.98×10^{-8} per year.

Scenario 2: Diesel Generator Damage Caused By Impact Of Design Basis or Smaller Aircraft

The probability that aircraft operating out of the Pottstown- Limerick Airport, the Pottstown Municipal Airport, and the LGS plant site heliport will impact the diesel generator enclosures is shown in Section 3.5.1.6.3 to be 3.2×10^{-6} per year, 2.59×10^{-7} per year, and 1.17×10^{-7} per year respectively, or a total probability,

$P_{ac} = 3.58 \times 10^{-6}$ per year.

Given that each unit's diesel generator enclosure is 108 ft wide, and that each of the 4 diesels per unit is located in a separate compartment inside that unit's diesel generator enclosure, it is highly unlikely that the impact of a typical twin-engine plane with a wingspan of 50 ft could disable more than 2 diesel generators.

In addition, only 2 of a unit's 4 diesel generators are required to achieve and maintain safe shutdown, assuming no additional failures. Despite the above, it is conservatively assumed for this analysis that any aircraft impacting a diesel generator enclosure disables all 4 diesel generators therein, leaving that unit dependent on offsite power for achieving and maintaining safe shutdown. It is further conservatively assumed that immediate action would be taken to repair the diesel generators, and that at least 2 of the 4 would be restored to service 1 year following the aircraft impact.

Using the methodology of appendix III of Reference 3.5-10, the probability, P_{LOOP}, that a LOOP occurs (during the 1 year in which the affected unit would have no onsite ac backup power) is conservatively determined to be 0.2 per year, thus leaving that unit dependent on its Class 1E dc battery system to achieve or maintain shutdown.

It has been shown (Reference 3.5-11) that under loss of all ac power (station blackout) conditions, in a BWR with electrical and mechanical system designs similar to LGS, the batteries could power all systems required to achieve or maintain safe shutdown for as long as 7 hours before exhaustion. For this analysis, it is conservatively assumed that battery exhaustion occurs 4 hours after the LOOP occurs, after which inadequate core cooling and offsite radiological consequences in excess of 10CFR50.67 could occur.

Again using the methodology of appendix III of Reference 3.5-10, the probability, P_4, that at least one offsite source of power is not returned to service within 4 hours following the LOOP is conservatively estimated to be 0.05 per LOOP event.

Based on the preceding information, the probability per year of an aircraft crash that disables one unit's diesel generators, leading to offsite radiological consequences in excess of 10CFR50.67 dose limits, can be calculated as follows:

$$P = P_{AC} \cdot P_{LOOP} \cdot P_4$$

$$= (3.58 \times 10^{-6}\ yr^{-1})(0.2\ yr^{-1})(0.05) \qquad \text{(EQ. 3.5-8)}$$

$$= 3.58 \times 10^{-8} \text{ per year.}$$

Conclusion

The total probability per year of an aircraft impact resulting in offsite radiological consequences in excess of 10CFR50.67 dose limits is the sum of the probabilities associated with Scenarios 1 and 2, or 9.56×10^{-8} per year. Realistically, this probability would be lower.

It is concluded that the acceptance criteria of SRP section 3.5.1.6 are met.

3.5.2 SYSTEMS TO BE PROTECTED

Safety-related systems and structures are reviewed for missile protection and are listed in Table 3.2-1. Structures and barriers designed to provide for protection from external missiles are discussed in Section 3.5.1 and listed in Table 3.5-7, and their characteristics are listed in Table 3.5-8.

As discussed in Section 3.5.1, the only postulated internally generated missiles are those arising from failure of the HPCI and RCIC pump turbines. In this case, the pump-room walls are designed as barriers to isolate such missiles from other safety-related components.

The locations of safety-related equipment and the arrangement of the various compartments are shown in drawings M-110, M-111, M-112, M-113, M-114, M-115, M-116, M-117, M-118, M-119, M-120, M-121,M-122, M-123, M-124, M-125, M-126, M-127, M-128, M-129, M-130, M-131, M-132,

M-133, M-134, M-135, M-136, M-137, M-138, M-140, M-141, M-142, M-143, M-144, M-145, M-146, M-388, M-389, and M-390.

3.5.3 BARRIER DESIGN PROCEDURES

Safety-related components necessary for safe shutdown and housed in the Category I structures are adequately protected against tornado missiles. The characteristics of structural wall barriers for Category I structures are shown in Table 3.5-8. Figure 3.5-2 shows typical reinforcement provided in the southernmost reactor enclosure concrete wall barrier.

The structures and barriers are designed to resist missile hazards in accordance with the procedures detailed in Reference 3.5-6.

The procedures include:

a. Prediction of local damage (penetration, perforation, and spalling) in the impact area, including estimation of the depth of penetration

b. Estimation of the barrier thickness required to prevent perforation

c. Prediction of the overall structural response of the barrier, and portions thereof, to missile impact

Tornado missiles, as described in Table 3.5-4, were considered as deformable upon impact, and the structures were considered as rigid targets. Eighteen inch thick concrete, with a compressive strength of 4000 psi, was used in concrete walls and roofs subject to tornado missile impact. This satisfies the penetration formulae for elements subject to missiles as specified in Reference 3.5-6.

The ESW and RHRSW piping located within the yard area are installed underground with adequate cover for missile protection. A detailed assessment of soil cover for Category I yard piping shows a minimum depth of 4 feet, with most soil coverings exceeding 6 feet. The 4 foot depth was found to be adequate for tornado missiles (Table 3.5-4) in accordance with the criteria set forth in Reference 3.5-3.

The physical routing of the piping and typical profiles showing soil cover and installation details are shown in Figure 2.5-37. The cementitious backfill for pipe bedding is shown in detail 3 of Figure 2.5-37. This backfill was used predominantly for Category I piping to provide additional missile protection. The properties of cementitious backfill are defined in Section 2.5.4.5.4. Figure 2.5-37 shows the 4 foot minimum depth dimension of soil cover for Category I yard piping.

Doors are designed for tornado missiles unless internal secondary barriers are provided to protect safety-related components. Louvers are not designed for tornado missiles; however, internal secondary barriers are provided to protect safety-related components which are located behind the louvers. Figure 3.5-3 shows a typical secondary barrier for the south wall of the diesel generator enclosure (concrete labyrinth behind the door) used for tornado missile protection.

3.5.4 REFERENCES

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3.5-3 "Depth Prediction for Earth-Penetrating Projectiles", Soil Mechanics and Foundation Division, ASCE, p. 6558, (May 1969).

3.5-4 "Probability of Missile Generation in General Electric Nuclear Turbines", GE Proprietary Report.

3.5-5 D.C. Gonyea, "An Analysis of the Energy of Hypothetical Wheel Missiles Escaping from Turbine Casings", GE Technical Information Series No. DF735L12, (February 1973).

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3.5-10 ASH-1400, "Reactor Safety Study: An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants", NRC, (October 1975).

3.5-11 NUREG/CR-2182, Vol. I, "Station Blackout at Browns Ferry Unit One - Accident Sequence Analysis, Oak Ridge National Laboratory", (November 1981).

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3.5-13 F.A. Vasallo, "Missile Impact Testing of Reinforced Concrete Panels", prepared for Bechtel Power Corporation, Calspan Corp., (January 1975).

3.5-14 "Safety Evaluation Report Relates to the Operation of Hope Creek Generating Station", NUREG-1048, Supplement 6, (July 1986).

3.5-15 “Missile Analysis Report, Limerick Units 1 and 2," Siemens Energy, Inc., CT-27554, November 29, 2016 (including, as Appendix A: "Missile Probability Analysis Methodology for Limerick Generating Station, Units 1 and 2, with Siemens Retrofit Turbines” Siemens Power Corporation Engineering Report – ER-9605, Revision 2, June 18, 1997 - SIEMENS PROPRIETARY)

3.5-16 "Westinghouse Limerick Generating Station Unit 1 & 2 Turbine Control System Upgrade Reliability Analysis and Electronic Overspeed Protection Fault Tree Analysis, Revision 4, November 2020."

3.5-17 LEAM-0017, Revision 1, Limerick Supplemental Turbine Missile Probability Analysis."

Table 3.5-1

AIRCRAFT IMPACT DESIGN PARAMETERS

AIRCRAFT DESCRIPTION	GROSS WEIGHT (lb)	APPROACH VELOCITY (knots)	(ft/sec.)	KINETIC ENERGY (K-ft)
Single reciprocating engine	<5,000	110	186	2,686
Cessna (twin recip engine)	7,250	111	188	3,979
Cessna jet (twin gas turbine)	10,500	115	194	6,136
Learjet(1) (twin gas turbine)	13,500	139	235	11,577
Navajo Chieftrain	7,000	100	169	3,104
Beech King Air-200	12,500	103	174	5,877
Cheyenne Turbo-Prop	11,200	115	194	6,545
Bell Long Ranger (helicopter)	4,150	50	85	466
Aerospatiale Twin Star (helicopter)	5,291	50	85	594
Bell 222 Model A (helicopter)	7,850	70 (takeoff)	118	1,697

(1) Largest aircraft capable of operating out of nearby airports; none are presently known to exist.

Table 3.5-2

CHARACTERISTICS OF LEARJET

Aircraft Components[1]	Weight (lbs)	Mass (Kip-sec^2/ft)	K.E. (Kip-ft)	Resultant Load on Walls[2]		
				Momentum (Kip-sec)	Assumed Impact Duration (sec)	Peak Force (Kips)
Fuselage	7,178	0.2229	6,155	52.3	0.10	846
Tip Tanks	1,358	0.0422	1,165	9.9	0.05	396
Wing	3,503	0.1088	3,005	25.6	0.10	512
Engines	1,158	0.0360	995	8.5	0.05	340
Empennage	305	0.0095	260	2.2	0.05	88
Total	13,500	0.4194	11,580	98.5	-	(2)

(1) All components are assumed traveling at 235 fps (139 knots) at impact.
(2) Resultant load curves on structure due to the different components and total are shown in Figure 3.5-1.

Table 3.5-3

ACCUMULATORS LOCATED IN SAFETY-RELATED AREAS

Description	Maximum Pressure (psig)	Maximum Temperature (°F)
MSRV Accumulators	125	150
MSIV Accumulators	125	150
Diesel Air Start Reservoirs	250	120
Instrument Gas Receivers	125	135

Table 3.5-4

TORNADO-GENERATED MISSILE PARAMETERS

MISSILE	WEIGHT (lb)	IMPACT AREA (ft^2)	HORIZONTAL[4] VELOCITY (mph)/(ft/sec)	KINETIC ENERGY (ft-lb)
1. Wood plank (4"x12"x12')	200	0.333	300/440	6.01×10^5
2. Steel pipe (3" dia x 10', schedule 40)[3]	78	0.067	144/211	5.39×10^4
3. Automobile[2][3]	4000	20	72/106	6.98×10^5
4. Steel rod (1" dia x 3')	8	0.007	216/317	1.25×10^4
5. Utility pole (13½" dia x 35', not more than 30' above all grade elevations within ½ mile of the plant)	1490	1.266	144/211	1.03×10^6
6. Steel pipe (6" dia x 15', schedule 40)[1]	285	0.239	144/211	1.97×10^5
7. Steel pipe (12" dia x 15', schedule 40)[1]	743	0.886	144/211	5.14×10^5

(1) The design basis for LGS included only missiles 1, 2, 3, 4 and 5. All safety-related structures and openings in structures have been assessed for the effects of missiles 6 and 7.

(2) LGS was originally designed for a postulated automobile missile not more than 25 ft above grade for all safety-related structures. All safety-related structures have been reassessed for the effect of the automobile at elevations up to 30 ft above all grade levels within ½ mile of the plant.

(3) LGS was originally designed for postulated missile velocities equal to 100 mph for the 3 in diameter steel pipe and 50 mph for the automobile. All safety-related structures have been reassessed for the revised velocities shown on the table.

(4) These missiles are considered to be capable of striking in all directions with vertical velocities equal to 80% of the horizontal velocities.

Table 3.5-5

RAILROAD ACCIDENT GENERATED MISSILE PARAMETERS

MISSILE	WEIGHT (lb)	INITIAL VELOCITY (mph)
Part of tank car tank (112" dia x 50')[1]	62,000	200 (during ignition, traveling end on)
Steel pipe (3" dia x 10' schedule 40)	78	200 (tumbling)
Rail (3' long, 130 lb/yd)	130	200 (tumbling)
Type E coupler (7 in^2 shank)	200	200 (tumbling)
Unfused bomb	750	100

(1) These have been observed being propelled by burning gases at a very low trajectory not exceeding 30-35 feet above the ground. The elevation difference (77 feet) between the railroad and safety-related structures prevents impingement of this missile, and therefore it was not considered in the design.

Table 3.5-6

POTENTIAL HVAC FAN MISSILES

Fan No.	Description	Area	Elevation	Notes
OAV-163, OBV-109	SGTS exhaust fans	8	350	(2)
OAV-127, OBV-127	Control room emergency fresh air supply fans	8	304	(1)
OOV-126	Toilet room exhaust air fan	8	332	(2)
1AV-206, 1BV-206, 2AV-206, 2BV-206	Reactor enclosure equipment compartment air exhaust fans	15,16, 17,18	313	(2)
OAV-132, OBV-132	Drywell purge exhaust fans	8	350	(2)
OAV-131, OBV-131	SGTS room exhaust fans	8	350	(2)
1AV-213, 1BV-213, 2AV-213, 2BV-213	Reactor enclosure air recirculation fans	15,18	313	(2)
OAV-120, OBV-120	Auxiliary equipment room air return/exhaust fans	8	304	(2)
OAV-121, OBV-121	Control room ac return/exhaust fans	8	304	(2)
1AV-512 thru 1HV-512 and 2AV-512 thru 2HV-512	Diesel generator enclosure ventilation air exhaust fans	DG Bldg		(3)

Table 3.5-6 (Cont'd)

Fan No.	Description	Area	Elevation	Notes
1AV-201 thru 1CV-201 and 2AV-201 thru 2CV-201	Refueling floor air supply fans	15,18	313	(2)
1AV-202 thru 1CV-202 and 2AV-202 thru 2CV-202	Reactor enclosure air supply fans	16,17	313	(2)
1AV-204 thru 1CV-204 and 2AV-204 thru 2CV-204	Refueling floor air exhaust fans	16,17	313	(2)
1AV-205 thru 1CV-205 and 2AV-205 thru 2CV-205	Reactor enclosure air exhaust fans	16,17	331	(2)
OAV-124, OBV-124	Battery room air exhaust fans	8	304	(2)
OAV-114, OBV-114	Auxiliary equipment room supply ac units	8	304	(2)
OAV-116, OBV-116	Control room supply ac units	8	304	(2)
OAV-118, OBV-118	Emergency switchgear and battery room ac units	8	217	(2)

Table 3.5-6 (Cont'd)

Fan No.	Description	Area	Elevation	Notes
1AV-208, 1BV-208, 2AV-208, 2BV-208	RCIC pump-room unit coolers	15,18	177	(3)
1AV-209, 1BV-209, 2AV-209, 2BV-209	HPCI pump-room unit coolers	15,18	177	(3)
1AV-210 thru 1HV-210 and 2AV-210 thru 2HV-210	RHR pump-room unit coolers	15,16, 17,18	177	(3)
1AV-211 thru 1HV-211 and 2AV-211 thru 2HV-211	CS pump-room unit coolers	11,12, 13,14	177	(3)
1AV-212 thru 1HV-212 and 2AV-212 thru 2HV-212	Drywell area unit coolers	Drywell	217	(4)
OAV-140, OBV-140	SGTS room unit coolers	8	332	(3)
OAV-141, OBV-141	SGTS room access area unit coolers	8	332	(3)
OAV-543 Thru ODV-543	Spray pond pumphouse air supply units	Spray pond		(2)
00V900	CRD Decontamination Room Unit Cooler	15	253	(3)

Table 3.5-6 (Cont'd)

(1) These potential missiles are installed in equipment that is only used during accident situations. They are not considered credible potential missiles because internal missile generation is not postulated to occur concurrently with other accidents.

(2) These potential missiles are either remote from or separated by adequate barriers from all essential systems. Therefore, essential systems are protected from these potential missiles.

(3) The potential missiles cannot impact on more than a single component. Therefore, redundant equipment will be available to effect safe shutdown.

(4) The casing thickness is sufficient to prevent penetration by a loose blade. (During the September 24, 1982 Palo Verde event where the description indicated that a portion of a fan blade cut the liner plate, investigation revealed that the portion of blade escaped through a neoprene-coated fiberglass flexible connection between the fan discharge connection and the downstream duct. Pieces of blade struck the fan casing and the downstream duct. The duct was dented but no penetration of the fan casing or duct by the blade occurred. In the case of the LGS drywell unit coolers, the fan discharge connections are connected to a Class I Seismic Y duct fitting directly. Downstream of the fitting, stainless steel bellows with sliding metal flow liners are utilized rather than flexible fabric connections, thus precluding blade penetration.)

Table 3.5-7

MISSILE BARRIERS AND PROTECTED COMPONENTS FOR EXTERNALLY GENERATED MISSILES

PROTECTED COMPONENTS	MISSILE BARRIER
Reactor coolant and other safety-related equipment inside the containment	Primary containment structure, reactor enclosure walls, refueling cavity walls, internal structures and beams
Control room, cable spreading room, switchgear, batteries, SGTS	Control structure
ECCS and other safety-related equipment outside the primary containment	Reactor enclosure and internal walls
Standby diesel generators	Diesel generator enclosure(1)
Diesel fuel oil tank	Earth; the tank is buried underground
Spent fuel pool	Reactor enclosure and fuel pool walls
ESW pumps and RHRSW pumps	Spray pond pump structure
ESW and RHRSW yard piping	Earth; piping is buried

(1) The diesel generator enclosure is not designed for design aircraft accident.

Table 3.5-8

CHARACTERISTICS OF EXTERNALLY GENERATED MISSILE BARRIERS

BARRIER	MINIMUM THICKNESS (in)	MINIMUM STRENGTH (psi)	CURING TIME (days)
Primary containment	74	4000	28
Reactor enclosure			
Walls	24	4000	28
Roofs	18	4000	28
Refueling cavity walls	48	4000	28
Spent fuel pool walls	54	4000	28
Control structure			
Walls	24	4000	28
Roof	18	4000	28
Diesel generator enclosure			
Walls	24	4000	28
Roof	24	4000	28
Spray pond pump structure			
Walls	24	4000	28
Roof	24	4000	28

(1) On which strength is based

Table 3.5-9

TURBINE SYSTEM RELIABILITY CRITERIA

CRITERION	PROBABILITY, YR^{-1} UNFAVORABLY ORIENTED TURBINE	REQUIRED ACTION
(A)	$P_1 < 10^{-5}$	This is the general, minimum reliability requirement for loading the turbine and bringing the system on-line.
(B)	$10^{-5} < P_1 < 10^{-4}$	If this condition is reached during operation, the turbine may be kept in service until the next scheduled outage, at which time the licensee is to take action to reduce P_1 to meet the appropriate A criterion (above) before returning the turbine to service.
(C)	$10^{-4} < P_1 < 10^{-3}$	If this condition is reached during operation, the turbine is to be isolated from the steam supply within 60 days, at which time the licensee is to take action to reduce P_1 to meet the appropriate (A) criterion (above) before returning the turbine to service.
(D)	$10^{-3} < P_1$	If this condition is reached at any time during operation, the turbine is to be isolated from the steam supply within 6 days, at which time the licensee is to take action to reduce P_1 to meet the appropriate (A) criterion (above) before returning the turbine to service.

3.6 PROTECTION AGAINST DYNAMIC EFFECTS ASSOCIATED WITH THE POSTULATED RUPTURE OF PIPING

This section describes the treatment of postulated ruptures in high energy and moderate energy piping located both inside and outside of the primary containment. The methods used to determine pipe rupture locations and to analyze the results of the ruptures, including jet thrust forces, jet impingement forces, piping dynamic responses, and compartment pressure-temperature transients, are described. Description is also provided for the design measures that have been implemented to ensure that the effects of any postulated rupture do not result in the loss of a required function that is necessary to mitigate the consequences of that pipe rupture.

The definitions of certain terms used within this section are provided in Section 3.6.3. The use of the term "low reactor level" in this section is generic rather than referring to a specific isolation signal set point.

NOTE: The computer program "COPDA", as described in Bechtel Topical Report BN-TOP-4 (Reference 3.6-1), was originally used to determine compartment pressure and temperature resulting from line breaks in Unit 1. The computer program "FLUD" (Reference 3.6.3), which replaced COPDA, was typically used for the same analysis in Unit 2. The mainframe program "FLUD" was later replaced in 1985 with a personal computer version "PCFLUD" (Reference 3.6-12). The "PCFLUD" program had additional features added in 1993 (hot pipes, multiple HVAC fans, and "CONCOIL" room air cooler routine) and was renamed "CONCOIL-FLUD" or "CFLUD" (Reference 3.6-13). The supporting calculations for UFSAR Table 3.6-7 must be consulted for information regarding which specific program was used.

3.6.1 POSTULATED PIPING FAILURES IN FLUID SYSTEMS

The failure of piping containing high energy or moderate energy has the potential of causing damage to surrounding structures, systems, and components. Depending on the fluid system involved and the rupture location, postulated piping failures can result in one or more of the effects described below. Essential systems and components are protected from these effects unless it can be demonstrated that their function is not impaired.

Pipe Whip

Pipe whip is the unrestrained movement of a pipe due to the reaction force imposed on the pipe by fluid discharging from a rupture. Protection against pipe whip can be provided by intervening structural members between high energy piping and the essential systems and components, by providing pipe whip restraints on the high energy piping, or by locating essential systems and components sufficiently distant from high energy piping. Examples of typical pipe whip restraints and bumpers are shown in Figure 3.6-1.

Jet Impingement

The blowdown of fluid from a rupture of a high energy pipe can exert forces on nearby equipment that could be high enough to cause damage to the equipment. Protection against jet impingement can be provided by installing jet impingement barriers to deflect the blowdown jet, or by locating essential systems and components a sufficient distance from high energy piping.

Environmental Effects

Pipe ruptures in high energy and moderate energy lines release fluid that can increase temperature, pressure, and humidity in the vicinity of the pipe rupture and also in remote areas that communicate with the local atmosphere. Essential systems and components may be exposed to abnormal conditions that have the potential of degrading the capability of the equipment to perform its function.

Piping systems whose rupture might generate hazardous environmental conditions are generally located in compartments that are capable of being isolated from other compartments containing essential systems and components. Isolation of compartments that enclose high energy lines is provided by maintaining normally closed access ways, automatically isolating ventilation duct-work, and sealing penetrations through walls and slabs. Compartments are designed to withstand the maximum internal pressurization developed as a result of a pipe rupture. Essential systems and components are either located in areas not affected by pipe ruptures or are qualified for operation under the maximum environmental conditions that they may be subjected to as a result of pipe ruptures.

Figures 3.6-43 through 3.6-45 are provided to show additional details of a typical pipe break analysis performed in accordance with SRP 3.6.1 and BTP ASB 3-1. The pipe break chosen is a break of the HPCI steam supply line in the HPCI compartment.

Water Spray

Water released from pipe ruptures is a hazard to certain equipment, particularly electrical components. In most cases, spatial separation is adequate to prevent water spray from reaching essential systems and components. Essential systems and components that can potentially be subjected to water spray are either designed to operate when wetted or will be provided with barriers to deflect the spray.

Flooding

Significant ruptures of fluid system piping may result in flooding in the vicinity of the rupture and in compartments through which the released fluid drains. The flooding rate and the total fluid volume released are computed based on the rupture configuration, the service of the fluid system, and the time required to isolate the rupture. The plant's drainage system handles minor releases of fluid with no adverse effects on essential systems and components.

Compartments that contain fluid systems with the potential for major releases of fluid are designed to contain the flooding and prevent significant leakage to adjoining compartments containing essential systems and components. Essential systems and components are either located in areas not subject to significant flooding or are designed to operate in a flooded environment.

3.6.1.1 Design Bases

Pipe breaks are postulated to occur in high energy fluid system piping in accordance with the criteria stated in Section 3.6.2.1.1. Pipe cracks are postulated to occur in moderate energy fluid system piping in accordance with the criteria stated in Section 3.6.2.1.2. The effects of these piping ruptures require special consideration to ensure the following:

a. The ability to shut the reactor down safely is maintained.

b. Primary containment integrity is maintained.

c. Resultant offsite doses are below the values of 10CFR50.67.

In analyzing the effects of postulated piping ruptures, the following assumptions are made:

a Each break in high energy fluid system piping or crack in moderate energy fluid system piping is considered separately as a single postulated initial event occurring during normal plant conditions.

b. Offsite power is assumed to be unavailable if a trip of the turbine-generator or the RPS is a direct consequence of the postulated piping rupture.

c. A single active component failure is assumed to occur in systems used to mitigate the consequences of the postulated piping rupture and to shut the reactor down, except as noted in item d. below.

d. Where the postulated piping rupture is assumed to occur in one of the two redundant loops of either the RHR system or the RHRSW system, single active failures of components in the other loop of that system need not be assumed. These two systems are dual-purpose moderate energy systems powered from both onsite and offsite sources and are designed, constructed, and inspected to standards appropriate for nuclear safety systems.

e. All available systems, including those actuated by operator actions, may be employed to mitigate the consequences of the postulated piping rupture. In judging the availability of systems, the postulated piping rupture and its direct consequences, and the assumed single active component failure and its direct consequences are considered. The feasibility of carrying out operator actions is judged on the availability of ample time and adequate access to equipment for the required actions.

f. An unrestrained whipping pipe is considered capable of causing breaks in impacted piping of smaller nominal pipe size and developing through-wall leakage cracks in impacted piping of equal or larger nominal pipe size with thinner wall thickness, except where experimental or analytical data demonstrates the capability to withstand the impact without failure. If such experimental or analytical data are used, additional documentation will be submitted to the NRC for review.

g. The effect of the jets resulting from each postulated pipe break in high energy fluid systems is reviewed and is evaluated only when such jets may have an effect on specific safety-related components that are required to effect a safe shutdown, maintain containment integrity, provide post-LOCA monitoring, or limit radioactive releases to site-allowable limits, as a result of a specific postulated pipe break event.

The effects of jet impingement on the piping required to effect a safe shutdown, maintain containment integrity, provide post-LOCA monitoring, or limit radioactive releases to site-allowable limits, regardless of size or wall thickness, are also reviewed. Bounding cases are evaluated to ensure that acceptable stress levels in such piping are not exceeded.

3.6.1.2 Description

A listing of high energy fluid system piping is provided in Table 3.6-1. All other piping in the plant that is pressurized above atmospheric pressure is considered to be moderate energy piping. The routing of piping within the reactor enclosure and the primary containment is shown in Figures 1.2-40 through 1.2-72.

For each pipe rupture location determined in accordance with the criteria of Section 3.6.2.1, an analysis is performed using the assumptions of Section 3.6.1.1 to verify that the consequences of the pipe rupture are acceptable. These analyses are summarized below for high energy and moderate energy fluid systems.

3.6.1.2.1 High Energy Fluid Systems

3.6.1.2.1.1 Reactor Recirculation System

The two reactor recirculation loops are located entirely within the primary containment and are arranged on opposite sides of the reactor pedestal and reactor shield wall. Pipe whip restraints anchored in the reactor pedestal and reactor shield wall are provided for the recirculation loops and are arranged as shown in Figure 3.6-2. This system of restraints prevents unrestrained pipe whip resulting from a postulated rupture at any of the identified break locations. The restraints consist of two basic components: the frame attached to a support member and straps attached to the frame (two straps per frame). Either carbon steel cables or stainless steel bars are used as straps. The restraints on the 28-inch recirculation loop piping utilize stainless steel bars. The restraints on the 22-inch discharge header and the 12-inch risers utilize carbon steel cables. A schematic detail of a restraint is shown in Figure 3.6-3.

A review of the potential consequences of jet impingement resulting from recirculation loop ruptures has shown that breaks at the lower end of two of the 12-inch risers in each recirculation loop could result in impingement on the CRD withdraw piping. An evaluation of the consequences of damage to CRD withdraw piping resulting from jet impingement has shown that such damage would not prevent the associated control rods from being inserted into the reactor as necessary to affect a reactor shutdown. Electrical cabling associated with essential systems and components is routed to avoid jet impingement from postulated ruptures of recirculation loop piping.

Pipe Break Locations

The postulated pipe break locations for the recirculation loop piping are shown in Figure 3.6-4. The calculated stress levels and usage factors, and the postulated break types, are listed in Table 3.6-2. Blowdown thrust time histories for each break location are provided in Table 3.6-3. The recirculation piping design basis has been evaluated for the effects of power rerate and demonstrated to be adequate for the increases in pressure, temperature and flow due to power rerate. Details of the evaluation performed are documented in Reference 3.6-11.

Compartment Pressure-Temperature Transient

The pressure-temperature transient in the primary containment resulting from a complete circumferential rupture of one recirculation loop is discussed in Section 6.2.1.

Verification of Reactor Shutdown Capability

The sequence of events that would occur automatically to shut the reactor down and cool the core in the event of a recirculation loop rupture is discussed in Section 6.3.3. A combination of pipe whip restraints, jet impingement barriers, and separation by distance is used to ensure the availability of sufficient equipment to accomplish these functions.

3.6.1.2.1.2 Main Steam System

The four 26-inch main steam lines are routed as shown in Figure 5.1-7 for the portion inside the primary containment, and in Figure 3.6-5 for the portion outside the primary containment. The A and B steam lines are connected to the east side of the reactor vessel and the C and D steam lines are connected to the west side of the vessel. All four steam lines penetrate the north side of the primary containment. The portion of the reactor enclosure through which the main steam lines are routed (between the primary containment and the turbine enclosure) is referred to as the main steam tunnel and is separated from other areas of the reactor enclosure by concrete walls and slabs. Only piping, valves, and associated instrumentation are located in the main steam tunnel. Figure 3.6-6 shows an elevation view of the main steam tunnel.

The following features are incorporated into the design of the main steam line and nearby structures to mitigate the consequences of a main steam line break or to minimize the probability of its occurrence:

a. A venturi-type flow restrictor is located in each main steam line inside the primary containment. The flow restrictor reduces the rate of loss of reactor coolant from a main steam line break for break locations downstream of the restrictor. (The flow restrictors are described in Section 5.4.)

b. Each main steam line is provided with either three or four MSRVs that reduce the probability of breaks by protecting the steam line against overpressurization. (The MSRVs are described in Section 5.2.)

c. Each main steam line is provided with two fast-acting fail-safe MSIVs, one upstream and one downstream of the primary containment penetration. These valves close automatically upon receipt of signals indicating high steam flow or high temperature in the vicinity of the piping outside the primary containment (as well as upon receipt of other initiating signals), in order to terminate blowdown through breaks outside the primary containment. (The MSIVs are described in Section 5.4.)

d. Moment-limiting pipe whip restraints are located upstream of the inboard MSIVs and downstream of the outboard MSIVs in order to ensure the operability of these valves in the event of a main steam line break in the general vicinity of the valves.

The main steam lines are provided with pipe whip restraints inside the primary containment and in the main steam tunnel. Typical restraints inside the primary containment are shown in Figure

3.6-1. Figure 3.6-6 shows the locations of the restraints in the main steam tunnel. As shown in Figure 3.6-7, the first two restraints downstream of the outboard MSIVs span between the east and west walls of the tunnel and restrain all four steam lines. Corbels extending out from the north wall of the main steam tunnel limit the possible upward movement of the upper elbow of each steam line in the tunnel. Additionally, the vertical portion of the steam line run in the tunnel is restrained against the north wall of the tunnel at two separate locations.

After entering the Unit 1 turbine enclosure from the main steam tunnel, the main steam lines are routed along the west side of the control structure before turning westward to run the length of the turbine enclosure. This arrangement is shown in Figure 3.6-5. In order to prevent a main steam line break in this portion of piping from causing pipe whip impact on the control structure wall, bumpers are provided between the control structure and the elbows of the two steam lines closest to the control structure (26" EBB-103 and 26" EBB-104). The Unit 2 arrangement is similar, but opposite hand.

In reviewing the potential consequences of jet impingement resulting from main steam line breaks, it was determined that breaks at the elbow at the lower end of the near-vertical piping run inside the primary containment could result in impingement on the CRD withdraw piping. An evaluation of the consequences of damage to CRD withdraw piping resulting from jet impingement has shown that such damage would not prevent the associated control rods from being inserted into the reactor core as necessary to affect a reactor shutdown. Electrical cabling associated with essential systems and components is routed to avoid jet impingement from postulated breaks of main steam piping.

Pipe Break Locations

The postulated pipe break locations for the main steam piping, and also the pipe whip restraint locations, are shown in Figures 3.6-8 and 3.6-9. The calculated stress levels and usage factors, and the postulated break types, for the main steam piping inside the primary containment are listed in Table 3.6-4. Breaks for the main steam piping outside containment are postulated to occur at each location of potential high stress, such as pipe fittings, valves, and welded attachments. The main steam piping basis has been evaluated for the effects of power rerate and demonstrated to be adequate for the increases in pressure, temperature and flow due to power rerate. Details of the evaluation performed are documented in Reference 3.6-11.

Compartment Pressure-Temperature Transients

The pressure-temperature transient in the primary containment resulting from a complete circumferential break of one main steam line is discussed in Section 6.2.1.

Protection against overpressurization of the main steam tunnel in the event of a main steam line break in the tunnel is provided by two sets of blowout panels. One set of blowout panels is located in the north wall of the tunnel and vents to the turbine enclosure. The second set of blowout panels is located in the vent stack that leads upward from the tunnel and discharges to the atmosphere above the top of the reactor enclosure. This vent stack can be seen in drawings M-123 and M-138.

A pressure-temperature transient analysis for the case of a main steam line break in the tunnel was performed using the analytical technique described in BN-TOP-4 (Reference 3.6-1) and the blowdown data provided in Table 3.6-6 and Figure 3.6-10. The flow model is shown in Figure 3.6-11 and the results of the analysis are listed in Table 3.6-7. The main steam tunnel is designed

to withstand the maximum pressure developed, and the MSIVs are qualified to operate under environmental conditions more severe than those calculated to occur.

Protection against overpressurization of the Unit 1 turbine enclosure as a result of a main steam line break within its boundaries is provided by blowout panels along the north exterior wall of the turbine enclosure. As shown in drawings M-111 and 112, these blowout panels are located between column lines 12 and 18 and vent the main condenser area of the turbine enclosure directly to the atmosphere. The main steam lines are routed in areas that communicate directly with the main condenser area for the entire length of their run within the turbine enclosure. The Unit 2 arrangement is similar.

A pressure-temperature transient analysis for the case of a main steam line break in the turbine enclosure was performed using the analytical technique described in Reference 3.6-1 and with the blowdown data provided in Table 3.6-6. The flow model is shown in Figure 3.6-12 and the results of the analysis are listed in Table 3.6-7. The turbine enclosure is designed to withstand the maximum pressure developed.

The secondary containment structure is capable of withstanding the effects of a high energy pipe rupture occurring inside the secondary containment without loss of integrity. For all pipe breaks except those in the RWCU system, the time-dependent mass and energy release rates are calculated using the Moody model including friction effects. Blowdown for the main steam line breaks is determined in accordance with the assumptions in Reference 3.6-14. A double-ended guillotine break is assumed, and both forward and reverse flows are included for all cases except for HPCI and RCIC line breaks in the HPCI and RCIC compartments, respectively. The postulated pipe breaks in the HPCI and RCIC compartments are at the upstream side of a normally closed isolation valve, therefore only forward flow is considered.

Mass and energy release rates for pipe breaks in the RWCU system are calculated with RELAP4/MOD5 using the Henry-Fauske model option for subcooled conditions and the Moody critical flow model option for saturated conditions.

Verification of Reactor Shutdown Capability

Breakage of a main steam line inside the primary containment would result in an unisolable blowdown of the reactor vessel. The sequence of events that would occur automatically to shut the reactor down and cool the core is discussed in Section 6.3.3.

For a main steam line break outside the primary containment, the MSIVs will be closed automatically because of high steam flow, low reactor water level, or high temperature in the vicinity of the main steam lines. Closure of the MSIVs will cut off steam flow to the feedwater pump turbines, causing the pumps to coast down and stop. The reactor will be scrammed by low reactor water level or closure of the MSIVs. After isolation of the reactor vessel, the RCS pressure will increase until the setpoint of the MSRVs is reached. Steam will then be automatically discharged to the suppression pool to limit the pressure rise.

Low reactor water level will initiate operation of the HPCI and RCIC systems to maintain reactor water level. If both the HPCI and RCIC systems are unavailable, the ADS will be automatically initiated to depressurize the reactor vessel so that the LPCI and core spray systems can inject

water into the vessel. These latter two systems are initiated automatically by low reactor water level, and will provide sufficient flow to restore reactor water level and cool the core.

After reactor water level has been restored, and the RCS pressure and temperature have decreased sufficiently, the shutdown cooling mode of the RHR system can be initiated to bring the reactor to cold shutdown.

A combination of pipe whip restraints, jet impingement barriers, and separation by distance or intervening structure is used to ensure the availability of essential systems and components in the event of a main steam line break in either the primary containment or the main steam tunnel. Essential systems and components located in these areas are qualified to operate under the environmental conditions resulting from a break. Since no essential systems and components are located in the turbine enclosure, no special provisions are necessary to provide protection for equipment in this area from the effects of pipe breaks. Blowout panels are provided to prevent overpressurization of the turbine enclosure, and bumpers are provided to prevent a whipping main steam line from impacting the control structure.

3.6.1.2.1.3 Feedwater System

The discharge lines from the three feedwater pumps are routed into a common mixing header in the turbine enclosure. From this header, two parallel 24-inch feedwater lines enter the main steam tunnel and then penetrate the primary containment. Inside the primary containment, the two lines diverge to form symmetrical headers on opposite sides of the reactor vessel. Each header splits into three 12-inch risers that attach to the reactor vessel nozzles. The routing of the feedwater lines in the main steam tunnel and primary containment is shown in drawings M-234, M-305 and Figure 3.6-6.

Each feedwater containment penetration is provided with three check valves as containment isolation valves, one inside the drywell and two in the main steam tunnel. In the event of a feedwater line break outside the primary containment, these check valves will, as described below, close to prevent backflow from the reactor vessel. Thus, flow from the break would be from the feedwater pump side only.

The operability of the first outboard containment isolation valve (i.e. closest to the drywell penetration) is ensured in the event of a feedwater line break by providing moment-limiting whip restraints designed for this purpose. The operability of the check valve inside containment and the second outboard check valve need not be protected from overstress due to pipe whip, since only two isolation valves are necessary to provide adequate redundancy to ensure the containment isolation function, and it is not possible for one pipe break to affect both the inboard and second outboard check valves. More detailed discussion of feedwater check valve operability is provided in Section 3.9.3.2b.2.

The feedwater lines are provided with pipe whip restraints inside the primary containment, in the main steam tunnel, and in the turbine enclosure immediately outside the main steam tunnel. Typical restraints inside the primary containment are shown in Figure 3.6-1. As shown in Figure 3.6-13, the restraint in the tunnel spans between the east and west walls of the tunnel and restrains both feedwater lines. Corbels extending out from the north wall of the main steam tunnel limit the possible upward movement of the upper elbows of the feedwater startup recirculation lines that connect to the feedwater lines in the main steam tunnel. Feedwater line restraints located in the turbine enclosure and which are attached to the control structure and reactor enclosure walls are

shown in Figure 3.6-14. Bumpers on the control structure walls protect the control structure from a whipping feedwater line.

Electrical cabling associated with other essential systems and components is routed to avoid jet impingement from postulated breaks of feedwater piping.

Pipe Break Locations

The postulated pipe break locations for the feedwater piping, and also the pipe whip restraint locations, are shown in Figures 3.6-15 and 3.6-16. The calculated stress levels and usage factors, and the postulated break types, for the feedwater piping inside the primary containment are listed in Table 3.6-8. Breaks for the feedwater piping outside containment are postulated to occur at each location of potential high stress, such as pipe fittings, valves, and welded attachments.

Compartment Pressure-Temperature Transients

The pressure-temperature transient in the primary containment resulting from a break of any of the sizes of feedwater lines in the drywell is exceeded in severity by the transients resulting from recirculation loop and main steam line breaks, which are discussed in Section 6.2.1. The pressure-temperature transient resulting from a feedwater line break in the main steam tunnel or turbine enclosure is exceeded in severity by the transient resulting from a main steam line break, which is discussed in Section 3.6.1.2.1.2.

Verification of Reactor Shutdown Capability

Breakage of a feedwater line inside the primary containment would result in an unisolable blowdown of the reactor vessel. The sequence of events that would occur automatically to shut the reactor down and cool the core is discussed in Section 6.3.3.

For a feedwater line break outside the primary containment, differential pressure across the containment isolation check valves in the reverse direction will cause these valves to close rapidly, isolating the reactor vessel from the break. The loss of feedwater flow will cause the reactor water level to drop, initiating a reactor scram. Water level will continue to drop because of steam generation from decay heat, causing closure of the MSIVs as well as initiation of the RCIC and HPCI systems. Once the reactor has been scrammed and the RCS isolated, the sequence of events is similar to that for a main steam line break outside the primary containment.

A combination of pipe whip restraints, jet impingement barriers, and separation by distance or intervening structure is used to ensure the availability of essential systems and components in the event of a feedwater line break in either the drywell or the main steam tunnel. Since no essential systems and components are located in the turbine enclosure, no special provisions are necessary to provide protection for equipment in this area from the effects of pipe breaks. Bumpers are provided in the turbine enclosure to protect the control structure from the impact of a whipping feedwater line.

3.6.1.2.1.4 Condensate System

The condensate system is located entirely within the turbine enclosure. No pipe whip restraints are provided for the condensate piping.

Pipe Break Locations

Since the condensate system consists of non-nuclear class piping, breaks are postulated to occur at each location of potential high stress, such as pipe fittings, valves, and welded attachments.

Compartment Pressure-Temperature Transients

Since the normal fluid temperature in the condensate system is less than 135°F, no significant pressure-temperature transient would result from condensate line breaks.

Verification of Reactor Shutdown Capability

In the event of a condensate line break, the feedwater pumps would trip because of low suction pressure. The resulting loss of feedwater flow would result in closure of the containment isolation check valves, preventing reactor blowdown through the break. The sequence of events that would occur from this point on is the same as for breakage of a feedwater line outside the primary containment.

Since no essential systems and components are located in the turbine enclosure, no special provisions are necessary to provide protection for equipment in this area from the effects of pipe breaks. The flooding effects of a condensate line break are exceeded by the effects of a circulating water line expansion joint rupture in the turbine enclosure, a discussion of which is contained in Sections 10.4.1 and 10.4.5.

3.6.1.2.1.5 Reactor Water Cleanup System

The RWCU system takes suction from reactor recirculation loop B via the RHR shutdown cooling suction line inside primary containment. The 6-inch RWCU suction line is routed up to el 297'-3", at which point it penetrates the primary containment. The RWCU piping is then routed through the various RWCU equipment compartments at el 283' and el 313' in the reactor enclosure, including the containment penetration compartment, three RWCU pump compartments, the regenerative heat exchanger compartment, two nonregenerative heat exchanger compartments, two RWCU holding pump compartments, and two RWCU filter/demineralizer compartments. The RWCU return piping is routed from the containment penetration compartment directly into the main steam tunnel, where the piping splits into two 4-inch lines. One line connects to the A feedwater line (DBB-103) and the other line connects to the RCIC injection line immediately upstream of its connection to the B feedwater line (DBB-104). Both of these connections to the feedwater lines are located between the two outboard containment isolation valves in the feedwater lines. Another RWCU line, the 4-inch RWCU alternate return line, has a branch connection to the RWCU return line at a point just upstream of the location where the return line splits into the two lines leading to the feedwater lines. From this branch connection, the RWCU alternate return line is routed downward to a containment penetration at elevation 261 feet, which is also in the main steam tunnel. The routing of this RWCU piping is shown in drawings M-210, M-211, M-225, M-231, M-232, M-235, M-296, M-302, M-303, M-306, M-322, and M-323.

The RWCU suction line is provided with two fast-acting isolation valves, one upstream and one downstream of the primary containment penetration. These valves close automatically upon receipt of signals indicating high differential flow (RWCU suction vs. return) or high temperature in

the vicinity of the piping outside the drywell (as well as upon receipt of other initiating signals), in order to terminate blowdown through breaks outside the drywell. In order to ensure the operability of these valves in the event of an RWCU suction line break, moment-limiting pipe whip restraints are located upstream of the inboard containment isolation valve and downstream of the outboard containment isolation valve. Whip restraints are also located on the portion of the RWCU suction line within the drywell and on the portion of the return line within the main steam tunnel.

In reviewing the potential consequences of jet impingement resulting from RWCU line breaks, it was determined that breaks near the connection of the RWCU return lines to the RCIC injection and feedwater line in the main steam tunnel could result in impingement

on the outboard MSIV operators. A steel plate barrier is provided to protect the MSIV operators from this potential source of jet impingement. It was also determined that RWCU line breaks in the RWCU containment penetration compartment could result in impingement on the RWCU outboard containment isolation valve. A steel plate barrier is provided to protect the isolation valve from this potential source of jet impingement.

Pipe Break Locations

The postulated pipe break locations for the RWCU pump suction piping inside the primary containment, and also the pipe whip restraint locations, are shown in Figure 3.6-17. The calculated stress levels and usage factors, and the postulated break types, for this portion of the RWCU piping are listed in Table 3.6-10. Piping isometrics for the RWCU pump suction piping in the RWCU isolation valve compartment and for the RWCU return piping in the main steam tunnel are shown in Figures 3.6-39 and 3.6-18, respectively. Breaks in the latter portions of the RWCU piping are postulated to occur at each location of potential high stress, such as pipe fittings, valves, and welded attachments.

Compartment Pressure-Temperature Transients

The pressure-temperature transient in the primary containment resulting from a break in the portion of the RWCU suction line in the drywell is exceeded in severity by the transients resulting from recirculation loop breaks, main steam line breaks, and small steam leaks, which are discussed in Section 6.2.1.

Protection against overpressurization of the RWCU equipment compartments in the reactor enclosure as a result of RWCU line breaks in these areas is provided by interconnecting steam venting paths between the various compartments and by blowout panels leading to the outside atmosphere. The two nonregenerative heat exchanger compartments are vented into the regenerative heat exchanger compartment via a short steam venting plenum. The regenerative heat exchanger compartment is vented in turn to the adjacent containment penetration compartment. Each of the three pump rooms is vented individually to the containment penetration compartment. The containment penetration compartment is vented, via a blowout panel, to an exhaust stack located on the west side of the reactor enclosure for Unit 1 and on the east side of the reactor enclosure for Unit 2. The stack is open to the atmosphere at its upper and lower ends. The venting pathway from the containment penetration compartment to the exhaust stack is shown in drawings M-215 and M-316.

Pressure-temperature transient analyses for the cases involving RWCU line breaks in the RWCU equipment compartments were performed using the analytical technique described in Reference 3.6-1 and with the blowdown data provided in Table 3.6-6. These blowdown data were developed using Reference 3.6-2. The flow model for breaks in the RWCU equipment compartments is shown in Figure 3.6-19, and the results of the analyses are listed in Table 3.6-7. No analyses are performed for the RWCU holding pump compartments and filter/demineralizer compartments since the piping in these areas contains fluid at a temperature of 150°F or less, so that no significant pressure-temperature transient results from a pipe break.

The RWCU equipment compartments are designed to withstand the maximum pressure developed due to a pipe break. The outboard containment isolation valves for the RWCU system and other systems located in the containment penetration compartment are qualified to operate under environmental conditions more severe than those calculated to occur due to pipe break.

Verification of Reactor Shutdown Capability

Breakage of the RWCU suction line inside the drywell would result in an unisolable blowdown of the reactor vessel. The sequence of events that would occur automatically to shut the reactor down and cool the core is discussed in Section 6.3.3.

For an RWCU line break outside the drywell, the RWCU containment isolation valves will be closed automatically due to high flow in the RWCU suction line or high temperature in the RWCU equipment compartments. Backflow from the feedwater lines into the RWCU return line will be prevented by closure of the check valve in the return line. If the break occurs in the RWCU piping within the main steam tunnel, the MSIVs will close automatically due to high temperature in the tunnel. Once MSIV isolation has occurred, the sequence of events is similar to that for a main steam line break outside the primary containment. If the break occurs in the RWCU equipment compartments, no reactor scram or MSIV closure will occur, due to the isolation of the RWCU system and rapid termination of the blowdown. After an RWCU isolation, there is sufficient capability to shutdown the reactor. The operator will investigate the cause of the RWCU isolation and take appropriate actions, in accordance with the plant Technical Specifications and approved operating procedures. The Technical Specifications and/or the operating procedures, which include off normal and EOPs, may, based on plant conditions, require the operator to initiate a normal shutdown of the reactor.

A combination of pipe whip restraints, jet impingement barriers, and separation by distance or intervening structure is used to ensure the availability of essential systems and components in the event of an RWCU line break occurring in the drywell, main steam tunnel, or RWCU equipment compartments. Essential systems and components located in these areas are qualified to operate under the environmental conditions resulting from the break. Among the RWCU equipment compartments, only the containment penetration compartment contains safety-related equipment: the primary containment purge line, two of the four LPCI injection lines, and the RWCU outboard containment isolation valve. The containment isolation valves in the purge line and the LPCI injection lines are normally closed during reactor operation and are not required to operate after a RWCU line break outside primary containment; therefore they require no protection. The RWCU outboard containment isolation valve is protected from jet impingement by a steel plate barrier, and the cabling to the valve is routed so as to avoid jet impingement.

3.6.1.2.1.6 Reactor Vessel Drain

The reactor vessel drain consists of 2-inch piping originating at a nozzle on the reactor vessel bottom head. From this location inside the reactor vessel pedestal, the piping increases to 2½ inches in diameter, penetrates the pedestal into the general drywell area, increases to 4 inches in diameter, and is routed upward to its point of connection to the 6-inch RWCU suction line inside the drywell.

Pipe Break Locations

The postulated pipe break locations for the reactor vessel drain line, and also the pipe whip restraint locations, are shown in Figure 3.6-20. The calculated stress levels and usage factors, and the postulated break types, are listed in Table 3.6-12.

Compartment Pressure-Temperature Transients

Since the reactor vessel drain line is located entirely within the drywell, breakage of this line would have no effect on plant areas outside the primary containment. The pressure-temperature transient in the primary containment resulting from a reactor vessel drain line break is exceeded in severity by the transients resulting from recirculation loop breaks and main steam line breaks, which are discussed in Section 6.2.1.

Verification of Reactor Shutdown Capability

Breakage of the reactor vessel drain line would result in an unisolable blowdown of the reactor vessel. The sequence of events that would occur automatically to shut the reactor down and cool the core is discussed in Section 6.3.3. A combination of pipe whip restraints and separation by distance or intervening structure is used to ensure the availability of essential systems and components in the event of a reactor vessel drain line break.

3.6.1.2.1.7 HPCI Steam Supply Line

The HPCI steam supply piping has a nominal diameter of 10 inches for the portion inside the drywell and 12 inches for the portion outside the drywell. The supply line connects to main steam line C inside the drywell. From its connection to the main steam line, the HPCI steam supply line is routed downward and then horizontally along the drywell wall. The line then penetrates the drywell at el 244'-8", entering the isolation valve compartment located at floor el 217' in the reactor enclosure. The steam supply line penetrates the floor of the isolation valve compartment and enters the HPCI pump compartment located at el 177'. The routing of this line is shown in drawings M-213, M-225, M-226, M-227, M-228, M-295, M-297, M-296, M-318, M-319, M-229, and M-320. During normal reactor operation, the line is pressurized from main steam line C up to the HPCI turbine steam supply valve (HV-55-F001).

The HPCI steam supply line is provided with two fast-acting isolation valves, one upstream and one downstream of the primary containment penetration. These valves close automatically upon receipt of signals indicating high steam flow or high temperature in the vicinity of the piping outside the drywell (as well as upon receipt of other initiating signals), in order to terminate blowdown through breaks outside the drywell.

Moment-limiting pipe whip restraints are located upstream of the inboard containment isolation valve and downstream of the outboard containment isolation valve in order to ensure the operability of these valves in the event of a break in the HPCI steam supply line near the valves.

Whip restraints are also located on the HPCI steam supply line and in the isolation valve compartment at el 217' in the reactor enclosure. A typical restraint inside the drywell is shown in Figure 3.6-1.

Pipe Break Locations

The postulated pipe break locations for the HPCI steam supply line, and also the pipe whip restraint locations, are shown in Figure 3.6-21 for the portion of the line inside the drywell and in Figure 3.6-22 for the portion of the line outside the drywell. The calculated stress levels and usage factors, and the postulated break types, are listed in Tables 3.6-13 and 3.6-14.

Compartment Pressure-Temperature Transients

The pressure-temperature transient in the primary containment resulting from a break in the portion of the HPCI steam supply line in the drywell is exceeded in severity by the transients resulting from recirculation loop breaks and main steam line breaks, which are discussed in Section 6.2.1.

Protection against overpressurization of the HPCI pump compartment and the isolation valve compartment at el 217' in the reactor enclosure as a result of HPCI steam supply line breaks in these areas is provided by steam venting paths and blowout panels leading to the outside atmosphere. The isolation valve compartment is vented to the atmosphere via blowout panels located on the south side of the reactor enclosure, as shown in drawings M-118, M-123 and M-138. The HPCI pump compartment is vented to the isolation valve compartment via hinged, metal plate blowout panels located in the floor at el 217'. These latter panels lift to relieve pressurization in the HPCI pump compartment but do not allow pressurization in the isolation valve compartment to result in steam flow in the reverse direction, i.e., down into the HPCI pump compartment.

Pressure-temperature transient analyses for the cases involving HPCI steam supply line breaks in the HPCI pump compartment and the HPCI piping area were performed using the analytical technique described in Reference 3.6-1 and the blowdown data provided in Table 3.6-6. The flow model for breaks in these two compartments is shown in Figure 3.6-23, and the results of the analyses are listed in Table 3.6-7. Figures 3.6-43 through 3.6-45 provide additional details of a typical pipe break analysis. The case of an HPCI steam supply line break in the isolation valve compartment was analyzed using the CFLUD computer program (Reference 3.6-13) and the blowdown data provided in Table 3.6-6. The flow model for this case is shown in Figure 3.6-24, and the results of the analysis are listed in Table 3.6-7.

The HPCI pump compartment and the isolation valve compartment are designed to withstand the maximum pressures developed due to pipe break. All equipment located in the isolation valve compartment that is required to operate following breakage of the HPCI steam supply line is qualified to operate under environmental conditions more severe than those calculated to occur due to pipe break. No equipment located in the HPCI pump compartment is required to operate following breakage of the HPCI steam supply line.

Verification of Reactor Shutdown Capability

Breakage of the HPCI steam supply line inside the drywell would result in an unisolable blowdown of the reactor vessel. The sequence of events that would occur automatically to shut the reactor down and cool the core is discussed in Section 6.3.3.

For an HPCI steam supply line break outside the drywell, the steam supply line containment isolation valves will be closed automatically, terminating reactor vessel blowdown. No reactor scram will occur, due to the isolation of the HPCI steam line and rapid termination of the blowdown. After a HPCI isolation, there is sufficient capability to shutdown the reactor. The operator will investigate the cause of the HPCI isolation and take the appropriate actions, in accordance with the plant Technical Specifications and approved operating procedures, to assure that the plant is in safe condition. The Technical Specifications and/or the operating procedures, which include off normal and EOPs, may, based on plant conditions, require the operator to initiate a normal shutdown of the reactor.

A combination of pipe whip restraints and separation by distance or intervening structure is used to ensure the availability of essential systems and components in the event of an HPCI steam supply line break occurring in the drywell, the isolation valve compartment, or the HPCI pump compartment. Essential systems and components located in these areas are qualified to operate under the environmental conditions resulting from the break. Electrical cabling associated with essential systems and components is routed so as to avoid jet impingement from the postulated break.

No pipe whip restraints are provided for the portion of the HPCI steam supply line located within the HPCI pump compartment. Since no essential systems and components (other than the HPCI system itself) are located in the HPCI pump compartment, such protection is not necessary.

3.6.1.2.1.8 RCIC Steam Supply Line

The RCIC steam supply line has a nominal diameter of 4 inches for the portion inside the drywell and 6 inches for the portion outside the drywell. The supply line connects to main steam line B inside the drywell. From its connection to the main steam line, the RCIC steam supply line is routed generally downward and then horizontally along the drywell wall. The line then penetrates the drywell at el 243'-6", entering the isolation valve compartment located at floor el 217' in the reactor enclosure. The steam supply line penetrates the floor of the isolation valve compartment and enters the RCIC pump compartment located at el 177'. The routing of this line is shown in drawings M-213, M-215, M-225, M-226, M-227, M-229, M-239, M-295, M-296, M-297, M-310, M-316, M-318, and M-320. During normal reactor operation, the line is pressurized from main steam line B up to the RCIC turbine steam supply valve (HV-50-F045).

The RCIC steam supply line is provided with two fast-acting isolation valves, one upstream and one downstream of the primary containment penetration. These valves close automatically upon receipt of signals indicating high steam flow or high temperature in the vicinity of the piping outside the drywell (as well as upon receipt of other initiating signals), in order to terminate blowdown through breaks outside the drywell.

Moment-limiting pipe whip restraints are located upstream of the inboard containment isolation valve and downstream of the outboard containment isolation valve in order to ensure the

operability of these valves in the event of a break in the RCIC steam supply line near the valves. Whip restraints are also located on the RCIC steam supply line inside the drywell and in the isolation valve compartment at el 217' in the reactor enclosure. A typical restraint inside the drywell is shown in Figure 3.6-1.

Pipe Break Locations

The postulated pipe break locations for the RCIC steam supply line, and also the pipe whip restraint locations, are shown in Figure 3.6-25 for the portion of the line inside the drywell and in Figure 3.6-26 for the portion of the line outside the drywell. The calculated stress levels and usage factors, and the postulated break types, are listed in Tables 3.6-15 and 3.6-16.

Compartment Pressure-Temperature Transients

The pressure-temperature transient in the primary containment resulting from a break in the portion of the RCIC steam supply line in the drywell is exceeded in severity by the transients resulting from recirculation loop breaks and main steam line breaks, which are discussed in Section 6.2.1.

Protection against overpressurization of the RCIC pump compartment and the isolation valve compartment at el 217' in the reactor enclosure as a result of RCIC steam supply line breaks in these areas is provided by steam venting paths and blowout panels leading to the outside atmosphere. The isolation valve compartment is vented to the atmosphere via blowout panels located on the south side of the reactor enclosure, as shown in drawings M-118, M-123 and M-138. The RCIC pump compartment is vented to the isolation valve compartment via hinged, metal plate blowout panels located in the floor at el 217'. These latter panels lift to relieve pressurization in the RCIC pump compartment but do not allow pressurization in the isolation valve compartment to result in steam flow in the reverse direction, i.e., down into the RCIC pump compartment.

Pressure-temperature transient analyses for the cases involving RCIC steam supply line breaks in the RCIC pump compartment and the RCIC upper pipe tunnel were performed using the analytical technique described in Reference 3.6-1 and the blowdown data provided in Table 3.6-6. The flow model for breaks in these two compartments is shown in Figure 3.6-27, and the results of the analyses are listed in Table 3.6-7.

The RCIC pump compartment is designed to withstand the maximum pressure developed due to pipe break. No equipment located in the RCIC pump compartment is required to operate following breakage of the RCIC steam supply line. The pressure-temperature transient in the isolation valve compartment at el 217' resulting from a break in the portion of the RCIC steam supply line within that compartment is exceeded in severity by the transient resulting from HPCI steam supply line breakage in the same compartment. All equipment located in the isolation valve compartment that is required to operate following breakage of the RCIC steam supply line is qualified to operate under environmental conditions more severe than those calculated to occur due to breakage of the HPCI steam supply line.

Verification of Reactor Shutdown Capability

Breakage of the RCIC steam supply line inside the drywell would result in an unisolable blowdown of the reactor vessel. The sequence of events that would occur automatically to shut the reactor down and cool the core is discussed in Section 6.3.3.

For an RCIC steam supply line break outside the drywell, the steam supply line containment isolation valves will be closed automatically, terminating reactor vessel blowdown. No reactor scram will occur, due to the isolation of the RCIC steam line and rapid termination of the blowdown. After a RCIC isolation, there is sufficient capability to shutdown the reactor. The operator will investigate the cause of the RCIC isolation and take appropriate actions, in accordance with the plant Technical Specifications and approved operating procedures, to assure that the plant is in a safe condition. The Technical Specifications and/or the operating procedures, which include off normal and EOPs, may, based on plant conditions, require the operator to initiate a normal shutdown of the reactor.

A combination of pipe whip restraints and separation by distance or intervening structure is used to ensure the availability of essential systems and components in the event of an RCIC steam supply line break occurring in the drywell, the isolation valve compartment, or the RCIC pump compartment. Essential systems and components located in these areas are qualified to operate under the environmental conditions resulting from the break. Electrical cabling associated with essential systems and components is routed so as to avoid jet impingement from the postulated break.

No pipe whip restraints are provided for the portion of the RCIC steam supply line located within the RCIC pump compartment. Since no essential systems and components are located within the RCIC pump compartment, such protection is not necessary.

3.6.1.2.1.9 Main Steam Drain Lines

The main steam drainage piping connects to the four main steam lines both inside and outside the drywell. Inside the drywell, 2-inch drain lines that connect to each of the main steam lines are headered together into a single 3-inch line, which then penetrates the drywell wall. This 3-inch drain header is provided with two containment isolation valves, one upstream and one downstream of the containment penetration, both of which are normally closed. Outside the drywell (in the main steam tunnel), 2-inch drain lines that connect to each of the main steam lines are headered together into a single 3-inch line, which then connects to the drain header from the drain lines inside the drywell. Downstream of the connection of the two drain headers, the common line splits into two 3-inch lines again, one routed to the main condenser and one routed to the liquid waste management system. These latter two lines are both provided with normally closed valves located within the main steam tunnel. The routing of the main steam drain lines is shown in drawings M-217, M-226, M-297, and M-326.

Pipe Break Locations

The postulated pipe break locations for the main steam drain lines inside the drywell are shown in Figure 3.6-28. The calculated stress levels and usage factors, and the postulated break types, are listed in Table 3.6-17. Breaks in the main steam drain lines within the main steam tunnel are postulated to occur at each location of potential high stress, such as pipe fittings, valves, and welded attachments.

Compartment Pressure-Temperature Transients

The pressure transient in the primary containment resulting from a break in a main steam drain line within the drywell is exceeded in severity by transients resulting from recirculation loop breaks and main steam line breaks. The temperature transient in the primary containment resulting from a

main steam drain line break is exceeded in severity by the transient resulting from a small steam leak. These design basis transients are discussed in Section 6.2.1.

The pressure-temperature transient in the main steam tunnel resulting from a main steam drain line break within the tunnel is exceeded in severity by the transient resulting from a main steam line break.

Verification of Reactor Shutdown Capability

Breakage of a main steam drain line inside the drywell would result in an unisolable blowdown of steam from the reactor vessel through the broken line. The sequence of events that would occur automatically to shut the reactor down and cool the core is discussed in Section 6.3.3.

For the case of a main steam drain line break inside the main steam tunnel, the resultant temperature rise in the tunnel would cause the MSIVs and the MSL drain isolation valves, if open to close automatically, thereby terminating steam blowdown through the break. Once the MSIVs and MSL drain isolation valves have been closed, the sequence of events is similar to that for a main steam line break outside the drywell.

Separation by distance and intervening structure is used to ensure the availability of essential systems and components in the event of a main steam drain line break in either the drywell or the main steam tunnel.

3.6.1.2.1.10 RPV Head Vent Line

The RPV head vent line is located entirely within the drywell. From its connection point to a 4-inch flanged nozzle on the RPV head, the line reduces to 2 inches in diameter and then is routed generally downward to a penetration through the containment seal plate. From this point, the line continues on downward to its connection with 26-inch main steam line C.

Pipe Break Locations

The postulated pipe break locations for the RPV head vent line, and also the pipe whip restraint locations, are shown in Figure 3.6-30. The calculated stress levels and usage factors, and the postulated break types, are listed in Table 3.6-19.

Compartment Pressure-Temperature Transients

Since the RPV head vent line is located entirely within the drywell, breakage of this line has no effect on plant areas outside the primary containment. The pressure transient in the primary containment resulting from a break in the RPV head vent line is exceeded in severity by transients resulting from recirculation loop breaks and main steam line breaks. The temperature transient in the primary containment resulting from a break in the RPV head vent line is exceeded in severity by the transient resulting from a small steam leak. These design basis transients are discussed in Section 6.2.1.

Verification of Reactor Shutdown Capability

Breakage of the RPV head vent line would result in an unisolable blowdown of steam into the drywell. The sequence of events that would occur automatically to shut the reactor down and cool the core is discussed in Section 6.3.3.

Separation by distance and intervening structure is used to ensure the availability of essential systems and components in the event of an RPV head vent line break.

3.6.1.2.1.11 Standby Liquid Control System Injection Line

The discharge lines from the SLCS injection pumps penetrate the drywell through two separate penetrations and are headered together inside the drywell to form a single 2-inch line. From the vicinity of the drywell penetrations (between el 265' and el 271'), this line is routed horizontally and upward to its connection to core spray injection line B (12" DCA-319). In addition to the containment isolation valves, the SLCS injection line is provided with a check valve near the connection to the core spray line. Only that portion of the SLCS injection line between the core spray line and the inboard check valve is considered high energy during periods when the reactor is pressurized.

Pipe Break Locations

The postulated pipe break locations for the SLCS injection line are shown in Figure 3.6-31. The calculated stress levels and usage factors, and the postulated break types, are listed in Table 3.6-20.

Compartment Pressure-Temperature Transients

Since the high energy portion of the SLCS injection line is located entirely within the drywell, breakage of this line would have no effect on plant areas outside the primary containment. The pressure-temperature transient in the primary containment resulting from a break in the SLCS injection line is exceeded in severity by the transients resulting from recirculation loop breaks and main steam line breaks, which are discussed in Section 6.2.1.

Verification of Reactor Shutdown Capability

Breakage of the SLCS injection line between the RPV and the first check valve in that line would result in an unisolable blowdown from the reactor vessel into the drywell. The sequence of events that would occur automatically to shut the reactor down and cool the core is discussed in Section 6.3.3.

Separation by distance and intervening structure is used to ensure the availability of essential systems and components in the event of an SLCS injection line break.

3.6.1.2.1.12 RHR Shutdown Cooling Suction Line

The RHR shutdown cooling suction line is a 20-inch line connected to recirculation loop B in the drywell. The line is routed downward and then horizontally to its containment penetration at el 244'-8". The line is provided with two containment isolation valves (one inboard and one outboard

of the penetration), both of which are normally closed. Thus, only that portion of the line between the recirculation loop and the inboard containment isolation valve is considered high energy. The routing of the line is shown in drawings M-213, M-217, M-225, M-295, M-296, and M-326.

The RHR shutdown cooling suction line is provided with pipe whip restraints on the portion of the line inside the drywell. Examples of these restraints are shown in Figure 3.6-1.

Pipe Break Locations

The postulated pipe break locations for the RHR shutdown cooling suction line, and also the pipe whip restraint locations, are shown in Figure 3.6-32. The calculated stress levels and usage factors, and the postulated break types, are listed in Table 3.6-21.

Compartment Pressure-Temperature Transients

Since the high energy portion of the RHR shutdown cooling suction line is located entirely within the drywell, breakage of the line would have no effect on plant areas outside the primary containment. The pressure-temperature transient in the primary containment resulting from a break in the RHR shutdown cooling suction line is exceeded in severity by the transients resulting from recirculation loop breaks and main steam line breaks, which are discussed in Section 6.2.1.

Verification of Reactor Shutdown Capability

Breakage of the RHR shutdown cooling suction line would result in an unisolable blowdown of the reactor vessel. The sequence of events that would occur automatically to shut the reactor down and cool the core is discussed in Section 6.3.3.

A combination of pipe whip restraints and separation by distance and intervening structure is used to ensure the availability of essential systems and components in the event of a break in the RHR shutdown cooling suction line.

3.6.1.2.1.13 RHR Shutdown Cooling Return Line

One 12-inch RHR shutdown cooling return line is associated with RHR loop A and a second return line is associated with RHR loop B. Since the two return lines are routed symmetrically on opposite sides of the drywell, the following discussion applies to both lines. The RHR shutdown cooling return line, from the discharge of the associated RHR pump and heat exchanger, penetrates the south side of the drywell at el 244'-8". The line is then routed horizontally following the curvature of the drywell wall until a point due west (for loop A; due east for loop B) of the reactor vessel centerline is reached. From this point, the line is routed upward to el 265'-4" and then horizontally to its connection with the discharge riser of the reactor recirculation loop. The routing of this piping is shown in drawings M-213, M-217, M-225, M-295, M-296, and M-326.

The RHR shutdown cooling return line is provided with two containment isolation valves: a normally closed globe valve outside the drywell and a check valve inside the drywell. Only that portion of the line between the reactor recirculation line and the inboard check valve is considered high energy during periods when the reactor is pressurized.

The RHR shutdown cooling return line is provided with one pipe whip restraint, located at the upper elbow of the vertical portion of the line. A detail of this restraint is shown in Figure 3.6-1.

Pipe Break Locations

The postulated pipe break locations for the RHR shutdown cooling return line, and also the pipe whip restraint locations, are shown in Figure 3.6-32. The calculated stress levels and usage factors, and the postulated break types, are listed in Table 3.6-21.

Compartment Pressure-Temperature Transients

Since the high energy portion of the RHR shutdown cooling return line is located entirely within the drywell, breakage of the line would have no effect on plant areas outside the primary containment. The pressure-temperature transient in the primary containment resulting from a break in the RHR shutdown cooling return line is exceeded in severity by the transients resulting from recirculation loop breaks and main steam line breaks, which are discussed in Section 6.2.1.

Verification of Reactor Shutdown Capability

Breakage of the RHR shutdown cooling return line would result in an unisolable blowdown of the reactor vessel. The sequence of events that would occur automatically to shut the reactor down and cool the core is discussed in Section 6.3.3.

A combination of pipe whip restraints and separation by distance and intervening structure is used to ensure the availability of essential systems and components in the event of a break in the RHR shutdown cooling return line.

3.6.1.2.1.14 LPCI Injection Line

There are four 12-inch LPCI injection lines, one associated with each of the four RHR pumps. The four lines are routed symmetrically inside the drywell, with the A and C injection lines entering the west side of the drywell and the B and D lines entering the east side of the drywell. The following discussion applies to all four lines. The LPCI injection line penetrates the drywell at el 285'-2" and is routed up to el 297'-3" inches where it connects to the reactor vessel nozzle. The routing of this piping is shown in drawings M-215, M-217, M-234, M-235, M-305, M-306, M-316, and M-326.

The LPCI injection line is provided with two containment isolation valves: a normally closed gate valve outside the drywell and a check valve inside the drywell. Only that portion of the line between the reactor vessel nozzle and the inboard check valve is considered high energy during periods when the reactor is pressurized.

The LPCI injection line is restrained to prevent pipe whip inside the drywell. A typical restraint is shown in Figure 3.6-1.

Pipe Break Locations

The postulated pipe break locations for the LPCI injection line, and also the pipe whip restraint locations, are shown in Figure 3.6-33. The calculated stress levels and usage factors, and the postulated break types, are listed in Table 3.6-22

Compartment Pressure-Temperature Transients

Since the high energy portion of the LPCI injection line is located entirely within the drywell, breakage of the line would have no effect on plant areas outside the primary containment. The pressure-temperature transient in the primary containment resulting from a break in the LPCI injection line is exceeded in severity by the transients resulting from recirculation loop breaks and main steam line breaks, which are discussed in Section 6.2.1.

Verification of Reactor Shutdown Capability

Breakage of the LPCI injection line would result in an unisolable blowdown of the reactor vessel. The sequence of events that would occur automatically to shut the reactor down and cool the core is discussed in Section 6.3.3.

A combination of pipe whip restraints and separation by distance and intervening structure is used to ensure the availability of essential systems and components in the event of a break in the LPCI injection line.

3.6.1.2.1.15 Core Spray Injection Line

There are two core spray injection lines, one associated with core spray pumps A and C and one associated with core spray pumps B and D. Since the two lines are routed symmetrically within the drywell, the following discussion applies to both lines. The core spray injection line penetrates the north side of the drywell at el 297'-3" and is routed up to el 306'-7" before connecting to the RPV nozzle. The routing of the piping is shown in drawings M-217, M-235, M-306, and M-326.

The core spray injection line is provided with containment isolation valves both inside and outside the drywell, the inboard valve being a check valve. Only that portion of the line between the reactor vessel nozzle and the inboard check valve is considered high energy during periods when the reactor is pressurized.

The core spray injection line is restrained to prevent pipe whip inside the drywell. Typical restraints are shown in Figure 3.6-1.

Pipe Break Locations

The postulated pipe break locations for the core spray injection line, and also the pipe whip restraint locations, are shown in Figure 3.6-34. The calculated stress levels and usage factors, and the postulated break types, are listed in Table 3.6-23.

Compartment Pressure-Temperature Transients

Since the high energy portion of the core spray injection line is located entirely within the drywell, breakage of the line would have no effect on plant areas outside the primary containment. The pressure-temperature transient in the primary containment resulting from a break in the core spray injection line is exceeded in severity by the transients resulting from recirculation loop breaks and main steam line breaks, which are discussed in Section 6.2.1.

Verification of Reactor Shutdown Capability

Breakage of the core spray injection line would result in an unisolable blowdown of the reactor vessel. The sequence of events that would occur automatically to shut the reactor down and cool the core is discussed in Section 6.3.3.

A combination of pipe whip restraints and separation by distance and intervening structure is used to ensure the availability of essential systems and components in the event of a break in the core spray injection line.

3.6.1.2.1.16 Control Rod Drive Hydraulic

The 2 CRD water pumps are located in the turbine enclosure. The high energy discharge pipes from the 2 pumps are headered together, and a single 2-inch pipe is routed from the turbine enclosure into the reactor enclosure at el 201'. This 2-inch line is then routed upward to the CRD hydraulic system master control station located at el 253' of the reactor enclosure. From the master control station, a 2-inch cooling water header and a 2-inch charging water header are routed to the groups of HCUs on the west side and east side of the drywell. Containment isolation valves are provided in each header between the master control station and the HCUs. The piping between the isolation valves has been upgraded to be equivalent to ASME III, Class 2.

Pipe Break Locations

Since the CRD pump discharge line, the cooling water header, and the charging water header originally consisted entirely of non-nuclear class piping, breaks are postulated to occur at each location of potential high stress, such as pipe fittings, valves, and welded attachments. The original analysis bounds the effects of the addition of containment isolation valves in the headers.

Compartment Pressure-Temperature Transients

Since the normal fluid temperature in the CRD hydraulic system is less than 120°F, no significant pressure-temperature transient would result from postulated breaks.

Verification of Reactor Shutdown Capability

Loss of water pressure due to a break in the CRD pump discharge line, cooling water header, or charging water header will not prevent the control rods from being inserted into the reactor core. At reactor pressures of 450 psig or higher, reactor pressure alone is sufficient to fully insert the control rods. At lower reactor pressures, the scram accumulators assist in supplying the energy necessary to insert the control rods.

3.6.1.2.1.17 Auxiliary Steam Line

From the auxiliary boiler, auxiliary steam is distributed via an 8-inch header to the various steam-consuming components in the turbine enclosure and the radwaste enclosure. This auxiliary steam header passes through the offgas pipe tunnel north of the control structure at el 187'. The auxiliary steam system also provides steam to the RCIC and HPCI systems for testing purposes.

Pipe Break Locations

Since the auxiliary steam line consists of non-nuclear class piping, breaks are postulated to occur at each location of potential high stress, such as pipe fittings, valves, and welded attachments.

Compartment Pressure-Temperature Transients

A pressure-temperature transient analysis for the case of an auxiliary steam line break in a safety-related area was not performed because the piping does not pass through any safety related areas with the exception of the test lines to HPCI and RCIC. However, a pressure-temperature transient analysis was performed for the auxiliary steam line break in the offgas pipe tunnel to ensure control structure integrity. The HPCI and RCIC test lines are normally isolated from the reactor enclosure by closed valves. The lines are only energized in the reactor enclosure for short periods (i.e., less than 1% of the time) and are therefore considered as moderate energy lines.

Verification of Reactor Shutdown Capability

Breakage of the auxiliary steam line would have no effect on operation of the reactor. Except for the test lines for HPCI and RCIC, auxiliary steam lines are not located in areas containing safety related equipment. In the case of the HPCI and RCIC test lines, they are considered to be moderate energy lines based on the short periods in which they are energized. As moderate energy lines, they are acceptable since all rooms containing safety related equipment are qualified for a moderate energy line break.

3.6.1.2.1.18 Plant Heating Steam Piping

From the auxiliary boiler, plant heating steam is distributed to various steam-consuming components in the turbine enclosure and the diesel generator compartments. Additionally, heating steam is provided to the refueling floor and the railroad air-lock in the reactor enclosure and in the diesel corridor outside of the reactor enclosure, however, none of these areas contain safety related equipment necessary to shut down the reactor or maintain primary containment integrity.

Pipe Break Locations

Because the plant heating steam piping consists of non-nuclear class piping, breaks are postulated to occur at each location of potential high stress, such as pipe fittings, valves, and welded attachments.

Verification of Reactor Shutdown Capability

Breakage of the plant heating steam piping would have no effect on operation of the reactor because reactor systems are not located in areas through which the heating steam piping is routed. The only areas of the plant through which heating steam piping is routed that contain safety-related systems are the diesel generator compartments, the refuel floor, the diesel corridor, and the railroad air lock. In addition to the diesel generators, the safeguard MCCs for the following valves are located within diesel generator enclosures:

a. ESW to RHRSW valves (HV-11-11A, 11B, 15A, 15B; drawing M-11).

b. ESW to TECW heat exchanger valves (HV-11-105, 107, 205, 207; Figure 9.2-2).

c. TECW heat exchanger to RHRSW valves (HV-12-110, 210; drawing M-12).

d. CST to ECCS (HV-55-124, 224; drawing M-55).

The MCCs for these valves are distributed throughout the diesel generator cells such that the loss of the MCCs in any one cell would not compromise the safety function of the systems. Thus, an HELB in one cell would not affect the safe shutdown capability of the plant.

A rupture of the plant steam heating piping in one cell would not affect the diesel generators located in other cells. Thus, a failure of this system would result in loss of only the one diesel. The safe shutdown capability of the plant would therefore not be compromised because only three of the four diesels are required in the event of a LOOP.

Because the loss of components in any diesel generator compartment from a high or moderate energy line break would not precipitate a trip of the turbine-generator or a trip of the RPS, offsite power is assumed to remain available in the analysis of the effects of postulated piping failures in these systems (BTP ASB 3.1, paragraph 3.b.1).

There are no essential systems or components as defined in Branch Technical Position SPLB 3-1 (Protection against postulated piping failures in fluid systems outside containment) on the refueling floor, the diesel corridor or the railroad airlock.

3.6.1.2.2 Moderate Energy Fluid Systems

Each room, compartment, or area containing components essential for safe shutdown has been evaluated for the effects of postulated ruptures in moderate energy piping.

Safe shutdown components were evaluated for operability in the postulated water spray and/or flooding environment. Safe shutdown components in the reactor enclosure, the control structure, the diesel generator enclosure, the spray pond pumphouse, the main steam tunnel, and the RHRSW pipe tunnel were considered.

Those components not designed for operability in a water spray and/or a flooding environment were assumed to fail. Electrical components that are needed for safe shutdown, but that would fail under the water spray/flooding conditions, were protected from water spray and flooding conditions.

The synergistic effects of an independent single active failure, in addition to the effects of the pipe break, were evaluated and were found acceptable subject to any limitations discussed below. For some systems (such as RHR), a single active failure in the redundant loop of the same system has been excluded in accordance with Section 3.6.1.1.

The crack sizes postulated, and the nominal pipe sizes in which moderate energy pipe cracks are postulated to occur, are discussed in Section 3.6.2.1.3. Additional criteria used in the moderate energy fluid systems analysis are discussed in Section 3.6.1.1.

3.6.1.2.2.1 Primary Containment

All equipment within the primary containment that must operate during or after a LOCA is qualified for the appropriate environmental conditions, as described in Section 3.11. Wetting associated

with the postulated failure of any moderate energy pipe is within the bounds of that qualification. Consequently, no item-by-item discussion of this less severe event is required to verify that capability of safely shutting down the plant.

3.6.1.2.2.2 Reactor Enclosure

Compartments or areas on each elevation that contain safe shutdown electrical equipment were evaluated. Piping and mechanical drawings for each elevation of the reactor enclosure are provided in Section 1.2. All safety-related equipment whose operability in a water spray or flooding environment must be ensured were either protected from the consequences of the pipe break or are designed to remain operable in that environment.

3.6.1.2.2.3 Control Structure

Compartments or areas that contain safety-related equipment on each elevation were evaluated beginning with el 200', the lowest elevation of the control structure. All safety-related equipment whose operability in a water spray or flooding environment must be ensured were either protected from the consequences of the pipe break or were designed to operate in that environment. Piping and mechanical drawings for each elevation of the control structure are provided in Section 1.2.

3.6.1.2.2.4 Diesel Generator Compartments

Moderate energy piping systems that are routed through the diesel generator compartments include:

a. ESW to the diesel generator heat exchangers

b. diesel fuel oil supply lines

c. diesel generator starting air

d. demineralized water from the jacket water expansion tank to the diesel generator

e. lube oil from the storage tank to the diesel generator

f. fire protection system (normally dry)

Each of the moderate energy piping systems is integral to the operation or protection of the diesel generator located in the same compartment as the piping. Thus, a failure of one or more of these systems would result in loss of only the one diesel. The safe shutdown capability of the plant would therefore not be compromised because only three of the four diesels are required in the event of a LOOP.

In addition to the diesel generators, a safeguard MCC is located within each diesel generator enclosure. The impact of a pipe break in the diesel generator enclosure on these MCCs is discussed in Section 3.6.1.2.1.18.

3.6.1.2.2.5 Spray Pond Pumphouse

The spray pond pumphouse contains two separate ESW and RHRSW pump areas, two RHRSW and ESW pipe-ways, two RHRSW valve compartments, and several other compartments.

Each pump-room contains two RHRSW pump motors and two ESW pump motors. The pumps are common to both Unit 1 and Unit 2.

During normal plant operation, the ESW and RHRSW piping is depressurized except during surveillance testing of ESW, RHRSW, and the diesel generators; and during operation for reactor shutdown cooling, suppression pool cooling, and spray pond cooling/chemistry control. The frequency of the surveillance tests is in accordance with the Technical Specifications, and the frequency of operation for other purposes varies with plant conditions.

A moderate energy line break in these lines during normal plant operation is unlikely. However, if a line break should occur, water spray could impinge on the pump motors in the room. In this event, up to two ESW and two RHRSW pumps could be disabled. The loss of the two ESW pumps is of no concern because shutdown cooling loads would be provided by the service water system. Because nonsafeguard heat removal systems are available, the RHRSW system is not critical for safe shutdown of the reactors.

The RHRSW valve compartments contain valves that are essential for the safe operation of the ESW system. However, as discussed above, shutdown cooling loads would be provided by the service water system because offsite power would be assumed to be available.

A pipe break in the wet pit, the ESW and RHRSW pipe-way, or the access hatch area would not impact safe shutdown capability because these compartments do not contain components that are essential for safe shutdown.

Spray pond pumphouse flooding is limited to the compartments adjoining the pump area. The pump area itself cannot flood because water would flow through open grating into the spray pond.

Flooding in the adjacent compartments could damage at most a single mechanical division. Because it is not necessary to postulate a single active failure in the redundant RHRSW system, and because flooding can damage only one mechanical division of RHRSW, safe shutdown capability will not be impaired.

3.6.1.2.2.6 Main Steam Tunnel

Safe shutdown components in the main steam tunnel include the outboard MSIVs.

The MSIVs are qualified to operate in environments more severe than that caused by moderate energy water spray. The valves are located well above the maximum water flood level. Therefore, the occurrence of a moderate energy pipe crack in this compartment would have no effect on safe shutdown capability.

3.6.1.2.2.7 RHRSW Pipe Tunnel

A moderate energy pipe break in the RHRSW pipe tunnel would not impact safe shutdown capability.

The only safe shutdown components on this elevation are two RHRSW valves. Each of these valves are qualified to be submersible and would withstand postulated water spray and flooding conditions.

3.6.1.3 Safety Evaluation

The analyses of postulated pipe ruptures summarized in Section 3.6.1.2 verify that the consequences of any single rupture of fluid system piping in the plant will not prevent safe shutdown of the reactor from being achieved.

The offsite radiological consequences of piping ruptures are enveloped by a reactor recirculation system break for all breaks inside primary containment, and by main steam system and feedwater system breaks for all breaks outside primary containment. The radiological consequences of these breaks are presented in Sections 15.6.5, 15.6.4, and 15.6.6, respectively.

Special consideration has been given to protecting the control room and other areas of the control structure containing essential systems and components from the effects of postulated pipe ruptures. Exterior walls of the control structure above the slab at el 217' are designed as steam-tight in those areas where the walls could be subject to steam pressurization resulting from rupture of high energy fluid system piping outside the control structure. HVAC ducts penetrating these portions of the control structure walls are equipped with back pressure dampers, and other types of penetrations through the walls are designed as steam-tight.

As described in Sections 3.6.1.2.1.2 and 3.6.1.2.1.3, those portions of the main steam and feedwater lines routed near the control structure are provided with pipe whip restraints and bumpers to prevent a postulated rupture of these lines from causing unacceptable damage to the control structure walls.

3.6.2 DETERMINATION OF PIPE FAILURE LOCATIONS AND DYNAMIC EFFECTS ASSOCIATED WITH POSTULATED PIPING FAILURES

Information concerning break and crack location criteria and methods of analysis is presented in this section. The location criteria and methods of analysis are needed to evaluate the dynamic effects associated with postulated ruptures of high energy and moderate energy piping inside and outside the primary containment.

3.6.2.1 Criteria Used to Determine Pipe Break and Crack Locations and Their Configurations

3.6.2.1.1 Break Locations in High Energy Fluid System Piping

3.6.2.1.1.1 Piping in Containment Penetration Areas

High energy pipes penetrating the primary containment are provided with moment-limiting restraints that are located reasonably close to the containment isolation valves and are designed to

withstand the loadings resulting from a pipe break either inboard of the inboard isolation valve or outboard of the outboard isolation valve so that neither isolation valve operability nor leak-tight integrity of the containment penetration would be impaired as a result of such pipe breaks. Terminal ends of high energy piping that penetrate the containment are considered to originate beyond the containment isolation valve and its moment-limiting restraint, both inboard and outboard.

Breaks are not postulated in these portions of high energy piping in containment penetration areas provided that the following design stress and fatigue limits are satisfied:

For ASME Section III, Class 1 Piping

a. The stress intensity range S_n, calculated for normal and upset conditions by equation (10) of paragraph NB-3653, does not exceed 2.4 S_m, and the cumulative usage factor associated with normal, upset, and testing conditions is less than 0.1, or

b. The stress intensity range S_n, calculated for normal and upset conditions by equation (10) of paragraph NB-3653 exceeds 2.4 S_m but does not exceed 3.0 S_m and the cumulative usage factor associated with normal, upset, and testing conditions is less than 0.1, or

c. The stress intensity range S_n, calculated for normal and upset conditions by equation (10), exceeds 3.0 S_m, but the stress intensity ranges computed by equations (12) and (13) of paragraph NB-3653 are less than 2.4 S_m and the cumulative usage factor associated with normal, upset, and testing conditions is less than 0.1

d. Breaks are always postulated whenever the usage factor exceeds 0.1 regardless of stress.

e. The loading resulting from a postulated pipe break beyond these portions of the piping does not cause the stress as calculated by equation (9) in paragraph NB-3652 to exceed 2.25 S_m, except for the portion of piping between the isolation valve and the adjacent restraints protecting the operability of the valve. For this latter portion of piping, higher stresses are permitted provided that a plastic-hinge is not formed and the operability of the isolation valve is ensured.

After the as-built analysis is completed, the licensee will conduct a comparison against the SRP criteria (NUREG-0800) (BTP MEB 3-1) and demonstrate no additional breaks for the following situations:

a. The stress calculated by equation (10) is between 2.4 S_m and 3.0 S_m and

b. The ASME Code version of 1979 Summer Addenda or later is used for analysis.

For ASME Section III, Class 2 and 3 Piping

a. The maximum stress ranges as calculated by the sum of equations (9) and (10) in paragraph NC-3652, considering normal and upset plant conditions, does not exceed $0.8(1.2\ S_h + S_A)$.

b. The maximum stress, as calculated by equation (9) in paragraph NC-3652, under the loadings resulting from a postulated rupture of fluid system piping beyond these portions of piping does not exceed $1.8\ S_h$, except for the portion of the piping between the isolation valve and the adjacent restraints protecting the operability of the valve. For this latter portion of the piping, higher stress is permitted, provided that a plastic-hinge is not formed and the operability of the isolation valve is assured.

In addition to these stress and fatigue criteria, high energy piping in containment penetration areas must meet the following requirements:

a. Welded pipe support attachments are avoided to eliminate stress concentrations.

b. The number of circumferential and longitudinal pipe welds and branch connections is minimized.

c. The length of the piping run is minimized, consistent with requirements to keep stress levels low and provide access for inservice inspection.

d. The design at points of pipe fixity (such as pipe anchors or welded connections at containment penetrations) does not require welding directly to the outer surface of the piping (flued, integrally forged pipe fittings are acceptable), except where such welds are 100% volumetrically examinable in service and a detailed stress analysis is performed to demonstrate compliance with the limits of the stress and fatigue criteria stated above.

e. In accordance with the inservice inspection plan, the inservice examination completed during each inspection interval will provide either a 100% volumetric examination of circumferential pipe welds within these portions of piping or those examinations required by the Risk Informed Inservice Inspection (RISI) Program as applied to these portions of piping also known as the Break Exclusion Region (BER). Inservice inspection of the RCPB is discussed in Section 5.2.4.

f. For piping constructed in accordance with ANSI B31.1, all welds will be fully radiographed.

After the as-built analysis is completed, the licensee will conduct a comparison against the SRP criteria (NUREG-0800) (BTP MEB 3-1) and demonstrate no additional breaks for the following situations:

a. The stress calculated by equation (10) is between $2.4\ S_m$ and $3.0\ S_m$ and

b. The ASME Code version of 1979 Summer Addenda or later is used for analysis.

3.6.2.1.1.2 Recirculation System Piping

Pipe breaks in the Unit 1 recirculation system are postulated to occur at the following locations:

a. Terminal ends of a piping run or branch run.

b. At intermediate locations between terminal ends where the maximum stress range between any two load sets (including the zero load set), as calculated according to ASME Section III, subarticle NB-3600, for upset plant conditions and an independent OBE event, meets the following requirements:

1. The stress range, as calculated using equation (12) or (13), exceeds 2.4 S_m and the cumulative usage factor associated with normal, upset, and testing conditions is less than 0.1.

2. The stress range calculated using equation (10) exceeds 2.4 S_m but is less than 3.0 S_m, and the cumulative usage factor exceeds 0.1.

3. The stress range calculated using equation (10) exceeds 3.0 S_m, and the cumulative usage factor exceeds 0.1.

4. Breaks are always postulated whenever the usage factor exceeds 0.1 regardless of stress.

5. If two or more intermediate break locations cannot be determined by stress or usage factor limits, two arbitrary intermediate break locations are selected on a reasonable basis. This basis includes consideration of fitting locations and/or highest stress or usage factor locations. Where more than two such intermediate locations are possible using the application of the above reasonable basis, those two locations possessing the greatest damage potential are used. A break at each end of a fitting can be classified as two discrete break locations when the stress analysis is sufficiently detailed to differentiate stresses at each postulated break.

After the as-built analysis is completed, the licensee will conduct a comparison against the SRP criteria (NUREG-0800) (BTP MEB 3-1) and demonstrate no additional breaks for the following situations:

a. The stress calculated by equation (10) is between 2.4 S_m and 3.0 S_m, and

b. The ASME Code version of 1979 Summer Addenda or later is used for analysis.

For Unit 2, break locations are similarly postulated except that the two arbitrary intermediate break locations of b.4 above need not be postulated provided the following criteria are met:

a. The piping system is adequately resistant to IGSCC and is not susceptible to unanticipated water hammer thermal transient events.

b. The piping system is included in the startup testing program for piping steady-state vibrations.

c. The elimination of the break location does not change equipment environmental qualification or structural design criteria.

3.6.2.1.1.3 Class 1 Piping (Other Than Recirculation System Piping and Piping in Containment Penetration Areas)

Breaks in Class 1 piping (ASME Section III) for Unit 1 are postulated to occur at the following locations:

a. At terminal ends of piping runs or branch runs.

b. At intermediate locations between terminal ends, as determined by one of the two following criteria:

1. At each location of potential high stress such as pipe fittings (elbows, tees, reducers, etc) valves, and welded attachments.

2. At each location where, for normal and upset load conditions, none of the following stress and fatigue limits are met:

(a) The stress intensity range S_n, calculated by equation (10) of paragraph NB-3653, does not exceed 2.4 S_m and the cumulative usage factor associated with normal, upset, and testing conditions is less than 0.1.

(b) The stress intensity range S_n, as calculated by equation (10) of paragraph NB-3653, exceeds 2.4 S_m but is less than 3.0 S_m, and the cumulative usage factor is less than 0.1.

(c) The stress intensity range S_n exceeds 3.0 S_m, but the stresses computed by equations (12) and (13) of paragraph NB-3653 are less than 2.4 S_m, and the cumulative usage factor is less than 0.1.

(d) Breaks are always postulated whenever the usage factor exceeds 0.1 regardless of stress.

3. When the above stress and fatigue criteria result in less than two intermediate break locations, a minimum of two locations are chosen based on highest stress, as calculated by equation (10) of paragraph NB-3653. The two locations are separated by a change of direction of the force resulting from pipe break. If the piping run has no more than one change of direction, a minimum of one intermediate break location is chosen. Any given fitting is considered as a single break location regardless of the number of breaks postulated at different locations on that fitting.

Intermediate pipe break locations are initially based on committed design piping stress calculations in accordance with the above criteria. As a result of piping reanalysis, the highest stress locations may be shifted. An initially determined pipe break location will not be changed as a consequence, however, unless one of the following conditions exists:

(a) Reanalysis shows that maximum stress range or cumulative usage factor at another location not only exceeds that for the initial pipe break location but also exceeds the above pipe break criteria. In addition, the break at the new location results in more serious consequences to safety-related systems than the initial break location.

(b) Significant changes are made in the routing, size, or wall thickness of the pipe after the initial pipe break determination.

4. After the as-built analysis is completed, the licensee will conduct a comparison against the SRP criteria (NUREG-0800) (BTP MEB 3-1) and demonstrate no additional breaks for the following situations:

(a) The stress calculated by equation (10) is between 2.4 S_m and 3.0 S_m and

(b) The ASME Code version of 1979 Summer Addenda or later is used for analysis.

For Unit 2, break locations are similarly postulated except that arbitrary intermediate breaks from b.3 above need not be postulated provided the following criteria are met:

a. The piping system is adequately resistant to IGSCC and is not susceptible to unanticipated water hammer thermal transient events.

b. The piping system is included in the startup testing program for piping steady-state vibrations.

c. The elimination of the break location does not change equipment environmental qualification or structural design criteria.

The following Unit 2 class 1 piping systems meet all of the above criteria:

- Main Steam Inside Containment
- Feedwater Inside Containment
- RWCU Inside Containment
- Reactor Vessel Drain
- HPCI Steam Supply Inside Containment

- RCIC Steam Supply Inside Containment
- SLCS
- RHR Shutdown Cooling Suction
- RHR Shutdown Cooling Return
- LPCI Injection
- Core Spray Injection

3.6.2.1.1.4 Class 2 and 3 Piping (Other Than Recirculation System Piping and Piping in Containment Penetration Areas)

Breaks in Class 2 and 3 piping (ASME Section III) for Unit 1 are postulated to occur at the following locations:

a. At terminal ends of piping runs or branch runs.

b. At intermediate locations between terminal ends, as determined by one of the three following criteria:

1. At each location of potential high stress, such as pipe fittings (elbows, tees, reducers, etc), valves, and welded attachments.

2. At each location where the maximum stress range, as calculated by the sum of equations (9) and (10) of paragraph NC-3652, considering normal and upset plant conditions, exceeds $0.8(1.2\ S_h + S_A)$.

3. When the above stress and fatigue criteria result in less than two intermediate break locations, a minimum of two locations are chosen based on highest stress, as calculated by the sum of equations (9) and (10) of paragraph NC-3652. The two locations are separated by a change of direction of the force resulting from pipe break. If the piping run has no more than one change of direction, a minimum of one intermediate break location is chosen. Any given fitting is considered as a single break location regardless of the number of breaks postulated at different locations on that fitting.

Intermediate pipe break locations are initially based on committed design piping stress calculations in accordance with the above criteria. As a result of piping reanalysis, the highest stress locations may be shifted. An initially determined pipe break location will not be changed as a consequence, however, unless one of the following conditions exists:

(a) Reanalysis shows that maximum stress range or cumulative usage factor at another location not only exceeds that for the initial pipe

break location but also exceeds the above pipe break criteria. In addition, the break at the new location results in more serious consequences to safety-related systems than the initial break location.

(b) Significant changes are made in the routing, size, or wall thickness of the pipe after the initial pipe break determination.

4. At each extreme of the piping run adjacent to basic protective structures, when the piping system contains no fitting, valve, or welded attachment.

For Unit 2, break locations are similarly postulated except that the arbitrary intermediate breaks from b.3 above need not be postulated provided the following criteria are met:

a. The piping system is adequately resistant to IGSCC and is not susceptible to unanticipated water hammer thermal transient events.

b. The piping system is included in the startup testing program for piping steady-state vibrations.

c. The elimination of the break location does not change equipment environmental qualification or structural design criteria.

The following Unit 2 Class 2, 3 piping systems meet all of the above criteria:

- RWCU Outside Containment
- HPCI Steam Supply Outside Containment
- RCIC Steam Supply Outside Containment
- Main Steam Outside Containment

3.6.2.1.1.5 Non-Nuclear Class Piping

Breaks in non-nuclear class piping are postulated to occur at the following locations:

a. At terminal ends of piping runs or branch runs.

b. At each intermediate location of potential high stress, such as pipe fittings (elbows, tees, reducers, etc), valves, and welded attachments.

Alternatively, the break locations for non-nuclear class piping can be selected according to the same criteria used for Class 2 and 3 piping, provided that all necessary analyses are made.

These breaks in nonseismic Category I piping have been postulated at those locations that would result in the maximum amount of damage and the safety-related systems and components have adequate protection from these piping breaks as discussed below.

The only high energy seismic Category II piping in the control structure is the portion of the steam supply line to the offgas recombiner preheater that is located within the recombiner compartments. The only high energy seismic Category II piping in the reactor enclosure is the RWCU piping inside the RWCU filter/demineralizer compartments and the RWCU holding pump compartments. In both cases, the walls of the compartments are capable of withstanding the pipe whip and jet impingement forces and the compartment pressurization that could result from breaks at the most adverse locations. Because there are no safety-related components located in these compartments, safety-related components will not be affected by high energy pipe breaks within these compartments.

The diesel generator enclosures have high energy seismic Category IIA piping in the form of heating steam supply lines (1½" JBD-330/430). A rupture of such a line could create maximum temperatures of less than 340°F and pressures less than 15 psia (0.3 psig) due to the large "bird grill" vent openings. As only one diesel generator enclosure is affected at any one time, the assumed loss of one diesel generator is acceptable.

Other safety-related structures, such as the spray pond pumphouse, do not contain high energy seismic Category II piping.

Safety-related components are protected from the effects of high energy pipe breaks in nonsafety-related structures by the walls that separate the safety-related structures from the nonsafety-related structures. To the extent necessary to prevent unacceptable damage to safety-related components, these walls are designed to withstand the pipe whip and jet impingement forces and compartment pressurization that could result from breaks at the most adverse locations in high energy seismic Category II piping within the nonsafety-related structures.

3.6.2.1.2 Crack Locations in Moderate Energy Fluid System Piping

Through-wall leakage cracks are postulated to occur in moderate energy piping located in areas containing essential systems and components. Cracks are postulated to occur at terminal ends of piping runs or branch runs, and at intermediate locations selected in accordance with either of the two following criteria:

a. At each location of potential high stress, such as pipe fittings (elbows, tees, reducers, etc), valves, and welded attachments

b. For Class 1 piping (ASME Section III), at locations where the maximum range of stress intensity as calculated by equation (10) of paragraph NB-3653 exceeds 1.2 S_m, and for Class 2 or 3 piping (ASME Section III) or non-nuclear piping, at locations where the maximum stress range as calculated by the sum of equations (9) and (10) of paragraph NC-3652 exceeds $0.4(1.2\ S_h + S_A)$.

The above criteria notwithstanding, cracks are not postulated in those portions of moderate energy piping located in the following areas:

a. Areas in which high energy pipe breaks are postulated, provided that moderate energy piping cracks would not result in more severe environmental conditions than the high energy pipe breaks.

b. Between containment isolation valves, provided that:

1. The piping meets the requirements of subarticle NE- 1120 of the ASME B&PV Code

2. The maximum range of stress intensity for Class 1 piping (ASME Section III) as calculated by equation (10) of paragraph NB-3653 does not exceed 1.2 S_m, and the maximum stress range for Class 2 and 3 (ASME Section III) or non-nuclear piping as calculated by the sum of equations (9) and (10) of paragraph NC-3652 does not exceed $0.4(1.2\ S_h + S_A)$.

3.6.2.1.3 Types of Breaks and Cracks in Fluid System Piping

Circumferential Breaks

A circumferential break is assumed to result in (a) severance of a high energy pipe on a plane perpendicular to the pipe axis, and (b) separation amounting to at least a one diameter lateral displacement of the ruptured piping ends unless physically limited by piping restraints, structural members, or piping stiffness. Pipe whipping is assumed to occur in the plane defined by the piping geometry and configuration, and to cause pipe movement in the direction of the jet reaction.

All analyses to determine the blowdown (reaction) force on the segment of piping that contains a circumferential break are based on unobstructed discharge from 100% of the cross-sectional area of the pipe. This is consistent with the assumption of a one diameter lateral displacement of the ruptured piping ends. The only pipe break analyses that have involved lateral displacements of less than one pipe diameter are analyses concerning jet impingement forces. In certain cases where pipe whip restraints are located on both sides of a postulated circumferential break, and the design of the restraints prevents the two ends of the break from achieving a one diameter displacement, credit is taken for one end of the broken pipe causing partial blockage of the fluid being discharged from the opposite side of the break. Similarly, in certain cases where one side of the break is an RPV nozzle safe-end and the other side of the break is restrained from achieving a one diameter displacement relative to the nozzle, credit is taken for partial blockage of the fluid discharging from the restraint pipe end. This methodology can result in a reduction of the jet impingement force on potential impingement targets.

Circumferential breaks are postulated in high energy fluid system piping of nominal pipe size greater than 1-inch, at the locations determined by the criteria listed in Section 3.6.2.1.1, except where it can be shown that the maximum stress is in the circumferential direction and is at least 1.5 times the longitudinal stress, in which case only a longitudinal break is postulated.

Longitudinal Breaks

A longitudinal break is assumed to result in an axial split parallel to the pipe axis, without causing pipe severance. The break opening area is assumed to be equal to the effective cross- sectional flow area of the pipe at the break location. The split is assumed to be oriented (but not concurrently) at two diametrically opposed points on the piping circumference so that the jet reaction force causes out-of-plane bending of the piping configuration. Piping movement is assumed to occur in the direction of the jet reaction unless limited by piping restraints, structural members, or piping stiffness.

Longitudinal breaks are postulated in high energy fluid system piping of nominal pipe sizes of 4 inches and larger, at the locations determined by the criteria listed in Section 3.6.2.1.1, with the following exceptions. Longitudinal breaks are not postulated:

a. At terminal ends

b. At intermediate break locations chosen to satisfy the criterion for a minimum number of break locations

c. At locations where it can be shown that the maximum stress is in the longitudinal direction and is at least 1.5 times the circumferential stress, in which case only circumferential breaks need to be postulated.

Through-Wall Leakage Cracks

Through-wall leakage cracks are postulated to occur in moderate energy fluid system piping exceeding a nominal pipe size of 1 inch, at the locations determined by the criteria listed in Section 3.6.2.1.2. A crack is assumed to occur at any orientation about the circumference of a pipe. Fluid flow from a crack is based on a circular opening with an area equal to that of a rectangle one-half pipe diameter in length and one-half pipe wall thickness in width.

3.6.2.2 Analytical Models to Define Forcing Functions and Response Models (Recirculation System Only)

3.6.2.2.1 Analytical Methods to Define Blowdown Forcing Functions

The rupture of a pressurized pipe causes the flow characteristics of the system to change, creating reaction forces that can dynamically excite the piping system. The reaction forces are a function of time and space and depend upon the fluid state within the pipe prior to rupture, break flow area, frictional losses, plant system characteristics, piping system, and other factors. The methods used to calculate the reaction forces for recirculation system piping are presented below.

The criteria that are used for calculation of fluid blowdown forcing functions include:

a. The dynamic force of the jet discharge at the break location is based on the effective cross-sectional flow area of the pipe and on a calculated fluid pressure as modified by an analytically or experimentally determined thrust coefficient. Limited pipe displacement at the break location, line restrictions, flow limiters, positive pump-controlled flow, and the absence of energy reservoirs may be taken into account, as applicable, in the reduction of jet discharge.

b. All breaks are assumed to attain full pipe break area instantaneously, i.e., a rise time not exceeding one millisecond is used for the initial pulse.

Blowdown forcing functions are determined by either of two methods as described below.

Moody Model

The predicated blowdown forces on pipes fed by a pressure vessel can be described by transient and steady-state forcing functions. The forcing functions used are based on methods described in Reference 3.6-4. These are simply described as follows:

a. The transient forcing functions at points along the pipe result from the propagation of waves (wave thrust) along the pipe, and from the reaction force due to the momentum of the fluid leaving the end of the pipe (blowdown thrust).

b. The waves cause various sections of the pipe to be loaded with time-dependent forces. It is assumed that the pipe is one-dimensional, in that there is no attenuation or reflection of the pressure waves at bends, elbows, and the like. Following the rupture, a decompression wave is assumed to travel from the break at a speed equal to the local speed of sound within the fluid. Wave reflections occur at the break end, changes in direction of piping, and the pressure vessel until a steady flow condition is established. Vessel and free space conditions are used as boundary conditions. The blowdown thrust causes a reaction force perpendicular to the pipe break.

c. The initial blowdown force on the pipe is taken as the sum of the wave and blowdown thrusts and is equal to the vessel pressure (P_o) times the break area (A). After the initial decompression period (i.e., the time it takes for a wave to reach the first change in direction), the force is assumed to drop off to the value of the blowdown thrust (i.e., 0.7 P_oA).

d. Time histories of transient pressure, flow rate, and other thermodynamic properties of the fluid can be used to calculate the blowdown force on the pipe using the following equation:

$$F = \left[(P-P_a) + \frac{\rho u^2}{g_c}\right] A \qquad \text{(EQ. 3.6-1)}$$

where:

F = blowdown force

P_a = pressure at exit plane

P = ambient pressure

u = velocity at exit plant

ρ = density at exit plane

A = area of break

g_c = Newton's constant

e. Following the transient period, a steady-state period is assumed to exist. Steady-state blowdown forces are calculated including frictional effects. For saturated steam, these effects reduce the blowdown forces from the theoretical maximum of 1.26 P_oA. The method accounting for these effects is presented in Reference 3.6-4. For subcooled water, a reduction from the theoretical maximum of 2.0 P_oA is found through the use of Bernoulli's equation and standard equations such as Darcy's equation, which account for friction.

RELAP3

The computer code RELAP3 (Reference 3.6-5) is used to obtain exit plane thermodynamic states for postulated ruptures. Specifically, RELAP3 supplies exit pressure, specific volume, and mass rate. From these data the blowdown reaction load is calculated using the following relation:

$$\frac{T}{A_E} = P_E - P_{oo} + \frac{G_E^2 \overline{V}_E}{G_c} \qquad \text{(EQ. 3.6-2)}$$

$$R = -\frac{T}{A_E} \cdot A_E \qquad \text{(EQ. 3.6-3)}$$

where:

$\frac{T}{A_E}$ = thrust per unit break area (lb_f/ft^2)

P_E = exit pressure (lb_f/ft^2)

P_{oo} = receiver pressure (lb_f/ft^2)

G_E = exit mass flux ($lb_m/sec\text{-}ft^2$)

$\overline{V}_E$ = exit specific volume (ft^3/lb_m)

g_c = Newton's constant (32.174 $ft\text{-}lb_m/lb_f\text{-}sec^2$)

R = reaction force on the pipe (lb_f)

3.6.2.2.2 Pipe Whip Dynamic Response Analyses

The prediction of time-dependent and steady-thrust reaction loads caused by blowdown of subcooled, saturated, and two-phase fluid from a ruptured pipe is used in design and evaluation of dynamic effects of pipe breaks. A detailed discussion of the analytical methods employed to compute these blowdown loads for recirculation system piping is given in Section 3.6.2.2.1. Analytical methods used to account for this loading are discussed below.

The criteria used for performing the pipe whip dynamic response analyses for recirculation system piping include:

a. A pipe whip analysis is performed for each postulated pipe break. However, a given analysis can be used for more than one postulated break location if the

blowdown forcing function, piping and restraint system geometry, and piping and restraint system properties are conservative for other break locations.

b. The analysis includes the dynamic response of the pipe in question and the pipe whip restraints that transmit loading to the structures.

c. The analytical model adequately represents the mass/inertia and stiffness properties of the system.

d. Pipe whipping is assumed to occur in the plane defined by the piping geometry and configuration, and is assumed to cause pipe movement in the direction of the jet reaction.

e. Piping within the broken loop is no longer considered part of the RCPB. Plastic deformation in the pipe is considered as a potential energy absorber. Limits of strain are imposed that are similar to strain levels allowed in restraint plastic members. Piping systems are designed so that plastic instability does not occur in the pipe at the design dynamic and static loads, unless damage studies are performed to show that the consequences do not result in direct damage to any essential system or component.

f. Components such as vessel safe ends and valves that are attached to the broken piping system and do not serve a safety function, or whose failure would not further escalate the consequences of the accident, are not designed to meet limits imposed by the ASME B&PV Code for essential components under faulted loading.

The pipe whip analysis was performed using the PDA computer program (Reference 3.6-6). PDA is a computer program used to determine the response of a pipe subjected to the thrust-force occurring after a pipe break. The program treats the situation in terms of generic pipe break configuration, which involves a straight, uniform pipe fixed at one end and subjected to a time-dependent thrust-force at the other end. A typical restraint used to reduce the resulting deformation is also included at a location between the two ends. Nonlinear and time-independent stress-strain relations are used for the pipe and the restraint. A static nonlinear cantilever beam analysis is used for these locations to obtain the relationship between the pipe bending moment and the deflection (or rotation). Similar to the plastic-hinge concept, bending of the pipe is assumed to occur only at the fixed end and at the location supported by the restraint.

Shear deformation is also neglected. The pipe bending moment- deflection (or rotation) relation used for these locations is obtained from a static nonlinear cantilever beam analysis. Using the moment-rotation relation, nonlinear equations of pipe motion are formulated using an energy consideration, and the equations are numerically integrated in small time steps to yield time history information of the deformed pipe.

Considerable testing and analyses have demonstrated that potential rebound does not cause unacceptable increases in restraint deformation following the first quarter cycle loading for the GE restraint design and piping system experiencing blowdown thrust forces. Generic tests were performed on a 12-inch pipe size restraint with two primary loading configurations that represent the typical conditions during the postulated pipe rupture. Any other loading condition results in a combination of these two extremes. These loading configurations are:

a. Load applied perpendicular to the restraint frame base against the cable

b. Load applied parallel to the base against one side of the frame.

The mass/inertia and stiffness properties of the recirculation system in the pipe dynamic analysis (PDA model) are represented as described below. A generic representation of the pipe in any given analysis is shown in Figure 3.6-41. If the stiffness of the piping segment located between A and B is such that:

a. The slope of BD at B = 0, then in the analysis, the pipe is treated as built-in at B.

b. The slope of BD at B ≠ 0 (considerably different), then in the analysis, the pipe is considered to have a fixed, simple support (pinned end) at B.

To analyze the pipe with both ends supported (Figure 3.6-42) with the above computer model, two simplifications were made in the PDA program. First, an equivalent point mass is assumed at D instead of pipe length DE. The inertia characteristics of this mass rotating around point B are calculated to be identical to those of pipe length DE rotating around point E. Secondly, an equivalent resisting force is calculated for any deflection for the case of a built-in end from the bending moment-angular deflection relationship for pipe length DE. This equivalent force is subtracted from the applied thrust-force when calculating the net energy. The new model resulting from these simplifications is shown in Figure 3.6-42. The PDA computer program is further described in Section 3.9.1.2.2.6.

A comprehensive verification has been performed to demonstrate the conservatisms inherent in the PDA pipe whip computer program and the analytical methods utilized. This is described in Reference 3.6-7. Part of this verification program included an independent analysis of the recirculation system piping for the 1969 Standard Plant Design by Nuclear Services Corporation, under contract to GE. The recirculation system piping was chosen for study due to its complex piping arrangement and assorted pipe sizes. The analysis included elastic-plastic pipe properties, elastic-plastic restraint properties, and gaps between the restraint and pipe as documented in Reference 3.6-7. The piping/restraint system geometry and properties and fluid blowdown forces were the same in both analyses. However, a linear approximation was made by Nuclear Services Corporation for the restraint load-deflection curve supplied by GE. This approximation is demonstrated in Figure 3.6-36. The effect of this approximation is to give lower energy absorption of a given restraint deflection. Typically, this yields higher restraint deflections and lower restraint-to-structure loads than the GE analysis. The deflection limit used by Nuclear Services Corporation is the design deflection at one-half of the ultimate uniform strain for the GE restraint design. The restraint properties used for both analyses are provided in Table 3.6-24.

A comparison of the Nuclear Services Corporation analysis with the PDA analysis, as presented in Table 3.6-25 and Figure 3.6-37, shows that PDA predicts higher loads in 15 of the 18 restraints analyzed. This is due to the Nuclear Services Corporation model including energy-absorbing effects in secondary pipe elements and structural members. However, PDA predicts higher restraint deflections in 50% of the restraints. The higher deflections predicted by Nuclear Services Corporation for the lower loads are caused by the linear approximation used for the force-deflection curve rather than by differences in computer techniques. This comparison demonstrates that the simplified modeling system used in PDA is adequate for pipe rupture loading, restraint

performance, and pipe movement predictions within the meaningful design requirements for these low probability postulated accidents.

3.6.2.3 Analytical Models to Define Forcing Functions and Response Models (Systems Other Than Recirculation System)

Analyses to determine the jet impingement effects and the piping and restraint displacements resulting from a pipe break are performed in accordance with BN-TOP-2 (Reference 3.6-8). Analysis of jet thrust forces are described in section 2.2 of BN-TOP-2. Fluid jet impingement forces are discussed in section 2.3 of BN-TOP-2. Impulsive loading and impact combined with impulsive loading are described in sections 3.2 and 3.3, respectively, of BN-TOP-2.

Alternatively, nonlinear time history dynamic analyses are performed. The forcing function used in piping dynamic analysis is obtained using either Reference 3.6-2 or 3.6-9. A typical forcing function and the piping system model used for the dynamic response analysis is provided in Figure 3.6-38. Pipe restraint rebound effects are also considered in this analysis.

A specific case for which time history dynamic analyses are used is the analysis of pipe breaks near containment isolation valves whose operability following the break must be ensured. For each break postulated to occur near a containment isolation valve in a high energy line, a dynamic analysis is performed using the appropriate pipe break forcing function in order to determine the stresses in the pipe and the loads on the moment-limiting restraints near the valve. The dynamic analysis verifies that the stress in the pipe at the isolation valve is maintained below the yield strength of material, in order to ensure valve operability. Since the section modulus of the valve is much greater than that of the pipe, the stress in the valve body is kept below the yield strength of the valve. Therefore, deformation in the valve body as a result of nearby pipe breaks is severely limited and remains in the elastic range so that binding of the valve internals cannot occur.

The criteria for dynamic analyses when used in verifying valve operability are as follows:

a. An analysis of the piping system is performed for the most severe of the postulated longitudinal and circumferential breaks at the break locations determined in accordance with the criteria of Section 3.6.2.1.

b. The loading condition of a piping system prior to a postulated rupture in terms of internal pressure, temperature, and stress state is that condition associated with reactor operation at 100% power.

   The basis of selecting 100% power as the loading condition of a piping system prior to rupture is as follows:

   1. Pipe rupture analysis state-of-the-art involves several conservative steps and assumptions in all phases of break design (e.g., probability of break, the postulated speed of break propagation, the structural material properties, and the structural stability characteristics of pipe break restraint structures).

   2. For those portions of piping systems that are normally pressurized during normal plant operation at power mode, the thermodynamic states in the piping systems are those of full (100%) thermal power.

3. There is a much higher probability for scheduled plant operation at 100% power (or less) than at higher ratings.

The combined effects of these considerations result in designs sufficiently capable of sustaining breaks at higher power levels.

c. For a circumferential break, pipe break dynamic transient force analyses are performed only for that end (or ends) of the pipe or branch that is connected to a contained fluid energy reservoir having sufficient capacity to develop a jet stream.

d. Dynamic analytic methods used for calculating the piping and piping/restraint system response to the pipe break forces adequately account for the effects of the following:

1. Translational masses (and rotational masses for major components) and stiffness properties of the piping system, restraint system, major components, and support walls

2. Transient forcing function(s) acting on the piping system

3. Elastic and inelastic deformation of piping and/or restraint

4. The design clearance between the pipe and the restraint

e. A 10% increase in minimum specified design yield strength (S_y) is used to account for strain rate effects in dynamic analyses.

The criteria for dynamic analyses when used in verifying the design of pipe whip restraints other than valve operability restraints are as follows:

a. A design analysis of the pipe whip restraint system is performed for each postulated longitudinal and circumferential break at the break locations determined in accordance with Section 3.6.2.1.

b. The loading condition of a piping system prior to a postulated break in terms of internal pressure, temperature, and stress state is that condition associated with reactor operation at 100% power.

c. For a circumferential break, pipe break dynamic transient forcing function calculations are performed only for that end (or ends) of the pipe or branch that is connected to a contained fluid energy reservoir having sufficient capacity to develop a jet stream.

d. An energy balance is established between the work done by the pipe break force on the pipe during the first quarter cycle of movement and the sum of the strain energy temporarily stored as elastic strain energy and that energy dissipated as plastic strain energy in members of the whip restraint.

e. In the event that the energy balance design analysis criteria are not satisfied, a dynamic analysis of the piping and piping restraint system is performed. This analysis is described by the same criteria described for valve operability dynamic analysis.

f. Dynamic analytical methods used for designing the pipe whip restraints adequately account for the effects of the following:

1. Transient forcing functions acting on the piping system.

2. Design clearance between the pipe and the restraint in the direction of pipe whip motion 3. Elastic stiffness and yield load capacity of the restraint under load applied in the direction of the pipe motion

4. Impact energy-absorbing capacity of crushable material used in the restraint is equivalent to 100% of the available capacity

5. Ductility capacity of the restraint loaded under impact beyond its yield load corresponds to not more than 50% of the ultimate uniform strain of the material.

3.6.2.4 Dynamic Analysis Methods to Verify Integrity and Operability (Recirculation System Only)

Pipe whip restraints, as differentiated from piping supports, are designed to function and carry load for an extremely low probability gross failure in a piping system carrying high energy fluid. The piping integrity does not usually depend on the piping whip restraints for any loading combination. When the piping integrity is lost because of a postulated break, the pipe whip restraint acts to limit the movement of the broken pipe to an acceptable distance. The pipe whip restraints (i.e., those devices that serve only to control the movement of a ruptured pipe following gross failure) will be subjected to once in a lifetime loading. For the purpose of design, the pipe break event is considered to be a faulted plant condition and the pipe, its restraints, and the structure to which the restraint is attached, are analyzed and designed accordingly.

As described in Section 3.6.1.2.1.1, the pipe whip restraints used for the recirculation system consist of straps (either carbon steel wire ropes or stainless steel bars) attached to a steel frame. The analytical methods used in the design of these restraints are similar to those used for the Fermi Unit 2 and Duane Arnold plants. They have, however, been improved by incorporation of the latest force-deflection data available for wire rope and by using the GE PDA code for the dynamic analysis. Load capacities for the restraint frames were developed by using the SAP code (a finite-element structural analysis program), and were confirmed by a test series using slowly applied loading methods to determine restraint load-deflection data in the tangential direction (parallel to the restraint base). The results of this test program are presented in Reference 3.6-10. The specific design objectives for the restraints are:

a. The restraints shall in no way increase the RCPB stresses by their presence during any normal mode of reactor operation or condition

b. The restraint system shall function to stop the movement of pipe failure (gross loss of piping integrity) without allowing damage to critical components or missile development

c. The restraints shall provide minimum hinderance to inservice inspection of the process piping.

For the purposes of design, the pipe whip restraints are designed for the following dynamic loads:

a. Blowdown thrust of the pipe section that impacts the restraint

b. Dynamic inertia loads of the moving pipe section that is accelerated by the blowdown thrust and subsequent impact on the restraint

c. Design characteristics of the pipe whip restraints are included and verified by the pipe whip dynamic analysis described in Section 3.6.2.2.2

d. Since the pipe whip restraints are not contacted during normal plant operation, the postulated pipe rupture event is the only design loading condition.

As previously described, the recirculation loop pipe whip restraints are composed of two parts, the straps and the restraint frame. Both parts of the restraining device function as load-carrying members, and will deflect under load. The load configurations for a restraint are shown in Figure 3.6-3. The components of the restraints are categorized as Type I and II, as described below:

a. Type I - radial load-carrying members: These members, consisting of cables or bars, will absorb energy when loaded in the direction perpendicular to the restraint base by elastic and plastic deformations (Figure 3.6-3).

b. Type II - tangential load-carry members: These members, consisting of restraint frames, will absorb energy when loaded in the direction parallel to the base by plastic deformation (Figure 3.6-3).

Each of these components is constructed of a different material in order to fulfill different design objectives. The design requirements and design limits for each component are therefore different. They are specified as below:

a. Type I - Straps

1. For carbon steel wire ropes, the maximum acceptable load is 90% of the load-carrying capacity of the cable in the restraint configuration. This limit takes into consideration the efficiency reduction experienced when a cable is wrapped around a pipe. This means that the design load is limited to about 75% of the minimum certified load-carrying capacity of the cable in tension.

2. For stainless steel bars, the design limit base was 50% of the minimum uniform ultimate tensile elongation.

b. Type 2 - Restraint Frames

Design limits for the ASTM A36 restraint frames are as follows:

1. Design Load

The load-bearing member is primarily a cantilever beam with an extra support (the diagonal plate) at approximately mid-span. At loads approaching the plastic moment capability of the beam, the plastic-hinge forms at the section determined by an elastic structural analysis. The maximum design load and the ultimate load are calculated based on plastic moment capability of this section, with the diagonal plate stressed uniformly at the minimum ultimate stress of 58,000 psi as specified for ASTM A36 material.

2. Design Deflection

The design and ultimate deflection are calculated assuming the beam remains straight and rotates about a point on the upper surface of the beam. The maximum design deflection at the load point is calculated assuming the diagonal plate undergoes 10% elongation. This corresponds to 50% of the minimum ultimate elongation of 20%, as specified for ASTM A36 material. The ultimate deflection of the beam is based on 20% ultimate elongation of the diagonal plate.

3.6.2.5 Dynamic Analysis Methods to Verify Integrity and Operability (Systems Other Than Recirculation System

The pipe whip restraints provided for protection from high energy pipe breaks are of two basic types: independent restraints and operability restraints. Independent restraints are provided solely to protect nearby structures and equipment from damage due to whipping pipes, and are designed so that a gap is maintained between the pipe and the restraint during normal plant conditions. Operability restraints are provided near primary containment isolation valves whose operability is required following a break of the pipe in which they are installed. These operability restraints are designed to limit the stress in the piping near the valve to below the yield strength of the material in order to ensure operability of the valve. To accomplish this function, it is necessary to minimize the gap between the pipe and the restraint so that contact will occur during normal plant conditions.

The following high energy piping systems in the drywell are not provided with pipe whip restraints:

a. Reactor vessel drain line (4" DCA-101)

b. Main steam drain lines (2" and 3" DBA-105)

c. RPV head vent line (2" DBA-108)

d. SLCS injection line (2" DCA-112)

Each of these lines has been evaluated, using the guidance of Regulatory Guide 1.46, to verify that in the event of a pipe break, damage to structures, systems, or components needed for safe shutdown would not occur. Therefore, the ability to shut the reactor down safely is maintained if a break should occur in any of these lines.

3.6.2.5.1 Design Loading Combinations

The design loading combinations applied in the design of pipe whip restraints are categorized with respect to the plant operating conditions which are identified as normal, upset, emergency, and faulted as described in Section 3.9.3.1.1. Pipe break is considered as a faulted plant condition.

3.6.2.5.2 Design Stress Limits

Operability Restraints

When restraints for piping are designed so that contact between pipe and restraint will occur during normal plant conditions, the design loading combinations for normal, upset, emergency, and faulted conditions are applicable. In evaluating the supports and restraints for ASME Section III Class 1, 2, and 3, the design stress limits applied in evaluating loading combinations for normal, upset, emergency, and faulted (except for pipe rupture) conditions are those given in Tables 3.9-12 and 3.9-16. After rupture of the supported pipe occurs, the piping system is no longer within the jurisdiction of ASME Section III because the pressure boundary has been breached. The restraints are evaluated for pipe rupture loads as described in Section 3.6.2.3.

Pipe restraints are included on main steam, feedwater, RWCU, HPCI, and RCIC system to ensure the operability of the containment isolation valves during a postulated break event that touch the pipe during normal operation. The restraints are modeled in the thermal and dynamic analysis as active (1/16 inch or less gaps) during all loading conditions.

The operability of the isolation valves protected by operability restraints is assured by limiting the pipe break dynamic stress in the adjacent pipe. Stresses at the junction of this component with the pipe are limited to the dynamic yield strength of the pipe material (1.1 S_y). Between the containment penetration inboard/outboard isolation valves, pipe dynamic stress is limited to be less than 2.25 S_m.

Independent Restraints

When restraints are designed solely to control movement following a postulated pipe rupture and to function independently of the normal support system, only the design pipe rupture loads are applicable.

To ensure that restraints function independently of the normal support system, the motions of the intact pipe due to all normal and upset plant conditions and the vibratory motion of the SSE are calculated and used to specify a minimum clearance between the pipe and the restraint. Wherever possible, gaps between pipes and restraints are maximized to avoid possible contact during plant operation. Where a particular location requires minimizing a gap, special features are provided to permit adjustment of the gap size during hot functional testing.

Independent restraints are evaluated for the pipe rupture loads as described in Section 3.6.2.3.

3.6.2.6 Guard Pipe Assembly Design Criteria

Guard pipe assemblies are not used in this plant.

3.6.3 DEFINITIONS

Certain terms used in Sections 3.6.1 and 3.6.2 have specified meanings as described below:

Essential Systems and Components - Systems and components required to shut down the reactor and mitigate the consequences of a postulated piping failure, without offsite power.

High Energy Fluid Systems - Fluid systems that, during normal plant conditions, are either in operation or maintained pressurized under conditions where either or both of the following are met:

a. Maximum operating temperature exceeds 200°F

b. Maximum operating pressure exceeds 275 psig

Moderate Energy Fluid Systems - Fluid systems that, during normal plant conditions, are either in operation or maintained pressurized (above atmospheric pressure) under conditions where both of the following are met:

a. Maximum operating temperature is 200°F or less

b. Maximum operating pressure is 275 psig or less

A system that qualifies as a high energy fluid system for only short periods and qualifies as moderate energy fluid system for the majority of the time is classified as a moderate energy fluid system provided that the total time the system operates within high energy pressure/temperature conditions is less than either of the following:

a. 2% of the time that the system operates as a moderate energy fluid system

b. 1% of the normal operating life span of the plant

Normal Plant Conditions - Plant operating conditions during reactor startup, operation at power, hot standby, or reactor cooldown to cold shutdown condition.

Upset Plant Conditions - Plant operating conditions during system transients that may occur with moderate frequency during plant service life and are anticipated operational occurrences, but not during system testing.

S_h and S_A - Allowable stresses at maximum (hot) temperature and allowable stress range for thermal expansion, respectively, as defined in ASME Section III, Article NC-3600.

S_m - Design stress intensity as defined in ASME Section III, Article NB-3600.

S_n - Primary plus secondary stress intensity range for normal and upset conditions as defined in ASME Section III, paragraph NB-3653.

Single Active Component Failure - Malfunction or loss of function of a component of electrical or fluid systems. The failure of an active component of a fluid system is considered to be a loss of component function as a result of mechanical, hydraulic, pneumatic, or electrical malfunction, but not the loss of component structural integrity. The direct consequences of a single active component failure are considered to be part of the single failure.

Terminal Ends - Extremities of piping runs that connect to structures, components (e.g., vessels, pumps, valves), or pipe anchors that act as rigid constraints to piping thermal expansion. A branch connection to a main piping run is a terminal end of the branch run, except when all three of the following conditions are in effect:

a. The nominal size of the branch run is at least half that of the main run

b. The intersection is not rigidly constrained to the building structure

c. The branch run and main run are included together in the same piping stress analysis model

For piping in containment penetration areas, terminal ends are selected at points located immediately beyond the required moment-limiting restraints inside and outside containment. In piping runs which are maintained pressurized during normal plant conditions for only a portion of the run (i.e., up to the first normally closed valve), a terminal end of such runs is the piping connection to this closed valve.

3.6.4 REFERENCES

3.6-1 "Subcompartment Pressure Analyses", BN-TOP-4, Rev. 0, Bechtel Power Corporation, San Francisco, California, (July 1976).

3.6-2 RELAP4/MOD5, "Computer Program for Transient Thermal-Hydraulic Analysis of Nuclear Reactors and Related Systems," ANCR-NUREG-1335, (September 1976).

3.6-3 FLUD, "Thermofluid Dynamics for a System of Interconnected Compartments," NE017, version 3, (July 18, 1980).

3.6-4 "System Criteria and Applications for Protection Against the Dynamic Effects of Pipe Break", GE Specification No. 22A2625.

3.6-5 RELAP3, "A Computer Program for Reactor Blowdown Analysis", IN-1321, Reactor Technology TID-4500, (June 1970).

3.6-6 "PDA - Pipe Dynamic Analysis Program for Pipe Rupture Movement" (proprietary filing), GE Report NEDE-10813.

3.6-7 "Final Report Pipe Rupture Analysis of Recirculation System for 1969 Standard Plant Design", Nuclear Services Corporation Report No. GEN-02-02.

3.6-8 "Design for Pipe Break Effects", BN-TOP-2, Rev. 2, Bechtel Power Corporation, San Francisco, California, (May 1974).

3.6-9 F.J. Moody, "Fluid Reaction and Impingement Loads", ASCE Specialty Conference on Structural Design of Nuclear Plant Facilities, Vol 1, pp. 219-262, (December 1973).

3.6-10 "Recirculation System Pipe Whip Restraint for the BWR 4, 218 and 251, Mark I and Mark II Product Line Plant", GE Design.

3.6-11 "Limerick Atomic Power Stations Units 1 & 2 Power Rerate Evaluation of Main Steam & Recirculation Piping System, "GE Report GE-NE-123-E014-0193, Rev. 0 (July 1993) (part of N-00E-177-00003).

3.6-12 PCFLUD, "Thermofluid Dynamics for a System of Interconnected Compartments," MAP-120, Version 4.0 (July 15, 1992).

3.6-13 CONCOIL-FLUD (CFLUD), "Thermofluid Dynamics for a System of Interconnected Compartments," Version 1.0 (December 1, 1993).

3.6-14 GEH 0000-0158-9651-NP, Revision 0, October 2013, LGS Main Steam Isolation Valve Response Time Testing Analysis (SDOC G-080-VC-00489).

Table 3.6-1

HIGH ENERGY FLUID SYSTEM PIPING

FLUID SYSTEM	EXTENT OF HIGH ENERGY PIPING
Reactor recirculation	From reactor vessel suction nozzle to recirculation pump to reactor vessel discharge nozzles (Drawing M-43)
Main steam	From reactor vessel nozzles to turbine stop valves (Drawings M-01 and M-41)
Feedwater	From condensate filter/demineralizers through feedwater heaters and feedwater pumps to reactor vessel nozzles (Drawings M-06 and M-41)
Condensate	From condensate pump discharge through steam jet air ejector condenser, steam packing exhauster, and condensate filter/ demineralizers (Drawings M-05 and M-16)
RWCU	From shutdown cooling suction line through RWCU pumps, regenerative and non-regenerative heat exchangers, and cleanup filter/demineralizers to feedwater lines (Drawings M-43, M-44 and M-45)
Reactor vessel drain	From reactor bottom head nozzle to RWCU line inside primary containment (Drawings M-43 and M-44)
HPCI steam supply	From main steam line C to HPCI turbine steam supply valve (Drawing M-55)
RCIC steam supply	From main steam line B to RCIC turbine steam supply valve (Drawings M-49 and M-50)
Main steam drain line	From main steam lines inside drywell to inboard containment isolation valve; from main steam lines outside drywell to outboard containment isolation valve and drain line isolation valves (Drawing M-41)

Table 3.6-1 (Cont'd)

RPV head vent line	From reactor vessel head nozzle to main steam line C (Drawing M-41)
SLCS	From reactor vessel nozzle to first upstream check valve (Drawing M-42 and M-48)
RHR shutdown cooling suction	From reactor recirculation loop to inboard containment isolation valve (Drawing M-51)
RHR shutdown cooling return	From reactor recirculation loop to first upstream check valve (Drawing M-51)
LPCI injection	From reactor vessel nozzle to first upstream check valve (Drawing M-51)
Core spray injection	From reactor vessel nozzle to first upstream check valve (Drawing M-52)
CRD hydraulic	From drive water pump to master control station to HCUs (Drawing M-46)
Auxiliary steam	From auxiliary boiler to various steam-consuming components (Drawing M-21)
Plant heating steam	From auxiliary boiler to various steam-consuming components

Table 3.6-2

RECIRCULATION PIPING SYSTEM
STRESS LEVELS AND PIPE BREAK DATA [5][6]

(UNIT 1)

Node Point[1]		STRESS RATIOS PER ASME CODE EQUATIONS Eq.(10) 3 S_m [2]	Eq.(12) 3 S_m [2]	Eq.(13) 3 S_m [2]	Usage Factor	Break Type[3]	Basis for Break Selection[4]
A.	RECIRCULATION LOOP A						
001		0.630	0.079	0.606	0.00	C	TE
500		1.225	0.447	0.847	0.06	L	MBL
220		1.209	0.136	0.957	0.05	C & L	MBL
236		0.734	0.088	0.646	0.00	C	TE
200		1.39	0.098	0.993	0.15	C & L	MBL
216		0.821	0.199	0.677	0.00	C	TE
165		1.849	0.198	0.831	0.12	C & L	MBL
296		0.786	0.099	0.698	0.00	C	TE
240		1.532	0.312	0.948	0.29	C & L	MBL
256		0.745	0.152	0.635	0.00	C	TE
260		1.222	0.265	0.784	0.05	C & L	MBL
276		0.727	0.218	0.560	0.00	C	TE
B.	RECIRCULATION LOOP B						
001		0.575	0.069	0.512	0.00	C	TE
16		1.590	0.281	0.741	0.16	L	MBL
800		1.179	0.401	0.826	0.04	L	MBL
220		1.175	0.112	0.945	0.04	C & L	MBL
236		0.708	0.074	0.642	0.00	C	TE
200		1.355	0.077	1.006	0.13	C & L	MBL
216		0.792	0.209	0.642	0.00	C	TE
165		1.838	0.203	0.832	0.11	C & L	MBL
296		0.817	0.093	0.739	0.00	C	TE
240		1.499	0.326	0.894	0.25	C & L	MBL
256		0.771	0.176	0.648	0.00	C	TE
260		1.235	0.274	0.799	0.06	C & L	MBL
276		0.793	0.223	0.585	0.00	C	TE

Table 3.6-2 (Cont'd)

RECIRCULATION PIPING SYSTEM
STRESS LEVELS AND PIPE BREAK DATA
(UNIT 2)

Node Point[1]		STRESS RATIOS PER ASME CODE EQUATIONS Eq.(10) 3 S_m [2]	Eq.(12) 3 S_m [2]	Eq.(13) 3 S_m [2]	Usage Factor	Break Type[3]	Basis for Break Selection[4]
A.	RECIRCULATION LOOP A						
001		0.40	0.08	0.37	0.00	C	TE
236		0.79	0.40	0.40	0.00	C	TE
216		0.79	0.37	0.44	0.00	C	TE
296		0.94	0.51	0.45	0.00	C	TE
256		1.18	0.79	0.43	0.02	C	TE
276		0.73	0.34	0.40	0.00	C	TE
B.	RECIRCULATION LOOP B						
001		0.43	0.06	0.41	0.00	C	TE
236		0.57	0.07	0.52	0.00	C	TE
216		0.72	0.19	0.54	0.00	C	TE
296		0.63	0.09	0.57	0.00	C	TE
256		0.70	0.16	0.54	0.00	C	TE
276		0.70	0.20	0.53	0.00	C	TE

(1) Locations of the nodes are shown in Figure 3.6-4

(2) S_m: Design stress intensity as defined in ASME Section III, Article NB-3600 (Section 3.6.3)

(3) Break types are indicated as follows:
- C - Circumferential
- L - Longitudinal

(4) Symbols used to denote the basis for break selection are as follows:
- TE - Terminal end
- MBL - Intermediate break locations selected to satisfy the requirement for a minimum number of break locations.

(5) The recirculation piping design basis has been evaluated for the effects of power rerate and demonstrated to be adequate for the increases in pressure, temperature and flow due to power rerate. Detail of the evaluation performed are documented in Reference 3.6-11.

(6) The information posted in this table was used for the original System piping analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-3

REACTOR RECIRCULATION PIPING SYSTEM
FLUID BLOWDOWN THRUST TIME HISTORIES

(UNIT 1)

(Refer to Diagram A below)

Node Point of Break Location[1]	Break Type	Side of Break	Initial Force F_o (kips)	Intermediate Force F_{int} (kips)	Steady-State Force F_{ss} (kips)	Time Duration sec) of $F_o(T_1)$	Time to Reach (sec) Steady-State (T_2)
001	CRCMF		540.00	476.80	179.80	0.00186	0.08006
16 (loop B only)	LONG		540.00	564.30	621.54	0.00064	0.0032
220	CRCMF	PUMP	373.48	291.98	330.53	0.00145	0.0210
236	CRCMF	PUMP	134.42	101.48	118.96	0.00143	0.02098
200	CRCMF	PUMP	373.48	281.78	330.53	0.00145	0.021
216	CRCMF	PUMP	134.42	101.48	118.96	0.00143	0.02098
296	CRCMF	PUMP	134.42	101.48	118.96	0.00143	0.02098
240	CRCMF	PUMP	373.48	281.98	330.53	0.00145	0.021
256	CRCMF	PUMP	134.42	101.48	118.96	0.00143	0.02098
260	CRCMF	PUMP	373.48	281.98	330.53	0.00145	0.021
276	CRCMF	PUMP	134.42	101.48	118.96	0.00143	0.02098
220	CRCMF	VESSEL	373.48	373.48	373.48	0.0038	0.0368
200	CRCMF	VESSEL	373.48	373.48	373.48	0.0038	0.0368
165	CRCMF	VESSEL	373.48	373.48	373.48	0.0038	0.0368
240	CRCMF	VESSEL	373.48	373.48	373.48	0.0038	0.0368
260	CRCMF	VESSEL	373.48	373.48	373.48	0.0038	0.0368

Table 3.6-3 (Cont'd)

REACTOR RECIRCULATION PIPING SYSTEM
FLUID BLOWDOWN THRUST TIME HISTORIES

(UNIT 2)

(Refer to Diagram A below)

Node Point of Break Location[1]	Break Type	Side of Break	Initial Force F_o (kips)	Intermediate Force F_{int} (kips)	Steady-State Force F_{ss} (kips)	Time Duration sec) of $F_o(T_1)$	Time to Reach (sec) Steady-State (T_2)
001	C		540.00	476.80	179.80	0.00186	0.08006
236	C	PUMP	134.42	101.48	118.96	0.00143	0.02098
216	C	PUMP	134.42	101.48	118.96	0.00143	0.02098
296	C	PUMP	134.42	101.48	118.96	0.00143	0.02098
256	C	PUMP	134.42	101.48	118.96	0.00143	0.02098
276	C	PUMP	134.42	101.48	118.96	0.00143	0.02098

(1) SEE FIGURE 3.6-4 FOR IDENTIFICATION OF POSTULATED BREAK LOCATIONS.

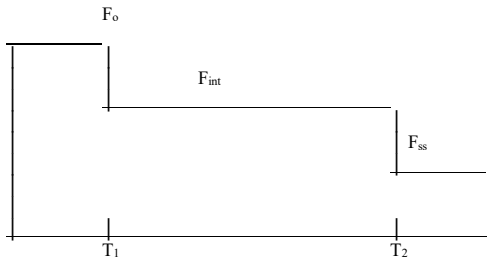


Diagram A

Table 3.6-4

MAIN STEAM PIPING STRESS LEVELS AND PIPE BREAK DATA [7][8]

(UNIT 1)

Node Point[1]	Node Type[2]	Stress By Eq. 10 Usage (ksi)[6]	Cumulative Stress Limit Factor	Pipe Break Break 2.4 S_m(ksi)	Type[3]	Basis for Break Selection[4]
LINE A						
1	BW	25.94	0.0	42.21	C	TE
3	CURB	51.45	0.14	42.21	C&L	SFL
3	CURE	50.18	0.20	42.21	C&L	SFL
5	SWE	[5]	[5]	42.21	C	TE (TYP for 3 PSVs)
6	FLA	[5]	[5]	42.21	C	TE (TYP for 3 PSVs)
24	CUR	39.03	0.01	42.21	C	MBL
40	BW	34.72	0.01	42.21	C	TE
LINE B						
1	BW	24.81	0.0	42.21	C	TE
3	CURB	48.56	0.11	42.21	C&L	SFL
3	CURE	45.87	0.19	42.21	C&L	SFL
5	SWE	[5]	[5]	42.21	C	TE (TYP for 4 PSVs)
6	FLA	[5]	[5]	42.21	C	TE (TYP for 4 PSVs)
23	CUR	36.19	0.01	42.21	C	MBL
46	BW	33.09	0.01	42.21	C	TE
LINE C						
2	BW	24.03	0.0	42.21	C	TE
3	CURB	46.48	0.10	42.21	C&L	SFL
4	CURE	44.56	0.17	42.21	C&L	SFL
5	SWE	[5]	[5]	42.21	C	TE (TYP for 3 PSVs)
6	FLA	[5]	[5]	42.21	C	TE (TYP for 3 PSVs)
26	CUR	36.73	0.01	42.21	C	MBL
48	BW	34.07	0.01	42.21	C	TE

Table 3.6-4 (Cont'd)

(UNIT 1)

Node Point[1]	Node Type[2]	Stress By Eq. 10 (ksi)[6]	Cumulative Usage Factor	Pipe Break Stress Limit 2.4 S_m(ksi)	Break Type[3]	Basis for Break Selection[4]
LINE D						
1	BW	33.21	0.01	42.21	C	TE
3	CURB	50.28	0.11	42.21	C&L	SFL
3	CURE	48.04	0.13	42.21	C&L	SFL
5	SWE	[5]	[5]	42.21	C	TE (TYP for 4 PSVs)
6	FLA	[5]	[5]	42.21	C	TE (TYP for 4 PSVs)
31	CUR	39.09	0.01	42.21	C	MBL
47	BW	34.13	0.01	42.21	C	TE

Table 3.6-4 (Cont'd)

MAIN STEAM PIPE STRESS LEVELS AND PIPE BREAK DATA

(UNIT 2)

Node Point[1]	Node Type[2]	Stress By Eq. 10 (ksi)[6]	Cumulative Usage Factor	Pipe Break Stress Limit 2.4 S_m(ksi)	Break Type[3]	Basis for Break Selection[4]
LINE A						
1	BW	32.44	0.007	42.48	C	TE
5	SWE	41.77	0.251	42.48	C	TE (TYP for 3 PSVs)
6	FLA	[5]	[5]	42.48	C	TE (TYP for 3 PSVs)
40	BW	32.30	0.008	42.48	C	TE
LINE B						
1	BW	32.00	0.007	42.48	C	TE
5	SWE	37.58	0.218	42.48	C	TE (TYP for 4 PSVs)
6	FLA	[5]	[5]	42.48	C	TE (TYPE for 4 PSVs)
46	BW	32.60	0.009	42.48	C	TE
LINE C						
2	BW	29.77	0.007	42.48	C	TE
5	SWE	41.65	0.294	42.48	C	TE (TYP for 3 PSVs)
6	FLA	[5]	[5]	42.48	C	TE (TYP for 3 PSVs)
48	BW	33.78	0.010	42.48	C	TE
LINE D						
1	BW	29.95	0.006	42.48	C	TE
5	SWE	40.32	0.126	42.48	C	TE (TYP for 4 PSVs)
6	FLA	[5]	[5]	42.48	C	TE (TYP for 4 PSVs)
47	BW	32.18	0.007	42.48	C	TE

Table 3.6-4 (Cont'd)

(1) Locations of nodes are shown in Figure 3.6-8.

(2) Node types are designated as follows:

BW - Butt-welding tee
CUR - Elbow
CURB - Elbow beginning
CURE - Elbow ending
SWE - Sweepolet
FLA - Flange

(3) Break types are indicated as follows:

C - Circumferential
L - Longitudinal

(4) Symbols used to denote the basis for break selection are as follows:

TE - Terminal end
SFL - The stress and fatigue limits established in Section 3.6.2.1.1.3 are not met.
MBL - Intermediate break location selected to satisfy the criteria for a minimum number of break locations.

(5) Stress values not calculated; terminal end break assumed.

(6) Refer to Section 3.6.2.1.1.3.

(7) The main steam piping design basis has been evaluated for the effects of power rerate and demonstrated to be adequate for the increase in pressure, temperature and flow due to power rerate. Details of the evaluation performed are documented in Reference 3.6-11.

(8) The information posted in this table was used for original System piping analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-5

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Table 3.6-6

BLOWDOWN DATA FOR HIGH ENERGY PIPE BREAKS OUTSIDE PRIMARY CONTAINMENT

	BLOWDOWN [2]				ISOLATION VALVE CLOSURE		
HIGH ENERGY LINE	TIME AFTER BREAK (sec)	MASS FLOW RATE (lb/sec)	ENTHALPY (Btu/lb)[3]	ISOLATION VALVES	VALVE CLOSING TIME (sec)	SIGNAL DELAY TIME (sec)	TOTAL INTERVAL (sec)
Main steam line	0.00	13,356	1192.4	HV41-F022A,B,C&D	5.0	1.0	6.0
(26 inch EBB-101, EBB-102,	0.076	8,543	1192.4	HV41-F028A,B,C&D	5.0	1.0	6.0
EBB-103, or EBB-104)	0.16	9,177	1192.4				
	1.0	15,972	1192.4				
	1.001	19,398	595.0				
	5.0	19,398	595.0				
	6.0	0	595.0				
RWCU suction line	0.0	2,820	525.3	HV44-F001	10.0 max.	2.0	12.0 max.
(6 inch DCC-103)	0.1	2,319	524.7	HV44-F004	10.0 max.	2.0	12.0 max.
	0.2	1,818	513.0	HV44-F039[1]	-	-	-
	0.3	1,486	509.8				
	0.4	1,200	506.3				
	0.5	1,027	503.7				
	0.6	905	501.3				
	0.7	791	497.4				
	0.8	723	495.0				
	0.9	701	491.0				
	1.0	638	485.1				
	1.26	563	485.0				
	6.0	563	485.0				
	9.0	0	485.0				
RWCU pump discharge line *	0.00	1410 *	526.4	HV44-F001	10.0 max.	2.0	12.0 max.
(4 inch DCC-101)	0.02	912 *	526.4	HV44-F004	10.0 max.	2.0	12.0 max.
	0.03	623 *	526.4	HV44-F039[1]	-	-	-
	0.11	473 *	526.4				
	0.25	688 *	526.4				
	0.37	583 *	526.4				
	2.00	531 *	526.4				
	15.00	273 *	526.4				

* Mass flow rate scale from values for 3” break to 4” break by using the ratio of the break areas as a scaling factor (A4”/A3”) = 1.74.

Table 3.6-6 (Cont'd)

	BLOWDOWN [2]				ISOLATION VALVE CLOSURE		
HIGH ENERGY LINE	TIME AFTER BREAK (sec)	MASS FLOW RATE (lb/sec)	ENTHALPY (Btu/lb)[3]	ISOLATION VALVES	VALVE CLOSING TIME (sec)	SIGNAL DELAY TIME (sec)	TOTAL INTERVAL (sec)
RWCU pump discharge line	0.0	1,164	526.4	HV44-F001	10.0 max.	2.0	12.0 max.
at inlet to regenerative	0.2	947	526.4	HV44-F004	10.0 max.	2.0	12.0 max.
heat exchanger	0.3	904	526.4	HV44-F039[1]	-	-	-
(4 inch DCC-101)	0.35	1,051	526.4				
	1.0	682	526.4				
	1.5	503	526.4				
	2.0	471	526.4				
	16.0	223	526.4				
RWCU pump discharge line	0.00	1,164	203.9	HV44-F001	10.0 max.	2.0	12.0 max.
at inlet to nonregenerative	0.34	1,056	203.9	HV44-F004	10.0 max.	2.0	12.0 max.
heat exchanger(4 inch DCC-102)	0.59	868	203.9	HV44-F039[1]	-	-	-
	0.59	868	125.2				
	1.00	677	131.4				
	3.72	464	149.4				
	3.72	464	316.2				
	16.00	464	316.2				
	16.00	224	91.0				
	20.00	224	91.0				
HPCI steam supply line	0.0	1,470	1192.4	HV55-F002	12.0	1.0	13.0
at turbine inlet valve	0.24	1,045	1192.4	HV55-F003	12.0	1.0	13.0
(12 inch EBB-108)	0.36	280	1192.4				
	13.0	280	1192.4				
	14.0	0	1192.4				
HPCI steam supply line	0.0	2,940	1192.4	HV55-F002	12.0	1.0	13.0
in piping area	0.11	1,958	1192.4	HV55-F003	12.0	1.0	13.0
(12 inch EBB-108)	0.14	1,594	1192.4				
	0.22	266	1192.4				
	13.0	266	1192.4				
	14.0	0	1192.4				

Table 3.6-6 (Cont'd)

HIGH ENERGY LINE	BLOWDOWN [2] TIME AFTER BREAK (sec)	BLOWDOWN [2] MASS FLOW RATE (lb/sec)	BLOWDOWN [2] ENTHALPY (Btu/lb)[3]	ISOLATION VALVES	ISOLATION VALVE CLOSURE VALVE CLOSING TIME (sec)	ISOLATION VALVE CLOSURE SIGNAL DELAY TIME (sec)	ISOLATION VALVE CLOSURE TOTAL INTERVAL (sec)
HPCI steam supply line	0.0	2,940	1192.4	HV55-F002	12.0	1.0	13.0
in isolation valve compartment	0.135	1,272	1192.4	HV55-F003	12.0	1.0	13.0
(12 inch EBB-108)	0.23	902	1192.4				
	0.475	328	1192.4				
	13.0	328	1192.4				
	14.0	0	1192.4				
RCIC steam supply line	0.0	380	1192.4	HV49-F007	7.2	1.0	8.2
at turbine inlet valve	0.311	168	1192.4	HV49-F008	7.2	1.0	8.2
(6 inch EBB-109)	0.43	40	1192.4				
	7.2	40	1192.4				
	8.2	0	1192.4				
RCIC steam supply line	0.0	760	1192.4	HV49-F007	7.2	1.0	8.2
in upper pipe tunnel	0.13	382	1192.4	HV49-F008	7.2	1.0	8.2
(6 inch EBB-109)	0.26	85.4	1192.4				
	0.302	42	1192.4				
	7.2	42	1192.4				
	8.2	0	1192.4				

(1) Valve closure time is not applicable for HV44-F039 since it is a check valve. This valve prevents backflow of water from the feedwater lines into the RWCU equipment compartments in the event of a break.

(2) The blowdown table is based on original power level. Environmental effects from blowdown are addressed based 3527 MWt conditions in Table 3.6-7 and 3.6-9, which bounds the operation at MUR power level of 3515 MWt.

(3) Enthalpy of system is conservatively assumed for saturated steam at 1000 psig (0% moisture carryover) based on original design conditions.

Table 3.6-7

PRESSURE-TEMPERATURE TRANSIENT ANALYSIS RESULTS FOR [6]
HIGH ENERGY PIPE BREAKS OUTSIDE PRIMARY CONTAINMENT

(Unit 1)

COMPARTMENT[1]	PEAK[2] PRESSURE (psig)	TIME[5] AFTER BREAK (sec)	PEAK TEMPERATURE (°F)	TIME [5] AFTER BREAK (sec)
A. Main Steam Line Break in Main Steam Tunnel				
1. Main steam tunnel	10.18	3.0	321	0.60
2. Main steam tunnel vent stack (lower-region)	8.18	3.1	324	0.62
3. Main steam tunnel vent stack (mid-region)	5.32	3.1	325	0.64
4. Main steam tunnel vent stack (upper-region)	2.93	3.2	319	0.74
5. Main steam tunnel security plenum (U2 Only)	--	--	--	--
6. Main condenser area	0.56	0.23	179	5.8
7. Steam venting plenum	0.61	0.23	182	5.5
B. Main Steam Line Break in Main Condenser Area				
6. Main condenser area	2.33	4.2	208	4.95
7. Steam venting plenum	2.33	4.3	208	5.16
C. RWCU Suction Line Break in Penetration Room				
6. Nonregenerative heat exchanger room "A"	3.02	0.65	129[4]	0.51
7. Nonregenerative heat exchanger room "B"	3.02	0.64	128[4]	0.51
9. Regenerative heat exchanger room	2.92	0.65	127[4]	0.65
10. RWCU pump-room	2.91	0.38	105[4]	0.80
13. RWCU penetration room	2.92	0.40	202[4]	7.12

Table 3.6-7 (Cont'd)

(Unit 1)

COMPARTMENT[1]	PEAK[2] PRESSURE (psig)	TIME[5] AFTER BREAK (sec)	PEAK TEMPERATURE (°F)	TIME[5] AFTER BREAK (sec)
D. RWCU Pump Discharge Line Break in Pump-Room				
6. Nonregenerative heat exchanger room "A"	0.44[4]	0.78	115[4]	0.78
7. Nonregenerative heat exchanger room "B"	0.45[4]	0.76	115[4]	0.76
9. Regenerative heat exchanger room	0.44[4]	0.74	112[4]	0.29
10. RWCU pump-room (B, C only)	1.96[4]	0.33	222	3.07
10A.RWCU pump room (A only)	6.2	0.33	229	3.07
13. RWCU penetration room	0.44[4]	0.87	206[4]	15.00
E. RWCU Pump Discharge Line Break in Regenerative Heat Exchanger Room				
6. Nonregenerative heat exchanger room "A"	2.45[4]	0.92	113[4]	0.11
7. Nonregenerative heat exchanger room "B"	2.45[4]	0.92	112[4]	0.11
9. Regenerative heat exchanger room	2.42[4]	1.01	221	6.65
10. RWCU pump-room	1.78[4]	1.13	113[4]	0.43
13. RWCU penetration room	1.77[4]	1.16	215	15.95
F. RWCU Pump Discharge Line Break in Nonregenerative Heat Exchanger Room "A"				
6. Nonregenerative heat exchanger room "A"	1.56[4]	10.18	221	16.00
7. Nonregenerative heat exchanger room "B"	1.06[4]	10.82	111[4]	0.10
9. Regenerative heat exchanger room	0.50[4]	15.44	208[4]	16.13
10. RWCU pump-room	0.36[4]	16.23	107[4]	0.38
13. RWCU penetration room	0.36[4]	16.20	183[4]	16.43

Table 3.6-7 (Cont'd)

(Unit 1)

COMPARTMENT[1]	PEAK[2] PRESSURE (psig)	TIME[5] AFTER BREAK (sec)	PEAK TEMPERATURE (°F)	TIME[5] AFTER BREAK (sec)
G. RWCU Pump Discharge Line Break in Nonregenerative Heat Exchanger Room "B"				
6. Nonregenerative heat exchanger room "A"	1.07[4]	10.73	111[4]	0.10
7. Nonregenerative heat exchanger room "B"	2.03[4]	10.03	217[4]	16.00
9. Regenerative heat exchanger room	0.50[4]	15.55	208[4]	16.17
10. RWCU pump-room	0.36[4]	16.20	107[4]	0.40
13. RWCU penetration room	0.36[4]	16.23	183[4]	16.49
H. HPCI Steam Supply Line Break in HPCI Pump-Room				
17. HPCI pump-room	2.94	0.24	307	15.16
18. HPCI piping area	2.22	0.25	308	15.20
21. Isolation valve compartment	1.03	0.33	241	14.00
22. Steam venting tunnel	0.61	0.33	238	15.99
I. HPCI Steam Supply Line Break in HPCI Piping Area				
17. HPCI pump-room	2.54	0.14	264	15.51
18. HPCI piping area	6.64	0.13	295	0.13
21. Isolation valve compartment	1.52	0.21	241	15.71
22. Steam venting tunnel	0.91	0.21	235	12.88
J. HPCI Steam Supply Line Break in Isolation Valve Compartment				
21. Isolation valve compartment	1.51	0.18	273	16.55
22. Steam venting tunnel	0.98	0.18	270	15.93

Table 3.6-7 (Cont'd)

(Unit 1)

COMPARTMENT[1]	PEAK[2] PRESSURE (psig)	TIME[5] AFTER BREAK (sec)	PEAK TEMPERATURE (°F)	TIME[5] AFTER BREAK (sec)
K. RCIC Steam Supply Line Break in RCIC Pump-Room				
19. RCIC pump-room	2.94	0.27	229	11.17
20. RCIC upper pipe tunnel	2.56	0.29	218	11.15
21. Isolation valve compartment	0.50	0.38	129	13.99
22. Steam venting tunnel	0.50	0.38	128	0.38
L. RCIC Steam Supply Line Break in RCIC Upper Pipe Tunnel				
19. RCIC pump-room	2.68	0.16	153	0.16
20. RCIC upper pipe tunnel	5.77	0.03	306	7.04
21. Isolation valve compartment	0.50	0.22	142	13.99
22. Steam venting tunnel	0.50	0.22	135	11.12

Table 3.6-7 (Cont'd)

PRESSURE-TEMPERATURE TRANSIENT ANALYSIS RESULTS FOR
HIGH ENERGY PIPE BREAKS OUTSIDE PRIMARY CONTAINMENT

(Unit 2)

COMPARTMENT[1]	PEAK[2] PRESSURE (psig)	TIME[5] AFTER BREAK (sec)	PEAK TEMPERATURE (°F)[3]	TIME[5] AFTER BREAK (sec)
A. Main Steam Line Break in Main Steam Tunnel				
1. Main steam tunnel	11.39	3.1	320	0.60
2. Main steam tunnel vent stack (lower-region)	9.78	3.2	325	0.62
3. Main steam vent stack (security plenum)	7.81	3.2	325	0.67
4. Main steam tunnel vent stack (upper-region)	2.72	3.4	319	0.75
5. Main steam tunnel security plenum	10.30	3.2	320	0.60
6. Main condenser area	0.5	0.23	182	5.9
7. Steam venting plenum	0.54	0.23	187	5.6
B. Main Steam Line Break in Main Condenser Area				
6. Main condenser area	2.33	4.2	208	5.0
7. Steam venting plenum	2.33	4.3	208	5.2
C. RWCU Suction Line Break in Penetration Room				
6. Nonregenerative heat exchanger room "A"	3.02	0.65	129[4]	0.51
7. Nonregenerative heat exchanger room "B"	3.02	0.64	128[4]	0.51
9. Regenerative heat exchanger room	2.92	0.65	127[4]	0.65
10. RWCU pump-room	2.91	0.38	105[4]	0.80
13. RWCU penetration room	2.92	0.40	202[4]	7.12

Table 3.6-7 (Cont'd)

(Unit 2)

COMPARTMENT[1]	PEAK[2] PRESSURE (psig)	TIME[5] AFTER BREAK (sec)	PEAK TEMPERATURE (°F)[3]	TIME[5] AFTER BREAK (sec)
D. RWCU Pump Discharge Line Break in Pump-Room				
6. Nonregenerative heat exchanger room "A"	0.44[4]	0.78	115[4]	0.78
7. Nonregenerative heat exchanger room "B"	0.45[4]	0.76	115[4]	0.76
9. Regenerative heat exchanger room	0.44[4]	0.74	112[4]	0.29
10. RWCU pump-room(B, C only)	1.96[4]	0.33	222	3.07
10A.RWCU pump-room (A only)	6.2	0.33	229	3.07
13. RWCU penetration room	0.44[4]	0.87	206[4]	15.00
E. RWCU Pump Discharge Line Break in Regenerative Heat Exchanger Room				
6. Nonregenerative heat exchanger room "A"	2.4[4]	0.92	113[4]	0.11
7. Nonregenerative heat exchanger room "B"	2.45[4]	0.92	11[4]	0.11
9. Regenerative heat exchanger room	2.42[4]	1.01	221	6.65
10. RWCU pump-room	1.78[4]	1.13	113[4]	0.43
13. RWCU penetration room	1.77[4]	1.16	215	15.95
F. RWCU Pump Discharge Line Break in Nonregenerative Heat Exchanger Room "A"				
6. Nonregenerative heat exchanger room "A"	1.56**[4]**	10.18	221	16.00
7. Nonregenerative heat exchanger room "B"	1.06[4]	10.82	111[4]	0.10
9. Regenerative heat exchanger room	0.50[4]	15.44	208[4]	16.13
10. RWCU pump-room	0.36[4]	16.23	107[4]	0.38
13. RWCU penetration room	0.36[4]	16.20	183[4]	16.43

Table 3.6-7 (Cont'd)

(Unit 2)

COMPARTMENT[1]	PEAK[2] PRESSURE (psig)	TIME[5] AFTER BREAK (sec)	PEAK TEMPERATURE (°F)[3]	TIME[5] AFTER BREAK (sec)
G. RWCU Pump Discharge Line Break in Nonregenerative Heat Exchanger Room "B"				
6. Nonregenerative heat exchanger room "A"	1.11[4]	10.73	111[4]	0.10
7. Nonregenerative heat exchanger room "B"	2.11[4]	10.03	214[4]	16.00
9. Regenerative heat exchanger room	0.50[4]	15.55	206[4]	16.17
10. RWCU pump-room	0.38[4]	16.20	107[4]	0.40
13. RWCU penetration room	0.38[4]	16.23	184[4]	16.49
H. HPCI Steam Supply Line Break in HPCI Pump-Room				
17. HPCI pump-room	2 50	0.25	299	15.17
18. HPCI piping area	2.03	0.25	298	15.20
21. Isolation valve compartment	1.04	0.34	241	17.00
22. Steam venting tunnel	0.68	0.35	239	16.03
23. Security plenum	0.51	0.35	238	15.98
I. HPCI Steam Supply Line Break in HPCI Piping Area				
17. HPCI pump-room	2.79	0.14	243	0.14
18. HPCI piping area	2.79	0.14	299	4.74
21. Isolation valve compartment	1.39	0.22	271	17.00
22. Steam venting tunnel	0.97	0.22	260	16.04
23. Security plenum	0.72	0.22	260	15.97

Table 3.6-7 (Cont'd)

(Unit 2)

COMPARTMENT[1]	PEAK[2] PRESSURE (psig)	TIME[5] AFTER BREAK (sec)	PEAK TEMPERATURE (°F)[3]	TIME[5] AFTER BREAK (sec)
J. HPCI Steam Supply Line Break in Isolation Valve Compartment				
21. Isolation valve compartment	1.60	0.20	271	16.99
22. Steam venting tunnel	1.21	0.20	270	16.06
23. Security plenum	0.83	0.20	270	15.97
K. RCIC Steam Supply Line Break in RCIC Pump-Room				
19. RCIC pump-room	1.84	0.27	228	11.21
20. RCIC upper pipe tunnel	1.47	0.29	218	11.19
21. Isolation valve compartment	0.50	0.38	129	14.00
22. Steam venting tunnel	0.50	0.38	128	0.38
23. Security plenum	0.50	0.38	128	0.38
L. RCIC Steam Supply Line Break in RCIC Upper Pipe Tunnel				
19. RCIC pump-room	2.00	0.16	152	0.16
20. RCIC upper pipe tunnel	2.47	0.03	295	6.97
21. Isolation valve compartment	0.50	0.22	142	14.00
22. Steam venting tunnel	0.50	0.22	137	12.31
23. Security plenum	0.50	0.22	135	11.10

(1) Compartment numbers used in this table correspond to the compartment numbers used in the flow models (Figures 3.6-11, 3.6-12, 3.6-19, 3.6-23, 3.6-24, and 3.6-27).
(2) The compartment design pressures and the pressure-temperature transient analysis results are in Table 3.6-9.
(3) For Unit 2, design bulk temperatures may be less. Note also that temperatures in this area due to breaks elsewhere may be bounding.
(4) The value shown is based on original power level. It is bounded by another break in this compartment where the value shown is for the 3527 MWt power level.
(5) Time shown is based on original power level and was not recalculated for rerate since it is not used for any design basis evaluations.
(6) Values shown unless noted are based on power level of 3527 MWt. The values (except the main steam line valves) were established based on the original values and a multiplier. The multiplier was calculated based on a maximum pressure increase associated with a power level of 3527 MWt and its impact on the blowdown and subsequent impact to subcompartment pressures and temperatures.

Table 3.6-8

FEEDWATER PIPING STRESS LEVELS AND PIPE BREAK DATA
(PORTION INSIDE PRIMARY CONTAINMENT) (5)(6)

Node Point(1)	Node Type(2)	Stress By EQ. 10 (ksi)	Cumula-tive Usage Factor	Pipe Break Stress Limit 2.4 S_m (ksi)	Break Type(3)	Basis for Break Selection(4)
UNIT 1						
10	TTJ	77.05	0.0603	42.21	C	TE
45	SWP	91.10	0.5213	42.21	C	TE
55	TEE	104.58	0.4841	42.21	C&L	SFL
70	EL	69.14	0.1374	42.21	C&L	SFL
75	TTJ	76.74	0.6192	42.21	C	TE
100	TEE	100.79	0.3651	42.21	C&L	SFL
110	EL	72.19	0.1337	42.21	C&L	SFL
115	TTJ	79.85	0.6136	42.21	C	TE
170	EL	73.22	0.1316	42.21	C&L	SFL
180	TTJ	78.87	0.6103	42.21	C	TE
197	TTJ	74.17	0.0575	42.21	C	TE
UNIT 2						
10	TTJ	43.06	0.0531	42.21	C	TE
45	SWP	70.45	0.2216	42.21	C	TE
55	TEE	87.89	0.3960	42.21	C&L	SFL
115	TTJ	56.98	0.2482	42.21	C	TE
180	TTJ	61.18	0.2388	42.21	C	TE
197	TTJ	68.59	0.1942	42.21	C	TE
75	TTJ	59.97	0.2699	42.21	C	TE
100	TEE	102.14	0.8011	42.21	C&L	SFL

(1) Locations of the nodes listed in this table are shown in Figure 3.6-15.

(2) Node types are designated as follows:
- TEE - butt-welding tee
- TTJ - tapered transition joint
- EL - elbow
- SWP - sweepolet

(3) Break types are indicated as follows:
- C - circumferential
- L - longitudinal

(4) Symbols used to denote basis for break selection are as follows:
- TE - terminal end
- SFL - the stress and fatigue limits established in Section 3.6.2.1.1.3 are not met
- MBL - intermediate break location selected in order to satisfy the requirement for a minimum number of break locations

(5) The values provided above are based upon original licensed power conditions. These CUF values are conservatively based derived by using Sm for design temperatures instead of the load pair operating temperatures. For rerate power conditions, using the more realistic approach, the CUF values are found to be equal to or less than those in the table. No new pipe break is required for rerate power conditions. The maximum equation 10 stresses may be increased by up to 2% for the rerate condition.

(6) The information posted in this table was used for original System piping analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-9

COMPARTMENT DESIGN PRESSURES AND PRESSURE-TEMPERATURE TRANSIENT ANALYSIS RESULTS

	UNIT 1		UNIT 2	
COMPARTMENT	DESIGN PRESSURE[1] PSIG	MAX TRANSIENT[2] PEAK PRESSURE PSIG	DESIGN PRESSURE[1] PSIG	MAX TRANSIENT[2] PEAK PRESSURE PSIG
Main Steam Tunnel	10.2	10.18	10.47	11.39
Main Steam Tunnel Vent Stack (Lower-Region)	8.2	8.18	8.99	9.78
Main Steam Tunnel Vent Stack (Mid-Region)	5.7	5.32	--	--
Main Steam Tunnel Vent Stack (Security Plenum)	--	--	6.97	7.81
Main Steam Tunnel Vent Stack (Upper-Region)	5.7	2.93	5.7	2.72
MST Security Plenum	--	--	2.14	2.33
Main Condenser Area	2.14	2.33	2.14	2.33
Steam Vent Plenum	2.14	2.33	10.47	10.30
HPCI Pump	2.7	2.94	2.7	2.79
HPCI Piping Area	6.1	6.64	6.1	2.79
RCIC Pump	2.8	2.94	2.8	2.00
RCIC Upper Piping Area	5.4	5.77	5.4	2.47
RHR, HPCI, RCIC Isolation Valve	1.41	1.52	1.47	1.60
HPCI, RCIC Steam Venting Tunnel	0.9	0.98	1.11	1.21
Security Plenum	- -	- -	1.11	0.83
Non-Regenerative Heat Exchanger	2.9	3.02	2.9	3.02
Non-Regenerative Heat Exchanger	2.9	3.02	2.9	3.02
Regenerative Heat Exchanger	2.9	2.92	2.9	2.92
RWCU Pump (A)	2.8	6.2	2.8	6.2
RWCU Pump (B and C)	2.8	2.91	2.8	2.91
RWCU Penetration	2.8	2.92	2.8	2.92

(1) In each compartment, the maximum pre-rerate peak transient pressure was used as a basis to establish the compartment design pressure. This is considered to be appropriate because of the conservatism in the analytical models used to calculate the mass and energy release rates.

(2) Maximum transient peak pressures are for power rerate conditions (3527 mwt). Although some peak pressures exceed listed design pressures, there are sufficient margin and conservatism in the existing design to accommodate the rerate condition. These pressures have been evaluated to be acceptable for each compartment.

Table 3.6-10

RWCU PIPING
STRESS LEVELS AND PIPE BREAK DATA
(PORTION INSIDE PRIMARY CONTAINMENT)[5][6]

Node Point[1]	Node Type[2]	Stress By EQ.10 (ksi)	Cumula-tive Usage Factor	Pipe Break Stress Limit 2.4 S_m (ksi)	Break Type[3]	Basis for Break Selection[4]
UNIT 1						
38	BW	28.735	0.0002	32.784	C	TE
77	TTJ	53.039	0.2145	32.784	C&L	SFL
79	TTJ	52.2	0.1883	32.784	C&L	SFL
82	TTJ	51.379	0.1666	32.784	C&L	SFL
90	TTJ	50.828	0.1497	32.784	C&L	SFL
103	TTJ	54.446	0.3216	32.784	C&L	SFL
115	SWP	45.461	0.0098	32.784	C	TE
UNIT 2						
39	STR	11.19	0.0	32.784	C	TE
103	TTJ	55.18	0.2643	32.784	C&L	SFL
115	SWP	45.36	0.0597	32.784	C	TE
47	TTJ	48.56	0.1348	32.784	C&L	SFL
53	TTJ	48.72	0.1394	32.784	C&L	SFL

(1) Locations of the nodes listed in this table are shown in Figure 3.6-17.

(2) Node types are designated as follows:
- TTJ - tapered transition joint
- BW - butt weld
- SWP - sweepolet
- STR - straight pipe

(3) Break types are indicated as follows:
- C - circumferential
- L - longitudinal

(4) Symbols used to denote the basis for break selection are as follows:
- TE - terminal end
- SFL - the stress and fatigue limits established in Section 3.6.2.1.1.3 are not met
- MBL - intermediate break location selected in order to satisfy the requirement for a minimum number of break locations

(5) The values provided above are based upon original licensed power conditions. These Cumulative Usage Factor (CUF) values are conservatively based derived by using Stress maximum (Sm) for design temperatures instead of the load pair operating temperatures. For rerate power conditions, using the more realistic approach, the CUF values are found to be equal to or less than those in the table. No new pipe break is required for rerate power conditions. The maximum equation 10 stresses may be increased by up to 2% for the rerate condition.

(6) The information posted in this table was used for the original System piping analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-11

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Table 3.6-12

REACTOR VESSEL DRAIN PIPING
STRESS LEVELS AND PIPE BREAK DATA[5][6]

Node Point[1]	Node Type[2]	Stress By EQ. 10 (ksi)	Cumula-tive Usage Factor	Pipe Break Stress Limit 2.4 S_m (ksi)	Break Type[3]	Basis for Break Selection[4]
UNIT 1						
553	RED	60.009	0.1068	33.936	C&L	SFL
643	TTJ	65.95	0.5875	33.936	C&L	SFL
645	TTJ	65.636	0.5678	33.936	C&L	SFL
670	WLD	49.61	0.0871	33.936	C&L	SFL
675	TTJ	56.538	0.1465	33.936	C&L	SFL
685	TTJ	56.273	0.1358	33.936	C&L	SFL
690	WLD	46.38	0.0573	33.936	C&L	SFL
720	RED	80.543	0.6964	33.936	C&L	SFL
725	TEE	61.08	0.2194	33.936	C	SFL
790	RED	57.937	0.1171	32.784	C	SFL
847	DMJ	54.883	0.1320	32.784	C	SFL
860	TTJ	39.605	0.0161	42.210	C	TE
866	RED	64.49	0.2543	32.784	C	SFL
875	TTJ	29.37	0.00	32.784	C	TE
917	TTJ	41.877	0.0237	32.784	C	SFL
925	TTJ	43.832	0.0311	32.784	C	SFL
935	TTJ	43.356	0.0289	32.784	C	SFL
UNIT 2						
553	RED	55.85	0.0979	32.78	C&L	SFL
643	TTJ	48.49	0.0555	32.78	C&L	SFL
645	TTJ	48.29	0.0527	32.78	C&L	SFL
670	WLD	45.62	0.0639	32.78	C&L	SFL
675	TTJ	42.75	0.0141	32.78	C&L	SFL
685	TTJ	42.83	0.0121	32.78	C&L	SFL
720	RED	65.23	0.7513	32.78	C&L	SFL
725	TEE	59.26	0.1430	32.78	C	SFL
860	TTJ	50.96	0.0535	42.210	C	TE
875	TTJ	50.74	0.1630	32.784	C	TE

(1) Locations of the nodes listed in this table are shown in Figure 3.6-20.

(2) Node types are designated as follows:

- TEE - butt-welding tee
- TTJ - tapered transition joint
- RED - reducer
- DMJ - dissimilar metal joint
- WLD - weldolet

Table 3.6-12 (Cont'd)

(3) Break types are indicated as follows:

C	-	circumferential
L	-	longitudinal

(4) Symbols used to denote the basis for break selection are as follows:

TE	-	terminal end
SFL	-	the stress and fatigue limits established in Section 3.6.2.1.1.3 are not met
MBL	-	intermediate break location selected in order to satisfy the requirement for a minimum number of break locations

(5) The values provided above are based upon original licensed power conditions. These Cumulative Usage Factor (CUF) values are conservatively based derived by using Stress Maximum (Sm) for design temperatures instead of the load pair operating temperatures. For rerate power conditions, using the more realistic approach, the CUF values are found to be equal to or less than those in the table. No new pipe break is required for rerate power conditions. The maximum equation 10 stresses may be increased by up to 2% for the rerate condition.

(6) The information posted in this table was used for the original System analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-13

HPCI STEAM SUPPLY PIPING STRESS LEVELS AND PIPE BREAK DATA
(PORTION INSIDE PRIMARY CONTAINMENT)[5][6]

Node Point[1]	Node Type[2]	Stress By EQ. 10 (ksi)	Cumula-tive Usage Factor	Pipe Break Stress Limit 2.4 S_m (ksi)	Break Type[3]	Basis for Break Selection[4]
UNIT 1						
197	TTJ	47.5	0.0084	42.2	C	TE
200	EL	48.4	0.0018	42.2	C	MBL
225	EL	58.4	0.0061	42.2	C	MBL
358	STR	21.1	0.0002	42.2	C	TE
UNIT 2						
197	TTJ	53.86	0.0289	42.2	C	TE
358	STR	19.16	0.0004	42.2	C	TE

(1) Locations of the nodes listed in this table are shown in Figure 3.6-21.

(2) Node types are designated as follows:
- TTJ - tapered transition joint
- EL - elbow
- STR - straight pipe

(3) Break types are indicated as follows:
- C - circumferential
- L - longitudinal

(4) Symbols used to denote the basis for break selection are as follows:
- TE - terminal end
- SFL - the stress and fatigue limits established in Section 3.6.2.1.1.3 are not met
- MBL - intermediate break location selected in order to satisfy the requirement for a minimum number of break locations

(5) The values provided above are based upon original licensed power conditions. These Cumulative Usage Factor (CUF) values are conservatively based derived by using Stress maximu (Sm) for design temperatures instead of the load pair operating temperatures. For rerate power conditions, using the more realistic approach, the CUF values are found to be equal to or less than those in the table. No new pipe break is required for rerate power conditions. The maximum equation 10 stresses may be increased by up to 6% for the rerate condition.

(6) The information posted in this table was used for the original System piping analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-14

HPCI STEAM SUPPLY PIPING STRESS LEVELS AND PIPE BREAK DATA (PORTION OUTSIDE PRIMARY CONTAINMENT)[5][6]

NODE POINT[1]	NODE TYPE[2]	STRESS (ksi) EQ. 9	EQ. 10	TOTAL	$0.8(1.2S_h+S_A)$ (ksi)	PIPE BREAK BREAK TYPE[3]	STRESS LIMIT BREAK SELECTION[4]	BASIS FOR
UNIT 1								
45	BW	6.87	18.19	25.06	32.4	C	TE	
55	TEE	7.52	15.59	23.11	32.4	C	MBL	
65	EL	7.50	10.83	18.33	32.4	C	MBL	
85	BW	7.02	5.49	12.51	32.4	C	TE	
UNIT 2								
95	ST	9.62	12.39	22.01	32.4	C	TE	
150	EL	10.72	11.03	21.75	32.4	C	TE	

(1) Locations of the nodes listed in this table are shown in Figure 3.6-22.

(2) Node type are designated as follows:
- TTJ - tapered transition joint
- TEE - butt-welding tee
- EL - elbow
- BW - butt weld
- ST - straight pipe

(3) Break types are indicated as follows:
- C - circumferential
- L - longitudinal

(4) Symbols used to denote the basis for break selection are as follows:
- TE - terminal end
- SFL - stress and fatigue limits established in Section 3.6.2.1.1.3 are not met
- MBL - intermediate break location selected to satisfy the requirement for a minimum number of break locations

(5) The values provided above are based upon original licensed power conditions. These Cumulative Usage Factor (CUF) values are conservatively based derived by using Stress maximum (Sm) for design temperatures instead of the load pair operating temperatures. For rerate power conditions, using the more realistic approach, the CUF values are found to be equal to or less than those in the table. No new pipe break is required for rerate power conditions. The maximum equation 10 stresses may be increased by up to 6% for the rerate condition.

(6) The information posted in this table was used for the original System piping analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-15

RCIC STEAM SUPPLY PIPING STRESS LEVELS AND PIPE BREAK DATA
(PORTION INSIDE PRIMARY CONTAINMENT)[5][6]

Node Point[1]	Node Type[2]	Stress By EQ.10 (ksi)	Cumula-tive Usage Factor	Pipe Break Stress Limit 2.4 S_m (ksi)	Break Type[3]	Basis for Break Selection[4]
UNIT 1						
250	EL	35.62	0.0003	42.2	C	TE
320	EL	41.7	0.0008	42.2	C	MBL
350	EL	47.4	0.0013	42.2	C	MBL
391	TTJ	68.5	0.29	42.2	C	TE
UNIT 2						
250	EL	12.05	0.0000	42.2	C	TE
391	TTJ	62.60	0.1201	42.2	C	TE

(1) Location of the nodes listed in this table are shown in Figure 3.6-25.

(2) Node types are designated as follows:
- TTJ - tapered transition joint
- EL - elbow
- RED - reducer

(3) Break types are indicated as follows:
- C - circumferential
- L - longitudinal

(4) Symbols used to denote the basis for break selection are as follows:
- TE - terminal end
- SFL - the stress and fatigue limits established in Section 3.6.2.1.1.3 are not met
- MBL - intermediate break location selected in order to satisfy the requirement for a minimum number of break locations

(5) The values provided above are based upon original licensed power conditions. These Cumulative Usage Factor (CUF) values are conservatively based derived by using Stress maximum (Sm) for design temperatures instead of the load pair operating temperatures. For rerate power conditions, using the more realistic approach, the CUF values are found to be equal to or less than those in the table. No new pipe break is required for rerate power conditions. The maximum equation 10 stresses may be increased by up to 6% for the rerate condition.

(6) The information posted in this table was used for the original System piping analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-16

RCIC STEAM SUPPLY PIPING STRESS LEVELS AND PIPE BREAK DATA
(PORTION OUTSIDE PRIMARY CONTAINMENT)[5],[6]

NODE POINT[1]	NODE TYPE[2]	STRESS (ksi) EQ. 9	EQ. 10	TOTAL	PIPE BREAK STRESS LIMIT $0.8(1.2S_h+S_A)$ (ksi)	BASIS FOR BREAK TYPE[3]	BREAK SELECTION[4]
UNIT 1							
40	BW	7.62	1.60	9.22	32.4	C	TE
100	EL	8.14	18.63	26.77	32.4	C	MBL
105	EL	7.66	16.84	24.50	32.4	C	MBL
117	STR	7.40	1.69	9.08	32.4	C	TE
UNIT 2							
30	TTJ	6706	927	7633	32400	C	TE
105	EL	6712	2618	9330	32400	C	TE

(1) Locations of the nodes listed in this table are shown in Figure 3.6-26.

(2) Node types are designated as follows:
- TTJ - tapered transition joint
- EL - elbow
- BW - butt weld
- STR - straight pipe

(3) Break types are indicated as follows:
- C - circumferential
- L - longitudinal

(4) Symbols used to denote the basis for break selection are as follows:
- TE - terminal end
- SFL - stress and fatigue limits established in Section 3.6.2.1.1.3 are not met
- MBL - intermediate break location selected to satisfy the requirement for a minimum number of break locations

(5) The values provided above are based upon original licensed power conditions. These cumulative usage factor (CUF) values are conservatively derived by using Stress maximum (Sm) for design temperatures instead of the load pair operating temperatures. For rerate power conditions, using the more realistic approach, the CUF values are found to be equal to or less than those in the table. No new pipe break is required for rerate power conditions. The maximum equation 10 stresses may be increased up to 6% for the rerate conditions.

(6) The information posted in this table was used for the original System piping analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-17
MAIN STEAM DRAINAGE PIPING STRESS LEVELS AND PIPE BREAK DATA
(PORTION INSIDE PRIMARY CONTAINMENT)[5][6]

Node Point[1]	Node Type[2]	Stress By EQ. 10 (ksi)	Cumula-tive Usage Factor	Pipe Break Stress Limit 2.4 S_m (ksi)	Break Type[3]	Basis for Break Selection[4]
UNIT 1						
10	SW	37.8	0.0196	42.2	C	TE
30	SW	39.12	0.0168	42.2	C	MBL
51	TEE	41.0	0.0075	42.2	C	MBL
65	SW	28.4	0.0143	42.2	C	MBL
90	SW	28.5	0.0124	42.2	C	TE
110	TTJ	13.24	0.0	42.2	C	TE
195	TEE	40.8	0.0014	42.2	C	MBL
220	SW	28.2	0.0141	42.2	C	MBL
240	SW	26.3	0.0113	42.2	C	TE
276	SW	39.5	0.0171	42.2	C	MBL
295	SW	37.64	0.0196	42.2	C	TE
UNIT 2						
10	SW	53.58	0.0402	42.2	C	TE
90	SW	38.49	0.0174	42.2	C	TE
110	TTJ	18.32	0.0006	42.2	C	TE
240	SW	38.93	0.0320	42.2	C	TE
295	SW	57.16	0.0582	42.2	C	TE

(1) Locations of the nodes listed in this table are shown in Figure 3.6-28.

(2) Node types are designated as follows:
- TEE - butt-welding tee
- TTJ - tapered transition joint
- SW - socket weld

(3) Break types are indicated as follows:
- C - circumferential
- L - longitudinal

(4) Symbols used to denote the basis for break selection are as follows:
- TE - terminal end
- SFL - the stress and fatigue limits established in Section 3.6.2.1.1.3 are not met
- MBL - intermediate break location selected in order to satisfy the requirement for a minimum number of break locations

(5) The values provided above are based upon original licensed power conditions. These Cumulative Usage Factor (CUF) values are conservatively based derived by using Stress maximum (Sm) for design temperatures instead of the load pair operating temperatures. For rerate power conditions, using the more realistic approach, the CUF values are found to be equal to or less than those in the table. No new pipe break is required for rerate power conditions. The maximum equation 10 stresses may be increased by up to 2% for the rerate condition.

(6) The information posted in this table was used for the original System piping analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-18

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Table 3.6-19

RPV HEAD VENT PIPING
STRESS LEVELS AND PIPE BREAK DATA[5][6]

Node Point[1]	Node Type[2]	Stress By EQ. 10 (ksi)	Cumula-tive Usage Factor	Pipe Break Stress Limit 2.4 S_m (ksi)	Break Type[3]	Basis for Break Selection[4]
UNIT 1						
5	TTJ	47.61	0.0541	42.21	C	TE
10	CUR	46.95	0.0012	42.21	C	MBL
28	RED	54.22	0.3862	42.21	C	SFL
30	DMJ	59.49	0.1037	42.21	C	SFL
33	TTJ	28.92	0.0	42.21	C	TE
500	TEE	44.85	0.0157	42.21	C	MBL
620	SW	25.50	0.0672	42.21	C	TE
835	SW	54.69	0.0621	42.21	C	MBL
920	SW	51.97	0.0232	42.21	C	TE
292	SW	74.85	0.5044	42.21	C	SFL
UNIT 2						
5	TTJ	32.80	0.0032	42.21	C	TE
292	SW	74.85	0.5044	42.21	C	SFL
40	TTJ	21.09	0.00	33.94	C	TE
620	SW	19.03	0.0017	42.21	C	TE
910	SW	68.56	0.2355	42.21	C	TE

(1) Locations of the nodes are shown in Figure 3.6-30.

(2) Node types are designated as follows:
- TTJ - Tapered transition joint
- CUR - Butt-weld elbow
- RED - Reducer
- DMJ - Dissimilar metal joint
- TEE - Butt-welding tee
- SW - Socket weld

(3) Break types are indicated as follows:
- C - Circumferential

(4) Symbols used to denote the basis for break selection are as follows:
- TE - Terminal end
- MBL - Intermediate break location selected to satisfy the requirement for a minimum number of break locations.
- SFL - The stress and fatigue limits established in Section 3.6.2.1.1.3 are not met.

(5) The values provided above are based upon original licensed power conditions. These Cumulative Usage Factor (CUF) values are conservatively based derived by using Stress maximum (Sm) for design temperatures instead of the load pair operating temperatures. For rerate power conditions, using the more realistic approach, the CUF values are found to be equal to or less than those in the table. No new pipe break is required for rerate power conditions. The maximum equation 10 stresses may be increased by up to 2% for the rerate condition.

(6) The information posted in this table was used for the original System piping analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-20

SLCS INJECTION PIPING
STRESS LEVELS AND PIPE BREAK DATA[5][6]

Node Point[1]	Node Type[2]	Stress By EQ. 10 (ksi)	Cumula-tive Usage Factor	Pipe Break Stress Limit 2.4 S_m (ksi)	Break Type[3]	Basis for Break Selection[4]
UNIT 1						
5	SW	57.25	0.1478	33.8	C	TE
15	SW	58.67	0.1784	33.8	C	SFL
20	SW	59.43	0.1887	33.8	C	SFL
35	SW	60.53	0.2049	33.8	C	SFL
40	SW	61.15	0.2208	33.8	C	SFL
42	SW	61.36	0.2285	33.8	C	SFL
43	SW	60.96	0.2204	33.8	C	SFL
70	SW	64.29	0.3164	33.8	C	SFL
75	SW	64.10	0.3139	33.8	C	SFL
76	SW	63.46	0.2940	33.8	C	TE
UNIT 2						
7	SW	40.31	0.0455	32.44	C	TE
76	SW	46.69	0.0559	32.44	C	TE

(1) Locations of the nodes are shown in Figure 3.6-31.

(2) Node type are designated as follows:
SW - Socket weld

(3) Break types are indicated as follows:
C - Circumferential

(4) Symbols used to denote the basis for break selection are as follows:
TE - Terminal end break
SFL - The stress and fatigue limits established in Section 3.6.2.1.1.3 are not met.

(5) The values provided above are based upon original licensed power conditions. These Cumulative Usage Factor (CUF) values are conservatively based derived by using Stress maximum (Sm) for design temperatures instead of the load pair operating temperatures. For rerate power conditions, using the more realistic approach, the CUF values are found to be equal to or less than those in the table. No new pipe break is required for rerate power conditions. The maximum equation 10 stresses may be increased by up to 2% for the rerate condition.

(6) The information posted in this table was used for the original System piping analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-21

RHR SHUTDOWN COOLING PIPING
STRESS LEVELS AND PIPE BREAK DATA[7][8]

Node Point[1]	Node Type[2]	Stress By EQ. 10 (ksi)	Cumula-tive Usage Factor	Pipe Break Stress Limit 2.4 S_m (ksi)	Break Type[3]	Basis for Break Selection[4]
UNIT 1						
107	BW	37.999	0.0193	32.79	C	TE
109	EL	60.727	0.3363	32.79	C&L	SFL
125	TTJ	60.924	0.976	32.79	C&L	SFL
142	TTJ	58.386	0.831	32.79	C&L	SFL
150	TTJ	60.330	0.8259	32.79	C	TE
288	TTJ	38.46	0.0242	32.79	C	TE
291	TTJ	37.659	0.0238	32.79	C	MBL
293	TTJ	40.264	0.0258	32.79	C	MBL
297	BW	32.920	0.0463	32.79	C	TE
325	TTJ	39.737	0.0269	32.79	C	TE
335	TTJ	41.565	0.0314	32.79	C	MBL
345	TTJ	45.696	0.0676	32.79	C	MBL
350	BW	34.127	0.0515	32.79	C	TE
UNIT 2						
107	TTJ	33.59	0.0141	32.79	C	TE
109[5]	EL	51.20	0.0415	32.79	C&L	SFL
125	TTJ	54.48	0.3439	32.79	C&L	SFL
142	TTJ	53.48	0.3065	32.79	C&L	SFL
150	TTJ	56.73	0.4447	32.79	C	TE
288	TTJ	35.98	0.0231	32.79	C	TE
297	TTJ	37.48	0.0396	32.79	C	TE
325	TTJ	38.16	0.0219	32.79	C	TE
350	BW	32.51	0.0319	32.79	C	TE
293[6]	TTJ	46.84	0.0527	32.79	C&L	SFL

(1) Locations of the nodes listed in this table are shown in Figure 3.6-32.

(2) Node types are designated as follows:

TTJ - tapered transition joint
EL - elbow
BW - butt weld

Table 3.6-21 (Cont'd)

(3) Break types are indicated as follows:

C	-	circumferential
L	-	longitudinal

(4) Symbols used to denote the basis for break selection are as follows:

TE	-	terminal end
SFL	-	the stress and fatigue limits established in Section 3.6.2.1.1.3 are not met
MBL	-	intermediate break location selected in order to satisfy the requirement for a minimum number of break locations

(5) EQ.13 = 38.37 ksi

(6) EQ.13 = 38.13 ksi

(7) The values provided above are based upon original licensed power conditions. These CUF values are conservatively based derived by using Sm for design temperatures instead of the load pair operating temperatures. For rerate power conditions, using the more realistic approach, the CUF values are found to be equal to or less than those in the table. No new pipe break is required for rerate power conditions. The maximum equation 10 stresses may be increased by up to 2% for the rerate condition.

(8) The information posted in this table was used for the original System piping analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-22

LPCI INJECTION PIPING
STRESS LEVELS AND PIPE BREAK DATA[5][6]

Node Point[1]	Node Type[2]	Stress By EQ. 10 (ksi)	Cumula-tive Usage Factor	Pipe Break Stress Limit 2.4 S_m (ksi)	Break Type[3]	Basis for Break Selection[4]
UNIT 1						
65	TTJ	30.87	0.0008	32.78	C	T
67	DMJ	56.97	0.12	32.78	C&L	SFL
90	EL	117.84	0.81	32.78	C&L	SFL
100	TTK	157.16	0.64	32.78	C&L	SFL
140	EL	156.47	0.80	32.78	C&L	SFL
145	STR	109.32	0.44	32.78	C&L	SFL
150	TTJ	154.95	0.62	32.78	C	TE
UNIT 2						
65	TTJ	37.48	0.0012	32.78	C	TE
90	EL	117.84	0.4709	32.78	C&L	SFL
100	TTJ	143.83	0.6160	32.78	C&L	SFL
140	EL	114.41	0.4580	32.78	C&L	SFL
150	TTJ	140.38	0.6493	32.78	C	TE

(1) Locations of the nodes listed in this table are shown in Figure 3.6-33.

(2) Node types are designated as follows:
- TTJ - tapered transition joint
- EL - elbow
- DMJ - dissimilar metal joint
- STR - straight pipe

(3) Break types are indicated as follows:
- C - circumferential
- L - longitudinal

(4) Symbols used to denote the basis for break selection are as follows:
- TE - terminal end
- SFL - the stress and fatigue limits established in Section 3.6.2.1.1.3 are not met
- MBL - intermediate break location selected in order to satisfy the requirement for a minimum number of break locations

(5) The values provided above are based upon original licensed power conditions. These Cumulative Usage Factor (CUF) values are conservatively based derived by using Stress maximum (Sm) for design temperatures instead of the load pair operating temperatures. For rerate power conditions, using the more realistic approach, the CUF values are found to be equal to or less than those in the table. No new pipe break is required for rerate power conditions. The maximum equation 10 stresses may be increased by up to 2% for the rerate condition.

(6) The information posted in this table was used for the original System piping analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-23

CORE SPRAY INJECTION PIPING
STRESS LEVELS AND PIPE BREAK DATA[5][6]

Node Point[1]	Node Type[2]	Stress By EQ. 10 (ksi)	Cumula-tive Usage Factor	Pipe Break Stress Limit 2.4 S_m (ksi)	Break Type[3]	Basis for Break Selection[4]
UNIT 1						
25	TTJ	30.19	0.0016	32.78	C	TE
30	DMJ	66.87	0.1365	32.78	C&L	SFL
63	STR	106.87	0.3789	32.78	C&L	SFL
65	EL	124.58	0.7034	32.78	C&L	SFL
72	RED	108.52	0.7573	32.78	C&L	SFL
73	STR	109.03	0.4141	32.78	C&L	SFL
75	TTJ	117.54	0.4955	32.78	C	TE
UNIT 2						
25	TTJ	30.49	0.0037	32.78	C	TE
75	TTJ	56.29	0.0733	32.78	C	TE

(1) Locations of the nodes listed in this table are shown in Figure 3.6-34.

(2) Node types are designated as follows:
- TTJ - tapered transition joint
- EL - elbow
- RED - reducer
- DMJ - dissimilar metal joint
- STR - straight pipe

(3) Break types are indicated as follows:
- C - circumferential
- L - longitudinal

(4) Symbols used to denote the basis for break selection are as follows:
- TE - terminal end
- SFL - the stress and fatigue limits established in Section 3.6.2.1.1.3 are not met
- MBL - intermediate break location selected in order to satisfy the requirement for a minimum number of break locations

(5) The values provided above are based upon original licensed power conditions. These Cumulative Usage Factor (CUF) values are conservatively based derived by using Stress maximum (Sm) for design temperatures instead of the load pair operating temperatures. For rerate power conditions, using the more realistic approach, the CUF values are found to be equal to or less than those in the table. No new pipe break is required for rerate power conditions. The maximum equation 10 stresses may be increased by up to 2% for the rerate condition.

(6) The information posted in this table was used for the original System piping analysis. Refer to System ASME III piping analysis for current information.

Table 3.6-24

RESTRAINT DATA USED IN VERIFICATION OF RECIRCULATION SYSTEM PIPE WHIP RESTRAINT DESIGN[1]

PIPE SIZE (in)	REST LOAD DIRECTION	C_2[2]	N[2]	LIMIT, Δ RESTRAINT[2]	INITIAL CLEARANCE (in)	EFFECTIVE CLEARANCE (in)	TOTAL CLEARANCE (in)
12	0°	27,733	0.24	6.129	4	1.941	5.941
12	90°	14,795	0.401	9.063	4	12.247	16.247
16	0°	109,265	0.24	6.278	4	1.934	5.934
6	90°	62,599	0.377	8.978	4	12.187	16.187
24	0°	102,228	0.24	8.222	4	1.984	5.984
24	90°	55,531	0.375	11.972	4	13.685	17.685
24	38°[3]	109,888	0.24	5.588	4	5.698	9.698
24	52°[3]	109,835	0.24	5.473	4	8.462	12.462

(1) The restraint data listed applies to one bar of a restraint.

(2) $F = C_2 (\Delta \text{ restraint})^N$
where F is the resistance force for one bar of a restraint and
where (Δ restraint) = (σ pipe) - (total clearance)

(3) Applies to restraint RCR 3 only.

Table 3.6-25

COMPARISON OF PDA AND NSC CODES

BREAK DESIGNATION[1]	RESTRAINT DESIGNATION[1]	NO. OF BARS		LOAD (kips)		RESTRAINT DEFLECTION(in)		FRACTION OF DESIGN RESTRAINT DEFLECTION (%)		PIPE DEFLECTION (in)	
		PDA	NSC	PDA	NSC	PDA	NSC	PDA	NSC	PDA	NSC
$RC1_J$	RCR1	5	5	803.2	788.3	6.57	7.926	79.93	96.4	17.72	15.58
$RC2_{LL}$	RCR1	5	5	766.4	458.4	14.99	7.495	125	62.6	35.83	24.52
$RC3_{LL}$	RCR2	6	6	747.0	639.7	2.27	3.73	27.65	45.35	17.16	20.11
$RC3_{LL}$	RCR2	6	6	796.6	780.3	10.22	10.54	57.8	59.6	41.48	43.0
$RC4_{LL}$	RCR3	5	5	846.0	838.4	7.64	8.05	92.95	97.98	18.87	16.43
$RC4_{LL}$	RCR3	8	8	1319.0	1073.9	5.43	4.62	99.23	76.85	23.28	17.25
$RC4C_V$	RCR3	8	8	1260.7	1275.0	4.49	5.58	80.37	99.89	22.56	18.73
$RC6A_V$	RCR3	8	8	928.5	722.5	1.22	1.77	22.46	31.7	23.68	95.39
$RC7_J$	RCR7	6	6	953.3	801.6	6.28	5.76	76.4	70.12	16.46	21.63
$RC8_{LL}$	RCR6	4	4	599.0	0	8.28	0	112.46	0	26.76	
		6	6	895.0	0	8.16	0	110.76	0	29.316	8.39
$RC9C_V$	RCR6	4	4	575.8	520.16	4.16	5.53	50.63	67.33	13.2	14.56
$RC9_{LL}$	RCR8	6	6	830.2	546.8	11.408	6.815	95.29	56.9	36.612	26.24
RC11A	RCR8	6	6	818.3	493.6	10.98	5.99	91.72	50.07	31.404	23.71
RC13	RCR10	4	4	668.4	478.4	5.87	3.66	93.5	58.39	13.37	10.44
RC16	RCR11	4	4	687.4	518.4	6.59	4.38	105	69.86	15.37	10.22
$RC14C_V$	RCR20	8	8	285.0	309.6	2.83	5.88	46.3	95.92	15.45	13.96
$RC14_{LL}$	RCR20	8	8	116.3	129.9	0.96	3.36	10.5	37.1	22.13	23.56

[1] Break designations and restraint designations are shown on Figure 3.6-37.

3.7 SEISMIC DESIGN

All systems and equipment of the NSSS are defined as either seismic Category I or nonseismic Category I. The requirements for seismic Category I qualification are given in Section 3.2, along with a list of systems, components, and equipment which are so categorized. Seismic design requirements for nonseismic Category I items are also defined in Section 3.2. These items are classified as either Category II or Category IIA.

All systems, components, and equipment related to plant safety are designed to withstand SSE and OBE.

The SSE is that earthquake which is based upon an evaluation of the maximum earthquake potential considering the regional and local geology, and seismology and specific characteristics of local subsurface material. It is that earthquake which produces the maximum vibratory ground motion for which seismic Category I systems and components are designed to remain functional. These systems and components are those necessary to ensure:

a. The integrity of the RCPB.

b. The capability to shut down the reactor and maintain it in a safe shutdown condition.

c. The capability to prevent or mitigate the radiological consequences of accidents which could result in potential offsite exposures, comparable to the dose limits of 10 CFR 50.67.

The OBE is that earthquake which, considering the regional and local geology, and seismology and specific characteristics of local subsurface material, could reasonably be expected to affect the plant site during the operating life of the plant. It is that earthquake which produces the vibratory ground motion for which those features of the nuclear power plant necessary for continued operation, without undue risk to the health and safety of the public, are designed to remain functional.

In addition to seismic loads, Category I structures, systems and components are also reviewed for hydrodynamic loads as described in Appendix 3A.

3.7.1 SEISMIC INPUT

3.7.1.1 Design Response Spectra

The site design response spectra used are shown in Figures 3.7-1 and 3.7-2. These spectra are for the horizontal components of the OBE and the SSE respectively. The response spectra for the OBE are scaled or normalized to a maximum horizontal ground acceleration of 7½% of gravity. The response spectra for the SSE are normalized to a maximum horizontal ground acceleration of 15% of gravity. The values for the vertical component of the design response spectra are 2/3 of the horizontal design response spectra described above. The response spectra are based on data developed from records of previous earthquake activity and represent an envelope of motion expected at a sound rock site from a nearby earthquake (Section 2.5.2).

Regulatory Guide 1.60 (December, 1973) "Design Response Spectra for Seismic Design of Nuclear Power Plants" was not used for the development of the spectra, because LGS Units 1 and 2 were docketed for construction permit review in March 1970, and the spectra were finalized in

1973. Further, a letter dated December 21, 1973 from J.M. Hendrie (NRC) to R.M. Collins (Bechtel) states that Regulatory Guide 1.60 is applicable only to the plants docketed for construction permit review after April 1, 1973.

3.7.1.2 Design Time History

A synthetic time history of motion was generated by modifying the actual records of the 1952 Taft earthquake according to the techniques proposed in Reference 3.7-1. This synthetic time history was then further modified to develop the time history shown in Figure 3.7-3, which corresponds to the design response spectra. The duration of the time history is 15 seconds. Figures 3.7-4 through 3.7-9 show a comparison of the time history response spectra and the design response spectra for 0.5%, 1%, 2%, 3%, 5%, and 7% damping values.

The spectra are computed at the frequency values as given in table 5-1 of Reference 3.7-2.

3.7.1.3 Critical Damping Values

3.7.1.3.1 Critical Damping Values (NSSS)

The damping values indicated in Table 3.7-1 are used in the response analysis of various structures and systems, and in preparation of floor response spectra used as forcing inputs for piping and equipment analysis or testing. It can be seen that the values given in Table 3.7-1 are somewhat less than those given in Regulatory Guide 1.61 (October 1973), "Damping Values for Seismic Design of Nuclear Power Plants". The calculated responses are, therefore, conservative. Alternative critical damping values for piping may be used as described in Section 3.7.1.3.3.

3.7.1.3.2 Critical Damping Values (Non-NSSS)

Critical damping values expressed as a percentage of critical damping and used for seismic Category I structures, equipment, and piping for both the OBE and SSE are given in Table 3.7-2. Alternative critical damping values for piping may be used as described in Section 3.7.1.3.3.

Regulatory Guide 1.61 is not used as a design basis as discussed in Section 1.8, except as discussed in Section 3.7.1.3.3. However, all the values shown in Table 3.7-2 are equivalent to or more conservative than those in Regulatory Guide 1.61 with the exception of the SSE value for welded steel structures. The damping value of 5% (PSAR table C.2.1) is based on information given in Reference 3.7-6. The 5% value has been used, with appropriate design margins, because the stress levels for SSE conditions are allowed to approach the yield point.

3.7.1.3.3 Alternative Critical Damping Values and Spectral Peak Broadening for Piping (NSSS and Non-NSSS)

Alternative critical damping values, as provided in ASME B&PV Code, Section III, Division 1 Code Case N-411 may be used. When used, the provisions listed below are applied unless otherwise approved by References 3.7-12 and 3.7-13. References 3.7-12 and 3.7-13 approved the use of Independent Support Motion (ISM) response spectra methodology in conjunction with the damping values specified in ASME Code Case N-411, as the basis for eliminating snubbers from 31 piping systems on Unit 1 and Unit 2.

- The code case damping is applied only to uniform (or envelope) response spectra loading analysis for seismic and seismiclike building filtered hydrodynamic loads and the annulus pressurization loading.

- The code case damping is applied to a spectral analysis load case in its entirety and is not mixed with other damping values within that one load case.

- Modal and direction combination of the three earthquake directions are combined in accordance with Regulatory Guide 1.92.

- Consideration of a sufficient number of modes such that the inclusion of additional modes would not result in more than a 10% increase in response.

- Assurance that the predicted piping displacements are such that adequate clearance exists with respect to adjacent components and equipment.

- Line mounted equipment is designed to withstand the increased pipe motion.

- The code case damping is not used for analyzing the dynamic response of piping systems incorporating supports designed to dissipate energy by yielding.

- The code case damping is not applied to piping analytical models that incorporate equipment with natural frequencies below 20 hertz.

- The code case damping is not applied to piping in which stress-corrosion cracking has occurred unless a case specific evaluation is reviewed by the NRC.

When time history or independent support motion response spectrum analysis is utilized, the following critical damping values are applied:

a. Time history analysis with 0.5% damping for OBE, 1% damping for SSE, or Regulatory Guide 1.61 damping for hydrodynamic loads.

b. Independent support motion response spectra analysis with Regulatory Guide 1.61 damping.

ASME Section III, Division I Code Case N-397, "Alternative Rules to the Spectral Broadening Procedures of N-1226.3 for Classes 1, 2 and 3 Piping, Section III, Division 1" may be selectively used on a load case basis. This code case is applicable to all spectral analysis load cases and all methodologies except it was not applied to a spectral analysis load case that utilized the independent support motion analysis methodology.

3.7.1.4 Supporting Media for Seismic Category I Structures

All seismic Category I structures are supported on sound rock or concrete backfill bearing on sound rock, except for some yard facilities such as valve pits and portions of electrical duct banks and underground piping which are supported on natural soil or fill (Section 2.5.4.10).

For the dynamic analysis of the rock-founded structures, soil-structure interaction is considered to be negligible due to the high stiffness of the rock. However, the floor response spectra developed

for the reactor enclosure and the containment for equipment analysis are based on a model that considered the flexibility of the supporting medium. The modulus of elasticity, the shear-wave velocity, and the density of the supporting medium used in the analysis are 3.0×10^6 psi, 6000 fps, and 150 lbs/ft^3, respectively. Additional soil-structure interaction studies were performed for the containment structure and reactor and control enclosures to assess the sensitivity of the structural response to variations in the design basis rock modulus. Modal analyses have demonstrated that for a ±50% of the design elastic modulus range, variations in structural frequency do not exceed 10% for predominant modes. These results indicate that a reduction in rock modulus to 1.5×10^6 psi would not produce significant effects on the structural response. It is therefore concluded that the average dynamic elastic modulus value of 3.0×10^6 psi is adequate for design.

3.7.2 SEISMIC SYSTEM ANALYSIS

Seismic Category I structures and systems, and components of the NSSS that fall under the category of a seismic system, are discussed here. Seismic systems are analyzed for both OBE and SSE.

3.7.2.1 Seismic Analysis Method

3.7.2.1.1 Seismic Analysis Methods (NSSS)

Analysis of seismic Category I NSSS systems and components was accomplished, where applicable, using the response spectrum or time history approach. Either approach utilizes the natural period, mode shapes, and appropriate damping factors of the particular system. Certain pieces of equipment having very high natural frequencies may be analyzed statically. In some cases, dynamic testing of equipment may be used for seismic qualification.

A time history analysis involves the solution of the equations of the dynamic equilibrium (Section 3.7.2.1.1.1) by means of the methods discussed in Section 3.7.2.1.1.2. In this case, the duration of motion is of sufficient length to ensure that the maximum values of response are obtained.

A response spectrum analysis involves the solution of the equations of motion (Section 3.7.2.1.1.1) by the method discussed in Section 3.7.2.1.1.3.

3.7.2.1.1.1 The Equations of Dynamic Equilibrium

Assuming that the force due to damping is proportional to velocity, the dynamic equilibrium equations for a lumped-mass, distributed stiffness system are expressed in matrix form as:

$$[M]\{\ddot{u}(t)\} + [C]\{\dot{u}(t)\} + [K]\{u(t)\} = \{P(t)\} \qquad \text{(EQ. 3.7-1)}$$

where:

$u(t)$ = time-dependent displacement of nonsupport points relative to the supports

$\dot{u}(t)$ = time-dependent velocity of nonsupport points relative to the supports

$\ddot{u}(t)$ = time-dependent acceleration of nonsupport points relative to the supports

[M] = diagonal matrix of lumped masses

[C] = damping matrix

[K] = stiffness matrix

P(t) = time-dependent inertial forces acting at nonsupport points

3.7.2.1.1.2 Solution of the Equations of Motion by Mode - Superposition

The first technique used for the solution of the equations of motion is the method of mode-superposition.

The set of homogeneous equations represented by the undamped free vibration of the system is:

$$[M]\{\ddot{u}(t)\} + [K]\{u(t)\} = \{0\} \qquad \text{(EQ. 3.7-2)}$$

Since the free oscillations are assumed to be harmonic the displacements can be written as

$$\{u(t)\} = \{\phi\}\, e \qquad \text{(EQ. 3.7-3)}$$

where:

$\{\phi\}$ = column matrix of the amplitude of displacement {u}

ω = circular frequency of oscillation

t = time

Substituting Equation 3.7-3 and its derivatives into Equation 3.7-2 and noting that (e) is not necessarily zero for all values of (ωt) yields

$$[-\omega^2[M] + [K]]\{\phi\} = \{0\} \qquad \text{(EQ. 3.7-4)}$$

Equation 3.7-4 is the classical algebraic eigenvalue problem, wherein the eigenvalues are the frequencies of vibrations, w_i, and the eigenvectors are the mode shapes, $\{\phi\}_i$.

For each frequency here is a corresponding solution vector $\{\phi\}_i$. It can be shown that the mode shape vectors are orthogonal with respect to the weighting matrix [K] in the n-dimensional vector space.

The mode shape vectors are also orthogonal with respect to the mass matrix [M].

The orthogonality of the mode shapes is used to effect a coordinate transformation of the displacements, velocities, and accelerations, so that the response in each mode is independent of the response of the system in any other mode. Thus, the problem becomes one of solving (n) independent differential equations rather than (n) simultaneous differential equations; and, since the system is linear, the principle of superposition holds, and the total response of the system oscillating simultaneously in (n) modes is determined by direct addition of the responses in the individual modes.

3.7.2.1.1.3 Analysis by Response Spectrum

As an alternative to the step-by-step mode-superposition method described in Section 3.7.2.1.1.2, the response spectrum method may be used. The response spectrum method is based on the fact that the modal responses can be expressed as a set of integral equations, rather than a set of differential equations. The advantage of this form of solution is that for a given ground motion, the only variables under the integral are the damping factor and the frequency. Thus, for a specified damping factor, it is possible to construct a curve which gives a maximum value of the integral as a function of frequency. This curve is called a response spectrum for the particular input motion and the specified damping factor. The integral has units of velocity, consequently the maximum of the integral is called the spectral velocity.

Using the calculated natural frequencies of vibration of the system, the maximum values of the modal responses are determined directly from the appropriate response spectrum. The modal maxima are then combined as discussed in Section 3.7.3.7.1.

The total seismic structural response is predicted by combining the response calculated from the two horizontal and the vertical analyses. When the response spectrum method is used, the methods for combining the loads from the three analyses is based on the method described in Section 3.7.2.6.

3.7.2.1.1.4 Support Displacements in Multisupported Structure

The methods described in Section 3.7.2.1.1.5 are used, where applicable, to account for the effects of relative anchor motion in the case of a multisupported structure.

3.7.2.1.1.5 Dynamic Analysis of Seismic Category I Systems and Components

The time history technique and the response spectrum technique were used as applicable for the dynamic analysis of seismic Category I NSSS systems and components which are sensitive to dynamic seismic events.

a. Dynamic Analysis of Piping Systems

Each pipeline is idealized as a mathematical model consisting of lumped masses connected by elastic members. The stiffness matrix for the piping system is determined using the elastic properties of the pipe. This includes the effects of torsional, bending, shear, and axial deformations, as well as change in stiffness due to curved members. Next the mode shapes and the undamped natural frequencies are obtained. The dynamic response of the system is calculated by using the response spectrum method of analysis. When the piping system is being anchored and supported at points with different excitations, the response spectrum analysis is performed using a response spectrum which envelopes all the response spectra of anchors and supports. Alternatively, except as restricted by Section 3.7.1.3.3, the multiple response spectra/independent support motion method of analysis may be used where distinct time histories or response spectra are applied to all piping system attachment points.

The relative modal displacement between anchors is determined from the dynamic analysis of the primary structures. The results of the relative anchor point

displacement per mode are used for a static analysis to determine the secondary stresses due to relative anchor point displacements. The modal stresses are combined by the SRSS method to obtain the resultant secondary stresses.

b. Dynamic Analysis of Equipment

Equipment is idealized as a mathematical model consisting of lumped masses connected by elastic members or springs. The Table 3.9-6 series documents calculated and allowable loads for various loading combinations, including seismic loads, applied to major NSSS systems and components.

The response spectrum analysis is performed using the enveloped response spectrum of all attachment points. Alternatively, for equipment supported at two or more points located at different elevations in the same primary structure, the response spectrum for the most severe single support can be applied uniformly to all support points. As a second alternative, if appropriate, the response spectra at the elevation near the center of gravity of the equipment may be taken as the design spectra.

The relative modal displacement between supports is determined from the dynamic analysis of the structure. The relative support point displacements per mode are used for a static analysis to determine the secondary stresses due to support displacements. The modal stresses are combined by the SRSS method to obtain the resultant secondary stresses. Further details are given below.

c. Differential Seismic Movement of Interconnected Components

The procedure for considering differential displacements for equipment anchored and supported at points with different displacement excitations is as follows:

The relative displacements between the supporting points induces additional stresses in the equipment supported at these points. These stresses can be evaluated by performing a static analysis where each of the supporting points is displaced a prescribed amount. From the dynamic analysis of the complete structure, the time history of displacement at each supporting point is available. These displacements are used to calculate stresses by determining the peak modal responses. The stresses thus obtained for each natural mode are then superimposed for all modal displacements of the structure by the SRSS method.

In the static calculation of the stresses due to relative displacements in the response spectrum method, the maximum value of the modal displacement is used. Therefore, the mathematical model of the equipment is subjected to the maximum displacement at its supporting points obtained from the modal displacements. This procedure is repeated for the significant modes (modes contributing most to the total displacement response at the supporting point) of the structure. The total stresses due to relative displacement are obtained by combining the modal results using the SRSS method. Since the maximum displacements for different modes do not occur at the same time, the SRSS method is a realistic and practical method.

When a component is covered by the ASME B&PV Code, then the stresses due to relative displacement as obtained above are treated as secondary stresses.

3.7.2.1.1.6 Seismic Qualification by Testing

For certain seismic Category I equipment and components where dynamic testing is necessary to ensure functional integrity, test performance data and results reflect the following:

a. Performance data of equipment which, under the specified conditions, has been subjected to dynamic loads equal to or greater than those to be experienced under the specified seismic conditions

b. Test data from previously tested comparable equipment which, under similar conditions, has been subjected to dynamic loads equal to or greater than those specified

c. Actual testing of equipment in accordance with one of the methods described in Sections 3.9 and 3.10

Alternate test procedures that satisfy the requirements of these criteria are allowed, subject to review by the responsible engineer.

3.7.2.1.2 Seismic Analysis Methods (Non-NSSS)

In the analysis of seismic Category I structures, two distinct objectives must be satisfied:

a. Development of in-structure seismic response characteristics, where necessary, for use in the analysis and design of seismic Category I systems, equipment, and components

b. Determination of seismic force distribution within the various structures resulting from the design criteria free-field seismic input, for use in the design of seismic Category I structures

Two analytical procedures were employed to determine the seismic responses to the Category I structures. In general, a modal response spectrum analysis was used to compute the in-structure seismic responses, including nodal accelerations, nodal displacements, and member forces. Alternatively, a time history analysis procedure was used to generate the in-structure seismic responses discussed above. In addition, time history analysis was used to generate all floor response spectra. The mathematical idealization of the structural characteristics of the various seismic Category I structures was accomplished by a lumped-parameter beam-stick model. The general analytical methods and modeling techniques used in these analyses are in accordance with Reference 3.7-2. The seismic design criteria input is defined in terms of the OBE and SSE design response spectra (Section 3.7.1.1), the synthetic time history (Section 3.7.1.2), and the soil-structure interaction parameters (Section 3.7.2.4) used for development of floor response spectra for equipment assessment. Refer to Figures 3.7-10 through 3.7-19 for either a pictorial representation or an actual sketch of the mathematical models used. A complete description of the formulation of the mathematical models and their use is provided in Section 3.7.2.3.2.

3.7.2.2 Natural Frequencies and Response Loads

The natural frequencies of the primary containment, the reactor enclosure, and the control structure below 33 cps are shown in Tables 3.7-5 and 3.7-6 respectively. The significant mode

shapes of the containment and the reactor enclosure and control structure are shown on Figures 3.7-20 through 3.7-30. The mode shapes for the primary containment are for the horizontal and vertical directions. The reactor enclosure and control structure mode shapes are for each of the three principal directions: east-west, north-south, and vertical.

Tables 3.7-7 through 3.7-16 show the response (i.e., displacements, accelerations, shear forces, bending moments, and axial forces) of the primary containment and the reactor enclosure and control structure for both OBE and SSE.

Response spectra at critical locations are shown on Figures 3.7-31 through 3.7-40. The curves are shown for each of the principal directions at the damping values shown (Section 3.7.2.15 for further discussion of damping values). Figures 3.7-41 and 3.7-42 represent the response spectra of the refueling area using soil-structure interaction.

3.7.2.3 Procedures Used for Modeling

3.7.2.3.1 Procedures Used for Modeling (NSSS)

3.7.2.3.1.1 Modeling Techniques for Seismic Category I Systems and Components

An important step in the seismic analysis of seismic Category I NSSS systems and components is the procedure used for modeling. The techniques currently being used are represented by lumped masses and a set of spring-dashpots idealizing both the inertial and stiffness properties of the system. The details of the mathematical models are determined by the complexity of the actual structures and the information required for the analysis.

3.7.2.3.1.2 Modeling of Reactor Pressure Vessel and Internals

The seismic loads on the RPV and internals are based on a dynamic analysis of an entire RPV enclosure complex, with the appropriate forcing function applied at ground level. For this analysis, the models shown in Figure 3.7-19 and the mathematical model of the enclosure are coupled together.

This mathematical model consists of lumped masses connected by elastic (linear) members. The stiffness properties of the model are determined using the elastic properties of the structural components. This includes the effects of both bending and shear. In order to facilitate hydrodynamic mass calculations, several mass points (fuel, shroud, vessel) are selected at the same elevation. The various lengths of CRD housings are grouped into the two representative lengths as shown in Figure 3.7-19. These lengths represent the longest and shortest housings in order to adequately represent the full range of frequency response of the housings. The high fundamental natural frequencies of the CRD housings result in very small seismic loads. Furthermore, the small frequency differences between the various housings, due to the length differences, result in negligible differences in dynamic response. Hence, the modeling of intermediate length members becomes unnecessary. Not included in the mathematical model are the stiffnesses of light components such as jet pumps, incore guide tubes and housings, spargers, and their supply headers. This is done to reduce the complexity of the dynamic model. To find seismic responses of these components, the floor response spectra generated from the system analysis are used.

The presence of fluid and other structural components (e.g., fuel within the RPV) introduces a dynamic coupling effect. Dynamic effects of water enclosed by the RPV are accounted for by

introduction of a hydrodynamic mass matrix, which serves to link the acceleration terms of the equations of motion of points at the same elevation in concentric cylinders with a fluid entrapped in the annulus. The details of the hydrodynamic mass derivation are given in Reference 3.7-5. The seismic model of the RPV and internals has two generalized coordinates in the horizontal directions for each mass point considered in the analysis. The remaining generalized vertical coordinate is excluded because the vertical mode frequencies of RPV and internals are well above the significant horizontal mode frequencies. A separate vertical analysis is performed. The two rotational coordinates about each node point are excluded because the moment contribution from rotary inertia is negligible. Since all deflections are assumed to be within the elastic range, the rigidity of some components may be accounted for by equivalent linear springs.

The shroud support plate is loaded in its own plane during a seismic event and hence is extremely stiff, and, therefore, may be modeled as a rigid link in the translational direction. The shroud support legs and the local flexibilities of the vessel and shroud contribute to the rotational flexibilities and are modeled as an equivalent torsional spring.

3.7.2.3.2 Procedures Used for Modeling (Non-NSSS)

The mathematical models used for the analysis of all major Category I structures are fixed base, lumped-mass, elastic spring models, except for the primary containment, the reactor enclosure and control structure, where the lumped-mass seismic model considers a rigid mass resting on soil springs. The soil spring constants are determined from formulae given in table 3-2 of Reference 3.7-2. Two separate and independent analyses are done for the containment structure. The section properties for these two analyses are based on uncracked and cracked concrete sections, respectively. The same models are used both for the response spectrum and time history analyses. The mathematical models of the primary containment are shown in Figures 3.7-10 and 3.7-11, and those of the reactor enclosure and control structure are shown in Figures 3.7-14 and 3.7-15. The additional mathematical models used for development of floor response spectra, using soil-structure interaction for these structures, are shown in Figures 3.7-12, 3.7-13, 3.7-16, and 3.7-17.

For all models, the masses are located at elevations of mass concentrations, such as floors and roofs. However, in the case of the containment, a structure of continuous mass distribution, masses are lumped at approximate maximum intervals of 15 feet along the containment shell and reactor pedestal. These methods of mass distribution are in accordance with the procedures of section 3.2 of Reference 3.7-2. All equipment, components, and piping systems are lumped into the supporting structure except for the reactor vessel, which is incorporated into the lumped-parameter analysis of the containment structure to account for potential coupling. The detailed analysis of the NSSS is performed using a decoupled model as discussed in Section 3.7.2.3.1.

A more refined RPV model is being used in the DAR (Appendix 3A) to evaluate the anticipated effects of hydrodynamic loads in combination with seismic loads.

3.7.2.4 Soil-Structure Interaction

Since the seismic Category I structures are founded on competent bedrock, a soil spring approach to characterize soil-structure interaction is not used in the dynamic analysis. A simplified lumped-mass method using a fixed base model is used. However, for a more refined analysis of containment and reactor enclosure, the underlying foundation medium is considered to interact with the structure. The equivalent soil spring constant and damping coefficient are computed in accordance with the formulae of table 3-2 of Reference 3.7-2, and the analysis carried out by the

methods discussed in appendix D of Reference 3.7-2. The resulting structure-foundation interaction coefficients are listed in Table 3.7-17.

3.7.2.5 Development of Floor Response Spectra

3.7.2.5.1 Floor Response Spectra (NSSS)

See Section 3.7.3.6.1.

3.7.2.5.2 Floor Response Spectra (Non-NSSS)

The time history method of analysis was used to develop the floor response spectra. A discussion of the technique of finding the nodal time history and then producing the spectrum may be found in Sections 4.2 and 5.2 of Ref 3.7-2.

3.7.2.6 Three Components of Earthquake Motion

3.7.2.6.1 NSSS

See Section 3.7.3.6.1.

3.7.2.6.2 Non-NSSS

The response spectrum method was used in seismic analysis of structures. Independent analyses are performed for the vertical and two horizontal (east-west and north-south) directions. Regulatory Guide 1.92, "Combining Responses and Spatial Components in Seismic Response Analysis" states that the design response value is obtained by taking the SRSS of the maximum co-directional responses caused by each of the three components of earthquake motion at a particular point of the structure. However, for design purposes, the response value used is the maximum value obtained by adding the response due to the vertical earthquake with the larger value of the response due to one of the horizontal earthquakes by the absolute sum method. A discussion of the adequacy of the conservatism provided by this two-component absolute summation technique as compared to the Regulatory Guide 1.92 requirement of a three-component SRSS procedure is provided below.

The general conditions for which the absolute summation of two resultants method is conservative may be demonstrated by considering the following:

$$R_H^{min} = fR_H^{max} \quad \text{where } 0 \leq f \leq 1 \text{ where } f = R_H^{min}/R_H^{max}$$

and

$$R_V = CR_H^{max} \quad 0 \leq C < \infty \text{ where } C = R_V/R_H^{max}$$

where:

R_H^{max} = Larger of the two seismic co-directional responses due to either of the horizontal earthquake components

R_H^{min} = Smaller seismic co-directional responses due to the other orthogonal horizontal earthquake component

R_V = Seismic co-directional response due to vertical earthquake

f = ratio of R_H^{min} to R_H^{max}

C = ratio of R_V to R_H^{max}.

Therefore SRSS of three components can be expressed as follows:

$$\sqrt{(R_H^{max})^2 + (R_H^{min})^2 = (R_V)^2}$$

$$\sqrt{(R_H^{max})^2 + f^2 \ (R_H^{max})^2 + C^2 \ (R_H^{max})^2}$$

$$\left(\sqrt{1 + f^2 + C^2} \ R_H^{max} \right) \qquad \text{(EQ. 3.7-5)}$$

The absolute sum of two components can be expressed as follows:

$$R_H^{max} + R_V$$

$$R_H^{max} + CR_H^{max}$$

$$(\sqrt{(1 + C)^2}) R_H^{max}$$

$$(\sqrt{1 + 2C + C^2}) R_H^{max} \qquad \text{(EQ. 3.7-6)}$$

Equation 3.7-6 (absolute sum of two components) will be greater than or equal to Equation 3.7-5 (three-component SRSS) when:

$$\sqrt{1 + 2C + C^2} \geq \sqrt{1 + f^2 + C^2}$$

or

$$1 + 2C + C^2 \geq 1 + f^2 + C^2$$

or

$$2C \geq f^2$$

or $C \geq \frac{1}{2} f^2$ where $0 \leq f = \frac{R_H^{min}}{R_H^{max}} \leq 1$ (EQ. 3.7-7)

This relationship is shown in Figure 3.7-46.

The relative conservatism of the two-component absolute and the three-component SRSS summation techniques may be illustrated by considering the ratio of Equations 3.7-6 and 3.7-5. This ratio will be defined as y. Then:

$$y = \frac{\text{ABS of EQ. 3.7-6}}{\text{SRSS of EQ. 3.7-5}} = \frac{\left(\sqrt{1 + 2C + C^2}\right) R_H^{max}}{\left(\sqrt{1 + f^2 + C^2}\right) R_H^{max}}$$

$$y = \left(\frac{1 + 2C + C^2}{1 + f^2 + C^2}\right)^{1/2} \quad \text{(EQ. 3.7-8)}$$

where:

$$0 \leq f = \frac{R_H^{min}}{R_H^{max}} \leq 1, \text{ as before}$$

This relationship is shown in Figure 3.7-47.

As shown above, the LGS two-component absolute summation method is conservative when the co-directional response due to the vertical excitation is equal to or greater than one-half the higher of the two horizontal responses ($C \geq ½$), regardless of the relationship between the two horizontal responses.

The minimum possible ratio between the two-component absolute summation method and the three-component SRSS procedure is equal to 0.707. This would occur only when the response due to the vertical excitation is zero (C = 0) and the two horizontal responses resulting from the two horizontal excitations are equal (f = 1). However, this case is unlikely to occur, and any other relationship of the various response components would produce a ratio larger than 0.707. The ratio between the two procedures, as shown in Figure 3.7-47 would be greater than one in most cases.

To further demonstrate the relationship of the seismic response components on the LGS structures, an evaluation has been performed for selected critical structural elements within the structures. Details of the evaluation are provided in the following paragraphs.

a. Containment Exterior Shell

   For the structural design of the containment shell, consideration of two horizontal components is not necessary due to the axisymmetric nature of the shell. The maximum resulting loads from two horizontal earthquake components would not be coincident and would occur 90° apart on the circumference of the shell. Furthermore, when the resultant force from one horizontal component is maximum at a given location, the resultant force from the orthogonal horizontal component would be zero. This relationship corresponds to f = 0 in Figures 3.7-46 and 3.7-47. Therefore, the two-component absolute summation technique would produce a more conservative design.

b. Reactor Enclosure and Control Structure

Stress evaluations were performed for critical locations in the reactor enclosure and control structure. The northeast control structure and southwest reactor enclosure corner model locations are selected because of their sensitivity to large orthogonal responses due to out-of-plane seismic motion. The results obtained from the SSE seismic analysis are combined by the two-component ABS and three-component SRSS methods and are compared in Table 3.7-20. For 14 out of 20 wall locations evaluated, the seismic stress response comparison shows that the two-component ABS method is more conservative than the three-component SRSS method. In general, the two-component ABS method and the three-component SRSS method produce comparable results. Although the differences between the combined stress from the two methods are small, the values for some locations suggest that the two-component ABS method may be conservative when the seismic load is considered to act alone.

There are 6 wall locations where the two-component ABS method is less conservative. The critical wall location is the southwest corner of the reactor enclosure, at el 177', where the differential between ABS stresses and SRSS stresses equals 14% (Table 3.7-20). (This location is considered critical not only because of the difference between the ABS and SRSS stresses but also because of the level of the stresses.) However, when the seismic stresses are combined with the stresses due to other design loads, the effect of the differential between ABS stresses and SRSS stresses is reduced in proportion with the ratio of seismic wall load to total wall load. In addition, the critical wall (wall line "D" at el 177') is loaded to only 52% of its capacity (based on combined axial and bending stresses due to all design loads as shown in Figure 3A-432).

Therefore, when considering the reduced effect of ABS vs. SRSS in conjunction with the ample excess capacity of the wall, the use of the ABS method for calculating seismic stresses provides adequate conservatism when considered in combination with other loads in the design of the reactor enclosure and control structure.

3.7.2.7 Combination of Modal Responses

3.7.2.7.1 Combination of Modal Responses (NSSS)

See Section 3.7.3.7.1.

3.7.2.7.2 Combination of Modal Responses (Non-NSSS)

The modal responses (i.e., shears, moments, deflections, accelerations, and inertia forces) are combined by either the sum of the ABS method, or by the SRSS method with consideration of closely spaced modes. Two consecutive modes are defined as closely spaced when their frequencies differ from each other by 10% or less of the lower frequency. When the SRSS method is used, Regulatory Guide 1.92 shall be adopted for the combination of modal responses.

3.7.2.8 Interaction of Non-Category I Structures with Seismic Category I Structures

The turbine enclosure, auxiliary boiler enclosure, and the administration building are the only major non-Category I structures adjacent to seismic Category I structures. These non-Category I

structures are designed for seismic loading in accordance with the UBC (Reference 3.7-3). In addition, the turbine enclosure was dynamically analyzed to ensure the capacity to withstand a SSE without collapsing on or impairing the integrity of the adjacent reactor and control structures. Similarly, the other non-Category I structures were analytically evaluated to ensure that they will not collapse on or otherwise impair the integrity of adjacent seismic Category I structures when subjected to the design seismic loads.

Structural separations have been provided to ensure that interaction between Category I and non-Category I structures does not occur. The minimum separation gap between the buildings is twice the relative displacement for the design seismic loads.

3.7.2.9 Effects of Parameter Variations on Floor Response Spectra

3.7.2.9.1 Effects of Parameter Variations on Floor Response Spectra (NSSS)

To account for potential variations in the primary structure frequencies due to uncertainties in material properties of the soil and structure, soil-structure interaction techniques, approximation in damping, and approximation in dynamic modeling, the computed floor response spectra are peak-broadened by ±15%. This is consistent with the requirements of Regulatory Guide 1.122, although this regulatory guide is not the design basis requirement for the LGS construction permit.

3.7.2.9.2 Effects of Parameter Variations on Floor Response Spectra (Non-NSSS)

To account for variations in the structural frequencies owing to uncertainties in the material properties of the structure and to approximations in the modeling techniques used in the seismic analysis, the computed floor response spectra are smoothed, and peaks associated with each of the structural frequencies are broadened. In lieu of making a parametric study considering changes in the material properties and other variables, the spectrum is broadened on either side of the peak value by 15% of the frequency at which the peaks occur.

3.7.2.10 Use of Constant Vertical Static Factors

Vertical seismic system multimass dynamic models are used to obtain vertical response loads for the seismic design of seismic Category I structures. Therefore, constant vertical static factors are not used to account for vertical response to earthquakes for the seismic design of Category I structures.

3.7.2.11 Methods Used to Account for Torsional Effects

Torsional effects for the reactor enclosure, diesel generator enclosure, spray pond pumphouse, and radwaste enclosure are accounted for as follows:

A static analysis is performed to account for torsion on these structures. The eccentricity is determined using the distance between the center of mass and the center of rigidity of the individual structure. The inertial force from the response spectrum analysis is applied at the center of mass. The resulting torsional moment is equal to the inertial force times the eccentricity. The shear forces due to the torsional moment are then distributed to the walls. The total seismic shear in a given structural element is equal to the sum of the absolute values of the shear due to translation and torsion. Torsional effects are negligible for the containment because of the symmetry of the structure about the vertical center line.

Dynamic analyses have been performed to verify the adequacy of the static-equivalent method described above. These dynamic analyses were performed for the reactor enclosure, diesel generator enclosure and spray pond pumphouse where structural eccentricities are larger than 5% of the larger building plan dimension.

Inertia forces, obtained from dynamic analysis, are multiplied by the mass eccentricity (distance between center of mass and center of rigidity) to obtain a torsional moment, which is distributed to structural walls for design assessment. This equivalent static method was found to produce conservative design torsional moments; more so than results obtained from a 3-D dynamic analysis which included structural eccentricities. The dynamic analysis was performed as follows:

a. 3-D horizontal stick models were constructed for the reactor enclosure, diesel generator enclosure, and spray pond pumphouse with structural masses at calculated eccentricities (Figures 3.7-48, 3.7-49, and 3.7-50). The direction that has the larger mass eccentricity was selected for dynamic response analysis.

b. Modal analysis was performed to determine the vibration frequencies of the structures with eccentricity accounted for. The vibration frequencies with eccentricity were compared to the vibration frequencies with zero eccentricity (Tables 3.7-21 through 3.7-23).

c. Time history analyses were performed for the east-west models of the spray pond pumphouse, diesel generator enclosure, and reactor enclosure.

Torsional moments and shear forces at the base slab were compared with the moments and shear forces of the original design obtained using the equivalent static approach (Tables 3.7-24 through 3.7-27) .

Torsional moment and shear data comparisons show that the original design values using the static approach are conservative.

3.7.2.12 Comparison of Responses

A comparison of the results of modal design response spectrum analysis and modal time history analysis for the containment is shown in Figures 3.7-4 through 3.7-9. The responses are calculated for both OBE and SSE. The uncracked containment model as described in Section 3.7.2.3.2 is used for the analyses. The responses due to synthetic time history input are lower than those due to response spectrum, because the sum of the absolute modal responses are used in the latter analysis, whereas the phase differences of the modal responses are considered in the time history analysis.

3.7.2.13 Methods for Seismic Analysis of Dams

Dams are not provided on LGS.

3.7.2.14 Determination of Seismic Category I Structure Overturning Moments

The overturning moment for seismic Category I structures is the absolute sum of the moments at the base of each stick of the mathematical model. For each stick, the moment at the base is

determined by combining the modal overturning moments. The modal moments are combined by the methods described in Section 3.7.2.7.

The components of the earthquake motion used are the same as those discussed in Section 3.7.2.6. Section 3.8.5 discusses the factor of safety against overturning for several loadings, including seismic loads.

3.7.2.15 Analysis Procedure for Damping

3.7.2.15.1 Analysis Procedure for Damping (NSSS)

In a linear dynamic analysis, the procedure to be utilized to properly account for damping in different elements of a coupled system model is as follows:

a. The values for structural damping of the various structural elements of the model are first specified. Each value is referred to as the damping ratio (B_j) of a particular component which contributes to the complete stiffness of the system.

b. Perform a modal analysis of the linear system model. This will result in a modal matrix (ϕ) normalized so that:

$$\phi_i^T K \phi_i = W_i^2$$

where:

K = the stiffness matrix

W_i = circular natural frequency of mode i

ϕ_i^T = the transpose (ϕ) which is a column vector of (ϕ) corresponding to the mode shape of mode i

Matrix (ϕ) contains all translational and rotational coordinates.

c. Using the strain energy of the individual components as a weighting function, the following equation can be derived to obtain a suitable damping ratio (B_i) for the ith mode.

$$B_i \quad \frac{\sum_{j=1}^{N} [\phi_i^T \beta_j K_j \phi_i]}{W_i^2} \qquad \text{(EQ. 3.7-9)}$$

where:

N = Total number of structural elements

ϕ_i = Mode shape for mode i (ϕ_i^T as transpose)

β_i = Percent damping associated with element j

K_j = Stiffness matrix of element j

W_i = Circular natural frequency of mode i

3.7.2.15.2 Analysis Procedure for Damping (Non-NSSS)

The structures consist of reinforced concrete and welded/bolted structural steel. Damping values for these materials are shown in Table 3.7-2. However, in the seismic analysis of structures supported on rock, damping values of 2% and 5% are used for OBE and SSE respectively for welded/bolted structural steel, as well as for reinforced concrete. Therefore, the analysis by composite modal damping is not necessary.

For the time history analysis of containment and reactor enclosure where the soil-structure interaction is taken into account, the composite modal damping technique was used as described in appendix D of Reference 3.7-2.

3.7.3 SEISMIC SUBSYSTEM ANALYSIS

This section discusses the seismic analysis of subsystems, i.e., equipment, piping, Class 1E cable trays, and supports for seismic Category I HVAC ducts and cable trays.

3.7.3.1 Seismic Analysis Methods

3.7.3.1.1 Equipment

Seismic qualification of equipment was performed by using one of the following methods:

a. Analysis

b. Dynamic testing

c. Combination of analysis and dynamic testing

3.7.3.1.1.1 Analysis

For the purpose of analysis, equipment is idealized as a system of lumped masses and springs, for which frequencies and mode shapes are determined for vibration in the vertical direction and two orthogonal horizontal directions. For each direction of vibration, the spectral acceleration per mode is obtained from the appropriate response spectrum curve (i.e., corresponding to the location of the equipment) at the natural frequency of the equipment. Seismic loading, in terms of inertia forces, moments and shears, is determined for each direction using the response spectrum technique, summing the absolute values per mode. If the orientation of the equipment is not designated on the equipment location drawing, the horizontal seismic loading is taken as the maximum loading (worst case) obtained, using each horizontal direction of vibration and the appropriate horizontal response spectrum curve(s). If the frequencies of all equipment modes (determined by either analysis or testing) are above the frequency of the appropriate response spectrum curve at which the acceleration is constant in the rigid (high frequency) range, the seismic loading consists of static loading corresponding to that acceleration level. If the equipment damping is unknown, the response spectrum curve for 0.5% damping is used to arrive at a conservative seismic loading.

The damping value used for the OBE is increased for the SSE, where sufficient justification is established.

3.7.3.1.1.2 Dynamic Testing

In lieu of performing dynamic analysis, seismic adequacy may be established by providing dynamic test or previous dynamic environmental (performance) data which demonstrate that the equipment meets the seismic design criteria. The data include at least one of the following:

a. Recent test data acquired from dynamic tests of equipment

b. Dynamic test data from previously tested comparable equipment

c. Performance data from equipment which, during normal operating conditions, have been subjected to dynamic loads equal to or greater than those defined in Section 3.7.3.1.1.1

Typical test methods used are as follows:

a. Single-frequency sine beat test

b. Single-frequency dwell test

c. Multifrequency test

3.7.3.1.1.3 Combination of Analysis and Dynamic Testing

Certain equipment was qualified by a combination of analysis and dynamic testing. Experimental methods are used to aid in the formulation of the mathematical model for the equipment. Mode shapes and frequencies are determined experimentally and incorporated in the mathematical model of the equipment. The model is then subsequently analyzed by the procedure described in Section 3.7.3.1.1.1.

3.7.3.1.2 Piping Systems

Reference 3.7-4 describes the methods used for seismic analysis of piping systems. Reference 3.7-4 is followed on LGS with the following exceptions:

In seismic analysis the modal responses are combined by SRSS, and lower damping values than specified in Reference 3.7-4 are used. Alternative analytical methods and damping values may be utilized as described in Section 3.7.1.3.3.

See Section 3.7.3.7.2.

3.7.3.1.3 Class 1E Cable Trays

The cable trays are seismically qualified by the capacity evaluation method which consists of the following:

a. Calculation of the fundamental frequency of the cable tray based on the tray properties obtained from static tests

b. Seismic load computation based upon the tray frequency and the design spectra

c. Calculation of the tray allowable capacity

d. Evaluation of the tray capacity by interaction formula

3.7.3.1.4 Supports for Seismic Category I HVAC Ducts

The supports for HVAC ducts are analyzed by the response spectrum method (Reference 3.7-2).

3.7.3.1.5 Supports for Seismic Category I Electrical Raceway Systems

This section defines the procedures used for the design of the supports of electrical raceway systems, i.e., cable tray, conduit, and wireway gutter systems, subject to the seismic and other applicable loads. The raceway support system usually consists of raceways, horizontal and vertical support members, and lateral and longitudinal bracing members.

3.7.3.1.5.1 Loading Combinations

The adequacy of raceway systems to withstand seismic and other applicable static loads is determined according to the loading combinations and allowable responses given in Table 3.7-3. Load combinations and allowable stresses including the effects of hydrodynamic loads due to LOCA and SRV discharge are given in Table 3A-21.

3.7.3.1.5.2 Analytical Techniques

Either of two methods of analysis is used. Method 1 is a simplified method of analysis which determine the fundamental frequency of braced supports using two-dimensional analysis. Frequencies are determined in each of three principal directions. Then loads are determined by taking the spectral accelerations times the weight; and stresses are determined from static analysis. All members and connections are checked using stress criteria.

Method 2 uses a three-dimensional computer analysis and includes springs to represent joint stiffnesses. Response spectrum analyses are done to determine stresses and deformations. The number of stress cycles is determined by multiplying the time of maximum earthquake motion by the natural frequency of the system.

The allowable number of cycles is taken from Reference 3.7-8 for the joint rotations calculated. Only overhead connections are checked for fatigue because the test results (Reference 3.7-8, p. 7-19) demonstrate that failures occur only in overhead connections.

The basis for the design criteria and analysis Method 2 is the "Cable Tray and Conduit Raceway Test Program" (References 3.7-7 through 3.7-10).

3.7.3.1.5.3 Damping

Damping of 10% of the critical is used for the design of cable tray support systems; 7% damping for conduit and wireway gutter trapeze-type support systems; 5% damping for conduit and wireway gutter nontrapeze-type support systems. The recommended damping values for cable tray and conduit systems, developed from the test program, are shown in Figure 3.7-45. Wireway gutters were not tested: however, the manner in which they are constructed (with more bolted connections and more cables than conduit) provides more damping mechanisms than are present in conduit systems so that using the same damping value as in conduit systems is conservative.

3.7.3.1.5.4 Operating Basis Earthquake

The OBE is considered in the load combinations only for the overhead connections which are checked for fatigue. The OBE stresses are not checked during design for two reasons: first, raceway systems do not fail in a brittle or catastrophic mode as demonstrated by the test program in which such failures did not occur and the electrical systems were able to continue to function in all cases. Thus, there is no need to limit the OBE stresses to the low levels usually used to preclude such failures. Second, the OBE stresses will always be less than the SSE stresses as demonstrated below.

Based on Figure 3.7-45, a comparison of response spectra for corresponding damping values specified in Section 3.7.3.1.5.3 demonstrates that for all response spectra the OBE acceleration values are less than the corresponding SSE acceleration values (References 3.7-8 and 3.7-10). Thus, the OBE acceleration response and stresses are below the SSE acceleration response and stresses.

3.7.3.2 Determination of Number of Earthquake Cycles

3.7.3.2.1 Determination of Number of Earthquake Cycles (NSSS)

3.7.3.2.1.1 NSSS Piping

Fifty peak OBE cycles are postulated for fatigue evaluation.

3.7.3.2.1.2 Other NSSS Equipment and Components

To evaluate the number of cycles which exist within a given earthquake, a typical BWR enclosure/reactor dynamic model was excited by three different recorded time histories: May 18, 1940, El Centro NS component 29.4 sec; 1952, Taft N 69° W component, 30 sec; and March 1957, Golden Gate S 80° E component, 13.2 seconds. The modal response is truncated so that the response of three different frequency bandwidths could be studied: 0-10 Hz; 10-20 Hz; and 20-50 Hz. This is done to give a good approximation to the cyclic behavior expected from structures with different frequency content.

Enveloping the results from the three earthquakes and averaging the results from several different points of the dynamic model, the cyclic behavior as given in Table 3.7-18 was formed. A comparison has shown that the LGS design basis response spectrum is bounded by the spectra of the three earthquakes (Golden Gate, Taft, and El Centro) in the GE base study (Figure 3.7-43).

Independent of earthquake or component frequency, 99.5% of the stress reversals occur below 75% of the maximum stress level, and 95% of the reversals lie below 50% of the maximum stress level.

In summary, the cyclic behavior number of fatigue cycles of a component during an earthquake was found in the following manner:

a. The fundamental frequency and peak seismic loads are found by a standard seismic analysis.

b. The number of cycles which the component experiences are found from Table 3.7-18 according to the frequency range within which the fundamental frequency lies.

c. For fatigue evaluation, 0.5% (0.005) of these cycles are conservatively assumed to be at the peak load and 4.5% (0.045) at or above three quarter peak. The remainder of the cycles have negligible contribution to fatigue usage.

The SSE has the highest level of response. However, the encounter probability of the SSE is so small that it is not necessary to postulate the possibility of more than one SSE during the 40 year life of a plant. Fatigue evaluation due to the SSE is not necessary, since it is a faulted condition, and thus the evaluation is not required by ASME Section III.

The OBE is an upset condition, and therefore, must be included in fatigue evaluations according to ASME Section III. Investigation of seismic histories for many plants show that during a 40 year life, it is probable that five earthquakes with intensities of one-tenth of the SSE intensity, and one earthquake of approximately 20% of the proposed SSE intensity, will occur. To cover the combined effects of these earthquakes and the cumulative effects of even lesser earthquakes, ten peak OBE cycles are postulated for fatigue evaluation.

Table 3.7-19 shows the calculated number of fatigue cycles and the number of fatigue cycles used in design.

3.7.3.2.2 Determination of Number of Earthquake Cycles (Non-NSSS)

In general, the design of the equipment is not fatigue controlled. For equipment qualified by analysis, fatigue is not a controlling factor because the equipment is designed to remain below 90% of the yield strength of the material for the extreme loading condition. The number of stress cycles considered is 60 (5 OBE and 1 SSE events at 10 cycles each). Based on ASME Section III, appendix I criteria (figure I-9-1), this number of cycles will not result in a reduction of allowable stresses.

Any fatigue effects in tested equipment are accounted for by the duration of the test. Consequently, the number of cycles of the earthquake is considered.

In order to conduct a fatigue evaluation for nuclear Class I piping, the number of cycles for a given load set is obtained. This is done by considering ten maximum stress cycles per earthquake and 5 OBEs and 1 SSE to occur within the life of the plant. The results of the fatigue calculations for the most limiting BWR/4 component are shown in Table 3.7-4.

3.7.3.3 Procedures Used for Modeling

3.7.3.3.1 Procedures Used for Modeling (NSSS)

3.7.3.3.1.1 Modeling of Piping Systems

The continuous piping system is modeled as an assemblage of beams. The mass of each beam is lumped at the nodes connected by weightless elastic members representing the physical properties of each segment. The pipe lengths between mass points are no greater than the length which would have a natural frequency of 33 Hz, when calculated as a simply supported beam. All concentrated weights on the piping system such as main valves, relief valves, pumps, and motors are modeled as lumped masses. The torsional effects of the valve operators and other equipment with offset centers of gravity, with respect to the center line of the pipe, is included in the analytical model. Where the torsional effect is found to cause pipe stresses less than 500 psi, this effect is neglected.

3.7.3.3.1.2 Modeling of Equipment

For dynamic analysis, seismic Category I equipment is represented by lumped-mass systems which consist of discrete masses connected by weightless springs. The criteria used to lump masses are:

a. The number of modes of a dynamic system is controlled by the number of masses used. Therefore, the number of masses is chosen so that all significant modes are included. A mode is considered significant if the corresponding natural frequency is less than 33 Hz, and the stresses calculated from this mode are greater than 10% of the total stresses obtained from lower modes.

b. Mass is lumped at any point where a significant concentrated weight is located. Examples are: the motor in the analysis of pump motor stand; the impeller in the analysis of pump shaft; etc.

c. If the equipment has a free-end overhang span whose flexibility is significant compared to the center span, a mass is lumped at the overhang span.

d. When a mass is lumped between two supports, it is located at a point where the maximum displacement is expected to occur. This tends to conservatively lower the natural frequencies of the equipment, because the natural frequencies of the equipment are generally in the higher frequency range of the floor spectra. Similarly, in the case of live loads (mobile) and a variable support stiffness, the location of the load and the magnitude of support stiffness are chosen so as to yield the lowest frequency content for the system. This is to ensure conservative dynamic loads, since equipment frequencies are higher than the frequency at which the floor spectra peak occurs. If such is not the case, the model is adjusted to give more conservative results.

3.7.3.3.1.3 Field Location of Supports and Restraints

The field location of seismic supports and restraints for seismic Category I piping and piping systems components was selected to satisfy the following two conditions:

a. The location selected must furnish the required response to control strain within allowable limits.

b. Adequate structure strength for attachment of the components must be available.

The final location of seismic supports and restraints for seismic Category I piping, piping system components, and equipment (including the placement of snubbers), was checked against the

drawings and instructions issued by the engineer. An additional examination of these supports and restraining devices was made to ensure that the location and characteristics of these supports and restraining devices are consistent with the dynamic and static analyses of the systems.

3.7.3.3.2 Procedures Used for Modeling (Non-NSSS)

Mathematical models which describe the mass and the stiffness properties of the equipment are used. The models define the dynamic behavior of the equipment within the frequency range of interest. The boundary conditions are modeled to reflect the actual mounting conditions. The equipment is represented by lumped-mass models. Massless elastic members are used to connect the masses.

Supports for HVAC ducts are modeled as two-dimensional, lumped- mass, plane frame models. The masses are lumped at the center of the ducts. The electrical raceway support system analytical techniques are discussed in Section 3.7.3.1.5.2. Equivalent structural properties for cable tray analysis were determined from the load-deflection tests (Reference 3.7-11).

Sections 2 and 3 of Reference 3.7-4 discuss the techniques and procedures used to model piping other than the buried type.

3.7.3.4 Basis of Selection of Frequencies

3.7.3.4.1 Basis of Selection of Frequencies (NSSS)

All frequencies in the range of 0.25-33 Hz are considered in the analysis and testing of structures, systems, and components. These frequencies cover the natural frequencies of most of the components and structures under consideration. If the fundamental frequency of a component is $\geq$33 Hz, it is treated as rigid and analyzed accordingly. Frequencies less than 0.25 Hz are not considered, as they represent very flexible structures and are not encountered in this plant.

The frequency range of between 0.25 Hz and 33 Hz covers the range of the broad-band response spectrum used in the design.

3.7.3.4.2 Basis of Selection of Frequencies (Non-NSSS)

The natural frequencies of components are calculated. Only those modes which have natural frequencies <33 Hz are considered in the dynamic analysis. If a component has a frequency $\geq$33 Hz, it is considered as rigid. If the natural frequency of the component falls within the broadened peak of the response spectrum curve, then it is designed to take the applied load.

3.7.3.5 Use of Equivalent Static Load Method of Analysis (Non-NSSS)

The equivalent static load method is used when the natural frequency of the equipment is not determined. If the equipment can be adequately represented by a single-degree-of-freedom system, then the applied inertia load is equal to the weight of the equipment times the peak value of the response spectrum curve. Seismic acceleration coefficients for multidegree of freedom systems, which may be in the resonance region of the amplified response spectra curves, are increased by 50% to account conservatively for the increased modal participation.

Appendix D of Reference 3.7-4 discusses the use of equivalent static load method of analysis as applicable to piping.

3.7.3.6 Three Components of Earthquake Motion

3.7.3.6.1 Three Components of Earthquake Motion (NSSS)

The simultaneous use of three components of earthquake motion was not a design basis requirement of the construction permit for the LGS plant. However, the NSSS systems and components are evaluated to the requirement of Regulatory Guide 1.92.

a. Response Spectrum Method

Response spectra generated by GE are developed considering three components of earthquake motion. The individual responses in each orthogonal direction are combined by SRSS of the colinear contribution due to the three directions of earthquake motion. These are used to predict the total response at each frequency.

b. Time history Method

When the time history method of analysis is used, one of the following options is used to obtain the peak value of any particular response of interest:

1. When maximum colinear contributions due to the three directions of earthquake motion are calculated separately, the total response is obtained as the SRSS combination of the colinear values.

2. When colinear time history responses from each of the three components of the earthquake motion are calculated individually by the step-by-step method and then combined algebraically at each time step, the maximum response is obtained as the peak value from the combined time solution.

3. When a response at each time step is calculated directly based on the simultaneous application of the three earthquake components, the maximum response is determined by scanning the combined time history solution.

The components of earthquake motion must be statistically independent for Options 2 and 3. Also, the time history method precludes the need to consider closely spaced modes.

3.7.3.6.2 Three Components of Earthquake Motion (Non-NSSS)

For equipment, cable trays, and supports for cable trays and HVAC ducts, the three spatial components of the earthquake are considered in the same manner as for structures (Section 3.7.2.6).

The criteria used for combining the results of horizontal and vertical seismic responses for piping systems are described in section 5.1 of Reference 3.7-4.

3.7.3.7 Combination of Modal Responses

3.7.3.7.1 Combination of Modal Responses (NSSS)

All piping and equipment analyzed or supplied by GE are evaluated to the requirements of Regulatory Guide 1.92.

When the response spectra method of modal analysis is used, all modes except the closely spaced modes (i.e., the difference between any two natural frequencies is equal to or less than 10%) are combined by the SRSS as described in Section 3.7.3.7.1.a. Closely spaced modes are combined by the double sum method with absolute sign as described in Section 3.7.3.7.1.b.

In the time history method of dynamic analysis, the vector sum at every time step is used to calculate the combined response. The use of the time history method precludes the need to consider modal spacing.

a. SRSS

The SRSS method is defined mathematically as:

$$R = \left[\sum_{i=1}^{n} (R_i)^2 \right]^{1/2} \qquad \text{(EQ. 3.7-10)}$$

where:

R = Combined response

R_i = Response in the (i) mode

n = Number of modes considered in the analysis

b. Procedure of Combining Closely Spaced Modal Response

This method is defined mathematically as:

$$R = \left[\sum_{k=1}^{N} \sum_{s=1}^{N} |R_k R_s| E_{ks} \right]^{1/2} \qquad \text{(EQ. 3.7-11)}$$

where:

R = representative maximum values of a particular response of a given element to a given component of excitation

R_k = peak value of the response of the element due to the kth mode

N = number of significant modes considered in the modal response combination

R_s = peak value of the response of the element attributed to the sth mode

also:

$$E_{ks} = 1 + \left[\frac{\bar{w}_k^1 - \bar{w}_s^1}{\beta_k^1 w_k + \beta_s^1 w_s} \right]^2 \qquad \text{(EQ. 3.7-12)}$$

in which:

$$\bar{w}_k^1 = w_k (1 - \beta_k^2)^{1/2} \quad \text{and}$$

$$\beta_k^1 = \beta_k + \frac{2}{t_d w_k}$$

where:

w_k = modal frequency

β_k = damping ratio in the kth mode

t_d = duration of the earthquake.

3.7.3.7.2 Combination of Modal Responses (Non-NSSS)

The modal responses of equipment are combined by the SRSS method. The absolute values of two closely spaced modes are added first before combining with the other modes by the SRSS method. Two consecutive modes are defined as closely spaced when their frequencies differ from each other by 10% or less.

Procedures given in Regulatory Guide 1.92 for combining modal responses, when closely spaced modes are present, are not complied with in the seismic response spectra analysis for piping. All modal responses are combined by SRSS in the response spectra method of modal analysis for seismic loading (OBE and SSE). Seismic response spectra used in the piping analysis corresponds to conservative damping values of ½% for OBE and 1% for SSE. Alternative analytical methods and damping values may be utilized as described in Section 3.7.1.3.3.

3.7.3.8 Analytical Procedure for Piping

3.7.3.8.1 Analytical Procedure for Piping (NSSS)

The analytical procedures for piping analysis have been described in Section 3.7.2.1.1.5.a. Methods to include differential piping support movements at different support points are also described there.

3.7.3.8.2 Analytical Procedure for Piping (Non-NSSS)

The design criteria and the analytical procedures applicable to piping systems are as described in section 2 of Reference 3.7-4. Alternatively, except as restricted by Section 3.7.1.3.3, the multiple response spectra/independent support motion method of analysis may be used where distinct response spectra are applied to the piping system attachment points. The methods used to consider differential piping support movements at different support points are described in section 4 of Reference 3.7-4.

3.7.3.9 Multiple Supported Equipment Components with Distinct Inputs

3.7.3.9.1 Multiple Supported Equipment Components with Distinct Inputs (NSSS)

The procedure and criteria for analysis has been described in Section 3.7.2.1.1.5.b.

3.7.3.9.2 Multiple Supported Equipment Components with Distinct Inputs (Non-NSSS)

For cable trays and HVAC ducts whose supports have two or more distinct inputs, a response spectrum curve envelopes the curves at all support locations. When a piping system whose supports have two or more distinct inputs, a response spectrum curve may be used for analysis that envelopes the curves at all locations. Alternatively, except as restricted by Section 3.7.1.3.3, the multiple response spectra/independent support motion method of analysis may be used where distinct response spectra are applied to the piping system attachment points. Section 4 of Reference 3.7-4 discusses the methods used for the analysis of multiple supported piping due to differential seismic anchor movement.

3.7.3.10 Use of Constant Vertical Static Factors

3.7.3.10.1 Use of Constant Vertical Static Factors (NSSS)

Constant vertical static factors are not used for NSSS components.

3.7.3.10.2 Use of Constant Vertical Static Factors (Non-NSSS)

Constant vertical static factors are not used in the seismic design of subsystems.

3.7.3.11 Torsional Effects of Eccentric Masses

3.7.3.11.1 Torsional Effects of Eccentric Masses (NSSS)

Torsional effects of eccentric masses is discussed in Section 3.7.3.3.1.1.

3.7.3.11.2 Torsional Effects of Eccentric Masses (Non-NSSS)

The torsional effects of valves and other eccentric masses are considered in the seismic analysis of piping by the techniques discussed in section 3.2 of Reference 3.7-4.

3.7.3.12 Buried Seismic Category I Piping Systems and Tunnels (Non-NSSS)

Buried seismic Category I piping is analyzed and designed for seismic effects in accordance with section 6.0 of Reference 3.7-2. For portions of buried piping in soil, the soil response along the pipeline is determined in accordance with the procedure in Section 2.5.4.7.1.

The diesel oil storage tank structures and the ESW/RHRSW pipe tunnel (located beneath the diesel generator enclosure) are seismic Category I and are analyzed using an equivalent static load method.

Other tunnels at LGS are nonseismic Category I.

3.7.3.13 Interaction of other Piping with Seismic category I Piping

3.7.3.13.1 Interaction of other Piping with seismic Category I Piping (NSSS)

When other piping is attached to seismic Category I piping, the other piping is analytically simulated in a manner that does not significantly degrade the accuracy of the seismic Category I piping analysis. Furthermore, the other piping is designed to withstand the SSE without failing in a manner that would cause the seismic Category I piping to fail.

3.7.3.13.2 Interaction of Other Piping with seismic Category I Piping (Non-NSSS)

The techniques used to consider the interaction of seismic Category I piping with non-Category I piping are as follows:

Seismic boundary anchors are designed for the combined loads generated from both sides of a boundary anchor. The loads from the seismic Category I side are actual calculated loads, and the loads from the nonseismic Category I side are determined by one of the following:

a. The actual calculated seismic loads if the nonseismic side piping is dynamically analyzed for seismic events

b. The actual calculated loads if the nonseismic side piping is designed to a conservative simplified seismic design criteria (e.g., by simplified span methods such as those used for designed of small piping)

c. The loads determined by the plastic capability of the piping.

3.7.3.14 Seismic Analysis for Reactor Internals (NSSS)

The modeling of RPV internals is discussed in section 3.7.2.3.1.2. The damping values are given in Table 3.7-1.

3.7.3.15 Analysis Procedures for Damping

3.7.3.15.1 Analysis Procedures for Damping (NSSS)

Analysis procedures for damping are discussed in section 3.7.2.15.1.

3.7.3.15.2 Analysis Procedure for Damping (Non-NSSS)

If the equipment damping is unknown, the response spectrum curve for 0.5% damping is used to arrive at a conservative seismic loading. The damping values used for the OBE are increased for the SSE, where sufficient justification is established.

3.7.4 SEISMIC INSTRUMENTATION

3.7.4.1 Comparison with Seismic Monitoring System Regulatory Guides

The seismic monitoring system instrumentation was designed to comply with the intent of Regulatory Guide 1.12 (Rev. 2), Regulatory Guide 1.166 and Regulatory Guide 1.167.

3.7.4.1.1 Comparison to Regulatory Guide 1.12, Rev. 2

Regulatory Guide 1.12 describes the seismic instrumentation that is acceptable to the NRC for satisfying the requirements of Part 20 and Appendix S to Part 50. Limerick is in compliance with the guidance with this Reg Guide and takes no exceptions.

3.7.4.1.2 Comparison to Regulatory Guide 1.166

Regulatory Guide 1.166 describes the pre-earthquake planning and post earthquake responses to a seismic event. The Reg Guide states that the response spectrum and Cumulative Absolute Velocity (CA V) be calculated to determine OBE exceedance. Limerick is in compliance with the guidance with this Reg Guide and takes no exceptions.

3.7.4.1.3 Comparison to Regulatory Guide 1.167

Regulatory Guide 1.167 describes the guidance on the restart of a nuclear reactor after a seismic event. Limerick is in compliance with the guidance with this Reg Guide and takes no exceptions.

3.7.4.2 Location and Description of Instrumentation

The following instrumentation is provided for Unit 1 only, as essentially the same response is expected at Unit 2.

a. Six triaxial time history Strong Motion Recorders with built in sensors.

b. One response spectrum analyzer (software run on local laptop computer).

c. A system control panel which provides seismic event visual and audible annunciators.

d. Analysis software for monitoring of equipment and determination of exceedance of QBE based on CAV and response spectra.

All instrument characteristics meet the requirements of Regulatory Guide 1.12, Rev. 2, Section 4.0.

The operability of the seismic monitoring instrumentation ensures that sufficient capability is available to promptly determine the magnitude of a seismic event and evaluate the response of those features important to safety. This capability is required to permit comparison of the measured response to that used in the design basis for the unit.

3.7.4.2.1 Triaxial Time History Strong Motion Recorders

Triaxial time history Strong Motion Recorders (SMR) contain solid state seismic sensors and they measure and record the time varying acceleration at the sensor location. This data is stored locally and then sent to the main control panel when requested by the system for conversion and comparison with reference information. Each SMR contains a three axis solid state accelerometer mounted inside the SMR. All SMR's have their principal axes oriented identically, with one horizontal axis parallel to the major horizontal axis assumed in the seismic analysis. The SMR's are located as shown in table 3. 7-28.

3.7.4.2.2 Remote Triaxial Time History Strong Motion Recorders

There are two self contained Strong Motion Recorders (SMR) located in the Spary Pond Pump House. The Spray Pond Pump House is the Alternate Category 1 building being monitored per Reg Guide 1.12. The first SMR is located at the building foundation at elevation 237' and the second SMR is located at elevation 268'. These two SMR's are not connected to the seismic control panel in the Main Control Room (MCR). These SMR are accessible by a dedicated laptop for download of the time history seismic response.

3.7.4.2.3 Triaxial Seismic Switch (DELETED)

3.7.4.2.4 Response Spectrum and CAV Analyzer

The response spectrum and CAV analyzer is software that resides in the Network Control Center (NCC) and Earthquake Analysis PC which is located in the seismic control panel in the MCR. This software is used for calculation of CAV based on the recorded seismic response to an earthquake, and to compare the recorded data with the site design spectra for each of the connected SMRs location. It determines if the response spectra or CAV has exceeded the OBE criteria for signaling the local annunciator to alarm.

3.7.4.2.5 System Control Panel

A panel located in the control room (OO-C693) houses the monitoring, and spectrum analysis units which are used in conjunction with the SMR sensors to produce a time history and frequency-amplitude record of the seismic event. The panel also contains display and alarm equipment associated with the NCC, Earthquake Analysis PC, and the system power supply units.

3.7.4.3 Control Room Operator Notification

Activation of the seismic monitoring system causes an audible and visual annunciation in the control room alerting plant operators in the MGR to the seismic monitoring system panel.

Should the system or seismic SMRs develop errors or equipment failures, the system will activate an audible and visual Trouble alarm at the Seismic Control panel.

Should the system sense a seismic event from the Free Field or the reactor building foundation sensor, of a large enough magnitude, the system will activate an audible and visual System Triggered alarm at the Seismic Control panel.

Should the system sense and analyze a seismic event that exceeds the OBE limits, the system will activate an audible and visual OBE Exceeded alarm at the Seismic Control panel.

The spray pond pump house SMRs are not interconnected, and have only local indication of error, data, run, and power. The locally recorded data from these two SMRs can be downloaded and analyzed.

3.7.4.4 Comparison of Measured and Predicted Responses

Initial determination of the seismic event level is performed immediately after the event by comparing the measured response spectra from the Free Field with the calculated OBE and SSE response spectra for the corresponding location. An outline of the order of actions to be taken after a seismic event is provided in Figure 3.7-44.

3.7.4.5 Controls

Applicability: The seismic monitoring instrumentation shall be operable at all times. This instrumentation is considered operable when it is capable of performing its specified functions and when all necessary attendant instrumentation, controls, electrical power, cooling or seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its functions are also capable of performing their related support functions.

Actions: For requirements when one or more seismic monitoring instruments are inoperable, reference the TRM actions.

3.7.4.6 Surveillance Requirements

Each of the seismic monitoring instruments shall be demonstrated operable by the performance of the channel check, channel functional test and channel calibration at the frequencies shown and defined in Table 3.7-29.

Each of the seismic monitoring instruments which is accessible during power operation and which is actuated during a seismic event greater than or equal to 0.01g, and which does not self-reset, shall be restored to operable status within 24 hours and a channel calibration performed within 5 days following the seismic event. Data shall be retrieved from the actuated instruments and analyzed to determine the magnitude of the vibratory ground motion. A Special Report shall be prepared and submitted to the Nuclear Regulatory Commission pursuant to Specification 6.9.2 of the Technical Specifications within ten days describing the magnitude, frequency spectrum and resultant effect upon unit features important to safety.

3.7.5 REFERENCES

3.7-1 N.C, Tsai, "Spectrum Compatible Motions for Design Purposes", Journal of Engineering Mechanics Division, ASCE, Vol, 98, No. EM2, Proc, Paper 8807, pp. 345-356 (April 1972) .

3.7-2 "Seismic Analyses of Structures and Equipment for Nuclear Power Plants", BC-TOP-4A, Rev. 3, Bechtel Power Corporation, San Francisco, California, (November 1974).

3.7-3 "Uniform Building Code", by International Conference of Building Officials, Whittier, California, 1970 Edition.

3.7-4 "Seismic Analysis of Piping Systems" BP-TOP-1 Rev. 3. Bechtel Power Corporation, San Francisco, California, (January 1976).

3.7-5 L.K. Liu, "Seismic Analysis of the Boiling Water Reactor", Symposium on Seismic Analysis of Pressure Vessel and Piping Components, First National Congress on Pressure Vessel and Piping, San Francisco, California, (May 1971).

3.7-6 N.M. Newmark, "Design Criteria for Nuclear Reactors Subject to Earthquake Hazards", Proc IAEA Panel on Aseismic Design and Testing of Nuclear Facilities, Japan Earthquake Engineering Promotion Society, Tokyo, Japan, (1967).

3.7-7 "Development of Analysis and Design Techniques from Dynamic Testing of Electrical Raceway Support Systems", Technical Report, Bechtel Power Corporation, (July 1979).

3.7-8 Cable Tray and Conduit Raceway Seismic Test Program- Release 4", Test Report #1053-21.1-4, Volumes 1 and 2, ANCO Engineers, Inc., (December 15, 1978).

3.7-9 P.Y. Hatago and G.S. Reimer, "Dynamic Testing of Electrical Raceway Support Systems for Economical Nuclear Power Plant Installations", presented at the IEEE-PES, (February 4-9, 1979).

3.7-10 "Cable Tray and Conduit Raceway Seismic Test Program- Release 4", Addendum to Test Report #1053-21.1-4, Volume 3, ANCO Engineers, Inc., (May 1980).

3.7-11 "Cable Trays Seismic Qualification Report for the Limerick Generating Station Units 1 and 2", Specification 8031-E-49, P-W Industries, Inc., (September 18, 1975).

3.7-12 "Safety Evaluation Report Relating to the Use of ASME Code Case N-411 for Limerick Generating Station, Unit 2", R.M. Bernero (NRC), (March 27, 1987).

3.7-13 NRC Letter to PECO, dated April 10, 1991, Snubber Reduction Program, Limerick Generating Station, Unit 1 (TAC No. 80069).

Table 3.7-1

CRITICAL DAMPING VALUES FOR NSSS MATERIALS[1,2]

ITEM	CRITICAL DAMPING (%) OBE CONDITION	SSE CONDITION
Reinforced concrete structures	2.0	5.0
Welded structural assemblies (equipment and supports)	1.0	2.0
Bolted or riveted structural assemblies	2.0	3.0
Vital piping systems	0.5	1.0
Drywell (coupled)	2.0	5.0
RPV support skirt, shroud head, separator, and guide tubes	2.0	2.0
CRD housings	3.5	3.5
Fuel	7.0	7.0
Steel frame structures	2.0	3.0

(1) Other values may be used if they are indicated to be reliable by experiment or study.

(2) Alternative critical damping values for piping systems may be used as described in Section 3.7.1.3.3.

Table 3.7-2

CRITICAL DAMPING VALUES FOR NON-NSSS MATERIALS[1]

ITEM	CRITICAL DAMPING (%) OBE CONDITION	SSE CONDITION
Equipment	0.5	1
Piping systems	0.5	1
Welded steel structures	2	5
Bolted steel structures	3	7
Reinforced concrete structures (except as noted below for specific loading conditions in primary containment)	2	5
Primary containment (for those loading conditions in which DBA and seismic loadings are combined)	3	7

(1) Alternative critical damping values for piping systems may be used as described in Section 3.7.1.3.3

Table 3.7-3

LOAD COMBINATIONS AND ALLOWABLE RESPONSES FOR ELECTRICAL RACEWAY SYSTEM

Equation	Condition	Load Combination[1]	Allowable Response[1]
1	Normal	D+L	F_s[4]
2[5]	Normal/ Severe	D+E	[2,4]
3	Abnormal/ Extreme	D+E'	[2,3,4]

(1) For notations, see Tables 3.8-2 and 3.8-9.

(2) The following equation is applicable for bending in overhead connections:

$$\frac{5n_{EQ}}{N_{OBE}} + \frac{n_{EQ}}{N_{SSE}} \leq 1.0$$

where:

n_{EQ} = Total number of load/stress cycles per earthquake.

N_{OBE} = Allowable number of load/stress cycles per OBE event.

N_{SSE} = Allowable number of load/stress cycles per SSE event.

(3) The following criteria are used for checking the members. In no case shall the allowable stress exceed 0.90 F_y in bending, 0.85 F_y in axial tension or compression, and 0.50 F_y in shear. Where the design is governed by requirements of stability (local or lateral buckling), the actual stress shall not exceed 1.5 F_s.

(4) Allowable shear and normal loads in connections are determined from the manufacturers' data or from code allowable stresses, whichever is applicable. The allowable values are increased 50% for load combination equation 3.

(5) Equation 2 applies only to connections for fatigue considerations.

Table 3.7-4

RESULTS OF FATIGUE CALCULATIONS FOR THE MOST LIMITING BWR/4 COMPONENT

BWR/4 RPV FEEDWATER NOZZLE[1]	
Loading	Fatigue Usage
10 OBE Cycles	0.006
All Others[2]	0.967
Total	0.973

(1) The most limiting calculation for the BWR/4 product line.

(2) All other fatigue contributions due to SRV, thermal operating transients, etc.

Table 3.7-5

NATURAL FREQUENCIES OF PRIMARY CONTAINMENT BELOW 33 Hz

MODE NO.	FREQUENCY (Hz)			
	HORIZONTAL		VERTICAL	
	UNCRACKED	CRACKED	UNCRACKED	CRACKED
1	4.496	2.878	10.620	7.731
2	8.545	7.589	17.573	12.857
3	15.393	9.864	-	19.809
4	17.831	14.836	-	26.954
5	27.389	17.221	-	-
6	29.135	22.085	-	-
7	-	23.735	-	-
8	-	28.448	-	-
9	-	31.175	-	-

Table 3.7-6

NATURAL FREQUENCIES OF THE REACTOR ENCLOSURE AND CONTROL STRUCTURE BELOW 33 Hz

MODE NO.	FREQUENCY (Hz) VERTICAL	N-S	E-W
1	1.993	2.495	3.235
2	3.007	7.757	10.515
3	3.272	11.531	15.108
4	3.888	16.119	22.063
5	4.043	21.310	30.057
6	4.154	28.090	-
7	4.262	-	-
8	4.314	-	-
9	4.546	-	-
10	4.575	-	-
11	4.630	-	-
12	4.862	-	-
13	5.088	-	-
14	5.959	-	-
15	7.949	-	-
16	9.339	-	-
17	9.975	-	-
18	10.069	-	-
19	10.112	-	-
20	10.329	-	-
21	10.618	-	-
22	10.661	-	-
23	10.814	-	-
24	11.053	-	-
25	11.333	-	-
26	12.553	-	-
27	12.998	-	-
28	13.254	-	-
29	13.328	-	-
30	13.527	-	-
31	13.731	-	-
32	13.882	-	-
33	13.923	-	-
34	14.896	-	-
35	17.918	-	-
36	22.877	-	-
37	24.077	-	-
38	25.244	-	-
39	30.395	-	-

Table 3.7-7

PRIMARY CONTAINMENT SEISMIC INERTIA FORCES, DISPLACEMENTS, AND ACCELERATIONS (HORIZONTAL DIRECTION)

	INERTIA FORCES (kips)				DISPLACEMENTS (10^{-2} ft)				ACCELERATIONS (g)			
	UNCRACKED CONDITION		CRACKED CONDITION		UNCRACKED CONDITION		CRACKED CONDITION		UNCRACKED CONDITION		CRACKED CONDITION	
MASS POINT	OBE	SSE	OBE	SSE	OBE	SSE	OBE	SSE	OBE	SSE	OBE	SSE
1	141	230	179	269	1.738	2.663	4.330	6.125	0.735	1.193	0.928	1.390
2	669	1083	816	1216	1.650	2.525	4.038	5.750	0.685	1.108	0.835	1.245
3	1346	2165	1481	2169	1.513	2.313	3.625	5.163	0.610	0.980	0.670	0.981
4	1321	2098	1330	1913	1.338	2.050	3.113	4.425	0.509	0.808	0.511	0.736
5	1114	1749	1254	1854	1.189	1.813	2.713	3.850	0.428	0.671	0.481	0.771
6	971	1520	1105	1658	1.054	1.613	2.325	3.313	0.361	0.566	0.411	0.618
7	739	1151	913	1360	0.941	1.438	2.050	2.925	0.308	0.480	0.380	0.566
8	733	1160	868	1275	0.848	1.300	1.813	2.575	0.306	0.488	0.363	0.533
9	649	1038	771	1135	0.773	1.184	1.613	2.300	0.300	0.480	0.358	0.526
10	2251	3631	2624	3850	0.700	1.074	1.425	2.038	0.291	0.470	0.340	0.498
11	993	1614	1171	1730	0.551	0.849	1.061	1.513	0.258	0.419	0.305	0.450
12	1153	1895	1463	2226	0.405	0.625	0.713	1.019	0.219	0.360	0.279	0.424
13	1271	2156	1356	2110	0.263	0.409	0.378	0.543	0.186	0.315	0.199	0.309
14	1976	3431	1509	2410	0.160	0.251	0.148	0.215	0.150	0.260	0.114	0.183
15	200	333	179	264	1.713	2.788	3.850	5.488	0.714	1.186	0.636	0.941
16	326	536	281	413	1.588	2.425	3.238	4.600	0.573	0.940	0.493	0.724
17	293	473	290	421	1.313	2.013	2.663	3.788	0.469	0.758	0.465	0.675
18	234	375	251	364	1.159	1.775	2.363	3.363	0.409	0.655	0.439	0.635
19	233	376	240	353	0.915	1.400	1.838	2.613	0.346	0.563	0.359	0.526
20	188	306	238	366	0.534	0.823	0.989	1.413	0.266	0.435	0.339	0.523
21	280	469	355	565	0.379	0.586	0.615	0.885	0.244	0.409	0.310	0.493
22	384	661	411	664	0.244	0.380	0.310	0.449	0.200	0.345	0.215	0.346
23	560	876	445	644	3.325	5.075	5.425	7.713	1.249	2.113	1.073	1.550
24	866	1334	755	1081	2.713	4.150	4.588	6.525	0.991	1.526	0.864	1.238
25	896	1413	793	1143	2.150	3.288	3.788	5.388	0.816	1.286	0.721	1.040
26	764	1223	720	1045	1.634	2.513	3.063	4.350	0.628	1.005	0.591	0.859
27	-	-	-	-	1.413	2.163	2.738	3.900	-	-	-	-
28	-	-	-	-	1.159	1.775	2.363	3.363	-	-	-	-
29	-	-	-	-	1.011	1.550	2.088	2.963	-	-	-	-
30	-	-	-	-	0.709	1.088	1.400	2.000	-	-	-	-
31	-	-	-	-	0.160	0.251	0.148	0.215	-	-	-	-
32	-	-	-	-	3.213	4.900	5.275	7.488	-	-	-	-
33	-	-	-	-	1.663	2.563	4.100	5.828	-	-	-	-
34	-	-	-	-	1.216	1.863	2.450	3.482	-	-	-	-

Table 3.7-8

PRIMARY CONTAINMENT SEISMIC DISPLACEMENTS AND ACCELERATIONS
(VERTICAL DIRECTION)

	DISPLACEMENTS (10^{-2} ft)				ACCELERATIONS (g)			
	UNCRACKED CONDITION		CRACKED CONDITION		UNCRACKED CONDITION		CRACKED CONDITION	
MASS POINT	OBE	SSE	OBE	SSE	OBE	SSE	OBE	SSE
1	0.133	0.201	0.386	0.551	0.205	0.318	0.395	0.591
2	0.133	0.200	0.386	0.551	0.204	0.316	0.394	0.589
3	0.133	0.200	0.376	0.535	0.201	0.314	0.368	0.543
4	0.131	0.198	0.353	0.500	0.198	0.305	0.321	0.466
5	0.129	0.195	0.329	0.466	0.193	0.298	0.285	0.411
6	0.128	0.191	0.304	0.433	0.188	0.289	0.258	0.373
7	0.125	0.189	0.284	0.404	0.184	0.283	0.244	0.355
8	0.123	0.185	0.264	0.375	0.180	0.275	0.233	0.343
9	0.121	0.183	0.245	0.349	0.175	0.269	0.221	0.326
10	0.119	0.179	0.226	0.321	0.171	0.261	0.206	0.308
11	0.114	0.171	0.190	0.271	0.165	0.251	0.178	0.264
12	0.109	0.164	0.155	0.220	0.159	0.243	0.151	0.224
13	0.103	0.155	0.116	0.168	0.150	0.231	0.129	0.198
14	0.098	0.148	0.088	0.125	0.145	0.223	0.109	0.166
15	0.169	0.266	0.171	0.243	0.260	0.403	0.238	0.345
16	0.168	0.255	0.170	0.241	0.256	0.398	0.235	0.341
17	0.165	0.250	0.168	0.238	0.249	0.385	0.228	0.329
18	0.163	0.248	0.166	0.235	0.248	0.375	0.223	0.320
19	0.155	0.235	0.155	0.220	0.234	0.360	0.200	0.288
20	0.146	0.223	0.144	0.203	0.221	0.343	0.180	0.259
21	0.138	0.203	0.128	0.180	0.201	0.310	0.154	0.223
22	0.121	0.183	0.113	0.160	0.179	0.275	0.138	0.203
23	0.108	0.161	0.099	0.140	0.155	0.238	0.121	0.183
24	0.184	0.280	0.186	0.264	0.293	0.459	0.275	0.405
25	0.183	0.278	0.185	0.261	0.289	0.451	0.270	0.398
26	0.179	0.271	0.181	0.256	0.278	0.433	0.259	0.378
27	0.174	0.264	0.176	0.250	0.266	0.413	0.245	0.356
28	0.159	0.241	0.161	0.228	-	-	-	-
29	0.170	0.258	0.173	0.248	-	-	-	-
30	0.165	0.250	0.168	0.238	-	-	-	-

Table 3.7-9

PRIMARY CONTAINMENT SHEAR FORCES AND MOMENTS

JOINT NO.	MEMBER NO.	SHEAR FORCES (kips) UNCRACKED CONDITION OBE	SHEAR FORCES (kips) UNCRACKED CONDITION SSE	SHEAR FORCES (kips) CRACKED CONDITION OBE	SHEAR FORCES (kips) CRACKED CONDITION SSE	MOMENTS (10^3k-ft) UNCRACKED CONDITION OBE	MOMENTS (10^3k-ft) UNCRACKED CONDITION SSE	MOMENTS (10^3k-ft) CRACKED CONDITION OBE	MOMENTS (10^3k-ft) CRACKED CONDITION SSE
	1	141	230	179	269	0	0	0	0
33						0.9	1.5	1.1	1.8
	34	628	966	966	796	2.0	3.1	2.3	3.3
2						16.3	25.9	18.8	27.6
	2	1,098	1,746	1,274	1,876	70.1	110.5	73.3	106.9
3						125.5	198.1	130.5	189.6
	3	3,454	5,438	3,475	5,060	184.3	291.1	189.1	273.3
4						237.9	375.9	239.8	344.6
	4	4,261	6,744	4,408	6,364	300.9	474.6	291.1	416.8
5						359.1	565.3	338.9	477.1
	5	5,179	8,183	4,974	7,133	418.6/ 420.5	657.5/ 654.6	374.4/ 371.6	534.1/ 530.4
6						546.4	850.9	453.4	646.0
	6	6,095	9,584	5,366	7,684	680.4	1052.8	543.9	776.0
7						807.0	1260.0	641.5	914.6
	7	6,749	10,561	6,061	8,735	919.0	1411.3	708.4	1008.5
8						0.0	0.0	0.0	0.0
	8	7,285	11,345	6,614	9,558	20.5	31.9	20.8	29.9
9									
	9	7,715	11,995	6,944	10,038				
10									
	10	9,278	14,263	7,835	11,308				
11									
	11	10,019	15,438	8,716	12,538				
12									
	12	11,085	17,163	9,455	13,500				
13									
	13	12,153	18,900	10,693	15,400				
14									
15									
	14	1,041	1,618	1,055	1,516				
16									
	15	814	1,285	813	1,173				

Table 3.7-9 (Cont'd)

JOINT NO.	MEMBER NO.	SHEAR FORCES (kips) UNCRACKED CONDITION OBE	UNCRACKED CONDITION SSE	CRACKED CONDITION OBE	CRACKED CONDITION SSE	MOMENTS (10^3k-ft) UNCRACKED CONDITION OBE	UNCRACKED CONDITION SSE	CRACKED CONDITION OBE	CRACKED CONDITION SSE
17						36.6	57.1	36.9	53.0
	16	616	995	569	829				
18						41.8/ 14.5	65.4/ 29.0	41.9/ 23.8	60.1/ 34.6
	17	1,565	2,440	1,394	2,000				
29						26.8	41.8	30.9	44.6
	18	1,565	2,440	1,394	2,000				
19		1,754	2,743	1,621	2,329				
30						55.0/ 46.9	84.6/ 72.3	47.6/ 37.4	74.3/ 68.3
	20	431	700	1,353	1,978				
20						42.5	65.4	55.9	80.0
	21	485	765	1,441	2,076				
21						39.0	60.0	65.1	93.5
	22	685	1,085	1,630	2,351				
22						34.6	53.0	78.5	112.0
	23	1,041	1,688	2,041	3,014				
31						44.4	68.5	96.1	137.5
23						0.0	0.0	0.0	0.0
	25	560	876	445	644				
32						1.8	2.8	1.4	2.0
	26	159	268	139	209				
24						2.4	4.1	2.0	3.1
	27	425	680	338	490				
25						9.9	16.1	8.0	11.9
	28	1,168	1,805	996	1,426				
26						26.6	41.5	20.9	30.1
	29	1,889	2,950	1,676	2,408				
27						37.4	57.5	31.5	45.1
	30	1,899	2,950	1,676	2,408				
34						49.4	76.1	42.1	60.3
	31	1,899	2,950	1,676	2,408				
28						52.6	81.1	45.0	64.4
10						1.9	2.9	2.8	3.9
	32	968	1,484	708	1,009				
30						8.1	12.4	4.3	6.3
	33	95,713	146,875	79,175	112,675				

Table 3.7-10

PRIMARY CONTAINMENT AXIAL FORCES

MEMBER NO.	AXIAL FORCE (kips) UNCRACKED CONDITION		CRACKED CONDITION	
	OBE	SSE	OBE	SSE
1	40	61	76	114
2	239	370	461	690
3	684	1063	1273	1889
4	1196	1854	2086	3063
5	1698	2626	2793	4064
6	2196	3393	3426	4953
7	2635	4064	3909	5615
8	3060	4711	4326	6186
9	3430	5273	4706	6735
10	4245	6513	5368	7680
11	4865	7450	5810	8304
12	5443	8319	6286	9003
13	5900	9003	6528	9345
14	73	113	66	96
15	219	340	240	291
16	374	579	341	495
17	1491	2310	1376	1998
18	1491	2310	1376	1998
19	1641	2539	1506	2181
20	2123	3269	1918	2755
21	2256	3474	2015	2889
22	2381	3661	2093	2944
23	2511	3854	2154	3071
24	118	185	110	164
25	331	519	311	459
26	429	670	401	590
27	988	1538	919	1341
28	988	1538	919	1341
29	988	1538	919	1341

Table 3.7-11

REACTOR ENCLOSURE AND CONTROL STRUCTURE E-W INERTIA FORCES, DISPLACEMENTS, AND ACCELERATIONS

	INERTIA FORCES (k)		DISPLACEMENTS (10^{-2} ft)		ACCELERATIONS (g)	
MASS POINT	OBE	SSE	OBE	SSE	OBE	SSE
1	8,840	14,393	0.412	0.637	0.184	0.300
2	6,681	10,574	0.736	1.140	0.250	0.396
3	10,605	16,776	0.957	1.470	0.290	0.459
4	1,446	2,269	1.260	1.940	0.314	0.493
5	11,955	18,851	1.450	2.240	0.341	0.538
6	1,660	2,600	1.650	2.540	0.332	0.520
7	11,794	18,564	1.830	2.810	0.350	0.551
8	1,718	2,689	2.060	3.180	0.336	0.526
9	21,634	33,907	2.160	3.330	0.334	0.524
10	2,729	4,250	2.290	3.520	0.338	0.527
11	25,796	40,472	2.440	3.760	0.395	0.620
12	17,795	27,783	3.020	4.650	0.658	1.027

Table 3.7-12

REACTOR ENCLOSURE AND CONTROL STRUCTURE N-S INERTIA FORCES, DISPLACEMENTS, AND ACCELERATIONS

	INERTIA FORCES (k)		DISPLACEMENTS (10^{-2} ft)		ACCELERATIONS (g)	
MASS POINT	OBE	SSE	OBE	SSE	OBE	SSE
1	8,354	13,645	0.419	0.647	0.174	0.284
2	6,791	10,735	0.932	1.440	0.302	0.475
3	11,026	17,361	1.300	2.000	0.302	0.475
4	1,475	2,311	1.800	2.760	0.320	0.502
5	12,320	19,355	2.120	3.270	0.351	0.552
6	1,809	2,841	2.470	3.800	0.361	0.568
7	12,469	19,661	2.770	4.270	0.370	0.584
8	1,892	2,945	3.210	4.940	0.370	0.576
9	26,060	40,829	3.410	5.250	0.403	0.631
10	2,996	4,638	3.740	5.750	0.371	0.575
11	29,068	45,167	4.140	6.370	0.445	0.692
12	20,473	31,545	5.510	8.470	0.757	1.166

Table 3.7-13

REACTOR ENCLOSURE AND CONTROL STRUCTURE VERTICAL INERTIA FORCES, DISPLACEMENTS, AND ACCELERATIONS

	INERTIA FORCES (k)		DISPLACEMENTS (10^{-2} ft)		ACCELERATIONS (g)	
MASS POINT	OBE	SSE	OBE	SSE	OBE	SSE
1	6,320	10,050	0.232	0.359	0.133	0.211
2	2,961	4,682	0.264	0.409	0.147	0.232
3	2,765	4,355	0.286	0.443	0.154	0.243
4	534	838	0.317	0.491	0.166	0.260
5	3,315	5,199	0.336	0.521	0.172	0.271
6	446	697	0.356	0.552	0.178	0.278
7	2,804	4,383	0.373	0.578	0.184	0.287
8	632	990	0.399	0.618	0.196	0.308
9	2,943	4,616	0.409	0.634	0.202	0.316
10	928	1,457	0.426	0.660	0.211	0.332
11	4,760	7,486	0.439	0.681	0.219	0.345
12	3,242	5,167	0.462	0.717	0.248	0.396
13	675	1,077	0.272	0.422	0.149	0.238
14	687	1,098	0.316	0.489	0.164	0.262
15	1,035	1,649	0.541	0.838	0.238	0.380
16	606	952	0.751	1.161	0.287	0.451
17	2,204	3,460	0.988	1.529	0.448	0.704
18	73	114	1.109	1.715	0.503	0.787
19	38	60	1.228	1.898	0.589	0.918
20	3,933	6,153	0.985	1.524	0.378	0.591
21	2,911	4,581	1.249	1.932	0.496	0.781
22	4,743	7,407	0.835	1.292	0.298	0.464
23	4,759	7,431	0.840	1.299	0.297	0.465
24	2,917	4,589	1.255	1.941	0.497	0.782
25	3,948	6,176	0.989	1.530	0.379	0.594
26	2,899	4,476	3.560	5.495	0.836	1.291
27	6,994	10,800	2.693	4.157	0.689	1.064
28	1,925	2,982	0.645	0.997	0.550	0.852
29	4,077	6,334	0.585	0.906	0.471	0.732
30	2,980	4,611	0.787	1.216	0.534	0.827
31	2,906	4,498	0.749	1.158	0.387	0.599
32	1,001	1,548	0.956	1.477	0.551	0.852
33	2,312	3,573	1.112	1.717	0.653	1.009
34	3,908	6,057	1.226	1.895	0.774	1.154
35	717	1,120	1.332	2.062	0.725	1.132
36	1,363	2,106	1.900	2.934	0.703	1.087
37	2,120	3,305	1.406	2.175	0.696	1.085
38	488	756	0.995	1.538	0.334	0.517
39	909	1,419	0.910	1.408	0.351	0.548
40	1,212	1,875	0.777	1.201	0.677	1.047
41	956	1,477	2.231	3.445	0.276	0.427
42	1,283	1,981	2.488	3.842	0.649	1.001
43	967	1,494	1.981	3.058	0.468	0.723

Table 3.7-13 (Cont'd)

MASS POINT	INERTIA FORCES (k)		DISPLACEMENTS (10^{-2} ft)		ACCELERATIONS (g)	
	OBE	SSE	OBE	SSE	OBE	SSE
44	3,060	4,723	5.016	7.743	1.062	1.639
45	1,594	2,460	2.356	3.637	0.633	0.978
46	1,680	2,593	3.501	5.405	1.028	1.587
47	3,144	4,854	3.105	4.794	0.712	1.098
48	893	1,379	2.489	3.844	0.375	0.580
49	490	759	0.999	1.544	0.335	0.519
50	899	1,403	0.905	1.401	0.347	0.542
51	2,122	3,308	1.404	2.171	0.697	1.086
52	713	1,113	1.333	2.063	0.721	1.126
53	2,510	4,020	3.994	6.418	0.215	0.344
54	455	720	0.842	1.317	0.958	1.516

Table 3.7-14

REACTOR ENCLOSURE AND CONTROL STRUCTURE E-W SHEAR FORCES AND MOMENTS

JOINT NO.	MEMBER NO.	SHEAR FORCE (10^2 k) OBE	SHEAR FORCE (10^2 k) SSE	MOMENTS (10^3 k-ft) OBE	MOMENTS (10^3 k-ft) SSE
1				11,040	17,000
	1	834	1,288		
2				9,486	14,600
	2	779	1,201		
3				8,439	12,990
	3	706	1,091		
4				7,032	10,830
	4	694	1,073		
5				6,146	9,474
	5	659	1,018		
6				5,162	7,966
	6	655	1,012		
7				4,306	6,654
	7	608	941		
8				3,098	4,797
	8	596	922		
9				2,589	4,013
	9	423	656		
10				1,794	2,781
	10	400	621		
11				1,032	1,611
	11	178	278		
12				0	0

Table 3.7-15

REACTOR ENCLOSURE AND CONTROL STRUCTURE N-S SHEAR FORCES AND MOMENTS

JOINT NO.	MEMBER NO.	SHEAR FORCE (10^2 k) OBE	SHEAR FORCE (10^2 k) SSE	MOMENTS (10^3 k-ft) OBE	MOMENTS (10^3 k-ft) SSE
				10,430	16,060
	1	832	1,283		
2				9,106	14,020
	2	780	1,204		
3				8,176	12,580
	3	719	1,111		
4				6,835	10,520
	4	712	1,100		
5				6,009	9,255
	5	640	988		
6				5,041	7,766
	6	628	969		
7				4,198	6,469
	7	592	915		
8				3,130	4,823
	8	584	902		
9				2,699	4,164
	9	448	693		
10				1,916	2,951
	10	423	655		
11				1,187	1,830
	11	205	316		
12				0	0

Table 3.7-16

REACTOR ENCLOSURE AND CONTROL STRUCTURE AXIAL FORCES

MASS POINT	AXIAL FORCE (k) OBE	SSE
1	62,283	96,586
2	47,396	73,527
3	44,400	68,961
4	40,645	63,210
5	39,736	61,810
6	35,719	55,599
7	34,779	54,144
8	31,475	49,013
9	30,699	47,814
10	20,903	32,677
11	18,163	24,838
12	5,162	8,273
13	13,581	21,050
14	12,796	19,810
15	12,484	19,305
16	11,121	17,201
17	6,483	10,053
18	4,009	6,203
19	3,454	5,354

Table 3.7-17

STRUCTURE-FOUNDATION INTERACTION COEFFICIENTS

STRUCTURE	MOTION			EQUIVALENT SPRING CONSTANT	EQUIVALENT DAMPING COEFFICIENT
Primary containment	Translational			4.15×10^{7} k/ft	2.01×10^{5} k-sec/ft
	Rocking			8.12×10^{10} k-ft/rad	7.82×10^{7} k-ft-sec/rad
	Vertical			4.87×10^{7} k/ft	3.48×10^{5} k-sec/ft
Reactor enclosure and control structure	Translational:		E-W	8.17×10^{7} k/ft	8.98×10^{5} k-sec/ft
			N-S	8.55×10^{7} k/ft	8.79×10^{5} k-sec/ft
	Rocking:	E-W		2.04×10^{12} k-ft/rad	9.23×10^{9} k-ft-sec/rad
		N-S		6.22×10^{11} k-ft/rad	2.63×10^{9} k-ft-sec/rad
	Vertical			9.90×10^{7} k/ft	1.74×10^{6} k-sec/ft

Table 3.7-18

NUMBER OF DYNAMIC RESPONSE CYCLES EXPECTED DURING
A SEISMIC EVENT
FOR NSSS SYSTEMS AND COMPONENTS

	FREQUENCY BAND WIDTH (Hz)		
	0-10	10-20	20-50
Total number of seismic cycles	168	359	643
Number of seismic cycles (0.5% of total) between 75% and 100% of peak load	0.8	1.8	3.2
Number of seismic cycles (4.5% of total) between 50% and 75% of peak load	7.5	16.2	28.9

Table 3.7-19

FATIGUE EVALUATION DUE TO SEISMIC LOAD

	COMPONENT	CALCULATED NO. OF CYCLES AT PEAK STRESS	DESIGN NO. OF PEAK STRESS CYCLES PER OBE
1.	Reactor Pressure Vessel		
	a. Vessel	See Table 3.7-18	10
	b. Shroud support	See Table 3.7-18	10
	c. Skirt	See Table 3.7-18	10
2.	Seismic Category I Piping		
	a. Recirculation lines	(1)	10
	b. Steam lines	(1)	10

(1) Design number of peak stress cycles used in analysis

Table 3.7-20

REACTOR ENCLOSURE AND CONTROL STRUCTURE - SEISMIC RESPONSE
COMPARISON OF 2-COMPONENT ABS VERSUS 3-COMPONENT SRSS METHODS

	Combined Axial and Bending Stresses on Concrete Wall Section Due to:			Total Seismic Stress (KSF) (Axial and Bending Stress on Concrete Wall Section)		
Elevation	SSE Vertical Excitation (P) (A) (KSF)	SSE N-S Excitation (Mc) I N-S (KSF)	SSE E-W Excitation (Mc) I E-W (KSF)	3 Component SRSS (Regulatory Guide 1.92)	2 Component ABS (Section 3.7.2.6)	% Difference
Reactor Enclosure Wall – Southwest Corner						
352	12.27	23.4	10.2	28.3	35.7	+26
333	0.92	18.6	13.4	22.9	19.5	-15
313	0.88	26.4	19.5	32.8	27.3	-17
304	13.85	26.5	22.1	37.2	40.4	+9
283	14.19	37.1	30.6	50.1	51.3	+2
269	14.56	43.4	33.0	56.4	58.0	+3
253	14.92	51.7	39.7	66.9	66.6	-
239	16.11	59.4	45.7	76.7	75.5	-2
217	16.44	71.4	55.2	91.7	87.8	-4
201	15.18	57.2	55.9	81.4	72.4	-11
177	14.35	63.1	64.2	91.2	78.6	-14
Control Structure – Northeast Corner						
352	12.27	25.4	3.9	28.5	37.7	+32
333	0.92	20.1	5.1	20.8	21.0	+1
313	0.88	29.1	7.5	30.1	30.0	-
304	13.85	29.8	8.5	33.9	43.7	+29
283	14.19	41.8	11.7	45.7	56.0	+23
269	14.56	45.6	12.6	49.5	60.2	+22
253	14.92	54.3	15.2	58.3	69.2	+19
239	16.11	61.9	17.5	66.3	78.0	+18
217	16.44	74.4	21.2	79.1	90.8	+15
201	15.18	74.7	21.4	79.2	89.9	+14
177	14.35	73.7	24.6	79.0	88.1	+12

Table 3.7-21

SPRAY POND PUMPHOUSE[1]

FREQUENCIES WITH AND WITHOUT ECCENTRICITIES

GLOBAL DIRECTION: E-W

MODE NO.	VIBRATION FREQUENCIES (CPS) 3-D MODEL WITH ECCENTRICITY	ORIGINAL MODEL WITHOUT ECCENTRICITY
1	17.8	18.2
2	41.8	42.3

(1) Figure 3.7-48

Table 3.7-22

DIESEL GENERATOR ENCLOSURE[1]

FREQUENCIES WITH AND WITHOUT ECCENTRICITIES

GLOBAL DIRECTION: E-W

	VIBRATION FREQUENCIES (CPS)	
MODE	ORIGINAL MODEL WITHOUT ECCENTRICITY	3-D MODEL WITH ECCENTRICITY
1	9.33	8.84
2	22.59	20.13
3	48.05	37.50

(1) Figure 3.7-49

Table 3.7-23

REACTOR ENCLOSURE[1]

FREQUENCIES WITH AND WITHOUT ECCENTRICITIES

GLOBAL DIRECTION: E-W

MODE NO.	VIBRATION FREQUENCIES (CPS) 3-D MODEL WITH ECCENTRICITY	ORIGINAL MODEL WITHOUT ECCENTRICITY
1	3.738	3.769
2	11.397	11.863
3	16.587	17.944
4	21.685	23.007
5	24.906	30.083

(1) Figure 3.7-50

Table 3.7-24

SPRAY POND PUMPHOUSE

COMPARISON OF TORSIONAL MOMENTS FROM
ORIGINAL DESIGN WITH VALUES OBTAINED
FROM 3-D MODEL WITH ECCENTRICITY

		TORSIONAL MOMENT (M_T, K-FT)	
DIRECTION	EARTHQUAKE	ORIGINAL DESIGN	3-D STICK MODEL
E-W	OBE	15,370	7,724
	DBE	27,620	14,230

Table 3.7-25

DIESEL GENERATOR ENCLOSURE

COMPARISON OF TORSIONAL MOMENTS FROM
ORIGINAL DESIGN WITH VALUES OBTAINED
FROM 3-D MODEL WITH ECCENTRICITY

		TORSIONAL MOMENT (M_T, K-FT)	
DIRECTION	EARTHQUAKE	ORIGINAL DESIGN	3-D STICK MODEL
E-W	OBE	96,804	74,940
	DBE	149,988	101,200

Table 3.7-26

REACTOR ENCLOSURE

COMPARISON OF TORSIONAL MOMENTS FROM
ORIGINAL DESIGN WITH VALUES OBTAINED
FROM 3-D MODEL WITH ECCENTRICITY

		TORSIONAL MOMENT (M_T, K-FT)	
DIRECTION	EARTHQUAKE	ORIGINAL DESIGN	3-D STICK MODEL
E-W	DBE (SSE)	$3.5X10^6$	$2.36X10^6$

Table 3.7-27

REACTOR ENCLOSURE

COMPARISON OF DESIGN SHEARS
AND SHEARS OBTAINED FROM 3-D MODEL
WITH ECCENTRICITY

SEISMIC EVENT - DBE

WALLS AT EL 177 FT (GROUND FLOOR)

WALL[1]	DESIGN SHEAR (KIPS)	SHEAR FROM 3-D MODEL WITH ECCENTRICITY (KIPS)
Line J	44,171	37,800
Line D	75,385	64,193
Line M_L	26,359	22,099

[1] Figure 3.7-50

TABLE 3.7-28

SEISMIC MONITORING INSTRUMENTATION

INSTRUMENTATION AND SENSOR LOCATIONS	MEASUREMENT RANGE	MINIMUM INSTRUMENTS OPERABLE
1. Triaxial Time-History Accelerometers (T/As)		
a. Sensors /Recorders		
1) XE-VA-131/XR-VA-131 Free Field (East of PPC)	+/- 4 g	1
2) XE-VA-132/XR-VA-132 Reactor Enclosure Foundation (Loc. 111-R11-177)	+/- 4 g	1
3) XE-VA-133/XR-VA-133 Reactor Enclosure Elevation "A" (Loc. 304-R 11-217)	+/- 4 g	1
4) XE-VA-134/XR-VA-134 Reactor Enclosure Elevation "B" (Loc. 506-R15-283)	+/- 4 g	1
5) XE-VA-135/XR-VA-135 Foundation of an Independent Seismic Category I Structure (Spray Pond Pump House, El 237')	+/- 4 g	1
6) XE-VA-136/XR-VA-136 Independent Seismic Cat. 1 Structure Elevation (Spray Pond Pump House, El 268')	+/- 4 g	1
2. Network Control Center/ Earthquake Analysis PC	0.1 - 100 Hz	1 *

* With reactor control room indication and annunciation. Receives signal from Strong Motion Recorders.

TABLE 3.7-29

SEISMIC MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTATION AND SENSOR LOCATIONS	CHANNEL* CHECK	CHANNEL** FUNCTIONAL TEST	CHANNEL*** CALIBRATION
1. Triaxial Time-History Accelerometers (T/As)			
a. Sensors /Recorders			
1) XE-VA-131/XR-VA-131 Free Field (East of PPC)	M	SA	R
2) XE-VA-132/XR-VA-132 Reactor Enclosure Foundation (Loc. 111-R 11-177)	M	SA	R
3) XE-VA-133/XR-VA-133 Reactor Enclosure Elevation "A" (Loc. 304-R11-217)	M	SA	R
4) XE-VA-134/XR-VA-134 Reactor Enclosure Elevation "B" (Loc. 506-R 15-283)	M	SA	R
5) XE-VA-135/XR-VA-135 Foundation of an Independent Seismic Category 1 Structure (Spray Pond Pump House, El 237')	M	SA	R
6) XE-VA-136/XR-VA-136 Independent Seismic Category I Structure (Spray Pond Pump House, El 268')	M	SA	R
2. Network Control Center/ Earthquake Analysis PC	M	SA	R

* Channel Check - The qualitative verification of the functional status of the instrument. This check is an "in situ" test and may be the same as a channel functional test.

** Channel Functional Test- (Secondary Calibration). The determination without adjustment that an instrument, sensor, or system responds to a known input of such character that it will verify the instrument, sensor, or system is functioning in a manner that can be calibrated.

*** Channel Calibration - (Primary Calibration). The determination and, if required, adjustment of an instrument, sensor, or system such that it responds within a specific range and accuracy to an acceleration, velocity, or displacement input, as applicable, or responds to an acceptable physical constant.

TABLE 3.7-29 (Cont'd)

SEISMIC MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

Surveillance Frequency Notation

Notation	Frequency
M	At least once per 31 days
SA	At least once per 184 days
R (Refueling Interval)	At least once per 24 months (731 days)

3.8 DESIGN OF CATEGORY I STRUCTURES

3.8.1 CONCRETE CONTAINMENT

3.8.1.1 Description of the Containment

The primary containment is divided by a horizontal diaphragm slab into two major volumes: the drywell and the suppression chamber. The drywell encloses the reactor vessel, reactor recirculation system, and associated piping and valves. The suppression chamber stores a large volume of water.

The primary containment, shown on Figures 3.8-1 through 3.8-8, is in the form of a truncated cone over a cylindrical section, with the drywell being the upper conical section and the suppression chamber being the lower cylindrical section. These two sections comprise a structurally integrated, reinforced concrete pressure vessel, lined with welded steel plate and provided with a steel domed head for closure at the top of the drywell. Connection of the drywell head to the top of the drywell wall is shown on Figure 3.8-9. The diaphragm slab is a reinforced concrete slab structurally connected to the containment wall, as shown on Figure 3.8-10.

The primary containment is structurally separated from the surrounding reactor enclosure.

The concrete dimensions of the primary containment are as follows:

a. Inside diameter

   1. Suppression chamber - 88'-0"

   2. Base of drywell - 86'-4"

   3. Top of drywell - 36'-4½"

b. Height

   1. Suppression chamber - 52'-6"

   2. Drywell - 87'-9"

c. Thickness

   1. Base foundation slab - 8'-0"

   2. Containment wall - 6'-2"

3.8.1.1.1 Base Foundation Slab

The containment base foundation slab is a reinforced concrete mat, the top of which is lined with carbon steel plate.

3.8.1.1.1.1 Reinforcement

The base foundation slab is reinforced with #18, Grade 60 rebar at the top and bottom faces. The maximum rebar spacing is 18 inches. Shear reinforcement consists of #8 and #9 vertical and inclined ties. Cadweld splices are used for splicing all main reinforcing bars. Figure 3.8-11 shows the plan and section views of reinforcement.

3.8.1.1.1.2 Liner Plate and Anchorages

The steel liner plate is ¼ inch thick, and is anchored to the concrete slab by structural steel beams embedded in the concrete and welded to the plate. Figure 3.8-12 shows details of the liner plate and anchorages.

3.8.1.1.1.3 Reactor Pedestal and Suppression Chamber Column, Base Liner Anchorages

Figures 3.8-13 and 3.8-14 show the base foundation slab liner anchorages for the reactor pedestal and the suppression chamber columns, respectively. For the pedestal anchorage, Cadweld sleeves are welded to the top and bottom surfaces of the thickened base liner to permit anchoring of the pedestal vertical rebar into the base foundation slab. Metal studs are welded to the top and bottom surfaces of the thickened base liner in order to transfer radial and tangential shear forces from the pedestal to the base foundation slab. For the suppression chamber column anchorage, pipe caps are welded to the thickened base liner at the locations where the column anchor bolts penetrate the base liner, in order to ensure the leak-tight integrity of the base liner.

3.8.1.1.2 Containment Wall

The containment wall is constructed of reinforced concrete 6'-2" thick, and is lined with carbon steel plate on the inside surface.

3.8.1.1.2.1 Reinforcement

The containment wall is reinforced with #18, Grade 60 rebar at the inner and outer faces. The inner rebar curtain consists of two meridional layers and one hoop layer. The outer rebar curtain consists of one meridional layer, two hoop layers, and two helical layers. Radial shear reinforcement consists of #6 horizontal and inclined ties. Cadweld splices are used for splicing all main reinforcing bars. Figures 3.8-15 and 3.8-16 show sections and developed elevation views of the suppression chamber wall reinforcement and drywell wall reinforcement, respectively.

3.8.1.1.2.2 Liner Plate and Anchorages

The steel liner plate is ¼ inch thick, and is anchored to the concrete wall by vertical stiffeners, using structural tees spaced horizontally every 2 feet, or less. Horizontal plate stiffeners provide additional stiffening. Figures 3.8-17 and 3.8-18 show details of the liner plate and anchorages.

Loads from internal containment attachments, such as beam seats and pipe restraints, are transferred directly into the containment concrete wall. This is accomplished by thickening the liner plate, and attaching structural weldments that transfer any type of load to the concrete, without relying on the liner plate or its anchorages. Where internal containment attachment loads are large, the structural weldments penetrate the liner plate, rather than being welded to opposite sides of the liner plate. This eliminates the possibility of lamellar tearing. Section 3.8.1.1.2.5 contains a further description of internal containment attachments.

3.8.1.1.2.3 Penetrations

Services and communications between the inside and the outside of the containment are performed through penetrations. Basic penetration types include pipe penetrations, electrical penetrations, and access hatches (equipment hatches, personnel lock, suppression chamber access hatches, and CRD removal hatch). Each penetration consists of a pipe sleeve with an annular ring welded to it. The ring is embedded in the concrete wall, and provides an anchorage for the penetration to resist normal operating and accident loads. The pipe sleeve is also welded to the containment liner plate to provide a leak-tight penetration.

Meridional and hoop reinforcement is bent around typical penetrations. Additional local reinforcement in the hoop and diagonal directions is added at all large penetrations, as shown on Figures 3.8-19 and 3.8-20. Local thickening of the containment wall at penetrations is generally not required. Section 3.8.2.1 contains further discussion of penetrations.

a. Pipe Penetrations

Details of typical pipe penetrations are shown on Figure 3.8-21. There are two basic types of pipe penetrations. For piping systems containing high temperature fluids, a sleeved penetration is furnished, providing an air gap between the containment concrete wall and the hot pipe. This air gap is large enough to maintain the concrete temperature below 200°F in the penetration area. A flued head outside the containment connects the process pipe to the pipe sleeve. For piping systems containing low temperature fluid, a separate sleeve for the penetration is not furnished. For this type of penetration, the process pipe is welded directly to the two ends of the embedded pipe penetration.

b. Electrical Penetrations

Figure 3.8-22 shows a typical electrical penetration assembly used to extend electrical conductors through the containment. The penetrations are hermetically sealed, and provide for leak testing at design pressure.

c. Equipment Hatches and Personnel Lock

Two equipment hatches, with inside diameters of 12 feet, are furnished in the drywell wall. One of these equipment hatches includes a personnel lock. Figure 3.8-21 shows a detail of an equipment hatch. Figures 3.8-16 and 3.8-23 show details of reinforcement around the equipment hatches. Additional meridional, hoop, helical, and shear reinforcement is used to accommodate local stress concentrations at the opening. The containment wall is thickened at the equipment hatches to accommodate the additional rebars.

d. Suppression Chamber Access Hatches

Two access hatches, with internal diameters of 4'-4", are furnished in the suppression chamber wall, as shown on Figure 3.8-21. Figure 3.8-15 shows a detail of reinforcement around the suppression chamber access hatches. Additional local reinforcement in the meridional and diagonal directions is added as shown on this figure.

3.8.1.1.2.4 Drywell Head Assembly

The drywell head lower flange is anchored to the top of the drywell wall by rigid attachment to 108 meridional reinforcing bars in the inner curtain of the containment wall, as shown on Figure 3.8-9. The remainder of the drywell head assembly is discussed in Section 3.8.2.1.1.

3.8.1.1.2.5 Internal Containment Attachments

The principal items attached to the containment wall from the interior are the diaphragm slab, beam seats, pipe restraints, and the seismic truss.

a. Diaphragm Slab Embedments

The diaphragm slab is attached to the containment wall by a structural weldment at the junction of the two components, as shown on Figure 3.8-10. Radial force and bending moment, carried by the diaphragm slab main reinforcement, are transferred to the containment wall by Cadwelding the diaphragm slab rebar to the top and bottom flanges of the structural weldment. The top and bottom flanges of the structural weldment are embedded in the containment concrete wall, and are anchored using structural steel anchors. Flexural shear in the diaphragm slab is transferred to the containment wall through the web of the structural weldment, which is welded to opposite sides of the thickened containment liner plate.

b. Beam Seat Embedments

Beam seats are provided to support the drywell platforms. A typical beam seat embedment is shown on Figure 3.8-24.

c. Pipe Restraint Embedments

Pipe restraints are provided to prevent pipe whip caused by rupture of high energy piping. Typical pipe restraint embedments are shown on Figure 3.8-25.

d. Seismic Truss Support Embedments

The seismic truss provides lateral support for the reactor vessel and reactor shield. A typical seismic truss support embedment in the drywell wall is shown on Figure 3.8-26.

3.8.1.1.2.6 External Containment Attachments

There are no major external structural attachments to the primary containment wall, except brackets providing vertical support for some of the reactor enclosure floor beams. These floor beams support checkered plate blowout panels, and are small enough to not cause any vertical interaction between the containment structure and the reactor enclosure. In addition, the beam-to-bracket connections are sliding connections, preventing horizontal interaction between the containment structure and the reactor enclosure.

3.8.1.1.2.7 Steel Components Not Backed by Structural Concrete

Descriptions of steel portions of the primary containment that are not backed by concrete, such as the drywell head, equipment hatches, personnel lock, suppression chamber access hatches, CRD removal hatch, and piping and electrical penetrations, are given in Section 3.8.2.

3.8.1.2 Applicable Codes, Standards, and Specifications

The codes, standards, and specifications used in the design and construction of the primary containment are listed in Table 3.8-1.

Specifications were prepared to cover the areas related to the design and construction of the containment. These specifications were prepared by Bechtel specifically for this containment. These specifications emphasize important points of the industry standards for this containment, and reduce options such as would otherwise be permitted by the industry standards. Unless specifically noted otherwise, these specifications do not deviate from the applicable industry standards, and, as such, are not included in the UFSAR. These specifications cover the following areas:

a. Furnishing and delivering concrete

b. Forming, placing, finishing, and curing concrete

c. Furnishing, detailing, fabricating, delivering, and placing reinforcing steel

d. Splicing reinforcing bars

e. Furnishing, delivering, and erecting liner plate

Section 1.8 provides references to regulatory guides discussed in the UFSAR. Regulatory guides specific to this section are discussed in this section.

3.8.1.3 Loads and Loading Combinations

Table 3.8-2 lists the loading combinations used for the design and analysis of the containment. Loading combinations listed in ASME Section III, Division 2 were considered for the containment design. Table 3.8-21 identifies and explains differences between the loads listed in Table 3.8-2 and the ASME Code.

The containment is also analyzed and designed for hydrodynamic loads resulting from MSRV discharge and LOCA phenomena. For a definition of these loads and loading combinations, including hydrodynamic loads, refer to Reference 3.8-1 and Appendix 3A.

3.8.1.3.1 Dead Load

The dead load includes the weight of the structure and major equipment, plus any other permanent loads, such as soil or hydrostatic loads, or operating pressure.

3.8.1.3.2 Live Load

The live load includes those loads expected to be present when the plant is operating, such as movable equipment, piping, and cables.

3.8.1.3.3 Design Basis Accident Pressure Load

Transients resulting from the DBA LOCA are presented in Section 6.2.1, and serve as the basis for the containment internal design maximum pressure of 55 psig.

3.8.1.3.4 Thermal Loads

The thermal loads used in the design of the primary containment are shown in Table 3.8-3 for the operating and the postulated accident conditions.

Thermal effects anticipated at the time of the structural integrity test are not considered. The ambient air temperature during testing is close to that of construction; therefore, the effects of thermal gradient are negligible.

3.8.1.3.5 Wind and Tornado Loads

Wind and tornado loads are not considered because the containment is enclosed by the reactor enclosure.

3.8.1.3.6 Seismic Loads

Loads from the OBE result from a horizontal ground acceleration of 0.075 g and a vertical ground acceleration of 0.05 g, acting simultaneously.

Loads from the SSE result from a horizontal ground acceleration of 0.15 g and a vertical ground acceleration of 0.10 g, acting simultaneously.

3.8.1.3.7 External Pressure Load

The containment shell is designed to withstand an external pressure of 5 psi above the internal pressure.

3.8.1.3.8 Pipe Rupture Loads

The containment wall is designed to withstand the loads due to a postulated rupture of a 26 inch diameter main steam pipe, which produces the largest loads on the containment wall. These loads include the effects of jet impingement, pipe whip, and pipe reaction. An equivalent static load of 1000 kips is considered. This load includes an appropriate dynamic load factor to account for the dynamic nature of the load. Section 3.6 contains a detailed discussion of postulated pipe ruptures and their effects. For pipe whip and impact on restraints, the steel stress may exceed yield stress. For jet impingement, these stresses should not exceed yield stress. See Section 3.8.1.4 for further explanation.

3.8.1.3.9 Prestress Loads

The primary containment uses reinforced concrete; therefore, prestress loads have not been considered.

3.8.1.4 Design and Analysis Procedures

This section describes the procedures used for the design and analysis of the containment. For a description of the design and analysis procedures that consider the effects of hydrodynamic loads resulting from MSRV discharge and LOCA phenomena, refer to Reference 3.8-1 and Appendix 3A.

The analysis procedure consists of two parts. First, the uncracked forces, moments, and shears for both axisymmetric and nonaxisymmetric loads are determined. Axisymmetric loads are dead

load, live load, design accident pressure load, vertical seismic load, and operating and design accident thermal loads. Nonaxisymmetric loads are horizontal seismic load and localized pipe rupture load. The second part of the procedure consists of taking into account the expected cracking of the concrete, and determining the concrete and reinforcing steel stresses and strains. The liner plate is not assumed to resist any load.

The 3D/SAP computer program, described in Section 3.8.7.1, is used to determine the uncracked forces, moments, and shears due to axisymmetric loads. The operating and design accident temperature gradients are computed using the ME 620 computer program, which is described in Section 3.8.7.9. For transient loads such as design accident pressure and thermal loads, the most critical combination of these loads is considered.

The seismic loads on the structure are determined by seismic analysis using the methods described in Section 3.7. The 3D/SAP program is used to analyze the containment for nonaxisymmetric loads due to missile and postulated pipe rupture, and for local construction loads.

The Concrete Element Cracking Analysis Program (CECAP), described in Section 3.8.7.3, is used to determine the extent of concrete cracking, and the concrete and rebar stresses and strains. The input data for the CECAP program consist of the uncracked forces, moments, and shears calculated by the 3D/SAP and seismic analysis programs. The CECAP program models a single element of unit height, unit width, and depth equal to the thickness of the wall or slab. The program assumes isotropic, linear-elastic material properties, and uses an iterative technique to obtain stresses, considering their redistribution due to cracking. The program determines the redistribution of thermal-stresses due to the relieving effect of concrete cracking.

3.8.1.4.1 Containment Wall

Figure 3.8-27 shows the 3D/SAP finite-element model used to analyze the containment wall for axisymmetric loads. A 10° wedge of the containment is modeled using solid finite-elements having isotropic, linear-elastic material properties. The model includes the containment wall, base foundation slab, diaphragm slab, reactor pedestal, and the foundation material. Boundary conditions are imposed on the analytical model by specifying nodal point forces or displacements. With reference to Figure 3.8-27, the nodal points lying along boundary A are allowed to move within the X-Z plane, and those along boundary B within the X-Y plane. Points along boundary C are prevented from moving in the radial direction, and points along boundary D are prevented from moving in the hoop direction. Nodal forces, moments, and shears are applied to boundaries E and F to account for reaction loads from the drywell head, and from the reactor vessel and reactor shield wall, respectively.

Figure 3.8-28 shows the 3D/SAP finite-element model used to analyze the drywell wall for nonaxisymmetric pipe rupture loads. A 180° half-model of the drywell wall, consisting of isotropic, linear-elastic, solid finite-elements, is used. With reference to Figure 3.8-28, the nodal points lying along boundary A are allowed to move within the X-Z plane. Points along boundary B are prevented from moving in the vertical and radial directions. Nodal forces, moments, and shears are applied to boundary C to account for reaction loads from the drywell head.

Tangential shears caused by seismic loads are totally resisted by helical reinforcing bars and concrete in compression. In calculating the reinforcing steel requirement, the helical reinforcement is designed to resist stresses due to design accident pressure and thermal loads, as well as tangential shears caused by seismic loads.

3.8.1.4.2 Base Foundation Slab

Figure 3.8-29 shows the 3D/SAP finite-element model used to analyze the base foundation slab. A 180° half-model of the base foundation slab, consisting of isotropic, linear-elastic solid finite-elements is used. The model includes the base foundation slab, a portion of the containment wall, and the foundation material. By virtue of continuous modeling of base slab and wall elements as finite elements in the 3D/SAP analysis, strain compatibility and stress equilibrium at the wall and slab boundary are satisfied. With reference to Figure 3.8-29, the nodal points lying along boundary A are allowed to move within the X-Z plane, and those along boundary B within the X-Y plane. Points along boundary C are prevented from moving in the radial direction. Axisymmetric forces, moments, and shears calculated using the 3D/SAP containment model, and seismically induced, tangential shears are applied to boundary D. The height of the model is chosen so that the overturning moment caused by the tangential shear is the same as the overturning moment determined by the seismic analysis. In order to be able to consider uplifting of the base foundation slab from its foundation, a thin layer of foundation material immediately beneath the foundation slab is considered separately from the remainder of the foundation material. If the computer output indicates tension in any of the elements in this thin layer of foundation material, the elements' modulus of elasticity is reduced to almost zero. Then a second computer run is made, and any additional uplift is identified. Further iterations and modifications of foundation material properties are made until the complete extent of uplift is determined.

3.8.1.4.3 Analysis of Areas Around Equipment Hatches

Figure 3.8-30 shows the 3D/SAP finite-element model used to analyze the areas of the containment wall around the equipment hatches. A 60° wedge of the containment wall is modeled using solid finite-elements having isotropic, linear-elastic material properties. To reduce the size of the analytical model, boundary A follows the equipment hatch's vertical plane of symmetry. The points delineating the outermost boundaries of the model are located at a sufficient distance from the opening so that the behavior of the model along the boundaries is compatible with that of the undisturbed shell. With reference to Figure 3.8-30, the nodal points lying along boundary A are allowed to move within the X-Z plane, and those lying along boundary B within the X-Y plane. Points along boundary C are prevented from moving in the hoop direction. Axisymmetric forces, moments, and shears calculated using the 3D/SAP containment model are applied to boundary D. Seismic loads calculated by the seismic analysis are applied locally to the elements. Seismically induced tangential shears around the equipment hatches are resisted by helical reinforcing bars and concrete in compression.

3.8.1.4.4 Liner Plate and Anchorages

The design and analysis of the liner plate and anchorages are performed in accordance with Reference 3.8-3.

3.8.1.5 Structural Acceptance Criteria

3.8.1.5.1 Reinforced Concrete

The containment wall, the diaphragm slab, and the reactor pedestal are designed for the factored load combinations listed in Table 3.8-2, in accordance with the strength method of ACI 318. The following allowable stresses are used:

a. Concrete

1. Compression - 0.85 $f_c^{'}$

2. Tension - not permitted

3. Radial shear - as specified in Chapter 11 of ACI 318 (1971)

4. Tangential shear - not permitted

b. Reinforcing Steel

1. Tension - 0.90 F

2. Compression - 0.90 F

The notations are defined as:

f_c' = specified compressive strength of concrete

F = specified yield strength of reinforcing steel

The calculated stresses are within the allowable limits.

3.8.1.5.2 Liner Plate and Anchorages

The structural acceptance criteria for the liner plate and anchorages are in accordance with Reference 3.8-3.

3.8.1.6 Materials, Quality Control, and Special Construction Techniques

3.8.1.6.1 Concrete Containment

The concrete and reinforcing steel materials for the containment are discussed in Section 3.8.6.

3.8.1.6.2 Liner Plate, Anchorages, and Attachments

a. Materials

Liner plate materials conform to the requirements of the standard specifications listed below:

Item	Specification
Liner plate (¼ inch thick)	ASTM A285, Grade A, Firebox Quality
Liner plate (>¼ inch thick)	ASME SA516, Grade 60 conforming to the requirements of ASME Section III, Subsection B, Article 12
Structural steel shapes, plates, and bars used for anchorages and attachments to the liner plate	ASTM A36

Pipe restraint attachments	ASTM A36 or ASTM A441

b. Welding

Liner plate and structural steel welding conforms to the applicable portions of Part UW, "Requirements for Unfired Pressure Vessels Fabricated by Welding" of ASME Section VIII. Welders and weld procedures are qualified in accordance with ASME Section IX. For seam welds of liner plate and attachments that penetrate the liner plate (penetrations), Paragraphs UW-26 through UW-38, except UW-35, apply in their entirety. In lieu of Paragraph UW-35, undercuts that do not exceed 1/32 inch and do not encroach on the required section thickness are in accordance with ASME Section III, Subsection NB(4424). The welding of liner plate butt welds and penetration attachment welds are performed by either the shielded metal arc, or the automatic, submerged arc process. The minimum number of individual weld layers for welds that must maintain leak-tightness is two. In addition, liner plate seam and penetration attachment welds are inspected in accordance with paragraph (d) below. Welding of liner anchorages and internal containment attachments to the liner plates are also performed in accordance with ASME Section VIII Paragraphs UW-26 through UW-38, and the visual inspection/acceptance of the nonpressure-retaining attachment weldments are in accordance with NCIG-01 (Reference 3.8-22).

c. Materials Testing

Liner plate material greater than ¼ inch thick, used with Cadweld connectors and other anchorages, is vacuum- degassed and ultrasonically tested, in accordance with the ASME Section III, Section A-N321-1, and conforms to the requirements of Article 12, Materials, of ASME Section III, Subsection B.

d. Nondestructive Examination of Liner Plate Seam Welds

Nondestructive examination of welds complies with Regulatory Guide 1.19, with the following alternate approaches:

Spot radiographic examination is performed for all radiographable liner plate seam welds. Radiography is performed in accordance with ASME Section V, Article 2. Personnel performing radiographic examinations are qualified in accordance with the Society for Nondestructive Testing's Recommended Practice No. SNT-TC-1A, Supplement A, Radiographic Testing Method, plus any additional requirements of the ASME Section V. Acceptance standards are in accordance with Paragraph UW-51 of ASME Section VIII, Division 1. Twelve inches of the first 10 feet of weld for each welder, and welding position are radiographed. Thereafter, one 12 inch long radiograph is taken for each welder and weld position, for each additional 50 foot increment of weld. A minimum of 2% of all liner seam welds are examined by radiography.

Where nonradiographable weld joints are used, the entire length of weld is magnetic particle examined. All magnetic particle examinations conform to the ASME Section V. Personnel performing magnetic particle examinations are qualified in accordance with SNT-TC-1A, plus any additional requirements of the ASME Section V. Acceptance standards are in accordance with the ASME Section VIII, Division 1, Appendix VI.

The vacuum box soap bubble test is performed on all accessible liner plate seam welds, except welds connecting thickened reinforcing liner plate to penetration nozzles with nominal diameter of 6 inches or less. A 5 psi minimum pressure differential is maintained for a minimum of 20 seconds. The leak detecting solution is continuously observed for bubbles that indicate leaks. If a leak is detected, the defective weld is repaired, and reinspected by vacuum box testing.

Welds that are inaccessible for vacuum box testing are 100% liquid penetrant tested. Liquid penetrant examinations conform to the ASME Section V. Personnel performing liquid penetrant examinations are qualified in accordance with SNT-TC-1A, plus any additional requirements of the ASME Section V. Acceptance standards conform to the ASME Section VIII, Division 1, Appendix VIII.

A leak chase channel system is provided only on liner plate seam welds which are inaccessible after the completion of construction, and those under water in the suppression chamber. Following installation, the leak chase system is pressurized with air to 72 psig. The pressure is monitored by valving off the air supply, and measuring any pressure decay with a pressure gauge. Any pressure decay in excess of the pressure gauge rated accuracy, observed within 15 minutes, is cause to reject that portion of the liner plate seam welds and the leak chase system. All leaks are repaired, and following repair, the affected portion of the leak chase system is retested.

e. Quality Control

Quality control requirements during construction are discussed in the document "Limerick Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction," referenced in FSAR Section 17.1.

f. Erection Tolerances

The erection tolerances for the liner plate are summarized as follows:

1. The slope of any 10 foot section of cylindrical liner plate, referred to as true vertical, does not exceed 1:180. The deviation from the theoretical slope of any 10 foot section of conical liner plate, measured within a vertical plane, does not exceed 1:120.

2. The cylindrical shell is plumb within 1/400 of the height, plus a 2 inch allowance for local "out-of- roundness." The vertical axis of the conical shell, as established at the top and bottom of the conical section, is plumb within 1/200 of the height.

3. The radial dimension to any point on the liner plate does not vary from the design radius by more than ±1 inch in the suppression chamber, or ±1½ inches in the drywell, except that the radial tolerance is ±2 inches for local "out-of-roundness." Local "out-of-roundness" tolerance is used where the maximum diameter minus the minimum diameter at the elevation does not exceed 4 inches. Radial measurements are taken at 24 locations, spaced equally around the containment at any elevation.

4. Plates joined by butt-welding are matched accurately, and retained in position during the welding operation. Misalignment in completed joints does not exceed the limitations of Paragraph UW-33 of ASME Section VIII, Division 1.

3.8.1.7 Testing and Inservice Surveillance Requirements

3.8.1.7.1 Preoperational Testing

3.8.1.7.1.1 Structural Acceptance Test

Structural and Pressure Integrity Tests were performed according to Article CC-6000 of the ASME Section III, Division 2, as applicable, after complete installation of all penetrations in the drywell and suppression chamber, and prior to initial fuel loading. The Structural and Pressure Integrity Tests complies with Regulatory Guide 1.18, with the following alternate approaches:

Paragraph C.1

A continuous increase in containment pressure, rather than incremental pressure increases, was used. This was considered justifiable because data observations at each pressure level were made rapidly by the computerized data acquisition system. "Rapidly" is defined as requiring a time interval for the data point sample sufficiently short so that the change in pressure during the observation would cause a change in structural response of less than 5% of the total anticipated change. Also, the rate of pressurization was limited to 3 psig/hr average to ensure that the structure responds to the pressure loading without any time lag. However, retesting for Unit 2 is performed at a rate of pressurization limited to 8 psig/hr average with adequate hold time at peak pressure to assure there is no time lag for the structural response. For a description of the structural integrity test for each unit, see the alternate approach to Paragraph C.12 in this section (3.8.1.7.1.1).

Measurements were recorded at atmospheric pressure, and at 5 psi increments of the pressurization and depressurization cycles. The data acquisition system allowed the measurements at all locations to be made and recorded simultaneously.

The pressure was held constant for at least 1 hour at the maximum test pressure, or for such time as was necessary for recording crack patterns.

Paragraph C.2

The number and distribution of measuring points for monitoring radial deflections were selected so that the as-built condition could be considered in the assessment of general shell response. In general, the locations of the measuring points for radial deflections were in agreement with figure B of the Regulatory Guide, with the exception of Point 1. Point 1 was provided at a distance of two times the wall thickness (12 feet) from the basemat. This variation was made to properly predict the containment behavior near the basemat to wall connection. If Point 1 was located at a height of three times the wall thickness (18 feet), it would be very close to Point 2 (suppression chamber wall midheight is 26 feet) and would not yield any additional behavior pattern of the containment.

Paragraph C.3

Radial deflections, but not tangential deflections, were recorded. The magnitude of the expected local tangential deformation under the test pressure conditions is negligibly small. The diametrical displacement of the hatch parallel to the tangential direction was measured and compared to the predicted displacement. This was in the location of largest predicted displacements for the hatch discontinuity and provided the most comprehensive check on structural integrity. The measurement of absolute tangential deflections at locations away from the immediate edge of the discontinuity was difficult because fixed reference points are difficult to define, making it impractical to attempt measurement of these small local deflections.

Paragraph C.9

The LGS containment is located inside and isolated from the reactor enclosure. The environmental conditions under which the test was conducted were controlled by the reactor enclosure internal environment. Therefore, limitations on testing during periods of extreme weather conditions, such as snow, heavy rain, and strong wind, had negligible effect on structural response and were not applicable.

Paragraph C.10

Rather than as suggested in the guide, if the test pressure dropped to, or below, the next lower pressure level due to an unexpected condition, the test would have continued without a restart at atmospheric pressure, unless the structural response deviated significantly from that expected. The LGS containment pressurization was not conducted using pressure increments. Therefore, the provisions of ASME Section III, Division 2, subsection CC-6252(b) were met, using a 3 psi pressure drop as a criterion for investigating deviation in structural response.

Paragraph C.12

LGS has provided a detailed description of the structural integrity test in the report prepared after the test.

The Structural and Pressure Integrity Test was conducted at 115% of the following design conditions:

a. A design pressure condition of 55 psig in both the drywell and suppression chamber

b. A design pressure condition of 55 psig in the drywell, and 25 psig in the suppression chamber

Additional pressure integrity tests may be made subsequently, during periods of plant shutdown.

The differential pressure test of the diaphragm slab described in item (b) above was accomplished by capping the downcomers above the diaphragm slab's upper surface.

The LGS Unit 1 test was performed in one test sequence which demonstrated the structural adequacy of the containment structure for both of the design conditions described above. However, for LGS Unit 2, the structural integrity test was conducted in two stages because the maximum differential pressure on the diaphragm slab could not be maintained during the initial

pressurization of the containment structure. During the initial test, the structural adequacy of the containment structure for the design condition of 55 psig in both the drywell and the suppression chamber was satisfactorily demonstrated. Subsequent to the re-isolation of the drywell and the suppression chamber, the containment structure was retested at a rate of pressurization limited to 8 psig/hr average to 115% of the design condition "b" described above (drywell pressure equal to 63.25 psig and suppression chamber pressure equal to 28.75 psig).

Provisions are made to test the integrity of the primary containment system during the life of the plant.

The seals on the personnel airlock doors, hatches, and drywell head are capable of being tested for leakage at design pressure without pressurizing the drywell. In addition, provisions are made so that the space between the airlock doors can be pressurized to full drywell design pressure.

Electrical penetrations are testable at 115% of design pressure. Locations of test taps and seals allow electrical penetrations to be tested without entering or pressurizing the drywell or suppression chamber.

A more detailed description of the structural integrity test was provided in the report prepared after the initial test.

3.8.1.7.1.2 Leak Rate Testing

Preoperational leak rate testing is discussed in Section 6.2.6.

3.8.1.7.2 Inservice Leak Rate Testing

Inservice leak rate testing is discussed in Section 6.2.6.

3.8.2 ASME CLASS MC STEEL COMPONENTS OF THE CONTAINMENT

This section pertains to the ASME Class MC steel components of the concrete containment that form a portion of the containment pressure boundary, and are not backed by structural concrete. These components include the drywell head assembly, the equipment hatches, the personnel lock, the suppression chamber access hatches, the CRD removal hatch, and piping and electrical penetrations.

3.8.2.1 Description of the ASME Class MC Components

3.8.2.1.1 Drywell Head Assembly

The drywell head provides a removable closure at the top of the containment for reactor access during refueling operations. The drywell head assembly consists of a 2:1 hemi-ellipsoidal head and a cylindrical lower flange. The lower flange is supported on the top of the drywell wall as shown on Figure 3.8-9. The head is made of 1½ inch thick plate and is secured with eighty 2¾ inch diameter bolts at the 4 inch thick mating flange. The head-to-lower flange connection is made leak-tight by two replaceable gaskets. The space between the gaskets is provided with test connections to allow pneumatic testing from a remote location, outside the primary containment. The inside diameter of the drywell head at the mating flange is 37 feet 7½ inches. A double-gasketed manhole is provided in the drywell head. Figure 3.8-31 shows details of the drywell head assembly.

3.8.2.1.2 Equipment Hatches and Personnel Lock

Two 12 foot diameter equipment hatches are furnished in the drywell wall to permit the transfer of equipment and components into and out of the drywell. One hatch consists of a double-gasketed flange and a bolted dished door. The other hatch is furnished with a personnel lock welded to the removable door. The personnel lock is an 8'-7" diameter cylindrical pressure vessel, with inner and outer flat bulkheads. Interlocked doors, 2'-6" wide by 6' high, with double tongue-and-groove single element compression seals, are furnished in each bulkhead. A quick-acting, equalizing valve vents the personnel lock to the drywell to equalize the pressure in the two systems when the doors are opened and then closed. The two doors in the personnel lock are mechanically interlocked to prevent them from being opened simultaneously, and to ensure that one door is closed before the opposite door can be opened. The personnel lock has an ASME Code N-stamp. Figures 3.8-32 and 3.8-33 show details of the equipment hatch, and the equipment hatch with personnel lock, respectively.

3.8.2.1.3 Suppression Chamber Access Hatches

Two 4'-4" diameter access hatches are furnished in the suppression chamber wall to permit personnel access, and the transfer of equipment and components into and out of the suppression chamber. Each hatch consists of a double-gasketed flange and a bolted flat cover. Details of a suppression chamber access hatch are shown in Figure 3.8-21.

3.8.2.1.4 Control Rod Drive Removal Hatch

One 3 foot diameter CRD removal hatch is furnished in the drywell wall to permit transfer of the CRD assemblies into and out of the drywell. The hatch is furnished with a double-gasketed flange and a bolted flat cover. Figure 3.8-34 shows details of the CRD removal hatch.

3.8.2.1.5 Piping and Electrical Penetrations

A portion of each of the penetration sleeves extends beyond the containment wall, and is not backed by concrete. The entire length of any penetration sleeve, therefore, is considered an MC component, and, as such, is designed in accordance with ASME Section III, subsection B. Figures 3.8-21 and 3.8-22 show details of typical pipe and electrical penetrations, respectively.

3.8.2.2 Applicable Codes, Standards, and Specifications

The codes, standards, and specifications used in the design and construction of the containment are listed in Table 3.8-1.

Specifications are prepared to cover the areas related to the design and construction of the containment. These specifications are prepared by Bechtel specifically for this containment. These specifications emphasize important points of the industry standards for this containment, and reduce options that would otherwise be permitted by the industry standards. Unless specifically noted otherwise, these specifications do not deviate from the applicable industry standards, and as such are not included in the UFSAR. These specifications cover the following areas:

a. Furnishing and delivering concrete

b. Forming, placing, finishing, and curing concrete

c. Furnishing, detailing, fabricating, delivering, and placing reinforcing steel

d. Splicing reinforcing bars

e. Furnishing, delivering, and erecting liner plate

Section 1.8 provides references to regulatory guides discussed in the UFSAR. Regulatory guides specific to this section are discussed in this section.

3.8.2.3 Loads and Loading Combinations

Table 3.8-4 lists the loading combinations used for the design and analysis of the ASME Class MC components.

The ASME Class MC components are also assessed for Mark II hydrodynamic loads resulting from MSRV discharge and LOCA phenomena. For a definition of loads and loading combinations including hydrodynamic loads, refer to Reference 3.8-1 and Appendix 3A.

3.8.2.3.1 Dead and Live Load

For descriptions of dead and live load, see Sections 3.8.1.3.1 and 3.8.1.3.2, respectively.

3.8.2.3.2 Design Basis Accident Pressure Load

The drywell head is designed for a DBA internal pressure of 56 psi. The other MC components are designed for a DBA internal pressure of 62 psi.

3.8.2.3.3 External Pressure Load

The MC components are designed to withstand an external pressure of 5 psi above the containment internal pressure.

3.8.2.3.4 Thermal Loads

The operating and postulated design accident temperatures for the MC components are as follows:

	Temperature (°F)	
Condition	Drywell	Suppression Chamber
Operating	135 ①	95 (maximum)
Design Accident	340	220

Thermal cycles used in design are as follows:

a. Startup and shutdown - 500 cycles, 105°F range

b. Design Basis Accident - 1 cycle, 220°F range

3.8.2.3.5 Seismic Loads

The MC components are designed for acceleration values which were calculated using the methods described in Section 3.7.

The following seismic acceleration values are used for the design of the drywell head assembly:

a. OBE - 0.60 g horizontal, ±0.30 g vertical

b. SSE - 0.80 g horizontal, ±0.40 g vertical

The following seismic acceleration values are used for the design of the equipment hatch, personnel lock, and CRD hatch:

a. OBE - 0.40 g horizontal, ±0.20 g vertical

b. SSE - 0.45 g horizontal, ±0.25 g vertical

The following seismic acceleration values are used in the design of the suppression chamber hatches:

a. OBE - 0.20 g horizontal, ±0.15 g vertical

b. SSE - 0.30 g horizontal, ±0.20 g vertical

① This information is based on original design basis conditions. Further evaluation has validated the MC components for a drywell operating temperature of 150°F. The Stresses indicated in UFSAR Figures 3A-362 to 3A-380, Design Assessment Report for Containment Structures reflect current plant conditions.

3.8.2.3.6 Pipe Rupture Loads

The drywell head assembly is designed for a local pipe rupture load of 48,000 pounds, uniformly distributed over a circular area of 0.56 square foot, at any location on the drywell head. This load is due to the postulated rupture of the 6 inch diameter reactor head spray pipe, which produces the largest load on the drywell head. The head spray line does not exist for Unit 2 and has been removed from Unit 1. However, the analysis is still applicable because it envelopes loads from rupture of any other pipe in this region.

The equipment hatches are designed for a postulated pipe rupture load of 130,000 pounds, uniformly distributed over a circular area 12 feet in diameter.

The CRD removal hatch is designed for a postulated pipe rupture load of 160,000 pounds, uniformly distributed over a circular area 3 feet in diameter.

The loads on the equipment hatches and the CRD removal hatch are based on the rupture of a 28 inch diameter recirculation loop outlet pipe, which produces the largest load on the components.

The above values of static load include an appropriate dynamic load factor to account for the dynamic nature of the load. Section 3.6 contains a detailed discussion of postulated pipe ruptures and their effects, including pipe whip, jet impingement, environmental effects, flooding, and water spray.

3.8.2.3.7 Missile Impact Loads

As discussed in Section 3.5.1 and summarized in Table 3.5-7, missile impact is not considered credible for safety-related components inside the containment or the reactor enclosure.

3.8.2.4 Design and Analysis Procedures

This section describes the procedures used for the design and analysis of ASME Class MC steel components.

ASME Class MC components are also assessed for Mark II hydrodynamic loads resulting from MSRV discharge and LOCA phenomena. Assessment procedures that consider the effect of hydrodynamic loads are described in Appendix 3A.

3.8.2.4.1 Drywell Head Assembly

The analysis of the drywell head assembly uses the thin-shell computer program E0781, described in Section 3.8.7.7. This program calculates the stresses and displacements in thin-walled, elastic shells of revolution, when subjected to static edge, surface, and/or temperature loads with an arbitrary distribution over the surface of the shell.

The drywell head assembly is divided into two analytical models. Figure 3.8-35 shows the drywell head model and the lower flange model. Displacement compatibility of the two models at the mating flange surface is maintained in the analysis. Boundary conditions are imposed on the analytical models by specifying boundary forces or displacements. With reference to Figure 3.8-35, the translation and rotation of the top of the drywell wall are imposed as boundary conditions to boundary A. Boundary forces applied to boundary B are calculated in accordance with thin-shell theory.

See Section 3A.7.2.1.9.1 for discussion of analysis to reduce the drywell head bolt preload.

3.8.2.4.2 Access Hatches

Access hatches, including the equipment hatches, personnel lock, suppression chamber access hatches, and the CRD removal hatch, are designed as pressure-retaining components. The portions of the sleeves not backed by concrete are designed and analyzed according to the provisions of ASME Section III, Subsection B.

At the junction of the hatch cover to the flange on the sleeve, where local bending and secondary stresses occur, the computer program E0119, described in Section 3.8.7.7, is used for analysis. This program is also used for the analysis of the flat head covers.

3.8.2.4.3 Piping and Electrical Penetrations

For nuclear Class I flued head penetrations, the procedures used in design and analysis comply with ASME Section III, Subsection B.

For Class 1E electrical cable penetrations, the procedures used in design and analysis comply with ASME Section III, Subsection B.

3.8.2.5 Structural Acceptance Criteria

The structural acceptance criteria comply with Regulatory Guide 1.57, with the clarification that the Code Addenda in effect at the time of design rather than that cited in the guide were used. Table 3.8-4 lists the allowable stress criteria for the design and analysis of the ASME Class MC components.

3.8.2.6 Materials, Quality Control, and Special Construction Techniques

3.8.2.6.1 Materials

All carbon steel materials and stainless steel materials for the CRD hydraulic line penetrations conform to the requirements of ASME Section III, Subsection B. The drywell head assembly and other steel components are painted to protect against corrosion.

3.8.2.6.1.1 Drywell Head Assembly

Materials used in construction of the drywell head assembly conform to the following ASME specifications:

Item	Specification
Drywell head and lower flange	SA516, Grade 70, normalized
Bolts	SA320, Grade L43
Nuts	SA194, Grade 7

3.8.2.6.1.2 Access Hatches

Materials used in construction of the access hatches conform to the following ASME specifications:

Item	Specification
Sleeve and cover	SA516, Grade 60 or 70, normalized
Bolts	SA193, Grade B7
Nuts	SA194, Grade 7

3.8.2.6.1.3 Penetrations

Materials used in construction of piping and electrical penetrations conform to the following ASME specifications:

Item	Specification
Carbon steel sleeves	SA333, Grade 1 or SA516, Grade 60 or 70, normalized
Carbon steel caps for spare penetrations	SA234, Grade WPB
Stainless steel sleeves for CRD hydraulic line penetrations	SA312, Type 304L

Stainless steel fittings for CRD hydraulic line penetrations	SA182, Type 304

3.8.2.6.2 Welding

Welding conforms to the requirements of ASME Section III, Subsection NE-4000 except that all welding of the CRD hydraulic line penetrations conforms to the requirements of ASME Section III, Subsection NC. All pressure boundary welds are full penetration welds of double-welded, bevel-type. Welders and weld procedures are qualified in accordance with ASME Section IX.

Penetrations, access hatches, and the drywell head flange are postweld heat treated in accordance with ASME Section III, Article NE-4000. Penetrations are preassembled into the liner plate sections, and postweld heat treated as complete subassemblies.

3.8.2.6.3 Nondestructive Examination of Welds

All welds between penetrations and liner plate, access hatches and liner plate, and pressure-retaining welds not backed by concrete are examined in accordance with ASME Section III, Article NE-5000. Nondestructive examination of welds complies with Regulatory Guide 1.19, with the following alternate approaches:

Paragraph C.1.a

LGS uses an alternate approach with respect to radiographic examination of the first 10 feet of weld. For each welder and welding position, only 12 inches of the first 10 feet of weld is examined radiographically, instead of the entire 10 foot length. LGS conforms with all other guidelines for nondestructive examination of liner seam welds.

Paragraph C.4

LGS conforms with the intent, subject to the following interpretation: Nondestructive examinations are performed by employees of the liner plate Subcontractor. Bechtel, as licensee's agent, verifies that all personnel performing nondestructive testing are qualified in accordance with ASME Section V.

Paragraph C.7.a

LGS radiography acceptance standards are in accordance with UW-51 of the ASME Section VIII, Division I.

Paragraph C.7.b

Magnetic particle acceptance standards are in accordance with the ASME Section VIII, Division I, Appendix VI.

3.8.2.6.4 Quality Control

Quality control requirements during construction are discussed in the document "Limerick Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction," referenced in FSAR Section 17.1.

3.8.2.6.5 Erection Tolerances

The specified erection tolerances for ASME Class MC steel components of the containment are summarized as follows:

a. Suppression chamber penetrations are within 1 inch of their design elevations and circumferential locations.

b. Drywell penetrations are within 1 inch of their design circumferential locations. Critical penetrations, such as main steam, feedwater, core spray, etc, are within 1 inch of their design elevations. All other drywell penetrations vary from within 1 inch of design elevations for penetrations near the base of the drywell wall, to within 2 inches of design elevations for penetrations near the top of the drywell wall.

c. Alignments of penetrations are within 1° of the design alignments.

d. The average elevation of the drywell head lower flange is within 3 inches of the design elevation. The lower flange is within ½ inch of level.

3.8.2.7 Testing and Inservice Inspection Requirements

3.8.2.7.1 Preoperational Testing

3.8.2.7.1.1 Structural Acceptance Test

The drywell head assembly, equipment hatches, suppression chamber access hatches, CRD removal hatch, and piping and electrical penetrations are pneumatically tested to 1.15 times the design accident pressure during the containment structural acceptance test.

The personnel lock is pneumatically tested to 1.25 times the design pressure of 62 psig, following shop fabrication, or following field erection if final assembly of lock is performed in the field, to verify its structural integrity.

The CRD hydraulic line penetrations are hydrotested to 1.5 times the design pressure of 1250 psig following shop fabrication, in accordance with the ASME Section III, Subsection NC.

3.8.2.7.1.2 Leak Rate Testing

Leak-tightness of the containment pressure-retaining Class MC components is verified during the integrated leak rate test. Section 6.2.6 contains a description of the containment integrated leak rate test.

The personnel air lock is leak rate tested to 100% of the design accident pressure following shop fabrication, and following field erection. The maximum allowable leak rate for the personnel air lock shall be 5% of the allowable leak rate for the containment, L_a. L_a is 0.5% by weight of the air in the containment per 24 hours at test pressure, P_a (44.0 psig).

3.8.2.7.2 Inservice Leak Rate Testing

Inservice leak rate testing is discussed in Section 6.2.6.

3.8.3 CONTAINMENT INTERNAL STRUCTURES

3.8.3.1 Description of the Internal Structures

The functions of the containment internal structures include: support and shielding of the reactor vessel, support of piping and equipment, and formation of the pressure-suppression boundary. The containment internal structures are constructed of reinforced concrete and structural steel. The containment internal structures include the following:

a. Diaphragm slab

b. Reactor pedestal

c. Reactor shield wall

d. Suppression chamber columns

e. Drywell platforms

f. Seismic truss

Figures 3.8-1 through 3.8-8 show an overview of the containment including the internal structures.

3.8.3.1.1 Diaphragm Slab

The diaphragm slab serves as a barrier between the drywell and the suppression chamber. It is a reinforced concrete circular slab, with an outside diameter of 88 feet, and a thickness of 3'-6". Figure 3.8-36 shows details of the diaphragm slab reinforcement.

The diaphragm slab is supported by the reactor pedestal, the containment wall, and 12 steel columns. The connection of the diaphragm slab to the containment wall is shown on Figure 3.8-10. The diaphragm slab is penetrated by 87, 24 inch diameter downcomers. Additional reinforcement is furnished at downcomer penetrations. Section 6.2.1 contains a description of the downcomers.

A ¼ inch thick, carbon steel liner plate is provided on top of the diaphragm slab, and is anchored to it. The liner plate prevents bypass flow around the downcomers during a LOCA. Refer to Section 6.2.1, for a description of the bypass leakage requirements. Figure 3.8-37 shows the diaphragm slab liner plate and anchorage system.

3.8.3.1.2 Reactor Pedestal

The reactor pedestal is an 82 foot high, upright cylindrical reinforced concrete shell that rests on the containment base foundation slab, and supports the diaphragm slab, reactor vessel, and reactor shield wall, as well as drywell platforms, pipe restraints, and recirculation pumps. The connection of the reactor pedestal to the base foundation slab is shown on Figure 3.8-13. The reactor pedestal below the diaphragm slab has an inside diameter of 20'-1", and a wall thickness of 4'-9". The reactor pedestal above the diaphragm slab has an inside diameter of 20'-3", and a wall thickness of 4'-5". The thickness at the top of the pedestal increases to 5'-4" where it supports the reactor vessel and the reactor shield wall. Attachment of the reactor shield wall to the pedestal is described in Section 3.8.3.1.3. Attachment of the reactor vessel to the pedestal is accomplished

through a ring girder, as described in Section 5.3.3.1.4.1. The ring girder is attached to the pedestal by 120, 3¼ inch diameter high strength anchor bolts, as shown on Figure 3.8-38.

Figures 3.8-39 and 3.8-40 show reinforcement details. Openings are provided in the reactor pedestal, to permit the flow of air and suppression pool water into and out of the pedestal cavity. Additional reinforcement is furnished at the openings. A ¼ inch thick carbon steel form plate is provided on the inside and outside surfaces of the reactor pedestal below the diaphragm slab. This plate acts as a concrete form during construction, and preserves the water quality of the suppression pool by preventing the leaching of chemicals from the reactor pedestal concrete into the suppression pool.

3.8.3.1.3 Reactor Shield Wall

The reactor shield wall is a 49 foot high upright cylindrical shell which rests on the top of the reactor pedestal, and provides primary radiation shielding, as well as support for pipe restraints and drywell platforms. The reactor shield wall is constructed of inner and outer carbon steel plates, with unreinforced concrete between the two plates. Figure 3.8-41 shows details of the reactor shield wall. The reactor shield wall has an inside diameter of 25'-7", and a wall thickness of 1'-9". The outer steel plate is 1½ inches thick, and is designed to withstand local loads transferred through pipe restraints and drywell platform attachments. The inner steel plate is ½ inch thick, and is designed to act with the outer plate to withstand local and nonlocal loads. The inner and outer plates are connected with shear ties spaced on approximately 5° centers in the hoop direction. The annular space between the inner and outer plates is filled with unreinforced high density concrete for radiation shielding. The reactor shield wall is connected to the top of the reactor pedestal by 48, 2 inch diameter high strength anchor bolts, as shown on Figure 3.8-38.

The seismic truss and reactor vessel stabilizer, which provide lateral support to the reactor vessel and reactor shield, are attached to the top of the reactor shield wall. Penetrations with hinged doors or removable plugs are provided in the reactor shield wall to accommodate piping connections to the reactor vessel, and to provide access for inservice inspection. The wall thicknesses of penetration sleeves are large enough to prevent local stress concentrations in the inner and outer plates.

3.8.3.1.4 Suppression Chamber Columns

Twelve hollow steel pipe columns are furnished to support the diaphragm slab. Each column is 52'-3" long, with an outside diameter of 42 inches, and a wall thickness of 1¼ inches. The columns are connected to the base foundation slab at the bottom, and to the diaphragm slab at the top with embedded anchor bolts. Figure 3.8-14 shows the connection to the base foundation slab; and Figure 3.8-42 shows the connection to the diaphragm slab.

3.8.3.1.5 Drywell Platforms

Platforms are furnished at six elevations in the drywell to provide access and support to electrical and mechanical components. The platforms consist of structural steel framing, with steel grating. Built-up box shapes are used for beams that must resist biaxial bending. Beams that span between the pedestal or reactor shield wall, and the containment wall are provided with sliding connections at one end. Figures 3.8-3 through 3.8-8 show details of the drywell platforms.

3.8.3.1.6 Seismic Truss and Reactor Vessel Stabilizer

The seismic truss and the reactor vessel stabilizer provide lateral support for the reactor vessel during earthquake and pipe rupture loading. The seismic truss horizontally spans the gap between the containment wall and the reactor shield wall; the reactor vessel stabilizer spans the gap between the reactor shield wall and the reactor vessel. The seismic truss is shaped like an eight-pointed star, and is fabricated of steel plates. Figure 3.8-43 shows details of the seismic truss. Figure 3.8-26 shows the connection of the seismic truss to the containment wall. This connection is designed to allow vertical and radial movement of the seismic truss relative to the containment wall, but to prevent tangential movement.

3.8.3.2 Applicable Codes, Standards, and Specifications

The codes, standards, and specifications used in the design and construction of the containment internal structures are listed in Table 3.8-1.

Specifications were prepared to cover the areas related to design and construction of the containment. These specifications were prepared by Bechtel specifically for this containment. These specifications emphasize important points of the industry standards for this containment, and reduce options that would otherwise be permitted by the industry standards. Unless specifically noted otherwise, these specifications do not deviate from the applicable industry standards, and as such are not included in the UFSAR. These specifications cover the following areas:

a. Furnishing and delivering concrete

b. Forming, placing, finishing, and curing concrete

c. Furnishing, detailing, fabricating, delivering, and placing reinforcing steel

d. Splicing reinforcing bars

e. Furnishing, detailing, fabrication, and delivering the suppression chamber columns, pedestal liner, structural steel for the diaphragm slab, and miscellaneous structural steel

f. Furnishing, delivering, and erecting liner plate

Section 1.8 provides references to regulatory guides discussed in the UFSAR. Regulatory guides specific to this section are discussed in this section.

3.8.3.3 Loads and Loading Combinations

Tables 3.8-2 and 3.8-5 through 3.8-8 lists the loading combinations used for the design and analysis of the containment internal structures. Tables 3.8-5 through 3.8-8 list only the most severe factored loading combinations used for miscellaneous internal steel components of the containment. These structures have been designed according to the working stress methods, except for the pipe restraints supported on the drywell platforms. Design of the pipe restraints and their box beam supports allows inelastic deformations due to postulated pipe rupture loads. However, there is no loss of restraint function due to pipe break load.

Apparent differences between the loads listed in Tables 3.8-5 through 3.8-8 and SRP 3.8.3, for the governing loading conditions, are identified and explained in Table 3.8-20.

The internal structures are also analyzed for hydrodynamic loads resulting from MSRV discharge and LOCA phenomena. For a definition of loads and loading combinations (including hydrodynamic loads), see Reference 3.8-1 and Appendix 3A.

3.8.3.3.1 Diaphragm Slab and Reactor Pedestal

Table 3.8-2 lists the loading combinations used for the design of the diaphragm slab and reactor pedestal. Descriptions of the loads are as follows:

a. Dead Load, Live Load, and Seismic Loads

For a description of dead load, live load, and seismic loads, see Section 3.8.1.3.

b. DBA Pressure Load

The diaphragm slab and the reactor pedestal are designed for the following pressures:

1. Maximum pressure: 55 psig in the drywell and the suppression chamber

2. Maximum differential pressure: 30 psig downward (55 psig in the drywell and 25 psig in the suppression chamber); 20 psig upward (55 psig in the suppression chamber and 35 psig in the drywell).

c. Thermal Loads

The temperatures above and below the diaphragm slab for the operating and the postulated design accident conditions are shown in Table 3.8-3. The portions of the reactor pedestal above and below the diaphragm slab are designed for the drywell and suppression chamber maximum temperatures listed in Table 3.8-3.

Thermal effects anticipated at the time of the structural acceptance test are insignificant, since the difference in temperatures inside and outside the containment during the test is small.

d. Pipe Rupture Loads

The diaphragm slab and the reactor pedestal are designed to withstand the pipe rupture loads due to a postulated rupture of a 28 inch diameter recirculation loop pipe, which produces the largest loads on the structures. These loads include the effects of jet impingement, pipe whip, and pipe reaction. An equivalent static load of 1000 kips is considered. This load includes an appropriate dynamic load factor to account for the dynamic nature of the load. Section 3.6 contains a detailed discussion of postulated pipe ruptures and their effects.

3.8.3.3.2 Reactor Shield Wall

The reactor shield wall was designed as a steel member using AISC working stress methods. This wall is filled with a high density grout that has a main function of shielding. No composite action is

assumed between the steel and the concrete. Table 3.8-5 lists the load combination used for the design of the reactor shield wall. The governing loading combination is the abnormal/extreme loading condition that combines the design basis accident loads with the maximum seismic loads. Descriptions of the loads are as follows:

a. Dead Load, Live Load, and Seismic Loads

For a description of dead load, live load, and seismic loads, see Section 3.8.1.3.

b. DBA Pressure Load

The reactor shield wall is designed for internal pressurization due to a postulated pipe rupture at the connection of the pipe to the reactor vessel nozzle safe end. The two following pressure conditions are considered:

1. Maximum unbalanced pressure: a pressure condition shortly after pipe break, which produces the largest lateral load on the reactor shield wall, resulting in a jet force of 1330 kips.

2. Maximum uniform pressure: a 94 psig internal pressure

c. Thermal Loads

The reactor shield wall is designed for the maximum drywell temperature listed in Table 3.8-3.

d. Pipe Rupture Loads

The reactor shield wall is designed to withstand the pipe rupture loads due to a postulated rupture of any high energy pipe penetrating the reactor shield wall, and connecting to the reactor vessel, such as the recirculation and feedwater pipes. These loads include the effects of jet impingement, pipe whip, and pipe reaction. Equivalent static loads are considered, which include an appropriate dynamic load factor to account for the dynamic nature of the load. Section 3.6 contains a detailed discussion of postulated pipe ruptures and their effects.

3.8.3.3.3 Suppression Chamber Columns

Table 3.8-6 lists the load combinations used for the design of the suppression chamber columns. The columns are designed to resist the reaction loads from the diaphragm slab, for the LOCA conditions. Section 3.8.3.3.1 includes a description of the diaphragm slab loads. Normal loading conditions are not listed because the abnormal loading conditions govern the design. Allowable stresses for the suppression chamber columns are in accordance with AISC (1970), 7th edition, for steel.

3.8.3.3.4 Pipe Whip Restraints/Drywell Platforms

The drywell platforms are designed using the AISC working stress design methods, except for the pipe whip restraints supported on the platforms. Design of the pipe whip restraints and their support structure allows inelastic deformations due to postulated pipe rupture loads. When considering elastic behavior, the design of pipe whip restraints is based on AISC working stress method with allowables up to 0.9 times the yield strength. For elasto-plastic behavior, the design is

in accordance with the procedure outlined in Reference 3.8-6. However, there is no loss of restraint function due to pipe break loads. All safety-related items which the inelastic deformations may affect are evaluated to verify that no required safety function would be compromised.

Table 3.8-7 lists the load combinations used to design the pipe whip restraints and the drywell platforms. Design accident pressure loads are small in comparison with pipe restraint and jet force loads and therefore do not affect the designs of the drywell platforms. The thermal load has been included in the loading combination as given in Table 3.8-7. Seismic loads due to the dead weight of the platform members are insignificant when compared with pipe rupture loads and are ignored. The uniform design live load for the grating and framing beams is 200 lb/ft^2. The live load for the framing beams also includes the gravity load, thermal reaction load, and seismic SSE reaction load of all piping and equipment supported on the beams. This design procedure is also applicable to pipe whip restraints and their support structures outside of the containment structure.

3.8.3.3.5 Seismic Truss

The seismic truss is designed using the AISC working stress design methods. It is designed primarily for lateral seismic loads. However, it is also designed for jet impingement loads due to the postulated rupture of a 26 inch diameter main steam pipe. Design accident pressure and design live loads are negligible in comparison with the main steam pipe jet forces and therefore do not affect the design of the seismic truss. The expansion of structural members under thermal loadings is permitted. Therefore, thermal loads are negligible. Table 3.8-8 lists the governing load combination used to design the seismic truss.

3.8.3.4 Design and Analysis Procedures

This section describes the procedures used for design and analysis of the containment internal structures. All computer programs referenced are described in Section 3.8.7.

For a description of the design and analysis procedures that consider the effects of hydrodynamic loads resulting from MSRV discharge and LOCA phenomena, refer to Reference 3.8-1 and Appendix 3A.

3.8.3.4.1 Diaphragm Slab

The design and analysis procedures used for the diaphragm slab are similar to those used for the containment wall. Computer programs used in the analysis include 3D/SAP, CECAP, ME620, and seismic programs. See Section 3.8.1.4 for a detailed description of the analysis procedures.

Figure 3.8-44 shows the 3D/SAP finite-element model used to analyze the diaphragm slab for all loads, other than the seismic loads. A 15° wedge of the diaphragm slab is modeled using solid finite-elements having isotropic, linear-elastic material properties. The model includes the diaphragm slab, suppression chamber wall, reactor pedestal below the diaphragm slab, and a suppression chamber column. One vertical boundary plane goes through a suppression chamber column, and the other is halfway between two columns. Boundary conditions are imposed on the analytical model by specifying nodal point forces, or displacements. With reference to Figure 3.8-44, the nodal points lying along boundary A are allowed to move within the X-Z plane, and those along boundary B within the X-Y plane. Points along boundary C are prevented from moving in the hoop direction. Points along boundary D are prevented from moving in the radial direction, to account for the restraining effect of the inner portion of the diaphragm slab. Nodal forces, moments,

and shears are applied to boundaries E and F, to account for reaction loads from the drywell wall and the reactor pedestal above the diaphragm slab, respectively.

Analytical techniques as described in Section 3.7 are used to analyze the diaphragm slab for seismic loads.

3.8.3.4.2 Diaphragm Slab Liner Plate and Anchorages

The design and analysis of the diaphragm slab liner plate and anchorages is in accordance with Reference 3.8-3.

3.8.3.4.3 Reactor Pedestal

The reactor pedestal is designed for axisymmetric loads using the FINEL computer program. Both concrete and reinforcing steel materials are included in the model. The operating and design accident temperature gradients are computed using the ME620 computer program. For transient loads such as design accident pressure and thermal loads, the most critical combination of these loads is considered. Figure 3.8-45 shows a vertical section through the FINEL model of the containment, used to analyze the reactor pedestal below the diaphragm slab. Points along boundary A are prevented from moving in the vertical direction, and points along boundary B are prevented from moving in the radial direction.

Figure 3.8-46 shows the FINEL model used to analyze the reactor pedestal above the diaphragm slab. The model includes the reactor pedestal above the diaphragm slab, and portions of the reactor vessel and the reactor shield wall. Local thermal effects at the top of the reactor pedestal due to heat input from the reactor vessel are determined by using the ME620 computer program. With reference to Figure 3.8-46, nodal points along boundary A are prevented from moving vertically and radially. Nodal forces, moments, and shears are applied to boundaries B and C to account for reaction loads from the reactor vessel and the reactor shield wall, respectively.

Nonaxisymmetric loads on the reactor pedestal include seismic loads, and reactor vessel and reactor shield reaction loads. Seismic forces, moments, and shears are calculated by the methods described in Section 3.7. Vertical forces, horizontal shears, and overturning moments at the base of the reactor shield wall are determined as described in Section 3.8.3.4.4. These loads are applied to the top of the reactor pedestal. Concrete and reinforcing steel stresses in the reactor pedestal due to the above loads are calculated using the design methods of ACI 307. ACI 307 includes equations for determining the neutral axis of reinforced concrete cylindrical shells subjected to axial force and overturning moment. The position of the neutral axis satisfies the equilibrium of internal stresses and external forces and moments.

Concrete and reinforcing steel stresses due to axisymmetric and nonaxisymmetric loads are combined to determine the total stress. Additional meridional, hoop, and shear reinforcement is provided at the top of the pedestal, as shown in Figure 3.8-38, to resist local loads on the pedestal from the reactor vessel and the reactor shield wall. Helical reinforcement is not needed in the reactor pedestal to resist seismically induced tangential shears. Meridional and hoop reinforcement is designed to carry the entire tangential shear by shear friction, using the design methods of ACI 318.

3.8.3.4.4 Reactor Shield Wall

The reactor shield wall is analyzed as an axisymmetric structure. The FINEL computer program is used for the axisymmetric loads, which include dead load and design accident thermal load. The temperature gradient across the thickness of the wall is determinedby using the ME620 computer program. For nonaxisymmetic loads, which include design accident pressure load, seismic load, and pipe rupture load, the ASHSD computer program is used. Figure 3.8-47 shows a vertical section through the model used for FINEL and ASHSD programs. Points along boundary A are prevented from moving vertically and radially. For nonaxisymmetric loads, boundary B, at the connection of the seismic truss to the containment wall, is prevented from moving radially. Total stresses in the reactor shield wall are determined by summing the axisymmetric and nonaxisymmetric stresses.

A second set of analyses of the reactor shield wall, as shown in Figure 3.8-48, was done by modeling a full 360° section of the wall, and by using the EASE finite-element computer program. This analysis ensures the integrity of the shield for loads equivalent to the DBA. The model includes one 64 inch diameter recirculation outlet penetration, and two adjacent 48 inch diameter recirculation inlet penetrations. Finer mesh sizes are used in the areas of the openings to obtain a good representation of the stress gradient. With reference to Figure 3.8-48, points along boundary A are prevented from moving vertically and radially. Boundary B is a free edge. No significant local stress concentrations are noted around the openings. The stiffening of the shell is provided by the thick walled penetration sleeves.

3.8.3.4.5 Suppression Chamber Columns

Axial force, shear, and moment in the columns due to axisymmetric loads, such as dead load, and design accident pressure and thermal loads, were determined using the FINEL computer program. Figure 3.8-45 shows the FINEL model of the containment used to analyze the suppression chamber columns. Boundary conditions are described in Section 3.8.3.4.3. Since the FINEL program can consider only axisymmetric structures, the 12 columns are modeled as an equivalent cylinder having the same axial stiffness as the total of the individual column stiffnesses. The axial force in the columns is calculated from the axial stress determined by the FINEL program. Shear and moment in the columns are calculated from relative displacements of the diaphragm slab and the base foundation slab determined by the FINEL program.

Axial force, shear, and moment in the columns due to seismic loads are determined using several methods. Axial force in the columns due to horizontal seismic load is determined using the ASHSD program. Figure 3.8-49 shows the model. Axisymmetric shell and solid finite-elements having isotropic, linear-elastic material properties are used. Nodal points lying along boundary A are prevented from moving vertically, and points along boundary B are prevented from moving radially. The load applied to the ASHSD model is the seismic horizontal shear and overturning moment for the containment calculated by the methods described in Section 3.7.

Shear and moment in the columns due to horizontal seismic load are determined using the analytical procedures described in Section 3.7. The lumped-mass model of the containment, including columns and downcomers, is shown in Figure 3.8-50.

Axial force in the columns due to vertical seismic load is determined by applying the vertical forces calculated from the containment seismic analysis, to the diaphragm slab at its connections to the containment wall and the reactor pedestal. The vertical force transmitted to the columns through the diaphragm slab is calculated considering the relative vertical stiffnesses of the containment wall, reactor pedestal, and columns.

The postulated rupture of a 28 inch diameter recirculation loop pipe produces a vertical jet impingement load on the top of the diaphragm slab, and, therefore, produces loads in the columns. Axial force, shear, and moment in the columns due to jet force are calculated by the CE 668 computer program. Figure 3.8-51 shows the 180° model of the diaphragm slab. A vertical jet force is applied along the axis of symmetry, and the reaction is calculated in the column adjacent to the applied load. Edges of the diaphragm slab along boundaries A and B are considered to have fixed supports.

The total axial force, shear, and moment in the columns for all load combinations are determined by summing the results of the separate analyses. Stability of the columns for the most critical load combinations is checked using the plastic design methods of Part 2 of the AISC "Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings."

3.8.3.4.6 Drywell Platforms

The drywell platforms are designed using conventional elastic design methods, in accordance with the AISC Specification, Part 1.

3.8.3.4.7 Seismic Truss

Seismic forces in the seismic truss are calculated using the methods described in Section 3.7. Axial force, shear force, and moment in the seismic truss due to postulated pipe rupture loads are calculated using moment distribution. Figure 3.8-52 shows the rigid frame model including boundary conditions.

3.8.3.5 Structural Acceptance Criteria

3.8.3.5.1 Reinforced Concrete

The allowable stresses for the reinforced concrete portions of the containment internal structures are the same as the allowable stresses for the reinforced concrete portions of the containment, as discussed in Section 3.8.1.5.1. The calculated stresses are within the allowable limits.

3.8.3.5.2 Diaphragm Slab Liner Plate and Anchorages

The structural acceptance criteria for the diaphragm slab liner plate and anchorages are in accordance with Reference 3.8-3.

3.8.3.5.3 Structural Steel

Structural steel portions of the containment internal structures include the reactor shield wall, suppression chamber columns, drywell platforms, and seismic truss. For normal loading conditions, the allowable stresses are in accordance with the AISC Specification. For extreme environmental and abnormal loading conditions, the allowable stresses are as follows:

a. Bending - 0.90 F_y

b. Axial tension or compression - 0.85 F_y, except that where allowable stress is governed by requirements of stability (local or lateral buckling), allowable stress does not exceed 1.5 F_s

c. Shear - 0.50 F_y

where:

F_s = allowable stress according to the AISC Specification, Part 1

F_y = specified yield strength of structural steel

The calculated stresses in all the structural steel elements are within the above allowable limits.

3.8.3.6 Materials, Quality Control, and Special Construction Techniques

The criteria of ACI 349, "Proposed ACI Standard: Code Requirements for Nuclear Safety-Related Concrete Structures," applicable to this section of the UFSAR are not used by LGS. This section discusses the alternate criteria used.

3.8.3.6.1 Concrete Containment Internal Structures

The concrete and reinforcing steel materials for the containment internal structures are discussed in Section 3.8.6.

3.8.3.6.2 Diaphragm Slab Liner Plate, Anchorages, and Attachments

a. Materials

Liner plate materials conform to the requirements of the following standard specifications:

Item	Specification
Liner plate (¼ inch thick)	ASTM A285, Grade A, Firebox Quality
Liner plate (>¼ inch thick)	ASME SA516, Grade 60 conforming to the requirements of the ASME Section III, Article NE-2000
Anchorages and attachments	ASTM A36 or ASTM A441

b. Welding

Welding requirements for the diaphragm slab liner plate and anchorages are the same as the welding requirements for the containment liner plate and anchorages. See Section 3.8.1.6.2 for a description of the welding requirements.

c. Nondestructive Examination of Liner Plate Seam Welds

Spot radiographic examination is performed for all radiographable liner plate seam welds. All nonradiographable liner plate seam welds are 100% magnetic particle examined, and 100% vacuum box soap bubble tested. Welds that are inaccessible

for vacuum box testing are 100% liquid penetrant tested. Examination procedures, personnel qualification, and acceptance standards are as described in Section 3.8.1.6.2.

3.8.3.6.3 Reactor Shield Wall and Seismic Truss

a. Materials

Materials used in construction of the reactor shield wall and the seismic truss conform to the following standard specifications:

Item	Specification
Inner reactor shield plate, seismic truss, and pipe restraint	ASTM A36 or ASTM A516, Grade 70
Outer reactor shield plate	ASTM A516, Grade 70

b. Welding and Nondestructive Examination of Welds

All welding and welder qualification procedures are in accordance with the requirements of ASME Section IX.

c. Materials Testing

The 1½ inch thick outer plate of the reactor shield wall is vacuum-degassed in accordance with supplementary requirements S-1 of ASTM A20, and is ultrasonically tested in accordance with ASME Section III, Subsection NB-2532-1.

d. Erection Tolerances

1. Each of the two concentric cylinders of the reactor shield wall is plumb within 1:500 of the height, plus a 1 inch allowance for local "out-of-roundness."

2. The radial dimension to any point on the reactor shield plates does not vary by more than ±1 inch from the center line as established by the design.

3. The clear distance between the two steel plates does not vary more than ±½ inch from the theoretical distance at any point.

4. The penetration sleeve center line is within ±1 inch of the projected center line of the theoretical location of RPV nozzles.

5. The elevation of the top of the shield is within ±¼ inch of that shown on the design drawings.

6. Seismic truss members do not deviate from axial straightness by more than 1/1000 of axial length.

3.8.3.6.4 Suppression Chamber Columns

a. Materials

The column shafts, base plates, and top plates are fabricated of ASME SA516, Grade 70 material.

b. Welding

Weld procedures and qualifications conform to the provisions of ASME Section III, Subsection NE, Class MC. All welders are qualified in accordance with ASME Section IX.

c. Nondestructive Examination of Welds

Complete magnetic particle examinations are performed on the welds of the suppression chamber columns, and on the top plate welds (anchor bolts to top plate and column to top plate) in accordance with the requirements of the ASME Section III, Subsection NE-5000.

d. Fabrication Tolerances

The specified fabrication tolerances for the suppression chamber columns are as follows:

1. The outside diameter, based on circumferential measurements, does not deviate from the theoretical outside diameter by more than 0.5%.

2. Out-of-roundness, defined by the difference between the maximum and minimum diameters related to the theoretical diameter, is in accordance with the ASME Section VIII, Division 1, Paragraph UG-80.

3. The finished length does not differ from the theoretical length by more than ¼ inch.

4. The finished column shaft does not deviate from straightness by more than 1/8 inch in 1 foot, with a maximum for the full length of 1/1000 of the total length.

3.8.3.6.5 Drywell Platforms

a. Materials

Materials used in construction of the drywell platforms conform to the following standard specifications.

Item	Specification
Box beams and built-up wide flange beams	ASTM A441 and ASTM A588, Grade A
Structural shapes, plate,	ASTM A36

and bar

Connection bolts ASTM A325

b. Welding

Welding is performed in accordance with the Structural Welding Code, AWS D1.1. Visual inspection and acceptance of structural welds is performed in accordance with NCIG-01 (Reference 3.8-22).

c. Nondestructive Examination of Welds

Welds in box beams and fabricated wide flange beams are subjected to magnetic particle examination in accordance with ASTM E109 (Reapproved 1971); the standards of acceptance are in accordance with paragraph 8.15 of AWS D1.1.

d. Erection Tolerances

Erection tolerances for the drywell platforms are in accordance with the AISC Specification.

3.8.3.6.6 Quality Control

Quality control requirements during construction are discussed in the document "Limerick Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction," referenced in FSAR Section 17.1.

3.8.3.7 Testing and Inservice Inspection Requirements

3.8.3.7.1 Preoperational Testing

3.8.3.7.1.1 Structural Acceptance Test

The diaphragm slab is tested to 1.15 times the design downward differential pressure. Section 3.8.1.7 contains a description of the structural acceptance test. Structural acceptance test results are available after testing is complete.

3.8.3.7.1.2 Leak Rate Testing

Preoperational leak rate testing is discussed in Section 6.2.6.

3.8.3.7.2 Inservice Leak Rate Testing

Inservice leak rate testing is discussed in Section 6.2.6.

3.8.4 OTHER SEISMIC CATEGORY I STRUCTURES

This section gives information on all seismic Category I structures, other than the primary containment and its internal structures. It also describes the turbine enclosure, which is a nonseismic Category I structure. The following structures are included in this section:

Seismic Category I, Safety-Related Structures

Secondary containment (Reactor enclosures and refueling area)
Control structure
Diesel generator enclosure
Spray pond pump structure
Spray pond
Miscellaneous structures

Seismic Category I, Nonsafety-Related Structure

Radwaste enclosure (including offgas portion)

Nonseismic Category I, Nonsafety-Related Structure

Turbine enclosure

The general arrangement of these structures is shown on drawing C-2.

3.8.4.1 Description of Structures

3.8.4.1.1 Secondary Containment

The reactor enclosures enclose the primary containments and, with the refueling area, provide secondary containment (Figures 1.2-2 through 1.2-16). The secondary containment houses the auxiliary systems of the NSSS, the spent fuel pool, the refueling facility, and equipment essential to the safe shutdown of the reactor. The secondary containment is structurally integral with the control structure described in Section 3.8.4.1.2.

The secondary containment, up to and including the roof slab, is of reinforced concrete construction. Exterior bearing walls are reinforced concrete, and are additionally designed as shear walls to resist lateral loads. The floors and roof are constructed of reinforced concrete, supported by steel beam and column framing systems. The concrete slabs are designed as diaphragms to transmit lateral loads to the shear walls. The structural steel beams and girders are supported by either structural steel columns, or reinforced concrete bearing walls. The steel columns are supported by base plates attached to the foundation. The reinforced concrete walls and floors meet structural, as well as radiation shielding, requirements. At certain locations, concrete block masonry walls are used to provide better access for erecting and installing equipment. The block walls also meet the structural and the radiation shielding requirements.

The refueling facility is located above the reactor enclosures. It consists of the spent fuel pool, the steam dryer and separator storage pool, the reactor well, the cask loading pit, the skimmer surge tank vaults, a 48 foot long refueling platform crane, and a 129 foot long reactor enclosure crane. The facility is supported by end bearing walls, and by two post-tensioned concrete girders with grouted tendons. The girders run east-west, and span over the primary containments without intermediate supports. Each girder spans approximately 162 feet, and is 6 feet wide. The depth is 46 feet at the supports, and is reduced to 26 feet at midspan, where the girders straddle the containments. The ends of the girders are supported by concrete pilasters. A gap between the bottom of the girders and the top of the containments ensures that loads from the refueling facility

are not transferred to the containment. The details of the post-tensioned girders, including the tendon layout, are shown in Figure 3.8-53. The walls and slabs of the spent fuel pool, the cask loading pit, the reactor cavity, and the steam dryer and separator storage pool are lined on the inside with a stainless steel liner plate. The refueling facility meets the radiation shielding requirements.

The reactor enclosure crane consists of a main and an auxiliary hoist, with capacities of 125 tons and 15 tons, respectively. The crane is used during maintenance and refueling operations. It spans approximately 129 feet, and is 28 feet above the refueling floor. The crane is mounted on two 175 pound rails, supported by a pair of runway girders. The runway girders are supported by a series of built-up columns spaced at 27 foot centers, which in turn are supported by bearing walls. Figure 3.8-54 shows the details of the runway girders and the supporting columns. The reactor enclosure crane is discussed in Section 9.1.5.

The reactor enclosure is separated from the primary containment by a gap filled with compressible material. A gap is also provided at the interface of the secondary containment with the diesel generator, radwaste, and turbine enclosures.

3.8.4.1.2 Control Structure

The control structure, shown in drawings M-110, M-111, M-112, M-113, M-114, M-115, M-124, M-125, M-126, M-127, M-128, M-129, and M-130, is a reinforced concrete enclosure, structurally integrated with the secondary containment. The bearing walls are of reinforced concrete, and are additionally designed as shear walls to resist lateral loads. The floors and roof are constructed of reinforced concrete supported by steel beams. They are designed as diaphragms to transmit lateral loads to the shear walls. The beams span in the north-south direction and are supported at the ends by the bearing walls. The reinforced concrete walls and floors meet structural, as well as radiation shielding requirements. At certain locations, concrete block masonry walls are used to provide better access for erection and installation of equipment. The block walls also meet the structural and radiation shielding requirements.

The control structure is separated from the turbine enclosure by a seismic gap.

3.8.4.1.3 Diesel Generator Enclosure

The diesel generator enclosures, shown in drawings M-145 and M-146, house the standby diesel generators, which are essential for safe shutdown of the plant.

Concrete walls separate each diesel generator enclosure into four cells, one for each of the four diesel generators provided per unit. Each diesel generator unit is enclosed in its own concrete missile-protected cell. The walls between each generator unit are 2 feet thick and are 3 hour fire rated. All penetrations are small (2-3 inches), cast in concrete conduits for electrical cables. A concrete overhang on the south side of the enclosure serves as an air intake plenum. A concrete exhaust plenum is located on the north side of the enclosure roof.

The diesel generator enclosure is a reinforced concrete structure on wall foundations. The bearing walls are of reinforced concrete, and are additionally designed as shear walls to resist lateral loads. The floors and roof are constructed of reinforced concrete supported by steel beams. They are designed as diaphragms to transmit lateral loads to the shear walls. The north side of the enclosure bears on the pipe tunnel beneath. At certain locations, concrete block masonry walls are used to provide better access for erection and installation of equipment. The diesel generators are supported by the floors.

The diesel generator structures provide protection from missiles generated by internal rotating or pressurized mechanisms to prevent any credible missiles from damaging more than one engine. Any postulated missiles from a crankcase explosion are expected to be of low energy and incapable of penetrating the concrete barrier into any other cell. Failure of one or all of the starting air receivers by explosion is not expected to produce any credible missiles capable of penetrating the 2 foot thick cell walls. The diesel generator piping is designed to withstand pipe breaks and cracks.

3.8.4.1.4 Spray Pond Pump Structure

The spray pond pump structure, shown in drawings M-388, M-389 and M-390, contains the ESW and RHRSW pumps, auxiliary equipment, and related piping and valves.

The spray pond pump structure is a two-story reinforced concrete structure. The bearing walls are of reinforced concrete, and are additionally designed as shear walls to resist lateral loads. The operating floor and roof are constructed of reinforced concrete supported by steel beams. They are designed as diaphragms to transmit lateral loads to the shear walls. A mezzanine floor composed of grating over steel beams is provided to support the heating and ventilating equipment. An intermediate floor in the wing areas is provided to support valves and piping.

3.8.4.1.5 Spray Pond

The spray pond serves as the UHS for the plant. It is shown in Figures 3.8-55 through 3.8-57. The operation of the spray pond system is discussed in Section 9.2.6.

Spray pond dimensions are given in Table 9.2-18. The spray pond is designed so that normal operating water is retained in excavation only, i.e., not by constructed embankments.

An emergency spillway is provided at the north side of the pond. The only anticipated use of this spillway is either during a malfunction of the blowdown line, or during certain postulated conditions of heavy rainfall. The emergency spillway is designed to ensure that the maximum water level does not adversely affect the spray pond system, and to direct run-off water away from safety-related facilities in a controlled manner. The roadway surrounding the remainder of the spray pond provides a minimum freeboard of 4 feet.

The bottom and soil cut slopes of the spray pond are lined with a 12 inch thick layer of soil-bentonite lining. The soil-bentonite lining is covered with a 12 inch thick layer of soil. The rock-cut slopes are lined with shotcrete.

The stability of the subsurface materials, slopes, and lining at the spray pond site are discussed in Sections 2.5.4 and 2.5.5. Protection of slopes against waves is discussed in Section 2.5.5.

The spray network piping, which is located above the water, is supported by reinforced concrete columns. The columns are founded on bedrock or on concrete fill on top of bedrock.

3.8.4.1.6 Miscellaneous Structures

Subgrade pits, manholes, and tunnels which contain safety-related components are constructed of reinforced concrete. The locations of these miscellaneous structures are shown on Figure 3.8-58.

Safety-related piping, tanks, and electrical ducts, which are not located inside structures, are buried underground with adequate cover for missile protection. Additionally, soil erosion due to failure of

nonseismic piping has also been considered. The integrity of safety-related seismic Category I buried pipe will not be impaired through soil erosion by a failure of one buried nonseismic Category I pipe. This conclusion was based on the following conditions.

a. All but approximately 170 feet of common trench has been constructed in rock, where erosion of the supporting medium would be insignificant.

b. The 170 feet of trench not constructed in rock is in Type 1 fill.

   The nonpressure pipes (gravity lines) in this section, such as the blowdown line and waste and storm lines, do not pose a significant erosion problem. The nonseismic Category I pressure lines in this section consist of a 36 inch Schuylkill River makeup water line and a 12 inch fire line (Figure 3.8-58).

   Failure of the nonseismic Category I pressure pipe may create progressive erosion in the Type 1 fill. It is anticipated that water under pressure would penetrate to the surface, creating a progressively enlarging crater. However, because the water will flow in the direction of least resistance, once the water penetrates to the surface, the crater will be enlarged at a relatively slow pace. The span capacity needed to support the weight of the safety-related pipes in the trench is conservatively estimated to be in excess of 30 feet, based on the maximum allowable spans given in the ASME code. A considerably long time would be required to erode a crater large enough to exceed this span capacity.

c. Instrumentation would give indication in the control room if a break occurred in the nonseismic Category I pressure pipe. Loss of flow from the makeup water line to the cooling tower would result in an alarm in the control room when low level is reached in the cooling tower basin. It is conservatively estimated that low level would be reached within 30 minutes.

   Low pressure in the 12 inch fire line, following a break, starts a fire pump that gives an alarm in the control room without a fire signal.

   Following an SSE, if either alarm described above is activated, personnel will investigate for evidence of a faulty condition in the pipelines described in (b) above and will initiate any necessary corrective action.

d. The procedures for operator response to a seismic event will include the requirement that, within two hours after an SSE, personnel will investigate for evidence of a faulty condition in the pipelines described in (b) above and will initiate any necessary corrective action.

3.8.4.1.7 Radwaste Enclosure

The radwaste enclosure is designed in accordance with seismic Category I criteria, even though: its integrity is not required to protect the RCBP, or to ensure the capability to safely shut down the reactor; and its failure would not result in potential offsite exposures comparable to the guideline exposures of 10CFR50.67. The radwaste enclosure, shown in drawings M-140 through M-144, houses systems for receiving, processing, and temporarily storing the radioactive waste products generated during the operation of the plant.

The radwaste enclosure, which includes the offgas enclosure, is a reinforced concrete structure. The bearing walls are of reinforced concrete, and are additionally designed as shear walls to resist

lateral loads. The exterior walls are waterproofed, and are designed for hydrostatic effects as necessary. The floors and roof in the main portion of the radwaste enclosure are constructed of reinforced concrete supported by beam and column framing systems. They are designed as diaphragms to resist lateral loads. The columns are supported by base plates on the foundation. The floors and roof of the offgas portion of the radwaste enclosure are of reinforced concrete supported by steel beams and bearing walls. The reinforced concrete walls and floors meet structural, as well as radiation shielding requirements. At certain locations, concrete block masonry walls are used to provide better access for erection and installation of equipment. The block walls also meet the structural and radiation shielding requirements.

The radwaste enclosure is separated from the turbine enclosure and reactor enclosure by seismic gaps.

3.8.4.1.8 Turbine Enclosure

The turbine enclosure, which is shown in drawings M-110, M-111, M-112, M-113, M-114, M-115, M-124, M-125, M-126, M-127, M-128, M-129, and M-130, is divided into two units, separated by an expansion joint. It houses two inline turbine-generator units, and auxiliary equipment including condensers, condensate pumps, moisture separators, air ejectors, feedwater heaters, reactor feed pumps, ASDs for reactor recirculation pumps, interconnecting piping and valves, switchgear, and heating and ventilating equipment.

Three 110 ton overhead cranes are provided above the operating floor for servicing both turbine-generator units. Two reinforced concrete tunnels, one for each unit, are provided for the offgas pipelines at the foundation level, running from the area around the control structure to the radwaste enclosure.

The turbine enclosure rests on a reinforced concrete mat foundation. The superstructure is framed with structural steel and reinforced concrete. Rigid steel frames support the two turbine enclosure cranes. They also resist all transverse (north-south) lateral loads. Steel bracings resist longitudinal (east-west) lateral loads above the operating floor. Below this level, reinforced concrete shear walls transfer all lateral loads to the foundations.

Seismic separation gaps are provided at the interface of the turbine enclosure with the reactor, control, and radwaste enclosures.

The floors of the turbine enclosure are of reinforced concrete supported by structural steel beams. They are designed as diaphragms for lateral load transfer to the shear walls. The roof is built-up roofing on metal decking.

Exterior walls are covered by nonstructural precast reinforced concrete panels.

Interior walls required for radiation shielding or fire protection are constructed of reinforced concrete block. These walls are not used as elements of the load resistant system.

The seismic Category II turbine enclosure may undergo some plastic deformation under seismic loading resulting from the SSE, but the plastic deformation is limited to a ductility factor of 2. Those portions of the turbine enclosure which support the main steam lines are designed so that the main steam lines and their supports maintain their integrity under the seismic loading resulting from the SSE. Furthermore, the Turbine Enclosure will maintain its integrity to ensure that the MSIV Leakage Alternate Drain Pathway will be capable of performing its function as described in Section 6.7 during and following an SSE.

The turbine-generator units are supported on freestanding reinforced concrete pedestals. The mat foundations for the pedestals are founded on rock at the same levels as the basemat for the turbine enclosure. Separation joints are provided between the pedestals, and the turbine enclosure floors and walls, to prevent transfer of vibration to the enclosure. The operating floor of the turbine enclosure is supported on vibration damping pads at the top edge of the pedestal.

3.8.4.2 Applicable Codes, Standards, and Specifications

The codes, standards, and specifications used in the design, fabrication, and construction of seismic Category I structures are listed in Table 3.8-1.

3.8.4.3 Loads and Load Combinations

Tables 3.8-9, 3.8-10, and 3.8-11 list the loading combinations considered in the design seismic Category I structures (other than the primary containment).

The reactor enclosure and control structure are also assessed for Mark II hydrodynamic loads resulting from MSRV discharge and LOCA phenomena. For a definition of loads and loading combinations including hydrodynamic loads, refer to Reference 3.8-1 and Appendix 3A. Hydrodynamic loads have no significant effect on other seismic Category I structures described in Section 3.8.4.

3.8.4.3.1 Description of Loads

3.8.4.3.1.1 Normal Loads

Normal loads are loads which are encountered during normal plant operation and shutdown. They include dead loads, live loads, thermal loads due to operating temperature, and other permanent loads contributing stress, such as hydrostatic loads. Dead and live loads are described in Sections 3.8.1.3.1 and 3.8.1.3.2, respectively.

3.8.4.3.1.2 Severe Environmental Loads

Severe environmental loads are loads that could infrequently be encountered during the plant life. They include those loads induced by the OBE and the design wind. Loads due to OBE are discussed in Sections 3.7 and 3.8.1.3.6. Wind loads are discussed in Section 3.3.

3.8.4.3.1.3 Extreme Environmental Loads

Extreme environmental loads are loads which are credible, but which are highly improbable. They include those loads induced by the SSE and the design tornado. Loads due to the SSE are discussed in Sections 3.7 and 3.8.1.3.6. Tornado loads are discussed in Section 3.3.

3.8.4.3.1.4 Abnormal Loads

Abnormal loads are loads generated by a DBA. Abnormal plant conditions generated by a DBA include the postulated rupture of high energy piping. Loads induced by such an accident include elevated temperatures and pressures within or across compartments, and jet impingement and impact forces associated with such ruptures. Loads due to postulated rupture of piping are discussed in Section 3.6. Other loads that may be generated by a DBA include railroad accident

blast loads and tornado loading (including missiles generated from both), and loading from aircraft impact, as described in Sections 2.2.3 and 3.5.1.6.

3.8.4.3.2 Load Combinations

Table 3.8-9 describes the load combinations applicable to the reactor enclosure and control structure. Table 3.8-10 contains the load combinations applicable to seismic Category I structures, other than the primary containment, reactor enclosure, and control structure. Load combinations considered in the design of miscellaneous structural components of seismic Category I structures are listed in Table 3.8-11. Applicable load combinations from Table 3.8-10 are used in the design of the turbine enclosure.

3.8.4.4 Design and Analysis Procedures

The structures are designed to maintain elastic behavior for the load combinations defined in Section 3.8.4.3. All reinforced concrete components of the structure are designed by the ultimate strength method, in accordance with ACI 318. Design of major reinforced and prestressed concrete structural components was completed prior to the formal adoption of ACI 349, and this standard was therefore not used for LGS. All structural steel components are designed by the working stress method, in accordance with the AISC Specification.

Roof and floor diaphragms transfer the horizontal loads to the shear walls, which then transfer the loads to the foundation. Standard analytical procedure is used to analyze the distribution of lateral loads from the diaphragms to the shear walls. Vertical loads are transferred to the foundation by bearing walls and steel columns.

Seismic analysis of the structures uses the techniques described in Section 3.7. The enclosures are analyzed dynamically.

Design of structures for missile and aircraft protection is covered in Section 3.5.3.

The design and analysis of the fuel pool girders of the reactor enclosures are in accordance with ACI 318.

Design and analysis of concrete block walls are by the working stress method, in accordance with the UBC.

The stainless steel liner plates, used on the inside of the spent fuel pool, the cask loading pit, the reactor well, and the steam dryer and separator storage pool, are designed to function as a leak-tight membrane and to facilitate decontamination. The liner plate is designed to accommodate stresses due to the combined effect of long-term shrinkage of the underlying structural concrete and temperature effects inside the pools.

The spray pond is basically a soil-structure. Its design is discussed in Sections 2.5.4 and 2.5.5.

The reactor enclosure and control structure are also assessed for Mark II hydrodynamic loads resulting from MSRV discharge and LOCA phenomena. Assessment procedures that consider the effect of hydrodynamic loads are described in Appendix 3A.

3.8.4.5 Structural Acceptance Criteria

3.8.4.5.1 Reinforced and Prestressed Concrete

The reinforced and prestressed concrete structural components are designed by the strength method, in accordance with ACI 318, for the loads and load combinations described in Section 3.8.4.3. The stresses resulting from the load combinations are within allowable limits.

3.8.4.5.2 Structural Steel

The structural steel components are designed by the working stress method in accordance with the AISC Specification for the loads and load combinations described in Section 3.8.4.3. The allowable stresses for different load combinations are indicated therein. The stresses developed in the structural components are within the allowable limits.

3.8.4.5.3 Concrete Masonry Block Walls

The design of masonry walls was performed in accordance with the criteria in the UBC. The masonry wall design was re-evaluated for conformance with the criteria in NRC IE Bulletin 80-11. A comparison of the LGS design criteria for masonry walls with the SEB criteria shows that the two are in good agreement except in the following two areas:

a. Under extreme environmental loading conditions, the LGS criteria (appendix I, part 1, Reference 3.8-21) lists the following combinations:

   1. $D + L + T_a + H_a + R + P + E'$

   2. $D + L + W' + T_o + H_o$

   where:

D	=	Dead load of structure and equipment plus any other permanent loads
L	=	Live loads expected to be present when the plant is operating
E'	=	Design basis earthquake loads
W'	=	Tornado loads
T_o	=	Operating temperature loads
T_a	=	Accident temperature loads
H_o	=	Thermal operating condition pipe load
H_a	=	Thermal accident condition pipe load
R	=	Jet impingement load and/or pipe whip
P	=	Pressurization load due to HELB

The SEB criteria, under similar conditions, lists the following load combinations:

1. $D + L + T_o + R_o + E'$

2. $D + L + T_o + R_o + W_t$

3. $D + L + T_a + R_a + 1.5P_a$

4. $D + L + T_a + R_a + 1.25P_a + 1.0 (Y_r + Y_j + Y_m) + 1.25E$

5. $D + L + T_a + R_a + 1.0P_a + 1.0 (Y_r + Y_j + Y_m) + 1.0E'$

where:

R_o = H_o of the LGS criteria

E = OBE loads

W_t = W' of the LGS criteria

R_a = H_a of the LGS criteria

P_a = P of the LGS criteria

Y_r = Equivalent static load on the structure generated by the reaction on the broken high energy pipe during the postulated break, and including an appropriate dynamic load factor to account for the dynamic nature of the load.

Y_j = Jet impingement equivalent static load on a structure generated by the postulated break, and including an appropriate dynamic load factor to account for the dynamic nature of the load, = R of the LGS criteria.

Y_m = Missile impact equivalent static load on a structure generated by or during the postulated break, as from pipe whipping, and including an appropriate dynamic load factor to account for the dynamic nature of the load, = R of the LGS criteria.

Comparing the load combination under the two criteria, it is seen that combinations (1) and (2) of the LGS criteria are the same as combinations (v) and (ii) of the SEB criteria. Further, combination (v) of SEB is clearly more severe than combination (k) of SEB which is, therefore, not used in the LGS criteria. A study made on the masonry walls and their applicable load combinations indicated that load combination (v) of SEB will, in most cases, be more severe than combinations (iii) and (iv). For the cases where this was not true, the difference in loadings was not significant and additional calculations were made to ensure that the walls would be structurally adequate under SEB load combinations (iii) and (iv).

The results of the re-evaluation contained in Reference 3.8-21 are unaffected if the SEB load combinations (iii) and (iv) are considered in addition to the LGS load combinations in the re-evaluation of the masonry walls.

b. The LGS criteria permits the use of an increase factor for shear and bond of 1.67 which, when multiplied with the allowable stresses for normal operating conditions, gives that allowables for extreme environmental conditions. The increase factors under the SEB criteria are 1.5 for tension parallel to bed joint and shear in the reinforcement and 1.3 for tension normal to the bed joint and masonry shear.

   All block walls at LGS contain steel tension reinforcement which takes all tension normal or parallel to the bed joint. Therefore the LGS allowable masonry tension stress normal or parallel to the bed joint was not used, i.e., zero psi was assumed for the reanalysis of block walls. Because the masonry tension strength at the bed joint was assumed to be zero, the increase factor stated in the question was also not used in the reanalysis of the block walls. Further, the factor 1.67 has also not been used for shear or bond calculations for the masonry wall re-evaluation; instead a factor of 1.0 has been used.

Because the code allowable stresses (Reference 3.8-23, chapter 10.1 of the commentary) are generally associated with a safety factor of 3, the 1.67 increase factor for stresses for masonry load combinations involving abnormal and/or extreme environmental conditions, provides a factor of safety against failure of 1.8 (3 divided by 1.67). The factor of safety of 1.8 is conservative and allows sufficient margin for abnormal and/or extreme conditions.

Reference 3.8-21 provides additional details and results of this evaluation.

3.8.4.6 Materials, Quality Control, and Special Construction Techniques

3.8.4.6.1 Reinforced Concrete, Masonry, and Prestressed Concrete

The reinforced concrete, masonry, and prestressed concrete materials are discussed in Section 3.8.6.

3.8.4.6.2 Structural Steel

3.8.4.6.2.1 Materials

The various structural steel components conform to the following ASTM Specifications:

Item	ASTM Specification
Beams, girders, and plates	A36 or A441
High strength bolts	A325 or A490
Anchor bolts	A36 or A307

3.8.4.6.2.2 Welding and Nondestructive Testing

All welding and nondestructive testing is performed in accordance with the AWS Structural Welding Code.

3.8.4.6.2.3 Fabrication

The fabrication of structural steel conforms to the AISC Specification.

3.8.4.6.3 Quality Control

Quality control requirements during construction are discussed in the document "Limerick Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction," referenced in FSAR Section 17.1.

3.8.4.6.4 Special Construction Techniques

No special construction techniques are involved in the construction of seismic Category I structures.

3.8.4.7 Testing and Inservice Inspection Requirements

Testing and inservice inspections are not required for seismic Category I structures (other than the primary and secondary containment). The operational test, to verify the inleakage requirements of SGTS in the reactor enclosure, is covered in Sections 6.5.3 and 9.4.2.

3.8.5 FOUNDATIONS

This section describes foundations for all seismic Category I structures, other than the primary containment and the spray pond. The primary containment foundation is described in Section 3.8.1. The spray pond is basically a soil-structure; its design is discussed in Sections 2.5.4 and 2.5.5. A description of the foundation for the turbine enclosure, which is a nonseismic Category I structure, is also included in this section.

3.8.5.1 Description of the Foundations

Reinforced concrete foundations resting on sound rock, or lean concrete on sound rock, are provided for the structures.

Bearing walls of the structures are rigidly connected to the foundation. Steel columns are attached to the foundation by base plates and anchor bolts. The bearing walls and the steel columns carry all the vertical loads; they also carry the vertical axial loads due to the overturning effect of lateral forces, from the structure to the foundation. Horizontal shears due to wind, tornado, and seismic loads are transferred to the shear walls by the roof and floor diaphragms. The shear walls transfer the horizontal shears to the foundation, and from there, to the foundation medium through friction and/or direct bearing. The sides of all structure foundations are keyed to the foundation rock by poured concrete. This helps transfer the horizontal shears to the foundation rock.

The foundation for each structure is separated from each adjacent foundation by a 1 inch minimum seismic gap, except along the east side of the radwaste enclosure foundation, which is supported by the reactor enclosure foundation (Figure 3.8-59).

Peripheral subterranean walls are designed to resist lateral pressures due to backfill and surcharge loads, in addition to dead loads, live loads, and seismic loads.

3.8.5.1.1 Reactor Enclosure and Control Structure

The foundation for the reactor enclosure and control structure is a single integral unit. The foundation plan and representative sections are shown in Figure 3.8-60. The reactor enclosure and control structure walls are supported on continuous wall footings. Columns are supported on spread footings. The wall footings and spread footings vary in dimension and reinforcing.

All of these elements of the foundation for the reactor enclosure and control structure are joined together by a continuous 3'-0" thick mat in the reactor structure area, and by a continuous 2'-0" thick mat in the control structure. The 3'-0" thick mat surrounds the primary containment basement, with a 1 inch seismic gap separating the two.

3.8.5.1.2 Diesel Generator Enclosure

Figure 3.8-61 shows the foundation plan and typical sections of the diesel generator enclosure. The wall foundations extend well below the diesel generator base slab to competent bedrock. The base slab is supported on fill, which for design purposes is considered to be both yielding and nonyielding. In addition, the base slab is designed to span between the wall foundations, without support from the fill.

3.8.5.1.3 Spray Pond Pump Structure

Figure 3.8-62 shows the foundation plan and typical sections of the spray pond pump structure. The walls are founded on competent bedrock. The walls do not have independent footings, but are connected monolithically by a 2'-0" thick slab at the foundation level.

3.8.5.1.4 Radwaste Enclosure

Figure 3.8-59 shows the foundation plan and typical sections of the radwaste enclosure. The walls of the radwaste enclosure are founded on competent bedrock and are supported on continuous wall footings. Columns are supported on spread footings. The wall footings and spread footings of the main portion of the radwaste enclosure are joined together by a 1'-10" thick slab at the foundation level.

The walls of the offgas portion of the radwaste enclosure are supported on continuous wall footings, connected by a 1'-6", or 2'-2" thick slab at the foundation level.

3.8.5.1.5 Turbine Enclosure

Figure 3.8-63 shows the foundation plan and typical sections of the turbine enclosure. The walls are supported on continuous wall footings. Columns are supported on spread footings. The wall footings and spread footings vary in dimension and reinforcing. All of these elements of the foundation are joined together by a continuous 1'-3" to 1'-6" thick mat.

3.8.5.1.6 Miscellaneous Structures

Figure 3.8-64 shows typical foundation details of some safety-related miscellaneous structures. These structures are founded on competent bedrock, compacted fill, or lean concrete which can safely withstand the superimposed loads. The walls of the subgrade pits, manholes, and trenches are connected monolithically with the floor slabs at the foundation level. The minimum thicknesses of the walls and the floor slabs are 1'-6" and 1'-0", respectively.

3.8.5.2 Applicable Codes, Standards, and Specifications

The codes, standards, and specifications used in the design, fabrication, and construction of structure foundations are listed in Table 3.8-1.

3.8.5.3 Loads and Load Combinations

The loads and load combinations used in the design of the primary containment foundation are described in Section 3.8.1.3. The loads and load combinations used in the design of other seismic Category I structure foundations are discussed in Section 3.8.4.3.

3.8.5.4 Design and Analysis Procedures

The foundations of all seismic Category I structures are designed in accordance with the same codes and standards as used in the design of the superstructure. The design and analysis procedures are discussed in Section 3.8.1.4 and Section 3.8.4.4 for the primary containment and other seismic Category I structures, respectively. The design loads and load combinations are discussed in Section 3.8.5.3.

The bearing walls and steel columns carry all the vertical loads from the structure to the foundation. The lateral loads are transferred to the shear walls by the roof and floor diaphragms, which then transmit them to the foundation. Determination of overturning moment due to seismic loads is discussed in Section 3.7.

Settlement of all seismic Category I structure foundations is considered negligible, as the foundations are supported by sound rock, or lean concrete on top of sound rock, except those of some yard facilities, such as valve pits, manholes, pipe trenches, electrical ducts, etc, which are supported on select fill and yard fill on dense residual fill, or on sound rock.

The sliding of seismic Category I structure foundations cannot occur because, as explained in Section 3.8.5.1, the sides of the foundations are keyed to the foundation rock by poured concrete.

Detailed description of the foundation rock and soil is contained in Section 2.5.4.

3.8.5.5 Structural Acceptance Criteria

The seismic Category I structure foundations are designed to meet the same structural acceptance criteria as the structures themselves. These criteria are discussed in Sections 3.8.1.5 and 3.8.4.5. In addition, for the load combinations described in Section 3.8.5.3, the minimum factor of safety against overturning is 1.5.

3.8.5.6 Materials, Quality Control, and Special Construction Techniques

The seismic Category I structure foundations are constructed of reinforced concrete. The reinforced concrete materials are discussed in Section 3.8.6. Cement for the ESW/RHRSW cross tie valve pits in the spray pond pump house yard is Type II. Concrete for these pits is commercial grade material dedicated for nuclear safety related use. The material characteristics identified in Section 3.8.6 were used as a basis for the dedication plan.

No special construction techniques are involved in the construction of these foundations.

3.8.5.7 Testing and Inservice Inspection Requirements

Foundation testing and inservice inspection are not considered necessary, since all seismic Category I structure foundations are supported on sound rock, or lean concrete on sound rock. The only testing carried out is as described in Section 3.8.1.7.

3.8.6 CONCRETE, REINFORCING, PRESTRESSED CONCRETE, AND MASONRY MATERIALS

Materials, workmanship, and quality control associated with the construction of reinforced concrete, prestressed concrete, and masonry features of seismic Category I structures are based on the codes, standards, recommendations, and specifications listed in Table 3.8-1. These documents are modified as required to suit the particular conditions associated with nuclear power plant design and construction while maintaining structural adequacy. The extent of application and principal exceptions are indicated herein, and as follows:

a. ACI 301-66

The provisions of ACI 301-66, "Specification for Structural Concrete for Buildings", are modified as follows:

1. The requirements of section 7.3.2 of ACI 318-71 apply in lieu of section 504(b).

2. The following requirements apply in lieu of section 804(b)2:

(b)2 Hot weather - Concrete deposited in hot weather shall have a placing temperature which shall not cause difficulty from loss of slump, flash set, or cold joints and not greater than 90°F.

3. Vertical construction joints are cleaned and roughened by waterblasting, sandblasting, or bush hammering after the concrete has reached its final set. Prior to receiving additional concrete, vertical construction joints are wetted in lieu of the use of neat cement grout as specified in section 805(c).

4. The following requirements apply in lieu of section 901(a) and the fifth sentence of section 902(d):

(a) Surface defects, such as form blowholes, honeycomb, etc., are repaired as soon as practicable, but no later than 28 days after form removal.

(b) Form tie holes on the structures below grade level and in concrete which is coated with a special protective coating are patched as soon as practicable, but no later than 28 days after form removal. Form tie holes in areas other than the above need not be patched. Form tie holes which are patched need not be cured or kept moist.

5. The following requirements apply in lieu of the requirements specified in section 1202(a) and (c) and 1405(d):

The requirements of ACI 306-66 apply during cold weather. In addition, when heated enclosures are used for curing and freezing protection for all thicknesses of concrete, the temperature at the surface of the concrete is maintained between 50°F and 70°F. Any housing, covering, or other protection remains in place and intact for at least 24 hours after the artificial heating is discontinued. The maximum allowable gradual drop in temperature throughout the first 24 hours after the end of the 7 day curing period is 30°F for concrete thicknesses greater than 36 inches.

6. The following requirements apply in lieu of the requirements of sections 1401(a), 1404(a), 1404(c), 1405(a), and 1405(c), respectively:

   (a) Concrete sections more than 3 feet in the least dimension are termed mass concrete.

   (b) The maximum working limit slump of the concrete is 3 inches, with an inadvertency margin of +2 inches, except for starter mixes, which have a maximum slump of 5 inches.

   (c) Concrete is placed in layers not more than 24 inches, with vibrator heads extending into the previously placed layer.

   (d) The minimum curing period is 7 days.

   (e) The concrete is either moist cured or liquid membrane cured for 7 days. Liquid membrane compounds are applied at the time that the free water on the surface has disappeared, and no water sheen is seen, but not so late that the liquid curing compound is absorbed into the surface pores of the concrete.

   (f) The following requirements apply in lieu of section 601(c):

   The surface of the concrete at all joints is thoroughly cleaned, and all laitance removed, except where a mechanical joint is used, in which case all laitance need not be removed. The use of a mechanical joint without the removal of laitance is permitted in areas not exposed to excessive moisture.

b. ACI 318-71

The provisions of ACI 318-71, "Building Code Requirements for Reinforced Concrete", are modified as follows:

1. Section 3.5.1(a) of the 1974 Supplement to ACI 318-71 applies in lieu of section 3.5.1(a) of ACI 318-71.

2. Starter mixes, defined as concrete with a 1 inch maximum size aggregate 3 inches and 5 inches, are used as an alternate to mortar in section 5.4.4 and grout in section 6.4.1.

3. The following requirements apply in place of the requirements specified in section 5.5.1:

   The concrete is moist cured or liquid membrane cured for 7 days. Liquid membrane compounds are applied at the time that the free water on the surface has disappeared and no water sheen is seen, but not so late that the liquid curing compound is absorbed into the surface pores of the concrete.

4. The following requirements apply in place of the requirements specified in section 6.3.2.2:

   The temperature of the liquid, gas or vapor shall not exceed 150°F except in local areas such as penetrations through walls and slabs where the temperature shall not exceed 200°F.

5. The following requirements apply in place of the requirements specified in section 6.3.2.4:

   Piping and fittings are tested in accordance with the requirements of the code governing that piping system (e.g., ASME B&PV Code, ANSI B31.1, state or local plumbing codes, etc.), as specified in other sections of the UFSAR.

   Whenever the piping system is not governed by such applicable codes or code cases, such systems are tested for leaks prior to concreting. The testing pressure above atmospheric pressure is 50% above the pressure to which the piping and fittings may be subjected in service; but the minimum testing pressure is not less than 150 psig. The pressure test is held for 4 hours, with no drop in pressure, except that which may be attributable to changes in ambient air temperatures; or the system is maintained at the hydrostatic test pressure for a minimum of 10 minutes, while all joints are visually examined for leakage.

6. The following requirements apply in place of the requirements specified in section 6.3.2.6:

   Piping systems not governed by applicable codes or code cases, carrying liquid, gas, or vapor, which is potentially explosive or injurious to health, are retested in accordance with item b.4 above, subsequent to the hardening of the concrete.

7. The following requirements apply in place of the requirements specified in section 6.3.2.7:

   Piping systems may be energized with water exceeding neither 50 psig, nor 90°F at any time, if approved by the responsible field engineer.

   Piping systems, including systems governed by piping system codes, may be energized above either 50 psig or 90°F, or energized with fluids other

than water during the period beyond 7 days after the concrete placement, provided that the temperature of the fluid does not exceed 150°F, and the pressure does not exceed 200 psig. Piping systems may be energized prior to, and remain energized during, placement of concrete, provided that: the above temperature and pressure restrictions are applied, and if the pressure in the energized system drops during concrete placement, the lowest pressure reached becomes the limiting pressure until the 7 day postplacement time limit has elapsed. However, if the pressure drops further within 24 hours after completion of the concrete placement, the system can be re-energized only up to the limiting pressure at any time after the 24 hour period has elapsed.

8. Vertical construction joints are cleaned and roughened by waterblasting, sandblasting, or bush hammering after the concrete reaches its final set. Prior to receiving additional concrete, vertical construction joints are wetted, in lieu of the use of neat cement grout specified in section 6.4.1.

9. The following requirements apply in lieu of the second sentence of section 6.4.1:

   Where a joint is to be made, the surface of the concrete is thoroughly cleaned. All standing water and laitance are removed, except where a mechanical joint is used, in which case all laitance need not be removed. The use of a mechanical joint without removing the laitance is permitted only in areas not exposed to excessive moisture.

10. The following requirements apply in lieu of the first sentence of section 4.14:

    f'_c for 5000 psi design strength concrete shall be based on tests of 90 days. f'_c for all other concrete design strengths shall be based on 28 day tests.

11. The following requirements apply in lieu of the last sentence of section 4.3.1:

    Each strength test result shall be the average of two cylinders from the same sample tested at 28 days for concrete with a design strength of 4000 psi or less and at 90 days for concrete with a design strength of 5000 psi.

c. ACI 613-54

The provisions of ACI 613-54, "Recommended Practice for Selecting Proportions for Concrete", are adhered to, except that the following recommended laboratory tests, mentioned on pages 211-14 through 211-16, are not used:

1. Fineness of Portland-Cement by Air Permeability Apparatus - ASTM Designation C204

2. Specific Gravity of Hydraulic Cement - ASTM Designation C188

3. Percentage of Shale in Aggregate - AASHTO Designation T10.

4. Alkali Reactivity, Potential, of Cement-aggregate Combinations - ASTM Designation C227

5. Air Content (volumetric) of Freshly Mixed Concrete - ASTM Designation C173

6. Air Content of Fresh Concrete by Pressure Methods (Washington-type meter) - Bureau of Reclamation Concrete Manual, Designation 24

7. Air Content of Freshly Mixed Concrete - U.S. Army Corps of Engineers Handbook for Concrete and Cement, Designation CRD-C 41

8. Laboratory Concrete Mixing - Bureau of Reclamation Concrete Manual, Designation 28

9. Flow of Portland-cement Concrete by Use of the Flow Table - ASTM Designation C124

10. Compressive Strength of Concrete Using Portions of Beams Broken in Flexure (modified cube method) - ASTM Designation C116

11. Flexural Strength of Concrete (using beam with third-point loading) - ASTM Designation C78

12. Fundamental Transverse and Torsional Frequencies of Concrete Specimens - ASTM Designation C215

13. Hardened Concrete, Securing, Preparing, and Testing Specimens from, for Compressive and Flexural Strengths - ASTM Designation C42

14. Cement Content of Hardened Portland-cement Concrete - ASTM Designation C85

15. Volume Change of Cement, Mortar and Concrete - ASTM Designation C157

16. Absorption of Concrete - AASHTO Designation T25

d. ACI 614-59

The provisions of ACI 614-59, "Recommended Practice for Measuring, Mixing, Transporting, and Placing Concrete", are modified as follows:

1. In addition to the requirements of ACI 614-59, storage of concrete materials shall be in accordance with ACI 304-73.

2. The following requirement applies in lieu of the second sentence of part II, item 6:

   The fineness modulus does not vary more than 0.20 from the value assumed in selecting proportions for the concrete.

3. The following requirements apply in lieu of the fourth sentence of part V, item 2:

   Concrete is not allowed or caused to flow to a distance, within the mass, more than the amount required for proper consolidation, and in no case more than 5 feet from the point of deposition.

4. The following requirements apply in lieu of the requirements of part VI, item 6:

   Immediately before the concrete is placed, all horizontal surfaces are covered with a nominal ½ inch of flowable grout mix thoroughly broomed into horizontal surfaces. For congested areas where brooming is impossible, the grout mix is forced ahead of the concrete. If the congestion may cause segregation, the grout thickness is increased to a nominal 1 inch thickness. Starter mixes, as defined above in item b.2, may be used as an alternate to the ½ inch or 1 inch grout. Starter mixes may be used to cover the bottom mat of reinforcing steel to a nominal depth of 2 inches above the reinforcing steel, or 6 inches above existing concrete on construction joints where no reinforcing mat exists.

5. The following requirement applies in lieu of the requirement of the fourth sentence of part VI, item 7:

   The maximum working limit slump of the concrete is 3 inches, with an inadvertency margin of +2 inches, except for starter mixes, which have a maximum slump of 5 inches.

e. ACI SP-2, Fifth Edition

The provisions of ACI SP-2, "Manual of Concrete Inspection", are modified as follows:

1. All samples are taken in accordance with ASTM C172.

2. Samples for cylinder strength tests of central mixed concrete are taken at the point of discharge from the central mixer plant. Samples for cylinder strength tests of truck mixed concrete, and slump, air content, and concrete temperature tests for all concrete are taken at the point of discharge from the delivery truck or at the end of the pump line for pumped concrete.

3. In order to establish a correlation between concrete properties at the central mixer plant and at the end of the pump line, pumped concrete is sampled at both of these locations to determine slump, air content, and concrete temperature. These correlation samples are taken from the same batch of concrete that is sampled for concrete cylinder strength tests at the central mixer plant, and again from this same batch of concrete as it reaches the end of the pump line. The correlation samples are taken at the following frequencies:

(a) Samples for slump and concrete temperature are taken from the first batch of each class of concrete produced per day, and for every 200 cubic yards of each class of concrete produced thereafter.

(b) Samples for air content are taken from every 400 cubic yards of each class of concrete produced, with a minimum of once per day for each class of concrete produced.

4. Vertical construction joints are cleaned and roughened by waterblasting, sandblasting, or bush hammering after the concrete has reached its final set. Prior to receiving additional concrete, vertical construction joints are wetted in lieu of using neat cement grout.

3.8.6.1 Concrete and Concrete Materials

3.8.6.1.1 Concrete Material Qualifications

3.8.6.1.1.1 Cement

Cement is Type II, Type I after June 1983, Portland-cement conforming to ASTM C150 except for RPV pedestal repair where the cement used is an expansive cement Type E-1(K) complying with ASTM C845. The following initial user tests are performed to ascertain conformance with ASTM Specification C-150:

Test	Designation
Chemical Analysis of Hydraulic Cement	ASTM C114
Fineness of Portland-Cement by the Turbidimeter	ASTM C115
Autoclave Expansion of Portland-Cement	ASTM C151
Time of Setting of Hydraulic Cement by Gillmore Needles	ASTM C266
Compressive Strength of Hydraulic Cement Mortars	ASTM C109
Air Content of Hydraulic Cement Mortar	ASTM C185

In addition, these tests are repeated during construction to check storage environmental effects on cement characteristics. The tests supplement visual inspection of material storage procedures.

Certified copies of material test reports showing chemical composition of the cement and verification that the cement being furnished complies with requirements are furnished by the manufacturer for each batch or lot.

3.8.6.1.1.2 Normal Weight Aggregate

Fine and coarse aggregates conform to ASTM C33. The following initial user tests are performed to ascertain conformance with ASTM C33:

Test	Designation
Organic Impurities in Sand for Concrete	ASTM C40
Effect of Organic Impurities in Fine Aggregate on Strength of Mortar	ASTM C87
Soundness of Aggregates by Use of Sodium Sulfate or Magnesium Sulfate	ASTM C88
Materials Finer Than No. 200 Sieve in Mineral Aggregates by Washing	ASTM C117
Lightweight Pieces in Aggregate	ASTM C123
Specific Gravity and Absorption of Coarse Aggregate	ASTM C127
Specific Gravity and Absorption of Fine Aggregate	ASTM C128
Resistance to Abrasion of Small Size Coarse Aggregate by Use of the Los Angeles Machine	ASTM C131
Sieve or Screen Analysis of Fine and Coarse Aggregates	ASTM C136
Clay Lumps and Friable Particles in Aggregates	ASTM C142
Scratch Hardness of Coarse Aggregate Particles	ASTM C235
Potential Reactivity of Aggregates	ASTM C289
Petrographic Examination of Aggregates for Concrete	ASTM C295
Test for Flat and Elongated Particles in Coarse Aggregate (except that the acceptance criteria for the ratio of flatness and elongation shall be 4 in lieu of 3)	CRD C119

Coarse aggregate grading is in accordance with size Nos. 4, 57, and 67, as defined in ASTM C33. The quantity of flat and elongated particles in the coarse aggregate is limited to 15% by weight.

3.8.6.1.1.3 High Density Aggregates

The requirements specified for normal density aggregates apply for high density aggregates, except as noted below.

Fine and coarse aggregates have a minimum bulk specific gravity of 4.4, as determined by ASTM C127 and ASTM C128. The high density aggregates are combined to produce a workable mix which meets all shielding requirements.

Certified test reports are prepared by the supplier for each material shipment, attesting to aggregate conformance to cleanliness requirements when tested per ASTM C117, and specific gravity requirements when tested per ASTM C127 and ASTM C128.

Metal aggregate consists of commercial S-930 and S-780 chilled iron or steel shot. This shot conforms to the appropriate SAE gradation presented in table 1 of the SAE Handbook.

3.8.6.1.1.4 Mixing Water and Ice

Water and ice used in mixing concrete is free of injurious amounts of oil, acid, alkali, organic matter, or other deleterious substances, as determined by AASHTO T26. Such water and ice contains no injurious impurities that would cause either a change in the setting time of portland-cement of more than 25%, as determined in accordance with ASTM C266, or a reduction in compressive strength of mortar of more than 5%, compared with results obtained with distilled water, as determined in accordance with ASTM C109 (using 2 inch cube specimens).

3.8.6.1.1.5 Admixtures

Air entraining admixtures conform to ASTM C260. Water reducing and retarding admixtures conform to ASTM C494, Type A and/or D. Types A and D are used in accordance with the manufacturer's recommendations. Certificates stating conformance to the applicable ASTM specification are furnished with each shipment. The use of any other admixture is not permitted.

3.8.6.1.2 Concrete Mix Design

3.8.6.1.2.1 Concrete Properties

Concrete properties required for each type of mix design are verified by testing for the applicable properties indicated below:

Property	Test Designation
Compressive strength	ASTM C39
Unit weight	ASTM C138
Slump	ASTM C143
Air content	ASTM C231

Samples for property testing are taken in accordance with ASTM C172.

The following additional properties of selected mix designs have been determined to ascertain material compatibility with design assumptions:

Property	Test Designation
Modulus of elasticity	ASTM C469
Poisson's ratio	ASTM C469
Thermal diffusivity	CRD C36
Thermal coefficient of expansion	CRD C39

3.8.6.1.2.2 Concrete Mix Proportions

Concrete mix designs are prepared in accordance with paragraphs 4.2.2.2 and 4.2.3 of ACI 318-71. Trial batches are prepared in accordance with ACI 613-54.

Four compressive strength cylinders are cast at each time of sampling for all normal density concrete. Two of these cylinders are tested at 7 days. The two remaining cylinders are tested at 28 days for concrete with a design strength of 4000 psi or less and at 90 days for concrete with a design strength of 5000 psi. For high density concrete, three compressive strength cylinders are cast at each time of sampling; one is tested at 7 days, and the other two are tested at 28 days.

Concrete design strengths for the various structures are in accordance with the following table:

Item	Strength (psi)
Fuel pool girders, critically stressed walls in the reactor enclosure	5000
Reactor enclosure, primary containment, control structure, spray pond pump structures, diesel generator enclosure, radwaste enclosure, cooling towers, turbine enclosure foundation and walls below el 217'	4000
All other structural concrete	3000
Mass concrete fill	2000

The total air content of the concrete, except for grout, varies with the concrete mix and aggregate size as follows:

Concrete mixes with a 1 inch maximum aggregate size (except for D-1 (5000 psi) concrete mix) have a total air content of not less than 4%, nor more than 7% of the concrete volume.

D-1 (5000 psi) concrete mix with a 1 inch maximum aggregate size has a total air content of not less than 4%, nor more than 6% of the concrete volume for onsite concrete, 7% for offsite concrete.

Concrete mixes with a maximum aggregate size of 1½ inches have a total air content of not less than 3%, nor more than 6% of the concrete volume.

Testing for air content is in accordance with ASTM C231.

In lieu of establishing limits on the water-cement ratio, the concrete is proportioned, mixed, and placed at specified slumps. The average slump at the point of placement is less than the "working limit", which is the maximum slump for estimating the quantity of mixing water used in the concrete. An "inadvertency margin" is the allowable deviation from the "working limit" for those occasional batches which may inadvertently exceed the "working limit." Job-site tests indicate that concrete with slumps at the "inadvertency margin" produce acceptable quality concrete.

3.8.6.1.3 Grout

3.8.6.1.3.1 Construction Grout

Construction grout for use at horizontal construction joints and similar applications is proportioned from the same materials as for concrete. Such grouts have a sand/cement ratio comparable to the concrete with which it is to be used. Grout strength is determined in accordance with ASTM C109.

3.8.6.1.3.2 Starter Mix

Starter mixes are used in applications, such as at the bottom of foundation slabs, and in lieu of construction grout. They are defined as concrete with a 1 inch maximum size aggregate, with a slump between 3 inches and 5 inches.

3.8.6.1.3.3 Nonshrink Grout

Nonshrink grout is prepared from proprietary materials such as Embeco 636 by Master Builders Company, or Five Star Grout by US Grout Corporation. Such grouts are proportioned in accordance with the manufacturer's recommendations, and are tested prior to use for expansion, compressive strength, and flow characteristics, with maximum water content recommended by the manufacturer.

3.8.6.1.4 Batching, Placing, Curing, and Protection

3.8.6.1.4.1 Storage

Storage of aggregates, cement, and admixtures is in accordance with the recommendations of ACI 614-59.

3.8.6.1.4.2 Batching, Mixing, and Delivering

Concrete for principal structures is provided as central mixed concrete from an onsite batch plant, or as truck mixed concrete from an offsite plant after June 1983. Concrete blockout grout, however, may be batched by volume and provided from a mortar mixer. Batch plant facilities are certified by the National Ready Mix Concrete Association. Measuring devices are calibrated at required intervals, and more frequently where deemed appropriate.

The measuring of materials, batching, mixing, and delivery of all concrete conforms to ASTM C94, except as otherwise noted.

3.8.6.1.4.3 Placing

Placing of concrete is in accordance with the recommendations of ACI 301-66, ACI 306-66, ACI 318-71, ACI 605-59, and ACI 614-59.

3.8.6.1.4.4 Consolidation

Consolidation of concrete is in accordance with the recommendations of ACI 614-59, and as specified below.

Concrete is placed with the aid of mechanical vibrating equipment, and supplemental hand spading and tamping. The vibrating equipment is of the internal type, with a minimum frequency of 7000 revolutions per minute.

Surface vibrators, or manual jitterbugs are permitted to consolidate concrete in slabs 8 inches thick or less.

3.8.6.1.4.5 Curing

Curing of concrete is in accordance with the recommendations of ACI 301-66, ACI 306-66, ACI 318-71, and ACI 605-59.

3.8.6.1.4.6 Hot and Cold Weather Concreting

Methods and means of placing and curing concrete in cold and hot weather comply with the recommended practices of ACI 306-66 and ACI 605-59, respectively.

3.8.6.1.5 Construction Testing of Concrete and Concrete Materials

A concrete and concrete materials testing laboratory operated by Bechtel QC personnel is established at the project site to monitor the quality of such work and materials, and to promptly report any deviations from specified conditions. Such testing personnel are qualified to meet the guidelines of Regulatory Guide 1.58. Qualifications and procedures in use by Bechtel QC personnel conform with Regulatory Guide 1.94. During operation, if repairs to concrete or concrete materials are required, the Company and contractor personnel performing NDE are trained, tested, qualified, or certified in accordance with a company procedure that meets applicable requirements of 10 CFR 50.55a and ASME Section XI with specific exceptions and clarifications as discussed in the QATR.

Production testing for concrete and concrete materials is as shown in Table 3.8-12. Production testing for concrete conforms with Regulatory Guide 1.94, with the following clarification.

For central mixed concrete, samples for concrete cylinder strength and unit weight tests are taken at the point of discharge from the central mixing plant. The concrete temperature is taken at the point of discharge from the central mixer when obtaining compressive strength samples. In addition, for each load of concrete represented by compressive strength samples, the concrete temperature is taken at the point of discharge from the delivery trucks, or at the end of the pump line for pumped concrete. For truck mixed concrete furnished from an offsite source, samples for concrete cylinder strength and unit weight tests, together with temperature readings, are taken at the point of discharge from the delivery truck or at the end of the pump line for pumped concrete. Materials that do not meet test requirements are not used in the construction.

Concrete cylinder test results are reviewed for compliance with section 4.3.3 of ACI 318-71, and are evaluated in accordance with ACI 214-65. Materials or portions thereof that do not meet the above criteria, but may inadvertently be used are handled as described in the document "Limerick Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction," referenced in FSAR Section 17.1.

3.8.6.2 Concrete Reinforcement Materials

3.8.6.2.1 Qualification

Reinforcing steel for concrete structures conforms to ASTM A615, Grade 60, including section S1 for bar sizes 14 and 18. Certified copies of material test reports indicating chemical composition, physical properties, and dimensional compliance are furnished by the manufacturer for each heat. Spiral reinforcing steel is plain wire conforming to ASTM A82.

Prior to installation at the job-site, all reinforcing steel is subjected to a testing program meeting the guidelines of Regulatory Guide 1.15. Any reinforcing steel which does not meet these requirements is not used in the construction.

Sleeves for reinforcing steel mechanical splices conform to ASTM A519 for Grades 1018 and 1026. Certified copies of material test reports indicating chemical composition and physical properties are furnished by the manufacturer for each sleeve lot.

3.8.6.2.2 Fabrication

3.8.6.2.2.1 Bending of Reinforcement

Hooks and bends are fabricated in accordance with ACI 318-71, section 7.1. Bars partially embedded in concrete are bent subject to the following conditions:

a. Bending Partially Embedded Reinforcement

Bending of reinforcement partially embedded in concrete is performed in accordance with the following description. The diameter of the bend measured on the inside of the bar, and the distance between the beginning of the bend and the existing concrete surface is not less than "D", shown below:

Bar Size	"D"
Nos. 3 through 8	6 bar diameters
Nos. 9, 10, and 11	8 bar diameters
Nos. 14S and 18S	10 bar diameters

Bar Nos. 3 to 5 inclusive may be bent once, and straightened once, cold.

Bar Nos. 6 to 9 inclusive may be bent once, and subsequently straightened. Heating is required for both bending and straightening, as described below.

However, when the bending does not exceed 30°, bar Nos. 6 to 9 *inclusive may be bent once, and straightened once, cold.

When only cold bending is applied, the distance between the beginning of the bend and the existing concrete may be decreased to a minimum of 0.5 "D" as shown above.

When heat is used, it is applied as uniformly as possible over a length of bar equal to 10 bar diameters, and is centered at the middle of the arc of the completed bend. The maximum bar temperature is between 1100°F and 1200°F, and is maintained at that level until bending (or straightening) is complete.

Temperature-measuring crayons, or a contact pyrometer is used to determine the temperature. Heat is applied with care so as to avoid damage to the concrete. Care is taken to prevent rapid quenching of heated bars.

The bars, which are heated for straightening and bending, are visually inspected to determine whether they are cracked, reduced in cross-section, or otherwise damaged. Any damaged portions are removed and replaced.

3.8.6.2.2.2 Splicing of Reinforcement

Lap Splices

In general, lapped splices are used for No. 11 and smaller bars. Such lap splices are in accordance with sections 7.5, 7.6, and 7.7 of ACI 318-71.

Mechanical Splices

Cadweld splices conform with Regulatory Guide 1.10, except for the alternate approaches to tensile testing frequency, and the procedure for substandard tensile test results, discussed below.

Cadweld splices are used most frequently for Nos. 14 and 18 main bars in the category I concrete structures. Cadweld splices are used most frequently for Nos. 14 and 18 main bars in other Category I concrete structures. Most completed splices are visually inspected for the presence of slag, excessive porosity, or voids in the filler metal, and for proper alignment and centering of the reinforcing bar. However, there are some instances where longitudinal centering of the splice sleeve on the splice ends is off center, and probing for voids in the filler metal cannot be performed due to interferences. In these instances, a test program simulating these conditions is performed. The test results conform with the tensile strength guidelines of Regulatory Guide 1.10.

For purposes of quality control, splices representing the work of each splicing crew are tensile tested for each position, bar size, and series (T or B). Bar-to-bar splices are designated as T-series splices. Bar-to-embedment splices are designated as B-series splices.

A crew is defined as the unique combination of persons preparing, assembling, and igniting the splice. Each unique combination of persons on a crew is considered as a separate crew. In the event that one or more members of the crew is unavailable for completing a production splice lot, or performing a sister splice, the remaining member or members of the crew complete the production splice lot, or perform the sister splice. For purposes of the tensile testing program, the remaining member or members are considered as comprising the crew.

A T-series "sister splice" consists of two 14 inch (+1 inch) bars spliced in sequence with, at the same location, under the same condition, and in an otherwise identical manner as the corresponding production splice. Straight sister splice samples are taken in lieu of production splice test samples for curved reinforcing bars, and for the splices in locations outside the primary containment where space limitations prohibit taking production splice test samples.

A B-series "sister splice" is made in the configuration shown on the design drawings, and is spliced in sequence with, at the same location, under the same condition, and in an otherwise identical manner as the corresponding production splice.

The number and frequency of Cadweld splice tensile tests performed by each crew for each position, bar size, and series are as follows:

a. One sister splice is tested, prior to the start of any production splicing. Qualification splices meet this requirement if performed by each member of the crew within the previous three calendar days, and the crew has made no production splices with visual defects or which fail tensile testing since making the qualification splices.

   Deviation from this criteria was allowed in some cases for the Cadweld splice installation. This deviating condition was documented in nonconformance report NCR#14244. The Cadweld splices installed without prior sister splice testing are acceptable per engineering review documented in the nonconformance report. The omission of sister splice testing prior to production splicing does not affect the performance safety-related structures because LGS meets the intent of Regulatory Guide 1.10. For the Cadweld installation without prior sister splice testing, the test frequency as stated in paragraph (b) below was implemented and completed satisfactorily. Therefore, the satisfactory completion of the testing frequency of paragraph (b) in conjunction with the crew qualification requirements, and the visual inspection requirement for production splices, combined to assure that the level of safety required for mechanical splices discussed in Regulatory Guide 1.10 is provided.

b. One test sample out of each lot of 25 consecutive production splices is tested, including the first group of 25.

   For T-series splices, each consecutive group of three such samples consists of one production splice and two sister splices. All test samples are sister splices for the B-series splices, and for splices of No. 18 bars to square Cadweld bars of the flange skirt assembly.

   Production splice test samples are selected at random by the inspector from any within the lot of 25 splices represented. Sister splice samples are made upon completion of the lot of 25 production splices. Horizontal sister splices are side or top filled to conform to the fill location of the majority of the splices.

   If fewer than a complete lot of 25 splices are made prior to the date of a concrete placement containing any of the splices in the incomplete lot, the test splices for that lot are made prior to the placement to determine the acceptability of the splices in that lot, and the lot is then treated as a complete lot.

Welded Splices

Whenever both lap and mechanical splices have been determined to be impractical, welded splices are used on a case-by-case approval basis. Such welding is performed by qualified welders using a procedure conforming to the basic recommendations of AWS D12.1.

3.8.6.2.2.3 Placing of Reinforcement

Reinforcement is securely tied with wire, and held in position by spacers, chairs, and other supports to maintain placement accuracy within the tolerances established for reinforcement protection, and the design requirements.

3.8.6.2.2.4 Spacing of Reinforcement

Spacing of reinforcement is in accordance with ACI 318-71.

3.8.6.2.2.5 Surface Condition of Reinforcement

Reinforcement surface conditions at the time of concrete placement are in compliance with section 7.2 of ACI 318-71.

3.8.6.2.3 Construction Testing of Concrete Reinforcement Materials

Inspection of reinforcement materials to ensure that bending, placing, splicing, spacing, and surface condition requirements are met is in accordance with Regulatory Guide 1.94, except as described in Section 3.8.6.2.2.2.

3.8.6.2.4 Formwork and Construction Joints

Formwork is constructed in accordance with the applicable provisions of ACI 347-68, so that the finished concrete surfaces do not exceed the tolerances of ACI 347-68.

Construction joints are made in accordance with ACI 301-66, ACI 318-71, and ACI 614-59. In addition, all horizontal construction joints are covered, immediately before the concrete is placed, with a nominal ½ inch of flowable grout mix, or a nominal ¾ inch of starter mix.

Concrete is placed in accordance with Regulatory Guide 1.55, except as discussed below.

Regulatory positions 2 and 3 of the Regulatory Guide state the presumed functional responsibilities of the "designer" and the "constructor." Under the designer's role, are listed the responsibilities for checking shop drawings and locations of construction joints. On this project, the former responsibility is fully delegated to the Bechtel field, although the design engineering office may check significant portions, and may advise the field accordingly. The responsibility for construction joint location is partly delegated to the field, in the sense that the field has to follow the guidelines set out in the design drawings and specifications prepared by the design engineering office.
Also, Regulatory Guide 1.55 references ACI 301-72 and ACI 305-72. However, concrete at LGS is placed in accordance with ACI 301-66 and ACI 605-59 respectively.

3.8.6.3 Prestressed Concrete

3.8.6.3.1 Post-Tensioning System for Prestressed Concrete

The post-tensioning system used for prestressed concrete is the VSL E5-55 post-tensioning system, described in the 1976 Edition of the Post-Tensioning Manual, published by the Post-Tensioning Institute.

3.8.6.3.2 Concrete for Prestressed Members

The concrete used for prestressed members is a 5000 psi concrete, designed and tested in accordance with Section 3.8.6.1.

3.8.6.3.3 Prestressing Steel

Prestressing steel consists of 7 wire, stress-relieved prestressing strands meeting the requirements of ASTM A416, and having a guaranteed minimum ultimate tensile strength of 270 ksi. Stress relaxation tests in accordance with ASTM E328 are also performed. The tests are performed for each 50 tons of a heat or fraction thereof. Any prestressing steel which does not meet the test requirements is not used in the construction.

3.8.6.3.4 Sheathing

Sheathing is spiral-wrapped, semirigid corrugated tubing, fabricated from a galvanized sheet, 24 gauge minimum split strip of lock-forming quality. The sheathing meets the requirements of ASTM A527, Coating Designation G90. It is not chemically treated, or oiled.

3.8.6.3.5 Anchorage Assembly

The anchorage assembly is the system of components consisting of the anchor head, wedge, bearing plate, and trumpet. The anchor head, wedge, and bearing plate materials meet the requirements of AISI 1026, AISI 86L20, and ASTM A537, respectively. After fabrication, bearing plates are galvanized in accordance with ASTM A123. Trumpets are fabricated from galvanized sheet meeting the requirements of ASTM A569.

3.8.6.3.6 Grout

The prestressing steel is bonded to the concrete by completely filling the entire void space between the sheathing and the tendon with grout. The grout consists of a mixture of Portland-cement, water, and admixture. The cement and water used to make the grout meet the testing requirements stipulated in Section 3.8.6.1. The grout is designed to have a minimum 7 day compressive strength of 2500 psi, in accordance with ASTM C109, and a minimum 28 day compressive strength of 3500 psi, in accordance with U.S. Army Corps of Engineers CRD-C589. Three samples for each test are taken each day grouting is performed for every 5 cubic yards, or fraction thereof produced.

3.8.6.3.7 Post-Tensioning System Performance Tests

Prior to actual post-tensioning operations, the post-tensioning system is subjected to static and dynamic tests in accordance with the recommendations of section 3.1.8 of the 1976 Edition of the Post-Tensioning Manual, published by the Post-Tensioning Institute.

3.8.6.4 Concrete Unit Masonry and Masonry Material

3.8.6.4.1 Material Qualification

3.8.6.4.1.1 Concrete Unit Masonry and Building Brick

Concrete unit masonry conforms to either ASTM C90, Type I, Grade N for hollow masonry units, or ASTM C145, Type I, Grade N for solid masonry units. Concrete building brick conforms to ASTM C55, Type I, Grade N. Certified test reports are prepared for each material.

3.8.6.4.1.2 Masonry Mortar

Masonry mortar conforms to ASTM C476, Type PL.

3.8.6.4.1.3 Masonry Grout

The three types of masonry grout described below have been used for filling cavities in masonry.

a. Chemtree Grout

Chemtree grout is a premixed grout manufactured by Chemtree Corporation. It has a minimum plastic unit weight of 206 lb/ft^3, and a minimum compressive strength of 1500 psi. Tests for unit weight and compressive strength are in accordance with Section 3.8.6.1.2.1.

Chemtree grout is used to fill the cavity and cells of a small number of multiple wythe walls in the radwaste enclosure and in the auxiliary bay portion of the turbine enclosure.

b. 2000 psi Masonry Grout

The second masonry grout used for filling cavities in masonry is a 2000 psi grout designed and tested in accordance with Section 3.8.6.1, as modified below:

1. Aggregate

Coarse and fine aggregate are combined as a single aggregate, graded to produce a workable mix that meets all shielding requirements.

2. User Tests

The following user tests are performed every 6 months during production:

Test	Designation
Potential Reactivity of Aggregates	ASTM C289
Specific Gravity and Absorption of Fine Aggregate	ASTM C128

Soundness of Aggregates by Use of Sodium Sulfate or Magnesium Sulfate	ASTM C88
Materials Finer than No. 200 Sieve in Mineral Aggregates by Washing	ASTM C117
Organic Impurities in Sand for Concrete	ASTM C40

3. Compressive Strength, Unit Weight, and Slump

   Three compressive strength cylinders are cast. One cylinder is tested at 7 days, and two are tested at 28 days. The minimum compressive strength, determined at 28 days, is 2000 psi.

   The minimum plastic unit weight for the masonry grout is 152 lb/ft^3.

   The masonry grout is allowed a slump of 9 inches ±1 inch.

c. 2000 psi Masonry Grout Using High Density Aggregates

   The third masonry grout used for filling cavities is a 2000 psi grout using high density and normal weight aggregates, designed and tested in accordance with Section 3.8.6.1, as modified below:

   1. Aggregate

      Normal weight and high density fine aggregate are used to produce a workable mix that meets all shielding requirements.

   2. User tests

      The user tests for normal weight fine aggregate are defined in Section 3.8.6.1.1.2. The user tests for high density fine aggregate are defined in Section 3.8.6.1.1.3

   3. Compressive Strength, Unit Weight, and Slump

      These requirements are the same as those discussed in Section 3.8.6.4.1.3.b.3

3.8.6.4.1.4 Concrete Infill

Concrete infill is used as an alternative to masonry grout for filling cavities in masonry. Concrete infill conforms to the requirements described in Section 3.8.6.1.

3.8.6.4.1.5 Steel Reinforcement

Steel reinforcement conforms to the requirements described in Section 3.8.6.2.

3.8.6.4.2 Construction Testing

Testing to monitor the quality of masonry work and masonry materials is in accordance with the program described in the document "Limerick Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction," referenced in FSAR Section 17.1.

Test frequency during the construction of concrete unit masonry is as shown in Table 3.8-12.

Materials that are inadvertently used in the construction, but do not meet test requirements, are handled as described in the document "Limerick Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction," referenced in FSAR Section 17.1.

3.8.7 COMPUTER PROGRAMS FOR STRUCTURAL ANALYSIS

This section describes the computer programs used for the structural analysis of all seismic Category I structures. Each program description includes a statement of the program's area of application, and a discussion of the modifications and assumptions made. In addition, the descriptions of the computer programs not in the public domain include a selection of the sample problems used to verify their solution accuracy.

3.8.7.1 3D/SAP (Finite-Element Analysis of Three-Dimensional Elastic Solids)

3.8.7.1.1 Application

Finite-element structural analysis program 3D/SAP is capable of performing static analyses of three-dimensional solid structures subjected to concentrated or distributed loadings, thermal expansion, and/or arbitrarily directed static body forces. It is a modern version of SAP (Reference 3.8-4) written as a general purpose structural analysis computer program.

3.8.7.1.2 Program Background

Program 3D/SAP was developed by the Control Data Corporation, and is in the public domain.

3.8.7.2 ASHSD (Axisymmetric Shell and Solid)

3.8.7.2.1 Application

ASHSD is a special purpose program which can be used in the elastic, static, or dynamic analysis of structural systems capable of being represented as axisymmetric shells and/or solids.

This program allows a useful study of the interaction between a typical nuclear containment structure, modeled as an axisymmetric shell, and the subsoil, modeled as an axisymmetric solid.

3.8.7.2.2 Program Background

This program is a refinement of the original ASHSD code developed at the University of California at Berkeley. The present program is highly modified for the special purpose of static and dynamic analysis of nuclear containment structures. The modified program has the following features:

a. The code has a shell finite-element which uses an interaction stiffness, allowing analysis of layered shells.

b. Since shell layers may be bonded or unbonded from each other, it is possible to describe concrete shells in their actual geometric form. For example, it is possible to describe liner plate, concrete, reinforcing steel, and post-tensioning steel in their real spatial locations.

c. Post-tension forces may be applied to the shell by subjecting only the unbonded post-tensioning elements to a pseudothermal loading.

d. Isotropic or orthotropic elastic constants are possible for both shell and solid elements. The orthotropic material properties may be used to describe the different stiffness of reinforcing steel in the hoop and meridional directions, for example.

e. Nonuniform thermal gradients through the wall thickness may be imposed.

f. Eigenvalues and eigenvectors may be computed by the program.

g. Three dynamic response routines are available in the program. They are:

    1. Arbitrary dynamic loading, or earthquake-based excitation using an uncoupled (modal) technique.

    2. Arbitrary dynamic loading, or earthquake-based excitation using a coupled (direct integration) technique.

    3. Response spectrum modal analysis for ABS and SRSS displacements and element stresses.

h. The coupled time history solution has the capability to allow an arbitrary damping matrix.

i. The stiffness and mass matrices may be obtained as punched output for input into other programs.

The version of this program currently used by Bechtel is maintained by the Control Data Corporation.

3.8.7.2.3 Sample Problems

This program is verified by comparing the computer results with hand-calculated solutions and published references. Three sample problems are presented as examples of verification.

a. Sample Problem A: Closed Cylinder Under Internal Pressure

This problem demonstrates the membrane state of stress in a closed cylinder subjected to a uniformly distributed internal pressure. Hand calculations are used to verify this aspect of the program.

The selected problem is a cylinder with closed ends subjected to internal pressure. Only one-half of the cylinder is required in the model because of symmetry. Furthermore, it is assumed that the closed ends are distant from the section being analyzed, and they are therefore excluded.

Two models of the cylinder are actually analyzed. One model uses the thin-shell elements, and the other uses the axisymmetric solid elements. These models are shown in Figures 3.8-65 and 3.8-66 with their key dimensions.

The problem parameters for both test cases are as follows:

Boundary Conditions

Node 1: Z displacement = 0
θ displacement = 0
Rotation in R-Z plane = 0
(free to move radially)

Node 16: θ displacement = 0
(free to move axially, radially, and to rotate about the θ axis)

Numerical Data

Material: concrete

Modulus of elasticity (E) = 4.031×10^6 psi

Thickness (t) = 36 inches

Radius (R) = 900 inches

Poisson's ratio (ν) = 0.17

Pressure (p) = 60 psi

Length (L) = 1800 inches

N = 27,000 lb/in (an equivalent node load applied at Node 16)

The theoretical values for the membrane force resultants are calculated to be pR/2 (= 27,000 lb/in) axial force, and pR (= 54,000 lb/in) for the circumferential force (hoop stress).

The results obtained from the ASHSD program are presented in Table 3.8-13, both for the thin-shell and the layered shell models. Analytical computations indicate

maximum errors at Node 16 of 0.4% for the longitudinal force and 3.2% for the circumferential force.

b. Sample Problem B: Cylindrical Shell Subjected to Internal Pressure and Uniform Temperature Rise

This test example demonstrates the use of a combined static load and thermal load condition. A short circular cylindrical shell clamped at both ends is subjected to an internal pressure and a uniform temperature rise.

The theoretical solutions given in Reference 3.8-4 are used to verify this analysis.

The general arrangement of the cylinder is shown in Figure 3.8-67. Only one-half of the cylinder is used for the finite-element model because of symmetry. This is shown in Figure 3.8-68, with Node 1 located at the middle of the cylinder.

The problem parameters are as follows:

Boundary Conditions

At center of cylinder,
Node 1:
Z displacement = 0
θ displacement = 0
Rotation in the R-Z plane = 0

At end of cylinder,
Node 26:
R displacement = 0
Z displacement = 0
θ displacement = 0 (tangential)
Rotation in the R-Z plane = 0

Numerical Data

Material: concrete

Modulus of elasticity (E) = 4.031×10^6 psi

Poisson's ratio (υ) = 0.17

Thermal coefficient of expansion (α) = 55×10^{-7} in/in/°F

Thickness (t) = 30 inches

Radius (R) = 600 inches

Length (L) = 1200 inches

Height (Z) = 600 inches

Pressure (p) = 60 psi

Temperature (T) = 150°F

R/t = 20

L/R = 2

The theoretical results are shown in Figure 3.8-69. These values are obtained by using the following equations from Reference 3.8-4:

Axial Moment: $M_x = 2\mu^2 D_x \left(\frac{PR^2}{Et} + R\alpha T\right)$ (EQ. 3.8-1)

where:

$$\mu^2 = \left[\frac{3(1-\upsilon^2)}{R^2t^2}\right]$$

$$D_x = \frac{Et^3}{12(1-\upsilon^2)}$$

Normalized length: Ln = (Z/R)(L/2R)

Figure 3.8-69 compares the results obtained from the ASHSD program and the theoretical solution. The results of ASHSD agree well with those of the reference.

c. Sample Problem C: Asymmetric Bending of a Cylindrical Shell

This sample problem illustrates the use of higher harmonics for asymmetric loading cases. As a comparison to the computer output, results for this problem are taken from Reference 3.8-5.

The cylindrical shell analyzed is a short, wide cylinder as shown in Figure 3.8-70. The finite-element idealization of the cylinder and the pertinent data are illustrated in Figure 3.8-71. At each end of the cylinder, moments of the form $M = M_o \cos\eta\theta$ were input for harmonics η = 0, 2, 5, 20.

The problem parameters are:

Material: steel

Modulus of elasticity (E) = 29×10^6 psi

Thickness (t) = 1.25 inches

Radius (R) = 60.0 inches

Poisson's ratio (υ) = 0.3

Length (L) = 60.0 inches

L/R = 1

R/t = 48

$$M_o = \frac{Et^2}{100(1-\upsilon^2)} = 497939.56 \text{ in-lb/in} \quad \text{(EQ. 3.8-2)}$$

The comparison results are taken directly from Reference 3.8-5. Those results are plotted in Figure 3.8-72.

The comparison of the computer results to the reference results are shown in Figure 3.8-72. (Note that the longitudinal moments and radial displacements are expressed as nondimensional ratios).

The reference and computer program results show good agreement. This verifies the accuracy of the program for this type of analysis.

3.8.7.3 CECAP (Concrete Element Cracking Analysis Program)

3.8.7.3.1 Application

CECAP computes stresses in a concrete element under thermal and/or nonthermal (real) loads, considering effects of concrete cracking. The element represents a section of a concrete shell or slab, and may include two layers of reinforcing, transverse reinforcing, prestressing tendons, and a liner plate.

The program outputs stresses and strains at selected locations in the concrete, reinforcement, tendons, and liner plate, and resultant forces and moments for the composite concrete element.

3.8.7.3.2 Program Background

CECAP assumes linear stress-strain relationships for steel and for concrete in compression. Concrete is assumed to have no tensile strength. The solution is an iterative process, whereby tensile stresses found initially in concrete are relieved (by cracking) and redistributed in the element. The equilibrium of nonthermal loads is preserved. For thermal effects, the element is assumed free to expand inplane, but is fixed against rotation. The capability for expansion and cracking generally results in a reduction in thermal-stresses from the initial condition.

The version of this program currently used by Bechtel is maintained by the Control Data Corporation.

3.8.7.3.3 Sample Problems

Sample problems are analyzed by CECAP and compared with hand-calculated solutions. These sample problems consider a reinforced concrete beam as shown in Figure 3.8-73. The parameters for all sample problems are as follows:

Modulus of elasticity of concrete (E_c) = 3×10^6 psi

Modulus of elasticity of reinforcing steel (E_s) = 30×10^6 psi

Poisson's ratio for concrete (υ_c) = 0.22

Coefficient of thermal expansion of concrete
(α_c) = 6×10^{-6} in/in/°F

Temperature difference (ΔT) = 100°F

Coefficient of thermal expansion of reinforcing steel
(α_r) = α_c

Three sample problems are presented as examples of verification.

a. Sample Problem A: Beam with a Thermal Moment

The analysis of a reinforced concrete beam subjected to a linear thermal gradient is performed to test the redistribution of thermal-stresses due to the relieving effect of concrete cracking.

Figure 3.8-74 shows the reinforced concrete beam, and the corresponding CECAP concrete element used in the analysis. Boundary conditions, geometry, and applied loads are illustrated.

The following illustrates how thermal loads are treated in a cracked section analysis of a reinforced concrete beam. The main assumptions pertaining to thermal boundary conditions are:

1. The beam is allowed to freely expand axially.

2. There is no rotation of the initial thermal-stress slope.

The beam cross-section and initial thermal-stress distribution are shown in Figure 3.8-75. For ΔT = 100°F, the equivalent thermal moment and thermal-stresses in concrete and steel are:

Thermal moment (M) = $\Delta T \alpha_c E_c b t^2/12$ (EQ. 3.8-3)
= 3,175,000 in-lbs

Concrete stress (σ_c) = $\Delta T \alpha_c E_c/2$ (EQ. 3.8-4)
= 900 psi (compression)

Rebar stress (σ'_c) = $\frac{(t/2-2)}{t/2}\sigma_c$ (EQ. 3.8-5)
= 814 psi (tension)

where:

b = width of beam = 12 inches

t = depth of beam = 42 inches

E_c = modulus of elasticity = 3×10^6 psi

α_c = coefficient of linear expansion for concrete
= 6×10^{-6} in/in/°F

The stress diagram used for the cracked section analysis with thermal loading is shown in Figure 3.8-76. The assumptions of free movement axially and constant thermal-stress slope are maintained by a lateral translation of the initial reference axis to a final cracked position.

From force equilibrium:

$$F_{rebar} + F_{concrete} = 0 \qquad \text{(EQ. 3.8-6)}$$

where:

$F_{rebar} = f_s$ = total stress in steel

$= 1.0\ (814 + \Delta\sigma_c)\ 10$ psi

$F_{concrete} = f_c$ = total stress in concrete

$$= -900\left(\frac{42}{2}\right)\left(\frac{12}{2}\right) + \frac{\Delta\sigma_c\,(12)}{2}\left[21 + \left(\frac{900-\Delta\sigma_c}{900}\right)2\right]$$

Solving for $\Delta\sigma_c$:

$\Delta\sigma_c = 582$ psi

From above, the rebar and concrete stresses are:

$f_s = (814+582)10 = 13{,}970$ psi (tension)

$f_c = 900-582 = 318$ psi (compression)

The location of the cracked neutral axis is:

$$kd = x = \frac{900-582}{900}\ (21) = 7.42 \text{ in} \qquad \text{(EQ. 3.8-7)}$$

The self-relieved thermal moment is:

$$M_T = \frac{f_s A_s (d - x/3)}{12} = 43{,}690 \text{ in-lb} \qquad \text{(EQ. 3.8-8)}$$

The rebar and concrete stresses, self-relieved thermal moment, and neutral axis location obtained from the CECAP program are compared with the hand calculations in Table 3.8-14. It can be seen that the CECAP results compare favorably with the hand calculation.

b. Sample Problem B: Beam with a Real Moment

The analysis of a reinforced concrete beam subjected to a real moment tests the CECAP program for nonthermal moments.

Figure 3.8-77 shows the loading and geometry for the reinforced concrete beam, and the corresponding CECAP concrete element model.

The following illustrates the working stress analysis of reinforced concrete beams. The beam cross-section, stress block, and transformed sections are shown in Figure 3.8-78. The resultant forces and moment are:

$$C = f_c\,(kd)(b)/2 \qquad \text{(EQ. 3.8-9)}$$

$$T = A_s(f_s) \qquad \text{(EQ. 3.8-10)}$$

$$M = Cjd = Tjd \qquad \text{(EQ. 3.8-11)}$$

Equating the first moments of the compression and tension areas about the neutral axis of the transformed section,

$$kd(b)\left(\frac{kd}{2}\right) = nA_s\,(d - kd) \qquad \text{(EQ. 3.8-12)}$$

where:

$$n = E_s/E_c = 10.0$$

which yields:

$$(kd)^2 + 1.67kd - 66.67 = 0$$

Solving for kd:

$$kd = 7.37 \text{ in}$$

For an applied moment (m) of 3,175,000 in-lbs, the resultant forces are:

$$C = T = \frac{M}{jd} = \frac{3{,}175{,}000}{(40 - \frac{7.37}{3})} = 84{,}570 \text{ lb} \qquad \text{(EQ. 3.8-13)}$$

Rebar and concrete stresses, respectively, are:

$$f_s = \frac{T}{A_s} = 84{,}570 \text{ psi (tension)} \qquad \text{(EQ. 3.8-14)}$$

$$f_c = \frac{2C}{kd(b)} = \frac{2(84{,}570)}{(7.37)(12)} \qquad \text{(EQ. 3.8-15)}$$

$$= 1193 \text{ psi (compression)}$$

Table 3.8-14 shows a comparison of rebar and concrete stresses, and neutral axis locations obtained from the CECAP program and hand calculations. The CECAP results are shown to compare to hand calculations within the force accuracy limits in the program.

c. Sample Problem C: Beam with a Real Moment and a Real Axial Load

This sample problem involves the analysis of a reinforced concrete beam subjected to both a real moment, and a real axial compressive load.

The loading and geometry for the reinforced concrete beam and corresponding CECAP model are illustrated in Figure 3.8-79.

The following illustrates the working stress analysis of reinforced concrete beams subjected to both moments and axial compressive loads. The beam cross-section and stress block are shown in Figure 3.8-80. The analysis uses the equations presented in Reference 3.8-7, simplified as follows:

$$(kd)^3 + 3\left[\frac{M}{N} - \frac{t}{2}\right](kd)^2 + \frac{6nA_s}{b}\left[d - \frac{t}{2} + \frac{M}{N}\right](kd) - \frac{6nA_s d}{b}\left[d - \frac{t}{2} + \frac{M}{N}\right] = 0 \qquad \text{(EQ. 3.8-16)}$$

$$f = \frac{N}{A_s}\left[\frac{M}{N} + \frac{kd}{3} - \frac{t}{2}\right] \Big/ \left[d - \frac{kd}{3}\right] \qquad \text{(EQ. 3.8-17)}$$

$$f = \frac{f_s kd}{n(d - kd)} \quad \text{for } \frac{M}{N} \geq t/6 \qquad \text{(EQ. 3.8-18)}$$

where:

M = moment = 375,000 in-lbs

N = axial load = 101,000 lbs

t = depth of beam = 42 inches

b = width of beam = 12 inches

Equation 3.8-16 becomes:

$kd^3 + 55.8kd^2 + 293kd - 11720 = 0$

$M/N = \frac{3{,}175{,}000}{101{,}000} = 31.4 \geq t/6 = \frac{42}{6} = 7$

Solving the above by iteration for (kd) yields:

kd = 12.7 in

The resulting rebar and steel stresses are:

f_s = 41,320 psi (tension)

f_c = 1922 psi (compression)

The rebar and concrete stresses, and neutral axis location obtained from the CECAP program are compared with the hand calculations in Table 3.8-14. The results for the two solution methods agree very closely.

3.8.7.4 CE668 (Plate Bending Analysis)

3.8.7.4.1 Application

This program performs the linear-elastic analysis of a plate with arbitrary shape and support, stiffener beams, and elastic subgrade, under loads normal to the middle plane of the plate.

3.8.7.4.2 Sample Problems

Sample problems were analyzed by CE668, and compared with hand-calculated solutions.

a. Sample Problem A: Rectangular Plate with a Concentrated Load at the Center

The simply supported rectangular plate, shown in Figure 3.8-81, is subjected to a concentrated load of 300 pounds at its center. Only one-half of the plate is modeled by finite-elements, because of symmetry. The boundary conditions are zero-displacement with free normal rotation at the simply supported edges, and free displacement with zero normal rotation at the symmetry axis. The plate has isotropic structural properties.

The problem parameters are:

Poisson's ratio (υ) = 0.3

Modulus of elasticity (E) = 29×10^6 psi

Plate thickness (h) = 0.5 in

Concentrated load (P) = 300 lb

Width of plate (a) = 10 inches

Length of plate (b) = 40 inches

The formulas for the deflections and moments are taken from Reference 3.8-8.

Deflection (at Center)

$$\omega = 0.01695 \frac{Pa^2}{D} \qquad \text{(EQ. 3.8-19)}$$

where:

$$D = \frac{Eh^3}{12(1-\upsilon^2)}$$

ω = 0.00153 in at Node 116

Moments

M_x: (for b >> a) (at x = 2, y = 0)

$$M_x = \frac{-P(1+\upsilon)}{8\pi} \ln \left[\frac{1 - \sin \frac{\pi x}{a}}{1 + \sin \frac{\pi x}{a}} \right] \quad \text{(EQ. 3.8-20)}$$

M_x = 20.92 in-lb at Node 113

M_y: (for b >> a) (at x = 6, y = 0)

$$M_y = -P \frac{(1+\upsilon)}{8\pi} \ln \left[\frac{1 - \sin \frac{\pi x}{a}}{1 + \sin \frac{\pi x}{a}} \right] \quad \text{(EQ. 3.8-21)}$$

M_y = 57.198 in-lb at Node 117

The hand-calculated values for deflections and moments are compared with the CE668 values in Table 3.8-15. The results for the two solution methods are in very close agreement, the largest difference being 1.55%.

b. Sample Problem B: Uniform Load on a Rectangular Plate with Various Edge Conditions

For this problem, the rectangular plate has one edge fixed, one edge free, and two edges simply supported, as shown in Figure 3.8-82. The plate is subjected to a uniformly distributed load (q) equal to 2.0 psi. Only one-half of the plate is modeled by finite-elements, because of symmetry. Boundary conditions are specified in accordance with the edge support conditions.

The problem parameters are as follows:

Poisson's ratio (υ) = 0.3

Modulus of elasticity (E) = 29×10^6 psi

Plate thickness (h) = 0.2 in

Uniformly distributed load (q) = 2.0 psi

Plate width (b) = 15 inches

Plate length (a) = 30 inches

The formulas for the deflections and moments were taken from Reference 3.8-8.

Deflection (at x = 15, y = 15)

$$\omega = 0.0582 \frac{qb^4}{D} \qquad \text{(EQ. 3.8-22)}$$

where:

$$D = \frac{Eh^3}{12(1-\upsilon^2)}$$

ω = 0.277 in at Node 11

Moments

M_x: (at x = 15, y = 15)

$$M_x = 0.0293\ qa^2$$

$$= 52.74 \text{ in-lb at Node 11} \qquad \text{(EQ. 3.8-23)}$$

M_y: (at x = 15, y = 0)

$$M_y = 0.319\ qb^2$$

$$= 143.55 \text{ in-lb at Node 121} \qquad \text{(EQ. 3.8-24)}$$

The hand-calculated values for deflections and moments are compared with the CE668 values in Table 3.8-15. The results for the two solution methods are in close agreement, the largest difference being 3.4%.

3.8.7.5 EASE (Elastic Analysis for Structural Engineering)

3.8.7.5.1 Application

EASE is a finite-element program which performs static analyses of two-dimensional and three-dimensional trusses and frames, plane elastic bodies, and plate and shell structures. The program library contains various types of elements, including truss, beam, plane stress and strain, plate bending, and shell elements. The EASE program accepts thermal loads, as well as pressure, gravity, and concentrated loads.

The program output includes joint displacements, beam forces and element stresses, and forces and moments.

3.8.7.5.2 Program Background

EASE was developed by the Engineering/Analysis Corporation, Redondo Beach, California, in 1969, and is in the public domain. The version currently used by Bechtel is maintained by the Control Data Corporation, Cybernet Service.

3.8.7.6 E0119

3.8.7.6.1 Application

This program analyzes a bolted flange. The program calculates allowable and actual bolt stresses, and longitudinal, radial, and tangential flange stresses.

3.8.7.6.2 Program Background

The symbols, terms, and analysis procedures used in this program are in accordance with ASME Section III, Appendix XI.

The version of this program currently used by Bechtel is maintained by the Control Data Corporation.

3.8.7.6.3 Sample Problems

Sample problems were analyzed by E0119 and compared with the solutions published in Reference 3.8-9.

The problem parameters for the two sample problems are as follows:

Design pressure = 400 psi

Design temperature = 500°F

Atmospheric temperature = 75°F

Poisson's ratio = 0.30

Corrosion allowance = 0

Gasket width = 0.75 inches

Effective gasket width = 0.306 inches

Gasket factor = 2.75

Gasket seating strength = 3700 psi

a. Sample Problem A: Welding Neck Flange

   Figure 3.8-83 details the dimensions of the welding neck flange. Table 3.8-16 compares the results obtained using E0119 with the results published in Reference 3.8-9.

b. Sample Problem B: Slip-on Flange

Figure 3.8-84 details the dimensions of the slip-on flange. Table 3.8-16 compares the results obtained using E0119 with the results published in Reference 3.8-9.

In both problems, the results obtained using E0119 compare favorably with the published results.

3.8.7.7 E0781 (Shells of Revolution Program)

3.8.7.7.1 Application

This program calculates the stresses and displacements in thin-walled elastic shells of revolution when subjected to static edge, surface, and/or temperature loads with arbitrary distribution over the surface of the shell. The geometry of the shell must be symmetric, but the shape of the median is arbitrary. It is possible to include up to three branch shells with the main shell in a single model. In addition, the shell wall may consist of different orthotropic materials, and the thickness of each layer and the elastic properties of each layer may vary along with the median.

3.8.7.7.2 Program Background

The Shells of Revolution Program is based on the analysis described in Reference 3.8-10.

The program numerically integrates the eight ordinary first-order differential equations of thin-shell theory. The equations are derived so that the eight variables chosen are those appearing on the boundaries of the axially symmetric shell; thus the entire problem is expressed in these fundamental variables.

The program has been altered so that a 4x4 force-displacement relation is used as a boundary condition, as an alternative to the usual procedure of specifying forces or displacements. This force-displacement relation describes the forces at the boundary in terms of displacements at the boundary, or the displacements at the boundary in terms of forces, or some compatible combination of the two. In this manner, it is possible to study the behavior of a large complex structure. It is also possible to introduce a "Spring Matrix" at the end of any part of the stress model. This matrix must be expressed in the form, Force = Spring Matrix · Displacement. In addition to the above changes, the program has been modified to increase the size of the problem that can be considered and to improve the accuracy of the solution.

3.8.7.7.3 Sample Problems

This program is verified by comparing the computer results with experimental measurements and published references. Two sample problems are presented as examples of verification.

a. Sample Problem A: Comparison of 2:1 Ellipsoidal and Torispherical Heads Subjected to an Internal Pressure Load

   This problem illustrates the program's ability to generate cylindrical, torispherical, and ellipsoidal shapes. The E0781 program's "solution" is compared to the experimental investigation of 2:1 ellipsoidal heads subjected to internal pressure discussed in Reference 3.8-11.

   The problem compares a 2:1 ellipsoidal head, to an equivalent torispherical head subjected to the same uniformly distributed internal pressure. An equivalent torisphere is defined as one having the same height above the tangent line as the

ellipsoid, and a minimal L/b ratio (thus having the least possible discontinuity between the torus and the sphere). For the geometry shown in Figure 3.8-85:

$$(L-b) \sin \phi_o = A-r \qquad \text{(EQ. 3.8-25)}$$

$$(L-b) \cos \phi_o = L-B \qquad \text{(EQ. 3.8-26)}$$

Minimizing L/b using equations 3.8-25 and 3.8-26:

$$\tan \phi_o = B/A = 0.5019 \qquad \text{(EQ. 3.8-27)}$$

$$\phi_o = 26.653^\circ$$

$$L/A = \frac{c \pm (c^2 - 2c)^{1/2}}{2} \qquad \text{(EQ. 3.8-28)}$$

where:

$c = B/A + A/B = 2.494$

$L = \frac{18.19}{2} [2.5 + (6.22 - 4.99)^{1/2} = 32.778$ in

$b = B [B/A - L/A] + A = 6.32$ in

and:

A = radius of cylinder = 18.19 inches

B = height of torisphere or ellipsoid above the base (tangent line) = 9.31 inches

L = major radius of torisphere

b = minor radius of torisphere

t = thickness of the shell

Segment lengths used are:

<u>cylinder</u>

$$(rt)^{1/2} = 2.37 \text{ inches} \qquad \text{(EQ. 3.8-29)}$$

where:

r = distance to pole = 18.16 inches

t = thickness of shell = 0.31 inches

<u>torisphere</u>

5° to 10° - 4 angular segments @ 1.25°

10° to 26.567° - 4 angular segments @ 4.13°

26.567° to 90° - 6 angular segments @ 10.57°

ellipsoid

5° to 10° - 2 4 angular segments @ 1.25°

10° to 30° - 4 angular segments @ 5°

30° to 90° - 6 angular segments @ 10°

Boundary Conditions:

It is assumed that at 5° from the pole, a membrane stress exists in both the ellipsoid and the torisphere:

$$Q = M\phi = 0 \qquad \text{(EQ. 3.8-30)}$$

$$N\phi = \frac{pr}{2 \sin \phi} \qquad \text{(EQ. 3.8-31)}$$

where:

r = distance to pole = 32.778 in

Q = transverse shear in ϕ direction, lb/in

$M\phi$ = moment resultant in ϕ direction, in-lb/in

$N\phi$ = membrane force in ϕ direction, lbs/in

Letting (p) = pressure = 680 psi, then for the torisphere:

$N\phi = (680/2)(32.778) = 11,144.5$ lb/in

If $N\phi = 11,144.5$ lb/in, a preliminary run yields:

Q = 95.202 lb/in, so a new value for $N\phi$ for the torisphere is calculated:

$$\Delta N = \frac{\Delta Q}{\tan \phi} \qquad \text{(EQ. 3.8-32)}$$

$N\phi = 11,144.5 + \Delta N = 10056.3$ lb/in and an appropriate membrane state was generated.

For the ellipsoid:

$$r = \frac{A \sin \phi}{R} \qquad \text{(EQ. 3.8-33)}$$

where:

$R = [C_1 + (1 - C_1)\sin^2\phi]^{1/2}$

$C_1 = (B/A)^2 = 0.2519$

$R = 0.5075$

$N\phi = \frac{A \sin\phi}{R} \frac{P}{2\sin\phi} = 12{,}185.78$ lb/in

To better compare the heads, it seems desirable to have the longitudinal displacement at the center of the cylinder equal to zero ($\mu\phi = \phi$). Thus the problem is run twice; the first run yielding the radial displacement, W, required for zero-displacement at the center (W = 0.0966 in).

Start	W = 0.0966 in
	$N\phi$ = 10,056 lb/in
	$M\phi = N = 0$
End	$Q = N = M0 = 0$
	$N\phi$ = 12,186 lb/in

Figure 3.8-86 shows the analytical model, with boundary conditions.

In order to check the results, the answers at the boundaries are examined first. It is assumed that there is a membrane state of stress at the boundaries. Therefore, at the edges Q and $M\phi$ must be approximately zero.

	Q (lb/in)	$M\phi$ (lb-in/in)
Start	-0.08636	0.0
End	-0.0009252	0.0001487

To satisfy equilibrium in the cylinder:

$N\phi \approx 0.5pr = 6169$ lb/in

Plots of the hoop force and longitudinal bending from E0781 results compare the ellipsoidal and torispherical heads. Even though the change in radii is minimized, the disturbance at the junction of the sphere and torus is considerable (Figure 3.8-87).

A comparison with the experimental ellipsoidal head shows a good correlation of stress values. Plots of $\nabla\phi$ and $\nabla\theta$ on the inside, outside, and meridian of the head

are shown in Figures 3.8-88 through 3.8-92. Any deviations are caused by the changes in thickness, and by the experimental head's variation from a true 2:1 ellipsoidal head. These variations are shown in Figures 3.8-93 and 3.8-94.

b. Sample Problem B: Cylindrical Water Tank with Tapered Walls

This problem illustrates the program's capability to analyze a pressure load with one fixed boundary and one free boundary.

The problem used for this verification is "Shell of Variable Thickness," taken from Reference 3.8-12 (pp. 289-295).

The problem consists of a tapered shell filled with water. The shell has a radius of 9 feet, and is 12 feet high. The shell thickness varies from 11 inches at the bottom, to 3 inches at the top. These dimensions, and the location of the Z axis, are shown in Figure 3.8-95. The length of a segment is 18 inches $[(rt)^{1/2}]$, where r and t are the same as defined in Sample Problem A.

Since the pressure varies linearly, only two points are needed in the function generator in order to fully describe the function.

It is known that the pressure at the top of the tank, exposed to the atmosphere, is zero. Assuming that the density of the water is 62.5 lb/ft^3, the pressure at the bottom of the tank is:

$$p = \frac{(12\ ft)(62.5\ lb/ft^3)}{(144\ in^2/ft^2)} = 5.21\ psi$$

The boundary conditions for this problem are as follows:

W = displacement normal to surface

$U\phi$ = displacement component in ϕ direction

$\beta\phi$ = rotation of reference surface in ϕ direction

Q = transverse shear in ϕ direction

$N\phi$ = membrane force in ϕ direction

$M\phi$ = moment resultant in ϕ direction

Fixed at start $W = U\phi = \beta\phi = 0$

Free at end $Q = N\phi = M\phi = 0$

Table 3.8-17 lists the Program E0781 results, and compares them with the theoretical solutions from Reference 3.8-12 at two locations.

Program E0781 yields a maximum hoop force, $N\phi$, equal to 346.8 lb/in (4160 lb/ft), 54 inches from the base. This value differs from the theoretical solution of 4180 lb/ft by 0.48%.

Program E0781 yields a maximum moment at the base, M□, equal to -1539 in-lb/in (-1539 ft-lb/ft). This value differs from the theoretical solution of -1470 ft-lb/ft by 4.69%.

3.8.7.8 FINEL (Finite-Element Program for Cracking Analysis)

3.8.7.8.1 Application

This program performs a static analysis of stresses and strains in plane and axisymmetric structures by the finite-element method. The program computes the displacements of the corners of each element, and the stresses and strains within each element.

3.8.7.8.2 Program Background

In this program, the structure is idealized as an assemblage of two-dimensional finite-elements of triangular or quadrilateral shapes, having arbitrary material properties. Reinforcement of concrete materials is included by adjusting the element material properties. Bilinearity in compression, and bilinearity or cracking in tension are specially emphasized.

The version of this program currently used by Bechtel is maintained by Control Data Corporation.

3.8.7.8.3 Sample Problems

To verify this program, sample problems were analyzed by FINEL, and compared to experimental and/or hand-calculated solutions. Three sample problems are presented as examples of verification.

a. Sample Problem A: Simply Supported Beam with a Concentrated Load at the Center

The beam shown in Figure 3.8-96 is investigated experimentally and analytically. This investigation compares results obtained from the FINEL program with those obtained from References 3.8-13 and 3.8-14.

The finite-element mesh used in Reference 3.8-14, and in the FINEL analysis are shown in Figures 3.8-97 and 3.8-98, respectively. The FINEL analysis requires a finer mesh because it uses linear displacement elements. Reference 3.8-14 uses quadratic displacement elements.

The material properties of the concrete and reinforcing steel, and the loading history used in the FINEL analysis are given in Table 3.8-18.

The cracking patterns obtained from Reference 3.8-14 and FINEL are shown in Figure 3.8-99. The load-deflection curves from References 3.8-13 and 3.8-14 and the FINEL analysis are shown in Figure 3.8-100. The load-deflection curve obtained from the FINEL analysis shows very good agreement with the experimental results. The cracked region grows faster in the FINEL analysis, and more slowly in Reference 3.8-14, since the FINEL and Reference 3.8-14 load-deflection curves show different gradients (stiffnesses).

The results of analytical, experimental, and FINEL solutions are shown in Figure 3.8-100. The FINEL analysis agrees well with the experimental results, up to the point where the reinforcing steel in the beam yields. After the yield point, the FINEL analysis incorrectly calculated the effective stiffness of elements which have yielded. Therefore, the solution is not valid for further loadings. However, since all reinforcing steel remains elastic for the containment analysis, the FINEL program is verified for that application.

b. Sample Problem B: Axially Constrained Hollow Cylinder with a Distributed Pressure Loading

This problem investigates the response of an axially constrained hollow cylinder to internal pressure. A hand-calculated solution yields values of tangential, axial, and radial stresses at various radii from the center of the cylinder, which are then compared to the FINEL values.

The finite-element model is illustrated in Figure 3.8-101. Nodal points are free to move only in the radial direction, representing the conditions of axisymmetry and plane strain.

The problem parameters are as follows:

Poisson's ratio (υ) = 0.25

Modulus of elasticity (E) = 4.32×10^5 ksf

Number of nodal points = 22

Number of elements = 10

Internal pressure (p) = 1.0 ksf

From References 3.8-15 and 3.8-16, the following equations were used:

Hoop or tangential stress, T :

$$T = p \frac{a^2 (b^2 + r^2)}{r^2 (b^2 - a^2)} \qquad \text{(EQ. 3.8-34)}$$

Axial stress, T_2:

$$T_2 = \frac{2\upsilon P a^2}{b^2 - a^2} = \frac{P}{2} \frac{a^2}{b^2 - a^2} \qquad \text{(EQ. 3.8-35)}$$

Radial stress, T_R:

$$T_R = - p \frac{a^2 (b^2 - r^2)}{r^2 (b^2 - a^2)} \qquad \text{(EQ. 3.8-36)}$$

where:

a = 65.0 feet

b = 68.75 feet

p = 1.0 ksf

$a \leq r \leq b$

The results from FINEL for the hollow cylinder tangential, axial, and radial stresses are compared with the hand-calculated values in Table 3.8-19. The results are exactly the same, except for one value, where there is a 4.17% difference.

c. Sample Problem C: Axially Constrained Hollow Cylinder with a Linear Temperature Gradient

This problem evaluates the response of an axially constrained hollow cylinder, to a radially varying linear temperature gradient. The tangential, axial, and radial stresses are determined by hand calculations, and compared to the FINEL results.

Figure 3.8-102 illustrates the finite-element mesh. The conditions of axisymmetry and plane strain are imposed by using the axisymmetric quadrilateral element, and restraining all nodes against axial displacement.

The temperature profile is shown in Figure 3.8-103.

The problem parameters are as follows:

Poisson's ratio (υ) = 0.25

Modulus of elasticity (E) = 4.32×10^5 ksf

Coefficient of thermal expansion (α) = 6×10^{-6} ft/ft/°F

Number of nodal points = 22

Number of elements = 10

From References 3.8-16 and 3.8-17, the following equations are used:

Hoop or tangential stress, ∂_θ :

$$\partial_\theta = \frac{\alpha E}{1-\upsilon}\frac{1}{r^2}\left[\frac{(r^2+a^2)}{b^2-a^2}\int_a^b Trdr + \int_a^r Tr'dr' - Tr^2\right] \qquad \text{(EQ. 3.8-37)}$$

Axial stress, ∂_z :

$$\partial_z = \frac{\alpha E}{1-\upsilon} \left[\frac{2\upsilon}{b^2 - a^2} \int_a^b Trdr - T \right] \quad \text{(EQ. 3.8-38)}$$

Radial stress, ∂_R :

$$\partial_R = \frac{\alpha E}{1-\upsilon} \frac{1}{r^2} \left[\frac{(r^2 - a^2)}{b^2 - a^2} \int_a^b Trdr - \int_a^r Tr'dr' \right] \quad \text{(EQ. 3.8-39)}$$

where:

a = 65.0 feet

b = 68.75 feet

T = T(r) = temperature above reference, °F (reference temperature = 100°F)

Expressions for the temperature field are:

$T(r) = C_2 r + C_1$ (EQ. 3.8-40)

$T(a) = 25 = C_1 + 65.0C_2$ (EQ. 3.8-41)

$T(b) = -25 = C_1 + 68.75C_2$ (EQ. 3.8-42)

Solving:

$$C_2 = \frac{-50}{68.75 - 65} = -13.33$$

$C_1 = -25 - 68.75(-13.33) = 891.67$

Then:

$T(r) = -13.33r + 891.67$

Evaluating the integral:

$$\int Trdr = \int (-13.33r + 891.67)rdr$$

$$= -\frac{13.33r^3}{3} + \frac{891.67r^2}{2} + C$$

$$= -4.44r^3 + 445.83r^2 + C$$

$$\int_a^b Trdr = -4.44(b^3 - a^3) + 445.83(b^2 - a^2)$$

$$\int_s^b Tr'dr' = -4.44(r^3 - a^3) + 445.83(r^2 - a^2)$$

The results from FINEL for the tangential, axial, and radial stresses are compared with the values obtained by hand calculations in Table 3.8-19. The results between the two methods of solution agree very closely.

3.8.7.9 ME620 (Transient Temperature Analysis of Plane and Axisymmetric Solids)

3.8.7.9.1 Application

The heat conduction program, ME620, is used to determine the temperature distribution as a function of time, within a plane or axisymmetric solid body subjected to step-function temperature or heat flux inputs. The program is also used for steady-state temperature analysis.

3.8.7.9.2 Program Background

The program utilizes a finite-element technique coupled with a step-by-step time integration procedure, as described in Reference 3.8-18.

The program was developed at the University of California, Berkeley, by Professor E. L. Wilson, and has been modified by Bechtel to incorporate the save and restart capabilities. The version of this program currently used by Bechtel is maintained by the Control Data Corporation.

3.8.7.9.3 Sample Problems

To verify this program, sample problems were analyzed by ME620 and compared with published data. Two sample problems are presented as examples of verification.

a. Sample Problem A: Heat Conduction in a Square Plate with One Edge Quenched

This problem tests the ability of the program to solve the temperature changes in a plane region subjected to conduction boundary conditions. The plate is brought to an equilibrium temperature, and one edge quenched while the other three edges are kept insulated.

A square plate is brought to equilibrium at a given initial temperature, T_o. Three edges are perfectly insulated, while a third edge is suddenly brought to a lower temperature, T_1. This quench is kept constant for the entire analysis. A temperature-time history is then obtained for the corner farthest from the quenched edge.

Figure 3.8-104 shows the actual plate arrangement, while Figure 3.8-105 shows a diagram of the finite-elements.

The problem parameters are as follows:

Nomenclature

L = length of longest heat flow path, inches

T_o = initial temperature of plate, °F

T_1 = quenching temperature of edge, °F

Data

The plate is 10 inches square

T_o = 100°F

T_1 = 0°F

Diffusivity α = 1.0 in^2/sec (chosen for convenience)

Time increment (ΔT) = 1 second for numerical solution

At any time, t, during the transient state, the time factor T (or characteristic time) is given by:

$$T = \alpha t/L^2$$

The time to reach steady-state is given when T = 1.0; hence the transient time is $t = L^2/\alpha$ = 100 seconds. The results derived from Reference 3.8-19 are plotted in Figure 3.8-106.

The temperature variation at point A is plotted in Figure 3.8-106 according to the results of ME620, and is compared with the theoretical transient change. The curves are seen to agree quite well. Deviations are due to the selected finite-element mesh size, and to the selected time step for the analysis.

b. Sample Problem B: Heat Conduction in a Surface Quenched Sphere

This problem tests the ability of ME620 to analyze the temperature distribution in an axisymmetric solid, with given temperature boundary conditions. The results of the program analysis are compared to a closed-form solution derived from Reference 3.8-20.

This problem considers a solid steel sphere (shown in Figure 3.8-107) which is brought to an equilibrium temperature, and suddenly quenched to a lower uniform temperature on its surface. The quenching environment is held at a constant temperature. A temperature-time history for three seconds is obtained from the program for all node points. The points used for the comparison are at a radius of 0.2 inches; only one time period is checked. The finite-element model is shown in Figure 3.8-108.

The problem parameters are as follows:

Nomenclature

L = length of the longest heat flow path (radius of sphere), inches

T_o = initial temperature of sphere, °F

T_1 = quenching temperature of outer surface, °F

Data

Radius of sphere (R) = 0.59 inches

T_o = 1472°F

T_1 = 68°F

Conductivity = 6.02×10^{-4} Btu/(in-sec-°F)

Diffusivity (α) = 0.0193 in^2/sec

Specific heat = 0.11 Btu/(lb-°F)

Density (p) = 0.284 lb/in^3

Time increment = 0.2 sec

At any time, t, during the transient state, the time factor T (or characteristic time) is given by:

$$T = \alpha t/L^2$$

The time to reach steady-state is given when T = 1.0; hence the transient time is $t = L^2/\alpha$ = 3.0 seconds.

The result from Reference 3.8-20 for the temperature at a radius of 0.2 inches and at time t = 1.8 seconds, is 933.8°F. The result obtained from ME620 is 923.4°F. The difference between these two values is 1.1%.

3.8.7.10 ANSYS

3.8.7.10.1 Application

The ANSYS engineering analysis system computer program is a large-scale general purpose computer program employing finite-element technology for the solution of several classes of engineering analysis problems. Analysis capabilities include static and dynamic; plastic, creep, and swelling; small and large deflections; steady-state and transient heat transfer; and steady-state fluid flow. A variety of finite-elements are available for use in the program. Structural loadings may be forces, displacements, pressures, temperatures, or response spectra. The program output includes joint displacements, element stresses, forces, and moments.

3.8.7.10.2 Program Background

ANSYS was developed by Swanson Analysis Systems, Inc, and is in the public domain. The version of the program currently used by Bechtel is maintained by the Control Data Corporation, Cybernet Service. Version 5.0 was used to evaluate the Spent Fuel Pool for increase storage capacity. This evaluation was performed by Gilbert/Commonwealth and Version 5.0 is maintained by Gilbert/Commonwealth.

3.8.7.11 IMAGES 3D

3.8.7.11.1 Application

The IMAGES 3D computer program is a three-dimensional general purpose finite element program for use on an IBM-compatible personal computer. Analysis capabilities include static, modal, and dynamic analysis of structures composed of frame, plates, shell and solid elements. Structural loadings may be forces, displacements, pressures, temperatures, response spectra, or time history. The program output includes joint displacements, element stresses, forces and moments. It also calculates natural frequencies and mode shapes.

3.8.7.11.2 Program Background

IMAGES 3D was developed by Celestial Software, which is a division of Robert L. Cloud & Associates. The program is in the public domain. Version 3.0 of the program is currently used by the licensee. The documentation package for IMAGES 3D includes a verification manual which documents a series of test problems that demonstrates that the results from IMAGES 3D are similar to those results of other public domain programs or classical solutions.

3.8.8 REFERENCES

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3.8-2 INTENTIONALLY LEFT BLANK

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3.8-20 Ingersol, Zobel, Ingersol, "Heat Conduction With Engineering, Geological, and Other Applications", Maple Press Co., Inc., York, Pennsylvania, p. 165, (1954).

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3.8-22 "Visual Weld Acceptance Criteria for Structural Welding at Nuclear Power Plants, NCIG-01", Nuclear Construction Issues Group, Revision 2, (May 7, 1985).

3.8-23 "Building Code Requirements for Concrete Masonry Structures", ACI 531 and ACI 531-R, American Concrete Institute, Detroit, (1979).

Table 3.8-1

CODES, STANDARDS, RECOMMENDATIONS, AND SPECIFICATIONS USED IN DESIGN AND CONSTRUCTION OF SEISMIC CATEGORY I STRUCTURES[1]

DESIGNATION	TITLE	EDITION
American Concrete Institute (ACI)		
ACI 214	Recommended Practice for Evaluation of Compression Test Results of Field Concrete	1965
ACI 301	Specifications for Structural Concrete for Buildings	1966
ACI 306	Recommended Practice for Cold Weather Concreting	1966
ACI 307	Specification for the Design of Reinforced Concrete Chimneys	1959
ACI 315	Manual of Practice for Detailing Reinforced Concrete Structures	1965
ACI 318	Building Code Requirements for Reinforced Concrete	1971
ACI 347	Recommended Practice for Concrete Formwork	1968
ACI 605	Recommended Practice for Hot Weather Concreting	1959
ACI 613	Recommended Practice for Selecting Proportions for Concrete	1954
ACI 614	Recommended Practice for Measuring, Mixing, Transporting and Placing Concrete	1959
ACI SP-2	Manual of Concrete Inspection	5th Ed.
American Welding Society (AWS)		
AWS D1.0	Code for Welding in Building Construction	1969
AWS D1.1	Structural Welding Code[2]	1972, 1973 (Rev 1), 1974 (Rev 2), 1975, 1976 (Rev 1), 1977 (Rev 2)
AWS D12.1	Recommended Practice for Welding Reinforcing Steel, Metal Inserts, and Connections in Reinforced Concrete Construction	1961

Table 3.8-1 (Cont'd)

DESIGNATION	TITLE	EDITION
American Society of Mechanical Engineers (ASME)		
ASME	ASME Boiler and Pressure Vessel Code	
	a. Section II, Part C: Welding Rods, Electrodes, and Filler Metals	1971, 1974 with Addenda through 1976
	b. Section III, Subsection B: Requirements for Class B Vessels	1968, 1971, 1974 with Addenda through 1976
	c. Section III, Subsection NB: Class 1 Components	1977 with Addenda through Summer 1979
	d. Section III, Subsection NC: Class 2 Components	1968, 1971, 1974, 1977 with Addenda through Summer 1978
	e. Section III, Subsection NE: Class MC Components	1977 with Addenda through Winter 1978
	f. Section V, Nondestructive Examination	1968, 1971, 1974, 1977 with Addenda through Summer 1978
	g. Section VIII, Parts UW and UG, and Division 1	1968, 1971, 1974, 1977 with Addenda through Summer 1978
	h. Section IX, Welding and Brazing Qualification	1968, 1971, 1974 with Addenda through 1976
American Society for Testing and Materials (ASTM)[3]		
ASTM A20	General Requirements for Steel Plates for Pressure Vessels	1970, 1974a
ASTM A36	Structural Steel	1969, 1970, 1970a, 1974, 1975, 1977, 1979
ASTM A53	Welded and Seamless Steel Pipe	1970, 1972a, 1973, 1976
ASTM A82	Cold-Drawn Steel Wire for Concrete Reinforcement	1976

Table 3.8-1 (Cont'd)

DESIGNATION	TITLE	EDITION
ASTM A106	Seamless Carbon Steel Pipe for High Temperature Service	1970, 1972a, 1974
ASTM A108	Steel Bars, Carbon, Cold Finished, Standard Quality	1969, 1973
ASTM A123	Zinc (Hot-Galvanized) Coatings on Products Fabricated from Rolled, Pressed and Forged Steel Shapes, Plates, Bars and Strip	1973
ASTM A153	Zinc Coating (Hot-Dip) on Iron and Steel Hardware	1967
ASTM A167	Stainless and Heat-Resisting Chromium-Nickel Steel Plate, Sheet, and Strip	1974
ASTM A193	Alloy-Steel and Stainless Steel Bolting Materials for High Temperature Service	1977
ASTM A240	Heat-Resisting Chromium and Chromium-Nickel Stainless Steel Plate, Sheet, and Strip for Fusion Welded Unfired Pressure Vessels	1977
ASTM A242	High Strength, Low Alloy Structural Steel	1975
ASTM A262	Detecting Susceptibility to Intergranular Attack on Stainless Steels	1970
ASTM A276	Stainless and Heat-Resisting Steel Bars and Shapes	1976
ASTM A285	Pressure Vessel Plates, Carbon Steel, Low and Intermediate Tensile Strength	1969, 1972
ASTM A306	Carbon Steel Bars Subject to Mechanical Property Requirements	1964
ASTM A307	Carbon Steel Externally and Internally Threaded Standard Fasteners	1968
ASTM A312	Seamless and Welded Austenitic Stainless Steel Pipe	1974
ASTM A325	High Strength Bolts for Structural Steel Joints, Including Suitable Nuts and Plain Hardened Washers	1970a, 1971a, 1974
ASTM A386	Zinc Coating (Hot-Dip) on Assembled Steel Products	1967
ASTM A403	Wrought Austenitic Stainless Steel Piping Fittings	1973a

Table 3.8-1 (Cont'd)

DESIGNATION	TITLE	EDITION
ASTM A416	Uncoated Seven-Wire Stress-Relieved Strand for Prestressed Concrete	1974
ASTM A441	High Strength Low Alloy Structural Manganese Vanadium Steel	1970, 1970a, 1975
ASTM A449	Quenched and Tempered Steel Bolts and Studs	1976c
ASTM A479	Stainless and Heat-Resisting Steel Bars and Shapes for Use in Boilers and Other Pressure Vessels	1974, 1977
ASTM A480	Delivery of Flat-Rolled Stainless and Heat-Resisting Steel Plate, Sheet, and Strip	1974a, 1975
ASTM A490	Quenched and Tempered Alloy Steel Bolts for Structural Steel Joints	1975, 1976
ASTM A500	Cold-Formed Welded and Seamless Carbon Steel Structural Tubing in Rounds and Shapes	1974, 1976
ASTM A501	Hot-Formed Welded and Seamless Carbon Steel Structural Tubing	1976
ASTM A516	Pressure Vessel Plates, Carbon Steel for Moderate- and Lower-Temperature Service	1971, 1972, 1973, 1974, 1974a, 1975, 1976
ASTM A519	Seamless Carbon and Alloy Steel Mechanical Tubing	1973, 1977b, 1979
ASTM A527	Steel Sheet, Zinc-Coated (Galvanized) by the Hot-Dip Process	1971
ASTM A570	Hot-Rolled Carbon Steel Sheet and Strip, Structural Quality	1972
ASTM A575	Merchant Quality Hot-Rolled Carbon Steel Bars	1971, 1973
ASTM A606	Steel Sheet and Strip, Hot-Rolled and Cold-Rolled, High Strength, Low Alloy, with Improved Corrosion Resistance	1975
ASTM A537	Pressure Vessel Plates, Heat Treated, Carbon-Manganese-Silicon	1967, 1974a
ASTM A569	Steel, Carbon (0.15%, maximum). Hot-Rolled Sheet and Strip, Commercial Quality	1972
ASTM A588	High Strength Low Alloy Structural Steel with 50,000 psi Minimum Yield Point to 4 inches Thick	1980a

Table 3.8-1 (Cont'd)

DESIGNATION	TITLE	EDITION
ASTM A615	Deformed and Plain Billet Steel Bars for Concrete Reinforcement	1968, 1972, 1975
ASTM A668	Steel Forgings, Carbon and Alloy for General Industrial Use	1972
ASTM A675	Special Quality Hot-Rolled Carbon Steel Bars Subject to Mechanical Property Requirements	1972
ASTM B209	Aluminum-Alloy Sheet and Plate	1974, 1977
ASTM B308	Aluminum-Alloy Standard Structural Shapes, Rolled or Extruded	1973
ASTM C31	Making and Curing Concrete Test Specimens in the Field	1969
ASTM C33	Concrete Aggregates	1971a, 1978
ASTM C39	Compressive Strength of Molded Concrete Cylinders	1971, 1972
ASTM C40	Organic Impurities in Sand for Concrete	1966, 1973
ASTM C55	Concrete Building Brick	1975
ASTM C70	Surface Moisture in Fine Aggregate	1966, 1973
ASTM C87	Effect of Organic Impurities in Fine Aggregate on Strength of Mortar	1969
ASTM C88	Soundness of Aggregates by Use of Sodium Sulfate or Magnesium Sulfate	1971, 1971a, 1973, 1976
ASTM C90	Hollow Load-Bearing Concrete Masonry Units	1975
ASTM C94	Ready-Mixed Concrete	1969, 1972, 1978a
ASTM C109	Compressive Strength of Hydraulic Cement Mortars	1970T, 1970, 1973, 1977
ASTM C114	Chemical Analysis of Hydraulic Cement	1969, 1973, 1977
ASTM C115	Fineness of Portland-Cement by the Turbidimeter	1970, 1973, 1977, 1978a
ASTM C117	Materials Finer than No. 200 Sieve in Mineral Aggregates by Washing	1969, 1976

Table 3.8-1 (Cont'd)

DESIGNATION	TITLE	EDITION
ASTM C123	Lightweight Pieces in Aggregate	1969
ASTM C127	Specific Gravity and Absorption of Coarse Aggregate	1968, 1977
ASTM C128	Specific Gravity and Absorption of Fine Aggregate	1968, 1973
ASTM C131	Resistance to Abrasion of Small Size Coarse Aggregate by Use of the Los Angeles Machine	1969, 1976
ASTM C136	Sieve or Screen Analysis of Fine and Coarse Aggregates	1971, 1976
ASTM C138	Unit Weight, Yield, and Air Content of Concrete	1971T, 1971, 1977
ASTM C140	Sampling and Testing of Concrete Masonry Units	1970
ASTM C142	Clay Lumps and Friable Particles in Aggregates	1971, 1978
ASTM C143	Slump of Portland-Cement Concrete	1971, 1974
ASTM C144	Standard Specification for Masonry Mortar	1966T, 1970
ASTM C145	Solid Load-Bearing Concrete Masonry Units	1975
ASTM C150	Portland-Cement	1968, 1970, 1971, 1972, 1973a, 1977, 1978a
ASTM C151	Autoclave Expansion of Portland-Cement	1971, 1977
ASTM C171	Standard Specification for Sheet Materials for Curing Concrete	1969
ASTM C172	Sampling Fresh Concrete	1971
ASTM C183	Sampling Hydraulic Cement	1971, 1973, 1976
ASTM C185	Air Content of Hydraulic Cement Mortar	1971, 1975
ASTM C186	Heat of Hydration of Hydraulic Cement	1968, 1977, 1978
ASTM C190	Tensile Strength of Hydraulic Cement Mortars	1970, 1972, 1977

Table 3.8-1 (Cont'd)

DESIGNATION	TITLE	EDITION
ASTM C192	Making and Curing Concrete Test Specimens in the Laboratory	1969, 1976
ASTM C207	Standard Specification for Hydrated Lime for Masonry Purposes	1976
ASTM C231	Air Content of Freshly Mixed Concrete by the Pressure Method	1971, 1972T, 1978
ASTM C233	Testing Air Entraining Admixtures for Concrete	1969, 1978
ASTM C235	Scratch Hardness of Coarse Aggregate Particles	1968
ASTM C260	Air Entraining Admixtures for Concrete	1969, 1977
ASTM C266	Time of Setting of Hydraulic Cement by Gillmore Needles	1971, 1977
ASTM C289	Potential Reactivity of Aggregates	1971
ASTM C295	Petrographic Examination of Aggregates for Concrete	1965
ASTM C451	False Set of Portland-Cement	1972, 1975
ASTM C452	Potential Expansion of Portland-Cement Mortars Exposed to Sulfate	1968, 1975
ASTM C469	Static Modulus of Elasticity and Poisson's Ratio of Concrete in Compression	1965
ASTM C476	Mortar and Grout for Reinforced Masonry	1971
ASTM C494	Chemical Admixtures for Concrete	1971
ASTM C566	Total Moisture Content of Aggregate by Drying	1967
ASTM C617	Capping Cylindrical Concrete Specimens	1971a, 1976
ASTM C845	Expansive Hydraulic Cement	1980
ASTM D75	Sampling Aggregates	1959, 1971
ASTM E109	Dry Powder Magnetic Particle Inspection	1963, 1971
ASTM E328	Stress-Relaxation Tests for Materials and Structures	1972

Table 3.8-1 (Cont'd)

DESIGNATION	TITLE	EDITION
ASTM E437	Industrial Wire Cloth and Screens (Square Opening Series)	1971
American Association of State Highway and Transportation Officials (AASHTO)		
AASHTO T26	Quality of Water to be Used in Concrete	1970
US Army Corps of Engineers		
CRD C36	Coefficient of Thermal Diffusivity	1948
CRD C39	Thermal Coefficient of Expansion	1955
CRD C79	Method of Test for Flow of Grout Mixtures	1958
CRD C119	Test for Flat and Elongated Particles in Coarse Aggregate	1953
CRD C589	Methods of Sampling and Testing Expensive Grouts	1970
American National Standards Institute (ANSI)		
ANSI N45.2.6	Qualifications of Inspection, Examination, and Testing of Personnel for the Construction Phase of Nuclear Power Plants	1973
American Institute of Steel Construction		
AISC	Specification for the Design, Fabrication and Erection of Structural Steel for Buildings Supplement #1 Supplement #2 Supplement #3	1969 1970 1971 1974
AISC	Code of Standard Practice for Steel Buildings and Bridges	1970
International Conference of Building Officials		
UBC	Uniform Building Code	1967, 1970

Table 3.8-1 (Cont'd)

DESIGNATION	TITLE	EDITION
American Iron and Steel Institute		
AISI	Specification for the Design of Cold-Formed Steel Structural Members	1968
Society of Automotive Engineers		
SAE J444a	Cast Shot Specification for Shot Peening or Blast Cleaning	1976
American Petroleum Institute		
API 5L	Specification for Line Pipe	1973
API 5LX	Specification for High Test Line Pipe	1973
American Waterworks Association		
AWWA M11	Steel Pipe Manual	1964
Regulations of the Commonwealth of Pennsylvania		
	Regulations for Boilers and Unfired Pressure Vessels	-

(1) For exceptions to the above codes, standards, recommendations and specifications, see Section 3.8.6.
(2) The contractor or fabricator may also qualify its welding procedures and welders in accordance with the latest edition of AWS D1.1 code at the time of qualification.
(3) Principal editions used for design are listed; later editions may be used for specific plant modifications.

Table 3.8-2

LOAD COMBINATIONS FOR PRIMARY CONTAINMENT WALL, DIAPHRAGM SLAB, AND REACTOR PEDESTAL

The primary containment, diaphragm slab, and reactor pedestal are designed for the following load combinations:

1. Normal Operating Conditions

   a. $U=1.5D+1.8L+1.0T_o+1.25H_o$

   b. $U=1.25(D+L+E+H_o)+1.0T_o$

   c. $U=0.9D+1.25(E+H_o)+1.0T_o$

   d. $U=1.0D+1.0L+1.8E+1.0T_o+1.25H_o$

2. Design Accident and Extreme Environmental Conditions

   a. $U=1.05D+1.05L+1.0T_A+1.0H_A+1.0R+1.5P$

   b. $U=1.05D+1.05L+1.0T_A+1.0H_A+1.0R+1.25P+1.25E$

   c. $U=1.0D+1.0L+1.0T_A+1.0H_A1.0R+1.0P+1.0E'$

   d. $U=0.95D+1.25E+1.0T_A+1.0H_A+1.0R$[1]

   e. $U=1.05D+1.0B+1.25P'+1.25E$

The pressure-retaining steel elements are designed for the following load combinations[2]:

		Stress Limits
a.	$D+L+1.15P$	1.15 times ASME Section III, Class B for "Normal Operating Conditions"
b.	$D+L+T_A+P$	ASME Section III, Class B for "Normal Operating Conditions"
c.	$D+L+T_A+P+H_A+R+E$	ASME Section III, Summer 1970 Addenda, Figure N-414, "For Emergency Conditions"
d.	$D+L+T_A+P+H_A+R+E'$	ASME Section III, Summer 1970 Addenda, Figure N-414, "For Faulted Conditions"

Table 3.8-2 (Cont'd)

Definitions:

U = Required ultimate load capacity, as defined in ACI 318-71

D = Dead load of structure and major equipment, plus any other major permanent loads contributing stress, such as soil or hydrostatic loads or operating pressures

L = Live loads expected to be present when the plant is operating. For loading conditions that include vertical seismic, replace L by $L_p + L_o$, where:

- L_p = permanent live load to include minor piping, minor equipment and the weight of equipment in lay-down areas: to be accelerated vertically
- L_o = 100 psf (except 50 psf for grating and platforms): not to be accelerated vertically

T_o = Thermal effects due to temperature gradient through the wall, under operating conditions

T_A = Thermal effects due to temperature gradient through the wall, under accident conditions

P = Design basis accident pressure load

R = Steam/water jet forces or reactions resulting from the rupture of process piping

E = Load due to the OBE resulting from a horizontal ground acceleration of 0.075 g, and a vertical ground acceleration of 0.05 g

E' = Load due to the design basis earthquake resulting from a horizontal ground acceleration of 0.15 g, and a vertical ground acceleration of 0.10 g

B = Hydrostatic loading due to postaccident flooding of the primary containment to the level of the reactor core

P' = Pressure of the atmosphere in the primary containment, with the containment flooded to the level of the reactor core

Table 3.8-2 (Cont'd)

H_o = Force on the structure due to thermal expansion or contraction of hanger critical pipes

H_A = Force on the structure due to thermal expansion of pipes, under accident conditions

T = Thermal loads resulting from temperature increases under accident conditions.

(1) Where overturning forces cause net tension in the absence of live load

(2) Bending from jet forces are considered as primary stresses.

Table 3.8-3

PRIMARY CONTAINMENT DESIGN PRESSURE AND TEMPERATURE CRITERIA

PORTION OF CONTAINMENT	TIME AFTER START OF ACCIDENT	CONTAINMENT ATMOSPHERE PRESSURE (psig)	CONTAINMENT ATMOSPHERE TEMPERATURE (°F)
Drywell	0 sec[2]	0.75	135[3]
Suppression Chamber	0 sec[2]	0.75	95
Drywell	0-45 sec	55	340
Suppression Chamber	0-45 sec	55	175
Suppression Chamber[1]	0-45 sec	25	175
Drywell	45 sec-60 min	35	340
Suppression Chamber	45 sec-60 min	35	175
Drywell	1-3 hrs	35	340
Suppression Chamber	1-3 hrs	35	220
Drywell	3-6 hrs	35	320
Suppression Chamber	3-6 hrs	35	220
Drywell	6-24 hrs	20	220
Suppression Chamber	6-24 hrs	20	220
Drywell	1-4 days	20	200
Suppression Chamber	1-4 days	20	200
Drywell	4-30 days	10	175
Suppression Chamber	4-30 days	10	175

(1) Drywell/suppression chamber maximum differential pressure condition

(2) Just before start of accident (i.e., at operating condition)

(3) This information is based on original design basis conditions. Further evaluation has validated the primary containment design for an initial drywell containment atmosphere temperature of 150°F. The stress indicated in UFSAR Figures 3A-362 to 3A-380, Design Assessment Report for Containment Structures reflects current plant conditions.

Table 3.8-4

LOAD COMBINATIONS AND ALLOWABLE STRESSES FOR ASME CLASS MC COMPONENTS[1]

The drywell head assembly, equipment hatches, personnel lock, suppression chamber access hatches, and CRD removal hatch are designed for the following loading combinations and allowable stresses:

	Stress Limits
D+L+1.15P	1.15 times ASME Section III, Class B for "Normal Operating Conditions"
$D+L+T_A+P$	ASME Section III, Class B for "Normal Operating Conditions"
$D+L+T_A+P+H_A+R+E$	ASME Section III, Summer 1970 Addenda, Figure N-414, "For Emergency Conditions"
$D+L+T_A+P+H_A+R+E'$	ASME Section III, Summer 1970 Addenda, Figure N-414, "For Faulted Conditions"

Piping and electrical penetrations are designed for the following load combinations and allowable stresses:

a. The loads used in the design are as follows:

   1. Moments and forces transmitted by the piping to the penetration due to thermal expansion, weight, earthquake (including inertial effects and anchor movements), and other dynamic loads
   2. Pressures
   3. Thermal transients
   4. Number of operating cycles
   5. Pipe failure loads for faulted condition

b. The loading combinations are specified in Section 3.9.

c. Stress limits specified in ASME Section III, Article NB-3220 are used as the design criteria for Class I flued heads for design, normal and upset, and emergency condition. The rules contained in ASME Section III, Appendix F are used in evaluating the faulted condition for Class I and II flued heads.

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[1] Definitions of symbols are given in Table 3.8-2.

Table 3.8-5

LOAD COMBINATION FOR THE REACTOR SHIELD WALL[1]

The reactor shield wall is designed for the following loading combination:

Condition	
Abnormal/Extreme	$D+L+T_A+R+P+E'$

[1] Symbols are defined in Table 3.8-2.

Table 3.8-6

LOAD COMBINATIONS FOR THE SUPPRESSION CHAMBER COLUMNS[1]

The suppression chamber columns are designed for the following loading combinations:

Condition	
Abnormal	$1.05D+1.05L+1.0T_A+1.0R+1.5P$
Abnormal/Severe	$1.05D+1.05L+1.0T_A+1.0R+1.25P+1.25E$
Abnormal/Extreme	$1.0D+1.0L+1.0T_A+1.0R+1.0P+1.0E'$

(1) Symbols are defined in Table 3.8-2.

Table 3.8-7

LOAD COMBINATIONS FOR THE PIPE WHIP RESTRAINTS AND DRYWELL PLATFORMS(1)

The pipe whip restraints and drywell platforms are designed for the following loading combinations:

Condition	
Normal	D+L
Abnormal(2,3)	D+L+R+T

(1) Symbols are defined in Table 3.8-2, except as noted below.

(2) For the design of pipe whip restraints which also support other pipe support(s), either pipe support SSE reaction load or the pipe rupture load (R) is considered.

(3) Thermal loads can be neglected when it can be shown that they are secondary and self-limiting in nature and where the material is ductile.

Table 3.8-8

LOAD COMBINATION FOR THE SEISMIC TRUSS[1]

The seismic truss is designed for the following loading combination:

Condition	
Abnormal/Extreme	D+R+E'

(1) Symbols are defined in Table 3.8-2.

Table 3.8-9

LOAD COMBINATIONS FOR THE REACTOR ENCLOSURE[6]

A. Reinforced Concrete

1. Normal Operating and Severe Environmental Conditions

a. $U=1.5D+1.8L+1.0T_o+1.25H_o$

b. $U=1.25(D+L+H_o+E)+1.0T_o$

c. $U=1.25(D+L+H_o+W)+1.0T_o$

d. $U=0.9D+1.25(H_o+E)+1.0T_o$[1]

e. $U=0.9D+1.25(H_o+W)+1.0T_o$[1]

f. $U=1.0D+1.0L+1.8E+1.0T_o+1.25H_o$[2]

2. Design Accident and Extreme Environmental Conditions

a. $U=1.05D+1.05L+1.0T_A+1.0H_A+1.0R+1.5P$

b. $U=1.05D+1.05L+1.0T_A+1.0H_A+1.0R+1.25P+1.25E$

c. $U=1.0D+1.0L+1.0T_A+1.0H_A+1.0R+1.0P+1.0E'$

d. $U=0.95D+1.25E+1.0T_A+1.0H_A+1.0R$[1]

e. $U=1.0D+1.0L+1.0E'+1.0T_o+1.25H_o+1.0R$

f. $U=1.0D+1.0L+1.0W'+1.0T_o+1.0H_o$

g. $U=1.0D+1.0L+1.0B_o+1.0E'$

h. $U=1.0D+1.0L+1.0R_o$

B. Steel Structures

1. Normal Operation and Severe Environmental Conditions		Stress Limits
a.	$D+L+T_o+H_o$	F_s
b.	$D+L+T_o+H_o+E$	$1.25F_s$
c.	$D+L+T_o+H_o+W$	$1.33F_s$
d.	$D+L+T_o+H_o+E$[2]	F_s

Table 3.8-9 (Cont'd)

2.	Design Accident and Extreme Environmental Conditions		Stress Limits
	a.	$D+L+R+T_o+H_o+P+E'$	See note (3)
	b.	$D+L+R+T_A+H_A+P+E'$	See note (3)
	c.	$D+L+A+T_o+H_o$	See note (3)
	d.	$D+L+T_o+H_o+W'$(4)	See note (3)
	e.	$D+L+R_o$	

C. Post-tensioned Concrete Fuel Pool Girders

1.	Normal Operating Conditions (Including Refueling)		Stress Limits
	For elastic analysis by straight line theory:		
	a.	$D+L+T_o+F$	F_c
	b.	$D+L+E+T_o+F$	$1.25F_c$
	c.	$D+E+T_o+F$(5)	$1.25F_c$
	d.	$D+E'+T_o+F$(5)	$1.50F_c$
	For ultimate strength method:		
	e.	$U=1.5D+1.8L+1.0T_o$	
	f.	$U=1.25(D+L+E)+1.0T_o$	
2.	Design Accident and Extreme Environmental Conditions		
	a.	$U=1.05D+1.05L+1.0T_A$	
	b.	$U=1.05D+1.05L+1.25E+1.0T_A$	
	c.	$U=1.0D+1.0L+1.0E'+1.0T_o$	

Definitions:

W = Wind load

W' = Tornado wind load

Table 3.8-9 (Cont'd)

B_o = Hydrostatic loading due to flooding of the ECCS and RCIC compartments in the reactor enclosure, to suppression pool equilibrium water level

A = Hydrostatic load due to probable maximum flood

f_s = Calculated stress in structural steel

F_s = Allowable stress for structural steel

F_y = Yield strength of structural steel

F = Prestressing force

F_c = Allowable flexural concrete stress, by straight-line theory

R_o = Blast pressure due to railroad accident or pipeline explosion as discussed in Section 2.2.3.1.1 and defined in Reference 2.2-1. (The effect of ground shock due to blast load is a subject of separate investigation.)

For all other definitions, see Table 3.8-2

---

(1) Where overturning forces cause net tension in the absence of live load

(2) For structural elements carrying mainly earthquake forces

(3) The allowable stress in structural steel does not exceed 0.9 F_y in bending, 0.85 F_y in axial tension or compression, and 0.5 F_y in shear. Where F_s is governed by requirements of stability (local or lateral buckling), f_s does not exceed 1.5 F_s. Thermal loads can be neglected when it can be shown that they are secondary and self-limiting in nature and where the material is ductile.

(4) Where protection against tornado forces is required

(5) When effects of upward vertical acceleration under earthquake conditions are considered

(6) Unless they are shown, stress limits comply with the ACI codes and AISC specifications. Deviations shown are consistent with typical nuclear power plant design practices.

Table 3.8-10

LOAD COMBINATIONS APPLICABLE TO SEISMIC CATEGORY I STRUCTURES OTHER THAN PRIMARY CONTAINMENT AND REACTOR ENCLOSURE[5]

A. Reinforced Concrete

1. Normal Operating and Severe Environmental Conditions

a. $U=1.5D+1.8L+1.0T_o+1.25H_o$

b. $U=1.25(D+L+H_o+E)+1.0T_o$

c. $U=1.25(D+L+H_o+W)+1.0T_o$

d. $U=0.9D+1.25(H_o+E)+1.0T_o$[2]

e. $U=0.9D+1.25(H_o+W)+1.0T_o$[2]

For structural elements carrying mainly earthquake forces:

f. $U=1.0D+1.0L+1.8E+1.0T_o+1.25H_o$

2. Design Accident and Extreme Environmental Conditions

a. $U=1.05D+1.05L+1.25E+1.0T_A+1.0H_A+1.0R$

b. $U=0.95D+1.25E+1.0T_A+1.0H_A+1.0R$[2]

c. $U=1.0D+1.0L+1.0E'+1.0T_o+1.25H_o+1.0R$

d. $U=1.0D+1.0L+1.0E'+1.0T_A+1.0H_A+1.0R$

e. $U=1.0D+1.0L+1.0A+1.0T_o+1.25H_o$

f. $U=1.0D+1.0L+1.0W'+1.0T_o+1.0H_o$

g. $U=1.0D+1.0L+1.0R_o$

Table 3.8-10 (Cont'd)

B. Steel Structures

		Stress Limits
1.	Normal Operating and Severe Environmental Conditions	
a.	$D+L+T_o+H_o$	F_s
b.	$D+L+T_o+H_o+E$	$1.25F_s$
c.	$D+L+T_o+H_o+W$	$1.33F_s$
d.	$D+L+T_o+H_o+E$ (3)	F_s
2.	Design Accident and Extreme Environmental Conditions	Stress Limits
a.	$D+L+R+T_o+H_o+E'+P$	See note (4)
b.	$D+L+R+T_A+H_A+E'+P$	See note (4)
c.	$D+L+A+T_o+H_o$	See note (4)
d.	$D+L+T_o+H_o+W'$	See note (4)
e.	D+L+Ro	

(1) Symbols are defined in Table 3.8-9.

(2) Where overturning forces cause net tension in the absence of live load

(3) For structural elements carrying mainly earthquake forces

(4) The allowable stress in structural steel does not exceed 0.9 F_y in bending, 0.85 F_y in axial tension, and 0.5 F_y in shear. Where F_s is governed by requirements of stability (local or lateral buckling), f_s does not exceed 1.5 F_s. Thermal loads can be neglected when it can be shown that they are secondary and self-limiting in nature and where the material is ductile.

(5) Unless they are shown stress limits comply with the ACI codes and AISC specifications. Deviations shown are consistent with typical nuclear power plant design practices.

Table 3.8-11

LOAD COMBINATIONS APPLICABLE TO MISCELLANEOUS STRUCTURAL COMPONENTS OF SEISMIC CATEGORY I STRUCTURES[3]

A.	Anchor Bolts		
	1.	Normal Operating and Severe Environmental Conditions	Stress Limits
		a. $D+L+H_o$	F_s
		b. $D+L+H_o+(E \text{ or } W)$	$1.25F_s$
	2.	Design Accident and Extreme Environmental Conditions	
		a. $D+L+R+H_o+P+E'$	[4]
		b. $D+L+R+H_A+P+E'$	[4]
B.	Masonry		
	1.	Normal Operating and Severe Environmental Conditions	Stress Limits
		a. D+L	1.0xUBC[2]
		b. D+L+E	1.25xUBC[2]
	2.	Design Accident and Extreme Environmental Conditions	
		a. D+L+P	1.0xUBC[2]
		b. D+L+P+E'	1.33xUBC[2]

(1) Symbols are defined in Table 3.8-9.

(2) As specified in UBC, but without the customary increase in normal allowable working stress due to earthquake

(3) Stress limits shown are deviations from the ACI codes and AISC specifications; these values are consistent with typical nuclear power plant design practices.

(4) Strength method is used. Stress limit in steel shall not exceed 0.85 F_y for tension and 0.50 F_y for shear. The allowable stress in concrete shall be in accordance with ACI 318-71.

Table 3.8-12

MINIMUM TESTING FREQUENCY FOR CONCRETE, CONCRETE MATERIALS, CONCRETE MASONRY, AND MASONRY MATERIALS

MATERIAL	REQUIREMENT	TEST	FREQUENCY
Cement properties	Standard physical and chemical	ASTM C150	Once for each 5000 cubic yards of concrete production
Aggregate	Organic impurities	ASTM C40	Once per 8 hour shift during concrete production
	Soundness of aggregate	ASTM C88	Once for each 5000 cubic yards of concrete production
	Material finer than No. 200 sieve	ASTM C117	Once for each 5000 cubic yards of concrete production
	Lightweight pieces in aggregates	ASTM C123	Once for mix qualification
	Specific gravity and absorption	ASTM C127/C128[(1)]	Once for mix qualification
	Abrasion of coarse aggregate	ASTM C131	Once for each 5000 cubic yards of concrete production
	Gradation of coarse aggregate	ASTM C136	Once for each size of coarse aggregate during each 8 hour shift of production
	Gradation of fine aggregate	ASTM C136	Twice during each 8 hour shift of production
	Potential reactivity	ASTM C289	Once for each 5000 cubic yards of concrete production
	Petrographic examination	ASTM C295	Once for mix qualification
	Flat and elongated particles	CRD C119	Once per week on each size of coarse aggregate
Water and ice	Quality of water to be used in concrete (to meet the requirements herein)	AASHTO T26	Once every 3 months
Admixtures	Air entraining agent	ASTM C260	Upon delivery at job-site, prior to approval for use
	Water reducing and retarding agent(s)	ASTM C494	Upon delivery at job-site, prior to approval for use

Table 3.8-12 (Cont'd)

MATERIAL	REQUIREMENT	TEST	FREQUENCY
Concrete	Mixer uniformity	National Ready Mix Concrete Association (NRMCA)	Initially, and then once every 2 years
	Slump	ASTM C143	Once for every 35 cubic yards of each class of concrete produced for concrete used in seismic Category I structures. For all other structures, once for every 50 cubic yards of each class of concrete.
	Air content, temperature, unit weight	ASTM C231/C138	Once for each 100 cubic yards of each class of concrete produced
	Compressive strength	ASTM C31/C39	The specified number of cylinders to be tested for design strength at the date specified are cast for each 100 cubic yards of each class of concrete, or at least once per day for each class of concrete
Masonry units	Compressive strength, absorption, weight, and moisture content	ASTM C140	Test frequency is in accordance with ASTM C140
Mortar aggregate	Physical properties	ASTM C144	The first load and each tenth successive load of masonry aggregate is tested
Cement for mortar	Standard physical and chemical properties	ASTM C150	Initially, and thereafter for every 10,000 pounds of cement delivered
Hydrated lime	Physical and chemical properties	ASTM C207, Type S or SA	Initially, and thereafter for every 5000 pounds of lime delivered
Chemtree grout	Compressive strength	ASTM C39	Two cylinders cast each day that grout is placed
	Unit weight	ASTM C138	Three times, at approximately equal time intervals, each day that grout is placed
Mortar	Compressive strength	UBC 24.23	Once per shift per mixer

(1) ASTM C128 is performed more frequently for medium and high density grout/concrete and masonry grout

Table 3.8-13

MEMBRANE FORCE RESULTANTS FROM "ASHSD" PROGRAM

	THIN-SHELL		LAYERED SHELL	
NODE POINT	LONGITUDINAL FORCE (lb/in)	CIRCUMFERENTIAL FORCE (lb/in)	LONGITUDINAL FORCE (lb/in)	CIRCUMFERENTIAL FORCE (lb/in)
1[1]	27,000	54,004	27,000	54,004
2	27,000	54,005	27,000	54,005
3	27,000	54,008	27,000	54,008
4	27,000	54,012	27,000	54,012
5	27,000	54,015	27,000	54,015
6	27,000	54,012	27,000	54,012
7	27,001	53,999	27,001	53,999
8	27,001	53,968	27,001	53,968
9	27,001	53,912	27,001	53,912
10	27,000	53,829	27,000	53,829
11	26,999	53,731	26,999	53,731
12	26,997	53,654	26,997	53,654
13	26,994	53,674	26,994	53,674
14	26,989	53,912	26,989	53,912
15	26,984	54,532	26,984	54,532
16	27,111	55,724	27,111	55,724

[1] Node point 1 represents the center of the cylinder.

Table 3.8-14

COMPARISON OF RESULTS FROM "CECAP" PROGRAM AND HAND CALCULATIONS

Sample Problem A: Beam with a Thermal Moment

PARAMETER	CECAP	HAND CALCULATION	% ERROR
f_s	13,150 psi	13,790 psi	5.9
f_c	-331 psi	-318 psi	4.1
kd	7.55 in	7.42 in	1.8
M_T	43,760 in-lb/in	43,690 in-lb/in	0.2

Sample Problem B: Beam with a Real Moment

PARAMETER	CECAP	HAND CALCULATION	% ERROR
f_s	79,170 psi	84,570 psi	6.4
f_c	-1845 psi	-1913 psi	3.6
kd	7.6 in	7.4 in	2.7

Sample Problem C: Beam with a Real Moment and Real Compressive Load

PARAMETER	CECAP	HAND CALCULATION	% ERROR
f_s	41,620 psi	41,320 psi	0.7
f_c	-1908 psi	-1922 psi	0.7
kd	12.2 in	12.7 in	3.9

Table 3.8-15

COMPARISON OF RESULTS FROM "CE668" PROGRAM AND HAND CALCULATIONS

Sample Problem A: Rectangular Plate with a Concentrated Load at the Center

	PARAMETER	HAND CALCULATION	CE668
1.	Deflection (in)		
	@ Node 116	0.00153	0.00151
2.	Moments (in-lbs)		
	M_x @ Node 113	20.92	21.24
	M_y @ Node 117	57.198	56.377

Sample Problem B: Uniform Load on a Rectangular Plate

	PARAMETER	HAND CALCULATION	CE668
1.	Deflection (in)		
	@ Node 11	0.277	0.278
2.	Moments (in-lbs)		
	M_x @ Node 11	52.72	50.92
	M_y @ Node 121	143.55	142.28

Table 3.8-16

COMPARISON OF RESULTS FROM "E0119" PROGRAM AND PUBLISHED RESULTS

Sample Problem A: Welding Neck Flange

1. Design (Operating) Condition

STRESS COMPONENT	ALLOWABLE STRESS (psi)	ACTUAL STRESS (psi) REFERENCE E0119	3.8-9
Bolts	25,000	21,801	-
Longitudinal flange	26,250	22,856	22,865
Radial flange	17,500	10,981	10,982
Tangential flange	17,500	6,799	6,800

2. Bolt-up Condition

STRESS COMPONENT	ALLOWABLE STRESS (psi)	ACTUAL STRESS (psi) REFERENCE E0119	3.8-9
Bolts	25,000	6,077	-
Longitudinal flange	26,250	20,278	20,288
Radial flange	17,500	9,743	9,744
Tangential flange	17,500	6,032	6,033

Sample Problem B: Slip-on Flange

1. Design (Operating) Condition

STRESS COMPONENT	ALLOWABLE STRESS (psi)	ACTUAL STRESS (psi) REFERENCE E0119	3.8-9
Bolts	25,000	20,971	-
Longitudinal flange	26,250	21,160	21,163
Radial flange	17,500	11,128	11,128
Tangential flange	17,500	13,763	13,764

Table 3.8-16 (Cont'd)

2. Bolt-up Condition

STRESS COMPONENT	ALLOWABLE STRESS (psi)	ACTUAL STRESS (psi) REFERENCE E0119	3.8-9
Bolts	25,000	5,671	-
Longitudinal flange	26,250	15,644	15,648
Radial flange	17,500	8,227	8,228
Tangential flange	17,500	10,175	10,177

Table 3.8-17

COMPARISON OF RESULTS FROM "E0781" PROGRAM AND PUBLISHED RESULTS[1]

PROGRAM E0781 RESULTS			PUBLISHED RESULTS
DISTANCE FROM BASE (in)	N_ϕ (lb/in)	M_ϕ (in-lb/in)	(Solution At Maximums)
0.0	5.919×10^{-6}	-1539.0	M_ϕ = -1470 in-lb/in
6.0	21.15	-903.9	-
12.0	71.29	-440.5	-
18.0	134.0	-124.8	-
24.0	194.3	71.47	-
30.0	253.3	177.1	-
36.0	297.2	218.3	-
42.0	327.3	217.6	-
48.0	343.3	192.8	-
54.0	346.8	157.1	N_ϕ = 348 lb/in
60.0	339.6	119.5	-
66.0	324.2	85.46	-
72.0	303.0	57.80	-
78.0	277.9	36.29	-
84.0	250.8	23.41	-
90.0	222.9	15.00	-
96.0	195.1	10.58	-
102.0	167.8	8.685	-
108.0	141.4	8.075	-
114.0	115.9	7.754	-
120.0	91.45	7.032	-
126.0	68.13	5.584	-
132.0	46.29	3.453	-
138.0	26.50	1.177	-
144.0	94.53	-1.481×10^{-3}	-

[1] Published results are from Reference 3.8-12.

Table 3.8-18

PARAMETERS ASSUMED FOR "FINEL" PROGRAM VERIFICATION

A. Material Properties - Concrete and Reinforcing Steel

PROPERTY	CONCRETE	STEEL
E	4.3×10^6 psi	29×10^6 psi
ν	0.15	0.29
T_{yield}	-4820 psi	±44,900 psi
E_{yield}	0.0	0.0
T_{crack}	+546 psi	-
E_{crack}	1.0	-
Shear stiffness reduction factor for once-cracked concrete	0.5	-

B. Loading History

LOAD, P (lb)	NUMBER OF CYCLES AT LOAD FOR CONVERGENCE
1	1
87,000	4
20,000	4
28,000	1
31,200	4
31,300	1(1)

(1) Reinforcing steel yielded

Table 3.8-19

COMPARISON OF RESULTS FROM "FINEL" PROGRAM AND HAND CALCULATIONS

Sample Problem B: Hollow Cylinder with Distributed Pressure Loading

		TANGENTIAL STRESS (ksf)		AXIAL STRESS (ksf)		RADIAL STRESS (ksf)	
ELEMENT	r (ft)	HAND CALCULATION	FINEL	HAND CALCULATION	FINEL	HAND CALCULATION	FINEL
1	65.19	17.79	17.79	4.212	4.212	-0.95	-0.95
2	65.56	17.69	17.69	4.212	4.212	-0.84	-0.84
3	65.94	17.58	17.58	4.212	4.212	-0.73	-0.73
4	66.31	17.48	17.48	4.212	4.212	-0.63	-0.63
5	66.69	17.38	17.38	4.212	4.212	-0.53	-0.53
6	67.06	17.28	17.28	4.212	4.212	-0.43	-0.43
7	67.44	17.18	17.18	4.212	4.212	-0.33	-0.33
8	67.81	17.08	17.08	4.212	4.212	-0.24	-0.23
9	68.19	16.99	16.99	4.212	4.212	-0.14	-0.14
10	68.56	16.89	16.89	4.212	4.212	0.05	-0.05

Sample Problem C: Hollow Cylinder with a Linear Temperature Gradient

		TANGENTIAL STRESS (ksf)		AXIAL STRESS (ksf)		RADIAL STRESS (ksf)	
ELEMENT	r (ft)	HAND CALCULATION	FINEL	HAND CALCULATION	FINEL	HAND CALCULATION	FINEL
1	65.19	-78.34	-78.33	-77.96	-77.96	-0.22	-0.23
2	65.56	-60.67	-60.66	-60.68	-60.68	-0.62	-0.62
3	65.94	-43.10	-43.09	-43.40	-43.40	-0.91	-0.91
4	66.31	-25.63	-25.62	-26.12	-26.12	-1.10	-1.10
5	66.69	- 8.26	- 8.25	- 8.84	- 8.84	-1.19	-1.19
6	67.06	9.01	9.02	8.44	8.44	-1.18	-1.18
7	67.44	26.19	26.20	25.72	25.72	-1.08	-1.08
8	67.81	43.27	43.28	43.00	43.00	-0.88	-0.88
9	68.19	60.26	60.27	60.28	60.28	-0.58	-0.59
10	68.56	77.16	77.17	77.56	77.56	-0.21	-0.21

Table 3.8-20

COMPARISON OF CONTAINMENT LOAD COMBINATIONS WITH SRP 3.8.3

LGS UFSAR TABLE	TYPE OF STRUCTURE	CONDITION	OMISSION	JUSTIFICATION
3.8-5 thru 3.8-8	Concrete and Steel internal structures of containment	All accident conditions	Thermal pipe (R_a)[1] were not included	Thermal pipe reactions are checked locally for structural adequacy. These loads are generally small compared to pipe loads and negligible in combination with other loads.
3.8-7	Drywell Platforms	1) Abnormal	1) Seismic not included	1) Seismic is small in comparison with pipe restraints and jet force loads which have been considered.
		2) Normal	2) Seismic not included	2) Combining seismic with dead and live loads gives higher allowable stresses and thus does not control the design.
3.8-7	Drywell Platforms	Normal Abnormal	1) T_a Neglected	1) Expansion of structural members under thermal loadings are permitted; therefore, thermal-stresses are negligible.
	Seismic Truss	Abnormal/ Extreme	2) P_a Neglected	2) The pressure differential along the supporting beams is negligible.
3.8-8	Seismic Truss	Abnormal/ Extreme	Live load (L) not included	Live loads are negligible in comparison with main steam pipe jet forces (R)[1]

[1] "R" as defined in the UFSAR is equivalent to the expression ($Y_r + Y_j + Y_m$) as defined in the SRP

Table 3.8-21

COMPARISON OF CONTAINMENT LOAD COMBINATIONS WITH ASME CODE, ARTICLE CC-3000

ASME LOAD	DIFFERENCES	ASME CATEGORY	JUSTIFICATION
F	Prestress not applicable	All	LGS has a reinforced concrete containment and no prestress loads exist.
W & W_t	Wind and tornado loads not considered	Construction Severe environmental Abnormal/Severe Environmental Extreme Environmental	Tornado or wind loadings do not apply. The primary containment is protected by the reactor enclosure.
T_t	Thermal not considered for structural integrity test.	Test	LGS design criteria addresses the structural integrity test. Pressure has been increased 15% over ASME. The ambient air temperature during testing is close to that of construction; therefore, the effects of thermal gradient are negligible.
E_o, P_a	Load Factors for E_o and P_a have been slightly reduced.	Abnormal Abnormal/Severe Environmental	Load factors for loading combination are based on probable occurrence. By introducing the hydrodynamic event, a slight load factor reduction for these loads (E_o, P_a) is justifiable.

3.9 MECHANICAL SYSTEMS AND COMPONENTS

The system and component design criteria and analyses in Section 3.9 are referenced to LGS operation at the originally licensed rated reactor power of 3293 MWt. The effects of increased power, pressure, and flow rates for power rerate conditions on the reactor vessel and internals, and main steam and recirculation piping were evaluated. The results demonstrate LGS compliance with appropriate design and licensing criteria at rerate conditions. These are documented in Ref. 3.9-23 and 3.9-24. Additional analyses were also performed which considered the use of GE13 and GE14 fuel; these analyses are documented in Reference 3.9-28 and Reference 3.9-34, respectively. The GE14 fuel is demonstrated to be bounded by the GE13 results. The reactor vessel components were evaluated for the effects of MUR power uprate in Reference 3.9-31. The results show that the reactor vessel components continue to comply with the structural requirements. The RPV internals were evaluated for loads associated with the MUR power uprate in Reference 3.9-32. The RPV internal components are demonstrated to be structurally qualified for operation in the MUR conditions. Reference 3.9-33 identifies new design basis values for Fuel Lift Margin and Control Rod Guide Tube Lift Forces under MUR conditions. Subsequently, analyses were performed which considered the use of GNF2 fuel; these analyses aere documented in Reference 3.9-35. The GNF2 fuel is demonstrated to be bounded by the analyses in Reference 3.9-33.

Analyses were performed which considered the use of GNF3 fuel. Reference 3.9-39 identified new design basis values for the reactor internal pressure differences for unbounded reactor internals during normal, upset, and faulted conditions. The GNF3 analyses also identified a new design basis value for maximum Control Rod Guide Tube Lift force at faulted conditions. Structural evaluations for the reactor internals were conducted based on these GNF3 results which demonstrated that all vessel internal components continue to meet structural requirements.

3.9.1 SPECIAL TOPICS FOR MECHANICAL COMPONENTS

3.9.1.1 Design Transients

This section discusses the transients used in the design and fatigue analysis of the ASME Code Class 1 components, component supports, and reactor internals. The number of cycles or events for each transient based on available and projected plant operating data at the time of design is included. The design transients shown in this section are included in the design specifications for the components. Transients or combinations of transients are classified with respect to the component operating condition categories, identified as "normal," "upset," "emergency," "faulted," or "testing" in the ASME B&PV Code, if applicable. The first four operating conditions correspond to service levels A, B, C and D, respectively.

3.9.1.1.1 Control Rod Drive Transients

The normal and test service load cycles used for design purposes in the 40 year life of the CRD are as follows:

	Transient	Category	Cycles
a.	Reactor startup and shutdown	Normal/Upset(1)	120
b.	Vessel pressure tests	Normal/Upset	130
c.	Vessel overpressure	Normal/Upset	10

d.	Scram test plus startup scrams	Normal/Upset	300
e.	Operational scrams	Normal/Upset	300[2]
f.	Jog cycles	Normal/Upset	30,000[3]
g.	Shim/drive cycles	Normal/Upset	1,000[3]

(1) In Section 3.9.1.1, whenever a transient is categorized with two classifications, i.e., normal/upset, the most limiting of the two is considered in the design.

(2) 180 scram cycles constitute the design basis; however, 300 cycles are applied to the CRD for conservatism.

(3) 30,000 jog cycles and 1000 shim/drive cycles are applied because they impose mechanical loads on the CRD while contributing negligible thermal loads.

In addition to the above cycles, the following have been considered in the design of the CRD:

	Transient	Category	Cycles
h.	Scram with inoperative buffer	Normal/Upset	10
i.	Scram with stuck control blade	Normal/Upset	1
j.	OBE[3]	Upset	10
k.	SSE	Faulted	1

All ASME Class 1 components of the CRD have been analyzed according to ASME Section III. The capability of the CRD to withstand other emergency and faulted conditions is verified by test rather than analysis.

3.9.1.1.2 CRD Housing and Incore Housing Transients

Transients, classifications, and number of cycles considered in the design and fatigue analysis of the CRD housing and incore housing are as follows:

	Transient	Category	Cycles
a.	Normal startup and shutdown	Normal/Upset	120
b.	Vessel pressure tests	Normal/Upset	130
c.	Vessel overpressure tests	Normal/Upset	10
d.	Interruption of feedwater flow	Normal/Upset	80[1]
e.	Scram	Normal/Upset	200[2]
f.	OBE	Upset	10
g.	SSE	Faulted	1

(1) The interruption of feedwater flow imposes thermal loads on the CRD housing while contributing negligible mechanical loads.

(2) 180 scram cycles constitute the design basis; however, 200 cycles are applied to the CRD housing for conservatism.

(3) The frequency of occurrence of this transient indicates the emergency category. However, for conservatism, the OBE was analyzed as an upset condition. Ten peak stress cycles are postulated.

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h.	Stuck rod scram	Normal/Upset	1
i.	Scram with no buffer	Normal/Upset	1

3.9.1.1.3 Hydraulic Control Unit Transients

	Transient	Category	Cycles
a.	Reactor startup and shutdown	Normal/Upset	120
b.	Scram tests	Normal/Upset	300
c.	Operational scrams	Normal/Upset	300
d.	Jog cycles	Normal/Upset	30,000
e.	Scram with stuck scram discharge valve	Emergency	1
f.	OBE	Upset	10
g.	SSE	Faulted	1

3.9.1.1.4 Core Support and Reactor Internals Transients

Cycles considered in the reactor internals design and fatigue analysis are listed in Table 3.9-2.

3.9.1.1.5 Main Steam System Transients

Transients considered in the main steam piping stress analysis are as follows:

	Transient	Category	Cycles
a.	Startup	Normal	120(1)
b.	Loss of feedwater pumps, isolation valves closed	Upset	10
c.	Scram	Upset	180
d.	Shutdown	Normal	111(1)
e.	Hydrostatic test	Test	3

(1) In the design of NSSS piping systems, there are 9 transients not counted for the shutdown; 8 are due to SRV blowdown and 1 is due to automatic depressurization.

f.	Design hydrotest	Test	130
g.	OBE	Upset	50
h.	Turbine stop valve closure	Upset	120
i.	Relief valve lift (at 3 cycles per actuation)	Upset	34,200

3.9.1.1.6 Recirculation System Transients

Transients considered in the recirculation piping stress analysis are as follows:

	Transient	Category	Cycles
a.	Startup	Normal	120(1)
b.	Turbine roll and increase to power	Normal	120
c.	Loss of feedwater heater	Upset	10
d.	Partial feedwater heater bypass	Upset	70
e.	Scrams	Upset	180
f.	Shutdown	Normal	111(1)
g.	Loss of feedwater pumps, isolation valves closed	Upset	10
h.	Single SRV blowdown	Upset	8
i.	Design hydrotest	Test	130
j.	OBE	Upset	50

3.9.1.1.7 Reactor Assembly Transients

The reactor assembly includes the RPV, support skirt, shroud support, and shroud plate. The cycles listed in Table 3.9-2 are as specified in the reactor assembly design and fatigue analysis.

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(1) In the design of NSSS piping systems, there are 9 transients not counted for the shutdown; 8 are due to SRV blowdown and 1 is due to automatic depressurization.

3.9.1.1.8 Main Steam Isolation Valve Transients

The MSIVs are designed for the following service conditions and thermal cycles:

	Transient	Category	Cycles
a.	Preop @100°F/hr	Normal/Upset	150
b.	Startup (heating @100°F/hr)	Normal/Upset	120
c.	Shutdown		
	1. Cooling cycles @100°F/hr, 540°F to 375°F	Normal/Upset	120
	2. Cooling cycles @270°F/hr, 375°F to 330°F	Normal/Upset	120
	3. Cooling cycles @100°F/hr, 330°F to 100°F	Normal/Upset	120
d.	Scram cooling cycles @100°F/hr	Normal/Upset	180
e.	Emergency and faulted transients		
	1. 546°F to 281°F in 15 seconds	Emergency/Faulted	1
	2. 546°F to 375°F in 3.3 minutes	Emergency/Faulted	1
	375°F to 281°F @300°F/hr	Emergency/Faulted	1
	3. 546°F to 375°F in 10 minutes	Emergency/Faulted	8
	375°F to 281°F @100°F/hr	Emergency/Faulted	8
	4. 546°F to 583°F in 2 seconds	Emergency/Faulted	1
	583°F to 538°F in 30 seconds	Emergency/Faulted	1
	538°F to 400°F @100°F/hr	Emergency/Faulted	1
	400°F to 546°F @100°F/hr	Emergency/Faulted	1
	5. 561°F to 500°F in 7 minutes	Emergency/Faulted	10
	500°F to 400°F @100°F/hr	Emergency/Faulted	10
	400°F to 546°F @100°F/hr	Emergency/Faulted	10

3.9.1.1.9 Main Steam Relief Valves Transients

The transients used in the analysis of the MSRVs are as follows:

	Transient	Category	Cycles
a.	Preop and inservice testing (100°F/hr)	Normal/Upset	150
b.	Startup (100°F/hr) and pressure increase (0 psig to 1000 psig)	Normal/Upset	120
c.	Shutdown (100°F/hr, pressure decrease to 0 psig, 270°F/hr between 375°F and 330°F)	Normal/Upset	120
d.	Scram	Normal/Upset	180
e.	System pressure and temperature decay is from 1000 psig and 546°F, to 35 psig and 281°F within 15 seconds.	Emergency/Faulted	1
f.	System temperature change is from 546°F to 375°F within 3.3 minutes, and from 375°F to 281°F at a rate of 300°F/hr. Pressure change is from 1000 psig to 35 psig.	Emergency/Faulted	1
g.	System temperature change is from 546°F to 375°F within 10 minutes, and from 375°F to 281°F, at a rate of 100°F/hr. Pressure change is from 1000 psig to 35 psig.	Emergency/Faulted	8
h.	System temperature change is from 546°F to 583°F within 2 seconds, from 583°F to 538°F within 30 seconds, and from 538°F to 400°F with return to 546°F at a rate of 100°F/hr. Pressure change is from 1000 psig to 1350 psig, thence to 240 psig, with return to 1000 psig.	Emergency/Faulted	1

i.	System temperature changes greater than 30°F, are from 561°F to 500°F within 7 minutes, and from 500°F to 400°F, with return-to-normal operating temperature of 546°F, at a rate of 100°F/hr. Pressure change is from 1000 psig to 1180 psig, to 240 psig, with return-to-normal operating pressure of 1000 psig.	Emergency/Faulted	10

In addition, for RPV, RPV internals and piping New Loads Adequacy Evaluation, at least 7700 SRV cycles are considered to account for the pool dynamic loads. These 7700 cycles are based on 1100 actuations (total for 40 years) of all SRVs times seven stress cycles per actuation. Further, 4700 actuations (total for 40 years) for the most frequently actuated SRV times three stress cycles per actuation (14,100 total cycles) are used in the analysis of the SRV downcomers and SRV discharge lines in the wetwell and in the main steam piping analysis. The 4700 actuations over the 40 year plant design life for the most frequently actuated SRV is based on the original two-stage Target Rock SRV design used for LGS. This SRV has a longer blowdown time, similar to the Crosby SRV design.

ASME Section III, Paragraph NB3552 excludes various transients, and provides means for combining those which are not excluded. Review and approval of the equipment supplier's certified calculation provides assurance of proper accounting for the specified transients.

3.9.1.1.10 Recirculation Flow Control Valve Transients

Not applicable; LGS has no flow control valve.

3.9.1.1.11 Recirculation Pump Transients

The following transients are listed in the design specification as a requirement for design considerations. The vendor was required to submit a certification of compliance with certified design calculations which considered only a pressure transient (no thermal-stresses were required to be considered). Nozzle piping loads were considered in accordance with the following paragraph from the design specification:

> "The pump case shall be designed to withstand secondary stresses due to piping reactions in accordance with Paragraph 452.4b of the ASME Standard Code for Pumps and Valves for Nuclear Power (1968 Draft)."

	Transient	Category	Cycles
a.	Heatup and cooldown at 100°F/hr	Normal/Upset	30
b.	±29°F temperature changes	Normal/Upset	600
c.	±50°F temperature changes	Normal/Upset	200
d.	RPV pressure transients to 110% design pressure	Normal/Upset	30
e.	SRV blowdowns	Emergency	1
f.	Improper pump startup, 100°F to 546°F in 15 seconds	Emergency	1
g.	Cooling transient, 552°F to 281°F in 15 seconds	Faulted	2
h.	Hydrotest to 1300 psig	Test	130
i.	Hydrotest to 1670 psig	Test	3

3.9.1.1.12 Recirculation Gate Valve Transients

The following transients are considered in the design of the recirculation gate valves.

	Transient	Cycles
a.	50°F-575°F-50°F at 100°F/hr	300
b.	±29°F between limits of 50°F and 575°F, instantaneous	600
c.	±50°F between limits of 50°F and 546°F, instantaneous	200
d.	546°F to 375°F, over a 10 minute period	30
e.	546°F to 281°F, over a 15 second period	2
f.	130°F to 546°F, over a 15 second period	1
g.	110% design pressure at 575°F	1
h.	1300 psi at 100°F installed hydrostatic test	130
i.	1670 psi at 100°F installed hydrostatic test	3

3.9.1.2 Computer Programs Used in Analysis

Sections 3.9.1.2.1 through 3.9.1.2.5 discuss computer programs used in the analysis of specific NSSS components (computer programs were not used in the analysis of all components, thus not all components are listed). Non-NSSS programs are discussed in Section 3.9.1.2.6.

GE Programs

The verification of the following GE programs has been performed in accordance with the requirements of 10CFR50, Appendix B. Evidence of the verification of input, output, and methodology is documented.

a. PIPST01
b. MASS
c. SNAP (MULTISHELL)
d. GASP
e. NOHEAT
f. FINITE
g. DYSEA
h. SHELL 5
i. HEATER
j. FAP 71
k. CREEP PLAST
l. ANSYS
m. SAP4
n. ANSI-7
o. NOZAR
p. TSFOR
q. PISYS
r. PDA
s. EZPYP
t. LION4
u. SIMOK
v. DISPL
w. WTNOZ
x. SPECA04
y. GEAPL01
z. POSUM
aa. FTFLG

Vendor Programs

The verification of the following two groups of vendor programs is assured by contractual requirements between GE and the vendors. In accordance with the requirements, the quality assurance procedure of these proprietary programs used in the design of N-stamped equipment and non-ASME code items is in full compliance with 10CFR50, Appendix B.

Pump Motor Vendor Programs

a. RTRMEC

Chicago Bridge and Iron Programs

a. 7-11-GENOZZ
b. 9-48-NAPALM
c. 1027
d. 846
e. 781-KALNINS
f. 979-ASFAST
g. 766-TEMAPR
h. 767-PRINCESS
i. 928-TGRV
j. 962-E09262A
k. 984
l. 992-GAS
m. 1037-DUNHAM'S
n. 1335
o. 1606&1657-HAP
p. 1634N

3.9.1.2.1 Reactor Vessel and Internals

3.9.1.2.1.1 Reactor Vessel

The computer programs used in the preparation of the reactor vessel stress report are identified, and their use summarized in the following paragraphs.

3.9.1.2.1.1.1 Chicago Bridge and Iron Program 7-11 - GENOZZ

The GENOZZ computer program is used to proportion barrel and double taper-type nozzles to comply with the specifications of ASME Section III, and contract documents. The program either designs such a configuration or analyzes the configuration input to comply to code. If the input configuration does not comply with the specifications, the program modifies the design and redesigns it to yield an acceptable result.

3.9.1.2.1.1.2 Chicago Bridge and Iron Program 9-48 - NAPALM

The basis for the Nozzle Analysis Program - All Loads Mechanical (NAPALM) is to analyze nozzles for mechanical loads and find the maximum stress intensity and location. The program provides analyses at each mechanical load point of application. The maximum stress intensity is calculated for both the inside and outside surfaces at each reference location. The program measures the maximum stress intensity for both the inside and outside surfaces of the nozzle, as well as their angular locations as measured from the 0° reference location. The principle stresses are also listed.

Stresses resulting from each component of loading (bending, axial, shear, and torsion) are listed, as well as the loadings which cause these stresses.

3.9.1.2.1.1.3 Chicago Bridge and Iron Program 1027

This program is a computerized version of the analysis method contained in Reference 3.9-1.

Part of this program provides for the determination of the shell stress intensities (S) around the perimeter of a loaded attachment on a cylindrical or spherical vessel. Eight (S) values are calculated, one at each of four cardinal points, for both the upper and lower shell plate surfaces (ordinarily considered outside and inside surfaces). With the determination of each (S), the components of that (S) (two normal stresses, δ_x and δ_y, and shear stress τ) are also determined. This program provides the same information as the manual calculation, and the input data is essentially the geometry of the vessel and attachment.

3.9.1.2.1.1.4 Chicago Bridge and Iron Program 846

This program computes the required thickness of a hemispherical head with a large number of circular parallel penetrations, by means of the area replacement method, in accordance with ASME Code, Section III.

In cases where the penetration has a counterbore, the thickness is determined so that the counterbore does not penetrate the outside surface of the head.

3.9.1.2.1.1.5 Chicago Bridge and Iron Program 781 - KALNINS

The KALNINS thin-shell program is used to establish the shell influence coefficient, and to perform the detailed stress analysis of the vessel. The stresses and the deformations of the vessel can be computed for any combination of the following axisymmetric loading:

a. Preload condition

b. Internal pressure

c. Thermal load

This program is a thin elastic shell program for shells of revolution developed by Dr. A. Kalnins of Lehigh University. Extensive revisions and improvements have been made by Dr. J. Endicott, to yield the Chicago Bridge and Iron version of this program.

The basic method of analysis was published by Professor Kalnins (Reference 3.9-2).

3.9.1.2.1.1.6 Chicago Bridge and Iron Program 979 - ASFAST

The ASFAST program performs the stress analysis of axisymmetric, bolted closure flanges between the head and cylindrical shell.

3.9.1.2.1.1.6.1 ANSYS Engineering Analysis System, Revision 5.6, ANSYS, Inc.

ANSYS Program performed the stress analysis of the reactor vessel head, flange & upper shell for reduced pass tensioning/detensioning of RPV studs connecting RPV head to RPV shell.

3.9.1.2.1.1.7 Chicago Bridge and Iron Program 766 - TEMAPR

This program reduces any arbitrary temperature gradient through the wall thickness to an equivalent linear gradient. The resulting equivalent gradient has the same average temperature, and the same temperature-moment as the given temperature gradient. The input consists of the wall thickness and actual temperature distribution. The output contains the average temperature and total gradient through the wall thickness. The program is written in FORTRAN IV.

3.9.1.2.1.1.8 Chicago Bridge and Iron Program 767 - PRINCESS

The PRINCESS program calculates the maximum alternating stress amplitudes from a series of stress values, by the method in ASME Section III.

3.9.1.2.1.1.9 Chicago Bridge and Iron Program 928 - TGRV

The TGRV program is used to calculate temperature distributions in structures or vessels. Although it is primarily a program for solving the heat conduction equations, some provisions have been made for including radiation and convection effects at the surfaces of the vessel.

The TGRV program is a highly modified version of the TIGER heat transfer program, written about 1958 at Knolls Atomic Power Laboratory, by A.P. Bray.

The program utilizes an electrical network analogy to obtain the temperature distribution of any given system as a function of time. The finite-difference representation of the three-dimensional equations of heat transfer are repeatedly solved for small time increments, and continually

summed. Linear mathematics is used to solve the mesh network for every time interval. Three basic forms of heat transfer (conduction, radiation, and convection), as well as internal heat generation, are included in the analysis.

TGRV calculates and outputs the steady-state or transient temperature distributions in a given structure, as a function of time. The program inputs are any odd-shaped structure which can be represented by a three-dimensional field, its geometry and physical properties, boundary conditions, and internal heat generation rates.

3.9.1.2.1.1.10 Chicago Bridge and Iron Program 962 - E0962A

Program E0962A is one of a group of programs (E0953A, E1606A, E0962A, E0992N, E1037N, and E0984N) which are used together to determine the temperature distribution and stresses in pressure vessel components, using the finite-element method.

Program E0962A is primarily a plotting program. Using the nodal temperatures calculated by program E1606A or Program E0928A, and the node and element cards for the finite-element model, it calculates and plots lines of constant temperature (isotherms). These isotherm plots are used as part of the stress report to present the results of the thermal analysis. They are also useful in determining at which points in time the thermal-stresses should be determined.

In addition to its plotting capability, the program can also determine the temperatures of some of the nodal points by interpolation. This feature of the program is intended primarily for use with the compatible TGRV and finite-element models that are generated by program E0953A.

3.9.1.2.1.1.11 Chicago Bridge and Iron Program 984

Program 984 is used to calculate the stress intensity of stress differences, on a component level, between two different stress conditions. The calculation of the stress intensity of stress component differences (the range of stress intensity) is required by ASME Section III.

3.9.1.2.1.1.12 Chicago Bridge and Iron Program 992 GASP

The GASP program, originated by Professor E.L. Wilson of the University of California at Berkeley, uses the finite-element method to determine the stresses and displacements of plane or axisymmetric structures of arbitrary geometry, and is written in FORTRAN IV. See Reference 3.9-3, for a detailed account. GASP structures may have arbitrary geometry, and have linear or nonlinear material properties. The loadings may be thermal, mechanical, accelerational, or a combination of these.

A structure to be analyzed is broken up into a finite number of discrete elements or "finite-elements", which are interconnected at a finite number of "nodal points" or "nodes." The actual loads on the structure are simulated by statically equivalent loads acting at the appropriate nodes. The basic input to the program consists of the geometry of the stress model and the boundary conditions. The program then gives the stress components at the center of each element and the displacements at the nodes, consistent with the prescribed boundary conditions.

3.9.1.2.1.1.13 Chicago Bridge and Iron Program 1037 - DUNHAM'S

DUNHAM'S program is a finite ring element stress analysis program. It determines the stresses and displacements of axisymmetric structures of arbitrary geometry subjected to either axisymmetric loads, or nonaxisymmetric loads represented by a Fourier series.

This program is similar to the GASP program (Chicago Bridge and Iron Program 992). The major differences are that DUNHAM'S can handle nonaxisymmetric loads (which requires that each node have three degrees of freedom), while the material properties for DUNHAM'S must be constant. As in GASP, the loadings may be thermal, mechanical, and accelerational.

3.9.1.2.1.1.14 Chicago Bridge and Iron Program 1335

To obtain stresses in the shroud support, the baffle plate must be made a continuous circular plate. The program makes this modification and allows the baffle plate to be included in Chicago Bridge and Iron program 781 (KALNINS) as two isotropic parts, with an orthotropic portion at the middle (where the diffuser holes are located).

3.9.1.2.1.1.15 Chicago Bridge and Iron Programs 1606 and 1657 - HAP

The HAP program is an axisymmetric nonlinear heat analysis program. It is a finite-element program, used to determine nodal temperatures in a two-dimensional or axisymmetric body subject to transient disturbances. Programs 1606 and 1657 are identical, except that 1606 has a larger storage area allocated, and can thus be used to solve larger problems. The model for program 1606 is compatible with Chicago Bridge and Iron stress programs 992 (GASP) and 1037 (DUNHAM'S).

3.9.1.2.1.1.16 Chicago Bridge and Iron Program 1634N

This program is used to analyze thin cylindrical shells subjected to local loading beyond the range where Bijlaard's curves are directly applicable, i.e., R/t >300.

This program computes stress and displacements in thin-walled elastic cylindrical shells subjected to mechanical loading such as radial loads, longitudinal and circumferential moments.

3.9.1.2.1.2 Reactor Internals

3.9.1.2.1.2.1 Core Plate Beam Buckling - PIPST01

PIPST01 is a computer program that calculates approximate core plate beam buckling capability. It uses the Rayleigh-Ritz energy method to determine the applied moment needed to begin yielding and then to buckle a given tee beam. The tee beam models a segment of a BWR/2-5 core plate with a stiffener beam. The pressure differential across the plate that would have created this moment is calculated for a given length of beam or size of core plate.

Generic dimension and material properties are all input by the user.

3.9.1.2.1.2.2 Other Programs

Other computer codes used for the analysis of the internal components are:

a. MASS
b. SNAP (MULTISHELL)
c. GASP
d. NOHEAT
e. FINITE
f. DYSEA
g. SHELL 5
h. HEATER
i. FAP 71
j. CREEP PLAST
k. ANSYS

Descriptions of these programs are given in Section 4.1.4.1.

3.9.1.2.2 Piping

3.9.1.2.2.1 Structural Analysis Program - SAP4

SAP4 is a general Structural Analysis Program for static and dynamic analysis of linear elastic complex structures. The finite-element displacement method is used to solve the displacements, and to compute the stresses of each element of the structure. The structure can be composed of unlimited numbers of three-dimensional truss, beam, plate, shell, solid, plate strain-plane stress, brick, thick shell, spring, or axisymmetric elements. The program can treat thermal and various forms of mechanical loading, as well as internal element loading. The dynamic analysis includes mode- superposition, time history, and response spectrum analyses. Earthquake loading, as well as time-varying pressure, can be treated. The program is very versatile and efficient in solving large and complex structural systems. The output contains displacements of each nodal point, as well as stresses at the surface of each element.

3.9.1.2.2.2 Component Analysis - ANSI-7

The ANSI-7 Computer Program determines stress and accumulative usage factors in accordance with NB-3600 of ASME Section III. The program performs stress analyses in accordance with the ASME sample problem, and has been verified by reproducing the results of the sample problem analysis.

3.9.1.2.2.3 Area Reinforcement - NOZAR

The computer program Nozzle Area Reinforcement Program (NOZAR) performs an analysis of the required reinforcement area for openings. The calculations performed by NOZAR are in accordance with the rules of the 1974 edition of ASME Section III.

3.9.1.2.2.4 Turbine Stop Valve Closure - TSFOR

The TSFOR program computes the time history forcing function in the main steam piping due to turbine stop valve closure. The program utilizes the method of characteristics to compute fluid momentum and pressure loads at each change in pipe section or direction.

3.9.1.2.2.5 Piping Analysis Program/PISYS

PISYS is a computer code for analyzing piping systems subjected to both static and dynamic piping loads. Stiffness matrices representing standard piping components are assembled by the program to form a finite-element model of a piping system. The piping elements are connected to each other via nodes called pipe joints. It is through these joints that the model interacts with the environment, and loading of the piping system becomes possible. PISYS is based on the linear-elastic analysis in which the resultant deformations, forces, moments, and accelerations at each joint are proportional to the loading and the superposition of loading is valid.

PISYS has a full range of static and dynamic load analysis options. Static analysis includes dead weight, uniformly distributed weight, thermal expansion, externally applied forces, moments, imposed displacements, and differential support movement (pseudostatic load case). Dynamic analysis includes mode shape extraction, response spectrum analysis, and time history analysis by modal combination or direct integration. In the response spectrum analysis, i.e., Uniform Support Motion Response Spectrum Analysis (USMA) or Independent Support Motion Response Spectrum Analysis (ISMA), the user may request modal response combination in accordance with Regulatory Guide 1.92. In the ground motion (uniform motion) or independent support time history analysis, the normal mode solution procedure is selected. In analysis involving time-varying nodal loads, the step-by-step direct integration method is used.

The PISYS program has been benchmarked against NRC piping models. The results are documented in a report to the Commission, "PISYS Analysis of NRC Benchmark Problems," NEDO-24210, August 1979, for mode shapes and USMA options. The ISMA option has been validated against NUREG/CR-1677, "Piping Benchmark Problems Dynamic Analysis Independent Support Motion Response Spectrum Method," published in August 1985.

3.9.1.2.2.6 Piping Dynamic Analysis Program - PDA

The pipe whip analysis was performed using the PDA computer program. PDA is used to determine the response of a pipe subjected to the thrust-force occurring after a pipe break. The program treats the situation in terms of generic pipe break configuration, which involves a straight, uniform pipe fixed at one end, subjected to a time-dependent thrust-force at the other end. A typical restraint used to reduce the resulting deformation is also included at a location between the two ends. Nonlinear and time-independent stress-strain relations are used to model the pipe and the restraint. Similar to the popular elastic-hinge concept, bending of the pipe is assumed to occur at the fixed end, and at the location supported by the restraint, only.

Shear deformation is also neglected. The pipe bending moment-deflection (or rotation) relation used for these locations is obtained from a static nonlinear cantilever beam analysis. Using moment-rotation relations, nonlinear equations of motion are formulated using energy considerations, and the equations are numerically integrated in small time steps to yield the time history of the pipe motion. Additional discussion of PDA is provided in Section 3.6.2.2.2.

3.9.1.2.2.7 Piping Analysis Program - EZPYP

EZPYP links the ANSI-7 and SAP programs together. The EZPYP program can be used to run several SAP cases by making user- specified changes to a basic SAP pipe model. By controlling

files and SAP runs, the EZPYP program makes it possible to perform a complete piping analysis in one computer run.

3.9.1.2.2.8 Thermal Transient Program - LION4

The LION4 program is used to compute radial axialthermal gradients in piping. The program calculates a time history of ΔT_1, ΔT_2, T_a, and T_b (defined in ASME Section III, Class 1 piping analysis) for uniform and tapered pipe wall thickness.

3.9.1.2.2.9 Synthetic Time History Program - SIMOK

The SIMOK program provides a time history that is equivalent to an input response spectrum. The synthetic time history is used to generate a new spectrum that is plotted with the input spectrum, to verify that the time history and spectrum are equivalent. Synthetic time histories are used in a multiple input analysis of the piping.

3.9.1.2.2.10 Differential Displacement Program - DISPL

The DISPL program provides differential movements at each piping attachment point, based on building modal displacements.

3.9.1.2.2.11 WTNOZ Computer Program

WTNOZ is a time-share program for piping weight calculations.

3.9.1.2.3 Pumps and Motors

3.9.1.2.3.1 Recirculation Pumps

No computer programs were used in the design of the recirculation pumps.

3.9.1.2.3.2 Core Spray Pumps and Motors

The RTRMEC computer program is used in the analysis of a motor design representative of (or very similar in mechanical construction to) the core spray pump motor.

RTRMEC calculates and displays the results of a mechanical analysis of a motor rotor assembly acted upon by external forces at any point along the shaft (rotating parts only). The shaft deflection analysis, including magnetic and centrifugal forces, was conducted. The calculation for the seismic condition assumes that the motor is operating, and that the seismic, magnetic, and centrifugal forces all act simultaneously and in phase on the rotor-shaft assembly. Note that the distributed motor assembly weight is lumped at the various stations. The shaft weight at a station is the sum of one-half the weight of the incremental shaft length just before the station, plus one-half the weight of the adjacent incremental shaft length just after the station. Bending and shear effects are accounted for in the calculations.

The FTFLG computer program was used to analyze the flange joints connecting the pump bowl castings. The description of this program is provided in Section 3.9.1.2.5.3.

3.9.1.2.4 Dynamic Loads Analysis

3.9.1.2.4.1 Acceleration Response Spectrum Program/SPECA04

The SPECA04 computer program generates acceleration response spectrum, consistent with Regulatory Guide 1.122 for an arbitrary input of time history of piecewise-linear accelerations, i.e., to compute maximum acceleration responses for a series of single-degree-of-freedom systems subjected to the same input. It can accept acceleration time histories from a random file.
It also has the capability of generating the broadened/enveloping spectra in conformance with Regulatory Guide 1.122 when the spectral points are generated equally spaced in a logarithmic scale axis of period/frequency. This program is also used in seismic and SRV transient analysis.

3.9.1.2.4.2 Forces and Moment Time Histories Program/GEAPL01

The GEAPL01 computer program converts distributed asymmetric pressure time histories over a given area into equivalent time-varying nodal forces and moments for use as input to perform dynamic analysis of a system. The overall resultant forces and moment time histories at specified points of resolution can also be obtained from GEAPL01.

3.9.1.2.5 Residual Heat Removal Heat Exchangers

3.9.1.2.5.1 Structural Analysis Program - SAP4

SAP4 is used to analyze the structural and functional integrity of the RHR heat exchangers. The description of this program is provided in Section 3.9.1.2.2.1.

3.9.1.2.5.2 Beam Element Data Processing Program/POSUM

POSUM is used to process SAP4 generated data. POSUM is a computer code designed to process SAP4 generated beam element data for pump or heat exchanger models. The purpose is to determine the load combination that would produce the maximum stress in a selected beam element. It is intended for use on RHR heat exchangers with four nozzles or core spray pumps with two nozzles.

3.9.1.2.5.3 Effects of Flange Joint Connections/FTFLG

The flange joints connecting the pump bowl castings are analyzed using FTFLG program. This program uses the local forces and moments determined by SAP4 to perform flat flange calculations in accordance with the rules set forth in ASME Appendix II and ASME Section III.

3.9.1.2.6 Seismic Category I Items Other than NSSS

A list of computer programs used in the non-NSSS system components is provided in Table 3.9-3. This list consists of computer programs developed and/or owned by Bechtel, and of computer programs that are recognized and widely used in industry.

The Bechtel developed and/or owned computer programs are documented, verified, and maintained by Bechtel, and meet the requirements of 10CFR50, Appendix B. A brief description of each of these Bechtel programs is provided below.

3.9.1.2.6.1 ME101, Linear-Elastic Analysis

ME101 is a finite-element computer program that performs linear-elastic analysis of piping systems using standard beam theory techniques. The input data format is specifically designed for pipe stress engineering. ME101 performs a thorough check of the input prior to analysis. In addition, the program automatically modifies the geometry to improve the finite-element model.

The output may be used directly for piping design, for conformation to Code, and for other regulatory requirements. Both ASME Section III and ANSI B31.1 piping code editions are incorporated in ME101 to the extent of computing flexibility factors, stress intensification factors, and stresses.

ME101 performs static and dynamic load analysis of piping systems, effective weight calculations, and ASME Section III, Class 2 and 3, and ANSI B31.1 Code stress checks.

Static analysis considers one or more of the following: thermal expansion, dead weight, uniformly distributed loads, and externally applied forces, moments, imposed displacements and rotations, individual force loads, static seismic (uniform directional acceleration) loads, or seismic anchor movement analysis.

Dynamic analysis is based on the standard normal superposition techniques. The input excitation may be in the form of seismic response spectra or time-dependent loading functions. In the single or multiple response spectrum analysis, the user may request modal synthesis by SRSS method or by Regulatory Guide 1.92 closely spaced mode 10% (equation 4) method. ME101 can consider further differential damping for large and small pipe according to Regulatory Guide 1.61. Various methods of eigenvalue solution are available. Determinant search or subspace iteration considers all data points as mass points. In the time history analysis, the excitation may be in the form of arbitrary nodal forces, support displacements, rotations, or support accelerations that are not necessarily in phase.

ME101 checks stresses from design loads versus allowable stresses according to ASME/ANSI Code equations. The user may request design load checks for sustained loads, occasional loads, multimode thermal expansion and pipe break, except for time history load cases.

The ME101 restraint load summary report prints the support load results from several load cases together in the same report, except for time history load cases.

The general loading combinations capability for ME101 can combine the results of several load cases together, according to certain algebraic rules, to form a new load case. The new load case resulting from this may be used in stress comparisons or restraint load summaries, except for time history load cases. ME101 has the capability of saving load case results on a tape and using these results in late runs for stress checks, restraint load summary reports, and general loading combinations, except for time history load cases.

For piping configurations with optional node numbering, ME101 generates isometric plots. The user may obtain plots on ZETA or CALCOMP plotters on a Tektronix 4014 graphics terminal, or on a RMS-600 printer/plotter.

ME101 uses out-of-core techniques for both static and response spectra analysis and has no practical limitations to the number of equations or band width. However, the use of very large

systems may become prohibitive due to cost of computation. The maximum number of mode shapes allowable for response spectra analysis is currently 125.

This program considers the zero period acceleration effect in seismic response analysis. It accepts coordinate and key-word data in English or metric units.

The ASME Benchmark Problem 1 demonstrates the solution for natural frequencies of a three-dimensional structure, as described in Reference 3.9-4.

Natural frequencies, in Hertz, from ME101 and Reference 3.9-4, are as follows:

Mode	Reference 3.9-4	ME101
1	110	112
2	117	116
3	134	138

A total of 26 test problems were used for the verification of the ME101 results. These verification problems have been compared against one of the following:

a. ME632, Computer Program, "Seismic Analysis of Piping Systems", VERB MODB, 1976 Bechtel International Corporation, San Francisco, CA.

b. "Pressure Vessel and Piping 1972 Computer Programs Verification", ASME.

c. Hand Calculations

d. EDS Superpipe, EDS Nuclear, San Francisco, CA.

e. NUPIPE-IIM, Nuclear Services Corporation Piping Analysis Program, Campbell, CA.

f. TPIPE, A Computer Program for Analysis of Piping Systems, PMB Systems Engineering, San Francisco, CA.

g. ADINA, A Computer Program, Massachusetts Institute of Technology, Boston, MA.

h. MSC/NASTRAN Program, McNeal Schwendler Corporation, Los Angeles, CA.

i. EASE2 Program, Engineering/Analysis Corporation, San Francisco, CA.

j. ANSYS, Swanson Analysis System, Inc., 1975, Elizabeth, PA.

The J1 version of ME101 also includes seven NRC benchmarked problems, as referenced in NUREG/CR-1677, dated August 1980.

ME-101 was also validated with the four benchmarked problems (using the multiple response spectrum/independent support motion method) that were transmitted from M. Hartzman (NRC) to G. Wang (Bechtel) on August 10, 1983. The results and comparisons of the problems using ME-101 were transmitted to M. Hartzman (NRC) from T.J. McDonald (Bechtel) on December 15, 1983.

The ME-101 MRS/ISM methodology was again validated with four multiple response spectrum problems, as referenced in NUREG/ CR-1677, Volume II, dated August 1985.

3.9.1.2.6.2 ME632, Piping System Analysis

Program Description

ME632 performs stress analyses of three-dimensional piping systems. The effects of thermal expansion, uniform load of the pipe, pipe contents and insulation, concentrated loads, movements of the piping system supports, and other external loads, such as wind and snow, may be considered. The input data format is specifically designed for pipe stress engineering, and the English system of units is used. A thorough checking of the input has been coordinated in the program.

The output may be used directly for piping design, and for conformation to code and other regulatory requirements. Piping codes, the ASME B&PV code, the B31.1 code, and the B31.3 code have been incorporated into the program to the extent of computing flexibility factors, stress intensification factors, and stresses.

A response spectrum analysis may be performed to analyze the effect of earthquake forces on the piping system; transient effects of water hammer, steam hammer, or other impulsive types of dynamic loading are also handled by the program. A plot of piping geometry and/or response spectrum curves may be obtained to verify the accuracy of the model.

Program Version and Computer

The current UNIVAC version of ME632 is being used by Bechtel.

Extent of Application

ME632 is a piping program developed by Bechtel. Its development began in 1970, and it is being continuously supported by Bechtel. It has been used by various Bechtel projects.

Test Problems

The ASME Benchmark Problem No. 1 demonstrates the solution for natural frequencies of a three-dimensional structure, as described in Reference 3.9-4.

The following table lists the natural frequencies from ME632 and Reference 3.9-4:

Natural Frequency Comparison, Hz

Mode No.	Reference 3.9-4	ME 632
1	110	111
2	117	116
3	134	137

3.9.1.2.6.3 ME912, Thermal-Stress

Program Description

Finite-difference representation of the heat diffusion equation is used for the pipe or component wall section in contact with fluid of specified temperature and flow rate time histories. The program is quasi-two-dimensional, so that reduction of severity of a given transient with distance from inlet is accounted for.

Thermal properties of water, and stainless and carbon steel are built in the program. Film transfer coefficients for water are computed by the program for each time step and pipe section. For other fluids such as steam, the program is used on a one-dimensional basis with user-supplied film coefficients. Sequential computations are done for pipe lengths of different diameters or wall thicknesses. Fluid outlet temperature data from one pipe length are stored for use as the inlet to the next pipe length downstream. Average temperature differences, T_a - T_b, are thus calculated for structural discontinuity.

Program Version and Computer

The ME912 program has been used by Bechtel on various Bechtel projects. A Univac 1110 computer is used to run the ME912 program.

Extent of Application

The ME912 program was developed from References 3.9-7, 3.9-8, and 3.9-9 by Bechtel. The ME912 program has been extensively used since 1975 for nuclear Class 1 component design on the Fast Flux Test Facility project.

Test Problem

For local gradients, the program has been compared with analytical flat plate data of Reference 3.9-8, and numerical results by in-house program ME643. The results are acceptable. Table 3.9-4 shows the comparison of ME912 with ME643 and analytical results from Reference 3.9-8. For axial variations of fluid and wall temperatures, the program agrees closely with the analytical solution of Reference 3.9-9.

The ME643 program was developed from References 3.9-11 and 3.9-12 by Bechtel.

The results of ME643 transient temperature responses on both inside and outside surfaces of a sample pipe are compared with Chart 36 of Reference 3.9-13, and plotted in Figure 3.9-1.

3.9.1.2.6.4 ME913, Nuclear Class 1 Piping Stress Analysis

Program Description

ME913 can determine stress intensity levels for Class 1 nuclear power piping components, equations 9 through 14 of subarticle NB-3650, "Analysis of Piping Components", ASME Section III.

Prior to using this program, the following information external to the program is required:

a. Piping configuration

b. Piping and piping component properties

c. Moment reactions due to:

   1. Thermal expansion loads

   2. Weight loads

   3. Dynamic loads

d. The thermal response of the piping system due to the specified transients is:

   ΔT_1, ΔT_2 and the (T_a-T_b) values for the key points during system life.

Program Version and Computer

The current ME913 version is being used by Bechtel. A Univac 1100 computer is used to run the ME913 program.

Extent of Application

ME913 is the revised and expanded version of the LOTEMP program, originally developed by Bechtel, and made available for use through the CDC 6600 computer. The LOTEMP program has been extensively used by the Bechtel Fast Flux Test Facility Systems Analysis Group since 1972, in the preliminary design of Fast Flux Test Facility Class 1 piping. The ME913 program has been used to analyze nuclear Class 1 piping for Bechtel nuclear power plant projects.

Test Problems

The Grand Gulf Project feedwater line was selected as a test problem. Hand calculations of a selected component in the piping system were performed in accordance with the sample problem (Reference 3.9-14). The results were compared with the computer output for code equations 9 through 14 in ME913. Table 3.9-5 shows the comparison between the ASME sample problem (Reference 3.9-14) and ME913 results.

3.9.1.2.6.5 NE452, Submerged Steam Line Reflood Analysis

Program Description

NE452 is used to analyze reflood transient in steam relief valve discharge lines that discharge to a water pool and are equipped with a vacuum relief valve. The code models the effect of the vacuum relief valve (considering both the air flow and the valve dynamics) on the line reflood phenomenon by calculating the dynamics of the slug motion of the reflooding water. The slug motion is affected by the steam condensation on the surface of the reflooding water and by the presence of noncondensable air admitted by the vacuum relief valve.

The output (predicted maximum reflood) can be used in relief line clearing transient analysis codes (such as NE805, discussed in Section 3.9.1.2.6.6) to determine pipe run forces. NE452, together with NE805, can be used for vacuum relief valve sizing.

Program Version and Computer

The current NE452 version is being used by Bechtel. A UNIVAC 1100 computer is used to run the NE452 program.

Extent of Application

Development of the NE452 program began in 1977 and is being continuously supported by Bechtel. It has been used for various Bechtel nuclear power plant projects.

Test Problems

The NE452 program was verified against PBAPS and Monticello ramshead and Mark I T-quencher test data. It has also been verified against Karlstein Mark II T-quencher and Caorso X-quencher test data. The predicted results agreed reasonably well with test data.

3.9.1.2.6.6 NE805, Relief Valve Clearing Analysis

Program Description

NE805 is a computer code that analyzes transients in discharge lines of changing cross-sectional area following a relief valve opening. The code predicts the time-dependent forces on the various pipe segments of the relief valve discharge line. It models the steam flow through the relief valve and the steam/air flows in the line. It also models the water flow in the submerged part of the line. The options for the exit device are a straight pipe, a ramshead, or a quencher model in the reservoir. The quencher model considers sequential uncovering of the quencher holes during air/water clearing. NE805 uses the method of characteristics and allows for heat transfer through the pipe wall. It calculates flow parameters, pressure, velocity, and density as functions of time and the distance along the discharge line. Using these calculated values, the code computes the dynamic forcing functions induced on various pipe segments of the relief valve discharge line.

The force output can be used directly for piping stress analysis in codes such as ME101, described in Section 3.9.1.2.6.1.

NE805 generates plots of flow parameter time histories and/or force time histories, an option specified by the user. The plots are obtained by CALCOMP 1036 plotter.

Program Version and Computer

The current UNIVAC version of NE805 is being used by Bechtel. A UNIVAC 1100 computer is used to run the NE805 program.

Extent of Application

NE805 was developed by Bechtel. Its development began in 1975 and is being continuously supported by Bechtel. It has been used by various Bechtel projects.

Test Problems

The NE805 program has been verified against Monticello Mark I T-quencher test, Karlstein Mark II T-quencher test, and Caorso X-quencher test. Comparison with test data was found to be reasonable.

3.9.1.2.6.7 ANSYS

Refer to Section 3.8.7.10

3.9.1.2.6.8 ME210 - Local Stress in Cylindrical Shells Due to External Loads

This standard presents a method of analyzing and determining local stresses in cylindrical shells due to external moments and forces acting on rigid attachments of circular or rectangular shape. This program is based on a paper "Local Stresses in Spherical and Cylindrical Shells Due to External Loadings" by Wichman, Hopper, and Mershon, published in Welding Research Council Bulletin No. 107, August 1965 and March 1979 Revision. Values from Bijlaard curves are obtained by interpolation procedures.

This program also calculates piping stress intensity due to internal pressures and moments in accordance with the pressure and moment stress calculations specified in equation 9 and equation 10 of ASME Section III, NB-3650. The local stress intensity and piping stress intensity are summed and printed out if the required information for piping stress calculation is specified in the input. If no information for piping stress calculation is given, only the local stresses including primary plus secondary stress intensity and primary membrane stress intensities are printed out.

3.9.1.2.6.9 ME602 - Spectra Merging and Simplified Seismic Analysis

ME602 performs the seismic analysis of small diameter piping systems (2 inch and under) using the modified response spectrum method described in BP-TOP-1, Revision 3. The program generates a set of tables of seismic spans, support reactions, and stresses for various pipe sizes.

This program performs response spectrum curve merging along with the calculation of the seismic span. The program can also be used independently for the sole purpose of merging spectrum curves and storing the combined spectrum data for ME101 analysis. A neutral plot file of the "RAW" or "COMBINED" spectrum curves can be generated for plotting on RMS, TEKTRONIX, CALCOMP, or any neutral file compatible plotter.

3.9.1.2.6.10 ME351 - Pipe Rupture Analysis Program

This program performs nonlinear elastic-plastic analysis of three-dimensional piping systems subjected to concentrated static or dynamic time history forcing functions. These forces may result from fluid jet thrust at the location of a postulated rupture of high energy piping. PIPERUP is an adaptation of the finite-element method to the specific requirements of pipe rupture analysis. Straight and curved beam (elbow) elements are used to mathematically represent the piping, and axial and rotational springs are used to represent restraints. The stiffness characteristics of piping and restraints can reflect elastic/linear strain hardening material properties, and gaps between piping and restraints can be modeled.

3.9.1.2.7 Computer Programs Used for Component Supports

A list of computer programs used in pipe support analysis is provided in Table 3.9-3. The list consists of computer programs developed and/or owned by Bechtel, and computer programs that are recognized and widely used in the industry.

The Bechtel developed and/or owned computer programs are documented, verified, and maintained by Bechtel and meet the requirements of 10CFR50, Appendix B. A brief description of each of these programs is provided below.

3.9.1.2.7.1 CE050 - BOLTS

BOLTS is an interactive program for determining the loads on concrete expansion anchors used for baseplates with symmetrical bolt patterns. The program incorporates the effects of plate flexibility, bolt stiffness, and attachment size. BOLTS is particularly well suited for the evaluation of baseplate expansion anchors commonly used in pipe, conduit, HVAC, cable tray, and such other small equipment supports.

3.9.1.2.7.2 ME150 - FAPPS - Frame Analysis for Pipe Supports

ME150 is an interactive program for the analysis and design of pipe support frames. It has built-in standard frames and the capability to design any other nonstandard ones. It optimizes member sizes, welds, and embedments based on various user-specified design criteria.

3.9.1.2.7.3 ME225 - Anchor Plate

ME225 presents a method of designing plate-type piping anchors. It determines thickness of anchor plate, thickness of guide plate, weld joining the plate and process pipe, weld joining the supporting structure, and take out dimension of anchor plate and guide plate.

3.9.1.2.7.4 ME035 - BASEPLATE

ME035 analyzes baseplate-type structural supports. It assumes a flexible plate resting on a nonlinear foundation. It gives concrete stresses, bolt factors of safety, and weld forces. It can analyze baseplates with variable thickness with multiple columnlike attachments.

3.9.1.2.7.5 ME226 - PICLAMP

PICLAMP will design the components of six special cases of pipe support clamps. It computes the minimum required thickness at two critical sections of the clamp. It also calculates the stress in the clamp studs. It computes the stresses in the stanchion and baseplate, when applicable, and the minimum weld size based on the stress. It also computes certain clamp dimensions and the total weight of the clamp and its associated hardware.

3.9.1.2.7.6 ME425 - STAND

STAND will design and evaluate pipe support base plates with concrete anchor bolt assemblies. Plates can be of arbitrary geometry anchored with bolts that can be located in a random pattern.

3.9.1.2.7.7 ME120 - WELD

The program presents a method of determining fillet weld sizes for connecting structural members. It accepts five different types of structural shapes and analyzes for 2-weld to 16-weld configurations. It is based on the approach described in "Design of Welded Structures" by O.W. Blodgett and "Solutions to Design of Weldments" by O.W. Blodgett.

3.9.1.2.7.8 ME152 - SMAPPS

SMAPPS analyzes and designs commonly used standard frames for pipe support including associated welds and baseplates with anchors for AISC and ASME Section III, Subsection NF requirements, as well as project deflection/stiffness requirements.

SMAPPS provides the benefits of a structural frame analysis program and the simplicity of pre-engineering standards. SMAPPS provides margin factors for frame, welds, and baseplate with anchors that minimize the need for re-evaluation of pipe support due to load changes and as-built reconciliation.

3.9.1.2.7.9 CE-901 - ICES STRUDL II

STRUDL is a broad, extensive, and general program for solving problems in structural engineering.

3.9.1.2.7.10 ME153 - MAPPS

MAPPS is a miscellaneous application program for pipe supports which enables the user to access any or all of the following pipe support analysis computer programs within the same run:

- Uniform weld
- Nonuniform welded
- Beta angle
- Clip angle
- Bolt spacing
- Anchor plate
- Local effects
- Clamp (PI clamp)

3.9.1.3 Experimental Stress Analysis

When experimental stress analysis is used in lieu of analytical methods for seismic Category I ASME Code items, the applicable ASME Code requirements for experimental testing of the specific component are applied. If testing is required for seismic Category I non-ASME code items, consideration is given to size effects, dimensional tolerances, and material properties of the tested

part to ensure that the test results are a conservative representation of the load-carrying capability of the item installed at LGS.

3.9.1.3.1 Experimental Stress Analysis of NSSS Seismic Category I Items

No experimental stress analysis methods are used.

3.9.1.3.2 Seismic Category I Items Other Than NSSS

No experimental stress analysis methods are used.

3.9.1.4 Considerations for the Evaluation of Faulted Conditions

All seismic Category I equipment is evaluated for the faulted loading conditions. However, emergency stress limits rather than faulted stress limits are used in many cases. The following paragraphs in this section show examples of the treatment of faulted conditions for the major components on a component-by- component basis. Additional discussion of faulted analysis can be found in Sections 3.9.3 and 3.9.5, and Table 3.9-6. These analyses are based on the power rerate analysis, and do not reflect the use of GE13 and GE14 fuel. The impact of GE13 fuel is documented in Reference 3.9-28. The impact of GE14 fuel is documented to be bounded by GE13 fuel in Reference 3.9-34. The impact of the MUR power uprate on GE14 fuel is evaluated in Reference 3.9-31 and Reference 3.9-32. Reference 3.9-33 identifies new design basis values for Fuel Lift Margin and Control Rod Guide Tube Lift Forces under MUR conditions. Additional analyses which consider the use of GNF2 fuel are documented in Reference 3.9-35. The GNF2 fuel is demonstrated to be bounded by the analyses in Reference 3.9-33.

Analyses were performed which considered the use of GNF3 fuel. Reference 3.9-39 identified new design basis values for the reactor internal pressure differences for unbounded reactor internals. The GNF3 analyses also identified a new design basis value for maximum Control Rod Guide Tube Lift force.

Sections 3.9.2.2 and 3.7 discuss the treatment of dynamic loads resulting from the postulated seismic and hydrodynamic events. Section 3.9.2.5 discusses the dynamic analysis of loads on the reactor internals under faulted conditions including additional blowdown forces. Deformations under faulted conditions have been evaluated in critical areas, and no cases have been identified where design limits, such as clearance limits, are violated.

Elastic-plastic analysis has not been used in evaluating LGS seismic Category I systems and components for compliance with service Level D Limits. The stress levels of these components are below the ASME allowable stress.

3.9.1.4.1 Control Rod Drive System Components

3.9.1.4.1.1 Control Rod Drives

The ASME Section III Code components of the CRD have been analyzed for faulted conditions shown in Section 3.9.1.1.1. The loading criteria, calculated, and allowable stresses for various operating conditions are summarized in Table 3.9-6(u).

The design adequacy of non-ASME code components of the CRD has been verified by analysis and extensive testing programs on component parts, specially instrumented prototype drives, and production drives. The testing included postulated abnormal events, as well as the service life cycle listed in Section 3.9.1.1.1. The following three types of tests were performed:

a. A test was conducted with the lower CRD flange oscillating with a 2 inch peak-to-peak displacement. No adverse effects were observed during the normal continuous drive-in or jog operation.

b. To simulate the seismic interaction, the core plate and top guide structures of the test vessel were displaced relative to the CRD housing centerline. The results showed no effect in CRD performance.

c. The test vessel fuel channels were deflected to simulate the seismic interactions. The test was performed with fuel channel deflections up to 1.5 inches, which are greater than the expected deflection values. Because the CRD and control rod were not permanently deformed, the drive operability was maintained.

The load criteria, calculated, and allowable stresses for various operating conditions is summarized in Table 3.9-6(v) including the results of the New Loads Adequacy Evaluation program.

3.9.1.4.1.2 Hydraulic Control Unit

The HCU was analyzed for the faulted condition. The seismic and hydrodynamic loads adequacy was demonstrated by test and analysis. The results show peak dynamic loads of 6.2 g (vertical) at the natural frequency of 8-12 Hz and 6 g (horizontal) at a natural frequency of 3-4 Hz. For comparison, the capability of the HCU to withstand loading is 15 g (vertical) at 8-12 Hz, 7 g (horizontal) at 3-4 Hz, and 9 g (horizontal z displacement) at 3-4 Hz.

In addition, a detailed analysis was performed to confirm that the test-mounting configuration is applicable to the LGS unique field installation.

The analysis of the HCU under faulted condition loads establishes the structural integrity of the system.

3.9.1.4.1.3 CRD Housing

The SSE is classified as a faulted condition; however, in the CRD housing analysis, the SSE event is treated as an emergency condition. The calculated and allowable stresses at various loading conditions are given in Table 3.9-6(v).

3.9.1.4.2 Standard Reactor Internal Components

3.9.1.4.2.1 Control Rod Guide Tube

The maximum calculated stress on the control rod guide tube occurs in the base during a faulted condition. In accordance with ASME Section III, the faulted limit is 2.4 S_m, where S_m = 16,000 psi at 575°F. The analysis and limiting stresses are summarized in Table 3.9-6(aa).

3.9.1.4.2.2 Incore Housing

The maximum calculated stress on the incore housing occurs at the outer surface of the vessel penetration during a faulted condition. The maximum allowable stress for the elastic analysis used is 2.4 S_m (39,948 psi), which bounds the calculated stress as given in Table 3.9-6(ab).

3.9.1.4.2.3 Jet Pump

The elastic analysis for the jet pump faulted conditions shows that the maximum stress is due to diffuser impulse loading during a pipe rupture and blowdown. The maximum allowable for this condition, in accordance with ASME Section III, is 3.6 S_m (60,840 psi). Table 3.9-6(w) summarizes the results of the analysis.

3.9.1.4.2.4 Low Pressure Coolant Injection Coupling

The maximum stress during a faulted condition on the LPCI coupling occurs at the "Bellows" (a purchased component designed to GE requirements for 120 normal operating condition cycles and 10 SSE cycles). Table 3.9-6(y) shows that calculated stresses are within allowable limits.

3.9.1.4.2.5 Orificed Fuel Support

Due to its complex configuration, a series of vertical and horizontal load tests were performed on the orificed fuel support to verify the design. The results show that the seismic and hydrodynamic loading is below the allowable limit with an average safety margin of 1.21 for normal and upset and 1.26 for faulted conditions.

3.9.1.4.3 Reactor Pressure Vessel Assembly

The RPV assembly was evaluated using elastic analysis methods for faulted conditions. Table 3.9-6(f) lists the calculated and allowable stresses for the various loading combinations.

3.9.1.4.4 Core Support Structure

The evaluations for faulted conditions for the core support structure are discussed in Section 3.9.5. The calculated and allowable stresses are summarized in Table 3.9-6(b).

3.9.1.4.5 Main Steam Isolation, Recirculation Gate, and MSRVs

Tables 3.9-6(g), 3.9-6(h), and 3.9-6(j) provide a summary of the analysis for the MSRVs, MSIVs, and recirculation gate valves, respectively.

Standard design rules, as defined in applied codes, are utilized in analyzing pressure boundary components of Class 1 active valves. Conventional, elastic stress analysis is used to evaluate components not defined in the code. The code allowable stresses are applied to determine acceptability of structure under applicable loading conditions, including faulted condition.

3.9.1.4.6 Main Steam and Recirculation Piping

For main steam and recirculation system piping, elastic analysis methods are used to evaluate faulted loading conditions. The allowable stresses using elastic techniques are obtained from the ASME Section III, Appendix F, "Rules for Evaluation of Faulted Conditions" (these are above

elastic limits). Additional information for the main steam, recirculation piping, and pipe-mounted equipment is contained in Tables 3.9-6(d) and 3.9-6(e), respectively.

3.9.1.4.7 NSSS Pumps, Heat Exchangers, and Turbines

The recirculation, ECCS, RCIC, and SLC pumps, RHR heat exchangers and RCIC turbine are analyzed for the faulted loading conditions identified in Section 3.9.1.1. In all cases, stresses are within the elastic limits. The analytical methods, stress limits, and allowable stresses are discussed in Sections 3.9.2.2a and 3.9.3.1.

3.9.1.4.8 Control Rod Drive Housing Supports

Design adequacy of the CRD housing supports is shown by comparing the static and dynamic loads to the original design loads. The comparison, summarized in Table 3.9-6(z), shows that the hydrodynamic loads combined with other loads are less than the design load capability of the CRD housing supports.

3.9.1.4.9 Fuel Storage Racks

All analyses related to the Fuel Storage Racks are provided in UFSAR Section 9.1.

3.9.1.4.10 Fuel Assembly (Including Channel)

GE/GNF BWR fuel assembly (including channel) design bases, analytical methods, and evaluation results, including those applicable to the faulted conditions are contained in References 3.9-16 and 3.9-17. Evaluations specific to the LGS fuel assemblies have been performed in accordance with the methodology presented in Reference 3.9-17. The resulting acceleration profiles and fuel lift gap are summarized in Table 3.9-6(x).

3.9.1.4.11 Refueling Equipment

Refueling and servicing equipment which is important to safety is classified under essential components, per the requirements of 10CFR50, Appendix A. This equipment and other equipment whose failure would degrade an essential component is defined in Section 9.1 and is classified as seismic Category I. These components are subjected to an elastic dynamic finite-element analysis to generate loadings. This analysis utilizes appropriate seismic floor response spectra, and combines loads at frequencies up to 33 Hz for seismic and up to 100 Hz for hydrodynamic loads, in three directions. Imposed stresses are generated and combined for normal, upset, and faulted conditions. Stresses are compared, depending on the specific safety class of the equipment, to allowables of Industrial Codes, ASME, ANSI or Industrial standards, or AISC. Loading conditions, acceptance criteria, calculated and allowable stresses are shown in Table 3.9-6(s).

3.9.1.4.12 Seismic Category I Items Other than NSSS

The stress allowables for statically applied loads, of ASME Section III, Appendix F, Winter 1972, are used for code components. For noncode components, allowables are based on tests or accepted standards consistent with those in Appendix F of the code.

Dynamic loads for components loaded in the elastic range are calculated using dynamic load factors, time history analysis, or any other method that assumes the elastic behavior of the component.

The limits of the elastic range are defined in paragraph 1323 of Appendix F for the code components. The local yielding due to stress concentration is assumed not to affect the validity of the assumptions of elastic behavior. The stress allowables of Appendix F for elastically analyzed components are used for code components. For noncode components, allowables are based on tests or accepted material standards consistent with those in Appendix F for elastically analyzed components.

The methods used in evaluating the pipe break effects are discussed in Section 3.6.

3.9.2 DYNAMIC TESTING AND ANALYSIS

3.9.2.1a Piping Vibration, Thermal Expansion, and Dynamic Effects Testing for NSSS Piping

The test program is divided into three phases: piping vibration, thermal expansion, and dynamic effects.

3.9.2.1a.1 Piping Vibration

3.9.2.1a.1.1 Preoperational Vibration Testing of Recirculation Piping

The purpose of the preoperational vibration test phase is to verify that operating vibrations in the recirculation piping are within acceptable limits. This phase of the test uses visual observation and manual measurements by hand-held vibrograph to supplement remote measurements. If, during steady-state operation, visual observation indicates that vibration is significant, measurements are made with a hand-held vibrograph. Visual observations, and manual and remote measurements are made during the following steady-state conditions:

a. Recirculation pumps minimum flow

b. Recirculation pumps at 50% of rated flow

c. Recirculation pumps at 75% of rated flow

d. Recirculation pumps at 100% of rated flow

3.9.2.1a.1.2 Preoperational Vibration Testing of Small Attached Piping

During visual observation of each of the above test conditions (a. through d.), special attention is given to small attached piping and instrument connections to ensure that they are not in resonance with the recirculation pump motors or flow-induced vibrations. If the operating vibration acceptance criteria are not met, corrective action, such as modification of supports, is taken.

3.9.2.1a.1.3 Startup Vibration Testing of Main Steam Recirculation and RCIC Piping

The purpose of this phase of the program is to verify that the main steam, recirculation, and RCIC piping are within acceptable limits. The main steam and recirculation piping are instrumented with

transducers to measure temperature, thermal movement, and vibration deflections. Because of limited access due to high radiation levels, no visual observation is required during this phase of the test. Remote measurements are made during the following steady-state conditions:

a. Main steam flow at 25% of rated

b. Main steam flow at 50% of rated

c. Main steam flow at 75% of rated

d. Main steam flow at 100% of rated

3.9.2.1a.1.4 Operating Transient Loads on Main Steam and Recirculation Piping

The purpose of the operating transient test phase is to verify that pipe stresses are within code limits. The amplitude of displacements and the number of cycles per transient of the main steam and recirculation piping are measured, and the displacements are compared with the acceptance criteria. The deflections are correlated with stresses to verify that pipe stresses remain within code limits. Remote vibration and deflection measurements are taken during the following transients:

a. Recirculation pump starts

b. Recirculation pump trip at 100% of rated flow

c. Turbine stop valve closure at 100% power

d. Manual discharge of each SRV at 1000 psig, and at planned transient tests that result in SRV discharge

3.9.2.1a.2 Thermal Expansion Testing of Main Steam and Recirculation Piping

The thermal expansion preoperational and startup testing program verifies that normal thermal movement occurs in the piping systems, and is performed through the use of potentiometer sensors. The main purpose of this program is to ensure the following:

a. The piping system is free to expand and move without unplanned obstruction or restraint in the x, y, and z directions, during system heatup and cooldown.

b. The piping system does "shake down" after a few thermal expansion cycles.

c. The piping system is working in a manner consistent with the assumption of the NSSS stress analysis

d. There is adequate agreement between calculated and measured displacements.

e. Thermal displacements are consistent and repeatable during heatup and cooldown of the NSSS systems.

Thermal expansion displacement limits are established prior to the start of piping testing. These are compared with the actual measured displacements to determine the acceptability of the actual motion. If the measured displacement does not vary by more than the specified tolerance from the

acceptance limit, the piping system is responding in a manner consistent with predictions, and is therefore acceptable. Two levels of displacement limits are established to check the systems, as discussed in Section 3.9.2.1a.4.

3.9.2.1a.3 Dynamic Effects Testing of Main Steam and Recirculation Piping

To verify that snubbers adequately perform their intended function during plant operation, a dynamic testing program is planned, as part of the normal startup operation testing. The main purpose of this program is to ensure the following:

a. The vibration levels from the various dynamic loadings during transient and steady-state conditions are below the predetermined acceptable limits.

b. Due to underestimating the dynamic effects caused by cyclic loading during plant transient operations, long-term fatigue failure does not occur.

This dynamic testing is to account for the acoustic wave due to the SRV lifts (RV1), SRV load resulting from air clearing (RV2), and turbine stop valve closure load. The maximum stresses developed in the piping by the RV1, RV2, and turbine stop valve closure transients analysis are used as a basis for establishing criteria which assures proper functioning of the snubbers. If field measurements exceed criteria limits, this may indicate that the snubbers are not operating properly. If field measurements are within criteria limits, it is assumed that the snubbers are functioning properly. Sample production snubbers of each size (i.e. 10 kips, 20 kips, 50 kips, etc.) will also be qualified and tested for design and faulted condition loadings, prior to shipment to field. Snubbers will be tested to allow free piping movements at low velocity. During plant startup, the snubbers will be checked for improper settings and checked for any evidence of oil leak.

The criteria for vibration displacements is based on the assumed linear relationship between displacements, snubber loads and magnitudes of applied loads, for any function and response of the system. Thus the magnitudes of limits of displacements, snubber loads, and nozzle loads are all proportional. Maximum displacements (Level 1 limits) are established to prevent the maximum stress in the piping systems from exceeding the normal and upset primary stress limits, and/or the maximum snubber load from exceeding the maximum load to which the snubber has been tested.

Based on the above criteria, Level 1 displacement limits are established for all instrumented points in the piping system. These limits will be compared with the field measured piping displacements. Method of acceptance is as explained in Section 3.9.2.1a.4.

3.9.2.1a.4 Test Evaluation and Acceptance Criteria for Main Steam and Recirculation Piping

The piping response to test conditions is considered acceptable if the organization responsible for the stress report reviews the test results, and determines that the tests verify that the piping responded in a manner consistent with the predictions of the stress report, and/or that the tests verify that piping stresses are within code limits (ASME Section III, NB-3600). Acceptable deflection limits are determined after the completion of the piping systems stress analysis and are provided in the startup test specifications.

To ensure test data integrity and test safety, criteria have been established to facilitate assessment of the test while it is in progress. These criteria, designated Level 1 and Level 2, are described in the following paragraphs.

3.9.2.1a.4.1 Level 1 Criteria

Level 1 establishes the maximum limits for the level of pipe motion which, if exceeded, makes a test hold or termination mandatory.

If the Level 1 limit is exceeded, the plant will be placed in a satisfactory hold condition, and the responsible piping design engineer will be advised. Following resolution, applicable tests must be repeated to verify that the requirements of the Level 1 limits are satisfied.

3.9.2.1a.4.2 Level 2 Criteria

If the Level 2 criteria are satisfied for both steady-state and operating transient vibrations, there will be no fatigue damage to the piping system due to steady-state vibration, and all operating transient vibrations are bounded by the values in the stress report.

Exceeding the Level 2 specified pipe motion requires that the responsible piping design engineer be advised. Plant operating and startup testing plans would not necessarily be altered. Investigations of the measurements, criteria, and calculations used to generate the pipe motion limits would be initiated. An acceptable resolution must be reached by all appropriate and involved parties, including the responsible piping design engineer.

Detailed evaluation is needed to develop corrective action or to show that the measurements are acceptable. Depending on the nature of such resolution, the applicable tests may or may not be repeated.

3.9.2.1a.4.3 Acceptance Limits

For steady-state vibration, the piping break stress due to vibration only (neglecting pressure) will not exceed 10,000 psi for Level 1 criteria and 5,000 psi for Level 2 criteria. These limits are below the piping material fatigue endurance limits as defined in Design Fatigue Curves in appendix I of ASME code for 10^6 cycles.

For operating transient vibration, the piping bending stress (zero to peak) due to operating transient only will not exceed 1.2 S_m or pipe support loads will not exceed the Service Level D ratings for Level 1 criteria. The 1.2 S_m limit ensures that the total primary stress including pressure and dead weight will not exceed 1.8 S_m, the new Code Service Level B limit. Level 2 criteria are based on pipe stresses and support loads not to exceed design basis predictions. Design basis criteria require that operating transients stresses and loads not to exceed any of the Service Level B limits including primary stress limits, fatigue usage factor limits, and allowable loads on snubbers.

3.9.2.1a.5 Corrective Actions for Main Steam and Recirculation Piping

During the course of the tests, the remote measurements are regularly checked to determine compliance with Level 1 criteria. If trends indicate that Level 1 criteria may be violated, the measurements are monitored at more frequent intervals. The test is held or terminated as soon as Level 1 criteria are violated. As soon as possible after the test hold or termination, the following corrective actions are taken:

a. Installation Inspection: A walkdown of the piping and suspension is made to identify any obstruction or improperly operating suspension components. Snubbers are located close to the midpoint of the total travel range at the operating temperature. Hangers are in their operating range between the hot and cold settings. If vibration exceeds the criteria, the source of the excitation must be identified to determine if it is related to equipment failure. Action is taken to correct any discrepancies before repeating the test.

b. Instrumentation Inspection: The instrumentation installation and calibration is checked, and any discrepancies are corrected. Additional instrumentation is added, if necessary.

c. Repeat Test: If actions a. or b. identify discrepancies that could account for failure to meet Level 1 criteria, the test is repeated.

d. Resolution of Findings: If the Level 1 criteria are violated on the repeat test, or no relevant discrepancies are identified in a. or b., the organization responsible for the stress report reviews the test results and the criteria to determine if the test can be safely continued.

If the test measurements indicate failure to meet Level 2 criteria, the following corrective actions are taken after completion of the test:

a. Installation Inspection: A walkdown of the piping and suspension is made to identify any obstruction or improperly operating suspension components. Snubbers are located close to the midpoint of the total travel range at the operating temperature. Hangers are in their operating range between the hot and cold settings. If the vibration exceeds limits, the source of the vibration must be identified. Actions, such as suspension adjustment, are taken to correct any discrepancies.

b. Instrumentation Inspection: The instrumentation installation and calibration are checked, and any discrepancies are corrected.

c. Repeat Test: If a. or b. above identify a malfunction or discrepancy that could account for failure to comply with Level 2 criteria, and appropriate corrective action is taken, the test may be repeated.

d. Documentation of Discrepancies: If the test is not repeated, the discrepancies found under actions a. or b. above are documented in the test evaluation report and correlated with the test condition. The test is not considered complete until the test results are reconciled with the acceptance criteria.

3.9.2.1a.6 Measurement Locations for Main Steam and Recirculation Piping

Remote vibration measurements during initial startup will be made for each of the main steam lines and recirculation lines. The locations of the measurements will be described in the startup test specification.

During preoperational testing of recirculation piping, visual observation and manual measurements by hand-held vibrograph are made to supplement the remote measurements.

3.9.2.1b Piping Vibration, Thermal Expansion, and Dynamic Effects Testing of Non-NSSS Piping

The dynamic effects on all safety-related ASME Class 1, 2, and 3 piping systems, including their supports and restraints, are considered as required by NB-3622.3, NC-3622, and ND-3622 of ASME Section III. The structural and functional integrity of each piping system under postulated seismic events is verified by dynamic analysis only. Piping systems having significant anticipated transient loads, caused by main stop valve closure or relief valve discharge for example, are analyzed for time-dependent forces. In addition, piping steady-state vibration and dynamic transient tests will be performed as summarized below, to ensure that:

a. Excessive steady-state vibration is not present in the piping that would result in piping stresses and restraint loads above the allowables

b. The piping is adequately restrained to withstand the dynamic transient loads.

The power ascension tests performed for each non-NSSS piping system are provided in Table 3.9-7. The table also describes the systems as to ASME Code class, high energy or moderate energy piping designation, and seismic category.

The startup test program specifications describe in detail the piping that is instrumented for remote monitoring of vibrations and thermal expansion and the piping that is accessible for preoperational or startup walkdown testing by test personnel. The test criteria limit the permissible pipe vibratory stress to the allowable limits prescribed in the industry standard for startup testing of nuclear power systems, ANSI/ASME OM3.

The LGS startup testing program requires that the following conditions be demonstrated in accordance with Regulatory Guide 1.70:

a. Thermal expansion is free from significant and unacceptable restraint not accounted for in the design.

b. Piping vibration is within acceptable limits for long-term vibratory stress.

c. Dynamic transient response of the piping is compared to the design analysis expected values. If those values are exceeded, the test results are compared with the maximum that would be allowed under the ASME Code stress limits.

Cognizant design personnel familiar with the systems to be tested participate in the development of test procedures, and in the evaluation of the test results. The data acquired from the tests are compared with the anticipated results to determine the acceptability of the total system response. Refer to STP-17, STP-33 and STP-36 in Table 14.2-3 for these startup test program procedures.

Test specifications governing the scope of startup testing of BOP piping were prepared and were intended to be the repository for all primary information relating to the scope, objectives, methods, instrumentation, measurements, and criteria for evaluation of the test results. The BOP piping systems are categorized in terms of the following:

a. Test environment (hot deflection, steady-state vibration or dynamic transient response).

b. Test measurements (remotely monitored, visual or none required due to small expected response to test environment).

c. The appropriate testing phase (preoperational or power ascension).

Piping thermal expansion tests are performed for the safety-related piping systems with normal operating temperatures exceeding 300°F. Safety-related piping systems with normal operating temperatures less than 300°F do not have significant thermal expansion to warrant these tests. Engineering review of all seismic Category I piping systems, including their supports, and restraints or snubbers, was performed after completion of construction and prior to fuel load. This ensures that no restraint of normal thermal movement occurs due to interferences and obstructions, and that the support and restraints are in accordance with the design intent. For those systems receiving thermal expansion tests, pipe movements are monitored to ensure that no restraint of normal thermal movement occurs at locations other than at the designed restraint locations.

By monitoring the thermal movement, the thermal expansion test program verifies that the free thermal expansion of piping systems takes place at the snubbers. Performance of the snubbers designed for transient loads, such as those resulting from main stop valve closure or MSRV discharge, are verified by measuring the load in the snubber during the dynamic transient tests. The snubbers are qualified by dynamic testing for cyclic loading as described in Section 3.9.3.5.2.

The acceptance criterion for thermal expansion tests and dynamic transient tests is that the measured pipe displacements, accelerations, dynamic pressures, or restraint loads are below the calculated or design values.

3.9.2.1b.1 Piping Dynamic Transient Tests

During the power ascension, the piping dynamic transient tests identified in Table 3.9-7 are performed. The following modes are considered:

a. Main steam piping outside the containment for main steam turbine stop valve trip at 25%, 75% (Unit 1 only), and 100% power. Main Steam Turbine trip test for Unit 2 at 100% power will be performed during commercial operation of that Unit.

b. Main steam bypass piping for the turbine stop valve closure

c. MSRV discharge piping for the MSRV opening

d. HPCI turbine steam supply piping for HPCI turbine trip.

e. Feedwater piping for reactor feed pump trip/coastdown

f. Feedwater heater drain piping for dump and drain valve actuation (Unit 1 only)

g. Moisture separator drain piping for flashing during normal operation and moisture separator depressurization (Unit 1 only).

From past experience, the dynamic transients in other piping systems are not significant.

Dynamic transient analysis of the subject lines is performed to determine the response of the piping system and the restraint loads. During the test the accelerations of the pipe, loads in the snubbers and restraints and the pressure at representative locations will be measured as required.

The acceptance criterion for this test is that the measured response of the piping system, the snubber, and restraint loads are below the design values. When the measured response exceeds the calculated response, or restraint loads, detailed evaluation of the design will be made to determine the acceptability.3.9.2.1b.2 Piping Steady-State Vibration Testing

The piping systems identified in Table 3.9-7 are tested for steady-state vibration during preoperational test programs or during power ascension. The following operating modes are considered:

a. RHR pump operation

b. HPCI pump and turbine operation

c. RCIC pump and turbine operation

d. Core spray pump operation

e. Main steam

f. Feedwater

g. RWCU

In addition, during the system walkdown, upon initial startup or power escalation, any abnormal vibrations of other systems observed are reviewed and instrumented, if necessary, to determine the acceptability of such vibration.

All safety-related process piping systems and safety-related instrument lines are included in the vibration monitoring program (Table 3.9-7). A vibration monitoring test specification is prepared to categorize the requirements for the testing program. Safety-related systems are categorized as follows:

a. Systems or portions of systems having no flow within a significant portion of their lines; for those system, no testing is required.

b. Systems with flow:

- Accessible lines (including attached instrument lines) monitored visually or with hand-held instruments.

- Inaccessible lines other than instrumentation lines will be monitored by remote instrumentation.

- Inaccessible instrument lines.

The inside containment instrumentation lines listed below that are inaccessible for visual inspection during power ascension testing will be included in the vibration monitoring program:

- RPV level indicator instrumentation lines

- Main steam instrumentation lines used for monitoring main steam flow

- RCIC steam supply instrument lines used for monitoring steam flow
- CRD lines
- Main steam sample lines.

The vibration monitoring program for the above lines consists of walkdown by stress analysts experienced in vibration assessment prior to power ascension testing. The review is to include proper restraining of the lines near the vibration source, at elbows and bends, and at the concentrated masses. Prior to walkdown, the stress engineer will review the mode shapes and piping analytical responses to normal and upset conditions. Any lines found to be inadequately restrained, resulting in the potential for excessive vibration, will be evaluated on a case-by-case basis to assess the impact on plant safety that could result from operation of the lines. The evaluation will identify the mode(s) of operation of such lines that cause the excessive vibration. Corrective action to prevent excessive vibration will be taken prior to operating any lines in the operating mode(s) that cause excessive vibration.

Steady-state vibration is primarily induced by the flow in the pipe and the equipment motion. In general, the nature of the steady-state vibration is not known a priori. Therefore, design engineers with stress analysis experience and with familiarity with the subject piping system observe the lines during significant modes of system operation as shown in Items a. through g. above, and classify each line as acceptable, if the vibration is not significant, or as questionable, if the vibration is significant. The lines with questionable steady-state vibration are monitored as applicable by suitable instrumentation to determine the system response.

The type of any necessary instrumentation is determined by the design engineer, so that the maximum amplitude and frequency response of the piping system can be determined. The instrumentation does not screen out the significant frequencies.

The acceptance criterion for the steady-state vibration tests is that the maximum measured amplitude of the piping vibration does not induce more stress in the pipe than the endurance limit of the material. By limiting the maximum stress in the pipe due to steady-state vibration below the allowable limits prescribed in the industry standard for startup testing of nuclear power systems (ANSI/ASME OM3), the steady-state vibration induced stress does not contribute to reducing piping fatigue life. These limits are based on the piping design fatigue curves of up to 10^6 cycles of vibration given in ASME Section III, Appendix I. To account for fatigue with higher cycles, the design fatigue strength of carbon steels will be reduced by applying a factor of 0.8 and further employing a safety factor of 1.3. Austenitic pipe steels design fatigue strength reduction factor will be 0.6, and is further reduced by employing a safety factor of 1.3. Piping stress indices (K_2C_2) and intensification factors (2i) as applicable to each particular system are also applied in accordance with the standard.

When required, additional restraints are provided to reduce the steady-state vibration, and to keep the stresses below the acceptance criteria levels. Table 3.9-7 provides a reference to the appropriate test descriptions in Chapter 14.

3.9.2.2 Dynamic Qualification of Safety-Related Mechanical Equipment

The qualification discussion in the following sections is generally divided into two types of equipment: NSSS equipment and non-NSSS equipment. The design criteria and qualification

procedures for NSSS equipment includes the effects of both seismic and hydrodynamic loads. The non-NSSS equipment qualification discussions include only seismic design criteria and qualification procedures. Refer to Appendix 3A.6.8 and 3A.7.1.7 for discussion of non-NSSS equipment subject to hydrodynamic loads. Appendix 3A.6.7 and 3A.7.1.5 contain further discussion of NSSS equipment qualification.

Safety-related NSSS and Non-NSSS mechanical equipment were reviewed to SRP 3.10 Seismic Qualification Review Team (SQRT) requirements including IEEE 344-1975 and Reg. Guides 1.100 and 1.92. The SQRT re-assessment concluded that the seismic and dynamic qualification program meets the intent of IEEE 344-1975 and Reg. Guides 1.100 and 1.92. Refer to Section 3.10.2.

3.9.2.2a Dynamic Qualification of NSSS Safety-Related Mechanical Equipment

This section describes the criteria for dynamic qualification of safety-related mechanical equipment, and the qualification testing and/or analysis applicable to this plant for all the major components, on a component-by-component basis. In some cases, a module or assembly consisting of mechanical and electrical equipment is qualified as a unit, for example, ECCS pumps. These modules are generally discussed in this section, rather than in Sections 3.10 and 3.11. Electrical supporting equipment, such as control consoles, cabinets, and panels, which are part of the NSSS, are discussed in Section 3.10. Dynamic qualification of NSSS pumps and valves is discussed in Section 3.9.3.2a.

3.9.2.2a.1 Tests and Analysis Criteria and Methods

The ability of equipment to perform its safety function during and after application of dynamic loads is demonstrated by tests and/or analysis. Selection of testing, analysis, or a combination of the two is determined by the type, size, shape, and complexity of the equipment being considered. When practical, equipment operability is demonstrated by testing. Otherwise, operability is demonstrated by analysis.

Analysis is also used to show there are no natural frequencies below 33 Hz for seismic loads and 100 Hz for hydrodynamic loads. If a natural frequency lower than these is discovered, dynamic tests may be conducted, and in conjunction with mathematical analysis, used to verify operability and structural integrity at the required dynamic input conditions.

When the equipment is qualified by dynamic testing, the response spectrum or time history of the attachment point is used in determining input motion.

Natural frequency may be determined by running a continuous sweep frequency search, using a sinusoidal steady-state input of low magnitude. Dynamic conditions are simulated by tests using random vibration input or single-frequency input (within equipment capability) at frequencies of interest. Whichever method is used, the input motion during testing envelopes the input amplitude expected during dynamic loading conditions.

Equipment having an extended structure, such as a valve operator, is analyzed by applying static-equivalent dynamic loads at the extended structure's center of gravity. In cases where the equipment's structural complexity makes mathematical analysis impractical, a test is used to determine operational capability at maximum equivalent dynamic load conditions. Pipe-mounted equipment are represented in the model used for the piping system dynamic analysis.

3.9.2.2a.1.1 Random Vibration Input

When random vibration input is used, the actual input motion envelopes the appropriate floor input motion at the individual modes. However, single-frequency input, such as sine beats, can be used, provided one of the following conditions are met:

a. The characteristics of the required input motion are dominated by one frequency.

b. The anticipated response of the equipment is adequately represented by no resonances, one resonance, or widely spaced resonances.

c. The input has sufficient intensity and duration to excite all modes to the required magnitude, so that the testing response spectra envelope the corresponding response spectra of the individual modes.

3.9.2.2a.1.2 Application of Input Motion

When dynamic tests are performed, the input motion is applied to one vertical and one horizontal axis simultaneously. However, if the equipment response along the vertical direction is not sensitive to the vibratory motion along the horizontal direction, and vice-versa, then the input motion is applied to one direction at a time. In the case of single-frequency input, the time phasing of the inputs in the vertical and horizontal directions is such that a purely rectilinear resultant input is avoided.

3.9.2.2a.1.3 Fixture Design

The fixture design simulates the actual service mounting, and causes no dynamic coupling to the equipment.

3.9.2.2a.1.4 Prototype Testing

Equipment testing is conducted on prototypes of the equipment installed in this plant.

3.9.2.2a.2 Dynamic Qualification of Specific NSSS Mechanical Components

The following sections discuss the testing or analytical qualification of NSSS equipment. Seismic and hydrodynamic qualification is also described in Sections 3.9.1.4, 3.9.3.1, and 3.9.3.2 and in Appendix 3A.6.7 and 3A.7.1.6.

3.9.2.2a.2.1 Jet Pumps

A dynamic analysis of the jet pumps was performed. The stresses resulting from the analysis are below the design allowables.

3.9.2.2a.2.2 CRD and CRD Housing

A dynamic analysis of the CRD housing (with enclosed CRD) was performed. The results of the analyses established the structural integrity of these components. Preliminary dynamic tests verified the operability of the CRD subjected to displacements resulting from a dynamic event. A simulation test, imposing a static bow in the fuel channels, was performed with the CRD functioning satisfactorily.

3.9.2.2a.2.3 Core Support (Fuel Support and Control Rod Guide Tube)

A detailed analysis imposing dynamic effects due to seismic and hydrodynamic events shows that the maximum stresses developed during these events are much lower than the maximum allowed for the component material.

3.9.2.2a.2.4 Hydraulic Control Unit

The HCU was evaluated by comparing the RRS with the TRS at mounting points through test and analysis.

3.9.2.2a.2.5 Fuel Assembly Including Channels

GE/GNF BWR fuel channel design bases, analytical methods, and evaluation results, including seismic and hydrodynamic considerations, are contained in References 3.9-16 and 3.9-17.

3.9.2.2a.2.6 Recirculation Pump and Motor Assembly

Calculations were made to assure that the recirculation pump and motor assembly is designed to withstand the specific static-equivalent seismic and hydrodynamic forces. The flooded assembly was analyzed as a free body supported by constant support hangers from the brackets on the motor mounting member, with snubbers attached to brackets located on the pump case and the top of the motor frame.

Primary stresses due to horizontal and vertical dynamic forces were considered to act simultaneously, and as a conservative measure, they were added directly. Horizontal and vertical seismic forces were applied at mass centers, and equilibrium reactions were determined for motor and pump brackets.

3.9.2.2a.2.7 ECCS Pump and Motor Assembly

The dynamic qualification of each ECCS pump and motor assembly (as a unit), while operating under faulted conditions, was met in the form of a response spectrum analysis. The maximum specified vertical and horizontal accelerations were applied, simultaneously, in the worst case combination. The results of the analysis indicate that the pumps are capable of sustaining the applicable loadings without overstressing the pump components.

A similarly designed motor was dynamically qualified by a combination of static analysis and dynamic testing. The complete motor assembly was seismically qualified by dynamic testing, in accordance with IEEE 344 (1975). The qualification test program included demonstration of startup and shutdown capabilities, as well as no-load operability during dynamic loading conditions. Refer to Section 3.10.

3.9.2.2a.2.8 RCIC Pump Assembly

The RCIC pump assembly was analytically qualified by static analysis for seismic and hydrodynamic loadings as well as the design operating loads of pressure, temperature, and external piping loads. The results of this analysis confirm that the stresses are less than the allowable.

3.9.2.2a.2.9 RCIC Turbine Assembly

The RCIC turbine was qualified for seismic and hydrodynamic loads by a combination of static analysis and dynamic testing.

The turbine assembly and its components were considered to be supported as designed, and horizontal/vertical accelerations were applied to the mass centers of gravity. The static analysis indicated that the turbine assembly is capable of sustaining the design accelerations and loadings without overstressing any components.

The complete turbine assembly was qualified by dynamic testing, in accordance with IEEE 344 (1975). The qualification test program demonstrated startup, steady-state operability, and shutdown capabilities. Refer to Section 3.10.

3.9.2.2a.2.10 SLCS Pump and Motor Assembly

The SLCS positive displacement pump and motor assembly is mounted on a common baseplate and qualified by a combination of static analysis and single-frequency testing.

The SLCS pump and motor assembly was analytically qualified by static analysis for dynamic loading, as well as for the design operating loads of pressure, temperature, and external piping loads. The results of this analysis confirm that the stresses are less than the allowable.

3.9.2.2a.2.11 RHR Heat Exchangers

A three-dimensional finite-element model of the RHR heat exchanger and its support was developed and analyzed using the response spectrum method to verify that the heat exchanger can withstand seismic and hydrodynamic loads. The same model was statically analyzed to evaluate the effect of the external piping loads and dead weight to ensure that the nozzle load criteria and stress limits were met. Critical location stresses were evaluated and found to be lower than the corresponding allowable values.

3.9.2.2a.2.12 SLCS Tank

The SLCS storage tank is a cylindrical tank, 9 feet in diameter and 12 feet high, bolted to the concrete floor. The SLCS tank was qualified by analysis for:

a. Stresses in the tank bearing plate

b. Bolt stresses

c. Sloshing loads imposed at the natural frequency of sloshing (0.58 Hz). The natural frequency of the tank is 58.8 Hz.

d. Minimum wall thickness

e. Buckling

The results confirm that the stresses at the investigated locations are below the allowable.

3.9.2.2a.2.13 Main Steam Isolation Valves

The MSIVs are qualified by dynamic testing and analysis. The dynamic characteristics of the MSIVs were modeled in the main steam piping analysis. The resulting moments and stresses from the piping interaction were below the test proven valve capability. This assured the structural integrity. The operability of the valve is demonstrated by the closure test while it was subjected to the faulted dynamic loads.

3.9.2.2a.2.14 Main Steam Relief Valves

Due to the complexity of this structure and the performance requirements of the valve, the total assembly of the MSRV (including electrical and pneumatic devices) was dynamically tested at accelerations equal to or greater than the combined SSE and hydrodynamic loading of this plant.

3.9.2.2a.2.15 HPCI Turbine

The HPCI turbine was dynamically qualified by a combination of static analysis and dynamic testing.

The turbine assembly and its components were considered to be supported as designed, and horizontal/vertical accelerations applied to the mass centers of gravity. The results of the analysis indicate that the turbine assembly is capable of sustaining the design accelerations and loadings without overstressing any components.

The complete turbine assembly was qualified by dynamic testing, in accordance with IEEE 344 (1975). The qualification test program demonstrated startup, steady-state operability, and shutdown capabilities. Refer to Section 3.10.

3.9.2.2a.2.16 HPCI Pumps

The HPCI booster pump and main pump assembly is a split body type, mounted on one common baseplate. The pump assembly was analytically qualified by three-dimensional dynamic analysis using the response spectrum modal analysis technique. Results are obtained by using acceleration forces acting simultaneously in two directions, one vertical and one horizontal.

3.9.2.2b Dynamic Qualification of Non-NSSS Safety-Related Mechanical Equipment

All non-NSSS seismic Category I equipment is designed to withstand the simultaneous horizontal and vertical accelerations caused by the OBE and the SSE, as defined herein, in conjunction with other applicable loads. Seismic Category I non-NSSS mechanical equipment and supports located in the containment, reactor enclosure, and control structure are also subjected to dynamic loads due to LOCA and MSRV discharge hydrodynamic phenomena. Appendix 3A.5.6, 3A.6.8 and 3A.7.1.7 provide a summary of the load combinations, capability assessment criteria, and methodology used to qualify the equipment to withstand these additional hydrodynamic loads in combination with seismic and all other applicable loads. The functions of instrumentation and controls, or other parts necessary for the functional requirements of the equipment, are not impaired when the equipment is subjected to these loads.

The criteria for the seismic qualifications of non-NSSS mechanical and electrical equipment, with the exception of valves and valve operators (other than relief valves), are contained in a project

specification. IEEE 344, "Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations," is used as a supplement to the project seismic specification in some of the individual equipment specifications. Both Standard IEEE 344 and the project specification address the requirements of the demonstration of the seismic adequacy of equipment by analysis and/or tests.

Seismic qualification of non-NSSS motor and air operated valves is addressed in Section 3.9.3.2b.2, and qualification of control valves is addressed in Section 3.10.

3.9.2.2b.1 Dynamic Qualification

Seismic Category I non-NSSS mechanical equipment is qualified by any one of the following methods:

a. Dynamic analysis

b. Testing

c. Combination of analysis and testing

d. Similarity to previously tested equipment.

A list of dynamic qualification package numbers for non-NSSS safety-related mechanical equipment is provided in Table 3.9-9. The qualification packages will be maintained by the licensee in a centrally located, readably auditable permanent file.

3.9.2.2b.2 Criteria

The criteria for dynamic qualification of the equipment are given below (Refer to Appendix 3A.6.8 for the criteria for the equipment subjected to hydrodynamic loads in addition to seismic loads).

3.9.2.2b.2.1 Response Spectrum Curves

The appropriate response spectrum curves for the equipment in question are issued with the material requisition or the equipment specification, for both OBE and SSE. Response spectrum curves are based upon the seismic analysis of the supporting structure, and represent a plot of the maximum dynamic response to a family of a single-degree-of-freedom damped oscillators at a particular location within the structure. Response spectrum curves, plotted in terms of acceleration versus frequency, correspond to various locations within the buildings, and are identified with respect to the points noted on the mathematical model for each direction of vibration to be considered. This may include the vertical, as well as both the north-south and the east-west horizontal directions. In addition, each response spectrum curve corresponds to a particular damping ratio, i.e., the ratio of damping of the single-degree-of-freedom system to critical damping. See Section 3.7 for the appropriate response spectrum curves.

3.9.2.2b.2.2 Load Combinations and Allowable Stress Limits

Seismic Category I equipment is designed to withstand the more severe of the following load combinations:

a. OBE Conditions

This includes gravity loads and operating loads (or DBA loads, if applicable), including associated temperatures and pressures combined by absolute sums, with the dynamic seismic loading of the OBE.

Allowable stresses in the structural steel portions may be increased to 125% of the allowable working stress limits as set forth in ASME Section III, or other applicable industrial codes. The customary increase in normal allowable working stress due to an earthquake is used if, according to the appropriate code, it is less than 25%. Resulting deflections, misalignment or binding of parts, or effects on electrical performance (for example, contact bounce) do not prevent operation of the mechanical equipment during or after the seismic disturbance.

b. SSE Conditions

This includes gravity loads and operating loads (or DBA loads, if applicable), including associated temperatures and pressures combined by absolute sums with the dynamic seismic loading of the SSE. Allowable stresses in the structural portions may be increased to 150% of allowable working stress limits (the appropriate codes listed in a.) but may not exceed 0.9 F_y in bending, 0.85 F_y for axial tension, and 0.5 F_y in shear, where (F_y) equals the material minimum yield stress at the design temperature. For equipment designed by the maximum shear stress theory, the difference between the maximum and minimum principal stresses does not exceed 0.9 F_y. The resulting deflections, misalignment, or binding of parts, or effects on electrical performance (for example, contact bounce) do not prevent operation of the mechanical equipment during or after the seismic disturbance.

3.9.2.2b.2.3 Prevention of Overturning and Sliding

Stationary equipment is designed to prevent overturning or sliding, by using anchor bolts or other suitable mechanical anchoring devices. The effect of friction on the ability to resist sliding is neglected. The effect of upward vertical seismic loads on reducing overturning resistance is considered. Anchoring devices are designed in accordance with the requirements of a. and b. above, and the AISC Manual of Steel Construction. The proposed anchoring system is shown on the Seller's drawings, so that the Buyer can provide the proper foundation.

3.9.2.2b.2.4 Dynamic Testing

For equipment qualified by testing, seismic adequacy was established by dynamically testing the equipment in accordance with the project specifications. The equipment was tested with its mountings simulating the actual installation conditions.

3.9.2.2b.2.5 Combined Analysis and Test

Some equipment is qualified by a combination of analysis and testing procedures.

An analysis is conducted on the overall assembly to determine its stress level and the transmissibility of motion from the base of the equipment to the critical components. The critical

components are removed from the assembly and subjected to a simulation of the environment on a test table.

Testing methods are also used to aid the formulation of the mathematical model for any piece of equipment. Mode shapes and frequencies are determined experimentally and incorporated into a mathematical model of the equipment.

3.9.2.2b.2.6 Criteria for the Diesel Fuel Oil Storage Tanks

These tanks are buried below-grade under a cover of 9 feet of earth.

Tanks and tank supports are designed to withstand Cooper E80 loading, applied above 9 feet of saturated overburden. Tank walls and ends do not deflect more than 3% maximum under the most unfavorable loading conditions.

The diesel fuel oil storage tanks conform to the requirements of the UL 58 Code.

Tanks and their supports are designated seismic Category I, and are designed to resist the increased earth pressure from the OBE and the SSE.

Tanks are designed to withstand external pressure resulting from being buried in the ground when the tanks are empty. Uplift forces on buried tanks are resisted by the weight of the empty tank and the foundation mat, plus 9 feet of overburden.

The tanks were analyzed using a mathematical model considering soil/structure interaction.

3.9.2.3 Dynamic Response of Reactor Internals Under Operational Flow Transients and Steady-State Conditions

The major reactor internal components are subjected to extensive testing, coupled with dynamic system analyses, to properly describe the flow-induced vibration phenomena resulting from normal reactor operation, and from anticipated operational transients.

In general, the vibration forcing functions for operational flow transients and steady-state conditions are not predetermined by detailed analysis. Special analyses of the response signals, measured from reactor internals of similar designs, are performed to obtain the parameters that determine the amplitude and modal contributions in the vibration responses. These studies are useful for extrapolating the results from tests of internals and components of similar designs, are also performed. This vibration prediction method is appropriate where standard hydrodynamic theory cannot be applied due to the complexity of the structure and flow conditions. Elements of the vibration prediction method are outlined as follows:

a. Dynamic analysis of major components and subassemblies is performed to identify natural vibration modes and frequencies. The analysis models used for seismic Category I structures are similar to those outlined in Section 3.7.2.

b. Data from previous plant vibration measurements are assembled and examined to identify predominant vibration response modes of major components. In general, response modes are similar, but response amplitudes vary among BWRs of differing size and design.

c. Parameters are identified which are expected to influence vibration response amplitudes among the several reference plants. These include hydraulic parameters such as velocity and steam flow rates, and structural parameters such as natural frequency and significant dimensions.

d. Correlation functions of the variable parameters are developed which, when multiplied by response amplitudes, tend to minimize the statistical variability between plants. A correlation function is obtained for each major component and response mode.

e. Predicted vibration amplitudes for components of the prototype plant are obtained from these correlation functions, based on applicable values of the parameters for the prototype plant. The predicted amplitude for each dominant response mode is stated in terms of a range, taking into account the degree of statistical variability in each of the correlations. The predicted mode and frequency are obtained from the dynamic analysis of a. above.

The dynamic modal analysis also forms the basis for interpreting prototype plant preoperational and initial startup test results (Section 3.9.2.4 below). Modal stresses are calculated, and relationships are obtained between sensor response amplitudes and peak component stresses, for each of the lower normal modes. The allowable amplitude in each mode is that which produces a peak stress amplitude of ±10,000 psi.

3.9.2.4 Confirmatory Flow-Induced Vibration Testing of Reactor Internals

The LGS reactor internals are tested in accordance with the provisions of Regulatory Guide 1.20 (Rev 2) for nonprototype Category I plants. The test procedure requires operating the recirculation system at the rated flow, with internals installed (less fuel), followed by inspection for evidence of vibration, wear, or loose parts. The test duration is sufficient to subject critical components to at least 10^6 cycles of vibration during two-loop and single-loop operation of the recirculation system. At the completion of the flow test, the vessel head and shroud head are removed. The vessel is drained, and the major components are inspected on a selected basis. The inspection covers all components which were examined on the prototype design, including the shroud, shroud head, core support structures, the jet pumps, and the peripheral CRD and incore guide tubes. Access is provided to the reactor lower plenum. The prototype reactor for LGS is the Browns Ferry-3 design docketed on July 31, 1968 (Reference 3.9-18).

Reactor internals for LGS are substantially the same as the internal design configurations which have been tested in prototype BWR/4 plants. Results of the prototype tests are presented in a Licensing Topical Report, Reference 3.9-18. This report also contains additional information on the confirmatory inspection program.

3.9.2.5 Dynamic System Analysis of the Reactor Internals Under Faulted Conditions

In order to assure that no significant dynamic amplification of load occurs as a result of the oscillatory nature of the blowdown forces (Figure 3.9-2), a comparison is made between the periods of the applied forces and the natural periods of the core support structures being acted upon by the applied forces. These periods are determined from a 12 node vertical dynamic model of the RPV and internals. In addition to the masses of the RPV and core support structures, allowance is made for the water inside the RPV.

The time-varying pressures are applied to the dynamic model of the reactor internals described above. Except for the nature and locations of the forcing functions and the dynamic model, the dynamic analysis method is identical to that described for seismic analysis, and is detailed in Section 3.7.2.1. These dynamic components are combined with other dynamic loads (including hydrodynamic and seismic) by the SRSS method. The resultant force is then combined with other steady-state and static loads on an ABS basis to determine the design load. The results of the dynamic analysis of the reactor internals are summarized in Table 3.9-6(b). These results are based on the power rerate analysis, and do not reflect the use of GE13 or GE14 fuel. The impact of GE13 fuel is documented in reference 3.9-28. The impact of GE14 fuel is documented to be bounded by GE13 fuel in Reference 3.9-24. The impact of the MUR power uprate is evaluated in Reference 3.9-31 and Reference 3.9-32. Reference 3.9-33 identifies new design basis values for Fuel Lift Margin and Control Rod Guide Tube Lift Forces under MUR conditions. Additional analyses which considered the use of GNF2 fuel are documented in Reference 3.9-35. The GNF2 fuel is demonstrated to be bonded by the analyses in Reference 3.9-33.

Analyses were performed which considered the use of GNF3 fuel. Reference 3.9-39 identified new design basis values for the reactor internal pressure differences for unbounded reactor internals. The GNF3 analyses also identified a new design basis value for maximum Control Rod Guide Tube Lift force.

3.9.2.6 Correlations of Reactor Internals Vibration Tests with the Analytical Results

Prior to initiating the instrumented vibration test program for the prototype plant, extensive dynamic analyses of the reactor and internals are performed. The results of these analyses are used to generate the allowable vibration levels during the vibration test. The vibration data obtained during the test are always analyzed in detail. The results of the data analysis, vibration amplitudes, natural frequencies, and mode shapes are then compared to those obtained from the theoretical analysis.

Such comparisons provide insight into the dynamic behavior of the reactor internals. The additional knowledge gained is utilized in the generation of the dynamic models for seismic and LOCA analyses for this plant. The models used for this plant are the same as those used for the vibration analysis of the prototype plant.

The vibration test data are supplemented by data from forced oscillation tests of reactor internal components, thereby providing the analysts with additional information concerning the dynamic behavior of the reactor internals.

3.9.3 ASME CODE CLASS 1, 2, AND 3 COMPONENTS, COMPONENT SUPPORTS, AND CORE SUPPORT STRUCTURES

3.9.3.1 Loading Combinations, Design Transients, and Stress Limits

This section delineates the criteria for selecting and defining design limits and loading combinations associated with normal operation, postulated accidents, and specified seismic and hydrodynamic events for the design of safety-related ASME Code components (except containment components, which are discussed in Section 3.8).

This section also lists the major ASME Class 1, 2, and 3 associated equipment and pressure-retaining parts and on a component-by-component basis, and identifies the applicable

loadings, calculation methods, calculated stresses, and allowable stresses. Design transients for ASME Class 2 equipment are not addressed in the section, they are covered in Section 3.9.1.1; seismic and hydrodynamic related loads are discussed in Section 3.9.2.2.

Table 3.9-6 is the major part of this section; it presents the loading combination analytical methods (by reference or example) and also the calculated stress or other design values for the most critical areas of all ASME Class 1, 2, and 3 components supports and core support structures. These values (which are based on the power rerate analysis and do not reflect the use of GE13 or GE14 fuel) are also compared to applicable code allowables. The impact of GE13 fuel is documented in Reference 3.9-28. The impact of GE14 fuel is documented to be bounded by GE13 fuel in Reference 3.9-34. The impact of the MUR power uprate is evaluated in Reference 3.9-31 and Reference 3.9-32. Reference 3.9-33 identifies new design basis values for Fuel Lift Margin and Control Rod Guide Tube Lift Forces under MUR conditions. Additional analyses which consider the use of GNF2 fuel are documented in Reference 3.9-35. The GNF2 fuel is demonstrated to be bounded by the analyses in Reference 3.9-33.

Analyses were performed which considered the use of GNF3 fuel. Reference 3.9-39 identified new design basis values for the reactor internal pressure differences for unbounded reactor internals. The GNF3 analyses also identified a new design basis value for maximum Control Rod Guide Tube Lift force.

3.9.3.1.1 Plant Conditions

All events that the plant might credibly experience during a reactor year are evaluated to establish a design basis for plant equipment. These events are divided into four plant conditions.

The plant conditions described in the following paragraphs are based on event probability (i.e., frequency of occurrence) and correlated design conditions as defined in the ASME Section III.

3.9.3.1.1.1 Normal Condition

Normal conditions are any conditions in the course of system startup; operation in the design power range; normal hot standby (with condenser available); and system shutdown other than upset, emergency, faulted, or testing.

3.9.3.1.1.2 Upset Condition

Upset conditions are any deviations from normal conditions which are anticipated to occur often enough that the design should include a capability to withstand the conditions without operational impairment. The upset conditions include those transients which result from any single operator error or control malfunction, transients caused by a fault in a system component requiring its isolation from the system, and transients due to loss of load or power. Vibratory motions due to an OBE are conservatively treated as upset. Hot standby with the main condenser isolated is an upset condition.

3.9.3.1.1.3 Emergency Condition

Emergency conditions are those deviations from normal conditions which require shutdown to correct the conditions or to repair damage in the RCPB. These conditions have a low probability of occurrence, but are included to provide assurance that no gross loss of structural integrity results as a concomitant effect of any damage developed in the system. Emergency condition events

include, but are not limited to, transients caused by one or more of the following: a multiple valve blowdown of the reactor vessel; loss of reactor coolant from a small break or crack which does not depressurize the reactor system, nor result in leakage beyond normal makeup system capacity, but which does require the safety functions of containment isolation and reactor shutdown; improper assembly of the core during refueling; or vibratory motions of an OBE in combination with associated system transients.

3.9.3.1.1.4 Faulted Condition

Faulted conditions are those combinations of conditions associated with extremely unlikely postulated events, with consequences such that the integrity and operability of the system may be so impaired that considerations of public health and safety are involved. Faulted conditions encompass events that are postulated because their consequences include the potential for releasing significant amounts of radioactive material. These postulated events are the most drastic that must be designed against, and thus represent limiting design bases. Faulted condition events include, but are not limited to, one or more of the following: a control rod-drop accident; a fuel handling accident; a main steam line break; a recirculation loop break; the combination of small break/large break accident, dynamic motion associated with an SSE and hydrodynamic, and a LOOP; or the SSE.

3.9.3.1.1.5 Correlation of Plant Conditions with Event Probability

The probability per reactor year, (P), of an event associated with the plant conditions is listed below. This correlation can be used to identify the appropriate plant condition for any hypothesized event or sequence of events.

PLANT CONDITIONS	EVENT ENCOUNTERED (Probability per reactor year)
Normal (planned)	1.0
Upset (moderate probability)	$1.0>P>10^{-2}$
Emergency (low probability)	$10^{-2}>P>10^{-4}$
Faulted (extremely low probability)	$10^{-4}>P>10^{-6}$

3.9.3.1.1.6 Regulatory Guide 1.48

Regulatory Guide 1.48 was issued after the design of this plant was established, and is therefore not used as a design basis requirement. However, the GE design basis was representative of good industry practices at the time of design, procurement, and manufacture, and is shown to be in general agreement with the guidelines of Regulatory Guide 1.48 through the use of the alternate approaches. For a comparison of NSSS compliance with Regulatory Guide 1.48, refer to Table 3.9-10. This comparison reflects general GE practice on BWR/4s and BWR/5s, and therefore is applicable to LGS.

The design limits and loading combinations for non-NSSS seismic Category I fluid systems components have been evaluated as being in conformance with Regulatory Guide 1.48, although in some cases the guidelines were not specifically a design basis.

Pump and valve operability assurance during and after design loading events, as discussed in footnotes 6 and 11 in section C of the regulatory guide, is discussed in Section 3.9.3.2b.

3.9.3.1.2 Reactor Pressure Vessel Assembly

The reactor vessel assembly consists of the RPV, RPV support skirt, shroud support, and shroud plate.

The RPV, RPV support skirt, and shroud support are constructed in accordance with ASME Section III. The shroud support consists of the shroud support plate, and the shroud support cylinder and its legs. The RPV is an ASME Class 1 component. Complete stress reports on these components have been prepared in accordance with ASME requirements. Table 3.9-6(f) provides a summary of stress criteria load combinations, calculated stress, and available stresses. The stress analyses performed for the reactor vessel assembly, including the faulted condition, were completed using elastic methods. The stress load combinations and stress analyses for core support structures and other reactor internals are discussed in Section 3.9.5.

3.9.3.1.3 Main Steam Piping

The main steam piping discussed in this paragraph includes that piping extending from the reactor pressure vessel to the outboard MSIV. This piping is designed in accordance with the ASME Section III, Class 1, Subsection NB-3650. The load combinations and stress criteria for the main steam piping and pipe-mounted equipment are shown in Table 3.9-6(d).

The rules contained in ASME Section III, Appendix F are used in evaluating faulted loading conditions, independently of all other design and operating conditions. Stresses calculated on an elastic basis are evaluated in accordance with F-1360.

3.9.3.1.4 Recirculation Loop Piping

The recirculation system piping which is bounded by the RPV nozzles is designed in accordance with the ASME Section III, Class 1, Subsection NB-3650. The load combinations and allowables for the recirculation piping and pipe-mounted equipment are shown in Table 3.9-6(e). The rules contained in ASME Section III, Appendix F are used in evaluating faulted loading conditions, independently of all other design and operating conditions. Stresses calculated on an elastic basis are evaluated in accordance with F-1360.

3.9.3.1.5 Recirculation System Valves

The recirculation system suction and discharge gate valves are designed in accordance with the ASME Section III, Class 1, Subsection NB-3600. Loading combinations and other stress analysis data are presented in Table 3.9-6(j).

3.9.3.1.6 Recirculation Pump

In the design of the recirculation pumps, the ASME Section VIII, Division 1, 1971 Edition (with latest addenda) is used as a guide in calculations made to determine the thickness of pressure-retaining parts and to size the pressure-retaining bolting. At the time the LGS recirculation pump

was procured, ASME Section III design rules for pumps were under development. The New Loads Adequacy Evaluation has demonstrated that the design meets ASME Section III requirements.

The pump vendor's calculations for the design of the pressure- containing components include the determination of minimum wall thickness and allowable stress and pressures. Loading conditions and stress information of those calculations are shown in Table 3.9-6(i).

Load, shear, and moment diagrams were constructed to scale, using live loads, dead loads, and calculated snubber reactions. Combined bending, tension and shear stresses were determined for each major component of the assembly, including the pump driver mount, motor flange bolting, and pump case.

The maximum combined tensile stress in the cover bolting was calculated using tensile stress from design pressure.

Combined primary stresses did not exceed 150% of the Code allowable stress shown in ASME Section VIII, 1971 Edition.

These methods and calculations demonstrate that the pump will maintain pressure integrity.

3.9.3.1.7 SLCS Tank

The ASME Code allowable stress limits for the faulted category are 1.2 S_m for general membrane, and 1.8 S_m for bending plus local membrane.

The SLCS tank is designed in accordance with ASME Section III. A summary of the design calculations and stress criteria used is shown in Table 3.9-6(m).

3.9.3.1.8 RHR Heat Exchangers

The RHR heat exchangers are designed in accordance with ASME Section III. The loading combinations and stress analyses for the RHR heat exchangers are given in Table 3.9-6(o).

3.9.3.1.9 RCIC Turbine

Although not under the jurisdiction of the ASME Code, the RCIC turbine is designed and fabricated following the basic guidelines for an ASME Section III, Class 2 component.

Operating conditions for the RCIC turbine include:

a. Surveillance Testing - Periodic operation with the reactor pressure at 1000 psia, nominal, and saturated temperature; and turbine exhaust pressure at 25 psia, peak, and saturated temperature.

b. Auto-Startup - 30 cycles per year with the reactor pressure at 1150 psia, nominal, and saturated temperature; and turbine exhaust pressure at 25 psia, peak, and saturated temperature.

Design conditions for the RCIC turbine include:

a. Turbine Inlet - 1250 psig at saturated temperature

b. Turbine Exhaust - 165 psig at saturated temperature

Table 3.9-6(q) contains a summary of the loading conditions, stress criteria, calculated stresses and allowable stresses of the RCIC turbine.

3.9.3.1.10 RCIC Pump

The RCIC pump has been designed and fabricated to the requirements for an ASME Section III, Class 2 component.

The RCIC pump is surveillance tested in conjunction with the RCIC turbine. An operational test is performed, in which the RCIC pump takes condensate from the CST, and discharges back to the CST at the design flow through a closed test loop.

Design conditions for the RCIC pump include:

a. Required NPSH - 20 feet

b. Total head - High speed 2800 feet
Low speed 525 feet

c. Pump capacity - 625 gpm

d. Normal ambient operating temperature - 60°F to 100°F

e. Normal plus upset conditions which control the pump design include:

1. Design pressure 1500 psig

2. Design temperature 40°F - 140°F

3. OBE(1) ½ of SSE

Table 3.9-6(r) contains a summary of the loading conditions, stress criteria, calculated and allowable stresses for the RCIC pump components.

3.9.3.1.11 ECCS Pumps

The RHR and core spray pumps are designed in accordance with ASME Section III. The stress criteria and calculated and allowable stresses are summarized in Table 3.9-6(n).

Design conditions for the RHR and core spray pumps are as follows:

	RHR	Core Spray
a. Design pressure		
1. Suction	220 psig	125 psig

2.	Discharge	500 psig	500 psig
b.	Design Temperature	40-360°F	40-212°F

3.9.3.1.12 SLCS Pump

The SLCS pumps are designed and fabricated following the requirements for an ASME Section III, Class 2 component.

The SLCS pumps and motors are functionally tested by pumping demineralized water through a closed test loop.

Design conditions for each SLCS pump include:

a.	Flow rate	43 gpm
b.	Available NPSH	12.9 psi @ 110°F
c.	Maximum operating discharge pressure	1220 psig

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(1) Combine with hydrodynamic loads of Table 3.9-6.

d. Ambient conditions:

1.	Temperature	65°F - 106°F
2.	Relative Humidity	20% - 95%

e. Normal plus upset conditions which control the pump design include:

1.	Design pressure	1400 psig
2.	Design temperature	150°F
3.	OBE	½ of SSE

f. Faulted or emergency conditions include:

1.	Design pressure		1400 psig
2.	Design temperature		150°F
3.	SSE(1)		
		horizontal	1.5 g
		vertical	0.14 g

A summary of loading combinations, stress criteria, and calculated and allowable stresses for the SLCS pump is contained in Table 3.9-6(l).

3.9.3.1.13 MSIVs and MSRVs

The MSIVs and MSRVs are designed in accordance with ASME Section III, NB-3500 for safety Class 1 components.

Load combination, analytical methods, calculated stresses, and allowable limits are shown for the MSRVs and MSIVs in Tables 3.9-6(g) and 3.9-6(h) respectively.

3.9.3.1.14 HPCI Turbine

Although not under the jurisdiction of the ASME Code, the HPCI turbine is designed and fabricated following the basic guidelines for an ASME Section III, Class 2 component.

Operating conditions for the HPCI turbine include:

a. Surveillance Testing - Periodic operation with the reactor pressure at 1000 psia, nominal, and saturated temperature; and the turbine exhaust pressure at 65 psia, peak, and saturated temperature.

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(1) Combine with hydrodynamic loads from Table 3.9-6.

b. Auto-Startup - 30 cycles per year with the reactor pressure at 1150 psia, nominal, and saturated temperature; and turbine exhaust pressure at 65 psia, peak, and saturated temperature.

Design conditions for the HPCI turbine include:

a. Turbine Inlet - 1250 psig at 575°F

b. Turbine Exhaust - 200 psig at 382°F

A summary of loading conditions, stress criteria, and calculated and allowable stresses for the HPCI turbine components is shown in Table 3.9-6(k).

3.9.3.1.15 HPCI Pump

The HPCI pump is designed and fabricated following the requirements for an ASME Section III, Class 2 component.

The HPCI pump is surveillance tested together with the HPCI turbine (Section 3.9.3.1.14). An operational test is performed in which the HPCI pump takes condensate from the CST, and discharges at the design flow rate back to the CST through a closed test loop.

Design conditions for the HPCI pump include:

REACTOR CONDITION(2,3)

			1	2	3
a.	Required NPSH (feet)		21	21	21
b.	Total head -	High speed (feet)	3030	850	700
		Low speed (feet)	525	525	525
c.	Constant flow rate (gpm)		5600	5600	3750

d. Normal ambient operating temperature - 60°F to 100°F

e. Normal plus upset conditions which control the pump design include:

1.	Design pressure	1500 psig
2.	Design temperature	40°F - 140°F
3.	OBE(1)	½ of SSE

A summary of calculated stresses, allowable stresses, criteria and loading conditions for critical components is provided in Table 3.9-6(t).

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(1) Combine with hydrodynamic loads from Table 3.9-6.

(2) Reactor Conditions 1 and 2 refer to the range of reactor pressures within which the rated performance of the HPCI pump is guaranteed. This range is bounded by 1156 psia (saturation pressure, Condition 1) and 215 psia. Condition 3 refers to the 100 psig pump interlock point, and is the corresponding pump performance obtained from manufacturer's input.

(3) The HPCI design basis is that it must be capable of injecting design rated flow into the reactor vessel at a maximum reactor pressure equal to the lowest SRV nominal setpoint, plus the allowable setpoint tolerance. References 3.9-26 and 3.9-27 re-evaluated HPCI system operation at the maximum reactor pressure of 1205 psig (lowest SRV setpoint, 1170 psig, plus 3% setpoint tolerance). It was concluded that maintaining the currently rated turbine speed of 4190 rpm at 1205 psig would result in a maximum rated flow rate of 5400 gpm. Reference 3.9-27 performed a conservative analysis that demonstrated a reduced flow rate of 5000 gpm between reactor pressures of 1182 and 1205 psig is adequate for all design basis requirements of the HPCI system.

3.9.3.1.16 RWCU System

The requirements of ASME Section III, Class 3 components are used as guidelines in evaluating the RWCU system pump and heat exchangers. The loading combinations, stress criteria, calculated and allowable stresses are summarized in Tables 3.9-6(p) and 3.9-6(c), respectively.

3.9.3.1.17 Non-NSSS ASME Code Constructed Items

The design loading combinations, categorized by plant operating conditions, identified as normal, upset, emergency, or faulted for Non-NSSS ASME code constructed items, are presented in Table 3.9-11.

The design criteria and stress limits associated with each of the plant operating conditions for each type of ASME code constructed items are presented in Tables 3.9-12 through 3.9-18.

The component operating condition is the same as the plant operating condition, except that the emergency or faulted plant condition is considered normal for a pump or valve whose function must be ensured during an emergency or faulted plant condition.

3.9.3.2a NSSS Pump And Valve Operability Assurance

The NSSS active pumps and valves are listed in Table 3.9-19.

Active mechanical equipment classified as seismic Category I is designed to function during the life of the plant, under postulated plant conditions. Equipment with faulted condition functional requirements includes "active" pumps and valves in fluid systems such as the ECCS. ("active" equipment performs a mechanical motion to accomplish a safety function.)

Operability is ensured by satisfying the requirements of the following programs. Safety-related valves are qualified by prototype testing and/or analysis; and safety-related active pumps are qualified by analysis and/or testing with suitable stress limits and nozzle loads. The content of these programs is detailed below.

3.9.3.2a.1 ECCS Pumps

All active pumps are qualified for operability by first being subjected to rigid tests, before and after installation in the plant. The in-shop tests include hydrostatic tests of pressure-retaining parts at 125% of the design pressure; seal leakage tests; and performance tests, while the pump is operated with flow, to determine total developed head, minimum and maximum head, and NPSH requirements. Bearing temperatures (except water-cooled bearings) and vibration levels are also monitored during these operating tests. Both are below specified limits. After the pump is installed in the plant, it undergoes cold hydrotests, functional tests, and the required periodic inservice inspection and operation. These tests demonstrate reliability of the pump for the design life of the plant.

In addition to these tests, the safety-related active pumps are analyzed for operability during a faulted condition to ensure that the pump will not be damaged during the seismic and hydrodynamic event, and that the pump will continue operating despite the faulted loads.

3.9.3.2a.1.1 Analysis of Loading, Stress, and Acceleration Conditions

In order to avoid damage during the faulted plant condition, the stresses caused by the combination of normal operating loads, SSE, and dynamic system loads are limited to the material elastic limit, as indicated in Section 3.9.3.1 and Table 3.9-6. A three-dimensional finite-element model of the pump/motor and supports was developed using the response spectrum method of dynamic analysis. The average membrane stress (δ_m) for the faulted condition loads is maintained at 1.2 S_m, or approximately 0.75 δ_y (δ_y = yield stress); the maximum stress in local fibers (δ_m plus bending stress (δ_b)) is limited to 1.8 S_m, or approximately 1.1 δ_y.

The maximum dynamic nozzle loads were also considered in an analysis of the pump supports to ensure that a system misalignment will not occur.

A dynamic analysis was performed to determine the magnitude of the seismic loading from the applicable floor response spectra. An analysis was made to ensure that faulted condition nozzle loads and dynamic accelerations would not impair the operability of the pumps during or following the faulted conditions. Pump components having a natural frequency above 33 Hz are considered rigid. This frequency is considered sufficiently high to avoid problems with amplification between the component and structure for all seismic areas.

If the natural frequency is below 33 Hz, an analysis is performed to determine the amplified input accelerations necessary to perform the static analysis. The adjusted accelerations are determined using conservatisms contained in the horizontal and the vertical accelerations used for rigid structures. The static analysis is performed using the adjusted accelerations and must meet the same stress limit criterion stated in Table 3.9-6.

These analyses, with the conservative loads stated and with the restrictive stress limits of Table 3.9-6 as allowables, assure that critical parts of the pump are not damaged during the faulted condition, and that, therefore, the reliability of the pump for postfaulted condition operation will not be impaired by a hydrodynamic or seismic event.

3.9.3.2a.1.2 Pump Operation During and Following Faulted Condition Loading

Active pump/motor rotor combinations are designed to rotate at a constant speed under all conditions. Motors are designed to withstand short periods of severe overload. The high rotary inertia in the operating pump rotor and the nature of the random shot-duration loading characteristics of the seismic and hydrodynamic events prevents the rotor from becoming seized. The dynamic loadings cause a slight increase, if any, in the torque (i.e., motor current) necessary to drive the pump at constant design speed. Therefore the pump does not shut down during the faulted condition but operates at the design speed despite the faulted loads.

The functional ability of the active pumps after a faulted condition is assured, since only normal operating loads and steady-state nozzle loads exist at this time. For the active pumps, the faulted condition is greater than the normal condition due to seismic and hydrodynamic loads on the equipment and the increase in nozzle loads from the SSE on the connecting pipe. The SSE event is infrequent and of short duration compared to the design life of the equipment. Because it is demonstrated that the pumps would not be damaged during the faulted condition, the postfaulted condition operating loads are less than the normal plant operating limits. This is assured by requiring that the imposed nozzle loads (steady-state loads) for normal conditions and postfaulted conditions are limited by the normal condition nozzle loads. The postfaulted condition ability of the pumps to function under these applied loads is proven during the normal operating plant conditions.

3.9.3.2a.2 SLCS Pump and Motor Assemblies and RCIC Pump Assembly

These equipment assemblies are small, compact, rigid assemblies, with natural frequencies greater than 100 Hz. With this fact verified, each equipment assembly is dynamically qualified by static analysis only. This static qualification verifies operability under seismic and hydrodynamic conditions, and ensures that structural loading stresses are within code limitations.

3.9.3.2a.3 RCIC Turbine

Refer to Section 3.9.2.2a.2.9 and Table 3.9-6(q).

3.9.3.2a.4 ECCS Motors

Qualification of the Class 1E motors used for the ECCS motors is in compliance with IEEE 323 (1971). The qualification of all motor sizes is based on completion of a type test, followed with review and comparison of design and material details and seismic analysis of production units, ranging from 500 Bhp to 3500 Bhp, with the motor used in the type test. All manufacturing, inspection, and routine tests by motor manufacturer on production units are performed on the test motor.

The type test was performed on a 1250 hp vertical motor, in accordance with IEEE 323 (1971). First normal operation during the design life was simulated; then the motor was subjected to a number of seismic events; and then subjected to the abnormal environmental conditions possible during and after a LOCA. The type test plan was as follows:

a. Thermal aging of the motor electrical insulation system (which is a part of the stator only) was based on extrapolation, in accordance with the temperature life of the characteristic curve from IEEE 275 (1966) for the insulation type used on the ECCS motors. The amount of aging equals the total estimated operation days of maximum insulation surface temperature.

b. Radiation aging of the motor electrical insulation equals the maximum estimated integrated gamma dose during normal and abnormal conditions.

c. The normal induced current vibration effect on the insulation system was simulated by a 1.5 g horizontal vibration acceleration for one hour at current frequency.

d. Motor bearings were selected and their operating life established on the basis of bearing manufacturer's tests and operating data using the loads calculated to act on the bearings.

e. The dynamic load-deflection analysis on the rotor-shaft, performed to ensure adequate rotation clearance, is verified by static loading and deflection of the rotor for the type test motor.

f. Dynamic loading aging and testing were performed on a biaxial test table in accordance with IEEE 344 (1971). During this type test, the shake table was activated, simulating the maximum design limit of the SSE and hydrodynamic loads with motor starts and operation combination, as may possibly occur during the life of the plant. Refer to Section 3.10.

g. An environmental test simulating a LOCA condition was performed for 100 days with the test motor fully loaded, simulating pump operation. The test consists of startup and six hours of operation at 212°F ambient temperature, and a 100% steam environment. After 1 hour standstill in the same environment, another startup and operation of the test motor was followed by sufficient operation at high humidity and temperature. This was based on extrapolation in accordance with the temperature life characteristic curve from IEEE 275 (1966) for the insulation type used on the ECCS motors.

3.9.3.2a.5 HPCI Pump

Operability of the HPCI pump assembly is demonstrated by a combination of analytical stress calculations, pump manufacturer's operating experience, and testing. The stress definitions and the allowable stress criteria are based on the ASME Section III. The code is directly applicable to the stamped pressure boundary components of the pump.

The witnessed hydrostatic and performance tests, as performed at the pump manufacturer's plant, demonstrate that the pump as designed meets the ASME Code requirements and the parameters of the design specification.

A dynamic analysis was performed by the pump manufacturer. A static analysis was performed for dead weight and nozzle loads. Dynamic analysis was used for the SSE loading condition.

Rotating parts are verified by analysis to ensure no contact with the stationary parts, except at engineered wear points, therefore, continued operation during and after an SSE is assured because the calculated stresses and deformations are less than the prescribed limits.

3.9.3.2a.6 NSSS Valves

3.9.3.2a.6.1 Class 1 Active Valves

The Class 1 active valves are the MSIVs and the MSRVs and SLCS valves. Each of these valves is designed to perform its mechanical motion in conjunction with a design basis accident. Dynamic qualification for operability is unique for each valve type; therefore, each method of qualification is detailed individually below.

3.9.3.2a.6.1.1 Main Steam Isolation Valve

The MSIVs were evaluated for operability during a dynamic loading event by analysis and test as follows:

a. The valve body was designed in accordance with ASME Section III, Class 1, which limits deformations in the operating area of the valve body to those within the elastic limit of the material by limiting pressure and pipe reaction input loads (including seismic and hydrodynamic), thereby ensuring no interference with valve operability.

b. The complete valve topworks, including the bonnet and a simulated stem of a similar design MSIV, was dynamically tested for upset loads and faulted load. The test sample was subjected to 30 seconds of bi-directional random frequency input for each test event. There were a total of 10 upset test events and 2 faulted test events. Valve closure was simulated half way through the testing duration during each event. After the complete test program, there was no significant change to the valve closure rate.

To ensure that design limits were not exceeded for both piping input loads and actuator dynamic loads, the MSIV was mathematically modeled in the main steam line system analysis. The valve dynamic characteristics were modeled in the overall steam line analysis. Pipe anchors and restraints are applied as required to limit pipe system resonance frequencies and amplified accelerations to within acceptable limits for the MSIVs. Details concerning the analysis of these valves is given in Table 3.9-6(h).

The MSIV operability during LOCA conditions is demonstrated as defined in report APED-5750 (March 1969). The test specimen is a 20 inch valve representative in design to the MSIVs. Operability during seismic acceleration is addressed in Section 3.9.2.2a.

3.9.3.2a.6.1.2 Main Steam Relief Valves

The MSRVs were evaluated for operability during seismic and hydrodynamic events. Structural integrity of the configuration during a seismic event was demonstrated by both code analysis and dynamic testing.

a. Each valve was designed for maximum moments which may be imposed on it when installed in service. These moments result from the dead weight, hydrodynamic, and seismic loading of both the valve and the connecting pipe, thermal expansion of the connecting pipe, and reaction forces from valve discharge.

b. Dynamic tests were performed on the LGS MSRV configuration. The tests validated the design static analysis and determined that the equipment remains functional during application of the specified "g" loads.

A mathematical model of this valve was included in the overall main steam line system analysis, along with the MSIVs, to ensure that design limits were not exceeded.

The MSRV analytical qualification results are shown in Table 3.9-6(g).

3.9.3.2a.6.1.3 Explosive Valves

The SLCS explosive valves are qualified to IEEE 344 (1975). The generic qualification test demonstrated the absence of natural frequencies below 35 Hz and the ability to remain operable after the application of horizontal dynamic loading equivalent to 6.5 g and a vertical dynamic loading equivalent to 4.5 g at 33 Hz. In addition, analysis shows that there are no natural frequencies below 100 Hz.

3.9.3.2a.6.2 Class 2 and 3 Active Valves

3.9.3.2a.6.2.1 Gate/Globe Valves

Class 2 active gate/globe valves provided by GE include five RHR valves, one HPCI valve, one RCIC valve, and three core spray valves; all valves are motor-operated. There are no Class 3 active valves in the GE scope of supply. The gate/globe valves are generically qualified by testing valves that are typical of the valves supplied by GE. Operability is ensured by testing under the maximum capability static load which envelopes the static design basis load. These tests ensure operability during and after the design basis load. The actuators are qualified to IEEE 382 (1972), up to levels that exceed the design loadings.

3.9.3.2a.6.2.2 Check Valves

GE provides one swing-check valve and one stop-check valve which are Class 2 active in each of the HPCI and RCIC systems. In addition, GE provides six Class 2 check valves for the RHR system and two Class 2 check valves for the core spray system. Operability of check valves is assured by performing design calculations and by providing sufficient structural margins so that

movement of the disc/hinge pin is not impaired under any loading conditions. There are no Class 3 active valves in the GE scope of supply.

3.9.3.2b Non-NSSS Pump and Valve Operability Assurance

3.9.3.2b.1 Pumps

The following pumps are active pumps:

a. Diesel oil transfer pumps

b. RHRSW pumps

c. ESW pumps

d. Control room chilled water pumps

e. Safeguard piping fill pumps.

The safeguard piping fill pumps are Class 2. All the remaining pumps are Class 3.

Safety-related active pumps are subjected to stringent tests both prior to and after installation in the plant. The in-shop tests include: hydrostatic tests of pressure-retaining parts to 150% of the design pressure; seal leakage tests at the same pressure used in the hydrostatic tests; and performance tests which are conducted while the pump is operated with flow to determine total developed head, minimum and maximum head, NPSH requirements, and other pump/motor properties. Bearing temperatures and vibration levels are also monitored during these operating tests. Both are shown to be within the limits specified by the manufacturer. After the pump is installed at the plant, it undergoes startup tests and required inservice inspection and operation.

In addition to these tests, the active pumps are qualified for operation during and after a faulted condition. That is, safety-related active pumps are qualified for operability during an SSE condition by assuring that the pump will not be damaged during the seismic event, and that the pump will continue operating despite the SSE loads. (Refer to 3A.7.1.7 for pumps subjected to hydrodynamic loads.)

In order to meet the first criterion, that the pump will not be damaged during the seismic event, the pump manufacturer is required to determine by test or dynamic analysis whether the lowest natural frequency of the pump is greater than 33 Hz. The pump, when having a natural frequency above 33 Hz, is considered essentially rigid. This frequency is considered sufficiently high to avoid problems with amplification between the component and structure for all seismic areas. A static shaft deflection analysis of the rotor is performed with the conservative SSE accelerations of 1.5 times the applicable floor acceleration. The deflections determined from the static shaft analysis are compared to the allowable rotor clearances.

If the lowest natural frequency is found to be below 33 hertz, the equipment is considered flexible. If flexible, the equipment is analyzed using the response spectrum modal analysis technique. The frequencies and mode shapes are determined in the vertical and horizontal directions. The loads due to the excitation of each mode and the loads due to the accelerations in the three orthogonal

directions are added using the square root of the sum of the squares method. Coupling effects are included in the mathematical model.

In order to avoid damage to the pumps during the faulted plant condition, the stresses caused by the combination of normal operating loads, SSE, and dynamic system loads are limited. The maximum seismic nozzle loads are also considered in an analysis of the pump supports to assure that a system misalignment cannot occur. Performance of these analyses, based upon conservative loads and restrictive stress limits, assures that critical parts of the pump will not be damaged during the faulted condition and, therefore, that the reliability of the pump for postfaulted condition operation will not be impaired by the seismic events.

The second criterion necessary to assure operability is that the pump will function throughout the SSE. The pump/motor combination is designed to rotate at a constant speed under all conditions unless the rotor becomes completely seized, i.e., with no rotation. Typically, the rotor can be seized five full seconds before a circuit breaker, used to prevent damage to the motor, opens to stop the pump. However, the high rotary inertia in the operating pump rotor and the nature of the random, short duration loading characteristics of the seismic event prevent the rotor from becoming seized. Actually, the seismic loadings cause only a slight increase, if any, in the torque, i.e., motor current, necessary to drive the pump at the constant design speed. Therefore, the pump will not shut down during the SSE and will operate at the design speed despite the SSE loads.

To complete the seismic qualification procedures, the pump motor and all appurtenances vital to the operation of the pump are independently qualified for operation during the maximum seismic event as discussed in Section 3.10.

From this regimen, it is concluded that the safety-related pump/motor assemblies will not be damaged and will continue to operate under SSE loadings and, therefore, will perform their intended functions. These proposed requirements take into account the complex characteristics of the pump and are sufficient to demonstrate and assure the seismic operability of the active pumps.

The functional ability of active pumps after a faulted condition is assured since only operating loads and steady-state nozzle loads exist. Since it is demonstrated that the pumps would not be damaged during the faulted condition, the postfaulted operating loads will be limited to the normal plant operating loads. This is assured by requiring that the imposed nozzle loads (steady-state loads) for normal conditions and postfaulted conditions are limited by the magnitudes of the normal condition nozzle loads. The postfaulted ability of the pumps to function under these applied loads is proved during the normal operating plant conditions for active pumps.

3.9.3.2b.2 Valves

The active valves are tabulated in Reference 3.9-25. Those active valves which are supplied by the NSSS vendor are identified. See Section 3.9.3.2a for a discussion of operability assurance of these valves.

Safety-related active valves are subjected to a series of stringent tests prior to service, and during the plant life. Before installation, the following tests are performed: the shell hydrostatic test, in accordance with ASME Section III requirements; back-seat and main-seat leakage tests; the disc hydrostatic test; functional tests which verify that the valve opens and closes within the specified time limits; and the operability qualification of motor operators for the environmental conditions over the installed life (i.e., aging, radiation, accident environment simulation, etc.), in accordance with

IEEE 382 (1972). After installation, cold hydrostatic tests, functional tests (in accordance with the requirements of Chapter 14), and periodic inservice operation (in accordance with the requirements of Chapter 16) are performed to verify and ensure the functional ability of the valve.

The valves are designed using either stress analyses, or the pressure-containing minimum wall thickness requirements. For all active valves with extended topworks, an analysis is also performed for static-equivalent SSE loads applied at the extended structure's center of gravity. The maximum stress limits allowed in the analyses demonstrate structural integrity, and are equal to the limits recommended by the ASME for the particular ASME class of valve analyzed. Limits for each of the loading combinations are presented in Tables 3.9-13 and 3.9-18.

In addition to these tests and analyses, a representative valve of each design type is tested to verify operability during a simulated seismic event by demonstrating operational capabilities within the specified limits. The qualification testing procedures are described below.

The valve is mounted in a manner that conservatively represents typical valve installations. The valve unit includes the actuator and all appurtenances normally attached to the valve in service. The operability of the valve during an SSE is demonstrated by satisfying the following criteria. (Refer to Appendix 3A.7.1.7 for valves subjected to hydrodynamic loads.)

a. All the active valves with topworks are basically designed to have a first natural frequency greater than 33 Hz. This may be shown by suitable testing or analysis. Regardless of value, the first natural frequency of the topworks is modeled into the piping analysis for determination of maximum accelerations.

b. While in the shop and installed in a suitable test rig, the extended topworks of the valve are subjected to a statically applied equivalent seismic load. The load (the specified g-force times the weight of the topworks) is applied at the center of gravity of the topworks, in the direction of the weakest axis of the yoke. The design pressure of the valve is simultaneously applied to the valve during the static load tests.

c. The valve is then operated at the minimum specified actuation supply voltage or pressure, with the equivalent seismic static load applied. The valve must perform its safety-related function within the specified operating time limits.

d. Motor operators are qualified as operable during and after the SSE prior to their installation on the valve, as discussed in Section 3.10.2.2.

The equivalent seismic static load, which is used for the static valve qualification, is the maximum load which the valve is designed to withstand. The piping designer must maintain the motor operator accelerations to these levels.

The valve is leak tested following the test described above, to show that the valve has not been damaged. The leak rates must not exceed the original allowable leakage rate specified for the valve.

The above factory testing program applies only to valves with overhanging structures, e.g., the motor operator or air actuator assembly. The testing is conducted on a representative number of valves. According to the size and pressure rating, valves from each of the primary safety-related design types, e.g., motor- operated gate valves, are tested. Valves that cover the range of sizes in service are qualified by tests, and the results are used to qualify all valves within the intermediate

range of sizes, as shown in Table 3.9-20. Stress analyses are used to support the interpolation. Because of their simple characteristics, check and other compact valves are not adversely affected by seismic acceleration. Check valves have no extended structures to distort the valves and cause malfunctions. Check valve discs are designed to allow sufficient clearance around the disc to prevent binding or interference due to distortions from nozzle or other imposed loads. They are qualified by a combination of the following factory tests and analysis:

a. Stress analysis of critical areas and parts for SSE loads in accordance with the allowable specified in Tables 3.9-13 and 3.9-18

b. In-shop hydrostatic test

c. In-shop seat leakage test

d. Periodic valve exercise and inspection to ensure the functional ability of the valve in accordance with the requirements of Chapter 16

A study was also performed that considered a feedwater pipe rupture outside containment to assure that the feedwater isolation check valves can perform their function following a postulated pipe break of the feedwater line outside containment. Analysis of a full circumferential break showed that the check valve inside containment (one of 3 feedwater PCIV's that are check valves) would close rapidly because of flow reversal in the pipe between the reactor and break location just outside containment. This results in a pressure surge of 2780 psia between the valve and reactor. It was determined that the piping and valves could adequately sustain this pressure.

To determine the capability of the check valve seat to withstand the initial impact caused by rapid closure and to sustain the pressure surge that follows, an estimate of check valve seat energy absorption capability was made for a postulated feedwater pipe break accident occurring upstream of the containment isolation valves. The basis for the seat stress calculation was for a valve disk closing velocity of 100 rad/sec and a pressure break in the pipe of 2780 psia.

The valve seat was assumed to consist of an assembly of six discrete, bilinear, elastic-plastic elements. The analysis assumed that the disc kinetic energy at impact equals work done in terms of seat under load, or area under the seat load-displacement curve. Valve seat yield strength was based on its being stressed to 50% of yield at a design pressure of 2132 psi. The load-displacement curve was constructed using Roark's stiffness equations for an annular plate loaded at the inner radius and fixed at the outer radius. Failure was assumed to occur at a ductility ratio of 30.

The analysis indicated that all of the seat elements reach yield, but none reach ultimate strain or fail. Effects not included that are believed to make the analysis conservative are:

a. No credit was taken for disc deformation and energy absorption

b. No credit was taken for hinge deformation and energy absorption

c. No credit was taken for valve body deformation and energy absorption

d. Hinge friction was omitted

e. No strain hardening or rate of strain effects in the seat were included.

The water hammer effects on the closed seat were determined. It was shown that the natural frequency of the combined valve seat stiffness and disc mass was much larger than the frequency of the pressure pulse, so that the effective pressure that the seat must withstand is only the peak pressure in the water hammer surge. The seat is able to withstand this maximum pressure.

Results of this analysis show that, although the conditions of a hypothetical pipe rupture on the feedwater check valves are severe, the valves should remain together at impact and are capable of withstanding 2800 psi. The valve seat should yield at disc impact but not fail, and the water hammer pressure pulse following closure will not cause failure.

An additional confirmatory analysis was also conducted which used a simplified model of single-phase, liquid flow from the reactor vessel to the pipe break, with the check valve disk being closed by drag forces.

Results of this simplified analysis indicate that the check valve disk closes in approximately 70 msec, with a closing velocity at impact of approximately 65 rad/sec. The peak pressure at the closed disk is estimated to be 2157 psi for a finite valve closure time of 70 msec. The precise pressure at valve closure cannot be predicted rigorously by the simplified method used in this study.

The results of this study confirmed the validity of the original design analysis and are consistent with the results of the analysis done for SSES and in particular for the Atwood Morrill check valves.

Operability testing is also not performed for relief valves. Due to the particular, simple characteristics of these SRVs, they are qualified by a combination of the following tests and analyses:

a. Stress analysis, including seismic loads where applicable

b. In-shop hydrostatic test

c. In-shop seat leakage test

d. Performance tests

e. Periodic in situ valve inspection as applicable and periodic valve removal, refurbishment, performance testing and reinstallation

The above testing and analysis is sufficient to ensure the functional capability of the valve.

During a seismic event, it is anticipated that the seismic acceleration imposed upon the valve may cause it to open momentarily and discharge under system conditions that otherwise would not result in valve opening, but this is considered to be of no real safety or other consequence.

Using the methods described, all the safety-related active valves in the systems are qualified for operability during a seismic event. These methods conservatively simulate the seismic event and ensure that the active valves perform their safety-related functions when necessary.

3.9.3.3 Design and Installation of Pressure Relief Devices

3.9.3.3.1 Main Steam Relief Valves (NSSS)

Lifting of an MSRV results in a transient that produces momentary unbalanced forces acting on the discharge piping system from the time the MSRV opens, until a steady discharge flow from the RPV to the suppression pool is established. This period includes clearing the water slug from the end of the discharge piping submerged in the suppression pool. Pressure waves traveling through the discharge piping following the relatively rapid opening of the MSRV cause the MSRV discharge piping to vibrate. This in turn produces forces that act on the main steam piping.

The analysis of the relief valve discharge transient consists of a step-wise time history solution of the fluid flow equation, to generate a time history of the fluid properties at numerous locations along the pipe. The fluid transient properties are calculated based on the maximum set pressure specified in the steam system specification, and the value of ASME flow rating increased by a factor to account for the conservative method of establishing the rating. Simultaneous discharge of all valves is assumed in the analysis, because simultaneous discharge is considered to induce maximum stress in the piping. Reaction loads on the pipe are determined at each location corresponding to the position of an elbow. These loads are composed of pressure times area, momentum change, and fluid friction terms. Figure 3.9-3 shows a set of fluid property and pipe section load transients typical of those produced by relief valve discharge.

The method of analysis applied to determine piping system response to MSRV operation is time history integration. The forces are applied at locations on the piping system where the fluid flow changes direction, thus causing momentary reactions. The resulting loads on the MSRV, the main steam line, and the discharge piping are combined with loads due to other effects, as specified in Section 3.9.3.1. The code stress limits corresponding to load combination classifications of normal, upset, emergency, and faulted, are applied to the main steam lines and MSRV discharge piping.

In addition, a series of water discharge tests of SRVs used in BWRs was conducted to demonstrate the operational adequacy of the SRV and SRV discharge piping integrity for expected operating conditions for transients and accidents. The tests were performed to satisfy requirements of NUREG-0737, Item II.D.1.

The tests were run at the Wyle Laboratories test facility in Huntsville, Alabama. The facility included a steam and water supply system, the test SRV mounted on a representative steam line, and a representative SRV discharge line routed to a pool of water. Opening and closing of the SRVs were monitored. Fluid conditions and flows were measured, as were strains, accelerations, temperatures, and pressures in the SRV and associated piping.

The water discharge test conditions simulated the alternate shutdown cooling condition, which is an operating condition which is considered in the design evaluation of many BWR plants. The results show that all of the tested SRVs opened and closed on command for all water tests. The measured SRV discharge line loads for water discharge were significantly less than those for the high pressure steam discharge condition for which the piping is designed. LGS specific analyses have been performed (Reference 3.9-22) to establish RPV temperature and pressure conditions where initiation of alternate shutdown cooling will result in acceptable SRV discharge line loads. Alternate shutdown cooling is manually initiated only.

The tests and analyses as described in NEDE-24988-P (Reference 3.9-15) verify the adequacy of SRV operation and the integrity of the SRV discharge piping under expected liquid discharge conditions, and satisfy requirements of NUREG-0737, Item II.D.1.

A basis for concluding that the test results presented in NEDE-24988-P on SRV testing are applicable to LGS is described in the following paragraphs:

a. The SRV discharge piping configuration at LGS uses a T-quencher at the discharge pipe exit. The average length of the 14 SRV discharge line is 132 feet of 12 inch diameter pipe, and the submergence length in the suppression pool is approximately 18'-6". The SRV test program used a ramshead at the discharge pipe exit, a pipe length of 112 feet, a diameter of 10 inches, and a submergence length of approximately 13 feet. Loads on valve internals in the LGS configuration are within acceptable limits for the following reasons:

   1. No dynamic mechanical load originating at the T-quencher is transmitted to the valve in the LGS configuration because there is at least one anchor point between the valve and the T-quencher.

   2. The length of the first segment of piping downstream of the SRV in the test facility was selected to result in the test program having a bounding dynamic mechanical load on the valve. The LGS SRV discharge line piping configuration differs from the test facility in that the first line segment does not terminate in a 90° elbow, and the pipe size increases in the first segment. An assessment of the LGS configuration has confirmed that the mechanical loads imposed on the LGS valves by the low pressure water flow are enveloped by the high pressure steam loads.

   3. Dynamic hydraulic loads (back pressure) are experienced by the valve internals in the LGS configuration. The back pressure loads may be either transient back pressures occurring during valve actuation or steady-state back pressures occurring during steady-state flow following valve actuation.

      The key parameters affecting the transient back pressures are the fluid pressure upstream of the valve, the valve opening time, the fluid inertia in the submerged SRV discharge line 0, and the SRV discharge line air volume. Transient back pressures increase with higher upstream pressure, shorter valve opening times, greater line submergence, and smaller SRV discharge line air volume. An evaluation of these differences has confirmed that the test facility and the LGS configuration have comparable back pressures. The maximum transient back pressure occurs with high pressure steam flow conditions. The transient back pressure for the alternate shutdown cooling mode of operation is always much less than the design for steam flow conditions because of the lower upstream pressure and the longer valve opening time.

      The steady-state back pressure in the test program was maximized by using an orifice plate in the SRV discharge line above the water level and before the ramshead. The orifice was sized to produce a back pressure greater than that calculated for any of the LGS SRV discharge lines.

An additional consideration in the selection of the ramshead for the test facility was to allow more direct measurement of the thrust load in the final pipe segment. The use of a T-quencher in the test program would have required quencher supports that would unnecessarily obscure accurate measurement of the pipe thrust loads.

The differences in the line configuration between the LGS plant and the test program as discussed above result in loads on the LGS valve internals that are within acceptable limits.

b. The LGS SRV discharge lines are supported by a combination of snubbers, rigid supports, and spring hangers. These supports were designed to accommodate combinations of loads resulting from piping, dead weight, thermal conditions, seismic and suppression pool hydrodynamic events, and a high pressure steam discharge transient. Each SRV discharge line at LGS has 2 to 5 spring hangers, all of which are located in the drywell. The test facility configuration utilized no spring hangers.

   The dynamic load effects on the piping and supports of the test facility due to the water discharge events (the alternate shutdown cooling mode) were found to be significantly lower than corresponding loads resulting from the high pressure steam discharge event. As stated in Reference 3.9-15, this finding is considered generic to all BWRs because the test facility was designed to be prototypical of the features pertinent to this issue. Furthermore, assessment of a typical LGS SRV discharge line configuration has confirmed the applicability of the generic statement to LGS. LGS specific analysis for acceptable alternate shutdown cooling initiating conditions has been performed (Reference 3.9-22).

   During the water discharge transient, there will be significantly lower dynamic loads acting on the snubbers and rigid supports than during the steam discharge transient. This will more than offset the small increase in the dead load on these supports due to the weight of the water during the alternate shutdown cooling mode of operation. Therefore, design adequacy of the snubbers and rigid supports is assured because they are designed for the larger steam discharge transient loads.

   The design adequacy of the spring hangers with respect to the increased dead load due to the weight of the water during the liquid discharge transient has been addressed. As was discussed with respect to snubbers and rigid supports, the dynamic loads resulting from liquid discharge during the alternate shutdown cooling mode of operation are significantly lower than those from the high pressure steam discharge. The spring hangers have been reviewed for the deflections resulting from the steam discharge dynamic event and were found to be acceptable. In addition, the spring hangers have been evaluated for the increased dead load due to a water-filled condition. Both the spring hangers and piping stresses were acceptable. Furthermore, the effects of the water dead weight load does not affect the ability of SRVs to open to establish the alternate shutdown cooling path because the loads occur in the SRV discharge line only after valve opening.

c. The purpose of the SRV test program was to demonstrate that the SRV will open and reclose under all expected flow conditions. The expected valve operating conditions were determined through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70 (Rev 2). Single failures were applied

to these analyses so that the dynamic forces on the SRVs would be maximized. Test pressures were the highest predicted by conventional safety analysis procedures. The BWROG, in their enclosure to the September 17, 1980 letter from D.B. Waters (BWROG) to R.H. Vollmer (NRC), identified 13 events that may result in liquid or two-phase SRV inlet flow that would maximize the dynamic forces on the SRV. These events were identified by evaluating the initial events described in Regulatory Guide 1.70 (Rev 2), with and without the additional conservatism of a single active component failure or operator error postulated in the event sequence. It was concluded from this evaluation that the alternate shutdown cooling mode is the only expected event that will result in liquid at the valve inlet. Consequently, this was the event simulated in the SRV test program. This conclusion and the test results applicable to LGS are discussed below.

The 13 events and the plant specific features that mitigate these events are summarized in Table 3.9-32. Of these 13 events, only nine are applicable to LGS because of its design and specific plant configuration. Four events (5, 6, 10 and 13) are not applicable to LGS for the reasons listed below:

1. Events 5 and 10 are not applicable because LGS does not have a high pressure core spray system.

2. Event 6 is not applicable because LGS does not have RCIC head sprays.

3. Event 13 is not applicable because large breaks will not be isolated at LGS.

For the nine remaining events, the LGS specific features, such as trip logic, power supplies, instrument line configuration, alarms and operator actions, have been compared to the base case analysis presented in the BWROG submittal of September 17, 1980. The comparison has demonstrated that, in each case, the base case analysis is applicable to LGS because the base case analysis does not include any plant features that are not already present in the LGS design. For these events, Table 3.9-32 demonstrates that the LGS specific features are included in the base case analysis presented in the BWROG submittal of September 17, 1980. It is seen from Table 3.9-32 that all plant features assumed in the event evaluation are also existing features in the LGS plant. All features included in this base case analysis are similar to plant features in the LGS design. Furthermore, the time available for operator action is expected to be longer in the LGS plant than in the base case analysis for each case where operator action is required due to the conservative nature of the base case analysis.

Event 7, the alternate shutdown cooling mode of operation, is the only expected event that will result in liquid or two-phase fluid at the SRV inlet. Consequently, this event was simulated in the BWR SRV test program. In LGS, the event involves flow of subcooled water (approximately 31°F subcooled) at a pressure of approximately 156 psig. The SRV inlet fluid conditions tested in the BWROG SRV test program, as documented in Reference 3.9-15, are 15°F to 50°F subcooled liquid at 20 psig to 250 psig. These fluid conditions envelope the conditions expected to occur at LGS in the alternate shutdown cooling mode of operation.

As discussed above, the BWROG evaluated transients including single active failures that would maximize the dynamic forces on the SRVs. As a result of this evaluation, the

alternate shutdown cooling mode is the only expected event involving liquid or two-phase flow. Consequently, this event was tested in the BWR SRV test program. The fluid conditions and flow conditions tested in the BWROG test program conservatively envelope the LGS plant specific fluid conditions expected for the alternate shutdown cooling mode of operation (Reference 3.9-22).

d. The flow coefficient, C_v, for the Target Rock SRV used in LGS was determined in the generic SRV test program (Reference 3.9-15). The average flow coefficient calculated from the test results for the Target Rock valve is reported in table 5.2-1 of Reference 3.9-15. This test value has been used by the licensee to confirm that the liquid discharge flow capacity of the LGS SRVs will be sufficient to remove core decay heat when injected into the RPV in the alternate shutdown cooling mode. The C_v of the valve determined in the SRV test demonstrates that the LGS SRVs are capable of returning sufficient flow to the suppression pool to accommodate injection by the RHR or core spray pump.

   If it were necessary to place the LGS plant in the alternate shutdown cooling mode, the operator would ensure that adequate core cooling was being provided by monitoring the following parameters: RHR or core spray flow rate, reactor vessel pressure, and reactor vessel temperature.

   The flow coefficient for the Target Rock valve reported in Reference 3.9-15 was determined from the SRV flow rate when the valve inlet was pressurized to approximately 250 psig. The valve flow rate was measured with the supply line flow venturi upstream of the steam chest. The C_v for the valve was calculated using the nominal measured pressure differential between the valve inlet (steam chest) and 3 feet downstream of the valve and the corresponding measured flow rate. Furthermore, the test conditions and test configuration were representative of LGS plant conditions for the alternate shutdown cooling mode, e.g., pressure upstream of the valve, fluid temperature, friction losses, and liquid flow rate. Therefore, the reported C_v values are appropriate for application to the LGS plant.

3.9.3.3.2 Design and Installation Details for Mounting of Pressure Relief Devices in ASME Class 1, 2, and 3 Systems (Non-NSSS)

The design of the pressure-relieving devices can be grouped into two categories: open discharge and closed discharge.

a. Open Discharge

   There are no open discharge pressure-relieving devices with limited runs of discharge piping mounted on ASME Code Class 1, 2, and 3 systems.

b. Closed Discharge

   A closed discharge system is characterized by piping between the valve and a tank, or some other terminal end. Under steady-state conditions, there are no net unbalanced forces. The initial transient response and resulting stresses are determined by using either a time history computer solution, or a conservative equivalent static solution. In

calculating initial transient forces, pressure and momentum terms are included. Water slug effects are also considered.

Time history dynamic analysis is performed for the discharge piping and its supports. The effect of the loading on the header is also considered. The design load combinations for a given transient are shown in Table 3.9-11, and the design criteria and stress limits are shown in Tables 3.9-12 and 3.9-16.

3.9.3.4 Component Supports Furnished with the NSSS

3.9.3.4.1 Piping

Hangers are designed in accordance with ANSI B31.7. In general, the load combinations for the various operating conditions correspond to those used to design the supported pipe. Design transient cyclic data are not applicable to hangers because no fatigue evaluation is necessary to meet the code requirements. All hangers are designed, fabricated, and assembled so that they cannot become disengaged by the movement of the supported pipe or equipment after they are installed. The design load on hangers is the load caused by dead weight. The hangers are calibrated to ensure that they support the design load at both their hot and cold load settings. Hangers provide a specified down travel and up travel in excess of the specified thermal movement. Visual inspection and acceptance of pipe supports are performed in accordance with NCIG-01 requirements (Reference 3.9-10).

For pipe supports, reactions produced by primary and secondary pipe loads are categorized as primary. The primary and secondary loads are summed and compared to the load rating to ensure that the rating is not exceeded. Because no distinction is made between primary and secondary loads, and load rated components are designed to primary limits or qualified by testing, the supports meet primary stress criteria for primary and secondary loads combined.

Required load capacity and snubber location for NSSS piping systems are determined by GE as a part of the NSSS piping system design and analysis scope. However, design, installation and inspection of snubbers are included in the non-NSSS scope (Section 3.9.3.5).

The entire piping system, including valves and the suspension system between anchor points, is mathematically modeled for complete structural analysis. In the mathematical model, the snubbers are modeled as springs with a given stiffness depending on the snubber size. The analysis determines the forces and moments acting on each component and the forces acting on the snubbers due to all dynamic loading conditions defined in the piping design specification. The design load on snubbers includes those loads caused by seismic forces (OBE and SSE), system anchor movements, and reaction forces caused by relief valve discharge, turbine stop valve closure, and other hydrodynamic forces (SRV, LOCA, annulus pressurization).

The assessment of all affected piping including their supports and structural modifications necessitated by reconciliation of the suppression pool hydrodynamic loads have been completed.

The snubber location and loading direction are decided by estimation so that the stresses in the piping system have acceptable values. The snubber locations and direction are refined by performing the computer analysis on the piping system as described above.

The spring constant required by the suspension design specification for a given load capacity snubber is compared against the spring constant used in the piping system model. If the spring

constants are not in agreement, they are brought into agreement, and the system analysis is redone to confirm the snubber loads.

If the stiffness of the backup structure for the snubber is not large compared to that of the snubbers, the reduced effective snubber stiffness (spring constant) is used in the analysis to account for backup structure flexibility.

Snubber design is discussed in Section 3.9.3.5.2.

3.9.3.4.2 NSSS Floor-Mounted Equipment (Pumps, Heat Exchangers, and RCIC and HPCI Turbines)

The ECCS pumps, RCIC and SLCS pumps, RHR heat exchanger, and RCIC and HPCI turbines are analyzed to verify the adequacy of their support structure under various plant operating conditions. In all cases, the stress loads in the critical support areas are within ASME Code allowables. The assessment of all affected equipment including their supports and structural modifications necessitated by reconciliation of the suppression pool hydrodynamic loads have been completed. The loading conditions, stress criteria, and allowable and calculated stresses in the critical support areas are summarized in Tables 3.9-6(k), 3.9-6(l), 3.9-6(m), 3.9-6(n), 3.9-6(o), 3.9-6(q), 3.9-6(r), and 3.9-6(t).

3.9.3.4.3 Supports for ASME Code Class 1, 2, and 3 Active Components

ASME Code Class 1, 2, and 3 active components are either pumps or valves. Because valves are supported by piping and are not tied to building structures, pipe design criteria govern.

Seismic Category I active pump supports are qualified for seismic and hydrodynamic loads by testing when the pump supports along with the pumps are fulfilling the following conditions:

a. Simulate actual mounting conditions

b. Simulate all static and dynamic loadings on the pump

c. Monitor pump operability during testing

d. Normal operation of the pump during and after the test indicates that the supports are adequate; any deflection or deformation of the pump supports that precludes the operability of the pump is not accepted.

e. Supports are inspected for structural integrity after the test; any cracking or permanent deformation is not accepted.

Seismic and hydrodynamic qualification of component supports by analysis is generally accomplished as follows:

a. Stresses at all support elements and parts such as pump holddown, baseplate holddown bolts, pump support pads, pump pedestal, and foundation are checked to be within the allowable limits as specified in ASME Subsection NF.

b. For normal and upset plant conditions, the deflections and deformations of the supports are assured to be within the elastic limits and not exceed the values permitted by the designer based on design verification tests to ensure the operability of the pumps.

c. For emergency and faulted plant conditions, the deformations must not exceed the values permitted by the designer to ensure operability of the pumps.

3.9.3.4.4 RPV Support Skirt

The permissible compressive load on the reactor vessel support skirt cylinder (modeled as plate and shell type component support) is limited by the design specification to 90% of the load which produces yield stress, divided by the safety factor for the condition being evaluated. The effects of fabrication and operational eccentricity are included. The safety factor for faulted conditions is 1.125.

An analysis of RPV support skirt buckling for faulted conditions shows that the support skirt has the capability to meet ASME Section III, paragraph F-1370(c), faulted condition limits of 0.67 times the critical buckling strength of the support at temperature. The faulted condition analyzed included the compressive loads due to the design basis maximum earthquake, the overturning moments and shears due to the jet reaction load resulting from a severed pipe, and the compressive effects on the support skirt due to the thermal and pressure expansion of the reactor vessel.

Subsequently, based on currently defined faulted condition loads, the maximum compressive stress in the support skirt including axial and bending loads in less than the faulted condition allowable of appendix F (paragraph F-1325) determined by the methods of ASME Section III, NB 3133.6. (Axial loads include weight, fuel interaction, seismic SSE, and the maximum of condensation oscillation, chugging and vent clearing due to a LOCA. Bending loads include seismic SSE and jet reaction, jet impingement, and annulus pressurization due to a LOCA.) The loading criteria, stress criteria, calculated and allowable stresses are summarized in Table 3.9-6(f).

3.9.3.4.5 Bolting Stress Limits (NSSS)

3.9.3.4.5.1 Component Support Bolting

The support bolting of the RWCU pump that is not essential to safety is designed for the effects of pipe load and SSE load to the requirements of ASME Section III, Appendix XVII. The stress limits of 0.41 S_y for tension and 0.15 S_y for shear are used.

For RCIC/SLCS pumps and RCIC turbine, the equipment-to-base plate bolting satisfies the following design criteria: For normal and upset conditions, 1.0S is used for primary membrane and 1.5S for primary membrane plus bending, where (S) is the allowable stress limit from ASME Section III, Appendix I, table I-7.3. For emergency and faulted conditions, stresses shall be less than 1.2 times the allowable limits for "normal and upset" given above.

There are no flange-type connections in pipe mounted component supports.

3.9.3.4.5.2 Piping Supports and Pipe-Mounted Equipment (Valves and Pump) Supports

The hanger type supports (including clamps) and their bolting are designed in accordance with the requirements of ANSI B31.7. The allowable stress limit for the bolting is equal to or less than the yield strength of the bolt material at temperature.

3.9.3.5 Component Supports Not Furnished with the NSSS

3.9.3.5.1 Design Basis

ASME Section III, Subsection NF, is used for the design and installation of the CRD piping supports and TIP piping supports. For the remainder of the non-NSSS portion of the LGS design and installation, Subsection NF is not used. The codes used instead are ANSI B31.7 for nuclear class piping and ANSI B31.1 for non-nuclear class piping. Visual inspection and acceptance of non-Subsection NF pipe supports are performed in accordance with NCIG-01 requirements (Reference 3.9-10). For a graphical definition of jurisdictional boundaries between pipe supports and supporting structures, refer to Figures 3.9-9 and 3.9-10.

The design loading combinations for supports for ASME Class 1, 2 and 3 components, categorized with respect to plant operating conditions identified as normal, upset, emergency, and faulted are given in Table 3.9-21. This table also provides the stress limits for each plant operating condition. The loads imposed on the ASME Class 1, 2 and 3 active valves and pumps are limited to values below the code allowable loads to ensure operability of the active components by the design of the supports. The supports are designed to remain elastic under the maximum loads. The minor local deformations associated with the elastic deformation of the support will not impair operability of the active components.

3.9.3.5.2 Snubbers

Snubbers are used in seismic Category I systems. The load ratings of the snubbers are appropriate for the design conditions and load combinations.

3.9.3.5.2.1 Analytical Methods

The methodology used for the stress analysis of seismic Category I, 2½ inches and larger piping systems is as follows:

a. For systems designed to seismic and hydrodynamic loads, the flexibility of the pipe supports are considered in the piping stress analysis. A stiffness tolerance criteria is used to facilitate support design and installation.

b. For systems designed to seismic loads, only the supports are considered as rigid members in the piping stress analysis model and are designed such that their fundamental frequencies in the direction of the applied load is within the rigid range of the seismic response spectra.

3.9.3.5.2.2 Snubber Design Specification

Snubbers for LGS are used to arrest shock due to seismic and other dynamic transient events. Under such applications, the snubbers will be subjected to a limited number of load cycles. Snubbers are not designed for vibration control. Therefore, no fatigue evaluation has been performed.

The purchase specification of new shock suppressors (snubbers) covers the following criteria for supplier's performance qualification tests and load tests. End clearance and lost motion are not considered in the piping stress analysis. Instead, linear average snubber stiffness is used in combination with that of the snubber support structure.

Mechanical Snubbers

a. The friction resistance of the suppressor to normal pipe movement shall be a maximum of 1% of the service level A rated load of the unit or 5 lb, whichever is greater.

b. The suppressor shall limit the acceleration of the pipe to a maximum of 0.02 g when subjected to any load up to the normal rated load.

   Based on experience from other plants, the activation threshold has been shown to be above the thermal growth rate of the piping systems.

c. The total lost movement at the suppressor shall not exceed ±0.040 inches due to any applied dynamic cycle load from 3-33 cps up to the rated load at the unit.

d. The suppressor shall be designed for an exposure to a temperature of room temperature (65° to 70°F) prior to initial startup and 200°F during continuous operations and to a radiation dose of $6.4x10^7$ rads during the life of the plant. Functioning of the shock suppressor under 340°F temperature for a short duration under rated load shall be demonstrated.

Hydraulic Snubbers

a. The friction resistance of the snubbers rated at 20 kips or greater shall have a friction resistance to normal movement of less than or equal to one percent of the service level A rated load. Snubbers rated at less than 20 kips shall have a friction resistance to normal movement of less than or equal to two percent of the rated load.

b. Activation of the snubber shall be defined as the velocity at which the snubber begins to support load, and restricts movement to the maximum bleed rate of the snubber. The activation velocity may be referred to as the lock-up velocity or activation velocity interchangeably. These requirements shall be satisfied under both tension and compression. The activation velocity of new snubbers at room temperature (65 to 75°F) shall be greater than or equal to 4.72 IPM and less than or equal to 14.17 IPM for all sizes.

c. The bleed rate shall be defined as that velocity at which the snubber will move under constant rated loads after the activation velocity has been reached and the control valves have closed. These requirements shall be satisfied under both tension and compression. The bleed velocity for the new snubbers at room temperature (65 to 75°F) shall be greater than or equal to 0.47 IPM and less than or equal to 4.72 IPM for all sizes.

d. The snubber shall be designed to withstand the normal environmental conditions inside the drywell of -0.5 to 2.0 psig, 160°F (based on Drywell Air Cooling System Design Bases described in Section 9.4.5.2), 40 to 90% relative humidity, and a radiation dose of 6.4×10^7 rads during the life of the plant. This bounding radiaton dose may be reduced by component or model specific evaluations of normal and design basis accident radiation environments.

3.9.3.5.2.3 Snubber Performance Test

A production test is required to be performed on each unit.

a. Check unit to confirm that it operates freely over the total stroke.

b. Measure and record the force required to initiate motion over the stroke in tension and compression.

c. On units which allow movement after the initial suppression of load, determine that the maximum allowable acceleration (mechanical snubbers) or velocity (hydraulic snubbers) is not exceeded. This requirement must be met in both tension and compression at room temperature.

d. Measure and record lost motion of the snubber mechanism (mechanical snubbers only).

Qualification tests are to be performed on randomly selected production models. These tests are used to demonstrate the required load performance (load rating) and specified displacement when subjected to dynamic load cycling. Also included in these tests are low temperature, high temperature, humidity, radiation and faulted load conditions.

Preinstallation, installation and postinstallation inspections of snubbers are performed before a preoperational test. Additional inspections are required if more than 6 months have elapsed between the last inspection and initial system power operation (Section 3.9.3.5.2.4).

Steady state vibration conditions will be identified during the preoperational test program. Snubbers have not been used to control steady state vibration. If the snubbers are used to correct such conditions, they will be evaluated for acceptability under those conditions.

In addition, the snubber inservice inspection program ensures that any potential malfunction due to fatigue-type failure will be detected.

3.9.3.5.2.4 Snubber Preservice Examination

Preservice examination of snubbers should be performed after installation, but not more than six months prior to initial system preoperational testing.

The mechanical snubber examination is described as follows. The objective is to verify adequate preservice examination to mechanical snubbers on all safety-related systems. The prerequisites of all preinstallation, installation, and postinstallation inspections have been performed on mechanical snubbers by designated inspection organizations. Verify through document review that all inspection activities have been completed, verified, and signed. Reviews will be made by systems and additional visual inspections will be made if original inspections are performed more than 6 months prior to initial power operation of the system.

The preservice examination should as a minimum verify the following:

a. There are no visible signs of damage or impaired operability as a result of storage, handling or installation.

b. The snubber location, orientation, position setting, and configuration (attachments, extensions, etc.) are according to design drawings and specifications.

c. Snubbers are not seized, frozen, or jammed.

d. Adequate swing clearance is provided to allow snubber movement.

e. Structural connections such as pins, fasteners, and other connecting hardware such as lock nuts, tabs, wire, and cotter pins are installed correctly.

If the period between the initial preservice examination and initial power operation exceeds 6 months, re-examination of items a. and d. shall be performed. Snubbers which are installed incorrectly or otherwise fail to meet the above requirements must be repaired or replaced and re-examined in accordance with the above criteria.

3.9.3.5.3 Struts

The design load on struts includes those loads caused by dead weight, thermal expansion, primary dynamic forces, (i.e., OBE and SSE), system anchor displacements, and reaction forces caused by relief valve discharge, turbine stop valve closure, etc.

For pipe supports, reactions produced by primary and secondary pipe loads are categorized as primary. The primary and secondary loads are summed and compared to the load rating to ensure that the rating is not exceeded. Because no distinction is made between primary and secondary loads, and load rated components are designed to primary limits or qualified by testing, the supports meet primary stress criteria for primary and secondary loads combined.

3.9.3.5.4 Bolting Stress Limits (Non-NSSS)

The bolting used in pipe support components is designed to an allowable stress equal to or less than the yield strength of the bolt material at temperature.

For flanged connections, the bolt allowables used in the piping are ASME Section III, 1979 Summer Addenda, Sections NB, NC and ND for Class 1, 2, and 3, respectively.

3.9.4 CONTROL ROD DRIVE SYSTEM

The discussion in this Section includes the CRDM, the HCU, the condensate supply system, and the scram discharge volume, and extends to the coupling interface with the control rods.

3.9.4.1 Descriptive Information on CRD System

Descriptive information on the CRD system is contained in Section 4.6.

3.9.4.2 Applicable CRD System Design Specifications

The CRD system is designed to meet the functional design criteria as outlined in Section 4.6, and consists of the following:

a. Locking piston CRD

b. HCU

c. Hydraulic power supply (pumps)

d. Interconnecting piping

e. Flow and pressure and isolation valves

f. Instrumentation and electrical controls

Those components of the CRD forming part of the primary pressure boundary are designed according to ASME Section III.

The quality group classification of the CRD hydraulic system is outlined in Table 3.2-1; and the components are designed according to the codes and standards governing the individual quality groups.

Pertinent aspects of the design and qualification of the CRD components are discussed in the following locations: transients in Section 3.9.1.1, faulted conditions in Section 3.9.1.4, and dynamic testing in Section 3.9.2.2a.

3.9.4.3 Design Loads, Stress Limits, and Allowable Deformation

The ASME Code components of the CRD system are evaluated analytically, and the design loading conditions, stress criteria, calculated stresses, and allowable stresses are summarized in Tables 3.9-6(u) and 3.9-6(v). For the noncode components, experimental testing is used to determine the CRD performance under all possible conditions, as described in Section 3.9.4.4.

Deformation is not a limiting factor in the analysis of the CRD components based on the results of the numerous tests performed on the drive.

3.9.4.3.1 CRD Housing Supports

The CRD housing support system functions are described in Section 4.6.1.3.

The AISC Manual of Steel Construction, "Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings," was used in designing the CRD housing support system. However, to provide a structure that absorbs as much energy as practical without yielding, the allowable tension and bending stresses used were 90% of yield and the shear stress used was 60% of yield. The design stresses are 1.5 times the AISC allowable stresses (60% and 40% of yield, respectively).

The CRD housing supports are designed as seismic Category I equipment. Loading conditions and examples of stress analysis results and limits are given in Table 3.9-6(z).

3.9.4.4 CRD Performance Assurance Program

The CRD test program consists of the following tests:

a. Development tests

b. Factory quality control tests

c. 5 year maintenance life tests

d. 1.5x design life tests

e. Operational tests

f. Acceptance tests

g. Surveillance tests

All of the above tests except c. and d. are discussed in Section 4.6.3. Tests c. and d. are discussed below:

Test c. - 5 Year Maintenance Life Tests

Four CRDs are normally picked at random from the production stock each year, and subjected to various tests under simulated reactor conditions and 1/6 of the cycles specified in Section 3.9.1.1.

Upon completion of the test program, CRDs must meet, or surpass, the minimum specified requirements.

Test d. - 1.5x Design Life Tests

When a significant design change is made to the components of the drive, the drive is subjected to a series of tests equivalent to 1.5 times the life test cycles specified in Section 3.9.1.1.

Two CRDs underwent such testing in 1976. Upon completion of the test program, these CRDs met or surpassed the minimum specified requirements.

3.9.5 REACTOR PRESSURE VESSEL INTERNALS

This section identifies and discusses the structural and functional integrity of the major RPV internals.

3.9.5.1 Design Arrangements

The core support structures and RPV internals (exclusive of fuel, control rods, CRDs, and incore nuclear instrumentation) are identified below:

Core Support Structures

Shroud

Shroud support

Core support plate and holddown bolts

Top guide (including bolts and keepers)

CRD housing

Fuel supports

Control rod guide tubes

Reactor Internals

*Jet pump assemblies and instrumentation

*Feedwater spargers

Vessel head spray nozzle (Removed-Unit 1. Never installed-Unit 2)

Differential pressure and liquid control lines

Incore flux monitor guide tubes

*Initial startup neutron sources

*Surveillance sample holders

Core spray lines and spargers

*Incore instrument housings

LPCI coupling

*Steam dryer

*Shroud head and steam separator assembly

*Guide rods

CRD thermal sleeves

* = Nonsafety class component

A general assembly drawing of the important reactor components is shown in Figure 3.9-4.

The floodable inner volume of the RPV can be seen in Figure 3.9-5. This is the volume inside the core shroud up to the level of the jet pump suction inlet.

The design arrangement of the reactor internals, such as the jet pumps, steam separators and guide tubes, is such that one end is unrestricted, and thus free to expand.

The LPCI couplings incorporate sleeves to allow free thermal expansion.

3.9.5.1.1 Core Support Structures

The core support structures consist of those items listed in Section 3.9.5.1. These structures form partitions within the reactor vessel, to sustain pressure differentials across the partitions, to direct the flow of the coolant water, and to laterally locate and support the fuel assemblies. Figure 3.9-5 shows the reactor vessel internal flow paths.

3.9.5.1.1.1 Shroud

The shroud support and shroud make up a stainless steel cylindrical assembly that provides a partition to separate the upward flow of coolant through the core, from the downward recirculation flow. This partition separates the core region from the downcomer annulus, thus providing a floodable region following a recirculation line break. The volume enclosed by this assembly is characterized by three regions. The upper portion surrounds the core discharge plenum, which is bounded by the shroud head on top and the top guide's grid plate below. The central portion of the shroud surrounds the active fuel, and forms the longest section of the assembly. This section is bounded at the top by the grid plate and at the bottom by the core plate. The lower portion, surrounding part of the lower plenum, is welded to the RPV shroud support.

3.9.5.1.1.2 Shroud Support

The shroud support is designed to support the shroud, and to support and locate the jet pumps. The shroud support provides an annular baffle between the RPV and the shroud. The jet pump discharge diffusers penetrate the shroud support to introduce the coolant to the inlet plenum below the core.

3.9.5.1.1.3 Shroud Head and Steam Separator Assembly

This component is not a core support structure. It is discussed here to describe coolant flow paths in the RPV. The shroud head and steam separator assembly is bolted to the top of the shroud, forming the top of the core discharge plenum. This plenum provides a mixing chamber for the steam-water mixture before it enters the steam separators. Individual stainless steel axial flow steam separators are attached to the top of standpipes that are welded into the shroud head. The steam separators have no moving parts. In each separator, the steam-water mixture rising through the standpipe passes vanes that impart a spin that establishes a vortex, separating the water from the steam. The separated water flows from the lower portion of the steam separator into the downcomer annulus.

3.9.5.1.1.4 Core Support Plate

The core support plate is a circular stainless steel plate with bored holes, which is stiffened with a rim and beam structure. The plate provides lateral support and guidance for the control rod guide tubes, incore flux monitor guide tubes, peripheral fuel supports, and startup neutron sources. The last two items are supported vertically by the core support plate.

The entire assembly is bolted to a support ledge on the lower portions of the shroud.

3.9.5.1.1.5 Top Guide

The top guide is formed by a series of stainless steel beams joined at right angles to form square openings, and fastened to a peripheral rim. Each opening provides lateral support and guidance

for 4 fuel assemblies, or in the case of peripheral fuel, for less than 4 fuel assemblies. Sockets are provided in the bottom of the beam intersections to anchor the incore flux monitors and startup neutron sources. The rim of the top guide rests on a ledge between the upper and central portions of the shroud. The top guide has alignment pins that engage and bear against slots in the shroud which are used to correctly position the assembly before it is secured. Lateral restraint is provided by wedge blocks between the top guide and the shroud wall.

3.9.5.1.1.6 Fuel Supports

The fuel supports, shown in Figure 3.9-6 are of two basic types; peripheral supports, and four-lobed orificed fuel supports. The peripheral fuel support is located at the outer edge of the active core, and is not adjacent to control rods. Each peripheral fuel support holds one fuel assembly, and contains a single orifice assembly designed to ensure proper coolant flow to the peripheral fuel assembly. Each four-lobed orificed fuel support holds four fuel assemblies, and is provided with four orifice plates to ensure proper coolant flow distribution to each rod-controlled fuel assembly. The four-lobed orificed fuel supports rest in the top of the control rod guide tubes, which are supported laterally by the core plate. The control rods pass through slots in the center of the four-lobed orificed fuel support. A control rod and the four adjacent fuel assemblies represent a core cell (Section 4.1.2).

3.9.5.1.1.7 Control Rod Guide Tubes

The control rod guide tubes, located inside the vessel, extend from the top of the CRD housings, and up through holes in the core plate. Each tube is designed as the guide for a control rod, and as the vertical support for a four-lobed orificed fuel support piece and the four fuel assemblies surrounding the control rod. The bottom of the guide tube is supported by the CRD housing, which in turn transmits the weight of the guide tube, fuel support, and fuel assemblies to the reactor vessel bottom head. A thermal sleeve is inserted into the CRD housing from below, and is rotated to lock the control rod guide tube in place. A key is inserted into a locking slot in the bottom of the CRD housing to hold the thermal sleeve in position.

3.9.5.1.1.8 Jet Pump Assemblies

The jet pump assemblies are not core support structures, but are discussed here to describe coolant flow paths in the vessel. The jet pump assemblies are located in two semicircular groups in the downcomer annulus, between the core shroud and the reactor vessel wall. The design and performance of the jet pumps are covered in detail in References 3.9-19 and 3.9-20. Each stainless steel jet pump consists of driving nozzles, a suction inlet, a throat or mixing section, and a diffuser (Figure 3.9-7). The driving nozzle, suction inlet, and throat are joined together as a removable unit, and the diffuser is permanently installed. High pressure water from the recirculation pumps is supplied to each pair of jet pumps through a riser pipe welded to the recirculation inlet nozzle thermal sleeve. A riser brace consists of cantilever beams welded to a riser pipe and to pads on the reactor vessel wall.

The nozzle entry section is connected to the riser by a metal-to-metal, spherical-to-conical seal joint. Firm contact is maintained by a holddown clamp. The throat section is supported laterally by a bracket attached to the riser. There is a slip-fit joint between the throat and diffuser. Some jet pumps have been equipped with a clamp on this slip-fit joint to dampen vibration forces. Some jet pumps have been equipped with an anti-vibration solution between the restrainer bracket and inlet mixer to dampen vibration forces. The diffuser is a gradual conical section, changing to a straight cylindrical section at the lower end.

The licensee will reduce the preload on the beams from 30 kips to 25 kips in accordance with GE recommendations. This increases the expected life of the beams to 19-40 years. Inservice inspection of the jet pump holddown beam will be performed to detect cracking. Inspection frequencies will be based on a lead-plant experience and GE testing, and will be such that any crack initiation will be detected prior to beam failure.

3.9.5.1.1.9 Steam Dryers

The steam dryer assembly is not a core support structure. It is discussed here to describe coolant flow paths in the vessel. The steam dryers remove moisture from the wet steam leaving the steam separators. The extracted moisture flows down the dryer vanes to the collecting troughs, then flows through tubes and into the downcomer annulus. A skirt extends from the bottom of the dryer vane housing to the steam separator standpipe, below the water level. This skirt forms a seal between the wet steam plenum and the dry steam flowing from the top of the dryers to the steam outlet nozzles.

The steam dryer and shroud head are positioned in the vessel during installation with the aid of vertical guide rods. The dryer assembly rests on steam dryer support brackets attached to the reactor vessel wall. Upward movement of the dryer assembly, which may occur under accident conditions, is restricted by steam dryer holddown brackets attached to the reactor vessel top head.

3.9.5.1.1.10 Feedwater Spargers

The feedwater nozzle and sparger design follows the resolution presented in Reference 3.9-6. These components are not core support structures. They are discussed here to describe flow paths in the vessel. The feedwater spargers are stainless steel headers located in the mixing plenum above the downcomer annulus. A separate sparger is fitted to each feedwater nozzle, and is shaped to conform to the curvature of the vessel wall. Sparger end brackets are pinned to vessel brackets to support the spargers. Feedwater flow enters the center of the spargers, and is discharged radially inward, mixing the cooler feedwater with the downcomer flow from the steam separators and steam dryer, before it contacts the vessel wall.

The feedwater also serves to condense the steam in the region above the downcomer annulus, and to subcool the water flowing to the jet pumps and recirculation pumps.

3.9.5.1.1.11 Core Spray Lines

This component is not a core support structure. It is discussed here because the core spray lines are the means for directing flow to the core spray nozzles, which distribute coolant during accident conditions.

Two core spray lines enter the reactor vessel through the two core spray nozzles. The lines divide immediately inside the reactor vessel. The two halves are routed to opposite sides of the reactor vessel, and are supported by clamps attached to the vessel wall. The lines are then routed downward into the downcomer annulus, passing through the upper shroud immediately below the flange. The flow divides again as it enters the center of the semicircular sparger, which is routed halfway around the inside of the upper shroud. The two spargers are supported by brackets designed to accommodate thermal expansion. The line routing and supports are designed to accommodate differential movement between the shroud and vessel. The other core spray line is identical, except that it enters the opposite side of the vessel, and the spargers are at a slightly

different elevation inside the shroud. The correct spray distribution pattern is provided by a combination of distribution nozzles pointed radially inward and downward from the spargers (Section 6.3).

3.9.5.1.1.12 Head Cooling Spray Nozzle (Removed)

This component is not a core support structure.

The head cooling spray nozzle (component B11-D072) was mounted on a short length of pipe and a flange, which was bolted to a mating flange (RPV Nozzle N6A) on the reactor vessel head. The piping supplying coolant to the nozzle has been disconnected, partially removed and the remainder abandoned in place in Unit 1 and was never installed in Unit 2. The head cooling spray nozzle in Unit 1 was removed with the discontinued piping and never installed in Unit 2. RPV Nozzle N6A is empty and blind flanged in both units.

3.9.5.1.1.13 Differential Pressure Line

This component is not a core support structure. It is discussed here to describe the coolant flow paths in the reactor vessel. The differential pressure line senses the differential pressure across the core support plate (Section 7.7). This line enters the reactor vessel at a point below the core shroud, as two concentric pipes. In the lower plenum, the two pipes separate. The inner pipe terminates inside the lower shroud support, with a capped, perforated length below the core support plate. This section of pipe was formerly utilized as the liquid control sprager but now is only used to sense the pressure below the core support plate. The outer pipe terminates open-ended immediately above the core support plate, and senses the differential pressure across the core support plate and the fuel support assemblies.

3.9.5.1.1.14 Incore Flux Monitor Guide Tubes

This component is not a core support structure, but is discussed here to describe the coolant flow paths in the reactor vessel. Incore flux monitor guide tubes provide a means of positioning fixed detectors in the core, as well as providing a path for calibration monitors (TIP system).

The incore flux monitor guide tubes extend from the top of the incore flux monitor housing (Section 5.3) in the lower plenum, to the top of the core support plate. The power range detectors for the PRNM System units, and the dry tubes for the SRM and IRM detectors are inserted through the guide tubes. A latticework of clamps, tie bars, and spacers give lateral support and rigidity to the guide tubes. The bolts and clamps are welded, after assembly, to prevent loosening during reactor operation.

3.9.5.1.1.15 Surveillance Sample Holders

This component is not a core support structure. It is discussed here to describe the coolant flow paths in the reactor vessel. The surveillance sample holders are welded baskets containing impact and tensile specimen capsules (Section 5.3). The baskets hang from the brackets that are attached to the inside wall of the reactor vessel, and extend to mid-height of the active core. The radial positions are chosen to expose the specimens to the same environment and maximum neutron fluxes experienced by the reactor vessel itself, while avoiding jet pump removal interference or damage.

3.9.5.1.1.16 Low Pressure Coolant Injection Lines

This component is not a core support structure, but is discussed here to describe the coolant flow paths in the reactor vessel. Four LPCI lines penetrate the core shroud through separate LPCI nozzles. Coolant is discharged inside the core shroud.

3.9.5.1.1.17 Startup Neutron Sources

The startup neutron sources are held in place by spring pressure between the top of the core support and the bottom of the top guide. For Unit 1, each source consists of two irradiated antimony rods within a single beryllium cylinder. Both the antimony and the beryllium are encased in stainless steel tubes. For Unit 2, californium is used; it is also encased in stainless steel tubes. The design provides for a sufficient source of neutrons present in the core to ensure that the core neutron flux is continuously detectable by installed neutron monitors and to ensure that significant changes in core reactivity are readily detectable by installed neutron flux instrumentation.

3.9.5.2 Design Loading Conditions

3.9.5.2.1 Events to be Evaluated

Examination of the spectrum of conditions that the safety design basis must satisfy by core support structure and ESF components reveals four significant faulted events:

a. Recirculation line break: a break in a recirculation line between the reactor vessel and the recirculation pump suction

b. Steam line break accident: a break in one main steam line between the reactor vessel and the flow restrictor. This accident results in significant pressure differentials across some of the structures within the reactor.

c. Earthquake: subjects the core support structures and reactor internals to significant forces as a result of ground motion.

d. SSE/relief valve discharge: SRV discharge in combination with SSE.

Analysis of other conditions existing during normal operation, abnormal operational transients, and accidents shows that the loads affecting the core support structures and other ESF reactor internals are less severe than these three postulated events. The faulted conditions for the RPV internals are discussed in Section 3.9.1.4. Loading combination and analysis for the RPV internals are discussed in Section 3.9.3.1, and Tables 3.9-2 and 3.9-6. These results are based on the power rerate analysis and do not reflect the use of GE13 or GE14 fuel; the impact of GE13 fuel is documented in Reference 3.9-28. The impact of GE14 fuel is documented to be bounded by GE13 fuel in Reference 3.9-34. The impact of the MUR power uprate is evaluated in Reference 3.9-31 and Reference 3.9-32. Reference 3.9-33 identifies new design basis values for Fuel Lift Margin and Control Rod Guide Tube Lift Forces under MUR conditions. Additional analyses which consider the use of GNF2 fuel are documented in Reference 3.9-35. The GNF2 fuel is demonstrated to be bounded by the analyses in Reference 3.9-33.

Analyses were performed which considered the use of GNF3 fuel. Reference 3.9-39 identified new design basis values for the reactor internal pressure differences for unbounded reactor internals. The GNF3 analyses also identified a new design basis value for maximum Control Rod Guide Tube Lift force.

3.9.5.2.2 Pressure Differential During Rapid Depressurization

A digital computer code is used to analyze the transient conditions within the reactor vessel following the recirculation line break accident and the steam line break accident. The analytical model of the vessel consists of nine nodes, connected to the necessary adjoining nodes by flow paths having the required resistance and inertial characteristics. The program solves the energy and mass conservation equations for each node, giving the depressurization rates and pressure in the various regions of the reactor. Figure 3.9-8 shows the nine reactor nodes. The computer code used is the GE Short-Term Thermal-Hydraulic Model, described in Reference 3.9-21. This model is approved for use in ECCS conformance evaluation under 10CFR50, Appendix K. In order to adequately describe the blowdown pressure effect on the individual assembly components, three features are included in the model that are not applicable to the ECCS analysis and are, therefore, not described in Reference 3.9-21. These additional features are discussed below:

a. The liquid level in the steam separator region, and in the annulus between the dryer skirt and the pressure vessel, is tracked to more accurately determine the flow and mixture quality in the steam dryer and in the steam line.

b. The flow path between the bypass region and the shroud head is more accurately modeled, since the fuel assembly pressure differential is influenced by flashing in the guide tubes and in the bypass region for a steam line break. In the ECCS analysis, the momentum equation is solved in this flow path; but its irreversible loss coefficient is conservatively set at an arbitrary low value.

c. The enthalpies in the guide tubes and the bypass region are calculated separately, since the fuel assembly ΔP is influenced by flashing in these regions. In the ECCS analysis, these regions are lumped.

3.9.5.2.3 Recirculation Line and Steam Line Break

3.9.5.2.3.1 Accident Definition

Both a recirculation line break (the largest liquid break) and an inside steam line break (the largest steam break) are considered in determining the design basis accident for the ESF reactor internals. The recirculation line break is the same as the design basis LOCA described in Section 6.3. A sudden, complete circumferential break is assumed to occur in one recirculation loop. The resulting pressure differentials on the reactor internals and core support structures are in all cases less than for the main steam line break.

The analysis of the steam line break assumes a sudden, complete circumferential break of one main steam line, between the reactor vessel and the main steam line restrictor. A steam line break upstream of the flow restrictors produces a larger blowdown area, and thus a faster depressurization rate, than a break downstream of the restrictors. A larger blowdown area results in greater pressure differentials across the reactor internal structures.

The steam line break accident produces significantly higher pressure differentials across the reactor internal structures than does the recirculation line break. This results from the higher reactor depressurization rate associated with the steam line break. Therefore, the steam line break is the DBA for internal pressure differentials.

3.9.5.2.3.2 Effects of Initial Reactor Power and Core Flow

The maximum internal pressure loads can be considered to be composed of two parts: steady-state and transient pressure differentials. For a given plant, the core flow and the core power are the two major factors which influence the reactor internal pressure differentials. The core flow essentially affects only the steady-state part. For a fixed power, the greater the core flow, the larger the steady-state pressure differentials. The core power affects both the steady-state and the transient parts. As the power is decreased, there is less voiding in the core, and consequently the steady-state core pressure differential is less. However, less voiding in the core also means that less steam is generated in the RPV, thus increasing the depressurization rate and the transient part of the maximum pressure load. As a result, the total loads on some components are higher at low power.

To ensure that the calculated pressure differences bound those which are expected if a steam line break should occur, an analysis is conducted at a low power, high recirculation flow condition, in addition to the standard safety analysis condition at high power-rated recirculation flow. The power chosen for analysis is the minimum value permitted by the recirculation system controls at rated recirculation drive flow (that is, the drive flow necessary to achieve rated core flow at rated power).

This condition maximizes those loads which are inversely proportional to power. It must be noted that this condition, while possible, is unlikely, because the reactor generally operates at or near full power; and because high core flow is neither required, nor desirable at such a reduced power condition.

3.9.5.2.4 Seismic and Hydrodynamic Loads

The seismic and hydrodynamic loads acting on the structures within the reactor vessel are based on a dynamic analysis, as described in Section 3.7. Seismic analysis is performed by coupling the lumped-mass model of the reactor vessel and internals (Section 3.7), with the building model to determine the acceleration, force, and moment time histories in the reactor vessel and internals. This is accomplished by using the modal superposition method. Acceleration response spectra are also produced for subsystem analysis of selected components.

3.9.5.3 Design Bases

3.9.5.3.1 Safety Design Bases

The reactor core support structures and internals meet the following safety design bases:

a. Core support structures are arranged to provide a floodable volume, in which the core can be adequately cooled in the event of a breach in the nuclear system process barrier, external to the reactor vessel.

b. Deformation is limited to ensure that the control rods and the core standby cooling systems can perform their safety functions.

c. Mechanical design of applicable structures ensures that safety design bases a. and b., above, are satisfied so that the safe shutdown of the plant and removal of decay heat are not impaired.

3.9.5.3.2 Power Generation Design Bases

The reactor core support structures and internals are designed to the following power generation design bases:

a. They provide the proper coolant distribution during all anticipated normal operating conditions up to full power operation of the core without fuel damage.

b. They are arranged to facilitate refueling operations.

c. They are designed to facilitate inspection.

3.9.5.3.3 Design Loading Categories

Loading combinations for the core support structures are shown in Table 3.9-26. The basis for determining faulted loads on the reactor internals is shown for seismic and hydrodynamic loads in Section 3.7, and for pipe rupture loads in Sections 3.9.5.2.3 and 3.9.5.3.4. Table 3.9-6(b) gives analytical methods and allowable and calculated stresses for typical core support structures and reactor internal components.

Stress intensity and other design limits are discussed in Section 3.9.5.3.5. The core support structures which are fabricated as part of the RPV assembly are discussed in Section 3.9.1.3.

LGS reactor internals were designed and procured prior to the issuance of ASME Section III, Subsection NG. However, an earlier draft of the ASME Code was used as a guide in the design of the reactor internals. These criteria are presented in this section and were used in lieu of Subsection NG. Subsequent to the issuance of Subsection NG, comparisons were made to ensure that the pre-NG design meets the equivalent level of safety as presented by Subsection NG.

The design requirements for equipment classified as "other internals," e.g., steam dryers and shroud heads, are specified by the designer with appropriate consideration of the intended service of the equipment and expected plant and environmental conditions under which it operates. Where possible, design requirements are based on applicable industry codes and standards. If these are not available, the designer relies on accepted industry or engineering practices.

3.9.5.3.3.1 Reactor Core Support and Internals Structural Margin Evaluations

The analyses of conditions found during inspections of reactor internal and core support structures use approved industry codes and standards as described in the LGS Inservice Inspection Program, references 5.2-10 and 5.2-11. These analyses are performed as described in the above referenced Sections except that limit load, linear elastic (LEFM), and elastic-plastic (EFPM) fracture mechanic methods may be used as discussed in Tables 3.9-23, 3.9-24, 3.9-28, and 3.9-30.

Neutron fluence is evaluated when the irradiation induced changes in the material fracture toughness properties are judged to be significant. These material properties include yield and ultimate tensile strengths, uniform elongation and upper-shelf Charpy energy. The trends in these properties as a function of fluence level are reviewed to determine a fluence value above which the use of LEFM or EPFM techniques would be necessary and to determine the appropriate flaw growth rate to be used in the structural margin analyses. The fluence calculations use the methodology discussed in Section 4.3.2.8.

a. The design loads for the LGS Unit 1 and Unit 2 core shroud horizontal welds H1 through H8 have been calculated and are documented in reference 3.9-29. The loads and their combinations are based on power rerate and new loads design adequacy evaluations as discussed in reference 3.9-23. The effects of additional loads from GE13 fuel design (reference 3.9-28), fuel lift loads, and increased core flow (3% noise) beyond power rerate and the new loads programs are included in the updated core shroud loads and analysis. The impact of GE14 fuel is documented to be bounded by GE13 fuel in Reference 3.9-34. Reference 3.9-33 identifies new design basis values for Fuel Lift Margin and Control Rod Guide Tube Lift Forces under MUR conditions. Additional analyses which consider the use of GNF2 fuel are documented in Reference 3.9-35. The GNF2 fuel is demonstrated to be bounded by the analyses in Reference 3.9-33. Analyses were performed which considered the use of GNF3 fuel. Reference 3.9-39 identified new design basis values for the reactor internal pressure differences for unbounded reactor internals. The GNF3 analyses also identified a new design basis value for maximum Control Rod Guide Tube Lift force.

b. Design loads for GNF3 fuel are documented in Reference 3.9-37 for LGS Unit 1 and 2 core shroud horizontal welds H1 through H7.

Reference 3.9-30 was prepared in response to Generic Letter (GL) 94-03, Intergranular Stress Corrosion Cracking of Core Shrouds in Boiling Water Reactors, which required a plant specific safety assessment supporting continued operation of core shrouds. The report provides accident loading information applicable to LGS Unit 1 and Unit 2, as well as the safety assessment for postulated through-wall flaws at core shroud horizontal welds H1 through H7. The analysis considers both normal plant operations and limiting abnormal operational occurrences. It provides information on the plant response i.e., control rod insertion and ECCS injection, to postulated Main Steam Line Break (MSLB) and Recirculation Line Break (RLB), including a coincident Safe Shutdown Earthquake (SSE). The overall conclusion concerning plant safety is that the core shroud is an extremely flaw tolerant core support structure such that the probability is a very small that flawed welds would result in shroud separation under any desgn basis operational event.

The design requirements for equipment classified as "other internals," e.g., steam dryers and shroud heads, are specified by the designer with appropriate consideration of the intended service of the equipment and expected plant and environmental conditions under which it operates. Where possible, design requirements are based on applicable industry codes and standards. If these are not available, the designer relies on accepted industry or engineering practices.

3.9.5.3.4 Response of Internals Due to Inside Steam Break Accident

The maximum pressure loads acting on the reactor internal components result from an inside steam line break; on some components the loads are maximum when operating at the minimum power associated with the maximum core flow. This is substantiated by the analytical comparison of liquid versus steam breaks, and by the investigation of the effects of core power and core flow.

It has also been pointed out that it is possible but not probable that the reactor is operating at the rather abnormal condition of minimum power and maximum core flow. More realistically, the reactor is at or near a full power condition, and thus the maximum pressure loads acting on the internal components would be less.

3.9.5.3.5 Stress, Deformation, and Fatigue Limits for ESF Reactor Internals (Except Core Support Structure)

Elastic displacement is considered in the design of reactor internal components in which deflection can affect control rod insertability. Plastic deformation will not occur in any permanent core support structure component of the reactor vessel. Radiation-induced deformation can occur in the fuel channel over the core life. These effects are considered in control rod insertability tests. No fatigue analysis is required under the faulted conditions due to the low encounter frequency of faulted events and the low number of cycles. The forcing functions applicable to the reactor internals are discussed in Section 3.9.2.5. The stress, deformation, and fatigue limits are given in Table 3.9-6(b).

3.9.5.3.6 Stress, Deformation, and Fatigue Limits for Core Support Structures

The stress, deformation, and fatigue limits are given in Table 3.9-6(f).

3.9.6 Inservice Testing Of Pumps And Valves

Inservice testing of pumps and valves is accomplished in accordance with the requirements of 10CFR50.55a, using the date of commercial operation for determining test intervals.

The Preservice Testing Program included provisions for design and access to enable the operational readiness testing of pumps and valves, and was required to comply, as a minimum, with the 1971 Edition of Section XI of the ASME B&PV Code, including the winter of 1972 Addenda (this being in effect 6 months prior to the LGS construction permit date of June 1974). That publication did not include requirements for preservice testing of pumps and valves to ensure operational readiness. The requirements for inservice testing of pumps and valves were added as Subsections IWV and IWP to the ASME B&PV Code, Section XI, Summer 1973 Addenda, effective December 30, 1973. The Preservice Testing Program for assessing operational readiness of pumps and valves was conducted, however, to the extent practical within design limitations, to comply with the 1980 Edition of ASME Section XI, with addenda through Winter 1981.

Inservice testing of pumps and valves to ensure operational readiness for the first 120-month interval was performed in accordance with the requirements of 10CFR50.55a and met, to the extent practical within design limitations, the requirements of the Code in effect 12 months prior to the date of commercial operation. The first 120-month interval for Unit 2 was required to comply with the 1986 Edition of ASME Section XI. As permitted by 10CFR50.55a, the Unit 1 IST Program was updated to comply with the 1986 Edition of ASME Section XI. Subsequently, NRC authorized a one-time extension of the first 120-month interval for Unit 1, resulting in both Units being on concurrent intervals.

During the second and successive 120-month intervals, inservice testing of pumps and valves to ensure operational readiness shall be performed in accordance with the requirements and limitations specified in 10CFR50.55a. Detailed information regarding current Code requirements, component selection, testing requirements, Code Class, and deviations from referenced Code requirements is provided in Reference 3.9-25.

There is a Risk Informed Categorization and Treatment Program at Limerick which is based on 10 CFR 50.69. This regulation provides an alternative approach for establishing requirements for treatment of SSCs using a risk-informed method of categorizing SSCs according to their

safety significance. Specifically, for SSCs categorized as low safety significant, alternate treatment requirements may be implemented rather than treatments chosen by the inservice testing of pumps and valves program. Refer to Section 13.5.5 for further information.

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Table 3.9-1

APPLICABLE THERMAL TRANSIENTS

PIPELINE	INITIAL TEMPERATURE (°F)	FINAL TEMPERATURE (°F)	TIME	TEMPERATURE RATE (°F/hr)(15)	ΔTEMPERATURE (°F)
A. 130 CYCLES, CONDITION - TEST (PRE-STARTUP LEAK TEST)(1)					
Main Steam Line	70	100	30 min	60	30
Recirculation Suction	70	100	30 min	60	30
Recirculation Discharge	70	100	30 min	60	30
Bottom Drain	70	100	30 min	60	30
SLCS	70	100	30 min	60	30
	100	50	Step	10 min	50
	50	100	Step	duration	50
Core Spray	70	100	30 min	60	30
Feedwater	70	100	30 min	60	30
B. 120 CYCLES, CONDITION - NORMAL (STARTUP)(2)					
Main Steam Line	100	546	-	100	446
Recirculation Suction	100	546	-	100	446
	546	538	Step	-	8
	538	522	Step	-	16
Recirculation Discharge	538	522	Step	-	16
Bottom Drain	538	522	Step	-	16
SLCS	538	522	Step	-	16
Core Spray	100	406	-	100	306
only 10 cycles	406	50	Step	-	356
	50	406	Step	-	356
	406	546	-	100	140
Feedwater	100	546	-	100	446
	546	90	Step	-	456
	90	420	30 min	660	330

Table 3.9-1 (Cont'd)

PIPELINE	INITIAL TEMPERATURE (°F)	FINAL TEMPERATURE (°F)	TIME	TEMPERATURE RATE (°F/hr)[15]	ΔTEMPERATURE (°F)
C. 10,400 CYCLES, CONDITION - NORMAL (DAILY POWER REDUCTION AND ROD PATTERN CHANGE)[3]					
Main Steam Line	546	546	-	-	-
Recirculation Suction	522	522	-	-	-
Recirculation Discharge	522	522	-	-	-
Bottom Drain	522	522	-	-	-
SLCS	522	522	-	-	-
Core Spray	522	522	-	-	-
Feedwater	420	354	15 min	264	66
	354	420	15 min	264	66
Cleanup Return	435	435	-	-	-
D. 2000 CYCLES, CONDITION - NORMAL (WEEKLY POWER REDUCTION)[3]					
Main Steam Line	546	546	-	-	-
Recirculation Suction	522	522	-	-	-
Recirculation Discharge	522	522	-	-	-
Bottom Drain	522	522	-	-	-
SLCS	522	522	-	-	-
Core Spray	522	522	-	-	-
Feedwater	420	324	30 min	192	96
	324	420	30 min	192	96
Cleanup Return	435	435	-	-	-
E. 70 CYCLES ,CONDITION - UPSET (PARTIAL FEEDWATER HEATER BYPASS)[3]					
Main Steam Line	546	546	-	-	-
Recirculation Suction	522	512	2 min	300	10
	512	522	4 min	150	10
Recirculation Discharge	512	522	4 min	150	10
Bottom Drain	512	522	4 min	150	10
SLCS	512	522	4 min	150	10
Core Spray	512	522	4 min	150	10
Feedwater	420	265	1.5 min	6200	155
	265	420	3 min	3100	155

Table 3.9-1 (Cont'd)

PIPELINE	INITIAL TEMPERATURE (°F)	FINAL TEMPERATURE (°F)	TIME	TEMPERATURE RATE (°F/hr)(15)	ΔTEMPERATURE (°F)
F. 10 CYCLES, CONDITION - UPSET (TURBINE TRIP 100 PERCENT BYPASS)(3)					
Main Steam Line	546	546	-	-	-
Recirculation Suction	522	490	1.5 min	1,280	32
	490	522	4 min	480	32
Recirculation Discharge	490	522	4 min	480	32
Bottom Drain	490	522	4 min	480	32
SLCS	490	522	4 min	480	32
Core Spray	490	522	4 min	480	32
Feedwater	420	100	1.5 min	12,800	320
	100	420	4 min	4,800	320
G. 40 CYCLES, CONDITION - UPSET (SCRAM - T/G TRIP FEEDWATER ON - MSIV OPEN)(4)					
Main Steam Line	546	565	10 sec7000		19
	565	538	15 sec6500		27
	538	400	-	100	138
	400	546	-	100	146
Recirculation Suction	522	400	-	100	122
	400	546	-	100	146
	546	538	Step	-	18
	538	522	Step	-	16
Recirculation Discharge	538	522	Step	-	16
Bottom Drain	538	522	Step	-	16
SLCS	538	522	Step	-	16
Core Spray	538	522	Step	-	16
Feedwater	420	275	1 min	8700	145
	275	100	15 min	700	175
	100	250	Step	-	150
	250	420	30 min	340	170

Table 3.9-1 (Cont'd)

PIPELINE	INITIAL TEMPERATURE (°F)	FINAL TEMPERATURE (°F)	TIME	TEMPERATURE RATE (°F/hr)[15]	ΔTEMPERATURE (°F)
H. 140 CYCLES, CONDITION - UPSET (ALL OTHER SCRAMS)[5]					
Main steam line	546	538	15 sec	1920	8
	538	400	-	100	138
	400	546	-	100	146
Recirculation Suction	522	400	-	100	122
	400	546	-	100	146
	546	538	Step	-	18
	538	522	Step	-	16
Recirculation Discharge	538	522	Step	-	16
Bottom Drain	538	522	Step	-	16
SLCS	538	522	Step	-	16
Core Spray	538	522	Step	-	16
Feedwater	420	275	1 min	8700	145
	275	100	15 min	700	175
	100	250	Step	-	150
	250	420	30 min	340	170
I. CYCLES LISTED BELOW, CONDITION - NORMAL (RATED POWER)[3]					
Main Steam Line	546	546	-	-	-
Recirculation Suction	522	546	-	-	-
Recirculation Discharge	522	522	-	-	-
Bottom Drain	522	150	1 hr	372	372
240 Cycles	150	522	Step	NA	372
SLCS	522	60	Step	NA	462
10 Cycles	60	522	60 min	462	462
Core Spray	522	522	-	-	-
Feedwater	420	420	-	-	-
Cleanup Return	435	435	-	-	-

Table 3.9-1 (Cont'd)

PIPELINE	INITIAL TEMPERATURE (°F)	FINAL TEMPERATURE (°F)	TIME	TEMPERATURE RATE (°F/hr)[15]	ΔTEMPERATURE (°F)
J. 111 CYCLES, CONDITION - NORMAL (SHUTDOWN)[6]					
Main Steam Line	546	375	-	100	171
	375	330	10 min	270	45
	330	100	-	100	230
RHR Return	375	50	Step	15 sec	325
	50	300	Step	duration	250
	300	100	-	100	200
Recirculation Suction	522	546	Step	-	24
	546	375	-	100	171
	375	330	10 min	270	45
	330	100	-	100	230
Bottom Drain	330	100	-	100	230
SLCS	330	100	-	100	230
Core Spray	330	100	-	100	230
Recirculation Discharge	522	546	Step	-	24
	546	375	-	100	171
	375	300	Step	-	75
	300	260	10 min	240	40
	260	100	-	100	160
Feedwater	420	265	30 min	310	155
	265	420	Step	-	155
	420	546	-	100	126
	546[7]	100	-	100	446
K. 10 CYCLES, CONDITION - EMERGENCY (LOSS OF FEEDWATER PUMPS - MSIV CLOSE)[8]					
Main Steam Line	546	573	3 sec	32,400	27
	573	561	10 sec	4300	12
	561	538	3 min	560	23
	538	561	73 min	19	23
	561	500	7 min	520	61
	500	400	-	100	100
	400	546	-	100	146
Recirculation Suction	522	300	30 min	444	222
	300	546	-	100	246
	546	538	Step	-	8
	538	522	Step	-	16

Table 3.9-1 (Cont'd)

PIPELINE	INITIAL TEMPERATURE (°F)	FINAL TEMPERATURE (°F)	TIME	TEMPERATURE RATE (°F/hr)[15]	ΔTEMPERATURE (°F)
Recirculation Discharge	538	522	Step	-	16
Bottom Drain	522	300	3.7 min	3600	222
	300	500	23 min	523	200
	500	300	7 min	1720	200
	300	546	-	100	246
	546	538	Step	-	8
	538	522	Step	-	16
SLCS	538	522	Step	-	16
Core Spray	538	522	Step	-	16
Feedwater	420	546	Step	-	126
	546	40	Step	-	506
	40	546	23 min	1300	506
	546	40	Step	-	506
	40	546	51 min	600	506
	546	40	Step	-	506
	40	300	5 min	3120	260
	300	546	-	100	246
	546	100	Step	-	446
	100	250	Step	-	150
	250	420	30 min	340	170
L. 1 CYCLE, CONDITION - EMERGENCY (REACTOR OVERPRESSURE DELAYED SCRAM)[9]					
Main Steam Line	546	583	2 sec	66,600	37
	583	538	30 sec	5,400	45
	538	400	-	100	138
Recirculation Suction	522	562	11 sec	13,100	40
	562	400	-	100	162
Recirculation Discharge	562	400	-	100	162
Bottom Drain	562	400	-	100	162
SLCS	562	400	-	100	162
Core Spray	562	400	-	100	162
Feedwater	420	276	1 min	8,640	144
	276	100	15 min	704	176

Table 3.9-1 (Cont'd)

PIPELINE	INITIAL TEMPERATURE (°F)	FINAL TEMPERATURE (°F)	TIME	TEMPERATURE RATE (°F/hr)[15]	ΔTEMPERATURE (°F)
M. 8 CYCLES, CONDITION - EMERGENCY (SINGLE SRV BLOWDOWN)[10]					
Main Steam Line	546	375	10 min	1026	171
	375	100	-	100	275
Recirculation Suction	522	375	10 min	882	147
	375	100	-	100	275
Recirculation Discharge	375	100	-	100	275
Bottom Drain	375	100	-	100	275
SLCS	375	100	-	100	275
Core Spray	375	100	-	100	275
Feedwater	420	276	1 min	8640	144
	276	100	15 min	704	176
N. 1 CYCLE, CONDITION - EMERGENCY (AUTOMATIC DEPRESSURIZATION)[11]					
Main Steam Line	546	375	3.3 min	3100	171
	522	375	3.3 min	2700	147
	375	281	-	300	94
Recirculation Discharge	375	281	-	300	94
Bottom Drain	375	281	-	300	94
SLCS	375	281	-	300	94
Core Spray	375	281	-	300	94
Feedwater	420	276	1 min	8640	144
	276	100	15 min	784	176
O. 1 CYCLE, CONDITION - EMERGENCY (IMPROPER START OF COLD RECIRCULATION LOOP)[3]					
Main Steam Line	546	546	-	-	-
Recirculation Suction	522	130	Step	26 sec	392
	130	522	Step	duration	392
Recirculation Discharge	522	130	Step	34 sec	392
	130	522	Step	duration	392
Bottom Drain	522	522	-	-	-
SLCS	522	522	-	-	-
Core Spray	522	268	Step	34 sec	254
	268	522	Step	duration	254
Feedwater	420	420	-	-	-

Table 3.9-1 (Cont'd)

PIPELINE	INITIAL TEMPERATURE (°F)	FINAL TEMPERATURE (°F)	TIME	TEMPERATURE RATE (°F/hr)[15]	ΔTEMPERATURE (°F)
P. 1 CYCLE, CONDITION - EMERGENCY (SUDDEN PUMP START IN COLD LOOP)[3]					
Main Steam Line	546	546	-	-	-
Recirculation Suction	522	522	-	-	-
Recirculation Discharge	522	130	Step	34 second	392
	130	522	Step	duration	392
Bottom Drain	522	350	Step	34 second	172
	350	522	Step	duration	172
SLCS	350	522	Step	34 second duration	172
Core Spray	522	522	-	-	-
Feedwater	420	420	-	-	-
Q. 1 CYCLE, CONDITION - EMERGENCY (IMPROPER START WITH RECIRCULATION PUMPS OFF)[12]					
Main Steam Line	100	546	-	100	446
Recirculation Suction	100	546	-	100	446
Recirculation Discharge	100	546	-	100	446
	546	130	Step	34 sec	416
	130	546	Step	duration	416
Bottom Drain	100	546	5 min	5352	446
SLCS	100	546	5 min	5352	446
Core Spray	100	546	-	100	446
Feedwater	90	546	-	100	456
	546	90	Step	-	456
	90	420	30 min	660	330
R. 1 CYCLE, CONDITION - FAULTED (PIPE RUPTURE AND BLOWDOWN)[13]					
Main Steam Line	546	281	15 sec	63,500	265
Recirculation Suction	522	281	15 sec	57,000	241
Recirculation Discharge	522	281	15 sec	57,000	241
	281	223	35 sec		58
	223	50	Step	90 sec	173
	50	130	Step	duration	80

Table 3.9-1 (Cont'd)

PIPELINE	INITIAL TEMPERATURE (°F)	FINAL TEMPERATURE (°F)	TIME	TEMPERATURE RATE (°F/hr)(15)	ΔTEMPERATURE (°F)
Bottom Drain	522	281	15 sec	57,000	241
	281	273	35 sec	822	8
	273	50	Step	90 sec	223
	50	130	Step	duration	80
SLCS	50	130	Step	90 sec duration	80
Core Spray	522	406	10 sec	41,700	116
	406	50	Step	90 sec	356
	50	130	Step	duration	80
Feedwater	420	281	15 sec	33,400	139

S. BECHTEL CRITERIA FOR BOP PIPING

1.	½ SSE Cycles (OBE)	Condition - Upset
	Expected number of equivalent ½ SSE in life of pipe system	5
	Average duration of strong motion vibration ½ SSE	15 sec
	Average number of maximum seismic load cycles of pipe system for each ½ SSE	10
	Total lifetime number of maximum seismic load cycles of piping system	50
2.	SSE Cycles (Design Basis Earthquake)	Condition - Faulted
	Expected number of equivalent SSE in life of pipe system	1
	Average duration of strong motion vibration SSE	15 sec

Table 3.9-1 (Cont'd)

T. GENERAL ELECTRIC CRITERIA FOR NSSS PIPING

1.	½ SSE Cycles (OBE)	Condition - Upset
	Expected number of equivalent ½ SSE in life of pipe system	1
	Average duration of strong motion vibration ½ SSE	30 sec
	Average number of maximum seismic load cycles of pipe system for each ½ SSE	10
	Total lifetime number of maximum seismic load cycles of piping system	10
2.	SSE Cycles (Design Basis Earthquake)	Condition - Faulted
	Expected number of equivalent SSE in life of pipe system	1
	Average duration of strong motion vibration SSE	30 sec
	Average number of maximum seismic load cycles of pipe system for each SSE	1
	Total lifetime number of maximum seismic load cycles of piping system	1
3.	Turbine Stop Valve(14) Closure	Condition - Upset 120 cycles
4.	Relief Valve Lift Cycles(14) (at 3 cycles per actuation)	Condition - Upset 34,200 cycles

Table 3.9-1 (Cont'd)

(1) After temperature is raised to 100°F, reactor pressure is increased to 1250 psig and then decreased to 0 psig.
(2) Reactor pressure increases from 0 to 1000 psig at rate of temperature increase.
(3) Reactor pressure remains at 1000 psig.
(4) Reactor pressure increases to 1125 psig all relief valves open. Pressure decreases to 240 psig and then increases to 1000 psig.
(5) Reactor pressure decreases to 240 psig and then increases to 1000 psig.
(6) Reactor pressure decreases from 1000 psig to 0 psig.
(7) 5 step changes to 100°F and back during cooldown.
(8) Reactor pressure increases to 1180 psig. All relief valves open. Pressure decreases to 1125 psig and relief valves close. RCIC initiates and pressure decreases to 875 psig. RCIC trips off on high level and pressure increases to 1125. One relief valve opens and then closes as pressure decreases at rate of 100°F/hr.
(9) Reactor pressure increases to 1350 psig. All relief valves and safety valves open. Pressure decreases to 240 psig.
(10) Reactor pressure decreases to 0 psig with one relief valve or safety valve open.
(11) Reactor pressure decreases with auto-blowdown relief valves open to 35 psig.
(12) Reactor pressure increases to 1000 psig as temperature increases.
(13) Reactor pressure decreases from 1000 psig to 35 psig in 15 seconds.
(14) Not applicable to recirculation piping due to negligible effect.
(15) Temperature rates are informational only and approximated.

Table 3.9-2

PLANT EVENTS

EVENT NO.		NO. OF CYCLES
	NORMAL, UPSET, AND TESTING CONDITIONS	
1.	Bolt-up[1]	123
2.	Design hydrostatic test	130
3.	Startup (100° F/hr heatup rate)[2]	120
4.	Daily reduction to 75% power[1]	10,000
5.	Weekly reduction to 50% power[1]	2,000
6.	Control rod pattern change[1]	400
7.	Loss of feedwater heaters	80
8.	OBE event at rated operating conditions	10/50[3]
9.	Scram:	
	a. Turbine-generator trip, feedwater on, isolation valves stay open	40
	b. Other scrams	140
10.	Reduction to 0% power, hot standby, shutdown (100 ° F/hr cooldown rate)[2]	111
11.	Unbolt	123
12.	Pre-op blowdown	10
13.	Loss of RWCU	240
14.	MSRV actuations	7700
15.	SLCS Operation	10

Table 3.9-2 (Cont'd)

EVENT NO.		NO. OF CYCLES
	EMERGENCY CONDITIONS	
16.	Scram:	
a.	Reactor overpressure with delayed scram, feedwater stays on, isolation valves stay open	1(4)
b.	Loss of feedwater pumps, isolation valves closed	5
c.	Automatic Blowdown	1(4)
d.	Single safety or relief valve blowdown	8
17.	Improper start of cold recirculation loop	1(4)
18.	Sudden start of pump in cold recirculation loop	1(4)
19.	Improper startup with reactor drain shut off	1(4)
	FAULTED CONDITION	
20.	SSE at rated operating conditions	1(4)
21.	Pipe rupture and blowdown	1(4)

(1) Applies to RPV only.
(2) Bulk average vessel coolant temperature change in any 1-hour period.
(3) An environmental fatigue calculation provides the basis for reduced OBE cycle limits for the following piping systems: RHR Return and Supply piping – 20 cycles; Recirculation Drain piping – 20 cycles; Core Spray piping – 40 cycles (Unit 1), 30 cycles (Unit 2); and Reactor Recirculation piping – 30 cycles. All other piping has a limit of 50 OBE cycles. These administrative transient cycle limits are imposed to meet License Renewal Commitment T04740.
(4) The annual encounter probability of the one cycle events is $<10^{-2}$ for emergency and $<10^{-4}$ for faulted events.

Table 3.9-3

LIST OF COMPUTER PROGRAMS USED FOR NON-NSSS MECHANICAL SYSTEMS, COMPONENTS, AND COMPONENT SUPPORTS

COMPUTER PROGRAM No.	NAME	DOCUMENT TRACEABILITY	SYSTEM USED
ME101	Linear Elastic Analysis of Piping	Bechtel	UNIVAC 1100 series, Unix Workstation
ME632	Piping System Analysis	Bechtel	Honeywell 6000, UNIVAC 1100 series
ME912	Thermal Stress Program	Bechtel	UNIVAC 1100 series
ME913	Nuclear Class 1 Piping Stress Analysis	Bechtel	UNIVAC 1100 series
CE798	ANSYS	Swanson Analysis System, Inc. Elizabeth, Penn.	UNIVAC 1100 series
NE452	Reflood Analysis	Bechtel	UNIVAC 1100 series
NE805	Relief Valve	Bechtel Clearing Analysis	UNIVAC 1100 series
ME210	Local Stresses in Cylindrical Shells Due to External Loadings	Bechtel	UNIVAC 1100 series
ME602	Spectra Merging and Simplified Seismic Analysis	Bechtel	UNIVAC 1100 series
ME351	Pipe Rupture Analysis Program	Control Data Corporation	CDC CYBER
ME150	Frame Analysis Program for Pipe Support	Bechtel	UNIVAC 1100 series, VAX/VMS, UNIX Workstation
ME152	Standard Frame Analysis Program for Pipe Support	Bechtel	VAX/VMS, UNIX Workstation

Table 3.9-3 (Cont'd)

COMPUTER PROGRAM No.	NAME	DOCUMENT TRACEABILITY	SYSTEM USED
ME035	Base-Plate Analysis Program	Bechtel	UNIVAC 1100 series, UNIX Workstation
CE050	Concrete Expansion Anchor Bolt Program	Bechtel	UNIVAC 1100 series
CE901	Frame Analysis Program	Bechtel	UNIVAC 1100 series
ME225	Anchor Plate Program	Bechtel	UNIVAC 1100 series
ME226	Pipe Clamp Program	Bechtel	UNIVAC 1100 series
ME120	Weld Program	Bechtel	UNIVAC 1100 series
ME425	Strength Design of Pipe Support Anchor Bolt	Bechtel	UNIVAC 1100 series
ME153	Miscellaneous Application Program for Pipe Supports	Bechtel	UNIVAC 1100 series, VAX/VMS, UNIX Workstation
NUPIPE-SWPC	Linear Elastic Analysis of Piping	Stone and Webster	PC Workstation

Table 3.9-4

COMPARISON OF ME912 WITH ME643 AND ANALYTICAL RESULTS

CASE	PROGRAM	TEMPERATURE GRADIENTS[1] ΔT_1	ΔT_2	$T_a - T_b$[1]
450° F to 553° F Step	ME643	79.0	38.0	24.0
3 Inch Schedule 160, Stainless	ME912	79.7	40.6	24.3
Thicknesses 1.50:1	Reference 3.9-8	82.0	41.0	-
408° F to 100° F Step	ME643	136.2	40.1	83.0
12 Inch Schedule 80, Carbon	ME912	134.4	41.9	81.6
Steel Thicknesses 1.69:1	Reference 3.9-8	139.0	43.0	-

(1) Defined in the ASME B&PV Code, Section III, Subsection NB-3650.

Table 3.9-5

COMPARISON BETWEEN SAMPLE PROBLEM AND
COMPUTER PROGRAM ME913 RESULTS[1]

	ME 913	Sample Problem[2]
Equation 9	20,810 psi	20,825 psi
Equation 10	65,567 psi	65,596 psi
Equation 11	128,950 psi	128,920 psi
Equation 12	39,536 psi	39,564 psi
Equation 13	23,152 psi	23,155 psi
Total Usage Factor	0.3439	0.3699

(1) Comparison made for Butt-Welding Tee, Location 10.
(2) See Reference 3.9-14.

Table 3.9-6

LOADING COMBINATIONS, STRESS LIMITS, AND ALLOWABLE STRESSES

The following is a list of the tables that give the design loading combinations, allowable stresses, and calculated stresses for the major mechanical safety-related components in the plant and referenced in Section 3.9.

3.9-6(a)	Load Combinations and Acceptance Criteria for ASME Class 1, 2, and 3 NSSS Piping, Equipment, and Supports
3.9-6(b)	Reactor Internals and Associated Equipment
3.9-6(c)	RWCU Heat Exchangers
3.9-6(d)	Class 1 Main Steam Piping and Pipe-mounted Equipment
3.9-6(e)	Class 1 Recirculation Loop Piping and Pipe-mounted Equipment
3.9-6(f)	RPV and Shroud Support Assembly
3.9-6(g)	Main Steam Relief Valves
3.9-6(h)	Main Steam Isolation Valve
3.9-6(i)	Recirculation Pump
3.9-6(j)	Reactor Recirculation System Gate Valves
3.9-6(k)	HPCI Turbine
3.9-6(l)	SLCS Pump
3.9-6(m)	SLCS Tank
3.9-6(n)	ECCS Pumps
3.9-6(o)	RHR Heat Exchanger
3.9-6(p)	RWCU Pump
3.9-6(q)	RCIC Turbine
3.9-6(r)	RCIC Pump

Table 3.9-6 (Cont'd)

3.9-6(s)	Reactor Refueling and Servicing Equipment
3.9-6(t)	HPCI Pump
3.9-6(u)	Control Rod Drive
3.9-6(v)	CRD Housing
3.9-6(w)	Jet Pumps
3.9-6(x)	Fuel Assembly (Including Channel)
3.9-6(y)	LPCI Coupling
3.9-6(z)	RPV Support Equipment; CRD Housing Support
3.9-6(aa)	Control Rod Guide Tube
3.9-6(ab)	Incore Housing

Table 3.9-6(a)

LOAD COMBINATION AND ACCEPTANCE CRITERIA FOR
ASME CLASS 1, 2, AND 3 NSSS PIPING, EQUIPMENT, AND SUPPORTS

LOAD COMBINATION	DESIGN BASIS	EVALUATION BASIS	SERVICE LEVEL
N + $SRV_{(ALL)}$	Upset	Upset	(B)
N + OBE	Upset	Upset	(B)
N + OBE + $SRV_{(ALL)}$	Emergency	Upset	(B)
N + SSE + $SRV_{(ALL)}$	Faulted	Faulted	(D)(1)
N + SBA + SRV	Emergency	Emergency	(C)(1)
N + SBA + $SRV_{(ADS)}$	Emergency	Emergency	(C)(1)
N + SBA/IBA + OBE + $SRV_{(ADS)}$	Faulted	Faulted	(D)(1)
N + SBA/IBA + SSE + $SRV_{(ADS)}$	Faulted	Faulted	(D)(1)
N + LOCA(2) + SSE	Faulted	Faulted	(D)(1)

LOAD DEFINITION LEGEND

N	-	Normal loads (e.g., weight, pressure, temperature, etc)
OBE	-	Operational basis earthquake loads
SSE	-	Safe shutdown earthquake loads
SRV	-	Safety/relief valve discharge induced loads from two adjacent valves (one valve actuated when adjacent valve is cycling)
SRV_{ALL}	-	Loads induced by actuation of all 14 safety/relief valves that activate within milliseconds of each other (e.g., turbine trip operational transient)

Table 3.9-6(a) (Cont'd)

SRV_{ADS}	-	Loads induced by the actuation of all 5 safety/relief valves associated with automatic depressurization system that actuate within milliseconds of each other during the postulated small or intermediate size pipe rupture.
LOCA	-	Loss-of-coolant accident associated with the postulated pipe rupture of large pipes (e.g., main steam, feedwater, recirculation piping)
$LOCA_1$	-	Pool-swell drag/fallback loads on piping and components located between the main vent discharge outlet and the suppression pool water upper surface
$LOCA_2$	-	Pool-swell impact loads on piping and components located above the suppression pool water upper surface
$LOCA_3$	-	Oscillating pressure induced loads on structures and equipment during condensation oscillation
$LOCA_4$	-	Oscillating pressure induced loads on structures and equipment during chugging
$LOCA_5$	-	Building motion induced loads from main vent air clearing
$LOCA_6$	-	Vertical and horizontal loads on main vent piping
$LOCA_7$	-	Annulus pressurization loads
SBA	-	Abnormal transients associated with a small break accident
IBA	-	Abnormal transients associated with an intermediate break accident.

(1) All ASME Class 1, 2 and 3 piping that are required to function for safe shutdown under the postulated events are designed to meet the requirements described in NEDO-21985.

(2) The most limiting case of load combinations among $LOCA_1$ through $LOCA_7$.

Table 3.9-6(b)

REACTOR INTERNALS AND ASSOCIATED EQUIPMENT

ASME SECTION III, SUBSECTION NG PRIMARY STRESS LIMIT CRITERIA	LOAD CASE NUMBER[1]	PRIMARY STRESS TYPE	ALLOWABLE STRESS (psi)	MAXIMUM CALCULATED STRESS[3] (psi)
TOP GUIDE - HIGHEST STRESSED BEAM				
MATERIAL 304 S.S.				
A. NORMAL AND UPSET CONDITION:				
$P_m \leq S_m$	Normal and Upset Condition Loads:	Primary membrane	16,900	1,889
S_m = 16,900 @ 550 ^{o} F	1. Normal loads 2. Upset pressure 3. OBE 4. SRV			
$P_L + P_b \leq 1.5\ S_m$		Primary membrane plus bending	25,350	17,735
1.5 S_m = 25,350 @ 550 ^{o} F				
B. EMERGENCY CONDITION:				
$P_m \leq 1.5\ S_m$	Emergency Condition Loads:	Primary membrane	25,350	326
1.5 S_m = 25,350 @ 550 ^{o} F	1. Normal loads 2. Upset pressure 3. Chugging 4. SRV_1			
$P_L + P_b$ 2.25 S_m		Primary membrane plus bending	38,025	12,192
2.25 S_m = 38,025 @ 550 ^{o} F[2]				

Table 3.9-6(b) (Cont'd)

ASME SECTION III, SUBSECTION NG PRIMARY STRESS LIMIT CRITERIA	LOAD CASE NUMBER[1]	PRIMARY STRESS TYPE	MAXIMUM ALLOWABLE STRESS (psi)	CALCULATED STRESS[3] (psi)
C. FAULTED CONDITION:				
$P_m \leq 2.4\ S_m$	Faulted Condition Loads:	Primary membrane	40,560	3,383
$2.4\ S_m = 40{,}560$ @ 550° F	1. Normal loads 2. Accident pressure 3. SSE 4. Jet reaction 5. Delta P			
$P_L + P_b \leq 3.0\ S_m$	1. Normal loads 2. Accident pressure	Primary membrane plus bending	50,700	34,412
$3.0\ S_m = 50{,}700$ @ 550° F[2]	3. SSE 4. SRV_1 5. Chugging			
D. MAXIMUM CUMULATIVE USAGE FACTOR: 0.901 at beam slot location				

Table 3.9-6(b) (Cont'd)

ASME SECTION III, SUBSECTION NG PRIMARY STRESS LIMIT CRITERIA	LOAD CASE NUMBER[1]	PRIMARY STRESS TYPE	MAXIMUM ALLOWABLE STRESS (psi)	CALCULATED STRESS[3] (psi)
CORE PLATE (LIGAMENT IN TOP PLATE)				
MATERIAL: 304 S.S.				
A. NORMAL AND UPSET CONDITION				
$P_m \leq S_m$	Normal and Upset Condition Loads:	Primary membrane	16,900	8,580
S_m = 16,900 @ 550° F	1. Normal loads 2. Upset pressure 3. OBE 4. SRV			
$P_L + P_b \leq 1.5\ S_m$		Primary membrane plus bending	25,350	15,270
1.5 S_m = 25,350 @ 550°F				
B. EMERGENCY CONDITION:				
$P_m \leq 1.5\ S_m$	Emergency Condition Loads:	Primary membrane	25,350	14,300
1.5 S_m = 25,350 @ 550°F	1. Normal loads 2. Upset pressure 3. Chugging 4. SRV_{ADS}			
$P_L + P_b \leq 2.25\ S_m$		Primary membrane plus bending	38,030	7,050
2.25 S_m = 38,030 @ 550°F[2]				

Table 3.9-6(b) (Cont'd)

ASME SECTION III, SUBSECTION NG PRIMARY STRESS LIMIT CRITERIA	LOAD CASE NUMBER[1]	PRIMARY STRESS TYPE	MAXIMUM ALLOWABLE STRESS (psi)	CALCULATED STRESS[3] (psi)
C. FAULTED CONDITION:				
$P_m \leq 2.4\ S_m$	Faulted Condition Loads:	Primary membrane	40,560	15,650
$2.4\ S_m$ = 40,560 @ 550° F	1. Normal loads 2. Accident pressure 3. Jet reaction 4. SSE 5. Delta P			
$P_L + P_b \leq 3\ S_m$		Primary membrane plus bending	50,700	25,650
$3\ S_m$ = 50,700 @ 550° F[2]				
D. MAXIMUM CUMULATIVE USAGE FACTOR: 0.257 at Core plate stud				

Table 3.9-6(b) (Cont'd)

ASME SECTION III, SUBSECTION NG PRIMARY STRESS LIMIT CRITERIA	LOAD CASE NUMBER[1]	PRIMARY STRESS TYPE	MAXIMUM ALLOWABLE STRESS (psi)	CALCULATED STRESS[3] (psi)
DIFFERENTIAL PRESSURE AND LIQUID CONTROL LINES				
MATERIAL: 304 S.S.				
A. NORMAL AND UPSET CONDITION:				
$P_m \leq S_m$ S_m = 16,950 @ 550°F	Normal and Upset Condition Loads: 1. OBE 2. SRV			
$P_L + P_b \leq 3\ S_m$ $3\ S_m$ = 50,850 @ 550°F		Primary membrane plus bending plus secondary membrane	49,200	8,654
B. EMERGENCY CONDITION:				
$P_m \leq S_m$ S_m = 16,950 @ 550°F	Emergency Condition Loads: 1. OBE 2. SRV			
$P_L + P_b \leq 2.25\ S_m$ $2.25\ S_m$ = 37,120 @ 550°F[2]		Primary membrane plus bending	36,900	8,654
C. FAULTED CONDITION:				
$P_m \leq S_m$ S_m = 16,950 @ 550°F	Faulted Condition Loads: 1. Annulus pressurization 2. SSE			
$P_L + P_b \leq 3.6\ S_m$ $3.6\ S_m$ = 61,020 @ 550°F[2]		Primary membrane plus bending plus secondary membrane	59,040	15,106

(1) Load cases are defined in Table 3.9-6.
(2) Value of S_m or S_y is shown depending on the controlling criteria (e.g., 1.8 S_m or 1.5 S_y for B)
(3) The loads listed here are associated with the operating level of 3458 MWt. Per Reference 3.9-32, the loads on the differential pressure and liquid control lines are bounding at MUR power uprate condition; the loads on the top guide and core plate are increased but within the allowable limits. Increased loads due to the revised Fuel Lift Margin and CRGT lift forces under MUR conditions are addressed in Reference 3.9-33.

Table 3.9-6(c)

RWCU HEAT EXCHANGERS

REGENERATIVE RWCU HX

Part	Thickness Required (in)	Allowable Stress(psi)	Actual Thickness (in)
Shell	0.779	15900	0.875
Shell head	0.745	15900	0.760
Channel shell	0.780	15900	2.6875
Tube sheet	3.087	15900	3.25
Tubes	0.0427	11950	0.0524
Piping	0.195	15900	0.337
Channel cover	3.09	17500	3.25

NONREGENERATIVE RWCU HX

Part	Thickness Required (in)	Allowable Stress(psi)	Actual Thickness (in)
Shell	0.1171	15000	0.375
Shell head	0.117	17500	0.375
Channel shell	0.7814	15900	2.6815
Channel cover	3.09	17500	3.25
Tube sheet	3.087	13900	3.25
Tubes	0.0561	11950	0.0585
Channel piping	0.185	15900	0.337
Shell piping	0.0608	15900	0.280

Table 3.9-6(d)

ASME CODE CLASS 1 MAIN STEAM PIPING AND PIPE-MOUNTED EQUIPMENT - HIGHEST STRESS SUMMARY

(UNIT 1)

Acceptance Criteria	Limiting Stress Type	Calculated Stress or Usage Factor	Allowable Limits	Ratio Actual/ Allowable	Loading	Identification of Locations of Highest Stress Points - NODG Point Numbers
ASME Section III, NB-3600						
Design Condition:	Primary	15,765	26,550	0.594	1. Pressure 2. Weight 3. OBE	Steam Line D Riser lug (009)
Eq. 9 $\leq$ 1.5 S_m						
Service Levels A & B (Normal & Upset) Condition:						
Eq. 12 $\leq$ 3.0 S_m	Secondary	32,318	54,600	0.59	1. Thermal expansion	Steam Line C Sweepolet (059)
Service Levels A & B (Normal & Upset) Condition:	Primary Plus Secondary (Except	54,509	54,600	0.99	1. Pressure 2. Weight 3. OBE	Steam Line A Sweepolet (063)
Eq. 13 $\leq$ 3.0 S_m	Thermal Expansion)				4. Temperature discontinuity	
Service Levels A & B (Normal & Upset) Conditions:						
Cumulative Usage Factor	N.A.	0.457	1.0		N/A	Steam Line A Sweepolet (063)
Service Level B (Upset) Condition:					1. Pressure 2. Weight 3. OBE	Steam Line D Sweepolet (060)
Eq. 9 $\leq$ 1.8 S_m & 1.5 S_y	Primary	22,453	32,760	0.69	4. SRV (Acoustic wave)	

Table 3.9-6(d) (Cont'd)

(Unit 1)

Acceptance Criteria	Limiting Stress Type	Calculated Stress or Usage Factor	Allowable Limits	Ratio Actual/ Allowable	Loading	Identification of Locations of Highest Stress Points - NODG Point Numbers
Service Level C (Emergency) Condition:					1. Pressure 2. Weight 3. OBE	Steam Line B Sweepolet (500)
Eq. 9 < 2.25 S_m & 1.8 S_y	Primary	22,050	40,950	0.54	4. Chugging	
Service Level D (Faulted) Condition:					1. Pressure 2. Weight 3. SSE	Steam Line B Sweepolet (500)
Eq. 9 < 3.0 S_m	Primary	48,775	54,600	0.89	4. Annulus pressurization	

Table 3.9-6(d) (Cont'd)

(Unit 1)

Component/ Load Type	Highest Calculated Load	Allowable Load	Ratio Calculated/ Allowable	Loading	Identification of Equipment with Highest Loads
Snubber					
Service Level B	44,988	50,000	0.900	OBE + SRV	Steam Line A Snubber - SA9
Service Level C	25,555	66,500	0.384	Chugging + SRV (acoustic wave)	Steam Line B Snubber - SB2
Service Level D	72,874	75,000	0.972	Annulus Pressurization + SSE	Steam Line A Snubber - SA9
Accelerations					
Horizontal Level D	6.314g	6.5g	0.9714	SSE + Condensation + SRV (acoustic wave)	Steam Line D SRV Inlet (086)
Vertical Level D	4.20g	6.0g	0.7	SSE + Condensation + SRV (acoustic wave)	Steam Line B SRV Inlet (075)

Table 3.9-6(d) (Cont'd)

ASME CODE CLASS 1 MAIN STEAM PIPING AND PIPE-MOUNTED EQUIPMENT - HIGHEST STRESS SUMMARY

(UNIT 2)

Acceptance Criteria	Limiting Stress Type	Calculated Stress or Usage Factor	Allowable Limits	Ratio Actual/ Allowable	Loading	Identification of Locations of Highest Stress Points - NODG Point Numbers
ASME Section III, NB-3650						
Design Condition: Eq. 9 $\leq$ 1.5 S_m	Primary	21,333	26,550	0.78	1. Pressure 2. Weight 3. OBE	Steam Line A Riser lug (063)
Service Levels A & B (Normal & Upset) Condition:						
Eq. 12 $\leq$ 3.0 S_m	Secondary	32,318	54,600	0.59	1. Thermal expansion	Steam Line C Sweepolet (059)
Service Levels A & B (Normal & Upset) Condition: Eq. 13 $\leq$ 3.0 S_m	Primary Plus Secondary (Except Thermal Expansion)	54,509	54,600	0.99	1. Pressure 2. Weight 3. OBE 4. Temperature discontinuity	Steam Line A Sweepolet (063)
Service Levels A & B (Normal & Upset) Conditions:						
Cumulative Usage Factor	N.A.	0.457	1.0		N/A	Steam Line A Sweepolet (063)

Table 3.9-6(d) (Cont'd)

(Unit 2)

Acceptance Criteria	Limiting Stress Type	Calculated Stress or Usage Factor	Allowable Limits	Ratio Actual/ Allowable	Loading	Identification of Locations of Highest Stress Points - NODG Point Numbers
Service Level B (Upset) Condition:					1. Pressure 2. Weight 3. OBE	Steam Line D Sweepolet (060)
Eq. 9 $\leq$ 1.8 S_m & 1.5 S_y	Primary	22,453	32,760	0.69	4. SRV (Acoustic wave)	
Service Level C (Emergency) Condition:					1. Pressure 2. Weight 3. OBE	Steam Line B Sweepolet (500)
Eq. 9 < 2.25 S_m & 1.8 S_y	Primary	22,050	40,950	0.54	4. Chugging	
Service Level D (Faulted) Condition:					1. Pressure 2. Weight 3. SSE	Steam Line B Sweepolet (500)
Eq. 9 < 3.0 S_m	Primary	48,715	54,600	0.89	4. Annulus pressurization	

Table 3.9-6(d) (Cont'd)

(Unit 2)

Component/ Load Type	Highest Calculated Load	Allowable Load	Ratio Calculated/ Allowable	Loading	Identification of Equipment with Highest Loads
Snubber					
Service Level B	44,988	50,000	0.900	OBE + SRV	Steam Line A Snubber - SA9
Service Level C	25,555	66,500	0.384	Chugging + SRV (acoustic wave)	Steam Line B Snubber - SB2
Service Level D	72,874	75,000	0.972	Annulus Pressurization + SSE	Steam Line A Snubber - SA9
Accelerations					
Horizontal Level D	6.314g	6.5g	0.9714	SSE + Condensation + SRV (acoustic wave)	Steam Line D SRV Inlet (086)
Vertical Level D	4.20g	6.0g	0.7	SSE + Condensation + SRV (acoustic wave)	Steam Line B SRV Inlet (075)

Table 3.9-6(e)

ASME CODE CLASS 1 RECIRCULATION PIPING AND PIPE-MOUNTED EQUIPMENT - HIGHEST STRESS SUMMARY

(UNIT 1)

Acceptance Criteria	Limiting Stress Type	Calculated Stress or Usage Factor	Ratio Allowable Limits	Actual/ Allowable	Loading	Identification of Locations of Highest Stress Points - NODG Point Numbers[1]
ASME Section III, NB-3650						
Design Condition: Eq. 9 $\leq$ 1.5 S_m	Primary	17,248	20,588	0.84	1. Pressure 2. Weight 3. OBE	Node (028) Recirculation Loop B (Hanger Lugs)
Service Levels A & B (Normal & Upset) Condition: Eq. 12 $\leq$ 3.0 S_m	Secondary	17,745	51,750	0.34	1. Pressure 2. Weight 3. Thermal expansion 4. OBE 5. SRV (structural feedback)	Node (500) Recirculation Loop A (Elbow)
Service Levels A & B (Normal & Upset) Condition: Eq. 13 $\leq$ 3.0 S_m	Primary plus secondary (except thermal expansion)	41,677	51,750	0.81	1. Pressure 2. Weight 3. OBE 4. SRV (structural feedback)	Node (200) Recirculation Loop B (Sweepolet)
Service Levels A & B (Normal and Upset) Condition:						
Cumulative Usage Factor	N.A.	0.25	1.0	0.25		

Table 3.9-6(e) (Cont'd)

(Unit 1)

Acceptance Criteria	Limiting Stress Type	Calculated Stress or Usage Factor	Ratio Allowable Limits	Actual/ Allowable	Loading	Identification of Locations of Highest Stress Points - NODG Point Numbers[1]
Service Level B (Upset) Condition:					1. Pressure 2. Weight 3. OBE	Node (016) Recirculation Loop B
Eq. 9 $\leq$ 1.8 S_m & 1.5 S_y	Primary	19,227	23,472	0.82	4. SRV (structural feedback)	(Small Tee)
Service Level C (Emergency) Condition:					1. Pressure 2. Weight 3. Chugging	Node (016) Recirculation Loop B
Eq. 9 $\leq$ 2.25 S_m & 1.8 S_y	Primary	18,886	28,166	0.67	4. SRV (structural feedback)	(Small Tee)
Service Level D (Faulted) Condition:					1. Pressure 2. Weight 3. SSE	Node (016) Recirculation Loop B
Eq. 9 $\leq$ 3.0 S_m	Primary	24,895	31,296	0.80	4. Annulus pressurization	(Small Tee)

Table 3.9-6(e) (Cont'd)

(Unit 1)

Component/ Load Type	Highest Calculated Load	Allowable Load	Ratio Calculated/ Allowable	Loading	Identification of Equipment with Highest Loads
Snubber Level B	104,265 lb	120,000 lb	0.87	OBE + SRV	Recirculation Loop A (SA 2)
Snubber Level C	20,022 lb	66,500 lb	0.301	Chugging + SRV	Recirculation Loop B (SB 9)
Snubber Level D	71,583 lb	75,000 lb	0.954	Annulus Pressurization + SSE	Recirculation Loop B (SB 9)
Suction Valve Level B	428,263 in-lb	1,747,285 in-lb	0.25	1. Weight 2. Thermal expansion 3. OBE 4. SRV	Recirculation Loop A (suction valve)
Discharge Valve Level C	284,213 in-lb	1,747,285 in-lb	0.16	1. Weight 2. Thermal expansion 3. OBE 4. SRV	Recirculation Loop B (discharge valve)
Discharge Valve Level D	1,438,256 in-lb	1,747,285 in-lb	0.82	1. Weight 2. Thermal expansion 3. Annulus pressurization 4. SSE	Recirculation Loop B (discharge valve)

Table 3.9-6(e) (Cont'd)

ASME CODE CLASS 1 RECIRCULATION PIPING AND PIPE-MOUNTED EQUIPMENT - HIGHEST STRESS SUMMARY

(UNIT 2)

Acceptance Criteria	Limiting Stress Type	Calculated Stress or Usage Factor	Allowable Limits	Ratio Actual/ Allowable	Loading	Identification of Locations of Highest Stress Points - NODG Point Numbers[1]
ASME Section III, NB-3650						
Design Condition: Eq. 9 $\leq$ 1.5 S_m	Primary	18,549	25,875	0.72	1. Pressure 2. Weight 3. OBE	Node (028) Recirculation Loop A (Buttweld)
Service Levels A & B (Normal & Upset) Condition: Eq. 12 $\leq$ 3.0 S_m	Secondary	40,919	51,750	0.79	1. Pressure 2. Weight 3. Thermal expansion 4. OBE 5. SRV (structural feedback)	Node (256) Recirculation Loop A (Transition)
Service Levels A & B (Normal & Upset) Condition: Eq. 13 $\leq$ 3.0 S_m	Primary plus secondary (except thermal expansion)	41,667	51,750	0.81	1. Pressure 2. Weight 3. OBE 4. SRV (structural feedback)	Node (200) Recirculation Loop B (Sweepolet)
Service Levels A & B (Normal and Upset) Condition:						
Cumulative Usage Factor	N.A.	0.098	1.0	0.098		

Table 3.9-6(e) (Cont'd)

(Unit 2)

Acceptance Criteria	Limiting Stress Type	Calculated Stress or Usage Factor	Ratio Allowable Limits	Actual/ Allowable	Loading	Identification of Locations of Highest Stress Points - NODG Point Numbers[1]
Service Level B (Upset) Condition:					1. Pressure 2. Weight 3. OBE	Node (016) Recirculation Loop B
Eq. 9 ≤ 1.8 S_m & 1.5 S_y	Primary	19,227	23,472	0.82	4. SRV (structural feedback)	Small Tee)
Service Level C (Emergency) Condition:					1. Pressure 2. Weight 3. Chugging	Node (016) Recirculation Loop B
Eq. 9 ≤ 2.25 S_m & 1.8 S_y	Primary	18,886	28,166	0.67	4. SRV (structural feedback)	(Small Tee)
Service Level D (Faulted) Condition:					1. Pressure 2. Weight 3. SSE	Node (016) Recirculation Loop B
Eq. 9 ≤ 3.0 S_m	Primary	24,895	31,296	0.80	4. Annulus pressurization	(Small Tee)

Table 3.9-6(e) (Cont'd)

(Unit 2)

Component/ Load Type	Highest Calculated Load	Allowable Load	Ratio Calculated/ Allowable	Loading	Identification of Equipment with Highest Loads
Snubber Level B	52,023 lb	120,000 lb	0.433	OBE + SRV	Recirculation Loop B (SB 2)
Snubber Level C	24,339 lb	159,600 lb	0.153	Chugging + SRV	Recirculation Loop B (SB 2)
Snubber Level D	86,272 lb	180,000 lb	0.479	Annulus Pressurization + SSE	Recirculation Loop B (SB 2)
Discharge Valve Level B	265,030 in-lb	1,747,285 in-lb	0.152	1. Weight 2. Thermal expansion 3. OBE 4. SRV	Recirculation Loop B (discharge valve)
Suction Valve Level C	250,422 in-lb	1,747,285 in-lb	0.143	1. Weight 2. Thermal expansion 3. OBE 4. SRV	Recirculation Loop B (suction valve)
Suction Valve Level D	535,499 in-lb	1,747,285 in-lb	0.307	1. Weight 2. Thermal expansion 3. Annulus pressurization 4. SSE	Recirculation Loop B (suction valve)

(1) Refer to Figure 3.6-4 for the identification of node point numbers.

Table 3.9-6(f)

RPV AND SHROUD SUPPORT ASSEMBLY

ASME SECTION III, SUBSECTION NB PRIMARY STRESS LIMIT CRITERIA	LOAD CASE NUMBER[1]	PRIMARY STRESS TYPE	MAXIMUM ALLOWABLE STRESS (psi)	CALCULATED STRESS[4] (psi)
VESSEL SUPPORT SKIRT				
MATERIAL: SA516, Grade 70				
A. NORMAL AND UPSET CONDITION:				
$P_m \leq S_m$ S_m = 19,150 @ 575°F	Normal and Upset Condition Loads: 1. Normal loads 2. Upset pressure 3. OBE 4. SRV	Primary membrane	19,150	15,553[5]
$P_L + P_b \leq 1.5\ S_m$ 1.5 S_m = 28,725 @ 575°F		Primary membrane plus bending	28,725	21,804[5]
B. EMERGENCY CONDITION:				
$P_m \leq S_y$ S_y = 28,425 @ 546°F	Emergency Condition Loads: 1. Normal loads 2. Upset pressure 3. OBE 4. Chugging 5. SRV_{ADS}	Primary membrane	29,425	20,565
$P_L + P_b \leq 1.5\ S_y$ 1.5 S_y = 44,137 @ 546°F[2]		Primary membrane plus bending	44,150	29,377

Table 3.9-6(f) (Cont'd)

ASME SECTION III, SUBSECTION NB PRIMARY STRESS LIMIT CRITERIA	LOAD CASE NUMBER[1]	PRIMARY STRESS TYPE	MAXIMUM ALLOWABLE STRESS (psi)	CALCULATED STRESS[4] (psi)
C. FAULTED CONDITION:				
$P_m \leq 2.4\ S_m$ $2.4\ S_m = 45{,}960$ @ 575°F	Faulted Condition Loads: 1. Normal loads 2. Accident pressure 3. Jet reaction 4. VC 5. SSE	Primary membrane	45,960	30,866[5]
$P_m + P_b \leq 3.6\ S_m$ $3.6\ S_m = 68{,}940$ @ 575°F[2]	1. Normal loads 2. Accident pressure 3. Chugging 4. SRV_{ADS} 5. SSE	Primary membrane plus bending	68,940	45,778[5]
D. MAXIMUM CUMULATIVE USAGE FACTOR: 0.83 at Skirt base junction				

Table 3.9-6(f) (Cont'd)

ASME SECTION III, SUBSECTION NB PRIMARY STRESS LIMIT CRITERIA	LOAD CASE NUMBER[1]	PRIMARY STRESS TYPE	MAXIMUM ALLOWABLE STRESS (psi)	CALCULATED STRESS[4] (psi)
SHROUD SUPPORT				
MATERIAL: SB168 Inconel				
A. NORMAL AND UPSET CONDITION:				
$P_m \leq S_m$	Normal and Upset Condition Loads:	Primary membrane	23,300	21,700
S_m = 23,300 @ 575°F	1. Dead weight 2. OBE			
$P_L + P_b \leq 1.5\ S_m$		Primary membrane plus bending	34,950	33,640
1.5 S_m = 34,950 @ 575°F				
B. EMERGENCY CONDITION:				
$P_m \leq S_y$	Emergency Condition Loads:	Primary membrane	28,120	25,440
S_y = 28,120 @ 575°F	1. Dead weight 2. SSE 3. Jet reaction			
$P_L + P_b \leq 1.5\ S_y$		Primary membrane plus bending	42,180	40,360
1.5 S_y = 42,180 @ 575°F[2]				

Table 3.9-6(f) (Cont'd)

ASME SECTION III, SUBSECTION NB PRIMARY STRESS LIMIT CRITERIA	LOAD CASE NUMBER[1]	PRIMARY STRESS TYPE	MAXIMUM ALLOWABLE STRESS (psi)	CALCULATED STRESS[4] (psi)
C. FAULTED CONDITION:				
$P_m \leq S_y$	Faulted Condition Loads:	Primary membrane	28,120	25,440
S_y = 28,120 @ 575°F	1. Dead weight 2. SSE 3. Jet reaction			
$P_L + P_b \leq 1.5\ S_y$		Primary membrane plus bending	42,180	40,360
1.5 S_y = 42,180 @ 575?F[2]				
D. MAXIMUM CUMULATIVE USAGE FACTOR: 0.373 at point 24 in shroud support plate				

Table 3.9-6(f) (Cont'd)

ASME SECTION III, SUBSECTION NB PRIMARY STRESS LIMIT CRITERIA	LOAD CASE NUMBER[1]	PRIMARY STRESS TYPE	MAXIMUM ALLOWABLE STRESS (psi)	CALCULATED STRESS[4] (psi)
RPV FEEDWATER NOZZLE				
MATERIAL: SA508 Class 1 Safe-end				
A. NORMAL AND UPSET CONDITION				
$P_m \leq S_m$ S_m = 17,700 @ 575°F	Normal and Upset Condition Loads: 1. Normal loads 2. Upset pressure 3. OBE 4. SRV	Primary membrane	17,700	16,220
$P_L + P_y \leq 1.5\ S_m$ 1.5 S_m = 26,550 @ 575°F		Primary membrane plus bending	26,550	22,930
B. EMERGENCY CONDITION				
$P_m \leq S_y$ S_y = 25,900 @ 594°F	Emergency Condition Loads: 1. Normal loads 2. Upset pressure 3. Chugging 4. SRV_{ADS}	Primary membrane	25,900	21,420
$P_L + P_b \leq 1.5\ S_y$ 1.5 S_y = 38,900 @ 594°F[2]		Primary membrane plus bending	38,850	22,400

Table 3.9-6(f) (Cont'd)

ASME SECTION III, SUBSECTION NB PRIMARY STRESS LIMIT CRITERIA	LOAD CASE NUMBER[1]	PRIMARY STRESS TYPE	MAXIMUM ALLOWABLE STRESS (psi)	CALCULATED STRESS[4] (psi)
C. FAULTED CONDITION				
$P_m \leq 2.4\ S_m$	Faulted Condition Loads:	Primary membrane	42,480	23,210
$2.4\ S_m$ = 42,480 @ 575°F	1. Normal loads 2. Accident pressure 3. Chugging 4. SSE 5. SRV_{ADS}			
$P_L + P_b \leq 1.5\ S_y$		Primary membrane plus bending	38,850	33,740
$1.5\ S_y$ = 38,900 @ 594°F[2]				
D. MAXIMUM CUMULATIVE USAGE FACTOR: 0.9957 at Safe-end				

Table 3.9-6(f) (Cont'd)

ASME SECTION III, SUBSECTION NB PRIMARY STRESS LIMIT CRITERIA	LOAD CASE NUMBER[1]	PRIMARY STRESS TYPE	MAXIMUM ALLOWABLE STRESS (psi)	CALCULATED STRESS[4] (psi)
CRD PENETRATION (Stub Tube)				
MATERIAL: SB167 - Inconel				
A. NORMAL AND UPSET CONDITION:				
$P_m \leq S_m$ $S = 20{,}000$ @ 575°F	Normal and Upset Condition Loads: 1. Normal leads 2. Upset pressure 3. OBE 4. SRV	Primary membrane	20,000	12,616[5]
$P_L + P_b \leq 1.5\ S_m$ $1.5\ S_m = 30{,}000$ @ 575°F		Primary membrane plus bending	30,000	28,200
B. EMERGENCY CONDITION:				
$P_m \leq S_y$ $S_y = 24{,}100$ @ 575°F	Emergency Condition Loads: 1. Normal loads 2. Upset pressure 3. Chugging 4. SRV_{ADS}	Primary membrane	24,100	6,755
$P_L + P_b \leq 1.5\ S_y$ $1.5\ S_y = 36{,}150$ @ 575°F[2]		Primary membrane plus bending	36,150	30,260

Table 3.9-6(f) (Cont'd)

ASME SECTION III, SUBSECTION NB PRIMARY STRESS LIMIT CRITERIA	LOAD CASE NUMBER[1]	PRIMARY STRESS TYPE	MAXIMUM ALLOWABLE STRESS (psi)	CALCULATED STRESS[4] (psi)
C. FAULTED CONDITION:				
$P \leq 2.4\ S_m$	Faulted Condition Loads:	Primary membrane	48,000	9,131[5]
$2.4\ S_m$ = 48,000 @ 575°F	1. Normal loads 2. Accident pressure 3. Jet reaction 4. Scram 5. SSE			
$P_L + P_b \leq 3.6\ S_m$		Primary membrane plus bending	72,000	30,260
$3.6\ S_m$ = 72,000 @ 575°F[2]				
D. MAXIMUM CUMULATIVE USAGE FACTOR: 0.192[5] at Stub tube				

(1) Load cases are defined in Table 3.9-6.
(2) Value of S_m or S_y is shown depending on the controlling criteria (e.g., 1.8 S_m or 1.5 S_y for B).
(3) Maximum calculated values are based on design loads because they are greater than new loads.
(4) The loads here correspond to the operating power level of 3458 MWt. Per Reference 3.9-31, the loads for the vessel support skirt, feedwater nozzle and the CRD penetration are not changed as a result of MUR power uprate. Per Reference 3.9-32, the loads on the shroud support are bounding at MUR power uprate condition.
(5) Numerical values can be found in Reference 3.9-38. Per Reference 3.9-38, these values are based off CLTP of 3515 MWt.

Table 3.9-6(g)

MAIN STEAM SAFETY/RELIEF VALVES (PILOT-OPERATED)
(ASME SECTION III, 1968, Including Addenda through Summer 1970)

Topic	Method of Analysis	Target Rock 9867F Analysis	Allowable Value	Calculated
1. Body inlet and outlet flange stresses Note, Topics 1 and 2: Design Pressures: P_d = 1250 psig (inlet) P_b = 500 psig (outlet) Analyses include applied moments of M = 409,000 in-lb (inlet) and M = 372,000 in-lb (outlet) Actual tested capability (including accelerations and moments) is as described in Topic No. 11. The analyses also include consideration of seismic, operational, and flow reaction forces. Allowable vs. tested capabilities are provided in Topic No. 12	$S_H = \frac{fM_o}{Lg^2B} + \frac{PB}{4g_o} < 1.5\ S_m$ $S_R = \frac{(4te/3+1)M_o}{Lt^2B} < 1.5\ S_m$ $S_T = \frac{YM_o}{t^2B} - Z\ S_R < 1.5\ S_m$ where: S_H = Longitudinal "hub" wall stress, psi S_R = Radial "flange" stress, psi S_T = Tangential "flange" stress, psi Body Material: A105 Grade II S_m = 19,400 psi (500°F, equivalent inlet and outlet temperature)	P_D (Target Rock) = P (codes)	1.5 S_m = 29,100 psi	Inlet: S_H = 27,656 psi S_R = 15,295 psi S_T = 14,257 psi Outlet: S_H = 15,591 psi S_R = 23,614 psi S_T = 557 psi

Table 3.9-6(g) (Cont'd)

Topic	Method of Analysis	Target Rock 9867F Analysis	Allowable Value	Calculated
2. Inlet and outlet stud area requirements	Total cross-sectional area excees the greater of: $Am_1 = \frac{Wm_1}{S_b}$, or $Am_2 = \frac{Wm_2}{S_a}$,	$Am_1 = \frac{Wm_1}{S_b}$ $Am_2 = \frac{Wm_2}{S_a}$ *	Inlet: Am_1 (>Am_2) = 8.15 in^2 Outlet: Am = 5.39 in^2	Inlet: A_b (actual area) = 13.85in^2 Outlet: A_b = 9.68 in^2
	where: Am_1 = total required bolt (stud) area for operating condition Am_2 = total required bolt (stud) area for gasket seating	Bolting Material: SA193 Grade B7 *Where AM (required minimum) is the greater of Am_1 and Am_2; and A_b (actual bolt area) must exceed Am.		
3. Body Wall thickness	1. Valve Wall Thickness Criterion:	Section at inlet:		t_{ACT} = 1.098 in.
	$t_{min.} < t_A$ where: $t_{min.}$ = minimum calculated thickness requirement, including corrosion allowance. t_A = Actual wall thickness (NOTE: This $t_{min.}$ is t_m per notation of the codes.)	$t_{RQD} < t_{ACT}$ Section at middle of body $t_{RQD} < t_{ACT}$ [c] Section at outlet: $t_{RQD} < t_{ACT}$ Section at neck: $t_{RQD} < t_{ACT}$	t_{RQD} = 0.7 in Actual thickness greater than t_m at the section under consideration.	t_{ACT} [c] = 0.805 in. t_{ACT} = 1.359 in. t_{ACT} = 0.953 in.

Table 3.9-6(g) (Cont'd)

Topic	Method of Analysis	Target Rock 9867F Analysis	Allowable Value	Calculated
3. (Cont'd)	Cycle Rating: Thermal $I_t = \Sigma \frac{N_{ri}}{N_i}$ Fatigue Na > 2,000 cycles, as based on S_a, where S_a is defined as the larger of $S_p = (2/3)Q_p + \frac{P_{eb}}{2}$ $_1$ $+ Q_T + 1.3Q_T$ $_2$ $_1$ or $S_P = 0.4\ Q_p + \frac{K(P_{eb}+2Q_T)}{2}$ $_2$ $_2$ where: Sp = Fatigue stress intensity at [1] inside surface of crotch psi Sp = Fatigue stress intensity [2] outside surface of crotch psi	$I_t = \Sigma \frac{N_{ri}}{N_i}$ (i = 1, 2 & 3) Na ≥ 2,000 cycles as based on $S_A = S_p$ ($>S_p$), where S_A (Target $_2$ $_3$ Rock) = S_a (codes) { Uses same notation as codes }	I_t (max.) ≤ 1.0 Na ≥ 2,000 cycles	I_t = 0.518 Na (based on S_p) $_2$ = 1.5×10^5 cycles ∴ satisfies criterion

Table 3.9-6(g) (Cont'd)

Topic	Method of Analysis	Target Rock 7567F Analysis	Allowable Value	Calculated
4. Body to pilot base Flange Stresses (body side)	$S_H = \frac{PB_1}{1} \pm \frac{6M_H}{4g_1 \quad \pi B_1 g^2_1}$ (longitude hub stress adjacent to flange)	$S_H < 1.5\ S_m$ $S_R < 1.5\ S_m$ $S_T < 1.5\ S_m$	1.5 S_m = 29,100 psi	S_H = 19,590 psi
	$S_H = \left(\frac{Q}{\pi B_1 t} + P\right)\left(Z + Y\right)$ $+ \frac{Et\theta_B}{B_1}$	P_{FD} (Target Rock) = P (codes)		S_R = 11,851 psi
	$+ \frac{0.075\ PB_1}{g_1} \pm \frac{1.8\ M_H}{\pi B_1 g^2_1}$ (circumferential stress in hub adjacent to flange)	Material: SA-105 Grade II		S_T = 6,364 psi
	$S_R = \frac{6(M_p + M_s)}{t^2(\pi C - nD)}$ (@ Bolt circle) $S_R = \left(\frac{Q}{\pi B_1 t} + P\right) \pm \frac{6M_s}{\pi B_1 t^2}$ (adjacent to hub)	S_m = 19,400 psi (@ 500°F)		
	$ST = \left(\frac{Q}{\pi B_1 t} + P\right)Z \pm \left(\frac{Et\theta_B}{B_1} + \frac{1.8M_S}{\pi B_1 t^2}\right)$			
Bonnet Flange Stresses (Bonnet side)	Base side flange stresses less than body side flange stresses (Both sides see identical loads. The base side is thicker than the body side at all points.)	Same as Topic 4 Analysis	1.5 S_m = 29,000 psi	S_H 19,590 psi S_R 11,851 psi S_T 6,364 psi

Table 3.9-6(g) (Cont'd)

Topic	Method of Analysis	Target Rock 9867F Analysis	Allowable Value	Calculated
6. Base of pilot body stud area requirements	Total cross-sectional area shall exceed: $Am_1 = \frac{Wm_1}{S_b}$ where: Am_1 = Total required bolt (stud) area.	$Am_1 = \frac{Wm_1}{S_b}$ Bolting Material: SA193 Grade B16	Am_1 = 7.10 in^2	A_b (actual) = 9.04 in^2
7. Pilot body wall thickness	Body Wall Per ASME Section VIIII $T_m = \frac{P R_i}{S_m - 0.5 P}$	$t_m < t_a$ Material: SB-166 Grade 600 Sm = 23,300 psi (@500°F)	Bonnet Wall t_m = .085 in	Bonnet Wall t_a = 3.22 in.
10. Main disc stress	Using Roark's formulas for stress and strain, 4th edition, page 250 $S_{max} = \frac{\beta W a^2}{t_o^2}$ where: $\beta = 1.63$ w = applied load a = radius of disc t_o = thickness at center	$S_{max} < S_m$ Material: SA182 S_m = 13,000 psi (@ 500°F)	S_m = 13,600 psi 1.55m = 19,500 psi	S_{max} = 18,180 psi
11. Seismic Capability: Stress analysis uses $F_{vertical}$ = (mass of value) • (2.0 g) and $F_{horizontal}$ = (mass of value) • (3.0 g), with concurrent 409,000 in-lb and 372,000 in-lb applied at the inlet and outlet, respectively. Valve operability has been verified by test, with applied moments of 800,000 in-lb and 600,000 in-lb at the inlet and outlet, respectively, and at equivalent acceleration levels of 6.5 g horizontal and 6.0 g vertical. Tests were per IEEE 344 (1975).				
12. Valve Loads: For comparison of calculated loadings vs. seismic capability see Table 3.9-6(e).				

Table 3.9-6(h)

MAIN STEAM ISOLATION VALVE

(UNIT 1)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
Design of Pressure-Retaining Parts	All references are made to ASME Code for Pumps and Valves for Nuclear Power, dated November 1968. Reference the same code for explanation of the symbols used.		
Body Minimum Wall Thickness	Reference Article 452.1b(2), Nonstandard Pressure - Rated Value. Table NB 451.4 For design condition of 1,250 psig and 575°F. The primary service rating = 655 based on a core diameter of 23 in		
	t_m = 1.925 in (including a corrosion allowance of 0.12 in).	1.925 in	1.9375 in
Body Shape Rules	Reference Article 452.2, Body Shape Rules		
Radius of Crotch	Reference Article 452.2a(1), Radius of Crotch. Criterion: $r_2 \geq 0.3\ t_m$; r_2 = 1.0 in, t_m = 1.925 (0.3 · 1.925) = 0.578 <1.0; criterion satisfied.	0.578 in	1.0 in
Out of Roundness	Reference Article 452.2e. Since no ovality was built into the valve body, the requirements of this article are satisfied.	Not applicable	Not applicable
Flat wall Limitation	Reference Article 452.2g, Flat Wall Limitation. Since no flat sections were built into the valve body design, the requirements of this article are satisfied.	Not applicable	Not applicable
Primary Crotch Stress Due to Internal Pressure	Reference Article 452.3 Criterion: $P_m = (A_f/A_m + 0.5)\ P_s < S_m$		
	where A_f = 504 in^2, A_m = 58 in^2, P_s = 1,375 psig, P_m = 12,650 psi, S_m = 19,400 psi; since $S_m > P_m$ criterion satisfied.	19,400 psi	12,650 psi
Valve Body Secondary Stress	Reference Article 452.4		
Primary Plus Secondary Stress Due to Internal Pressure	Reference Article 452.4a $Q_p = C_p\ (r_i/t_e + 0.5)\ P_s\ C_a$		
	where C_p = 3, r_i = 11.625 in, P_s = 1,375 psi, t_e = 2.75 for wye-type valve C_a = 1.33 ---> Q_p = 25,965 psi		

Table 3.9-6(h) (Cont'd)

(Unit 1)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
Secondary Stress Due to Pipe Reaction	Reference Article 452.4b, figures 452.4b(3), 452.4b(4), 452.4b(5)		
Direct or Axial Load Effect	$P_{ed} = F_d S/G_d$ where S = 30,750, F_d = 30 in^2, G_d = 183 in^2	19,400 psi	5,040 psi
	---> P_{ed} = 5,040 psi		
Bending Load Effect	$P_{eb} = C_b F_b S/G_b$ where S = 30,750, F_b = 340 in^3,		
	i.d. = 23.25 in, r_i = 11.625, t_e = 2.75, $\bar{Y}$ = 13.90 in as t_e/r = .197 > .19 ---> C_b = 1		
	$G_b = I/(r_i + t_e)$ where I = 15,028 in^4, r_i = 11.625 in,		
	t_e = 2.75 in ---> G_b = 1052 in^3		
	---> P_{eb} = 9,940 psi	19,940 psi	9,940 psi
Torsion Load Effect	Reference Article 452.4b		
	$P_{et} = 2 F_b S/G_t$ where F_b = 340 in^3, S = 30,750 psi		
	G_t = 2,162 in^3	19,400 psi	9,670 psi
	P_{et} = 9,670 psi		

Table 3.9-6(h) (Cont'd)

(Unit 1)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
Thermal Secondary Stress at Crotch Region	Reference Article 452.4C, figures 452.4C(4), 452.4C(3), 452.4C(5) $Q_T = Q_{T_1} + Q_{T_2}$ where $Te_1 = 3$ in, $Q_T = 1{,}100$ psi $Q_{T_2} = C_6C_2\Delta T_2$ where $C_2 = .21$, $C_6 = 220$, and $T_2 = 5.6$ $Q_{T_2} = 260$ psi, $Q_T = 1{,}360$ psi Criterion: $S_N = Q_{P_2} + P_e = 2Q_T \leq 3 S_m$ where $Q_p = 25{,}965$, $P_e = 9{,}940$, $Q_T = 1360$ as $38{,}625 \leq 58{,}200$; criterion satisfied	58,200 psi	38,625 psi
Normal Duty Valve Fatigue Requirements	Reference Article 452.5, figure 452.5(a) Criterion $N_a \geq 2{,}000$ cycles $S_{p_1} = 2/3\ Q_p + P_{eb}/2_2 + Q_{T_1} + 1.3\ Q_T$, $S_{p_2} = 0.4\ Q_p + (K/2)_2 (P_{eb} + 2Q_T)$ where $Q_p = 25{,}965$, $P_{eb} = 9{,}940$ K-2, $Q_{T_1} = 1{,}160$, $Q_{T_2} = 260$ psi $\rightarrow S_{p_1} = 23{,}970$, $S_{p_2} = 20{,}845$, S_a equal to the larger of S_{p_1} and S_{p_2} $\rightarrow S_a = 23{,}970$ psi $\rightarrow$ $N_a = 55{,}000 \geq 2{,}000$; criterion satisfied		

Table 3.9-6(h) (Cont'd)

(Unit 1)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
Cyclic Loading Requirements at Valve Crotch	Reference Article 454 Thermal Transients Not Excluded by Code Criterion: $?(N_{fi}/N_i) < 1$ Calculate the fatigue usage factor (I_t) as follows: S_n Max = $Q_p + P_{eb} + C_6 (C_3 + C_4) \Delta T_f$ max ---> S_n max = 105,810 psi for ΔT_{fi} = 90, N_{fi} = 120, N_i = 2,700 N_{fi}/N_i = 0.044 for ΔT_{fi} = 122, N_{fi} = 10, N_i = 1,600 N_{fi}/N_i = 0.006 for ΔT_{fi} = 342, N_{fi} = 8, N_i = 55 N_{fi}/N_i = 0.143 -->$I_t = ?(N_{fi}/N_i)$ = 0.196 < 1; criterion satisfied		

Table 3.9-6(h) (Cont'd)

(Unit 1)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
Disk Design Calculation	From Reference 3.9-5, Pages 198, 200, 201 Disk design conditions, P_S = 1,250 psi at 575°F, S_m = 17,800 psi at 600°F		
	Case No. 13: $S_t = \frac{3W}{4mt^2 (a^2-b^2)} [a^4 (3m + 1) + b^4 (m - 1) -$ $4m\, a^2b^2 - 4(m + 1)\, a^2b^2 (1n(a/b))]$ where W = 1,250 psi, m = 10/3, t = 5.625 in, a = 10.75 in, b = 1.75 in, $S_{t_{13}}$ = 10,354 psi		
	Case No. 14: $S = \frac{3W}{2\pi mt^2} \frac{[2a^2 (m + 1)}{a^2 - b^2} 1n(a/b) + (m - 1)]$ where W = 59,044 lb_f, t = 5.625 in, m = 10/3, a = 10.75 in, b = 1.75 in, $S_{t_{14}}$ = 4,943 psi	17,800 psi	15,297 psi
	Case No. 21: $S_r = \frac{3W}{4t^2} \frac{[4a^4(m + 1) 1n(a/b)\, a^4(m + 3) + b^4(m - 1) + 4a^2b^2]}{a^2(m + 1) + b^2(m - 1)}$ where W = 1,250, m = 10/3, t = 3.125 in, a = 10.75 in, b = 7.25 in --> $S_{r_{21}}$ = 5760 psi		
	Case No. 22: $S_r = \frac{3W}{2t^2} \frac{[2a^2(m + 1) 1n(a/b) + a^2(m - 1) - b^2(m - 1)]}{a^2(m + 1) + b^2(m - 1)}$ where W = 1,250, m = 10/3, t = 3,125, a = 10.75, b = 7.25 --> $S_{r_{22}}$ = 10,740 psi		
	Total stress = $S_{r_{21}} + S_{r_{22}}$ = 16,500 psi, allowable stress = 17,800 psi	17,800 psi	16,500 psi

Table 3.9-6(h) (Cont'd)

(Unit 1)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
Tensile Stress at Thread Relief Valve Stem	Valve open $S_A = F/A_t$ where F = 31,586 lbs, A_t = 1,956 in^2, S_{max} = 16,148 psi		
	Valve Closed F = 46,342 lbs S_{max} = 23,692 psi	30,600 psi	23,692 psi
Bonnet Design Calculations Including Seismic Accelerations For SSE	Paragraph UG-34c(2) on ASME Code Section VIII		
Minimum Thickness	$P_{fd} = P + P_{eg}$, $P_{eg} = \frac{16M}{\pi G^3} + \frac{4F}{\pi G^2}$		
	where M = 1,292,000 in-lbs, F = 53,739 lbs, G = 24.75 in		
	P_{eg} = 546 psi, P_{fd} = 1,796 psi		
	$t = d\left(\frac{CR}{1.5S} + \frac{1.78\ W\ hg}{1.5\ S_d{}^3}\right)^{1/2}$		
	where C = 0.3, P_{fd} = 1,459 psi, S = 17,800 psi, hg = 2.625 in, W = 1,120,000 lbs, d = 24.75 in -->t = 4.503 in, t = 4.503 + 0.120 = 4.623 in (corrosion allowance is 0.120 in)	4.623 in	5.344 in
Reinforcement	Reference paragraph I-704.41(c) of USAS B31-7 to account for the opening for stem in the bonnet Required reinforcement d x t x 0.5 = $(d_3t_3 = d_4t_4)/2$ d_3 = 1.875, t_4 = 2.223, t_3 = 2.875, d_4 = 3 Reinforcement = 6.030 in^2 required = 6.6126 in^2 available	6.030 in^2	6.6126 in^2
Bonnet Studs Design Calculation	Reference Article E-1000 Bolt used 20 pieces of 2.652 in^2/bolts Total bolt area = 53.04 in^2		
Normal Operation	1. Pressure stress at Operating Condition $S_1 = W_{m1}/A_b$ = 21,116 psi where W_{m1} = 1,120,000 lbs and A_b = 53.04 in^2	27,700 psi	21,116 psi

Table 3.9-6(h) (Cont'd)

(Unit 1)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
	2. Gasket load at ambient condition with no internal pressure $S_2 = W_{m2}/A_b$ = 2,019 psi where W_{m2} = 107,065 lb_f and A_b = 53.04 in^2 Maximum tensile stress = 21,116 psi Thermal-stress is assumed negligible because the coefficients of thermal expansion of bonnet place and stud are the same.	35,000 psi	2,019 psi
Body Flange Design Calculations	Reference paragraph I-704.5.1 of USAS B 317 Total flange moment under operating conditions $M_O = M_D + M_G + M_T$ $M_D = H_D h_D$, $H_D = 0.785 B^2P$, $h_D = R + 0.591$ where B = 21.75, P = 1,796 psi --> H_D = 667,290 lb_f, h_D = 2.813 in, M_D = 1,877,000 in-lbs $M_G = H_G h_g$, $H_G = W - H$, $h_G = \frac{C-G}{2}$ where W is the higher of W_{m1} and W_{m2} W_{m1} = 1,120,000 lbs W_{m2} = 107,065 lbs H_G = 256,392 lbs, h_G = 2.625 in -->M_G = 673,000 in-lbs $M_T = H_T h_T$ H_T = 196,775 lbs, h_T = 3.375 in, M_T = 664,000 in-lb_f M_o = 3,214,000 in-lbs Total flange moment under gasket seating condition $M_o = W(C-G)/2$, $W = S_a(A_m + A_b)/2$ where C = 30 in, A_b = 53.04 in^2, G = 24.75 in, A_m = 32.857 in^2, s_a = 35,000 psi at 100°F --->W = 1,503,193 lbs ---> M_o = 3,945,895 in-lbs		

Table 3.9-6(h) (Cont'd)

(Unit 1)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
Longitudinal Hub Stress	$S_H = fM_o/((LS_1)^2B) + PB/(4g_o) = 22{,}317$ psi $< 1.5\ S_{fo} = 26{,}700$ psi	26,700 psi	22,317 psi
Radial Stress	Reference UA-51 (1), Equation (7) of Section VIII of ASME B&PV Code, 1971 Edition		
	$S_R = \frac{(1.33\ t_e+1)M_o}{Lt^2B} = 13{,}132$ psi $< 1.5\ S_{fo} = 26{,}700$ psi	26,700 psi	13,132 psi
Tangential	$S_T = \frac{(YM_o)}{t^2B} - ZS_R = 7{,}563$ psi $< 1.5\ S_{fo} = 26{,}700$		
	where Y = 4.5, t = 4.125 in, z = 2.4, B = 21.75 in	26,700 psi	7,563 psi

Table 3.9-6(h) (Cont'd)

MAIN STEAM ISOLATION VALVE

(UNIT 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
Design of Pressure-Retaining Parts	All references are made to ASME Code for Pumps and Valves for Nuclear Power, dated November 1968. Reference the same code for explanation of the symbols used.		
Body Minimum Wall Thickness	Reference Article 452.1b(2), Nonstandard Pressure - Rated Value. Table NB 451.4 For design condition of 1,250 psig and 575°F. The primary service rating = 655 based on a core diameter of 23 in		
	t_m = 1.925 in (including a corrosion allowance of 0.12 in).	1.925 in	1.9375 in
Body Shape Rules	Reference Article 452.2, Body Shape Rules		
Radius of Crotch	Reference Article 452.2a(1), Radius of Crotch. Criterion: $r_2 \geq 0.3\ t_m$; r_2 = 1.0 in, t_m = 1.925 $(0.3 \cdot 1.925) = 0.578 < 1.0$; criterion satisfied.	0.578 in	1.0 in
Out of Roundness	Reference Article 452.2e. Since no ovality was built into the valve body, the requirements of this article are satisfied.	Not applicable	Not applicable
Flat wall Limitation	Reference Article 452.2g, Flat Wall Limitation. Since no flat sections were built into the valve body design, the requirements of this article are satisfied.	Not applicable	Not applicable
Primary Crotch Stress Due to Internal Pressure	Reference Article 452.3 Criterion: $P_m = (A_f/A_m + 0.5)\ P_s < S_m$		
	where A_f = 504 in^2, A_m = 58 in^2, P_s = 1,375 psig, P_m = 12,650 psi, S_m = 19,400 psi; since $S_m > P_m$, criterion satisfied.	19,400 psi	12,650 psi
Valve Body Secondary Stress	Reference Article 452.4		
Primary Plus Secondary Stress Due to Internal Pressure	Reference Article 452.4a $Q_p = C_p\ (r_i/t_e + 0.5)\ P_s\ C_a$		
	where C_p = 3, r_i = 11.625 in, P_s = 1,375 psi, t_e = 2.75 for wye-type valve C_a = 1.33 ---> Q_p = 25,965 psi		

Table 3.9-6(h) (Cont'd)

(Unit 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
Secondary Stress Due to Pipe Reaction	Reference Article 452.4b, figures 452.4b(3), 452.4b(4), 452.4b(5)		
Direct or Axial Load Effect	$P_{ed} = F_d S/G_d$ where S = 30,750, F_d = 30 in^2, G_d = 183 in^2	19,400 psi	5,040 psi
	---> P_{ed} = 5,040 psi		
Bending Load Effect	$P_{eb} = C_b F_b S/G_b$ where S = 30,750, F_b = 340 in^3,		
	i.d. = 23.25 in, r_i = 11.625, t_e = 2.75, $\bar{r}$ = 13.90 in as t_e/r = .197 > .19 ---> C_b = 1		
	$G_b = I/(r_i + t_e)$ where I = 15,028 in^4, r_i = 11.625 in,		
	t_e = 2.75 in ---> G_b = 1052 in^3		
	---> P_{eb} = 9,940 psi	19,940 psi	9,940 psi
Torsion Load Effect	Reference Article 452.4b		
	$P_{et} = 2 F_b S/G_t$ where F_b = 340 in^3, S = 30,750 psi		
	G_t = 2,162 in^3	19,400 psi	9,670 psi
	P_{et} = 9,670 psi		

Table 3.9-6(h) (Cont'd)

(Unit 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
Thermal Secondary Stress at Crotch Region	Reference Article 452.4C, figures 452.4C(4), 452.4C(3), 452.4C(5) $Q_T = Q_{T_1} + Q_{T_2}$ where $Te_1 = 3$ in, $Q_T = 1{,}100$ psi $Q_{T_2} = C_6 C_2 \Delta T_2$ where $C_2 = .21$, $C_6 = 220$, and $T_2 = 5.6$ $Q_{T_2} = 260$ psi, $Q_T = 1{,}360$ psi Criterion: $S_N = Q_{P_2} + P_e = 2Q_T \leq 3 S_m$ where $Q_p = 25{,}965$, $P_e = 9{,}940$, $Q_T = 1360$ as 38,625 ≤ 58,200; criterion satisfied	58,200 psi	38,625 psi
Normal Duty Valve Fatigue Requirements	Reference Article 452.5, figure 452.5(a) Criterion $N_a \geq 2{,}000$ cycles $S_{p_1} = 2/3\ Q_p + P_{eb}/2_2 + Q_{T_1} + 1.3\ Q_T$, $S_{p_2} = 0.4\ Q_p + (K/2)_2 (P_{eb} + 2Q_T)$ where $Q_p = 25{,}965$, $P_{eb} = 9{,}940$ K-2, $Q_{T_1} = 1{,}160$, $Q_{T_2} = 260$ psi --> $S_{p_1} = 23{,}970$, $S_{p_2} = 20{,}845$, S_a equal to the larger of S_{p_1} and S_{p_2} ---> $S_a = 23{,}970$ psi ---> $N_a = 55{,}000 \geq 2{,}000$; criterion satisfied		

Table 3.9-6(h) (Cont'd)

(Unit 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
Cyclic Loading Requirements at Valve Crotch	Reference Article 454 Thermal Transients Not Excluded by Code Criterion: $?(N_{fi}/N_i) < 1$ Calculate the fatigue usage factor (I_t) as follows: S_n Max = $Q_p + P_{eb} + C_6 (C_3 + C_4) \Delta T_f$ max ---> S_n max = 105,810 psi for ΔT_{fi} = 90, N_{fi} = 120, N_i = 2,700 N_{fi}/N_i = 0.044 for ΔT_{fi} = 122, N_{fi} = 10, N_i = 1,600 N_{fi}/N_i = 0.006 for ΔT_{fi} = 342, N_{fi} = 8, N_i = 55 N_{fi}/N_i = 0.143 -->$I_t = ?(N_{fi}/N_i) = 0.196 < 1$; criterion satisfied		

Table 3.9-6(h) (Cont'd)

(Unit 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
Disk Design Calculation	From Reference 3.9-5, Pages 198, 200, 201 Disk design conditions, P_S = 1,250 psi at 575°F, S_m = 17,800 psi at 600°F		
	Case No. 13: $S_t = \frac{3W}{4mt^2(a^2-b^2)}[a^4(3m+1)+b^4(m-1)-4m a^2b^2-4(m+1)a^2b^2(1n(a/b))]$ where W = 1,250 psi, m = 10/3, t = 5.625 in, a = 10.75 in, b = 1.75 in, $S_{t_{13}}$ = 10,354 psi		
	Case No. 14: $S = \frac{3W}{2\pi mt^2}\left[\frac{2a^2(m+1)}{a^2-b^2}1n(a/b)+(m-1)\right]$ where W = 59,044 lb_f, t = 5.625 in, m = 10/3, a = 10.75 in, b = 1.75 in, $S_{t_{14}}$ = 4,943 psi	17,800 psi	15,297 psi
	Case No. 21: $S_r = \frac{3W}{4t^2}\cdot\frac{[4a^4(m+1)1n(a/b)a^4(m+3)+b^4(m-1)+4a^2b^2]}{a^2(m+1)+b^2(m-1)}$ where W = 1,250, m = 10/3, t = 3.125 in, a = 10.75 in, b = 7.25 in --> $S_{r_{21}}$ = 5760 psi		
	Case No. 22: $S_r = \frac{3W}{2t^2}\cdot\frac{[2a^2(m+1)1n(a/b)+a^2(m-1)-b^2(m-1)]}{a^2(m+1)+b^2(m-1)}$ where W = 1,250, m = 10/3, t = 3,125, a = 10.75, b = 7.25 --> $S_{r_{22}}$ = 10,740 psi		
	Total stress = $S_{r_{21}} + S_{r_{22}}$ = 16,500 psi, allowable stress = 17,800 psi	17,800 psi	16,500 psi

Table 3.9-6(h) (Cont'd)

(Unit 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
Tensile Stress at Thread Relief Valve Stem	Valve open $S = F/A_t$ where F = 31,586 lbs, A_t = 1,956 in^2, S_{max} = 16,148 psi		
	Valve Closed F = 46,342 lbs S_{max} = 23,692 psi	30,600 psi	23,692 psi
Bonnet Design Calculations Including Seismic Accelerations For SSE	Paragraph UG-34c(2) on ASME Code Section VIII		
Minimum Thickness	$P_{fd} = P + P_{eg}$, $P_{eg} = \frac{16M}{\pi G^3} + \frac{4F}{\pi G^2}$		
	where M = 1,292,000 in-lbs, F = 53,739 lbs, G = 24.75 in		
	P_{eg} = 546 psi, P_{fd} = 1,796 psi		
	$t = d\left(\frac{CR}{1.5S} + \frac{1.78\ W\ hg}{1.5\ S_d{}^3}\right)^{1/2}$		
	where C = 0.3, P_{fd} = 1,459 psi, S = 17,800 psi, hg = 2.625 in, W = 1,120,000 lbs, d = 24.75 in -->t = 4.503 in, t = 4.503 + 0.120 = 4.623 in (corrosion allowance is 0.120 in)	4.623 in	5.344 in
Reinforcement	Reference paragraph I-704.41(c) of USAS B31-7 to account for the opening for stem in the bonnet Required reinforcement d x t x 0.5 = ($d_3t_3 = d_4t_4$)/2 d_3 = 1.875, t_4 = 2.223, t_3 = 2.875, d_4 = 3 Reinforcement = 6.030 in^2 required = 6.6126 in^2 available	6.030 in^2	6.6126 in^2
Bonnet Studs Design Calculation	Reference Article E-1000 Bolt used 20 pieces of 2.652 in^2/bolts Total bolt area = 53.04 in^2		
Normal Operation	1. Pressure stress at Operating Condition $S_1 = W_{m1}/A_b$ = 21,936 psi where W_{m1} = 1,163,504 lbs and		
	A_b = 53.04 in^2	27,700 psi	21,936 psi

Table 3.9-6(h) (Cont'd)

(Unit 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
	2. Gasket load at ambient condition with no internal pressure $S_2 = W_{m2}/A_b$ = 2,019 psi where W_{m2} = 107,065 lb_f and A_b = 53.04 in^2 Maximum tensile stress = 21,116 psi Thermal-stress is assumed negligible because the coefficients of thermal expansion of bonnet place and stud are the same.	35,000 psi	2,019 psi
Body Flange Design Calculations	Reference paragraph I-704.5.1 of USAS B 317 Total flange moment under operating conditions $M_O = M_D + M_G + M_T$ $M_D = H_D h_D$, $H_D = 0.785 B^2P$, $h_D = R + 0.591$ where B = 21.75, P = 1,865 psi --> H_D = 692,927 lb_f, h_D = 2.813 in, M_D = 1,949,204 in-lbs $M_G = H_G h_g$, $H_G = W - H$, $h_G = \frac{C-G}{2}$ where W is the higher of W_{m1} and W_{m2} W_{m1} = 1,163,504 lbs W_{m2} = 107,065 lbs H_G = 266,242 lbs, h_G = 2.625 in -->M_G = 698,885 in-lbs $M_T = H_T h_T$ H_T = 204,335 lbs, h_T = 3.375 in, M_T = 689,631 in-lb_f M_o = 3,337,720 in-lbs Total flange moment under gasket seating condition $M_o = W(C-G)/2$, $W = S_a(A_m + A_b)/2$ where C = 30 in, A_b = 53.04 in^2, G = 24.75 in, A_m = 32.857 in^2, s_a = 35,000 psi at 100°F --->W = 1,503,193 lbs ---> M_o = 3,945,895 in-lbs		

Table 3.9-6(h) (Cont'd)

(Unit 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS, (psi) MINIMUM THICKNESS (in), OR MINIMUM AREA (in^2)	CALCULATED STRESS, (psi) ACTUAL THICKNESS (in), OR MINIMUM AREA (in^2)
Longitudinal Hub Stress	$S_H = fM_o/((LS_1)^2B) + PB/(4g_o) = 23{,}031$ psi $< 1.5\ S_{fo} = 27{,}900$ psi	27,900 psi	23,031 psi
Radial Stress	Reference UA-51 (1), Equation (7) of Section VIII of ASME B&PV Code, 1971 Edition		
	$S_R = \frac{(1.33\ t_e+1)M_o}{Lt^2B} = 13{,}637$ psi $< 1\ S_{fo} = 18{,}600$ psi	18,600 psi	13,637 psi
Tangential	$S_T = \frac{(YM_o)}{t^2B} - ZS_R = 7{,}855$ psi $< 1\ S_f = 18{,}600$		
	where Y = 4.5, t = 4.125 in, z = 2.4, B = 21.75 in	18,600 psi	7,855 psi

Table 3.9-6(i)

RECIRCULATION PUMP

STRESS OR CRITERIA	METHOD OF ANALYSIS	ANALYTICAL RESULTS	ALLOWABLE / ACTUAL THICKNESS
1. Casing Minimum Wall Thickness	$t = \frac{PR}{SE - 0.6P} + C$		
A. Loads: Normal and upset condition Design pressure and temperature	where: t = minimum required thickness, in P = design pressure, psig R = maximum internal radius, in S = allowable working stress, psi E = joint efficiency C = corrosion allowance, in	t = 2.69 in	S_{allow} = 15,075 psi t_{act} = 3.00 in
B. Primary membrane stress limit Allowable working stress per ASME Section III, Class 1			
2. Casing Cover Minimum Thickness			
A. Loads: Normal and upset condition Design pressure and temperature	Bending Stress S_B max. = $\frac{KQa^2}{h^2}$	S_B max = 5950 psi	$S_{B\ allow}$ = 15,075 psi t_{act} = 7 in

Table 3.9-6(i) (Cont'd)

CRITERIA	METHOD OF ANALYSIS	ANALYTICAL RESULTS	ALLOWABLE STRESS OR ACTUAL THICKNESS
B. Primary membrane stress limit Allowable working stress per Section III, Class 1	where: Q = design pressure a = outer radius b = inner radius a = K = 0.711 b h = thickness		
	Shear Stress S_S max = F/A_S	S_S max = 3380 psi	$S_{S_{allow}}$ = 8750 psi
	where: F = force A_S = area		t_{act} = 3.5 in
3. Pump Discharge Nozzle Stress (Pressure Pending, Axial and Torsional)	Pressure $P_P = \frac{SEt}{R + 0.6t}$	P_P = 1594 psi P_{eb} = 18,500 psi	1.5 S_m = 28,837 psi (S_m = 19,225 psi)
	where: S = allowable stress E = joint efficiency t = thickness R = inside radius P_P = pressure load		
A. Loads: Normal and upset condition Design pressure and temperature piping reaction during normal operation	Bending $P_{eb} = \frac{C_b F_b S}{G_b}$	P_{ed} = 7670 psi P_{et} = 16,000 psi	

Table 3.9-6(i) (Cont'd)

CRITERIA	METHOD OF ANALYSIS	ANALYTICAL RESULTS	ALLOWABLE STRESS OR ACTUAL THICKNESS
B. Combined Stress limit: 1.5 S_m per ASME Code for Pumps and Valves for Nuclear Power Class I	Axial $P_{ed} = \frac{F_d S}{G_d}$ Torsional $P_{et} = \frac{2F_b S}{G_t}$		
4. Cover and Seal Flange Bolt Areas A. Loads: Normal and upset condition Design pressure and temperature Design gasket load B. Bolting Stress Limit Allowable working stress per ASME Section III, Class C	Bolting loads, areas and stresses shall be calculated in accordance with "Rules for bolted Flange Connections" - ASME Section VIII, Paragraph UA-49.	Cover Flange Bolts S_{act} = 19,050 psi A_m = 90.2 in^2 Seal Flange Bolts S_{act} = 18,000 psi A_m = 9.85 in^2	S_{allow} = 20,000 psi A_{act} = 101.0 in^2 S_{allow} = 20,000 psi A_{act} = 11.1 in^2

Table 3.9-6(i) (Cont'd)

CRITERIA	METHOD OF ANALYSIS	ANALYTICAL RESULTS	ALLOWABLE STRESS OR ACTUAL THICKNESS
5. Cover Clamp Flange Thickness A. Loads: Normal and upset condition Design pressure and temperature Design gasket load Design bolting load B. Tangential Flange Stress Limit Allowable working stress per ASME Section III, Class C	Flange thickness and stress shall be calculated in accordance with "Rules for Bolted Flange Connections" - ASME Section VIII, Paragraph UA-49.	Flange Thickness and Stress t = 8.9 in	t_{act} = 9.25 in S_{allow} = 17,500 psi
6. Seal Compartment Wall Thickness A. Loads: Normal and upset condition Design pressure and temperature B. Primary membrane stress limit Allowable working stress per ASME Section III, Class C	$t = \frac{PR}{SE - 0.6P} + C$ where: t = minimum required thickness, in P = design pressure, psig R = maximum internal radius, in S = allowable working stress, psi E = joint efficiency C = corrosion allowance, in	t = 0.741	S_m = 15,075 psi t_{act} = 1.375 in

Table 3.9-6(i) (Cont'd)

CRITERIA	METHOD OF ANALYSIS	ANALYTICAL RESULTS	ALLOWABLE STRESS OR ACTUAL THICKNESS
7. Stresses Due to Seismic Loads A. Loads: Operation pressure and temperature SSE horizontal seismic force = 2.27 g SSE vertical seismic force = 1.39 g B. Combined Stress Limit: Yield stress per ASME Section VIII	The flooded pump-motor assembly shall be analyzed as a free body supported by constant support hangers from the pump brackets. Horizontal and vertical seismic forces shall be applied at mass center of assembly and equilibrium reactions shall be determined for the motor and pump brackets. Load, shear, and moment diagrams shall be constructed using live loads, dead loads, and calculated snubber reactions. Combined bending tension and shear stresses shall be determined for each major component of the assembly including motor support barrel, bolting and pump casing. The maximum combined tensile stress in the cover bolting shall be calculated using tensile stresses determined from loading diagram plus tensile stress from operating pressure.	Motor Bolt Tensile Stress S_{act} = 22,471 psi Pump Cover Bolt Tensile stress S_{act} = 19,417 psi Motor Support Barrel Combined Stress S_{act} = 3307 psi	 S_{allow} = 30,800 psi S_{allow} = 32,000 psi S_{allow} = 22,400 psi

Table 3.9-6(j)

**REACTOR RECIRCULATION SYSTEM GATE VALVES,
STRUCTURAL AND MECHANICAL LOADING CRITERIA**

(UNIT 1)

COMPONENT/ LOADS/ DESIGN	DESIGN PROCEDURE(1)	ALLOWABLE DESIGN VALUE(2)	ACTUAL DESIGN VALUE(2)
I. 28" DISCHARGE VALVE			
Body and Bonnet			
Loads: Design pressure, design temperature, pipe reaction, thermal effects	System requirement not specified	1525 psi 575?F	1525 psi 575?F
Pressure rating, psi	Used ASME Section III Figure NB-3545.1-2	p_r = 800	p_r = 800
Minimum wall thickness, inches	Used ASME Section Para NB-3542	$t_m \geq$ 2.1164 in	t_m = 2.25 minimum
Primary membrane stress, psi	Used ASME Section III Para NB-3545.1	$P_m \leq S_m$ (500°F) = 19,600 psi	P_m = 11,068 psi
Secondary stress due to pipe reaction	Used ASME Section III Para NB-3545.2 (b)(1) (S = 30,000 psi)	$P_e \leq 1.5\ S_m$ (500°F) 1.5 (16,800) = 25,200 psi	P_{ed} = 5,580 psi P_{eb} = 12,702 psi P_{et} = 12,277 psi $P_e = P_{eb}$=12,702 psi
Primary plus secondary stress due to internal pressure	Used ASME Section III Para NB-3545.2(a)(1)	$S_n \leq 3\ S_m$ (500°F) = 58,800 psi	Q_p = 24,284 psi
Thermal secondary stress	Used ASME Section III Para NB-3545.2(c)	$S_n \leq 3\ S_m$ (500°F) = 58,800 psi	Q_T = 5,409 psi
Sum of primary plus secondary stress	Used ASME Section III Para NB-3545.2	$S_n \leq 3\ S_m$ (500°F) = 58,800 psi	$S_n = Q_p + P_e + 2Q_T$ = 47,804 psi

Table 3.9-6(j) (Cont'd)

(Unit 1)

COMPONENT/ LOADS/ DESIGN	DESIGN PROCEDURE(1)	ALLOWABLE DESIGN VALUE(2)	ACTUAL DESIGN VALUE(2)
Fatigue requirements	Used ASME Section III Para NB-3545.3	$N_a \geq 2{,}000$ cycles	$N_a > 10^5$ cycles
Cyclic rating	Used ASME Section III Para NB-3550	$I_t \leq 1$	$I_t = 0.00387$
Body-to-Bonnet Bolting			
Loads: Design pressure and temperature, gasket loads, seismic, hydrodynamic	Used ASME Section III Para NB-3647.1		
Bolt area	Used ASME Section III Para NB-3647.1	$A_b \geq 44.41$ in^2 ($S_b \leq 27{,}975$ psi)	$A_b = 55.86$ in^2 $S_b = 23{,}437$ psi
Body flange stresses	Used ASME Section III Para NB-3647.1		
Operating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m$ (575°F) = 28,838 psi $S_R \leq S_m$ (575°F) = 19,225 psi $S_T \leq S_m$ (575°F) = 19,225 psi	$S_H = 27{,}854$ psi $S_R = 8{,}220$ psi $S_T = 9{,}270$ psi
Gasket seating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m$ (100°F) = 30,000 psi $S_R \leq 1.5\ S_m$ (100°F) = 30,000 psi $S_T \leq 1.5\ S_m$ (100°F) = 30,000 psi	$S_H = 29{,}981$ psi $S_R = 11{,}671$ psi $S_T = 12{,}972$ psi
Bonnet flange			
Operating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m$ (575°F) = 28,838 psi $S_R \leq S_m$ (575°F) = 19,225 psi $S_T \leq S_m$ (575°F) = 19,225 psi	$S_H = 27{,}854$ psi $S_R = 8{,}220$ psi $S_T = 9{,}270$ psi
Gasket seating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m$ (100°F) = 30,000 psi $S_R \leq 1.5\ S_m$ (100°F) = 30,000 psi $S_T \leq 1.5\ S_m$ (100°F) = 30,000 psi	$S_H = 29{,}981$ psi $S_R = 11{,}671$ psi $S_T = 12{,}972$ psi

Table 3.9-6(j) (Cont'd)

(Unit 1)

COMPONENT/ LOADS/ DESIGN	DESIGN PROCEDURE[1]	ALLOWABLE DESIGN VALUE[2]	ACTUAL DESIGN VALUE[2]
Stresses in Stem			
Not applicable valve is passive			
Disc Analysis			
Loads: Maximum differential pressure			
Maximum stress in the disc	Calculate maximum stress according to table 10 of Reference 3.9-5	$S_{max} < 1.5\ S_m$ (500°F) = 28,500	S_{max} = 22,885 psi
Yoke and Yoke Connections			
Loads: Seismic and hydrodynamic	Calculate stresses in the yoke and yoke connections to acceptable structural analysis methods.		

Table 3.9-6(j) (Cont'd)

(Unit 1)

COMPONENT/ LOADS/ DESIGN	DESIGN PROCEDURE[1]	ALLOWABLE DESIGN VALUE[2]	ACTUAL DESIGN VALUE[2]
Stress in yoke legs bolts		$S_{max} \leq S_m$ = 28,800 psi (500°F)	S_{max} = 9,767 psi
Stress of yoke legs		$S_{max} \leq S_m$ = 19,400 psi (500°F)	S_{max} = 13,949 psi
Stress of yoke-bonnet connection		$S_{max} \leq S_m$ = 19,225 psi (575°F)	S_{max} = 15,650 psi
II. 28" SUCTION VALVE			
Body and Bonnet			
Loads: Design pressure, design temperature, pipe reaction thermal effects	System requirement not specified	1,275 psi 575°F	1,275 psi 575?F
Pressure rating, psi	Used ASME Section III Figure NB-3545.1-2	p_r = 668	p_r = 668
Minimum wall thickness, inches	Used ASME Section III Para NB-3542	$t_m \geq$ 1.7724 in	t_m = 2.0 minimum
Primary membrane stress, psi	Used ASME Section III Para NB-3545.1	$P_m \leq S_m$ (500°F) = 19,600 psi	P_m = 9,275 psi
Secondary Stress due to pipe reaction	Used ASME Section III Para NB-3545.2(b) (1) (S = 30,000 psi)	$P_e < 1.5\ S_m$ (500°F) 1.5 (16,800) = 25,200 psi	P_{ed} = 5,318 psi P_{eb} = 11,980 psi P_{et} = 11,575 psi P_e = 11,980 psi
Primary plus secondary stress due to internal pressure	Used ASME Section III Para NB-3545.2(a)(1)	$S_n \leq 3\ S_m$ (500°F) - 58,800 psi	Q_p = 20,580 psi
Thermal secondary stress	Used ASME Section III Para NB-3545.2	$S_n \leq 3\ S_m$ (500°F) - 58,800 psi	Q_t = 5,489 psi

Table 3.9-6(j) (Cont'd)

(Unit 1)

COMPONENT/ LOADS/ DESIGN	DESIGN PROCEDURE[1]	ALLOWABLE DESIGN VALUE[2]	ACTUAL DESIGN VALUE[2]
Sum of primary plus secondary stress	Used ASME Section III Para NB-3545.2	$S_n \leq 3\ S_m$ (500°F) = 58,800	$S_n = Q_p + P_e + 2Q_t$ = 43,538 psi
Fatigue Requirements	Used ASME Section III Para NB-3545.3	$N_a \geq 2{,}000$ cycles	$N_a = >10^6$ cycles
Cyclic rating	Used ASME Section III Para NB-3550	$I_t \leq 1$	$I_t = 0.00274$
Body-to-Bonnet Bolting			
Loads: Design pressure and temperature, gasket loads, seismic, and hydrodynamic	Used ASME Section III Para NB-3647.1		
Bolt area	Used ASME Section III Para NB-3647.1	$A_b \geq 37.53$ in^2 $S_b \leq 27{,}975$ psi (575°F)	$A_b = 55.86$ in^2 $S_b = 19{,}470$ psi
Body flange stresses	Used ASME Section III Para NB-3647.1		
Operating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m$(575°F) = 28,838 psi $S_R \leq\ S_m$(575°F) = 19,225 psi $S_T \leq\ S_m$(575°F) = 19,225 psi	$S_H = 24{,}456$ psi $S_R = 6{,}539$ psi $S_T = 8{,}718$ psi
Gasket seating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m$(100°F) = 30,000 psi $S_R \leq 1.5\ S_m$(100°F) = 30,000 psi $S_T \leq 1.5\ S_m$(100°F) = 30,000 psi	$S_H = 28{,}945$ psi $S_R = 10{,}253$ psi $S_T = 13{,}619$ psi
Bonnet flange			
Operating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m$(575°F) = 28,838 psi $S_R \leq\ S_m$(575°F) = 19,225 psi $S_T \leq\ S_m$(575°F) = 19,225 psi	$S_H = 24{,}456$ psi $S_R = 6{,}539$ psi $S_T = 8{,}718$ psi

Table 3.9-6(j) (Cont'd)

(Unit 1)

COMPONENT/ LOADS/ DESIGN	DESIGN PROCEDURE[1]	ALLOWABLE DESIGN VALUE[2]	ACTUAL DESIGN VALUE[2]
Gasket seating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m(100°F) = 30,000$ psi $S_R \leq 1.5\ S_m(100°F) = 30,000$ psi $S_T \leq 1.5\ S_m(100°F) = 30,000$ psi	$S_H = 28,945$ psi $S_R = 10,253$ psi $S_T = 13,619$ psi
Stress in Stem			
Not applicable valve is passive			
Disc Analysis			
Loads: Maximum differential pressure			
Maximum stress in the disc	Calculate maximum stress according to table 10 of Reference 3.9-5	$S_{max} \leq 1.5\ S_m(500°F) = 28,500$ psi	$S_{max} = 19,418$ psi

Table 3.9-6(j) (Cont'd)

(Unit 1)

COMPONENT/ LOADS/ DESIGN	DESIGN PROCEDURE[1]	ALLOWABLE DESIGN VALUE[2]	ACTUAL DESIGN VALUE[2]
Yoke and Yoke Connections			
Loads: Seismic and hydrodynamic	Calculate stresses in the yoke and yoke connections to acceptable structural analysis methods		
Stress in yoke legs bolts		$S_{max} \leq S_m$ (500°F) = 28,800 psi	S_{max} = 5,247 psi
Stress at yoke legs		$S_{max} \leq S_m$ (500°F) = 19,400 psi	S_{max} = 7,372 psi
Stress at yoke-bonnet connection		$S_{max} \leq S_m$ (575°F) = 19,225 psi	S_{max} = 8,248 psi

Table 3.9-6(j) (Cont'd)

**REACTOR RECIRCULATION SYSTEM GATE VALVES,
STRUCTURAL AND MECHANICAL LOADING CRITERIA**

(Unit 2)

COMPONENT/ LOADS/ DESIGN	DESIGN PROCEDURE[1]	REQUIRED DESIGN VALUE[2]	ACTUAL DESIGN VALUE[2]
III. 28" DISCHARGE VALVE			
Body and Bonnet			
Loads: Design pressure, design temperature, pipe reaction, thermal effects	System requirement not specified	1525 psi 575°F	1525 psi 575°F
Pressure rating, psi	Used ASME Section III Figure NB-3545.1-2	p_r = 800	p_r = 800
Minimum wall thickness, inches	Used ASME Section III Para NB-3542	$t_m \geq$ 2.1164 in	t_m = 2.25 minimum
Primary membrane stress, psi	Used ASME Section III Para NB-3545.1	$P_m \leq S_m$ (500°F) = 19,600 psi	P_m = 11,068 psi
Secondary stress due to pipe reaction	Used ASME Section III Para NB-3545.2 (b)(1) (S = 30,000 psi)	$P_e \leq 1.5\ S_m$ (500°F) 1.5 (16,800) = 25,200 psi	P_{ed} = 5,580 psi P_{eb} = 12,702 psi P_{et} = 12,277 psi $P_e = P_{eb}$ = 12,702 psi
Primary plus secondary stress due to internal pressure	Used ASME Section III Para NB-3545.2(a)(1)	$S_n \leq 3\ S_m$ (500°F) = 58,800 psi	Q_p = 24,284 psi
Thermal secondary stress	Used ASME Section III Para NB-3545.2(c)	$S_n \leq 3\ S_m$ (500°F) = 58,800 psi	Q_T = 5,409 psi
Sum of primary plus secondary stress	Used ASME Section III Para NB-3545.2	$S_n \leq 3\ S_m$ (500°F) = 58,800 psi	$S_n = Q_p + P_e + 2Q_T$ = 47,804 psi

Table 3.9-6(j) (Cont'd)

(Unit 2)

COMPONENT/ LOADS/ DESIGN	DESIGN PROCEDURE[1]	REQUIRED DESIGN VALUE[2]	ACTUAL DESIGN VALUE[2]
Fatigue requirements	Used ASME Section III Para NB-3545.3	$N_a \geq 2{,}000$ cycles	$N_a > 10^5$ cycles
Cyclic rating	Used ASME Section III Para NB-3550	$I_t \leq 1$	$I_t = 0.00387$
Body-to-Bonnet Bolting			
Loads: Design pressure and temperature gasket loads, stem operational load, seismic load (SSE)	Used ASME Section III Para NB-3647.1		
Bolt area	Used ASME Section III Para NB-3647.1	$A_b \geq 44.41$ in^2 ($S_b \leq 27{,}975$ psi (575°F)	$A_b = 55.86$ in^2 $S_b = 22{,}619$ psi
Body flange stresses	Used ASME Section III Para NB-3647.1		
Operating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m$ (500°F) = 28,838 psi $S_R \leq 1.5\ S_m$ (500°F) = 19,225 psi S_T ? $1.5\ S_m$ (500°F) = 19,225 psi	$S_H = 27{,}049$ psi $S_R = 7{,}934$ psi $S_T = 8{,}946$ psi
Gasket seating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m$ (100°F) = 30,000 psi $S_R \leq 1.5\ S_m$ (100°F) = 30,000 psi $S_T \leq 1.5\ S_m$ (100°F) = 30,000 psi	$S_H = 29{,}981$ psi $S_R = 11{,}671$ psi $S_T = 12{,}972$ psi
Bonnet flange			
Operating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m$ (500°F) = 28,838 psi $S_R \leq 1.5\ S_m$ (500°F) = 19,225 psi $S_T \leq 1.5\ S_m$ (500°F) = 19,225 psi	$S_H = 27{,}049$ psi $S_R = 7{,}934$ psi $S_T = 8{,}946$ psi
Gasket seating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m$ (100°F) = 30,000 psi $S_R \leq 1.5\ S_m$ (100°F) = 30,000 psi $S_T \leq 1.5\ S_m$ (100°F) = 30,000 psi	$S_H = 29{,}981$ psi $S_R = 11{,}671$ psi $S_T = 12{,}972$ psi

Table 3.9-6(j) (Cont'd)

(Unit 2)

COMPONENT/ LOADS/ DESIGN	DESIGN PROCEDURE	REQUIRED DESIGN VALUE[2]	ACTUAL DESIGN VALUE[2]
Stresses in Stem			
Not applicable, valve is passive			
Disc Analysis			
Loads: Maximum differential pressure			
Maximum stress in the disc	Calculate maximum stress according to table 10 of Reference 3.9-5	$S_{max} < 1.5\ S_m$ (500°F) = 28,500	S_{max} = 22,885 psi
Yoke and Yoke Connections			
Loads: Stem operational load	Calculate stresses in the yoke and yoke connections to acceptable structural analysis methods.		
Tensile stress in yoke legs bolts		$S_{max} \leq S_m$ = 28,800 psi (500°F)	S_{max} = 3,716 psi
Stress of yoke legs		$S_{max} \leq 1.5\ S_m$ = 19,400 psi (500°F)	S_{max} = 5,145 psi
Stress of yoke-bonnet connection		$S_{max} \leq S_m$ = 19,225 psi (575°F)	S_{max} = 5,741 psi

Table 3.9-6(j) (Cont'd)

(Unit 2)

COMPONENT/ LOADS/ DESIGN	DESIGN PROCEDURE[1]	REQUIRED DESIGN VALUE[2]	ACTUAL DESIGN VALUE[2]
IV. 28" SUCTION VALVE			
Body and Bonnet			
Loads: Design pressure, design temperature pipe reaction thermal effects	System requirement not specified	1,275 psi 575°F	1,275 psi 575°F
Pressure rating, psi	Used ASME Section III Figure NB-3545.1-2	p_r = 668	p_r = 668
Minimum wall thickness, inches	Used ASME Section III Para NB-3542	$t_m \geq$ 1.7724 in	t_m = 2.0 minimum
Primary membrane stress, psi	Used ASME Section III Para NB-3545.1	$P_m \leq S_m$ (500°F) = 19,600 psi	P_m = 9,275 psi
Secondary stress due to pipe reaction	Used ASME Section III Para NB-3545.2(b)(1) (S = 30,000 psi)	$P_e < 1.5\ S_m$ (500°F) 1.5 (16,800) = 25,200 psi	P_{ed} = 5,318 psi P_{eb} = 11,980 psi P_{et} = 11,575 psi P_e = 11,980 psi
Primary plus secondary stress due to internal pressure	Used ASME Section III Para NB-3545.2(a)(1)	$S_n \leq 3\ S_m$ (500°F) = 58,800	Q_p = 20,580 psi
Thermal secondary stress	Used ASME Section III Para NB-3545.2	$S_n \leq 3\ S_m$ (500°F) = 58,800	Q_t = 5,489 psi

Table 3.9-6(j) (Cont'd)

(Unit 2)

COMPONENT/ LOADS/ DESIGN	DESIGN PROCEDURE(1)	REQUIRED DESIGN VALUE(2)	ACTUAL DESIGN VALUE(2)
Sum of primary plus secondary stress	Used ASME Section III Para NB-3545.2	$S_n \leq 3\ S_m$ (500?F) = 58,800	$S_n = Q_p + P_e + 2Q_t$ = 43,538 psi
Fatigue Requirements	Used ASME Section III Para NB-3545.3	$N_a \geq 2{,}000$ cycles	$N_a > 10^6$ cycles
Cyclic rating	Used ASME Section III Para NB-3550	$I_t \leq 1$	$I_t = 0.00274$
Body-to-Bonnet Bolting			
Loads: Design pressure and temperature, gasket loads, stem operational load, seismic load (SSE)	Used ASME Section III Para NB-3647.1		
Bolt area	Used ASME Section III Para NB-3647.1	$A_b \geq 37.53$ in^2 $S_b \leq 27{,}975$ psi (575°F)	$A_b = 55.86$ in^2 $S_b = 19{,}283$ psi
Body flange stresses	Used ASME Section III Para NB-3647.1		
Operating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m$(575°F) = 28,838 psi $S_R \leq 1.5\ S_m$(575°F) = 19,225 psi $S_T \leq 1.5\ S_m$(575°F) = 19,225 psi	$S_H = 24{,}264$ psi $S_R = 6{,}476$ psi $S_T = 8{,}364$ psi
Gasket seating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m$(100°F) = 30,000 psi $S_R \leq 1.5\ S_m$(100°F) = 30,000 psi $S_T \leq 1.5\ S_m$(100°F) = 30,000 psi	$S_H = 28{,}945$ psi $S_R = 10{,}253$ psi $S_T = 13{,}619$ psi
Bonnet flange			
Operating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m$(575°F) = 28,838 psi $S_R \leq 1.5\ S_m$(575°F) = 19,225 psi $S_T \leq 1.5\ S_m$(575°F) = 19,225 psi	$S_H = 24{,}264$ psi $S_R = 6{,}476$ psi $S_T = 8{,}634$ psi

Table 3.9-6(j) (Cont'd)

(Unit 2)

COMPONENT/ LOADS/ DESIGN	DESIGN PROCEDURE[1]	REQUIRED DESIGN VALUE[2]	ACTUAL DESIGN VALUE[2]
Gasket seating condition	Used ASME Section III Para NB-3647.1	$S_H \leq 1.5\ S_m(100°F) = 30{,}000$ psi $S_R \leq 1.5\ S_m(100°F) = 30{,}000$ psi $S_T \leq 1.5\ S_m(100°F) = 30{,}000$ psi	$S_H = 28{,}945$ psi $S_R = 10{,}253$ psi $S_T = 13{,}619$ psi
Stress in Stem			
Not applicable, valve is passive			
Disc Analysis			
Loads: Maximum differential pressure			
Maximum stress in the disc	Calculate maximum stress according to table 10 of Reference 3.9-5	$S_{max} \leq 1.5\ S_m(500°F) = 28{,}500$ psi	$S_{max} = 19{,}418$ psi
Yoke and Yoke Connections			
Loads: Stem operational load	Calculate stresses in the yoke and yoke connections to acceptable structural analysis methods		

Table 3.9-6(j) (Cont'd)

(Unit 2)

COMPONENT/ LOADS/ DESIGN	DESIGN PROCEDURE[1]	REQUIRED DESIGN VALUE[2]	ACTUAL DESIGN VALUE[2]
Tensile stress in yoke legs bolts		$S_{max} \leq S_m$ (500°F) = 28,800 psi	S_{max} = 3,877 psi
Stress at yoke legs		$S_{max} \leq 1.5\ S_m$ (500°F) = 19,400 psi	S_{max} = 5,378 psi
Stress at yoke-bonnet connection		$S_{max} \leq S_m$ (575°F) = 19,225 psi	S_{max} = 6,004 psi

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(1) ASME Section III refers to 1968 Edition of ASME B&PV Code.

(2) Terms used are defined as follows:

A_b	=	actual total cross-sectional area of bolts at root of thread or section of least diameter under stress, in^2	
I_t	=	thermal cyclic index for a particular valve application	
N_a	=	permissible number of complete startup/shutdown cycles at 100°F/hour fluid temperature change rate	
p_r	=	primary pressure rating, lb	
P_e	=	largest value among P_{eb}, P_{ed}, P_{et}, psi	
P_{eb}	=	secondary stress in crotch region of valve body caused by bending of connected standard pipe, psi	
P_{ed}	=	Secondary stress in crotch region of valve body caused by direct or axial load imposed by connected standard	piping, psi
P_{et}	=	secondary stress in crotch region of valve body caused by twisting of connected standard pipe, psi	
P_m	=	general primary-membrane stress intensity at crotch region, psi	
Q_p	=	sum of primary-plus-secondary stresses at crotch resulting from internal pressure, psi	
Q_T	=	thermal-stress in crotch region resulting from 100°F/hour fluid temperature change rate, psi	
S_b	=	allowable bolt stress at design temperature, psi	
S_B	=	bending stress, psi	
S_H	=	calculated longitudinal stress in hub, psi	
S_m	=	design stress intensity, psi	
S_{max}	=	maximum stress, psi	
S_n	=	sum of primary-plus-secondary stress intensities at crotch region resulting from 100?F/hour temperature change rate,	psi
S_R	=	calculated radial stress in flange, psi	
S_s	=	shear stress due to operator torque, psi	
S_t	=	stress due to operator thrust, psi	
S_T	=	tangential stress in flange, psi	
t_m	=	minimum body wall thickness, in	

Table 3.9-6(k)

HPCI TURBINE

CRITERIA/COMPONENT	LOADING CONDITION	STRESS TYPE	ALLOWABLE STRESS (PSI)	CALCULATED STRESS (PSI)
PRESSURE BOUNDARY CASTINGS				
Allowable stresses based on ASME Section III. Pressure boundary castings for Type SA216-WCB				
	For normal condition: Design pressure Design temperature Inlet and exhaust nozzle loads			
1. Stop Valve (100% radiograph)		General membrane	8,975	17,500
2. Turbine inlet (high pressure)		General membrane	6,550	14,000
3. Turbine wheel case (low pressure)		General membrane	6,000	14,000
	For upset, Emergency, or faulted condition: Design pressure Design temperature Controlling combination of OBE, SSE, SRV, & LOCA Inlet and exhaust nozzle loads			
1. Stop valve (100% radiograph)		General membrane	17,700	19,250
2. Turbine inlet (high pressure)		General membrane	15,250	15,400
3. Turbine wheel case (low pressure)		General membrane	13,690	15,400
PRESSURE BOUNDARY BOLTING				
Allowable stresses are based on ASME Section III, for pressure boundary bolting for Type SA193-B7				
	For normal condition: Design pressure Design temperature Inlet and exhaust nozzle loads			

Table 3.9-6(k) (Cont'd)

CRITERIA/COMPONENT	LOADING CONDITION	STRESS TYPE	ALLOWABLE STRESS (PSI)	CALCULATED STRESS (PSI)
PRESSURE-CONTAINING BOLTS				
Stop valve		Tensile	17,600	25,000
Turbine flange		Tensile	18,290	25,000
	For upset emergency, or faulted condition: Design pressure Design temperature Controlling combination of OBE, SSE, SRV, & LOCA Inlet and exhaust nozzle loads			
PRESSURE-CONTAINING BOLTS				
Stop valve		Tensile	17,950	25,000
Turbine flange		Tensile	18,655	25,000
	For faulted condition: Design pressure Design temperature Combination (ABS) of SSE, SRV, & LOCA Inlet and exhaust nozzle loads			
Turbine shaft stress		Bending	12,850 psi	45,000 psi
Turbine shaft deflection	-		0.032 inch	0.125 inch
Thrust bearing load		Force	4,600 lb_f	5,600 lb_f
Journal bearing load		Force	5,020 lb_f	19,500 lb_f
Pedestal bolts, coupling end		Tension	28,740 lb	31,100 lb
Taper pins, coupling end		Shear	39,110 lb	42,050 lb
Guide block weld, governor end		Shear	43,550 lb	43,650 lb

Table 3.9-6(l)

SLCS PUMP

Criteria/Loading		Component	Limiting Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
Based on ASME Section III.					
Pressure Boundary Parts:					
1. Fluid Cylinder - SA182-F304,	S_y = 30,000 psi				
2. Discharge valve stop, stuffing box and cylinder head extension SA479-304,	S_y = 30,000 psi				
3. Discharge valve cover, cylinder head and stuffing box flange plate, SA285, Grade C	S_y = 30,000 psi				
4. Stuffing box gland, ASTM A461, Grade 630	S_y = 90,000 psi				
5. Studs, SA193-B7,	S_y = 105,000 psi				
6. Dowel pins(2) alignment, SAE4140,	S_y = 117,000 psi				
7. Studs, cylinder tie, SA193-B7,	S_A = 25,000 psi				
8. Pump holddown bolts, SAE Grade 1	T_A = 15,000 psi Q_A = 12,000 psi				
9. Power frame, foot area, cast iron,	S_A = 15,000 psi				
10. Motor holddown bolts, SAE Grade 1	T_A = 15,000 psi Q_A = 12,000 psi				
11. Motor frame foot area, cast iron,	S_A = 15,000 psi				

Table 3.9-6(l) (Cont'd)

Criteria/Loading	Component	Limiting Stress Type	Allowable Stress (psi)	Calculated Stress (psi)
Normal and Upset Condition Loads:				
1. Design pressure	1. Fluid Cylinder	General membrane	17,800	
2. Design temperature	2. Discharge valve stop	General membrane	17,800	(3)
3. Operating basis earthquake	3. Cylinder head extension	General membrane	17,800	
4. Nozzle loads(1)	4. Discharge valve cover	General membrane	17,800	
5. Thermal expansion	5. Cylinder head	General membrane	17,800	
6. SRV	6. Stuffing box flange plate	General membrane	17,800	
7. Dead weight	7. Stuffing box gland	General membrane	35,000	
	8. Cylinder head studs	Tensile	25,000	
	9. Stuffing box studs	Tensile	25,000	
Emergency or Faulted Condition:				
1. Design pressure	1. Fluid cylinder	General membrane	21,360	4,450
2. Design temperature	2. Discharge valve stop	General membrane	21,360	13,600
3. Weight of structure	3. Cylinder head extension	General membrane	21,360	13,600
4. Thermal expansion	4. Discharge valve cover	General membrane	21,360	8,150
5. Safe shutdown earthquake	5. Cylinder head	General membrane	21,360	8,150
6. LOCA	6. Stuffing box flange plate	General membrane	21,360	10,390
7. Nozzle loads	7. Stuffing box gland	General membrane	42,000	11,420
	8. Cylinder head studs	Tensile	25,000	18,820
	9. Dowel pins(2)	Shear only(2)	23,400	19,400
	10. Studs, cylinder tie	Tensile(2)	25,000	24,750
	11. Pump holddown bolts	Shear	12,000	7,560
	12. Pump holddown bolts	Tensile	15,000	9,950
	13. Power frame-foot area	Shear	15,000	1,850
	14. Power frame-foot area	Tensile	15,000	11,390
	15. Motor holddown bolts	Shear	12,000	3,470
	16. Motor holddown bolts	Tensile	15,000	5,660
	17. Motor frame-foot area	Shear	15,000	2,550
	18. Motor frame-foot area	Tensile	15,000	4,125

Table 3.9-6(l) (Cont'd)

Criteria/Loading	Component	Allowable Loads [5] (lb, ft-lb)	Calculated Loads (lb,ft-lb)
Normal and Upset Condition Loads:			
1. Design pressure	Suction	F_o = 730	F_i = 571
2. Design temperature	Nozzle	M_o = 282	M_i = 218
3. Weight of structure			
4. Thermal expansion	Discharge	F_o = 350	F_i = 138
5. Operating basis earthquake	Nozzle	M_o = 69	M_i = 38
6. SRV			
Emergency or Faulted Condition Loads:			
1. Design pressure	Suction	F_o = 730	F_i = 620
2. Design temperature	Nozzle	M_o = 282	M_i = 228
3. Weight of structure			
4. Thermal expansion	Discharge	F_o = 350	F_i = 170
5. Safe shutdown earthquake	Nozzle	M_o = 67	M_i = 46
6. LOCA			

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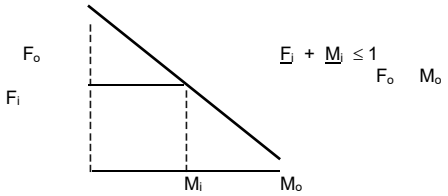
(1) Nozzle loads produce shear loads only.
(2) Dowel pins take all shear.
(3) Calculated stresses for emergency or faulted condition are less than the allowable stresses for the normal and upset condition loads, therefore the normal and upset condition is not evaluated.
(4) Operability: The sum of the plunger and rod assembly, pounds mass times 1.75, acceleration is much less than the thrust loads encountered during normal operating conditions. Therefore, the loads during the faulted condition have no significant effect on pump operability.

Table 3.9-6(l) (Cont'd)

(5) Allowable nozzle load criteria:

Units: Forces - lb
Moments - ft-lb

The allowable combinations of forces and moments are as follows:



$$\frac{F_i}{F_o} + \frac{M_i}{M_o} \leq 1$$

where:

F_i = Largest absolute value of the three actual external orthogonal forces (F_x, F_y, F_z) that may be imposed by the interface pipe.

M_i = Largest absolute value of the three actual external orthogonal moments (M_x, M_y, M_z) permitted from the interface pipe when they are combined simultaneously for a specific condition.

F_o = Allowable value of F_i when all moments are zero.

M_o = Allowable value of M_i when all forces are zero.

Table 3.9-6(m)

SLCS TANK

(UNIT 1)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS OR MIN. THICKNESS REQ'D OR LOAD		ACTUAL STRESS OR MIN. THICKNESS REQ'D OR LOAD
1. Shell Thickness				
Loads: Normal and Upset	Brownell and Young			
Design Pressure and Temperature	"Process Equipment Design" $t = \frac{PR}{SE-0.6P}$	0.01542 in		0.1875 in
where:	t = min req'd. thickness, in P = design pressure, psig R = maximum internal radius, in S = allowable working stress, psi E = joint efficiency			
Stress Limit	Dynamic Analysis	25,800 psi		1200 psi
2. Nozzle Loads				
Loads: Normal and Upset Design pressure and temperature	The maximum moments due to pipe reaction and maximum forces shall not exceed the allowable limits.	Design Upset Emergency	25,800 psi 28,380 psi 30,960 psi	
Overflow Nozzle and Discharge Nozzle				Less than faulted
Loads: Faulted Dead weight, thermal expansion, and SSE	The maximum moments due to pipe reaction and maximum forces shall not exceed the allowable limits.	Faulted	41,280 psi	
Overflow nozzle				9556 psi
Discharge nozzle				4962 psi

Table 3.9-6(m) (Cont'd)

(Unit 1)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS OR MIN. THICKNESS REQ'D OR LOAD	ACTUAL STRESS OR MIN. THICKNESS REQ'D OR LOAD
3. Anchor Bolts	API - 650 (ASME Section III)	18,750 psi (tensile) 15,000 psi (shear)	11,770 psi (tensile) 8,962 psi (shear)
4. Dynamic Loads	Equivalent static	Horizontal 1.5 g	0.578 g
SSE SRV LOCA		Vertical 0.14 g	0.898 g
Chugging	Dynamic Analysis	Load - See RRS curves	1,200 psi

Table 3.9-6(m) (Cont'd)

SLCS TANK

(UNIT 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS OR MIN. THICKNESS REQ'D OR LOAD		ACTUAL STRESS OR MIN. THICKNESS REQ'D OR LOAD
1. Shell Thickness				
Loads: Normal and Upset	Brownell and Young			
Design Pressure and Temperature	"Process Equipment Design" $t = \frac{PR}{SE-0.6P}$	0.01542 in		0.1875 in
where:	t = min req'd. thickness, in P = design pressure, psig R = maximum internal radius, in S = allowable working stress, psi E = joint efficiency			
Stress Limit	Dynamic analysis	25,800 psi		1200 psi
2. Nozzle Loads				
Loads: Normal and Upset Design pressure and temperature	The maximum moments due to pipe reaction and maximum forces shall not exceed the allowable limits.	Allowables: Design Upset Emergency	 25,800 psi 28,380 psi 30,960 psi	
Overflow Nozzle and Discharge Nozzle				5556 psi(1) 6357 psi
Loads: Faulted Dead weight, thermal expansion, and SSE	The maximum moments due to pipe reaction and maximum forces shall not exceed the allowable limits			
Overflow nozzle Discharge nozzle		Faulted Faulted	41,280 psi 41,280 psi	9556 psi(1) 6357 psi

Table 3.9-6(m) (Cont'd)

(Unit 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS OR MIN. THICKNESS REQ'D OR LOAD	ACTUAL STRESS OR MIN. THICKNESS REQ'D OR LOAD
3. Anchor Bolts	ASME Section III	18,750 psi (tensile) 15,000 psi (shear)	11,770 psi tensile 8,962 psi shear
4. Dynamic Loads	Equivalent static	Horizontal 1.5 g	0.578 g
SSE SRV LOCA		Vertical 0.14 g	0.898 g
Chugging	Dynamic Analysis	28,500 psi	1200 psi

(1) Since the actual stresses resulting from the analysis using the faulted loads are so low, it is not necessary to reanalyze for actual stresses from upset and emergency conditions.

Table 3.9-6(n)

ECCS PUMPS

LOCATION	LOADING CONDITION	CRITERIA	CALCULATED STRESS (psi)	ALLOWABLE STRESS (psi)
RESIDUAL HEAT REMOVAL PUMP				
Stuffing Box Pipe	FAULTED CONDITION Design Pressure Static Loads Dynamic Loads	ASME Section III	11,718	26,250
Discharge Elbow	FAULTED CONDITION Design Pressure Static Loads Dynamic Loads	ASME Section III	16,172	20,000
Nozzle Shell Intersection	FAULTED CONDITION Design Pressure Static Loads Dynamic Loads	ASME Section III	15,661	28,875
Motor Stand	FAULTED CONDITION Static Loads Dynamic Loads	Bolting Loads and Stresses per ASME Section III, Subsection NF	15,374 (Tensile) 3,058 (Compressive)	22,800 19,326
Motor Bolting	FAULTED CONDITION Static Loads Dynamic Loads	Bolting Loads and Stresses per ASME Section III, Subsection NF	18,755 (Tensile) 4,623 (Shear)	62,500 25,833

Table 3.9-6(n) (Cont'd)

LOCATION	LOADING CONDITION	CRITERIA	CALCULATED STRESS (psi)	ALLOWABLE STRESS (psi)
CORE SPRAY PUMP				
Stuffing Box Pipe	FAULTED CONDITION Design Pressure Static Loads Dynamic Loads	ASME Section III	12,629	26,250
Discharge Elbow	FAULTED CONDITION Design Pressure Static Loads Dynamic Loads	ASME Section III	18,097	20,000
Nozzle Shell Intersection	FAULTED CONDITION Design Pressure Static Loads Dynamic Loads	ASME Section III	28,352	34,650
Motor Stand	FAULTED CONDITION Static Loads Dynamic Loads	Bolting Loads and Stresses per ASME Section III, Subsection NF	11,626 (Tensile) 2,031 (Compressive)	22,800 19,352
Motor Bolting	FAULTED CONDITION Static Loads Dynamic Loads	Bolting Loads and Stresses per ASME Section III, Subsection NF	7,203 (Tensile) 2,622 (Shear)	62,500 25,833

Table 3.9-6(o)

RHR HEAT EXCHANGER

(UNIT 1)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS OR MINIMUM THICKNESS REQUIRED	ACTUAL STRESS OR MINIMUM THICKNESS REQUIRED
1. Closure Bolting	Bolting loads and stresses calculated per "Rules for Bolted Flange Connections" ASME Section VIII, Appendix II		
Loads: Normal and upset			
Design pressure and temperature			
Design gasket load			
Bolting Stress Limit	a. Shell to tube sheet bolts	39,375 psi	33,599 psi
Allowable working stress per ASME Section VIII	b. Channel cover bolts	39,375 psi	31,797 psi
2. Wall Thickness	Shell side ASME Section III Class 2 and TEMA Class C		
Loads: Normal and upset			
Design pressure and temperature	Tube side ASME Section VIII-Div. I and TEMA Class C		
Stress Limit			
ASME Section III	a. Shell	0.7915 in	0.8125 in
	b. Shell cover	1.0214 in	1.0625 in (minimum)
	c. Channel	1.1372 in	1.1825 in
	d. Tubes	0.047 in*	0.049 in
	e. Channel cover	6.856 in	6.875 in
	f. Tube sheet	5.7119 in	5.75 in
	g. Shell at nozzles	1.1372 in	1.1875 in

* Minimum wall thickness based on general corrosion.

Table 3.9-6(o) (Cont'd)

(Unit 1)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS OR MINIMUM THICKNESS REQUIRED	ACTUAL STRESS OR MINIMUM THICKNESS REQUIRED
3. Nozzle Loads		See (a) and (b) below	See (c) below
Design pressure and temperature			
Dead weight, thermal expansion and SSE	Primary local membrane stress less than 1.8 ASME Section VIII allowable.		

a) Maximum allowable piping loads for faulted conditions (including SSE) shall not exceed the following relationship for each nozzle:

$$\frac{F_{ix}}{F_{ox}} + \frac{F_{iy}}{F_{oy}} + \frac{F_{iz}}{F_{oz}} \leq 1 \quad \text{and} \quad \frac{M_{ix}}{M_{ox}} + \frac{M_{iy}}{M_{oy}} + \frac{M_{iz}}{M_{oz}} \leq 1$$

where F_i (lbs) is the maximum piping load imposed on each nozzle in the x, y and z direction and M_i (lb-ft) is the maximum moment imposed on each nozzle in the x, y and z directions.

b) Allowable design basis limits (forces F_{ox}, F_{oy}, F_{oz} and Moments M_{ox}, M_{oy}, M_{oz}) for nozzles N1, N2, N3, and N4:

	N1 (Channel inlet)	N2 (Channel outlet)	N3 (Shell inlet)	N4 (Shell outlet)
F_{ox}	11,395 lb	11,395 lb	44,143 lb	26,692 lb
F_{oy}	25,621 lb	25,621 lb	19,630 lb	26,692 lb
F_{oz}	25,621 lb	25,621 lb	44,143 lb	11,871 lb
M_{ox}	65,926 lb-ft	65,926 lb-ft	21,839 lb-ft	12,230 lb-ft
M_{oy}	8,537 lb-ft	8,537 lb-ft	113,596 lb-ft	12,230 lb-ft
M_{oz}	8,537 lb-ft	8,537 lb-ft	21,839 lb-ft	68,680 lb-ft

Note: The calculated loads in (c) below that exceed these allowable loads have been evaluated and are acceptable.

Table 3.9-6(o) (Cont'd)

(Unit 1)

CRITERIA		METHOD OF ANALYSIS		ALLOWABLE STRESS OR MINIMUM THICKNESS REQUIRED	ACTUAL[2] STRESS OR MINIMUM THICKNESS REQUIRED
c)[1]					
F_{ox}	6,367 lb	6,822 lb	6,638 lb	1,101 lb	
F_{oy}	4,442 lb	8,034 lb	10,370 lb	2,526 lb	
F_{oz}	4,836 lb	1,818 lb	11,327 lb	8,178 lb	
M_{ox}	6,141 lb-ft	9,669 lb-ft	37,996 lb-ft	7,900 lb-ft	
M_{oy}	28,863 lb-ft	1,168 lb-ft	16,782 lb-ft	4,195 lb-ft	
M_{oz}	10,670 lb-ft	52,242 lb-ft	16,966 lb-ft	1,863 lb-ft	
4. Support Brackets and Attachment Welds		Stress allowables per ASME Section III Subsection NT (Upset Condition).			
Loads: Faulted		a. Lower bracket welds			
Design pressure and temperature, dead weight, nozzle loads, SSE.		Bending stress		12,863 psi	10,907 psi
		Shear stress		7,074 psi	6,496 psi
		b. Upper Bracket welds			
		Bending stress		14,438 psi	6,069 psi
		Shear stress		7,074 psi	3,631 psi
5. Anchor Bolts		Stress allowable per ASME III, Subsection NF XVIII			
Loads: Faulted		Lower support bolting			
Design pressure and temperature, dead weight, nozzle loads, SSE, SRV.		Interaction criteria		52,500 psi	33,048 psi

Table 3.9-6(o) (Cont'd)

(Unit 1)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS OR MINIMUM THICKNESS REQUIRED	ACTUAL[2] STRESS OR MINIMUM THICKNESS REQUIRED
6. Shell Adjacent to Support Brackets Loads: Faulted Design pressure and temperature, dead weight, nozzle loads, SSE.	Shell stress allowables per ASME Section III Subsection NC (Upset Condition).		
	a. Maximum principal stress adjacent to upper support	28,875 psi	17,068 psi
	b. Maximum principal stress adjacent to lower support	28,875 psi	20,929 psi
7. Shell Away from Discontinuities Loads: Faulted Design pressure and temperature, dead weight, nozzle loads, SSE.	Stress allowable per ASME Section III Subsection NC (Upset Condition)		
	Principal stress	19,250 psi	15,662 psi

Table 3.9-6(o) (Cont'd)

RHR HEAT EXCHANGER

(UNIT 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS OR MINIMUM THICKNESS REQUIRED	ACTUAL STRESS OR MINIMUM THICKNESS REQUIRED
1. Closure Bolting	Bolting loads and stresses calculated per "Rules for Bolted Flange Connections" ASME Section VIII, Appendix II		
Loads: Normal and upset			
Design pressure and temperature			
Design gasket load			
Bolting Stress Limit	a. Shell to tube sheet bolts	39,375 psi	31,973 psi
Allowable working stress per ASME Section VIII	b. Channel cover bolts	39,375 psi	30,721 psi
2. Wall Thickness	Shell side ASME Section III Class 2 and TEMA Class C		
Loads: Normal and upset			
Design pressure and temperature	Tube side ASME Section III Class 3 and TEMA Class C		
Stress Limit			
ASME Section III	a. Shell	0.7915 in	0.8125 in
	b. Shell cover	1.0214 in	1.0625 in (minimum)
	c. Channel	1.1372 in	1.1825 in
	d. Tubes	0.047 in	0.049 in
	e. Channel cover	6.856 in	6.875 in
	f. Tube sheet	5.7119 in	5.75 in

Table 3.9-6(o) (Cont'd)

(Unit 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS OR MINIMUM THICKNESS REQUIRED	ACTUAL STRESS OR MINIMUM THICKNESS REQUIRED
3. Nozzle Loads		See (a) and (b) below	See (c) below
Design pressure and temperature			
Dead weight, thermal expansion and SSE	Primary local membrane stress less than 1.8 ASME Section VIII allowable.		

a) Maximum allowable piping loads for faulted conditions (including SSE) shall not exceed the following relationship for each nozzle:

$$\frac{F_{ix}}{F_{ox}} + \frac{F_{iy}}{F_{oy}} + \frac{F_{iz}}{F_{oz}} \leq 1 \quad \text{and} \quad \frac{M_{ix}}{M_{ox}} + \frac{M_{iy}}{M_{oy}} + \frac{M_{iz}}{M_{oz}} \leq 1$$

where F_i (lbs) is the maximum piping load imposed on each nozzle in the x, y and z direction and M_i (lb-ft) is the maximum moment imposed on each nozzle in the x, y and z directions.

b) Allowable design basis limits (forces F_{ox}, F_{oy}, F_{oz} and Moments M_{ox}, M_{oy}, M_{oz}) for nozzles N1, N2, N3, and N4:

	N1 (Channel inlet)	N2 (Channel outlet)	N3 (Shell inlet)	N4 (Shell outlet)
F_{ox}	11,395 lb	11,395 lb	44,143 lb	26,692 lb
F_{oy}	25,621 lb	25,621 lb	19,630 lb	26,692 lb
F_{oz}	25,621 lb	25,621 lb	44,143 lb	11,871 lb
M_{ox}	65,926 lb-ft	65,926 lb-ft	21,839 lb-ft	12,230 lb-ft
M_{oy}	8,537 lb-ft	8,537 lb-ft	113,596 lb-ft	12,230 lb-ft
M_{oz}	8,537 lb-ft	8,537 lb-ft	21,839 lb-ft	68,680 lb-ft

Note: The calculated loads in (c) below that exceed these allowable loads have been evaluated and are acceptable.

Table 3.9-6(o) (Cont'd)

(Unit 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS OR MINIMUM THICKNESS REQUIRED	ACTUAL STRESS OR MINIMUM THICKNESS REQUIRED

c)[1]

RHR HEAT EXCHANGER NO. 2AE205

COMP. (FAULTED)	NOZZLE NOS. N1 (Channel Inlet)	N2 (Channel Outlet)	N3 (Shell Inlet)	N4 (Shell Outlet)
F_x (lbs)	4,253	4,792	7,079	2,384
F_y (lbs)	2,626	3,452	7,940	6,250
F_z (lbs)	2,144	1,861	13,677	4,417
M_x (ft-lbs)	10,895	12,011	21,948	43,883
M_y (ft-lbs)	16,393	1,461	33,124	7,688
M_z (ft-lbs)	23,153	7,357	31,163	3,242

RHR HEAT EXCHANGER NO. 2BE205

COMP. (FAULTED)	NOZZLE NOS. N1 (Channel Inlet)	N2 (Channel Outlet)	N3 (Shell Inlet)	N4 (Shell Outlet)
F_x (lbs)	6,720	8,469	5,568	2,870
F_y (lbs)	3,254	7,950	9,440	3,369
F_z (lbs)	404	1,867	10,762	3,977
M_x (ft-lbs)	3,521	9,418	24,813	14,848
M_y (ft-lbs)	81	693	21,090	11,111
M_z (ft-lbs)	11,116	49,060	25,455	2,521

Table 3.9-6(o) (Cont'd)

(Unit 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS OR MINIMUM THICKNESS REQUIRED	ACTUAL[2] STRESS OR MINIMUM THICKNESS REQUIRED
4. Support Brackets and Attachment Welds Loads: Faulted Design pressure and temperature, dead weight, nozzle loads, SSE.	Stress allowables per ASME Section III Subsection NF (Upset Condition).		
	a. Lower bracket welds		
	Bending stress	14,149 psi	10,107 psi
	Shear stress	7,074 psi	6,200 psi
	b. Upper Bracket welds		
	Bending stress	14,149 psi	3,766 psi
	Shear stress	7,074 psi	2,183 psi
5. Anchor Bolts Loads: Faulted Design pressure and temperature, dead weight, nozzle loads, SSE, SRV.	Stress allowable per ASME III, Subsection NF Lower support bolting Interaction criteria	52,500 psi	25,427 psi
6. Shell Adjacent to Support Brackets Loads: Faulted Design pressure and temperature, dead weight, nozzle loads, SSE.	Shell stress allowables per ASME Section III Subsection NC (Upset Condition).		
	a. Maximum principal stress adjacent to upper support	28,875 psi	18,083 psi
	b. Maximum principal stress adjacent to lower support	28,875 psi	19,311 psi

Table 3.9-6(o) (Cont'd)

(Unit 2)

CRITERIA	METHOD OF ANALYSIS	ALLOWABLE STRESS OR MINIMUM THICKNESS REQUIRED	ACTUAL[3] STRESS OR MINIMUM THICKNESS REQUIRED
7. Shell Away from Discontinuities	Stress allowable per ASME Section III Subsection NC (Upset Condition)		
Loads: Faulted			
Design pressure and temperature, dead weight, nozzle loads, SSE.	Principal stress	19,250 psi	12,080 psi

(1) The actual nozzle loads are provided by AE and are used to calculate the actual stresses.

(2) The "actual" stresses tabulated were calculated using the "maximum" nozzle loads that the RHR Heat Exchanger can withstand without exceeding the allowable stress.

(3) The "actual" stresses tabulated were calculated using the "actual" nozzle loads supplied by the AE for the Limerick 2 RHR Heat Exchanger.

Table 3.9-6(p)

RWCU PUMP

Following is a summary of the design calculations on the RWCU pump (B, C only):

Pump Part[1]	CALCULATED STRESS (psi)	ALLOWABLE STRESS (psi)
Casing wall	10,820	12,814
Cover bolting	20,000	25,000
Pedestal bolt (shear)	18,015	44,000
Motor Part[2]		
Motor foot bolts (shear)	174	60,000
Pump pedestal bolt (shear)	194	60,000
Foundation bolting	230	60,000

Following is a summary of the design calculations on the “A” RWCU pumps:

Part(1)	Calc. Stress (psi)	Allowable Stress (psi)
Pump Suction Nozzle	12,774 (U1) 1,582 (U2)	15,000
Pump Discharge Nozzle	12,824 (U1) 1,546 (U2)	17,500
Motor Case Outlet Nozzle	5,995 (U1) 5,995 (U2)	17,500
Motor Case Inlet Nozzle	5,997 (U1) 5,997 (U2)	17,500
Pump Support Flange Bolts (shear)	3,437 (U1) 3,325 (U2)	25,833 (U1) 11,800 (U2)
Pump Case/Motor Case Studs	23,229 (U1) 23,229 (U2)	25,000

(1) ASME Code calculations.
(2) Non-ASME Code calculations.

Table 3.9-6(q)

RCIC TURBINE

(UNIT 1)

CRITERIA/LOADING	COMPONENT	LIMITING STRESS TYPE	ALLOWABLE STRESS (PSI)	CALCULATED STRESS (PSI)
The highest stressed sections of the various components of the RCIC turbine assembly are identified. Allowable stresses are based on ASME Section III, for:				
Pressure Boundary Castings SA216-WCB				
Pressure Boundary Boltings, SA193-B7				
Alignment Dowel Pins: AISI 4037, Rc 28-35				
Normal Condition Loads:				
1. Design pressure	Castings:			
2. Design Temperature	1) Stop valve(3)	General membrane	17,500	(1)
3. Inlet Nozzle Loads	2) Governor valve(3)	General membrane	17,500	
4. Exhaust Nozzle Loads	3) Turbine inlet	Local bending	21,000	
	4) Turbine case	Local bending	21,000	
	Pressure-containing bolts:	Tensile	25,000	
	Structure alignment pins:	Shear	61,100	
Upset, Emergency or Faulted Condition:				
1. Design Pressure	Castings:			
2. Design Temperature	1) Stop valve(3)	General membrane	19,250	14,160
3. Controlling Combinations of SSE, SRV, and LOCA	2) Governor valve(3)	General membrane	19,250	15,300
	3) Turbine inlet	Local bending	23,100	15,300
4. Inlet nozzle loads	4) Turbine case	Local bending	23,100	18,000
5. Exhaust Nozzle loads	Pressure-Containing Bolts	Tensile	25,000	20,100
	Structure Alignment pins	Shear	61,100	51,600

Table 3.9-6(q) (Cont'd)

(Unit 1)

CRITERIA/LOADING	COMPONENT	ALLOWABLE LOAD CRITERIA[4]	CALCULATED CRITERIA[4]
Nozzle Load Definition:			
Turbine vendor has defined allowable nozzle loads for the turbine assembly. The above calculated stresses assume these allowable nozzle loads have been satisfied.			
Normal Condition Loads:			
1. Design pressure 2. Design temperature 3. Weight of structure 4. Thermal expansion	Inlet Nozzle	$F = \frac{2620-M}{3}$	F = 421 lb M = 814 ft-lb
	Exhaust Nozzle	$F = \frac{6000-M}{3}$	F = 1,226 lb M = 2,043 ft-lb
Upset, Emergency, and Faulted Condition Loads:			
1. Design pressure 2. Design temperature 3. Weight of structure 4. Thermal expansion 5. Controlling combination of SSE, SRV, and LOCA	Inlet Nozzle	$F = \frac{7500-M}{3.75}$	F = 1,156 lb M = 1,432 ft-lb
	Exhaust Nozzle	$F = \frac{8500-M}{0.34}$, but less than 7000 lb	F = 2,440 lb M = 6,253 ft-lb

Table 3.9-6(q) (Cont'd)

RCIC TURBINE

(UNIT 2)

CRITERIA/LOADING	COMPONENT	LIMITING STRESS TYPE	ALLOWABLE STRESS (PSI)	CALCULATED STRESS (PSI)
The highest stressed sections of the various components of the RCIC turbine assembly are identified. Allowable stresses are based on ASME Section III, for:				
Pressure Boundary Castings SA216-WCB				
Pressure Boundary Boltings, SA193-B7				
Alignment Dowel Pins: AISI 4037, Rc 28-35				
Normal Condition Loads:				
1. Design pressure 2. Design Temperature 3. Inlet Nozzle Loads 4. Exhaust Nozzle Loads	Castings: 1) Stop valve(3) 2) Governor valve(3) 3) Turbine inlet 4) Turbine case Pressure-containing bolts: Structure alignment pins:	 General membrane General membrane Local bending Local bending Tensile Shear	 17,500 17,500 21,000 21,000 25,000 61,100	(1)
Upset, Emergency or Faulted Condition:				
1. Design Pressure 2. Design Temperature 3. Controlling Combinations of SSE, SRV, and LOCA 4. Inlet nozzle loads 5. Exhaust Nozzle loads	Castings: 1) Stop valve(3) 2) Governor valve(3) 3) Turbine inlet 4) Turbine case Pressure-Containing Bolts Structure Alignment pins	 General membrane General membrane Local bending Local bending Tensile Shear	 19,250 19,250 23,100 23,100 25,000 61,100	 14,160 15,300 15,300 18,000 20,100 51,600

Table 3.9-6(q) (Cont'd)

(Unit 2)

CRITERIA/LOADING	COMPONENT	ALLOWABLE LOAD CRITERIA[4]	CALCULATED CRITERIA[4]
Nozzle Load Definition:			
Turbine vendor and GE have defined allowable nozzle loads for the turbine assembly. The above calculated stresses assume these allowable nozzle loads have been satisfied.			
Normal Condition Loads:			
1. Design pressure 2. Design temperature 3. Weight of structure 4. Thermal expansion	Inlet Nozzle	$F = \frac{2620-M}{3}$	F = 563 lb M = 575 ft-lb
	Exhaust Nozzle	$F = \frac{6000-M}{3}$	F = 324 lb M = 1,748 ft-lb
Upset, Emergency, and Faulted Condition Loads:			
1. Design pressure 2. Design temperature 3. Weight of structure 4. Thermal expansion 5. Controlling combination of SSE, SRV, and LOCA	Inlet Nozzle	$F = \frac{7500-M}{3.75}$	F = 1,518 lb M = 1,137 ft-lb
	Exhaust Nozzle	$F = \frac{8500-M}{0.34}$, but less than 7000 lb	F = 1,016 lb M = 3,030 ft-lb

_____

(1) Calculated stresses for the faulted condition are lower than the allowable stresses for the normal condition, therefore the normal condition is not evaluated.

(2) Operability: Analysis indicated that shaft deflection with faulted loads is 0.014 inch; which is fully acceptable; and maximum bearing load with faulted condition is 80% of allowable.

(3) 100% radiograph

(4) F = resultant force (lb); M = resultant moment (ft-lb).

Table 3.9-6(r)

RCIC PUMP

CRITERIA/LOADING		COMPONENT	LIMITING STRESS TYPE	ALLOWABLE STRESS (PSI)	CALCULATED STRESS (PSI)
Pressure boundary stress limits of the various components for the RCIC pump assembly are based on ASME Section III, for pressure boundary parts at 140°F.					
1. Forged barrel, SA105 Grade II	S_y = 36,000 psi				
2. End cover plates, SA105 Grade II	S_y = 36,000 psi				
3. Nozzle connections, SA105 Grade II	S_y = 36,000 psi				
4. Aligning pin, SA105 Grade II	S_y = 36,000 psi				
5. Closure bolting, SA193-87	S_y = 105,000 psi				
6. Pump holddown bolting, SA449	S_y = 81,000 psi				
7. Taper pins, SA108 Grade B1112	S_y = 75,000 psi				
Normal and Upset Condition Loads:					
1. Design pressure		1. Forged barrel	General membrane[1]		
2. Design temperature		2. Nozzle reinforcement	Tensile shear		
3. Operating basis earthquake		3. Alignment pin	Tensile		
4. Suction nozzle loads		4. Taper pins			
5. Discharge nozzle loads		5. Pump holddown bolts			
6. Thermal expansion					
7. SRV					
8. Dead weight					
Emergency or Faulted Condition Loads:					
1. Design pressure		1. Forged barrel	General membrane	17,500	7,792
2. Design temperature		2. Nozzle reinforcement at barrel	General membrane	26,250	8,680
3. Safe shutdown earthquake		3. Alignment pin	Shear	18,000	2,465
4. Suction nozzle loads		4. Taper pins (bearing housing)		15,000	2,520
5. Discharge nozzle loads		5. Pump holddown bolts	Tension	48,000	37,196
6. Thermal expansion					
7. LOCA					
8. Dead weight					

Table 3.9-6(r) (Cont'd)

CRITERIA/LOADING	COMPONENT	ALLOWABLE LOADS[4] (lb, ft-lb)	CALCULATED LOADS (lb, ft-lb)
Normal and Upset Condition Loads:			
1. Design pressure	Suction	F_o = 1940	F_i = 1173
2. Design temperature	Nozzle	M_o = 2950[3]	M_i = 2555
3. Weight of structure			
4. Thermal expansion	Discharge	F_o = 3715	F_i = 913
5. Operating basis earthquake	Nozzle	M_o = 4330	M_i = 1193
6. SRV			
Emergency or Faulted Condition Loads:			
1. Design pressure	Suction	F_o = 2325	F_i = 1033
2. Design temperature	Nozzle	M_o = 2950	M_i = 2438
3. Weight of structure			
4. Thermal expansion	Discharge	F_o = 4450	F_i = 1061
5. Safe shutdown earthquake	Nozzle	M_o = 5200	M_i = 1751
6. LOCA			

(1) Calculated stresses for emergency or faulted condition are less than the allowable for normal plus upset condition.

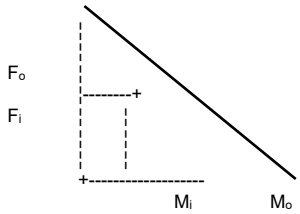
(2) Operability static analysis for emergency or faulted condition shows that the maximum shaft deflection is 0.0044 inch with a 0.0055 inch allowable, shaft stresses are 5602 psi with 32,000 psi allowable, drive end bearing loads are 45 lb with 7670 lb allowable, and thrust end bearing loads are 1462 lb with 17,200 lb allowable.

(3) This allowable moment was determined by analytical qualification which exceeds the Code-determined allowable.

Table 3.9-6(r) (Cont'd)

(4) Allowable nozzle load criteria:
Units: Forces - lb
Moments - ft-lb

The allowable combinations of forces and moments are as follows:



$$\frac{F_i}{F_o} + \frac{M_i}{M_o} \leq 1$$

where:

F_i = Largest absolute value of the three (F_x, F_y, F_z) that may be imposed by actual external orthogonal forces the interface pipe.

M_i = Largest absolute value of the three actual external orthogonal moments (M_x, M_y, M_z) permitted from the interface pipe when they are combined simultaneously for a specific condition.

F_o = Allowable value of F_i when all moments are zero.

M_o = Allowable value of M_i when all forces are zero.

Table 3.9-6(s)

REACTOR REFUELING AND SERVICING EQUIPMENT

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Table 3.9-6(s) (Cont'd)

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Table 3.9-6(s) (Cont'd)

ACCEPTANCE CRITERIA	LOADING	PRIMARY STRESS TYPE	ALLOWABLE STRESS (psi)	CALCULATED STRESS (psi)
FUEL PREPARATION MACHINE				
The allowable axial plus bending loads stresses are based on manual of steel construction, 1980, 8th edition				
F_y = 35,000 psi				
F_u = 38,000 psi				
For normal condition:(2)	For normal condition:	Axial load	23,100	4,441
S_{limit} = 0.66 F_y	1. Static	plus bending		
For emergency condition:(2)	For emergency condition:	Axial load	30,800	27,619
S_{limit} = 0.88 F_y	1. Static 2. OBE 3. LOCA 4. SRV	plus bending		
For faulted condition:(2)	For faulted condition:	Axial load	30,800	30,118
S_{limit} = 0.88 F_y	1. Static 2. SSE 3. LOCA 4. SRV	plus bending		

Table 3.9-6(s) (Cont'd)

ACCEPTANCE CRITERIA	LOADING	PRIMARY STRESS TYPE	ALLOWABLE STRESS (psi)	CALCULATED STRESS (psi)
REFUELING PLATFORMS				
The allowable axial plus bending loads stresses are based on ASME Section III, Subsection NA				
For type				
S_u = 58,000 psi				
S_y = 36,000 psi				
For normal condition: $S_{limit} = S_m = 0.66\ S_y$	For normal condition: 1. Static loads	Axial load plus bending	23,760	6,366 (3)
For upset condition: $S_{limit} = 0.9\ S_y$	For upset condition: 1. Static 2. OBE 3. LOCA 4. SRV	Axial load plus bending	31,680	31,552 (3)
For faulted condition: $S_{limit} = 0.7\ S_u$	For faulted condition: 1. Static 2. SSE 3. LOCA 4. SRV	Axial load plus bending	40,600	32,455 (3)

(1) Pins in shear are limiting factor for horizontal loads applied to all rack castings. Allowable S_s assumed @ 50% allowable stress.
(2) The allowable stresses are shape dependent; therefore, these factors apply only at the location of the calculated stress.
(3) Calculated stresses shown on this table are based on conservative set of spectra, and pre-upgrade conditions. Calculation LS-0266 demonstrates on a comparative basis that these stresses bound the stresses in the upgraded configuration.

Table 3.9-6(t)

HPCI PUMP

LOCATION[1]	LOADING CONDITION	CRITERIA[2]	CALCULATED STRESS (psi)	ALLOWABLE STRESS (psi)
PRESSURE BOUNDARY PARTS				
Closure Bolting (Main)	Emergency/Faulted Condition: 1. Design pressure 2. Design temperature 3. Seismic loads 4. Nozzle loads 5. SRV 6. LOCA	The allowable stresses are based on normal and upset condition in accordance with ASME Section III for boundary parts at 140°F	19,950	25,000
Closure Bolting (Booster)			17,400	25,000
Casing Wall Thickness (Main)			12,050	14,000
Casing Wall Thickness (Booster)			3,650	14,000
NON-PRESSURE BOUNDARY PARTS				
Pump Bolts (Booster) (Tensile)	Emergency/Faulted Condition: 1. Design pressure 2. Design temperature 3. Seismic loads 4. Nozzle loads	F_o, M_o Actual	20,860 15,929	30,000 25,000
Pump Bolts (Main) (Tensile)		F_o, M_o Actual	29,042 14,813	30,000 25,000
Dowel Pins (Booster) (Shear)		F_o, M_o Actual	30,880 21,498	42,000 33,600
Dowel Pins (Main) (Shear)		F_o, M_o Actual	38,488 23,451	42,000 33,600

(1) Eight anchor bolts, each carries the stresses for both units mounted on a common base-plate.

(2) The allowable stress values for bolts are 0.5 S_u, and 0.4 S_u for pins where F_o, M_o criteria are used. For actual nozzle loads, the stress limits are based on ASME Section III at 140°F.

Table 3.9-6(u)

CONTROL ROD DRIVE (INDICATOR TUBE)

CRITERIA	LOADING	PRIMARY STRESS TYPE	ALLOWABLE STRESS (psi)	CALCULATED STRESS[2] (psi)
Allowable primary membrane stress plus bending stress plus bending is based on ASME Section III for type 316 stainless steel @ 250°F S_m = 20,000 psi				
For normal and upset condition: S_{allow} = 50,000 psi	For normal and upset condition: 1. Normal loads[1]	Primary membrane plus bending	50,000	45,500
For emergency condition: S_{allow} = 50,000 psi	For emergency condition: 1. Dynamic P 2. OBE 3. SRV	primary membrane plus bending	50,000	45,500
For faulted condition: S_{allow} = 59,900 psi	For faulted condition: 1. Dynamic P 2. SSE 3. LOCA 4. SRV	Primary membrane plus bending	59,900	46,600

[1] Normal loads include pressure, temperature, weight and mechanical loads.
[2] The loads listed here correspond to the operating power level of 3458 MWt. Per Reference 3.9-31, the loads are not changed for the MUR power uprate conditions.

Table 3.9-6(v)

CRD HOUSING[1]

CRITERIA	LOADING	PRIMARY STRESS TYPE	ALLOWABLE STRESS (psi)	CALCULATED STRESS[2] (psi)
Primary Stress Limit - The allowable primary membrane stress is based on ASME Section III, for Class 1 vessels, stainless steel.				
For normal and upset condition: $S_{limit} = 1.0\ S_m$ = 16,660 psi @ 575?F	Normal and upset condition loads: 1. Design pressure 2. Stuck rod scram loads 3. OBE, with housing lateral support installed 4. SRV 5. Hydraulic line loads	Maximum membrane stress intensity occurs at the tube-to-tube weld near the center of the housing for normal, upset, emergency, and faulted conditions.	16,660	11,900
For faulted conditions:	Faulted conditions loads: 1. Design pressure 2. Stuck rod scram loads 3. SSE, with housing lateral support installed 4. Annulus pressurization 5. LOCA 6. Hydraulic line loads		59,760	25,850

[1] Analyzed to emergency conditions limits
[2] The loads listed here correspond to the operating power level of 3458 MWt. Per Reference 3.9-32, the loads are bounding for the MUR power uprate condition.

Table 3.9-6(w)

JET PUMPS

Criteria	Loading Combinations	Stress Type	Allowable Stress (psi)	Calculated Stress[1] (psi)
Primary membrane plus bending stress based on ASME Section III				
For service levels A and B (normal and upset) condition: For type 304SS @ 550°F S_m = 16,900 psi S_{limit} = 3.0 S_m psi	Normal and Upset Condition Loads: 1. Pressure 2. Weight 3. Clamping force 4. OBE 5. Vibration force 6. Thermal loads 7. SRV_{ALL}	Primary membrane plus bending plus secondary	50,700	18,185
For service level C (emergency) condition: For type 304SS @ 550°F S_m = 16,900 psi S_{limit} = 2.25 S_m psi	Emergency Condition Loads: 1. Pressure 2. Weight 3. Clamping force 4. Chugging 5. SRV_{ALL}	Primary membrane plus bending	38,025	10,702
For service level D (faulted) condition: For type 304SS @ 550°F S_m = 16,900 psi S_{limit} = 3.6 S_m psi	Faulted Condition Loads: 1. Pressure (internal) 2. Pressure (external) 3. Weight 4. Clamping force 5. Shock wave loads 6. SSE 7. Annulus pressurization 8. Jet reaction	Primary membrane plus bending	60,840	46,788

[1] The loads listed here correspond to the operating power level of 3458 MWt. Per Reference 3.9-32, the loads are bounding for the MUR power uprate condition.

Table 3.9-6(x)

FUEL ASSEMBLY (INCLUDING CHANNEL)[1][2][3]

Acceptance Criteria	Loading	Primary Load Type	Calculated Peak Acceleration	Evaluation Basis Acceleration
Acceleration Envelope	Horizontal Direction: Peak Pressure SSE Annulus Pressurization	Horizontal Acceleration	2.45 g	[5]
	Vertical Direction: Peak Pressure SSE Safety/Relief Valve Chugging	Vertical Accelerations	3.7 g	[5]

(1) Evaluation basis accelerations and evaluations are contained in NEDE-21175-3-P.

(2) The calculated maximum fuel assembly gap opening for the most limiting load combination is <0.01 inch based on the methodology contained in NEDE-21175-3-P.

(3) The fatigue analysis indicates that the fuel assembly has adequate fatigue capability to withstand the loadings resulting from multiple SRV actuations and the OBE + SRV event.

(4) This value is determined using the methodology contained in NEDE-21175-3-P.

(5) These are bounding values from GNF2 and GNF3. The evaluation basis accelerations are proprietary and bound the calculated values. For GNF3, these are found in Reference 3.9-36 and for GNF2, these are found in Reference 3.9-35.

Table 3.9-6(y)

HIGHEST STRESSED REGION ON THE LPCI COUPLING (ATTACHMENT RING)

Criteria	Loading Combinations	Stress Type	Allowable Stress (psi)	Calculated Stress[1] (psi)
Primary membrane plus bending stress based on ASME Section III NG-3000 for type CF3				
For service levels A and B (normal & upset) condition: $S_{limit} = 1.5\ S_m$ psi S_m = 16,900 psi @ 550°F	Normal and Upset Condition Loads: 1. Normal loads 2. Upset pressure 3. OBE 4. SRV	Primary membrane + bending	25,350	12,000
For service level C (emergency) condition: $S_{limit} = 2.25\ S_m$ S_m = 16,900 psi @ 550°F	Emergency Condition Loads: 1. Normal loads 2. Emergency pressure 3. Chugging 4. SRV	Primary membrane + bending	38,025	21,100
For service level D (faulted) condition: $S_{limit} = 3.6\ S_m$ S_m = 16,900 psi @ 550°F	Faulted Condition Loads: 1. Normal loads 2. Faulted pressure 3. Annulus pressurization 4. SSE	Primary membrane + bending	60,840	28,000

[1] The loads listed here correspond to the operating power level of 3458 MWt. Per Reference 3.9-32, the loads are bounding for the MUR power uprate condition.

Table 3.9-6(z)

REACTOR VESSEL SUPPORT EQUIPMENT:
CRD HOUSING SUPPORT

CRITERIA	LOADING	LOCATION	ALLOWABLE STRESS (psi)	CALCULATED STRESS (psi)
Primary Stress Limit				
AISC specification for the design, fabrication, and erection of structural steel for buildings	Faulted condition loads 1. Deadweight 2. Impact force from failure of a CRD housing	Beams (top chord) Beams (bottom chord)	33,000 33,000 33,000 33,000	f_a = 12,200 f_b = 16,500 f_a = 10,300 f_b = 11,700
For normal and upset condition: $f_a = 0.60\ f_y$ (tension) $f_b = 0.60\ f_y$ (bending) $f_v = 0.40\ f_y$ (shear) For faulted conditions: f_a limit = 1.5 f_a (tension) f_b limit = 1.5 f_b (bonding) f_v limit = 1.5 f_v (shear) f_y = material yield strength	(Deadweights and earthquake loads are very small compared to jet forces.)	Grid structure	41,500 27,500	f_b = 40,700 f_v = 11,100

Table 3.9-6(aa)

CONTROL ROD GUIDE TUBE

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress[1] (psi)
Control Rod Guide Tube Primary stress limit - The allowable primary membrane stress plus bending stress is based on ASME Section III for type 304 stainless steel tubing.		Maximum stress occurs in the guide tube base		
For normal and upset conditions: 1.5 S_m = 1.5x16,000 psi = 24,000 psi	Upset condition loads 1. dead weight 2. external pressure 3. lateral flow impingement 4. OBE + SRV_{max} 5. scram	$P_m + P_b$	24,000	14,820
For emergency condition: 2.25 S_m = 36,000 psi	Emergency condition loads: 1. dead weight 2. external pressure 3. lateral flow impingement 4. SRV_{ADS} + CHUG	$P_m + P_b$	36,000	20,920
For faulted condition: 2.4 S_m = 38,400 psi	Faulted condition loads: 1. dead weight 2. external pressure 3. lateral flow impingement 4. SSE + SRV_{LSPA} + BCO	$P_m + P_b$	38,400	33,230

(1) The loads are calculated in Reference 3.9-32.

Table 3.9-6(ab)

INCORE HOUSING

Criteria	Loading	Primary Stress Type	Allowable Stress (psi)	Calculated Stress[1] (psi)
Primary Stress Limit - The allowable primary membrane stress is based on ASME Section III for Class 1 vessels for type 304 stainless steel.				
For normal, upset and emergency condition: $S_{limit} = 1.0\ S_m$ = 16,660 psi at 575°F	Service Level C (Emergency) condition loads 1. Design pressure 2. Design basis earthquake 3. SRV	Maximum membrane stress intensity occurs at the outer surface of the vessel penetration.	16,660	13,850
For faulted condition: $S_{limit} = 2.4\ S_m$	Faulted condition loads: 1. Faulted pressure 2. LOCA 3. SRV 4. SSE	Maximum membrane stress intensity occurs at the outer surface of the vessel penetration.	39,984	21,225

(1) The loads listed here correspond to the operating power level of 3458 MWt. Per Reference 3.9-32, the loads are bounding for the MUR power uprate condition.

Table 3.9-7

NON-NSSS PIPING SYSTEMS POWER ASCENSION TESTING

PIPING SYSTEM	CODE(S)/ SC/HE ME [1]	TEMP>200°F	THERMAL EXPANSION TEST [2]	DYNAMIC TRANSIENT TEST [3]	STEADY-STATE VIBRATION TEST [4]	REMARKS
Main steam and main steam relief	ASME III-2, B 31.1; SC I, SC II; HE	yes	yes	yes	yes	Main stop valve closure and SRV opening transients
Extraction steam	B 31.1; SC II; HE	yes	N/A[5]	N/A	N/A	
Condensate storage and transfer	B 31.1; SC II; ME	no	N/A	N/A	N/A	
Feedwater	ASME III-1,2, B 31.1; SC I, SC II; HE	yes	yes	yes	yes	Power ascension test for safety-related piping portion only
Air removal and seal steam	B 31.1; SC II, HE	yes	N/A	N/A	N/A	
Service water	B 31.1; SC IIA; ME	no	N/A	N/A	N/A	A portion of the system has 200°F < T < 300°F.
Condensate	B 31.1; SC II; HE	yes	N/A	N/A	N/A	
Clarified water	B 31.1; SC II; ME	no	N/A	N/A	N/A	
Fuel and diesel oil storage and transfer	B 31.1; SC I, SC II; ME	no	N/A	N/A	N/A	Emergency diesel exhaust has T>300°F and thermal expansion test performed.
RHRSW	ASME III-3, B 31.1; SC I, SC IIA, SC II; ME	no	N/A	N/A	N/A	

Table 3.9-7 (Cont'd)

PIPING SYSTEM	CODE(S)/ SC/HE ME [1]	TEMP>200°F	THERMAL EXPANSION TEST [2]	DYNAMIC TRANSIENT TEST [3]	STEADY-STATE VIBRATION TEST [4]	REMARKS
ESW	ASME III-3, B 31.1; SC I, SC IIA; ME	no	N/A	N/A	N/A	
Auxiliary steam	B 31.1; SC II; HE	yes	N/A	N/A	N/A	
Lube oil	B 31.1; SC II; ME	no				
Fire protection	SC II, SC IIA; ME	no	N/A	N/A	N/A	
Process sampling	ASME III-1,2,3, B 31.1; SC I, SC II; ME	no	N/A	N/A	N/A	
Chlorination	B 31.1; SC II; ME	no	N/A	N/A	N/A	
Compressed air	ASME III-2,3, B 31.1; SC I, SC II; ME	no	N/A	N/A	N/A	
Instrument gas	ASME III-2,3, B 31.1; SC I, SC II; ME	no	N/A	N/A	N/A	
TECW	B 31.1; SC II; ME	no	N/A	N/A	N/A	
Circulating water	B 31.1; SC II; ME	no	N/A	N/A	N/A	
Demineralized water makeup	B 31.1; SC II; ME	no	N/A	N/A	N/A	
Safeguard piping fill	ASME III-2, B 31.1; SC I, SC IIA; ME	no	N/A	N/A	N/A	
RECW	ASME III-2, 3, B 31.1; SC I, SC IIA; ME	no	N/A	N/A	N/A	
MSIV-LCS	ASME III-1,2, B 31.1; SC I, SC II; HE	yes	no	N/A	N/A	Abandoned

Table 3.9-7 (Cont'd)

PIPING SYSTEM	CODE(S)/ SC/HE ME [1]	TEMP>200°F	THERMAL EXPANSION TEST [2]	DYNAMIC TRANSIENT TEST [3]	STEADY-STATE VIBRATION TEST [4]	REMARKS
CSCWS	B 31.1; SC I; ME	no	N/A	N/A	N/A	
HPCI	ASME III-1,2, B 31.1; SC I, SC IIA, SC II; HE, ME	yes	yes	yes	yes	Steady-state vibration for steam supply and turbine exhaust Dynamic transient for turbine stop valve closure.
RCIC	ASME III-1,2, B 31.1; SC I; HE, ME	yes	yes	N/A	yes	Steady-state vibration for RCIC steam supply and turbine exhaust
Plant heating steam	B 31.1; SC II, SC IIA; HE	yes	N/A	N/A	N/A	
RWCU	ASME III-1,2,3; SC I, SC II, SC IIA; HE, ME	yes	yes	N/A	yes	Steady-state vibration for RWCU line inside containment
RHR	ASME III-1,2,3; SC I; HE, ME	yes	yes	N/A	yes	Majority of the system has normal operating temperature less than 300°F. Thermal expansion tests are done for SC I systems with T>300°F. Steady-state vibration for inside containment piping and RHR pump discharge

Table 3.9-7 (Cont'd)

PIPING SYSTEM	CODE(S)/ SC/HE ME [1]	TEMP>200?F	THERMAL EXPANSION TEST [2]	DYNAMIC TRANSIENT TEST [3]	STEADY-STATE VIBRATION TEST [4]	REMARKS
Condensate filter demineralizer	B 31.1; SC II; ME	no	N/A	N/A	N/A	
CRD hydraulic	ASME III-2, B 31.1; SC I, SC II, SC IIA; ME	no	N/A	N/A	N/A	
SLCS	ASME III-1,2, B 31.1; SC I, SC IIA; HE, ME	no (See remarks)	N/A (See remarks)	N/A	N/A	Only a small portion of the line near RPV has temperature >200°F.
Core spray	ASME III-1,2; SC I; HE, ME	yes	yes	N/A	yes	Steady-state vibration for core spray pump discharge
FPCC	ASME III-2,3, B 31.1; SC I, SC II, SC IIA; ME	no	N/A	N/A	N/A	
CAC	ASME III-2, B 31.1; SC I, SC IIA; ME	no	N/A	N/A	N/A	No safety-related piping with T>300°F
Solid radwaste	B 31.1; SC II; ME	no	N/A	N/A	N/A	
Liquid radwaste	B 31.1; SC II; ME	no	N/A	N/A	N/A	
Gaseous radwaste	B 31.1; SC II; ME	yes	N/A	N/A	N/A	
DCWS	B 31.1; SC II; ME	no	N/A	N/A	N/A	
Generator H_2 cooling and CO_2 purge	B 31.1; SC II; ME	no	N/A	N/A	N/A	

Table 3.9-7 (Cont'd)

(1) Code(s): ASME III B&PV Code, -1, -2 or -3: Denotes nuclear Class 1, 2, or 3 piping;
B 31.1: Denotes ANSI B 31.1, Code for Pressure Piping;
SC I, II, or IIA: Denotes seismic Category I, II, or IIA;
HE: Denotes high energy piping system, i.e., pressure ≥275 psi or temperature ≥200°F during normal plant operation;
ME: Denotes moderate energy piping system.

(2) Thermal expansion test for the indicated systems corresponds to test description STP-17 in Table 14.2-3.

(3) Dynamic transient test for the indicated systems corresponds to test description STP-36 in Table 14.2-3. Main steam turbine trip test for Unit 2 (ref. Startup Test STP-36) at 100% power level will be performed during commercial operation of that Unit.

(4) Steady-state vibration tests for the indicated systems corresponds to test description STP-33 Table 14.2-3.

Instrument lines connected to process pipes on which steady-state vibration testing is performed are evaluated on the following basis;
a) for accessible lines; visually monitored
b) for inaccessible lines; instrument lines are monitored, inspected, and measured in accordance with startup test specification for BOP piping as committed in SSER-2.

(5) N/A: Denotes not applicable. Test is not performed for the following reason:
a) For thermal expansion tests: The system is not safety-related or the normal operating temperature < 300°F;
b) For dynamic transient test: The system is not safety-related or does not experience any significant transients;
c) For steady-state vibration tests: The system is not safety-related or no significant vibration is expected.

Table 3.9-8

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Table 3.9-9

DYNAMIC QUALIFICATION SUMMARY
NON-NSSS SAFETY-RELATED MECHANICAL EQUIPMENT

EQUIPMENT DESCRIPTION	ITEM NO.	SUPPLIER	DYNAMIC QUALIFICATION PACKAGE NO.
ESW pumps	8031-M-12	Byron Jackson	D-2
RHRSW pumps	8031-M-12	Byron Jackson	D-3
Diesel generators	8031-M-71	Colt Industries	D-7
Diesel oil transfer pumps	8031-M-79	Crane Dening	D-8
Diesel fuel oil storage tanks	8031-C-28	Buffalo Tank Div., Bethlehem Steel	D-209
Centrifugal fans	8031-M54A	Buffalo Forge	D-55
Drywell Sumps	8031-M-43A	Process Equip-ment Co.	D-5
Control room chilled water pumps	8031-M-58	Ingersoll-Rand	D-139
Control room chiller	8031-M-57A	Carrier Corp	D-138
Reactor enclosure crane	8031-M-16	Harnischfeger	D-50
Fuel pool skimmer surge tanks	8031-C-45	Pittsburgh-Des Moines Steel	D-172
RHR pump suction strainers	NE-265	ABB-Combustion Engineering	D-69
RCIC pump suction strainers	8031-M-162	Newark Wire Cloth	D-69

Table 3.9-9 (Cont'd)

EQUIPMENT DESCRIPTION	ITEM NO.	SUPPLIER	DYNAMIC QUALIFICATION PACKAGE NO.
HPCI pump suction strainers	8031-M-162	Newark Wire Cloth	D-69
Core spray pump suction strainers	NE-265	ABB-Combustion Engineering	D-69
Safeguard piping fill pumps	8031-M-164	Hayward Tyler Pump Co.	D-73
Primary containment vacuum breakers	8031-M-81	Anderson Greenwood Co.	D-135
Nuclear safety and relief valves	8031-M-204B	Crosby	D-74 D-154
		Lonergan	D-65 D-66
	8031-M-204C	Crosby	D-197
RHR HX vacuum relief valve	8031-M-204B	Crosby	D-67
RHR HX relief valve	8031-M-204B	Crosby	D-68
Pressure relief valves		Lonergan	D-31
CREFAS and RERS filter assembly	8031-M-72A	CIV	D-140
SGTS filters	8031-M-56	American Air Filter	D-137

Table 3.9-9 (Cont'd)

EQUIPMENT DESCRIPTION	ITEM NO.	SUPPLIER	DYNAMIC QUALIFICATION PACKAGE NO.
Containment hydrogen recombiners, recombiner power supply panels, recombiner control panels	8031-M-40	Atomics International	D-75
Rupture discs	8031-M-106	Continental Disc Corp.	D-97
MSIV and MSRV accumulator tanks	8031-M-170	Western piping and Engineering	D-157
Diesel oil transfer pump strainers	8031-M-36	Zurn Industries	D-4
Spray pond nozzles	8031-M-112	Spray Engineering Co.	D-9
Spray pond nozzle junction boxes	8031-M-112	Spray Engineering Co.	D-10
Drywell HVAC pressure relief valves	8031-M-123	American Air Filter	D-11
HPCI/RCIC Exhaust steam traps	8031-M-90A	Yarway	D-71
Nuclear wye strainers	8031-M-92AA	Western Piping and Engineering	D-76
MSRV Vacuum relief valves	8031-M-81	Anderson Greenwood Co.	D-136
HVAC Isolation valves	8031-M-70	Allis Chalmers	D-141 D-145
Back pressure steam isolation dampers	8031-M-113	American Warming and Ventilation Co.	D-142

Table 3.9-9 (Cont'd)

EQUIPMENT DESCRIPTION	ITEM NO.	SUPPLIER	DYNAMIC QUALIFICATION PACKAGE NO.
Volume control balancing dampers	8031-M-113	American Warming and Ventilation, Co.	D-148
Fire dampers	8031-M-113	American Warming and Ventilation, Co.	D-150
Slide gate dampers	8031-M-113	American Warming and Ventilation, Co.	D-151
SGTS heaters	8031-M-56	Industrial Engineering and Equipment Co.	D-184
Fuel oil and lube oil filter	8031-M-71	Colt Industries	D-218
Back flood check valves	8031-M-178	Zurn Industries	D-122
HVAC control panels	8031-M-66	Alison	D-162
HVAC control panels (Groups 1-10)	8031-M-66	MCC Powers	D-57 D-187 D-188 D-189 D-190 D-191 D-192 D-193 D-215 D-216
Drywell coolers	8031-M-123	American Air Filter	D-30
Spray pond pumphouse fan cabinets	8031-M-123	American Air Filter	D-48
Reactor enclosure fan cabinets	8031-M-123	American Air Filter	D-62

Table 3.9-9 (Cont'd)

EQUIPMENT DESCRIPTION	ITEM NO.	SUPPLIER	DYNAMIC QUALIFICATION PACKAGE NO.
Control enclosure fan cabinets	8031-M-123	American Air Filter	D-64
Diesel generator enclosure exhaust fans	8031-M-69C	Joy Mfg. Co.	D-6
Control enclosure recirculation fans	8031-M-69C	Joy Mfg. Co.	D-181
Reactor enclosure recirculation fans	8031-M-69C	Joy Mfg. Co.	D-63
Electro-hydraulic operated fan isolation and flow control dampers	8031-M-113	American Warming and Ventilation, Inc.	D-149
Pneumatic operated dampers	8031-M-113	American Warming and Ventilation, Inc.	D-152
Gravity back draft dampers	8031-M-113	American Warming and Ventilation, Inc.	D-153

Table 3.9-10

NSSS COMPARISON WITH REGULATORY GUIDE 1.48

	REGULATORY GUIDE 1.48[1]			LGS[1]				
COMPONENT	PLANT CONDITION[2]	LOADING COMBINATION 1/	DESIGN LIMIT	REGULATORY GUIDE PARAGRAPH	LOADING COMBINATION[c]	CODE ALLOWABLE STRESSES	ASME SECTION III REFERENCE	HOW LGS COMPARES WITH REGULATORY GUIDE 1.48
Class 1 Vessels	U	(NPC or UPC) + 0.5 SSE	NB-3223[2/]	1.a	(NPC or UPC), 0.5 SSE	3.0 S_m (includes) secondary stresses)	NB-3223	GE reflects industry position
	E	EPC	NB-3224[2/]	1.b	EPC, 0.5 SSE + transient	1.8_m	NB-3224 NB-3225	
	F	NPC + SSE +DSL	NB-3225[2/]	1.c	NPC + SSE + DSL	App. F - Section III		
Class 1 Piping	U	(NPC or UPC) + 0.5 SSE	NB-3654[2/]	1.a	(NPC or UPC), 0.5 SSE	3.0 S_m (includes secondary stresses	NB-3654	GE reflects industry position
	E	EPC	NB-3655[2/]	1.b	EPC, 0.5 SSE + transient	2.25 S_m	NB-3655	
	F	NPC + SSE + DSL	NB-3656[2/]	1.c	NPC + SSE + DSL	3.0 S_m	NB-3656	
Class 1 Pumps (inactive)	U	(NPC or UPC) + 0.5 SSE	NB-3223[5/1/]	2.a	(NPC or UPC), 0.5 SSE	1.63 S_m	NB-3223	GE reflects industry position
	E	EPC	NB-3224[1/]	2.b	EPC, 0.5 SSE + transient	1.8 S_m	NB-3224	
	F	NPC + SSE + DSL	NB-3225[1/]	2.c	NPC + SSE + DSL	App. F - Section III	NB-3225	
Class 1 Pumps (active)	U	(NPC or UPC) + 0.5 SSE	NB-3222[5/6/7 8]	4.a	(NPC or UPC), 0.5 SSE	Not applicable	Not applicable	Not applicable
	E	EPC	NB-3222[5/6/7/8/]	4.a	EPC			
	F[7/8/]	NPC + SSE + DSL	NB-3222[5/6/]	4.a	NPC + SSE + DSL			
Class 1 Valves (inactive) Designed by analysis.	U	(NPC or UPC) + 0.5 SSE	NB-3223[5/4/]	2.a	(NPC or UPC), 0.5 SSE	Not applicable	Not applicable	Not applicable
	E	EPC	NB-3224[4/]	2.b	EPC			
	F	NPC + SSE + DSL	NB-3225[2/4/]	2.c	NPC + SSE + DSL			

Table 3.9-10 (Cont'd)

		REGULATORY GUIDE 1.48[1]			LGS[1]			
COMPONENT	PLANT CONDITION[2]	LOADING COMBINATION 1/	DESIGN LIMIT	REGULATORY GUIDE PARAGRAPH	LOADING COMBINATION[c]	CODE ALLOWABLE STRESSES	ASME SECTION III REFERENCE	HOW LGS COMPARES WITH REGULATORY GUIDE 1.48
Class 1 Valves (inactive)	U	(NPC or UPC) + 0.5 SSE	1.1 Pr	3.a	(NPC or UPC), 0.5 SSE	1.1 P_r	NB-3525	GE reflects industry position
Designated by either standard or alternative design rules.	E	EPC	1.2 Pr	3.b	EPC, 0.5 SSE + transient	1.2 P_r	NB-3526	
	F	NPC + SSE + DSL	1.5 Pr	3.c	NPC + SSE + DSL	1.5 P_r	NB-3527	
Class 1 Valves (active)	U	(NPC or UPC) + 0.5 SSE	NB-3222[5/6/7/8/]	4.a	(NPC or UPC), 0.5 SSE	Not applicable	Not applicable	Not applicable
Designed by analysis.	E	EPC	NB-3222[5/6/7/8/]	4.a	EPC			
	F	NPC + SSE + DSL	NB-3222[5/6/7/8/]	4.a	NPC + SSE + DSL			
Class 1 Valves (active)	U	(NPC or UPC) + 0.5 SSE	1.0 Pr[6/]	5.a	(NPC or UPC), 0.5 SSE	1.0 P_r[(a)]	NB-3525	GE reflects industry position
Designed by standard or alternative design rules.	E	EPC	1.0 Pr[6/]	5.a	EPC, 0.5 SSE + transient	1.0 P_r[(a)]	NB-3626	
	F	NPC + SSE + DSL	1.0 Pr[6/]	5.a	NPC + SSE + DSL	1.0 P_r[(a)]	NB-3527	
Class 2 & 3 Vessels (Division 1) of ASME Section VIII	U	(NPC or UPC) + 0.5 SSE	1.1 g[9/]	6.a	(NPC or UPC), 0.5 SSE	σ_m = 1.1 S[(b)]	Code Case 1607	Faulted condition: NRC more conservative. GE reflects industry position.
	E	EPC	1.1 g[9/]	6.a	EPC, 0.5 SSE + transient		NC/ NB 3221.1(b)	
	F	NPC + SSE + DSL	1.5 g[9/]	6.b	NPC + SSE + DSL	?$_m$ = 2.0 S[(b)]		
Class 2 Vessels (Division 2) of ASME Section VIII	U	(NPC or UPC) + 0.5 SSE	NB-3223[2/]	7.a	(NPC or UPC), 0.5 SSE	Not applicable	Not applicable	Not applicable
	E	EPC	NB-3224[2/]	7.b	EPC			
	F	NPC + SSE + DSL	NB-3225[2/]	7.c	NPC + SSE + DSL			

Table 3.9-10 (Cont'd)

		REGULATORY GUIDE 1.48[1]			LGS[1]			
COMPONENT	PLANT CONDITION[2]	LOADING COMBINATION 1/	DESIGN LIMIT	REGULATORY GUIDE PARAGRAPH	LOADING COMBINATION[c]	CODE ALLOWABLE STRESSES	ASME SECTION III REFERENCE	HOW LGS COMPARES WITH REGULATORY GUIDE 1.48
Class 2 & 3 Piping	U	(NPC or UPC) + 0.5 SSE (b)(1)	NC-3611.1[10/] (b)(4)(c)	8.a	(NPC or UPC), 0.5 SSE	1.2 S_h	NC/ND 3611.3(b)	NRC more conservative. GE reflects industry position.
	E	EPC (b)(1)	NC-3611.1[10/] (b)(4)(c)	8.a	EPC, 0.5 SSE + transient	1.8 S_h	NC/ND 3611.3(c) (4)(b)	
	F	NPC + SSE + DSL (b)(4)(c) (b)(2)	NC-3611.1[10/]	8.b	NPC + SSE + DSL	2.4 S_h	Code case 1606	
Class 2 & 3 Pumps (inactive)	U	(NPC or UPC) + 0.5 SSE	$\sigma_m \leq 1.1 S \geq \frac{\sigma_m + \sigma_b}{1.5}$	9.a	(NPC or UPC), 0.5 SSE	Not applicable	Not applicable	Not applicable
	E	EPC	$\sigma_m \leq 1.1 S \geq \frac{\sigma_m + \sigma_b}{1.5}$	9.a	EPC			
	F	NPC + SSE + DSL	$\sigma_m \leq 1.2 S \geq \frac{\sigma_m + \sigma_b}{1.5}$	9.b	NPC + SSE + DSL			
Class 2 & 3 Pumps (active)	U	(NPC or UPC) + 0.5 SSE	$\sigma_m \leq 1.0 S \geq^{11/} \frac{\sigma_m + \sigma_b}{1.5}$	10.a	(NPC or UPC), 0.5 SSE	$\sigma_m = 1.1 S^{(b)(d)}$	Code case 1636	GE reflects industry position
	E	EPC	$\sigma_m \leq 1.0 S \geq^{11/} \frac{\sigma_m + \sigma_b}{1.5}$	10.a	EPC, 0.5 SSE + transient		NC/ND 3423	
	F	NPC + SSE + DSL	$\sigma_m \leq 1.0 S \geq^{11/} \frac{\sigma_m + \sigma_b}{1.5}$	10.a	NPC + SSE + DSL	$\sigma_m = 1.2 S^{(b)(d)}$		
Class 2 & 3 Valves (inactive)	U	NPC or UPC) + 0.5 SSE	1.1 P_r	11.a	(NPC or UPC), 0.5 SSE	$\sigma_m = 1.1 S^{(b)}$	Code case 1635	Equally conservative
	E	EPC	1.1 P_r	11.a	EPC, 0.5 SSE + transient			
	F	NPC + SSE + DSL	1.2 P_r	11.b	NPC + SSE + DSL	$\sigma_m = 1.2 S^{(b)}$	NC/ND 3621	

Table 3.9-10 (Cont'd)

	REGULATORY GUIDE 1.48[1]				LGS[1]			
COMPONENT	PLANT CONDITION[2]	LOADING COMBINATION 1/	DESIGN LIMIT	REGULATORY GUIDE PARAGRAPH	LOADING COMBINATION[c]	CODE ALLOWABLE STRESSES	ASME SECTION III REFERENCE	HOWLGSCOMPARES WITH REGULATORYGUIDE 1.48
Class 2 & 3 Valves (active)	U	(NPC or UPC) + 0.5 SS	1.0 P_r 11/	12.a	(NPC or UPC), 0.5 SSE	σ_m = 1.1 S[(a)(b)]	Code case 1635	Equally conservative. One valve, E41-F005, does not meet this LGS alternate position.
	E	EPC	1.0 P_r 11/	12.a	EPC, 0.5 SSE + transient			
	F	NPC + SSE + DSL	1.0 P_r 11/	12.a	NPC + SSE + DSL	σ_m = 1.2 S[(a)(b)]	NC/ND 362	Structural integrity under its peak transient conditions was justified under applicable provisions of B31.1 (1967). This valve fully meets the load combination and acceptance criteria of Table 3.9-6.

(1) Numerical indicators (e.g. 1/) in the Regulatory Guide portion of the table correspond to footnotes of Regulatory Guide 1.48.
Alphabetical indicators in the LGS portion of table (or comparative column) correspond to the following:

(a) In addition to compliance with the design limits specified, assurance of operability under all design loading combinations shall be in accordance with Section 3.9.3.2.

(b) The design limit for local membrane stress intensity or primary membrane plus primary bending stress intensity is 150% of that allowed for general membrane (except as limited to 2.45 for inactive components under faulted condition).

(c) When selecting plant events for evaluation, the choice of the events to be included in each plant condition is selected based on the probability of occurrence of the particular load combination. The combination of loads are those identified in Table 3.9-2.

UPC = Upset Plant Conditions
NPC = Normal Plant Conditions
EPC = Emergency Plant Conditions
DSL = Dynamic System Loading
SSE = Safe Shutdown Earthquake

(d) Inactive limits may be used since operability will be demonstrated in accordance with Section 3.9.3.2.

(2) U = Upset
E = Emergency
F = Faulted

Table 3.9-11

DESIGN LOADING COMBINATIONS FOR ASME CODE
CLASS 1, 2, AND 3 NON-NSSS COMPONENTS(2)

CONDITION		DESIGN LOADING COMBINATIONS(1)
Design		PD
Normal		PD + DW
Upset	(a)	$PO + DW + (OBE^2 + SRV_x^2)^{1/2}$
	(b)	$PO + DW + (RVC^2 + OBE^2)^{1/2}$
	(c)	PO + DW + FV
	(d)	PO + DW + OBE + RVO
Emergency	(a)	$PO + DW + (OBE^2 + SRV^2_{ADS} + SBA^2)^{1/2}$
	(b)	$PO + DW + (FV^2 + OBE^2)^{1/2}$
Faulted	(a)	$PO + DW + (OBE^2 + SRV^2_{ADS} + IBA^2)^{1/2}$
	(b)	$PO + DW + (SSE^2 + SRV^2_{ADS} + IBA^2)^{1/2}$
	(c)	$PO + DW + (SSE^2 + DBA^2)^{1/2}$

where:

PD = design pressure
PO = operating pressure
DW = dead weight
OBE = operating basis earthquake (inertia portion)
SSE = safe shutdown earthquake (inertia portion)
SRV_x = loads due to SRV blow, axisymmetric or asymmetric
SRV_{ADS} = loads due to automatic depressurization SRV blow, axisymmetric
SBA = small break accident
IBA = intermediate break accident
DBA = design basis accident
FV = transient response of the piping system associated with fast valve closure (transients associated with valve closure times less than 5 seconds are considered)
RVC = transient response of the piping system associated with relief valve opening in a closed system
RVO = sustained load or response of the piping system associated with relief valve opening in an open system or last segment of the closed system with steady-state load

Table 3.9-11 (Cont'd)

SBA, IBA, and DBA include all event induced loads, as applicable, such as chugging, condensation oscillation, pool swell, drag loads, annulus pressurization, etc.

(1) As required by the appropriate subsection (ie, NB, NC, or ND, of ASME Section III, Division I), other loads, such as thermal transient, thermal gradients, and anchor point displacement portion of the OBE or SRV, are considered in addition to the primary stress-producing loads listed.

(2) Table 3.9-6 lists the load combinations for ASME Code Class 1, 2, and 3 NSSS piping, equipment, and supports.

Table 3.9-12

DESIGN CRITERIA FOR ASME CLASS 1 NON-NSSS PIPING

CONDITION	SERVICE LEVEL	APPLICABLE CODE PARAGRAPH[1][2]	PRIMARY STRESS LIMITS
Design	-	NB-3221 and NB-3652	1.5 S_m
Normal	A	NB-3222 and NB-3653	1.5 S_m
Upset	B	NB-3223 and NB-3654	1.8 S_m and 1.5 S_y
Emergency	C	NB-3224 and NB-3655	2.25 S_m and 1.85 S_y
Faulted	D	NB-3225 and NB-3656	3.0 S_m

(1) As specified by ASME Section III, 1977 Edition through Summer 1979 Addenda.
(2) Functional capability of essential piping is assured in accordance with NEDO-21985, September 1978.

Table 3.9-13

DESIGN CRITERIA FOR NON-NSSS ASME CODE CLASS 1 VALVES

CONDITION	STRESS LIMITS
Design	NB-3521(1)
Normal and upset	NB-3200 or NB-3500(1) (Standard Design Rules)
Emergency(2)	NB-3526(3)
Faulted(2)	NB-3527(3)

(1) As specified by ASME Section III, 1971 through Winter 1972 Addenda.

(2) Where valve function must be ensured (active valve) during the emergency or faulted conditions, the specified emergency or faulted condition for the plant shall be considered the normal condition for the valve.

(3) As specified by ASME Section III, 1971, through Winter 1973 Addenda.

Table 3.9-14

DESIGN CRITERIA FOR NON-NSSS ASME CODE CLASS 2 AND 3
VESSELS DESIGNED TO NC-3300 AND ND-3300

CONDITION	STRESS LIMITS[1]
Design and normal	The vessel shall conform to the requirements of NC-3300 and ND-3300.
Upset, emergency, and faulted	The vessel shall conform to the requirements of ASME Code Case 1607-1.

(1) As specified by ASME Section III, 1971 through Winter 1972 Addenda.

Table 3.9-15

DESIGN CRITERIA FOR NON-NSSS ASME CODE CLASS 2 VESSELS
DESIGNED TO ALTERNATE RULES OF NC-3200

CONDITION	STRESS LIMITS[1][2]
Design and normal	The vessel shall conform to the requirements of NC-3200.
Upset[3]	$P_e \leq 3\ S_m$
	$P_m \leq 1.1\ S_m$
	$(P_m \text{ or } P_L) + P_b \leq 1.65\ S_m$
Emergency	$P_m \leq$ greater of $1.2\ S_m$ or $1.0\ S_y$
	$(P_m \text{ or } P_L) + P_b \leq$ greater of
	$1.8\ S_m$ or $1.5\ S_y$
Faulted[4]	$P_m \leq 2.0\ S_m$
	$(P_m \text{ or } P_L) + P_b \leq 2.4\ S_m$

(1) Definition of symbols:

P_m = General primary membrane stress intensity. This stress intensity is derived from the average value across the solid section under consideration. Excludes discontinuities and concentrations. Produced only by pressure and other mechanical loads.

P_L = Local primary membrane stress intensity. Same as P_m except that discontinuities are considered.

P_b = Primary bending stress intensity. Component of primary stress intensity proportional to distance from centroid of solid section. Excludes discontinuities and concentrations. Produced only by pressure and other mechanical loads.

P_e = Secondary stress intensity range. Developed by constraint of adjacent parts or by self-constraint of a structure. Considers discontinuities but not concentrations. Produced by mechanical loads and by thermal expansion.

Table 3.9-15 (Cont'd)

S_m = Design stress intensity value, ASME Section III, Appendix I, Table I-1.0.

S_y = Yield strength value, ASME Section III, Appendix I, Table I-2.0.

(2) These limits do not take into account either local or general buckling that might occur in thin-wall vessels. Such buckling shall be considered for upset conditions, but need not be considered for emergency or faulted conditions unless required by the design specification.

(3) Fatigue analysis requirements of NC-3219 and Appendix XIV are considered.

(4) As an alternative to satisfying these limits, the faulted condition stress limits of Appendix F may be applied provided that a complete analysis in accordance with NC-3211.1(c) is performed.

Table 3.9-16

DESIGN CRITERIA FOR NON-NSSS ASME CLASS 2 AND 3 PIPING

CONDITION	APPLICABLE CODE PARAGRAPH[1][2]	PRIMARY STRESS LIMITS
Design:		
Sustained Loads	NC, ND 3652.1	1.0 S_h
Occasional Loads	NC, ND 3652.2	1.2 S_h
Normal & Upset	NC, ND 3652.2 & 3611	1.2 S_h
Emergency	NC, ND 3611	1.8 S_h
Faulted	Code Case 1606	2.4 S_h

(1) As specified by ASME Code Section III, 1971 through Winter 1972 Addenda except the following:

Nuclear Class 2 and 3 flanges are analyzed in accordance with ASME Section III 1977 edition through 1979 Summer Addenda.

(2) Functional capability of essential piping is assured in accordance with NEDO-21985, September 1978.

Table 3.9-17

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Table 3.9-18

SEISMIC CATEGORY I SYSTEM SNUBBER DESIGN INFORMATION

DESIGN CRITERIA FOR NON-NSSS ASME CODE CLASS 2 AND 3 VALVES

CONDITION	STRESS LIMITS(2)
Design and normal	The valve shall conform to the requirements of Section III, Paragraphs NC-3500 and ND-3500
Upset, emergency(1), and faulted(1)	The valve shall conform to the requirements of ASME Code Case 1635-1

(1) Where valve function must be ensured (active valve) during the emergency or faulted condition, the specified emergency or faulted conditions for the plant shall be considered as the normal condition for the valve.

(2) As specified by ASME Section III, 1971 through Winter 1972 Addenda.

Table 3.9-19

SEISMIC CATEGORY I ACTIVE PUMPS AND VALVES
(GE SCOPE OF SUPPLY)

COMPONENT NAME	IDENTIFICATION NUMBER	GE MPL NUMBER
MSIVs	M41-F022(A,B,C,D) M41-F028(A,B,C,D)	B21-F022(A,B,C,D) B21-F028(A,B,C,D)
MSRVs	M41-F013(A,B,C,D E,F,G,H,J,K,L, M,N,S)	B21-F013(A,B,C,D, E,F,G,H,J,K,L, M,N,S)
CRD Vent and Drain Globe Valves	M47-F010 M47-F011 M47-F180 M47-F181	C11-F010 C11-F011 C11-F180 C11-F181
SLCS Pump	1AP208 1BP208 1CP208(1)	C41-C001A C41-C001B C41-C001C(1)
SLCS Relief Valves	M48-F029(A,B,C)	C41-F029(A,B,C)
SLCS Explosive Valves	M48-F004(A,B,C)	C41-F004(A,B,C)
RHR Pump	1AP202 1BP202 1CP202 1DP202	E11-C002A E11-C002B E11-C002C E11-C002D
Core Spray Pump	1AP206 1BP206 1CP206 1DP206	E21-C001A E21-C001B E21-C001C E21-C001D
RCIC Pump	10P203	E51-C001
RCIC Turbine	10S212	E51-C002
HPCI Pump	10P204	E41-C001
HPCI Turbine	10S211	E41-C002

Table 3.9-19 (Cont'd)

COMPONENT NAME	IDENTIFICATION NUMBER	GE MPL NUMBER
RHR System		
Globe Valves	M51-F015(A,B)	E11-F015(A,B)
Gate Valves	M51-F016(A,B)	E11-F016(A,B)
Gate Valves	M51-F017(A,B,C,D)	E11-F017(A,B,C,D)
Gate Valves	M51-F021(A,B)	E11-F021(A,B)
Globe Valves	M51-F027(A,B)	E11-F027(A,B)
Testable Check Valves	M51-F041(A,B,C,D)	E11-F041(A,B,C,D)
Testable Check Valves	M51-F050(A,B)	E11-F050(A,B)
Core Spray		
Gate Valves	M52-F001(A,B,C,D)	E21-F001(A,B,C,D)
Gate Valve	M52-F005	E21-F005
Testable Check Valves	M52-F006(A,B)	E21-F006(A,B)
Gate Valve	M52-F037	E21-F037
HPCI		
Swing-Check	M55-F005	E41-F005
Globe Valve	M55-F012	E41-F012
Stop-Check Valve	M55-F021	E41-F021
RCIC		
Globe Stop-Check	M49-F001	E51-F001
Swing-Check	M49-F014	E51-F014
Globe Valve	M49-F019	E51-F019

(1) This SLCS pump is not within the GE scope of supply.

Table 3.9-20

VALVE QUALIFICATION TEST RANGE
(NON-NSSS SCOPE OF SUPPLY)

QUALIFICATION VALID FOR OTHER VALVES (in)[1]

Valve Size Tested	½	1	1 ½	2	3	4	6	8	10	12	14	16	18	20	22	24	26	28	30	36
½	X	X																		
1	X	X	X																	
1½		X	X	X																
2			X	X	X															
3				X	X	X														
4					X	X	X													
6						X	X	X												
8							X	X	X	X										
10								X	X	X	X									
12								X	X	X	X									
14									X	X	X	X	X	X						
16										X	X	X	X	X	X					
18											X	X	X	X	X	X				
20											X	X	X	X	X	X	X	X		
22												X	X	X	X	X	X	X	X	
24													X	X	X	X	X	X	X	
26														X	X	X	X	X	X	X
28														X	X	X	X	X	X	X
30															X	X	X	X	X	X
36																	X	X	X	X

[1] Test data acquired for a qualified valve may be used to qualify valves of the same type that fall within the range of sizes permitted by this table, provided geometric similarity is maintained and supporting stress calculations are provided. If the qualified valve is larger than 36 inch nominal diameter, extrapolation may be made to valves whose nominal size does not vary more than 25% from that of the qualified valve.

Table 3.9-21

DESIGN LOADING COMBINATIONS FOR SUPPORTS FOR ASME CODE CLASS 1, 2, AND 3 COMPONENTS

CONDITION STRESS[2][3]	DESIGN LOADING COMBINATIONS[1]	ALLOWABLE
Hydrostatic Test	a) HTDW	0.8 S_y
Normal and Upset	a) DW + TH + $(OBE^2 + SRV_x^2)^{1/2}$	S_h
	b) DW + TH + $(RVC^2 + OBE^2)^{1/2}$	
	c) DW + TH + FV	
	d) DW + TH + OBE + RVO	
Emergency	a) DW + TH + $(OBE^2 + SRV^2_{ADS} + SBA^2)^{1/2}$	1.8 S_h
	b) DW + TH + $(OBE^2 + FV^2)^{1/2}$	
Faulted	a) DW + TH + $(SSE^2 + SRV^2_{ADS} + IBA^2)^{1/2}$	0.9 S_y
	b) DW + TH + $(OBE^2 + SRV^2_{ADS} + IBA^2)^{1/2}$	
	c) DW + TH + $(SSE^2 + DBA^2)^{1/2}$	

where:

HTDW = piping dead weight due to hydrostatic test

TH = reaction of the support due to thermal expansion of the pipe

S_y = yield stress

S_h = allowable stress per ANSI B31.1

See Table 3.9-11 for additional nomenclature.

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(1) Loads due to OBE, SSE, SRV_x, SRV_{ADS}, SBA, IBA, and DBA include both the inertia portion and the anchor motion portion when the response spectra method is used. The loads from the inertia portion and anchor motion are combined by the SRSS method.

(2) The allowable stress shall be limited to 2/3 of the critical buckling stress.

(3) Snubbers, compensating starts, and struts comply with all the requirements of ASME Section III, Subsection NF; they are not commercially available to meet the requirements of ANSI B31.1.

Table 3.9-22

FATIGUE LIMIT
(FOR SAFETY CLASS REACTOR INTERNAL STRUCTURES ONLY)

Summation of fatigue damage usage with design and operation loads following Miner hypotheses [1]

CUMULATIVE DAMAGE IN FATIGUE	LIMIT FOR SERVICE LEVELS A AND B (NORMAL AND UPSET) DESIGN CONDITIONS
Design fatigue cycle usage from analysis using the method of ASME Code	$\leq$1.0

(1) M.A. Miner, "Cumulative Damage in Fatigue," Journal of Applied Mechanics, 12, (67), pp. A159-164, (September 1945).

Table 3.9-23

CORE SUPPORT STRUCTURES
STRESS CATEGORIES AND LIMITS OF STRESS INTENSITY FOR SERVICE LEVELS A AND B (NORMAL AND UPSET) CONDITIONS

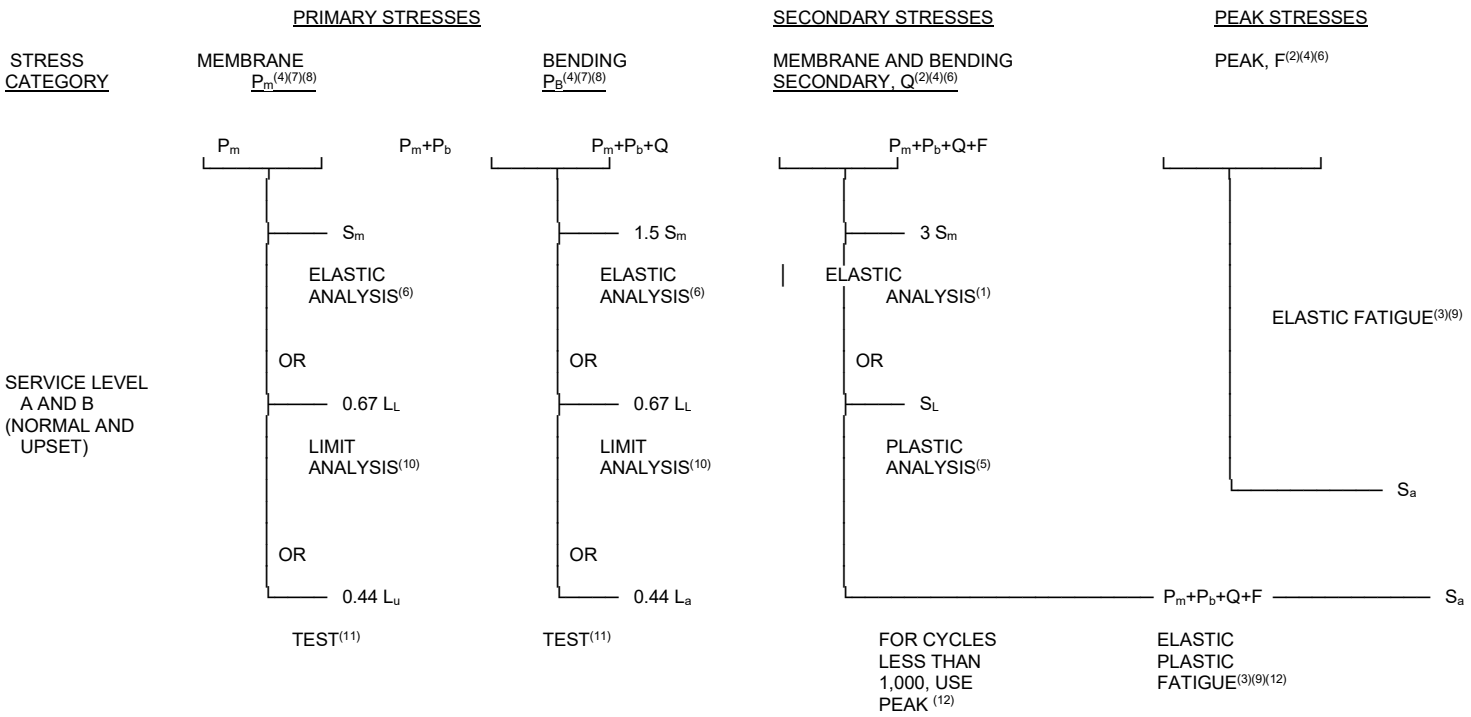


Table 3.9-23 (Cont'd)

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(1) This limitation applies to the range of stress intensity. When the secondary stress is due to a temperature excursion at the point at which the stresses are being analyzed, the value of S_m shall be taken as the average of the S_m values tabulated in tables I-1.1, I-1.2, and I-1.3 of ASME Section III for the highest and the lowest temperature of the metal during the transient. When part of the secondary stress is due to mechanical load, the value of S_m shall be taken as the S_m value for the highest temperature of the metal during transient.

(2) The stresses in Category Q are those parts of the total stress which are produced by thermal gradients, structural discontinuities, etc, and do not include primary stresses which may also exist at the same point. It should be noted, however, that a detailed stress analysis frequently gives the combination of primary and secondary stresses directly and, when appropriate, this calculated value represents the total of $P_m + P_b + Q$ and not Q alone. Similarly, if the stress in Category F is produced by a stress concentration, the quantity F is the additional stress produced by the notch, over and above the nominal stress. For example, if a plate has a nominal stress intensity, $P_m = S$, $P_b = O$, $Q = O$ and a notch with a stress concentration K is introduced, then $F = P_m (K-1)$ and the peak stress intensity equals $P_m + P_m (K-1) = KP_m$.

(3) S_a is obtained from the fatigue curves, figures I-9.1 and I-9.2 of ASME Section III. The allowable stress intensity for the full range of fluctuation is $2 S_a$.

(4) The symbols P_m, P_b, Q, and F do not represent single quantities, but rather sets of six quantities representing the six stress components σ_t, σ_1, σ_r, γ_{tl}, γ_{lr}, γ_{rt}.

(5) S_L denotes the structural action of shakedown load as defined in paragraph NB 3213.18 of ASME Section III calculated on a plastic basis as applied to a specific location on the structure.

(6) The triaxial stresses represent the algebraic sum of the three primary principal stresses ($\sigma_1 + \sigma_2 + \sigma_3$) for the combination of stress components. Where uniform tension loading is present, triaxial stresses are limited to $4 S_m$.

(7) For configurations where compressive stresses occur, the stress limits shall be revised to take into account critical buckling stresses (see paragraph NB-3211(c) of ASME Section III). For external pressure, the permissible "equivalent static" external pressure shall be as specified by the rules of paragraph NB-3133 of ASME Section III. Where dynamic pressures are involved, the permissible external pressure shall be limited to 25% of the dynamic instability pressure.

(8) When loads are transiently applied, consideration should be given to the use of dynamic load amplification, and possible change in modulus of elasticity.

(9) In the fatigue data curves, where the number of operating cycles are less than 10, use the S_a value for 10 cycles; where the number of operating cycles are greater than 10^6, use the S_a value for 10^6 cycles.

Table 3.9-23 (Cont'd)

(10) L_L is the lower bound limit load with yield point equal to 1.5 S_m (where S_m is the tabulated value of allowable stress at temperature as contained in ASME Section III). The "lower bound limit load" is here defined as that produced from the analysis of an ideally plastic (nonstrain hardening) material where deformations increase with no further increase in applied load. The lower bound load is one in which the material everywhere satisfies equilibrium and nowhere exceeds the defined material yield strength using either a shear theory or a strain energy of distortion theory to relate multiaxial yielding to the uniaxial case.

(11) For service levels A and B (normal and upset) conditions, the limits on primary membrane plus primary bending need not be satisfied in a component if it can be shown from the test of a prototype or model that the specified loads (dynamic or static-equivalent) do not exceed L_u, where L_u is the ultimate load or the maximum load to load combination used in the test. In using this method, account shall be taken of the size effect and dimensional tolerances which may exist between the actual part and the test part, or parts, as well as differences which may exist in the ultimate strength or other governing material properties of the actual part and the tested part to assure that the loads obtained from the test are a conservative representation of the load-carrying capability of the actual component under the postulated loading for service level A and B (normal and upset) conditions.

(12) The allowable value for the maximum range of this stress intensity is 3 S_m except for cyclic events which occur less than 1000 time during the design life of the plant. For this exception, in lieu of meeting the 3 S_m limit, an elastic-plastic fatigue analysis in accordance with ASME Section III may be performed to demonstrate that the cumulative fatigue usage attributable to the combination of these low events, plus all other cyclic events, does not exceed a fatigue usage value of 1.0.

Table 3.9-24

CORE SUPPORT STRUCTURES
STRESS CATEGORIES AND LIMITS OF STRESS INTENSITY FOR SERVICE LEVEL C (EMERGENCY) CONDITIONS

STRESS CATEGORY	PRIMARY STRESSES: MEMBRANE P_m[1][2][10]		PRIMARY STRESSES: BENDING P_B[1][2][10]		SECONDARY STRESSES: MEMBRANE AND BENDING SECONDARY, Q	PEAK STRESSES: PEAK F
	P_m		P_m+P_B			
SERVICE LEVEL D (FAULT)[9]	$1.5\ S_m$	ELASTIC ANALYSIS[3]	$2.25\ S_m$	ELASTIC ANALYSIS[3]	EVALUATION NOT REQUIRED	EVALUATION NOT REQUIRED
	OR		OR			
	L_L	LIMIT ANALYSIS[4]	L_L	LIMIT ANALYSIS[4]		
	OR		OR			
	$1.5\ S_n$	PLASTIC ANALYSIS[6]	$2.25\ S_m$	PLASTIC ANALYSIS[5][6]		
	OR		OR			
	$0.6\ L_e$	TESTS[7]	$0.5\ S_u$	[5]		
	OR		OR			
	S_E	STRESS RATIO ANALYSIS[8]	$0.6\ L_e$	TESTS[7]		
			OR			
			KS_E	STRESS RATIO ANALYSIS[8]		

Table 3.9-24 (Cont'd)

(1) The symbols P_m, P_b, Q, and F do not represent single quantities, but rather sets of six quantities representing the six stress components σ_t, σ_l, σ_r, γ_{tl}, γ_{lr}, γ_{rt}.

(2) For configurations where compressive stresses occur, stress limits shall be revised to take into account critical buckling stresses. For external pressure, the permissible "equivalent static" external pressure shall be taken as 150% of that permitted by the rules of paragraph NB-3133 of ASME Section III. Where dynamic pressures are involved, the permissible external pressure shall satisfy the preceding requirements or be limited to 50% of the dynamic instability pressure.

(3) The triaxial stresses represent the algebraic sum of the three primary principal stresses ($\sigma_1 + \sigma_2 + \sigma_3$) for the combination of stress components. Where uniform tension loading is present, triaxial stresses should be limited to 6 S_m.

(4) L_L is the lower bound limit load with yield point equal to 1.5 S_m (where S_m is the tabulated value of allowable stress at temperature as contained in ASME Section III). The "lower bound limit load" is here defined as that produced from the analysis of an ideally plastic (nonstrain hardening) material where deformations increase with no further increase in applied load. The lower bound load is one in which the material everywhere satisfies equilibrium and nowhere exceeds the defined material yield strength using either a shear theory or a strain energy of distortion theory to relate multiaxial yielding to the uniaxial case.

(5) S_u is the ultimate strength at temperature. Multiaxial effects on ultimate strength shall be considered.

(6) This plastic analysis uses an elastic-plastic evaluated nominal primary stress. Strain hardening of the material may be used for the actual monotonic stress-strain curve at the temperature of loading or any approximation to the actual stress-strain curve which everywhere has a lower stress for the same strain as the actual monotonic curve may be used. Either the shear or strain energy of distortion flow rule shall be used to account for multiaxial effects.

(7) For service level C (emergency) conditions, the stress limits need not be satisfied if it can be shown from the test of a prototype or model that the specified loads (dynamic or static-equivalent) do not exceed 60% of L_e, where L_e is the ultimate load or the maximum load or load combination used in the test. In using this method, account shall be taken of the size effect and dimensional tolerances which may exist between the actual part and the tested part or parts as well as differences which may exist in the ultimate strength or other governing material properties of the actual part and the tested parts to assure that the loads obtained from the test are a conservative representation of the load-carrying capability of the actual component under postulated loading for service level C (emergency) conditions.

(8) Stress ratio is a method of plastic analysis which uses the stress ratio combinations (combination of stresses that consider the ratio of the actual stress to the allowable plastic or elastic stress) to compute the maximum load a strain hardening material can carry. K is defined as the section factor; $S_e \leq 2\ S_m$ for primary membrane loading.

(9) Where deformation is of concern in a component, the deformation shall be limited to two-thirds the value given for service level C (emergency) conditions in the Design Specification.

(10) When loads are transiently applied, consideration should be given to the use of dynamic load amplification and possible change in modulus of elasticity.

Table 3.9-25

MAXIMUM PRESSURE DIFFERENTIALS ACROSS REACTOR VESSEL INTERNALS DURING A STEAM LINE BREAK

Reactor Component	Pressure Differential(psid)[3] Case 1[1]	Case 2[2]
Core Plate and Guide Tube	24.5	24.5
Shroud Support Ring and Lower Shroud	48	49.0
Upper Shroud	28.0[4][5]	29.0[4][6]
Average Channel Wall (Bottom)	13.1	10.6
Top Guide	2.4	3.6[4][5]

(1) Reactor initially at 1.02 of 110% original power, 110% recirculation flow

(2) Reactor initially at 20% rated steam flow, 110% recirculation flow

(3) Values taken from Reference 3.9-28

(4) Values taken from Reference 3.9-39

(5) Analyzed at 3527.2 MWt, 110 Mlbm/hr core flow

(6) Analyzed at 846.5 MWt, 110 Mlbm/hr core flow

Table 3.9-26

CORE SUPPORT STRUCTURE DESIGN LOADING
CONDITIONS AND COMBINATIONS

OPERATING CONDITION AND STRESS LIMITS	SERVICE LEVEL	DESIGN LOADINGS CONDITIONS AND COMBINATIONS
Normal and Upset	A and B	$N + A_D$ and $N + U$
Emergency	C	N and R, or other conditions which have a 40 year encounter probability from 10^{-1} to 10^{-3}
Fault	D	N and A_m and $\overline{R}$ or other conditions which have a 40 year encounter probability from 10^{-3} to 10^{-6}

where:

N	=	service level A (normal) loads
U	=	service level B (upset) loads excluding earthquake
A_D	=	½SSE including any associated transients.
A_m	=	SSE
R	=	automatic blowdown or equivalent auxiliary pipe rupture loading (pipe rupture loadings are not directly considered on piping itself because this is handled by a failure mode analysis)
$\overline{R}$	=	primary loadings which result from rupture of a main steam line or a recirculation line

Table 3.9-27

DEFORMATION LIMIT
(FOR REACTOR INTERNAL STRUCTURES ONLY)

EITHER ONE OF (NOT BOTH)		GENERAL LIMIT
a.	$\left[\frac{\text{Permissible deformation, DP}}{\text{Analyzed deformation causing loss of function, DL}}\right]$	$\leq \frac{0.9}{SF_{min}}$
b.	$\left[\frac{\text{Permissible deformation, DP}}{\text{Experiment deformation causing loss of function, DE}}\right]^{(1)}$	$\leq \frac{1.0}{SF_{min}}$

where:

DP = permissible deformation under stated conditions of service levels A, B, C or D (normal, upset, emergency or faulted)

DL = analyzed deformation which could cause a system loss of function(2)

DE = experimentally determined deformation which could cause a system loss of function

SF_{min} = minimum safety factor

(1) Equation b is not used unless supporting data are provided to the NRC by GE.

(2) "Loss of function" can only be defined quite generally until attention is focused on the component of interest. In cases of interest, where deformation limits can affect the function of equipment and components, they are specifically delineated. From a practical viewpoint, it is convenient to interchange some deformation condition at which function is assured with the loss of function condition if the required safety margins from the functioning conditions can be achieved. Therefore, it is often unnecessary to determine the actual loss of function condition because this interchange procedure produces conservative and safe designs. Examples where deformation limits apply are: CRD alignment and clearances for proper insertion, core support deformation causing fuel disarrangement or excess leakage of any component.

Table 3.9-28

PRIMARY STRESS LIMIT
(FOR SAFETY CLASS REACTOR INTERNAL STRUCTURES ONLY)

ANY ONE OF (NO MORE THAN ONE REQUIRED)		GENERAL LIMIT
a.	$\left[\frac{\text{Elastic evaluated primary stresses, PE}}{\text{Permissible primary stresses, PN}}\right]$	$\leq \frac{2.25}{SF_{min}}$
b.	$\left[\frac{\text{Permissible load, LP}}{\text{Largest lower bound limit load, CL}}\right]$	$\leq \frac{1.5}{SF_{min}}$
c.	$\left[\frac{\text{Elastic evaluated primary stresses, PE}}{\text{Conventional ultimate strength at temperature, US}}\right]$	$\leq \frac{0.75}{SF_{min}}$
d.	$\left[\frac{\text{Elastic – plastic evaluated nominal primary stress, EP}}{\text{Conventional ultimate strength at temperature, US}}\right]$	$\leq \frac{0.9}{SF_{min}}$
e.	$\left[\frac{\text{Permissible load, LP}}{\text{Plastic instability load, PL}}\right]^{(1)}$	$\leq \frac{0.9}{SF_{min}}$
f.	$\left[\frac{\text{Permissible load, LP}}{\text{Ultimate load from fracture analysis, UF}}\right]^{(1)}$	$\leq \frac{0.9}{SF_{min}}$
g.	$\left[\frac{\text{Permissible load, LP}}{\text{Ultimate load or loss of function load from test, LE}}\right]^{(1)}$	$\leq \frac{1.0}{SF_{min}}$

Table 3.9-28 (Cont'd)

where:

PE = primary stresses evaluated on an elastic basis. The effective membrane stresses are to be averaged through the load-carrying section of interest. The simplest average bending, shear or torsion stress distribution which will support the external loading will be added to the membrane stresses at the section of interest.

PN = permissible primary stress levels under service levels A or B (normal or upset) conditions under ASME Section III.

LP = permissible load under stated conditions of service levels A, B, C, or D (emergency or faulted).

CL = lower limit load with yield point equal to 1.5 S_m where S_m is the tabulated value of allowable stress at temperature of the ASME Section III Code or its equivalent. The "lower bound limit load" is here defined as that produced from the analysis of an ideally plastic nonstrain hardening material where deformations increase with no further increase in applied load. The lower bound load is one in which the material everywhere satisfies equilibrium and nowhere exceeds the defined material yield strength using either a shear theory or a strain energy of distortion theory to relate multiaxial yield to the uniaxial case.

US = conventional ultimate strength at temperature or loading which would cause a system malfunction, whichever is more limiting.

EP = elastic-plastic evaluated nominal primary stress. Strain hardening of the material may be used for the actual monotonic stress-strain curve at the temperature of loading or any approximation to the actual stress-strain curve which everywhere has a lower stress for the same strain as the actual monotonic curve may be used. Either the shear or strain energy of distortion flow rule may be used.

PL = plastic instability load. The "plastic instability load" is defined here as the load at which any load- bearing section begins to diminish its cross-sectional area at a faster rate than the strain hardening can accommodate the loss in area. This type analysis requires a true stress-true strain curve or a close approximation based on monotonic loading at the temperature of loading.

Table 3.9-28 (Cont'd)

UF = ultimate load from fracture analyses. For components which involve sharp discontinuities (local theoretical stress concentration <3) the use of a "fracture mechanics" analysis where applicable utilizing measurements of plane strain fracture toughness may be applied to compute fracture loads. Correction for finite plastic zones and thickness effects as well as gross yielding may be necessary. The methods of linear-elastic stress analysis may be used in the fracture analysis where its use is clearly conservative or supported by experimental evidence. Examples where "fracture mechanics" may be applied are for fillet welds or end of fatigue life crack propagation.

LE = ultimate load or loss of function load as determined from experiment. In using this method, account shall be taken of the dimensional tolerances which may exist between the actual part and the tested part or parts as well as differences which may exist in the ultimate tensile strength of the actual part and the tested parts. The guide to be used in each of these areas is that the experimentally determined load shall use adjusted values to account for material property and dimension variations, each of which has no greater probability than 0.1 of being exceeded in the actual part.

SF_{min} = minimum safety factor

(1) Equations e., f., and g. are not used unless supporting data are provided to the NRC by GE.

Table 3.9-29

BUCKLING STABILITY LIMIT
(FOR SAFETY CLASS REACTOR INTERNAL STRUCTURES ONLY)

ANY ONE OF (NO MORE THAN ONE REQUIRED)	GENERAL LIMIT
a. $\left[\frac{\text{Permissible load, LP}}{\text{Service level A (normal) permissible load, PN}}\right]$	$\leq \frac{2.25}{SF_{min}}$
b. $\left[\frac{\text{Permissible load, LP}}{\text{Stability analysis load, SL}}\right]$	$\leq \frac{0.9}{SF_{min}}$
c. $\left[\frac{\text{Permissible load, LP}}{\text{Ultimate buckling collapse load from test, SE}}\right]$(1)	$\leq \frac{1.0}{SF_{min}}$

where:

LP = permissible load under stated conditions of service levels A, B, C or D (normal, upset emergency or faulted)

PN = applicable service level A (normal) permissible load

SL = stability analysis load. The ideal buckling analysis is often sensitive to otherwise minor deviations from ideal geometry and boundary conditions. These effects shall be accounted for in the analysis of the buckling stability loads. Examples of this are ovality in externally pressurized shells or eccentricity on column members.

SE = ultimate buckling collapse load as determined from experiment. In using this method, account shall be taken of the dimensional tolerances which may exist between the actual part and the tested part. The guide to be used in each of these areas is that the experimentally determined load shall be adjusted to account for material property and dimension variations, each of which has no greater probability than 0.1 of being exceeded in the actual part.

SF_{min} = minimum safety factor

(1) Equation c. is not used unless supporting data are provided to the NRC by GE.

Table 3.9-30

CORE SUPPORT STRUCTURES
STRESS CATEGORIES AND LIMITS OF STRESS INTENSITY FOR SERVICE LEVEL D (FAULT) CONDITIONS

	PRIMARY STRESSES		SECONDARY STRESSES	PEAK STRESSES
STRESS CATEGORY	MEMBRANE P_m[1][2][10]	BENDING P_B[1][2][10]	MEMBRANE AND BENDING SECONDARY, Q	PEAK F
	P_m	P_m+P_B		
	$2.4\ S_m$ ELASTIC ANALYSIS[3]	$3.0\ S_m$ ELASTIC ANALYSIS[3]		
	OR	OR		
	$0.75\ S_u$ [5][10]	$1.33\ L_L$ LIMIT ANALYSIS[4]		
	OR	OR		
	$1.33\ I_L$ LIMIT ANALYSIS[4][11]	$0.75\ S_u$ PLASTIC ANALYSIS[5][6]	EVALUATION NOT REQUIRED	EVALUATION NOT REQUIRED
	OR	OR		
	$0.67\ S_u$ PLASTIC ANALYSIS [5][6][11]	$0.8\ L_F$ TESTS[7]		
	OR	OR		
	$0.8\ L_F$ TESTS[7][11]	KS_F STRESS-RATIO ANALYSIS[8]		
	OR			
	S_F STRESS-RATIO ANALYSIS[8]			

Table 3.9-30 (Cont'd)

(1) The symbols P_m, P_b, Q, and F do not represent single quantities, but rather sets of six quantities representing the six stress components δ_t, δ_l, δ_r, γ_{tl}, γ_{tr}, γ_{rl}.

(2) When loads are transiently applied, consideration should be given to the use of dynamic load amplification and possible changes in modulus of elasticity.

(3) For configurations where compressive stresses occur, stress limits take into account critical buckling stresses. For external pressure the permissible "equivalent static" external pressure shall be taken as 2.5 times that given by the rules of paragraph NB-3133 of ASME Section III. Where dynamic pressures are involved, the permissible external pressure satisfies the preceding requirements or be limited to 75% of the dynamic instability pressure.

(4) L_L is the lower bound limit load with yield point equal to 1.5 S_m (where S_m is the tabulated value of allowable stress at temperature as contained in ASME Section III). The "lower bound limit load" is defined as that produced from the analysis of an ideally plastic (nonstrain hardening) material where deformations increase with no further increase in applied load. The lower bound load is one in which the material everywhere satisfies equilibrium and nowhere exceeds the defined material yield strength using either a shear theory or a strain energy of distortion theory to relate multiaxial yielding to the uniaxial case.

(5) S_u is the ultimate strength at temperature. Multiaxial effects on ultimate strength are considered.

(6) This plastic analysis uses an elastic-plastic evaluated nominal primary stress. Strain hardening of the material may be used for the actual monotonic stress-strain curve at the temperature of loading or any approximation to the actual stress-strain curve which everywhere has a lower stress for the same strain as the actual monotonic curve may be used. Either the maximum stress or strain energy of distortion flow rule shall be used to account for multiaxial effects.

(7) For service level D (fault) conditions, the stress limits need not be satisfied if it can be shown from the test of a prototype or model that the specified loads (dynamic or static-equivalent) do not exceed 80% of L_F, where L_F is the ultimate load or load combination used in the test. In using this method, account is taken of the size effect and dimensional tolerances, as well as differences which may exist in the ultimate strength or other governing material properties of the actual part and the tested parts, to assure that the loads obtained from the test are a conservative representation of the load-carrying capability of the actual component under postulated loading for service level D (fault) condition.

(8) Stress ratio is a method of plastic analysis which uses the stress ratio combinations (combination of stresses that consider the ratio of the actual stress to the allowable plastic or elastic stress) to compute the maximum load a strain hardening material can carry. K is defined as the section factor; S_f is the lesser of 2.4 S_m or 0.75 S_u for primary membrane loading.

(9) Where deformation is of concern in a component, the deformation is limited to 80% of the value given for service level D (fault) conditions in the Design Specifications.

(10) 0.7 S_u per ASME Section III Appendix F.

(11) Same as ASME Section III Appendix F.

(12) 3.6 S_m per ASME Section III Appendix F.

Table 3.9-31

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Table 3.9-32

SRV TEST PROGRAM

	EVENTS [1][2]												
PLANT FEATURES	1	2	3	4	5	6	7	8	9	10	11	12	13
High Water Level 7 Alarm	X, S		X, S	X, S	X, NA				X, S	X, NA	X, S	X, S	X, NA
High Drywell Pressure Alarm													
FW Level 8 Trip	X, S	X, S											
RCIC Level 8 Trip			X, S	X, S	X, NA				X, S	X, NA	X, S		X, NA
HPCS Level 8 Trip				X, NA	X, NA				X, NA	X, NA			X, NA
HPCI Level 8 Trip			X, S	X, S					X, S		X, S		X, NA
HPCI/S and RCIS Initiation on Low Water Level	X, S	X, S	X, S	X, S	X, NA	X, NA		X, S	X, S				X, NA
HPCI/S Initiation of High Drywell Pressure			X, S	X, S					X, S	X, NA	X, S	X, S	X, NA
RCIC Initiation on High Drywell Pressure													X, NA
Low Pressure ECCS Initiation on High Drywell Pressure												X, S	X, NA
Low Pressure ECCS Initiation on Low Water Level													X, NA
FW Pumps Trip on Low Suction Pressure	X, S												
HPCI Trip on High Back pressure			X, S								X, S		
RCIC Trip on High Back pressure				X, S					X, S				
Turbine Trip on Vessel High Level	X, S	X, S											
MSIVs Closure on Low Turbine Inlet Pressure	X, S	X, S					X, S						
MSIVs Closure on High Steam Flow		X, S					X, S						

Table 3.9-32 (Cont'd)

PLANT FEATURES	EVENTS (1)(2) 1	2	3	4	5	6	7	8	9	10	11	12	13
MSIVs Closure on High Steam Tunnel Temperature								X, S					
MSIV Closure on High Radiation								X, S					
Reactor Scram on Turbine Trip	X, S	X, S											
Reactor Scram on Nuetron Flux Monitor		X, S											
Reactor Scram on MSIVs Closure		X, S											
Reactor Scram on High Radiation								X, S					
Reactor Scram on High Drywell Pressure									X, S	X, NA	X, S	X, S	X, NA
Reactor Scram on Low Water Level													X, NA
Reactor Isolation on Low Water Level													X, NA

(1) Events

1 FW Cont. Failure, FW L8 Trip Failure
2 Pressure Regulator Failure
3 Transient HPCI, HPCI L8 Trip Failure
4 Transient RCIC, RCIC L8 Trip Failure
5 Transient HPCS, HPCS L8 Trip Failure
6 Transient RCIC Hd. Spr.
7 Alternate Shutdown Cooling, Shutdown Suction Unavailable
8 Main Steam Line Break - Outside Containment
9 SBA, RCIC, RCIC L8 Trip Failure
10 SBA, HPCS, HPCS L8 Trip Failure
11 SBA, HPCI, HPCI L8 Trip Failure
12 SBA, Depressurization & ECCS Overfill, Operator Error
13 LBA, ECCS Overfill Break Isolation

(2) X - Feature considered in Base Case Analysis
S - Feature in Plant Specific Design
NA - Not Applicable

3.10 QUALIFICATION OF SEISMIC CATEGORY I INSTRUMENTATION AND ELECTRICAL EQUIPMENT

The dynamic qualification criteria applicable to the seismic Category I instruments, electrical equipment, and their supports are provided in this section. The methods and procedures used to qualify them are also discussed. Seismic Category I instruments, equipment, and supporting structures are identified in Table 3.2-1.

3.10.1 DYNAMIC QUALIFICATION CRITERIA

The seismic Category I instruments and electrical equipment are designed to withstand the effects of the SSE defined in Section 3.7 and the hydrodynamic loads discussed in Section 3.9 and Appendix 3A.4 through 3A.7 without functional impairment.

The qualification discussion covered in the following sections is generally divided into two types of equipment: NSSS equipment and non-NSSS equipment.

The following design criteria and qualification procedures for NSSS equipment include the effects of both seismic and hydrodynamic loads. The non-NSSS equipment qualification discussions include only seismic design criteria and procedures. Refer to Appendix 3A.6.8 and 3A.7.1.7 for non-NSSS equipment subjected to hydrodynamic loads. Appendix 3A.6.7 and 3A.7.1.6 contain further discussion of NSSS equipment qualification.

There is a Risk Informed Categorization and Treatment Program at Limerick which is based on 10 CFR 50.69. This regulation provides an alternative approach for establishing requirements for treatment of SSCs using a risk-informed method of categorizing SSCs according to their safety significance. Specifically, for SSCs categorized as low safety significant, alternate treatment requirements may be implemented rather than treatments chosen by the seismic qualification program. Refer to Section 13.5.5 for further information.

3.10.1.1 Dynamic Loading Design Criteria (NSSS Equipment)

The criterion used in the design and subsequent qualification of all Class 1E instruments and electrical equipment supplied by GE is as follows: "The Class 1E equipment shall be capable of performing all safety-related functions during (1) normal plant operation, (2) anticipated transients, (3) DBAs, and (4) postaccident operation while being subjected to, and after the cessation of, the accelerations resulting from the SSE and hydrodynamic loads at the point of attachment of the equipment to the building or supporting structure."

The criteria for each of the devices used in the Class 1E systems depend on the use in a given system; for example, a relay in one system may have as its safety function to de-energize and open its contacts within a certain time, while in another system it must energize and close its contacts. Since GE supplies many devices for many applications, the approach taken was to test the device in the worst case configuration. In this way, the capability of protective action initiation and the proper operation of safety-related circuits is assured.

From the basic input ground motion data, a series of response curves at various structure elevations is developed after the building layout is completed. Standard requirement levels that meet or exceed the maximum expected unique plant information are included in the purchase specifications for seismic Category I equipment. Suppliers of equipment such as batteries and racks, instrument racks, control consoles, etc., are required to submit test data, operating

experience and/or calculations to substantiate that their components, systems, etc will not suffer loss of function during or after dynamic loadings. The magnitude and frequency content of the loadings which each component will experience are determined by its specific location within the plant. All Class 1E equipment will be evaluated for the capability of performing its safety function during and after dynamic loading combinations given in Table 3.9-6.

3.10.1.2 Dynamic Loading Design Criteria (Non-NSSS Equipment)

The seismic Category I instruments and electrical equipment is the equipment that is designed to maintain its functional capability and/or to maintain the pressure boundary integrity during and after an SSE and at least 5 OBEs. (Refer to Appendix 3A.6.8 for criteria for equipment subjected to hydrodynamic loads.)

Seismic Category I equipment is designed to withstand the more severe of the following load combinations:

a. OBE Conditions:

The load combinations include gravity loads and operation loads (or LOCA loads, if applicable) including associated temperatures and pressures, combined with the seismic loading of an OBE.

Stresses in the structural steel portions may be increased to 125% of the allowable working stress limits accepted as good practice as set forth in the appropriate design standards; that is, AISC Manual of Steel Construction, ASME B&PV Code, ANSI B31.1 and B31.7 codes for pressure piping, or other equivalent industrial codes. The resulting deflections do not prevent continuous normal operation of the equipment during and after the seismic disturbance.

b. SSE Conditions:

The load combinations include gravity loads and operating loads (or LOCA loads, if applicable) including associated temperatures and pressures combined with the seismic loading of the SSE. Stresses in the structural portions may be increased to 150% of code allowable working stress limits but are not to exceed 0.9 F_y in bending, 0.85 F_y for tension, and 0.5 F_y in shear, where (F_y) equals the material yield stress at the design temperature. The resulting deflections will not prevent the operation of the equipment during and after the seismic disturbance.

The performance requirements of the seismic Category I items and their respective supports are structural as well as functional. Where applicable, the structural requirements are in accordance with AISC "Specifications for the Design, Fabrication, and Erection of Structural Steel for Buildings," adopted February 12, 1969, or similar codes applicable for other construction materials.

The structural requirements for electrical and instrumentation equipment and systems that are required to maintain pressure boundary integrity are in accordance with the ASME Section III.

3.10.2 METHODS AND PROCEDURES FOR QUALIFYING ELECTRICAL EQUIPMENT AND INSTRUMENTATION

Seismic Category I instruments and electrical equipment are qualified according to the criteria discussed in Section 3.10.1 by the methods and procedures described in this section. The qualification methods and procedures are discussed in two parts: NSSS and non-NSSS equipment; both of which were re-assessed to SRP 3.10 Seismic Qualification Review Team (SQRT) requirements including IEEE 344-1975, and Reg. Guides 1.10 and 1.92. The SQRT re-assessment concluded that the seismic and dynamic qualification program meets the intent of IEEE 344-1975 and Reg. Guides 1.100 and 1.92.

3.10.2.1 Methods and Procedures for Qualifying NSSS Electrical Equipment and Instruments (Excluding Motors and Valve-Mounted Equipment)

3.10.2.1.1 Methods of Showing NSSS Equipment Compliance with IEEE 344 (1975) and Regulatory Guide 1.100

Originally, NSSS equipment were qualified to IEEE 344 (1971), which was the plant commitment, and as such did not demonstrate compliance with Regulatory Guide 1.100 and other SQRT criteria. However, a re-assessment of all NSSS equipment qualifications to NEDE-24788 "SQRT Technical Approach" ensures an adequate degree of equipment conformance to IEEE 344-1975 and Regulatory Guides 1.100 and 1.92 requirements which represents an acceptable basis for qualifying the equipment.

GE-supplied Class 1E equipment meets the requirement that the dynamic qualification should demonstrate the capability to perform the required function during and after the dynamic event. Both analysis and testing were used, but most equipment was tested. Analysis was primarily used to determine the adequacy of mechanical strength (mounting bolts, etc) after operating capability was established by testing.

a. Analysis

GE-supplied Class 1E equipment performing primarily a mechanical safety function (pressure boundary devices, etc) was analyzed, since the passive nature of its critical safety role usually made testing impractical. Analytical methods sanctioned by IEEE 344 (1971) were used in such cases and were re-evaluated to IEEE 334 (1975) criteria with satisfactory results. Table 3.10-1 shows which items were qualified by analysis.

b. Testing

GE-supplied Class 1E equipment having primarily an active electrical safety function was tested in compliance with IEEE 344 (1971), section 3.2 and were re-evaluated to IEEE 344 (1975) criteria with satisfactory results.

Available documentation verifies that the dynamic qualification of GE-supplied Class 1E equipment is in accordance with the requirements of IEEE 344 (1975).

3.10.2.1.2 Testing Procedures for Qualifying NSSS Electrical Equipment and Instruments (Excluding Motors and Valve-Mounted Equipment)

The test procedure requires that the device be mounted on the table of the vibration machine in a manner similar to how it is normally installed. The device is tested in the operating states as if it were performing its Class 1E functions and these states are monitored before, during, and after the test to assure proper function and absence of spurious function. In the example of a relay, both

energized and de-energized states and normally open and normally closed contact configurations are tested if the relay is used in those configurations in its Class 1E functions.

The dynamic excitation is a single-frequency test in which the applied vibration is a sinusoidal table motion at a fixed peak acceleration and a discrete frequency at any given time. The vibratory excitation is applied in three orthogonal axes individually, with the axes chosen as those coincident with the most probable mounting configuration.

The first step is to search for resonances in each axis. This is done because resonances cause amplification of the input vibration and are the most likely cause of malfunction. The resonance search is usually run at low acceleration levels (0.2 g) to avoid damaging the test sample in case a severe resonance is encountered. The resonance search is run in accordance with IEEE 344; if the device is large enough, the vibrations are monitored by accelerometers placed at critical locations, from which resonances are determined by comparing the acceleration level with that at the table of the vibration machine. If the devices are either too small for an accelerometer, have their critical parts in an inaccessible location, or have critical parts that would be adversely affected by the mounting of an accelerometer, the vibrations are monitored at the closest location.

Following the frequency scan and resonance determination, the devices are tested to determine their malfunction limit. This test is a necessary adjunct to the assembly test, as shown later. The malfunction limit test is run at each resonant frequency as determined by the frequency scan. In this test, the acceleration level is gradually increased until either the device malfunctions or the limit of the vibration machine is reached. If no resonances are detected (as is usually the case), the device is considered to be rigid (all parts move in unison), and the malfunction limit is therefore independent of frequency. To achieve maximum acceleration from the vibration machine, rigid devices are malfunction tested at the upper test frequency because that allows the maximum acceleration to be obtained from deflection-limited machines.

The summary of the tests on the devices used in Class 1E applications given in Table 3.10-1 includes the "qualification" limit for each device tested.

The above procedures are required of purchased devices, as well as of those made by GE. Vendor test results are reviewed, and, if unacceptable, the tests are repeated either by GE or by the vendor. If the vendor tests are adequate, the device is considered qualified to the limits of the test.

3.10.2.1.3 Qualification of Valve-Mounted Equipment

The piping analysis establishes the response spectra, the power spectral density function or time history characteristics, and develops horizontal and vertical accelerations for the pipe-mounted equipment. Class 1E MOV actuators are qualified in accordance with IEEE 382 (1972).

The SRV, including the electrical components mounted on the valve, is subjected to a dynamic test. This testing is described in Sections 3.9.2.2a.2.14 and 3.9.3.1.13.

3.10.2.1.4 Qualification of NSSS Motors

The seismic qualification of the ECCS motors is discussed in Section 3.9.2.2a.2.7 in conjunction with the ECCS pump and motor assembly. The seismic qualification of the SLCS pump motor is discussed in Section 3.9.2.2a.2.10 in conjunction with the SLC pump motor assembly.

3.10.2.2 Methods and Procedures for Qualifying Non-NSSS Instruments and Electrical Equipment

In regard to compliance with Regulatory Guide 1.100, the analysis and testing for the seismic qualification of non-NSSS Class 1E instruments and electrical equipment required to function during and after an SSE are in compliance with IEEE 344 (1971) for components purchased before issuance of IEEE 344 (1975) and are in compliance with IEEE 344 (1975) for components purchased after its issuance. In addition, all non-NSSS instruments and controls were re-evaluated to IEEE 344 (1975) and Reg. Guide 1.100 requirements (SQRT requirements) and found satisfactory.

Pipe-mounted instrumentation is qualified by analysis and/or testing to the acceleration levels allowed for piping systems. These levels include gravity and operation loading, as well as loading that is due to seismic excitation. Passive instruments that must only maintain mechanical and pressure boundary integrity are tested to the acceleration levels of the response spectra for the area in which they are to be installed.

Seismic Category I equipment is shown to be capable of withstanding the horizontal and vertical accelerations of five OBEs and one SSE by one of the following methods: dynamic analysis; dynamic testing; or a combination of dynamic analysis and testing. (Refer to Appendix 3A.7.1.7 for qualification methods for equipment subjected to hydrodynamic loads.)

3.10.2.2.1 Dynamic Analysis

For the analysis, equipment is idealized as a system of lumped masses and springs for which frequencies and mode shapes are determined for vibration in the vertical direction and two orthogonal horizontal directions. For each direction of vibration, the spectral accelerations per mode are obtained from the appropriate spectrum response curve corresponding to the location and damping of the equipment. Seismic loading in terms of inertia forces, moments, and shears is determined for each direction using the spectrum response method summing the absolute values per mode. If the orientation of the equipment is not designated, the horizontal seismic loading is taken as the maximum loading (worst case) obtained using each horizontal direction of vibration and the appropriate horizontal spectrum response curve(s). If the frequencies of all equipment modes (determined by either analysis or testing) are greater than the frequency of the appropriate spectrum response curve at which the acceleration is constant in the rigid (high frequency) range, the seismic loading consists of the static loading corresponding to that acceleration level.

If the equipment damping is unknown, the following values shall be used:

a. OBE - ½% damping

b. SSE - 1% damping

In lieu of determining the vibrational frequencies of equipment, the seismic loading of structurally simple equipment (that can be adequately represented as a single mass and spring) consists of a static load corresponding to 1.5 times the peak acceleration of the appropriate response spectrum curve. Total seismic loading consists of both the vertical seismic loading and the maximum horizontal seismic loading applied to the equipment simultaneously.

Where equipment must meet IEEE 344 (1975), the dynamic analysis is in accordance with section 5 of IEEE 344 (1975). Equipment qualified by analysis to IEEE 344 (1971) were re-evaluated to IEEE 344 (1975) criteria and found satisfactory.

3.10.2.2.2 Dynamic Tests

In lieu of performing a dynamic analysis, seismic adequacy is established by providing dynamic test or previous dynamic environmental (performance) data that demonstrate that the equipment meets the seismic design criteria as defined in this section. The previous data include at least one of the following:

a. Recent test data acquired from dynamic tests of equipment

b. Dynamic test data from previously tested comparable equipment

c. Performance data from equipment that, during normal operating conditions, is subjected to dynamic loads equal to or greater than those defined in this section

3.10.3 METHODS AND PROCEDURES OF ANALYSIS OR TESTING OF SUPPORTS OF ELECTRICAL EQUIPMENT AND INSTRUMENTATION

3.10.3.1 Dynamic Analysis Testing Procedures And Restraint Measures For NSSS Equipment Supports (Other Than Motors And Valve-Mounted Equipment)

Some GE-supplied Class 1E devices are qualified by analysis only (Table 3.10-1). Analysis is used for passive mechanical devices and sometimes is used in combination with testing for larger assemblies containing safeguard devices. For instance, a test may be run to determine if there are natural frequencies in the equipment within the critical frequency range. If the equipment is determined to be free of natural frequencies, then it is assumed to be rigid and a static analysis is performed. If the equipment has natural frequencies in the critical frequency range, then calculations of transmissibility are performed and responses to varying input accelerations are determined to see whether Class 1E devices mounted in the assembly would operate without malfunctioning. In general, the testing of Class 1E equipment is accomplished using the following procedure.

Assemblies (i.e., control panels) containing devices that have had dynamic loading malfunction limits established are tested by mounting the assembly on the table of a vibration machine, in a manner similar to that in which it is to be mounted when in use, and vibration testing the assembly by running a low level resonance search. As with the devices, the assemblies are tested in the three major orthogonal axes. The resonance search is run in the same manner as described for devices. If resonances are present, the transmissibility between the input and the locations of each Class 1E device is determined by measuring the accelerations at each device location and calculating the magnification between it and the input. Once known, the transmissibilities could be used analytically to determine the response at any Class 1E device location for any given input. It is assumed that the transmissibilities are linear as a function of acceleration, even though they actually decrease as acceleration is increased; therefore, this is a conservative assumption. As long as the device input accelerations are determined to be below their malfunction limits, the assembly is considered a rigid body with a transmissibility equal to 1, so that a device mounted on it is limited directly by the assembly input acceleration.

Since control panels and racks constitute the majority of seismic Category I electric assemblies supplied by GE, the qualification testing of these is discussed in more detail. There are basically four generic panel types: vertical board; instrument rack; local rack; and NEMA-12 enclosures. One or more of each type is tested using the above procedures.

Figures 3.10-1 through 3.10-4 illustrate the four basic panel types referenced above and show typical accelerometer locations. The status of the dynamic tests on the Class 1E panels supplied by GE for LGS is summarized in Table 3.10-2.

The full acceleration level tests described above disclose that most of the panel types have more than adequate mechanical strength and that a given panel design acceptability is just a function of its amplification factor and the malfunction levels of the devices mounted in it. Subsequent panels are therefore tested at lower acceleration levels, and the transmissibilities are measured to the various devices as described above. By dividing the devices' malfunction levels by the panel transmissibility between the device and the panel input, the panel qualification level can be determined. Several high level tests have been run on selected generic panel designs to assure the conservatism in using the transmissibility analysis described.

3.10.3.2 Non-NSSS Equipment Supports

Analyses or tests are performed for all supports of electrical equipment and instruments, such as switchgear, battery racks, instrument racks, control consoles, cabinets, and panels to ensure their structural capability to withstand seismic excitation.

The following bases are used in the seismic design and analysis of seismic Category I instrument tubing supports:

a. All instrument tubing supports are qualified by analysis, using the response spectrum method described in Section 3.10.2.2.1.

b. Analysis and design of seismic restraint measures for instrument tubing supports are based on combined limiting values for static load, span length, and computed seismic response.

c. Maximum stress is limited to 90% of minimum yield stress.

d. The seismic Category I instrument tubing systems are supported so that the allowable stresses permitted by ASME Section III are not exceeded when the tubing is subjected to the loads specified in Section 3.9 for Class 2 and 3 piping.

For field-mounted instruments, the following are applicable. (Refer to Appendix 3A.7.1.7 for instrument supports subjected to hydrodynamic loads.)

a. The mounting structures for seismic Category I instruments have a fundamental frequency of 33 Hz or higher (rigid range), which corresponds to the maximum floor acceleration. Therefore the ZPA for the installation is applicable.

b. The stress level in the mounting structure does not exceed the material allowable stress when the mounting structure is subjected to the maximum acceleration level for its location, in combination with other design loads.

3.10.4 OPERATING LICENSE REVIEW

3.10.4.1 NSSS Equipment

3.10.4.1.1 NSSS Control and Electrical Equipment (Other Than Motors and Valve-Mounted Equipment)

The qualification test plans and results for safety-related panels and control equipment within the NSSS scope of supply are maintained as follows:

a. Proprietary documents will be maintained by GE in a centrally located, readily auditable, permanent file.

b. Nonproprietary summary documents will be maintained by the licensee in a centrally located, readily auditable, permanent file.

If equipment fails to pass the tests, it is rejected. In some cases, equipment that fails one test is modified or repaired to meet the performance requirements and is retested. If the retested equipment passes the latter test, it may be used in a Class 1E application.

Table 3.10-1 lists the NSSS control devices by item number and vendor. The table also gives the corresponding acceleration levels for the devices used in Class 1E applications. The acceleration level shown in the right columns of Table 3.10-1 is the acceleration at which either the device malfunctioned or the limit of the vibration machine was reached.

3.10.4.1.2 NSSS Motors

Qualification test results for the ECCS motors are discussed in Section 3.9.2.2a.2.7 in conjunction with the ECCS pump and motor assembly. Qualification test results for the SLCS motor are discussed in Section 3.9.2.2a.2.10 in conjunction with the SLCS pump motor assembly.

3.10.4.1.3 Valve-Mounted Equipment

The SRVs, including the electrical components mounted on the valves, are subjected to dynamic tests. The results of these tests are discussed in Sections 3.9.2.2a.2.14 and 3.9.3.1.13, and are maintained in the same manner as discussed in Section 3.10.4.1.1.

3.10.4.2 Non-NSSS Equipment

A list of dynamic qualification packages for non-NSSS safety-related instruments and electrical equipment is given in Table 3.10-3. The qualification packages will be maintained by the licensee in a centrally located, readily auditable permanent file.

Table 3.10-1

NSSS ESSENTIAL ELECTRICAL COMPONENTS AND INSTRUMENTS (CLASS 1E) *

DESCRIPTION				SEISMIC QUALIFICATION			
					SEISMIC QUALIFICATION[3] (g)		
ITEM NO.	NAME	VENDOR	QUANTITY	OTHERS OF SAME TYPE IN SIMILAR AREA	F-B	S-S	V
System Title - Reactor							
B11-D193	Power range detector[2]	GE	43	-	4.5	4.5	4.5
System Title - Nuclear Boiler							
B21-K613	Power supply	Elma Eng.	2	-	7.0	7.0	5.5
B21-N004	Temp. element & thermowell[1]	PYCO	14	-			
B21-N010	Temp. element	PYCO	19	N011-N014,N016,N017	5.0	5.0	5.0
B21-N027	Level transmitter	Rosemount	1	-	10.0	5.8	1.8
B21-N040	Temp. element (thermowell)	Rosemount	3	N057	S.A.	S.A.	S.A.
B21-N064	Temp. element & thermowell[1]	Calif. Alloy	1	-			
B21-N075	Press. transmitter	Rosemount	4	-	10.0	5.8	1.8
B21-N076	Press. transmitter	Rosemount	4		10.0	5.8	1.8
B21-N078	Press. transmitter	Rosemount	24	N090,N094	10.0	5.8	1.8
B21-N080	Level transmitter	Rosemount	38	N081,N085-N089, N091,N095,N097	10.0	5.8	1.8
B21-N402	Level transmitter	Rosemount	4	-	9.4	9.4	7.2
B21-N403	Press. transmitter	Rosemount	4	-	9.4	9.4	7.2
B21-N600	Temp. switch	Riley Inst.	18	N603,N605-N608	4.5	4.5	4.5
B21-N675	Press. indicator switch	Rosemount	86	N676,N678-N681,N684, N686-N695,N693A,E,B,F, N697	15.0	15.0	15.0
B21-N693	Trip unit	Rosemount	4	N698	15.0	15.0	15.0
B21-R005	Diff. press. indicator	Barton	1	-	5.0	10.0	10.0
System Title - Reactor Recirculation							
B32-N014	Flow transmitter	Rosemount	8	N024	10.0	5.8	1.8
B32-N015	Diff. press. transmitter	Rosemount	2	-	10.0	5.8	1.8
B32-N023	Temp. element	Rosemount	2	-	S.A.	S.A.	S.A.

* NOTE: Table for historical purposes only.

Table 3.10-1 (Cont'd)

NSSS ESSENTIAL ELECTRICAL COMPONENTS AND INSTRUMENTS (CLASS 1E) *

DESCRIPTION				SEISMIC QUALIFICATION			
					SEISMIC QUALIFICATION[3] (g)		
ITEM NO.	NAME	VENDOR	QUANTITY	OTHERS OF SAME TYPE IN SIMILAR AREA	F-B	S-S	V
System Title - CRD HCU							
C11-N012	Level transmitter	Gould	4	-	5.0	5.0	10.2
C11-N013	Level switch	Magnetrol	4	-	4.6	4.6	3.6
C11-N013 (E-H)	Level switch	Magnetrol	4	-	4.1	4.1	9.5
C11-N601	Level indicator switch	Rosemount	4	-	15.0	15.0	15.0
System Title - Feedwater Control							
C32-N003	Diff. press. transmitter	Rosemount	8	N004	10.0	5.8	1.8
C32-N005	Press. transmitter	Rosemount	2	N008	10.0	5.8	1.8
C32-N017	Level transmitter	Statham	1	-	10.0	5.8	1.8
System Title - Standby Liquid							
C41-N003	Temp. switch	Fenwell	1	-	S.A.	S.A.	S.A.
C41-N004	Press. transmitter	Rosemount	3	-	9.4	9.4	7.2
C41-N006	Temp. element[1]	Fenwell	1	-			
C41-N010	Level transmitter	Gould	6	-	5.0	5.0	10.2
C41-N610	Level switch	GE	2	-	2.4	2.4	4.0
System Title - Neutron Monitoring							
C51-K002	Voltage preamplifier	GE	8	-	≥10.0	≥10.0	≥10.0
C51-K601	Intermediate range monitor	GE	8	-	8.5	8.5	8.5
C51-K605	Power range neutron monitor	GE	1		3.8	3.8	3.0
C51-N002	Detector	GE	8	-	S.A.	S.A.	S.A.
System Title - Remote Shutdown							
C61-K001	Sq Root converter	GE	1	-	9.0	9.0	13.0
C61-K002	Dc-ac inverter		1	-	5.0	3.0	8.5
C61-K005	Power supply	GE	2	K010	2.5	2.5	2.5
C61-N001	Flow transmitter	Rosemount	2	N010	10.0	5.8	1.8
C61-N006	Press. transmitter	Rosemount	1	-	10.0	5.8	1.8
C61-R001	Flow indicator controller	Bailey Meter	1	-	7.5	6.5	2.0

* NOTE: Table for historical purposes only.

Table 3.10-1 (Cont'd)

NSSS ESSENTIAL ELECTRICAL COMPONENTS AND INSTRUMENTS (CLASS 1E) *

DESCRIPTION				SEISMIC QUALIFICATION			
					SEISMIC QUALIFICATION[3] (g)		
ITEM NO.	NAME	VENDOR	QUANTITY	OTHERS OF SAME TYPE IN SIMILAR AREA	F-B	S-S	V
System Title - RPS							
C71-N050	Press. transmitter	Rosemount	4	-	10.0	5.8	1.8
C71-N052	Press. transmitter	Rosemount	4	-	10.0	5.8	1.8
System Title - PRMS							
D12-K603	Radiation Monitor	GE	4	-	3.0	3.0	3.0
D12-K609	Indicator/trip unit	GE	8	K610	3.0	3.0	3.0
D12-N006	Detector (steam line)	GE	4	-	8.0	8.0	8.0
D12-N010	Detector (sensor & converter)	GE	8	N011	15.0	15.0	15.0
System Title - RHR							
E11-N001	Cond. element	Balsbaugh	2	-	S.A.	S.A.	S.A.
E11-N004	Temp. element	Calif Alloy	7	N005,N027,N032	S.A.	S.A.	S.A.
E11-N008	Level transmitter	Barton	2	-	9.1	10.6	6.0
E11-N009	Temp. element	Calif Alloy	6	N029,N030	5.0	5.0	5.0
E11-N013	Flow transmitter	Rosemount	7	N015, N060	10.0	5.8	1.8
E11-N026	Press. transmitter	Rosemount	7	N028,N053	10.0	5.8	1.8
E11-N052	Transmitter	Rosemount	8	N258	10.0	5.8	1.8
E11-N055	Press. transmitter	Rosemount	8	N056	10.0	5.8	1.8
E11-N057	Press. transmitter	Rosemount	1	-	10.0	5.8	1.8
E11-N600	Temp. switch	Riley Inst.	4	N601	4.5	4.5	4.5
E11-N652	Trip unit	Rosemount	29	N655, N656	15.0	15.0	15.0
System Title - Core Spray							
E21-K601	Dc-ac inverter		4	-	15.0	10.0	7.0
E21-K602	Power supply	Elma Eng.	8	-	7.0	7.0	5.5
E21-K605	Ac/dc power supply	GE/Sola	1	-	5.5	5.5	5.5
E21-N003	Flow transmitter	Rosemount	2	-	3.0	3.0	3.0
E21-N051	Diff. press. transmitter	Rosemount	2	-	10.0	5.8	1.8
E21-N054	Press. transmitter	Rosemount	2	-	10.0	5.8	1.8
E21-N055	Press. transmitter	Rosemount	4	-	10.0	5.8	1.8
E21-N056	Diff. press. transmitter	Rosemount	1	-	3.0	3.0	3.0
E21-N651	Trip unit	Rosemount	12	N655	15.0	15.0	15.0

* NOTE: Table for historical purposes only

Table 3.10-1 (Cont'd)

NSSS ESSENTIAL ELECTRICAL COMPONENTS AND INSTRUMENTS (CLASS 1E) *

DESCRIPTION				SEISMIC QUALIFICATION			
					SEISMIC QUALIFICATION[3] (g)		
ITEM NO.	NAME	VENDOR	QUANTITY	OTHERS OF SAME TYPE IN SIMILAR AREA	F-B	S-S	V
System Title - MSIV-LCS							
E32-K601	Power supply	Elma Eng.	2	K602	7.0	7.0	5.5
E32-N006	Flow meter	S&K Inst.	4	-	3.55	3.55	4.87
E32-N050	Press. transmitter	Rosemount	8	N055,N058,N060,N061	10.0	5.8	1.8
E32-N051	Press. transmitter	Rosemount	5	N056	10.0	5.8	1.8
E32-N053	Flow transmitter	S&K Inst.	4	-	3.0	3.0	2.0
E32-N054	Diff. press. transmitter	Rosemount	2	N059	3.0	3.0	3.0
E32-N600	Time delay switch	Eagle Signal	13	N601,N602,N604	2.5	2.5	2.5
E32-N650	Press. indicator switch	Rosemount	20	N651,N653-N661	15.0	15.0	15.0
E32-R601	Millivolt to current converter	Bailey Meter	4	-	8.0	8.0	8.0
E32-R653	Flow indicator	GE	14	R654-R656, R658-R661	18.0	18.0	7.0
System Title - HPCI							
E41-K600	Power supply	GE	1	-	5.5	5.5	5.5
E41-K601	Sq root converter	Bailey Meter	1	-	9.0	9.0	13.0
E41-K603	Dc-ac inverter		1	-	15.0	10.0	7.0
E41-N008	Flow transmitter	Rosemount	1	-	10.0	5.8	1.8
E41-N013	Press. transmitter	Rosemount	2	N052	10.0	5.8	1.8
E41-N014	Level switch	Robert Shaw	1	-	4.6	4.6	3.6
E41-N024	Temp. element	Calif. Alloy/ PYCO	15	N025,N028-N030	5.0	5.0	5.0
E41-N050	Press. transmitter	Rosemount	5	N055B, F, N056	10.0	5.8	1.8
E41-N051	Flow transmitter	Rosemount	3	N061	10.0	5.8	1.8
E41-N053	Press. transmitter	Rosemount	1	-	10.0	5.8	1.8
E41-N055 (D,H)	Press. transmitter	Rosemount	2	-	10.0	5.8	1.8
E41-N057	Press. transmitter	Rosemount	6	N058	10.0	5.8	1.8
E41-N062	Level transmitter	Gould	2	-	7.0	7.0	8.0
E41-N600	Temp. switch	Riley Inst.	13	N601-N603	4.5	4.5	4.5
E41-N650	Trip unit	Rosemount	23	N651-N653, N655-N662	15.0	15.0	15.0
E41-R600	Flow indicator controller	Bailey Meter	1	-	7.5	6.5	20.0
System Title - RCIC							
E51-K600	Power supply	GE	1	-	2.5	2.5	2.5
E51-K601	Sq root convertor	Bailey Meter	1	-	9.0	9.0	13.0
E51-K603	Dc-ac inverter		1	-	15.0	10.0	7.0
E51-N003	Flow transmitter	Rosemount	4	N051,N057	10.0	5.8	1.8
E51-N007	Press. transmitter	Rosemount	1	-	10.0	5.8	1.8

* NOTE: Table for historical purposes only

Table 3.10-1 (Cont'd) *

DESCRIPTION				SEISMIC QUALIFICATION			
					SEISMIC QUALIFICATION[3] (g)		
ITEM NO.	NAME	VENDOR	QUANTITY	OTHERS OF SAME TYPE IN SIMILAR AREA	F-B	S-S	V
E51-N010	Level switch	Magnetrol	1	-	4.6	4.6	3.6
E51-N011	Temp. element	Calif. Alloy	15	N021-N023,N025	5.0	5.0	5.0
E51-N035	Level transmitter	Rosemount	2	-	3.0	3.0	3.0
E51-N050	Press. transmitter	Rosemount	2	N052	3.0	3.0	3.0
E51-N053	Press. transmitter	Rosemount	1	-	10.0	5.8	1.8
E51-N055	Press. transmitter	Rosemount	10	N056,N058	10.0	5.8	1.8
E51-N600	Temp. switch	Riley Inst.	11	N603	4.5	4.5	4.5
E51-N650	Press. indicator switch	Rosemount	21	N635,N651-N653,N655-N660	15.0	15.0	15.0
E51-R600	Flow indicator controller	Bailey Meter	1	-	7.5	6.5	20.0
System Title - RWCU							
G31-K602	Sq root converter	Bailey Meter	6	K603,K605	9.0	9.0	13.0
G31-K604	Five input summer	Bailey Meter	2	-	9.0	9.0	13.0
G31-N012	Flow transmitter	Rosemount	6	N036,N041	10.0	5.8	1.8
G31-N016	Temp. element	Calif Alloy	36	N022,N023	5.0	5.0	5.0
G31-N600	Temp. switch	Riley Inst.	24	N602	4.5	4.5	4.5
G31-N603	Diff. flow switch	Bailey Meter	2	-	7.5	8.5	20.0
G31-R616	Cycle timer	Eagle Signal	2	-	2.5	2.5	2.5

(1) Classified as pressure integrity or passive instrument
(2) Qualified by analysis
(3) S.A. = Stress Analysis

* NOTE: Table for historical purposes only

Table 3.10-2

SEISMIC QUALIFICATION TEST SUMMARY
NSSS SAFEGUARD CONTROL PANELS, LOCAL PANELS, AND RACKS

PANEL	DESCRIPTION	TYPE	CLASS 1E EQUIPMENT DESCRIPTION	COMMENTS
H12-P601	Reactor and containment cooling and isolation	Vertical board	Control switches, GE/MAC instruments, recorders	Seismic test complete
H12-P602	Reactor water cleanup and recirculation control	Bench board	Control switches	Qualification by similarity(1)
H12-P603	Reactor control	Bench board	Switches (range, push button, control)	Seismic test complete
H12-P606	Radiation monitor instrument Panel A	Instrument rack	Startup neutron monitoring electronics, radiation monitor trips units	Qualification by similarity
H12-P608	Power range neutron monitor	Instrument rack	APRM electronics, RBM electronics, Two-Out-Of-Four Logic Modules, power supplies, isolators, interface panels	Seismic test complete
H12-P609	Reactor protection system Division 1 & 2 logic	Vertical board	Relays, contactor, temperature monitor, trip units, switches, power supply	Seismic test complete
H12-P611	Reactor protection system Division 3 & 4 logic	Vertical board	Relays, contactor, temperature monitor, trip units, switches, power supply	Qualification by similarity
H12-P613	NSSS process instrument	Vertical board	Relays, trip limits, power supply	Qualification by similarity
H12-P614	NSSS temperature recorder	Vertical board	Relays	Seismic test complete
H12-P617	Division 1 RHR relay	Vertical board	Relays, trip units	Qualification by similarity
H12-P618	Division 2 RHR relay	Vertical board	Relays trip units, switches, power supply	Seismic test complete
H12-P620	HPCI relay	Vertical board	Relays, temperature monitor, switches	Seismic test complete

Table 3.10-2 (Cont'd)

PANEL	DESCRIPTION	TYPE	CLASS 1E EQUIPMENT DESCRIPTION	COMMENTS
H12-P621	RCIC relay	Vertical board	Relays, temperature monitor, switches	Qualification by similarity
H12-P622	Inboard valve relay	Vertical board	Relays	Qualification by similarity
H12-P623	Outboard valve relay	Vertical board	Relays	Qualification by similarity
H12-P626	ADS	Vertical board	Switches, indicators	Qualification by similarity
H12-P628	Prompt relief trip and ADS Division 1 relay	Vertical board	Relays, control switches	Qualification by similarity
H12-P631	ADS Division 3 relay	Vertical board	Relays, control switches	Qualification by similarity
H12-P633	Radiation monitor instrument Panel B	Instrument rack	Startup neutron monitoring electronics, radiation monitor trip units	Qualification by similarity
H12-P640	Division 3 RHR relay	Vertical board	Control switches, trip units, relays, temp. monitors, power supply	Qualification by similarity
H12-P641	Division 4 RHR relay	Vertical board	Control switches, trip units, temperature monitors, power supply	Qualification by similarity
H12-P647	HPCI	Vertical board	Controller, switches, power supply	Qualification by similarity
H12-P648	RCIC	Vertical board	Switches, power supply	Qualification by similarity
H12-P661	Safeguard systems A,B,C,D	Vertical board	Switches (non-NSSS supply)	Seismic test complete

Table 3.10-2 (Cont'd)

PANEL	DESCRIPTION	TYPE	CLASS 1E EQUIPMENT DESCRIPTION	COMMENTS
H12-P787	Termination cabinet	Cabinet	Cables	Qualification by similarity
H12-P788	Termination cabinet	Cabinet	Cables	Qualification by similarity
H12-P789	Termination cabinet	Cabinet	Cables	Qualification by similarity
H12-P790	Termination cabinet	Cabinet	Cables	Qualification by similarity
H12-P791	Termination cabinet	2 Bay cabinet	Cables	Qualification by similarity
H12-P792	Termination cabinet	2 bay cabinet	Cables	Qualification by similarity
H12-P793	Termination cabinet	2 bay cabinet	Cables	Qualification by similarity
H23-P001	Core spray system, Panel A	Local panel	Pressure transmitters	Seismic test complete
H23-P002	Reactor water cleanup	Local panel	Pressure transmitters, indicators, temperature control	Seismic test complete
H23-P004	Reactor vessel level & pressure, Panel A	Local panel	Pressure transmitters and indicators, level indicator, switches	Qualification by similarity
H23-P005	Reactor vessel level & pressure, Panel B	Local panel	Pressure transmitters	Qualification by similarity
H23-P006	Recirc pump, Panel A	Local panel	Pressure transmitters	Qualification by similarity
H23-P009	Jet pump, Panel A	Local panel	Pressure transmitters	Seismic test complete
H23-P010	Jet pump, Panel B	Local panel	Pressure transmitters	Qualification by similarity
H23-P014	HPCI system, Panel B	Local panel	Pressure transmitters, indicators	Qualification by similarity
H23-P015	Main steam flow, Panel B	Local panel	Pressure transmitters	Qualification by similarity
H23-P016	HPCI leak detection, Panel A	Local panel	Pressure transmitters	Qualification by similarity
H23-P017	RCIC, Panel A	Local panel	Pressure transmitters	Qualification by similarity
H23-P018	RHR System, Panel A	Local panel	Pressure transmitters	Qualification by similarity

Table 3.10-2 (Cont'd)

PANEL	DESCRIPTION	TYPE	CLASS 1E EQUIPMENT DESCRIPTION	COMMENTS
H23-P019	CS system, Panel B	Local panel	Pressure transmitters	Qualification by similarity
H23-P022	Recirc pump, Panel B	Local panel	Pressure transmitters	Qualification by similarity
H23-P025	Main steam flow, Panel D	Local panel	Pressure transmitters	Qualification by similarity
H23-P026	Reactor vessel level & pressure, Panel D	Local panel	Pressure transmitters	Qualification by similarity
H23-P027	Reactor vessel level & pressure, Panel C	Local panel	Switches, pressure transmitters	Qualification by similarity
H23-P030	SRM & IRM preamp A-D	NEMA - 12 enclosure	SRM-IRM preamplifiers	Seismic test complete
H23-P031	SRM & IRM preamp A-D	NEMA - 12 enclosure	SRM-IRM preamplifiers	Qualification by similarity
H23-P032	SRM & IRM preamp A-D	NEMA - 12 enclosure	SRM-IRM preamplifiers	Qualification by similarity
H23-P033	SRM & IRM preamp A-D	NEMA - 12 enclosure	SRM-IRM preamplifiers	Qualification by similarity
H23-P034	HPCI system, Panel A	Local panel	Pressure transmitters	Qualification by similarity
H23-P035	RCIC leak detection, Panel A	Local panel	Pressure transmitters	Qualification by similarity
H23-P036	HPCI leak detection, Panel B	Local panel	Pressure transmitters	Qualification by similarity
H23-P037	RCIC system, Panel B	Local panel	Pressure transmitters	Qualification by similarity
H23-P038	RCIC leak detection, Panel B	Local panel	Pressure transmitters	Qualification by similarity
H23-P041	Main steam flow, Panel C	Local panel	Pressure transmitters	Qualification by similarity
H23-P042	Main steam flow, Panel D	Local panel	Pressure transmitters	Qualification by similarity
H23-P073	MSIV LCS Division 1	Local panel	Pressure transmitters	Qualification by similarity
H23-P074	MSIV LCS Division 2	Local panel	Pressure transmitters	Qualification by similarity
H23-P075	RHR A/ADS, Panel A	Local panel	Pressure transmitters, indicators	Qualification by similarity

Table 3.10-2 (Cont'd)

PANEL	DESCRIPTION	TYPE	CLASS 1E EQUIPMENT DESCRIPTION	COMMENTS
H23-P076	RHR B/ADS, Panel C	Local panel	Pressure transmitters, indicators	Qualification by similarity
H23-P077	RHR C/ADS, Panel A	Local panel	Pressure transmitters, indicators	Qualification by similarity
H23-P078	RHR D/ADS, Panel C	Local panel	Pressure transmitters, indicators	Qualification by similarity
C61-P001	Remote shutdown	Local panel	Switches, square root converter, power supply	Qualification by similarity

(1) Qualification by similarity - Panel is structurally similar and in some cases identical to a panel that was tested.

Table 3.10-3

DYNAMIC QUALIFICATION TEST SUMMARY
NON-NSSS SAFETY-RELATED INSTRUMENTS AND ELECTRICAL EQUIPMENT

ITEM NUMBER	EQUIPMENT DESCRIPTION	SUPPLIER	DYNAMIC QUALIFICATION PACKAGE NO.
8031-E-7	Medium-voltage metal clad switchgear (4.16 kV)	Brown Boveri	D-14
8031-E-7	4.16 kV ATWS switchgear	Brown Boveri	D-167
8031-E-8B	4 kV Induction motors	GE	D-2 D-3
8031-E-10	Load centers	Brown Boveri	D-15
8031-E-11	480 V motor control centers	Cutler-Hammer	D-12 D-16
8031-E-11	Lighting panels	Cutler-Hammer	D-46
8031-E-13	Batteries and racks	C&D Batteries Div.	D-17 D-143
8031-E-14	250 V dc motor control centers	Westinghouse	D-18
8031-E-16	Dc distribution panels & fuse boxes	B-K Electrical Products Div.	D-13 D-19 D-70
8031-E-17	Battery chargers	C&D Batteries Div.	D-20
8031-E-33D	Heat tracing panels	Thermon	D-26
8031-E-37	Ac power dry-type transformers	Square D	D-45
8031-E-40	Primary containment electrical penetrations	Conax Corp.	D-27
8031-E-51	In-line plug connectors	Litton	D-44

Table 3.10-3 (Cont'd)

ITEM NUMBER	EQUIPMENT DESCRIPTION	SUPPLIER	DYNAMIC QUALIFICATION PACKAGE NO.
8031-M-66	HVAC control instruments	Various	D-144
8031-M-66	HVAC flow switches	FCI	D-155
8031-M-66	HVAC RTDs	Minco	D-156
8031-M-66	HVAC panel-mounted instruments	Various	D-159
8031-M-66	HVAC humidity transmitter/ sensor	American Instruments	D-160
8031-M-66	HVAC solenoid valves	ASCO	D-161
8031-M-66	HVAC flow elements	Annubar	D-163
8031-M-66	HVAC flow element air stations	Air Monitor	D-164
8031-M-66	Duct-mounted RTDs	Minco	D-182
8031-M-66	HVAC ITE time delay relay	Brown Boveri	D-211
8031-M-203	Radiation monitors, consisting of:	General Atomic	
	Item 1: Control room radiation monitors (4 each)		D-196
	Item 2: Control room emergency fresh air radiation monitors (2 each)		D-196
	Item 3: Primary containment post-LOCA radiation monitors (4 each)		D-58
8031-M-203	Single pen strip-chart recorders	General Atomic	D-200

Table 3.10-3 (Cont'd)

ITEM NUMBER	EQUIPMENT DESCRIPTION	SUPPLIER	DYNAMIC QUALIFICATION PACKAGE NO.
8031-M-203	Radiation monitoring control pen	General Atomic	D-201
8031-M-203	Communication and isolation devices	General Atomic	D-203
8031-M-206	Electronic transmitters	Rosemount	D-1
8031-M-212A	Flow elements venturi	BIF	D-214
8031-M-224	Pressure switches	Mercoid Corp.	D-28 D-49
8031-M-230	Differential pressure instruments	ITT-Barton	D-51 D-52
8031-M-231	Excess flow check valves	Marotta	D-134
8031-M-235	Containment gas sampling and analyzing system	Comsip-Delphi	D-59
8031-M241	Nuclear pressure regulators	Target Rock Corp.	D-72
8031-M-242	Nuclear butterfly control valves	Fisher Controls	D-60
8031-M-243	Quality assured pressure gauges	Dresser Industries	D-32 D-53
8031-M-245	Quality assured solenoid valves	Target Rock Corp.	D-54
8031-M-245C	Solenoid valves	Valcor	D-212
8031-M-250A	Nuclear control valves	Masoneilan	D-56
8031-M-253	Wide range accident monitoring system	General Atomic	D-210

Table 3.10-3 (Cont'd)

ITEM NUMBER	EQUIPMENT DESCRIPTION	SUPPLIER	DYNAMIC QUALIFICATION PACKAGE NO.
8031-M-263	Suppression pool temperature monitoring system	WestronicsSimmonds-precision	D-178
8031-M-266	Class 1E pressure switches	ITT-Barton	D-180
8031-M-267	Class 1E RTDs	Weed	D-179

3.11 ENVIRONMENTAL DESIGN OF ELECTRICAL EQUIPMENT

This description provides a summary of the information addressed and substantiated in the separate Environmental Qualification Report (Section 1.1). The EQR identifies and documents the licensee's program for the environmental qualification of safety-related electric equipment installed in the LGS, in accordance with 10CFR50.49.

3.11.1 ENVIRONMENTAL DESIGN CRITERIA FOR ELECTRICAL EQUIPMENT

All safety-related equipment must be capable of performing its safety function and/or remaining in a safe mode under all conditions postulated to occur during its installed life. This requirement is embodied in GDC 1, 2, 4, and 23 of 10CFR50, Appendix A, in Criterion III and Criterion XI of 10CFR50, Appendix B, 10CFR50.55a(h), which incorporates by reference IEEE 279 (1971), "Criteria for Protection Systems for Nuclear Power Generating Stations," and in 10CFR50.49.

The NRC has issued definitive criteria in NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment", which contains the following criteria:

a. Category I, for plants whose construction permit SERs were issued after July 1, 1974, incorporates and supplements IEEE 323 (1974).

b. Category II, for plants whose construction permit SERs were issued before July 1, 1974, incorporates and supplements IEEE 323 (1971) unless the operating license applicant's record indicates that IEEE 323 (1974) is to be used, in which case Category I criteria are applicable.

The LGS construction permit SER was issued in June 1974, therefore, NUREG-0588 Category II criteria are applicable.

In February 1980 and June 1982, the NRC requested that the licensee perform a review of their environmental qualification program for safety-related equipment to identify the degree to which the program complied with the regulatory criteria. The EQR has been developed to provide detailed information on the LGS EQ program. The following sections provide a summary of the information contained in the EQR including mild environment qualification.

There is a Risk Informed Categorization and Treatment Program at Limerick which is based on 10 CFR 50.69. This regulation provides an alternative approach for establishing requirements for treatment of SSCs using a risk-informed method of categorizing SSCs according to their safety significance. Specifically, for SSCs categorized as low safety significant, alternate treatment requirements may be implemented rather than treatments chosen by the environmental qualification program. Refer to Section 13.5.5 for further information.

3.11.2 EQUIPMENT REQUIRING ENVIRONMENTAL QUALIFICATION

The list of equipment that is included in the environmental qualification program was established by considering those systems which are required to mitigate the consequences of a LOCA or HELB. This list also includes certain postaccident monitoring equipment. This list specifically includes the equipment required to achieve or support (1) emergency reactor shutdown, (2) containment isolation (3) reactor core cooling, (4) containment heat removal, (5) core residual heat removal, and (6) prevention of significant release of radioactive material to the environment.

Subsequent to identifying the equipment requiring qualification, equipment locations are identified using design drawings and are verified, where practicable, by field inspection. Equipment locations are identified by architectural room numbers with defined boundaries.

3.11.3 ENVIRONMENTAL SERVICE CONDITIONS

Environmental conditions have been determined for normal, abnormal, and accident conditions.

All areas inside containment and rooms containing high energy lines or post-LOCA recirculatory fluid lines outside of containment are considered to be harsh environments.

3.11.3.1 Environmental Conditions During Normal Plant Operation

Redundant plant HVAC systems are designed to maintain the temperature and humidity within the normal limits which are shown in the EQR. Section 9.4 describes the HVAC system.

The TID for normal operation for 40 years of equipment life have been calculated assuming a 100% load factor and rated power. The doses are based on the design radiation source terms of the radiation sources within each plant area.

Aging effects on all equipment are considered in the qualification program to conform to the requirements of section 4 of NUREG-0588. Components susceptible to aging effects are identified, and refurbishment and/or replacement is incorporated into the LGS Preventive Maintenance/Surveillance Program. Known susceptibility to aging degradation, results of inspections and manufacturer's recommendations are factored into the Maintenance/Surveillance Program.

Effects of known normal vibratory loads on equipment are considered in the EQ program when significant.

3.11.3.2 Accident Environmental Conditions

Operability duration requirements have been determined based on the length of time the equipment must maintain its ability to perform its safety function.

The primary containment time-dependent pressure and temperature profiles for the spectrum of postulated LOCAs and main steam line breaks have been generated using NRC approved methodology.

Temperature and pressure conditions resulting from a HELB outside containment have been determined using plant specific profiles. These profiles bound accident environments caused by other events. Sections 3.6 and 9.4 describe the analyses used in generating these profiles. Additional information is contained in the EQR.

Post-LOCA radiation doses inside primary and secondary containments were calculated in accordance with NUREG-0737, item II.B.2. The source terms are consistent with those specified in NUREG-0588 and NUREG-0737. Additional information is contained in Section 1.13.

Dynamic qualification of equipment due to seismic and hydrodynamic loads from SRV and LOCA is addressed in Section 3.10 and Appendix 3A.7.1.7.

The potential for submergence of equipment inside and outside containment is identified. Identified equipment is either qualified for submergence or analyzed to ensure both that it completes its function prior to submergence and that failure after submergence is acceptable. If these conditions cannot be met, the equipment will be relocated above flood level.

LGS has the capability of water spray actuation to mitigate the effects of a LOCA. Although no credit for spray actuation has been taken in determining temperature/pressure conditions inside containment, equipment inside containment is evaluated for the effects of spray.

Synergistic effects, where known, are considered. Specifically, where a supplier has identified synergisms or where the licensee is aware of synergistic effects for a particular component, it has been addressed. Appropriate documentation is included in the qualification file.

Margins appropriate to account for unquantified uncertainties in the effects of production variations and/or inaccuracies in test instruments are included in the qualification program.

3.11.4 QUALIFICATION TESTING AND ANALYSIS OF EQUIPMENT

All qualification testing and analysis of safety-related electrical equipment is performed according to the appropriate NUREG-0588 guidelines. Sequential testing and analysis or a combination thereof is performed for all electrical equipment. Analyses, performed on a case-by-case basis, have been conducted using approved methodologies to provide adequate justification.

3.11.5 METHODOLOGY FOR EVALUATING ENVIRONMENTAL QUALIFICATION TO SERVICE CONDITIONS

A comparison of environmental qualification to equipment service conditions is performed for all equipment located in harsh environmental zones. The equipment is evaluated for the 40 year normal environment and accident environments resulting from the spectrum of LOCAs and HELBs inside and outside containment. A point-by-point comparison is made between service condition parameters and qualified levels.

In addition, reviews and analyses were completed to ensure that the equipment tested was either identical or similar to the installed plant equipment.

3.11.6 MAINTENANCE/SURVEILLANCE PROGRAM

A Maintenance/Surveillance Program has been developed to encompass vendor prescribed maintenance procedures and periodic inspections of equipment to ensure that degradation is not occurring sooner than predicted. The program requires replacement of subcomponents (e.g., seals, gaskets, etc) at predetermined intervals to maintain the designated life. In addition, the program encompasses procedures to ensure that the environment is maintained relatively clean to avoid the possible adverse effects of dust.

3.11.7 REPLACEMENT PARTS PROGRAM

Safety-related equipment and spare and replacement parts are being ordered to meet or exceed the original specifications. For replacement parts being procured from the original specification and which are identical to the originally supplied equipment, a certificate of conformance is considered sufficient documentation to support qualification. However, if identical replacement parts are not available, environmental qualification for the new replacement parts will be demonstrated.

3.11.8 MILD ENVIRONMENT QUALIFICATION

Mild environment qualification is not included in the EQ program. A mild environment is an environment that would at no time be significantly more severe than the environment that would occur during normal plant operation, including anticipated operational occurrences.

3.12 CONTROL OF HEAVY LOADS

3.12.1 Introduction/Licensing Background

Site Licensing documentation is discussed in Section 1.12 (Subsection A-36) of the LGS UFSAR. Section 1.12 states "requirements for heavy loads, NUREG-0612, were addressed in the initial operating license review." Section 1.12 mentions a submittal dated August 13, 1984, which includes Bechtel Revision 3 of the LGS Overhead Handling Systems Review Final Report. Limerick Generating Station, Limerick Units 1 and 2, Overhead Handling Systems Review Final Report, Bechtel Revision 6/PECO Revision 1 (SDOC M-038-00008), August 1989 is incorporated in the LGS UFSAR as reference 9.1-1. The report summarizes the site correspondence to and from the NRC with respect to GL 81-07 and GL 85-11. Licensee submittal dated May 10, 1996, in response to NRC Bulletin 96-02 determines that at the time, NUREG-0612, Phase I commitments were being effectively implemented at LGS.

3.12.2 Safety Basis

UFSAR Section 1.12 (Subsection A-36) provides documentation of the site's compliance with Phase I of NUREG-0612 and Overhead Handling Systems Review Final Report (Reference 9.1-1) provides documentation that the site utilizes a single failure proof crane for RPVH/specified lifts and performed load drop analysis that demonstrates the fuel in the RPV will not be damaged and by providing electrical or mechanical interlocks on the crane to prevent travel of crane over spent fuel pool.

3.12.3 Scope of Heavy Load Handling Systems

The scope of load handling systems is documented in tabular form in M-038-00008 (Reference 9.1-1).

3.12.4 Control of Heavy Loads Program

3.12.4.1 Commitments in Response to NUREG-0612, Phase I Elements

The station is committed to NUREG-0612, Phase I elements as summarized in section 1.12 (Subsection A-36) of the LGS UFSAR. Detailed information is documented in M-038-00008 (Reference 9.1-1).

3.12.4.2 Reactor Pressure Vessel Head (RPVH) Lifting Procedures

The LGS UFSAR documents a single failure proof crane to be utilized to perform RPV head lifts in UFSAR Section 9.1.5 and is also documented further in reference 9.1- 1 (SDOC M-038-00008). In addition, the strong back/carousel used as a special lifting device for this evolution is single failure proof per UFSAR Section 9.1.4.2.5.8.

This safety basis (single failure proof lift for RPVH) is reflected in procedures M-041-200 (Reactor Pressure Vessel Disassembly) and M-041-400 (Reactor Pressure Vessel Reassembly).

3.12.4.3 Single Failure Proof Cranes for Spent Fuel Casks

The spent fuel cask will be equipped with lifting lugs and yoke(s) which are single failure proof and compatible with the single failure proof reactor enclosure crane and main hook, thus precluding a cask-drop due to a single failure (UFSAR section 15.7.5). Refer to Section 9.1.5 for a description of the reactor enclosure crane and the interlocks that prevent moving the crane over the fuel pool in the absence of specific action by the crane operator to allow such movement.

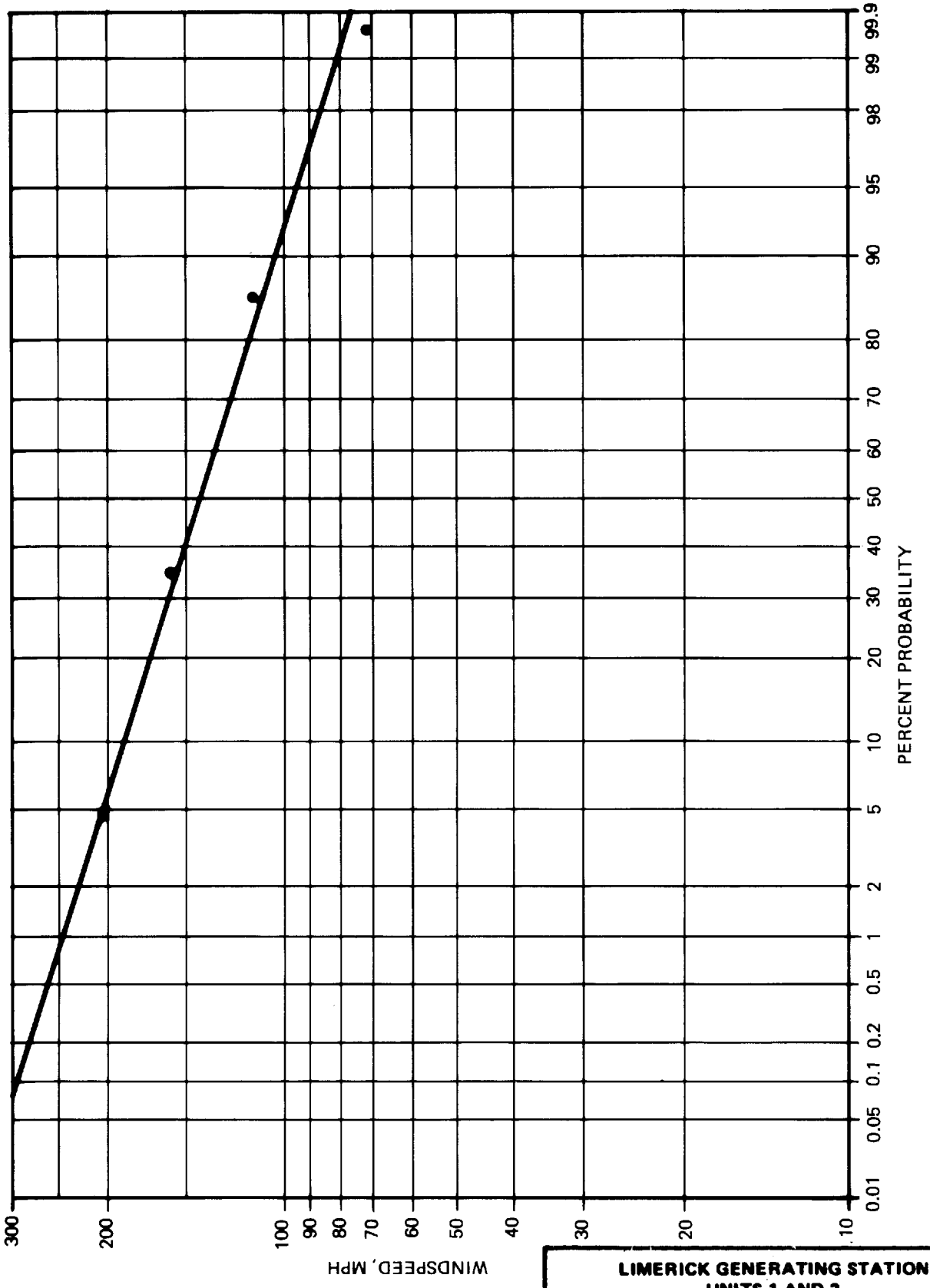
3.12.5 Safety Evaluation

The basis for the site's conclusion that the existing heavy loads program is compliant with the NUREG-0612, Phase 1 requirements is documented in UFSAR Section 1.12 under the heading of "Implementation and Status Summary." This section states, "the requirements for heavy loads, NUREG-0612, were addressed in the initial operating license submittal and Unit I Operating License NPF-27 License Condition 2.C(19)." This demonstrates that the LGS heavy loads program is compliant with the appropriate regulations, codes, and standards.

Reference 9.1 1 documents, that in the event of postulated load drops, the consequences are acceptable, as demonstrated by load drop analyses. Restrictions on load height, weight, medium under the load and safe paths are reflected in plant procedures.

Reference 9.1-1 documents that when using single failure proof cranes or equivalent to perform heavy loads lifts, the risk of a load drop is extremely unlikely and acceptably low.

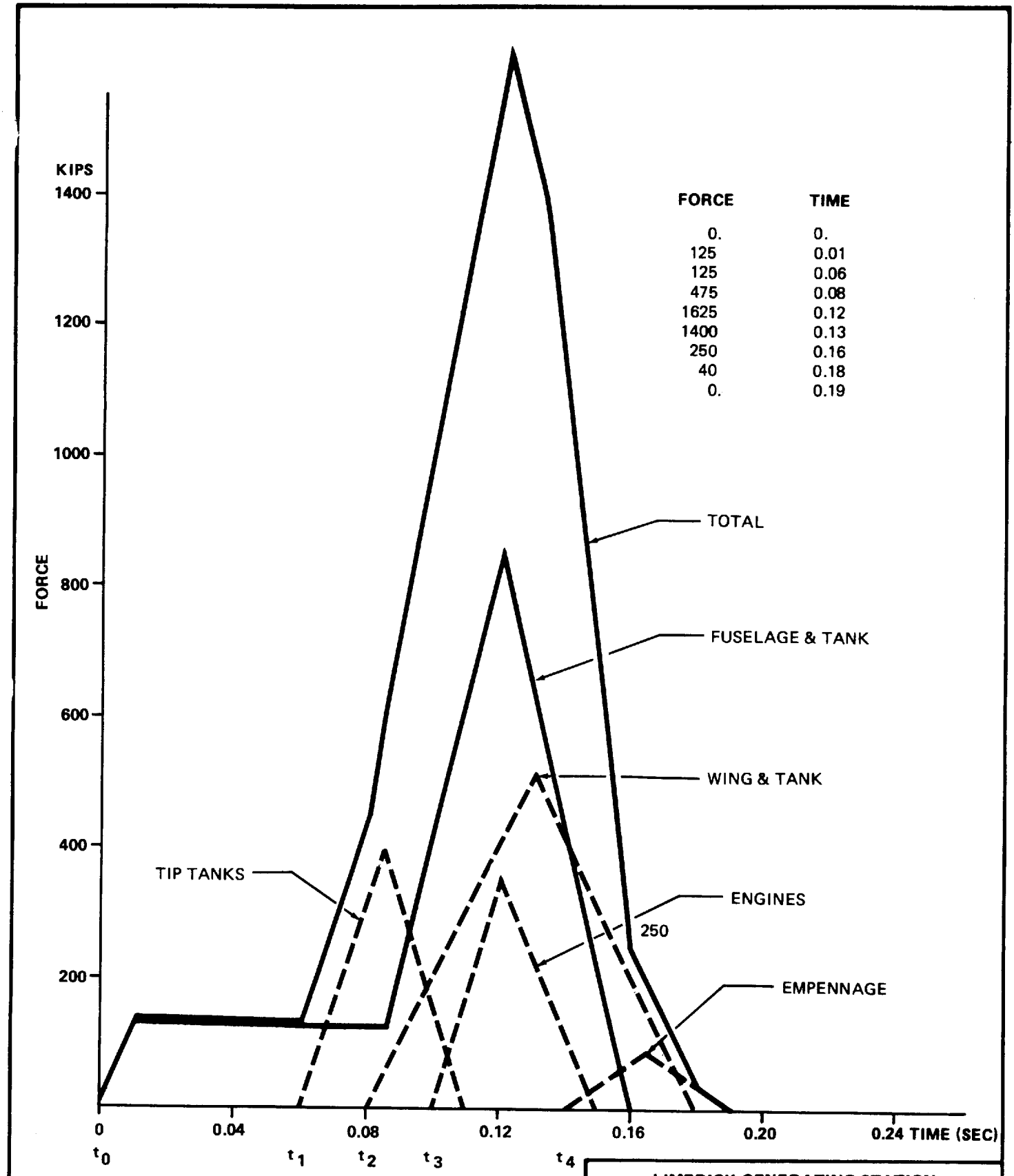
Detailed review of load handling systems as documented in Reference 9.1-1 (SDOC M-038-00008) provides sufficient documentation (along with controls required by station rigging procedures) that heavy load lifts are done safely.



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PERCENT PROBABILITY OF EXCEEDING ORDINATE VALUE OF WINDSPEED FOR TORNADOES WITHIN 125 NM OF POTTSTOWN, PA.

FIGURE 3.3-1

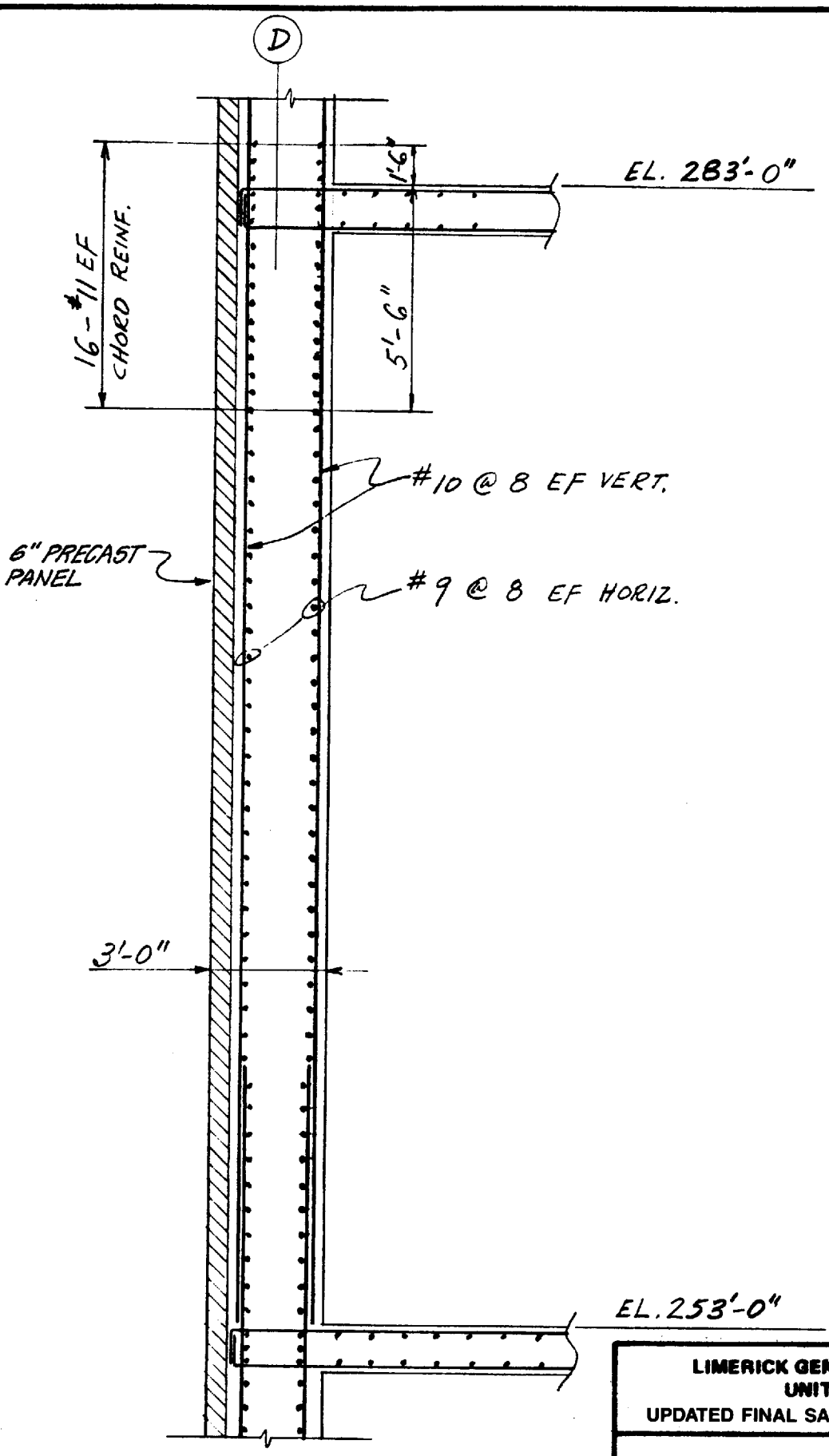


FORCE	TIME
0.	0.
125	0.01
125	0.06
475	0.08
1625	0.12
1400	0.13
250	0.16
40	0.18
0.	0.19

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RESULTANT LOAD CURVE
ON STRUCTURE
DUE TO IMPACT OF DESIGN AIRCRAFT

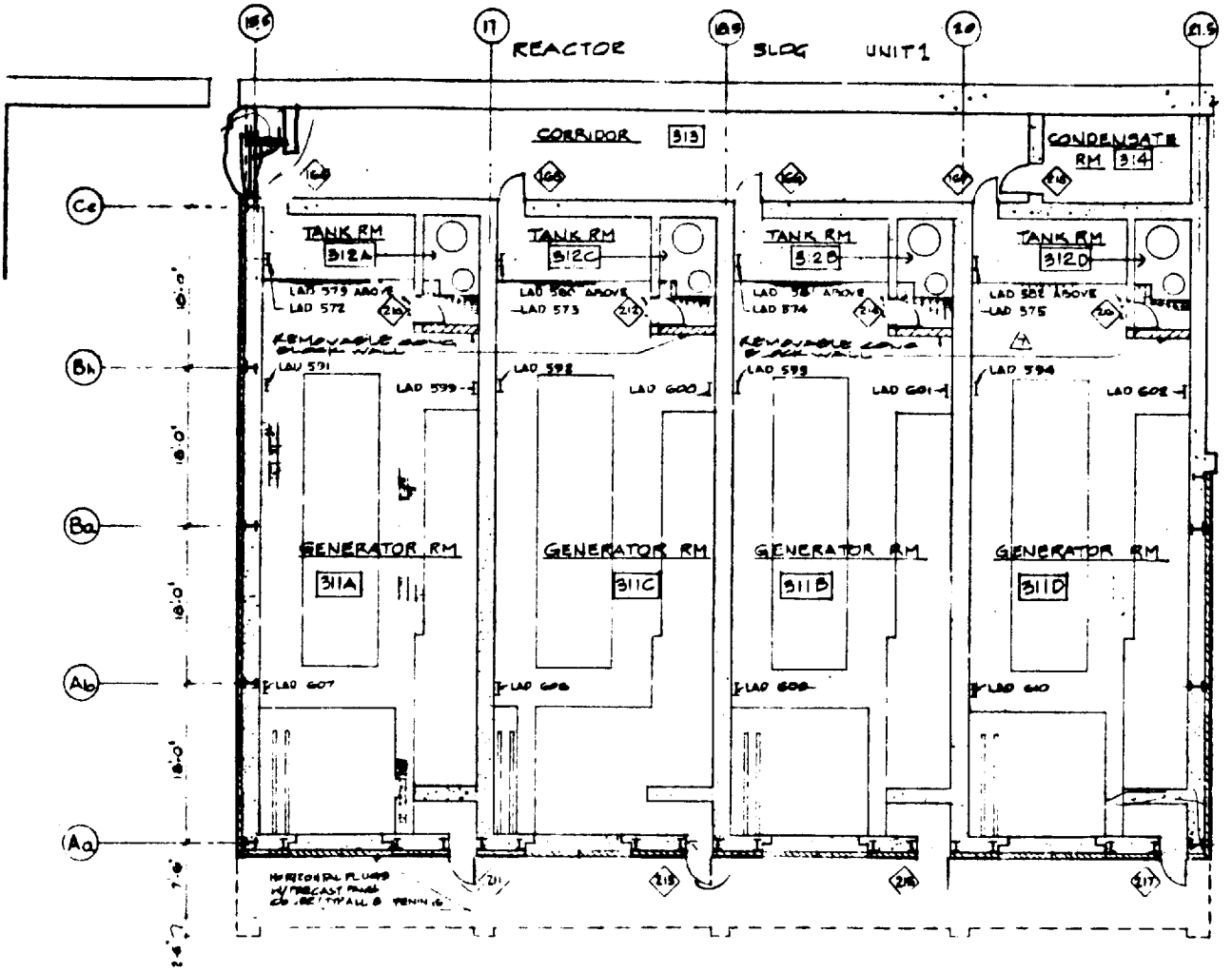
FIGURE 3.5-1



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE WALL SECTION AT COLUMN LINE D

FIGURE 3.5-2



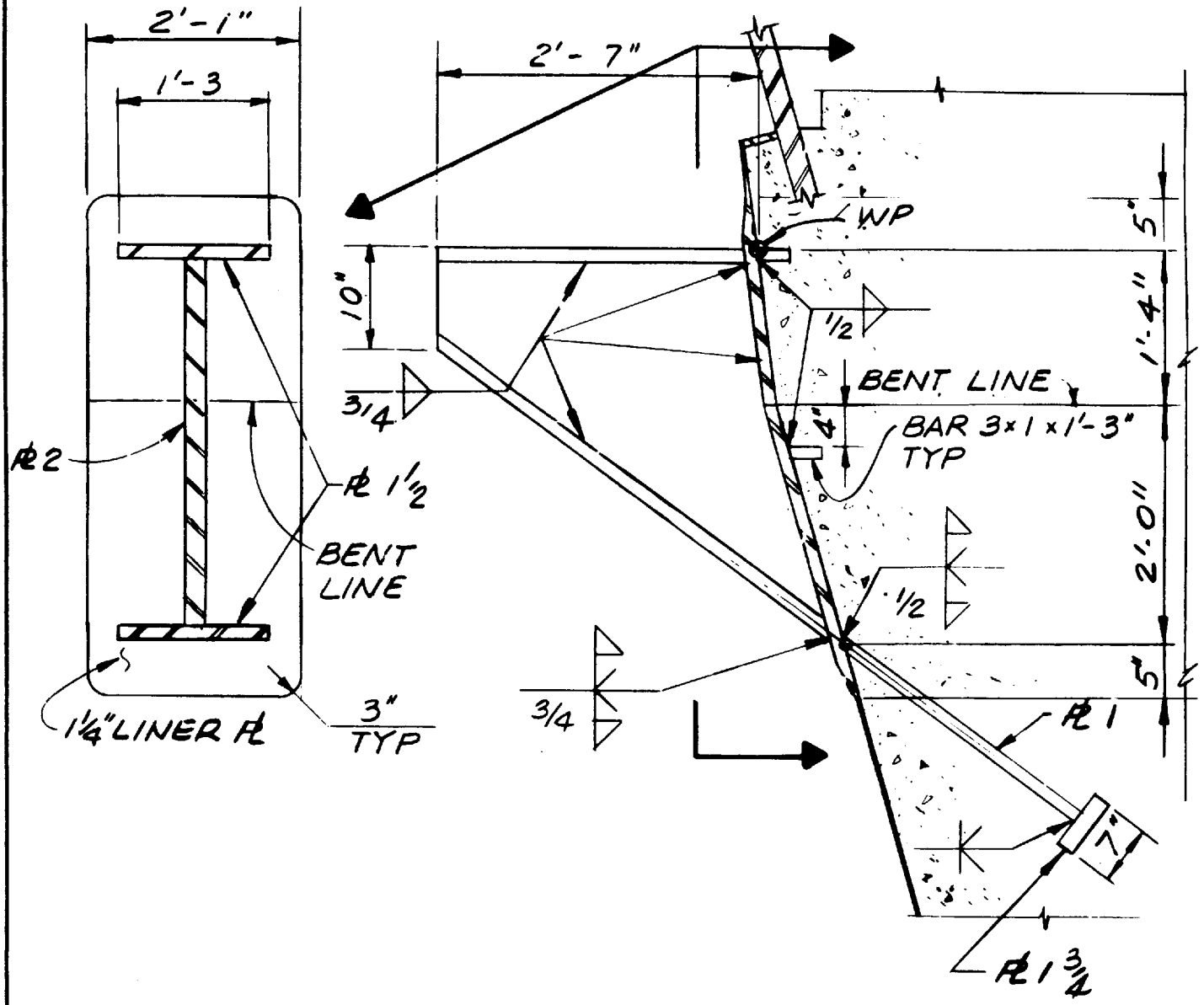
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FLOOR PLAN, DIESEL GENERATOR, UNIT 1

FIGURE 3.5-3

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-291.



MAIN STEAM LINE PIPE WHIP BUMPER ANCHORED TO DRYWELL WALL

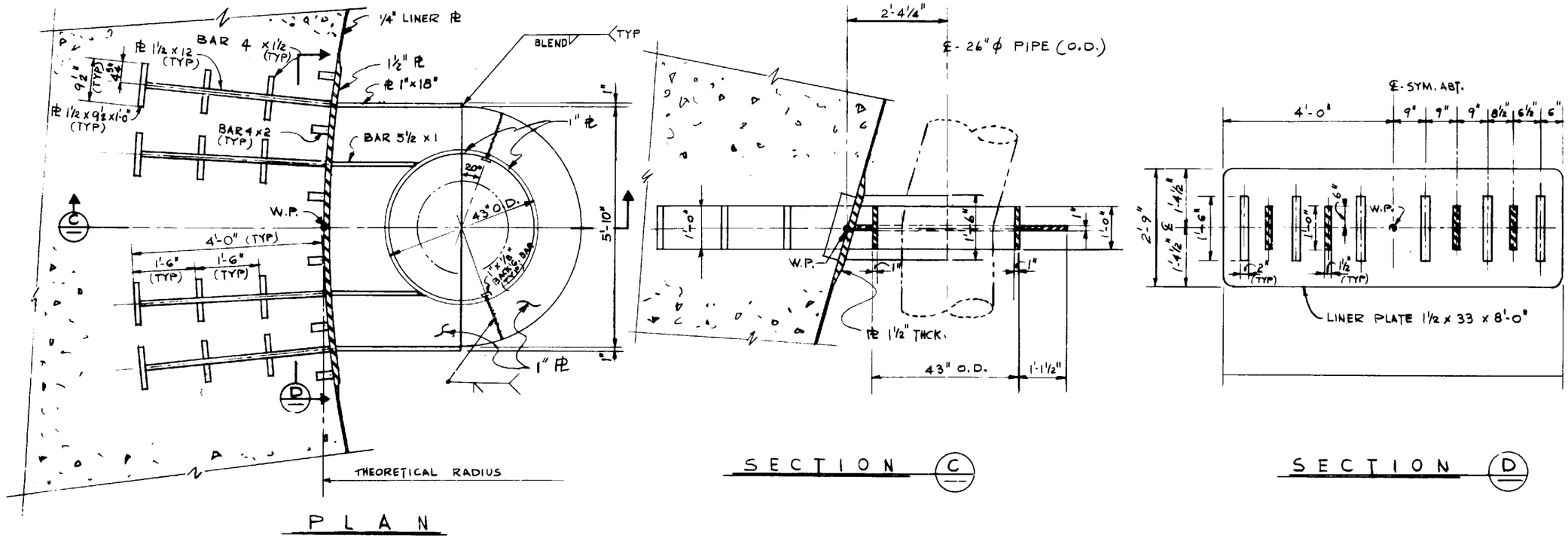
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL PIPE WHIP RESTRAINT DETAILS
(SHEET 1 OF 16)

FIGURE 3.6-1

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-292.



MAIN STEAM LINE WHIP RESTRAINT ANCHORED TO DRYWELL WALL

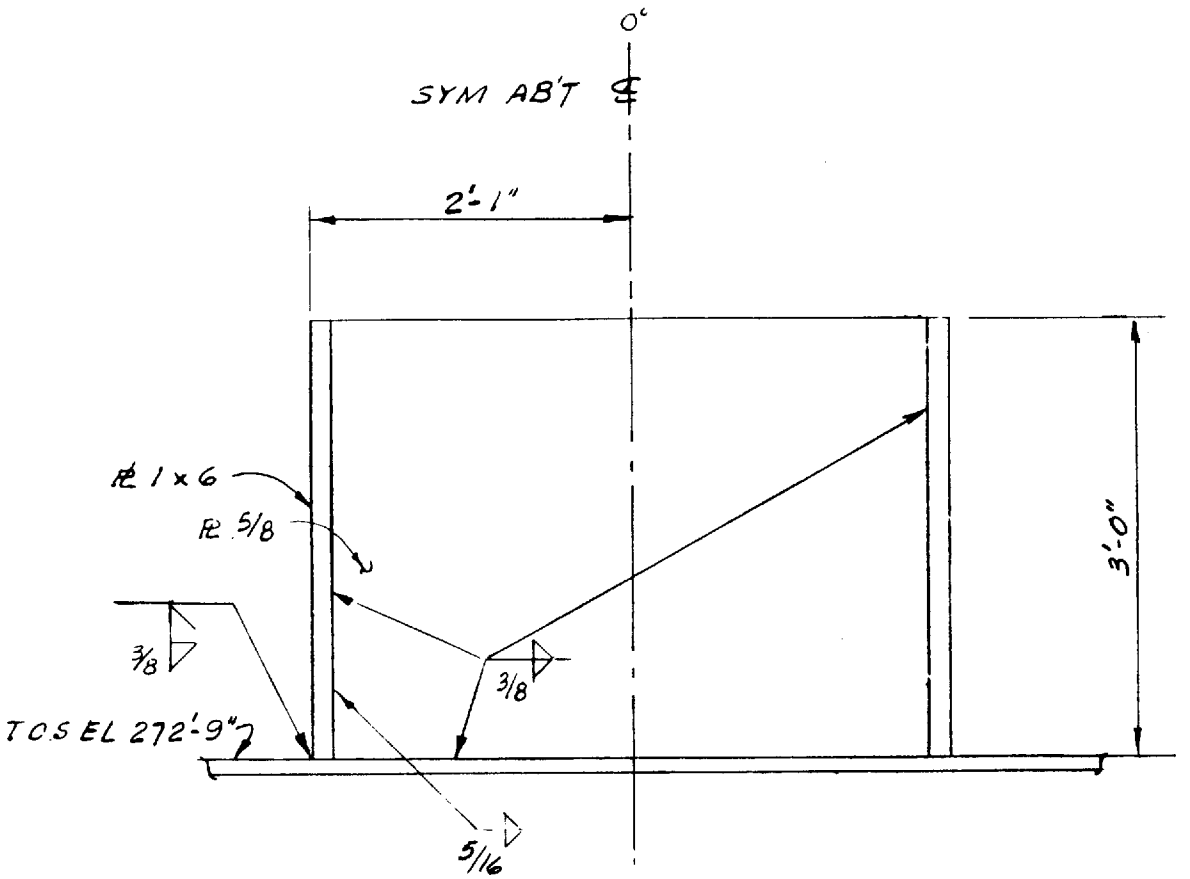
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL PIPE WHIP RESTRAINT DETAILS
(SHEET 2 OF 16)

FIGURE 3.6-1

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-938.



MAIN STEAM LINE PIPE WHIP BUMPER CONNECTED TO STRUCTURAL STEEL IN DRYWELL

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

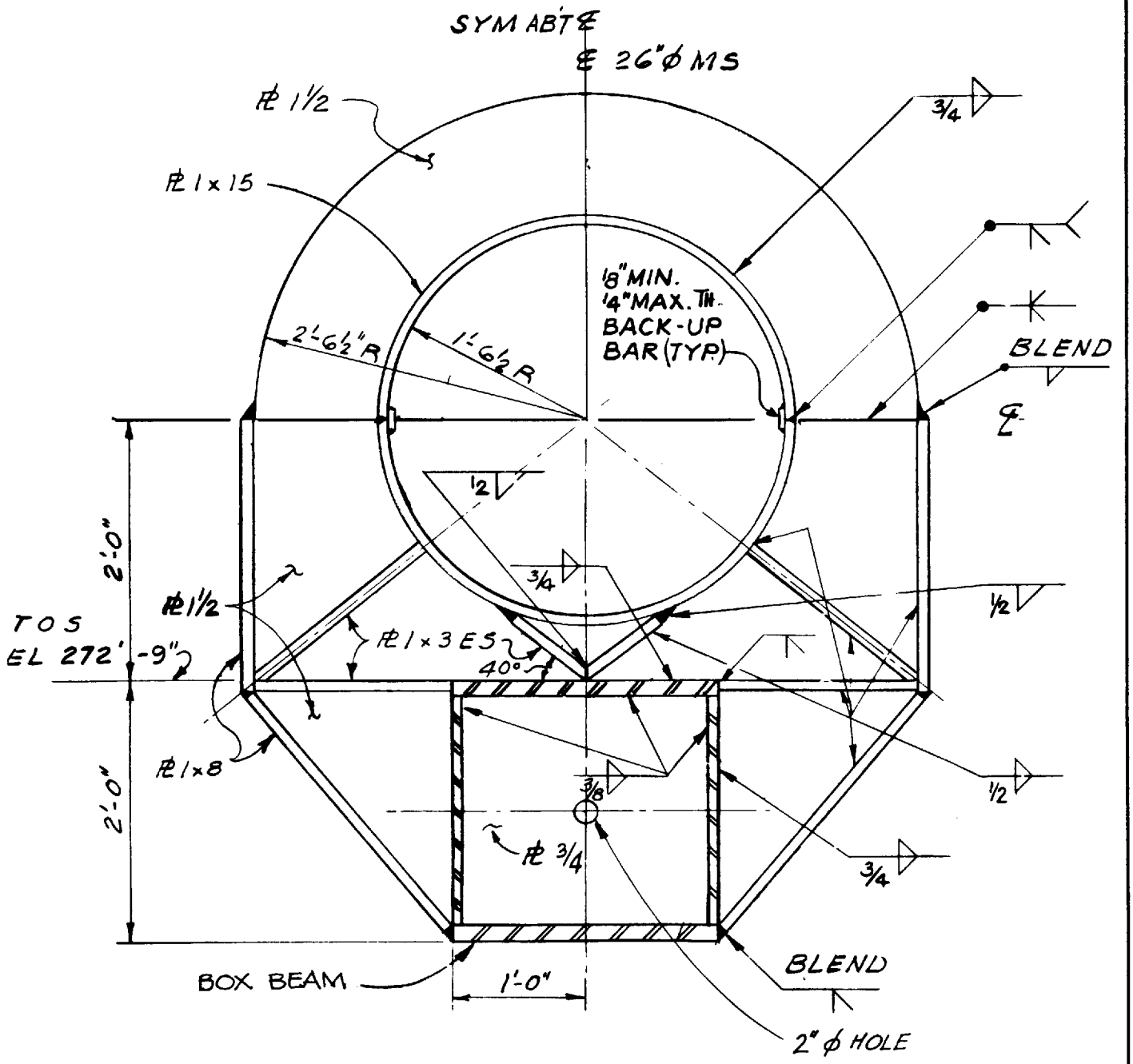
TYPICAL PIPE WHIP RESTRAINT DETAILS

(SHEET 3 OF 16)

FIGURE 3.6-1

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-938.



MAIN STEAM LINE PIPE WHIP RESTRAINT CONNECTED TO STRUCTURAL STEEL IN DRYWELL

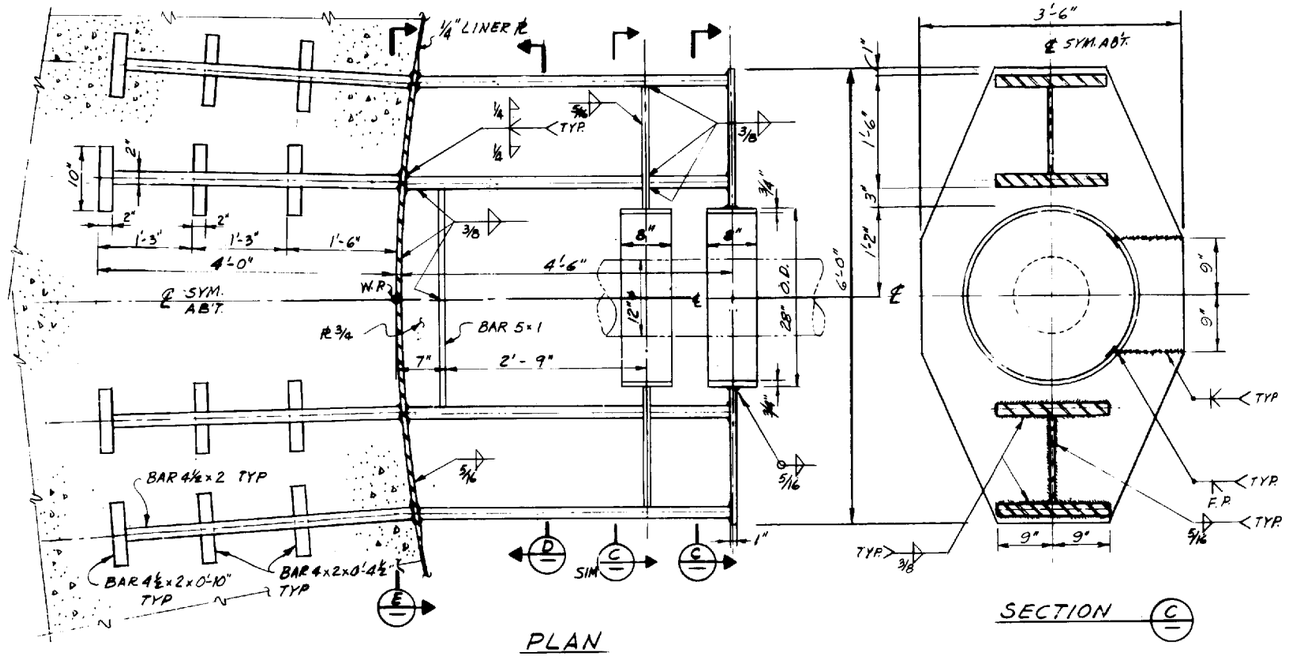
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

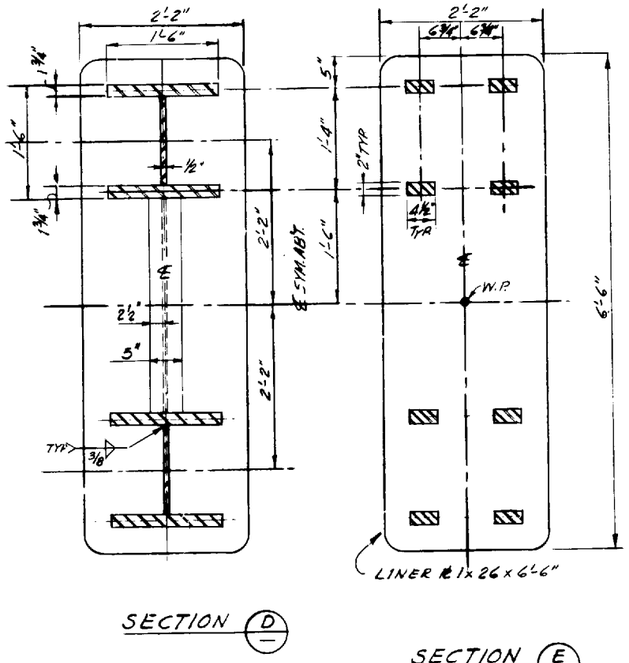
TYPICAL PIPE WHIP RESTRAINT DETAILS
(SHEET 4 OF 16)

FIGURE 3.6-1

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-291.





FEEDWATER LINE PIPE WHIP RESTRAINT ANCHORED TO DRYWELL WALL

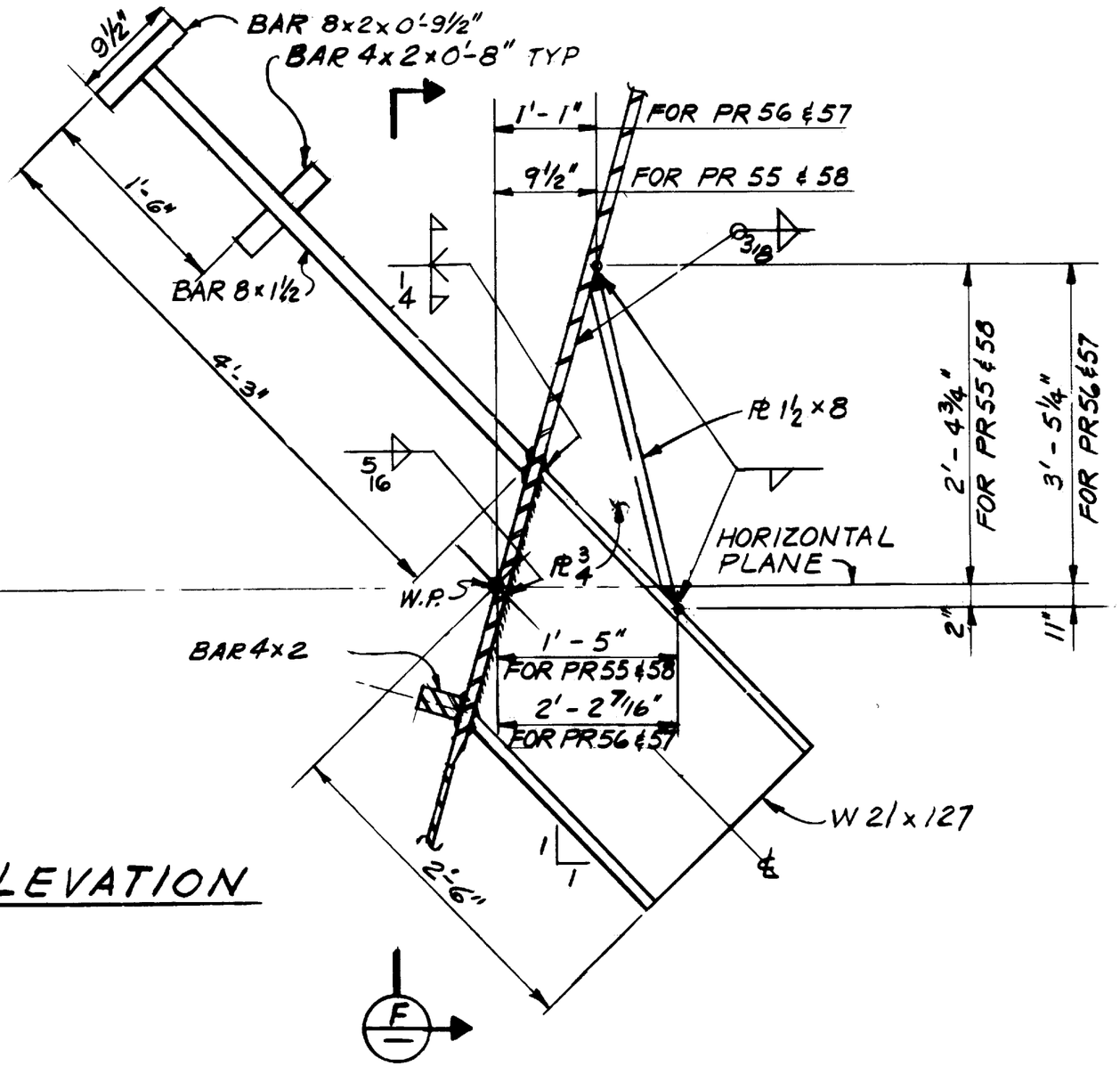
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL PIPE WHIP RESTRAINT DETAILS
(SHEET 5 OF 16)

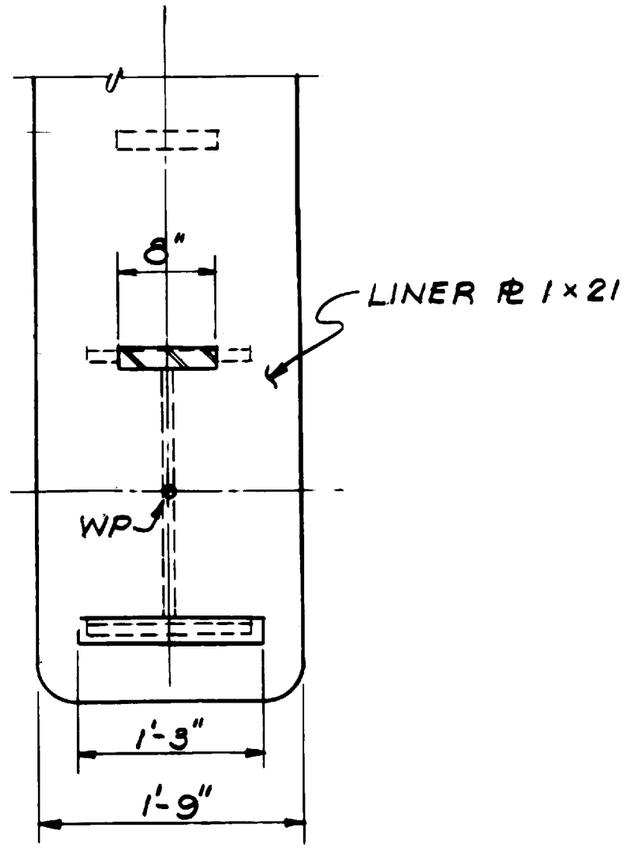
FIGURE 3.8-1

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-291.



ELEVATION



SECTION F

FEEDWATER LINE PIPE WHIP BUMPER ANCHORED TO DRYWELL WALL

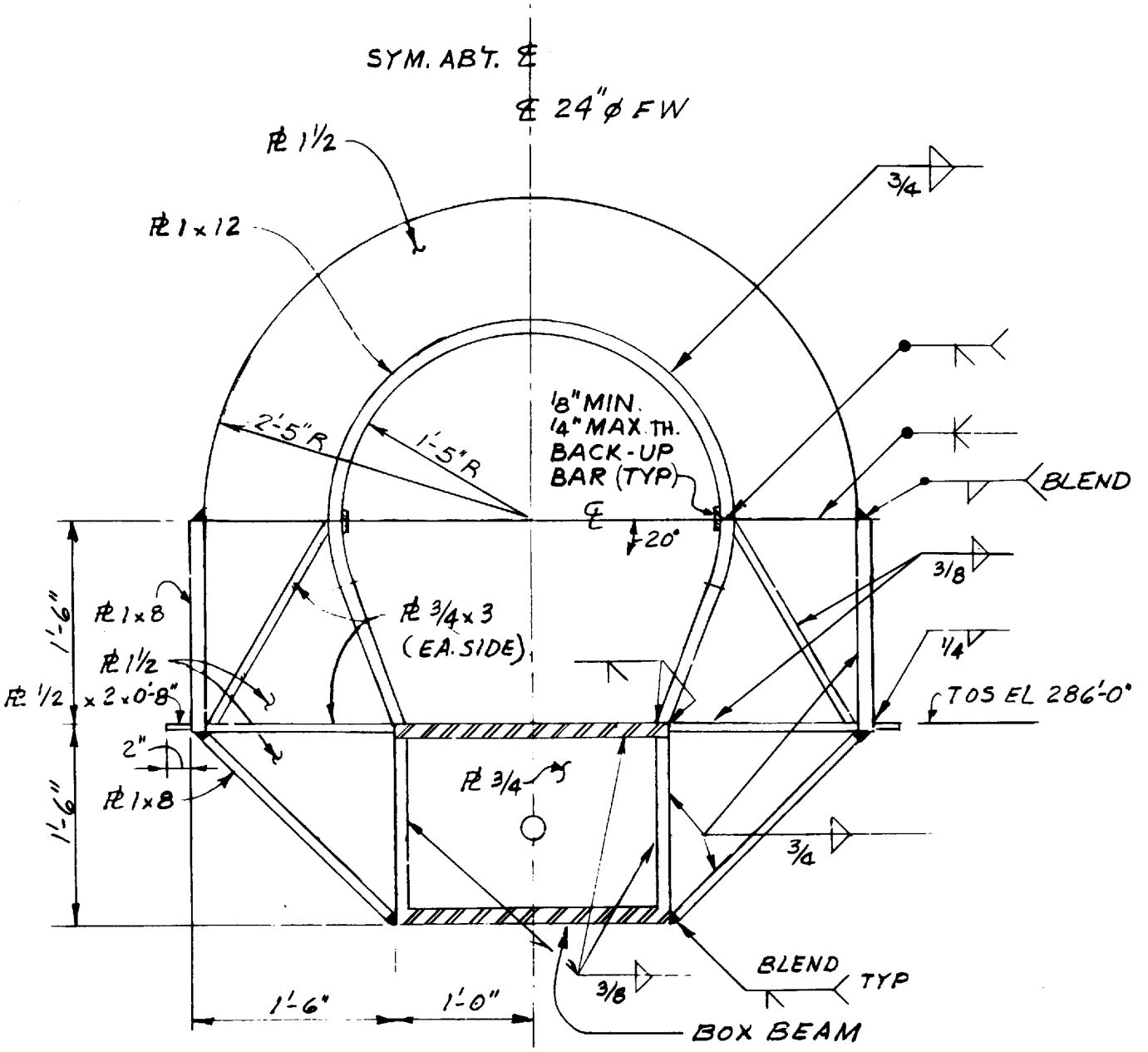
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL PIPE WHIP RESTRAINT DETAILS
(SHEET 6 OF 16)

FIGURE 3.6-1

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-938.



FEEDWATER LINE PIPE WHIP RESTRAINT CONNECTED TO STRUCTURAL STEEL IN DRYWELL

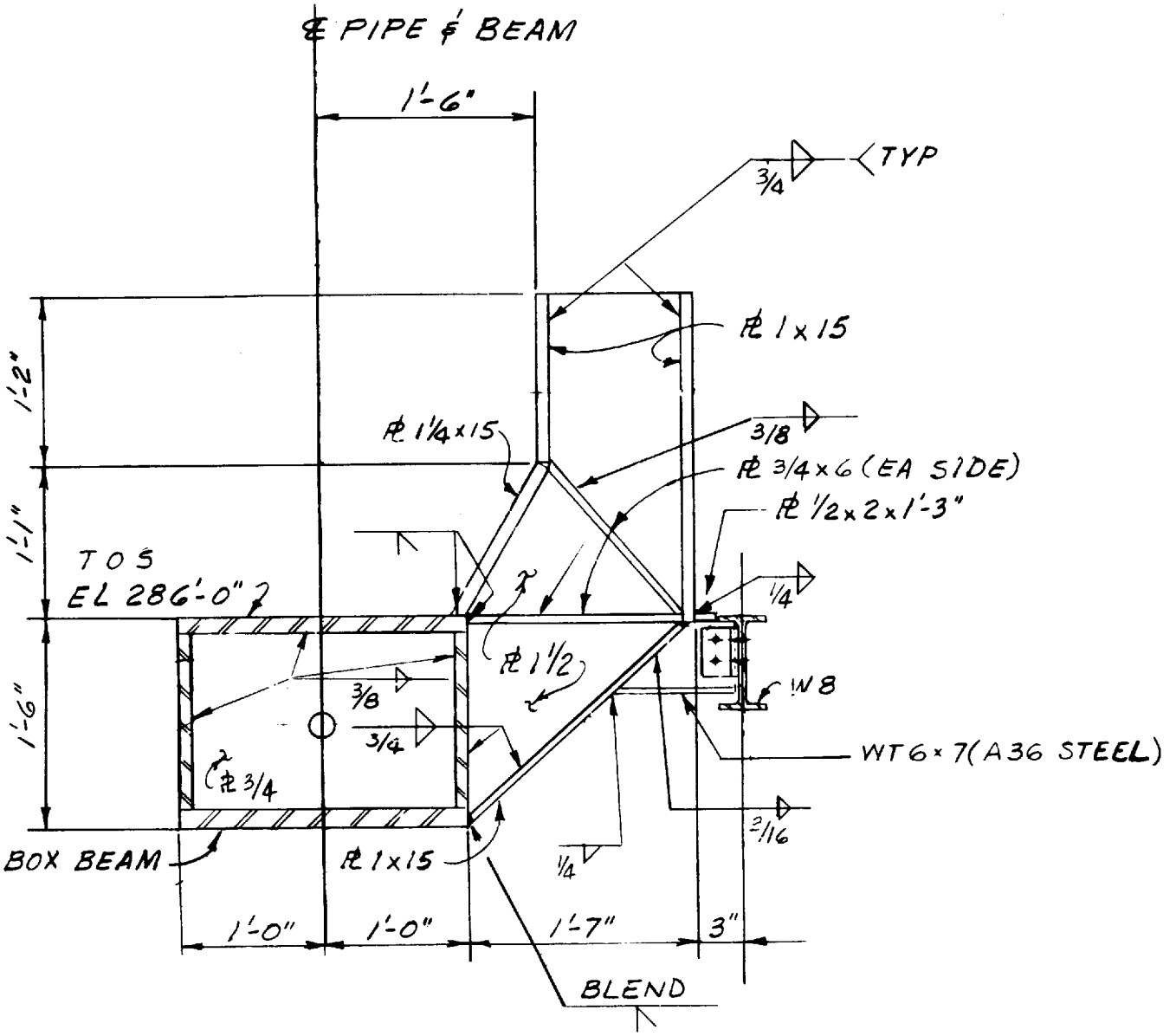
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL PIPE WHIP RESTRAINT DETAILS
(SHEET 7 OF 16)

FIGURE 3.6-1

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-938.



FEEDWATER LINE PIPE WHIP BUMPER CONNECTED TO STRUCTURAL STEEL IN DRYWELL

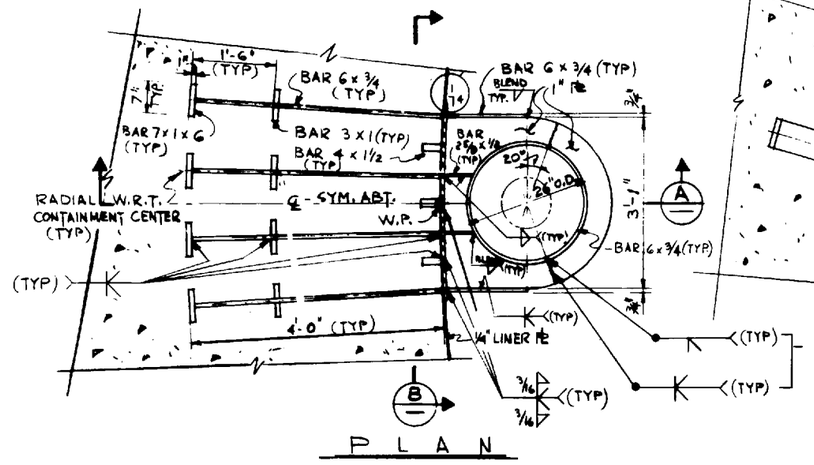
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

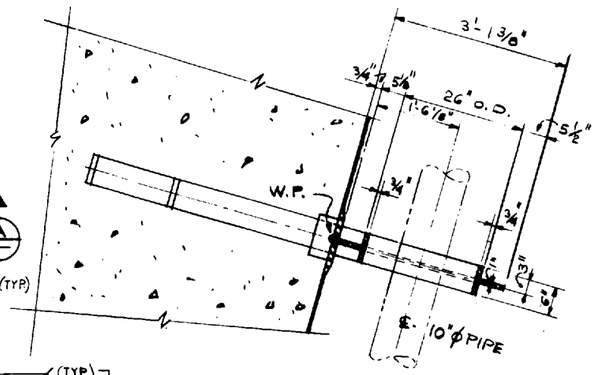
TYPICAL PIPE WHIP RESTRAINT DETAILS
(SHEET 8 OF 16)

FIGURE 3.6-1

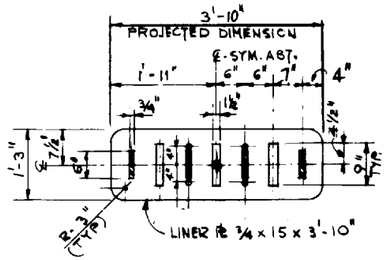
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-289.





SECTION (A)



SECTION (B)

HPCI STEAM SUPPLY LINE PIPE WHIP RESTRAINT ANCHORED TO DRYWELL WALL

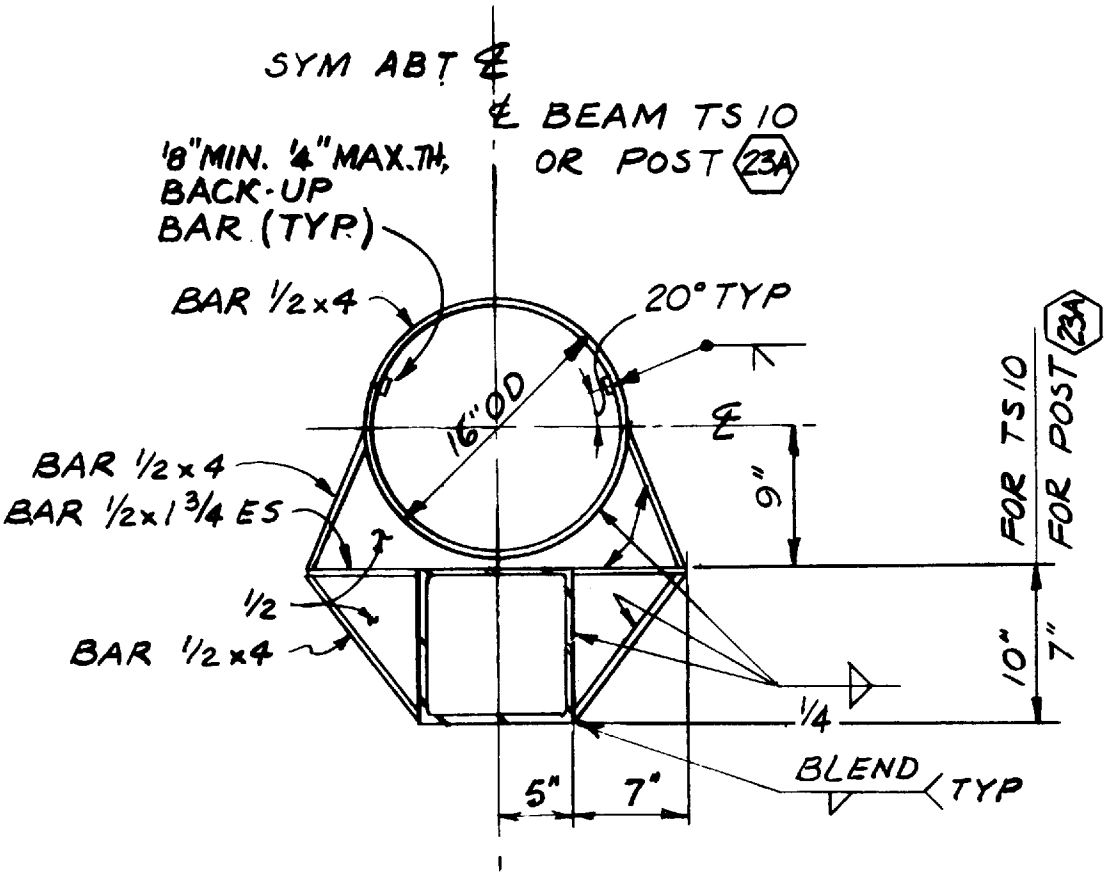
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL PIPE WHIP RESTRAINT DETAILS
(SHEET 9 OF 16)

FIGURE 3.6-1

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-940



RCIC STEAM SUPPLY LINE PIPE WHIP RESTRAINT CONNECTED TO STRUCTURAL STEEL IN DRYWELL

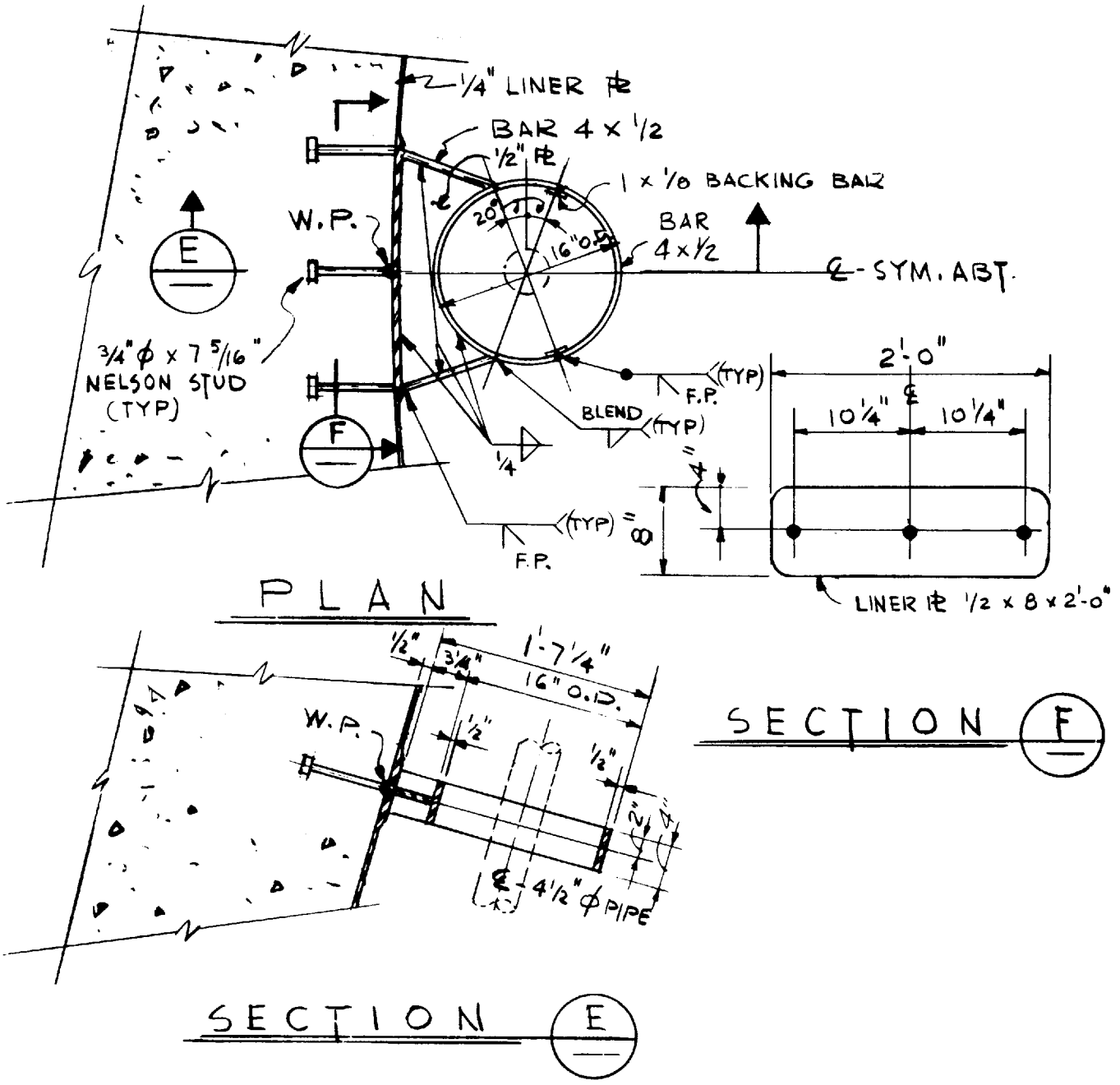
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL PIPE WHIP RESTRAINT DETAILS
(SHEET 10 OF 16)

FIGURE 3.6-1

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-289.



RCIC STEAM SUPPLY LINE PIPE WHIP RESTRAINT ANCHORED TO DRYWELL WALL

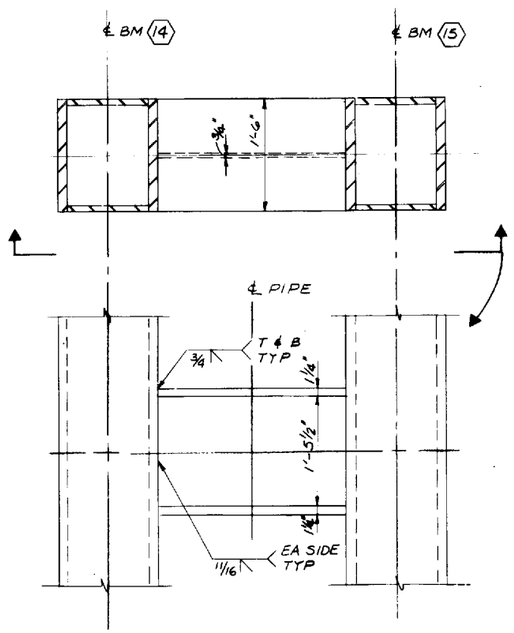
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

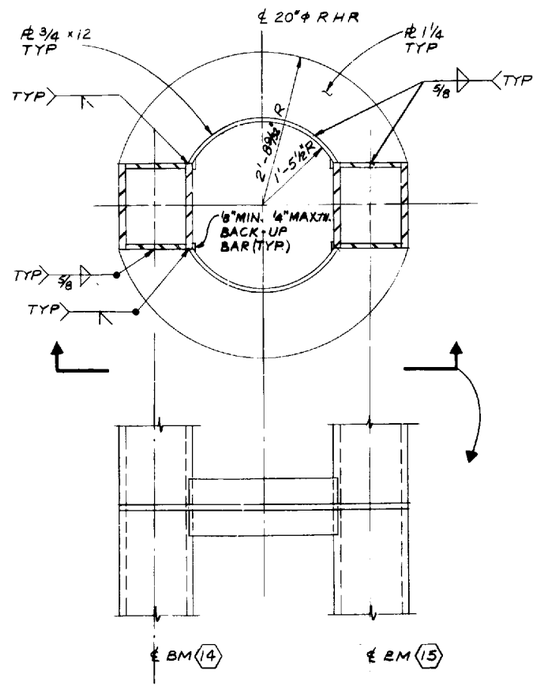
TYPICAL PIPE WHIP RESTRAINT DETAILS
(SHEET 11 OF 16)

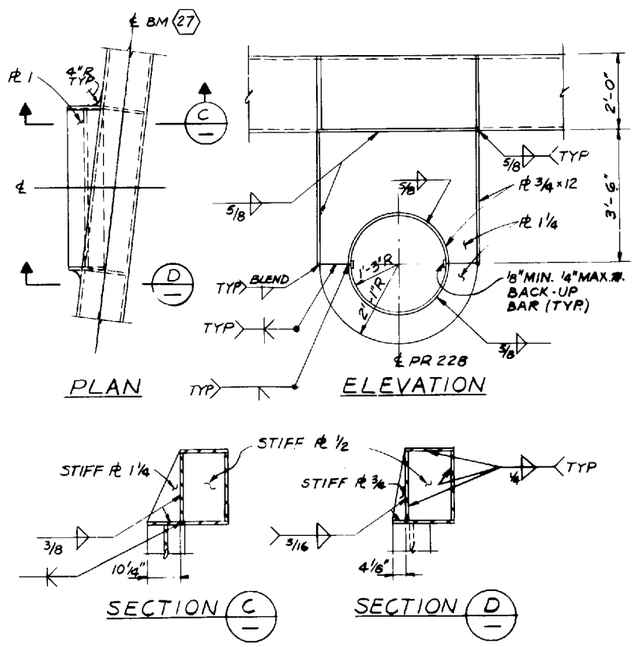
FIGURE 3.6-1

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-940.





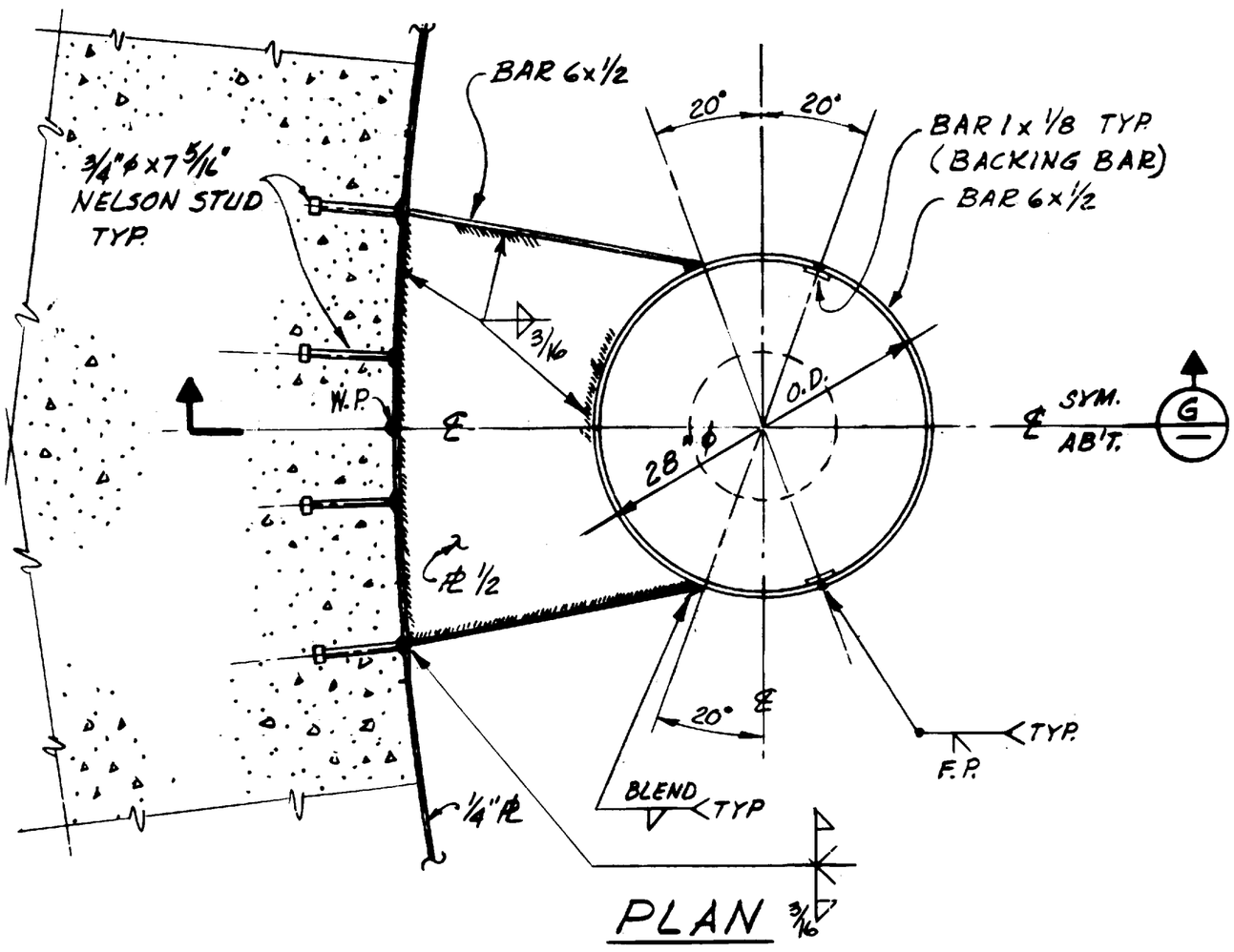


RHR SHUTDOWN COOLING SUCTION LINE PIPE WHIP BUMPERS AND RESTRAINTS CONNECTED TO STRUCTURAL STEEL IN DRYWELL

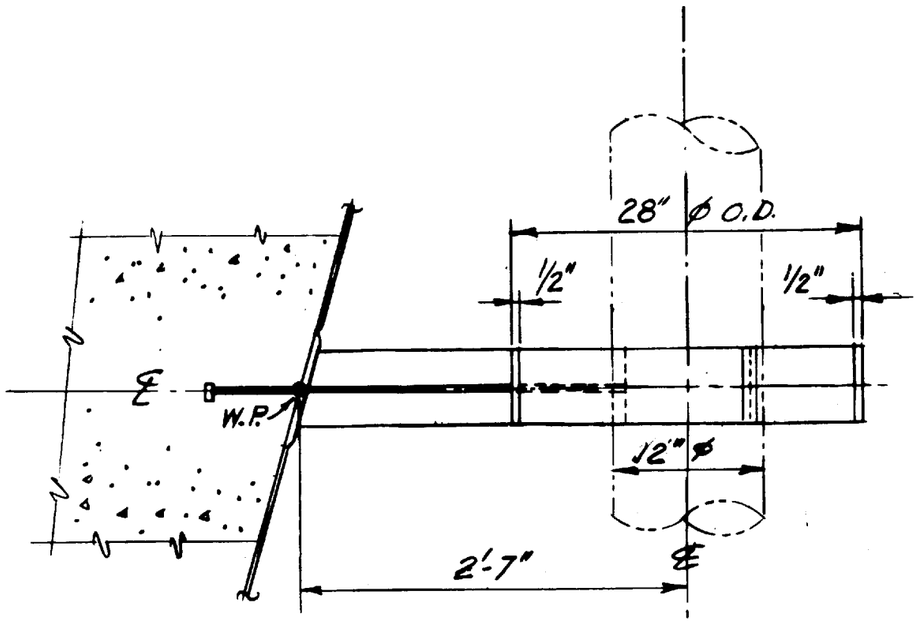
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL PIPE WHIP RESTRAINT DETAILS
(SHEET 12 OF 16)

FIGURE 3.6-1



PLAN



SECTION G

RHR SHUTDOWN COOLING RETURN LINE PIPE WHIP RESTRAINT ANCHORED TO DRYWELL WALL

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-291.

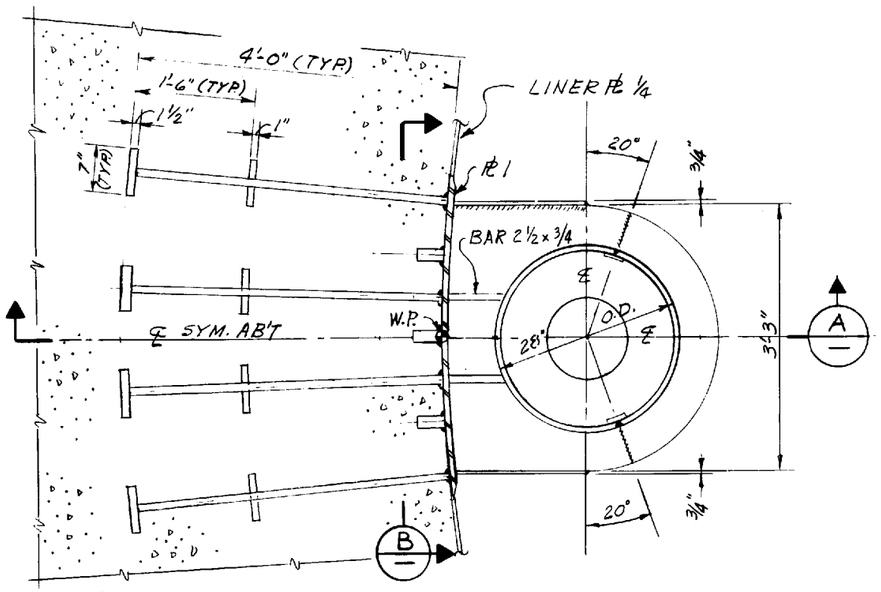
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL PIPE WHIP RESTRAINT DETAILS
(SHEET 13 OF 16)

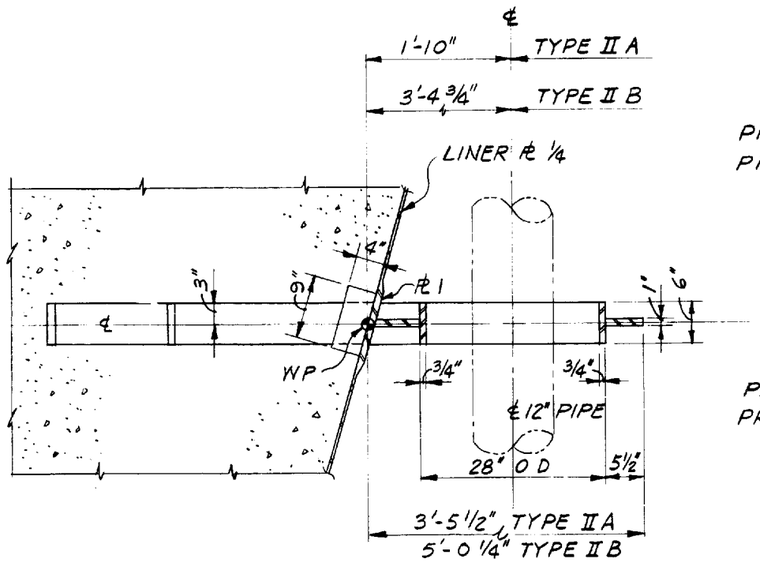
FIGURE 3.8-1

NOTE:

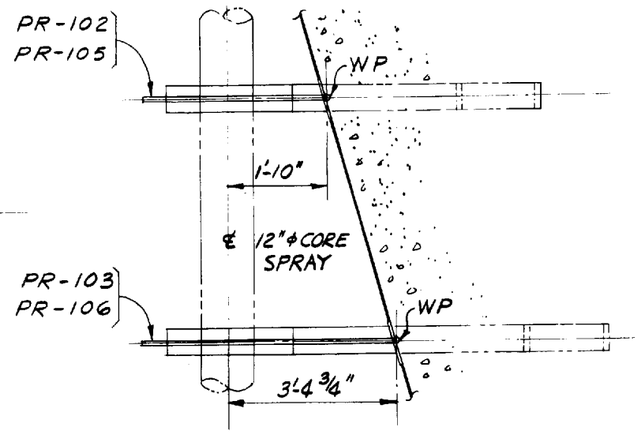
This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-295.



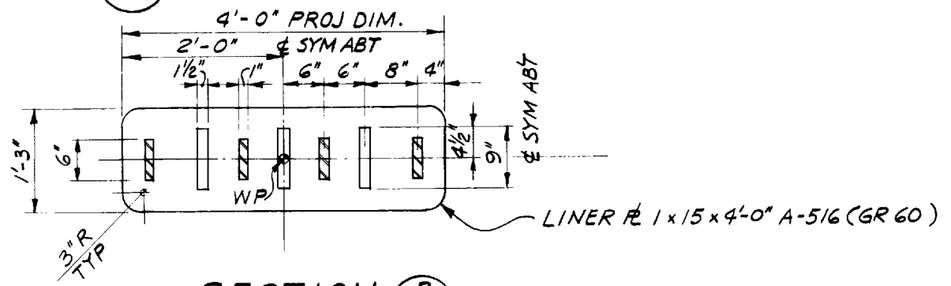
PLAN



SECTION (A)



ELEVATION
NTS



SECTION (B)

CORE SPRAY INJECTION LINE PIPE WHIP RESTRAINTS ANCHORED TO DRYWELL WALL

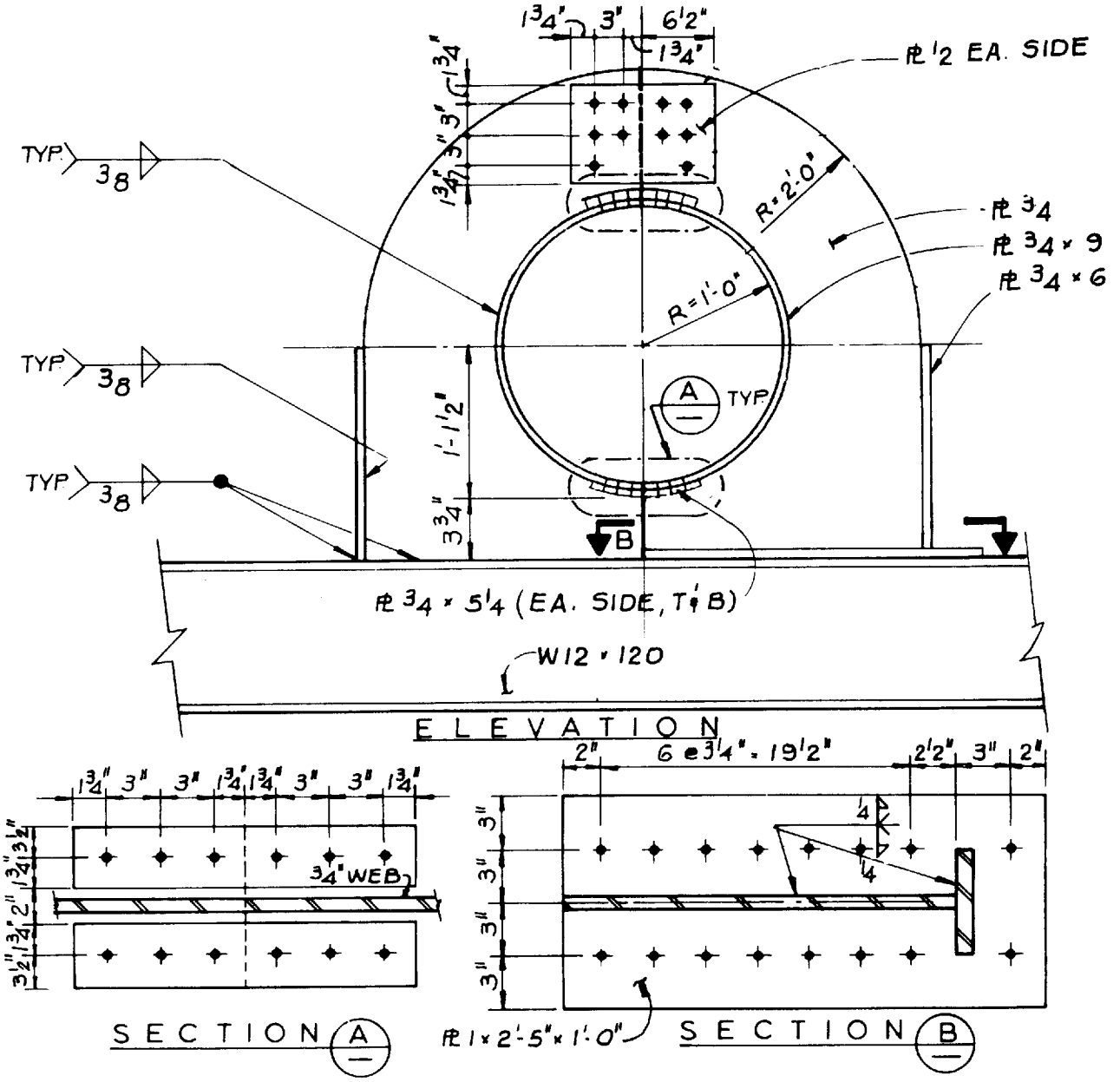
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL PIPE WHIP RESTRAINT DETAILS
(SHEET 14 OF 16)

FIGURE 3.8-1

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-977.

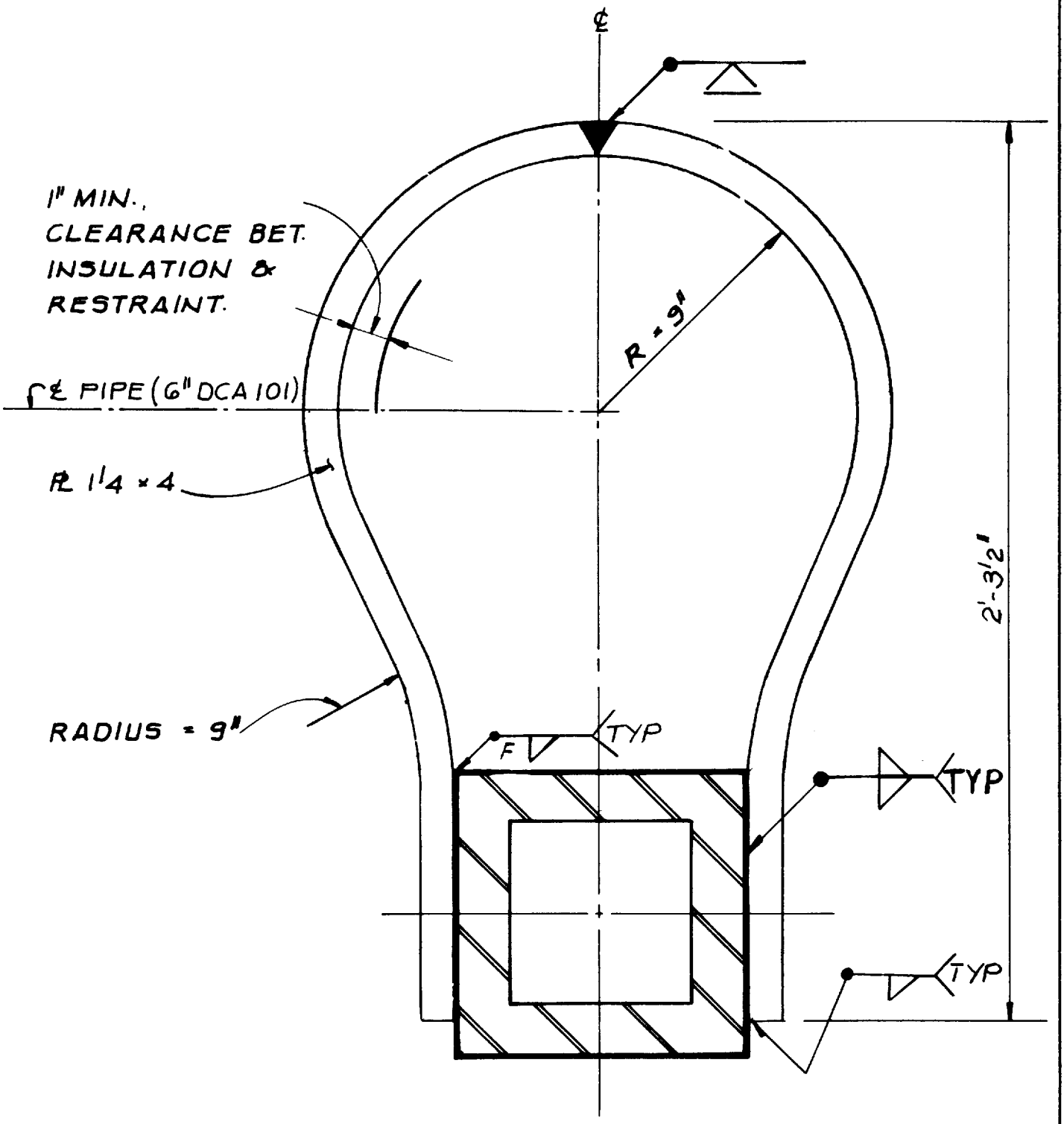


LPCI INJECTION LINE PIPE WHIP RESTRAINT CONNECTED TO STRUCTURAL STEEL IN DRYWELL

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL PIPE WHIP RESTRAINT DETAILS
(SHEET 15 OF 16)

FIGURE 3.6-1



RWCU LINE PIPE WHIP RESTRAINT CONNECTED TO STRUCTURAL STEEL IN DRYWELL

NOTE:

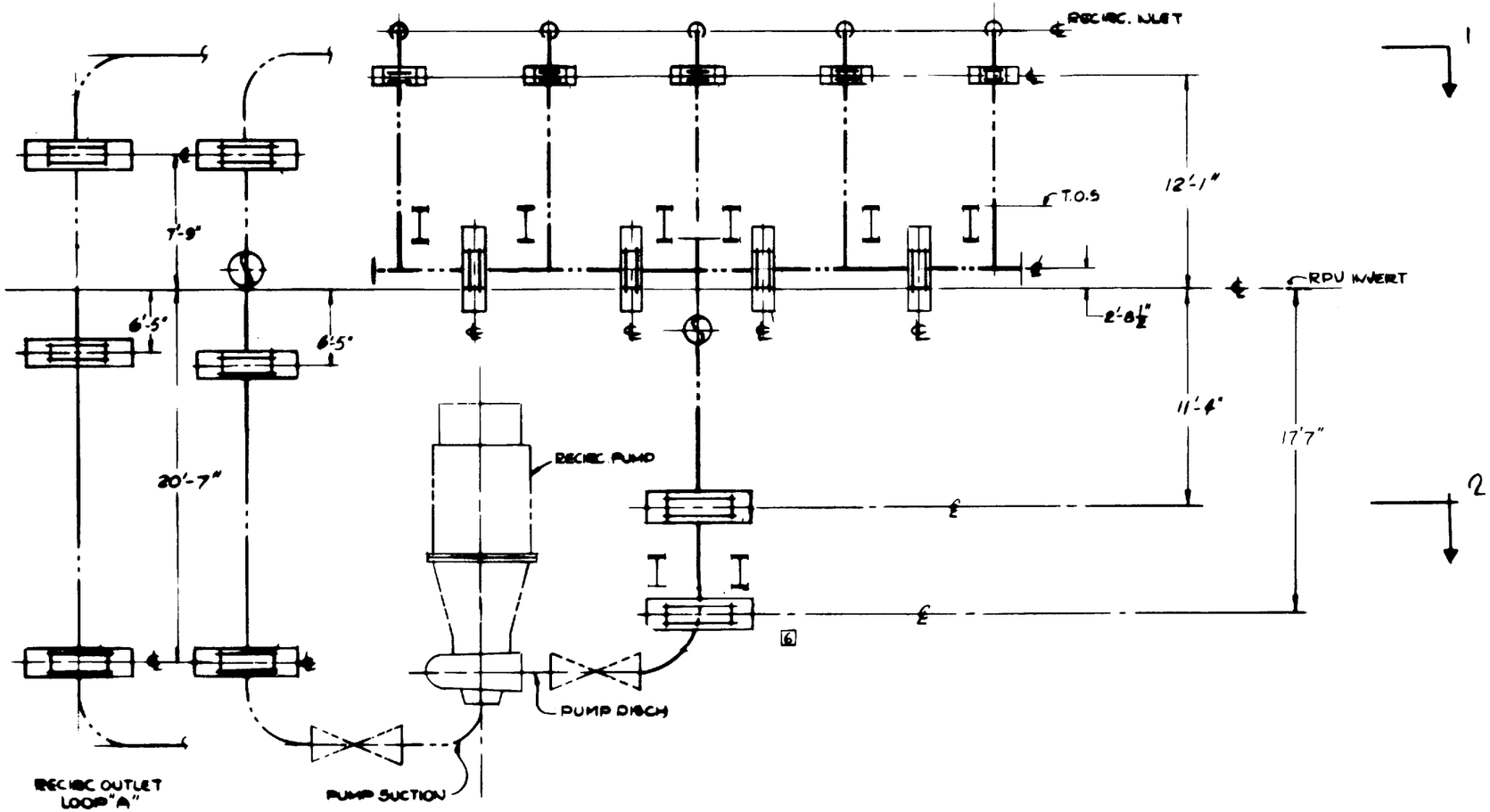
This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-977.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL PIPE WHIP RESTRAINT DETAILS

(SHEET 16 OF 16)

FIGURE 3.6-1

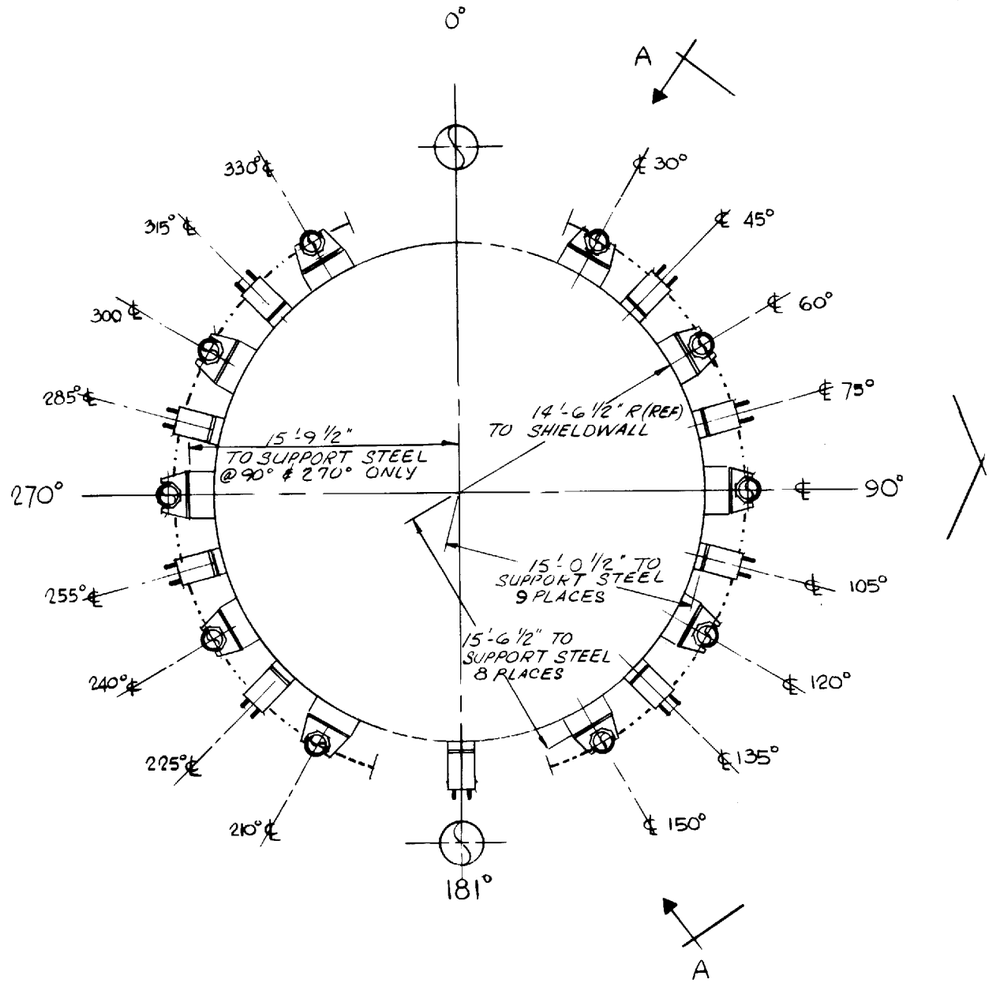


ELEVATION A-A
LOOP "B"
LOOP A SAME AS LOOP B UNLESS OTHERWISE SPECIFIED

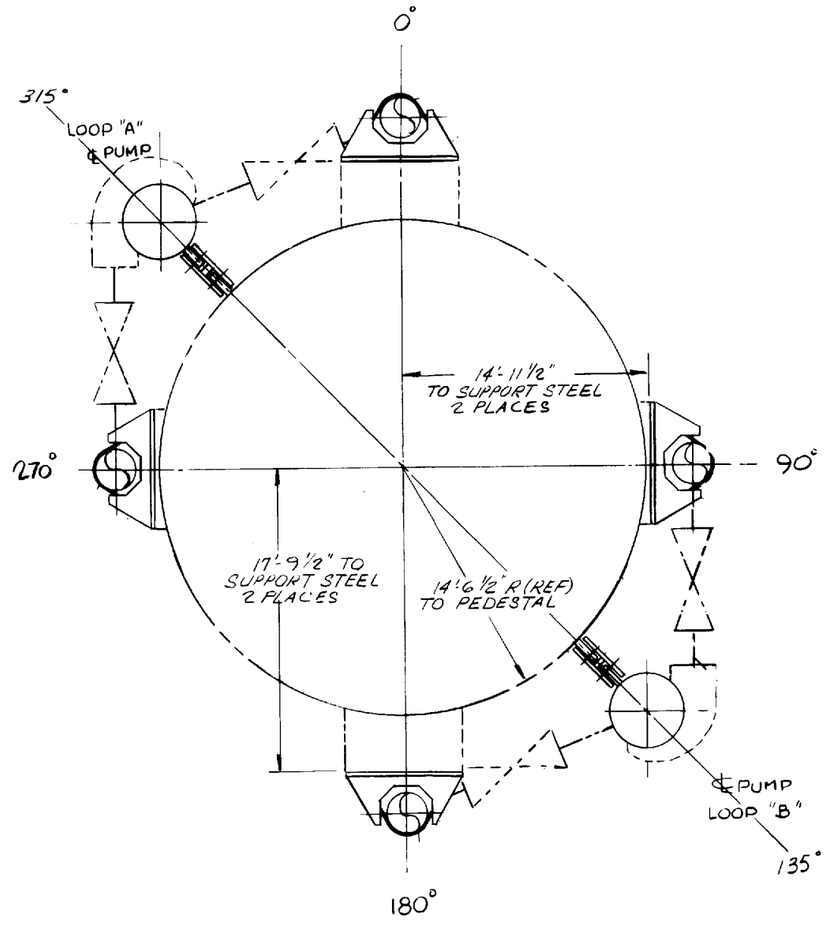
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

ARRANGEMENT OF RECIRCULATION
LOOP PIPE WHIP RESTRAINTS
(SHEET 1 OF 2)

FIGURE 3.6-2



PLAN 1

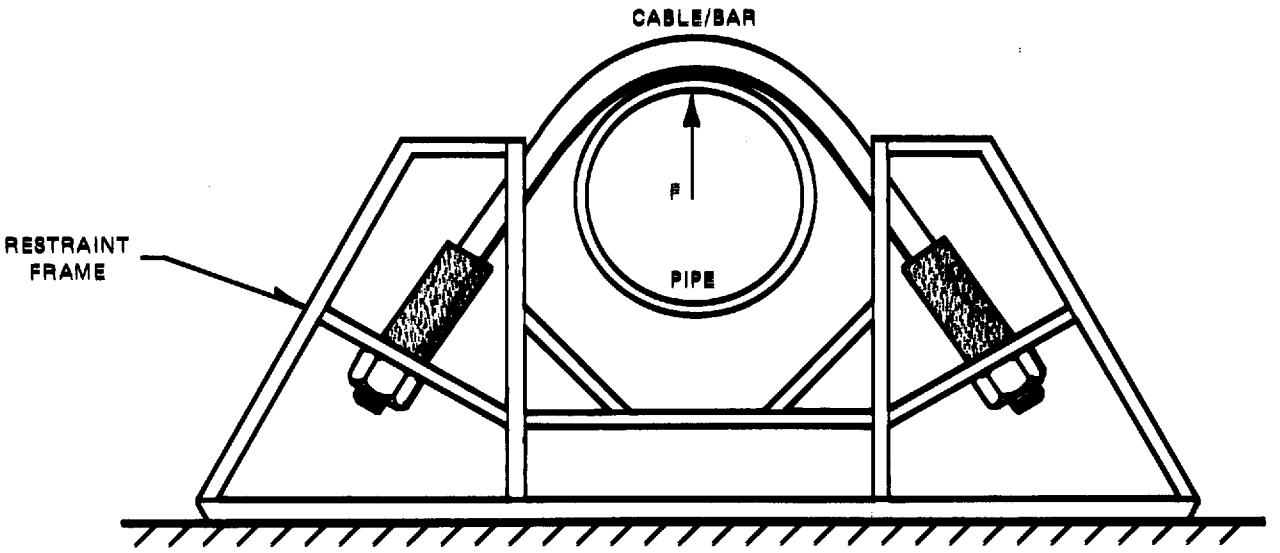


PLAN 2

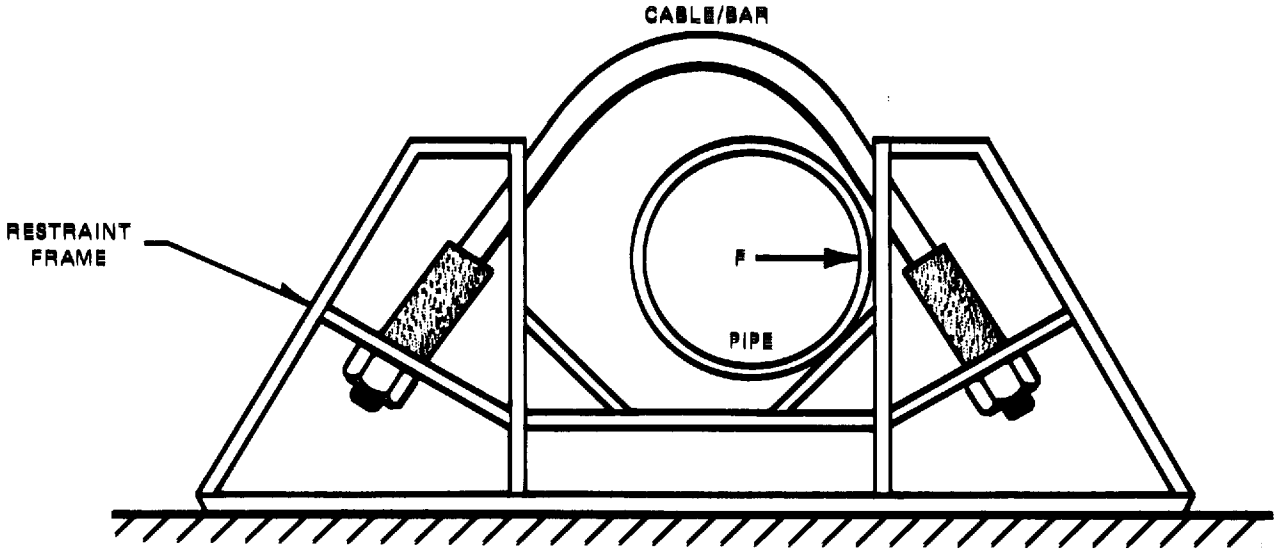
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

ARRANGEMENT OF RECIRCULATION LOOP PIPE WHIP RESTRAINTS (SHEET 2 OF 2)

FIGURE 3.6-2



(a) Load Applied Perpendicular to Restraint Base Against Cables

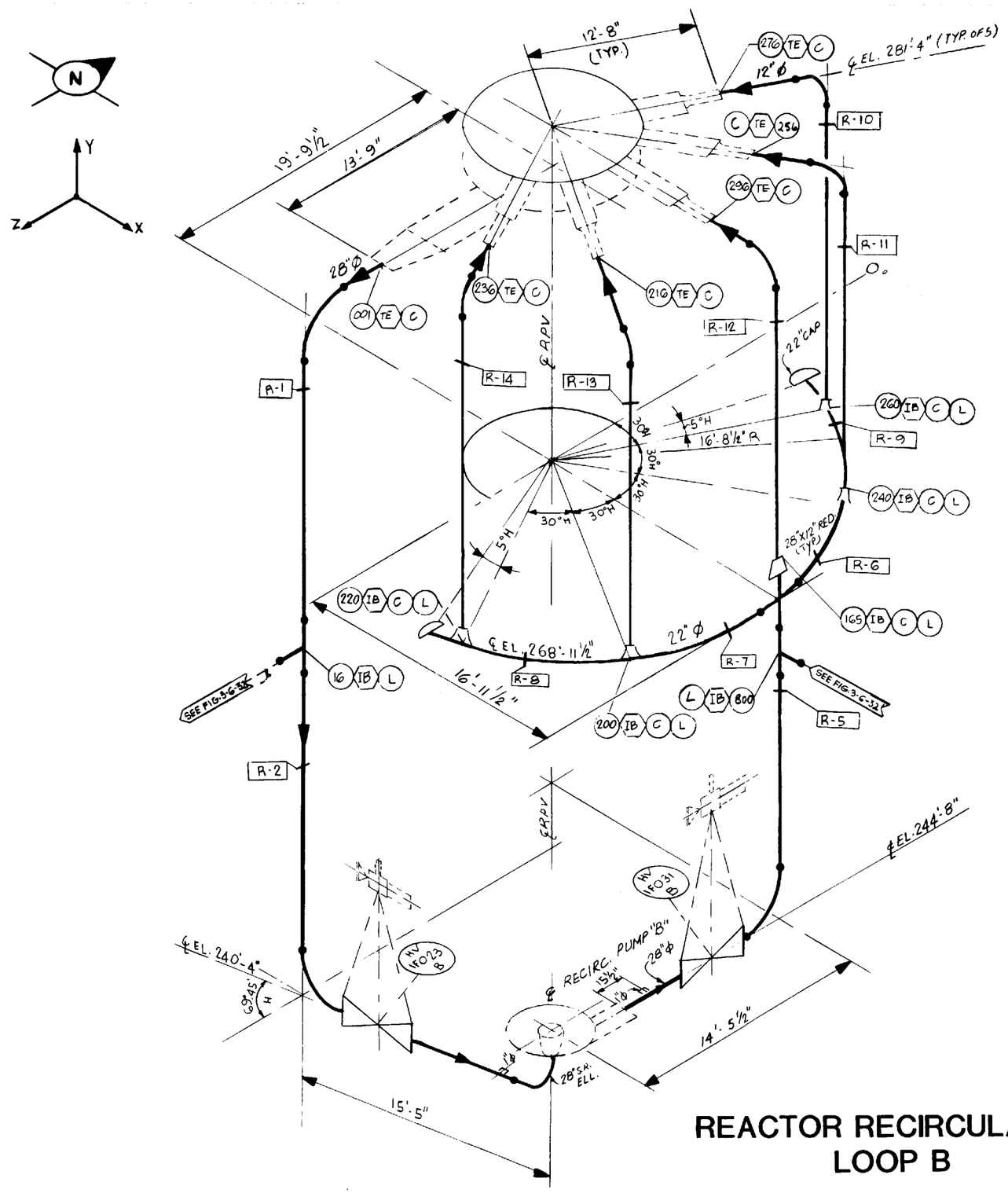


(b) Load Applied Parallel to Frame Base Against One Side of Restraint Frame

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL RECIRCULATION SYSTEM PIPE WHIP RESTRAINT

FIGURE 3.6-3



REACTOR RECIRCULATION LOOP B

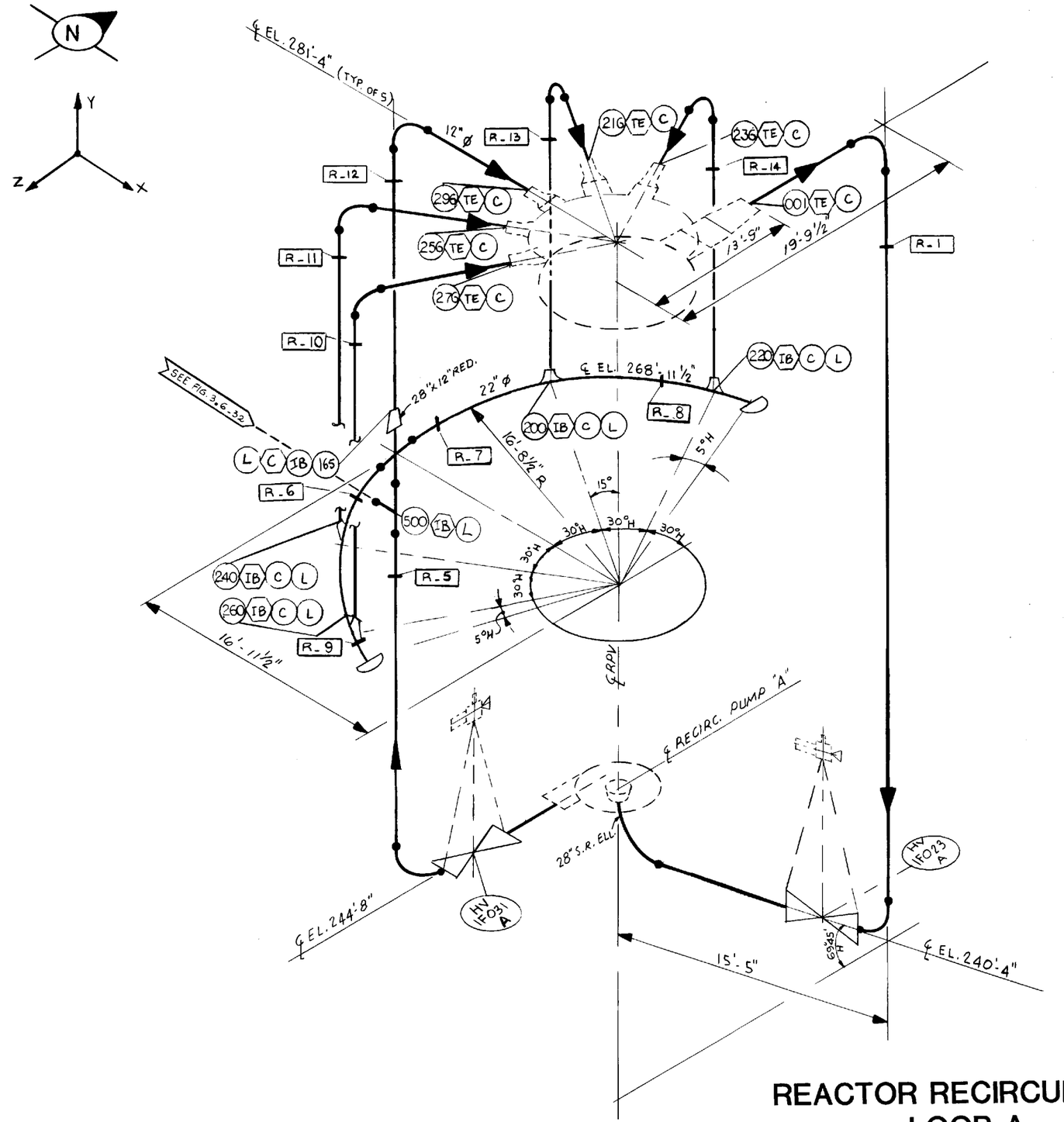
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-2.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RECIRCULATION SYSTEM ISOMETRIC
(UNIT 1 ONLY)
(SHEET 1 OF 4)

FIGURE 3.6-4



REACTOR RECIRCULATION LOOP A

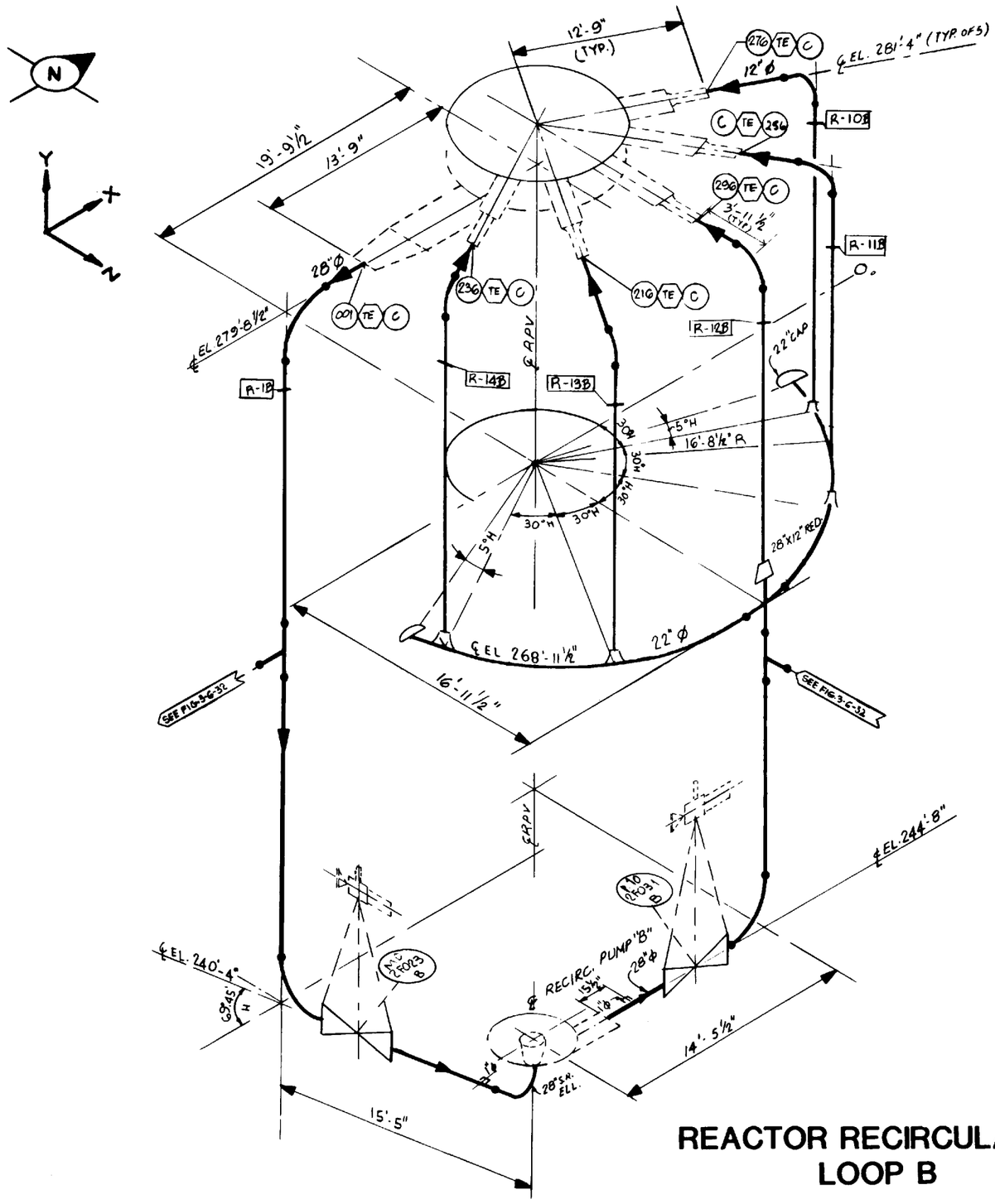
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-2.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
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   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RECIRCULATION SYSTEM ISOMETRIC
(UNIT 1 ONLY)
(SHEET 2 OF 4)

FIGURE 3.6-4



REACTOR RECIRCULATION LOOP B

NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-2
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. INTERMEDIATE BREAKS ARE ELIMINATED FOR LIMERICK UNIT 2 (SEE TABLE 3.6-2 FOR LOCATIONS)

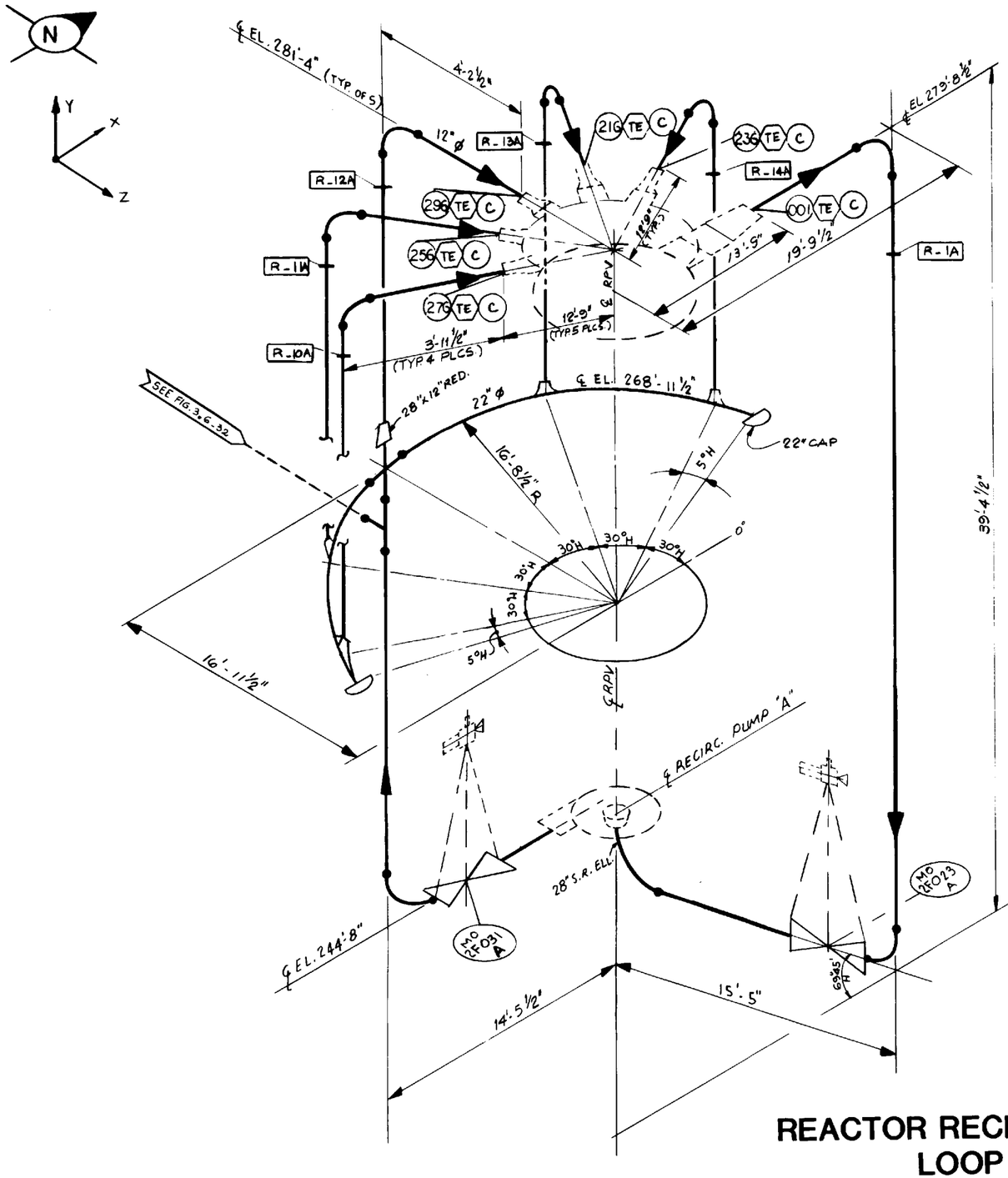
REFERENCE

1. G.E. DRAWING NO. 112D3727 REV. 0

LIMERICK GENERATING STATION UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RECIRCULATION SYSTEM ISOMETRIC (UNIT 2) (SHEET 3 OF 4)

FIGURE 3.6-4



NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-2
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
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   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. INTERMEDIATE BREAKS ARE ELIMINATED FOR LIMERICK UNIT 2 (SEE TABLE 3.6-2 FOR LOCATIONS)

REFERENCE

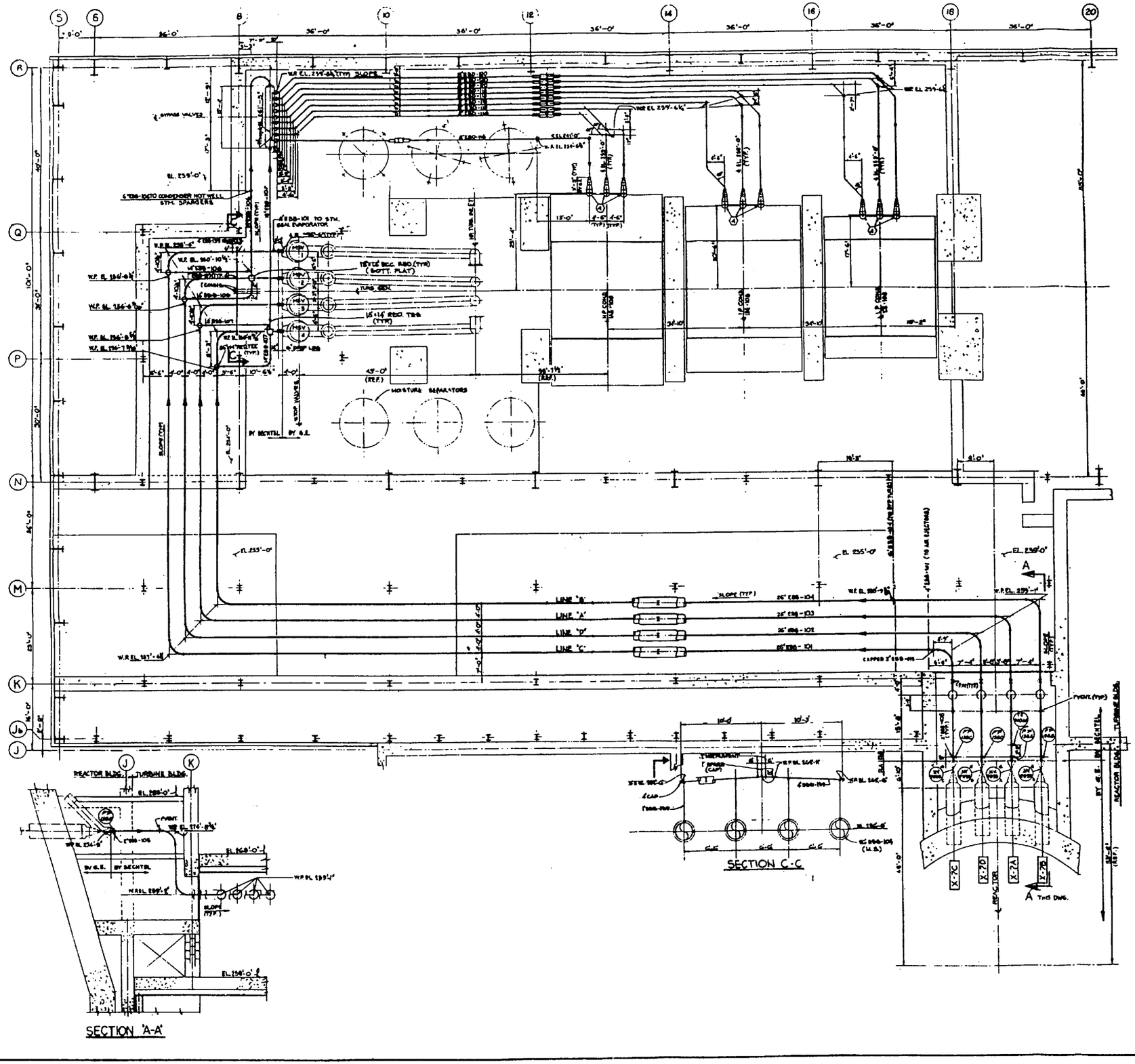
1. G.E. DRAWING NO. 112D3727 REV. 0

REACTOR RECIRCULATION LOOP A

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RECIRCULATION SYSTEM ISOMETRIC
(UNIT 2)
(SHEET 4 OF 4)

FIGURE 3.6-4

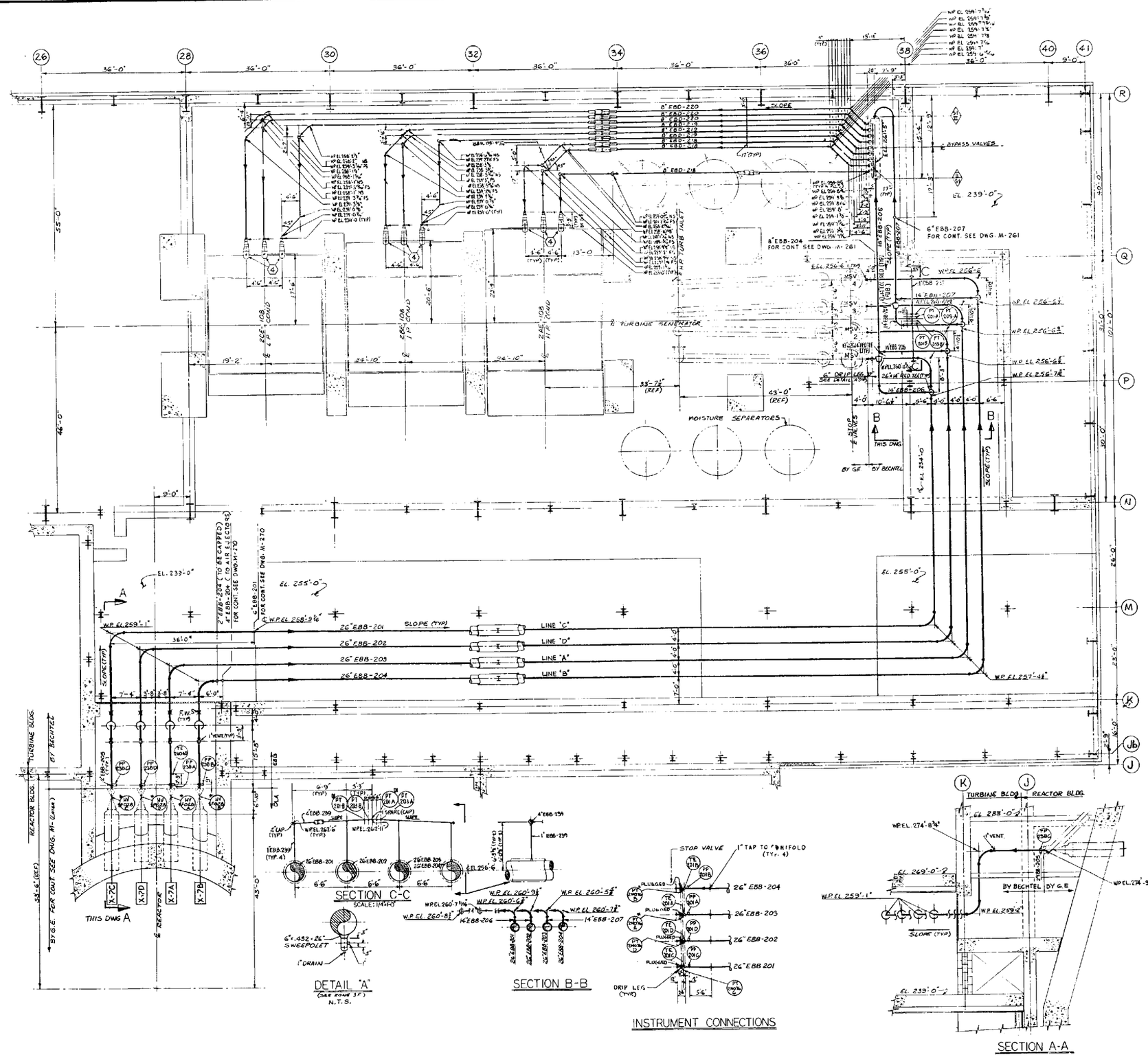


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

(UNIT 1)

MAIN STEAM PIPING LAYOUT
OUTSIDE PRIMARY CONTAINMENT
(SHEET 1 OF 2)

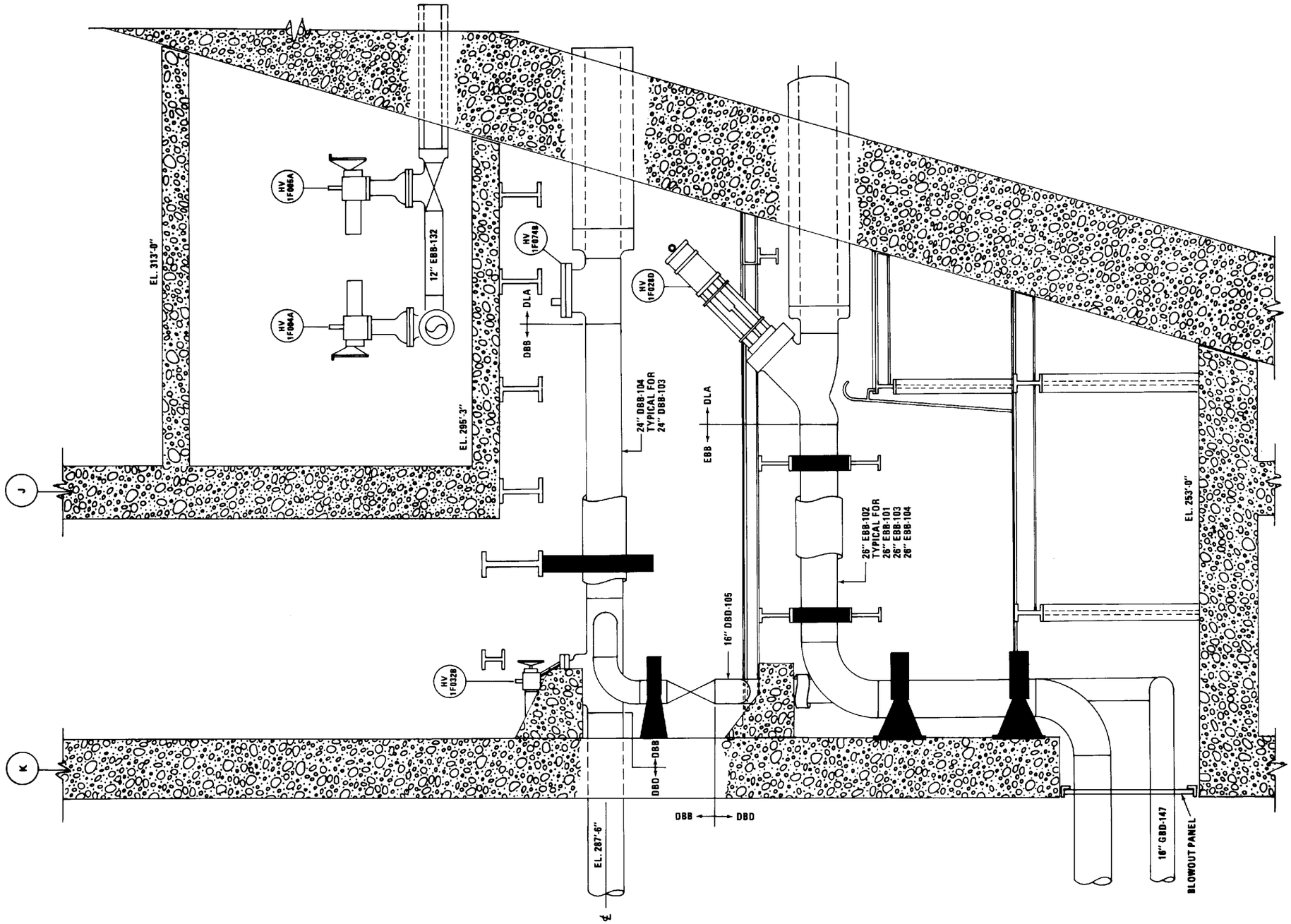
FIGURE 3.6-5 Rev. 6,12/96



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM PIPING SYSTEM
OUTSIDE PRIMARY CONTAINMENT
(UNIT 2)
(SHEET 2 OF 2)

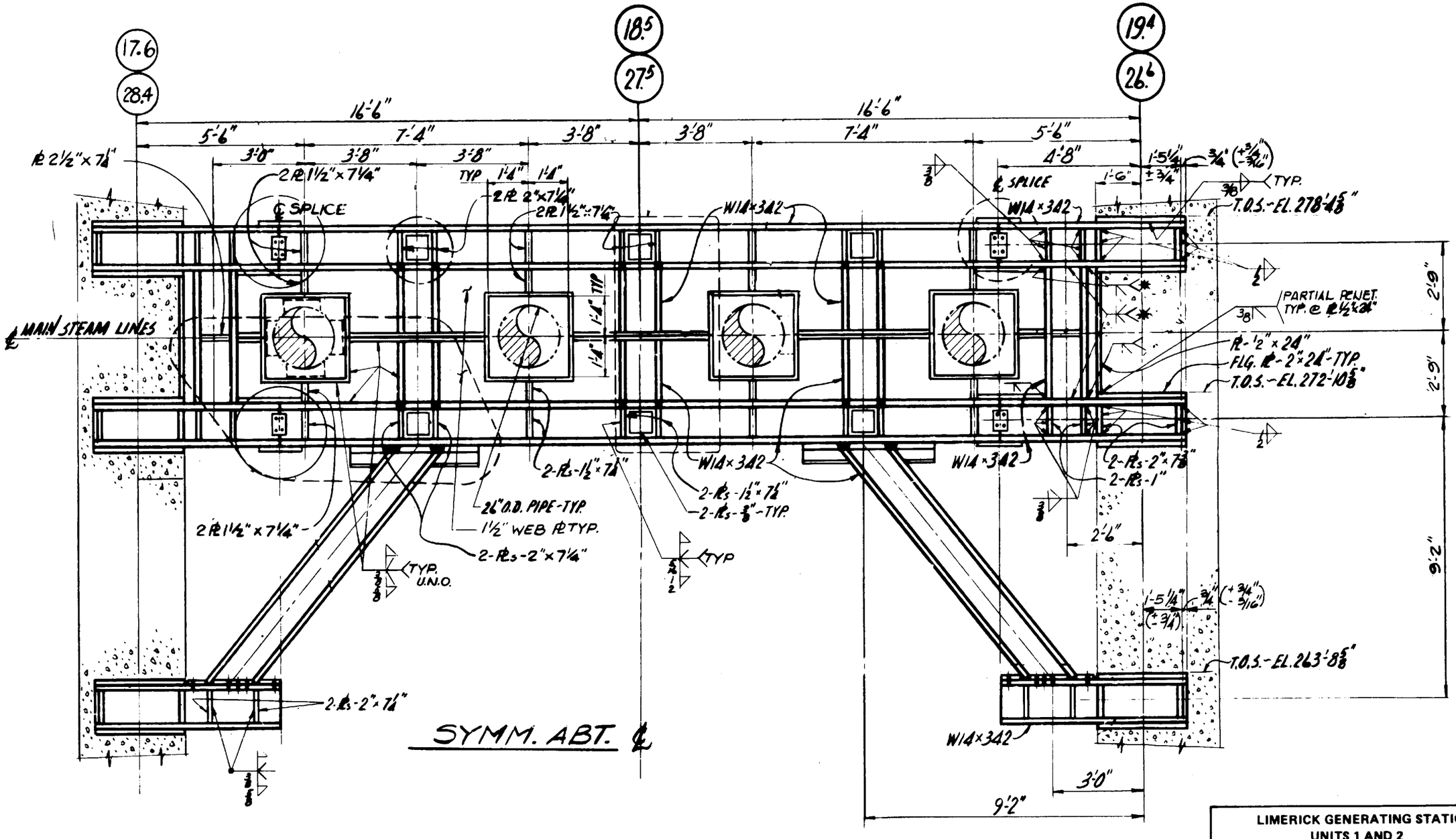
FIGURE 3.6-5



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM TUNNEL ELEVATION VIEW

FIGURE 3.6-6



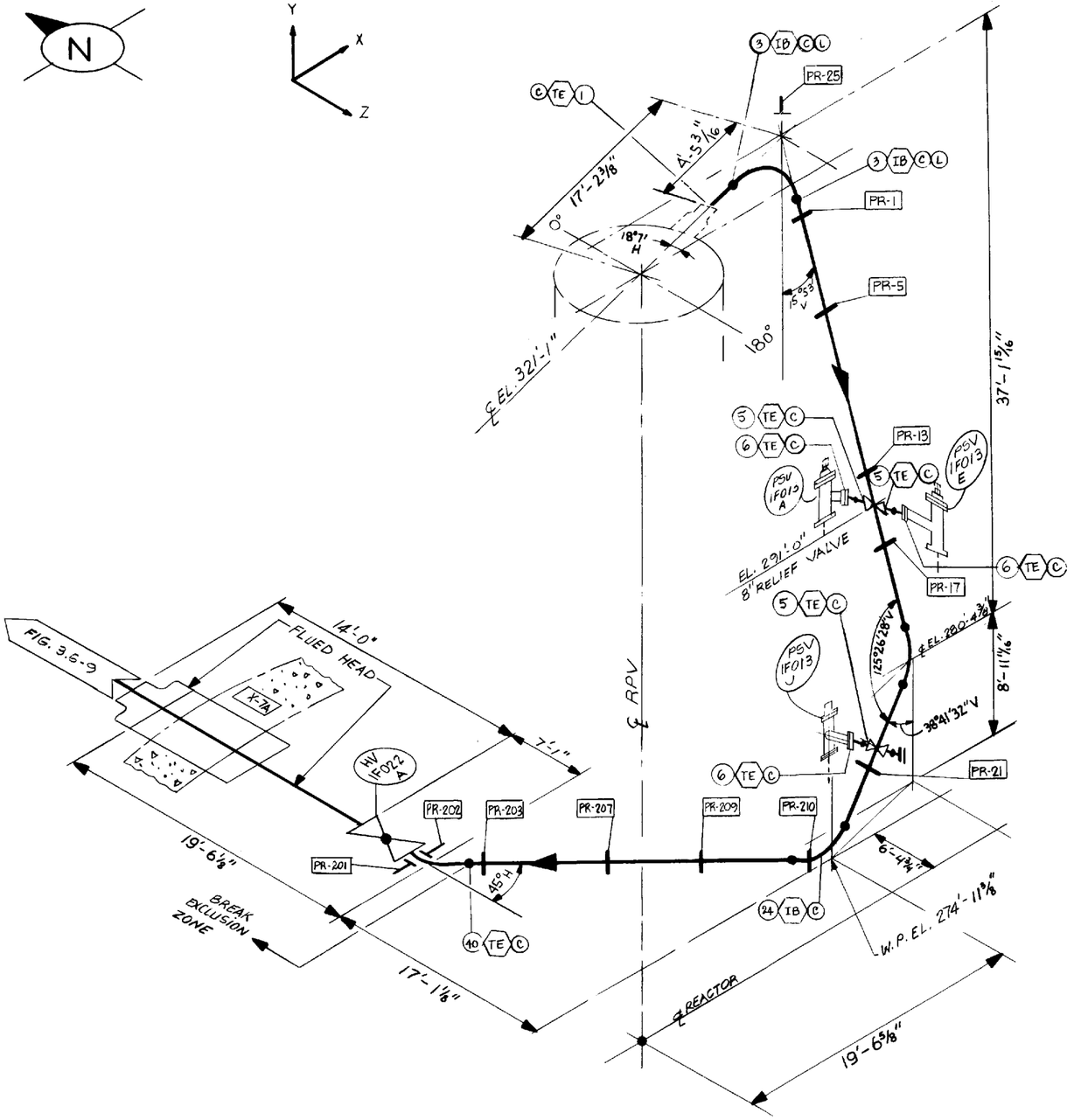
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-835.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM PIPING RESTRAINTS INSIDE MAIN STEAM TUNNEL

FIGURE 3.8-7



MAIN STEAM LINE A

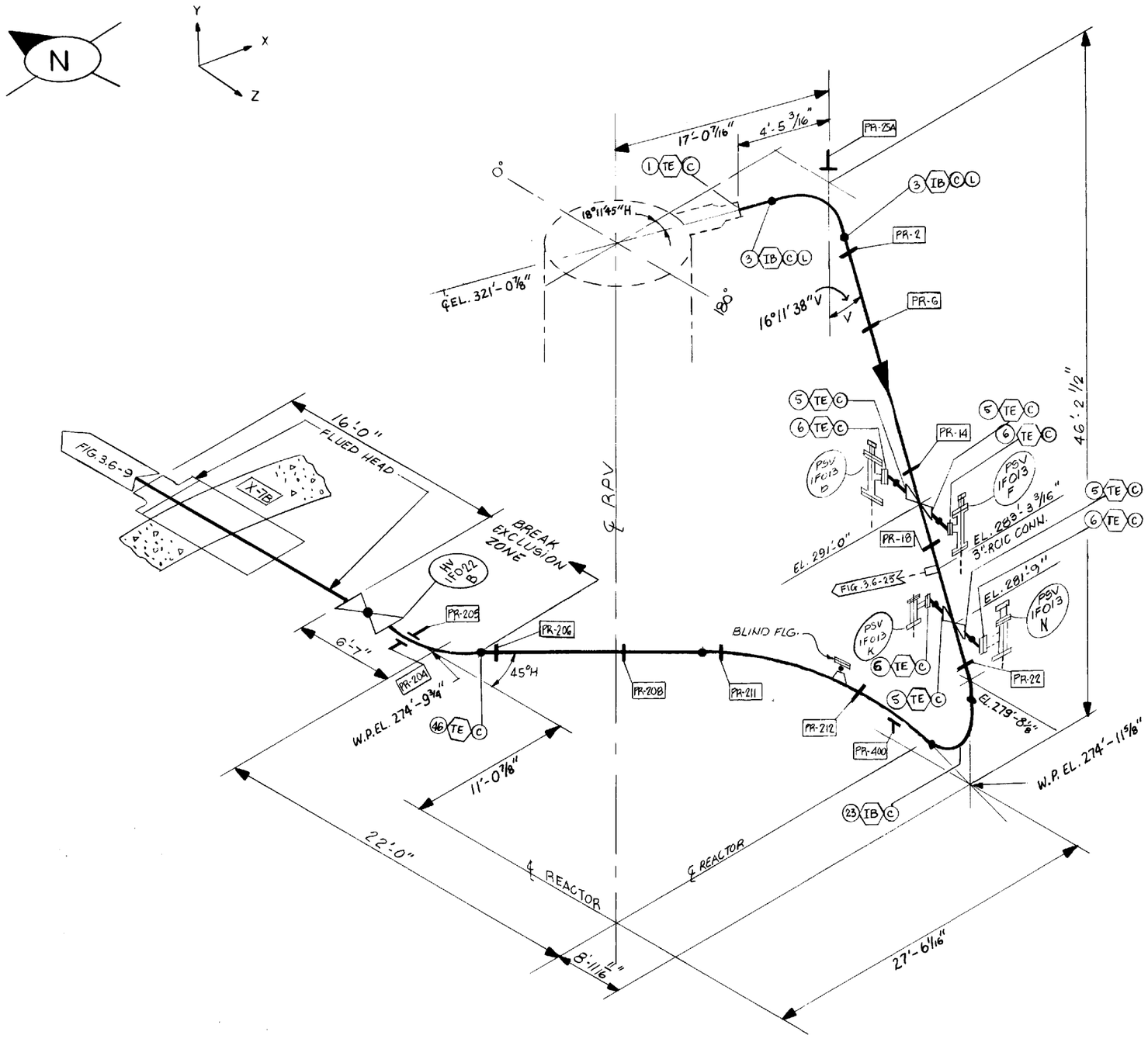
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-4.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM PIPING ISOMETRIC
(PORTION INSIDE PRIMARY CONTAINMENT)
(UNIT 1 ONLY)
(SHEET 1 OF 8)

FIGURE 3.6-8



MAIN STEAM LINE B

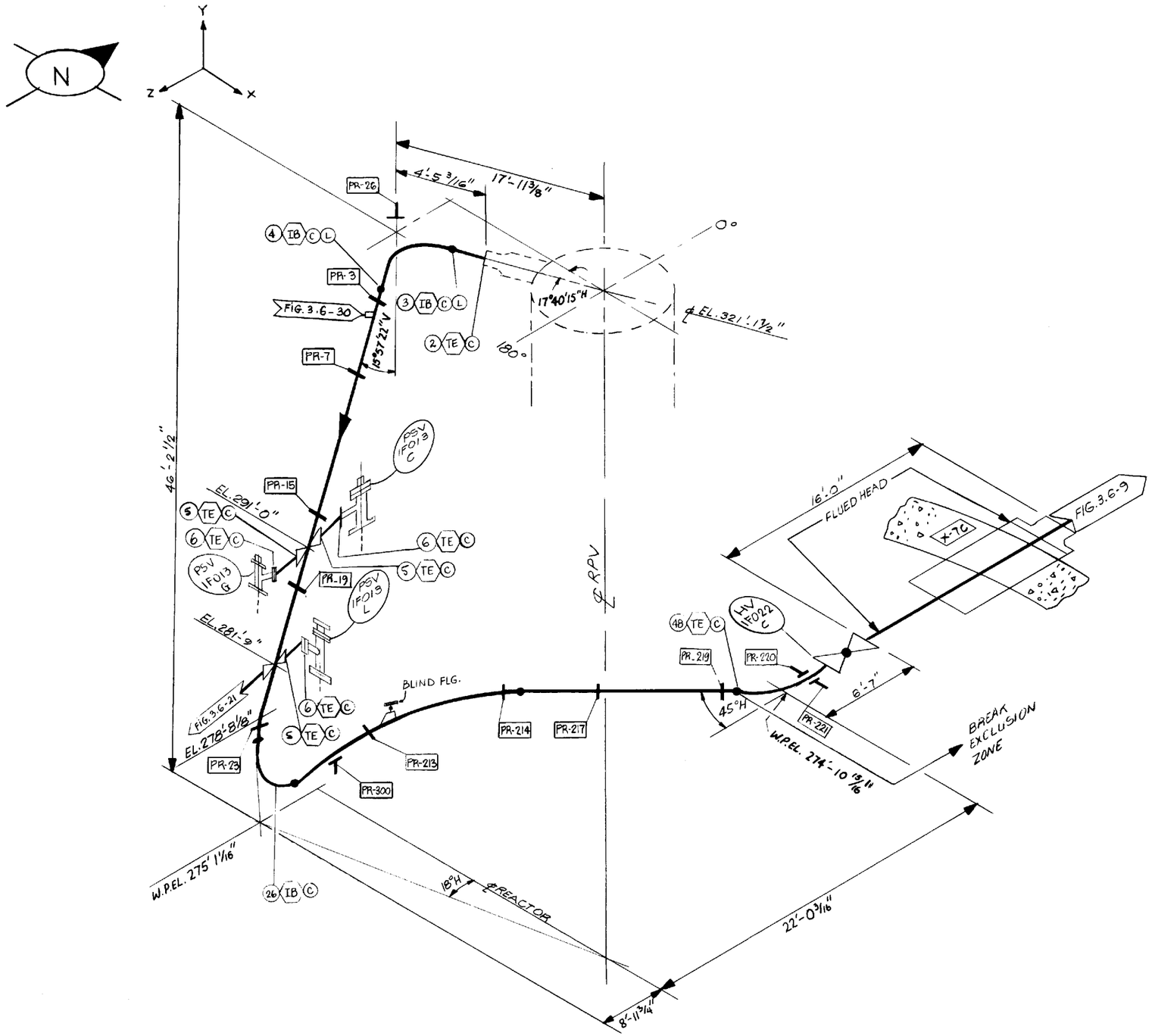
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-4.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM PIPING ISOMETRIC
(PORTION INSIDE PRIMARY CONTAINMENT)
(UNIT 1 ONLY)
(SHEET 2 OF 8)

FIGURE 3.6-8



MAIN STEAM LINE C

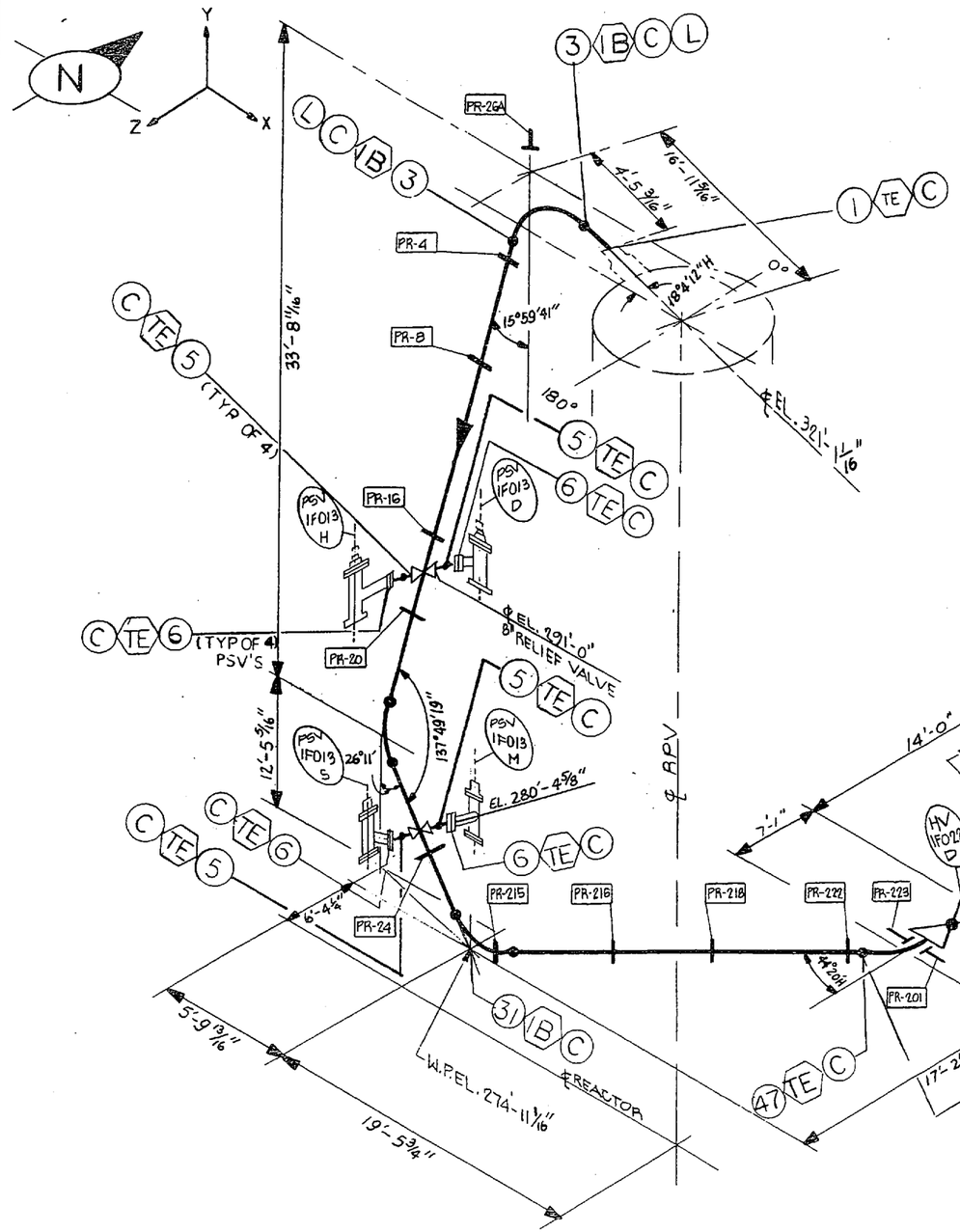
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-4.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM PIPING ISOMETRIC
(PORTION INSIDE PRIMARY CONTAINMENT)
(UNIT 1 ONLY)
(SHEET 3 OF 8)

FIGURE 3.6-8



MAIN STEAM LINE D

NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-4

2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:

   (TE) – TERMINAL END BREAK

   (IB) – INTERMEDIATE BREAK

   (C) – CIRCUMFERENTIAL BREAK

   (L) – LONGITUDINAL BREAK

3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:

   – PIPE WHIP RESTRAINT

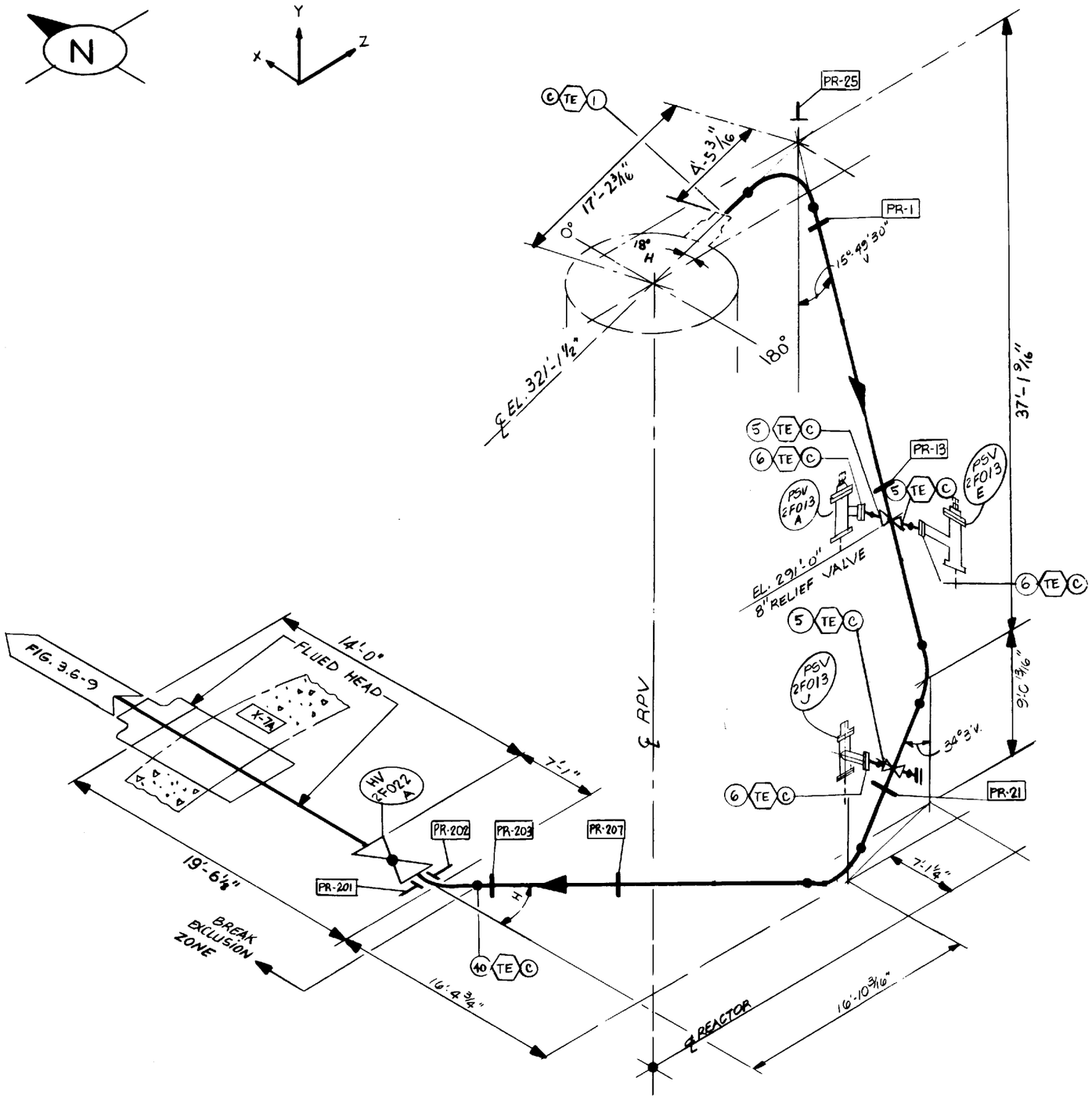
   – BUMPER-TYPE RESTRAINT

   – ANCHOR

LIMERICK GENERATING STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM PIPING ISOMETRIC
(PORTION INSIDE PRIMARY CONTAINMENT)
(UNIT 1 ONLY)

Figure 3.6-8 Sht. 4 of 8 Rev. 10 10/00



MAIN STEAM LINE A

NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-4

2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:

   TE – TERMINAL END BREAK

   IB – INTERMEDIATE BREAK

   C – CIRCUMFERENTIAL BREAK

   L – LONGITUDINAL BREAK

3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:

   – PIPE WHIP RESTRAINT

   – BUMPER-TYPE RESTRAINT

   – ANCHOR

4. INTERMEDIATE BREAKS ARE ELIMINATED FOR LIMERICK UNIT 2 (SEE TABLE 3.6-4 FOR LOCATIONS)

REFERENCE

1. MAIN STEAM PWR (BY OTHERS)

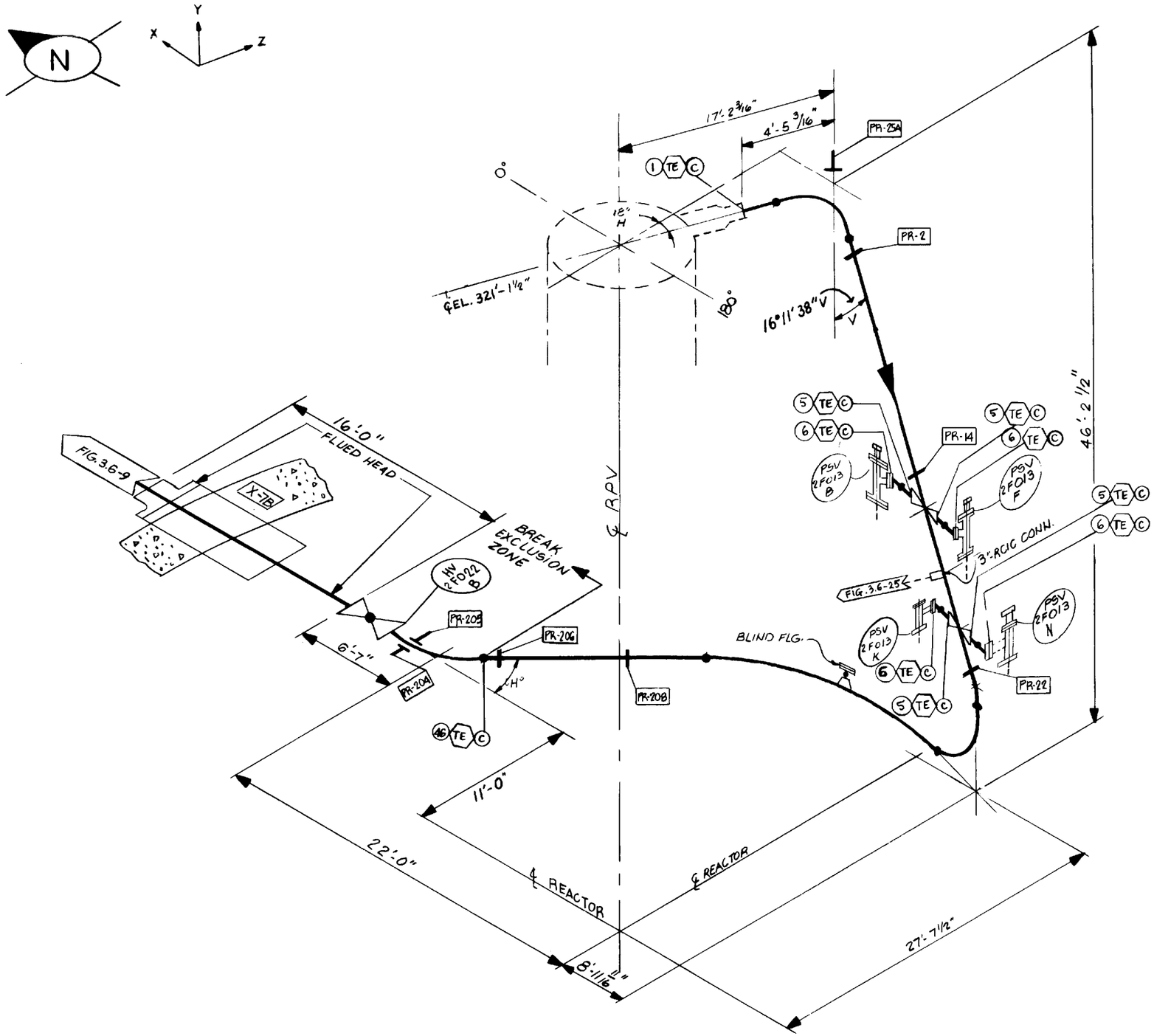
LIMERICK GENERATING STATION UNITS 1 AND 2

UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM PIPING ISOMETRIC (PORTION INSIDE PRIMARY CONTAINMENT) (UNIT 2)

(SHEET 5 OF 8)

FIGURE 3.6-8



MAIN STEAM LINE B

NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-4.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - TE – TERMINAL END BREAK
   - IB – INTERMEDIATE BREAK
   - C – CIRCUMFERENTIAL BREAK
   - L – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. INTERMEDIATE BREAKS ARE ELIMINATED FOR LIMERICK UNIT 2 (SEE TABLE 3.6-4 FOR LOCATIONS)

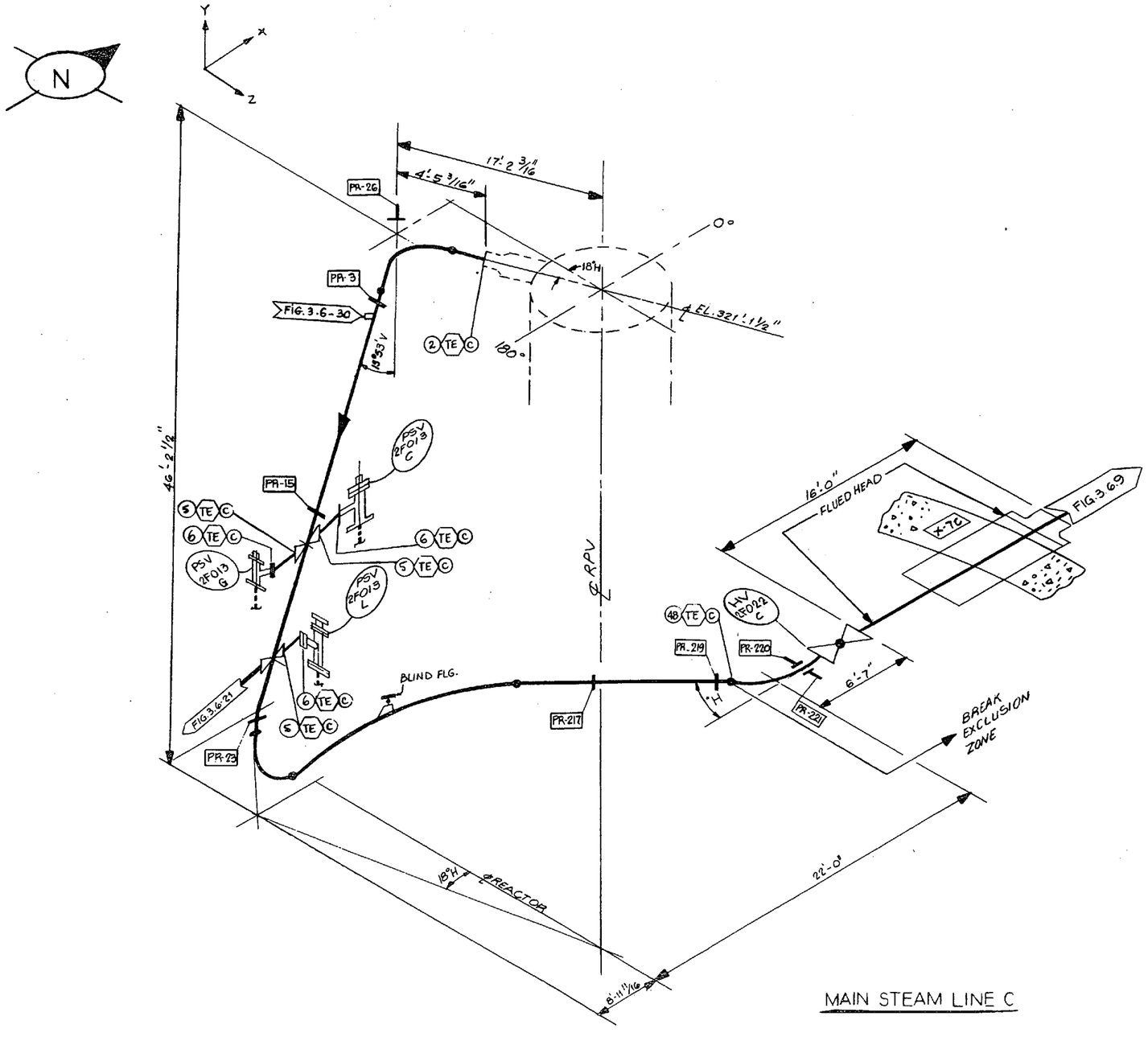
REFERENCE

1. MAIN STEAM PWR (BY OTHERS)

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM PIPING ISOMETRIC (PORTION INSIDE PRIMARY CONTAINMENT) UNIT 2
(SHEET 6 OF 8)

FIGURE 3.6-8



MAIN STEAM LINE C

NOTES

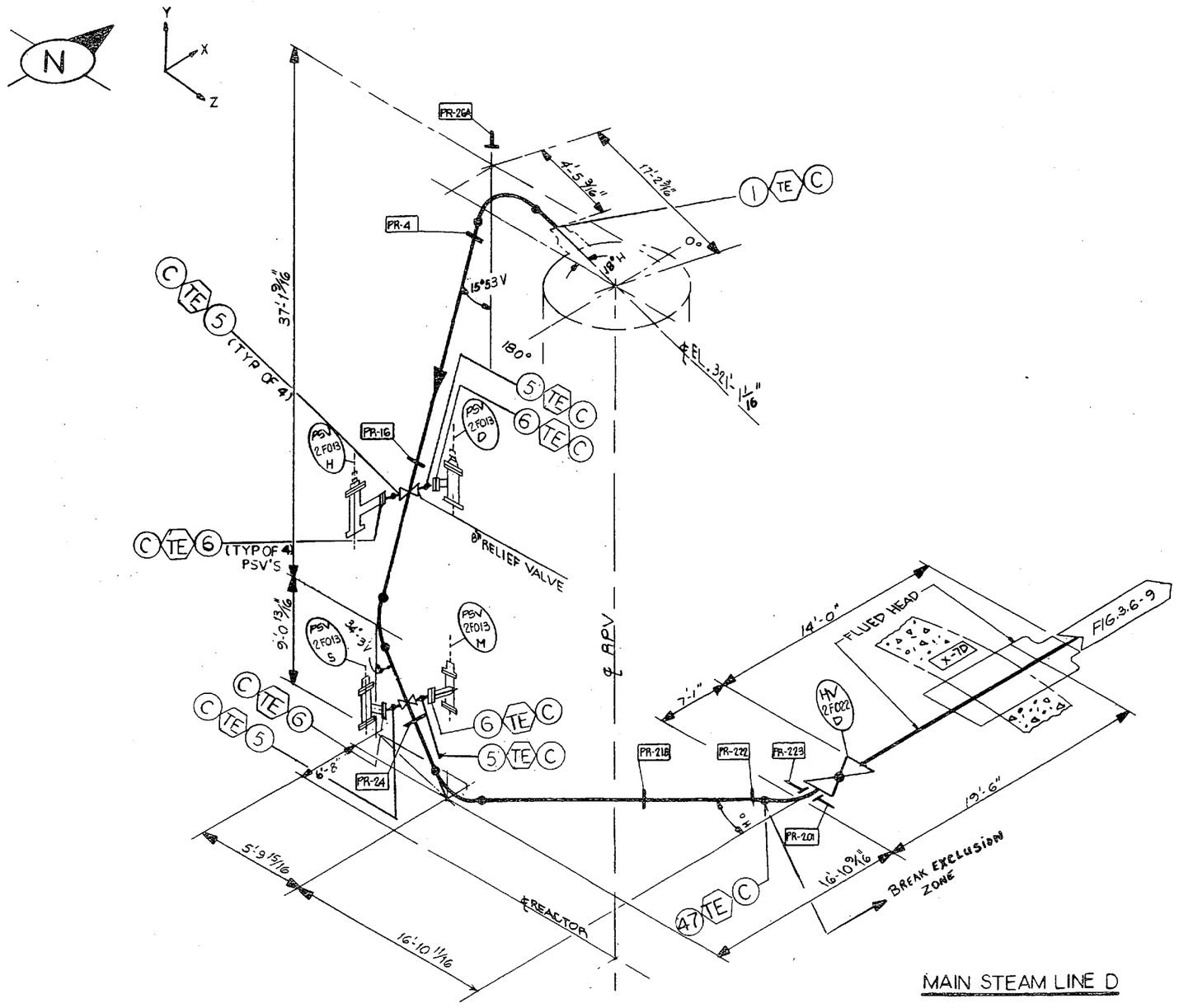
1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-4
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
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   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. INTERMEDIATE BREAKS ARE ELIMINATED FOR LIMERICK UNIT 2 (SEE TABLE 3.6-4 FOR LOCATIONS)

REFERENCE

1. MAIN STEAM PWR (BY OTHERS)

LIMERICK GENERATING STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM PIPING ISOMETRIC
(PORTION INSIDE PRIMARY CONTAINMENT)
(UNIT 2 ONLY)



MAIN STEAM LINE D

NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-4
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. INTERMEDIATE BREAKS ARE ELIMINATED FOR LIMERICK UNIT 2 (SEE TABLE 3.6-4 FOR LOCATIONS)

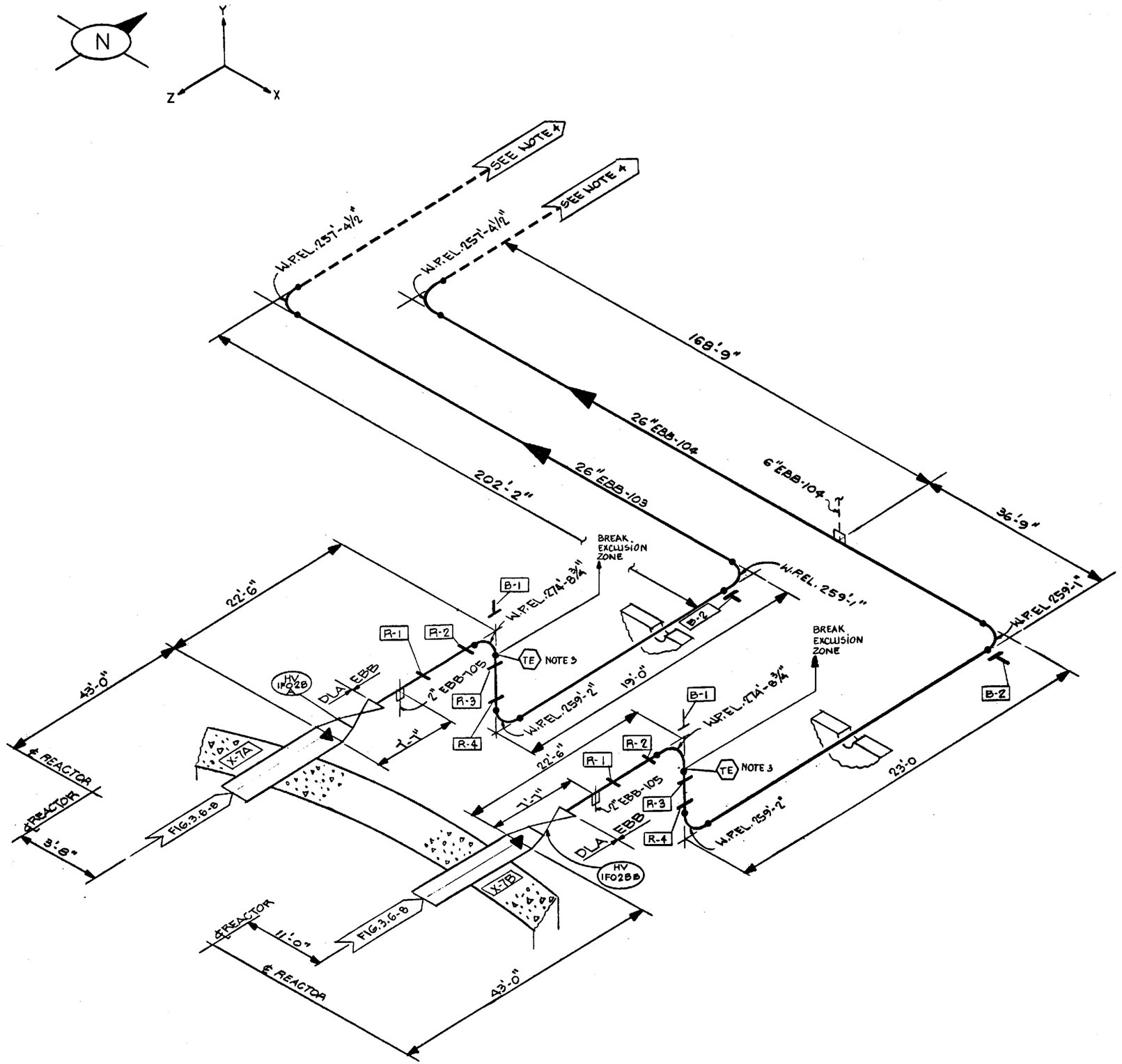
REFERENCE

1. MAIN STEAM PWR (BY OTHERS)

LIMERICK GENERATING STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM PIPING ISOMETRIC
(PORTION INSIDE PRIMARY CONTAINMENT)
(UNIT 2 ONLY)

Figure 3.6-8 Sht. 8 of 8 Rev. 10 10/00



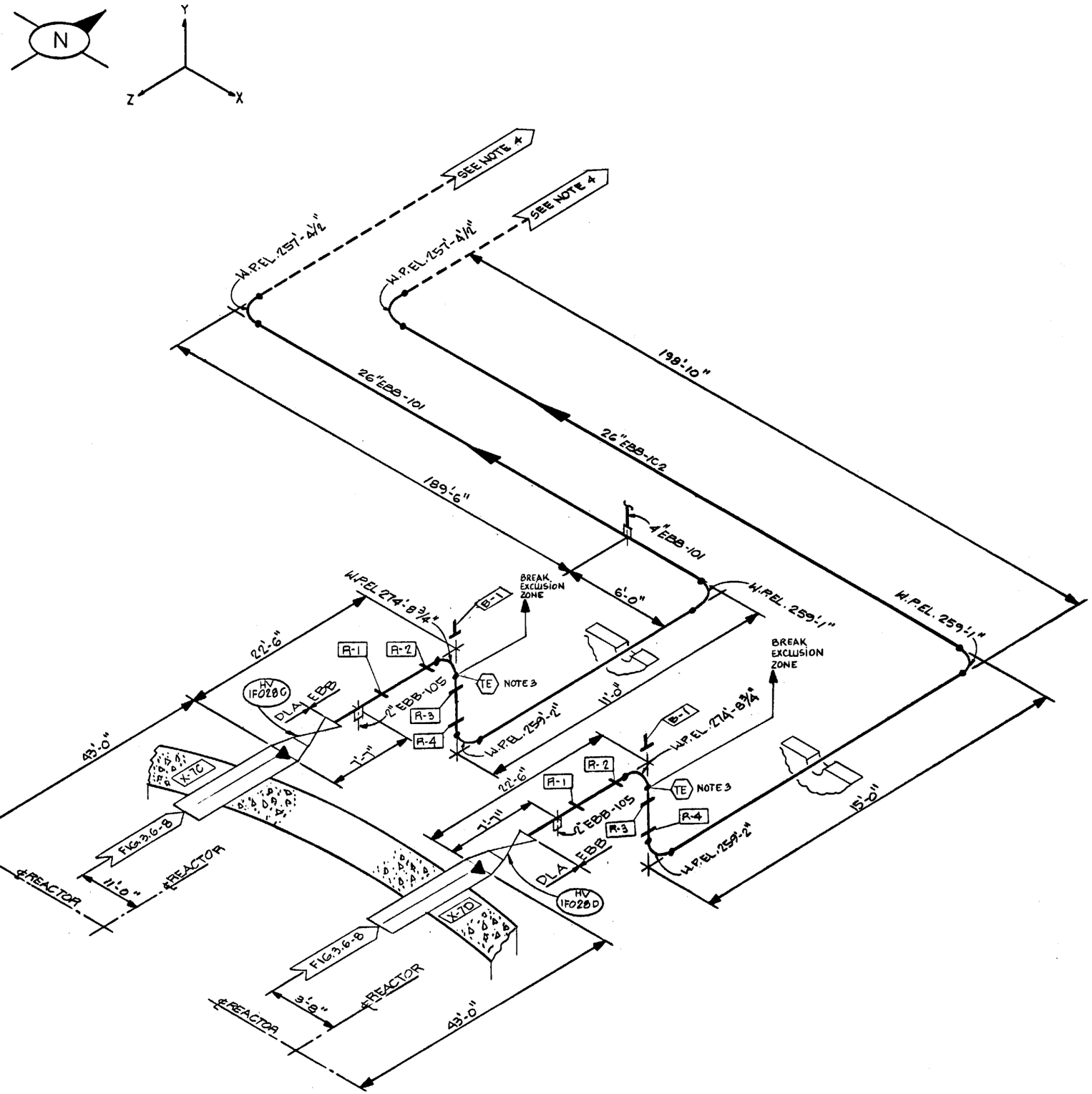
NOTES

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   - (TE) – TERMINAL END BREAK
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   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
2. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
3. INTERMEDIATE BREAK LOCATIONS DOWNSTREAM OF THE TERMINAL END ARE LOCATIONS OF POTENTIAL HIGH STRESS IN ACCORDANCE WITH SECTION 3.6.2.1.1.4.
4. THE ROUTING OF HIGH-ENERGY MAIN STEAM PIPING CONTINUES THROUGH THE TURBINE ENCLOSURE UP TO THE HIGH-PRESSURE TURBINE AS SHOWN ON FIGURE 3.6-5.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM PIPING ISOMETRIC
(PORTION OUTSIDE PRIMARY CONTAINMENT)
(UNIT 1 ONLY)
(SHEET 1 OF 4)

FIGURE 3.6-9



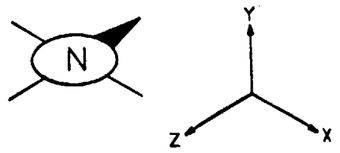
NOTES

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   - (IB) – INTERMEDIATE BREAK
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2. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
3. INTERMEDIATE BREAK LOCATIONS DOWNSTREAM OF THE TERMINAL END ARE SELECTED AT LOCATIONS OF POTENTIAL HIGH STRESS IN ACCORDANCE WITH SECTION 3.6.2.1.1.4.
4. THE ROUTING OF HIGH-ENERGY MAIN STEAM PIPING CONTINUES THROUGH THE TURBINE ENCLOSURE UP TO THE HIGH-PRESSURE TURBINE AS SHOWN ON FIGURE 3.6-5.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

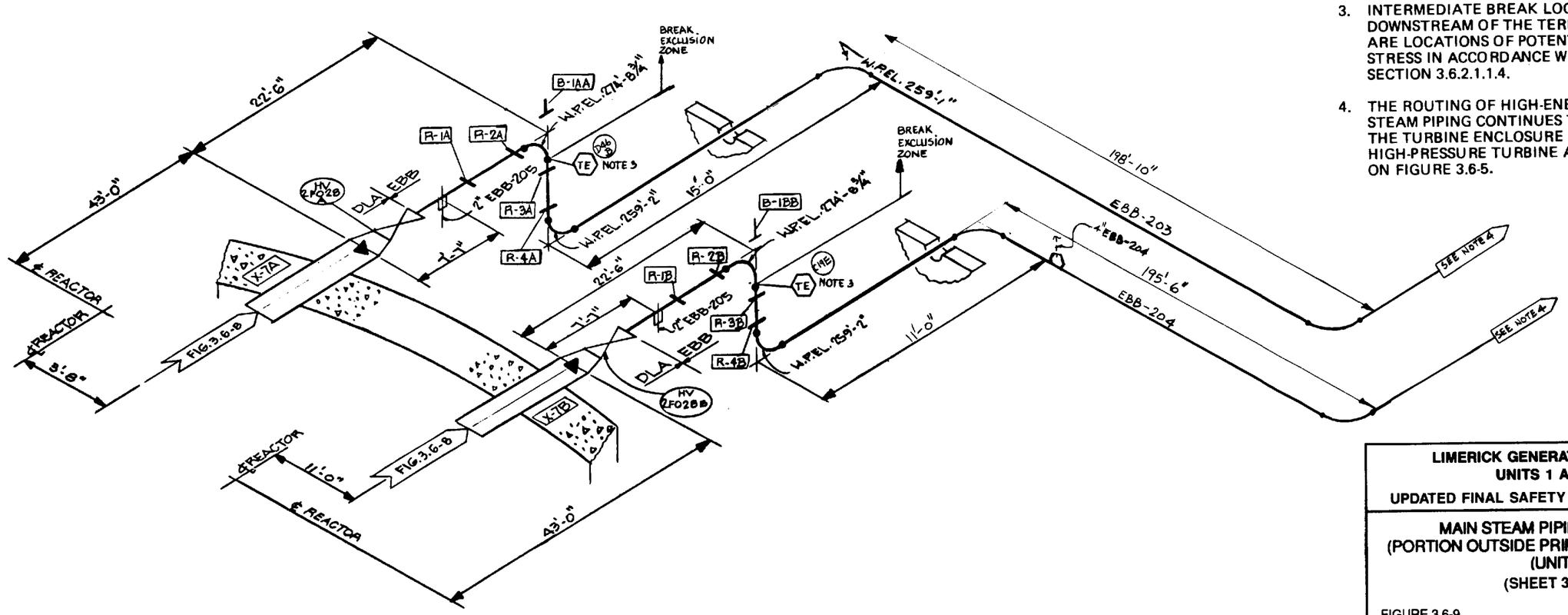
MAIN STEAM PIPING ISOMETRIC
(PORTION OUTSIDE PRIMARY CONTAINMENT)
(UNIT 1 ONLY)
(SHEET 2 OF 4)

FIGURE 3.6-9



NOTES

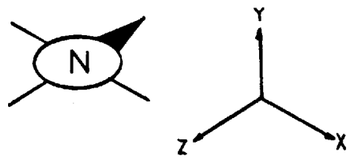
1. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - TE – TERMINAL END BREAK
   - IB – INTERMEDIATE BREAK
   - C – CIRCUMFERENTIAL BREAK
   - L – LONGITUDINAL BREAK
2. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS.
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
3. INTERMEDIATE BREAK LOCATIONS DOWNSTREAM OF THE TERMINAL END ARE LOCATIONS OF POTENTIAL HIGH STRESS IN ACCORDANCE WITH SECTION 3.6.2.1.1.4.
4. THE ROUTING OF HIGH-ENERGY MAIN STEAM PIPING CONTINUES THROUGH THE TURBINE ENCLOSURE UP TO THE HIGH-PRESSURE TURBINE AS SHOWN ON FIGURE 3.6-5.

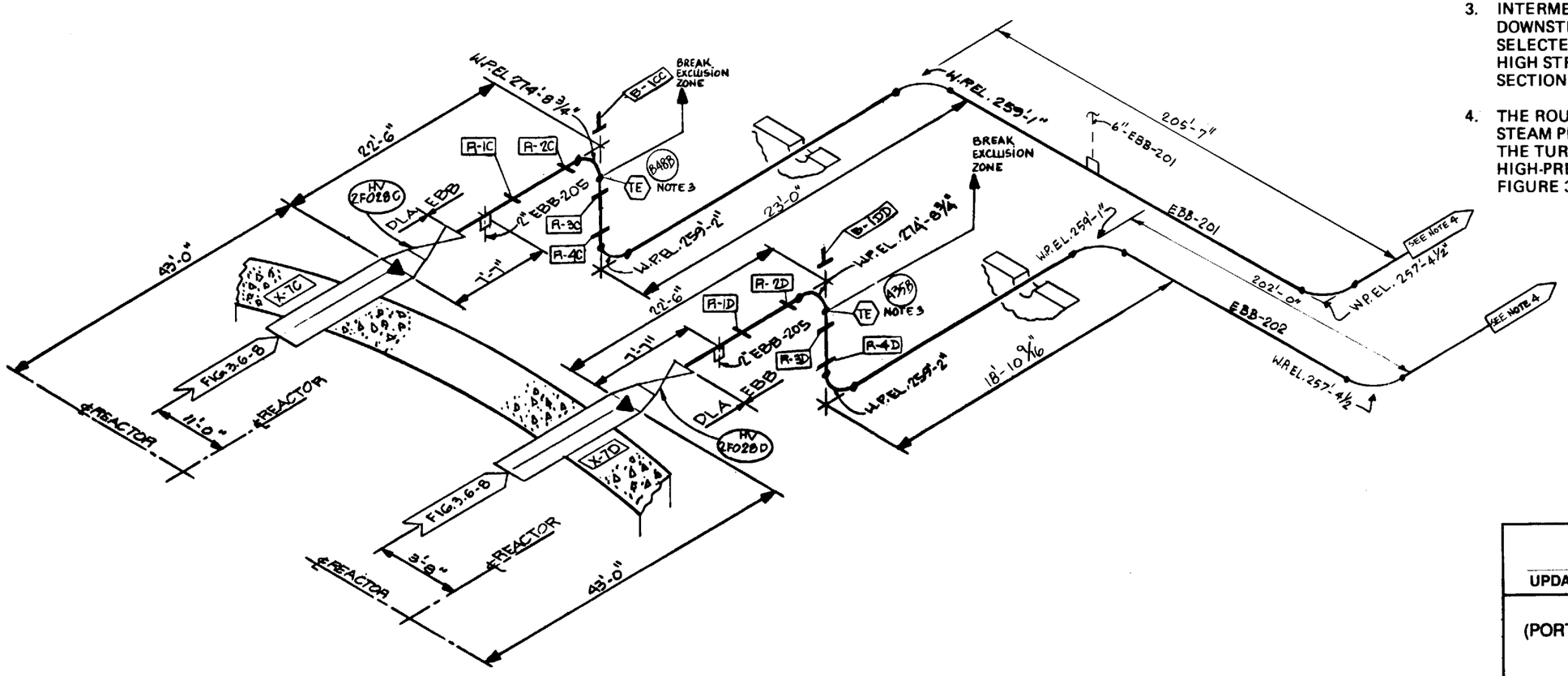


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM PIPING ISOMETRIC
(PORTION OUTSIDE PRIMARY CONTAINMENT)
(UNIT 2)
(SHEET 3 OF 4)

FIGURE 3.6-9





NOTES

1. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:

   TE – TERMINAL END BREAK

   IB – INTERMEDIATE BREAK

   C – CIRCUMFERENTIAL BREAK

   L – LONGITUDINAL BREAK

2. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:

   – PIPE WHIP RESTRAINT

   – BUMPER-TYPE RESTRAINT

   – ANCHOR

3. INTERMEDIATE BREAK LOCATIONS DOWNSTREAM OF THE TERMINAL END ARE SELECTED AT LOCATIONS OF POTENTIAL HIGH STRESS IN ACCORDANCE WITH SECTION 3.6.2.1.1.4.

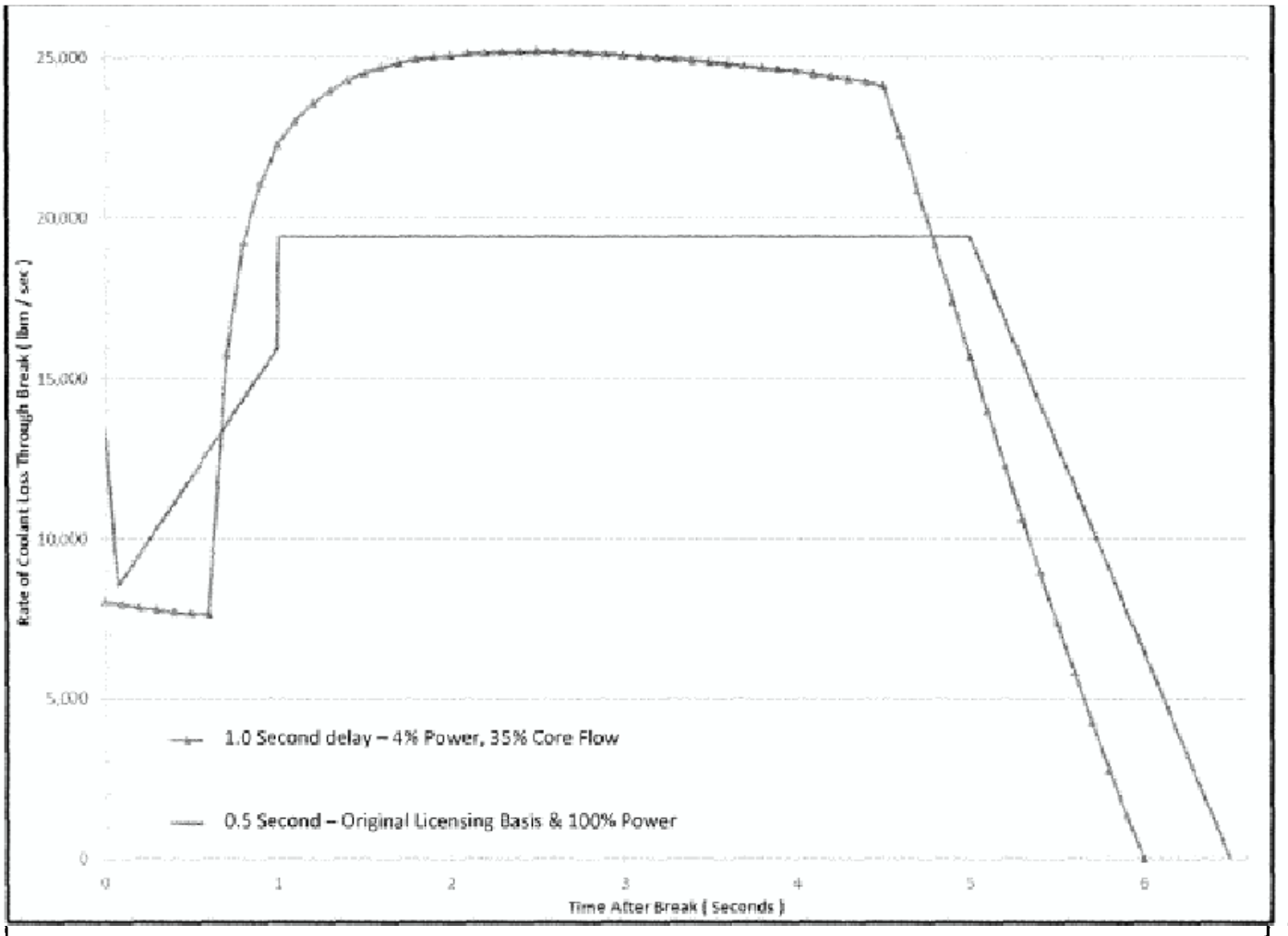
4. THE ROUTING OF HIGH-ENERGY MAIN STEAM PIPING CONTINUES THROUGH THE TURBINE ENCLOSURE UP TO THE HIGH-PRESSURE TURBINE AS SHOWN ON FIGURE 3.6-5.

LIMERICK GENERATING STATION
UNITS 1 AND 2

UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM PIPING ISOMETRIC
(PORTION OUTSIDE PRIMARY CONTAINMENT)
(UNIT 2)
(SHEET 4 OF 4)

FIGURE 3.6-9

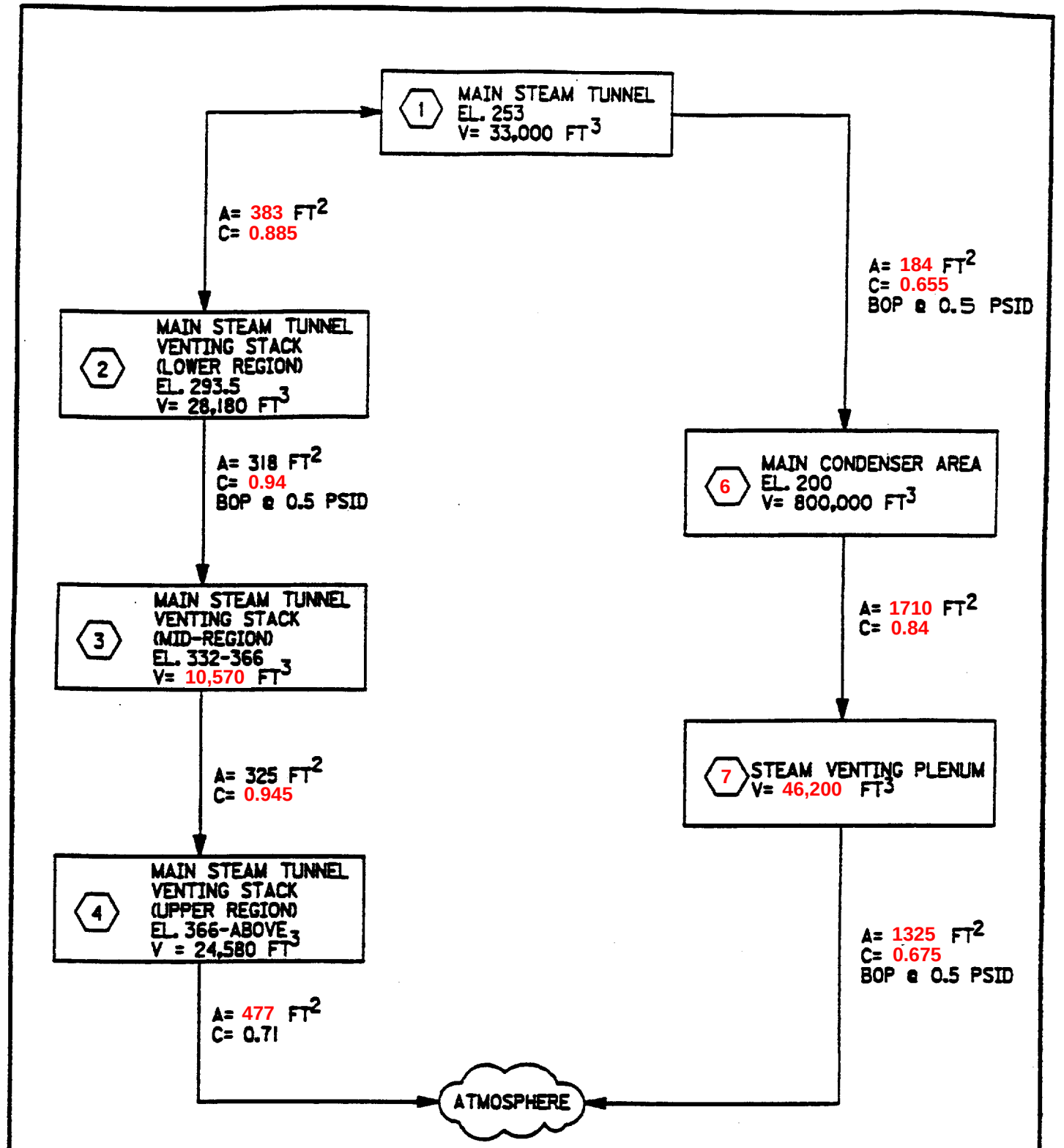


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RATE OF COOLANT LOSS FOR MAIN STEAM LINE BREAK OUTSIDE PRIMARY CONTAINMENT

FIGURE 3.6-10

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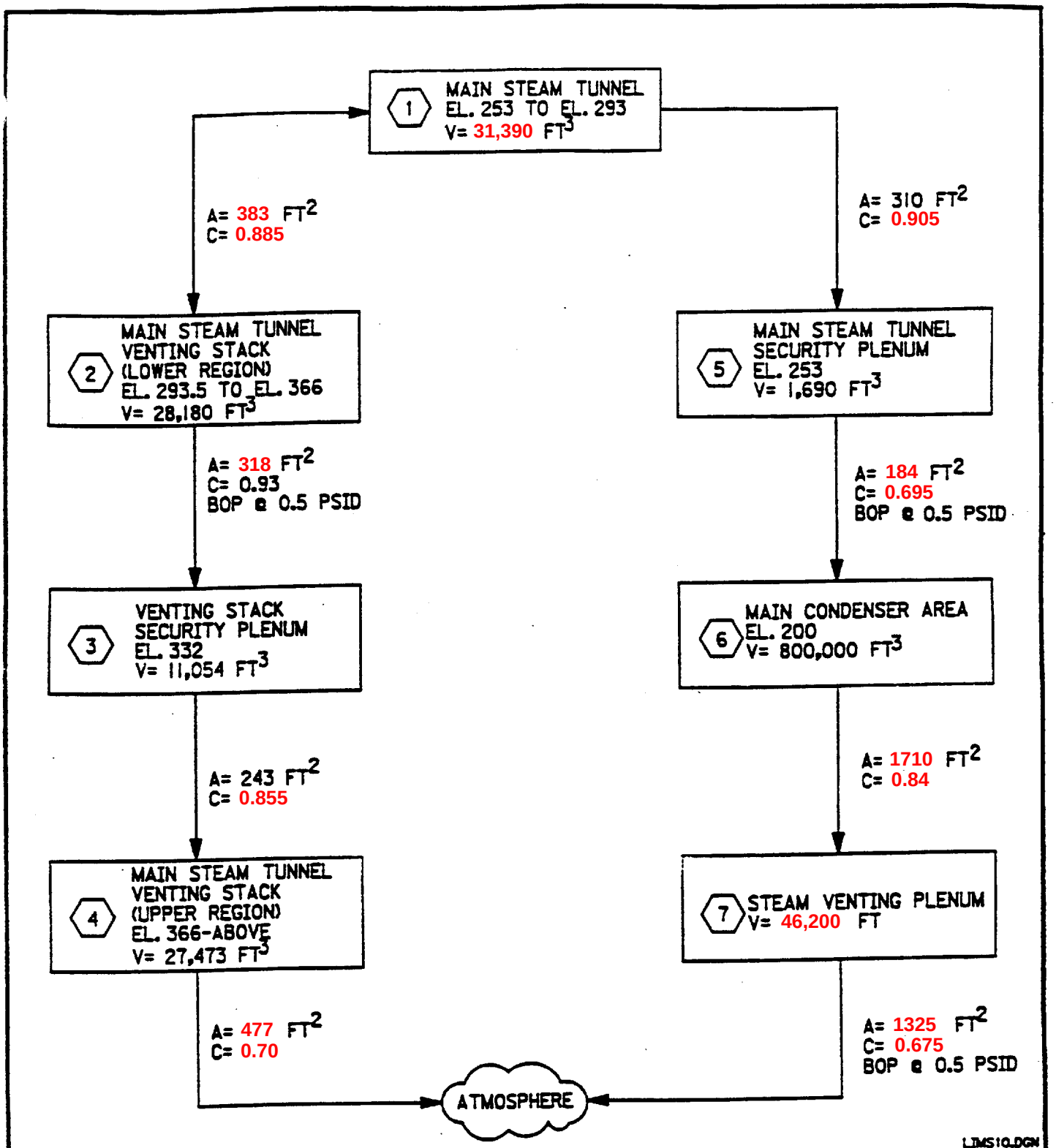
A= VENT AREA
C= FLOW COEFFICIENT
V= FREE VOLUME
BOP= BLOWOUT PANEL

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE TEMPERATURE TRANSIENT ANALYSIS MODEL FOR MAIN STEAM LINE BREAK IN MAIN STEAM TUNNEL
(UNIT 1)
(SHEET 1 OF 2)

FIGURE 3.6-11

Rev. 18 09/16



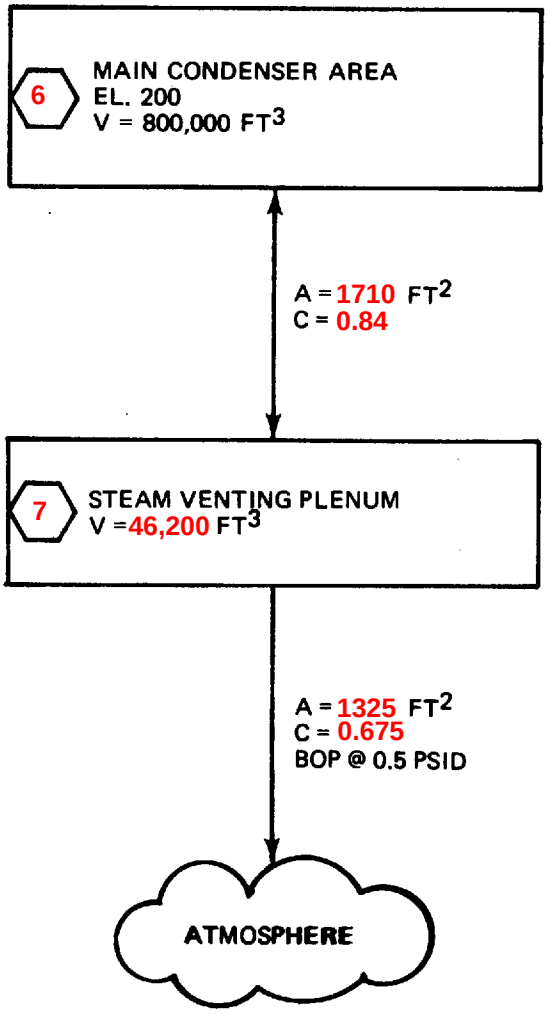
A= VENT AREA
C= FLOW COEFFICIENT
V= FREE VOLUME
BOP= BLOWOUT PANEL

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE TEMPERATURE TRANSIENT ANALYSIS MODEL FOR MAIN STEAM LINE BREAK IN MAIN STEAM TUNNEL
(UNIT 2)
(SHEET 2 OF 2)

FIGURE 3.6-11

Rev. 18 09/16



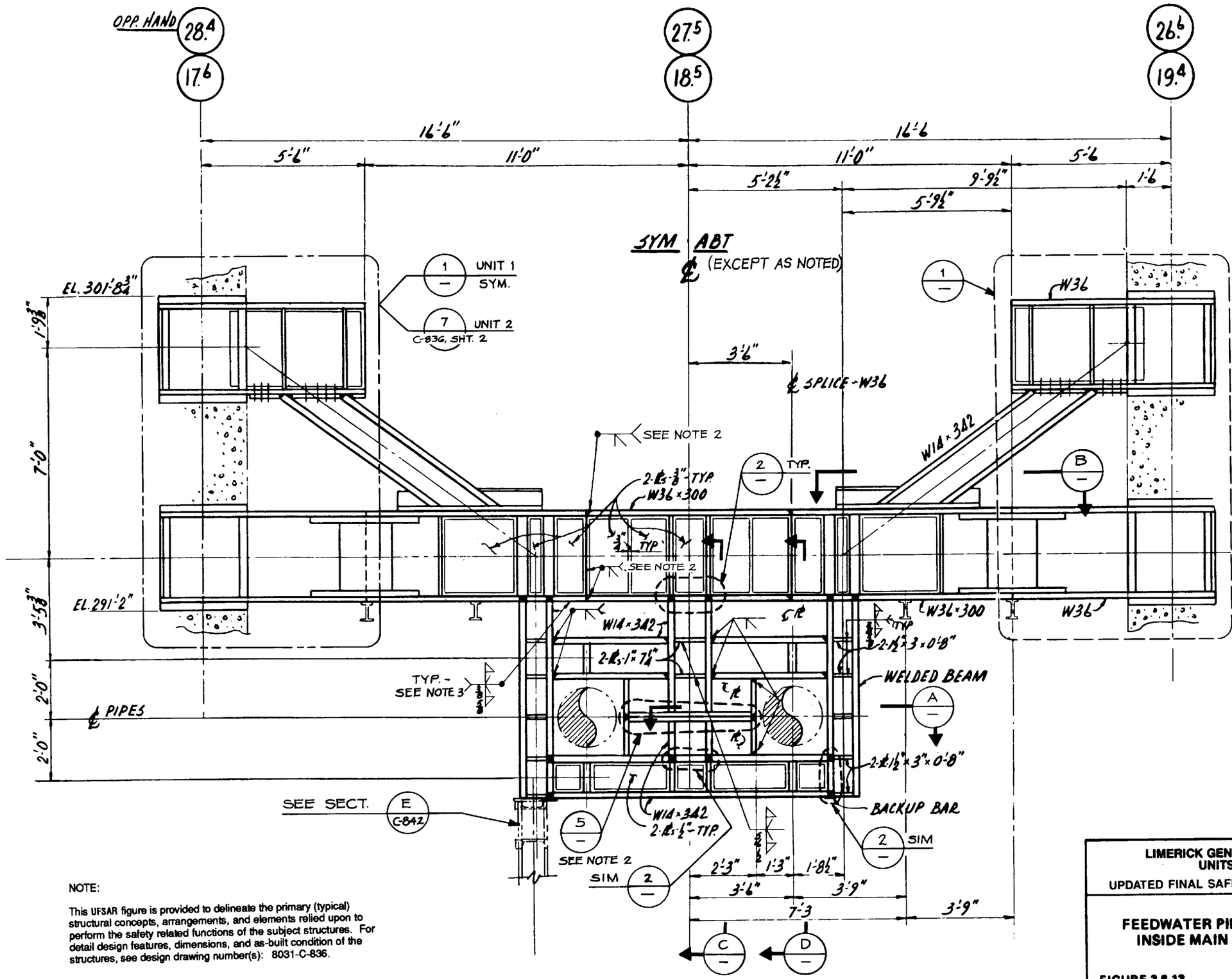
A = VENT AREA
C = FLOW COEFFICIENT
V = FREE VOLUME
BOP = BLOWOUT PANEL

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE-TEMPERATURE TRANSIENT ANALYSIS MODEL FOR MAIN STEAM LINE BREAK IN TURBINE ENCLOSURE

FIGURE 3.6-12

Rev. 18 09/16



NOTE:

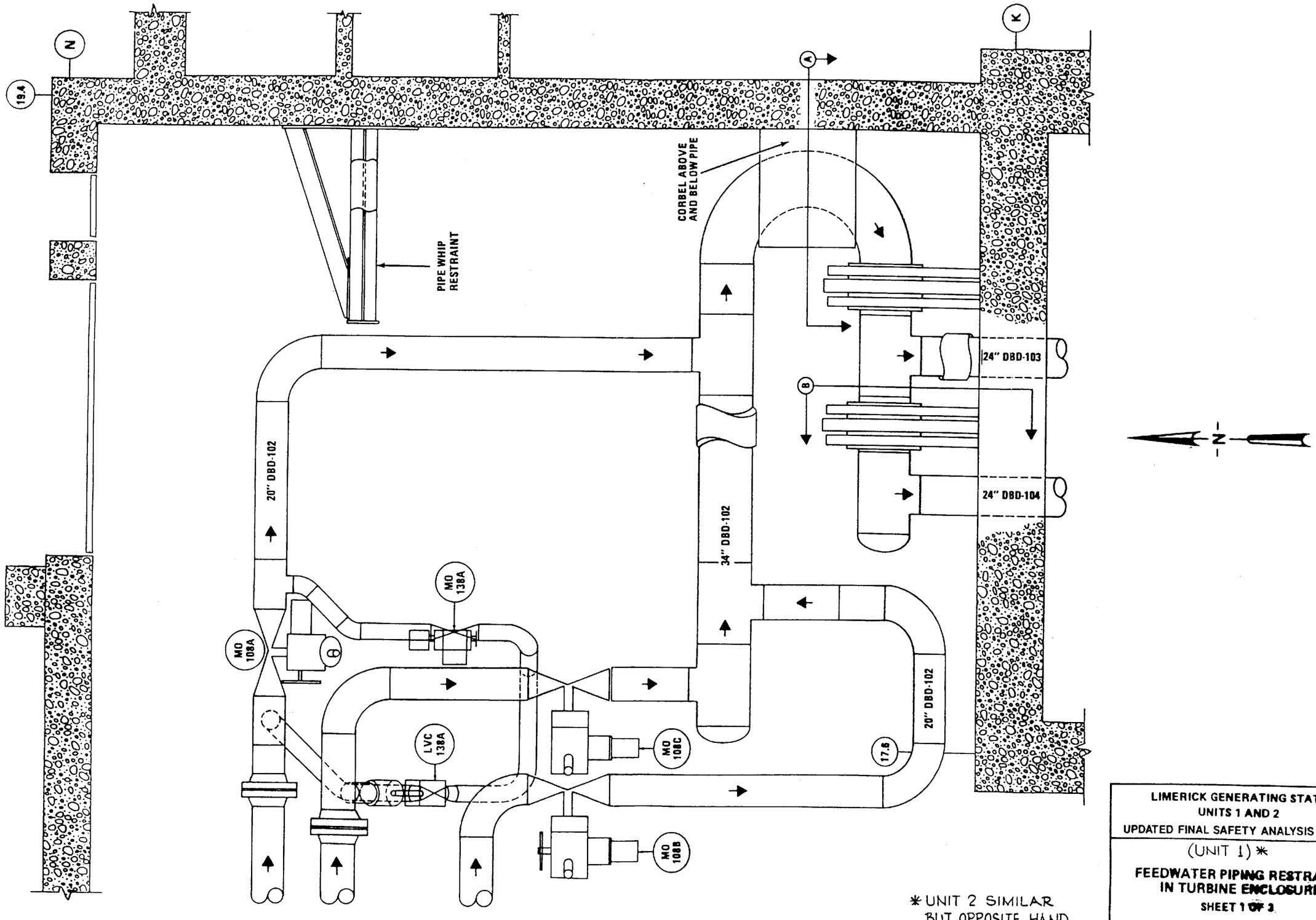
This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-836.

LIMERICK GENERATING STATION UNITS 1 AND 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FEEDWATER PIPING RESTRAINTS INSIDE MAIN STEAM TUNNEL

FIGURE 3.8-13



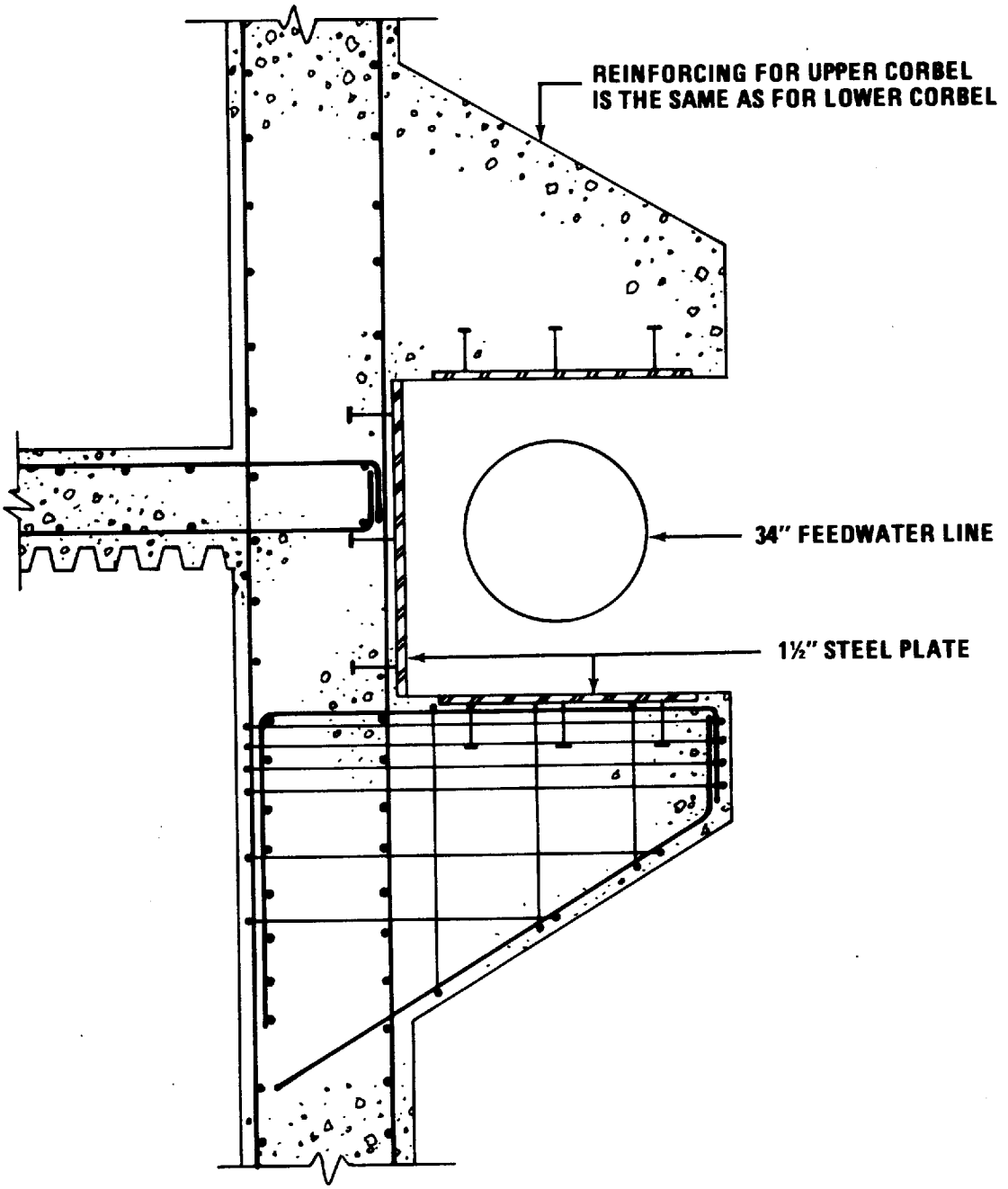
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

(UNIT 1) *

FEEDWATER PIPING RESTRAINTS IN TURBINE ENCLOSURE

SHEET 1 OF 3

FIGURE 3.8-14 Rev. 6,12/96



SECTION A
CORBELS ABOVE AND BELOW 34" FEEDWATER HEADER

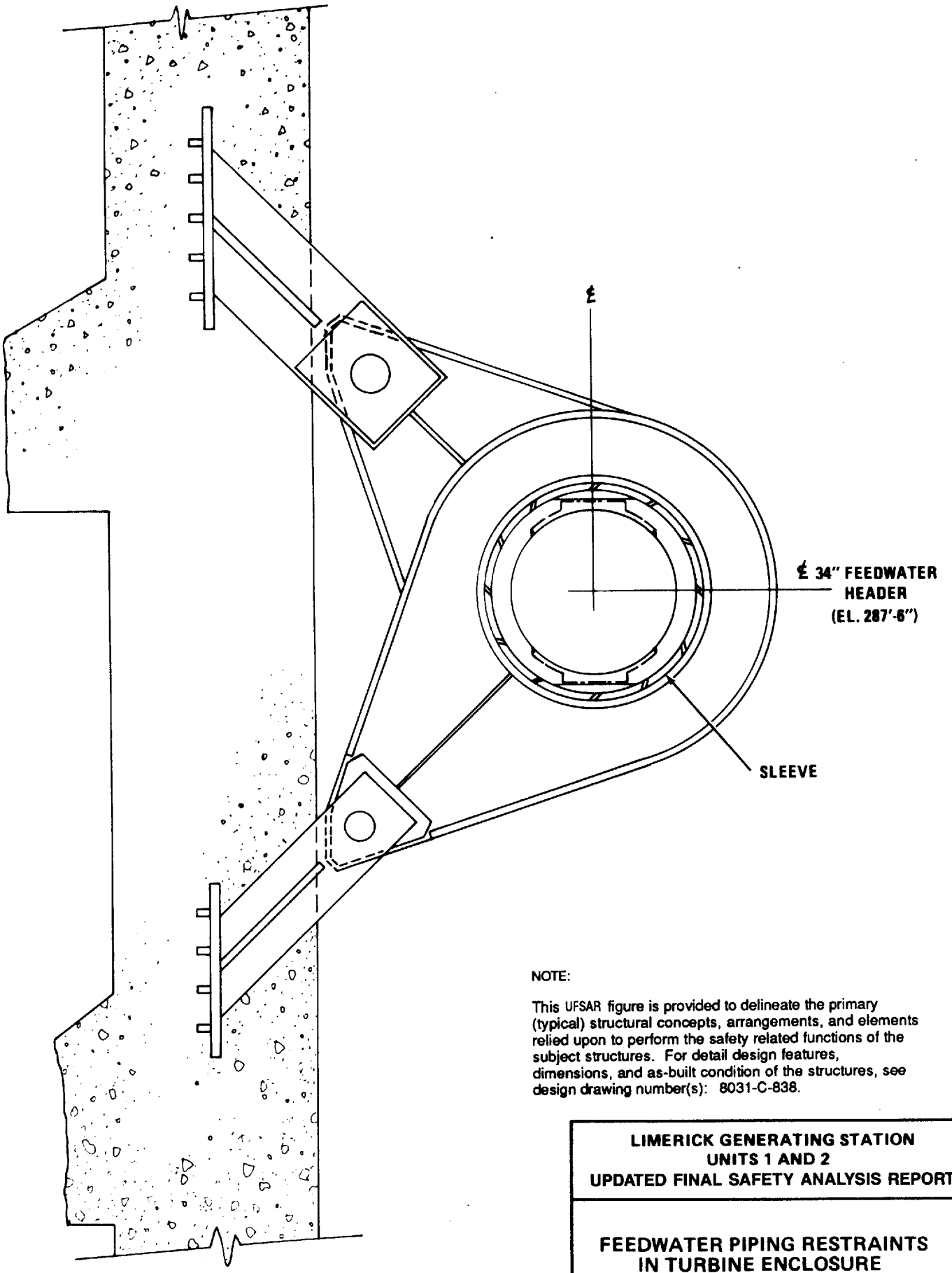
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-754.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FEEDWATER PIPING RESTRAINTS IN TURBINE ENCLOSURE
(SHEET 2 OF 3)

FIGURE 3.6-14



SECTION B
RESTRAINT FOR 34" FEEDWATER HEADER

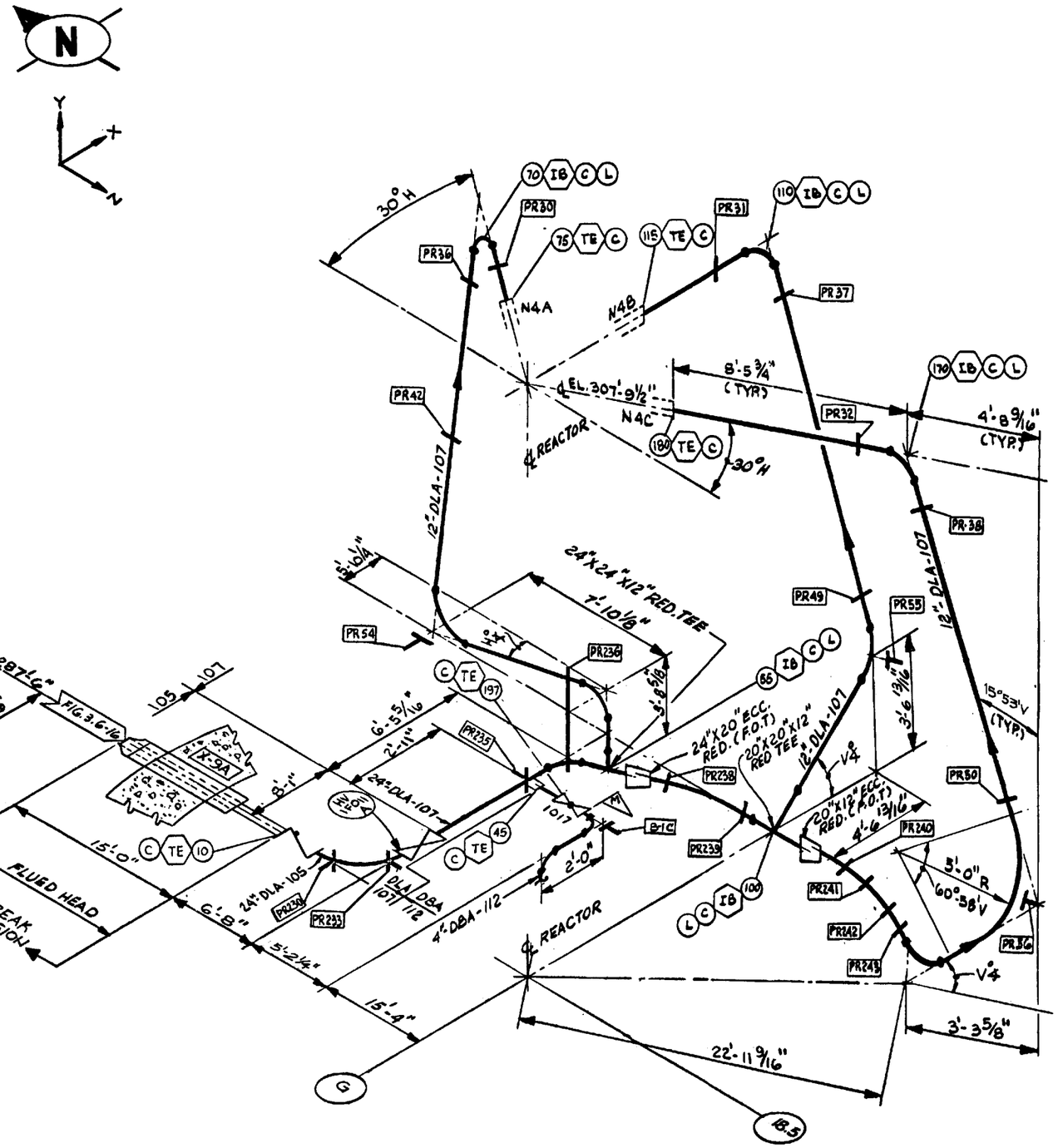
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-838.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FEEDWATER PIPING RESTRAINTS IN TURBINE ENCLOSURE
(SHEET 3 OF 3)

FIGURE 3.6-14



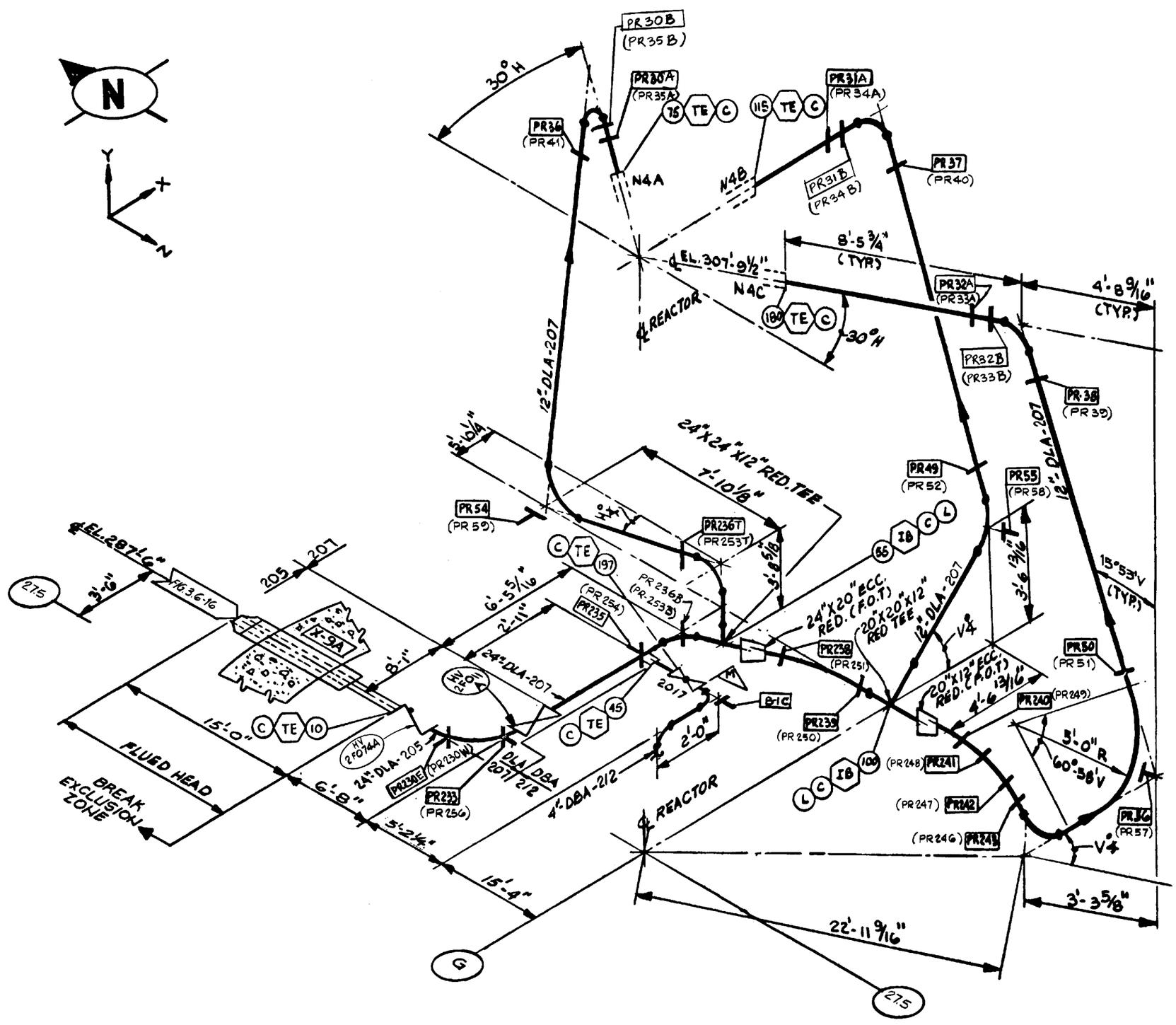
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-8.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. (M) – PIPING UPSTREAM OF VALVE 1017 IS MODERATE-ENERGY.
5. FEEDWATER LOOP A IS SHOWN. THE BREAK LOCATIONS INDICATED ARE TYPICAL FOR LOOP B, WHICH IS ARRANGED SYMMETRICALLY (EXCEPT THAT LOOP B DOES NOT HAVE A CONNECTION TO 4" DBA-112).

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FEEDWATER PIPING ISOMETRIC
(PORTION INSIDE PRIMARY CONTAINMENT)
(UNIT 1 ONLY)
(SHEET 1 OF 2)

FIGURE 3.6-15



NOTES

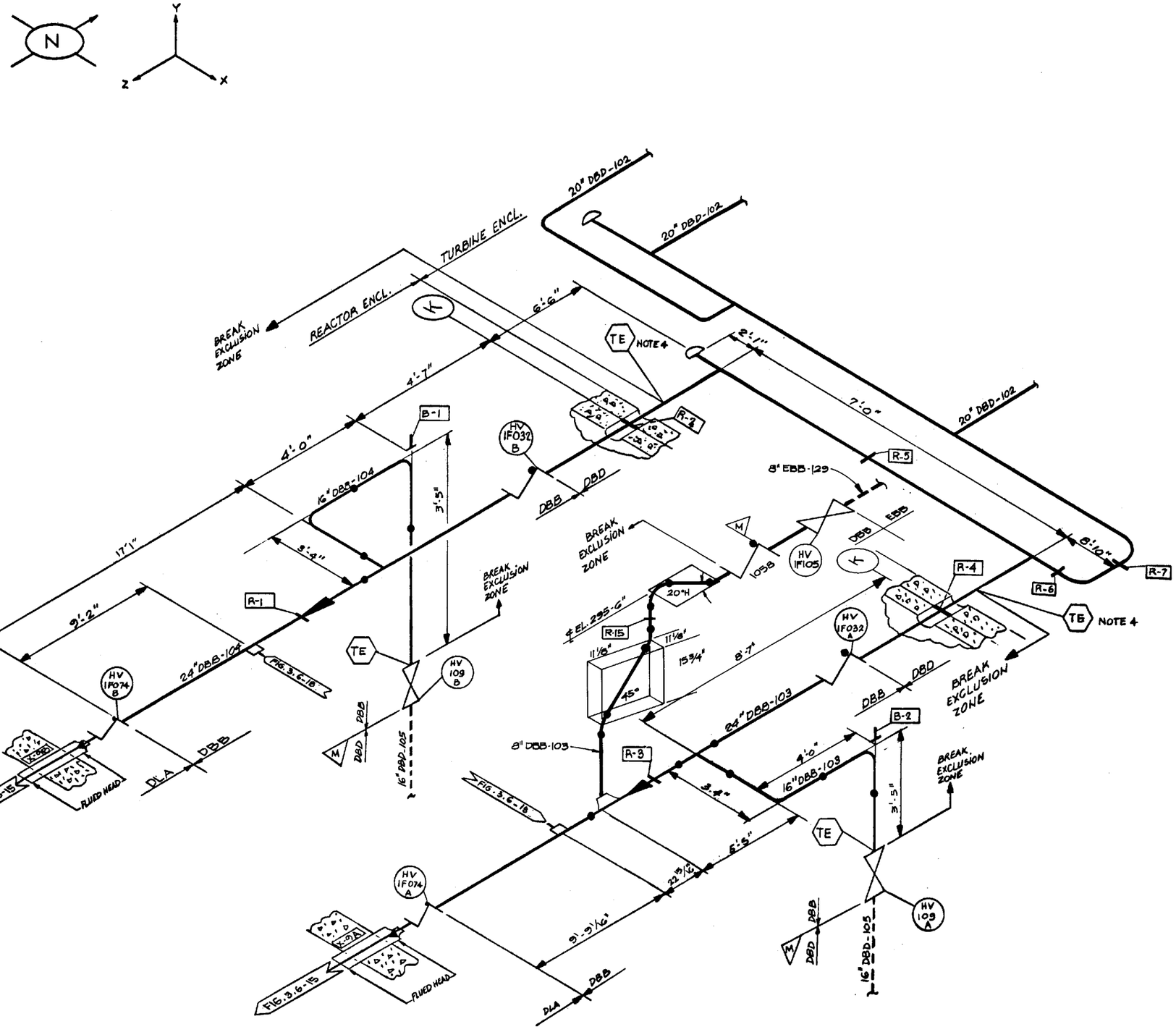
1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-8
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. (M) – PIPING UPSTREAM OF VALVE 1017 IS MODERATE-ENERGY.
5. FEEDWATER LOOP A IS SHOWN. THE BREAK LOCATIONS INDICATED ARE TYPICAL FOR LOOP B, WHICH IS ARRANGED SYMMETRICALLY (EXCEPT THAT LOOP B DOES NOT HAVE A CONNECTION TO 4" DBA-112).

   PR'S IN PARENTHESIS ARE MEANT FOR FEEDWATER LOOP B.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FEEDWATER PIPING ISOMETRIC (PORTION INSIDE PRIMARY CONTAINMENT) (UNIT 2) (SHEET 2 OF 2)

FIGURE 3.6-15



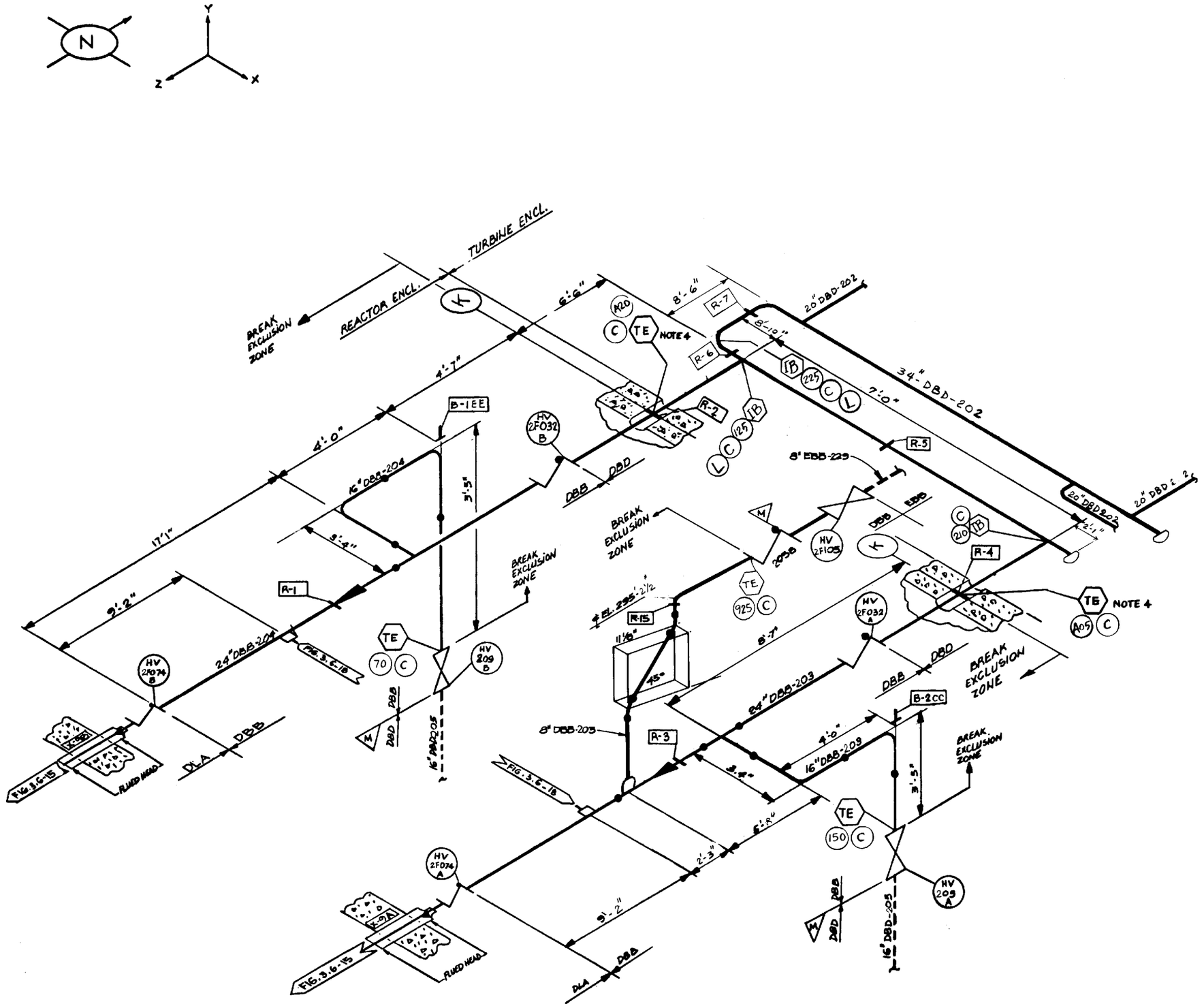
NOTES

1. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
2. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
3. (M) PIPING UPSTREAM OF CHECK VALVE 1058 AND DOWNSTREAM OF VALVES HV-109A AND 109B IS MODERATE-ENERGY
4. INTERMEDIATE BREAK LOCATIONS UPSTREAM OF THE INDICATED TERMINAL ENDS IN THE TURBINE ENCLOSURE ARE SELECTED AT LOCATIONS OF POTENTIAL HIGH STRESS IN ACCORDANCE WITH SECTION 3.6.2.1.1.4.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FEEDWATER PIPING ISOMETRIC
(PORTION OUTSIDE PRIMARY CONTAINMENT)
(UNIT 1 ONLY)
(SHEET 1 OF 2)

FIGURE 3.6-16



NOTES

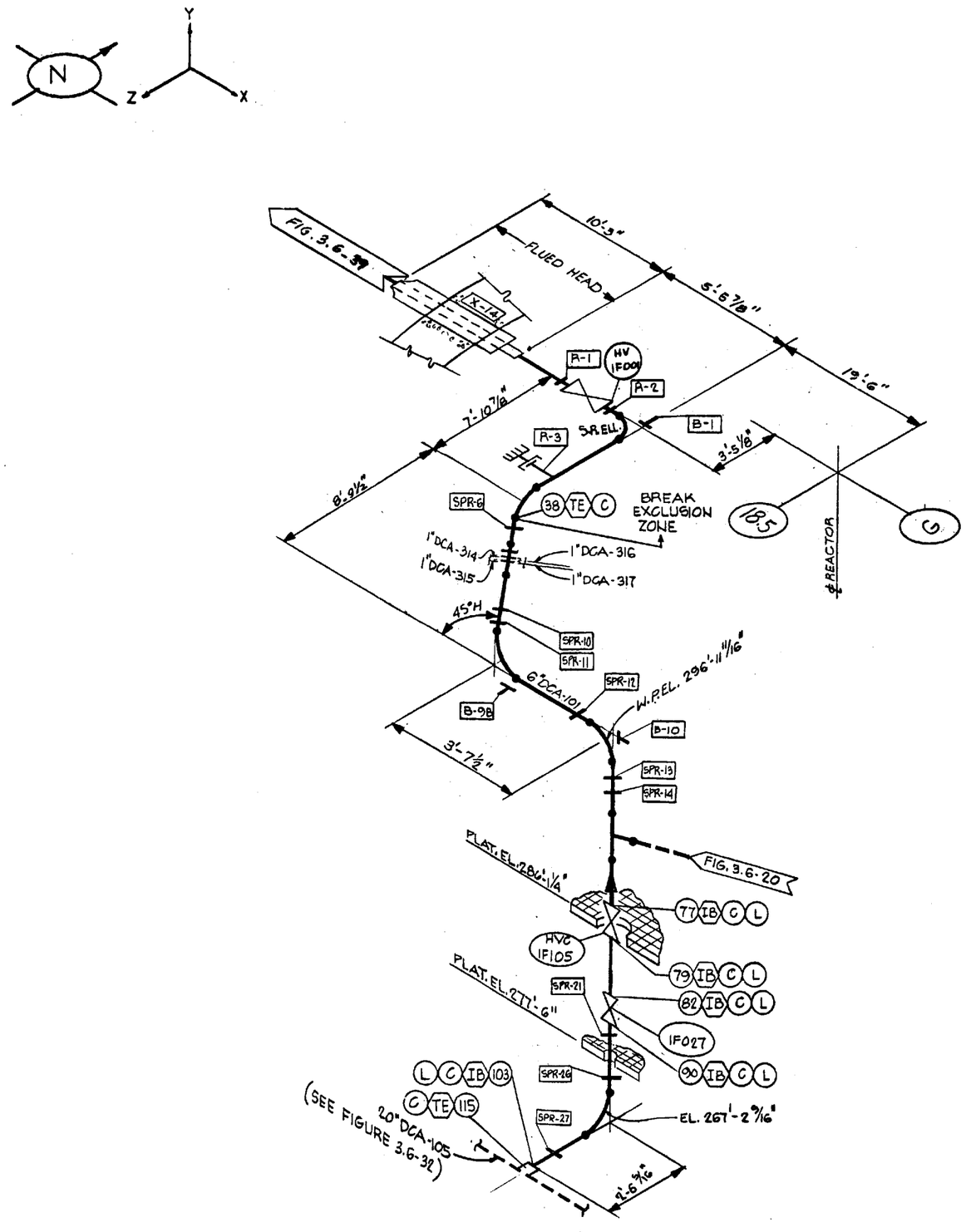
1. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - TE – TERMINAL END BREAK
   - IB – INTERMEDIATE BREAK
   - C – CIRCUMFERENTIAL BREAK
   - L – LONGITUDINAL BREAK
2. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
3. M – PIPING UPSTREAM OF CHECK VALVE 2058 AND DOWNSTREAM OF VALVES HV-209A AND 209B IS MODERATE-ENERGY
4. INTERMEDIATE BREAK LOCATIONS UPSTREAM OF THE INDICATED TERMINAL ENDS IN THE TURBINE ENCLOSURE ARE SELECTED AT LOCATIONS OF POTENTIAL HIGH STRESS IN ACCORDANCE WITH SECTION 3.6.2.1.1.4.

LIMERICK GENERATING STATION UNITS 1 AND 2

UPDATED FINAL SAFETY ANALYSIS REPORT

FEEDWATER PIPING ISOMETRIC (PORTION OUTSIDE PRIMARY CONTAINMENT) (UNIT 2) (SHEET 2 OF 2)

FIGURE 3.6-16



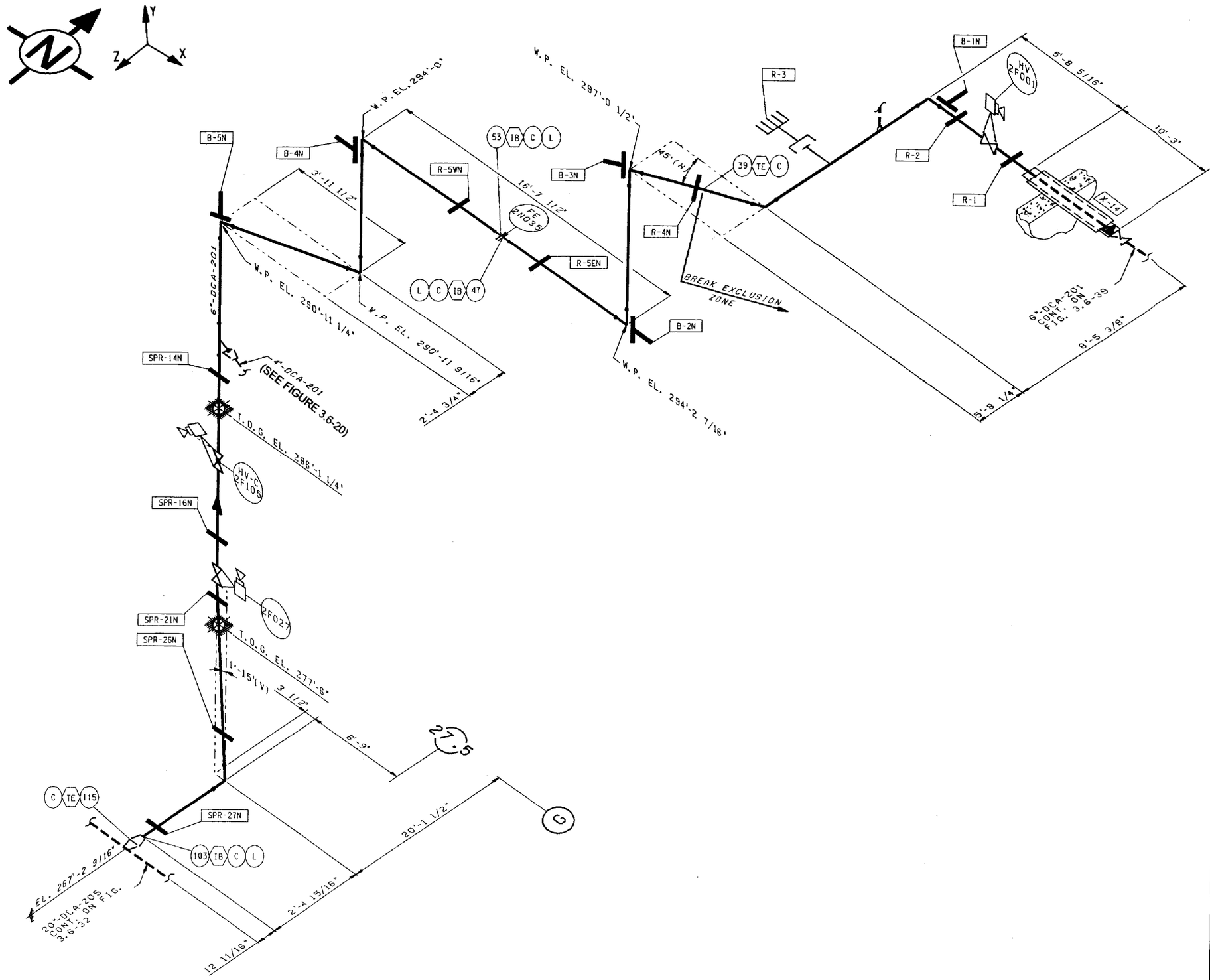
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-10.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - TE – TERMINAL END BREAK
   - IB – INTERMEDIATE BREAK
   - C – CIRCUMFERENTIAL BREAK
   - L – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
   - – COMPENSATING STRUT

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RWCU PUMP SUCTION PIPING ISOMETRIC (PORTION INSIDE PRIMARY CONTAINMENT) (UNIT 1 ONLY) (SHEET 1 OF 2)

FIGURE 3.6-17



NOTES:

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-10
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) - TERMINAL END BREAK
   - (IB) - INTERMEDIATE BREAK
   - (C) - CIRCUMFERENTIAL BREAK
   - (L) - LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - - PIPE WHIP RESTRAINT
   - - BUMPER-TYPE RESTRAINT
   - - ANCHOR
   - - COMPENSATING STRUT

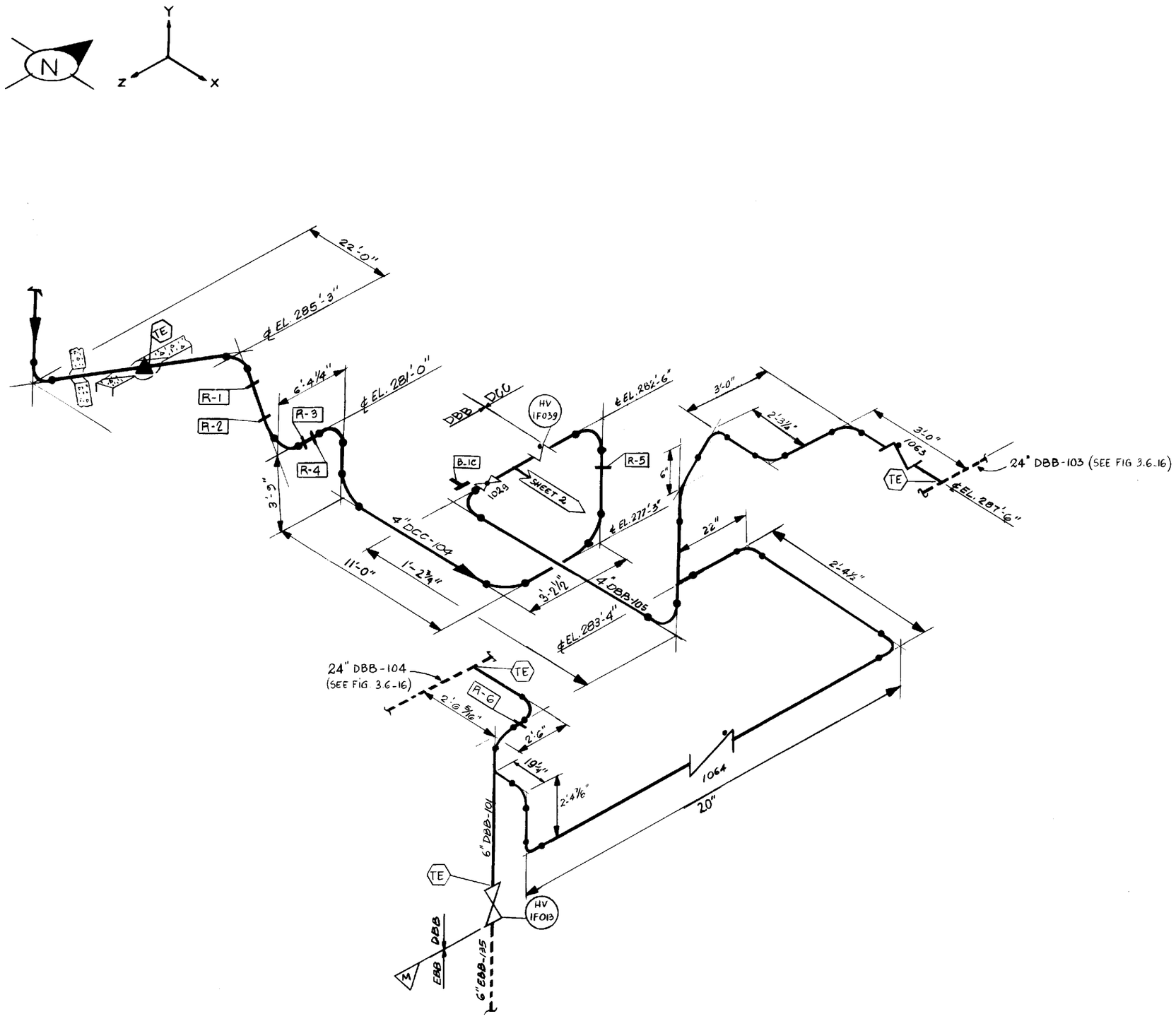
LIMERICK GENERATING STATION UNITS 1 AND 2

UPDATED FINAL SAFETY ANALYSIS REPORT

RWCU PUMP SUCTION PIPING ISOMETRIC (PORTION INSIDE PRIMARY CONTAINMENT) (UNIT 2)

(SHEET 2 OF 2)

FIGURE 3.6-17 Rev. 11 9/02



NOTES

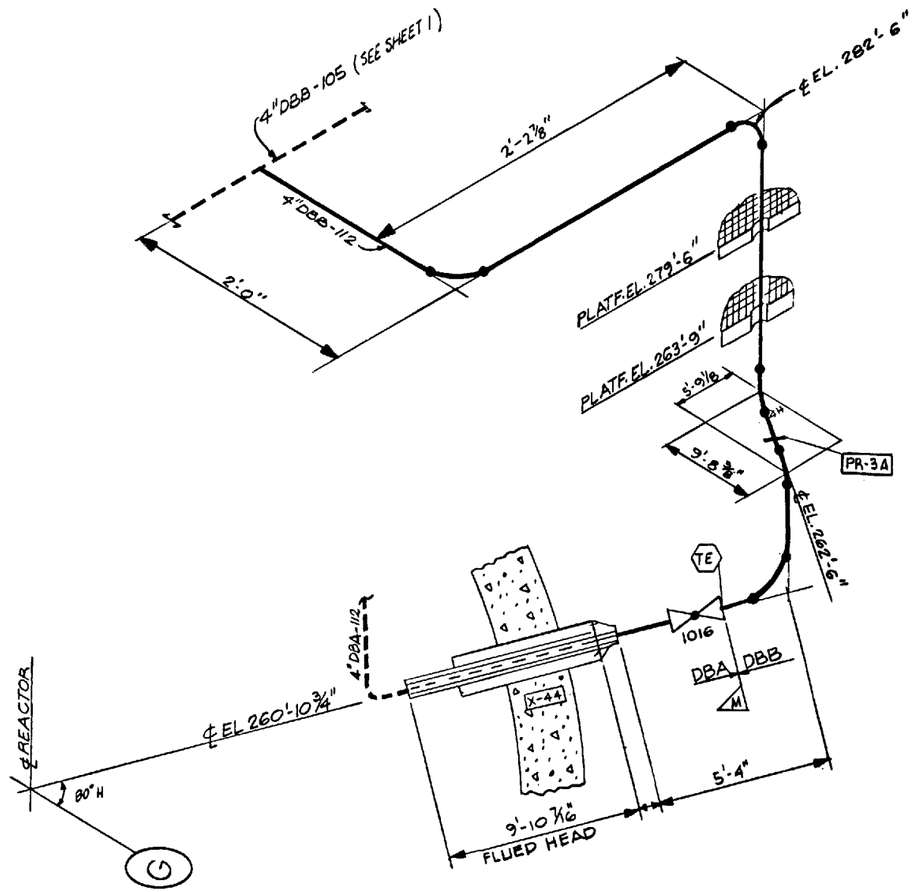
1. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
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   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
2. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
3. – PIPING UPSTREAM OF VALVE HV-1F013 IS MODERATE-ENERGY.
4. INTERMEDIATE BREAK LOCATIONS IN THE HIGH-ENERGY PIPING SHOWN ARE SELECTED AT LOCATIONS OF POTENTIAL HIGH STRESS IN ACCORDANCE WITH SECTION 3.6.2.1.1.4.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RWCU RETURN PIPING ISOMETRIC
(PORTION INSIDE MAIN STEAM TUNNEL)
(UNIT 1 ONLY)
(SHEET 1 OF 4)

FIGURE 3.6-18





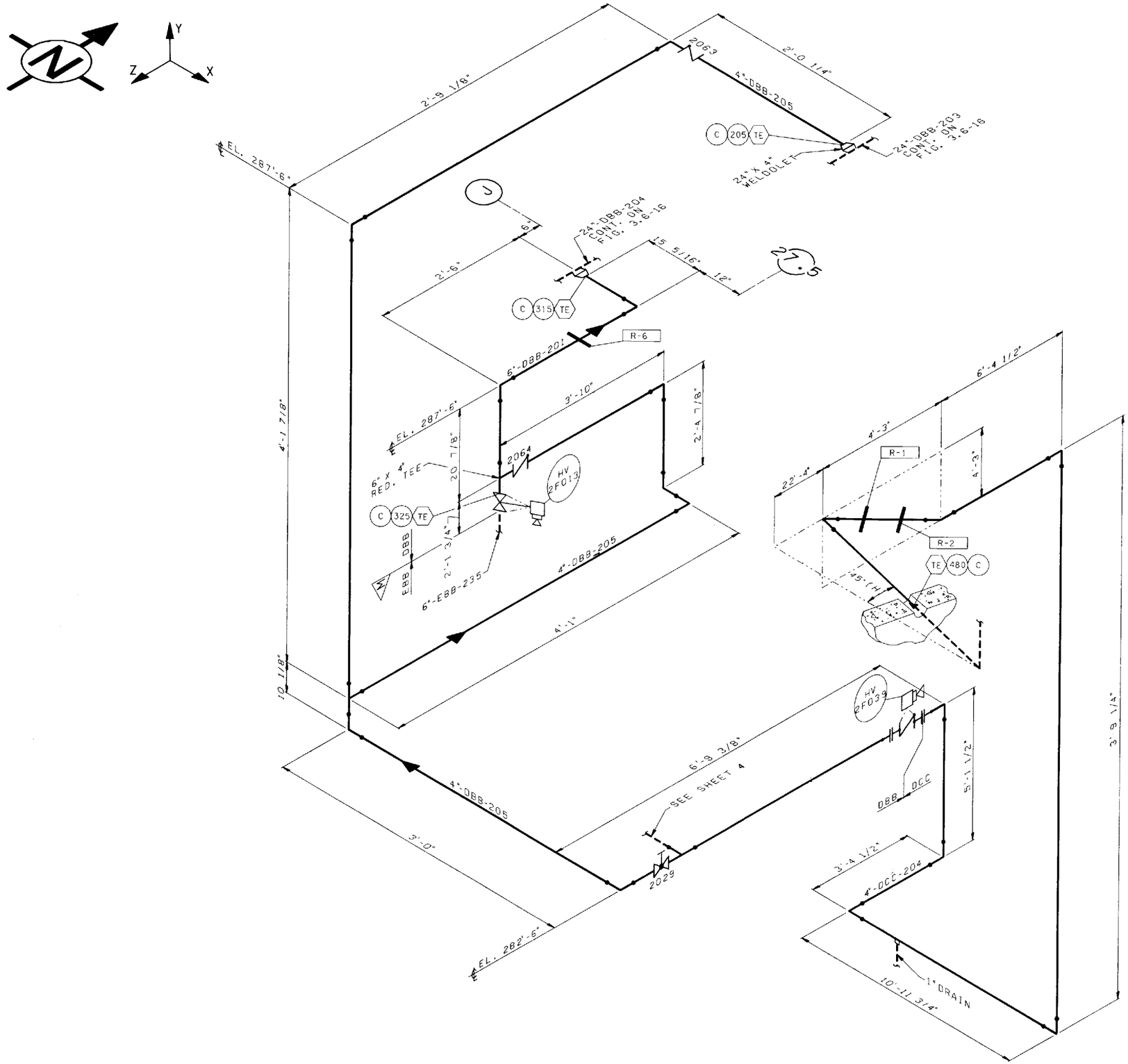
NOTES

1. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
2. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
3. – PIPING INBOARD OF VALVE 1016 IS MODERATE-ENERGY.
4. INTERMEDIATE BREAK LOCATIONS IN THE HIGH-ENERGY PIPING SHOWN ARE SELECTED AT LOCATIONS OF POTENTIAL HIGH STRESS IN ACCORDANCE WITH SECTION 3.6.2.1.1.4.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RWCU RETURN PIPING ISOMETRIC
(PORTION INSIDE MAIN STEAM TUNNEL)
(UNIT 1 ONLY)
(SHEET 2 OF 4)

FIGURE 3.6-18



NOTES:

1. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:

   (TE) - TERMINAL END BREAK

   (IB) - INTERMEDIATE BREAK

   (C) - CIRCUMFERENTIAL BREAK

   (L) - LONGITUDINAL BREAK

2. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:

   - PIPE WHIP RESTRAINT

   - BUMPER-TYPE RESTRAINT

   - ANCHOR

   - COMPENSATING STRUT

3. (M) - PIPING UPSTREAM OF VALVE HV-2F013 IS MODERATE ENERGY.

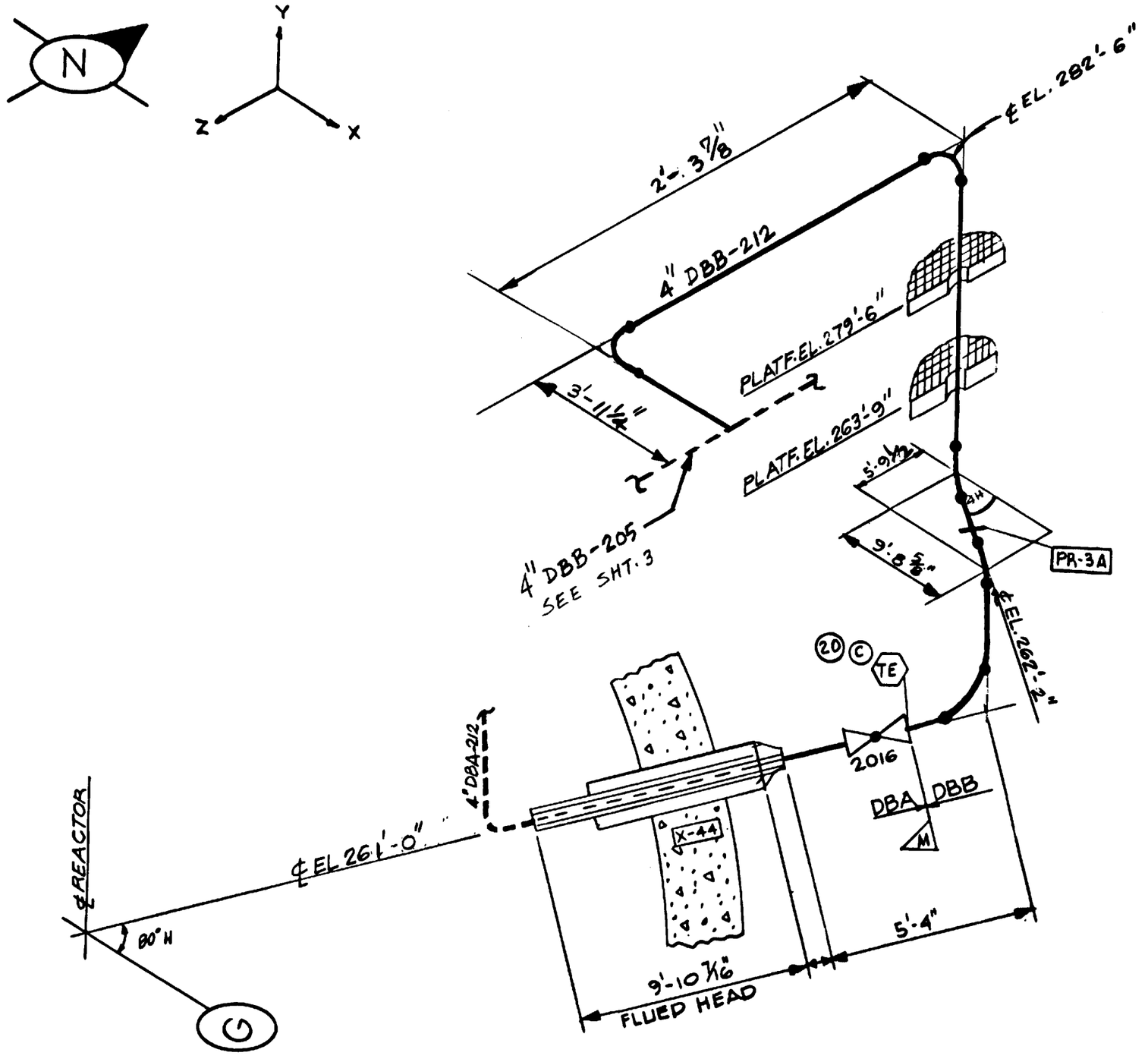
4. INTERMEDIATE BREAK LOCATIONS IN THE HIGH-ENERGY PIPING SHOWN ARE SELECTED AT LOCATIONS OF POTENTIAL HIGH STRESS IN ACCORDANCE WITH SECTION 3.6.2.1.1.4.

LIMERICK GENERATING STATION
UNITS 1 AND 2

UPDATED FINAL SAFETY ANALYSIS REPORT

RWCU RETURN PIPING ISOMETRIC (PORTION INSIDE MAIN STEAM TUNNEL) (UNIT 2)
(SHEET 3 OF 4)

FIGURE 3.6-18



NOTES

1. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:

   TE – TERMINAL END BREAK

   IB – INTERMEDIATE BREAK

   C – CIRCUMFERENTIAL BREAK

   L – LONGITUDINAL BREAK

2. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:

   – PIPE WHIP RESTRAINT

   – BUMPER-TYPE RESTRAINT

   – ANCHOR

3. M – PIPING INBOARD OF VALVE 2016 IS MODERATE-ENERGY.

4. INTERMEDIATE BREAK LOCATIONS IN THE HIGH-ENERGY PIPING SHOWN ARE SELECTED AT LOCATIONS OF POTENTIAL HIGH STRESS IN ACCORDANCE WITH SECTION 3.6.2.1.1.4.

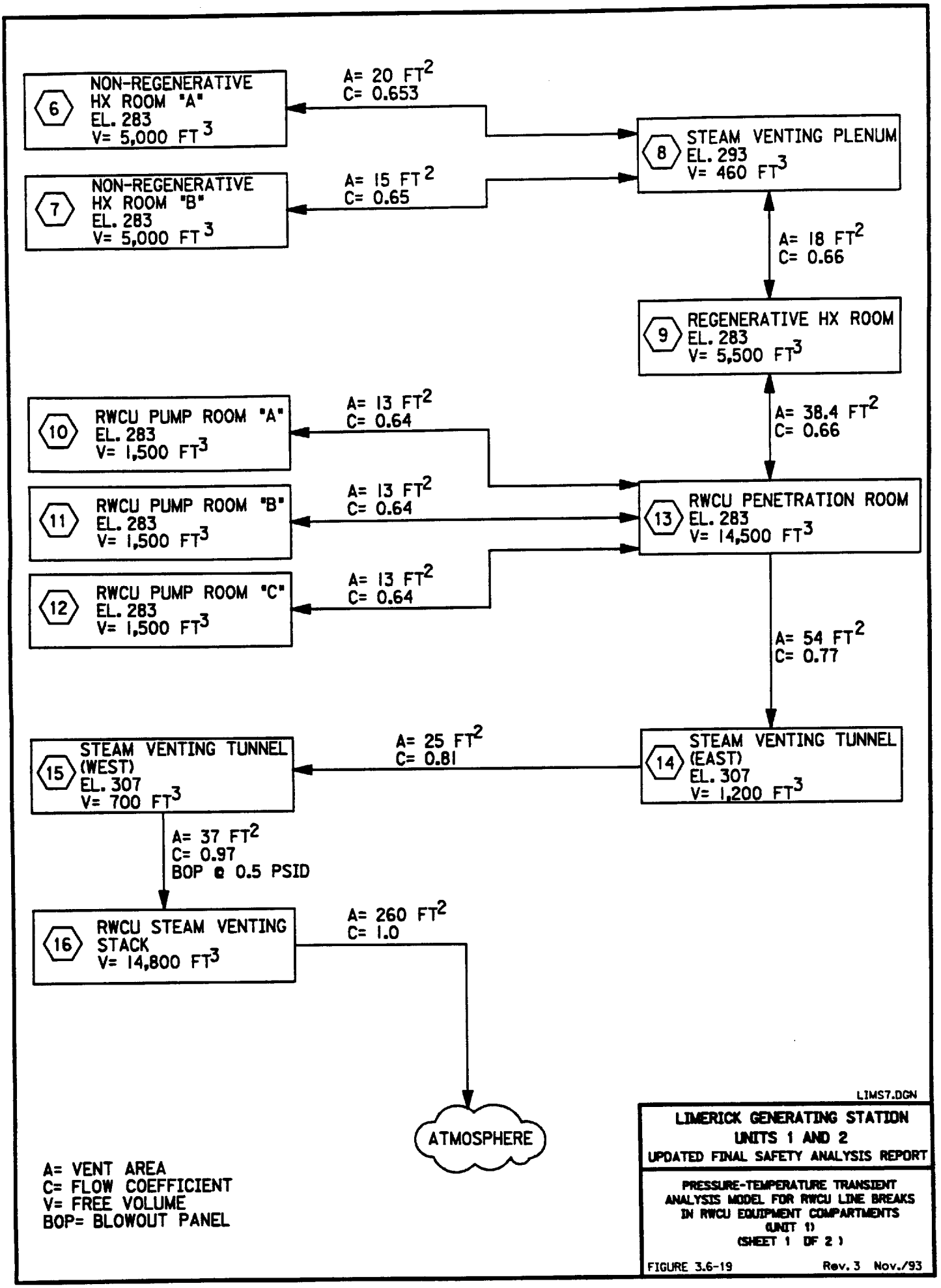
LIMERICK GENERATING STATION
UNITS 1 AND 2

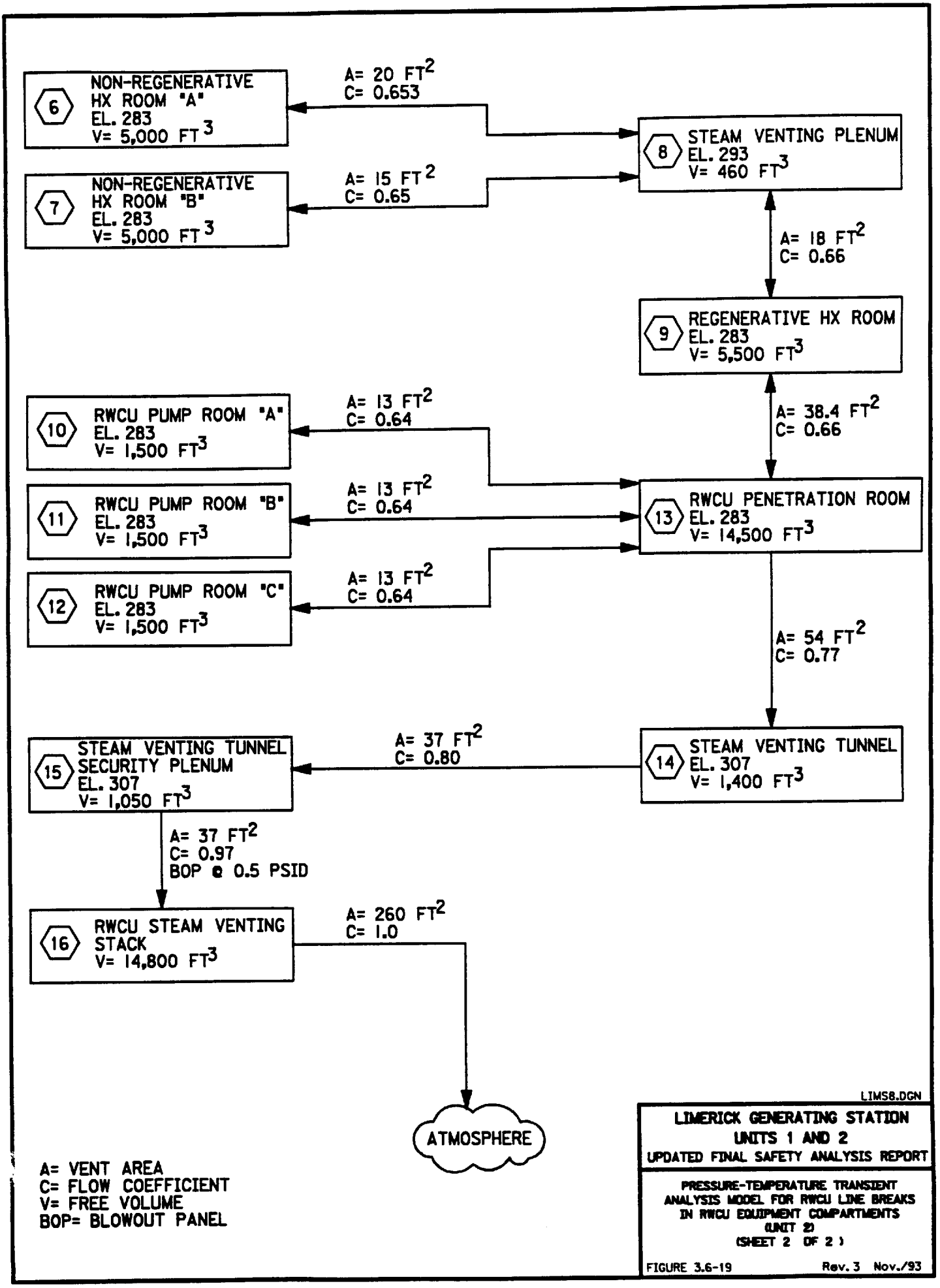
UPDATED FINAL SAFETY ANALYSIS REPORT

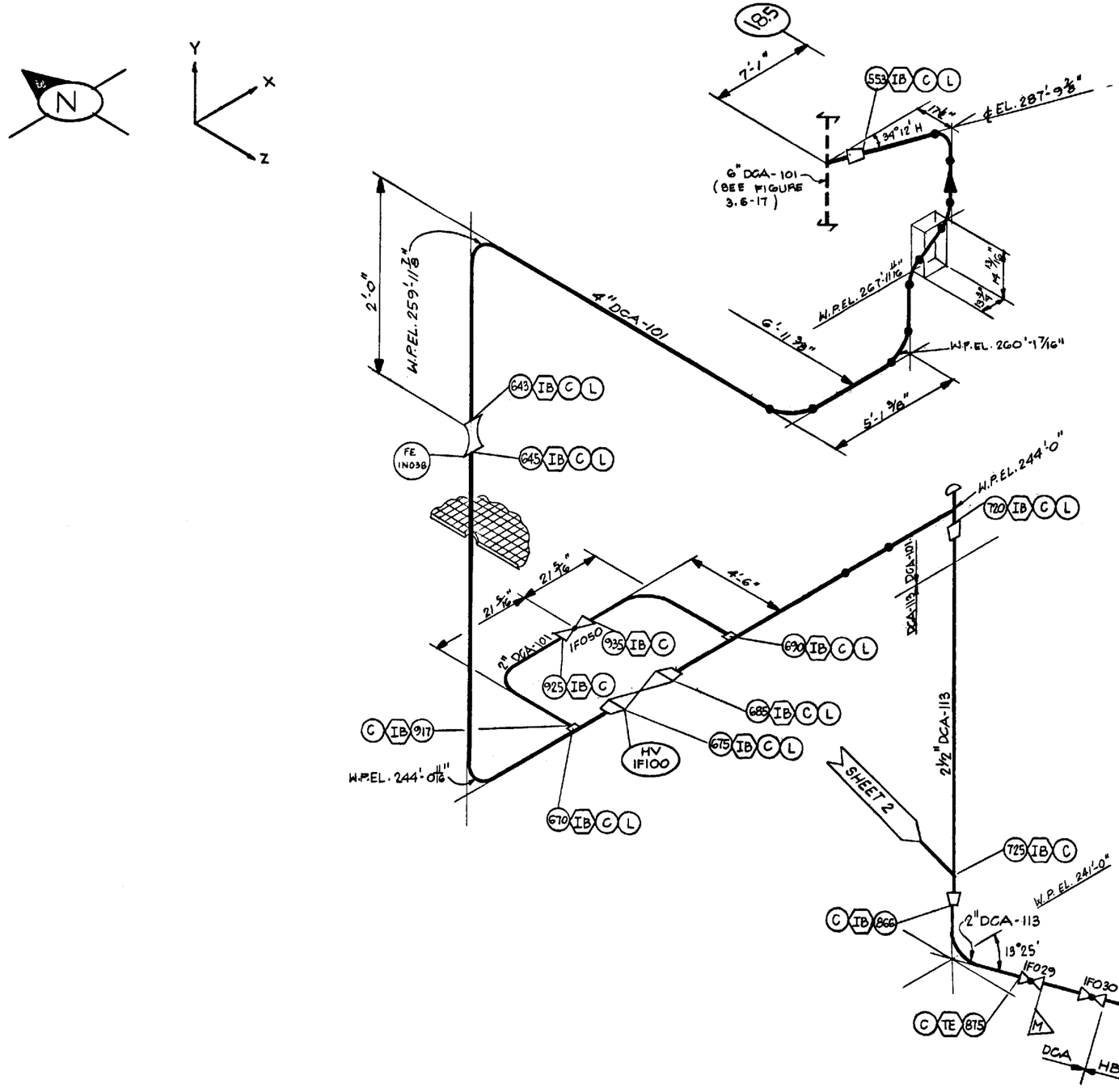
RWCU RETURN PIPING ISOMETRIC
(PORTION INSIDE MAIN STEAM TUNNEL)
(UNIT 2)

(SHEET 4 OF 4)

FIGURE 3.6-18


6
NON-REGENERATIVE HX ROOM "A"
EL. 283
V= 5,000 FT3
A= 20 FT2
C= 0.653
7
NON-REGENERATIVE HX ROOM "B"
EL. 283
V= 5,000 FT3
A= 15 FT2
C= 0.65
8
STEAM VENTING PLENUM
EL. 293
V= 460 FT3
A= 18 FT2
C= 0.66
9
REGENERATIVE HX ROOM
EL. 283
V= 5,500 FT3
A= 38.4 FT2
C= 0.66
10
RWCU PUMP ROOM "A"
EL. 283
V= 1,500 FT3
A= 13 FT2
C= 0.64
11
RWCU PUMP ROOM "B"
EL. 283
V= 1,500 FT3
A= 13 FT2
C= 0.64
12
RWCU PUMP ROOM "C"
EL. 283
V= 1,500 FT3
A= 13 FT2
C= 0.64
13
RWCU PENETRATION ROOM
EL. 283
V= 14,500 FT3
A= 54 FT2
C= 0.77
14
STEAM VENTING TUNNEL (EAST)
EL. 307
V= 1,200 FT3
A= 25 FT2
C= 0.81
15
STEAM VENTING TUNNEL (WEST)
EL. 307
V= 700 FT3
A= 37 FT2
C= 0.97
BOP @ 0.5 PSID
16
RWCU STEAM VENTING STACK
V= 14,800 FT3
A= 260 FT2
C= 1.0
ATMOSPHERE
A= VENT AREA
C= FLOW COEFFICIENT
V= FREE VOLUME
BOP= BLOWOUT PANEL
LIMS7.DGN
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT
PRESSURE-TEMPERATURE TRANSIENT ANALYSIS MODEL FOR RWCU LINE BREAKS IN RWCU EQUIPMENT COMPARTMENTS
(UNIT 1)
(SHEET 1 OF 2)
FIGURE 3.6-19
Rev. 3 Nov./93


6
NON-REGENERATIVE HX ROOM "A"
EL. 283
V= 5,000 FT3
A= 20 FT2
C= 0.653
7
NON-REGENERATIVE HX ROOM "B"
EL. 283
V= 5,000 FT3
A= 15 FT2
C= 0.65
8
STEAM VENTING PLENUM
EL. 293
V= 460 FT3
A= 18 FT2
C= 0.66
9
REGENERATIVE HX ROOM
EL. 283
V= 5,500 FT3
A= 38.4 FT2
C= 0.66
10
RWCU PUMP ROOM "A"
EL. 283
V= 1,500 FT3
A= 13 FT2
C= 0.64
11
RWCU PUMP ROOM "B"
EL. 283
V= 1,500 FT3
A= 13 FT2
C= 0.64
12
RWCU PUMP ROOM "C"
EL. 283
V= 1,500 FT3
A= 13 FT2
C= 0.64
13
RWCU PENETRATION ROOM
EL. 283
V= 14,500 FT3
A= 54 FT2
C= 0.77
14
STEAM VENTING TUNNEL
EL. 307
V= 1,400 FT3
A= 37 FT2
C= 0.80
15
STEAM VENTING TUNNEL SECURITY PLENUM
EL. 307
V= 1,050 FT3
A= 37 FT2
C= 0.97
BOP @ 0.5 PSID
16
RWCU STEAM VENTING STACK
V= 14,800 FT3
A= 260 FT2
C= 1.0
ATMOSPHERE
A= VENT AREA
C= FLOW COEFFICIENT
V= FREE VOLUME
BOP= BLOWOUT PANEL
LIMS8.DGN
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT
PRESSURE-TEMPERATURE TRANSIENT ANALYSIS MODEL FOR RWCU LINE BREAKS IN RWCU EQUIPMENT COMPARTMENTS
(UNIT 2)
(SHEET 2 OF 2)
FIGURE 3.6-19
Rev. 3 Nov./93



NOTES

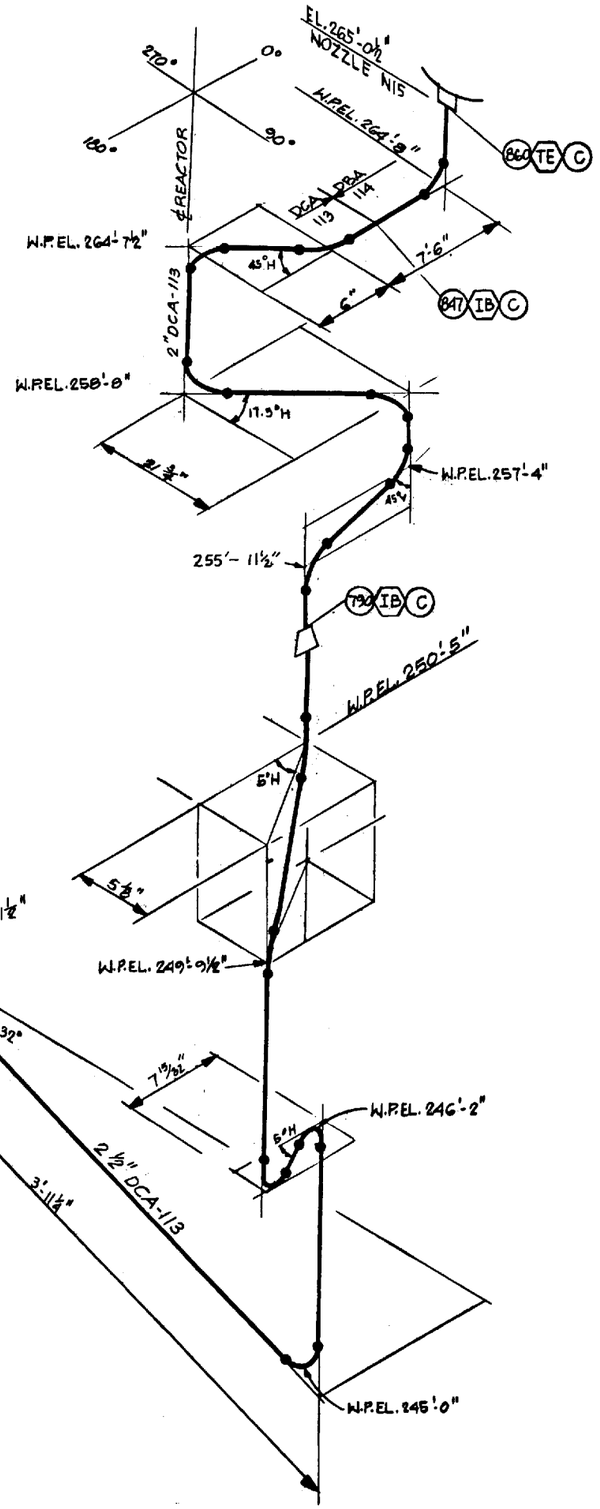
1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-12.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - TE – TERMINAL END BREAK
   - IB – INTERMEDIATE BREAK
   - C – CIRCUMFERENTIAL BREAK
   - L – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - ▲ – ANCHOR
4. M – PIPING DOWNSTREAM OF VALVE 1F029 IS MODERATE-ENERGY.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL DRAIN
PIPING ISOMETRIC
(UNIT 1 ONLY)
(SHEET 1 OF 4)

FIGURE 3.6-20





NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-12.

2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:

   - TE – TERMINAL END BREAK
   - IB – INTERMEDIATE BREAK
   - C – CIRCUMFERENTIAL BREAK
   - L – LONGITUDINAL BREAK

3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:

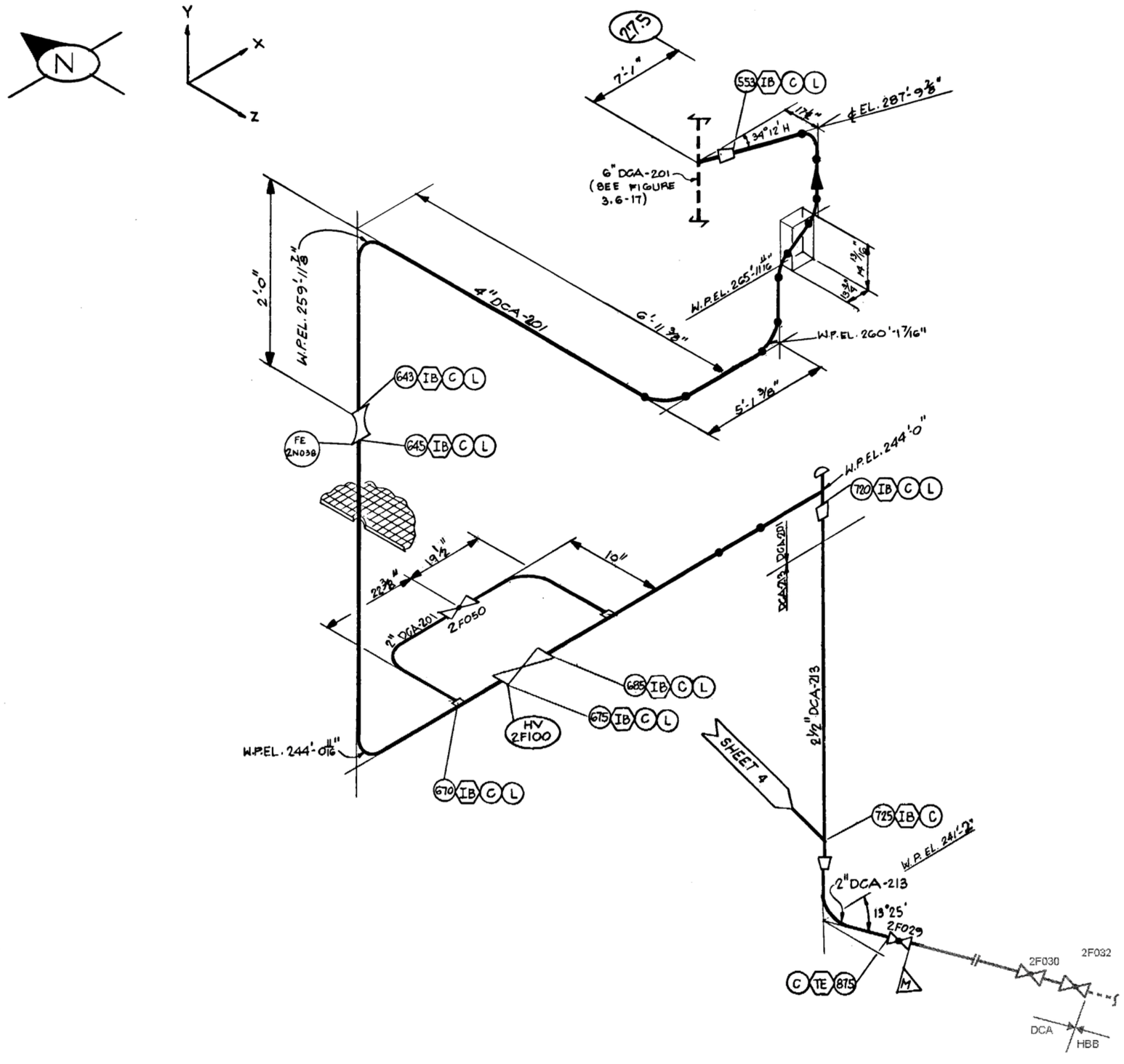
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR

LIMERICK GENERATING STATION
UNITS 1 AND 2

UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL DRAIN PIPING ISOMETRIC (UNIT 1 ONLY) (SHEET 2 OF 4)

FIGURE 3.6-20



NOTES

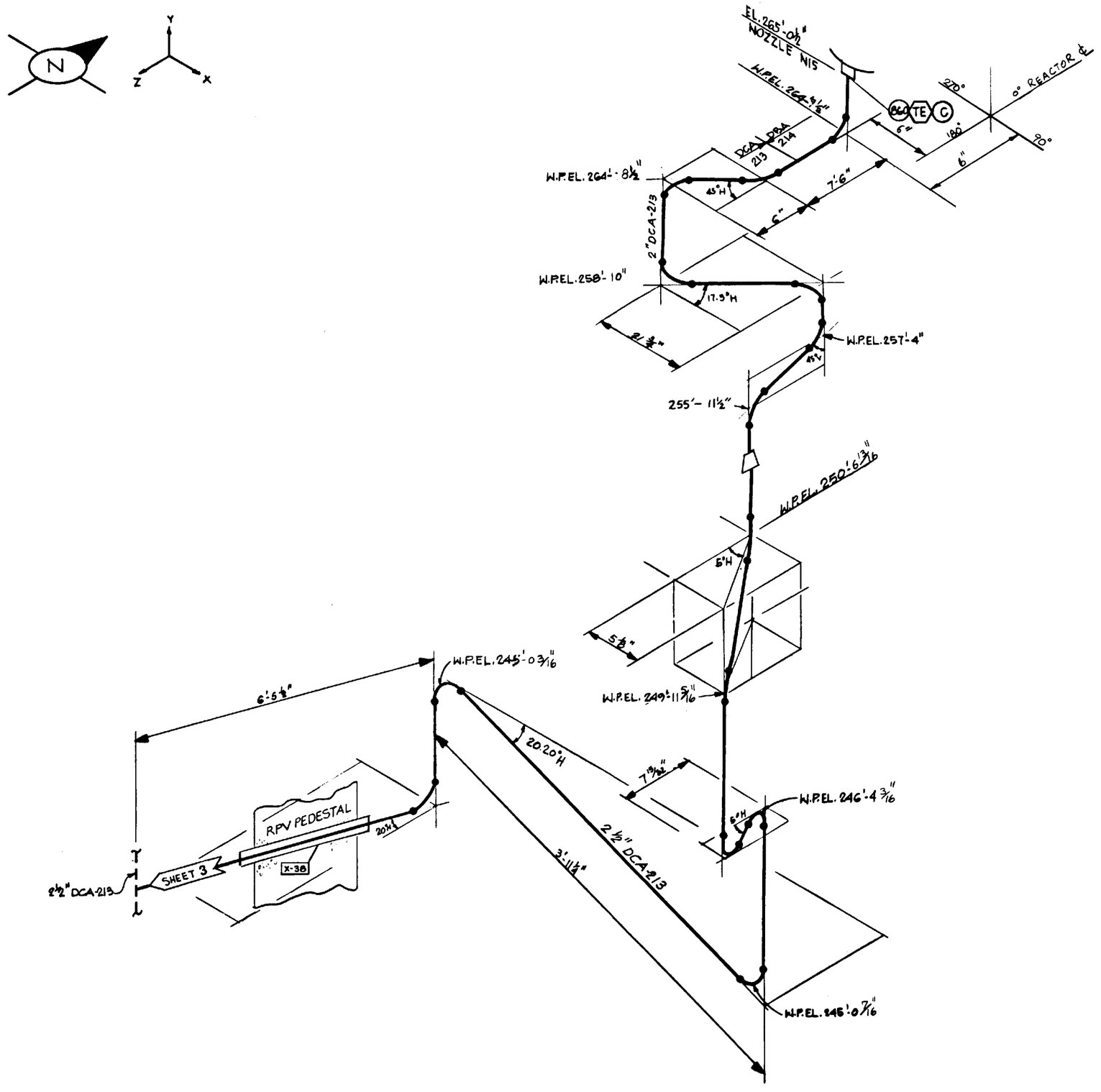
1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-12.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. (M) – PIPING DOWNSTREAM OF VALVE 2F029 IS MODERATE-ENERGY.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL DRAIN
PIPING ISOMETRIC
(UNIT 2)
(SHEET 3 OF 4)

FIGURE 3.6-20

Rev. 14, 09/08



NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-12

2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:

   TE – TERMINAL END BREAK

   IB – INTERMEDIATE BREAK

   C – CIRCUMFERENTIAL BREAK

   L – LONGITUDINAL BREAK

3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:

   – PIPE WHIP RESTRAINT

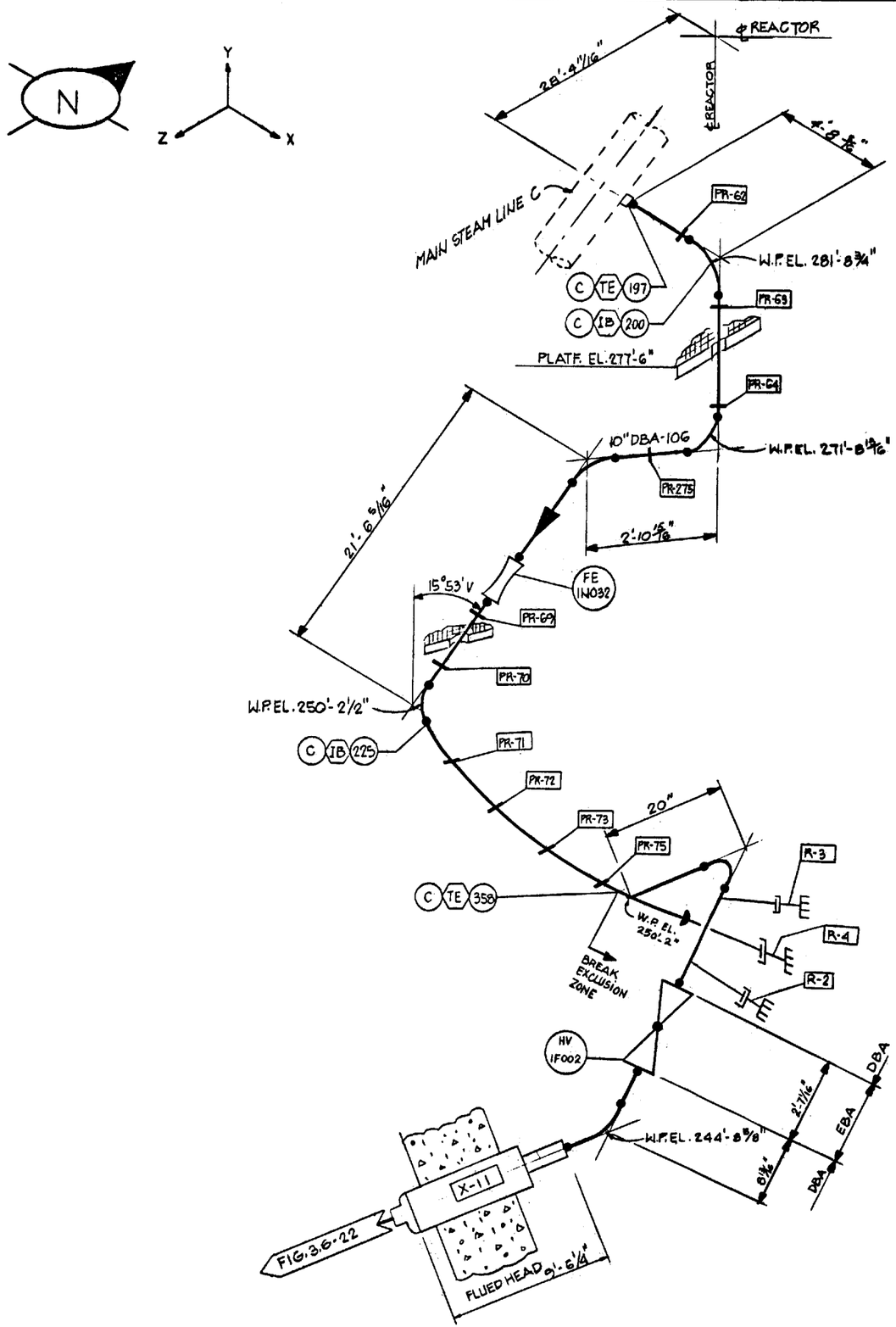
   – BUMPER-TYPE RESTRAINT

   – ANCHOR

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL DRAIN PIPING ISOMETRIC (UNIT 2)
(SHEET 4 OF 4)

FIGURE 3.6-20



NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-13.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:

   TE – TERMINAL END BREAK

   IB – INTERMEDIATE BREAK

   C – CIRCUMFERENTIAL BREAK

   L – LONGITUDINAL BREAK

3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:

   – PIPE WHIP RESTRAINT

   BUMPER-TYPE RESTRAINT

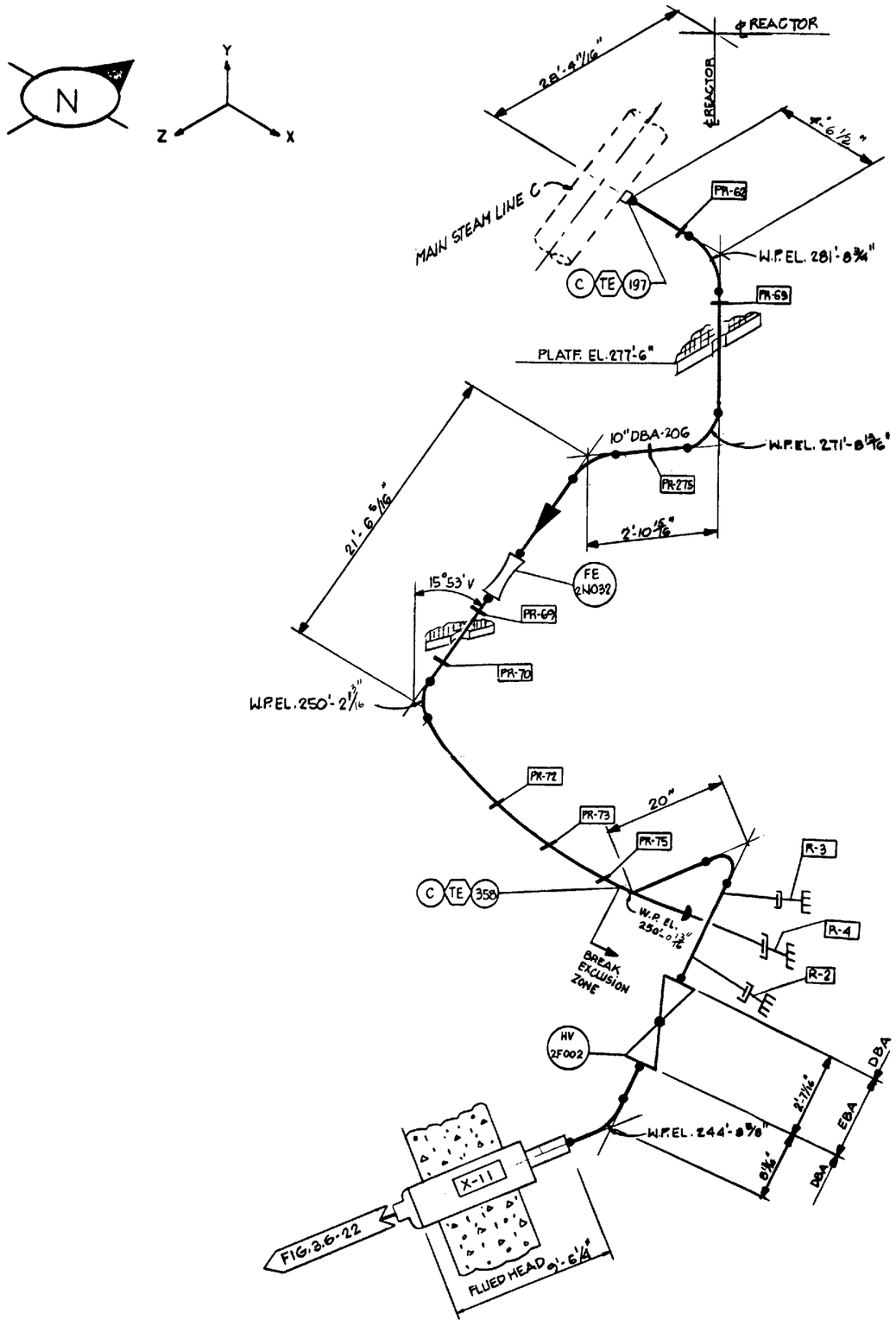
   ANCHOR

   COMPENSATING STRUT

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

HPCI STEAM SUPPLY PIPING ISOMETRIC (PORTION INSIDE PRIMARY CONTAINMENT) (UNIT 1 ONLY)
(SHEET 1 OF 2)

FIGURE 3.6-21



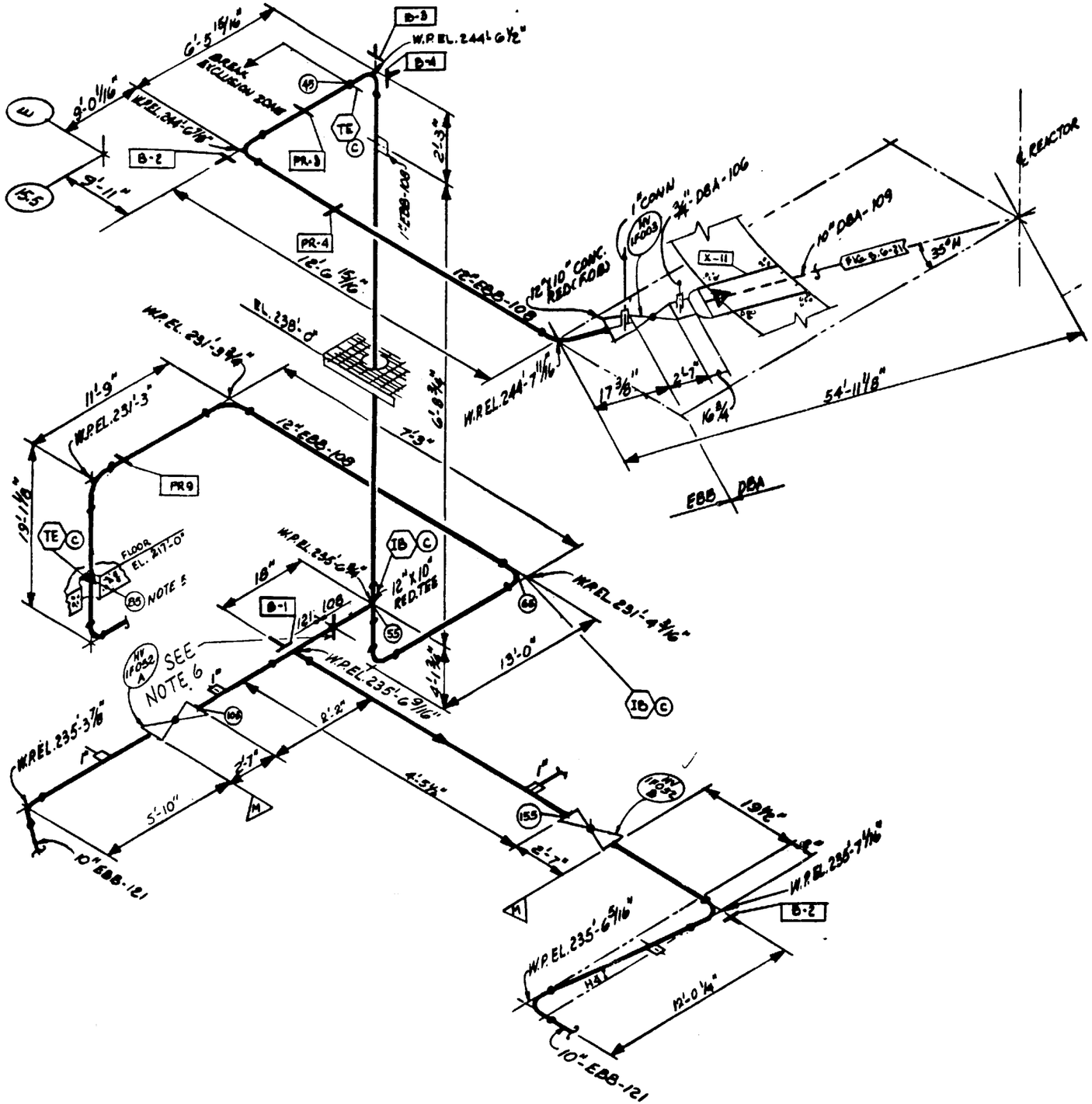
NOTES

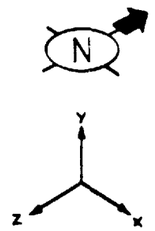
1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-13.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
   - – COMPENSATING STRUT

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

HPCI STEAM SUPPLY PIPING ISOMETRIC (PORTION INSIDE PRIMARY CONTAINMENT) (UNIT 2)
(SHEET 2 OF 2)

FIGURE 3.6-21





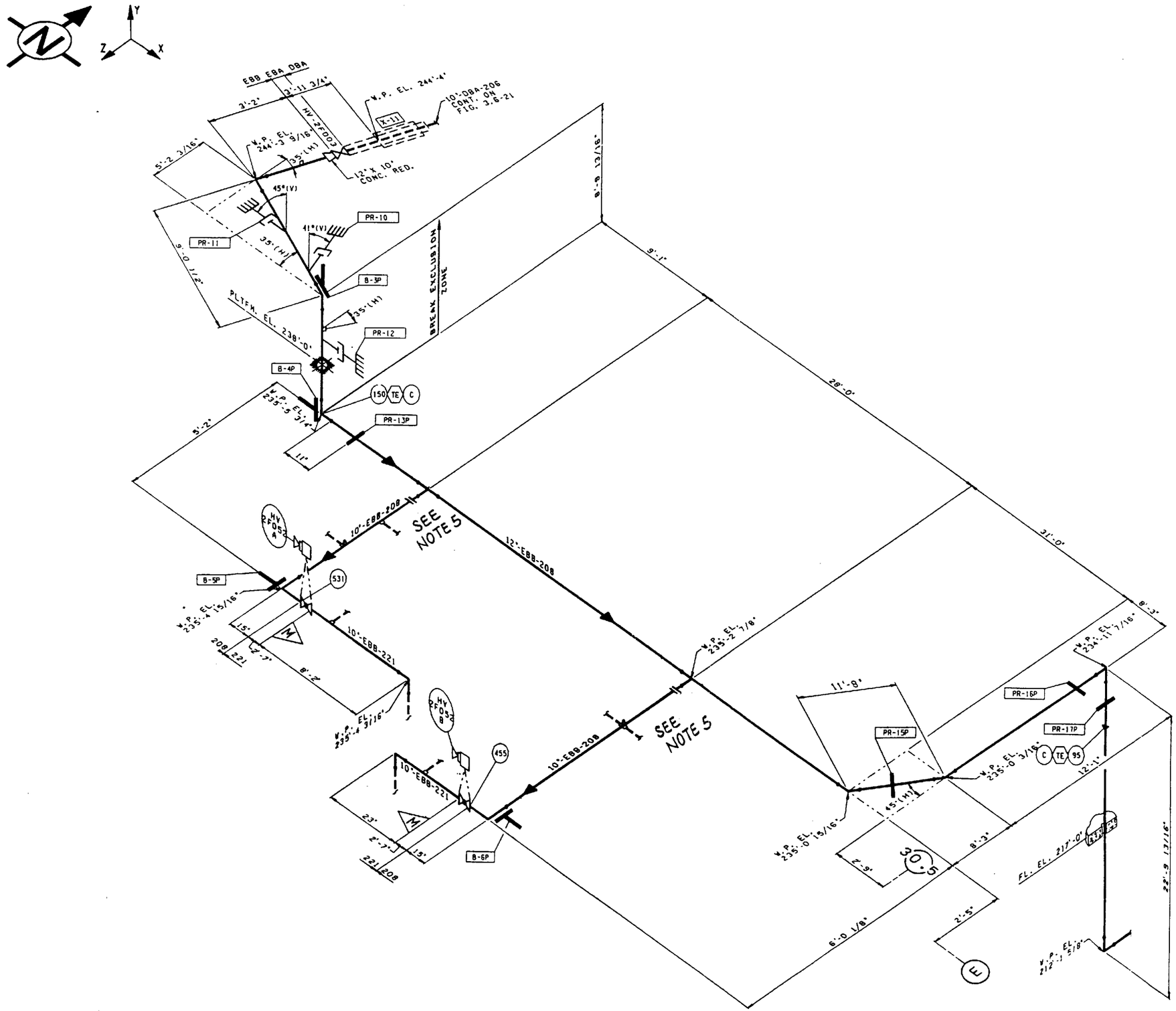
NOTES:

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-14.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - ▲ – ANCHOR
4. (M) – PIPING DOWNSTREAM OF VALVES HV–1F052A AND HV–1F052B IS MODERATE-ENERGY.
5. INTERMEDIATE BREAK LOCATIONS DOWNSTREAM OF NODE POINT 85 ARE SELECTED AT LOCATIONS OF POTENTIAL HIGH STRESS IN ACCORDANCE WITH SECTION 3.6.2.1.1.4.
6. FLOW TO RHR ISOLATED BY BLANK PLATE.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

HPCI STEAM SUPPLY PIPING ISOMETRIC
(PORTION OUTSIDE PRIMARY CONTAINMENT)
(UNIT 1 ONLY)
(SHEET 1 OF 2)

FIGURE 3.6-22 Rev. 6,12/96



NOTES:

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-14.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) - TERMINAL END BREAK
   - (IB) - INTERMEDIATE BREAK
   - (C) - CIRCUMFERENTIAL BREAK
   - (L) - LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - - PIPE WHIP RESTRAINT
   - - BUMPER-TYPE RESTRAINT
   - - ANCHOR
   - - COMPENSATING STRUT
4. (M) - PIPING DOWNSTREAM OF THE VALVES HV-2F052A AND HV-2F052B IS MODERATE-ENERGY.
5. BRANCH PIPE IS AN INTEGRAL ATTACHMENT TO 12" EBB-208 FOR STRUCTURAL COUPLING AND DOES NOT CARRY ANY FLOW.

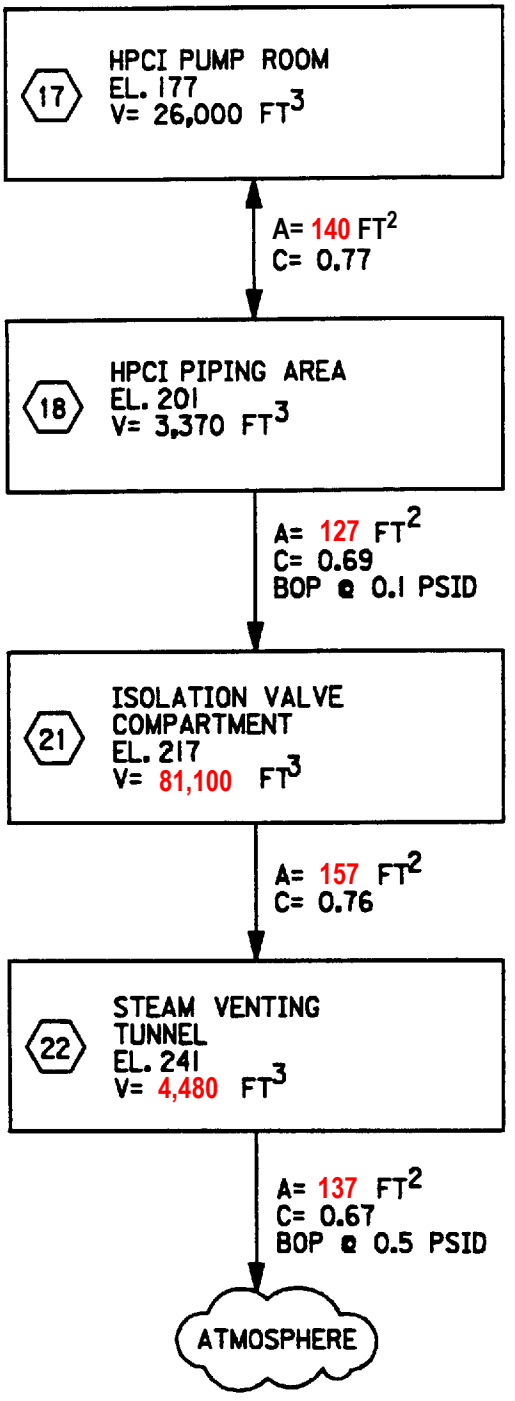
LIMERICK GENERATING STATION
UNITS 1 AND 2

UPDATED FINAL SAFETY ANALYSIS REPORT

HPCI STEAM SUPPLY PIPING ISOMETRIC (PORTION OUTSIDE PRIMARY CONTAINMENT)
(UNIT 2)
(SHEET 2 OF 2)

FIGURE 3.6-22

Rev. 6,12/96



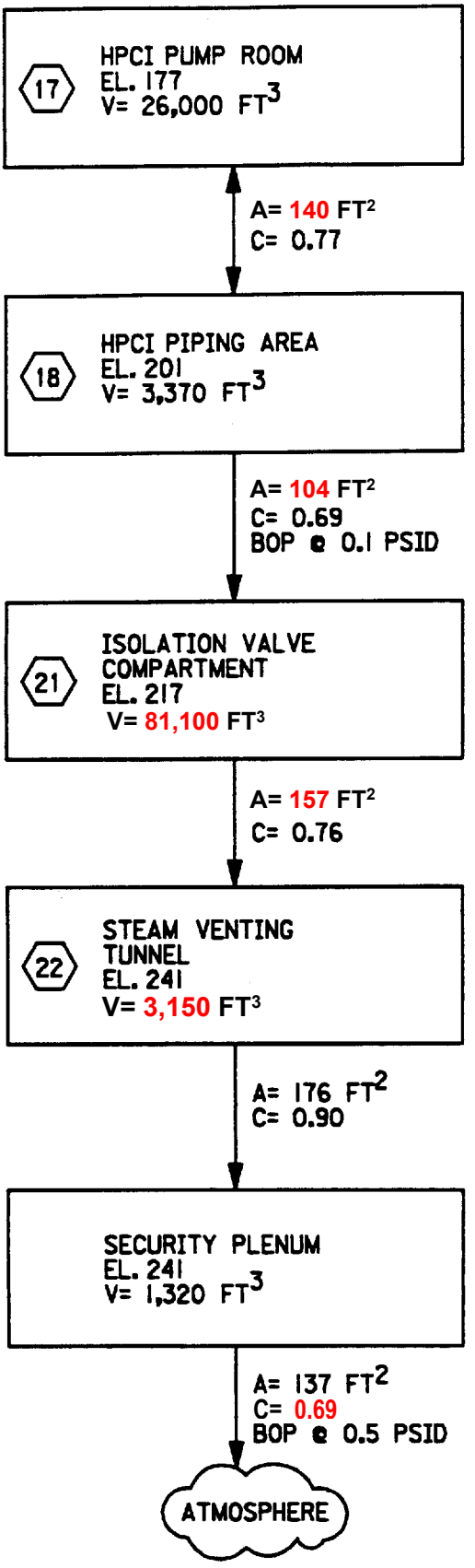
A= VENT AREA
C= FLOW COEFFICIENT
V= FREE VOLUME
BOP= BLOWOUT PANEL

LIMS1.DGN

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE-TEMPERATURE TRANSIENT ANALYSIS MODEL FOR HPCI STEAM SUPPLY LINE BREAK IN HPCI COMPARTMENT (UNIT 1) (SHEET 1 OF 2)

FIGURE 3.6-23 Rev. 18 Sept./16



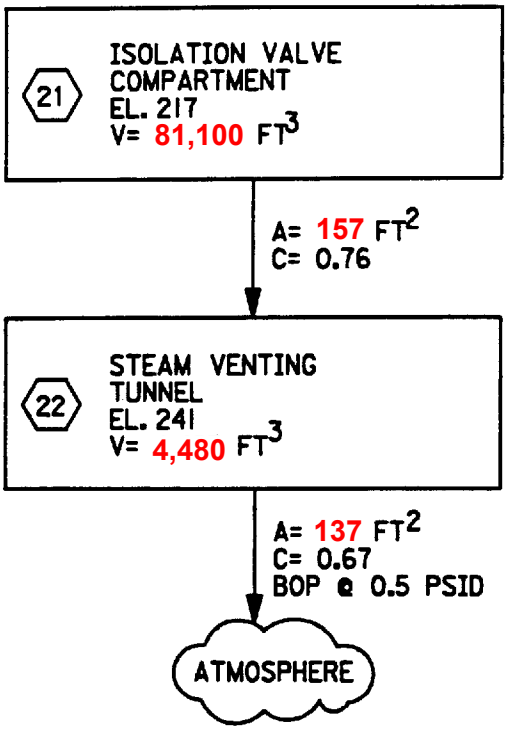
A= VENT AREA
C= FLOW COEFFICIENT
V= FREE VOLUME
BOP= BLOWOUT PANEL

LIMS2.DGN

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE-TEMPERATURE TRANSIENT ANALYSIS MODEL FOR HPCI STEAM SUPPLY LINE BREAK IN HPCI COMPARTMENT (UNIT 2) (SHEET 2 OF 2)

FIGURE 3.6-23 Rev. 18 Sept./16



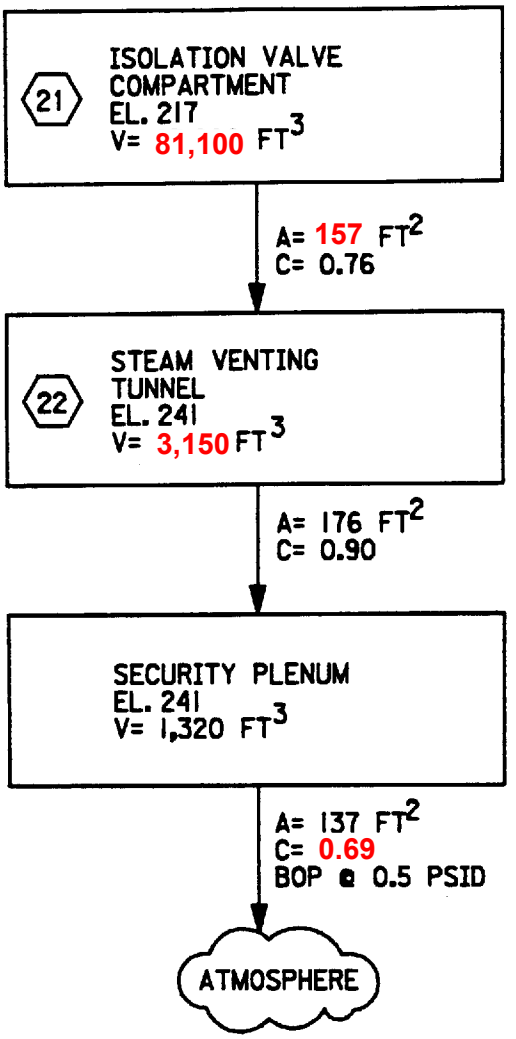
A= VENT AREA
C= FLOW COEFFICIENT
V= FREE VOLUME
BOP= BLOWOUT PANEL

LIMS3.DGN

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE-TEMPERATURE TRANSIENT ANALYSIS MODEL FOR HPCI STEAM SUPPLY LINE BREAK IN ISOLATION VALVE COMPARTMENT (UNIT 1) (SHEET 1 OF 2)

FIGURE 3.6-24 Rev. 18 Sept./16



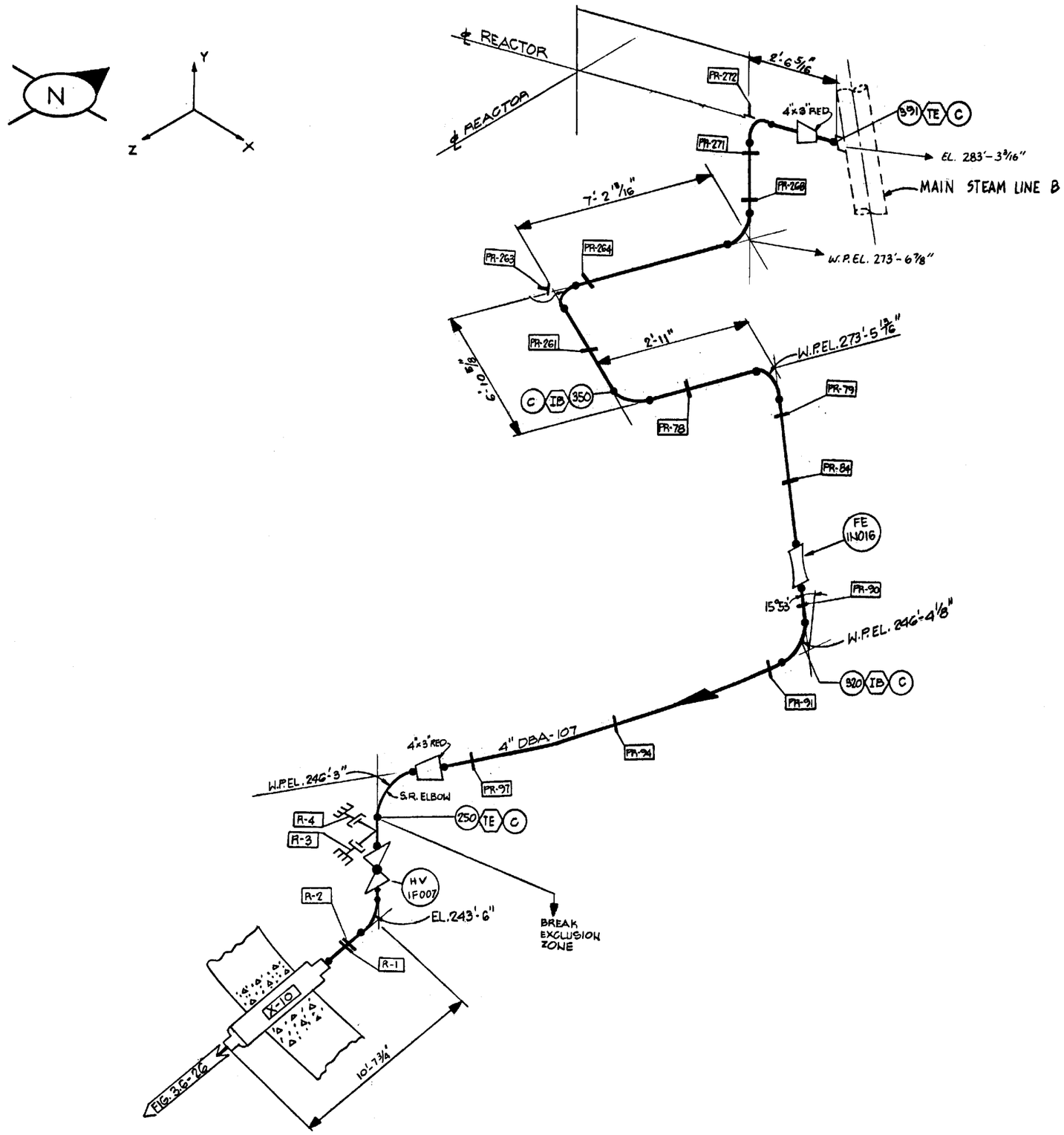
A= VENT AREA
C= FLOW COEFFICIENT
V= FREE VOLUME
BOP= BLOWOUT PANEL

LIMS4.DGN

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE-TEMPERATURE TRANSIENT ANALYSIS MODEL FOR HPCI STEAM SUPPLY LINE BREAK IN ISOLATION VALVE COMPARTMENT (UNIT 2) (SHEET 2 OF 2)

FIGURE 3.6-24 Rev. 18 Sept./16



NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-15.

2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:

   TE – TERMINAL BREAK END
   IB – INTERMEDIATE BREAK
   C – CIRCUMFERENTIAL BREAK
   L – LONGITUDINAL BREAK

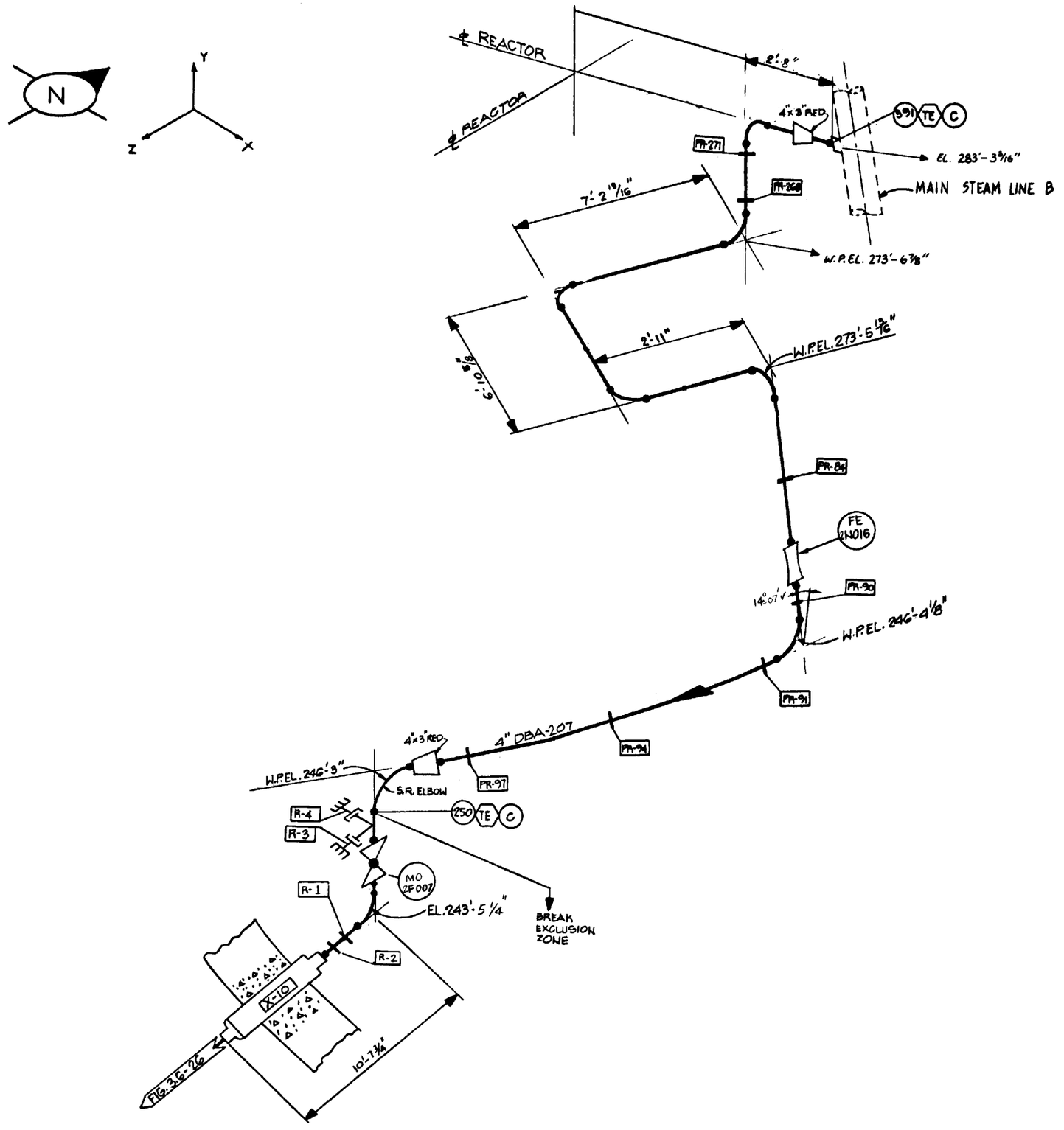
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:

   – PIPE WHIP RESTRAINT
   – BUMPER-TYPE RESTRAINT
   – ANCHOR
   – COMPENSATING STRUT

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RCIC STEAM SUPPLY PIPING ISOMETRIC
(PORTION INSIDE PRIMARY CONTAINMENT)
(UNIT 1 ONLY)
(SHEET 1 OF 2)

FIGURE 3.6-25



NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-15

2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:

   (TE) – TERMINAL BREAK END
   (IB) – INTERMEDIATE BREAK
   (C) – CIRCUMFERENTIAL BREAK
   (L) – LONGITUDINAL BREAK

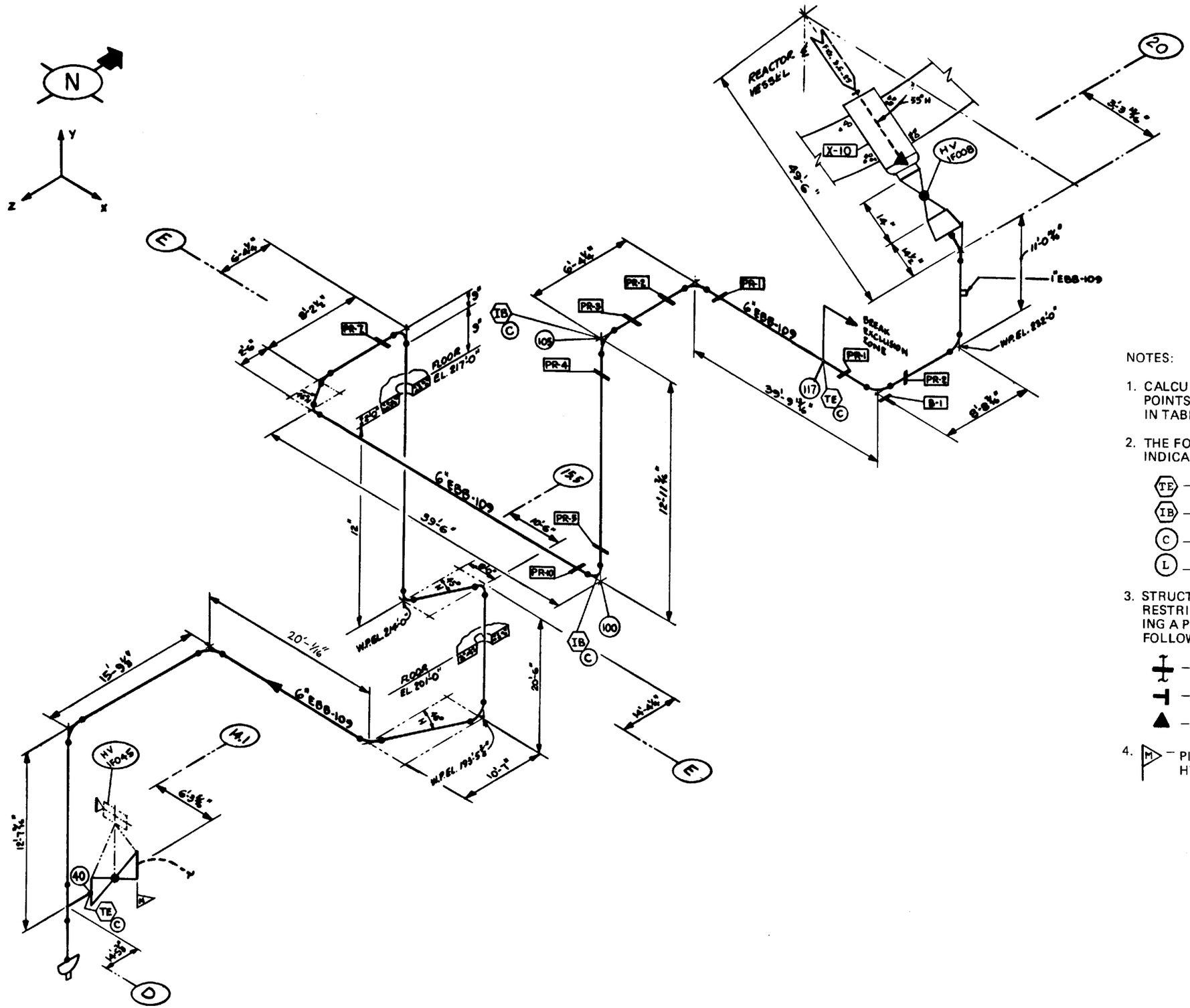
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:

   – PIPE WHIP RESTRAINT
   – BUMPER-TYPE RESTRAINT
   – ANCHOR
   – COMPENSATING STRUT

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RCIC STEAM SUPPLY PIPING ISOMETRIC
(PORTION INSIDE PRIMARY CONTAINMENT)
(UNIT 2)
(SHEET 2 OF 2)

FIGURE 3.6-25



NOTES:

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-16.

2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:

   (TE) – TERMINAL END BREAK

   (IB) – INTERMEDIATE BREAK

   (C) – CIRCUMFERENTIAL BREAK

   (L) – LONGITUDINAL BREAK

3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:

   – PIPE WHIP RESTRAINT

   – BUMPER-TYPE RESTRAINT

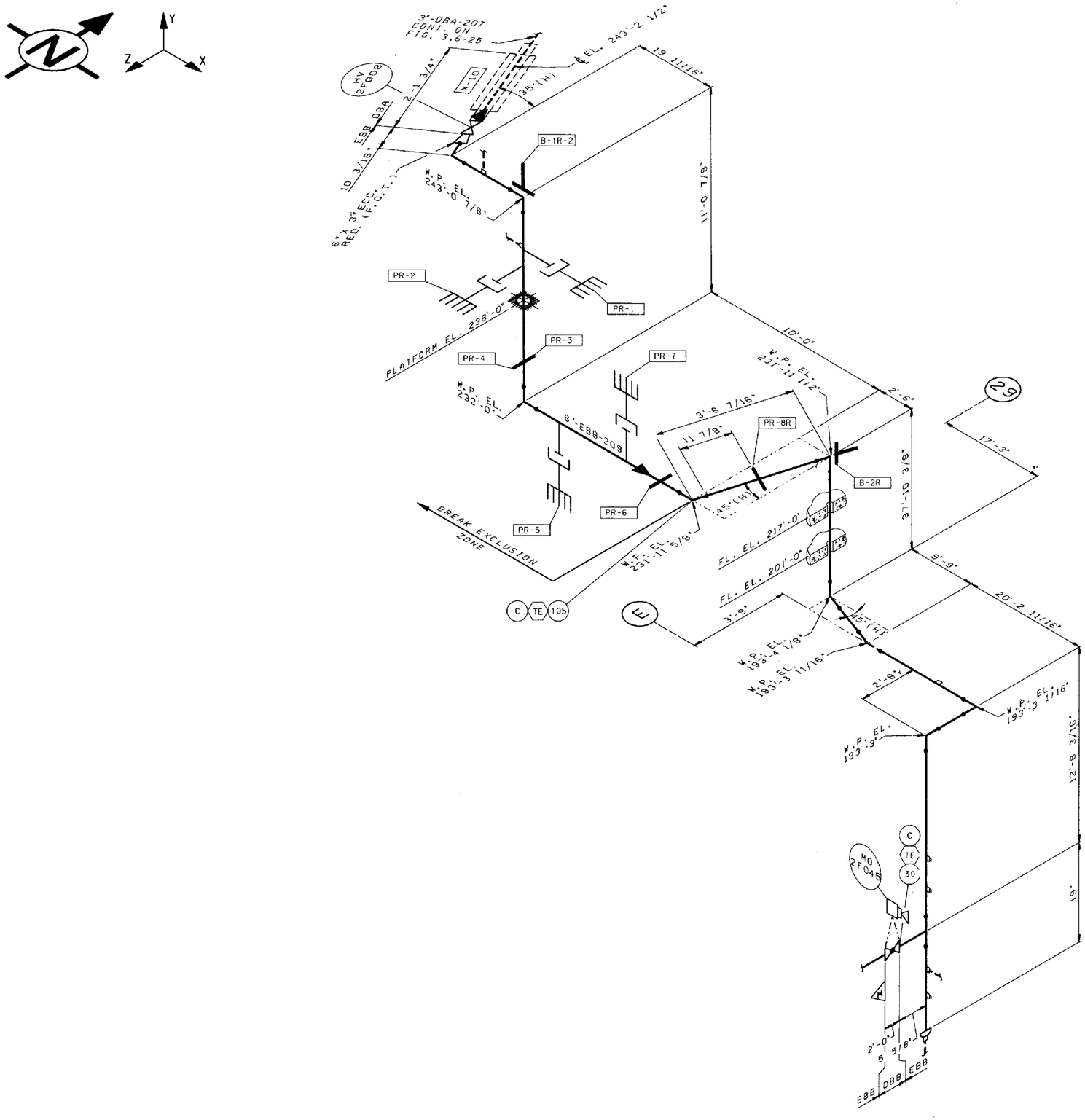
   – ANCHOR

4. (M) – PIPING DOWNSTREAM OF VALVE HV–1F045 IS MODERATE-ENERGY

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RCIC STEAM SUPPLY PIPING ISOMETRIC (PORTION OUTSIDE PRIMARY CONTAINMENT) (UNIT 1 ONLY) (SHEET 1 OF 2)

FIGURE 3.6-26

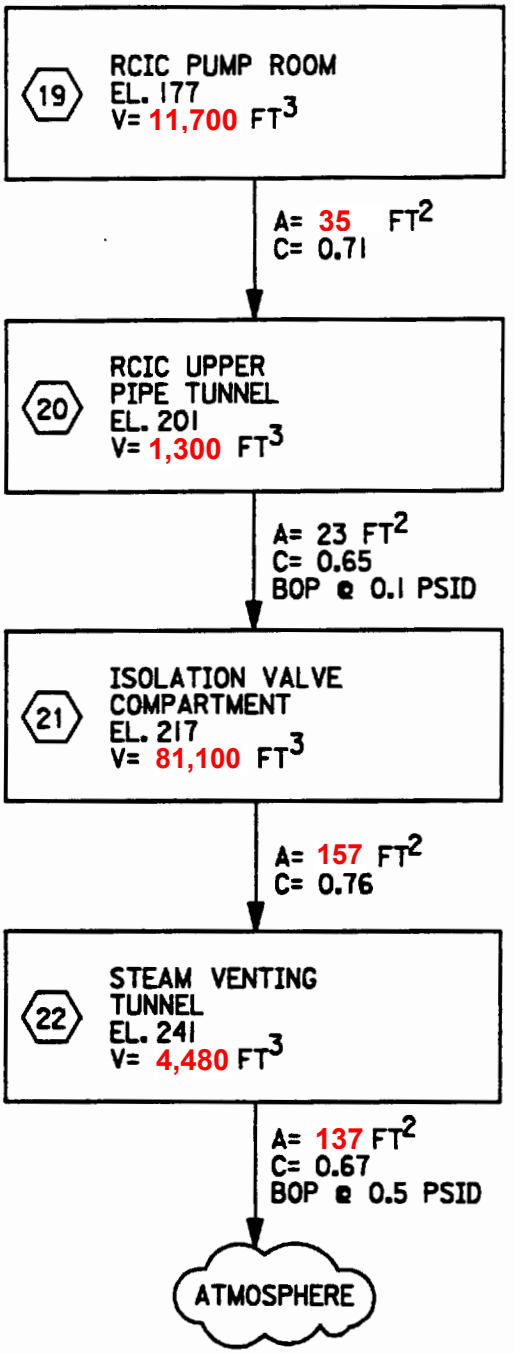


1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-16.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) - TERMINAL END BREAK
   - (IB) - INTERMEDIATE BREAK
   - (C) - CIRCUMFERENTIAL BREAK
   - (L) - LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - - PIPE WHIP RESTRAINT
   - - BUMPER-TYPE RESTRAINT
   - - ANCHOR
   - - COMPENSATING STRUT
4. (M) - PIPING DOWNSTREAM OF THE VALVE MO-2F045 IS MODERATE ENERGY.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RCIC STEAM SUPPLY PIPING ISOMETRIC (PORTION OUTSIDE PRIMARY CONTAINMENT) (UNIT 2)
(SHEET 2 OF 2)

FIGURE 3.6-26



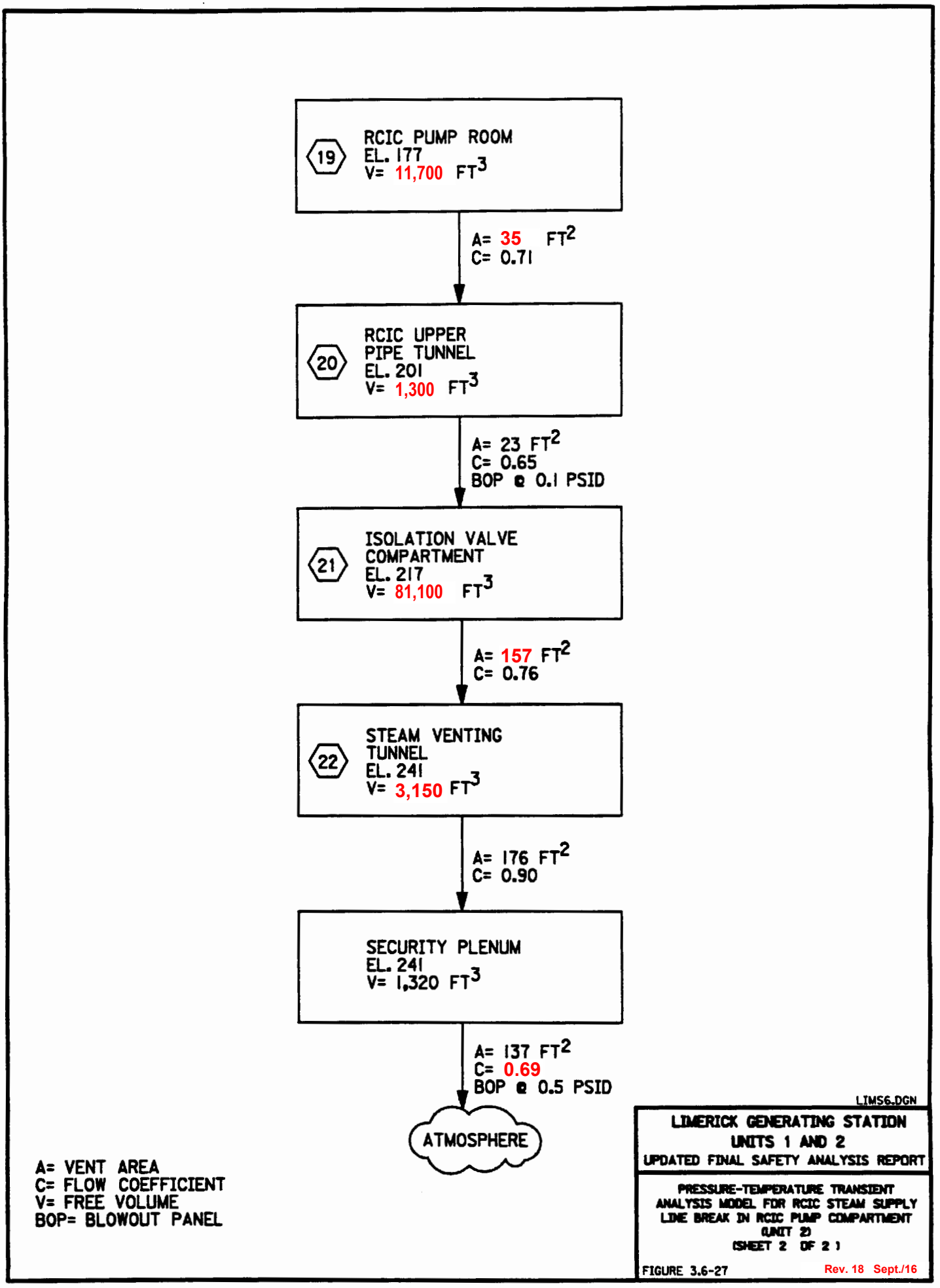
A= VENT AREA
C= FLOW COEFFICIENT
V= FREE VOLUME
BOP= BLOWOUT PANEL

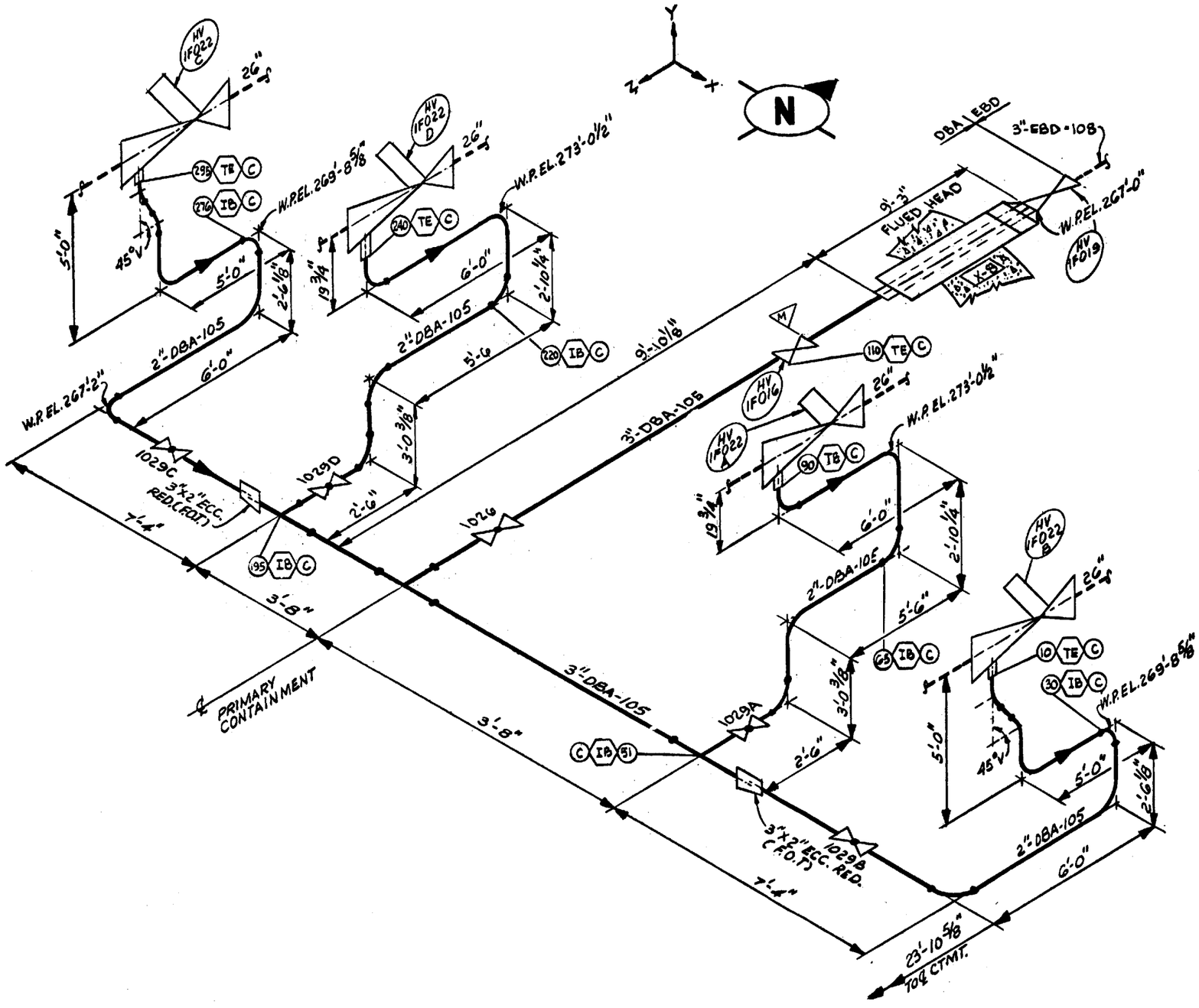
LIMS5.DGN

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE-TEMPERATURE TRANSIENT ANALYSIS MODEL FOR RCIC STEAM SUPPLY LINE BREAK IN RCIC PUMP COMPARTMENT (UNIT 1)
(SHEET 1 OF 2)

FIGURE 3.6-27 Rev. 18 Sept./16


19
RCIC PUMP ROOM
EL. 177
V= 11,700 FT3
A= 35 FT2
C= 0.71
20
RCIC UPPER
PIPE TUNNEL
EL. 201
V= 1,300 FT3
A= 23 FT2
C= 0.65
BOP @ 0.1 PSID
21
ISOLATION VALVE
COMPARTMENT
EL. 217
V= 81,100 FT3
A= 157 FT2
C= 0.76
22
STEAM VENTING
TUNNEL
EL. 241
V= 3,150 FT3
A= 176 FT2
C= 0.90
SECURITY PLENUM
EL. 241
V= 1,320 FT3
A= 137 FT2
C= 0.69
BOP @ 0.5 PSID
ATMOSPHERE
A= VENT AREA
C= FLOW COEFFICIENT
V= FREE VOLUME
BOP= BLOWOUT PANEL
LIMS6.DGN
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT
PRESSURE-TEMPERATURE TRANSIENT
ANALYSIS MODEL FOR RCIC STEAM SUPPLY
LINE BREAK IN RCIC PUMP COMPARTMENT
(UNIT 2)
(SHEET 2 OF 2)
FIGURE 3.6-27
Rev. 18 Sept./16



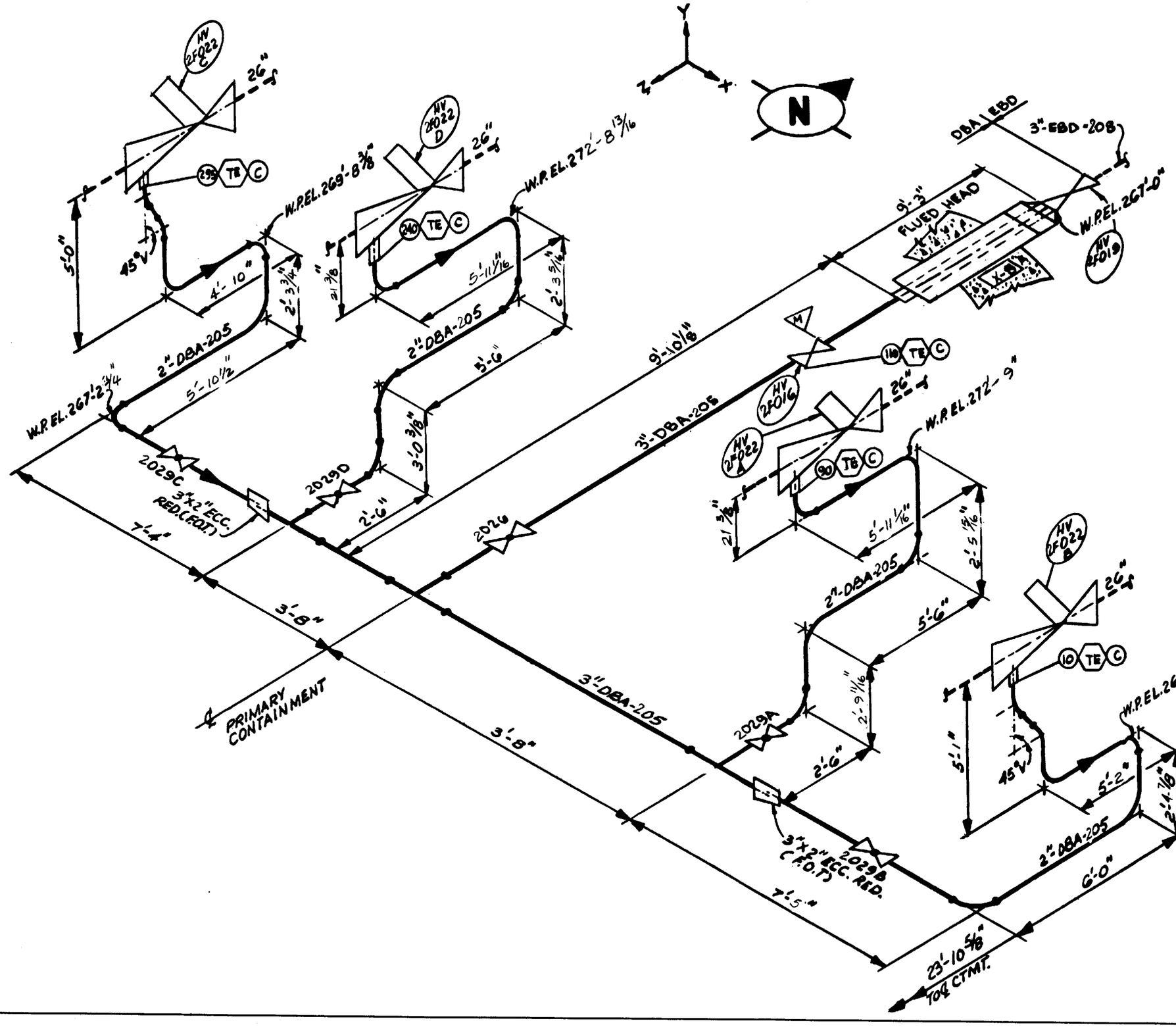
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-17.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - ▲ – ANCHOR
4. (M) – PIPING OUTBOARD OF THE CLOSED VALVE IS MODERATE-ENERGY.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM DRAINAGE PIPING ISOMETRIC (PORTION INSIDE PRIMARY CONTAINMENT) (UNIT 1 ONLY) (SHEET 1 OF 2)

FIGURE 3.6-28



NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-17.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. (M) – PIPING OUTBOARD OF THE CLOSED VALVE IS MODERATE-ENERGY.

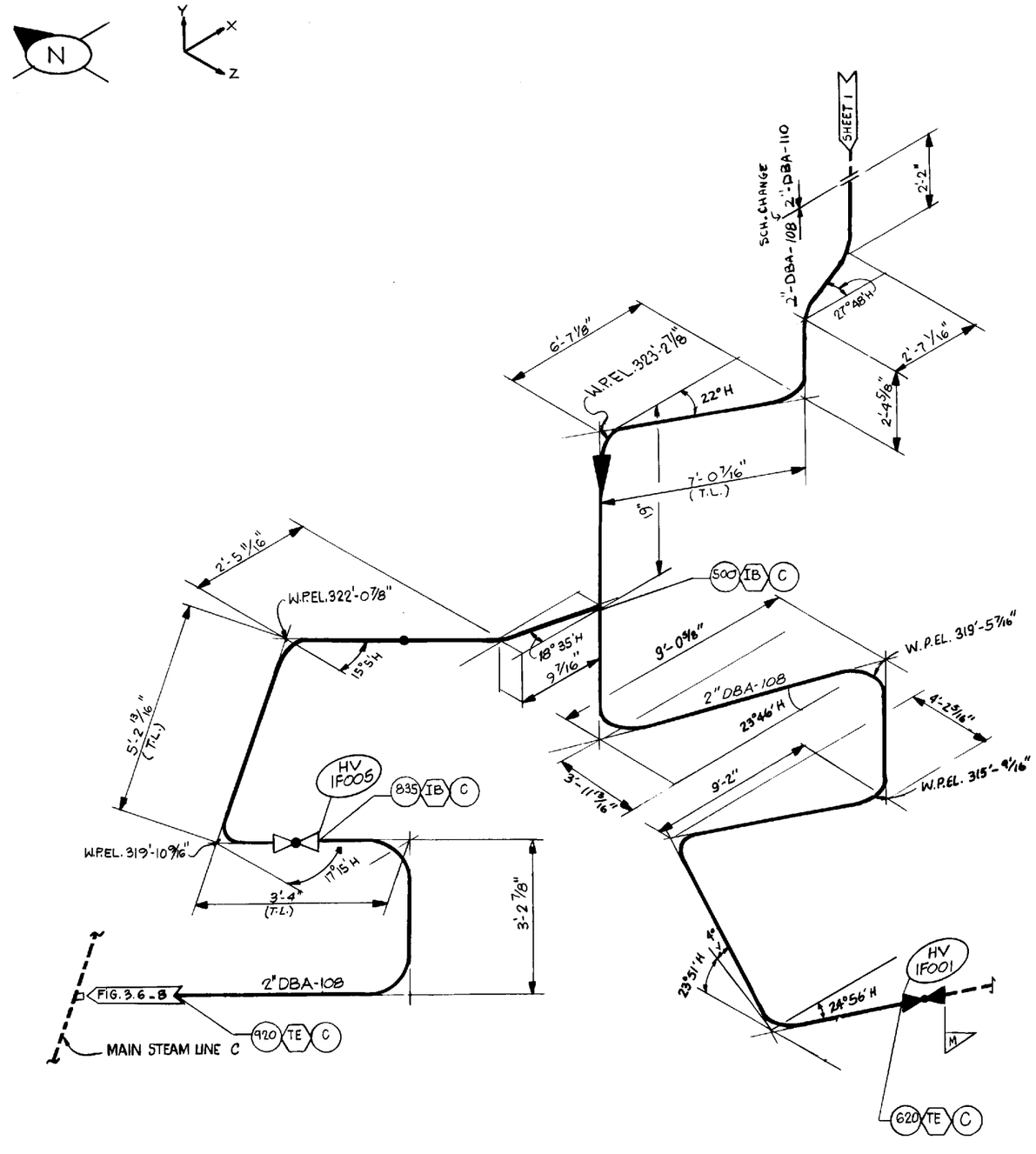
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM DRAINAGE PIPING ISOMETRIC
(PORTION INSIDE PRIMARY CONTAINMENT)
(UNIT 2)
(SHEET 2 OF 2)

FIGURE 3.6-28

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Figure 3.6-30 Sheet 1 of 4 has been
DELETED



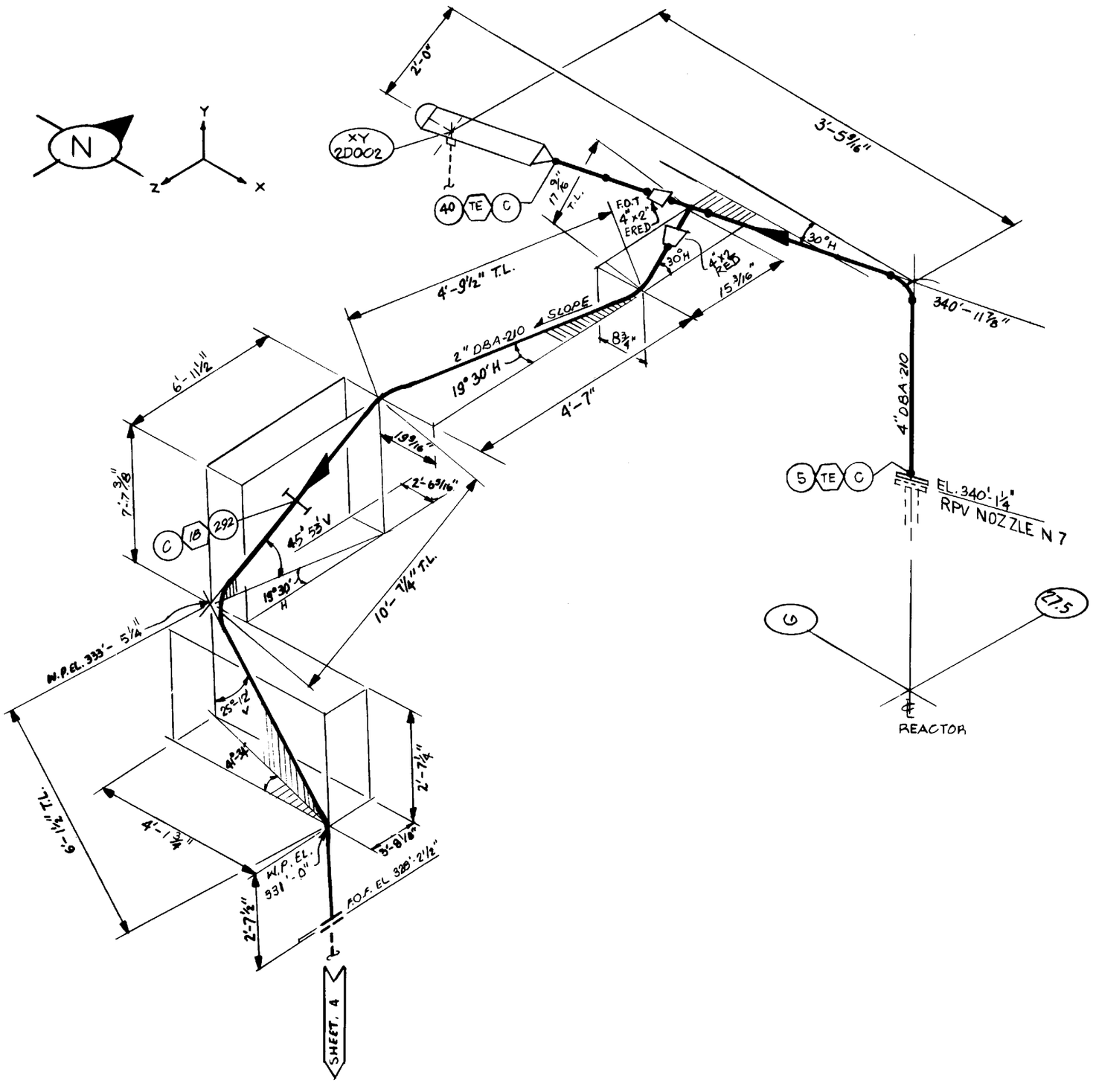
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-19.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. M – PIPING DOWNSTREAM OF VALVE HV-1F001 IS MODERATE-ENERGY.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RPV HEAD VENT PIPING ISOMETRIC
(UNIT 1 ONLY)
(SHEET 2 OF 4)

FIGURE 3.6-30



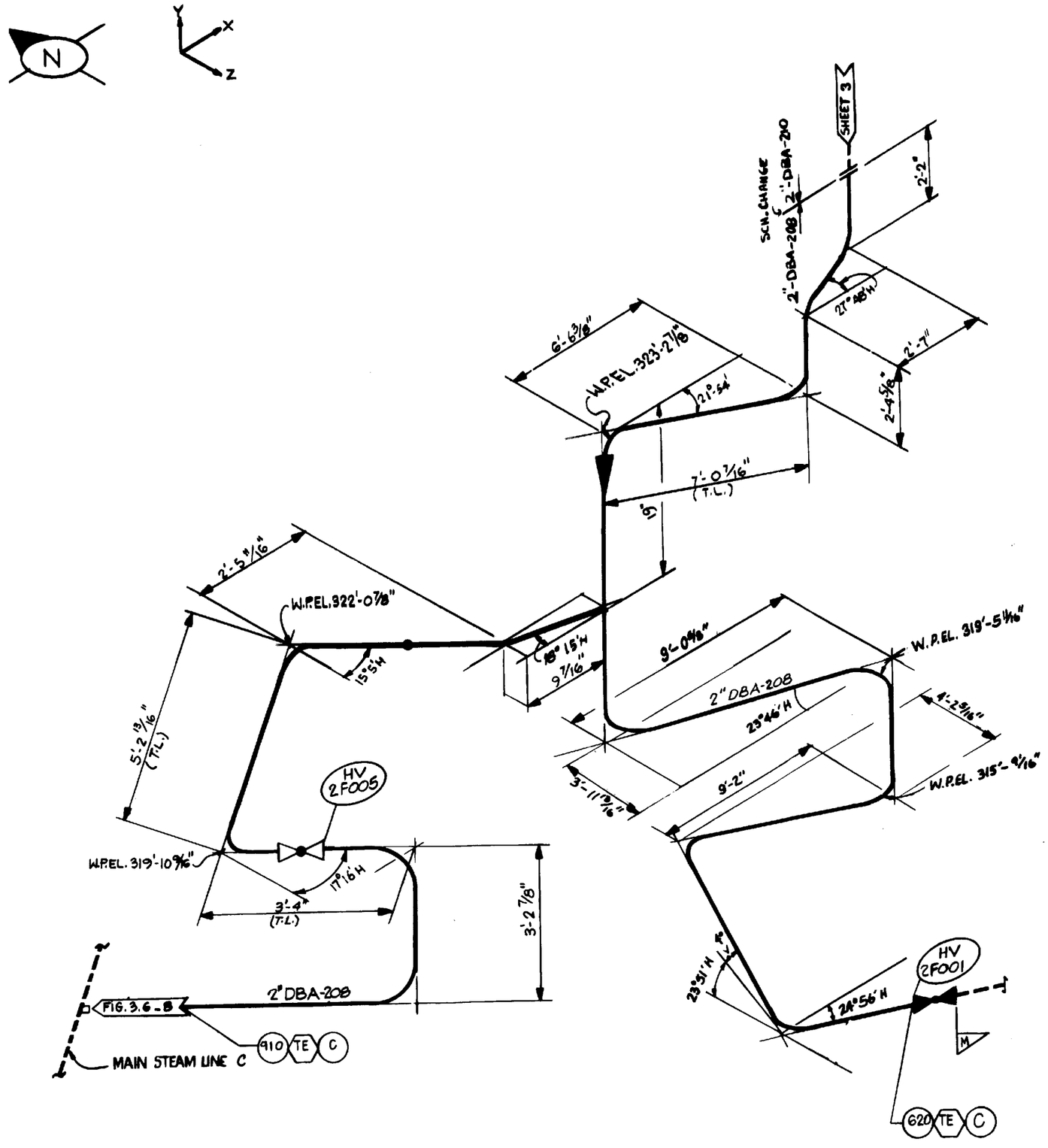
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-19
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RPV HEAD VENT PIPING ISOMETRIC
(UNIT 2)
(SHEET 3 OF 4)

FIGURE 3.6-30



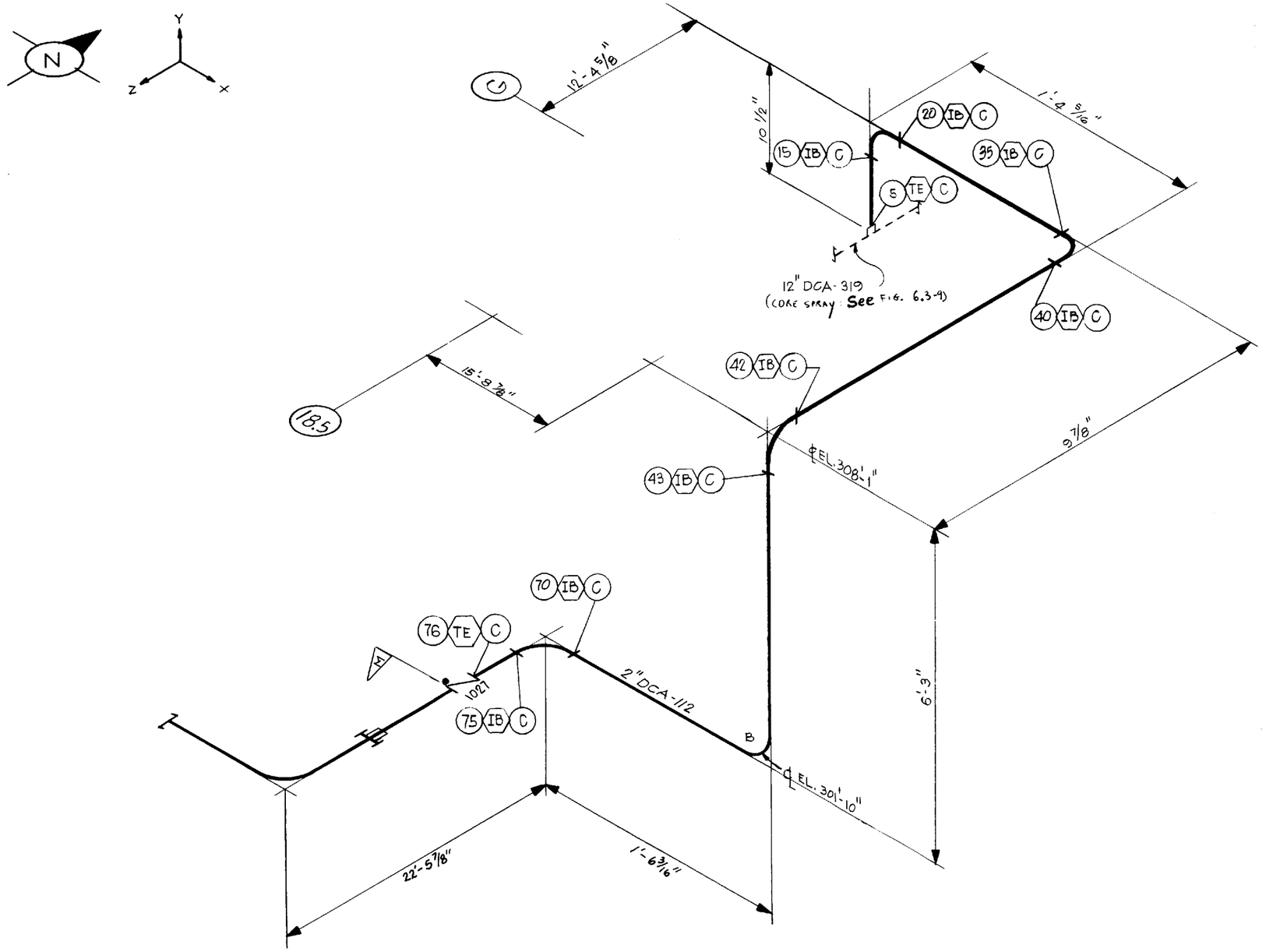
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-19.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. (M) – PIPING DOWNSTREAM OF VALVE HV-2F001 IS MODERATE-ENERGY.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RPV HEAD VENT PIPING ISOMETRIC
(UNIT 2)
(SHEET 4 OF 4)

FIGURE 3.6-30



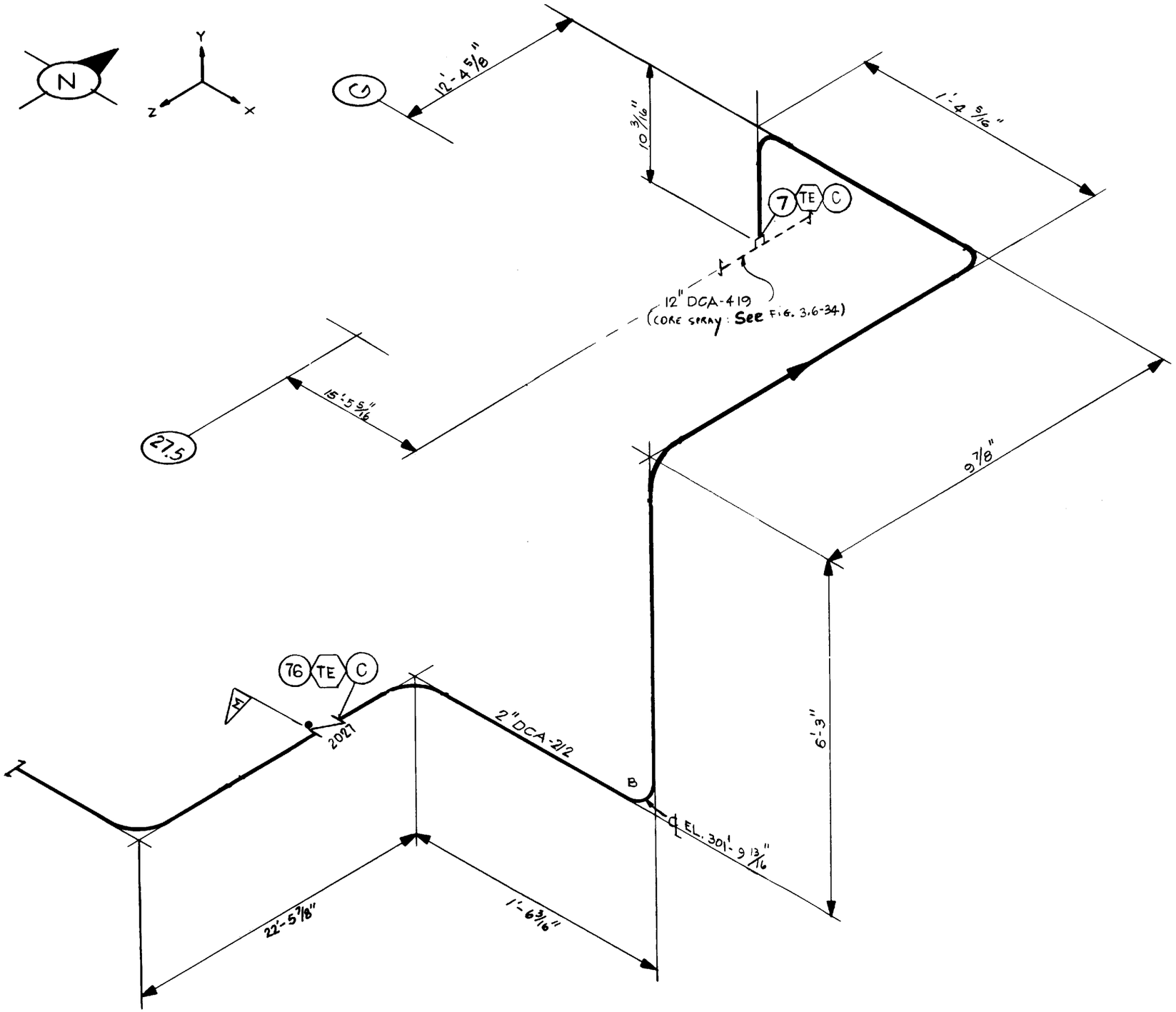
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-20.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - TE – TERMINAL END BREAK
   - IB – INTERMEDIATE BREAK
   - C – CIRCUMFERENTIAL BREAK
   - L – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. – PIPING DOWNSTREAM OF VALVE 1027 IS MODERATE-ENERGY.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

STANDBY LIQUID CONTROL
INJECTION PIPING ISOMETRIC
(UNIT 1 ONLY)
(SHEET 1 OF 2)

FIGURE 3.6-31



NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-20

2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:

   (TE) – TERMINAL END BREAK

   (IB) – INTERMEDIATE BREAK

   (C) – CIRCUMFERENTIAL BREAK

   (L) – LONGITUDINAL BREAK

3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:

   – PIPE WHIP RESTRAINT

   – BUMPER-TYPE RESTRAINT

   – ANCHOR

4. (M) – PIPING DOWNSTREAM OF VALVE 2027 IS MODERATE-ENERGY.

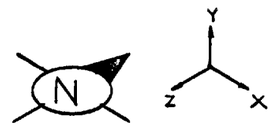
LIMERICK GENERATING STATION UNITS 1 AND 2

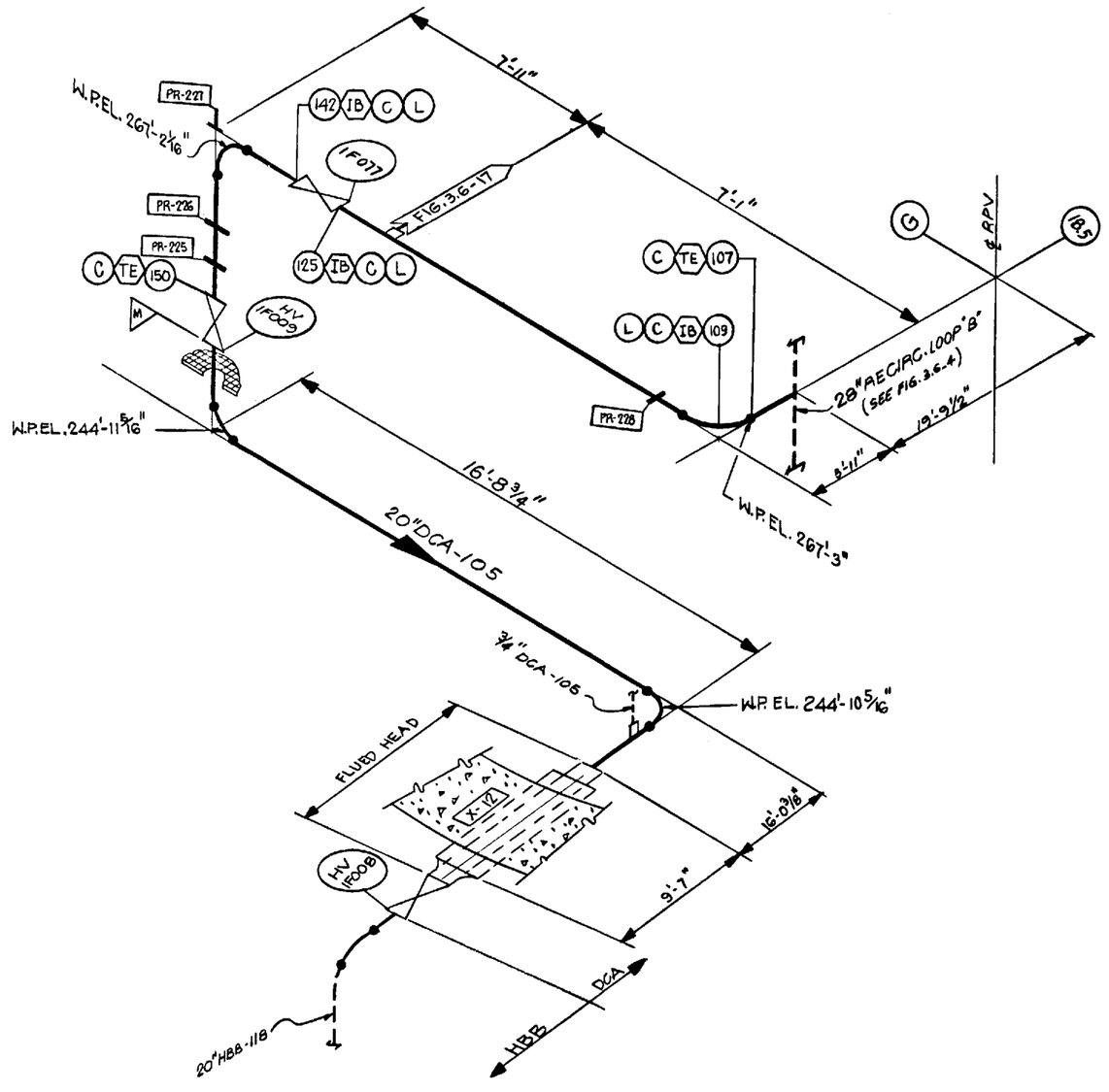
UPDATED FINAL SAFETY ANALYSIS REPORT

STANDBY LIQUID CONTROL INJECTION PIPING ISOMETRIC (UNIT 2)

(SHEET 2 OF 2)

FIGURE 3.6-31





SHUTDOWN COOLING SUCTION LINE

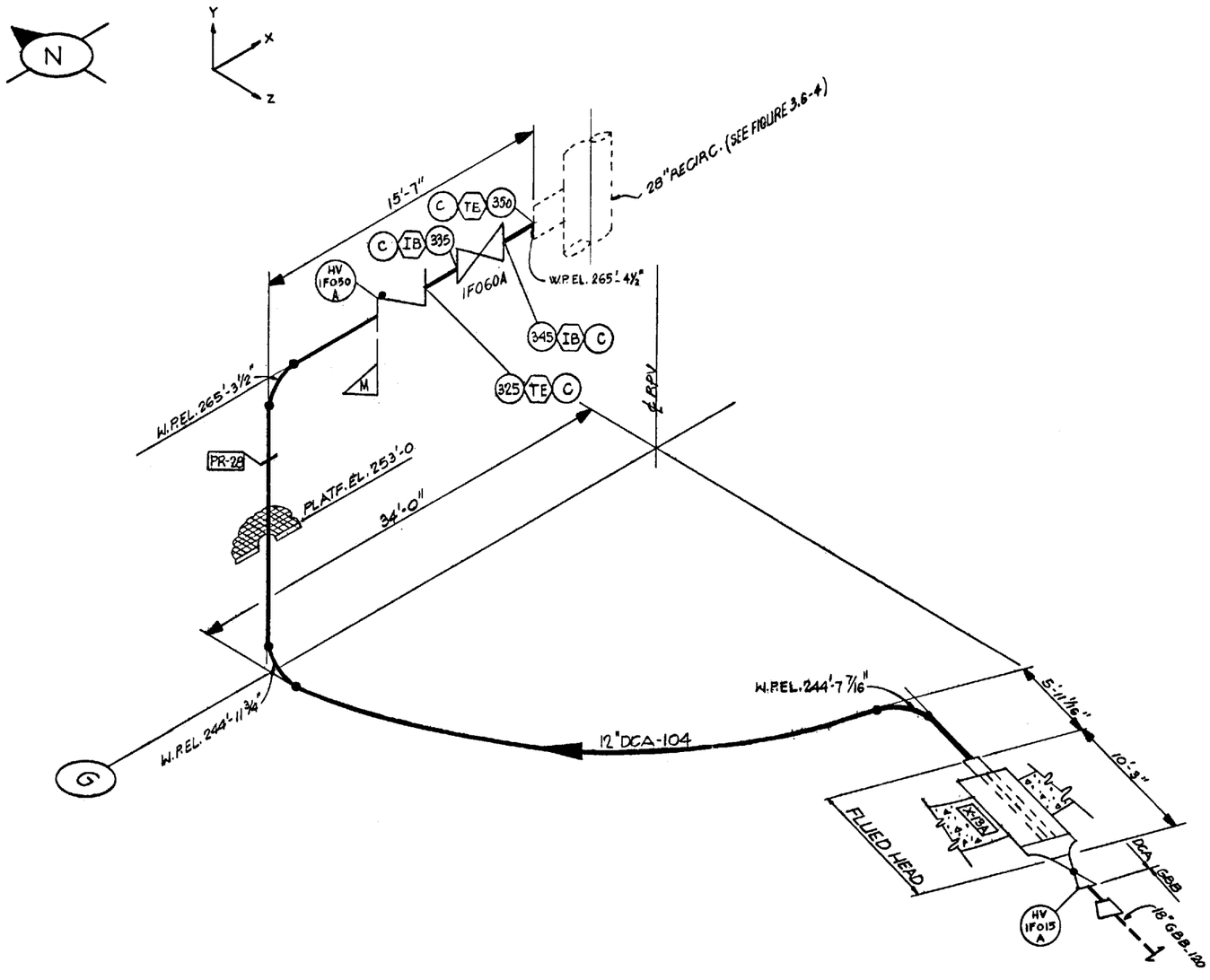
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-21.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - TE – TERMINAL END BREAK
   - IB – INTERMEDIATE BREAK
   - C – CIRCUMFERENTIAL BREAK
   - L – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. M – PIPING DOWNSTREAM OF VALVE HV-1F009 IS MODERATE-ENERGY.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RHR SHUTDOWN COOLING PIPING ISOMETRIC (UNIT 1 ONLY) (SHEET 1 OF 6)

FIGURE 3.6-32



SHUTDOWN COOLING RETURN LINE A

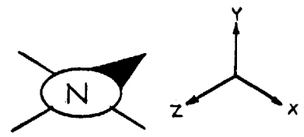
NOTES

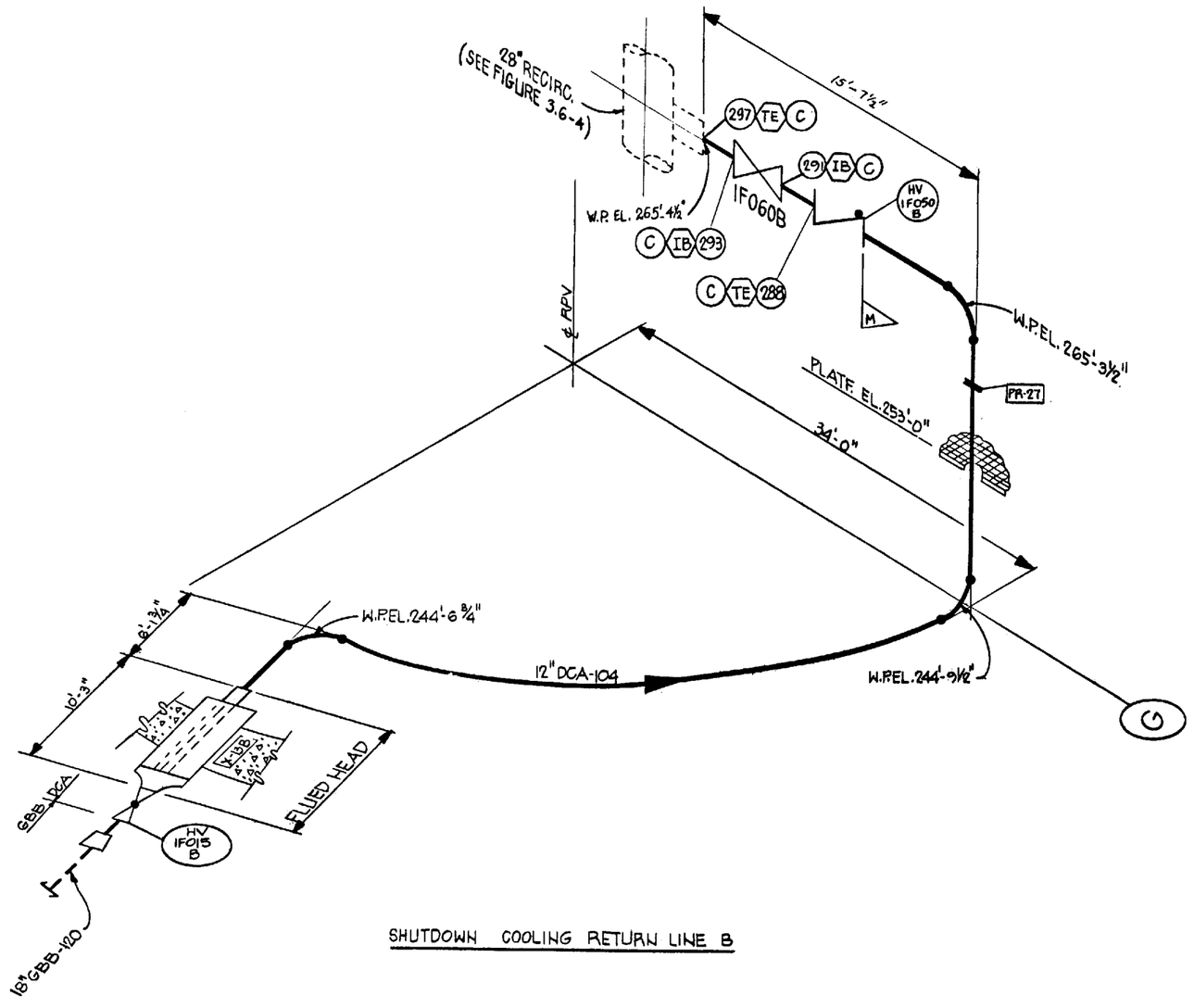
1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-21.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. (M) – PIPING UPSTREAM OF VALVE HV-1F050A IS MODERATE-ENERGY.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RHR SHUTDOWN COOLING PIPING ISOMETRIC (UNIT 1 ONLY) (SHEET 2 OF 6)

FIGURE 3.6-32





SHUTDOWN COOLING RETURN LINE B

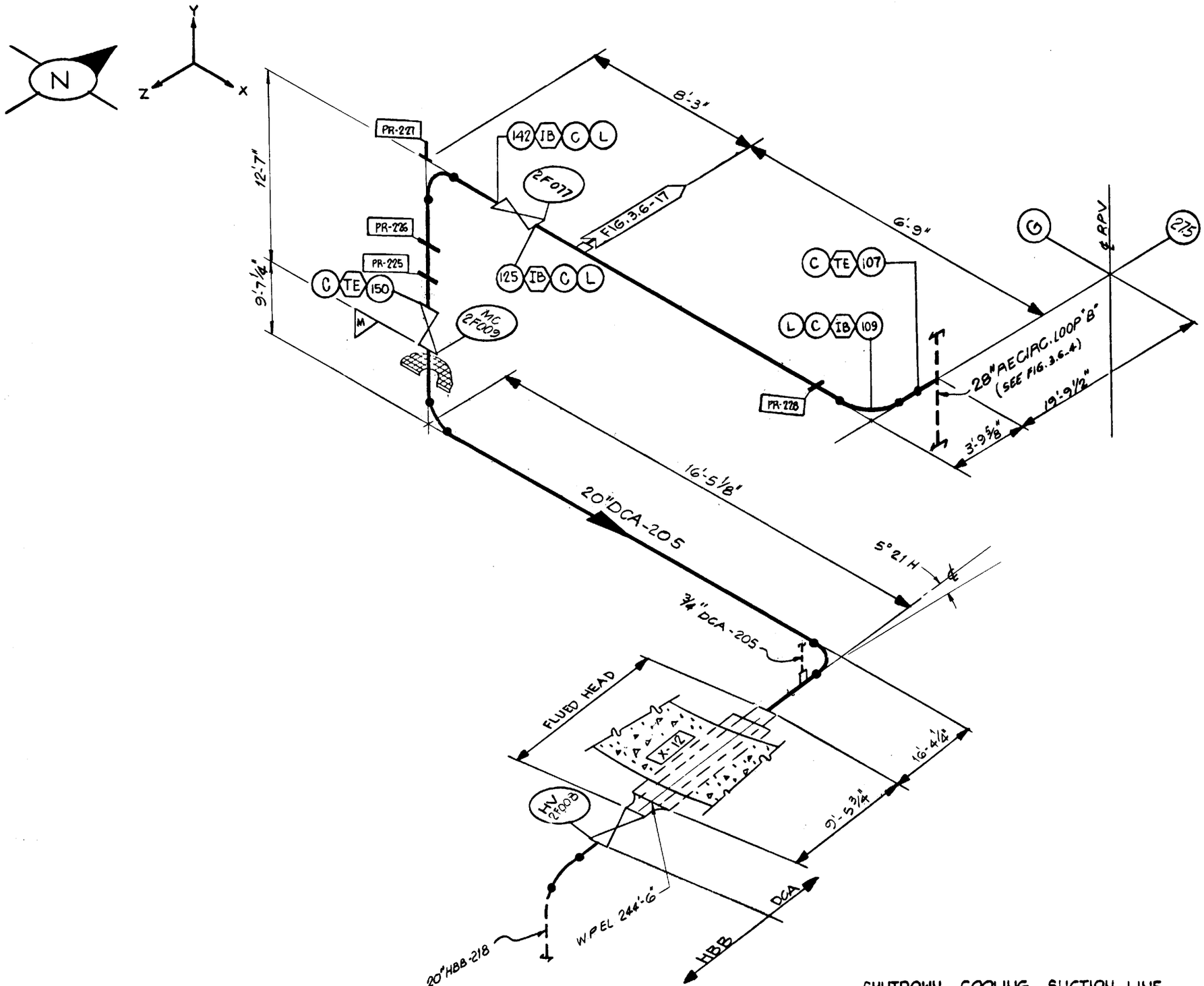
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-21.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - TE – TERMINAL END BREAK
   - IB – INTERMEDIATE BREAK
   - C – CIRCUMFERENTIAL BREAK
   - L – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. M – PIPING UPSTREAM OF VALVE HV-1F050B IS MODERATE-ENERGY.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RHR SHUTDOWN
COOLING PIPING ISOMETRIC
(UNIT 1 ONLY)
(SHEET 3 OF 6)

FIGURE 3.6-32



SHUTDOWN COOLING SUCTION LINE

NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-21

THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:

- TE – TERMINAL END BREAK
- IB – INTERMEDIATE BREAK
- C – CIRCUMFERENTIAL BREAK
- L – LONGITUDINAL BREAK

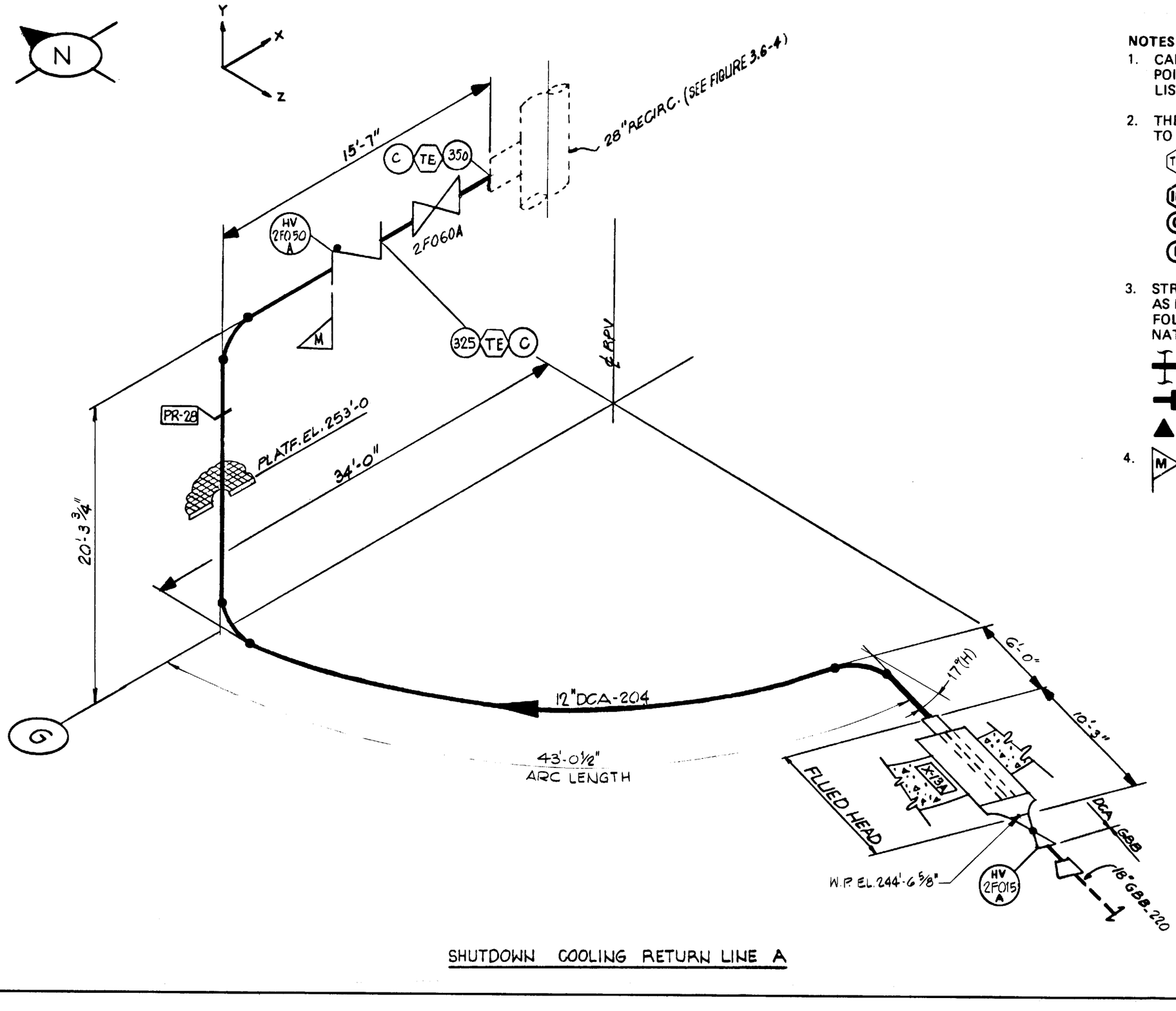
STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:

- – PIPE WHIP RESTRAINT
- – BUMPER-TYPE RESTRAINT
- – ANCHOR
- M – PIPING DOWNSTREAM OF VALVE MO-2F009 IS MODERATE-ENERGY.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RHR SHUTDOWN COOLING PIPING ISOMETRIC (UNIT 2)
(SHEET 4 OF 6)

FIGURE 3.6-32



SHUTDOWN COOLING RETURN LINE A

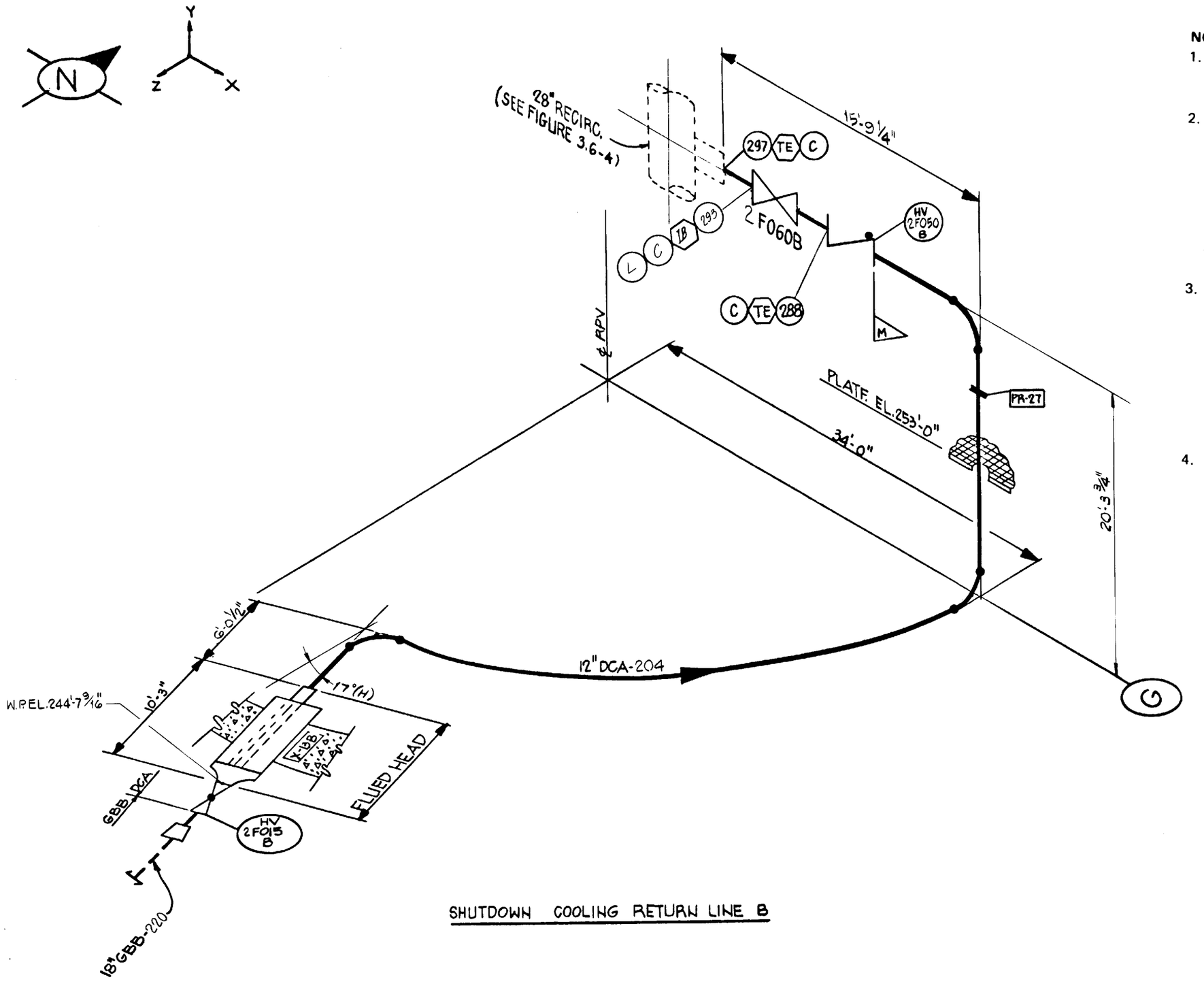
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-21
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. (M) – PIPING UPSTREAM OF VALVE HV-2F050A IS MODERATE-ENERGY.

LIMERICK GENERATING STATION UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RHR SHUTDOWN COOLING PIPING ISOMETRIC (UNIT 2)
(SHEET 5 OF 6)

FIGURE 3.6-32



SHUTDOWN COOLING RETURN LINE B

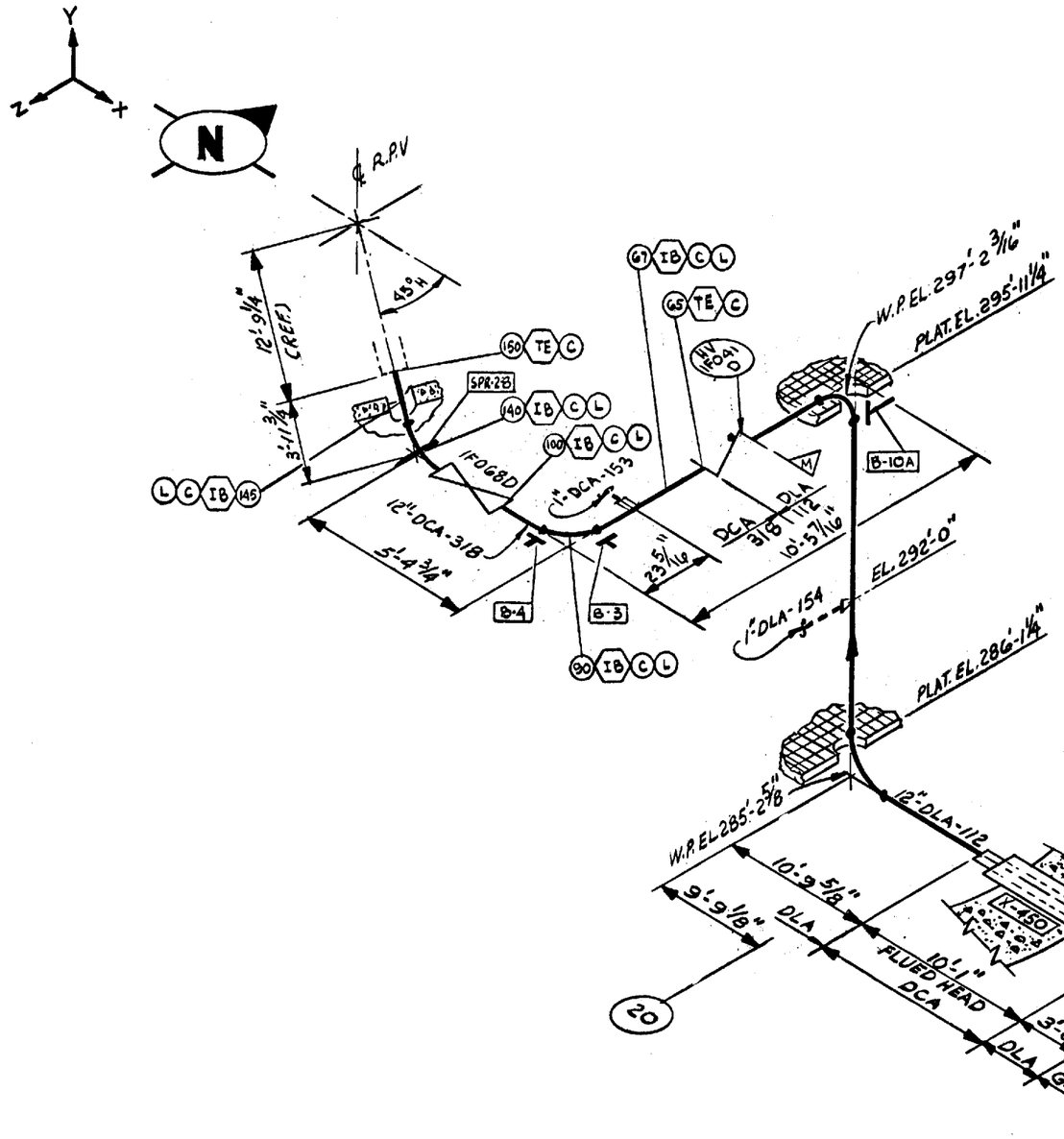
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-21
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - TE – TERMINAL END BREAK
   - IB – INTERMEDIATE BREAK
   - C – CIRCUMFERENTIAL BREAK
   - L – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. M – PIPING UPSTREAM OF VALVE HV-2F050B IS MODERATE-ENERGY.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RHR SHUTDOWN COOLING PIPING ISOMETRIC (UNIT 2)
(SHEET 6 OF 6)

FIGURE 3.6-32



NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-22.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - TE – TERMINAL END BREAK
   - IB – INTERMEDIATE BREAK
   - C – CIRCUMFERENTIAL BREAK
   - L – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. M – PIPING UPSTREAM OF THE CHECK VALVE IS MODERATE-ENERGY.
5. LPCI LOOP D IS SHOWN. THE BREAK LOCATIONS INDICATED ARE TYPICAL FOR LOOPS A, B, AND C, WHICH ARE ARRANGED SYMMETRICALLY.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LPCI INJECTION PIPING ISOMETRIC
(UNIT 1 ONLY)
(SHEET 1 OF 2)

FIGURE 3.6-33

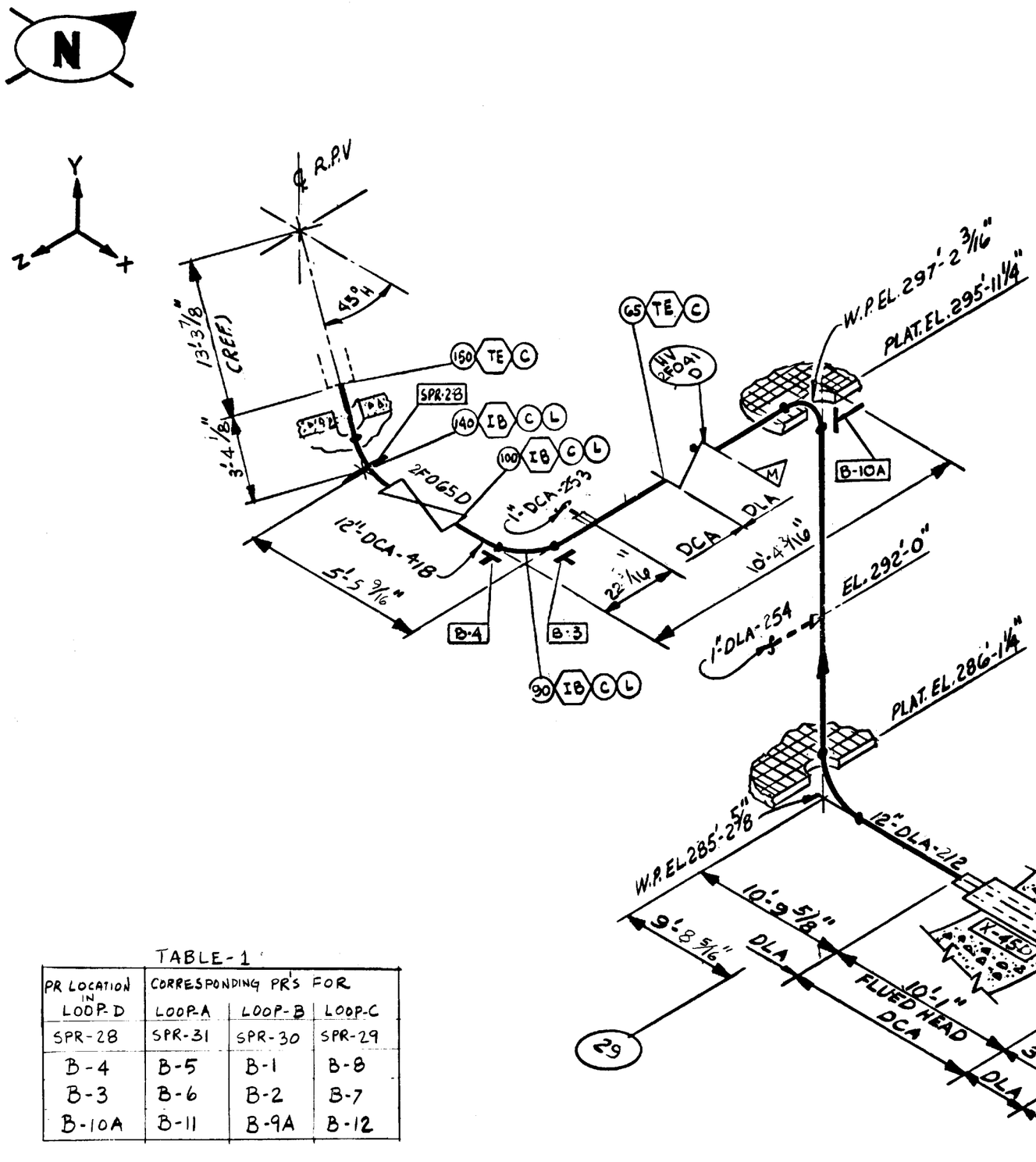


TABLE-1

PR LOCATION IN LOOP D	CORRESPONDING PR'S FOR		
	LOOP-A	LOOP-B	LOOP-C
SPR-28	SPR-31	SPR-30	SPR-29
B-4	B-5	B-1	B-8
B-3	B-6	B-2	B-7
B-10A	B-11	B-9A	B-12

NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-22.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - (TE) – TERMINAL END BREAK
   - (IB) – INTERMEDIATE BREAK
   - (C) – CIRCUMFERENTIAL BREAK
   - (L) – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. (M) – PIPING UPSTREAM OF THE CHECK VALVE IS MODERATE-ENERGY.
5. LPCI LOOP D IS SHOWN. THE BREAK LOCATIONS INDICATED ARE TYPICAL FOR LOOPS A, B, AND C, WHICH ARE ARRANGED SYMMETRICALLY. SEE TABLE-1.

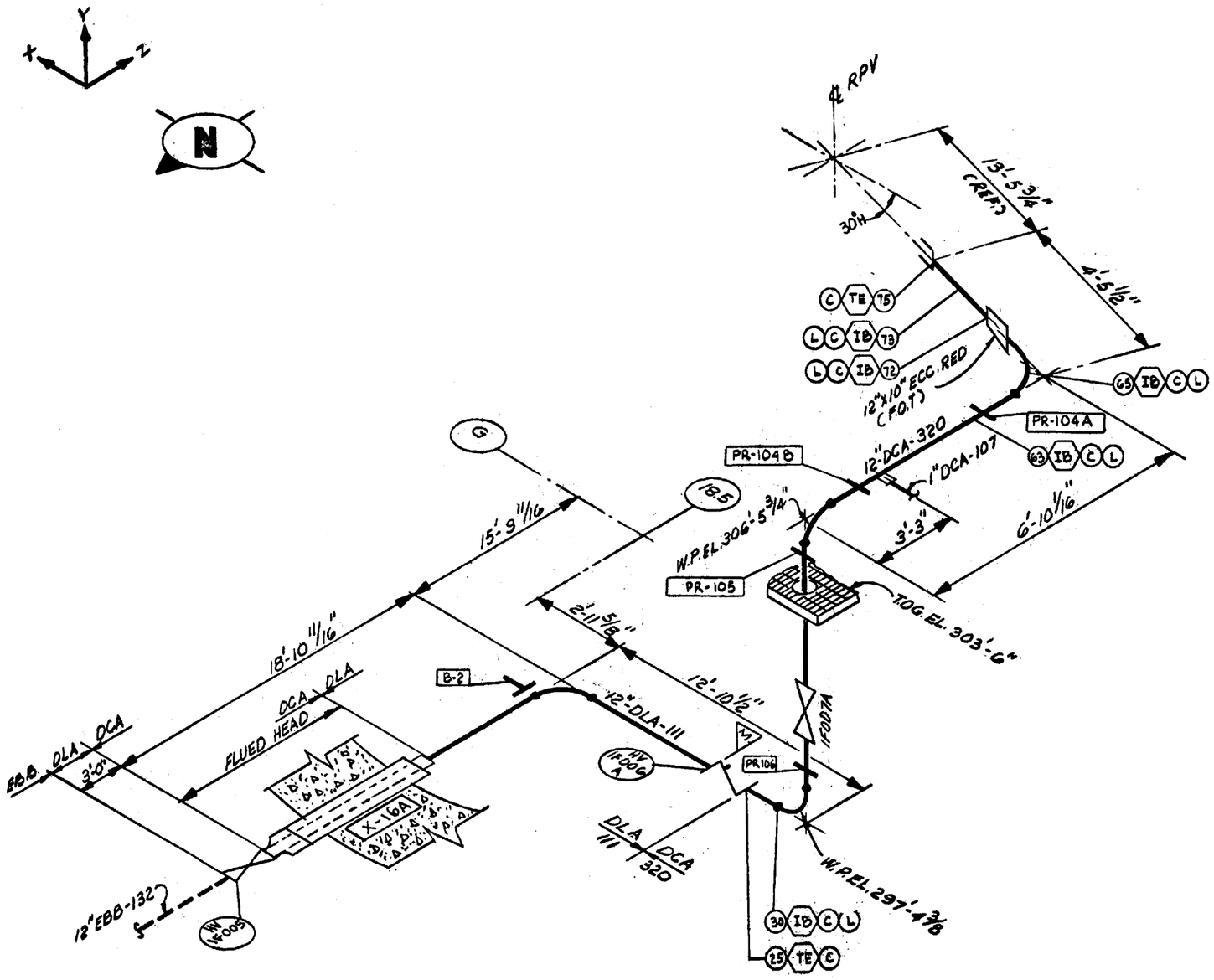
LIMERICK GENERATING STATION UNITS 1 AND 2

UPDATED FINAL SAFETY ANALYSIS REPORT

LPCI INJECTION PIPING ISOMETRIC (UNIT 2)

(SHEET 2 OF 2)

FIGURE 3.6-33



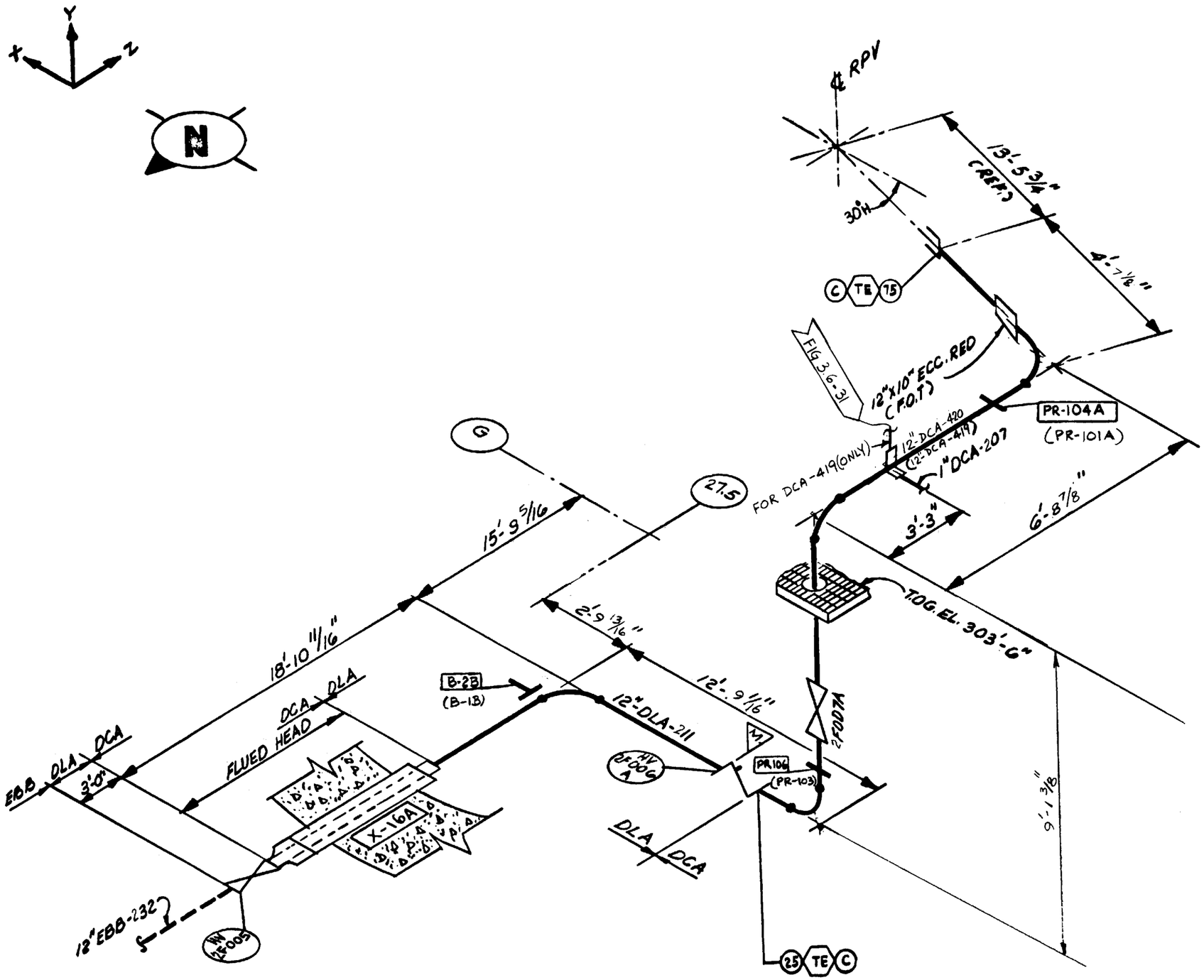
NOTES

1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-23.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - TE – TERMINAL END BREAK
   - IB – INTERMEDIATE BREAK
   - C – CIRCUMFERENTIAL BREAK
   - L – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. – PIPING UPSTREAM OF THE CHECK VALVE IS MODERATE-ENERGY.
5. CORE SPRAY LOOP A IS SHOWN. THE BREAK LOCATIONS INDICATED ARE TYPICAL FOR LOOP B, WHICH IS ARRANGED SYMMETRICALLY.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CORE SPRAY
INJECTION PIPING ISOMETRIC
(UNIT 1 ONLY)
(SHEET 1 OF 2)

FIGURE 3.6-34



NOTES

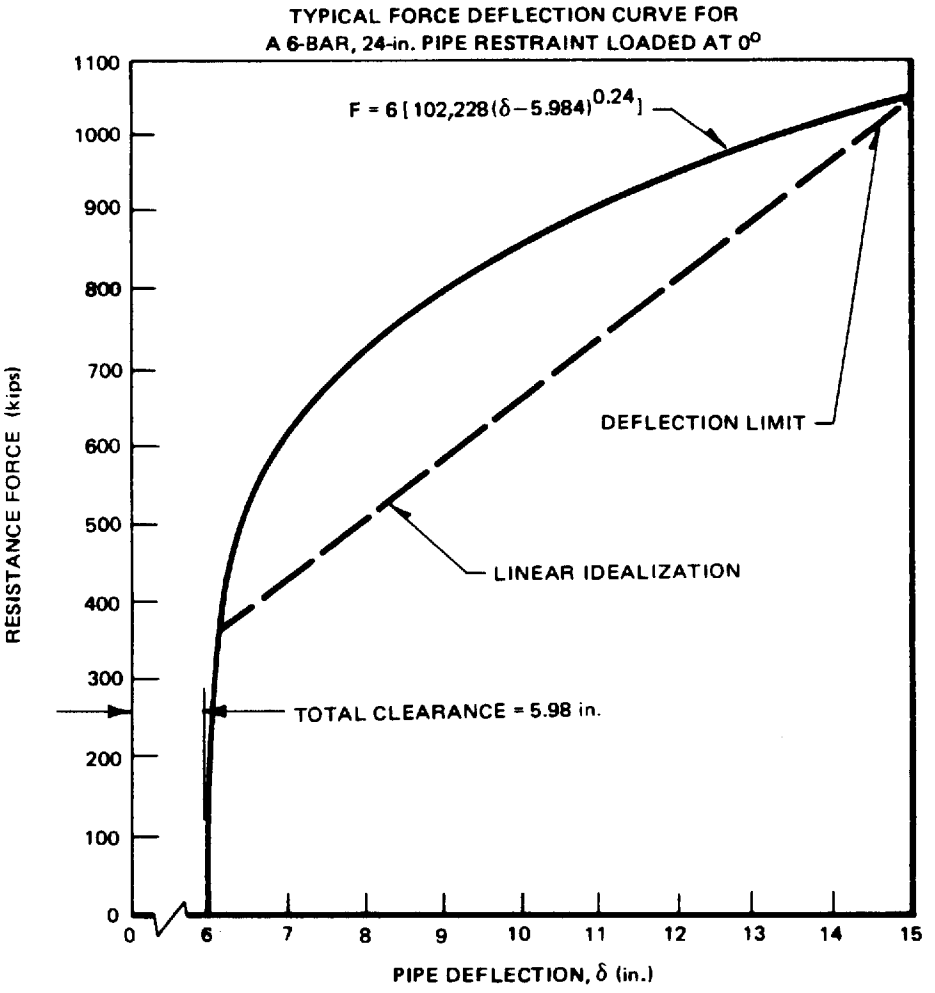
1. CALCULATED STRESSES FOR THE NODE POINTS SHOWN IN THIS FIGURE ARE LISTED IN TABLE 3.6-23.
2. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:
   - TE – TERMINAL END BREAK
   - IB – INTERMEDIATE BREAK
   - C – CIRCUMFERENTIAL BREAK
   - L – LONGITUDINAL BREAK
3. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:
   - – PIPE WHIP RESTRAINT
   - – BUMPER-TYPE RESTRAINT
   - – ANCHOR
4. M – PIPING UPSTREAM OF THE CHECK VALVE IS MODERATE-ENERGY.
5. CORE SPRAY LOOP A IS SHOWN. THE BREAK LOCATIONS INDICATED ARE TYPICAL FOR LOOP B, WHICH IS ARRANGED SYMMETRICALLY. PR'S IN PARENTHESIS ARE FOR LOOP B.

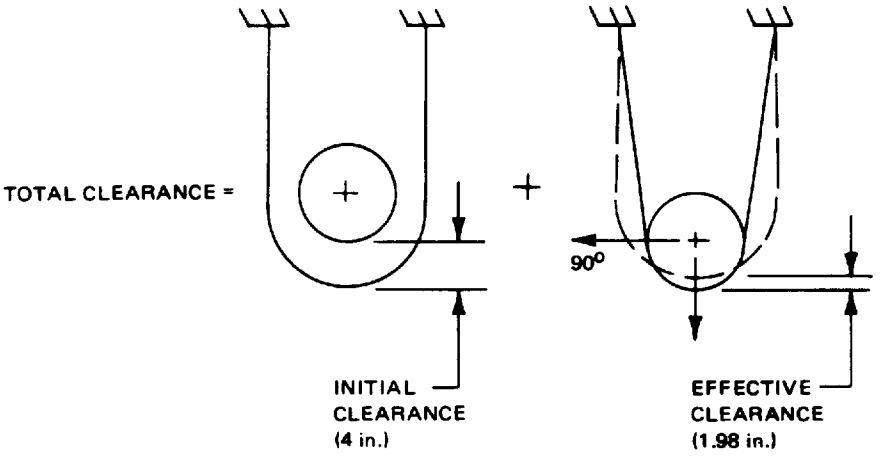
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CORE SPRAY
INJECTION PIPING ISOMETRIC
(UNIT 2)
(SHEET 2 OF 2)

FIGURE 3.6-34

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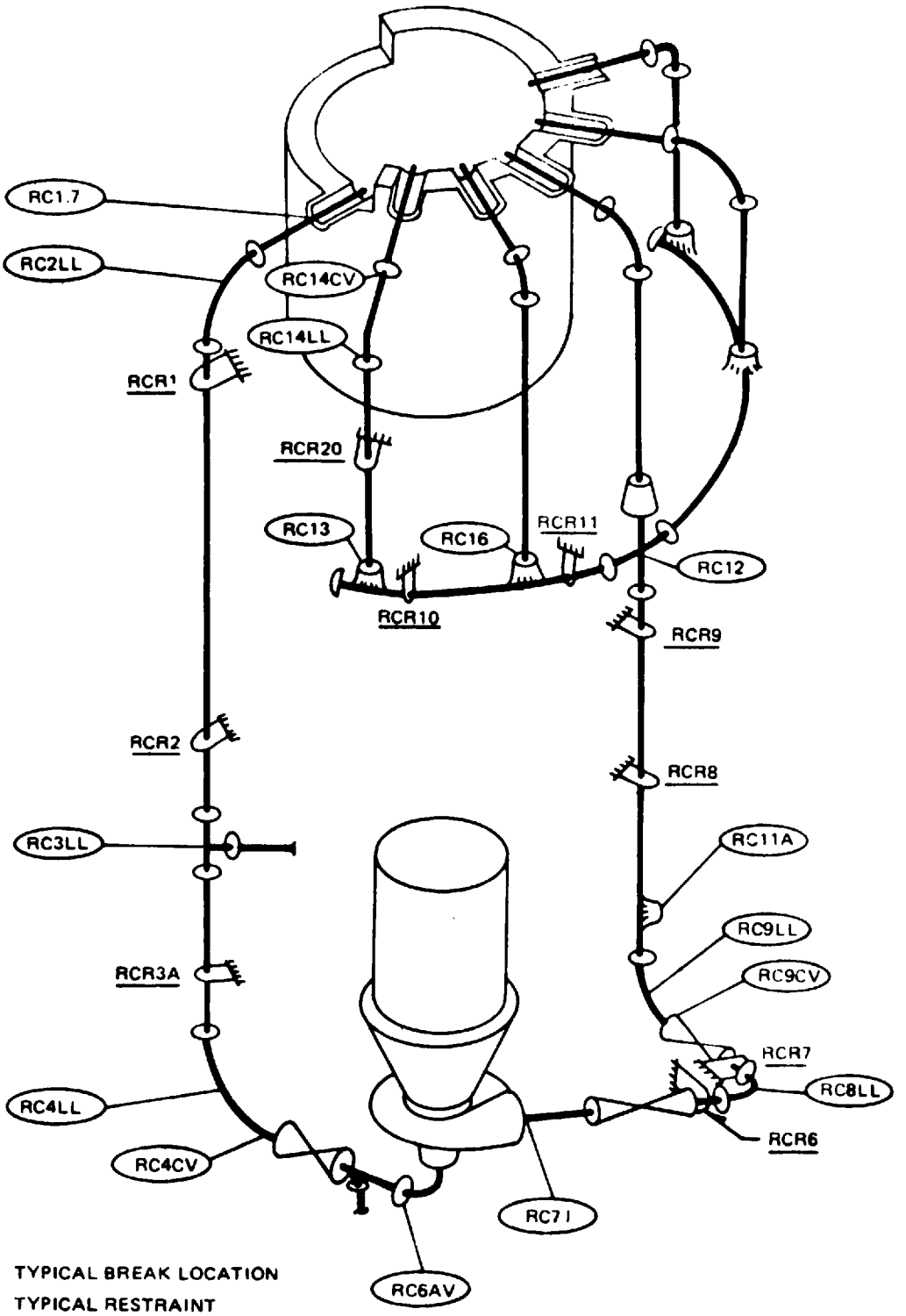




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TYPICAL FORCE-DEFLECTION CURVE FOR RECIRCULATION SYSTEM PIPE WHIP RESTRAINT

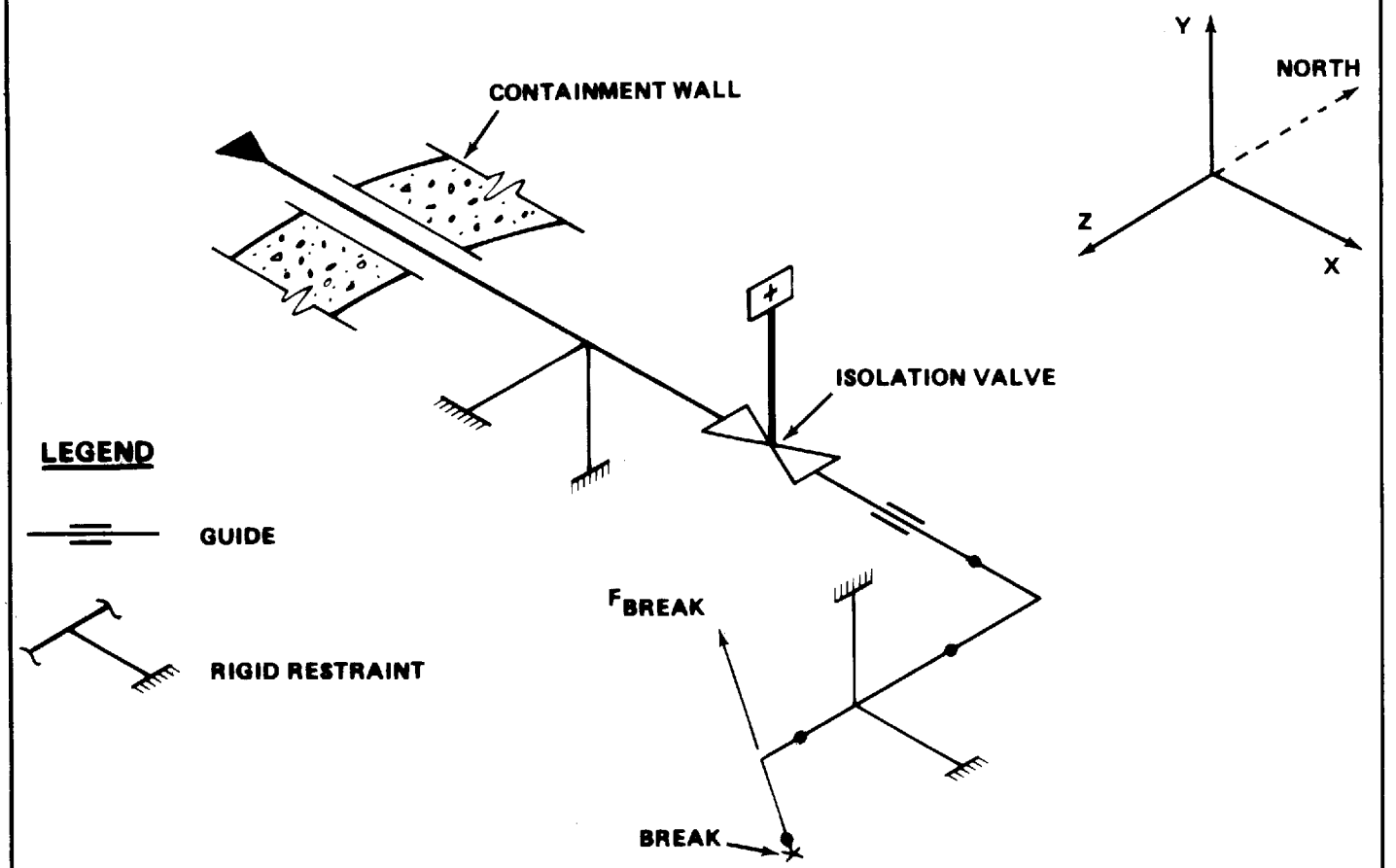
FIGURE 3.6-36



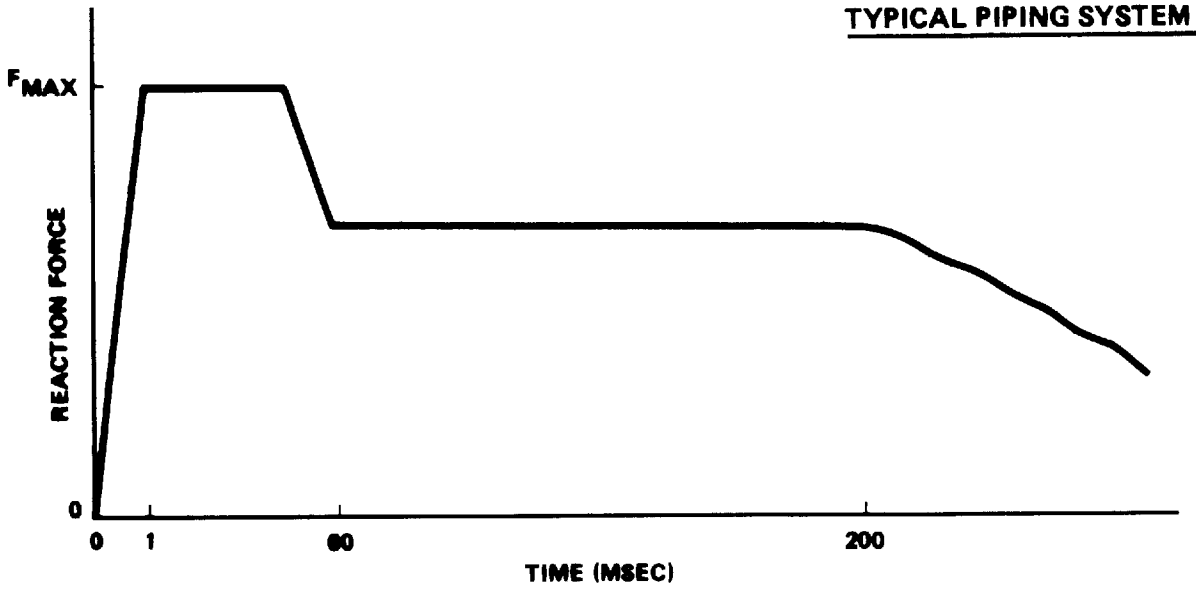
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BREAK LOCATIONS AND RESTRAINTS ANALYZED FOR PDA VERIFICATION PROGRAM

FIGURE 3.6-37



TYPICAL PIPING SYSTEM MODEL

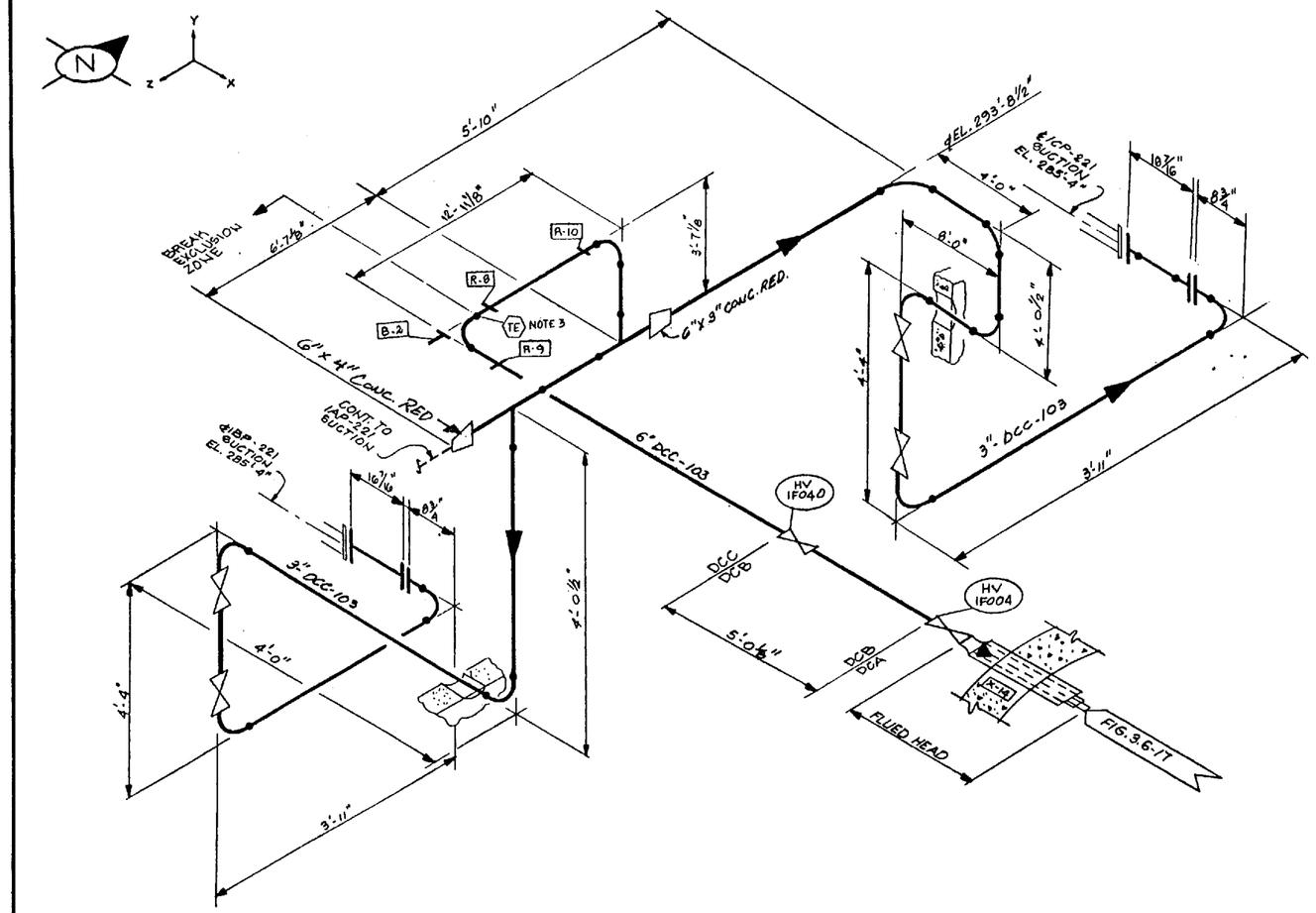


TYPICAL PIPE BREAK
FORCING FUNCTION

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UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL PIPE BREAK
ANALYSIS MODELS

FIGURE 3.6-38



NOTES

1. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS.

   (TE) – TERMINAL END BREAK
   (IB) – INTERMEDIATE BREAK
   (C) – CIRCUMFERENTIAL BREAK
   (L) – LONGITUDINAL BREAK

2. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING

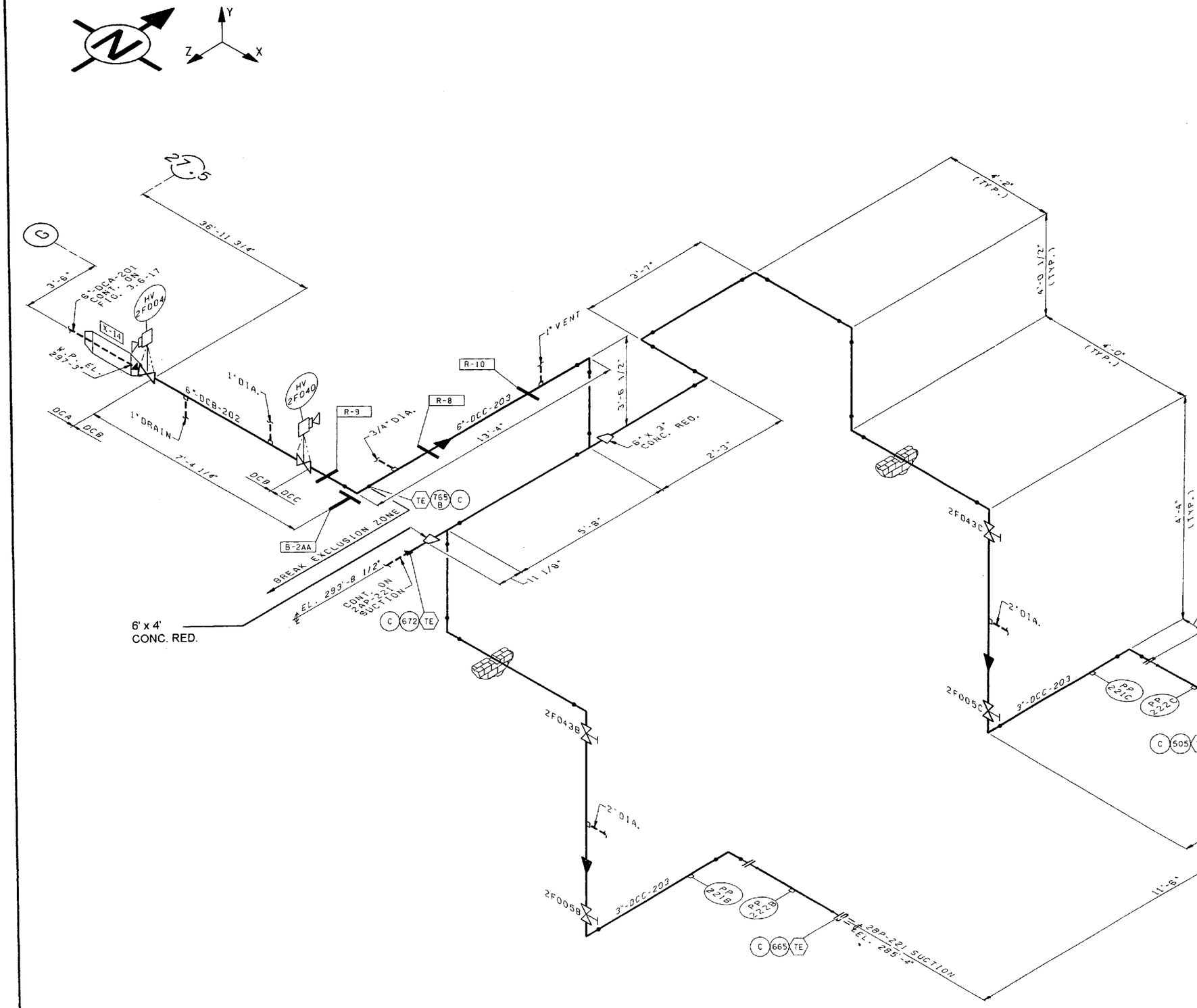
   – PIPE WHIP RESTRAINT
   – BUMPER-TYPE RESTRAINT
   – ANCHOR

3. INTERMEDIATE BREAK LOCATIONS DOWNSTREAM OF THE TERMINAL END ARE SELECTED AT LOCATIONS OF POTENTIAL HIGH STRESS IN ACCORDANCE WITH SECTION 3.6.2.1.1.4.

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RWCU PUMP SUCTION PIPING ISOMETRIC
(PORTION INSIDE RWCU ISOLATION VALVE COMPARTMENT)
(UNIT 1 ONLY)

FIGURE 3.6-39 Sht. 1 OF 2 Rev. 10 10/00



NOTES:

1. THE FOLLOWING SYMBOLS ARE USED TO INDICATE BREAK LOCATIONS:

   TE - TERMINAL END BREAK

   IB - INTERMEDIATE BREAK

   C - CIRCUMFERENTIAL BREAK

   L - LONGITUDINAL BREAK

2. STRUCTURES AND DEVICES THAT ACT AS RESTRICTIONS TO PIPE MOVEMENT FOLLOWING A PIPE BREAK ARE DESIGNATED BY THE FOLLOWING SYMBOLS:

   - PIPE WHIP RESTRAINT

   - BUMPER-TYPE RESTRAINT

   - ANCHOR

   - COMPENSATING STRUT

3. INTERMEDIATE BREAK LOCATIONS DOWNSTREAM OF THE TERMINAL END ARE SELECTED AT LOCATIONS OF POTENTIAL HIGH STRESS IN ACCORDANCE WITH SECTION 3.6.2.1.1.4.

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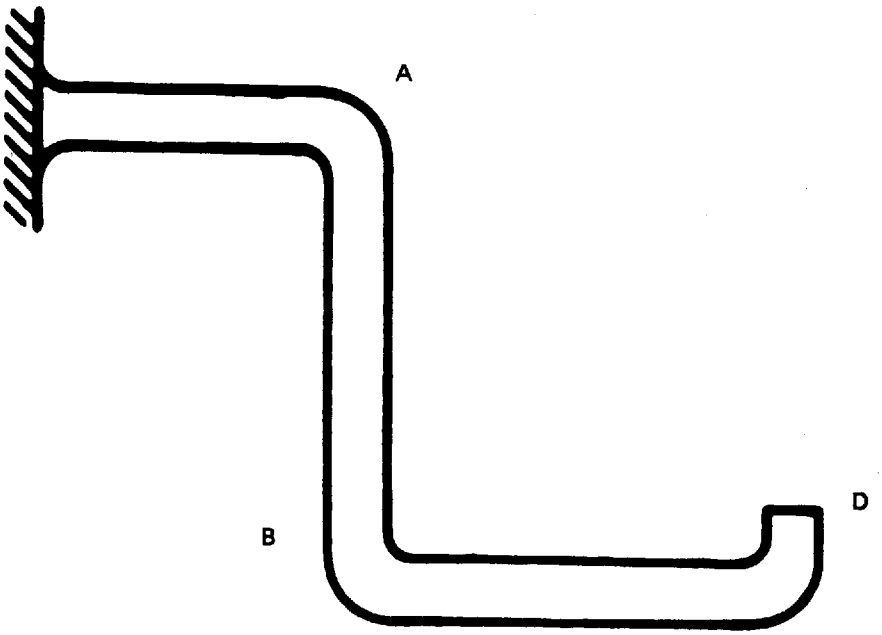
RWCU PUMP SUCTION PIPING ISOMETRIC (PORTION INSIDE RWCU ISOLATION VALVE COMPARTMENT) (UNIT 2)
(SHEET 2 OF 2)

FIGURE 3.6-39

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Figure 3.6-40

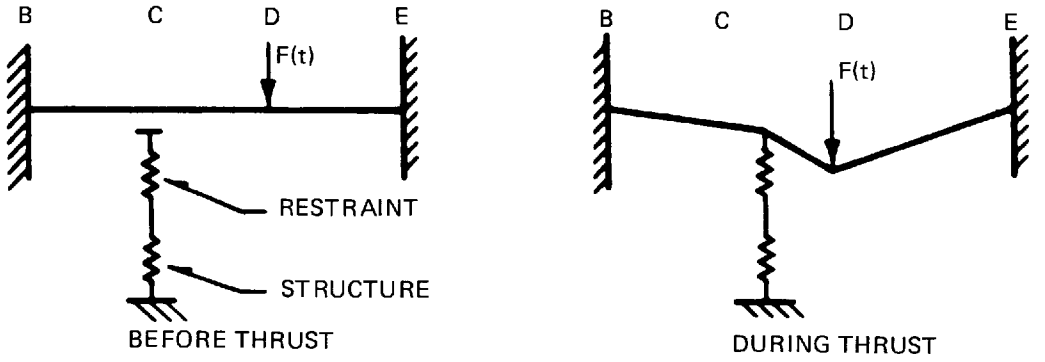
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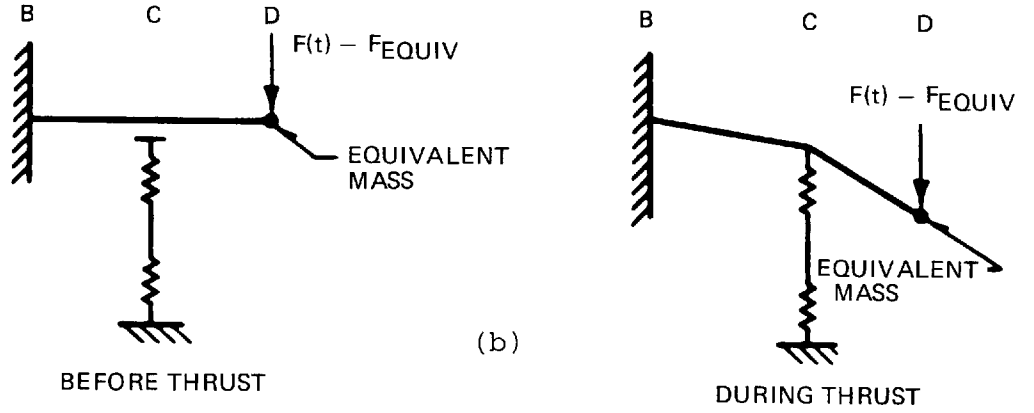
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GENERIC REPRESENTATION OF PIPE

FIGURE 3.6-41



(a)



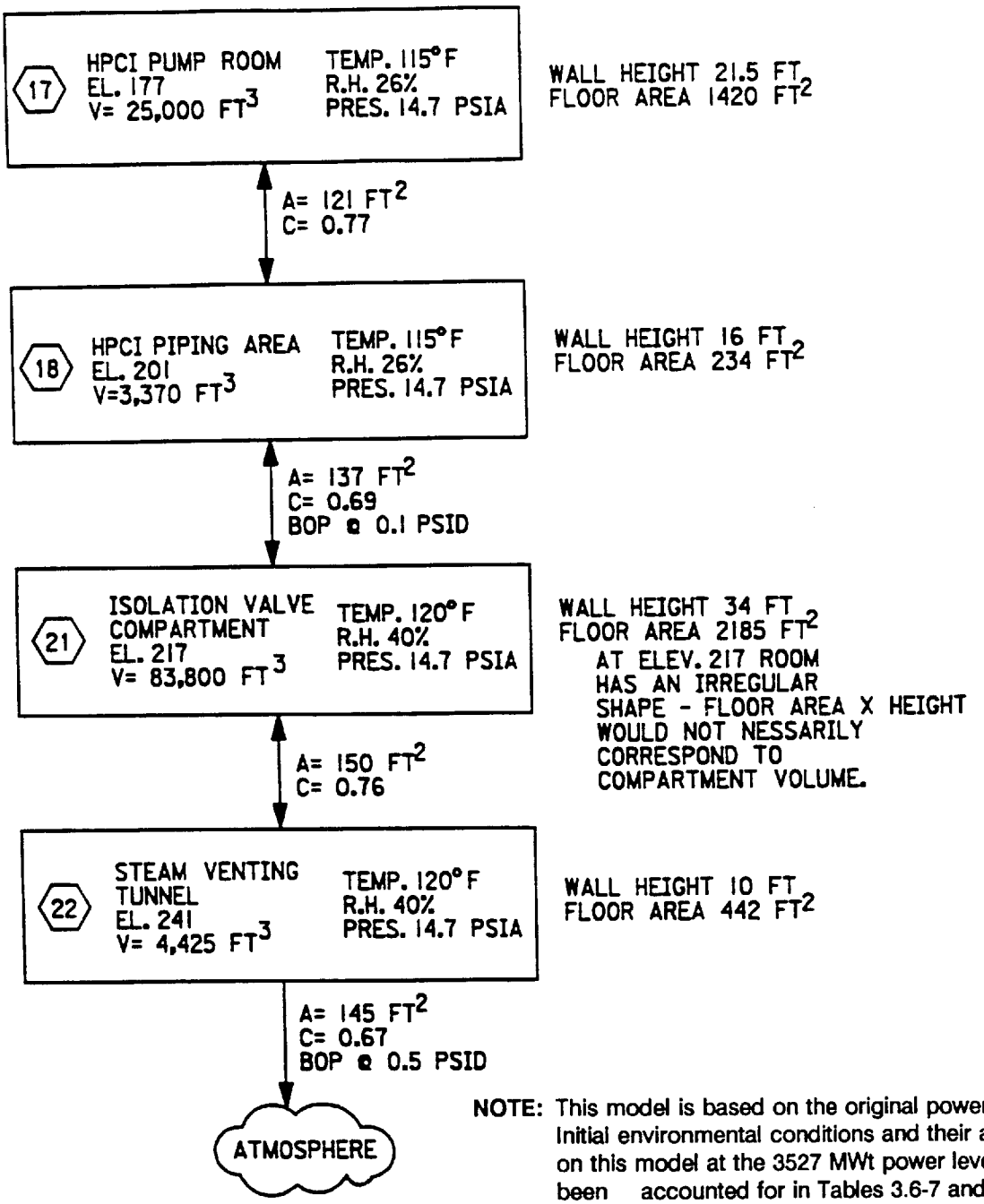
(b)

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REPRESENTATION OF PIPE WITH BOTH ENDS BUILT-IN

FIGURE 3.6-42

HPCI STEAM LINE BREAK IN HPCI COMPARTMENT STEAM LINE TEMP. 547.5°F PRES. 1024 PSIA



NOTE: This model is based on the original power level. Initial environmental conditions and their affect on this model at the 3527 MWt power level have been accounted for in Tables 3.6-7 and 3.6-9.

A= VENT AREA
C= FLOW COEFFICIENT
V= FREE VOLUME
BOP= BLOWOUT PANEL

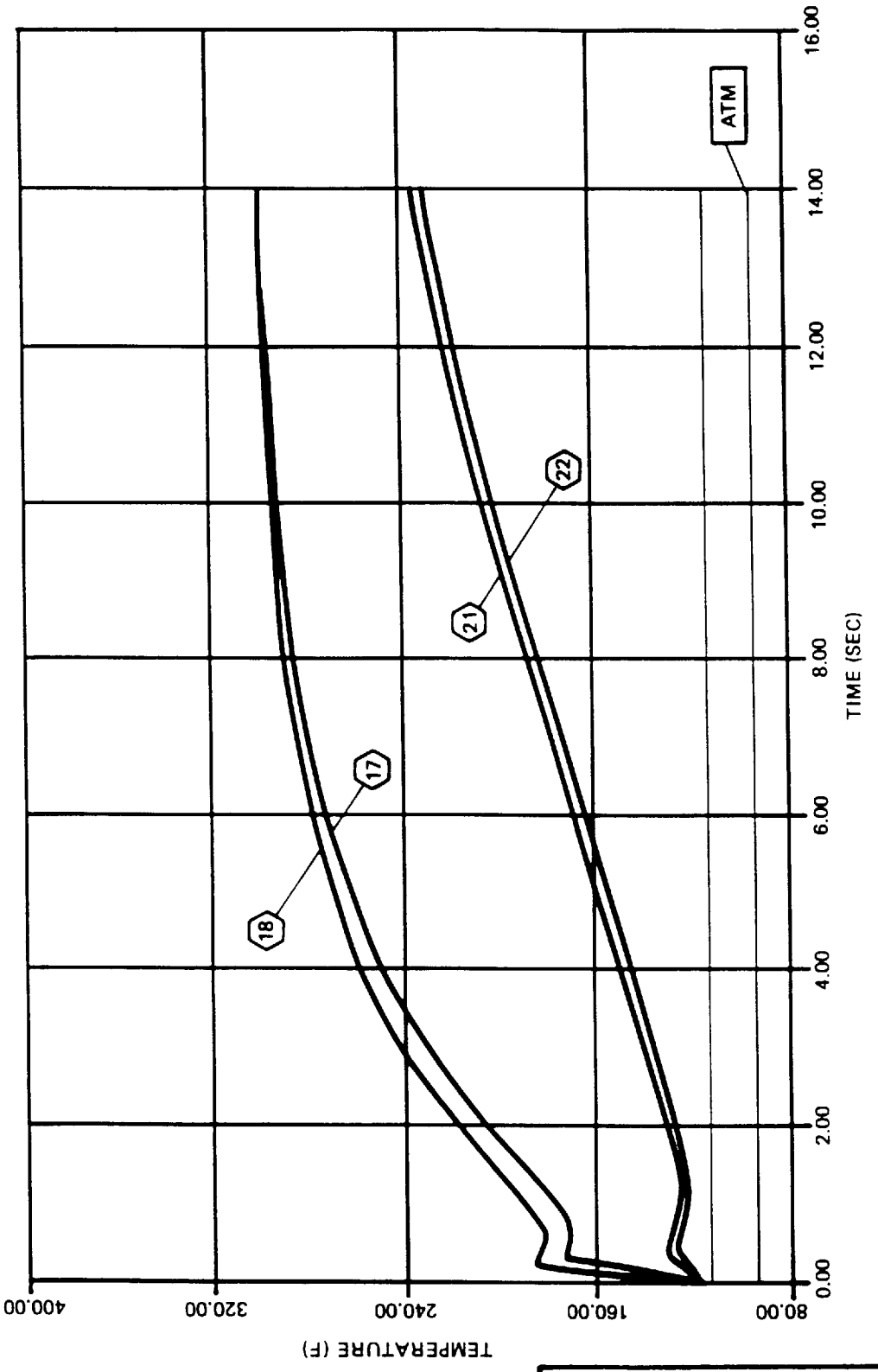
LIMS13.DGN

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ENVIRONMENTAL CONDITIONS AND COMPARTMENT DIMENSIONS FOR HPCI STEAM LINE BREAK

FIGURE 3.6-43

Rev. 5, 4/96

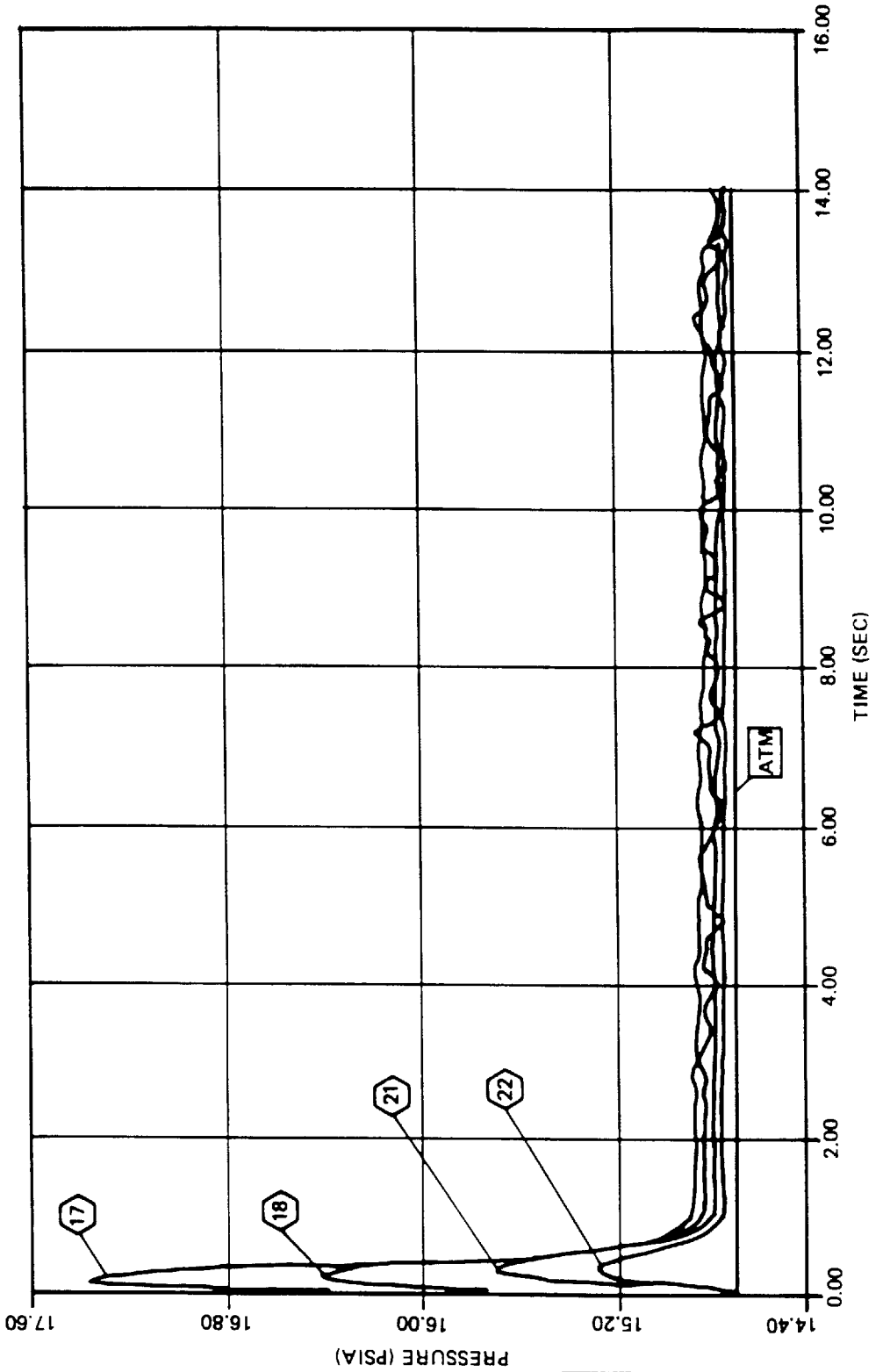


NOTE: This temperature transient is based on the original power level. Environmental conditions for the break based on a power level of 3527 MWt are listed in Tables 3.6-7 and 3.6-9.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

HPCI STEAM SUPPLY LINE BREAK IN HPCI COMPARTMENT TEMPERATURE TRANSIENT

FIGURE 3.6-44 Rev. 5, 4/96

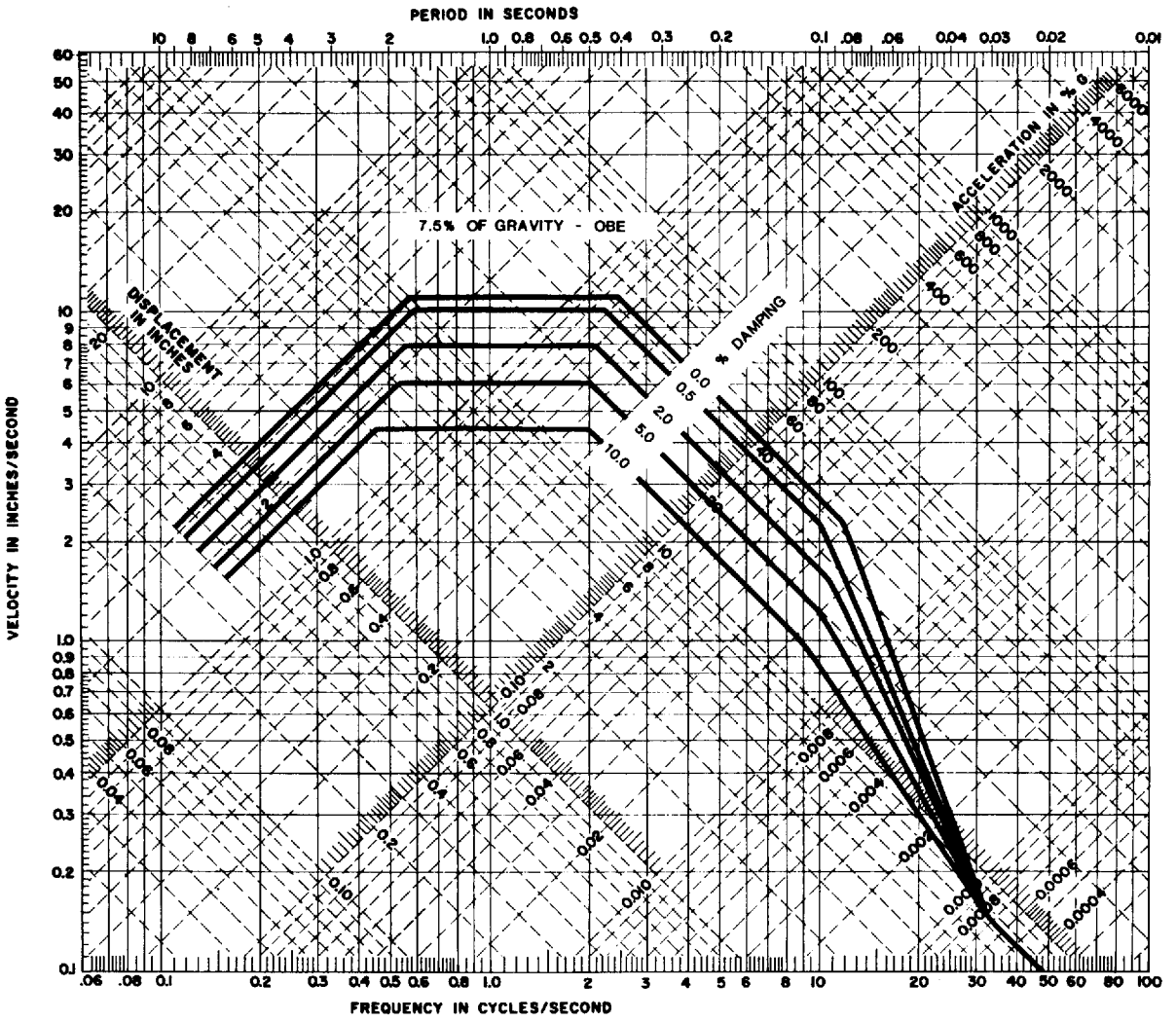


NOTE: This pressure transient is based on the original power level. Environmental conditions for the break based on a power level of 3527 MWt are listed in Tables 3.6-7 and 3.6-9.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

HPCI STEAM SUPPLY LINE BREAK
IN HPCI COMPARTMENT
PRESSURE TRANSIENT

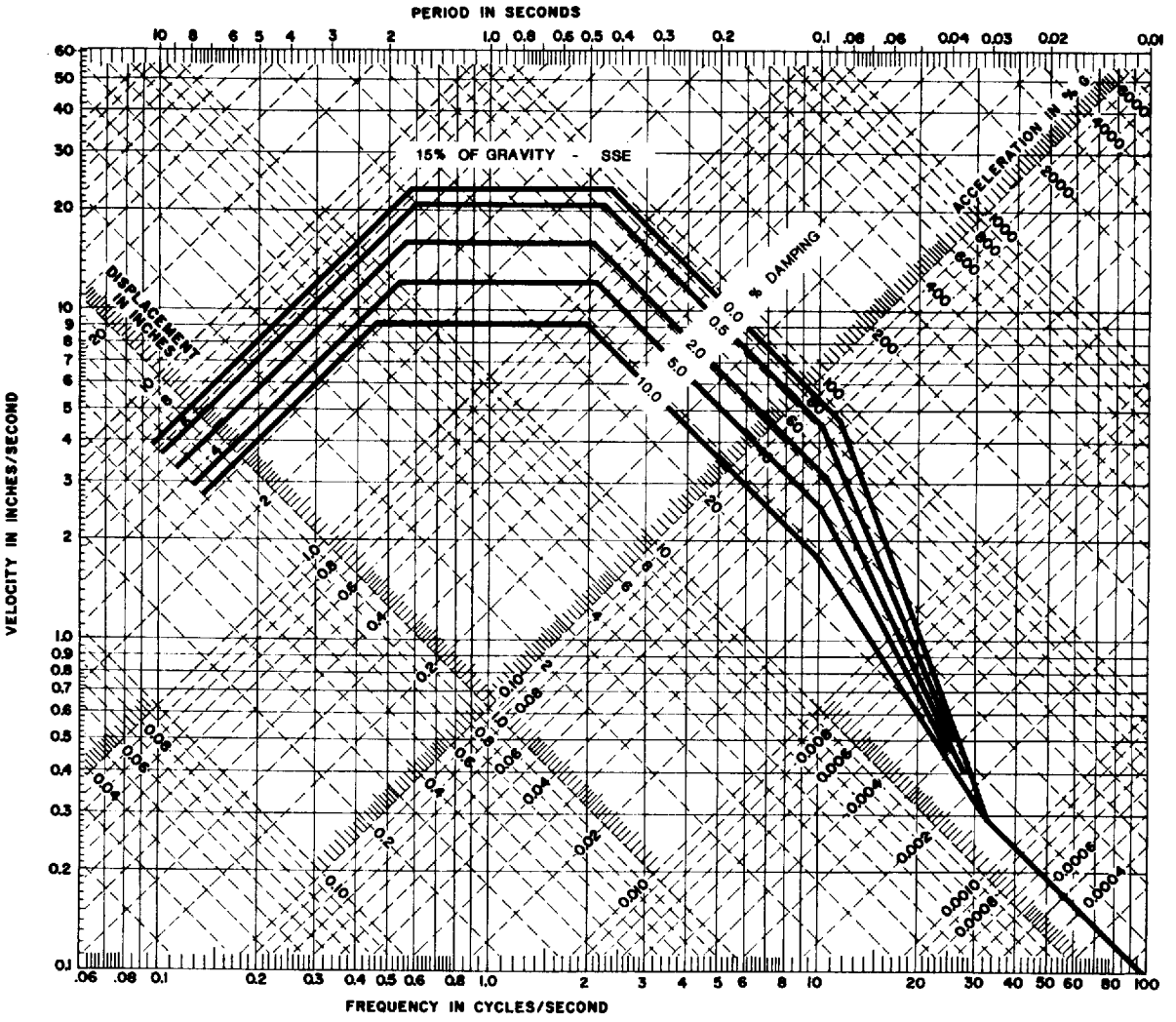
FIGURE 3.6-45 Rev. 5, 4/96



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DESIGN RESPONSE SPECTRA FOR OPERATING BASIS EARTHQUAKE (HORIZONTAL COMPONENT)

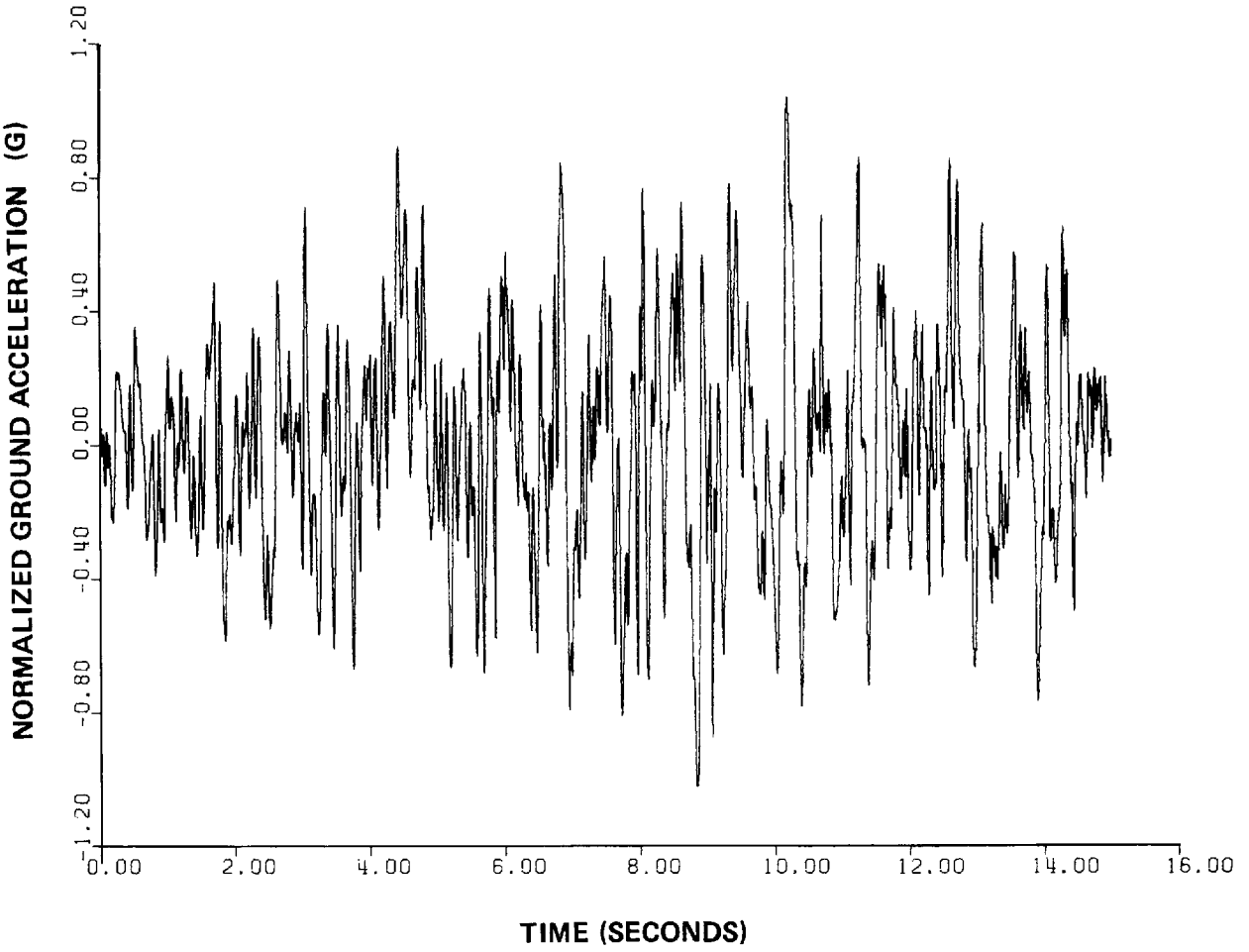
FIGURE 3.7-1



LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN RESPONSE SPECTRA FOR SAFE SHUTDOWN EARTHQUAKE (HORIZONTAL COMPONENT)

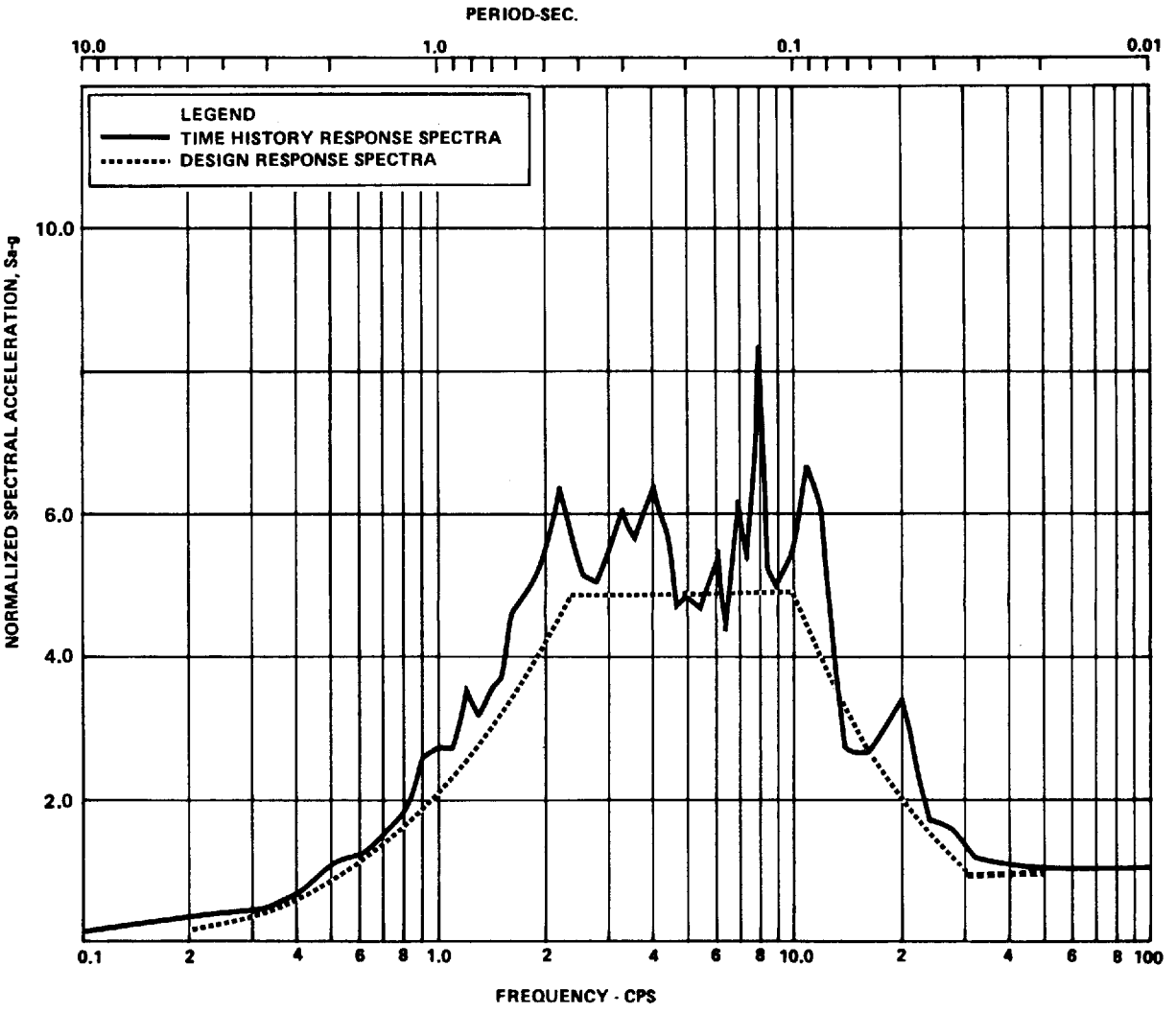
FIGURE 3.7-2



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SYNTHETIC TIME HISTORY NORMALIZED TO 1G

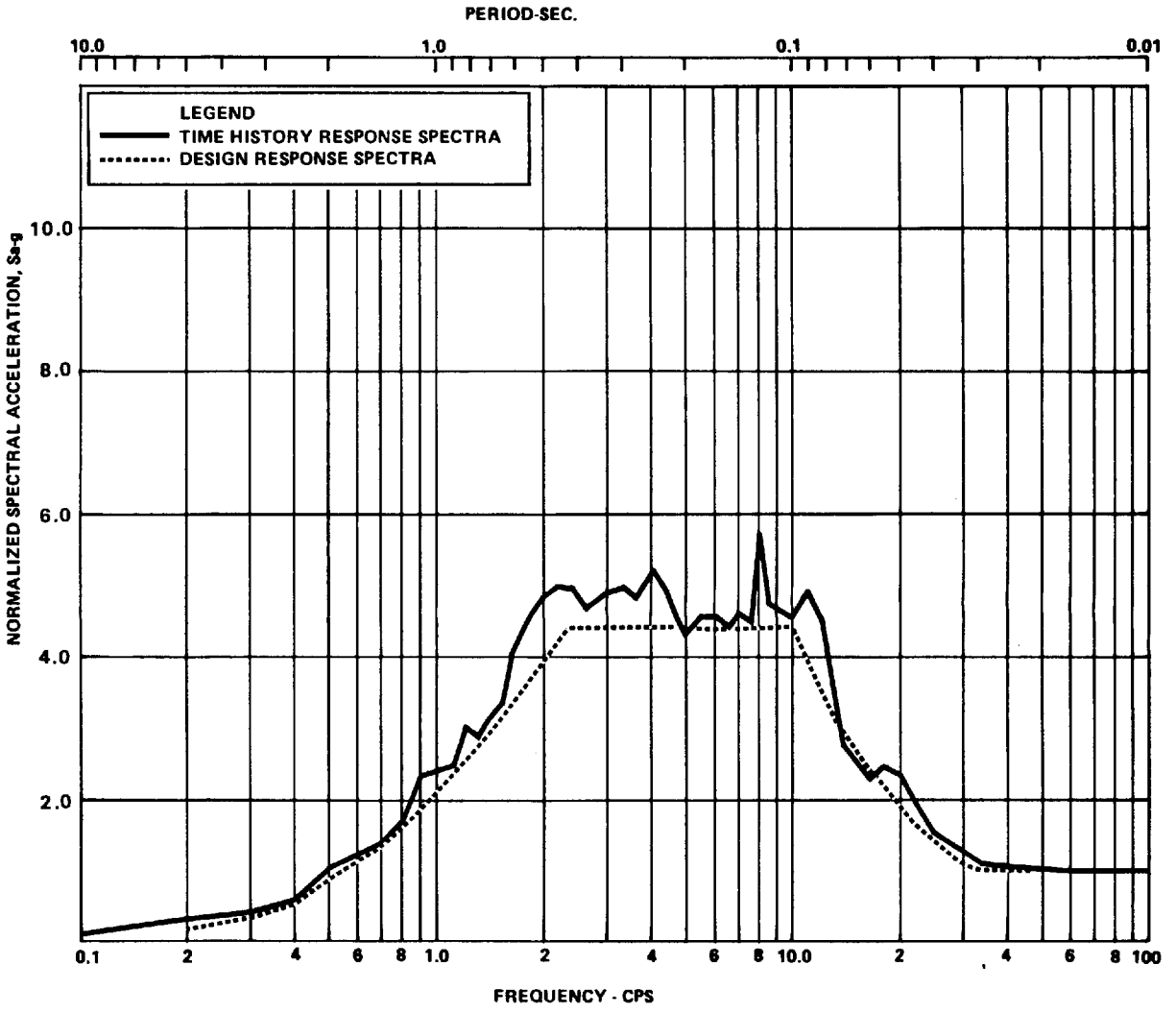
FIGURE 3.7-3



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

COMPARISON OF TIME HISTORY RESPONSE SPECTRA AND DESIGN RESPONSE SPECTRA (0.5% DAMPING) (NORMALIZED TO 1g)

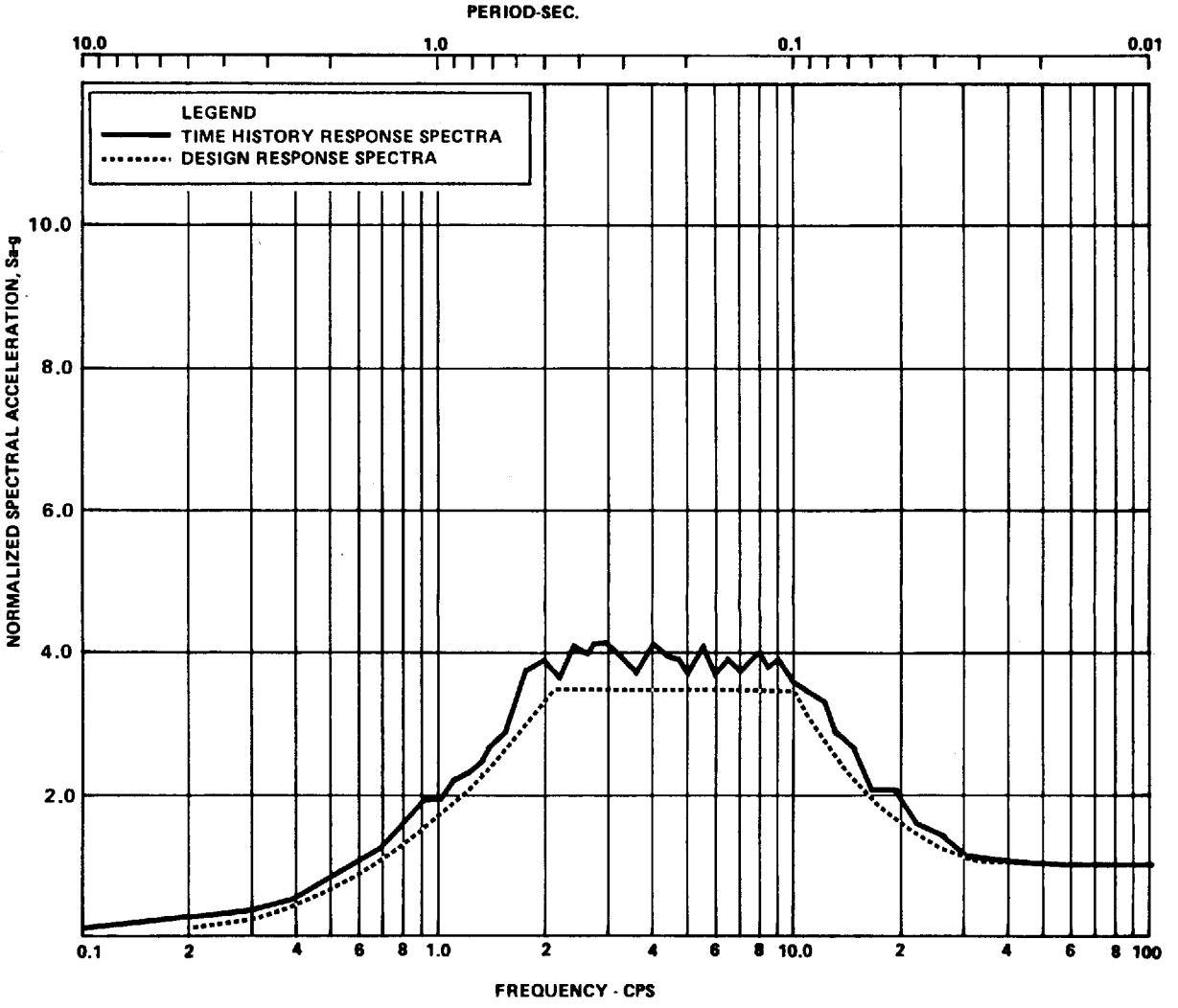
FIGURE 3.7-4



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

COMPARISON OF TIME HISTORY RESPONSE SPECTRA AND DESIGN RESPONSE SPECTRA (1% DAMPING) (NORMALIZED TO 1g)

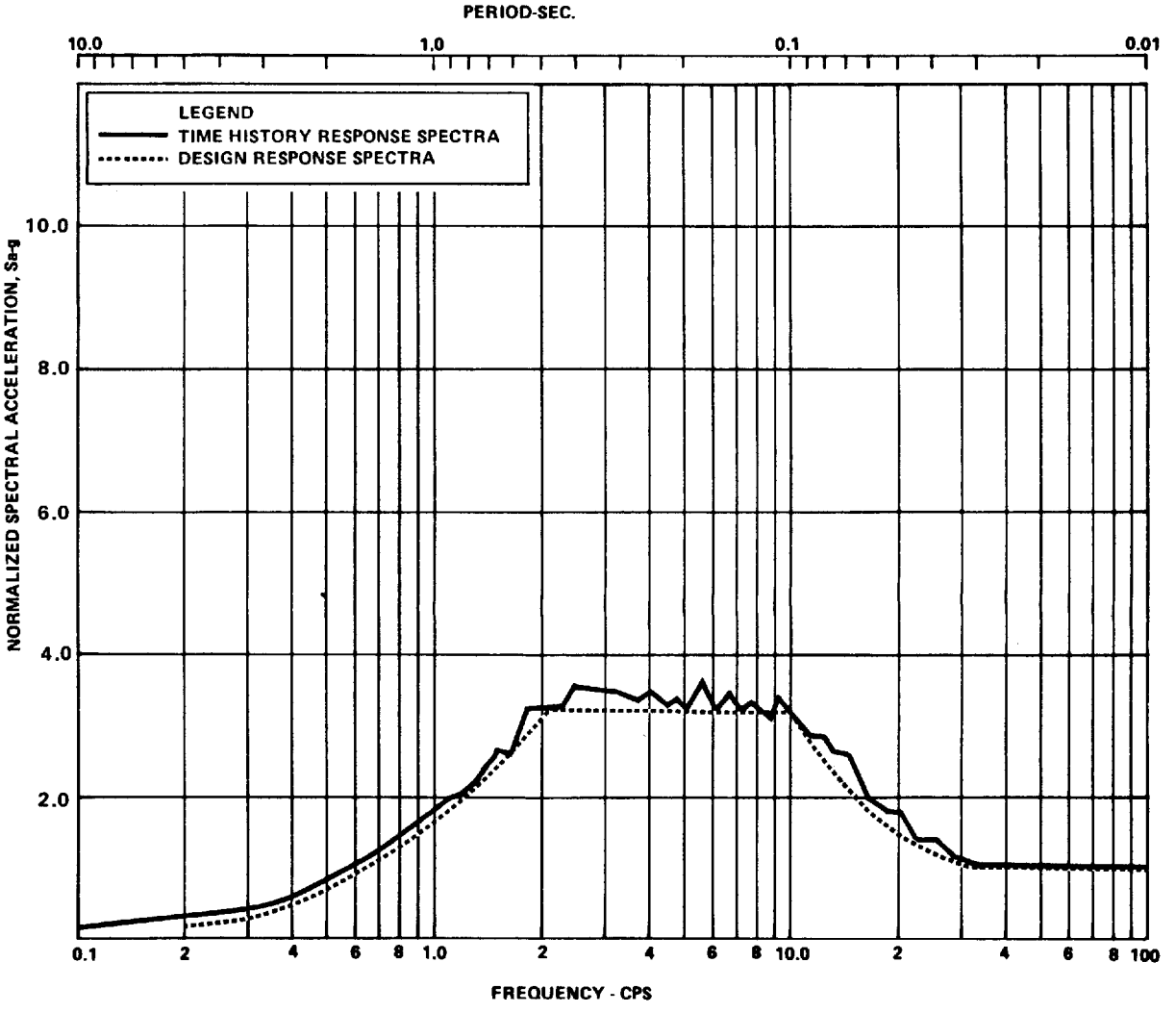
FIGURE 3.7-5



LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

COMPARISON OF TIME HISTORY RESPONSE SPECTRA AND DESIGN RESPONSE SPECTRA (2% DAMPING) (NORMALIZED TO 1g)

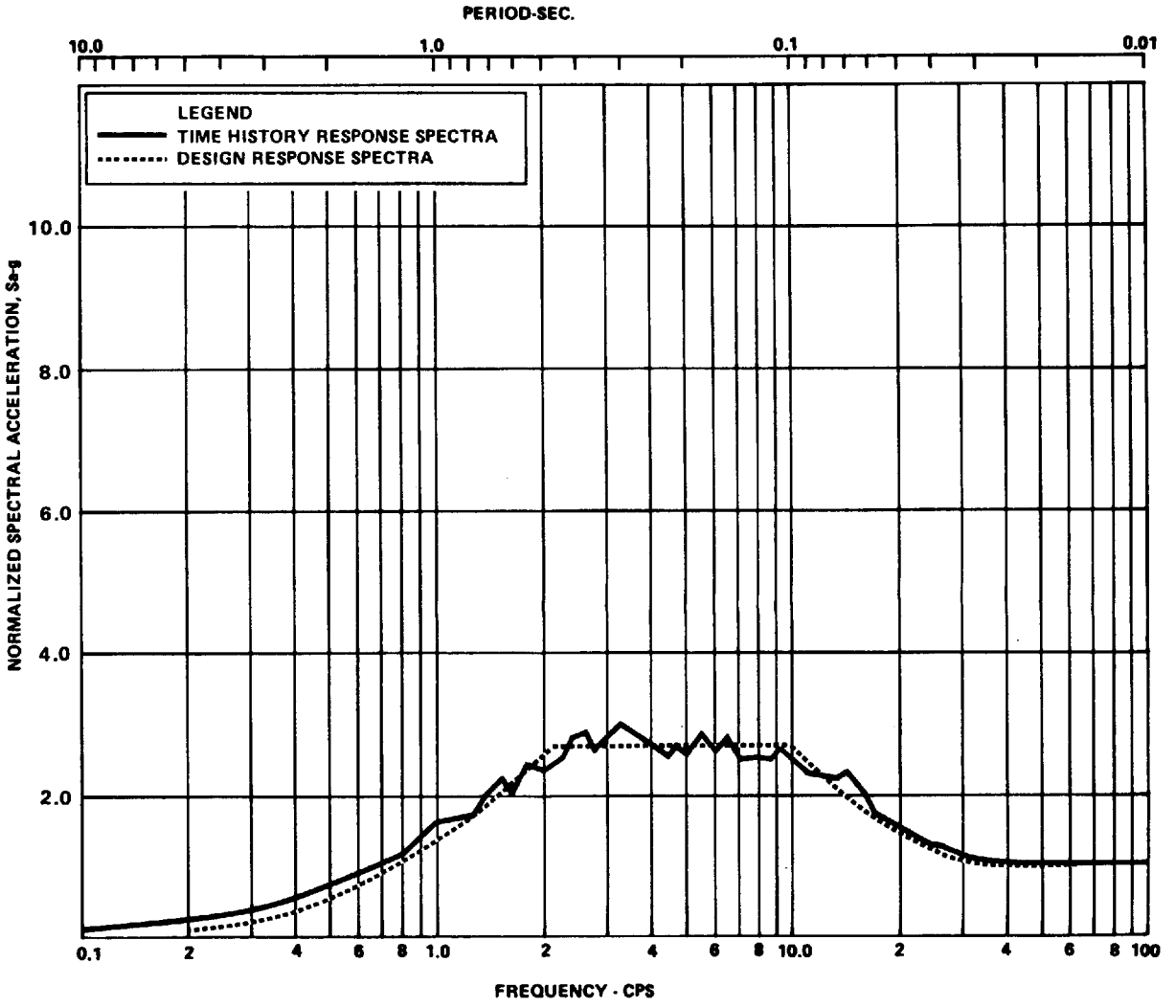
FIGURE 3.7-6



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

COMPARISON OF TIME HISTORY RESPONSE SPECTRA AND DESIGN RESPONSE SPECTRA (3% DAMPING) (NORMALIZED TO 1g)

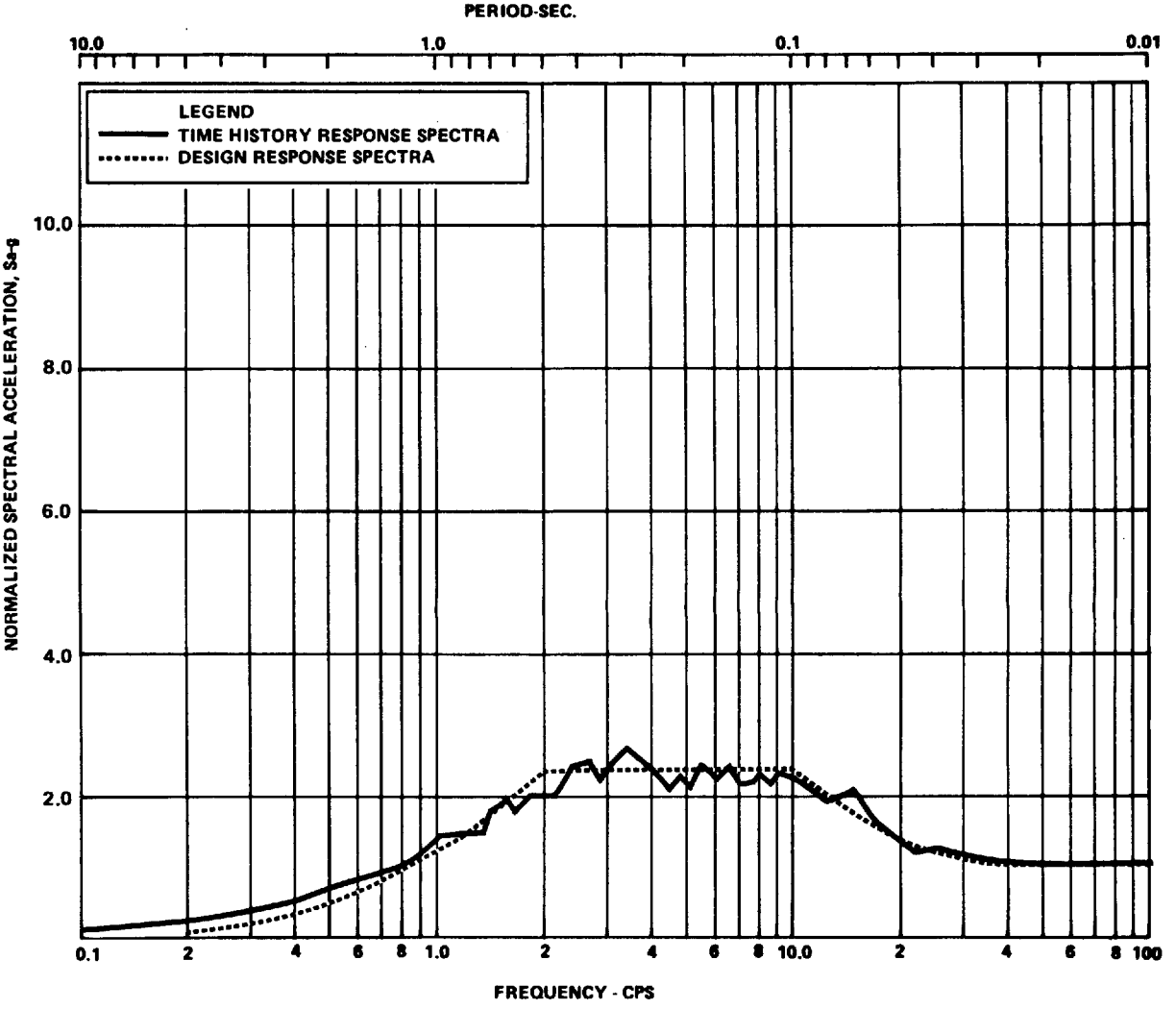
FIGURE 3.7-7



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

COMPARISON OF TIME HISTORY RESPONSE SPECTRA AND DESIGN RESPONSE SPECTRA (5% DAMPING) (NORMALIZED TO 1g)

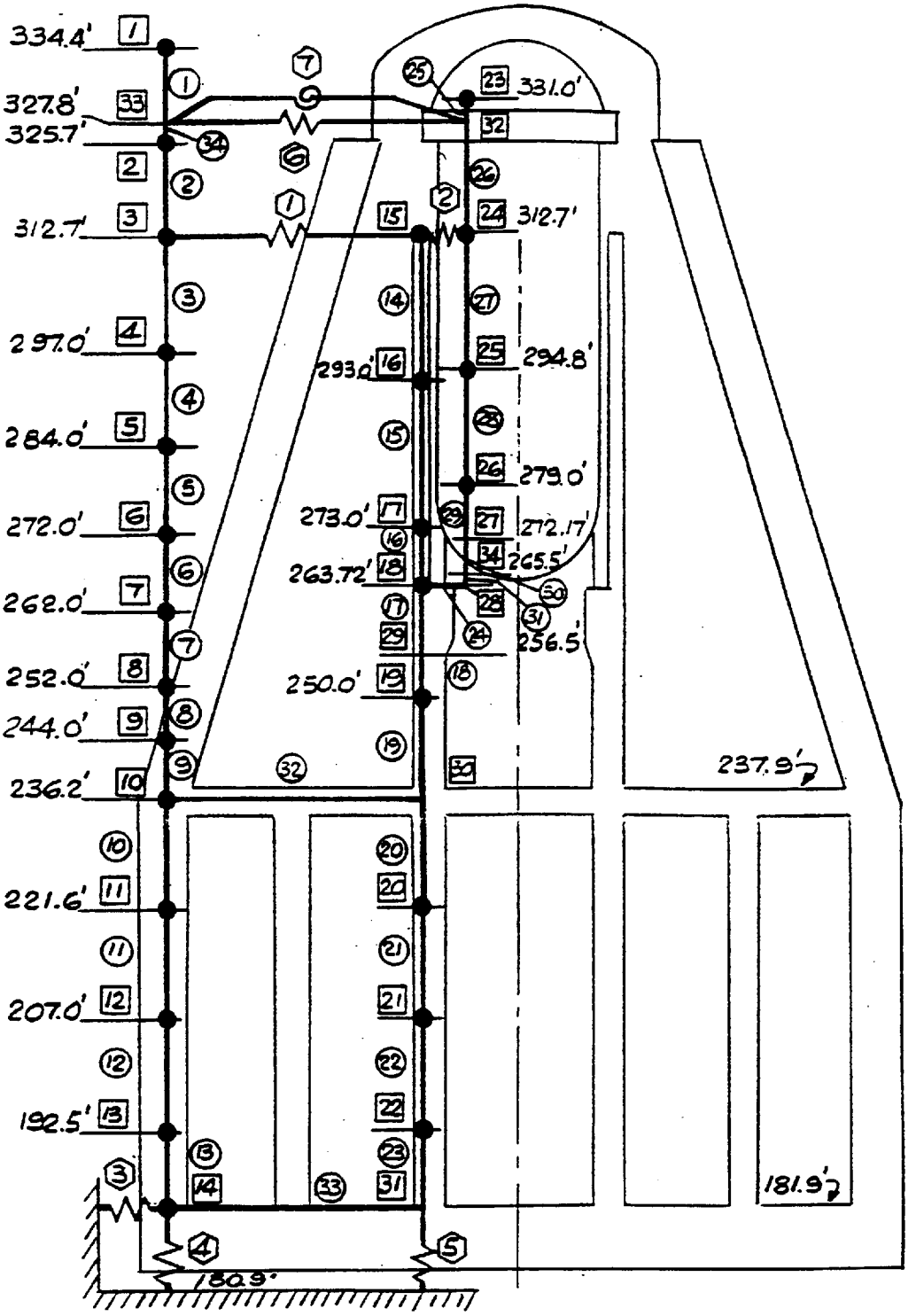
FIGURE 3.7-8



LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

COMPARISON OF TIME HISTORY RESPONSE SPECTRA AND DESIGN RESPONSE SPECTRA (7% DAMPING) (NORMALIZED TO 1g)

FIGURE 3.7-9



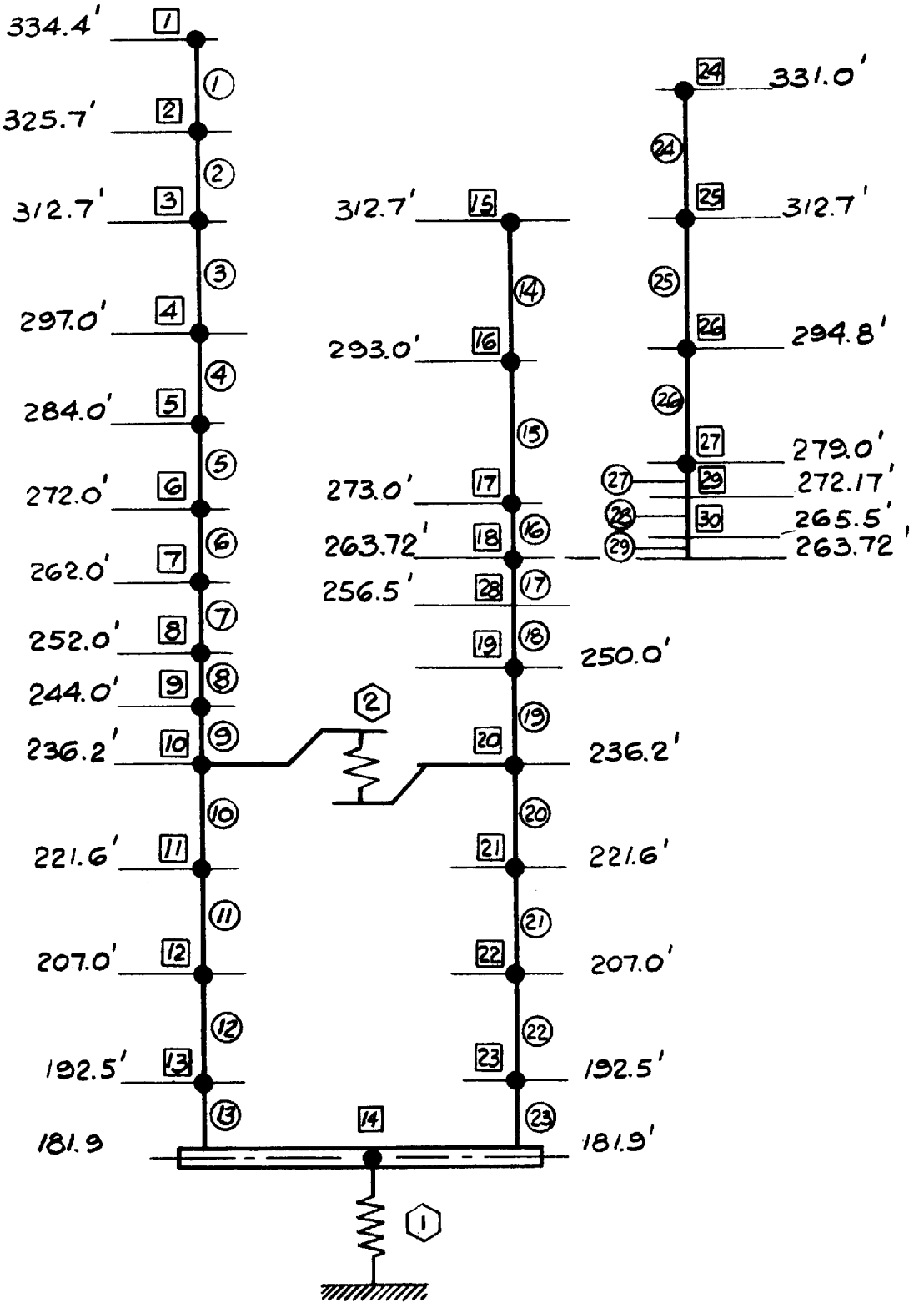
LEGEND :

- ● MASS POINT
- □ JOINT NUMBER
- ○ MEMBER NUMBER
- ⬡ SPRING NUMBER

LIMERICK GENERATING STATION
UNITS 1 AND 2
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HORIZONTAL SEISMIC MODEL OF PRIMARY CONTAINMENT

FIGURE 3.7-10 Rev 08 11/98



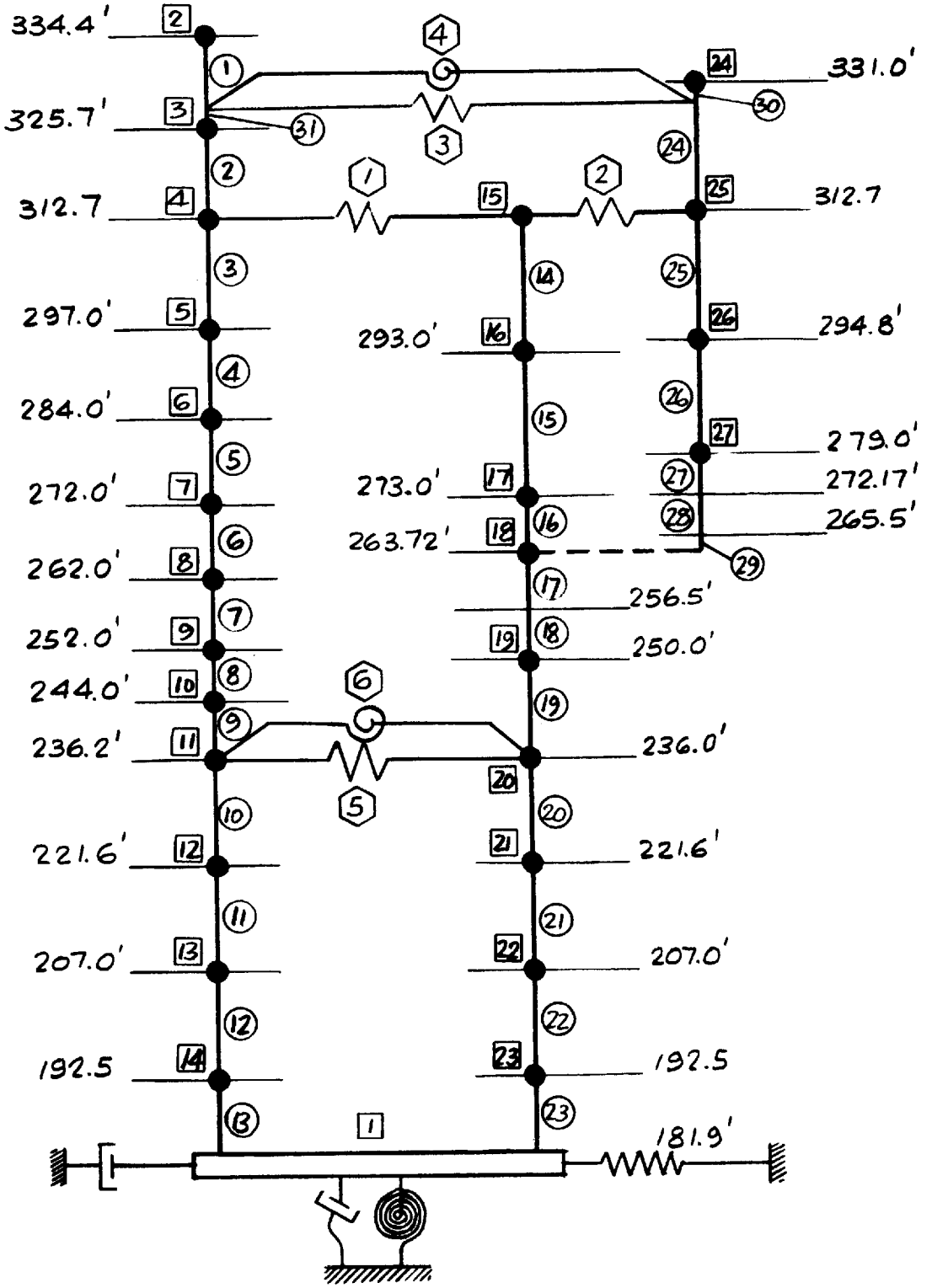
LEGEND:

- ● MASS POINT
- □ JOINT NUMBER
- ○ MEMBER NUMBER
- ⬡ SPRING NUMBER

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

VERTICAL SEISMIC MODEL OF PRIMARY CONTAINMENT

FIGURE 3.7-11



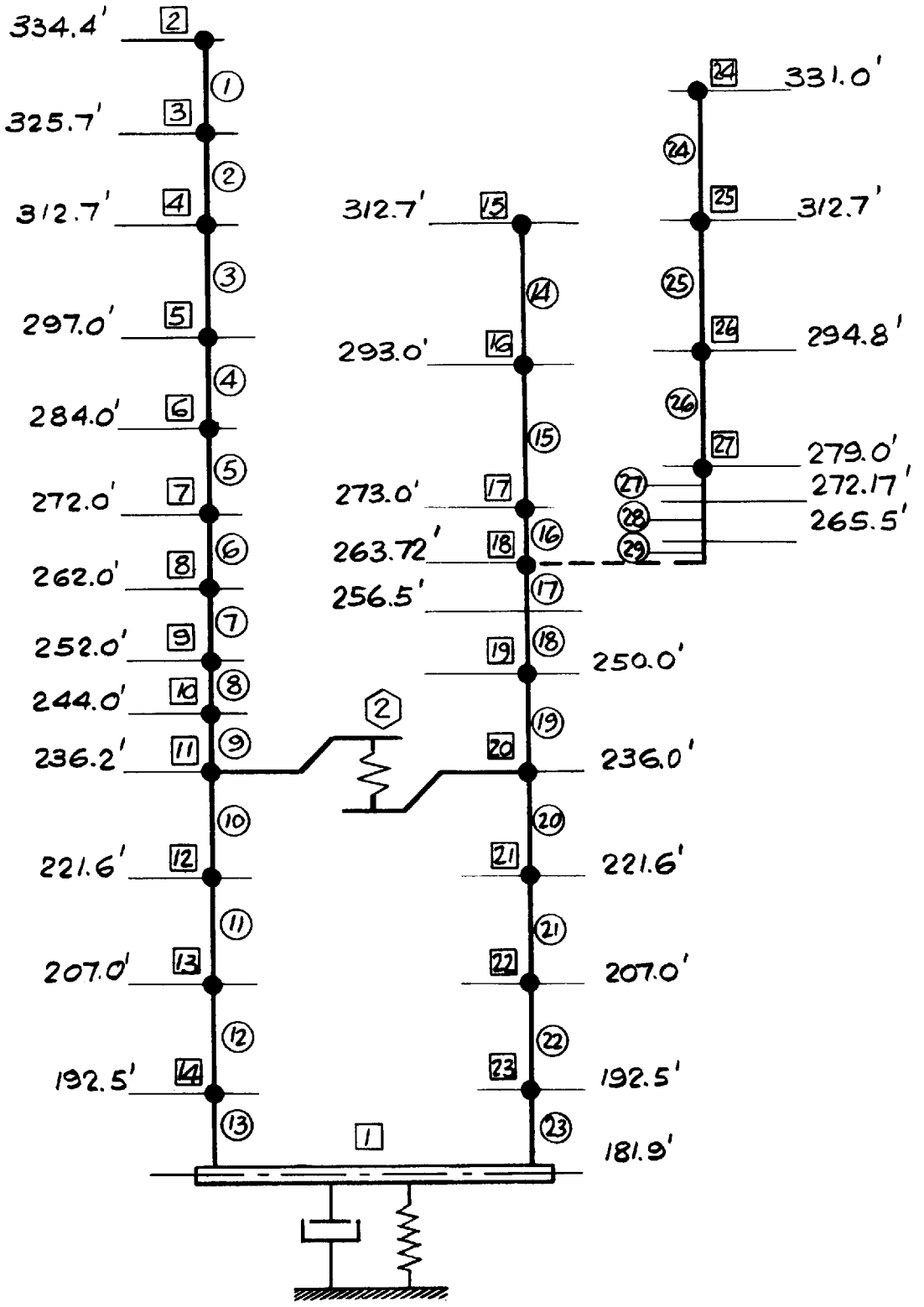
LEGEND :

- ☐ ● MASS POINT NUMBER
- — JOINT
- ○ MEMBER NUMBER
- ⬡ SPRING NUMBER

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

HORIZONTAL SEISMIC MODEL OF PRIMARY CONTAINMENT WITH SOIL-STRUCTURE INTERACTION

FIGURE 3.7-12



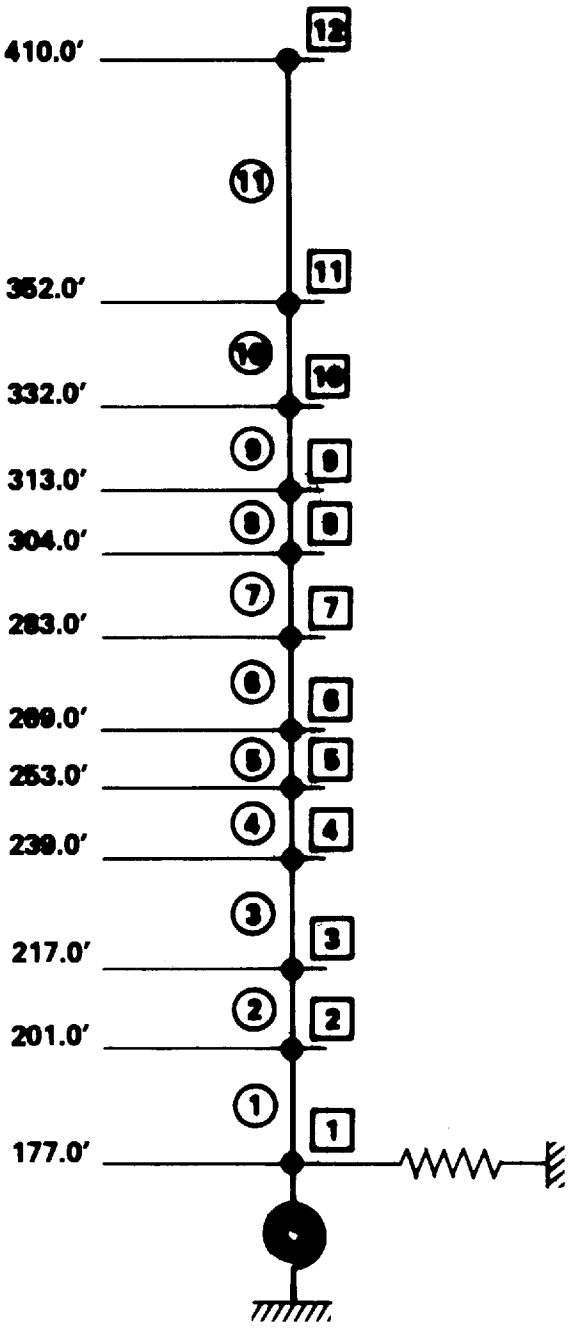
LEGEND :

- □ ● MASS POINT NUMBER
- — JOINT
- ○ MEMBER NUMBER
- ⬡ SPRING NUMBER

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

VERTICAL SEISMIC MODEL OF PRIMARY CONTAINMENT WITH SOIL-STRUCTURE INTERACTION

FIGURE 3.7-13



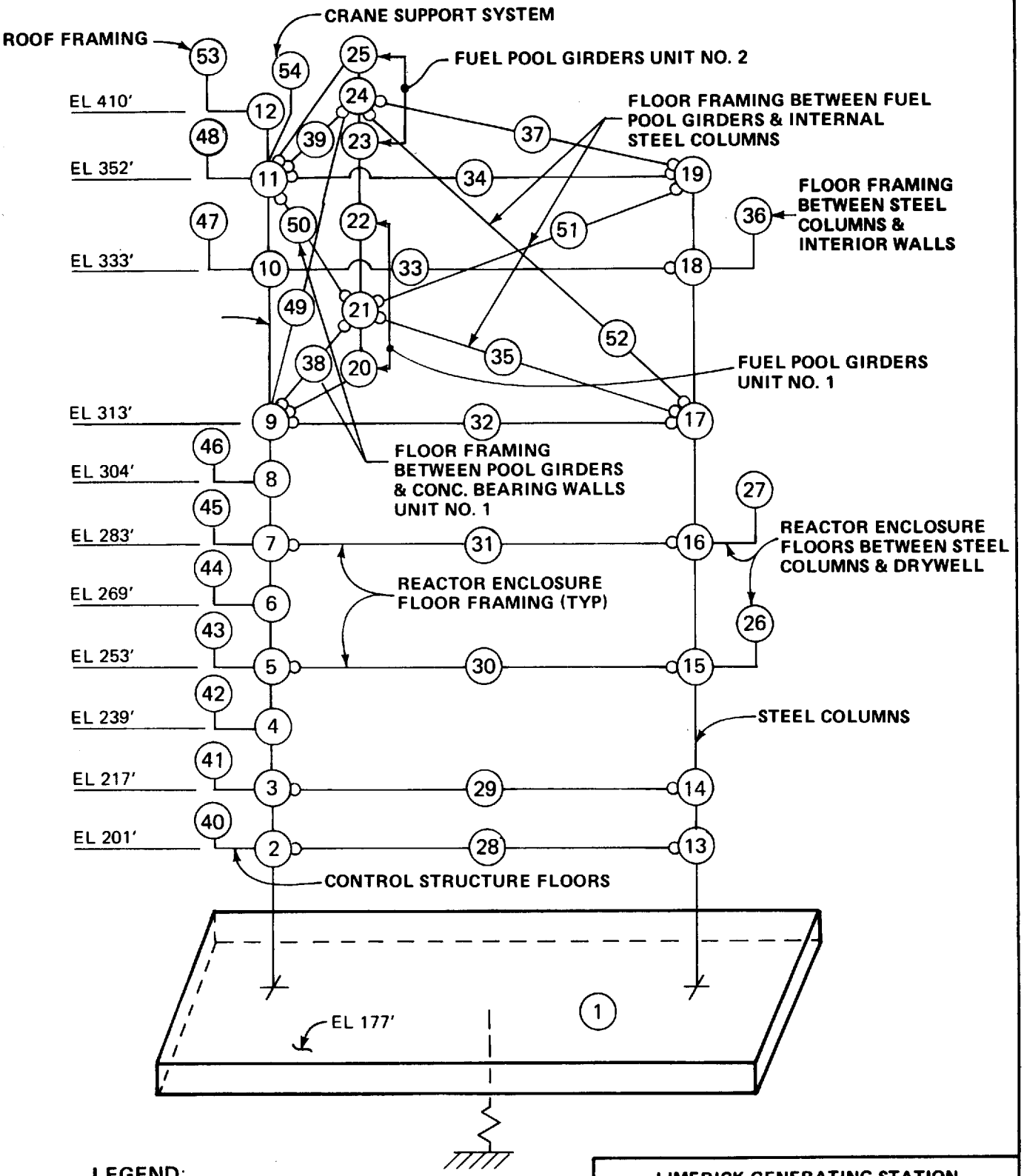
LEGEND:

- ● MASS POINT
- □ JOINT NUMBER
- ○ MEMBER NUMBER

LIMERICK GENERATING STATION
UNITS 1 AND 2
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HORINZONTAL SEISMIC MODEL OF REACTOR ENCLOSURE AND CONTROL STRUCTURE

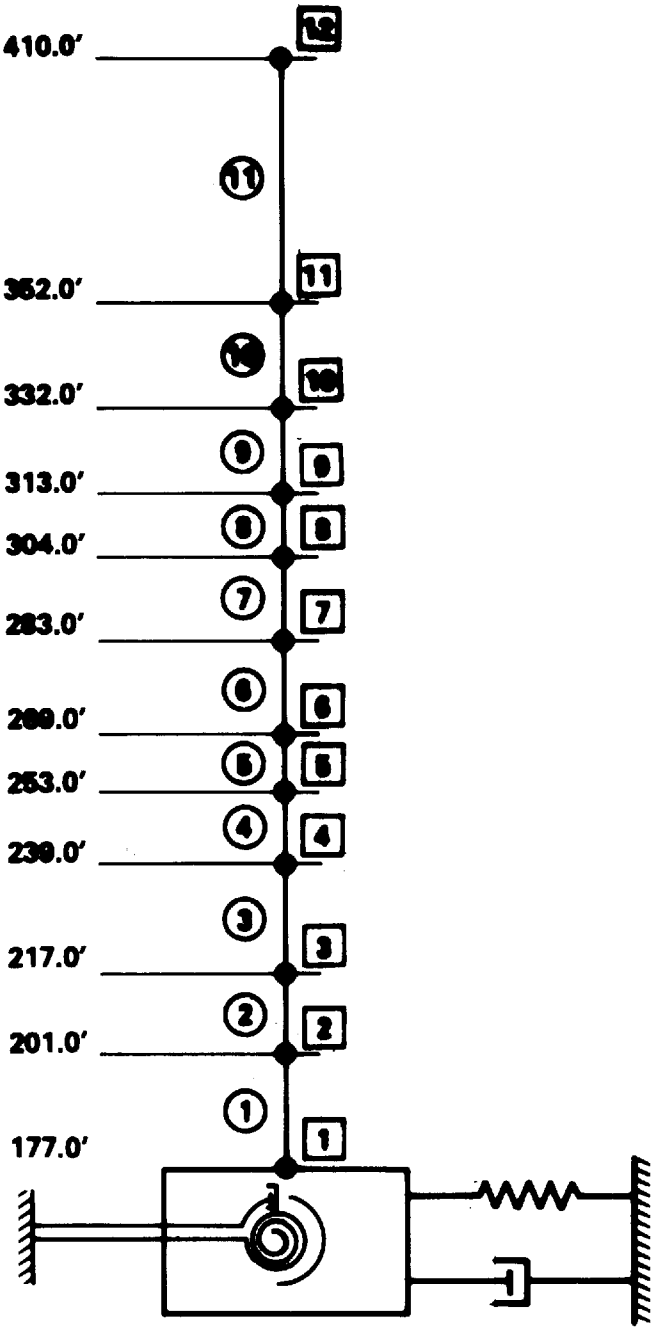
FIGURE 3.7-14



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VERTICAL SEISMIC MODEL OF REACTOR ENCLOSURE AND CONTROL STRUCTURE

FIGURE 3.7-15



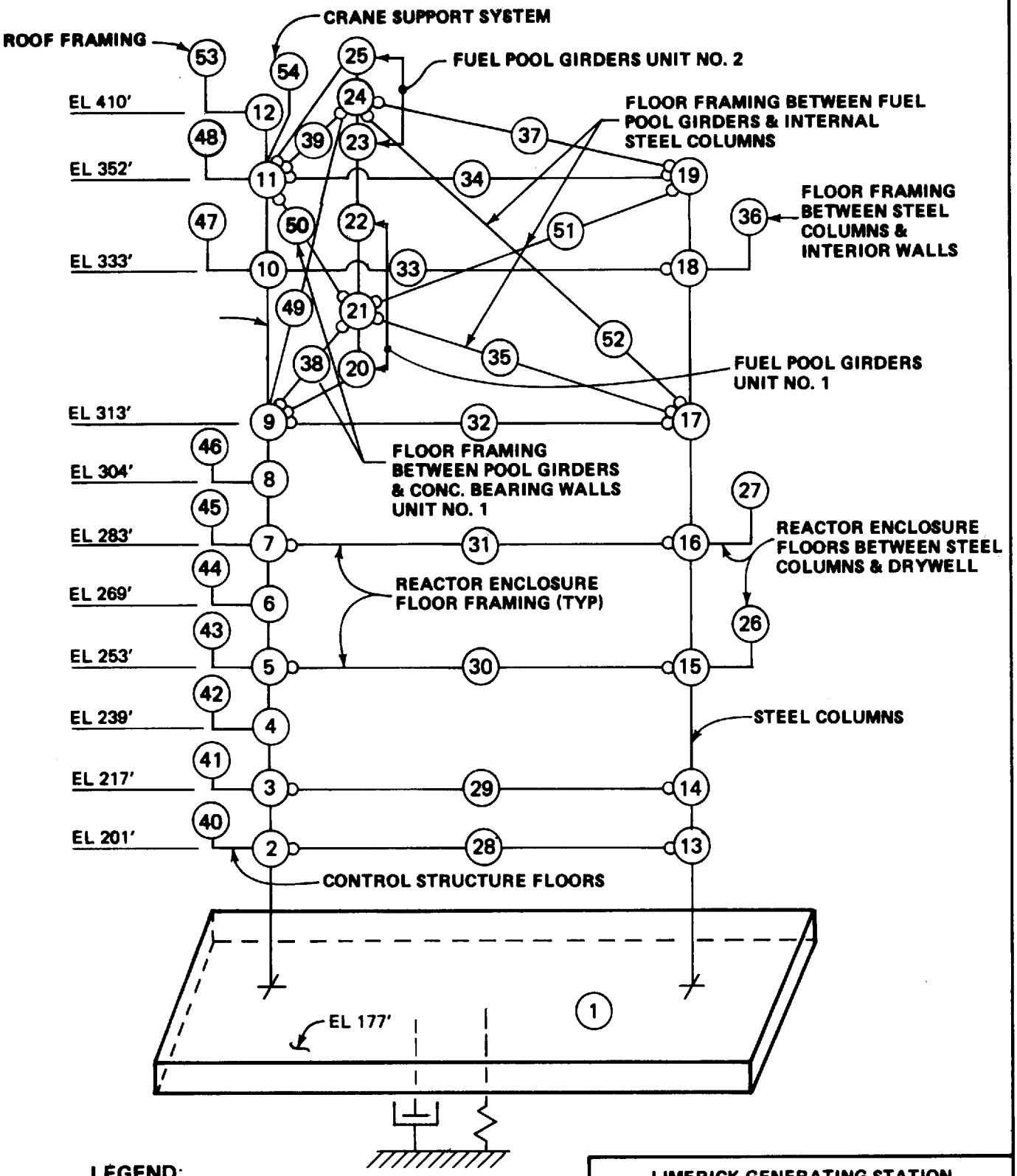
LEGEND:

- ● MASS POINT
- □ JOINT NUMBER
- ○ MEMBER NUMBER

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

HORIZONTAL SEISMIC MODEL OF REACTOR ENCLOSURE AND CONTROL STRUCTURE WITH SOIL-STRUCTURE INTERACTION

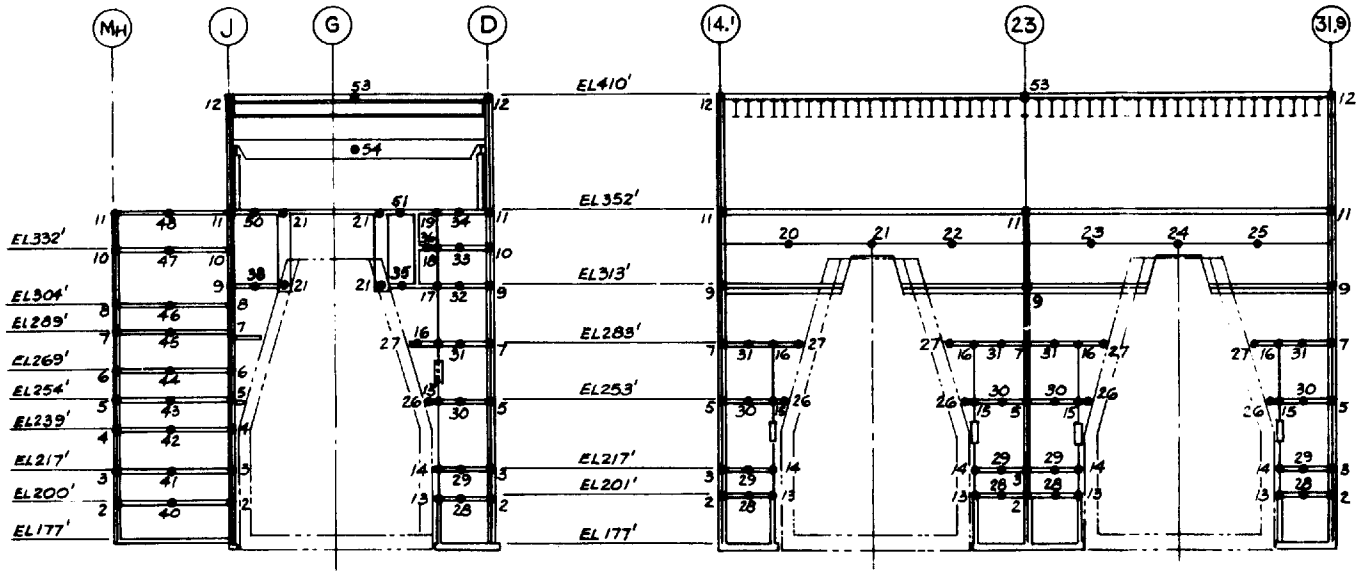
FIGURE 3.7-16



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

VERTICAL SEISMIC MODEL OF REACTOR ENCLOSURE AND CONTROL STRUCTURE WITH SOIL-STRUCTURE INTERACTION

FIGURE 3.7-17



TRANSVERSE SECTION

LONGITUDINAL SECTION

LEGEND:

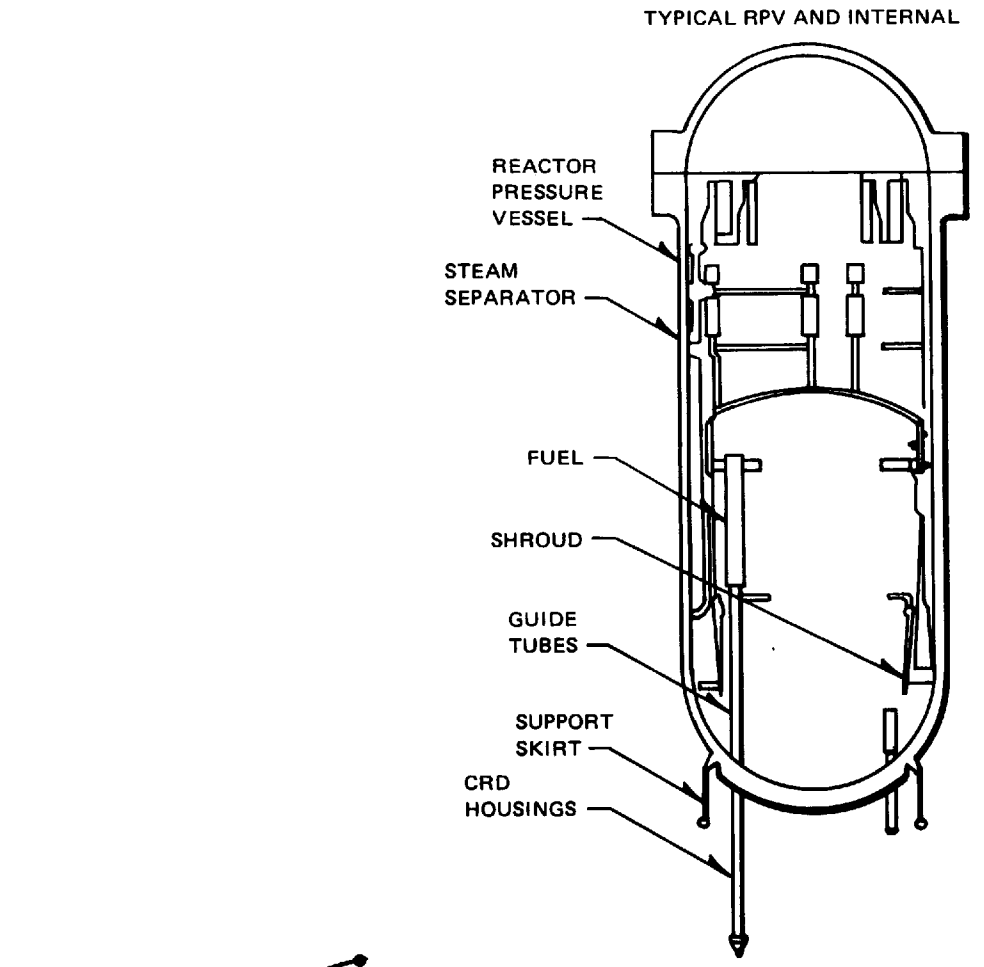
● MASS POINT AND JOINT NUMBER

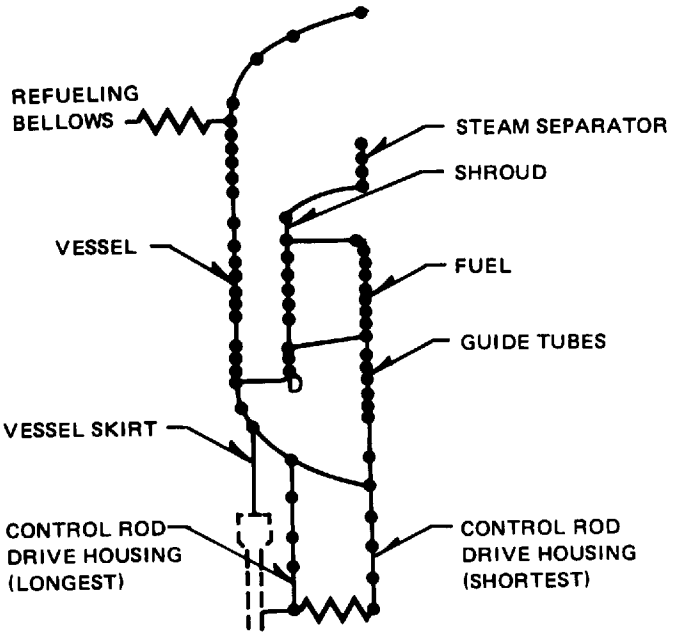
REACTOR AND CONTROL ENCLOSURE

LIMERICK GENERATING STATION
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CORRELATION OF VERTICAL SEISMIC MODEL MASS POINTS TO THE PHYSICAL STRUCTURE

FIGURE 3.7-18

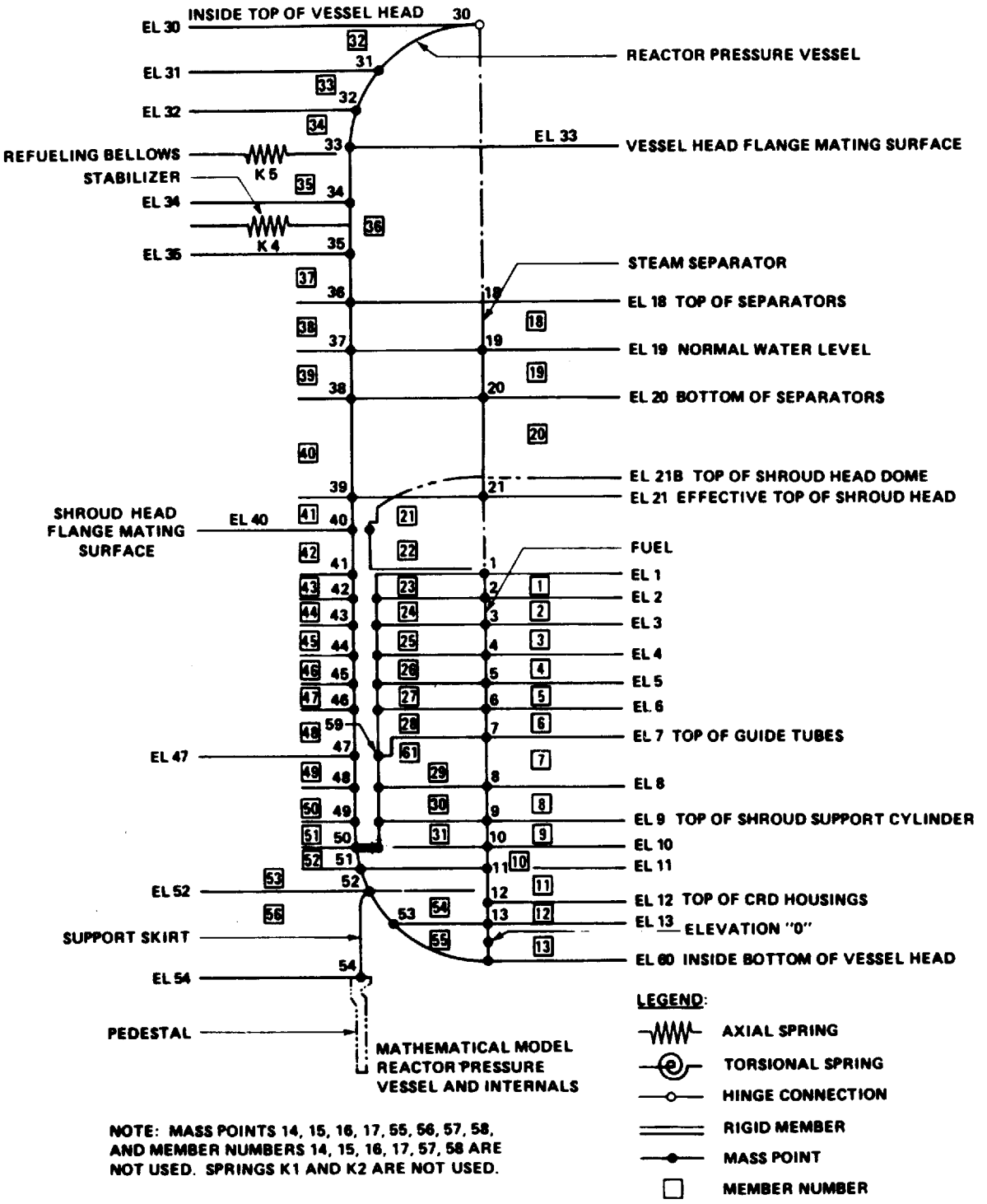




LIMERICK GENERATING STATION
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SEISMIC MODEL OF REACTOR PRESSURE VESSEL AND INTERNALS (SHEET 1 OF 2)

FIGURE 3.7-19

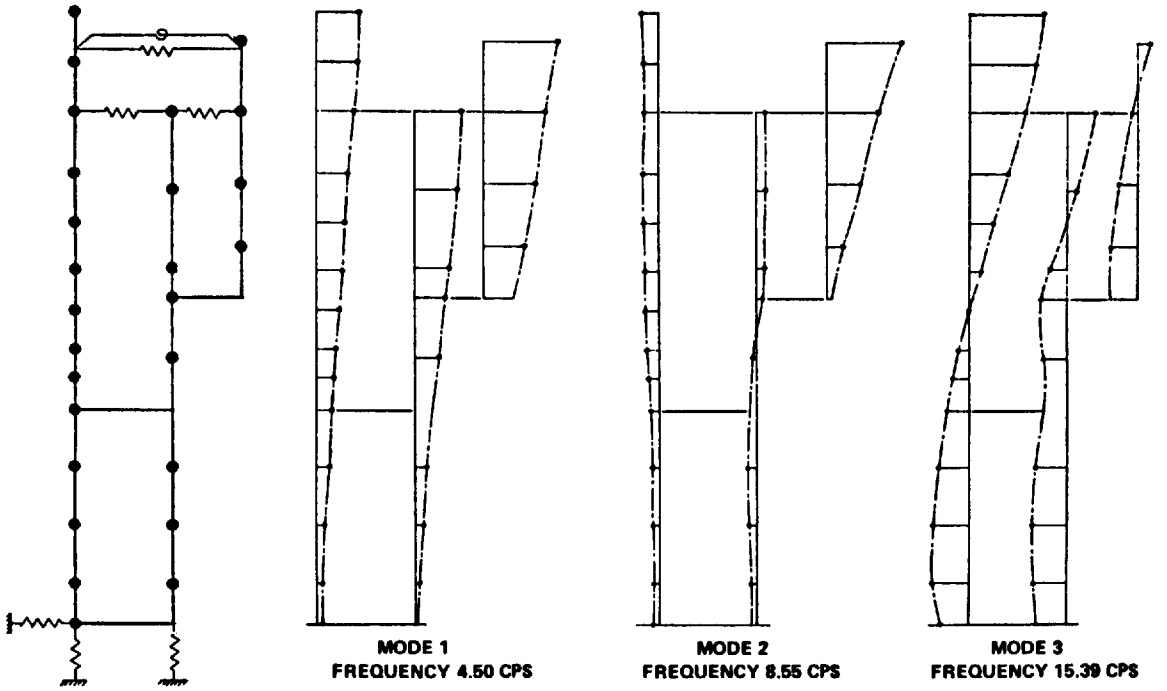


NOTE: MASS POINTS 14, 15, 16, 17, 55, 56, 57, 58, AND MEMBER NUMBERS 14, 15, 16, 17, 57, 58 ARE NOT USED. SPRINGS K1 AND K2 ARE NOT USED.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SEISMIC MODEL OF REACTOR PRESSURE VESSEL AND INTERNALS (SHEET 2 OF 2)

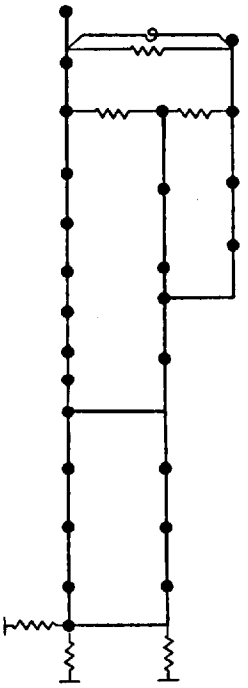
FIGURE 3.7-19



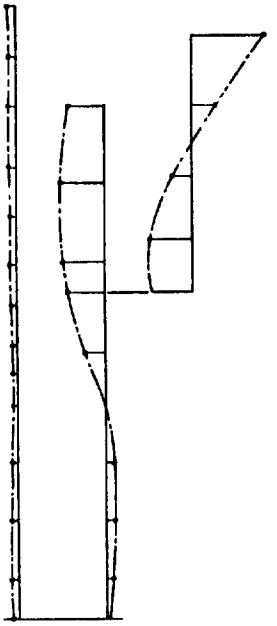
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT HORIZONTAL MODE SHAPES UNCRACKED CONDITION (SHEET 1 OF 2)

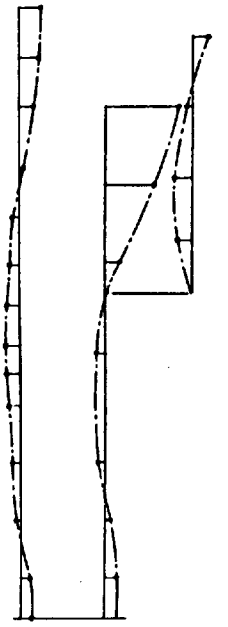
FIGURE 3.7-20



MODEL



MODE 4
FREQUENCY 17.83 CPS

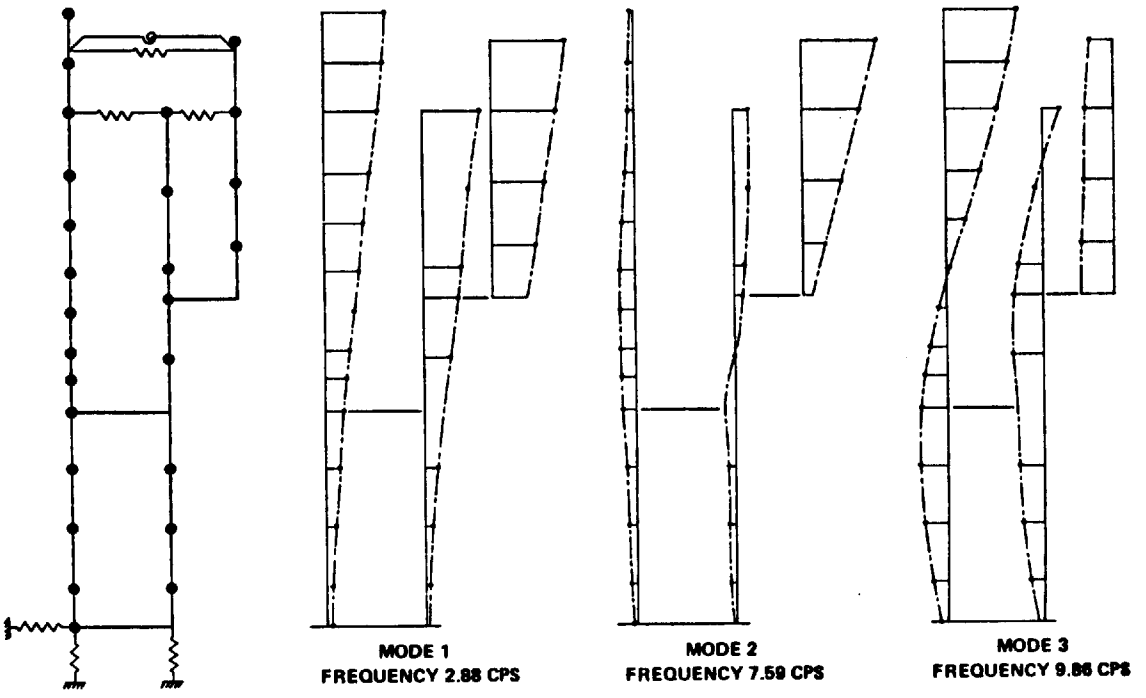


MODE 5
FREQUENCY 27.39 CPS

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT
HORIZONTAL MODE SHAPES
UNCRACKED CONDITION
(SHEET 2 OF 2)

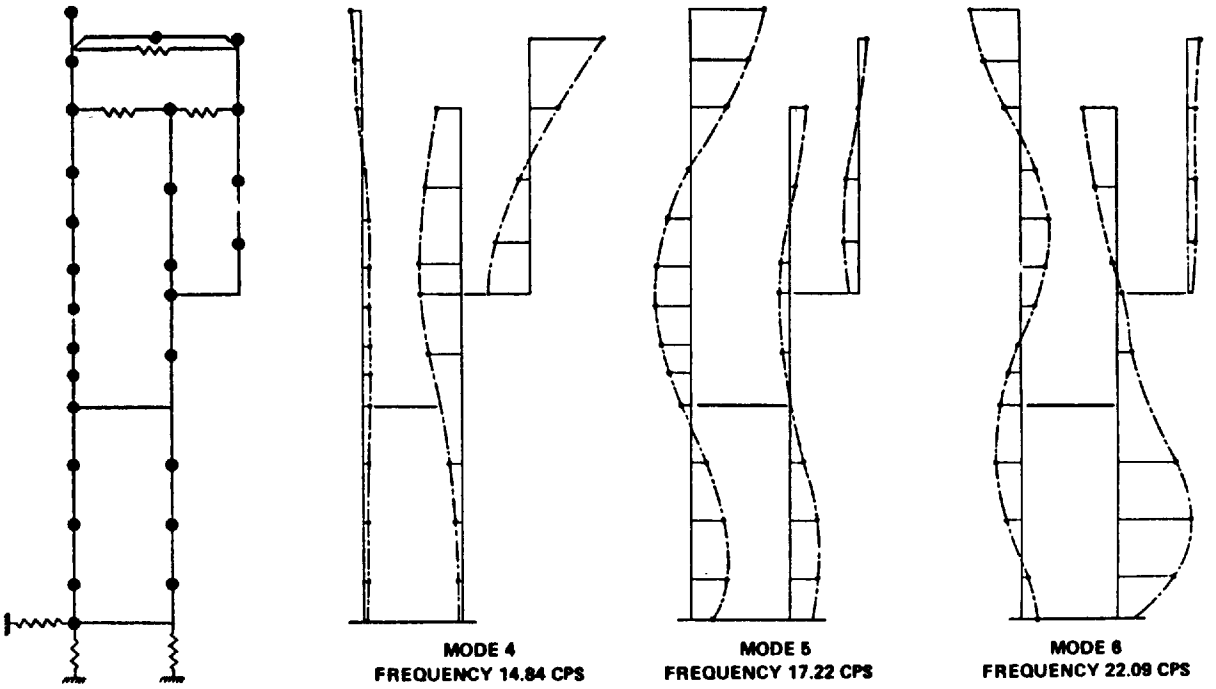
FIGURE 3.7-20



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT HORIZONTAL MODE SHAPES CRACKED CONDITION (SHEET 1 OF 2)

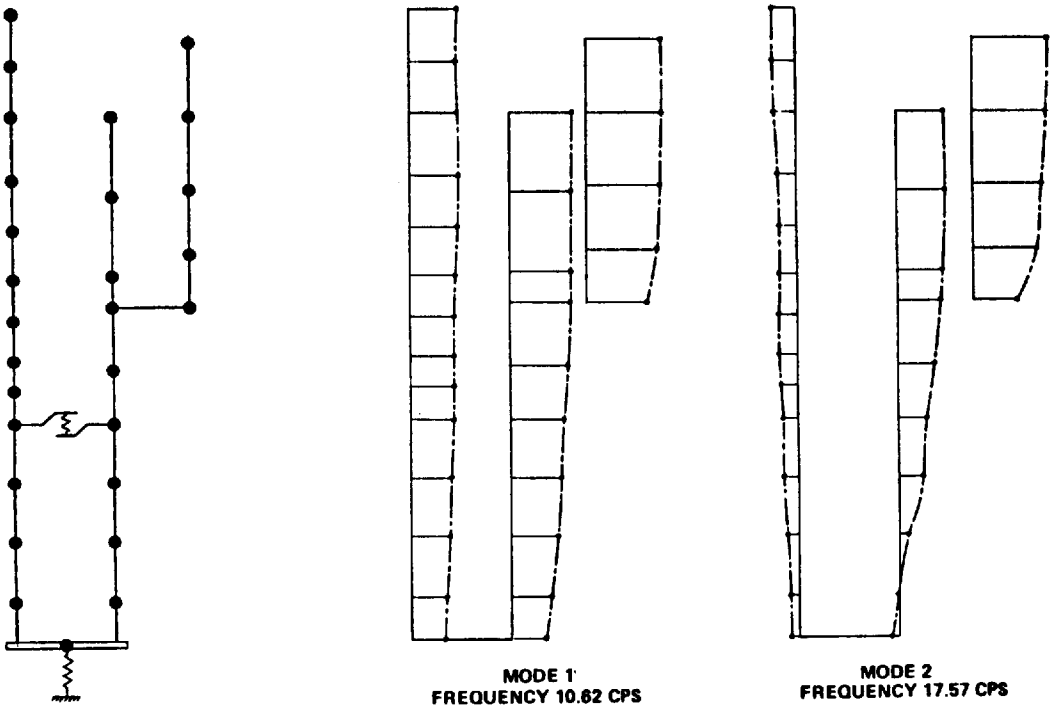
FIGURE 3.7-21



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT
HORIZONTAL MODE SHAPES
CRACKED CONDITION
(SHEET 2 OF 2)

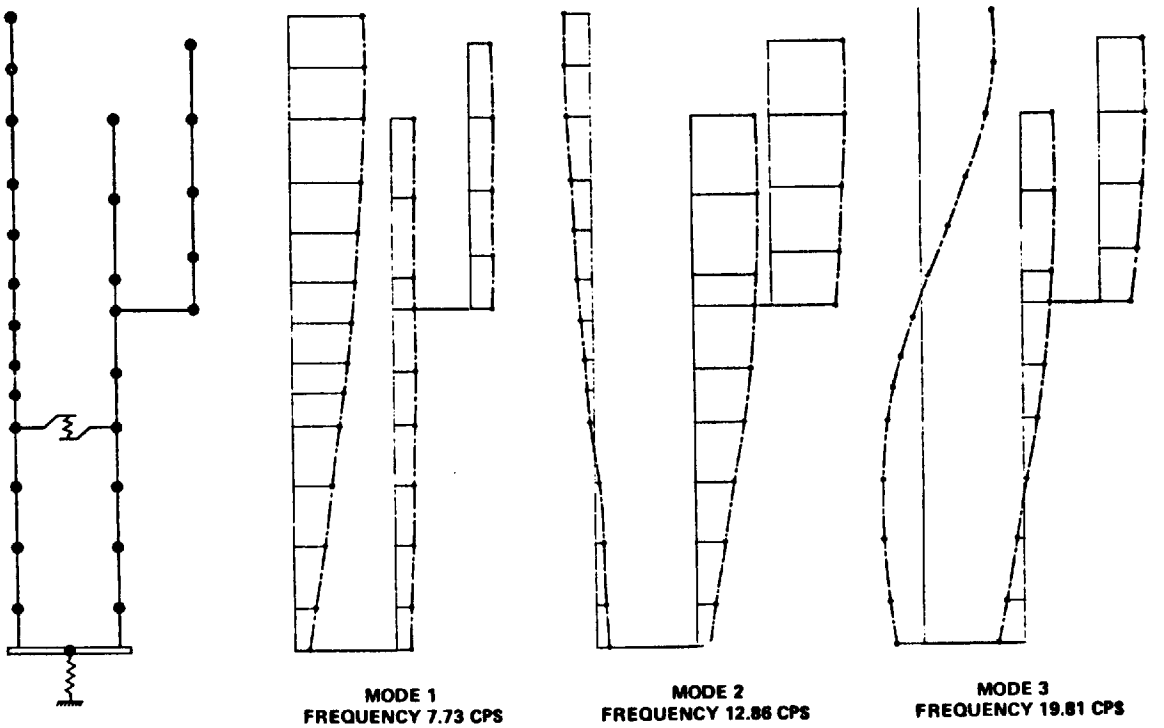
FIGURE 3.7-21



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT
VERTICAL MODE SHAPES
UNCRACKED CONDITION

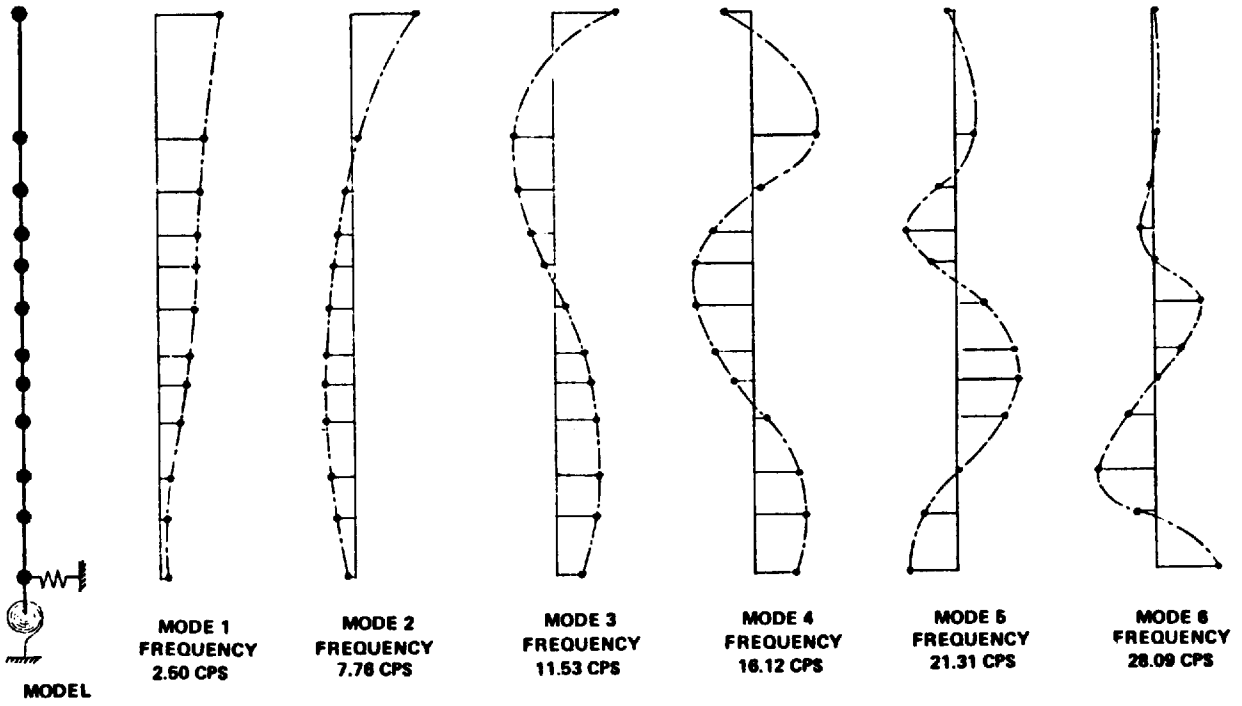
FIGURE 3.7-22



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT
VERTICAL MODE SHAPES
CRACKED CONDITION

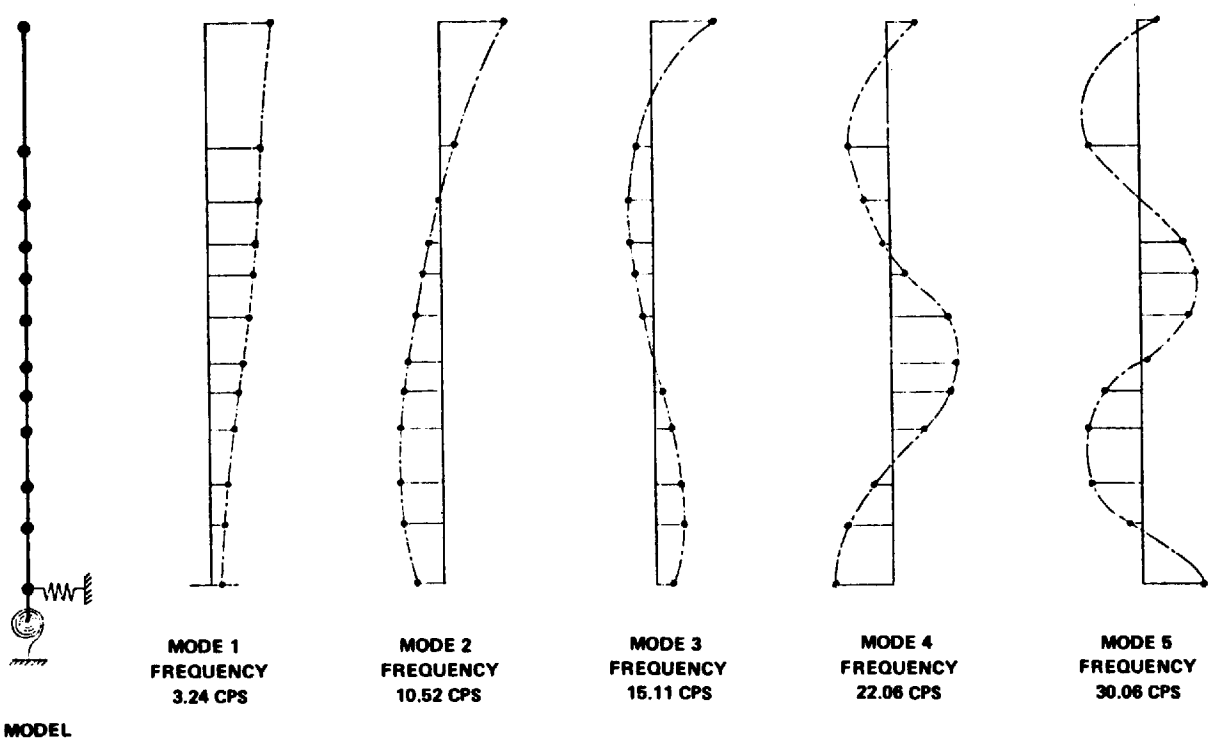
FIGURE 3.7-23



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE AND CONTROL STRUCTURE N-S MODE SHAPES

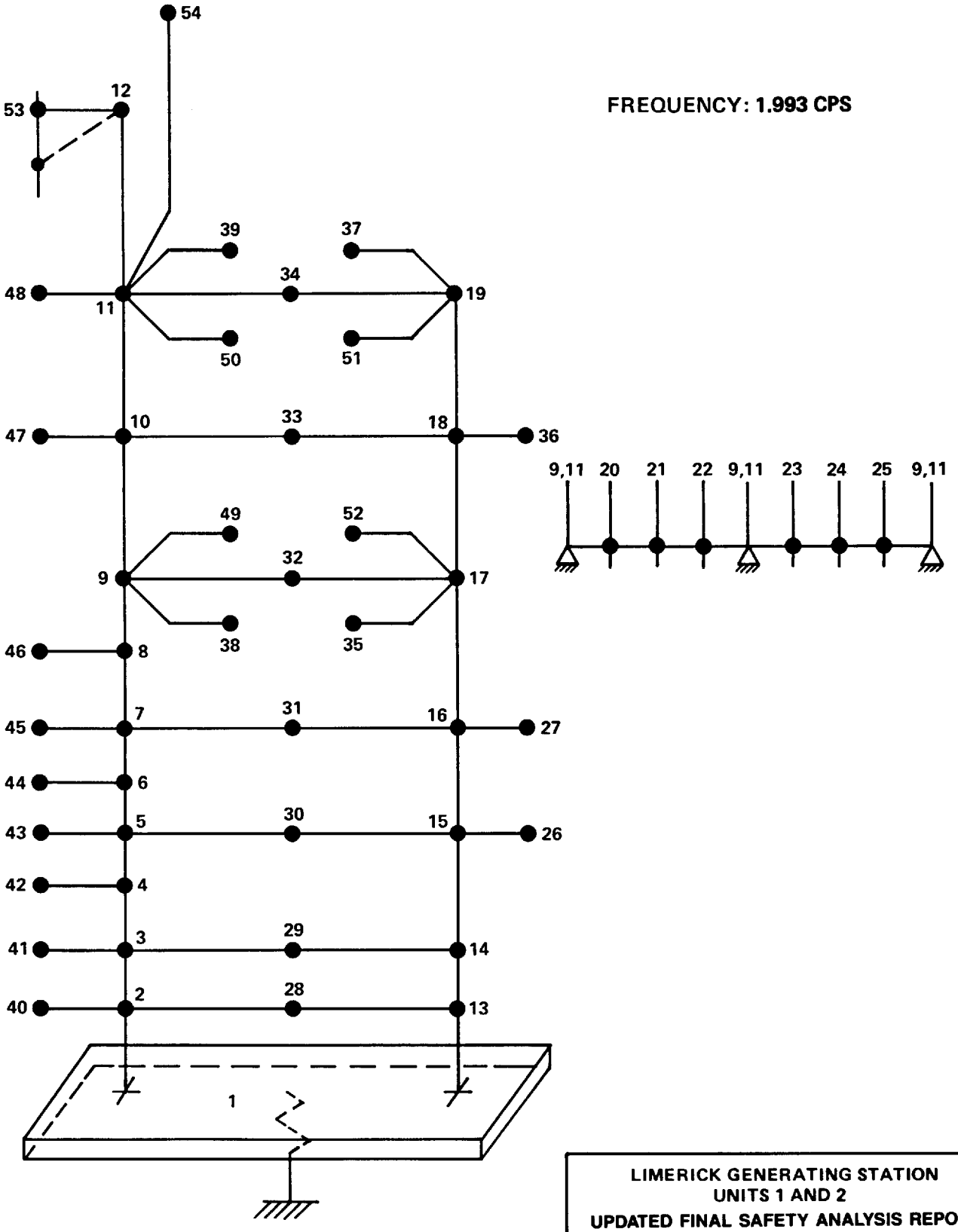
FIGURE 3.7-24



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE AND CONTROL STRUCTURE E-W MODE SHAPES

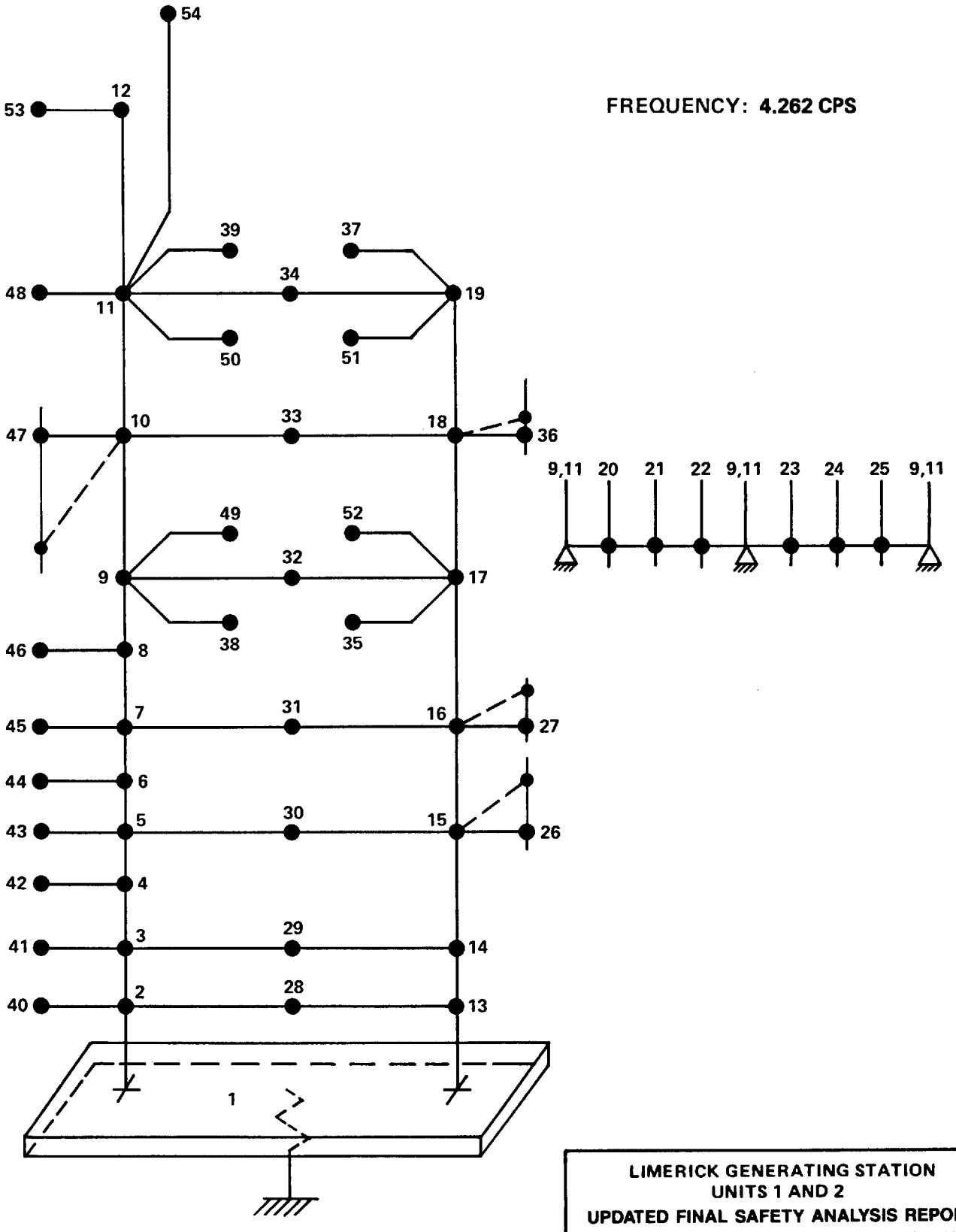
FIGURE 3.7-25



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE AND CONTROL STRUCTURE VERTICAL MODE SHAPES (MODE 1)

FIGURE 3.7-26

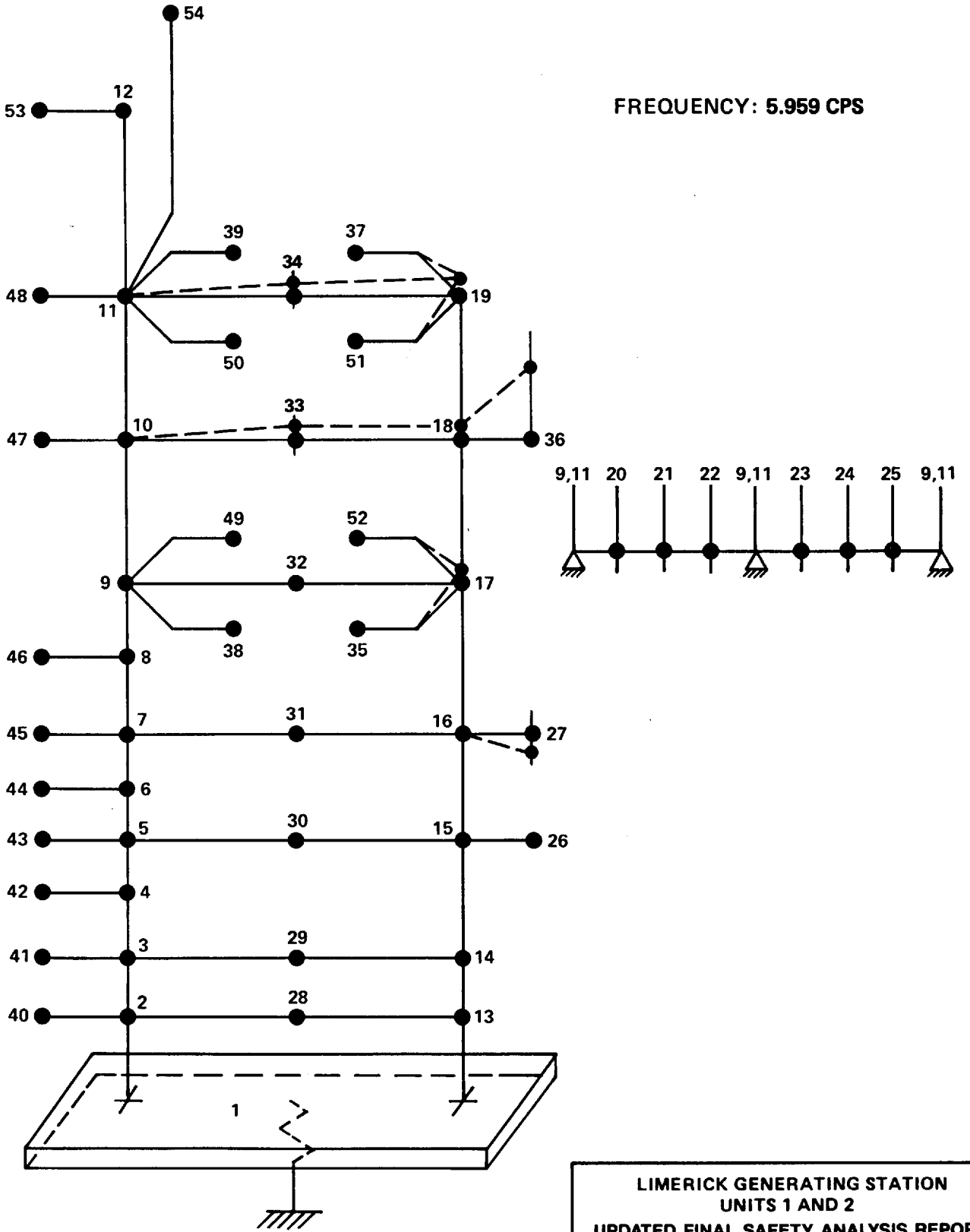


FREQUENCY: **4.262 CPS**

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE AND CONTROL STRUCTURE VERTICAL MODE SHAPES (MODE 7)

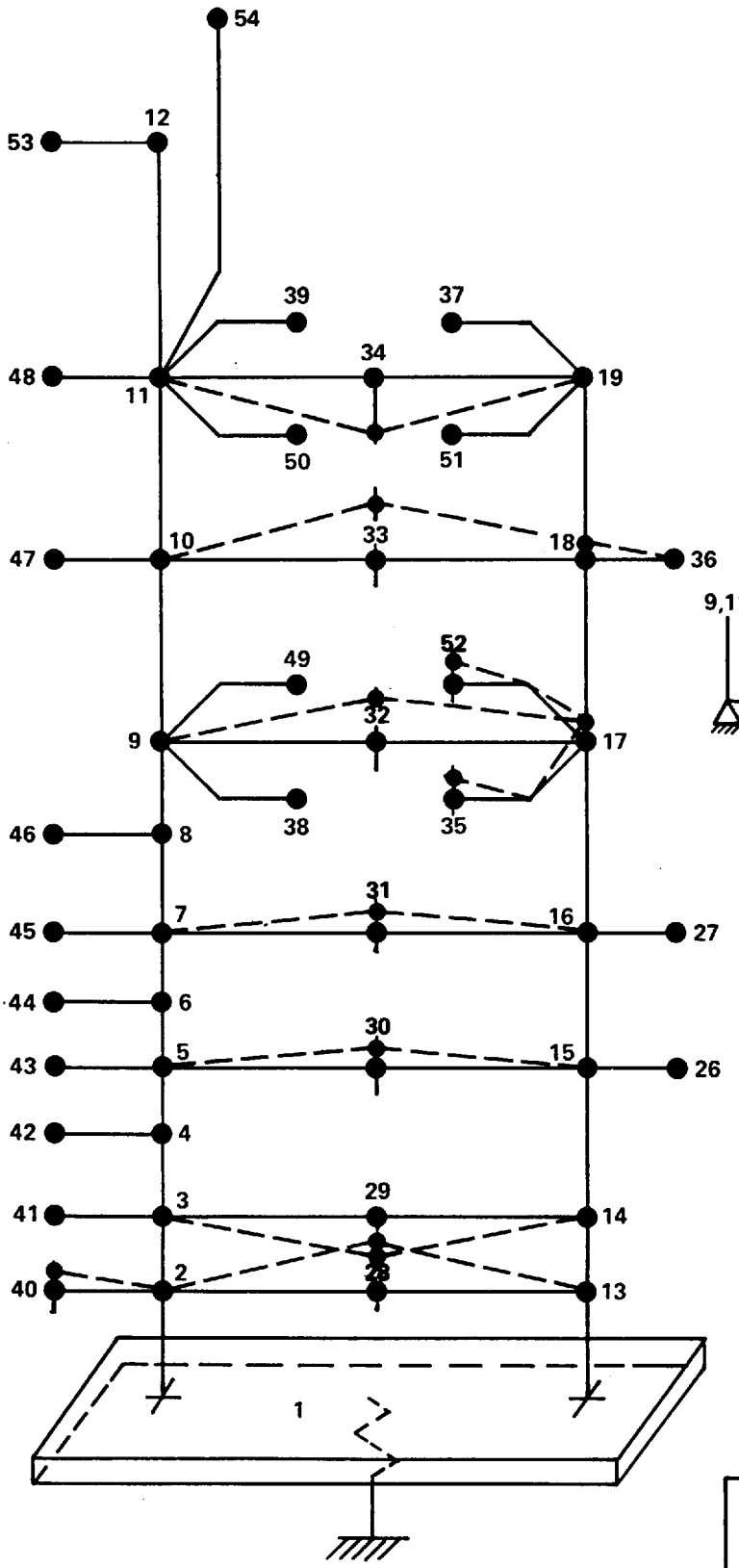
FIGURE 3.7-27



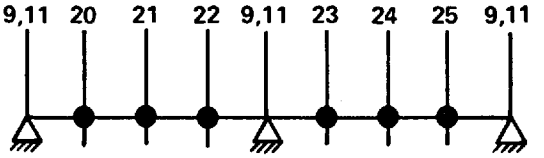
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE AND CONTROL STRUCTURE VERTICAL MODE SHAPES (MODE 14)

FIGURE 3.7-28



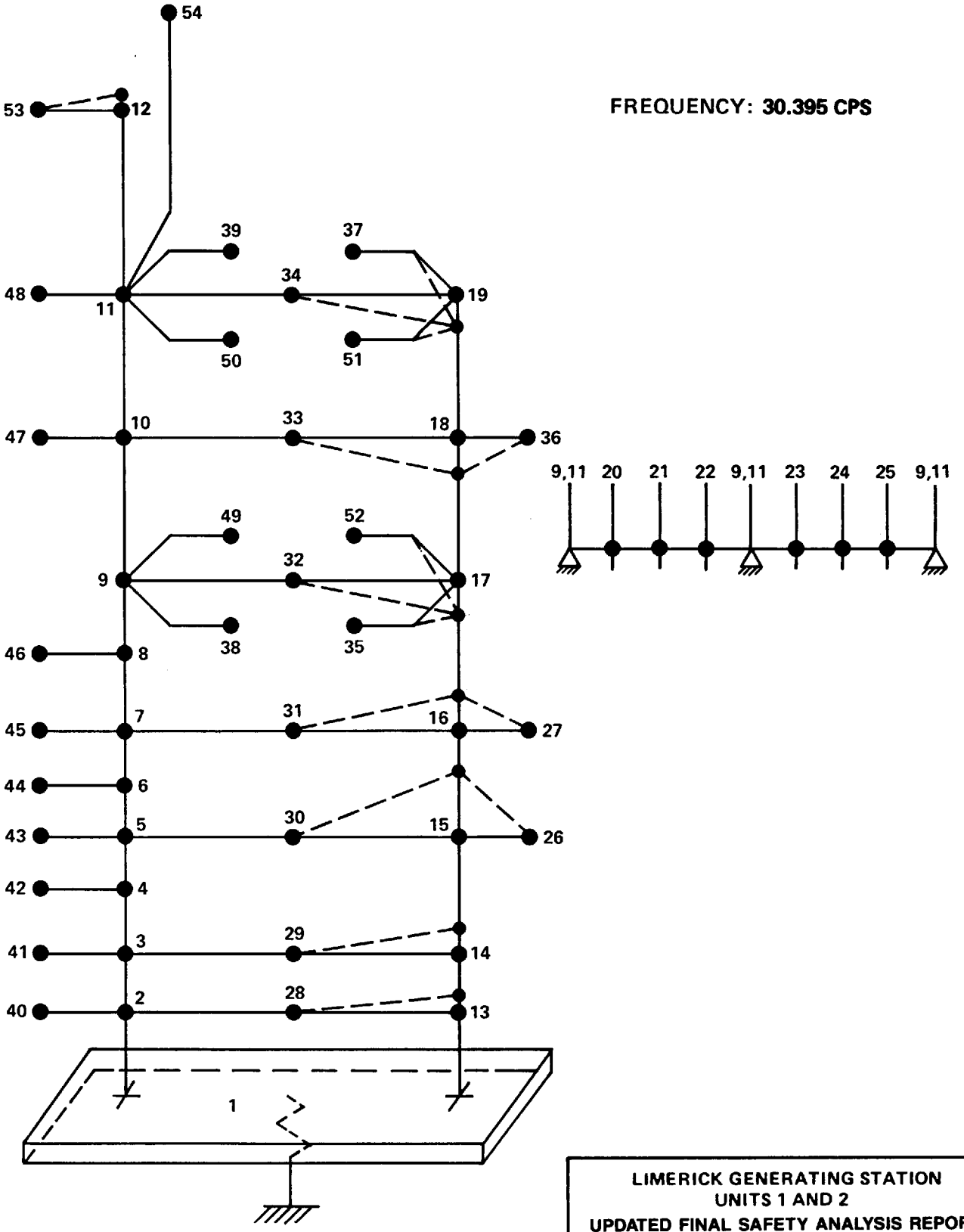
FREQUENCY: **10.661 CPS**



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE AND CONTROL STRUCTURE VERTICAL MODE SHAPES (MODE 22)

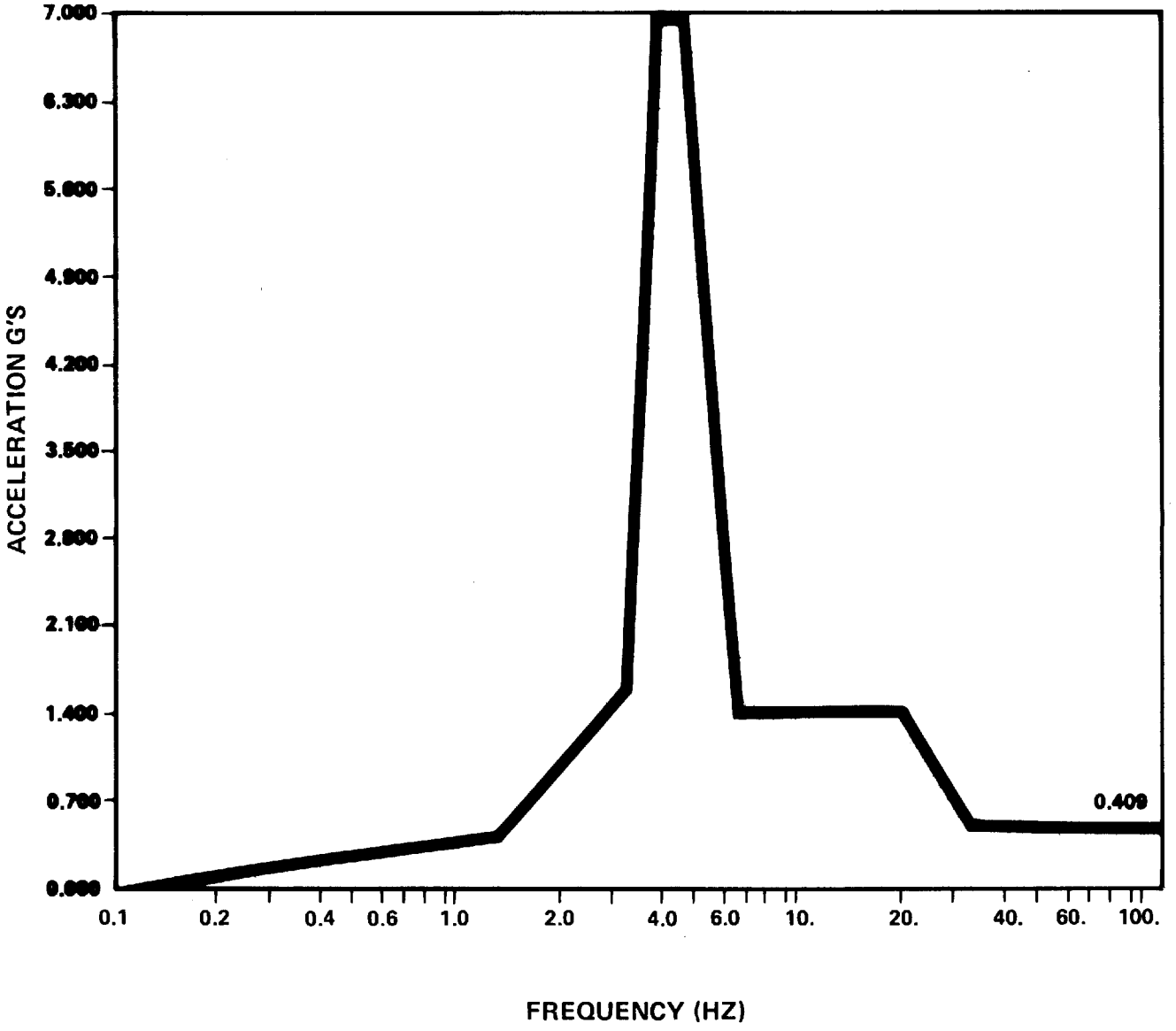
FIGURE 3.7-29



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE AND CONTROL STRUCTURE VERTICAL MODE SHAPES (MODE 39)

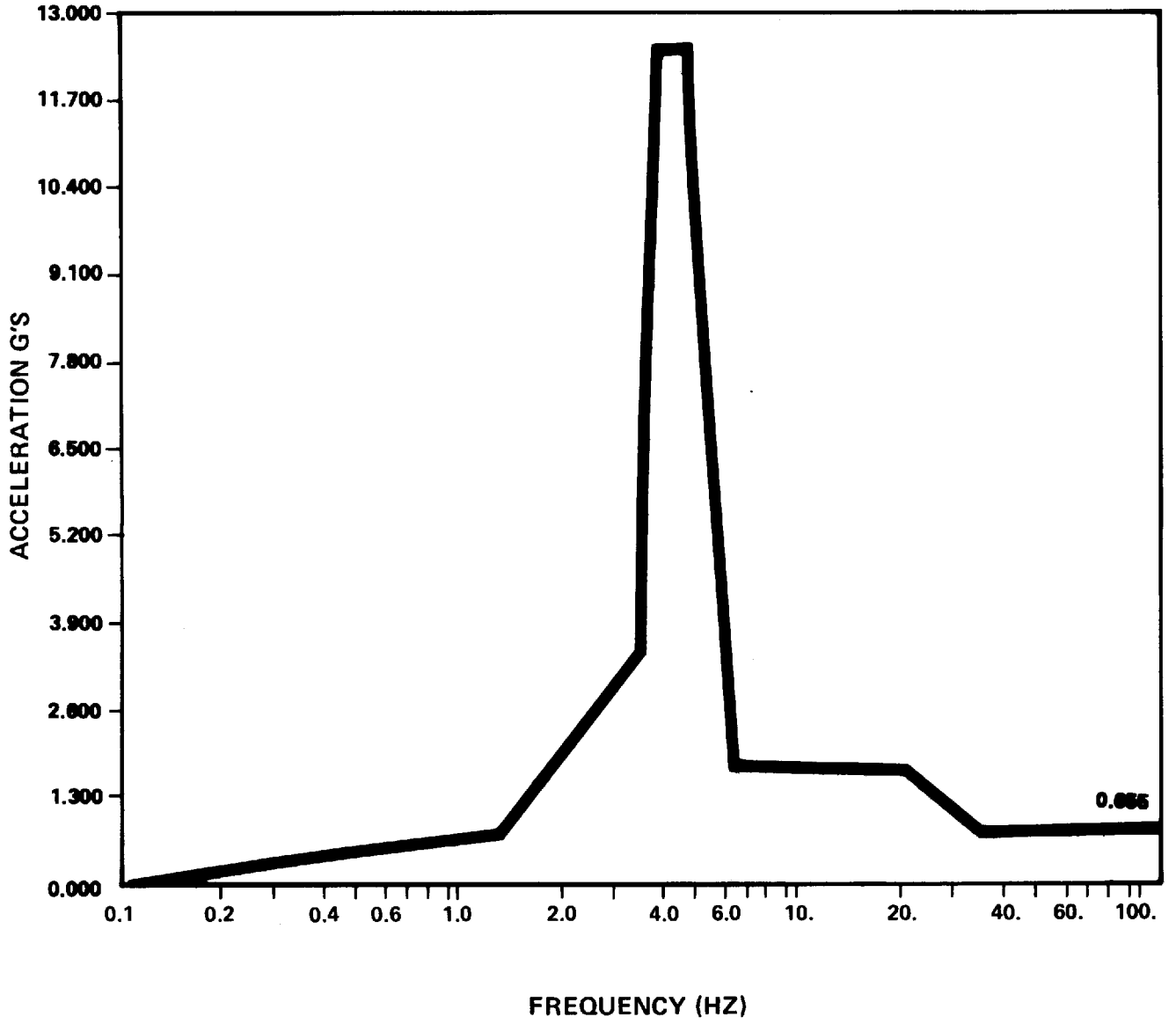
FIGURE 3.7-30



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RESPONSE SPECTRUM AT RPV PEDESTAL HORIZONTAL OBE (DAMPING = 0.005) UNCRACKED CONDITION

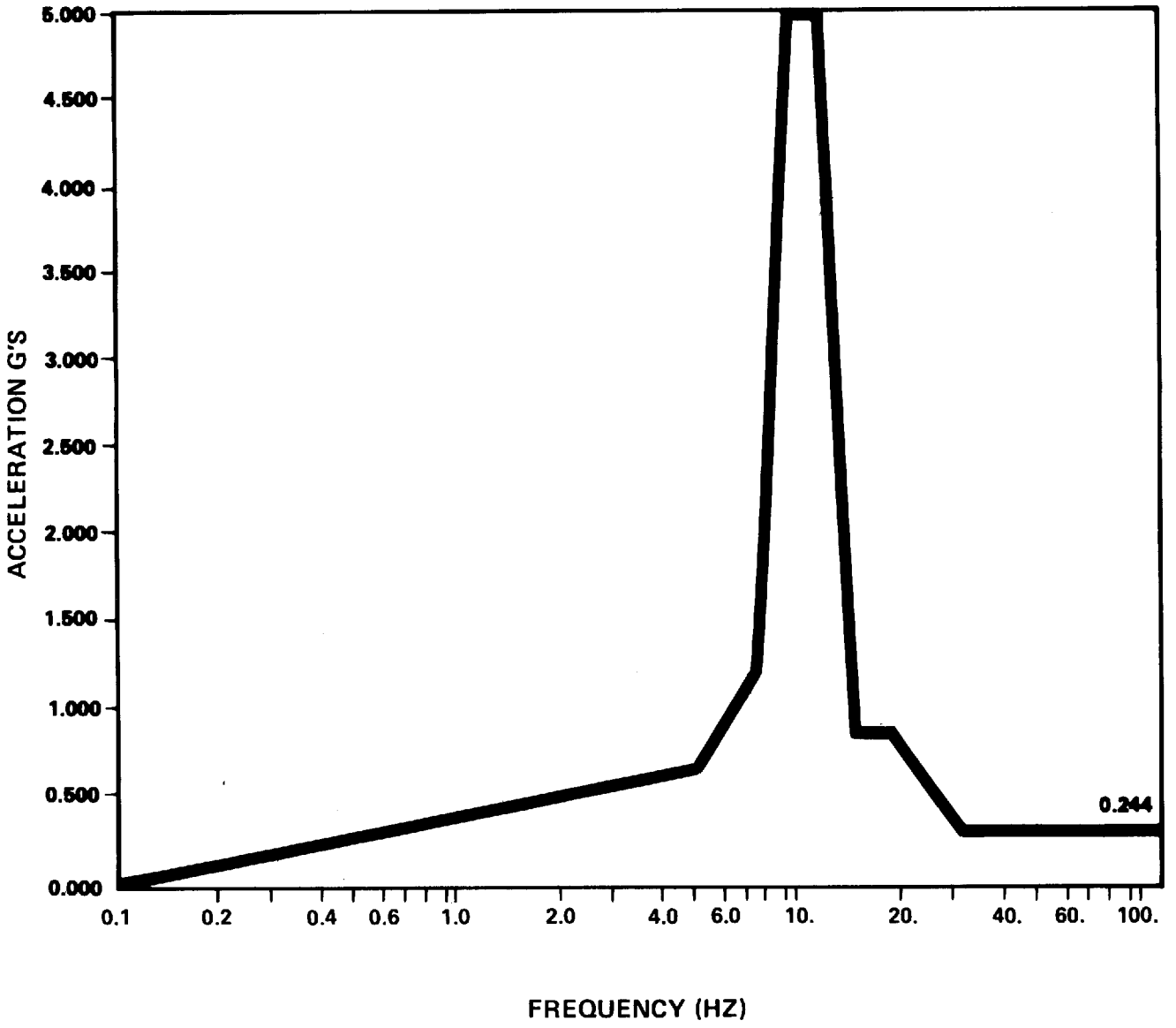
FIGURE 3.7-31



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RESPONSE SPECTRUM AT RPV PEDESTAL HORIZONTAL SSE (DAMPING = 0.005) UNCRACKED CONDITION

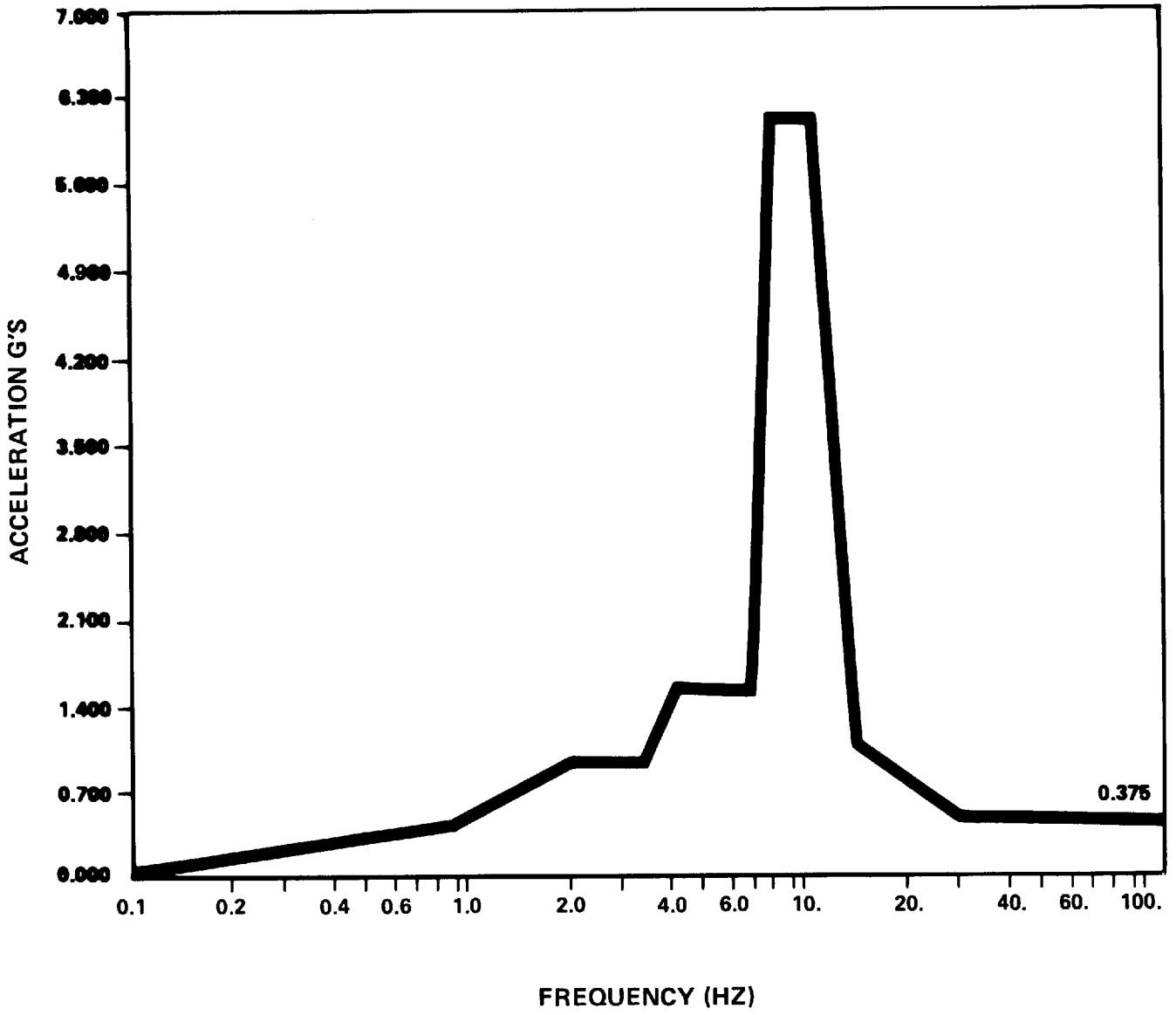
FIGURE 3.7-32



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RESPONSE SPECTRUM AT RPV PEDESTAL VERTICAL OBE (DAMPING = 0.005) UNCRACKED CONDITION

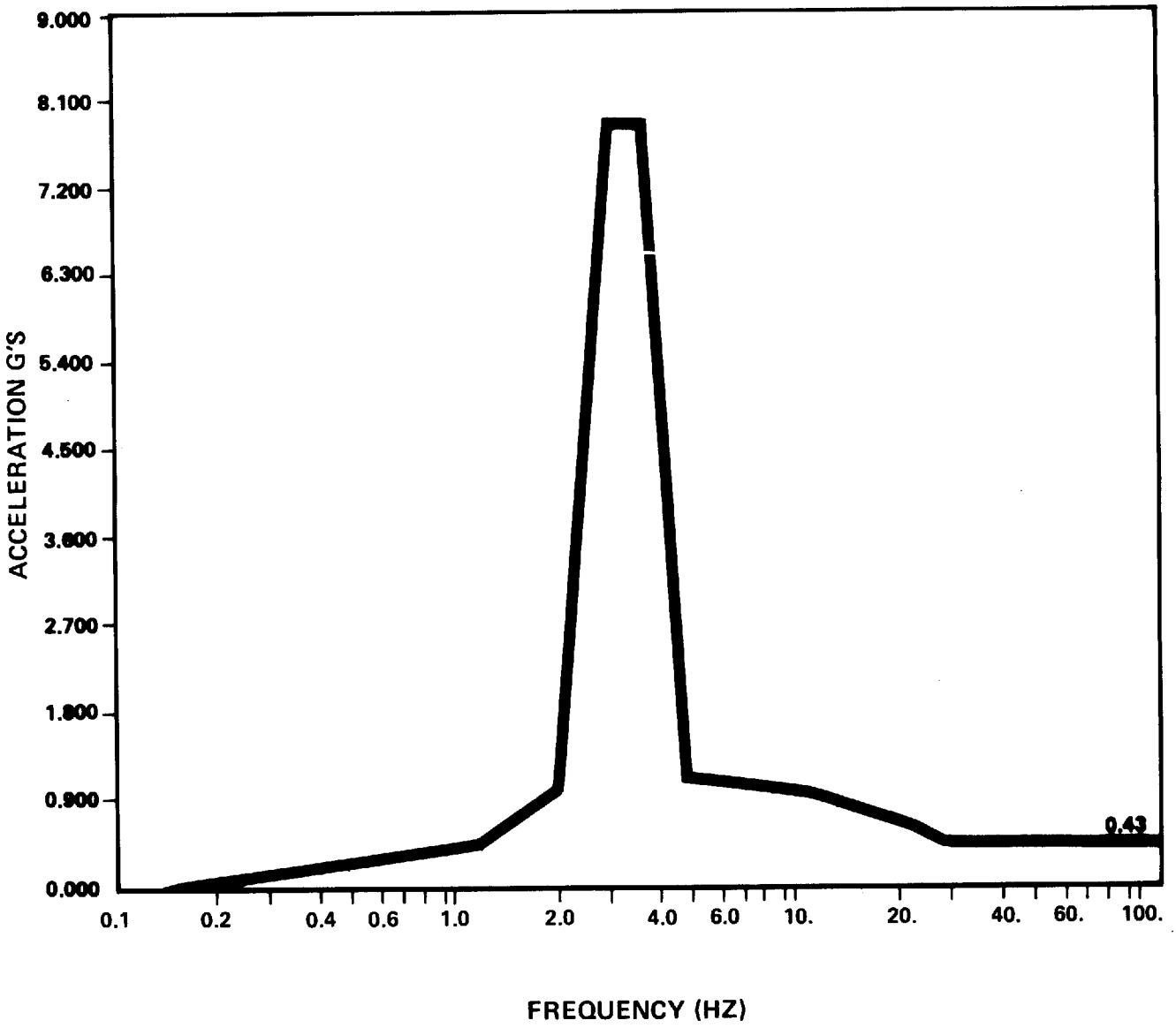
FIGURE 3.7.33



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RESPONSE SPECTRUM AT
RPV PEDESTAL
VERTICAL SSE (DAMPING = 0.005)
UNCRACKED CONDITION

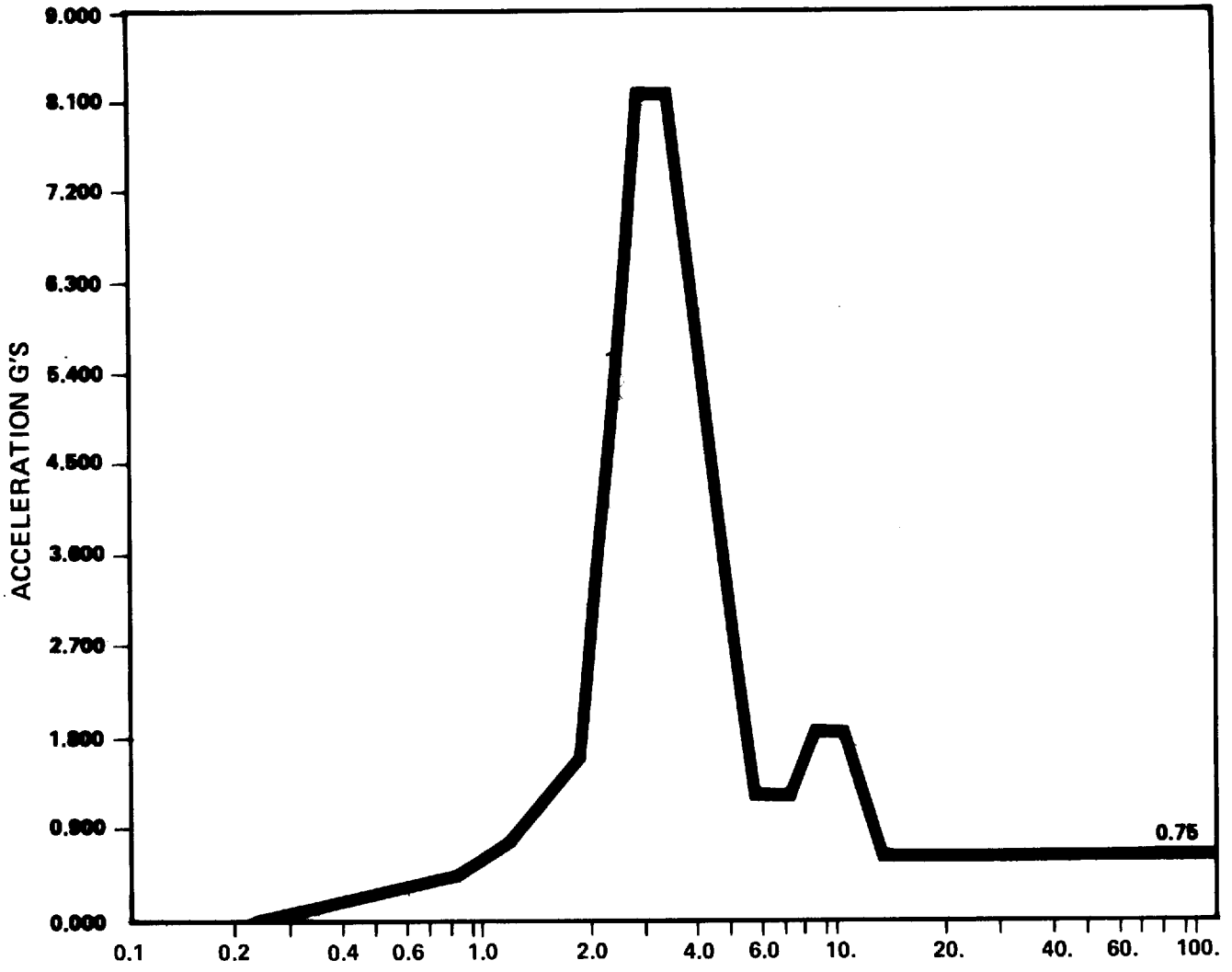
FIGURE 3.7-34



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RESPONSE SPECTRUM AT REFUELING AREA E-W OBE (DAMPING = 0.005)

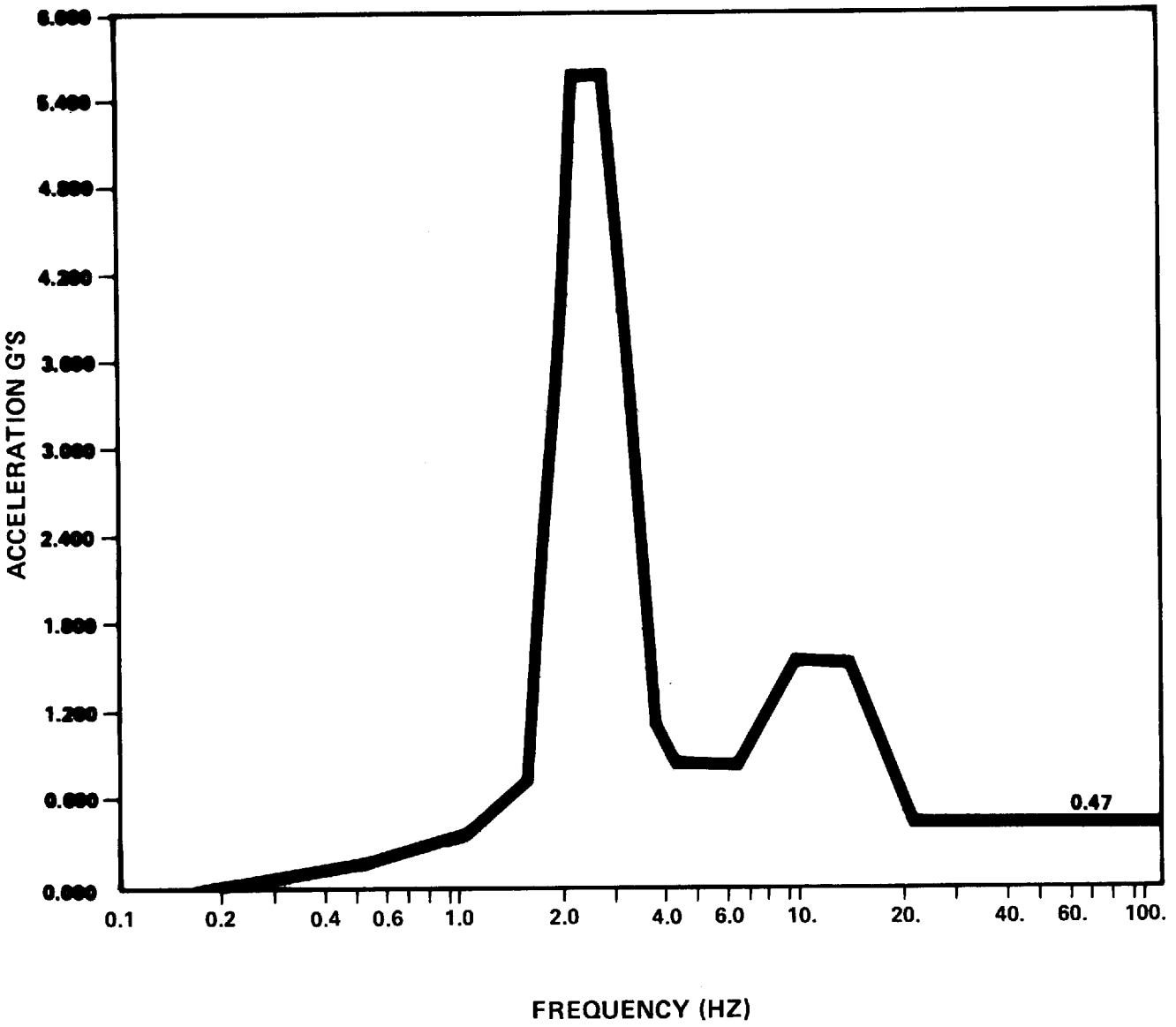
FIGURE 3.7-35



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RESPONSE SPECTRUM AT REFUELING AREA E-W SSE (DAMPING = 0.005)

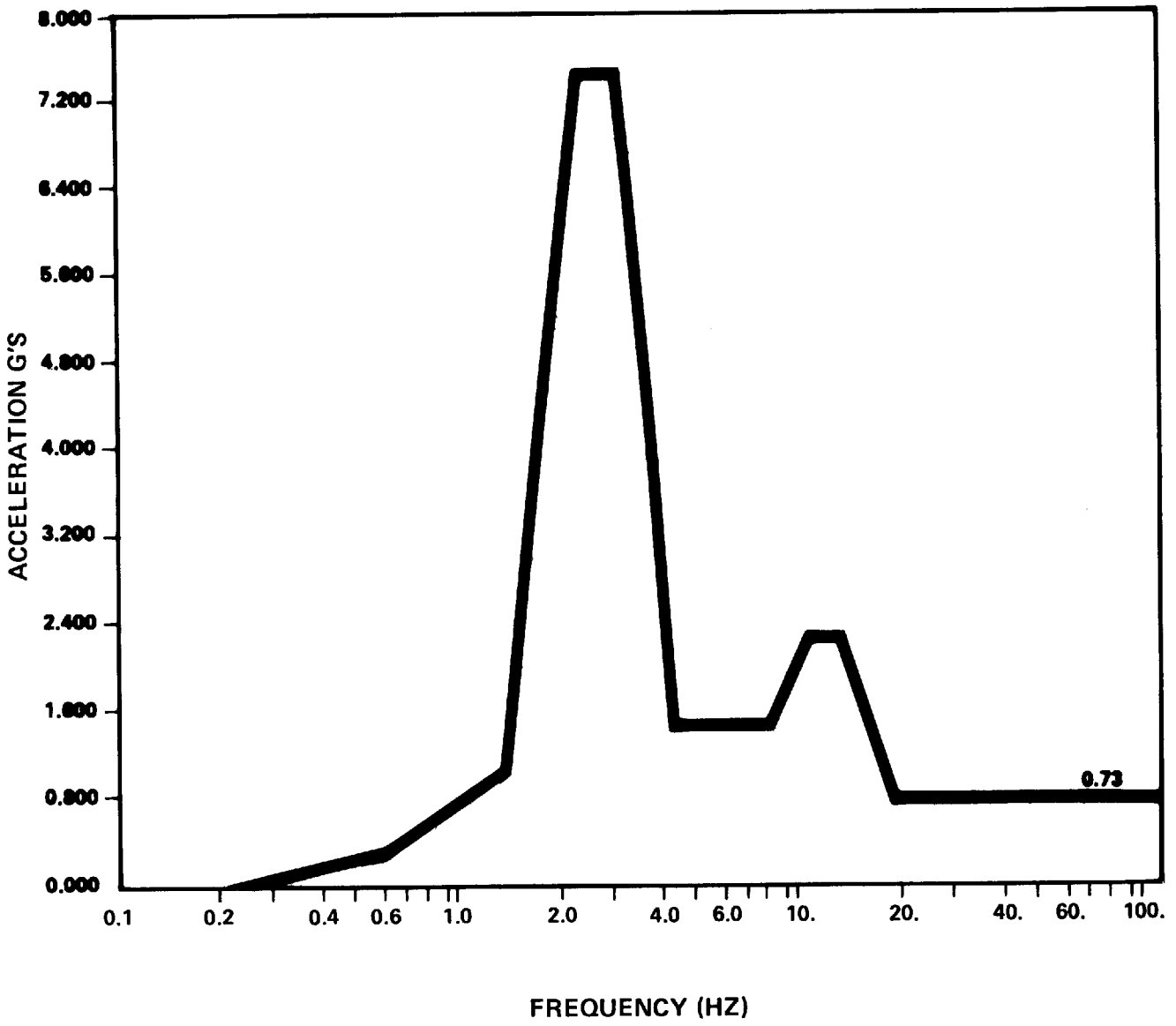
FIGURE 3.7-36



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RESPONSE SPECTRUM AT REFUELING AREA N-S OBE (DAMPING = 0.005)

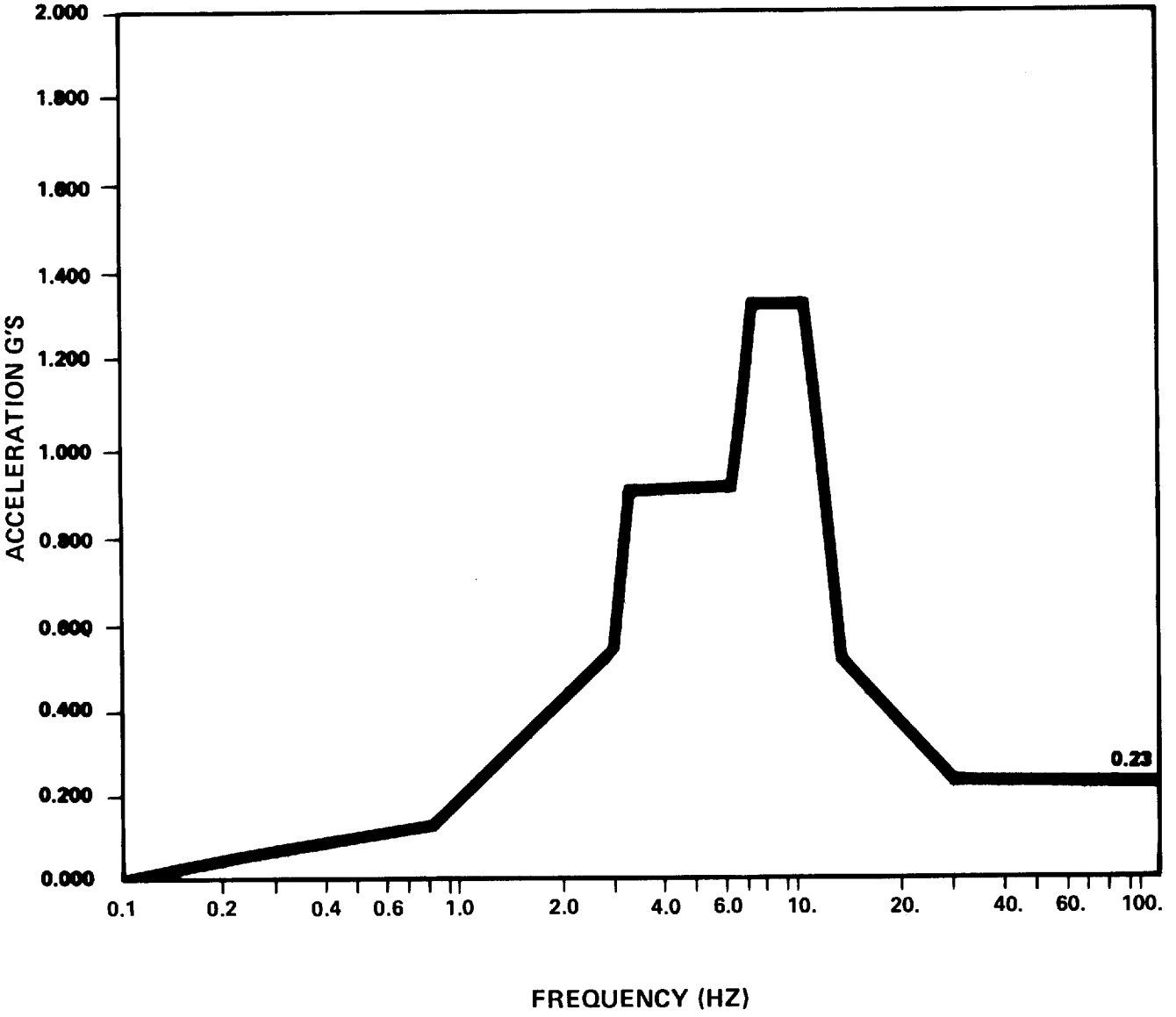
FIGURE 3.7-37



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RESPONSE SPECTRUM AT REFUELING AREA N-S SSE (DAMPING = 0.005)

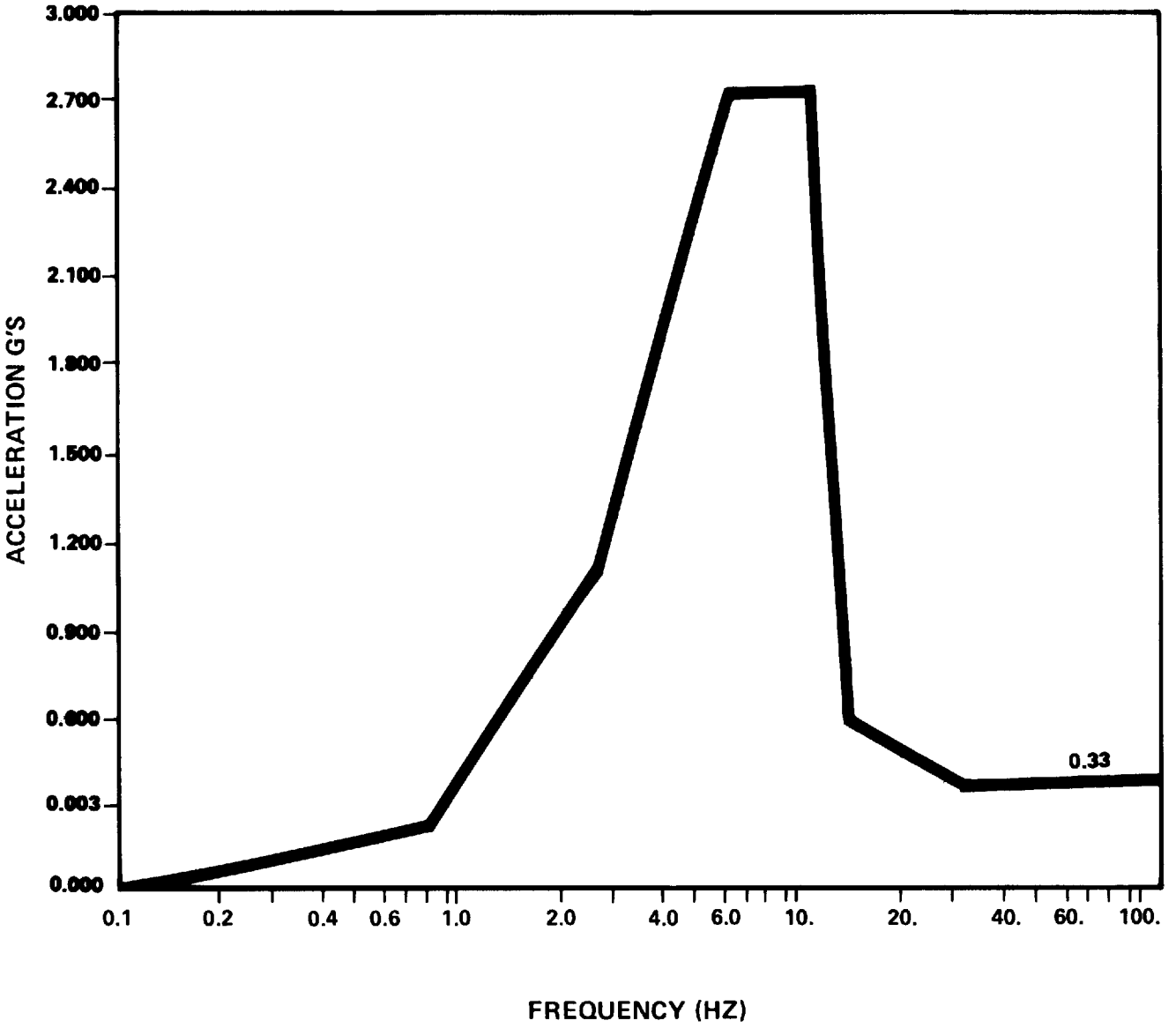
FIGURE 3.7-38



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RESPONSE SPECTRUM AT REFUELING AREA VERTICAL OBE (DAMPING = 0.005)

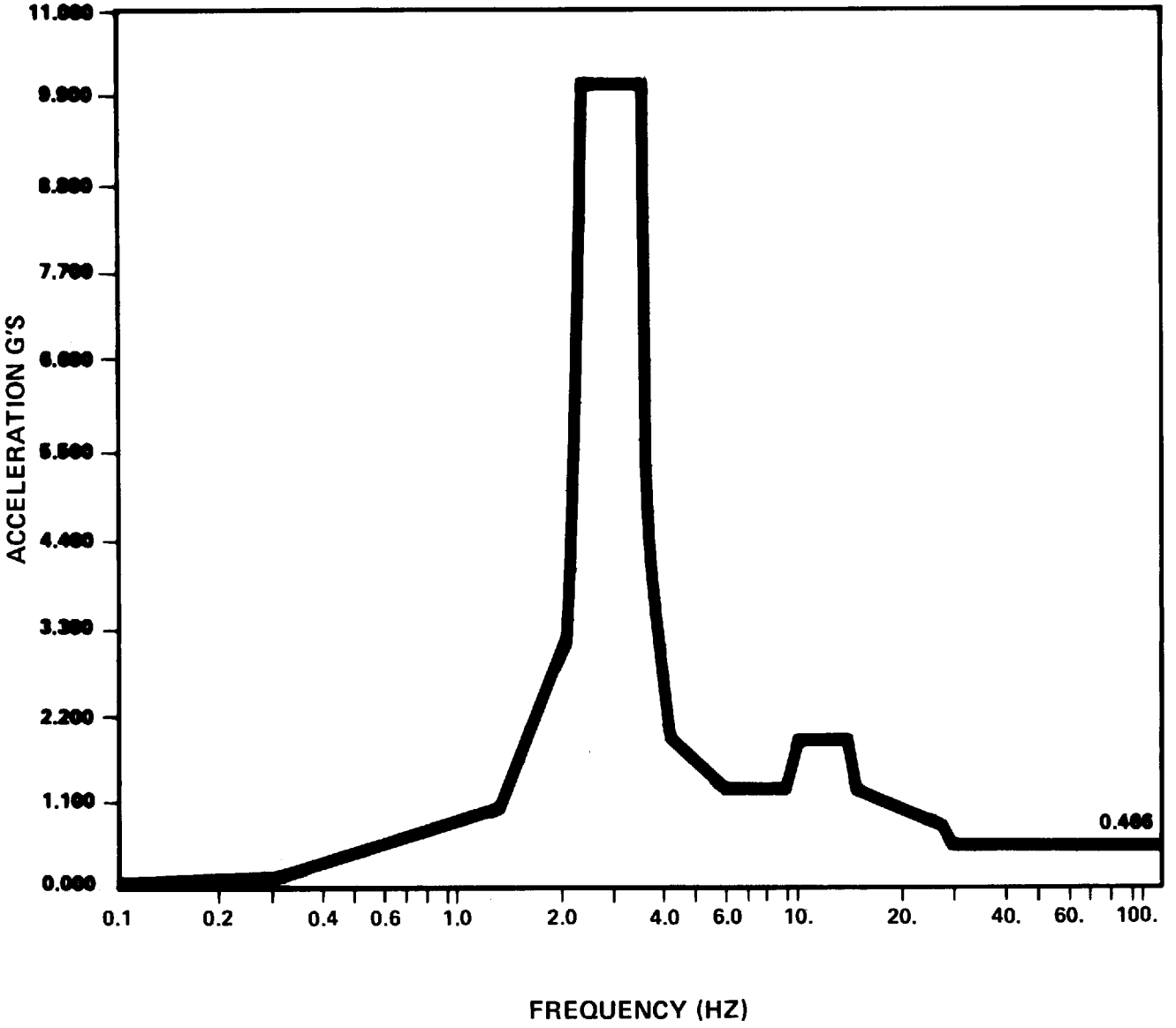
FIGURE 3.7-39



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RESPONSE SPECTRUM AT REFUELING AREA VERTICAL SSE (DAMPING = 0.005)

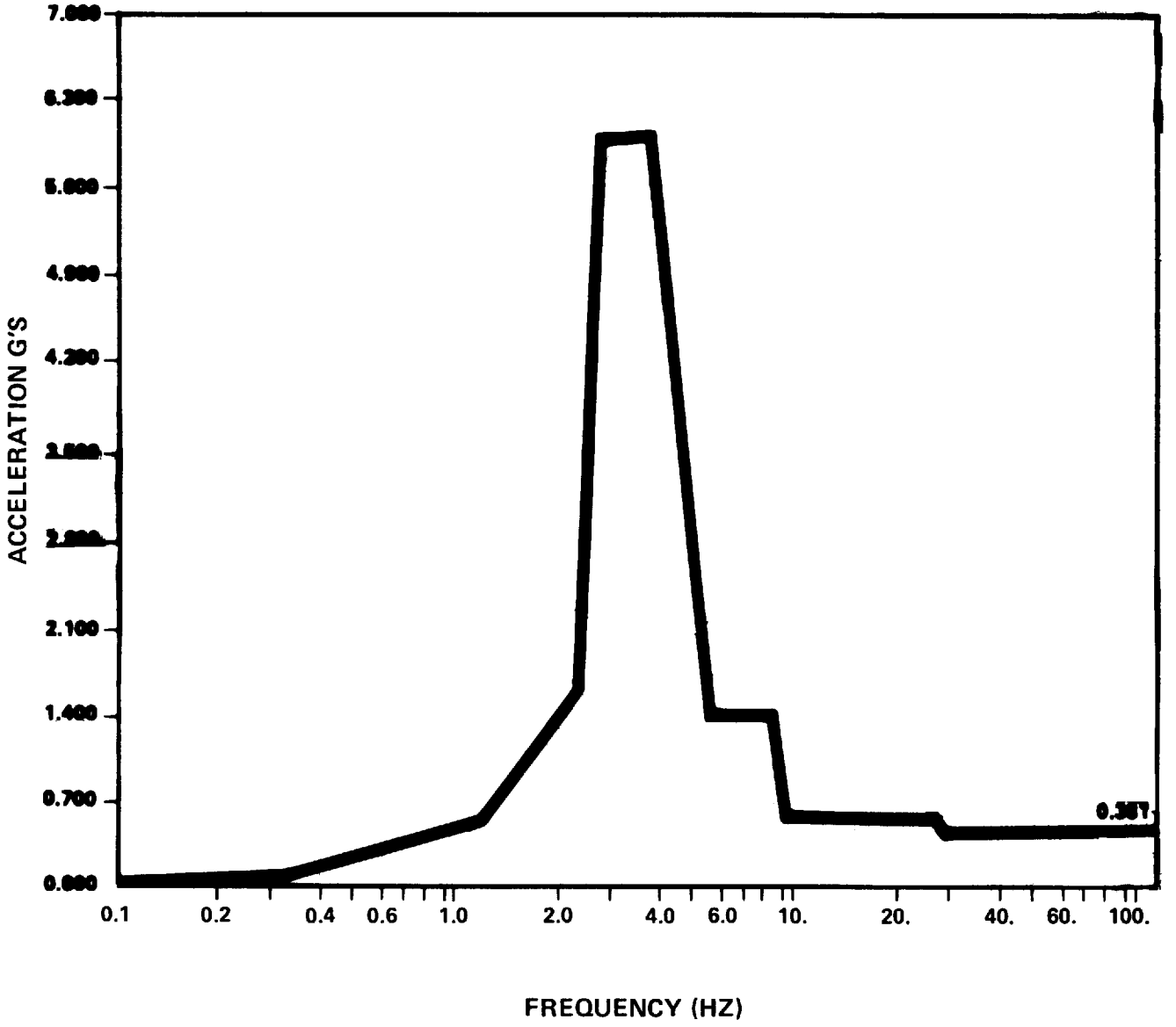
FIGURE 3.7-40



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RESPONSE SPECTRUM AT
REFUELING AREA
N-S SSE (DAMPING = 0.005)
SOIL-STRUCTURE INTERACTION

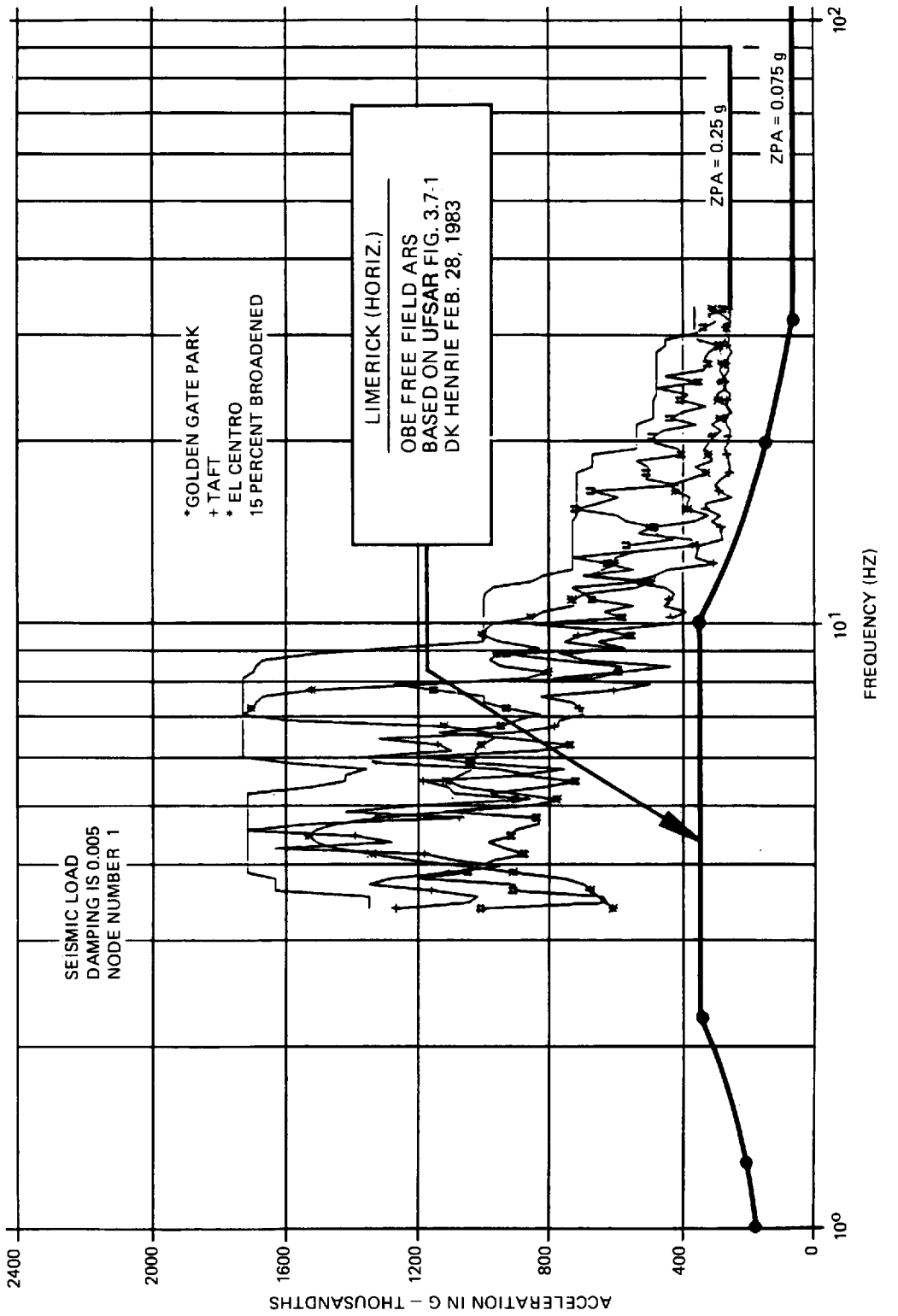
FIGURE 3.7-41



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RESPONSE SPECTRUM AT
REFUELING AREA
VERTICAL SSE (DAMPING = 0.005)
SOIL-STRUCTURE INTERACTION

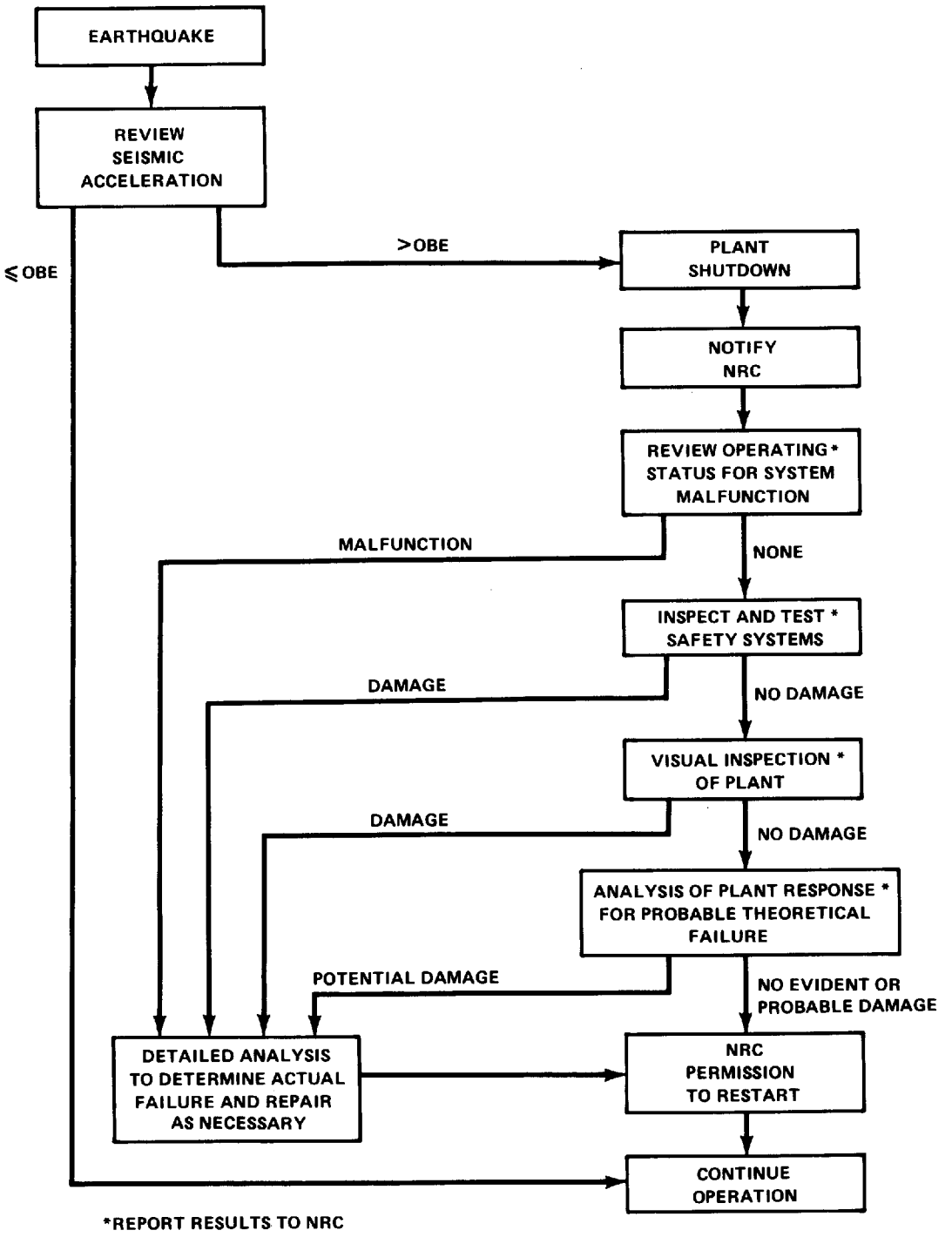
FIGURE 3.7-42



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

EARTHQUAKE RESPONSE SPECTRA

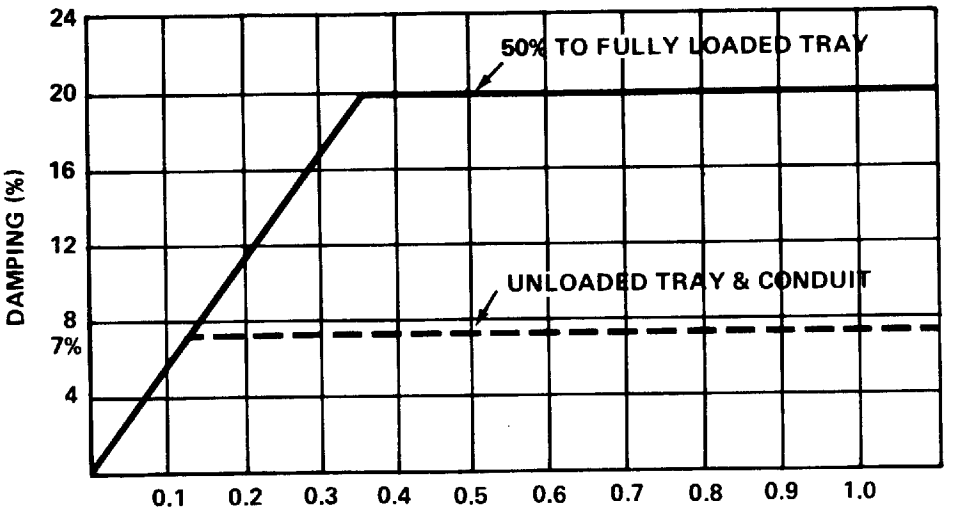
FIGURE 3.7-43



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

POST SEISMIC EVENT PLANT PROCEDURES

FIGURE 3.7-44

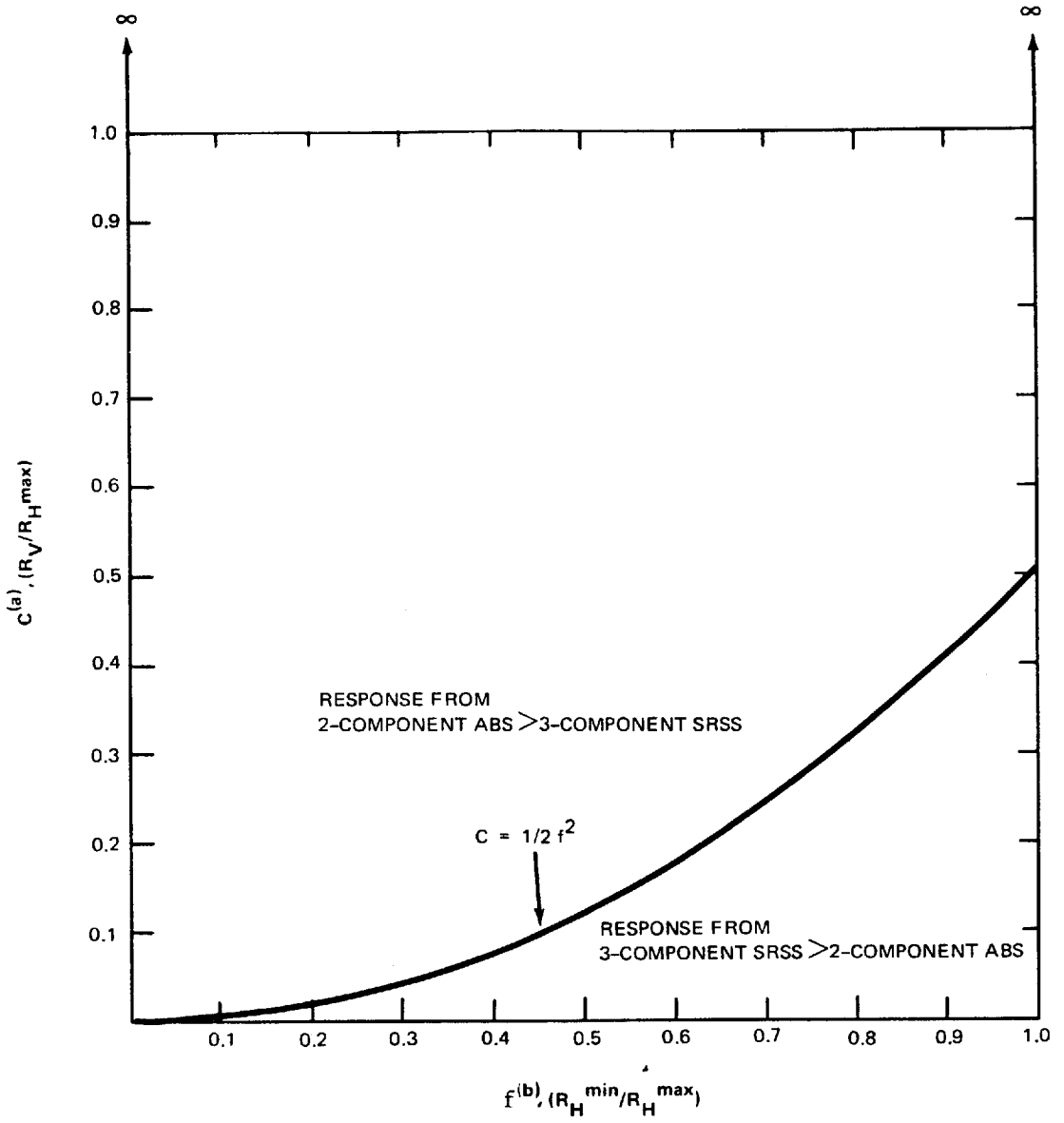


SOURCE: REF. 3.7-7

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DAMPING VS. ZPA FOR
RACEWAY SYSTEM

FIGURE 3.7-45



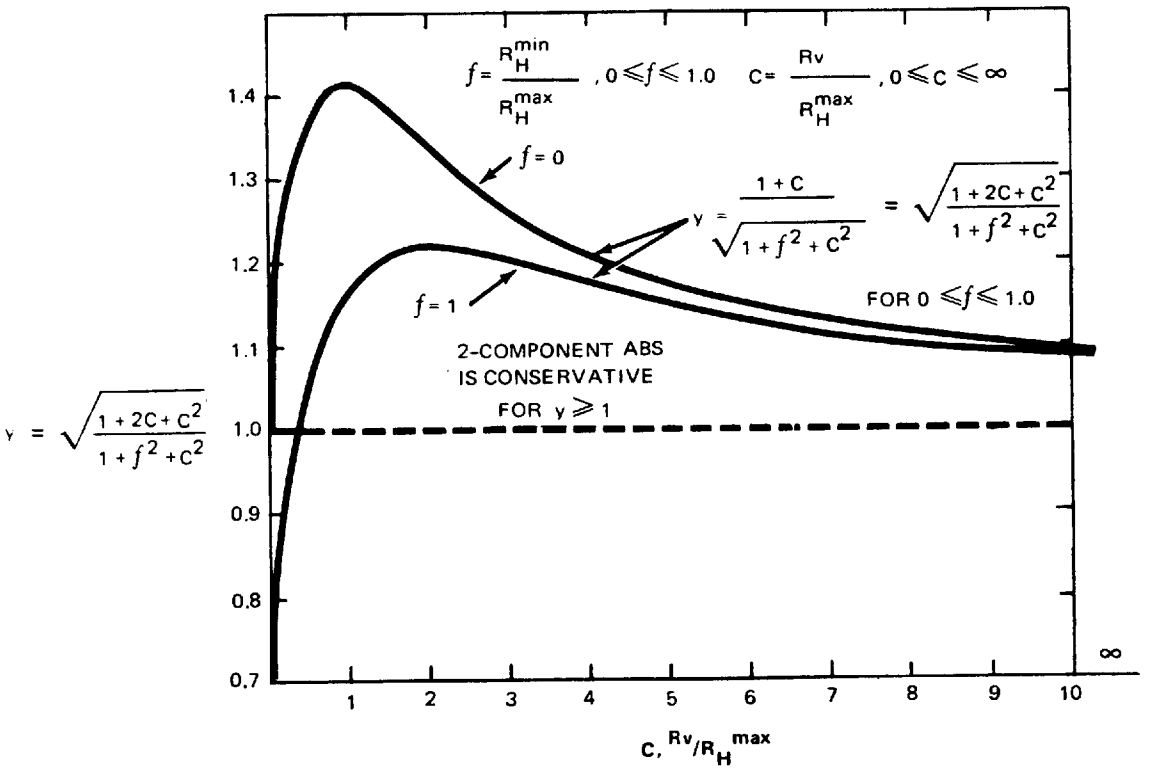
a. C = RATIO OF THE RESULTANT DUE TO THE VERTICAL COMPONENT TO THE MAXIMUM RESULTANT DUE TO EITHER OF THE HORIZONTAL COMPONENTS

b. f = RATIO OF THE SMALLER RESULTANT DUE TO EITHER OF THE HORIZONTAL COMPONENTS TO THE LARGER RESULTANT ($f \leq 1.0$)

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

COMPARISON OF 3–COMPONENT SRSS TO 2–COMPONENT ABS

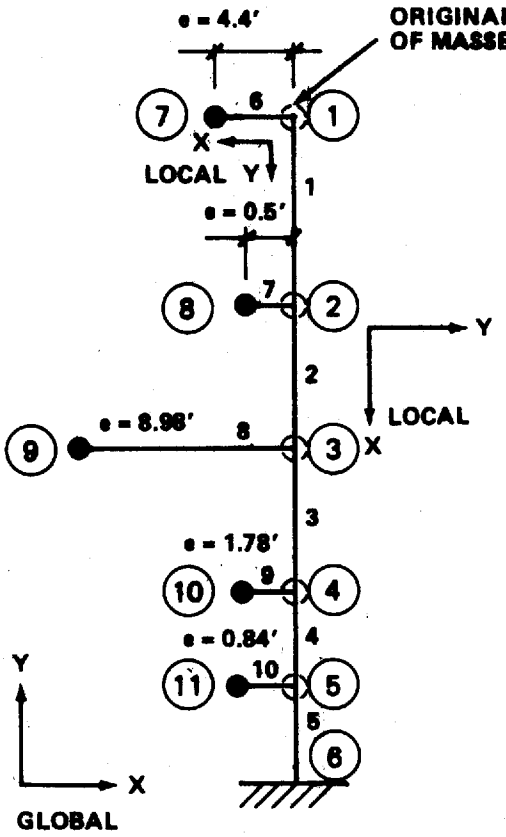
FIGURE 3.7-46



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RELATIVE CONSERTIVISM OF THE TWO–COMPONENT ABSOLUTE AND THREE –COMPONENT SRSS TECHNIQUES

FIGURE 3.7-47

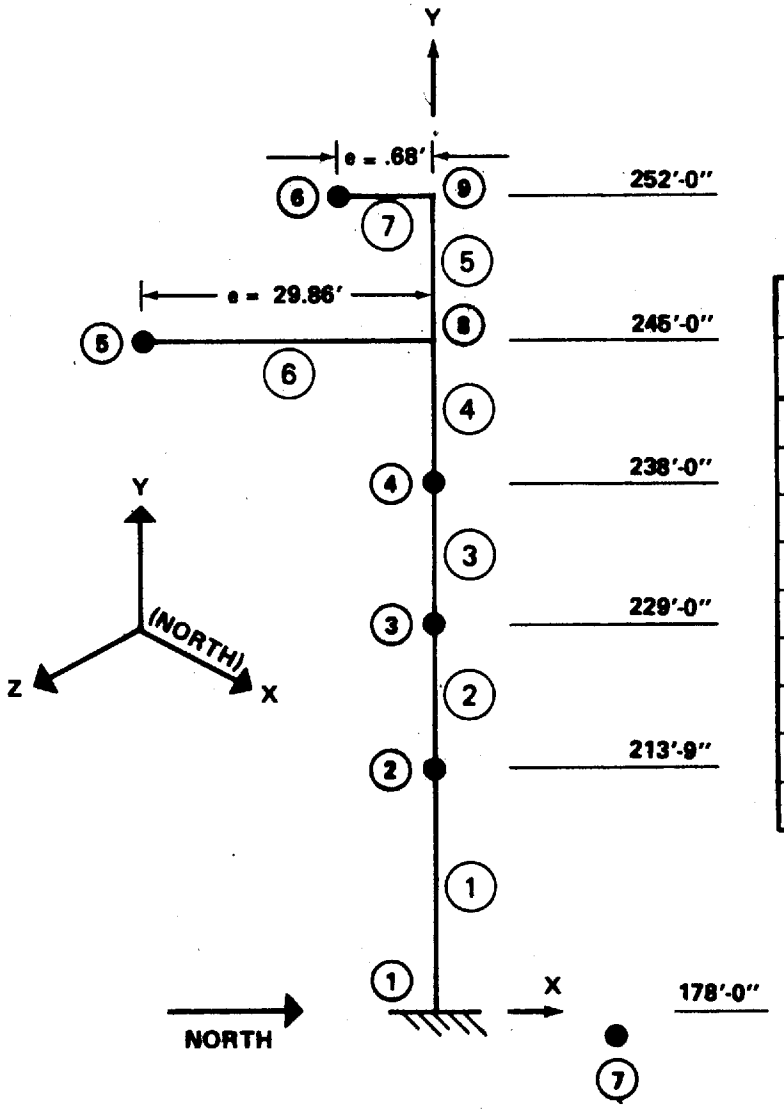


COORDINATES (Ft.)			
NODES	X	Y	Z
1	0.0	286.0	0.0
2	0.0	268.0	0.0
3	0.0	259.5	0.0
4	0.0	251.0	0.0
5	0.0	244.0	0.0
6	0.0	237.0	0.0
7	−4.40	286.0	0.0
8	−0.50	268.0	0.0
9	−8.98	259.5	0.0
10	−1.78	251.0	0.0
11	−0.84	244.0	0.0

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SPRAY POND PUMPHOUSE
3–D STICK MODEL
(E–W DIRECTION)

FIGURE 3.7-48



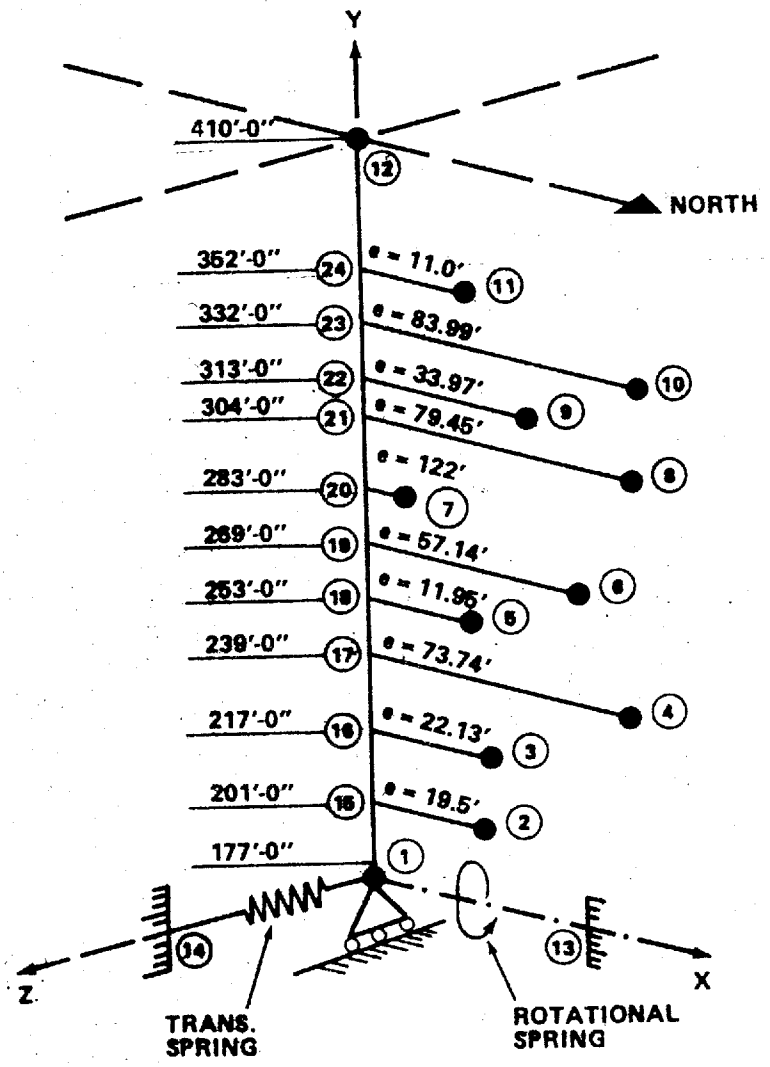
COORDINATES (Ft.)			
NODES	X	Y	Z
1	0.0	178.0	0.0
2	0.0	213.75	0.0
3	0.0	229.0	0.0
4	0.0	238.0	0.0
5	−29.86	245.0	0.0
6	− 0.68	252.0	0.0
* 7	10.00	178.0	0.0
8	0.0	245.0	0.0
9	0.0	252.0	0.0

* REFERENCE NODE FOR ELEMENT ORIENTATION

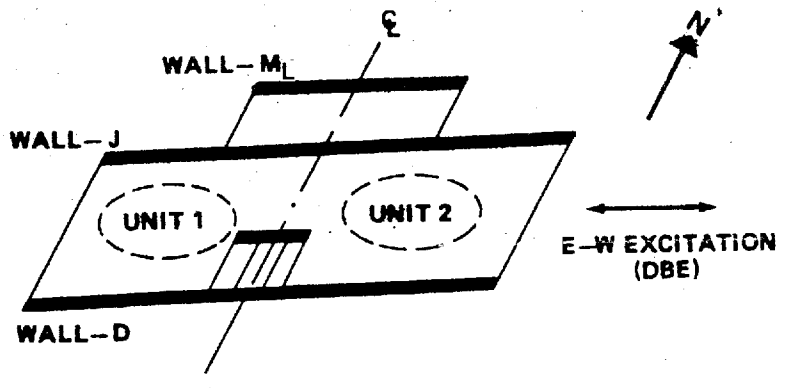
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DIESEL GENERATOR ENCLOSURE 3– STICK MODEL (E–W DIRECTION)

FIGURE 3.7-49



COORDINATES (Ft.)			
NODES	X	Y	Z
1	0.00	177.0	0.0
2	19.50	201.0	0.0
3	22.13	217.0	0.0
4	73.74	239.0	0.0
5	11.95	253.0	0.0
6	57.14	269.0	0.0
7	1.22	283.0	0.0
8	79.45	304.0	0.0
9	33.97	313.0	0.0
10	83.99	332.0	0.0
11	11.00	352.0	0.0
12	0.00	410.0	0.0
13	1.00	177.0	0.0
14	0.00	177.0	1.0
15	0.00	201.0	0.0
16	0.00	217.0	0.0
17	0.00	239.0	0.0
18	0.00	253.0	0.0
19	0.00	269.0	0.0
20	0.00	283.0	0.0
21	0.00	304.0	0.0
22	0.00	313.0	0.0
23	0.00	332.0	0.0
24	0.00	352.0	0.0

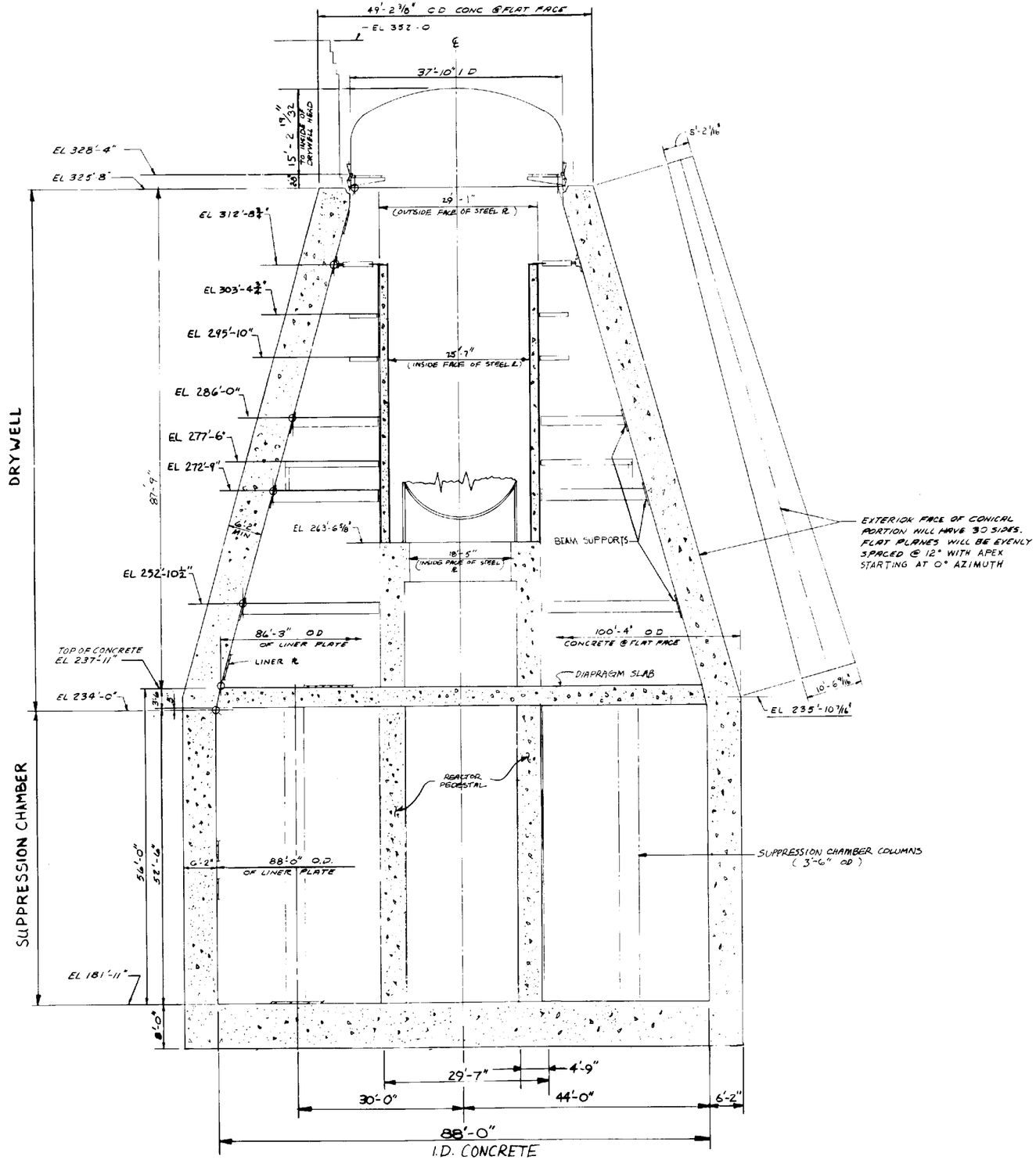


(SEE TABLE 3.7-26)

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE 3–D STICK MODEL (E–W DIRECTION)

FIGURE 3.7-50



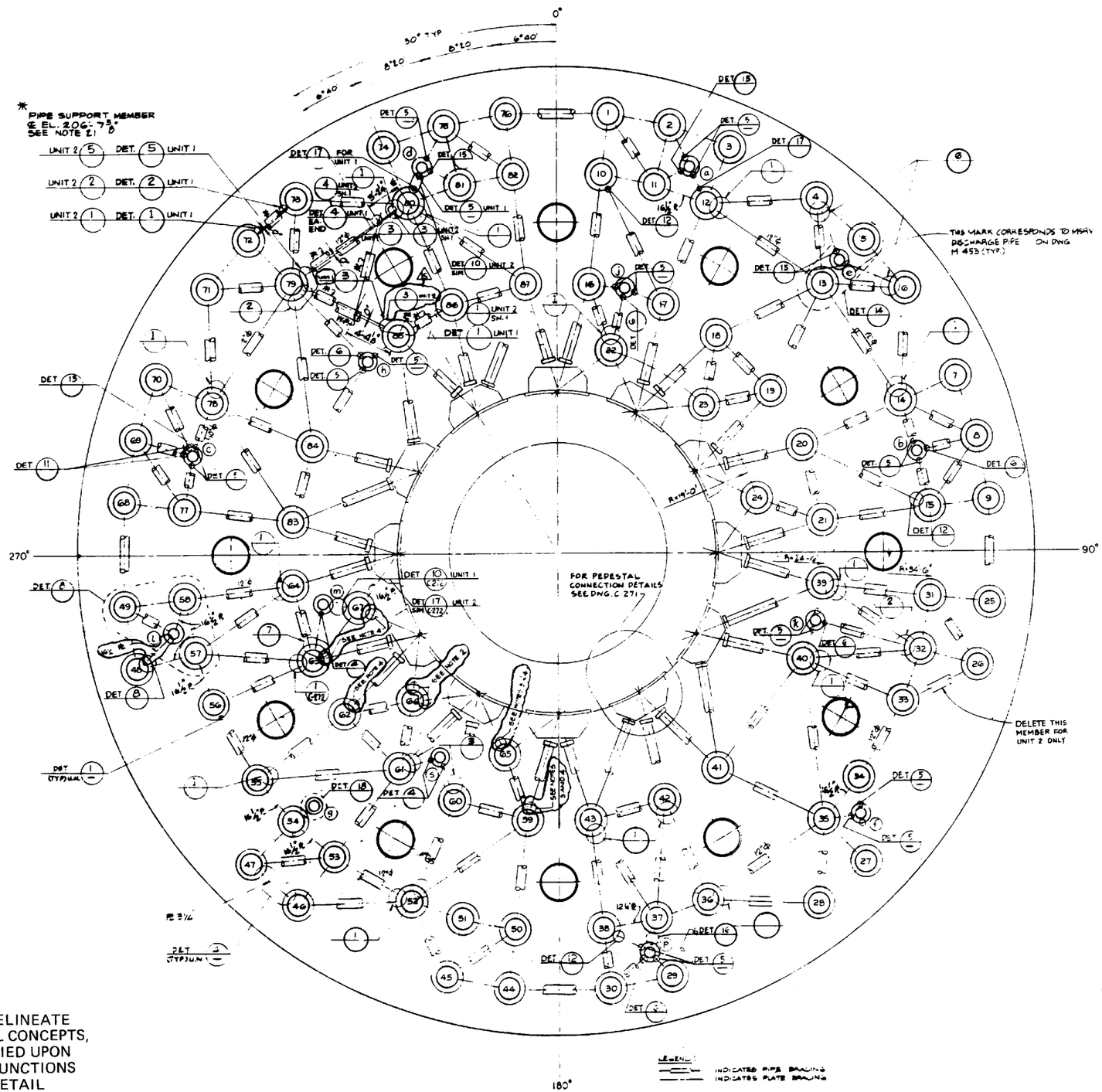
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-276.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRIMARY CONTAINMENT
ELEVATION VIEW

FIGURE 3.8-1



PLAN AT ELEVATION 203'-5" U.N.O.

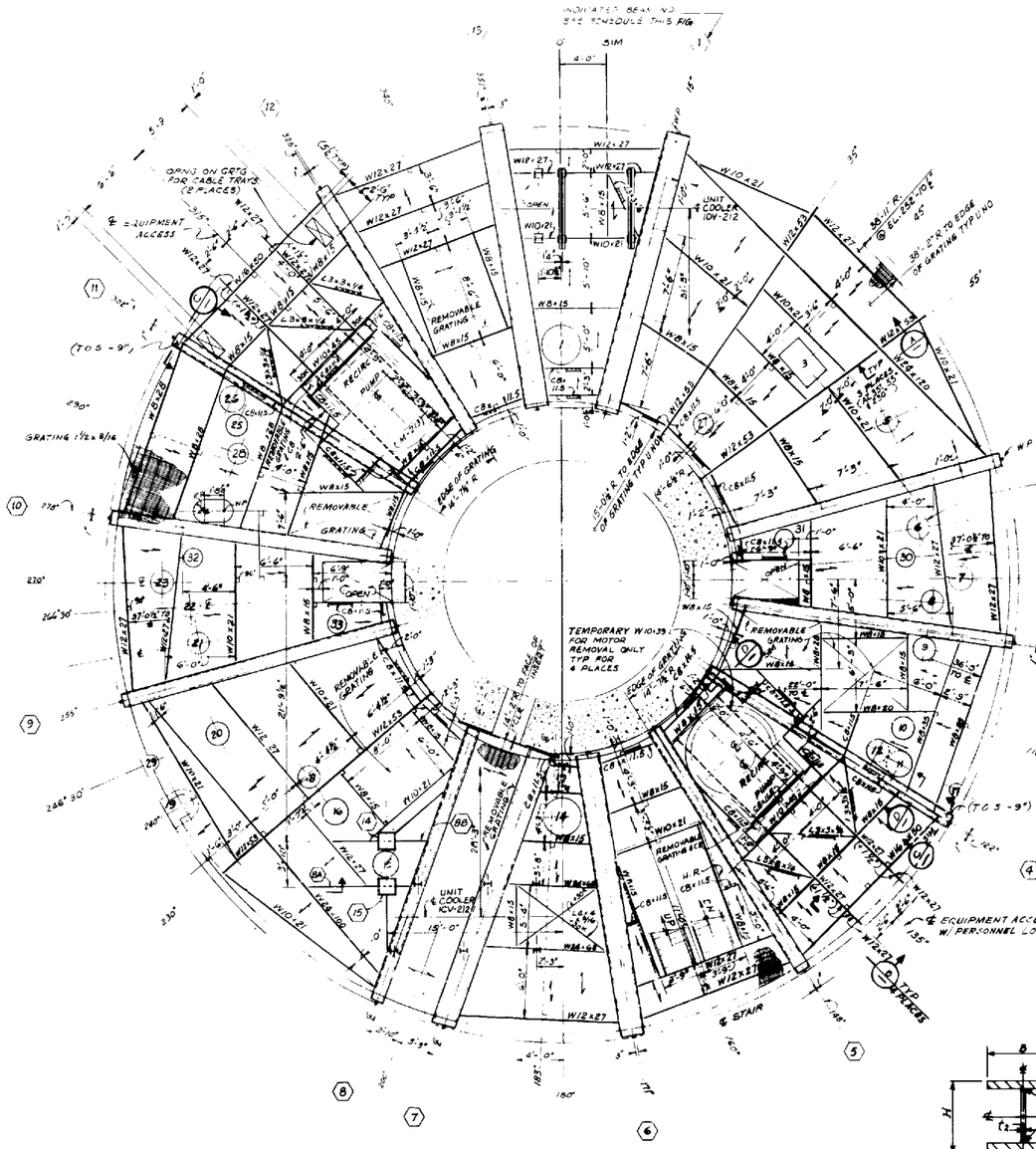
NOTE:

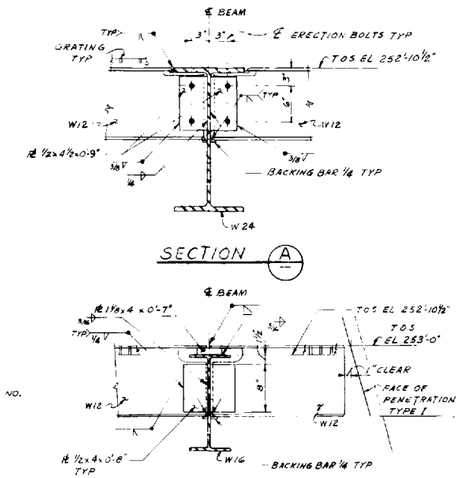
THIS UFSAR FIGURE IS PROVIDED TO DELINEATE THE PRIMARY (TYPICAL) STRUCTURAL CONCEPTS, ARRANGEMENTS, AND ELEMENTS RELIED UPON TO PERFORM THE SAFETY RELATED FUNCTIONS OF THE SUBJECT STRUCTURES. FOR DETAIL DESIGN FEATURES, DIMENSIONS AND AS-BUILT CONDITION OF THESE STRUCTURES, SEE DESIGN DRAWING #8031-C-270.

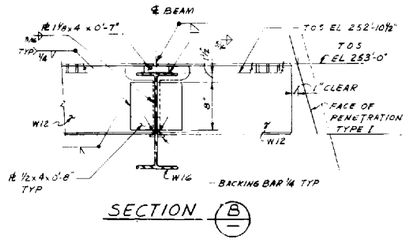
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

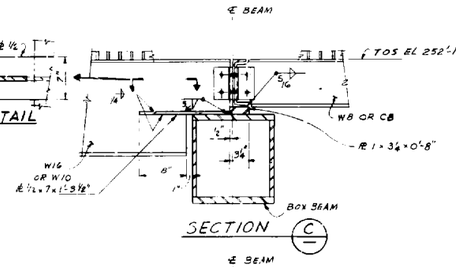
PRIMARY CONTAINMENT PLAN VIEW AT ELEVATION 203'-5"

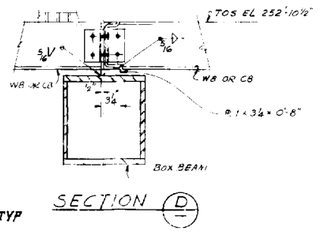
FIGURE 3.8-2

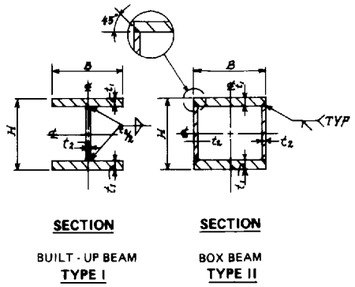












BEAM SCHEDULE

BEAM	TYPE	* BEAM DIMENSIONS B	H	t1	t2
1	II	24	24	11/16	3/4
2		12	24	3/4	
3		14	24	3/4	
4		14	15	1	
5		14	24	3/4	
6		24	24	11/16	
7		24	24	11/16	
8		14	24	3/4	
9		14	24	3/4	
10		14	24	3/4	
11		14	15	1	
12		14	24	3/4	
13		24	24	11/16	3/4
14		18	16	1½	1
15	II	18	16	1½	1
8A	I	18	12	3/4	½
8B	I	18	12	3/4	½

* DIMENSIONS IN INCHES

NOTE:

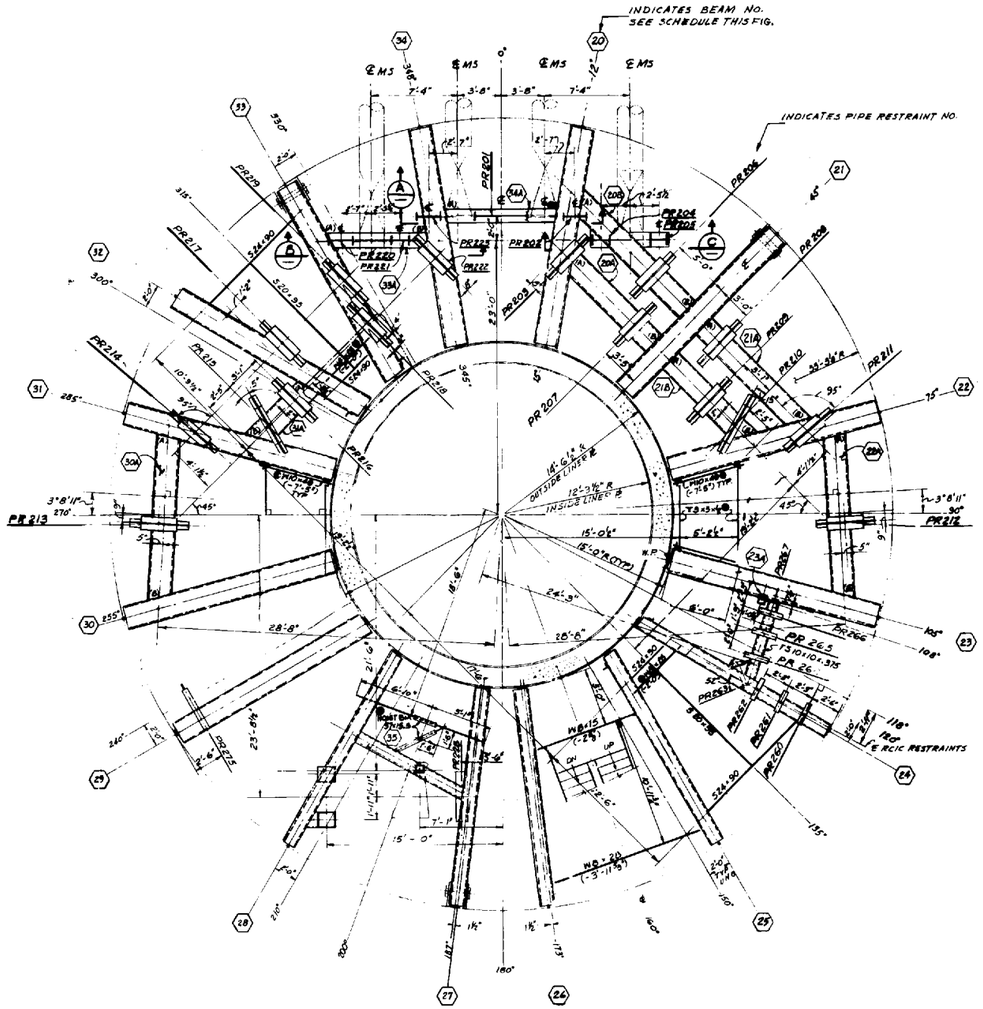
This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-926 for Unit 1, and 8031-C-927 for Unit 2.

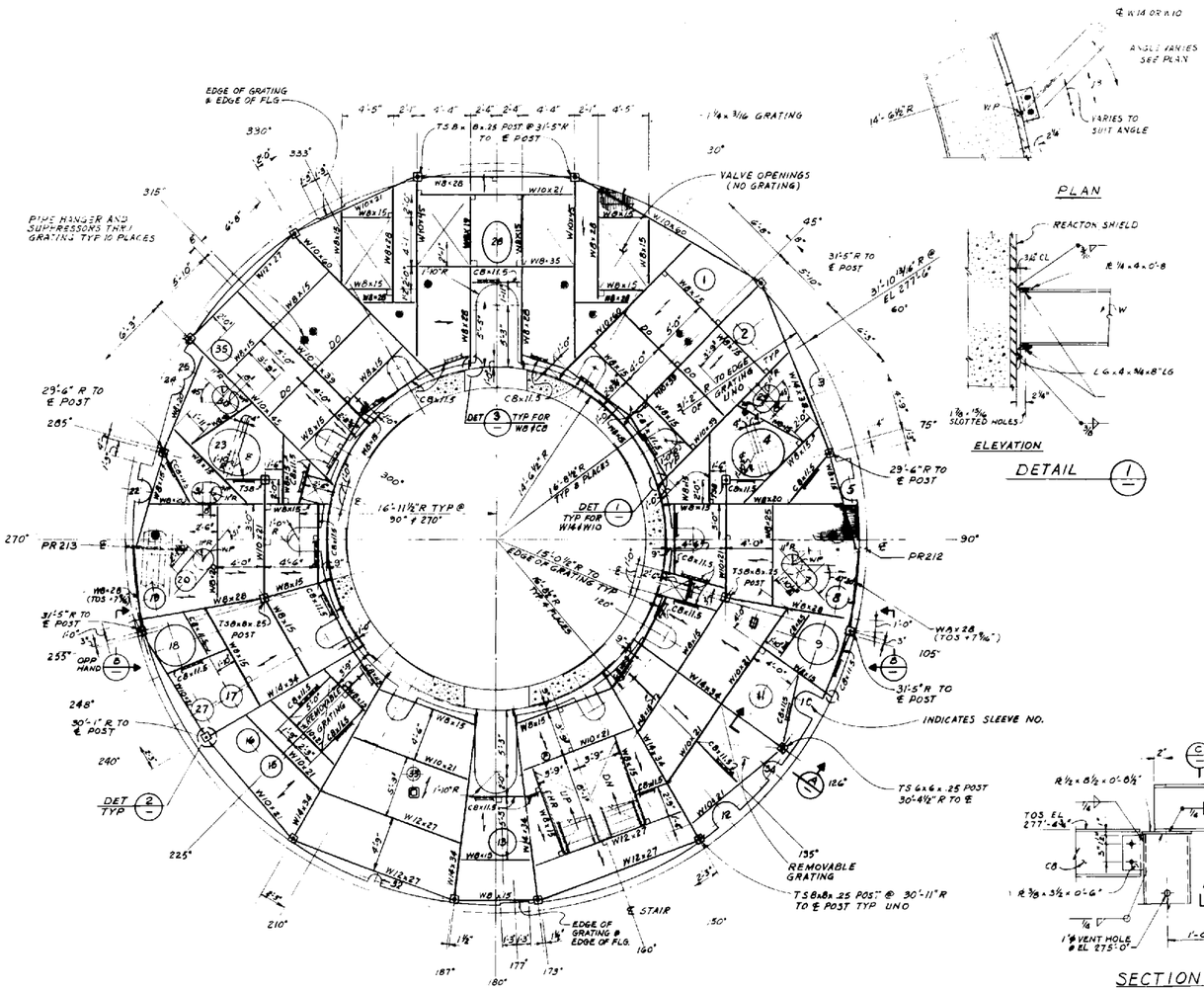
DETAIL 1

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRIMARY CONTAINMENT PLAN VIEW AT ELEV. 253'-0"

FIGURE 3.8-3


INDICATES BEAM NO. SEE SCHEDULE THIS FIG.
INDICATES PIPE RESTRAINT NO.
PR 207
PR 201
PR 202
PR 203
PR 204
PR 205
PR 206
PR 208
PR 209
PR 210
PR 211
PR 212
PR 213
PR 214
PR 215
PR 216
PR 217
PR 218
PR 219
PR 220
PR 221
PR 222
PR 223
PR 224
PR 225
PR 226
PR 227
PR



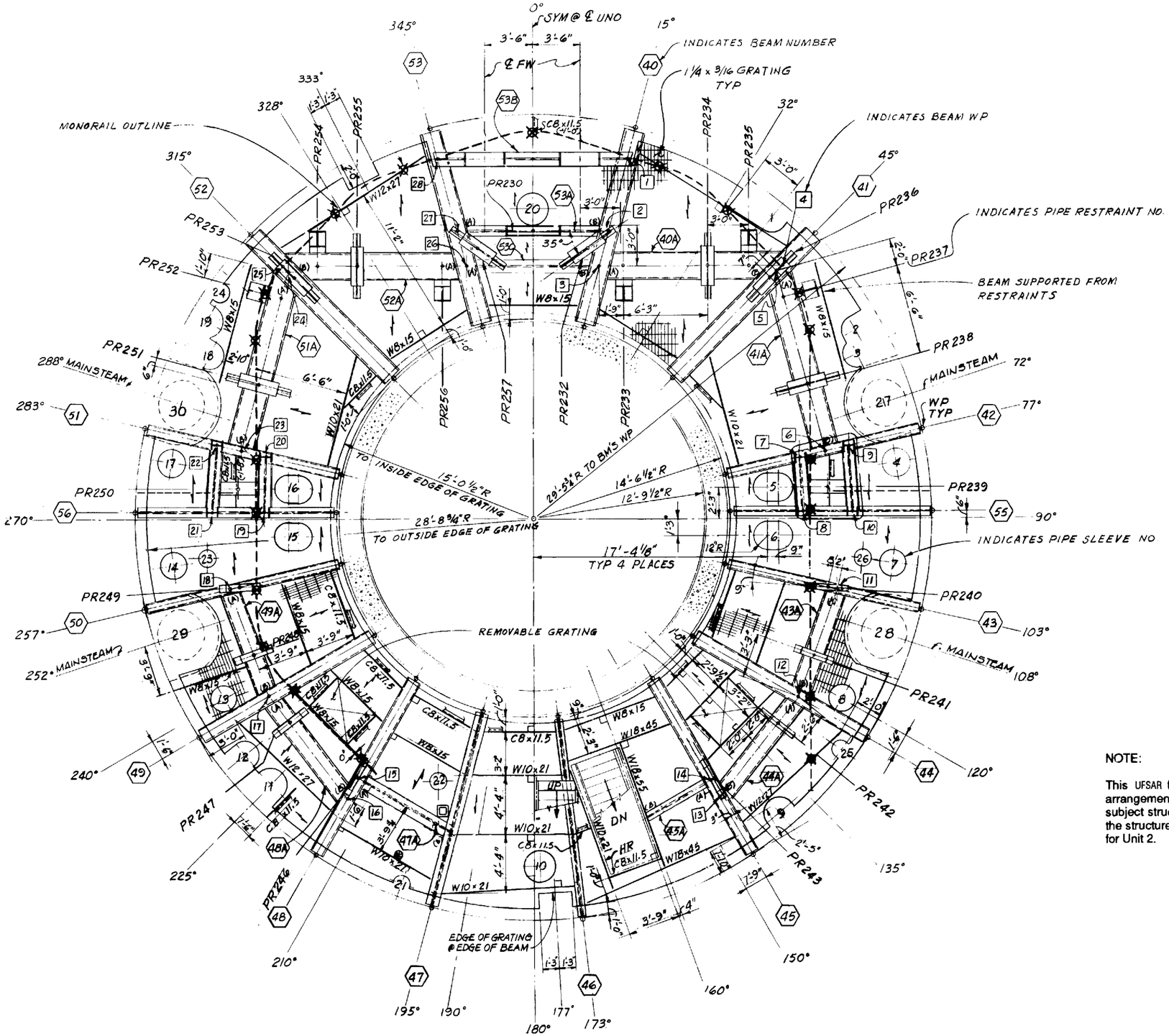
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-930 for Unit 1, and 8031-C-931 for Unit 2.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRIMARY CONTAINMENT PLAN VIEW AT ELEV. 277'-6"

FIGURE 3.8-5



BEAM SCHEDULE

B No.	TYPE	*DIMENSIONS B	H	t_1	t_2
40	II	18	18	2 1/4	3/4
40A		24		1 1/2	1
41		18		2 1/4	3/4
41A		24		1 1/2	1
42		9		2 1/2	3/4
43		9		1 1/4	1/2
43A		18		1/2	
44		12		3/4	
44A	↓	18	↓	1/2	↓
45	II	12	18	3/4	1/2
45A	W18x77	—	—	—	—
46	W18x45	—	—	—	—
47	W18x60	—	—	—	—
47A	W18x96	—	—	—	—
48	II	12	18	3/4	1/2
48A		18		1/2	
49		12		3/4	
49A		18		1/2	↓
50		9		1 1/4	1/2
51		9		2 1/2	3/4
51A		24		1 1/2	1
52		18		2 1/4	3/4
52A	↓	24	↓	1 1/2	1
53	II	18	18	2 1/4	3/4
53A	I	12	18	1	3/4
53B					
53C	I	12	18	1 1/2	1
54	THIS	NUMBER	NOT	USED	
55	I	9	18	1 1/2	1/2
56	I	9	18	1 1/2	1/2

* DIMENSIONS IN INCHES

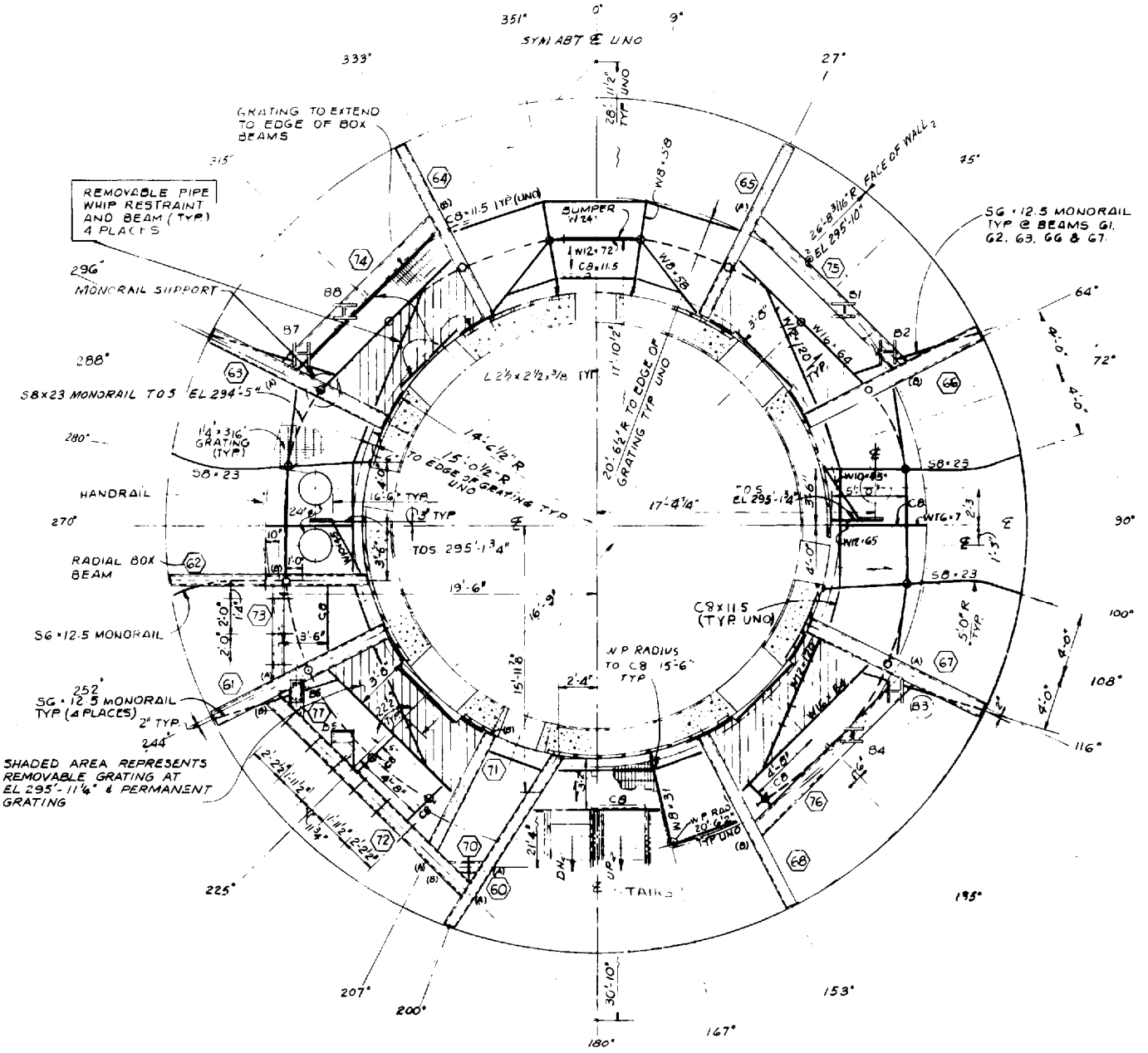
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-932 for Unit 1, and 8031-C-933 for Unit 2.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRIMARY CONTAINMENT PLAN VIEW AT ELEV. 286'-1"

FIGURE 3.8-6



PLATFORM & MONORAIL

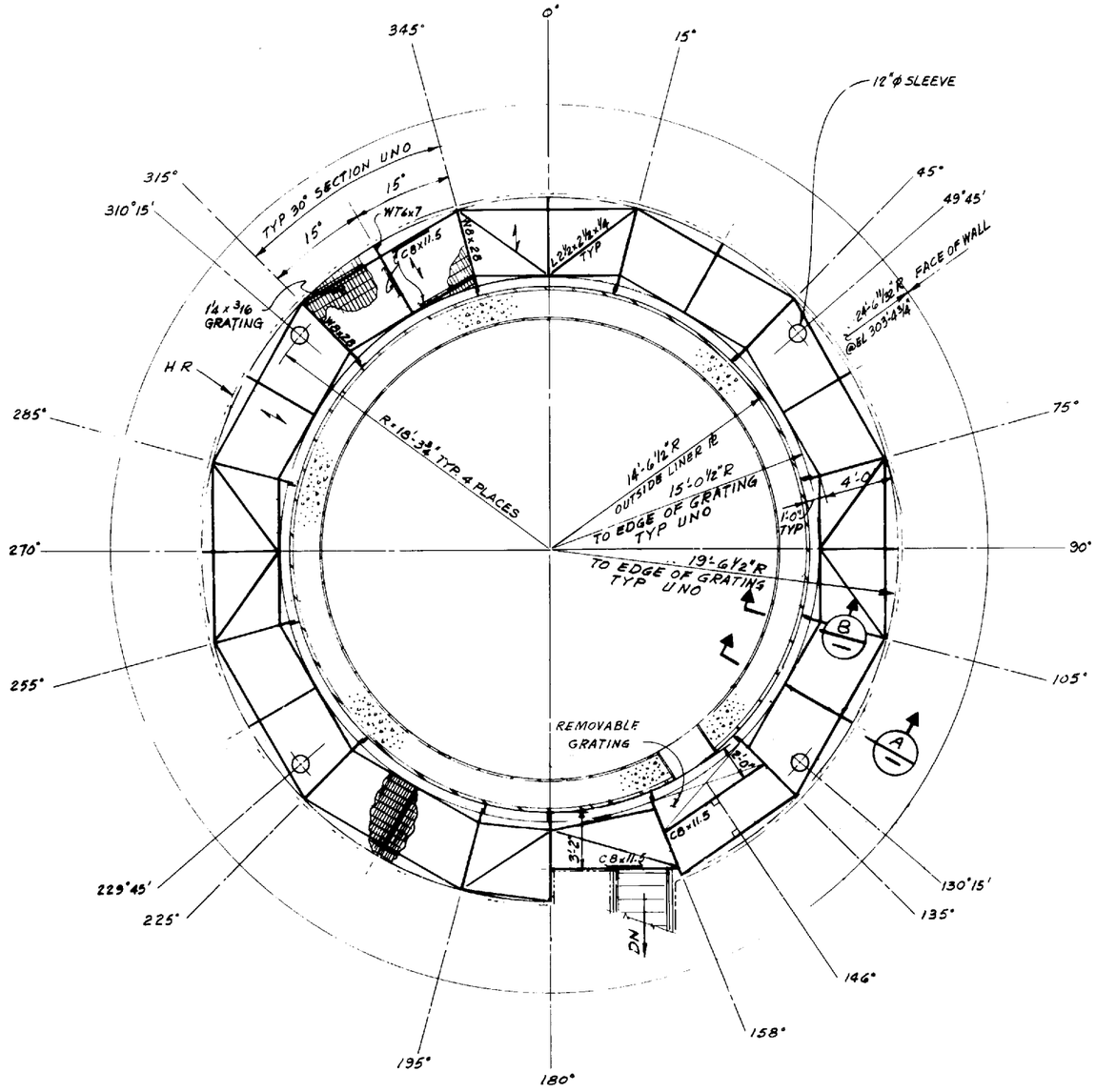
NOTE:

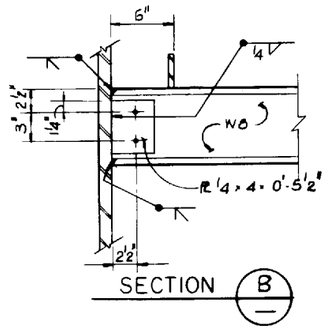
This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-934 for Unit 1, and 8031-C-935 for Unit 2.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

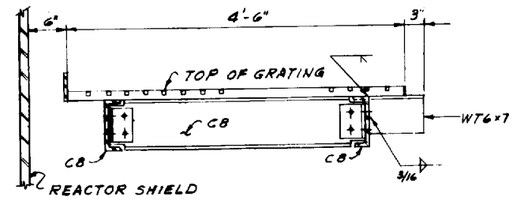
PRIMARY CONTAINMENT PLAN VIEW AT ELEV. 295'-11"

FIGURE 3.8-7





SECTION B



SECTION A

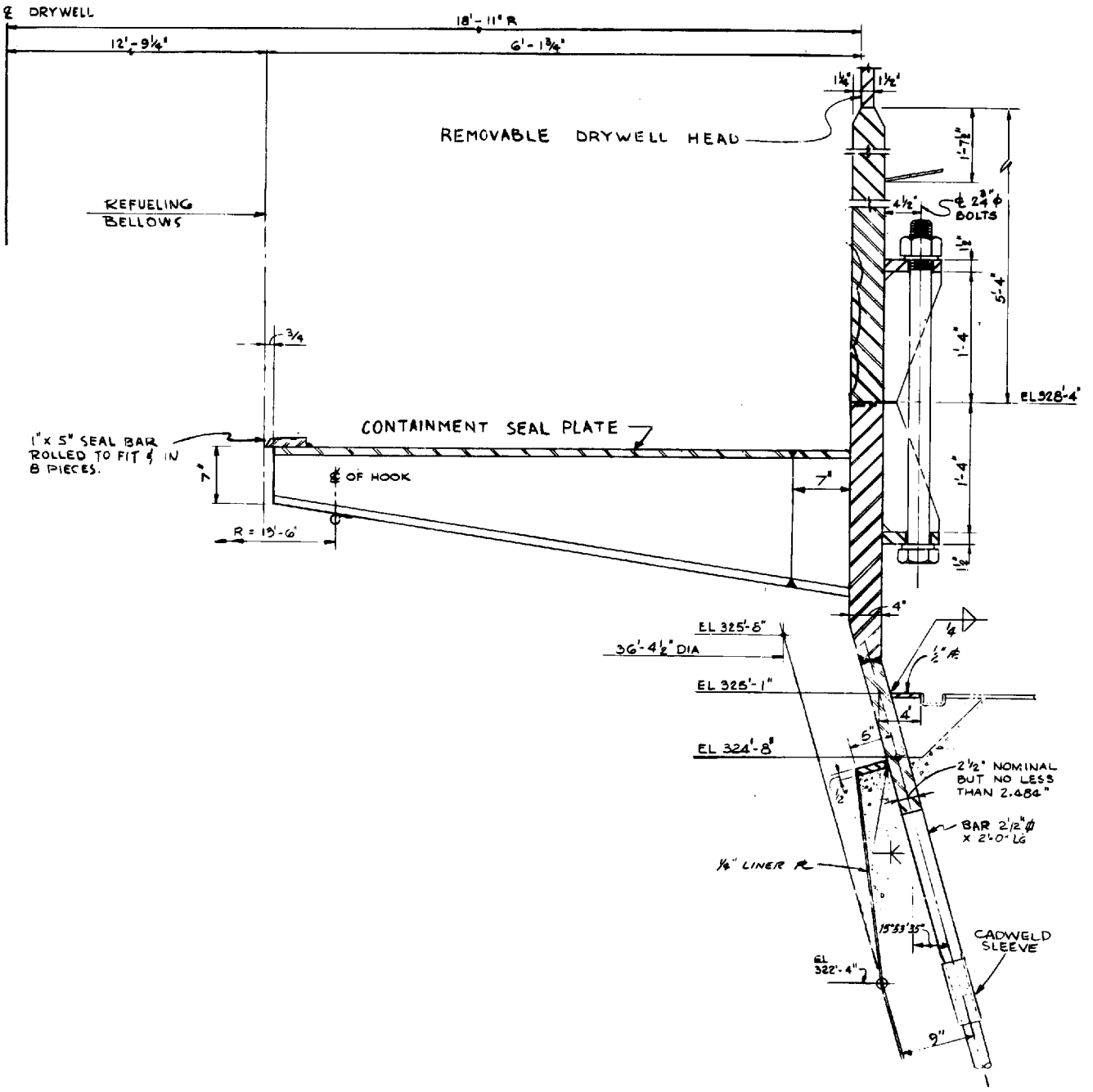
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-934 for Unit 1, and 8031-C-935 for Unit 2.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRIMARY CONTAINMENT PLAN VIEW AT ELEV. 303'-6"

FIGURE 3.8-8



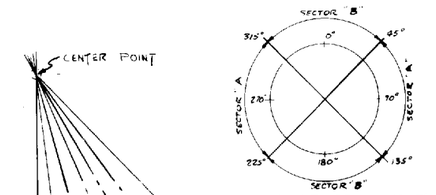
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-290.

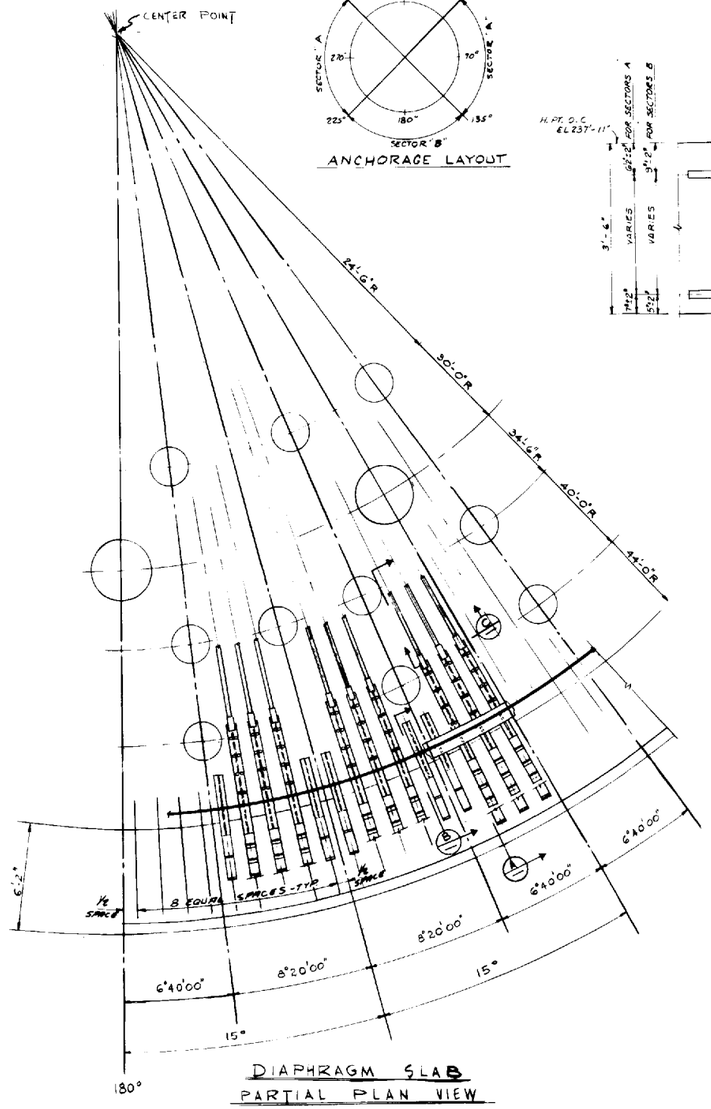
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL HEAD CONNECTION TO CONTAINMENT WALL

FIGURE 3.8-9

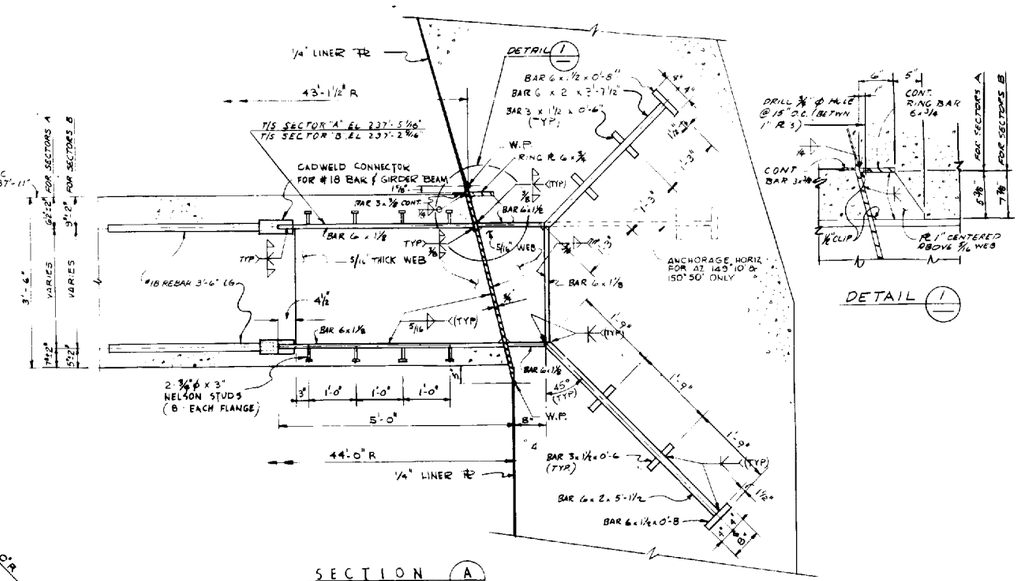


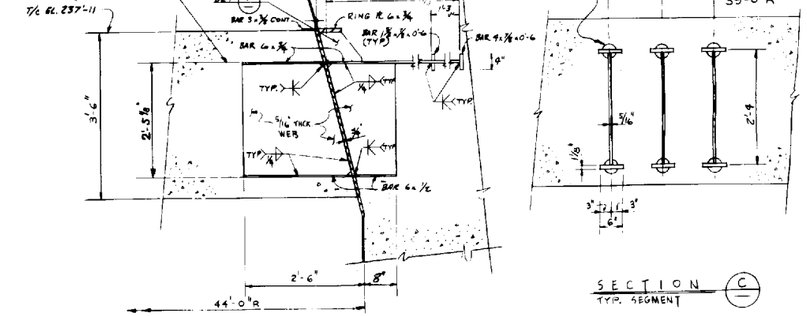
ANCHORAGE LAYOUT



DIAPHRAGM SLAB
PARTIAL PLAN VIEW

TYPICAL LAYOUT SEGMENT FOR GIRDER CONNECTIONS





NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-284.

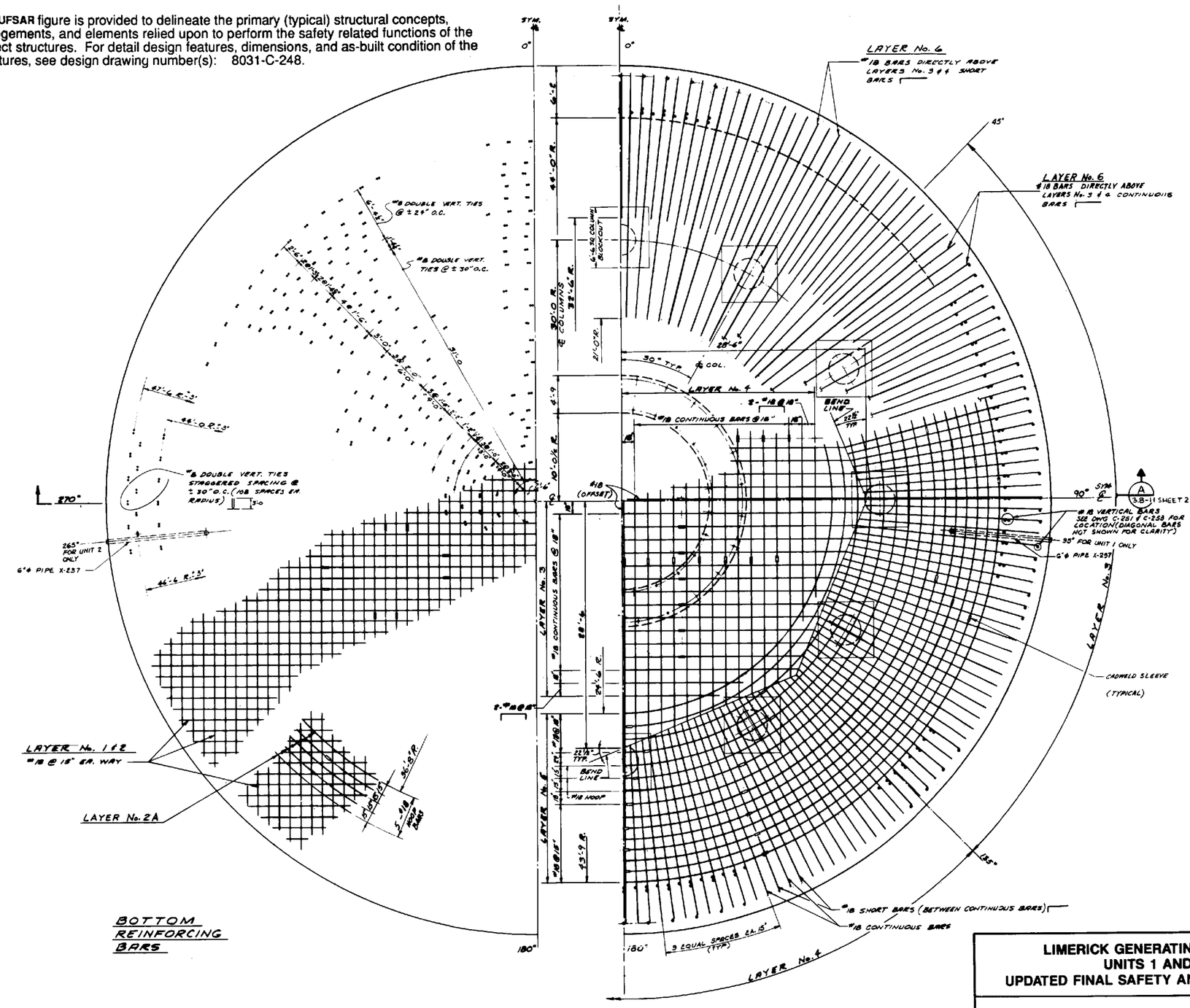
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DIAPHRAGM SLAB CONNECTION TO CONTAINMENT WALL

FIGURE 3.8-10

NOTE:

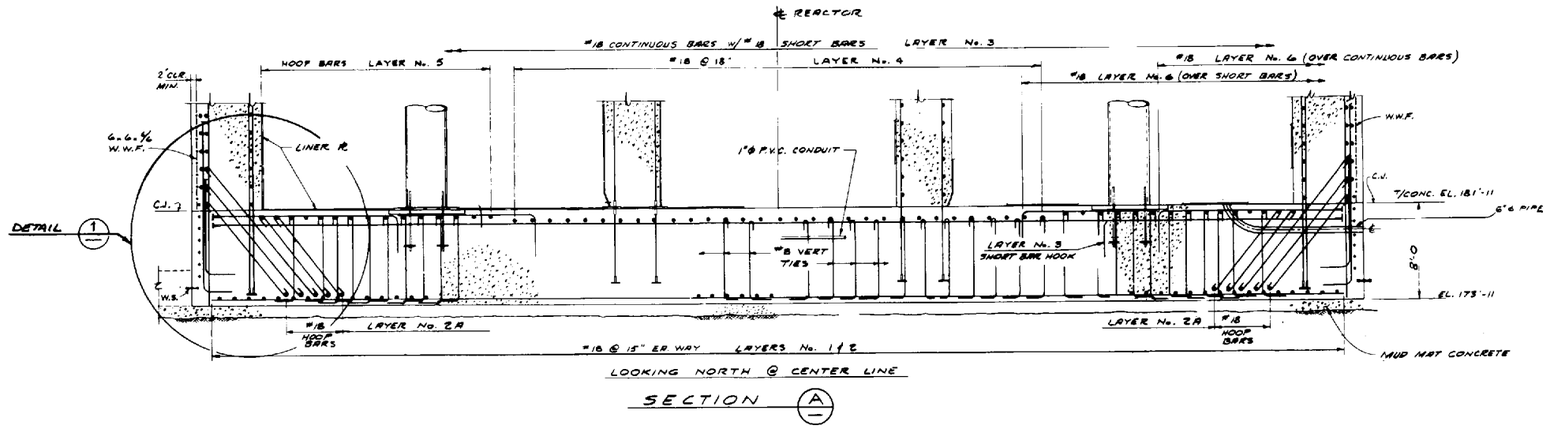
This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-248.

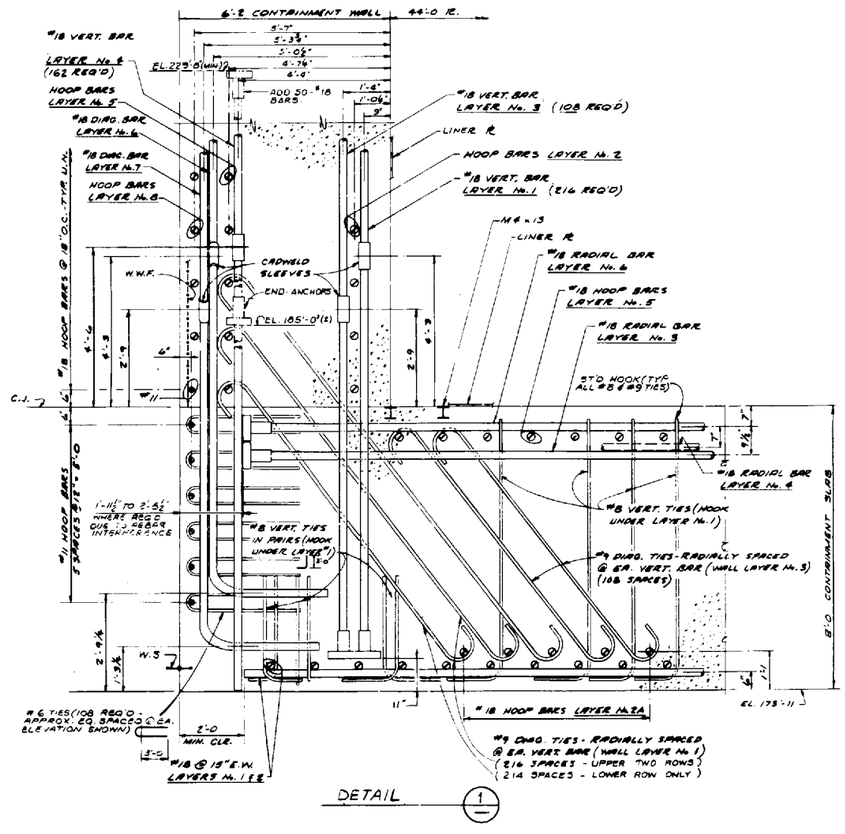


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

BASE FOUNDATION SLAB REINFORCEMENT
(SHEET 1 OF 2)

FIGURE 3.8-11





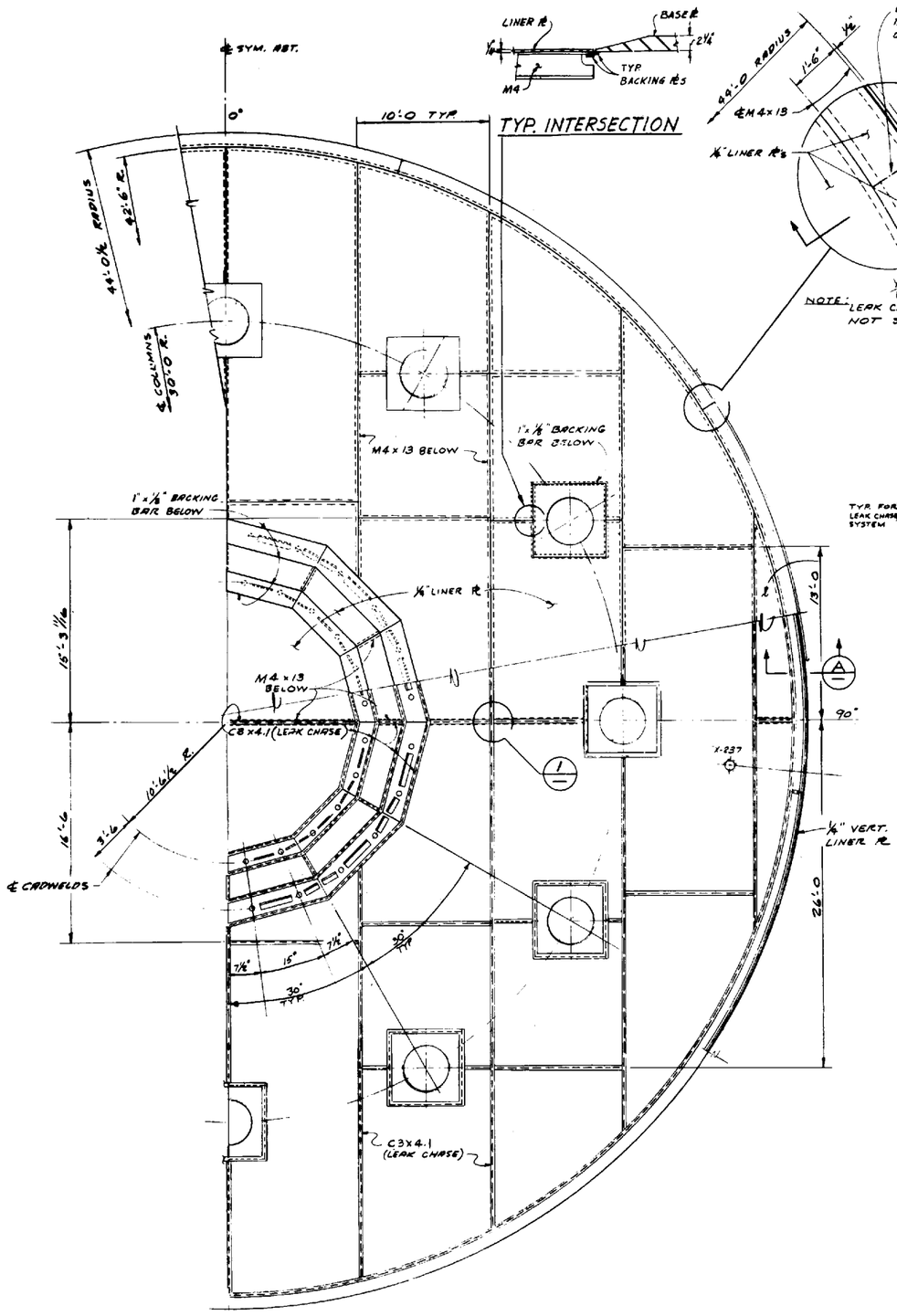
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-249.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

BASE FOUNDATION SLAB REINFORCEMENT (SHEET 2 OF 2)

FIGURE 3.8-11



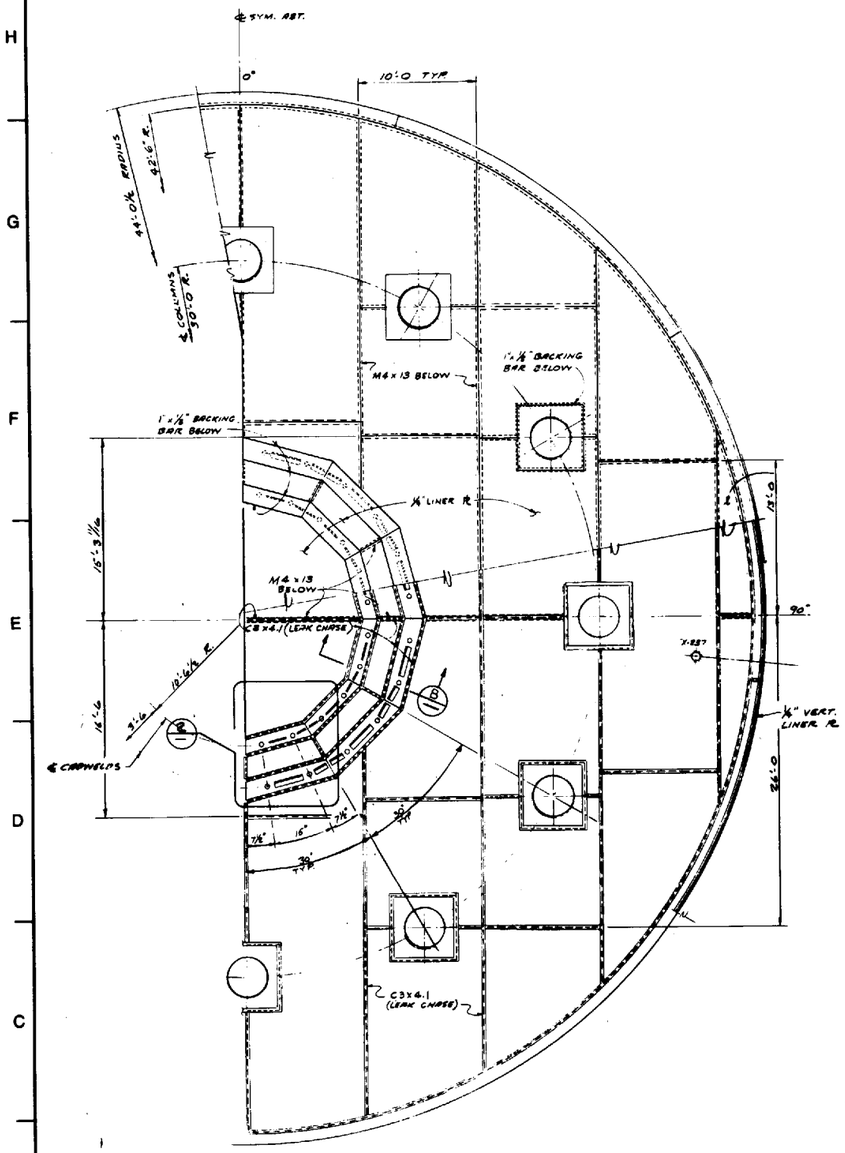
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-281.

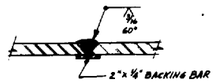
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

BASE FOUNDATION SLAB LINER PLATE AND ANCHORAGES

FIGURE 3.8-12



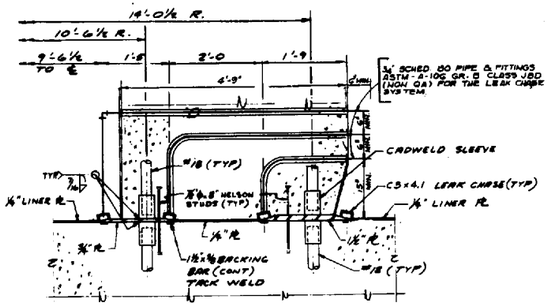
FLOOR PLAN



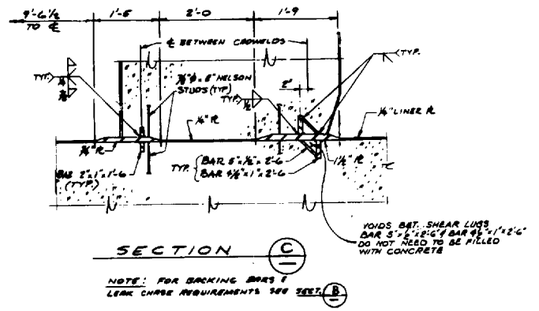
FIELD SPLICE

NOTE: SPLICES OF ⅜" OR 1½" PLATE ARE NOT TO BE LEAK CHASED UNLESS SHOWN.

TYPICAL JOINT BETWEEN PLATES LARGER THAN ¼"

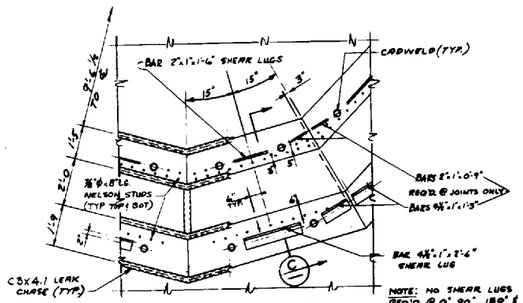


SECTION B



SECTION C

NOTE: FOR BACKING BARS & LEAK CHASE REQUIREMENTS SEE SHEET B



DETAIL 2

NOTE: NO SHEAR LUGS REQ'D @ 0°, 90°, 180° & 270° AZIMUTHS

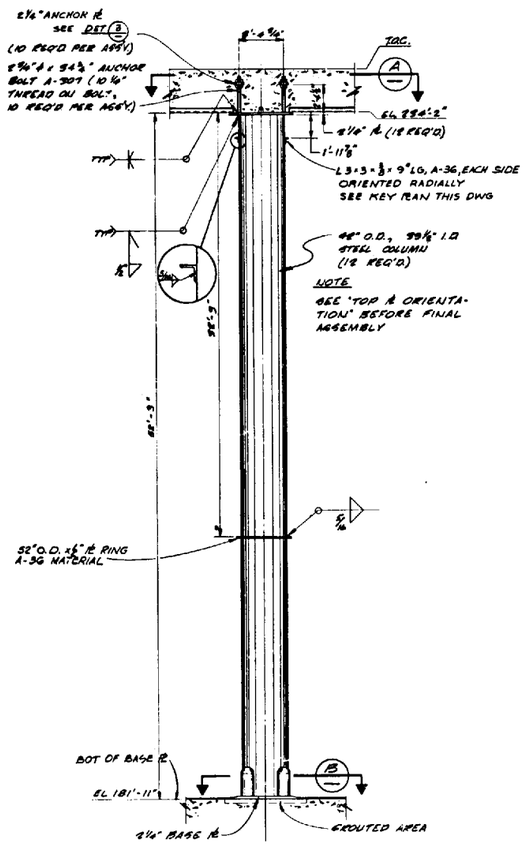
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-281.

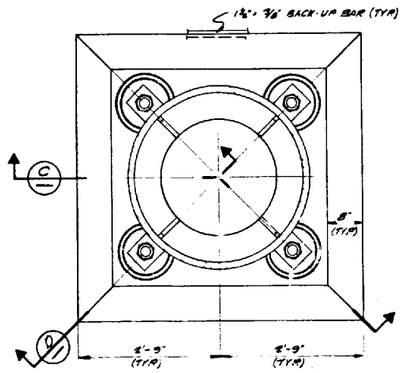
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR PEDESTAL BASE LINER ANCHORAGE

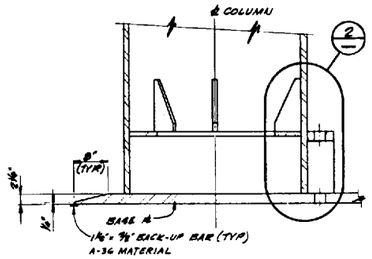
FIGURE 3.8-13



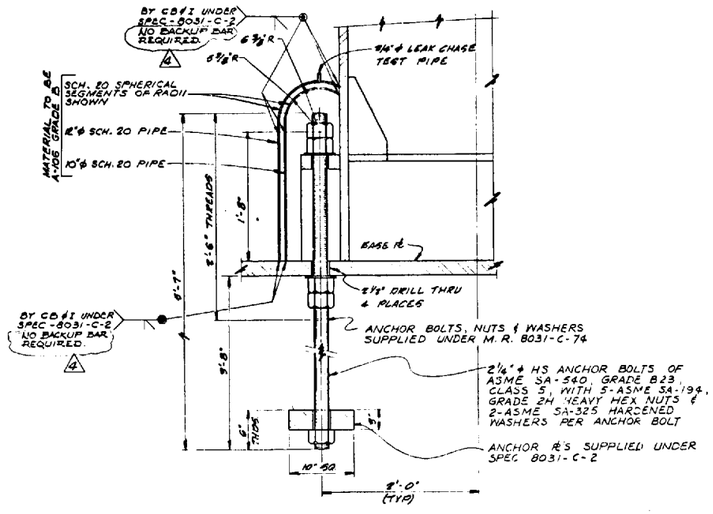
ELEVATION
⅛" = 1'-0"



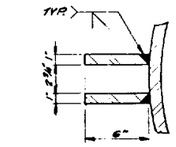
SECTION 5
1" = 1'-0"



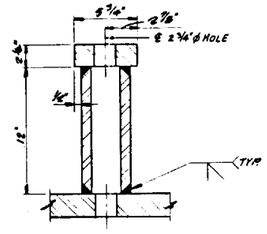
SECTION C
1" = 1'-0"



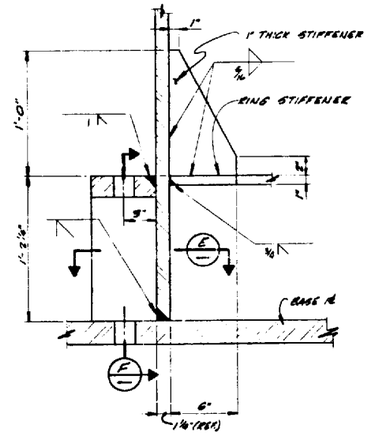
SECTION D
1¼" = 1'-0"



SECTION E
N.T.S.



SECTION F
N.T.S.



DETAIL 7
N.T.S.

NOTE:

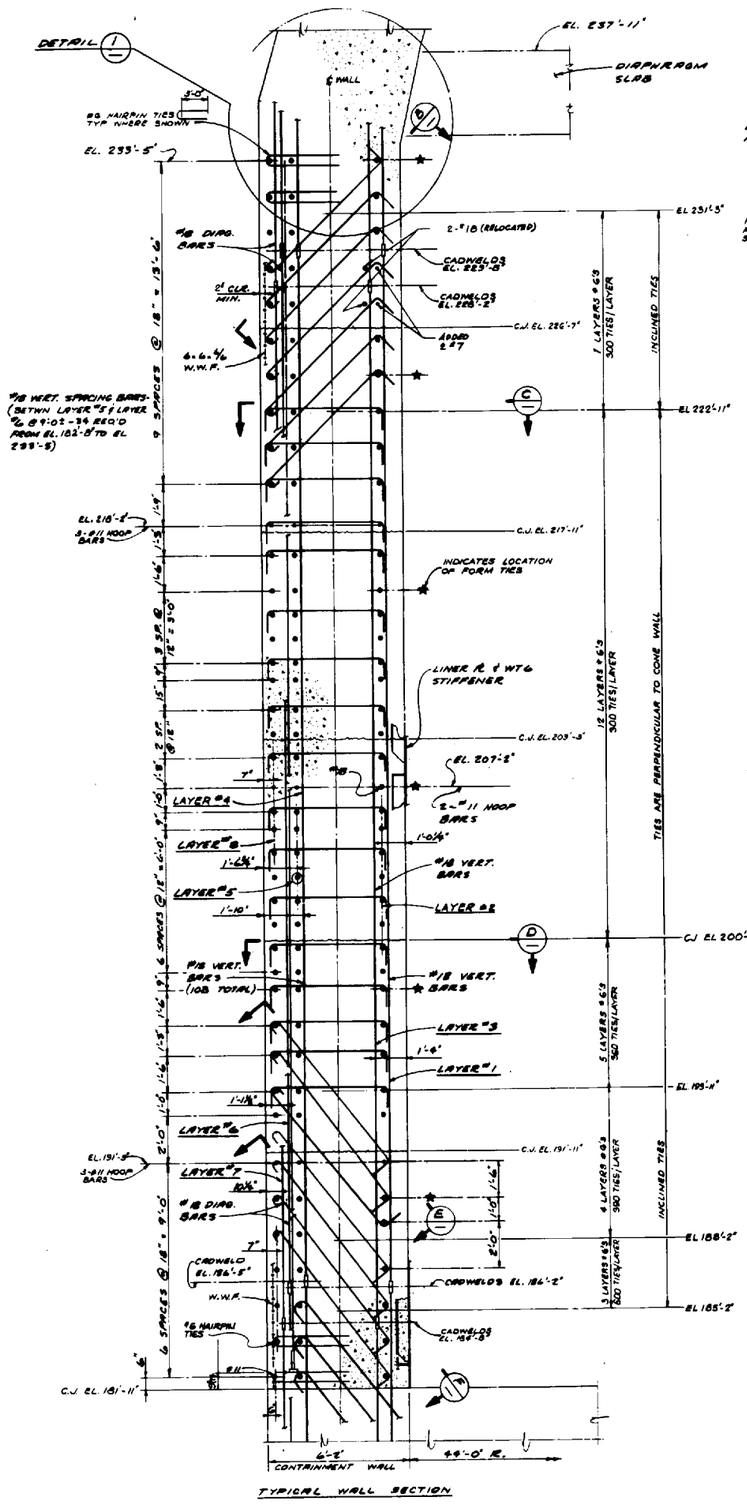
This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-300.

NOTE: SEE FIGURE 3.8-12 FOR COLUMN ORIENTATION AND CONNECTION DETAILS TO DIAPHRAM SLAB.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION CHAMBER COLUMN BASE LINER ANCHORAGE

FIGURE 3.8-14



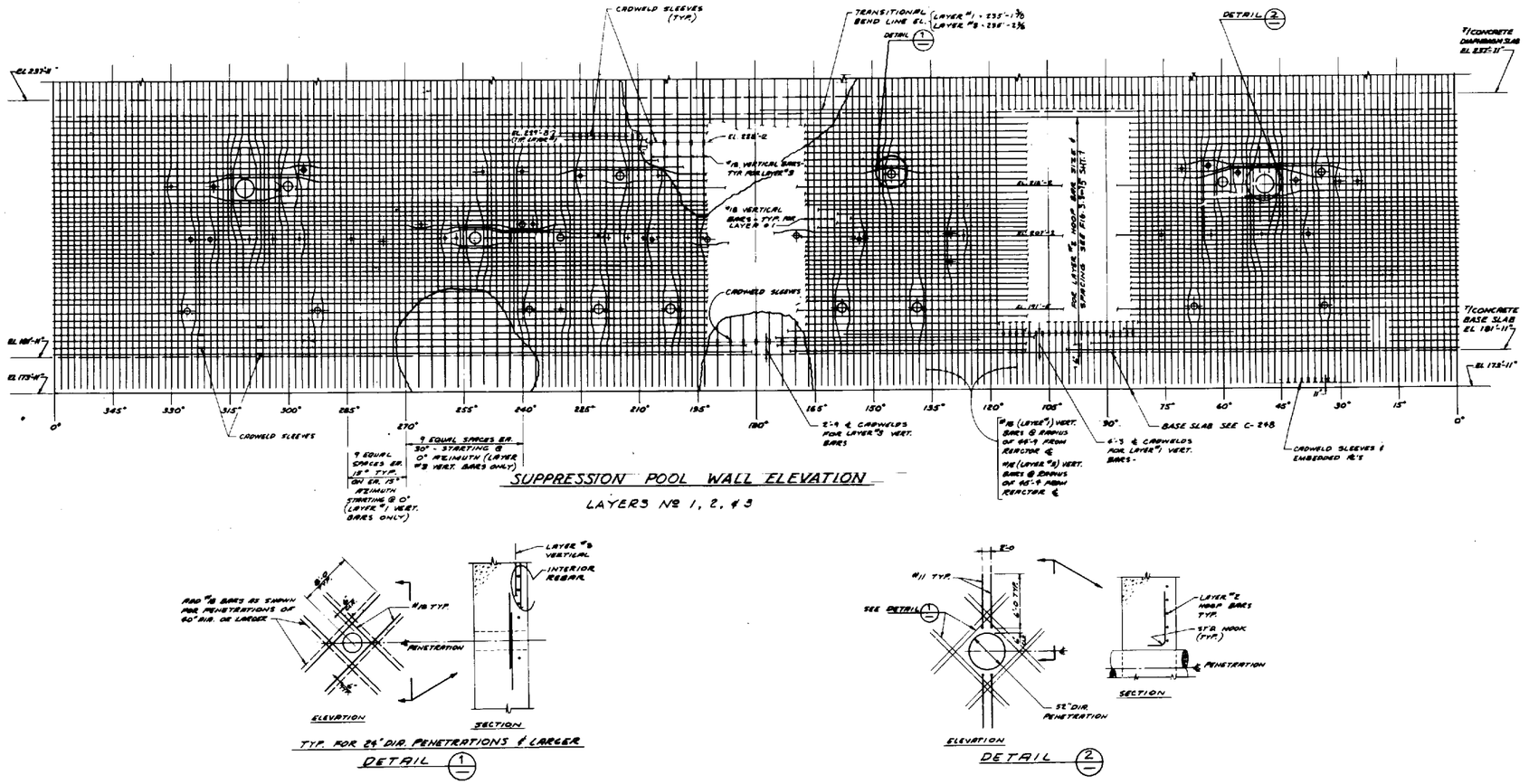
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-250.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION CHAMBER WALL REINFORCEMENT
(SHEET 1 OF 5)

FIGURE 3.8-15



SUPPRESSION POOL WALL ELEVATION

LAYERS Nº 1, 2, & 3

TYP. FOR 24" DIA. PENETRATIONS & LARGER

DETAIL 1

DETAIL 2

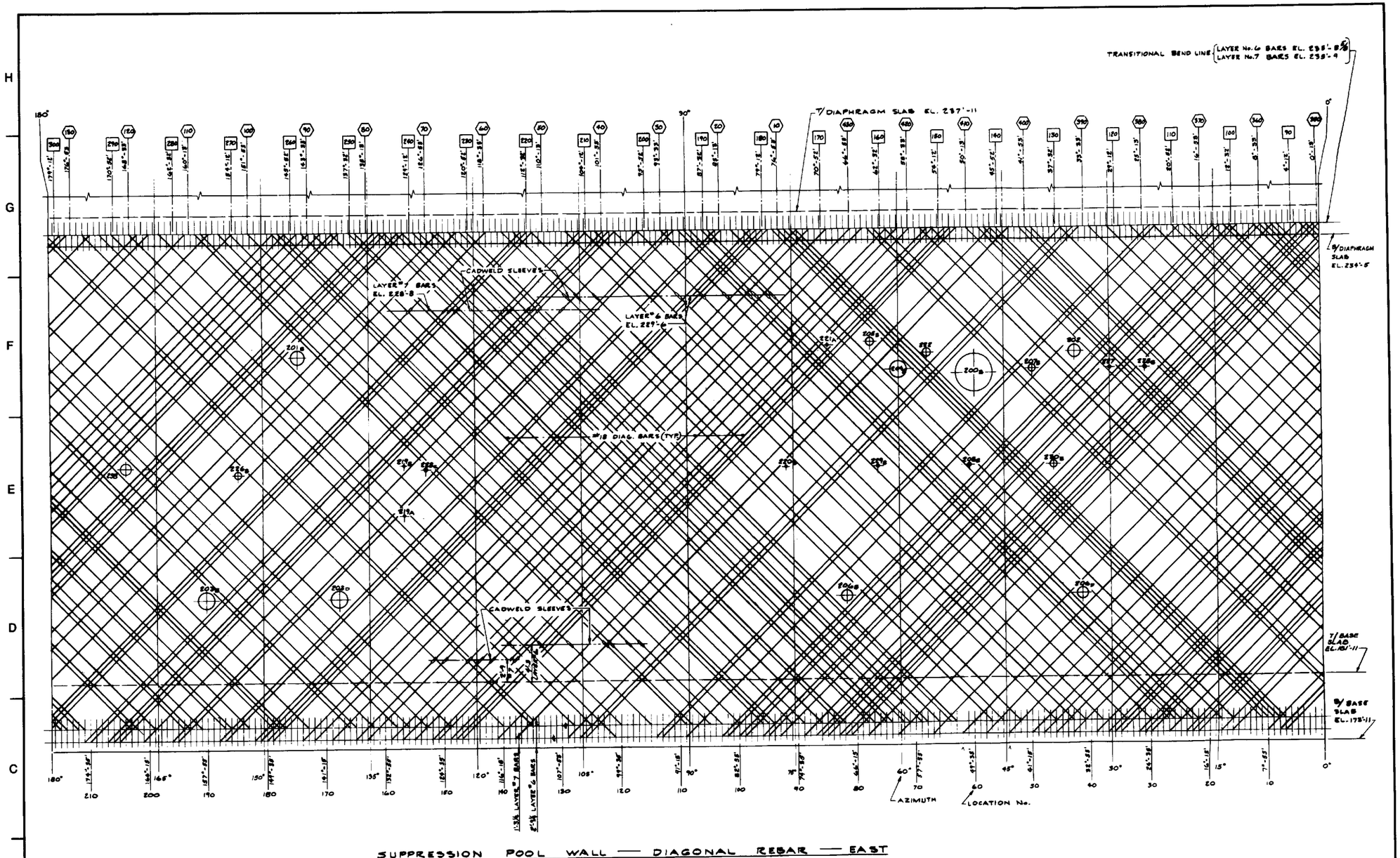
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-251 for Unit 1, and 8031-C-265 for Unit 2.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION CHAMBER WALL REINFORCEMENT
(SHEET 2 OF 5)

FIGURE 3.8-15



SUPPRESSION POOL WALL — DIAGONAL REBAR — EAST

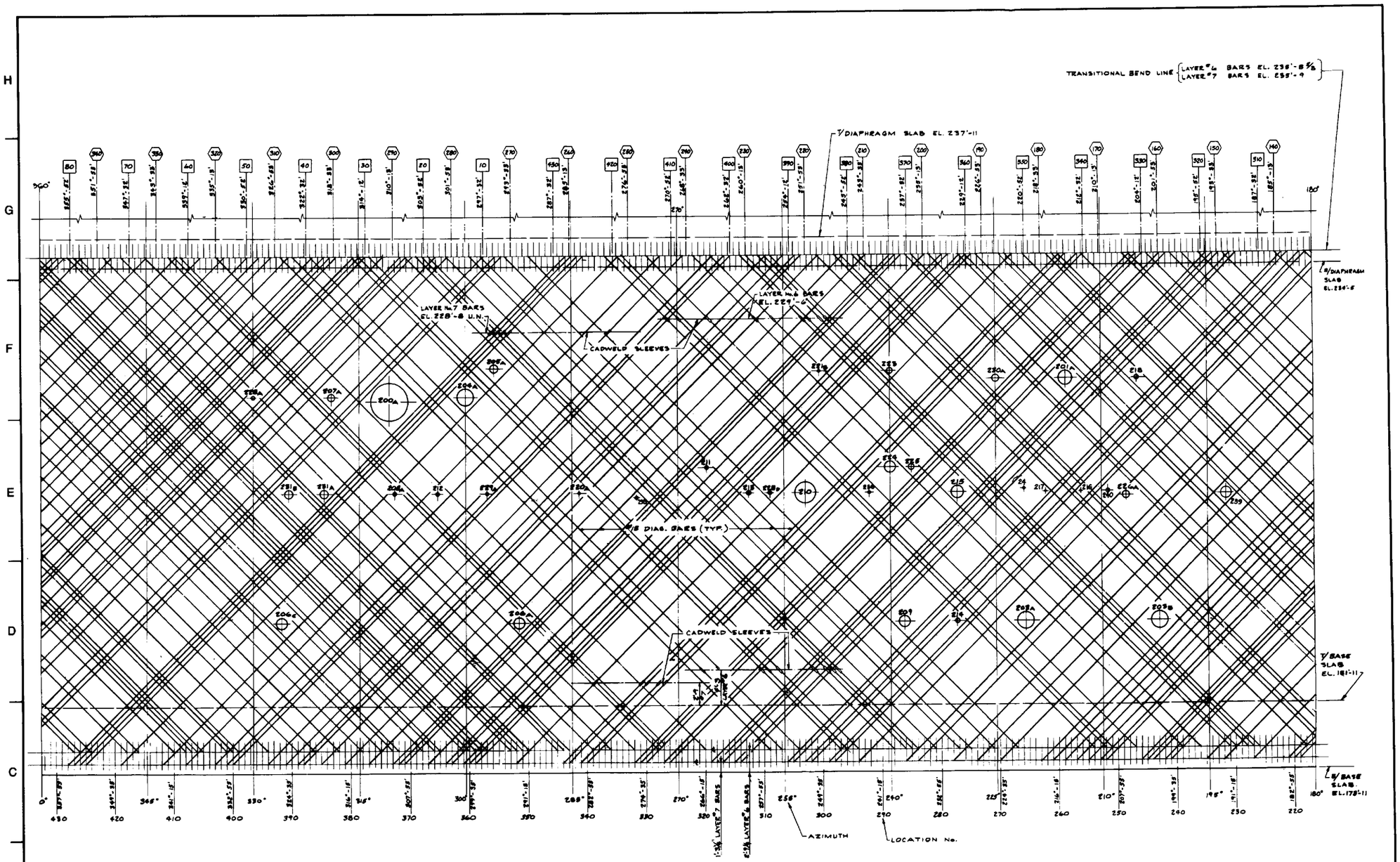
NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-252 for Unit 1 and 8031-C-266 for Unit 2.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION CHAMBER WALL REINFORCEMNT
(SHEET 3 OF 5)

FIGURE 3.8-15



SUPPRESSION POOL WALL — DIAGONAL REBAR — WEST

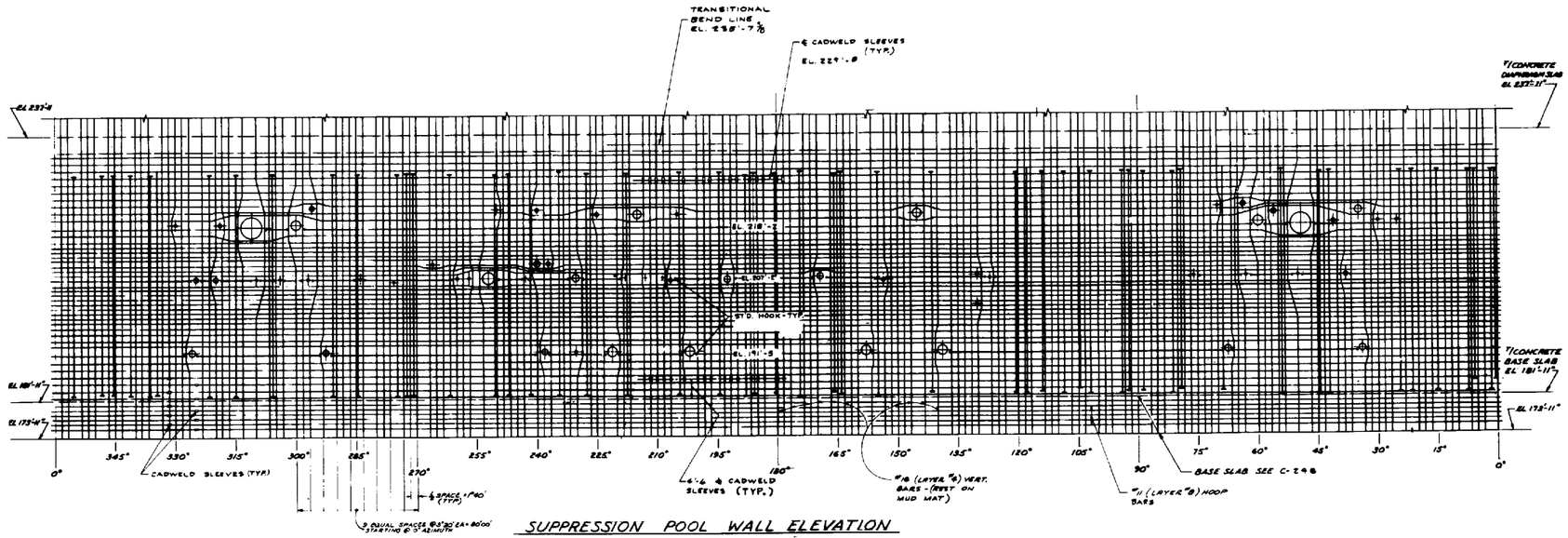
NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-254 for Unit 1, and 8031-C-268 for Unit 2.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION CHAMBER WALL REINFORCEMENT
(SHEET 4 OF 5)

FIGURE 3.8-15



SUPPRESSION POOL WALL ELEVATION

LAYERS Nº 4, 5, & 8

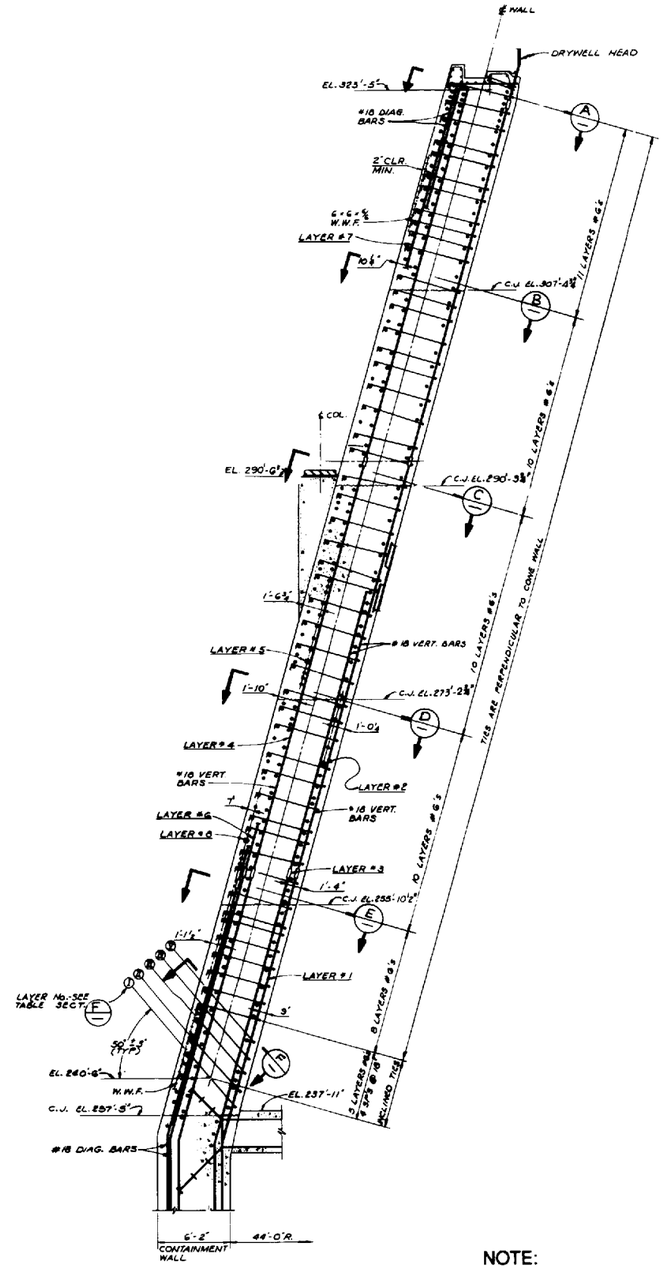
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-253 for Unit 1, and 8031-C-267 for Unit 2.

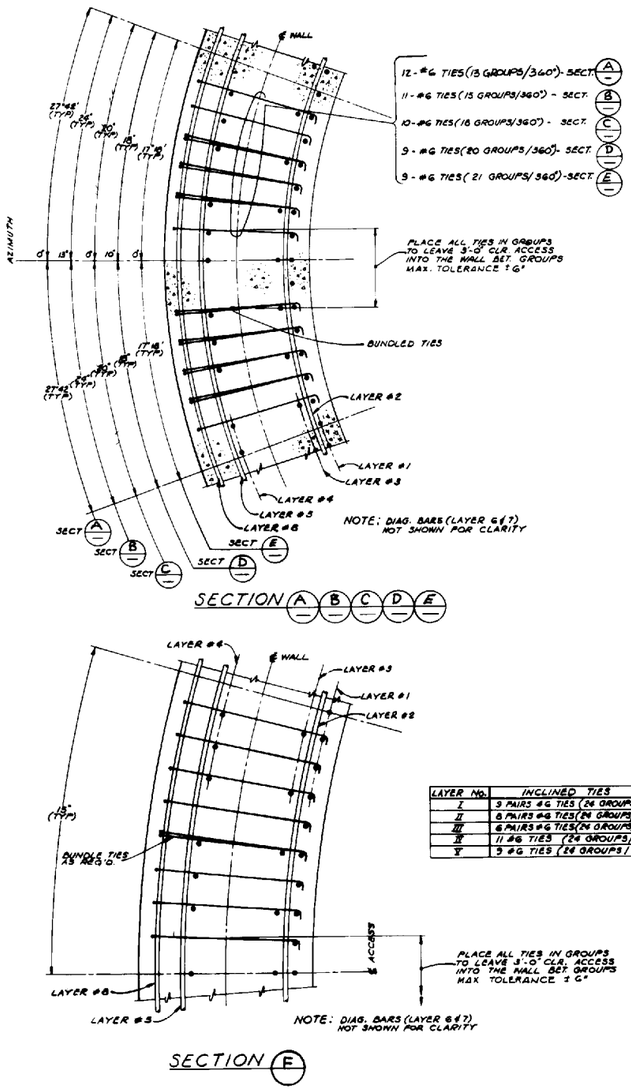
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION CHAMBER WALL REINFORCEMENT
(SHEET 5 OF 5)

FIGURE 3.8-15



TYPICAL WALL SECTION



SECTION (A)(B)(C)(D)(E)

LAYER No.	INCLINED TIES	TOTAL
I	3 PAIRS #6 TIES (24 GROUPS/360°)	432
II	8 PAIRS #6 TIES (24 GROUPS/360°)	384
III	6 PAIRS #6 TIES (24 GROUPS/360°)	288
IV	11 #6 TIES (24 GROUPS/360°)	264
V	9 #6 TIES (24 GROUPS/360°)	216

SECTION (E)

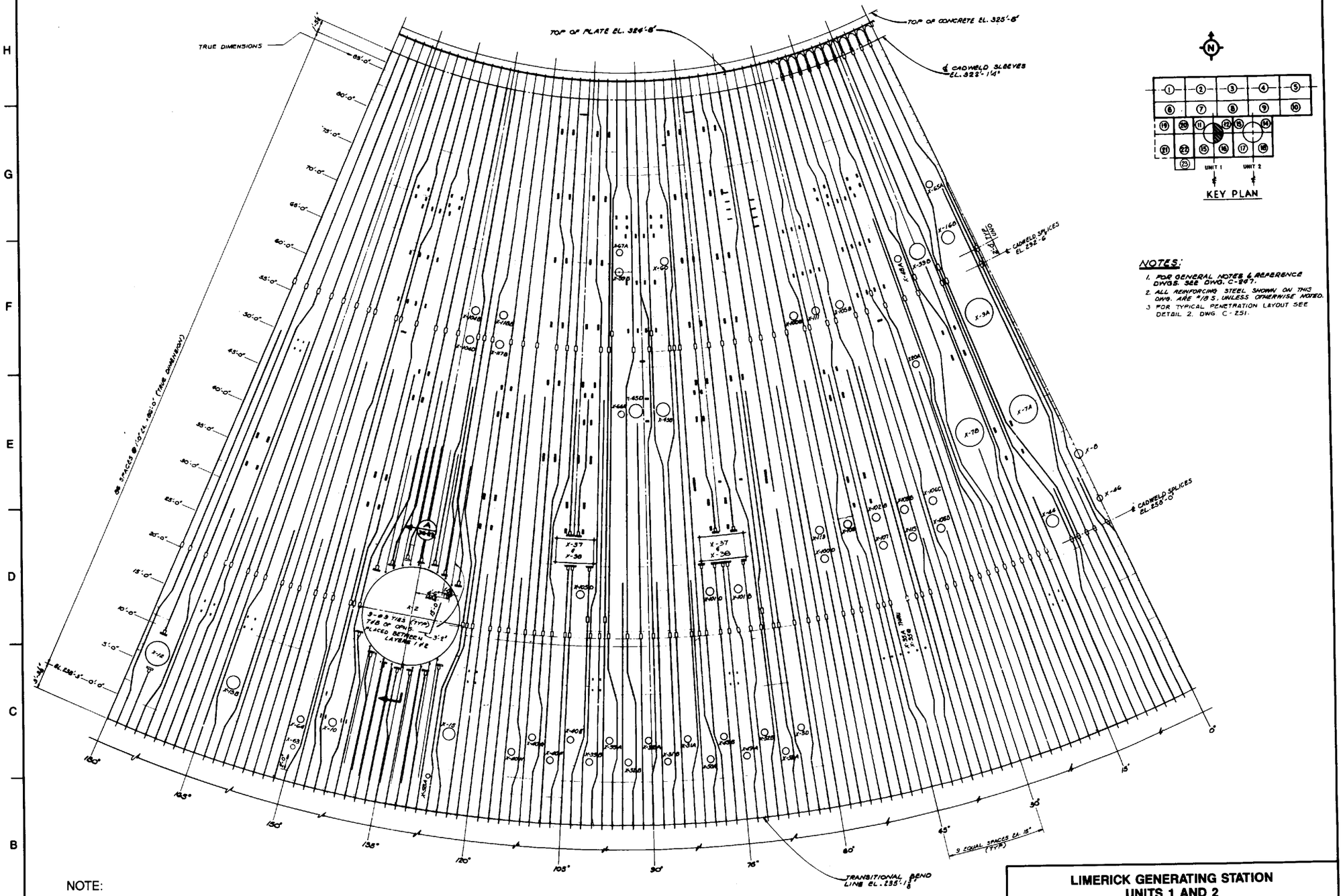
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-866.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 1 OF 17)

FIGURE 3.8-16



NOTES:

1. FOR GENERAL NOTES & REFERENCE DWGS. SEE DWG. C-907.
2. ALL REINFORCING STEEL SHOWN ON THIS DWG. ARE #18 S. UNLESS OTHERWISE NOTED.
3. FOR TYPICAL PENETRATION LAYOUT SEE DETAIL 2, DWG. C-251.

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-850 for Unit 1 and 8031-C-980 for Unit 2.

DRYWELL WALL ELEVATION

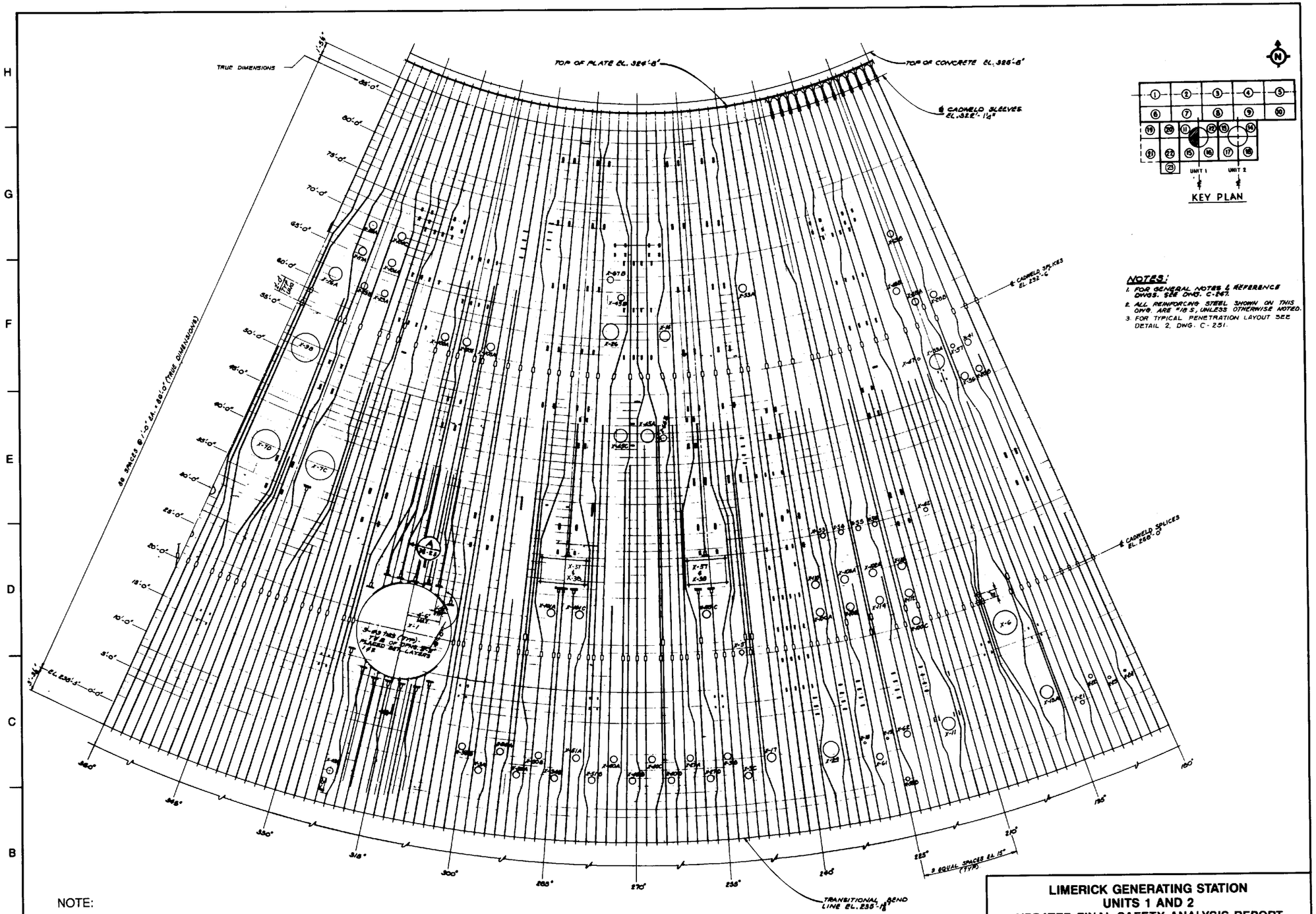
LAYER No. 1 (0°–180°)

VIEW FROM OUTSIDE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 2 OF 17)

FIGURE 3.8-16



NOTES:

1. FOR GENERAL NOTES & REFERENCE DWGS. SEE DWG. C-147.
2. ALL REINFORCING STEEL SHOWN ON THIS DWG. ARE #18'S, UNLESS OTHERWISE NOTED.
3. FOR TYPICAL PENETRATION LAYOUT SEE DETAIL 2, DWG. C-251.

NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-851 for Unit 1, and 8031-C-981 for Unit 2.

DRYWELL WALL ELEVATION

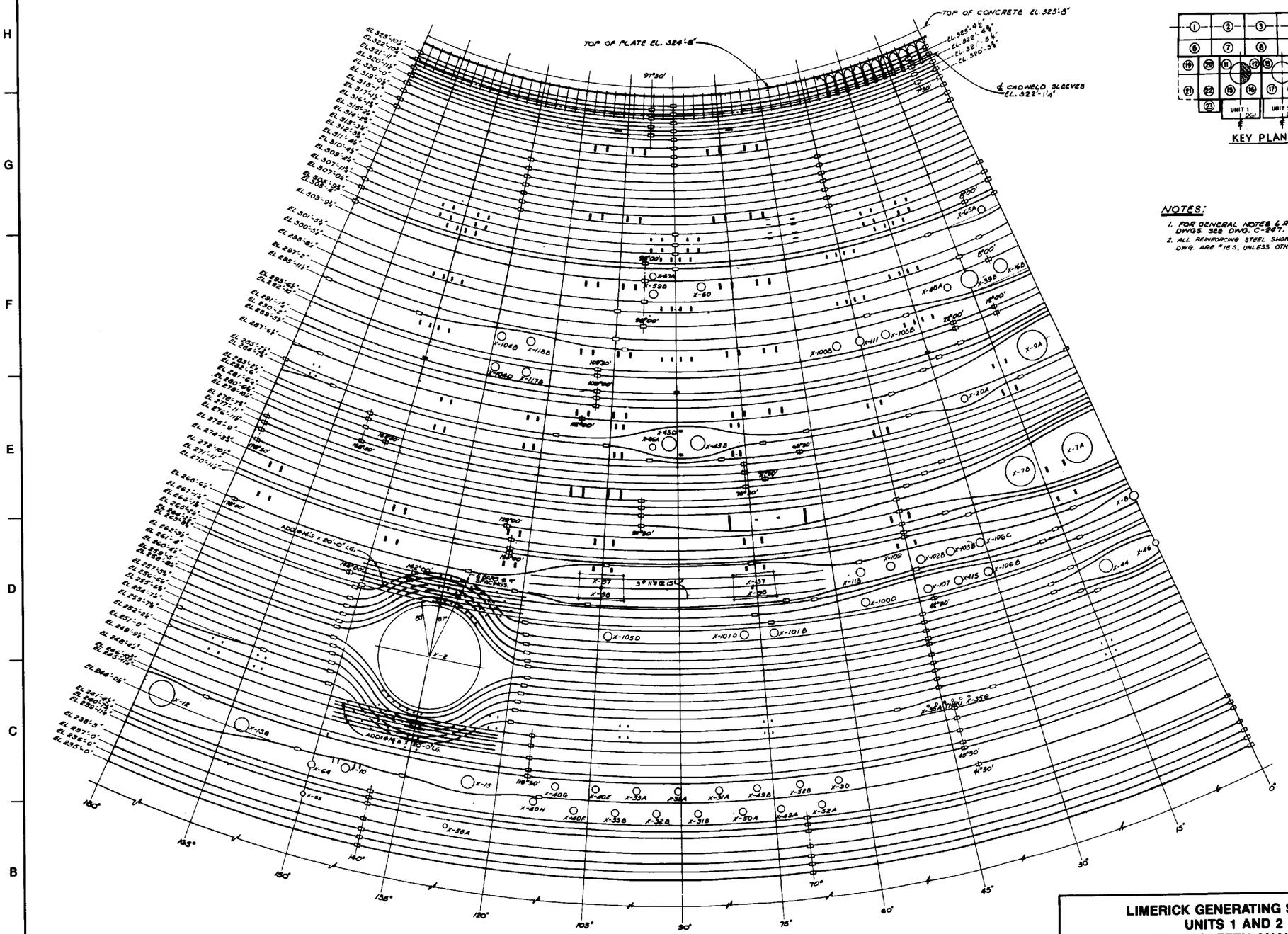
LAYER No. 1 (180°- 360°)

VIEW FROM OUTSIDE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 3 OF 17)

FIGURE 3.8-16



KEY PLAN

NOTES:

1. FOR GENERAL NOTES & REFERENCE DWGS. SEE DWG. C-867.
2. ALL REINFORCING STEEL SHOWN ON THIS DWG. ARE #18 S, UNLESS OTHERWISE NOTED.

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-852 for Unit 1, and 8031-C-982 for Unit 2.

DRYWELL WALL ELEVATION

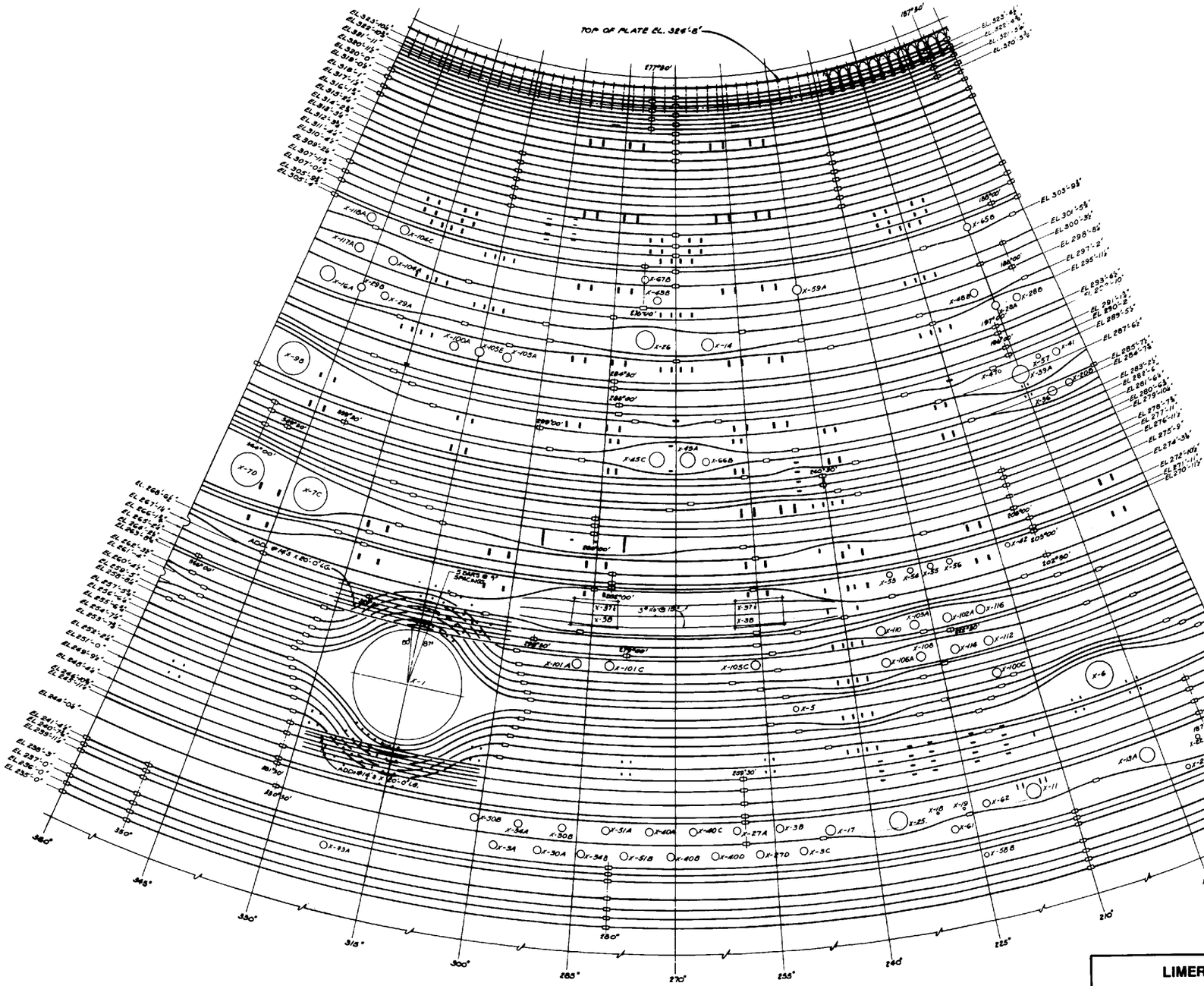
LAYER N₂ 2 (0°-180°)

VIEW FROM OUTSIDE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 4 OF 17)

FIGURE 3.8-16



NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-853 for Unit 1 and 8031-C-983 for Unit 2.

DRYWELL WALL ELEVATION

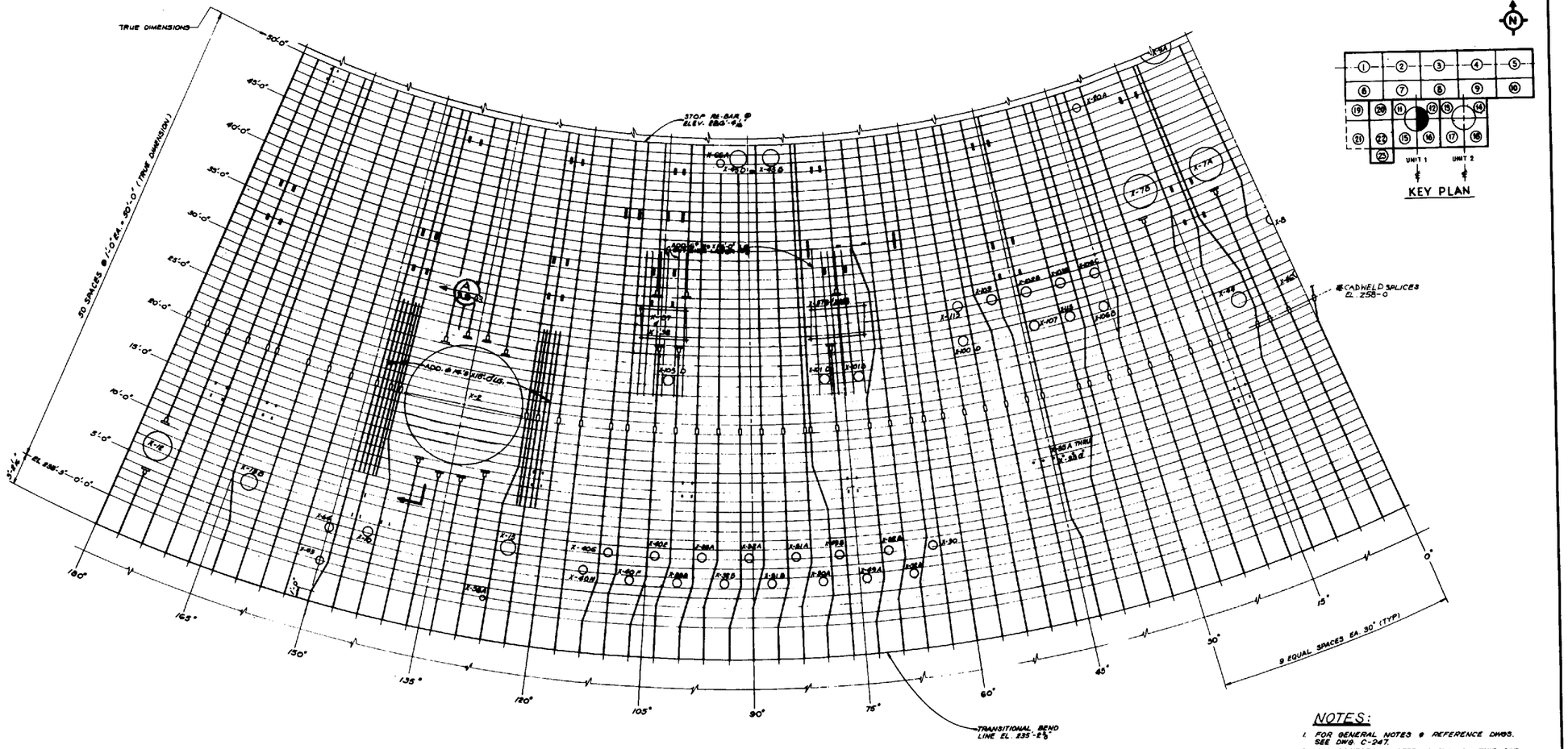
LAYER NO 2 (180°-360°)

VIEW FROM OUTSIDE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 5 OF 17)

FIGURE 3.8-16



DRYWELL WALL ELEVATION

LAYER No. 3 (0°-180°)

VIEW FROM OUTSIDE

NOTES:

1. FOR GENERAL NOTES & REFERENCE DWGS. SEE DWG. C-247.
2. ALL REINFORCING STEEL SHOWN ON THIS DWG. ARE #18 S. UNLESS OTHERWISE NOTED
3. FOR TYPICAL PENETRATION LAYOUT. SEE DETAIL 2, DWG. C-251

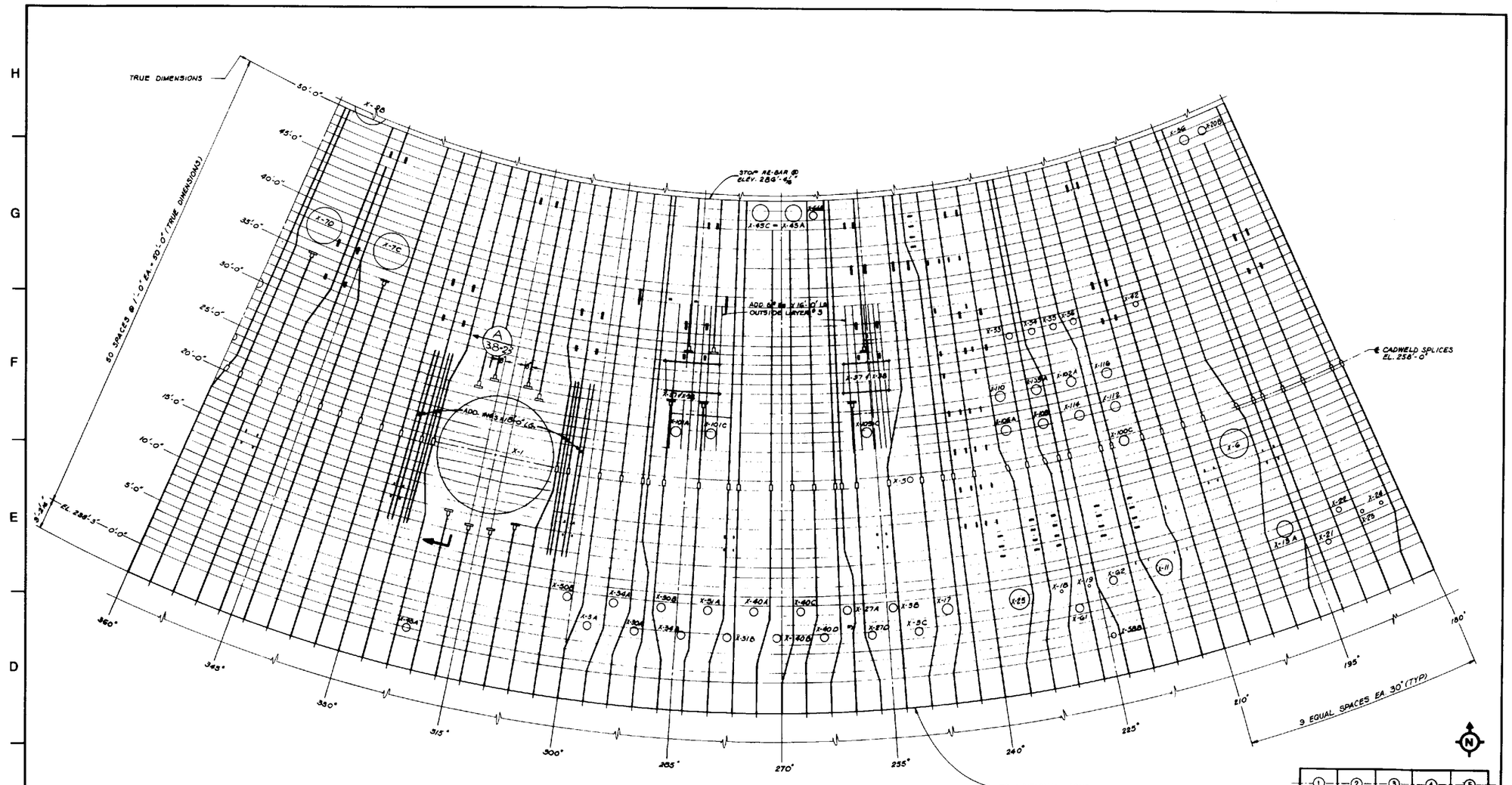
NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-854 for Unit 1 and 8031-C-984 for Unit 2.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 6 OF 17)

FIGURE 3.8-16



DRYWELL WALL ELEVATION

LAYER No. 3 (180°–360°)

VIEW FROM OUTSIDE

NOTES:

1. FOR GENERAL NOTES & REFERENCE DWGS. SEE DWG C-247.
2. ALL REINFORCING STEEL SHOWN ON THIS DWG. ARE #18 S. UNLESS OTHERWISE NOTED.
3. FOR TYPICAL PENETRATION LAYOUT, SEE DETAIL 2, DWG C-251.

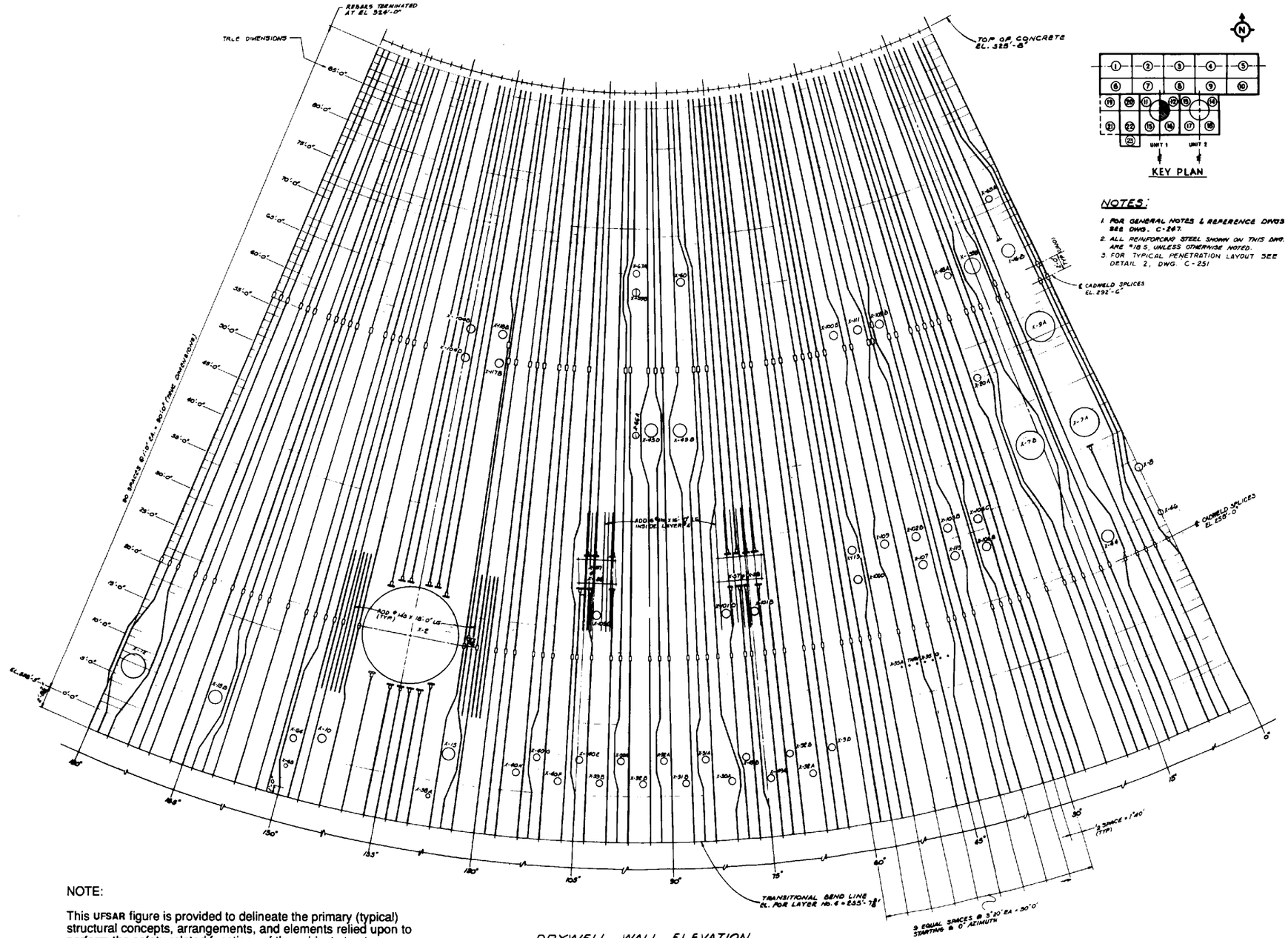
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-855 for Unit 1 and 8031-C-985 for Unit 2.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 7 OF 17)

FIGURE 3.8-16



NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-856 for Unit 1 and 8031-C-986 for Unit 2.

DRYWELL WALL ELEVATION

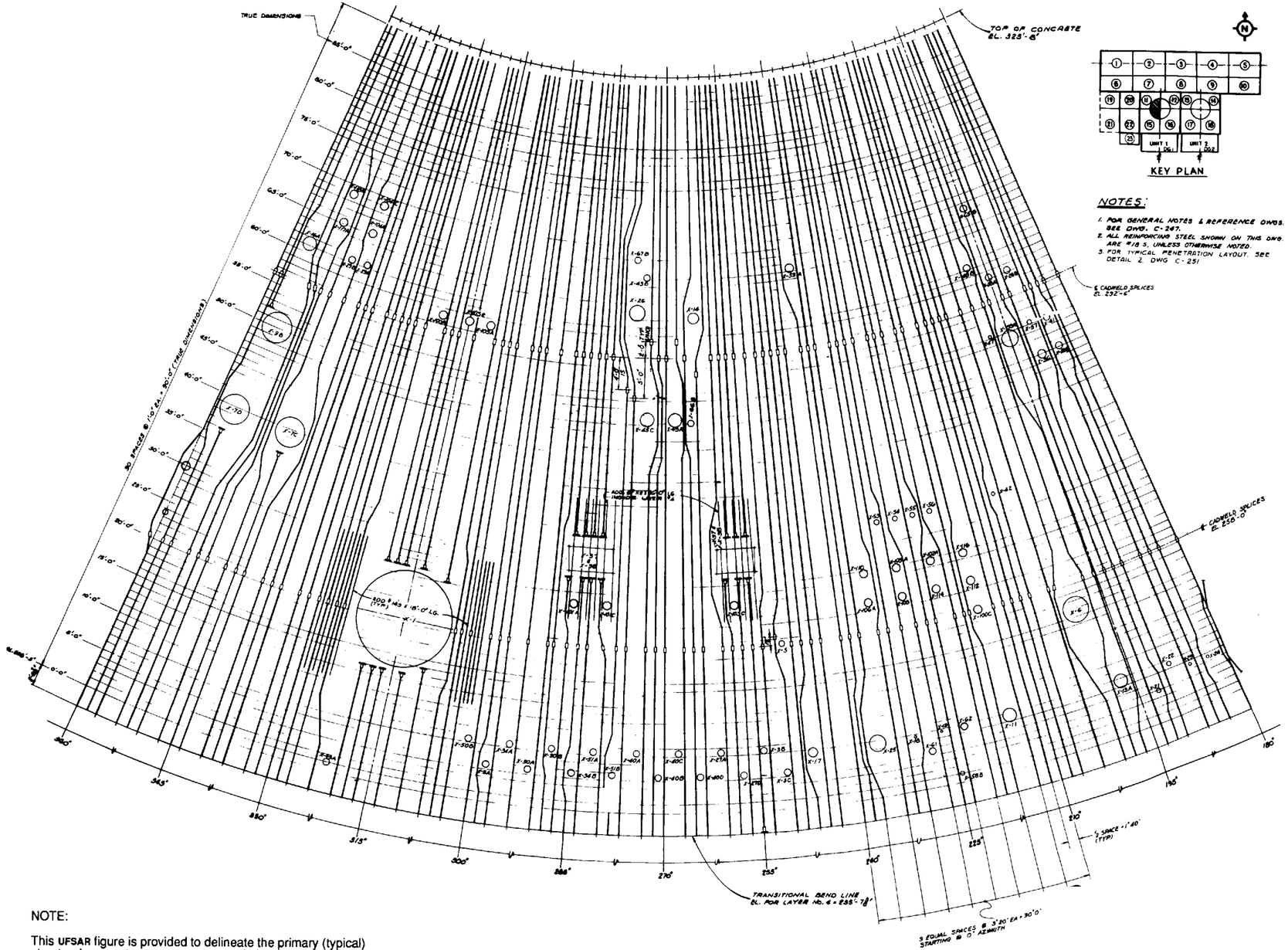
LAYER No. 4 (0°-180°)

VIEW FROM OUTSIDE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 8 OF 17)

FIGURE 3.8-16



NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-857 for Unit 1 and 8031-C-987 for Unit 2.

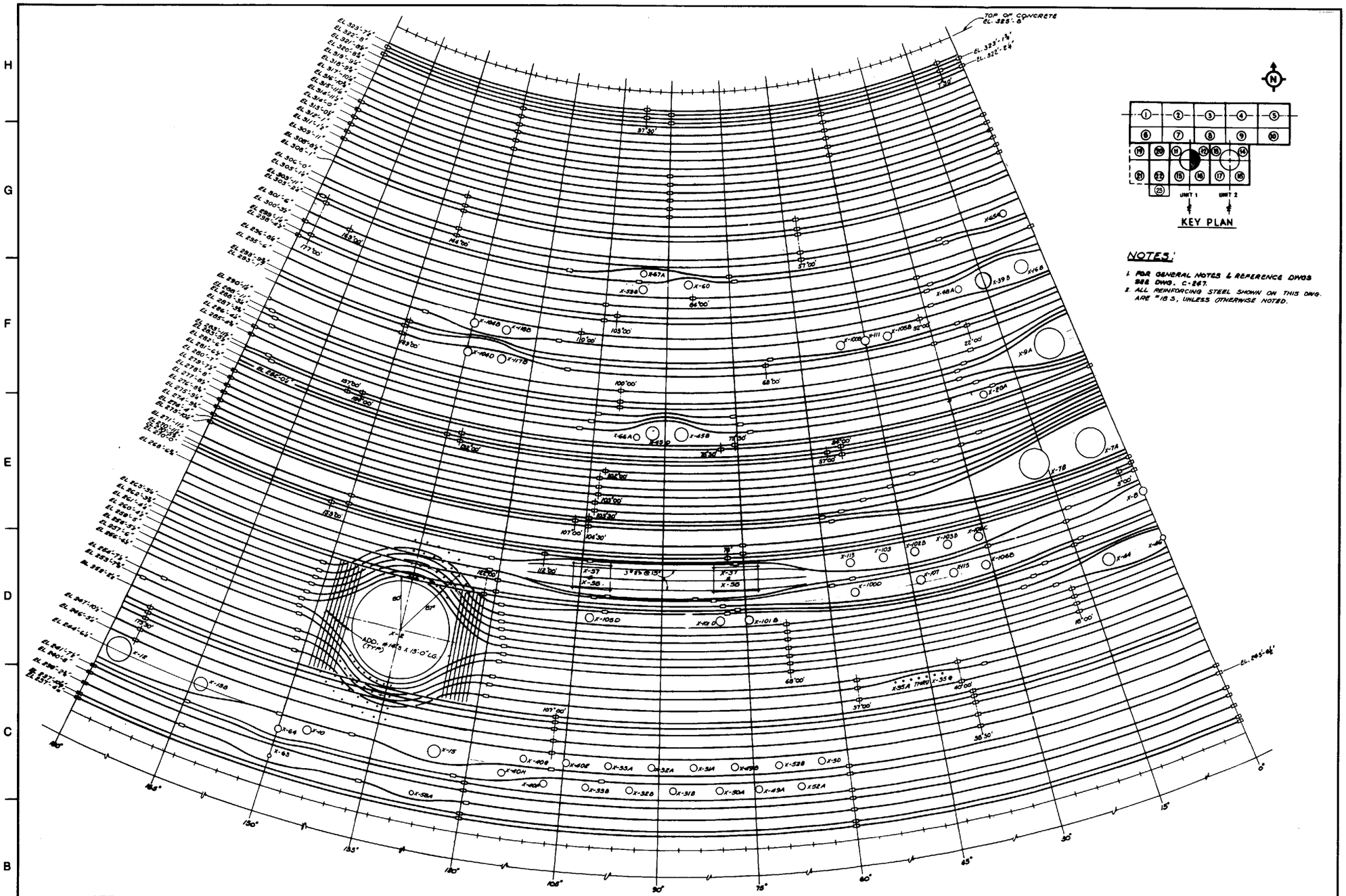
DRYWELL WALL ELEVATION

LAYER No. 4 (180°-360°)
VIEW FROM OUTSIDE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 9 OF 17)

FIGURE 3.8-16



NOTES:

1. FOR GENERAL NOTES & REFERENCE DWGS SEE DWG. C-867.
2. ALL REINFORCING STEEL SHOWN ON THIS DWG. ARE #18 S, UNLESS OTHERWISE NOTED.

NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-858 for Unit 1 and 8031-C-988 for Unit 2.

DRYWELL WALL ELEVATION

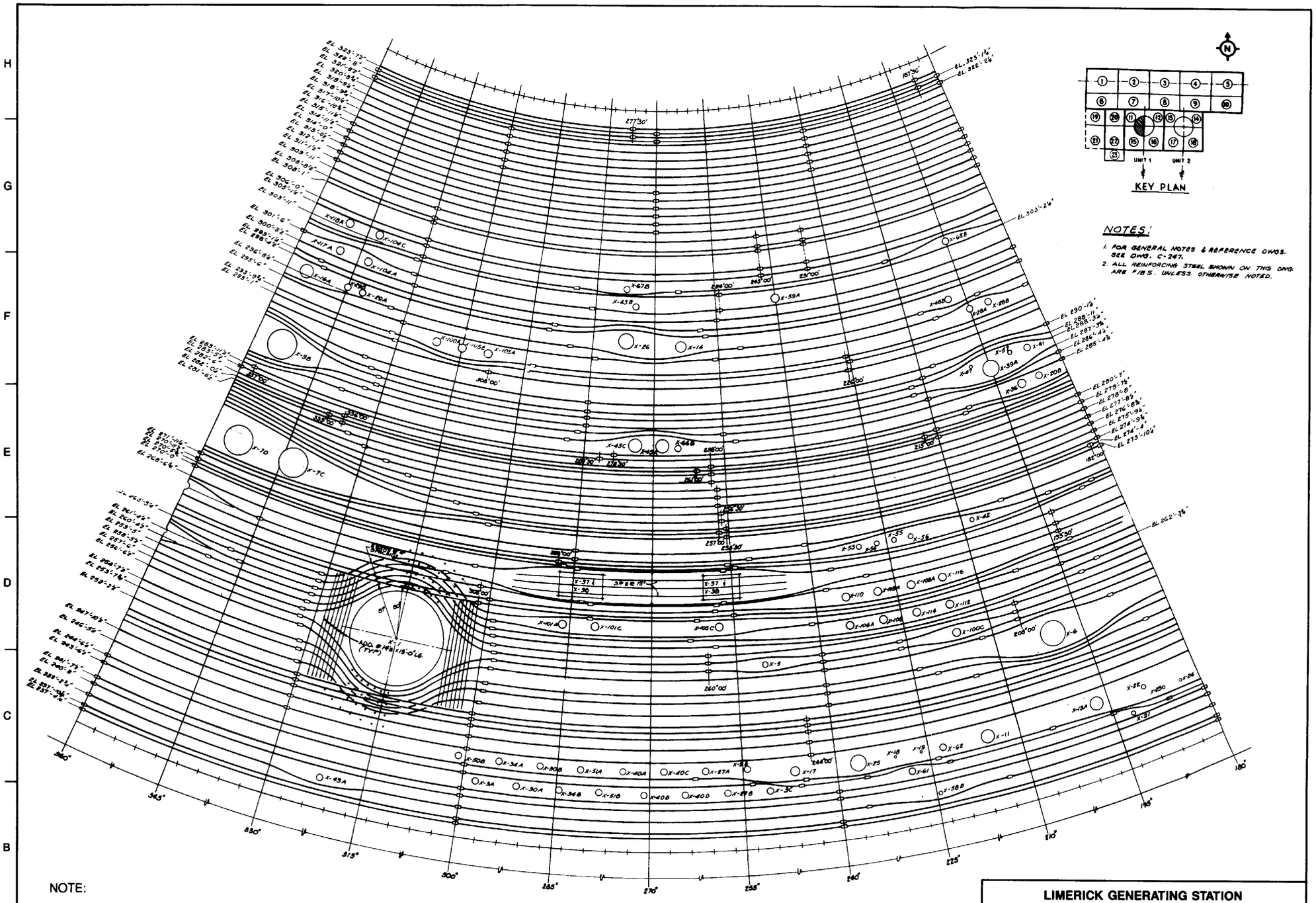
LAYER No. 5 (0°-180°)

VIEW FROM OUTSIDE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 10 OF 17)

FIGURE 3.8-16



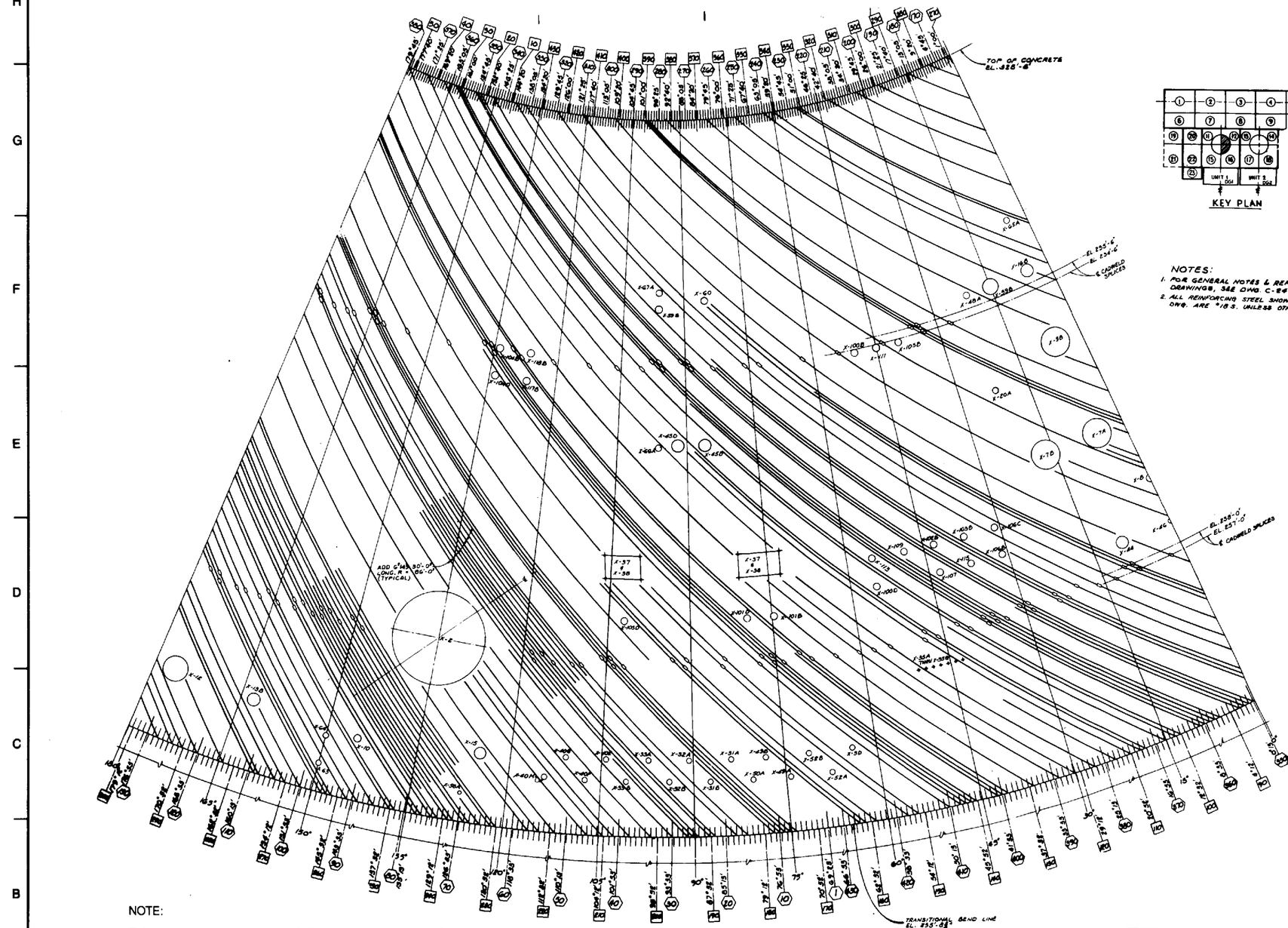
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-859 for Unit 1 and 8031-C-989 for Unit 2.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 11 OF 17)

FIGURE 3.8-16



NOTES:
1. FOR GENERAL NOTES & REFERENCE DRAWINGS, SEE DWG. C-847.
2. ALL REINFORCING STEEL SHOWN ON THIS DWG. ARE #18 S. UNLESS OTHERWISE NOTED.

NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-860 for Unit 1 and 8031-C-990 for Unit 2.

DRYWELL WALL ELEVATION

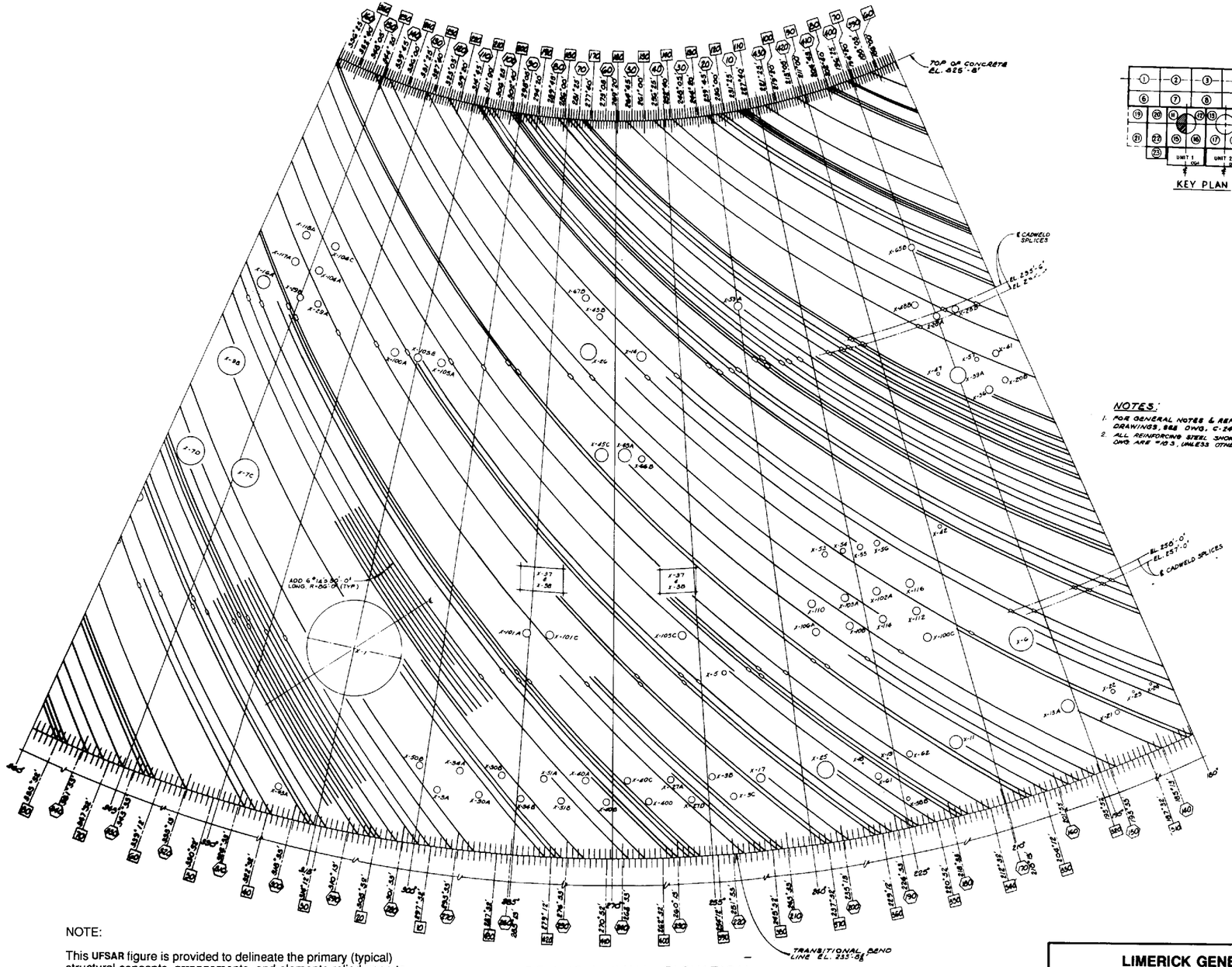
LAYER No. 6 (0°–180°)

VIEW FROM OUTSIDE

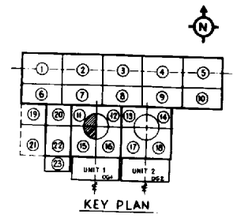
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 12 OF 17)

FIGURE 3.8-16



DRYWELL WALL ELEVATION
(180° – 360°)
LAYER No. 6
VIEW FROM OUTSIDE



KEY PLAN

NOTES:
1. FOR GENERAL NOTES & REFERENCE DRAWINGS, SEE DWG. C-267.
2. ALL REINFORCING STEEL SHOWN ON THIS DWG ARE #18, UNLESS OTHERWISE NOTED.

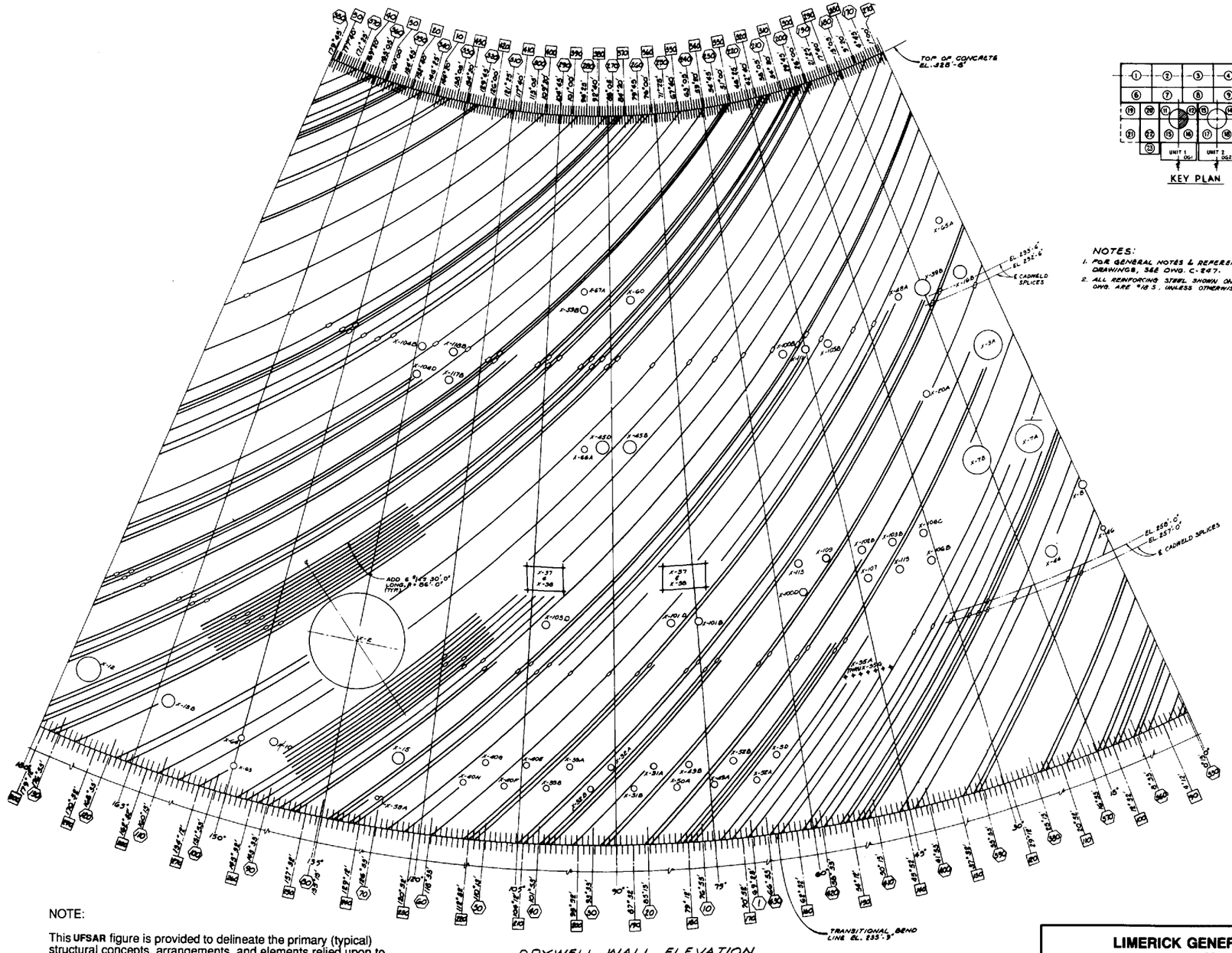
NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-861 for Unit 1 and 8031-C-991 for Unit 2.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 13 OF 17)

FIGURE 3.8-16



NOTES:

1. FOR GENERAL NOTES & REFERENCE DRAWINGS, SEE DWG. C-247.
2. ALL REINFORCING STEEL SHOWN ON THIS DWG. ARE #18 S, UNLESS OTHERWISE NOTED.

NOTE:

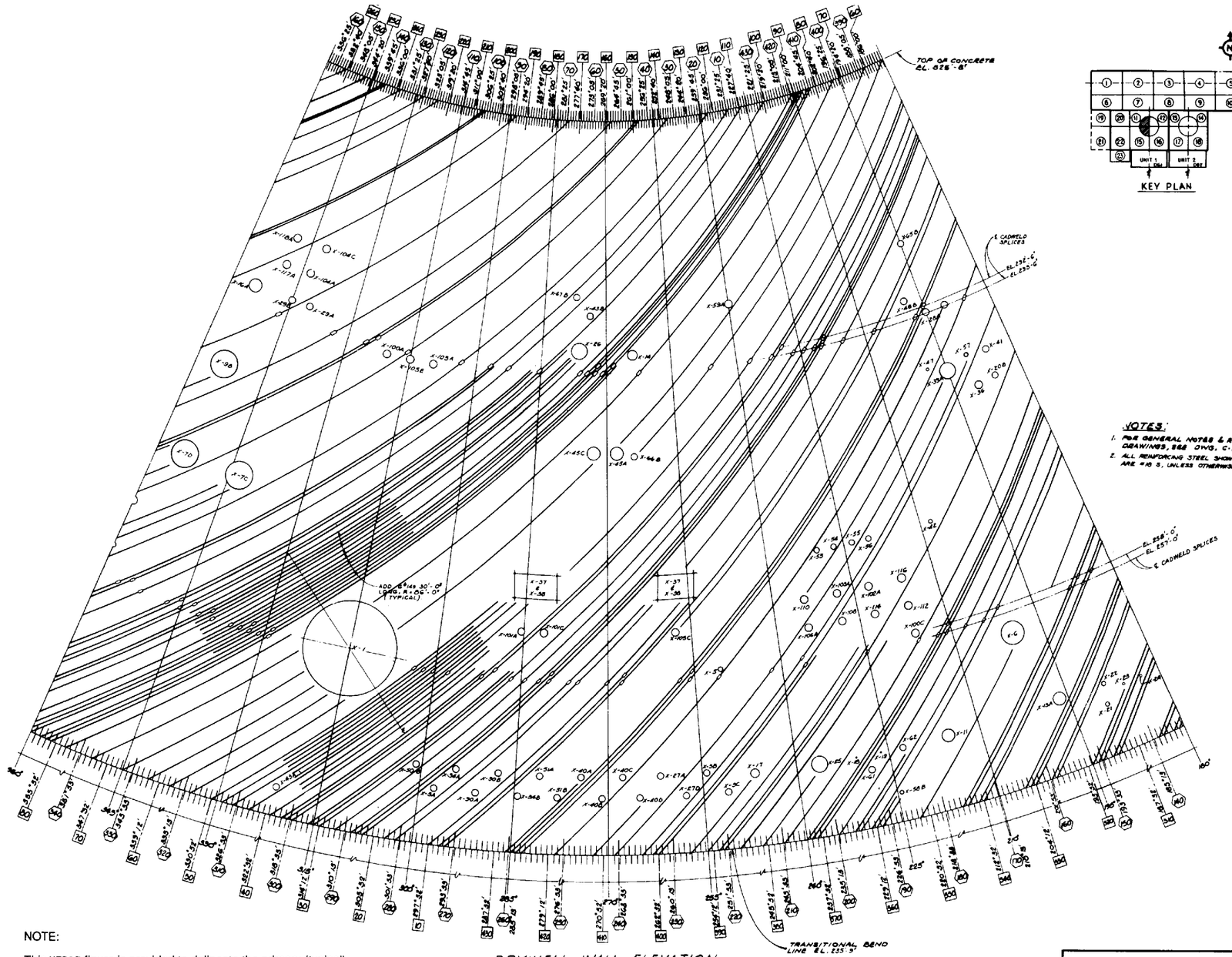
This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-862 for Unit 1 and 8031-C-992 for Unit 2.

DRYWELL WALL ELEVATION
70°-180°
LAYER No. 7
VIEW FROM OUTSIDE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 14 OF 17)

FIGURE 3.8-16



DRYWELL WALL ELEVATION
(180° - 360°)
LAYER No. 7

VIEW FROM OUTSIDE

NOTES:

1. FOR GENERAL NOTES & REFERENCE DRAWINGS, SEE DWG. C-267.
2. ALL REINFORCING STEEL SHOWN ON THIS DWG. ARE #18 S, UNLESS OTHERWISE NOTED.

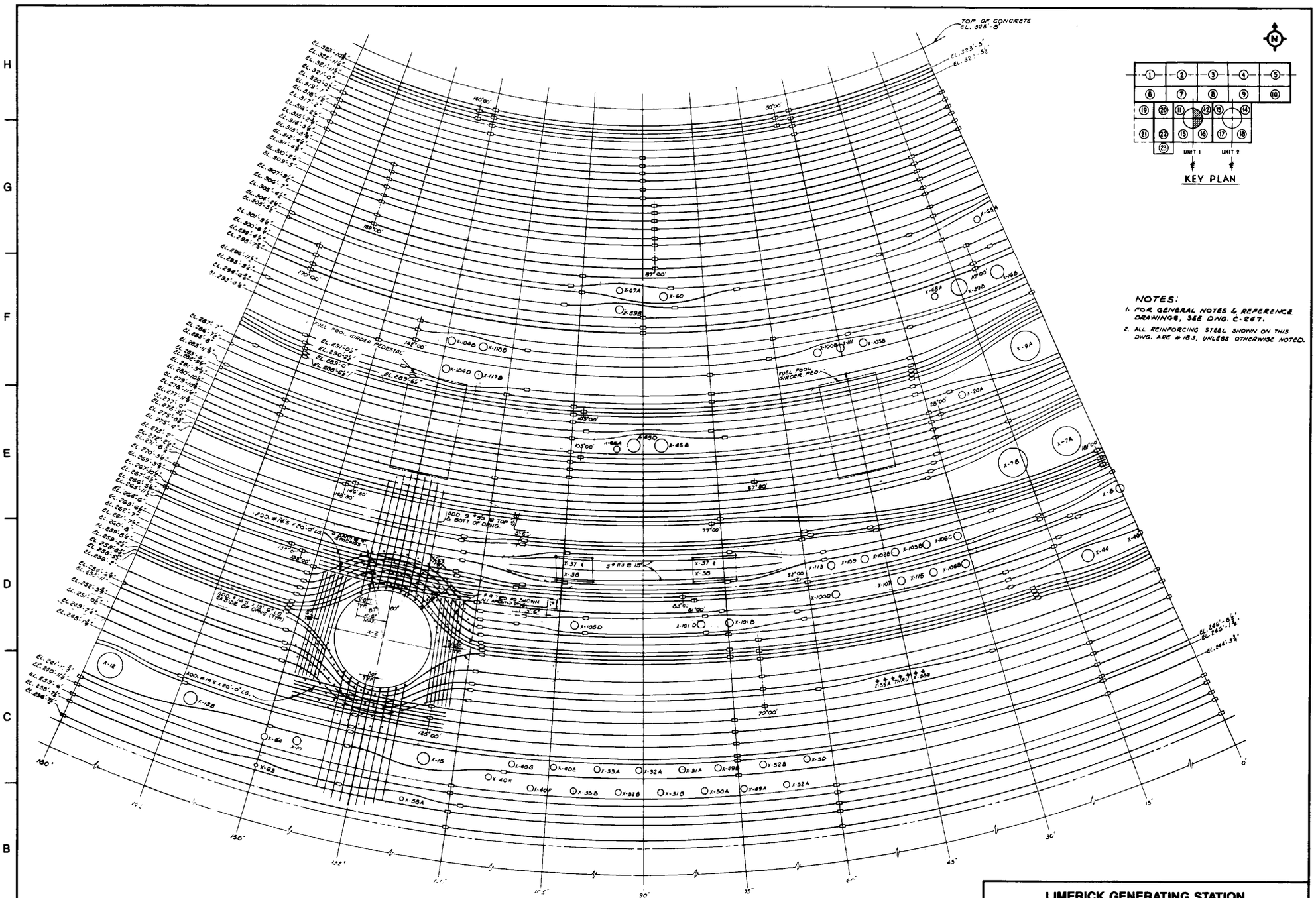
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-863 for Unit 1 and 8031-C-993 for Unit 2.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 15 OF 17)

FIGURE 3.8-16



NOTES:

1. FOR GENERAL NOTES & REFERENCE DRAWINGS, SEE DWG. C-247.
2. ALL REINFORCING STEEL SHOWN ON THIS DWG. ARE #18S, UNLESS OTHERWISE NOTED.

NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-864 for Unit 1 and 8031-C-994 for Unit 2.

DRYWELL WALL ELEVATION

LAYER NO. 8

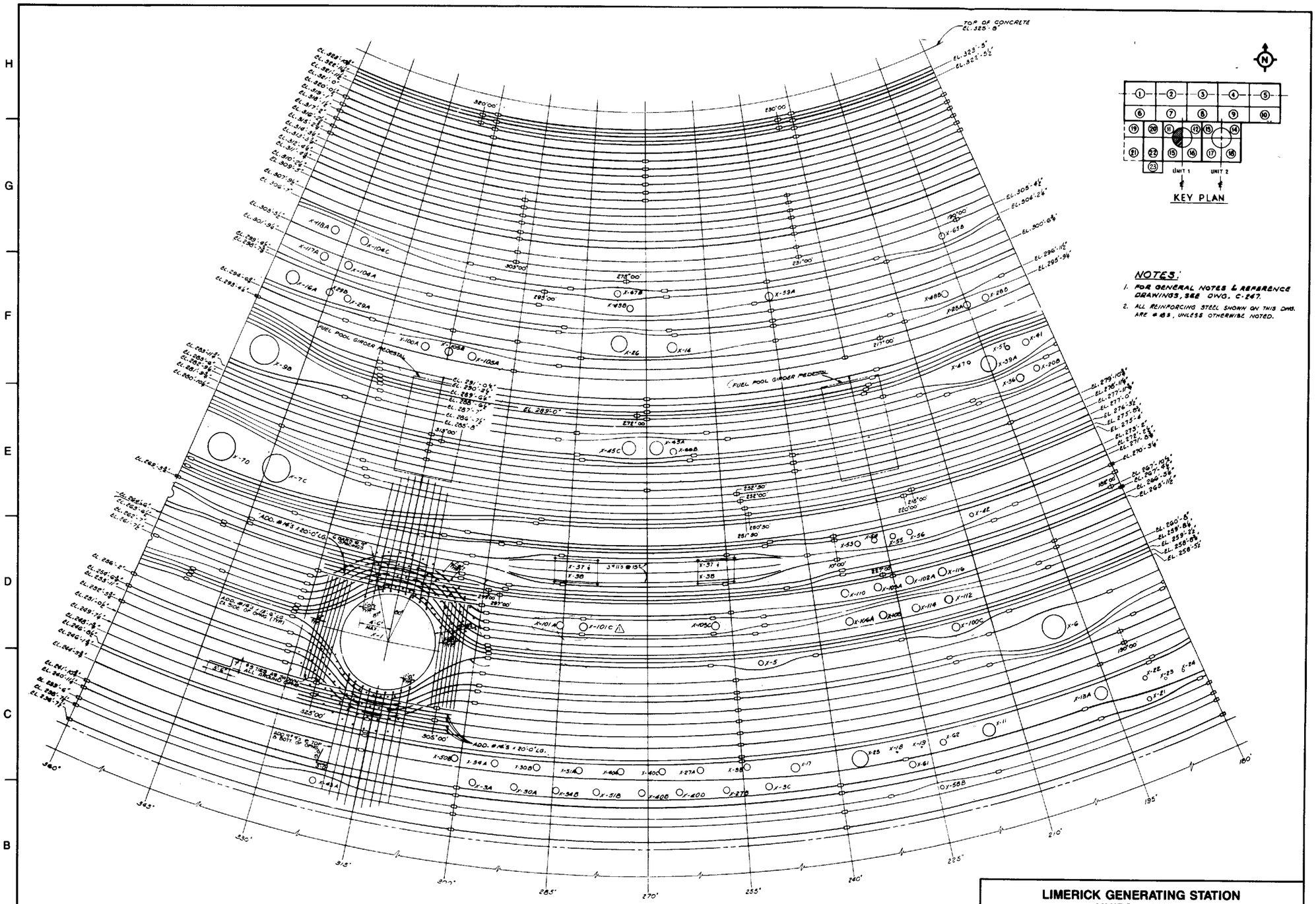
(0° - 180°)

VIEW FROM OUTSIDE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT
(SHEET 16 OF 17)

FIGURE 3.8-15



NOTES:

1. FOR GENERAL NOTES & REFERENCE DRAWINGS, SEE DWG. C-267.
2. ALL REINFORCING STEEL SHOWN ON THIS DWG. ARE #8S, UNLESS OTHERWISE NOTED.

NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-865 for Unit 1 and 8031-C-995 for Unit 2.

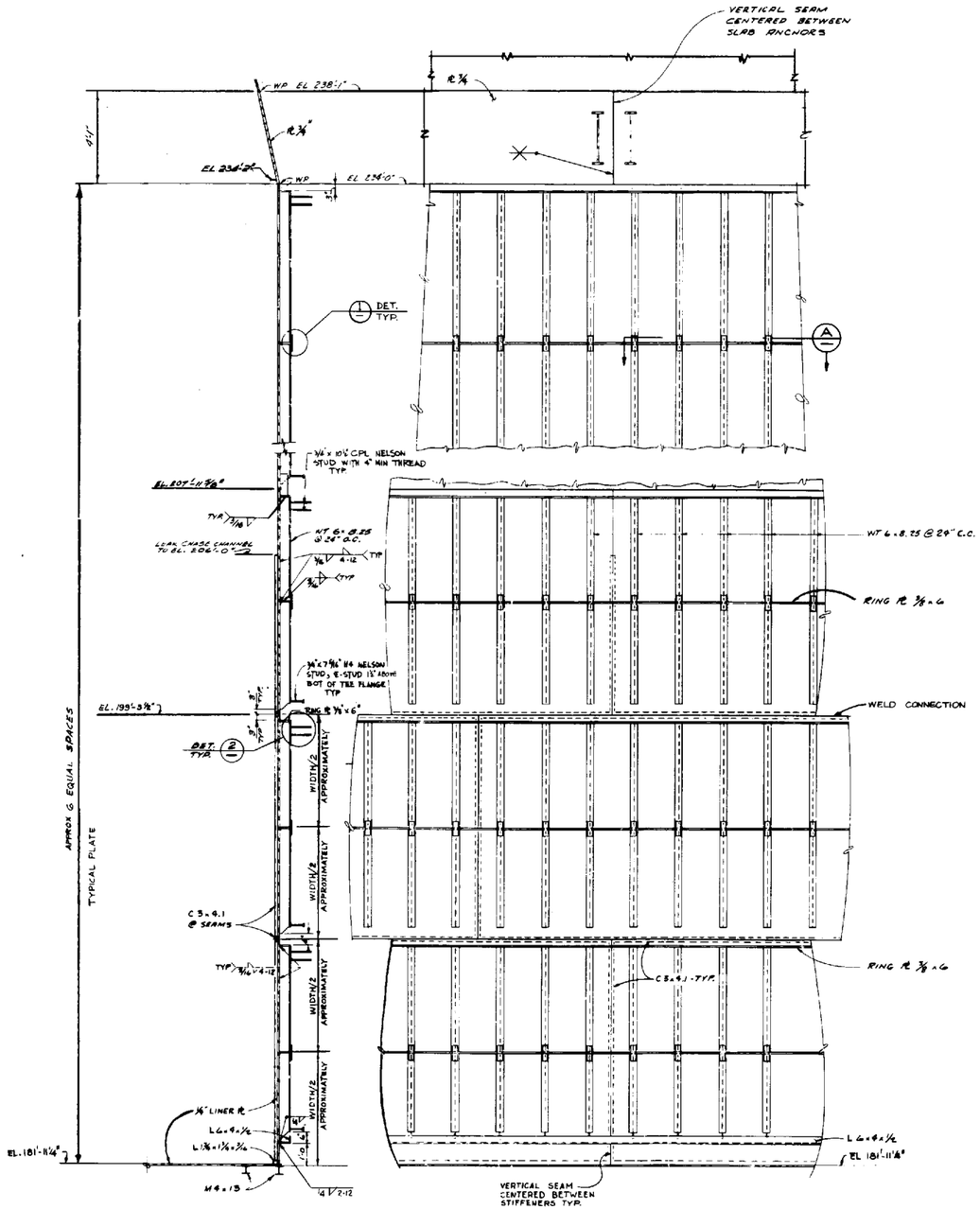
DRYWELL WALL ELEVATION

LAYER NO. 8
(180 - 360°)
VIEW FROM OUTSIDE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

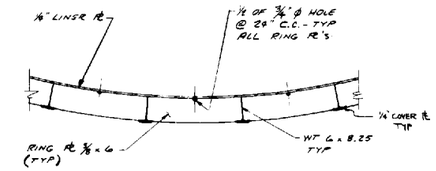
DRYWELL WALL REINFORCEMENT
(SHEET 17 OF 17)

FIGURE 3.8-16

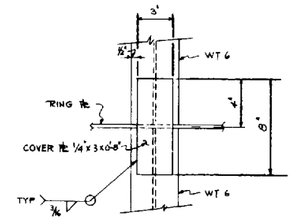


TYPICAL SECTION

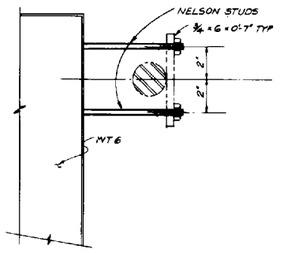
TYPICAL ELEVATION



SECTION A



DETAIL 1



DETAIL 2

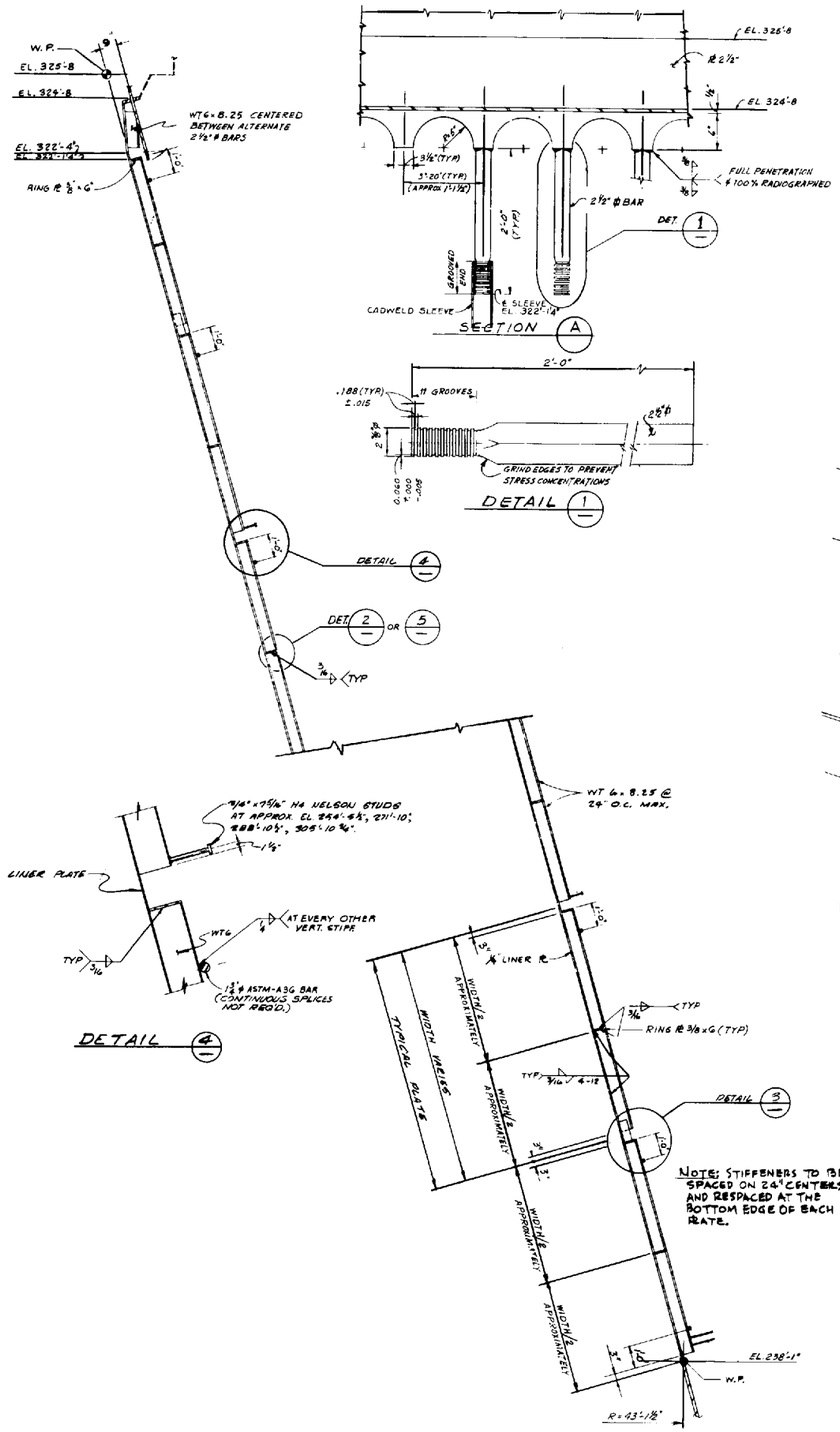
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-282.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION CHAMBER WALL LINER PLATE AND ANCHORAGES

FIGURE 3.8-17



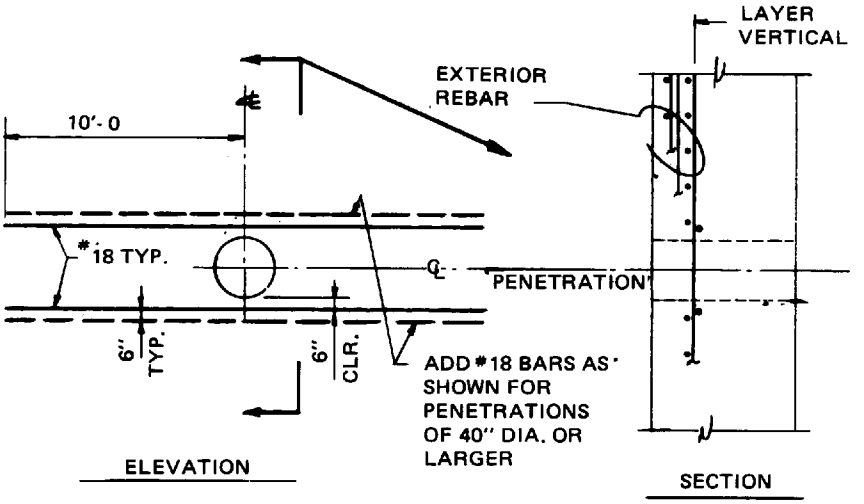
NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-285.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL LINER PLATE AND ANCHORAGES

FIGURE 3.8-18



TYP. FOR 24" DIA. PENETRATIONS & LARGER

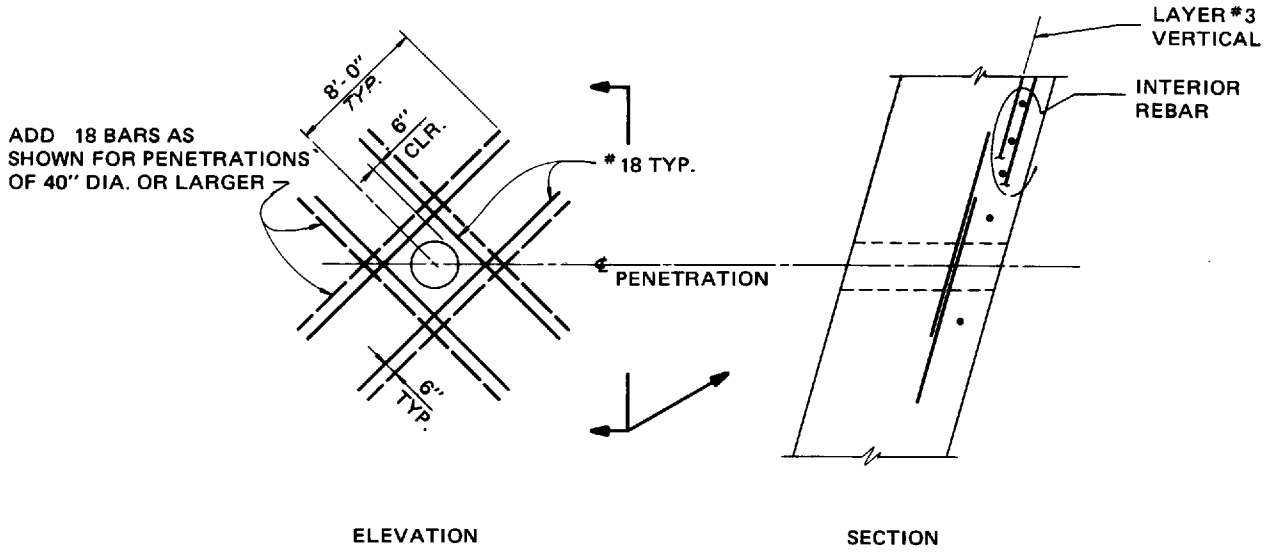
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-253.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION CHAMBER WALL REINFORCEMENT DETAIL AT TYPICAL PENETRATION

FIGURE 3.8-18



TYP. FOR 24" DIA. PENETRATIONS & LARGER

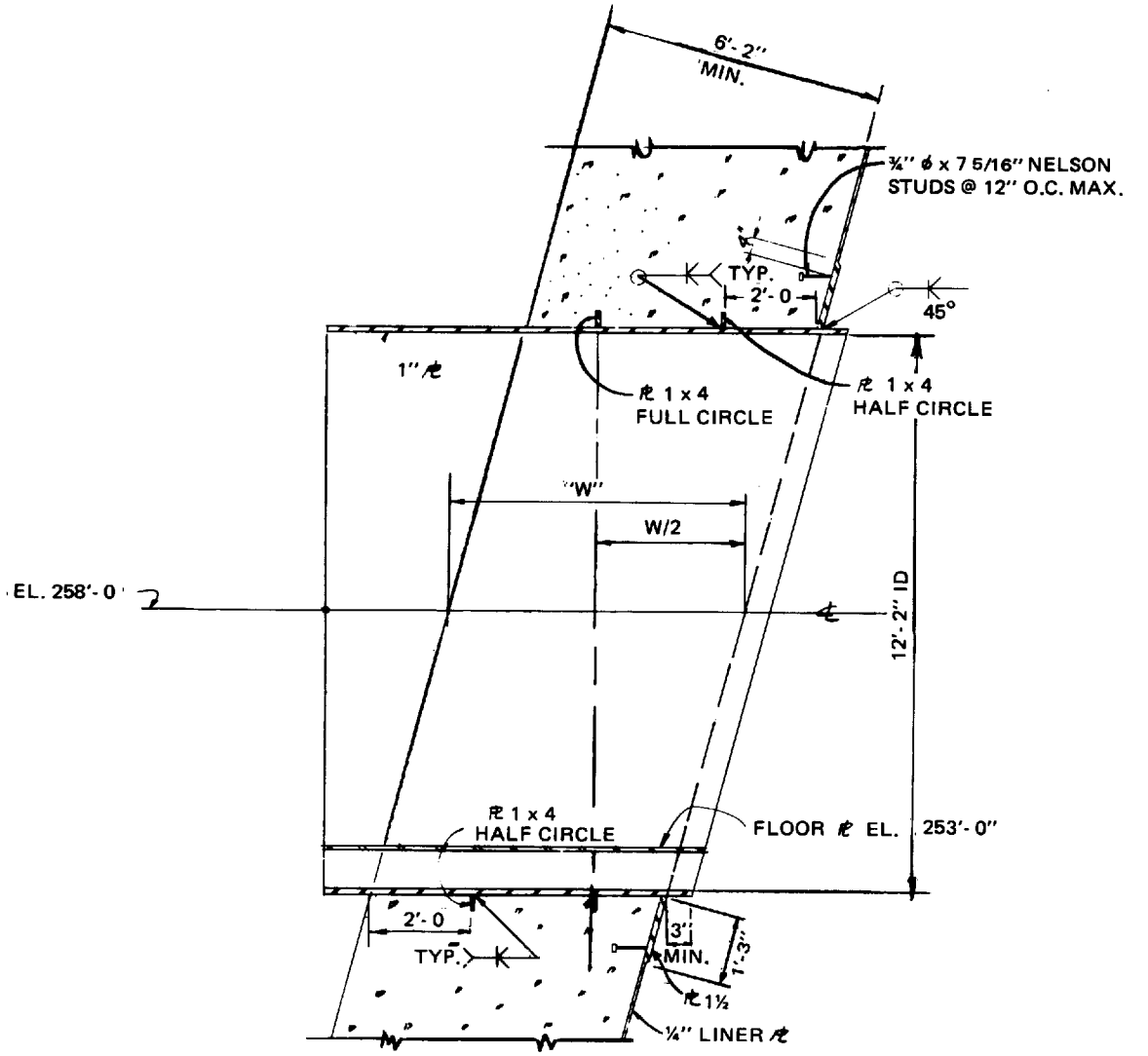
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-866.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL REINFORCEMENT DETAIL AT TYPICAL PENETRATION

FIGURE 3.8-20



PENETRATION TYPE I

NOTE:

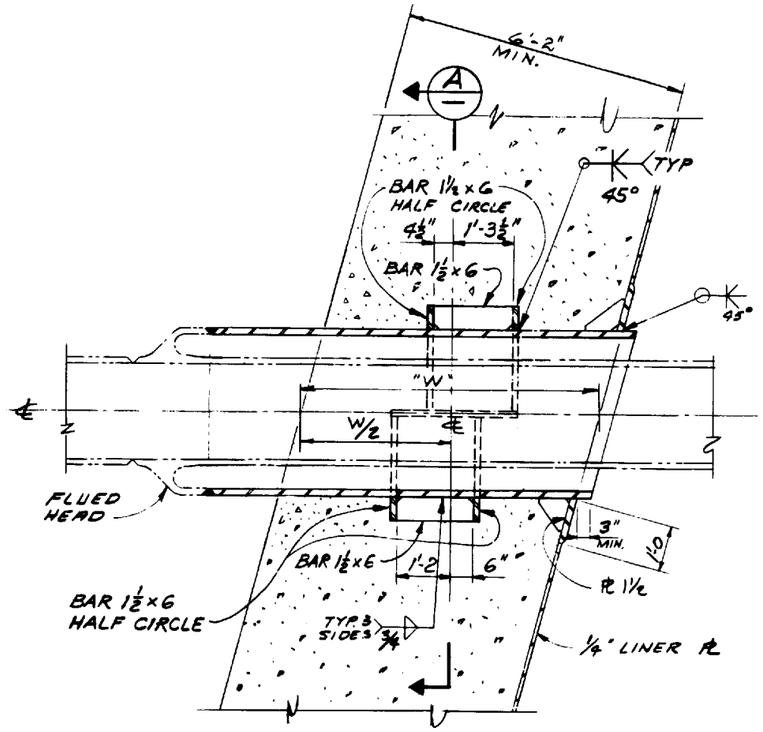
This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-287.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PIPE PENETRATION DETAILS

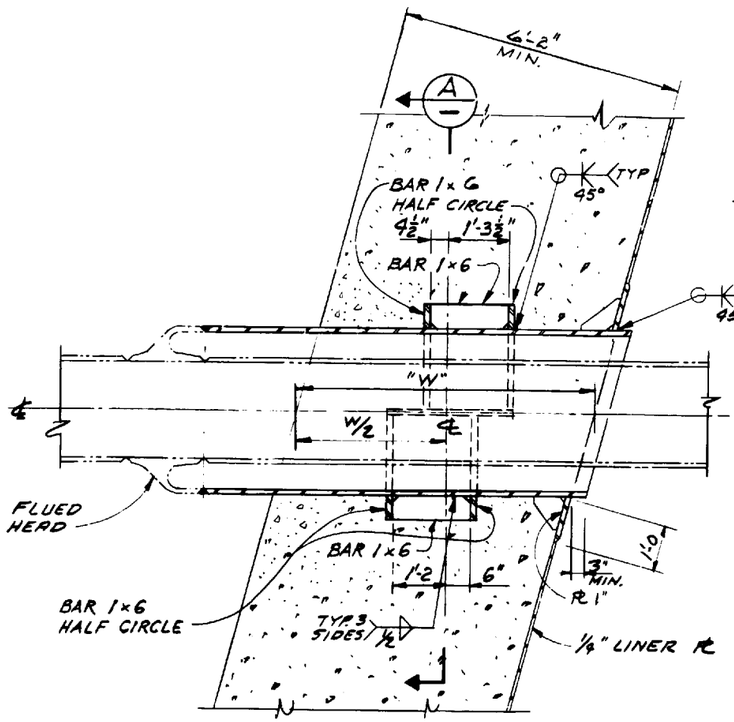
(SHEET 1 OF 8)

FIGURE 3.8-21



PENETRATION TYPE III

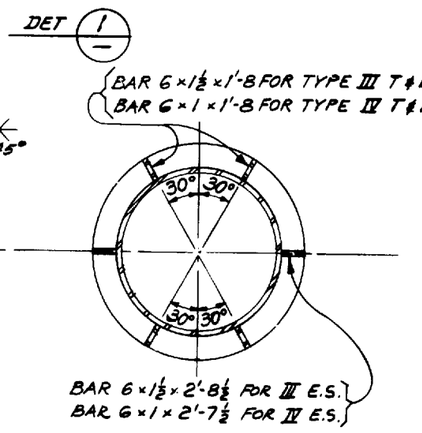
FEEDWATER LINES



PENETRATION TYPE IV

MAIN STEAM LINES

RHR SHUTDOWN COOLING SUCTION LINE



SECTION A

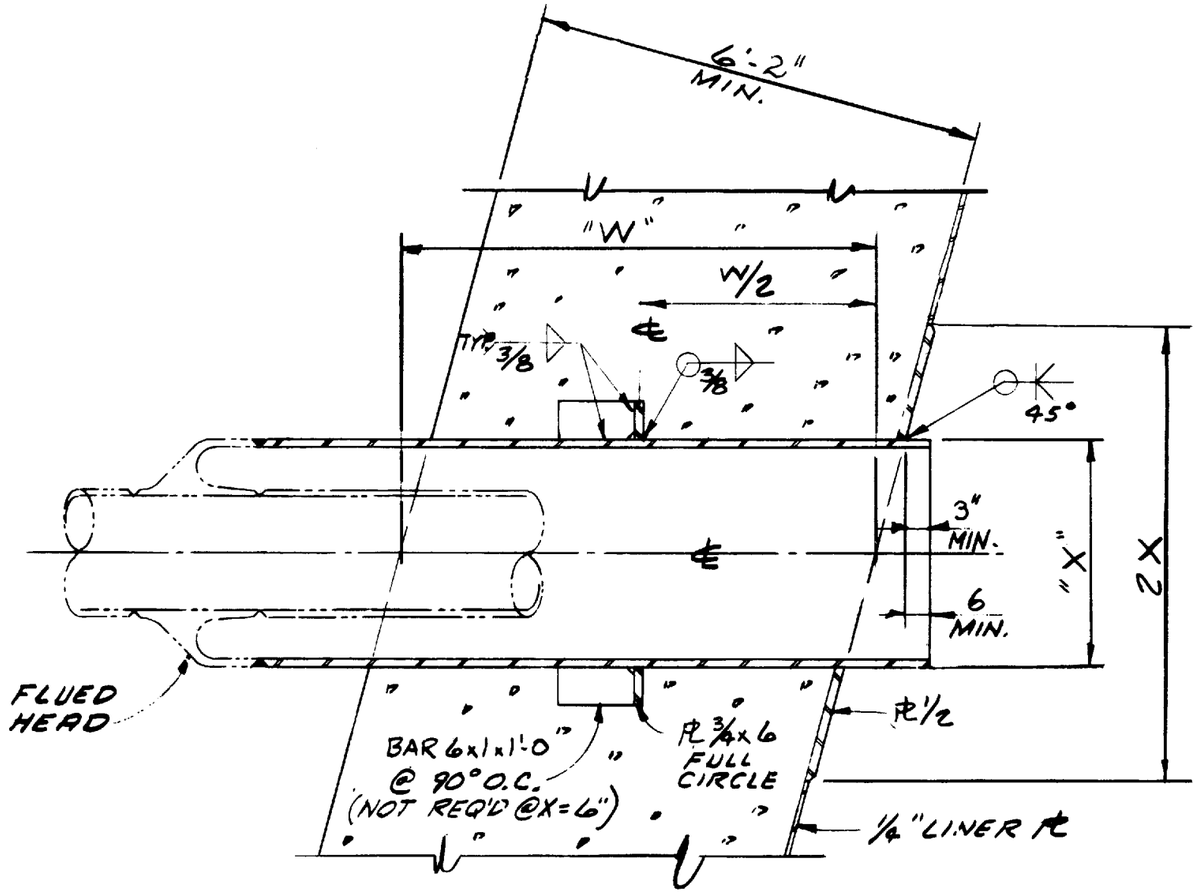
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-287.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

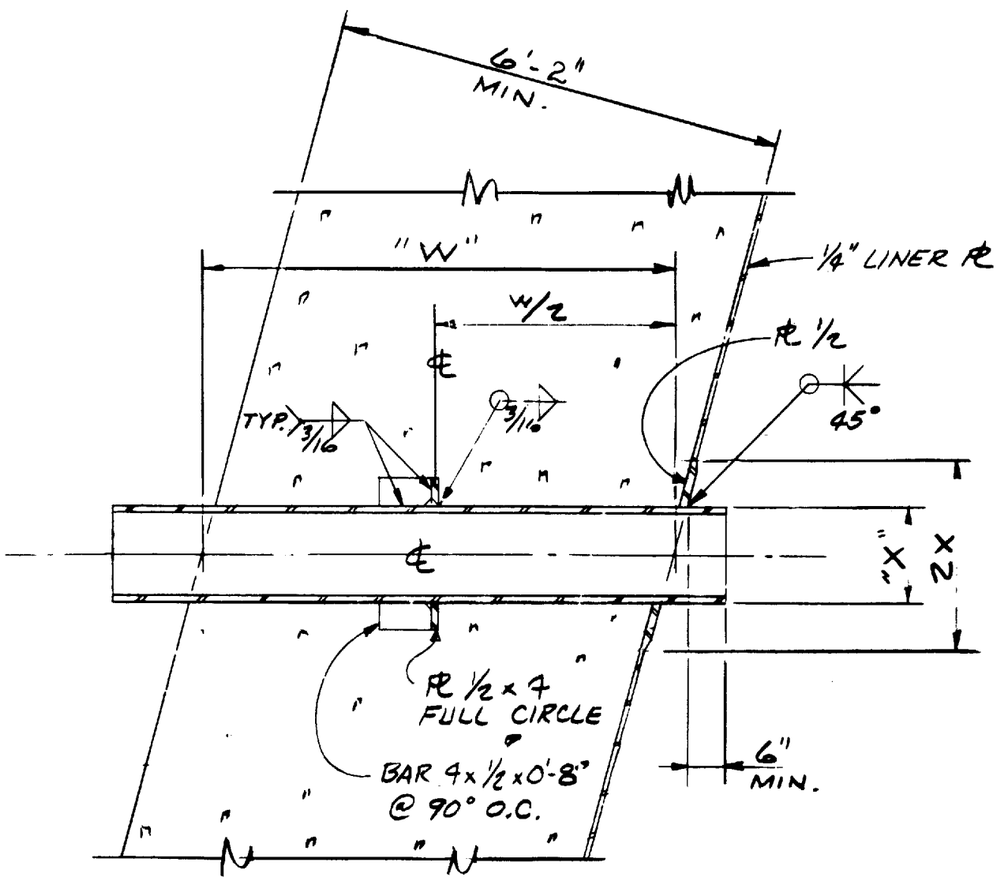
PIPE PENETRATION DETAILS
(SHEET 2 OF 8)

FIGURE 3.8-21



PENETRATION TYPE V

HIGH TEMPERATURE PROCESS FLUID



PENETRATION TYPE VI

INSTRUMENTATION

NOTE:

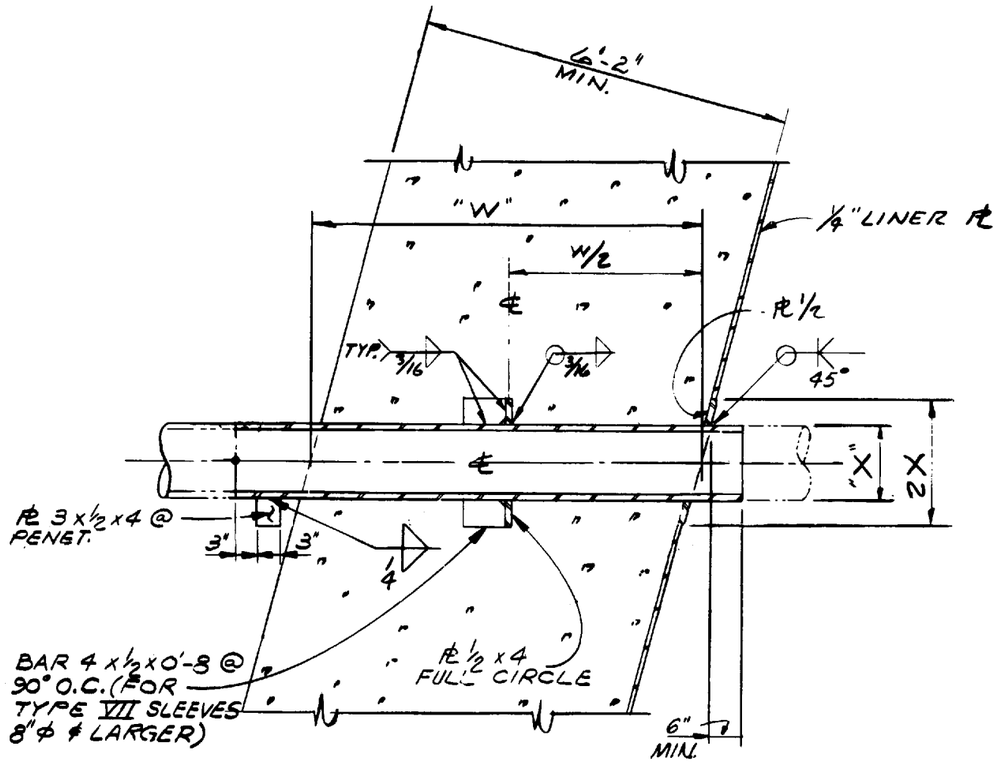
This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-287.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PIPE PENETRATION DETAILS

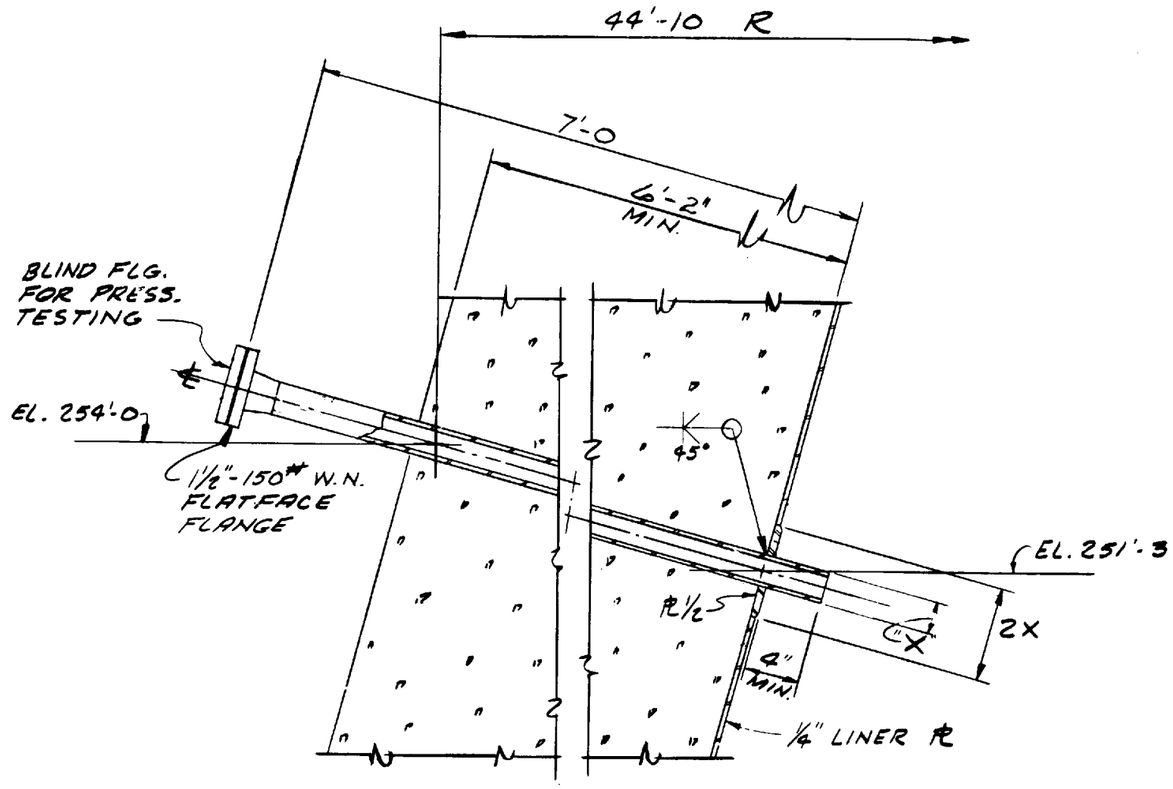
(SHEET 3 OF 8)

FIGURE 3.8-21



PENETRATION TYPE VII

LOW TEMPERATURE PROCESS FLUID



PENETRATION TYPE VIII

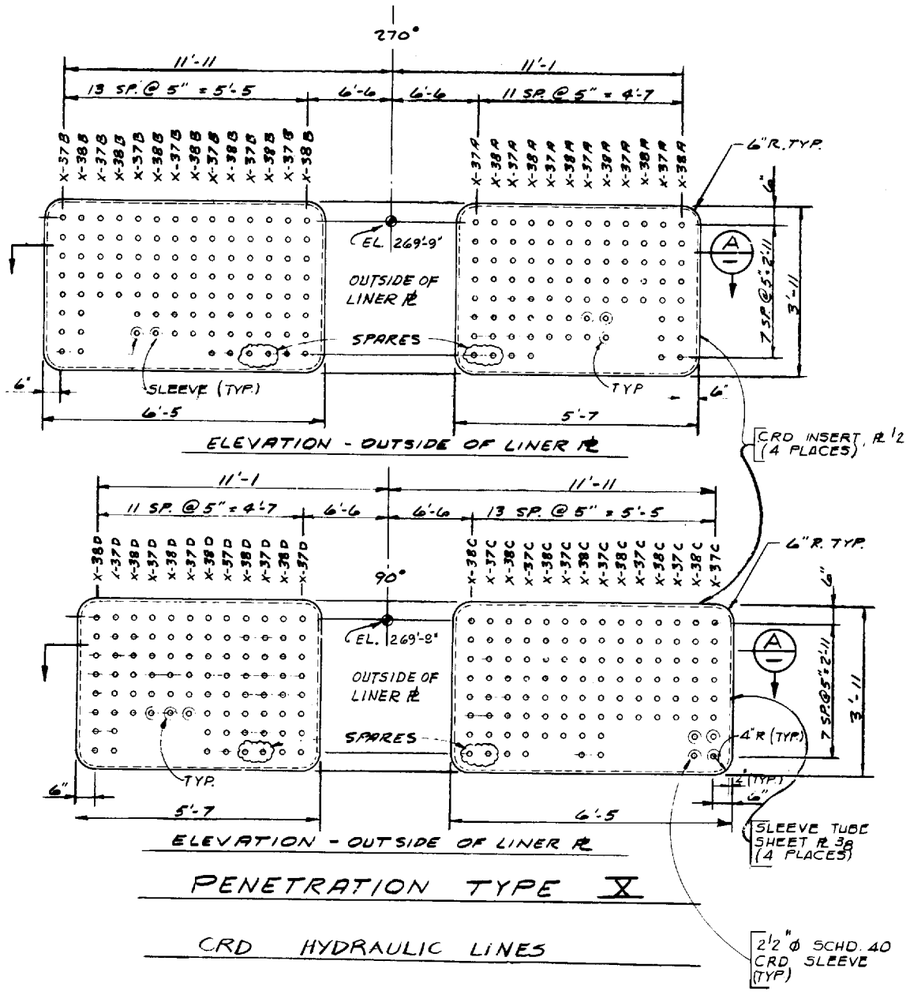
TRAVERSING INCORE PROBES

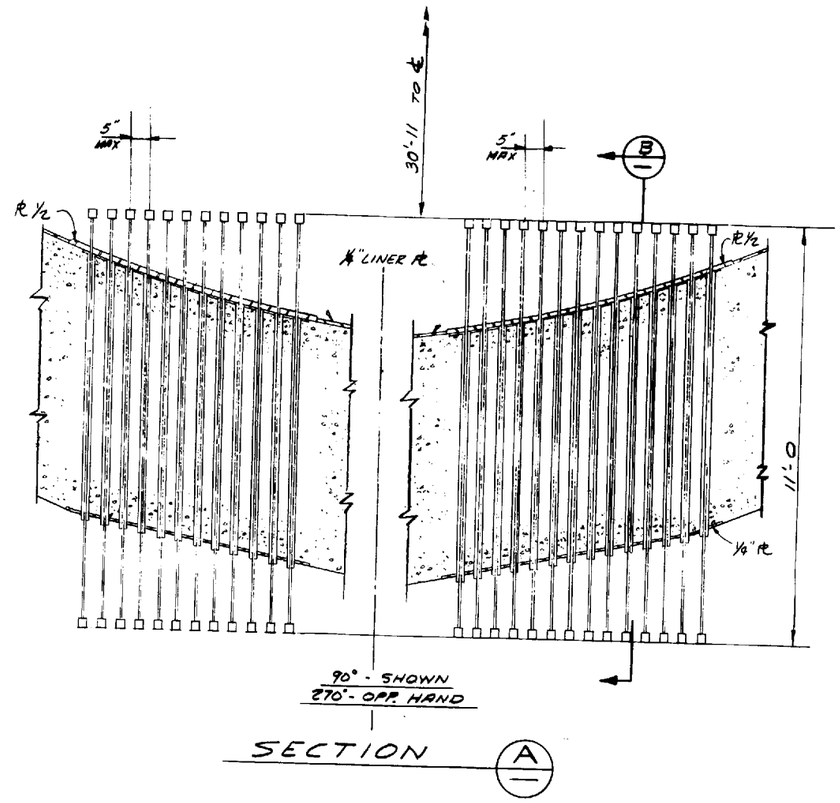
NOTE:

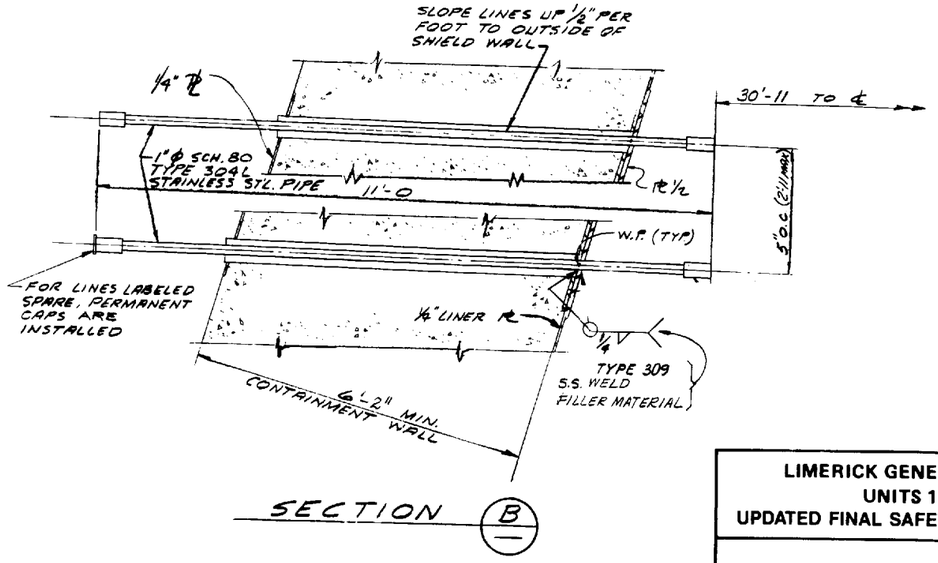
This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-287.

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-288.



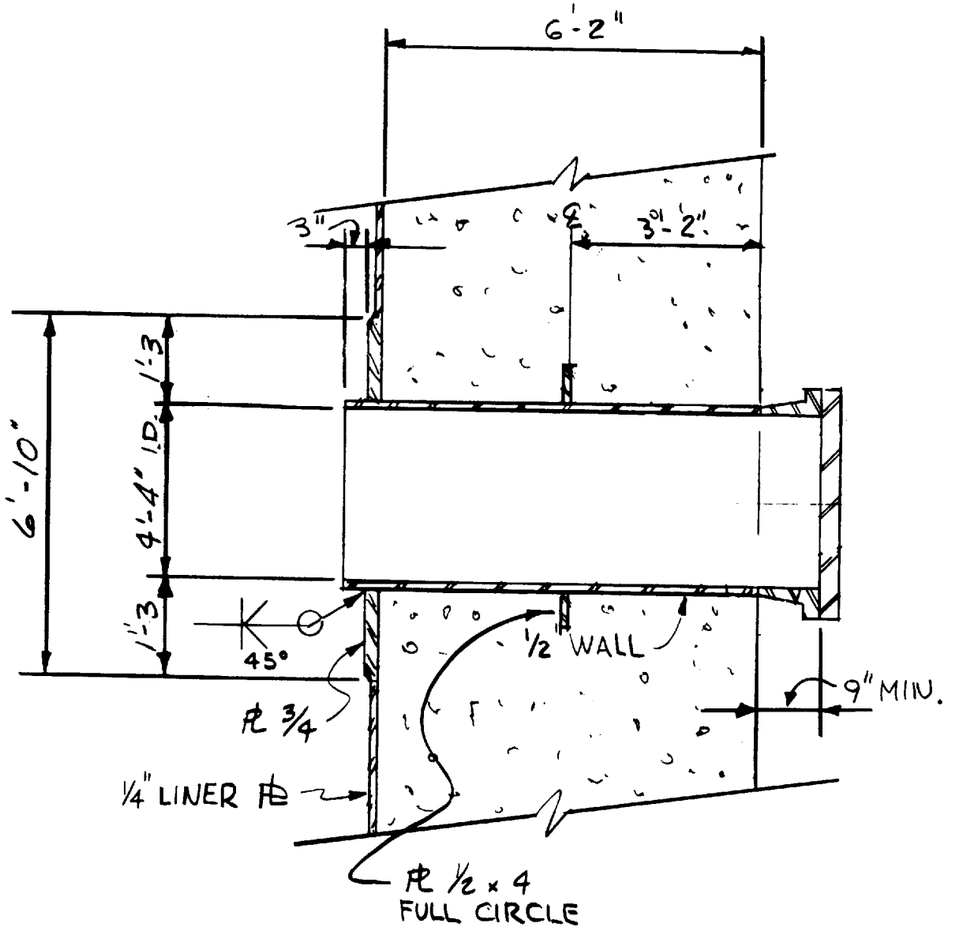




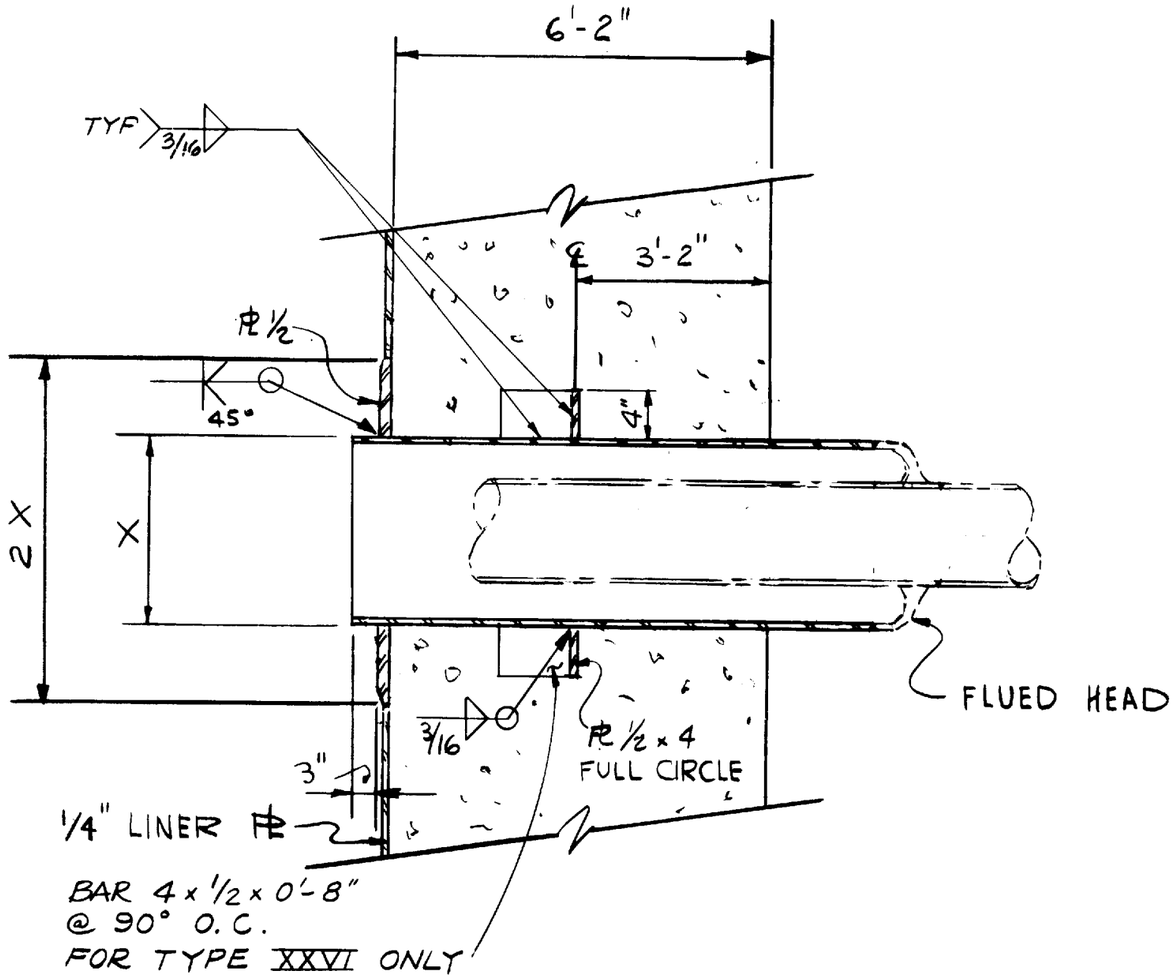
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PIPE PENETRATION DETAILS
(SHEET 5 OF 8)

FIGURE 3.8-21



SUPPRESSION POOL ACCESS TYPE XXI



PENETRATION TYPE XXII

PENETRATION TYPE XXVI

MODERATE TEMPERATURE PROCESS FLUID

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-283.

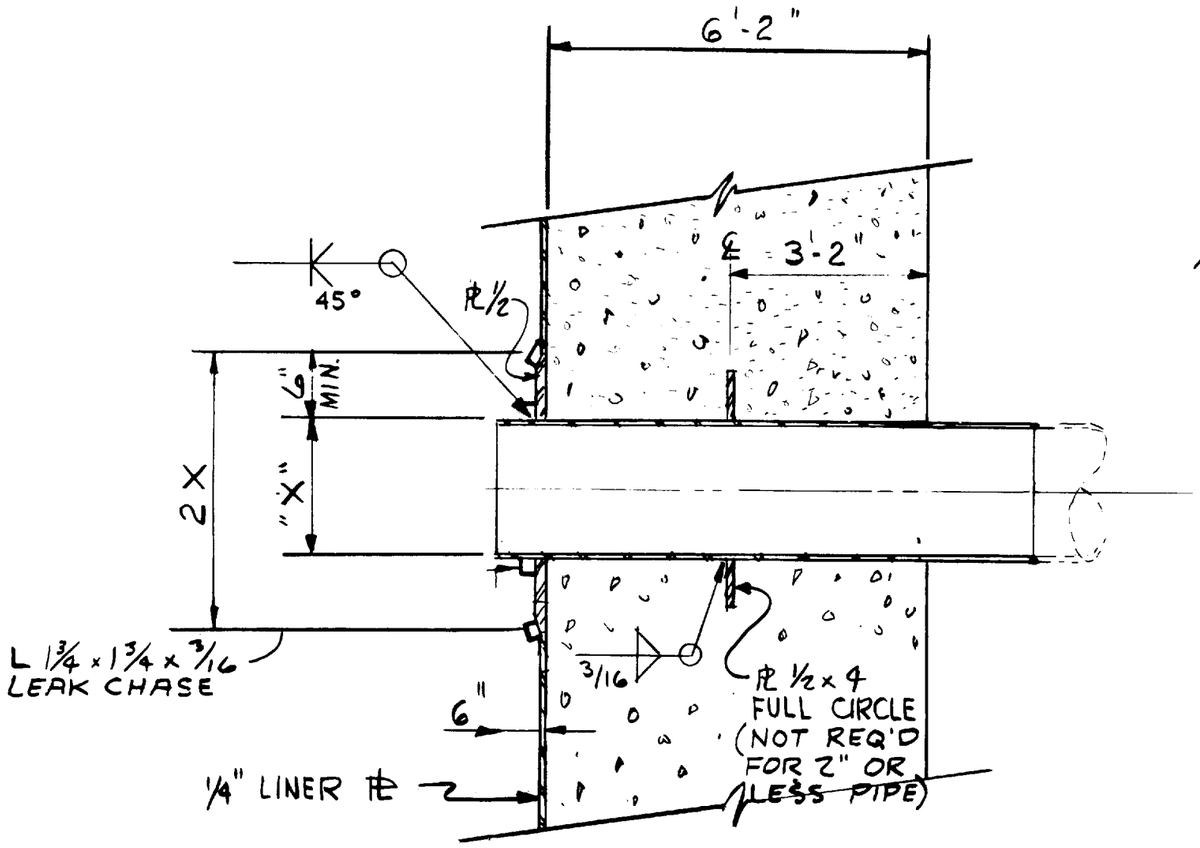
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PIPE PENETRATION DETAILS
(SHEET 6 OF 8)

FIGURE 3.8-21

NOTE:

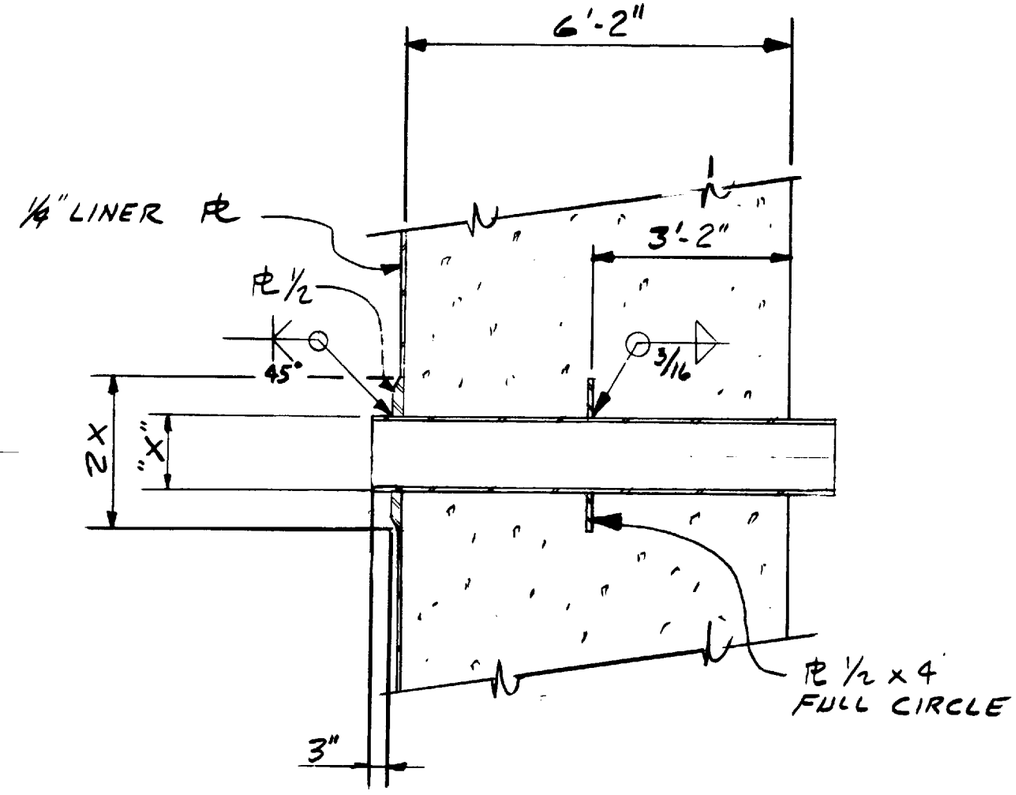
This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-283.



PENETRATION TYPE XXIII

INSTRUMENTATION

LOW TEMPERATURE PROCESS FLUID



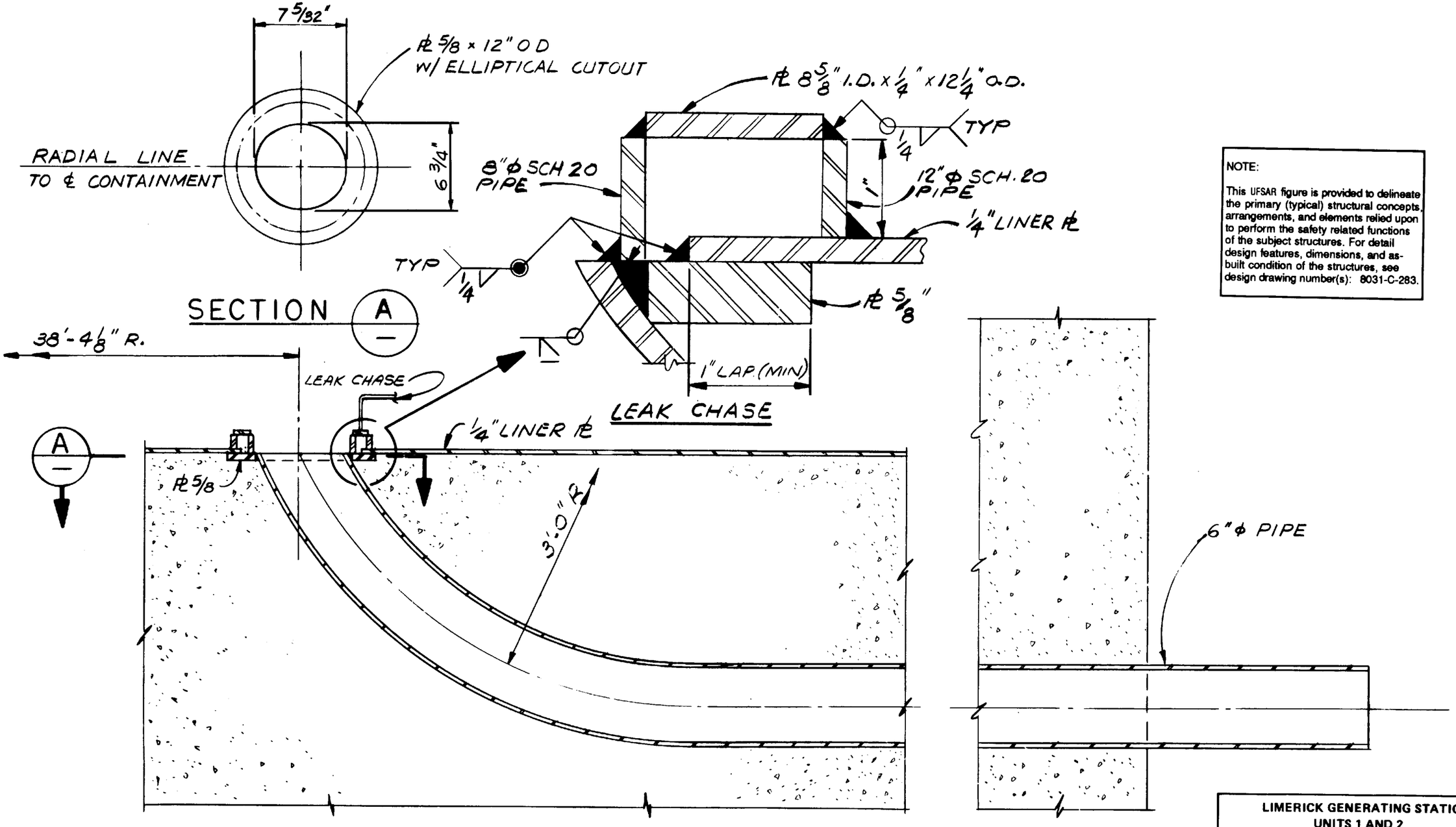
PENETRATION TYPE XXIV

STRAIN GAUGE INSTRUMENTATION

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PIPE PENETRATION DETAILS
(SHEET 7 OF 8)

FIGURE 3.8-21



NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-283.

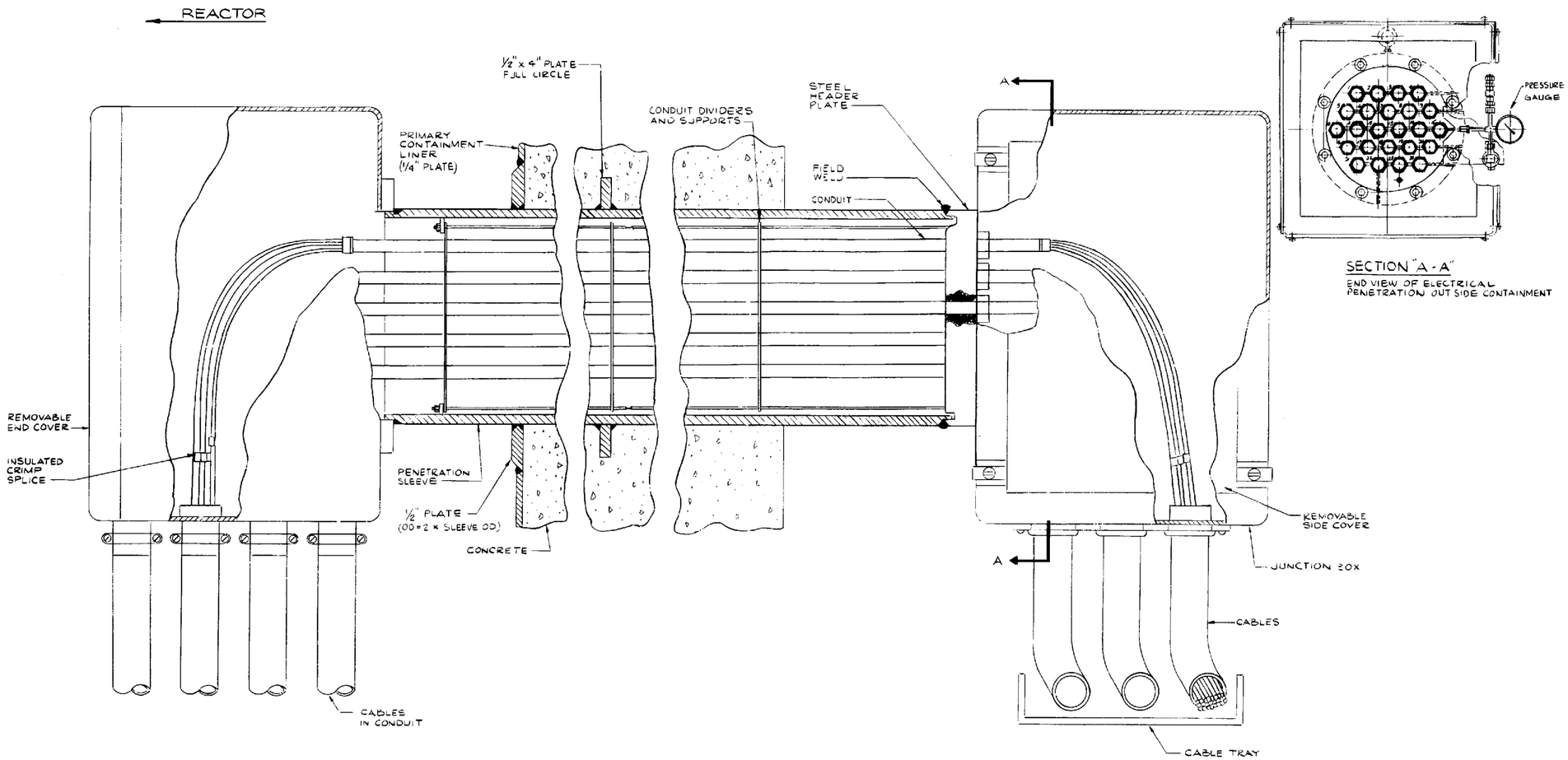
PENETRATION TYPE XXV

SUPPRESSION CHAMBER DRAIN

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PIPE PENETRATION DETAILS
(SHEET 8 OF 8)

FIGURE 3.8-21

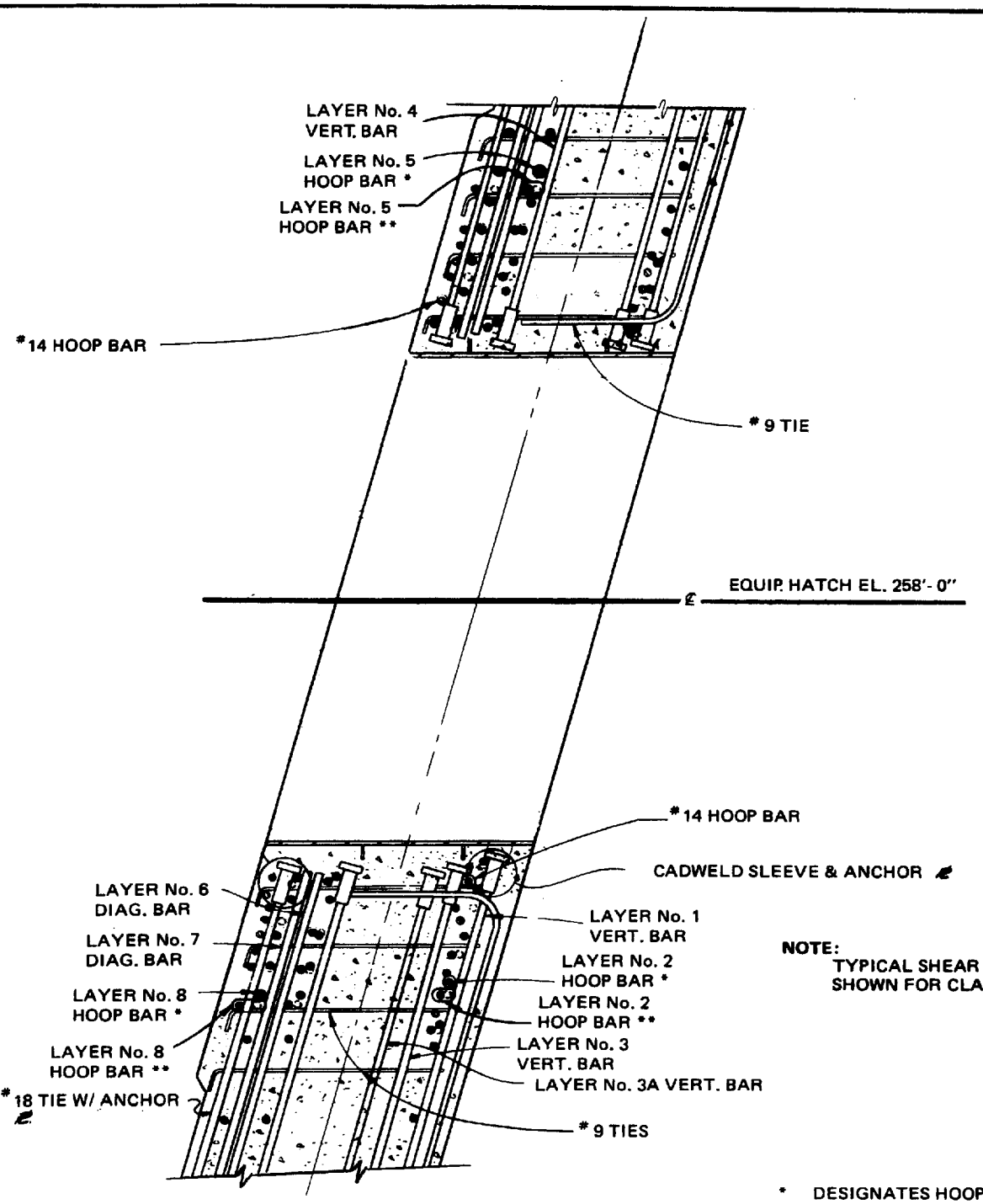


TYPICAL INSTALLED ELECTRICAL PENETRATION ASSEMBLY

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

ELECTRICAL PENETRATION DETAILS

FIGURE 3.8-22



NOTE:
TYPICAL SHEAR TIES NOT SHOWN FOR CLARITY.

* DESIGNATES HOOP BARS BENT AROUND EQUIP. HATCH

** DESIGNATES HOOP BARS PLACED OUTSIDE CONICAL SURFACE OF HOOP BARS @ EQUIP. HATCH

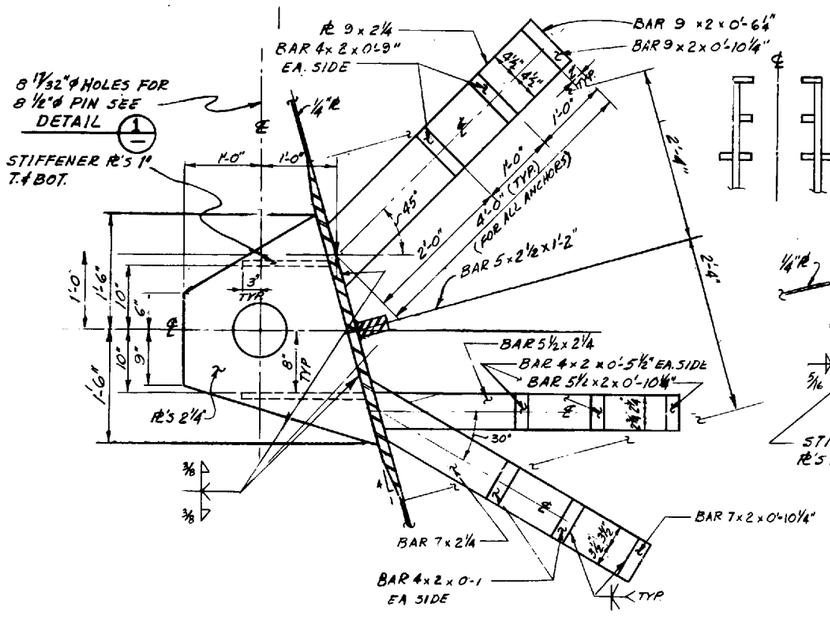
TYPICAL SECTION AT EQUIPMENT HATCH

SECTION A

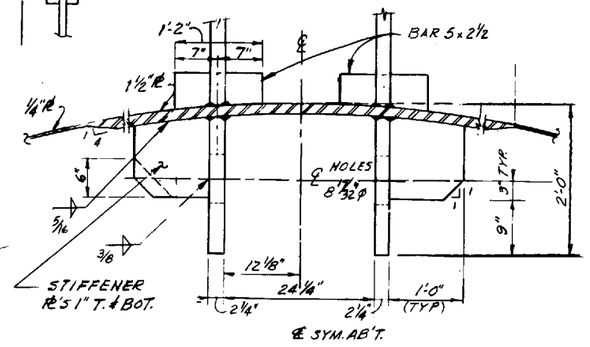
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REINFORCEMENT DETAIL AT EQUIPMENT HATCHES

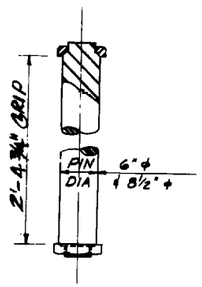
FIGURE 3.8-23 Rev. 11 9/02



SECTION



PLAN



PIN DETAIL 1
NTS

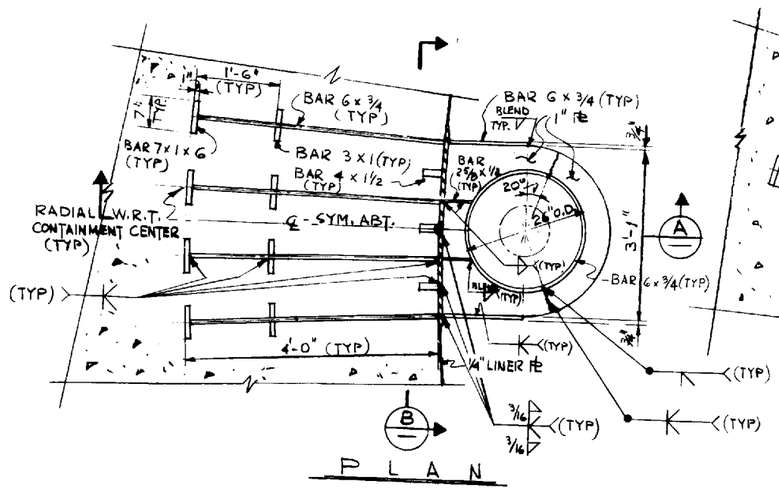
NOTE:

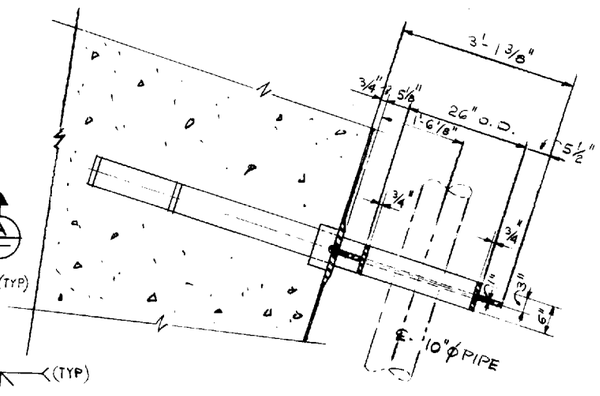
This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-286.

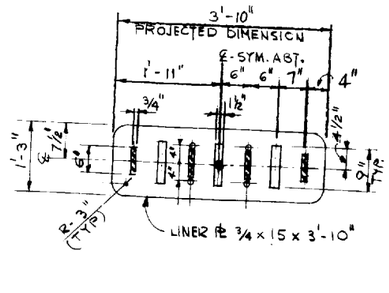
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

BEAM SEAT EMBEDMENT

FIGURE 3.8-24







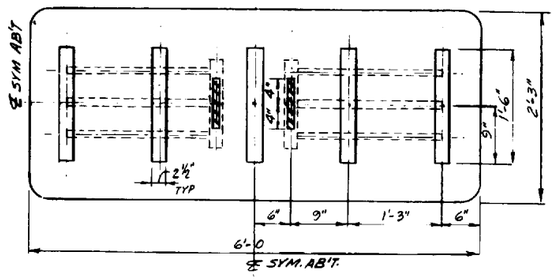
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-289.

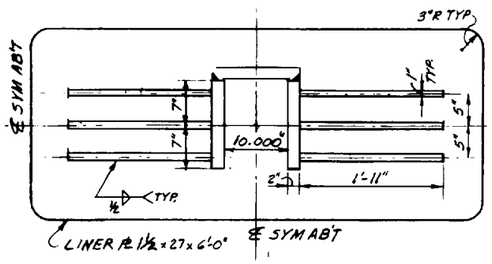
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PIPE WHIP RESTRAINT EMBEDMENT

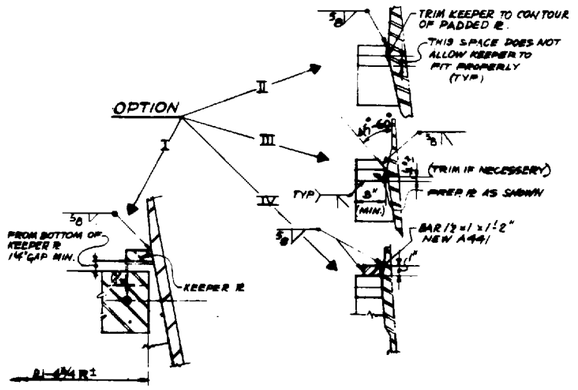
FIGURE 3.8-25



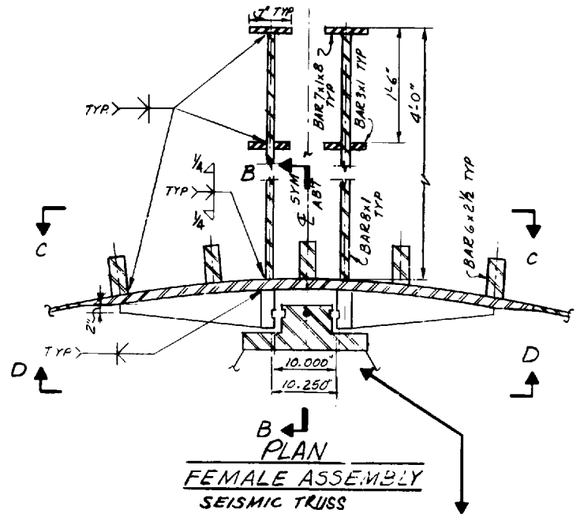
SECTION C-C

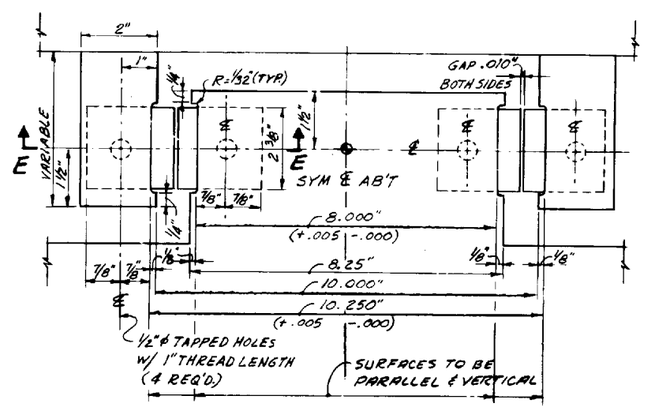


SECTION D-D

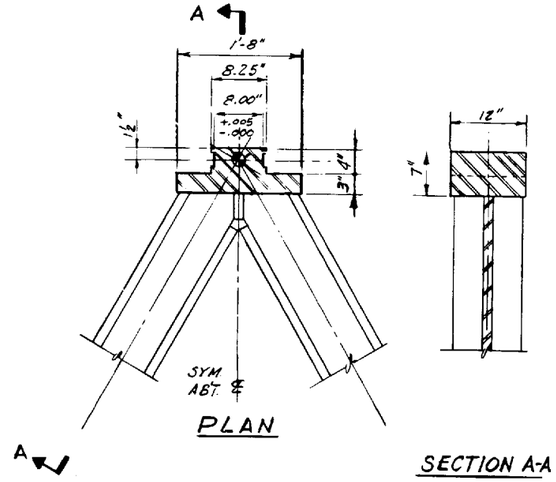


SECTION B-B





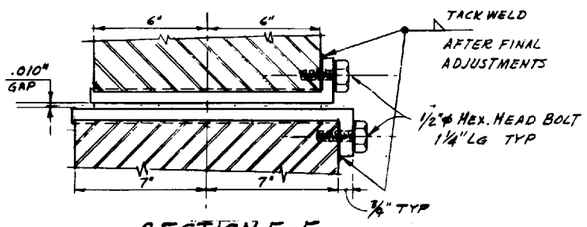
ENLARGED PLAN



PLAN

SECTION A-A

MALE ASSEMBLY



SECTION E-E

(ROTATED 90°)

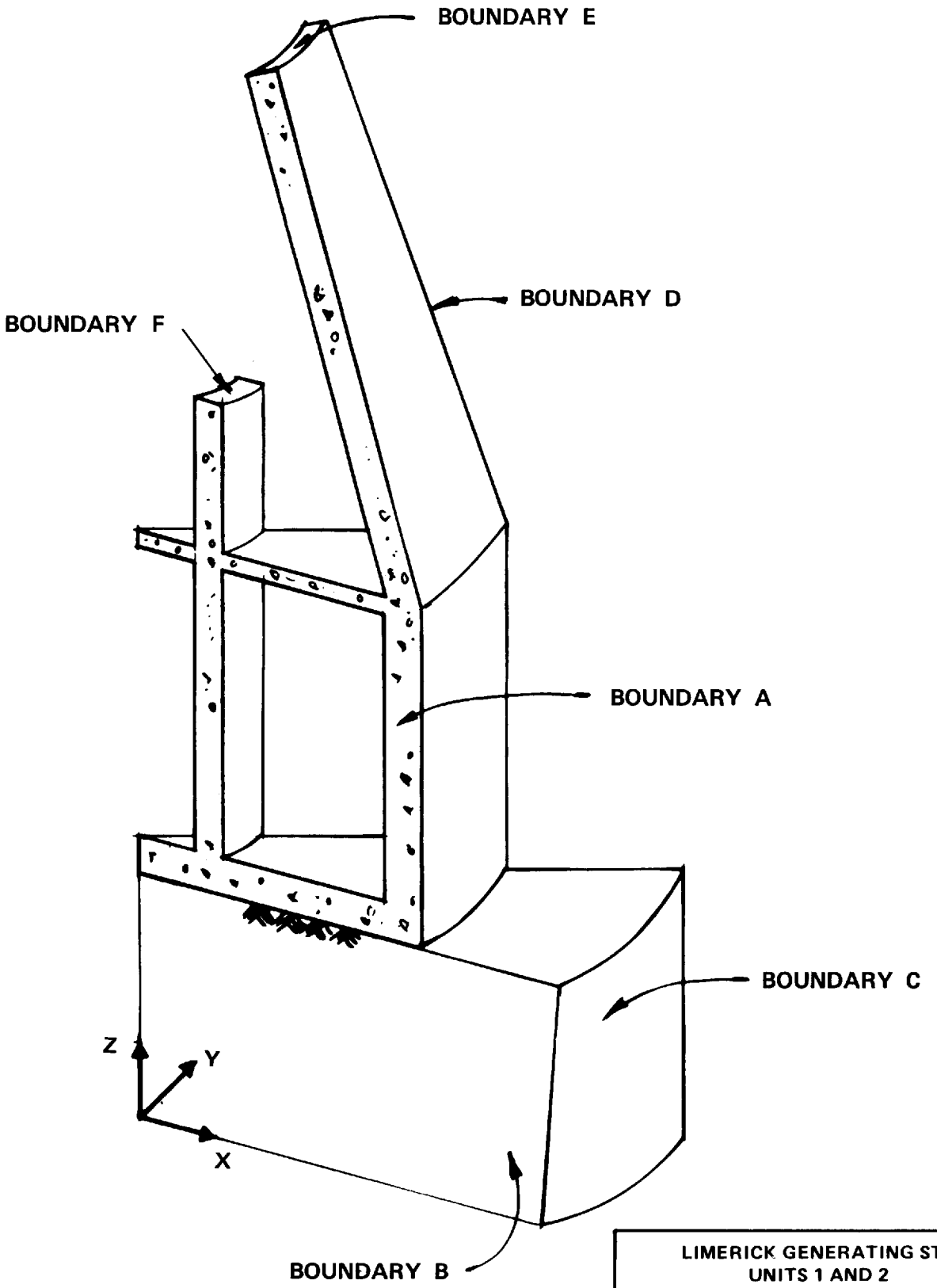
NOTE:

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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SEISMIC TRUSS SUPPORT (EMBEDMENT)

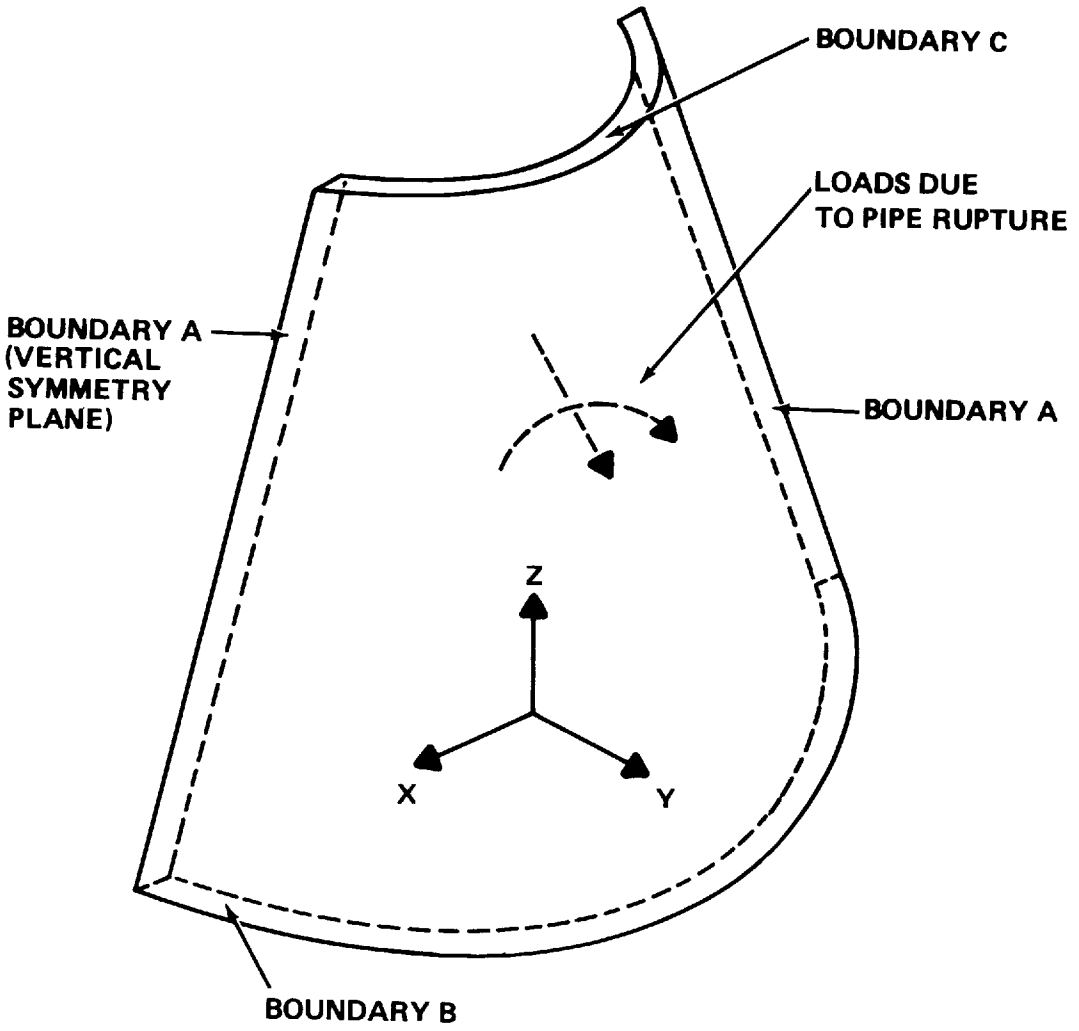
FIGURE 3.8-26



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT WALL ANALYTICAL MODEL FOR AXISYMMETRIC LOADS

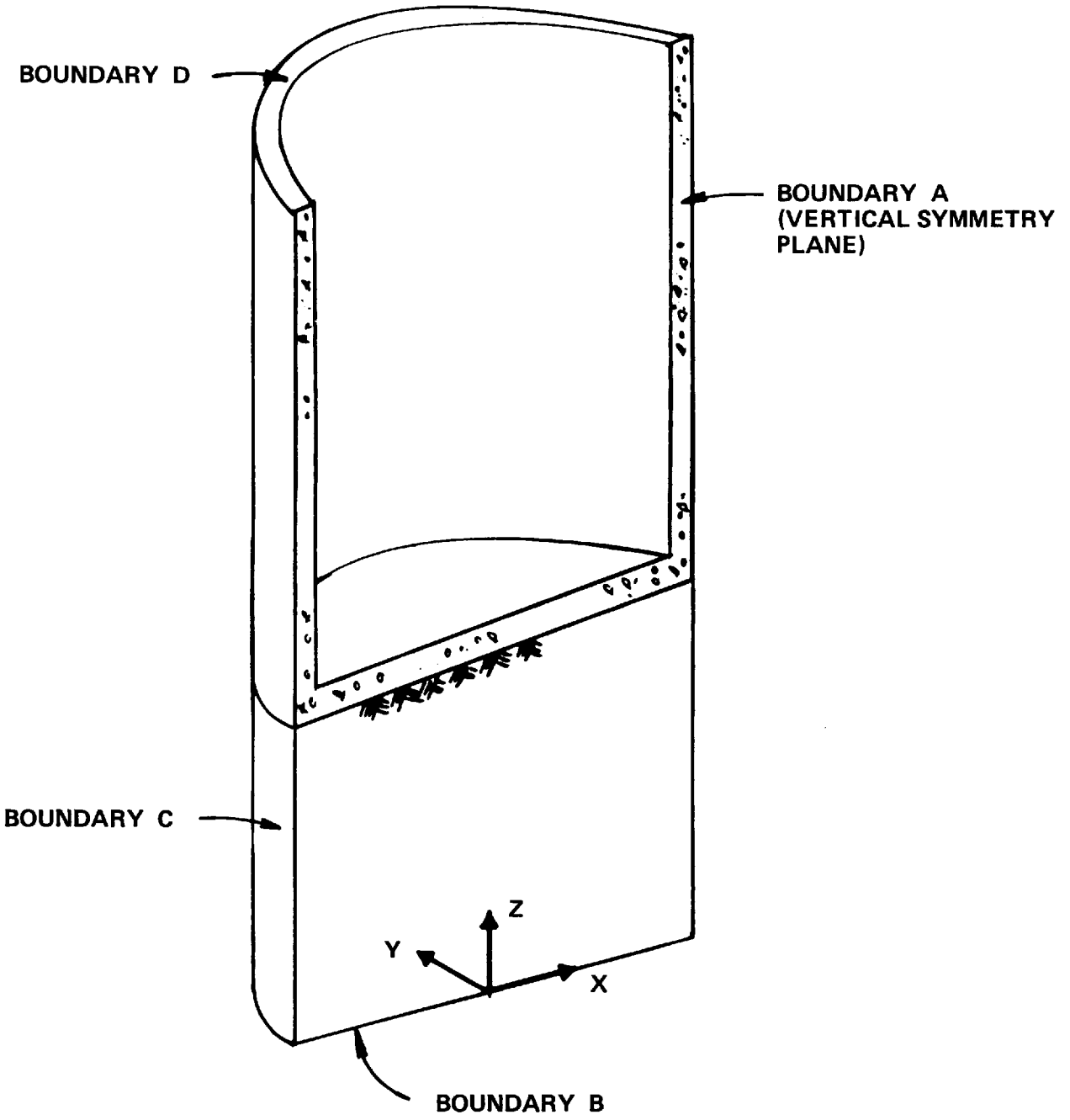
FIGURE 3.8-27



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL WALL ANALYTICAL MODEL FOR NON-AXISYMMETRIC POSTULATED PIPE RUPTURE LOADS

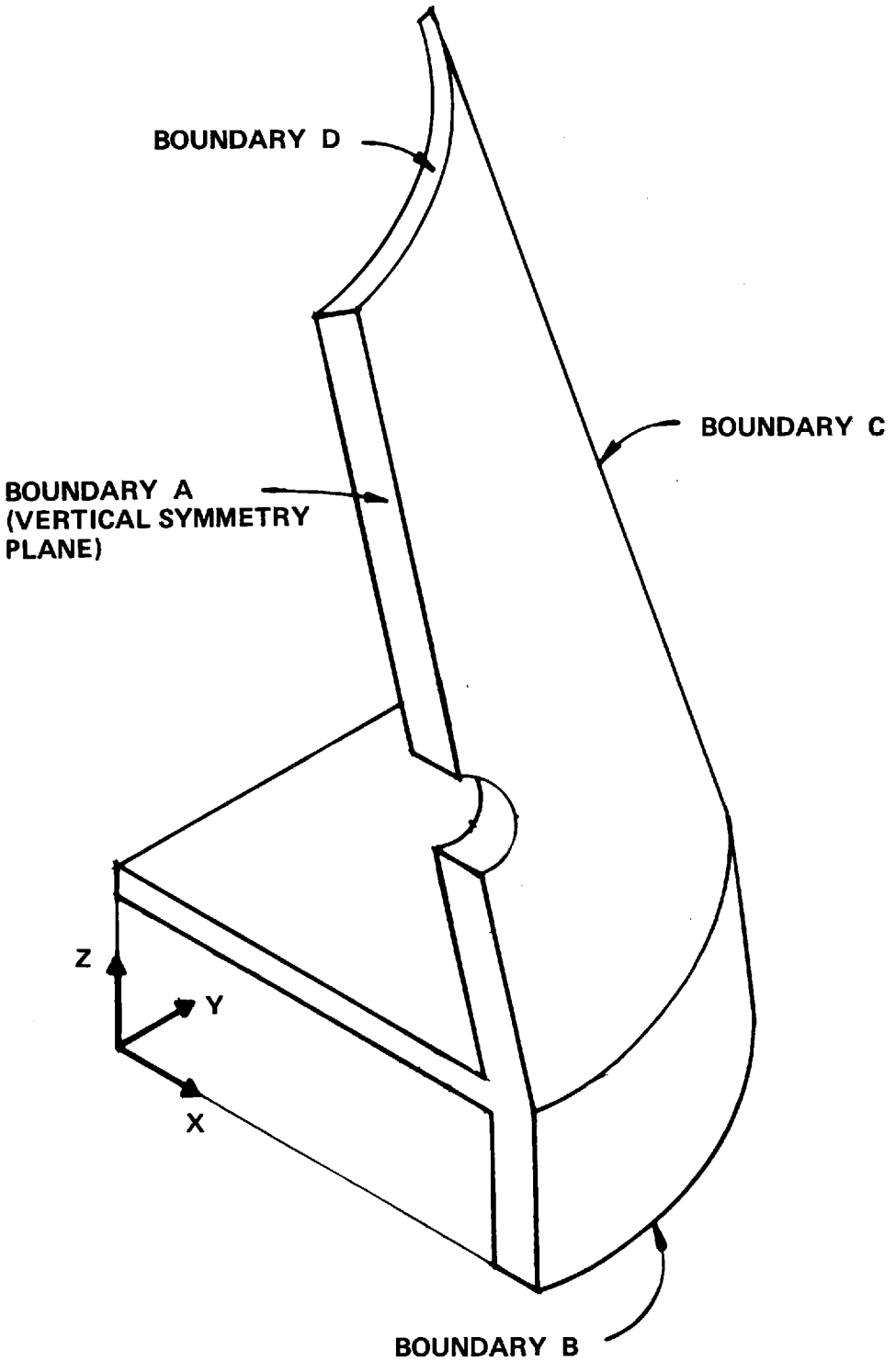
FIGURE 3.8-28



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

BASE FOUNDATION SLAB
ANALYTICAL MODEL

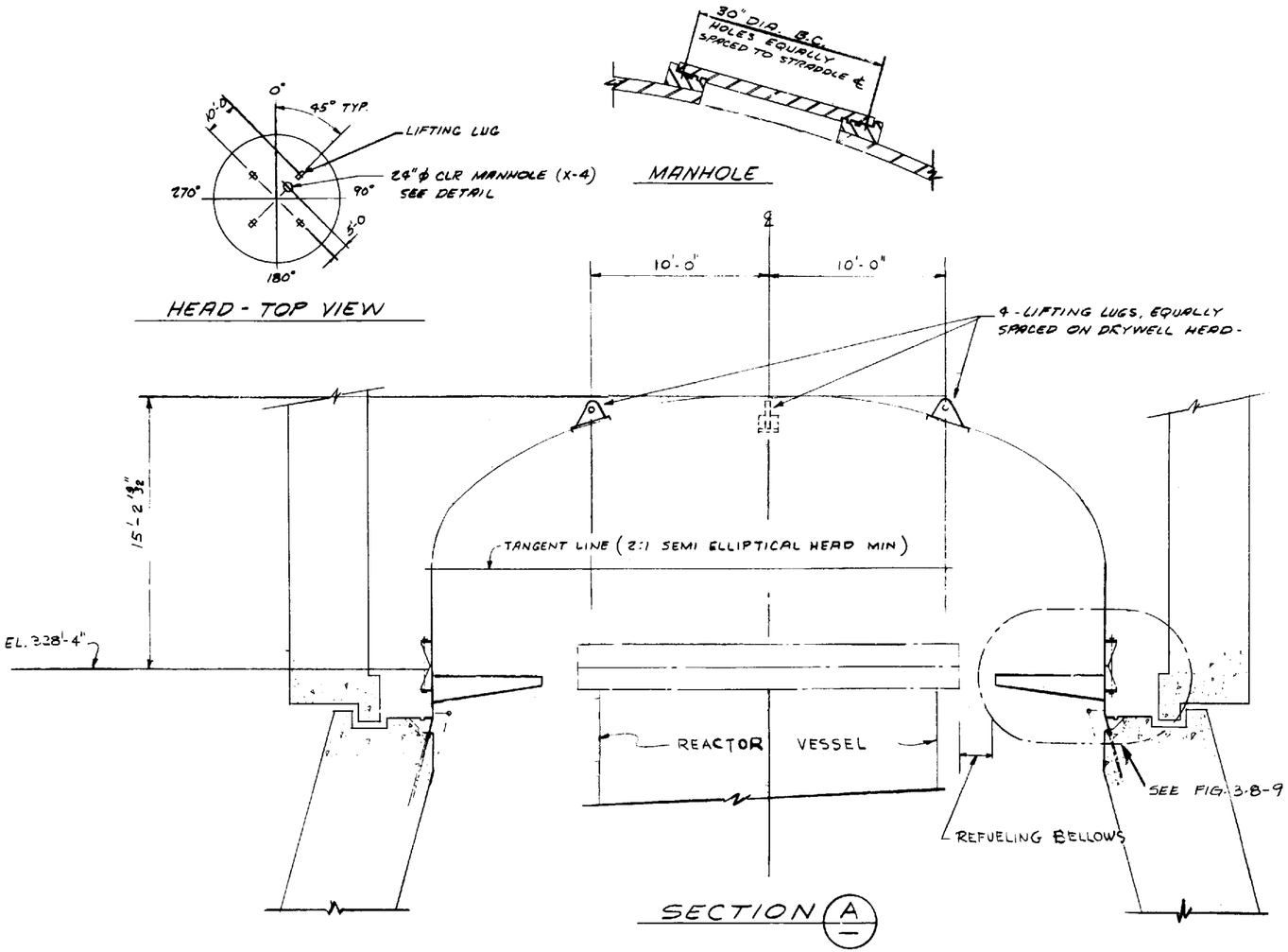
FIGURE 3.8-29



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

EQUIPMENT HATCH ANALYTICAL MODEL

FIGURE 3.8-30



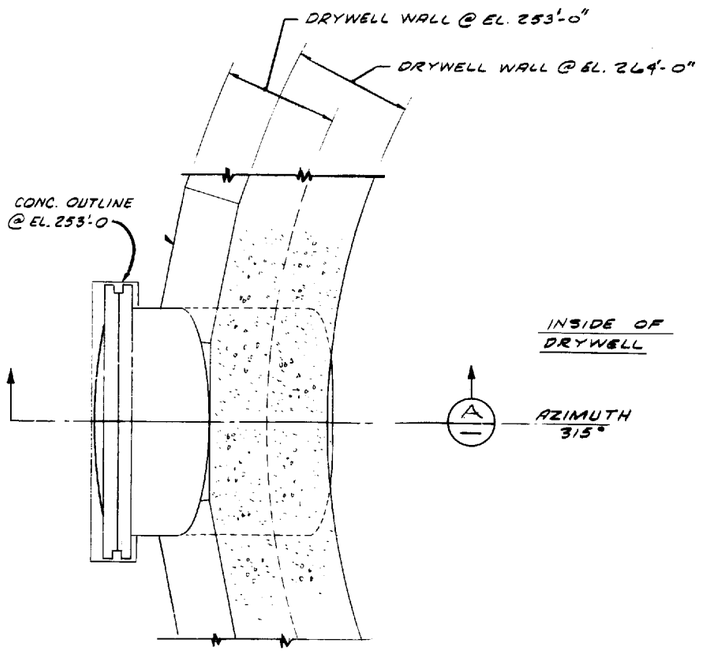
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-290.

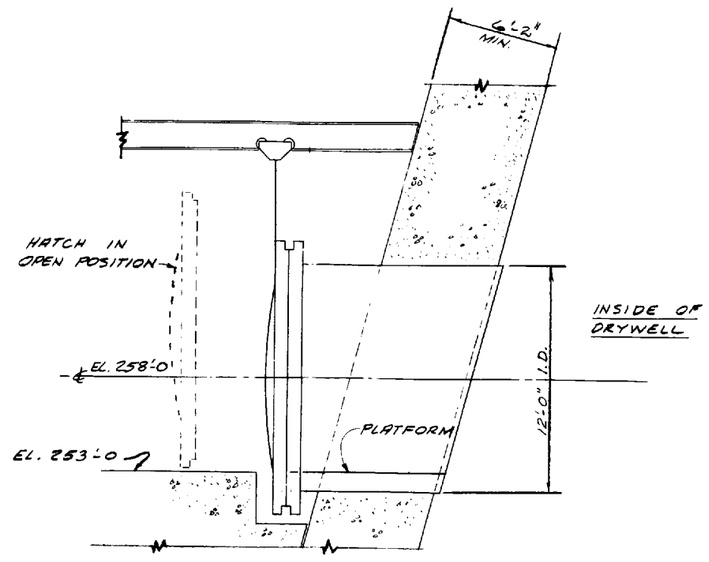
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL HEAD

FIGURE 3.8-31



PLAN



SECTION A

EQUIPMENT ACCESS

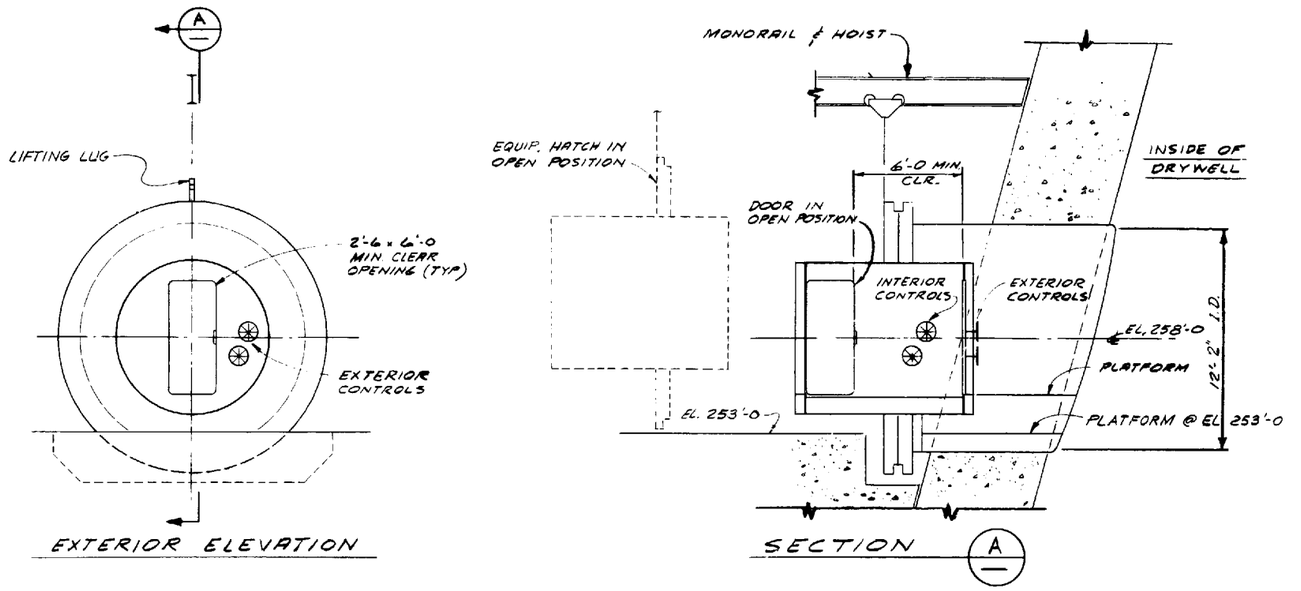
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-288.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

EQUIPMENT HATCH

FIGURE 3.8-32



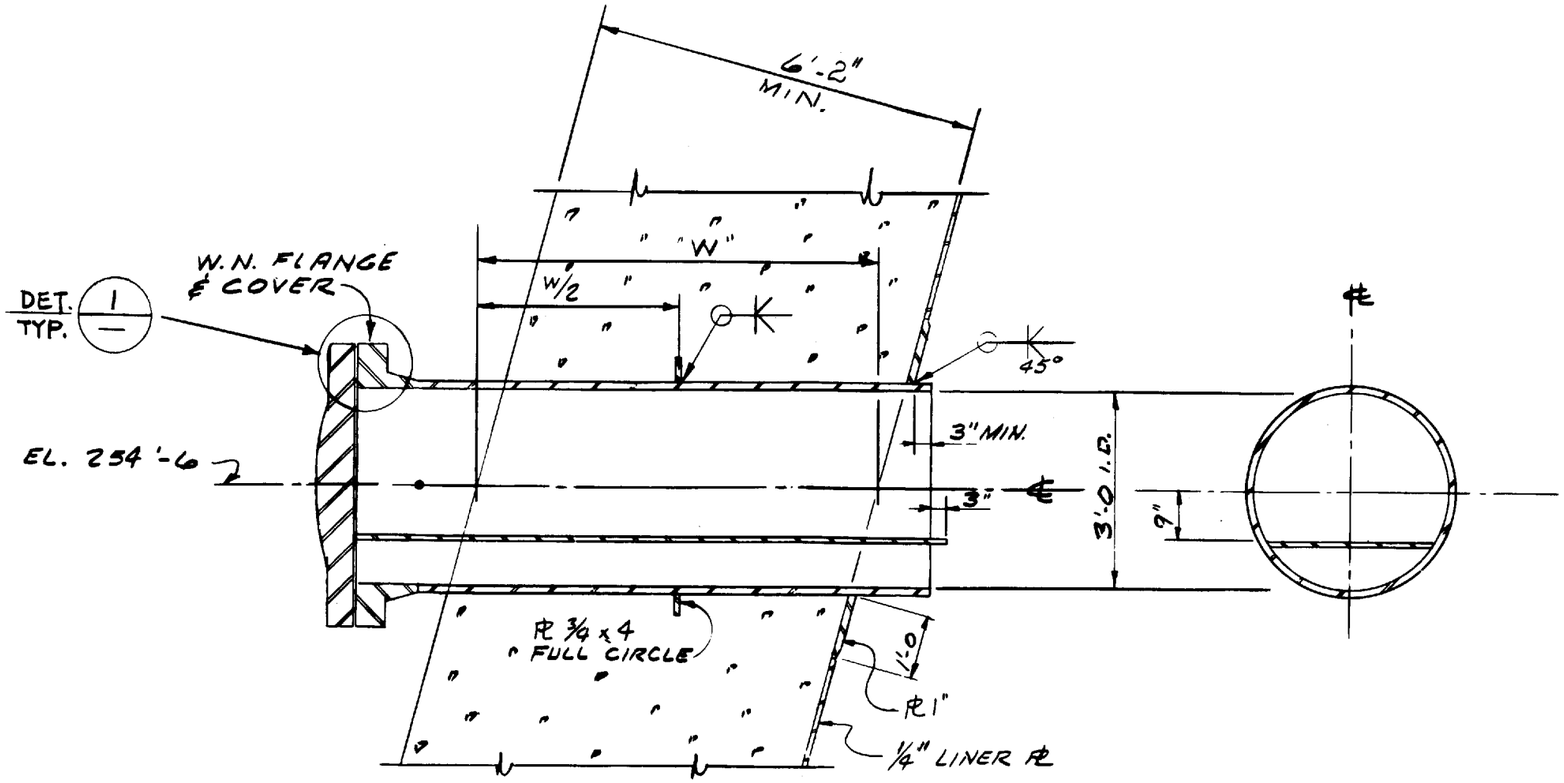
EQUIPMENT ACCESS W/ PERSONNEL LOCK (X-2)
AZIMUTH 135°

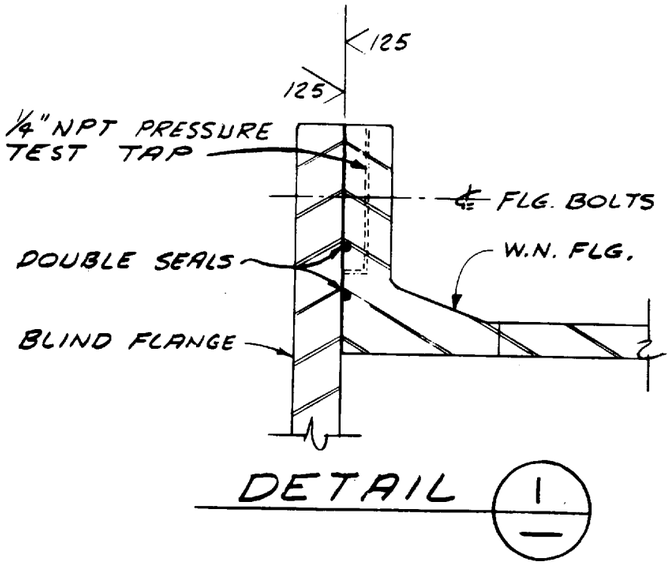
NOTE:
This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-288.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

EQUIPMENT HATCH WITH PERSONNEL LOCK

FIGURE 3.8-33





DETAIL 1

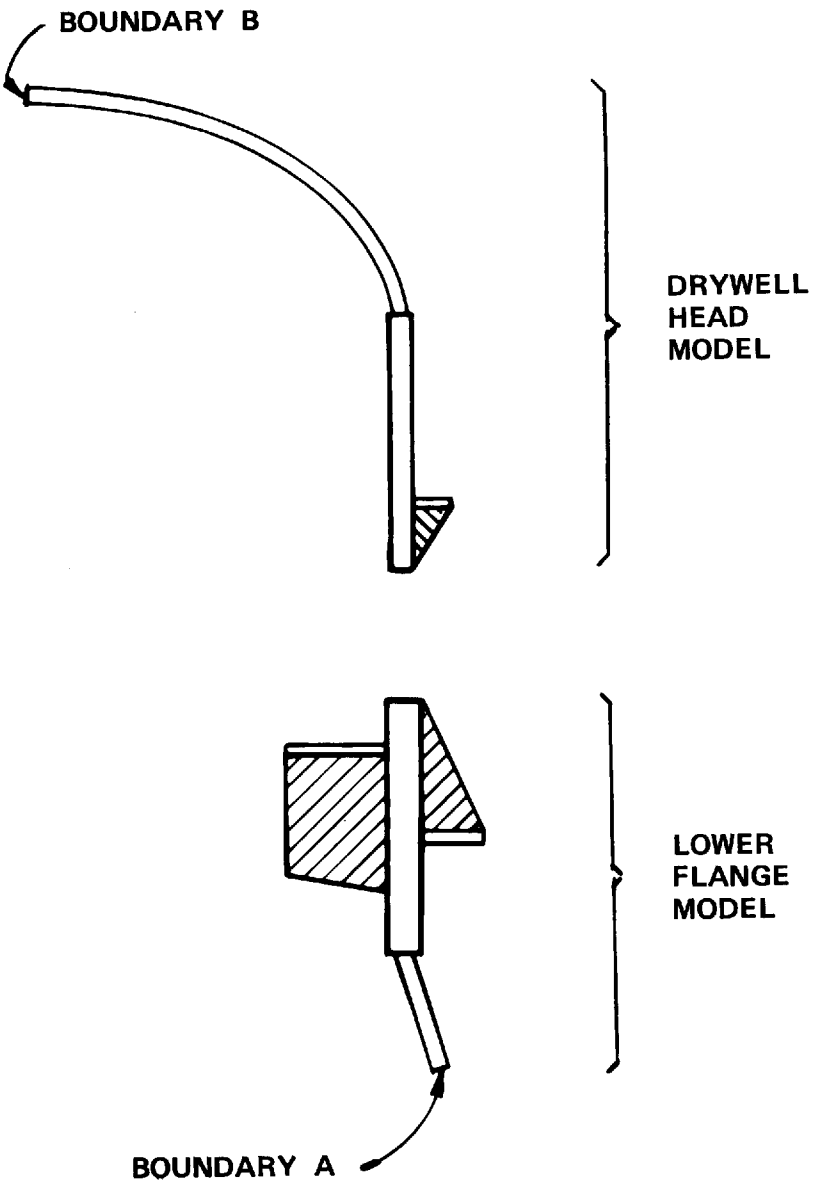
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-287.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTROL ROD DRIVE
REMOVAL HATCH

FIGURE 3.8-34

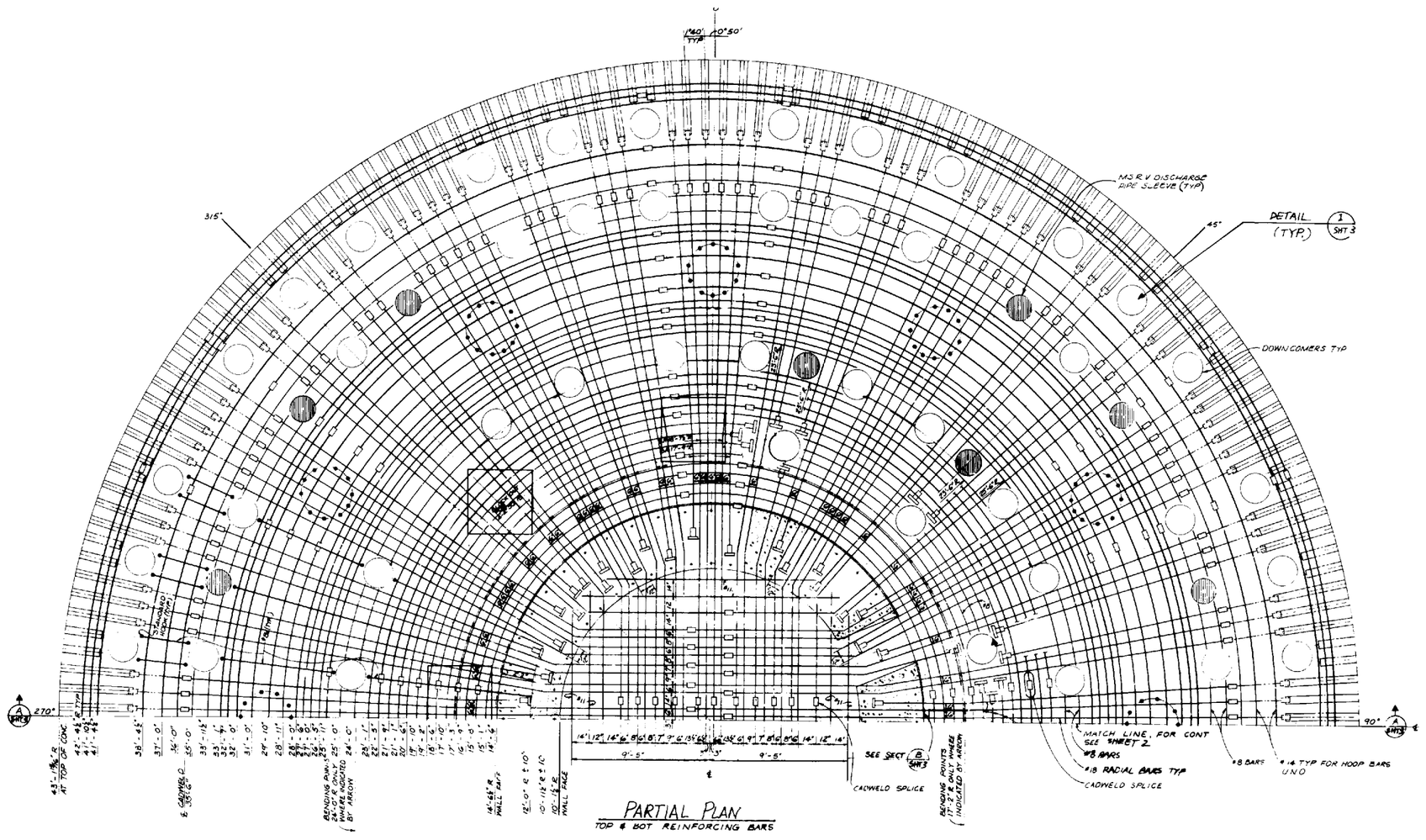


NOTE:
CROSS-HATCHED AREAS ARE MODELLED AS ORTHOTROPIC LAYERS.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

ANALYTICAL MODEL OF
DRYWELL HEAD
ASSEMBLY

FIGURE 3.8-35



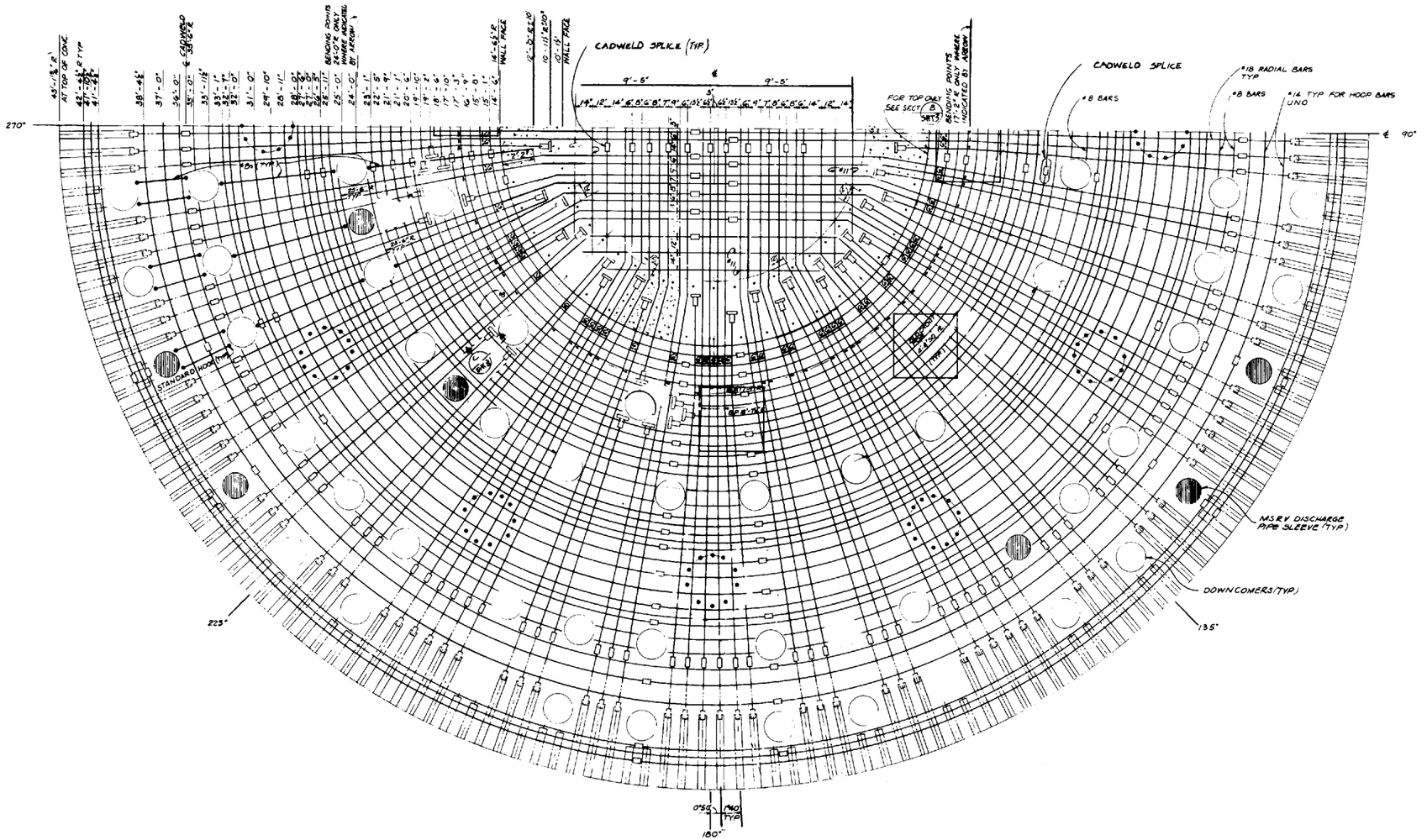
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-259.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DIAPHRAGM SLAB REINFORCEMENT
(SHEET 1 OF 3)

FIGURE 3.8-36



PARTIAL PLAN

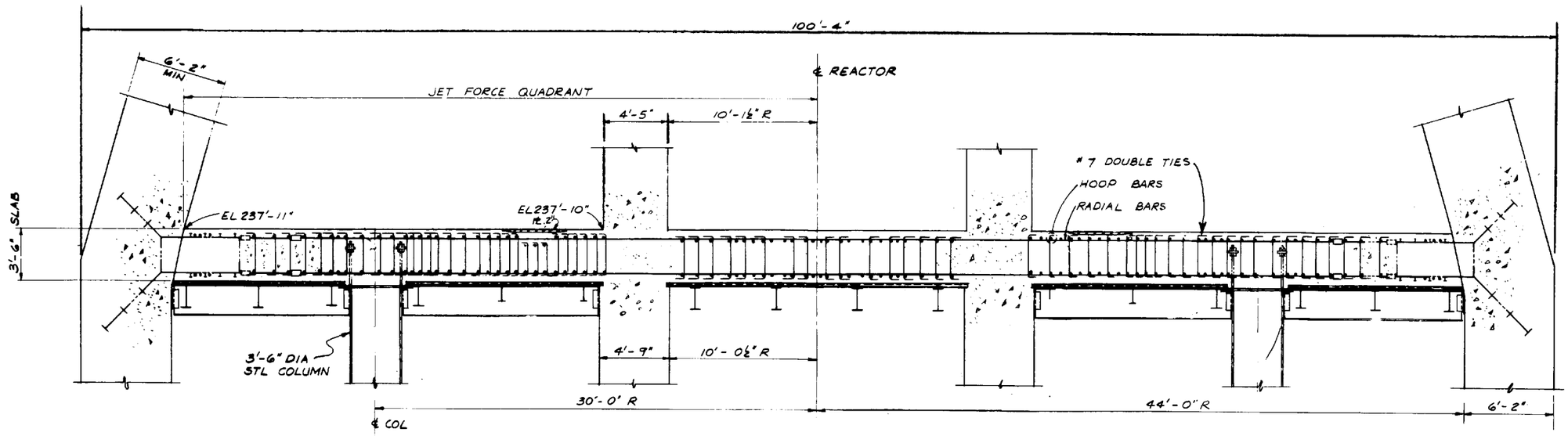
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-260.

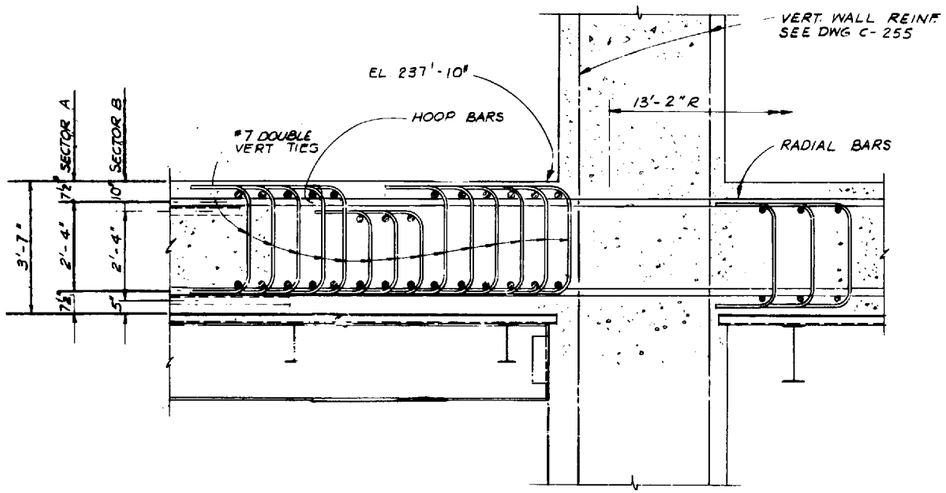
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DIAPHRAGM SLAB REINFORCEMENT
(SHEET 2 OF 3)

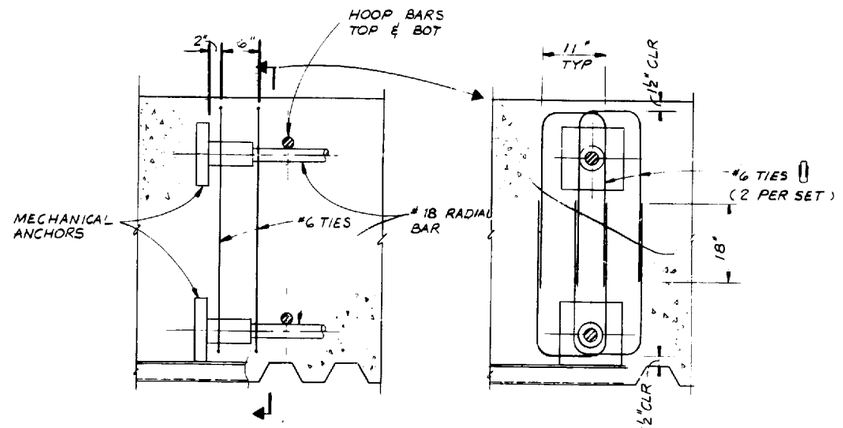
FIGURE 3.8-36



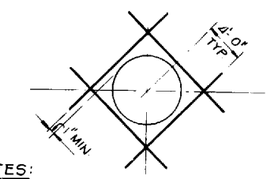
SECTION A



SECTION B



SECTION C



NOTES:
1. FOR PENETRATIONS 20" DIA. OR LARGER, ADD 4 #8's 8'-0" LONG TOP & BOTTOM.
2. STANDARD HOOKS MAY BE USED WHERE #8 BARS INTERFERE WITH COLUMN SHEAR HEADS, EMBEDS OR REBAR END ANCHORS.

DETAIL 1 (TYP.)

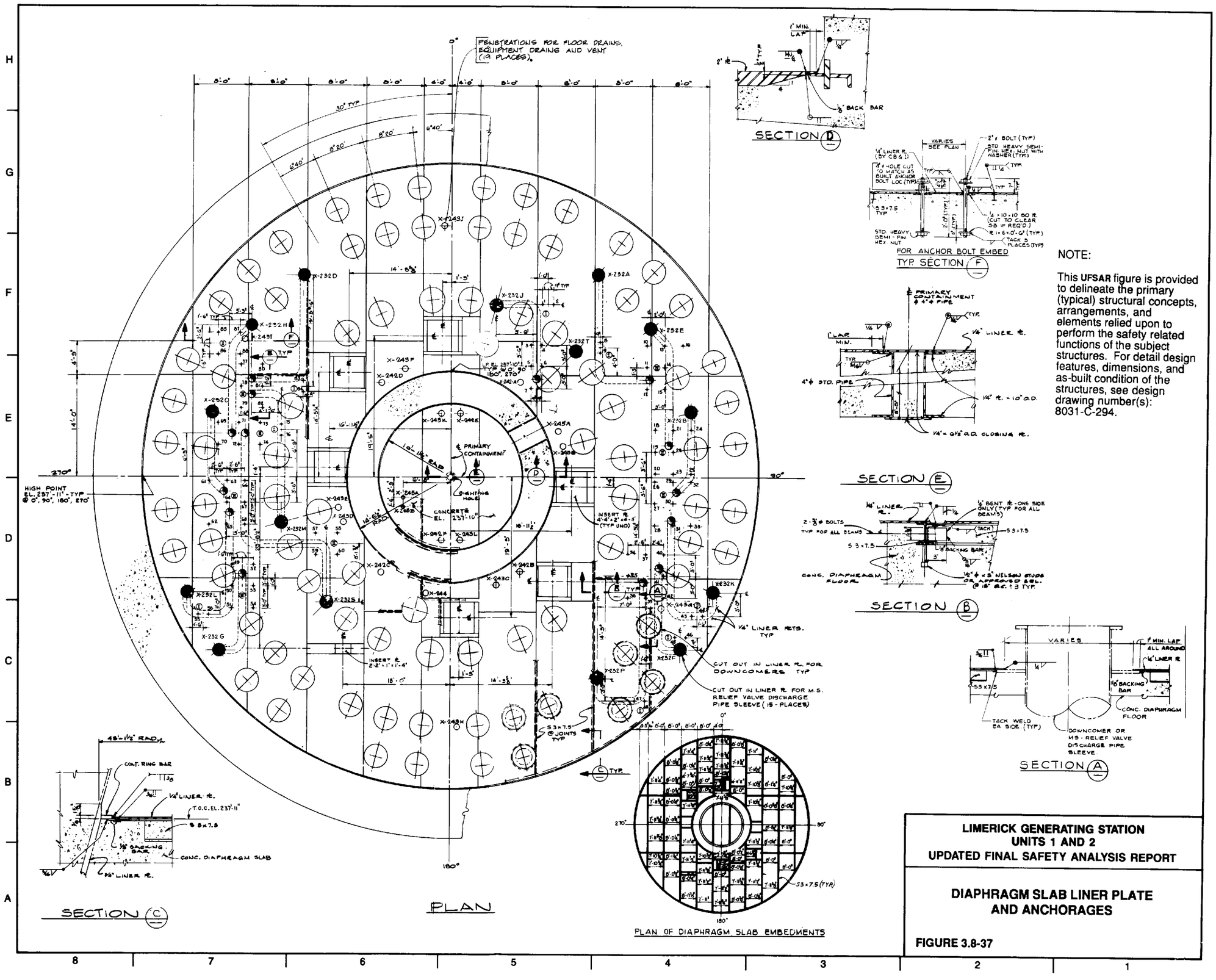
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-261.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DIAPHRAGM SLAB REINFORCEMENT
(SHEET 3 OF 3)

FIGURE 3.8-36



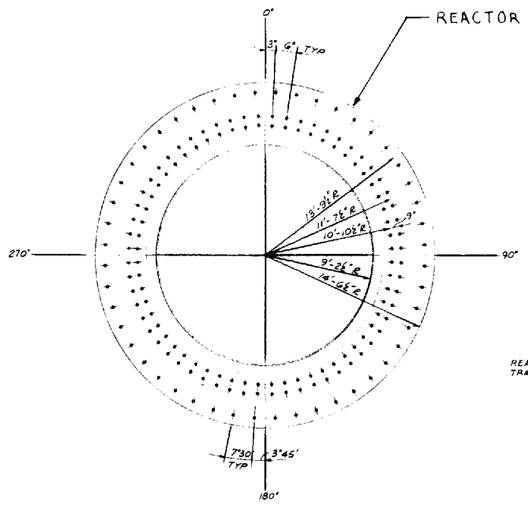
NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-294.

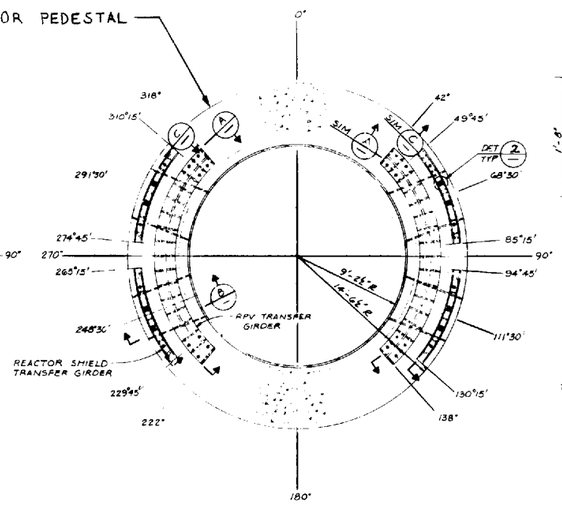
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DIAPHRAGM SLAB LINER PLATE AND ANCHORAGES

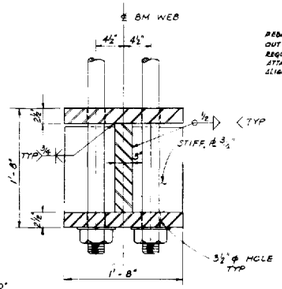
FIGURE 3.8-37



PLAN-ANCHOR BOLT ARRANGEMENT

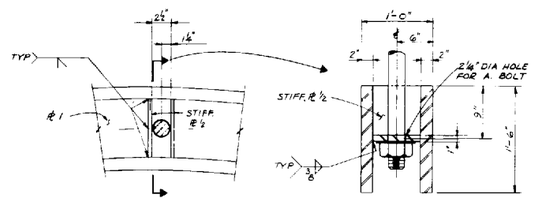


ANCHOR BOLT TRANSFER GIRDERS
PLAN AT EL 263'-6"

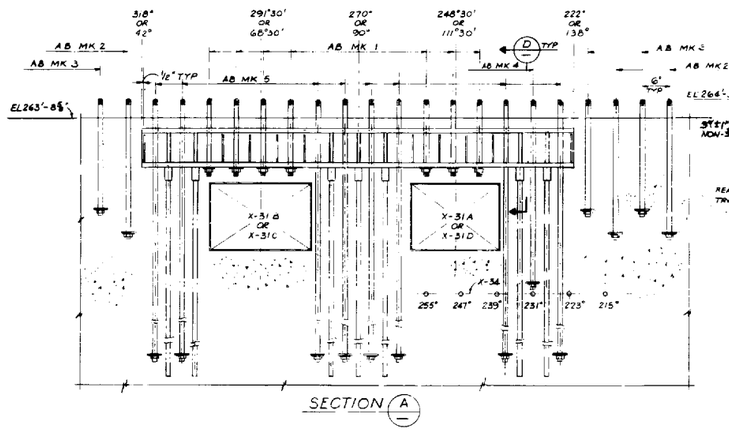


DETAIL (1)

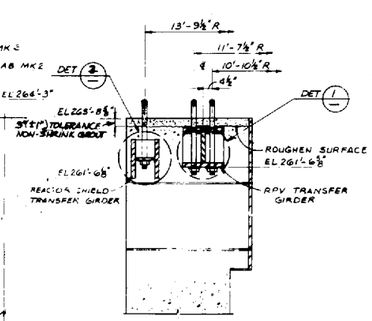
SECTION (E)



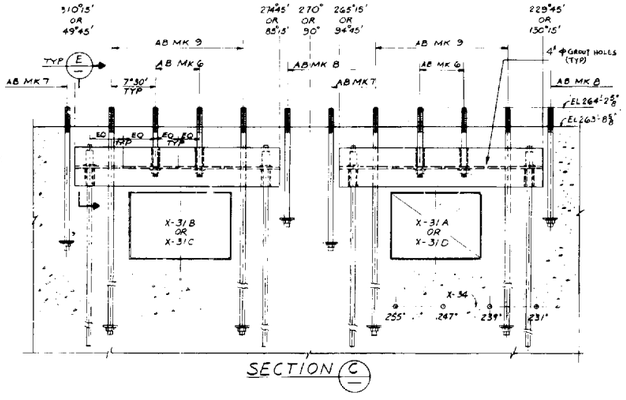
DETAIL (2)



SECTION (A)

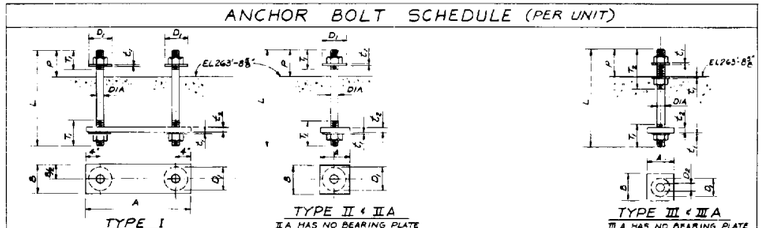


SECTION (B)

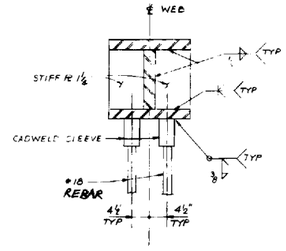


SECTION (C)

ANCHOR BOLT SCHEDULE (PER UNIT)



MARK	NO. OF BOLTS	NO. OF BEARING PLATES	TYPE	BOLT DIA	BOLT L	BOLT P	BOLT T_1	BOLT T_2	BEARING PLATE A	BEARING PLATE B	BEARING PLATE t_2	BEARING PLATE D_2	WASHER * D_1	WASHER * D_2	WASHER * t_1	REMARKS
1	28	—	IIA	2½"	3'-0⅝"	6½"	5"	—	—	—	—	—	6"	—	¾"	RPV ANCHOR BOLTS
2	28	14	I	3½"	6'-4"	6½"	5"	—	17"	5"	2"	—	6"	—	¾"	"
3	28	14	I	3½"	5'-4"	6½"	5"	—	17"	8"	2"	—	6"	—	¾"	"
4	4	3	I	3½"	7'-6"	6½"	5"	—	17"	8"	2"	—	6"	—	¾"	"
5	32	32	II	3½"	13'-6"	6½"	5"	—	7"	7"	2"	—	6"	—	¾"	"
6	8	—	IIA	2"	2'-4"	6"	5"	9"	—	—	—	—	3⅝"	2⅝"	¼"	REACTOR SHIELD ANCHOR BOLTS
7	16	16	III	2"	6'-4"	6"	5"	9"	7"	7"	2"	2⅝"	3⅝"	2⅝"	¼"	"
8	16	16	III	2"	5'-4"	6"	5"	9"	7"	7"	2"	2⅝"	3⅝"	2⅝"	¼"	"
9	6	6	III	2"	12'-6"	6"	5"	9"	7"	7"	2"	2⅝"	3⅝"	2⅝"	¼"	"



SECTION (D)

* FIELD MAY USE OVERSIZE WASHERS AS REQUIRED FOR SLOTTED OR OVERSIZE HOLES.

NOTE:

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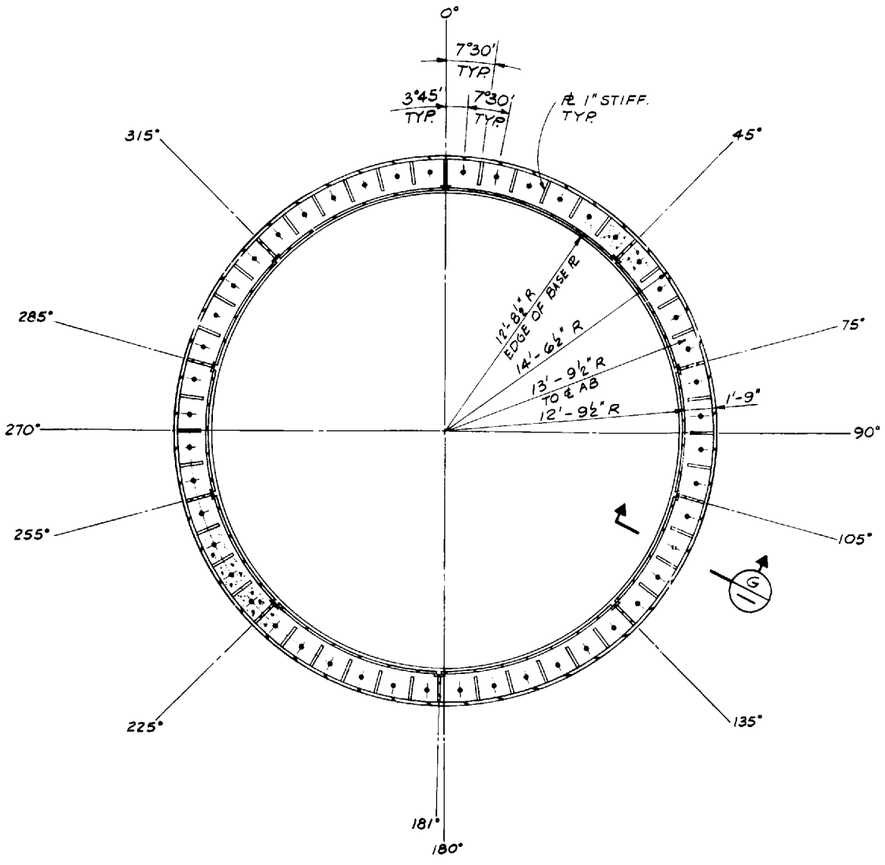
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL AND REACTOR SHIELD WALLBASE CONNECTIONS
(SHEET 1 OF 2)

FIGURE 3.8-38

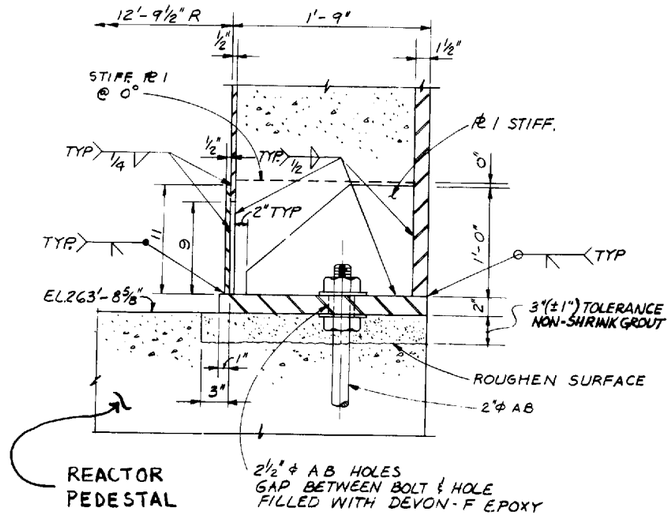
NOTE:

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SECTIONAL PLAN

REACTOR SHIELD WALL BASE

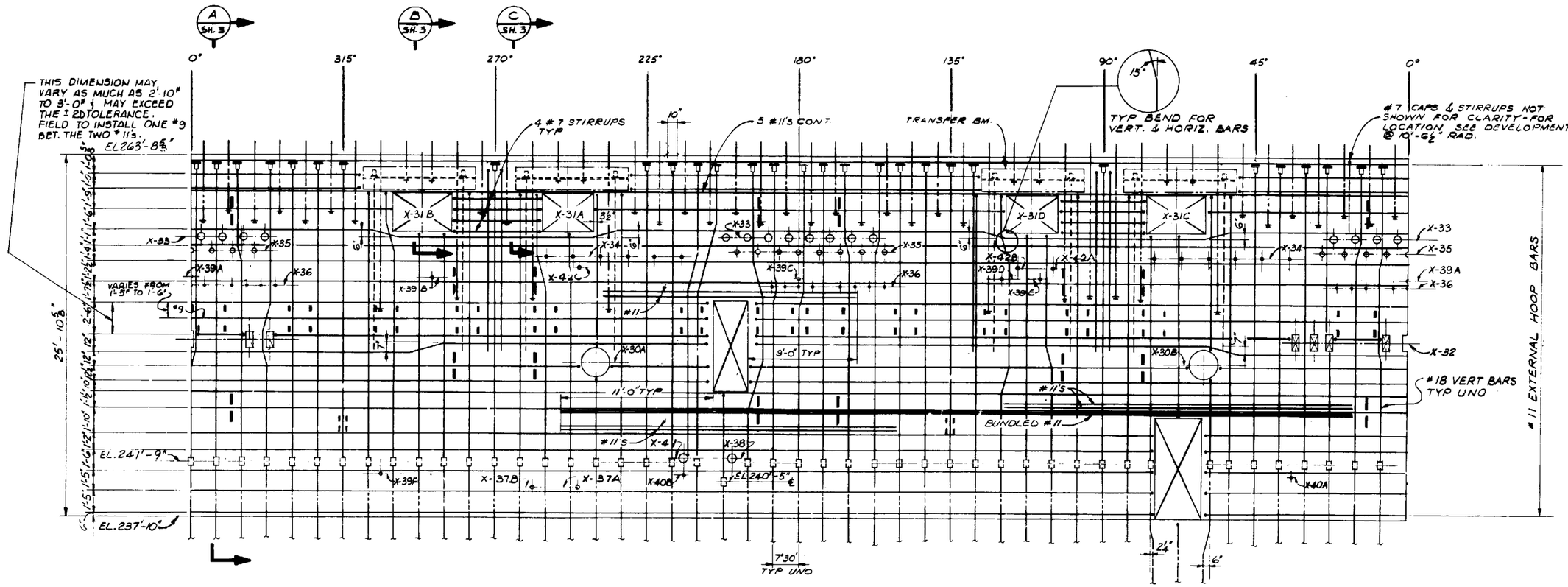


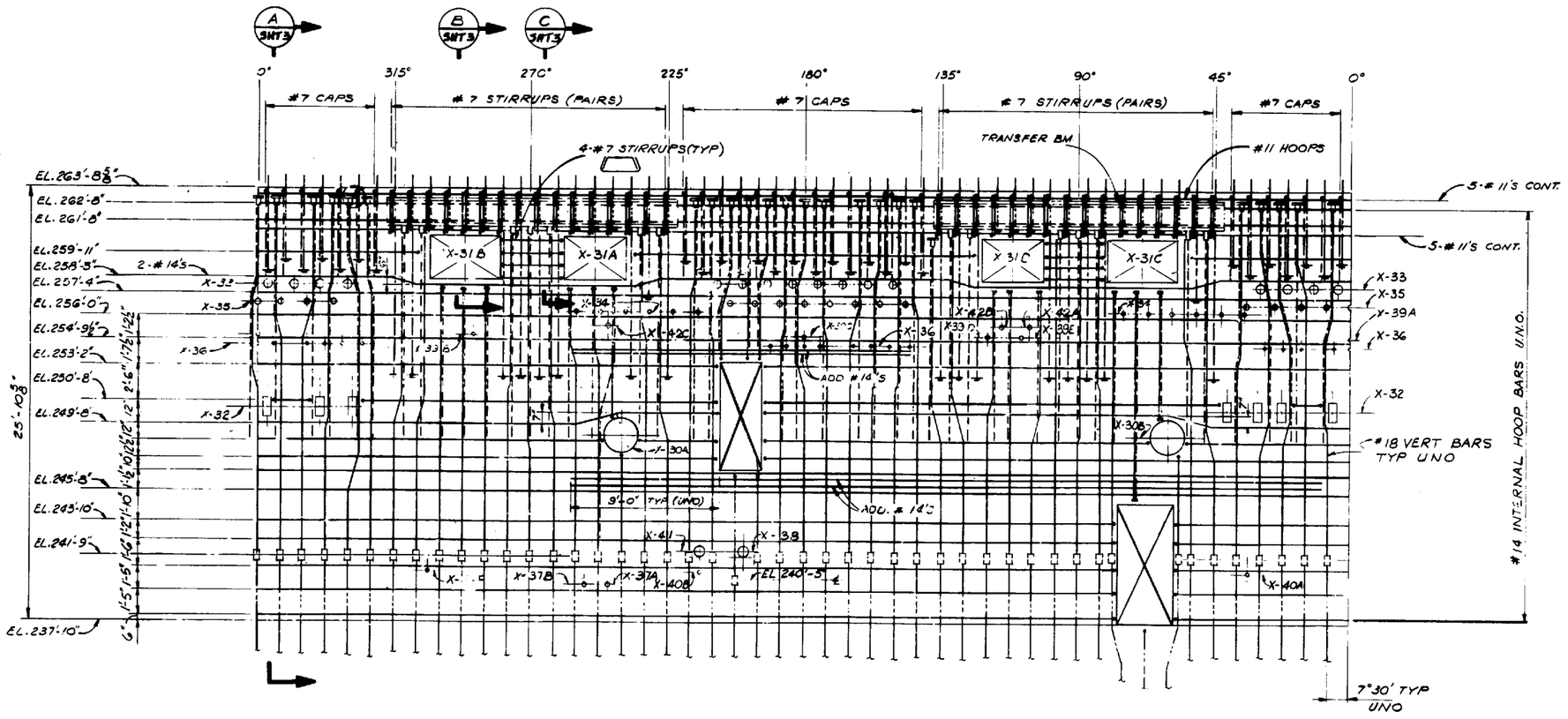
SECTION G

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL AND REACTOR SHIELD WALL BASE CONNECTIONS
(SHEET 2 OF 2)

FIGURE 3.8-38


A SH. 3
B SH. 3
C SH. 3
0°
315°
270°
225°
180°
135°
90°
45°
0°
THIS DIMENSION MAY VARY AS MUCH AS 2'-10" TO 3'-0" & MAY EXCEED THE ± ED TOLERANCE. FIELD TO INSTALL ONE #9 BET. THE TWO #11s.
EL 263'-8½"
4 #7 STIRRUPS TYP
10"
5 #11's CONT.
TRANSFER BM.
TYP BEND FOR VERT. & HORIZ. BARS
15°
#7 CAPS & STIRRUPS NOT SHOWN FOR CLARITY - FOR LOCATION SEE DEVELOPMENT @ 10'-6½" RAD.
#11 EXTERNAL HOOP BARS
#18 VERT BARS TYP UNO
X-31B
X-31A
X-31D
X-31C
X-33
X-35
X-39A
X-36
X-34
X-32
X-30A
X-30B
X-42C
X-42B
X-42A
X-39C
X-39D
X-39E
X-39B
#11
#11S
BUNDLED #11
9'-0" TYP
11'-0" TYP
X-41
X-38
X-39F
X-37B
X-37A
X-40B
X-40A
EL 241'-9"
EL 240'-5"
EL 237'-10"
25'-10⅜"
VARIES FROM 1'-5" TO 1'-6"
#9
7'-0"
2'-6"
1'-5"
1'-6"
1'-10"
1'-6"
1'-10½"
1'-6"
1'-9"
1'-6"
1'-9"
1'-6"
1'-9



PEDESTAL DEVELOPMENT AT 10'-6½"R

(INTERNAL REINFORCEMENT)

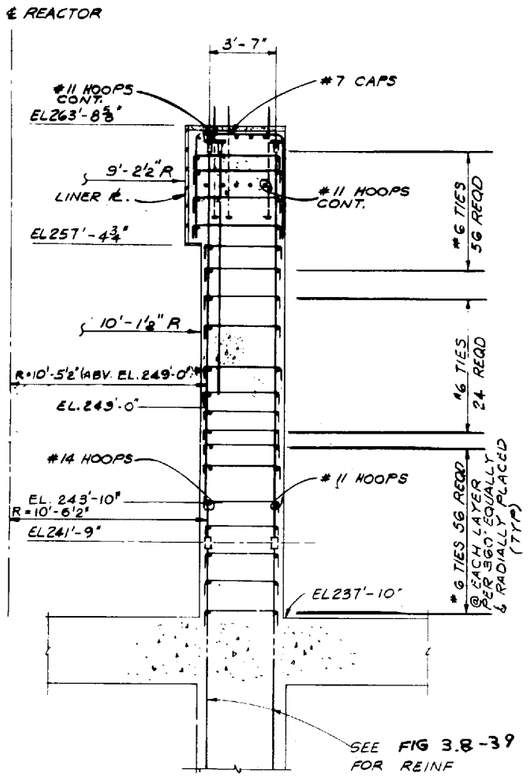
NOTE:

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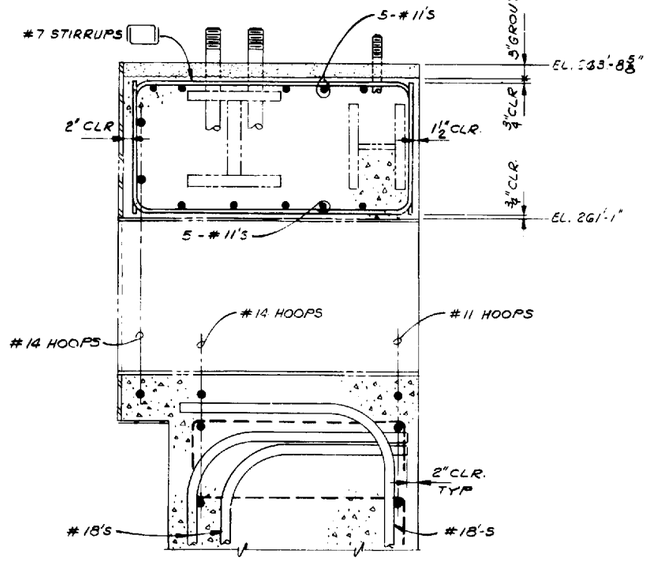
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR PEDESTAL REINFORCEMENT ABOVE DIAPHRAGM SLAB
(SHEET 2 OF 3)

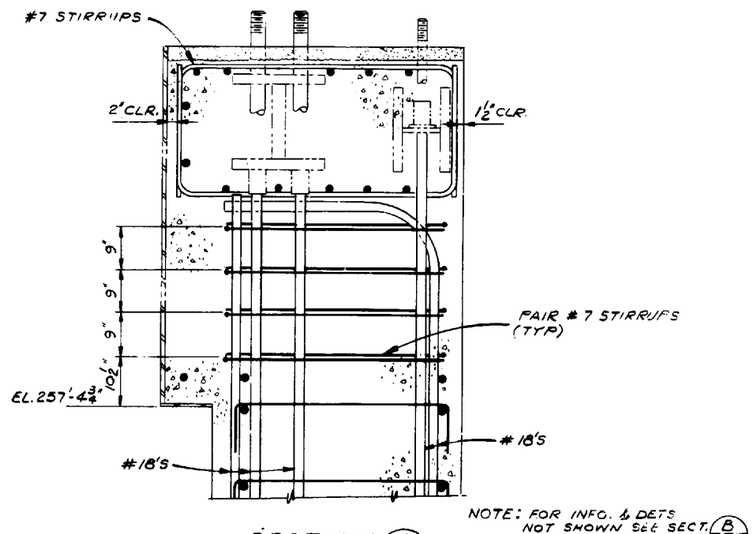
FIGURE 3.8-39



SECTION A (SHT 1, 2)



SECTION B (SHT 1, 2)



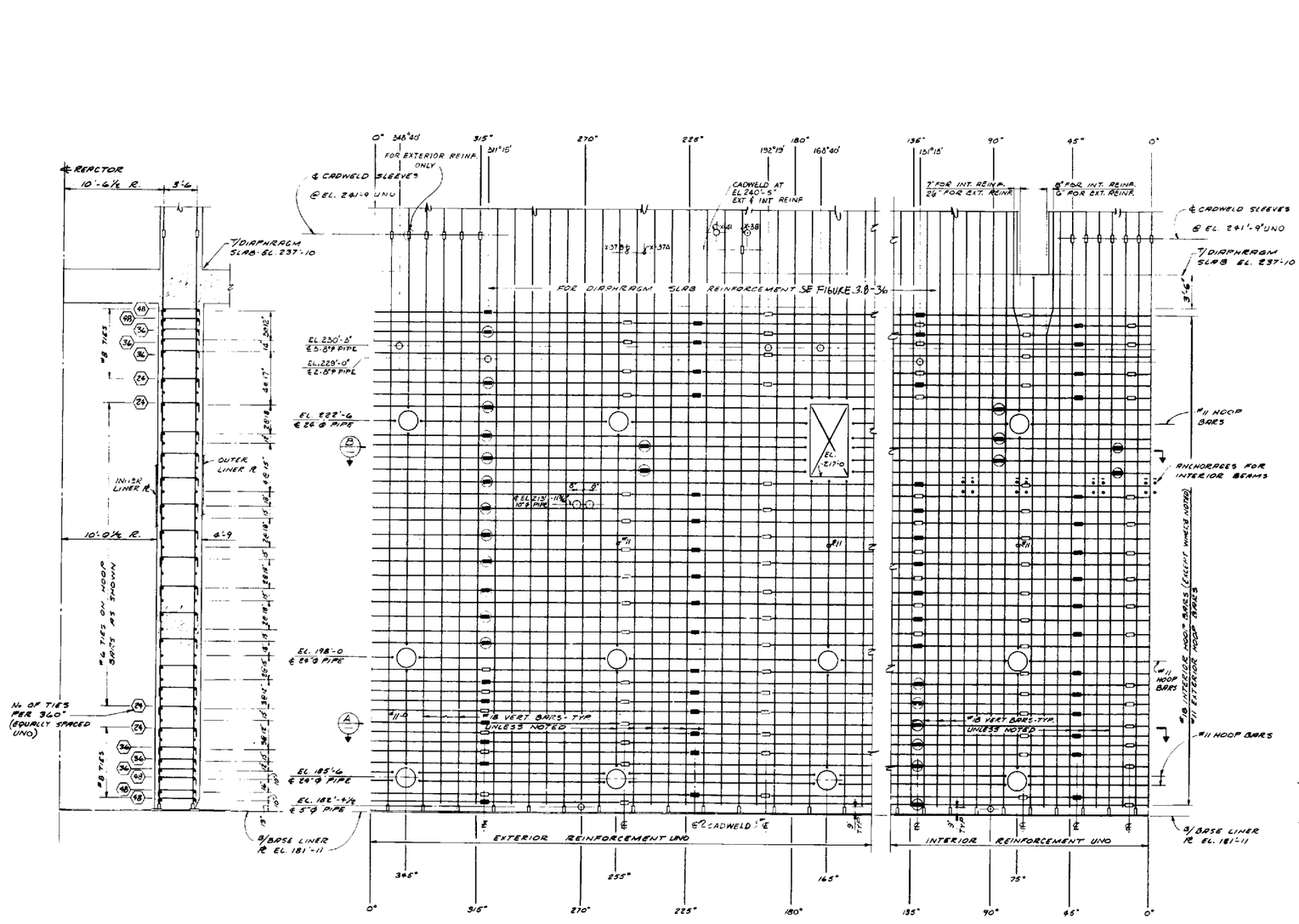
SECTION C (SHT 1, 2)

NOTE:

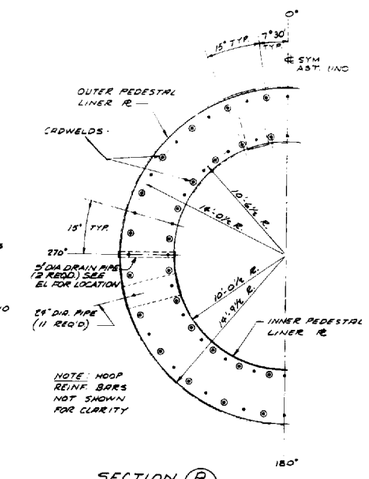
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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR PEDESTAL REINFORCEMENT ABOVE DIAPHRAGM SLAB
(SHEET 3 OF 3)
FIGURE 3.8-39

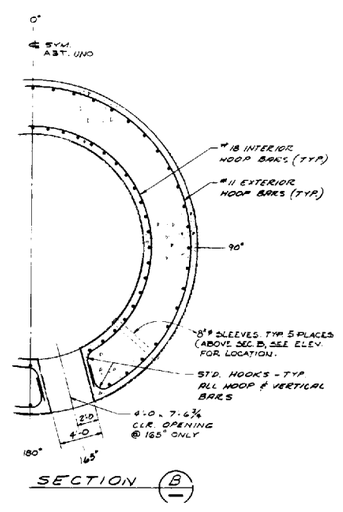


FLAT DEVELOPMENT OF R.P.V. PEDESTAL REINFORCEMENT



NOTE: HOOP REINF. BARS NOT SHOWN FOR CLARITY

SECTION (A)



SECTION (B)

LEGEND:

- DENOTES CADWELD-EXTERIOR REINF.
- DENOTES CADWELD-INTERIOR REINF.
- DENOTES CADWELD-INT. & EXT. REINF.

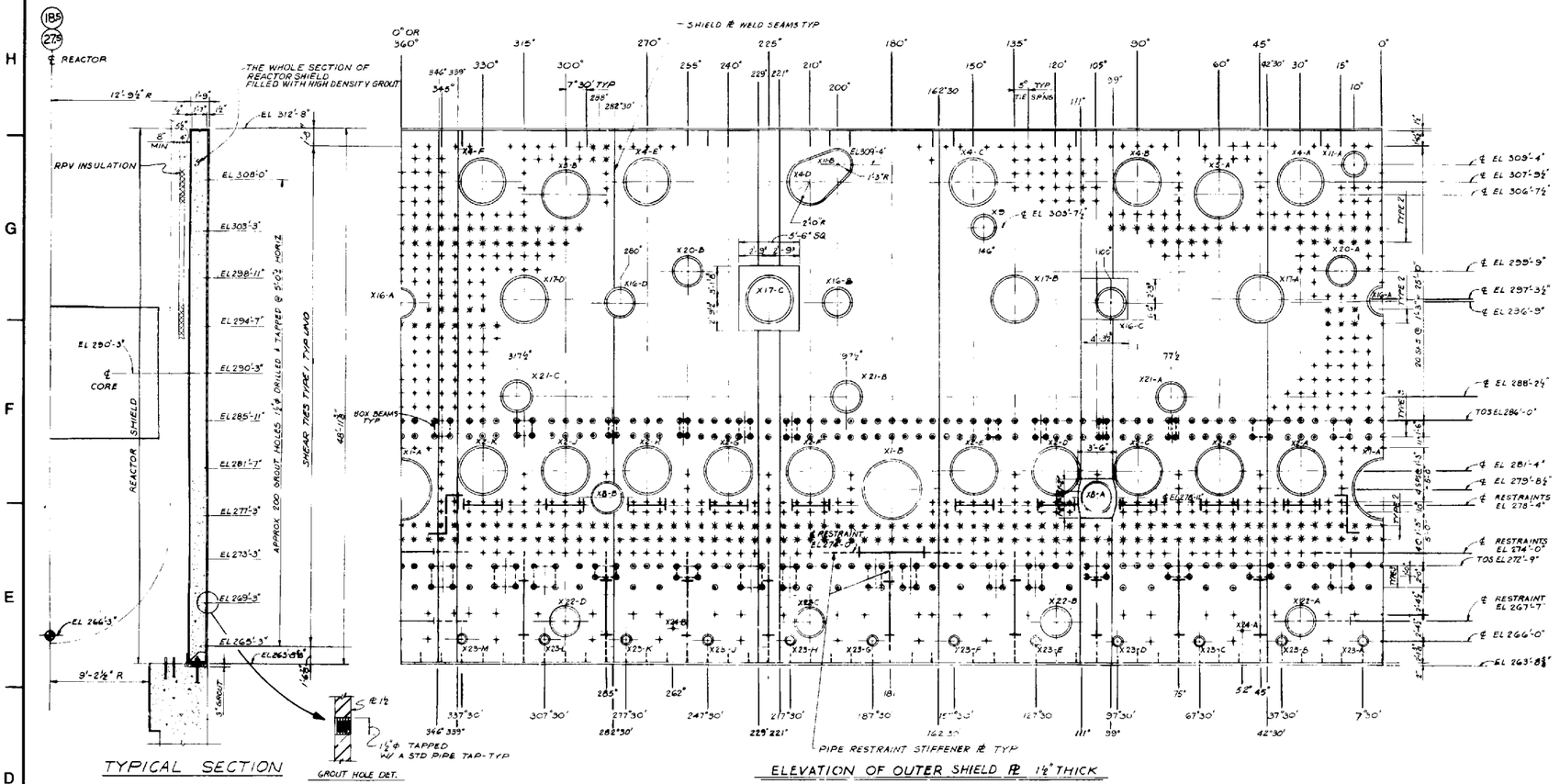
NOTE:

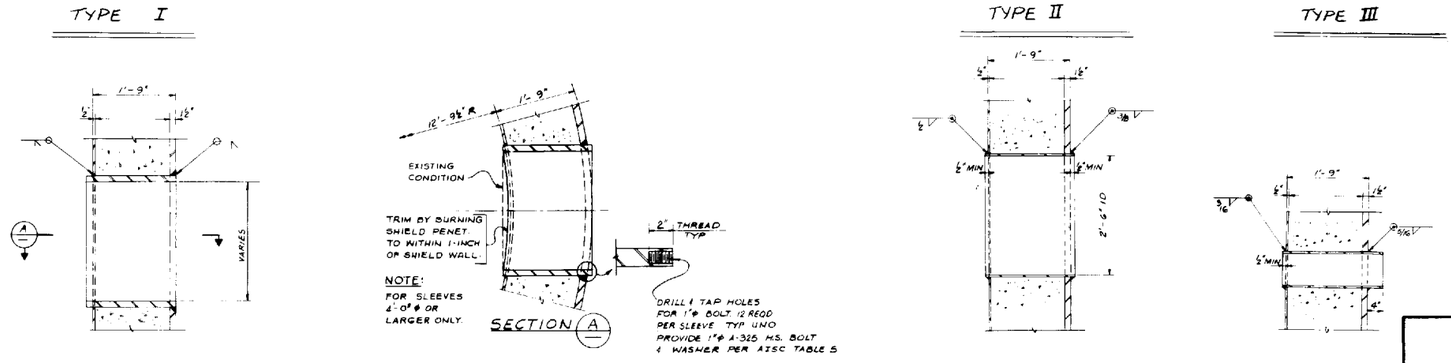
This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-256.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR PEDESTAL REINFORCEMENT BELOW DIAPHRAM SLAB

FIGURE 3.8-40





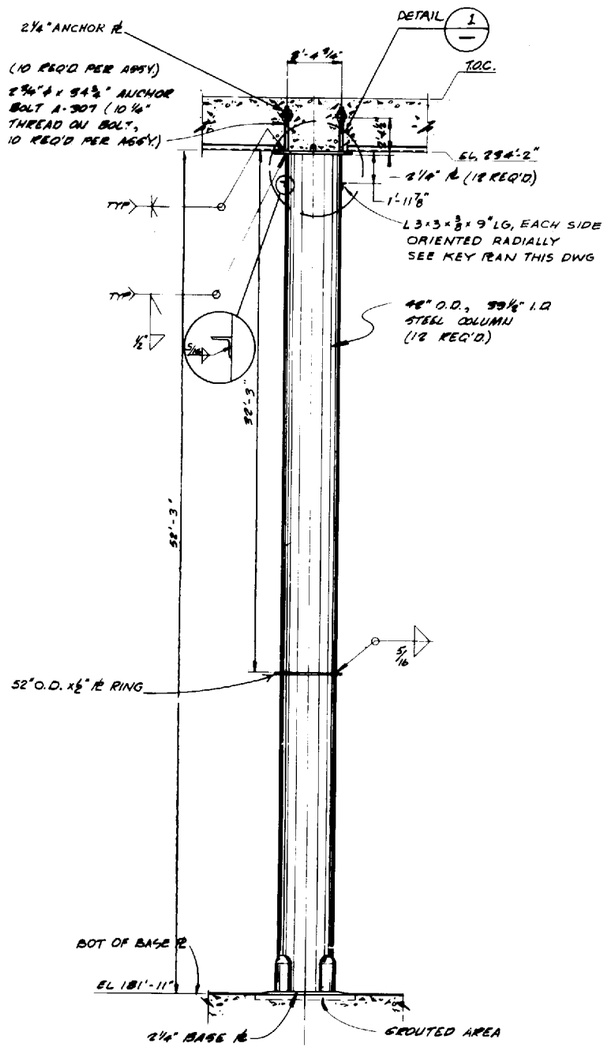
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-950.

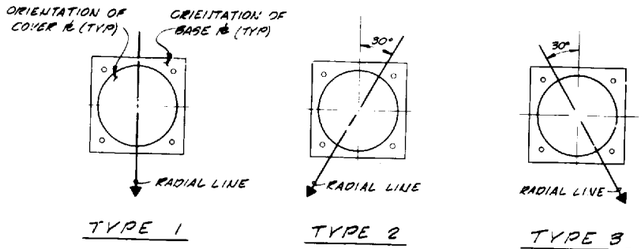
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR SHIELD WALL

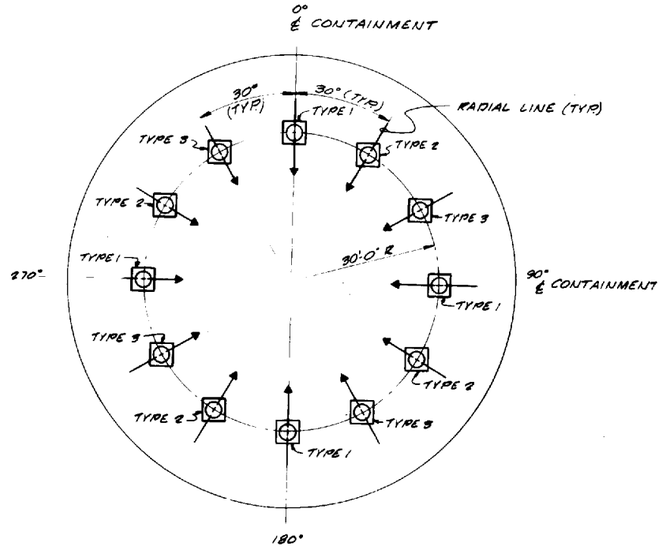
FIGURE 3.8-41



ELEVATION



TOP ℄ ORIENTATION
(4 REQUIRED EACH TYPE)



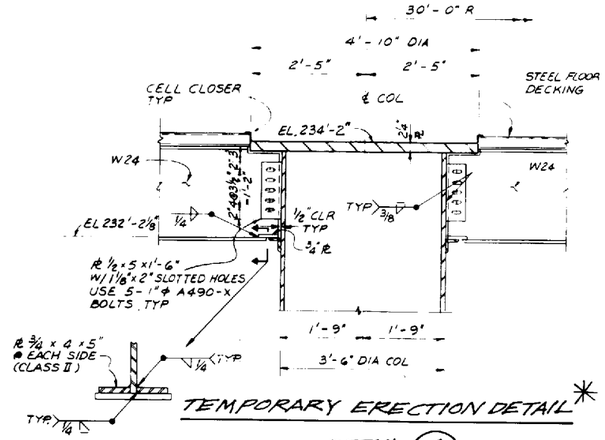
KEY PLAN

RELATION BETWEEN BASE PLATE □ AND TOP PLATE ⊖ OF SET COLUMNS ENCLOSED BY THIS AREA

NOTE: SEE FIGURE 3.8-14 FOR COLUMN CONNECTION DETAILS TO THE FOUNDATION SLAB.

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-297 and -300.



TEMPORARY ERECTION DETAIL*

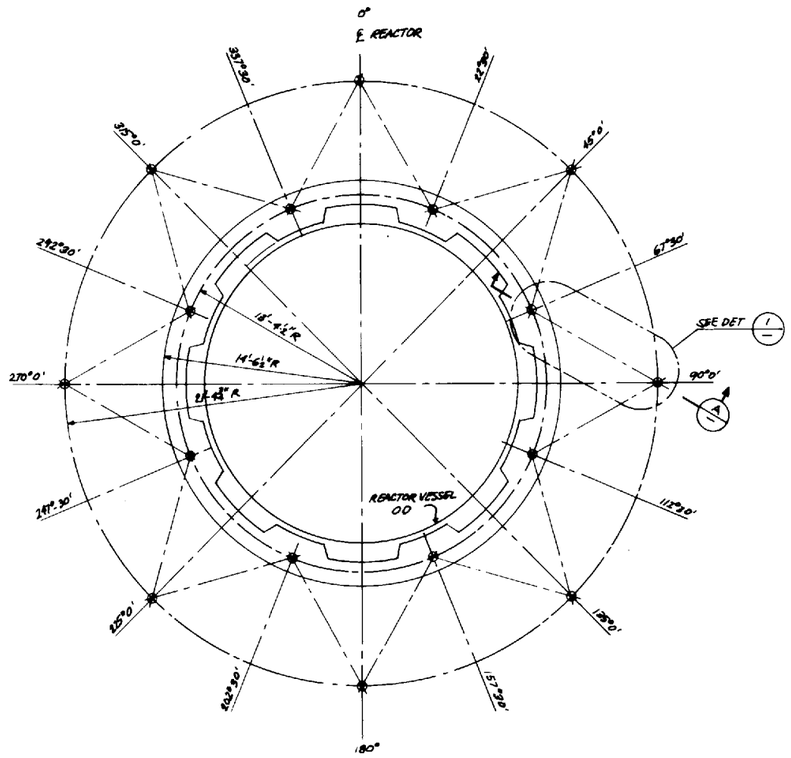
DETAIL 1

*ALL RADIAL GIRDERS SHALL BE DISCONNECTED FROM THE COLUMNS AFTER SLAB CONCRETE HAS ATTAINED STRENGTH OF AT LEAST 3000 PSI BUT PRIOR TO CONTAINMENT PRESSURE TEST.

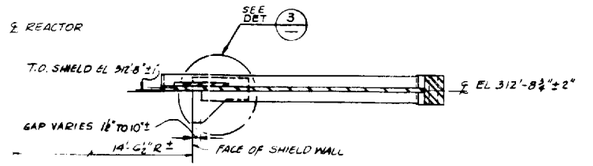
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION CHAMBER COLUMNS

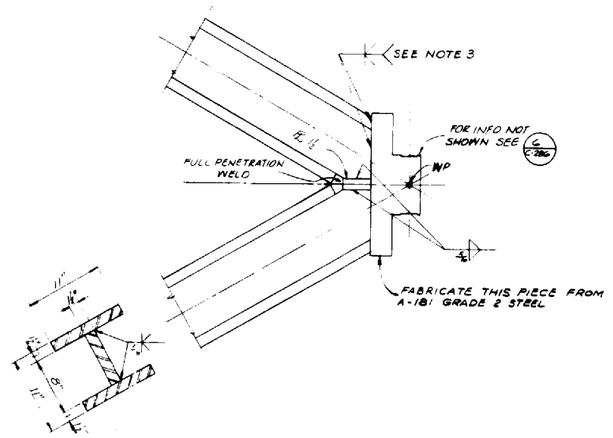
FIGURE 3.8-42



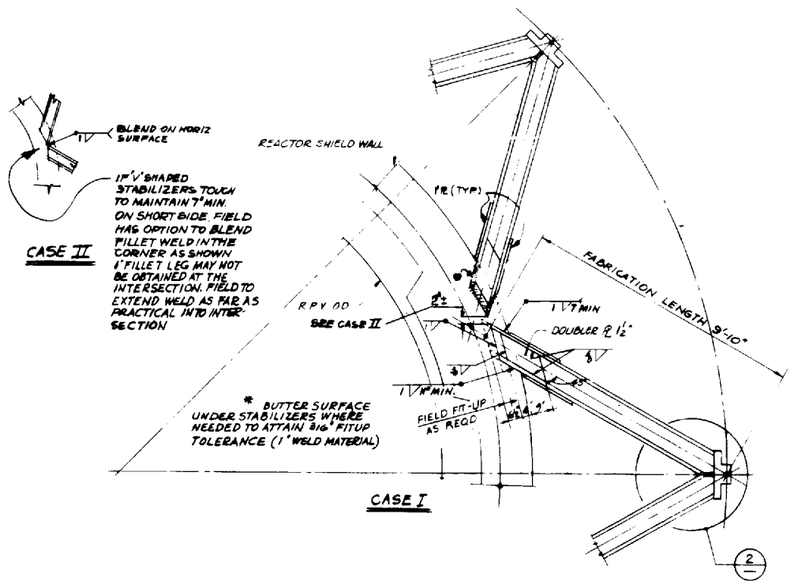
PLAN AT ELEVATION 312'-8"



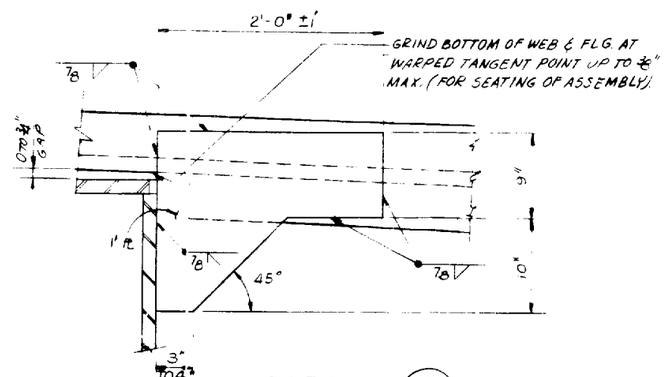
SECTION A



DETAIL 2



DETAIL 1



DETAIL 3

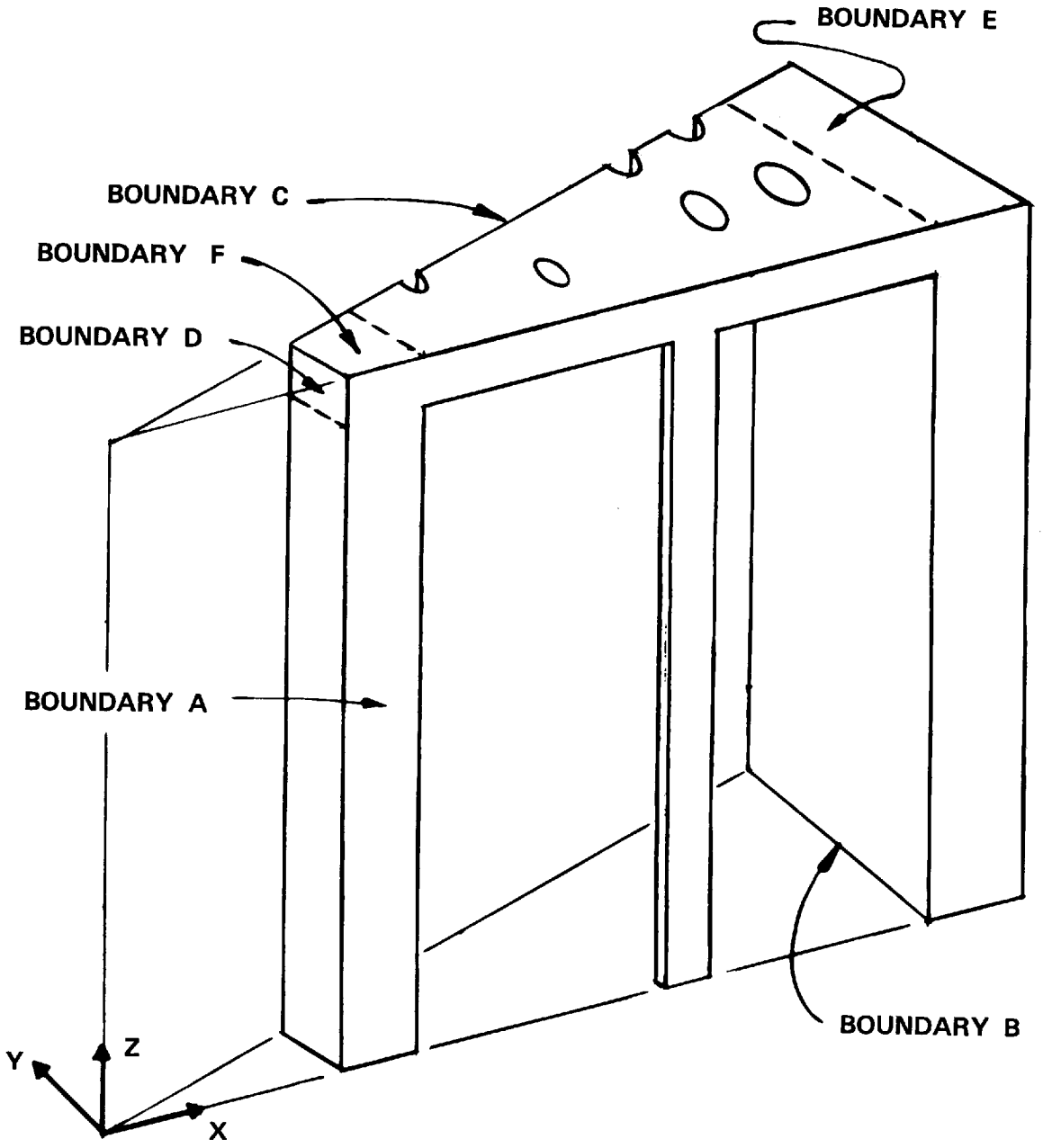
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-936.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SEISMIC TRUSS

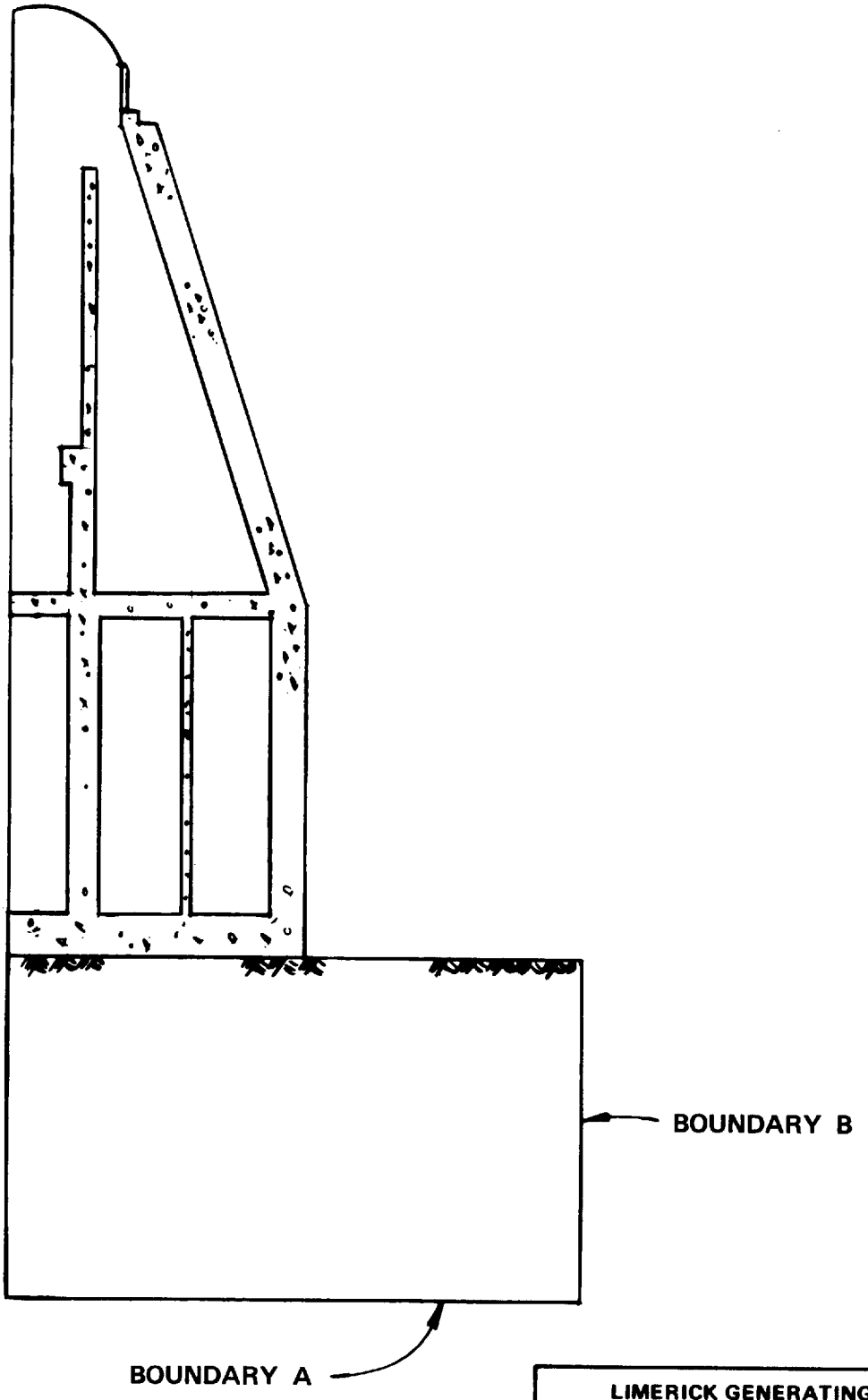
FIGURE 3.8-43



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DIAPHRAGM SLAB ANALYTICAL MODEL

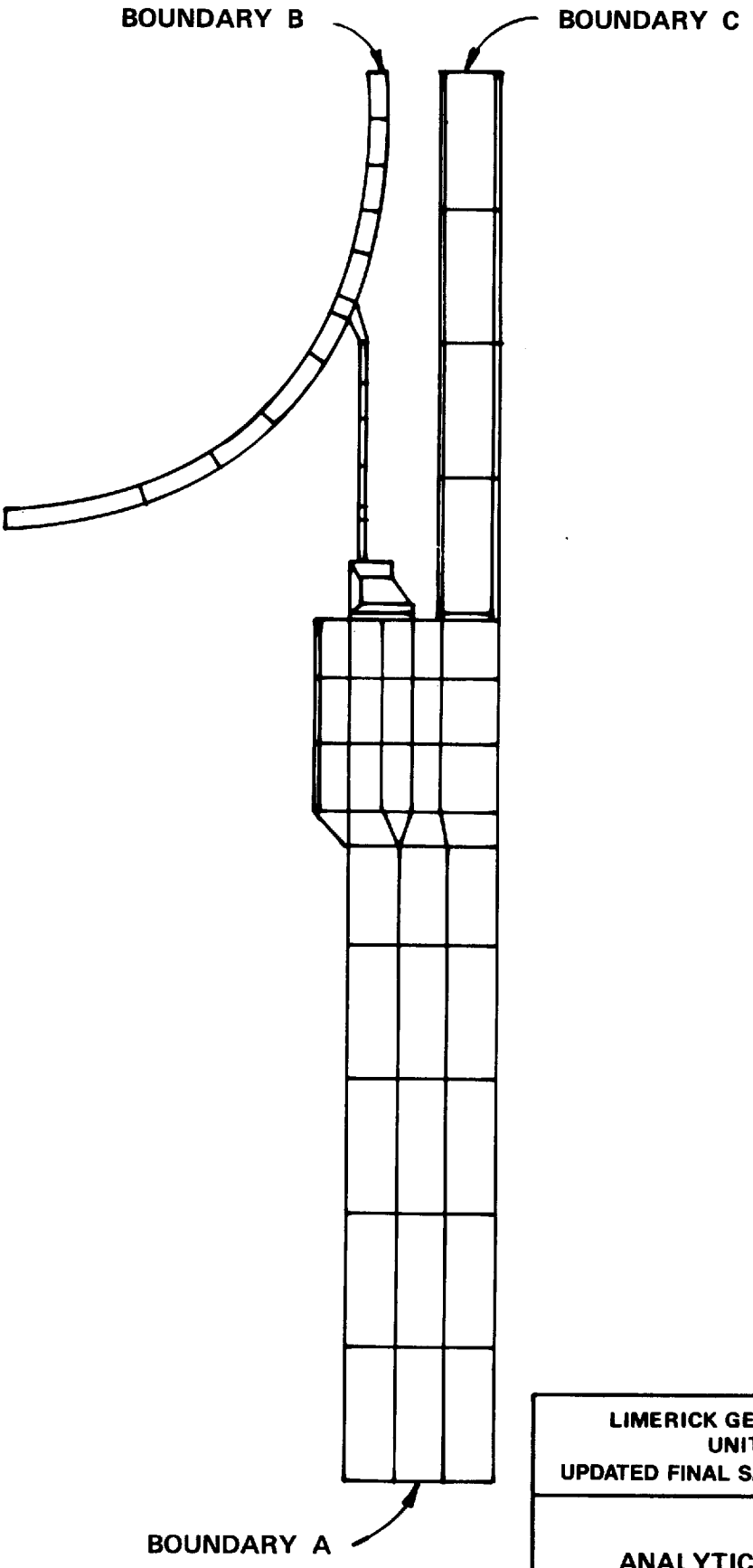
FIGURE 3.8-44



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

ANALYTICAL MODEL FOR
SUPPRESSION CHAMBER COLUMNS
AND
LOWER REACTOR PEDESTAL

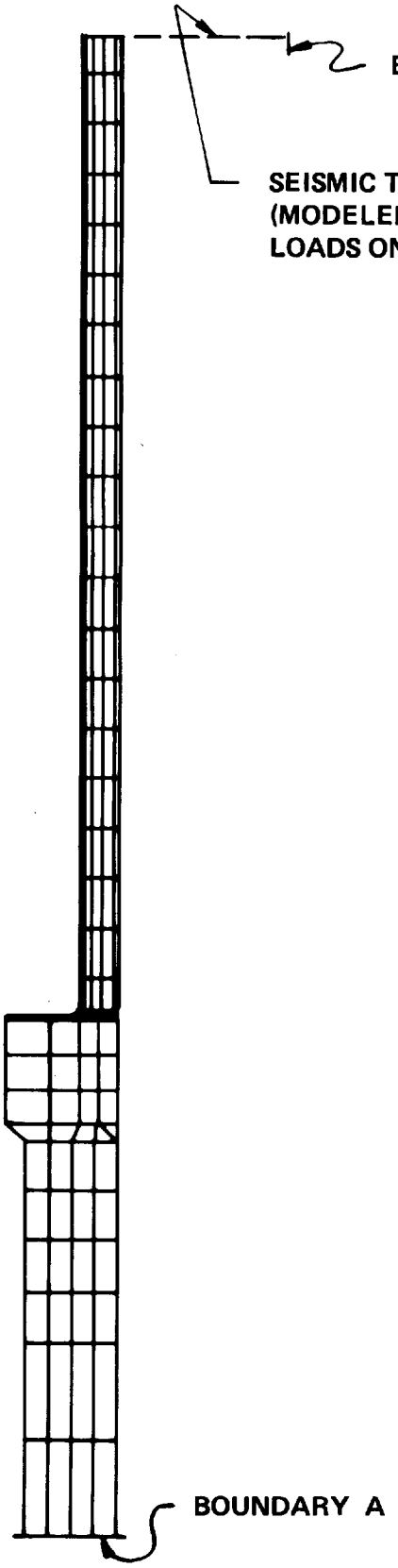
FIGURE 3.8-45



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

ANALYTICAL MODEL FOR
UPPER REACTOR PEDESTAL

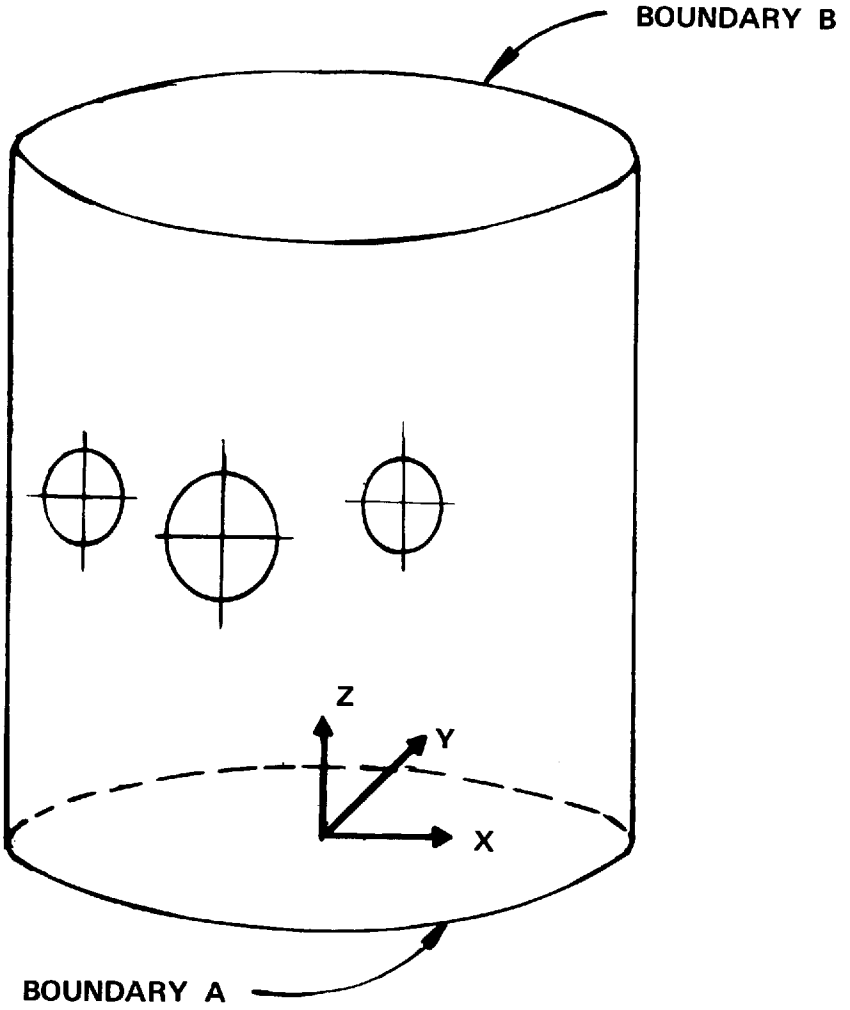
FIGURE 3.8-46



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR SHIELD WALL ANALYTICAL MODEL FOR "FINEL" AND "ASHSD" PROGRAMS

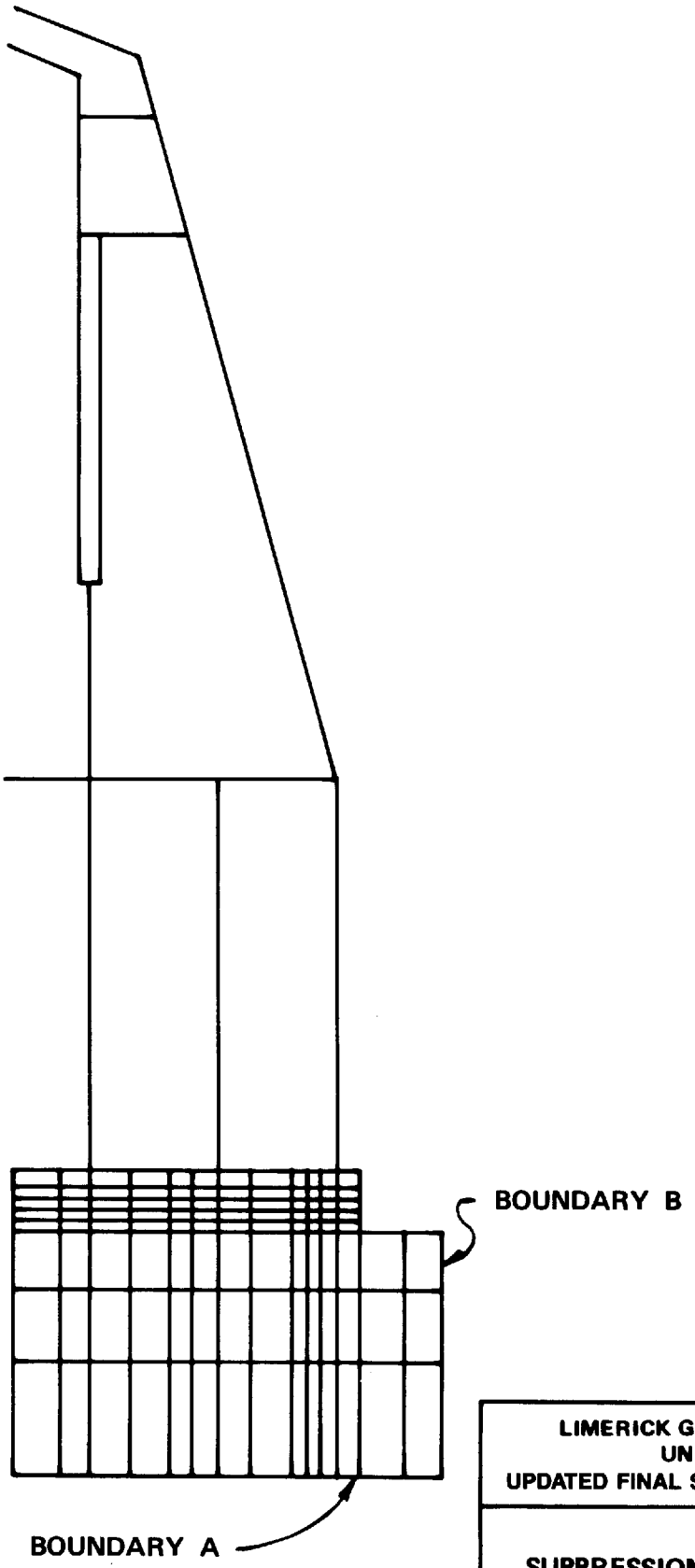
FIGURE 3.8-47



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR SHIELD WALL
ANALYTICAL MODEL FOR
"EASE" PROGRAM

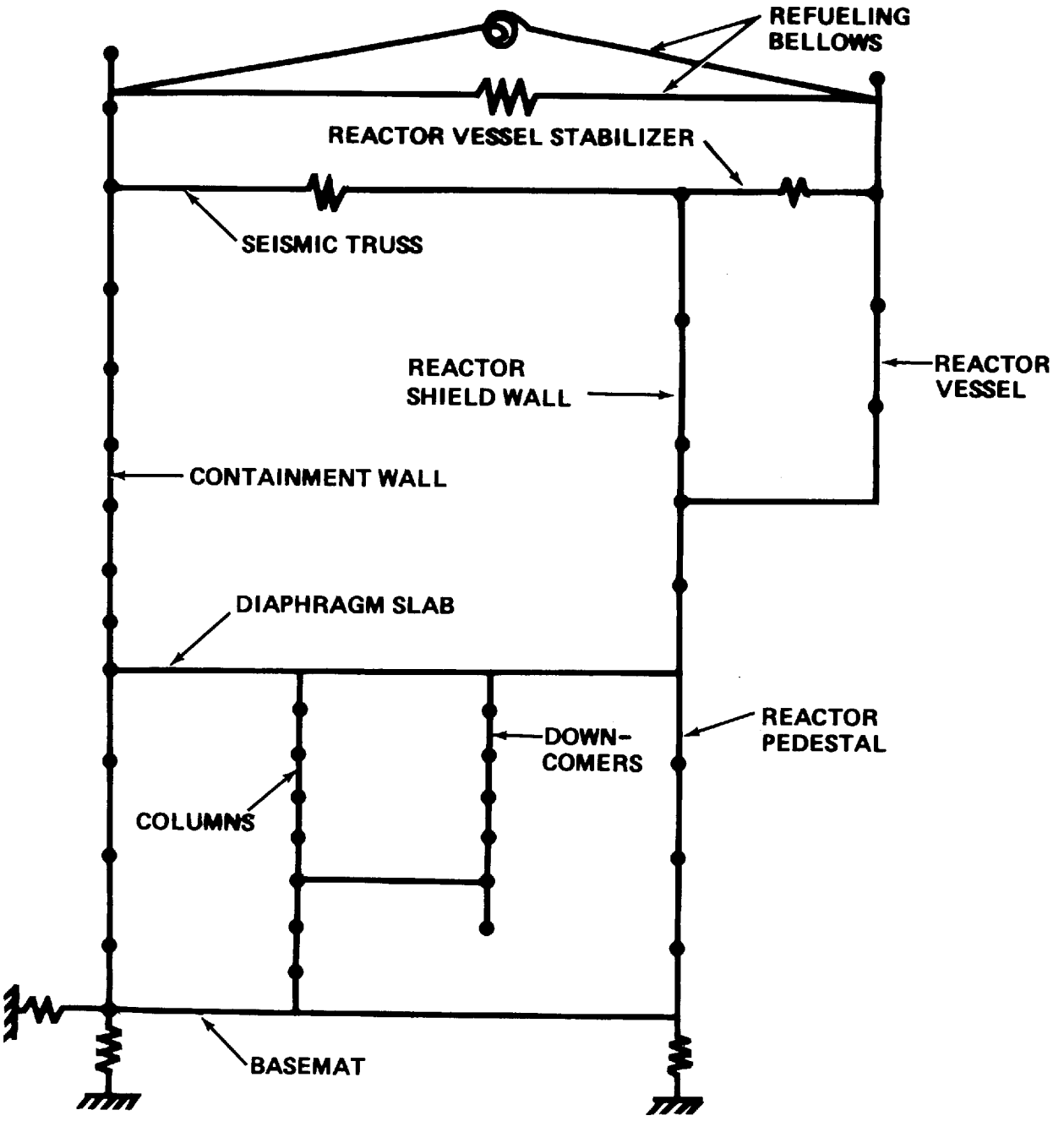
FIGURE 3.8-48



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION CHAMBER COLUMN
ANALYTICAL MODEL FOR
"ASHSD" PROGRAM

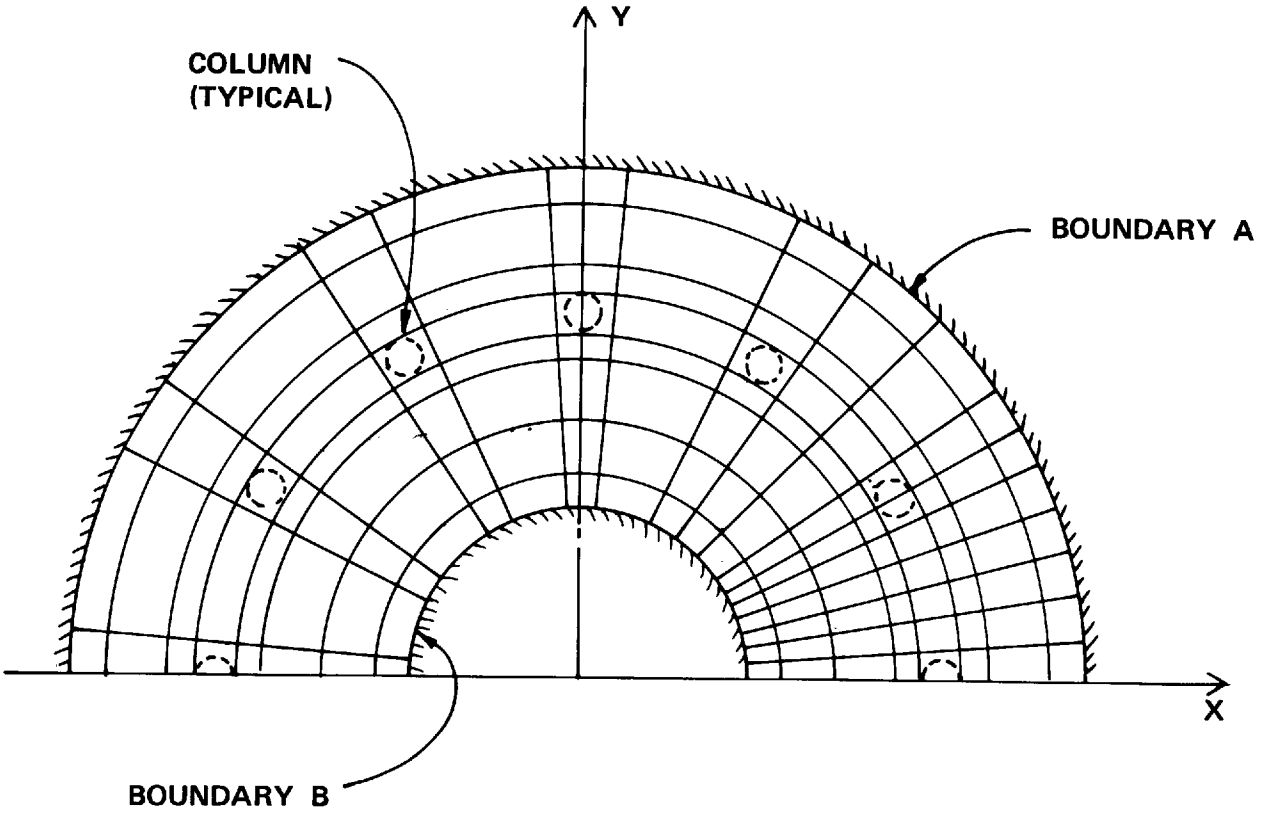
FIGURE 3.8-49



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION CHAMBER COLUMN SEISMIC MODEL

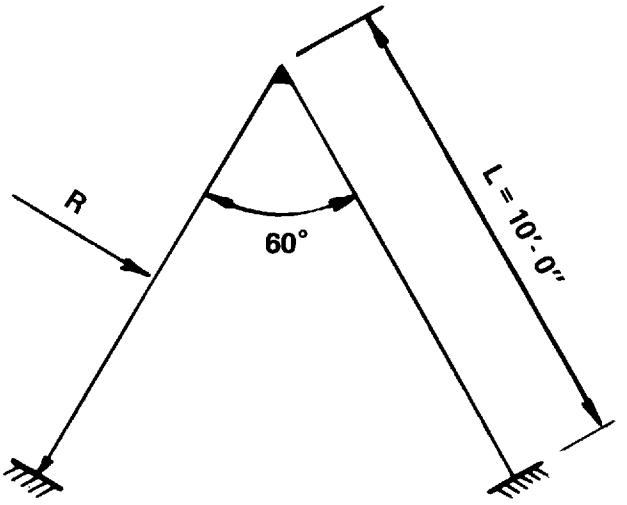
FIGURE 3.8-50



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION CHAMBER COLUMN
ANALYTICAL MODEL FOR
"CE668" PROGRAM

FIGURE 3.8-51

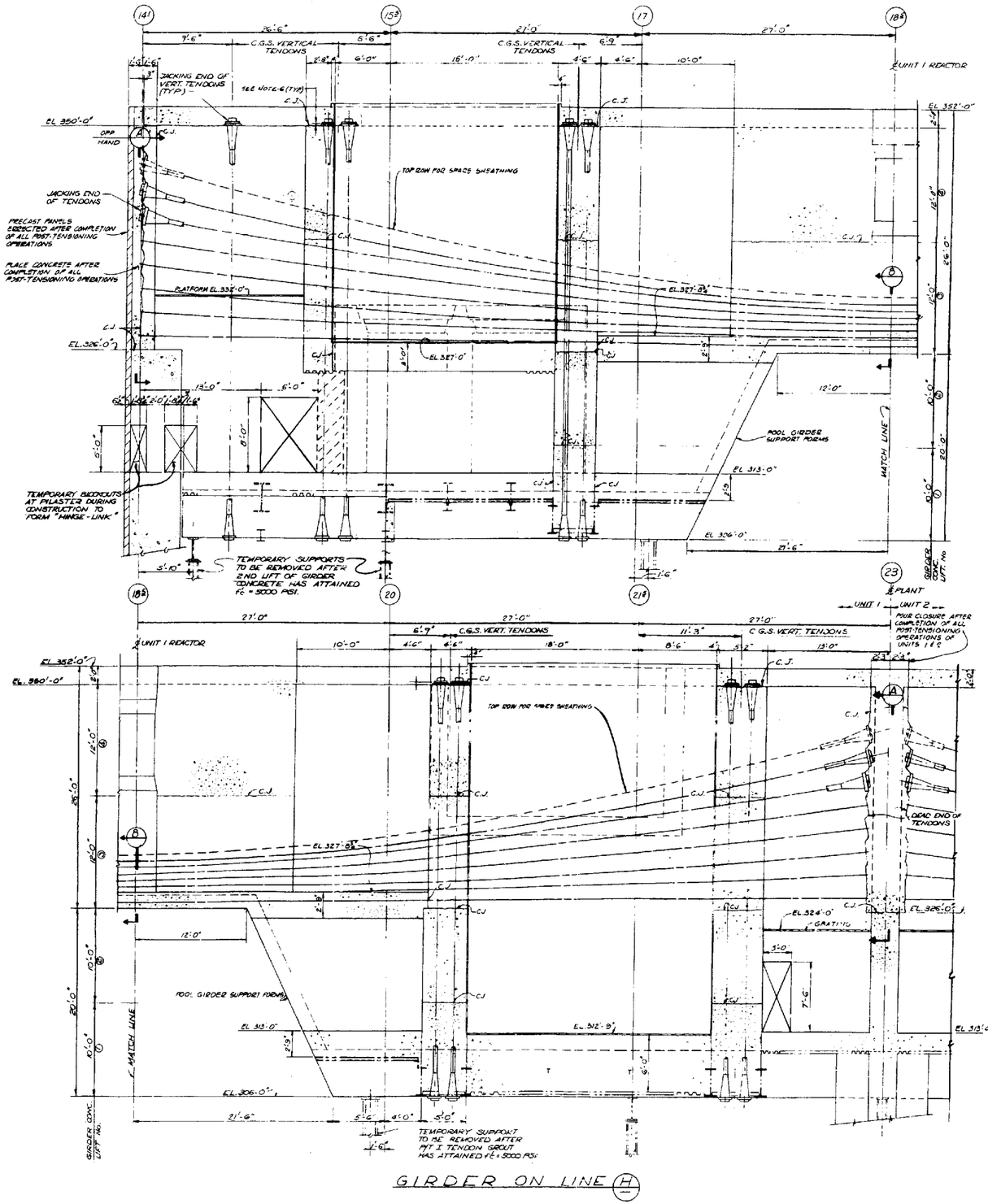


R = PIPE RUPTURE LOAD

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

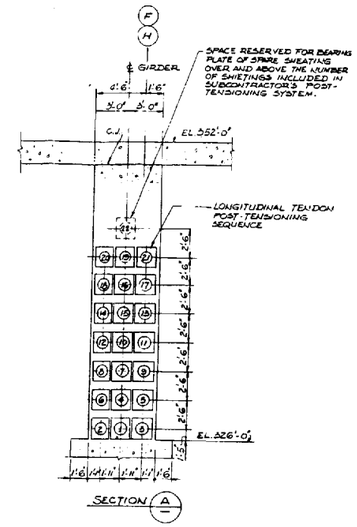
SEISMIC TRUSS ANALYTICAL MODEL FOR "STRESS" PROGRAM

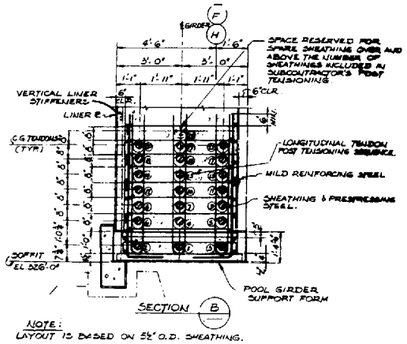
FIGURE 3.8-52



NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-771 and 8031-C-772 .

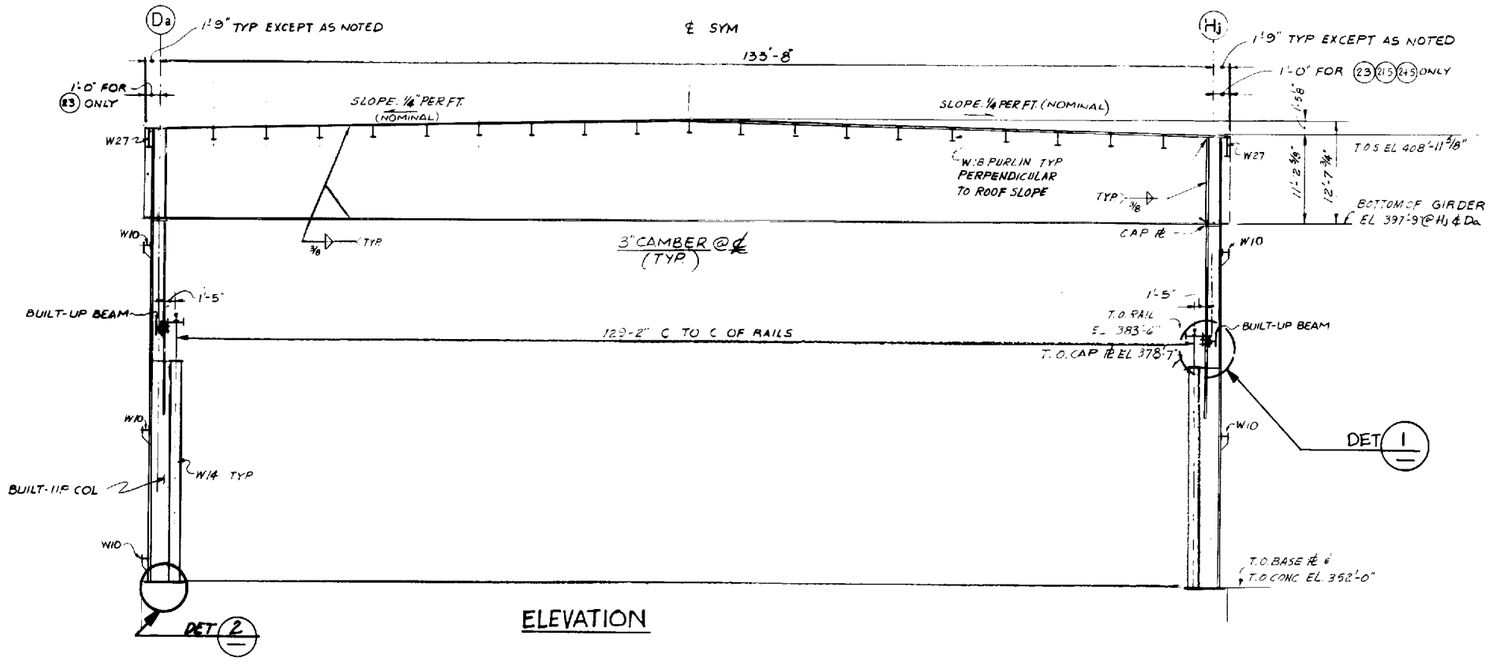




LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE, FUEL POOL GIRDER

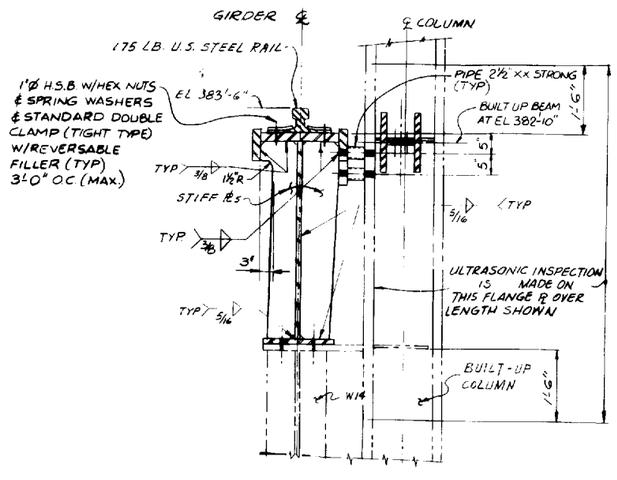
FIGURE 3.8-53 Rev. 11 9/02



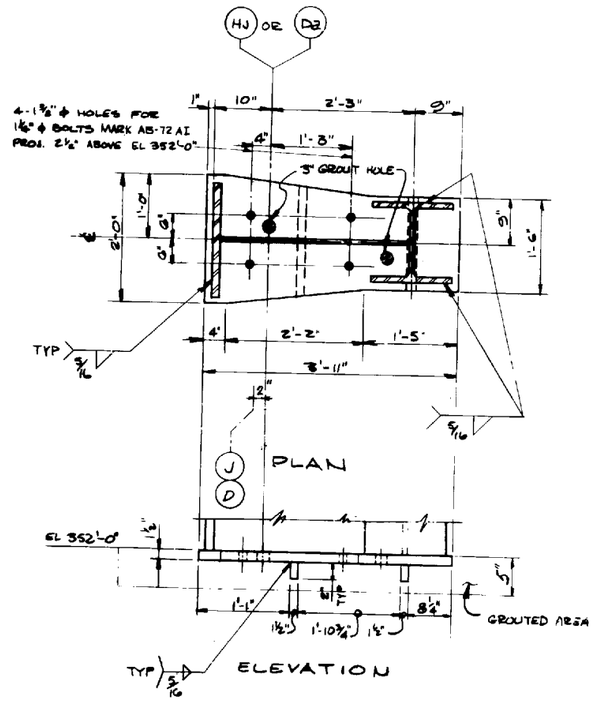
ELEVATION

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-192, -216 , and -223.



DETAIL 1

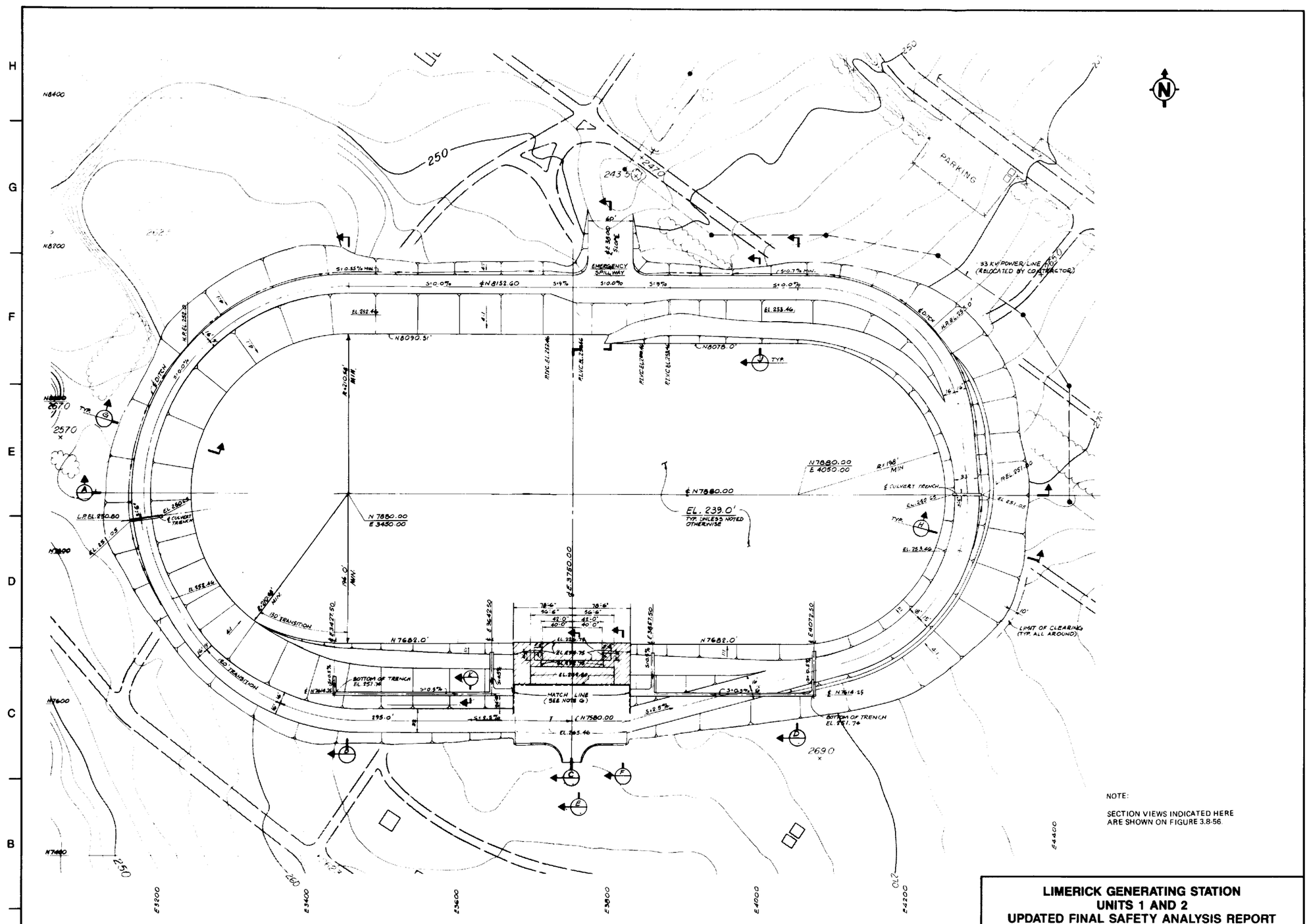


DETAIL 2

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE UPPER FRAME AND CRANE RUNWAY DETAILS

FIGURE 3.8-54



NOTE:

SECTION VIEWS INDICATED HERE ARE SHOWN ON FIGURE 3.8-56.

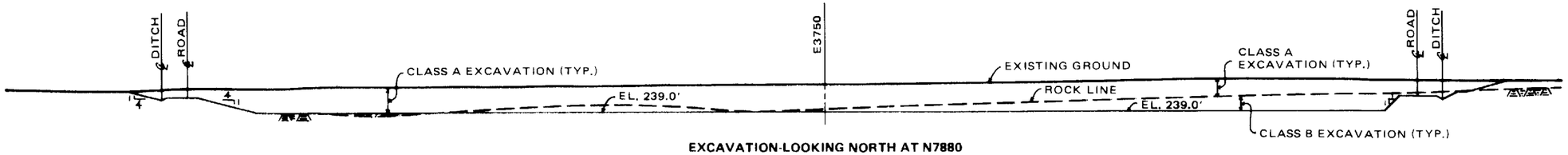
NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-1102.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

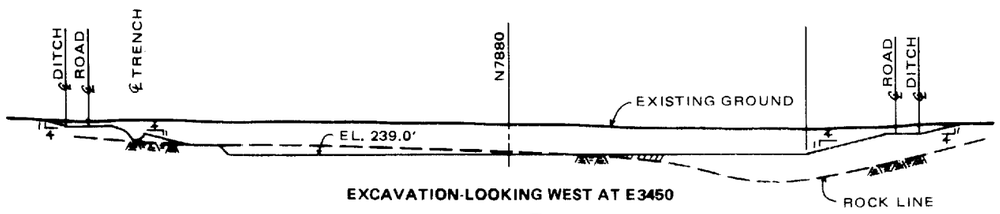
SPRAY POND EXCAVATION
PLAN VIEW

FIGURE 3.8-55



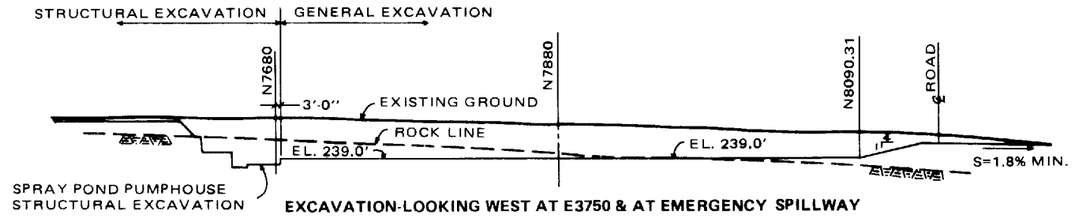
EXCAVATION-LOOKING NORTH AT N7880

SECTION (A)



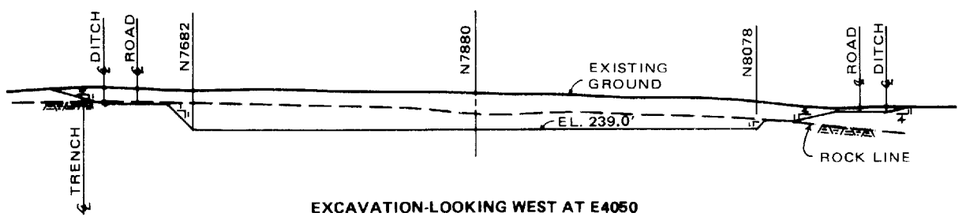
EXCAVATION-LOOKING WEST AT E3450

SECTION (B)



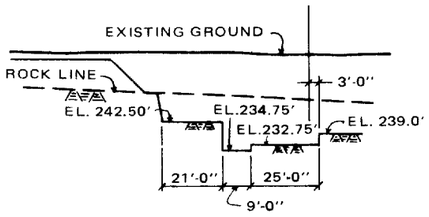
EXCAVATION-LOOKING WEST AT E3750 & AT EMERGENCY SPILLWAY

SECTION (C)



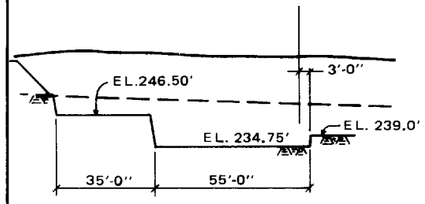
EXCAVATION-LOOKING WEST AT E4050

SECTION (D)



STRUCTURAL EXCAVATION

SECTION (E)



STRUCTURAL EXCAVATION

SECTION (F)

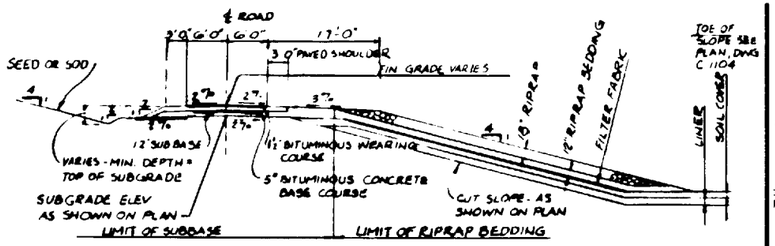
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-1103.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

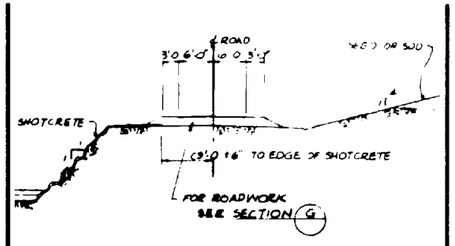
SPRAY POND EXCAVATION AND GRADING SECTIONS AND DETAILS
(SHEET 1 OF 2)

FIGURE 3.8-56



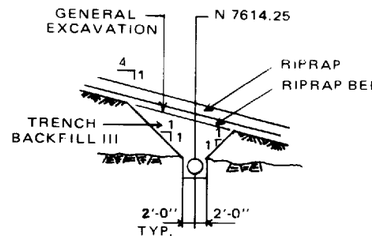
TYPICAL AT SOIL CUT

SECTION G



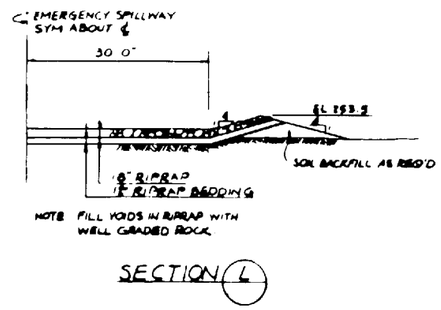
TYPICAL AT ROCK CUT

SECTION H

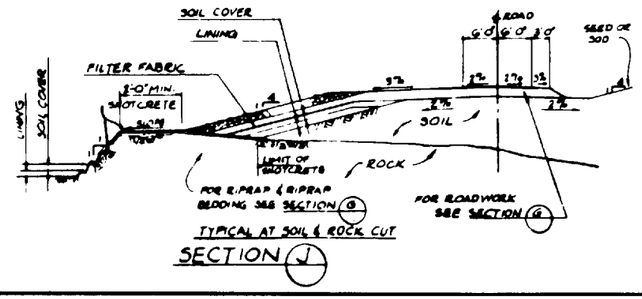


TYPICAL PIPE TRENCH EXCAVATION

SECTION K

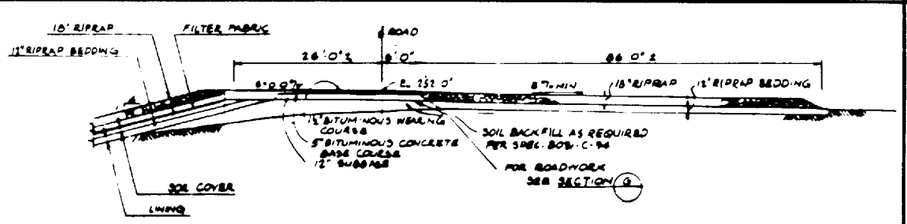


SECTION L

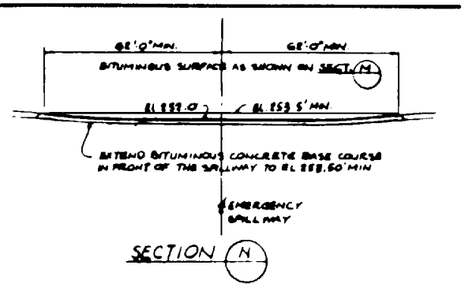


TYPICAL AT SOIL & ROCK CUT

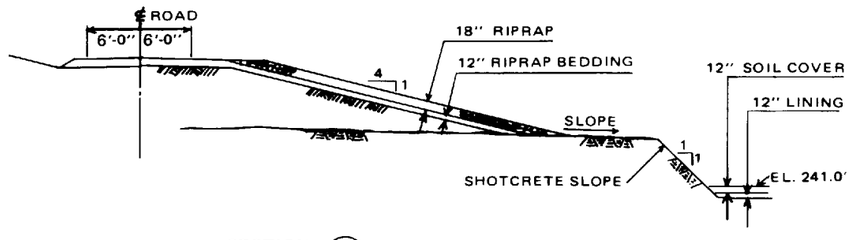
SECTION J



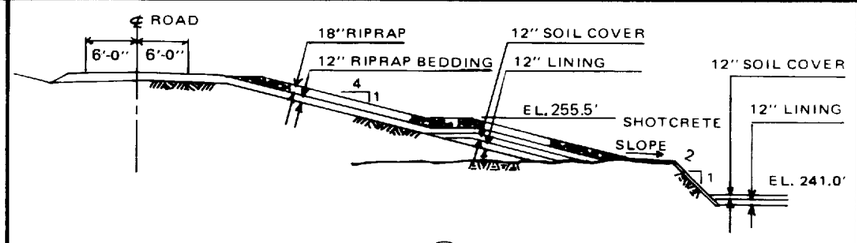
SECTION M SIM



SECTION N



SECTION P



SECTION Q

NOTE:

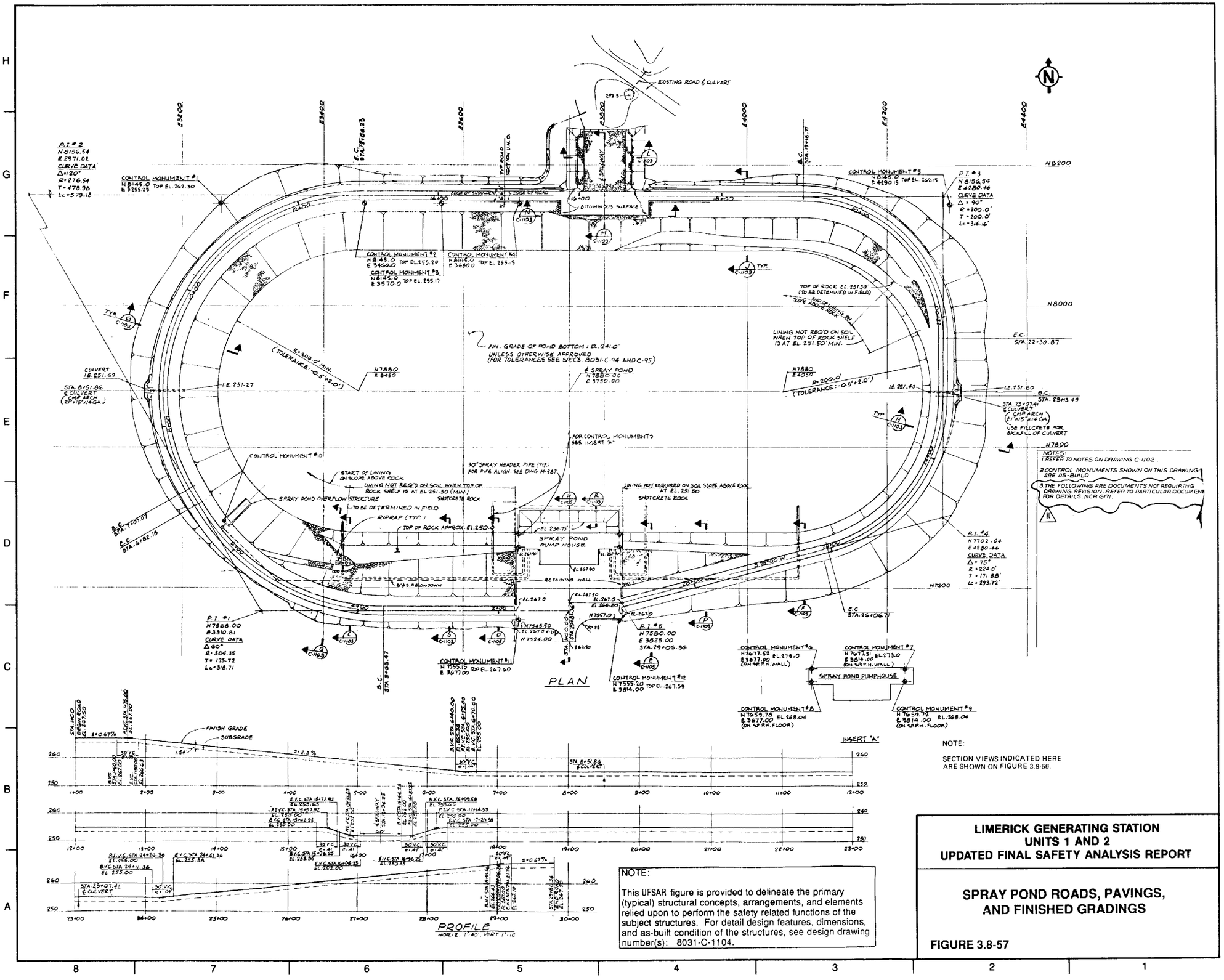
THE UFSAR FIGURE IS PROVIDED TO DELINEATE THE PRIMARY (TYPICAL) STRUCTURAL CONCEPTS, ARRANGEMENTS, AND ELEMENTS RELIED UPON TO PERFORM THE SAFETY RELATED FUNCTIONS OF THE SUBJECT STRUCTURES. FOR DETAIL DESIGN FEATURES, DIMENSIONS, AND AS-BUILT CONDITION OF THESE STRUCTURES, SEE DESIGN DRAWING #8031-C-1103.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SPRAY POND EXCAVATION AND GRADING SECTIONS AND DETAILS

(SHEET 2 OF 2)

FIGURE 3.8-56



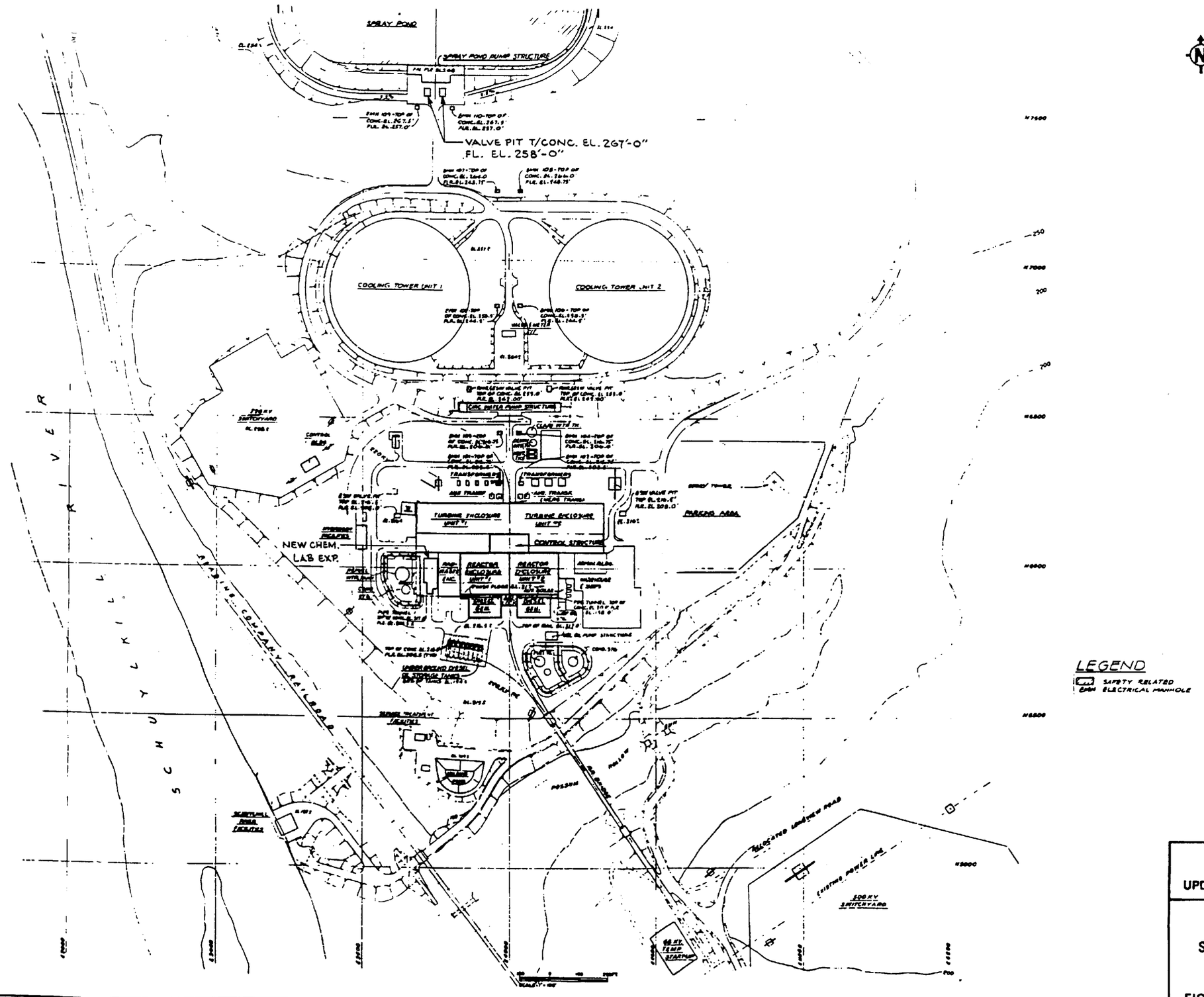
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-1104.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SPRAY POND ROADS, PAVINGS, AND FINISHED GRADINGS

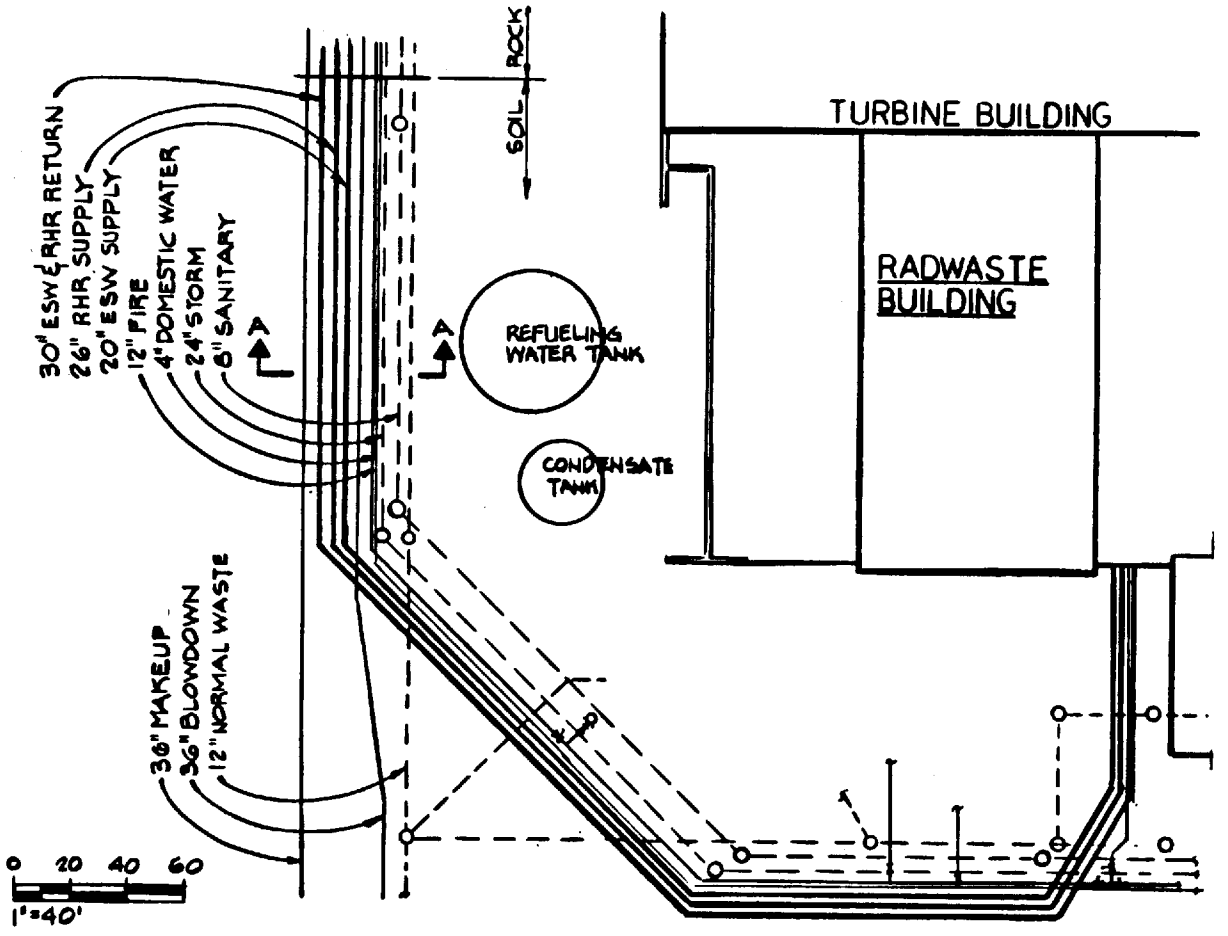
FIGURE 3.8-57



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SAFETY-RELATED STRUCTURES
(SHEET 1 OF 3)

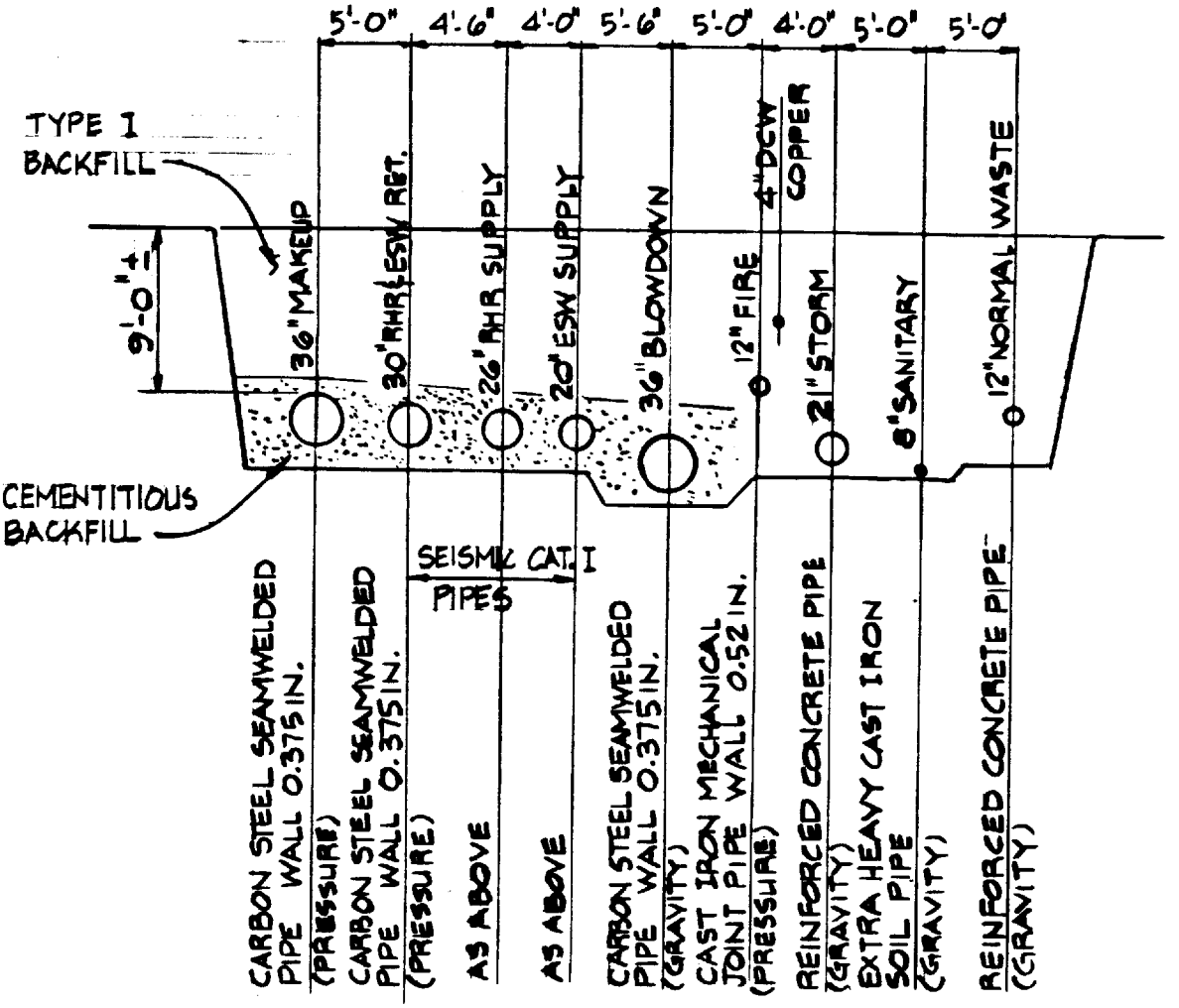
FIGURE 3.8-68 Rev. 6,12/96



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

YARD PIPING
(SHEET 2 OF 3)

FIGURE 3.8-58

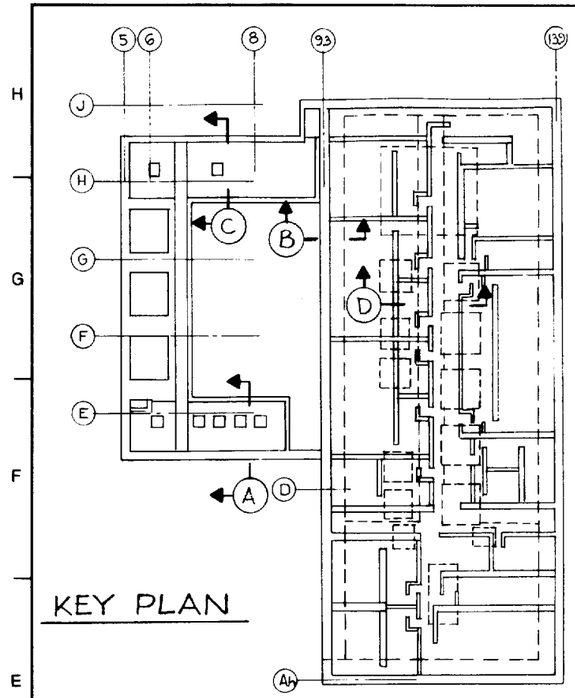


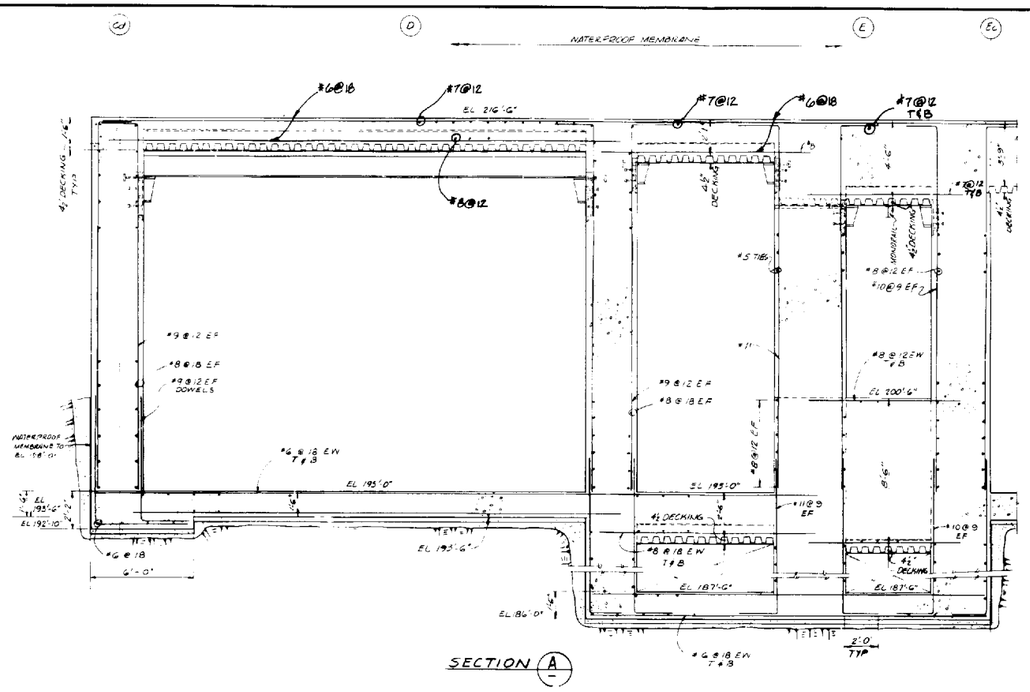
SECTION A-A

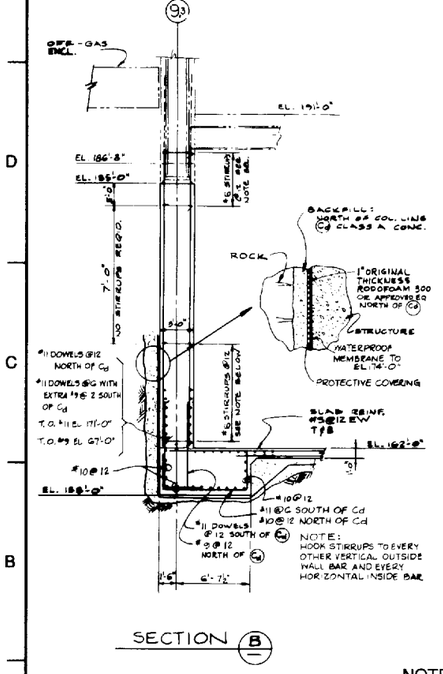
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

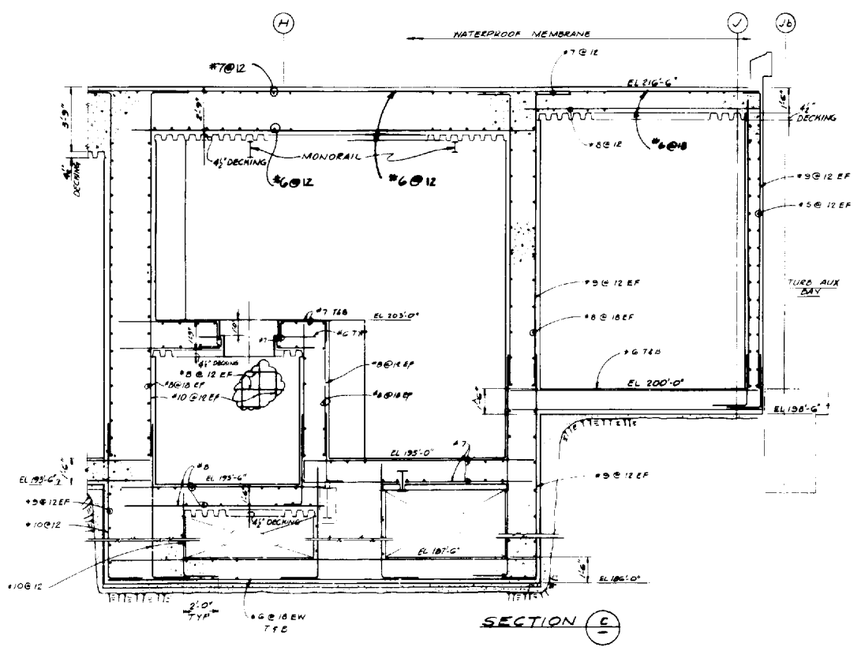
YARD PIPING
(SHEET 3 OF 3)

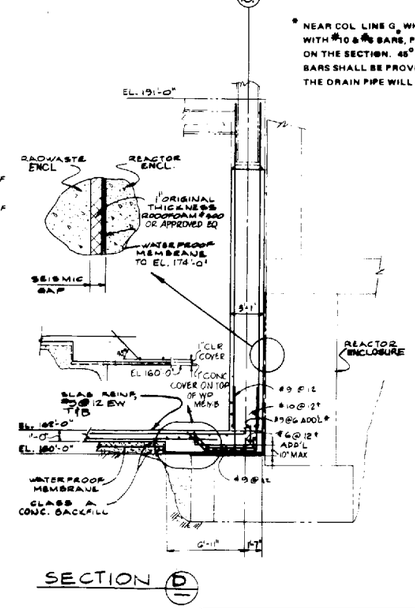
FIGURE 3.8-58











* NEAR COL. LINE G, WHERE FPW DRAIN PIPE INTERFERES WITH #10 & #6 BARS, PROVIDE ADDITIONAL #9@6 AS SHOWN ON THE SECTION. 45° BEND IN THE INTERFERING #10 & #6 BARS SHALL BE PROVIDED AS FAR WEST OF 13.9 LINE AS THE DRAIN PIPE WILL ALLOW.

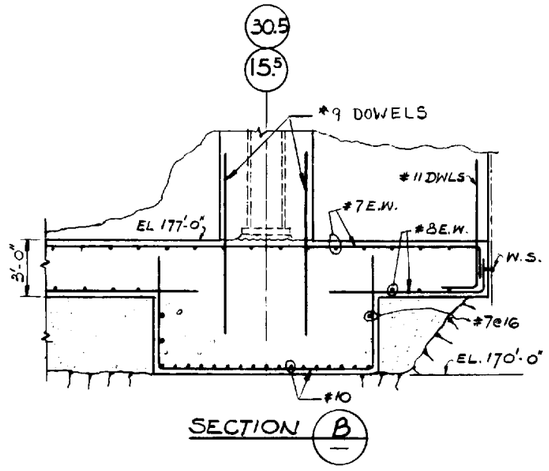
NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-505 and -557.

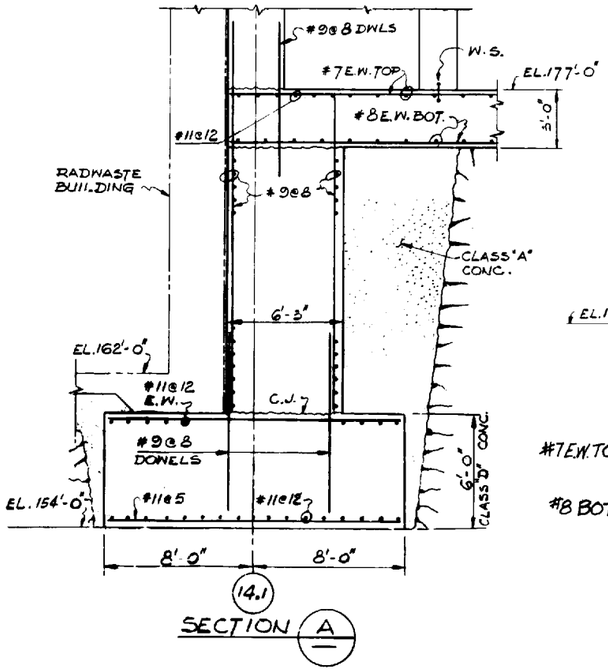
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RADWASTE ENCLOSURE FOUNDATION DETAILS

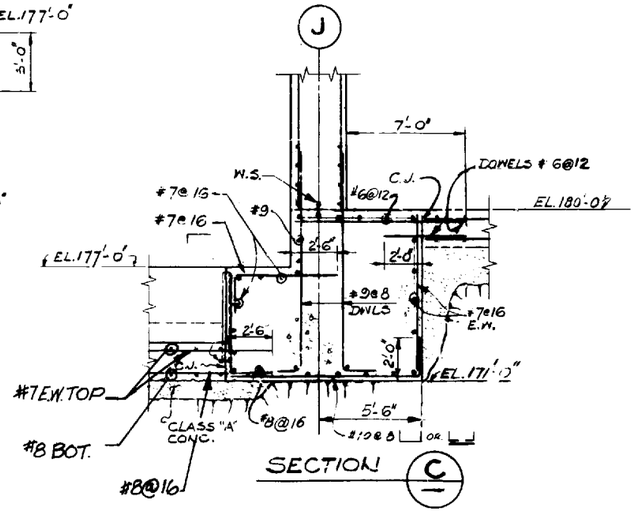
FIGURE 3.8-59



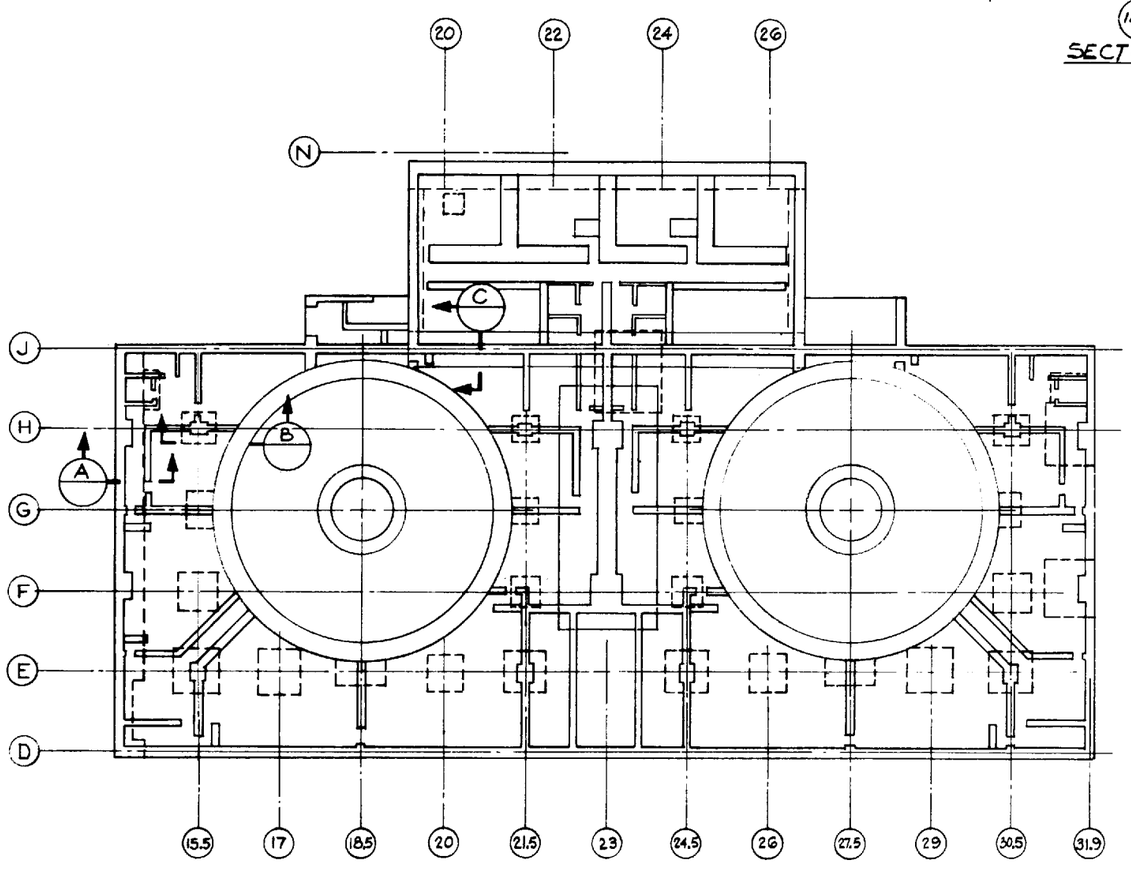
SECTION B



SECTION A



SECTION C



KEY PLAN

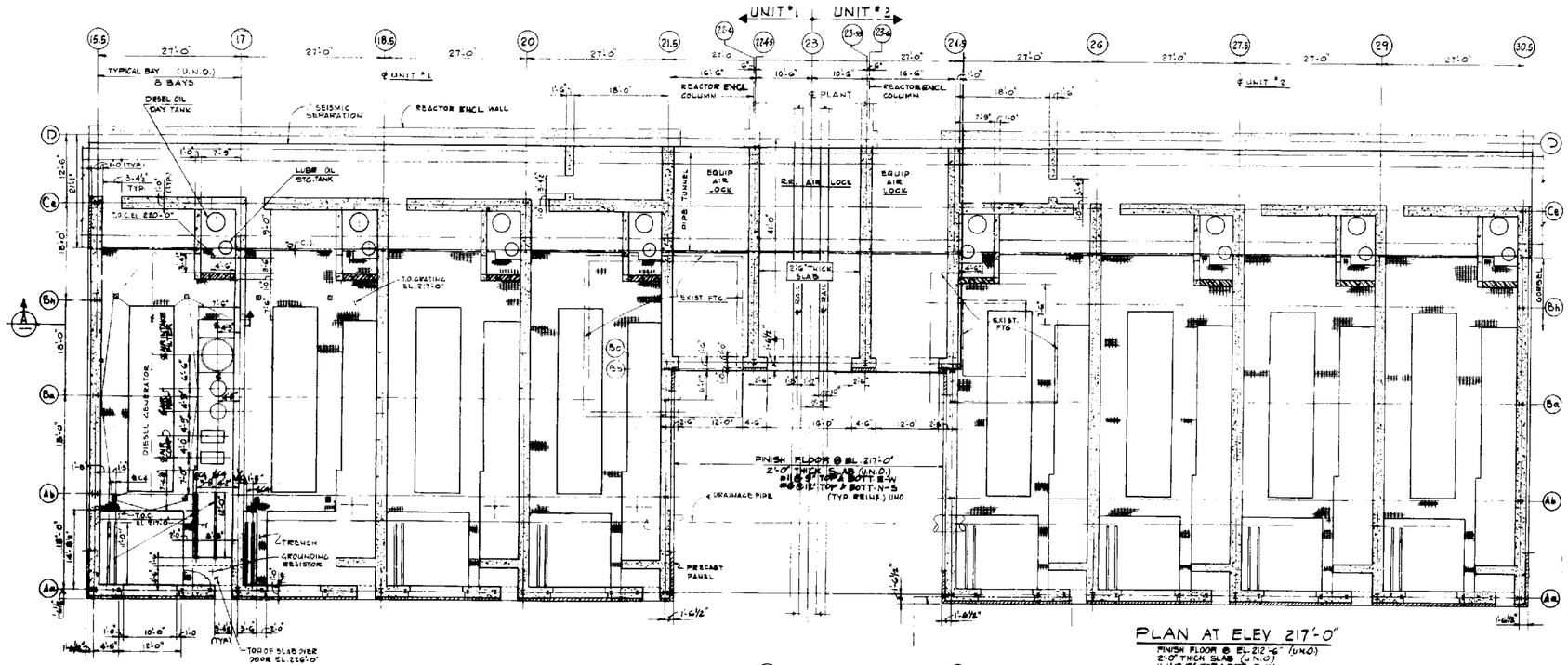
NOTE:

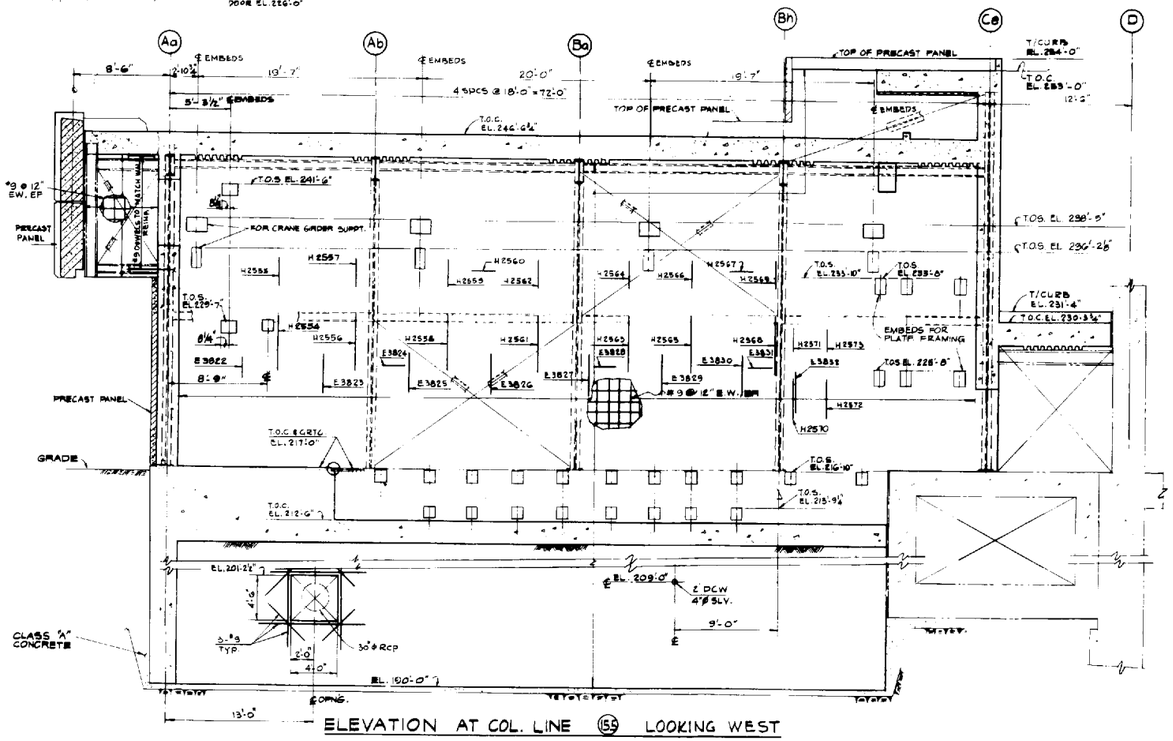
This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-101 and -102.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

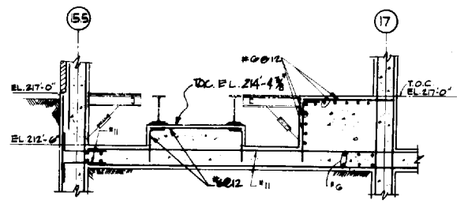
REACTOR ENCLOSURE AND CONTROL STRUCTURE FOUNDATION DETAILS

FIGURE 3.8-60





ELEVATION AT COL. LINE (55) LOOKING WEST



SECTION (A)

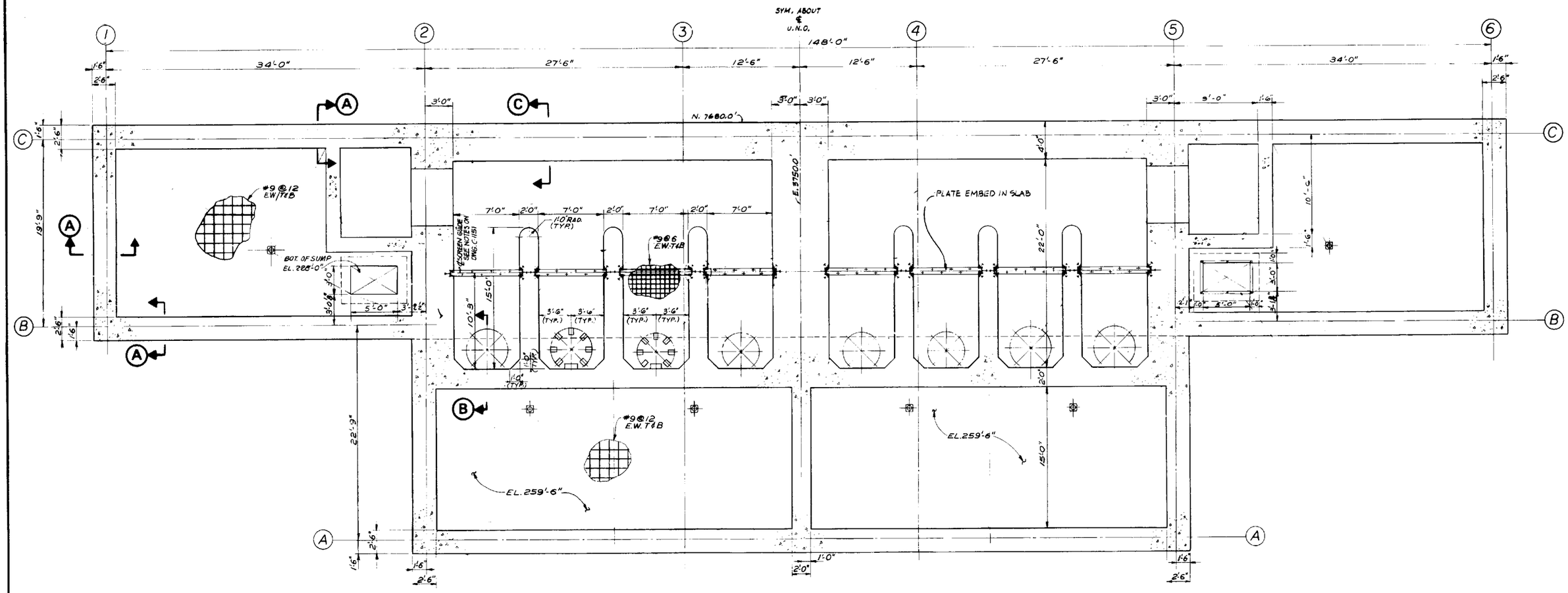
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-656 and -662.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DIESEL-GENERATOR ENCLOSURE FOUNDATION DETAILS

FIGURE 3.8-61



FOUNDATION MAT PLAN AT EL. 237'-0"

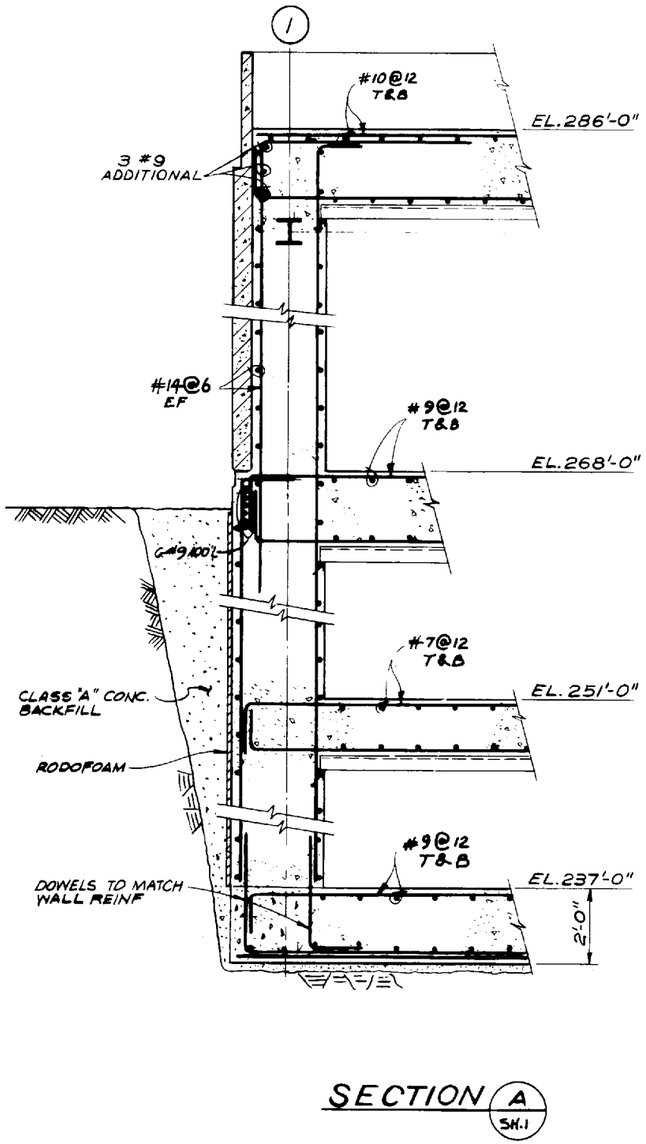
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-1132.

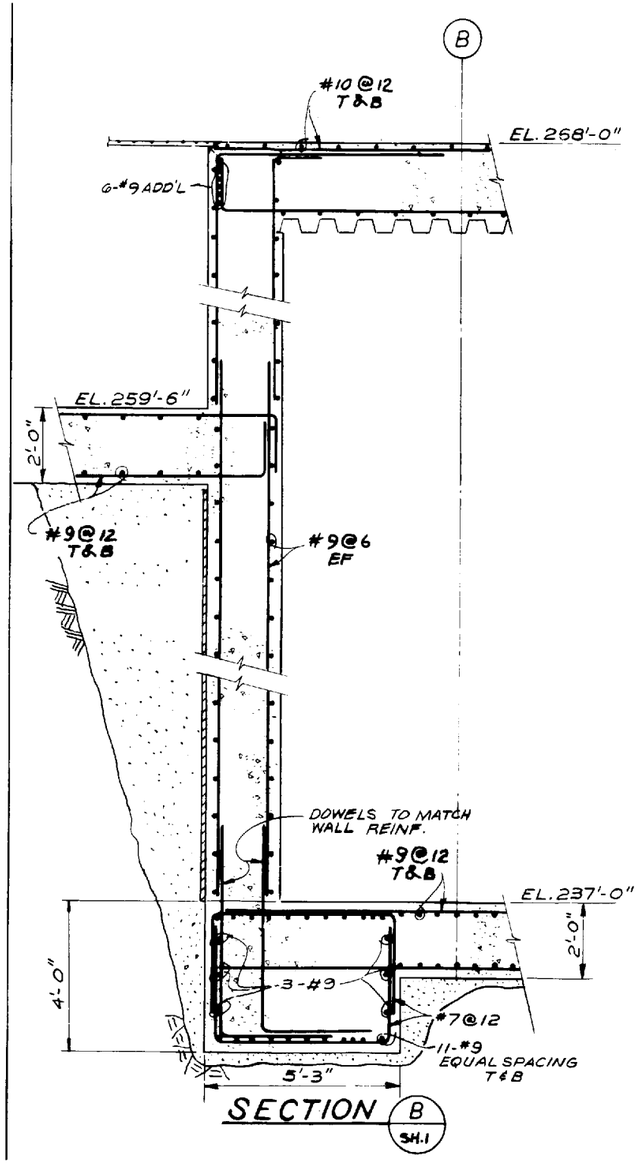
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SPRAY POND PUMP STRUCTURE FOUNDATION DETAILS
(SHEET 1 OF 2)

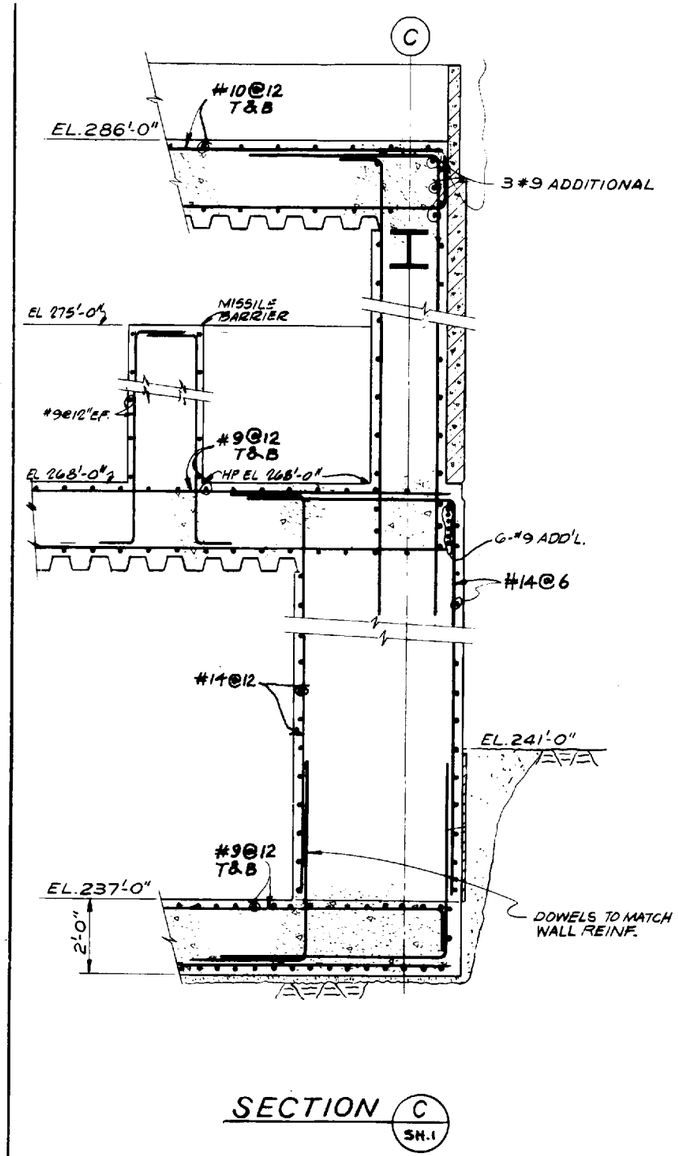
FIGURE 3.8-62



SECTION A SH.1



SECTION B SH.1



SECTION C SH.1

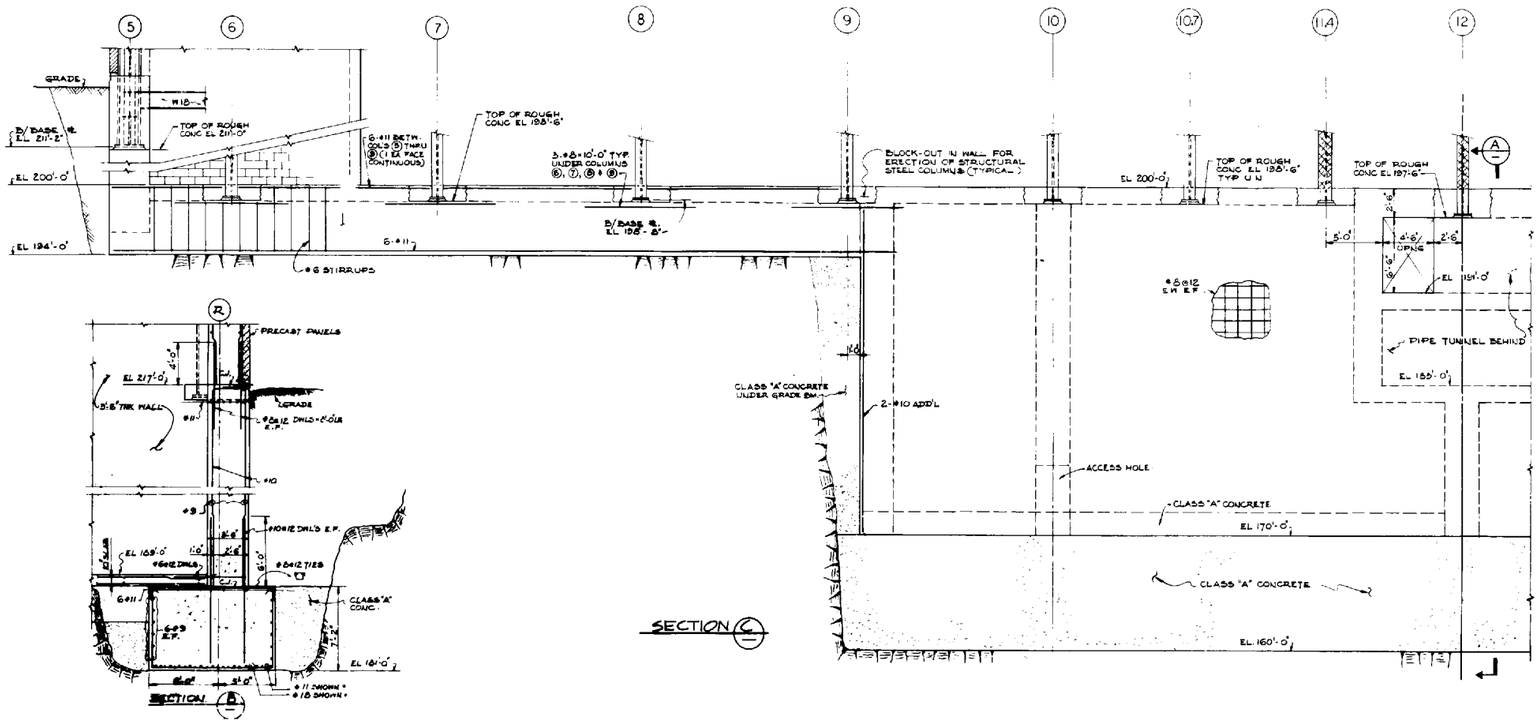
NOTE:

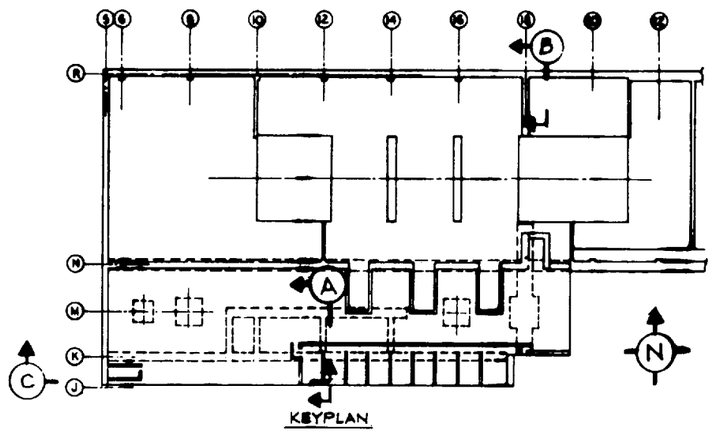
This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-1133.

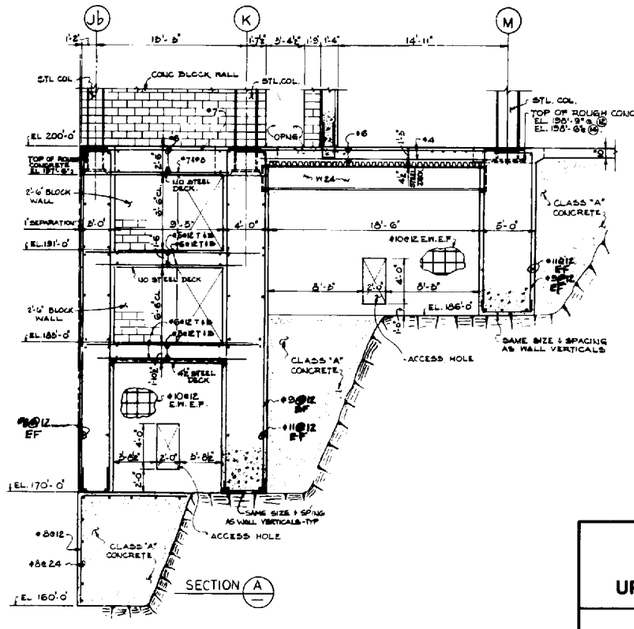
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SPRAY POND PUMP STRUCTURE FOUNDATION DETAILS
(SHEET 2 OF 2)

FIGURE 3.8-62







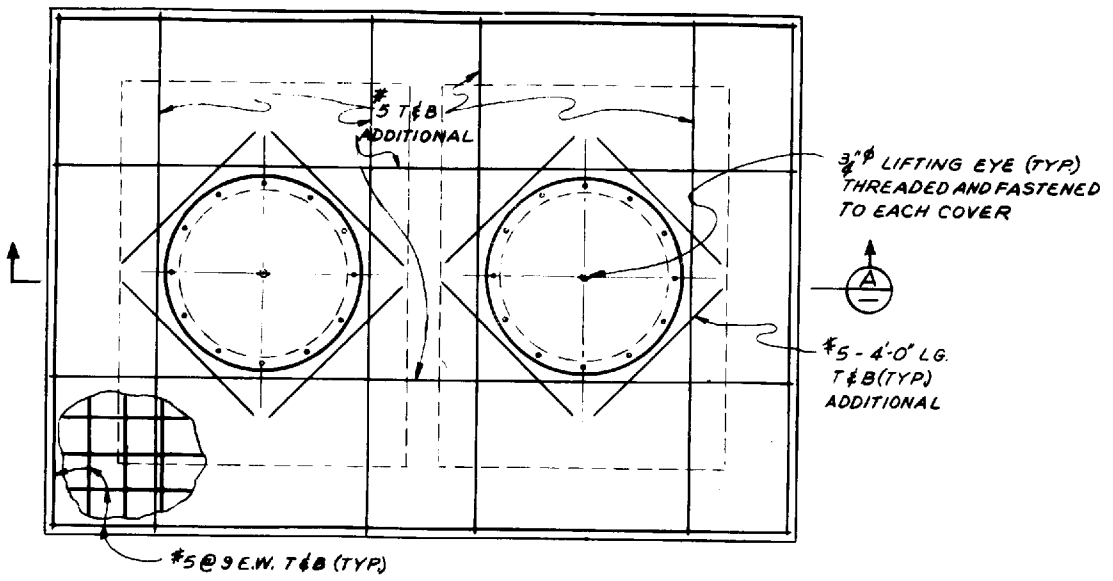
NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-308 and -407.

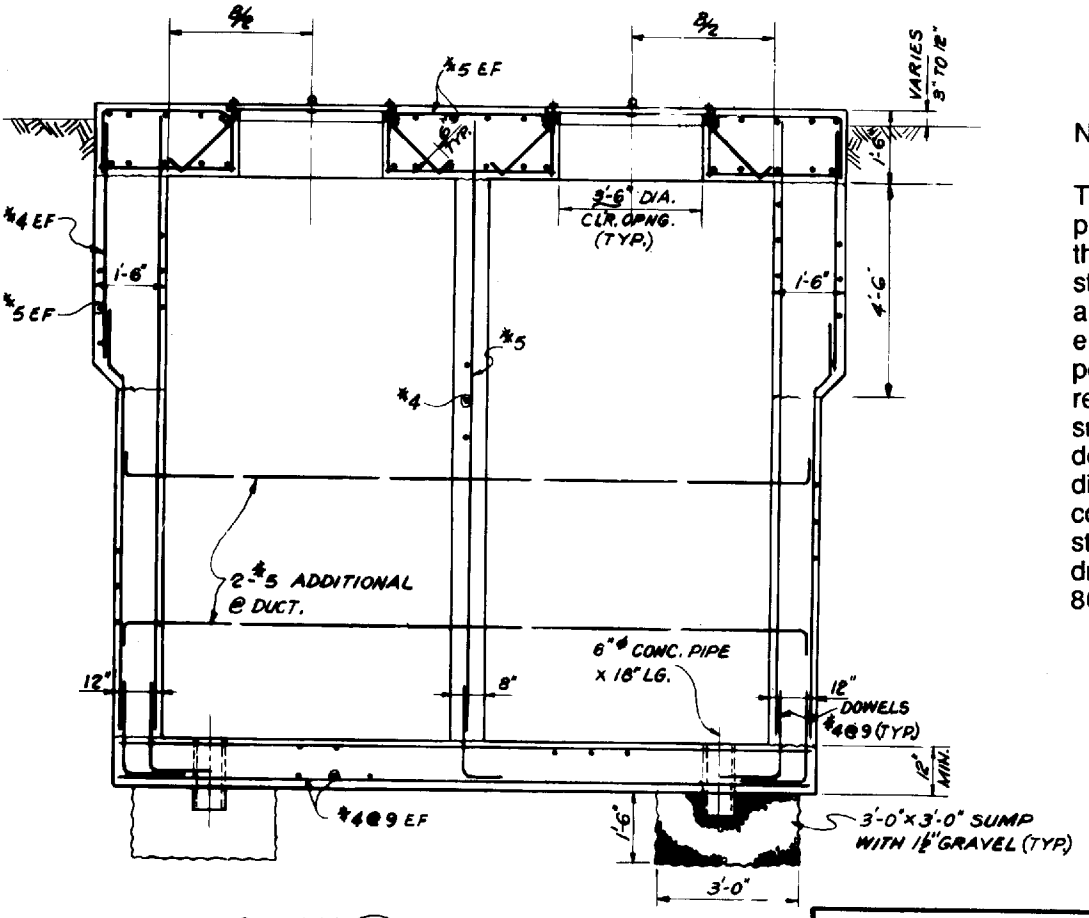
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TURBINE ENCLOSURE FOUNDATION DETAILS

FIGURE 3.8-63



ROOF PLAN
DOUBLE-CELL MANHOLE



SECTION A
ELECTRICAL MANHOLES

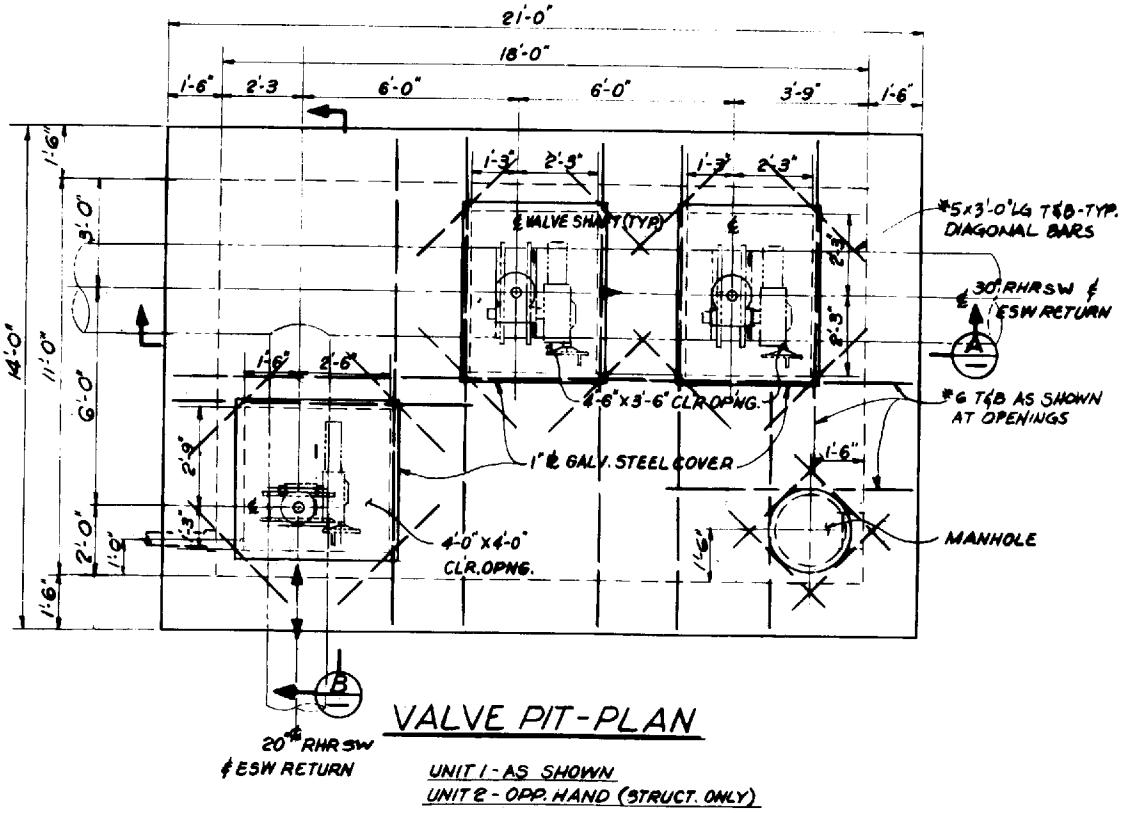
VALVE PITS-RHRSW & ESW PIPING

NOTE:

This **UFSAR** figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-40.

MISCELLANEOUS STRUCTURES FOUNDATION DETAILS
(SHEET 1 OF 5)

FIGURE 3.8-64



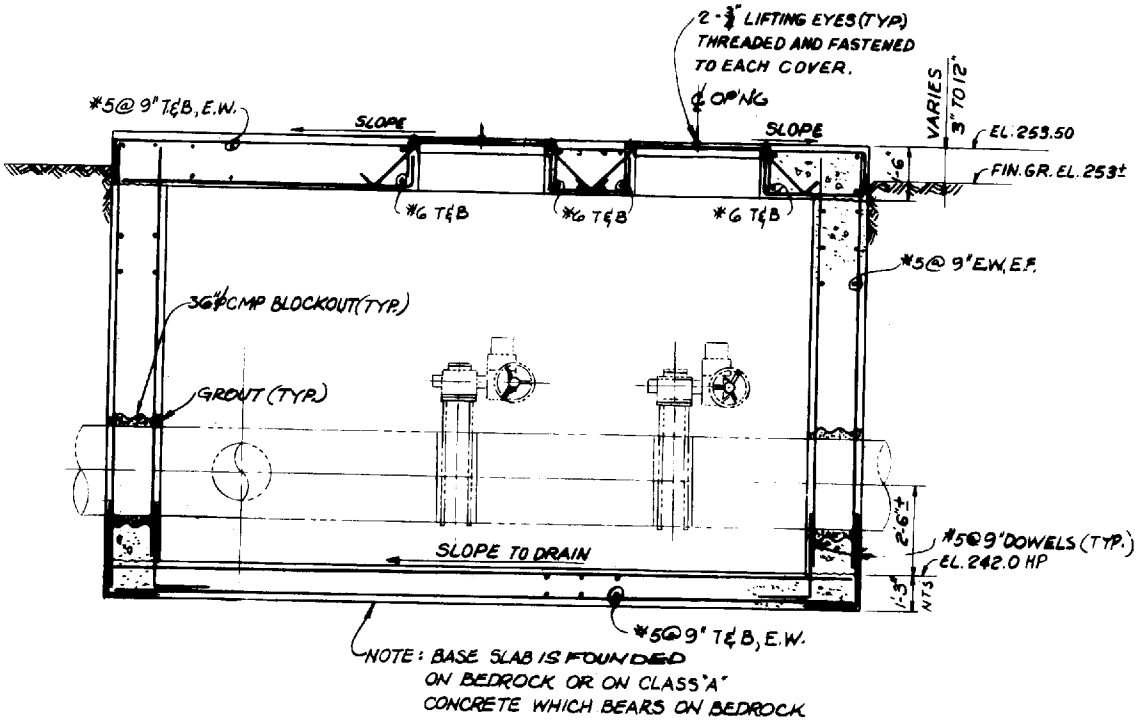
VALVE PIT-PLAN

UNIT 1 - AS SHOWN
UNIT 2 - OPP. HAND (STRUCT. ONLY)

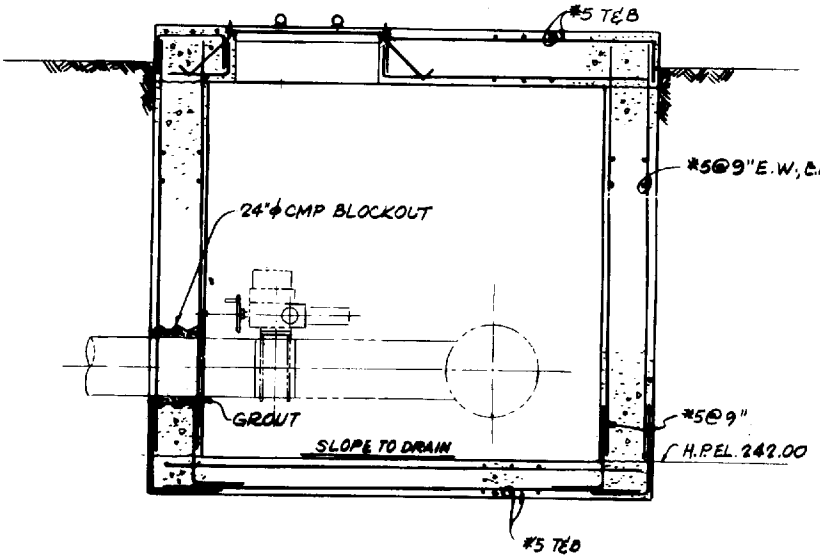
VALVE PITS-RHRSW & ESW PIPING

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-43.



SECTION (A)

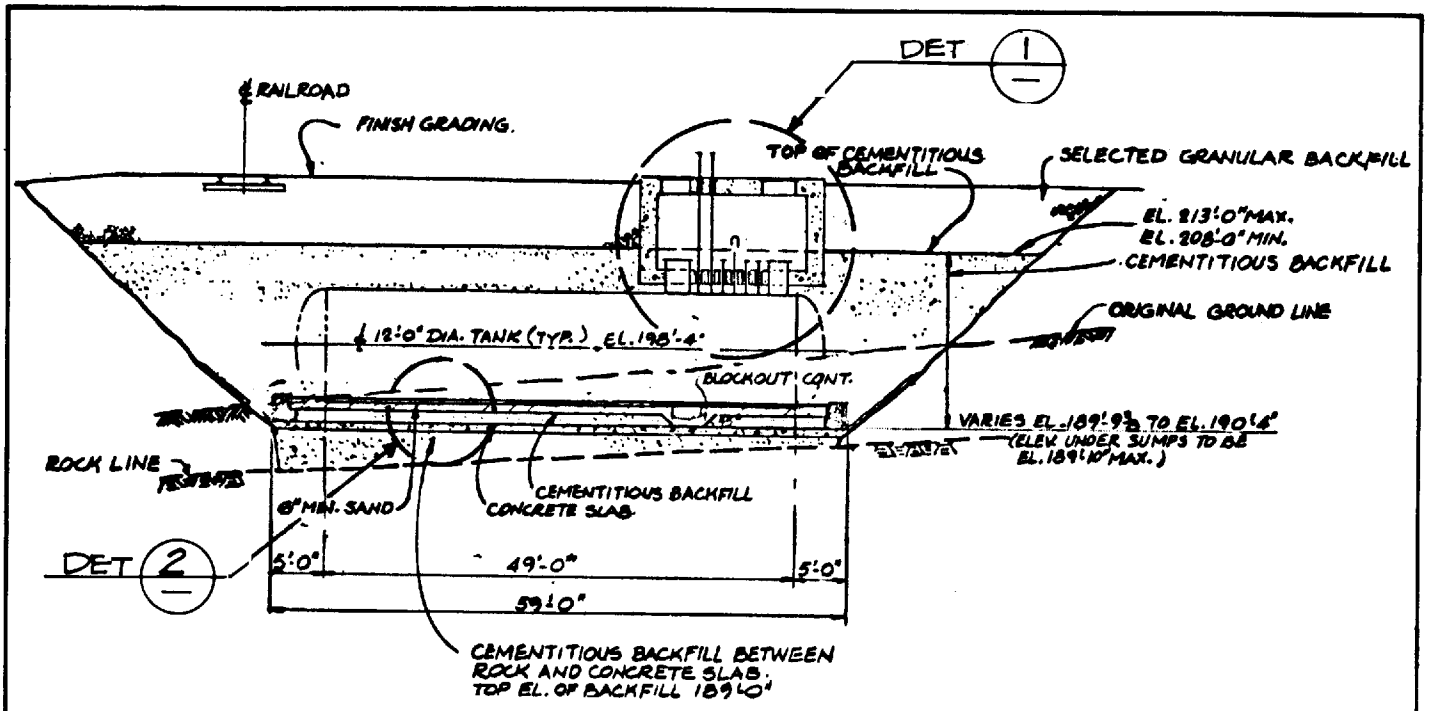


SECTION (B)

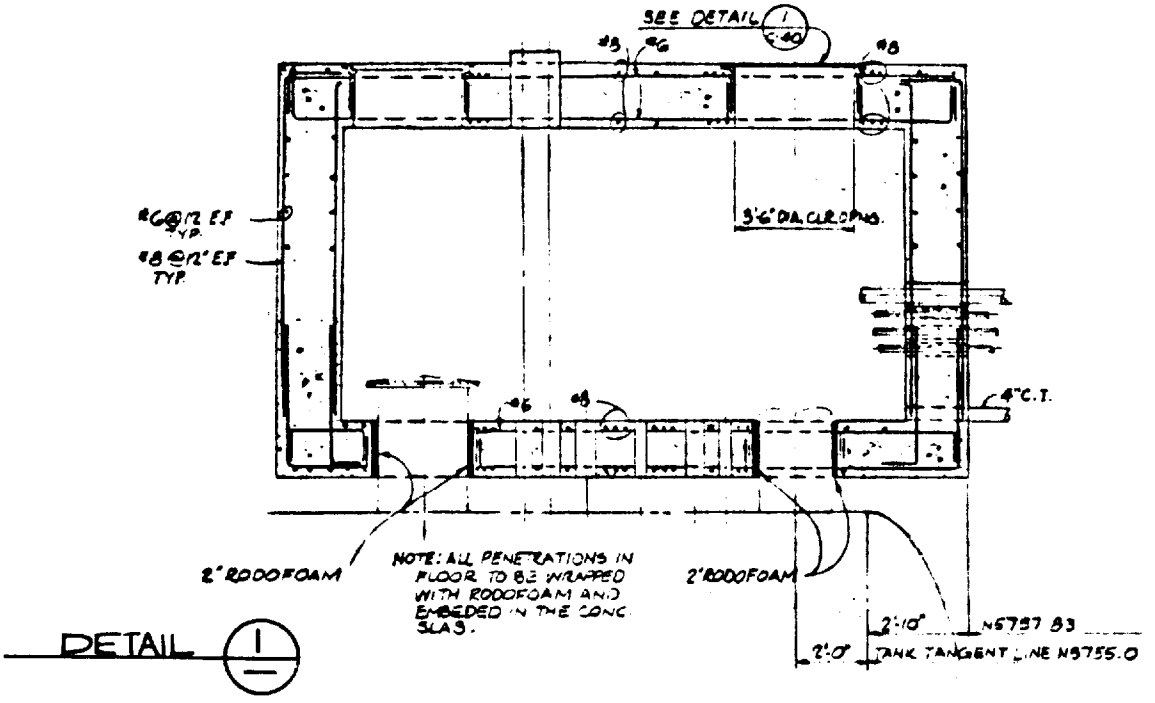
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-43.

VALVE PITS-RHRSW & ESW PIPING



ELEVATION VIEW



DIESEL OIL STORAGE TANK STRUCTURES

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-1063 and -1064.

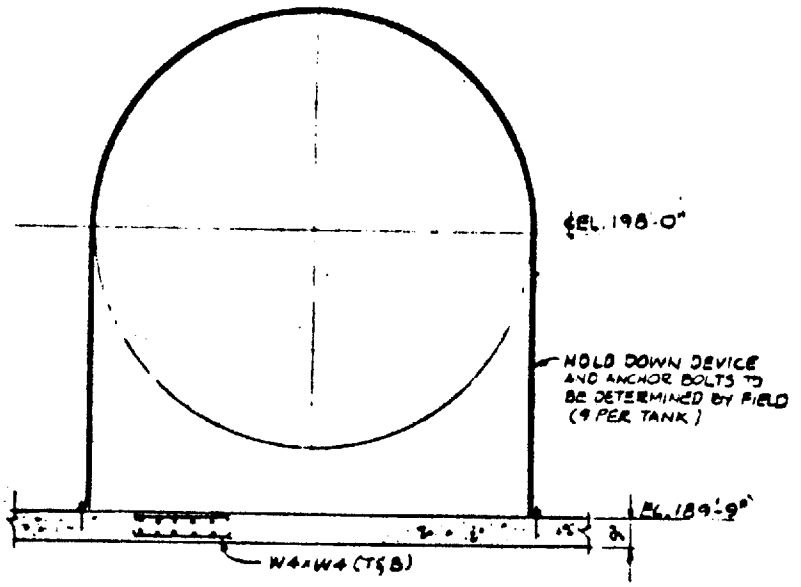
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MISCELLANEOUS STRUCTURES
FOUNDATION DETAILS
(SHEET 4 OF 5)

FIGURE 3.8-64

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-1064.



TYP. TANK ANCHORAGE TO BASE SLAB

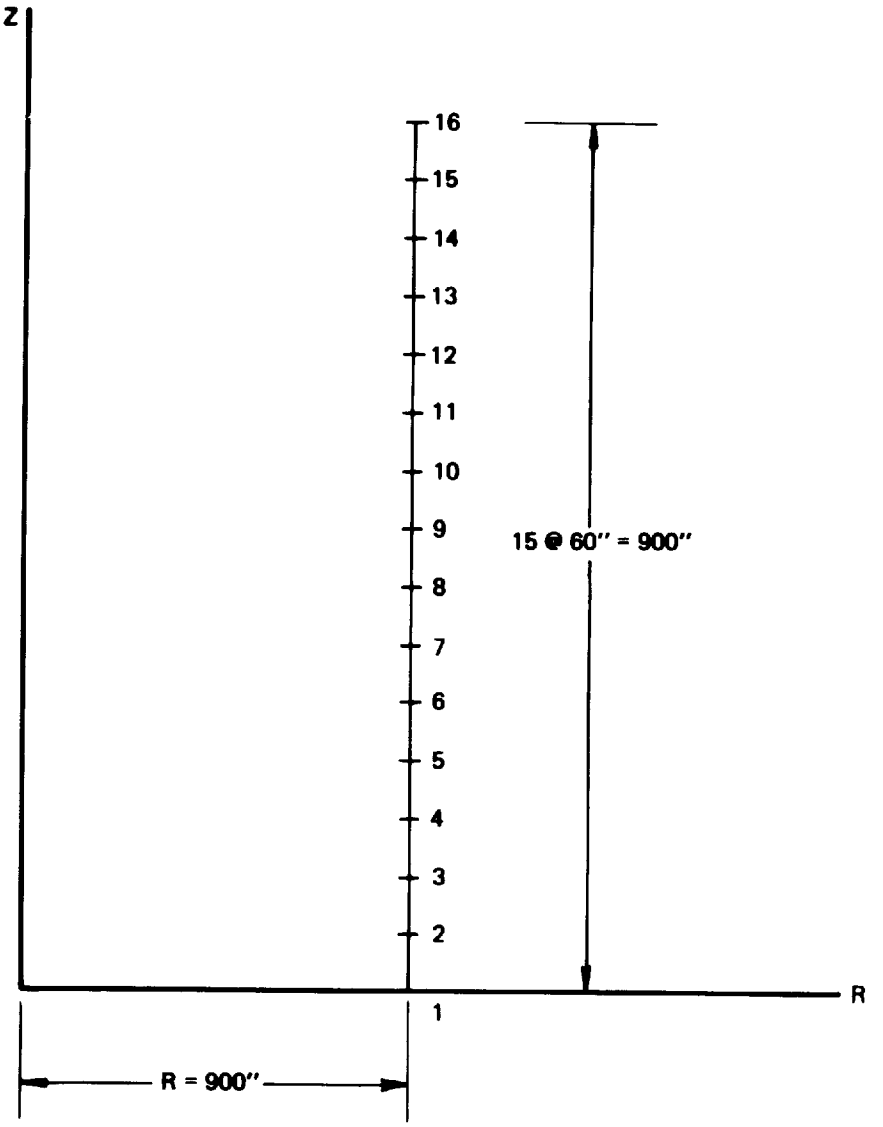
DETAIL 2

DIESEL OIL STORAGE TANK STRUCTURES

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MISCELLANEOUS STRUCTURES FOUNDATION DETAILS
(SHEET 5 OF 5)

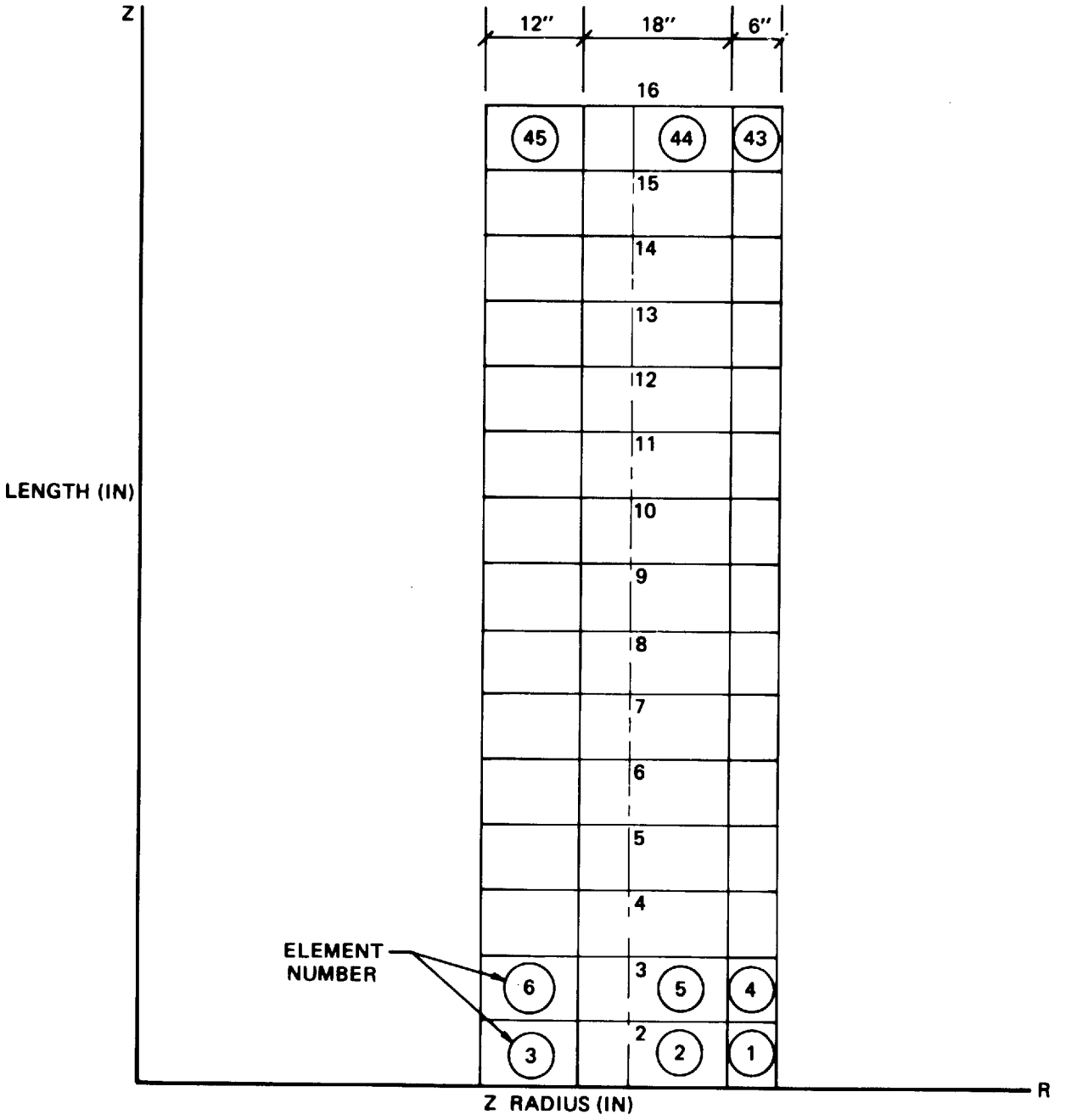
FIGURE 3.8-64



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

THIN SHELL CYLINDER MODEL
(ASHSD PROGRAM, SAMPLE
PROBLEM A)

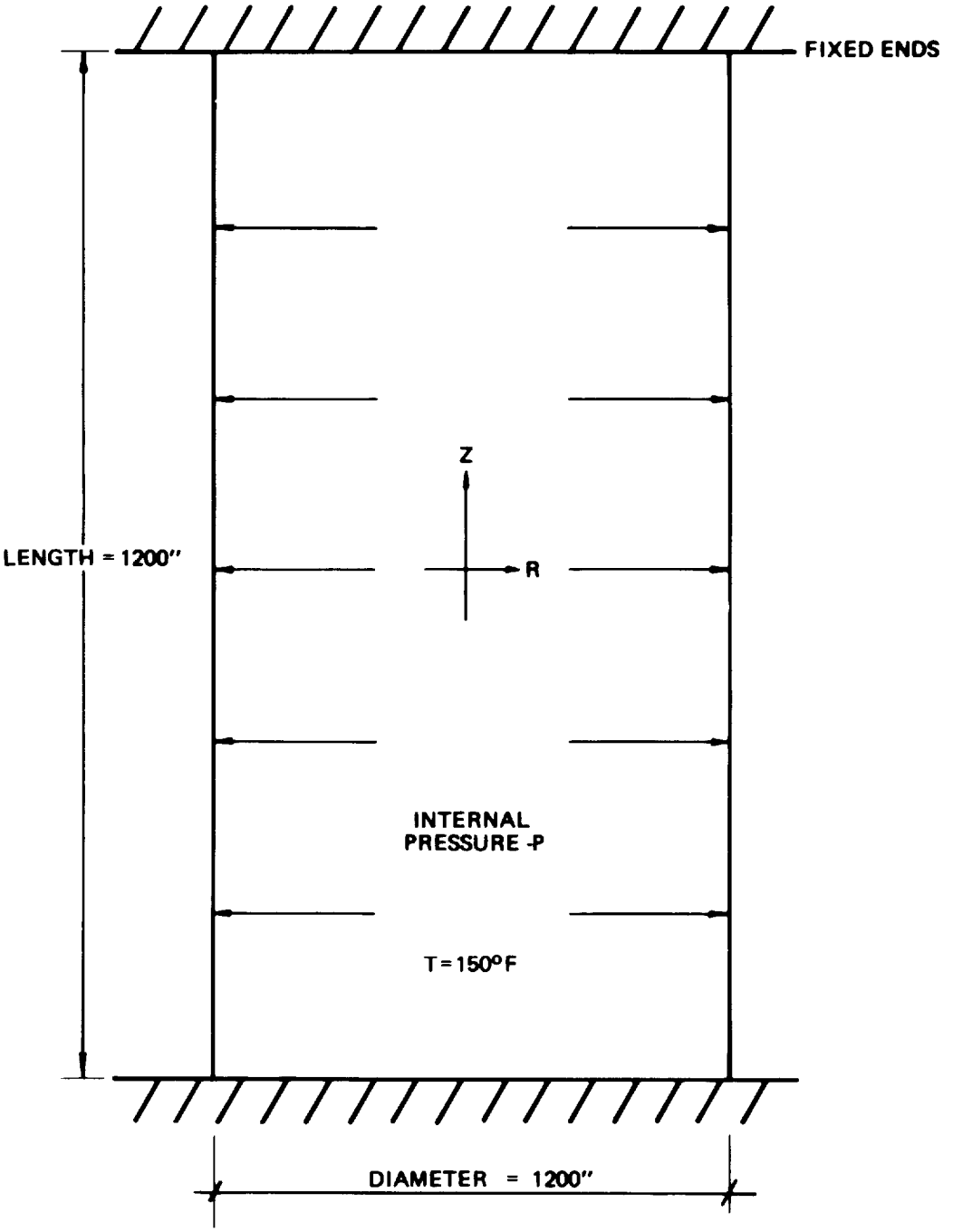
FIGURE 3.8-65



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

AXISYMMETRIC SOLID CYLINDER MODEL (ASHSD PROGRAM, SAMPLE PROBLEM A)

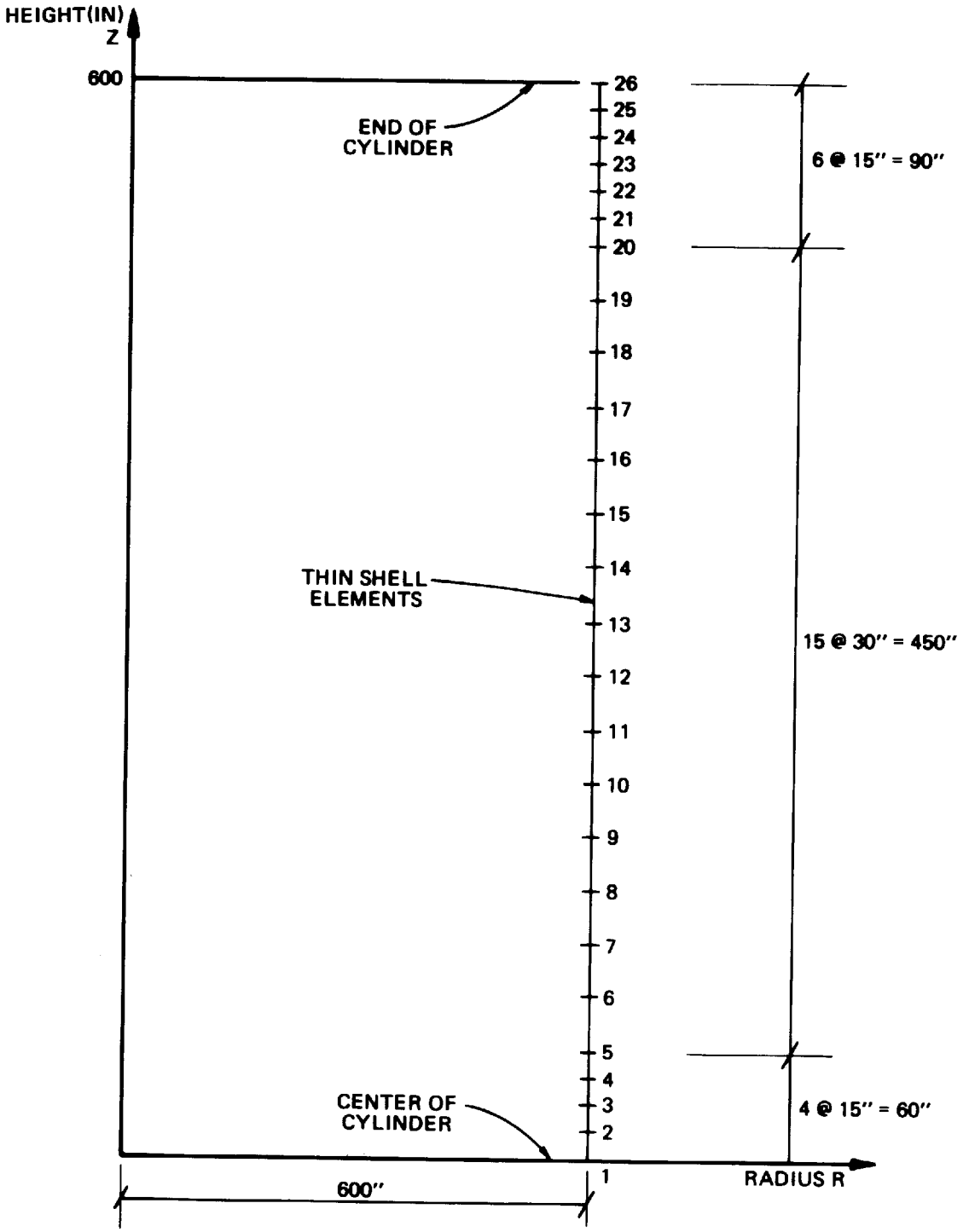
FIGURE 3.8-66



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CYLINDER MODEL (ASHSD PROGRAM, SAMPLE PROBLEM B)

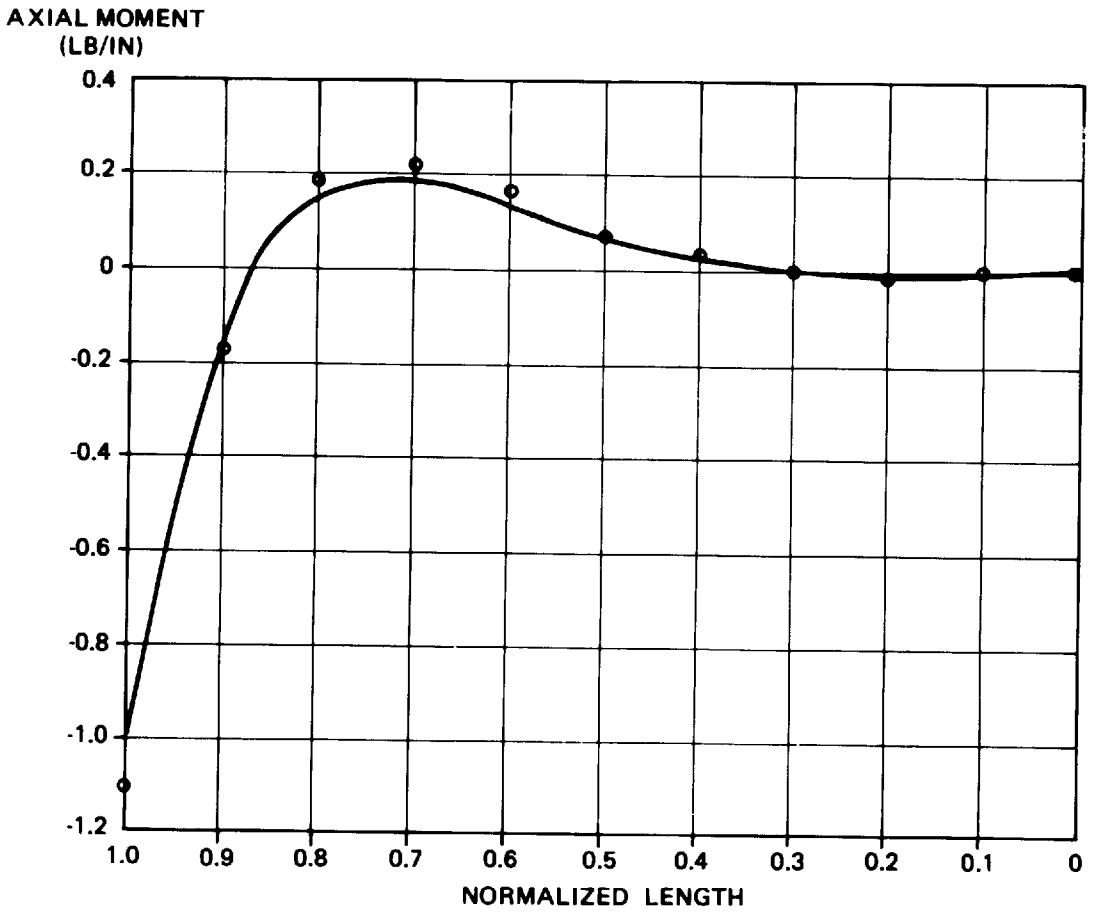
FIGURE 3.8-67



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FINITE ELEMENT MODEL (ASHSD PROGRAM, SAMPLE PROBLEM B)

FIGURE 3.8-68

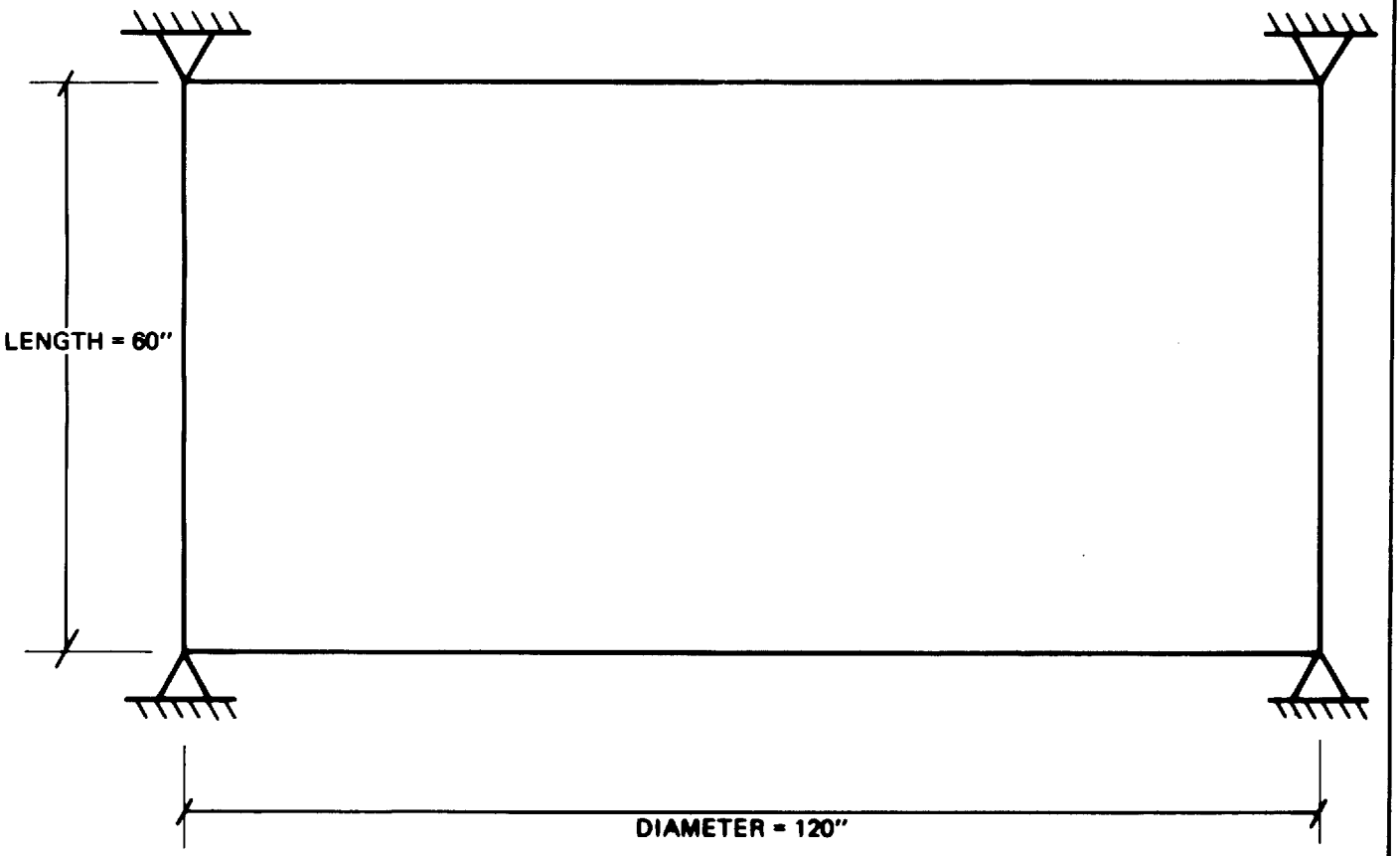


o = ASHSD
— = REFERENCE 3.8-4

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

COMPARISON OF COMPUTER RESULTS AND THEORETICAL SOLUTION (ASHSD PROGRAM, SAMPLE PROBLEM B)

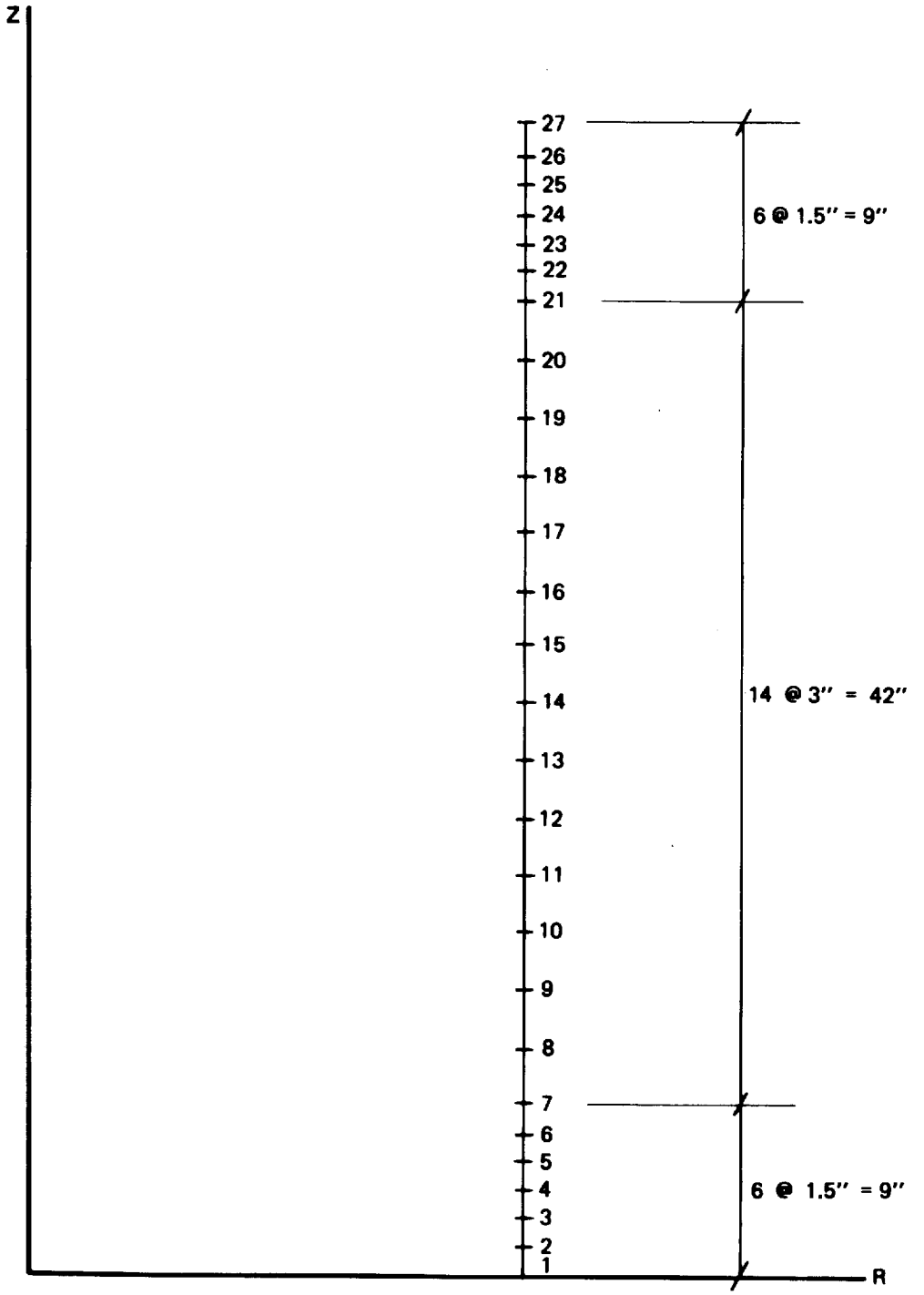
FIGURE 3.8-69



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

**CYLINDER MODEL
(ASHSD PROGRAM,
SAMPLE PROBLEM C)**

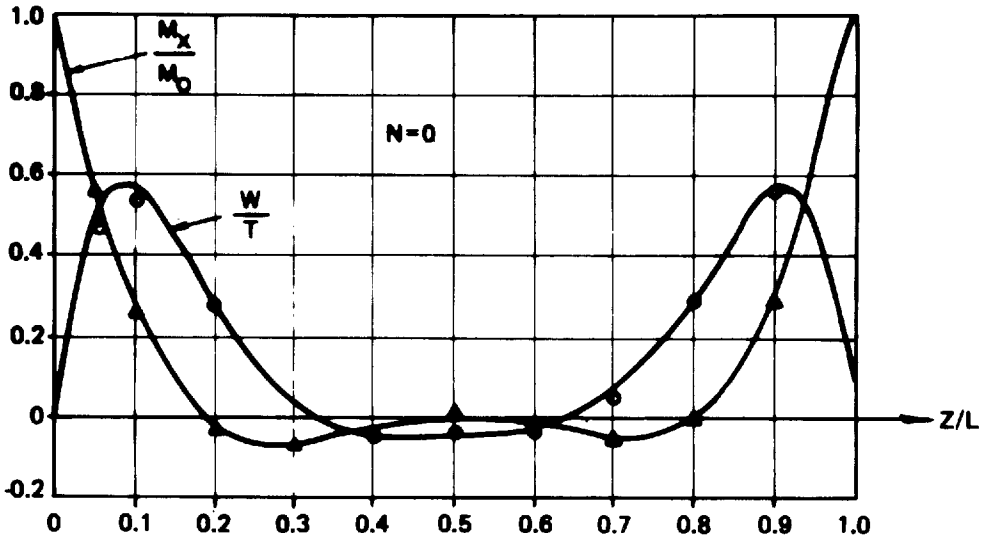
FIGURE 3.8-70

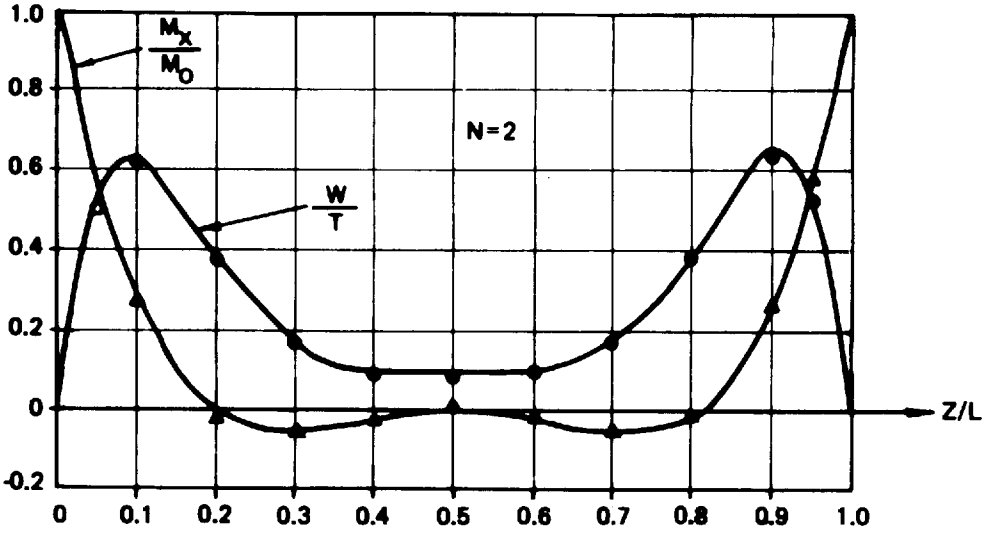


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FINITE ELEMENT MODEL (ASHSD PROGRAM, SAMPLE PROBLEM C)

FIGURE 3.8-71





o ASHSD (RADIAL DISPLACEMENT W)

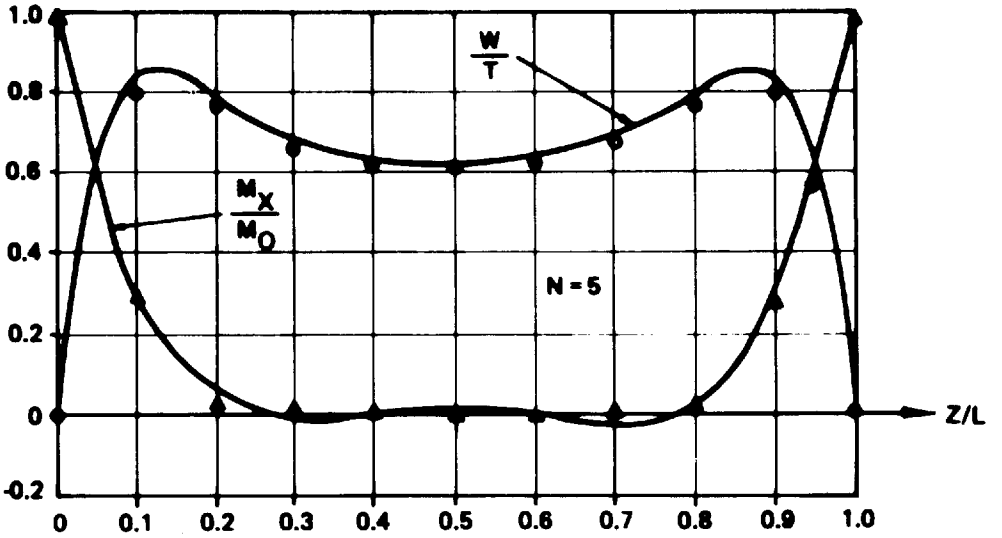
Δ ASHSD (LONGITUDINAL MOMENT M_X)

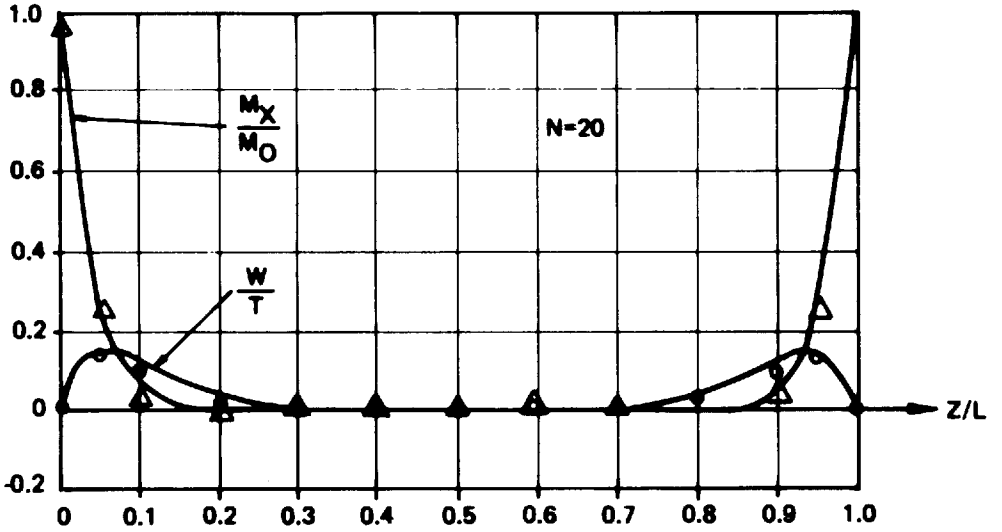
— REFERENCE 3.8-5

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

COMPARISON OF COMPUTER RESULTS AND THEORETICAL SOLUTION (ASHSD PROGRAM, SAMPLE PROBLEM C)
(SHEET 1 OF 2)

FIGURE 3.8-72





o ASHSD (RADIAL DISPLACEMENT W)

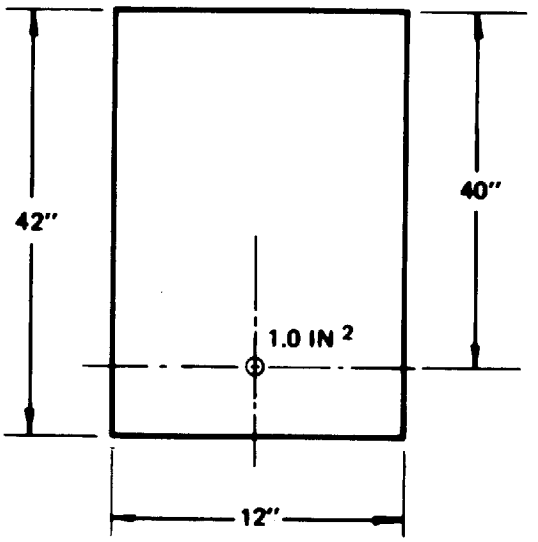
Δ ASHSD (LONGITUDINAL MOMENT M_X)

— REFERENCE 3.8-5

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

COMPARISON OF COMPUTER RESULTS AND THEORETICAL SOLUTION (ASHSD PROGRAM, SAMPLE PROBLEM C)
(SHEET 2 OF 2)

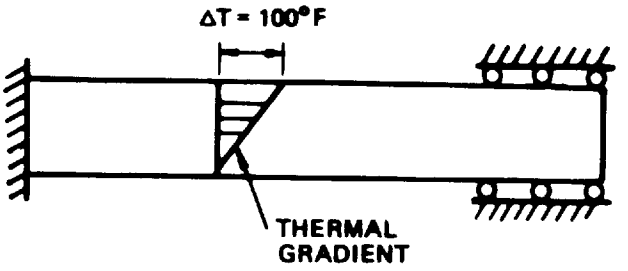
FIGURE 3.8-72



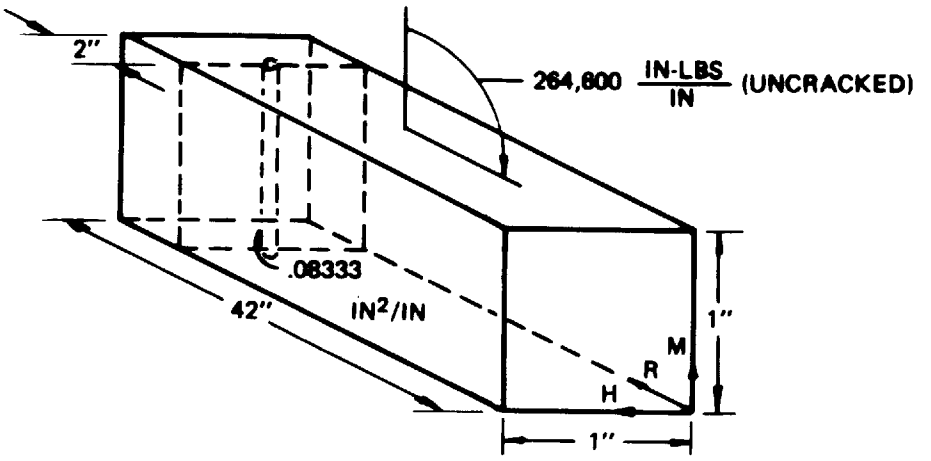
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REINFORCED CONCRETE BEAM (CECAP PROGRAM)

FIGURE 3.8-73



REINFORCED CONCRETE BEAM

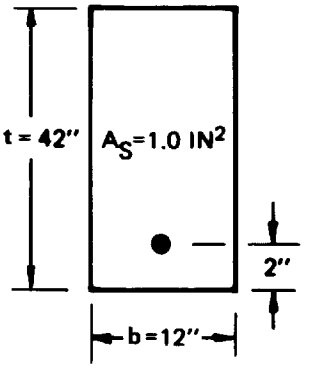


CECAP CONCRETE ELEMENT MODEL

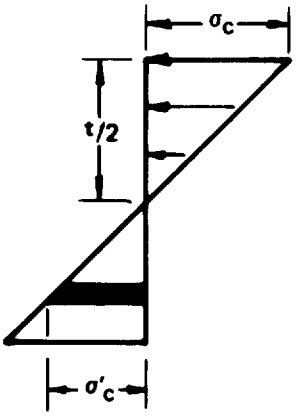
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONCRETE BEAM MODEL (CECAP PROGRAM, SAMPLE PROBLEM A)

FIGURE 3.8-74



BEAM CROSS - SECTION

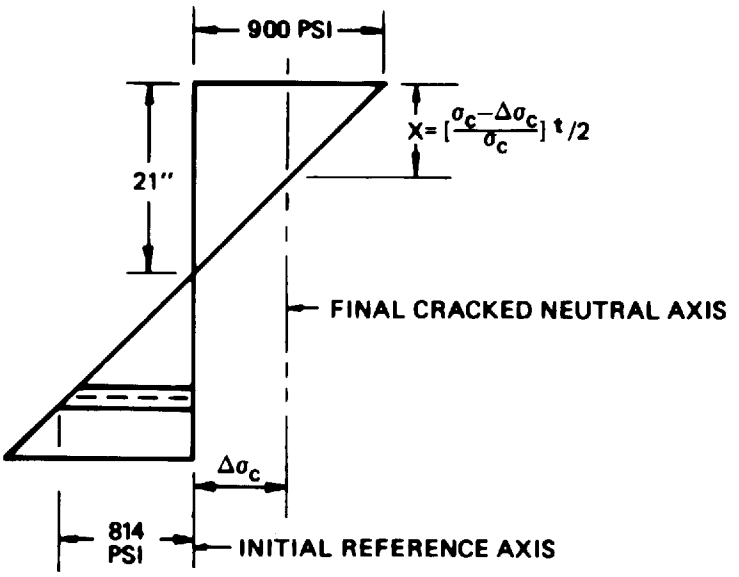


INITIAL THERMAL STRESS DISTRIBUTION

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

BEAM CROSS–SECTION AND THERMAL STRESS DISTRIBUTION (CECAP PROGRAM,SAMPLE PROBLEM A)

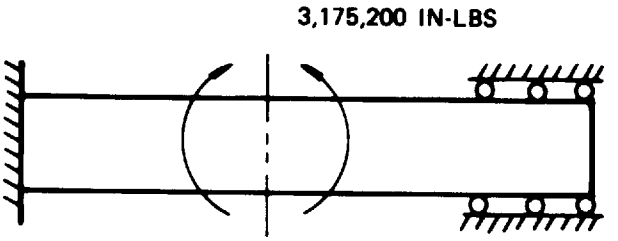
FIGURE 3.8-75



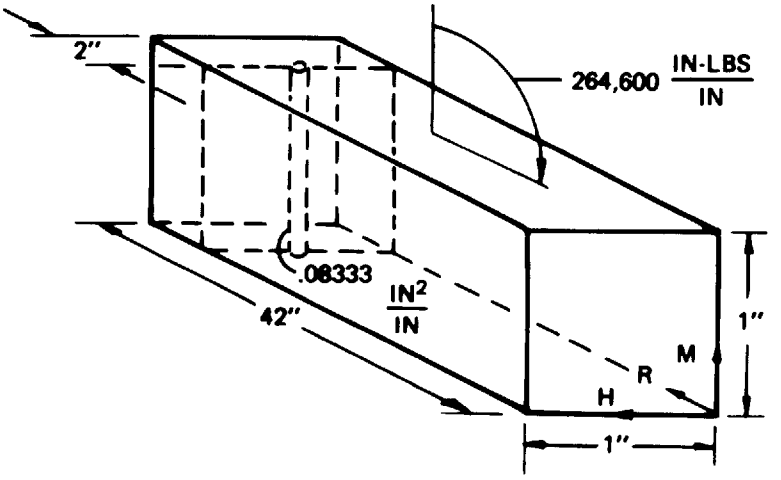
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

STRESS DIAGRAM (CECAP PROGRAM, SAMPLE PROBLEM A)

FIGURE 3.8-76



REINFORCED CONCRETE BEAM

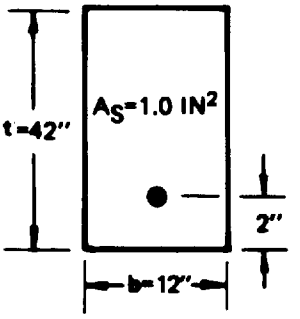


CECAP CONCRETE ELEMENT MODEL

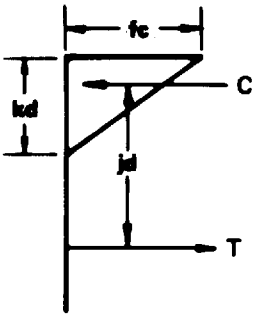
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONCRETE BEAM MODEL (CECAP PROGRAM, SAMPLE PROBLEM B)

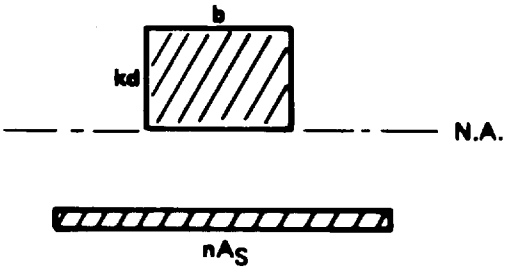
FIGURE 3.8-77



BEAM CROSS - SECTION



STRESS BLOCK

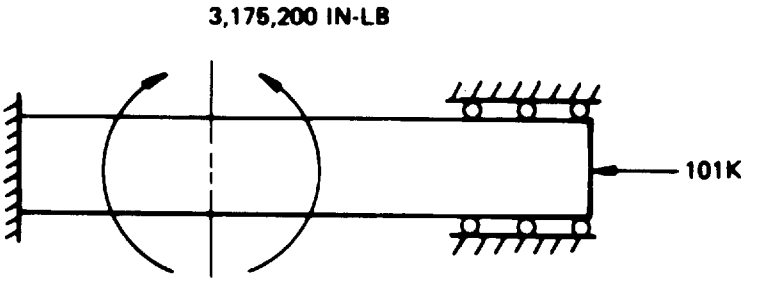


TRANSFORMED SECTION

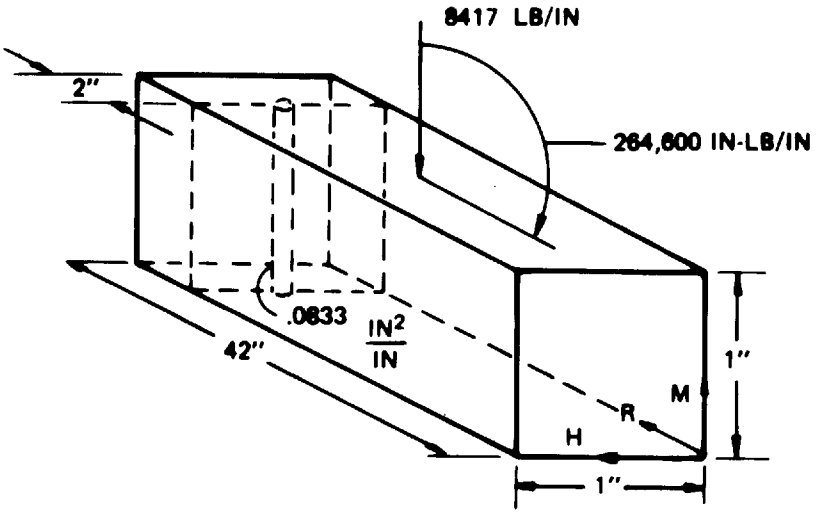
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

BEAM CROSS-SECTION, STRESS BLOCK, AND TRANSFORMED SECTION (CECAP PROGRAM, SAMPLE PROBLEM B)

FIGURE 3.8-78



REINFORCED CONCRETE BEAM

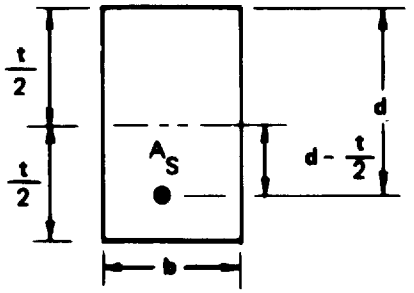


CECAP CONCRETE ELEMENT MODEL

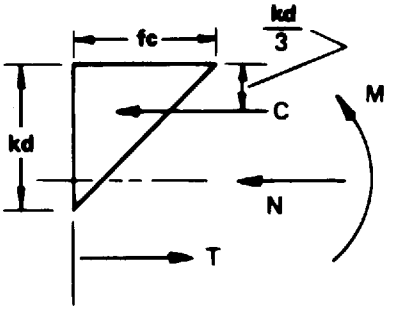
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONCRETE BEAM MODEL (CECAP PROGRAM, SAMPLE PROBLEM C)

FIGURE 3.8-79



BEAM CROSS-SECTION

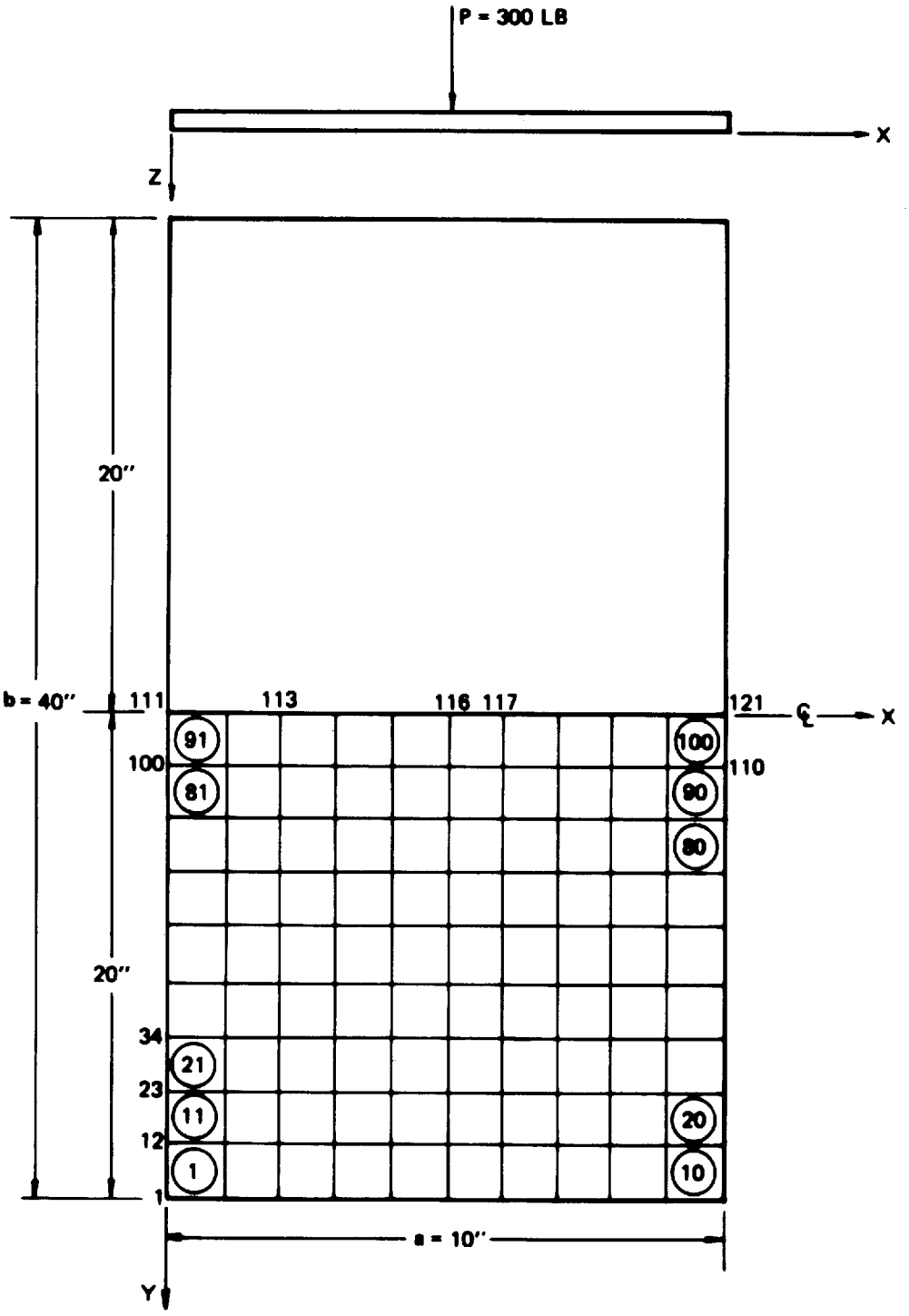


STRESS BLOCK

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

BEAM CROSS-SECTION AND STRESS BLOCK (CECAP PROGRAM, SAMPLE PROBLEM C)

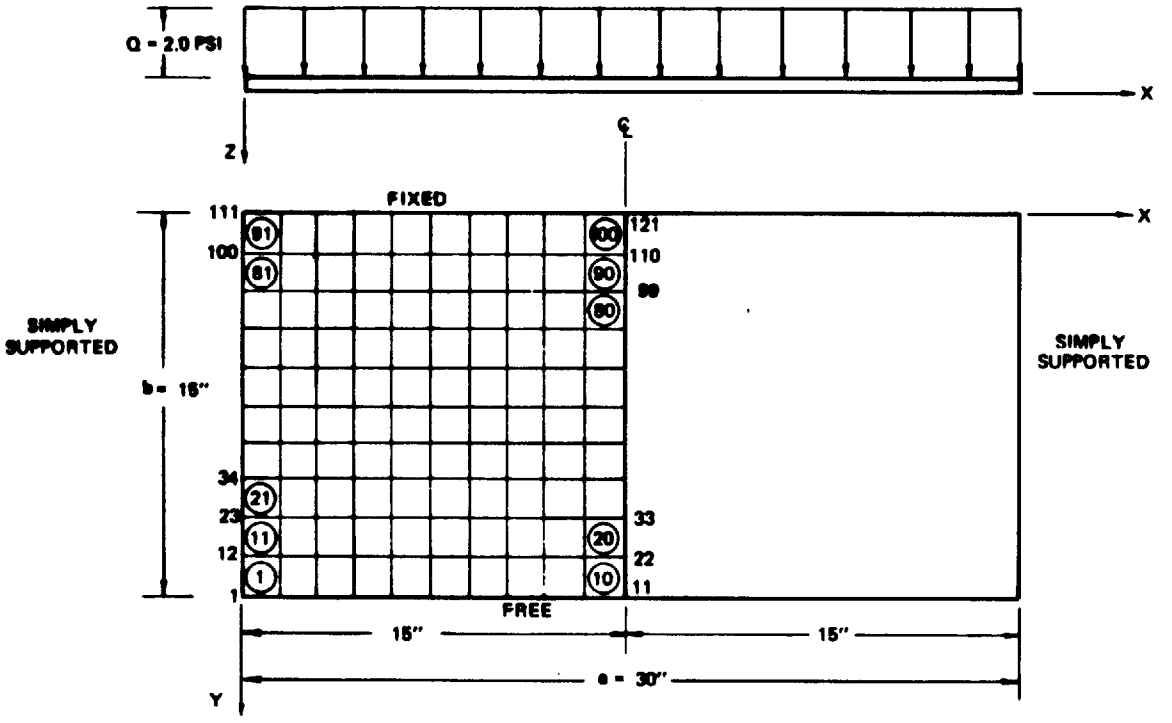
FIGURE 3.8-80



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PLATE GEOMETRY, LOADING, AND FINITE ELEMENT MESH (CE668 PROGRAM, SAMPLE PROBLEM A)

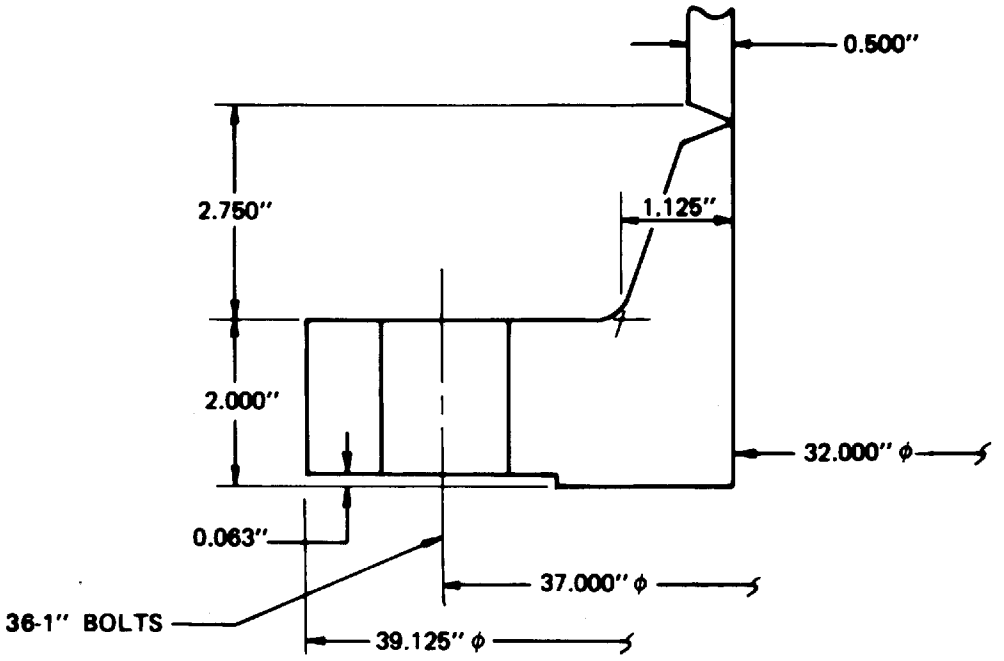
FIGURE 3.8-81



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PLATE GEOMETRY, LOADING, AND FINITE ELEMENT MESH CE668 PROGRAM, SAMPLE PROBLEM B)

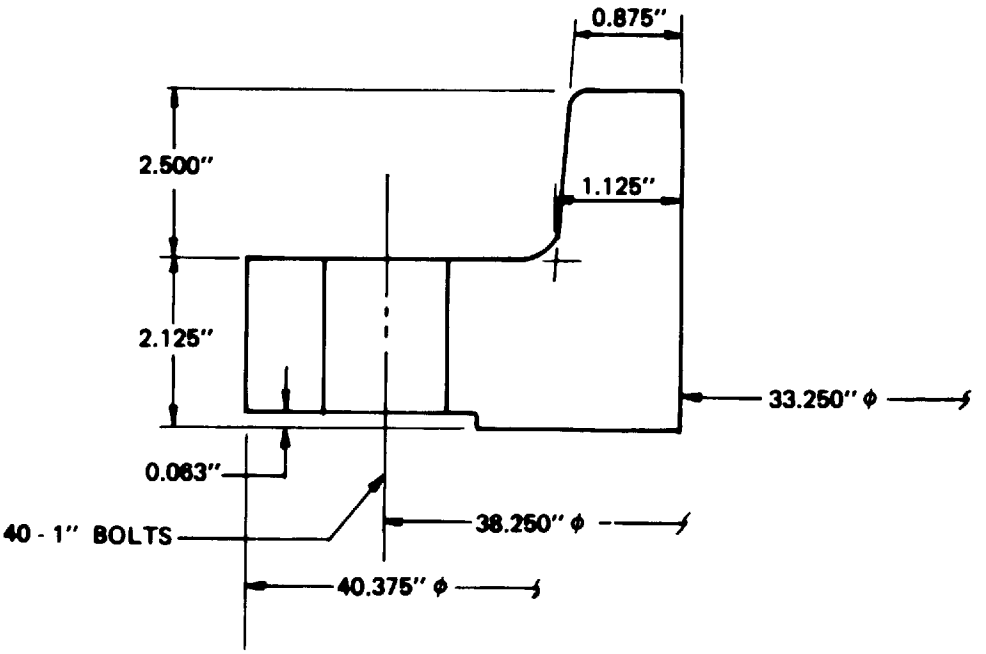
FIGURE 3.8-82



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

WELDING NECK FLANGE DETAIL
(E0119 PROGRAM, SAMPLE
PROBLEM A)

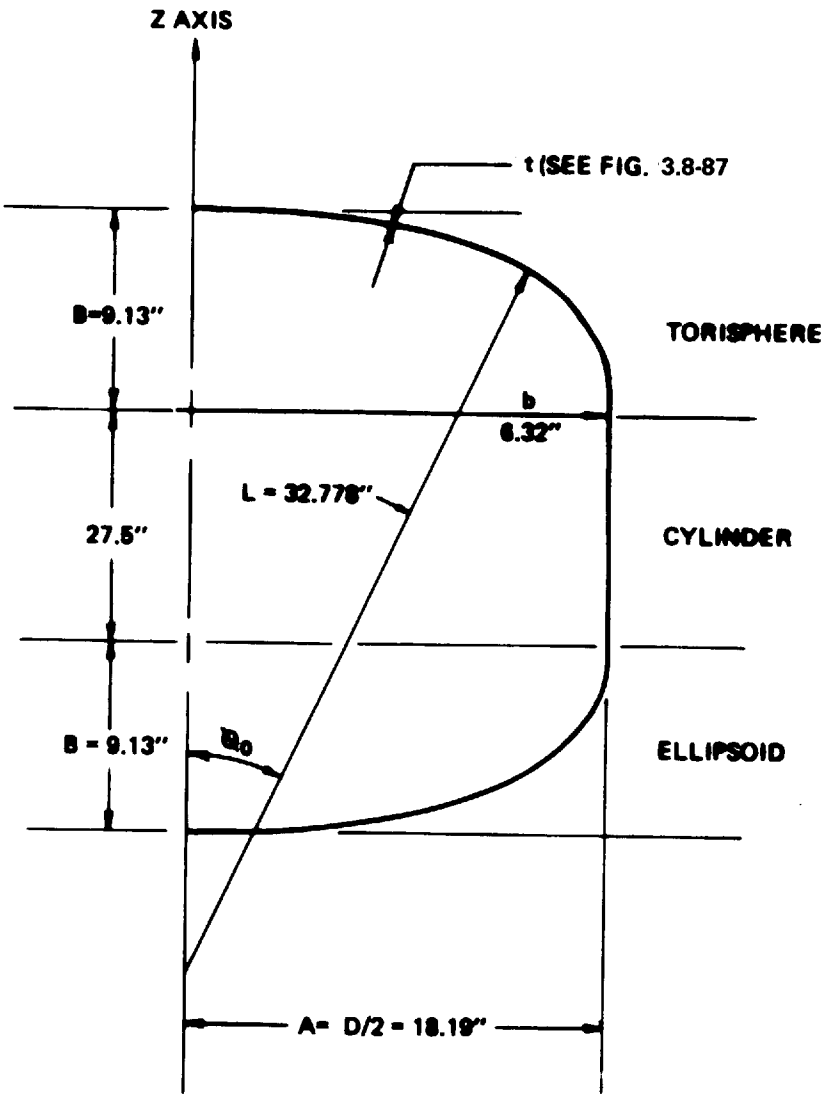
FIGURE 3.8-83



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SLIP-ON FLANGE DETAIL
(E0119 PROGRAM, SAMPLE
PROBLEM B)

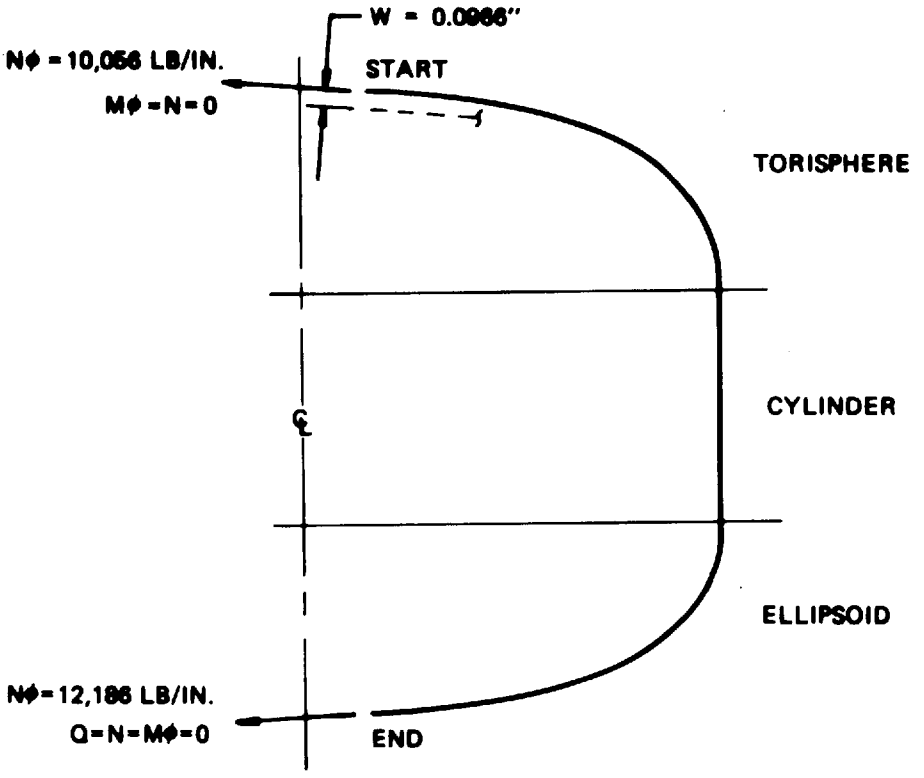
FIGURE 3.8-84



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GEOMETRY OF ELLIPSOIDAL AND TORISPHERICAL HEADS (E0781 PROGRAM, SAMPLE PROBLEM A)

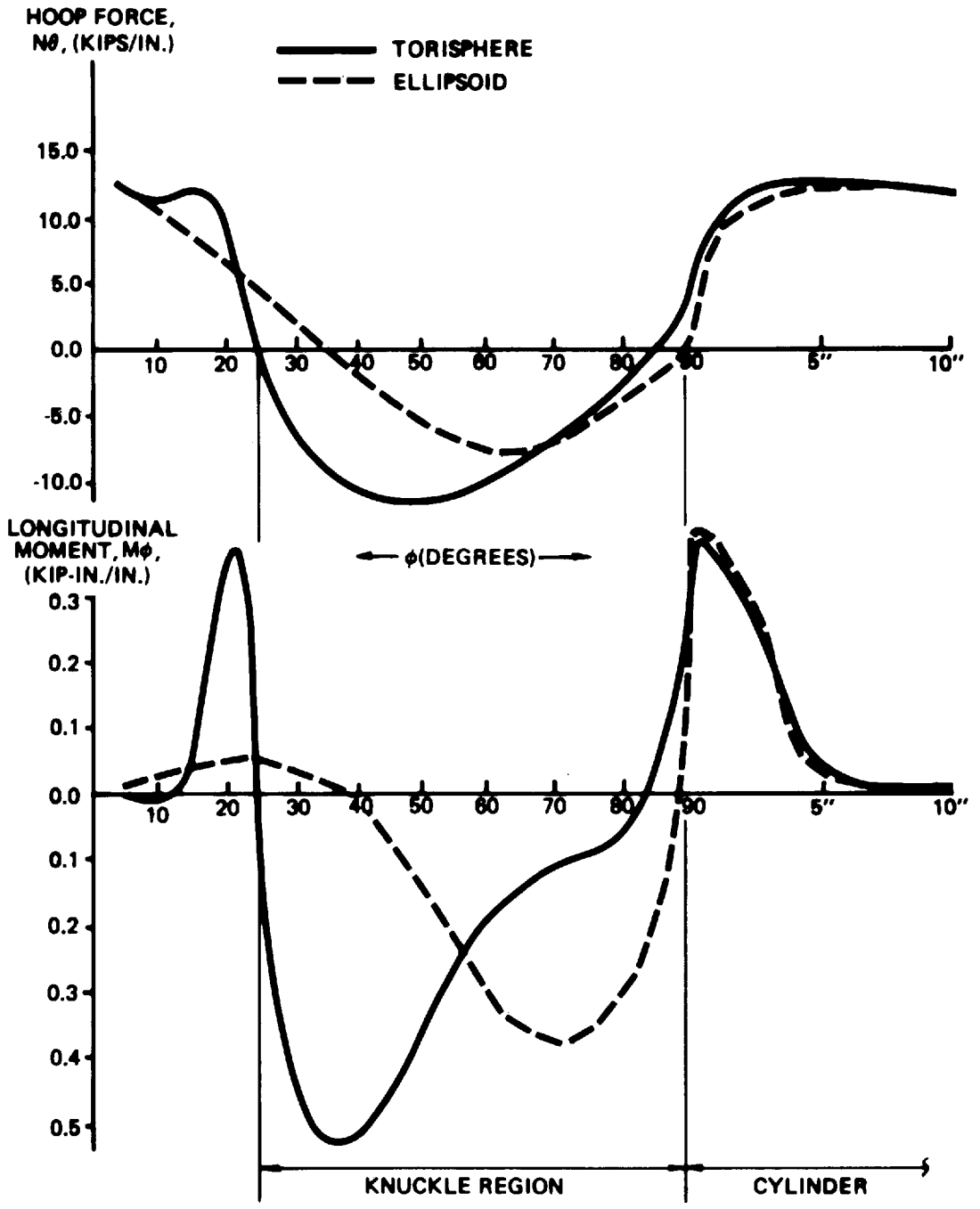
FIGURE 3.8-85



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

ANALYTICAL MODEL WITH BOUNDARY CONDITIONS (E0781 PROGRAM, SAMPLE PROBLEM A)

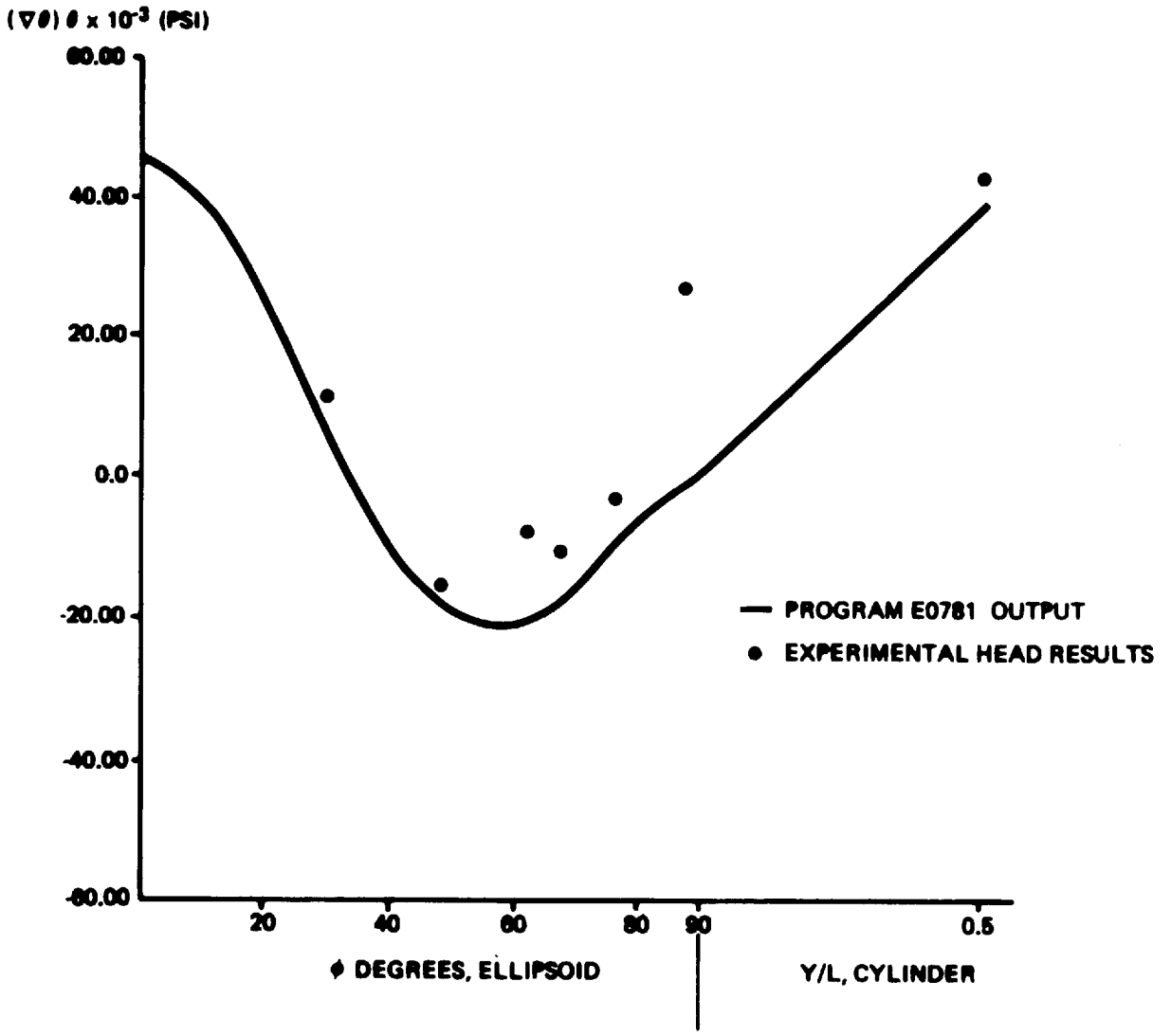
FIGURE 3.8-96



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PLOTS OF HOOP FORCE (N_θ) AND LONGITUDINAL MOMENT (M_ϕ) (E0781 PROGRAM, SAMPLE PROBLEM A)

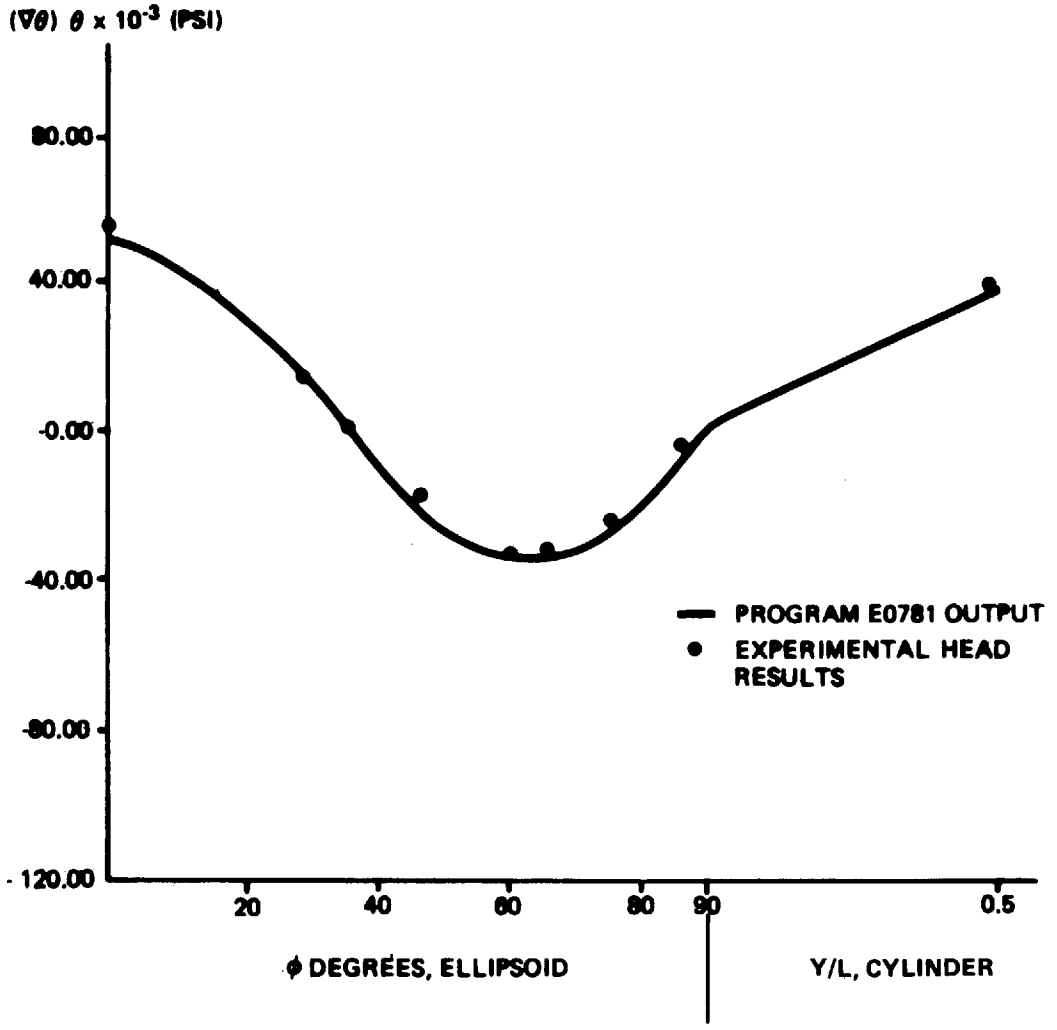
FIGURE 3.8-87



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PLOT OF STRESS IN THE HOOP (θ) DIRECTION ON THE INSIDE SURFACE ($\theta = 0^{o}$) (E0781 PROGRAM, SAMPLE PROBLEM A)

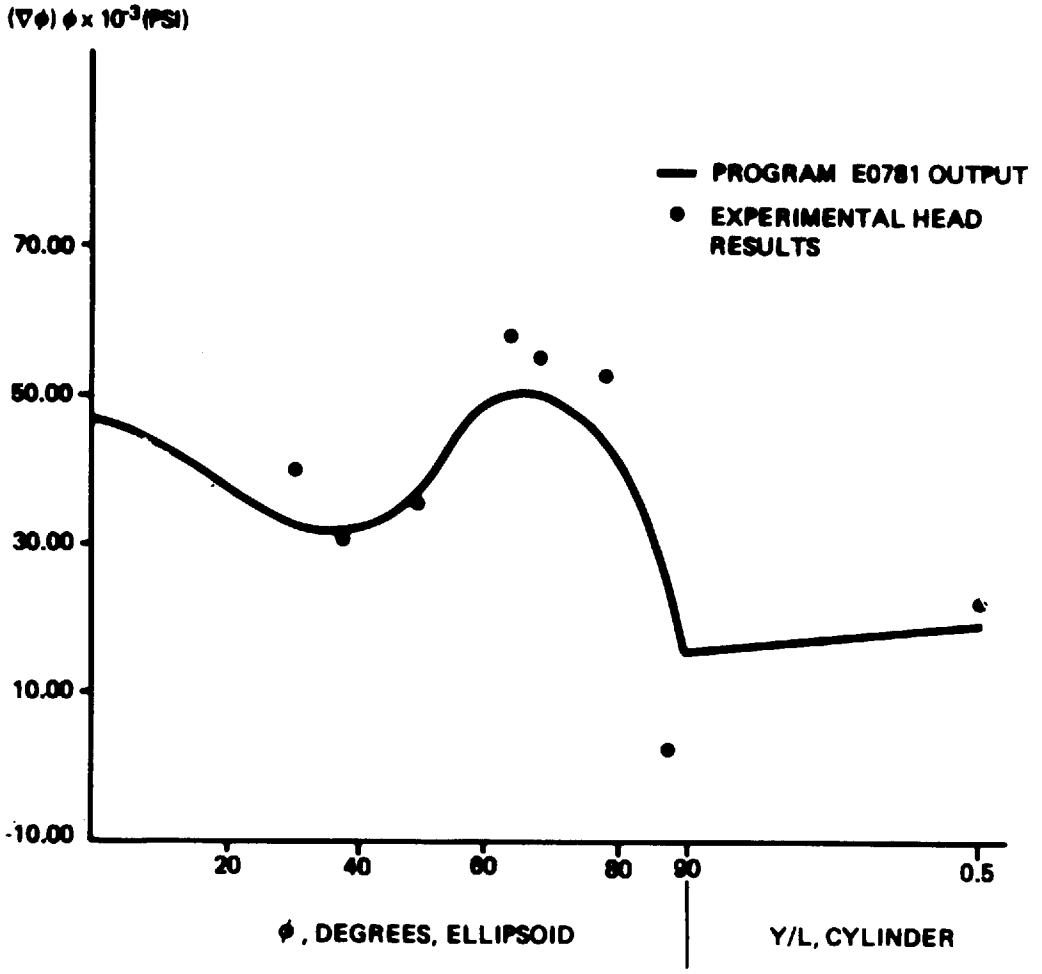
FIGURE 3.8-88



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PLOT OF STRESS IN THE HOOP(θ) DIRECTION ON THE OUTSIDE SURFACE($\theta=0^{o}$) (E0781 PROGRAM, SAMPLE PROBLEM A)

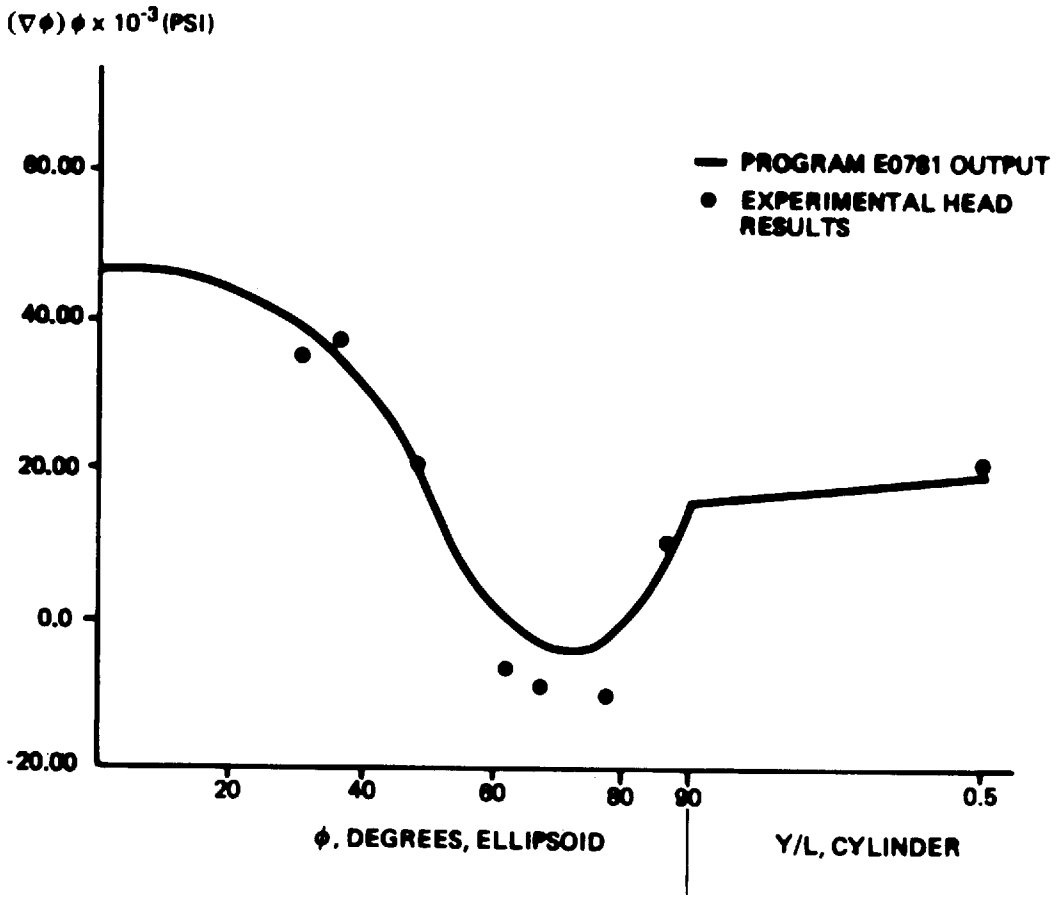
FIGURE 3.8-80



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PLOT OF STRESS IN THE LONGITUDINAL(ϕ) DIRECTION ON THE INSIDE SURFACE ($\theta=0^{o}$) (E0781 PROGRAM, SAMPLE PROBLEM A)

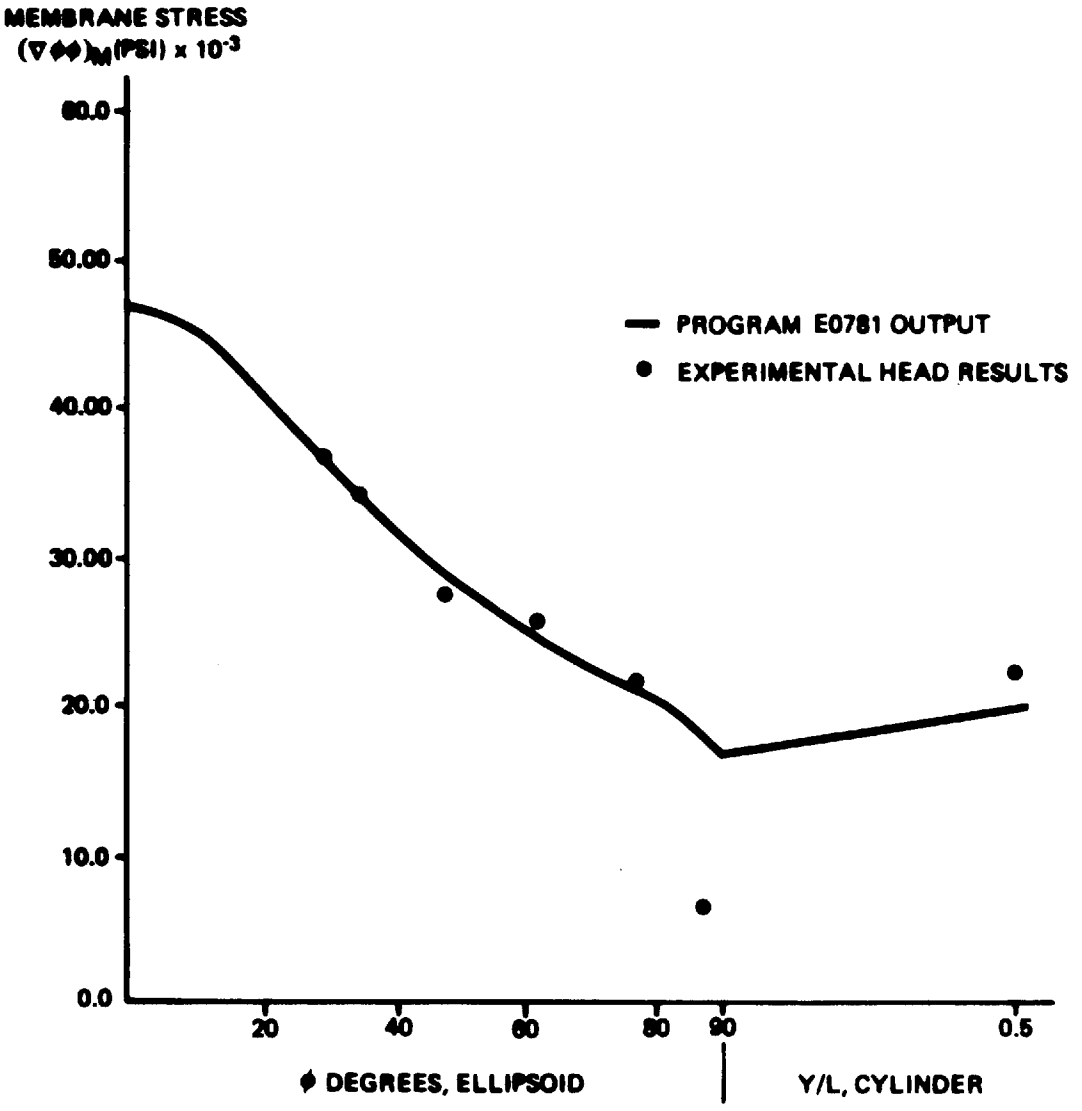
FIGURE 3.8-90



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PLOT OF STRESS IN THE LONGITUDINAL (ϕ) DIRECTION ON THE OUTSIDE SURFACE (E0781 PROGRAM, SAMPLE PROBLEM A)

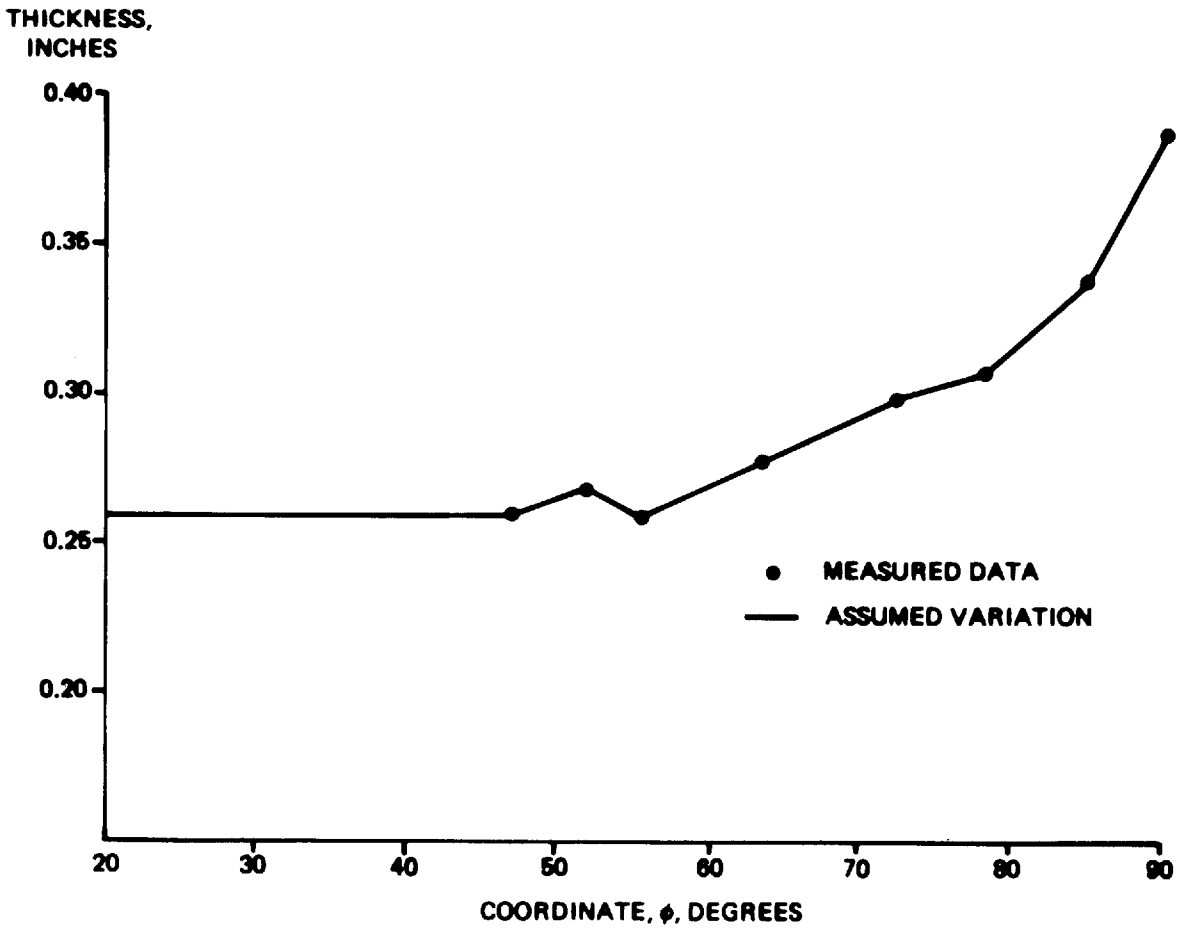
FIGURE 3.8-91



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PLOT OF MEMBRANCE STRESS (θ=0°)
(E0781 PROGRAM, SAMPLE PROBLEM A)

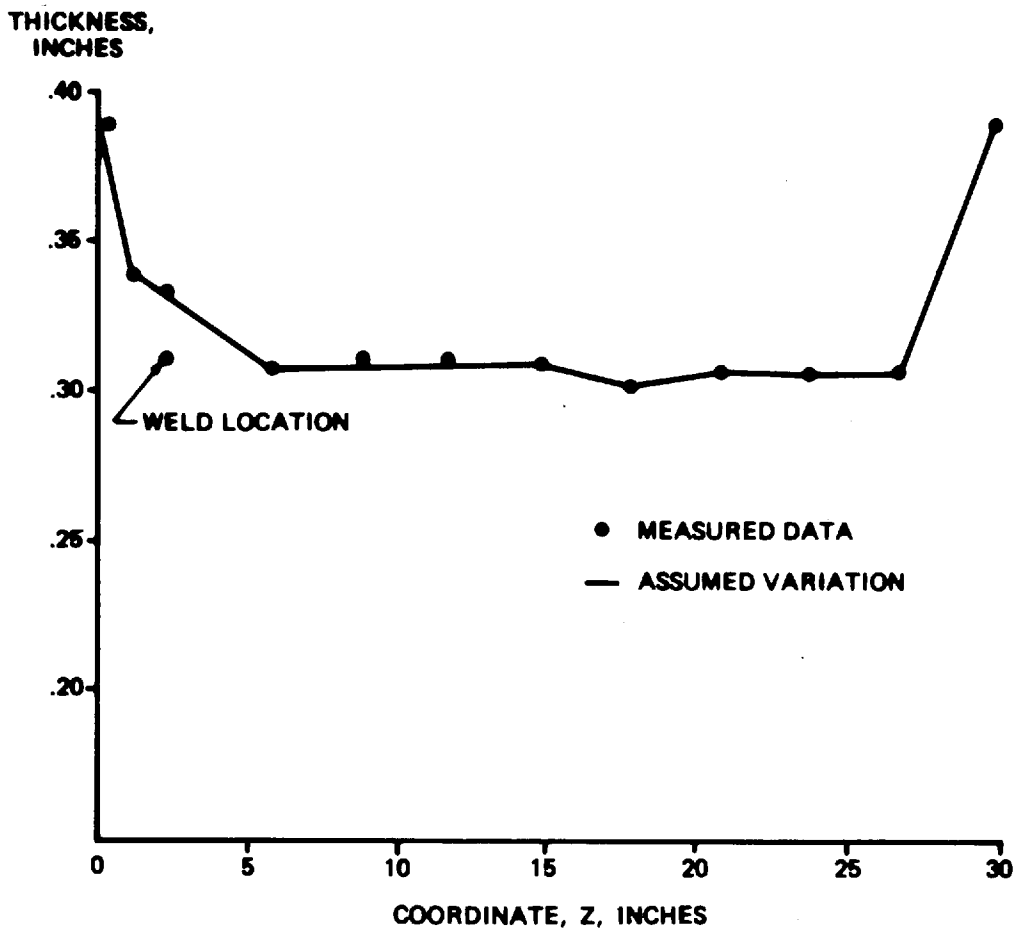
FIGURE 3.8-62



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

THICKNESS VARIATION IN EXPERIMENTAL HEAD NO. 1 (E0781 PROGRAM, SAMPLE PROBLEM A)

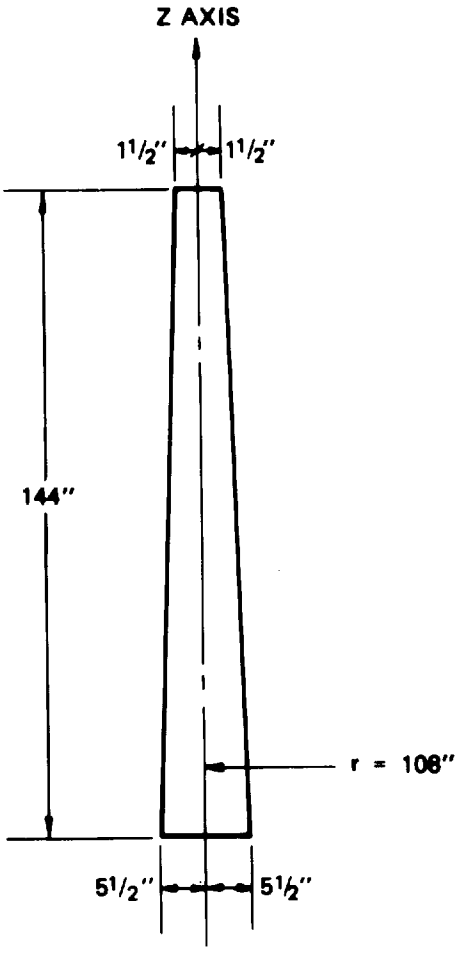
FIGURE 3.8-83



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

THICKNESS VARIATION IN CYLINDER NO. 1 (E0781 PROGRAM, SAMPLE PROBLEM A)

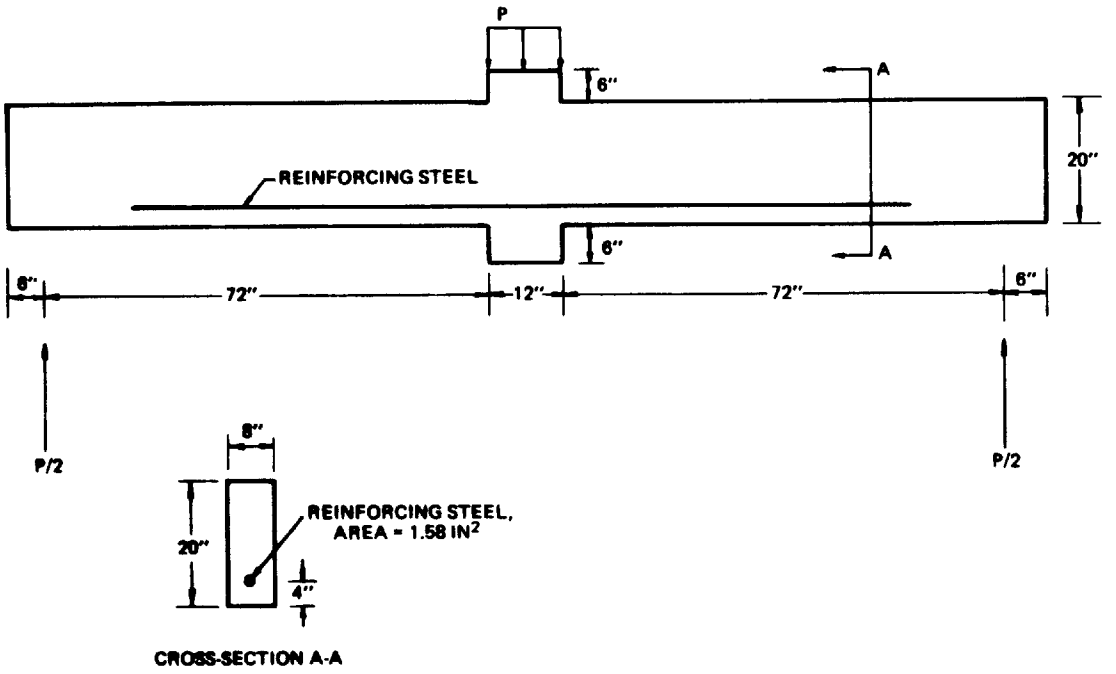
FIGURE 3.8-94



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GEOMETRY OF CYLINDRICAL WATER TANK (E0781 PROGRAM, SAMPLE PROBLEM B)

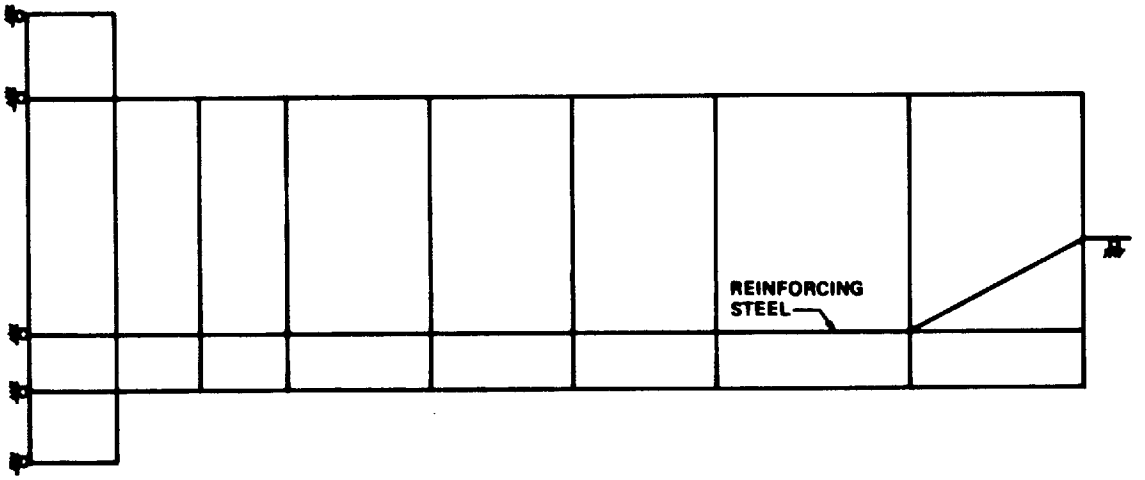
FIGURE 3.8-95



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

EXPERIMENTAL BEAM GEOMETRY (FINEL PROGRAM, SAMPLE PROBLEM A)

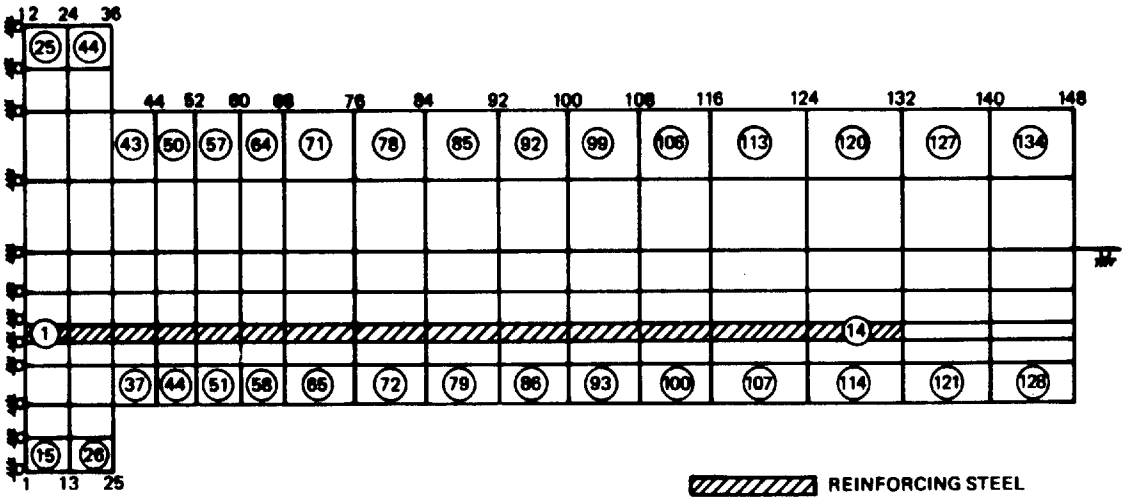
FIGURE 3.8-96



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FINITE ELEMENT MESH USED IN REFERENCE 3.8-14 (FINEL PROGRAM, SAMPLE PROBLEM A)

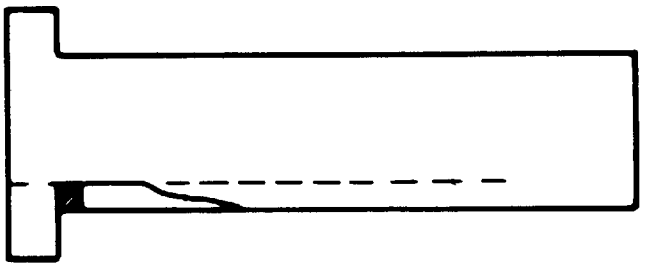
FIGURE 3.8-97



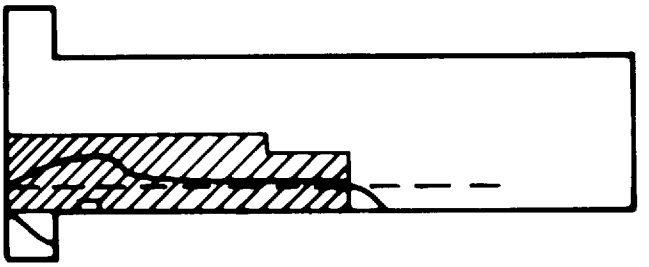
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FINITE ELEMENT MESH USED IN PROGRAM VERIFICATION (FINEL PROGRAM, SAMPLE PROBLEM A)

FIGURE 3.8-98



FINEL. 8.7 kips REF. 3.8-14 — 8.0 KIPS
(NO CRACKING IN FINEL BELOW 8.7 KIPS)



FINEL AND REF. 3.8-14 — 20.0 KIPS

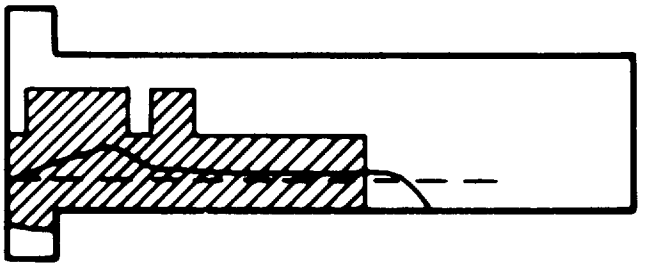
——— BOUNDARY OF CRACKED REGION, REF. 3.8-14

CRACKED REGION, FINEL

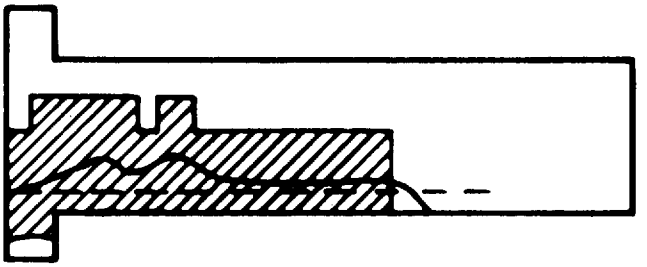
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REGIONS OF CRACKING FROM REFERENCE 3.8-14 AND FINEL ANALYSIS (FINEL PROGRAM, SAMPLE PROBLEM A)
(SHEET 1 OF 2)

FIGURE 3.8-99



FINEL AND REF. 3.8-14 — 28.0 KIPS

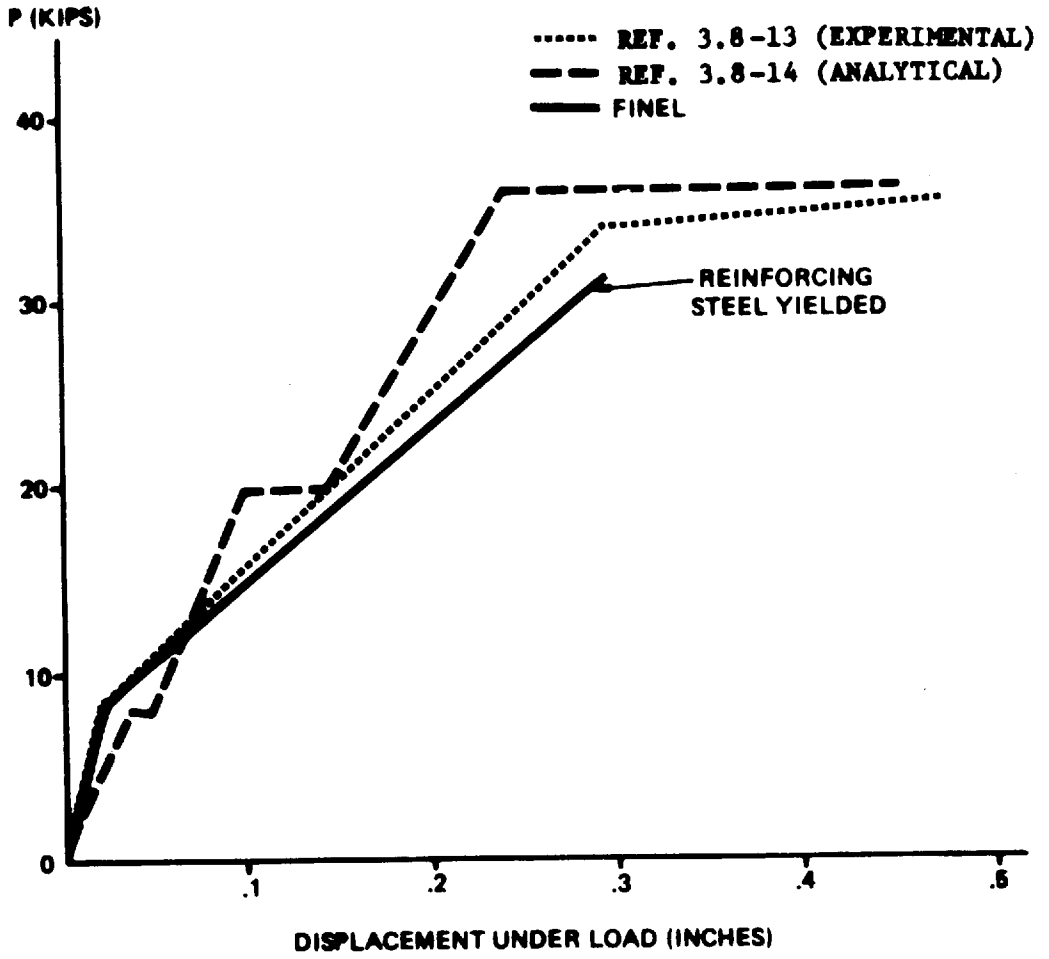


FINEL AND REF. 3.8-14 — 31.2 KIPS

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REGIONS OF CRACKING FROM REFERENCE 3.8-14 AND FINEL ANALYSIS (FINEL PROGRAM, SAMPLE PROBLEM A)
(SHEET 2 OF 2)

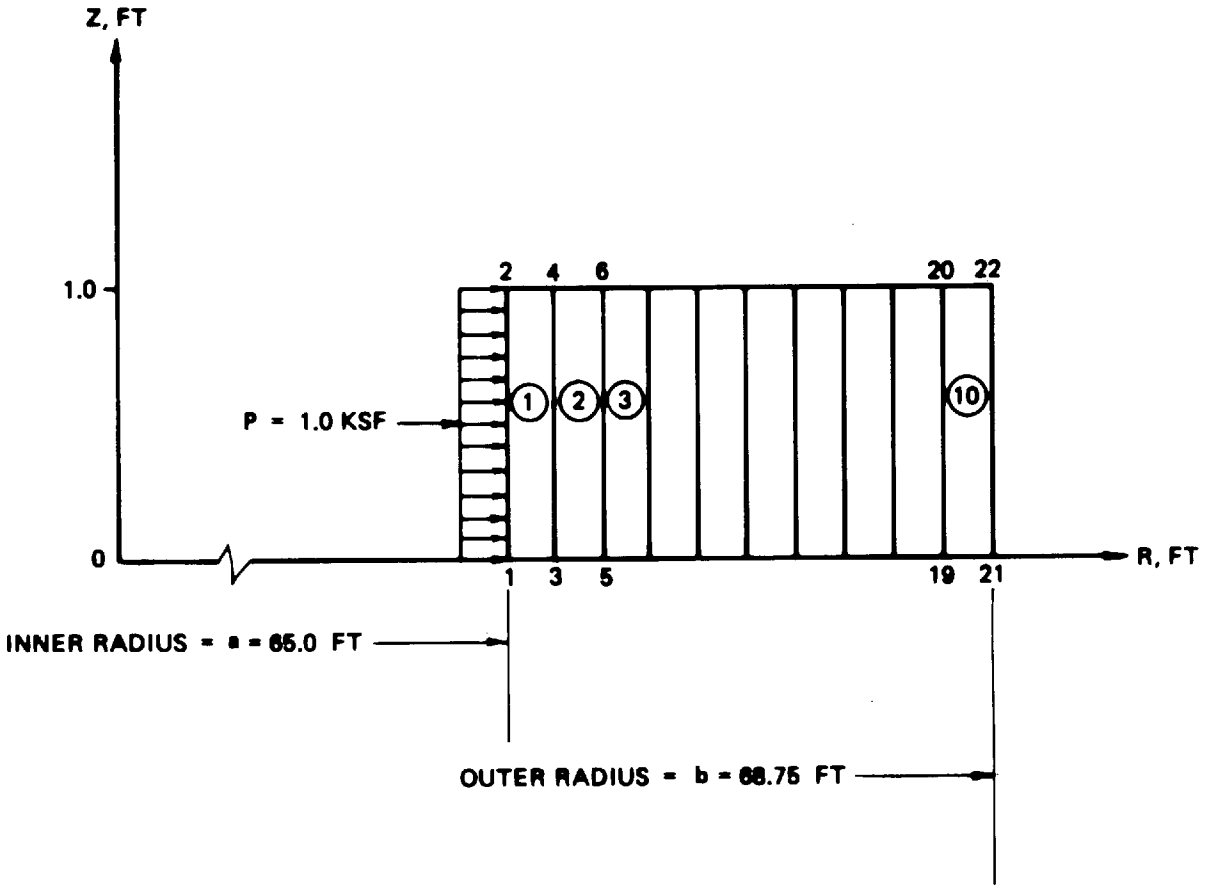
FIGURE 3.8-90



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LOAD-DEFLECTION CURVES FROM REFERENCE 3.8-13, REFERENCE 3.8-14, AND FINEL ANALYSIS (FINEL PROGRAM, SAMPLE PROBLEM A)

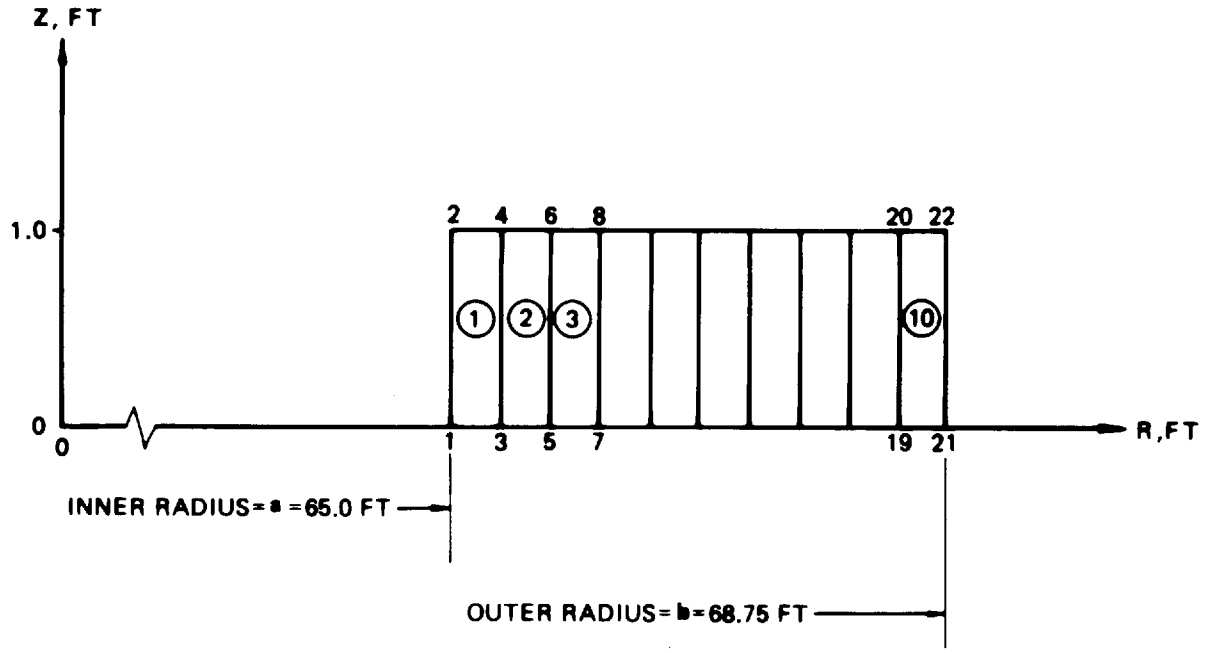
FIGURE 3.8-100



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FINITE ELEMENT MODEL FOR HOLLOW CYLINDER WITH DISTRIBUTED PRESSURE LOADING (FINEL PROGRAM, SAMPLE PROBLEM B)

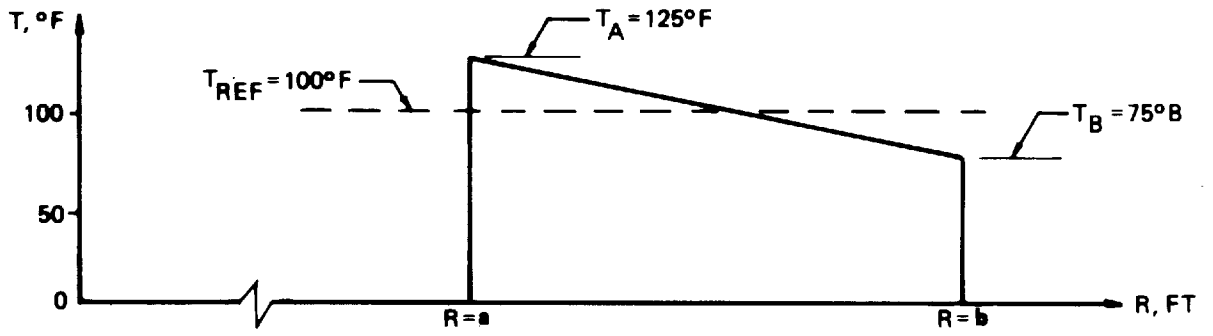
FIGURE 3.8-101



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FINITE ELEMENT MODEL FOR HOLLOW CYLINDER WITH LINEAR TEMPERATURE GRADIENT (FINEL PROGRAM, SAMPLE PROBLEM C)

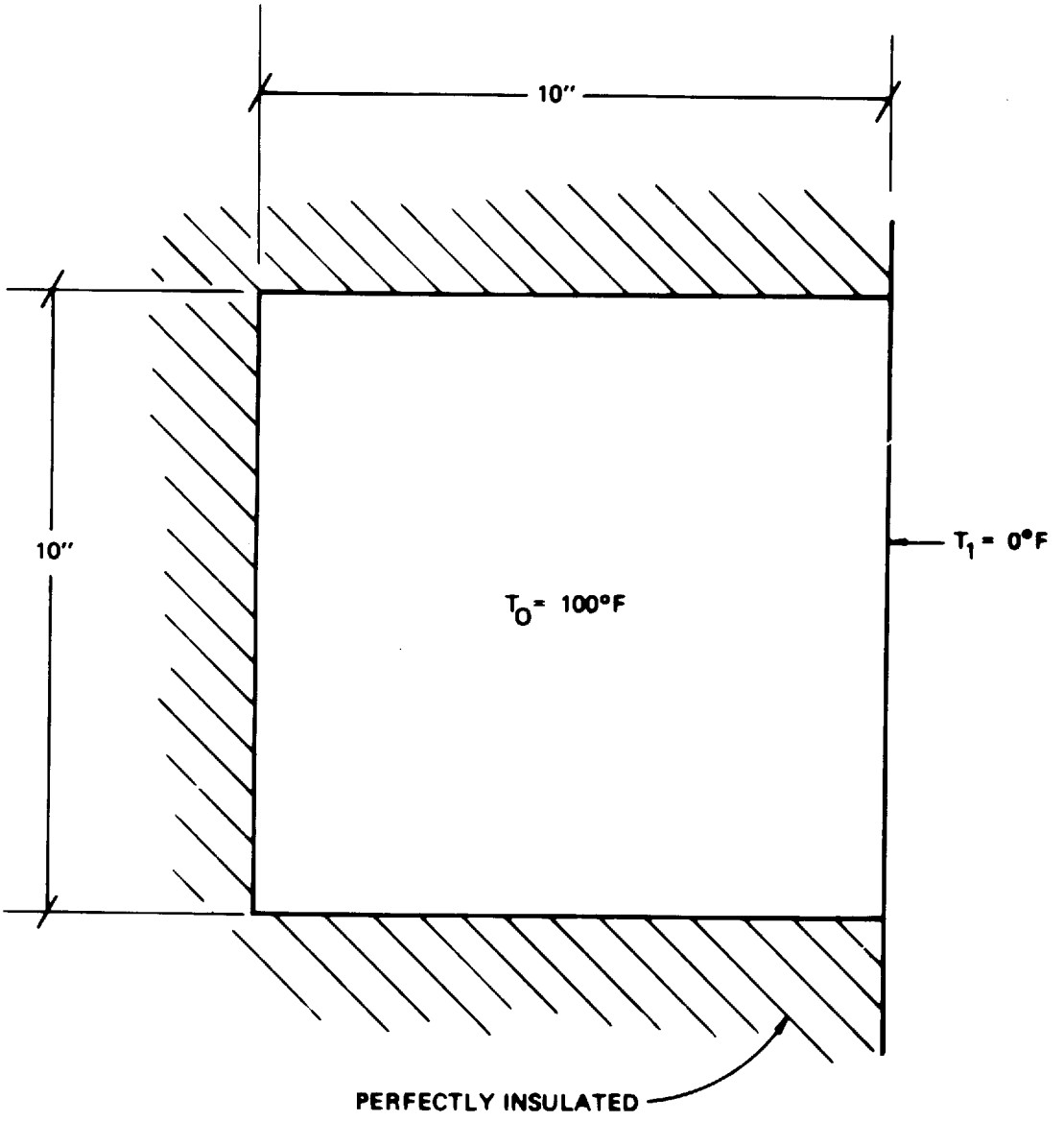
FIGURE 3.8-102



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TEMPERATURE GRADIENT THROUGH WALL OF HOLLOW CYLINDER (FINEL PROGRAM, SAMPLE PROBLEM C)

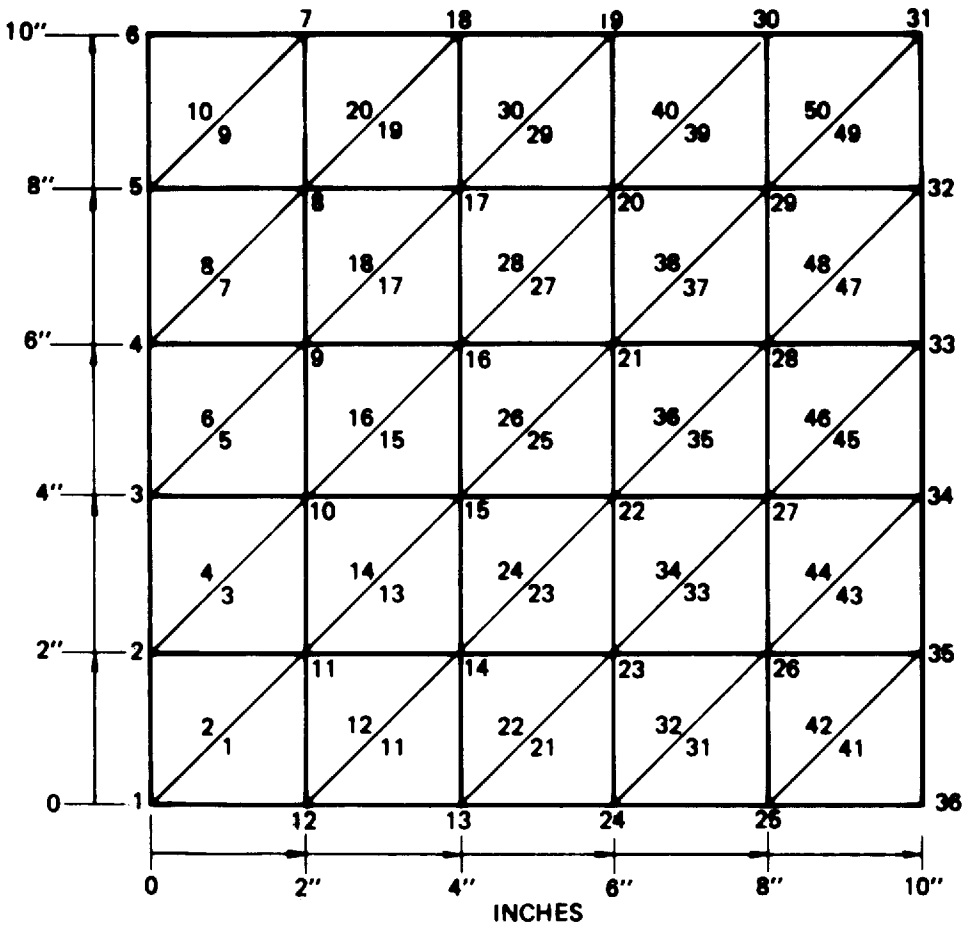
FIGURE 3.8-103

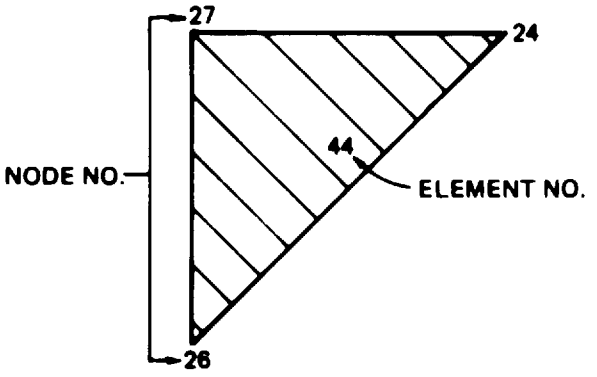


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TEMPERATURE CONDITIONS AND ARRANGEMENT OF SQUARE PLATE (ME620 PROGRAM, SAMPLE PROBLEM A)

FIGURE 3.8-104

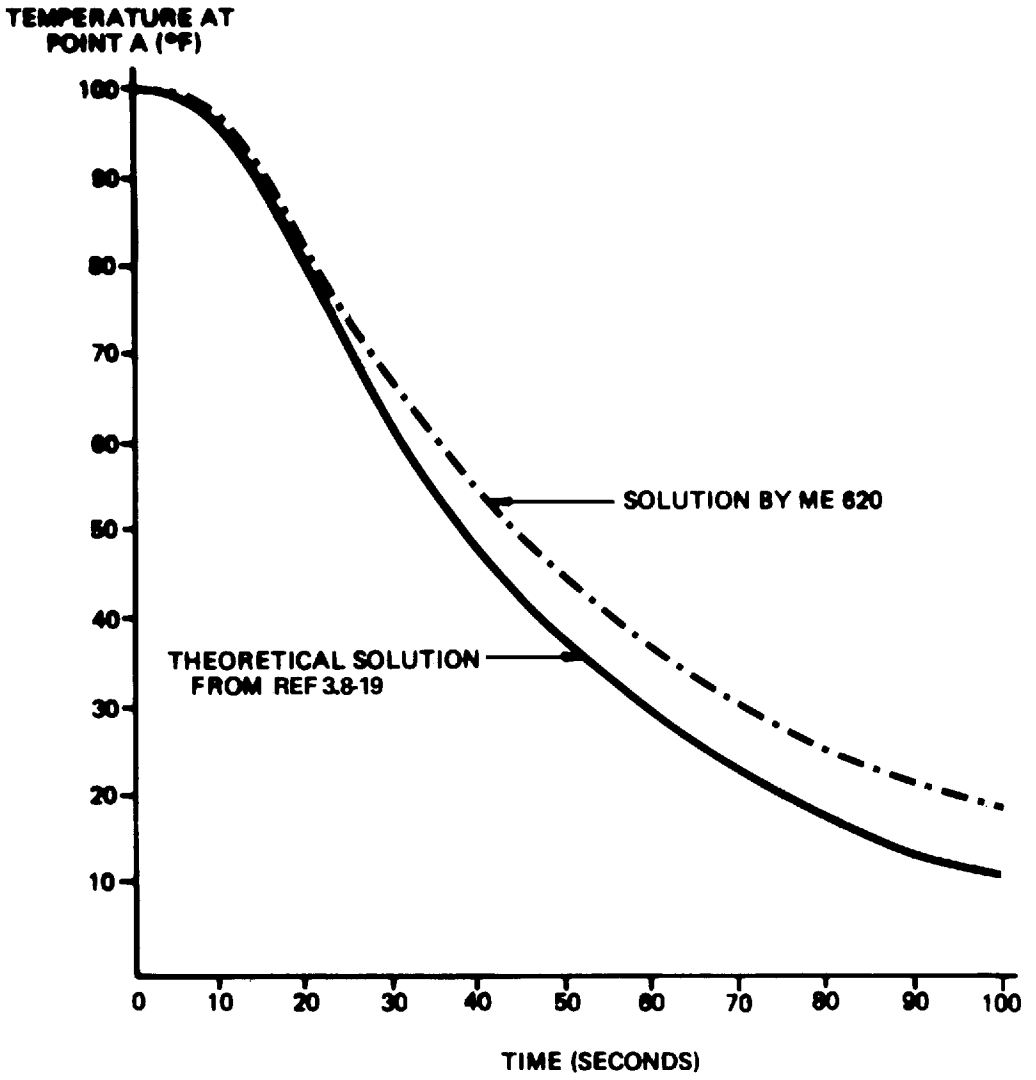




LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FINITE ELEMENT MODEL OF SQUARE PLATE (ME620 PROGRAM, SAMPLE PROBLEM A)

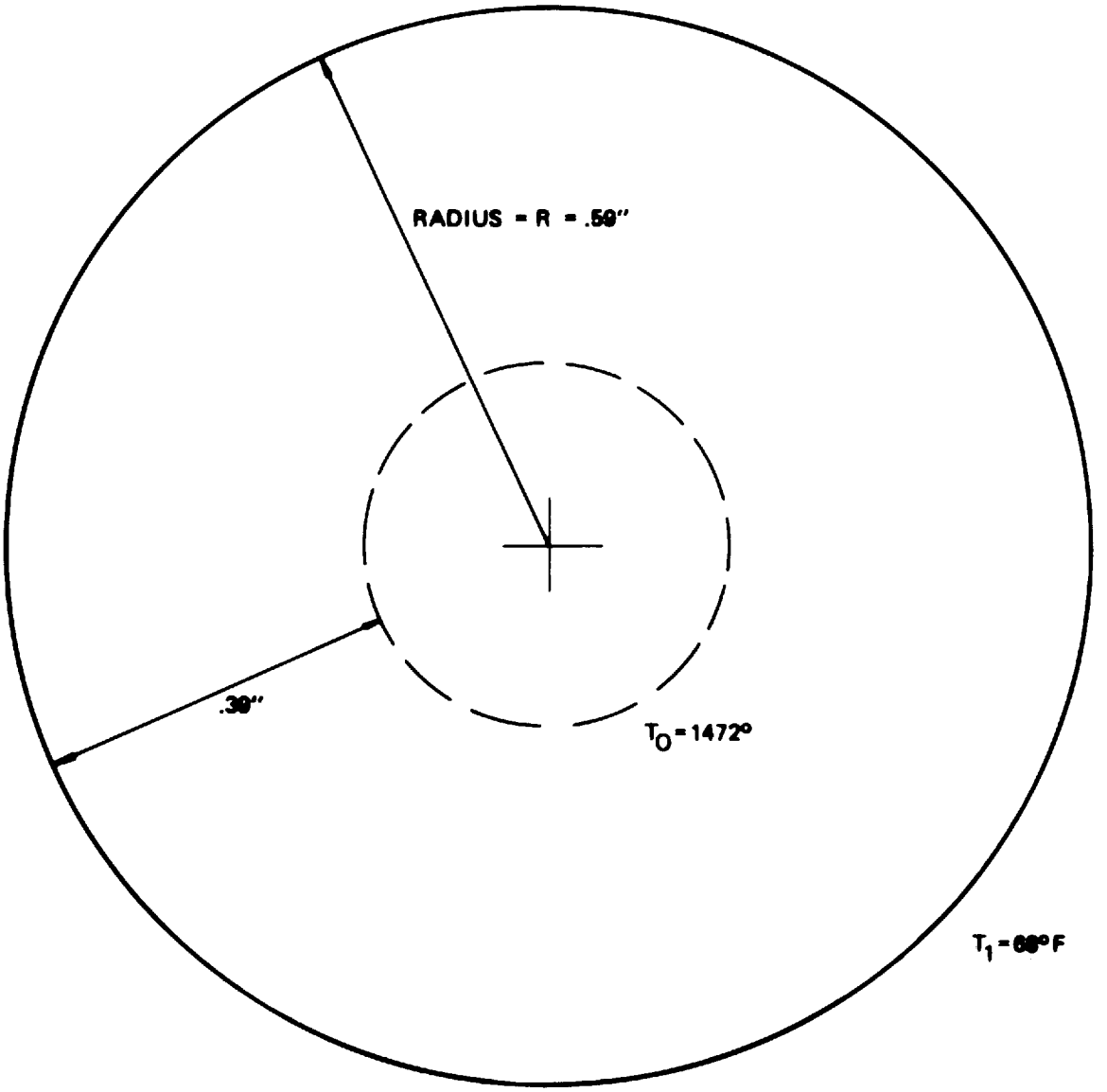
FIGURE 3.8-105



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

COMPARISON OF TEMPERATURE TRANSIENTS FROM ME620 AND REFERENCE 3.8-19 (ME620 PROGRAM, SAMPLE PROBLEM A)

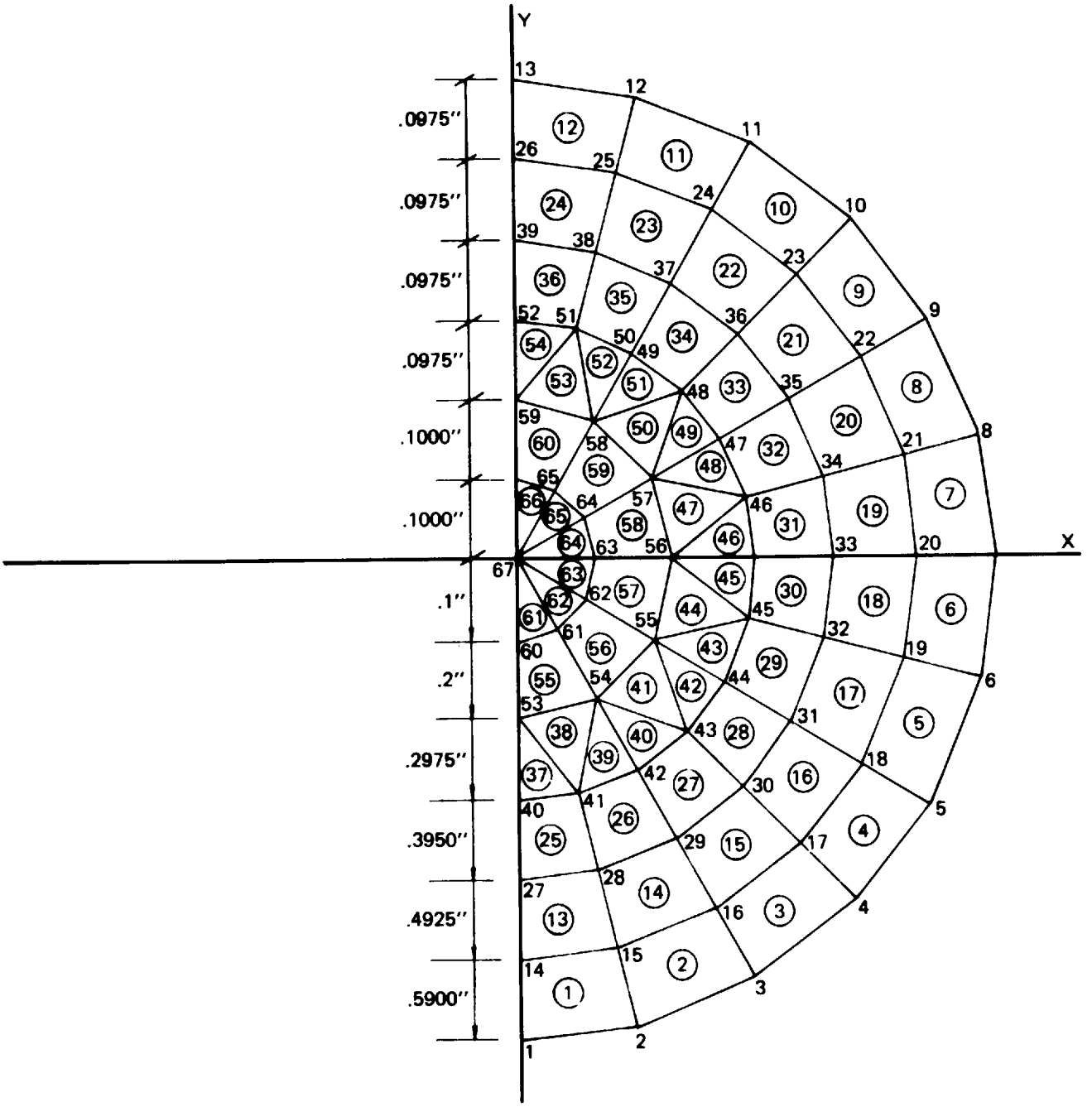
FIGURE 3.8-106



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SIZE AND TEMPERATURE CONDITIONS OF SOLID STEEL SPHERE (ME620 PROGRAM, SAMPLE PROBLEM B)

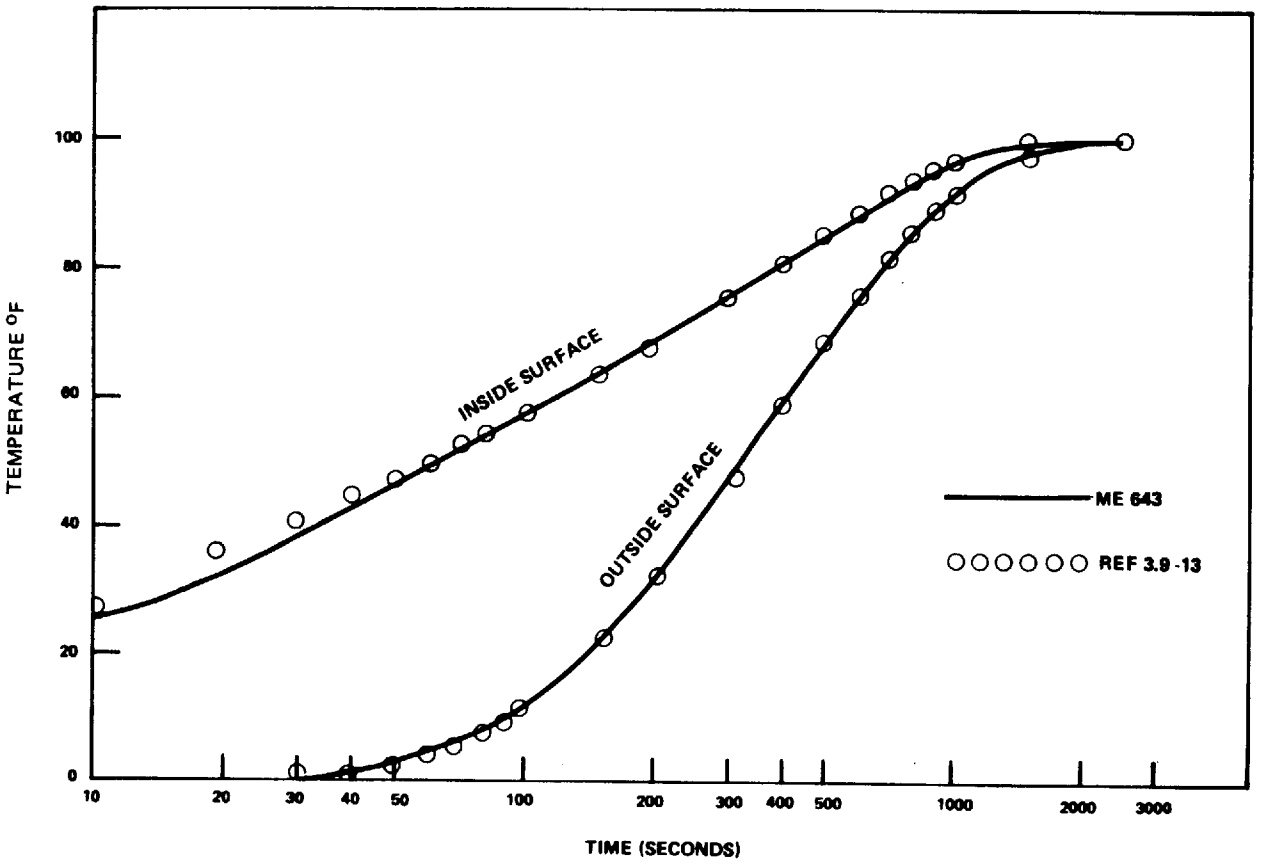
FIGURE 3.8-107



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FINITE ELEMENT MODEL OF SOLID STEEL SPHERE (ME620 PROGRAM, SAMPLE PROBLEM B)

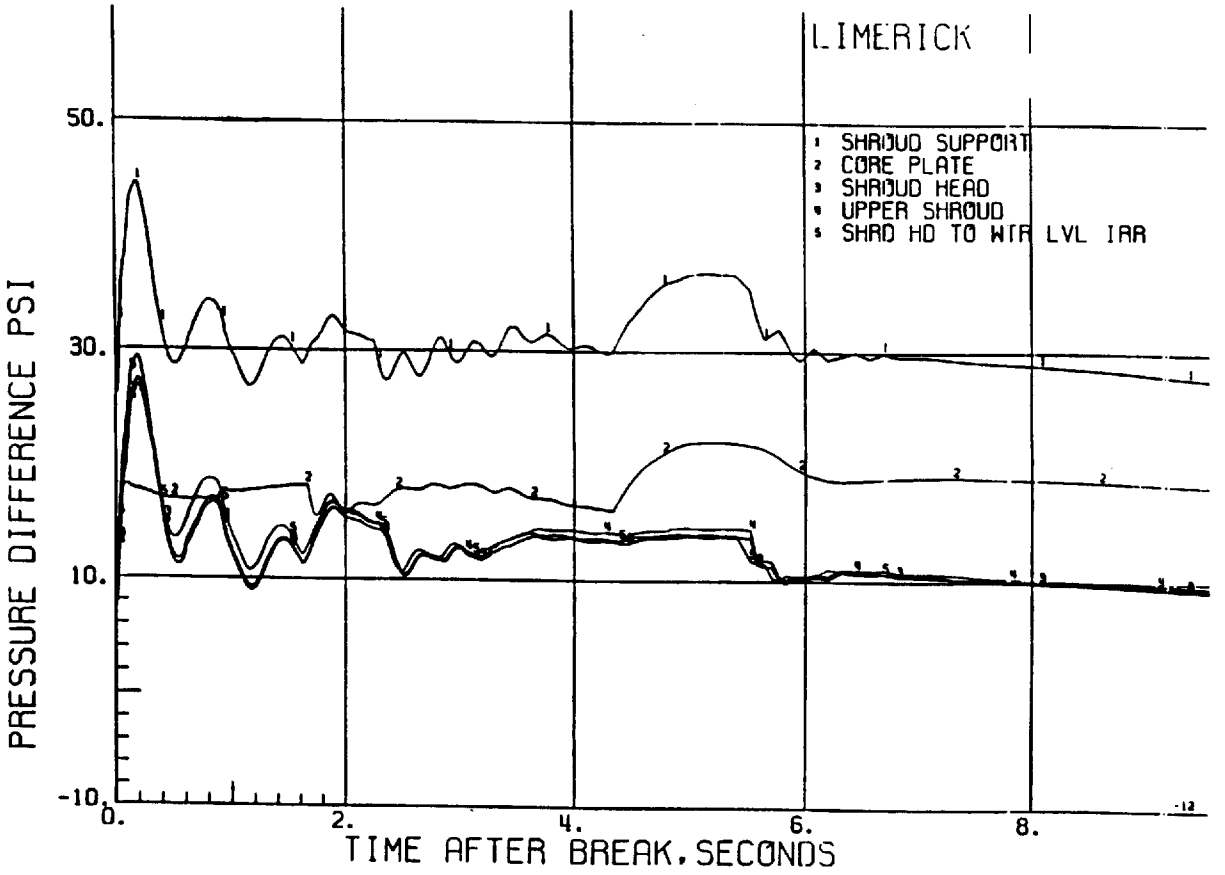
FIGURE 3.8-108



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TRANSIENT TEMPERATURE RESPONSE OF A SAMPLE PIPE

FIGURE 3.9-1

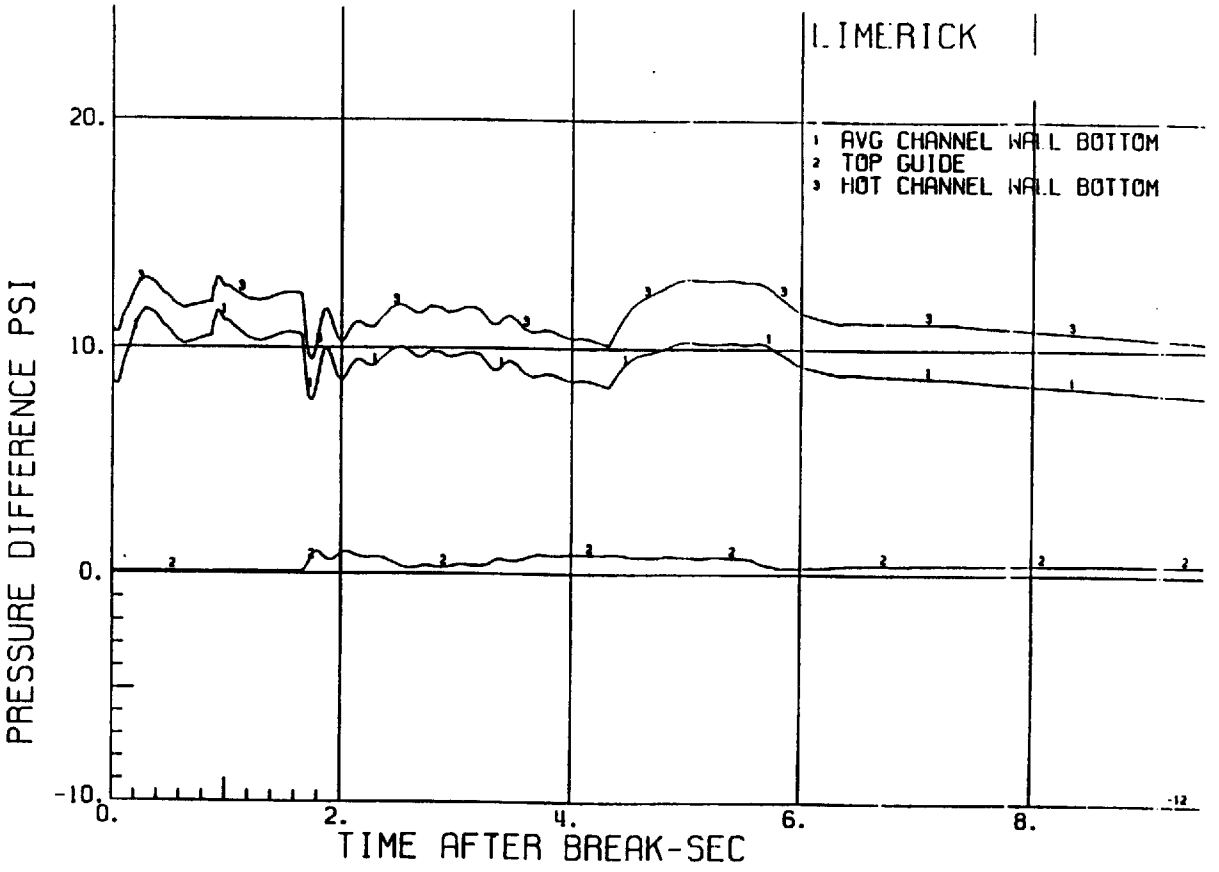


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TRANSIENT PRESSURE DIFFERENTIALS FOLLOWING A STREAMLINE BREAK (SHEET 1 OF 2)

FIGURE 3.9-2

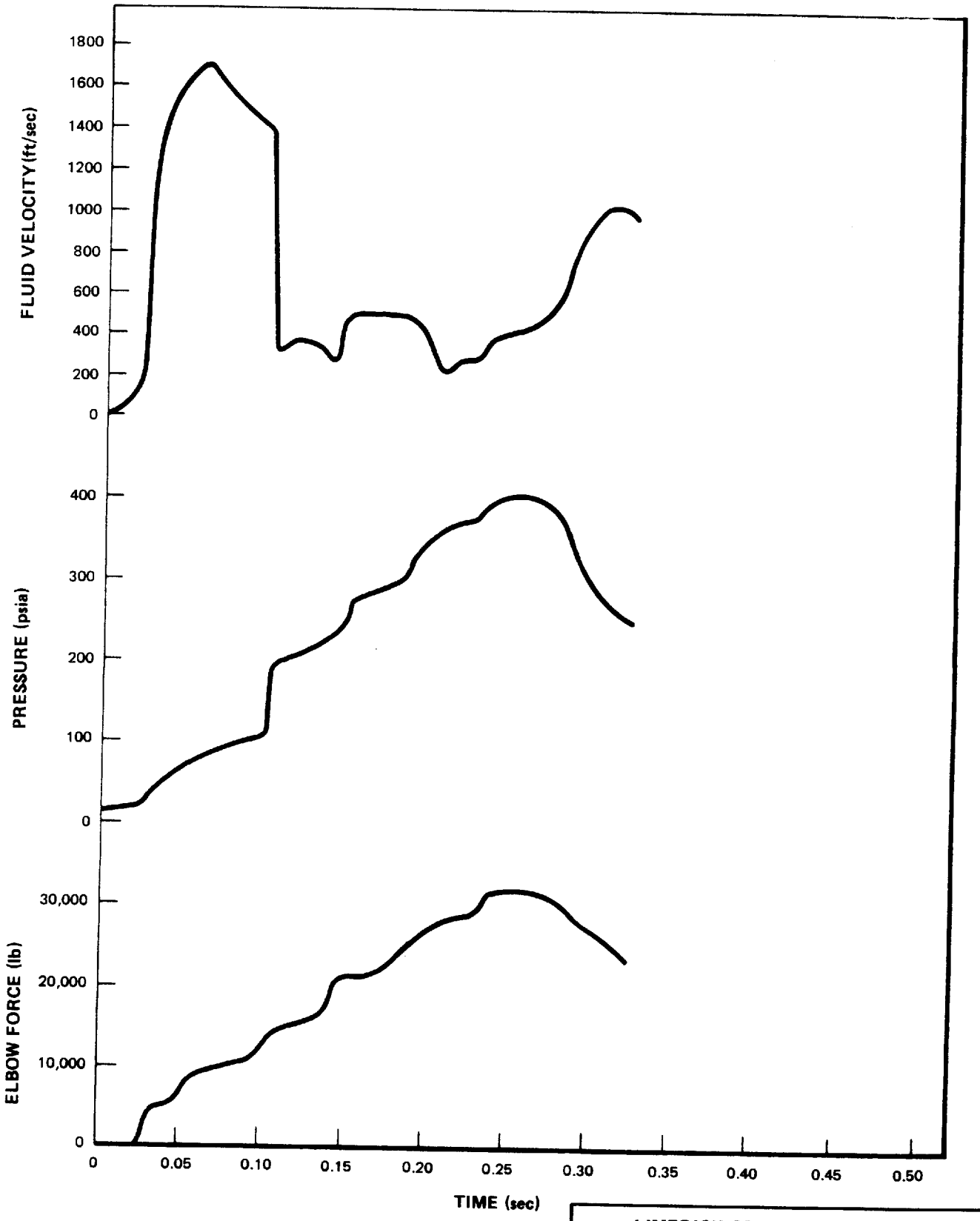
Rev. 5, 4/96



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TRANSIENT PRESSURE DIFFERENTIALS FOLLOWING A STREAMLINE BREAK (SHEET 2 OF 2)

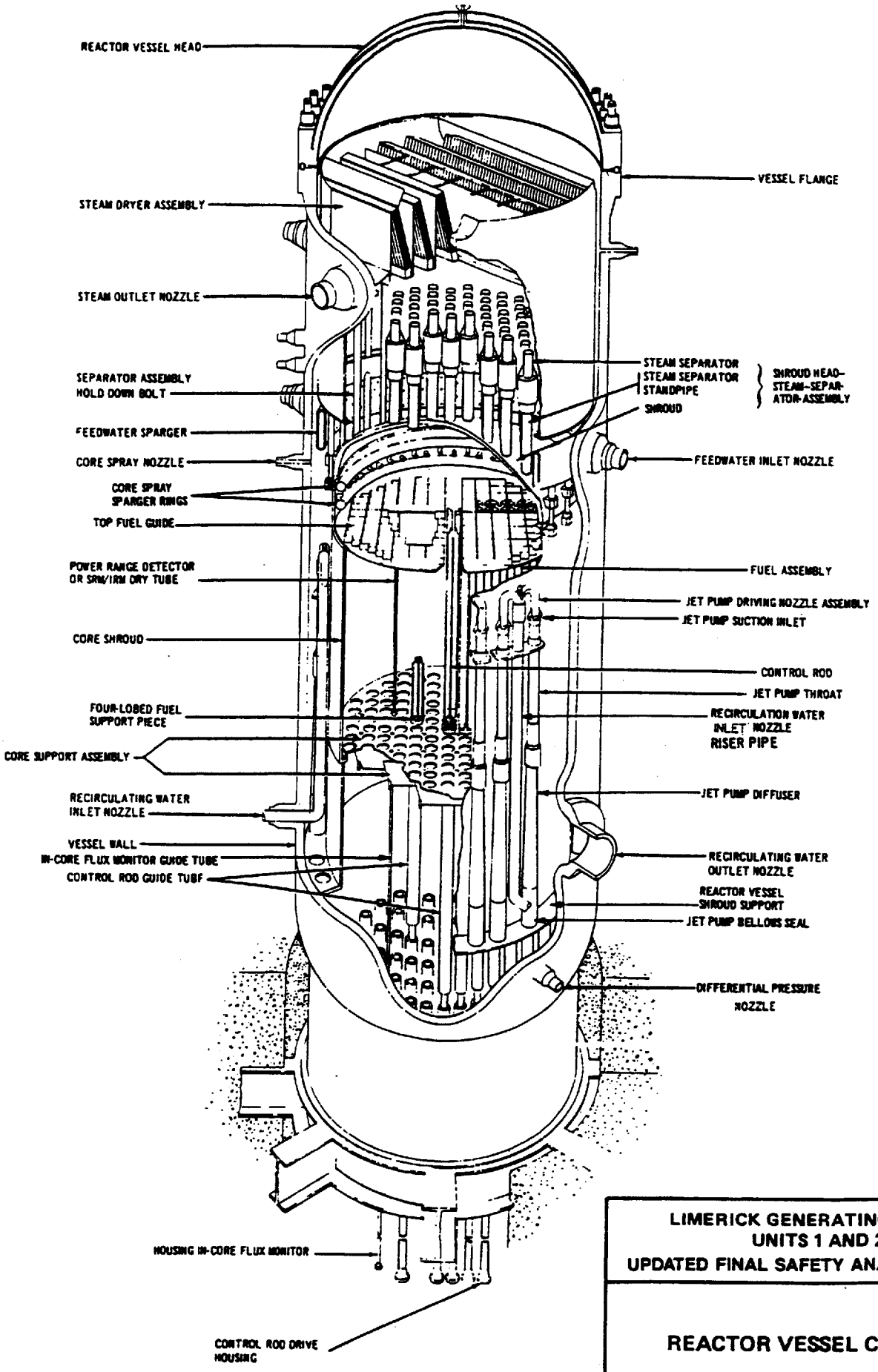
FIGURE 3.9-2 Rev. 5, 4/96



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL RELIEF VALVE TRANSIENT

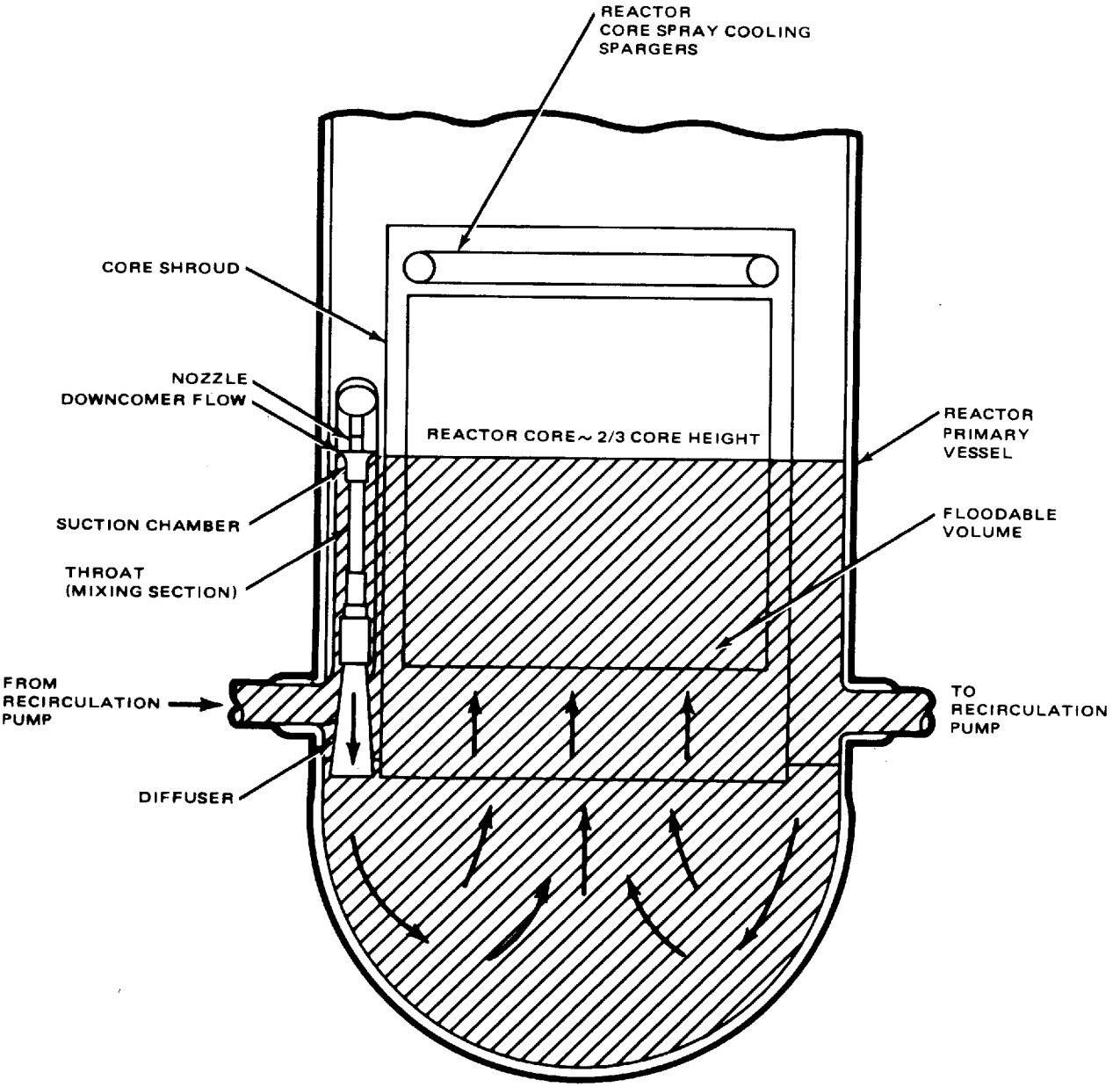
FIGURE 3.9-3



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL CUTAWAY

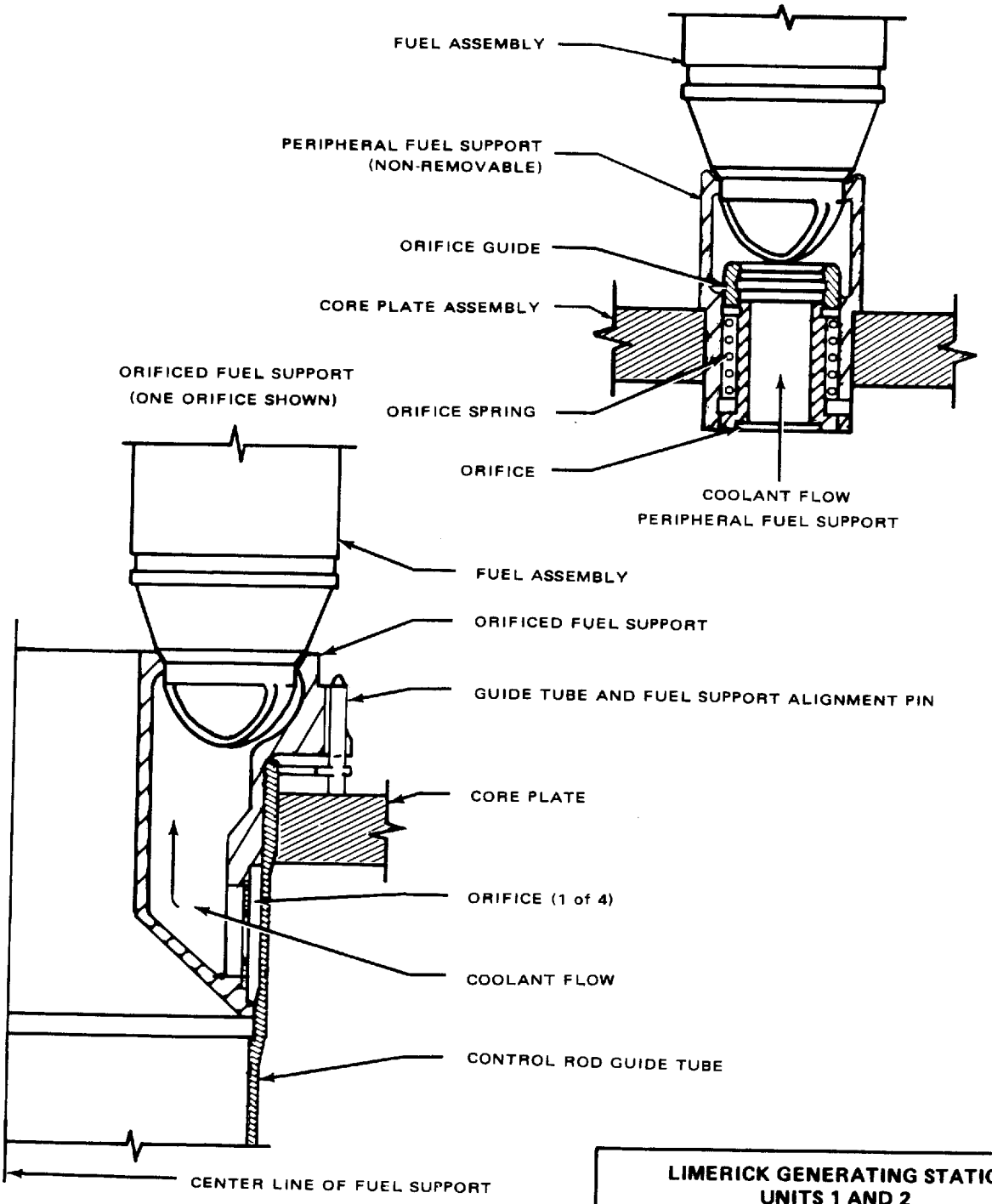
FIGURE 3.9-4 Rev 08 11/98



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR INTERNALS FLOW PATHS

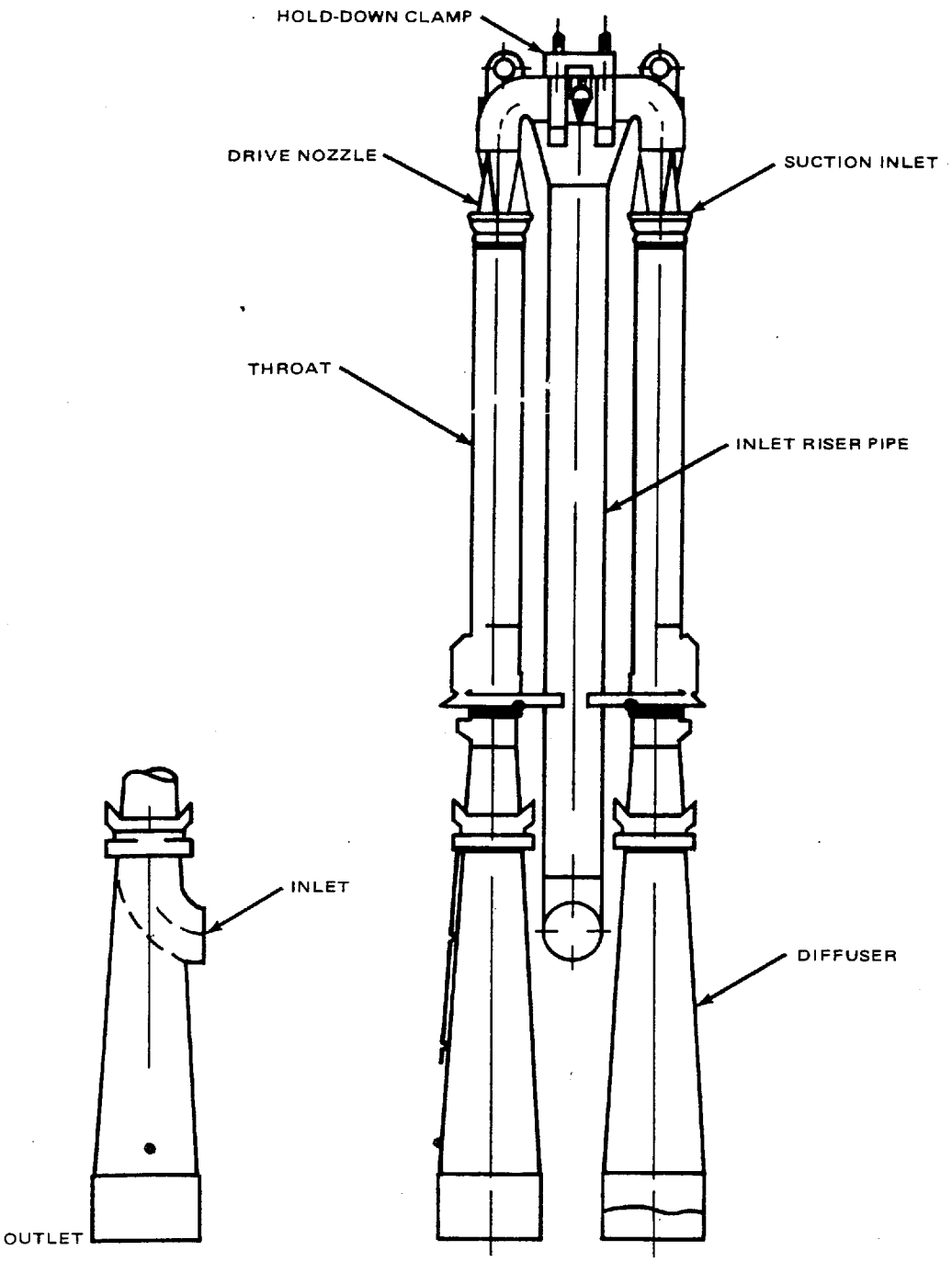
FIGURE 3.9-5



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FUEL SUPPORT PIECES

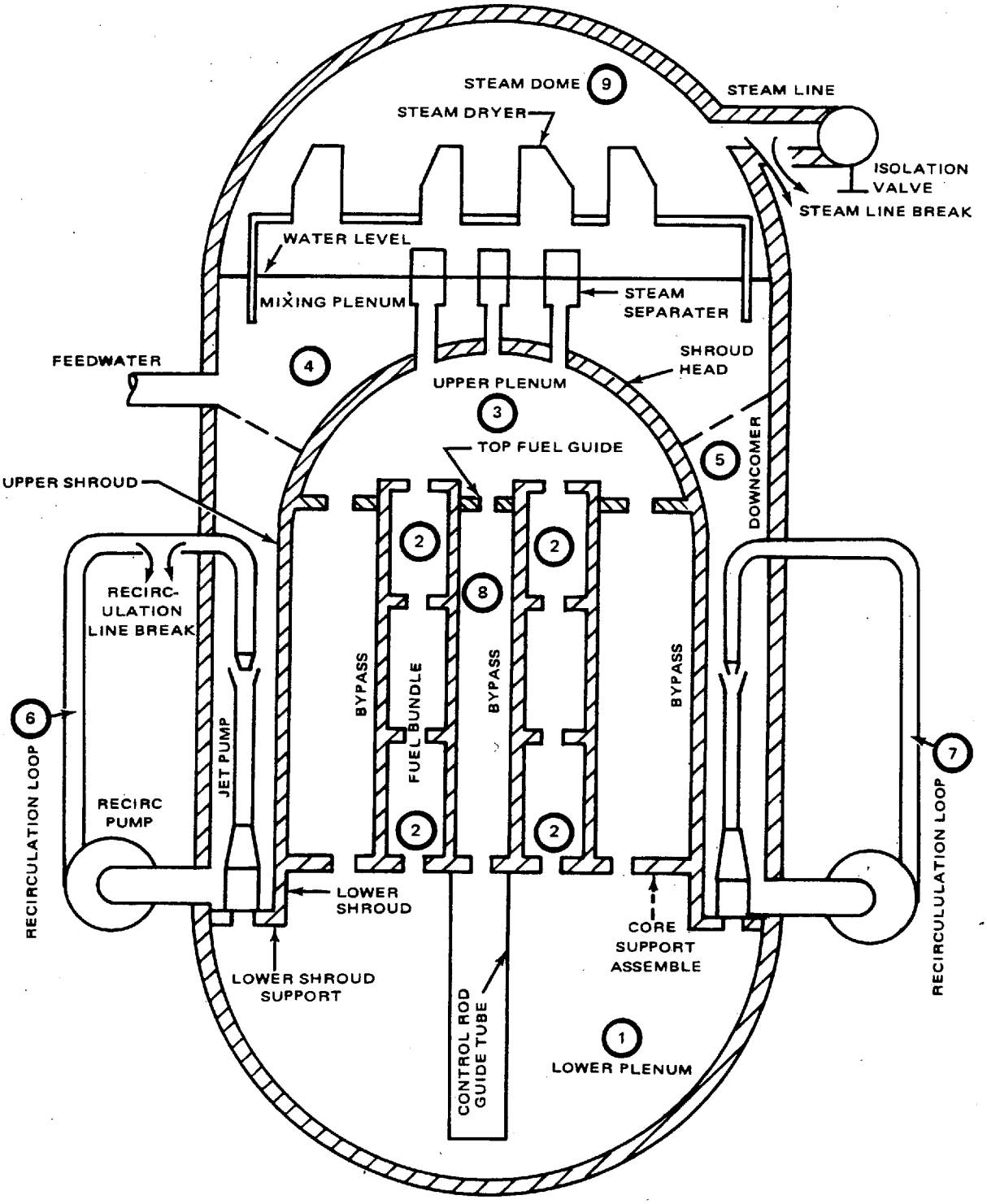
FIGURE 3.9-6



LIMERICK GENERATING STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

JET PUMP

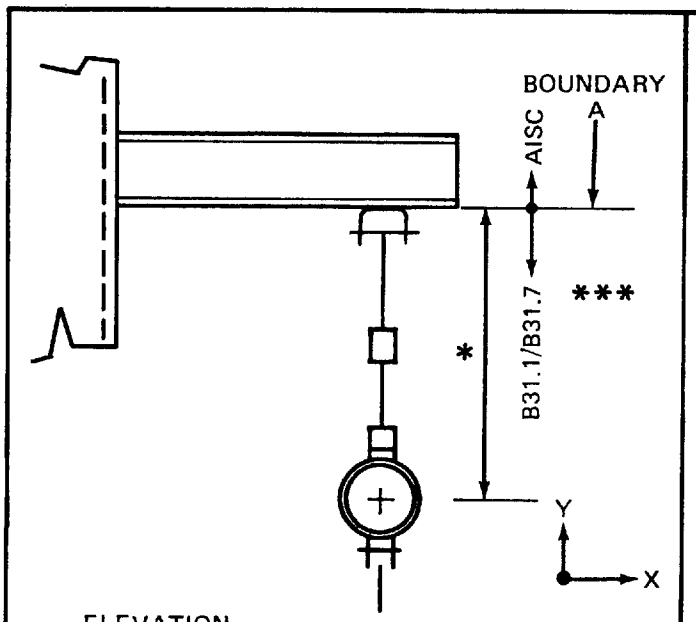
FIGURE 3.9-7 Rev. 10 10/00



LIMERICK GENERATING STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

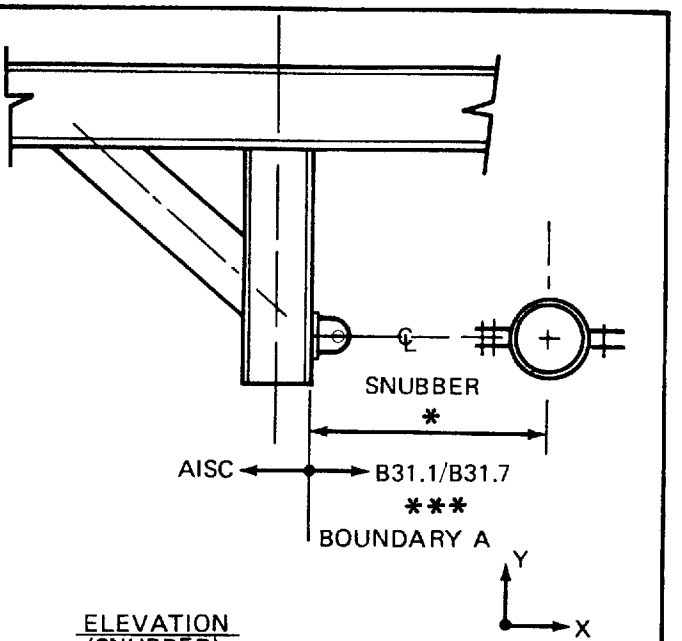
PRESSURE NODES USED FOR DEPRESSURIZATION ANALYSIS

FIGURE 3.9-8 Rev. 10 10/00



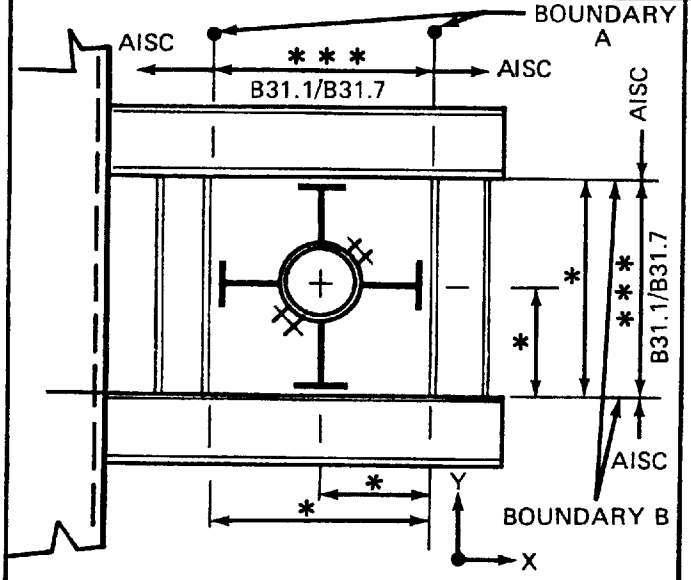
ELEVATION
(HANGER)

BOUNDARY	FORCE FY
A	**



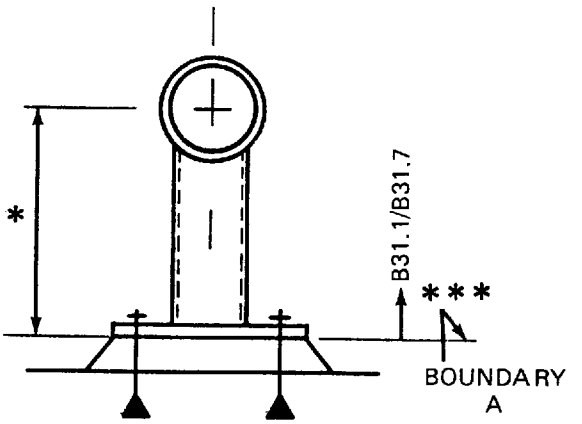
ELEVATION
(SNUBBER)

BOUNDARY	FORCE FX
A	**



ELEVATION
(TWO-WAY RESTRAINTS)

BOUNDARY	FORCES FX	FORCES FY
A	**	
B		**



ELEVATION
(ANCHOR)

BOUNDARY	FORCE			MOMENT		
	FX	FY	FZ	MX	MY	MZ
A	**	**	**	**	**	**

* INDICATES DIMENSIONAL LOCATION OF B31.1/B31.7 ELEMENTS
** INDICATES LOADS IMPOSED ON THE B31.1/B31.7 BOUNDARY
*** INDICATES B31.1/B31.7 BOUNDARIES (INCLUDING WELD, IF ANY)
B31.1 CODE FOR NON-NUCLEAR PIPING SYSTEMS.
SNUBBERS AND COMPENSATING STRUTS ARE CONSTRUCTED TO THE REQUIREMENTS OF ASME SECTION III, SUBSECTION NF

NOTE 1: EXAMINATION OF FULL PENETRATION WELDS ON ALL PRIMARY MEMBERS (WHETHER B31.1, B31.7 OR AISC) OF NUCLEAR CLASS 1. PIPE SUPPORTS SHALL BE EXAMINED ONCE BY MT OR PT AND VISUALLY EXAMINED THEREAFTER AS PART OF THE ISI PROGRAM, IN ACCORDANCE WITH ASME SECTION XI.

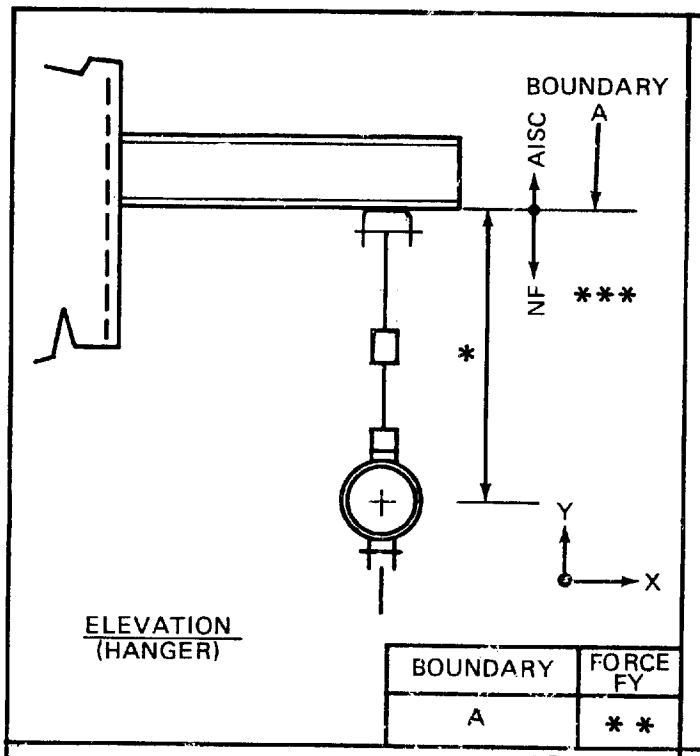
NOTE 2: FOR NUCLEAR CLASS 1 PIPE SUPPORTS . ALL WELDS, OTHER THAN FULL PENETRATION WELDS, INCLUDING THOSE WITHIN AISC JURISDICTIONAL BOUNDARIES, SHALL BE VISUALLY EXAMINED AS PART OF THE ISI PROGRAM, IN ACCORDANCE WITH ASME SECTION XI.

NOTE 3: FOR NUCLEAR CLASS 2 AND 3 PIPE SUPPORTS, ALL WELDS, INCLUDING THOSE WITHIN AISC JURISDICTIONAL BOUNDARIES, SHALL BE VISUALLY EXAMINED AS PART OF THE ISI PROGRAM, IN ACCORDANCE WITH ASME SECTION XI.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

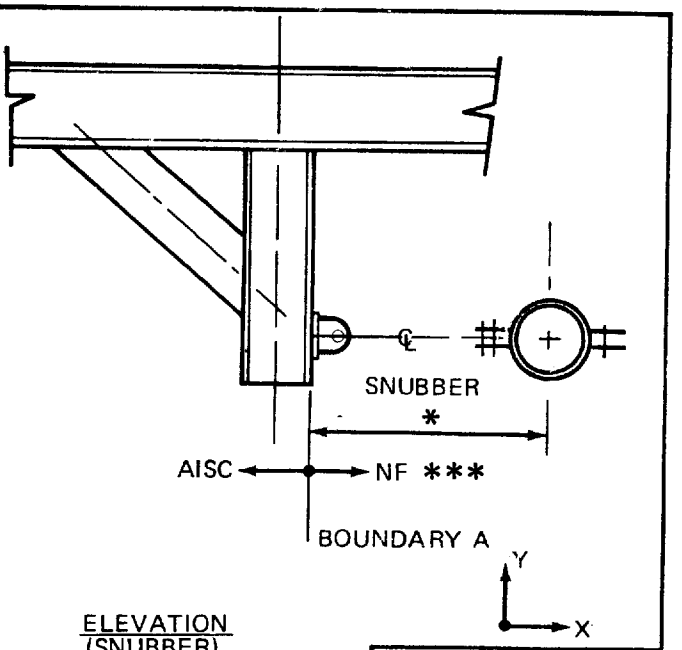
JURISDICTIONAL BOUNDARY BETWEEN PIPE SUPPORTS AND SUPPORTING STRUCTURE FOR SUPPORTS NOT FURNISHED WITH NSSS

FIGURE 3.9-9



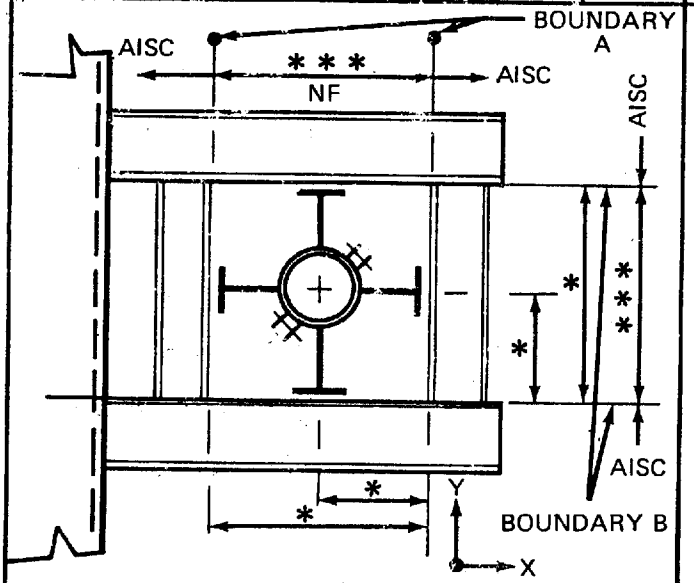
ELEVATION
(HANGER)

BOUNDARY	FORCE FY
A	**



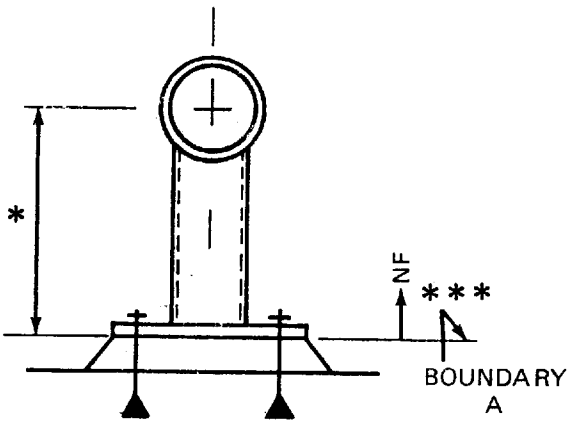
ELEVATION
(SNUBBER)

BOUNDARY	FORCE FX
A	**



ELEVATION
(TWO-WAY RESTRAINTS)

BOUNDARY	FORCES FX	FORCES FY
A	**	
B		**



ELEVATION
(ANCHOR)

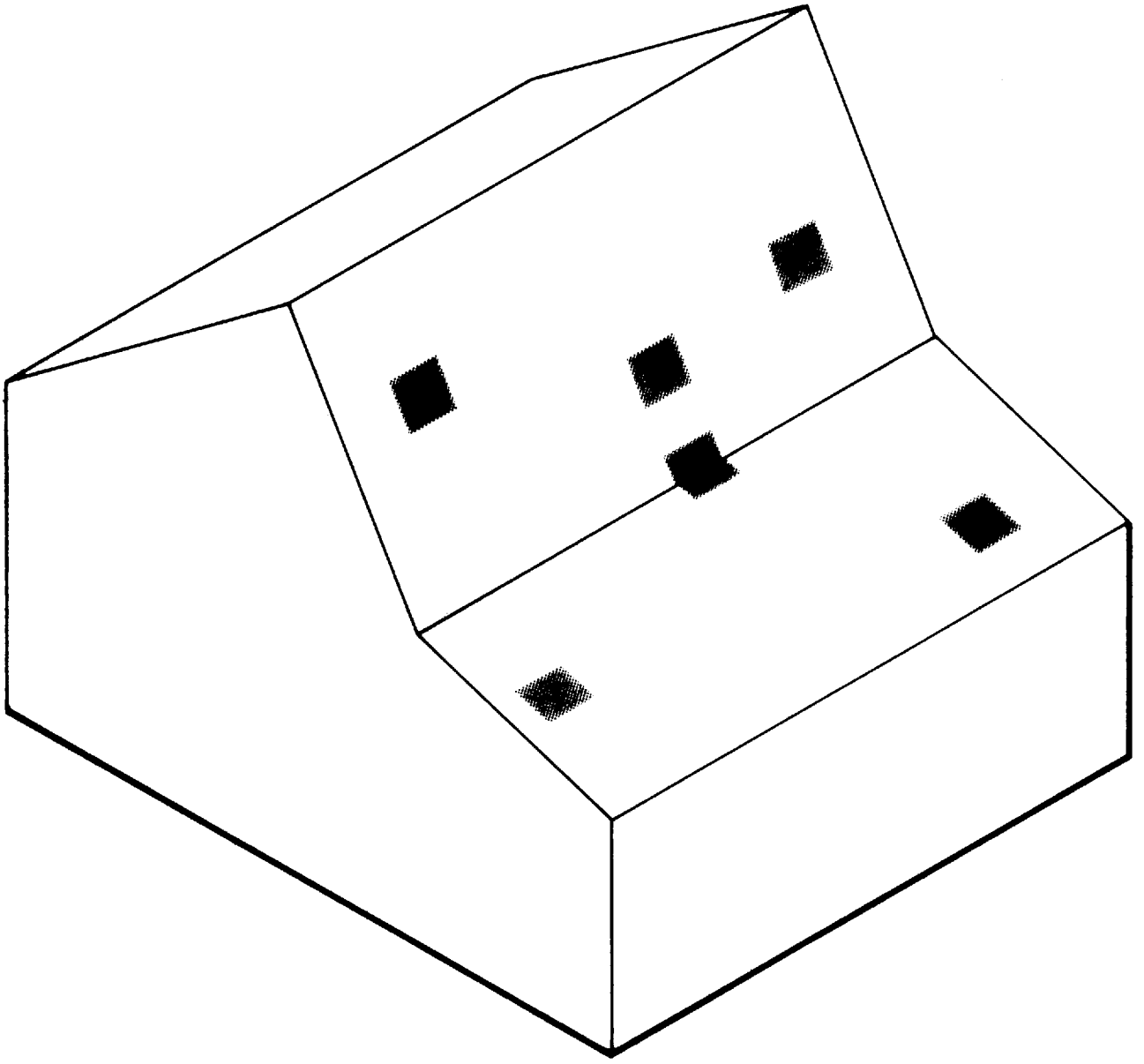
BOUNDARY	FORCE			MOMENT		
	FX	FY	FZ	MX	MY	MZ
A	**	**	**	**	**	**

* INDICATES DIMENSIONAL LOCATION OF NF ELEMENTS
** INDICATES LOADS IMPOSED ON THE NF BOUNDARY
*** INDICATES NF BOUNDARIES (INCLUDING WELD, IF ANY)

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

JURISDICTIONAL BOUNDARY BETWEEN PIPE SUPPORTS AND SUPPORTING STRUCTURE FOR SUPPORTS FURNISHED WITH CONTROL ROD DRIVE SYSTEM AND TIP SYSTEM

FIGURE 3.9-10

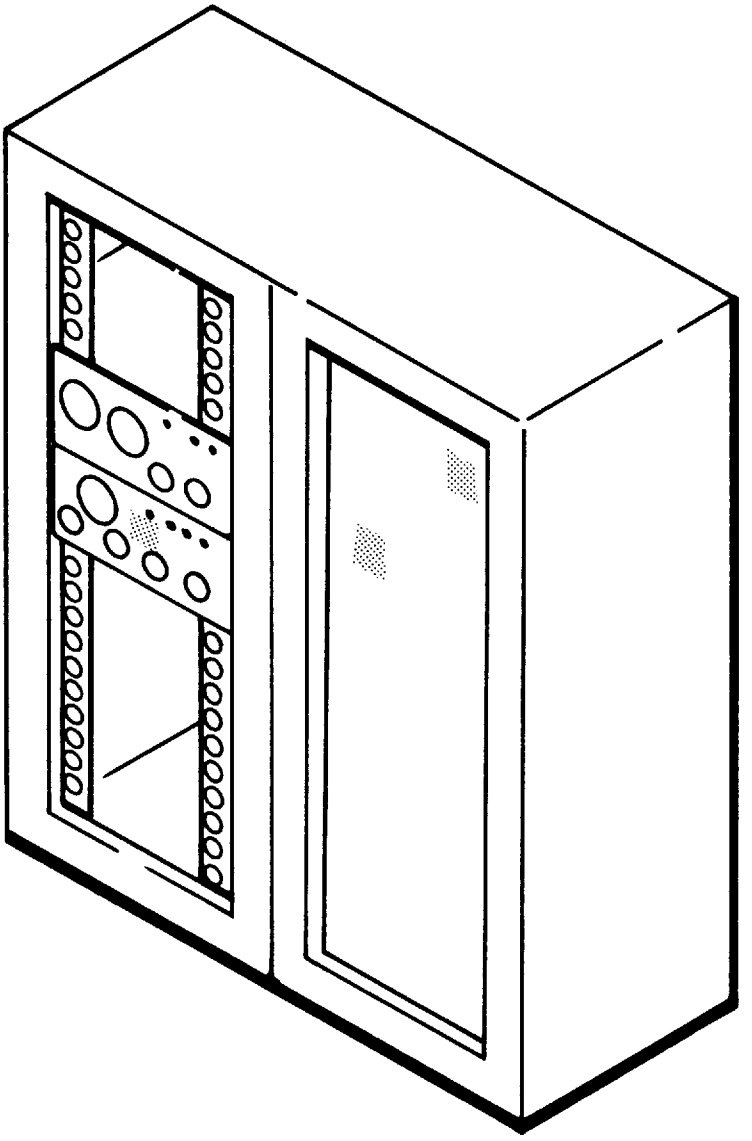


TYPICAL ACCELEROMETER LOCATION

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL BENCH BOARD

FIGURE 3.10-1

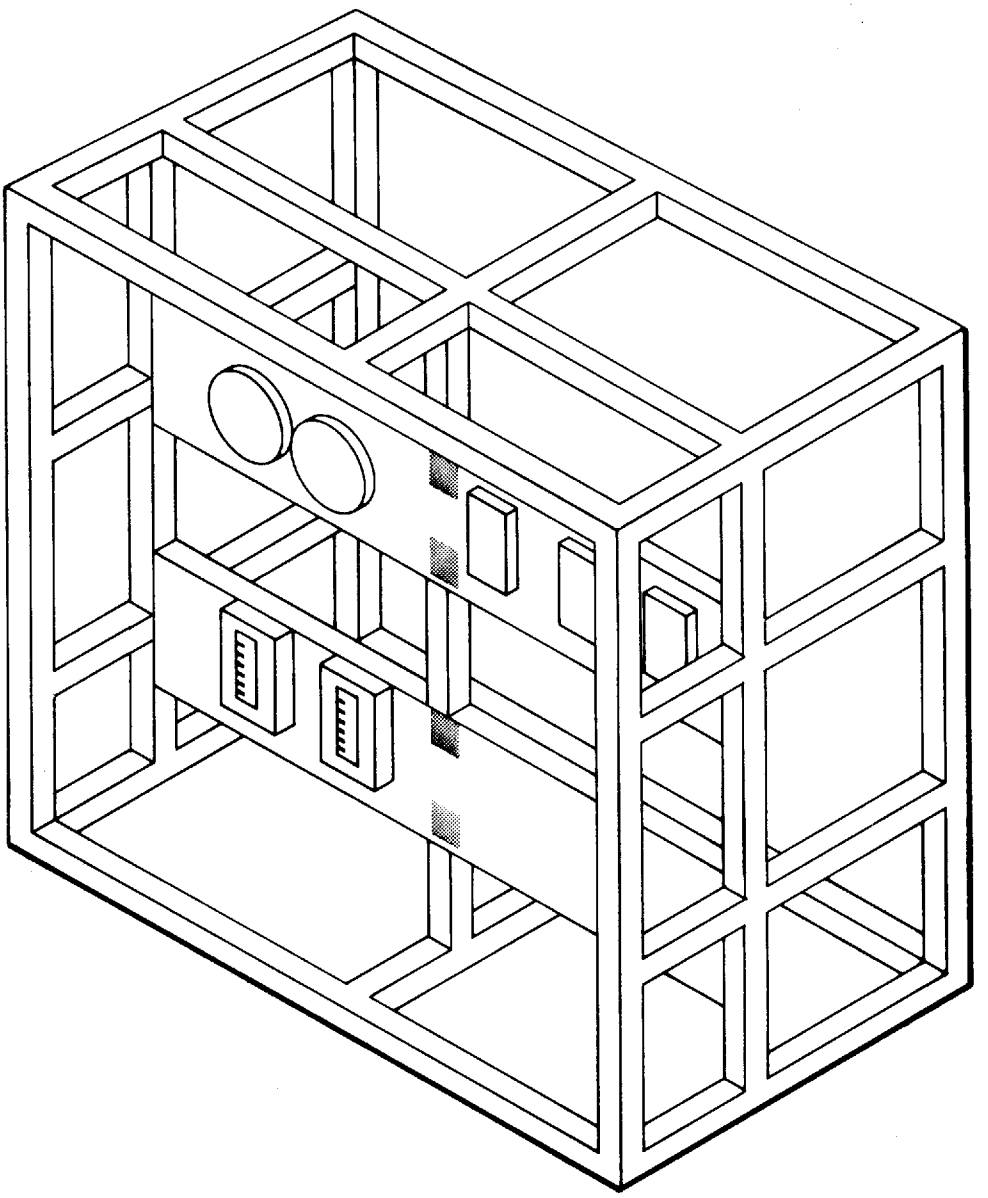


TYPICAL ACCELEROMETER LOCATION

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

INSTRUMENT RACK

FIGURE 3.10-2

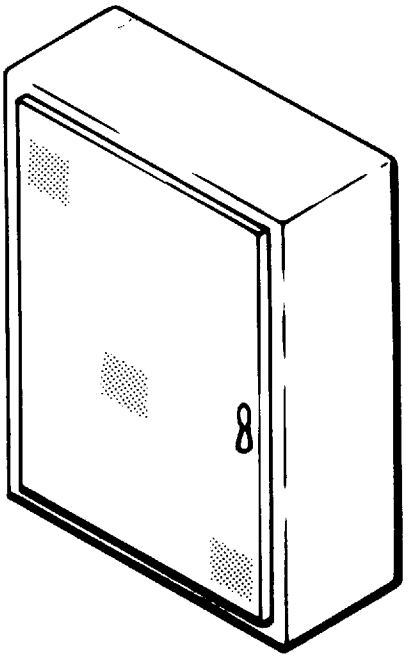


TYPICAL ACCELEROMETER LOCATION

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL LOCAL RACK

FIGURE 3.10-3



[redacted]

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

NEMA TYPE-12 ENCLOSURE
(INSTRUMENTS MOUNTED INSIDE
ON INTERNAL MEMBRANE
MOUNTED ON STANDOFFS
ATTACHED TO BACK)

FIGURE 2.10-4

APPENDIX - 3A DESIGN ASSESSMENT REPORT

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APPENDIX 3A- DESIGN ASSESSMENT REPORT

3A.1 GENERAL INFORMATION

3A.1.1 PURPOSE OF REPORT

The purpose of this Design Assessment Report is to present evidence that the Limerick Generating Station design margins are adequate if the plant should be subjected to the recently defined thermohydrodynamic loads that result from SRV operations and/or discharges during a LOCA in a GE boiling water reactor.

3A.1.2 BACKGROUND

The history of the recently defined Mark II thermohydrodynamic loading issue is based on two distinctive events. First, in April 1972, at the German AEG-Kraftwerk Union Wurgassen Nuclear Plant, a BWR SRV was opened during startup testing and failed to close. The reactor remained at full pressure, and the valve discharged reactor steam into the containment suppression chamber until the suppression pool water heated from just above ambient to almost 170°C (in approximately 30 minutes). Pulsating condensation developed and large impulsive forces with substantial underpressure amplitudes acted upon the containment, eventually causing leakage from the bottom liner plate. Therefore, concern was expressed that the structural integrity of other BWR pressure containment systems could be sensitive to SRV induced dynamic loads. The Nuclear Regulatory Commission issued Bulletin 74-14 to all BWR owners on November 14, 1974, to alert them to the potential problems of condensation instability (Wurgassen effect) due to SRV operation. The NRC requested verification that BWR suppression pools had been designed to withstand loads similar to those being experienced.

Secondly, in January 1975, GE-NEPD identified the dynamic loading conditions due to LOCA hydrodynamic phenomena that result from vent clearing and pool-swell. These loads had not been fully considered in the design criteria of Mark II BWR containments.

It became evident that a complex technical issue existed for all Mark II plants. PECo took part in the formation of a unified utility group to address the matter. A Mark II BWR containment owners group was formed in June 1975 to define the suppression pool dynamic loads and to explore ways to assess their impact. As the direct result of action taken by the Mark II containment owners organization, a generic Dynamic Forcing Function Information Report was issued jointly by GE-NEPD and Sargent and Lundy for the Mark II owners in September 1975 (Section 3A.1.3).

3A.1.3 MARK II CONTAINMENT PROGRAM

PECo is a member of the Mark II owners group that was formed in June 1975 to define and investigate the dynamic loads due to SRV discharge and LOCA. The methods for calculating these hydrodynamic loads are described in the DFFR (Reference 3A-1). The DFFR also specifies load combinations for plant design assessment. The methods provided in the DFFR are based on a combination of analytical models, test data, and engineering judgment. The methods and information provided are sufficient for use in a conservative evaluation of the design adequacy of Mark II structures and components.

The Mark II Owners Group Containment Program concentrated initially on the tasks required for the licensing of the lead-plants (Zimmer, LaSalle, and Shoreham). This Lead-Plant Program established interim bounding loads appropriate for the anticipated life of each of the lead-plants. The NRC

acceptance criteria for the lead-plant LOCA and SRV load definitions are described in NUREG-0487 (Reference 3A-2) and NUREG-0487 Supplements 1 and 2 (References 3A-3 and 3A-4, respectively).

The remainder of the Mark II Owners Group Program concentrated on the tasks required to license the long-term plants, which include LGS. The NRC acceptance criteria for the long-term plant LOCA and SRV load definitions are described in NUREG-0808 (Reference 3A-5) and NUREG-0802 (Reference 3A-6), respectively. The objectives of the Long-Term Program were (a) to provide justification, by tests and analyses, for refinement of selected lead-plant bounding loads, and (b) to provide additional confirmation of certain loads used in the Lead-Plant Program.

As a task separate from the Mark II Owners Group Program, a Mark II SRV discharge Line T-quencher device and load specification was developed in 1978 by Kraftwerk Union for Pennsylvania Power and Light for use in the Susquehanna Steam Electric Station. The T-quencher provides a reduction in the containment wall loads as compared to the loads generated by the original Ramshead quencher design. The T-quencher also promotes effective heat transfer and condensation of discharge steam in the suppression pool. PECo decided to use the same T-quencher design for LGS. Following this decision, KWU compared the LGS and SSES SRV-related parameters and concluded that the same load specification could be used by PECo for the LGS containment analysis. The LGS and SSES SRV-related parameters are compared in Table 3B-1.

The quencher load specification was submitted to the NRC by PP&L in April 1978. In addition, a full-scale SSES unique unit cell test (Section 3B.8) was performed by KWU in 1979. This test verifies KWU's design approach for the quencher load specification used for LGS.

Table 3A-1 provides a summary of the LGS licensing basis as a result of the Mark II Containment Program.

Table 3A-2 presents a summarizing review of the LGS suppression pool dynamic loadings. This is achieved by comparing the NRC Acceptance Criteria with the LGS plant unique position.

3A.1.4 PLANT DESCRIPTION

The LGS, Units 1 and 2, is located on the east bank of the Schuylkill River in Limerick Township of Montgomery County, Pennsylvania, approximately 1.7 miles southeast of the limits of the Borough of Pottstown and approximately 20.7 miles northwest of the Philadelphia city limits. Each of the LGS units employs a GE BWR designed to operate at a rerated core thermal power of 3515 MWt.

3A.1.4.1 Primary Containment

The containment is a reinforced concrete structure consisting of a cylindrical suppression chamber beneath a truncated conical drywell. Figures 3A-1 and 3A-2 show the cross-section of the containment and suppression chamber (including pedestal), respectively. The conical portion of the primary containment (drywell) encloses the reactor vessel, reactor coolant recirculation loops, and associated components of the RCS. The drywell is separated from the wetwell, i.e., the pressure-suppression chamber and pool, by the drywell floor, also named the diaphragm slab. The cone and cylinder form a structurally integrated reinforced concrete vessel, lined with steel plate and closed at the top of the drywell with a steel domed head. The carbon steel liner plate is anchored to the concrete by structural steel members embedded in the concrete and welded to the liner plate.

The entire containment is structurally separated from the surrounding reactor enclosure except at the base foundation slab (a reinforced concrete mat, top lined with a carbon steel liner plate) where a seismic gap filled with rodofoam is provided between the two adjoining foundation slabs. The containment structure dimensions and parameters are listed in Tables 3A-3 and 3A-4.

Major systems and components in the containment include the vent pipe system (downcomers) connecting the drywell and wetwell, vacuum relief system, containment cooling system, and MSRV discharge piping and associated quencher components. Figure 3A-3 shows the locations and orientation of the quenchers and discharge piping.

3A.1.4.1.1 Penetrations

Services and communications between the inside and the outside of the containment are performed through penetrations. Basic penetration types include pipe penetrations, electrical penetrations, and access hatches (equipment hatches, personnel lock, suppression chamber access hatches, and CRD removal hatch). Each penetration consists of a pipe sleeve with an annular ring welded to it. The ring is embedded in the concrete wall and provides an anchorage for the penetration to resist normal operating and accident loads. The pipe sleeve is also welded to the containment liner plate to provide a leak-tight penetration.

3A.1.4.1.2 Internal Structures

The internal structures consist of reinforced concrete and structural steel and have the major functions of supporting and shielding the rector vessel, supporting the piping and equipment, and forming the pressure-suppression boundary. These structures include the diaphragm slab, the reactor pedestal (a concentric cylindrical reinforced concrete shell resting on the containment base foundation slab and supporting the reactor vessel; Figure 3A-2 shows pedestal cross-section), the reactor shield wall, the suppression chamber columns (hollow steel pipe columns supporting the diaphragm slab), the drywell platforms, the seismic trusses, the quencher supports, and the reactor steam supply systems supports.

3A.2 SUMMARY

3A.2.1 LOAD DEFINITION SUMMARY

3A.2.1.1 SRV Load Definition Summary

Hydrodynamic loads resulting from SRV actuation fall into two categories: loads on the SRV system itself (the discharge line and the discharge quencher device), and the loads on the suppression pool walls and submerged structures.

Loads on the SRV system during SRV actuation include loads on the SRV piping due to effects of steady back pressure, transient water slug clearing, and SRV line temperature. Determination of loading on the quencher body, arms, and support is based on transients resulting from valve opening (water clearing and air clearing), valve closing, and operation of an adjacent quencher.

Air clearing loads are examined for four loading cases: symmetric (all-valve) SRV actuation, asymmetric adjacent SRV actuation, single SRV actuation, and automatic depressurization system (ADS-five valve) actuation. Dynamic forcing functions for loading of the containment walls, pedestal, basemat, and submerged structures are developed using techniques discussed in Section 3B.4.1 and 3A.11. Loads on the SRV system due to SRV actuation are discussed in Section 3B.4.1.3, and

loads on suppression pool walls and submerged structures due to SRV actuation are discussed in Section 3B.4.1.4. A full-scale, unit cell test program was conducted at the KWU laboratories to verify these SRV loading specifications. These tests are described in Section 3B.8.

Adjacent structures indirectly affected by SRV loads include the reactor enclosure, control structure, and associated equipment and components. The assessment methodology used in determining the SRV load effect on these adjacent structures is described in Section 3A.7.1.1.2.

3A.2.1.2 LOCA Load Definition Summary

The spectrum of LOCA-induced loads acting on the LGS containment structure is characterized by LOCA loads associated with pool-swell and condensation oscillation and chugging, as well as long-term and secondary LOCA loads.

The LOCA loads associated with pool-swell result from short duration transients and include downcomer clearing loads, water jet loads, pool-swell impact and drag loads, poll fallback drag loads, pool-swell air bubble loads, and loads due to drywell and wetwell temperature and pressure transients. Techniques used to evaluate these loads are described in Section 3A.4.2.1.

Condensation oscillations result from mixed flow (air-steam) and pure steam flow effects in the suppression pool. Chugging loads result from low mass flux pure steam condensation. The load definitions from these phenomena are contained in Section 3A.4.2.2.

Long-term LOCA loads result from those wetwell and drywell pressure and temperature transients associated with DBAs, IBAs, and SBAs. Their load definitions are contained in Section 3A.4.2.4.

Structures directly affected by LOCA loads include the drywell walls and floor, wetwell walls, RPV pedestal, basemat, liner plate, columns, downcomers, downcomer bracing system, and wetwell piping. Their loading conditions are described in Section 3A.4.2.5.

Adjacent structures indirectly affected by LOCA loads include the reactor enclosure, control structure, and associated equipment and components. The assessment methodology used in determining the LOCA load effect on these adjacent structures is described in Section 3A.7.1.1.2.

3A.2.2 Design Assessment Summary

Design assessment of the LGS structures and components is achieved by analyzing the response of the structures and components to the load combinations explained in Section 3A.5. In Section 3A.7, predicted stresses and responses (from the loads defined in Sections 3A.4 and 3B.4 and combined as described in Section 3A.5) are compared with the applicable code allowable values identified in Section 3A.6.

3A.2.2.1 Containment Structure, Reactor Enclosure, and Control Structure Assessment Summary

3A.2.2.1.1 Containment Structure Assessment Summary

The primary containment walls, base slab, diaphragm slab, reactor pedestal and reactor shield are analyzed for the effects of SRV and LOCA in accordance with Table 3A-14. The ANSYS finite-element program is used for the dynamic analysis of structures.

Response spectra curves are developed at various locations within the containment structure to assess the adequacy of components. Stress resultants due to dynamic loads are combined with

other loads in accordance with Table 3A-14 to evaluate rebar and concrete stresses. Design safety margins are defined by comparing the actual concrete and rebar stresses at critical sections with the code allowable values. The assessment methodology of the containment structure is given in Section 3A.7.1.1.1.

The containment mode shapes, modal frequencies, and hydrodynamic response spectra are given in Section 3A.9.

The results of the structural assessment of the containment structure are given in Section 3A.12.

3A.2.2.1.2 Reactor Enclosure and Control Structure Assessment Summary

The reactor enclosure and control structure are assessed for the effects of SRV and LOCA loads in accordance with Table 3A-14 and Table 3A-15.

Pressure time histories in the wetwell are used to investigate the reactor enclosure and control structure response to SRV and LOCA loads. Maximum time history force responses and broadened response spectra curves are approximately used to assess the adequacy of associated structural components. The assessment methodology of the reactor enclosure and control structure is presented in Section 3A.7.1.1.2.

The mode shapes, modal frequencies, and hydrodynamic response spectra of the reactor enclosure and control structure are presented in Section 3A.10.

The results of the structural assessment are summarized in Section 3A.13.

3A.2.2.2 Containment Submerged Structures Assessment Summary

Load combinations for the downcomer bracing and suppression chamber columns are presented in Table 3A-15. Load combinations for the downcomers are presented in Table 3A-17. The hydrodynamic design assessment methodology for the downcomers, bracing, and columns is presented in Sections 3A.7.1.2 and 3A.7.1.4. The results of the analysis are presented in Section 3A.12.

The suppression pool liner plate loads are combined in accordance with Table 3A-14. Results from the analysis indicated that no structural modification is required (Sections 3A.7.1.3 and 3A.7.2.1.5).

3A.2.2.3 BOP Piping Systems Assessment Summary

Containment and reactor enclosure BOP piping systems were analyzed by the methods presented in Section 3A.7.1.5. The load combinations for piping are described in Table 3A-18. The results of the analysis are presented in Section 3A.14.

3A.2.2.4 NSSS Assessment Summary

3A.2.2.4.1 Introduction

GE performed a design assessment of LGS Unit 1 to demonstrate that the NSSS piping and safety-related equipment and associated supports have sufficient capability to accommodate combinations of seismic and hydrodynamic loadings. The scope of the evaluation included the RPV, RPV internals and associated equipment, main steam and recirculation piping, and GE-supplied floor-mounted

equipment, pipe-mounted equipment, and control and instrumentation equipment and all associated supports.

The methodologies described in Section 3A.7.1.6 were used to perform the evaluation. Load combinations and acceptance criteria listed in Table 3A-19 were used for the evaluation of ASME Class 1, 2 and 3 piping, equipment, and supports.

3A.2.2.4.2 Design Assessment Results

The results of the assessment have demonstrated that the NSSS piping and safety-related equipment have sufficient capability to accommodate combinations of seismic and hydrodynamic loadings for the normal, upset, emergency and faulted conditions.

Detailed results of the NSSS piping and major safety-related equipment evaluations are given in Sections 3.9 and 3.10.

3A.2.2.5 BOP Equipment Assessment Summary

Safety-related BOP equipment in the containment, reactor enclosure, and control structure are assessed by the methods contained in Section 3A.7.1.7. Loads are combined as shown in Table 3A-20.

3A.2.2.6 Electrical Raceway System Assessment Summary

The electrical raceway system located in the containment, reactor enclosure, and control structure is assessed for load combinations in accordance with Table 3A-21. The assessment methodology and analysis results are presented in Section 3A.7.1.8.

3A.2.2.7 HVAC Duct System Assessment Summary

The HVAC duct system located in the containment, reactor enclosure, and control structure is assessed for load combinations in accordance with Table 3A-22. The assessment methodology and analysis results are presented in Section 3A.7.1.9

3A.2.2.8 Suppression Pool Temperature Assessment Summary

SPTMS design criteria and adequacy assessment, analysis of suppression pool temperature response to SRV discharge, and analysis of the suppression pool local-to-bulk temperature difference (ΔT) are presented in Section 3A.15.

3A.2.2.9 Wetwell-to-Drywell Vacuum Breaker and Downcomer Capping Assessment Summary

The assessment of the wetwell-to-drywell vacuum breakers to adequately withstand the dynamic effects of pool-swell and chugging is summarized in Section 3A.16. The design assessment of the downcomer capping arrangement is also summarized in Section 3A.16.

3A.3 SRV DISCHARGE AND LOCA TRANSIENT DESCRIPTION

3A.3.1 DESCRIPTION OF SAFETY/RELIEF VALVE DISCHARGE

LGS is equipped with a safety/relief system that condenses reactor steam in a suppression chamber pool. By this arrangement, reactor steam is conducted to the wetwell via fast-acting SRVs and quencher-equipped discharge lines. This section discusses the causes of SRV discharge, describes the SRV discharge process, and identifies the resultant SRV discharge actuation cases. Section 3B.4.1 presents a quantitative description of specific SRV-related loads.

3A.3.1.1 Causes of SRV Discharge

During certain reactor operating transients, the SRVs may be actuated (by pressure, by electrical signal, or by operator action) for rapid relief of pressure in the RPV. The following reactor operating transients have been identified as those which may result in SRV actuation:

a. Turbine-generator trip (with bypass or without)

b. MSIV closure

c. Loss of condenser vacuum

d. Feedwater controller failure - maximum demand

e. Pressure regulator failure - closed

f. Generator load rejection (with and without bypass)

g. Loss of ac or auxiliary power

h. Loss of feedwater flow

i. Trip of two recirculation pumps

j. Recirculation flow control failure - decreasing flow

k. Inadvertent safety/relief valve opening

l. Control rod withdrawal error

m. ATWS

n. Failure of shutdown cooling

A description of these transients is provided in Chapter 15.

3A.3.1.2 Description of the SRV Discharge Phenomena and SRV Loading Cases

Before an individual SRV opens, the water level in the discharge line is approximately equal to the water level in the pool. As a valve opens, steam flows into the discharge line air space between the valve and the water column and mixes with the air. Because the downstream portion of the discharge line contains a water slug, the pressure inside the line increases. The increased pressure expels the water slug from the SRV discharge line and quencher. The magnitude of the water clearing pressure is primarily influenced by the steam flow rate through the valve, the degree to which entering steam

is condensed along the discharge line walls, the volume of the discharge line airspace, and the volume of the water slug to be accelerated.

The clearing of water is followed by an expulsion of the enclosed air-steam. The exhausted gas forms an oscillating systems with the surrounding water, where the gas acts as the spring and the water acts as the mass. This oscillating system is the source of short-term air clearing loads.

As the air-steam mixture oscillates in the pool, its also rises because of buoyancy and eventually breaks through the pool water surface, at which time air clearing loads cease. When all the air leaves the safety/relief system, steam flows into the suppression pool through the quencher holes and condenses. The LGS quencher design ensures stable condensation even with elevated pool water temperature.

The SRV actuation cases resulting from the transients listed in Section 3A.3.1.1 are classified as being bounded by one of the following cases:

a. Symmetric all-valve, or abnormal operating transient discharge

b. Asymmetric discharge

c. Single valve discharge

d. ADS discharge

The symmetric discharge case is classified as the type of SRV discharge that would follow rapid isolation of the vessel from the turbine such as turbine trip, closure of all MSIVs, loss of condenser vacuum, etc. As pressure builds up following isolation of the vessel, the SRVs actuate sequentially according to the pressure setpoints of the valves. This may or may not result in actuation of all the SRVs, but for conservatism in loading considerations, all valves are assumed to actuate simultaneously.

Asymmetric discharge is defined as the firing of the SRVs for the three adjacent quencher devices which results in the greatest asymmetric pressure loading on the containment. This situation is hypothesized when, following a reactor scram and isolation of the vessel, decay heat raises vessel pressure so that low setpoint valves actuate. If, during this time of discharge of decay heat energy, manual actuation of the two other adjacent SRVs that comprise the asymmetric case is assumed, this actuation would result in the maximum asymmetric pressure load on the containment.

The single valve discharge case is classified as the firing of the SRV which gives the single largest hydrodynamic load. Transients that could potentially initiate such a case are an inadvertent SRV discharge or DBA. Refer to Section 3A.3.2.3 for a discussion of the latter possibility.

The ADS discharge is defined as the simultaneous actuation of the five SRVs associated with the ADS. Figure 3A-3 shows the location of the quencher devices associated with the ADS valves. The ADS is assumed to actuate during an IBA or SBA. (The IBA and SBA are described in Sections 3A.3.2.2 and 3A.3.2.1, respectively.) The effects of an increased suppression pool temperature (resulting from steam condensation during the LOCA transient) and increased suppression chamber pressure (resulting from clearing of the drywell air into the pool during the transient) are considered in the calculation of pressure loadings for the ADS discharge case.

Section 3A.4.1.4.2 describes the loads resulting from symmetric, asymmetric, single valve, and ADS discharge transients.

3A.3.2 Description Of Loss-Of-Coolant Accident

This event involves the postulation of a spectrum of piping breaks inside the containment varying in size, type, and location. For the analysis of hydrodynamic loadings on the containment, the postulated LOCA event is identified as a SBA, and IBA, or a DBA.

3A.3.2.1 Small Break Accident

This section discusses the containment transient associated with small primary system blowdowns. The primary system ruptures in this category are those ruptures that will not result in reactor depressurization from either loss of reactor coolant or automatic operation of the ECCS equipment, i.e., those ruptures with a break size less than 0.1 ft^2.

The following sequence of events is assumed to occur. With the reactor and containment operating at the maximum normal conditions, a small break occurs that allows blowdown of reactor steam or water to the drywell. The resulting pressure increase in the drywell leads to high drywell pressure signal that scrams the reactor and activates the containment isolation system. The drywell pressure continues to increase at a rate dependent upon the size of the steam leak. The pressure increase lowers the water level in the downcomers. At this time, air and steam enter the suppression pool at a rate dependent upon the size of the leak. Once all the drywell air is carried over to the suppression chamber, pressurization of the suppression chamber ceases and the system reaches an equilibrium condition. The drywell contains only superheated steam, and continued blowdown of reactor steam condenses in the suppression pool. The principal loading condition in this case is the gradually increasing pressure in the drywell and suppression pool chamber and the loads related to the condensation of steam at the end of the vents.

3A.3.2.2 Intermediate Break Accident

This section discusses the containment transient associated with intermediate primary system blowdowns. This classification covers breaks for which the blowdown will result in limited reactor depressurization and operation of the ECCS, i.e., the break size is equal to slightly greater than 0.1 ft^2.

Following the break, the drywell pressure increases at approximately 1.0 psi/sec. This drywell pressure transient is sufficiently slow so that the dynamic effect of the water in the vents is negligible and the vents will clear when the drywell-to-suppression chamber differential pressure is equal to the hydrostatic pressure corresponding to the vent submergence. The resulting pressure increase in the drywell will lead to a high drywell pressure signal that will scram the reactor and activate the containment isolation system. Approximately 5 seconds after the 0.1 ft^2 break occurs, air, steam, and water will be condensed, and the air will rise to the suppression chamber free space. The continual purging of drywell air to the suppression chamber will result in a gradual pressurization of both the wetwell and drywell. The ECCS will be initiated by the break and will provide emergency cooling of the core. The operation of these systems is such that the reactor will be depressurized in approximately 600 seconds. This will terminate the blowdown phase of the transient. The principal loading condition in this case will be gradually increasing pressure in the drywell and suppression chamber and the loads related to the condensation of the steam at the end of the vents.

3A.3.2.3 Design Basis Accident

An occurrence of events that could result in a DBA (instantaneous rupture of main steam or recirculation line) is a remote possibility. Because such an accident provides an upper limit estimate to the resultant effects for this category of pipe breaks, it is evaluated without causes being identified. For LGS, an assumed instantaneous double-ended rupture of a recirculation line causes the maximum drywell pressure and therefore the governing LOCA hydrodynamic loads.

The sequence of events immediately following the rupture of a recirculation line has been determined. A drywell high pressure signal is almost instantaneously sensed, initiating a scram and containment isolation and signaling the HPCI, CS and LPCI to start. The flow in both sides of the break will accelerate to the maximum allowed by the critical flow considerations. In the side adjacent to the suction nozzle, the flow will correspond to critical flow in the pipe cross-section. In the side adjacent to the injection nozzle, the flow will correspond to critical flow at the 10 jet pump nozzles associated with the broken loop. In addition, the cleanup line cross-tie will add to the critical flow area. This high rate of flow out of the ruptured recirculation line results in a drywell pressure rise of approximately 42.1 psig in 8.7 seconds (Table 6.2-5A and Figure 6.2-3A).

This rapid increase in drywell pressure accelerates the water initially in the containment vent system out through the vents. Immediately following vent water clearing, a coalescing air-steam bubble starts to form at the downcomer exits. Initially, the bubble pressure is essentially equal to the current drywell pressure. As the flow of air-steam from the drywell becomes established in the vent system, the initial vent exit bubble expands, thus accelerating upward the suppression pool water above the vent exits. The steam fraction of the flow is condensed, but continued injection of drywell air and expansion of the air bubble results in a rapid rise in the suppression pool surface known as pool-swell.

Following the pool-swell and fall back, there is a period of high steam flow rate through the containment vent system. For large primary system ruptures, reactor blowdown and, therefore, vent steam condensation last for approximately 40 seconds (approximately 60 seconds for MSLB; see Tables 6.2-10 and 6.2-11).

Shortly after a DBA, the ECCS pumps (HPCI, CS, and LPCI) automatically start pumping CST water or suppression pool water in to the RPV. Within 70 seconds, all ECCS pumps are at rated flow (Table 6.3-2). This floods the reactor core until water starts to cascade into the drywell from the break. The time at which this occurs would depend upon break size and location. Because the drywell would be full of steam at the time of vessel flooding, the sudden introduction of cold water causes steam condensation and drywell depressurization. When the drywell pressure falls below the suppression chamber pressure, the drywell vacuum relief system is actuated and air from the suppression chamber enters the drywell. Eventually, sufficient air returns to the drywell to equalize the pressures. Similarly, small differential pressures between the drywell and the suppression chamber can be produced if the containment spray system is actuated, condensing steam in the drywell.

Following the vessel flooding and drywell/suppression chamber pressure equalization phase of the accident, suppression pool water will be continuously recirculated through the core by the ECCS pumps. The energy associated with the core decay heat will result in a slow heatup of the suppression pool. The suppression pool temperature is controlled by the RHR heat exchangers. The capacity of these heat exchangers is such that the maximum suppression pool temperature increase is reached after several hours. The suppression pool can experience a peak temperature of 205°F under worst case conditions (Table 6.2-5A). The post-LOCA containment heatup and pressurization transient is terminated when the RHR heat exchangers reduce the pool temperature and containment pressure to nominal values.

The primary loads on the containment generated by a DBA are the pressure build-ups in the drywell and suppression chamber, and loads resulting from various modes of steam condensation at the vent ends. The high rate of system depressurization resulting from a DBA militates against the firing of an SRV; however, for conservatism, SRV discharges are considered coincident with the DBA for containment structural loading purposes (Table 3A-14).

3A.4 LOAD DEFINITION

3A.4.1 MAIN STEAM SAFETY/RELIEF VALVE DISCHARGE LOAD DEFINITION (PROPRIETARY - SEE APPENDIX 3B)

3A.4.2 LOCA Load Definition

Sections 3A.4.2.1 and 3A.4.2.2 discuss the numerical definition of loads resulting from a LOCA in the LGS containment. The LOCA loads are divided into four groups:

a. Short-term LOCA loads associated with pool-swell (Section 3A.4.2.1)

b. Condensation oscillation and chugging loads (Section 3A.4.2.2)

c. Secondary loads (Section 3A.4.2.3)

d. Long-term LOCA loads (Section 3A.4.2.4)

The application of these loads to the various components and structures on the LGS containment is discussed in Section 3A.4.2.5.

3A.4.2.1 LOCA Loads Associated with Pool-Swell

NOTE: The load definition defined in Section 3A.4.2.1 for the LOCA loads associated with pool swell is historical and is based on original design basis conditions. Section 6.2.1.8 discusses the methods and results used for current plant conditions. However, the short-term containment response conditions with power rerate are within the conditions used to define the pool swell loads. The initial drywell pressurization rate used to define the pool swell load is negligibly affected by rerated power. The short-term containment response conditions for vent flow rate and pool temperature are negligibly affected by power rerate. Therefore, the LOCA load definition for loads associated with pool swell is not affected by power rerate.

In the first few seconds following a postulated LOCA, a mixture of air and steam is carried through the containment downcomers into the suppression pool. The loads associated with the transfer of the air-steam mixture are referred to as pool-swell loads. A description of the LOCA/pool-swell transient is given in Section 3A.3.2.3. The LOCA loads associated with pool-swell are listed in Table 3A-5.

3A.4.2.1.1 Wetwell/Drywell Pressures During Pool-Swell

The drywell pressure transient used for the pool-swell portion of the LOCA transient ($\leq$2.0 sec) is tabulated in Table 3A-6. This drywell pressure transient includes the blowdown effects of pipe inventory and reactor subcooling and is the highest possible drywell pressure case for pool-swell. This drywell pressure transient is calculated using the method documented in Reference 3A-7.

The short-term wetwell pressure transient due to pool-swell is calculated by applying the pool-swell model contained in Reference 3A-8 and section 4.2.2 of Reference 3A-1. Input used for calculation of the LGS unique pool-swell transient is shown in Table 3A-7.

The short-term wetwell pressure transient calculated with the pool-swell code is shown in Figure 3A-6. The short-term wetwell pressure peak is 53.644 psia (38.944 psig).

3A.4.2.1.1.1 Differential Pressure Load on Diaphragm Floor

A vertical load on the diaphragm floor will occur because of the pressure difference between the drywell and the wetwell airspace. Normally, the net load acts downward, although an upward load my occur due to rapid pressurization of the wetwell airspace during the pool-swell transient. A value of 5.5 psid will be used as a design value for the upward load on the diaphragm floor in Mark II containments, as recommended in Reference 3A-5 and section 4.2.5.2 of Reference 3A-1.

3A.4.2.1.2 Submerged Boundary Loads During Vent Clearing

The submerged jet formed by the expulsion of the water leg in the downcomers creates a vent clearing load on the basemat and the submerged wetwell walls. This loading is defined by Reference 3A-9 as a 24 psi overpressure statically applied with hydrostatic pressure to surfaces below the vent exit, linearly attenuating to zero at the pool surface (Figure 3A-4). This load is applied during vent clearing as required by section 2.1.2.1 of Reference 3A-5.

3A.4.2.1.3 LOCA Jet Loads

The LOCA jet formed by the expulsion of the water leg in the downcomers also imposes jet loads and induced drag loads on structures in the paths and in the vicinity of the jet respectively. The direct jet loads is calculated based on a simple stoppage of momentum [Ref. 3A.10]:

$$F = KA_lV^2/2g_c,$$

where V is the jet velocity, A_l is the intercepted jet area normal to the jet direction, and K = 2 for structures which fully or partially intercepts the jet. The induced drag loads are caused by the induced velocity and acceleration fields created by the passing jets in the suppression pool.

The original methodology employed to predict the drag forces is contained in Reference 3A-10 (often called the Moody jet model) and is an analytical representation of an unsteady water jet discharging into a suppression pool. The jet is made up of constant velocity fluid particles traveling at the speed at which they exited the discharge pipe. The jet front is described as the locus of points through which a particle overtakes the one exiting immediately before it. No velocities or accelerations are defined in the fluid external to the jet.

Reference 3A-2, subsection III.D.1.a, proposed that velocity and acceleration be predicted throughout the pool using the potential function of a sphere at the jet front. A modification of the load calculated at jet impingement was also required. The acceptance criteria was a simple method to determine a bounding jet load for all structures below the downcomer exits.

The Moody jet model was clearly derived from jets with constant or linearly increasing acceleration. However, the vent clearing transients predicted for Mark II plants typically have an increase in acceleration greater than linear. Strict application of Reference 3A-10 leads to unrealistic mathematical results. Two interpretations of the results are possible depending on the time base employed. Examining the jet in "real-time" (Reference 3A-10), a jet can be seen with two independent fronts traveling at different speeds at different locations which coincide only at the point of jet dissipation. On the other hand, if the "exit-time" (τ) is used as a basis, the jet reverses and moves backward in both space and "real-time" before dissipation. Clearly neither of these observations is of much use in calculating loads on structures.

To overcome the difficulties of using this model, an alternative methodology has been formulated. The jet front will be described by the motion of the particle having traveled the farthest at any instant in time. This will be identical to the Moody jet motion for jets with linearly increasing acceleration but will yield a single continuous velocity and acceleration time history even if the acceleration increases more rapidly.

A sphere is then placed at the jet front generating a potential flow described by the following function:

$$\varphi = \frac{-3}{8\pi} U_j V_w \frac{\cos\theta}{r^2} \qquad \text{(EQ. 3A-1)}$$

where:

(r, θ) = spherical coordinates from the sphere center to some position in the suppression pool with θ measured from the jet direction

U_j = the velocity of the sphere determined by the velocity of the particle having traveled the farthest at the instant in the time the draft forces are being computed

V_w = the initial volume of water in the vent.

The local velocity (U_∞) and acceleration ($\mathring{U}_\infty$) are then calculated from the above relation by the methods of Reference 3A-10. Once the local velocity and acceleration are known, the drag forces are computed from Reference 3A-11 as follows:

$$F_A = \frac{\mathring{U}_{\infty n} \nu \rho}{g_c} \qquad \text{(EQ. 3A-2)}$$

$$F_S = \frac{C_D A_X U^2_{\infty n} \rho}{2 g_c}$$

where:

F_A = the acceleration drag

$\mathring{U}_{\infty n}$ = the local acceleration field normal to the structure

ν = the acceleration drag volume for flow normal to the structure

ρ = the fluid density

F_S = the standard drag

C_D = the drag coefficient for flow normal to the structure

A_x = the projected structure area normal to $U_{\infty n}$

$U_{\infty n}$ = the local velocity field normal to the structure.

When the jet is predicted to dissipate, the sphere is traveling at the final jet velocity at the point of maximum jet penetration. This condition is used as the final load calculation point. The final jet velocity is that of the jet front just before the last particle leaving the vent reaches the jet front. The velocity of the last particle is disregarded.

The largest induced water jet drag loads on affected components are given in Table 3A-8 for the original plant operating conditions.

For power rerate plant conditions, the increase in drywell pressurization rate and maximum vent velocity is 2% or less. The LOCA jet loads are controlled by the drywell pressure history and vent clearing velocities up to the time of vent clearing. There is sufficient conservatism in the methodology used to calculate the original LOCA jet loads and margin to design limits in the resulting component stress calculations to accommodate this increase in LOCA jet loads. Therefore, power rerate does not impact the pool swell design loads which occur up to the time of vent clearing.

3A.4.2.1.4 Boundary Loads During Pool-swell

During the pool-swell transient, the high pressure air bubble that forms in the vicinity of the vent exit creates an increase in pressure on all suppression pool boundaries below the vent exit as well as those walls with which it is in direct contact. Boundaries that are between the bubble location and the point of maximum pool elevation also experience increased pressure loads corresponding to the increased pressure in the wetwell airspace, as well as the hydrostatic contribution of the water slug.

Reference 3A-1, section 4.2.5, and Reference 3A-5, section 2.1.2.5, describe the methodology for specification of these boundary loads. The pool-swell analytical model is used to determine the maximum values of bubble pressure and wetwell airspace pressure. The analysis takes the maximum pool elevation as 1.5 times the initial submergence. Using this data, a static loading is applied to the containment structure as follows:

a. For the basemat - uniform pressure equal to the maximum bubble pressure superimposed on the hydrostatic load corresponding to a submergence from vent exit to the basemat

b. For the containment walls below the vent exit - maximum bubble pressure plus hydrostatic head corresponding to vertical distance from vent exit.

c. For the containment walls between the vent exit and maximum pool elevation - linear variation between maximum bubble pressure and maximum wetwell airspace pressure.

d. For the containment walls above maximum pool elevation - maximum wetwell airspace pressure.

The pressure distribution used for the LGS analysis is shown in Figure 3A-5 for the original plant operating conditions.

The original pool swell boundary loads calculations were reassessed for power rerate conditions. The original calculations for both the maximum calculated bubble pressure and peak wetwell pressure assume no credit for bubble breakthrough which occurs when the wetwell pressure exceeds the drywell pressure by about 2.5 psi.

The highest wetwell pressure for power rerate shown in Table 6.2-5A (39.0 psig or 53.7 psia) is essentially the same as the original peak wetwell pressure value of 53.64 psia shown in figure 3A-5. The maximum pool swell elevation of 19.51 ft is valid for Power Rerate operation. The peak bubble pressures at the time of peak pool swell are about six (6) psi lower than that was assumed in the original calculations (48.25 psia). If credit was taken for bubble breakthrough, the bubble pressure at breakthrough would be about 12 psi lower than the 48.25 psia in the original calculations. In addition, the containment design is based on the design pressure of 55 psig (69.7 psia) and that the boundary loads during pool swell are not the governing load for the design of the containment walls,

basemat, or liners. Therefore, there is sufficient conservatism in the original calculation of the boundary loads during pool swell to accommodate Power Rerate operation.

3A.4.2.1.5 Pool-Swell Asymmetric Air Bubble Load

The methodology used in Section 3A.4.2.1.4 assumes that the air flow rate in each downcomer is equal, leading to a symmetric loading of the containment boundary. Concern has been expressed (Reference 3A-2, subsection III.B.3.e) that circumferential variations in the downcomer air flow rate can occur, due to drywell air-steam mixture variation, that would result in variations in the bubble pressure load on the wetwell wall. This asymmetric loading condition is calculated by statically applying the maximum air bubble pressure, obtained from the PSAM computer code, to half of the submerged boundary and statically applying the hydrostatic pressure of the water column to the other half of the submerged boundary. The pressure load on the basemat and wetwell walls below the vent exit is the sum of the air pressure and the hydrostatic pressure. For the portion of the wall above the vent exit, the pressure increase due to the air bubble is linearly attenuated from the bubble pressure at the vent exit to zero at the pool surface. This increase is then added to the local hydrostatic pressure to obtain the total pressure. The time period of application of the load is from the termination of vent clearing until the maximum swell height is reached.

These loading conditions are conservative with respect to the NRC's long-term criteria for asymmetric bubble loads (Reference 3A-5, Appendix A).

3A.4.2.1.6 Pool-Swell Impact Load

As the pool rises during pool-swell, structures located between the initial suppression pool surface and the peak pool-swell height are subject to the pool-swell impact load. The pool-swell maximum elevation is determined by the pool-swell analytical model with polytropic exponent of 1.2 for wetwell air compression to a maximum swell height which is the greater of 1.5 times the maximum vent submergence or the elevation corresponding to the drywell floor uplift pressure of 2.5 psid (References 3A-1 and 3A-5). For LGS, Reference 3A-1 separates all impacted structures into two classes:

a. Impact loads on small structures (one dimension < 20 in)

b. Impact loads on large structures (both dimensions > 20 in). These structures are treated on a case-by-case basis.

Pool-swell impact loads on small structures are determined as specified in Reference 3A-5, Appendix A.

The PSAM computer runs summary is provided on Figures 3A-6 through 3A-10for the original plant operating conditions. These graphs present various pool-swell plant unique characteristics, including pressure-time, ΔP-time, velocity-time, velocity-height, and height-time parameters. The pool swell response was reanalyzed assuming power rerate plant operating conditions. This analysis showed that the peak pool velocity and pool swell height is insensitive to changes in the plant operating conditions. Therefore, the original pool swell impact load definition remains bounding for power rerate operation.

3A.4.2.1.7 LOCA Air Bubble Submerged Structure Load

During the drywell air purge phase of a LOCA, an expanding bubble is created at the downcomer exits. These rapidly expanding bubbles create three-dimensional velocity and acceleration fields.

To determine the drag loads, the system was modeled acoustically by the inhomogeneous wave equation (Reference 3A-14). A bubble source was developed from 4T test data and qualitative information. Table 3A-9 presents major LOCA air bubble loads for the original plant operating conditions. The LOCA air bubble response was reanalyzed assuming power rerate plant operating conditions. This analysis showed that the drywell pressurization rate is insensitive to changes in the plant operating conditions. Therefore, the original LOCA air bubble submerged structure load definition remains bounding for power rerate operation.

3A.4.2.1.8 Pool-Swell Drag Load

Subsequent to bubble contact, all bubbles are assumed to coalesce into a blanket of air, and the pool-swell drag loads are due to the slug of water rapidly accelerating upward. The loads act in the vertical direction only (except for lift forces that act in the transverse direction to the flow). The one-dimensional pool-swell model is used to predict the velocity and acceleration at the structure location. As recommended in References 3A-5 and 3A-2 and consistent with section 3A.4.2.3.5 of Reference 3A-1, the velocity is increased by 10% for additional conservatism to account for possible bubble asymmetry. Once the flow field is known, the drag forces are calculated by the methods of Section 3A.11. This methodology conservatively estimates a standard drag coefficient for unsteady flow. This drag load applies to any structure located between the elevation of the vent exit and the peak pool-swell height. The duration of the drag load begins when the vent clears, except for structures that are originally not submerged. For structures that are not submerged, the drag load duration is based on the slug transient time (Reference 3A-12, pp. 4-78, step 3). Friction drag forces on vertical piping, downcomers, and columns are given in Table 3A-10 for the original plant operating conditions. The pool swell response was reanalyzed assuming power rerate plant operating conditions. This analysis showed that the peak pool velocity and pool swell height is insensitive to changes in the plant operating conditions. Therefore, the original pool swell impact load definition remains bounding for power rerate operation.

3A.4.2.1.9 Pool-Swell Fallback Load

After the termination of pool-swell, the slug of water falls under the influence of gravity, causing drag forces on structures located between the peak pool-swell height and the vent exit. The motion of water is described by the following equations:

$$H(t) = H_{max} - \tfrac{1}{2}gt^2 \qquad \text{(EQ. 3A-3)}$$

$$V_{FB}(t) = gt$$

$$\dot{V}_{FB} = g$$

where:

- g = the acceleration of gravity
- $H(t)$ = the height above initial water level at time (t)
- H_{max} = the maximum swell height
- t = the time (starting with t = 0) at maximum swell height

The drag load is then calculated from the methods of Section 3A.11. The loading stops when H(t) has fallen below the structure or when H(t) has returned to the normal water level, whichever is calculated to occur first.

The pool-swell fallback analysis of piping that has interference effects was performed by using the FORCE II computer code. The results indicate that the interference effects increase the vertical load component by a maximum of 16%, depending on the elevation.

3A.4.2.2 Condensation Oscillations and Chugging Loads

Condensation oscillation and chugging loads follow the pool-swell loads in time. There are basically three loads in this secondary time period, i.e., from about 4-60 seconds after the break. Condensation oscillation is broken down into two phenomena, a mixed flow regime and a steam flow regime. The mixed flow regime is a relatively high mass flux phenomenon that occurs during the final period of air purging from the drywell to the wetwell when the mixed flow through the downcomer vents contains some air as well as steam. The steam flow portion of the condensation oscillation phenomena occurs after all the air has been carried over to the wetwell and a relatively high intermediate mass flux of pure steam flow is established.

Chugging is a pulsating condensation phenomenon that can occur either following the intermediate mass flux phase of a LOCA or during the class of smaller postulated pipe breaks that result in steam flow through the vent system into the suppression pool. A necessary condition for chugging to occur is that only pure steam flows from the LOCA vents. Chugging imparts a loading condition to the suppression pool boundary and all submerged structures.

3A.4.2.2.1 Containment Boundary Loads Due to Condensation Oscillations

The containment boundary loads due to condensation oscillation are based on direct application of pressure measurements in the drywell and the suppression pool from the full-scale 4TCO tests, as described in section 4.3 of Reference 3A-1, and Reference 3A-13.

The basic condensation oscillation load is a bounding load for any condensation oscillation condition expected during a hypothetical LOCA in the plant. All 28 of the 4TCO test runs were analyzed to determine the bounding time periods. The criterion for the selection of these time periods was to bound the maximum power spectral density values observed at the bottom center pressure throughout the condensation oscillation period in all runs - in any 2.048 second block for all frequencies from 0-60 Hz - in approximately 0.5 Hz increments. The selected time periods were independently confirmed to be bounding by the amplified response spectra analysis (Reference 3A-13, Appendix A).

The pressure response spectrum envelope for the time periods selected is shown in Figure 3A-11; the spatial pressure distribution is shown in Figure 3A-12. The drywell pressure histories for the time periods defined in Reference 3A-13 are applied uniformly throughout the drywell.

3A.4.2.2.2 Pool Boundary Loads Due to Chugging

The Mark II generic chugging load definition was developed by applying the acoustic chugging methodology described in Reference 3A-14 to the chugging data base provided by the Mark II 4T Condensation Oscillation (4TCO) Test Program (Reference 3A-15). The definition of a chugging load starts with the identification of steam-bubble collapse as the fundamental excitation mechanism. The collapse produces acoustic responses in the suppression pool and the vents. The combined excitation of the suppression pool and vent response is characterized as a time-varying volumetric point source in the acoustic model. Point sources for the 4TCO facility are inferred from 4TCO wall pressures via the 4TCO acoustic model. These point sources can be applied to an acoustic model of the Mark II suppression pool because the bubble collapse and vent response in Mark II are correctly simulated by the prototypical 4TCO geometry and blowdown conditions. The multivent effects of variation in chug strength and chug time among vents are incorporated in the Mark II application (Reference 3A-16).

Seven large (key) chugs from the 4TCO data base were used to develop design sources to be applied to the acoustic model of the LGS containment. These design sources are to be applied desynchronized, using the set of chug start times having the smallest variance in one-thousand Monte Carlo trails drawn from a uniform distribution of start times having a width of 500 milliseconds. The chug start times are randomly assigned to the vents in the Mark II containment.

The observation of vent desynchronization has been verified by determining the time delay between individual bubble collapses in the full-scale, 7 vent tests conducted by the Japan Atomic Energy Research Institute. Conservatism is ensured by applying to the Mark II plant models a minimum estimate of the time window within which the individual bubble collapses must occur.

Two cases of source application are specified: symmetric and asymmetric. The symmetric case is defined as the desynchronized application of each of the design sources in turn, at every vent exit location in the LGS pool. The definition of the asymmetric case starts with the identification of a design moment axis which divides the suppression pool into two halves. Adjustment factors are applied to the design sources to raise their strength on one side of the pool and lower their strength on the other side. This procedure and its rationale are described in Reference 3A-16.

3A.4.2.2.3 Downcomer Lateral Loads

During chugging and condensation oscillation, a downcomer will experience intermittent lateral loading. However, the 4TCO tests (Reference 3A-15) have shown that the magnitude of the lateral loading in a Mark II facility during the condensation oscillation phase is relatively small compared to chugging-induced lateral loads. The chugging lateral load may be the result of asymmetric steam-bubble collapse or the result of the impact on the vent caused by rapidly inflowing water. In either case, the loads occur near the downcomer exit and have been observed to be impulsive in nature and random in both magnitude and direction. The stochastic nature of the loads appears unaffected by the proximity of other structures such as containment walls or another downcomer as close as three vent diameters away. The duration of an individual lateral load is typically less than 10 ms half sine wave. The single vent, lateral load specification for LGS consists of a static-equivalent load of 10 kips and 6 ms for low intensity chugs, 30 kips and 3 ms for the high intensity chugs, and 65 kips and 3 ms for the low probability, very high intensity chugs (Figure 3A-13). This 65,000 lbf load (Reference 3A-5) corresponds to the maximum load implied by extrapolation in the cold pool tests of GKM II data with an exceedance of 0.1 per LOCA.

3A.4.2.2.4 Multiple Vent Lateral Loads

Test data observations indicate that chugging forces on a single downcomer occur periodically in random directions for short time durations. The probability that the number of downcomers loaded with the maximum force in a particular time interval in the same direction is extremely small. Nonetheless, there is a small but finite probability that some fraction of the downcomers may experience a fraction of the load acting in the same direction at the same time.

The methodology used for driving the lateral loads on the various downcomer group combinations that will result in a conservative assessment is described in Reference 3A-5. The results indicate that a probability level of 10^{-4} for exceeding an impulse in 265 chugs is adequate for determining the total load on a group of downcomers. Phasing between vents is completely neglected. These two factors result in a conservative methodology for multiple vent lateral loads. The value of 265 chugs was reached based on consideration of a range of small liquid breaks (Reference 3A-2).

3A.4.2.2.5 Submerged Structure Loads Due to Condensation Oscillation and Chugging

Condensation oscillation and chugging create velocity and acceleration fields in the suppression pool that cause submerged structure drag loads. The pressure distributions corresponding to sources from the GE 700 series (Reference 3A-16) are computed at several elevations (nodes) around the submerged structure using IWEGS/MARSOFT (for condensation oscillation) and IWEGS/MARS-P (for chugging). These pressure responses around the body of each level are then spatially integrated to obtain the dynamic load due to fluid motion (force per unit length).

$$F = \int Pds \qquad \text{(EQ. 3A-4)}$$

where p is the fluid pressure acting on an area increment ds = nds, n being the inward-pointing normal unit vector at ds. The submerged structure load is equal to double the dynamic load due to the effect of the hydrodynamic mass. Table 3A-11 provides a summary of maximum force per unit length on various submerged structures for condensation oscillation and chugging phases.

3A.4.2.3 Secondary Loads

The previous sections have identified and specified loading methodologies that result in significant containment dynamic loads. In addition, several pool dynamic loads can occur that are considered secondary when compared to the previous loads or because the containment and related equipment response is small when subjected to them. The following sections identify the secondary loads and the load criteria to be applied to the LGS containment.

3A.4.2.3.1 Downcomer Friction Drag Loads

Friction drag loads are experienced internally by the downcomers during vent clearing and subsequent air or steam flow. In addition, the downcomers experience an external drag load during pool-swell. Using standard drag force calculation procedures, these loads are determined to be 0.6 kips and 0.3 kips per downcomer, respectively, and are not considered in the structural evaluation of the containment.

3A.4.2.3.2 Sonic Waves

Immediately following the postulated instantaneous rupture of a large primary system pipe, a sonic wave front is created at the break location and propagates through the drywell to the vent system. This load has been determined to be negligible and, therefore, none is specified.

3A.4.2.3.3 Compressive Wave

The compression of the air in the drywell and vent system causes a compressive wave to be generated in the downcomer water legs. This compressive wave propagates through the pool and causes a differential pressure loading on the submerged structures and on the wetwell wall. This load has been evaluated and is considered negligible.

3A.4.2.3.4 Fallback Loads on Submerged Boundaries

During fallback, water hammer type loads could exist if the water slug remained intact during this phase. However, available test data indicate that this does not occur, and the fallback process

consists of a relatively gradual setting of the pool water to its initial level as the air bubble percolates upward. This is based on visual observations during the EPRI tests (Reference 3A-17) as well as indirect evidence provided by an examination of pool bottom pressure forces from the 4T, EPRI, foreign licensee, and Marviken tests. Thus, these loads are small and will not be considered.

3A.4.2.3.5 Vent Clearing Loads on the Downcomers

The expulsion of the water leg in the downcomers at vent clearing creates a transient water jet in the suppression pool. This jet formation may occur asymmetrically leading to lateral reaction loads on the downcomer. However, this load is bounded by the load specification during chugging and will not be considered for containment analysis.

3A.4.2.3.6 Postpool-Swell Waves

Following the pool-swell process, continued flow through the vent system generates random pool motion. The pool motion creates waves that have potential loading impingement effects on the LGS wetwell wall and internal components. In accordance with the response to Question M020.8 documented in Appendix A of the DFFR, Revision 3 (June 1978), this load is considered negligible when compared to the other design basis loads.

3A.4.2.3.7 Seismic Slosh

The computer code SOLA-3D was used to estimate the suppression pool seismic slosh hydrodynamic loads. The results indicate the seismic slosh loads in the plant are much less that the LOCA chugging loads or the SRV air clearing bubble oscillation loads (on the order of a few psi at a relatively low frequency depending on location and direction).

The maximum wave (sloshing) height is 1.6 feet. The nodal force close to the pool bottom oscillates between 112 kips to 88 kips (including static load). Therefore, the bottom pressure rises to about 1.2 psi above the static pressure due to sloshing. The dominant frequency of the sloshing motion is 0.1 Hz, whereas the dominant frequency of the seismic acceleration is about 2 Hz.

3A.4.2.3.8 Thrust Loads

Thrust loads are associated with the rapid venting of air and/or steam through the downcomers. To determine this load, a momentum balance for a control volume consisting of the drywell, diaphragm floor, and vents is taken. Results of the analysis indicate that the load reduces the downward pressure differential on the diaphragm.

3A.4.2.4 Long-Term LOCA Loads

The LOCA causes pressure and temperature transients in the drywell and wetwell due to mass and energy released from the line break. The drywell and wetwell pressure and temperature time histories are required to establish the structural loading conditions in the containment because they are the basis for other containment hydrodynamic phenomena. The response must be determined for a range of parameters such as break size, reactor pressure, and containment initial conditions.

3A.4.2.4.1 Design Basis Accident Transients

The DBA LOCA for LGS is conservatively estimated to be a 3.538 ft^2 break of the recirculation line. This transient results in the maximum drywell pressure and therefore governs the LOCA

hydrodynamic loads. The LGS unique assumptions and input for the analysis are given in Section 6.2.1. Drywell and wetwell pressure and temperature responses are shown in Figures 3A-14 and 3A-15. This description of the transient does not include the effect of reactor subcooling.

3A.4.2.4.2 Intermediate Break Accident Transients

The worst case intermediate break for LGS is a 0.1 ft^2 break of a liquid line. The drywell and wetwell pressure and temperature responses are shown in Figures 3A-16 and 3A-17. This description of the transient does not include the effect of reactor subcooling.

3A.4.2.4.3 Small Break Accident Transients

Plant unique SBA data for LGS is not available. The wetwell and drywell pressure and temperature transients for a typical Mark II containment are used to estimate the LGS containment response to these accidents. These curves are shown in Figure 3A-18 (extracted from Reference 3A-12).

3A.4.2.5 LOCA Loading Histories for LGS Containment Components

The various components directly affected by LOCA loads are shown schematically in Figure 3A-19. These components may in turn load other components as they respond to the LOCA loads. For example, lateral loads on the downcomer vents produce minor reaction loads in the drywell floor from which the downcomers are supported. The reaction load in the drywell floor is an indirect load resulting from the LOCA and is defined by the appropriate structural model of the downcomer/drywell floor system. Only the direct loading situations are described in detail here. Table 3A-12 is a LOCA load chart for LGS. This chart shows which LOCA loads directly affect the various structures. Details of the loading time histories are discussed below.

3A.4.2.5.1 LOCA Loads on the Containment Wall and Pedestal

Figure 3A-20 shows the LOCA loading history for the LGS containment wall and the RPV pedestal. The wetwell pressure loads apply to the unwetted elevations in the wetwell; addition of the appropriate hydrostatic pressure is made for loads on the wetted elevations. Condensation oscillation and chugging loads are applied to the wetted elevations in the wetwell only. The pool-swell air bubble load applies to the wetwell boundaries as shown in Figures 3A-11 and 3A-12.

3A.4.2.5.2 LOCA Loads on the Basemat and Liner Plate

Figure 3A-21 shows the LOCA loading history for the LGS basemat and liner plate. Wetwell pressures are applied to the wetted and unwetted portions of the liner plate as discussed in Section 3A.4.2.5.1. The downcomer water jet impacts the basemat line plate as does the pool-swell air bubble load. Chugging and condensation oscillation loads are applied to the wetted portion of the liner plate.

3A.4.2.5.3 LOCA Loads on the Drywell and Drywell Floor

Figure 3A-22 shows the LOCA loading history for the LGS drywell and drywell floor. The drywell floor undergoes a vertically applied, continuously varying differential pressure, the upward component of which is especially prominent during pool-swell when the wetwell airspace is highly compressed.

3A.4.2.5.4 LOCA Loads on the Columns

Figure 3A-23 shows the LOCA loading history for the LGS columns. Pool-swell drag and fallback loads are minor because the column surface is oriented parallel to the pool-swell and fallback velocities. The pool-swell air bubble, condensation oscillations, and chugging will provide loads on the submerged (wetted) portion of the columns.

3A.4.2.5.5 LOCA Loads on the Downcomers

Figure 3A-24 shows the LOCA loading history for the LGS downcomers. The downcomer clearing load is a lateral load applied at the downcomer exit (in the same manner as the chugging lateral load) plus a vertical thrust load. Pool-swell drag and fallback loads are minor because the downcomer surfaces are oriented parallel to the pool-swell and fallback velocities. The pool-swell air bubble load is applied to the submerged portion of the downcomer as are the chugging and condensation oscillation loads.

3A.4.2.5.6 LOCA Loads on the Downcomer Bracing

Figure 3A-25 shows the LOCA loading history for the LGS downcomer bracing system. This system is not subject to impact loads because it is submerged at el 203'-5". As a submerged structure, it is subject to pool-swell drag, fallback, and air bubble loads. Condensation oscillations and chugging at the vent exit will also load the bracing system both through downcomer reaction (indirect load) and directly through the hydrodynamic loading in the suppression pool.

3A.4.2.5.7 LOCA Loads on the Wetwell Piping

Figure 3A-26 shows the LOCA loading history for piping in the LGS wetwell. Because the wetwell piping occurs at a variety of elevations in the LGS wetwell, sections may be completely submerged, partially submerged, or initially uncovered. Piping may occur parallel to pool-swell and fallback velocities, as with the main steam safety/relief piping. For these reasons, there are a number of potential loading situations that arise, as shown in Table 3A-13. In addition, the pool-swell air bubble load applies to the submerged portion of the wetwell piping as do the condensation oscillation and chugging loads.

3A.5 LOAD COMBINATIONS FOR STRUCTURES, PIPING, AND EQUIPMENT

3A.5.1 INTRODUCTION

To verify the adequacy of mechanical and structural design, it is necessary first to define the load combinations to which structures, piping, and equipment may be subjected. In addition to the loads due to pressure, weight, thermal expansion, seismic, and fluid transients, hydrodynamic loads resulting from LOCA and SRV discharge are also considered in the design of structures, piping, and equipment in the drywell and suppression pool. This chapter specifies how the LOCA and SRV discharge hydrodynamic loads will be combined with the other loading conditions. For the load combinations discussed in this chapter, seismic and hydrodynamic responses are combined by the methods specified in Reference 3A-1, section 5.1.2.

3A.5.2 LOAD COMBINATIONS FOR CONCRETE DESIGN IN CONTAINMENT, REACTOR ENCLOSURE, AND CONTROL STRUCTURE

The loads on the containment, its concrete internals (i.e., RPV pedestal, diaphragm slab), reactor enclosure, and control structure are combined to assess the structural integrity in accordance with

the design load combinations given in Table 3A-14. The factored load approach is used in the assessment of the concrete structural components. The load factors adopted are based on the degree of certainty and probability of occurrence for the individual loads as discussed in Reference 3A-1, section 5.1.2.

The LOCAs are characterized by several phenomena that result in nonconcurrent loadings on the structures. Time sequences of occurrence of the various time-dependent loads, as shown in figures 5-5 through 5-20 of Reference 3A-1, are taken into account to determine the most critical loading conditions.

3A.5.3 STRUCTURAL STEEL AND ASME CLASS MC STEEL COMPONENTS LOAD COMBINATIONS

The load combinations for structural steel in the containment, reactor enclosure, and control structure are given in Table 3A-15. These combinations apply to the suppression chamber steel columns, the downcomer bracing, and miscellaneous structural steel within the containment, reactor enclosure, and control structure.

The LOCAs are characterized by several phenomena that result in nonconcurrent loadings on the structures. Time sequences of occurrence of the various time-dependent loads, as shown in figures 5-5 through 5-20 in Reference 3A-1, are taken into account to determine the most critical loading conditions.

The load combinations for the ASME Class MC steel components in the concrete containment are given in Table 3A-16. These combinations apply to the drywell head assembly, equipment hatches, personnel lock, suppression chamber access hatches, CRD removal hatch and piping and electrical penetrations.

3A.5.4 LINER PLATE LOAD COMBINATIONS

The liner plate and its anchorage system, being an integral part of the containment system, is assessed for the same load combinations listed in Table 3A-14. However, for the liner system, the load factors are taken as unity and the acceptance criteria are specified in Section 3A.6.4.

The LOCAs are characterized by several phenomena that result in nonconcurrent loadings on the structures. Time sequences of occurrence of the various time-dependent loads, as shown in figures 5-5 through 5-20 in Reference 3A-1 are taken into account to determine the most critical loading conditions.

3A.5.5 DOWNCOMER LOAD COMBINATIONS

Load combinations and stress allowables for the downcomers are given in Table 3A-17. These load combinations are based in the load combinations given in table 5-2 of Reference 3A-1.

The LOCAs are characterized by several phenomena that result in nonconcurrent loadings on the structures. Time sequences of occurrence of the various time-dependent loads, as shown in figures 5-5 through 5-20 in Reference 3A-1, are taken into account to determine the most critical loading conditions.

3A.5.6 PIPING, QUENCHER, AND QUENCHER SUPPORT LOAD COMBINATIONS

LOCA loads considered on piping systems include pool-swell impact loads, pool-swell drag loads, downcomer water jet loads, pool-swell air bubble loads, fallback drag loads, condensation oscillation loads, chugging loads, and inertial loading due to the acceleration of the containment structure produced by LOCA loads. Loads due to SRV discharge on piping systems include water clearing loads, air clearing loads, fluid transient loads on SRV discharge piping, reaction forces at the quencher, and inertial loading due to the acceleration of the containment structure produced by SRV discharge loads.

The load combinations and stress limits for piping systems are given in Table 3A-18.

3A.5.6.1 Load Considerations for Piping Inside the Drywell

Piping systems inside the drywell are subjected to inertial loading due to the acceleration of the containment produced by LOCA and SRV discharge loads in the wetwell. The SRV discharge piping in the drywell is also subjected to fluid transient forces due to SRV discharge.

3A.5.6.2 Load Considerations for Piping Inside the Wetwell

All piping in the wetwell is subject to the inertial loading due to LOCA and SRV discharge.

Drag and impact loads due to LOCA and SRV discharge on individual pipes in the wetwell depend on the physical location of the piping. Other SRV discharge and LOCA loads applicable to piping in the wetwell are discussed in the paragraphs that follow.

Piping systems located below the suppression chamber water level are shown on Figures 3A-27 and 3A-28. In addition to the inertial loads, these piping systems are subjected to SRV air bubble and LOCA air bubble loads, condensation oscillation loads, and chugging loads. The SRV piping, quencher, and quencher support are also subject to fluid transient forces due to SRV discharge. Piping systems located within the jet impingement cone of the downcomer are also subjected to downcomer water jet loads.

Piping systems within the pool-swell zone are shown on Figures 3A-28, 3A-29, and 3A-30. All horizontal runs of these pipes are above the suppression chamber water level. The following loads, in addition to the inertial loads, act on these systems:

a. The horizontal runs of pipe below el 225'-8", experience pool-swell impact, pool-swell drag, and fallback drag loads.

b. The vertical portions of pipe in the water below el 225'-8" experience pool-swell drag and fallback drag loads.

3A.5.6.3 Quencher and Quencher Support Load Considerations

The quencher and quencher supports are subjected to the following hydrodynamic loads in addition to the pressure, weight, thermal, and seismic loads:

a. Unbalanced loads on the quencher due to SRV water clearing and air clearing transients, irregular condensation, and steady-state blowdown.

b. Drag loads due to SRV discharge and LOCA.

c. SRV piping end loads.

d. Inertial loading due to the acceleration of he containment produced by SRV discharge and LOCA.

3A.5.6.4 Load Considerations for Piping in the Reactor Enclosure

The effects of the inertial loading due to acceleration of the containment produced by SRV discharge and LOCA loads are evaluated for this piping.

3A.5.7 NSSS LOAD COMBINATIONS

Load combinations and acceptance criteria for ASME Class 1, 2, and 3 NSSS piping, equipment, and supports are provided in Table 3A-19.

3A.5.8 BOP EQUIPMENT LOAD COMBINATIONS

Safety-related equipment located within the primary containment, reactor enclosure, and control structure are assessed for the governing load combinations shown in Table 3A-20.

3A.5.9 ELECTRICAL RACEWAY SYSTEM LOAD COMBINATIONS

Load combinations for the electrical raceway system are given in Table 3A-21.

3A.5.10 HVAC DUCT SYSTEM LOAD COMBINATIONS

Load combinations for the HVAC duct system are given in Table 3A-22.

3A.6 DESIGN CAPABILITY ASSESSMENT CRITERIA

3A.6.1 INTRODUCTION

The criteria by which the design capability is determined are discussed in this chapter. Design of the LGS is assessed as adequate when the design capability of the structures, piping, and equipment is greater then the loads (including LOCA and SRV discharge) to which the structures piping and equipment are subjected. Loading combinations are discussed in Section 3A.5. The margins by which design capabilities exceed these loads are discussed in Section 3A.7.

3A.6.2 CONTAINMENT, REACTOR ENCLOSURE, AND CONTROL STRUCTURE CAPABILITY ASSESSMENT CRITERIA

3A.6.2.1 Containment Structure Capability Assessment Criteria

The acceptance criteria detailed in Section 3.8.1.5 have been used to assess the structural integrity of the containment and internal structures. No changes are made in these acceptance criteria when the effects of the dynamic SRV discharge and LOCA loads are included.

3A.6.2.2 Reactor Enclosure and Control Structure Capability Assessment Criteria

The acceptance criteria for seismic Category I structures presented in Section 3.8.4.5 have been used to assess the structural integrity of the reactor enclosure, control structure, and their

components. No changes are made in these acceptance criteria when the effects of the dynamic SRV discharge and LOCA loads are included.

3A.6.3 STRUCTURAL STEEL AND ASME CLASS MC STEEL COMPONENT CAPABILITY ASSESSMENT CRITERIA

The allowable stresses for structural steel in the containment, reactor enclosure, and control structure are given in Table 3A-15. These criteria apply to the suppression chamber steel columns, the downcomer bracing, and miscellaneous structural steel within the containment, reactor enclosure, and control structure.

The allowable stresses for ASME Class MC steel components in the concrete containment are given in Table 3A-16. These allowable stresses apply to the drywell head assembly, equipment hatches, personnel lock, suppression chamber access hatches, and piping and electrical penetrations.

3A.6.4 LINER PLATE CAPABILITY ASSESSMENT CRITERIA

The strains in the liner plate and anchorage system (welds and anchors) from self-limiting loads such as dead load, creep, shrinkage, and thermal effects are limited to the allowable values specified in table CC-3720-1 of Reference 3A-18. The displacements of the liner anchorage are limited to the displacement values of table CC-3730-1 of Reference 3A-18.

Stresses in the liner plate and anchorage system (welds and anchors) from mechanical loads such as SRV discharge and chugging are checked according to Reference 3A-19. Specifically, primary plus secondary membrane plus bending stresses are checked according to subsection NE-3222.2. Fatigue strength evaluation is based on subsection NE-3222.4. Allowable design stress intensity values, design fatigue curves, and material properties that are used conform to subsection NA, Appendix I.

The capacity of the liner plate anchorage is limited by the concrete pull-out to the service load allowable for concrete as specified in Reference 3A-20.

3A.6.5 DOWNCOMER CAPABILITY ASSESSMENT CRITERIA

The allowable stresses for the downcomers are given in Table 3A-17. These allowable stresses are in accordance with subsection NE of Reference 3A-19. As permitted by subsection NE-1120 for MC components, the downcomers are analyzed in accordance with subsection NB-3650 of Reference 3A-19. However, the lower allowable stresses, S_m, from table I-10.1 for MC components, are used when performing the analysis.

3A.6.6 BOP PIPING, QUENCHER, AND QUENCHER SUPPORT CAPABILITY ASSESSMENT CRITERIA

BOP piping systems in the containment and reactor enclosure are analyzed in accordance with ASME Section III, Division 1 (1971 Edition with Addenda through Winter 1972 for Class 2 and 3 piping, and 1977 Edition through Summer 1979 Addenda for Class 1 piping and Class 2 and 3 flanges), subsections NB-3600, NC-3600, and ND-3600, and ANSI B31.1 (Power Piping Code) for the loading described in Table 3A-18. In addition to these code requirements, when piping is required to deliver rated flow during or following an emergency or faulted event, the functional capability requirement shall be met for the load combinations with the event.

The quencher and quencher support are designed in accordance with ASME Section III, Division 1 (1977 Edition with Addenda through Summer 1979), subsections NC-3200 and NF-3000, respectively, for the loading discussed in Section 3A.5.6.3.

3A.6.7 NSSS CAPABILITY ASSESSMENT CRITERIA

The capability assessment criteria used for the evaluation of NSSS piping systems, RPV, RPV supports, RPV internals and floor-mounted equipment are shown in Table 3A-19. Table 3A-19 is in agreement with a conservative general interpretation of the NRC technical position, "Stress Limits for ASME Class 1, 2 and 3 Components and Component Supports of Safety-Related Systems and Core Support Structures Under Specific Service Loading Combinations".

Peak response due to related dynamic loads postulated to occur in the same time frame but from different events are combined by the SRSS method. A discussion of this load combination technique is given in Reference 3A-24.

3A.6.8 BOP EQUIPMENT CAPABILITY ASSESSMENT CRITERIA

All BOP equipment is required to withstand the dynamic loads resulting from seismic and hydrodynamic loads (SRV, SBA, IBA, and DBA) as follows:

a.	OBE alone	½% damping
b.	SSE alone	1% damping
c.	Combination of seismic and hydrodynamic loads	2% damping

Cases a and b are discussed in Section 3.7.3. Case c is considered in accordance with the load combinations shown in Table 3A-20. The adequacy of the qualification is verified by the following methods:

a. Analysis

b. Testing

c. Combination of analysis and testing

3A.6.8.1 Analysis

Safety-related equipment located in the primary containment, reactor enclosure, and control structure are analyzed to satisfy load combinations 1a, 1b, 2, 3d, and 3e of Table 3A-20. The maximum load effects result from simultaneous excitation in all three principal directions for all combinations involving dynamic loads as detailed in Section 3A.7.1.7.4.1.3.

3A.6.8.2 Testing

When safety-related equipment is qualified by testing, the TRS is to envelope the RRS for load combinations 1b, 3e, and 4 of Table 3A-20. The minimum test sequence is to perform five runs for load combination 1b, followed by one run of load combination 3e. The input motion for load combination 3e is such that the TRS generated for 2% damping envelopes the RRS for load

combination 4. Qualification is achieved if the equipment does not fail or malfunction during the test. Operability is verified before and after the test sequence. Active components required to function during a dynamic event are also verified during the test.

3A.6.8.3 Combined Analysis and Test

Some equipment is qualified by a combination of analysis and testing procedures.

An analysis is conducted on the overall assembly to determine its stress level and the transmissibility of motion from the base of the equipment to the critical components. The critical components are removed from the assembly and subjected to a simulation of the environment on a test table.

Testing methods are used to aid the formulation of the mathematical model for any piece of equipment. Mode shapes and frequencies are determined experimentally and incorporated into a mathematical model of the equipment. The model and subsequent analysis will meet the requirements of Section 3A.7.1.7.4.1.

3A.6.9 ELECTRICAL RACEWAY SYSTEM CAPABILITY ASSESSMENT CRITERIA

The allowable stresses for the electrical raceway system are given in Table 3A-21.

3A.6.10 HVAC DUCT SYSTEM CAPABILITY ASSESSMENT CRITERIA

The allowable stresses for the miscellaneous steel for the HVAC duct system are given in Table 3A-22.

3A.7 DESIGN ASSESSMENT

3A.7.1 ASSESSMENT METHODOLOGY

Loads on LGS structures, piping, and equipment are defined in Sections 3A.4 and 3B.4. The methods by which these loads are combined are discussed in Section 3A.5. The criteria for establishing design capability are stated in Section 3A.6.

This section describes the assessment methodology used in the final evaluation of structures, piping, and equipment.

3A.7.1.1 Containment, Reactor Enclosure, and Control Structure Assessment Methodology

3A.7.1.1.1 Containment Structure

3A.7.1.1.1.1 Hydrodynamic Loads

3A.7.1.1.1.1.1 Structural Models

The dynamic analysis for the structural response of the containment and internal structures due to the SRV discharge loads and LOCA loads is performed using the finite-element method. The ANSYS (Section 3.8.7) finite-element computer program was chosen for the transient dynamic analysis. Figure 3A-31 shows the ANSYS finite-element model. The concrete containment walls, slabs, RPV, RPV pedestal, and shield wall are modeled with shell elements. The refueling bellows

and stabilizer truss are modeled with spar elements. The RPV internals are modeled with beam elements. The suppression pool fluid mass is modeled with lumped-mass elements. The ANSYS model includes a total of 797 elements and 206 dynamic degrees of freedom.

The soil-structure interaction is taken into consideration by modelling the soil using a series of discrete springs and dampers in three directions as shown in Figure 3A-31. The properties of the discrete springs and dampers are calculated based on the formulae for lumped-parameter foundations found in Reference 3A-21.

3A.7.1.1.1.1.2 Damping

a. Structural Damping

The equations of motion for a discrete structure must include a term to account for viscous damping that is linearly proportional to the velocity. The equations of motion for a damped system are:

$$[M]\{\ddot{r}\} + [C]\{\dot{r}\} + [K]\{r\} = \{R(t)\} \qquad \text{(EQ. 3A-5)}$$

where [C] is the viscous damping matrix.

A viscous damping matrix of the form

$$[C] = \alpha [M] + \beta [K] \qquad \text{(EQ. 3A-6)}$$

was used (Reference 3A-22) where α and β are proportionality constants that relate damping to the velocity of the nodes and the strain rates, respectively. This damping matrix leads to the following relation between α and β and the damping ratio of the ith mode C_i:

$$C_i = \alpha/2\omega_i + \beta\omega_i/2 \qquad \text{(EQ. 3A-7)}$$

where ω is the natural circular frequency of the ith mode. For the usual case of only structural damping, $\alpha = 0$ and therefore $\beta = 2C_i/\omega_i$.

Because only a single value of β is permitted in the ANSYS input, the most dominant natural frequency of the structure is selected for the computation of β (Reference 3A-23).

A value of β equal to 0.00063 is used in the ANSYS model which corresponds to structural modal damping of approximately 4% of critical at 20 Hz which is the most dominant natural frequency of the structure.

Figure 3A-32 shows modal damping ratio versus modal frequency for structural stiffness-proportional damping.

b. Soil Springs and Radiation Damping

The elastic half-space theory as described by Reference 3A-21 was used to compute the values of the spring constants and dampers in the horizontal, vertical, and rocking directions (K_H, K_V, K_ψ, C_H, C_V, C_ψ).

The following parameters are used to represent the rock foundation:

G = Shear modulus of foundation medium
= 1.154×10^3 KSI

ν = Poisson's ratio of foundation medium
= 0.3

ρ_s = Material density of foundation medium
= 0.00481 k-sec^2/ft^4

V_S = Shear-wave velocity
= 6180 ft/sec

From which we get the following:

K_H = 3.37×10^6 k/in

C_H = 1.57×10^4 k-sec/in

K_V = 3.96×10^6 k/in

C_V = 2.72×10^4 k-sec/in

K_ψ = 9.5×10^{11} k-in/Rad

C_ψ = 2.29×10^9 k-in-sec/Rad

The above-lumped foundation springs and dampers were then distributed to every node on the basemat according to the tributary area.

3A.7.1.1.1.1.3 Fluid-Structure Interaction

The ANSYS finite-element model with appropriate fluid-structure coupling was developed for the analysis of the containment structure. The water mass constitutes only 1/7 of the total mass of the reinforced concrete structure. The model used considers fluid-structure coupling by lumping the water mass in the suppression pool at each node of the wetted surface. The weighted area approach was considered to determine the fluid mass at each node of the suppression pool.

3A.7.1.1.1.1.4 Supplementary Computer Programs

Supplementary computer programs were used for preprocessing and postprocessing of data generated for or by the ANSYS computer program.

Preprocessing programs called PREPRC1, PREPRC2, and PREPRC3 were developed to convert the SRV, condensation oscillation, and chugging pressure time histories into force time histories, respectively, acting at the associated nodes of the ANSYS model. The programs write the nodal force time histories onto a file for processing by ANSYS.

A postprocessor program was developed to calculate the nodal acceleration time history. This program is called DISQGE. It reads the structural response displacement time histories generated

from ANSYS (displacement pass option), scans for the maximum displacements, and generates the acceleration time histories using the Fast Fourier Transformation method.

Bechtel in-house computer program MSPEC was used to compute the ARS obtained from DISQGE. The program also performs plotting and broadening of the spectrum.

A computer program ENVELOP was developed to envelope response spectra obtained from MSPEC.

Computer program SCALE was developed to scan the maximum absolute stresses generated by ANSYS (stress pass option). An explanation of SCALE is given in Section 3A.7.1.1.1.1.6.2.

Verification of PREPRC1, PREPRC2, PREPRC3, DISQGE, ENVELOP, and SCALE are available for review.

3A.7.1.1.1.1.5 Load Application

3A.7.1.1.1.1.5.1 SRV Discharge Loads

The SRV discharge load used in the analyses was taken from the KWU load report (Reference 3B-2). The analyses were done for KWU SRV pressure traces 35, 76, and 82. Axisymmetric and asymmetric pressure distributions were considered. Section 3B.4.1 contains a detailed SRV load definition. The load definition takes into account the variation in pressure amplitude and frequency in the input forcing functions by applying a change of key frequencies in the assumed range of 55% to 125% of original frequency content (included are 55%, 67%, 87%, 100%, and 125% of the original frequencies) and a pressure multiplier of 1.5 to each input load trace. A total of 15 axisymmetric load traces and 15 asymmetric load traces were used in the analyses.

3A.7.1.1.1.1.5.2 LOCA-Related Loads

The main LOCA loads that significantly affect the dynamic analysis are condensation oscillation and chugging loads.

Because CO and chugging are sequential nonsimultaneous events, formulation of the LOCA load is conservatively accomplished by enveloping the CO and chugging results obtained from dynamic analyses.

The CO analysis was performed for two cases: the basic CO case and the CO-ADS case. Both CO and CO-ADS load definitions are based on direct application of measured pressure data from the 4TCO facility, a BWR Mark II prototypical unit cell used to produce expected bounding CO load data (Reference 3A-1). The CO load case is related to the basic CO load that covers all LOCA blowdown conditions resulting in CO, whereas the CO-ADS load case is data associated with the combination of CO and ADS events. Both events (CO and CO-ADS) produce wall pressure loading of axisymmetric nature. The wetwell pressure load vector was appropriately applied to the ANSYS model for a dynamic analysis. Also considered in the analysis is associated drywell pressure load defined in Reference 3A-1, based on a direct application of the measured drywell acoustic pressure time histories. A total of 17 time segments of CO and two time segments of CO-ADS are considered in the analysis.

The LGS Mark II chugging load pressure transients were calculated by Bechtel proprietary computer code IWEGS/MARS-P using GE700 series CHUG source data supplied by GE (Reference 3A-1).

The source data were based on measured data from 4TCO test facility, a BWR Mark II prototypical unit cell used to simulate the chugging loads during a postulated Mark II LOCA. A total of 14 chugging time histories are considered in the chugging analyses.

3A.7.1.1.1.1.6 Analysis

3A.7.1.1.1.1.6.1 Response Spectra Generation

Acceleration time histories, maximum structural displacements and accelerations, and broadened ARS are developed for the analysis of piping, equipment, and NSSS systems. Gross acceleration time histories are generated at the interface between pedestal and diaphragm slab, the stabilizer location at the containment wall, the top of drywell at the refueling bellows, and at the interface between wetwell wall and base slab.

The maximum containment response to SRV axisymmetric loads is obtained by enveloping the ARS of the 15 axisymmetric SRV cases. Likewise, the response spectra for the 15 asymmetric SRV cases are enveloped.

The maximum containment response to the condensation oscillation loads is obtained by enveloping the ARS of the 17 CO segments. Likewise, the response spectra of the two CO-ADS segments are enveloped.

The maximum containment response to the chugging loads is obtained by enveloping the ARS of the 14 chugging cases.

Enveloped floor response spectra of 8 damping values, between 0.5% and 20% of critical are generated. For clarity, these 8 enveloped floor spectra are grouped into two separate plot sets of 4 dampings each. The low damping plot sets, furnished in Section 3A.9, include damping ratios of ½%, 1%, 2%, and 5% of critical. The high damping plot sets include damping ratios of 7%, 10%, 15%, and 20% of critical. Floor response spectra of high damping values (i.e., greater than 7% critical) are generated for application to systems and components where larger system or material damping values are justified. Reference 3A-31 provides an example of such an application. The spectra are broadened by ±15% to account for the uncertainties in the structural modeling techniques and material properties.

3A.7.1.1.1.1.6.2 Stress Analysis

The ANSYS computer program (stress pass option) is used to compute the force and moment resultants due to SRV and LOCA-related loads. A postprocessor program called SCALE is used to scan for the maximum absolute values of forces and moments in the circumferential and meridional directions.

The forces and moments due to chugging and condensation oscillation loads are considered for the load combinations including the LOCA loads. The governing forces and moments from the six different frequencies are used in the stress analysis.

3A.7.1.1.1.2 Seismic Loads

Seismic loads constitute a significant loading in the structural assessment. The same seismic loads as those used in the initial building design are used. In that design, a dynamic analysis was made using discrete mathematical idealization of the entire structure using lumped masses. The resulting

axial forces, moments, and shear forces at various levels due to OBE and SSE are used (Section 3.7). The effects of the seismic overturning moment and vertical accelerations are converted into forces at the elements.

3A.7.1.1.1.3 Static and Thermal Loads

The loads under consideration are the static loads (dead load and accident pressure) and temperature loads (operating and accident temperature) which are all axisymmetrical.

a. To analyze the above static loads, an in-house computer program, FINEL (Section 3.8.7), is used. Moments, axial forces, and shear forces are computed by FINEL in an uncracked axisymmetric finite-element containment model.

b. The operating and accident temperature gradients are computed using ME 620 (Section 3.8.7) computer program (Bechtel program).

c. The results from a, b, and the hydrodynamic/seismic analysis are combined and applied to a containment element. The element contains data relative to rebar location, direction, and quantity and concrete properties. Within that wall element, force equilibrium and strain compatibility between the rebar and concrete is established by allowing the concrete to crack in tension. In this way, the stresses in the rebar and concrete are determined. The program used for this analysis is called CECAP (Section 3.8.7).

3A.7.1.1.1.4 Load Combinations

All load combinations from equations 1 through 7a as presented in Table 3A-14 have been analyzed.

The reversible nature of the structural responses due to the pool dynamic loads and seismic loads is taken into account by considering the peak positive and negative magnitudes of the response forces and maximizing the total positive and negative forces and moments governing the design.

Seismic and pool dynamic load effects (SRV and LOCA) are combined by conservatively summing the peak responses of each load by the absolute sum method. Even though the SRSS method is more appropriate because the peak effects of all loads may not occur simultaneously (Reference 3A-24), the conservative absolute sum method is used in the design assessment of the containment and internal concrete structures to expedite licensing.

3A.7.1.1.1.5 Design Assessment

Material stresses at the critical sections in the primary containment and internal concrete structure are analyzed using the CECAP computer program. Critical sections for bending moment, axial force and shear in three directions are located throughout the containment structure. Liner plate is not considered as a structural element. The CECAP program considers concrete cracking in the analysis of reinforced concrete sections. CECAP uses an iterative technique to obtain stresses considering redistribution of forces due to cracking and, in the process, it reduces the thermal-stresses due to the relieving effect of concrete cracking. The program is also capable of describing the spiral and transverse reinforcement stresses directly. The input data for the program consists of the uncracked forces, moments and shears calculated by FINEL, ANSYS, and seismic analysis. The loads are then combined in accordance with Table 3A-14 with appropriate load factors. The stress margins are calculated in Section 3A.7.2.

3A.7.1.1.2 Reactor Enclosure and Control Structure

3A.7.1.1.2.1 Hydrodynamic Loads

3A.7.1.1.2.1.1 Load Definitions

The reactor enclosure and control structure were analyzed for both the SRV discharge load and the LOCA condensation oscillation and chugging loads. Description of the different load cases are presented in Section 3A.7.1.1.1.1.5.

3A.7.1.1.2.1.2 Hydrodynamic Analysis Models

For the hydrodynamic loads described in Section 3A.7.1.1.2.1.1, different mathematical models are constructed for the determination of the reactor enclosure and control structure hydrodynamic responses. The mathematical models are presented in detail in the following sections and are summarized in Table 3A-23.

3A.7.1.1.2.1.2.1 SRV Analysis Models

The reactor enclosure and control structure were modeled to simulate global structural response during SRV actuation. Included in the analyses were an axisymmetric model for axisymmetric SRV loads and flexible base vertical, N-S, and E-W stick models for the asymmetric SRV loads. The latter uses the ANSYS containment finite-element model response as input. The mathematical models and analysis procedures are described below.

3A.7.1.1.2.1.2.1.1 Axisymmetric SRV Analysis Model

An axisymmetric model, based on Bechtel proprietary code CE971-FESS, was created to generate vertical response data for the NSSS new loads' structure and equipment adequacy assessment. The axisymmetric model has been closely correlated with in-plant test data (Reference 3A-25).

The model represents a containment system, adjacent structure (including reactor enclosure and control structure), and the soil medium as shown in Figure 3A-33. Figure 3A-38 shows a mass-proportional and stiffness-proportional damping simulation. The containment system and soil medium were modeled as FESS axisymmetric finite-elements, whereas the adjacent structure was simulated by a coupled stick model. Altogether, the model has a combination of 673 dynamic degrees of freedom.

The model was modified to simulate as-built conditions (i.e., concrete aging effect, etc.) and normal plant operating conditions (i.e., RPV mass, etc.) for generation of response data used for associated equipment adequacy evaluation. The analytical elements have the material properties as shown in Table 3A-31.

3A.7.1.1.2.1.2.1.2 Asymmetric SRV Analysis Models

Analysis models for the asymmetric load include the combined use of the ANSYS finite-element containment model response as input to the flexible base vertical, N-S horizontal and E-W horizontal stick models of the reactor enclosure and control structure. The ANSYS containment model is shown in Figure 3A-31, and the stick models are shown in Figures 3A-34 and 3A-35. The stick model damping uses the composite damping method (Reference 3A-21).

The vertical stick model was taken from the verified axisymmetric (FESS) coupled model. This model has 46 dynamic degrees of freedom. The flexible base was simulated by a soil spring and a damper as recommended in the Bechtel design guide (Reference 3A-21).

The N-S and E-W analytical stick models were similar to those used in the seismic analyses. Each stick model has 12 dynamic degrees of freedom.

Input load data were taken from associated ANSYS containment analysis output data. This includes use of a vertical input time history at the adjacent structure base equal to an average vertical response acceleration time history (from ANSYS) at the containment wall base, multiplied by an attenuation factor and use of horizontal input acceleration time history at the adjacent structure base equal to the gross motion generated from the associated containment ANSYS output data.

3A.7.1.1.2.1.2.2 CO Analysis Model

The reactor enclosure and control structure were modeled to simulate global structural response due to CO loads. Included in the analyses were an axisymmetric model for basic CO load case and CO-ADS load case, as was used in the axisymmetric SRV analysis described in Section 3A.7.1.1.2.1.2.1.1.

3A.7.1.1.2.1.2.3 CHUG Analysis Models

The reactor enclosure and control structure were modeled to simulate global structural response during various CHUG events. Included in the time history analyses were flexible base stick models presented in Section 3A.7.1.1.2.1.2.1.2, which use the ANSYS containment model response as input for the CHUG asymmetric loads, and an axisymmetric model for the CHUG equivalent axisymmetric loads. The mathematical models and analytical procedures are described below.

3A.7.1.1.2.1.2.3.1 CHUG Asymmetric Analysis Models

Analysis models for the CHUG asymmetric loads, as were used for SRV asymmetric loads, include the combined use of the ANSYS finite- element containment model response as input to the flexible base vertical, N-S horizontal and E-W horizontal stick models of the reactor enclosure and control structure. The ANSYS containment model is shown in Figure 3A-31, and the stick models are shown in Figures 3A-34 and 3A-35. The stick model damping used the composite damping method (Reference 3A-21).

The vertical stick model used was taken from the verified axisymmetric (FESS) coupled model. This model has 46 dynamic degrees of freedom. The flexible base was simulated by a soil spring and damper as recommended in the Bechtel design guide (Reference 3A-21).

The N-S and E-W analytical stick models were the same as were used in the seismic analyses. Each stick model has 12 dynamic degrees of freedom.

Input load data were taken from associated ANSYS containment analysis output data. This includes the use of a vertical input time history at the reactor enclosure and control structure base equal to an average vertical response acceleration time history (from ANSYS) at the containment wall base, multiplied by an attenuation factor, and the use of horizontal input acceleration time history at the reactor enclosure and control structure base equal to the gross motion generated from the associated containment ANSYS output data (no attenuation factor being used).

3A.7.1.1.2.1.2.3.2 CHUG Axisymmetric Analysis Model

An axisymmetric model, based on Bechtel proprietary code CE971-FESS, was created to generate vertical response data for the NSSS new loads' structure and equipment adequacy assessment.

Similar to the axisymmetric SRV analysis model (Section 3A.7.1.1.2.1.2.1.1) and the axisymmetric CO analysis model (Section 3A.7.1.1.2.1.2.2), CHUG axisymmetric analysis model represents a containment system, an adjacent structure (including reactor enclosure and control structure), and the soil medium as shown in Figure 3A-33. The containment system and soil medium were modeled as FESS axisymmetric finite-elements, whereas the adjacent structure was simulated by a coupled stick model. The model has a combination of 673 dynamic degrees of freedom. The model was modified to simulate as-built conditions (i.e., concrete aging effect, etc.) and normal plant operating conditions (i.e., RPV mass, etc.), for generation of response data used for associated equipment adequacy evaluation.

The analytical elements have the material properties as shown in Table 3A-31.

3A.7.1.1.2.1.2.4 Control Structure Floor/Local Models

Based on the excitation source at floor-wall junctions, analytical models for the selected floors were constructed to generate floor vertical response. Each floor considered was as a finite-element model, with boundaries at walls simulated by clamped edges. Along the line of symmetry (N-S direction), symmetric boundary conditions were imposed in the construction of a "half-model" for the transient analyses, i.e., SRV and CHUG loads.

To deal with dynamic problems of larger load duration, i.e., CO, CO-ADS, and seismic loads, a "quarter-model" was formed by taking a symmetric line in the E-W direction of the "half-model". Symmetric boundary were imposed similarly.

The half-model (Figure 3A-36) consists of 42 model nodes and 30 quadrilateral elements. By choosing five dynamic degrees of freedom to each interior node and three DDOF to each symmetric node, the model has 115 DDOF. Similarly, the quarter-model has 9 model nodes and 4 quadrilateral elements (Figure 3A-37), with 12 DDOF selected for analysis.

All floor models considered have identical nodal coordinates and similar model material properties (i.e., equivalent floor element thickness and mass density to take into account the beam-slab system action).

Floor-supporting steel girders have contributed a substantial portion of equivalent floor element thickness calculated for the beam-slab system. The contribution of the girders are different in magnitude, depending upon girder size and junction with or without shear connectors. The floors, except that of el 269' (control room), were built with shear connectors. The floor model at el 269' (control room) was verified by data correlation/ comparison with an in-plant test.

In addition, the models were modified to simulate as-built conditions (e.g., concrete aging effect, etc). To deal with seismic events, the models were further modified to consider cracking effects.

Floor model material properties are shown in Table 3A-24.

3A.7.1.1.2.1.3 Hydrodynamic Analysis

3A.7.1.1.2.1.3.1 Analysis Procedures

3A.7.1.1.2.1.3.1.1 Axisymmetric Analysis Procedure

The axisymmetric analysis general procedure is to perform a time history analysis using equivalent axisymmetric input forcing vectors described in Sections 3A.7.1.1.1.1.5.1 and 3A.7.1.1.1.1.5.2, using Bechtel proprietary code CE971-FESS. ARS data are generated using the acceleration response time histories obtained from the time history analysis using Bechtel proprietary code CE789-MSPEC. All associated ARS data are enveloped, widened ±15%, and plotted, using Bechtel proprietary codes ENVLPS and MSPEC.

3A.7.1.1.2.1.3.1.2 Asymmetric Analysis Procedure

The general analytical procedure for asymmetric analysis consists of generating input load vectors to ANSYS model from appropriate use of the load definition and applying ANSYS transient response for asymmetric loadings to adjacent structure decoupled stick models (N-S, E-W, and vertical). A transient analysis is performed using decoupled BSAP stick models for each load case. The ARS data are generated using the response acceleration time histories and Bechtel proprietary code CE789-MSPEC. All associated ARS data are enveloped, widened ±15%, and plotted.

3A.7.1.1.2.1.3.1.3 Floor/Local Model Analysis Procedure

The floor model analysis general procedure is to perform a time history analysis using input forcing vectors taken from the output of stick model analyses described in Sections 3A.7.1.1.2.1.3.1.1 and 3A.7.1.1.2.1.3.1.2 and using the model according to Bechtel proprietary code CE800-BSAP. ARS data are developed using the acceleration response time histories and Bechtel proprietary codes CE789-MSPEC and ENVLPS.

3A.7.1.1.2.1.3.2 Generation of Response Data

3A.7.1.1.2.1.3.2.1 Acceleration Response Spectra Data

3A.7.1.1.2.1.3.2.1.1 SRV ARS Data

Two sets of ARS data were generated. One set is for SRV axisymmetric analysis and the other set is for SRV asymmetric analysis. The ARS data, enveloped from associated data and broadened ±15% at peak frequencies, represent global response, applicable to structural assessment and NSSS equipment (or other safety-related equipment) adequacy evaluations located at or near the adjacent structure walls and/or columns. The ARS at selected typical locations on the reactor enclosure and control structure are presented in Section 3A.10.

3A.7.1.1.2.1.3.2.1.2 CO ARS Data

Two sets of ARS data are generated. One set is for basic CO load case analysis and the other set is for the CO-ADS load case. Again, the ARS data, enveloped from associated data and broadened ±15% at all peak frequencies, represent global response. The data are applicable to structure and/or equipment adequacy assessment located at or near the adjacent structure walls and/or columns. The ARS at selected locations are presented in Section 3A.10.

3A.7.1.1.2.1.3.2.1.3 CHUG ARS Data

Two sets of broadened ARS data are presented in Section 3A.10 for appropriate use in structure and equipment adequacy assessment. Set one is for CHUG asymmetric analysis case, and set two is for the CHUG equivalent axisymmetric analysis case.

The ARS data for the CHUG asymmetric case were developed and plotted similar to the SRV asymmetric analysis case. The data plots include the broadened ARS data in the three global directions (vertical, N-S, and E-W axes).

The CHUG asymmetric vertical ARS data provide responses for the applicable areas for the NSSS equipment adequacy assessment. The N-S and E-W ARS data apply to all NSSS equipment situated in any location of the reactor enclosure and control structure.

The ARS data for CHUG equivalent axisymmetric analysis cases were developed and plotted similar to SRV axisymmetric analysis cases.

Again, the data represent only global response, applicable to the NSSS equipment adequacy evaluations located at or near the adjacent structure walls and/or columns. Local/floor models are required for generating vertical ARS data for some floor-mounted equipment.

3A.7.1.1.2.1.3.2.1.4 Hydrodynamic Local ARS Data

The local ARS data in the control structure were generated based on the floor/local model analytical procedure described in Sections 3A.7.1.1.2.1.2.4 and 3A.7.1.1.2.1.3.1.3. The data was broadened ±15 percent at all peaks of the data enveloped from associated dynamic events.

The hydrodynamic events considered in the enveloping were SRV, CHUG, CO (basic), and CO-ADS.

The hydrodynamic local ARS data are used for the structures, components, and floor-mounted equipment where the global ARS data are not applicable.

3A.7.1.1.2.2 Seismic Loads

The seismic analysis methodology is discussed in Section 3.7.2.1. A seismic local model (Section 3A.7.1.1.2.1.2.4) was developed to generate local ARS data for the floors of the control structure.

3A.7.1.1.2.3 Static Loads

The static loads are discussed in Section 3.8.4.3.

3A.7.1.1.2.4 Load Combinations

All individual loads for concrete structures are combined with the appropriate load factors, as shown in Table 3A-14, for analysis of all loading combinations.

Steel structures are checked for the load combinations listed in Table 3A-15.

3A.7.1.1.2.5 Design Assessment

Critical sections for bending moment, axial force, and shear in all three directions are located throughout the reactor enclosure and control structure. Design capability at the critical sections is

determined, and then the design capability is compared with the actual forces and moments acting on the sections under all the load combinations. This comparison yields design margins. The design margins are discussed in Section 3A.7.2.

3A.7.1.2 Structural Steel and ASME Class MC Steel Components Assessment Methodology

3A.7.1.2.1 Suppression Chamber Columns

There are 12 suppression chamber columns, which are 42 inch diameter pipe with 1¼ inch wall thickness. The columns are attached at the underside of the diaphragm slab at el 234'-2" and at the basemat at el 181'-11".

3A.7.1.2.1.1 Structural Models

The columns were independently analyzed for static and dynamic loads. The analytical methods used for nonhydrodynamic loads such as dead, live, pressure, temperature, seismic, and pipe rupture loads are described in Section 3.8.3.4.5.

To deal with dynamic effects from seismic and hydrodynamic events, two analytical approaches were used. The ANSYS containment model (Section 3A.7.1.1.1), in which the columns were also modeled, was used for LOCA load cases. For seismic and SRV loads, the BSAP beam model (Figure 3A-44) was used. The beam model has 13 beam elements and 14 nodes, with effective water mass in the submerged portion. The column ends were modeled as clamped edges.

3A.7.1.2.1.2 Loads

The columns, partially submerged in the suppression pool, are subjected to direct pressure loads from air bubble oscillation, etc, and inertia loads due to building response (or movement) from dynamic loads (seismic and hydrodynamic). Thermal loads are induced due to the rise of temperature during hydrodynamic LOCA events.

3A.7.1.2.1.2.1 SRV Discharge Loads

The SRV discharge pressure time histories are considered as acting on the submerged portions of the columns.

The inertia forces from building response due to SRV discharge load are included by using the response spectra shown in Section 3A.9.

3A.7.1.2.1.2.2 LOCA-Related Loads

The manner in which the LOCA-related loads are applied to the column is the same as described for SRV loads in Section 3A.7.1.2.1.2.1.

3A.7.1.2.1.2.3 Seismic Loads

The seismic loads on the column were obtained by response spectrum method. The response spectra used are developed for OBE and SSE as described in Section 3.7.

3A.7.1.2.1.2.4 Static Load

Static loads, including dead load and thermal load, were considered in the column analysis.

3A.7.1.2.1.2.5 Load Combinations

The load combinations and allowable stresses are in accordance with Section 3A.5.3. The peak dynamic responses due to the seismic and pool dynamic load effects are combined by the SRSS method. The resulting combined dynamic loads are combined with the static loads by the absolute sum technique.

3A.7.1.2.1.2.6 Design Assessment

The combined stresses due to axial force and bending moment were calculated and compared with allowable stresses.

3A.7.1.2.2 Downcomer Bracing

The following covers the methodology used in the assessment of the bracing system at el 203'-5" in the primary containment suppression pool.

3A.7.1.2.2.1 Bracing System Description

The downcomer bracing system is designed as a two-dimensional truss system to provide horizontal support for 87 downcomers, 14 MSRV discharge lines, and other miscellaneous piping in the suppression pool. The bracing system is supported vertically by the 87 downcomers and at 12 anchor points around the RPV pedestal wall. The bracing system is made of stainless steel members connected to carbon steel collars at the downcomers and embedment plates at the pedestal wall by high strength stainless steel bolts. The bracing members consist of 10 inch and 12 inch diameter schedule 160 pipe sections, and 3¼ inch end connection plates. The bracing system is designed in accordance with Reference 3A-30.

The bracing system layout and typical connection details are shown in Figures 3A-39 and 3A-40. The mathematical model used in the bracing system is presented in Figure 3A-396.

3A.7.1.2.2.2 Loads

The bracing system is assessed for all plant operation induced loads described below. The basis for all hydrodynamic loads considered in the analysis is presented in Section 3A.4 and 3B.4.

3A.7.1.2.2.2.1 SRV Discharge Loads

Discharge through the SRV discharge pipe creates horizontal as well as vertical loading on the bracing system due to unbalanced pressures. The horizontal (lateral) load is considered as acting on the downcomers and the SRV discharge pipes. The vertical load is considered acting on the bracing members alone. These loads are applied to the bracing system by considering them as equivalent static loads using a dynamic magnification factor which is obtained from the dynamic analysis of the downcomer, as described in Section 3A.7.1.4.

The SRV discharge also induces hydrodynamic forces in the containment structure. Inertial forces of the bracing system, due to the response of the containment structure, are considered using hydrodynamic response spectra of the containment structure shown in Section 3A.9.

The lateral loads and the containment structure response form the complete SRV discharge load set on the bracing system.

3A.7.1.2.2.2.2 LOCA-Related Loads

LOCAs are characterized by several phenomena that result with nonconcurrent loadings on the bracing system as described in Section 3A.4.2. These hydrodynamic loads induce accelerations of the containment structure, which in turn induce additional loads on the bracing system. These loads are obtained from the hydrodynamic ARS shown in Section 3A.9.

In addition, the LOCA event induces lateral forces on the submerged portion and tip of downcomers. The loads include drag loads, pressure loads, and chugging tip load. The hydrodynamic analysis of a single downcomer for the lateral loads is presented in Section 3A.7.1.4. The resulting reaction forces at the bracing support are applied as equivalent static load in accordance with section 3.1 of Reference 3A-26.

3A.7.1.2.2.2.3 Seismic Loads

The forces due to the seismic accelerations of the downcomers, the SRV lines, and the bracing members are obtained by analysis of these structures using the response spectra developed for OBE and SSE as described in Section 3.7.2.

3A.7.1.2.2.2.4 Static Loads

The dead load of the bracing members is considered with allowance for buoyancy.

3A.7.1.2.2.2.5 Thermal Load

The operating and accident temperature considered is 90°F and 210°F, respectively. The reference temperature of the system is assumed to be 60°F.

3A.7.1.2.2.2.6 Load Combinations

The load combinations and allowable stresses are described in Table 3A-15. Although the loads on the bracing system under consideration act in random horizontal directions, each individual load is applied on the system in the worst possible direction to find the maximum resultant forces.

3A.7.1.2.2.3 Design Assessment

The two-dimensional truss model of the bracing system is analyzed for the static, thermal, and equivalent static hydrodynamic loads using the computer program STRUDL. The ASME truss model is analyzed for the containment structure inertia response due to seismic and hydrodynamic events using the computer program ANSYS. The bracing member forces calculated above for the various loading conditions are combined by the SRSS method and assessed in accordance with the loading combinations and stress allowables specified in Table 3A-15.

3A.7.1.2.3 ASME Class MC Steel Components

The ASME Class MC steel components include suppression chamber access hatch, equipment hatch, equipment hatch/personnel airlock, refueling head and CRD removal hatch. Details of these components are shown in Figures 3.8-31 through 3.8-34. All of these components were reevaluated

for additional loads due to Mark II hydrodynamic effects (SRV and LOCA) by Chicago Bridge and Iron Company under subcontract from Bechtel. The refueling head and the equipment hatch/personnel airlock were analyzed using Chicago Bridge and Iron computer program E0781. This computer program calculates the stresses and displacements in thin wall elastic shells of revolution when subjected to static edge, surface, and/or temperature loads with an arbitrary distribution over the surface of the shell. The other components (CRD removal hatch, suppression chamber access hatch, and equipment hatch) were reassessed using manual computations in accordance with the load combinations and allowable stresses shown in Table 3A-16.

An analysis, using the ANSYS 5.7, was performed by Structural Integrity Associates to reduce the Unit 2 drywell head bolt preload, (See Section 3A.7.2.1.9.1).

3A.7.1.2.3.1 Loads

Loads considered in the assessment of the components included dead load, live load, design accident pressure and thermal load, external pressure load, and jet load resulting from postulated pipe rupture as discussed in Section 3.8.2.3. Equivalent static loads were considered for the seismic load and Mark II hydrodynamic loads using appropriate peak spectral accelerations.

3A.7.1.2.3.2 Load Combinations

Load combinations and allowable stresses used in the re-assessment are given in Table 3A-16. Loads due to SRV, seismic, and LOCA events were combined using the SRSS technique.

3A.7.1.2.3.3 Design Assessment

The resultant membrane stresses, surface stresses, shear stresses and stress in welds were evaluated against allowable stresses given in Table 3A-16 for all components. The preloads and maximum stresses in connecting bolts were also assessed. Relative deflections and rotations were examined at locations where leak-tightness is required. The assessment results for the components are discussed in Section 3A.7.2.

3A.7.1.3 Liner Plate Assessment Methodology

Section 3.8.1.1.2 provides a description of the containment liner plate and its anchorage system.

The analysis and design of the liner plate anchorages for nonhydrodynamic loads is in accordance with Reference 3A-27.

In the assessment of the concrete-backed liner plate and anchorages for hydrodynamic pressure loads, the controlling load on the liner plate and anchorage system is that due to the net negative pressure load if present. The net negative pressure load is determined from the dynamic negative pressure due to SRV actuation and/or LOCA chugging minus the static positive pressure due to the wetwell hydrostatic pressure and/or LOCA wetwell pressure. Figures 3A-41 and 3A-42 describe the loads on the suppression chamber liner plate for the normal and abnormal load conditions.

For the normal condition, the hydrostatic pressure on the basemat liner is 10.4 psi (positive) and the maximum negative pressure due to the actuation of all SRVs is 7.8 psi (negative). The distribution of these pressures on the suppression chamber wall is shown in Figure 3A-41. The maximum net pressure is 2.6 psi (positive).

For the abnormal condition, the combined pressure distribution due to hydrostatic, LOCA wetwell pressure, SRV, and chugging loads is shown in Figure 3A-42. The total positive pressure on the basemat linear is 35.4 psi which consists of 10.4 psi (positive) from hydrostatic pressure plus 25.0 (positive) from a small or intermediate break LOCA. The total cyclic pressure on the basemat liner is 17.6 psi (negative) due to the axisymmetric chugging and SRV loads. Although the maximum negative pressures due to SRV actuation and chugging are combined for conservatism, it is recognized that the probability of these two phenomena producing peak negative pressures at the same time is very low.

The assessment of the liner plate is contained in Section 3A.7.2.1.5.

3A.7.1.4 Downcomer Assessment Methodology

3A.7.1.4.1 Structural Model

There are 87, 24 inch OD, steel pipe downcomers running vertically down from the diaphragm slab. The downcomers are embedded in the diaphragm slab and extend downward to el 193'-11", which is approximately 12 feet below high water level, as shown in Figure 3A-2. All downcomers are supported laterally at el 203'-5" by the downcomer bracing system. Any vertical loads are transmitted by the bracing system to the downcomers and therefore to the diaphragm slab.

The structural model considers the downcomer as a vertical pipe fixed at the underside of the diaphragm slab with a spring in the horizontal direction at bracing level. This model is shown in Figure 3A-43. The inertial effect of the water in the submerged portion of the downcomer (12 feet) was approximated by the addition of a equivalent mass of water lumped at the appropriate nodal points. The model is evaluated for three spring values for a representative support stiffness provided by the bracing system to the downcomers. The bracing spring is set to 50 k/in, 350 k/in, and 15000 k/in to represent the tangential mode, the radial mode, and rigid response of the bracing system.

3A.7.1.4.2 Loads

The downcomer is subjected to static and dynamic loads due to normal, upset, emergency, and faulted conditions. Loading cases and combinations are described in Table 3A-17. The basis for all hydrodynamic loads considered in the analysis is presented in Section 3A.4 and 3B.4.

3A.7.1.4.3 Analysis

Downcomers are analyzed for the specified loading conditions using the Bechtel computer program BSAP. The downcomers are analyzed for both the hydrodynamic loads acting directly on the submerged portions and the inertial forces due to containment responses to the hydrodynamic and seismic loads.

The hydrodynamic load analyses, due to SRV discharge and LOCA- related loads acting on the submerged portion of the downcomers, are performed using the mode-superposition time history technique. The seismic and hydrodynamic load analyses, due to containment responses, are performed using the response spectrum analysis procedure. Damping values used are equal to 2% of critical for OBE and SRV loads, and 7% of critical for SSE and LOCA loads.

3A.7.1.4.4 Design Assessment

The resultant stresses in the downcomers due to the load combinations described in Table 3A-17 are compared with the allowable stresses in accordance with the criteria given in Reference 3A-19.

3A.7.1.4.5 Fatigue Evaluation Of Downcomers In Wetwell Air Space

A fatigue analysis of the downcomers was conducted in accordance with ASME Section III, Division 1 (1979 Summer Addendum), subsection NB-3650. Only that portion of the downcomer in the air space of the suppression chamber need be evaluated for fatigue. Figures 3A-394 and 3A-395 show the number of cycles considered and the load histogram, respectively.

3A.7.1.5 BOP Piping and SRV Systems Assessment Methodology

BOP piping and SRV systems were analyzed for the load combinations described in Table 3A-18 using Bechtel computer program ME101. This program is described in Section 3.9. Hydrodynamic load considerations are provided in Section 3A.5.6. Static and dynamic analysis of the piping and SRV systems are performed as described in the paragraphs below.

Static analysis techniques are used to determine the stresses due to steady-state loads and/or dynamic loads having equivalent static loads.

Response spectra at the piping anchors are obtained from the dynamic analysis of the containment subjected to LOCA and SRV loading. Piping systems are then analyzed for these response spectra following the method described in Reference 3A-28. Alternatively, the multiple response spectra/independent support motion method of analysis may be used where distinct response spectra are applied to the piping system attachment points.

Time history dynamic analysis of the SRV discharge piping subjected to fluid transient forces in the pipe due to relief valve opening is performed using Bechtel computer code ME101.

3A.7.1.5.1 Fatigue Evaluation of MSRV Discharge Lines in Wetwell Air Volume

In an effort to evaluate the steam bypass potential arising from a failure of the MSRV discharge line in the wetwell air space, a complete fatigue analysis has been performed. Specifically, structural analyses of the MSRV discharge lines from the diaphragm

slab penetration to the quencher was performed. Fatigue evaluations of flued head penetration, elbows, tees, taper transitions, and anchors were done. This analysis considered the cyclic loading acting on the MSRV discharge lines and is in accordance with the applicable portions of ASME Code. This evaluation is considered supplemental and does not displace the original design basis for these lines as set forth in the appropriate UFSAR sections.

3A.7.1.5.1.1 Loads and Load Combinations Used for Assessment

The MSRV discharge lines are subject to numerous dynamic and hydrodynamic loads from normal, upset, and LOCA-related plant operating conditions. For purposes of fatigue evaluation, the following loads are included: (1) significant thermal and pressure transients, (2) cyclic loads due to hydrodynamic effects including MSRV actuations, CO and chugging, and (3) seismic effects. The determination of load combinations as well as number and duration of each event is obtained from the applicable sections of Reference 3A-1 and the UFSAR.

3A.7.1.5.1.2 Acceptance Criteria

The design rules, as set forth in ASME Section III, subsection NB, were used for the fatigue assessment.

3A.7.1.5.1.3 Methods of Analysis

The MSRV discharge lines in the wetwell air volume were analyzed for the appropriate load combinations and their associated number of cycles. The combined stresses and corresponding equivalent stress cycles were computed to obtain the fatigue usage factors in accordance with the equations of subsection NB-3600 of the ASME Code.

3A.7.1.5.1.4 Results and Design Margins

The cumulative usage factors for flued head, elbows, tees, tapered transitions, and anchors are summarized in Table 3A-27.

3A.7.1.6 NSSS Assessment Methodology

Safety-related NSSS piping and equipment located within the containment, reactor enclosure, and control structure are subjected to hydrodynamic loads due to SRV and LOCA discharge effects principally originating in the suppression pool of the containment structure. The NSSS piping and equipment are assessed to verify their adequacy to withstand these hydrodynamic loads in combination with seismic and all other applicable loads in accordance with the load combinations given in Table 3A-23.

The structural system responses for the SRV and LOCA suppression pool hydrodynamic phenomena are generated by Bechtel using defined forcing functions. These structural system responses are transmitted to GE in the form of (1) broadened response spectra and (2) acceleration time histories at the pedestal to diaphragm floor intersection and at the stabilizer elevation.

The response spectra for piping attachment points on the RPV, shield wall and pedestal complex (above the pool area) are generated by GE, based on the acceleration time histories supplied by Bechtel, using a detailed lumped-mass beam model for the reactor pressure vessel internals, including a representation of the structure. For the assessment of the NSSS primary piping (main steam and recirculation), a combination of GE and Bechtel developed response spectra are used as input responses for all attachment points of each piping system. For the assessment of the NSSS floor-mounted equipment, except the RPV, the broadened response spectra supplied directly by Bechtel are used.

The acceleration time histories and the detailed RPV and structure lumped-mass beam model are used to generate the forces and moments acting on the RPV supports and internal components. These forces and moments are used for the GE assessment of RPV supports and internals.

The structural system response to the LOCA-induced annulus pressurization transient asymmetric pressure buildup in the annular region between the biological shield wall and RPV is based on pressure time histories supplied by Bechtel. These pressure time histories are combined with jet reaction, jet impingement, and pipe whip restraint loads for the assessment. A time history analysis is performed resulting in accelerations, forces and moment time histories as well as response spectra at the piping attachment points on the RPV, shield wall, pedestal, RPV supports, and external components.

3A.7.1.6.1 NSSS Qualification Methods

3A.7.1.6.1.1 NSSS Piping

The NSSS piping stress analyses are conducted to consider the secondary dynamic responses from: (1) the original design basis loads including seismic vibratory motions, (2) the structural system feedback loads from the suppression pool hydrodynamic events, and (3) the structural system loads from the LOCA-induced annulus pressurization from postulated feedwater and recirculation pipe breaks.

Lumped-mass models are developed by GE for the NSSS primary piping systems, main steam, and recirculation. These lumped-mass models include the snubbers, hangers, and pipe-mounted valves and represent the major BOP branch piping connected to the main steam and recirculation systems. Amplified response spectra for all attachment points within the piping system are applied; i.e., distinct acceleration excitations are specified at each piping support and anchor point. The detailed models are analyzed independently to determine the piping system resulting loads (shear and moments) for:

a. Each design basis load which includes pressure, temperature, weight, seismic events, etc.

b. Bounding suppression pool hydrodynamic event

c. Annulus pressurization dynamic effects on the unbroken piping system.

In addition, the end reaction forces and/or accelerations for the pipe mounted/connected equipment (valves and nozzles) are simultaneously calculated.

The piping stresses from the resulting loads (shears and moments) for each load event are determined and combined in accordance with the load combinations given in Table 3A-19. These

stresses are calculated at geometrical discontinuities and compared to ASME code allowable determined stresses (ASME Section III, NB-3650) for the appropriate loading condition to ensure design adequacy. Fatigue usage is calculated for the range of stress between all operating and upset events and summed to ensure that the fatigue usage factor is less than one.

3A.7.1.6.1.2 Valves

The reaction forces and/or accelerations acting on the pipe-mounted equipment when combined in accordance with the required load combinations are compared to the valve allowables to assure design adequacy. The RCPB valves are qualified for operability during seismic and hydrodynamic loading events by both analysis and test.

3A.7.1.6.1.3 Reactor Pressure Vessel, Supports, and Internal Components

The bounding load combinations for seismic, hydrodynamic, and annulus pressurization forces are established within each service condition category (upset, emergency, and faulted).

The loads for these bounding load combinations are compared to the design basis loads originally used to establish the component design. When the calculated bounding loads are less than the design basis loads, the component design is deemed adequate. When the calculated loads are greater than the design basis loads, the new stresses are calculated and are compared to the code allowable stresses. When the calculated stresses are below the code allowable stresses, the design is deemed adequate. If the increased stresses are above the code allowable stresses, the specific load combination is identified and a more refined stress analysis is performed, if possible, to demonstrate the component design adequacy.

In certain cases, component test results are combined with analyses to assess component adequacy. Fatigue evaluations of the RPV, supports, and internal components are also conducted for SRV cyclic duty loads. The equipment is analyzed for fatigue usage due to SRV load cycles based on the loading during the SRV events. SRV fatigue usage factors are calculated and combined with all other upset condition usage factors to obtain a cumulative fatigue usage factor.

3A.7.1.6.1.4 Floor-Mounted Equipment

3A.7.1.6.1.4.1 Qualification Methods

The adequacy of the design of the equipment is assessed by one of the following methods:

a. Dynamic analysis

b. Testing

c. Combination of testing and analysis

The choice depends on function, type, size, shape, and complexity of the equipment and the reliability of the qualification method.

In general, the requirements outlined in IEEE 344 (1975) are followed for the qualification of equipment. See Section 3.10.

3A.7.1.6.1.4.1.1 Dynamic Analysis

3A.7.1.6.1.4.1.1.1 Methods and Procedures

The dynamic analysis of various equipment is classified into three groups according to the relative rigidity of the equipment based on the magnitude of the fundamental natural frequency described below.

a. Structurally simple equipment - comprises equipment that can be adequately represented by frame-type structures consisting of members physically similar to beams and columns.

b. Structurally rigid equipment - Comprises that equipment whose fundamental frequency is:

   1. Greater than 33 Hz for the consideration of seismic loads, and,

   2. Greater than the zero period acceleration frequency of the suppression pool hydrodynamic load RRS.

c. Structurally complex equipment - Comprises equipment that cannot be classified as structurally simple or structurally rigid.

The appropriate response spectra for specific equipment are obtained from the response spectra for the floor at which the equipment is located in a building for OBE, SSE, and hydrodynamic loads. This includes the vertical as well as both the N-S and E-W horizontal directions. For equipment that is structurally simple, the dynamic loading (either seismic or hydrodynamic) consists of a static load corresponding to the equipment weight times the acceleration selected from the appropriate response spectrum. The acceleration selected corresponds to the equipment natural frequency, if the equipment natural frequency is known. If the equipment natural frequency is not known, the acceleration selected corresponds to the maximum value of the response spectra, which is multiplied by a static coefficient of 1.5 to take into account the effects of both multifrequency excitation and multimode response.

For equipment that is structurally rigid, the seismic load consists of a static load corresponding to the equipment weight times the acceleration at 33 Hz, selected from the appropriate response spectrum. The hydrodynamic loading consists of a static load corresponding to the equipment weight times the acceleration at the zero period acceleration, selected from the appropriate response spectrum.

The analysis of structurally complex equipment uses an idealized mathematical model which predicts the dynamic properties of the equipment. A dynamic analysis is performed using any standard analysis procedure. An acceptable alternative method of analysis is by static coefficient analysis for verifying structural integrity of frame-type structures that can be represented by a simple model. No determination of natural frequencies is made, and the response of the equipment is assumed to be the peak of the response spectrum. This response is multiplied by a static coefficient to take into account the effects of both multifrequency excitation and multimode response. The static coefficient used for structurally complex equivalent is justified and is consistent with Regulatory Guide 1.100 guidelines.

3A.7.1.6.1.4.1.2 Testing

Dynamic adequacy for some equipment is established by providing dynamic test data instead of performing dynamic analysis. Such data must conform to one of the following:

a. Performance data of equipment that has been subjected to equal of greater dynamic loads (considering appropriate frequency range) than those to be experienced under the specified dynamic loading conditions.

b. Test data from comparable equipment previously tested under similar conditions that has been subjected to equal or greater dynamic loads than those specified.

c. Actual testing of equipment in operating conditions simulating, as closely as possible, the actual installation, the required loadings and load combinations.

The equipment to be tested is mounted in a manner that simulates the actual service mounting. Sufficient monitoring devices are used to evaluate the performance of the equipment. With the appropriate test method selected, the equipment is considered to be qualified when the TRS envelopes the RRS and the equipment does not malfunction or fail. A new test does not need to be conducted if equipment requires only minor modifications such as additional bracings or change in switch model, etc, and if proper justification is given to show that the modifications would not jeopardize the strength and function of the equipment.

3A.7.1.6.1.4.1.3 Combined Analysis and Testing

This method has not been used in the NSSS piping and safety-related equipment adequacy evaluations.

3A.7.1.7 BOP Equipment Assessment Methodology

Safety-related equipment located within the containment, the reactor enclosure, and the control structure are subjected to hydrodynamic loads due to SRV and LOCA (SBA, IBA, and DBA) discharge effects principally originating in the suppression pool of the containment structure. The equipment and equipment supports are assessed to verify their adequacy to withstand these hydrodynamic loads in combination with seismic and all other applicable loads in accordance with the load combinations given in Table 3A-20. In addition, safety-related active pumps and valves located within the containment, the reactor enclosure, and the control structure are qualified for operability during seismic and hydrodynamic events.

3A.7.1.7.1 Dynamic Loads

3A.7.1.7.1.1 SRV Discharge Loads

Loadings associated with the axisymmetric and asymmetric SRV discharges are described in Sections 3A.3, 3A.4, and 3B.4. ARS at the various elevations where the equipment are located have been generated for all appropriate pressure history traces (Figures 3B-25 through 3B-27) for damping values of ½%, 1%, 2%, and 5%.

3A.7.1.7.1.2 LOCA-Related Loads

Loadings associated with a LOCA are described in Sections 3A.3, 3A.4 and 3B.4. The various LOCA loadings considered include condensation oscillation and chugging (Section 3A.4.2.2). ARS at

various elevations where the equipment are located have been generated for the above LOCA loads for damping values of ½%, 1%, 2%, and 5%.

3A.7.1.7.1.3 Seismic Loads

The details of seismic input and seismic loads are discussed in Section 3.7. The effects of both the OBE and SSE are considered. These loads are provided in the form of ARS at each floor for damping values of ½%, 1%, 2%, and 5% for each of N-S, E-W and vertical directions.

3A.7.1.7.2 Load Combinations

Seismic, SRV, and LOCA loads have been combined for various load combinations in accordance with Table 3A-20 at all floor elevations. For the same equipment located at various elevations, the combined response spectra are enveloped into a single curve for a damping value of 2%. Such enveloped curves are generated for each of the N-S, E-W, and vertical directions.

3A.7.1.7.3 Other Loads

In addition to hydrodynamic and seismic loads, other loads such as dead loads, live loads, operating loads, pressure loads, thermal loads, nozzle loads and equipment piping interaction loads, as applicable, are also considered.

3A.7.1.7.4 Qualification Methods

The adequacy of the design of the equipment is assessed by one of the following:

a. Dynamic analysis

b. Testing

c. Combination of testing and analysis.

The choice is based on the practicality of the method depending upon function, type, size, shape, complexity, and nonlinear effects of the equipment and the reliability of the qualification method.

In general, the requirements outlined in Reference 3A-29 are followed for the qualification of equipment.

3A.7.1.7.4.1 Dynamic Analysis

3A.7.1.7.4.1.1 Methods and Procedures

The dynamic analysis of various equipment is classified into three groups according to the relative rigidity of the equipment based on the magnitude of the fundamental natural frequency described below:

a. Structurally simple equipment - comprised of that equipment which can be adequately represented by one degree of freedom system.

b. Structurally rigid equipment - Comprised of that equipment whose fundamental frequency is:

1. Greater than 33 Hz for the consideration of seismic loads, and,

2. Greater than 100 Hz for the consideration of hydrodynamic loads.

c. Structurally complex equipment - Comprised of that equipment which cannot be classified as structurally simple or structurally rigid.

When the equipment is structurally simple or rigid in one direction but complex in the other, each direction may be classified separately to determine the dynamic loads.

The appropriate response spectra for specific equipment are obtained from the response spectra for the elevation at which the equipment is located in a building for OBE, SSE, and hydrodynamic loads. This includes the vertical as well as both the N-S and E-W horizontal directions.

For equipment that is structurally simple, the dynamic loading (either seismic or hydrodynamic) consists of a static load corresponding to the equipment weight times the acceleration (in "g's") selected from the appropriate response spectrum. The acceleration selected from the response spectrum corresponds to the equipment's natural frequency, if the equipment's natural frequency is known. If the equipment's natural frequency is not known, the acceleration selected corresponds to the maximum "g" value of the response spectra.

For equipment that is structurally rigid, the seismic load consists of a static load corresponding to the equipment weight times the acceleration at 33 Hz, selected from the appropriate response spectrum and the hydrodynamic loading consists of a static load corresponding to the equipment weight times the acceleration at 100 Hz, selected from the appropriate response spectrum.

For the analysis of structurally complex equipment, the equipment is idealized by a mathematical model that adequately predicts the dynamic properties of the equipment, and a dynamic analysis is performed using any standard analysis procedures such as response spectrum modal analysis or a time history analysis. The responses of interest such as deflection, stress, acceleration, etc., are determined by combining each modal response considering all significant modes by the SRSS. The absolute sum of similar effects is considered for closely spaced in-phase modes. Closely spaced modes are those with frequencies differing by 10% or less.

An acceptable alternative method of analysis is by static coefficient analysis for verifying structural integrity of frame-type structures such as members physically similar to beams and columns that can be represented by a simple model. No determination of natural frequencies is made, and the response of the equipment is assumed to be the peak of the response spectrum at damping values in accordance with Section 3A.7.1.7.4.1.2. This response is then multiplied by a static coefficient of 1.5 to take into account the effects of both multifrequency excitation and multimode response.

For nonlinear analysis that may be necessary to account for the nonlinear material properties or the geometry-related nonlinearities, the analysis will include a detailed justification for the approach used for the qualification. Alternatively, the testing method of qualification is used where the effects of nonlinearities are to be considered.

3A.7.1.7.4.1.2 Appropriate Damping Values

The following damping values are used for the design assessment:

a.	Load combinations involving OBE but not hydrodynamic loads	½%
b.	Load combinations involving SSE but not hydrodynamic loads	1%
c.	Load combinations involving hydrodynamic loads, or seismic and hydrodynamic loads	2%

Higher damping values may be used where justified.

3A.7.1.7.4.1.3 Three Components of Dynamic Motions

The responses such as internal forces, stresses, and deformations at any point from the three principal orthogonal directions of the dynamic loads are combined as follows.

The response value used shall be the maximum value obtained by adding the response due to vertical earthquake with the larger value of the responses due to one of the horizontal earthquakes by the ABS method.

For the other dynamic loads, the response value shall be obtained by combining the response due to three orthogonal directions of an individual load by the SRSS method.

3A.7.1.7.4.2 Testing

Qualification by testing is used in cases where operability requires verification and the effects of nonlinearities have to be considered. For these instances, dynamic adequacy is established by providing dynamic test data. Such data must conform to one of the following:

a. Performance data of equipment that has been subjected to equal or greater dynamic loads (considering appropriate frequency range) than those to be experienced under the specified dynamic loading conditions.

b. Test data from comparable equipment previously tested under similar conditions that has been subjected to equal or greater dynamic loads than those specified.

c. Actual testing of equipment in operating conditions simulating, as closely as possible, the actual installation, the required loadings and load combinations.

A continuous sinusoidal test, sine beat test, or decaying sinusoidal test is used when the applicable floor acceleration spectrum is a narrow band response spectrum. Otherwise, random motion test (or equivalent) with broad frequency content is used.

The equipment to be tested is mounted in a manner that simulates the actual service mounting. Sufficient monitoring devices are used to evaluate the performance of the equipment. With the appropriate test method selected, the equipment is considered to be qualified when the TRS envelopes the RSS and the equipment does not malfunction or fail. A new test does not need to be conducted if equipment requires only minor modifications such as additional bracings or change in switch model, etc, and if proper justification is given to show that the modifications would not jeopardize the strength and function of the equipment.

3A.7.1.7.4.3 Combined Analysis and Testing

There are several instances where the qualification of equipment by analysis alone or testing alone is not practical or adequate because of its size, or its complexity, or large number of similar configurations. In these instances, a combination of analysis and testing is the most practical. The following are general approaches:

a. An analysis is conducted on the overall assembly to determine its stress level and the transmissibility of motion from the base of the equipment to the critical components. The critical components are removed from the assembly and subjected to a simulation of the environment on a test table.

b. Experimental methods are used to aid in the formulation of the mathematical model for any piece of equipment. Mode shapes and frequencies are determined experimentally and incorporated into a mathematical model of the equipment.

3A.7.1.8 Electrical Raceway System Assessment Methodology

3A.7.1.8.1 General

The analysis and design of supports of electrical raceway systems for nonhydrodynamic loads are in accordance with Reference 3A-32. SRV discharge and LOCA loads are considered similar to seismic loads by using appropriate floor response spectra for the hydrodynamic loads. A damping value of 3% critical is used for all raceway systems for the normal load condition involving SRV discharge loading only. The damping ratios used for the electrical raceway assessment are in accordance with Reference 3A-32. For the abnormal/extreme load condition, a damping value of 10% of critical is used for cable tray support systems; 7% damping for conduit and wireway gutter trapeze-type support systems; 5% damping for conduit and wireway gutter nontrapeze-type support systems. These damping values are based on the results of the Cable Tray and Conduit Raceway Seismic Test Program (Reference 3A-31).

The cable tray system damping is substantially greater than that of bolted steel structures due to the cable motion within the trays. The test program demonstrated that cable tray system damping is, in general, much higher than 10%, and damping values up to 50% were reported. The damping values recommended in Reference 3A-32, and shown in Figure 3A-45, are based on the lower bound values developed from the test program. An unloaded tray will have an associated lower bound damping value of about 7% as shown in Figure 3A-45.

Analysis using 10% damping for a fully loaded tray system under the abnormal/extreme load conditions is conservative and will envelop an analysis of an unloaded tray with a 7% damping ratio for the following reasons:

The frequency shift resulting from reduced mass in a relatively unloaded tray may result in either higher of lower response, depending on the individual response spectrum. However, when the combined effects of frequency shift, reduced damping, and lower weights are considered, the result will be a more conservative design. For example, consider the comparison of accelerations, weights, and resulting seismic forces for fully loaded and unloaded trays shown in Table 3A-26. A fully loaded tray typically weighs approximately eight times more than an empty tray. The maximum acceleration for the unloaded tray case (at 7% damping) is four times that for the fully loaded tray case (at 10% damping) assuming that frequency shift, due to the reduced mass of the unloaded tray, results in the maximum

increase in acceleration. In calculating the resulting seismic forces for both cases, it is apparent that the loaded tray case yields the higher seismic load.

In addition, based on a random sampling of cable tray supports and conservatively assuming a fully loaded tray and peak acceleration, approximately 75% of the sampled members have a stress margin of 30% or more. The remaining 25% of the members are within allowable stress limits.

LGS cable tray systems are similar to those tested in Reference 3A-32, i.e., the trays are of the same material and of similar construction, and the hangers and installation are similar in construction and design. Therefore, the dynamic behavior of LGS tray systems will parallel the dynamic behavior of the tested tray systems.

For conduit systems, the test program demonstrates that, at the abnormal/extreme load condition, the damping value equals 7% of critical. This damping value is consistent with Regulatory Guide 1.61 recommended values for bolted steel structures. Therefore, 7% damping is used for conduit with trapeze-type support systems, and a more conservative 5% damping is used for conduit with nontrapeze-type support systems.

Wireway gutters were not tested; however, the manner in which they are constructed (with more bolted connections and more cables than conduit) provides more damping mechanisms than those present in conduit systems. Therefore, it is conservative to use the conduit system damping value.

3A.7.1.8.2 Loads

3A.7.1.8.2.1 Static Loads

The static loads are the dead loads and live loads. For cable trays, the weight of the cable plus tray is considered to be 36 lb/ft (except unique situations where heavier weights are considered) and a concentrated live load of 200 lb applicable at any point on the cable tray span is used.

3A.7.1.8.2.2 Seismic Loads

The details of the seismic motion input are discussed in Section 3.7. The effects of the OBE and the SSE are considered.

For the normal load condition, involving SRV discharge loading, a damping value equal to 3% of critical is used for all raceway systems. The SRV load is considered similar to an OBE load; therefore, a 3% damping value is considered conservative because 4% damping is recommended by Regulatory Guide 1.61 for bolted steel structures for the OBE loading.

3A.7.1.8.2.3 Hydrodynamic Loads

The details of the axisymmetric and asymmetric SRV discharge loads as well as LOCA loads including condensation oscillation and chugging are discussed in Sections 3A.4 and 3B.4.

The enveloped ARS at each floor for N-S, E-W, and vertical directions have been generated and widened by ±15%. These curves form the basis for the hydrodynamic load assessment of the electrical raceway system. Examples of the response spectrum curves for the containment and reactor and control enclosures are presented in Sections 3A.9 and 3A.10.

3A.7.1.8.3 Analytical Methods

Electrical raceway systems are modeled as a three-dimensional dynamic system consisting of several consecutive supports complete with raceways and longitudinal and transverse bracing. The cable tray properties are determined from the load-deflection tests. Member joints are modeled as spring elements having rotational stiffness with known spring values as determined from the test results.

Composite spectra are developed by enveloping the floor response spectra after broadening by ±15% for critical floors for seismic, SRV, and LOCA loading conditions. The design spectrum is obtained by adding these response spectra curves by either the SRSS method or the ABS method. A frequency variation of ±20% is used to further broaden the spectrum at the fundamental frequency of the electrical raceway system. The composite response spectra curves are obtained for vertical and two horizontal directions.

Modal and response spectrum analyses are performed using the Bechtel Structural Analysis Program (BSAP), which is a general purpose finite-element computer program. The total response due to the dynamic loads is calculated by determining the absolute sum of the vertical response and only the larger response of the two horizontal responses.

Dead and live load stresses are determined from a static analysis of a plane frame model using the BSAP computer program or hand calculation, and these results are combined with those from the response spectrum analysis. For normal load conditions, SRV discharge stresses are proportioned from the response spectrum analysis of SSE plus SRV discharge plus LOCA loads according to their spectral acceleration ratios at the fundamental frequencies. Several different support types that are widely used have been analyzed by these methods.

An alternative method for analyzing other support types uses hand calculations by a response spectrum analysis technique. The support may be idealized as a single degree of freedom system. In general, the maximum peak spectral accelerations were used in the analysis. In some cases where the stresses are critical, a more refined value for the acceleration response was used corresponding to the computed system fundamental frequency and considering a frequency variation as explained earlier in this section. The total response due to the dynamic loads is calculated by determining the absolute sum of the vertical response and only the larger response of the two horizontal responses. The member stresses are kept within the elastic limit.

3A.7.1.9 HVAC Duct System Assessment Methodology

The SRV discharge and LOCA loads are considered similar to seismic loads by using appropriate floor response spectra generated for the CO, chugging, and SRV loads described in Sections 3A.4 and 3B.4.

A damping value of 5% of critical is used for load combinations involving SSE, SRV discharge, and LOCA loads, while a damping value of 3% of critical is used for load combinations involving OBE and/or SRV discharge loads. For a discussion of the seismic and hydrodynamic loads input for HVAC duct system assessment, refer to Sections 3A.7.1.8.2.2 and 3A.7.1.8.2.3, respectively. The HVAC duct system has been analyzed by determining the fundamental frequencies of the system in three directions. The inertia forces are determined from the composite spectra to establish member forces and moments due to hydrodynamic as well as seismic loads.

3A.7.2 DESIGN CAPABILITY MARGINS

This section describes the design margins for structures, piping, and equipment resulting from the LGS design assessment which uses the methods of Section 3A.7.1.

3A.7.2.1 Stress Margins

Stresses at the critical sections for all of the structures, piping, and equipment described in Section 3A.7.1 are evaluated for the loading combinations presented in Section 3A.5.

The stress margin (SM) in percent is defined as follows:

$$SM = (1 - SR) \times 100$$

where SR represents the stress ratio. SR is calculated by dividing the factored stress ($C_n f_n$) by the associated stress allowable (F_n) or, mathematically,

$$SR = \Sigma (C_n f_n / F_n) \qquad \text{(EQ. 3A-8)}$$

3A.7.2.1.1 Containment Structure

The detailed results from the structural assessment of the containment structure are summarized in Section 3A.12.1. Figure 3A-362 shows the design sections in the basemat, shield walls, containment walls, reactor pedestal, and the diaphragm slab that were considered in the structural assessment. Figures 3A-363 through 3A-386 give the calculated maximum design stresses for the load combinations listed in Table 3A-14.

Both rebar stresses and concrete stresses are calculated based on the applicable load combination equations. The stresses in the drywell wall are calculated at design sections 1 to 5 and are tabulated in Figures 3A-363 through 3A-366. The stresses in the wetwell wall are calculated at design sections 6 to 11 and are tabulated in Figures 3A-367 through 3A-370. The stresses in the shield wall are calculated at design sections 12 and 13 and are tabulated in Figures 3A-371 and 3A-372, respectively. The RPV pedestal stresses are calculated at design sections 14 to 20 and are tabulated in Figures 3A-373 through 3A-377. The stresses in the diaphragm slab are calculated at design sections 21 to 25 and are tabulated in Figures 3A-378 through 3A-381. The stresses in the basemat are calculated at design sections 26 to 30 and are tabulated in Figures 3A-382 through 3A-386.

The containment assessment is summarized as follows:

a. The calculated stress level is very low for load combination equation 1 (an operating condition), i.e., rebar stresses are far less than 20 ksi.

b. The maximum rebar stress is predicted as 53.9 ksi at design sections 6 and 11, located in the wetwell vertical direction. The magnitude is within the rebar stress allowable ($0.9 F_y = 54$ ksi).

c. In general, rebar stresses and concrete compressive stresses are within stress allowables.

3A.7.2.1.2 Reactor Enclosure and Control Structure

Results of the structural assessment of the reactor enclosure and control structure are summarized in Section 3A.13. Figures 3A-398 through 3A-418 show the selected structural elements and sections where stresses were calculated.

Section 3A.13 contains tabulations of predicted stresses, stress allowables, and design margins for critical loading combinations considered. The sections selected for assessment were considered to be the most critical based on previous seismic calculations.

The critical load combinations are tabulated considering critical locations/sections related to reactor enclosure and control structure shear walls, foundations, floor slabs and supporting steel, steel platforms, and floor support columns.

Emphasis is placed on margins of principal resisting structural elements, with reinforcing bar stresses for reinforced concrete structures and axial and/or bending stresses for steel structures.

Also included in Section 3A.13 are diagrams of axial forces, N-S shear forces, N-S overturning moments, E-W shear forces, E-W overturning moments for reactor enclosure and control structure as shown in Figures 3A-419 through 3A-428.

The reactor enclosure floor system stress margins were calculated for both slabs and floor support steel beams, including floors at el 201', 217', 253', 283', 313', 333', and 352'. Calculated slab stress levels were generally governed by either equation 1 or 7a of Table 3A-14. The highest reinforcing bar stress was found at the floor of el 253', having a stress intensity of 51.26 ksi and an associated stress margin of approximately 5%. Figure 3A-429 shows rebar stresses and related stress margins of the aforementioned floors. In addition, the stresses and related stress margins of floor support steel beams are presented in Figure 3A-430. The governing equations were equations 1 and 7 of Table 3A-15. Stress levels were generally low.

In the case of reactor enclosure support columns, load combination 7 of Table 3A-15 governs the column stress interaction. Stress interaction calculations were performed and show that columns were generally understressed (Figure 3A-431). The column at column lines 30.5 and E of el 217' to el 253' has a fully stressed situation.

The reactor enclosure shear wall sections close to the base (el 177') were assessed as shown in Figure 3A-432. The highest stress conditions occurred in the walls of column lines 14.1 (west wall) and 31.9 (east wall) due to shearing effect at the base. The corresponding stress margin was approximately 1%.

The floor system of the control structure, including the concrete slabs and their supporting steel beams, are shown in Figure 3A-406 through 3A-414, while the stress margins are listed in Figures 3A-433 and 3A-434.

In general, none of those selected critical sections were found overstressed in the control structure. All concrete floors were assessed. The concrete slabs are governed by the normal load conditions, equation 1 of Table 3A-14. The steel floor beams supporting the concrete slabs are governed by the abnormal extreme environmental load conditions, equation 7 of Table 3A-14. Generally, the concrete slabs have a higher stress margin than the supporting steel beams.

For the control structure shear walls, the stress levels are critical in the walls close to the base due to seismic loads. The stress margins for the shear walls at column lines 19.4 and 26.6, as shown in

Figure 3A-435, were found most critical under the abnormal extreme environmental load condition including DBE and seismic torsional effects.

The steel platforms at el 313', el 322', el 340', and el 350' were also assessed. The dynamic loads applied on the steel frames which support the platforms were found less significant than the normal loads. All the steel frames are governed by the normal load condition, equation 2 of Table 3A-15, with its associated allowable stresses. Those assessed steel members are shown in Figures 3A-415 through 3A-418. As demonstrated in Figure 3A-436, steel frames are generally understressed.

3A.7.2.1.3 Suppression Chamber Columns

The column vibration mode shapes are calculated using computer program BSAP. The mode shapes are shown in Figure 3A-387. The equivalent water mass is equal to the column volume.

The stresses at the top and bottom of the suppression chamber columns were calculated and combined in accordance with the load combinations shown in Table 3A-15. The maximum stresses in the column are governed by load combination equation 7. The maximum stresses in the column (42 inch diameter pipe), top anchorage, and bottom anchorage are shown in Figure 3A-388. The lowest stress margin in the column structure is 10%.

3A.7.2.1.4 Downcomer Bracing

The bracing member forces and the corresponding design margins due to the governing load combinations are given in Figure 3A-397 for the critical bracing members.

3A.7.2.1.5 Liner Plate

For the normal and abnormal conditions, the liner plate system does not experience any net negative pressures as demonstrated in Figures 3A-41 and 3A-42. There is a large stress margin because the liner plate is designed for resisting a large suction (i.e., 5 psi negative).

3A.7.2.1.6 Downcomers

The downcomer vibration mode shapes are calculated for the modal analyses using computer program BSAP. The mode shapes are shown in Figures 3A-389 through 3A-391, for the three representative bracing system spring stiffnesses. The equivalent water mass included in the model is equal to the downcomer volume.

The downcomers were assessed in accordance with ASME Section III, Division 1, subsection NB-3652, using load combinations in Table 3A-17. Stresses and design margins are given in Figure 3A-392.

Downcomer fatigue at three critical locations were also checked. Loads are combined by the absolute sum method. Figure 3A-393 shows the fatigue usage factors at these critical locations, computed in accordance with ASME Section III, Division 1, subsection NB-3650 (1979 Summer Addenda). Downcomers are adequate for fatigue considerations.

3A.7.2.1.7 Electrical Raceway System

The electrical raceway system was analyzed using the load combinations in Table 3A-21 in accordance with the methodology described in Section 3A.7.1.8. The stress margins were found to

be most critical under the abnormal/extreme load condition. Stresses are below allowable stress levels for all members of the electrical raceway system.

3A.7.2.1.8 HVAC Duct System

The HVAC duct system was analyzed using the load combinations in Table 3A-22 in accordance with the methodology described in Section 3A.7.1.9. The stress margins were found to be most critical under the abnormal/extreme load condition. Stresses are below allowable stress levels for all members of the HVAC duct system.

3A.7.2.1.9 ASME Class MC Steel Components Margins

3A.7.2.1.9.1 Refueling Head And Flange

The refueling head and flange were found to have no stresses exceeding the specified allowable limits.

The leak-tightness of the flanged joint is investigated for the combined effect of temperature, pressure, seismic, SRV, LOCA and jet forces. Vertical separation at the flange faces is prevented by providing sufficient bolt preload to offset uplift due to the applied loads. Similarly, relative horizontal movement between the flange faces is prevented by the bolt preload induced frictional forces. For Unit 1 a preload of 157k per bolt is required to maintain leak-tightness at the flange joint. For Unit 2 a preload of 130k per bolt is required to maintain leak-tightness at the flange joint. (The Unit 2 preload is based on an analysis performed by Structural Integrity Associates.)

3A.7.2.1.9.2 Suppression Chamber Access Hatch, CRD Removal Hatch, and Equipment Hatch

For these components, the analysis by Chicago Bridge and Iron Company indicated that there are no stresses in excess of the specified allowable limits when considering the additional hydrodynamic loading.

3A.7.2.1.9.3 Equipment Hatch/Personnel Airlock

The equipment hatch with personnel airlock has been assessed for hydrodynamic and seismic loads. Modifications to some cap screws of the attachment brackets are required to accommodate the additional hydrodynamic loading. The equipment hatch with personnel airlock and all related components are within the specified allowable limits.

3A.7.2.1.10 BOP Piping and MSRV Systems Margins

As described in Section 3A.7.1.5, all seismic Category I BOP piping components and their supports located inside the containment, reactor enclosure, and control structure have been included in the design assessment and have been analyzed for seismic and hydrodynamic loads. The loads from the analyses are combined as described in Table 3A-18. Additional supports and modification of existing supports where required to accommodate the hydrodynamic and seismic loads for some piping systems have been completed.

Stresses and stress margins for selected BOP piping systems are summarized in Section 3A.14. The stress reports for the evaluation of the BOP piping will be available for NRC review.

3A.7.2.1.11 BOP Equipment Margins

All seismic Category I BOP equipment and their supports have been included in the design assessment and analyzed for hydrodynamic and seismic loads (Section 3A.7.1.7) via the LGS SQRT

program. Structural modifications necessitated by the addition of suppression pool hydrodynamic loads have been completed. For each piece of BOP equipment, a five page SQRT summary form has been prepared documenting the re-evaluation of the equipment.

3A.7.2.1.12 NSSS Margins

Safety-related NSSS piping, equipment and their supports have been assessed for hydrodynamic and seismic loads. Detailed results of the evaluation are given in Sections 3.9 and 3.10. Structural modifications necessitated by addition of suppression pool hydrodynamic loads have been completed. In addition, GE has prepared Seismic Qualification Reevaluation Program forms, NSSS Loads Adequacy Evaluation Program Summary reports, and design stress reports to document the assessment of seismic and hydrodynamic loads on NSSS piping, safety-related equipment and all related supports. These forms and reports will be available for NRC review.

3A.7.2.2 Acceleration Response Spectra

3A.7.2.2.1 Containment Structure

The method of analysis and load description for the ARS generation are outlined in Section 3A.7.1.1.1.6.1. From a review of the ARS curves for the containment structure, the maximum spectral accelerations are tabulated for 1 percent damping of critical. For SRV and LOCA loads, the maximum spectral accelerations are presented in Table 3A-25.

The hydrodynamic ARS of the containment structure are presented in Section 3A.9.2.

3A.7.2.2.2 Reactor Enclosure and Control Structure

The method of analysis and load applications for the computation of the hydrodynamic ARS in the reactor enclosure and the control structure are described in Section 3A.7.1.1.2. The response spectra of the reactor enclosure and the control structure are shown in Section 3A.10.

3A.8 MARK II T-QUENCHER VERIFICATION TEST (PROPRIETARY – SEE APPENDIX 3B)

3A.9 CONTAINMENT MODE SHAPES AND HYDRODYNAMIC RESPONSE SPECTRA

3A.9.1 CONTAINMENT MODE SHAPES

The containment model is shown in Figure 3A-46. Figure 3A-47 shows containment frequencies from the modal analysis with water mass included as discussed in Section 3A.7.1.1.1.3. Containment mode shapes are shown in Figures 3A-48 through 3A-70, covering mode shapes 1 through 23.

3A.9.2 CONTAINMENT HYDRODYNAMIC RESPONSE SPECTRA

This section shows examples of the horizontal and vertical response spectra curves of the containment structure due to LOCA and SRV loading. Four spectral damping values, i.e., 0.005, 0.01, 0.02, and 0.05, are shown on each group of curves. The structural model of the containment is shown on Figure 3A-46. The modal frequencies and mode shapes are shown on Figures 3A-47 through 3A-70. The broadened response spectrum curves, shown on Figures 3A-71 through 3A-150, are submitted as representative examples of the containment structure response spectra. The loads under consideration are SRV and LOCA.

The KWU SRV loads consist of 3 pressure time histories. Five different time factors are applied to each pressure time history to account for possible variations in the frequency content. Therefore, a total of 15 axisymmetric and 15 asymmetric SRV load cases were analyzed.

The LOCA loads considered include 17 segments of CO, 2 segments of condensation oscillation with ADS (CO-ADS), and 14 cases of chugging.

Enveloped and broadened ARS at selected nodes for the respective hydrodynamic loads are included in this report. The locations of the selected nodes are shown on Figure 3A-46. The hydrodynamic response spectra included at the selected nodes are shown on Figures 3A-71 through 3A-86 for SRV axisymmetric load, on Figures 3A-87 through 3A-102 for SRV asymmetric load, on Figures 3A-103 through 3A-118 for CO load, on Figures 3A-119 through 3A-134 for CO-ADS load, and on Figures 3A-135 through 3A-150 for chugging load. However, the chugging response spectra presented is the envelope spectra of all nodal points at the same elevation and radius. Therefore, the chugging spectra consist of representative spectra at containment locations with the same elevation and radius as the labeled nodal points on Figure 3A-46.

3A.10 REACTOR ENCLOSURE AND CONTROL STRUCTURE MODE SHAPES AND HYDRODYNAMIC RESPONSE SPECTRA

3A.10.1 REACTOR ENCLOSURE AND CONTROL STRUCTURE MODE SHAPES

The reactor enclosure and control structure horizontal mathematical stick model (for N-S and E-W directions) is shown in Figure 3A-35. Mode frequencies and participation factors are shown in Figure 3A-151. Representative vibration mode shapes that have significant participation are plotted in Figures 3A-152 and 3A-153.

The reactor enclosure and control structure vertical mathematical decoupled stick model is shown in Figure 3A-34. Mode frequencies and participation factors are shown in Figure 3A-154. Representative vibration mode shapes that have significant participation are plotted in Figures 3A-155 to 3A-163.

The control structure floor vertical "half-model" is shown in Figure 3A-36. Mode frequencies and participation factors for a typical local floor model at el 269' in the control structure are shown in Figure 3A-164. Representative vibration mode shapes that have significant participation are plotted in Figures 3A-165 to 3A-168.

3A.10.2 REACTOR ENCLOSURE AND CONTROL STRUCTURE HYDRODYNAMIC ACCELERATION RESPONSE SPECTRA

This section shows representative examples of the horizontal and vertical response spectra curves of the structure due to LOCA and SRV loading. Five special damping values, i.e., 0.005, 0.01, 0.02, 0.03 and 0.05, are shown on each group of curves. The response spectra presented in this section are at representative locations of the building models (Figures 3A-33 to 3A-35).

The SRV loads are defined by KWU from measured pressure traces. Figures 3A-169 to 3A-226 show broadened response spectra for the SRV loads, considering both asymmetric and axisymmetric cases.

The LOCA loads consist of chugging and condensation oscillation. The chug loads were generated form the improved Mark II chugging load definition based on GE 700 series design sources. The source data were based on 4TCO test data. Figures 3A-227 to 3A-284 show broadened response spectra curves for chugging, considering both asymmetric and axisymmetric cases. The CO loads were generated from GE's generic 4TCO test data. Figures 3A-285 to 3A-352 show broadened response spectra curves for CO-Basic and CO-ADS (axisymmetric only).

The seismic loads are described in Section 3.7.

3A.11 SUBMERGED STRUCTURE METHODOLOGY

3A.11.1 INTRODUCTION

The Mark II suppression pool is expected to experience fluid motion as a result of SRV actuation and postulated LOCA. The velocity and acceleration fields will cause drag loads on structures submerged in the pool. These loads have been calculated in the past by assuming the existence of a uniform flow field and applying steady-state standard and acceleration drag coefficients. The NRC Lead Plan Acceptance Criteria, NUREG-0487, (Reference 3A-2) pointed out that this method might not be conservative under certain flow conditions and for certain structure geometries. This section explains the methods used by the lead-plants and LGS to ensure that the design loads are conservative.

Section 3A.11.2 presents a method of evaluating the correction to both standard and acceleration drag coefficients in unsteady flow and a method to evaluate the transverse (lift) force in this flow. Sections 3A.11.3 and 3A.11.4 describe the effect of neighboring structures on the submerged structure drag loads. This method provides modified drag coefficients for the range of geometries existing in Mark II plants.

Section 3A.11.5 presents the results of sensitivity studies that verify the adequacy of the nodalization used in predicting loads. These studies show that increasing the number of points at which loads are calculated will not make significant changes in the result.

All of the drag coefficients used for submerged structure load calculations for each particular accident condition were determined directly from the data that are presented in the references listed in Section 3A.17 and 3B.17. In addition, all modifications made to the drag coefficients describing the effects of neighboring structures and unsteady flow were based on actual data listed in these references. The theory provided in this section is used as background information and provides support to the load calculations performed on this plant. The theory presented also addresses the concerns raised in NUREG-0487.

3A.11.2 DRAG AND LIFT COEFFICIENTS FOR UNSTEADY FLOW

3A.11.2.1 General Considerations

Drag and lift loads on submerged structures in the suppression pool due to the LOCA charging air bubble, pool-swell, fallback, and the SRV air bubble are considered. In calculating these loads on submerged structures, acceleration and standard drag and lift coefficients are used whenever they are applicable to a specific situation. The effects of unsteady flow on the above mentioned coefficients are treated in this section, and interference effects,

if present, are addressed in Sections 3A.11.3 and 3A.11.4. The steady-state drag coefficients are corrected appropriately to include the effects of unsteady flow.

Because the majority of the available data for unsteady flow have been developed for a cylinder, the discussion provided herein is in terms of a cylinder. The structures in the LGS suppression pool are all analyzed as cylinders. If differently shaped structures were present, a cylinder with an equivalent diameter would be used for calculations. This approach is conservative for drag load calculations, with the possible exception of the prediction of initiation of vortex shedding. Lift forces due to vortex shedding on sharp-edged structures are calculated conservatively based on available data.

Possible shapes of submerged structures in a Mark II suppression pool include circular cylinders, box beams, and I-beams. Equivalent diameters can easily be determined for these structures.

First, to determine the unsteady effects on a submerged structure, a circular cylinder with an equivalent diameter is considered. Then, for the appropriate literature, the drag coefficient due to unsteady flow for cylinders are determined, and a drag coefficient multiplier is calculated as the ratio of the unsteady drag coefficients to the steady-state drag coefficients. Finally, these multipliers are applied to the steady-state drag coefficients of the particular submerged structure of interest. However, in computing the loads, the actual dimensions of the structure are used in order to properly determine the loads.

An equivalent diameter is determined by circumscribing a circle about any structure (Reference 3A-33). For a cylinder, the equivalent diameter is equal to the diameter of the cylinder.

If a box beam is considered, its equivalent diameter is:

$$D_{EQ} = \sqrt{a^2 + b^2} \qquad \text{(EQ. 3A-9)}$$

where:

a = height of box beam
b = width of box beam

For an I-beam, the equivalent diameter is:

$$D_{EQ} = \sqrt{a^2 + b^2} \qquad \text{(EQ. 3A-10)}$$

where:

a = depth of I-beam flange
b = width of I-beam flange

The nondimensional numbers on which drag coefficients depend are based on the equivalent diameter. They are:

$$\text{Reynolds number} - Re = \frac{U_m D_{EQ}}{\nu} \qquad \text{(EQ. 3A-11)}$$

$$\text{Period parameter} - K = \frac{U_m T}{D_{EQ}} \quad \text{(EQ. 3A-12)}$$

$$\text{Strouhal number} - S = \frac{f D_{EQ}}{U_m} \quad \text{(EQ. 3A-13)}$$

where:

U_m = maximum velocity at the location of the loaded structure during the transient

D_{EQ} = equivalent diameter

T = period of flow oscillation

f = vortex shedding frequency

ν = kinematic viscosity.

To properly determine the effect of unsteady flow, a drag coefficient multiplier is defined as the ratio of the unsteady to steady-state drag coefficients:

$$f_d = \frac{C_{D1}}{C_D} \quad \text{(EQ. 3A-14)}$$

$$f_m = \frac{C_{M1}}{C_M} \quad \text{(EQ. 3A-15)}$$

where:

C_D = steady-state standard drag coefficient

C_{D1} = unsteady standard drag coefficient

C_M = steady-state acceleration drag coefficient

C_{M1} = unsteady acceleration drag coefficient

f_d = standard drag coefficient multiplier

f_m = acceleration drag coefficient multiplier.

These factors are based on drag coefficients for circular cylinders. Once they are determined for cylinders using the appropriate data, the factors are applied to the steady-state drag coefficients for the particular structure of interest. These steady-state drag coefficients are described in Reference 3A-33. The factors are applied in the following manner:

$$C_{D3} = f_d C_{D2} \quad \text{(EQ. 3A-16)}$$

$$C_{M3} = f_m C_{M2} \qquad \text{(EQ. 3A-17)}$$

where:

C_{D2} = steady-state standard drag coefficient for the particular submerged structure

C_{D3} = corrected unsteady standard drag coefficient

C_{M2} = steady-state acceleration drag coefficient for the particular submerged structure

C_{M3} = corrected unsteady acceleration drag coefficient.

The lift coefficients are determined using the actual lift data for the specific structure analyzed for the applicable transient conditions.

However, if submerged structures of unique shapes are encountered in the suppression pool, they need to be considered on a plant unique basis.

Finally, when all the coefficients are determined, the standard and acceleration drag forces are calculated based on the corrected drag coefficients and the actual structure dimensions. The sum of these forces is the in-line force.

The transverse force consists only of lift. The following equations present the contributions of the standard and acceleration drag forces to the in-line force:

$$F_S = \frac{C_{D3} \; A \; \rho \; U(t) \left| U(t) \right|}{2 \; g_c} \qquad \text{(EQ. 3A-18)}$$

$$F_A = \frac{C_{M3} V_S \rho \dot{U}(t)}{g_c} \qquad \text{(EQ. 3A-19)}$$

$$F_{IN-LINE} = F_S + F_A \qquad \text{(EQ. 3A-20)}$$

where:

F_S = standard drag force

F_A = acceleration drag force

$F_{IN-LINE}$ = total in-line force

C_{D3} = corrected unsteady standard drag coefficient

C_{M3} = corrected unsteady acceleration drag coefficient

A = projected area of submerged structure

V_S = volume of submerged structure

ρ = fluid density

$U(t)$ = velocity in the in-line direction

$\mathring{U}(t)$ = acceleration in the in-line direction.

g_c = gravitational acceleration

The determination of the lift force is considered separately in each of the following sections.

3A.11.2.2 LOCA Charging Air Bubble

The LOCA charging air bubble is considered to be a nonoscillatory accelerating flow. It is readily observed from the velocity and acceleration time histories of the transient (Figures 3A-353 and 3A-354) that the transient exhibited an increasing velocity and high positive values of acceleration. In addition, the fluid flow never reverses and the acceleration is nearly constant. This is true for all locations in the suppression pool. Comparing typical velocity time histories (Figure 3A-353) to acceleration time histories (Figure 3A-354), one can observe that the acceleration is the major contributor to the drag load because the velocity is small. The velocity and acceleration time histories were generated using the LOCA charging air bubble model described in Reference 3A-33.

The geometric configuration that was used to determine the LOCA charging air bubble transient on a submerged structure is shown in Figures 3A-355 and 3A-356. A 36° segment of a typical Mark II suppression pool was used, which contained 10 downcomers. The LOCA charging air bubbles were used at these downcomer histories on a vertical submerged structure in the pool.

For this transient, Reference 3A-34 is used in determining the standard and acceleration drag coefficients, which are conservatively taken as 1.2 and 2.0, respectively.

Due to the low velocities and small duration of this transient, lift due to vortex shedding is not present. In Reference 3A-34, the author indicates that for unsteady flow, no lift force due to vortex shedding is present for small-period parameters. In addition, the author states that for a fluid starting from rest, vortex shedding is to be present.

With the information in Reference 3A-34, it was determined that the time required for separation to occur was longer than the duration of the LOCA charging air bubble transient. Therefore, lift due to unsteady flow effects is not considered for this transient.

3A.11.2.2.1 Lift Due to Vortex Shedding

According to Reference 3A-34, the separation necessary for vortex shedding to be present does not occur until a fluid has moved a distance:

$$S = 0.293D \qquad \text{(EQ. 3A-21)}$$

where:

S = traveled distance

D = cylinder diameter

The authors also state in Reference 3A-34 that:

$$S = \tfrac{1}{2}Vt \qquad \text{(EQ. 3A-22)}$$

where:

V = velocity

t = time for separation to occur

Assuming a representative case for LOCA charging air bubble velocity in a Mark II suppression pool, the maximum pipe diameter required for separation to occur can be determined. A linear velocity increase from 0.0 ft/sec to 3.0 ft/sec was assumed to closely resemble the actual transient velocity with a transient duration of 60 msec. Integrating the velocity, a traveled distance (S) of 0.09 foot was determined. Using the above mentioned equations, the traveled distance translates to a maximum pipe diameter of 3½ inches. In other words, for a pipe with a diameter of 3½ inches that experienced a velocity transient increasing linearly form 0.0 ft/sec to 3.0 ft/sec, separation would occur at 60 msec. This is the time when the LOCA charging air bubble transient has ended.

Following this procedure for other piping within the suppression pool experiencing the LOCA charging air bubble transient, it can be concluded that lift due to vortex shedding is not present and does not need to be considered for Mark II pool geometries.

3A.11.2.3 Pool-Swell

Pool-swell is regarded as being an oscillatory flow, with the pool-swell duration considered to be the half period of the flow field. This flow is exhibited by experimental data, namely, the EPRI and 4T tests. For Reynolds numbers in the subcritical region, the drag coefficients are determined from Reference 3A-35. These drag coefficients are dependent only on the period parameter. However, if the Reynolds number is in the supercritical region ($>4x10^5$), the steady-state standard drag coefficient reduces from 1.2 to 0.71 (Reference 3A-36). To determine the unsteady standard and acceleration drag coefficients for flow at the supercritical Reynolds numbers, Reference 3A-37 is used, which correlates the Reynolds number, period parameter, and the pipe roughness to both the standard and acceleration drag coefficients. The correlations for smooth pipes are used because these correlations best represent the structures within the Mark II suppression pool.

In addition, lift due to vortex shedding is considered. Reference 3A-38 provides the necessary information to determine lift loads. As before, the lift coefficient is based on the period parameter and

the Reynolds number where both are evaluated at the maximum velocity observed in the transient. Moreover, the vortex shedding frequency must also be defined. Reference 3A-37 provides a correlation of the relative frequency, f_r, to the period parameter and the Reynolds number evaluated at the maximum velocity.

$$f_r = \frac{f_v}{f_w} \qquad \text{(EQ. 3A-23)}$$

where:

f_r = relative frequency

f_v = vortex shedding frequency

f_w = oscillating fluid frequency

However, if the relative frequency falls out of the range shown in figure 21 of Reference 3A-37, Reference 3A-38 indicates that a Strouhal number of 0.3 should be used at high Reynolds numbers.

When determining the lift force due to vortex shedding, the maximum amplitude is based on the maximum velocity that the structure sees (Reference 3A-38):

$$F_L = \frac{C_L \; A \; \rho \; U_m^2 \; \sin 2 \; \pi f_v t}{2 g_c} \qquad \text{(EQ. 3A-24)}$$

where:

F_L = lift force (transverse to flow direction)

C_L = lift coefficient

A = projected area of structure

g_c = gravitational acceleration

ρ = fluid density

U_m = maximum in-line velocity the structure observes

f_v = vortex shedding frequency

t = time

The vortex shedding frequency is specified from the correlation mentioned previously. With the maximum amplitude and frequency, the lift force is defined. The lift force varies with time and is sinusoidal in nature for viscous lift.

In this case, the acceleration drag force considers the effect of gravity and is determined in the following manner:

$$F_A = \frac{V_S \rho \ C_{M3} \ \dot{U}(t)}{g_c} \qquad \text{(EQ. 3A-25)}$$

where:

F_A = acceleration drag force

V_S = volume of submerged structure

C_{M3} = corrected unsteady acceleration drag coefficient

$\mathring{U}(t)$ = acceleration in the in-line direction.

3A.11.2.4 Fallback

Fallback is considered to be a constantly accelerating flow. It is assumed that fallback behaves as a falling water slug. For this case, the standard and acceleration drag coefficients are determined from Reference 3A-34. As with pool-swell, the lift coefficients due to vortex shedding are also determined. The lift coefficient is given by Reference 3A-39 as CL = 1.0 for Karman vortices. To determine the vortex shedding frequency, Reference 3A-39 indicates that a Strouhal number of 0.22 should be used. This is also substantiated by Reference 3A-40. The force is then determined as:

$$F_L = \frac{C_L \ \Delta\rho \ U_m^2 \ \sin 2\pi ft}{2g_c} \qquad \text{(EQ. 3A-26)}$$

In this case, the acceleration drag force is determined in the following manner:

$$F_A = \frac{C_H \ g \ V_S \ \rho}{g_c} \qquad \text{(EQ. 3A-27)}$$

where:

C_H = hydrodynamic mass coefficient ($C_H = C_M - 1$).

3A.11.2.5 SRV Air Bubbles

SRV air bubbles are considered to be of oscillatory nature. Reference 3A-35 is used to determine the unsteady standard and acceleration drag coefficients. These drag coefficients are based on the period parameter evaluated at the maximum velocity. However, if the unsteady drag coefficients are less than the steady-state drag coefficients, then the steady-state coefficients are used for load determination. If any lift is present, Reference 3A-35 is used, which also bases the lift coefficients on the period parameter. This reference mentions that no lift is present for period parameters less than 5. The drag loads are determined as described in Section 3A.11.2.1.

3A.11.3 INTERFERENCE EFFECTS ON ACCELERATION DRAG

When submerged structures are closely located in a flow field, they can interfere with one another, affecting the acceleration drag. The proximity effect can be accounted for by either (a) using actual data that is presented in References 3A-44, 3A-46, and 3A-47, (b) performing a detailed analysis, or (c) applying a conservative factor of 4 on the acceleration drag. For LGS, actual data that are presented in References 3A-44, 3A-46, and 3A-47 were used to determine the interference effects on acceleration drag.

A detailed method is presented in the following sections for determining interference effects of nearby cylinders and/or a boundary on the acceleration drag for circular cylinders and is based on References 3A-41 through 3A-46.

According to the method, the interference effect between any two stationary cylinders can be completely determined by six force coefficients that are functions solely of the radius ration and the relative spacing. For the case of more than two cylinders, the total proximity effect on a given cylinder may be approximately obtained simply by superimposing each interference effect between cylinder pairs.

3A.11.3.1 Method of Analysis

The following assumptions are considered in the method:

a. Two-dimensional potential flow without separations and wakes is considered.

b. The velocity and acceleration in the flow field are the same as those seen locally by the submerged structure (cylinder).

c. The containment and pedestal walls are considered as plane boundaries.

d. Coordinate system

+x : radially outward from reactor pressure vessel centerline.

+y : vertically upward.

+z : by right-hand rule parallel to the plane boundary.

Origin: at the center of cylinder in question.

3A.11.3.2 Two Stationary Cylinders (Real Cylinders)

If the pth cylinder is isolated in a free stream, the hydrodynamic (acceleration drag) force per unit length of the cylinder is:

$$F_{po} = 2 \rho \pi A_p^2 \dot{U}_{\infty n} \qquad \text{(EQ. 3A-28)}$$

where:

F_{po} = acceleration drag force per unit length

ρ = fluid density

A_p = radius of pth cylinder

$\mathring{U}_{\infty n}$ = acceleration normal (in-line) to p^{th} cylinder

When the nth cylinder is in the vicinity of the pth cylinder, the change in the force of the pth cylinder, ΔF_{pn}, is:

$$\Delta F_{pn} = \rho \pi A_p^2 |\mathring{U}_{\infty n}| \{ (C_1 - 1)\exp(i\alpha_1) - C_2\exp[i(2\beta_{pn} - \alpha_1)] \}$$

$$+ \rho A_p |U_{\infty n}|^2 \{ (C_3 + C_4)\exp(i\beta_{pn}) - C_5\exp[i(3\beta_{pn} - 2\alpha_2)]$$

$$-C_6\exp(i(2\alpha_2 - \beta_{pn})] \} \qquad \text{(EQ.3A-29)}$$

where:

$U_{\infty n}$ = velocity normal (in-line) to the pth cylinder

α_1 = angle of acceleration with respect to z-axis

α_2 = angle of velocity with respect to z-axis

β_{pn} = angle between the line through centers of cylinders and the z-axis.

$$C_1 = 1 + 2 \sum_{j=1}^{\infty} b_{1,2j+1}$$

$$C_2 = 2 \left(\frac{A_n}{A_p}\right)^2 \sum_{j=1}^{\infty} b_{1,2j+1}$$

$$C_3 = 4\pi \sum_{k=1}^{\infty} \sum_{j=1}^{\infty} \frac{b_{1,2k-1} b_{2,2j}}{\left(\frac{L_{pn}}{A_p} - q_{1,2k-1} - \frac{A_n}{A_p} q_{2,2j}\right)^3}$$

$$C_4 = 4\pi \left(\frac{A_n}{A_p}\right)^4 \sum_{k=1}^{\infty} \sum_{j=1}^{\infty} \frac{b_{1,2k-1} b_{2,2j-1}}{\left(\frac{L_{pn}}{A_p} - q_{1,2k-1} - \frac{A_n}{A_p} q_{2,2j-1}\right)^3}$$

$$C_5 = 4\pi \left(\frac{A_n}{A_p}\right)^2 \sum_{k=1}^{\infty} \sum_{j=1}^{\infty} \frac{b_{1,2k-1} b_{2,2j-1}}{\left(\frac{L_{pn}}{A_p} - q_{1,2k-1} - \frac{A_n}{A_p} q_{2,2j-1}\right)^3}$$

$$C_6 = 4\pi \left(\frac{A_n}{A_p}\right)^2 \sum_{k=1}^{\infty} \sum_{j=1}^{\infty} \frac{b_{1,2k}\, b_{2,2j}}{\left(\frac{L_{pn}}{A_p} - q_{1,2k} - \frac{A_n}{A_p} q_{2,2j}\right)^3}$$

where:

$b_{1,1} = 1$

$b_{2,1} = 1$

$b_{1,m} = b_{2,m-1}\, q_{1,m}^2$ for $m \geq 2$

$b_{2,m} = b_{1,m-1}\, q_{2,m}^2$ for $m \geq 2$

in which:

$q_{1,1} = 0,$

$q_{2,1} = 0,$

$q_{1,j} = \frac{A_p}{L_{pn} - A_n q_{2,j-1}}$ for $j \geq 2,$

$q_{2,j} = \frac{A_n}{L_{pn} - A_p q_{1,j-1}}$ for $j \geq 2,$

A_n = radius of the nth cylinder

L_{pn} = distance between the centers of cylinders

3A.11.3.3 Stationary Cylinders Near a Plane Boundary (Real and Imaginary Cylinders)

A single stationary cylinder in a uniform stream, $U_{\infty n}$, is hydrodynamically equivalent to a cylinder moving at a speed $-U_{\infty n}$ in a still fluid, except that the former cylinder experiences an extra force, $\rho\pi A_p^2 \dot{U}_{\infty n}$, from the pressure field that has been created to provide the fluid acceleration $(\dot{U}_{\infty n})$. This is also true for any number of cylinders if the cylinders move together.

When a cylinder is moving in a arbitrary direction (on a line or on a curve) with respect to the plane boundary, it can be considered as two equal cylinders moving symmetrically with respect to the plane boundary because the plane acts as a perfect reflector (mirror) of the hydrodynamic pressure. A similar argument can be applied to multiple cylinders.

Based on the above discussion, the plane boundary can be removed and replaced by an imaginary cylinder of the same size as the original (real) cylinder and the plane boundary away from the original cylinder. Similarly, multiple imaginary cylinders can be obtained by reflecting those multiple real cylinders near the plane boundary.

Now if the nth imaginary cylinder is in the proximity of the pth cylinder, the change in the hydrodynamic force of the pth cylinder (ΔF_{pn}) can be derived from Reference 3A-41 and is:

$$\Delta F_{pn} = \rho\pi A_p^2 |U_{\infty n}| \{ (C_1 - 1)\exp(i\alpha_1) - C_2\exp[i(\alpha_1 + 2\beta_{pn})] \}$$

$$+ \rho A_p |U_{\infty n}|^2 \{ (C_3 + C_4)\exp(i\beta_{pn}) - C_5\exp(i3\beta_{pn}) - C_6\exp(-i\beta_{pn}) \}$$

(EQ. 3A-30)

where:

C_1 through C_6 are the same as described earlier.

3A.11.3.4 Total Acceleration Drag Force

Summing up each effect from all the surrounding N real and imaginary cylinders, the force on the pth cylinder is approximately given as:

$$F_p = F_{po} + \sum_{\substack{n=1 \\ n\neq p}}^{n} \Delta F_{pn} = 2\rho\pi A_p^2 \dot{U}_{\infty n} + \sum_{\substack{n=1 \\ n\neq p}}^{n} \Delta F_{pn} \quad \text{(EQ. 3A-31)}$$

or:

$$F_p = C_m \rho\pi A_p^2 |\dot{U}_{\infty n}| + C_v \rho A_p |U_{\infty n}|^2 \quad \text{(EQ. 3A-32)}$$

where:

C_m = acceleration drag coefficient

C_v = convective force coefficient

3A.11.3.5 Practical Application

When the increase in force on the pth cylinder arising from interference effects is calculated, only those real and imaginary cylinders that have a significant contribution should be considered. Significant contributions to the summation equations presented in Section 3A.11.3.4 arise only from those cylinder pairs within a gap distance of 3D, where D is the larger diameter of the pair being considered.

If the flow is omnidirectional during a specific transient, a magnification factor K_M may be obtained from the maximum $|C_m|$ that is determined in the range of $0° \leq \alpha_1 \leq 180°$. This is performed to account for the interference effect on the acceleration drag. Similarly, to account for the lift force, the maximum $|C_v|$ can be determined by varying α_2 in the range of $0° \leq \alpha_2 \leq 180°$. Then the maximum lift coefficient is combined with the standard drag coefficient, C_D, by the SRSS to include the lift force due to the proximity effect.

The acceleration and drag forces are determined as follow:

$$|F_{Ap}| = \frac{2K_M \rho \pi A_p^2 |\ddot{U}_{\infty n}|}{g_c} \quad \text{(EQ. 3A-33)}$$

$$|F_{sp}| = \sqrt{C_D^2 + |C_L|^2}\ \frac{\rho A_p |U_{\infty n}| U_{\infty n}}{2g_c} \quad \text{(EQ. 3A-34)}$$

where:

F_{Ap} = acceleration drag per unit length on p^{th} cylinder

K_M = $|C_m|/2$ magnification factor and $|C_m|$ is the maximum acceleration drag coefficient

ρ = fluid density

A_p = radius of pth cylinder

$\dot{U}_{\infty n}$ = acceleration in the normal (in-line) direction to the cylinder

$U_{\infty n}$ = velocity in the normal (in-line) direction to the cylinder

C_D = standard drag coefficient

$|C_L|$ = maximum lift coefficient

F_{sp} = standard drag per unit length on the pth cylinder.

The directions of the acceleration and standard drags are the same as those without the interference effect.

However, if the flow field is well defined and the direction of flow known, then the actual acceleration drag and lift coefficients are used. In this case, the lift force is applied in the transverse direction. The equations used are then:

$$F_{Ap} = \frac{2C_m \rho \pi A_p^2 \ddot{U}_{\infty n}}{g_c} \quad \text{(EQ. 3A-35)}$$

$$F_{Lp} = \frac{C_L\ \rho A_p |U_{\infty n}| U_{\infty n}}{2g_c} \quad \text{(EQ. 3A-36)}$$

where:

C_m = acceleration drag coefficient determined through the analysis

C_L = lift coefficient determined through the analysis

F_{Lp} = lift force in the transverse direction

3A.11.3.6 Model/Data Comparisons

The method has been tested numerically as well as experimentally, and the results (Figure 3A-357) indicate excellent agreement with both known numerical values (References 3A-41, 3A-42, and 3A-44) and experimental data (References 3A-43 and 3A-45).

3A.11.4 INTERFERENCE EFFECTS ON STANDARD DRAG

When submerged structures are located closely together in a flow field, they can interfere with one another, causing an effect on the standard drag. Actual data presented in the references can be used, a detailed analysis can be used, or a factor of four can be applied to the standard drag force. For LGS, actual data that are presented in Reference 3A-49 were used to determine the interference effects on standard drag.

Three technical papers (References 3A-48, 3A-49, and 3A-50) have described this phenomenon and presented experimental data on interference effects. Most of the data presented in these references are applicable to interference between two cylinders.

Reference 3A-49 has presented some data for three cylinders whose axes are co-planar. Cylinder spacing, Reynolds number, and the angle between flow direction and the plane containing cylinder axes were varied in the above investigations. In many instances the data obtained from the above references can be applied directly to Mark II suppression pool conditions.

A procedure has been developed to use the above data for interference between more than two cylinders. The results have been compared with measured data of three cylinders and are found to be conservative.

3A.11.4.1 Interference Between Two Cylinders of Equal Diameter

As indicated by the data given in References 3A-48, 3A-49, and 3A-50, the interference between two parallel cylinders alters the flow direction drag and also induces a lift force normal to flow direction. For two cylinders of equal diameter, the interference effect on drag forces is small, and in most cases negative (i.e., the drag is reduced due to interference). The lift force, however, is not always insignificant.

The following bounding values for interference between two cylinders of equal diameter can be used without any further detailed analysis. A bounding value of C_D for a Reynolds number greater than 8,000 and a S/d ratio greater than 0.2 is 1.4, and the bounding value for C_L is 1.0.

3A.11.4.2 Interference Between More than Two Cylinders of Equal Diameter

To evaluate the drag coefficient of a cylinder that is interfered by more than one cylinder, the maximum of C_{Do}, C_{Di}, and $D_{Di,j}$ should be used.

$$C_{Di} - C_{Do} = \sum_{\substack{j=1 \\ j \neq 1}}^{n} (C_{Di,j} - C_{Do}) \qquad \text{(EQ. 3A-37)}$$

where:

C_{Di} = standard drag coefficient for the ith cylinder

C_{D0} = standard drag coefficient for a single cylinder without any interference

$C_{Di,j}$ = drag coefficient of ith cylinder when it is interfered by Cylinder j alone.

Figure 3A-358 illustrates an arrangement of cylinders. The standard drag coefficient of Cylinder 1 would be:

$$C_{D_1} = C_{D_0} + (C_{D_{1/2}} - C_{D_0}) + (C_{D_{1/3}} - C_{D_0}) + (C_{D_{1/4}} - C_{D_0})$$

From this, the maximum value of C_{D_1}, C_{D_0}, $C_{D_{1/2}}$, and $C_{D_{1/4}}$ would be used for the standard drag coefficient.

To evaluate the lift coefficient, the maximum of C_{Li} and $C_{Li,j}$ should be used:

$$C_{Li,j} = \sum_{\substack{j=1 \\ j \neq 1}}^{n} \qquad \text{(EQ. 3A-38)}$$

where:

C_{Li} = lift coefficient of ith cylinder

$C_{Li,j}$ = lift coefficient of ith cylinder when it is interfered by Cylinder j alone.

From Figure 3A-358, the lift coefficient would be determined in the following manner:

$$C_{Li} = C_{L_{1,2}} + C_{L_{1,3}} + C_{L_{1,4}} \qquad \text{(EQ. 3A-39)}$$

The maximum value of C_{L_1}, $C_{L_{1,2}}$, $C_{L_{1,3}}$, and $C_{L_{1,4}}$ would be used for the lift coefficient.

The above described method yielding interference on standard drag between more than two cylinders of equal diameter (bounding procedure) is illustrated in the following examples:

Example 1

Consider the three cylinder arrangement shown in Figure 3A-359.

Let $\frac{S}{d} = 1$, $\theta = 60°$, and $Re = 2.78 \times 10^4$

For this arrangement:

$C_{D_{1,2}}$ = Drag coefficient of Cylinder 1 when interfered by Cylinder 2 only.

$= \quad 1.01$ (S/d = 1)

$C_{D_{1,3}} = \quad 1.02$ (S/d = 3)

$C_{D0} = \quad 1.16$ [Reference 3A-36, p. 341]

$C_{Di} - C_{D_0} = (C_{D_{1,2}} - C_{D_0}) + (C_{D_{1,3}} - C_{D_1})$

$= \quad 0.37$

$\therefore$ Maximum of C_{Di}; $C_{D_{1,2}}$; $C_{D_{1,3}}$; C_{D_0} is 1.16

$\therefore$ Use $C_D = 1.16$

From measurements (Reference 3A-49):

$C_D = \quad 0.97$, which is less than the calculated drag coefficient.

Example 2

Consider the three cylinder side-by-side arrangement shown in Figure 3A-360.

Let S/d = 1 and Re = 2.78×10^4

$C_{D_{1,2}} = 1.03$(S/d = 1)

$C_{D_{1,3}} = 1.05$ (S/d = 3)

$C_{D_o} = 1.16$

$\therefore C_{D_1} - 1.16 = 1.03 - 1.16 + 1.05 - 1.16$

or $C_{D_1} = 0.92$

Maximum of C_{D_o} ; C_{D_1} ; $C_{D_{1,2}}$; $C_{D_{1,3}}$ is 1.16

Use $C_D =$ 1.16

The measured value is 0.98, which is less than the calculated value.

3A.11.4.3 Drag on Small Cylinder Upstream of Large Cylinder

Figure 3A-361 presents the flow around cylinders of unequal diameters.

The coordinates of point A (center of smaller cylinder) are (-a,b). Let R and R_1 be the radii of larger and smaller cylinders, respectively. The velocity potential of flow around the larger cylinder in the absence of smaller cylinder is

$$\phi = Ux\left(1 + \frac{R^2}{x^2 + y^2}\right)$$

where:

ϕ = velocity potential

U = free stream velocity

R = radius of large cylinder.

If u and v are the x and y components of velocity at point "A" (smaller cylinder absent) then,

$$u = U\left[1 + R^2\left\{\frac{b^2 - a^2}{\left(a^2 + b^2\right)^2}\right\}\right] \qquad \text{(EQ. 3A-40)}$$

and

$$v = \frac{2ab\ R^2\ U}{\left(a^2 + b^2\right)^2} \qquad \text{(EQ. 3A-41)}$$

where:

u = the velocity parallel to the free stream velocity at the centerline of the smaller cylinder

v = the velocity perpendicular to the free stream velocity at the centerline of the smaller cylinder.

To use the above velocity correction, it is more convenient to increase the standard drag coefficient and use the corrected standard drag coefficient with the free stream velocity. The standard drag force on the smaller cylinder with interference present is:

$$F_1 = \frac{C_D\ \rho\ A\left(u^2 + v^2\right)}{2g_c} \qquad \text{(EQ. 3A-42)}$$

where:

F_1 = standard drag force with interference

C_D = standard drag coefficient

ρ = fluid density

A = projected area of smaller cylinder.

The direction of flow is:

$$\beta = \tan^{-1}\left(\frac{v}{u}\right)$$

The standard drag force without interference is:

$$F = \frac{C_D \rho A U^2}{2g_c} \qquad \text{(EQ. 3A-43)}$$

where:

F = standard drag force without interference

U = free stream velocity.

The ratio of the two standard drag forces yields the following expression for the correction of the standard drag coefficients:

$$\frac{C_D \text{ (interference)}}{C_D \text{ (without interference)}} = m^2 + n^2 \qquad \text{(EQ. 3A-44)}$$

where:

$$m = 1 + R^2\left\{\frac{b^2 - a^2}{(a^2 + b^2)^2}\right\}$$

$$n = \frac{2ab\ R^2}{(a^2 + b^2)^2}$$

If the determined ratio of the standard drag coefficients is less than 1, then a ratio of 1 is used. However, if the determined ratio is greater than 1, then the determined ratio is used.

The standard drag force on the smaller cylinder is then determined by:

$$F_1 = \frac{C_D \rho A U |U|}{2g_c} \qquad \text{(EQ. 3A-45)}$$

where:

F_1 = standard drag force on smaller cylinder

C_D = the corrected standard drag coefficient for interference

U = free stream velocity in the in-line direction.

The lift force on the smaller cylinder is determined in the same manner as was the standard drag force:

$$\frac{C_L \text{ (interference)}}{C_L \text{ (without interference)}} = m^2 + n^2 \qquad \text{(EQ. 3A-46)}$$

where m and n are the same as previously described. Once again, if the determined ratio is less that 1, then the ratio of 1 is used. However, if the determined ratio is greater than 1, then the determined ratio is used. The lift force is then determined by:

$$F_L = \frac{C_L \rho A U |U|}{2g_c} \qquad \text{(EQ. 3A-47)}$$

where:

F_L = lift force

C_L = corrected lift coefficient for interference.

The lift force is applied in the transverse direction to the resultant flow.

3A.11.4.4 Standard Drag on Smaller Cylinder Downstream of Large Cylinder

If the smaller cylinder is located downstream of the larger cylinder, then the lift and standard drag coefficients are evaluated corresponding to S/d (where S is the distance between the cylinder surfaces and d is the diameter of the cylinders) ratios of for both cylinders, assuming equal diameters. The coefficients are first determined by assuming both cylinders are equal to the diameter of the smaller cylinder, and then assuming booth cylinders are equal to the diameter of the larger cylinder. When determining the coefficients, the centerline distance between the two submerged structures is maintained at the actual distance.

Afterwards, the larger coefficients are used for determining submerged structure loads. In addition, if the lift and standard drag coefficients are less than the coefficients without interference, then the coefficients without interference are used.

3A.11.4.5 Standard Drag on the Large Cylinder

The method described in Section 3A.11.4.4 is used to determine the standard drag and lift on the large cylinder.

3A.11.4.6 Structures of Noncircular Cross-Section

The methodology of determining an equivalent diameter described in Section 3A.11.4.2 is used to determine the coefficients due to interference effects.

3A.11.4.7 Interference Between Nonparallel Cylinders

To estimate the interference effects between nonparallel structures, the lift and standard drag coefficients are determined by assuming that the structures are parallel. The distance used between them would be the minimum distance between the two structures. In the same manner, the larger coefficients of either with or without interference effects are chosen for submerged structure load determination.

3A.11.5 FLOW BLOCKAGE EFFECTS OF DOWNCOMER BRACING

The downcomer bracing is a flow restriction that increases the fluid velocity and acceleration during pool-swell. As a result, the standard drag, acceleration drag, and lift loads on structures in the pool-swell zone are higher than those which would exist if no downcomer bracing was present. Although the pool-swell loads are not design-controlling criteria, the load calculations were adjusted for blockage effects by introducing a multiplicative factor to the fluid velocity and acceleration.

A method of correction has been developed based on References 3A-51 and 3A-52. A multiplicative factor has been determined based upon Maskell's paper (Reference 3A-52).

$$\frac{C_{Dm}}{C_{Df}} = 1 + n\, C_{Df}\ S/C \qquad \text{(EQ. 3A-48)}$$

where:

C_{Dm} = modified drag coefficient of structures in the pool-swell zone

C_{Df} = steady flow, free steam drag coefficient

n = blockage factor

S = total blocked area

C = unrestricted flow area.

The value of the blockage factor, n, depends upon the structure's geometry. The blockage ratio varies from 0.96 to 2.77 for structures with aspect ratios, AR, from ∞ to 1.0, respectively. Maskell (Reference 3A-52) recommends a blockage factor of 2.5 for bluff bodies, and this value is considered conservative for the suppression pool bracing system.

The unrestricted flow area, C, is the pool surface area minus the area of the columns, downcomers and MSRV lines. THe blocked area, S, includes all the flanges and members of the bracing system. The drag coefficient used on the right side of Equation 3A-48 is the steady flow, free stream drag coefficient of the particular structure being analyzed.

Equation 3A-48 can be rearranged to obtain

$$C_{Dm} = \left(1 + n\ C_{Df}\ \frac{S}{C} \right) C_{Df} \qquad \text{(EQ. 3A-49)}$$

$$= f\ C_{Df}$$

where (f) is defined as the blockage correction factor. Because (f) is proportional to the drag coefficients, and therefore to the square of the velocity, the fluid velocity and acceleration are multiplied by the square root of (f). For consistency, the same multiplicative factor is used for the velocity and acceleration.

As a result, the pool-swell loads are calculated by the following equations:

Standard Drag Load: $F_X = \frac{1}{2} \rho (\sqrt{f}\ V)^2 C_D A$ (EQ. 3A-50)

Acceleration Drag Load: $F_A = \rho(\sqrt{f}\ a) C_m V_s$ (EQ. 3A-51)

Lift Load: $F_L = \frac{1}{2} \rho (\sqrt{f}\ V)^2 C_L A$ (EQ. 3A-52)

where:

ρ = fluid density

f = blockage correction factor

V = fluid velocity

C_D = standard drag coefficient which accounts for any interference effects

A = projected cross-sectional area of the structure

C_L = lift coefficient

a = fluid acceleration

C_m = inertial coefficient

V_S = structure's volume.

3A.12 CONTAINMENT AND SUBMERGED STRUCTURE - STRUCTURAL DESIGN ASSESSMENT

3A.12.1 CONTAINMENT STRUCTURE - STRUCTURAL DESIGN ASSESSMENT

Figure 3A-362 indicates the containment structural elements and cross-sections where stresses are determined, and Figures 3A-363 through 3A-386 contain a tabulation of the predicted stresses and allowable stresses for each loading combination considered.

Load Combinations, taken from Table 3A-14, are tabulated to cover all of the critical sections in the containment concrete structures. Load combination equation 2 for all sections and equations 1 and/or 3 and 6 for some sections are not executed because they do not represent the governing cases.

3A.12.2 SUBMERGED STRUCTURE - STRUCTURAL DESIGN ASSESSMENT

The submerged structures in the suppression chamber include the diaphragm slab support columns, the downcomer bracing system, and the downcomers. The bracing system and the columns are assessed in accordance with Table 3A-15. In the column assessment, the dynamic loads are combined by the SRSS method and then combined with the static loads using the absolute sum procedure. In the assessment of the downcomer bracing system, all loads are combined using the absolute sum method. For both the downcomer bracing system and the columns, equation 7 of Table 3A-15 is the most critical combination.

The natural vibration frequencies and shapes of the suppression chamber columns are presented in Figure 3A-387, and the assessment results are summarized in Figure 3A-388. Bolt stresses are not shown in the bottom anchorage because the design is more critical at the connecting flange, which yields a design margin of 10%.

The natural vibration frequencies and mode shapes of the downcomers are presented in Figures 3A-389 through 3A-391. Downcomer design margins are provided in Figure 3A-392. Fatigue usage factors, fatigue cycles, and fatigue histogram are provided in Figures 3A-393, 3A-394 and 3A-395, respectively.

The downcomer bracing system mathematical model is shown in Figure 3A-396, and the design margins for the most critical member in each quadrant are summarized in Figure 3A-397.

3A.13 REACTOR ENCLOSURE AND CONTROL STRUCTURE - STRUCTURAL DESIGN ASSESSMENT

Figure 3A-398 presents the reactor enclosure and control structure general floor plan at el 177' to aid in the location of wall marks.

Figures 3A-399 through 3A-418 identify and locate the selected critical structural elements where stresses are assessed in the reactor enclosure and control structure.

Figures 3A-419 through 3A-428 present diagrams of combined vertical (axial) forces, N-S and E-W shear forces, and N-S and E-W overturning moments, based on the dynamic portion of the load combinations specified in Tables 3A-14 and 3A-15.

Figures 3A-429 through 3A-436 contain tabulations of predicted stresses, stress allowables, and/or stress margins for the reactor enclosure and control structure floor slabs, floor support steel, and shear walls.

3A.14 BOP PIPING DESIGN ASSESSMENT

Table 3A-27 provides maximum cumulative fatigue usage factors for the MSRV discharge lines in the wetwell airspace. Table 3A-28 summarizes the stresses and stress margins for selected BOP piping systems.

The stress reports for the evaluation of the BOP piping will be available for NRC review.

3A.15 SUPPRESSION POOL TEMPERATURE DESIGN ASSESSMENT

3A.15.1 SUPPRESSION POOL TEMPERATURE MONITORING SYSTEM

3A.15.1.1 Suppression Pool Temperature Monitoring System Design Criteria

The SPTMS monitors the suppression pool temperature during normal plant operations and after transient or accidents. Operator monitoring of pool temperature is required to ensure that the suppression pool is operated within the allowable temperature limits set forth in the LGS Technical Specifications. Operation of the pool within the Technical Specifications will provide assurance that the suppression pool temperature will be maintained within the limits specified in NUREG-0783. Section 3A.15.1.1.4 describes the Technical Specification temperature alarm setpoints for pool operation.

The SPTMS is designed in conformance with the acceptance criteria specified in NUREG-0487 (Reference 3A-56) and NUREG-0783 (Reference 3A-58).

3A.15.1.1.1 Sensor Locations

The suppression pool temperature is redundantly monitored by two divisionalized systems. Eight dual element RTDs are provided for each system and are evenly distributed around the pool to provide a reasonable measure of the bulk water temperature. The eight monitoring locations and individual RTD identifications are shown in Figure 3A-437.

The sensors are located at a depth of 4'-4" below the minimum Technical Specification pool water level. This depth ensures a conservative measurement of bulk temperature because the hottest water will rise to the pool surface. This depth also provides adequate sensor submergence to preclude the possibility of sensor uncovery during an accident or transient.

3A.15.1.1.2 Safety Evaluation

The indication of suppression pool temperature in the control room is required to ensure that the plant is always operating within the Technical Specification limits. Manual operator action is required to maintain the plant within the Technical Specifications. Suppression pool temperature is also required for postaccident monitoring. These functions are safety-related.

The system design conforms to all applicable criteria for physical separation, redundancy and divisionalization. Physical and electrical separation is provided for the safety-related instrumentation. The safety-related instrumentation is powered from divisionalized Class 1E power sources.

The suppression pool temperature sensors are qualified to seismic Category I and Class 1E criteria and are energized from onsite emergency power supplies.

A CF Card located on the recorder records the average temperature, the individual temperature, and the current date and time. The data saved on a CF card can be converted by data conversion software to Lotus 1-2-3, Excel, or ASCII format file, facilitating processing on a PC. The Viewer software allows a PC to display waveforms on its screen and to print out waveforms. Trending information may also be printed at the Operator's request. Alarm conditions are printed along with the temperature. This function is not safety-related.

3A.15.1.1.3 Equipment Design

The signals from the redundant sensors are processed by two independent divisionalized recorders located on a main control room cabinet. The recorders convert the RTD signals into degrees Fahrenheit and compute the average of the eight temperatures. The average value is displayed by the recorders and on the remote indicators located at the main control board. A keypad located on the microprocessor allows the operator to display any individual temperature input.

The SPTMS trouble alarm located in the main control room is generated if the calculated average temperature exceeds any of the four distinct high temperature setpoints that are stored in the microprocessors. (Section 3A.15.1.1.4 provides details on the temperature alarm setpoints.) Also, appropriate high temperature status lights are initiated on the associated recorder and remote indicator. Electrically isolated outputs interface with the SPTMS trouble alarm located in the main control room.

The SPTMS trouble alarm is also initiated if one of the RTDs fails or if non-Class 1E power to the cabinet cooling fans is lost. A keypad allows the operator to remove a failed RTD from the calculated average.

Both elements of each dual element RTD are wired out through containment penetrations. One element of each RTD is connected to the associated recorder inputs. This design provides the capability to easily connect the backup RTD elements in case of a failure, with the exception of the backup RTD elements for TE41-101D and H.

For temperature elements TE41-101D and H only, the second dual element is used for providing suppression pool temperature indication at the remote shutdown panel. This is an independent Division 1 loop to provide the operator with suppression pool water temperature indication when the main control room is inaccessible (Method R shutdown as described in (Appendix 9A).

A CF Card located on the recorder records the average temperature, the individual temperature, and the current date and time. The data saved on a CF card can be converted by data conversion software to Lotus 1-2-3, Excel, or ASCII format file, facilitating processing on a PC. The Viewer software allows a PC to display waveforms on its screen and to print out waveforms. Trending information may also be printed at the Operator's request. Alarm conditions are printed along with the temperature.

Output signals are provided to interface with other plant information systems including a signal to the PMS computer. The recorder has a self checking diagnostic system that provides an alarm if a failure is detected in any critical part of the system.

3A.15.1.1.4 Alarm Setpoints

The SPTMS provides alarm at four pool temperature setpoints (95°F, 105°F, 110°F, and 120°F) to provide assurance that the suppression pool will be maintained within the temperature limits defined in NUREG-0783. Section 3A.15.2 describes these pool temperature limits and provides LGS analysis for suppression pool temperature response to SRV discharge. This analysis demonstrates the adequacy of these alarm setpoints with regard to alerting the operator to maintain the pool temperature below the NUREG-0783 limit. The alarm setpoints are based on Reference 3A-53 and are defined as follows:

a. 95°F: maximum allowable pool temperature for continuous power operation without suppression pool cooling

b. 105°F: maximum allowable pool temperature during testing at power which adds heat to the pool.

c. 110°F: manual reactor scram setpoint

d. 120°F: manual reactor depressurization setpoint.

3A.15.1.2 SPTMS Adequacy Assessment

As mentioned in Section 3A.15.1.1, the selection of the SPTMS sensor locations conforms with the acceptance criteria specified in NUREG-0487 (Reference 3A-56) and NUREG-0783 (Reference 3A-58). Section 3A.15.1.2 provides data for confirming the adequacy of the SPTMS sensor locations shown on Figure 3A-437, in predicting the bulk pool temperature.

The following assessment is based on a SPTMS sensor location of 2' below minimum Technical Specification water level. Subsequent to the assessment, the sensors were relocated at 4'-4" below the minimum Technical Specification water level to be below the resultant post-LOCA water level.

A sensitivity study as to the effect of the lower SPTMS sensor elevation on the following assessment was performed and the differences were negligible. Therefore, the following assessment, which was originally performed corresponding to SPTMS sensor elevation of 2' below the minimum Technical Specification water level, remains as an adequate representation of the SPTMS prediction capability.

In lieu of conducting LGS unique confirmatory in-plant tests of SRV discharges, analyses were performed using the KFIXTM computer code. KFIXTM is a three-dimensional thermal-hydraulic computer code which was developed to provide an analytical tool for predicting the thermal mixing and temperature response in the LGS suppression pool resulting from SRV actuation. The calculated results from the KFIXTM code have been verified against LaSalle and Caorso SRV extended blowdown in-plant test data. The KFIXTM code verification and methodology have been provided to the NRC (Reference 3A-54).

Section 3A.15.1.2.1 describes the scenarios that were analyzed for assessment of the LGS SPTMS. These scenarios are also used in Section 3A.15.3 to assess the adequacy of the suppression pool local-to-bulk temperature difference (ΔT). Sections 3A.15.1.2.1.1 and 3A.15.1.2.1.2 describe the initial/operating conditions and KFIXTM modeling, respectively. The calculated temperature time histories for the individual SPTMS sensors are discussed in Section 3A.15.1.2.2 The arithmetic average values among these sensors are presented in Section 3A.15.1.2.3. Conclusions of the SPTMS adequacy assessment are provided in Section 3A.15.1.2.4.

3A.15.1.2.1 Stuck Open Relief Valve Scenarios

The KFIXTM code is employed for the simulation of three SORV scenarios to predict the LGS suppression pool thermal mixing and temperature response.

To parallel the scenarios chosen in the LaSalle in-plant tests, two single SORV blowdown scenarios under conditions of high reactor pressure and relatively low pool temperature were selected. This analysis quantifies the thermal mixing effectiveness in the pool due to the large momentum associated with the heated fluid jet induced by high reactor pressure steam discharges through the quencher.

The third scenario considers a single SORV blowdown scenario under conditions of low reactor pressure and high pool temperature. This analysis quantifies the thermal mixing effectiveness in the pool even under conditions of reduced fluid jet momentum associated with steam discharges under low reactor pressure.

The LGS SRV set pressures are provided in Table 3A-3. The associated quencher orientations are shown in Figure 3A-3. Among the 14 SRVs, the two with designations of L and H, which are located along the outer and inner quencher circles, respectively, were selected for the high reactor pressure

analysis because these valves have the lowest set pressure values among those on the corresponding quencher circles. SRV-H was chosen for the low reactor pressure analysis. Quenchers H and L have off-radial orientations of 30° and 10° in the counterclockwise direction, respectively. Discharge associated with the end gap of Quencher H is towards the containment wall, while discharge associated with the end cap of Quencher L is towards the pedestal. Figures 3A-438 and 3A-441 show these quencher configurations in the KFIXTM models.

In the KFIXTM code, the LGS suppression pool is subdivided into a large number of computational cells which is on the order of 5500. Among these computational cells, the containment walls, major submerged structures and boundaries are treated as obstruction (or fictitious) cells, the containment walls, major submerged structures, and boundaries are treated as obstruction (or fictitious) cells while the remainder are called fluid cells. The governing conservation equations are solved with respect to the fluid cells. Fluid cells which contain the quencher discharge areas are called special cells. Additional source terms are included in the conservation equations in these special cells to account for the steam blowdown precess. The source terms are derived from various operating conditions, i.e., the reactor pressure, the SRV steam flow rate, the geometrical data of the quencher, and the quencher orientation. Geometrical data of the Mark II T-quencher is provided in Section 3B.4.1.

3A.15.1.2.1.1 Initial and Operating Conditions

The initial and operating conditions pertinent to the high and low reactor pressure SORV scenarios are tabulated below:

Parameter	High Reactor Pressure Analysis	Low Reactor Pressure Analysis
Reactor vessel pressure	1025 psia	90 psia
SRV steam flow rate	239.6 lb_m/sec	21 lb_m/sec
Suppression pool initial water depth	22 ft	23 ft
Initial pool temperature	95° F	199° F
Duration of blowdown	10 minutes or longer	20 minutes or longer

The 1025 psia reactor pressure corresponds to the nominal pressure in the RPV steam dome at 105% of nuclear boiler rated steam flow. The 90 psia reactor pressure corresponds to the lowest pressure just prior to clearing the shutdown cooling pressure interlock. The SRV flow rates correspond to the nominal flow rates adjusted to the specified reactor pressures.

The high pressure analysis initial pool water depth (22 feet) corresponds to the low pool level (Figure 3A-2). The initial pool temperature (95°F) corresponds to the maximum operating temperature without suppression pool cooling.

The low pressure analysis initial pool water depth (23 feet) corresponds to the normal pool level. The normal water level was chosen in lieu of the low level to account for the additional water condensed from the incoming SRV steam during reactor depressurization to 90 psia.

The low pressure analysis initial pool temperature corresponds to the highest temperature at a reactor pressure of 90 psia. From LGS analysis of suppression pool temperature response to SRV discharge presented in Section 3A.15.2, a pool temperature of 199°F exists at 90°F and 10^4 seconds into the transient (Figure 3A-456, Case 3.a).

The blowdown durations selected for the high and low pressure SORV scenarios allow the pool temperature to reach a quasi-steady rate of increase.

In addition to the above initial and operating conditions, several conservative assumptions are made in the high and low reactor pressure analyses. For example, the water in the pedestal is neglected, no RHR operation is considered, the initial pool motion is assumed to be stagnant, and containment wall boundaries are treated adiabatically.

3A.15.1.2.1.2 Geometrical Modeling

The plan and section views of the mesh systems used in the KFIXTM model to simulate the SRV-H and SRV-L blowdown scenarios are shown in Figures 3A-438 through 3A-442. The mesh compositions associated with each scenario are summarized as follows:

Parameter	SRV-H Blowdown (High Reactor Pressure)	SRV-L Blowdown (High Reactor Pressure)	SRV-H Blowdown (Low Reactor Pressure)
Total Cell Number	11x12x39=5148	12x12x40=5760	11x12x39=5148
Grid size variation along radial direction (ΔR)	2 ft to 4.076 ft	2 ft to 3.5 ft	2 ft to 4.076 ft
Grid size variation along Circumferential direction ($\Delta\phi$)	7° to 11.5°	5.5° to 11.5°	7° to 11.5°
Grid size variation along Vertical direction (ΔZ)	2.333 ft to 2.695 ft	2.333 ft to 2.695 ft	2.333 ft to 2.841 ft

The following KFIXTM geometrical modeling aspects apply to the mesh system summarized above and shown in Figures 3A-438 through 3A-442:

- Variable grid sizes are used in the mesh systems. Note that finer mesh sizes in the vicinity of the quencher allow KFIXTM to more accurately predict the pool response in the local region.

- Because the pool normal water level (23') was used in analyzing the SRV-H scenario under the low reactor pressure condition in comparison with the minimum level (22') associated with the high pressure case, the grid sizes along the vertical direction for the low pressure case have to be slightly expanded to account for the additional one foot of water.

- The free surface at the top of the suppression pool is calculated by tracing the surface waves kinematically.

- Because the SPTMS sensors are not located at cell centers, the calculated SPTMS temperatures are interpolated or extrapolated from the temperature values defined at the neighboring cell centers in the code calculations.

- The suppression chamber columns are modeled as stacks of obstruction cells which conservatively approximate the circular cross-section of the actual columns.

- The two T-quencher arms are modeled by means of two special cells separated by an obstruction cell representing the quencher hub/assembly.

- The size of the special cells (i.e., fluid cells which contain the quencher discharge arms) are chosen to be comparable with those used in the LaSalle simulation runs for verifying the KFIXTM code (Reference 3A-54).

- A greater number of fluid cells are needed to model the SRV-L blowdown scenario than that needed for the SRV-H blowdown scenario. This is due to the fact that a better resolution with respect to the outer quenchers (e.g., Quencher L) generally requires more cells in the cylindrical coordinates (compare Figures 3A-438 and 3A-441).

- The obstruction effects of the downcomers are neglected to simplify the geometrical modeling. The downcomers have neglected obstruction effects on SPTMS sensor predictions because of their relative distance from the sensor locations.

3A.15.1.2.2 Individual SPTMS Sensor Predictions

The SPTMS sensor identifications and locations are shown in Figure 3A-437. The SPTMS sensor locations can be classified into two categories: 1) four dual element sensors mounted on columns with approximate azimuthal locations of 0°, 90°, 180°, and 270°, (i.e., TE 101/103-B, D, F, & H); and 2) four dual element sensors mounted on the containment wall with approximate azimuthal locations of 45°, 135°, 225°, and 315° (i.e., TE 101/103-A, C, E, & G).

The calculated sensor predications for each SORV blowdown scenario are shown in Figures 3A-443 through 3A-448 and are discussed in the following sections. The four temperature traces associated with each SPTMS sensor category (as defined above) are shown in the same figure. Sensor temperature traces may vary among each other because of the relative distances between the active quenchers and the various sensor locations. Only division TE 101 predictions are provided. Temperature traces of redundant Division TE 103 are not presented because they are nearly identical. Also shown on these figures is the analytical bulk pool temperature trace which provides a measure of how close the individual sensor predicts the bulk temperature. The bulk pool temperature is calculated by KFIXTM an is based on a mass-energy balance assuming that the pool is a uniform heat sink.

3A.15.1.2.2.1 SRV-H Blowdown Under High Reactor Pressure

Figures 3A-443 and 3A-444 show the KFIXTM calculated temperature time histories of the SPTMS sensors mounted on the columns and the containment wall, respectively, resulting form the SRV-H blowdown under the high reactor pressure condition.

Time delays, or response times, exist before the SPTM sensors start sensing the heat-up process in the suppression pool. These time delays result from the considerable vertical elevation difference between the sensors and the active quencher (i.e., 16.5 feet). However, within this short time delay period, the pool will experience only minor bulk heat-up. Figures 3A-443 and 3A-444 show a bulk pool heat-up on the order of $3^{O}F$ during a response time ranging from 1-1.5 minutes.

3A.15.1.2.2.2 SRV-L Blowdown Under High Reactor Pressure

Figures 3A-445 and 3A-446 show the KFIXTM calculated temperature time histories of the SPTMS sensors mounted on the columns and the containment wall, respectively, resulting form the SRV-L blowdown under the high reactor pressure condition. The response times range from about 0.5-1 minute.

3A.15.1.2.2.3 SRV-H Blowdown Under Low Reactor Pressure

Figures 3A-447 and 3A-448 show the KFIXTM calculated temperature traces of the SPTMS sensors mounted on the columns and the containment wall, respectively, resulting from the SRV-H blowdown under the low reactor pressure condition. The response times range from 1.5-3 minutes.

Note that Figures 3A-447 and 3A-448 show that the time scale (abscissa) is compressed in comparison to the high pressure cases to accommodate the longer transient (approximately 25 minutes). The temperature scale (ordinate) is stretched to suit the milder temperature variation resulting form a smaller SRV steam flow rate associated with low reactor pressure condition. Note also that the elevated pool temperature reflects the assumption of RHR system not in operation (i.e., no pool cooling or shutdown cooling) during the SORV transient analysis.

3A.15.1.2.3 Average SPTMS Sensor Prediction

The arithmetic average values of the eight traces for the three blowdown cases are presented in Figures 3A-449, 3A-450, and 3A-451. Also shown on these figures are the corresponding analytical bulk pool temperatures (based on a pool mass-energy balance) and code predicted overall average temperatures. The KFIXTM predicted overall average temperature is defined as the average of the entire set of computational fluid cells in the LGS pool model.

In principle, the predicted overall average temperature should adhere closely to the bulk pool temperature to warrant a global calculation. However, due to the accumulated errors in the numerical computation spanning a large number of computational cycles (on the order of 10,000 for the present calculations), the overall average temperature may deviate slightly from the bulk pool temperature.

Figure 3A-449 provides the average SPTMS sensor prediction resulting form SRV-H blowdown under high reactor pressure. The response time is approximately 45 seconds. The SPTMS overpredicts the bulk pool temperature by approximately $1.7^{O}F$. The bulk pool temperature and overall average temperature traces are nearly identical, reflecting the adequacy of the overall energy conservation equations in the suppression pool model.

Figure 3A-450 provides the average SPTMS sensor prediction resulting for SRV-L blowdown under high reactor pressure. The response time is about 25 seconds. The SPTMS overpredicts the bulk pool temperature by approximately 2°F. The bulk pool temperature and the overall average temperature traces are nearly identical.

Figure 3A-451 provides the average SPTMS sensor prediction resulting from SRV-H blowdown at low reactor pressure. The response time is about 60 seconds. Both the SPTMS and overall average temperature prediction diverge from and underpredict (by about 1°F) the analytical bulk pool temperature. The apparent inaccuracy in the overall average and SPTMS temperature predictions are due to inherent interpolation errors associated with the large variations in subcooled water properties at elevated pool temperatures amplified by the large number of computational cycles in the code. Regardless of these apparent inaccuracies, the fact that the SPTMS adheres closely to the overall average temperature implies that the in-plant SPTMS sensor average reading will closely follow the actual suppression pool bulk temperature.

Note that the elevated pool temperature shown in Figure 3A-451 reflects the assumption of RHR system not in operation (i.e., no pool cooling or shutdown cooling) during the SORV transient analysis.

3A.15.1.2.4 Conclusion

In light of the code results presented in the preceding sections, it can be concluded that the SPTMS sensor locations are adequate in predicting the bulk pool temperature. The temperature traces indicate that short response times exist for the heated fluid, induced by the quencher discharge at the low pool elevation to rise near the top of the suppression pool where the SPTMS sensors are located. The SPTMS sensor average conservatively overpredicts the pool bulk temperature by 1.7°F to 2°F for the high reactor pressure blowdown scenario.

For the low pressure blowdown scenario, the calculated results for the SPTMS adequately predict the calculated overall average temperature. Because the calculated overall average temperature slightly deviates from the bulk temperature by about 1°F, it is concluded that the code calculated results for the SPTMS predict the bulk pool temperature with an accuracy of 1°F for the low reactor pressure/high pool temperature scenario.

Based on the sensitivity study discussed in Section 3A.15.1.2 to ascertain the effect of lowering the sensors from the original 2' to 4'-4" below the minimum Technical Specification water level, it was concluded that the foregoing results provide an adequate representation of the SPTMS prediction capability.

The SPTMS will adequately monitor the suppression pool bulk temperature in accordance with the requirements of NUREG-0487 (Reference 3A-56) and NUREG-0783 (Reference 3A-58).

3A.15.2 SUPPRESSION POOL TEMPERATURE RESPONSE TO SRV DISCHARGE

The information presented in Section 3A.15.2 is based on the original design basis conditions. The local pool temperature limit for SRV discharge is specified in NUREG-0783 because of concerns resulting from unstable condensation observed at high pool temperatures in plants without quenchers. Reference 3A-62 provides justification for elimination of this limit for plant with quenchers on the SRV discharge lines. Because LGS has quenchers, no evaluation of this limit is necessary, as stated in Supplement 1 of Reference 3A-63. However, the limiting case presented in Section 3A.15.2 (Case 3.a) was reanalyzed at the current plant conditions using the methodology and inputs described in Section 6.2.1.8. The results of this analysis were found to be acceptable.

3A.15.2.1 Introduction

In late 1974, the NRC alerted the BWR Owners to the potential for severe vibratory loads on the containment structure due to SRV discharge at elevated suppression pool temperature (Reference 3A-55). This phenomenon, or condensation instability, was associated with certain SRV discharge device configurations and occurred above given threshold values of pool temperature and steam mass flux. While the condensation instability phenomenon described above has never been exhibited for quencher devices, even in large-scale tests where local temperatures approached saturation, the NRC (Reference 3A-56) has taken the position that a local pool temperature limit of 200°F "will provide additional conservatism and will ensure that unstable steam condensation will not occur with a quencher device" and that "applicants will have to provide plant unique analyses for pool temperature responses to transients involving SRV operations to demonstrate that the plants will operate within the limit of 200°F."

The Mark II Owners Group subsequently prepared a generic report, the "White Paper" (Reference 3A-57), which was used by the utilities, including PECo, as a guideline for plant unique analyses. In conjunction with the development of this report, the Mark II Owners Group proposed alternative suppression pool temperature limits. These alternative acceptance criteria were subsequently accepted by the NRC for plants using the generic Mark II T-Quencher design. The alternative pool temperature limits are defined in NUREG-0783 (Reference 3A-58) as follows:

a. For all plant transients involving SRV operations during which the steam flux through the quencher perforations exceeds 94 lb_m/ft^2-sec, the suppression pool local temperature shall not exceed 200°F.

b. For all plant transients involving SRV operations during which steam flux through the quencher perforations is less than 42 lb_m/ft^2-sec, the suppression pool local temperature shall be at least 20°F subcooled. This is equivalent to a local temperature of 210°F with quencher submergence of 14 feet.

c. For plant transients involving SRV operations during which the steam flux through the quencher perforations exceeds 42 lb_m/ft^2-sec but is less than 94 lb_m/ft^2-sec, the suppression pool local temperature can be established by linearly interpolating the local temperatures established under items a and b above.

The following presentation of the suppression pool temperature analysis for LGS conforms with NUREG-0783 in terms of the pool temperature limit acceptance criteria, assumptions, and pool heatup events required for analysis.

3A.15.2.2 Events for the Analysis of Pool Temperature Transients

The following events have been analyzed on the basis of mass and energy balance on the suppression pool during SRV blowdown. The results of the pool temperature transients demonstrate the history of the pool bulk temperature of for all the events analyzed. Assumptions for the events are discussed in Section 3A.15.2.3. The associated peak pool temperatures calculated for each event are summarized in Table 3A-30.

3A.15.2.2.1 Event 1: Stuck Open SRV at Power Operation

SORV at power cases are analyzed to demonstrate that the spurious opening of an SRV during normal power operation will not result in high pool temperatures.

Two cases of SORV at power are considered separately:

Case 1.a: Single failure of one RHR heat exchanger

Case 1.b: Initiation of the MSIV closure signal at the time of scram and subsequent unavailability of main condenser.

3A.15.2.2.2 Event 2: SRV Discharge Following Isolation/Scram

Isolation/scram cases are analyzed to demonstrate that the loss of the main condenser by the sudden closure of the MSIVs and subsequent scram, SRV openings at set pressure, and manual depressurization will not result in high pool temperature.

Two single failures are considered separately:

Case 2.a: Single failure of one RHR heat exchanger

Case 2.b: Failure of an SRV to reclose (SORV)
(Note: Case 2.b is not required by NUREG-0783 but is presented to maintain consistency with the "White Paper: cases.)

3A.15.2.2.3 Event 3: SRV Discharge Following a Small Break Accident

SBA cases are analyzed to demonstrate that SRV discharge required to depressurize the reactor coolant system following a small break will not result in high pool temperatures. As a result of continued flow through the break, peak pool temperature is not reached until after SRV discharge has terminated.

Two cases of SBA are considered separately:

Case 3.a: Single failure of one RHR heat exchanger

Case 3.b: Loss of shutdown cooling
(Note: Case 3.b is not required by NUREG-0783 but is presented to maintain consistency with the "White Paper" cases.)

3A.15.2.3 Assumptions Used in the Analysis

3A.15.2.3.1 General Assumptions

The following general assumptions and initial conditions have been used for all transients. Table 3A-29 summarizes the values for important system characteristics and input parameters listed below.

a. Power level, decay heat standard, RHR heat exchanger capability (considering design fouling factors), and suppression pool initial temperature (maximum Technical Specification temperature of continuous power operation without pool cooling) are consistent with those used for the analysis of containment pressure and temperature response to a LOCA.

b. The service water temperature is characterized as a transient starting at 88°F (Technical Specification limit for average spray pond temperature).

c. The initial water level of the suppression pool is at the minimum level in the Technical Specifications.

d. MSIV closure is complete 3.5 seconds after the isolation signal (t=0) for transients where isolation occurs.

e. The water volume within the reactor vessel pedestal is not included in the calculation of pool temperature response.

f. To maximize heat addition to the pool, feedwater at the temperature in excess of instantaneous pool temperature is assumed to maintain RPV level rather than CST inventory via RCIC and HPCI. Feedwater injection is terminated when additional feedwater will ultimately result in cooling the pool. (Note: This requirement is more conservative than the NUREG-0783 assumption that "feedwater pumps supply feedwater to the reactor until the feed pumps trip on an automatic signal.") HPCI (From the suppression pool) and CRD (from the CST) systems provide vessel makeup after all the hot feedwater is expended. CRD flow was used for all cases except SBA with one RHR.

g. Offsite power is not available for isolation/scram and SBA events or where MSIV closure is assumed, except SBA Case 3.b Offsite power is available for Case 3.b; however, Case 3.b is conservative due to the conservatism associated with feedwater addition (see assumption "f" above) and the unavailability of the main condenser. Also, Case 3.b is not the controlling event for calculation of peak pool temperature (Table 3A-30).

h. HPCI system is terminated at or before a pool temperature of 170°F.

i. A single electrical division failure may result in the unavailability of RHR shutdown cooling and one loop of RHR pool cooling. The assessment of this single failure assumption on suppression pool temperature response to SRV discharge is provided in Section 3A.15.2.3.2.3.1.

j. The calculation of mass and energy release to the suppression pool due to SRV discharge follows the methodology described in Reference 3A-59.

k. There are no heat losses to the containment atmosphere and structures.

l. The RHR operates in the suppression pool cooling mode 10 minutes after the high pool temperature alarm (95°F).

m. All transients involving one RHR heat exchanger operation assume a minimum controlled depressurization rate and employ a rapid transfer (16 minutes, without flush) from pool cooling to shutdown cooling using the available RHR heat exchanger when the reactor pressure reaches the permissive value (89.7 psia). Shutdown cooling is not used in the analyses for those transients having both RHR trains available.

n. In accordance with the LGS Technical Specifications, manual depressurization at a rate of 100°F/hour begins at a pool temperature of 120°F unless the depressurization rate for the event itself (e.g., SORV, SBA) exceeds the required rate at that time. Manual depressurization is terminated upon initiation of shutdown cooling.

o. SRV flow rate = 122.5% of ASME rated.

3A.15.2.3.2 Assumptions for Specific Events

This section describes the specific assumptions used for the events described in Section 3A.15.2.2. Operator actions are also described for justification of the assumptions.

3A.15.2.3.2.1 Event 1: SORV at Power

This initiating event postulates that an SRV is inadvertently actuated while the plant is operating at power. Following actuation, the SRV fails to reseat and remains open throughout the transient. As a result of this malfunction, steam from the primary systems is discharged through the SRV and released to the suppression pool.

Two independent systems will generate alarms and displays in the control room so as to give the operator immediate and unambiguous indications of an SORV. First, the SRVPI system (Section 7.6.1.5.1) provides positive indication and alarm of SRV position through the use of acoustic sensors (two per valve) which detect noise generated by steam flow through an open SRV. Secondly, the SPTMS will indicate a rise in the suppression pool temperature and alert the operator to initiate corrective action. A control room alarm is generated when the average pool temperature increases to 95°F, 105°F, 110°F, and 120°F. Further details of the SPTMS are provided in Section 3A.15.1.

In accordance with the EOPs, the operator will manually scram the reactor prior to suppression pool temperature reaching 110°F by turning the mode switch to "shutdown" if the SRV cannot be reclosed immediately.

For analysis purposes, it is conservatively assumed that manual scram does not occur until the Technical Specification limit on pool temperature for power operation is reached (110°F).

Case 1.a: Single Failure - One RHR Heat Exchanger Unavailable

- Manual scram at pool temperature = 110°F.
- Offsite power is available.
- One RHR system is placed in pool cooling mode 10 minutes after the SORV.
- The MSIVs remain open because the mode switch has been taken out of the "run" position.
- Following scram, the reactor steam generation will decrease so that the TCV will mechanistically close as the RPV pressure drops, thus isolating the turbine from the reactor. The turbine bypass valves are also mechanistically closed. The SJAE will continue to maintain vacuum in the main condenser.
- The operator manually depressurizes the reactor by reestablishing the main condenser as a heat sink through the main turbine bypass system. It is assumed that the operator will manually open the turbine bypass valve 20 minutes after scram.
- The main condenser is available using full bypass capacity until the reactor vessel pressure permissive for RHR shutdown cooling is reached (89.7 psia).

- RHR out of pool cooling when pressure permissive for RHR shutdown cooling is reached; 16 minute delay for RHR transfer to shutdown cooling.

Case 1.b: Single Failure - Spurious Main Steam Line Isolation at Scram

- Manual scram at pool temperature - 110°F
- Nonmechanistic main steam line isolation occurs at scram (t = 0)
- LOOP
- Two RHR systems are placed in the pool cooling mode 10 minutes after the SORV.
- When the pool temperature = 120°F, the operator begins manual depressurization to maintain 100°F/hour cooldown rate by opening additional SRVs as needed.
- RHR shutdown cooling is not initiated.

3A.15.2.3.2.2 Event 2: SRV Discharge Following Isolation/Scram

Case 2.a: Single Failure - One RHR Heat Exchanger Unavailable

- Nonmechanistic main steam line isolation and automatic scram at t=0
- LOOP
- One RHR system placed in pool cooling mode 10 minutes after the event.
- When the pool temperature = 120°F, the operator begins manual depressurization at a rate of 100°F/hour by opening SRVs as needed.
- RHR out of pool cooling when pressure permissive for RHR shutdown cooling is reached; 16 minute delay for RHR transfer to shutdown cooling.

Case 2.b: Single Failure - SORV

- Nonmechanistic main steam line isolation and automatic scram at t=0.
- SORV occurs at t=0
- LOOP
- Two RHR systems are placed in the pool cooling mode 10 minutes after the event.
- When the pool temperature = 120°F, the operator begins manual depressurization to maintain 100°F/hour cooldown rate by opening additional SRVs as needed.
- RHR shutdown cooling is not initiated.

3A.15.2.3.2.3 Event 3: SRV Discharge Following SBA

Case 3.a: Single Failure - One RHR Heat Exchanger Unavailable

- Automatic scram on high drywell pressure at t=0.
- Nonmechanistic main steam line isolation at t=0.
- LOOP
- One RHR system is placed in the pool cooling mode 10 minutes after event.
- When the pool temperature = 120°F, the operator begins manual depressurization at a rate of 100°F/hour by opening SRVs as needed.
- Automatic RHR switch-over to the LPCI system mode on LPCI initiation signal. (LPCI signal occurs at (a) low reactor level or (b) high drywell pressure combined with low reactor pressure.) The operator manually converts back to the pool cooling mode in 10 minutes.
- RHR out of pool cooling when pressure permissive for RHR shutdown cooling is reached; 16 minute delay for RHR transfer to shutdown cooling.

Case 3.b: Single Failure - Shutdown Cooling Unavailable

- Automatic scram on high drywell pressure at t=0.
- Nonmechanistic main steam line isolation at t=0.
- Offsite power is available.
- Two RHR systems are placed in the pool cooling mode 10 minutes after event.
- When the pool temperature = 120°F, the operator begins manual depressurization at a rate of 100°F/hour by opening SRVs as needed.
- Automatic RHR switch-over to the LPCI system mode on LPCI initiation signal. The operator manually converts back to the pool cooling mode in 10 minutes.
- RHR shutdown cooling is not initiated. The operator will ultimately reach cold shutdown by establishing the alternate shutdown cooling path as outlined in Section 15.2.9.

3A.15.2.3.2.3.1 SRV Discharge Following SBA: Single Electrical Division Failure

In response to NUREG-0783, sections 5.7.1(8) and 5.7.2.3(2), LGS has evaluated the effect of a most limiting single failure on the suppression pool peak temperature. It was concluded that a worst case single failure of an electrical division power source may result in the unavailability of RHR shutdown cooling and one loop of RHR pool cooling. However, the peak pool temperature resulting from this single failure will be bounded by the peak temperature calculated for limiting SBA Case 3.a when taking credit for manual operator action to regain the lost loop of pool cooling.

Approximately 2½ hours are available to the operator for manual realignment of affected valves to obtain additional pool cooling capability from the second RHR heat exchanger. This available time

is conservatively derived from the pressure-temperature time history for comparable Case 3.a (Figure 3A-456). Limiting Case 3.a is similar to the single electrical division failure case because only one loop of RHR pool cooling is available during the depressurization phase of the event.

The time is based on the conservative assumption that LOOP (and subsequent operator awareness of loss of both RHR shutdown cooling and one loop of pool cooling) occurs at a pool temperature of 120°F (Technical Specification limit for manual depressurization). From Figure 3A-456 (Case 3.a), the pool temperature reaches 120°F at approximately 1000 seconds. The time available for manual operator action after t=1000 seconds without the pool exceeding the peak calculated temperature is limited to the same point in time in Case 3.a where shutdown cooling was initiated (89.7 psia), i.e, approximately 10,000 seconds. Therefore, the total time available based on limiting Case 3.a is approximately 9,000 seconds or 2½ hours.

A study of required manual operator actions has concluded that a second RHR heat exchanger could be available in the pool cooling mode in less than 2½ hours (the time when Case 3.a peak pool temperature is reached). The pool temperature will decrease following the initiation of the second RHR loop in the pool cooling mode because the heat removal rate of both RHR exchangers will exceed the heat addition rate to the pool at this time in the
event.

Because the RHR shutdown cooling mode is not initiated, the operator will ultimately reach cold shutdown by establishing the alternative shutdown cooling path as outlined in Section 15.2.9. The heat addition rate to the pool resulting from this alternate path of shutdown cooling will be controlled to preclude the possibility of additional pool heatup.

If manual operator actions are required in case of a worst case single electrical division failure, the plant operator could actually reduce the blowdown rate to extend the time before the peak pool temperature is reached. This scenario allows additional time for operator actions and would result in a peak pool temperature which is lower than Case 3.a.

3A.15.2.4 Analysis Results and Conclusions

Table 3A-30 lists the peak bulk suppression pool temperatures that were calculated using the GE computer code HEX for the scenarios described in Sections 3A.15.2.2 and 3A.15.2.3. Figures 3A-452 through 3A-457 provide plots of the suppression pool temperature and the respective reactor pressure versus time.

As stated earlier, the pool temperatures summarized in Table 3A-30 represent "bulk" temperatures, i.e., they were calculated assuming a homogeneously mixed suppression pool. In reality, pool mixing will not be perfect and differences will exist between the "local" temperature of the water in the immediate vicinity of the quencher and the calculated "bulk" temperature. However, because of the special design features of quenchers and their predominantly radial orientation in the suppression pool to optimize pool thermal mixing (Figure 3A-3), the local-to-bulk ΔT is expected to be small and not exceed the value that was previously derived for ramshead discharge devices in Mark I plants (10°F, Reference 3A-56). This number has been verified to be conservative for LGS using in-plant tests and analysis (Section 3A.15.3).

The suppression pool temperature limits defined in NUREG-0783 and listed in Section 3A.15.2.1 are specified in terms of "local" pool temperature and quencher mass flux criteria. Because Figures 3A-452 through 3A-457 specify the LGS time histories in terms of "bulk" pool temperature and reactor pressure, it is necessary to convert the NUREG-0783 local pool temperature limit criteria to

bulk pool temperature and reactor pressure criteria. Applying a local-to-bulk ΔT of 10°F as described above and calculating the LGS reactor pressures corresponding to steam fluxes of 42 lb_m/ft^2 sec and 94 lb_m/ft^2 sec, respectively, a bulk suppression pool temperature limit curve is developed. These curves are shown on Figures 3A-452 through 3A-457 and demonstrate that the LGS suppression pool temperatures due to SRV discharge comply with the temperature limits defined in NUREG-0783.

3A.15.3 SUPPRESSION POOL LOCAL-TO-BULK TEMPERATURE DIFFERENCE ADEQUACY ASSESSMENT

3A.15.3.1 Introduction

NUREG-0783 (Reference 3A-58) defines the suppression pool temperature limits for steam discharges through the Mark II T-quenchers (e.g., those used in the LGS suppression pool). These limits stem from the NRC's concern that, for certain combinations of pool temperatures and quencher mass fluxes, the steam condensation in the vicinity of the quencher exit may lead to higher vibratory loads on the submerged structures within the suppression pool. These pool temperature limits depend on the quencher steam mass flux and the saturation temperature at the quencher centerline submergence. The NUREG-0783 local pool temperature limits are expressed in terms of a local pool temperature. According to NUREG-0783, the local pool temperature is defined as the average water temperature in the vicinity of the quencher discharge device and represents the relevant temperature which controls the condensation process occurring at the quencher exit.

To confirm that LGS will not exceed the pool temperature limits stipulated in NUREG-0783 for all design basis scenarios which involve T-quencher operation, the LGS mass and energy analysis has been performed as reported in Section 3A.15.2. The analysis calculates a bulk pool temperature, defined as the pool temperature obtained by an energy balance on the pool assuming the pool acts as a uniform heat sink (i.e., no thermal stratification).

If ideal pool mixing would occur during steam discharges through the quenchers, the bulk temperature calculated by the mass and energy analysis would become the local pool temperature, and could be used directly to confirm that the LGS suppression pool will not exceed the NUREG-0783 temperature limits. In reality, thermal stratification occurs in the suppression pool, resulting in higher values of local pool temperature in comparison with the bulk pool temperature. The difference between these two temperatures in the local-to-bulk pool temperature difference (ΔT). Therefore, once the LGS unique local-to-bulk ΔT is determined, it can be used with the results of the mass and energy analysis (Section 3A.15.2) to confirm that the LGS suppression pool conforms to the local pool temperature criteria provided in NUREG-0783.

In conjunction with the SPTMS adequacy assessment provided in Section 3A.15.1.2, the KFIXTM code is used to calculate the local-to-bulk ΔT in the LGS suppression pool for the SORV blowdown scenarios described in Section 3A.15.1.2.1. Sections 3A.15.1.2.1.1 and 3A.15.1.2.1.2. provide the initial/operating conditions and KFIXTM geometrical models associated with these scenarios, respectively. Summarizing, these scenarios consist of two single SORV blowdowns under the high reactor pressure condition (SRV-H and SRV-L) and one single SORV blowdown under the low reactor pressure condition (SRV-H).

The two conditions of high and low reactor pressures correspond to the early and late stages of the SORV transient, respectively. The magnitude of the local-to-bulk ΔT gains significance at the later stages of the transient due to the smaller margin between the elevated bulk pool temperature and NUREG-0783 pool temperature limits. The results from the KFIXTM analysis, to be delineated in

the following sections, indicate that the low reactor pressure analysis yields a lower local-to-bulk ΔT than that associated with the high pressure analysis.

NUREG-0783 provides a specific definition of local pool temperature stated as follows:

> "To define the local pool temperature, a qualitative picture of the flow pattern during quencher discharge can be evolved by a combination of physical reasoning and experimental evidence...., it is apparent that the temperature which controls the condensation process (that is, the "local" temperature) is best characterized by that which would occur at a point directly above and below the quencher arms (perhaps one or two arms diameters distant), with the former providing a more conservative measure of this parameter."

Based on this definition, the local pool temperature can be calculated for both the high and low reactor pressure cases by mass averaging the temperature traces from the four fluid cells located directly above and below the two special cells representing the quencher arms. From Figures 3A-439, 3A-440, and 3A-442, the distances from the centers of these four cells to the centerline of the quencher arm varies from 2.333' to 2.47', or approximately twice the quencher arm diameter. The distances from the centers of these four cells to the top or bottom surface of the quencher arm is about 1½ times the quencher arm diameter. Thus, the methodology for calculating the local temperature conforms to the NUREG-0783 criteria.

Sections 3A.15.3.2, 3A.15.3.3, and 3A.15.3.4 discuss the KFIXTM calculated local and bulk pool temperature traces and corresponding local-to-bulk ΔTs for the SORV scenarios. Concluding remarks regarding the LGS local pool temperature and the related NUREG-0783 pool temperature limits are presented in Section 3A.15.3.5.

3A.15.3.2 SRV-H Blowdown Under High Reactor Pressure

Figure 3A-458 shows that the quasi steady-state local-to-bulk ΔT is about 8.6°F for SRV-H blowdown under high reactor pressure. The calculation of the local temperature is described in Section 3A.15.3.1. The bulk pool temperature is calculated by KFIXTM and is based on a mass-energy balance assuming that the pool is a uniform heat sink.

3A.15.3.3 SRV-L Blowdown Under High Reactor Pressure

Figure 3A-459 illustrates that the predicted local pool temperature follows the bulk pool temperature closely for SRV-L blowdown under high reactor pressure (i.e., local-to-bulk ΔT is minimal). The favorable thermal mixing characteristics associated with this analysis result from the combination of the quencher location (outer ring) and its orientation.

3A.15.3.4 SRV-H Blowdown Under Low Reactor Pressure

Section 3A.15.3.2 shows that a peak local-to-bulk ΔT of approximately 8.6°F is calculated for the high reactor pressure and relatively low pool temperature conditions. At this time in the transient, the steam flux through the active quencher is greater than 94 lb_m/ft^2 sec. As discussed in Section 3A.15.2.1, the NUREG-0783 local pool temperature limit at this flux is 200°F. Because the bulk pool temperature is much lower than 200°F at high reactor pressures (Figures 3A-452 through 3A-457), the local-to-bulk ΔT is relatively unimportant at these conditions.

As the reactor depressurizes and SRV flow rate decreases, the momentum transfer to the pool (i.e., pool mixing) decreases. The bulk pool temperature continues to increase and the local-to-bulk ΔT

gains significance. Therefore, the KFIXTM code is used to quantify the local-to-bulk ΔT calculated earlier is conservative with respect to the low reactor pressure ΔT.

Figure 3A-460 shows the bulk temperature trace along with the code predicted local temperature trace and overall average temperature trace (of all fluid cells) for SRV-H blowdown under low reactor pressure. The slight deviations between the bulk pool temperature and the KFIXTM predicted overall average temperature are due to the minor inaccuracies of KFIXTM temperature predications under low reactor pressure and elevated pool temperature conditions (Section 3A.15.1.2.3). Regardless of the apparent inaccuracy, the local pool temperature adheres closely to the overall average temperature and the local-to-bulk ΔT for the low pressure scenario is both minimal and bounded by the ΔT for the high pressure scenario.

3A.15.3.5 Conclusion

The local pool temperature limits stipulated in NUREG-0783 have been restated in Section 3A.15.2.1. Figures 3A-452 to 3A-457 plot these pool temperature limits relative to the bulk temperature time histories for the six mass and energy cases described in Section 3A.15.2.2. The local temperature limits have been converted to bulk limits by applying a local-to-bulk ΔT equal to 10°F. A local-to-bulk ΔT of 10°F was previously derived for ramshead discharge devices in Mark I plants (Reference 3A-56). Figures 3A-452 to 3A-457 indicate that adequate margin exists between the NUREG-0783 local limits (converted to bulk limits by 10°F ΔT) and the calculated bulk temperatures from the mass and energy analyses. The minimum margin occurs for Case 3.a near the end of the transient at low reactor pressure when the maximum bulk temperature peaks at 202°F (Figure 3A-456).

The peak calculated local-to-bulk ΔT has been established to be 8.6°F for SRV-H blowdown under high reactor pressure (Section 3A.15.3.2) and is adequately bounded by 10°F ΔT. In addition, the results of the low reactor pressure analysis (Section 3A.15.3.4) confirm that the low reactor pressure ΔT is much lower than the high pressure ΔT. Therefore, LGS has demonstrated that the NUREG-0783 maximum local pool temperature specification will not be exceeded.

3A.16 WETWELL-TO-DRYWELL VACUUM BREAKER AND DOWNCOMER CAPPING ADEQUACY ASSESSMENT

3A.16.1 INTRODUCTION

In April 1981, the ACRS expressed concern regarding the potential pool bypass from a stuck open wetwell-to-drywell vacuum breaker. This concern stems from the fact that following the onset of a LOCA about 20 seconds into the transient, the chugging phenomenon takes place. This rapid steam condensation will cause repeated and strong dynamic under and overpressure conditions in the downcomer. As a result of this pressure variation, the vacuum breaker attached to the downcomer may open.

Because chugging is a repetitive phenomenon, the vacuum breaker may be called on to function in a cyclic manner during these intermittent steam condensation events. These potential opening and closing impact loads could exceed the original design basis of the vacuum breakers. Failure of a vacuum breaker to close during this time could result in steam bypass of the suppression pool and subsequent pressurization of the wetwell air space, thus jeopardizing the integrity of the containment.

In July 1981, the NRC staff was informed that the Mark II owners who have vacuum breakers attached to the downcomer were conducting a joint qualification test program to demonstrate the

operability of the vacuum breaker under this intermittent steam condensation loading. The Mark II owners also identified the potential adverse effect of pool-swell on the performance of vacuum breakers. Because the wetwell air space will pressurize during the pool-swell event, the resulting differential pressure will cause the vacuum breaker to cycle open and then cycle closed when he pool falls back to the normal water level. The potential opening and closing impact load could exceed the potential opening and closing impact load could exceed the original design basis of the vacuum breakers.

3A.16.2 DESIGN ASSESSMENT

3A.16.2.1 Vacuum Breaker Cycling During Pool-Swell

To qualify the LGS vacuum breakers to withstand the dynamic effects of pool-swell, design modifications to the vacuum breakers have been implemented based on results from the Anderson Greenwood Company vacuum breaker test program. The modifications and test program results have been transmitted to the NRC (References 3A-60 and 3A-61).

3A.16.2.2 Vacuum Breaker Cycling During Chugging

To qualify the LGS vacuum breakers to withstand the dynamic effects of chugging, the four downcomers on which the wetwell-to-drywell vacuum breakers are counted have been capped. Capping the downcomers will eliminate the dynamic under and overpressures caused by the sudden steam condensation at the downcomer exit and eliminate the vacuum breaker cyclic actuation due to chugging phenomena. The locations of these capped downcomers are shown in Figure 3A-461.

3A.16.2.2.1 Downcomer Capping Design Assessment

3A.16.2.2.1.1 Downcomer Modifications

Figure 3A-462 shows a configuration of a modified downcomer with vacuum breaker (typical of four). The modifications include installation of a cap, a 3 inch drain line, and a 1 inch weir at the drywell entrance of the downcomer.

The capping design incorporates a 3 inch Schedule 160 drain line. Water motion in the 3 inch drain line has been modeled. As a result of this work, the drain has been extended 9'-7¾" above the downcomer exit plane. This extended length will prevent water from streaming into the downcomer during the rapid drywell depressurization caused by the gross chugging at the downcomer exits. In addition, to prevent water from exiting the drain line during the chugging/CO phase of a LOCA, the drain line is extended 4 feet below the downcomer exit plane. Therefore, potential chugging/CO dynamic loading phenomena at the drain exit are precluded.

The addition of a 1 inch weir at the drywell entrance of each capped downcomer is designed to limit the maximum ECCS flow into these downcomers during the recirculation mode after a LOCA. The 3 inch drain line is capable of passing this limited flow of ECCS water while preventing the downcomers from being filled to the vacuum breaker elevation.

3A.16.2.2.1.2 Containment Evaluation

Capping 4 out of 87 downcomers requires an evaluation to determine its effect on the containment design basis LOCA loading conditions and safety margins. To resolve this concern, Bechtel's computer program COPDA was used to evaluate the drywell conditions based on 83 and 87 downcomers, respectively. The results indicate that there is no significant change in either drywell

pressure and temperature or steam blowdown rate through the downcomers for the capped and uncapped situations.

Based on this analysis, capping 4 out of 87 downcomers will have no adverse effects on the LGS containment safety margins resulting from design basis LOCA loads, as defined in Section 3A.4.2, including pool-swell loads, containment functional pressure, submerged structure loads, boundary loads, and asymmetric effects.

3A.17 REFERENCES

3A.17.1 REFERENCES

3A-1 "Mark II Containment Dynamic Forcing Function Information Report", NEDO-21061, Revision 4, GE, (November 1981).

3A-2 "Mark II Containment Lead-Plant Program Load Evaluation and Acceptance Criteria", NUREG-0487, NRC, (October 1978).

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3A-64 GE Nuclear Energy, “Quencher Water Jet Loads Analytical Model”, Topical Report NEDE-23539-P, Class III (Proprietary), August 1979.

3A.17.2 REFERENCES (Proprietary - See Appendix 3B)

Table 3A-1

LGS LICENSING BASIS

I. MARK II GENERIC PROGRAM

A. LOCA-RELATED TASKS

TASK NUMBER	ACTIVITY	ACTIVITY TYPE	DOCUMENTATION	DOC DATE	USED FOR LGS LICENSING
A.1	"4T" PROGRAM	Phase I Test Report	NEDE-13442-01-P NEDO-13442-01	5/76 6/76	Yes Yes
		Phase I Application Memorandum	Application Memorandum	6/76	Yes
		Phase II & III Test Report	NEDE-13468-P NEDO-13468	12/76 3/77	Yes Yes
		Application Memorandum	NEDE-23678-P NEDO-23678	1/77 1/77	Yes Yes
A.2	POOL-SWELL MODEL REPORT	Model Report	NEDE-21544-P NEDO-21544	12/76 2/77	Yes Yes
A.3	IMPACT TESTS	PSTF 1/3 Scale Tests	NEDE-13426-P NEDO-13426	8/75 8/75	Yes Yes
		Mark I 1/12 Scale Tests	NEDC-20989-2P NEDO-20989-2	9/75 9/75	No No
A.4	IMPACY MODEL	PSTF 1/3 Scale Tests	NEDE-13426-P NEDO-13426	8/75 8/75	Yes Yes
		Mark I 1/12 Scale Tests	NEDE-20989-2P NEDO-20989-2	9/75 9/75	No No
A.5	LOADS ON SUBMERGED STRUCTURES	LOCA/RH Air Bubble Model	NEDE-21471-P NEDO-21471	9/77 9/77	Yes Yes
		LOCA/RH Water Jet Model	NEDE-21472-P NEDO-21472	9/77 9/77	Yes Yes
		Appplications Memorandum	NEDE-21730-P NEDO-21730	12/77 7/78	Yes Yes
		¼ Scaling Tests	NEDE-23817-P	9/78	No
A.5.5	RING VORTEX MODEL, PHASE I	Model Development	Letter Report	5/79	No

Table 3A-1 (Cont'd)

TASK NUMBER	ACTIVITY	ACTIVITY TYPE	DOCUMENTATION	DOC DATE	USED FOR LGS LICENSING
A.5.7	RING VORTEX MODEL, PHASE II	Model Extension Steam Condensation Methods	Burns & Roe Proprietary Report, Plant DARs	9/80	No
		Steam Condensation Methods	Burns & Roe Non Proprietary Report,	9/80	No
A.6	CHUGGING ANALYSIS AND TESTING	Single Cell Report	NEDE-23703-P NEDO-23703	9/77 9/77	Yes Yes
		Multivent Model	NEDO-21669-P NEDO-21669	2/78 2/78	Yes Yes
		4T FSI Report	NEDE-23710-P NEDO-23710	4/78 9/78	Yes Yes
A.7	CHUGGING SINGLE VENT	CREARE Report	NEDE-21851-P NEDO-21851	6/78 6/78	Yes Yes
A.9	EPRI TEST EVALUATION	EPRI-4T Comparison	NEDO-21667	8/77	Yes
	EPRI 1/13 SCALE TESTS	3 D Tests	EPRI NP-441	4/77	Yes
	EPRI SINGLE CELL TESTS	Unit Cell Tests	EPRI NP-1353	3/80	Yes
A.11	MULTIVENT SUBSCALE TESTING AND ANALYSIS	Preliminary MV Program Plan	NEDO-23697	12/77	Yes
		MV Test Program Plan & Procedures – Phase I	NEDO-23697A, Rev. 1	1/79	Yes
		Phase I Test Report	NEDE-24781-1-P	1/80	Yes
		MV Test Progress Plan & Procedures – Phase II	NEDO-23697A, Rev. 1, Supp. 1	8/79	Yes
		Phase II Test Report	NEDE-25289-1-P NEDO-25289-1	8/80 11/80	Yes Yes
		CONMAP Tests	CREARE Report TN-297	6/79	Yes
		MHM Verification 1/10 Scale	NEDE-25116-P NEDO-25116	5/79 8/79	Yes Yes
		Scaling and Data Correlation	NEDE-24300-P NEDO-24300	4/81 7/81	Yes Yes
A.13	SINGLE VENT LATERAL LOADS	Dynamic Analysis	NEDE-24106-P NEDO-24106	3/78 3/78	Yes Yes
		Summary Report	NEDE-23606-P NEDO-23606	10/78 12/78	Yes Yes
		Responses to NRC Questions	Letter Report	1/81	Yes

Table 3A-1 (Cont'd)

TASK NUMBER	ACTIVITY	ACTIVITY TYPE	DOCUMENTATION	DOC DATE	USED FOR LGS LICENSING
A.13	NEW LATERAL LOADS	Dynamic Analysis Report	NEDE-24794-P NEDE-24794-P Errata NEDO-24794	3/80 9/80 3/80	Yes Yes Yes
		Method of Mulitple Application	Vent Letter Report	4/80	Yes
A.16	IMPROVED CHUGGING LOAD DEFINITION	Impulse Evaluation Improved Chug Load	Letter Report NEDE-24822-P NEDE-24822-P Errata NEDO-24822 NEDO-24822 Errata	6/78 5/80 8/80 6/80 8/80	No Yes Yes Yes Yes
A.17	CONDENSATION OSCILLATION TESTING AND IMPROVED CO LOAD DEFINITION	4TCO Test	NEDE-24811-P NEDE-24811-P Errata NEDO-24811 NEDO-24811 Errata	5/80 9/80 7/80 9/80	Yes Yes Yes Yes
		Improved CO Load Definition	NEDE-24288-P NEDO-24288	11/80 2/81	Yes Yes
A.22	A.16 SOURCE EVALUATION	Confirm/Revise Source based on 4TCO Data	NEDE-24302-P	4/81	Yes
		4TCO Chugging Data – Six key runs	NEDE-24285-P NEDO-24285	1/81	Yes Yes
A.29	V.B. MODEL	Methodology Report	NEDE-22178-P	8/82	Yes
A.30	RESPONSE TO BIENKOWSKI/NRC CHUGGING QUESTION	Load Evaluation for frequency	Letter Report	4/82	Yes
B. SRV-RELATED TASKS					
B.1	QUENCHER EMPIRICAL MODEL	DFFR Model	NEDE-21061-P NEDE-21061	9/76 9/76	No No
		Supporting Data	NEDE-21061-P NEDO-21078	5/75 10/75	No No

Table 3A-1 (Cont'd)

TASK NUMBER	ACTIVITY	ACTIVITY TYPE	DOCUMENTATION	DOC DATE	USED FOR LGS LICENSING
B.2	RAMSHEAD MODEL	DFFR MODEL	NEDE-21061-P NEDO-21062	9/76 9/76	No No
		Supporting Data	NEDE-21061-P NEDO-21062	7/75 7/75	No No
		Analysis	NEDE-20942-P NEDO-20942	5/75 5/75	No No
B.3	MONITCELLO IN-PLANT SRV TESTS	Preliminary Test Report	NEDC-21465-P NEDO-21465	12/76 12/76	No No
		Hydrodynamic Report	NEDC-21581-P NEDO-21581	8/77 8/77	No No
B.5	SRV QUENCHER IN-PLANT	Test Plan	NEDM-20988 Rev. 2	12/76	No
	CAORSO TESTS	Test Plan Addendum 1	NEDM 20988 Rev. 2 Add. 1	10/77	No
		Test Plan Addendum 2	NEDM 20988 Rev. 2 Add. 2	4/78	No
		Test Summary	Letter Report	3/79	No
	Phase I	Test Report	NEDE-25100-P NEDE-25100-P Errata NEDO-25100-P NEDO-25100-P Errata	5/79 2/81 8/79 2/81	No No No No
	Phase II	Test Report	NEDE-24757-P NEDO-24757	5/80 7/80	No No
	Re-evaluate	AMN Report	NEDE-24835-P	3/81	No
B.5.1	EXTENDED BLOWDOWN	Test Report	NEDE-24798-P NEDO-24798	7/80 8/80	No No
B.6	THERMAL MIXING BOWL	Analytical Model	NEDC-23689-P NEDO-23689	3/78 3/78	No No
B.10	MONITCELLO FSI	Analysis of FSI	NEDO-23834	6/78	No
B.11	DFFR RAMSHEAD MODEL TO MONITCELLO DATA	Data/Model Comparison	NSC-GEN 0394	9/77	No
B.12	RAMSHEAD SRV METHODOLOGY SUMMARY	Analytical Methods	NEDO-24070	10/77	N0

Table 3A-1 (Cont'd)

TASK NUMBER	ACTIVITY	ACTIVITY TYPE	DOCUMENTATION	DOC DATE	USED FOR LGS LICENSING
C. MISCELLANEOUS TASKS					
C.0	SUPPORTING PROGRAM	Supp Prog Report	NEDO-21297	5/76	No
		Supp Prog Report Rev. 1	NEDO-21297 Rev. 1	4/78	No
C.1	DFTR REVISIONS (See also TASK C.18)	Revision 1	NEDE-21061-P Rev. 1 NEDO-21061 Rev. 1	9/75 9/75	No No
		Revision 2	NEDE-21061-P Rev. 2 NEDO-21061 Rev. 2	9/76 9/76	No No
		Revision 3	NEDE-21061-P Rev. 3 NEDO-21061 Rev.3	6/78 6/78	Yes Yes
C.3	NRC ROUND 1 QUESTIONS	DFFR Rev 2	NEDO-21061 Rev. 2	9/76	Yes
		DFFR Rev 2 Amendment 1	NEDO-21061 Rev. 2 Amendment 1	12/76	Yes
		DFFR Round 1 Questions	Letter Report	6/78	Yes
C.5	SRSS JUSTIFICATION	Interim Report	(NEDE-24010)	4/77	Yes
		SRRS Report	NEDE-24010-P NEDE-24010	7/77 7/77	Yes Yes
C.5.1	SRSS PROGRAM SUMMARY	SRSS Executive Summary	Summary Report	4/78	Yes
C.5.2	SRSS APPLICATION CRITERIA	SRSS Criteria Application	NEDO-24010, Supp. 1	10/78	Yes
		SRSS Criteria Basis	NEDO-24010, Supp. 2	12/78	Yes
C.5.3	SRSS JUSTIFICATION CRITERIA	SRSS Justification Supp	NEDO-24010, Supp. 3	8/79	Yes
		SRSS Criteria Evaluation	Letter Report	1/80	Yes
C.5.4	BROOKHAVEN REPORT CRITIQUE	BNL Critique	EDAC 134-242-03	1/80	Yes

Table 3A-1 (Cont'd)

TASK NUMBER	ACTIVITY	ACTIVITY TYPE	DOCUMENTATION	DOC DATE	USED FOR LGS LICENSING
C.6	NRC ROUND 2 QUESTIONS	DFFR Amend 2	NEDE-21061-P Rev 2 Amend.2	6/77	Yes
			NEDE-21061 Rev 2 Amend.2	6/77	Yes
		DFFR Amend 2, Supp 1	NEDE-21061 Rev 2 Amend.2 Supp.1	8/77	Yes
		DFFR Amend 2, Supp 2	NEDE-21061-P Rev 2 Amend.2 Supp.2	9/77	Yes
		DFFR Rev. 3, Appendix A-2	NEDE-21061-P Rev 3 Appendix A-2		Yes
			NEDE-21061 Rev 3 Appendix A-2		Yes
C.7	JUSTIFICATION OF "4T" BOUNDING LOADS	Chugging Loads Justification	NEDE 23617-P NEDO 23617 NEDE 24013-P NEDO 24013 NEDE 24014-P NEDO 24014 NEDE 24015-P NEDO 24015 NEDE 24016-P NEDO 24016 NEDE 24017-P NEDO 24017 NEDE 23627-P NEDO 23627	7/77 7/77 6/77 7/77 6/77 7/77 6/77 7/77 6/77 7/77 6/77 7/77 6/77 7/77	Yes Yes Yes Yes Yes Yes Yes Yes Yes Yes Yes Yes Yes Yes
C.8	SRV AND CHUGGING FSI	Prestressed Concrete, Reinforced Concrete, Steel	NEDE 21936-P NEDE 21936-P	7/78 7/78	Yes Yes
C.9	MONITOR WORLD TESTS	Monitor Tests	None		No
C.11	MASS-ENERGY RELEASE	SRV Pool Temperature Analysis Assumption	White Paper – Revision 0 White Paper – Revision 1	4/80 1/81	Yes No
		Methods for calculating mass and energy release for SRV discharges	Letter Report	5/81	Yes

Table 3A-1 (Cont'd)

TASK NUMBER	ACTIVITY	ACTIVITY TYPE	DOCUMENTATION	DOC DATE	USED FOR LGS LICENSING
C.13	LOAD COMBINATIONS AND FUNCTIONAL CAPABILITY CRITERIA	Criteria Justification	NEDO 21985	9/78	Yes
C.14	NRC ROUND 3 QUESTIONS	Letter Report	Letter Report	6/78	Yes
		DFFR Round 3 Questions	Letter Report	6/78	Yes
C.15	SUBMERGERD STRUCTURE CRITERIA	NRC Question Responses	Letter Report	4/80	Yes
C.16	QUENCHER MASS ENERGY CUTOFF	Quencher Temperature Limit	Letter Report	1/81	Yes
C.18	DFFR REVISION	Revision 4	NEDO-21061-4	12/81	Yes

Table 3A-1 (Cont'd)

Document Number	Title	Documentation	Document Date	Used for LGS Licensing
II. KWU Tests and Reports				
1	Formation and oscillation of spherical gas bubble	AEG – Report 2241	12/72	Yes
2	Analytical model for clarification or pressure pulsation in the wetwell after vent clearing	AEG – Report 2208	3/72	Yes
3	Tests on mixed condensation with model quenchers	KWU – Report 2593	5/73	Yes
4	Condensation and vent clearing tests at GKM with quenchers	KWU – Report 2594	5/73	Yes
5	Concept and design of the pressure relief system with quenchers	KWU – Report 2703	7/73	Yes
6	KKB vent clearing with quencher	KWU – Report 2796	10/73	Yes
7	Experimental approach to vent clearing in a model tank	KWU – Report 3129	7/75	Yes
8	Anticipated data for blowdown tests with pressure relief system during the non-nuclear hot functional test at KKB	KWU – Report 3141		Yes
9	Results of the non-nucleat hot functional tests with the pressure relief system in the nuclear power station Brunsbuttel	KWU - Report 3267	12/74	Yes

Table 3A-1 (Cont'd)

Document Number	Title	Documentation	Document Date	Used for LGS Licensing
10	Analysis of the loads measured on the pressure relief system during the non-nuclear hot functional test at KKB	KWU – Report 3346	4/75	Yes
11	KKB – Listing of test parameters and important test data of the non-nuclear hot functional tests with the pressure relief system	KWU – Working Report R 521/40/77	8/77	Yes
12	KKB – Results from nuclear startup testing of pressure relief system	KWU – Working Report R 142-136/76	9/76	Yes
13	Results of non-nuclear hot functional tests with pressure relief system in KKPI	KWU – Working Report R 142-38/77	3/77	Yes
14	KKPI – Listing of test parameters and important test data of the non-nucleat hot functional tests with the pressure relief system	KWU – Working Report R 521/41/77	8/77	Yes
15	KKB hot functional test results, loads on internals in pool of the suppression chamber during pressure relief processes	KWU – Working Paper R 113/203	11/74	Yes

Table 3A-2

COMPARISON OF LGS LICENSING BASIS WITH NRC ACCEPTANCE CRITERIA

Load or Phenomenon	NRC Acceptance Criteria	Criteria Source	LGS Position
I. LOCA-Related Hydrodynamic Loads			
A. Submerged Boundary Loads During Vent Clearing	24 psi overpressure added to local hydrostatic pressure below vent exit (walls and basemat) – linear attenuation to pool surface	NUREG-0487 Supplement 1	Acceptable
B. Pool-swell Loads			
1. Pool-swell Analytical Model			
a. Air Bubble Pressure	Calculated by the pool swell analytical model (PSAM) used in calculation of submerged boundary loads.	NUREG-0487	Acceptable
b. Pool-swell Elevation	Use PSAM with polytropic exponent of 1.2 to a maximum swell height which is the greater of 1.5x vent submergence or the corresponding to the drywell floor uplift ΔP = 2.5 psid.	NUREG-0808	Acceptable. Used NUREG-0487, Supplement 1

Table 3A-2 (Cont'd)

Load or Phenomenon	NRC Acceptance Criteria	Criteria Source	LGS Position
c. Pool-swell Velocity	Velocity history vs. pool elevation predicted by the PSAM used to compute impact loading on small structures and drag on gratings between initial pool surface and maximum pool elevation and steady-state drag between vent wxit and maximum pool elevation. Analytical velocity variation is used up to maximum velocity. Maximum velocity applies thereafter up to maximum pool-swell. PSAM predicted velocities multiplied by a factor of 1.1.	NUREG-0808	Acceptable. Used NUREG-0487. PSAM calculated velocity without 1.1 multiplier However multiplied by 1.1 when used in force code.
d. Pool-swell Acceleration	Acceleration predicted by the PSAM. Pool acceleration is used in the calculation of acceleration loads on submerged components during pool-swell.	NUREG-0487	Acceptable
e. Wetwell Air Compression	Wetwell air compression is calculated by PSAM consistent with maximum pool-swell elevation calculated in B.1.b above.	NUREG-0487 Supplement 1	Acceptable. Maximum pool-swell elevation calculated in accordance with NUREG-0487, Supplement 1.
f. Drywell Pressure	Methods of NEDM-10320 and NEDO-20533 Appendix B. Used in PSAM to calculate pool-swell loads.	NUREG-0487	Acceptable.

Table 3A-2 (Cont'd)

Load or Phenomenon	NRC Acceptance Criteria	Criteria Source	LGS Position
2. Loads on Submerged Boundaries	Maximum bubble pressure predicted by the PSAM added uniformly to local hydrostatic pressure below vent exit (walls and basemat) – linear attenuation to pool surface. Applied to walls up to maximum pool-swell elevation.	NUREG-0487	Acceptable
3. Impact Loads			
a. Small Structures	1.35 x Pressure-Velocity correlation for pipes and I-beams based on PSTF impulse data and flat pool assumption. Variable pulse duration.	NUREG-0808	Acceptable
b. .Large Structures	None – Plant unique laod where applicable.	NUREG-0487	Not Applicable. No large structures.
c. Grating	Pool-swell drag vs. grating area correlation and pool velocity vs. elevation. Pool velocity from the PSAM. Pool-swell drag multiplied by dynamic laod factor.	NUREG-0808	Acceptable
4. Wetwell Air Compression			
a. Wall Loads	Direct application of the PSAM calculated pressure due to wetwell compression.	NUREG-0487	Acceptable

Table 3A-2 (Cont'd)

Load or Phenomenon	NRC Acceptance Criteria	Criteria Source	LGS Position
b. Diaphragm Upward Loads	5.5 psid diaphragm loadings only.	NREG-0808	Acceptable. Calculated diaphragm uplift ΔP = 10.6 psid (Figures 3A-6 and 3A-7) Design diaphragm uplift ΔP = 20 psid.
5. Asymetric LOCA Pool	Use 20 percent of maximum bubble pressure statiscally applied to ½ of the submerged boundary.	NUREG-0808	Acceptable
C. Steam Condensation and Chugging Loads			
1. Downcomer Lateral Loads			
a. Single Vent Loads (24 in.)	Dynamic load to end of vent. Half sine wave with a duration of 3-6 ms and corresponding maximum amplitudes of 65-10 k-lb_f.	NUREG-0808	Acceptable
b. Multiple Vent Loads (24 in.)	Prescribed variation of load per vent vs. number of vents. Determined from single vent dynamic load specification and multivent reduction factor.	NUREG-0808	Acceptable
c. Single/Mulitple vent loads (28 in)	Multiply basic vent loads by factor f = 1.34	NUREG-0808	Not Acceptable

Table 3A-2 (Cont'd)

Load or Phenomenon	NRC Acceptance Criteria	Criteria Source	LGS Position
2. Submerged Boundary Loads			
a. High/Medium Steam Flux Condensation Oscillaiton Load	Bounding CO pressure histories observed in 4TCO tests. In-phase application.	NUREG-0808	Acceptable
b. Low Steam Flux Chugging Load	Conservative set of 10 sources derived from 4TCO tests. Applied to plants using the IEWGS/MAPS acoustic model. Source desynchronization of 50 ms or alternate load using 7 sources derived from 4TCO key chugs without averaging.	NUREG-0808	Acceptable
- Symmetric Load	All vents use source of equal strength for each of the sources.		
- Asymmetric Load Case	Source strengths $S\pm = S(1\pm\alpha)$ applied to all vents on + and – side of containment. Sources based on the symmetric sources. Asymmetric parameter α based on rms moment method of interpreting experimental 4TCO single vent and JAERI multivent data.		

Table 3A-2 (Cont'd)

Load or Phenomenon	NRC Acceptance Criteria	Criteria Source	LGS Position
II. SRW Related Hydrodynamic Loads			
A. Pool Temperature Limits	For plants using a discharge device with the exact hole pattern as described in the SSES DAR Section 4.1, the following limits shall apply:	NUREG-0783	
	1. For all plant transients involving SRV operations during which steam flux exceeds 94 lb_m/ft^2-sec, the local pool temperature shall not exceed 200°F.	NUREG-0783	Acceptable
	2. For all plant transients involving SRV operations during which steam flux is less than 42 lb_m/ft^2-sec, the local pool temperature shall be at least 20°F subcooled. This is equivalent to a temperature of 210°F with quencher submergence of 14 feet.	NUREG-0783	Acceptable

Table 3A-2 (Cont'd)

Load or Phenomenon	NRC Acceptance Criteria	Criteria Source	LGS Position
	3. For all plant transients involving SRV operations during which steam flux is between 42 lb_m/ft^2-sec and 94 lb_m/ft^2-sec, the local pool temperature can be determined by linear interpolation between the temperatures defined in items 1 and 2 above.	NUREG-0783	Acceptable
B. Evaluation of Air Cleaning Load Definition Procedures	The T-quencher load specification described in section 4.1 of the SSES DAR may be applied for evaluation of SRV containment boundary pressure loads with the following restrictions:	NUREG-0802	Acceptable
	1. All valves load case The DLV and DLWL combinations must lie below the limit line of figure A.1 defined in the criteria where: a. DLV shall be equal to the arithmetic average of all discharge line volumes (m^3)	NUREG-0802	Acceptable

Table 3A-2 (Cont'd)

Load or Phenomenon	NRC Acceptance Criteria	Criteria Source	LGS Position
	b. DLW shall be equal to the quencher submergence at high water level (m).		
	2. ADS Load Case The DLV and DLWL combinations must lie below the limit line of figure A.2 defined in the criteria where: a. DLV shall be equal to the arithmetic average of all ADS discharge line volumes (m^3) b. DLWL shall be equal to the differences between the plant downcomer exit elevation and the quencher center line elevation (m)	NUREG-0802	Acceptable
	3. Frequency Range For the single valve and asymmetric load cases, the time-wise compression of the design pressure signatures shall be increased to provide an overall dominant frequency range that extends to 11 Hz.	NUREG-0802	Acceptable (Section 3B.4.1.4.1)

Table 3A-2 (Cont'd)

Load or Phenomenon	NRC Acceptance Criteria	Criteria Source	LGS Position
	4. Vertical Pressure Distribution The maximum pressure amplitudes shall be applied uniformly to the containment and pedestal walls up to an el 2.5' above the quencher centerline followed by linear attenuation to zero at pool surface.	NUREG-0802	Acceptable
C. T-Quencher Tie-Down Loads	The T-Quencher load specification described in SSES DAR section 4.1.2, as interpreted in sections 2.2.3 and 2.3.3 of NUREG-0802, may be applied for evaluation of quencher and quencher support.	NUREG-0802	Acceptable
D. SRV Boundary Loads	The acceptance criteria specified in NUREG-0802. Appendix A (A.1.1 through A.1.7), are recommended for plants following the "alternate" load methodology (i.e., T-Quencher load specification described in SSES DAR section 4.1)	NUREG-0802	Acceptable Section 3B.4.1.1.1 demonstrates the acceptability of using the SSES SRV load specification for LGS.

Table 3A-2 (Cont'd)

Load or Phenomenon	NRC Acceptance Criteria	Criteria Source	LGS Position
III. LOCA/SRV Submerged Structure Loads			
A. LOCA Downcomer Jet Load	Alternate methodology presented in Zimmer DAR may be applied.	NUREG-0487 Supplement 1	Acceptable
B. SRV T-Quencher Jet	SRV T-quencher jet loads may be neglected betond a 5 ft cylindrical zone of influence. Cyliner should be extended 10 hole diameters on the arm with holes in the end cap.	NUREG-0487	Acceptable
C. LOCA Air Bubble Drag Loads	Calculate based on methods described in NEDE-21471 subject to the following constraints and modifications:	NUREG-0487	Applying plant unique methodology defined in Section 3A.4.2.1.5
	1. To account for bubble asymmetry, accelerations and velocities shall be increased 10 %.	NUREG-0487	Acceptable
	2. For standard drag in accelerating flow fields, use draft coefficients presented in Zimmer FSAR Attachement 1.k with following modifications:	NUREG-0487 Supplement 1	Acceptable

Table 3A-2 (Cont'd)

Load or Phenomenon	NRC Acceptance Criteria	Criteria Source	LGS Position
	a. Use $C_H = C_m^{-1}$ in the F_A formula b. For noncylindrical structures, use lift coefficient for appropriate shape or $C_L = 1.6$ c. The standard drag coefficient for pool-swell and SRV oscillating bubbles should be based on data for structures with sharp edges.		
	3. For equivalent uniform flow velocity and acceleration calculations, structures are segmented into small sections such that $1.0 \leq L/D \leq 1.5$. The loads are then applied to the geometric center of each segment. This approach, as presented in Zimmer FSAR Attachment 1.k. may be applied.	NUREG-0487 Supplement 1	Acceptable
	4. A detailed methodology on the approach for considering effects as presented in Zimmer FSAR Attachment 1.k may be applied.	NUREG-0487 Supplement 1	Acceptable

Table 3A-2 (Cont'd)

Load or Phenomenon	NRC Acceptance Criteria	Criteria Source	LGS Position
	5. Formula 2-23 of NEDE-21739 shall be modified by replacing M_H by ρ_{FB} V_A where V_A is obtained from tables 2-1 & 2-2.	NUREG-0487	Acceptable
D. SRV Air Bubble Drag Load	No criteria specifiec for T-quencher		Applying plant unique methodology defined in Section 3B.4.1.4 and applying the Mark II Submerged structure load methodology for SRV - bubbles described in Section 3A.11
E. Steam Condensation Drag Load	No criteria specifiec		Applying plant unique methodology defined in Section 3A.4.2
IV. Secondary Loads			
1. Sonic Wave Load	Negligible Load	NUREG-0487	Acceptable
2. Comprehensive Wave Load	Negligible Load	NUREG-0487	Acceptable
3. Fallback Load on Submerged Boundary	Negligible Load	NUREG-0487	Acceptable
4. Thrust Load	Negligible Load	NUREG-0487	Acceptable
5. Friction Load on Submerged Boundary	Negligible Load	NUREG-0487	Acceptable
6. Vent Clearing Loads	Negligible Load	NUREG-0487	Acceptable

Table 3A-2 (Cont'd)

Load or Phenomenon	NRC Acceptance Criteria	Criteria Source	LGS Position
7. Postswell Wave Load	Methodology for establishing loads resulting from postswell waves to be evaluated on a plant unique basis	NUREG-0487	Load is negligible when compared to design basis loads (Section 3A.4.2.3.6)
8. Seismic Slosh Load	Methodology for establishing loads resulting from seismic slosh to be evaluated on a plant unique basis	NUREG-0487	Load is negligible when compared to design basis loads (Section 3A.4.2.3.7)
V. Confirmatory In-plant Tests of SRV Discharge			
A. SRV Load Specification	In the event that an applicant cannot demonstrated to the staff's satisfaction, equivalence in any of the areas cited in acceptance criteria A.1.1 through A.1.7 of confirmatory testing may be employed to demonstrate the applicability of the acceptance criteria for individual plants. Such testing if proposed should conform to the guidelines set down in NUREG-0763	NUREG-0802 Appendix A	Acceptable. No In-plant test is required. Section 3B>4.1.1.1 demonstrates the acceptability of using SSES SRV load specification for LGS.
B. Pool Temperature Specification (Thermal Mixing)	The acceptability of the safety/relief valve in-plant confirmatory test program shall be based on conformance guidelines specified in sections 6, 7, and 8 of NUREG-0763. I f the applicant/licensee elects not to perform the SRV in-plant tests, justification should be provided following the guidelines specified in section 4 of NUREG-0763.	NUREG-0763	Acceptable. The LGS pool thermal mixing capability has been adequately demonstrated by in-plant testing at LaSalle and analysis (Sections 3A.15.1.2 and 3A.15.3).

Table 3A-3

CONTAINMENT DESIGN PARAMETERS

	Drywell	Suppression Chamber
DRYWELL AND SUPPRESSION CHAMBER		
Internal design pressure, psig	55	55
External to internal design differential pressure, psid	5	5
Drywell deck design differential pressure, psid	30 downward	20 upward
Design temperature, ^{o}F	340	220
Drywell net free volume, at suppression pool low water level, including downcomers, ft^3	243,580(3)	
Suppression chamber free volume including pedestal interior, ft^3		
Low water level		159,540(3)
High water level		147,670(3)
Suppression pool water volume including pedestal interior, ft^3		
Low water level		122,120(3)(5)
High water level		134,600(3)
Suppression pool net surface area, ft^2		
Outside pedestal		4974
Inside pedestal		293
Suppression pool depth, ft		
Low level		22'
Normal level		23'
High level		24'-3"

Table 3A-3 (Cont'd)

	Drywell	Suppression Chamber
VENT SYSTEM		
Number of downcomers		87[4]
Nominal downcomer diameter, ft		2[5]
Downcomer area (each), ft^2		2.95
Downcomer submergence, ft		
Low water level		10'
Normal water level		11'
High water level		12'-3"
Downcomer loss coefficient (including exit loss)		2.23[3]
SAFETY/RELIEF VALVES		
Number		14

Spring Set Pressures, Mass Flow Rates:

Valve	Set Pressure (psig)	Mass Flow (lb_m/hr) at 103% of Spring Set Pressure
A	1190	948,785
B	1190	948,785
C	1190	948,785
D	1180	940,906
E*	1180	940,906
F	1190	948,785
G	1190	948,785
H*	1170	933,028
J	1170	933,028

Table 3A-3 (Cont'd)

Valve	Set Pressure (psig)	Mass Flow (lb_m/hr) at 103% of Spring Set Pressure
K*	1180	940,906
L	1170	933,028
M*	1180	940,906
N	1170	933,028
S*	1180	940,906

*ADS Valves

SAFETY/RELIEF VALVE DISCHARGE LINES

Nominal Diameter 12"

Length, Number of Bends, and Air Volume for each SRV Pipe:

Valve	Bends	Length(1) (ft)	Volume(2) (ft^3)
A	9	144.5	94.3
B	7	116.4	74.2
C	7	118.2	75.7
D	9	144.9	94.8
E	9	137.4	89.1
F	11	136.3	88.3
G	11	136.6	88.5
H	11	140.5	91.2
J	7	118.6	76.0
K	12	134.0	86.2
L	10	134.3	86.5
M	13	137.0	88.2
N	10	144.5	93.8
S	12	142.3	93.2

Table 3A-3 (Cont'd)

(1) Line lengths are measured from the valve to the quencher inlet.
(2) Air volume is calculated up to pool normal water level.
(3) These values vary slightly from those actually used in the analysis. The difference in analysis results is negligible.
(4) Four of 87 downcomers are capped (Section 3A.16).
(5) These values were used in the original design basis analyses. Refer to Table 6.2-4A for the values used in the containment analyses for the current plant conditions.

Table 3A-4

LGS CONTAINMENT DIMENSIONS

SUPPRESSION CHAMBER	
Inside Diameter	88'-0"
Height	52'-6"
DRYWELL	
Inside Diameter of Base	86'-4"
Inside Diameter of Top	36'-4.5"
Height	87'-9"
REACTOR PEDESTAL	
Inside Diameter Below Diaphragm Slab	20'-0.5"
Inside Diameter Above Diaphragm Slab	20'-3"
Wall Thickness Below Diaphragm Slab	4'-9.5"
Wall Thickness Above Diaphragm Slab	4'-5"
Height	82'
REINFORCED CONCRETE THICKNESS	
Base Foundation Slab	8'-0"
Containment Wall	6'-2"
Diaphragm Slab	3'-6"
STEEL LINER PLATE THICKNESS	
Base Foundation, Containment Wall, and Diaphragm Slab)	0.25"
SUPPRESSION CHAMBER COLUMNS	
Outside Diameter	3'-6"
Wall Thickness	1.25"
Height	52'-3"

Table 3A-5

SHORT-TERM LOCA LOADS ASSOCIATED WITH POOL-SWELL

Load
1. Wetwell/drywell pressures during pool-swell
2. Pool-swell impact loads
3. Pool-swell drag loads
4. Downcomer clearing loads
5. Downcomer water jet load
6. Pool-swell air bubble load
7. Pool-swell fallback load

Table 3A-6

SHORT-TERM DRYWELL PRESSURES DURING POOL-SWELL

Time (sec)	Pressure (psia)
0.0000[1]	36.11
0.0600	36.29
0.1000	36.82
0.1200	37.08
0.1600	37.57
0.2000	38.04
0.2400	38.49
0.2800	38.91
0.3200	39.30
0.3600	39.67
0.4000	40.01
0.5000	40.75
0.6000	40.75
0.7000	41.39
0.8000	42.07
0.9000	42.80
1.0000	43.56
1.1000	44.603
1.2000	45.36
1.3000	46.08
1.4000	46.75

(1) Represents the beginning of the pool-swell phase, which starts 0.7107 seconds after the break.

NOTE: The information presented in this table is historical and is based on the original design basis conditions. The initial drywell pressurization rate is negligibly affected by the current plant conditions. The results presented here reasonably represent the general characteristics of the drywell pressure response.

Table 3A-7

LGS PLANT UNIQUE POOL-SWELL CODE INPUT DATA

Downcomer area (each)	2.95 ft^2
Suppression pool free surface area (outside pedestal)	4973.89 ft^2
Maximum downcomer submergence	12.25 ft
Downcomer loss coefficient (without exit loss)	1.23
Number of downcomers	87
Initial wetwell pressure	15.45 psia
Wetwell free air volume	149,425 ft^3
Vent clearing time	0.7107 sec
Slug velocity in downcomer at vent clearing	3.096 ft/sec
Initial drywell temperature	135°F
Initial drywell relative humidity	0.20
Downcomer friction coefficient, f	0.0115 (nominal)
Bubble initialization parameter (nominal)	50

NOTE: The information presented in this table is based on the original design basis conditions. Refer to Table 6.2.4A for input values used in the containment analyses for the current plant conditions.

Table 3A-8

INCLUDED LOCA WATER JET DRAG LOADS

Largest vertical downward force density acting on RHR pump suction line strainer	49 psi
Largest horizontal force density acting on RHR pump suction line strainer	29 psi
Largest vertical force on closest MSRV discharge line (distance = 2 ft)	1207 lb/ft
Largest horizontal force on closest MSRV discharge line (distance = 2 ft)	1394 lb/ft

NOTE: The information presented in this table is pertains to the original design basis. At current plant conditions, the LOCA water jet loads are approximately 2% higher than the load values shown in the table. However, margin between the design limits and the resulting component stress calculations exists to accommodate the increase in the LOCA jet loads.

Table 3A-9

POOL-SWELL AIR BUBBLE LOADS

Water volume in downcomers	3142.16 ft^3
Pool surface area (outside pedestal)	4973.89 ft^2
Maximum pool-swell after water discharge	18.88 ft
Height of downcomer water in the pool	7.58 in (0.632 ft)
Maximum pool-swell height (18.88 ft + 0.632 ft)	19.51 ft
Basemat hydrostatic pressure	10.51 psig
Downcomer tip hydrostatic pressure	5.20 psig
Maximum air bubble pressure	48.25 psia
Maximum pressure at basemat	58.76 psia
Maximum pressure at downcomer tip	48.25 psia
Maximum pool-swell inside the pedestal	212'-9" (6.62 ft above the high water level)

NOTE: The information presented in this table is based on the original design basis conditions. Refer to Sections 3A.4.2.1.4 and 3A.4.2.1.7 for the air bubble loads evaluation at the current operating conditions.

Table 3A-10

POOL-SWELL WATER FRICTION DRAG LOADS

Friction drag loads on columns	
Number of columns	12
Surface area per column	214.55 ft^2
Friction force for 12 columns	5098 lb_f
Shear stress	0.01375 lb/in^2
Friction drag load on downcomers	
Number of downcomers	87
Surface area of downcomer	122.6 ft^2
Frictional drag coefficient	0.00216
Friction force for 87 downcomers	2112.2 lb
Friction drag load on MSRV pipes	1806 lb
Air friction drag inside downcomers	303 lb
Downcomer bracing fallback loads	
Vertical load (12" nominal diameter)	3720 lb/ft
Horizontal load (12" nominal diameter)	2823 lb/ft
Vertical load (10" nominal diameter	2616 lb/ft
Horizontal load (10" nominal diameter	2046 lb/ft

NOTE: The information presented in this table is based on the original design basis conditions. Refer to Section 3A.4.2.1.8 for the pool swell drag load evaluation at the current operating conditions.

Table 3A-11

MAXIMUM LOAD ON SUBMERGED STRUCTURES

Submerged Structure	Max CO Load (lb/in)	Max Chugging Load (lb/in)
MSRV Discharge Line	3.8	24.0
Downcomer	22.0	41.0
Bracer	0.8	10.2
Core spray discharge line	0.22	6.6
HPCI discharge line	22.0	22.0
RHR discharge line	2.2	16.0
Column	51.6	190.0

Table 3A-12

COMPONENT LOCA LOAD CHART FOR LGS

Structure Directly Affected	Load												
	1	2	3	4	5	6	7	8	9	10	11	12	13
Containment Wall	X					X		X	X	X	X	X	X
Pedestal (incl. Interior)	X					X		X	X	X	X	X	X
Basemat	X				X	X		X	X	X	X	X	X
Liner plate	X				X	X		X	X	X	X	X	X
Drywell floor	X										X	X	X
Drywell	X										X	X	X
Columns			X			X	X	X	X	X			
Downcomers			X	X		X	X	X	X	X			
Downcomer bracing			X			X	X	X	X	X			
Wetwell piping		X	X		X	X	X	X	X	X			

Load Legend

1	Wetwell/drywell pressure during pool-swell
2	Pool-swell impact load
3	Pool-swell drag load
4	Downcomer clearing load
5	Downcomer water jet load
6	Pool-swell air bubble load
7	Fallback load
8	High mass flux condensation load
9	Medium mass flux condensation load
10	Chugging load
11	Wetwell/drywell P and T during DBA
12	Wetwell/drywell P and T during IBA
13	Wetwell/drywell P and T during SBA

Table 3A-13

WETWELL PIPING LOCA LOADING SITUATIONS

Piping Configuration	LOCA Load to be Applied
1. Completely Submerged	
(a) vertical	skin drag load only (C_f)
(b) horizontal	drag load (C_D)
2. Partially Submerged	
(a) vertical	skin drag load only (C_f)
3. Initially Uncovered	
(a) vertical	skin drag load only (C_f)
(b) horizontal	impact load, then drag load (C_D)

Table 3A-14

LOAD COMBINATIONS FOR CONCRETE DESIGN IN CONTAINMENT, REACTOR ENCLOSURE, AND CONTROL STRUCTURES
(CONSIDERING HYDRODYNAMIC LOADS)

Equation	Load Condition	D	L	P_o	T_o	R_o	E_o	E_{ss}	P_B	P_A	T_A	B_A	R_V	SRV	AOT[1]	ADS	ASYM	Single Valve	LOCA[3]
1	Normal w/o Temp.	1.4	1.7	1.0	-	-	-	-	-	-	-	-	-	1.5	X[2]	X	X	-	-
2	Normal w/Temp.	1.0	1.3	1.0	1.0	1.0	-	-	-	-	-	-	-	1.3	X	-	X	-	-
3	Normal Sev. Env.	1.0	1.0	1.0	1.0	1.0	1.25	-	-	-	-	-	-	1.25	X	-	X	-	-
4	Abnormal	1.0	1.0	-	-	-	-	-	1.25	-	1.0	1.0	-	1.25	-	X	X	-	X
4a	Abnormal	1.0	1.0	-	-	-	-	-	-	1.25	1.0	1.0	-	1.0	-	-	-	X	X
5	Abnormal Sev. Env.	1.0	1.0	-	-	-	1.1	-	1.1	-	1.0	1.0	-	1.1	-	X	X	-	X
5a	Abnormal Sev. Env.	1.0	1.0	-	-	-	1.1	-	-	1.1	1.0	1.0	-	1.0	-	-	-	X	X
6	Normal Ext. Env.	1.0	1.0	1.0	1.0	1.0	-	1.0	-	-	-	-	-	1.0	X	-	X	-	-
7	Abnormal Ext. Env.	1.0	1.0	-	-	-	-	1.0	1.0	-	1.0	1.0	1.0	1.0	-	X	X	-	X
7a	Abnormal Ext. Env.	1.0	1.0	-	-	-	-	1.0	-	1.0	1.0	1.0	1.0	1.0	-	-	-	X	X

Table 3A-14 (Cont'd)

Load Description

D	=	Dead Loads
L	=	Live Loads
P_o	=	Operating Pressure Loads
T_o	=	Operating Temperature Loads
R_o	=	Operating Pipe Reactions
SRV	=	Safety Relieve Valve Loads
E_o	=	Operating Basis Earthquake
E_{ss}	=	Safe Shutdown Earthquake
P_B	=	SBA or IBA (LOCA) Pressure Load
B_A	=	Pipe Break Temperatures Reaction Loads
P_A	=	DBA (LOCA) Pressure Load
T_A	=	Pipe Break temperature Load
R_V	=	Reaction and jet forces associated with the pipe break
AOT	=	Abnormal Operating Transient
ADS	=	Automatic Depressurization System
ASYM	=	Asymmetric

(1) For columns designated AOT, ADS, ASYM, and Single Valve, only one of the four possible columns may be included in the load combination for any one equation. For example, in Equation 1, either AOT or ASYM may be considered with the other loads but not both AOT and ASYM simultaneously.

(2) X indicates applicability for the designated load combination.

(3) LOCA includes chugging, condensation oscillation, and large air bubble loads.

Table 3A-15

LOAD COMBINATIONS AND ALLOWABLE STRESSES FOR
STRUCTURAL STEEL COMPONENTS
(Suppression Chamber Columns, Downcomer Bracing,
and Reactor Enclosure Structural Steel)

Equation	Condition	Load Combination	Allowable Stress
1	Normal w/o Temp.	$D+L+P_o+SRV$	F_s
2	Normal w/ Temp.	$D+L+P_o+T_o+SRV$	F_s
3	Normal/ Severe	$D+L+P_o+T_o+E+SRV$	$1.25\ F_s$
4	Normal/ Extreme	$D+L+P_o+T_o+E'+SRV$	(1)
5	Abnormal	$D+L+P+(T_o+T_a)+R+SRV+LOCA$	(1)
6	Abnormal/ Severe	$D+L+P+(T_o+T_a)+R+E+SRV+LOCA$	(1)
7	Abnormal/ Extreme	$D+L+P+(T_o+T_a)+R+E'+SRV+LOCA$	(1)

(1) In no case shall the allowable stress exceed $0.90\ F_y$ in bending, $0.85\ F_y$ in axial tension or compression, and $0.50\ F_y$ in shear. Where the design is governed by requirements of stability (local or lateral buckling), the actual stress shall not exceed $1.5\ F_s$.

Table 3A-15 (Cont'd)

Notations:

F_s	=	Allowable stress according to the AISC, "Specification for the Design, Fabrication, and Erection of Structural Steel for Building," dated 1969, Part 1
F_y	=	Minimum specified yield strength
D	=	Dead load
L	=	Live load
T_o	=	Thermal effects during normal operating conditions including temperature gradients and equipment and pipe reactions
T_a	=	Added thermal effects (over and above operating thermal effects) that occur during a design accident
P_o	=	Operating Pressure Load
P	=	Design basis accident pressure load
R	=	Local force or pressure on structure due to postulated pipe rupture including the effects of steam/water jet impingement, pipe whip, and pipe reaction
E	=	Load due to operating basis earthquake
E'	=	Load due to safe shutdown earthquake
SRV	=	Safety relief valve loads
LOCA	=	Loads due to loss-of-coolant accident conditions (chugging, condensation oscillation, or large air bubble loads)

Table 3A-16

LOAD COMBINATIONS AND ALLOWABLE STRESSES FOR
ASME CLASS MC COMPONENTS

The drywell head assembly, equipment hatches, personnel lock suppression chamber access hatches, CRD removal hatch, and piping and electrical penetrations are designed for the following loading combinations and allowable stresses:

Equation	Condition	Load Combination	Stress Limits
1	Normal	D+L+1.15P	1.15 times ASME Section III, Class B
2	Normal	$D+L+T_A+P$	ASME Section III, Class B
3	Emergency	$D+L+T_A+P+H_A+R+E$	ASME Section III, Summer 1970 Addenda, Figure N-414
4	Faulted	$D+L+T_A+P+H_A+R+E'$	ASME Section III, Summer 1970 Addenda, Figure N-414
5	Normal w/Temp.	$D+L+T_o$ +SRV	ASME Section III, Class MC Components
6	Abnormal/ Severe	$D+L+T_A+P+H_A+R+E$ +SRV+LOCA	ASME Section III, Fig. NB-3224-1 for "Emergency Conditions"
7	Abnormal/ Extreme	$D+L+T_A+P+H_A+R+E'$ +SRV+LOCA	ASME Section III, Fig. NB-3225-1 for "Faulted Conditions"

Definitions

D = Dead load

L = Live Load

T_o = Thermal effects due to temperature gradient through the wall, under operating conditions

T_A = Thermal effects due to temperature gradient through the wall, under accident conditions

P = Design basis accident pressure load

Table 3A-16 (Cont'd)

R	=	Steam/water jet forces or reactions resulting from the rupture of process piping
E	=	Load due to the operating basis earthquake
E'	=	Load due to the design basis earthquake
B	=	Hydrostatic loading due to postaccident flooding of the primary containment to the level of the reactor core
H_A	=	Force on the structure due to thermal expansion of pipes, under accident conditions
SRV	=	Safety/relief valve loads
LOCA	=	Loads due to loss-of-coolant accident conditions (chugging, condensation oscillation, annulus pressurization or large air bubble loads)

Table 3A-17

LOAD COMBINATIONS AND ALLOWABLE STRESSES FOR DOWNCOMERS

Equation	Condition	Load Combination	Allowable Stress
1	Upset	$D+P_o+SRV_{ALL}$	1.5 S_m
2	Emergency	$D+P_o+SRV_{ALL}+E$	2.25 S_m
3	Emergency	$D+P_{SBA}+SRV_{ADS}+E+LOCA(SBA)$	2.25 S_m
4	Faulted	$D+P_o+SRV_{ALL}+E'$	3 S_m
5	Faulted	$D+P_{IBA}+SRV_{ADS}+E+LOCA(IBA)$	3 S_m
6	Faulted	$D+P_{SBA}$ (or P_{IBA}) $+SRV_{ADS}+E'+LOCA(SBA \text{ or } IBA)$	3 S_m
7	Faulted	$D+P_A+E'+LOCA(DBA)$	3 S_m

Notations:

S_m = Maximum allowable stress

D = Dead weight of the downcomer

P_o = Pressure differential between drywell and suppression chamber during normal operating condition

P_{SBA} = Pressure differential between drywell and suppression chamber during SBA.

P_{IBA} = Pressure differential between drywell and suppression chamber during IBA.

P_A = Pressure differential between drywell and suppression chamber during DBA.

SRV_{ALL} = Dynamic lateral pressure and inertia load due to the discharge of all 14 safety/relief valves simultaneously.

Table 3A-17 (Cont'd)

SRV_{ADS} = Dynamic lateral pressure and inertia load due to the discharge of all 5 ADS safety/relief valves simultaneously.

E = Load due to operating basis earthquake

E' = Load due to safe shutdown earthquake

LOCA = Loads due to chugging, condensation oscillation, or air bubble loads. The governing applicable loading case should be considered. The loads should include:

1. Lateral load at the tip of the downcomer
2. Horizontal and vertical inertial loads
3. Submerged structure loads

Table 3A-18

LOAD COMBINATIONS AND STRESS LIMITS FOR BOP PIPING SYSTEMS

Equation	Condition	Load Combination	Stress Limit
1	Design	PD	NB-3652 NC-3600, ND-3600
2	Normal	PD + DW	NB-3654, NC-3600, ND-3600
3	Upset	(a) $PO+DW+(OBE^2+SRV_x^2)^{1/2}$ (b) $PO+DW+(RVC^2+OBE^2)^{1/2}$ (c) PO+DW+FV (d) PO+DW+OBE+RVO	NB-3654, NC-3600, ND-3600
4	Emergency	(a) $PO+DW+(OBE^2+SRV_{ADS}^2+SBA^2)^{1/2}$ (b) $PO+DW+(FV^2+OBE^2)^{1/2}$	NB-3655, NC-3600, ND-3600
5	Faulted	(a) $PO+DW+(OBE^2+SRV_{ADS}^2+IBA^2)^{1/2}$ (b) $PO+DW+(SSE^2+SRV_{ADS}^2+IBA^2)^{1/2}$ (c) $PO+DW+(SSE^2+DBA^2)^{1/2}$	NB-3656 ASME Code Case 1606

Notations:

PD = Design pressure

PO = Operating pressure

DW = Dead weight

OBE = Operating basis earthquake (inertia portion)

SSE = Safe shutdown earthquake (inertia portion)

SRV_x = Loads due to safety/relief valve blow, axisymmetric or asymmetric

Table 3A-18 (Cont'd)

SRV_{ADS}	=	Load due to automatic depressurization SRV blow, axisymmetric
SBA	=	Small break accident(1)
IBA	=	Intermediate break accident(1)
DBA	=	Design basis accident(1)
FV	=	Transient response of the piping system associated with fast valve closure (transients associated with valve closure times less than 5 seconds are considered)
RVC	=	Transient response of the piping system associated with relief valve opening in a closed system
RVO	=	Sustained load or response of the piping system associated with relief valve opening in an open system or last segment of the closed system with steady-state load

(1) SBA, DBA, and IBA include all event-induced loads, as applicable, such as chugging, condensation oscillation, pool-swell, annulus pressurization, etc.

Table 3A-19

LOAD COMBINATIONS AND ACCEPTANCE CRITERIA FOR
ASME CLASS 1, 2, AND 3 NSSS PIPING, EQUIPMENT, AND SUPPORTS

LOAD COMBINATION	DESIGN BASIS	EVALUATION[3] BASIS	SERVICE LEVEL
N + $SRV_{(ALL)}$	Upset	Upset	(B)
N + OBE	Upset	Upset	(B)
N + OBE + $SRV_{(ALL)}$	Emergency	Upset	(B)
N + SSE + $SRV_{(ALL)}$	Faulted	Faulted	(D)[1]
N + SBA + SRV	Emergency	Emergency	(C)[1]
N + SBA + $SRV_{(ADS)}$	Emergency	Emergency	(C)[1]
N + SBA/IBA + OBE + $SRV_{(ADS)}$	Faulted	Faulted	(D)[1]
N + SBA/IBA + SSE + $SRV_{(ADS)}$	Faulted	Faulted	(D)[1]
N + LOCA[2] + SSE	Faulted	Faulted	(D)[1]

LOAD DEFINITION LEGEND

N - Normal loads (e.g., weight, pressure, temperature, etc)

OBE - Operating basis earthquake loads

SSE - Safe shutdown earthquake loads

SRV - Safety/relief valve discharge induced loads from two adjacent valves (one valve actuated when adjacent valve is cycling)

SRV_{ALL} - Loads induced by actuation of all 14 safety/relief valves that activate within milliseconds of each other (e.g., turbine trip operational transient)

SRV_{ADS} - Loads induced by the actuation of all 5 safety/relief valves associated with automatic depressurization system that actuate within milliseconds of each other during the postulated small or intermediate size pipe rupture.

LOCA - Loss-of-coolant accident associated with the postulated pipe rupture of large pipes (e.g., main steam, feedwater, recirculation piping)

Table 3A-19 (Cont'd)

$LOCA_1$ - Pool-swell drag/fallback loads on piping and components located between the main vent discharge outlet and the suppression pool water upper surface

$LOCA_2$ - Pool-swell impact loads on piping and components located above the suppression pool water upper surface

$LOCA_3$ - Oscillating pressure induced loads on submerged piping and components during condensation oscillations

$LOCA_4$ - Building motion induced loads from chugging

$LOCA_5$ - Building motion induced loads from main vent air clearing

$LOCA_6$ - Vertical and horizontal loads on main vent piping

$LOCA_7$ - Annulus pressurization loads

SBA - Abnormal transients associated with a small break accident

IBA - Abnormal transients associated with an intermediate break accident.

---

(1) All ASME Class 1, 2 and 3 piping that are required to function for safe shutdown under the postulated events are designed to meet the requirements described in NEDO-21985 (Sept. 1978).

(2) The most limiting case of load combinations among $LOCA_1$ through $LOCA_7$.

(3) Evaluation basis in accordance with NRC requirements.

Table 3A-20

LOAD COMBINATIONS AND DAMPING VALUES FOR SAFETY-RELATED BOP EQUIPMENT IN THE PRIMARY CONTAINMENT, REACTOR ENCLOSURE, AND CONTROL STRUCTURES

Equation	Condition	Load Combination	Damping(1)
1	Upset	a. $N+[OBE^2 + SRV^2]^{1/2}$	2%
		b. N+OBE	0.5%
2	Emergency	a. $N+[OBE^2 + SRV^2 + SBA^2]^{1/2}$	2%
3	Faulted	a. $N+[OBE^2 + SRV^2 + IBA^2]^{1/2}$	2%
		b. $N+[SSE^2 + SRV^2 + IBA^2]^{1/2}$	2%
		c. $N+[SSE^2 + DBA^2]^{1/2}$	2%
		d. Envelope of a, b & c	2%
		e. N+SSE	1%
4	Worst	a. Envelope of 1a, 2 and 3d	2%

Notations:

N = Normal loads (dead weight + operating temp + operating pressure, etc.

OBE = Operating basis earthquake loads

SSE = Safe shutdown earthquake loads

SRV = Safety/relief valve discharge loads

SBA = Small break accident loads

IBA = Intermediate break accident loads

DBA = Design basis accident loads

(1) Where justified, a higher damping value may be used.

Table 3A-21

LOAD COMBINATIONS AND ALLOWABLE STRESSES FOR ELECTRICAL RACEWAY SYSTEM

Equation	Condition	Load Combination	Allowable Stress
1	Normal	D+L+SRV	F_s
2[1]	Normal/Severe	D+E	[2]
3	Abnormal/Extreme	D+E'+SRV+LOCA	[2,3]

Notations:

F_s = Allowable stress for normal condition

D = Dead weight of raceway and cables

L = A 200 lb concentrated live load is applied at any point on cable trays only between supports

E = Load due to operating basis earthquake

E' = Load due to safe shutdown earthquake

SRV = Safety/relief valve loads

LOCA = Loss-of-coolant accident loads

F_y = Minimum specified yield strength

Table 3A-21 (Cont'd)

(1) Applies only to connections for fatigue considerations.

(2) The following equation is applicable for connections:

$$\frac{5n_{EQ}}{N_{OBE}} + \frac{n_{EQ}}{N_{SSE}} \leq 1.0$$

where:

n_{EQ} = Total number of load/stress cycles per earthquake.

N_{OBE} = Allowable number of load/stress cycles per OBE event.

N_{SSE} = Allowable number of load/stress cycles per SSE event.

Allowable shear and normal loads on proprietary connection fittings shall be determined from the manufacturer's data or from code allowable stresses, whichever is applicable and as provided by Specification C-98.

(3) In no case shall the allowable stress exceed 0.90 F_y in bending, 0.85 F_y in axial tension or compression, and 0.50 F_y in shear. Where the design is governed by requirements of stability (local or lateral buckling), the actual stress shall not exceed 1.5 F_s.

Table 3A-22

LOAD COMBINATIONS AND ALLOWABLE STRESSES FOR HVAC DUCT SYSTEMS

DUCTS

Equation	Condition	Load Combination	Allowable Stress
1	Normal	D+L+SRV	F_s
2	Normal	$D+P_M$+SRV	F_s
3	Abnormal	$D+P_T$	1.25 F_s
4	Normal/Severe	$D+P_M$+E	1.25 F_s
5	Normal/Severe	$D+P_M$+E+SRV	1.25 F_s
6	Normal	D+Po	F_s
7	Normal/Severe	D+Po+E	1.25 F_s
8	Normal/Extreme	D+Po+E'	(2)
9	Normal/Extreme	$D+P_M$+E'+SRV	(2)
10	Normal/Abnormal	$D+P_O+P_A$+E'+SRV+LOCA	(2)
11	Normal/Abnormal	When protection against tornado depressurization is required:	
		$D+P_O+W_D$+SRV+LOCA	(2)
12	Extreme/Abnormal	For ducts inside drywell of containment, the following additional load combination is also applicable:	
		$D+H_A+P_O+P_A$+E'+SRV+LOCA	(2)

Table 3A-22 (Cont'd)

DUCT SUPPORTS

Equation	Condition	Load Combination	Allowable Stress
1	Normal	D+L+SRV	F_s
2	Normal/Severe	D+E	1.25 F_s (1)
3	Normal/Severe	D+E+SRV	1.25 F_s
4	Extreme/Abnormal	D+E'+SRV+LOCA	(2)

Notations:

D = Dead load

L = Live load

P_O = Duct normal operating pressure load

P_T = Duct test pressure load

P_A = Design basis accident pressure load

P_M = Duct maximum operating pressure load, excluding P_A & P_T, e.g., fan cutoff pressure load

E = Load due to operating basis earthquake

E' = Load due to safe shutdown earthquake

W_D = Tornado depressurization load

H_A = Forces due to thermal expansion of HVAC ducts under accident conditions

SRV = Safety/relief valve loads

LOCA = Loss-of-coolant accident loads

F_s = Allowable stress for steel, governed by AISI or AISC Codes, as applicable

F_y = Yield strength for steel (ASTM specification minimum)

Table 3A-22 (Cont'd)

(1) This value shall be F_s for transverse and longitudinal bracing and their connections.

(2) In no case shall be allowable stress exceed 0.90 F_y in bending, 0.85 F_y in axial tension or compression, and 0.50 F_y in shear. Where the design is governed by requirements of stability (local or lateral buckling), the actual stress shall not exceed 1.5 F_s.

Table 3A-23

REACTOR ENCLOSURE AND CONTROL STRUCTURE:
SUMMARY OF HYDRODYNAMIC ANALYSES AND
CORRESPONDING MATHEMATICAL MODELS

Load Case	SRV		CO		CHUGGING	
MODEL (Figure Number)	AXISYMMETRIC	ASYMMETRIC	BASIC	ADS	AXISYMMETRIC	ASYMMETRIC
Axisymmetric "FESS" Vertical Coupled Model (Figure 3A-33)	X		X	X	X	
Vertical Flexible Base Stick Model (Figure 3A.34)		X				X
Horizontal Flexible Base Sticl Model (Figure 3A-35)		X				X
Control Structure Floor Half-Model (Figure 3A-36)	X	X			X	X
Control Structure Floor Quarter Model (Figure 3A.37)			X	X		

Table 3A-24

CONTROL STRUCTURE FLOOR MODEL MATERIAL PROPERTIES

Control Structure Floor Elevation (ft)	Slab Thickness t (ft)	Equiv. Floor Element Thickness, t_{eff}	Floor Element Mass Density ρ' kip-s^2/ft^4
el 217	1.25 2.125, 2.5	2.66 3.26	.002554 .003334
el 239	1.0	2.93	.003241
el 253	1.0	2.61	.002538
el 269	1.5	2.63	.003219
el 289	1.5	2.96	.002610
el 304	1.0	2.50	.002145
el 331	2, 1.5	3.595 2.965	.0040821 .0044573

(1) Equivalent floor element thickness and mass density ρ' to take into account the beam-slab system action.

Table 3A-25

MAXIMUM SPECTRAL ACCELERATIONS OF CONTAINMENT DUE TO SRV AND LOCA LOADS AT 1% DAMPING

Type of Load	Direction	Elevation	Maximum Spectral Acceleration (g)	Structural Frequency (Hz)
SRV				
Axisymmetric	Vertical	312'-8"	1.09	14
	Horizontal	198'-9"	1.88	38
Asymmetric	Vertical	236'-2"	0.917	40
	Horizontal	207'-1"	1.15	25
CO	Vertical	236'-2"	3.2	40
	Horizontal	198"-9"	6.0	40
CO-ADS	Vertical	236'-2"	0.75	38
	Horizontal	205'-11"	1.16	42
Chugging	Vertical	236"-2"	1.76	40
	Horizontal	189'-5"	3.13	75

Table 3A-26

EXAMPLE COMPARISON OF SEISMIC FORCES ACTING ON FULLY LOADED AND EMPTY CABLE TRAYS

	Fully Loaded Tray (10% Damping)	Empty Tray (7% Damping)
Acceleration	a	4a
Weight	8w	w
Seismic Force (= Acceleration X Weight)	8aw	4aw

Table 3A-27

MAXIMUM CUMULATIVE USAGE FACTORS
FOR MSRV DISCHARGE LINES IN WETWELL AIR SPACE

Component	Calculated Cumulative Usage Factors	Code Cumulative Usage Factors
Flued head	0.401	1.0
Flush weld (weld between process pipe and flued head)	0.059	1.0
Short radius elbow	0.110	1.0
Long radius elbow	0.179	1.0
Tapered transition (thin end)	0.868	1.0
Tapered transition (thick end)	0.084	1.0
Tee	0.106	1.0
Flush weld for pipe anchor	0.870	1.0

Table 3A-28

SUMMARY OF BOP PIPING STRESSES

(UNIT 1)

Stress Ratio[1] = Maximum Stress / Allowable Stress

Maximum Calculated Stress (PSI)[3]

Piping System	I.C./O.C[2]	Reference Stress Calculation[4]
RWCU	I.C.	1-10-11B
	O.C.	P1-37-52
	O.C.	R1-37-53
RHR	I.C.	1-10-05
	O.C.	1-10-65B
	O.C.	P1-10-75
CS	I.C.	1-20-02
	O.C.	P1-20-54
	O.C.	P1-20-56
FPCC	I.C.	1-33-01
	I.C.	1-33-02
	O.C.	1-33-62
HPCI	I.C.	1-01-03
	O.C.	P1-10-72

Table 3A-28 (Cont'd)

SUMMARY OF BOP PIPING STRESSES
(UNIT 2)

Stress Ratio[1] = Maximum Stress / Allowable Stress

Piping System	I.C./O.C[2]	Maximum Calculated Stress (PSI)[3]	Reference Stress Calculation[4]
RWCU	I.C.		2-10-11
	O.C.		2-37-63
RHR	I.C.		2-10-05
	O.C.		2-10-84
	O.C.		2-10-83
CS	I.C.		2-20-02
	O.C.		2-20-64
	O.C.		2-20-63
FPCC	I.C.		2-33-02
	I.C.		2-33-01
	O.C		2-43-02
HPCI	I.C.		2-01-03
	O.C.		2-10-83

(1) Design Margin = 1 - Max. Stress / Allowable Stress

(2) I.C. = Inside Containment
O.C. = Outside Containment

(3) Calculated stresses are based on original analysis. Changes due to re-rate are small and stress ratios are less than 1.0. Changes due to “A” RWCU pump replacement result in stress ratios that are less than 1.0.

(4) Calculated stresses are maintained within the Reference Stress Calculation from the Table.

Table 3A-29

SYSTEM CHARACTERISTICS AND INPUT PARAMETERS

REACTOR	
Initial core power (105% Rated)	3.26×10^6 Btu/sec
Initial RPV liquid mass	608,142 lb_m
Initial RPV steam mass	24,669 lb_m
RPV and internals mass	2.772×10^6 lb_m
Initial vessel pressure	1025 psia
Initial steam flow (105% Rated)	4129 lb_m/sec
REACTOR MAKEUP	
Initial CRD flow	8.89 lb_m/sec
CRD flow after scram (P_{RPV} = 0 psig)	23.6 lb_m/sec
CRD enthalpy (from CST)	108 Btu/lb_m
Feedwater flow rate	as required to maintain RPV level

Feedwater mass/enthalpy

Mass (lb_m)	Enthalpy (Btu/lb_m)
165,385	402
256,919	342
370,885	235
359,442	156
235,746	126

HPCI "on" volume (RPV level 2)	12,675 ft^3
HPCI "off" volume (RPV level 8)	15,281 ft^3
VALVES	
MSIV closure time	3.5 sec
SRV flow rate (122.5% ASME)	390 lb_m/sec at 1500 psia
SRV setpoints	See Table 3A-29A

NOTE: The information presented in this table is based on the original design bais conditons. Refer to Section 6.2.1.8 for the initial conditions and methodology used to analyze current plant conditions.

Table 3A-29 (Cont'd)

RHR SYSTEM	
RHR heat exchanger effectiveness, K (shutdown cooling)	288.9 Btu/sec °F
RHR heat exchanger effectiveness, K (pool cooling)	288.9 Btu/sec °F
RHR flow rate in pool cooling	1390 lb_m/sec
RHR flow rate in shutdown cooling	1390 lb_m/sec
RHR pump horsepower	1250 hp/pump
RHRSW temperature	88°F at time = 0 sec 91.2°F at time = 18,000 sec 92.5°F at time = 36,000 sec
RHRSW flow rate	9000 gpm
Maximum reactor pressure for switch-over from RHR pool cooling to shutdown cooling	89.7 psia
WETWELL/SUPPRESSION POOL	
Wetwell airspace pressure	15.45 psia
Initial suppression pool water mass (at low water level, without water mass inside pedestal)	7.194×10^6 lb_m
Initial suppression pool temperature	95°F
Suppression pool temperature Technical Specification limits for:	
a. Continuous operation without suppression pool cooling	95°F
b. Continuous testing at power	105°F
c. Power operation (Scram Technical Specification temperature	110°F
d. Hot standby (Depressurization Technical Specification temperature)	120°F
Quencher submergence (at low water level)	18.5 feet

NOTE: The information presented in this table is based on the original design bais conditons. Refer to Section 6.2.1.8 for the initial conditions and methodology used to analyze current plant conditions.

Table 3A-29A

SRV SETPOINTS USED FOR SUPPRESSION POOL TEMPERATURE RESPONSE ANALYSIS

SAFETY/RELIEF VALVES

Number 14

Spring Set Pressures, Mass Flow Rates:

Valve	Set Pressure (psig)	Mass Flow (lb_m/hr) at 103% of Spring Set Pressure
A	1150	917,00
B	1150	917,000
C	1150	917,000
D	1140	909,000
E*	1140	909,000
F	1150	917,000
G	1150	917,000
H*	1130	301,500
J	1130	901,500
K*	1140	909,000
L	1130	901,500
M*	1140	909,000
N	1130	901,500
S*	1140	909,000

* ADS Valves

NOTE: The information presented in this table is historical and is based on the original design bais conditons. Refer to Table 3A-3 for the current SRV setpoints.

Table 3A-30

PEAK SUPPRESSION POOL TEMPERATURES[1]

EVENT	TEMPERATURE
1. SORV at Power	
Case 1.a	169°F
Case 1.b	187°F
2. Isolation/Scram	
Case 2.a	201°F
Case 2.b	183°F
3. SBA	
Case 3.a	202°F[2]
Case 3.b	182°F

(1) The information presented in this table for the suppression pool temperature response is based on the original design basis conditions. The current suppression pool temperature results are discussed in Section 3A.15.2. The results shown in this table reasonably represent the general characteristics and relative differences between the cases.

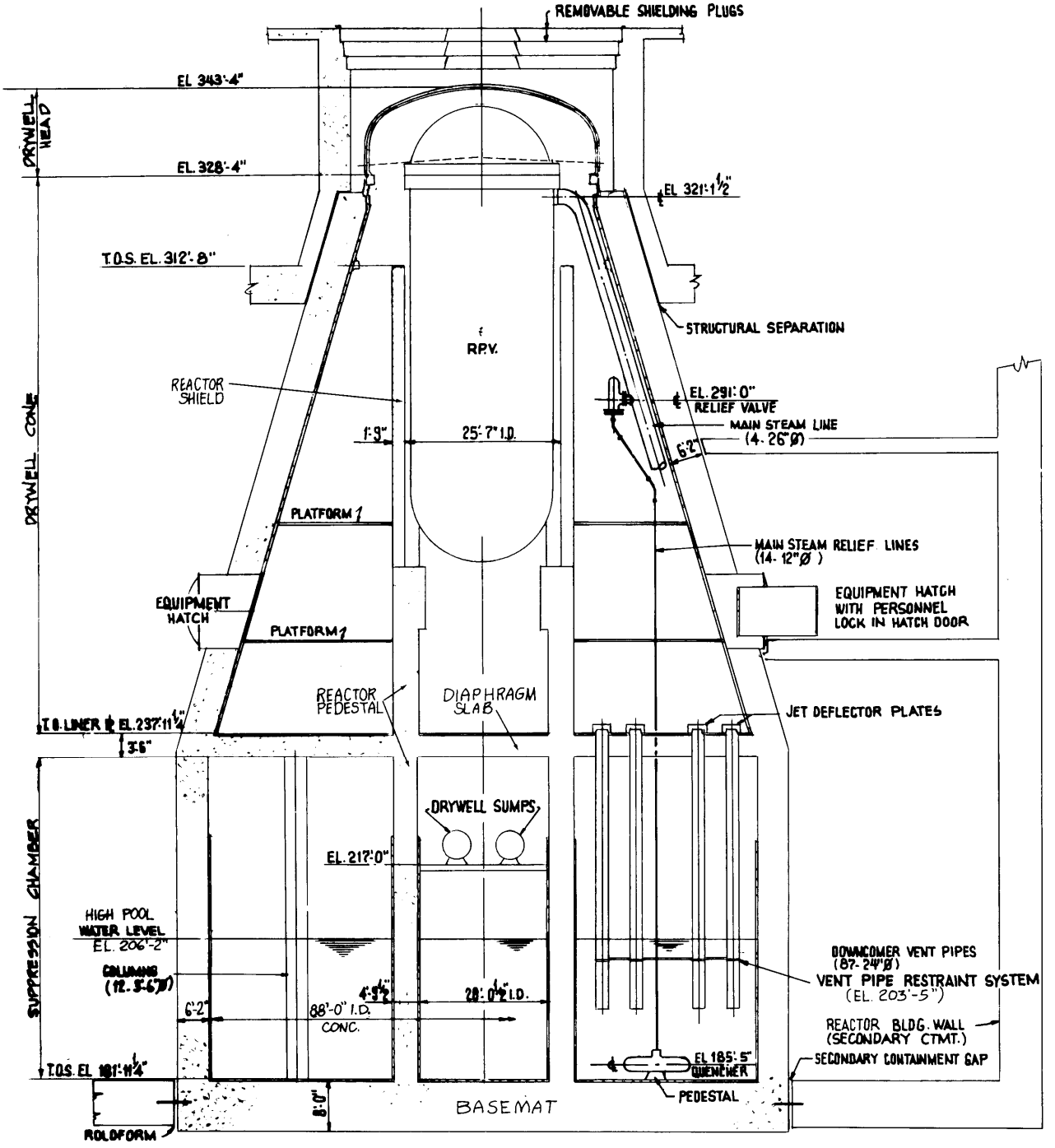
(2) The limiting case (Case 3.a) was reanalyzed for the current plant conditions and the resulting peak suppression pool temperature was 203°F.

Table 3A-31

MATERIAL PROPERTIES FOR ANALYTICAL ELEMENTS
OF THE AXISYMMETRIC SRV ANALYSIS MODEL

Element Material Type	Young's Modulus, E kip/ft^2	Material Density, ρ $kip\text{-}s^2/ft^4$	Poisson's Ratio	Shear Wave, V_s (ft/s)
Concrete	0.0936E+6*	0.00446	0.22	-
Steel	0.4176E+7	0.01524	0.33	-
Soil Medium	0.432E+6	0.00481	0.30	5950**

*The modulus represents a dynamic modulus of elasticity.
**The shear-wave velocity, V_s, is used to simulate a soil shear modulus ($G = V_s^2\rho$), equal to $0.166x10^6$ kip/ft^2.

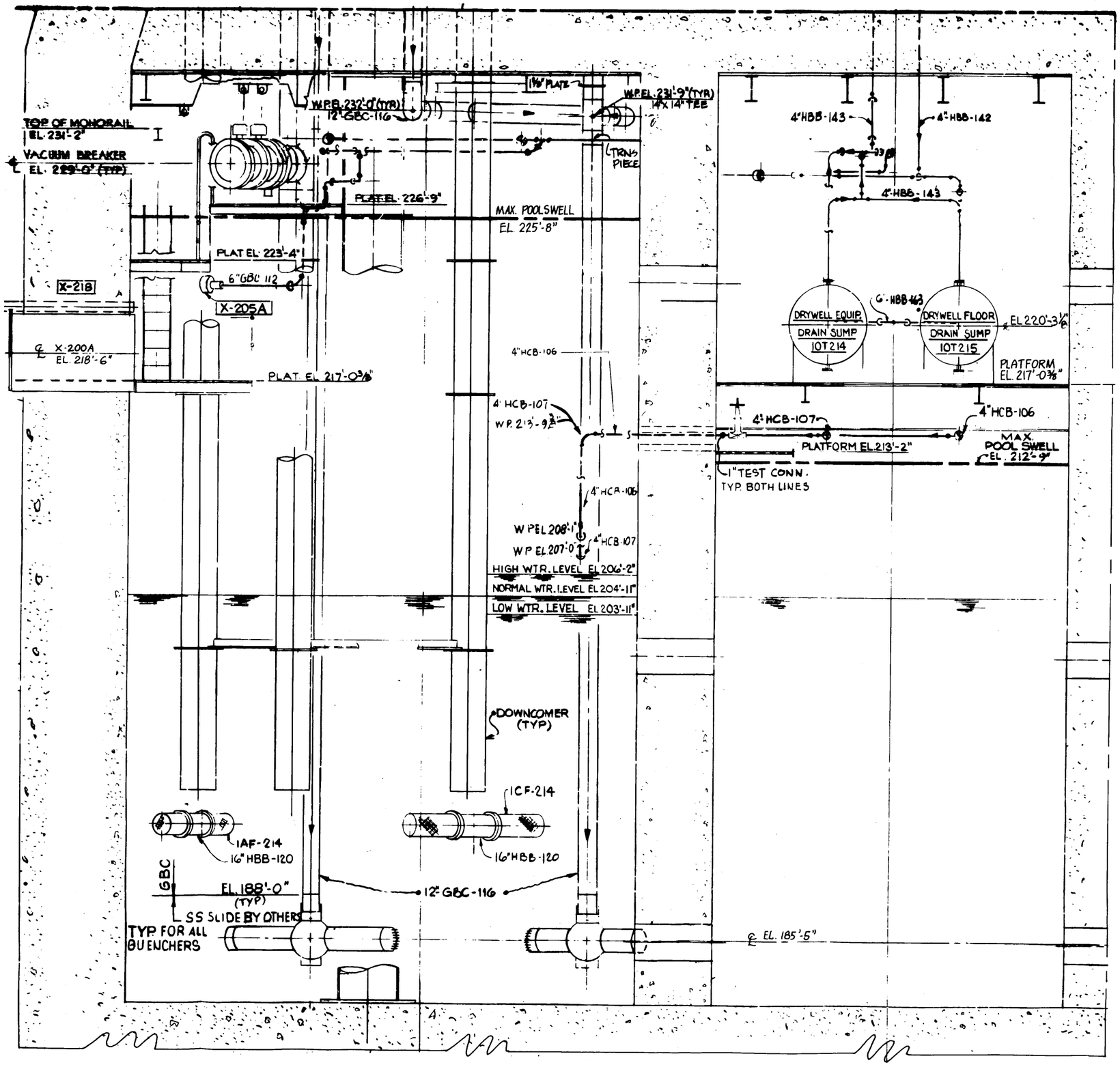


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

CROSS SECTION OF CONTAINMENT

FIGURE 3A-1

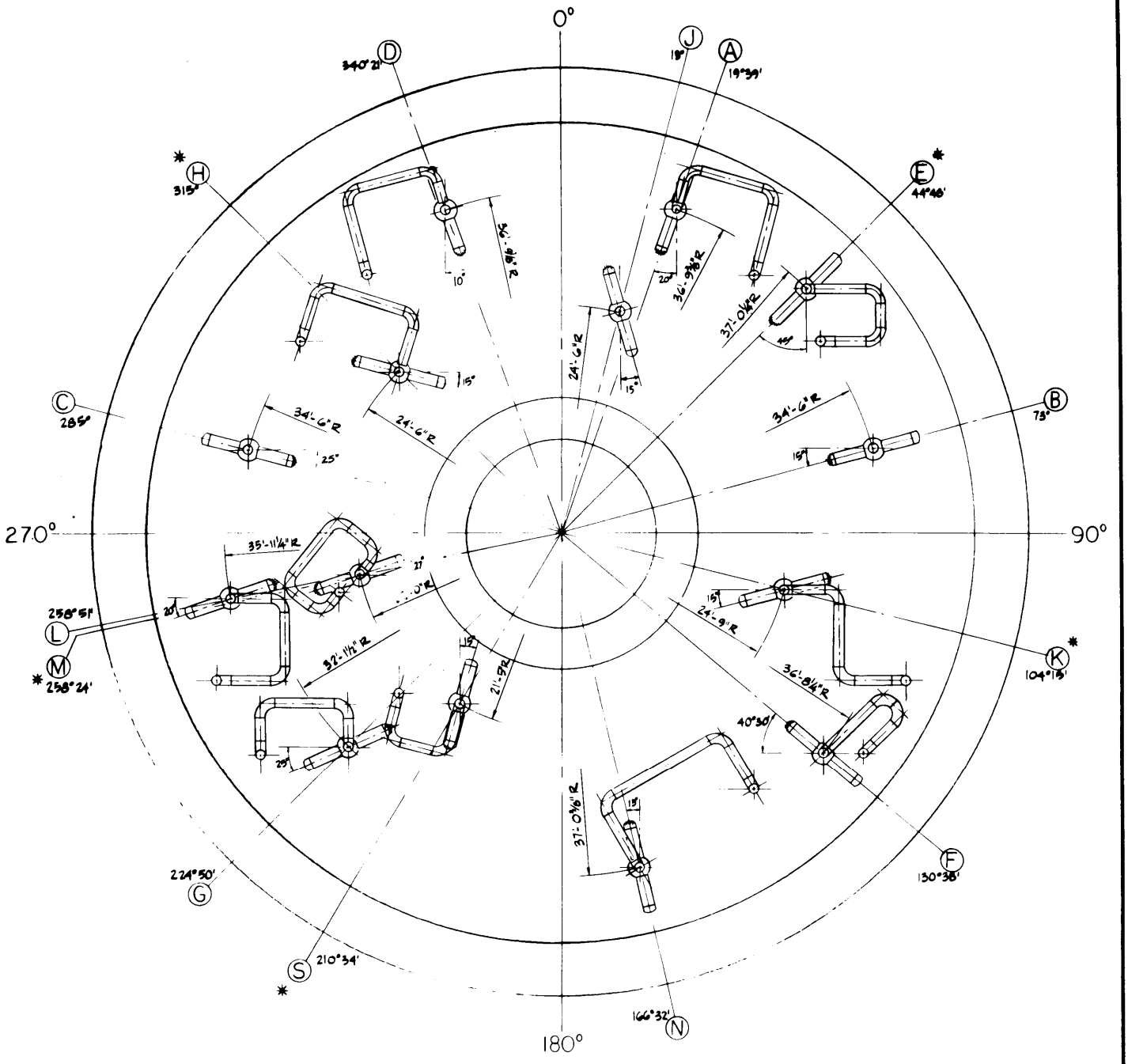


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

SUPPRESSION CHAMBER AND PEDESTAL INTERIOR - SECTION VIEW

FIGURE 3A-2



PLAN AT EL 181'-11"

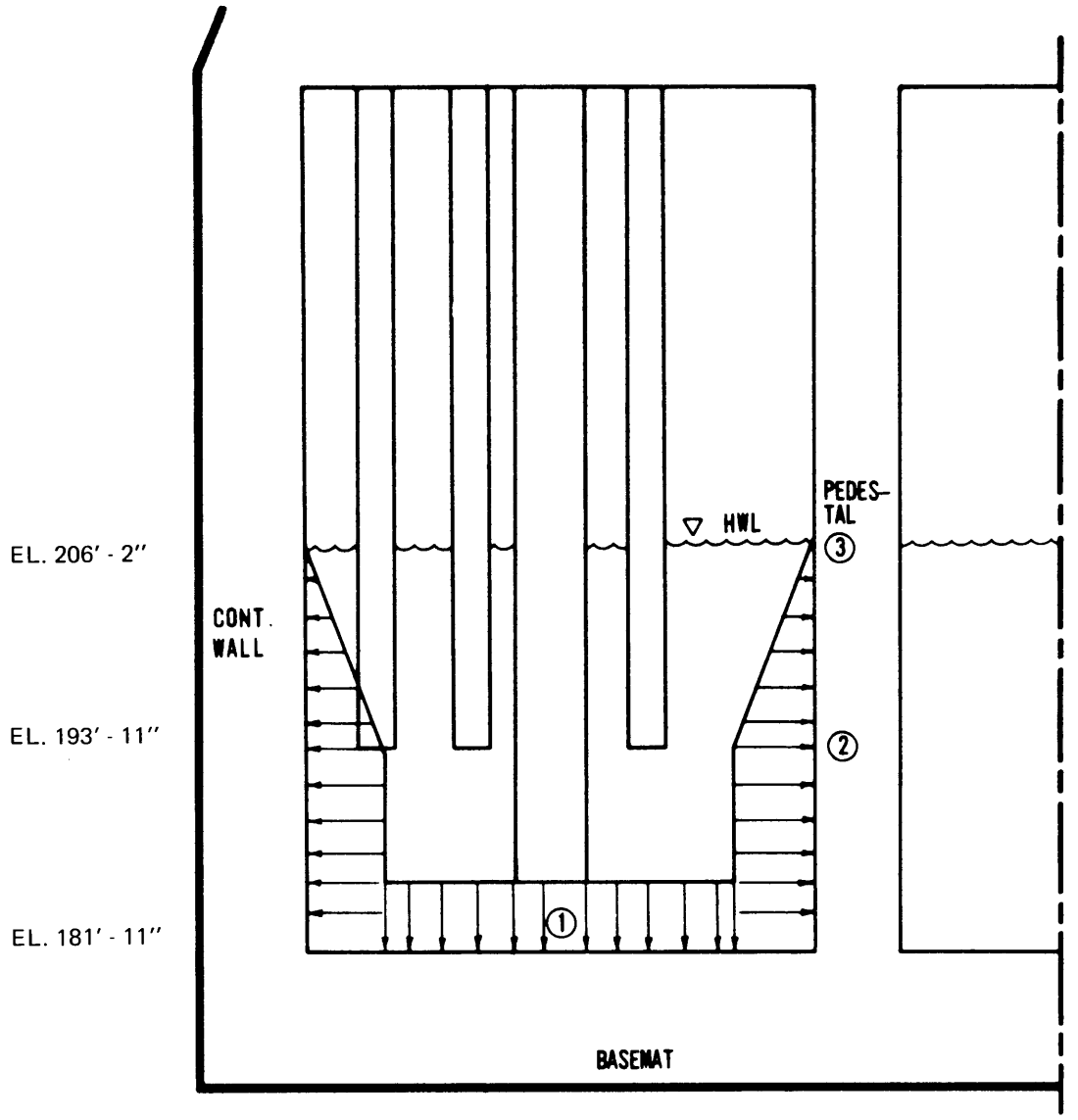
* A.D.S. VALVES. H,M,K,E,S.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

QUENCHER LOCATIONS AND ORIENTATION

FIGURE 3A-3



① 24 + 14.7 + 10.51 = 49.21 psia

② 24 + 14.7 + 5.2 = 43.9 psia

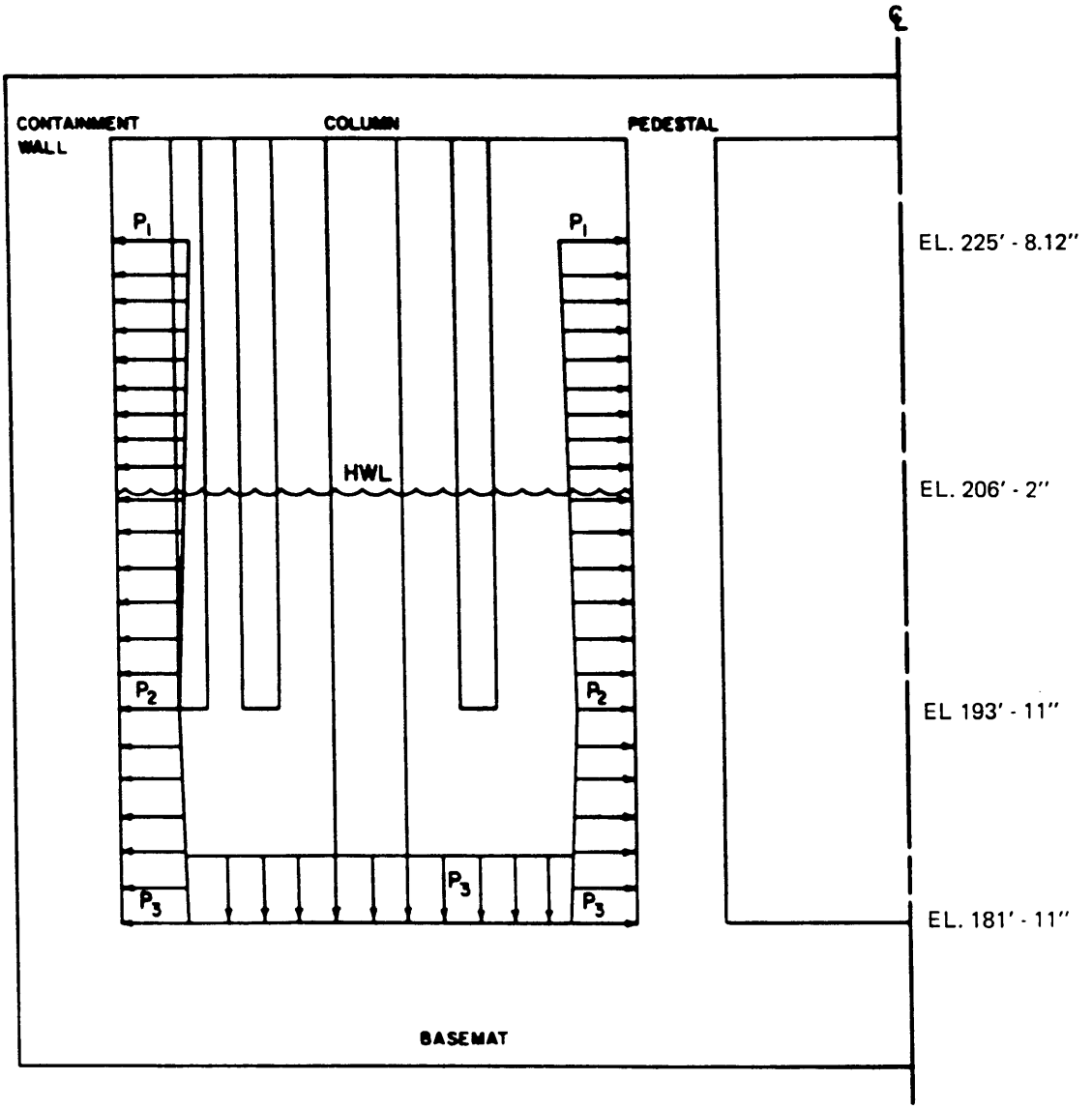
③ 0 + 14.7 + 0 = 14.7 psia

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VENT CLEARING PRESSURE DISTRIBUTION

FIGURE 3A-4



P_1 = 53.64 psia

P_2 = 48.25 psia

P_3 = 58.76 psia

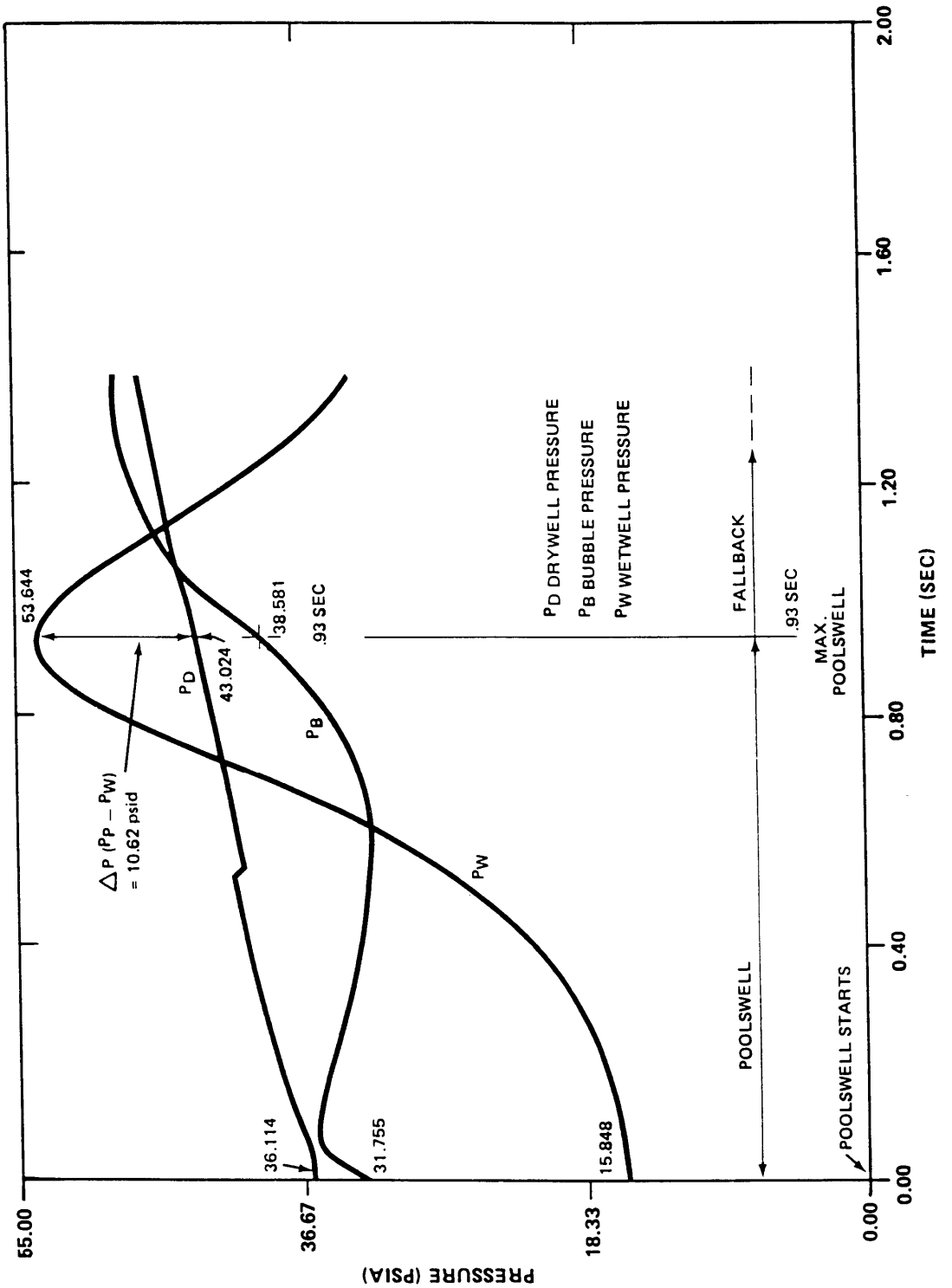
NOTE: The information presented in this figure is based on the original design basis conditions. Refer to Section 3A.4.2.1.4 for the pool swell air bubble distribution at the current operations.

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POOLSWELL AIR BUBBLE PRESSURE ON SUPPRESSION POOL WALLS

FIGURE 3A-5 Rev. 5, 4/96



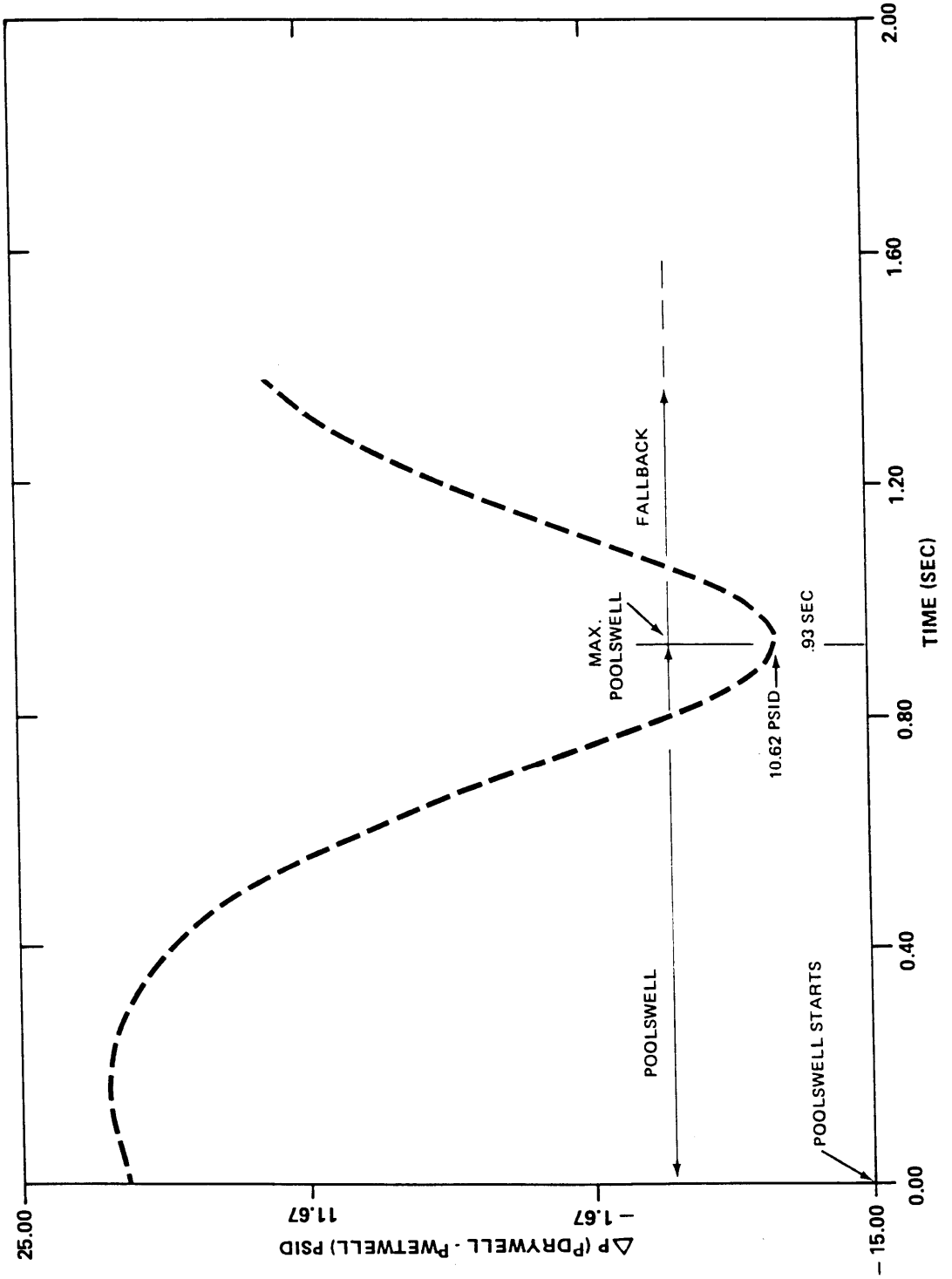
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Section 3A.4.2.1.6 for the pool swell evaluation at the current operating conditions. The results presented here reasonably represent the general characteristics of the pressure response during pool swell.

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WETWELL, DRYWELL, AND AIR BUBBLE PRESSURES DURING POOLSWELL

FIGURE 3A-6 Rev. 5, 4/96



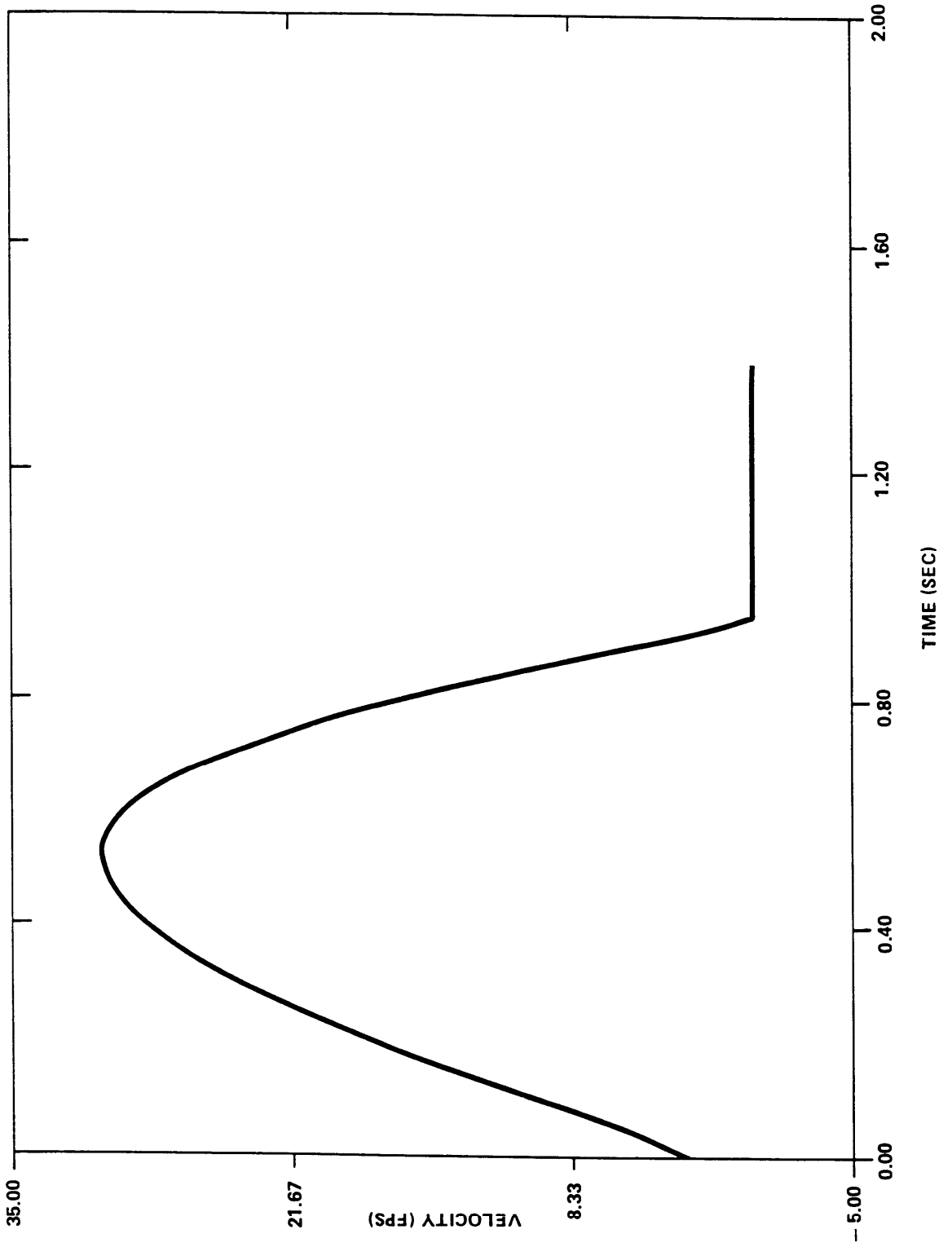
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Section 3A.4.2.1.6 for the pool swell evaluation at the current operating conditions. The results presented here reasonably represent the general characteristics of the pressure response during pool swell.

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DRYWELL AND WETWELL ΔP DURING POOLSWELL

FIGURE 3A-7 Rev. 5, 4/96



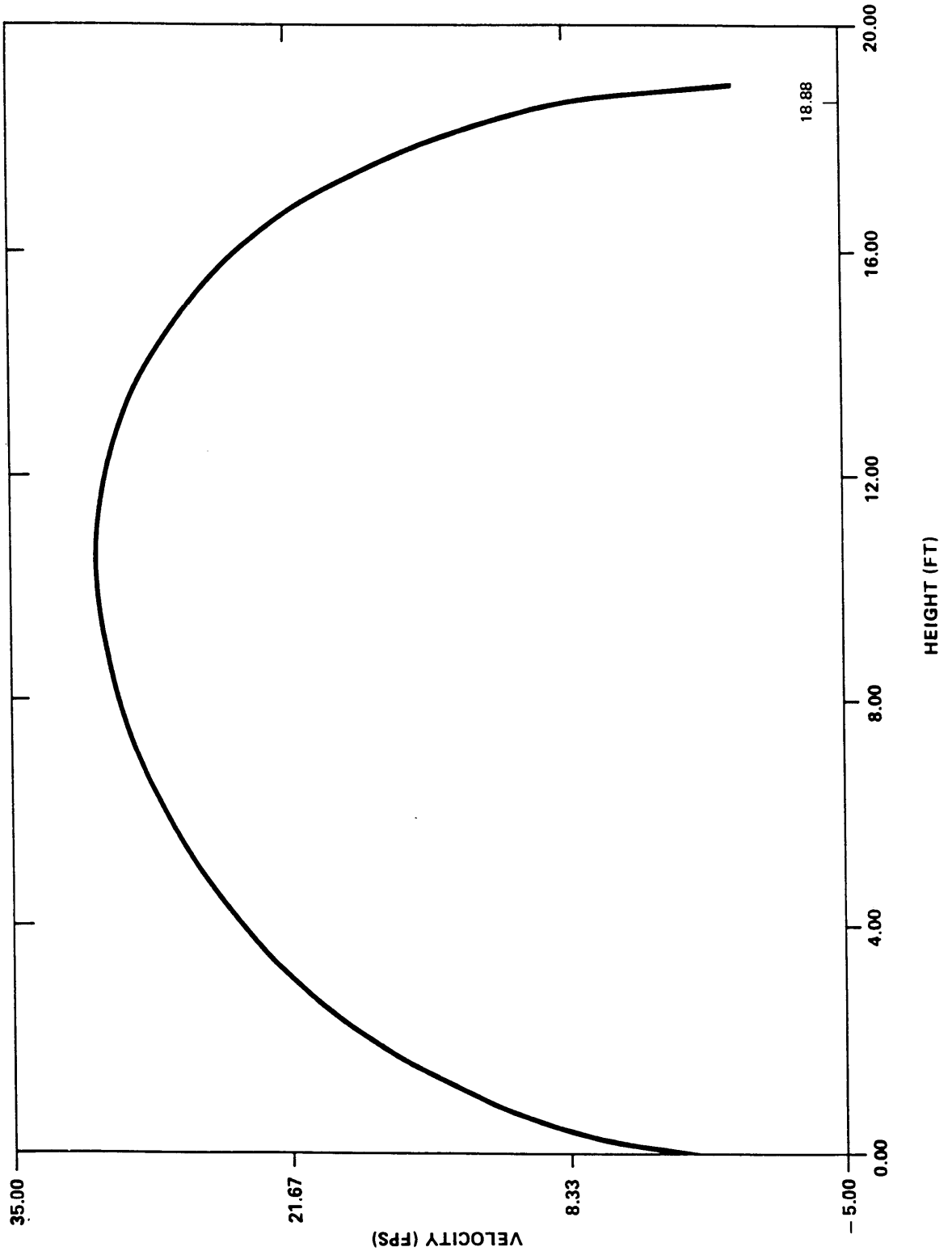
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Section 3A.4.2.1.6 for the pool swell evaluation at the current operating conditions. The results presented here reasonably represent the general characteristics of the pressure response during pool swell.

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POOL SURFACE VELOCITY DURING POOLSWELL

FIGURE 3A-8 Rev. 5, 4/96



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Section 3A.4.2.1.6 for the pool swell evaluation at the current operating conditions. The results presented here reasonably represent the general characteristics of the pressure response during pool swell.

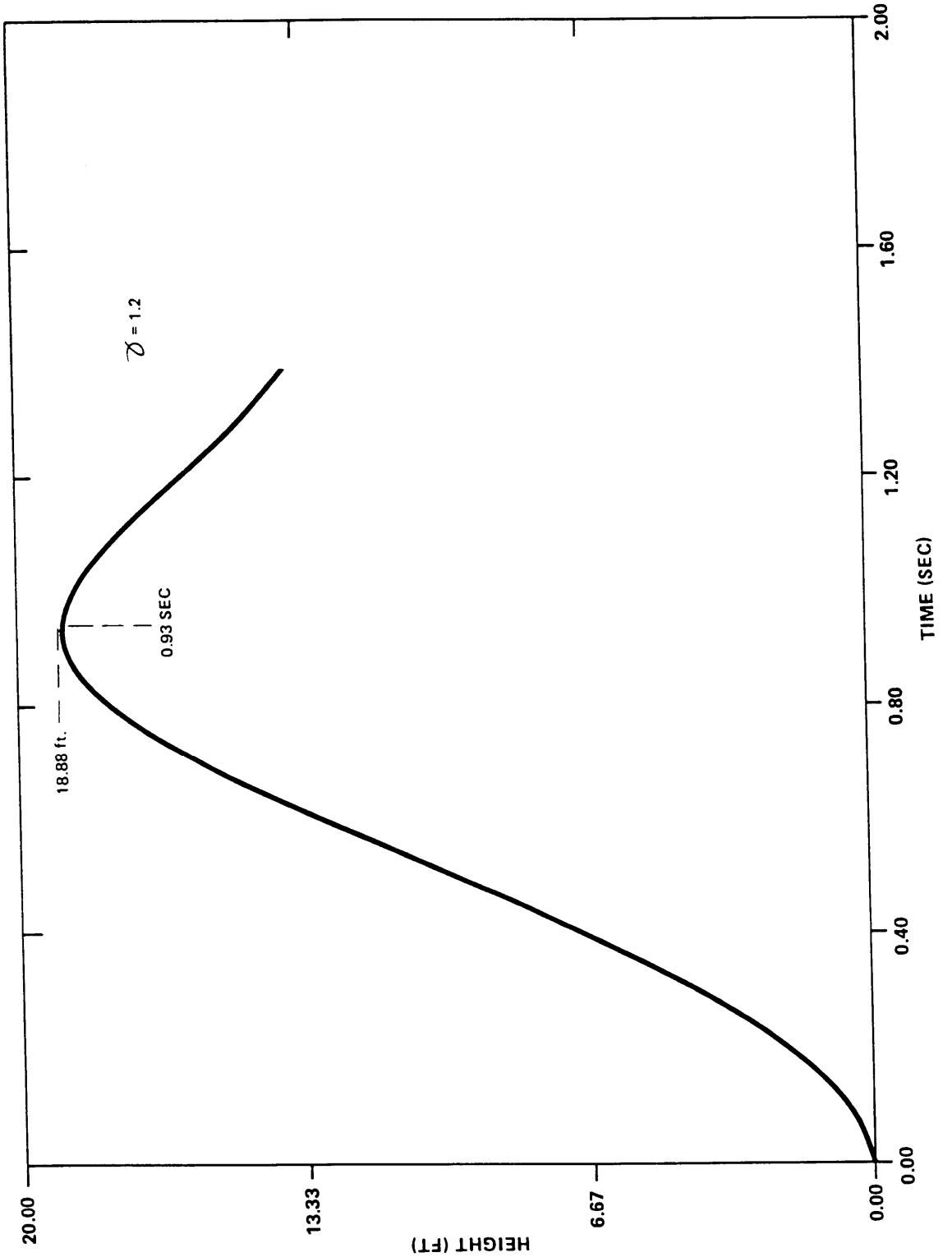
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POOL SURFACE VELOCITY VERSUS POOL HEIGHT

FIGURE 3A-9

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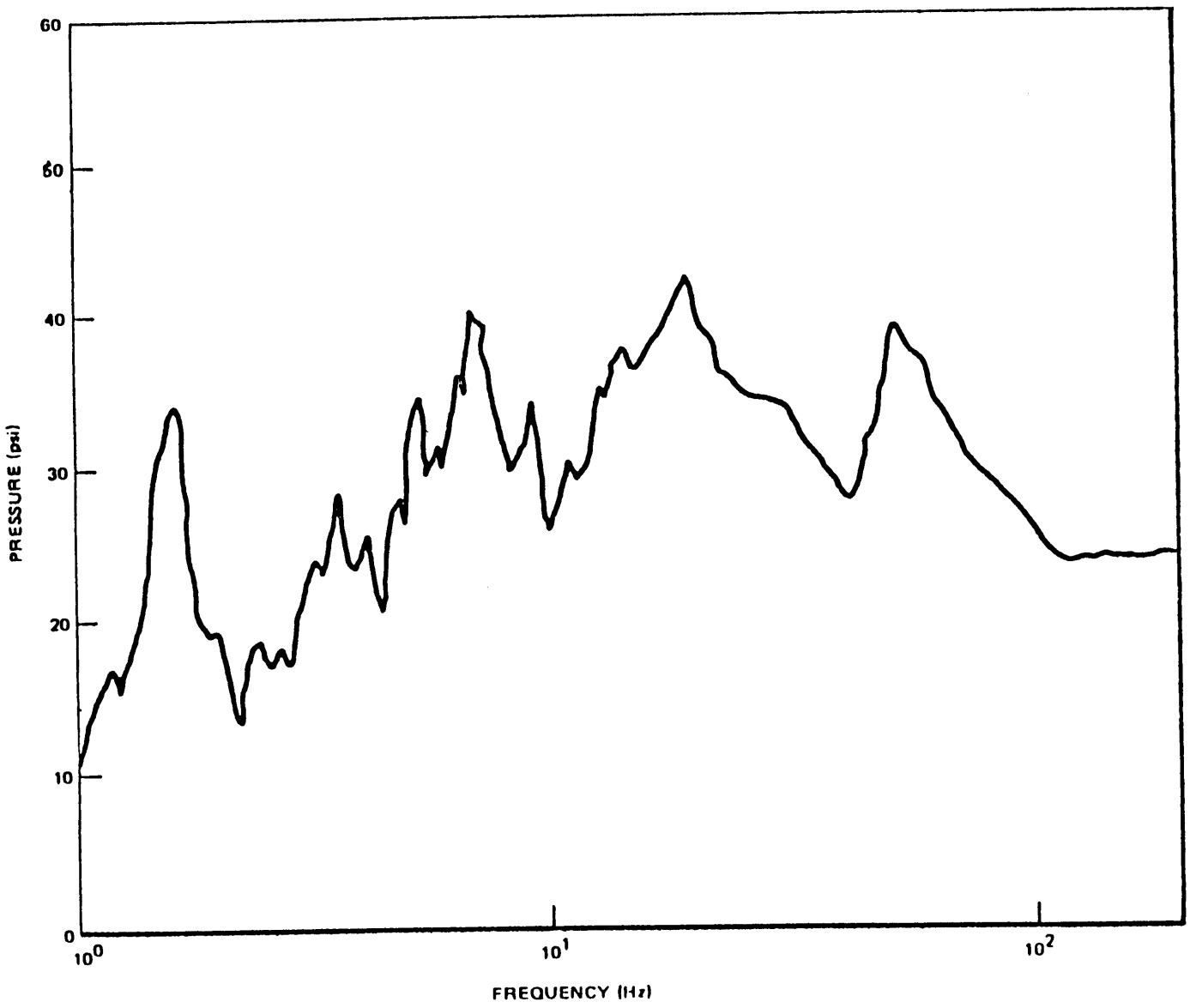
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Section 3A.4.2.1.6 for the pool swell evaluation at the current operating conditions. The results presented here reasonably represent the general characteristics of the pressure response during pool swell.

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POOL HEIGHT DURING POOLSWELL

FIGURE 3A-10 Rev. 5, 4/96

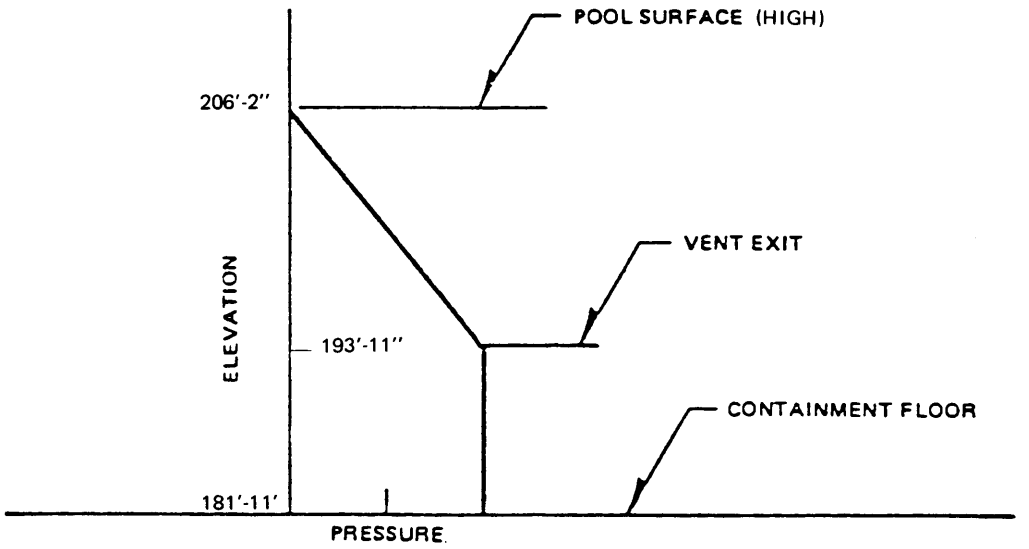


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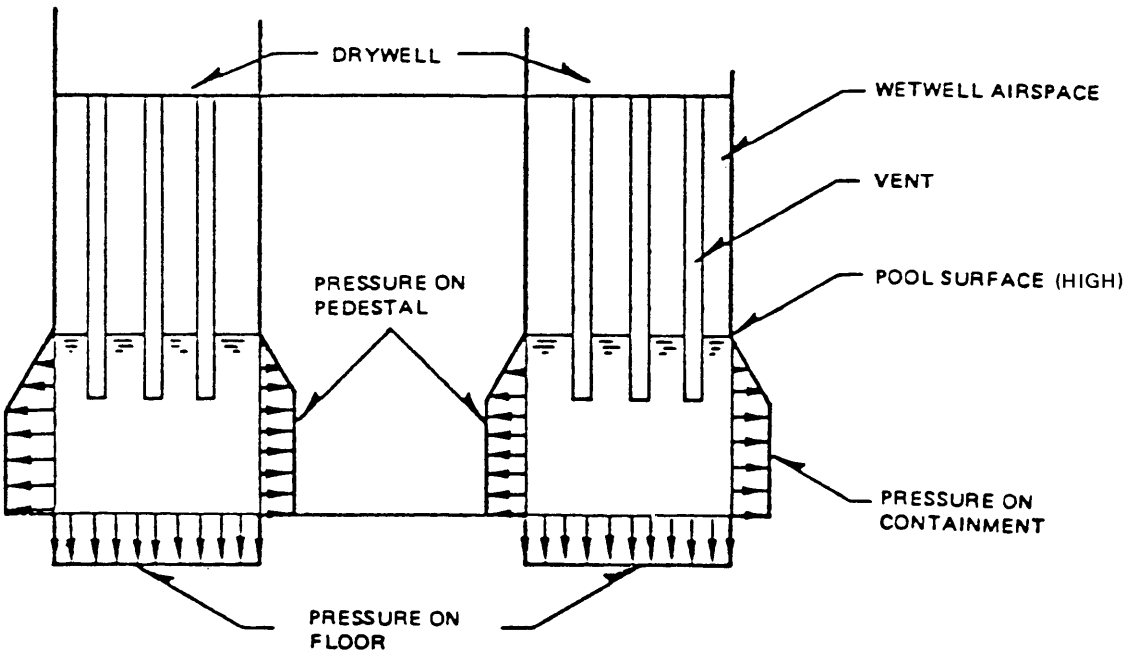
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PRESSURE-RESPONSE-SPECTRUM ENVELOPE FOR TIME PERIODS SELECTED FOR CO LOAD DEFINITION

FIGURE 3A-11



DETAIL OF PRESSURE DISTRIBUTION



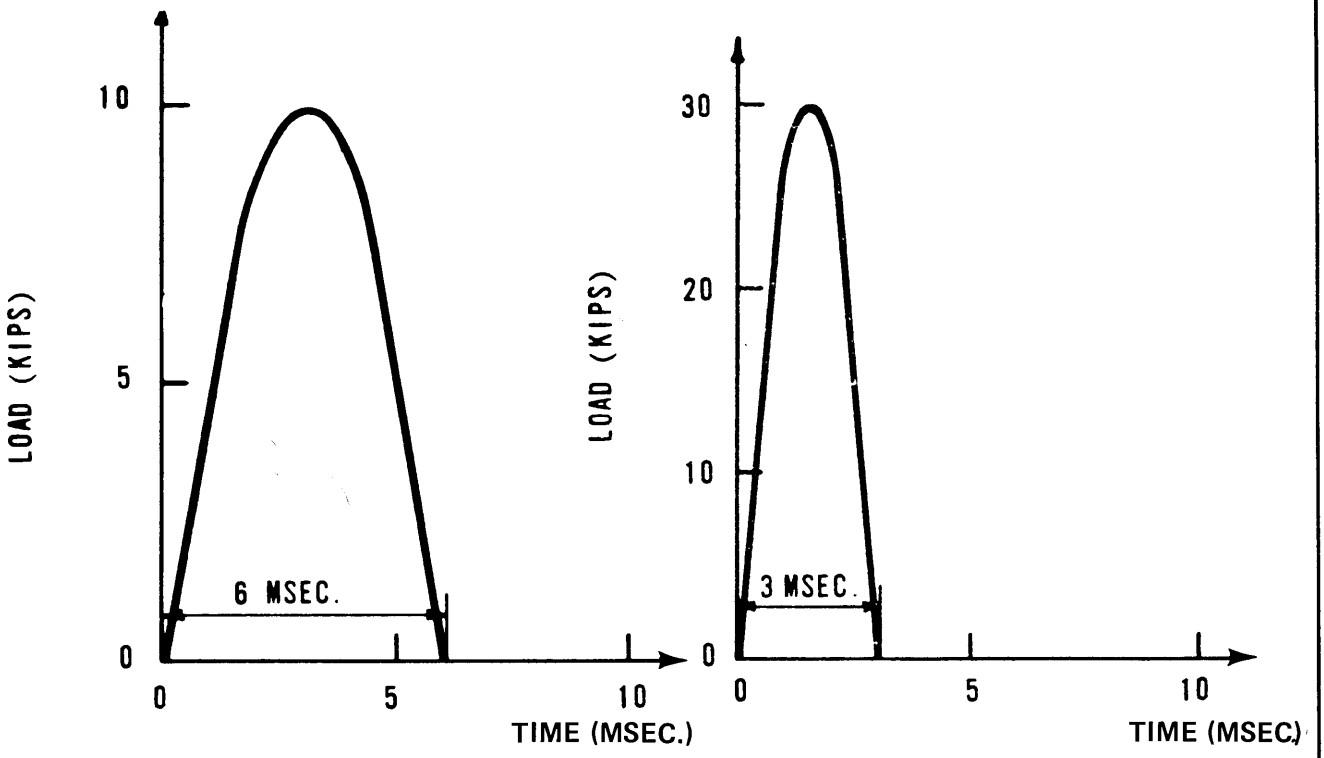
OVERVIEW OF PRESSURE DISTRIBUTION

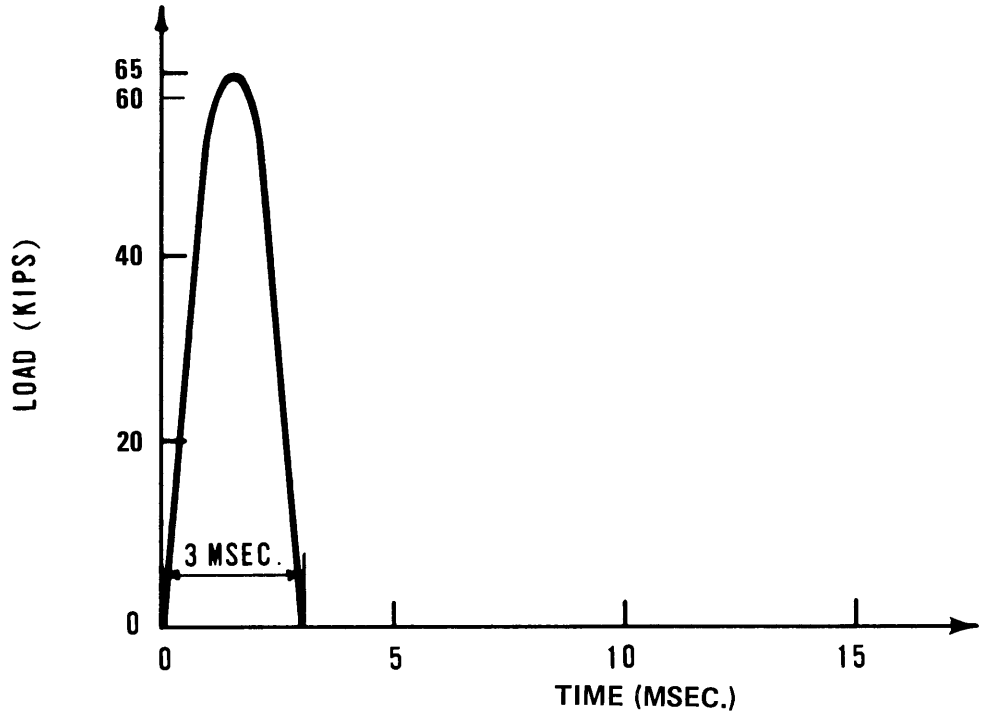
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SPATIAL DISTRIBUTION OF CO LOAD

FIGURE 3A-12



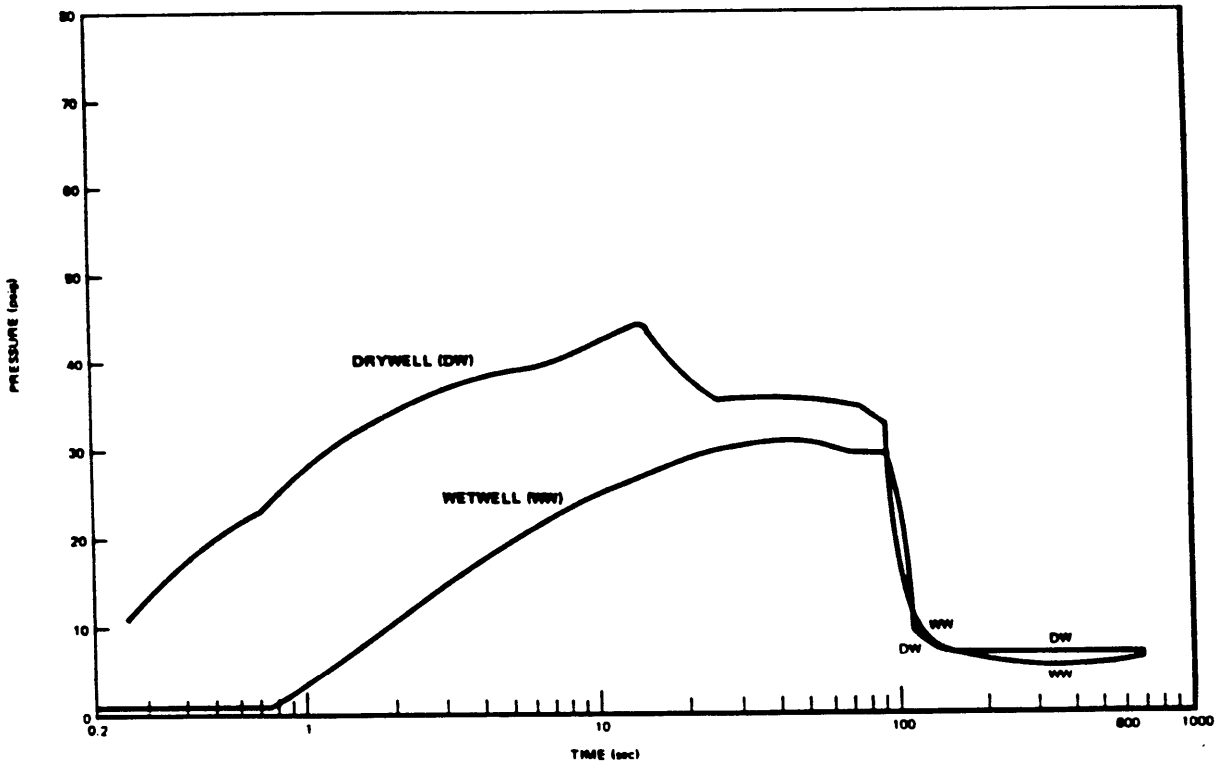


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DYNAMIC DOWNCOMER LATERAL LOAD DUE TO CHUGGING

FIGURE 3A-13



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Figure 6.2-3A for the recirculation line break results for current plant conditions.

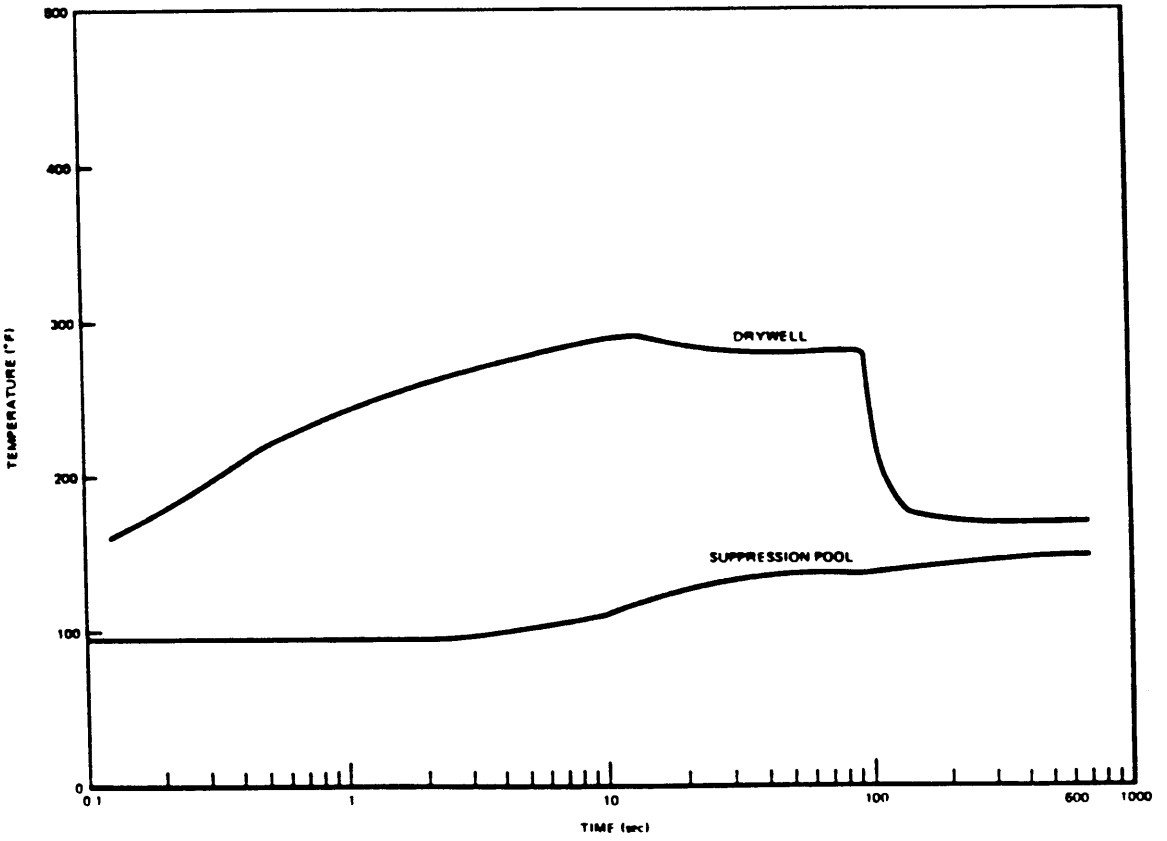
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SHORT-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK

FIGURE 3A-14

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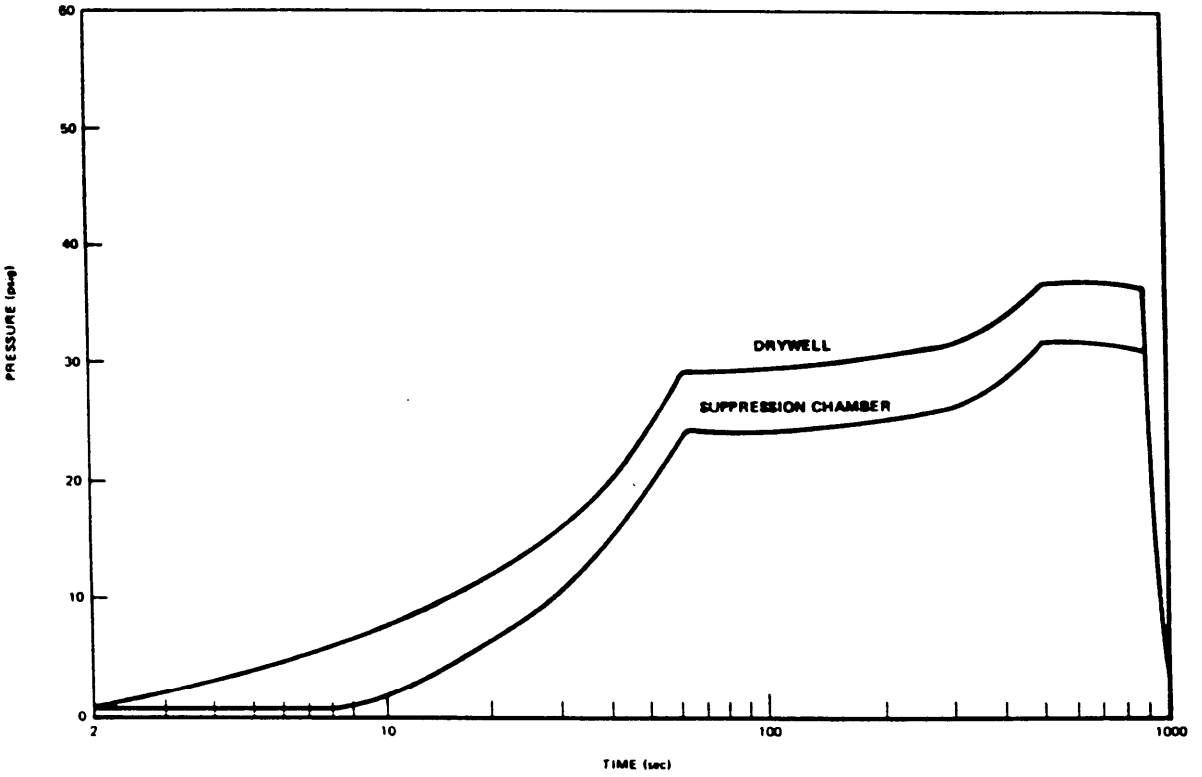
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Figure 6.2-4A for the recirculation line break results for current plant conditions.

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SHORT-TERM CONTAINMENT TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK

FIGURE 3A-15 Rev. 5, 4/96



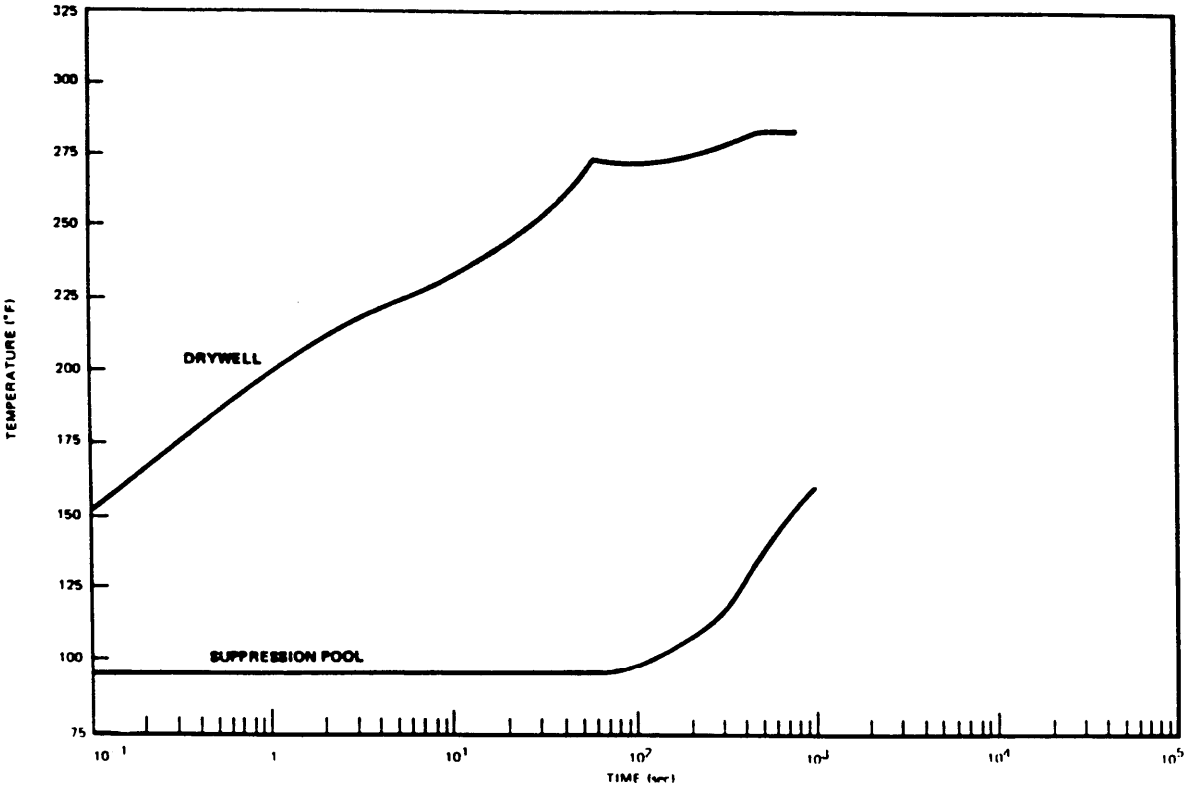
NOTE: The information presented in this figure is based on the original design basis conditions. As described in Section 6.2.1.1.3, the intermediate size break was not reanalyzed for the current conditions; however, the results presented here reasonably represent the general characteristics of an intermediate size break analysis results.

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SHORT-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING AN INTERMEDIATE SIZE BREAK (0.1 ft^2 LIQUID BREAK)

FIGURE 3A-16 Rev. 5, 4/96



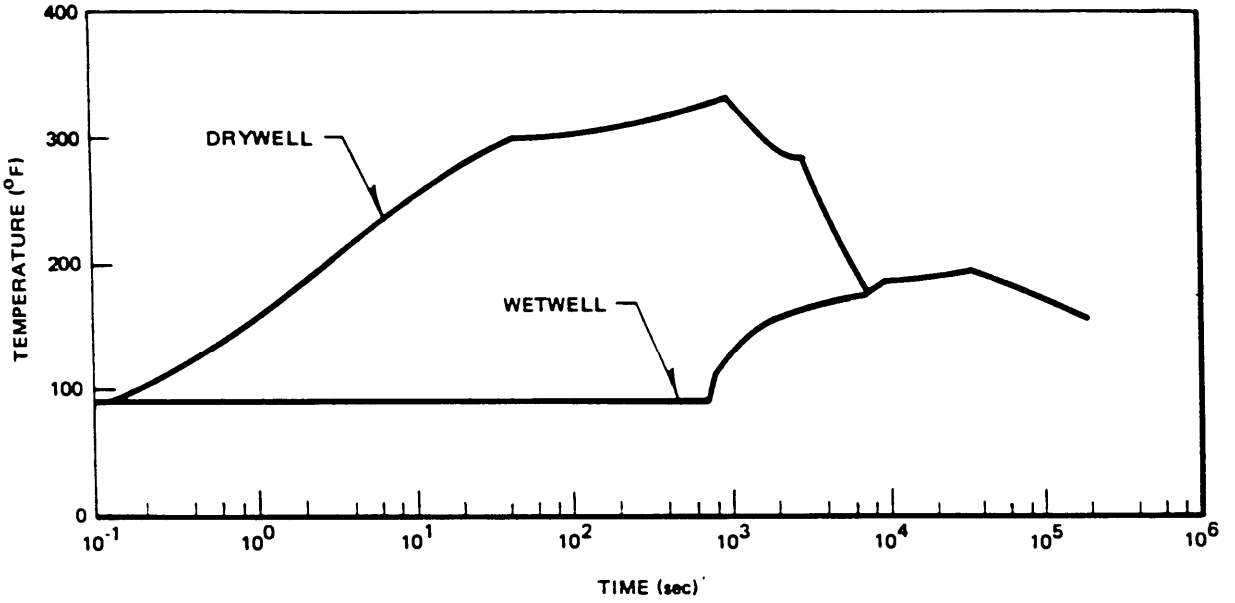
NOTE: The information presented in this figure is based on the original design basis conditions. As described in Section 6.2.1.1.3, the intermediate size break was not reanalyzed for the current conditions; however, the results presented here reasonably represent the general characteristics of an intermediate size break analysis results.

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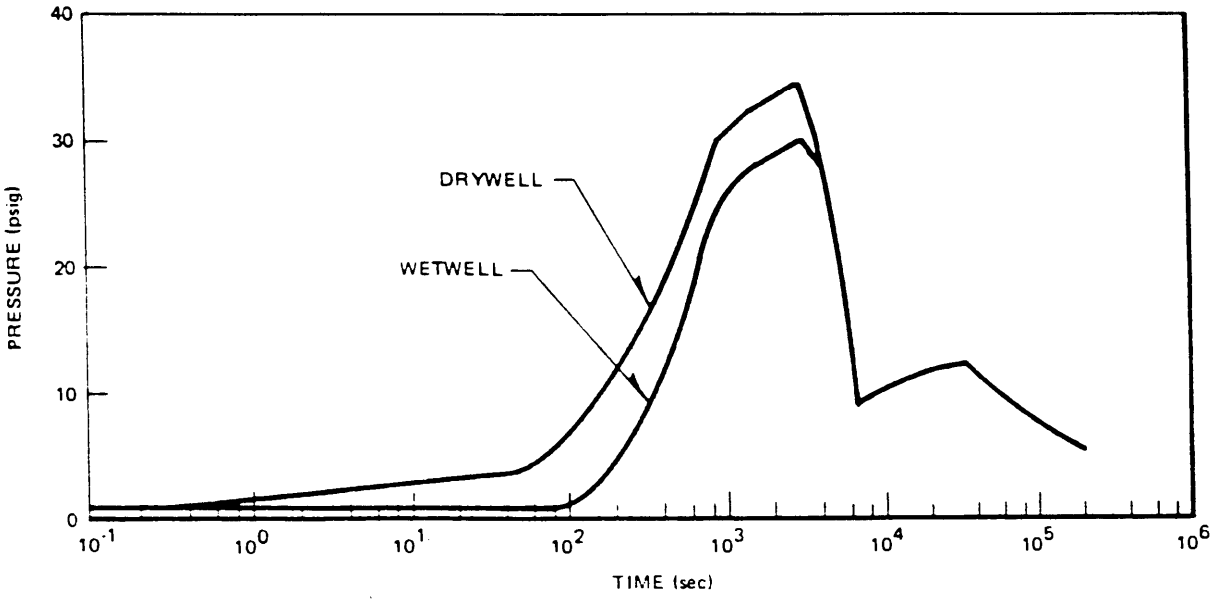
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SHORT-TERM CONTAINMENT TEMPERATURE RESPONSE FOLLOWING AN INTERMEDIATE SIZE BREAK (0.1 ft^2 LIQUID BREAK)

FIGURE 3A-17 Rev. 5, 4/96



CONTAINMENT TEMPERATURE RESPONSE FOLLOWING SMALL BREAK



CONTAINMENT PRESSURE RESPONSE FOLLOWING SMALL BREAK

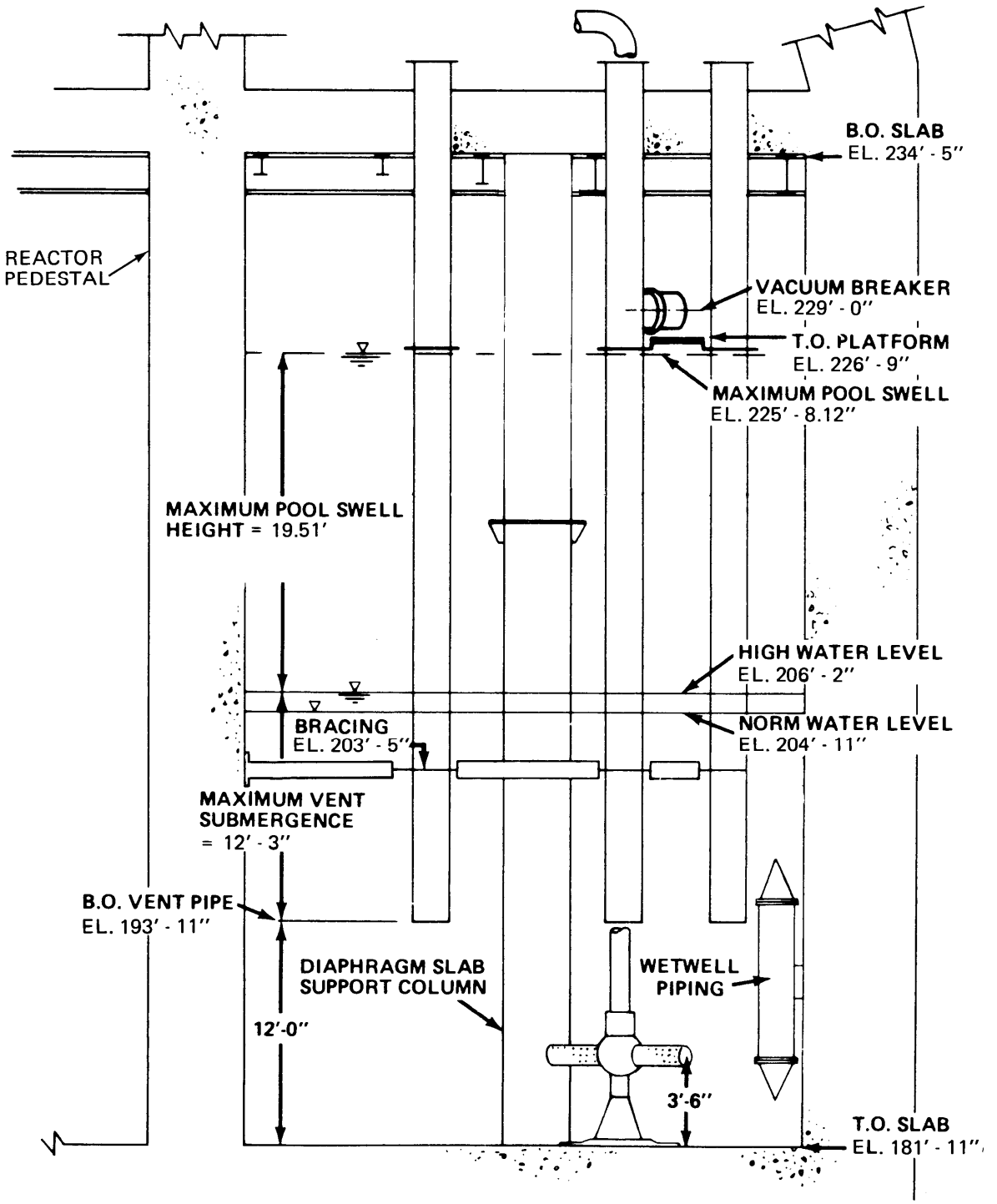
NOTE: The information presented in this figure is based on the original design basis conditions. As described in Section 6.2.1.1.3, the small break was not reanalyzed for the current conditions; however, the results presented here reasonably represent the general characteristics of an small break analysis results.

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TYPICAL MARK II CONTAINMENT RESPONSE TO THE SBA

FIGURE 3A-18 Rev. 5, 4/96

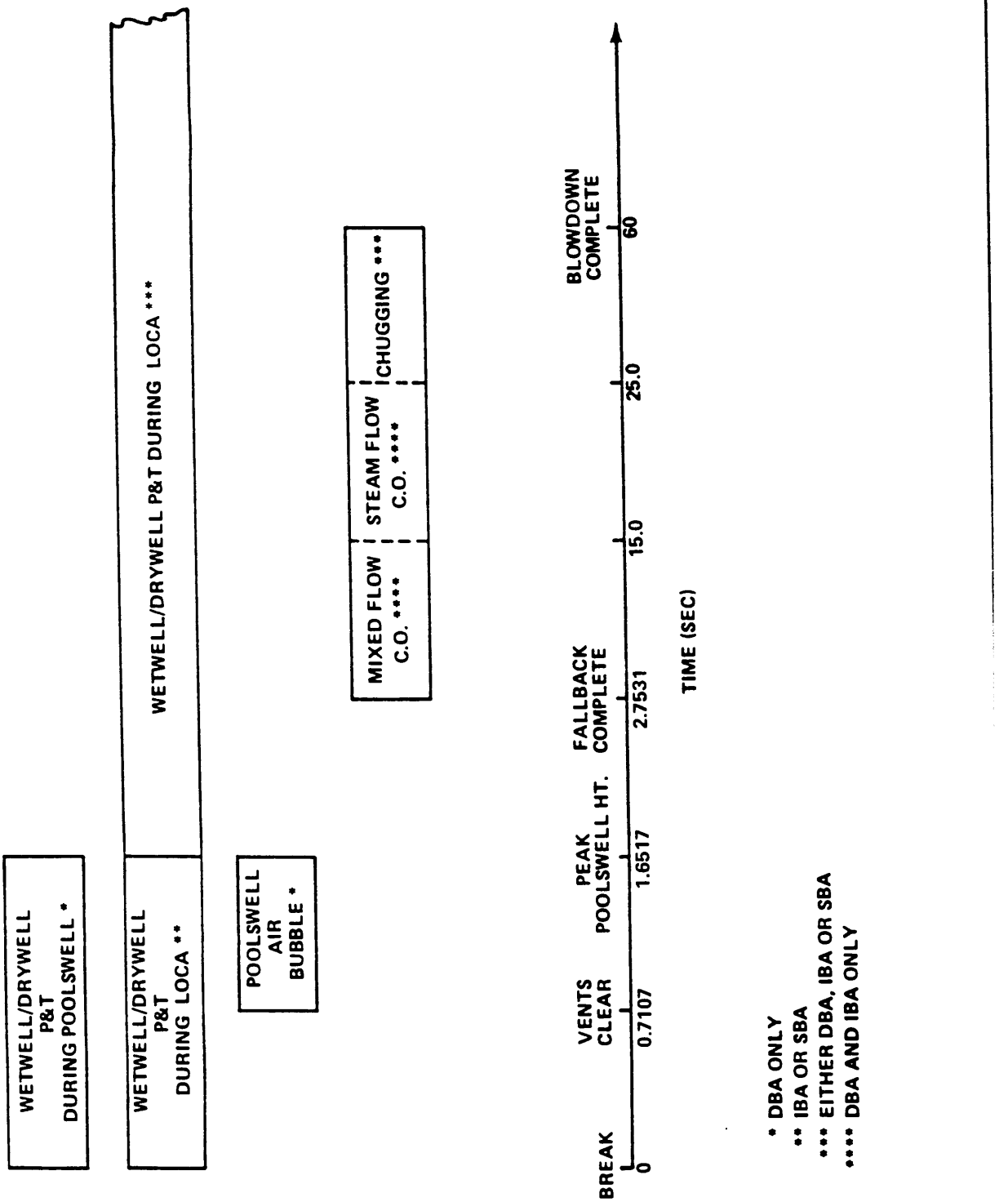


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COMPONENTS AFFECTED BY LOCA LOADS

FIGURE 3A-19



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The results reasonably represent the general characteristics of the LOCA loading history.

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LOCA LOADING HISTORY FOR THE CONTAINMENT WALL AND PEDESTAL

FIGURE 3A-20

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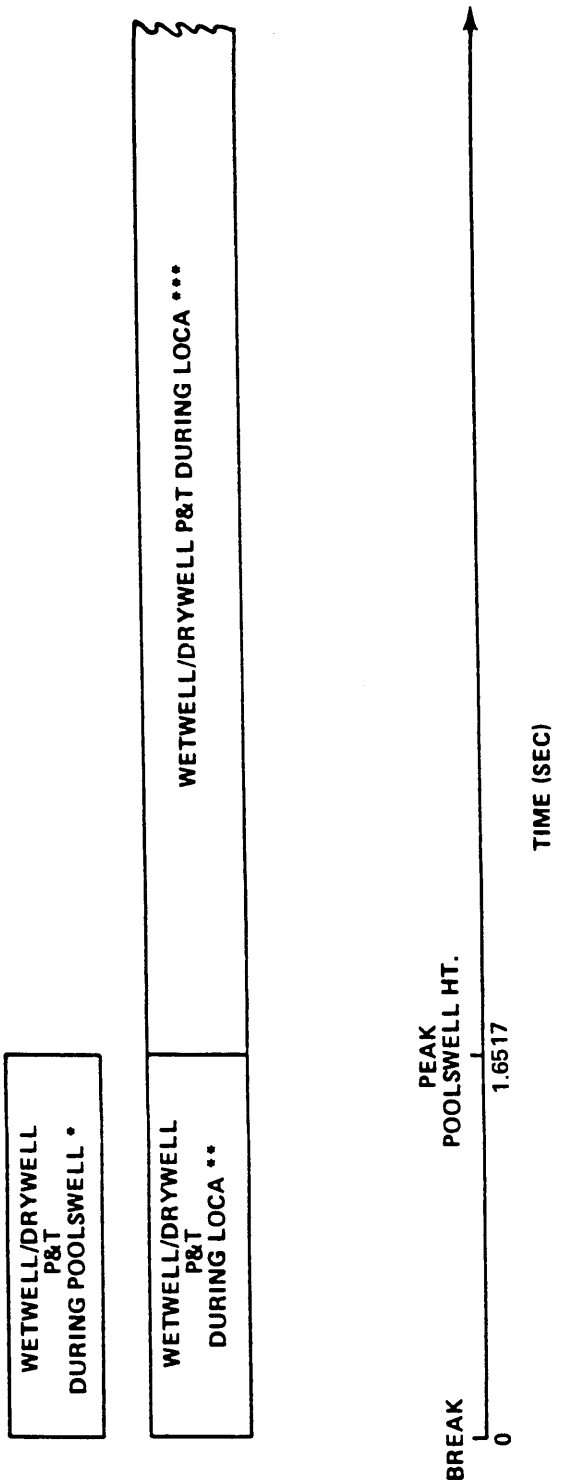
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The results reasonably represent the general characteristics of the LOCA loading history.

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LOCA LOADING HISTORY FOR THE BASEMAT AND LINER PLATE

FIGURE 3A-21 Rev. 5, 4/96



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The results reasonably represent the general characteristics of the LOCA loading history.

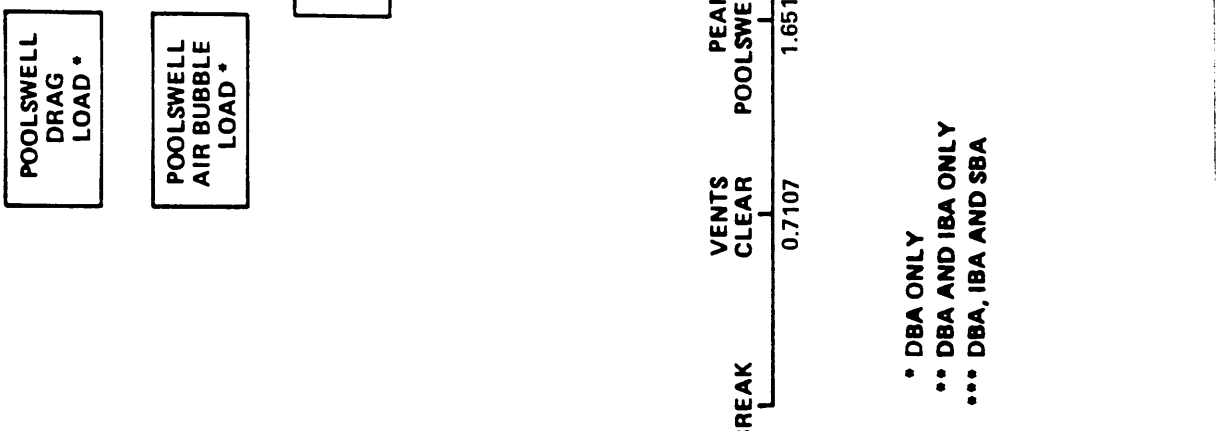
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LOCA LOADING HISTORY FOR THE DRYWELL AND DRYWELL FLOOR

FIGURE 3A-22

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NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The results reasonably represent the general characteristics of the LOCA loading history.

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LOCA LOADING HISTORY FOR THE COLUMNS

FIGURE 3A-23

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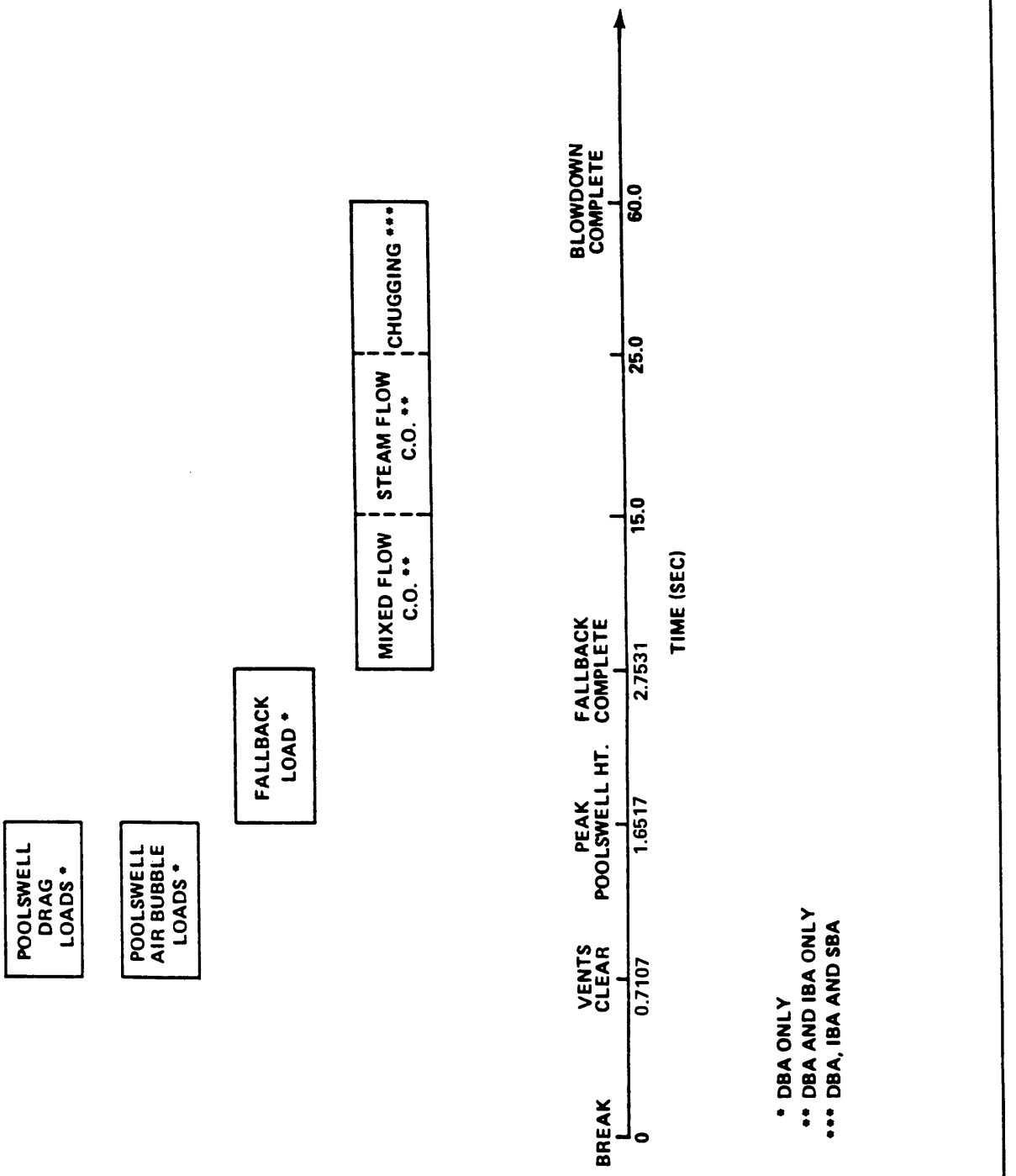
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The results reasonably represent the general characteristics of the LOCA loading history.

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LOCA LOADING HISTORY FOR THE DOWNCOMERS

FIGURE 3A-24

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NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The results reasonably represent the general characteristics of the LOCA loading history.

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LOCA LOADING HISTORY FOR THE DOWNCOMER BRACING SYSTEM

FIGURE 3A-25

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NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The results reasonably represent the general characteristics of the LOCA loading history.

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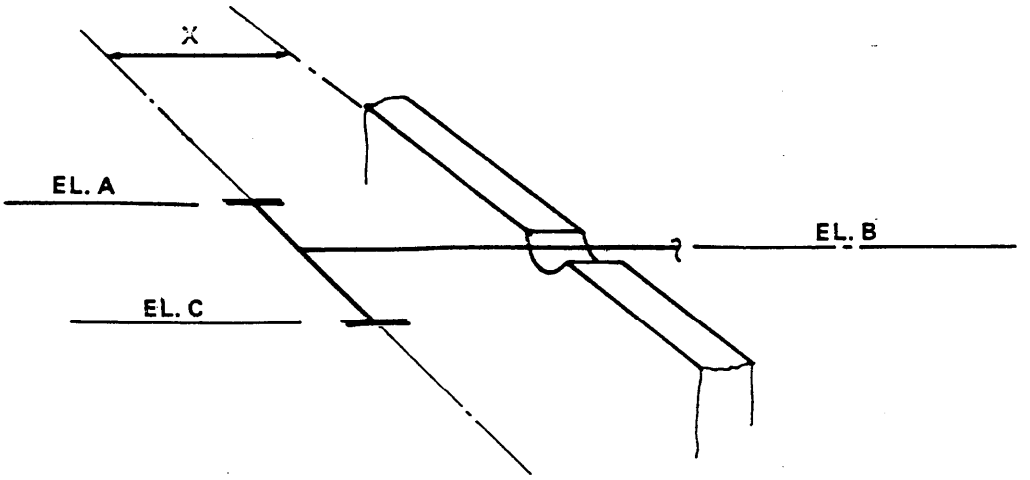
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LOCA LOADING HISTORY FOR THE WETWELL PIPING

FIGURE 3A-26

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LINE No.	QTY	SYSTEM	PENE-TRATION NO.	TYPE OF PENE-TRATION	ELEVATION			DIMENSION X
					A	B	C	
16"-HBB-120	4	CORE SPRAY	X-206A, B, C, D	EMBEDDED	192'-0"	192'-0"	192'-0"	1"-8"
24"-HBB-117	4	RHR	X-203A, B, C, D	EMBEDDED	192'-0"	192'-0"	192'-0"	1"-11"
6"-HBB-102	1	RCIC	X-214	EMBEDDED	192'-9 1/8"	192'-0"	191'-2 7/8"	0'-11 5/8"
16"-HBB-109	1	HPCI	X-209	EMBEDDED	193'-5"	192'-0"	190'-7"	1'-6"

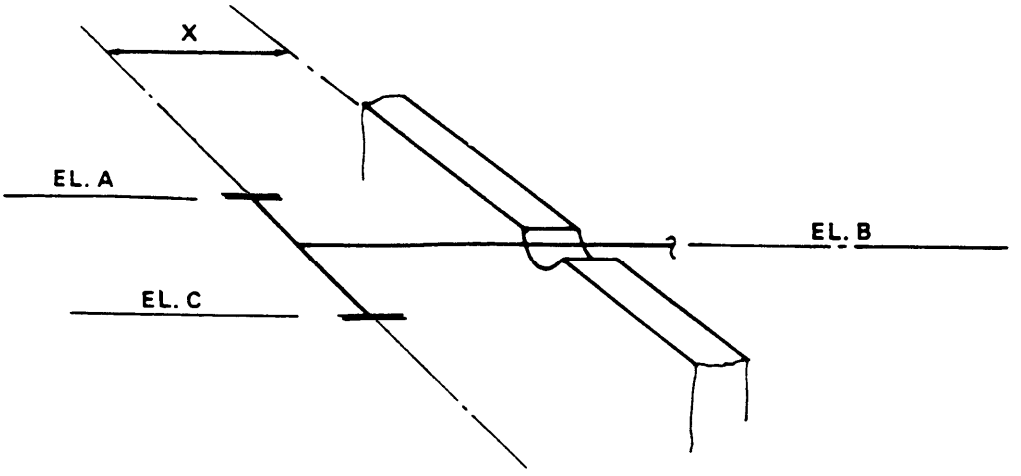


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STRESS DIAGRAMS AND TABLES FOR PIPING SYSTEMS BELOW SUPPRESSION CHAMBER WATER LEVEL

FIGURE 3A-27 Sht 1 of 2 **Rev. 09 11/99**

LINE No.	QTY	SYSTEM	PENE-TRATION No.	TYPE OF PENE-TRATION	ELEVATION			DIMENSION X
					A	B	C	
16"-HBB-220	4	CORE SPRAY	X-206A, B, C, D	EMBEDDED	192'-0"	192'-0"	192'-0"	1'-6"
24"-HBB-217	4	RHR	X-203A, B, C, D	EMBEDDED	192'-0"	192'-0"	192'-0"	1'-11"
6"-HBB-202	1	RCIC	X-214	EMBEDDED	192'-9 1/8"	192'-0"	191'-2 7/8	0'-11 5/8"
16"-HBB-209	1	HPCI	X-209	EMBEDDED	193'-5"	192'-0"	190'-7"	1'-6"

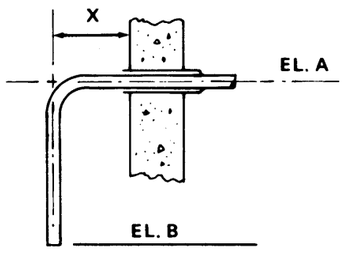


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UNIT 2
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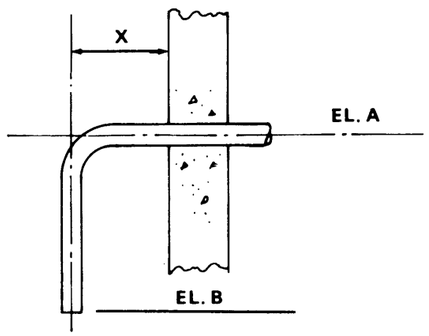
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STRESS DIAGRAMS AND TABLES FOR PIPING SYSTEMS BELOW SUPPRESSION CHAMBER WATER LEVEL

FIGURE 3A-27 Sht 2 of 2 Rev. 09 11/99

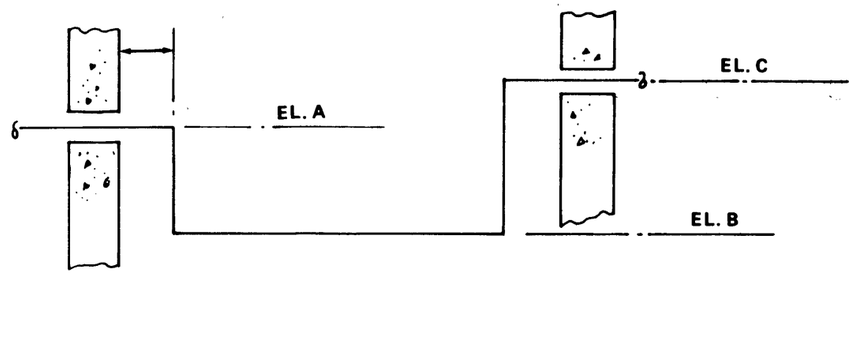
DWG No.	LINE No.	QTY	SYSTEM	PENE-TRATION No.	TYPE OF PENE-TRATION	ELEVATION			DIMENSION X
						A	B	C	
B	4"-HBD-187	1	HPCI	X-212	EMBEDDED	207'-6"	199'-11"	–	1'-0"
B	4"-HBD-188	1	HPCI	X-236	EMBEDDED	207'-6"	199'-11"	–	1'-0"
A	24"-HBD-189	1	HPCI	X-210	SLEEVE	207'-6"	192'-8"	–	6'-9"
B	4"-HBD-171	2	CORE SPRAY	X-208B X-235	EMBEDDED	207'-6" 207'-0"	199'-11"	–	1'-0"
B	10"-HBD-169	2	CORE SPRAY	X-207A X-207B	EMBEDDED	219'-0"	199'-11"	–	1'-9"
A	18"-GBD-143	2	RHR	X-204A,B	SLEEVE	219'-0"	197'-8"	–	2'-6"
A	4"-GBD-144	2	RHR	X-226A,B	SLEEVE	207'-0"	199'-11 1/2"	–	0'-9"
A	12"-HBD-173	1	RCIC	X-215	SLEEVE	207'-6"	199'-11"	–	2'-9"
B	6"-HBB-139	1	RHR	X-240	EMBEDDED	207'-3 1/4"	199'-8 1/4"	–	1'-3"
A	10"-HBB-140	1	RHR	X-238	SLEEVE	207'-9"	199'-11"	–	1'-6"
A	10"-HBB-140	1	RHR	X-239	SLEEVE	207'-1"	199'-11"	–	1'-6"
C	4"-HCB-106	1	LIQ. AND SOLID RADWASTE	X-231A	SLEEVE	207'-5 1/16"	207'-3 3/8"	213'-9 3/4"	–
C	4"-HCB-107	1	LIQ. AND SOLID RADWASTE	X-231B	SLEEVE	207-5 3/8"	207'-2 5/8"	213'-9 1/2"	–
B	2"-HBD-357	1	REACTOR CORE ISOLATION COOLING	X-217	EMBEDDED	207'-6"	199'-11"	–	0'-6"
B	2"-HBD-356	1	REACTOR CORE ISOLATION COOLING	X-216	EMBEDDED	207'-6"	199'-11"	–	0'-6"



DRAWING A



DRAWING B



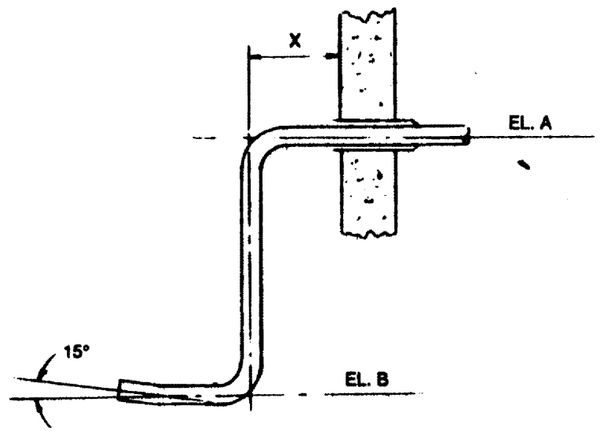
DRAWING C

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UNITS 1 AND 2
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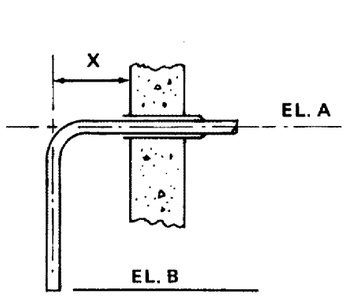
DESIGN ASSESSMENT REPORT
STRESS DIAGRAMS AND TABLES FOR PIPING SYSTEMS WITHIN POOLSWELL ZONE (UNIT 1)
SHEET 1 OF 2

FIGURE 3A-28

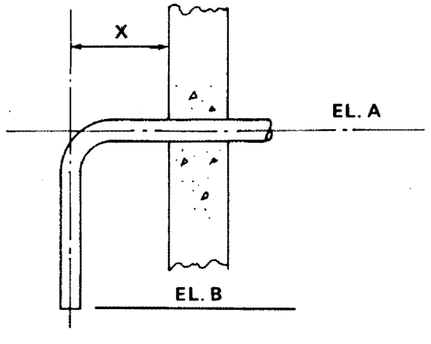
DWG No.	LINE No.	QTY	SYSTEM	PENE-TRATION No.	TYPE OF PENE-TRATION	ELEVATION			DIMENSION X
						A	B	C	
B	4"-HBD-287	1	HPCI	X-212	EMBEDDED	207'-6"	199'-11"	–	1'-0"
B	4"-HBD-288	1	HPCI	X-236	EMBEDDED	207'-6"	199'-11"	–	1'-0"
A	24"-HBD-289	1	HPCI	X-210	SLEEVE	207'-6"	199'-11"	–	6'-9"
B	4"-HBD-271	2	CORE SPRAY	X-208B X-235	EMBEDDED	207'-6" 207'-0"	199'-11"	–	1'-0"
B	10"-HBD-269	2	CORE SPRAY	X-207A X-207B	EMBEDDED	219'-0"	199'-11"	–	1'-9"
D	18"-GBD-243	2	RHR	X-204A,B	SLEEVE	219'-0"	199'-11"	–	2'-6"
A	4"-GBD-244	2	RHR	X-226A,B	SLEEVE	207'-0"	199'-11"	–	0'-9"
A	12"-HBD-273	1	RCIC	X-215	SLEEVE	207'-6"	199'-11"	–	2'-9"
B	6"-HBB-239	1	RHR	X-240	EMBEDDED	207'-6"	199'-11"	–	1'-3"
A	10"-HBB-240	1	RHR	X-238	SLEEVE	207'-9"	199'-11"	–	1'-6"
A	10"-HBB-240	1	RHR	X-239	SLEEVE	207'-1"	199'-11"	–	1'-6"
C	4"-HCB-206	1	LIQ. AND SOLID RADWASTE	X-231A	SLEEVE	207'-5"	207'-2 1/2"	213'-9 1/2"	–
C	4"-HCB-207	1	LIQ. AND SOLID RADWASTE	X-231B	SLEEVE	207'-6"	207'-3 1/4"	213'-9 5/8"	–
B	2"-HBD-457	1	REACTOR CORE ISOLATION COOLING	X-217	EMBEDDED	207'-6"	199'-11"	–	0'-6"
B	2"-HBD-456	1	REACTOR CORE ISOLATION COOLING	X-216	EMBEDDED	207'-6"	199'-11"	–	0'-4 1/2"



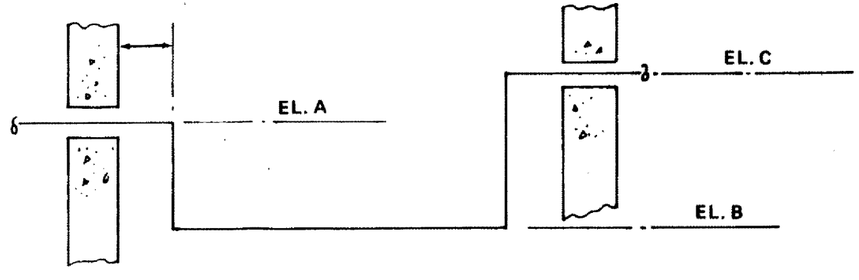
DRAWING D



DRAWING A



DRAWING B



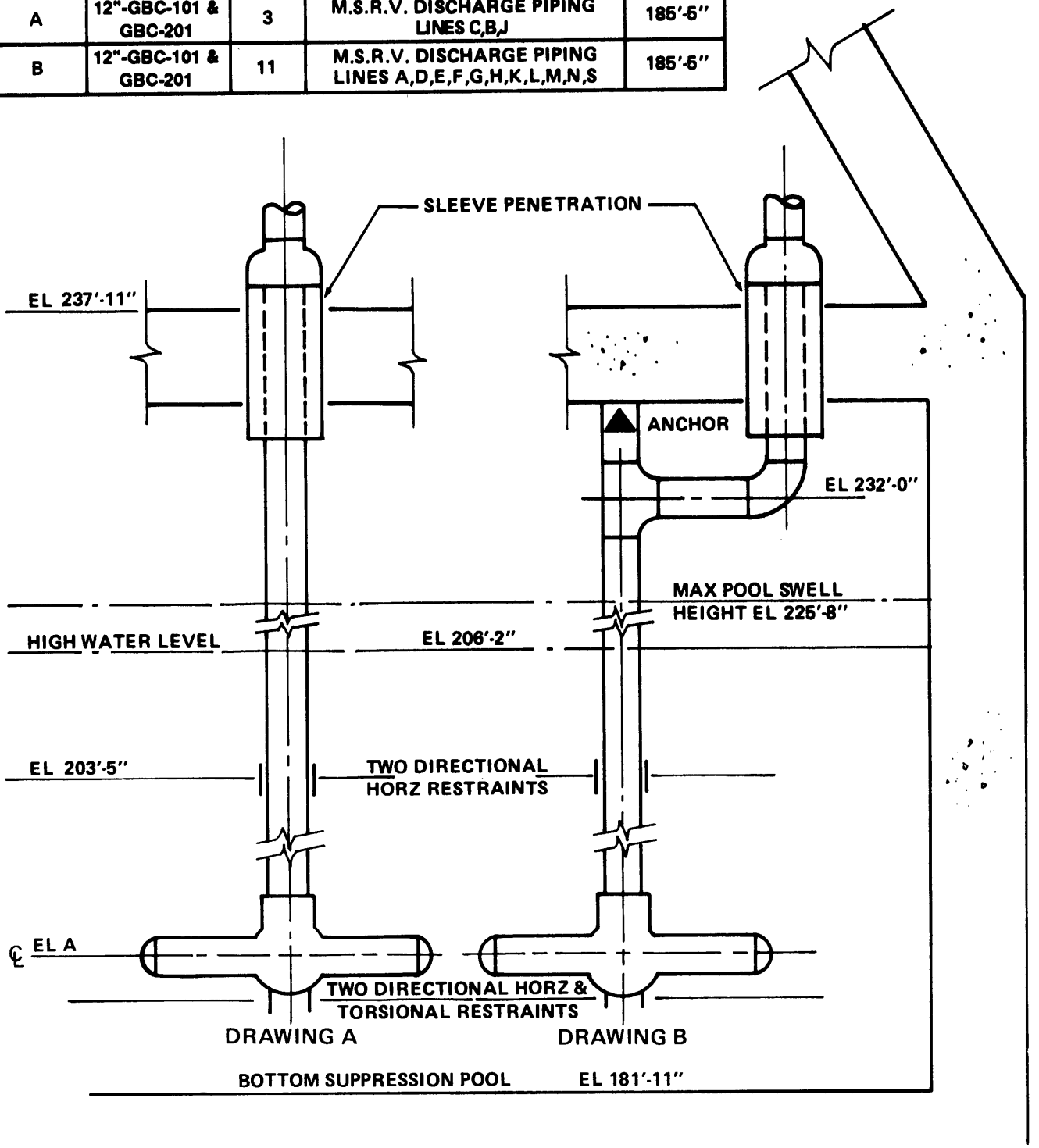
DRAWING C

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
STRESS DIAGRAMS AND TABLES FOR PIPING SYSTEMS WITHIN POOLSWELL ZONE (UNIT 2)
SHEET 2 OF 2

FIGURE 3A-28

DWG. No.	LINE No.	QTY	SYSTEM	EL A
A	12"-GBC-101 & GBC-201	3	M.S.R.V. DISCHARGE PIPING LINES C,B,J	185'-5"
B	12"-GBC-101 & GBC-201	11	M.S.R.V. DISCHARGE PIPING LINES A,D,E,F,G,H,K,L,M,N,S	185'-5"

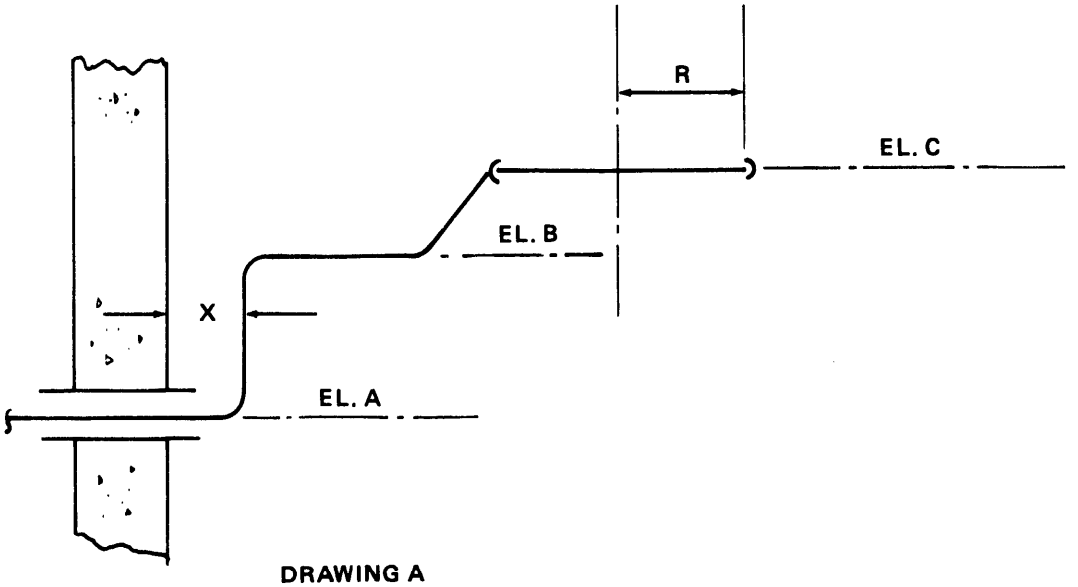


LIMERICK GENERATING STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

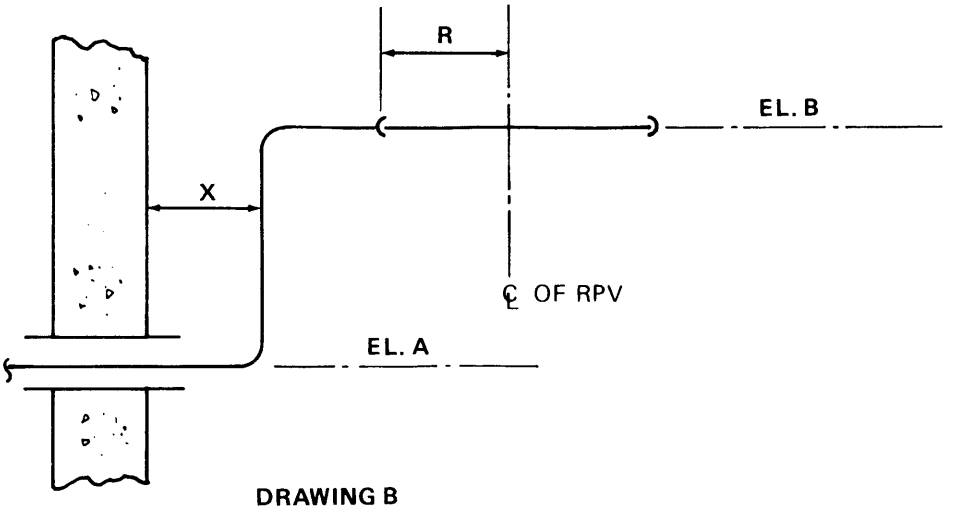
DESIGN ASSESSMENT REPORT
STRESS DIAGRAMS AND TABLES FOR
PIPING WITHIN POOLSWELL ZONE

FIGURE 3A-29

DWG No.	LINE No.	QTY	SYSTEM	PENE-TRATION No.	RADIUS OF SPRAY RING, R	ELEVATION			DIMENSION
						A	B	C	X
A	6"-GBC-112	1	RHR	X-205A	21'-6"	222'-4 1/2"	229'-11 3/8"	230'-6"	3'-8"
B	6"-GBC-112	1	RHR	X-205B	32'-8"	222'-4 1/2"	–	230'-6"	3'-6 11/16"



DRAWING A



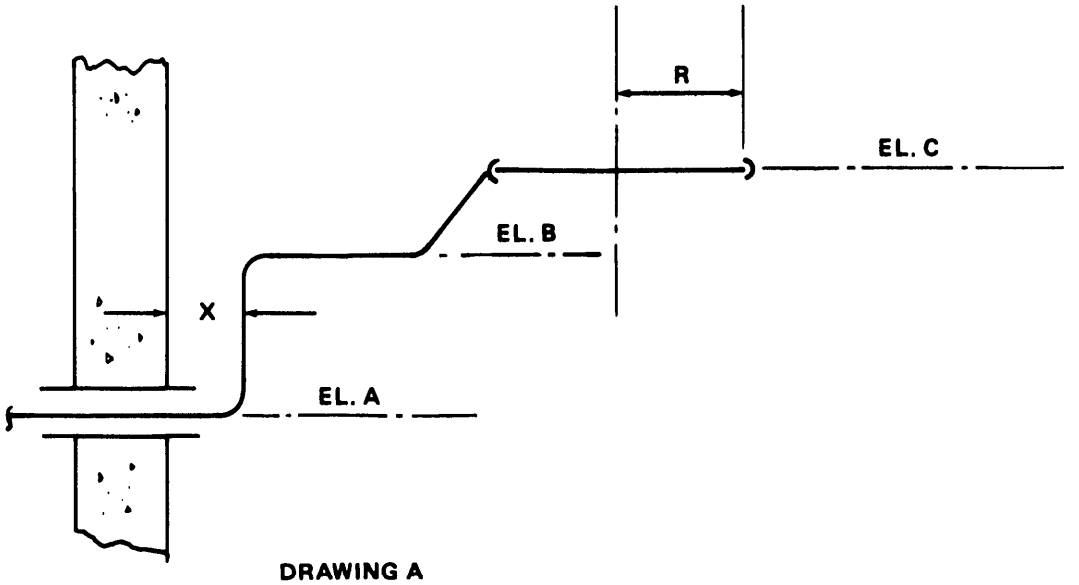
DRAWING B

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

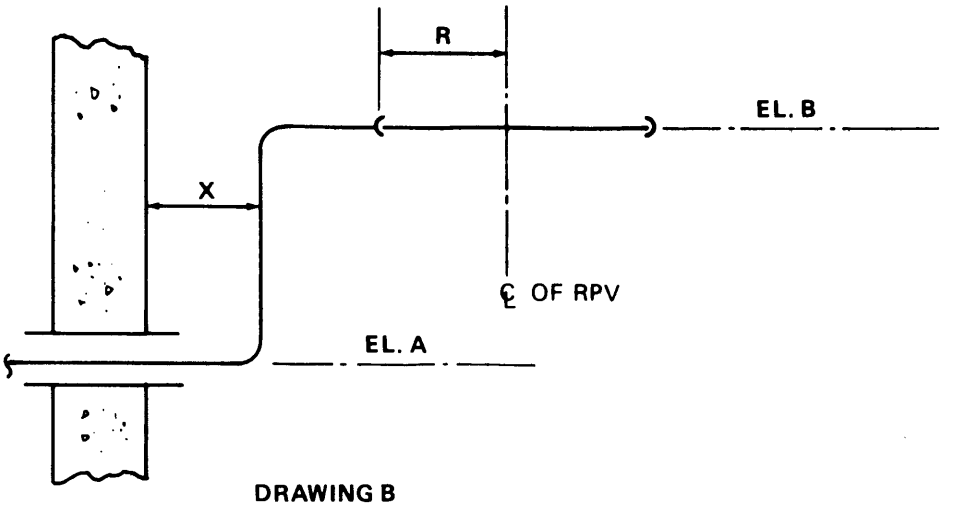
DESIGN ASSESSMENT REPORT
STRESS DIAGRAMS AND TABLES FOR PIPING SYSTEMS WITHIN POOLSWELL ZONE (UNIT 1)
SHEET 1 OF 2

FIGURE 3A-30

DWG No.	LINE No.	QTY	SYSTEM	PENE-TRATION No.	RADIUS OF SPRAY RING, R	ELEVATION			DIMENSION
						A	B	C	X
A	6"-GBC-212	1	RHR	X-205A	21'-6 1/2"	222'-4 1/2"	229'-11 3/8"	230'-6"	3'-8"
B	6"-GBC-212	1	RHR	X-205B	32'-8"	222'-4 1/2"	–	230'-6"	3'-6 11/16"



DRAWING A



DRAWING B

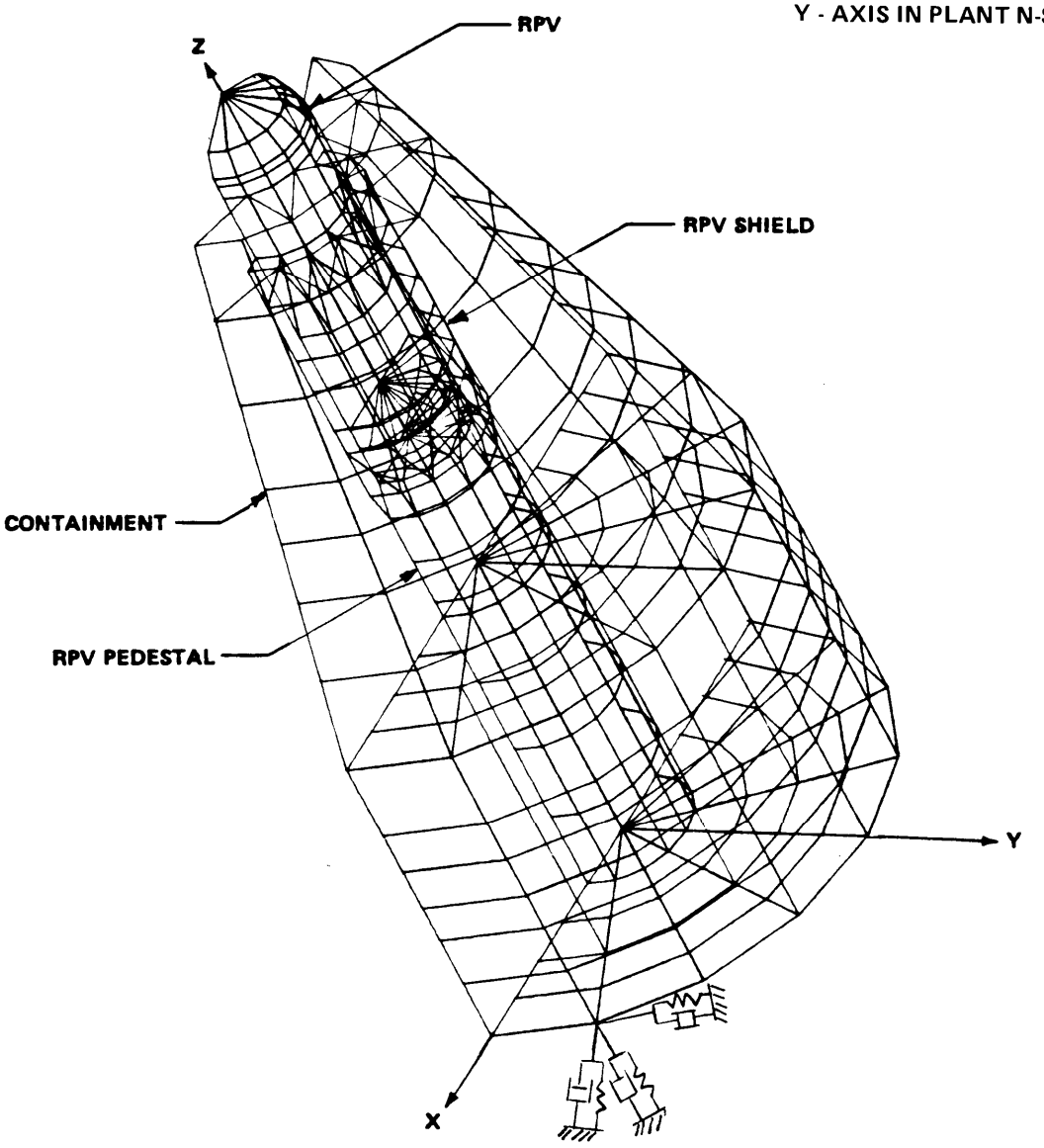
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
STRESS DIAGRAMS AND TABLES FOR PIPING SYSTEMS WITHIN POOLSWELL ZONE (UNIT 2)
SHEET 2 OF 2

FIGURE 3A-30

NOTE:

X - AXIS IS IN PLANT E-W AND
Y - AXIS IN PLANT N-S DIRECTION

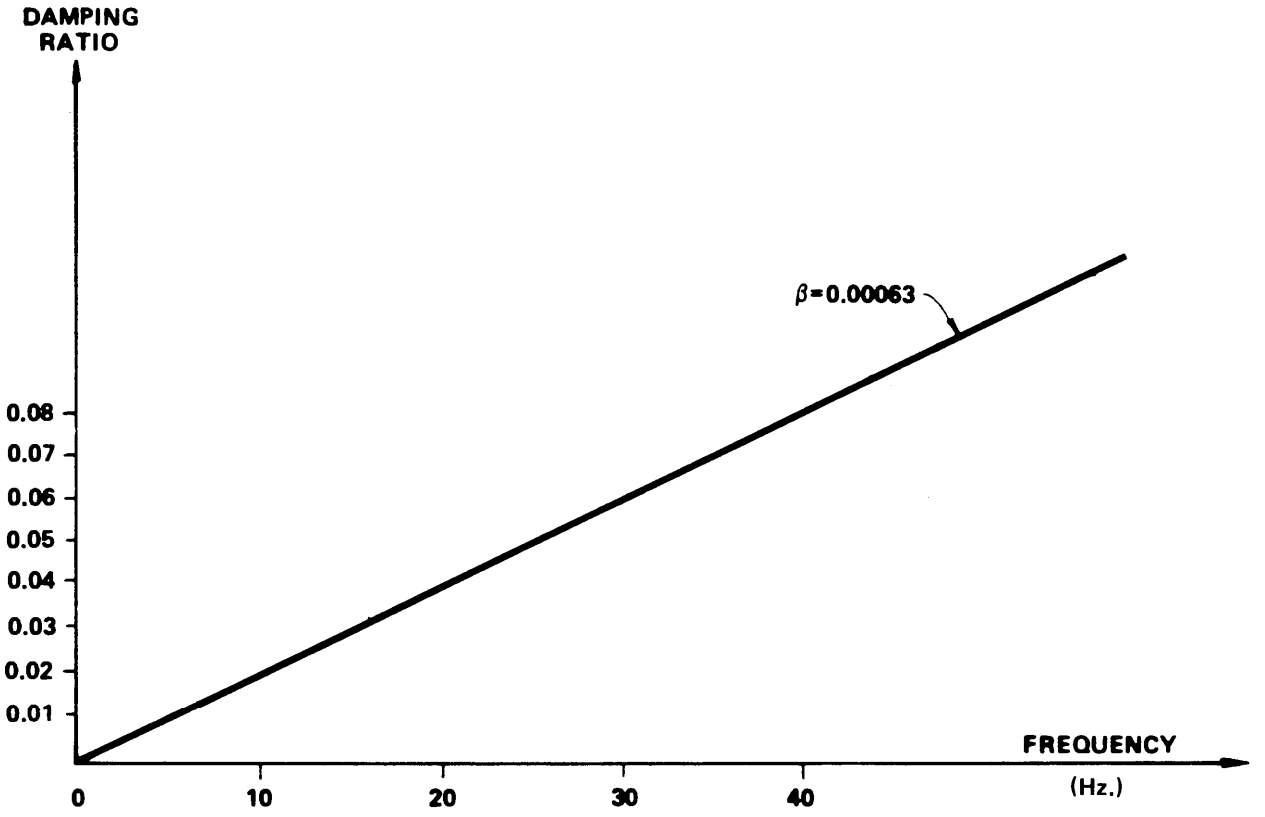


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

3-D CONTAINMENT FINITE ELEMENT MODEL (ANSYS MODEL)

FIGURE 3A-31

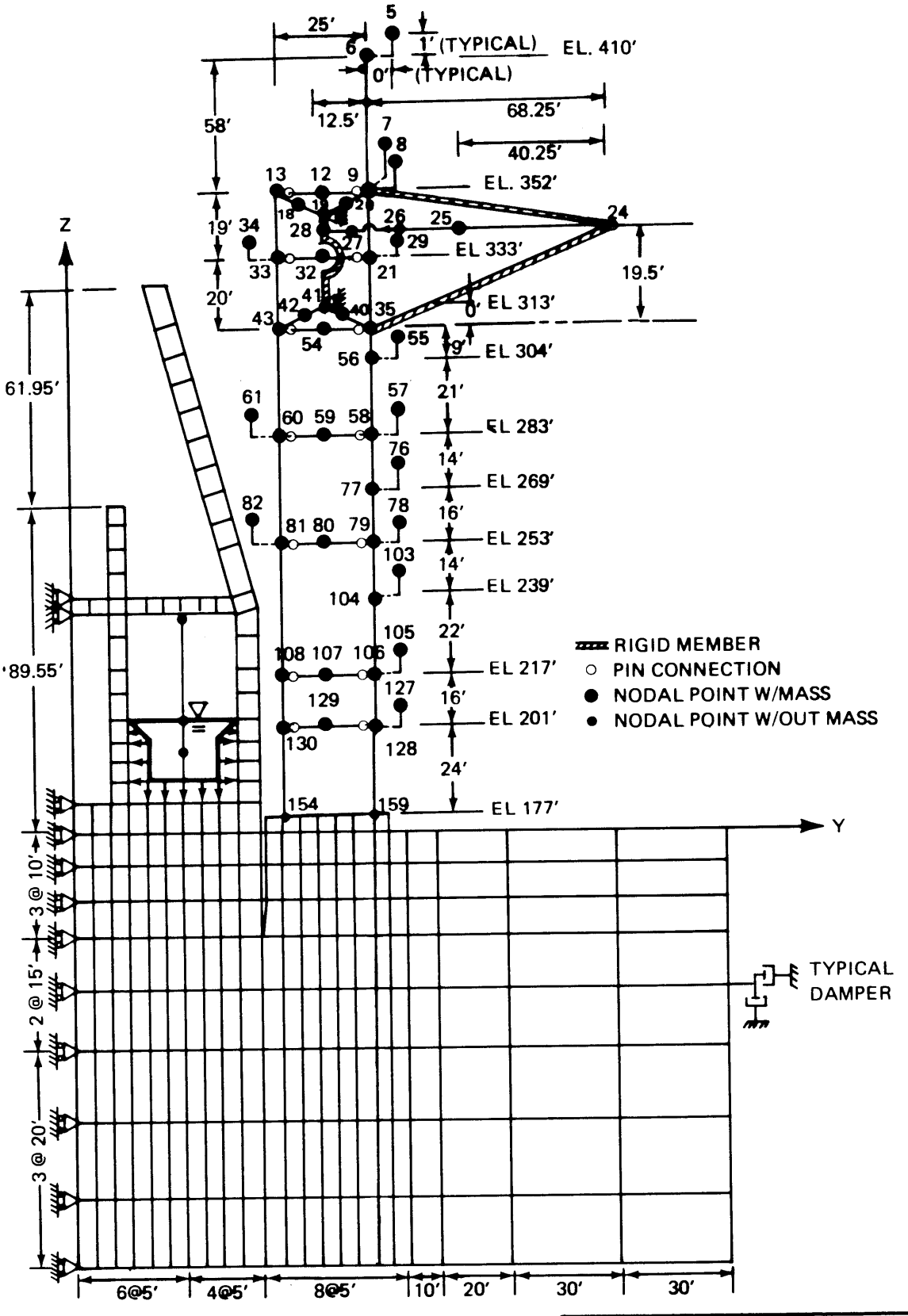


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UNITS 1 AND 2
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DESIGN ASSESSMENT REPORT

EQUIVALENT MODAL DAMPING RATIO VERSUS MODAL FREQUENCY FOR STRUCTURAL STIFFNESS PROPORTIONAL DAMPING (CONTAINMENT BUILDING)

FIGURE 3A-32

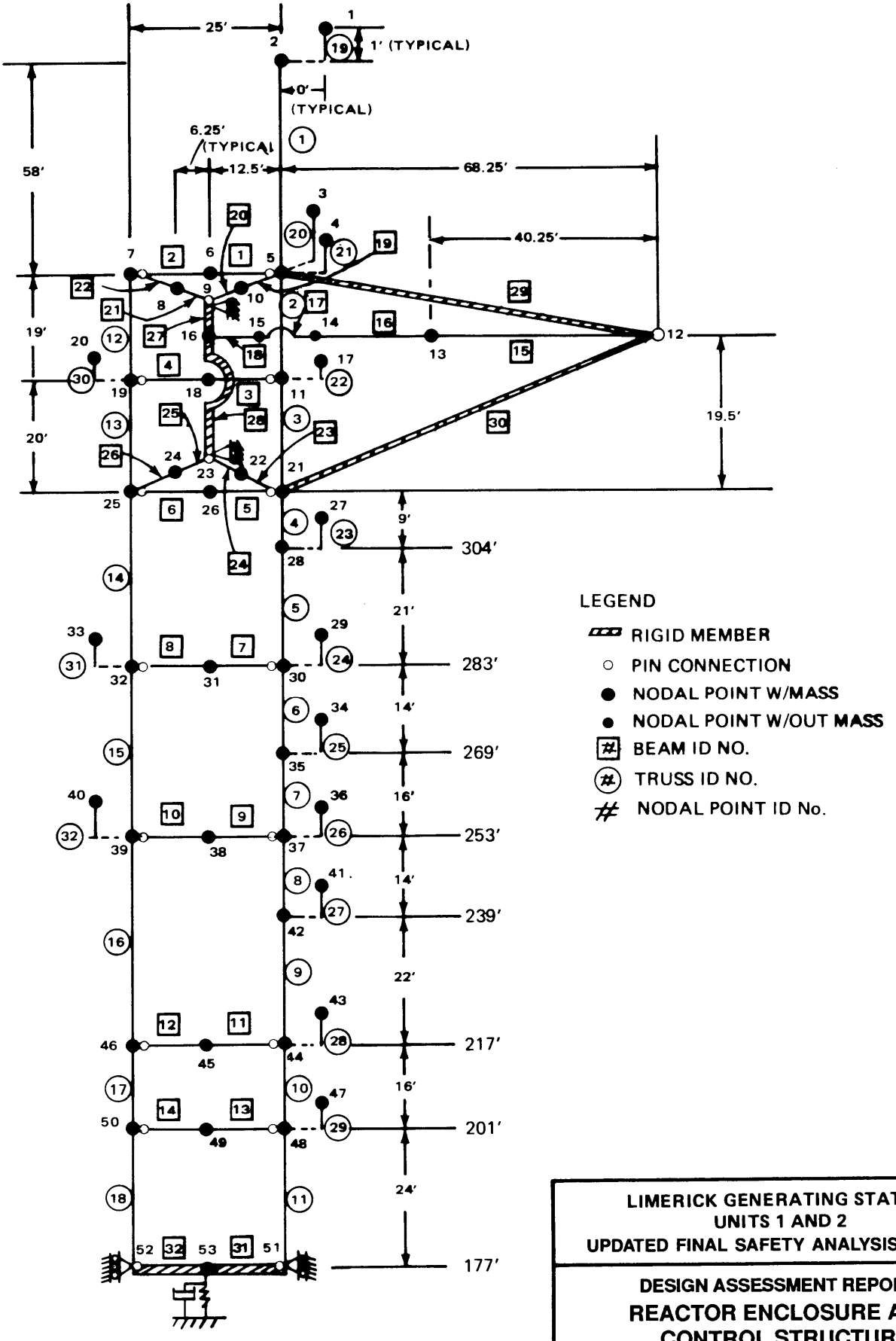


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE AND CONTROL STRUCTURE VERTICAL AXISYMMETRIC COUPLED MODEL (FESS)

FIGURE 3A-33

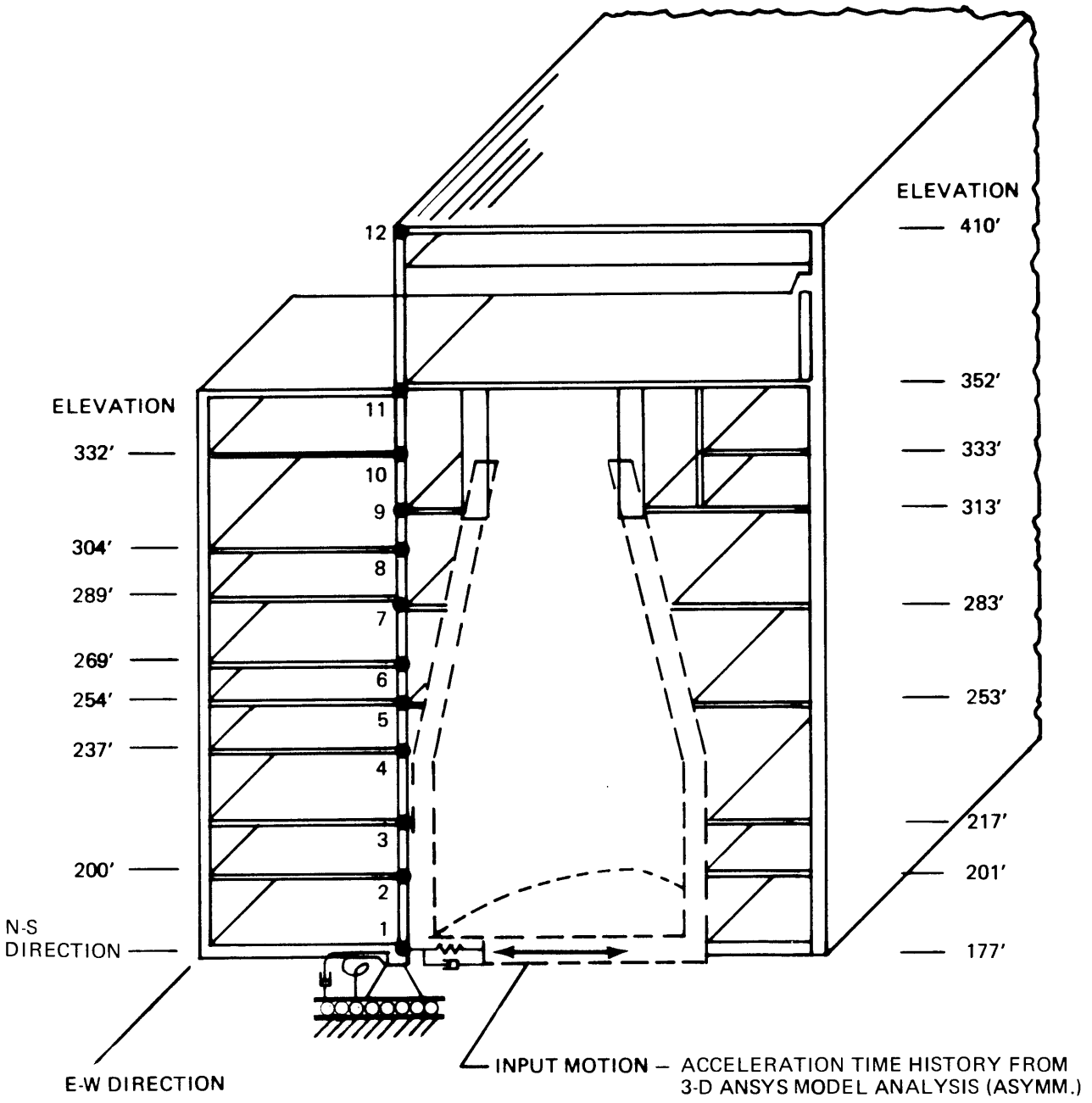


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE AND CONTROL STRUCTURE VERTICAL STICK MODEL

FIGURE 3A-34

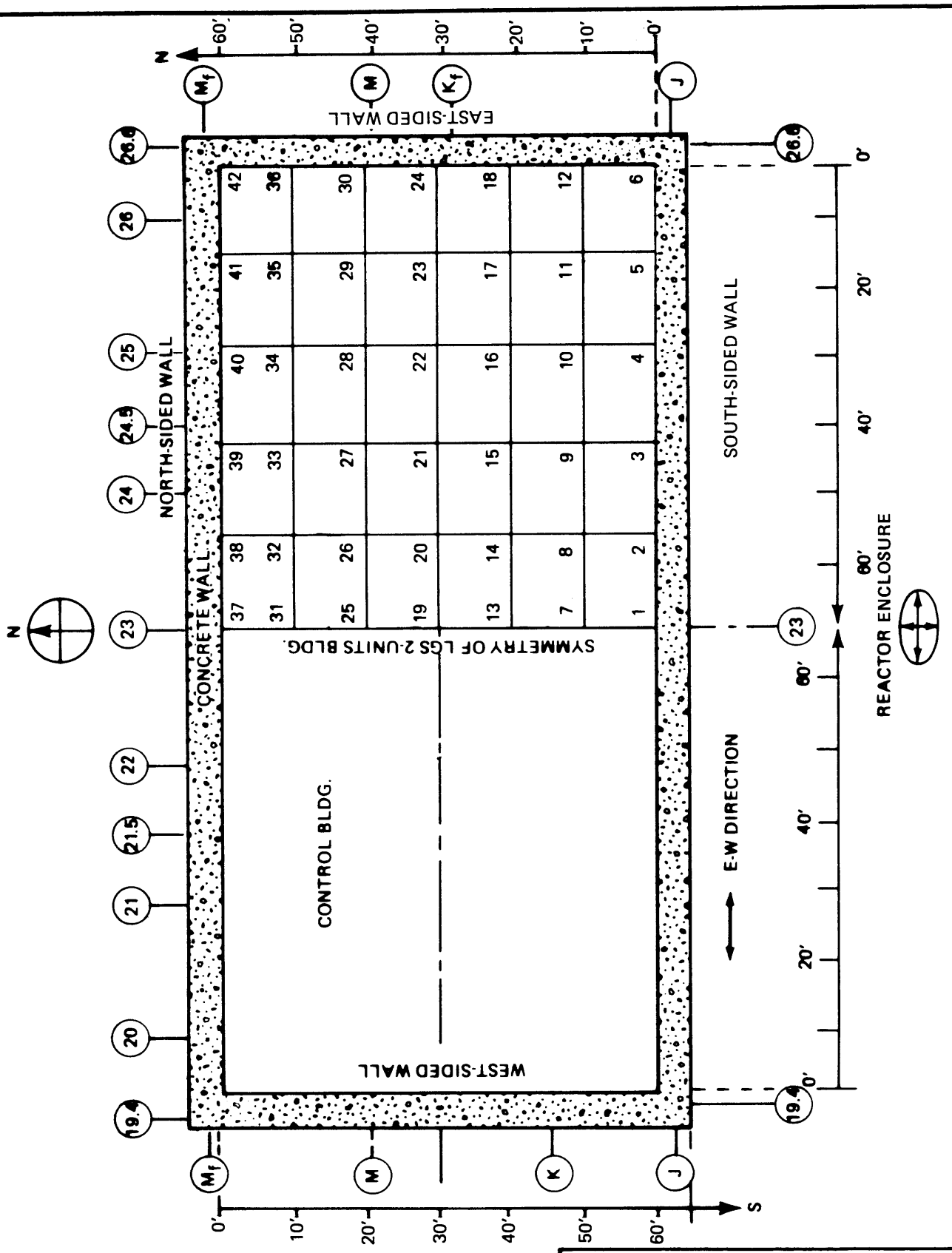


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UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE AND CONTROL STRUCTURE HORIZONTAL STICK MODEL

FIGURE 3A-35

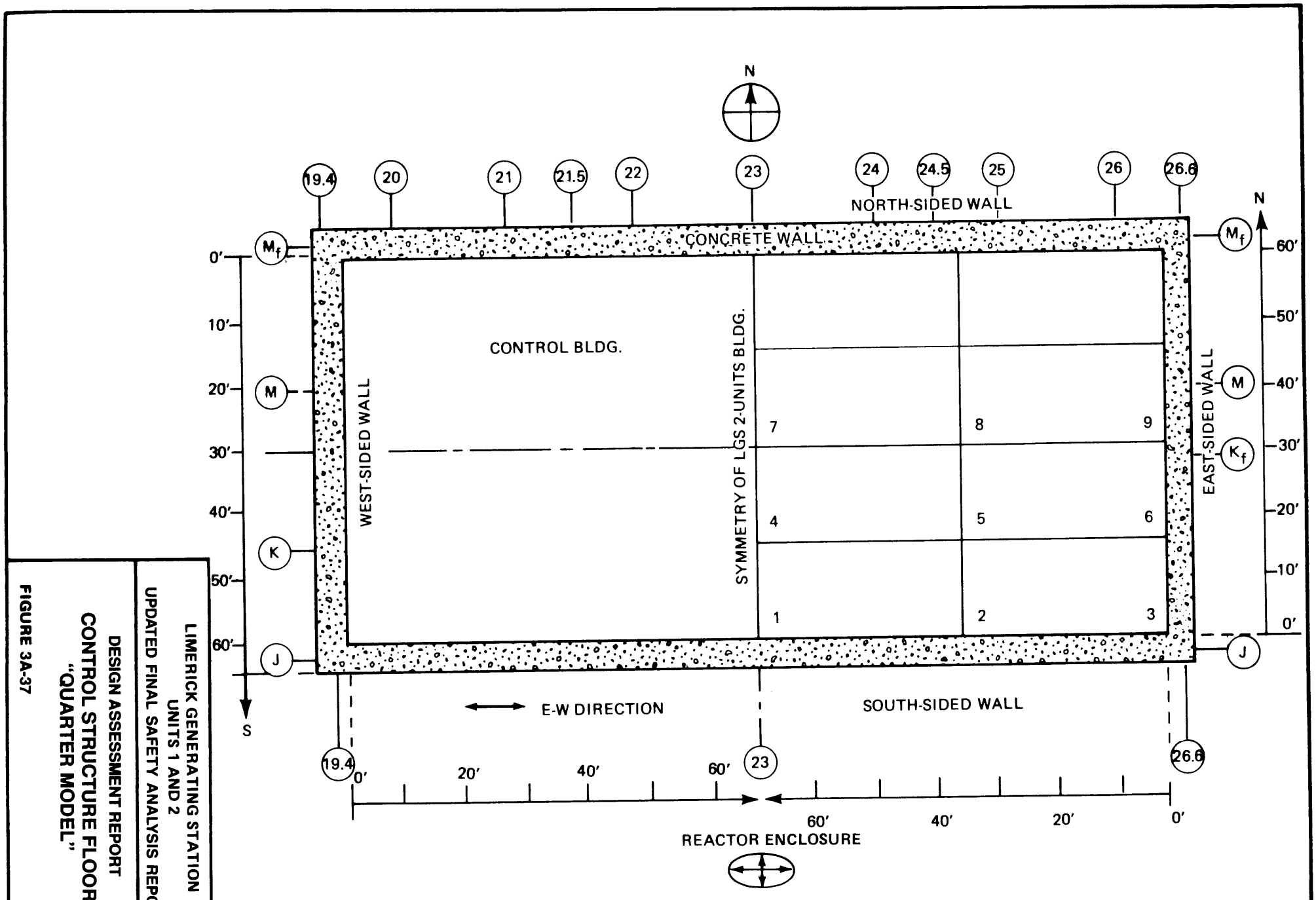


LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

CONTROL STRUCTURE FLOOR "HALF MODEL"

FIGURE 3A-36



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UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT
DESIGN ASSESSMENT REPORT

CONTROL STRUCTURE FLOOR "QUARTER MODEL"

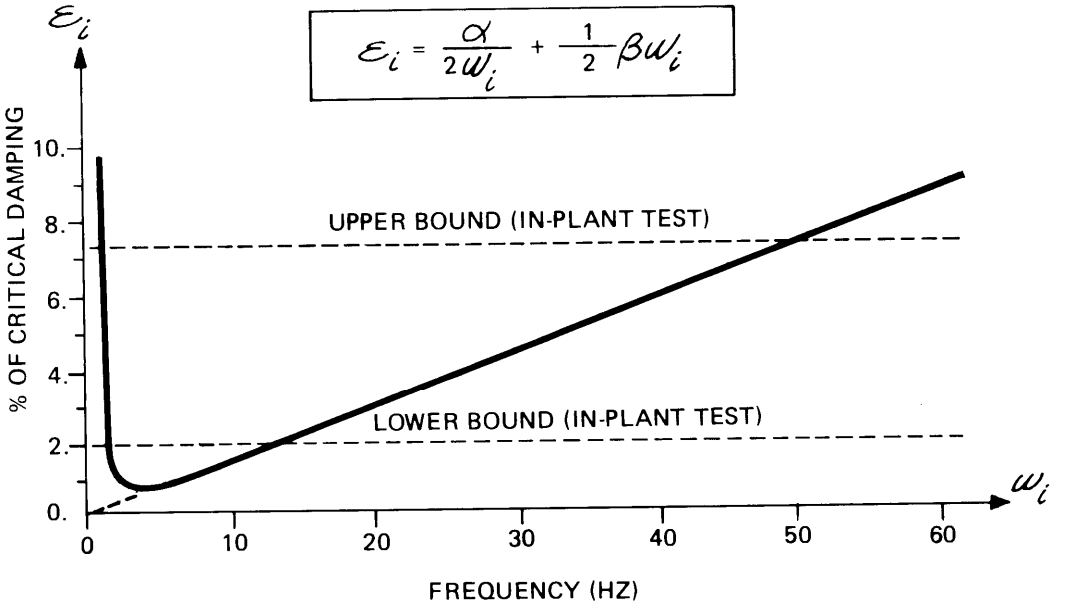
FIGURE 3A-37

MASS–PROPORTIONAL AND STIFFNESS–PROPORTIONAL

$$[C] = \alpha [M] + \beta [K]$$

VARIABLE DAMPING

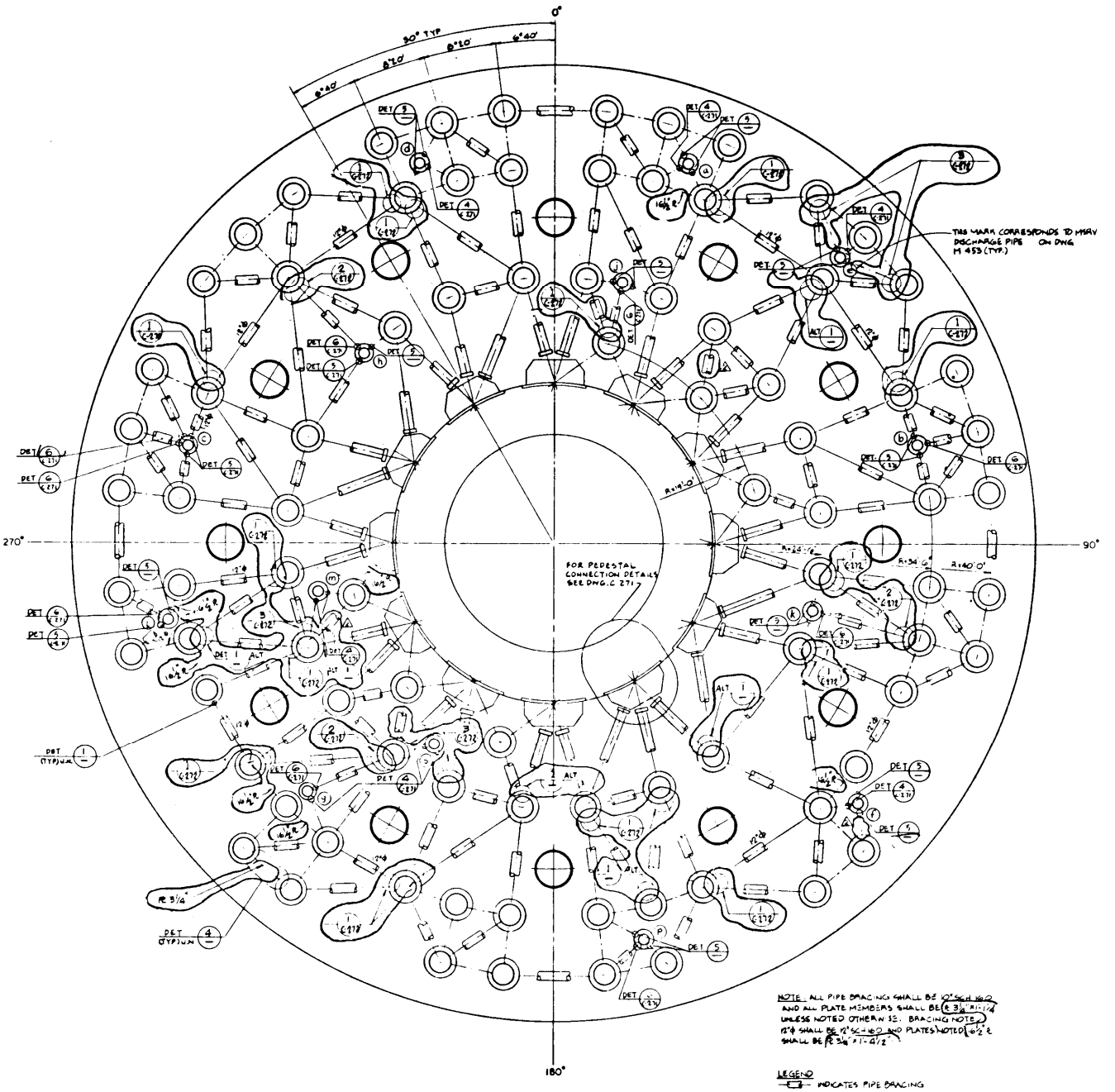
$$\varepsilon_i = \frac{\alpha}{2\omega_i} + \frac{1}{2}\beta\omega_i$$



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
EQUIVALENT MODAL DAMPING RATIO VERSUS MODAL FREQUENCY FOR STRUCTURAL DAMPING (REACTOR ENCLOSURE AND CONTROL STRUCTURE)

FIGURE 3A-38



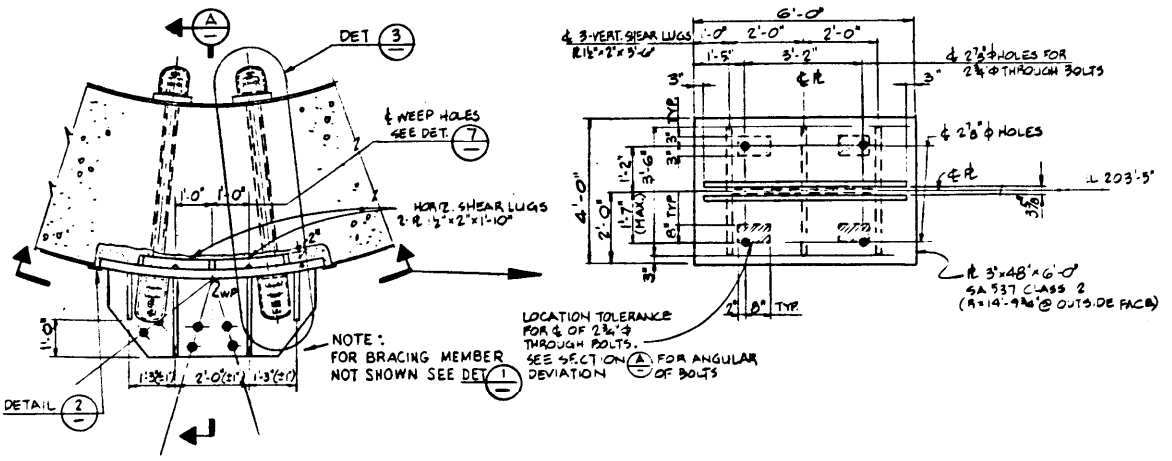
PLAN AT ELEVATION 203'-5"
1/8"=1'-0"

NOTE: MISCELLANEOUS PIPING THAT IS LATERALLY SUPPORTED ON THE BRACING SYSTEM IS NOT SHOWN.

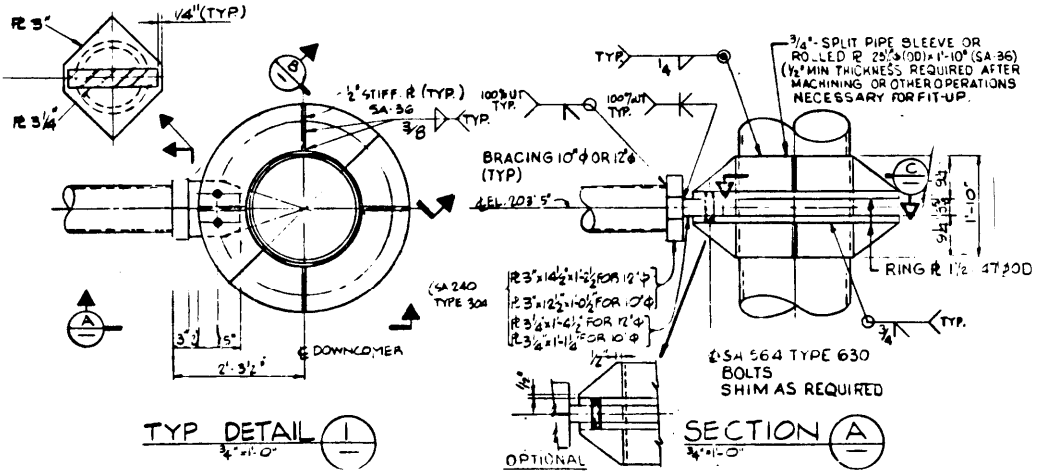
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
DOWNCOMER BRACING SYSTEM

FIGURE 3A-39

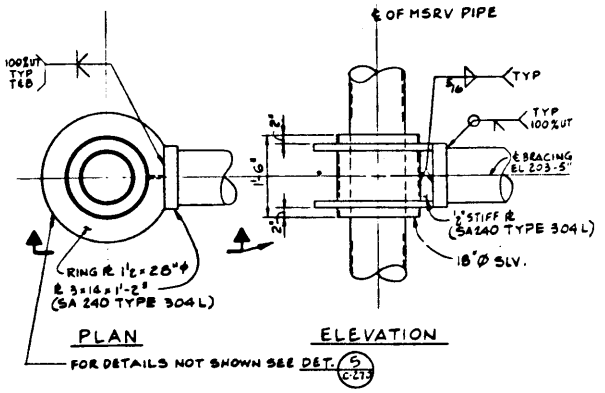


ALTERNATE DETAIL 1
½" = 1'-0"



TYP DETAIL 1
¾" = 1'-0"

SECTION A
¾" = 1'-0"

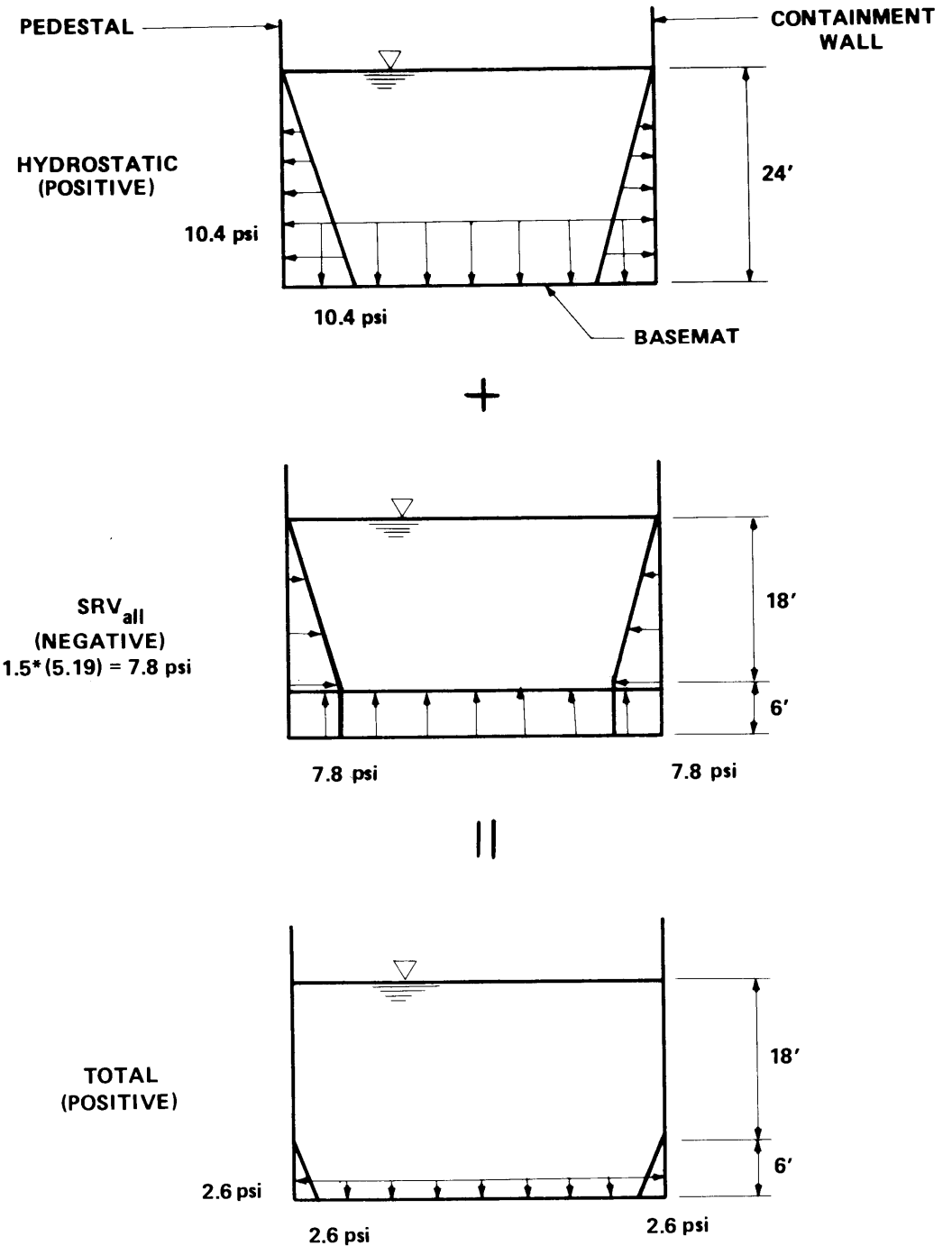


DETAIL 5
¾" = 1'-0"

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
DOWNCOMER BRACING SYSTEM DETAILS

FIGURE 3A-40



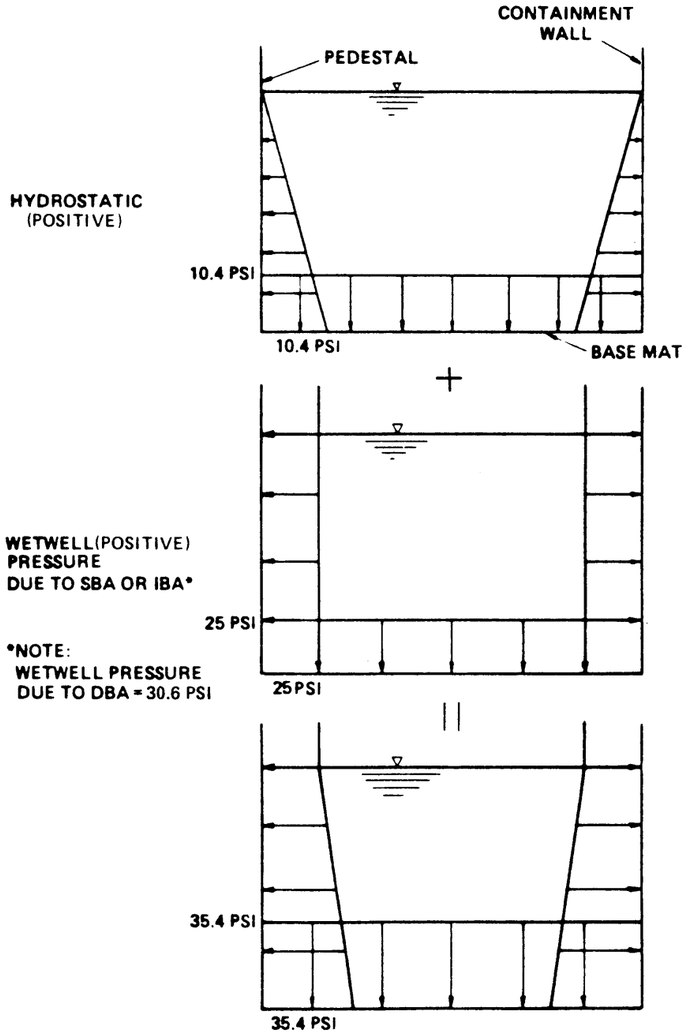
*PRESSURE MULTIPLIER

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

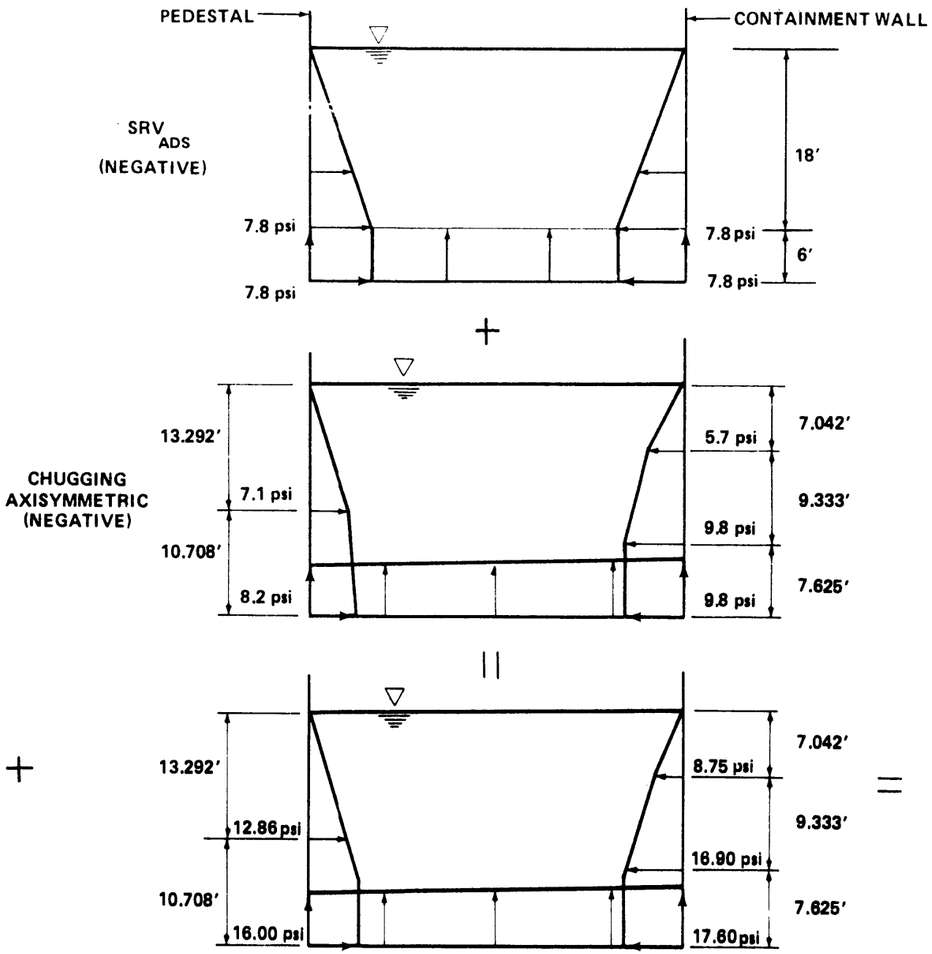
DESIGN ASSESSMENT REPORT

LINER PLATE PRESSURES NORMAL CONDITION

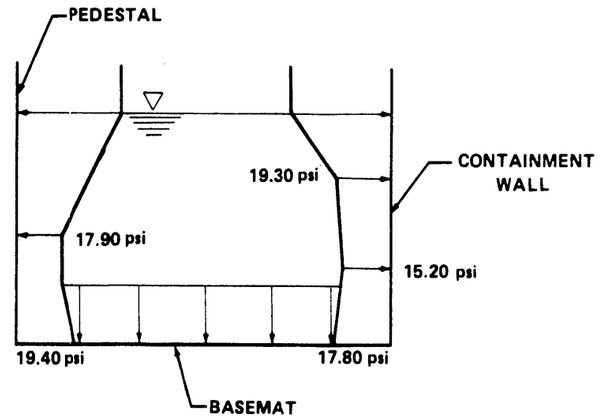
FIGURE 3A-41



TOTAL
CONSTANT POSITIVE PRESSURE



TOTAL
CYCLIC
NEGATIVE PRESSURE



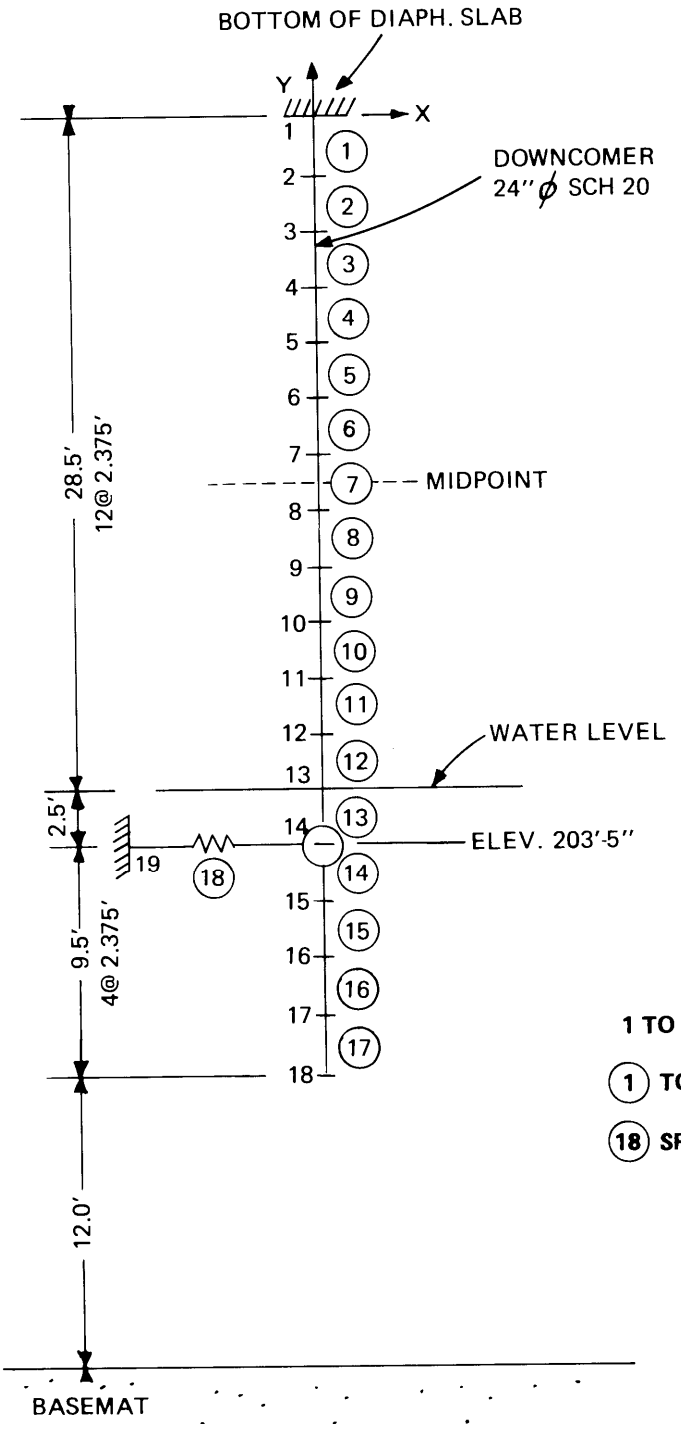
NET PRESSURE =
TOTAL POSITIVE PRESSURE + TOTAL NEGATIVE PRESSURE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

LINER PLATE PRESSURES ABNORMAL CONDITION

FIGURE 3A-42

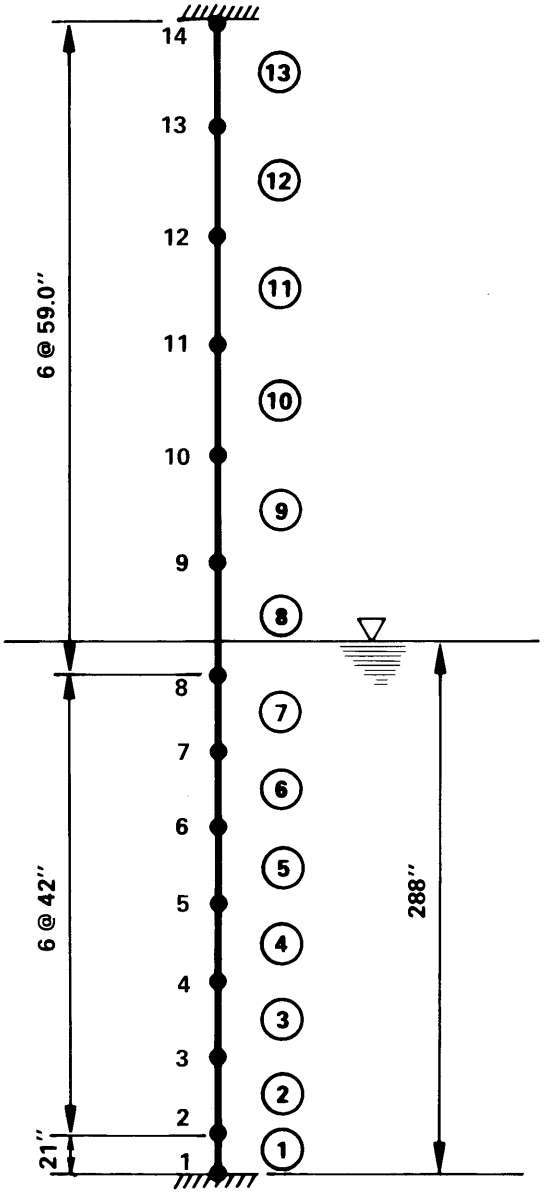


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

DOWNCOMER ANALYTICAL MODEL

FIGURE 3A-43

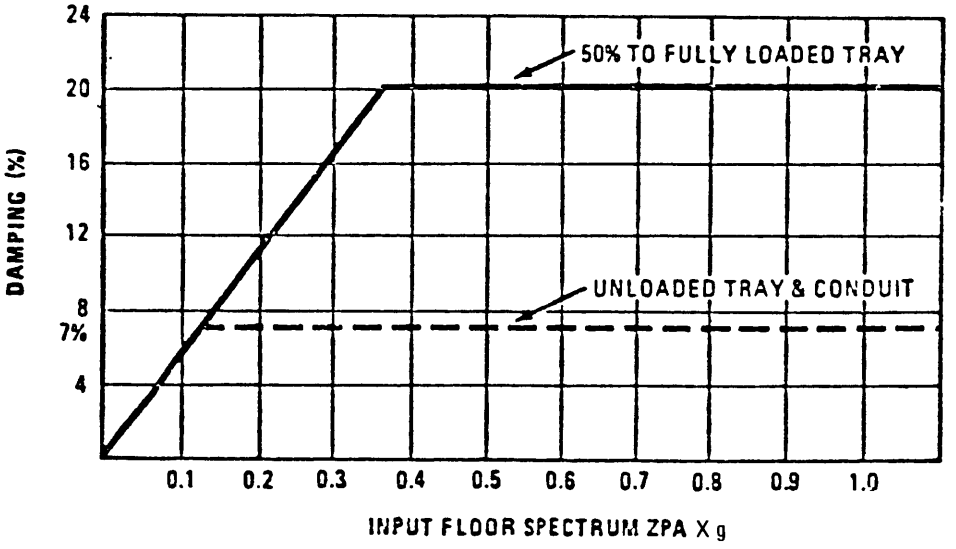


LIMERICK GENERATING STATION
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DESIGN ASSESSMENT REPORT

SUPPRESSION CHAMBER COLUMN ANALYTICAL MODEL

FIGURE 3A-44



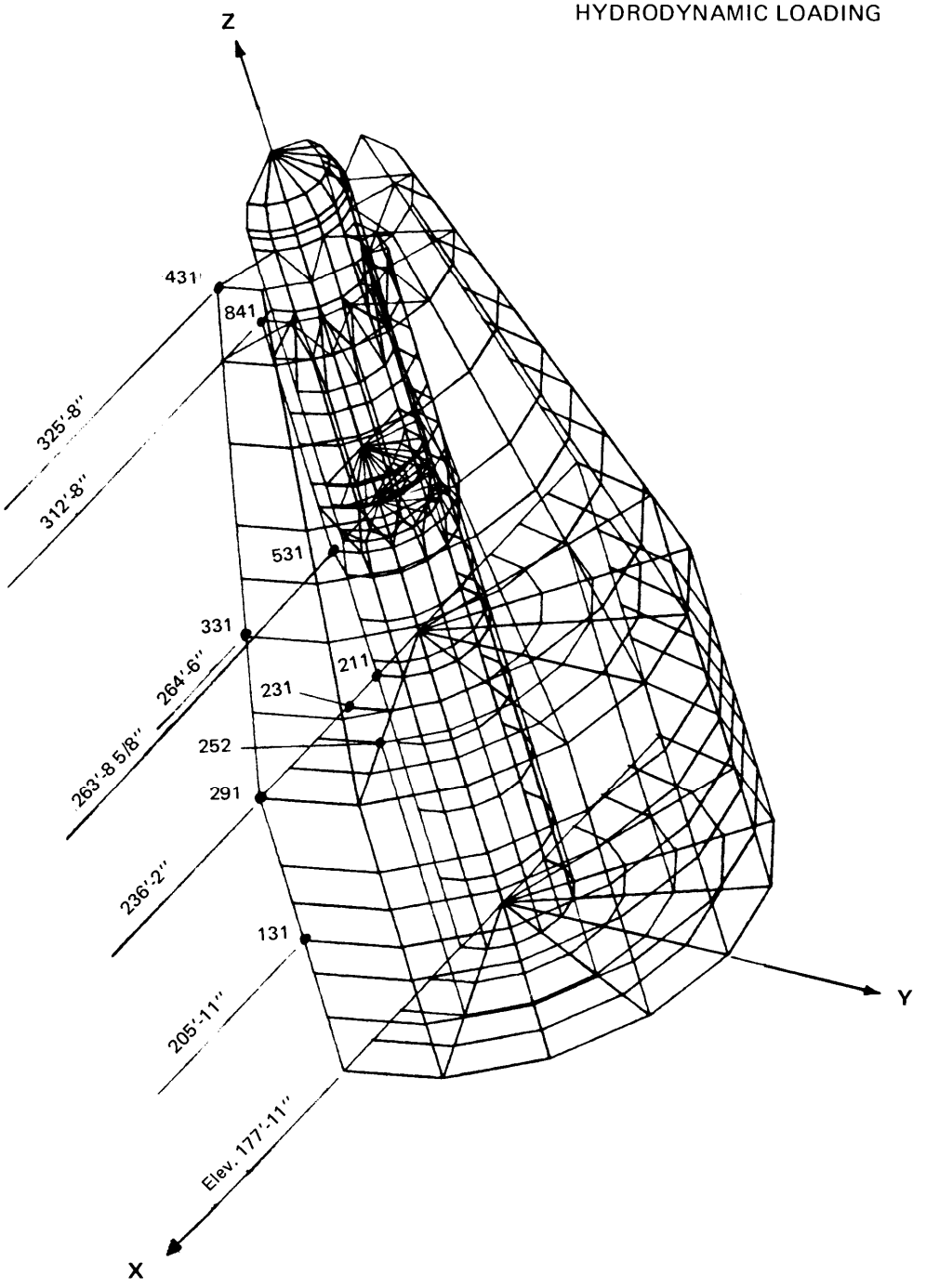
(SOURCE: DAR REF. 3A-32)

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT DESIGN

ALLOWABLE DAMPING VALUES FOR ELECTRICAL RACEWAY SYSTEM DESIGN

FIGURE 3A-45



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

MODEL FOR CONTAINMENT RESPONSE SPECTRA

FIGURE 3A-46

MODE NO.	FREQUENCY (Hz)	DIRECTION	LOCATION MAX. DISPLACEMENT
1	3.92	H	RPV INTERNAL
2	5.04	H	RPV INTERNAL
3	6.85	H	RPV INTERNAL
4	8.00	H	RPV INTERNAL
5	9.43	H	RPV INTERNAL
6	14.01	V	RPV INTERNAL
7	14.86	B	CONTAINMENT
8	16.59	H	RPV INTERNAL
9	18.32	V	CONTAINMENT
10	19.38	H	RPV INTERNAL
11	19.60	H	RPV INTERNAL
12	23.24	B	RPV SHIELD
13	23.94	B	RPV SHIELD
14	26.09	H	CONTAINMENT
15	26.42	H	PEDESTAL
16	27.88	B	CONTAINMENT
17	28.52	H	RPV SHIELD
18	32.08	V	RPV INTERNAL
19	32.54	H	CONTAINMENT
20	34.21	B	CONTAINMENT
21	34.87	H	RPV SHIELD
22	36.78	V	RPV INTERNAL
23	39.31	V	RPV INTERNAL

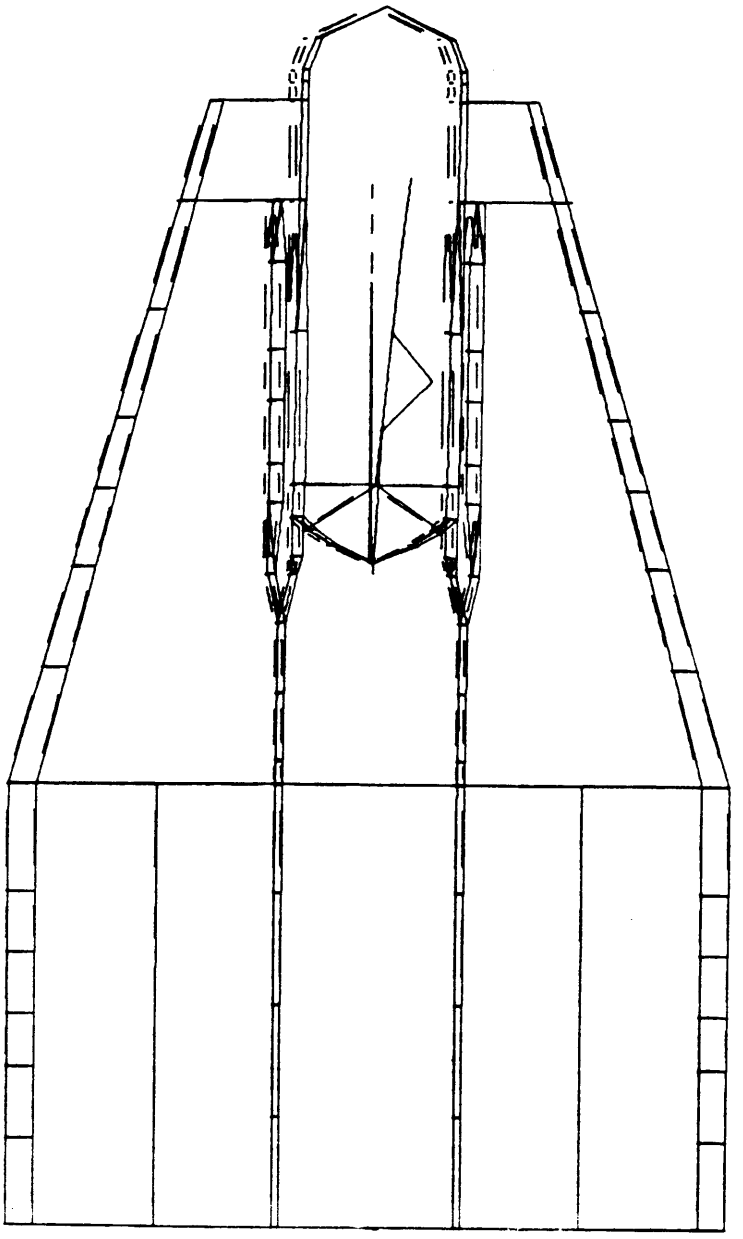
NOTES: H - HORIZONTAL
V - VERTICAL
B - BREATHING

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

CONTAINMENT MODES AND FREQUENCIES

FIGURE 3A-47



MODE 1
(WITH WATER MASS)

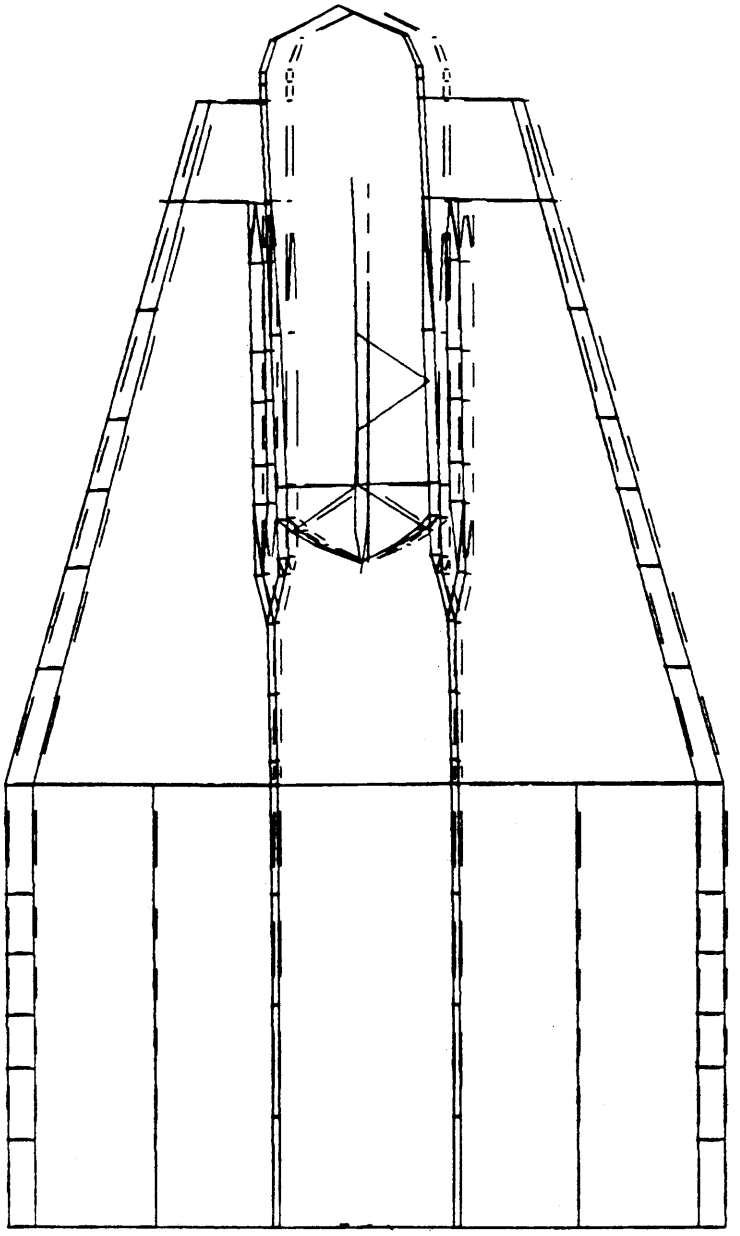
f = 3.92 Hz

LIMERICK GENERATING STATION
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DESIGN ASSESSMENT REPORT

CONTAINMENT MODE SHAPES

FIGURE 3A-48



MODE 2
(WITH WATER MASS)

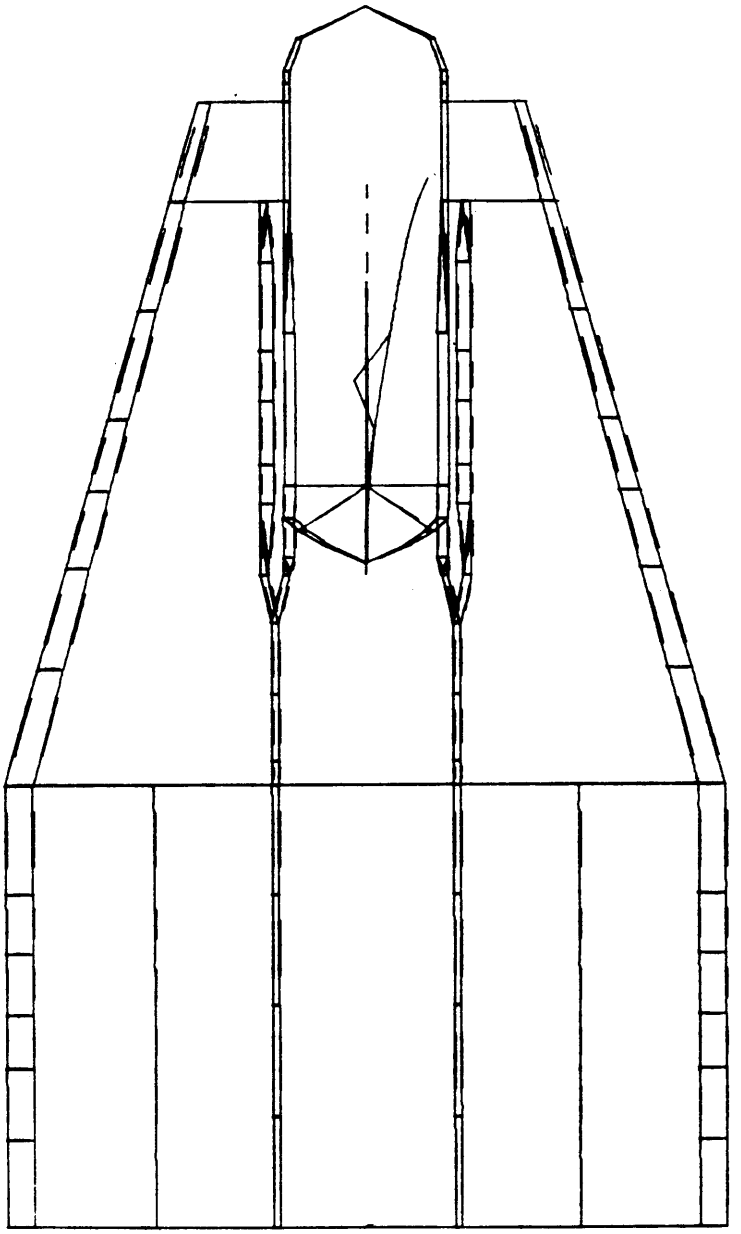
f = 5.04 Hz

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

CONTAINMENT MODE SHAPES

FIGURE 3A-49



MODE 3
(WITH WATER MASS)

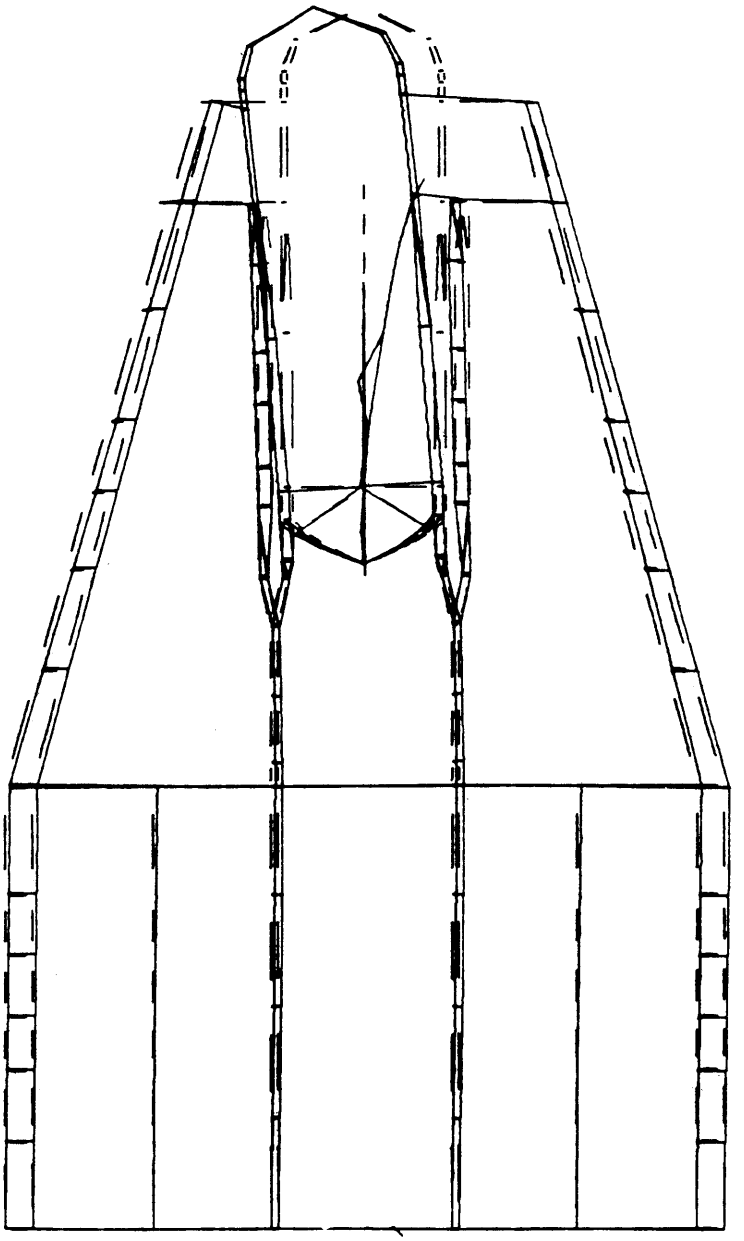
f = 6.85 Hz

LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

CONTAINMENT MODE SHAPES

FIGURE 3A-50



MODE 4
(WITH WATER MASS)

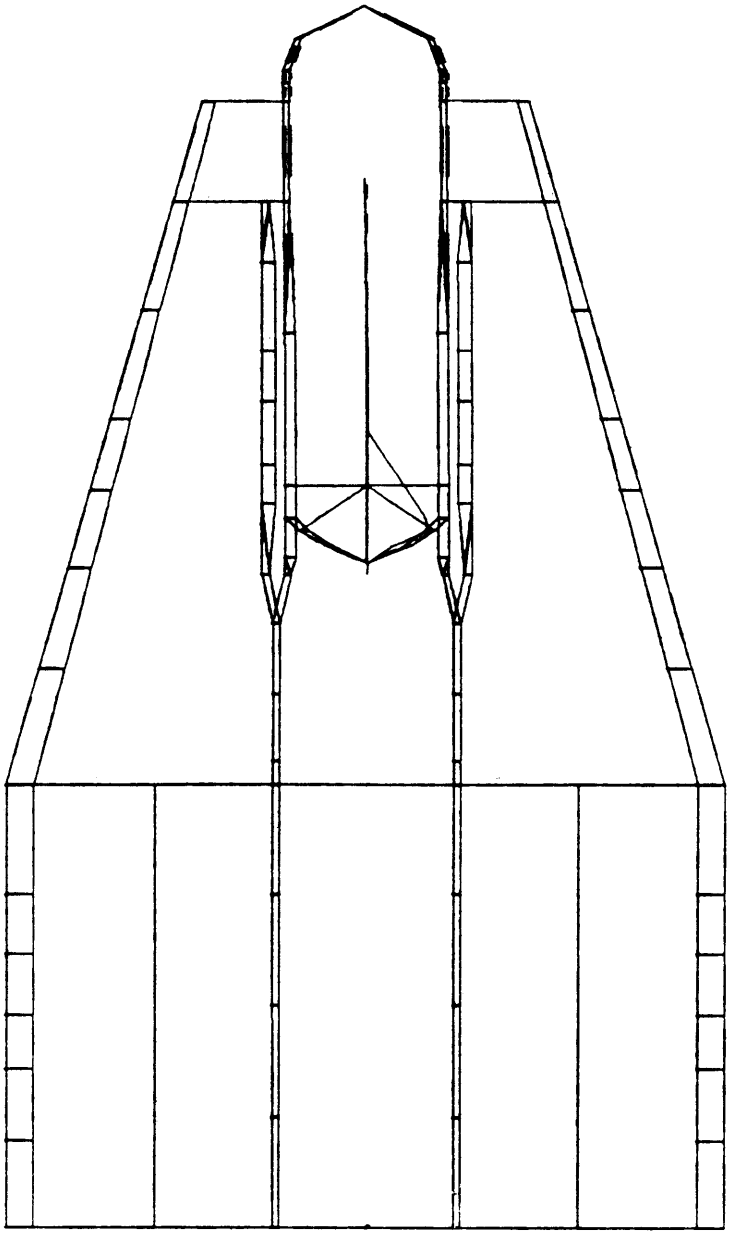
f = 8.00 Hz

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FIGURE 3A-51



MODE 5
(WITH WATER MASS)

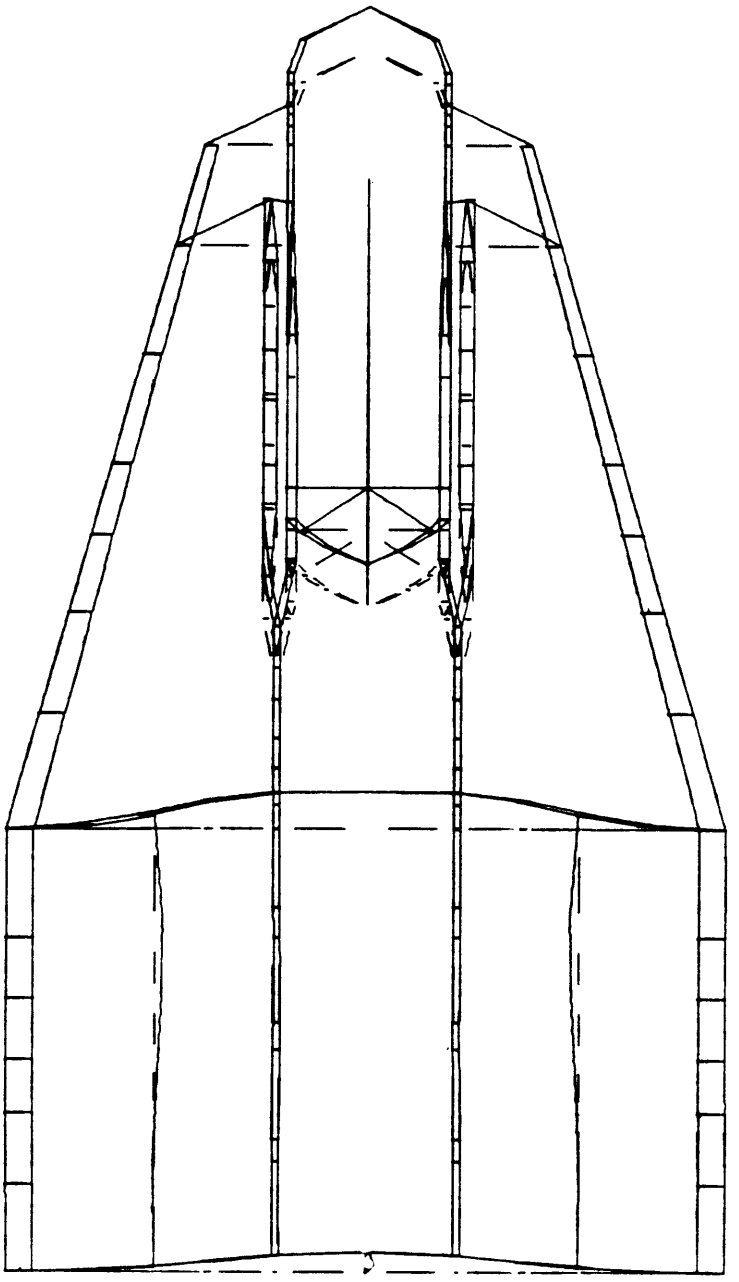
f = 9.43 Hz

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FIGURE 3A-52



MODE 6
(WITH WATER MASS)

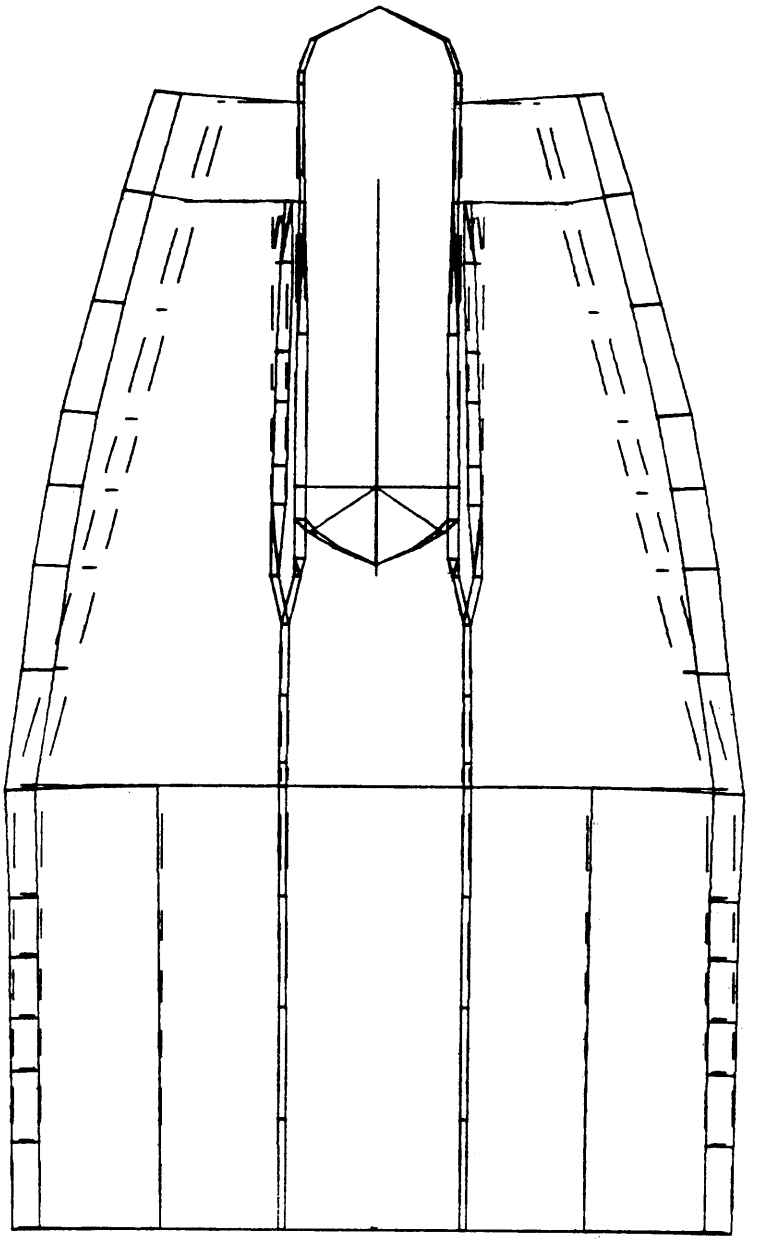
f = 14.01 Hz

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FIGURE 3A-53



MODE 7
(WITH WATER MASS)

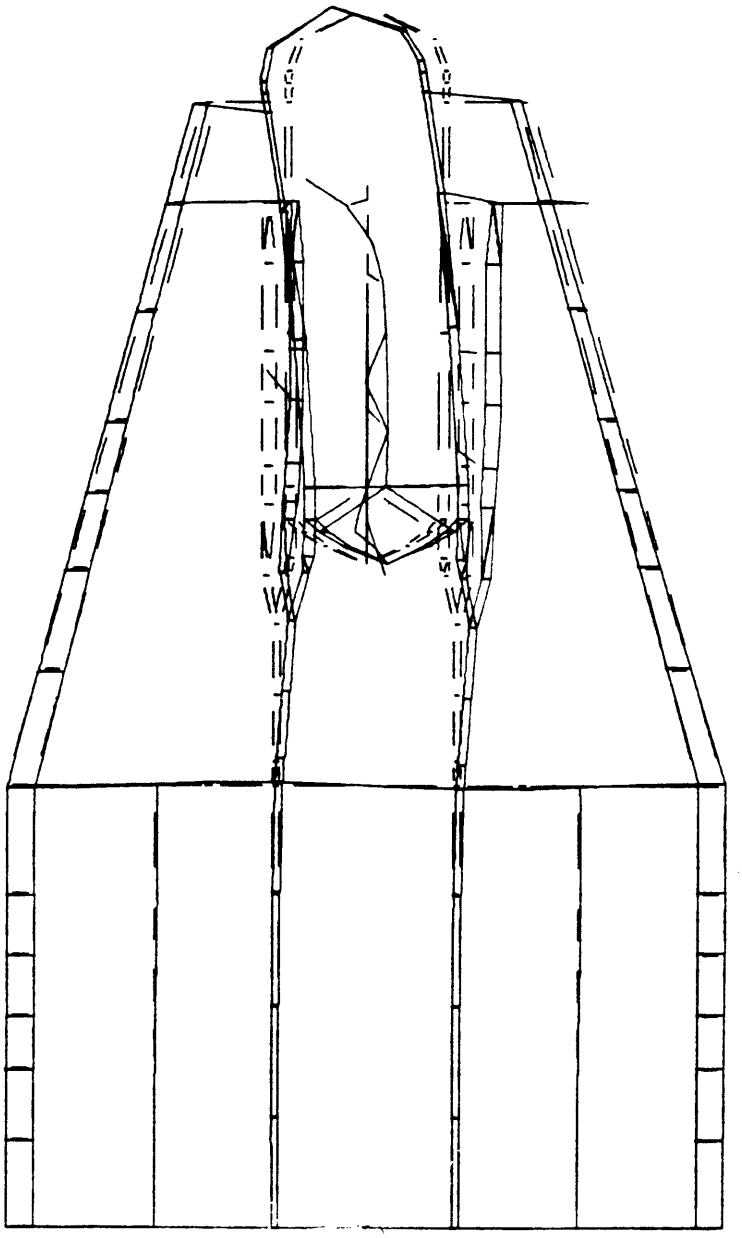
f = 14.86 Hz

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FIGURE 3A-54



MODE 8
(WITH WATER MASS)

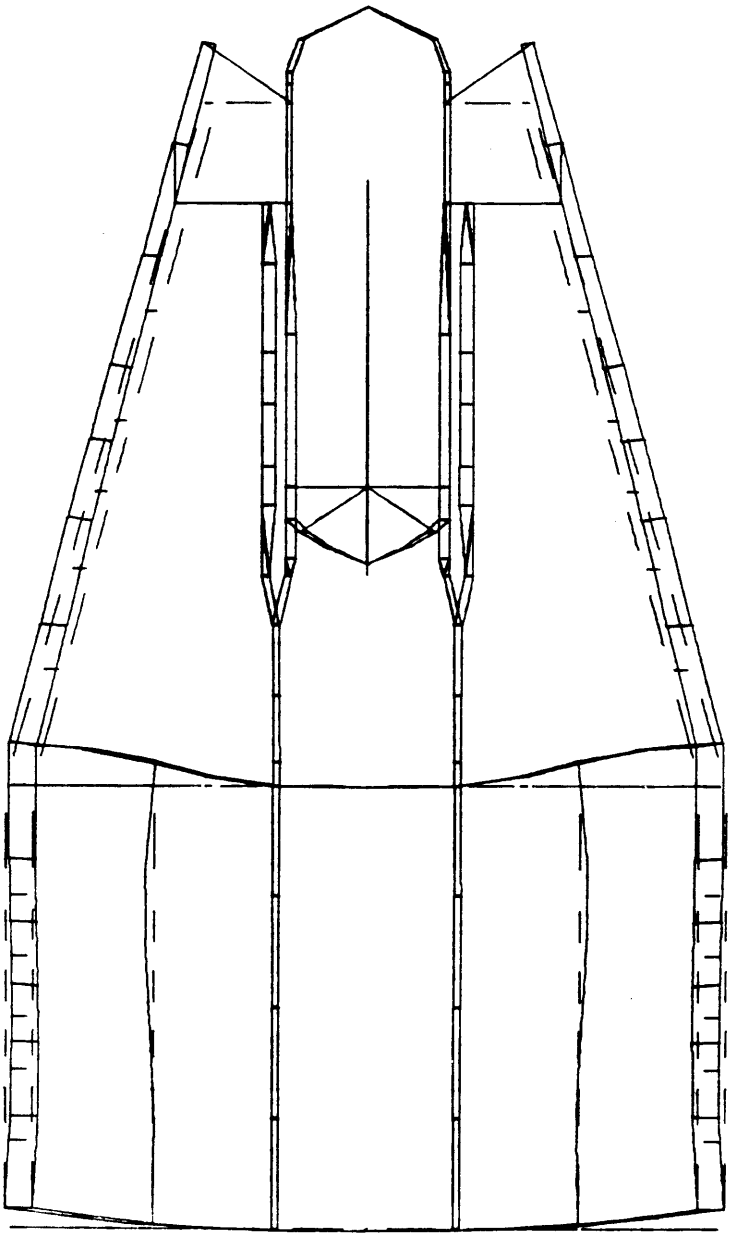
f = 16.59 Hz

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FIGURE 3A-55



MODE 9
(WITH WATER MASS)

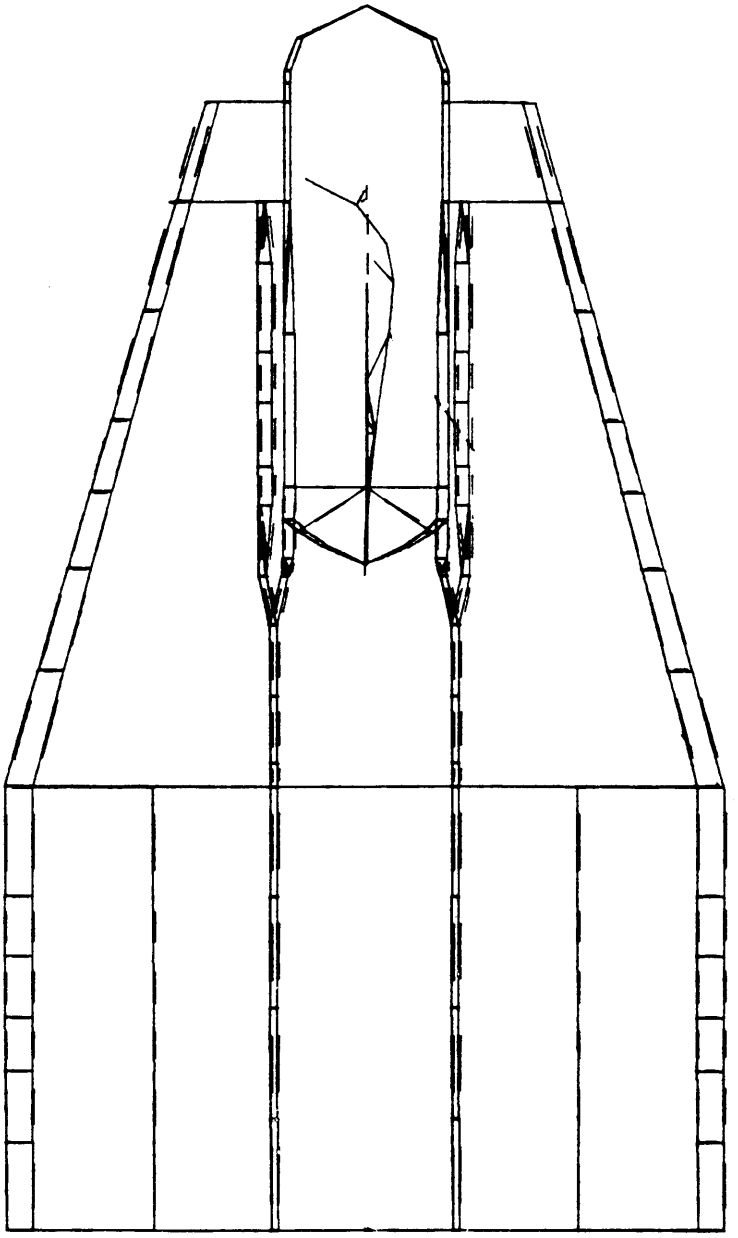
f = 18.32 Hz

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FIGURE 3A-56



MODE 10
(WITH WATER MASS)

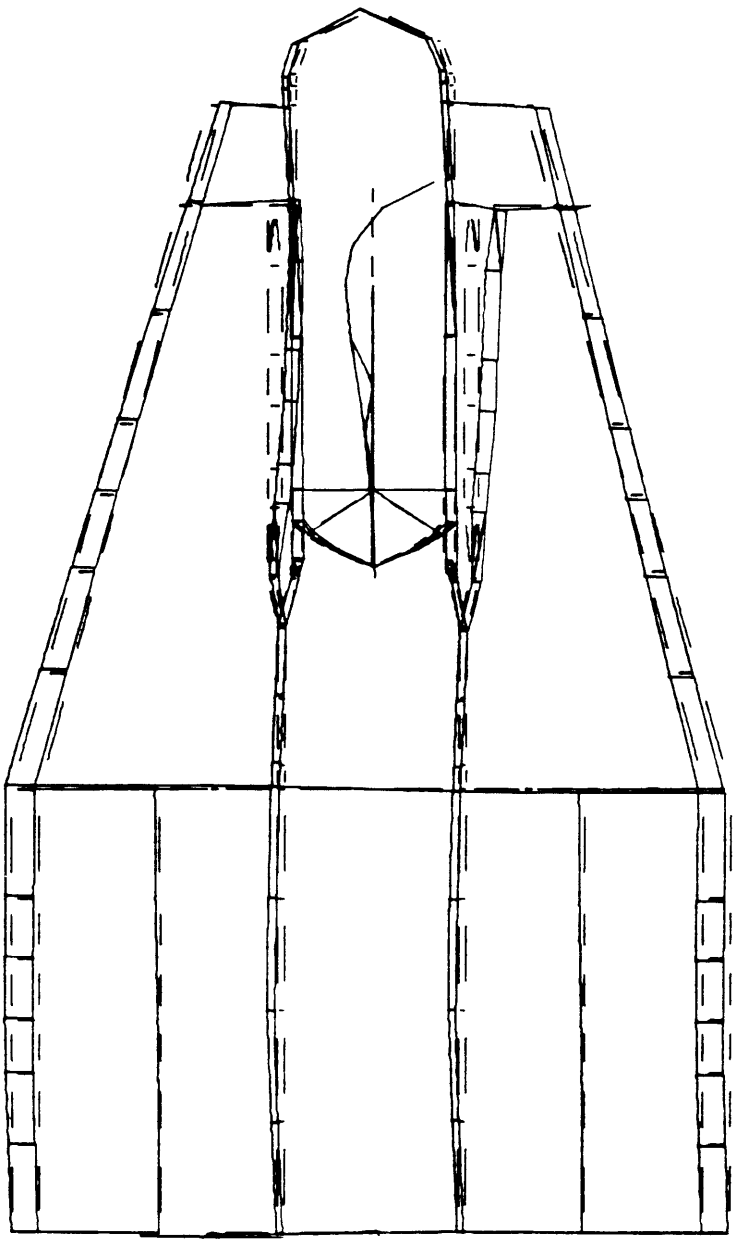
f = 19.38 Hz

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FIGURE 3A-57



MODE 11
(WITH WATER MASS)

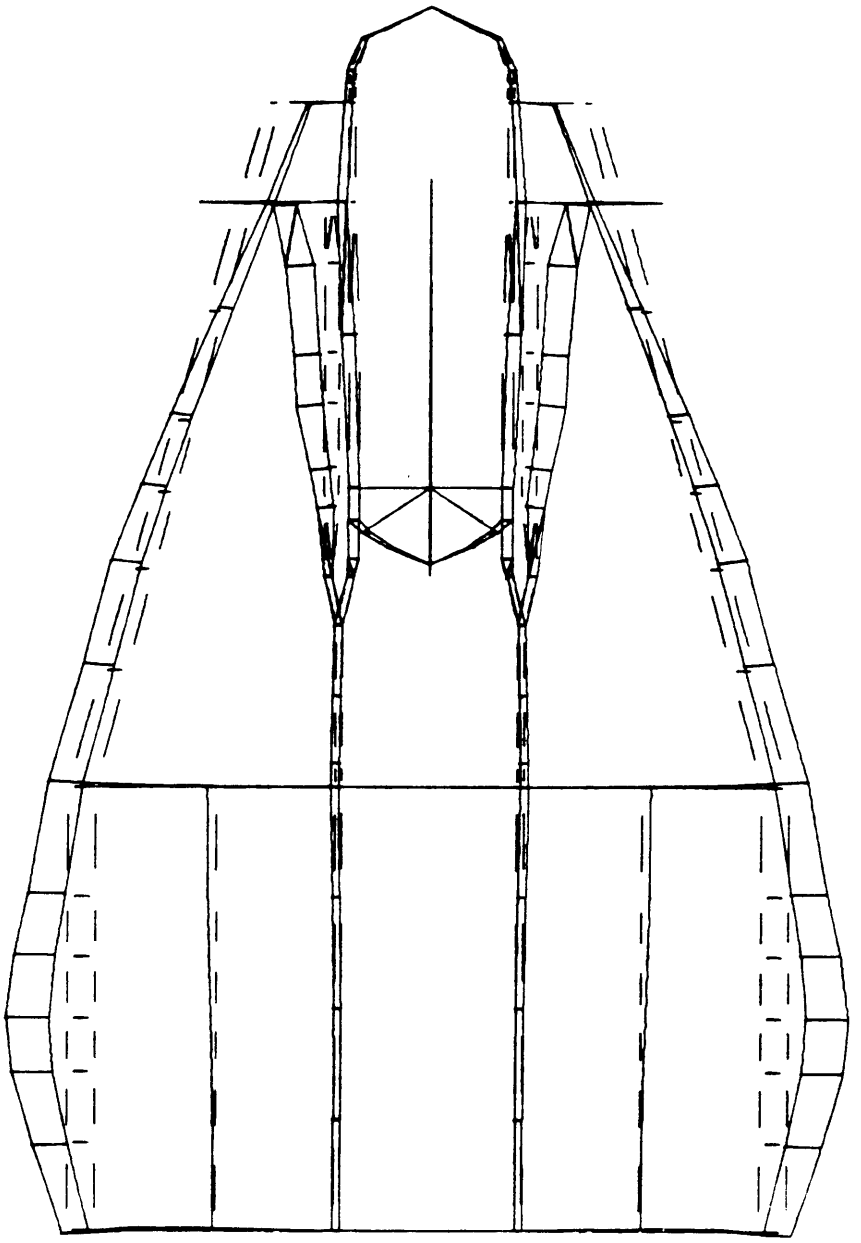
f = 19.60 Hz

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FIGURE 3A-58



MODE 12
(WITH WATER MASS)

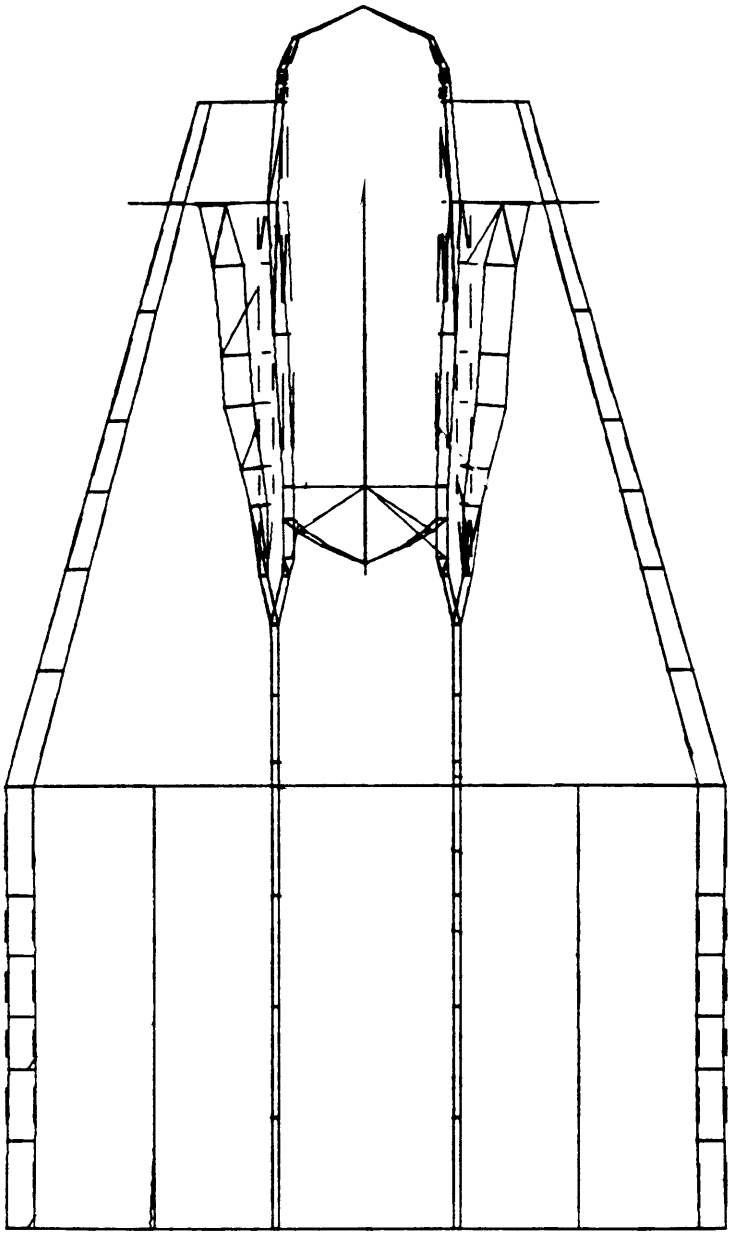
f = 23.24 Hz

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FIGURE 3A-59



MODE 13
(WITH WATER MASS)

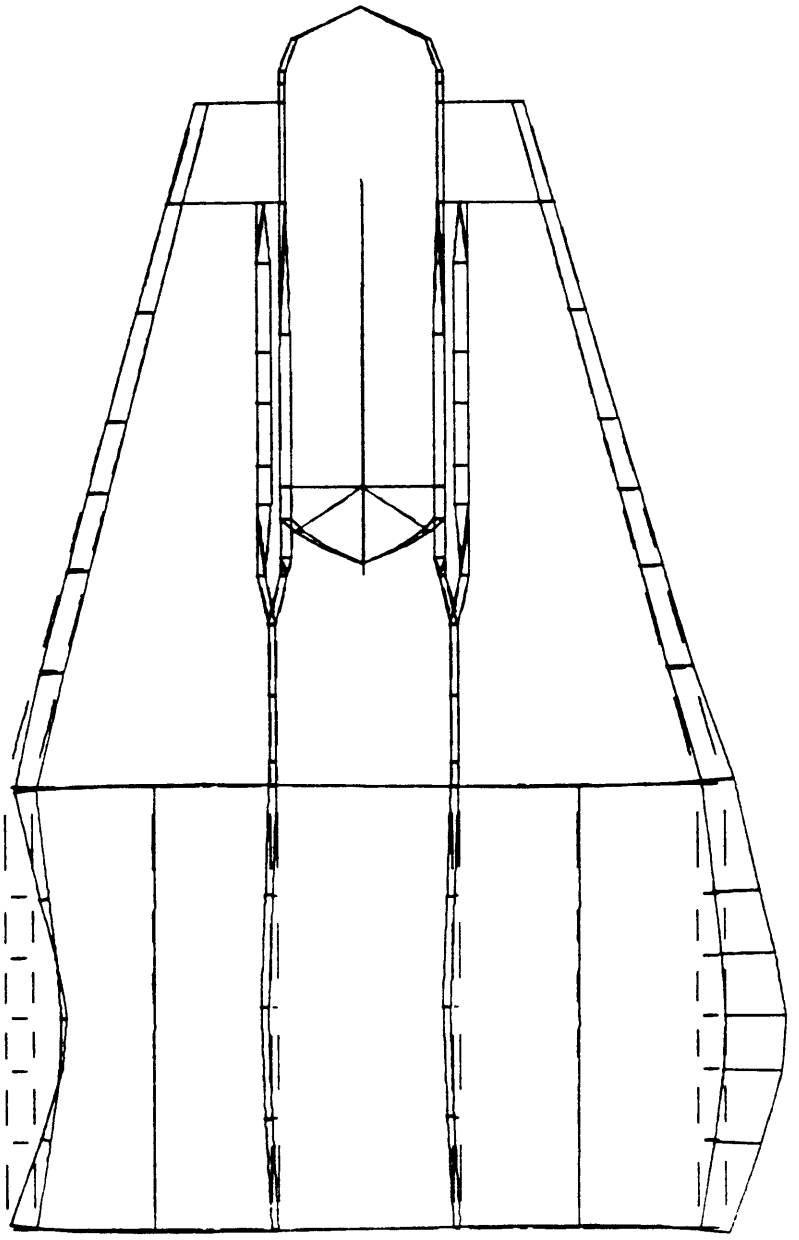
f = 23.94 Hz

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FIGURE 3A-60



MODE 14
(WITH WATER MASS)

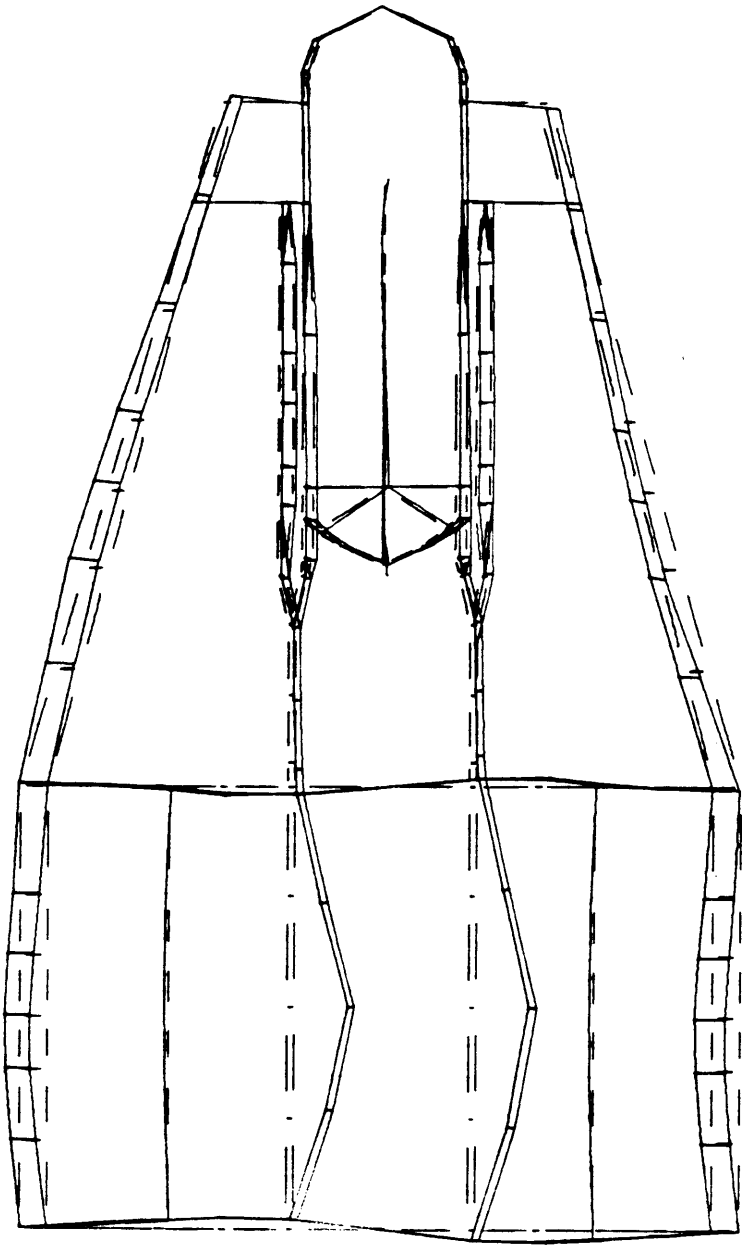
f = 26.09 Hz

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FIGURE 3A-61



MODE 15
(WITH WATER MASS)

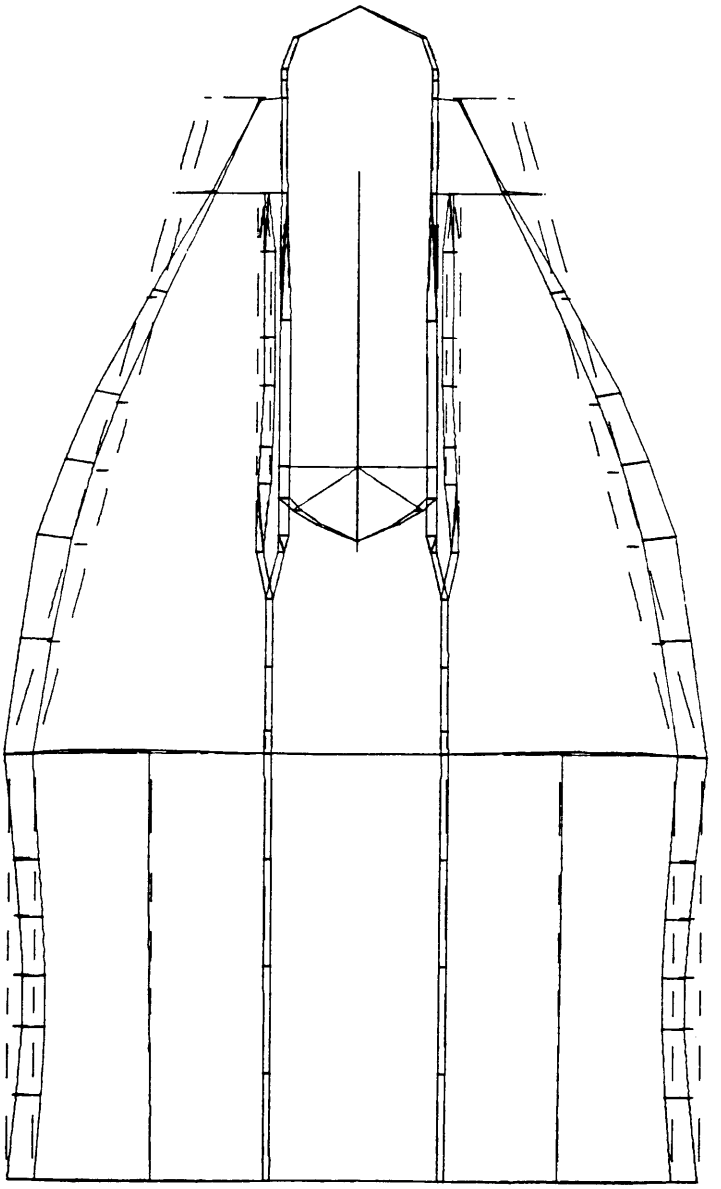
f = 26.42 Hz

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FIGURE 3A-62



MODE 16
(WITH WATER MASS)

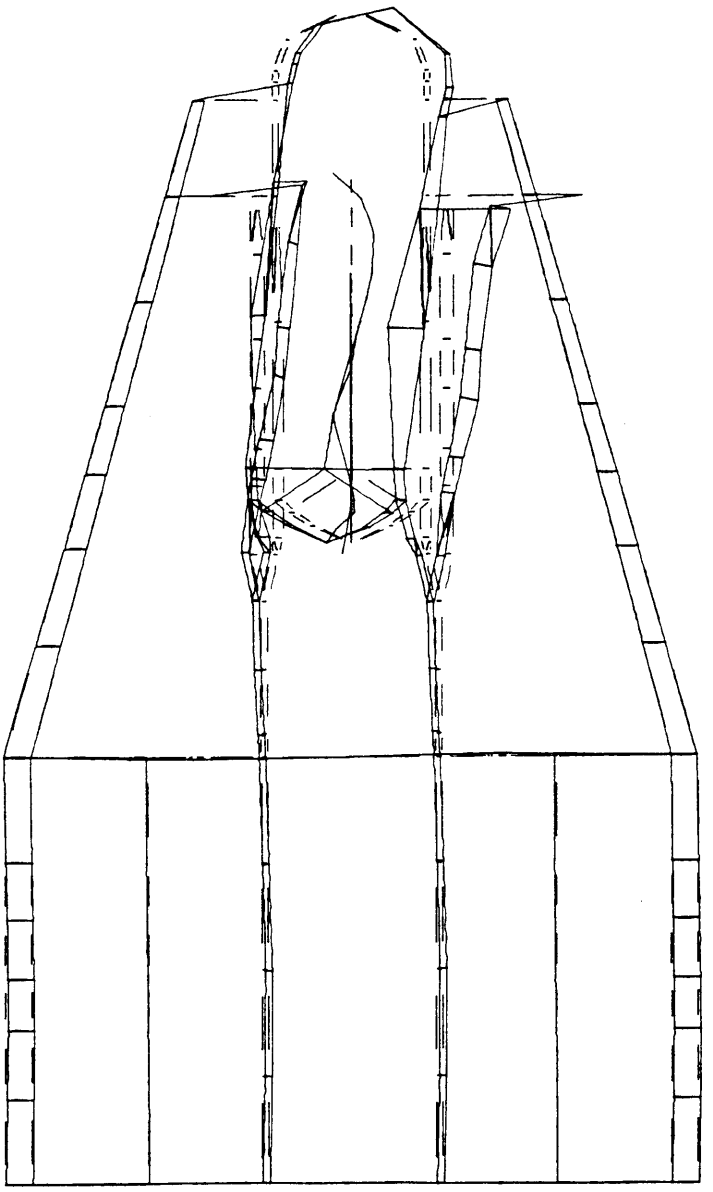
f = 27.88 Hz

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FIGURE 3A-63



MODE 17
(WITH WATER MASS)

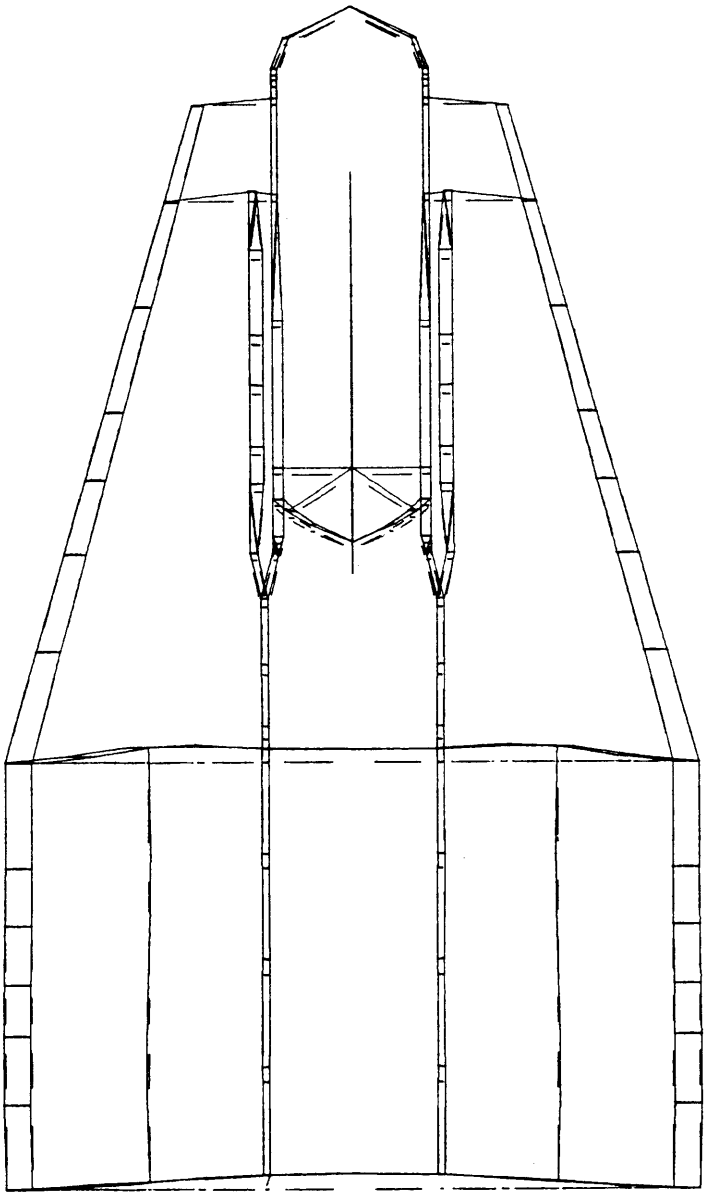
f = 28.52 Hz

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FIGURE 3A-64



MODE 18
(WITH WATER MASS)

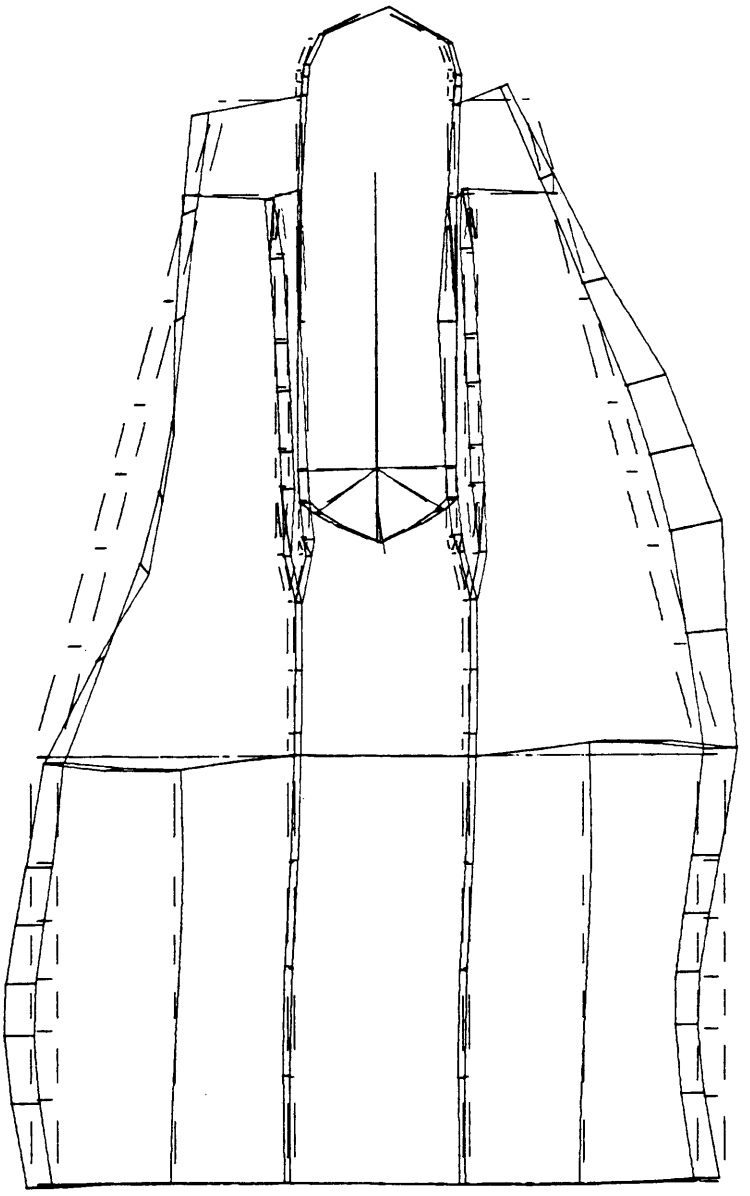
f = 32.08 Hz

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FIGURE 3A-65



MODE 19
(WITH WATER MASS)

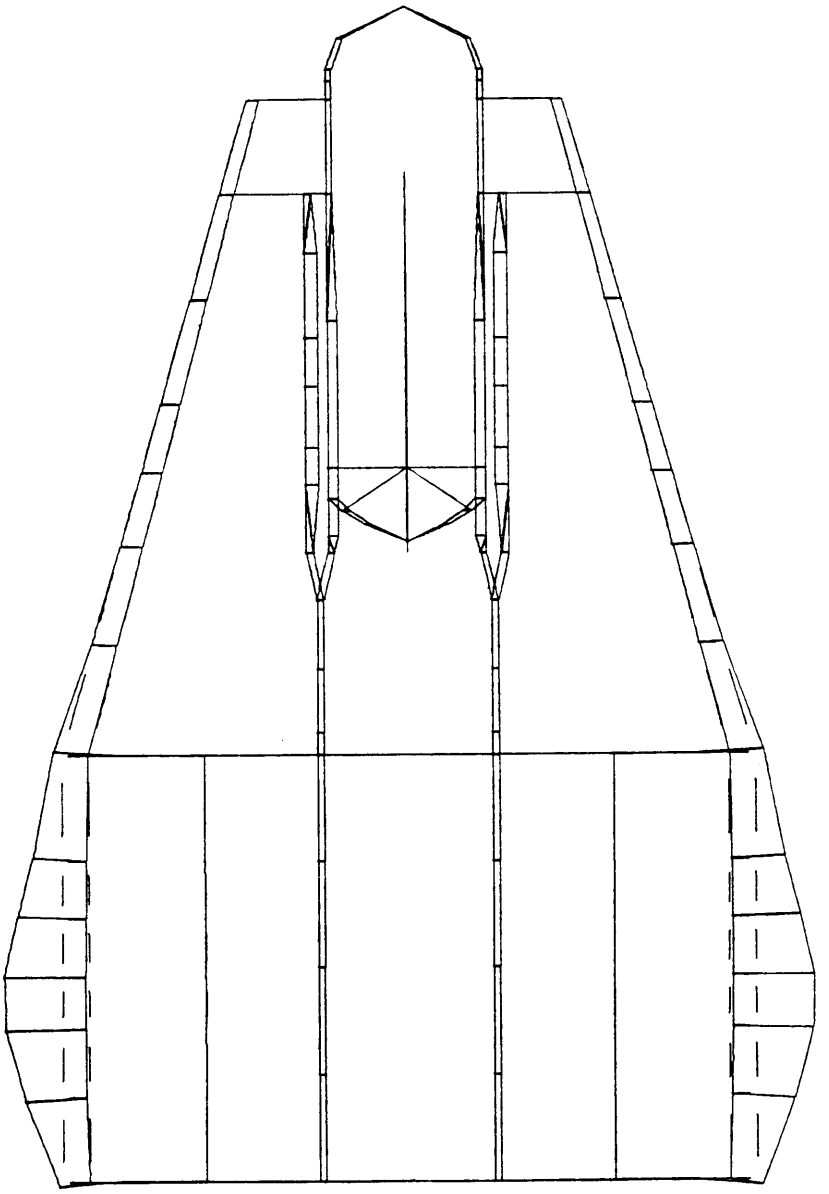
f = 32.54 Hz

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FIGURE 3A-66



MODE 20
(WITH WATER MASS)

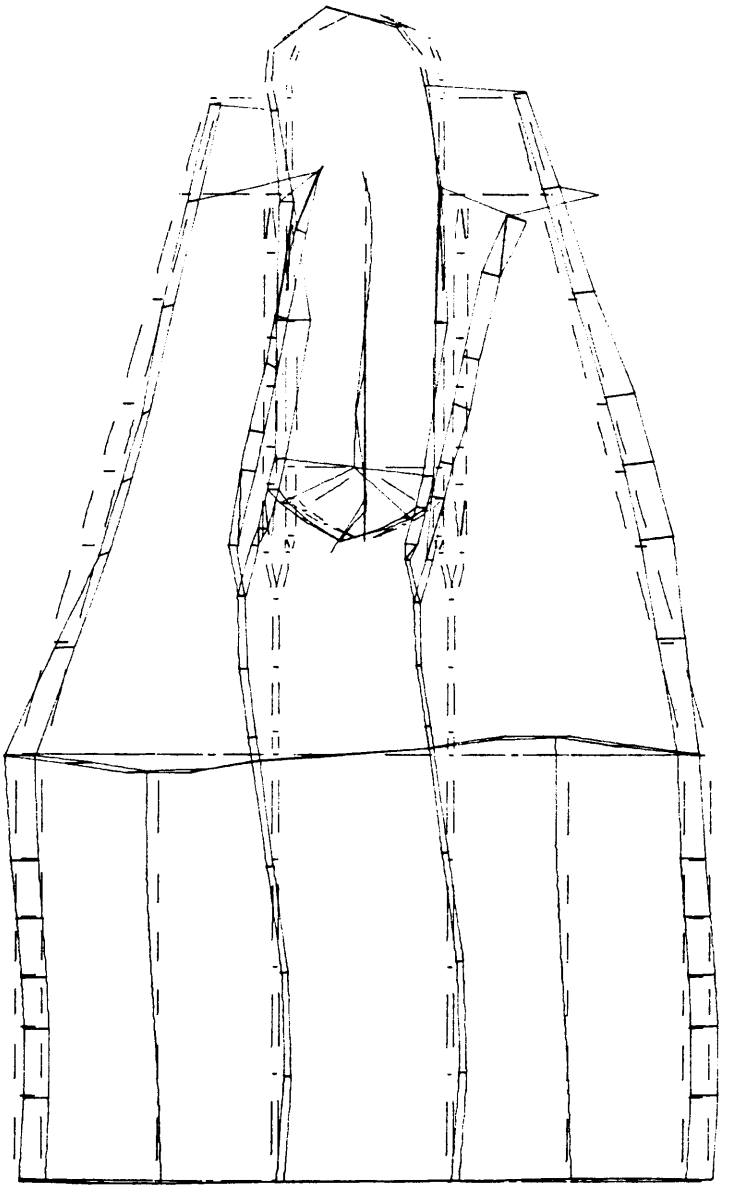
f = 34.21 Hz

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FIGURE 3A-67



MODE 21
(WITH WATER MASS)

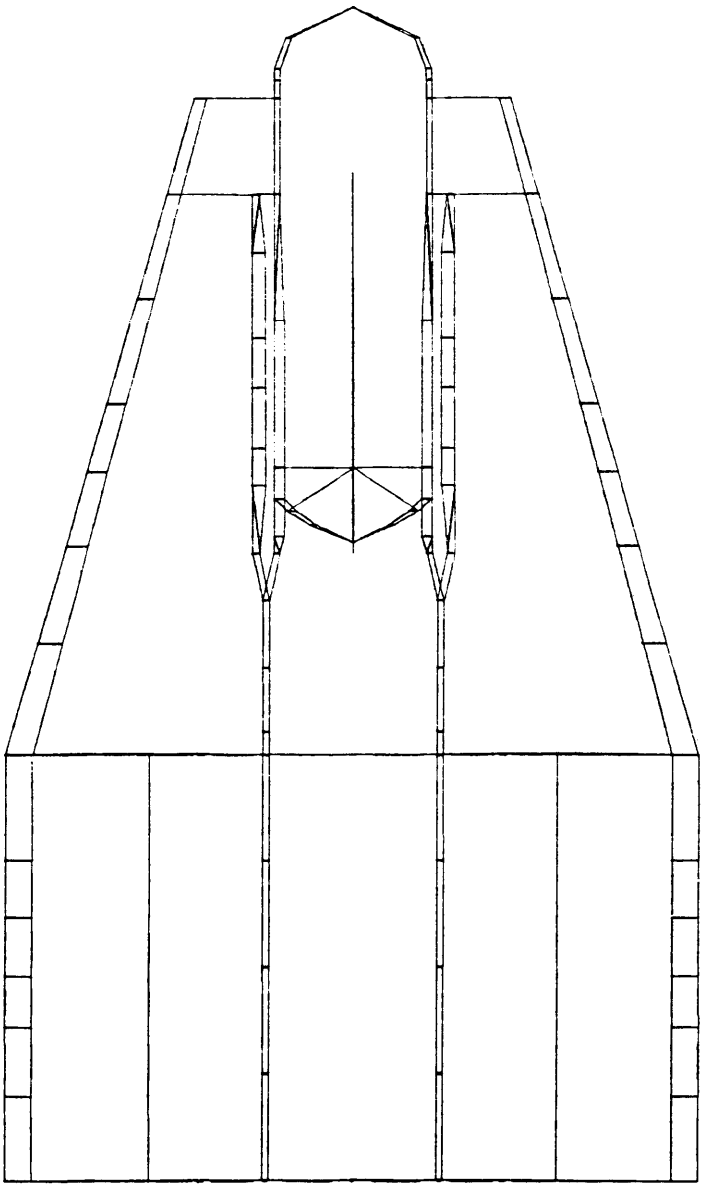
f = 34.87 Hz

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FIGURE 3A-68



MODE 22
(WITH WATER MASS)

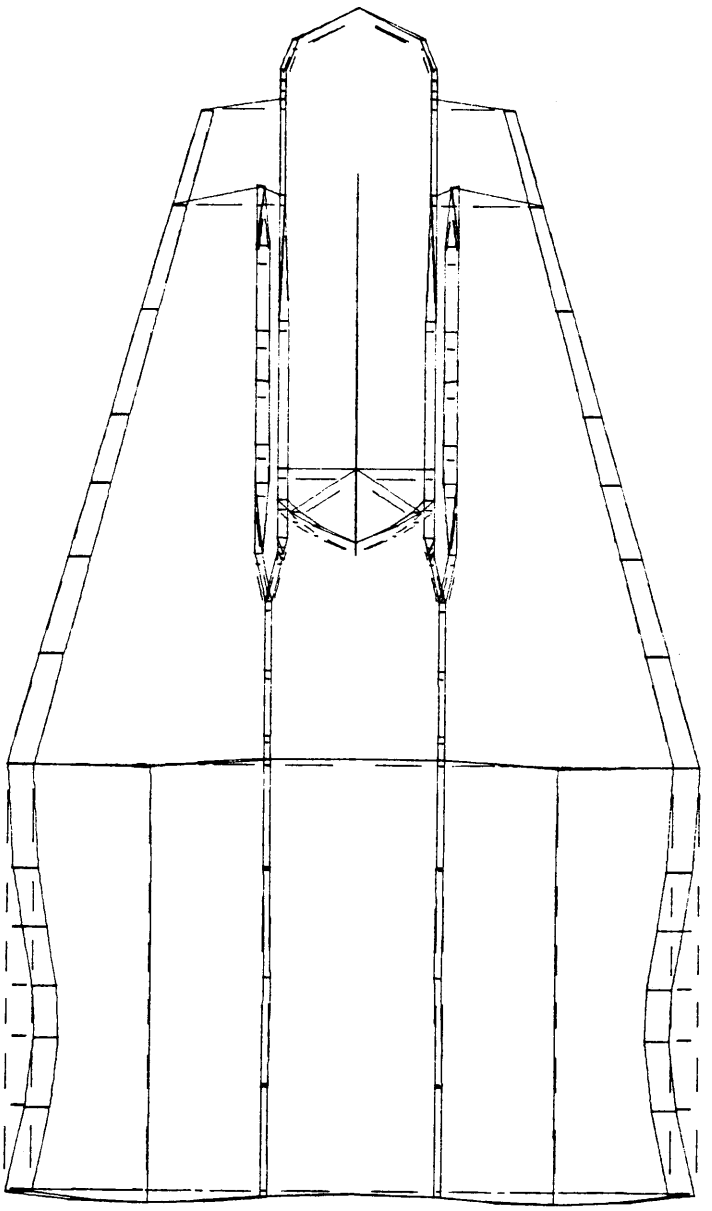
f = 36.78 Hz

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FIGURE 3A-69



MODE 23
(WITH WATER MASS)

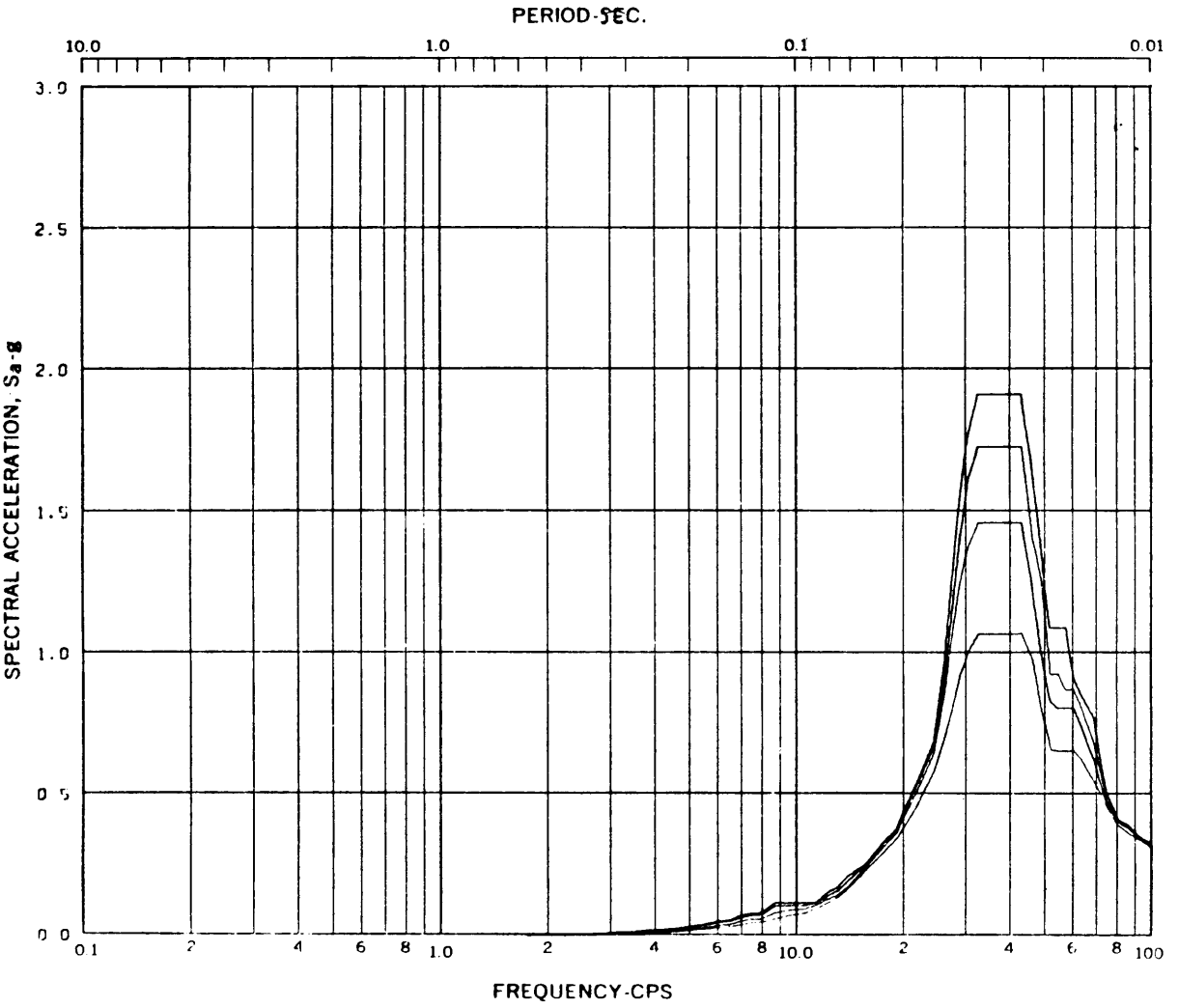
f = 39.31 Hz

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FIGURE 3A-70



Acceleration Spectra for WETWELL WALL

Load Case: SRV - AXISYMMETRIC

Node: 131 Direction: HORIZ Elev: 205'-11" Angle: 0°

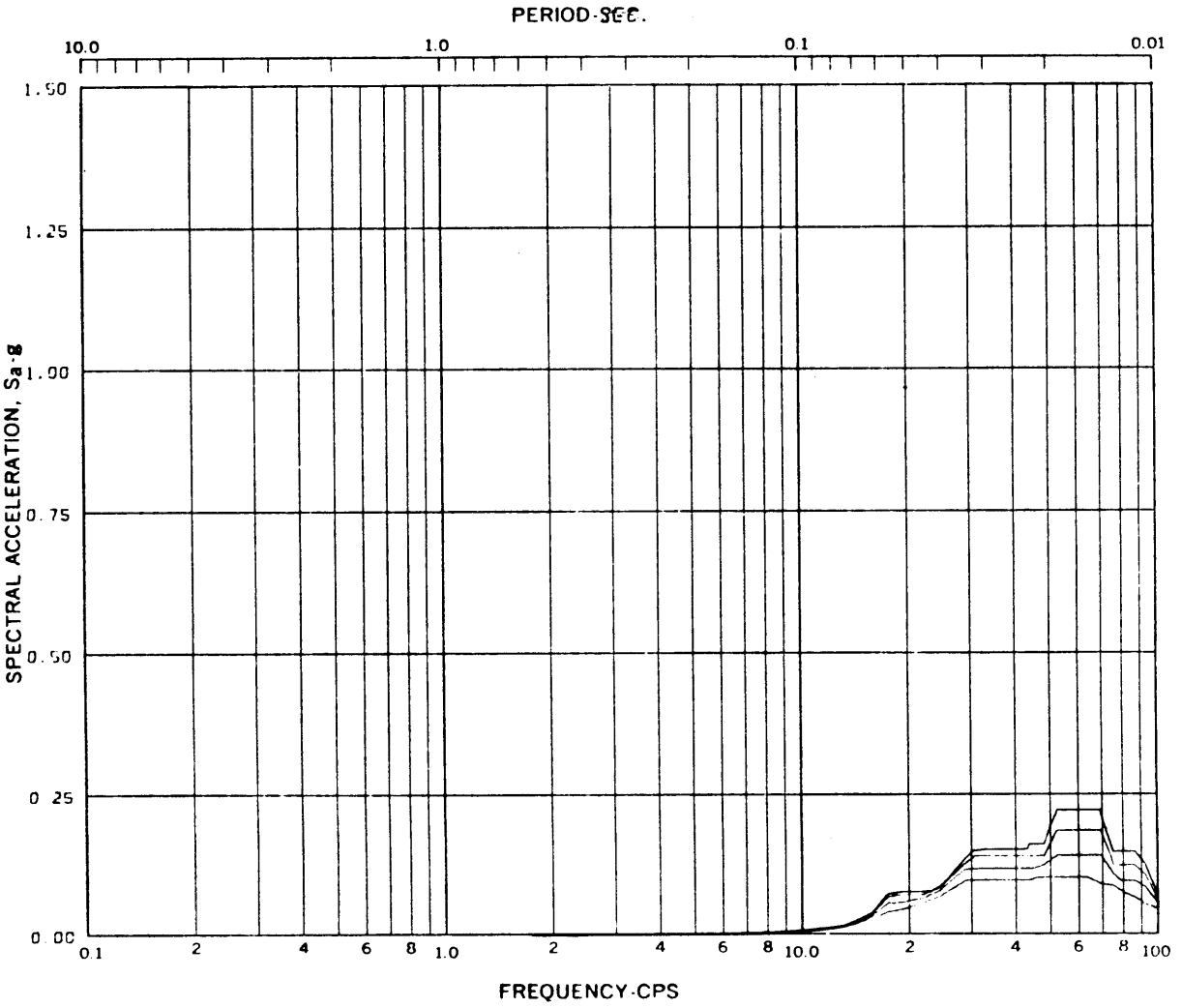
Damping: 0.005,0.01,0.02,0.05

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SRV AXISYMMETRIC
DIRECTION X

FIGURE 3A-71



Acceleration Spectra for WETWELL WALL

Load Case: SRV - AXISYMMETRIC

Node: 291 Direction: HORIZ Elev: 236'-2" Angle: 0°

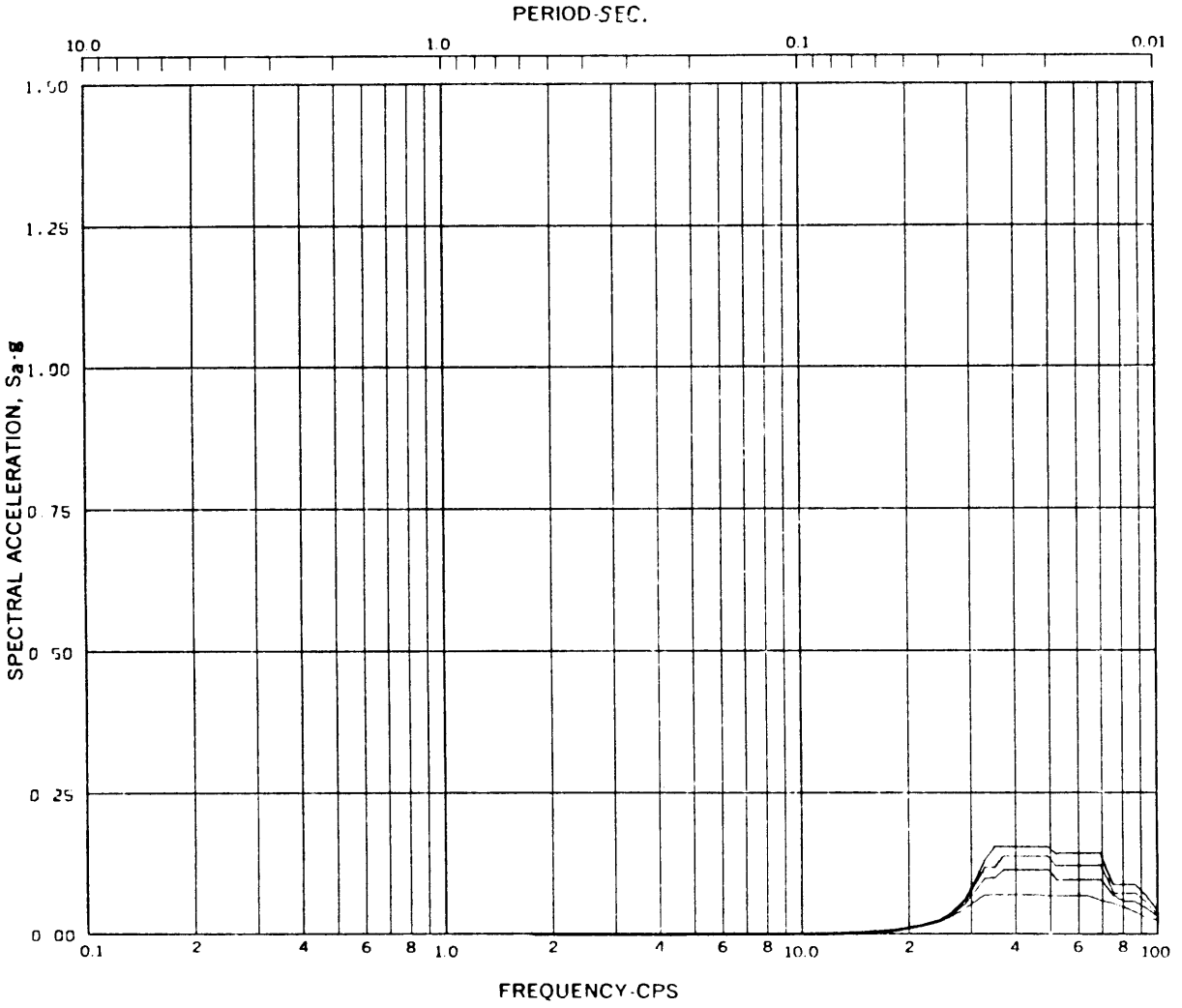
Damping: 0.005,0.01,0.02,0.05

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SRV AXISYMMETRIC
DIRECTION X

FIGURE 3A-72



Acceleration Spectra for DRYWELL WALL

Load Case: SRV - AXISYMMETRIC

Node: 331 Direction: HORIZ Elev: 264'-6" Angle: 0°

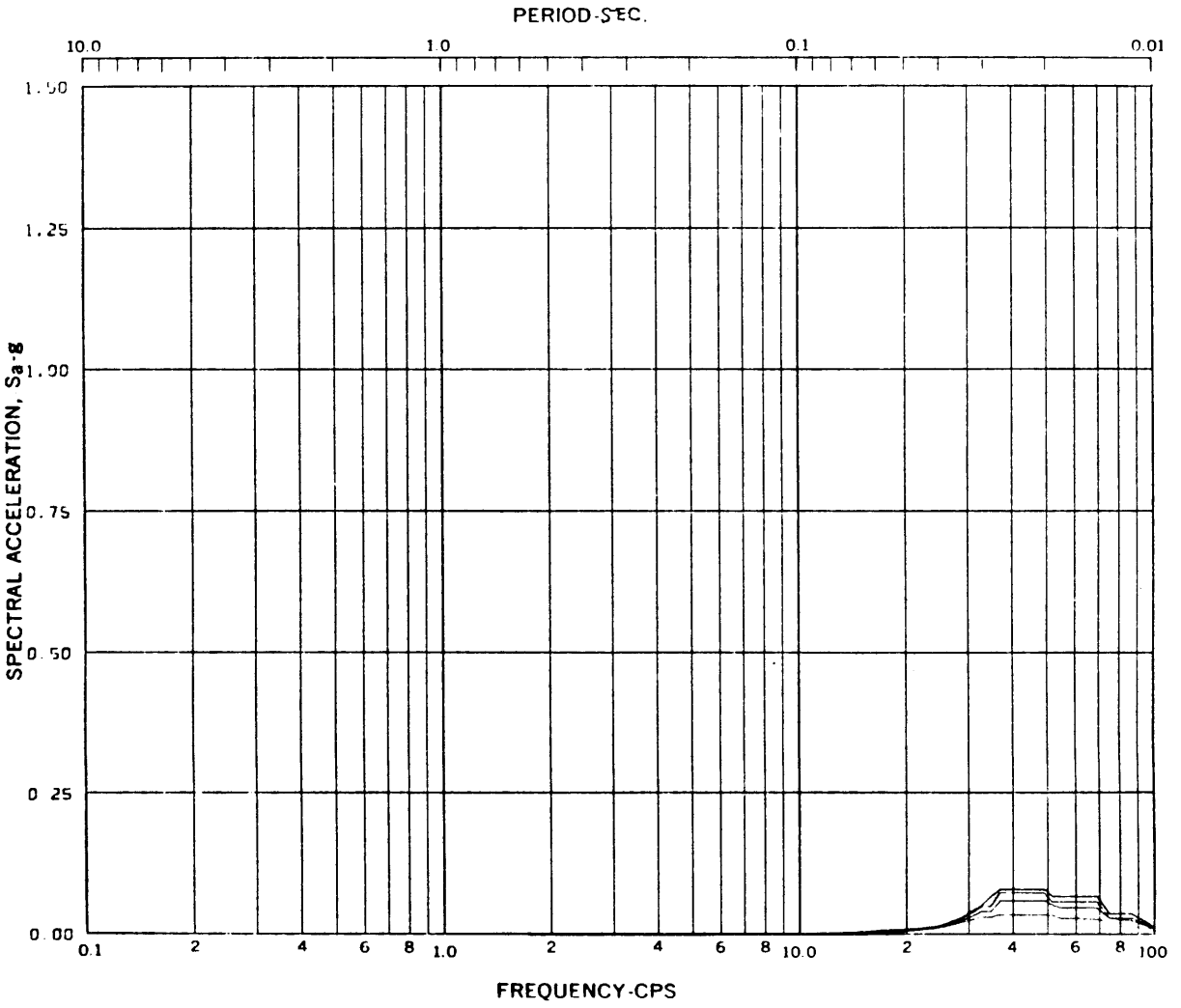
Damping: 0.005,0.01,0.02,0.05

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CONTAINMENT RESPONSE SPECTRA
SRV AXISYMMETRIC
DIRECTION X

FIGURE 3A-73



Acceleration Spectra for DRYWELL WALL

Load Case: SRV - AXISYMMETRIC

Node: 431 Direction: HORIZ Elev: 325'-8" Angle: 0°

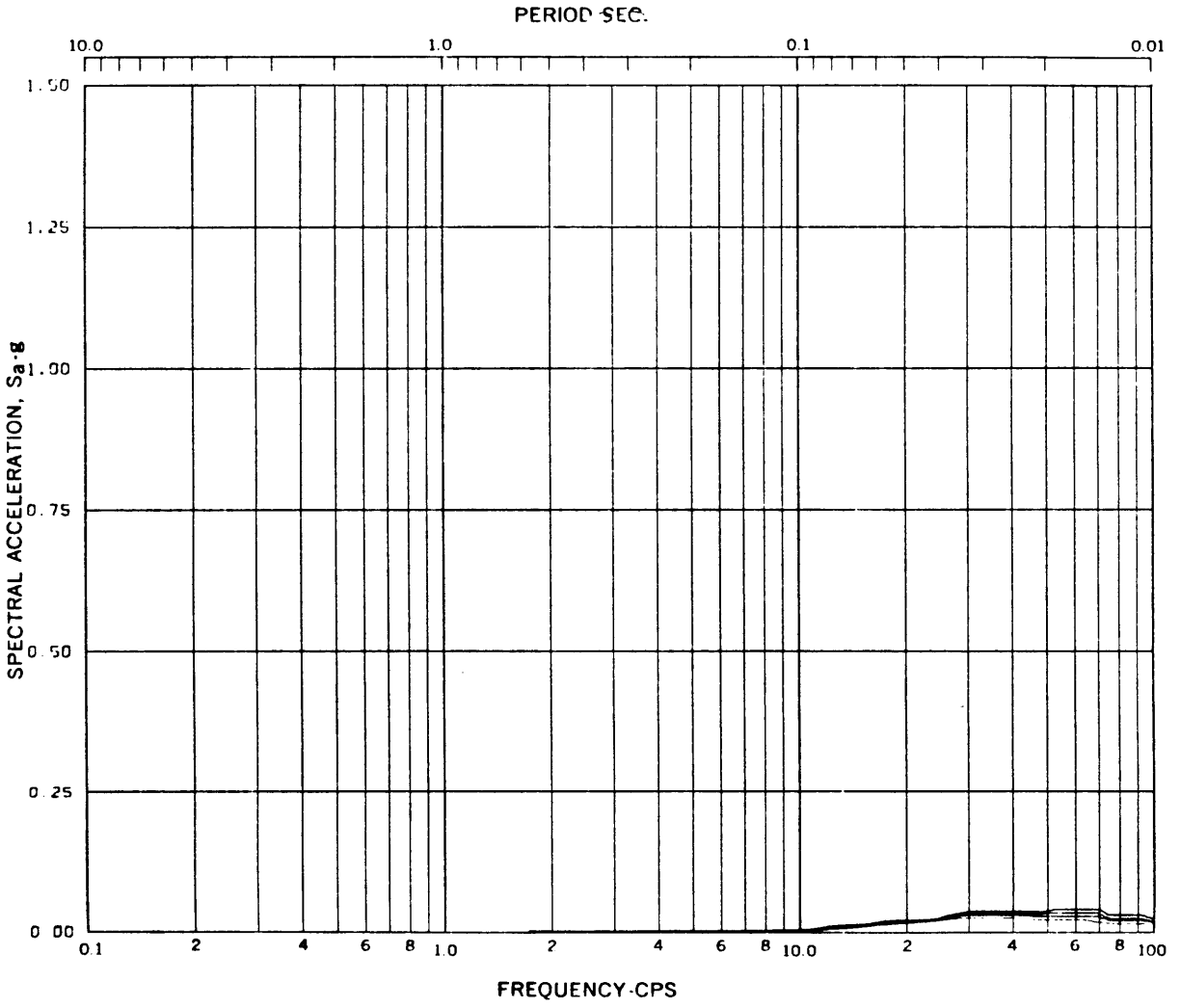
Damping: 0.005,0.01,0.02,0.05

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SRV AXISYMMETRIC
DIRECTION X

FIGURE 3A-74



Acceleration Spectra for PEDESTAL

Load Case: SRV - AXISYMMETRIC

Node: 211 Direction: HORIZ Elev: 236'-2" Angle: 0°

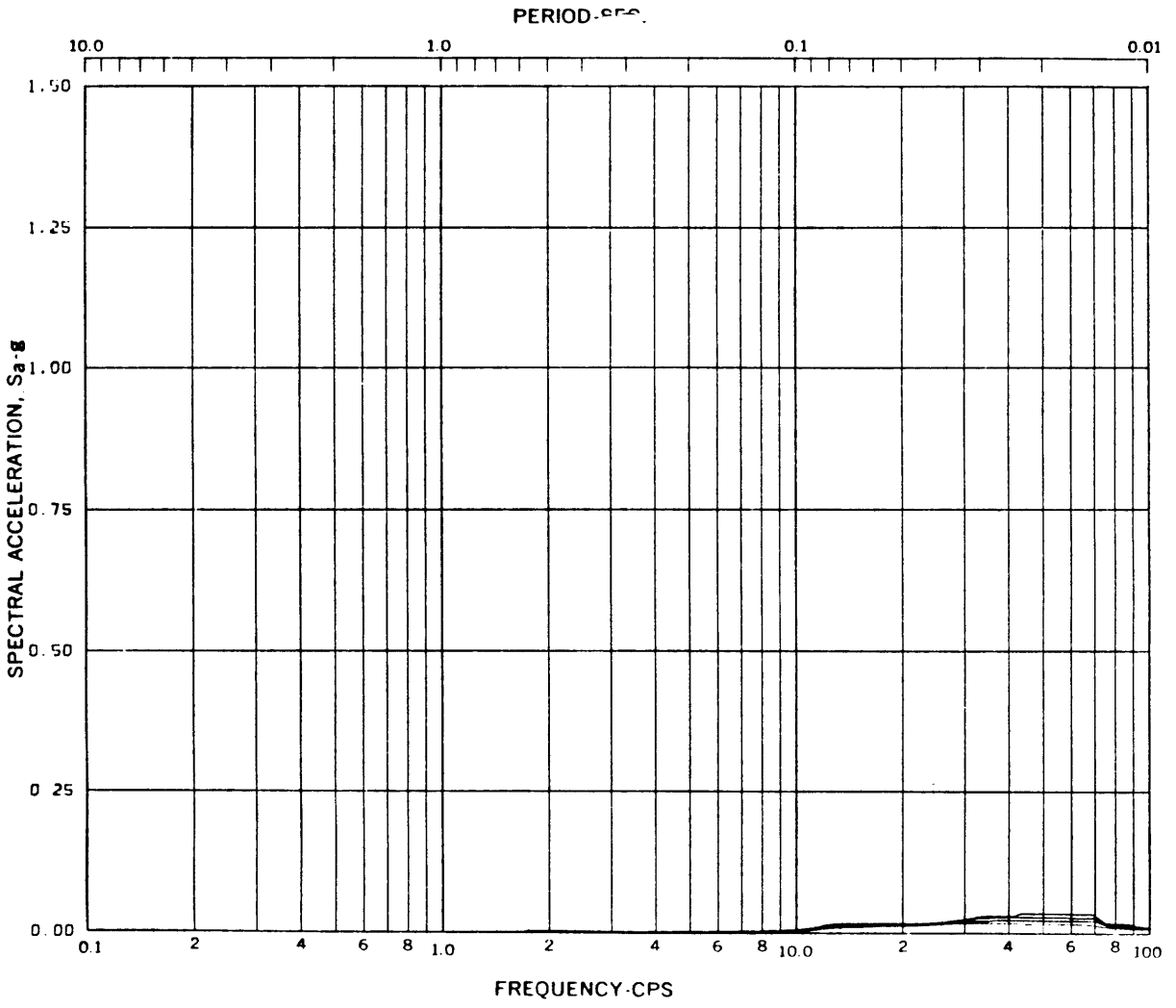
Damping: 0.005,0.01,0.02,0.05

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CONTAINMENT RESPONSE SPECTRA
SRV AXISYMMETRIC
DIRECTION X

FIGURE 3A-75



Acceleration Spectra for PEDESTAL

Load Case: SRV - AXISYMMETRIC

Node: 531 Direction: HORIZ Elev: 263'-8 5/8" Angle: 0°

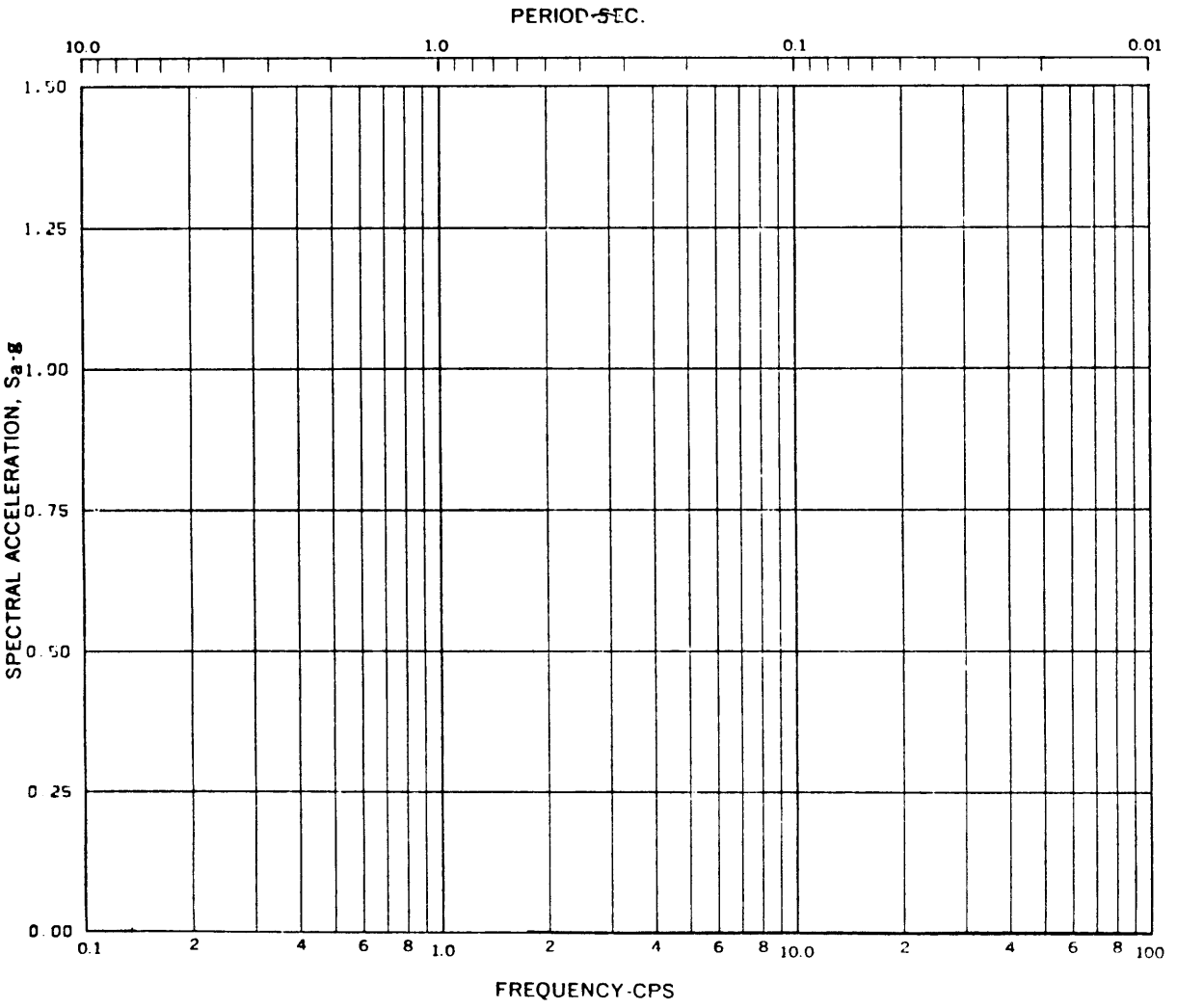
Damping: 0.005,0.01,0.02,0.05

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SRV AXISYMMETRIC
DIRECTION X

FIGURE 3A-76



Acceleration Spectra for SHIELD WALL

Load Case: SRV - AXISYMMETRIC

Node: 841 Direction: HORIZ Elev: 312'-8" Angle: 0°

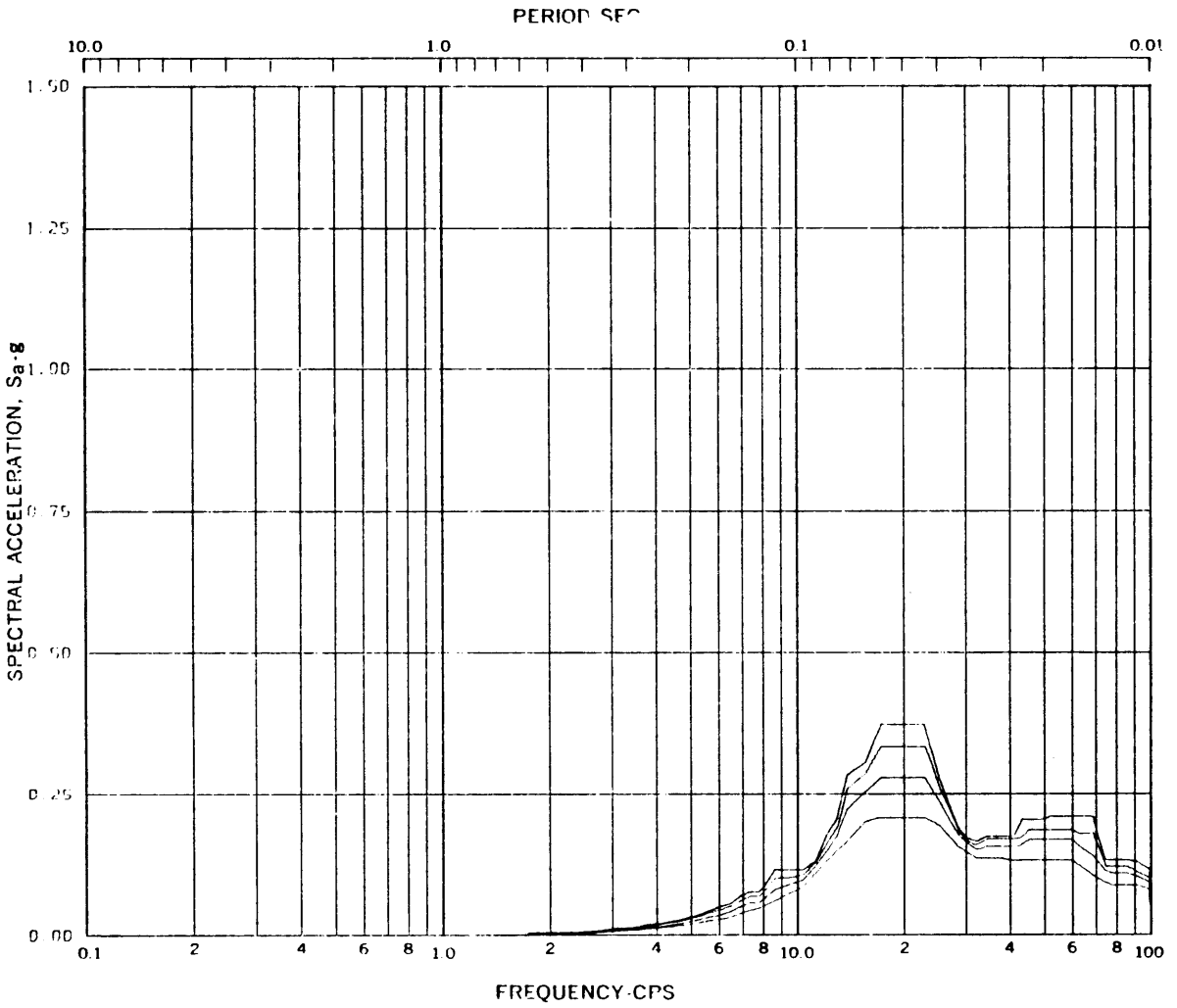
Damping: 0.005,0.01,0.02,0.05

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CONTAINMENT RESPONSE SPECTRA
SRV AXISYMMETRIC
DIRECTION X

FIGURE 3A-77



Acceleration Spectra for WETWELL WALL

Load Case: SRV - AXISYMMETRIC

Node: 131 Direction: VERT Elev:205'-11"Angle: 0°

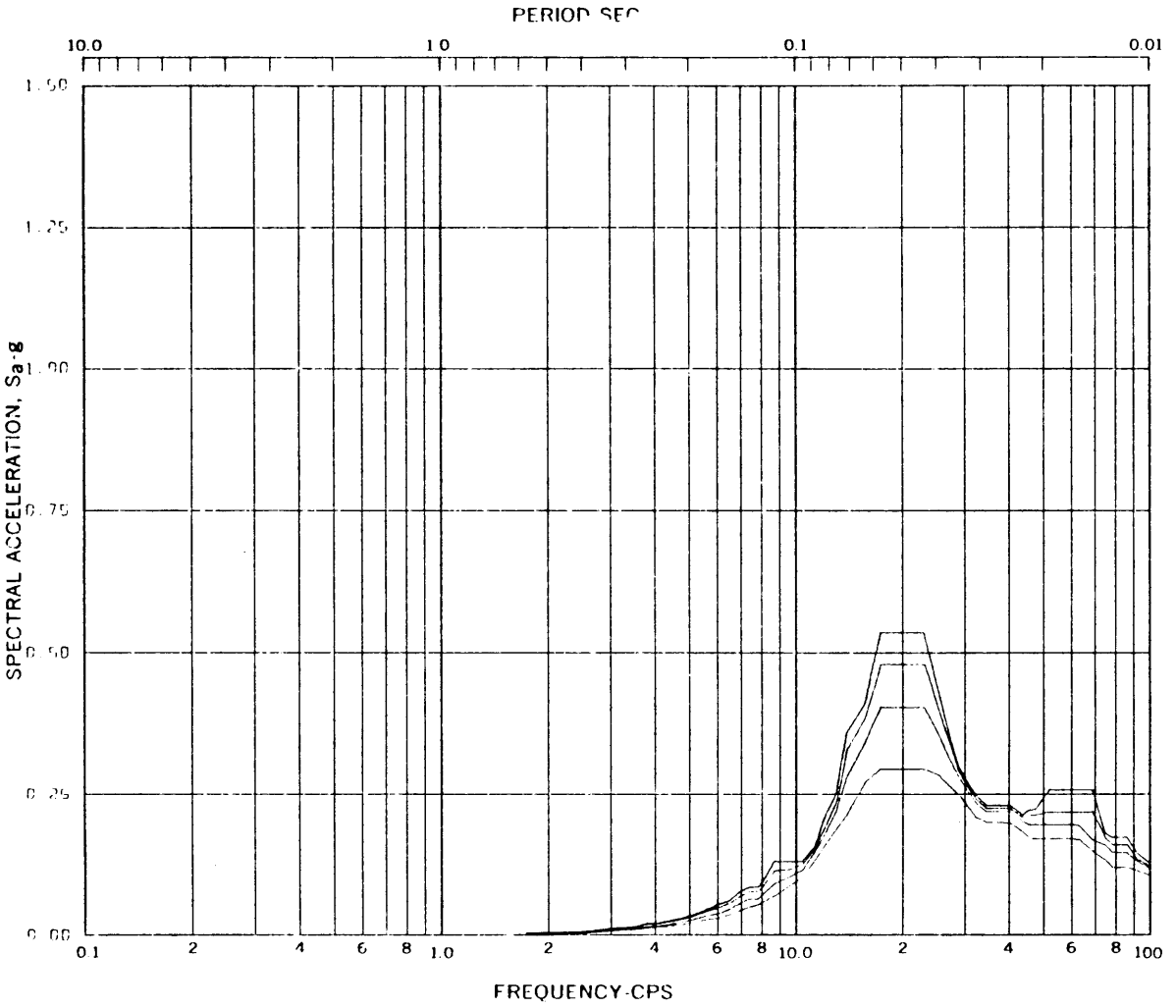
Damping: 0.005,0.01,0.02,0.05

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SRV AXISYMMETRIC
DIRECTION Z

FIGURE 3A-78



Acceleration Spectra for WETWELL WALL

Load Case: SRV - AXISYMMETRIC

Node: 291 Direction: VERT Elev: 236'-2" Angle: 0°

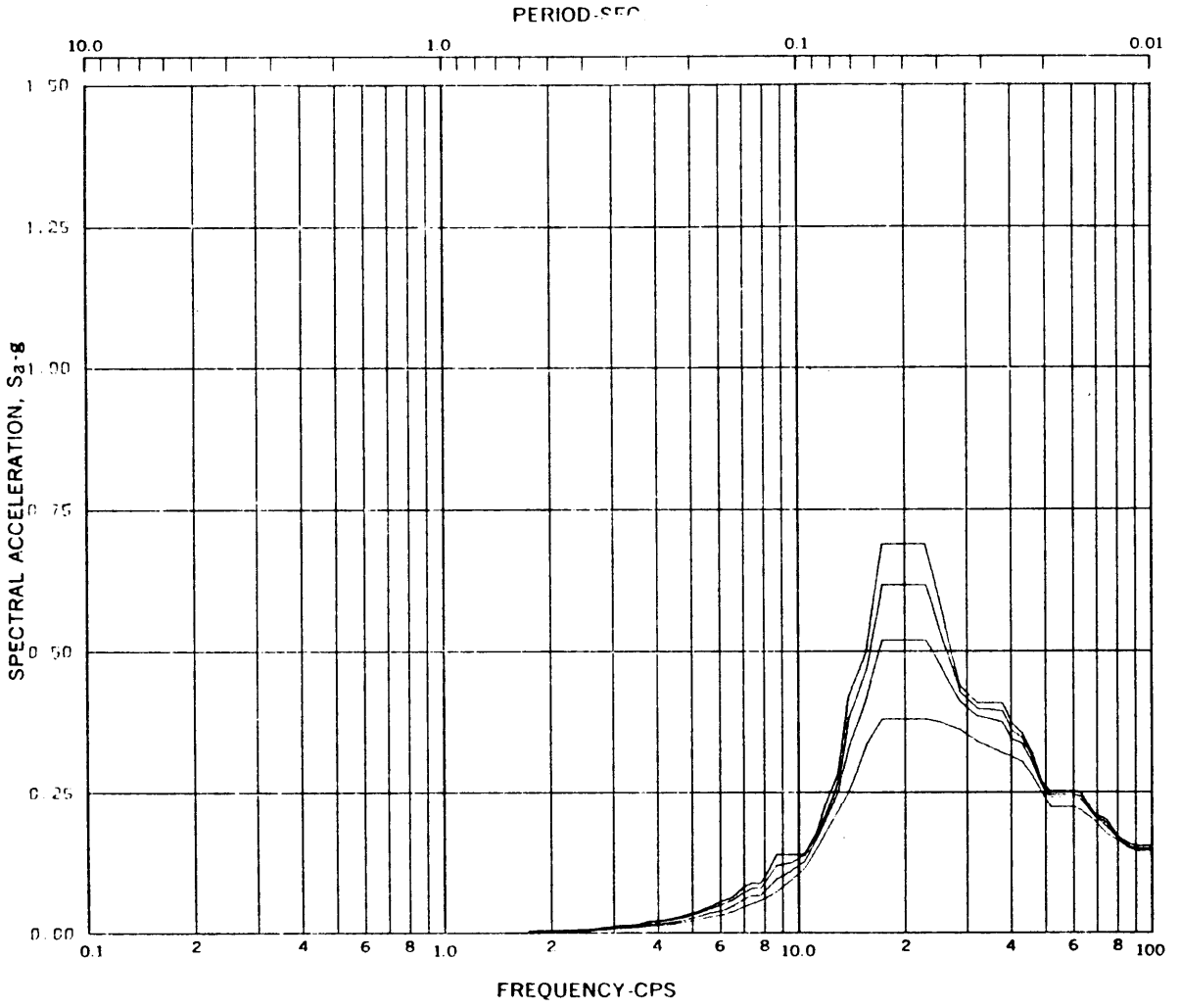
Damping: 0.005,0.01,0.02,0.05

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CONTAINMENT RESPONSE SPECTRA
SRV AXISYMMETRIC
DIRECTION Z

FIGURE 3A-79



Acceleration Spectra for DRYWELL WALL

Load Case: SRV - AXISYMMETRIC

Node: 331 Direction: VERT Elev: 264'-6" Angle: 0°

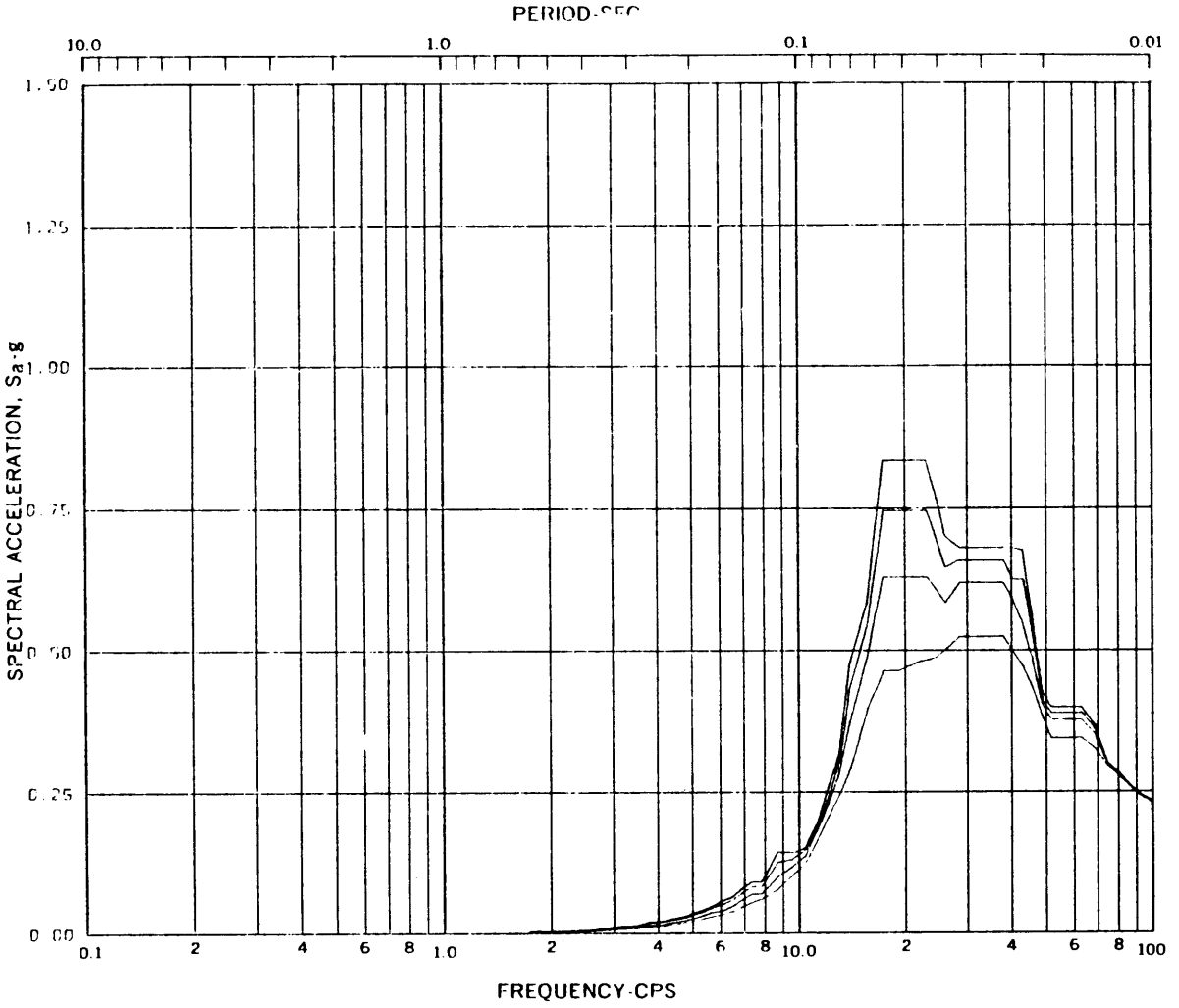
Damping: 0.005,0.01,0.02,0.05

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CONTAINMENT RESPONSE SPECTRA
SRV AXISYMMETRIC
DIRECTION Z

FIGURE 3A-80



Acceleration Spectra for DRYWELL WALL

Load Case: SRV - AXISYMMETRIC

Node: 431 Direction: VERT Elev: 325'-8" Angle: 0°

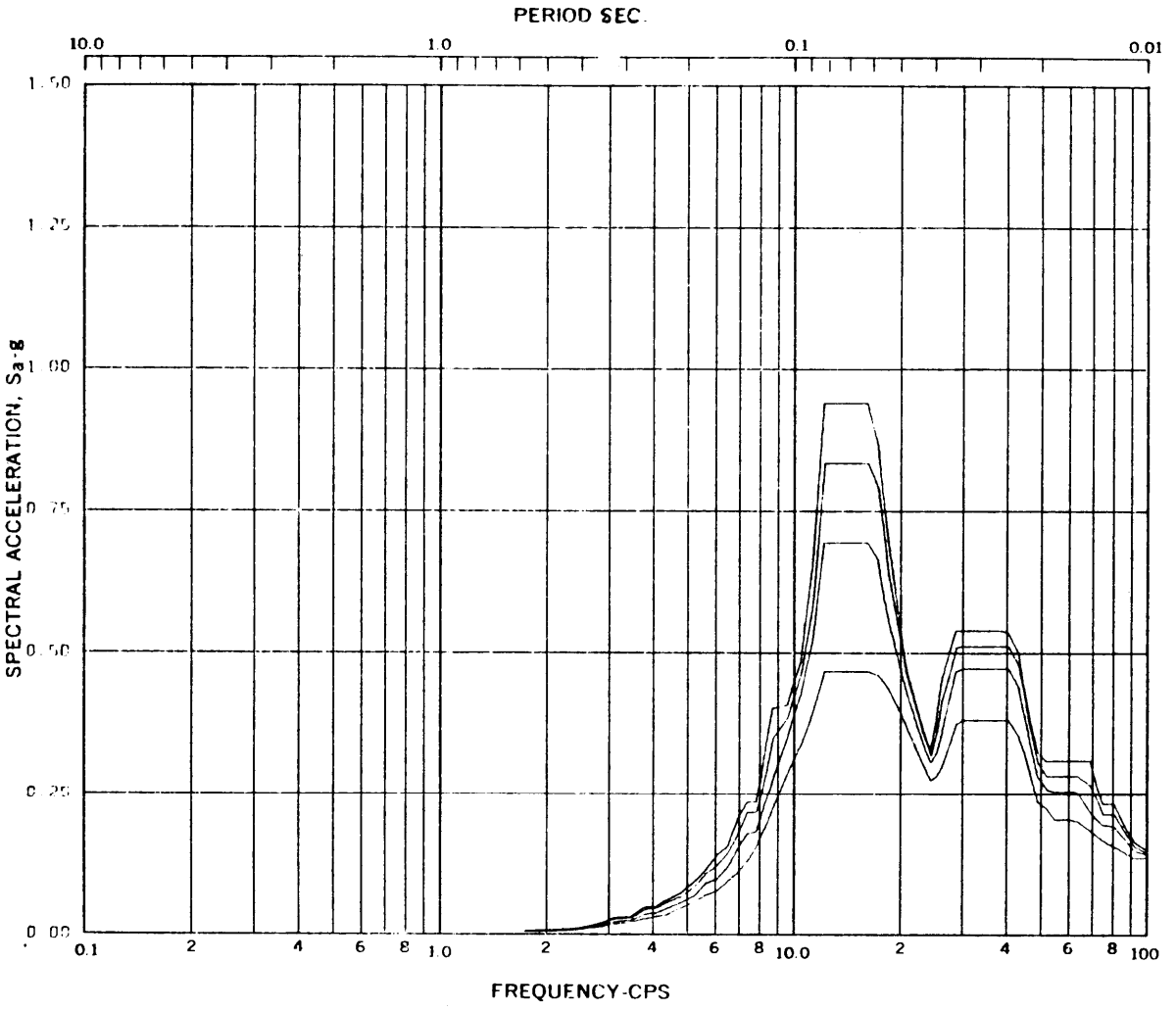
Damping: 0.005,0.01,0.02,0.05

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CONTAINMENT RESPONSE SPECTRA
SRV AXISYMMETRIC
DIRECTION Z

FIGURE 3A-81



Acceleration Spectra for PEDESTAL

Load Case: SRV - AXISYMMETRIC

Node: 211 Direction: VERT Elev: 236'-2" Angle: 0°

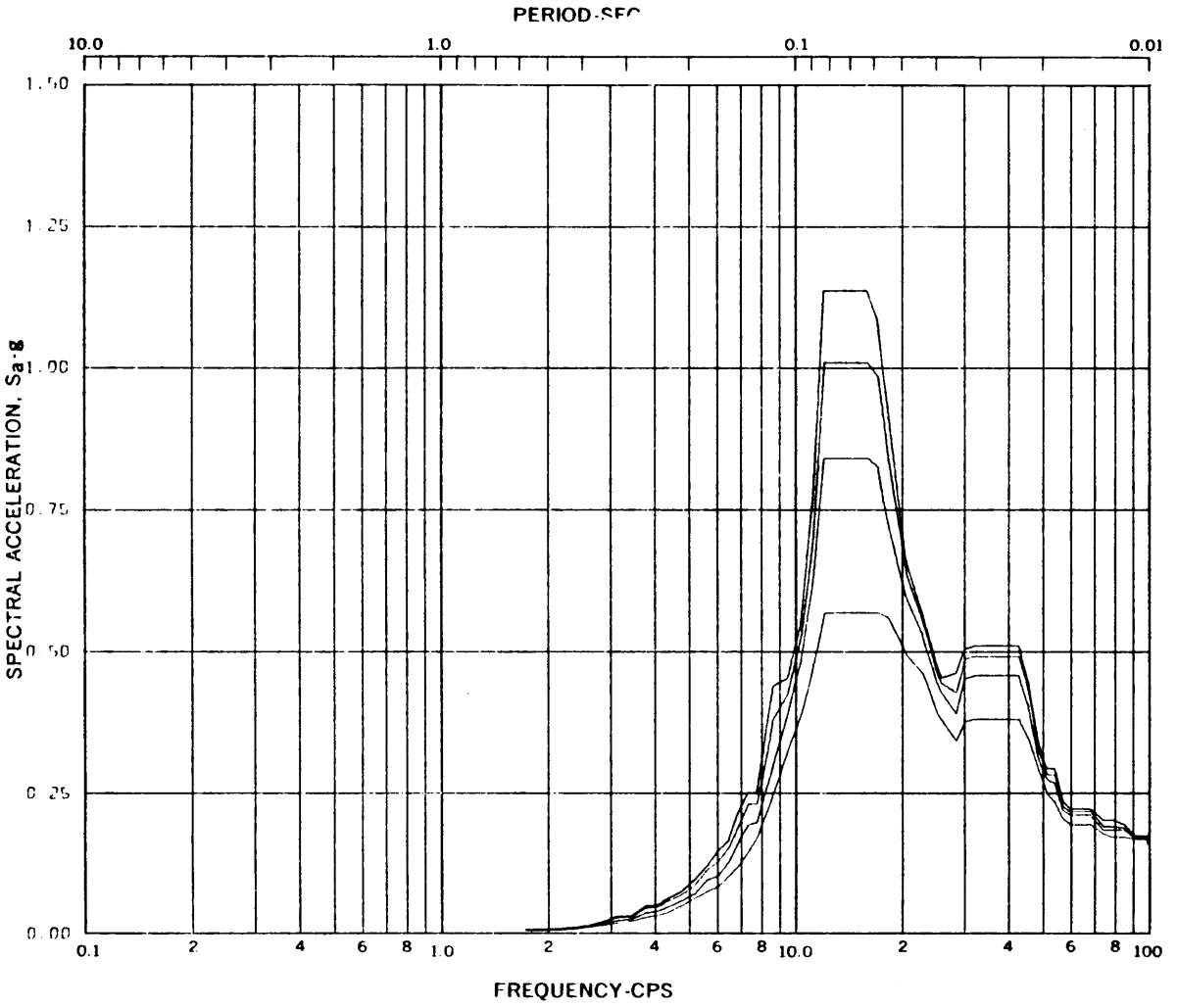
Damping: 0.005,0.01,0.02,0.05

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CONTAINMENT RESPONSE SPECTRA
SRV AXISYMMETRIC
DIRECTION Z

FIGURE 3A-82



Acceleration Spectra for PEDESTAL

Load Case: SRV - AXISYMMETRIC

Node: 531 Direction: VERT Elev: 263'-8 5/8" Angle: 0°

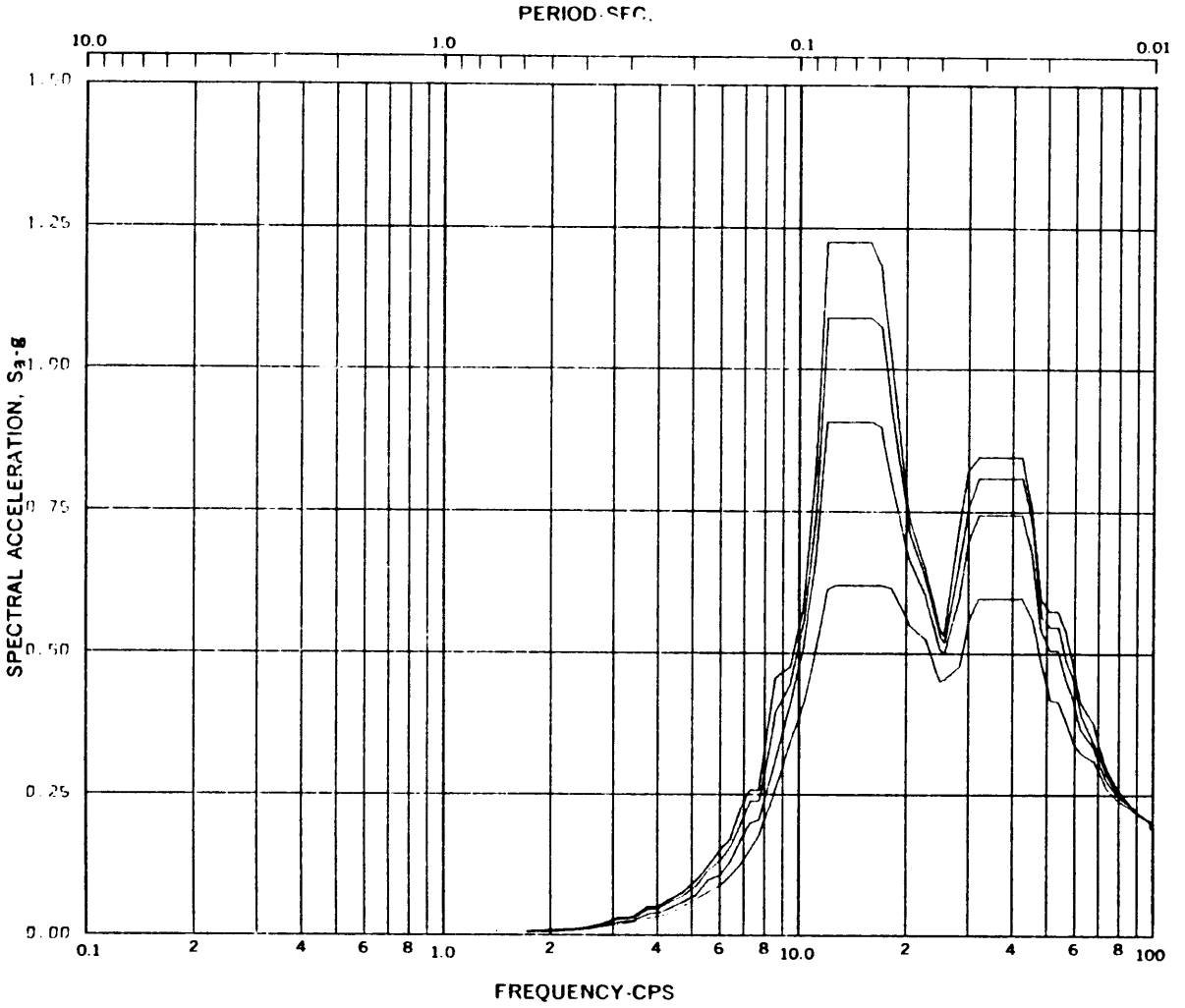
Damping: 0.005,0.01,0.02,0.05

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SRV AXISYMMETRIC
DIRECTION Z

FIGURE 3A-83



Acceleration Spectra for SHIELD WALL

Load Case: SRV - AXISYMMETRIC

Node: 841 Direction: VERT Elev: 312'-8" Angle: 0°

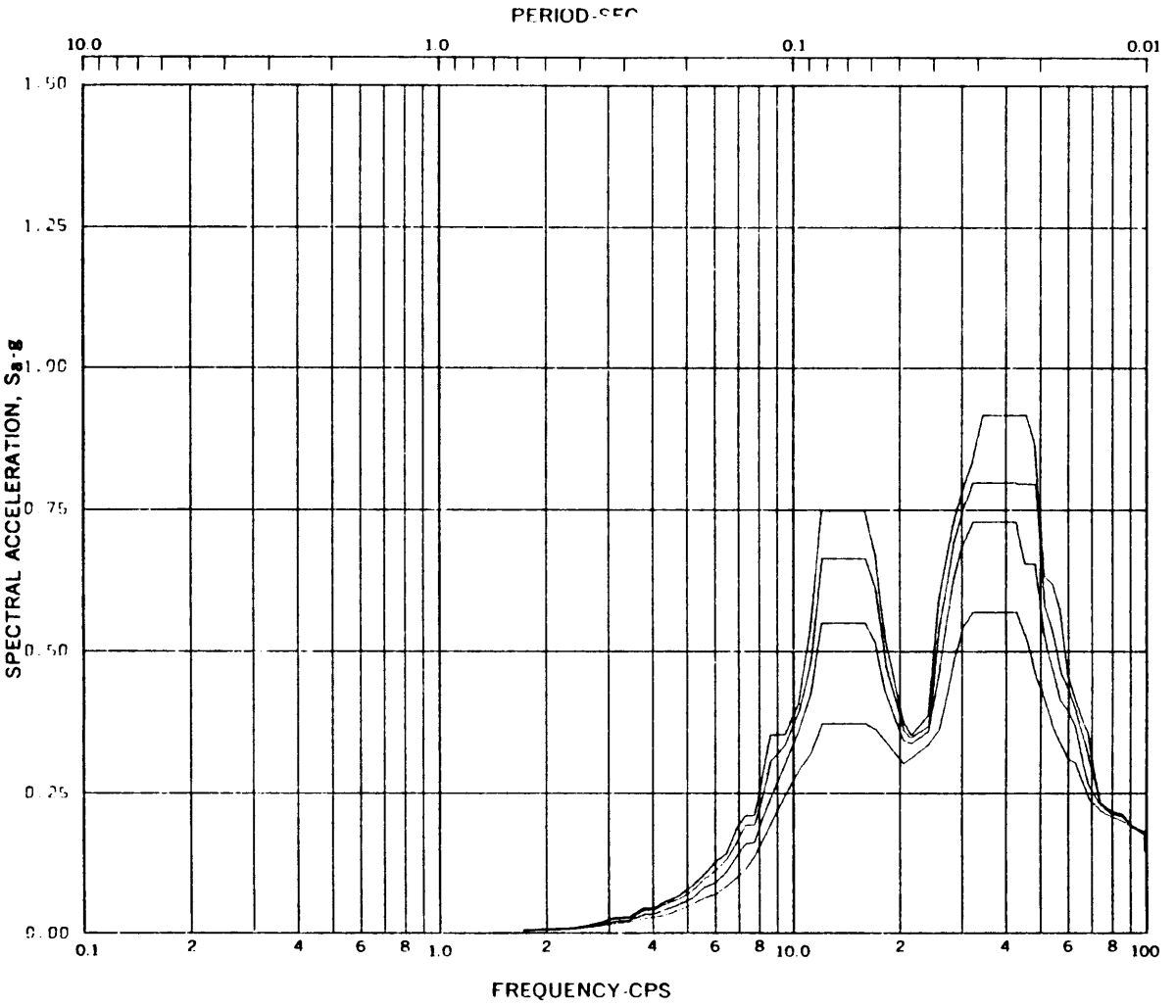
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-84



Acceleration Spectra for DIAPHRAGM SLAB

Load Case: SRV - AXISYMMETRIC

Node: 231 Direction: VERT Elev: 236'-2" Angle: 0°

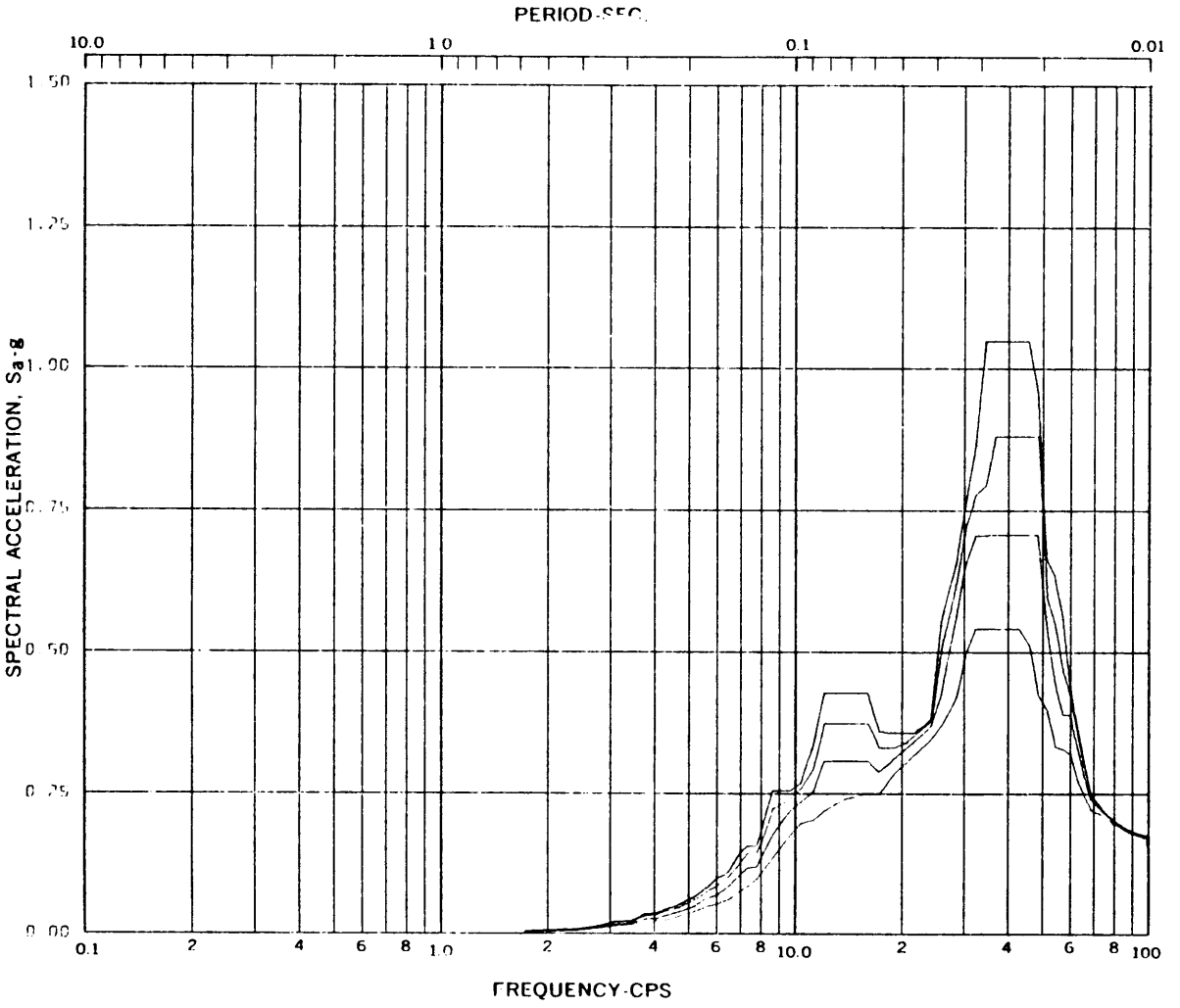
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-85



Acceleration Spectra for DIAPHRAGM SLAB

Load Case: SRV - AXISYMMETRIC

Node: 252 Direction: VERT Elev: 236'-2" Angle: 22°-30'

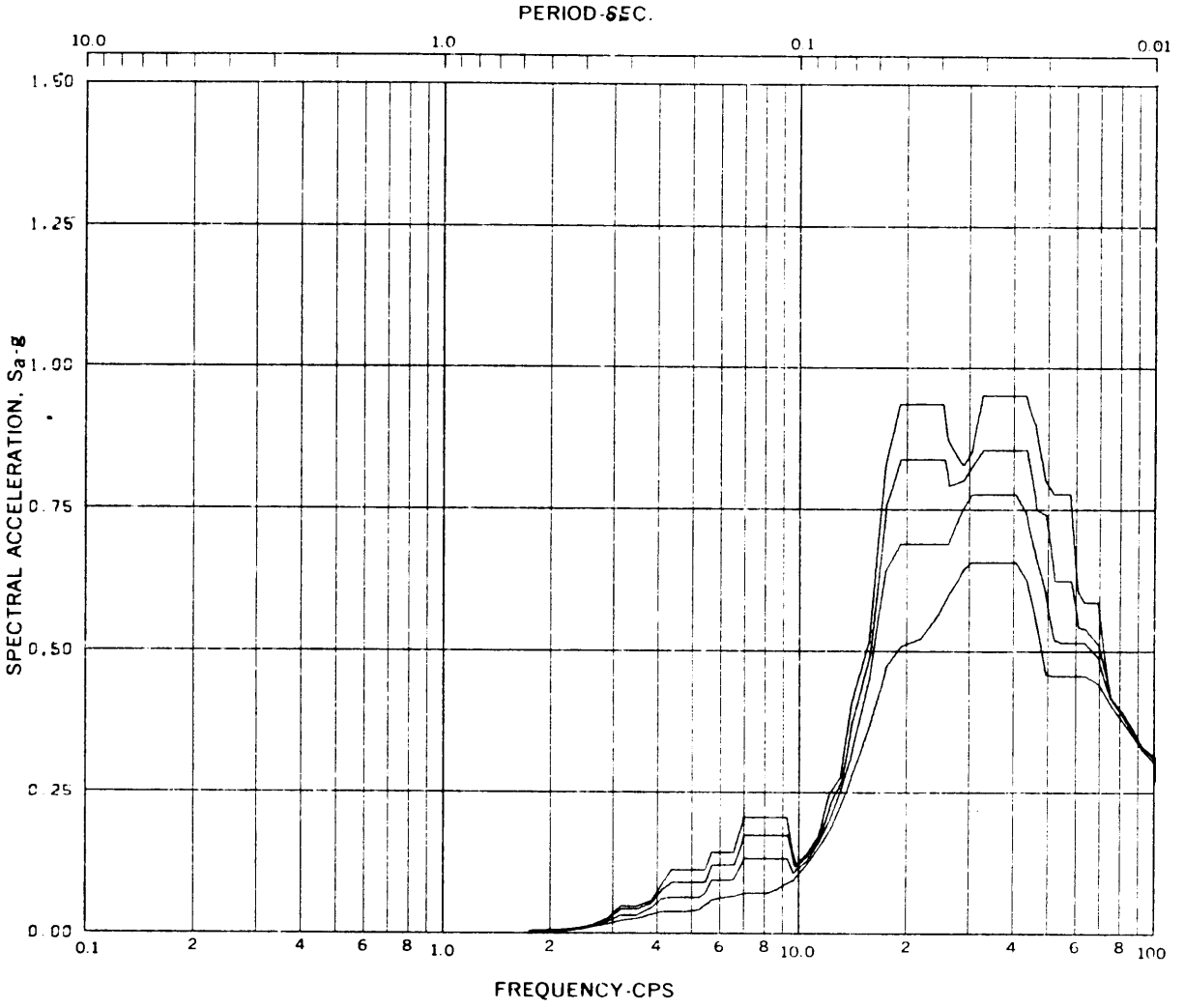
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-86



Acceleration Spectra for WETWELL WALL

Load Case: SRV - ASYMMETRIC

Node: 131 Direction: HORIZ Elev: 205'-11" Angle: 0°

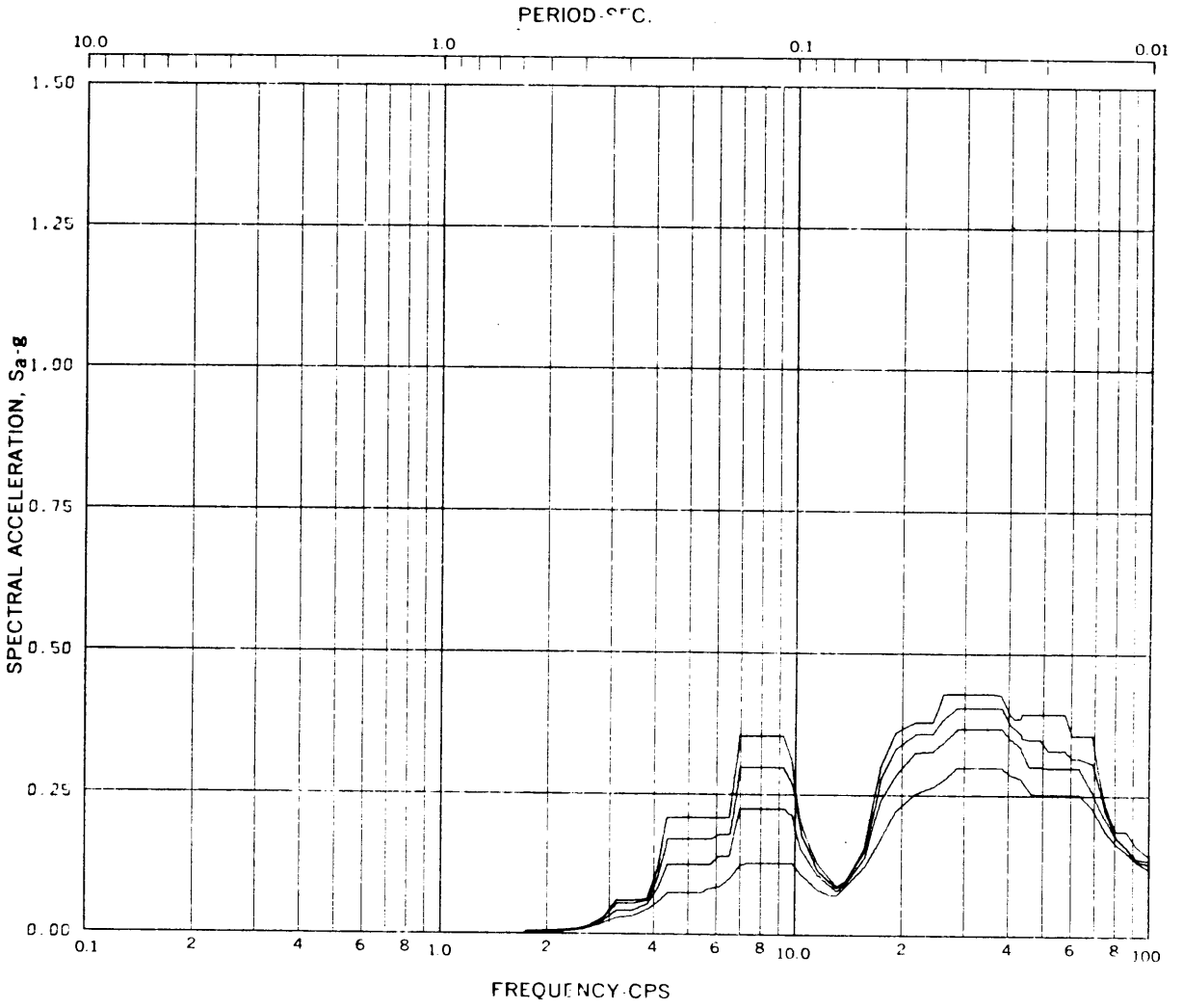
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-87



Acceleration Spectra for WETWELL WALL

Load Case: SRV - ASYMMETRIC

Node: 291 Direction: HORIZ Elev: 236'-2" Angle: 0°

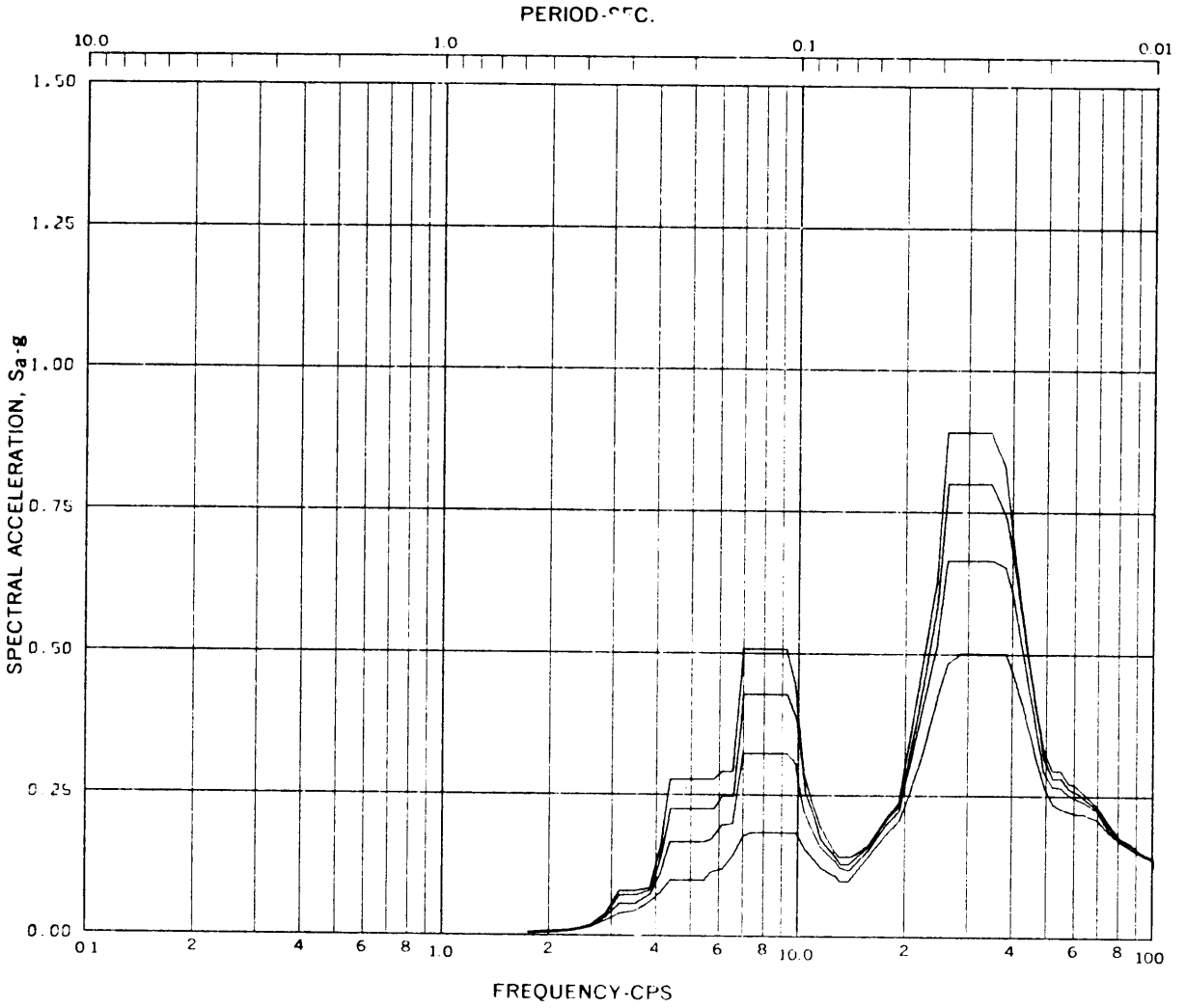
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-88



Acceleration Spectra for DRYWELL WALL

Load Case: SRV - ASYMMETRIC

Node: 331 Direction: HORIZ Elev: 264'-6" Angle: 0°

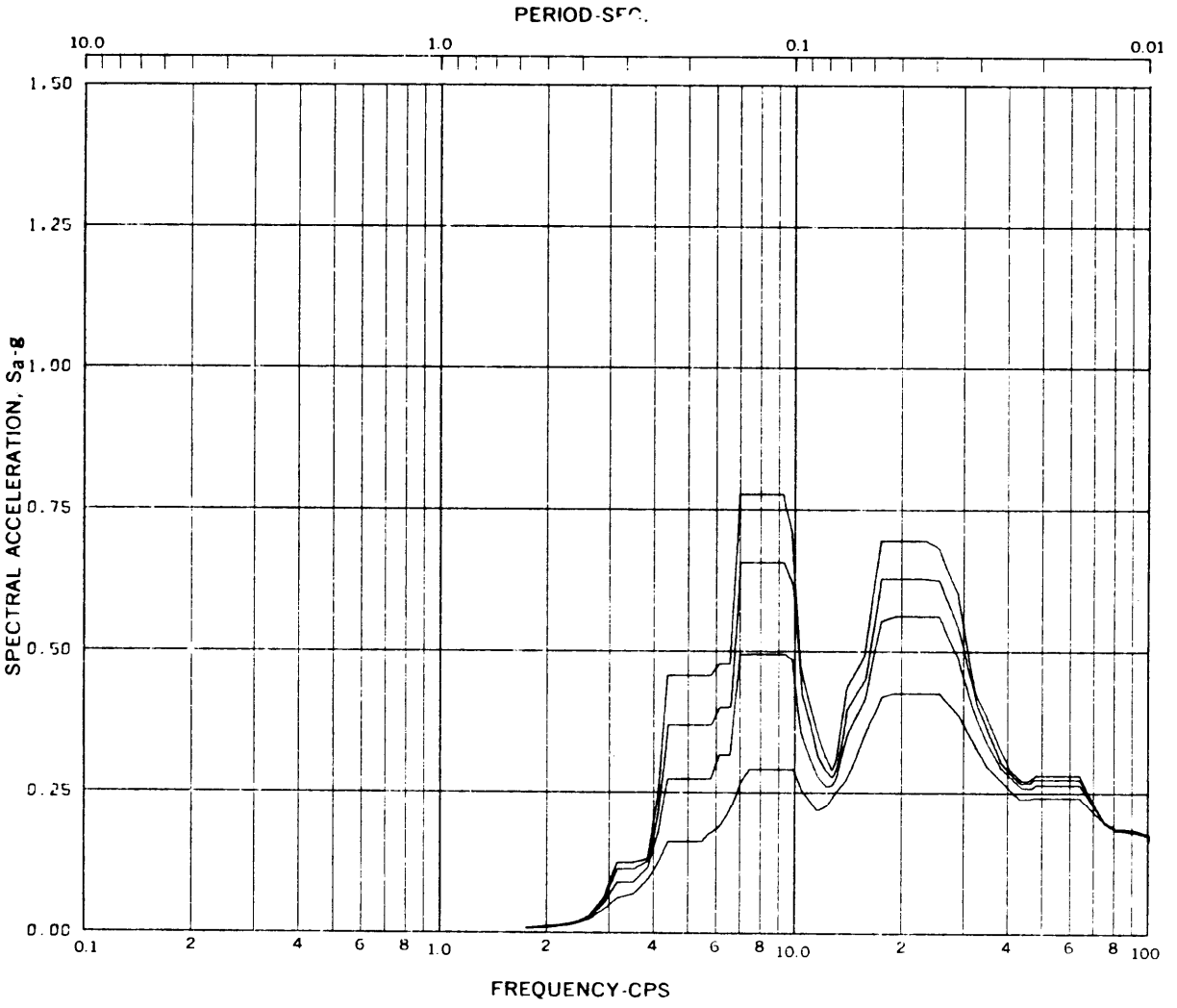
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-89



Acceleration Spectra for DRYWELL WALL

Load Case: SRV - ASYMMETRIC

Node: 431 Direction: HORIZ Elev: 325'-8" Angle: 0°

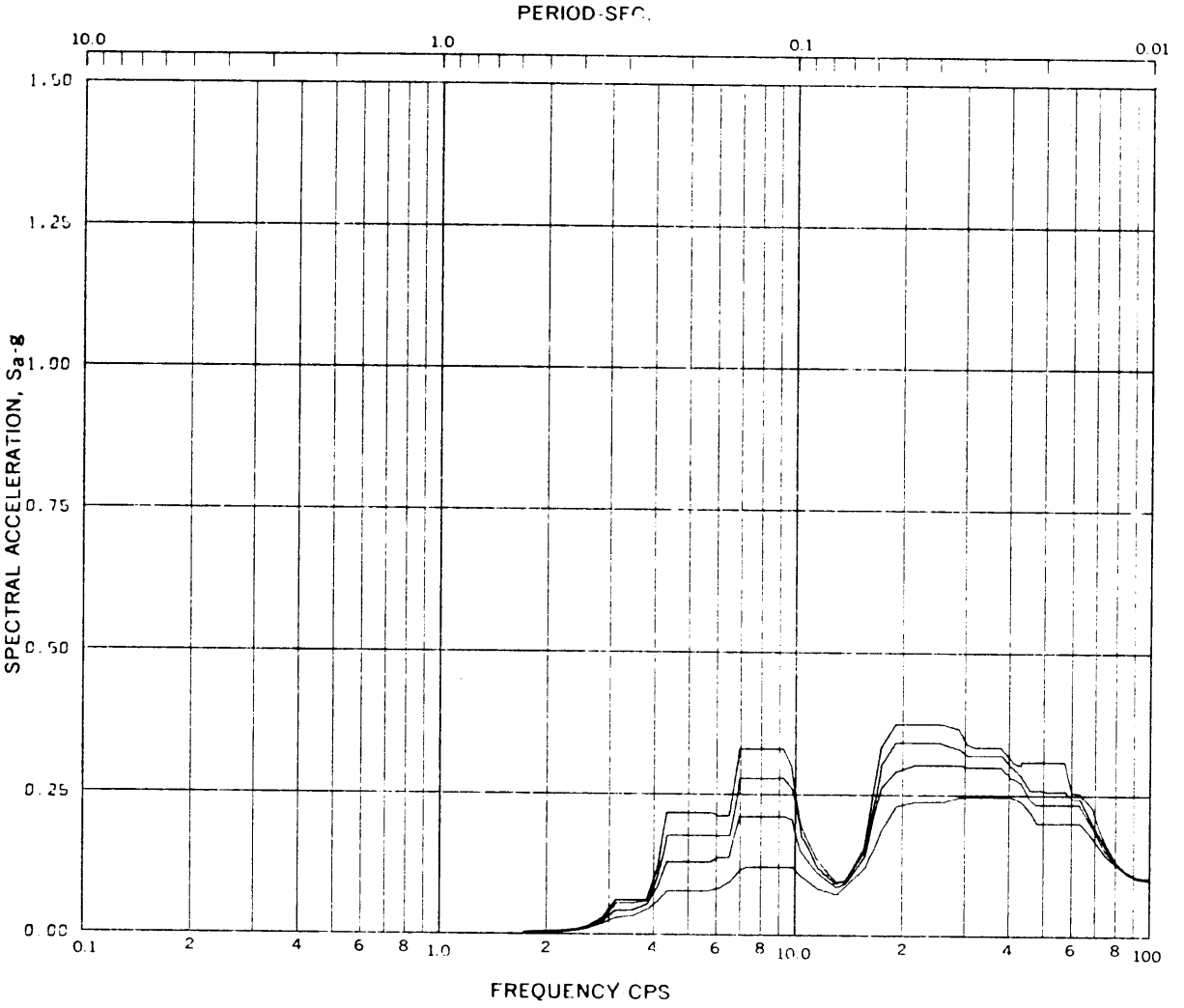
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-90



Acceleration Spectra for PEDESTAL

Load Case: SRV - ASYMMETRIC

Node: 211 Direction: HORIZ Elev: 236'-2" Angle: 0°

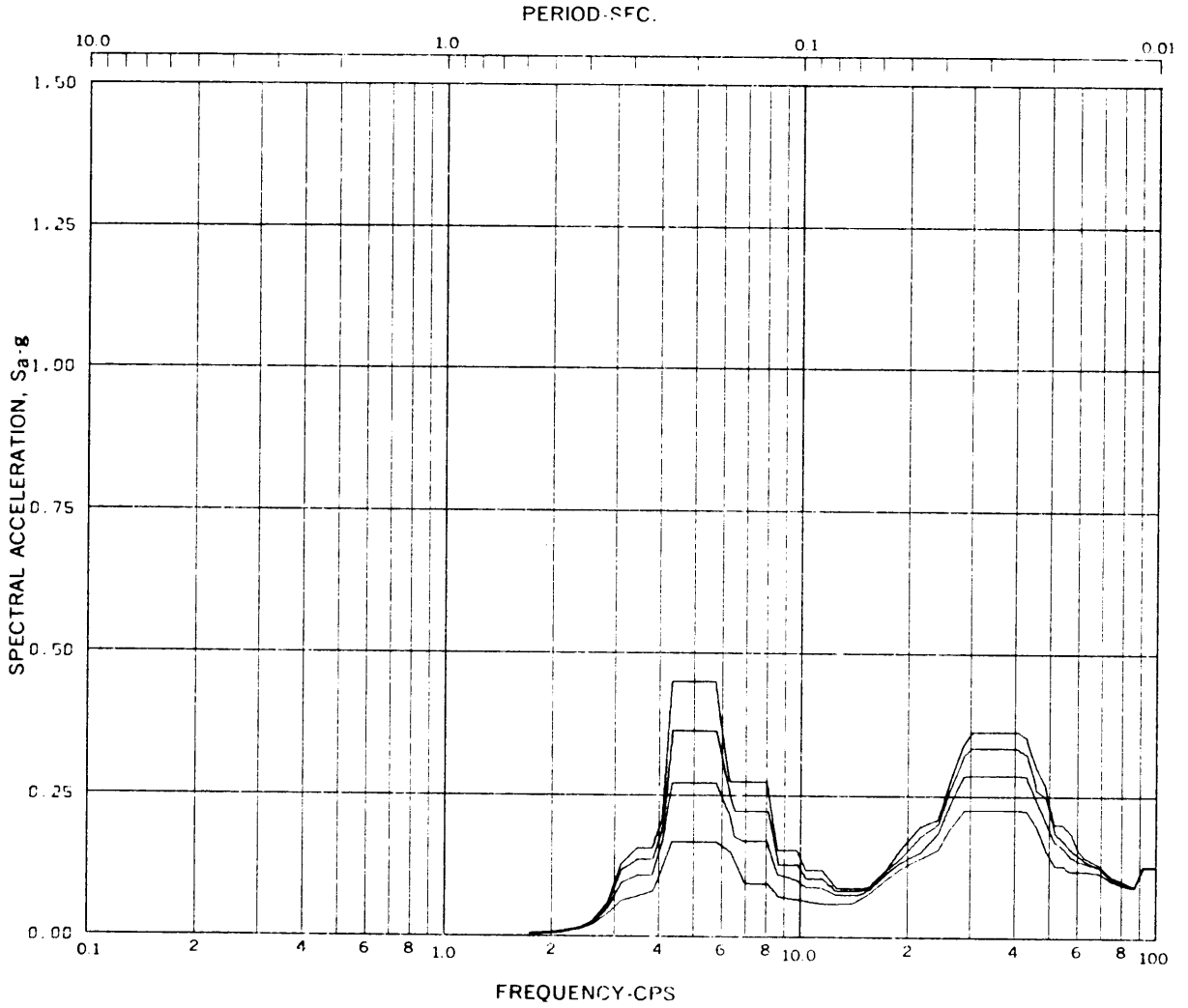
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-91



Acceleration Spectra for PEDESTAL

Load Case: SRV - ASYMMETRIC

Node: 531 Direction: HORIZ Elev: 263'-8 5/8" Angle: 0°

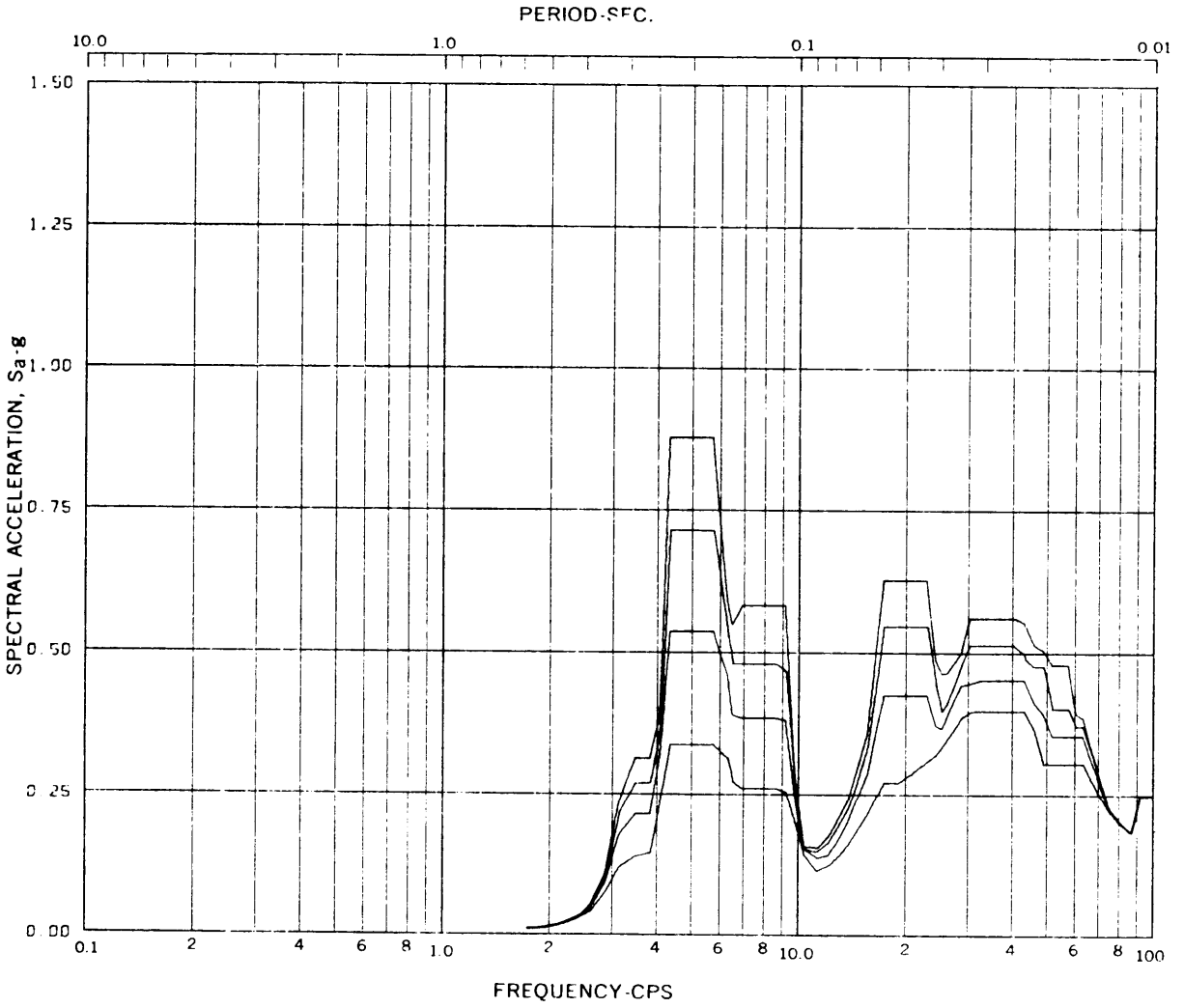
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-92



Acceleration Spectra for SHIELD WALL

Load Case: SRV - ASYMMETRIC

Node: 841 Direction: HORIZ Elev: 312'-8" Angle: 0°

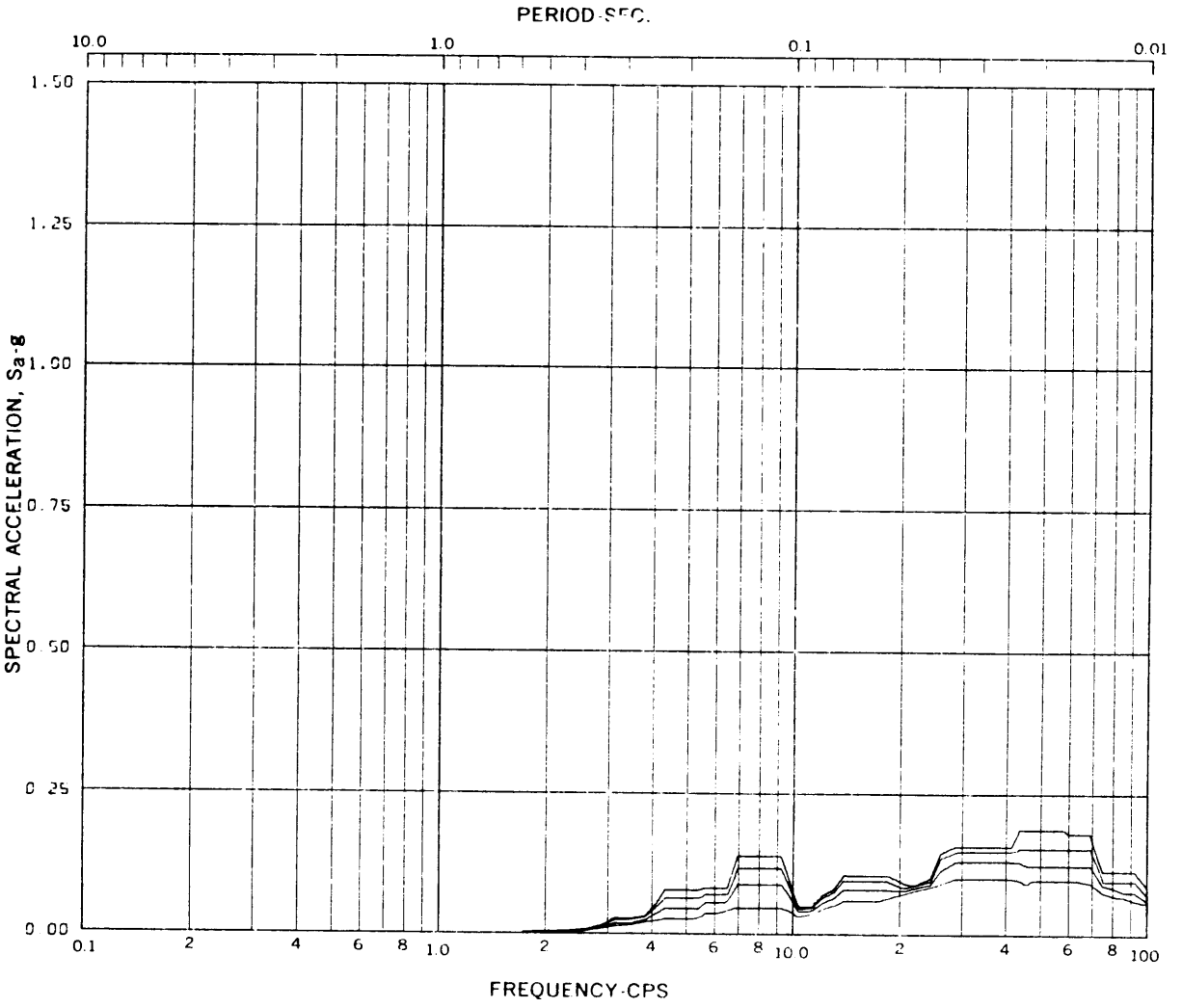
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-93



Acceleration Spectra for WETWELL WALL

Load Case: SRV - ASYMMETRIC

Node: 131 Direction: VERT Elev:205'-11" Angle: 0°

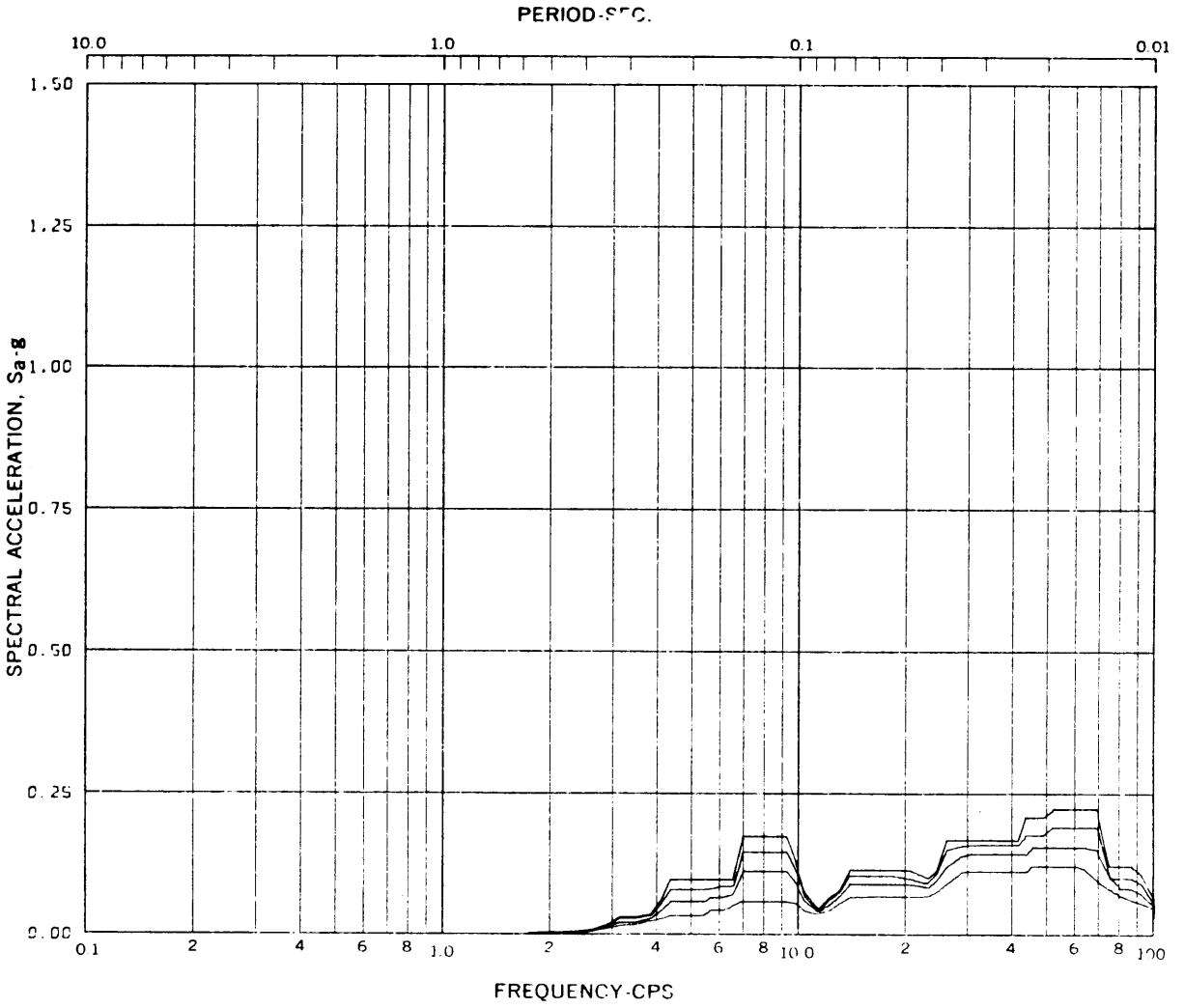
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-94



Acceleration Spectra for WETWELL WALL

Load Case: SRV - ASYMMETRIC

Node: 291 Direction: VERT Elev: 236'-2" Angle: 0°

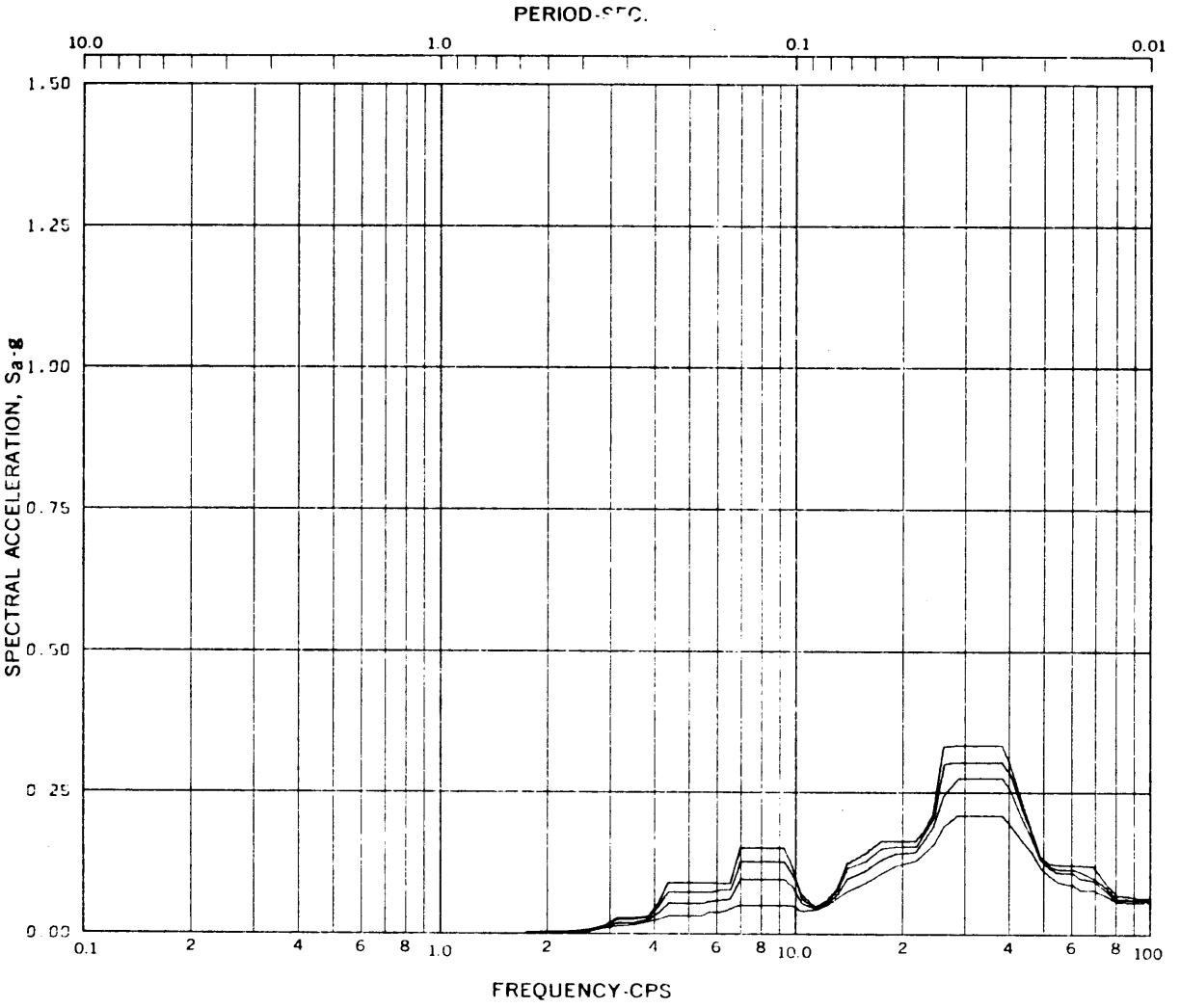
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-95



Acceleration Spectra for DRYWELL WALL

Load Case: SRV - ASYMMETRIC

Node: 331 Direction: VERT Elev: 264'-6" Angle: 0°

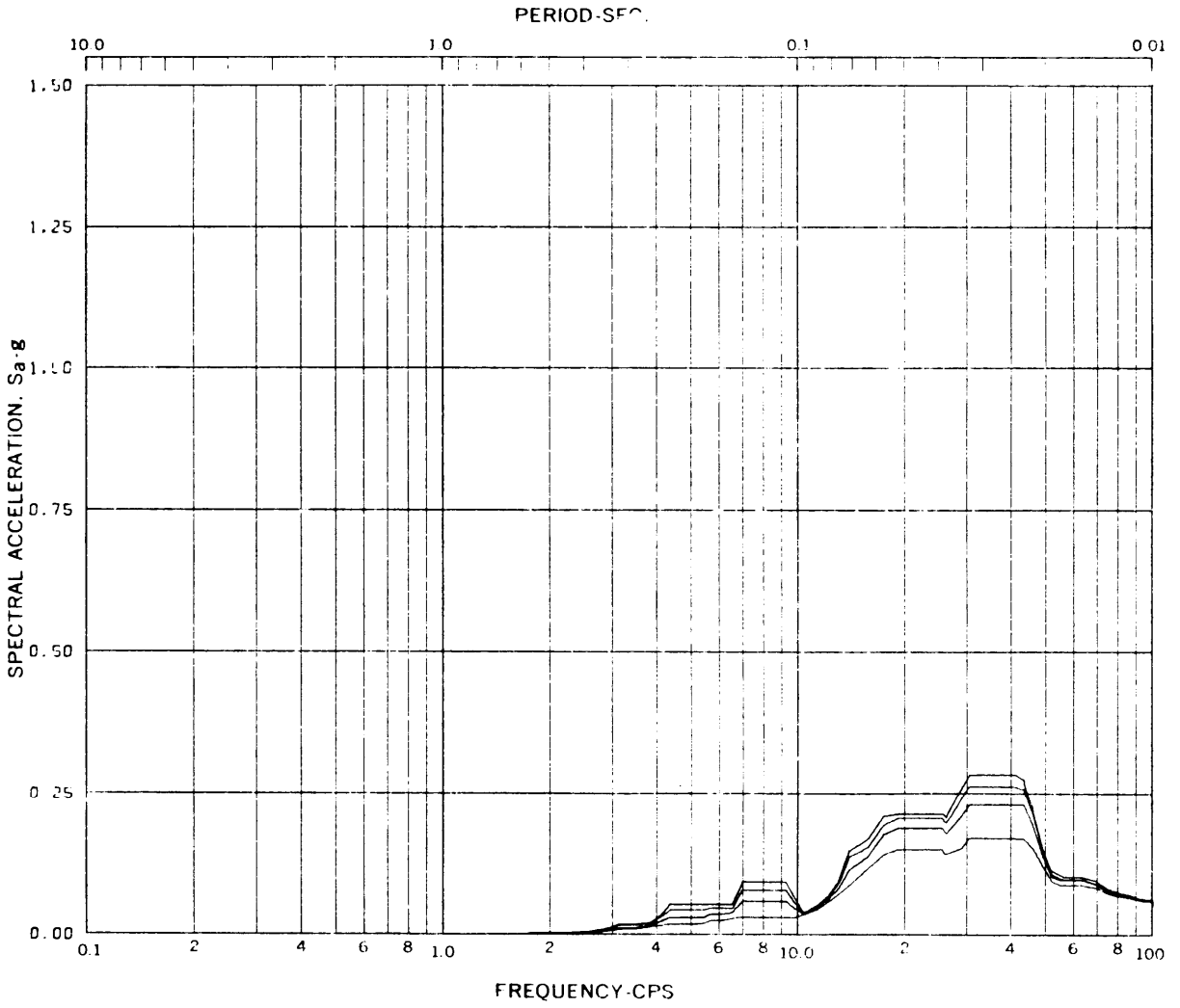
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-96



Acceleration Spectra for DRYWELL WALL

Load Case: SRV - ASYMMETRIC

Node: 431 Direction: VERT Elev: 325'-8" Angle: 0°

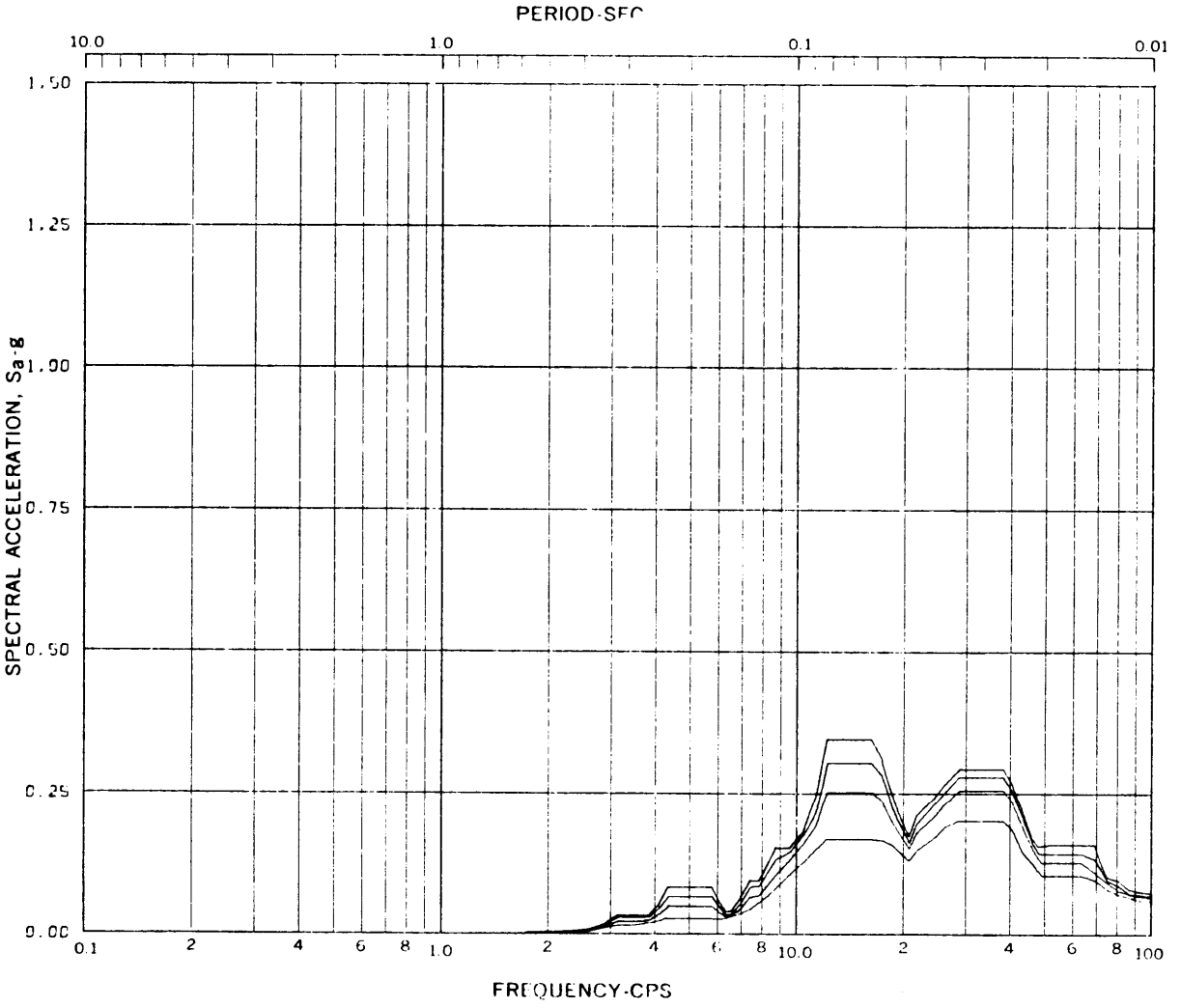
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-97



Acceleration Spectra for PEDESTAL

Load Case: SRV - ASYMMETRIC

Node: 211 Direction: VERT Elev: 236'-2" Angle: 0°

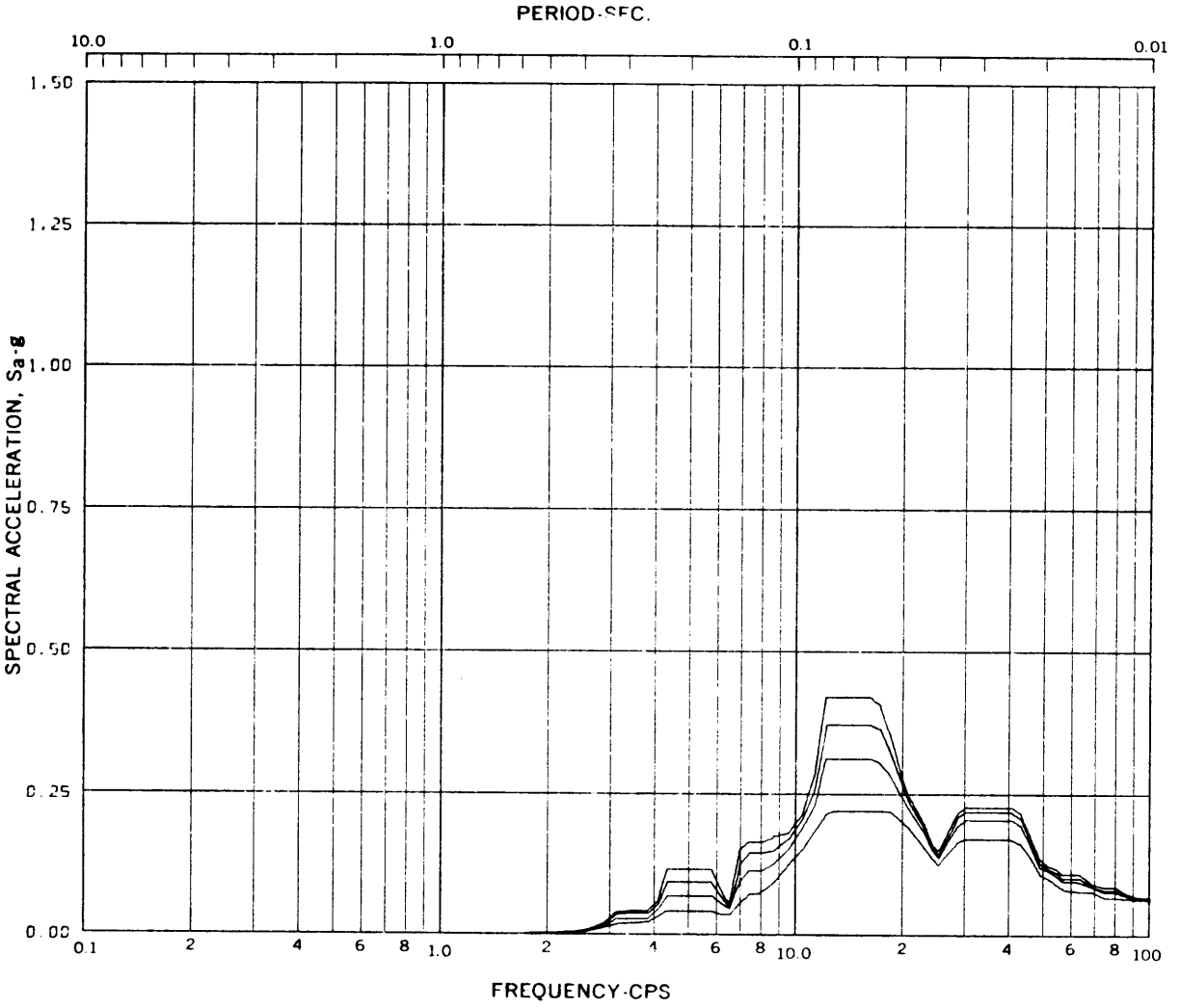
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-98



Acceleration Spectra for PEDESTAL

Load Case: SRV - ASYMMETRIC

Node: 531 Direction: VERT Elev: 263'-8 5/8" Angle: 0°

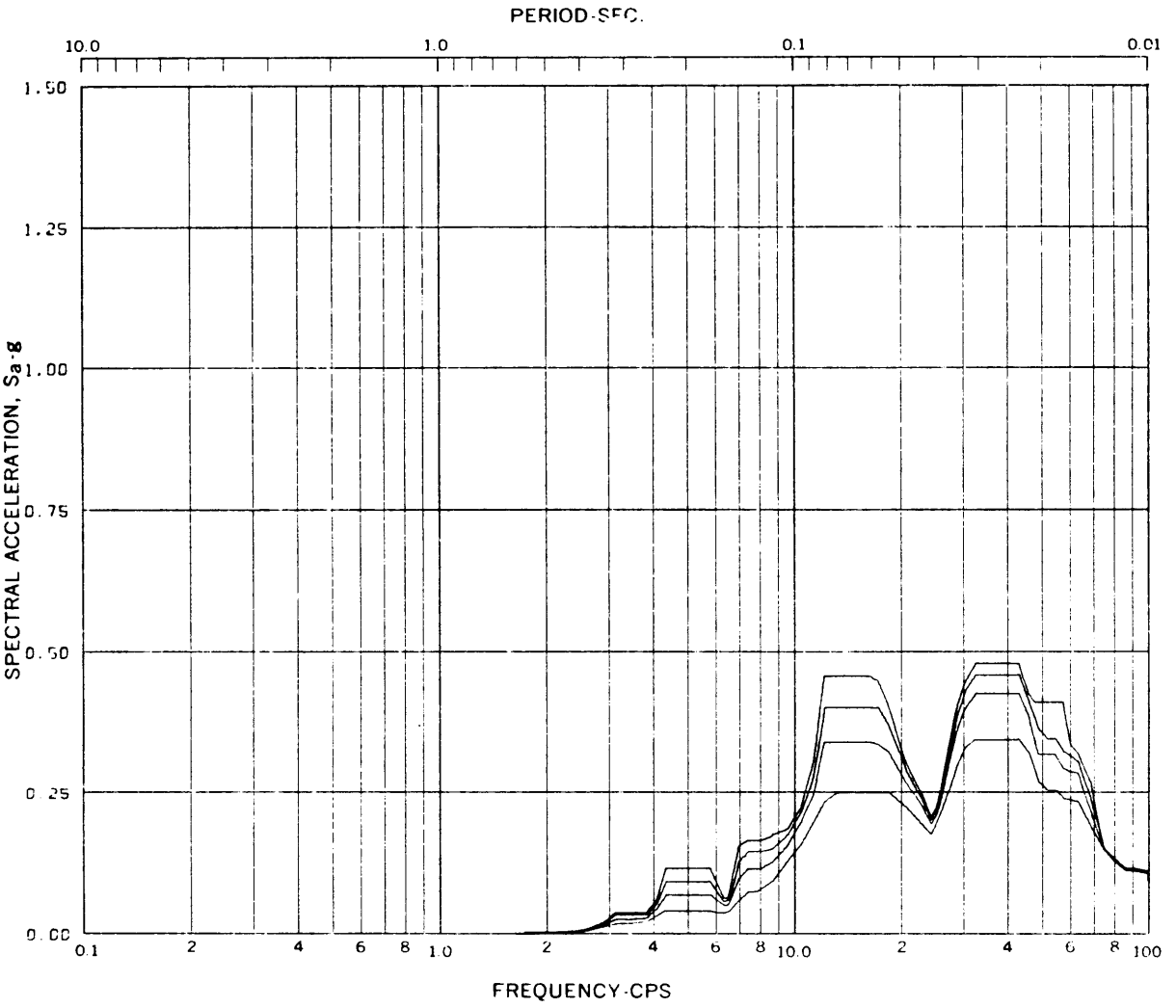
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-89



Acceleration Spectra for SHIELD WALL

Load Case: SRV - ASYMMETRIC

Node: 841 Direction: VERT Elev: 312'-8" Angle: 0°

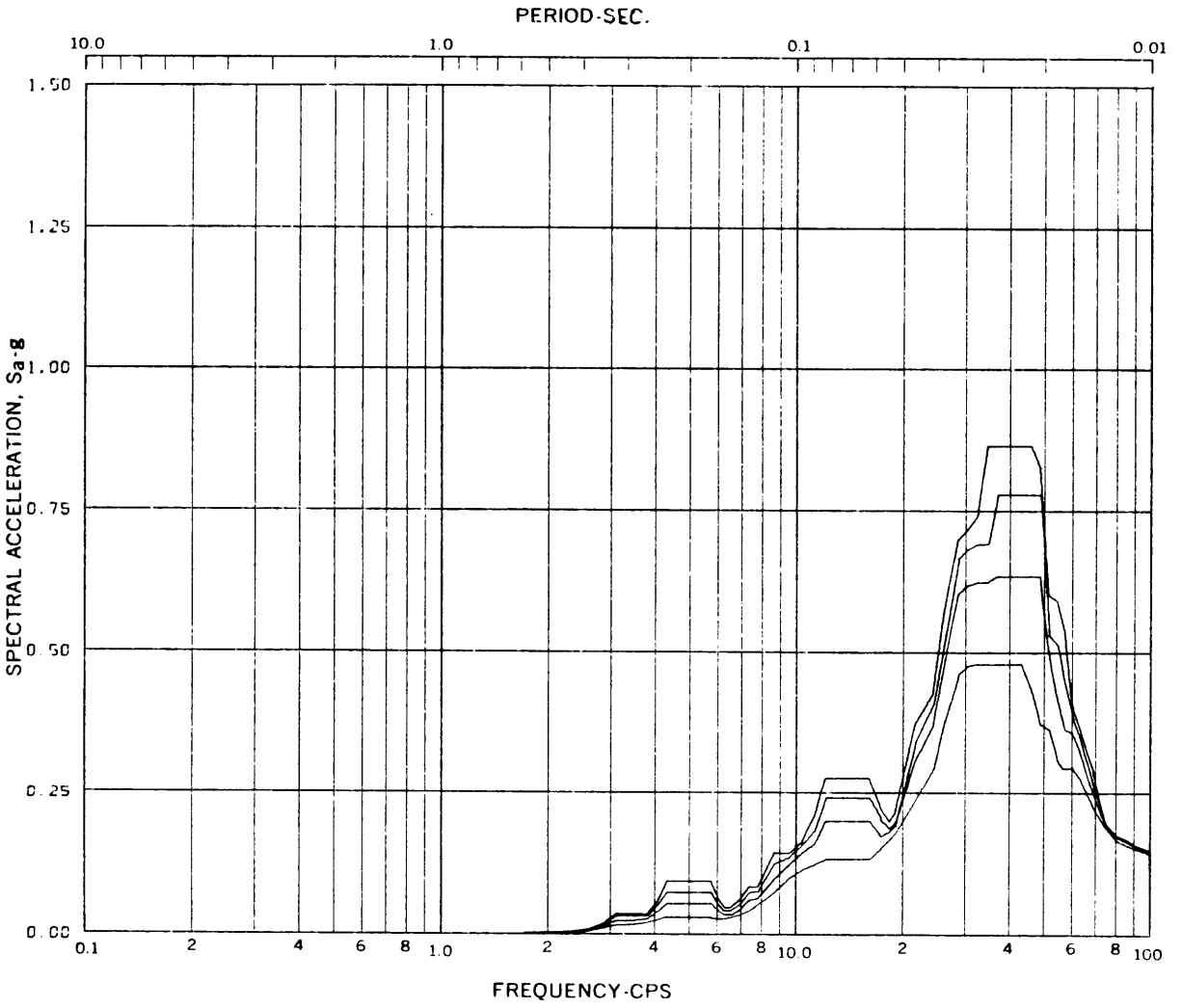
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-100



Acceleration Spectra for DIAPHRAGM SLAB

Load Case: SRV - ASYMMETRIC

Node: 231 Direction: VERT Elev: 236'-2" Angle: 0°

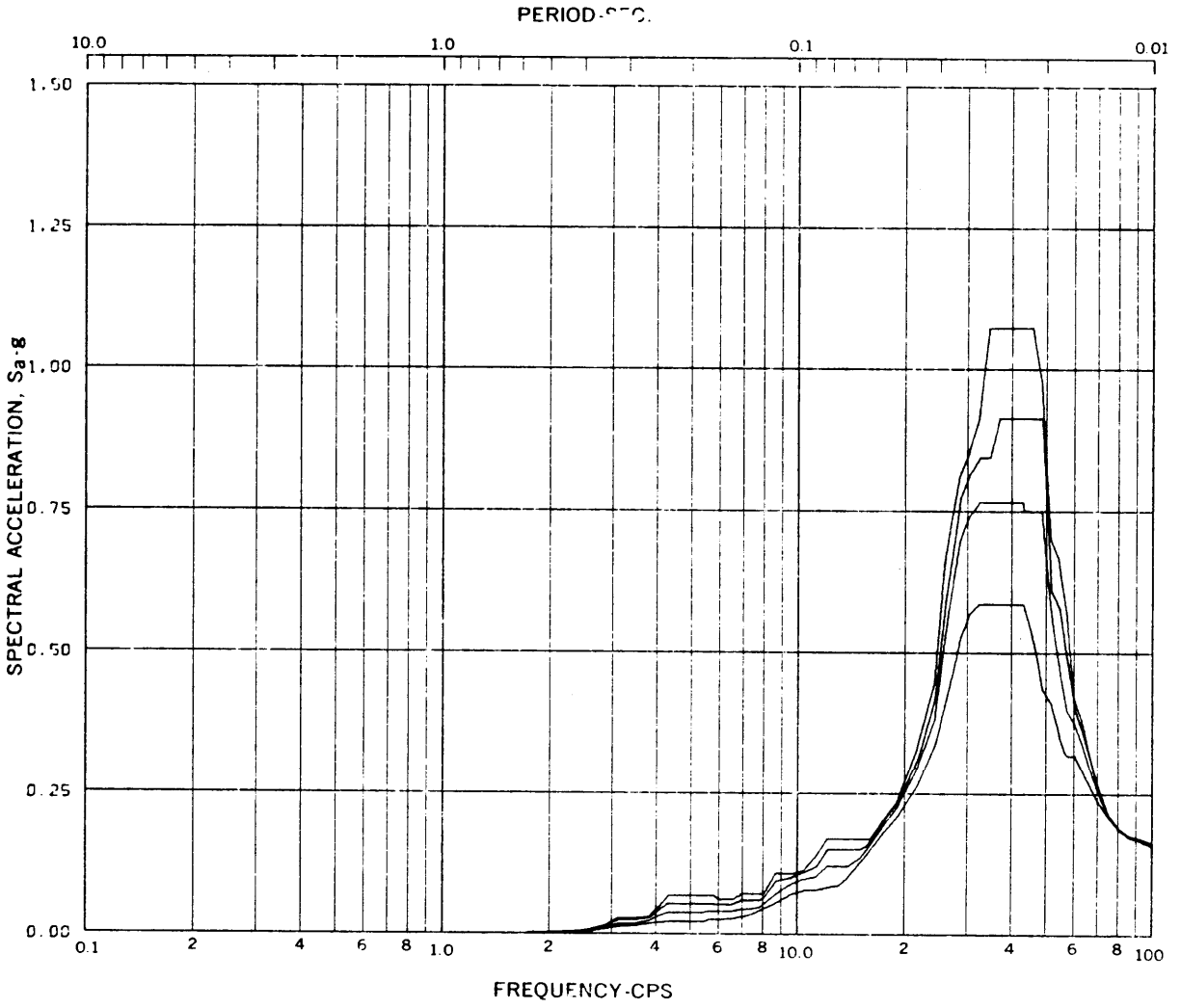
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-101



Acceleration Spectra for DIAPHRAGM SLAB

Load Case: SRV - ASYMMETRIC

Node: 252 Direction: VERT Elev: 236'-2" Angle: 22°-30'

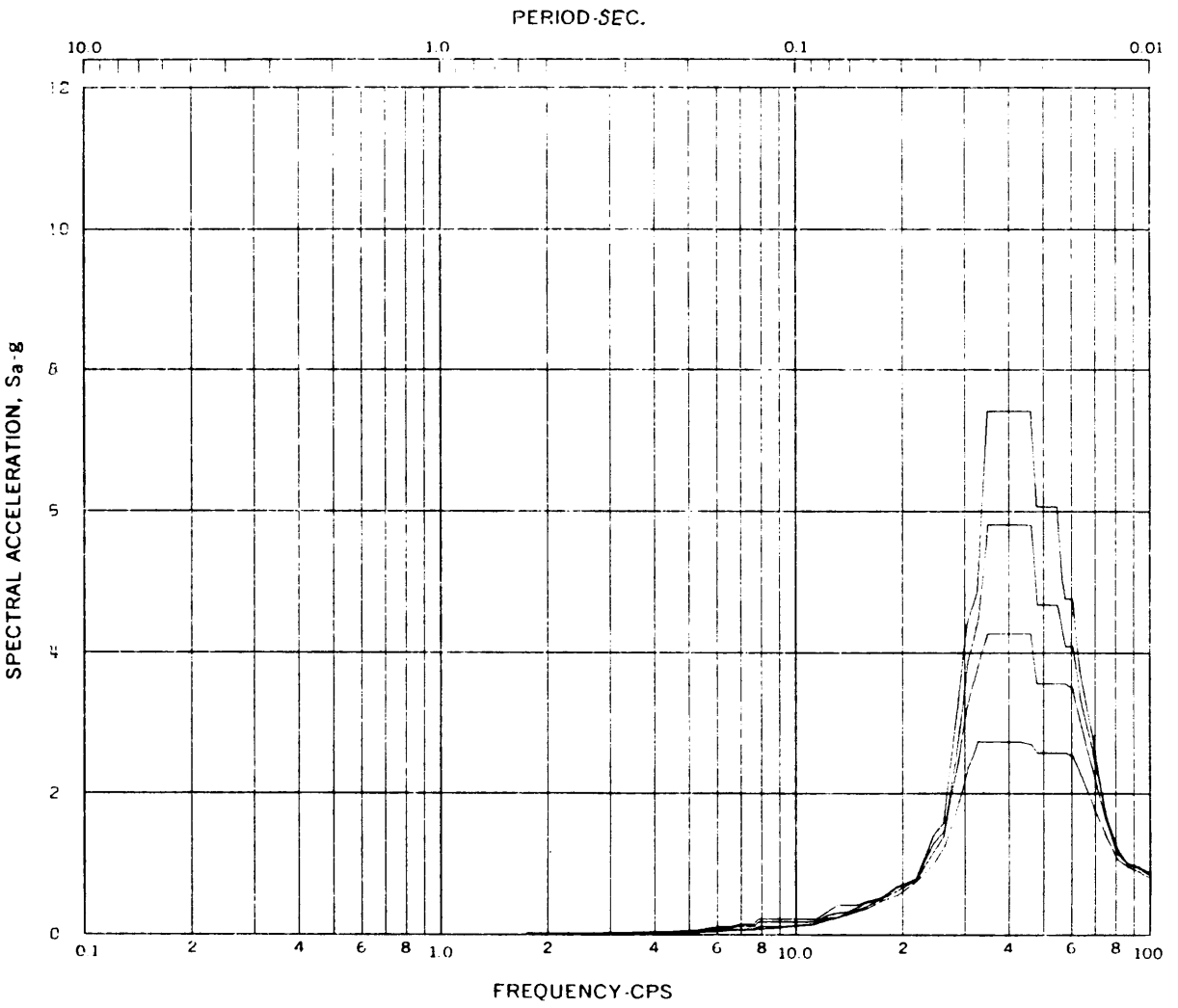
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-102



Acceleration Spectra for WETWELL WALL

Load Case: C04B

Node: 131 Direction: HORIZ Elev: 205'-11" Angle: 0°

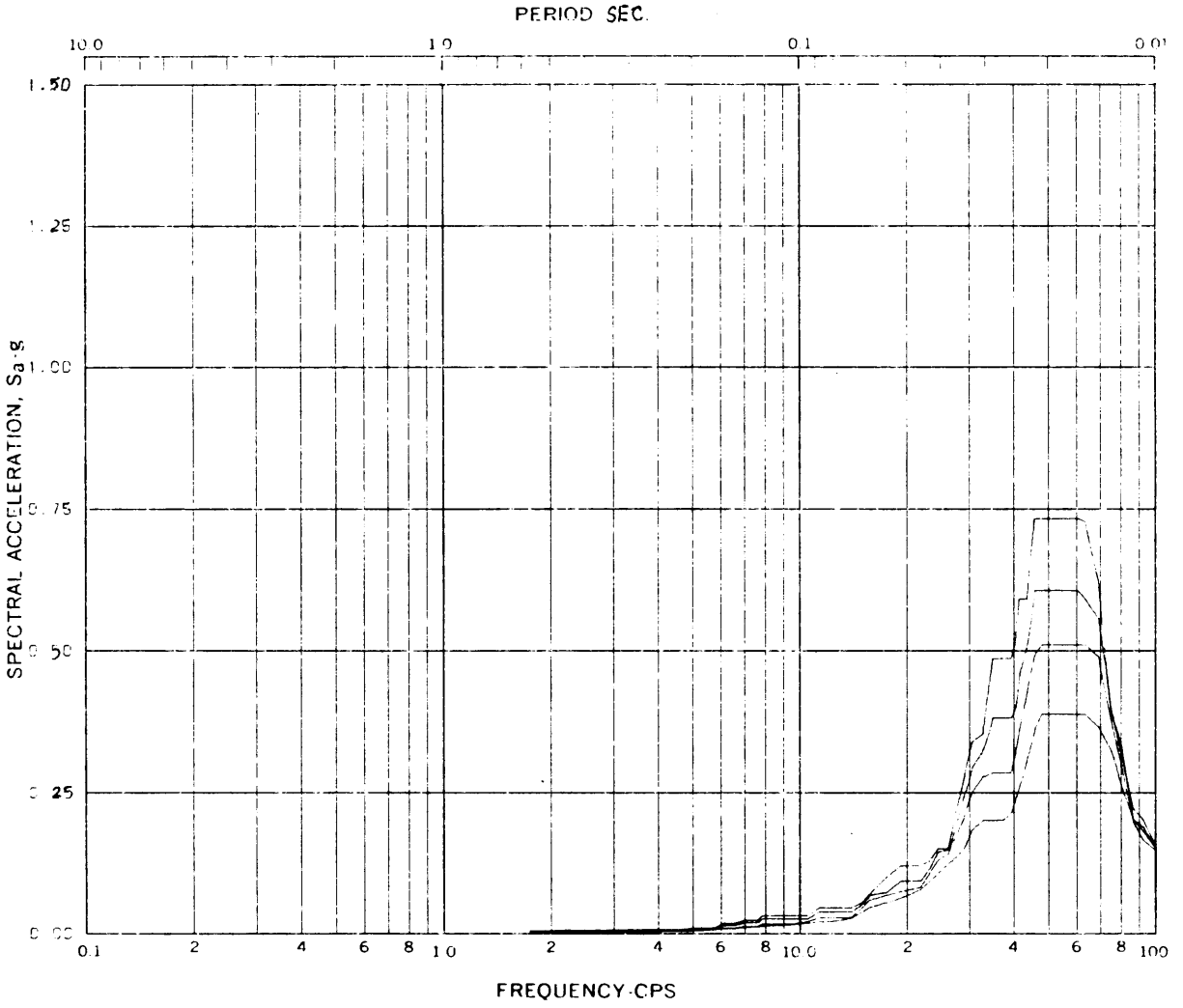
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-103



Acceleration Spectra for WETWELL WALL

Load Case: C04B

Node: 291 Direction: HORIZ Elev: 236'-2" Angle: 0°

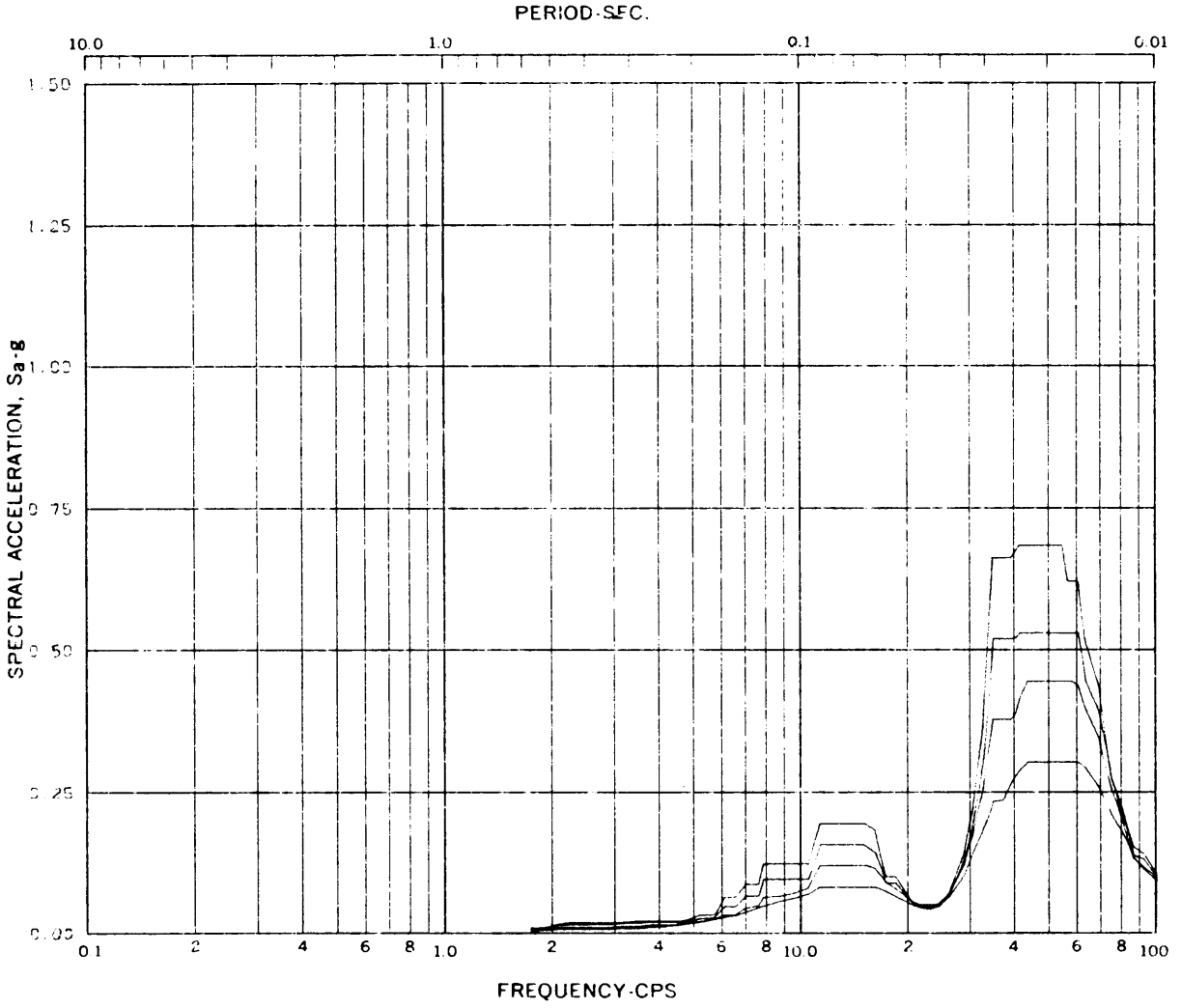
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-104



Acceleration Spectra for DRYWELL WALL

Load Case: C04B

Node: 331 Direction: HORIZ Elev: 264'-6" Angle: 0°

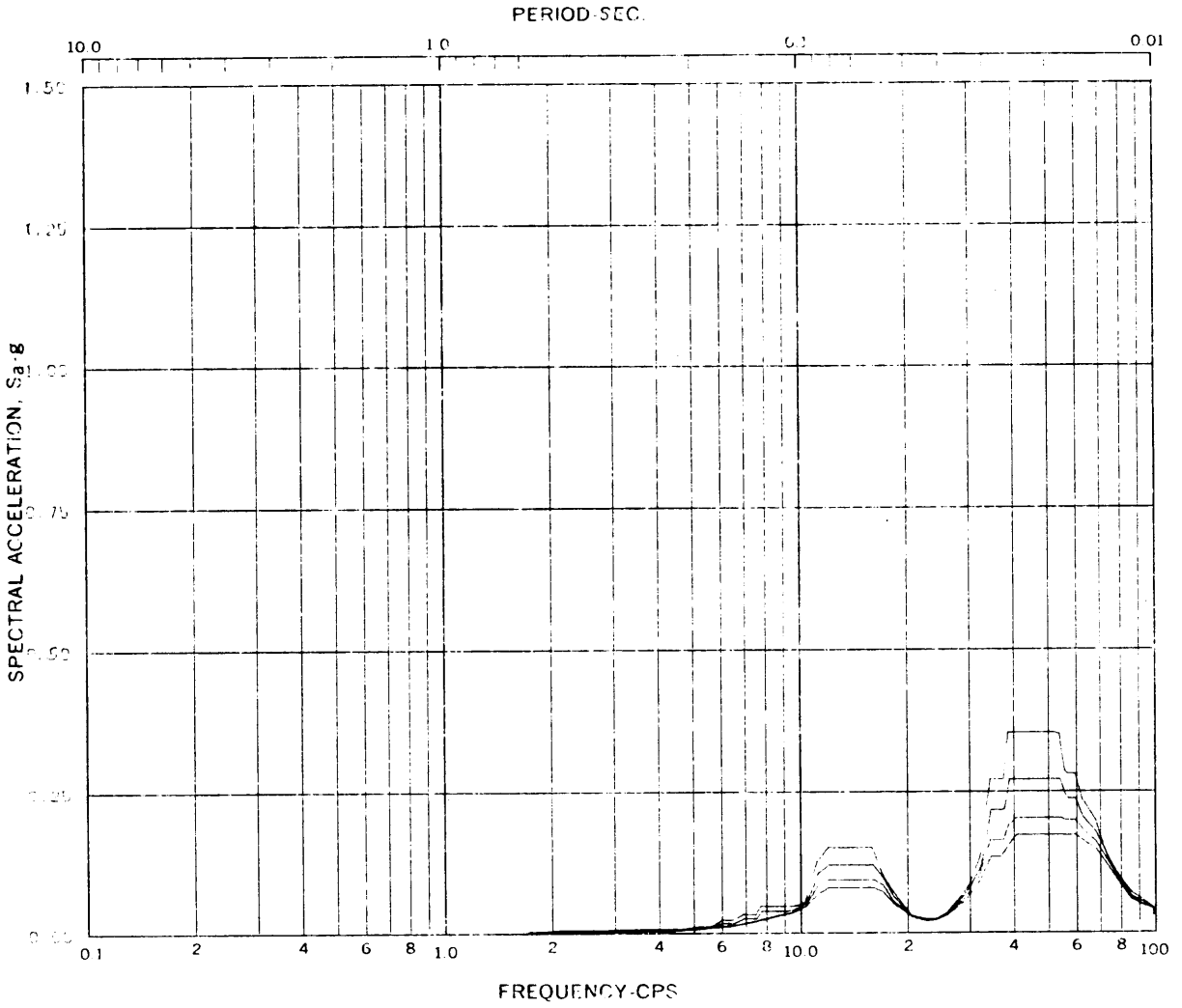
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-105



Acceleration Spectra for DRYWELL WALL

Load Case: C04B

Node: 431 Direction: HORIZ Elev: 325'-8 "Angle: 0°

Damping: 0.005,0.01,0.02,0.03

NOTE:

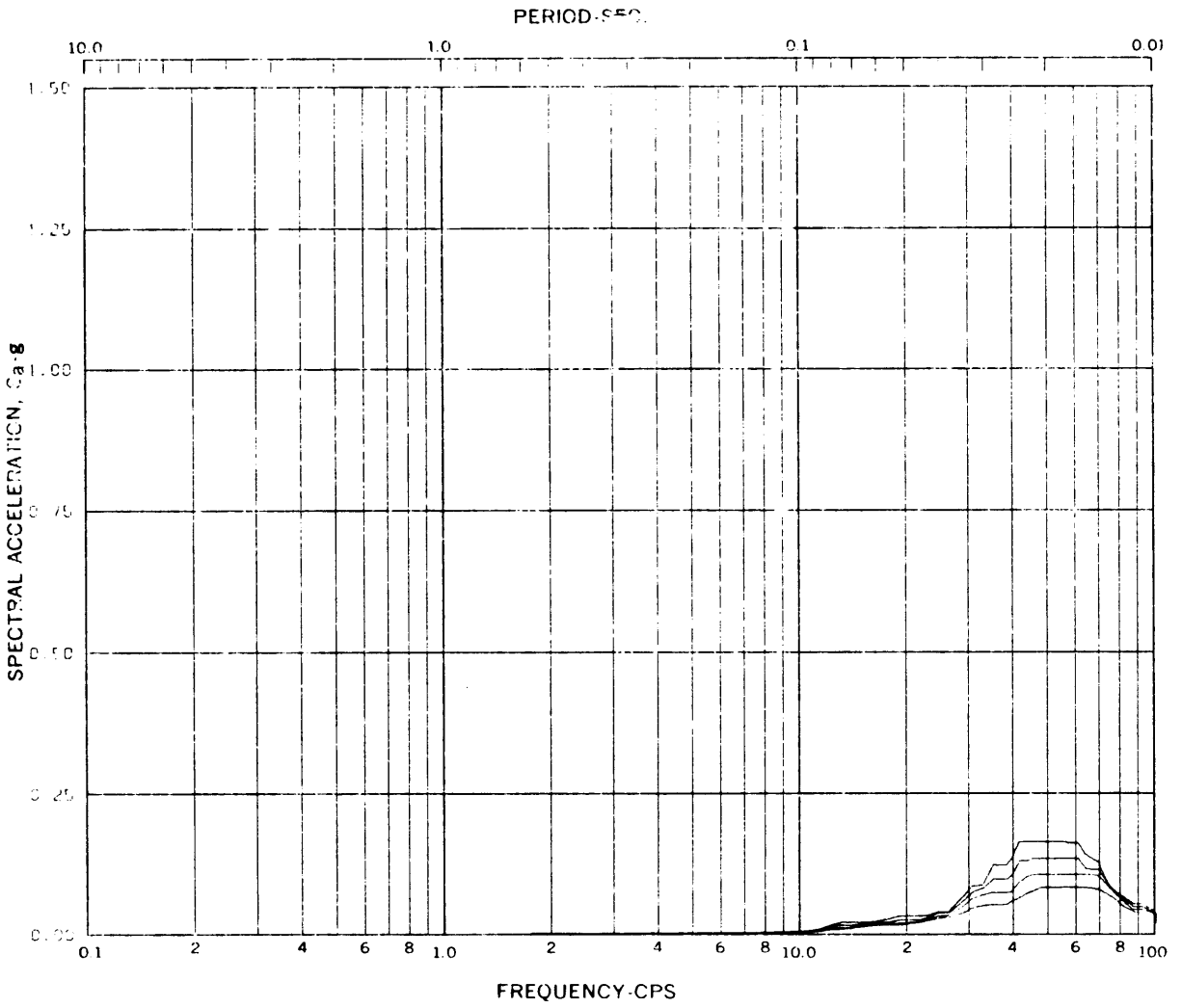
1. 0.05 DAMPING NOT INCLUDED.

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FIGURE 3A-106



Acceleration Spectra for PEDESTAL

Load Case: C04B

Node: 211 Direction: HORIZ Elev: 236'-2" Angle: 0°

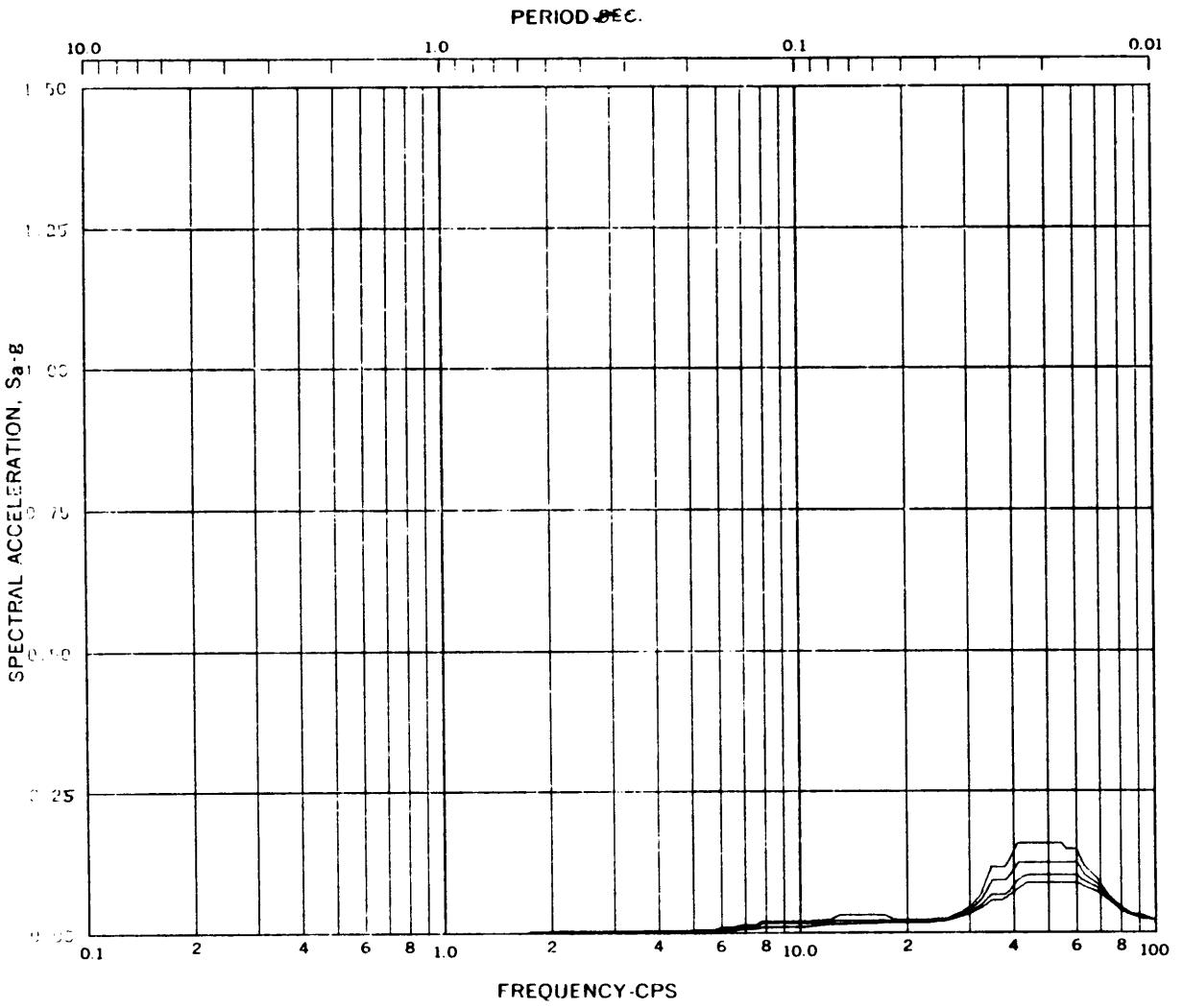
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-107



Acceleration Spectra for PEDESTAL

Load Case: C04B

Node: 531 Direction: HORIZ Elev: 263'-8 5/8" Angle: 0°

Damping: 0.005,0.01,0.02,0.03

NOTE:

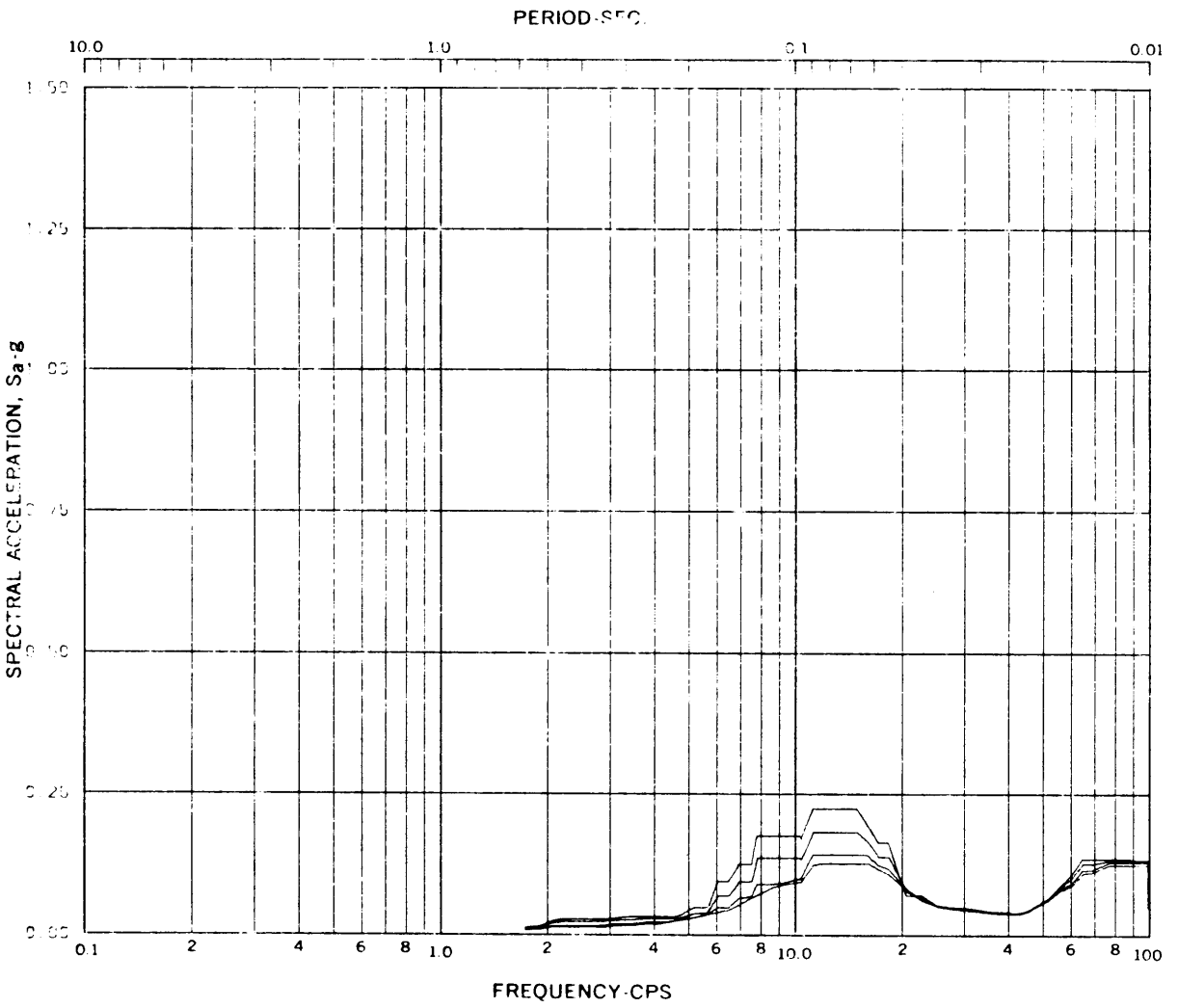
1. 0.05 DAMPING NOT INCLUDED.

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FIGURE 3A-108



Acceleration Spectra for SHIELD WALL

Load Case: C04B

Node: 841 Direction: HORIZ Elev: 312'-8" Angle: 0°

Damping: 0.005,0.01,0.02,0.03

NOTE:

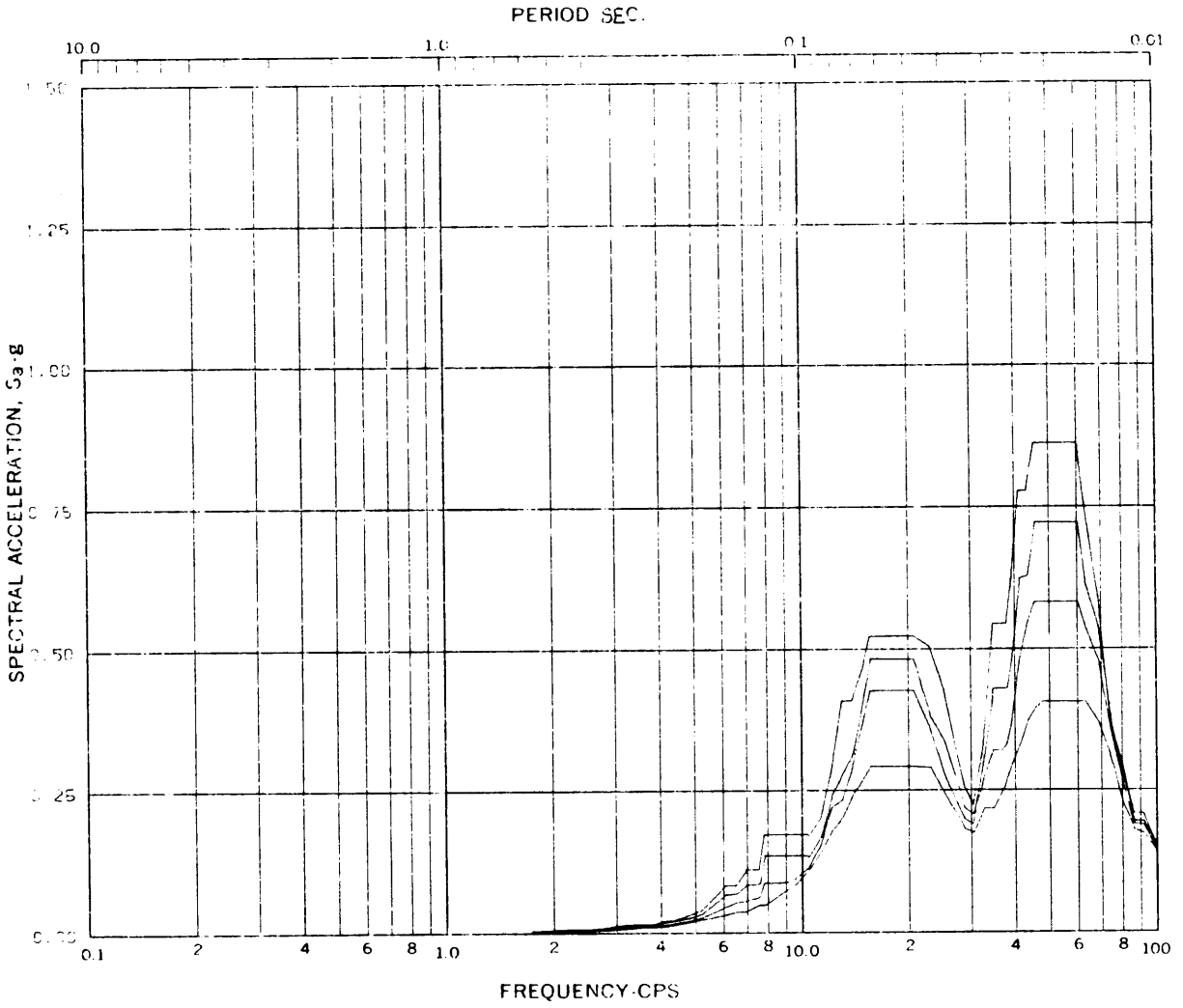
1. 0.05 DAMPING NOT INCLUDED.

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FIGURE 3A-109



Acceleration Spectra for WETWELL WALL

Load Case: C04B

Node: 131 Direction: VERT Elev: 205'-11" Angle: 0°

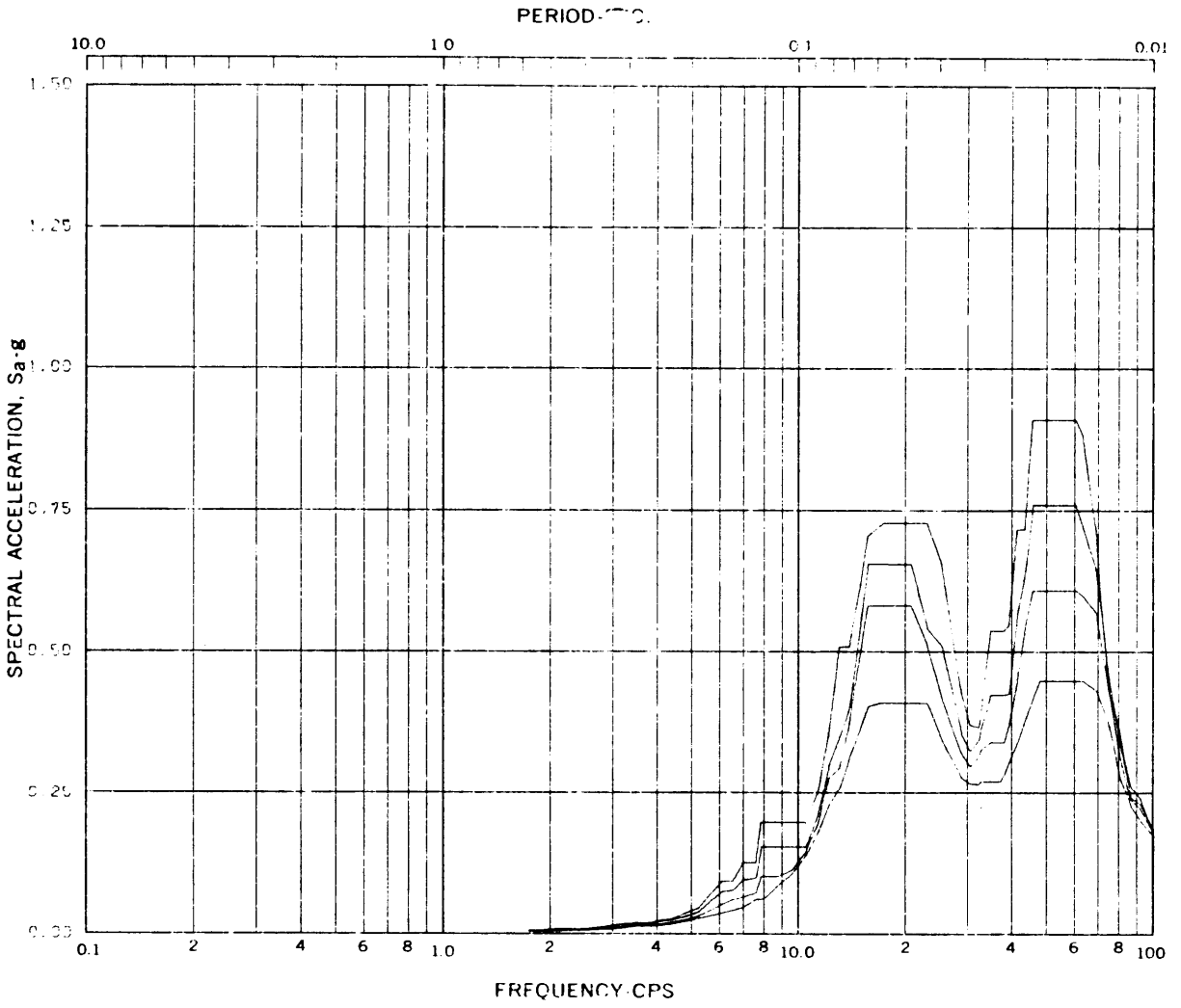
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-110



Acceleration Spectra for WETWELL WALL

Load Case: C04B

Node: 291 Direction: VERT Elev: 236'-2" Angle: 0°

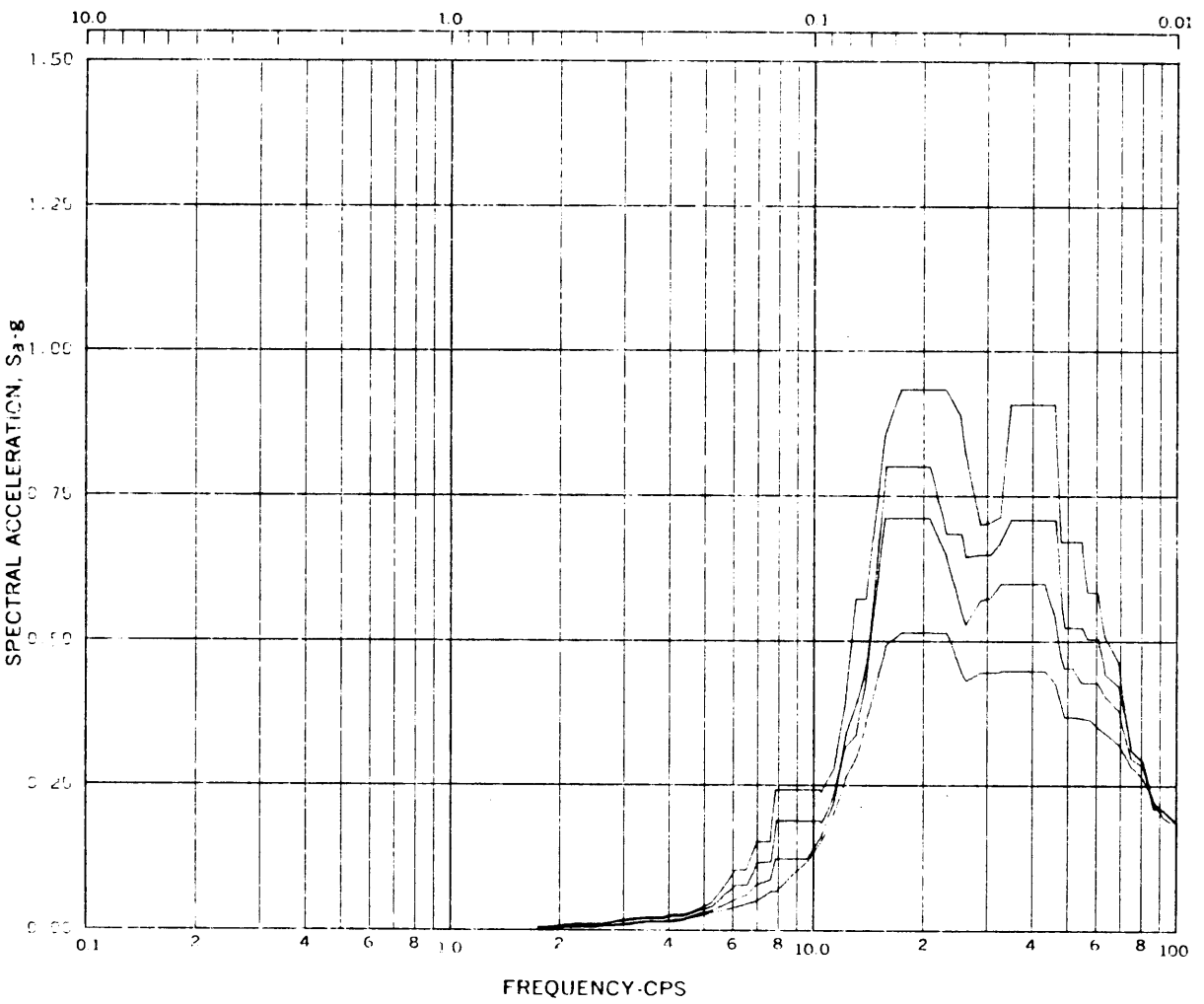
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-111



Acceleration Spectra for DRYWELL WALL

Load Case: C04B

Node: 331 Direction: VERT Elev: 264'-6" Angle: 0°

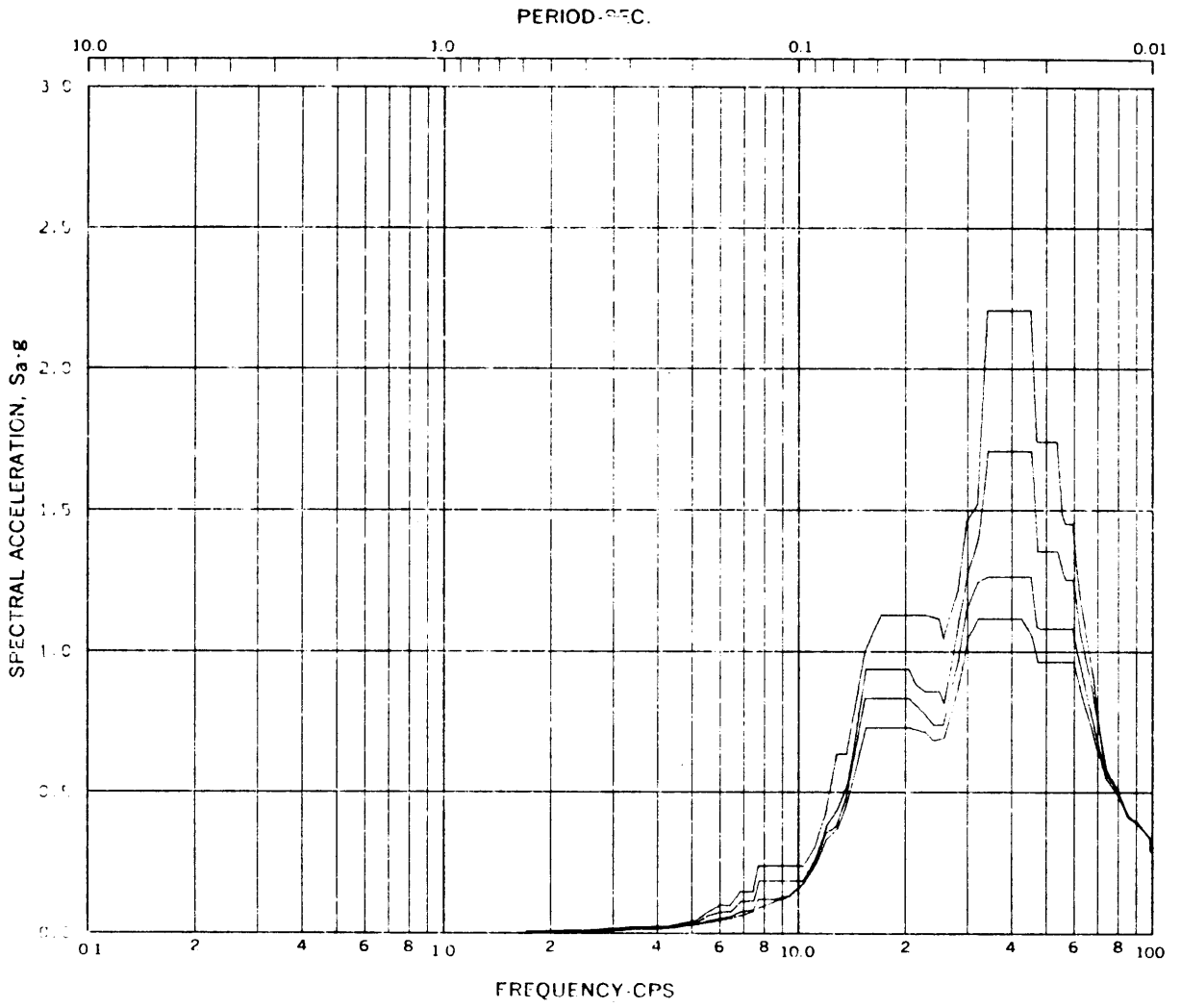
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-112



Acceleration Spectra for DRYWELL WALL

Load Case: C04B

Node: 431 Direction: VERT Elev: 325'-8" Angle: 0°

Damping: 0.005,0.01,0.02,0.03

NOTE:

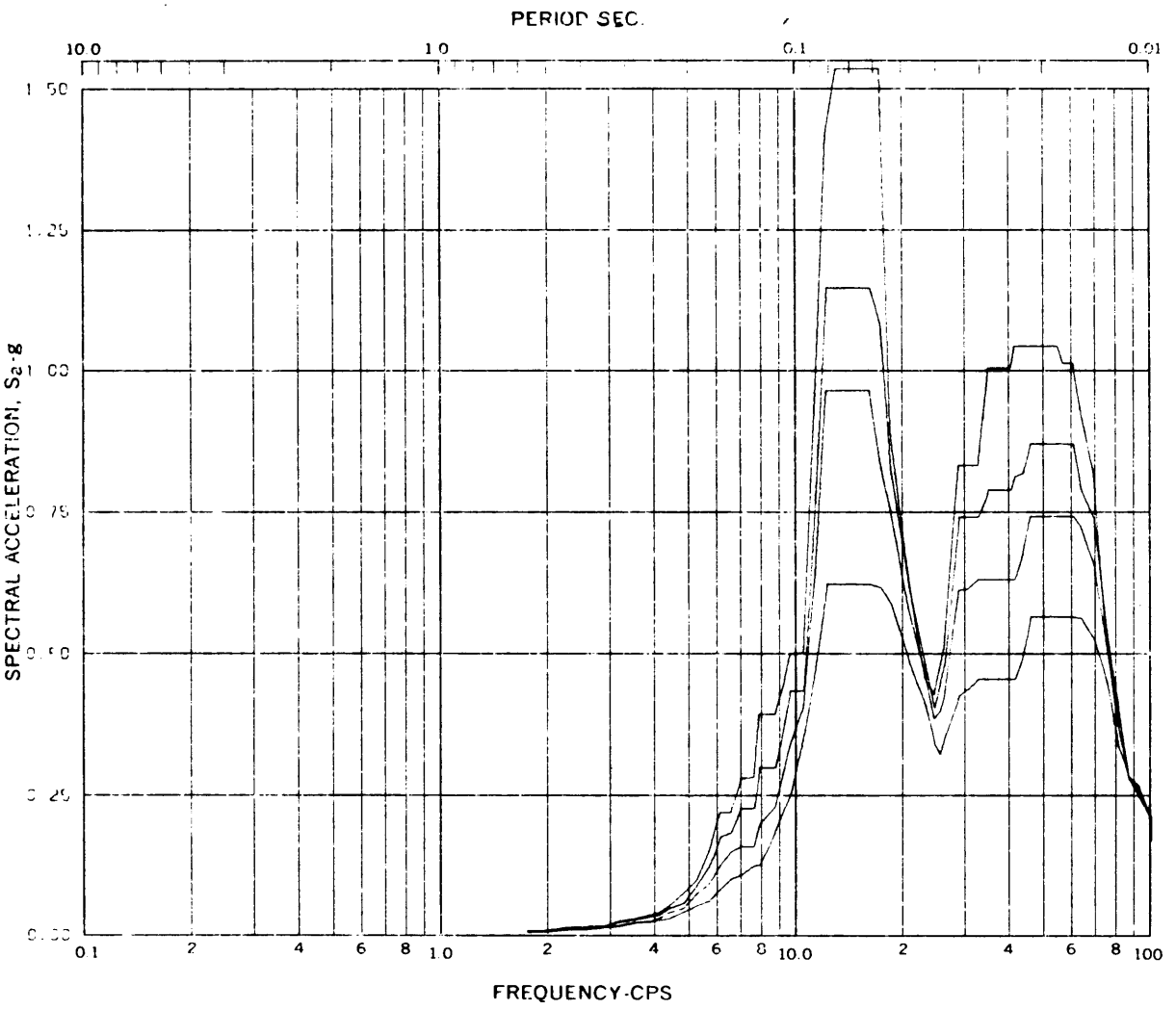
1. 0.05 DAMPING NOT INCLUDED.

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FIGURE 3A-113



Acceleration Spectra for PEDESTAL

Load Case: C04B

Node: 211 Direction: VERT Elev: 236'-2" Angle: 0°

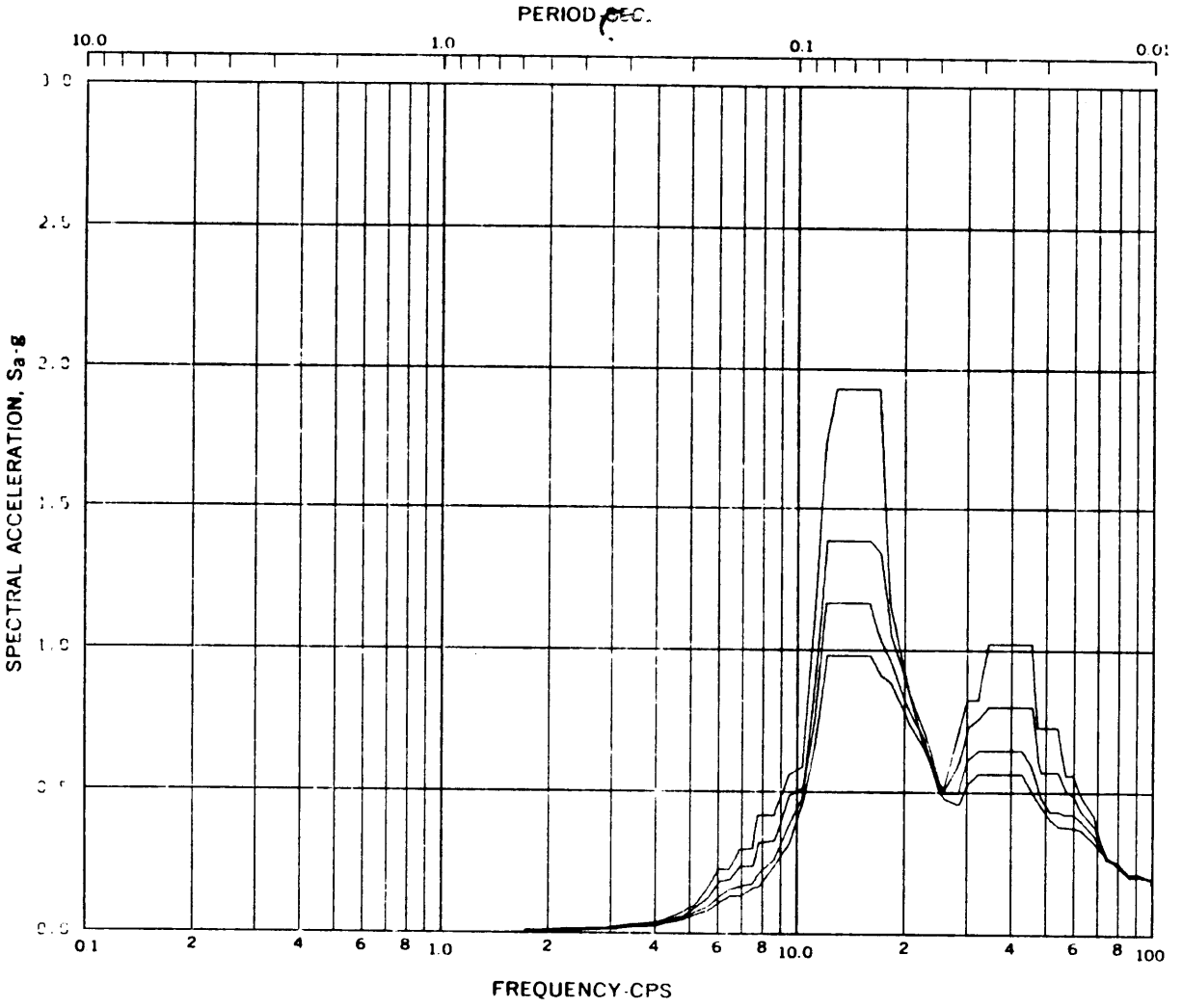
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-114



Acceleration Spectra for PEDESTAL

Load Case: C04B

Node: 531 Direction: VERT Elev: 263'-8 5/8" Angle: 0°

Damping: 0.005,0.01,0.02,0.03

NOTE:

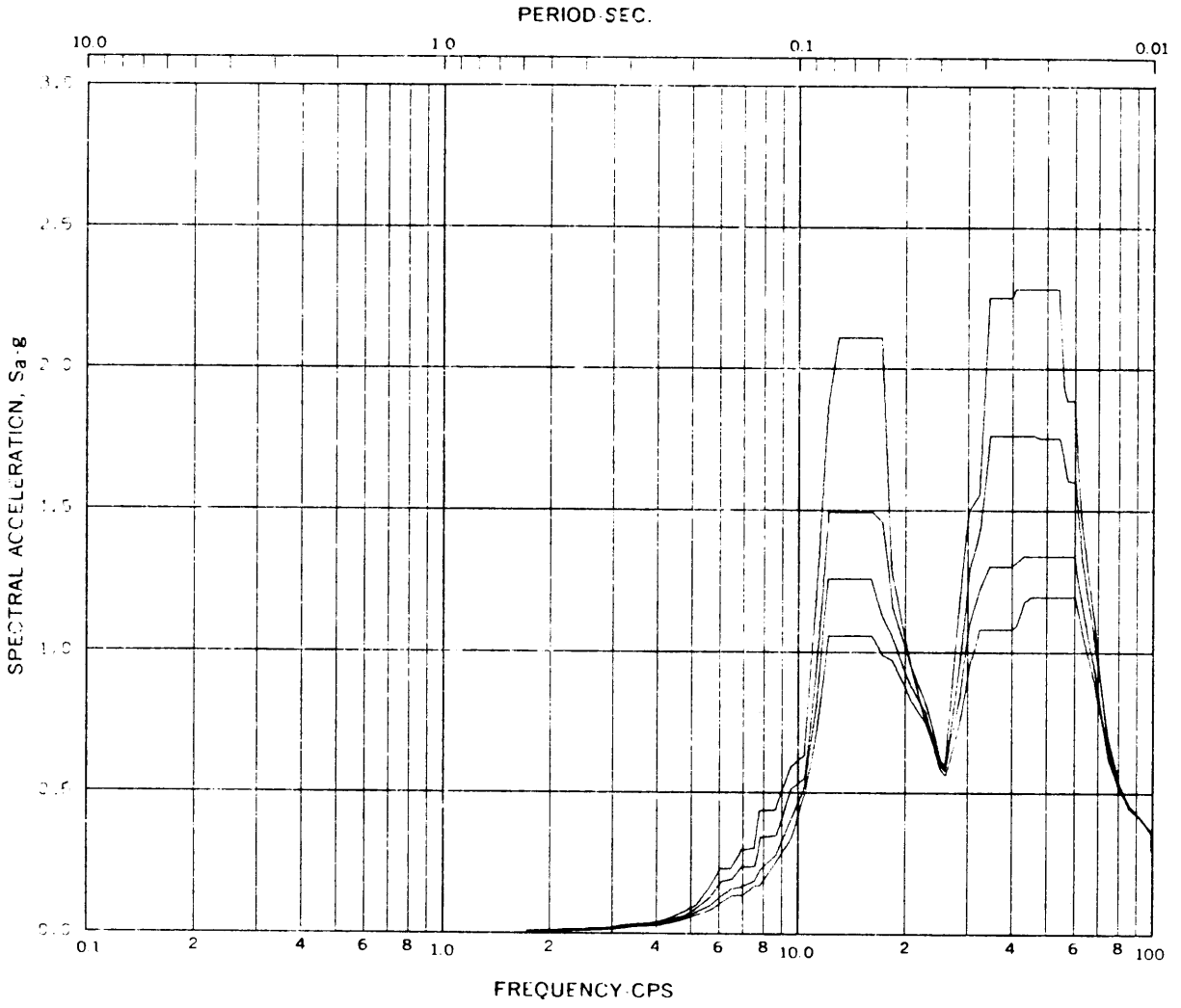
1. 0.05 DAMPING NOT INCLUDED.

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FIGURE 3A-115



Acceleration Spectra for SHIELD WALL

Load Case: C04B

Node: 841 Direction: VERT Elev: 312'-8" Angle: 0°

Damping: 0.005,0.01,0.02,0.03

NOTE

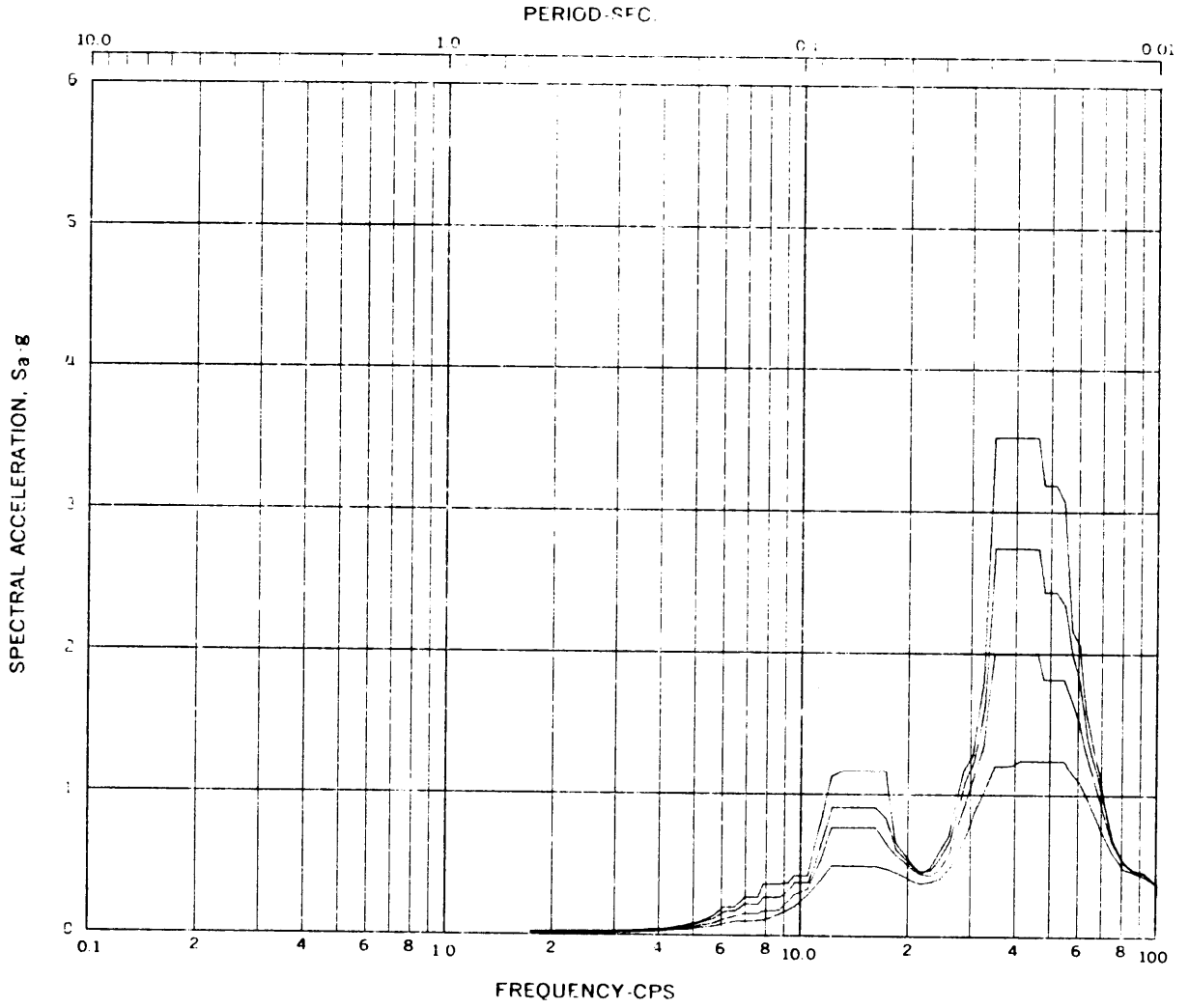
1. 0.05 DAMPING NOT INCLUDED.

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FIGURE 3A-116



Acceleration Spectra for DIAPHRAGM SLAB

Load Case: C04B

Node: 231 Direction: VERT Elev: 236'-2" Angle: 0°

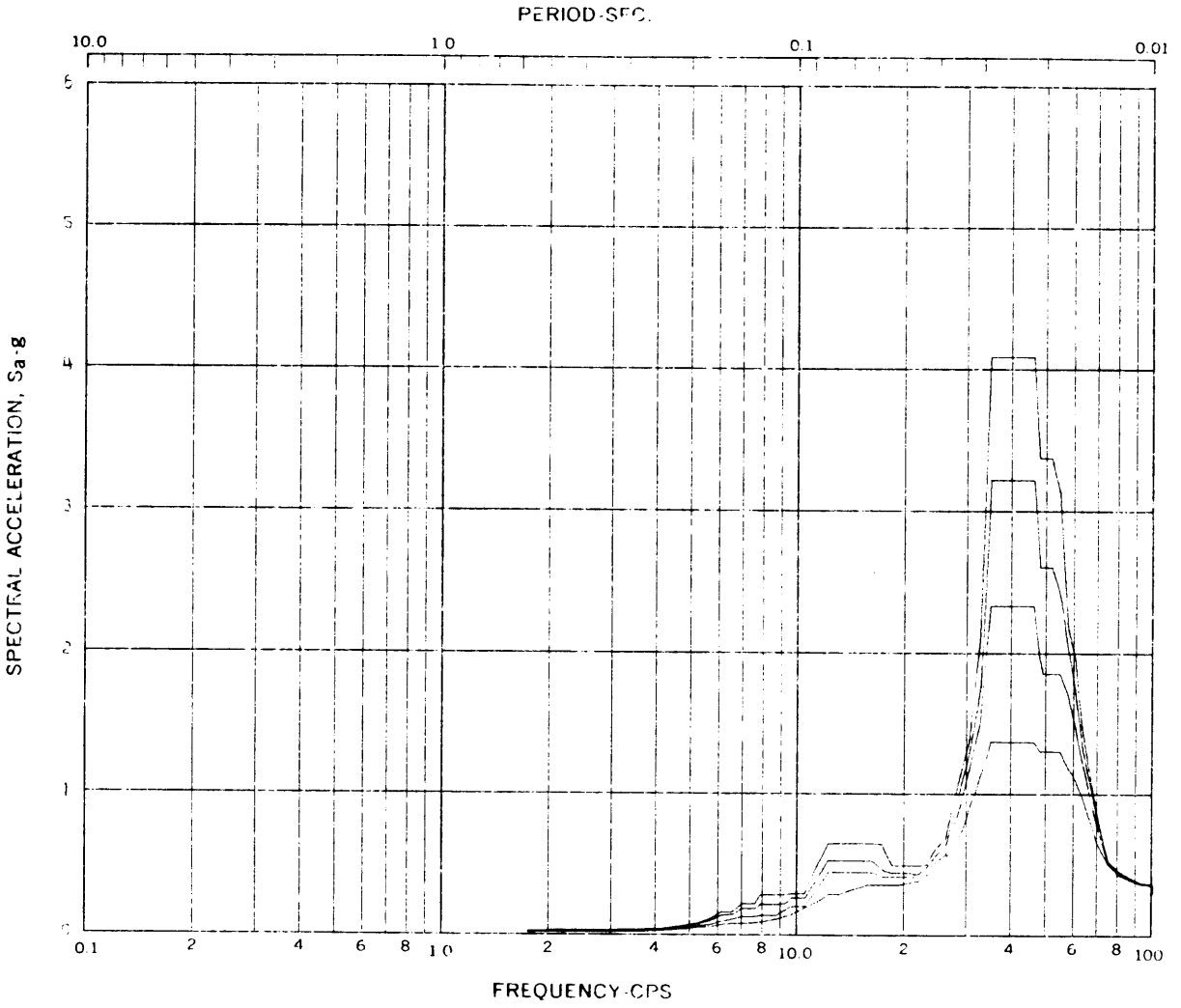
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-117



Acceleration Spectra for DIAPHRAGM SLAB

Load Case: C04B

Node: 252 Direction: VERT Elev: 236'-2" Angle: 22°30'

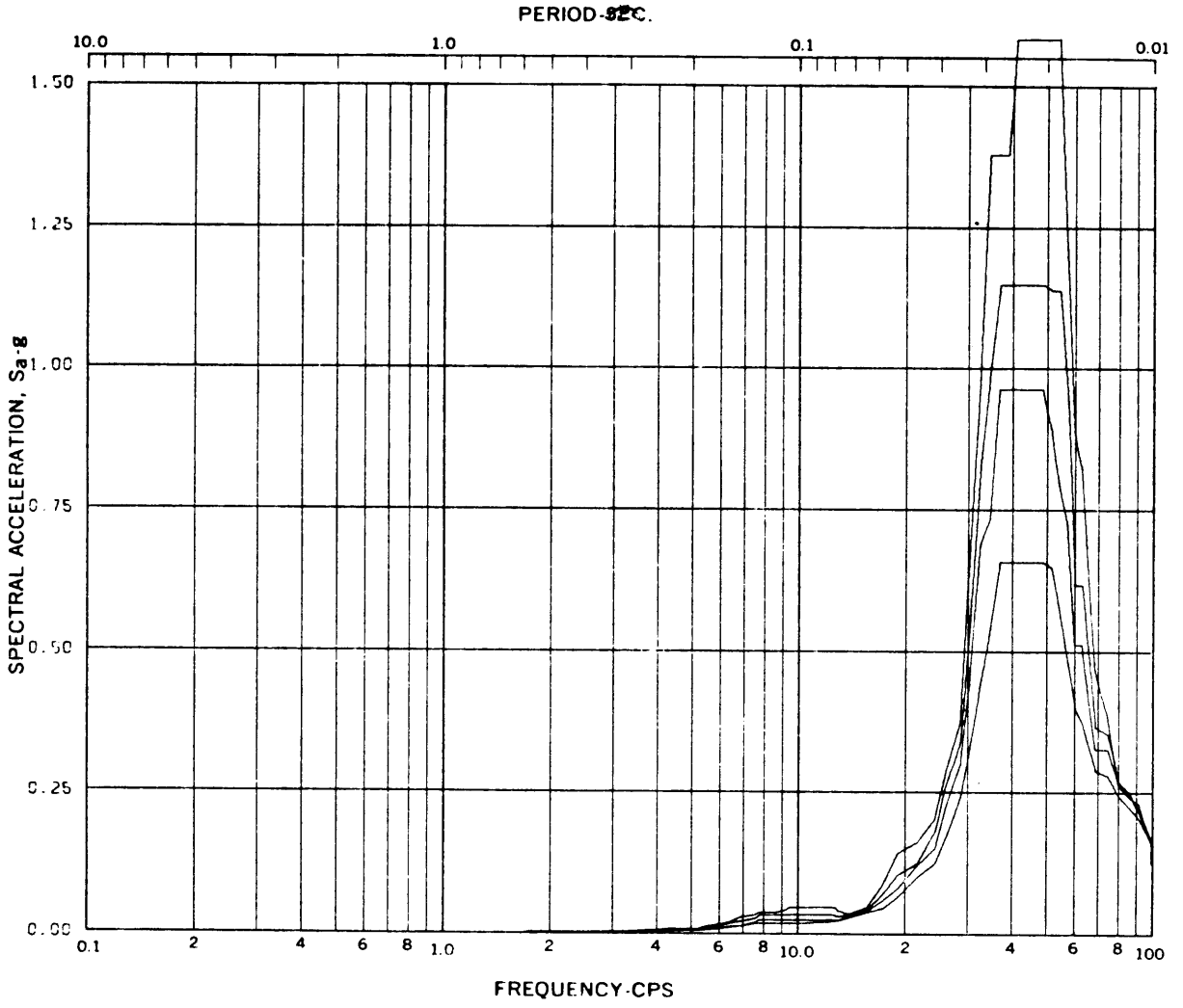
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-118



Acceleration Spectra for WETWELL WALL

Load Case: CO FOR COMBINATION WITH ADS

Node: 131 Direction: HORIZ Elev: 205'-11" Angle: 0°

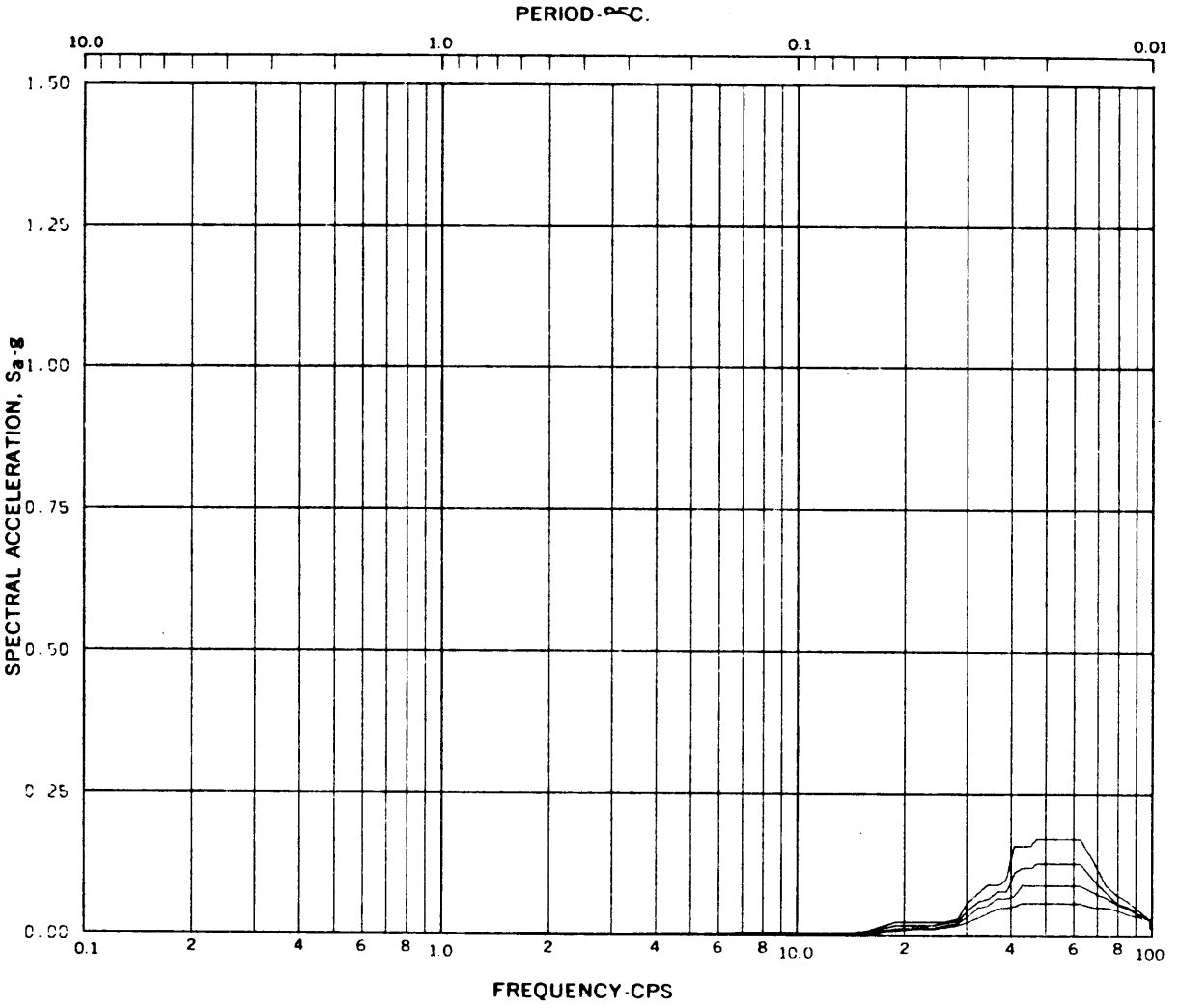
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-119



Acceleration Spectra for WETWELL WALL

Load Case: CO FOR COMBINATION WITH ADS

Node: 291 Direction: HORIZ Elev: 236'-2" Angle: 0°

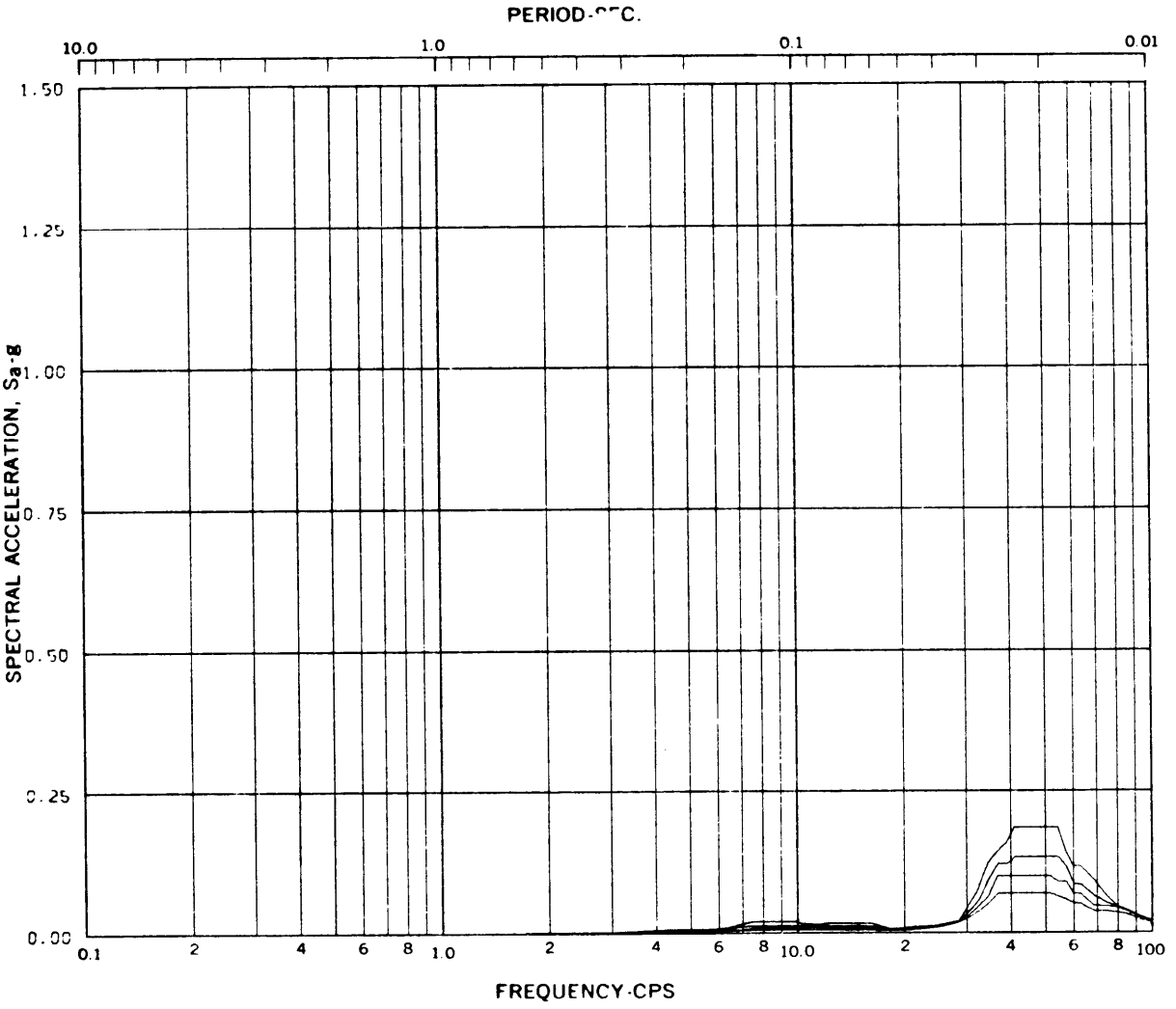
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-120



Acceleration Spectra for DRYWELL WALL

Load Case: CO FOR COMBINATION WITH ADS

Node: 331 Direction: HORIZ Elev: 264'-6" Angle: 0°

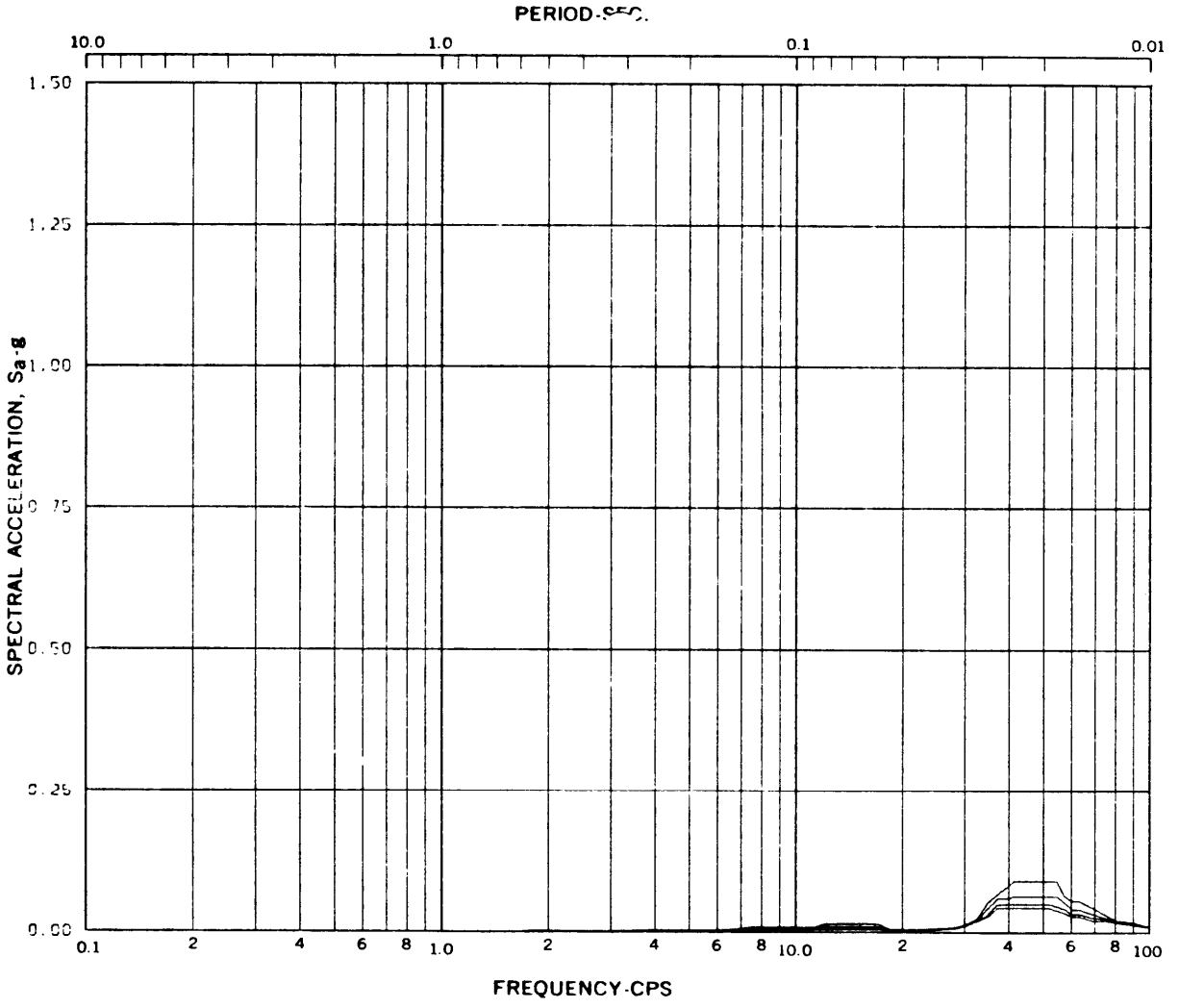
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-121



Acceleration Spectra for DRYWELL WALL

Load Case: CO FOR COMBINATION WITH ADS

Node: 431 Direction: HORIZ Elev: 325'-8" Angle: 0°

Damping: 0.005,0.01,0.02,0.03

NOTE:

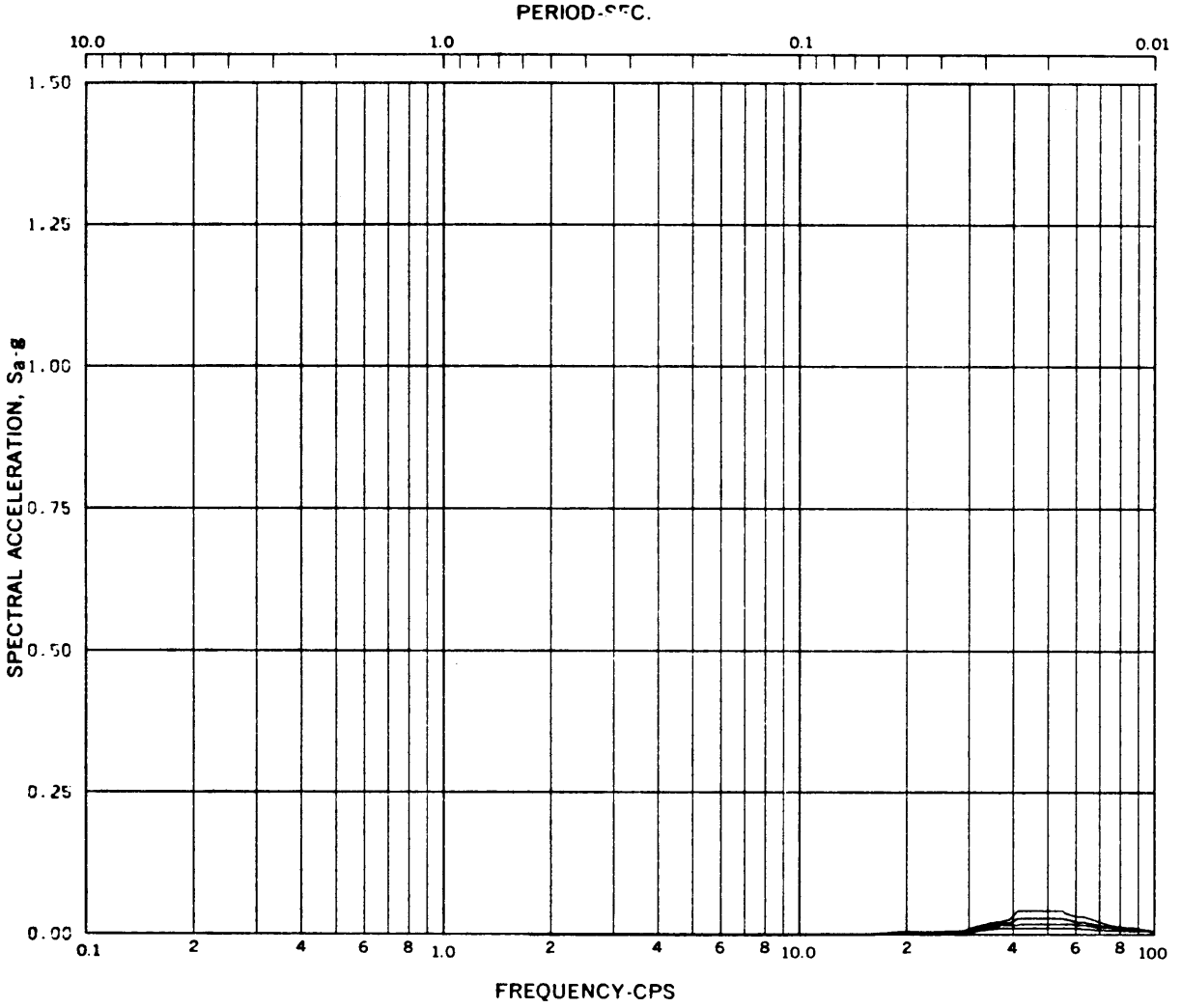
1. 0.05 DAMPING NOT INCLUDED.

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FIGURE 3A-122



Acceleration Spectra for PEDESTAL

Load Case: CO FOR COMBINATION WITH ADS

Node: 211 Direction: HORIZ Elev: 236'-2" Angle: 0°

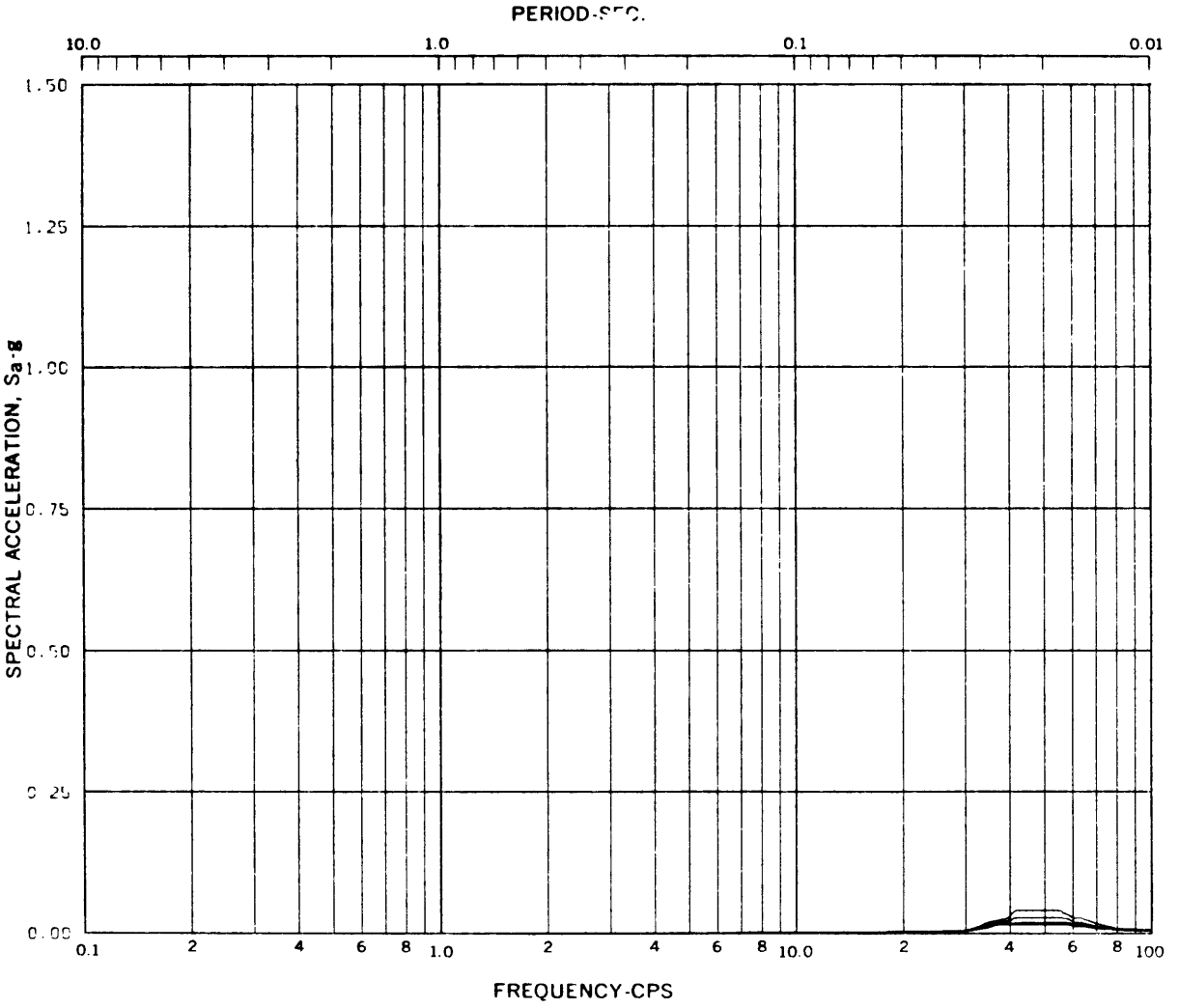
Damping: 0.005,0.01,0.02,0.05

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DIRECTION X

FIGURE 3A-123



Acceleration Spectra for PEDESTAL

Load Case: CO FOR COMBINATION WITH ADS

Node: 531 Direction: HORIZ Elev: 263'-8 5/8" Angle: 0°

Damping: 0.005,0.01,0.02,0.03

NOTE:

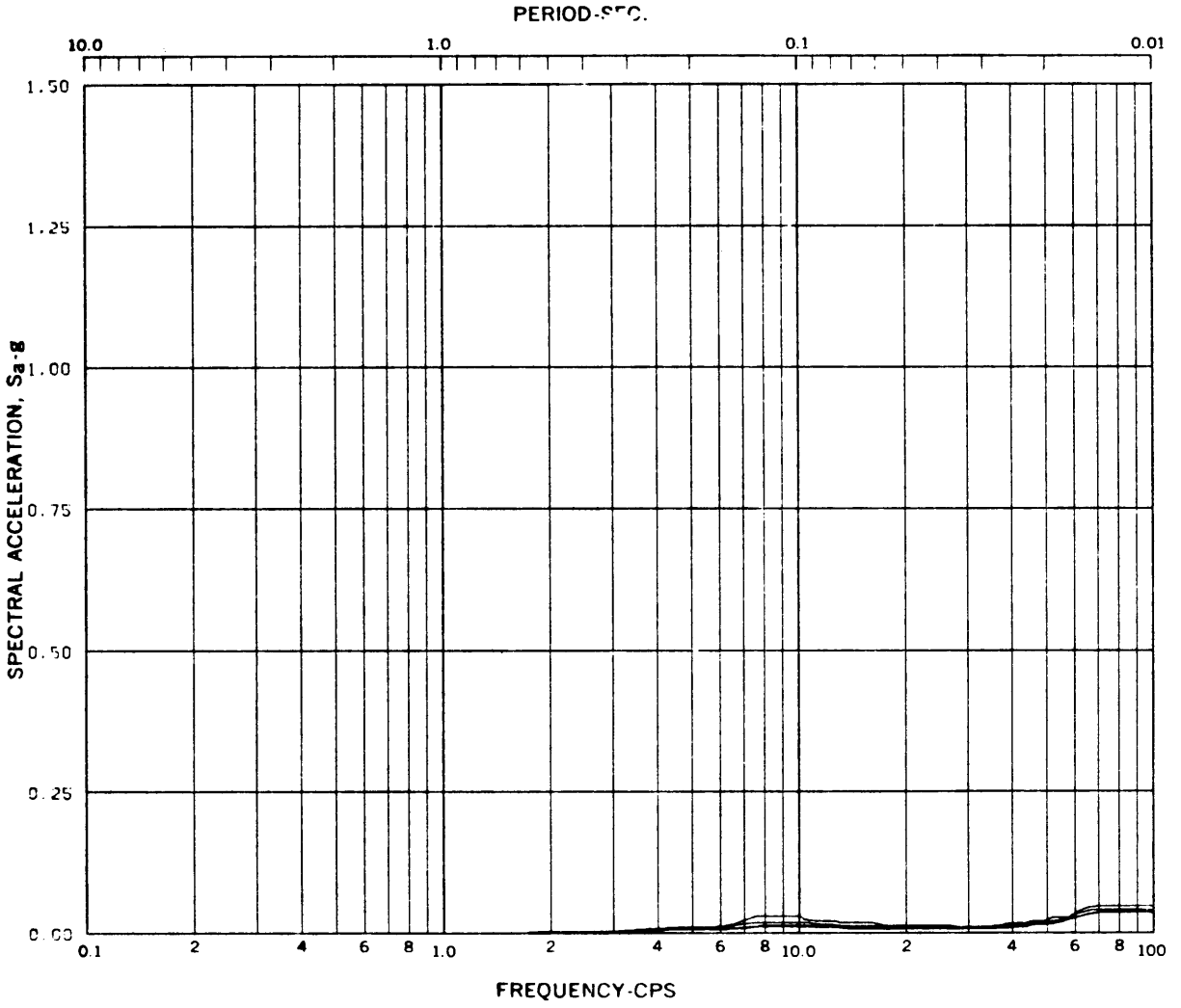
1. 0.05 DAMPING NOT INCLUDED.

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FIGURE 3A-124



Acceleration Spectra for SHIELD WALL

Load Case: CO FOR COMBINATION WITH ADS

Node: 841 Direction: HORIZ Elev: 312'-8" Angle: 0°

Damping: 0.005,0.01,0.02,0.03

NOTE:

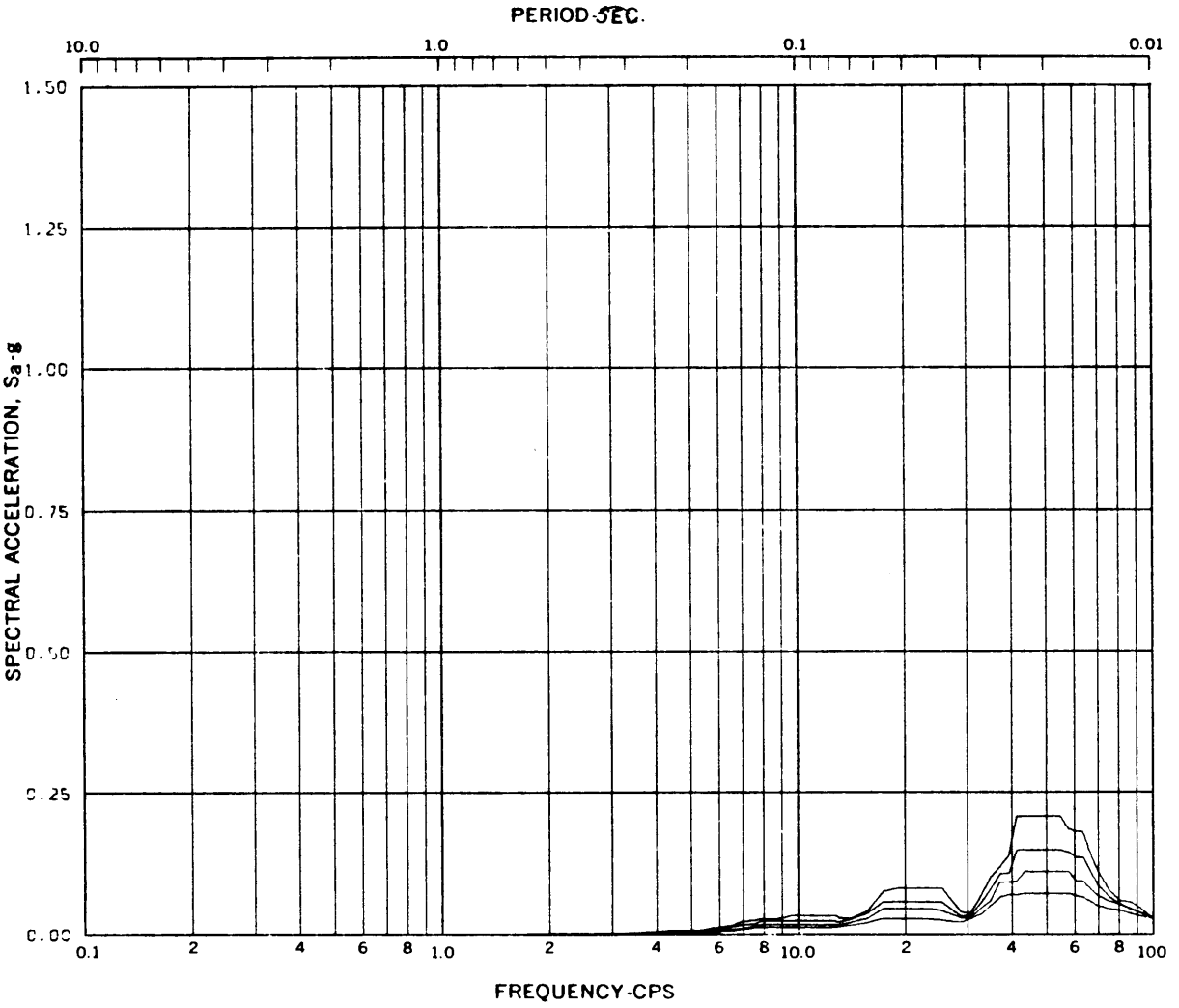
1. 0.05 DAMPING NOT INCLUDED.

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FIGURE 3A-125



Acceleration Spectra for WETWELL WALL

Load Case: CO FOR COMBINATION WITH ADS

Node: 131 Direction: VERT Elev: 205'-11" Angle: 0°

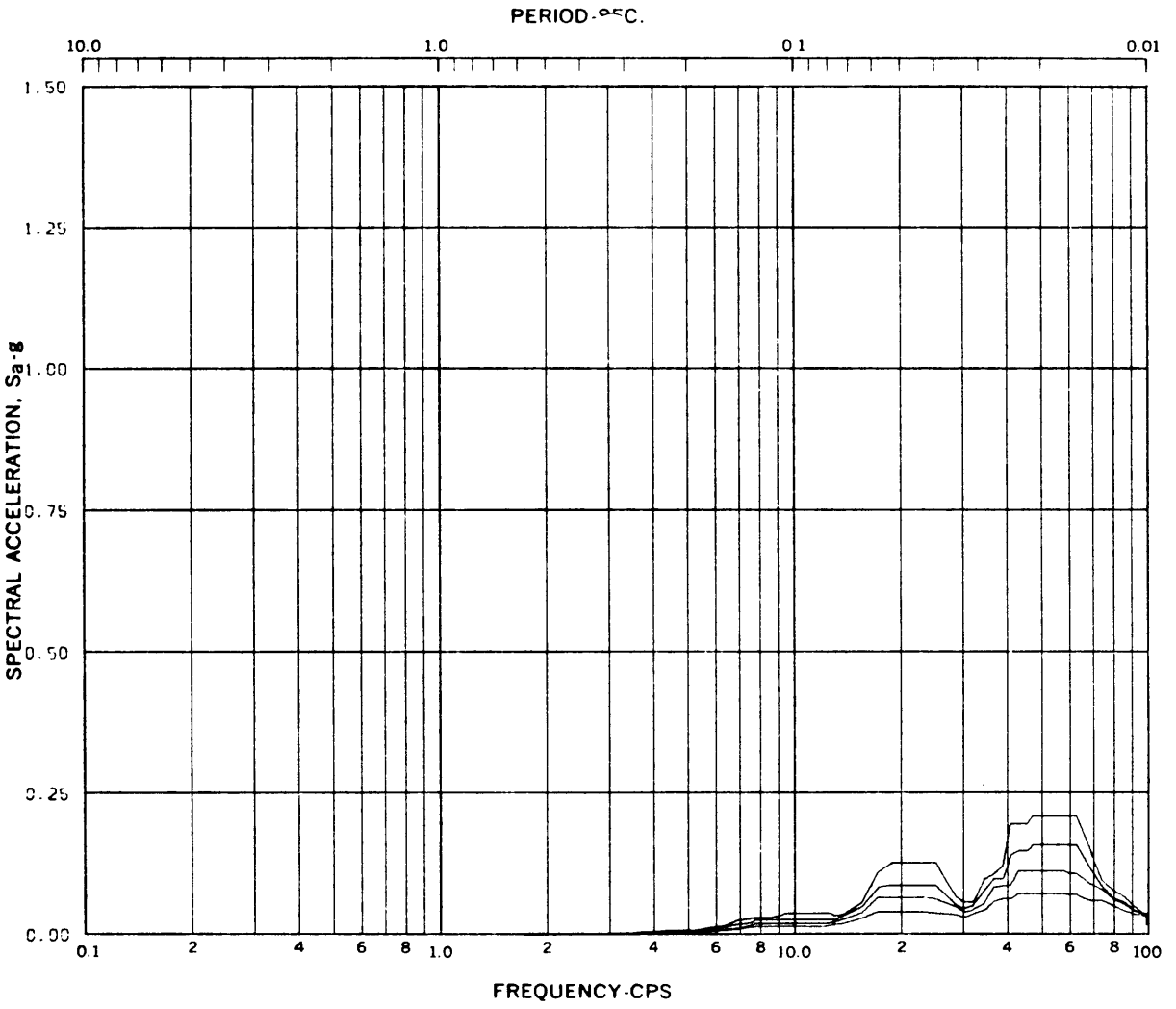
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-126



Acceleration Spectra for WETWELL WALL

Load Case: CO FOR COMBINATION WITH ADS

Node: 291 Direction: VERT Elev: 236'-2" Angle: 0°

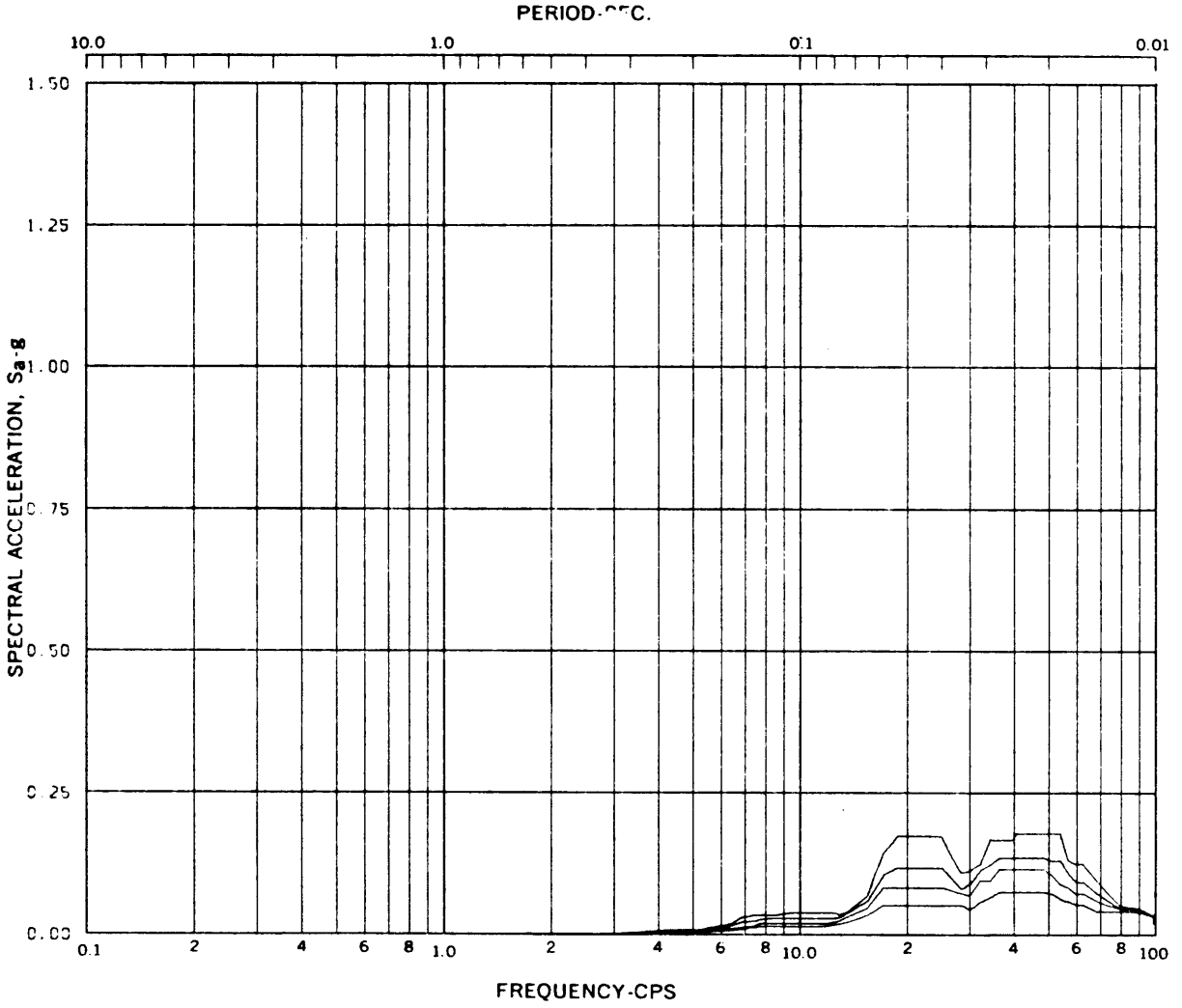
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-127



Acceleration Spectra for DRYWELL

Load Case: CO FOR COMBINATION WITH ADS

Node: 331 Direction: VERT Elev: 264'-6" Angle: 0°

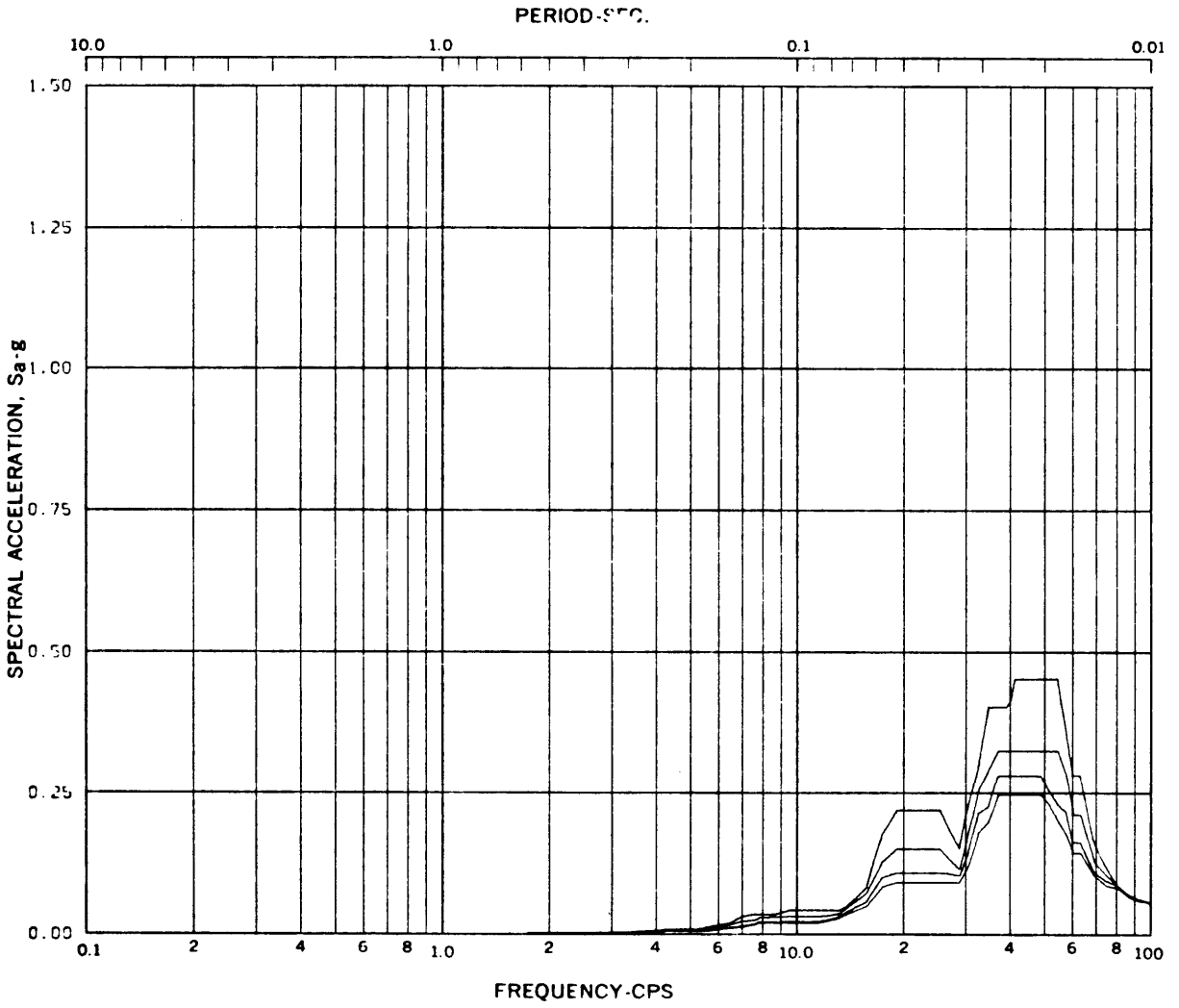
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-128



Acceleration Spectra for DRYWELL

Load Case: CO FOR COMBINATION WITH ADS

Node: 431 Direction: VERT Elev: 325'-8" Angle: 0°

Damping: 0.005,0.01,0.02,0.03

NOTE:

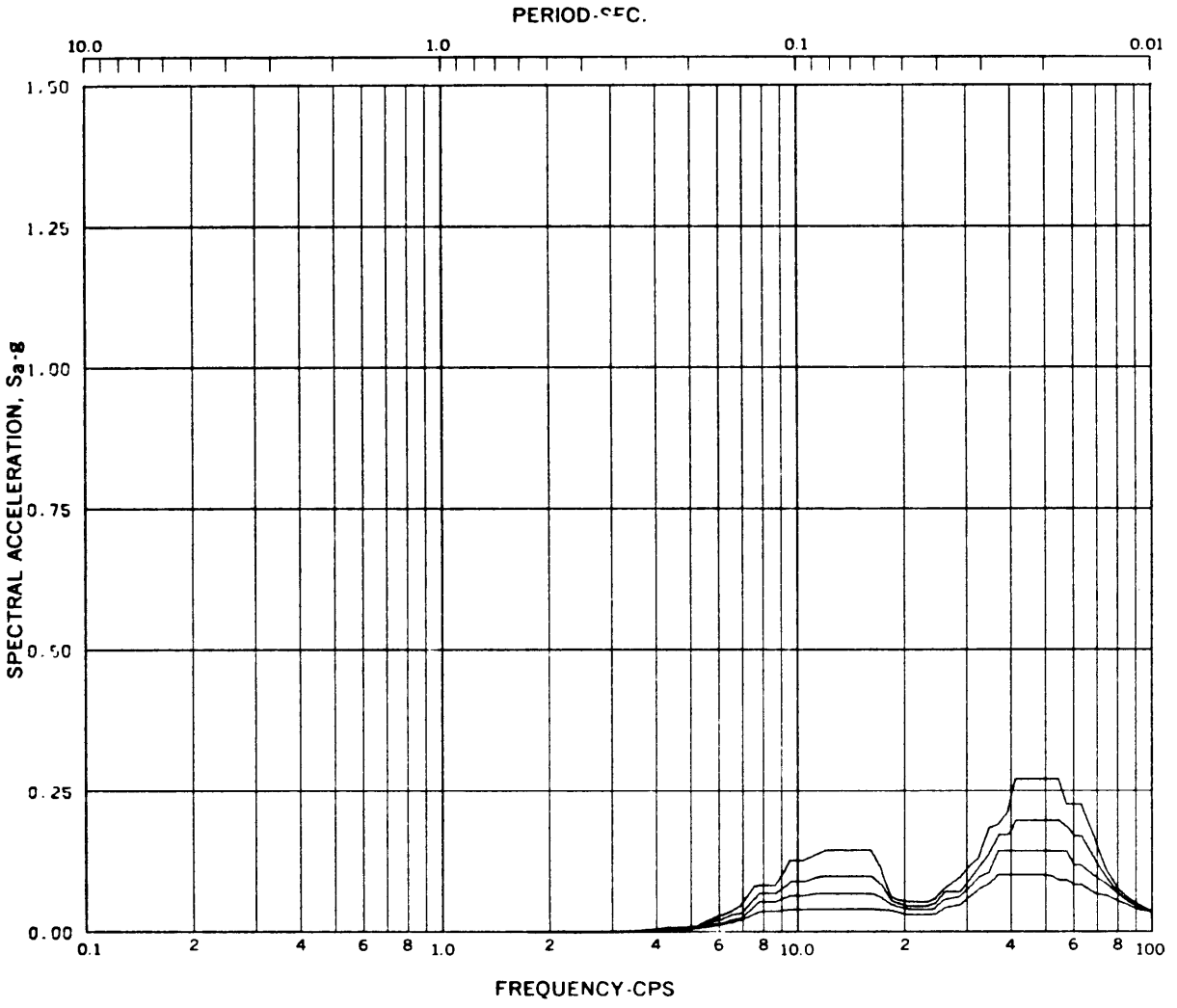
1. 0.05 DAMPING NOT INCLUDED.

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FIGURE 3A-129



Acceleration Spectra for PEDESTAL

Load Case: CO FOR COMBINATION WITH ADS

Node: 211 Direction: VERT Elev: 236'-2" Angle: 0°

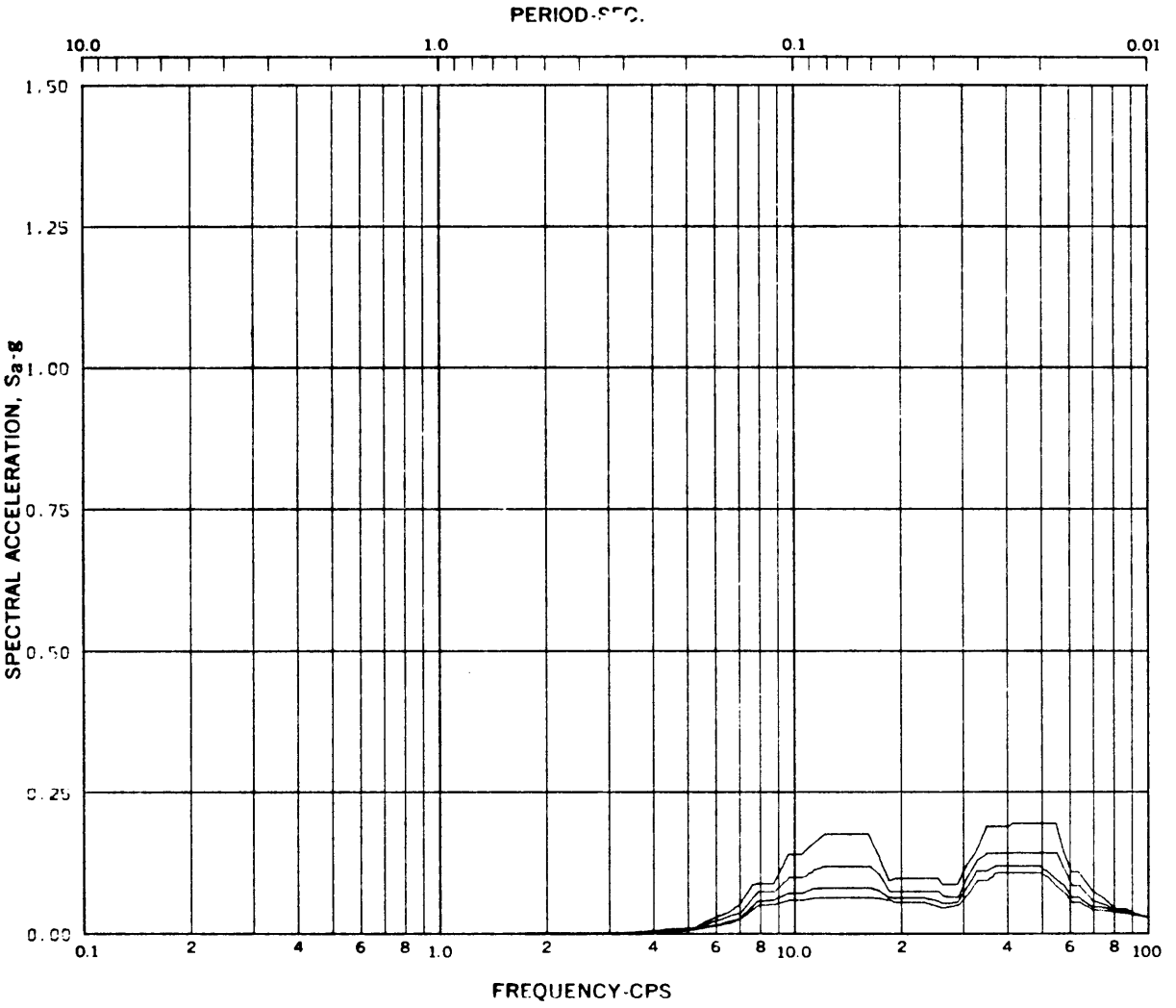
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-130



Acceleration Spectra for PEDESTAL

Load Case: CO FOR COMBINATION WITH ADS

Node: 531 Direction: VERT Elev: 263'-8 5/8" Angle: 0°

Damping: 0.005,0.01,0.02,0.03

NOTE:

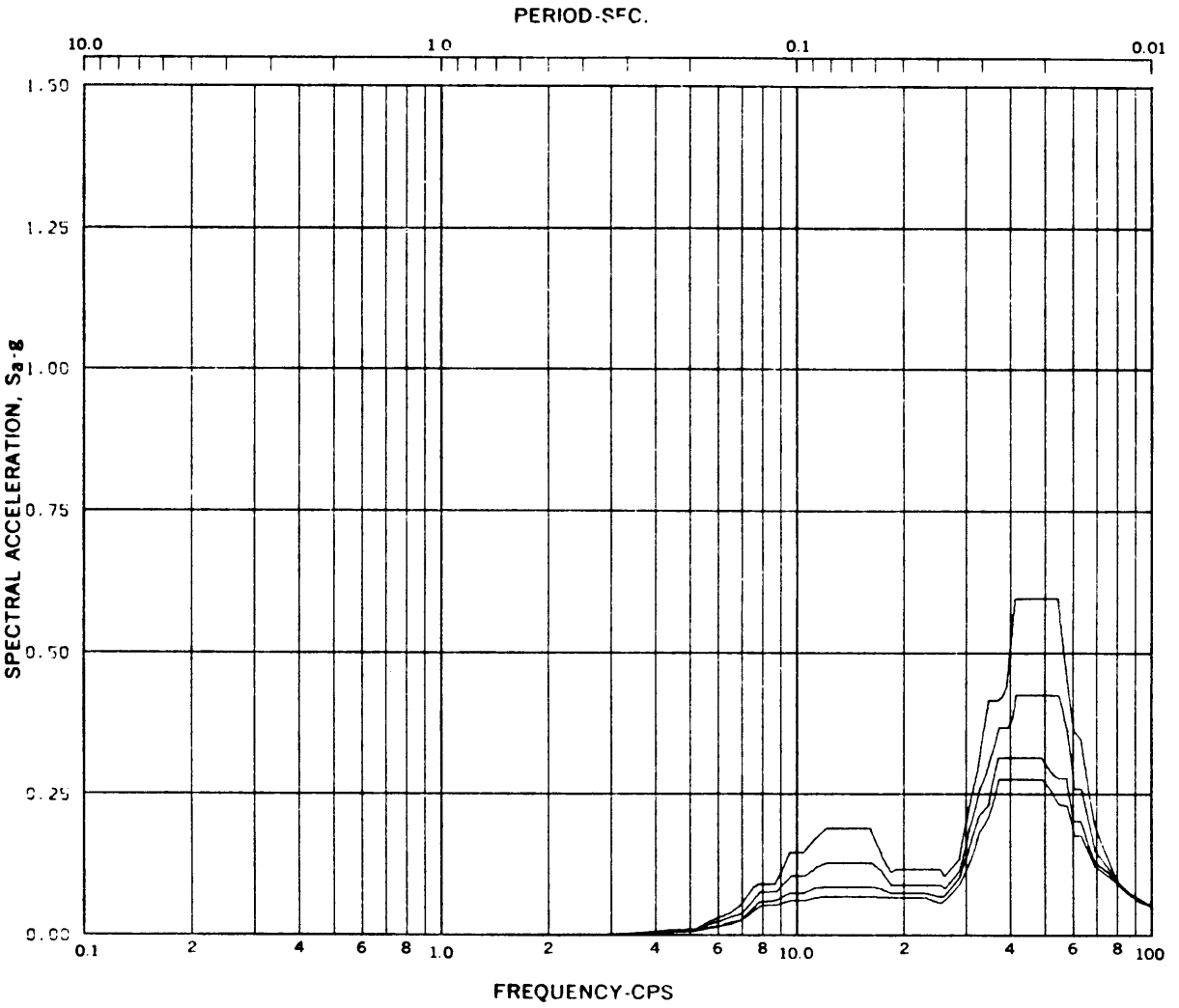
1. 0.05 DAMPING NOT INCLUDED.

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FIGURE 3A-131



Acceleration Spectra for SHIELD WALL

Load Case: CO FOR COMBINATION WITH ADS

Node: 841 Direction: VERT Elev: 312'-8" Angle: 0°

Damping: 0.005,0.01,0.02,0.03

NOTE:

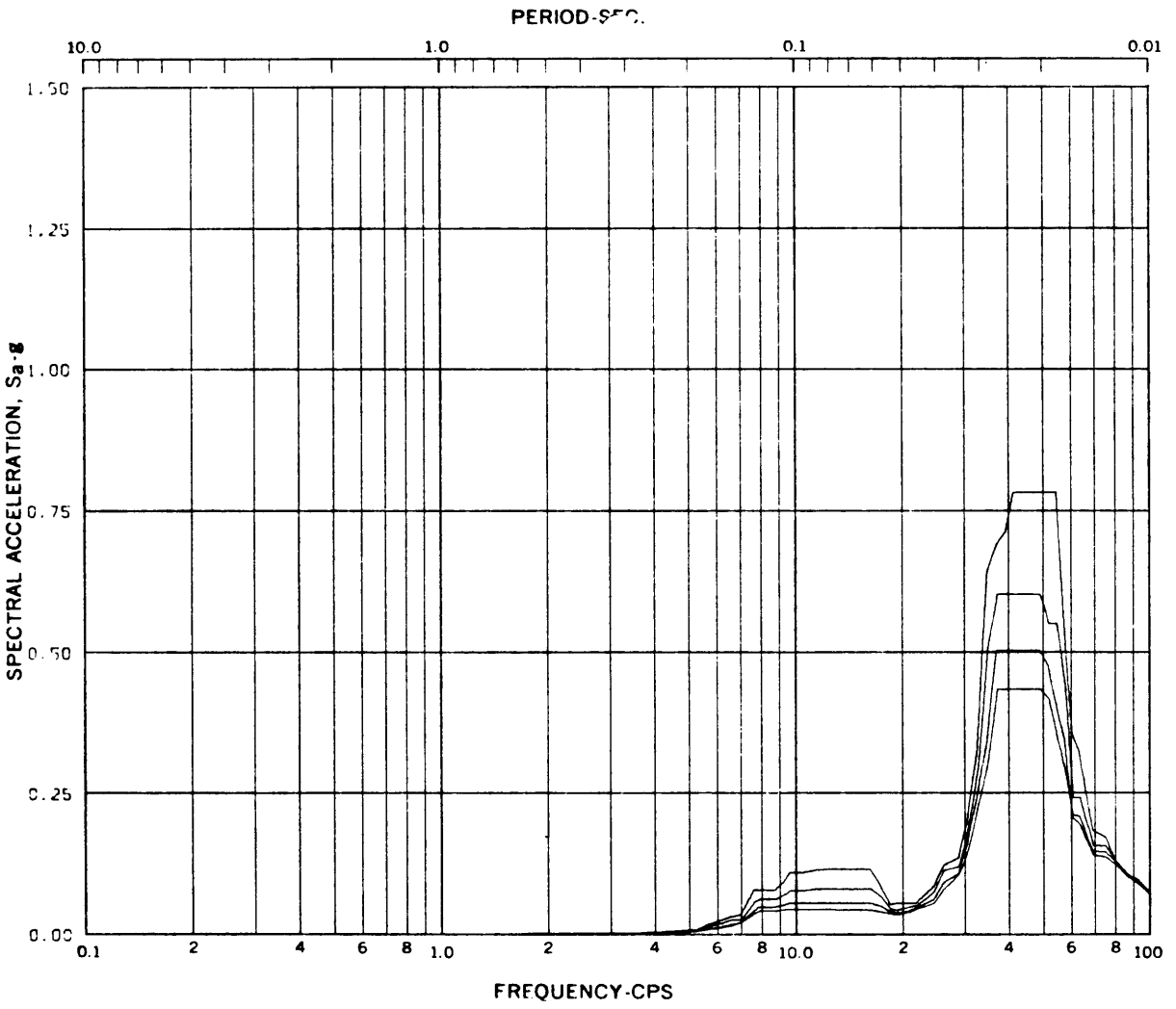
1. 0.05 DAMPING NOT INCLUDED.

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FIGURE 3A-132



Acceleration Spectra for DIAPHRAGM SLAB

Load Case: CO FOR COMBINATION WITH ADS

Node: 231 Direction: VERT Elev: 236'-2" Angle: 0°

Damping: 0.005,0.01,0.02,0.03

NOTE:

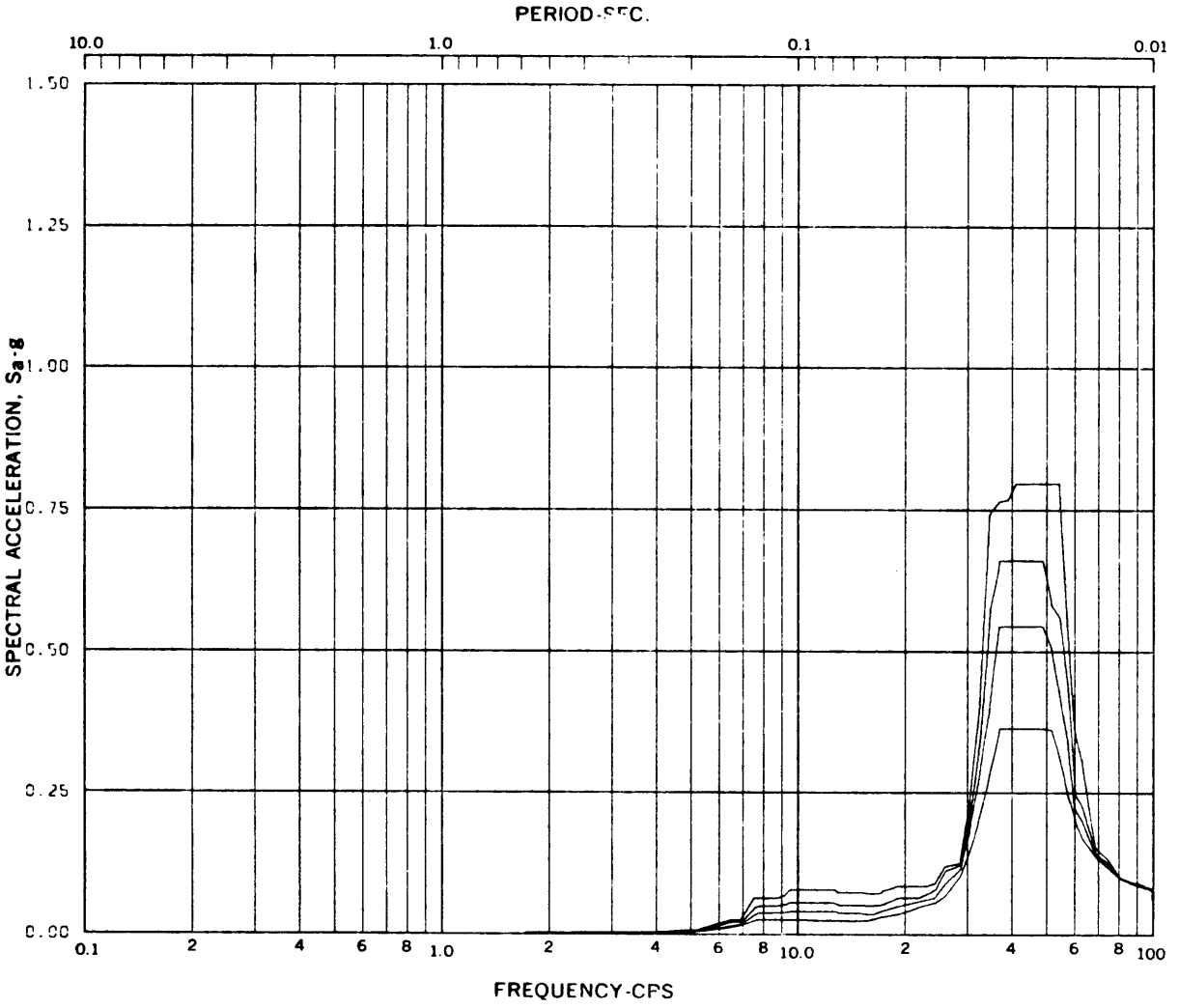
1. 0.05 DAMPING NOT INCLUDED.

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FIGURE 3A-133



Acceleration Spectra for DIAPHRAGM SLAB

Load Case: CO FOR COMBINATION WITH ADS

Node: 252 Direction: VERT Elev: 236'-2" Angle: 22°30'

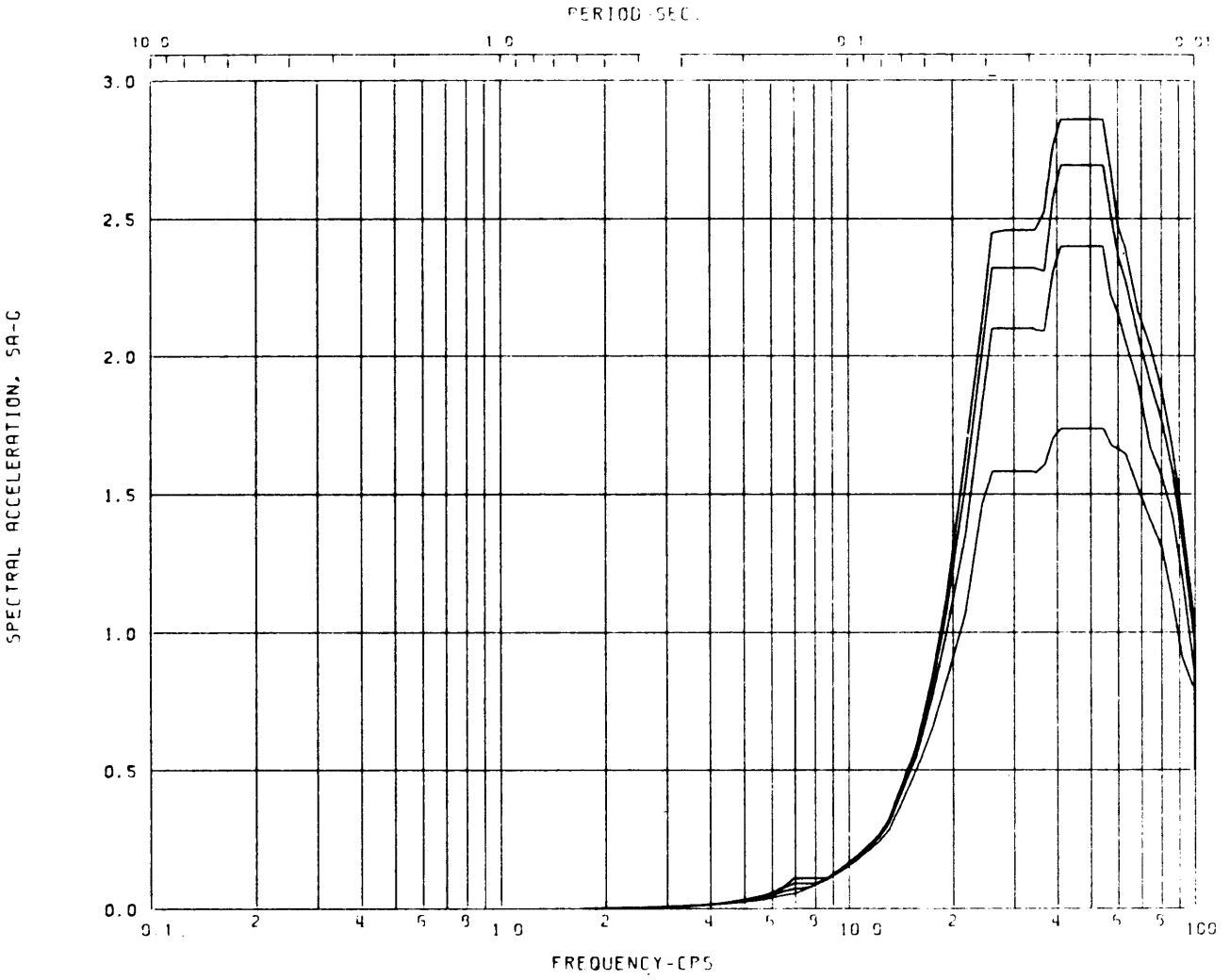
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-134



Acceleration Spectra for WETWELL WALL

Load Case: CHUG 700 SYM/700A ASYM

Node: 131 Direction: HORIZ Elev: 205'-11" Angle: -

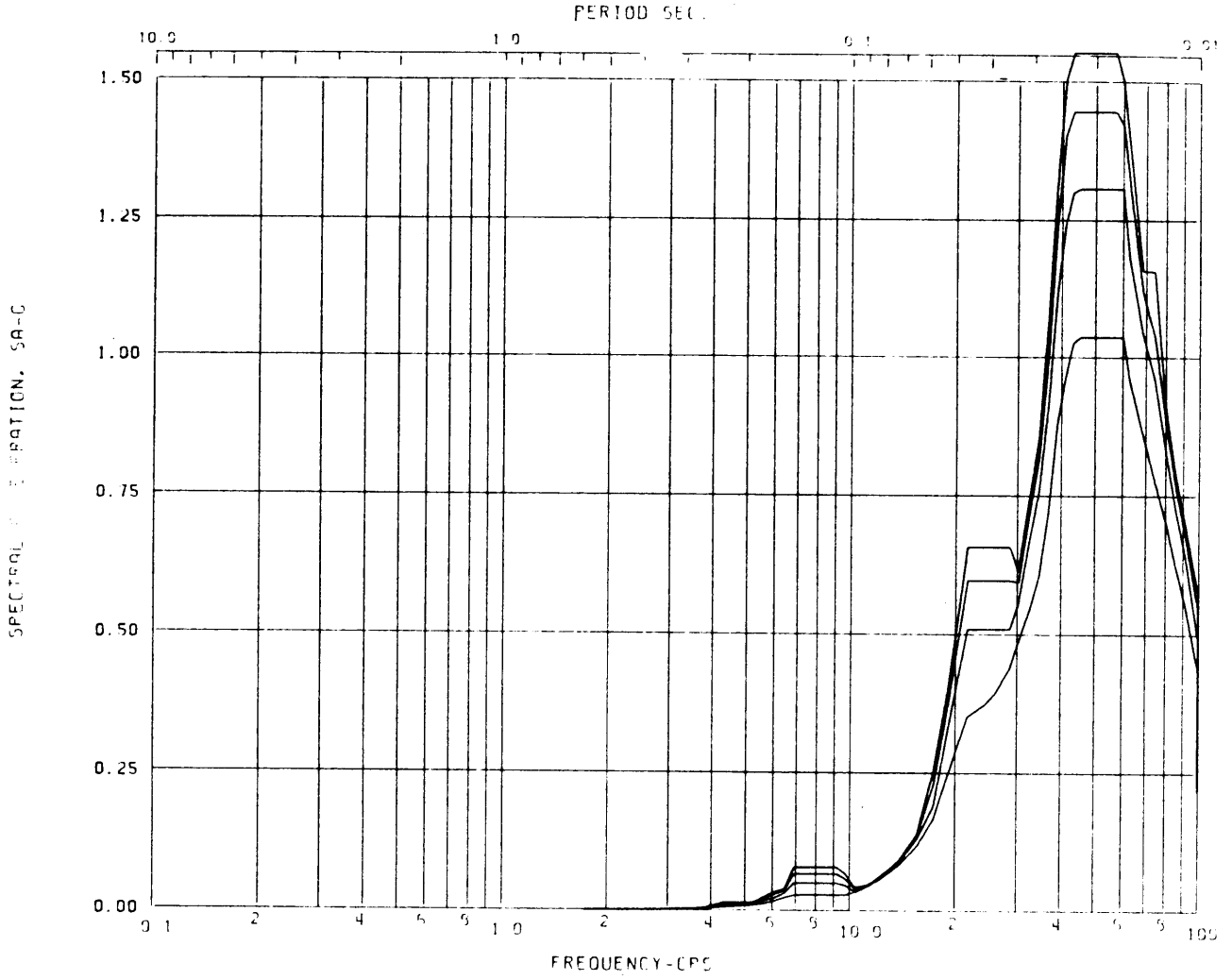
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-135



Acceleration Spectra for WETWELL WALL

Load Case: CHUG 700 SYM/700A ASYM

Node: 291 Direction: HORIZ Elev: 236'-2" Angle: -

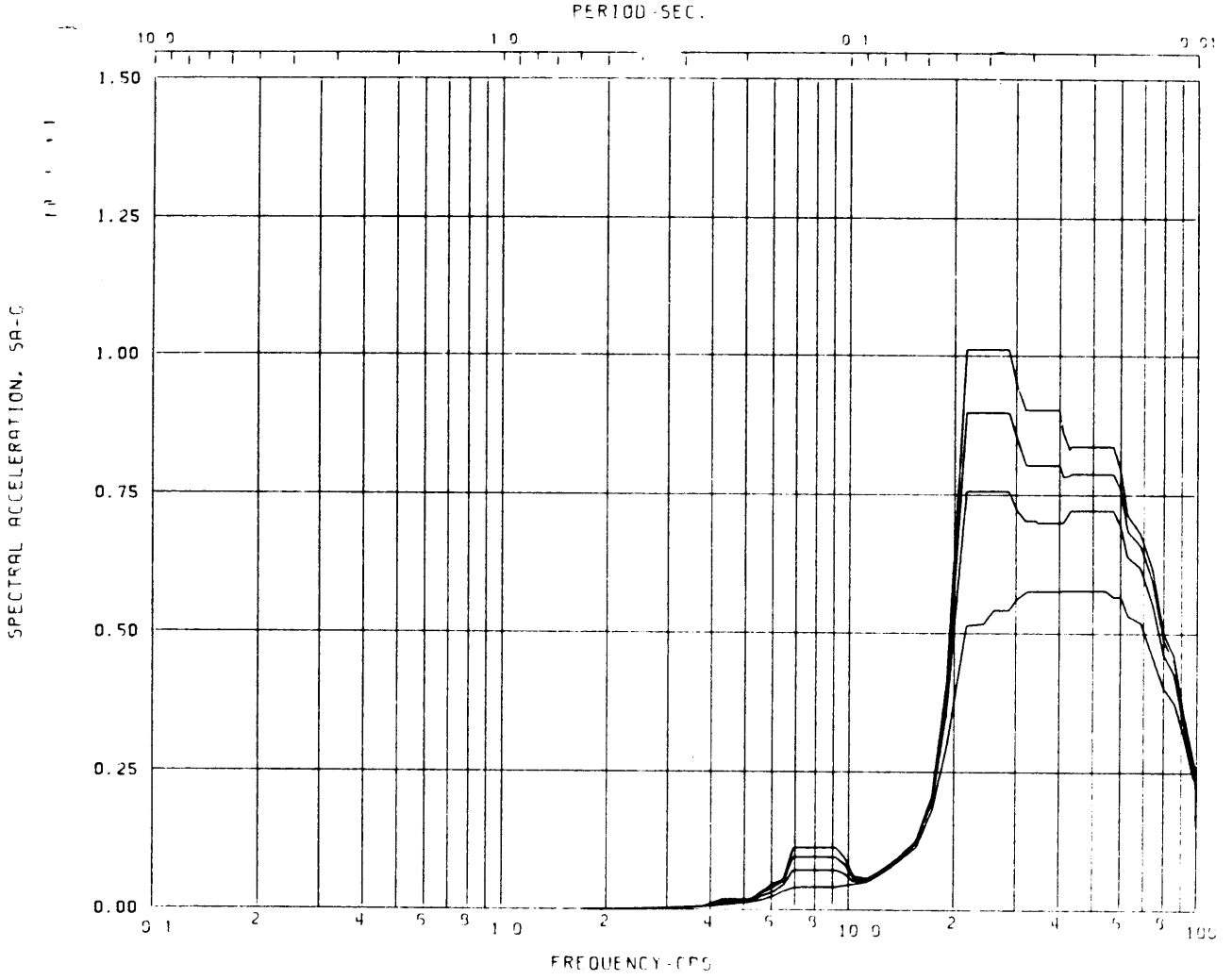
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-136



Acceleration Spectra for DRYWELL WALL

Load Case: CHUG 700 SYM/700A ASYM

Node: 331 Direction: HORIZ Elev: 264'-6" Angle: -

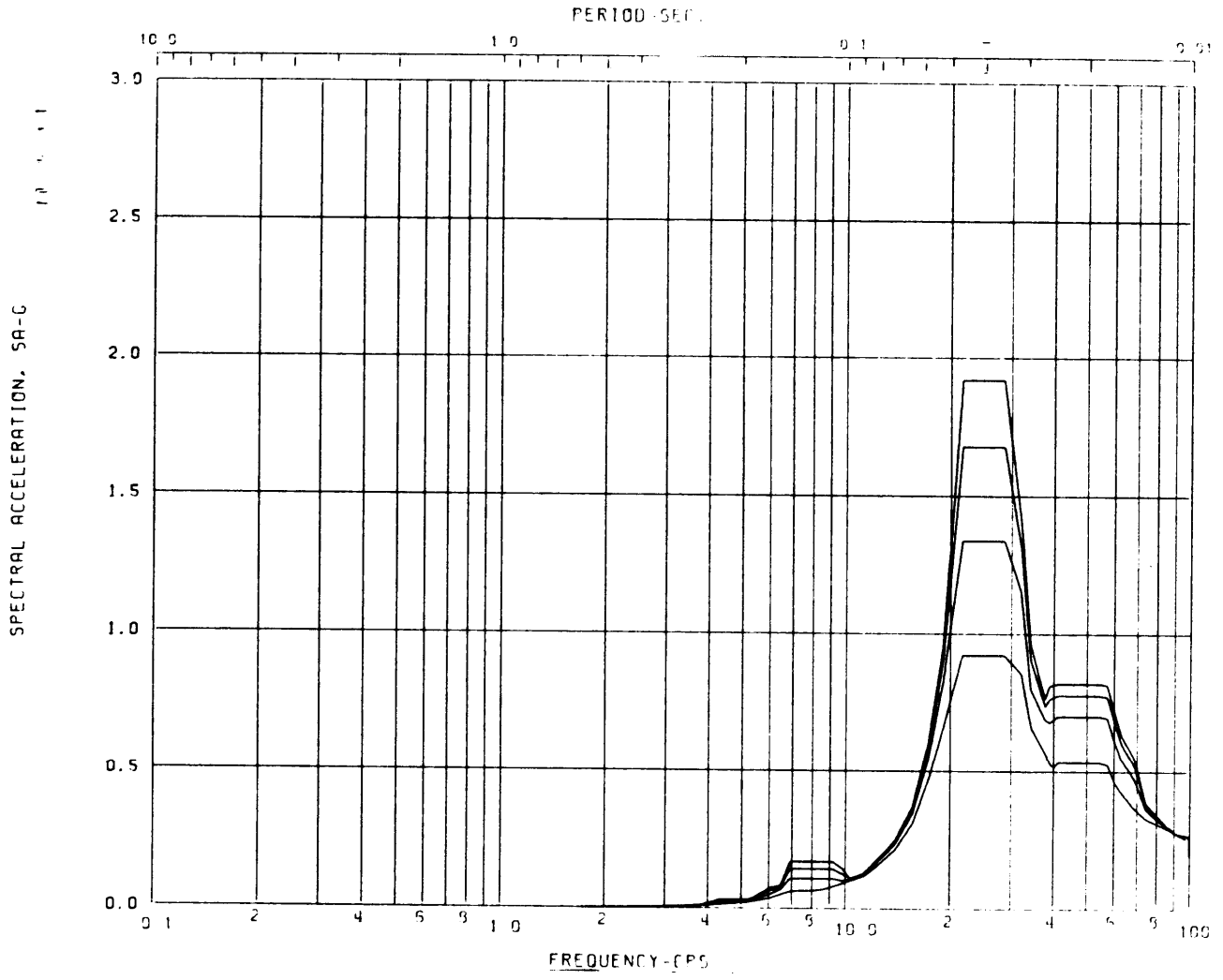
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-137



Acceleration Spectra for DRYWELL WALL

Load Case: CHUG 700 SYM/700A ASYM

Node: 431 Direction: HORIZ Elev: 325'-8" Angle: -°

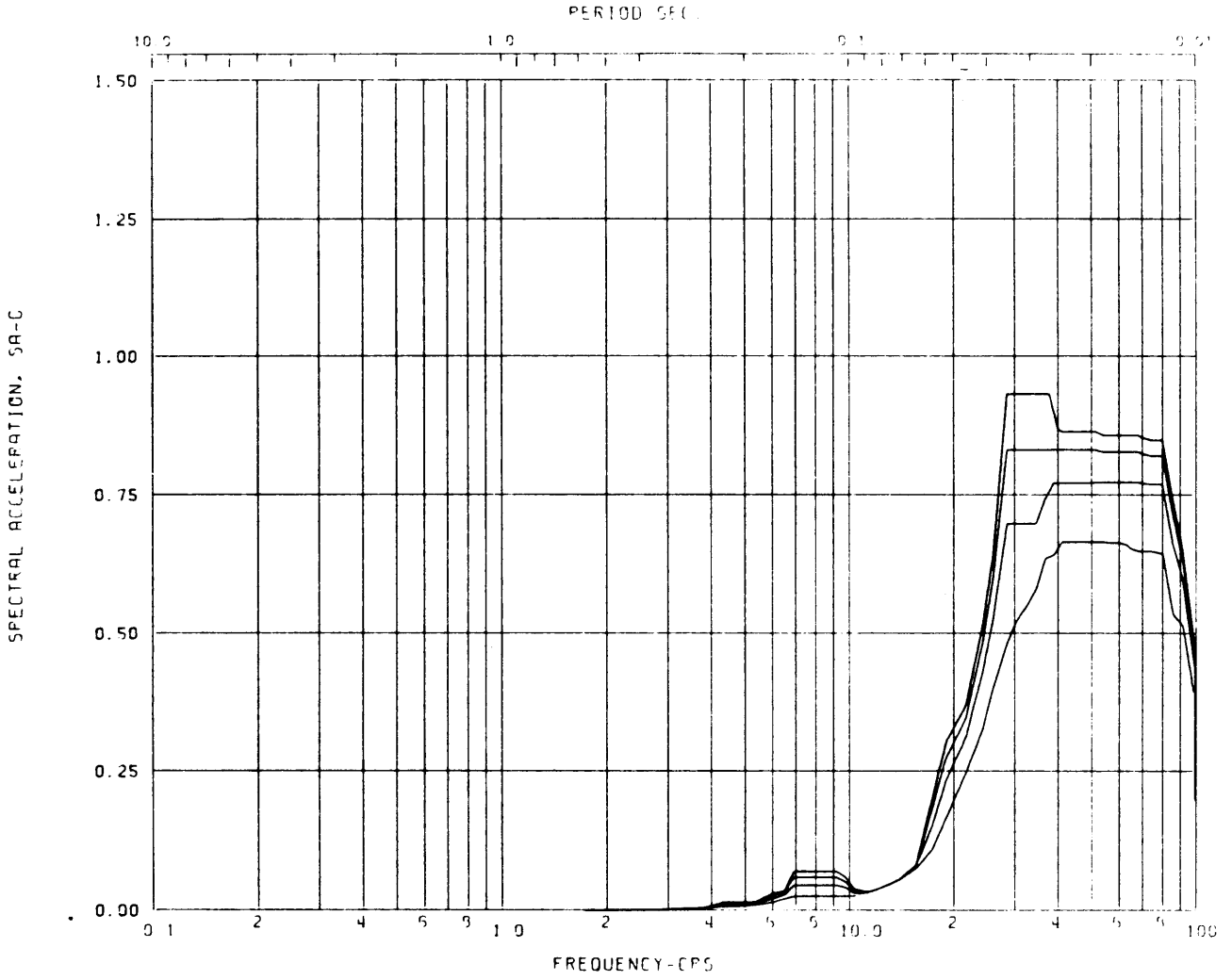
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-138



Acceleration Spectra for PEDESTAL

Load Case: CHUG 700 SYM/700A ASYM

Node: 211 Direction: HORIZ Elev: 236'-2" Angle: -

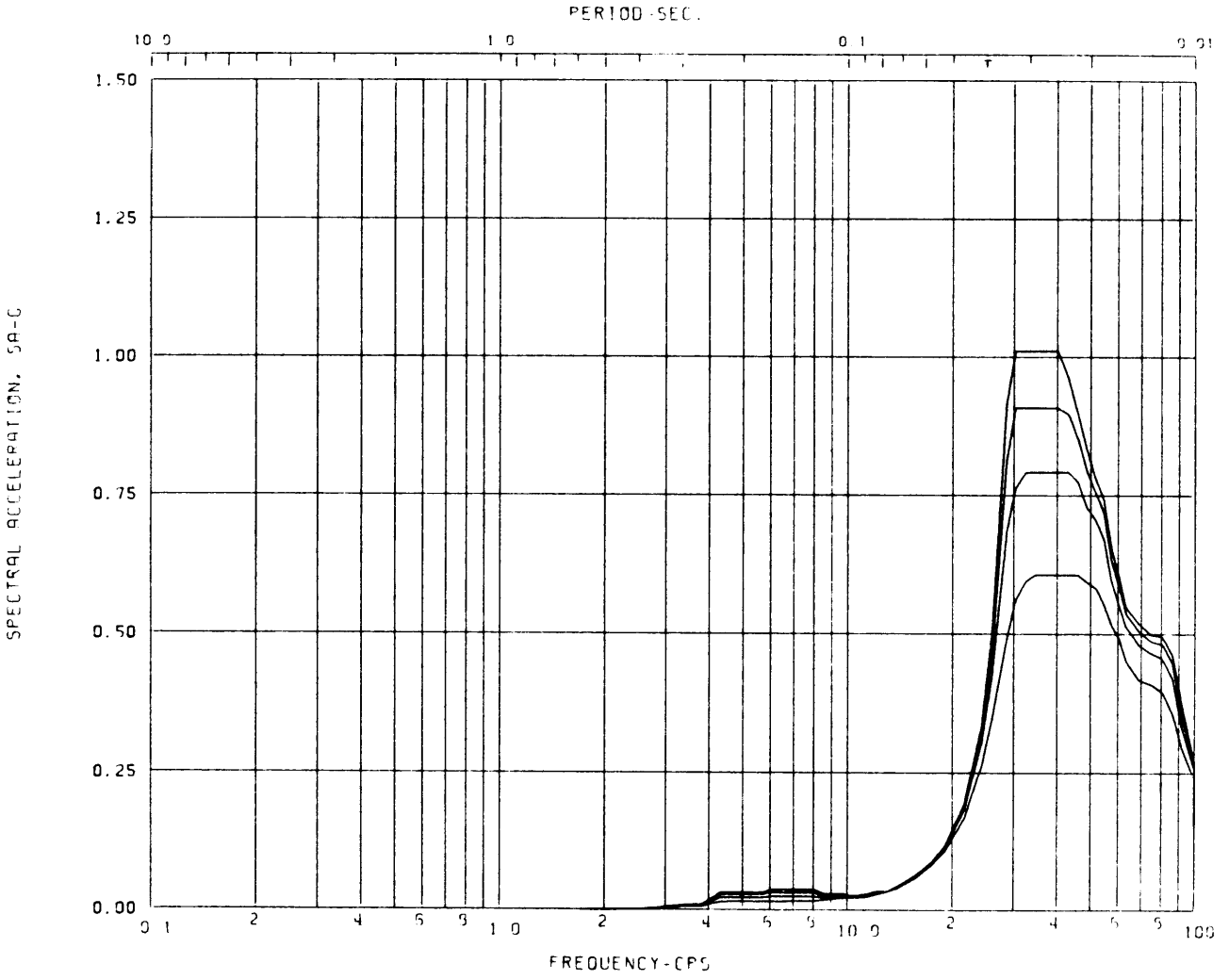
Damping: 0.005,0.01,0.02,0.05

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CHUGGING
DIRECTION X

FIGURE 3A-139



Acceleration Spectra for PEDESTAL

Load Case: CHUG 700 SYM/700A ASYM

Node: 531 Direction: HORIZ Elev: 263'-8 5/8" Angle: -

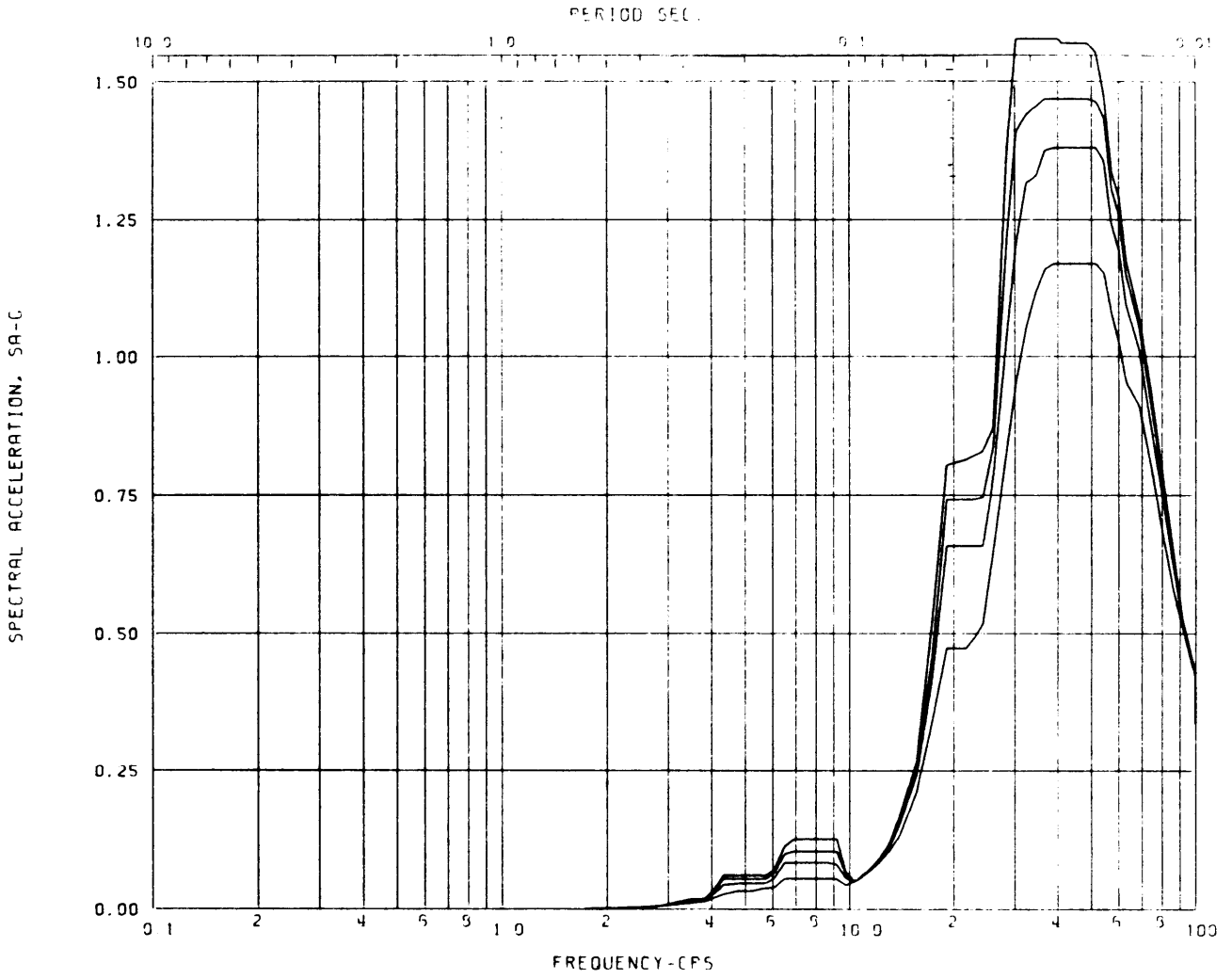
Damping: 0.005,0.01,0.02,0.05

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DIRECTION X

FIGURE 3A-140



Acceleration Spectra for SHIELD WALL

Load Case: CHUG 700 SYM/700A ASYM

Node: 841 Direction: HORIZ Elev: 312'-8" Angle: -

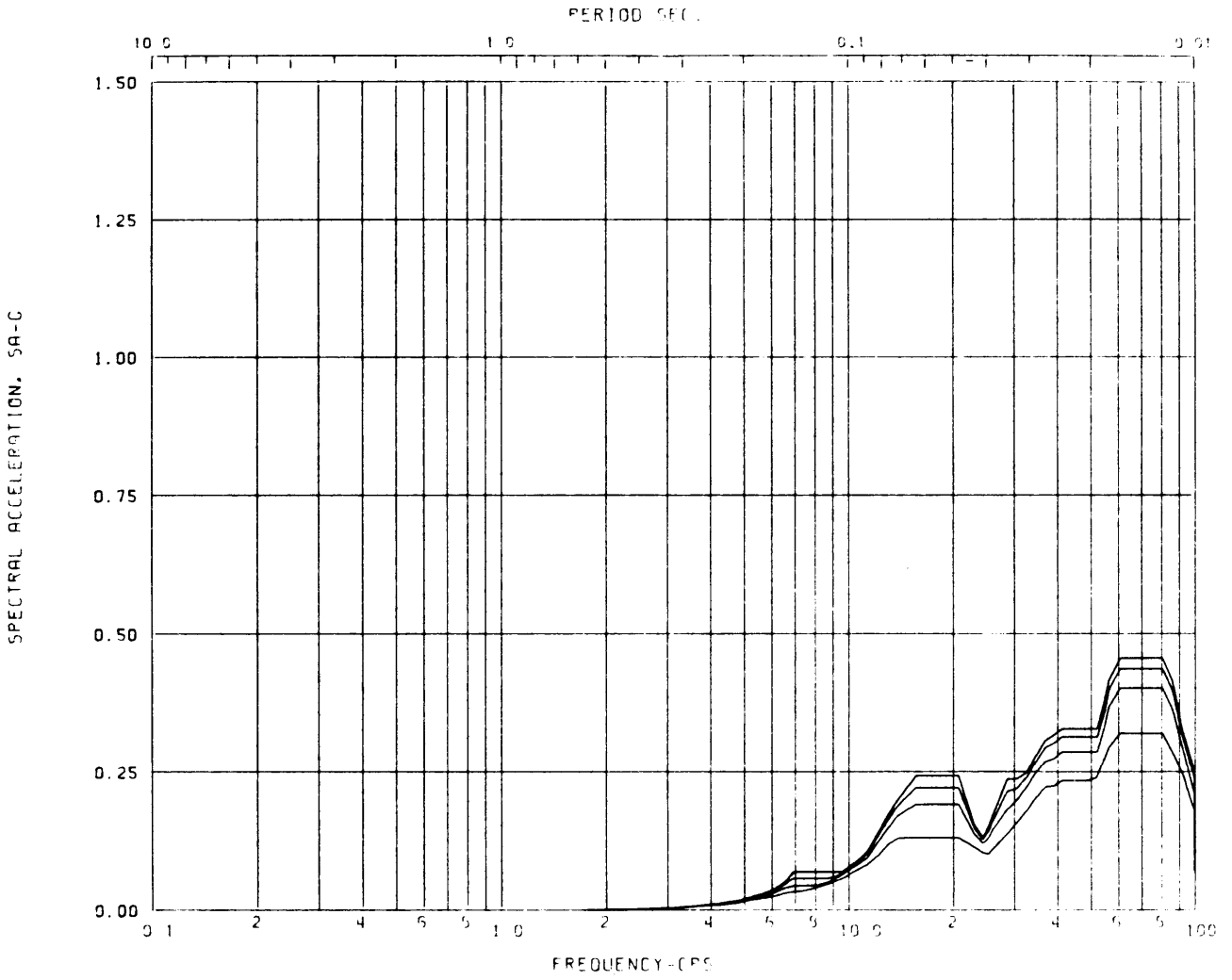
Damping: 0.005,0.01,0.02,0.05

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CHUGGING
DIRECTION X

FIGURE 3A-141



Acceleration Spectra for WETWELL WALL

Load Case: CHUG 700 SYM/700A ASYM

Node: 131 Direction: VERT Elev: 205'-11" Angle: -

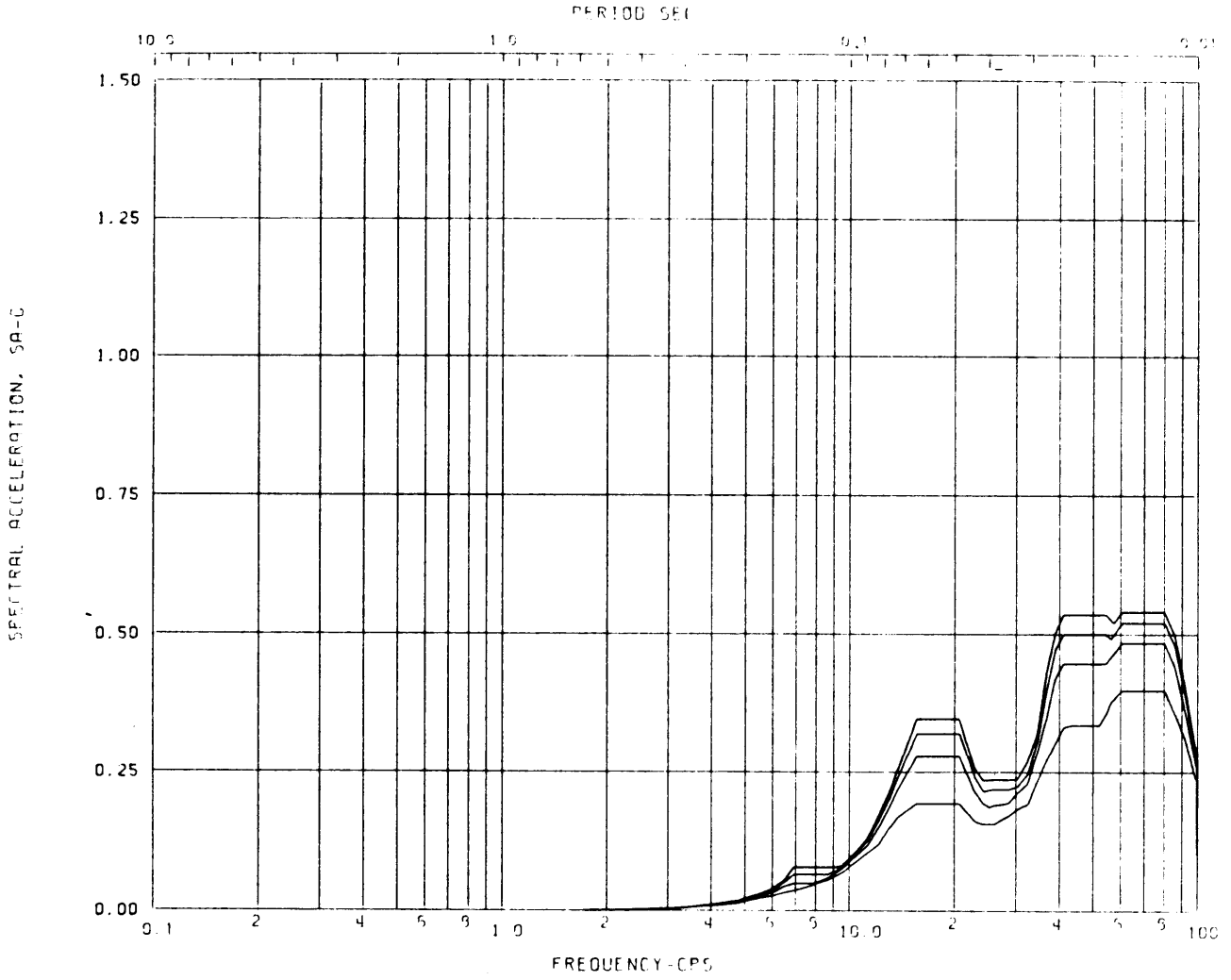
Damping: 0.005,0.01,0.02,0.05

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CONTAINMENT RESPONSE SPECTRA
CHUGGING
DIRECTION Z

FIGURE 3A-142



Acceleration Spectra for WETWELL WALL

Load Case: CHUG 700 SYM/700A ASYM

Node: 291 Direction: VERT Elev: 236'-2" Angle: -

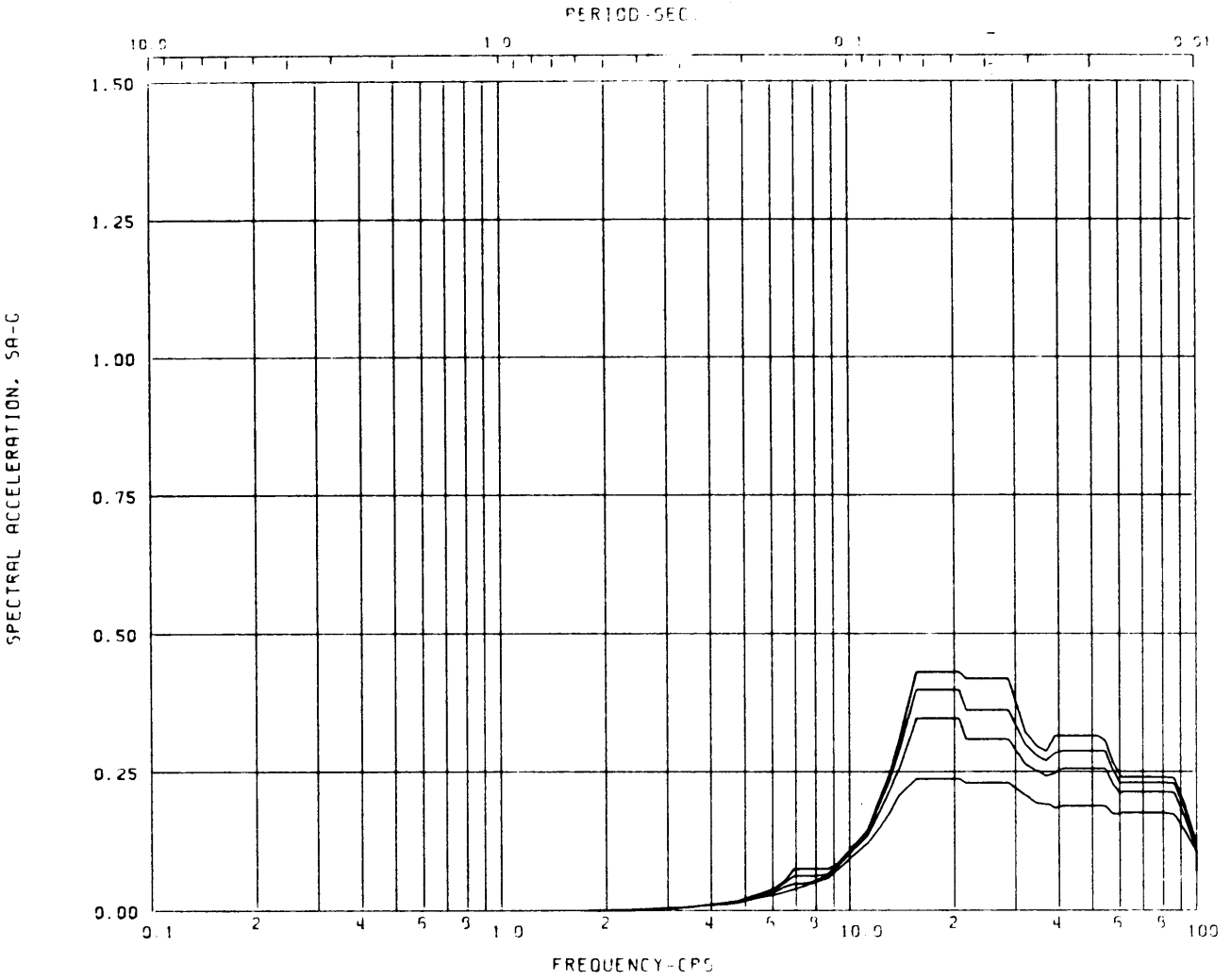
Damping: 0.005,0.01,0.02,0.05

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DIRECTION Z

FIGURE 3A-143



Acceleration Spectra for DRYWELL WALL

Load Case: CHUG 700 SYM/700A ASYM

Node: 331 Direction: VERT Elev: 264'-6" Angle: -

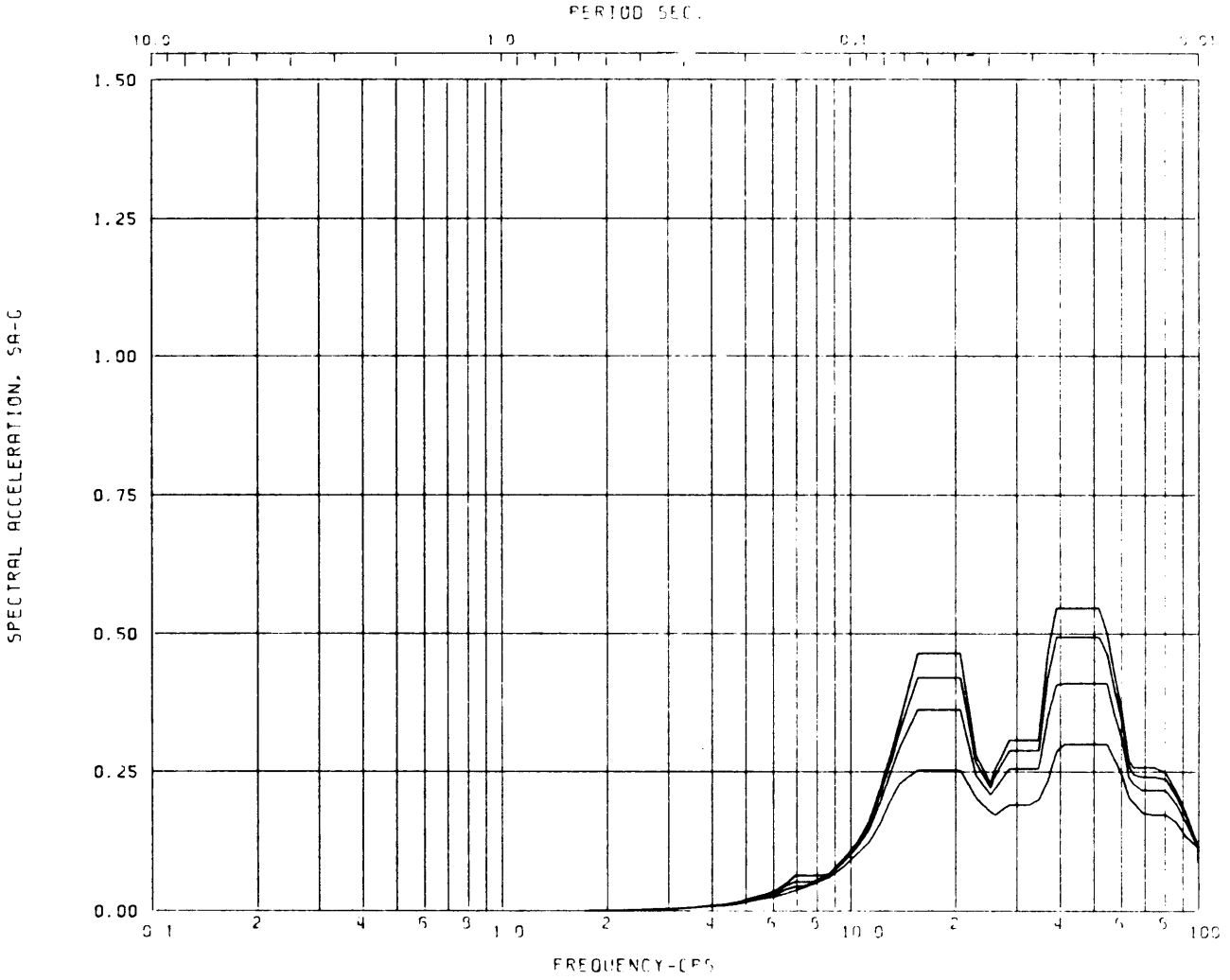
Damping: 0.005,0.01,0.02,0.05

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FIGURE 3A-144



Acceleration Spectra for DRYWELL WALL

Load Case: CHUG 700 SYM/700A ASYM

Node: 431 Direction: VERT Elev: 325'-8" Angle: -

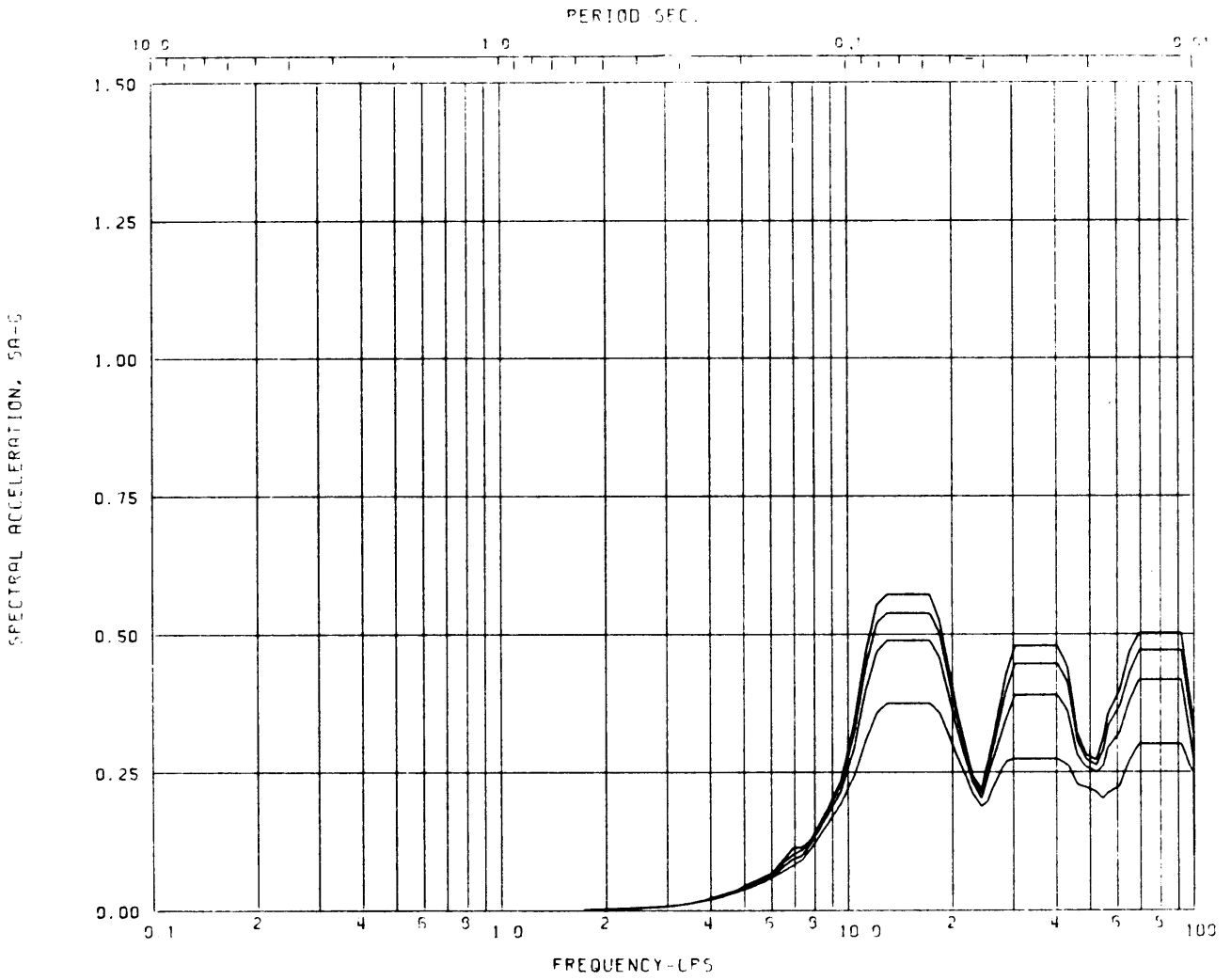
Damping: 0.005,0.01,0.02,0.05

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CONTAINMENT RESPONSE SPECTRA
CHUGGING
DIRECTION Z

FIGURE 3A-145



Acceleration Spectra for PEDESTAL

Load Case: CHUG 700 SYM/700A ASYM

Node: 211 Direction: VERT Elev: 236'-2" Angle: -

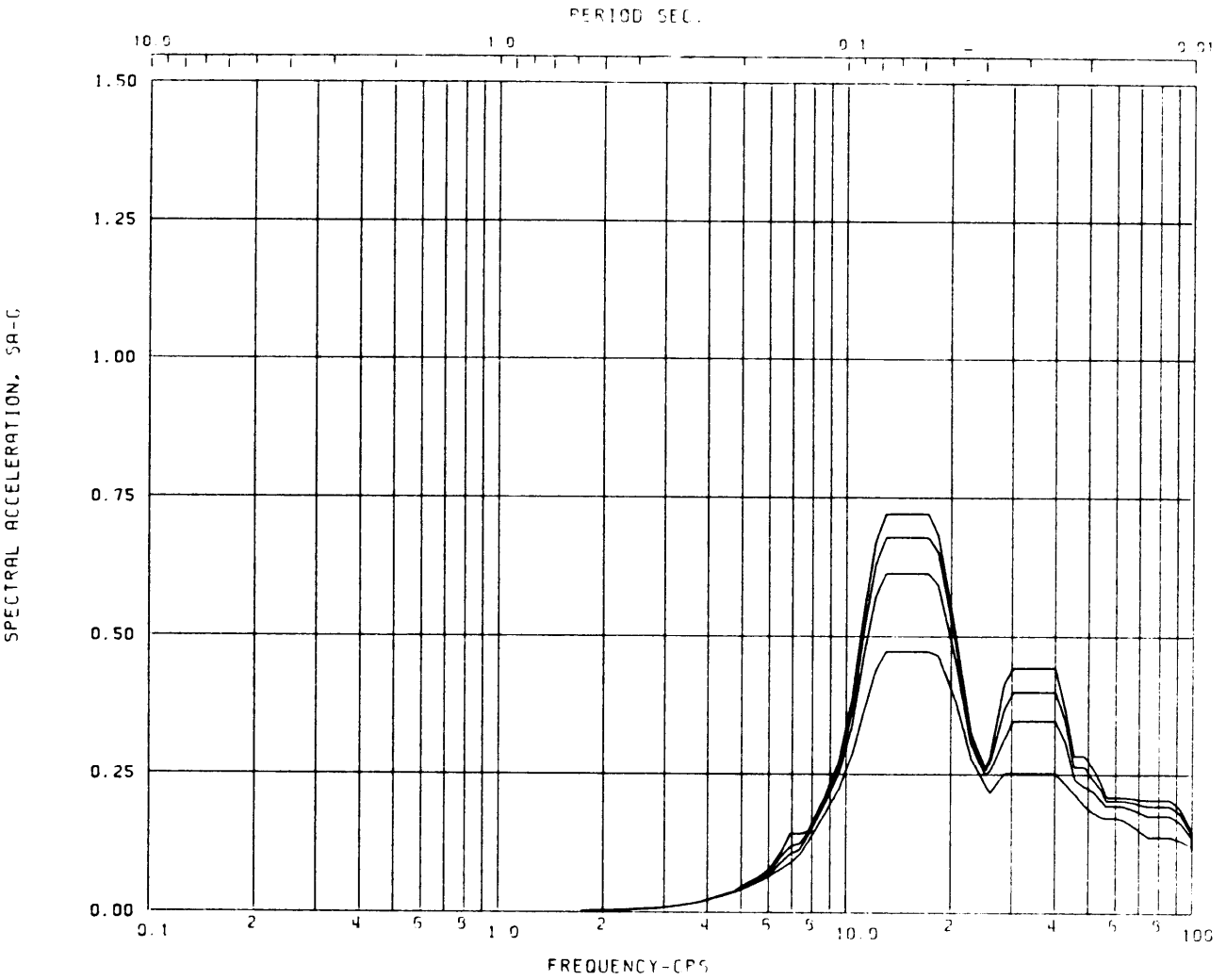
Damping: 0.005,0.01,0.02,0.05

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CONTAINMENT RESPONSE SPECTRA
CHUGGING
DIRECTION Z

FIGURE 3A-146



Acceleration Spectra for PEDESTAL

Load Case: CHUG 700 SYM/700A ASYM

Node: 531 Direction: VERT Elev: 263'-8 5/8" Angle: -

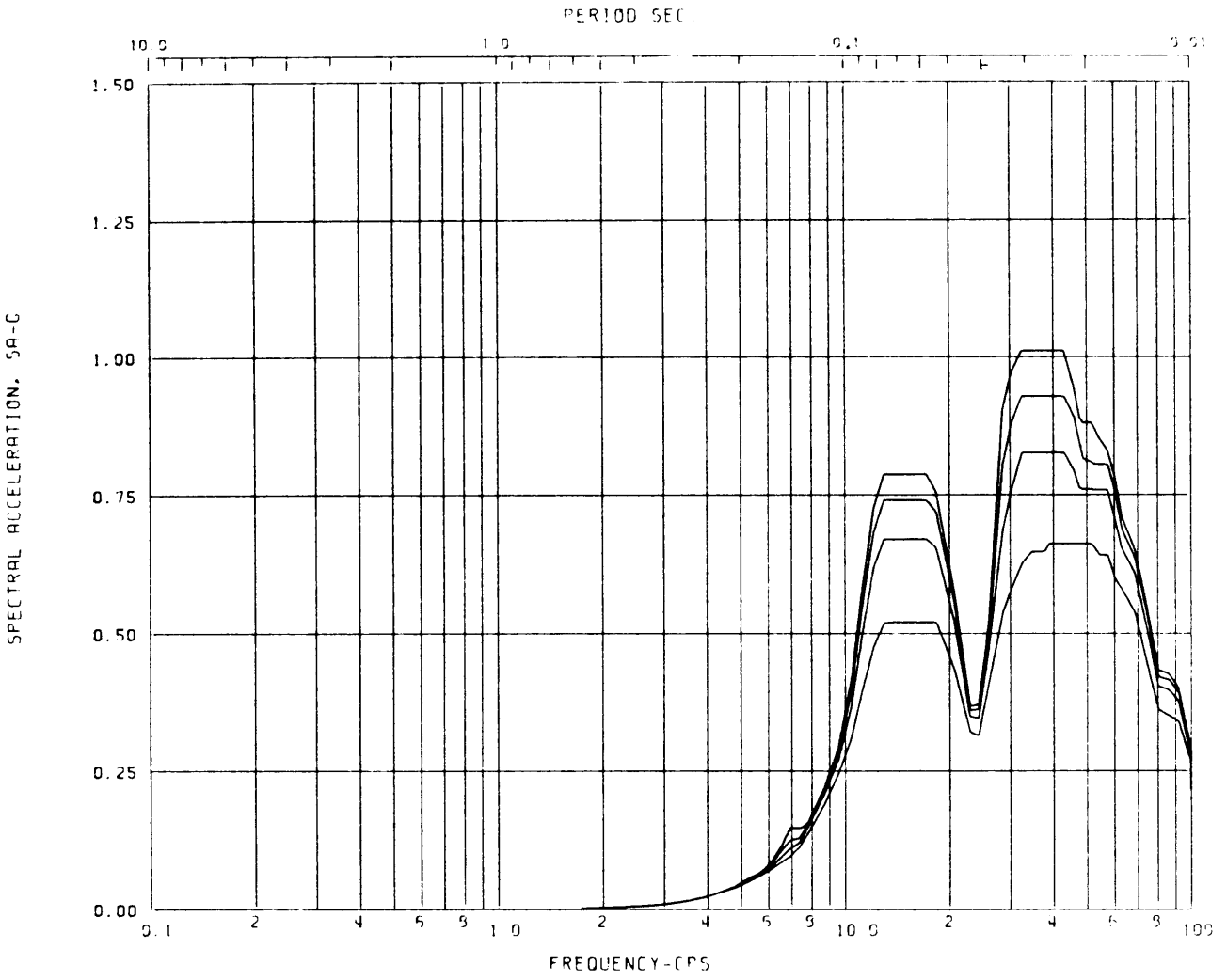
Damping: 0.005,0.01,0.02,0.05

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CHUGGING
DIRECTION Z

FIGURE 3A-147



Acceleration Spectra for SHIELD WALL

Load Case: CHUG 700 SYM/700A ASYM

Node: 841 Direction: VERT Elev: 312'-8" Angle: -

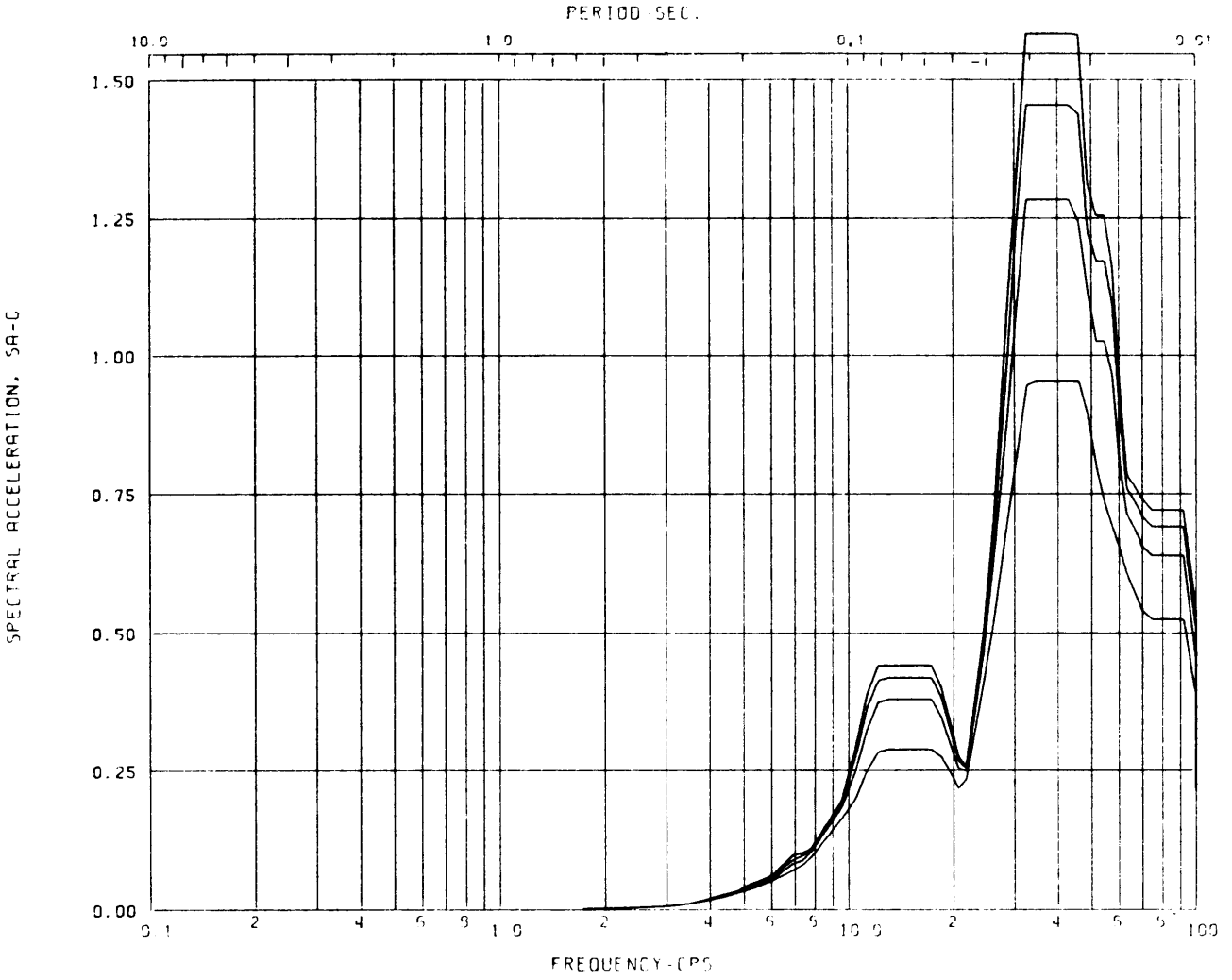
Damping: 0.005,0.01,0.02,0.05

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CONTAINMENT RESPONSE SPECTRA
CHUGGING
DIRECTION Z

FIGURE 3A-148



Acceleration Spectra for DIAPHRAGM SLAB

Load Case: CHUG 700 SYM/700A ASYM

Node: 231 Direction: VERT Elev: 236'-2" Angle: -

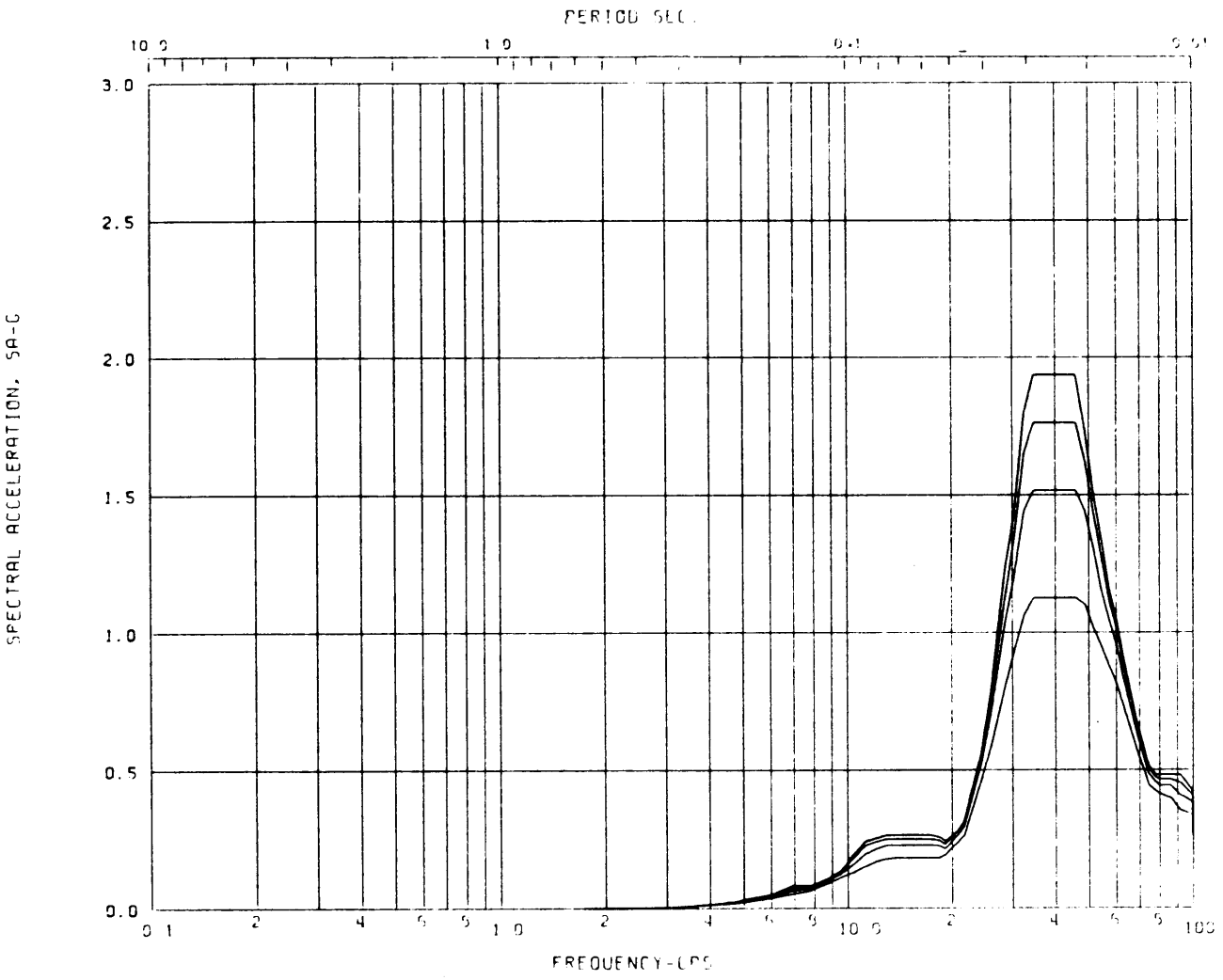
Damping: 0.005,0.01,0.02,0.05

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DIRECTION Z

FIGURE 3A-149



Acceleration Spectra for DIAPHRAGM SLAB

Load Case: CHUG 700 SYM/700A ASYM

Node: 252 Direction: VERT Elev: 236'-2" Angle: -

Damping: 0.005,0.01,0.02,0.05

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DIRECTION Z

FIGURE 3A-150

HORIZONTAL EAST-WEST DIRECTION

MODE No.	FREQUENCY (Hz.)	PARTICIPATION FACTOR
1	3.96	-89.98
2	12.50	-32.68
3	18.77	-22.52
4	24.20	15.29
5	31.63	-12.80
6	44.39	4.77
7	58.78	15.41
8	76.17	10.67
9	90.00	0.0003
10	133.78	-0.008
11	139.92	0.002
12	148.41	-0.0003

HORIZONTAL NORTH-SOUTH DIRECTION

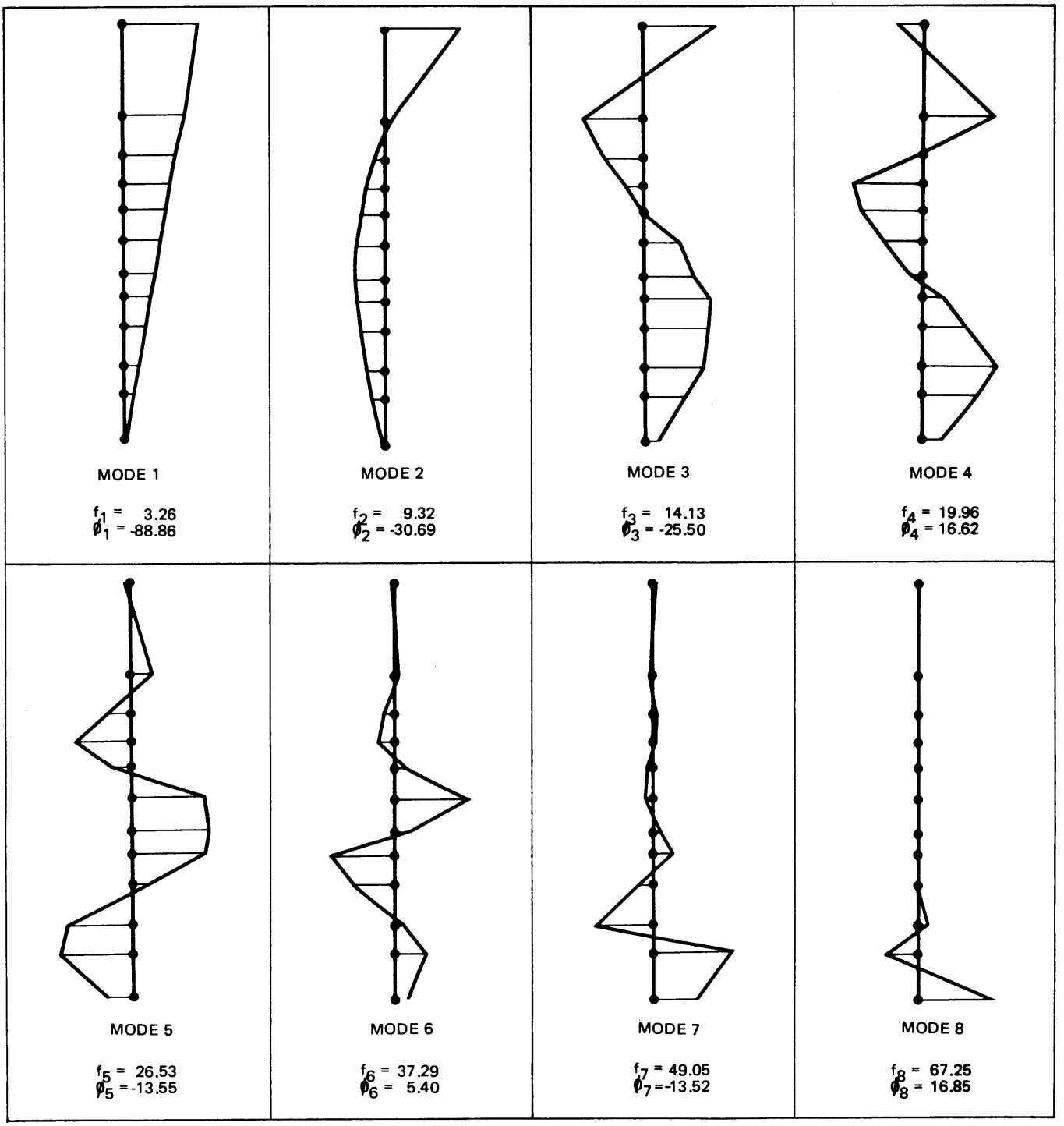
MODE No.	FREQUENCY (Hz.)	PARTICIPATION FACTOR
1	3.26	-88.86
2	9.32	-30.69
3	14.13	-25.50
4	19.96	16.62
5	26.53	-13.55
6	37.29	5.40
7	49.05	-13.52
8	67.25	16.85
9	76.13	0.0003
10	114.47	-0.007
11	118.02	-0.002
12	120.51	0.0007

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REACTOR ENCLOSURE AND CONTROL STRUCTURE MODE FREQUENCIES AND PARTICIPATION FACTORS (HORIZONTAL STICK MODEL)

FIGURE 3A-151



NOTE:

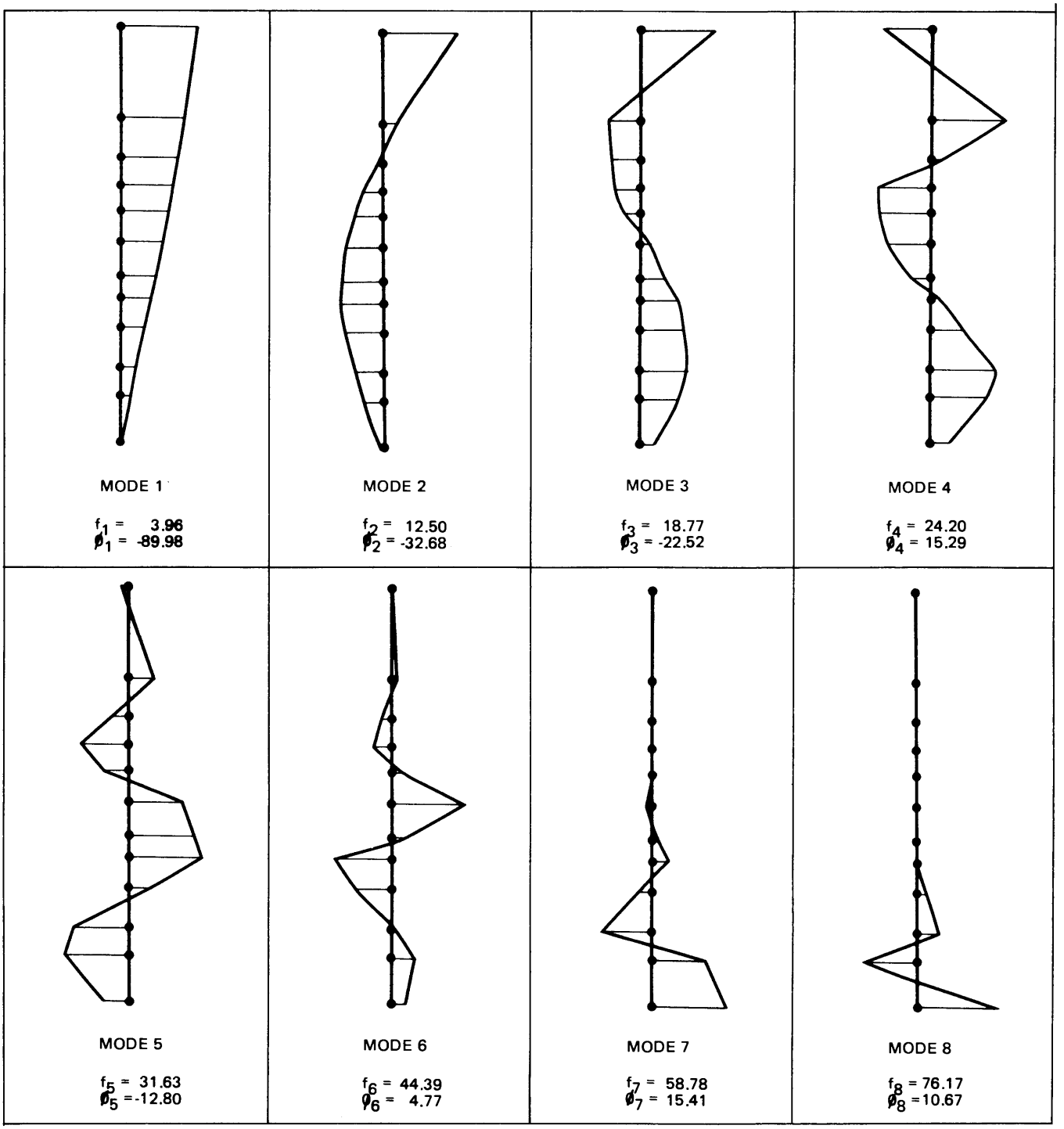
f = FREQUENCY (Hz)
ϕ = PARTICIPATION FACTOR

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REACTOR ENCLOSURE AND CONTROL STRUCTURE HORIZONTAL N-S MODE SHAPES

FIGURE 3A-152



NOTE:

f = FREQUENCY Hz
ϕ = PARTICIPATION FACTOR

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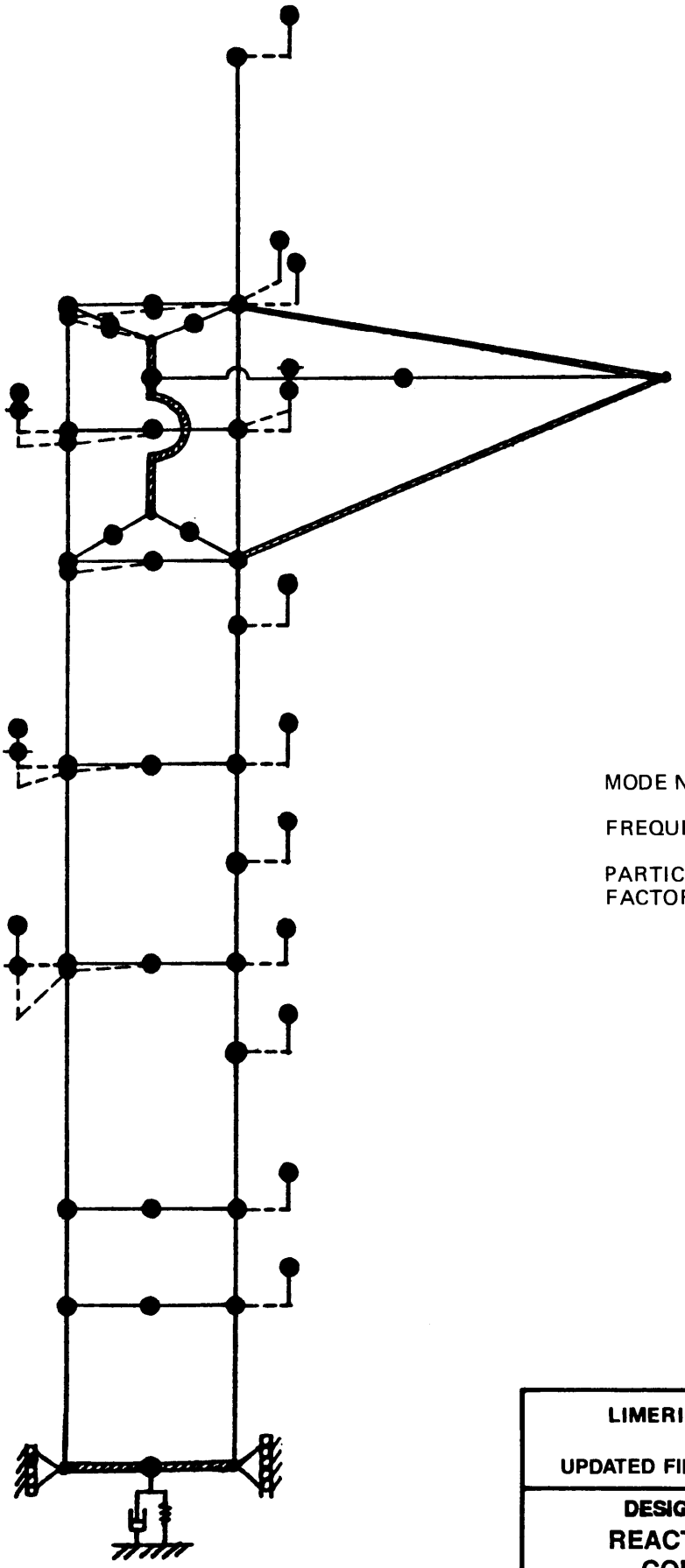
REACTOR ENCLOSURE AND CONTROL STRUCTURE HORIZONTAL E-W MODE SHAPES

FIGURE 3A-153

MODE No.	FREQUENCY (Hz.)	PARTICIPATION FACTOR
1	2.00	20.14
2	3.01	11.16
3	3.28	-10.05
4	4.07	-13.13
5	4.25	-27.59
6	4.28	-24.40
7	4.32	-5.29
8	4.57	-11.99
9	4.58	-9.33
10	4.64	9.27
11	4.89	-8.56
12	5.91	17.06
13	7.82	-59.71
14	9.23	-38.78
15	10.42	-5.16
16	11.29	-18.72
17	11.72	-14.46
18	11.81	2.31
19	12.03	0.75
20	12.24	1.85
21	12.34	9.61
22	12.54	-0.26
23	13.58	10.44
24	13.94	-14.85
25	15.37	-14.46
26	15.50	5.37
27	18.39	27.28
28	20.22	5.36
29	29.86	-10.40
30	38.20	-23.12
31	47.54	7.00
32	51.75	-4.61
33	59.14	-0.63
34	74.39	7.82
35	103.48	3.19
36	114.33	4.43
37	121.98	0.07
38	128.79	-1.78
39	136.47	-0.24
40	171.12	-0.91
41	241.59	-0.0001
42	252.96	0.00004
43	334.43	-0.002
44	372.81	-0.00008
45	399.96	-0.0003

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REACTOR ENCLOSURE AND CONTROL STRUCTURE MODE FREQUENCIES AND PARTICIPATION FACTORS (VERTICAL STICK MODEL)
FIGURE 3A-154



MODE No. 6

FREQUENCY = 4.28 Hz

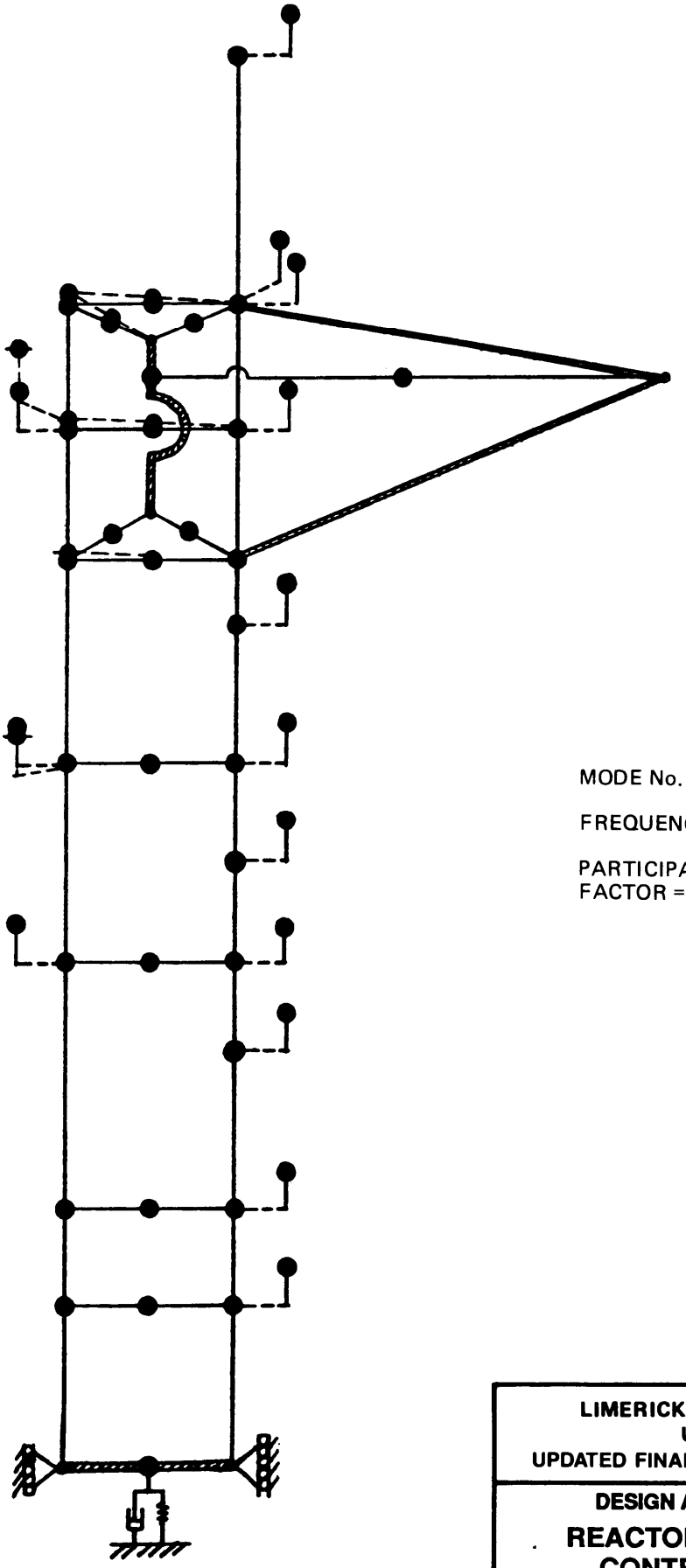
PARTICIPATION
FACTOR = –24.40

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REACTOR ENCLOSURE AND
CONTROL STRUCTURE
VERTICAL MODE SHAPES

FIGURE 3A-155



MODE No. 12

FREQUENCY = 5.91 Hz

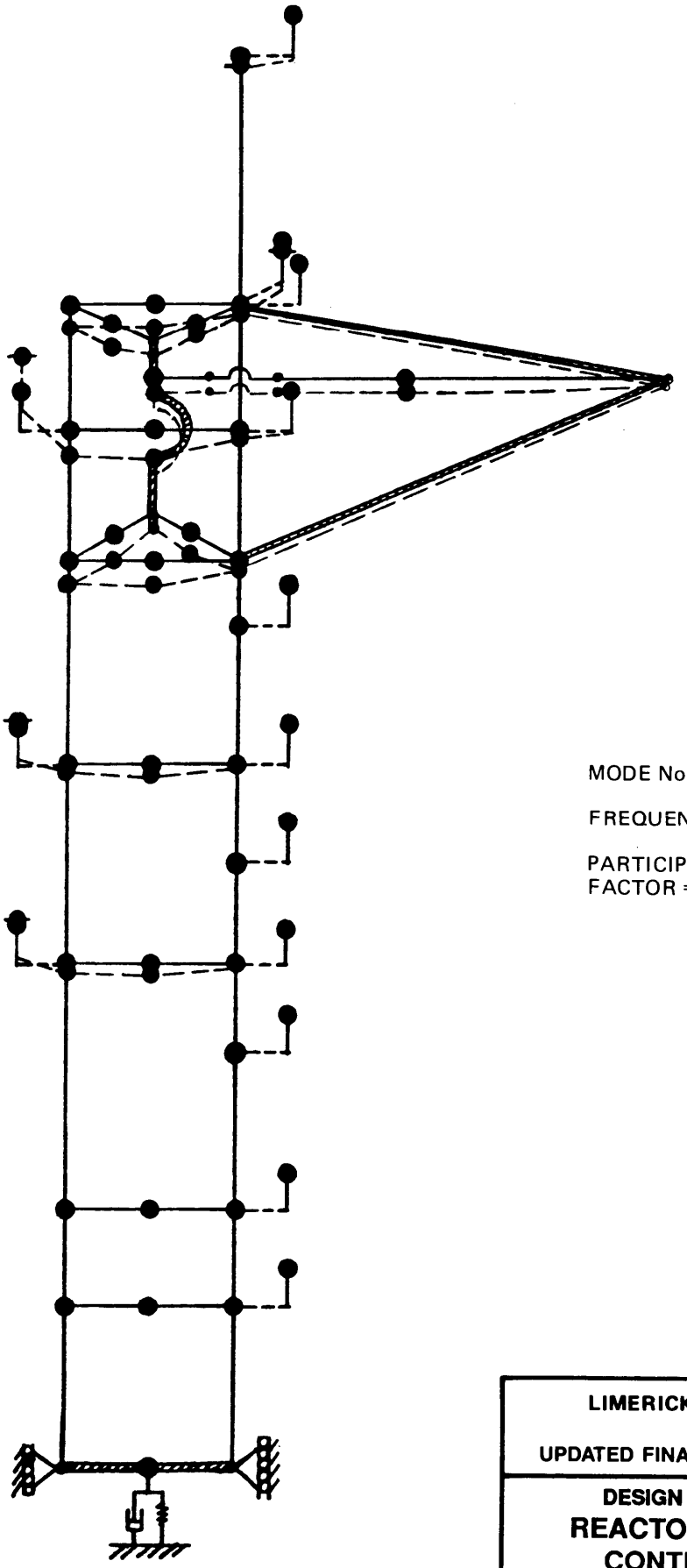
PARTICIPATION
FACTOR = 17.06

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REACTOR ENCLOSURE AND CONTROL STRUCTURE MODE SHAPES

FIGURE 3A-156



MODE No. 13

FREQUENCY = 7.82 Hz

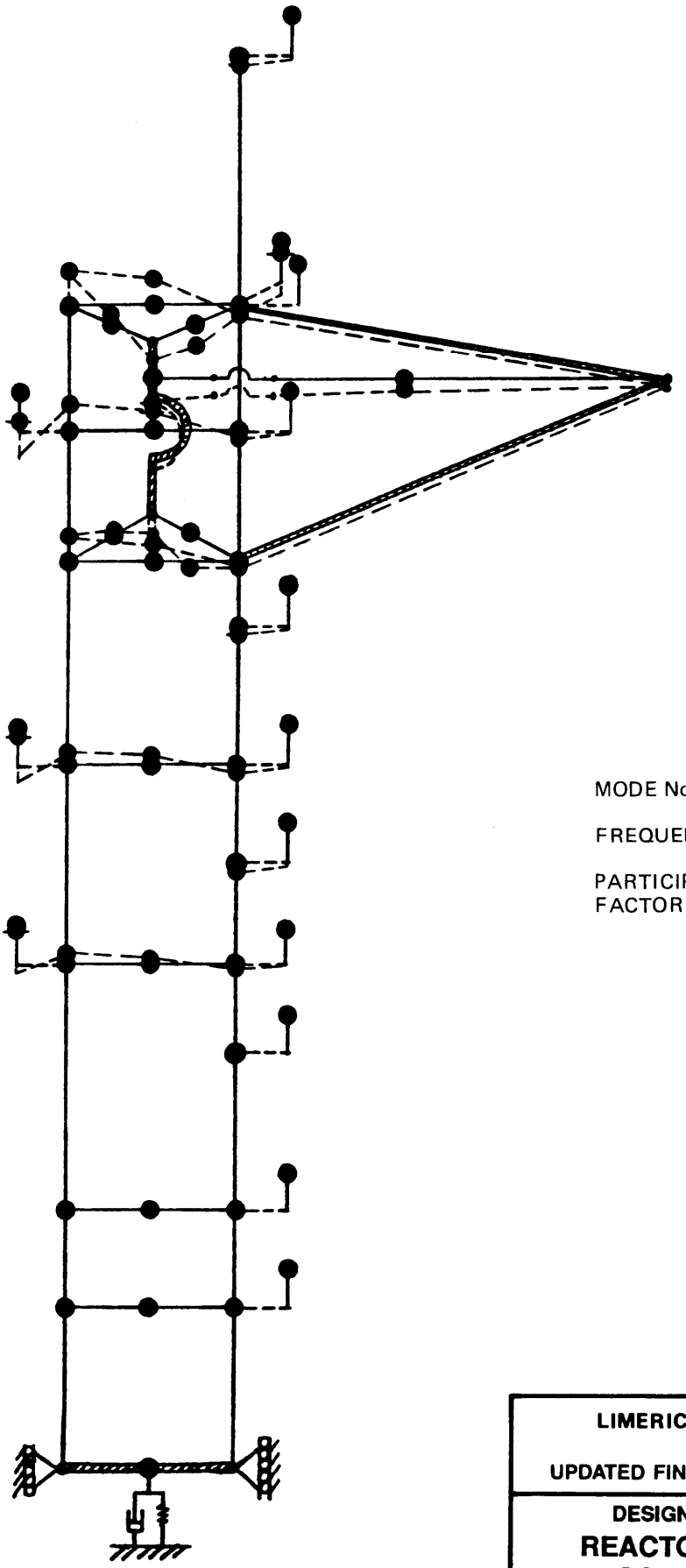
PARTICIPATION
FACTOR = -59.71

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REACTOR ENCLOSURE AND CONTROL STRUCTURE MODE SHAPES

FIGURE 3A-157



MODE No. 14

FREQUENCY = 9.23 Hz

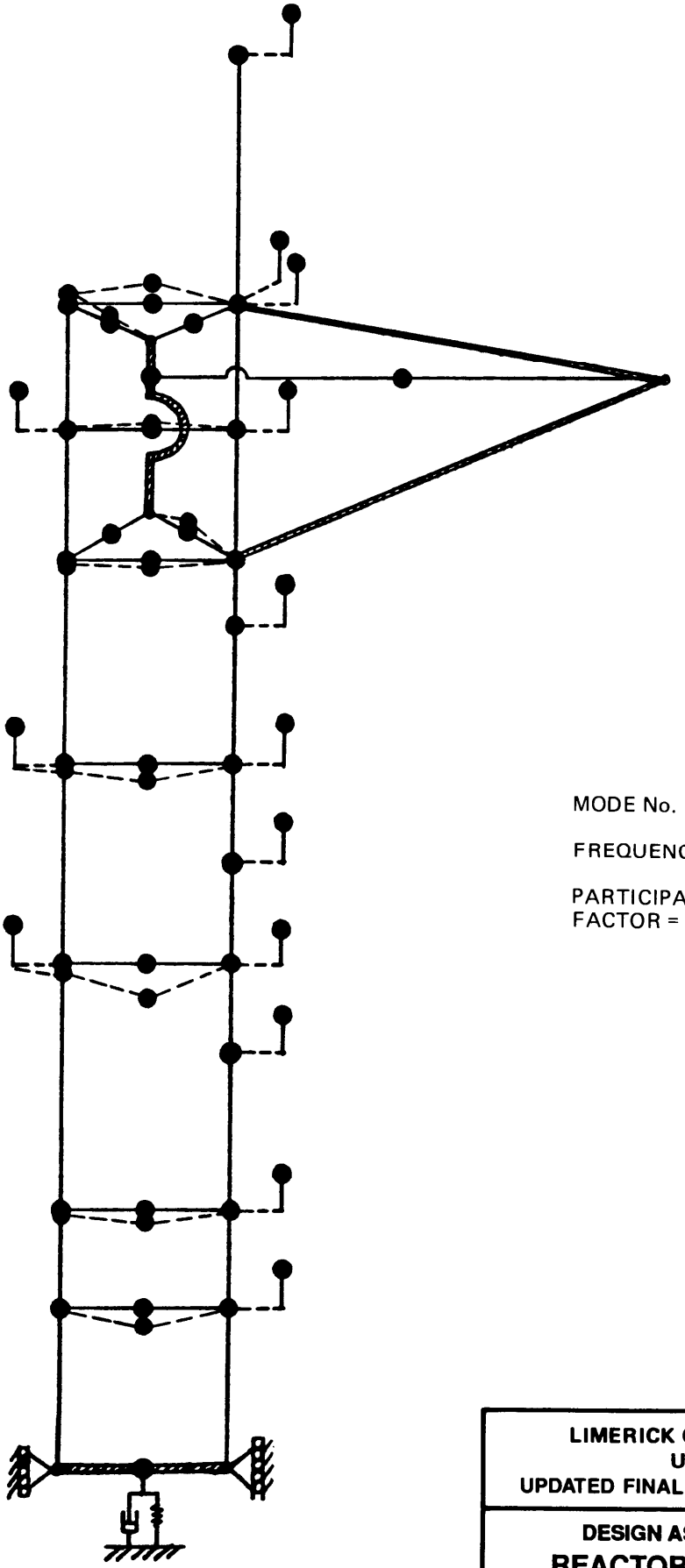
PARTICIPATION
FACTOR = -38.78

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REACTOR ENCLOSURE AND CONTROL STRUCTURE MODE SHAPES

FIGURE 3A-158



MODE No. 16

FREQUENCY = 11.29 Hz

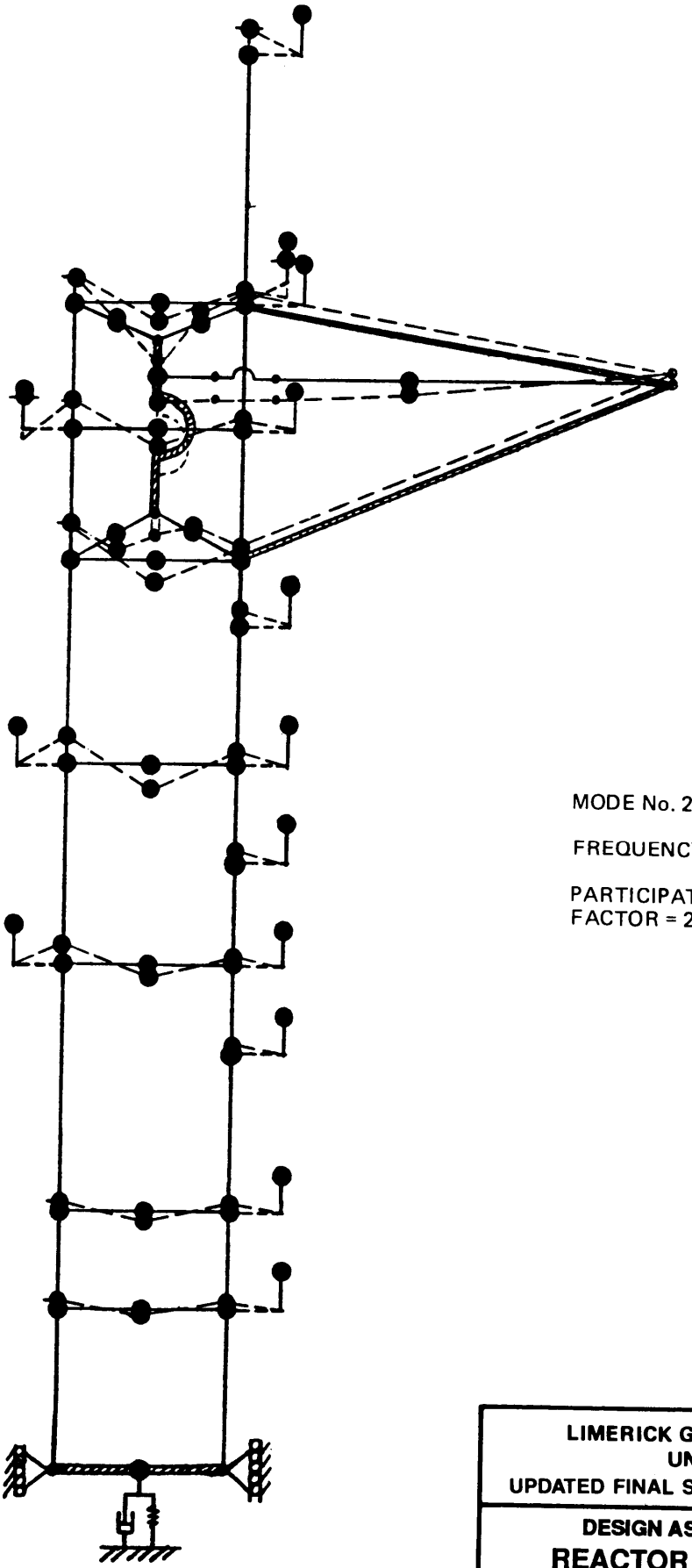
PARTICIPATION
FACTOR = -18.72

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REACTOR ENCLOSURE AND CONTROL STRUCTURE MODE SHAPES

FIGURE 3A-159



MODE No. 27

FREQUENCY = 18.39 Hz

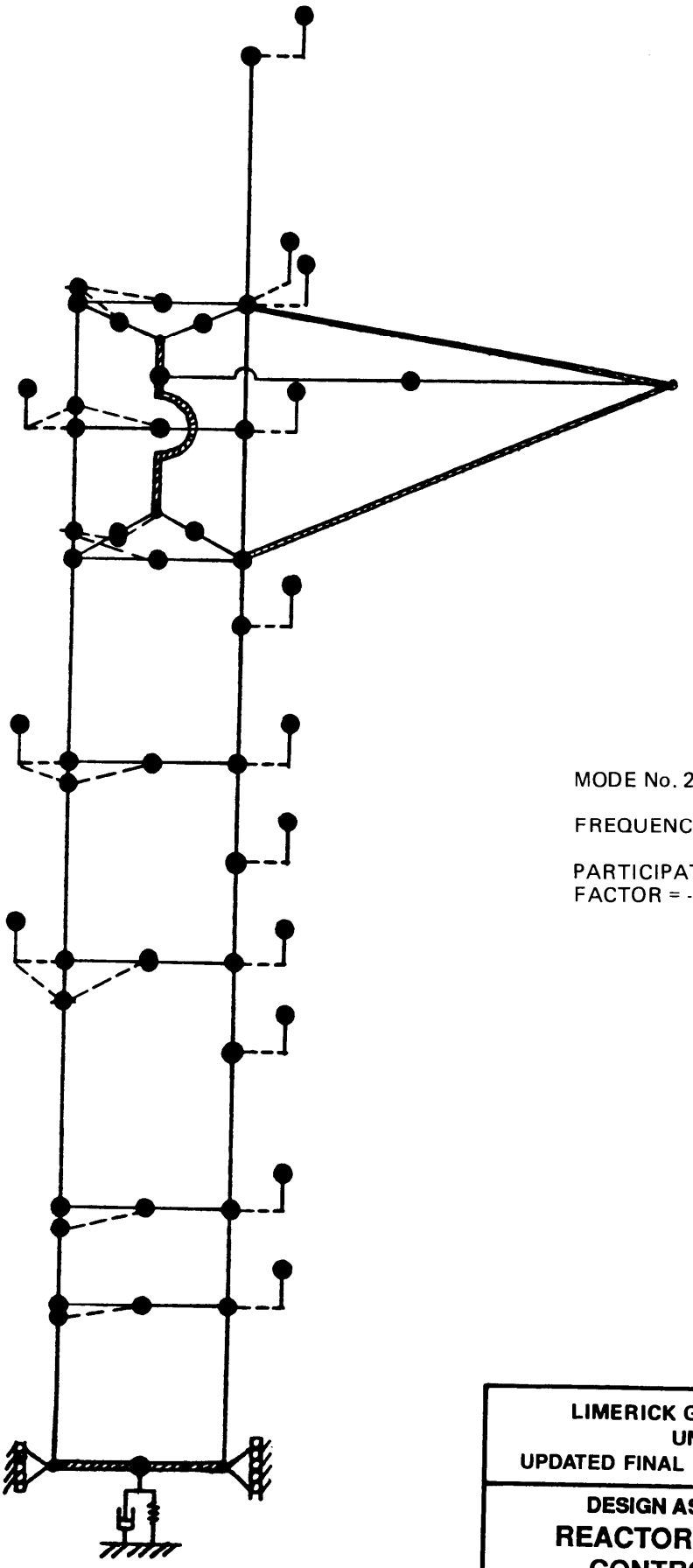
PARTICIPATION
FACTOR = 27.28

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REACTOR ENCLOSURE AND CONTROL STRUCTURE MODE SHAPES

FIGURE 3A-160



MODE No. 29

FREQUENCY = 29.86 Hz

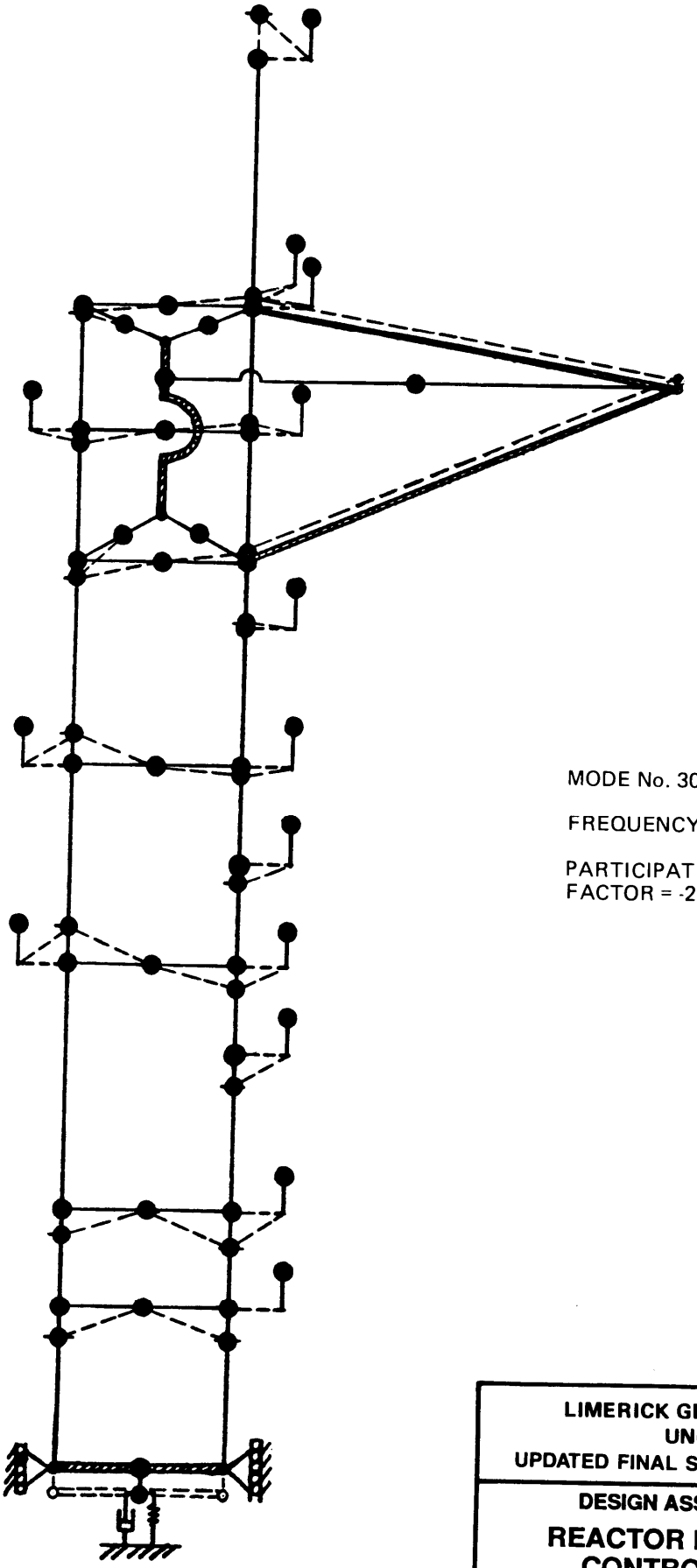
PARTICIPATION
FACTOR = -10.40

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REACTOR ENCLOSURE AND CONTROL STRUCTURE MODE SHAPES

FIGURE 3A-161



MODE No. 30

FREQUENCY = 38.20 Hz

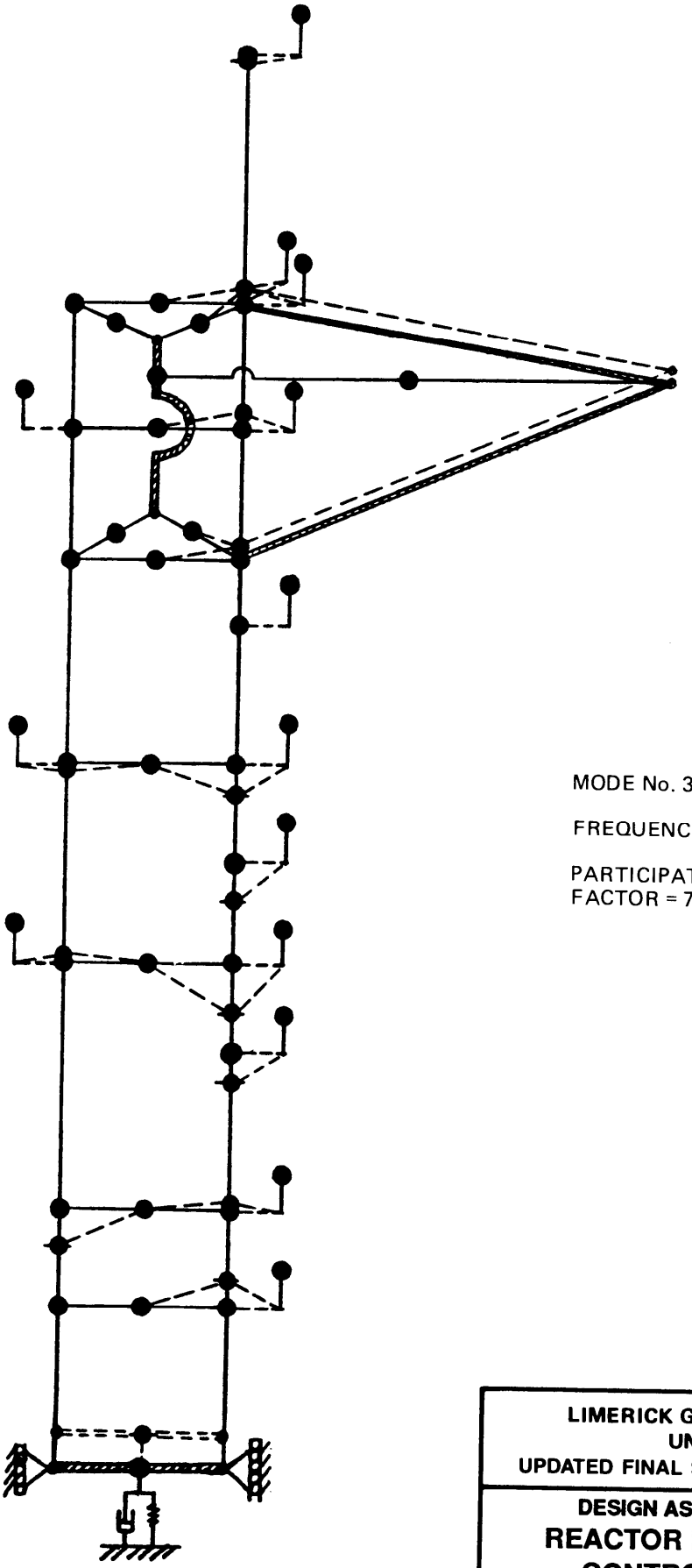
PARTICIPATION
FACTOR = -23.12

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REACTOR ENCLOSURE AND CONTROL STRUCTURE MODE SHAPES

FIGURE 3A-162



MODE No. 34

FREQUENCY = 74.39 Hz

PARTICIPATION
FACTOR = 7.82

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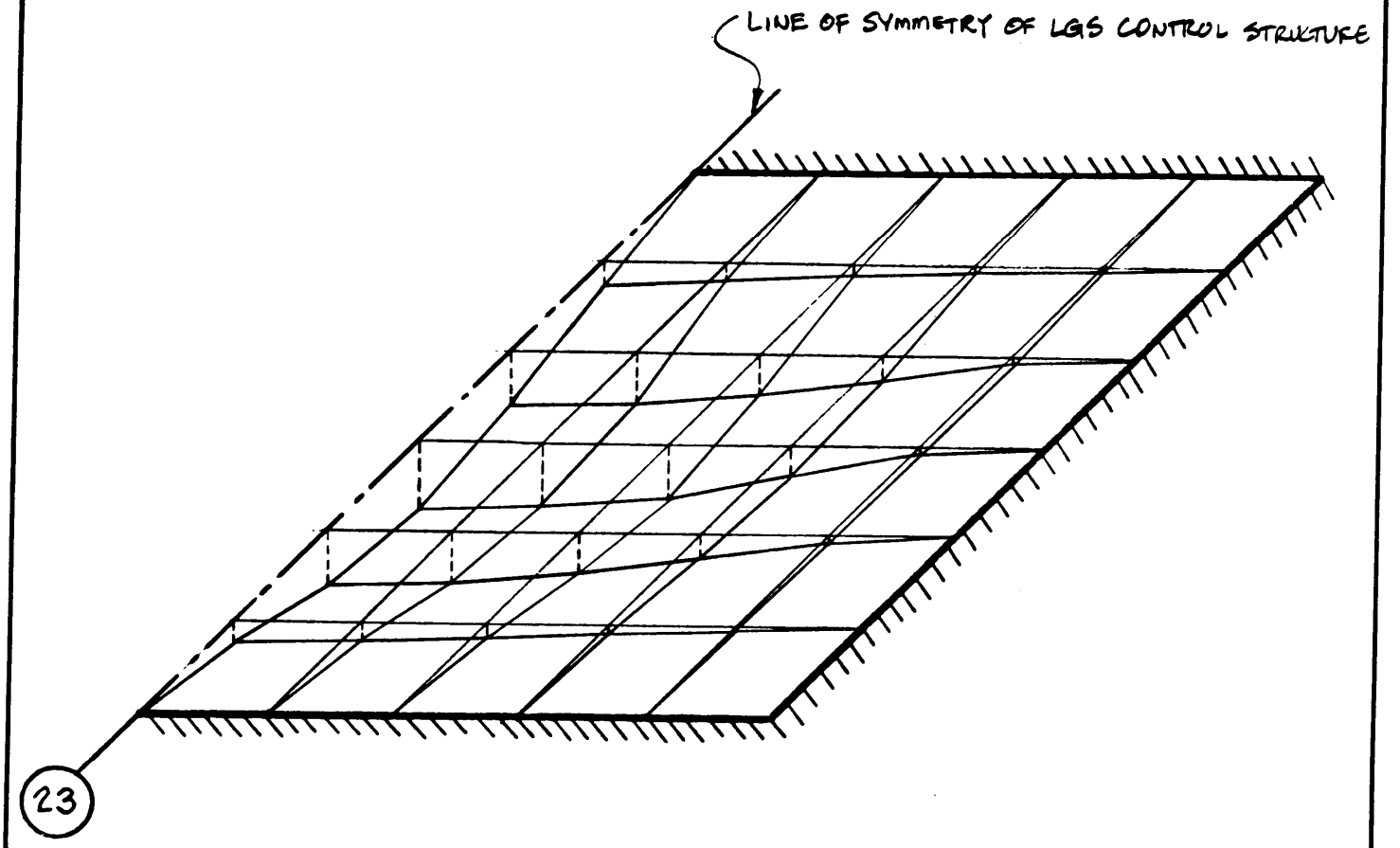
REACTOR ENCLOSURE AND CONTROL STRUCTURE MODE SHAPES

FIGURE 3A-163

MODE No.	FREQUENCY (Hz.)	PARTICIPATION FACTOR
1	14.20	-4.04
2	24.75	1.59
3	37.67	-0.0003
4	47.39	-1.04
5	48.03	-0.0001
6	68.63	-0.00005
7	73.01	1.77
8	78.53	0.71
9	82.70	0.59
10	94.42	-0.00007
11	99.84	-0.31

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CONTROL STRUCTURE MODE FREQUENCIES AND PARTICIPATION FACTORS (VERTICAL LOCAL FLOOR MODEL AT EL. 269'-0")
FIGURE 3A-164



MODE No. 1

FREQUENCY = 14.20 Hz

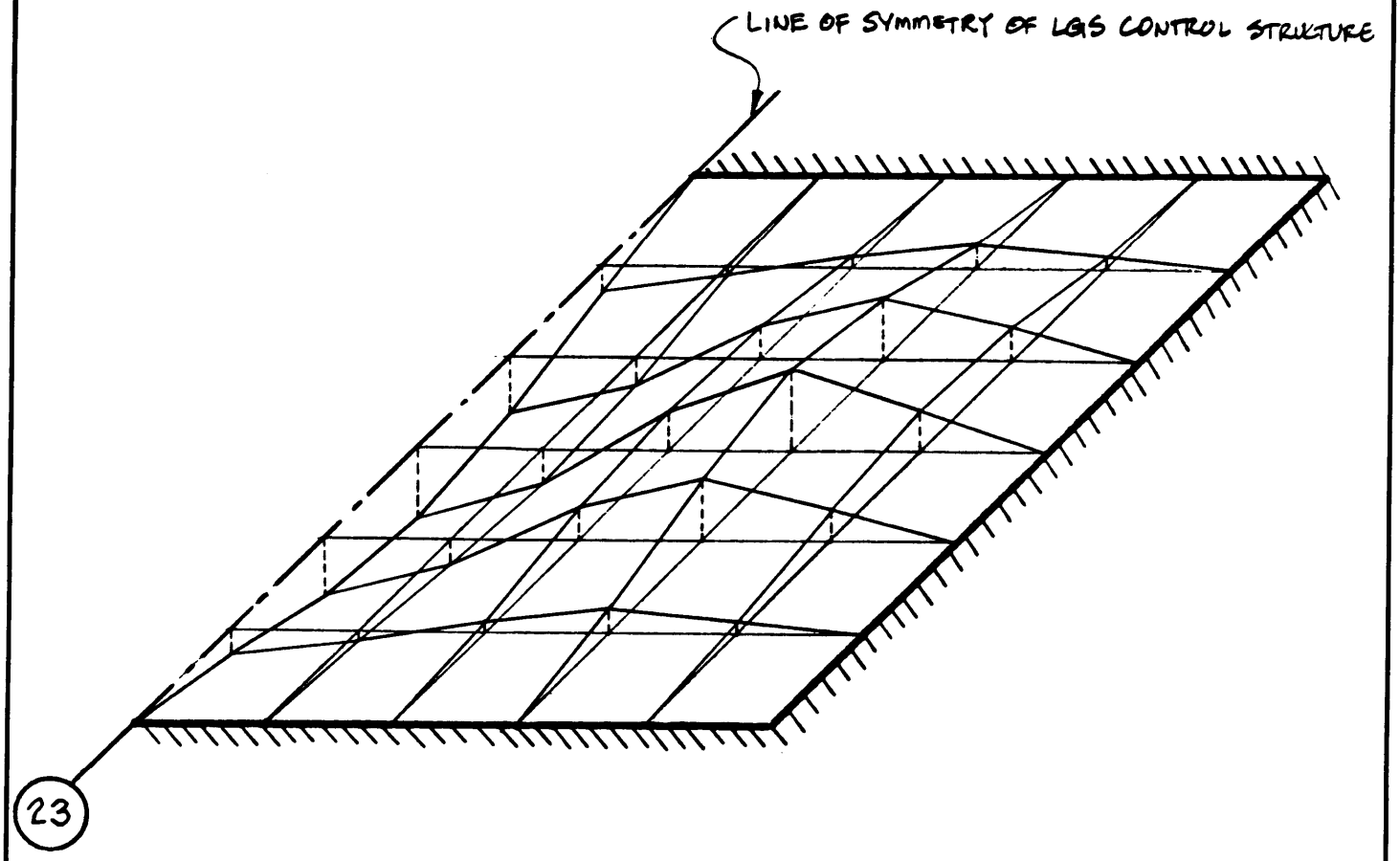
PARTICIPATION
FACTOR = -4.04

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CONTROL STRUCTURE VERTICAL LOCAL FLOOR MODEL MODE SHAPES (EL. 269'-0")

FIGURE 3A-165



MODE No. 2

FREQUENCY = 24.75 Hz

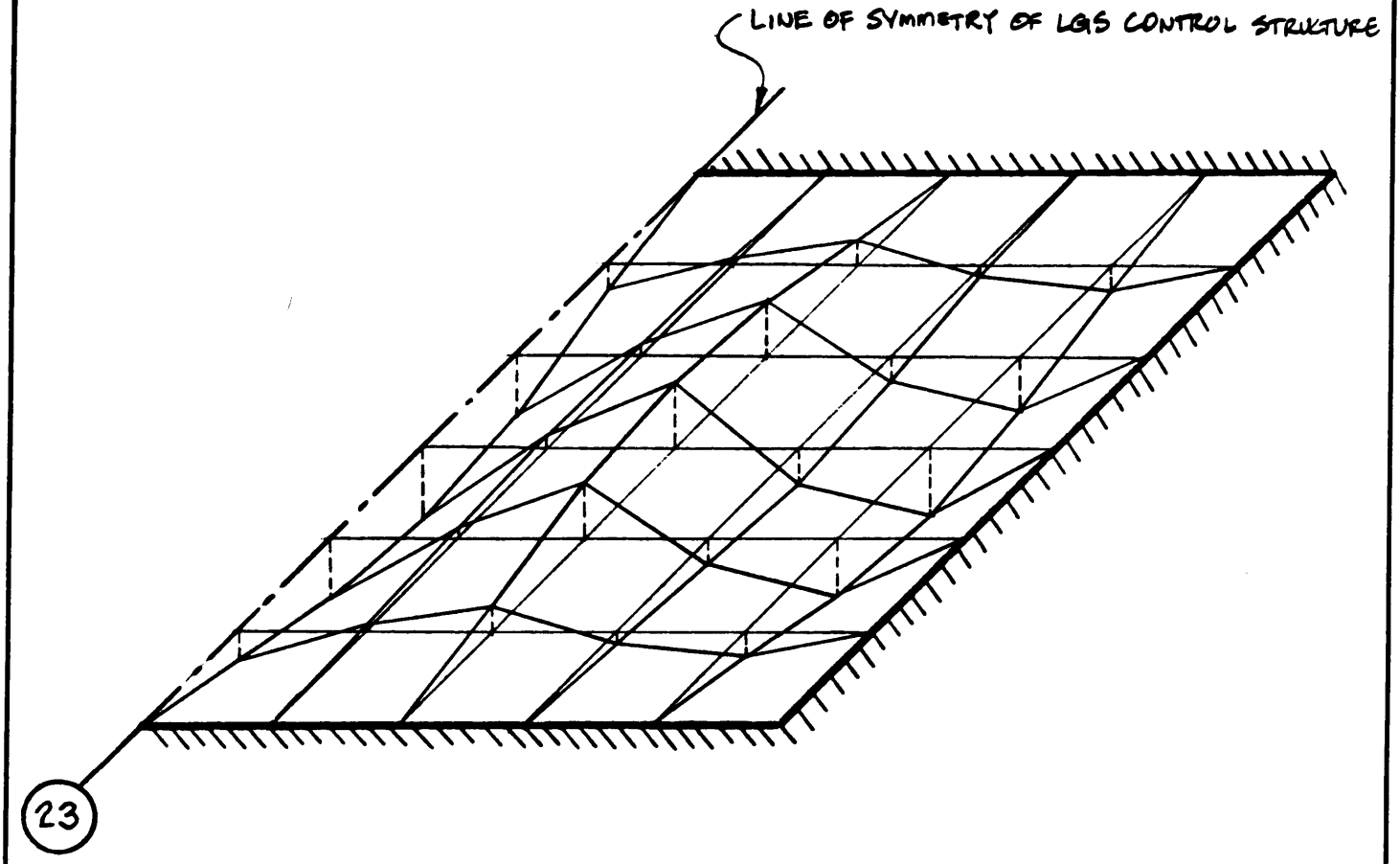
PARTICIPATION
FACTOR = 1.59

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CONTROL STRUCTURE VERTICAL LOCAL FLOOR MODEL MODE SHAPES (EL. 269'-0")

FIGURE 3A-166



MODE No. 4

FREQUENCY = 47.39 Hz

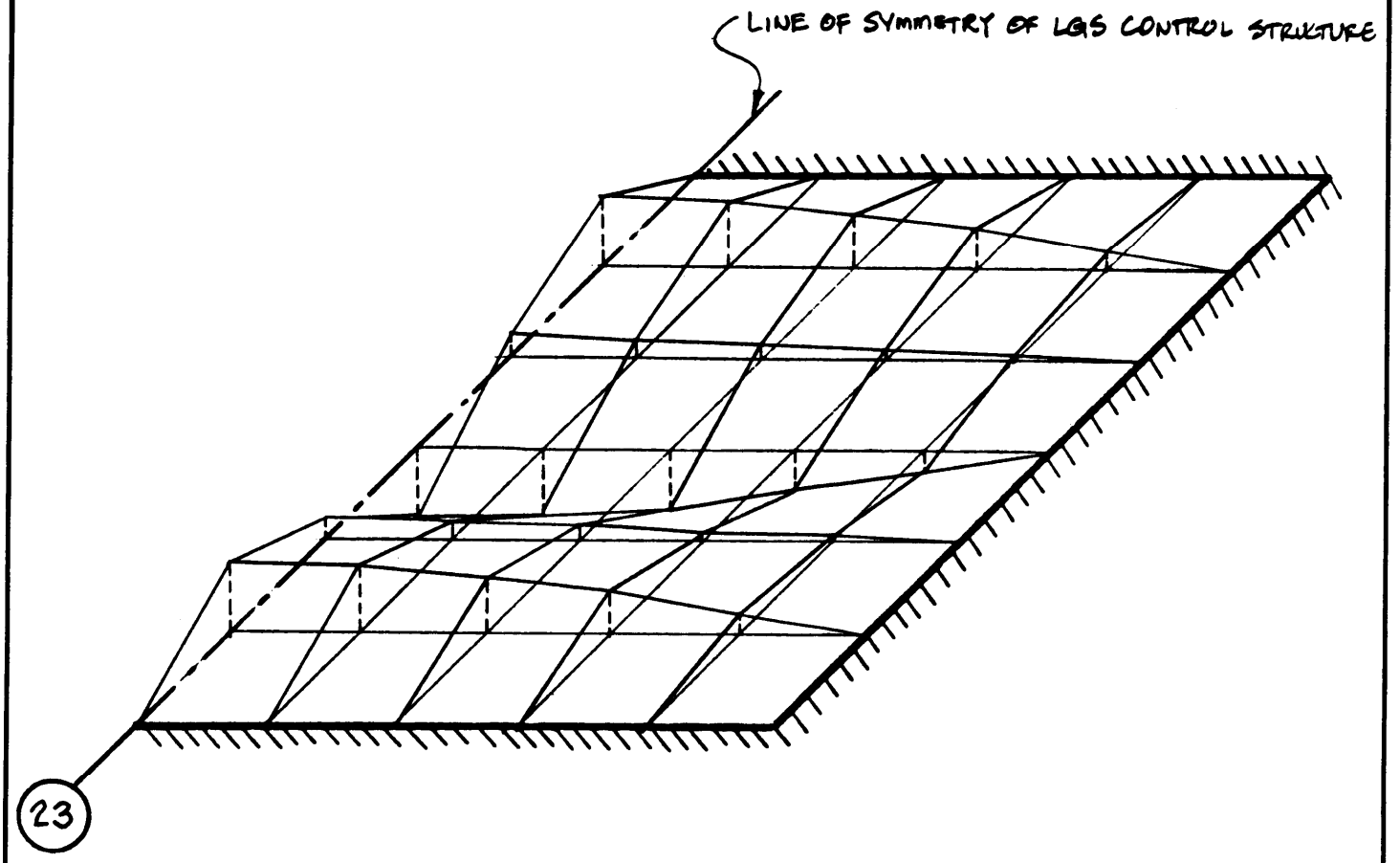
PARTICIPATION
FACTOR = -1.04

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CONTROL STRUCTURE VERTICAL LOCAL FLOOR MODEL MODE SHAPES (EL. 269'-0")

FIGURE 3A-167



MODE No. 7

FREQUENCY = 73.01 Hz

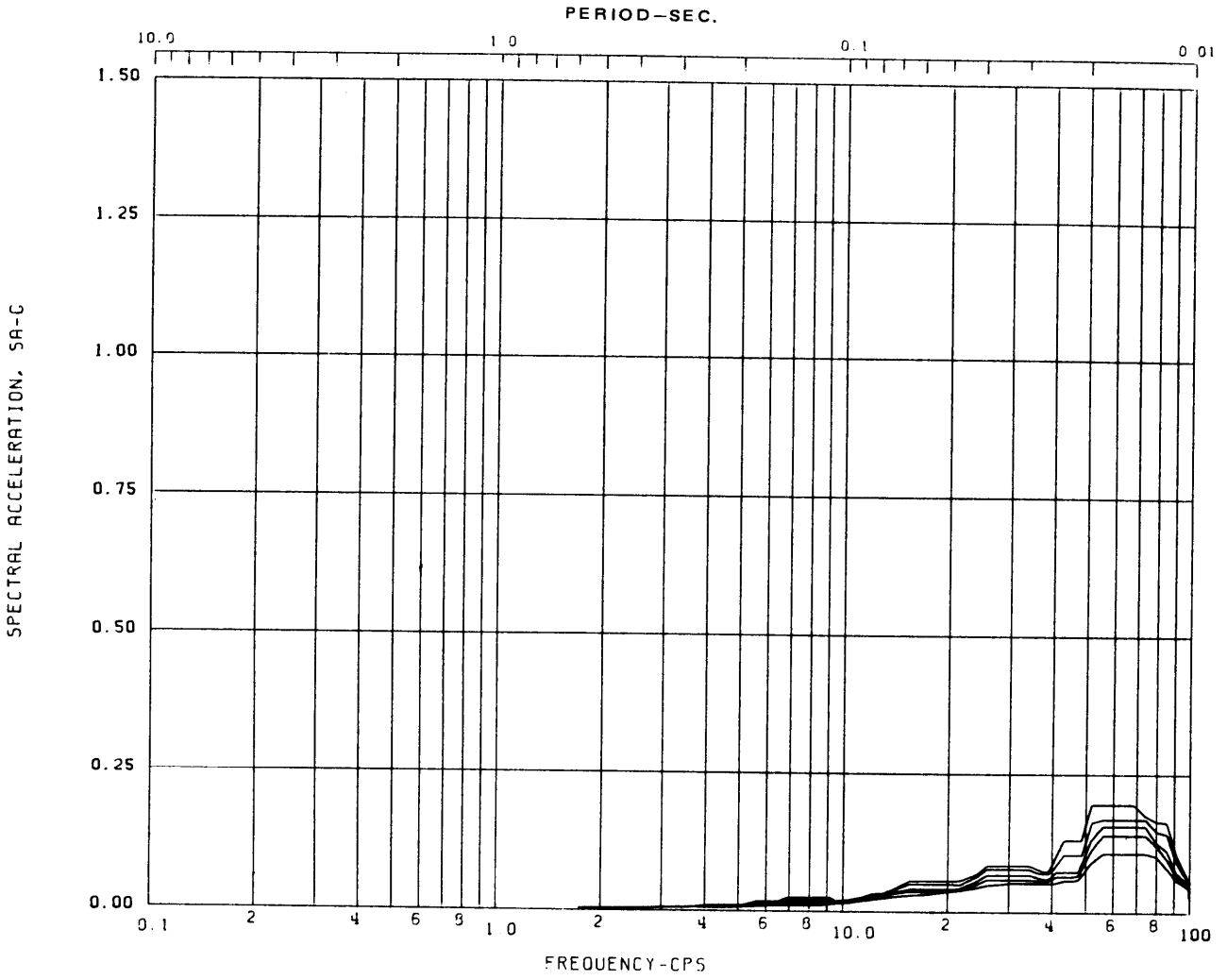
PARTICIPATION
FACTOR = 1.77

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CONTROL STRUCTURE VERTICAL LOCAL FLOOR MODEL MODE SHAPES (EL. 269'-0")

FIGURE 3A-168



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 1 Direction: N-S HORIZ Elev: 177'-0

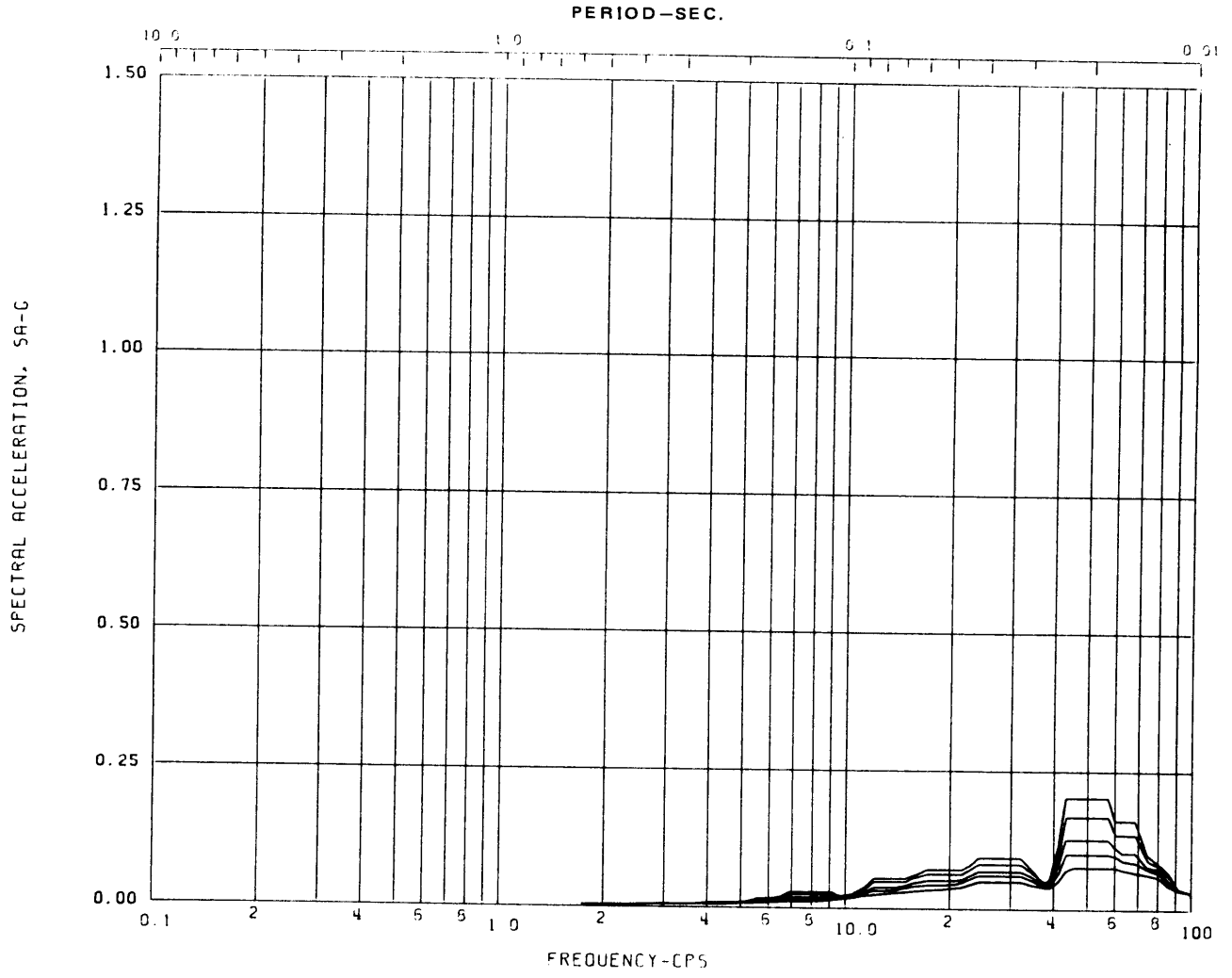
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, SRV ASYMMETRIC

FIGURE 3A-169



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

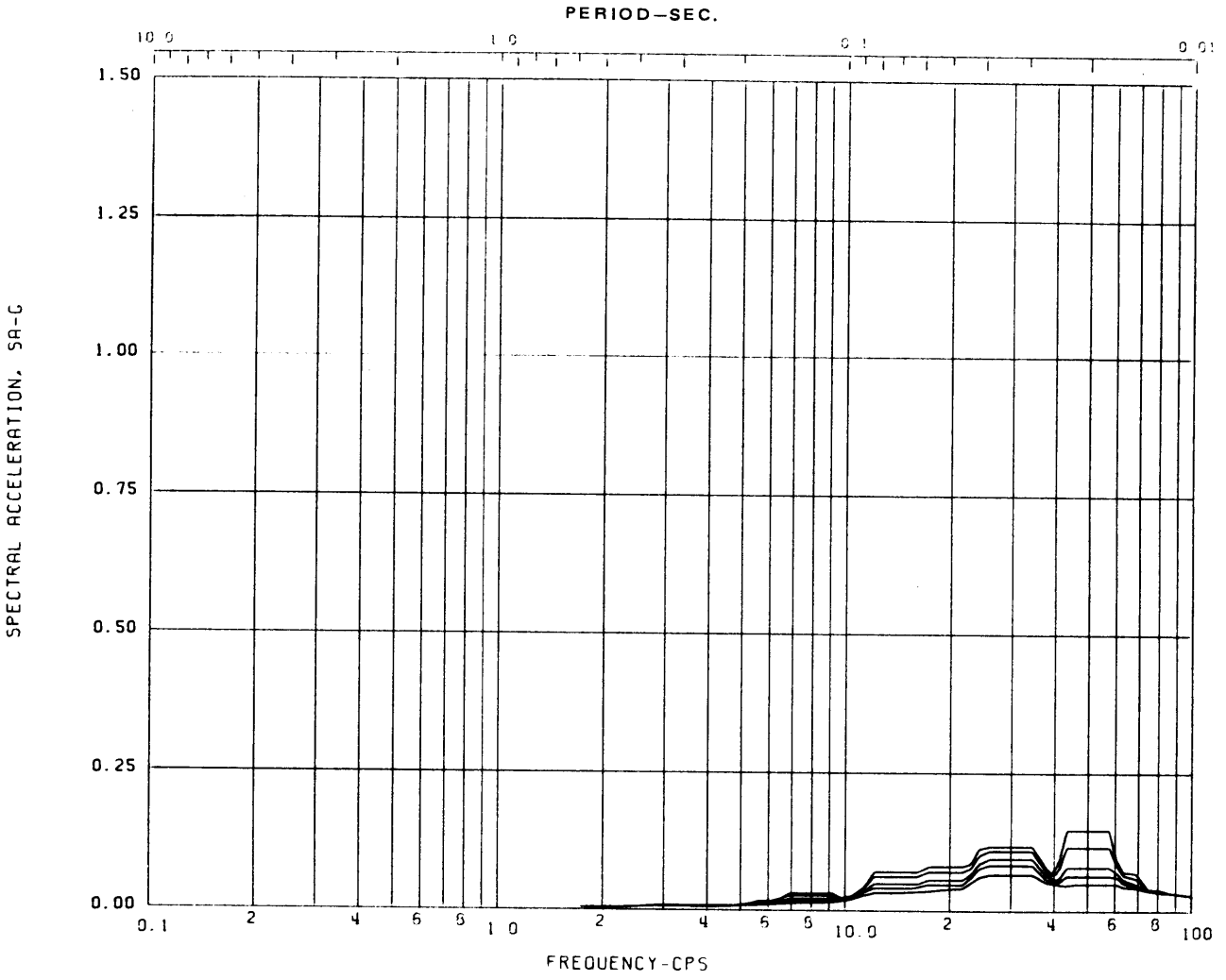
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 2 Direction: N-S HORIZ Elev: 201'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, SRV ASYMMETRIC
FIGURE 3A-170



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 3 Direction: N-S HORIZ Elev: 217'-0

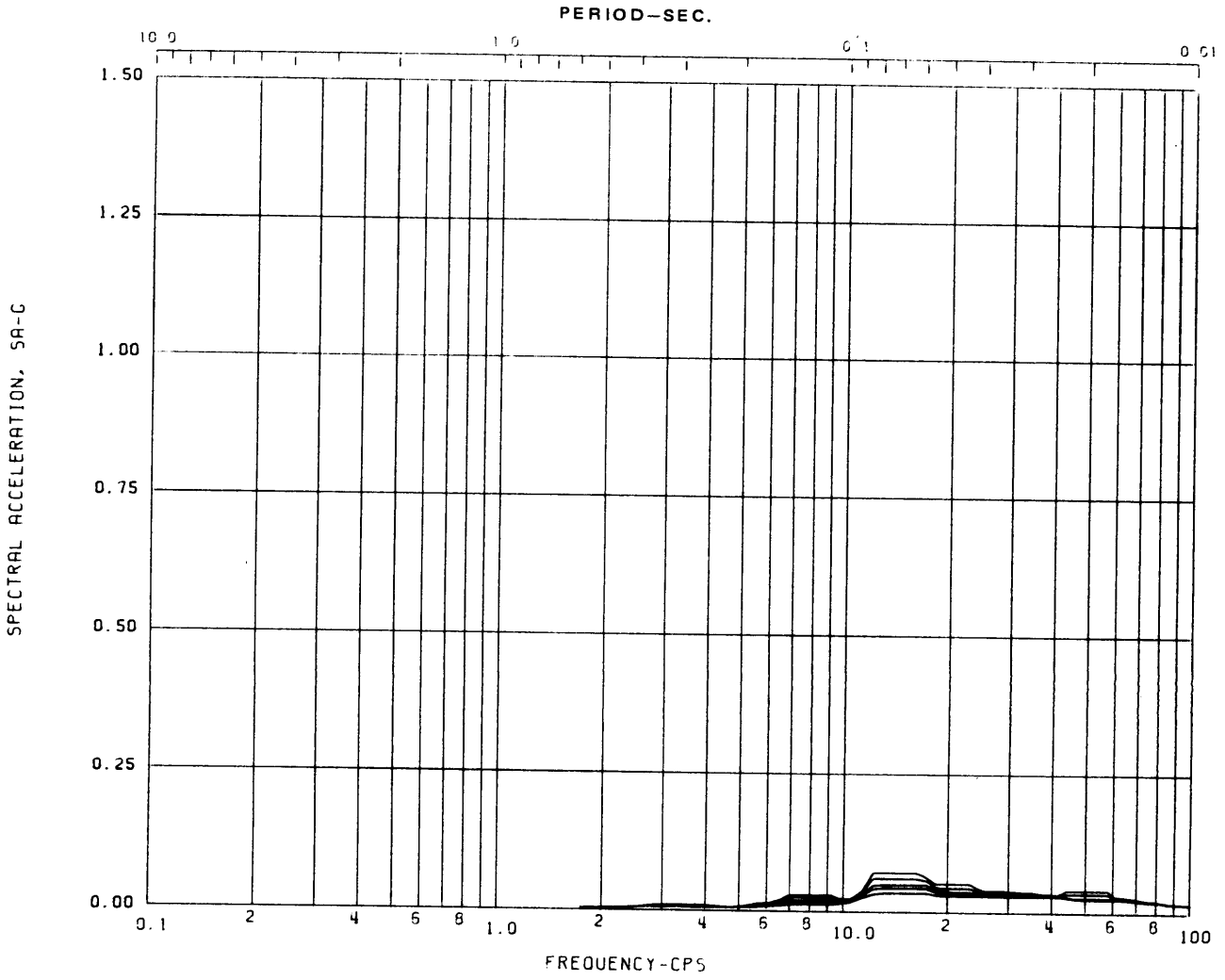
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, SRV ASYMMETRIC

FIGURE 3A-171



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 4 Direction: N-S HORIZ Elev: 239'-0

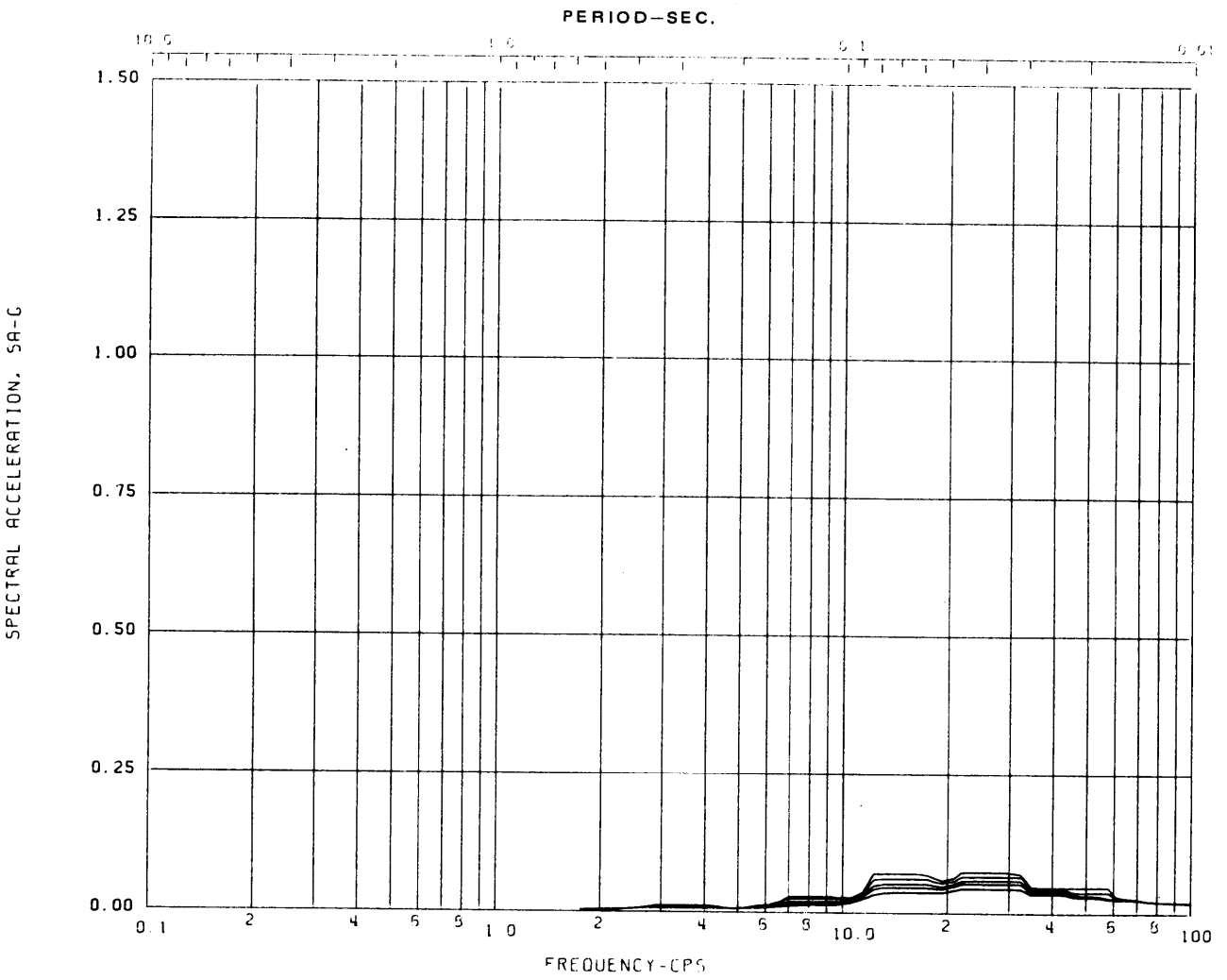
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, SRV ASYMMETRIC

FIGURE 3A-172



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

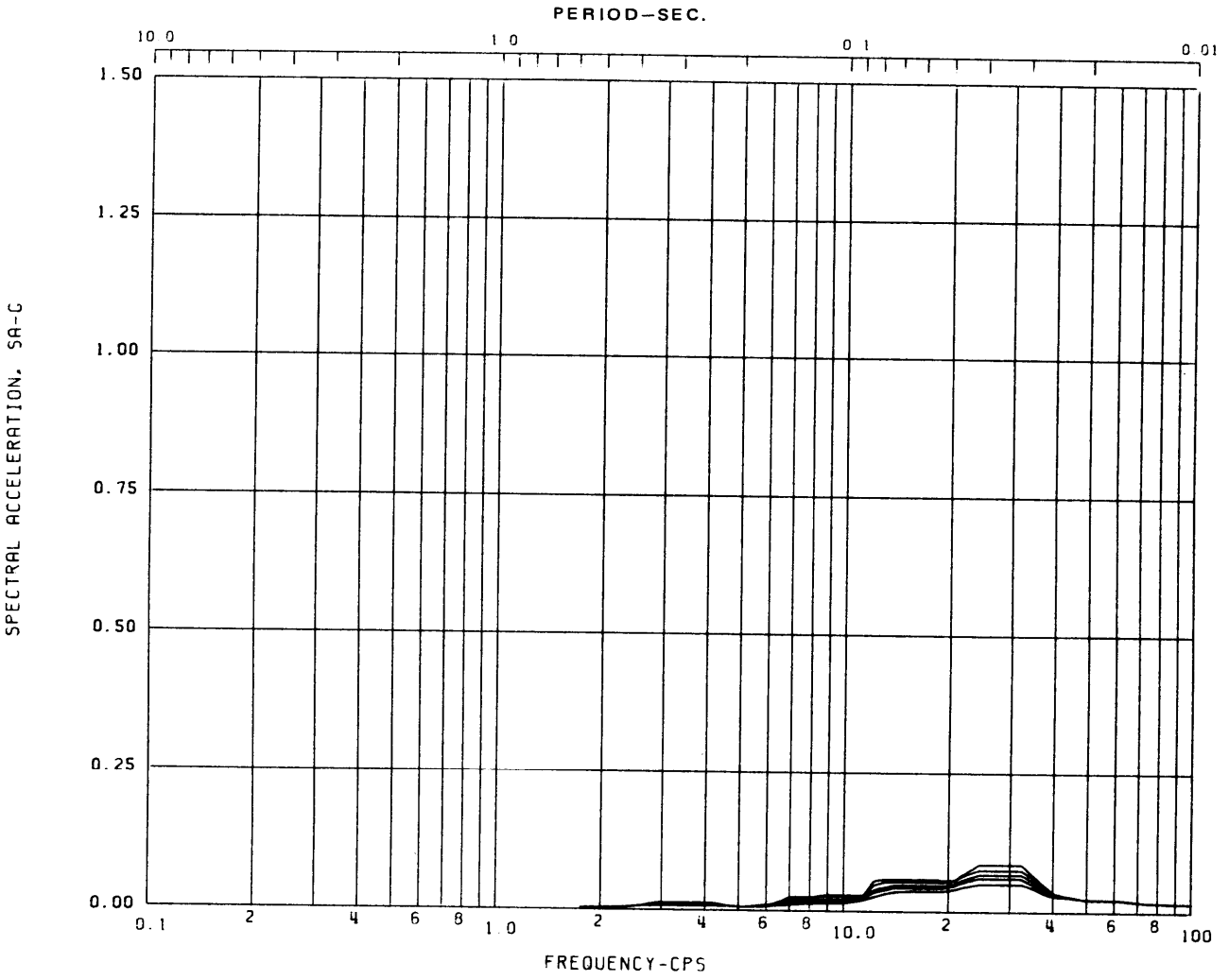
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 5 Direction: N-S HORIZ Elev: 253'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, SRV ASYMMETRIC
FIGURE 3A-173



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

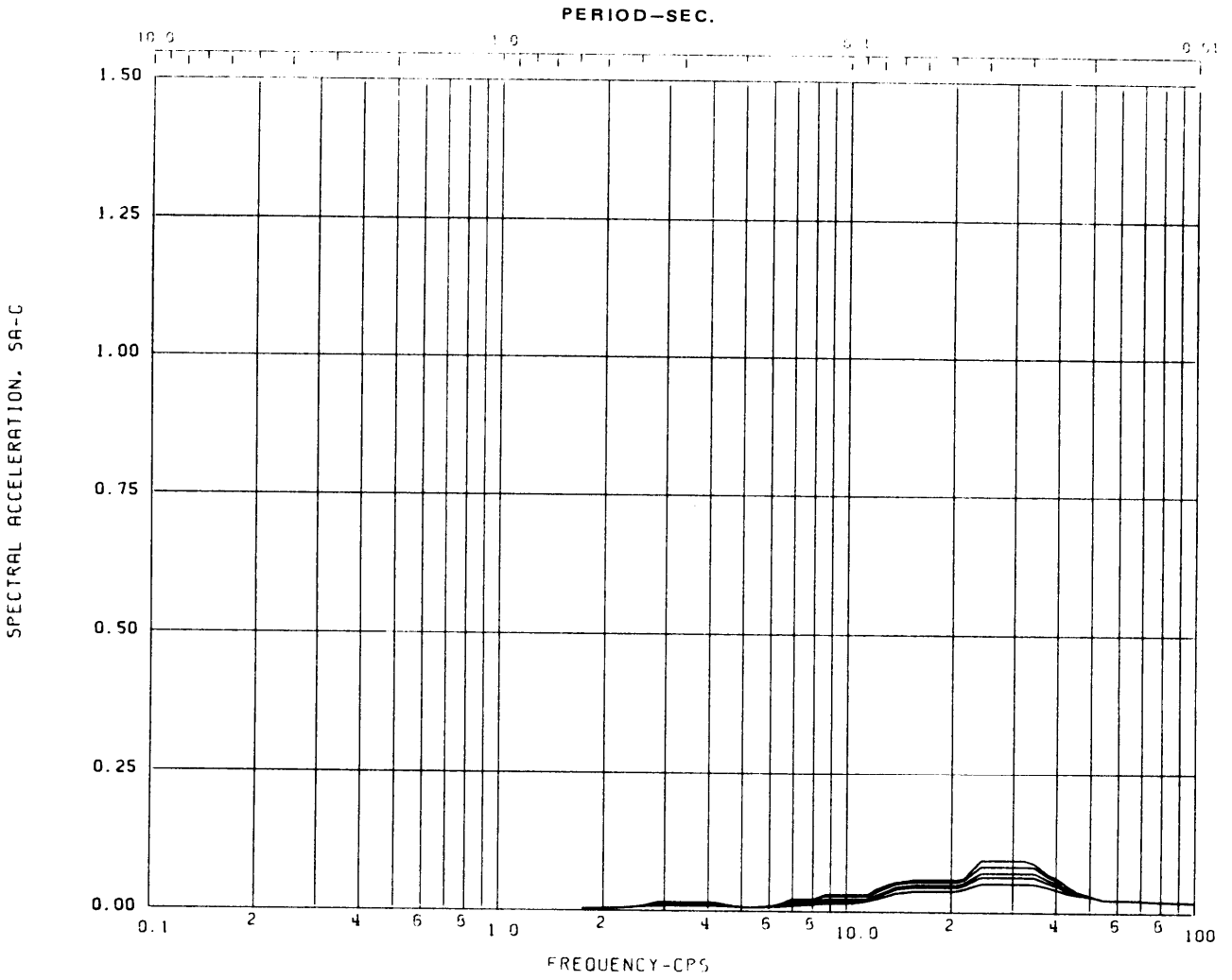
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 6 Direction: N-S HORIZ Elev: 269'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, SRV ASYMMETRIC
FIGURE 3A-174



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 7 Direction: N-S HORIZ Elev: 283'-0

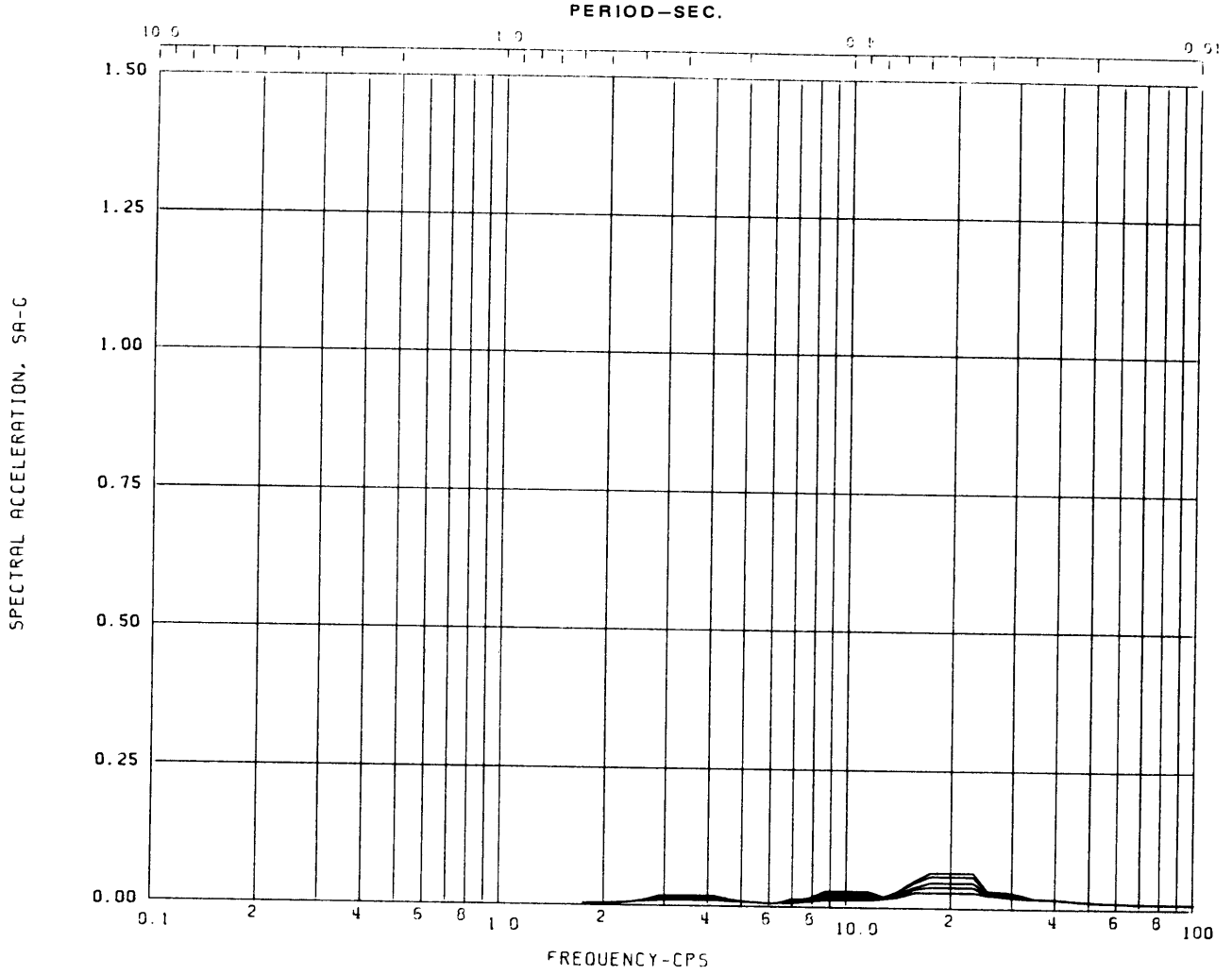
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, SRV ASYMMETRIC

FIGURE 3A-175



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

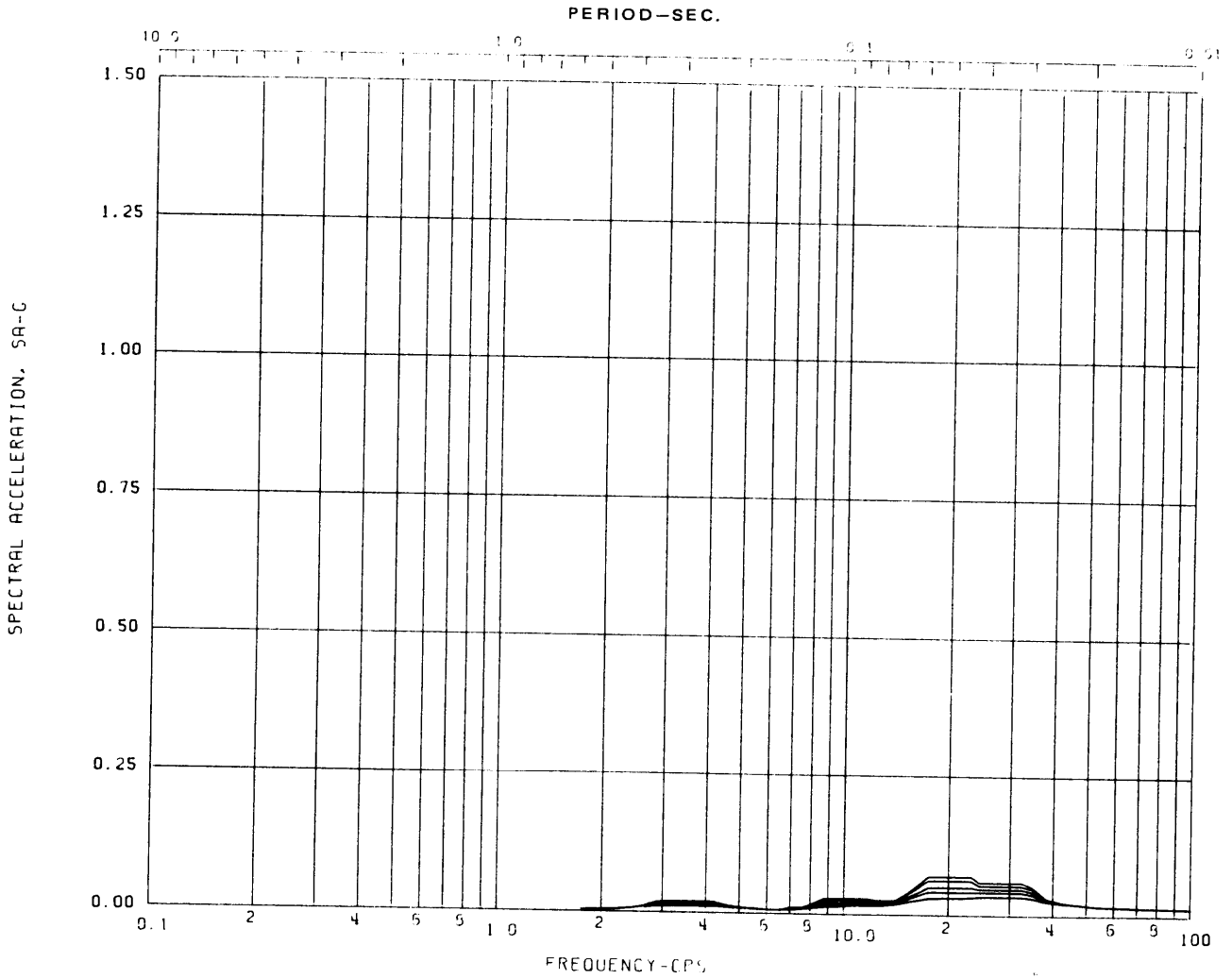
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 8 Direction: N-S HORIZ Elev: 304'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-176



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

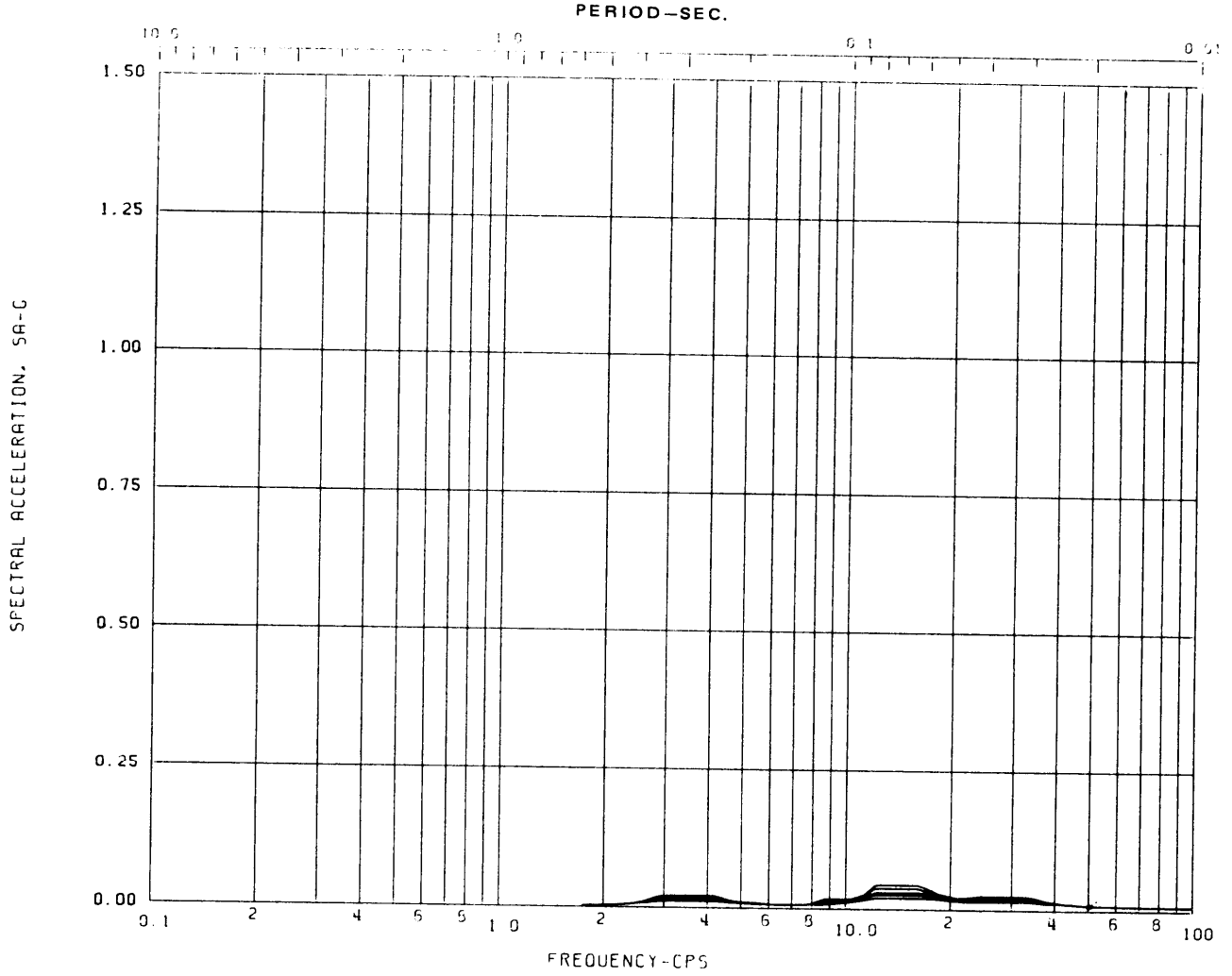
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 9 Direction: N-S HORIZ Elev: 313'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-177



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 10 Direction: N-S HORIZ Elev: 332'-0

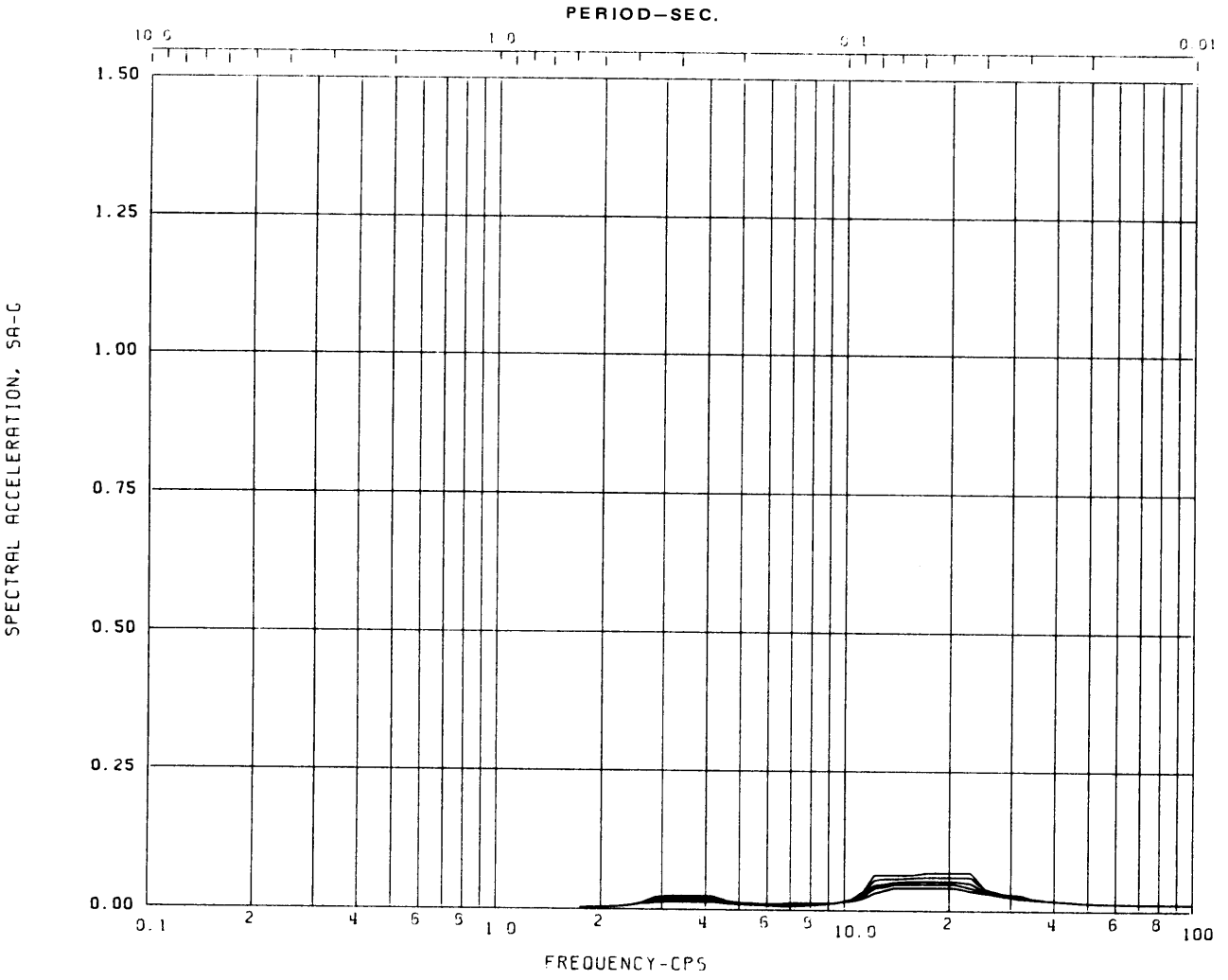
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, SRV ASYMMETRIC

FIGURE 3A-178



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

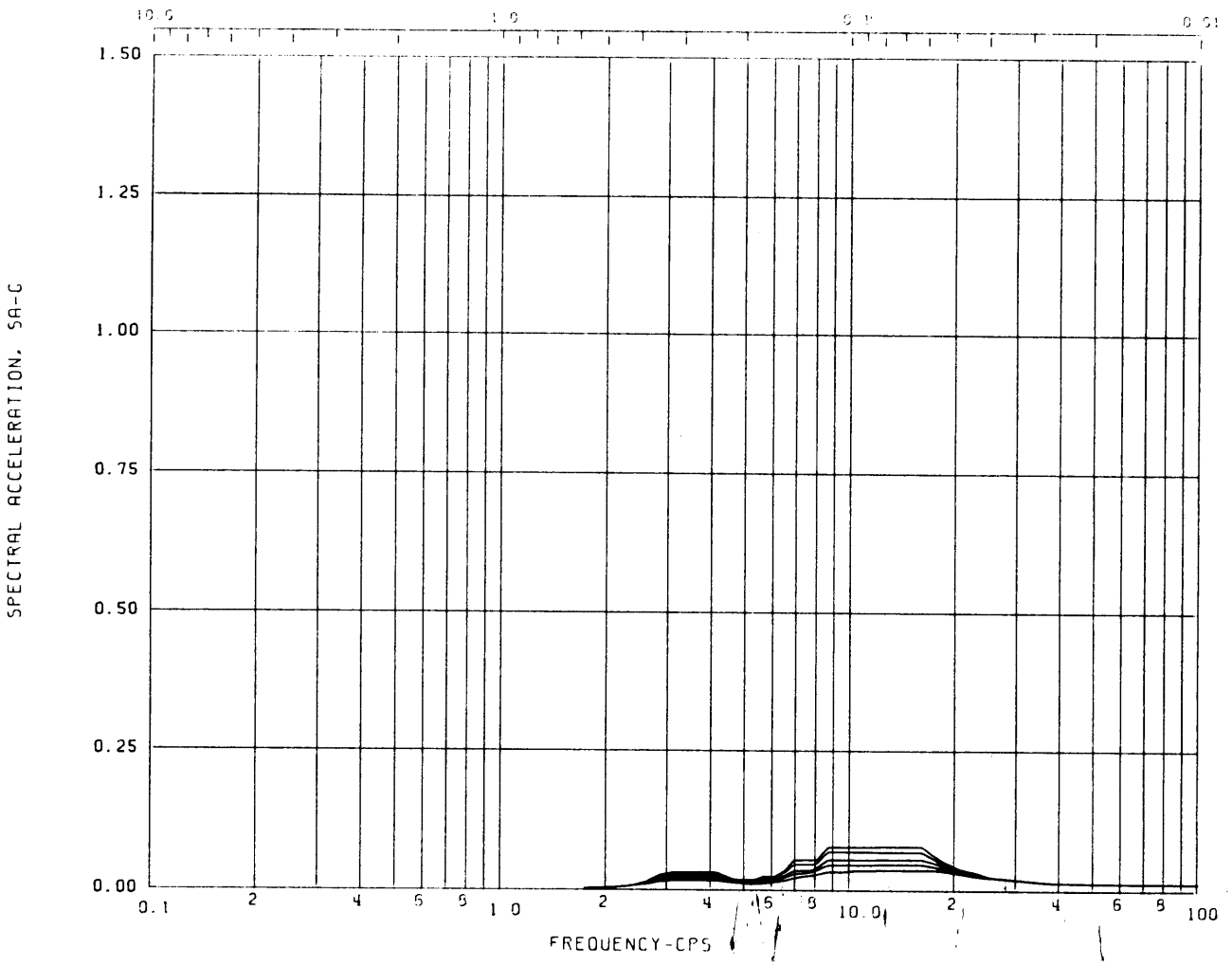
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 11 Direction: N-S HORIZ Elev: 352'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, SRV ASYMMETRIC
FIGURE 3A-179



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

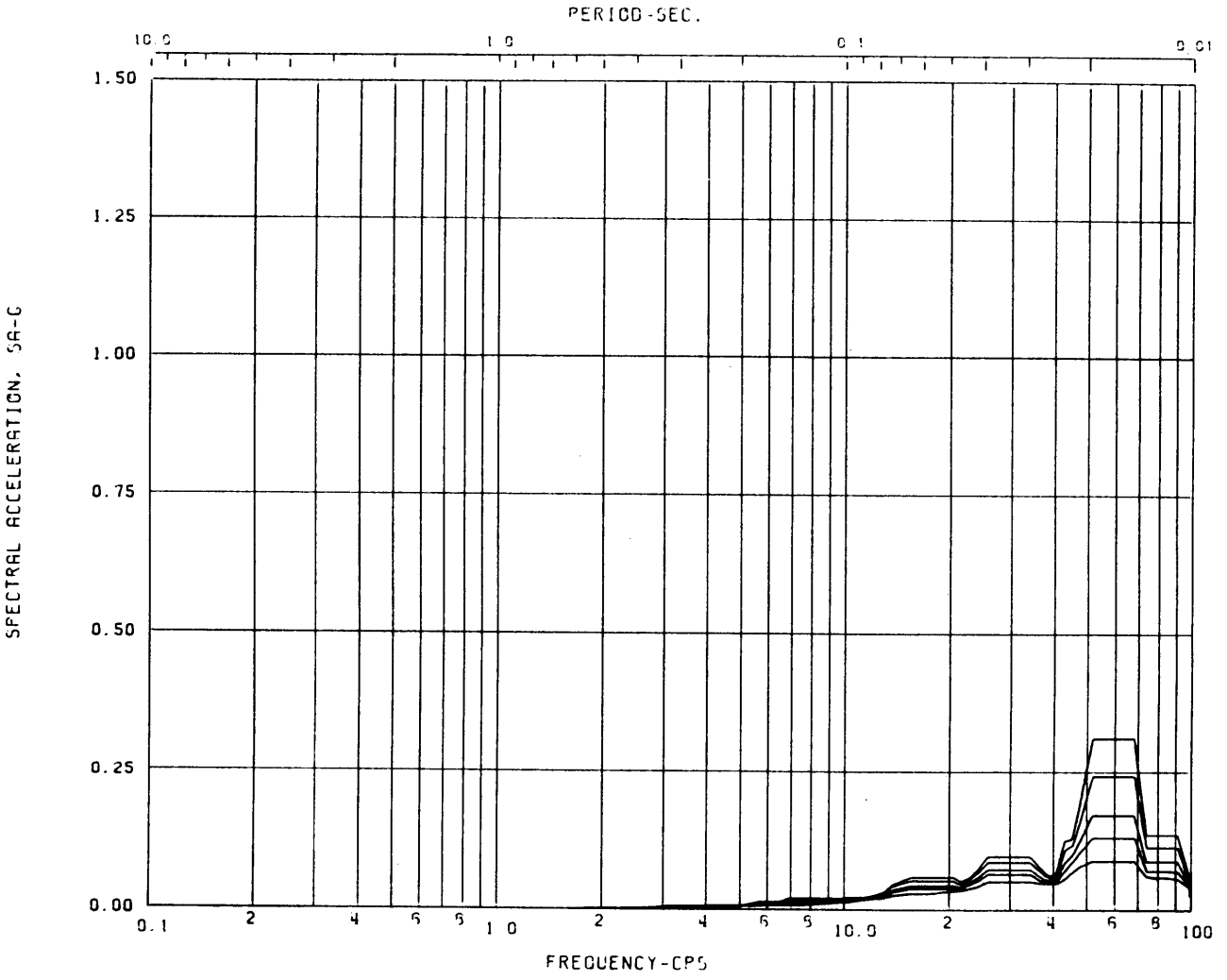
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 12 Direction: N-S HORIZ Elev: 410'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-180



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

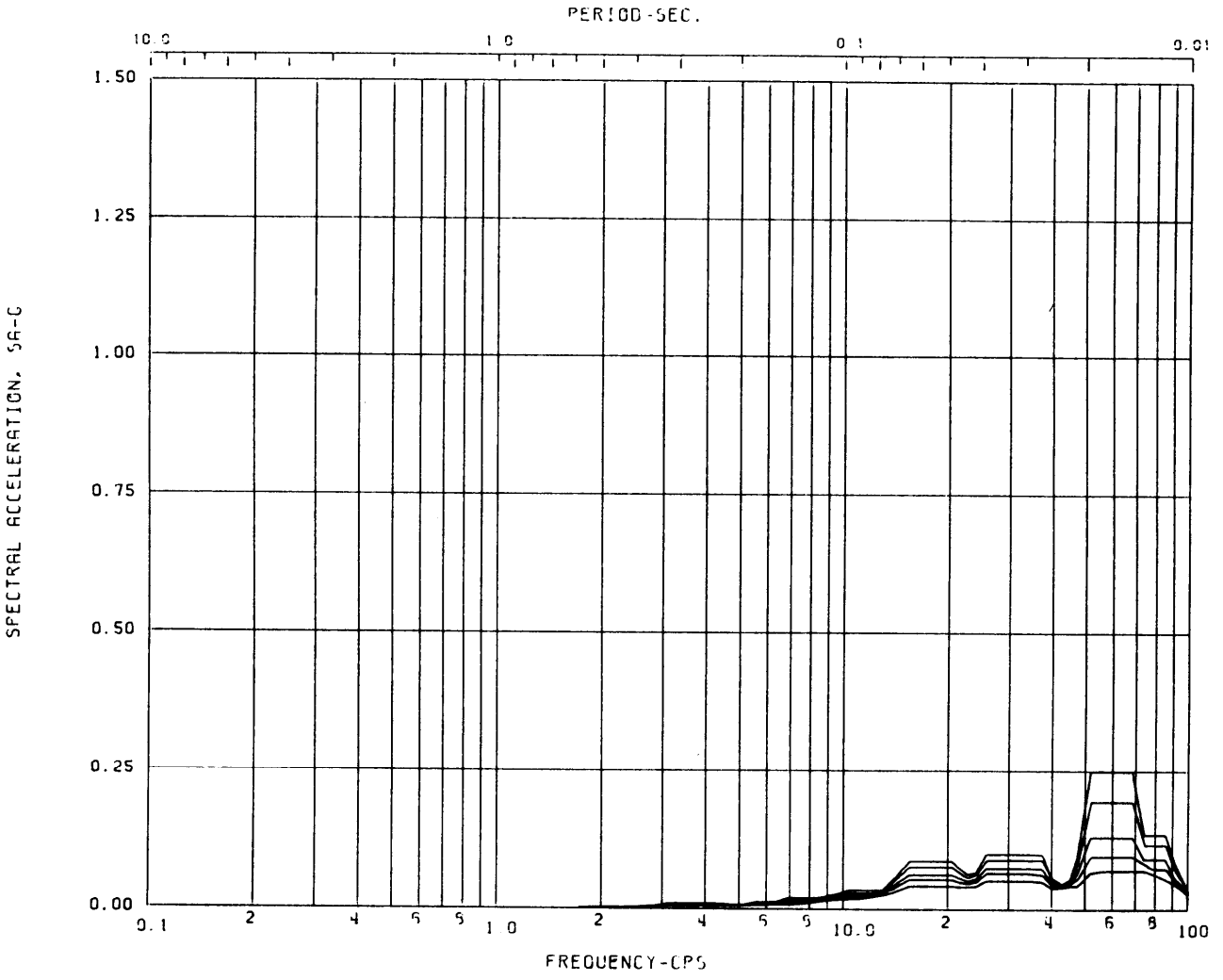
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 1 Direction: E-W HORIZ Elev: 177'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-181



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

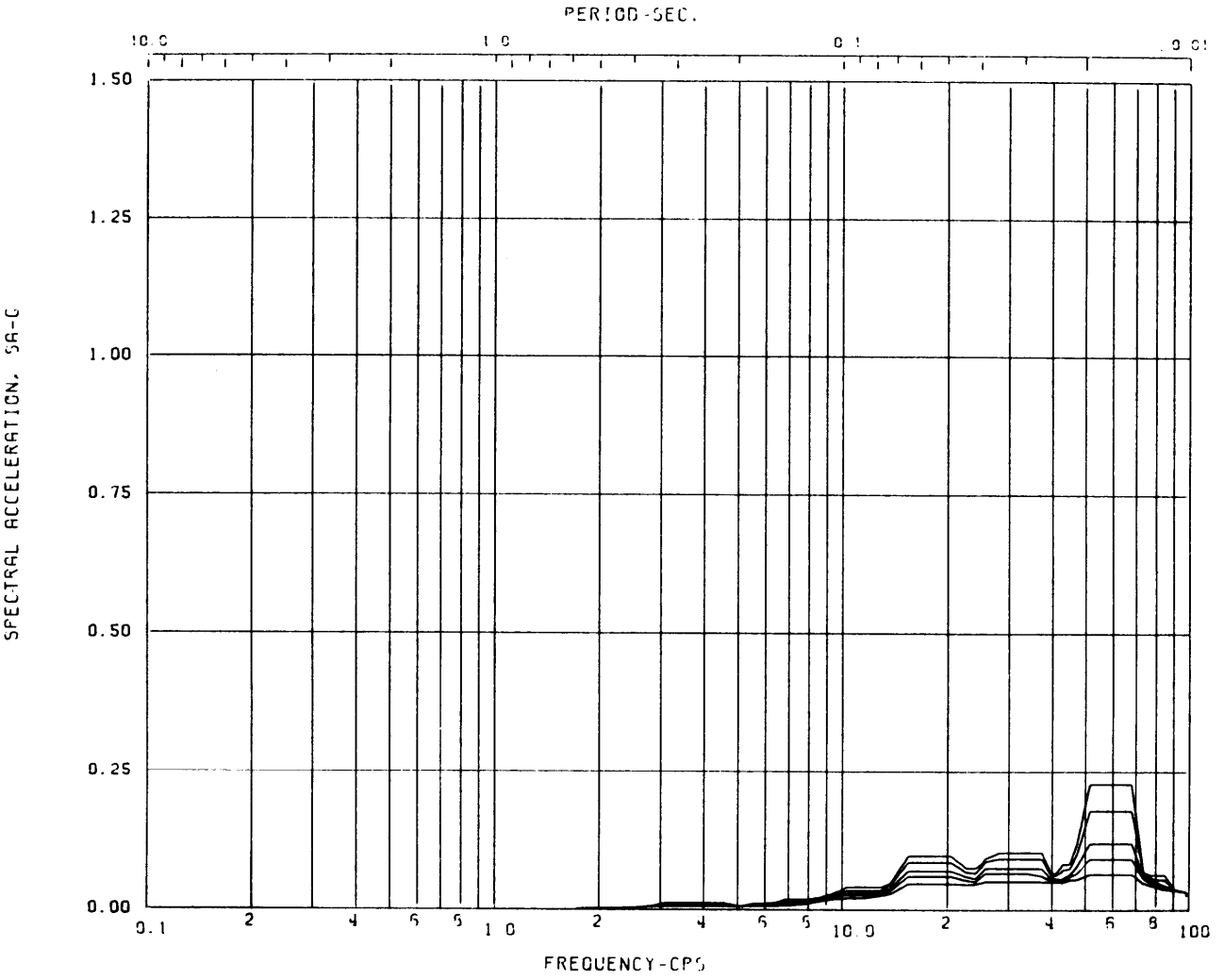
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 2 Direction: E-W HORIZ Elev: 201'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-182



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

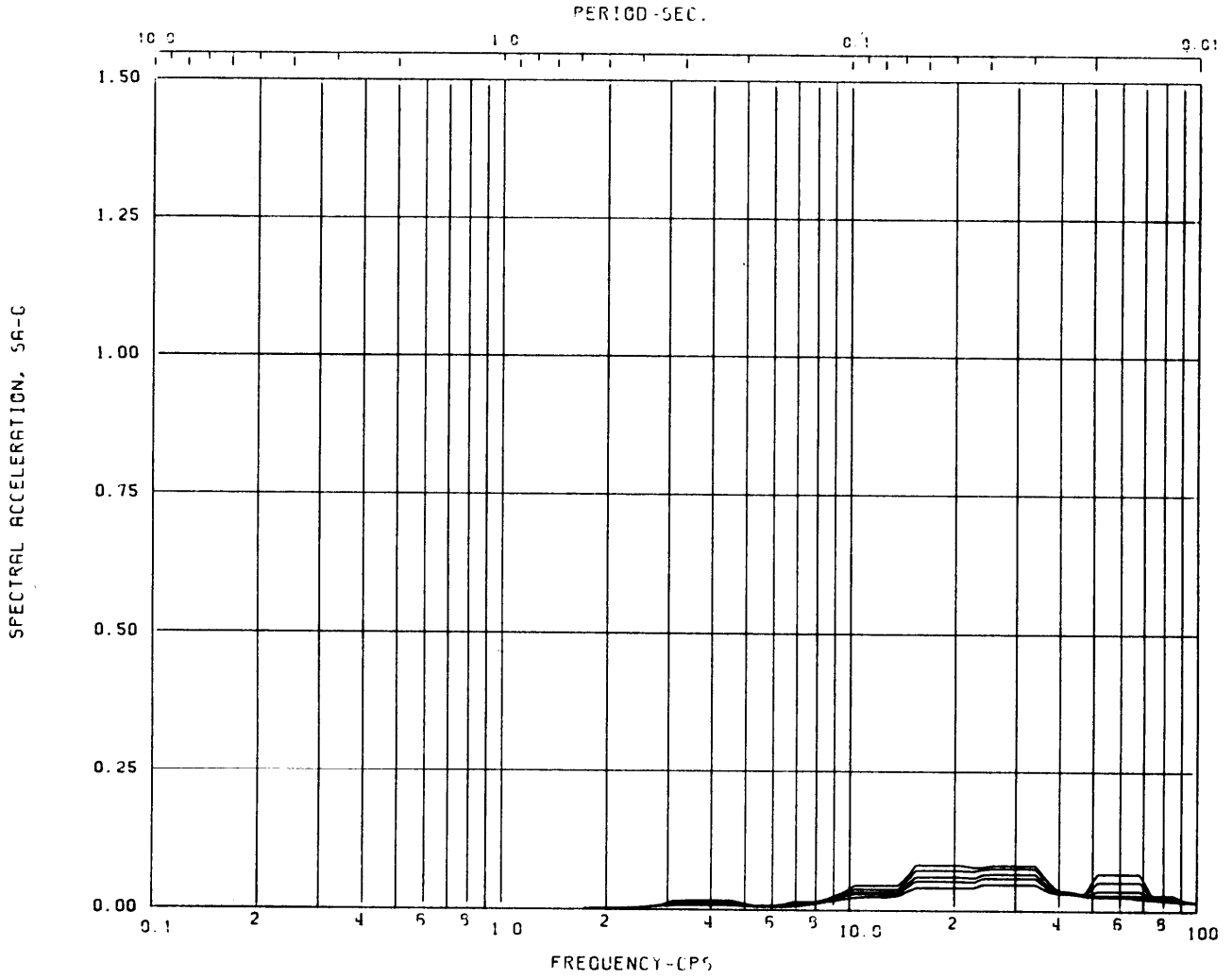
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 3 Direction: E-W HORIZ Elev: 217'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-183



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

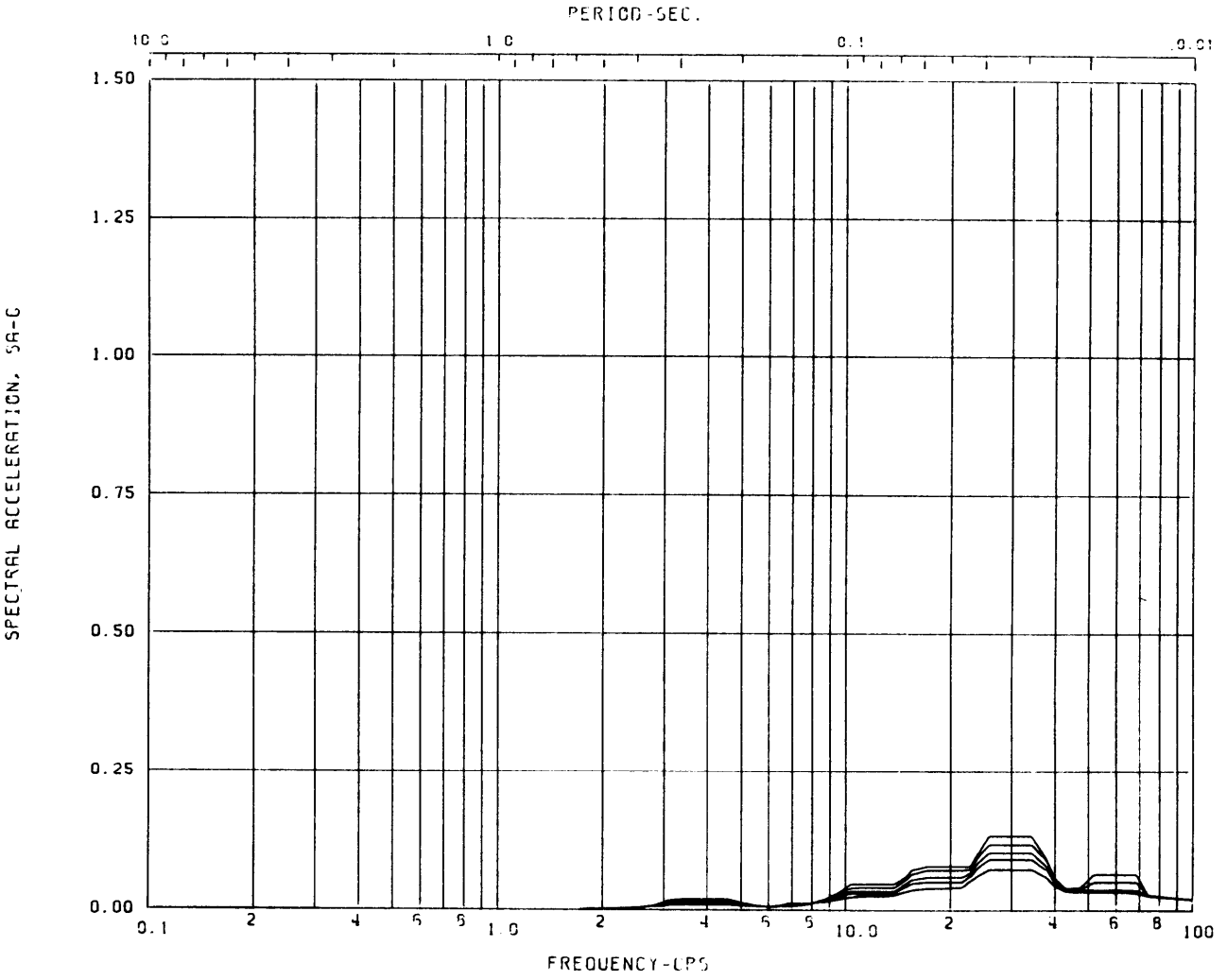
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 4 Direction: E-W HORIZ Elev: 239'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, E-W HORIZONTAL, SRV ASYMMETRIC
FIGURE 3A-184



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

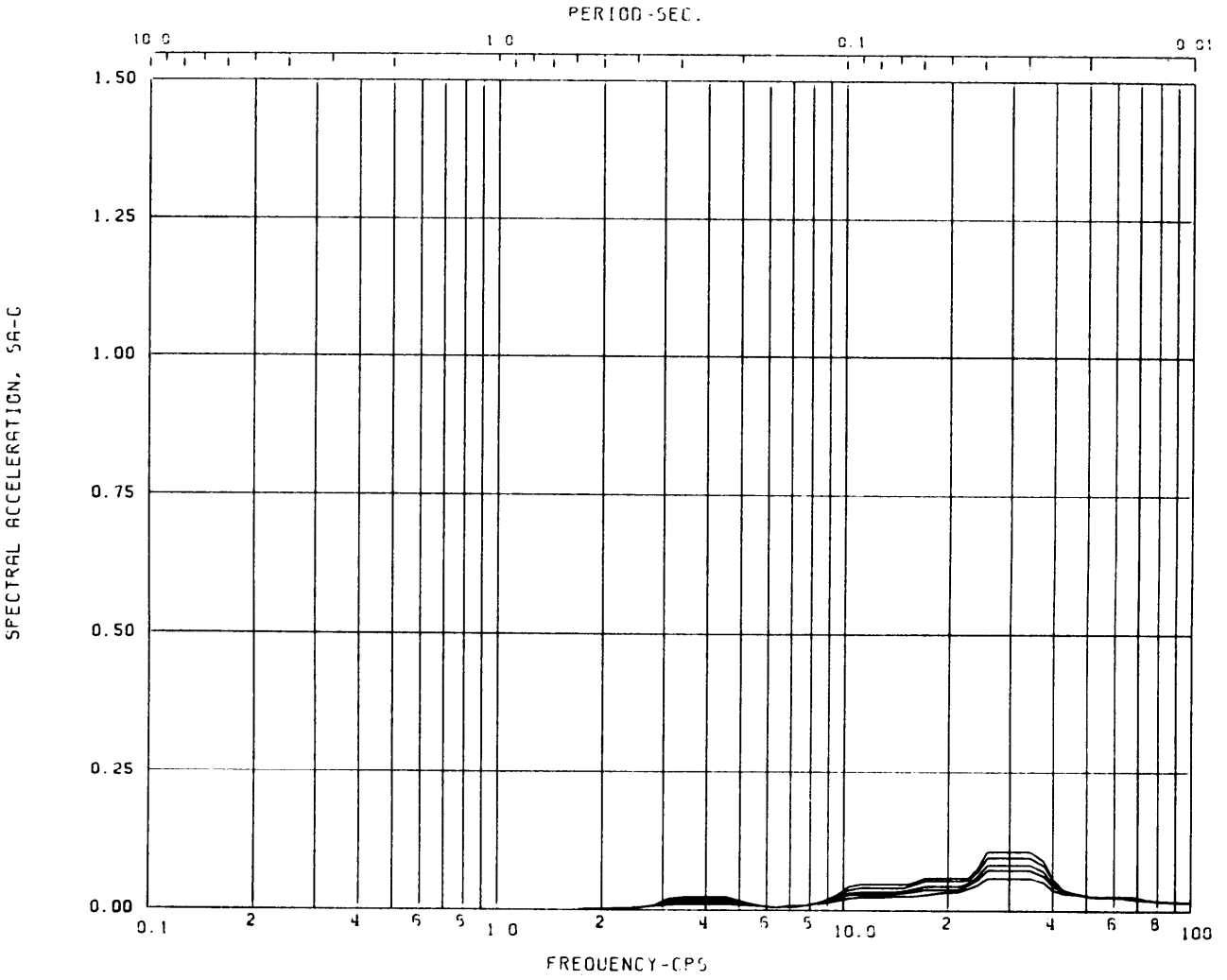
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 5 Direction: E-W HORIZ Elev: 253'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, E-W HORIZONTAL, SRV ASYMMETRIC
FIGURE 3A-185



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

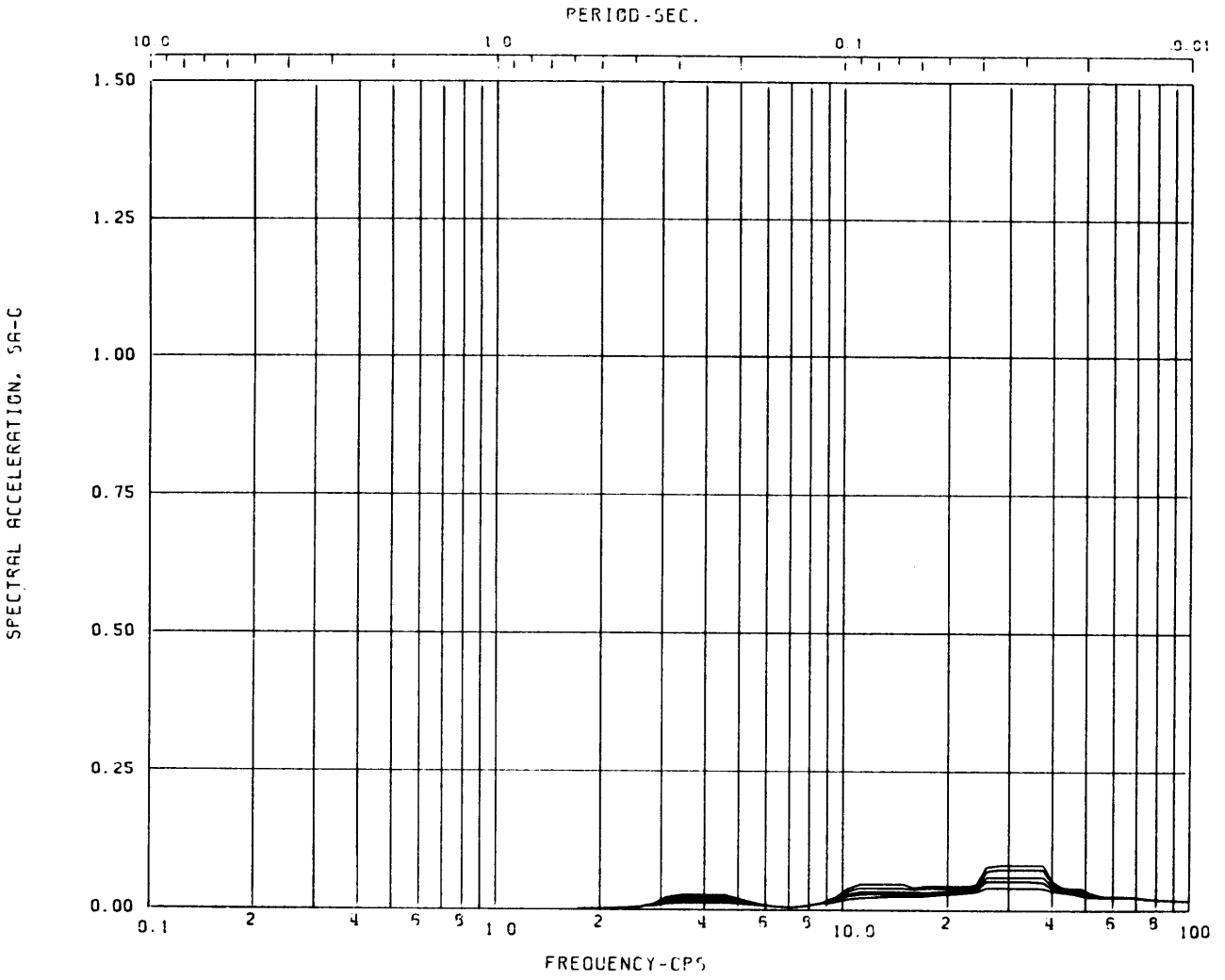
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 6 Direction: E-W HORIZ Elev: 269'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, E-W HORIZONTAL, SRV ASYMMETRIC
FIGURE 3A-186



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

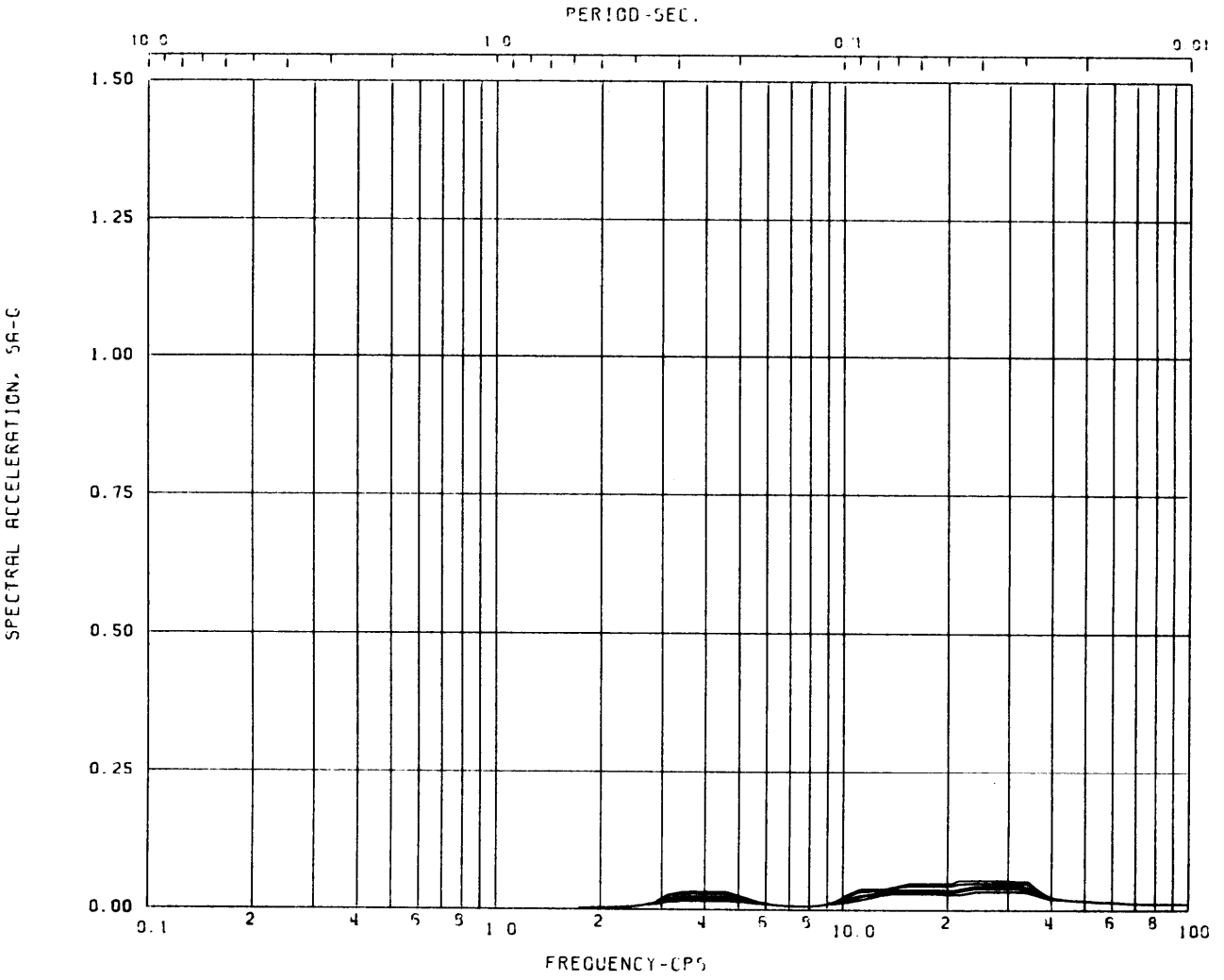
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 7 Direction: E-W HORIZ Elev: 283'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-187



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 8 Direction: E-W HORIZ Elev: 304'-0

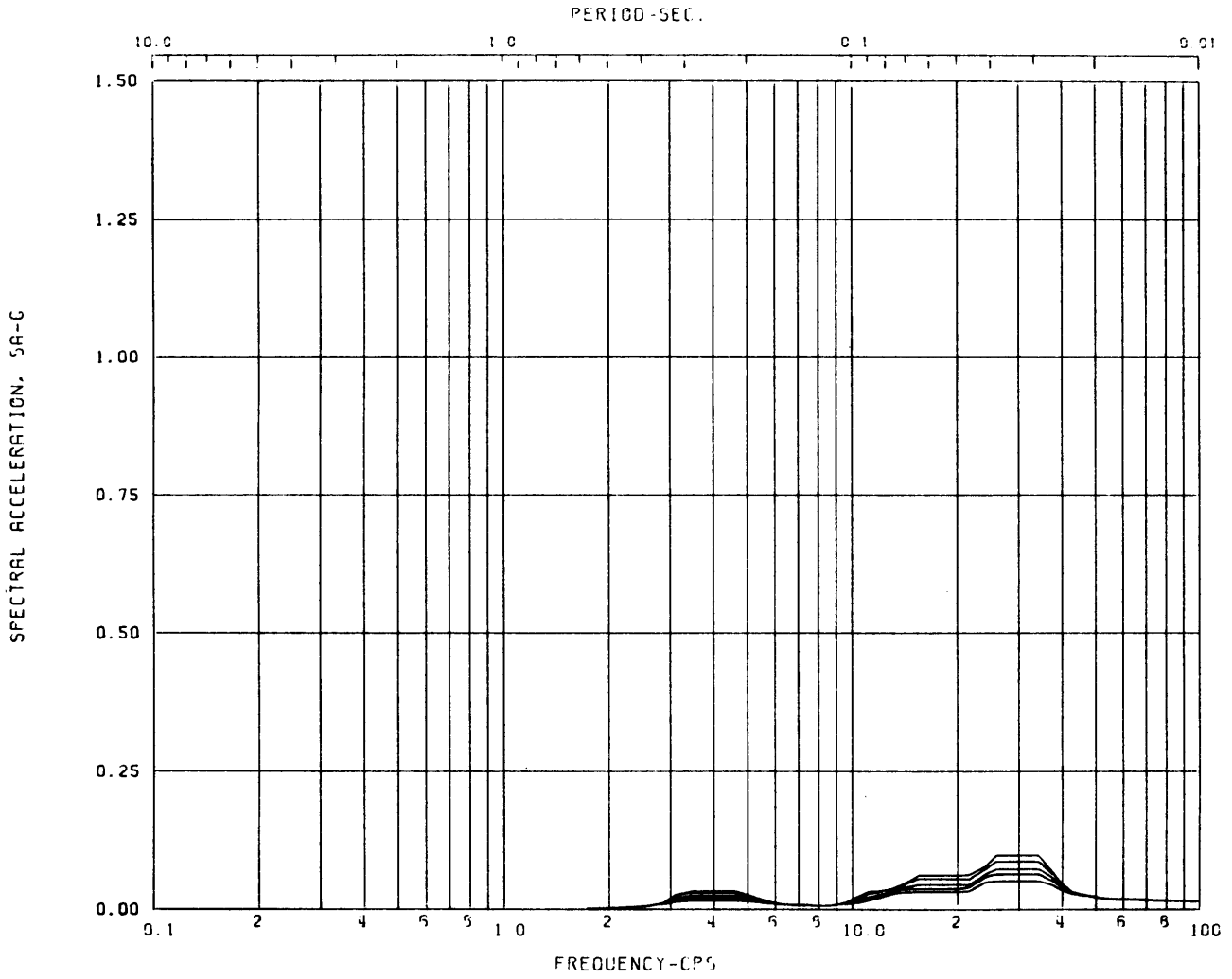
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-188



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

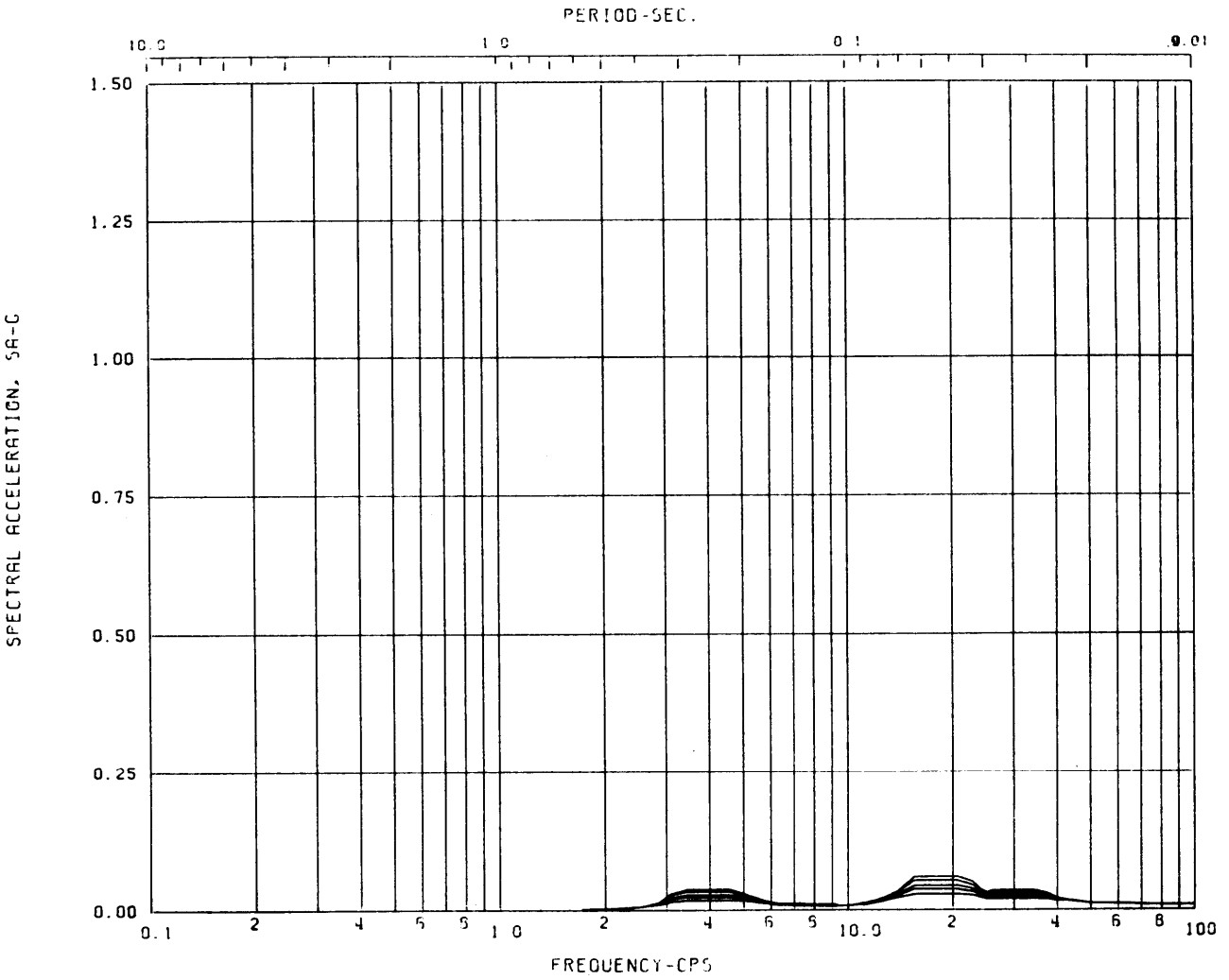
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 9 Direction: E-W HORIZ Elev: 313'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-189



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 10 Direction: E-W HORIZ Elev: 332'-0

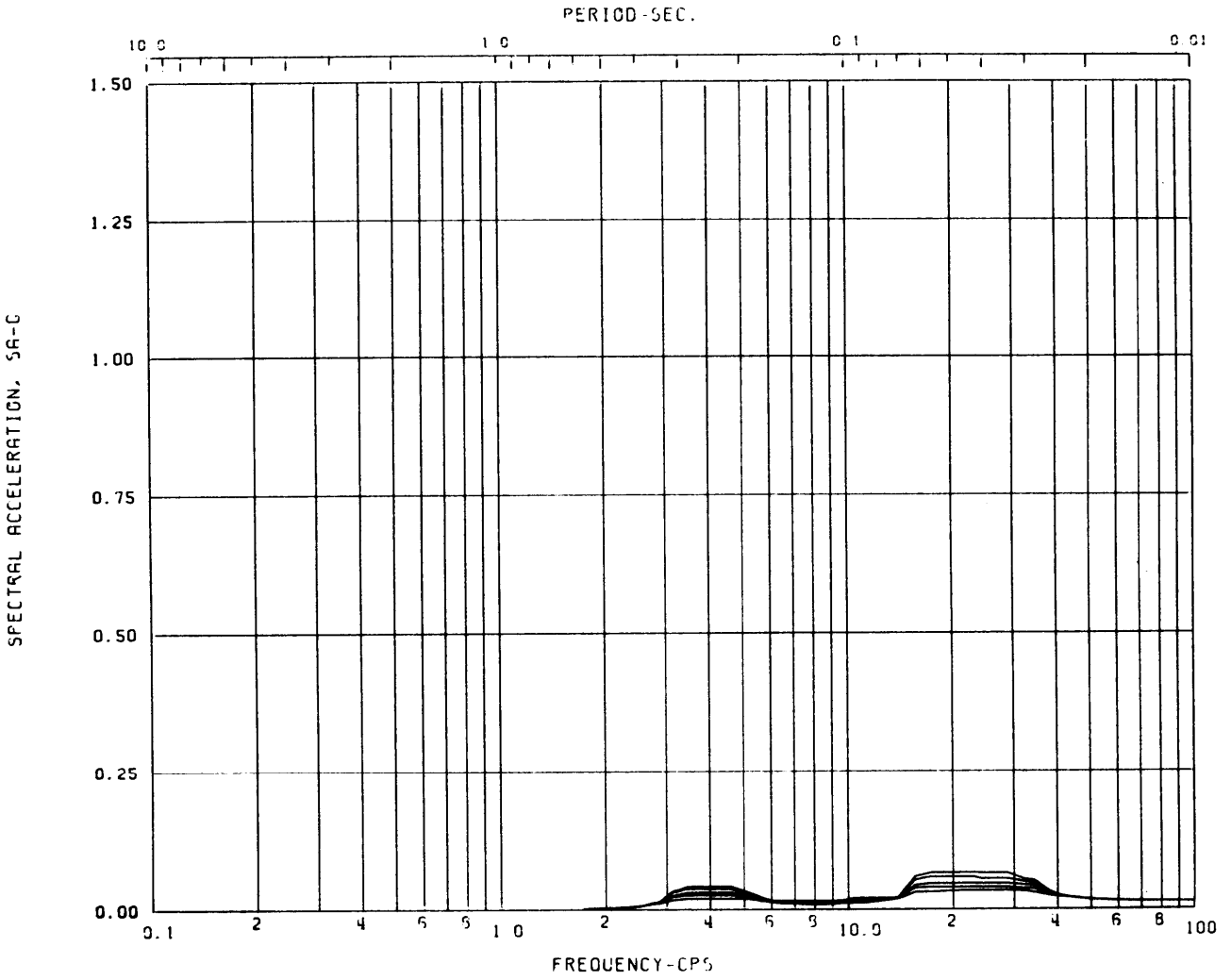
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-190



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

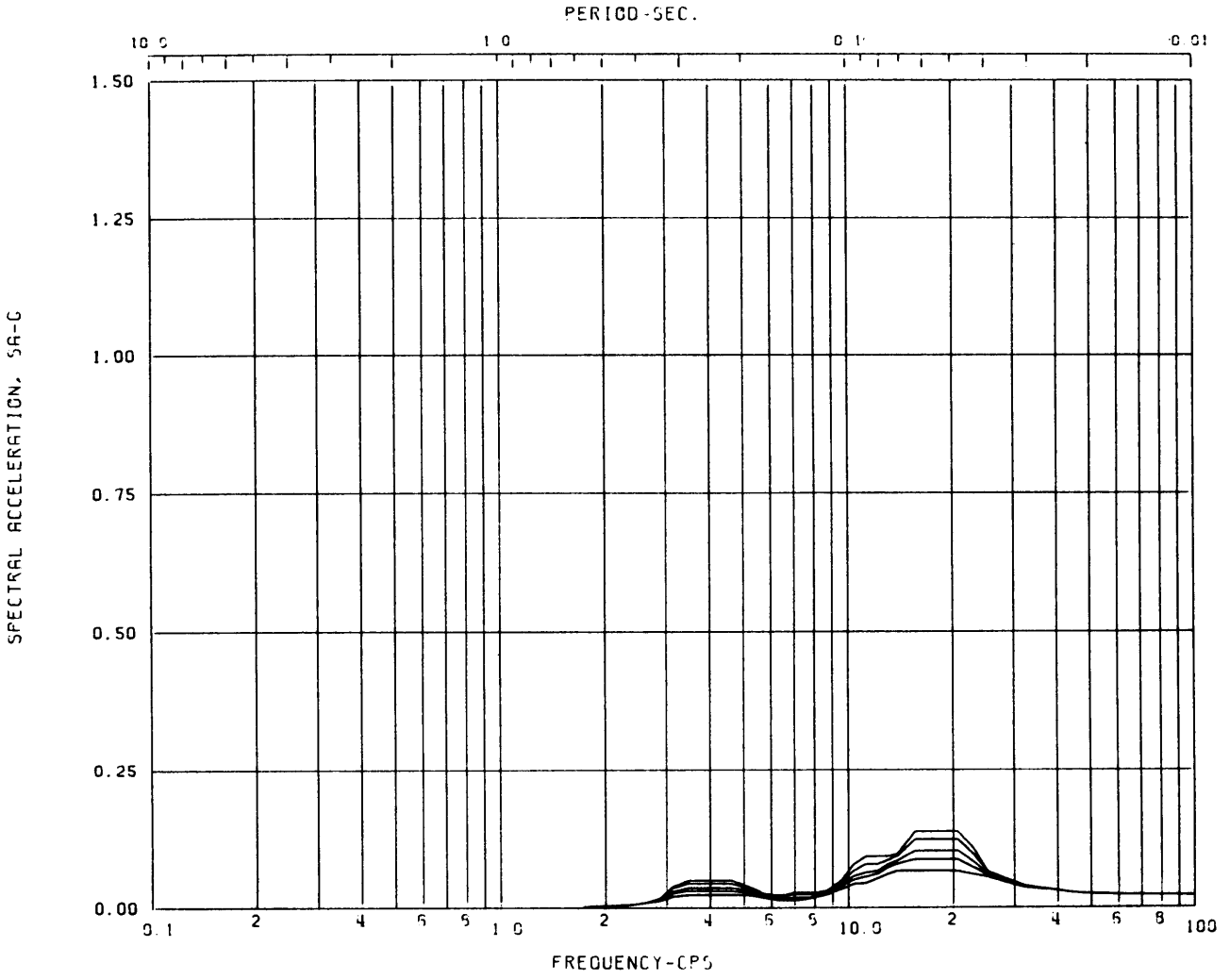
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 11 Direction: E-W HORIZ Elev: 352'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-191



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

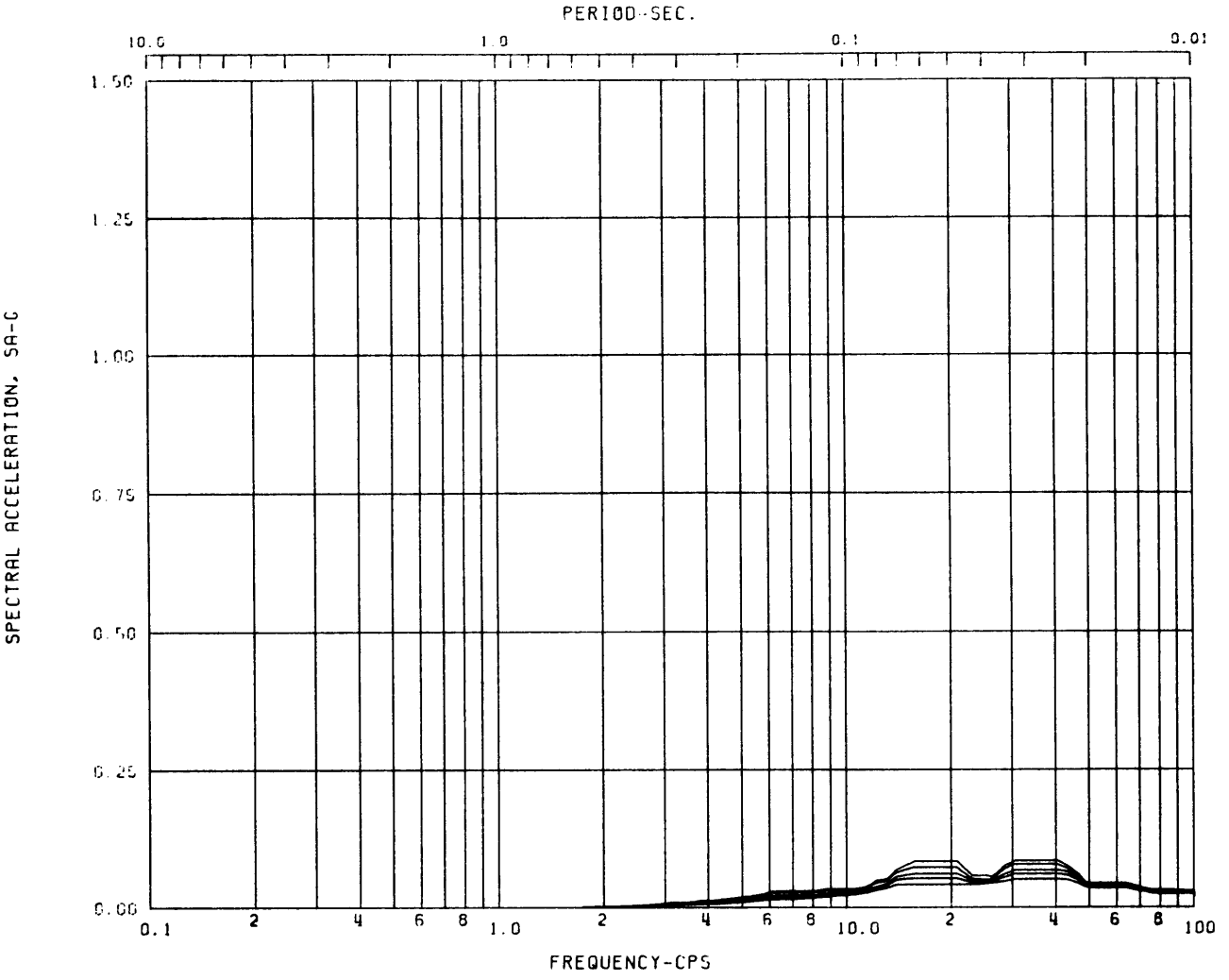
Load Case: KWU SRV ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 12 Direction: E-W HORIZ Elev: 410'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-192



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

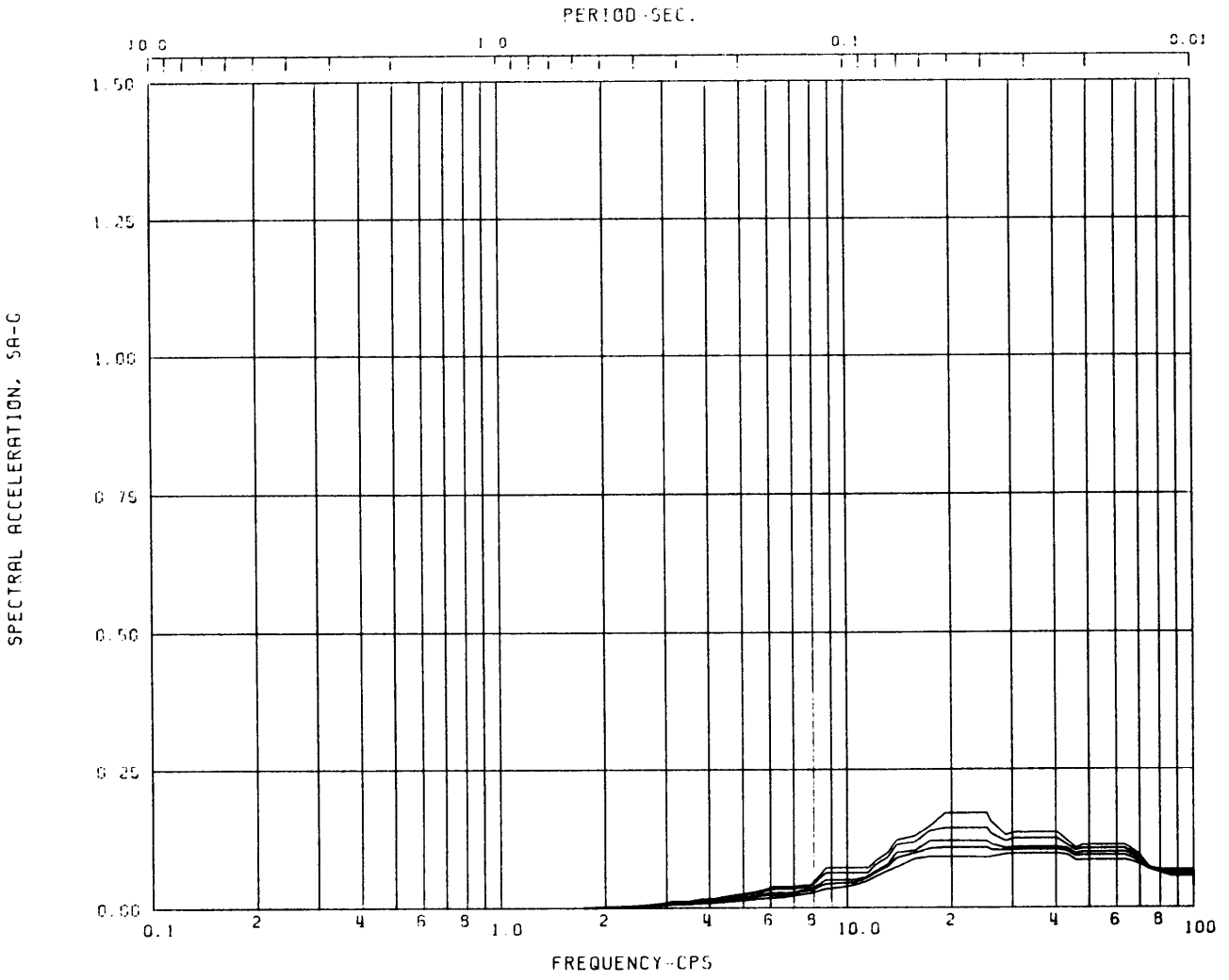
Node: 159 Direction: VERTICAL Elev: 177'

Damping: 0.005,0.01,0.02,0.03,0.05

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GLOBAL RESPONSE SPECTRA
VERTICAL,SRV AXISYMMETRIC

FIGURE 3A-193



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 154 Direction: VERTICAL Elev: 177'

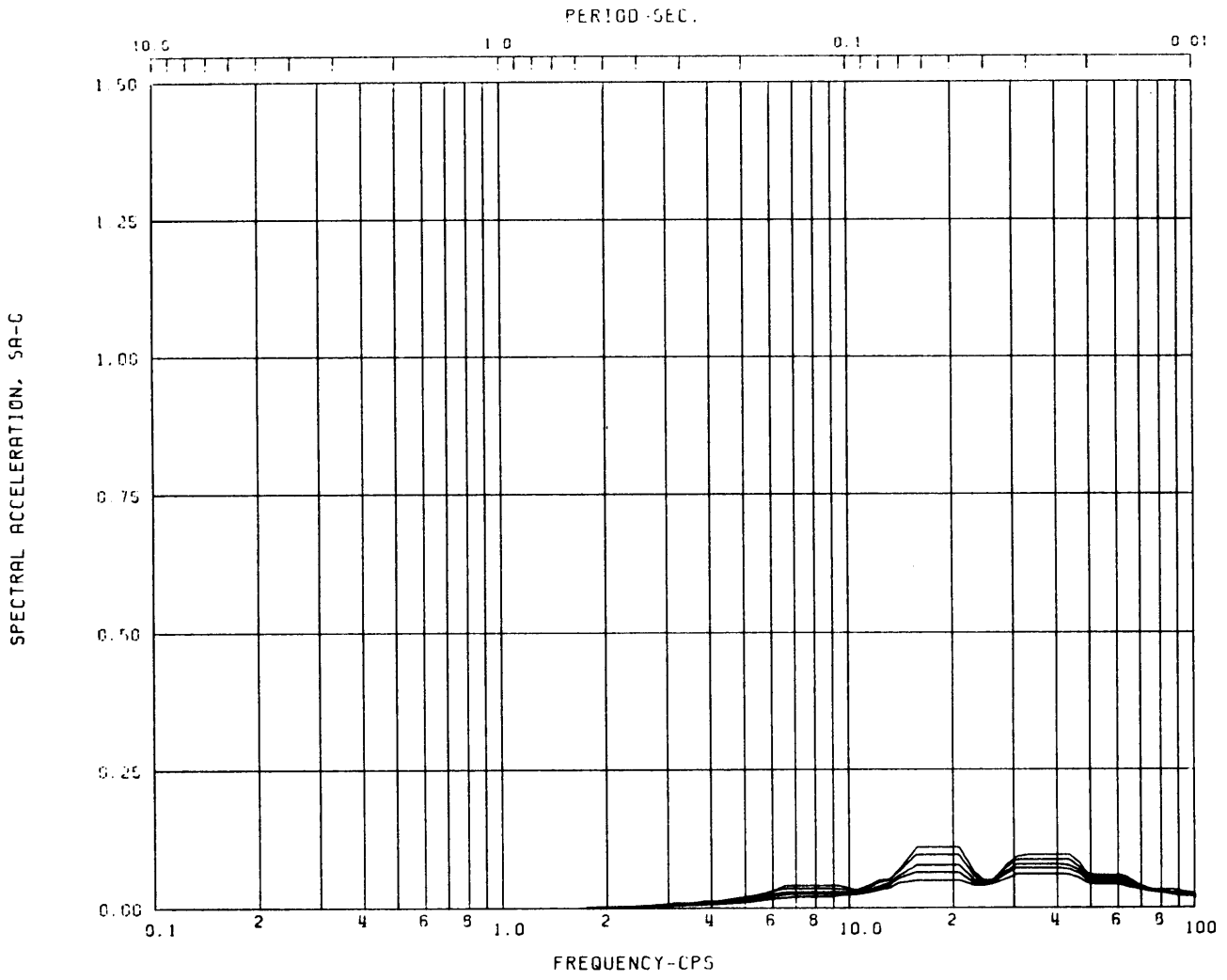
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE
GLOBAL RESPONSE SPECTRA
VERTICAL,SRV AXISYMMETRIC

FIGURE 3A-194



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 128 Direction: VERTICAL Elev: 201'

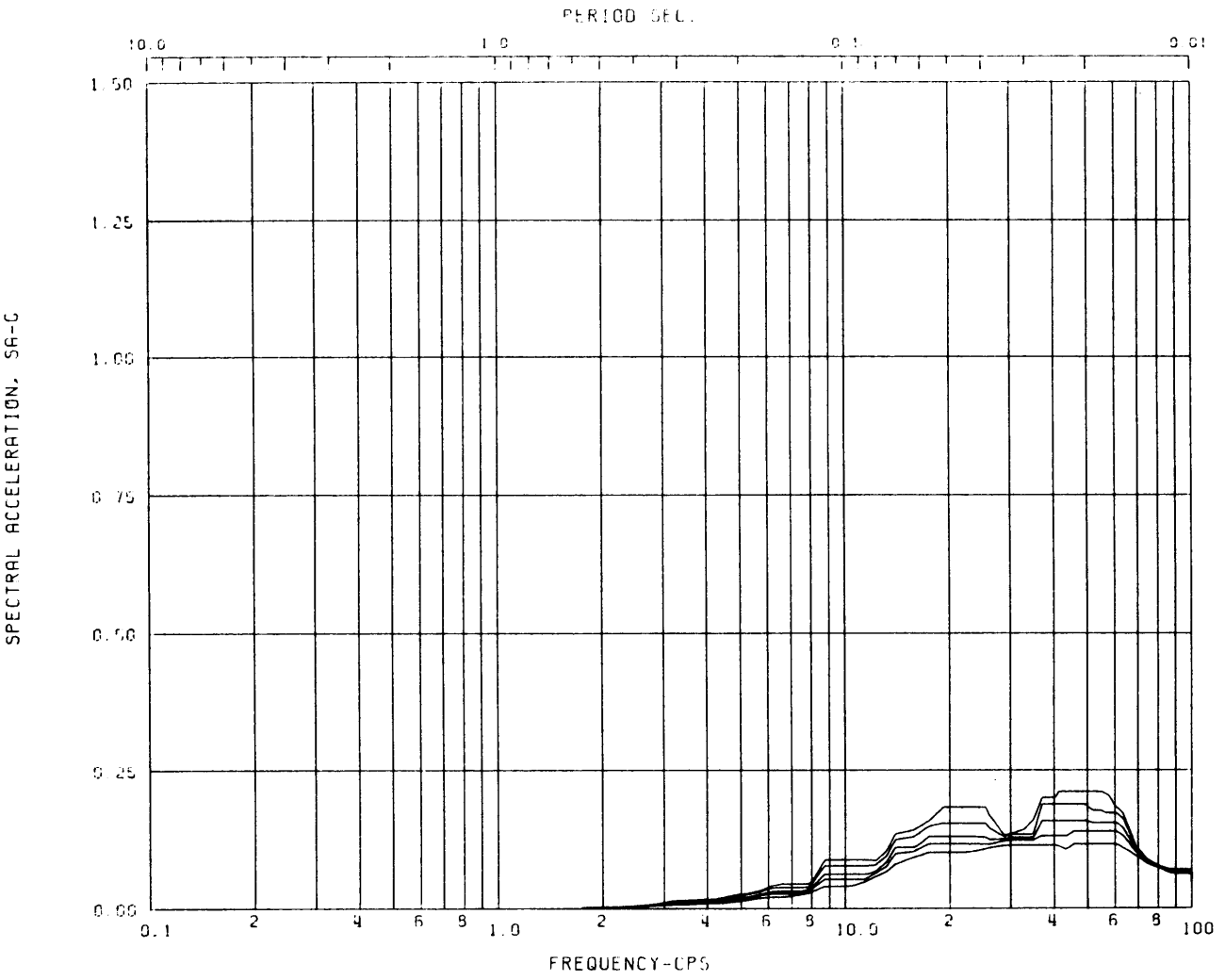
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE
GLOBAL RESPONSE SPECTRA
VERTICAL,SRV AXISYMMETRIC

FIGURE 3A-195



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 130 Direction: VERTICAL Elev: 201'

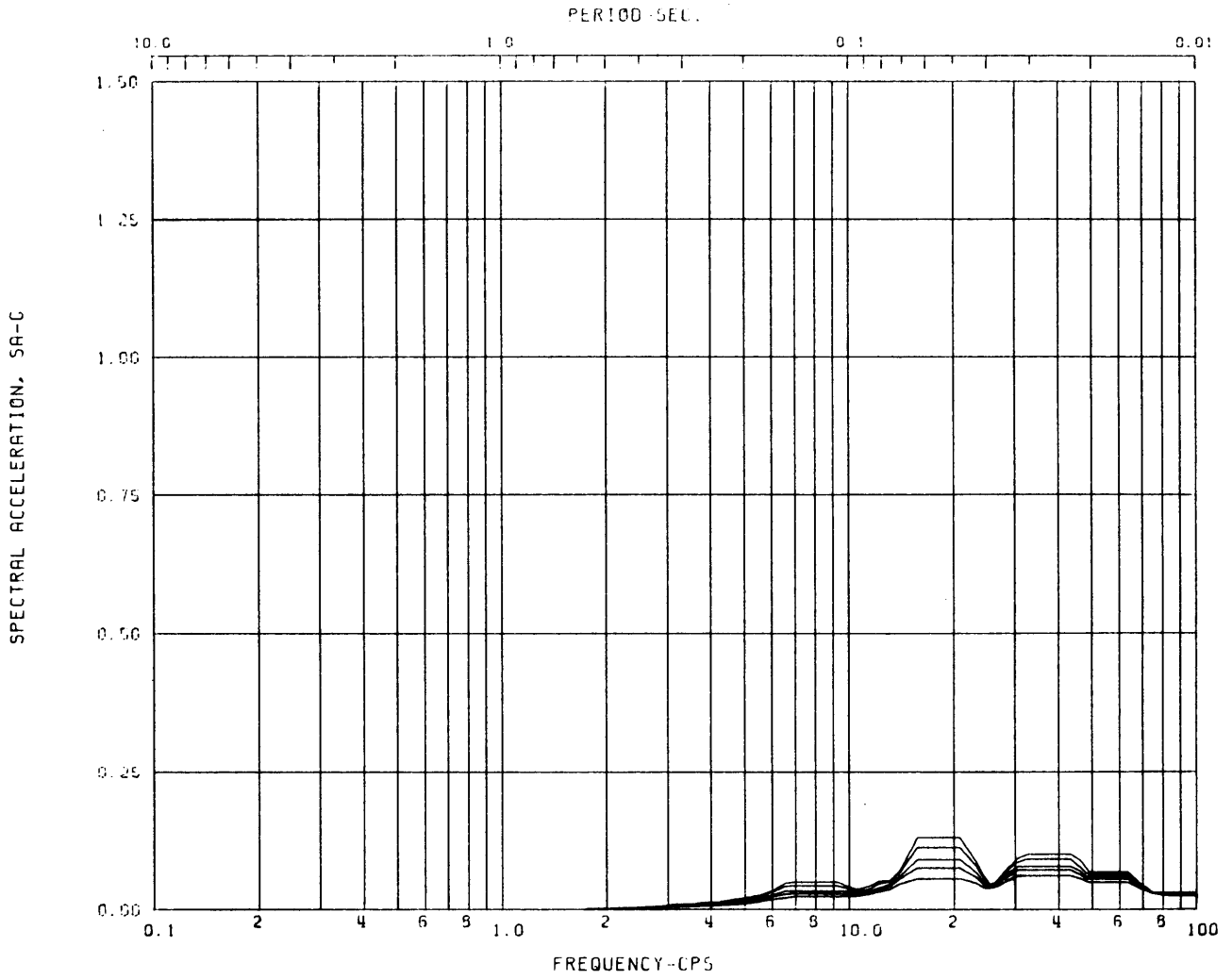
Damping: 0.005,0.01,0.02,0.03,0.05

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VERTICAL,SRV AXISYMMETRIC

FIGURE 3A-196



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

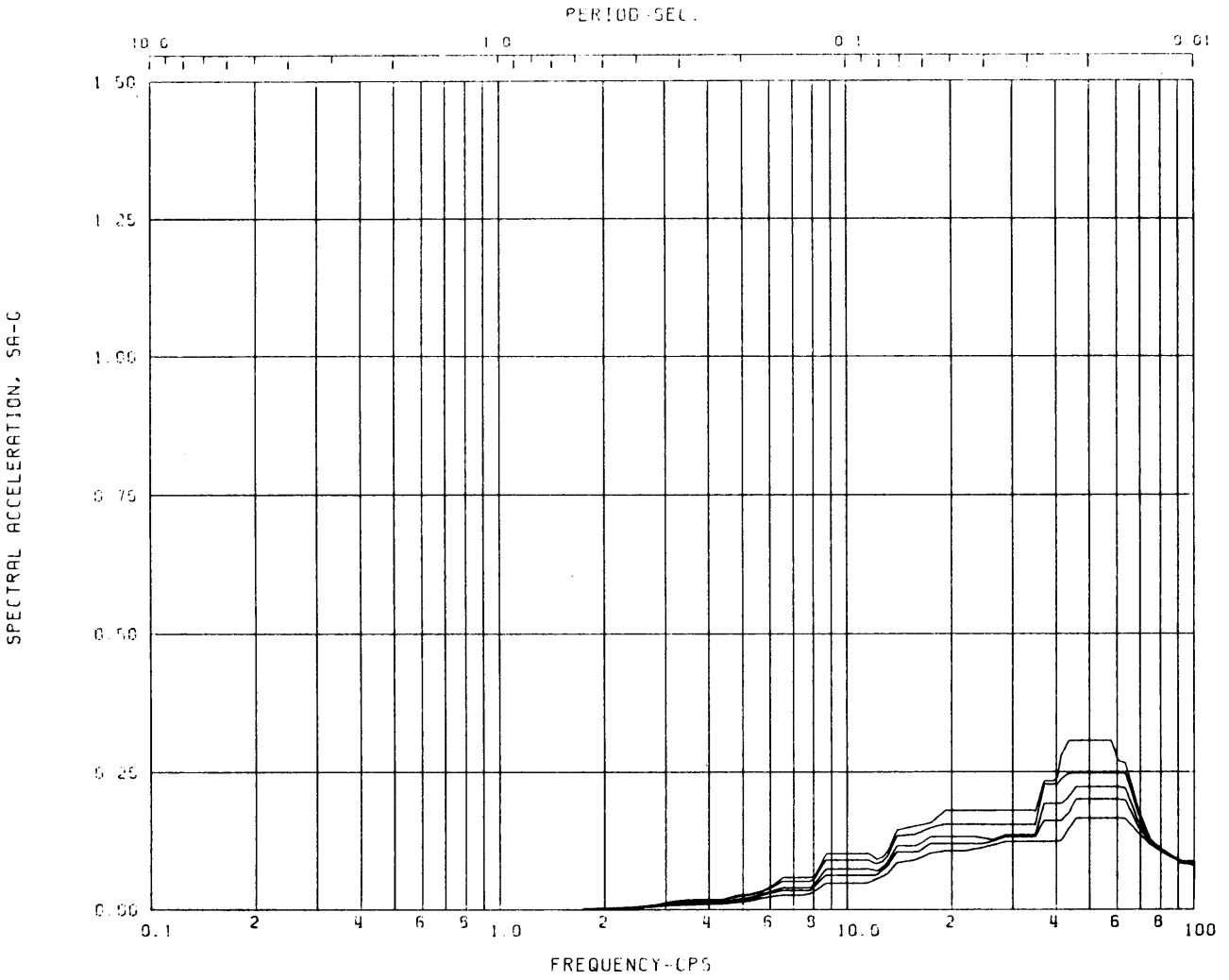
Node: 106 Direction: VERTICAL Elev: 217'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-197



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 108 Direction: VERTICAL Elev: 217'

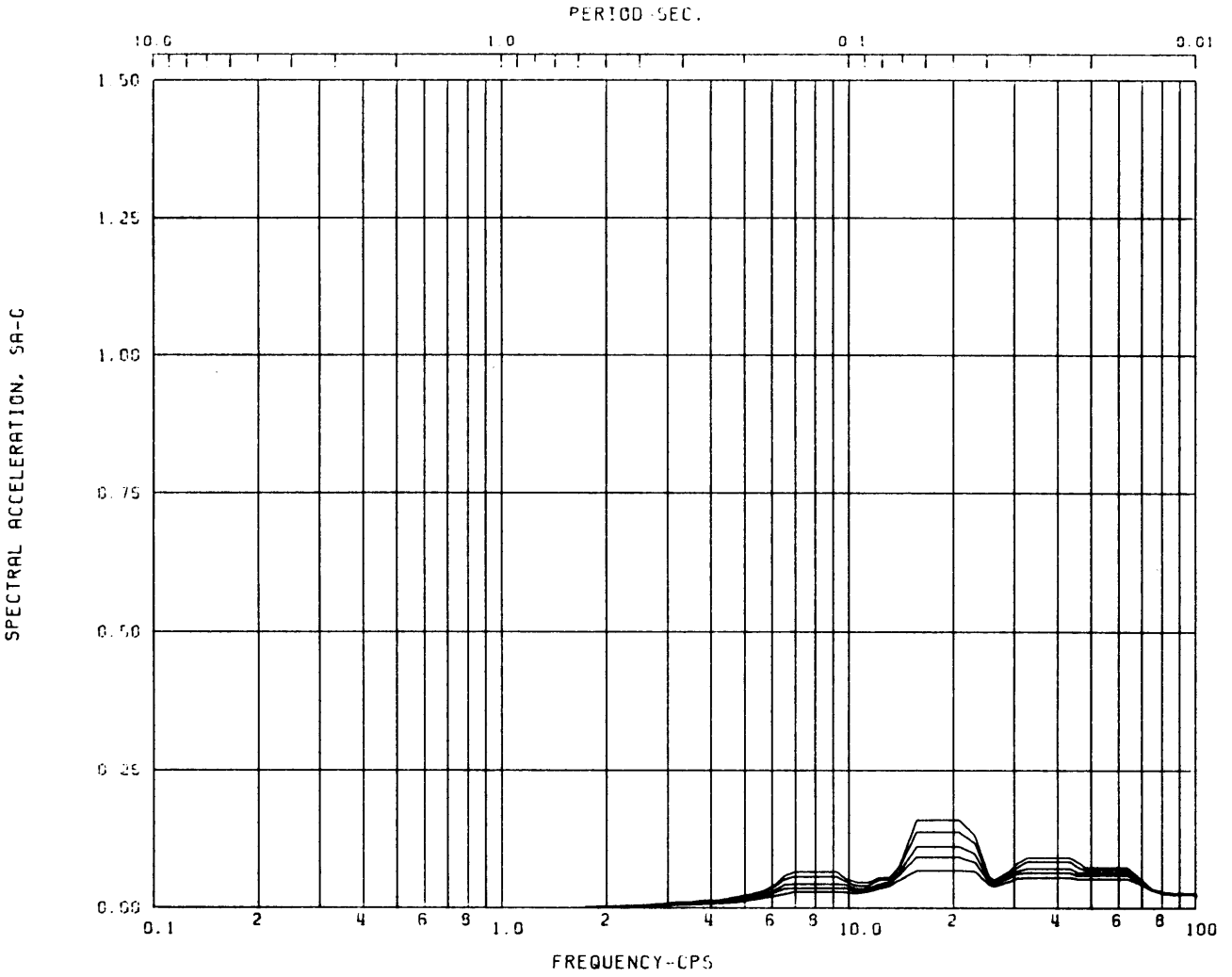
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-198



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 104 Direction: VERTICAL Elev: 239'

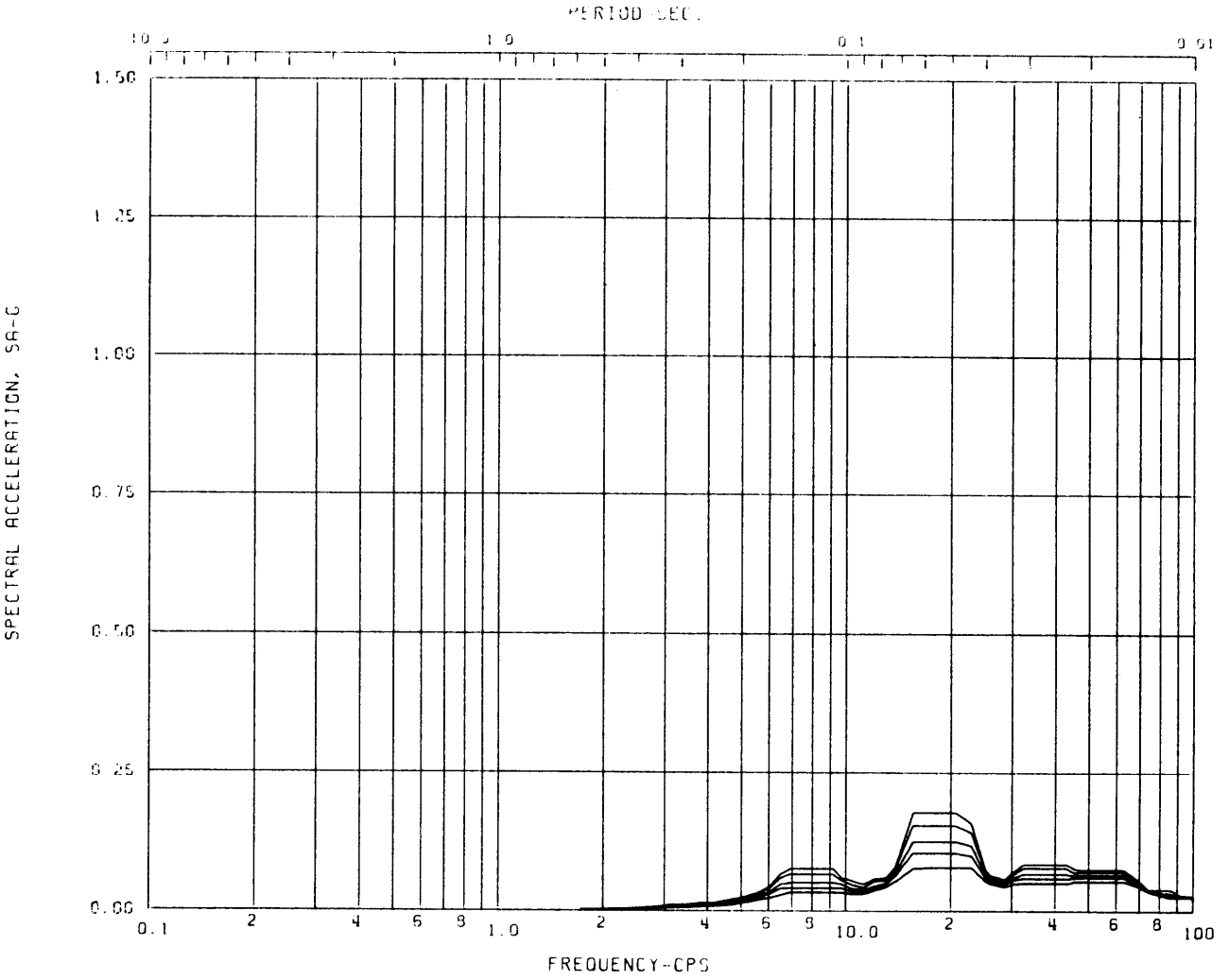
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-199



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 79 Direction: VERTICAL Elev: 253'

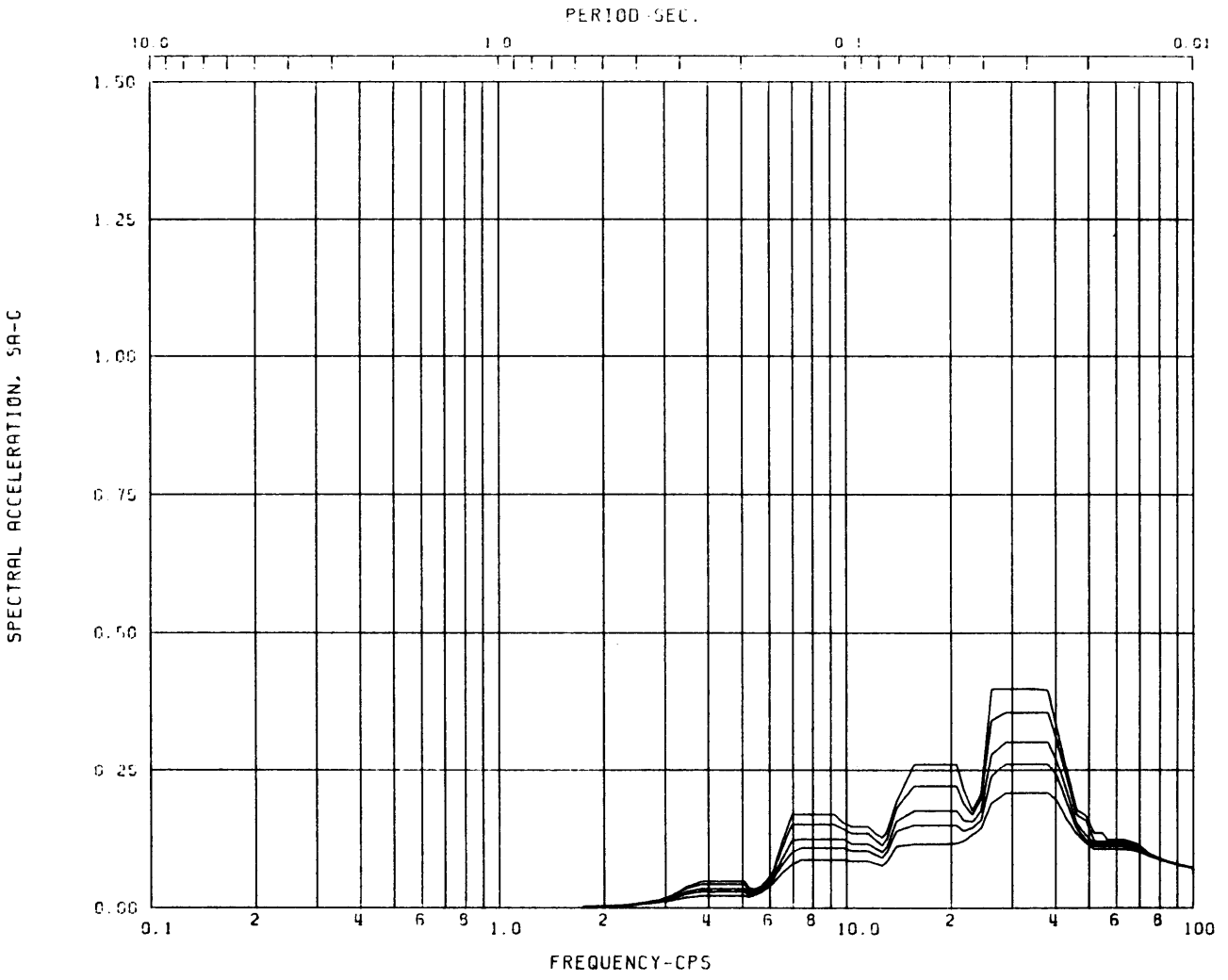
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-200



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 81 Direction: VERTICAL Elev: 253'

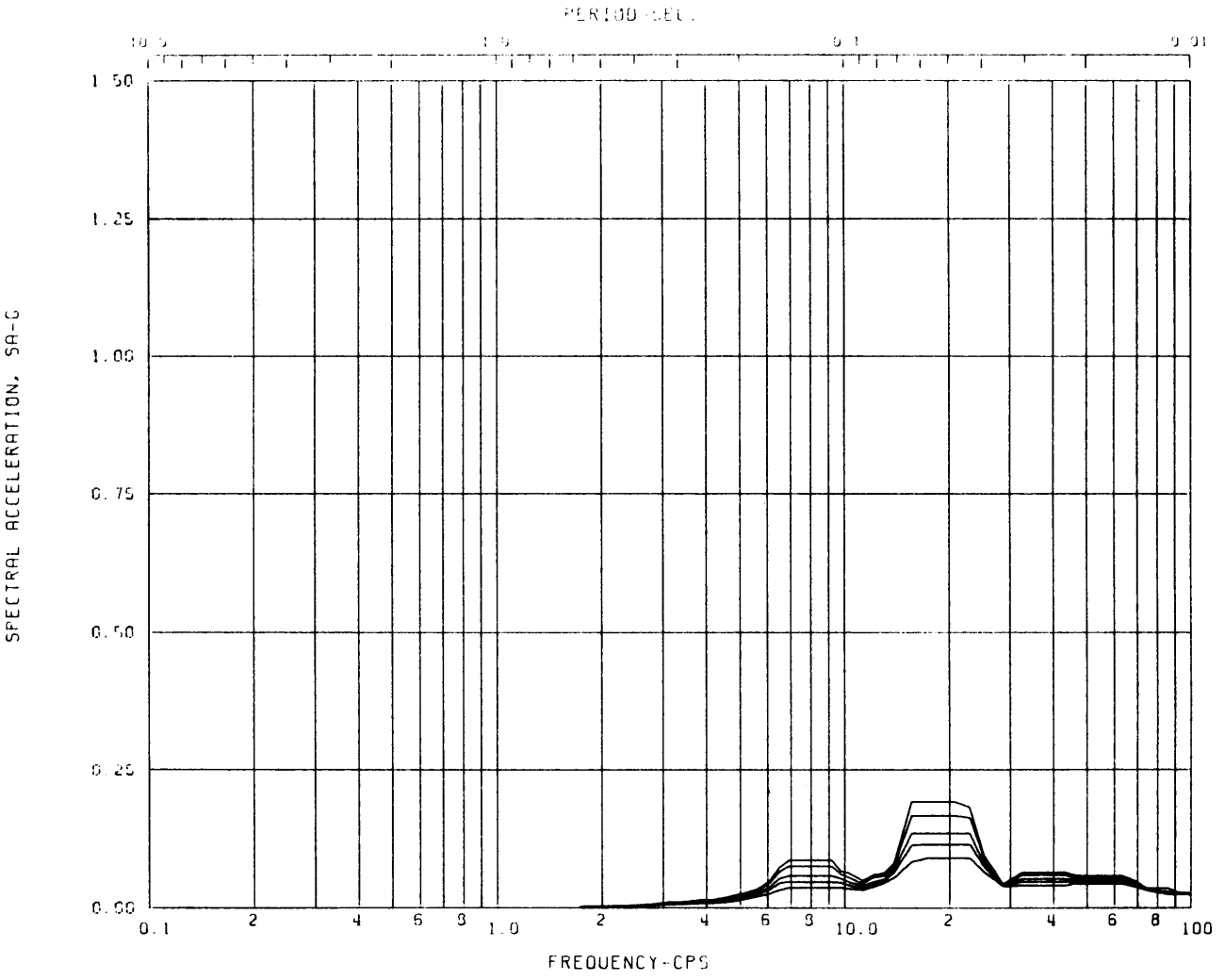
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-201



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 77 Direction: VERTICAL Elev: 269'

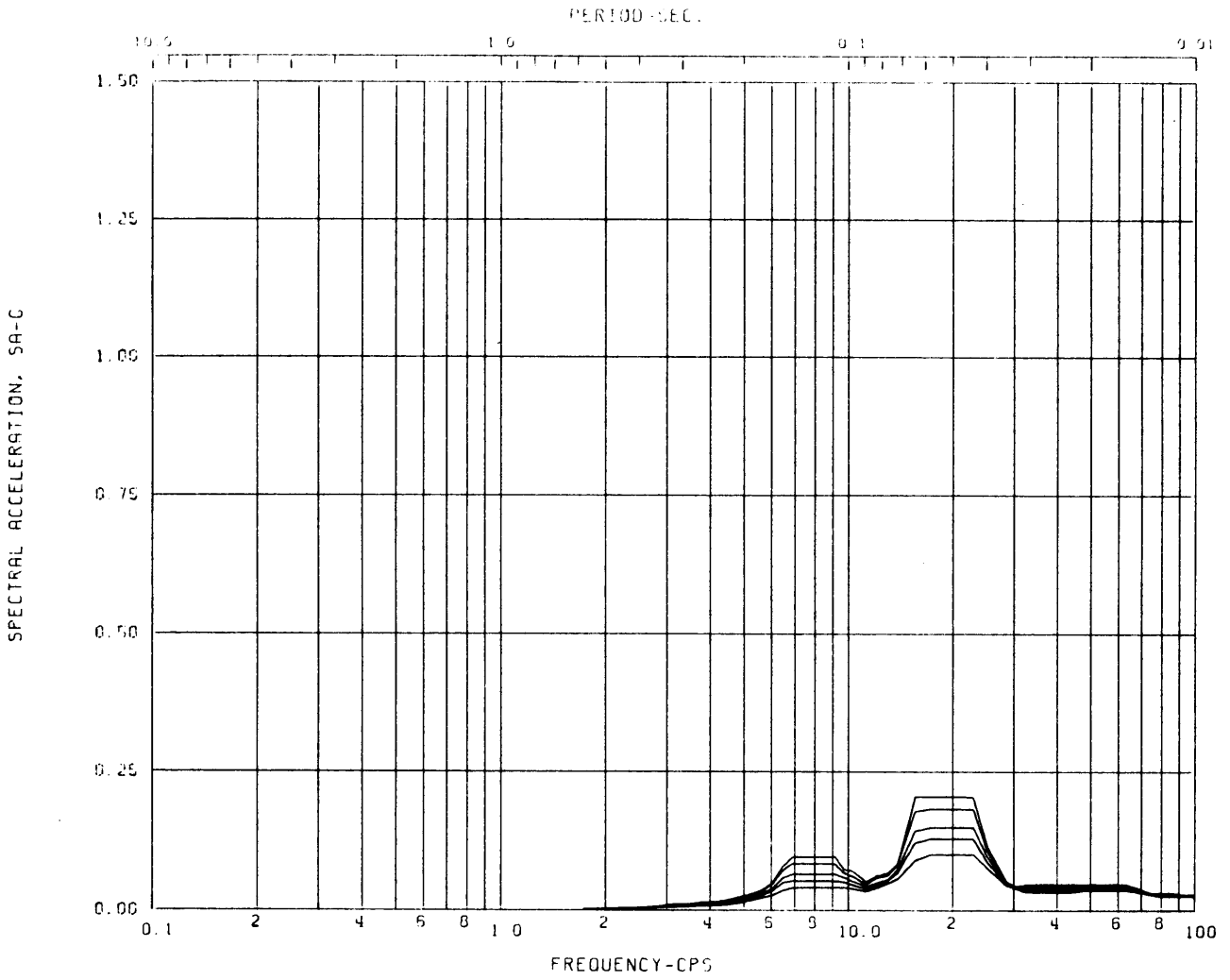
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-202



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

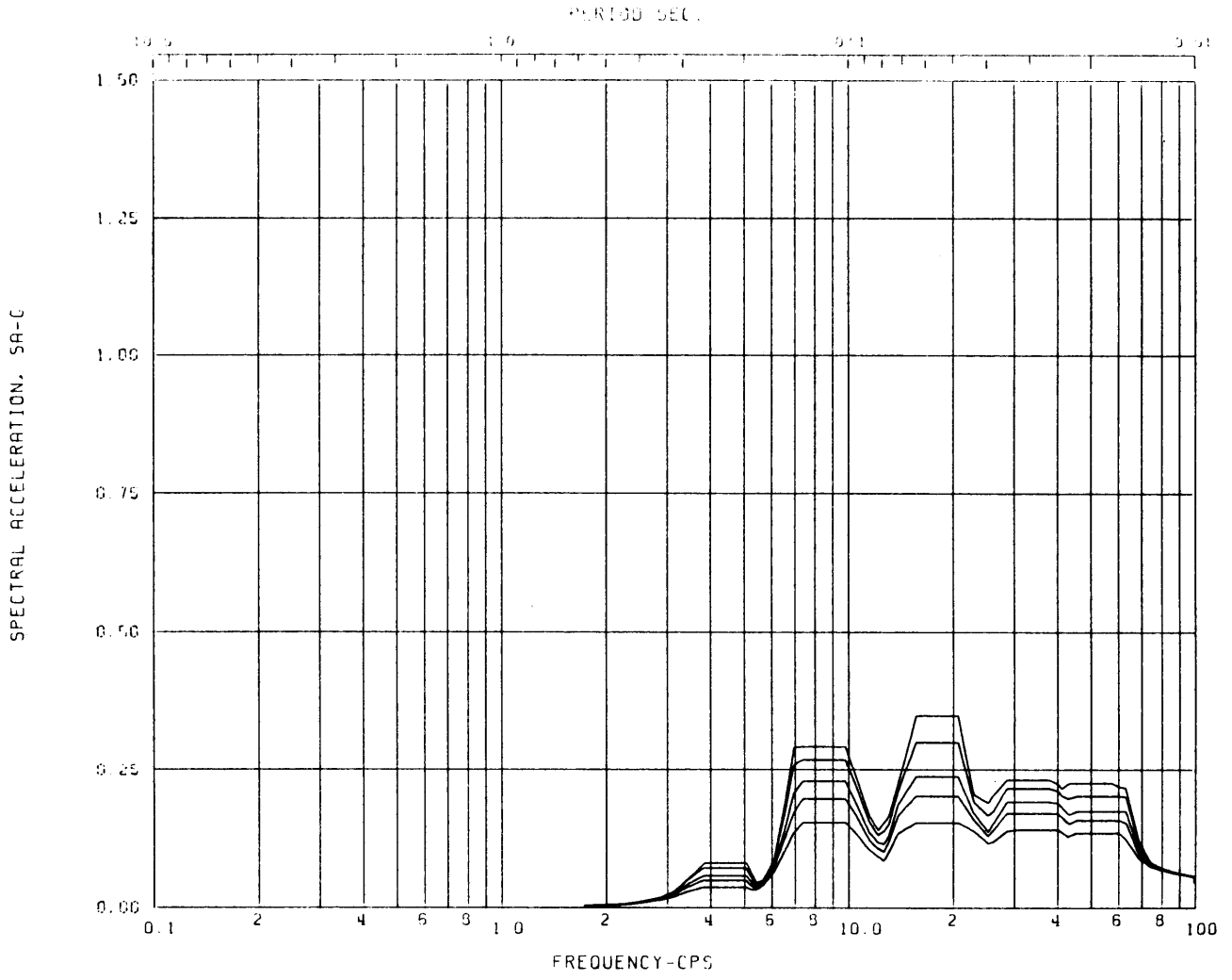
Node: 58 Direction: VERTICAL Elev: 283'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-203



Acceleration Spectra for REACTOR ENCL..

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

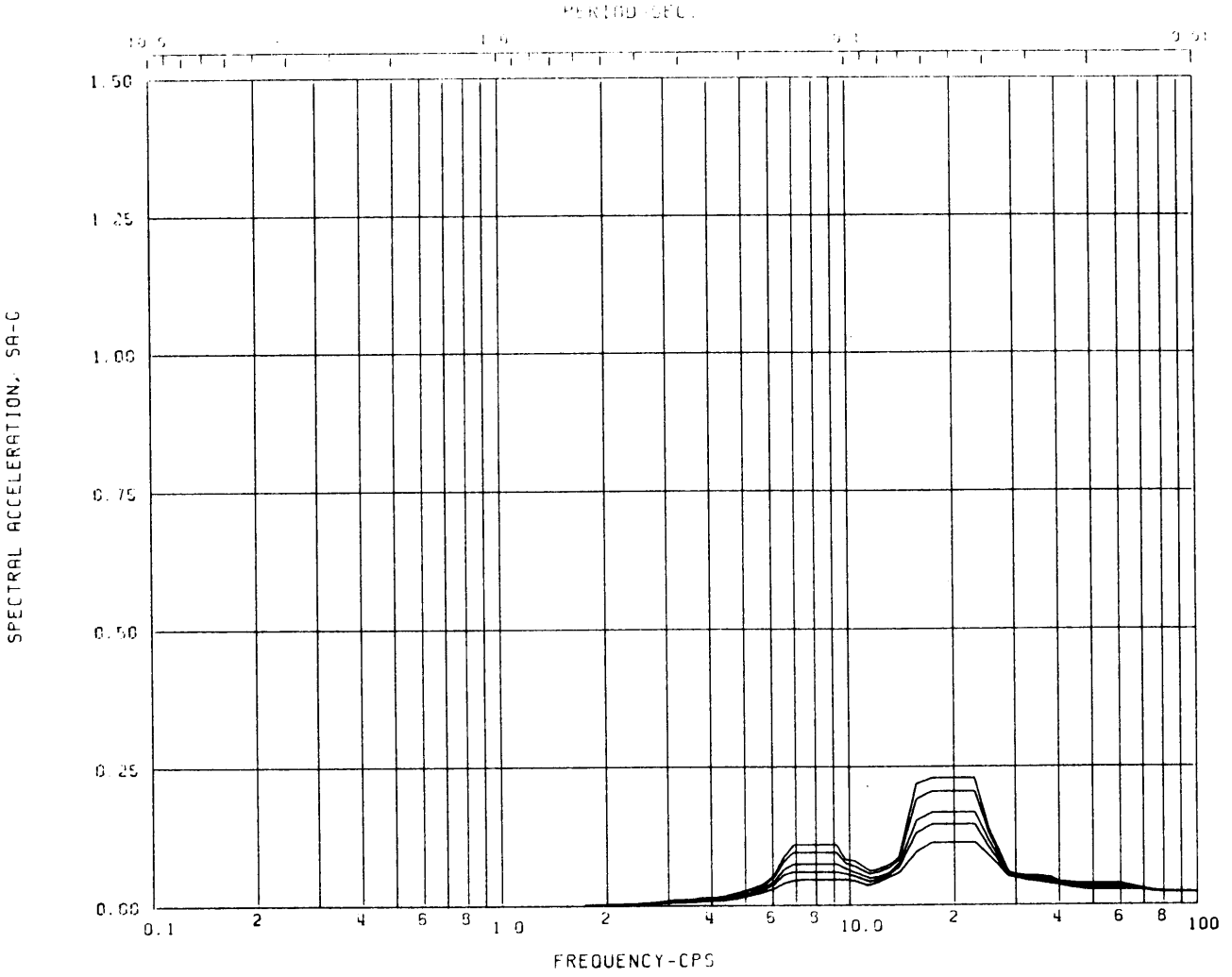
Node: 60 Direction: VERTICAL Elev: 283'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-204



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

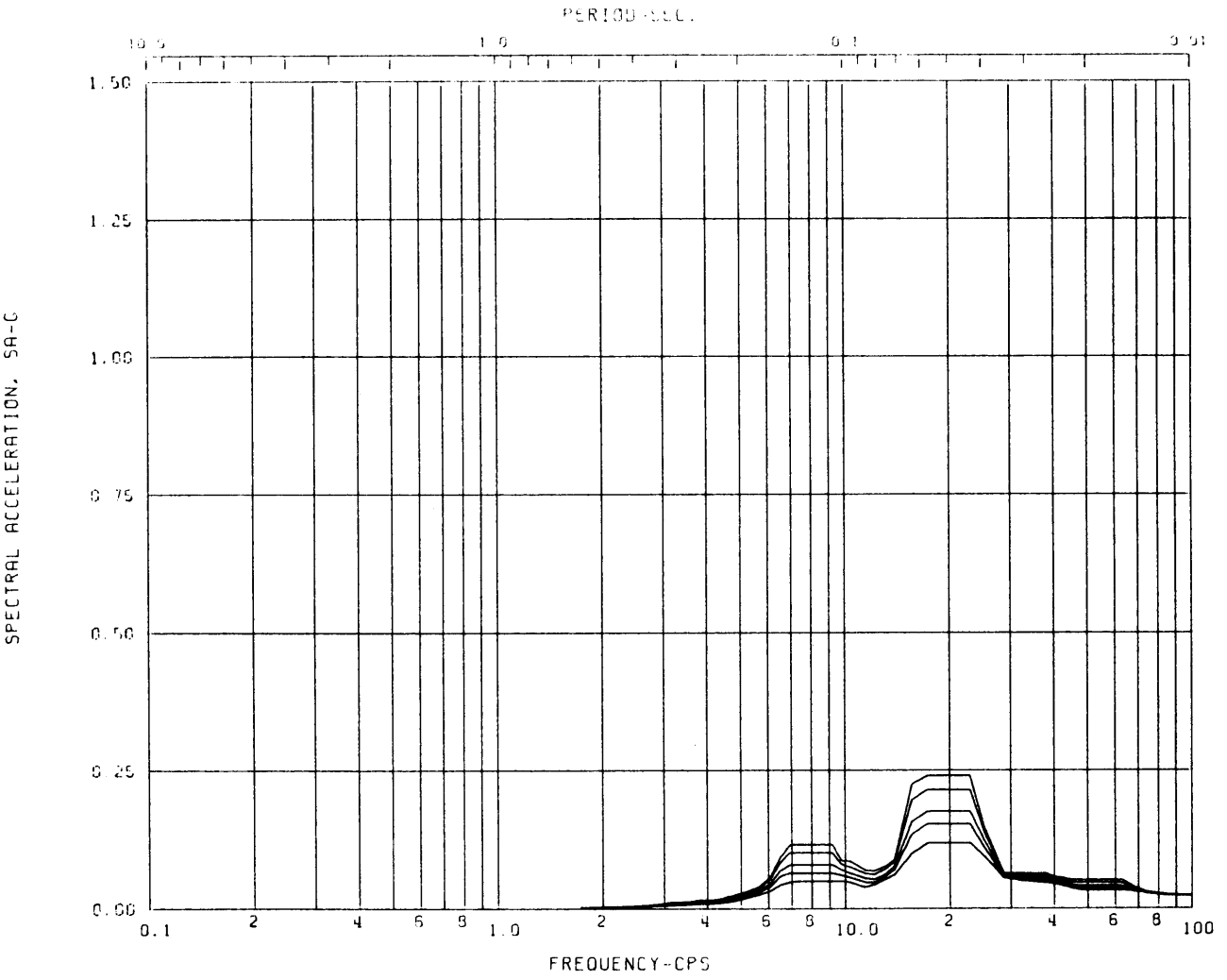
Node: 56 Direction: VERTICAL Elev: 304'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-205



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

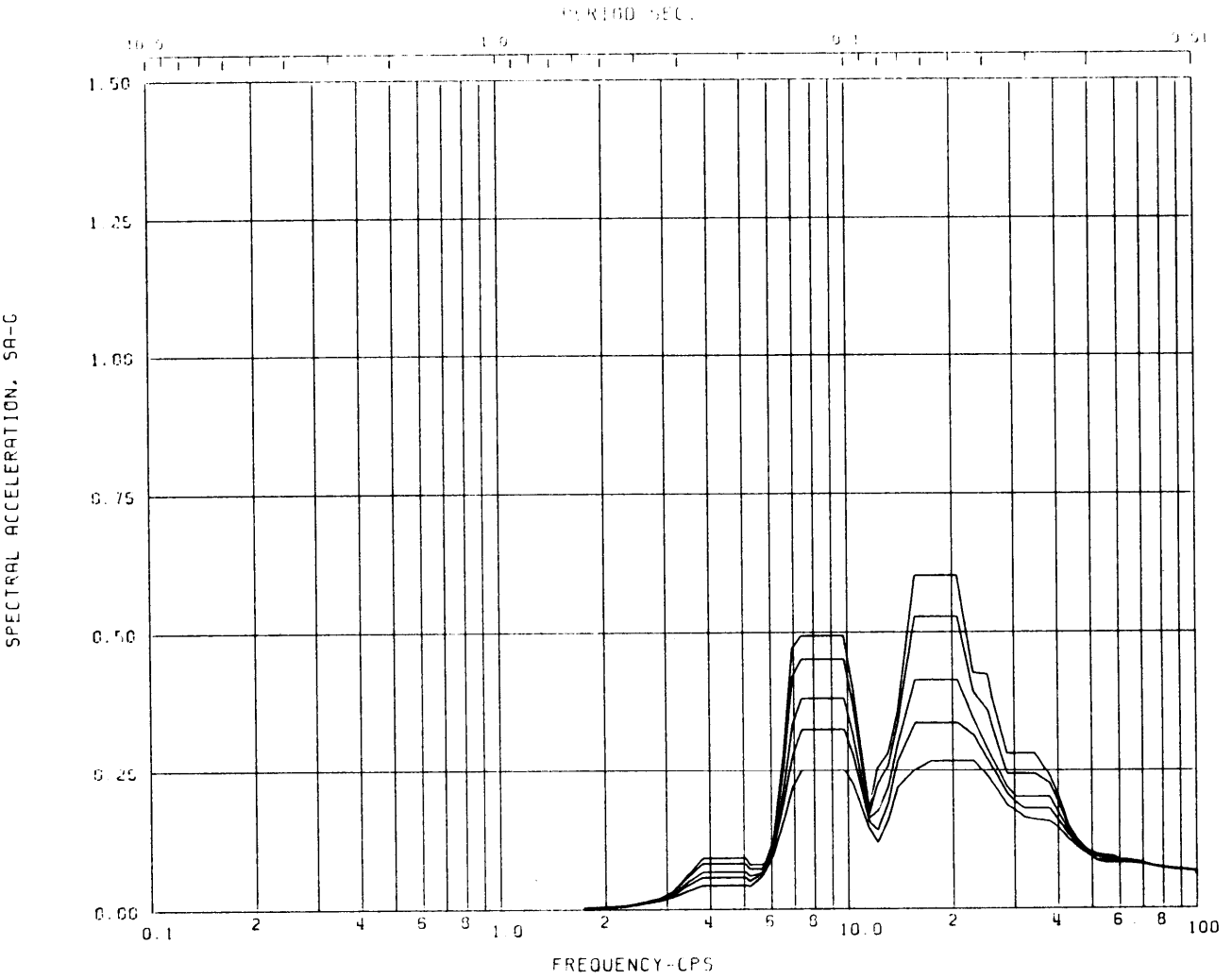
Node: 35 Direction: VERTICAL Elev: 313'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-206



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

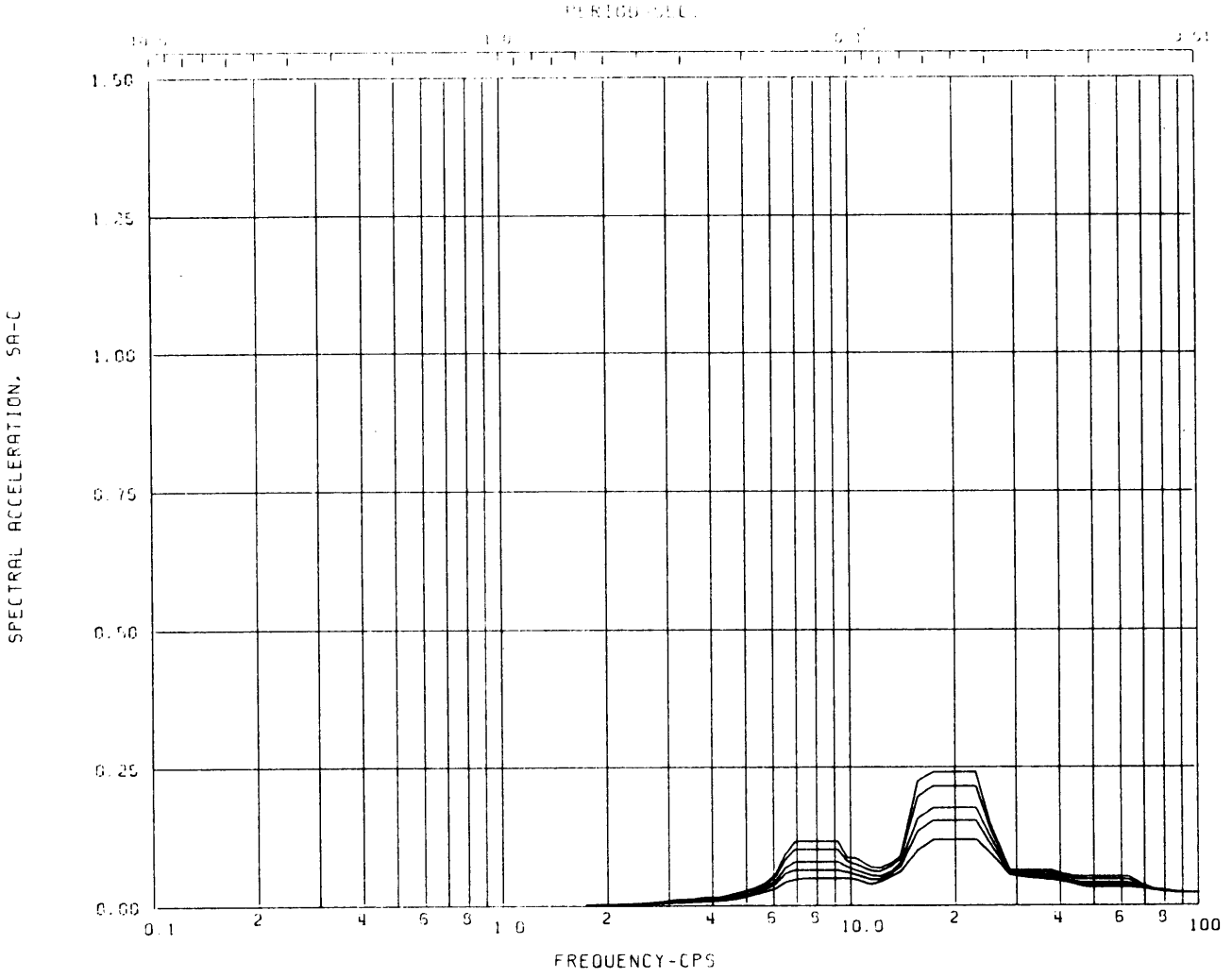
Node: 43 Direction: VERTICAL Elev: 313'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-207



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

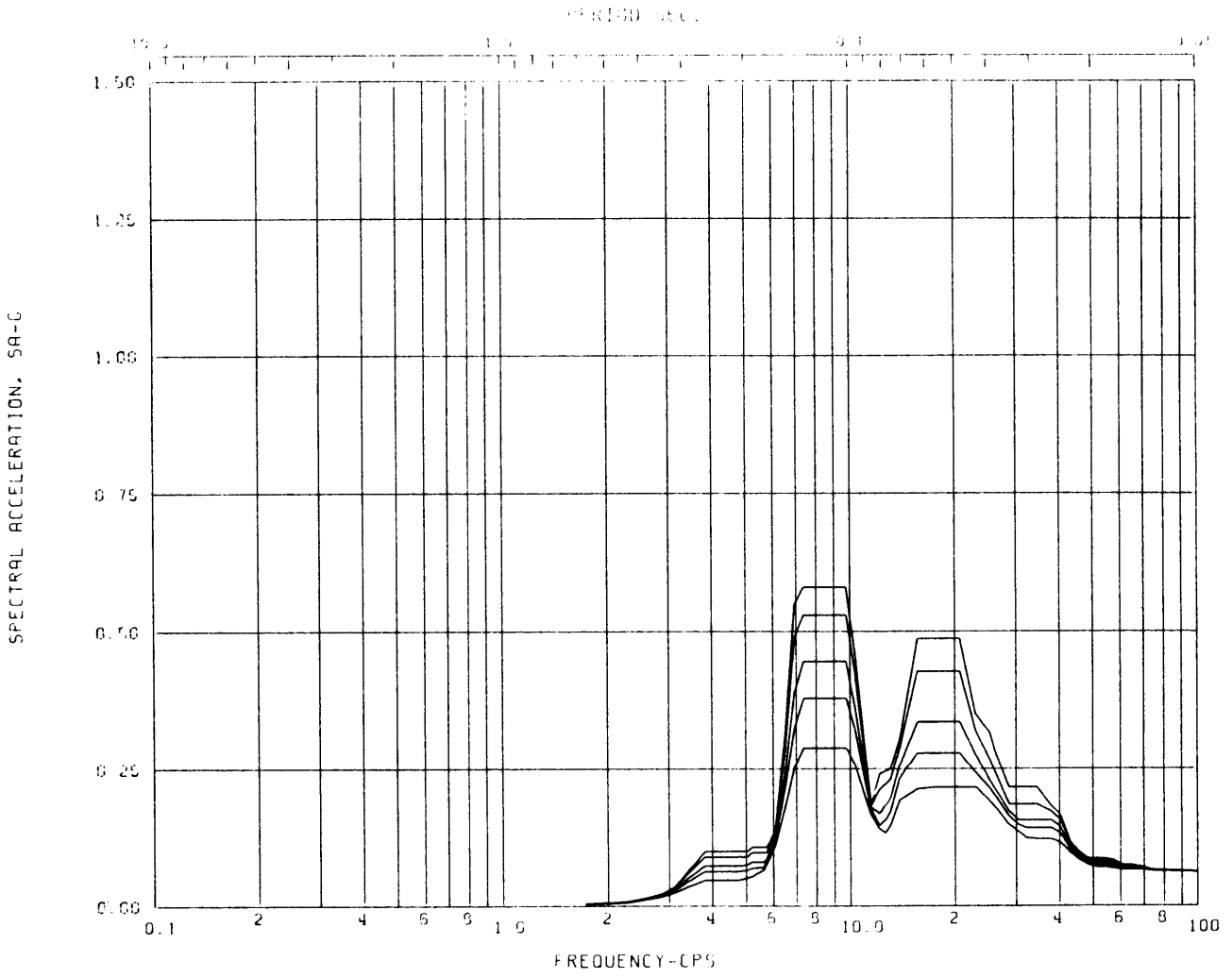
Node: 21 Direction: VERTICAL Elev: 333'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-208



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

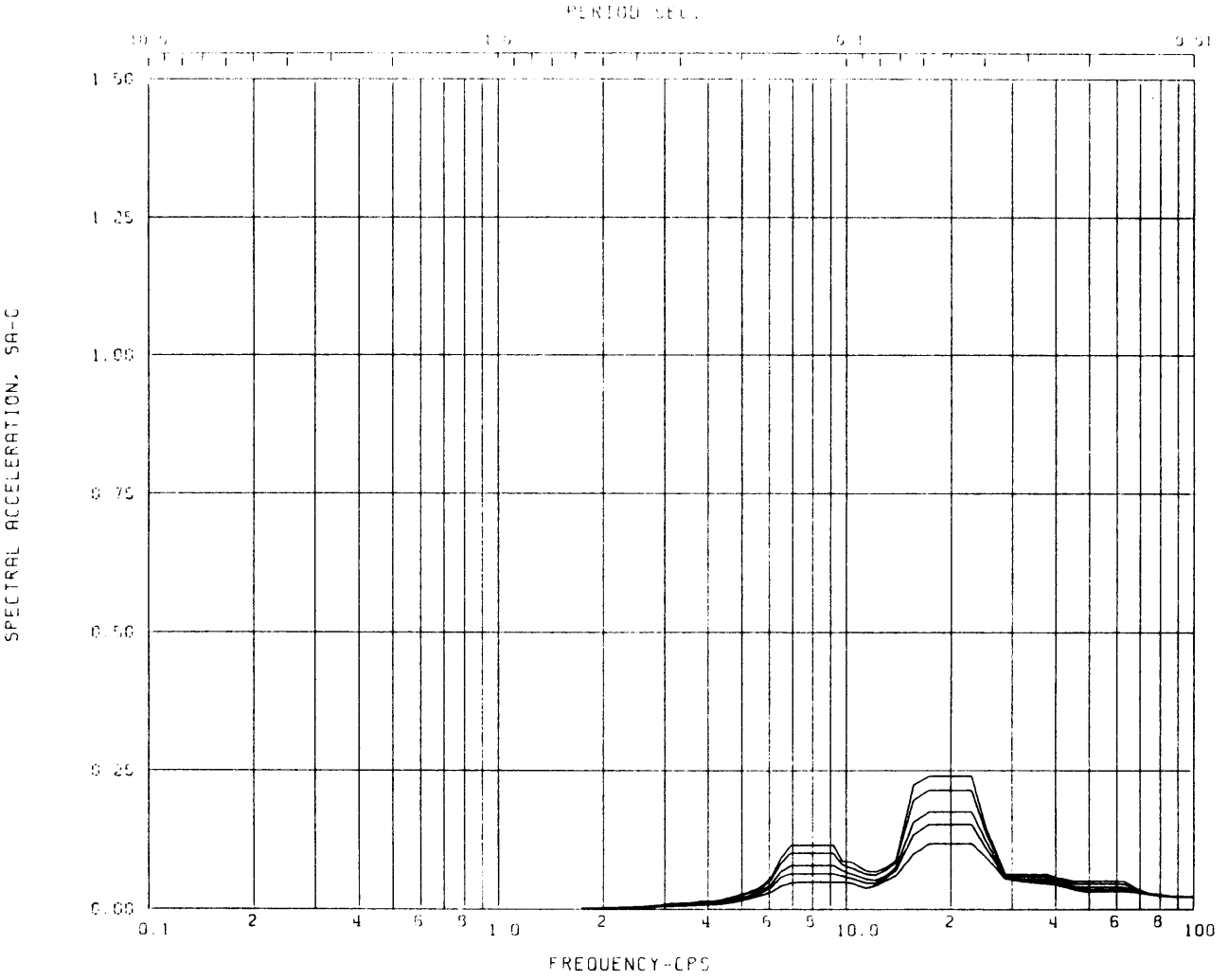
Node: 33 Direction: VERTICAL Elev: 333'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-209



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

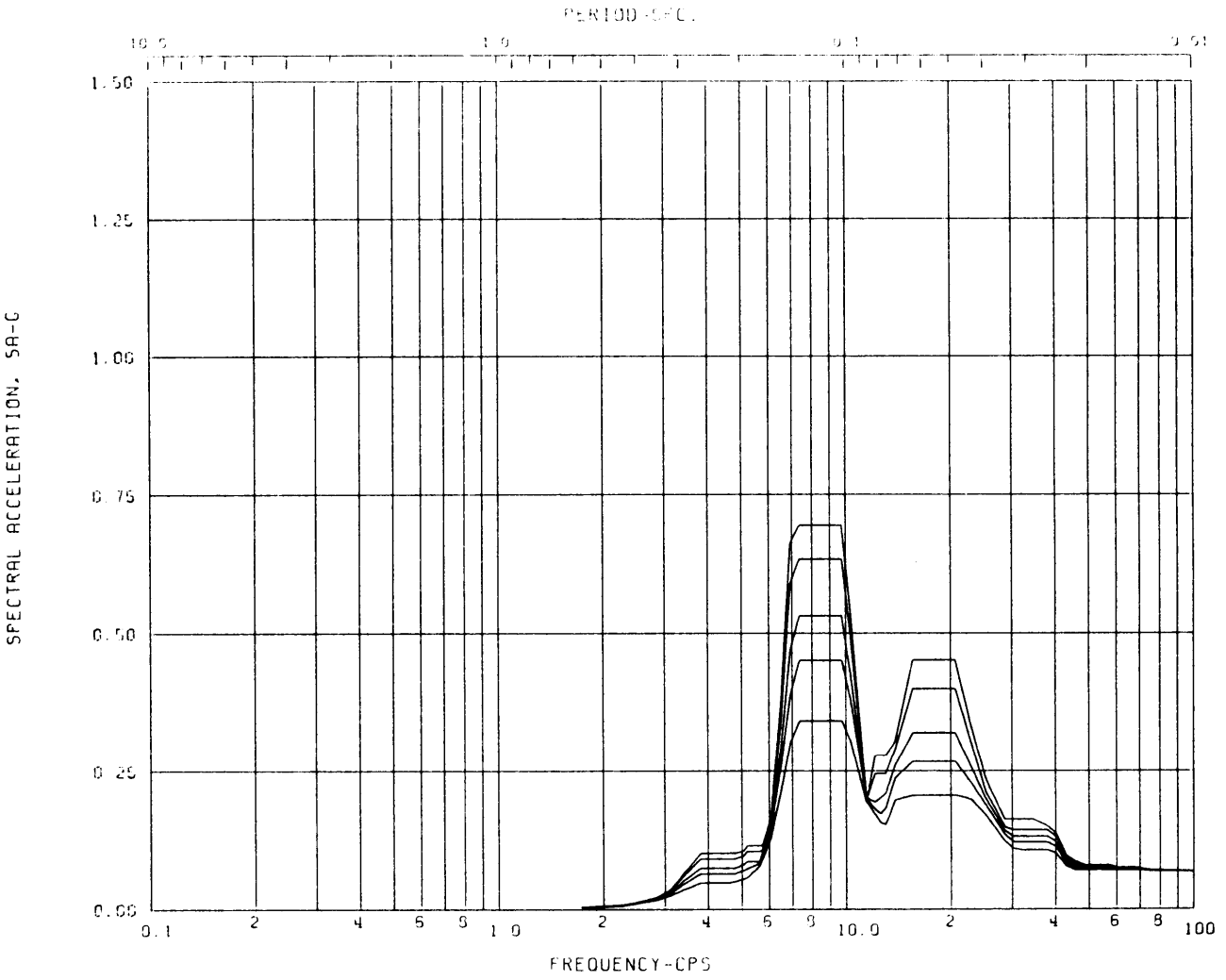
Node: 9 Direction: VERTICAL Elev: 352'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-210



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

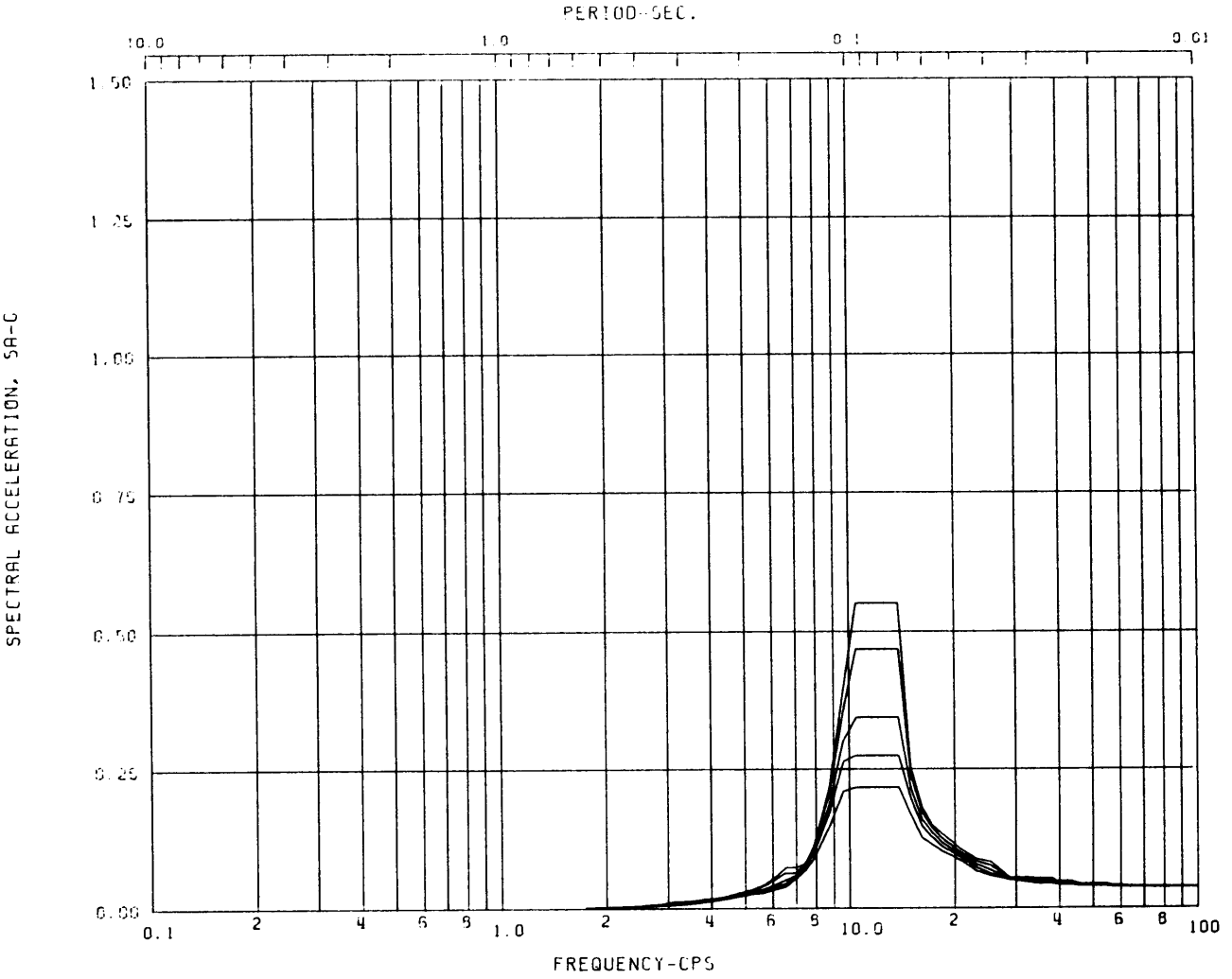
Node: 13 Direction: VERTICAL Elev: 352'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-211



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

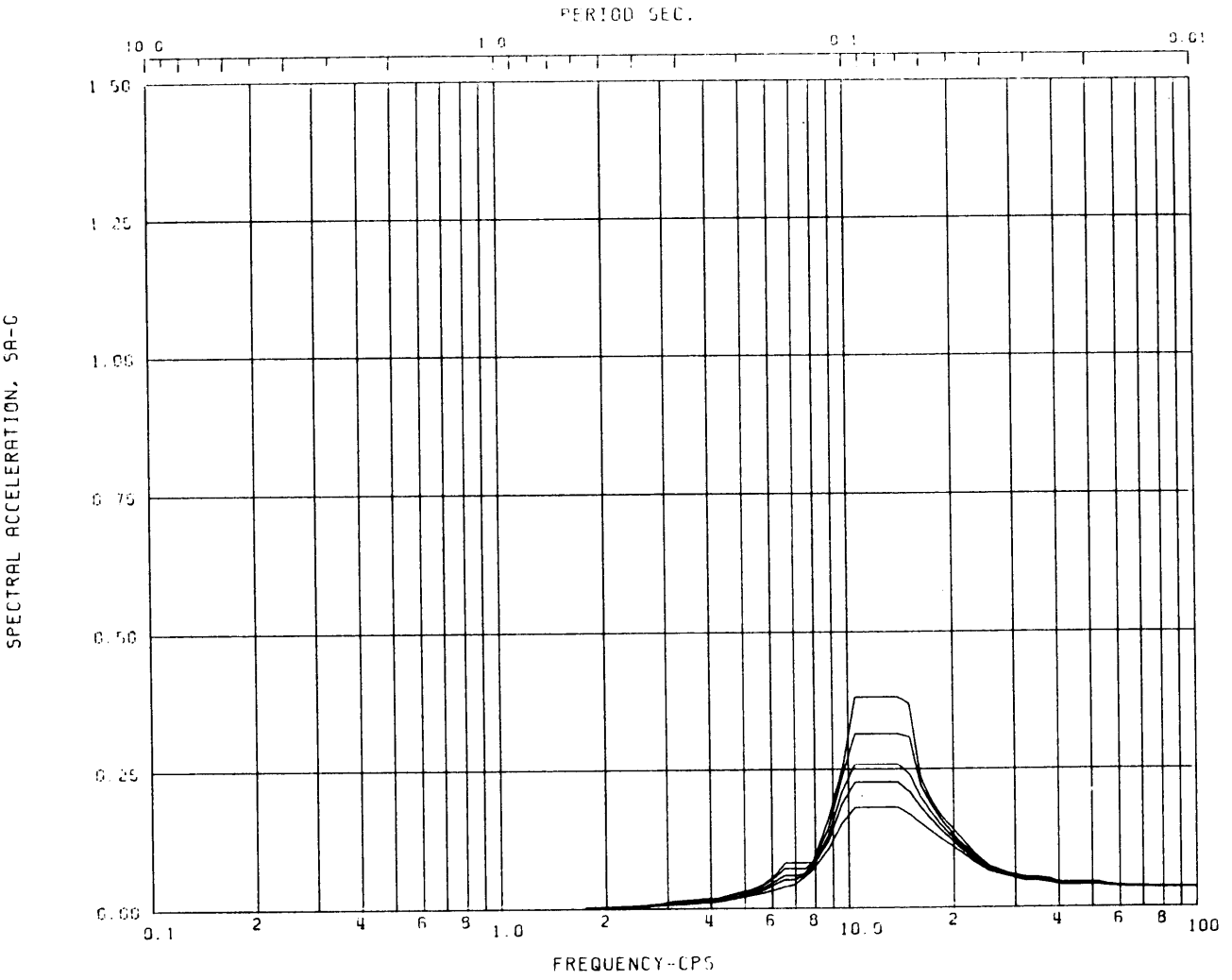
Node: 129 Direction: VERTICAL Elev: 201'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-212



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

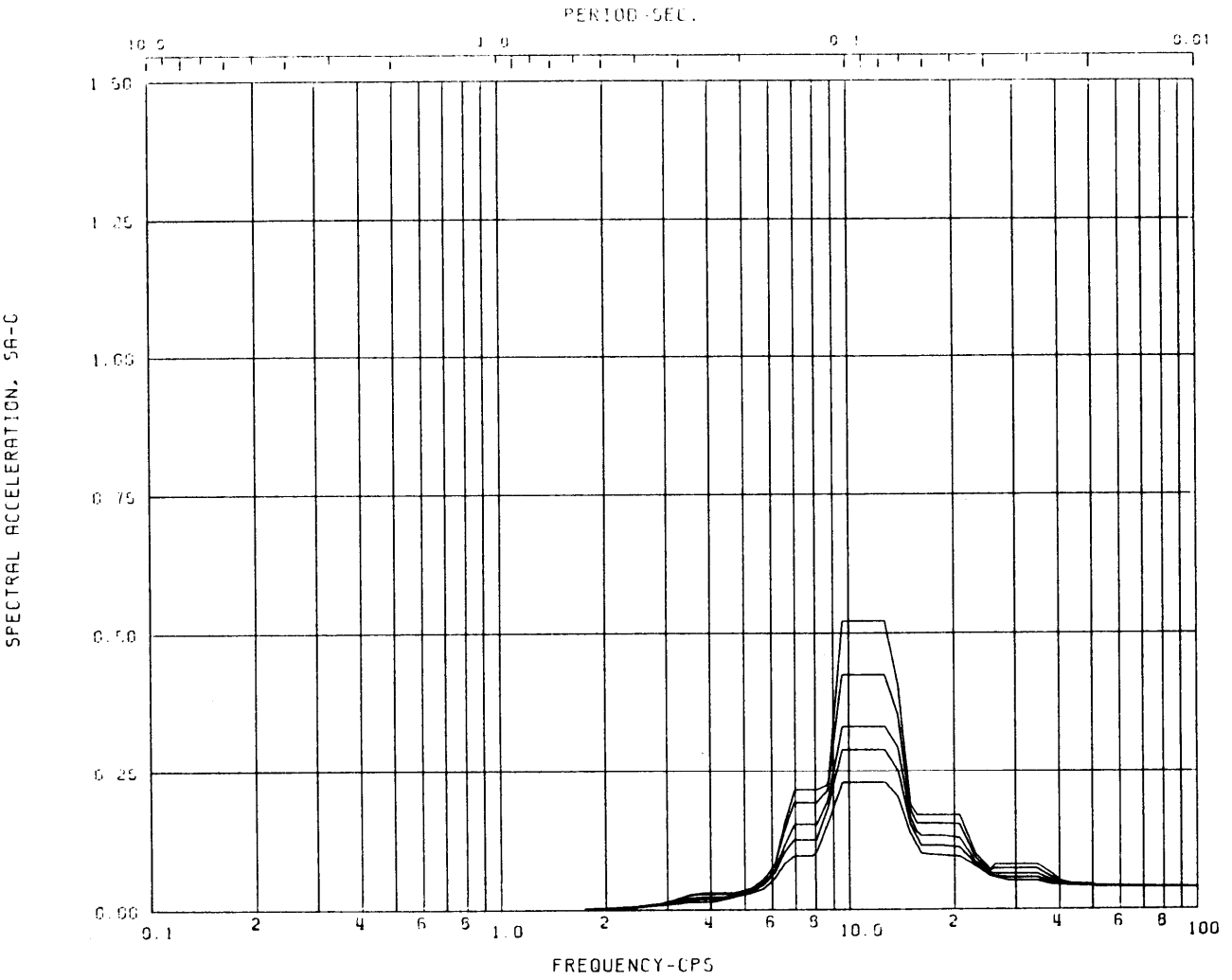
Node: 107 Direction: VERTICAL Elev: 217'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-213



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

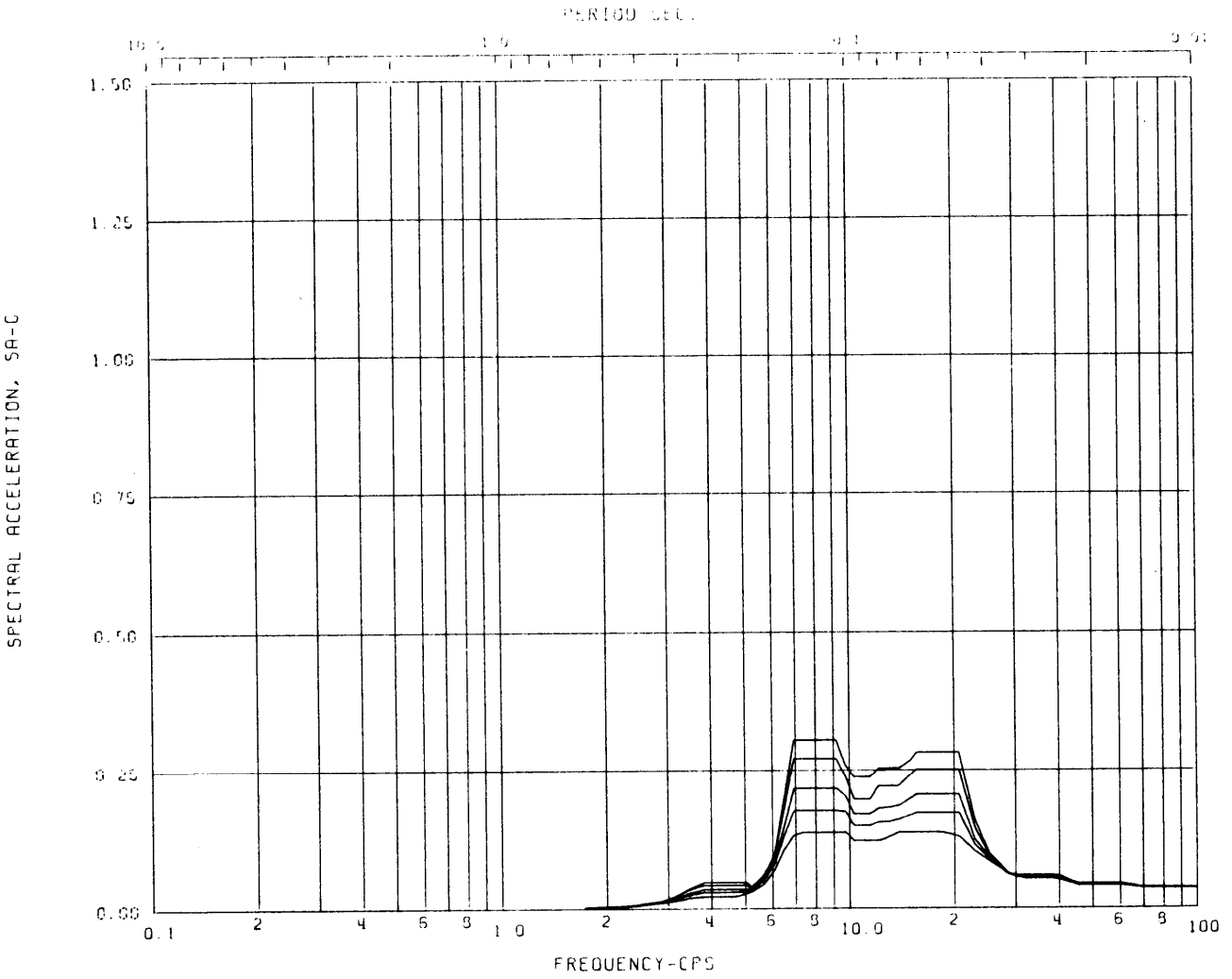
Node: 80 Direction: VERTICAL Elev: 253'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-214



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

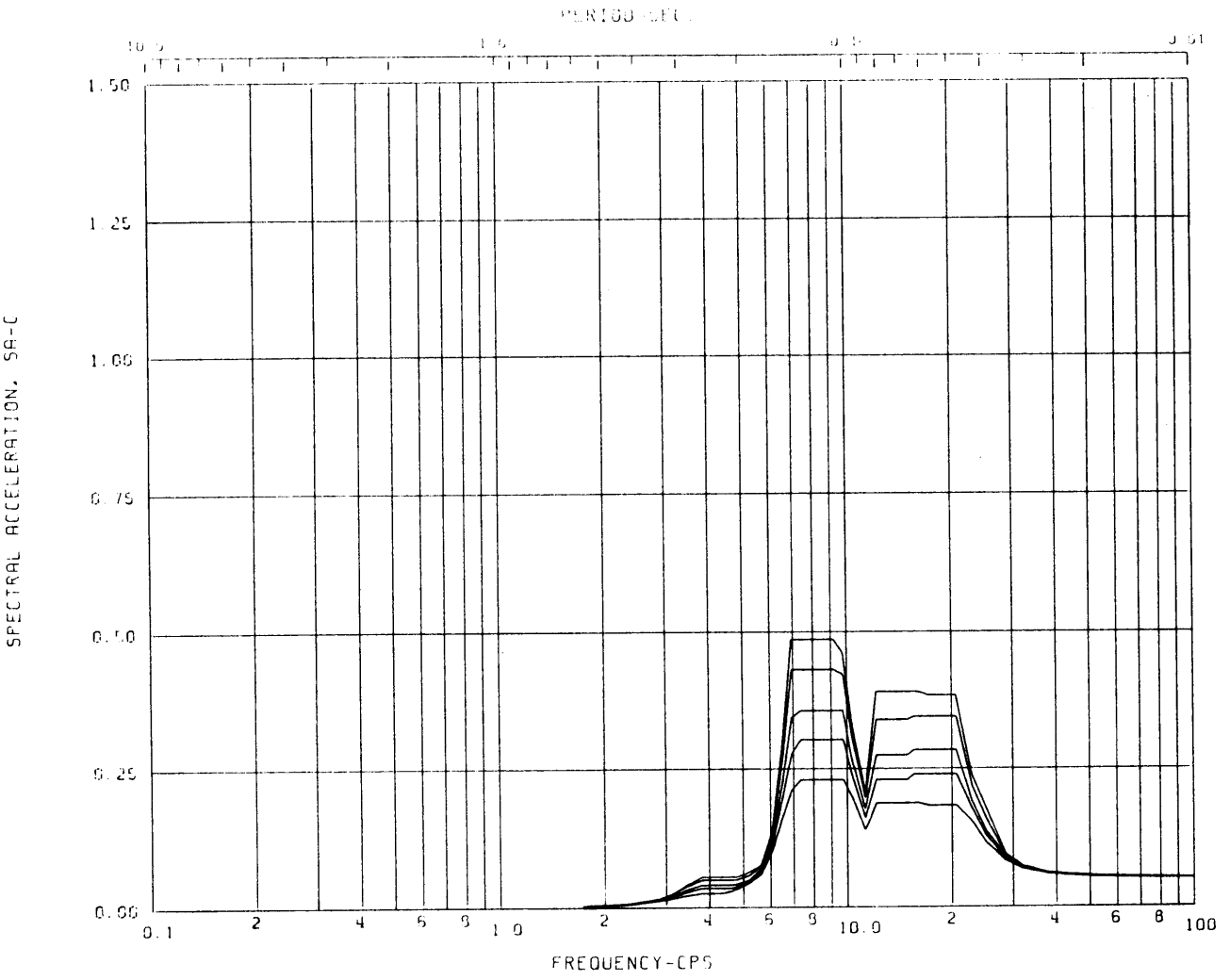
Node: 59 Direction: VERTICAL Elev: 283'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-215



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

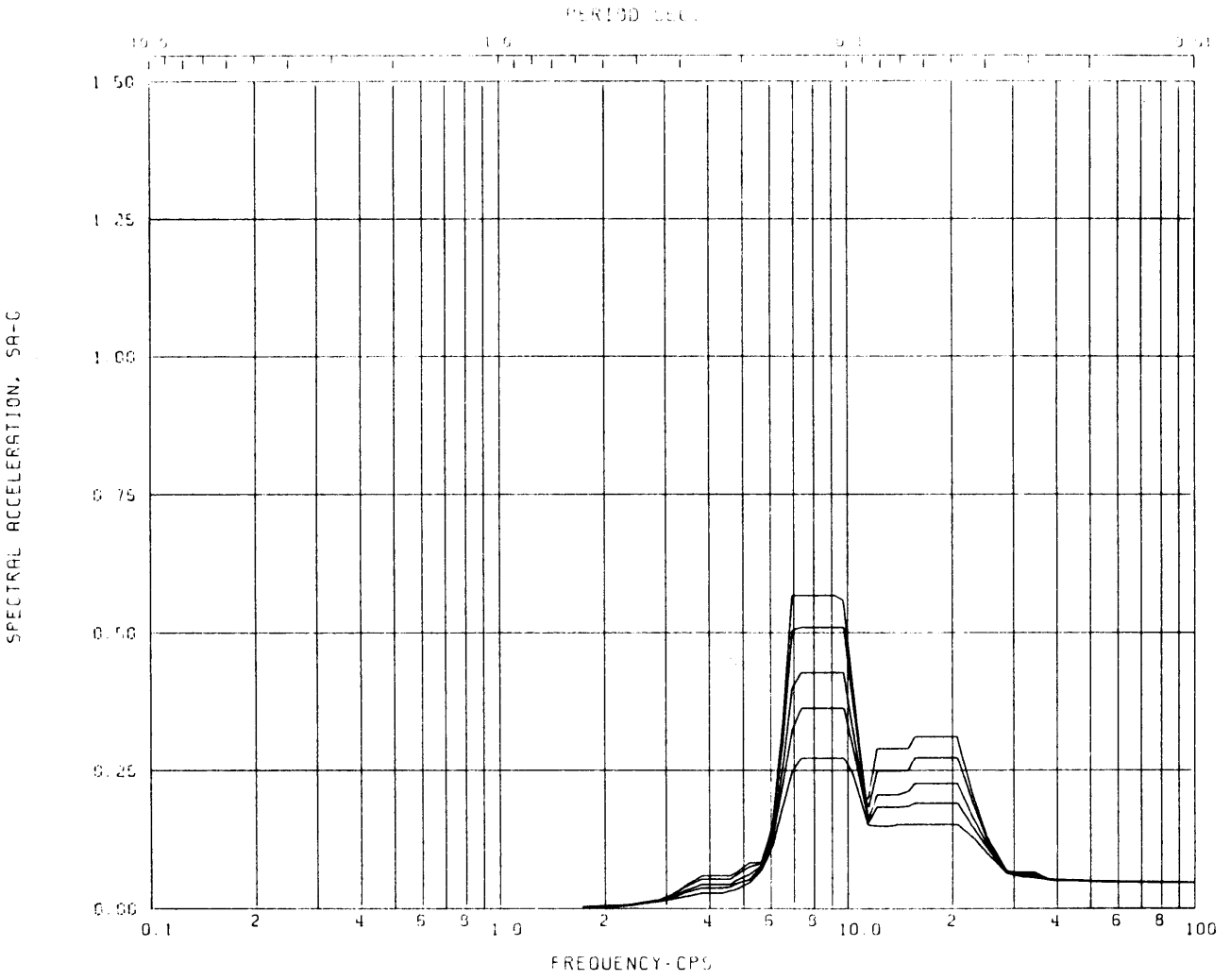
Node: 54 Direction: VERTICAL Elev: 313'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-216



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

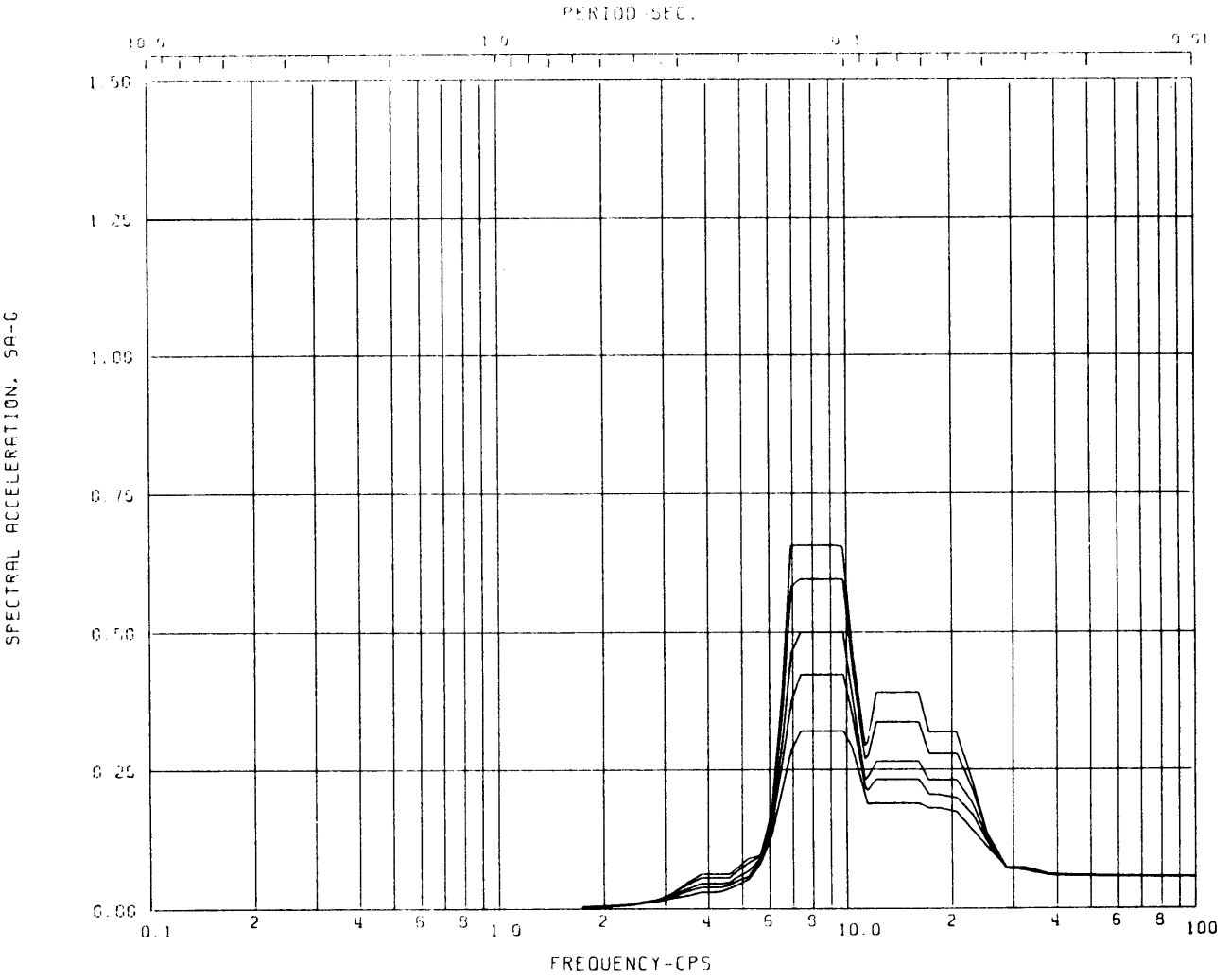
Node: 32 Direction: VERTICAL Elev: 333'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-217



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

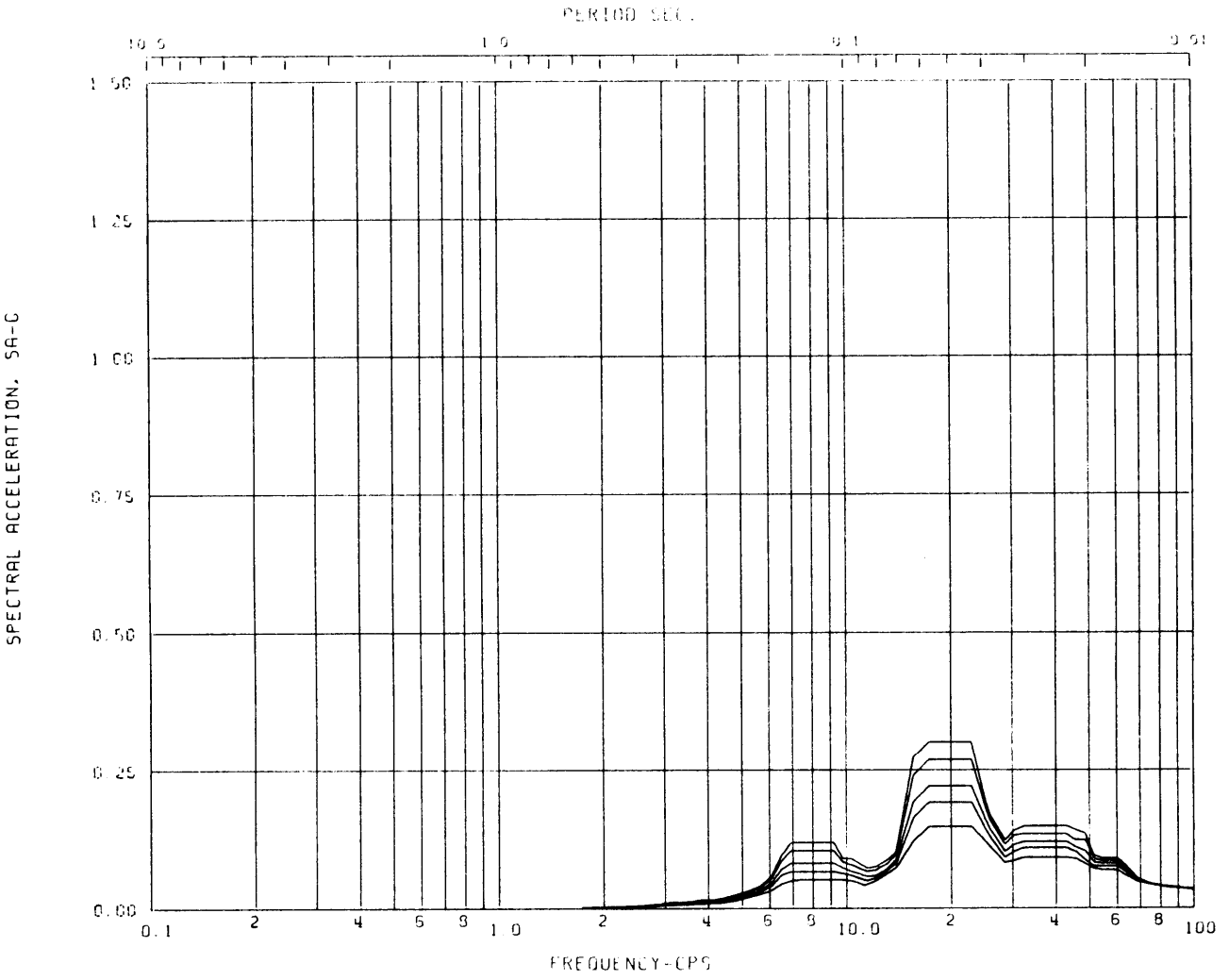
Node: 12 Direction: VERTICAL Elev: 352'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-218



Acceleration Spectra for REACTOR ENCL.

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

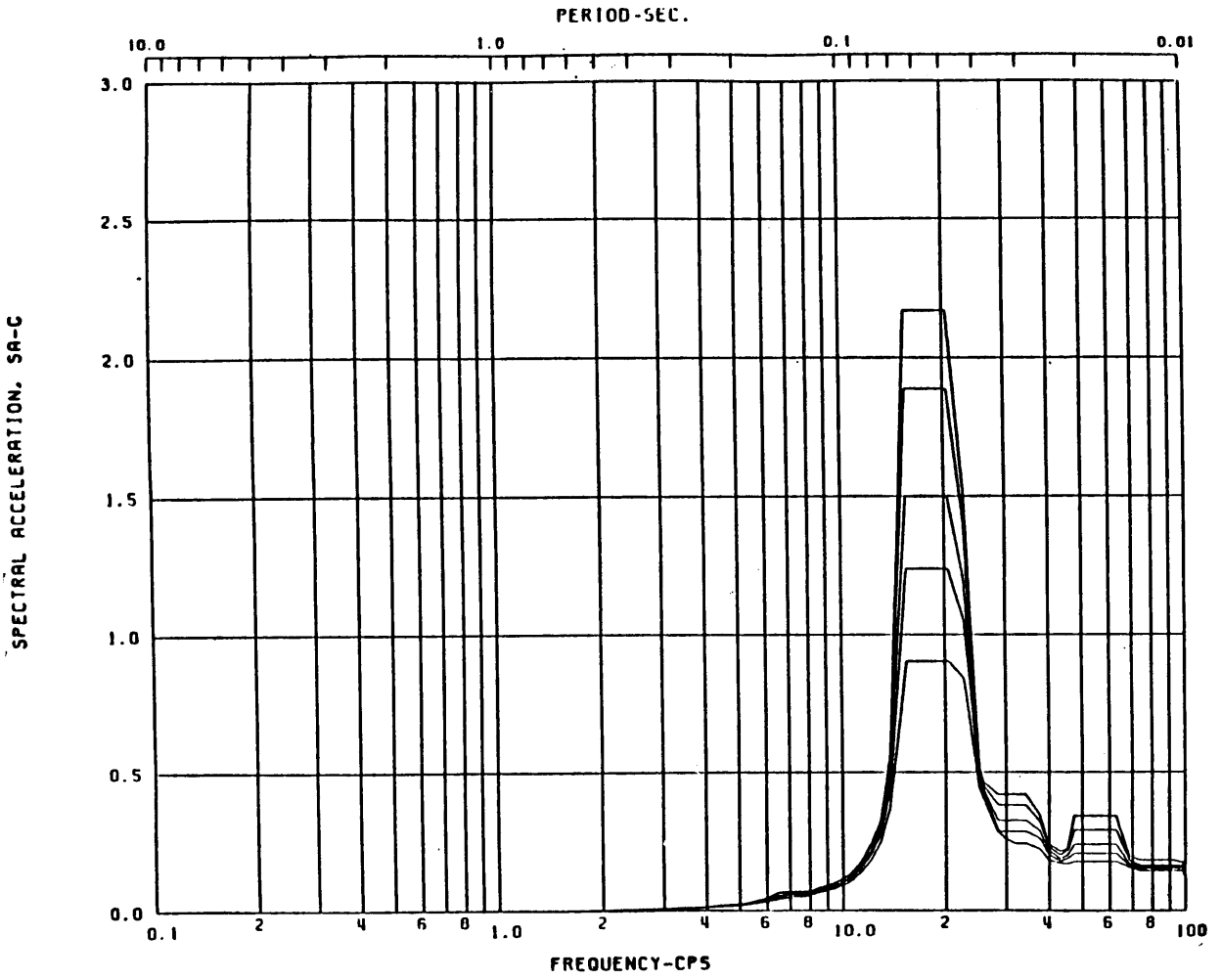
Node: 6 Direction: VERTICAL Elev: 410'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-219



Acceleration Spectra for CONTROL STRUCTURE

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 19 Direction: VERTICAL Elev: 217'

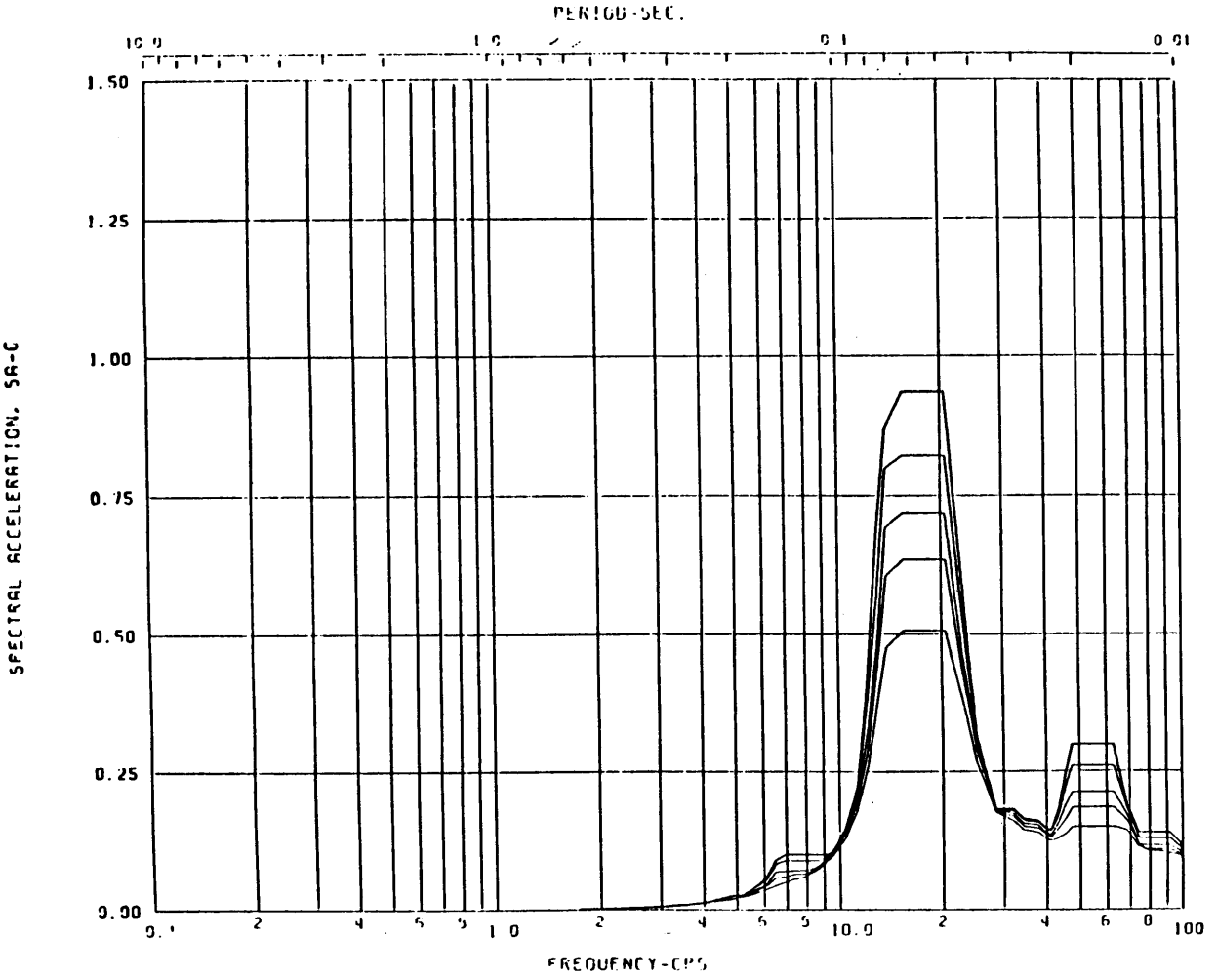
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-220



Acceleration Spectra for CONTROL STRUCTURE

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 19 Direction: VERTICAL Elev: 239'

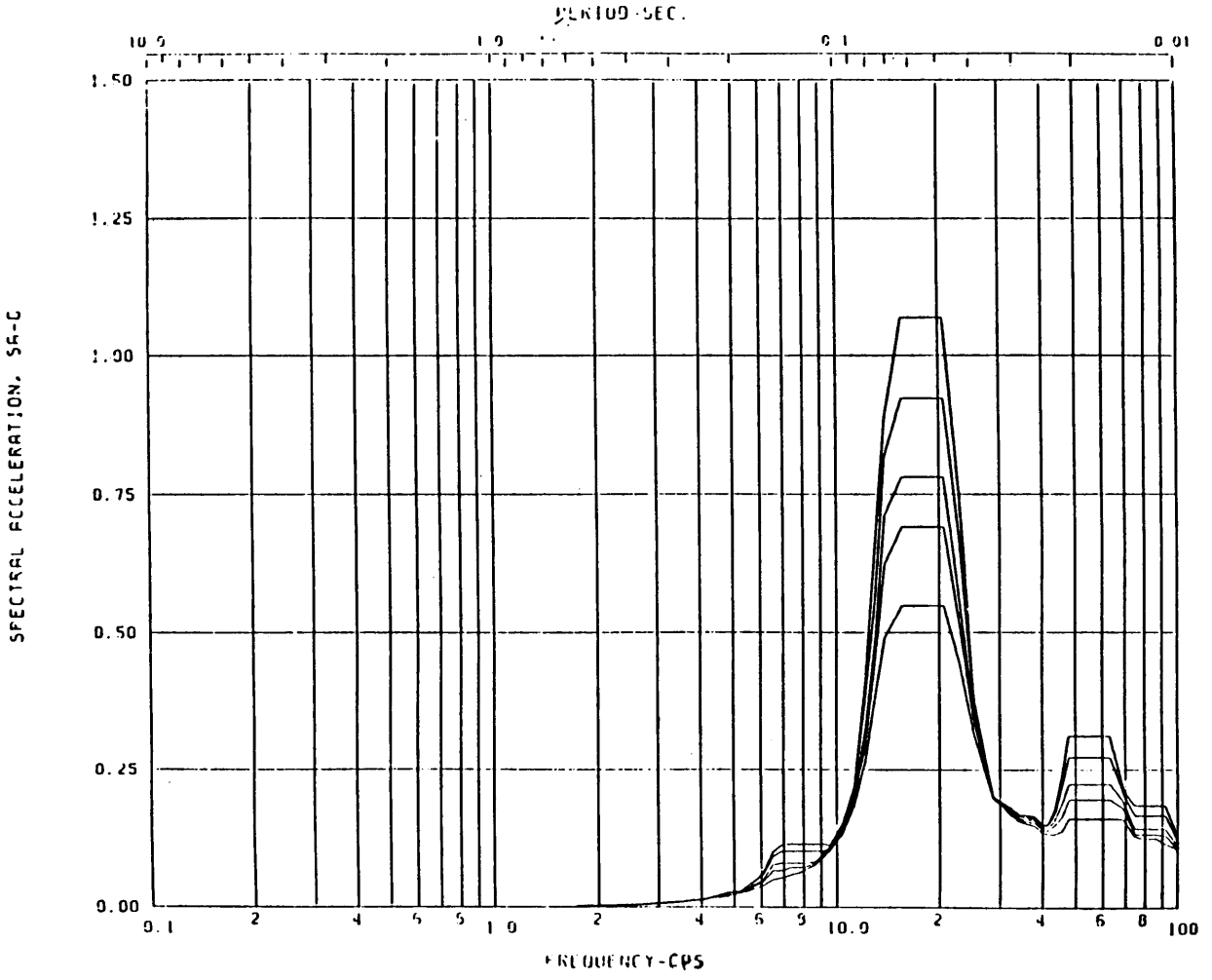
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-221



Acceleration Spectra for CONTROL STRUCTURE

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 19 Direction: VERTICAL Elev: 254'

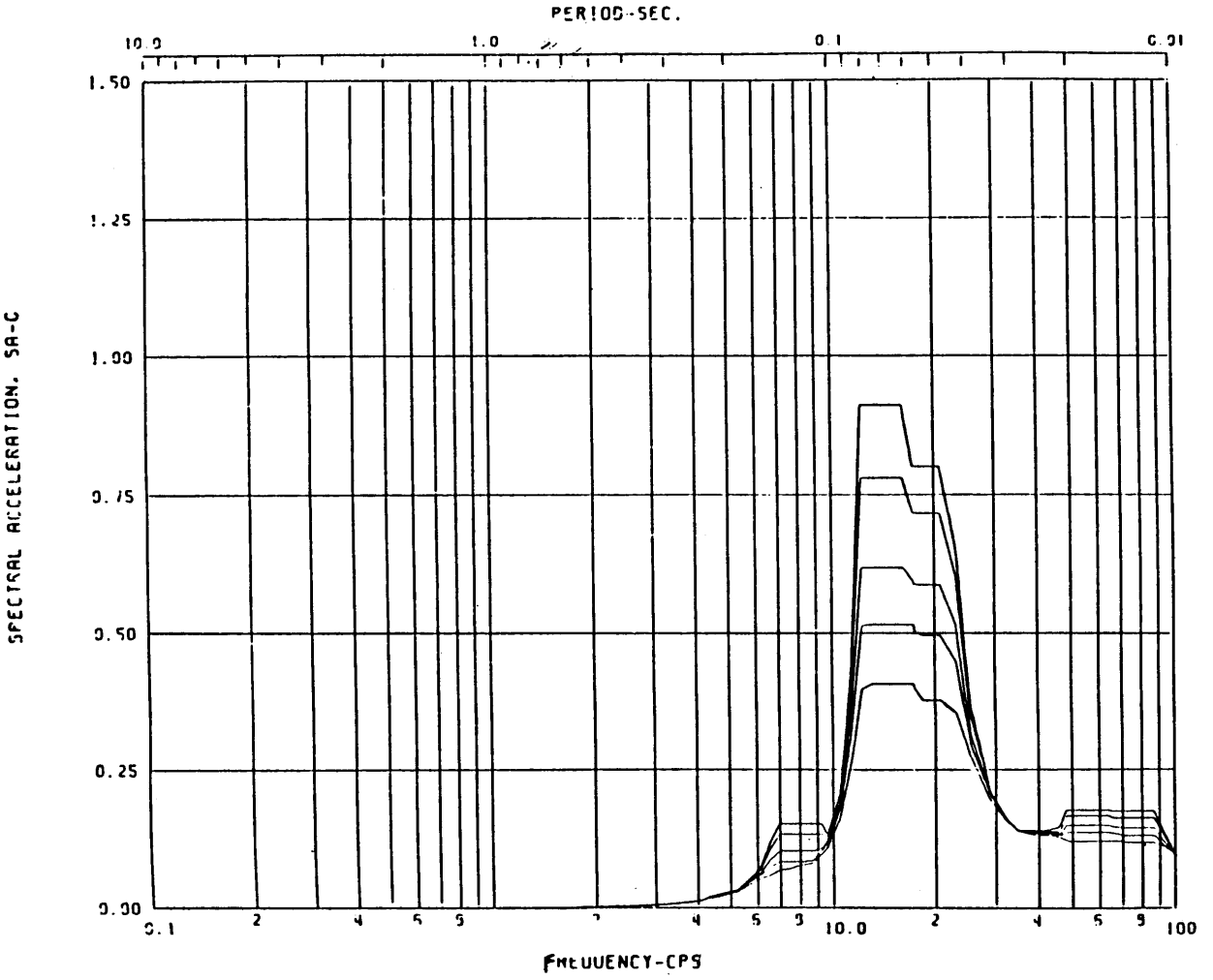
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-222



Acceleration Spectra for CONTROL STRUCTURE

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 19 Direction: VERTICAL Elev: 269'-0

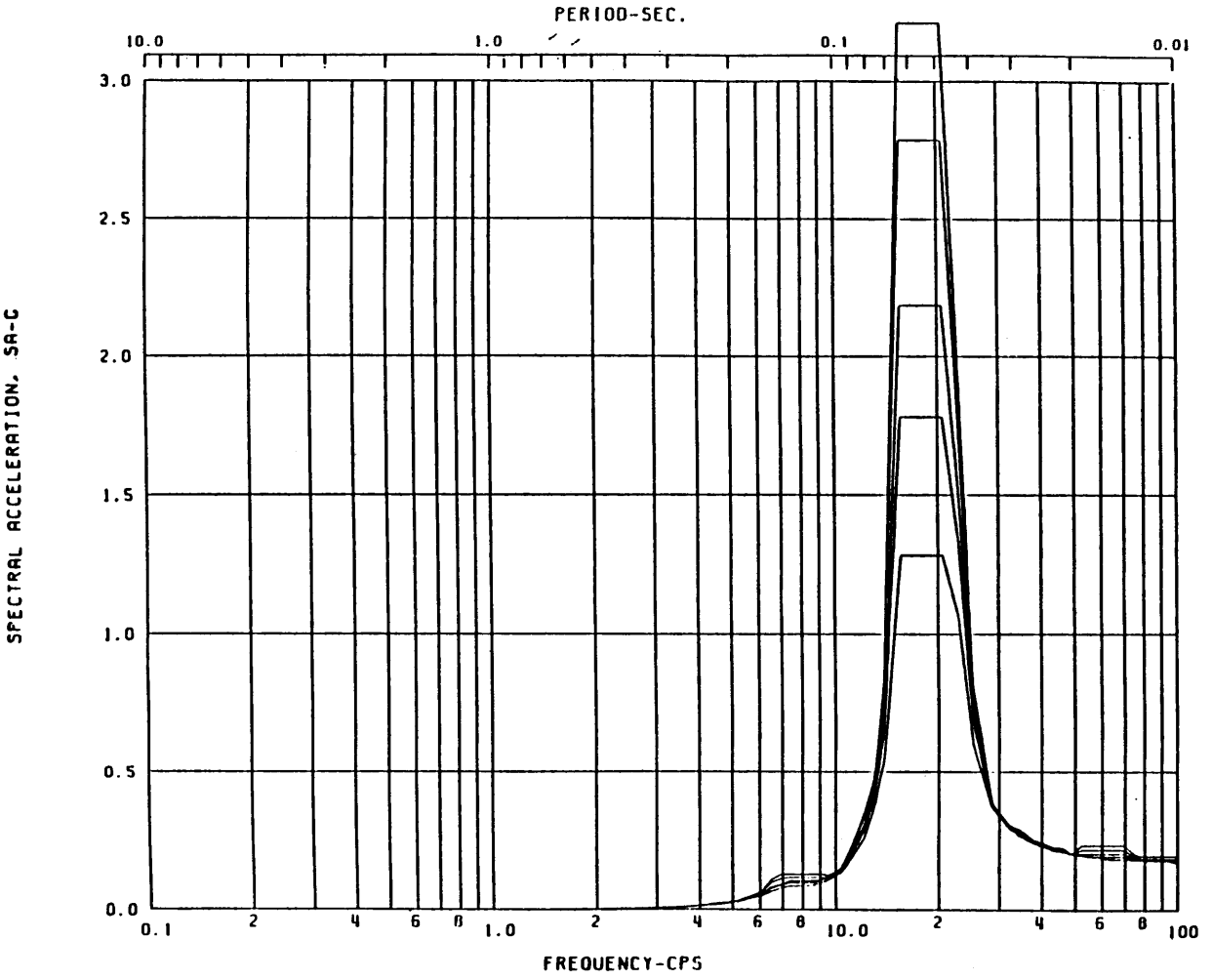
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-223



Acceleration Spectra for CONTROL STRUCTURE

Load Case: KWU SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 19 Direction: VERTICAL Elev: 289'

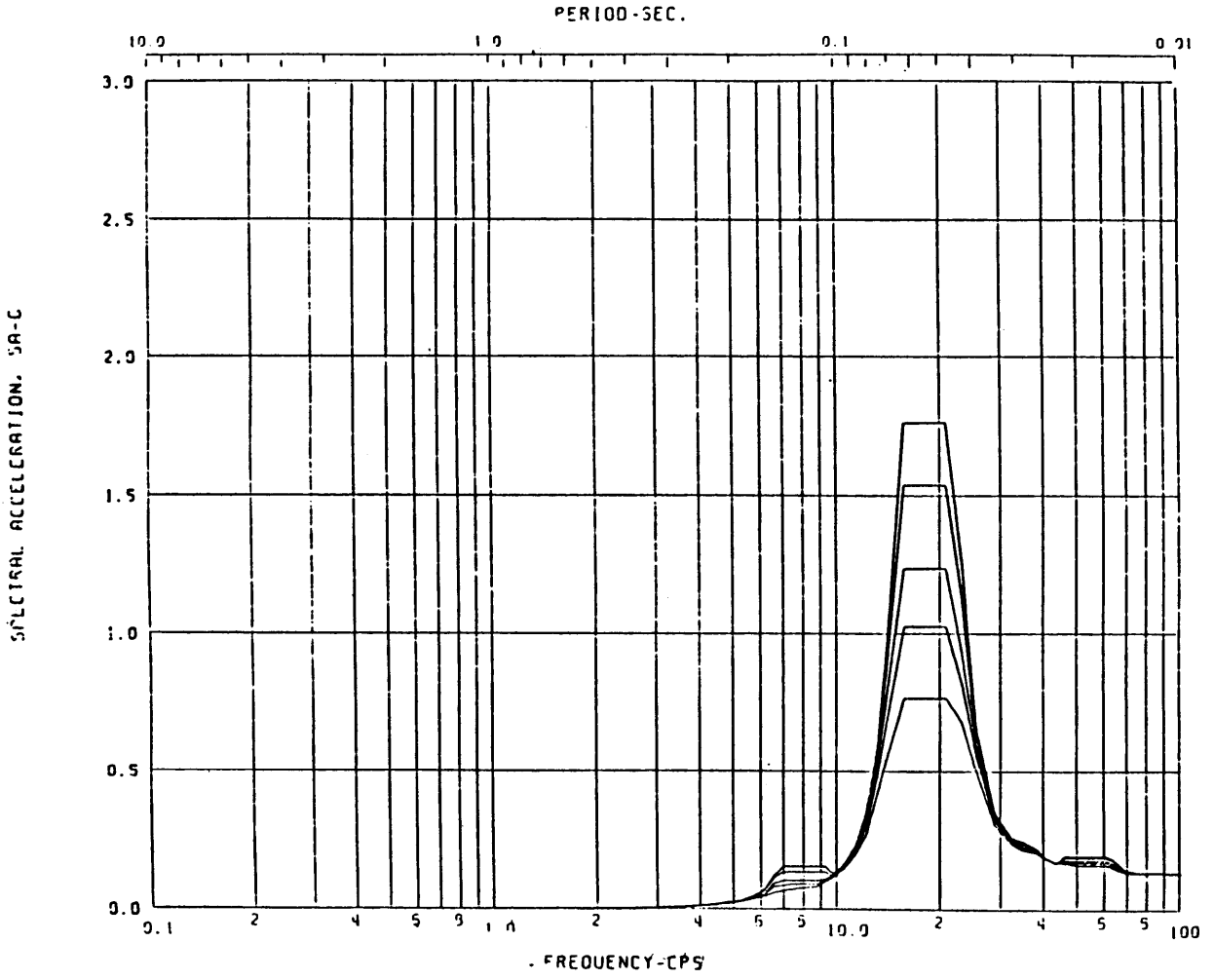
Damping: 0.005,0.01,0.02,0.03,0.05

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CONTROL STRUCTURE
LOCAL RESPONSE SPECTRA,
VERTICAL, SRV AXISYMMETRIC

FIGURE 3A-224



Acceleration Spectra for CONTROL STRUCTURE

Load Case: KWU-SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 19 Direction: VERTICAL Elev: 304'-0

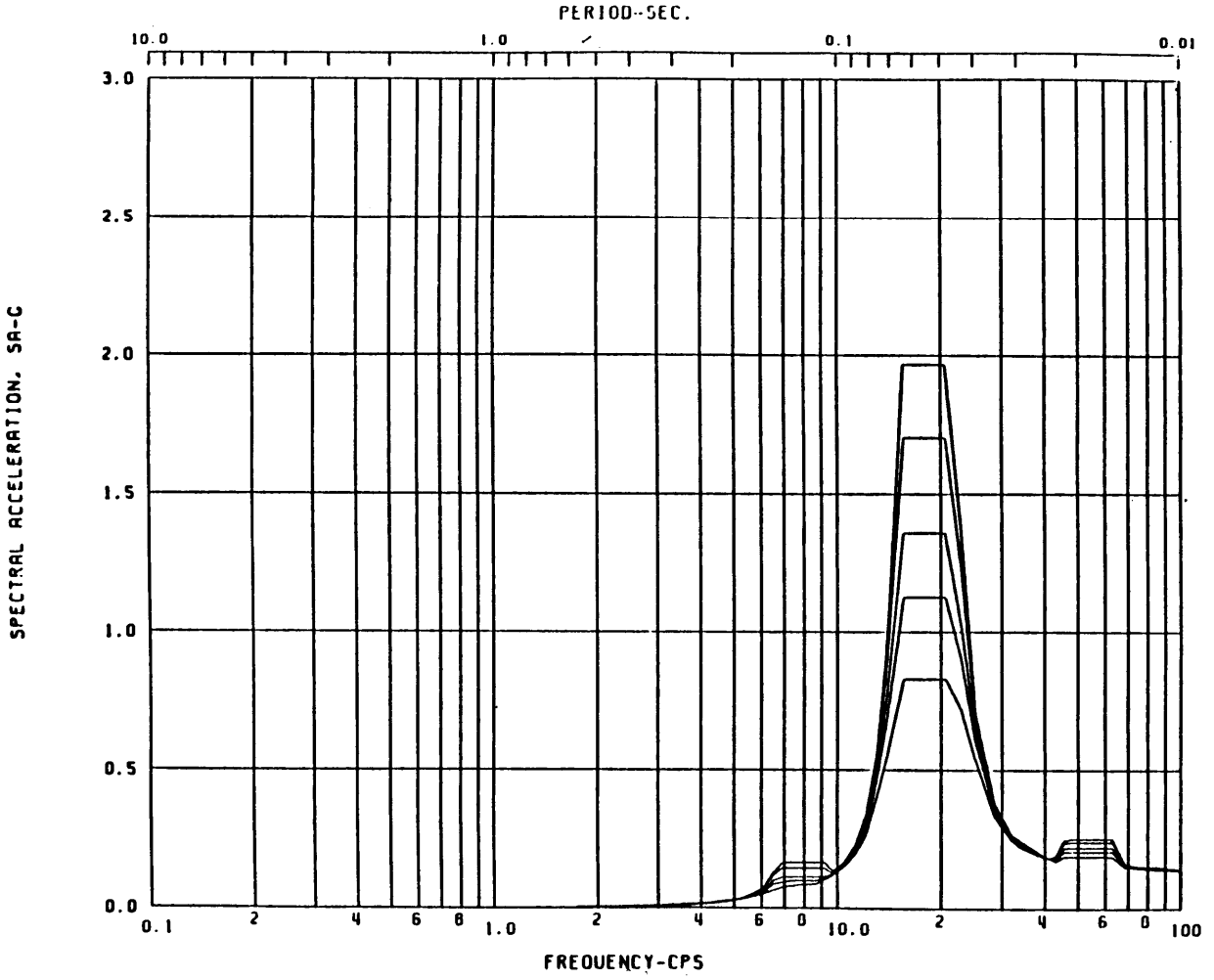
Damping: 0.005,0.01,0.02,0.03,0.05

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CONTROL STRUCTURE LOCAL RESPONSE SPECTRA, VERTICAL, SRV AXISYMMETRIC

FIGURE 3A-225



Acceleration Spectra for CONTROL STRUCTURE

Load Case: KWU-SRV AXISYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 19 Direction: VERTICAL Elev: 332'

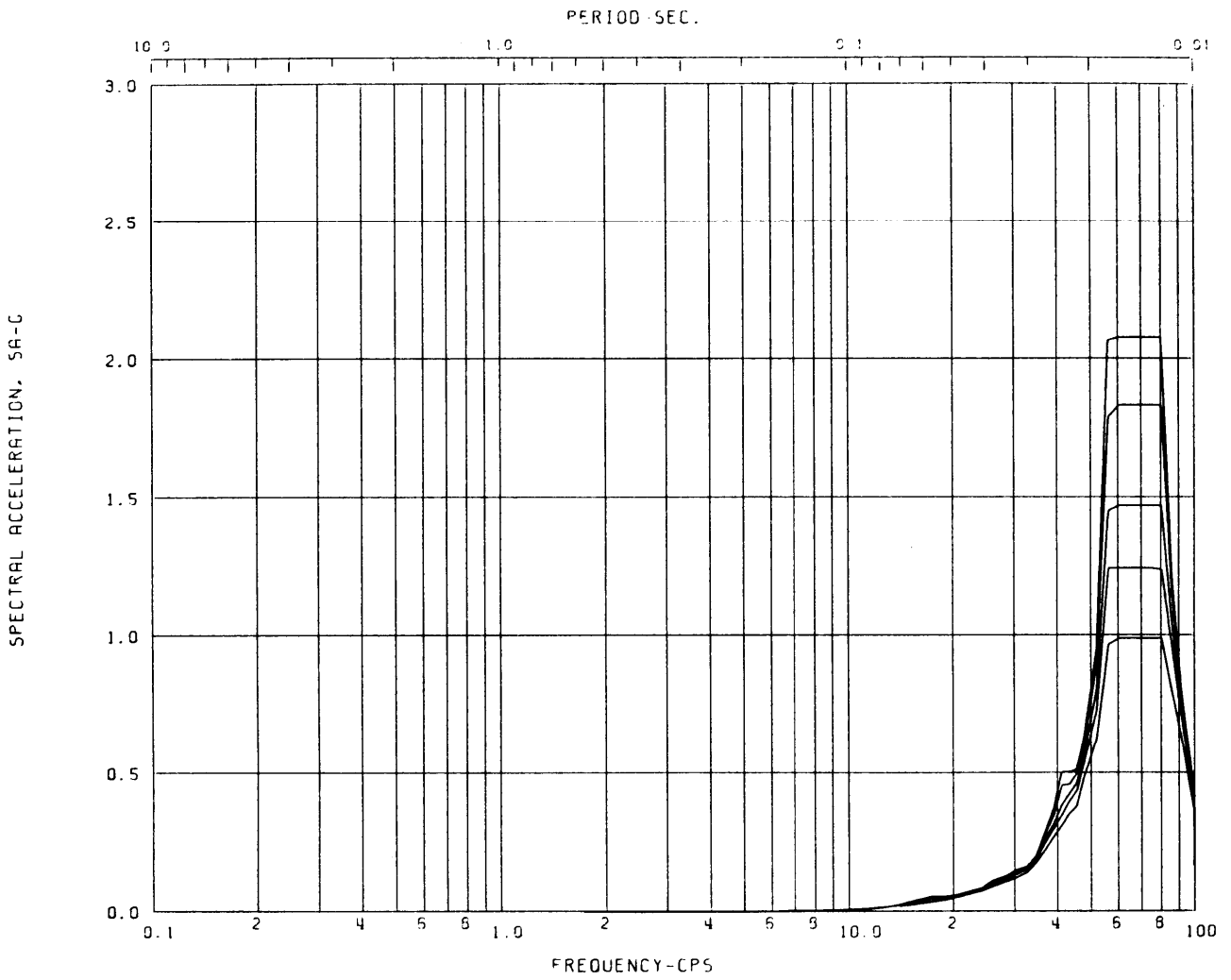
Damping: 0.005,0.01,0.02,0.03,0.05

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CONTROL STRUCTURE
LOCAL RESPONSE SPECTRA,
VERTICAL, SRV AXISYMMETRIC

FIGURE 3A-226



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: CHUGGING GE700 SERIES ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 1 Direction: HORIZ N-S Elev: 177'-0

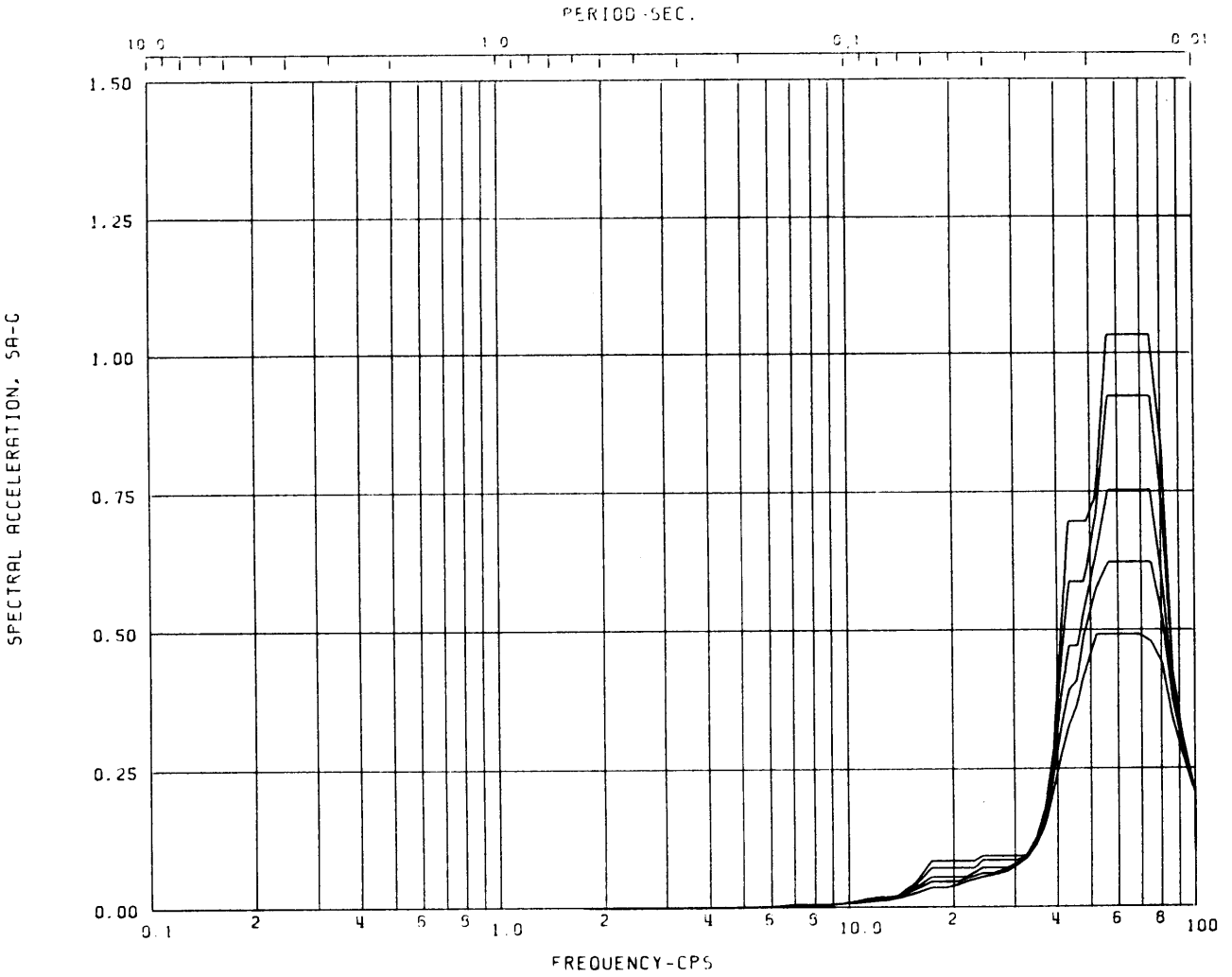
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-227



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: CHUGGING GE700 SERIES ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 2 Direction: HORIZ N-S Elev: 201'-0

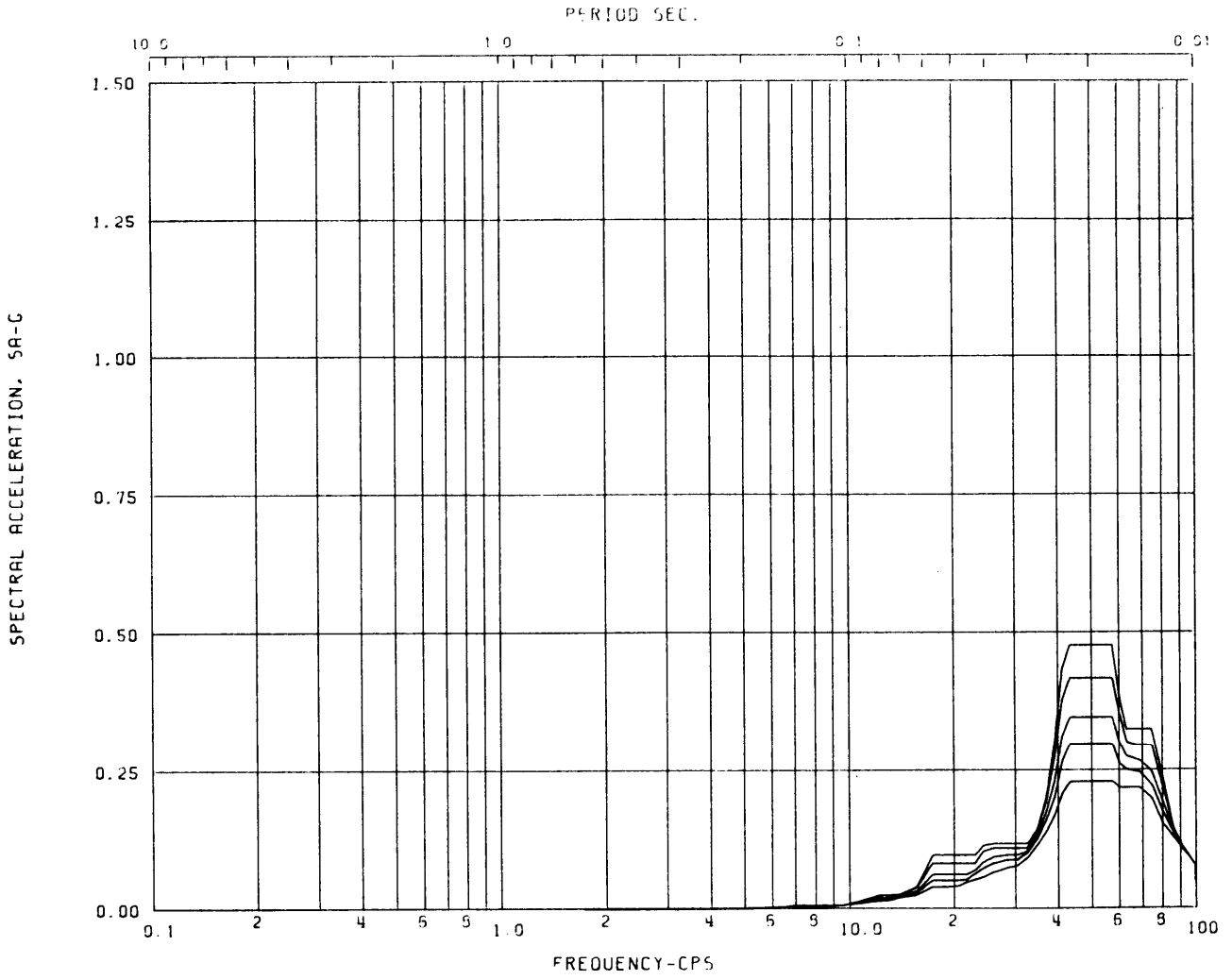
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-228



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: CHUGGING GE700 SERIES ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 3 Direction: HORIZ N-S Elev: 217'-0

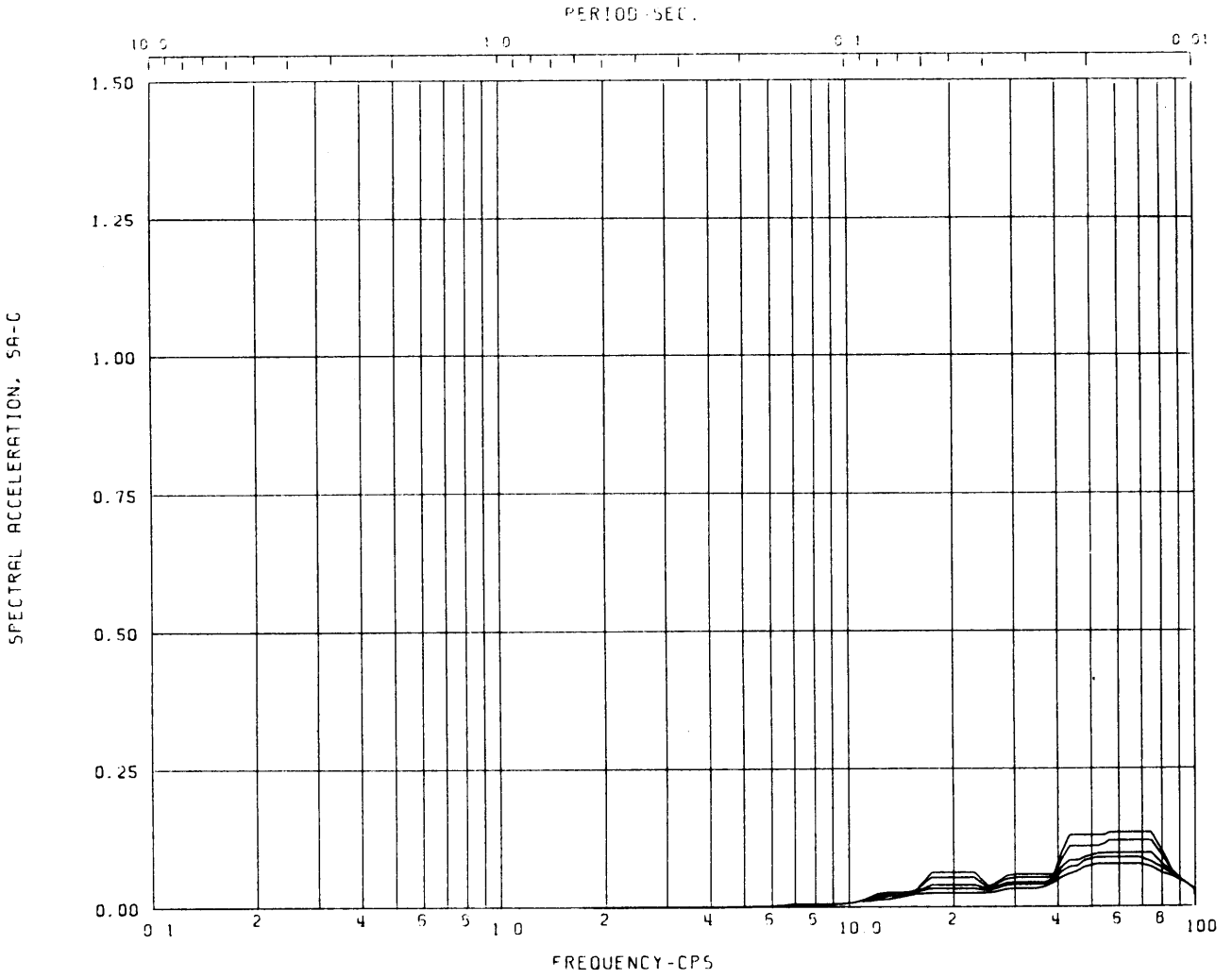
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-229



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: CHUGGING GE700 SERIES ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 4 Direction: HORIZ N-S Elev: 239'-0

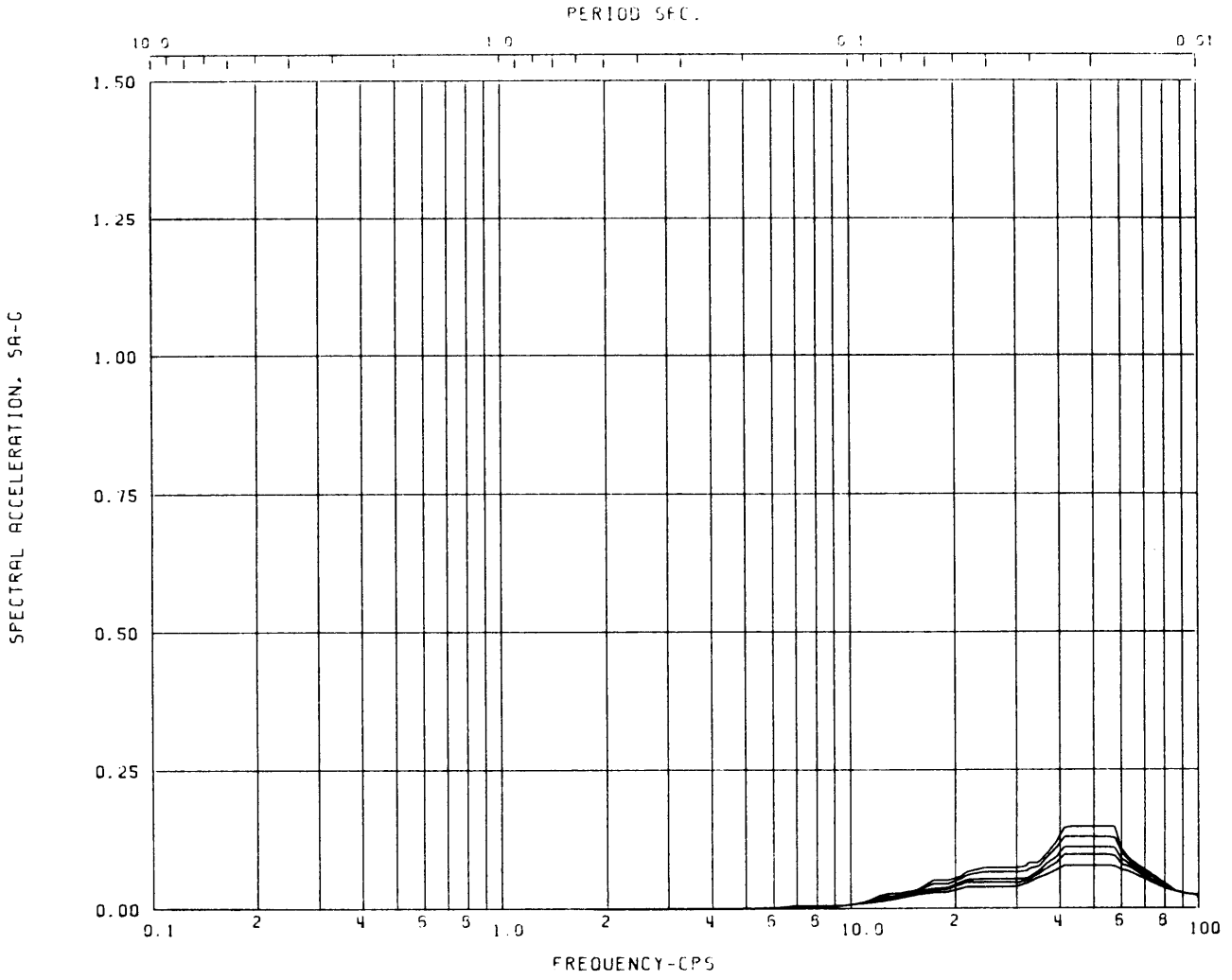
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-230



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: CHUGGING GE700 SERIES ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 5 Direction: HORIZ N-S Elev: 253'-0

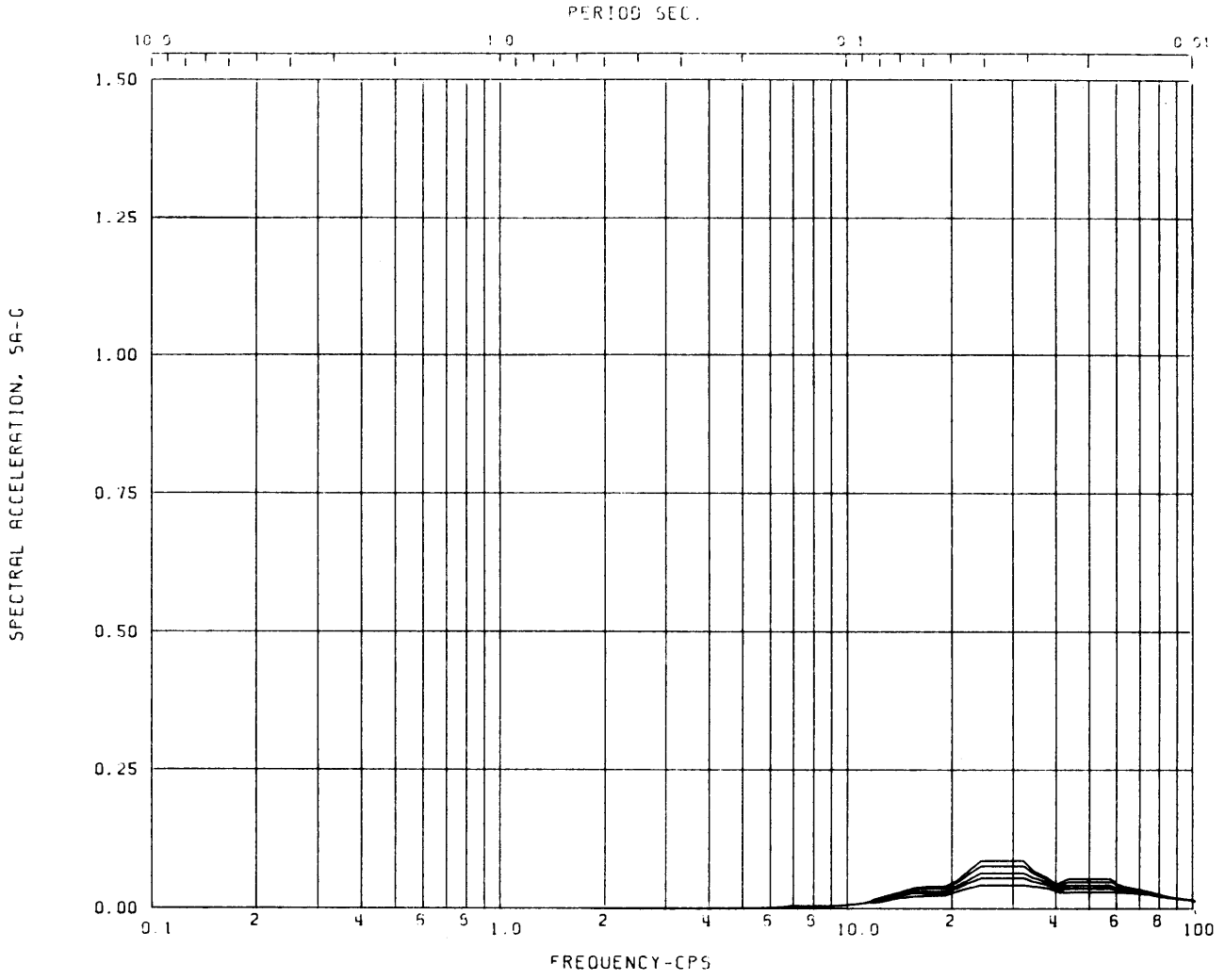
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-231



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: CHUGGING GE700 SERIES ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 6 Direction: HORIZ N-S Elev: 269'-0

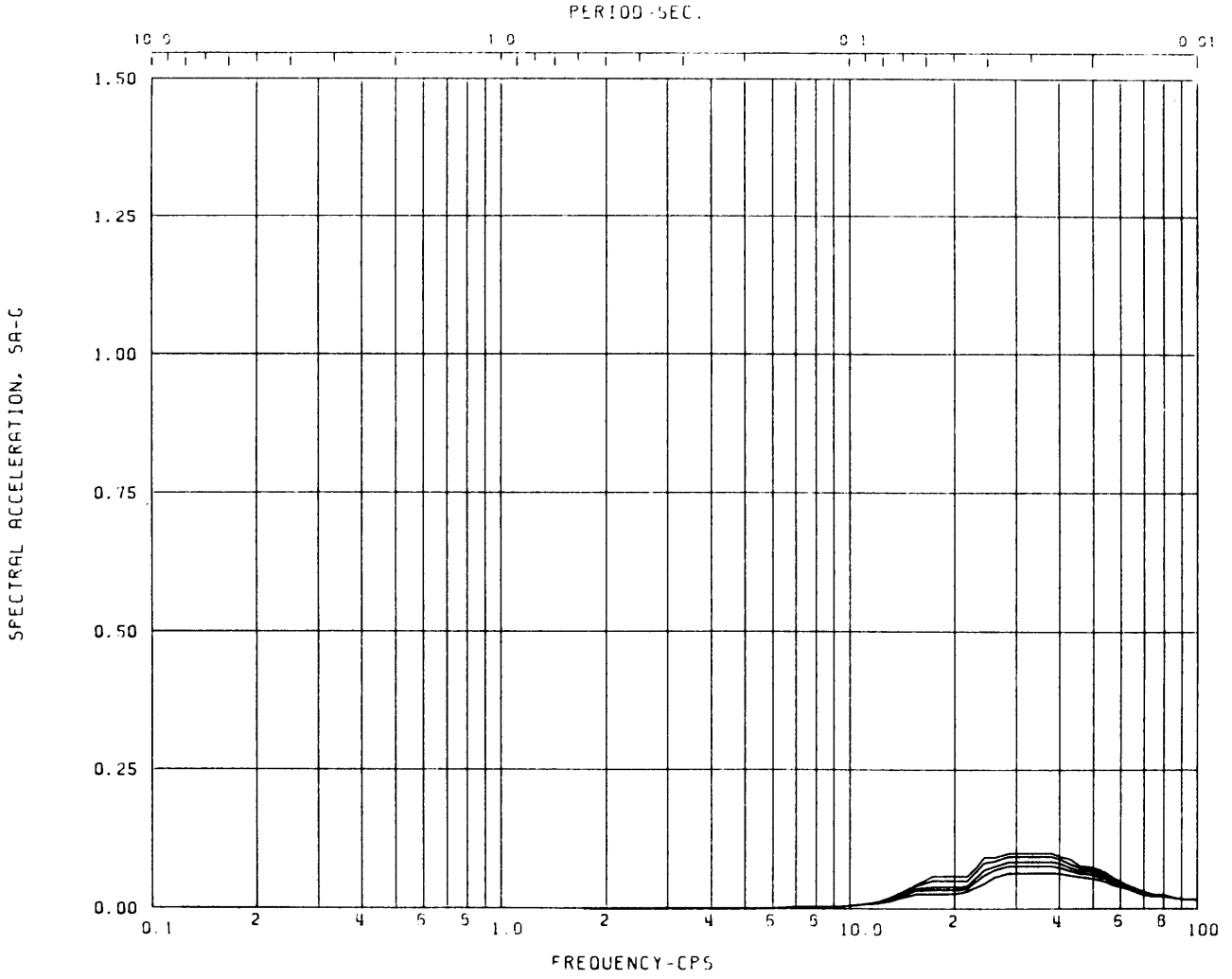
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-232



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: CHUGGING GE700 SERIES ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 7 Direction: HORIZ N-S Elev: 283'-0

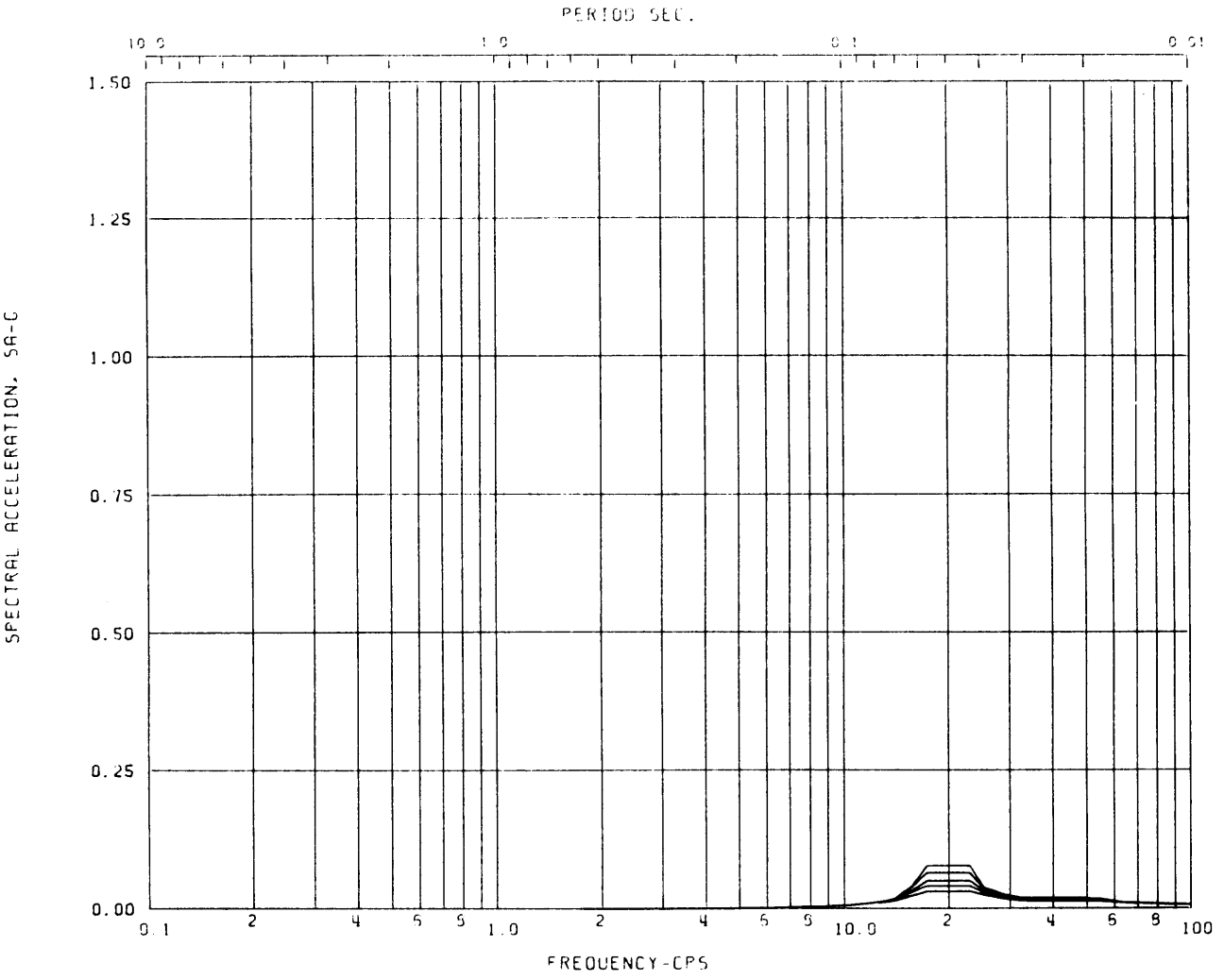
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-233



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: CHUGGING GE700 SERIES ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 8 Direction: HORIZ N-S Elev: 304'-0

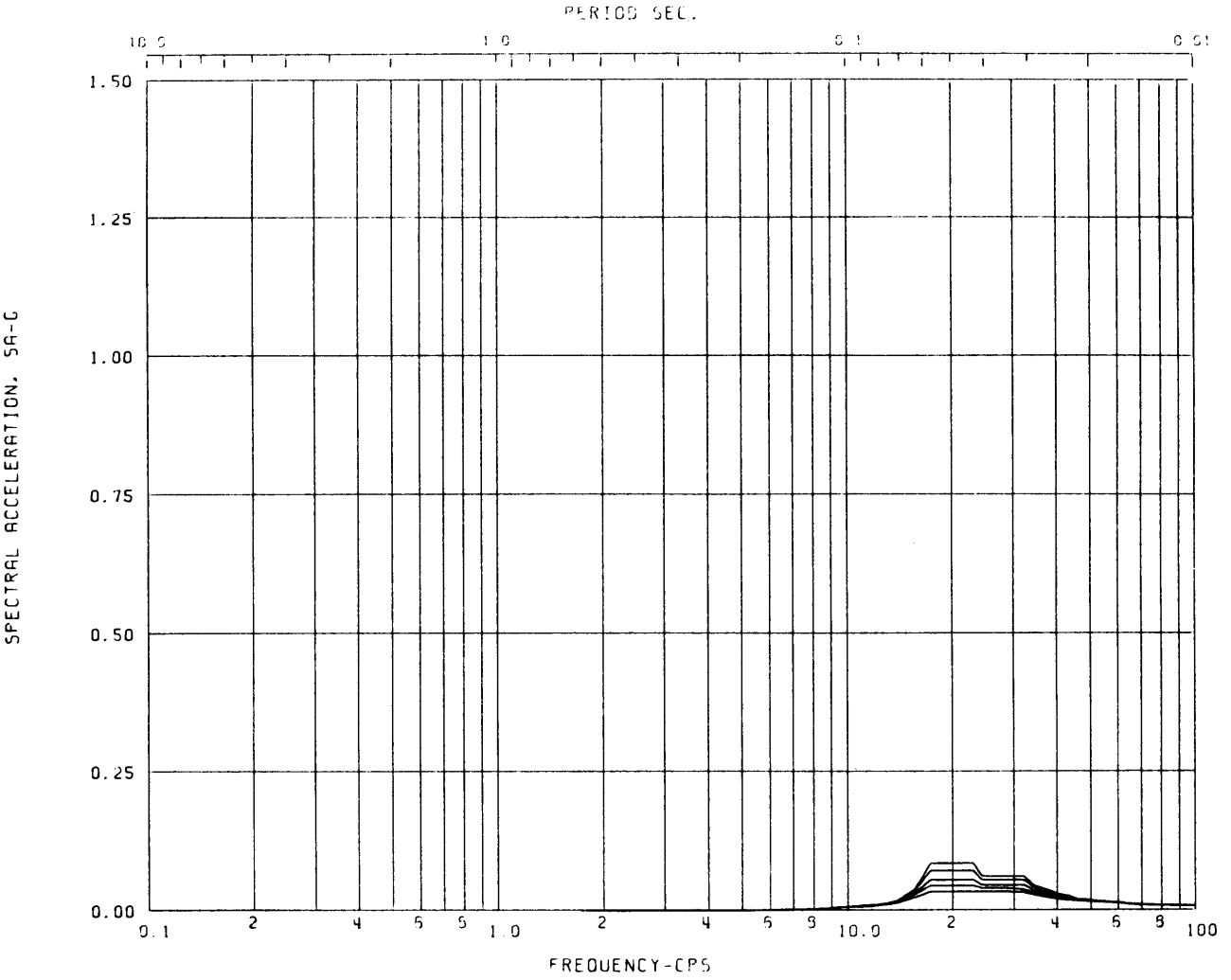
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-234



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: CHUGGING GE700 SERIES ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 9 Direction: HORIZ N-S Elev: 313'-0

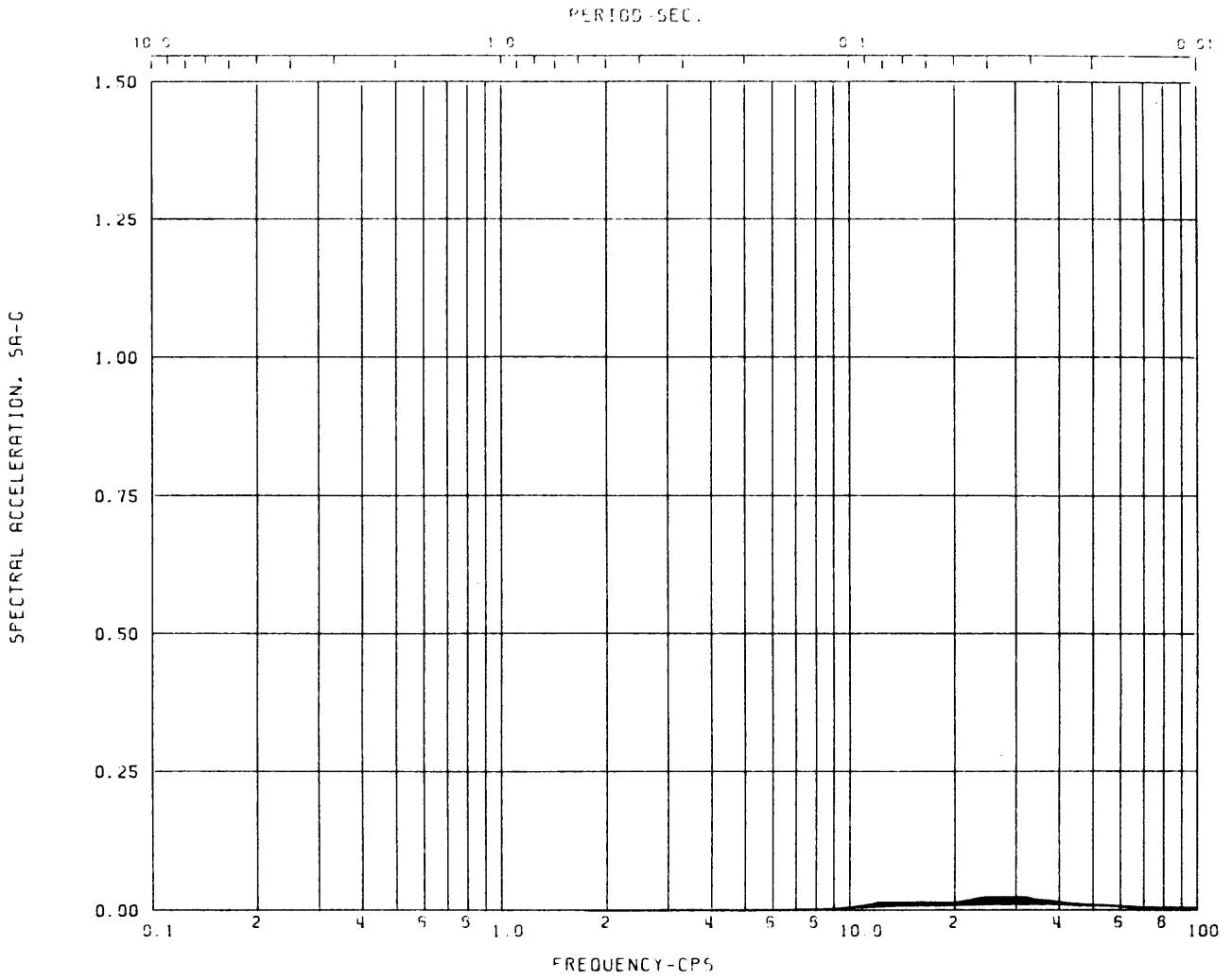
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-235



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: CHUGGING GE700 SERIES ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 10 Direction: HORIZ N-S Elev: 332'-0

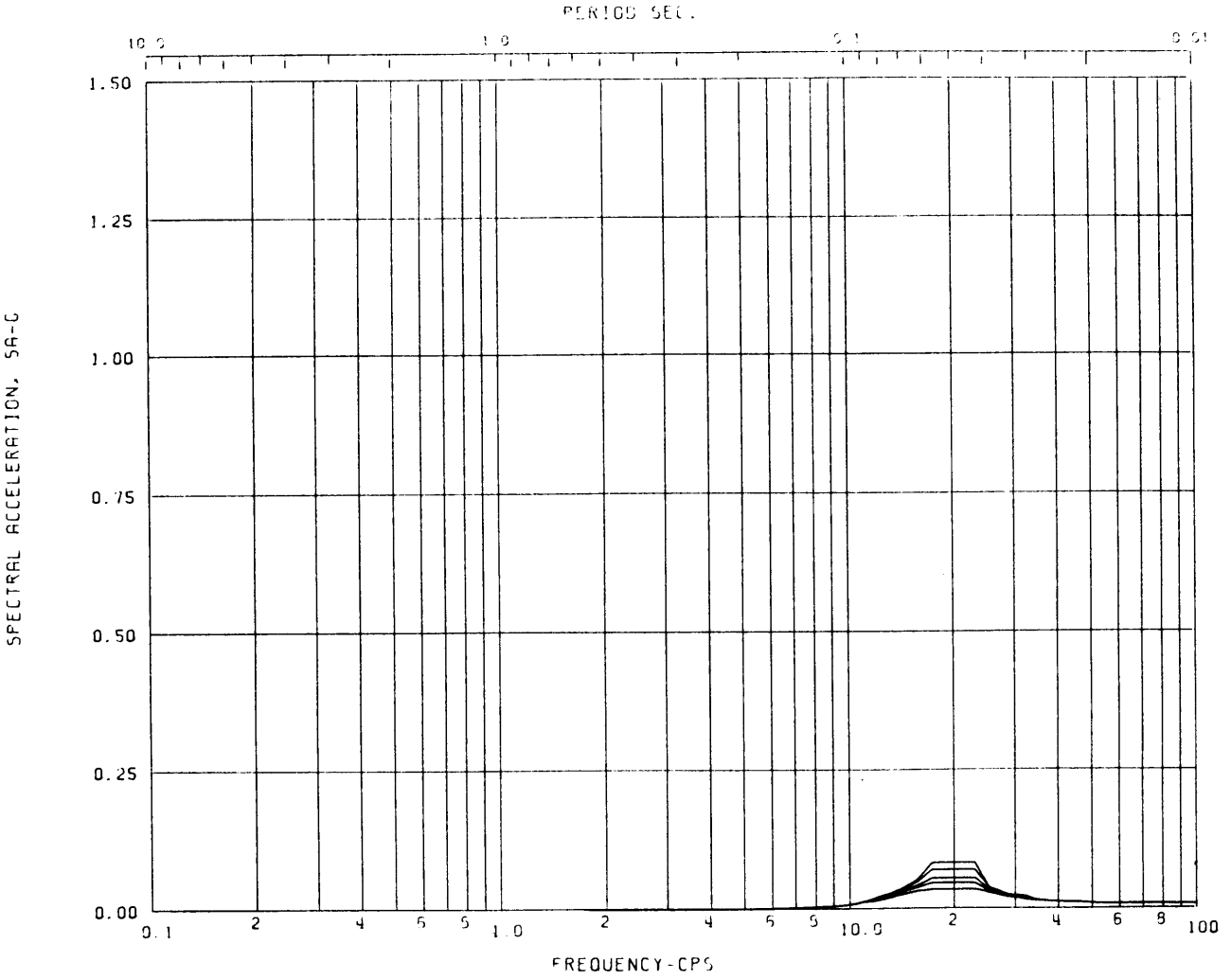
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-236



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

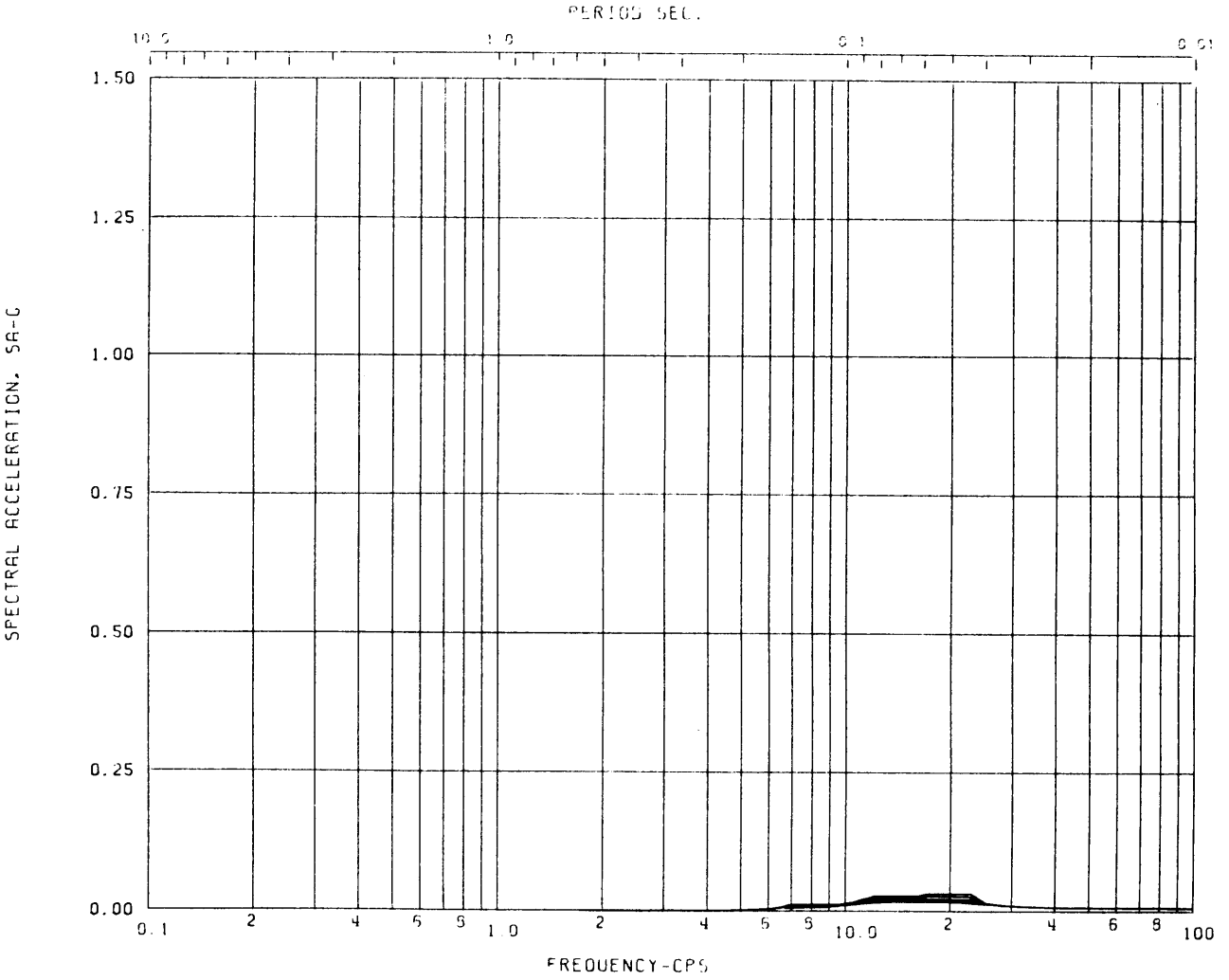
Load Case: CHUGGING GE700 SERIES ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 11 Direction: HORIZ N-S Elev: 352'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-237



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

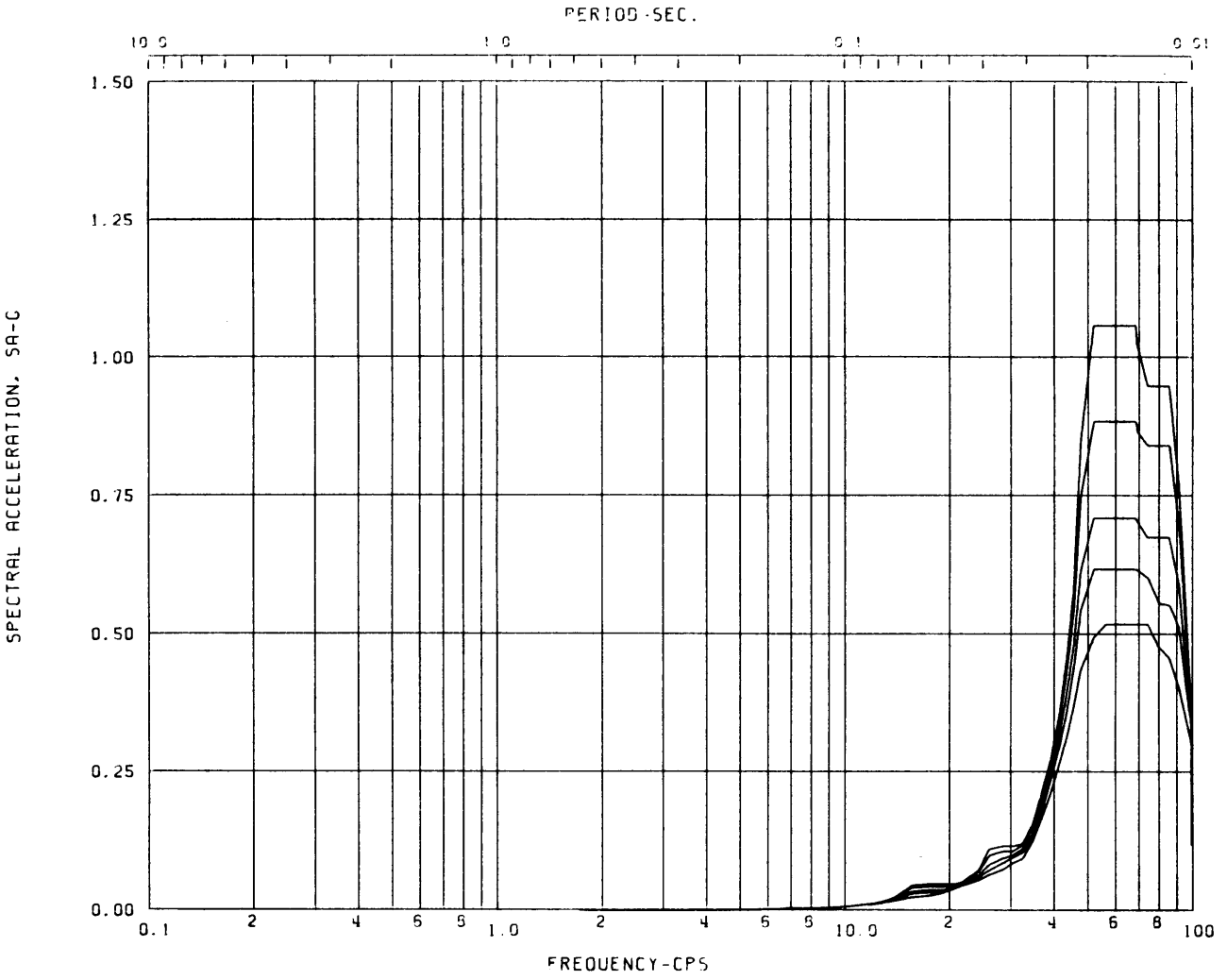
Load Case: CHUGGING GE700 SERIES ASYMMETRIC ENVELOPE (WIDENED - 15%)

Node: 12 Direction: HORIZ N-S Elev: 410'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, N-S HORIZONTAL, CHUG ASYMMETRIC
FIGURE 3A-238



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: ASYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 1 Direction: HORIZ E-W Elev: 177'-0

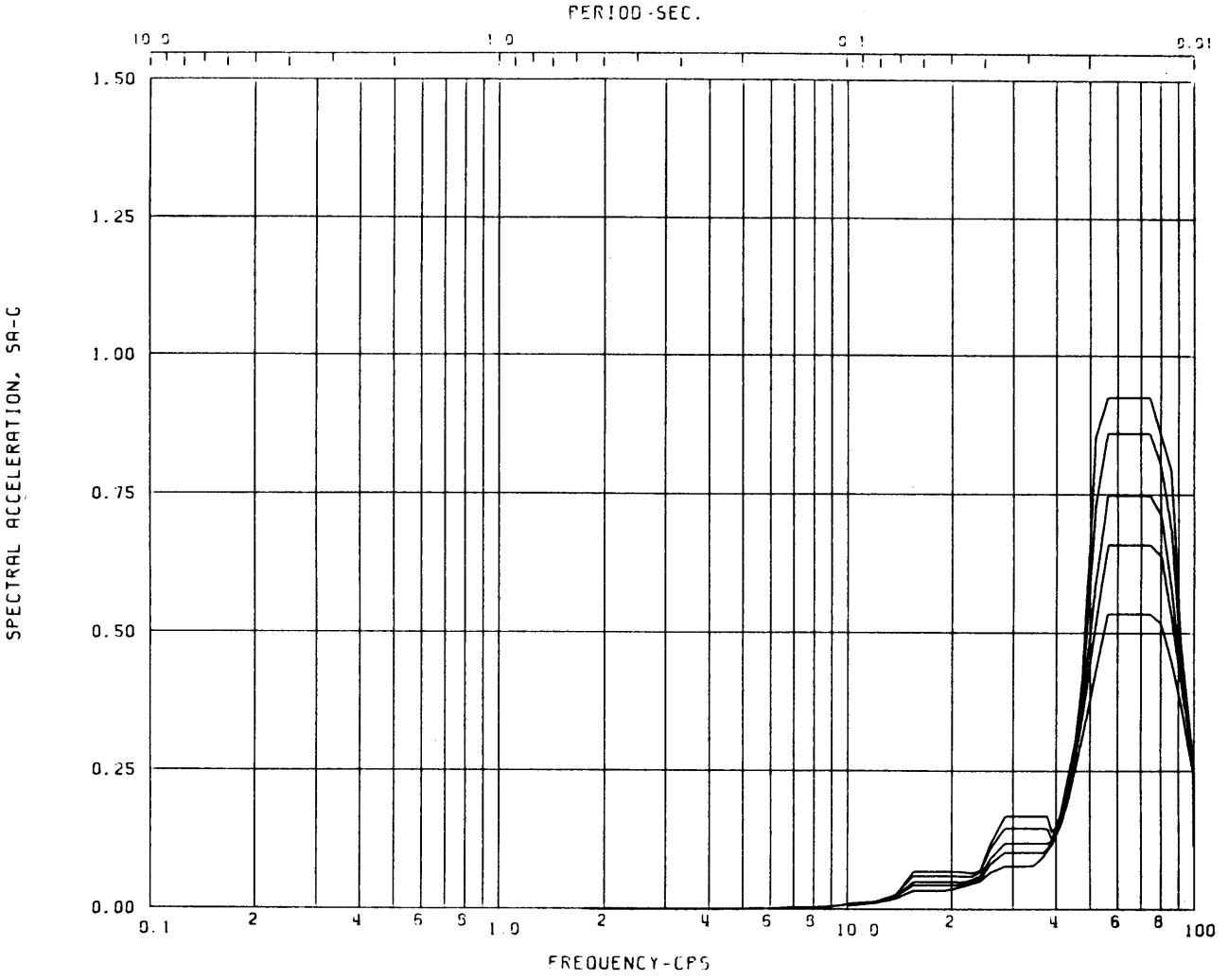
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, E-W HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-239



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: ASYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 2 Direction: HORIZ E-W Elev: 201'-0

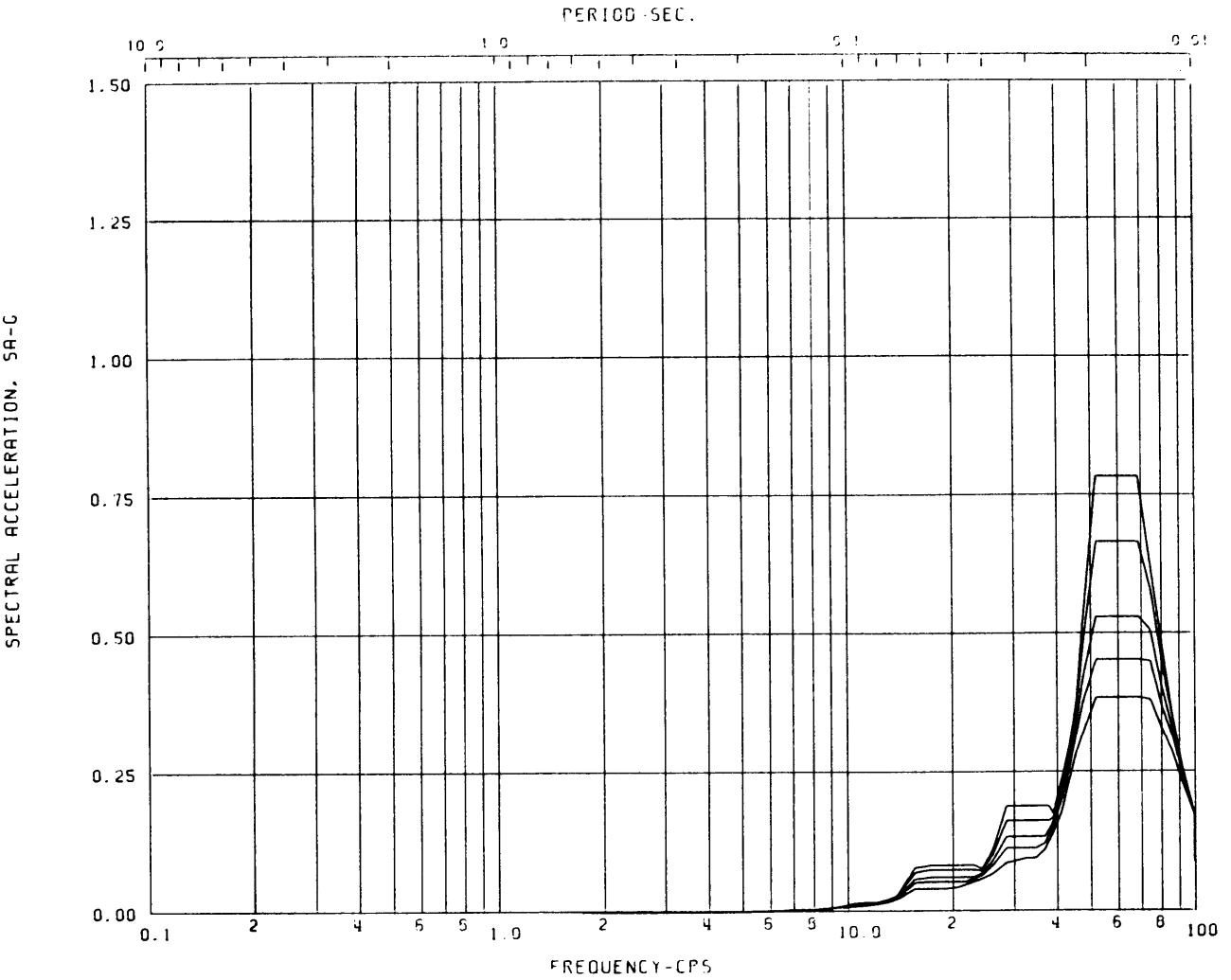
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, E-W HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-240



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

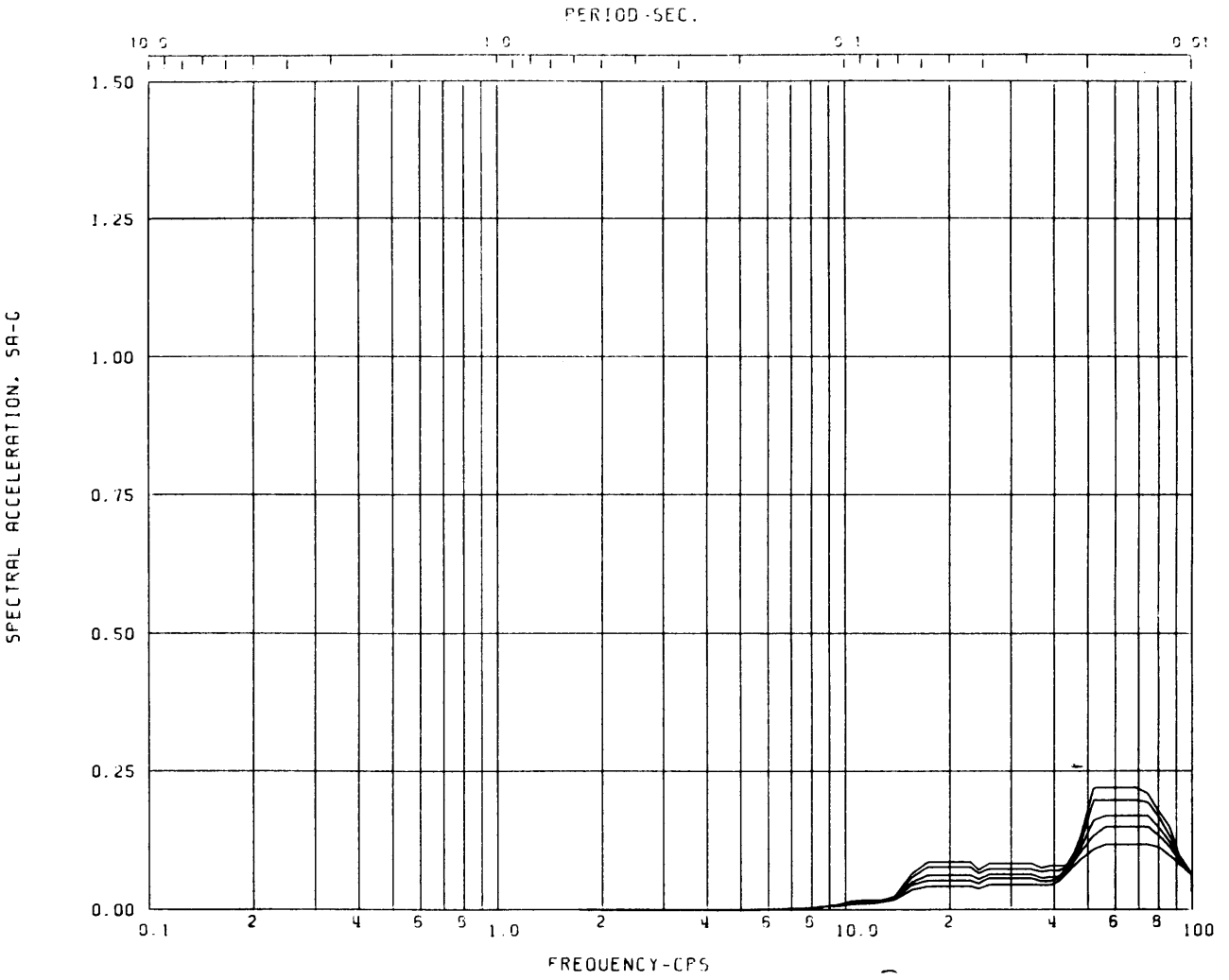
Load Case: ASYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 3 Direction: HORIZ E-W Elev: 217'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, E-W HORIZONTAL, CHUG ASYMMETRIC
FIGURE 3A-241



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

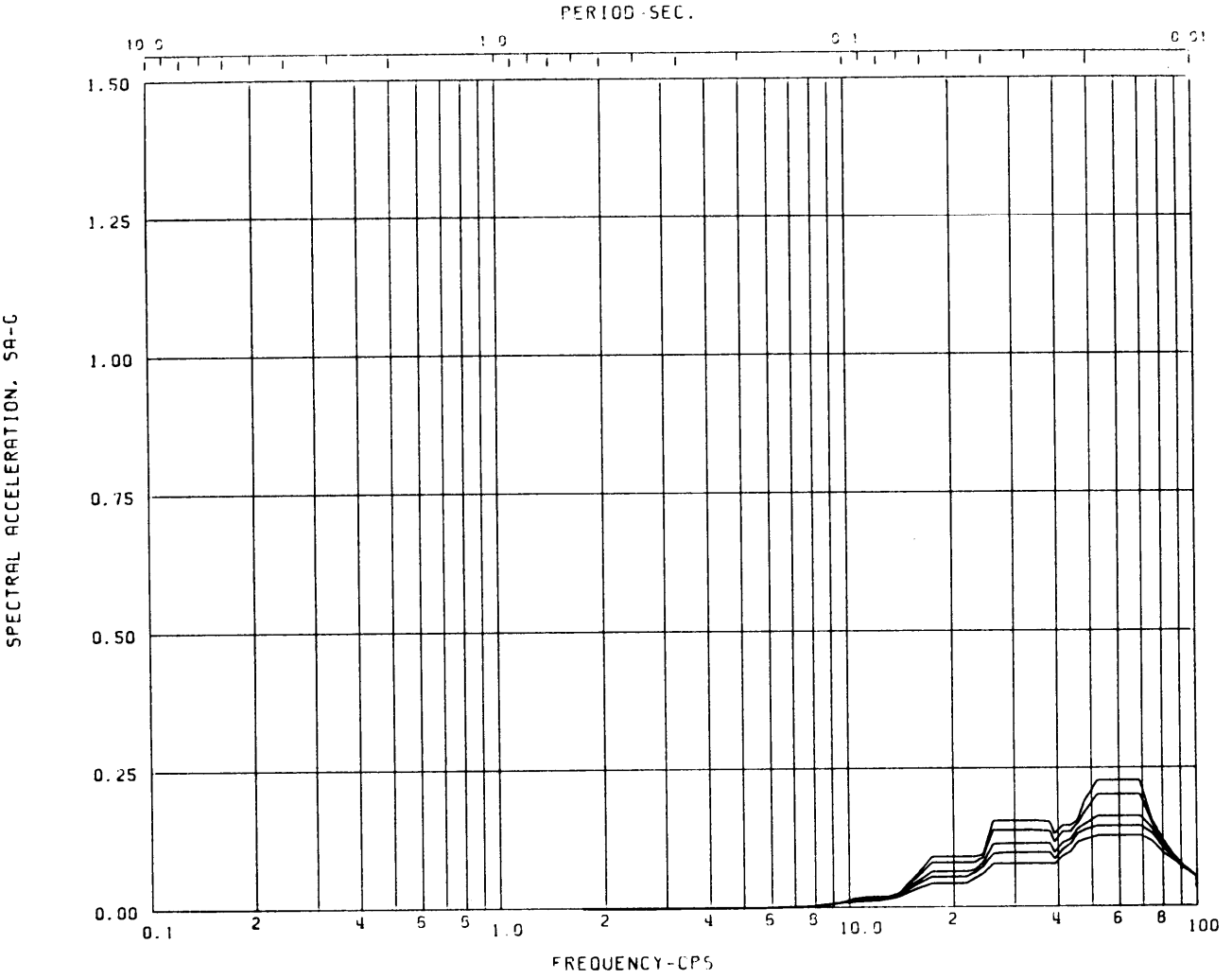
Load Case: ASYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 4 Direction: HORIZ E-W Elev: 239'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, E-W HORIZONTAL, CHUG ASYMMETRIC
FIGURE 3A-242



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

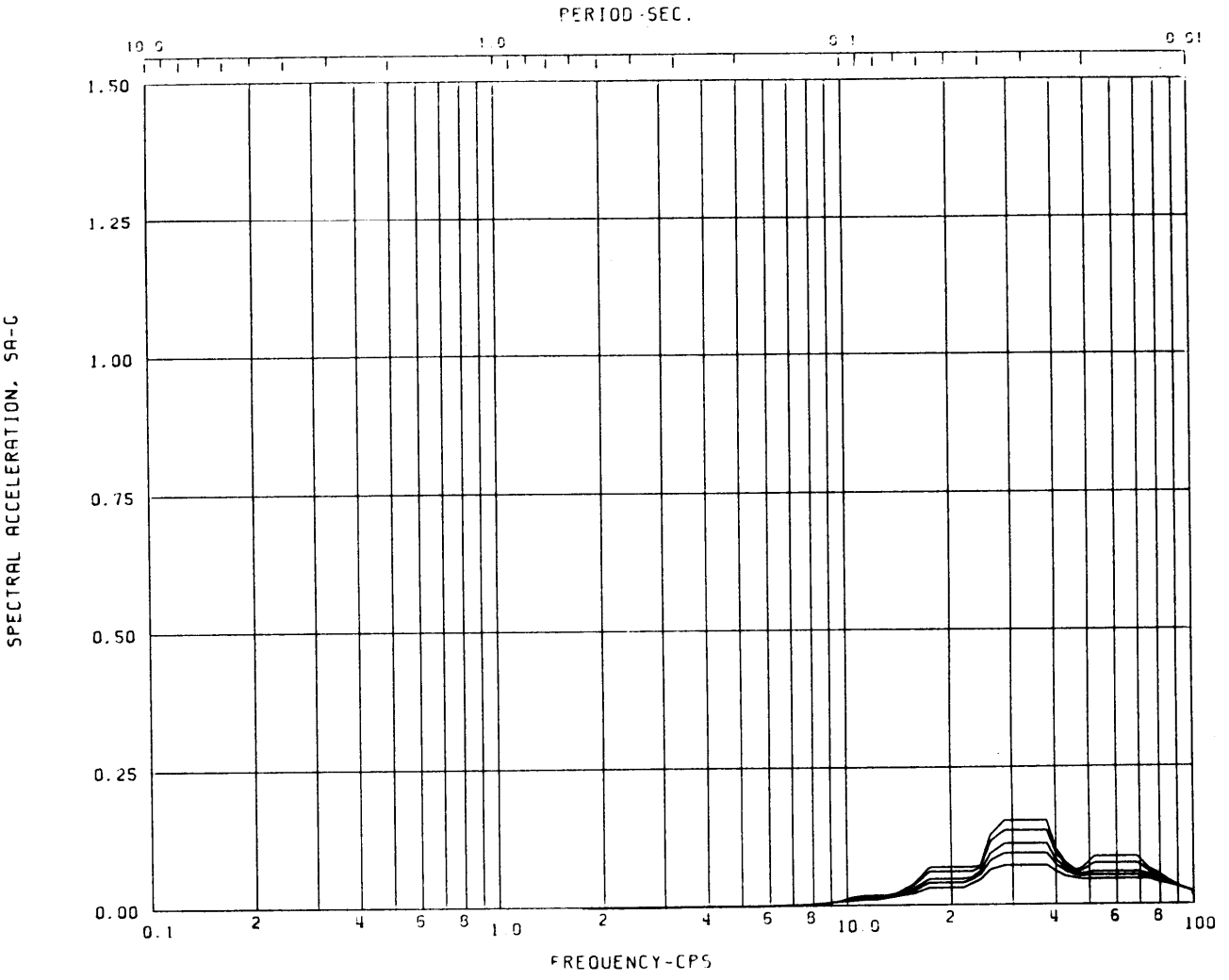
Load Case: ASYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 5 Direction: HORIZ E-W Elev: 253'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, E-W HORIZONTAL, CHUG ASYMMETRIC
FIGURE 3A-243



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: ASYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

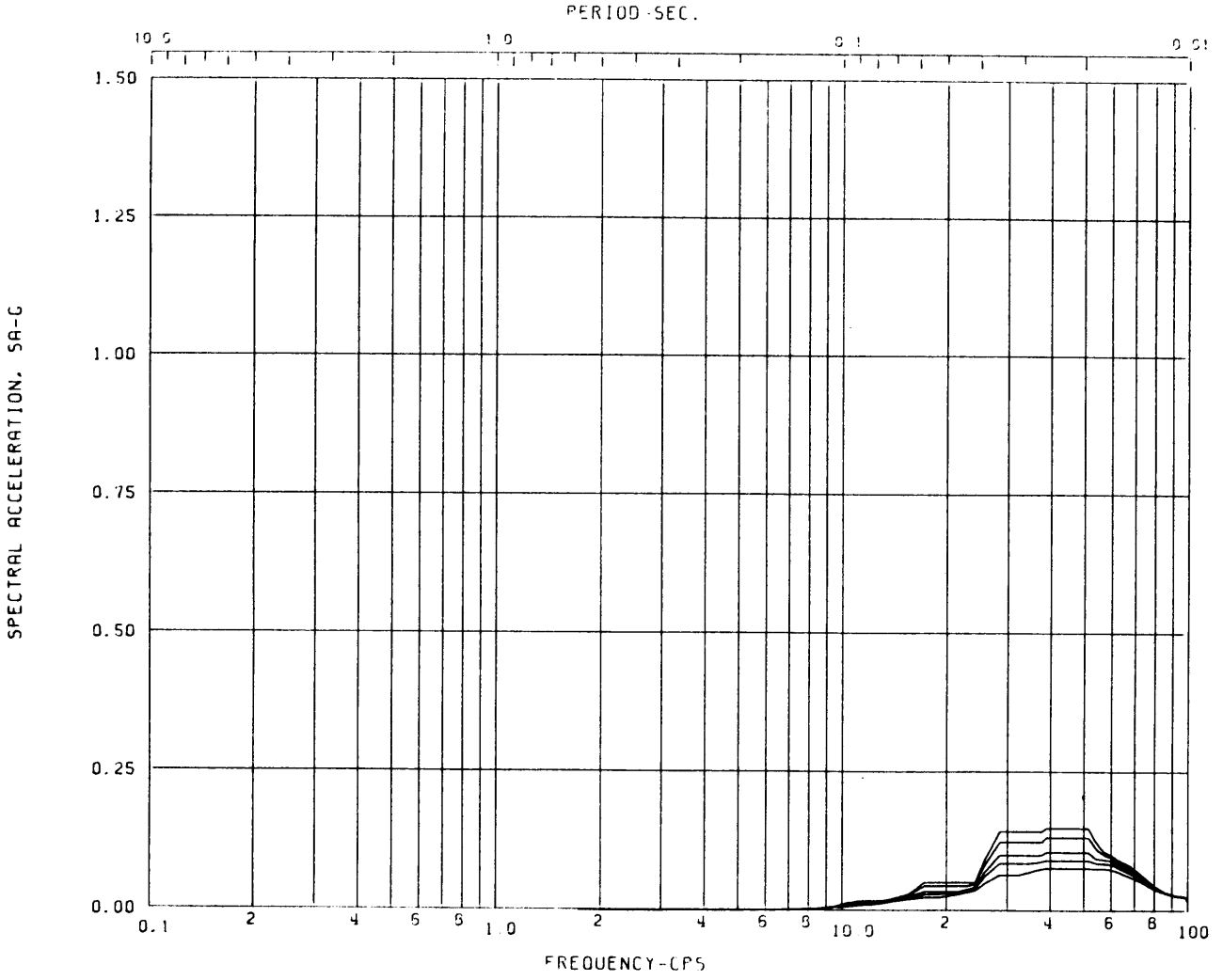
Node: 6 Direction: HORIZ E-W Elev: 269'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, E-W HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-244



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: ASYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 7 Direction: HORIZ E-W Elev: 283'-0

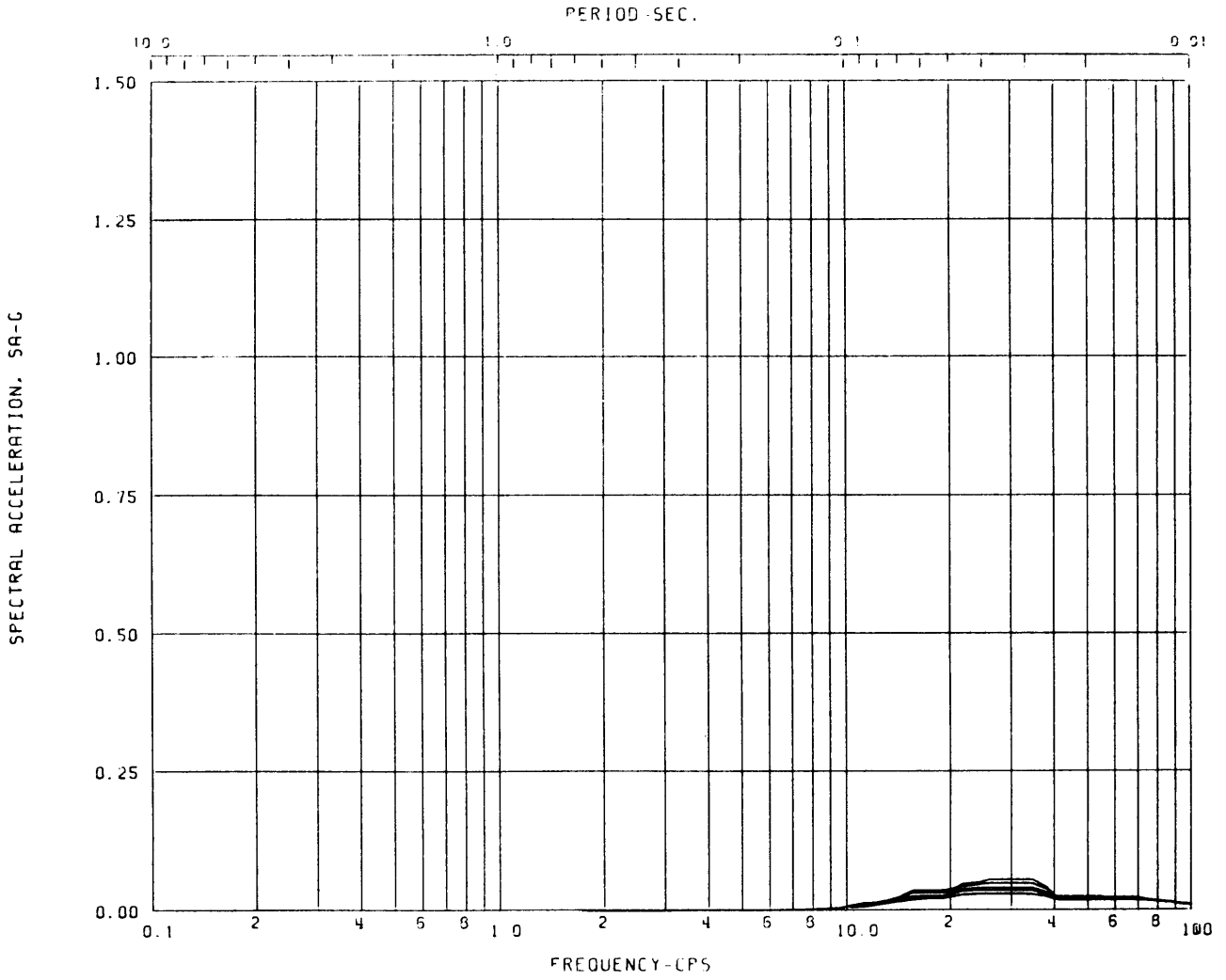
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, E-W HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-245



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: ASYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 8 Direction: HORIZ E-W Elev: 304'-0

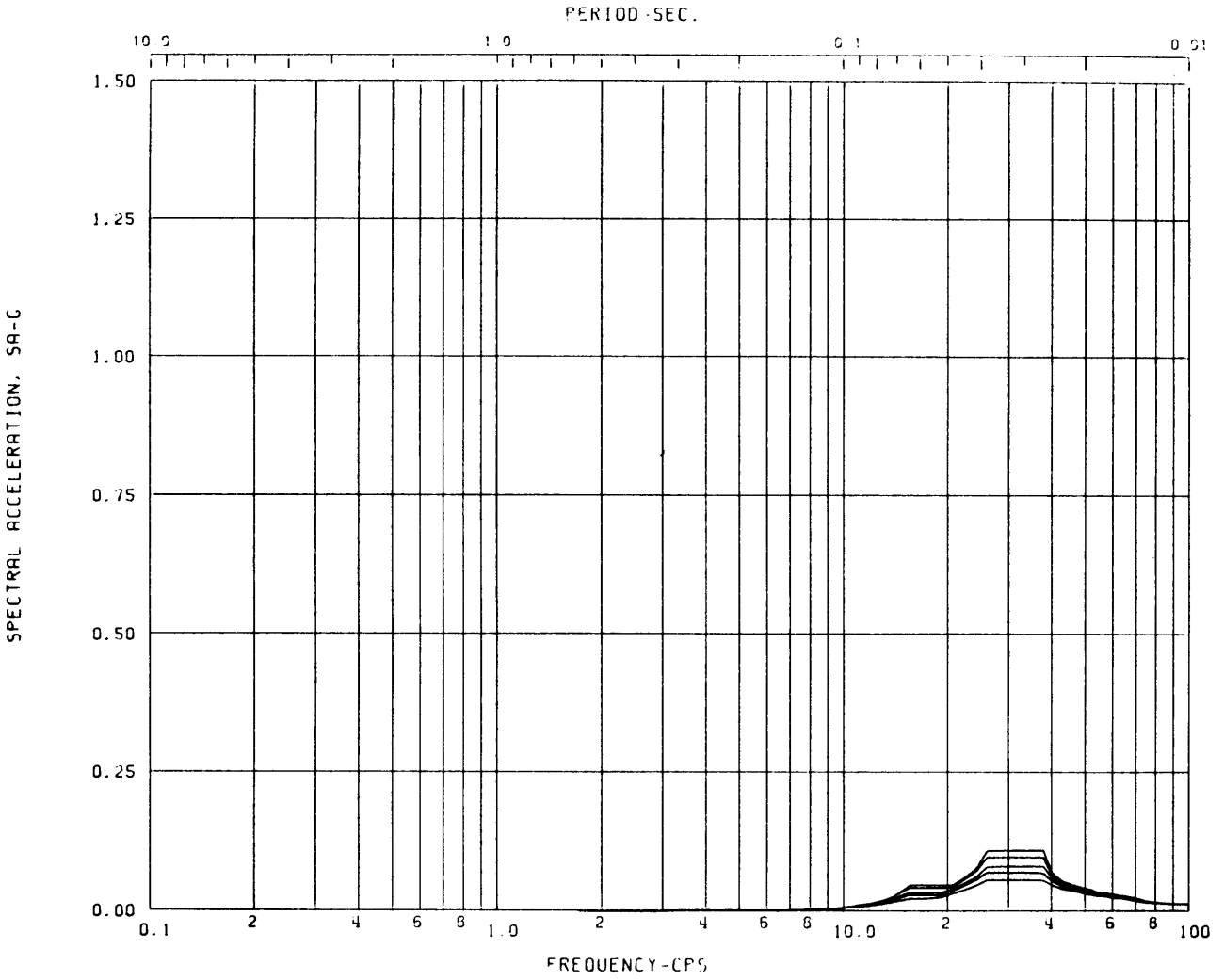
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, E-W HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-246



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: ASYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 9 Direction: HORIZ E-W Elev: 313'-0

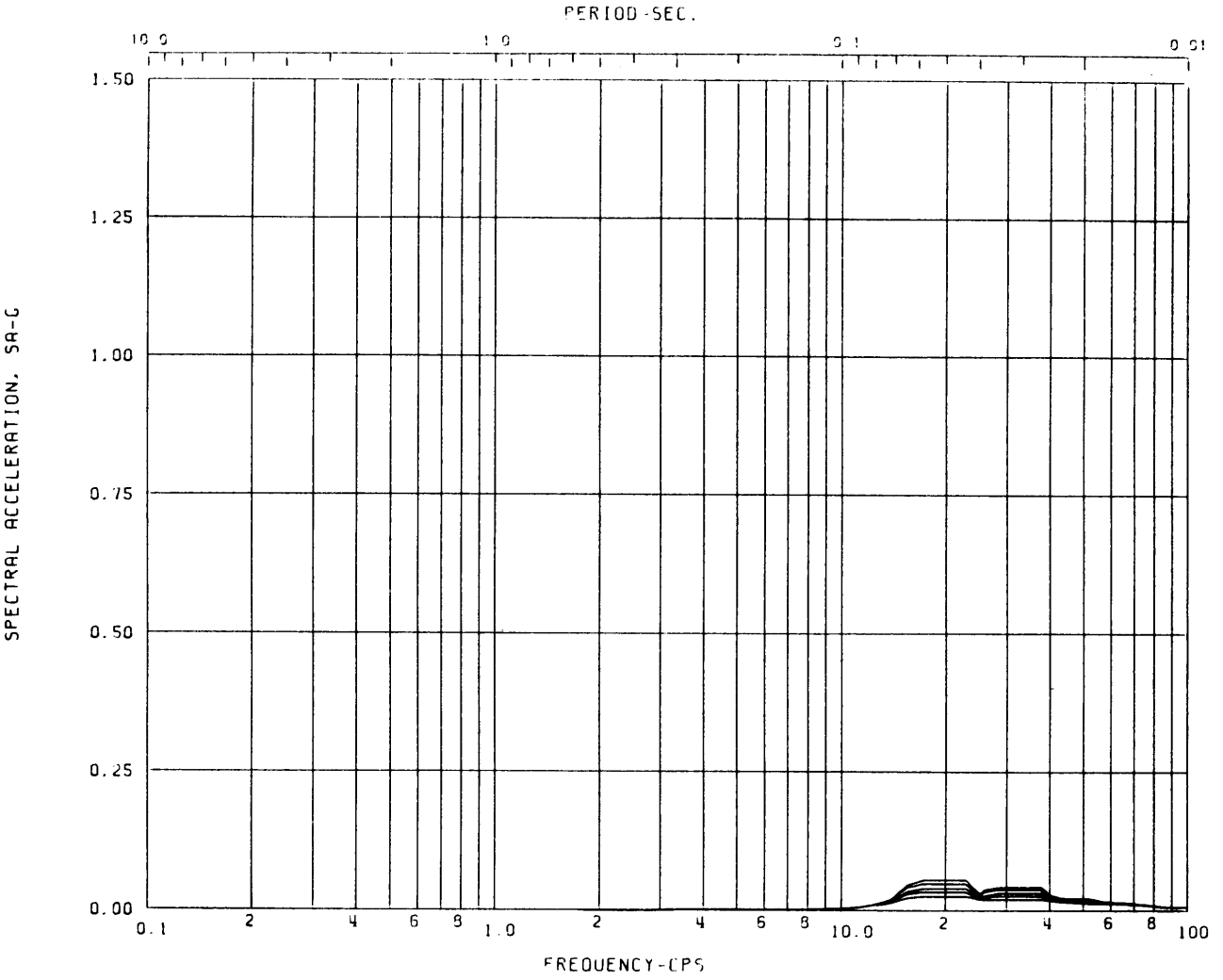
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, E-W HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-247



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: ASYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

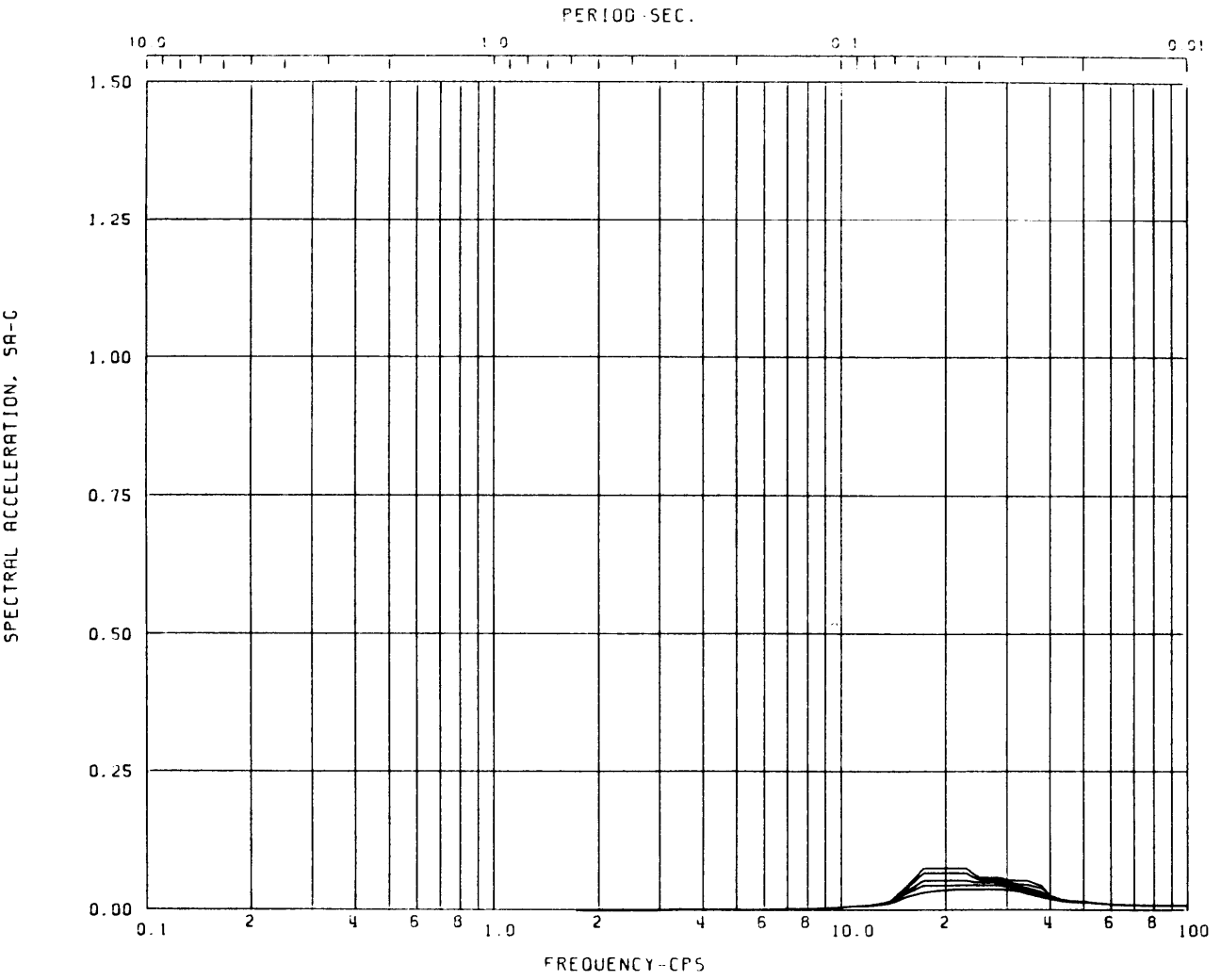
Node: 10 Direction: HORIZ E-W Elev: 332'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-248



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: ASYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 11 Direction: HORIZ E-W Elev: 352'-0

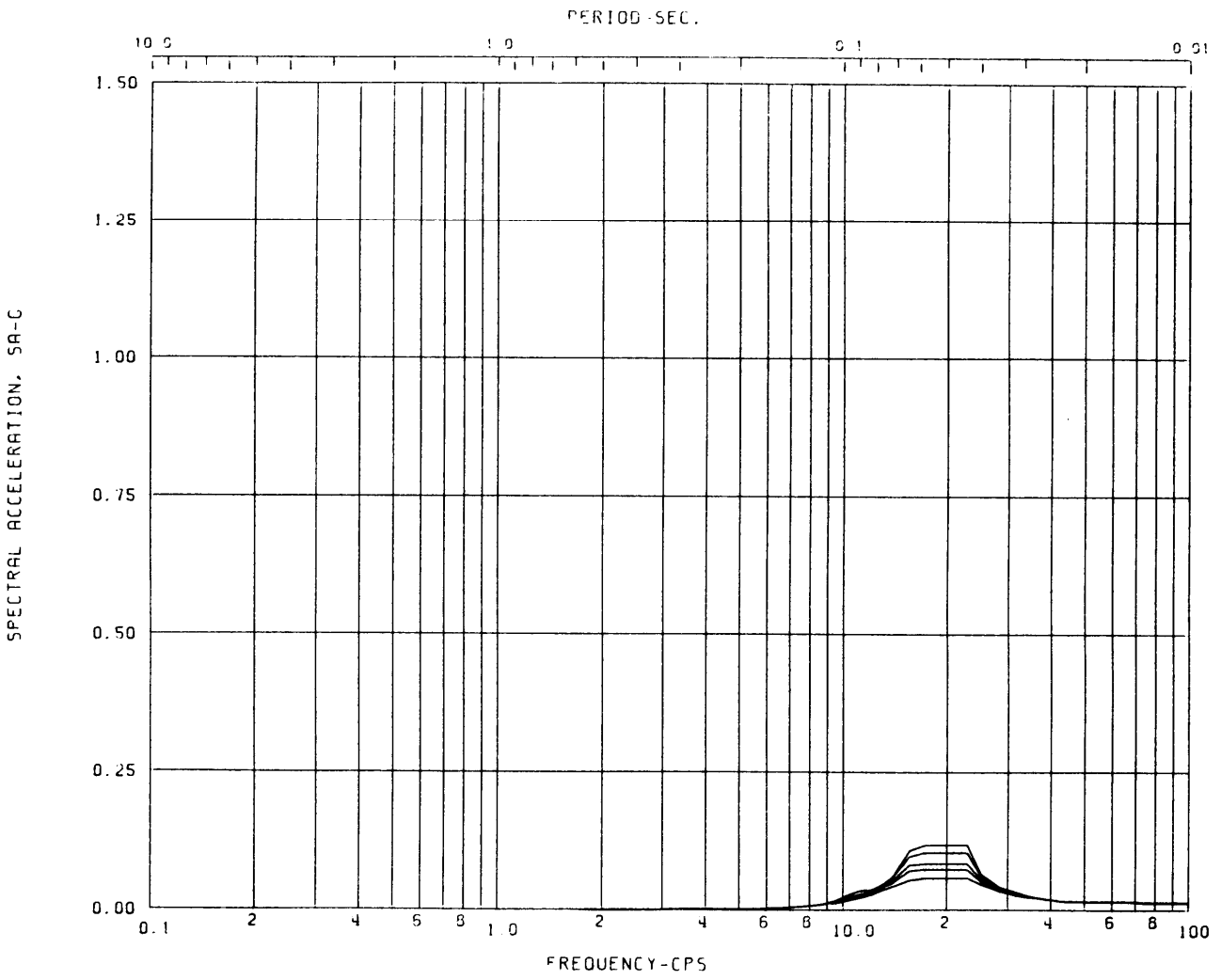
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE AND CONTROL STRUCTURE GLOBAL RESPONSE SPECTRA, E-W HORIZONTAL, CHUG ASYMMETRIC

FIGURE 3A-249



Acceleration Spectra for REACTOR ENCL., CONTROL STRUCTURE

Load Case: ASYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 12 Direction: HORIZ E-W Elev: 410'-0

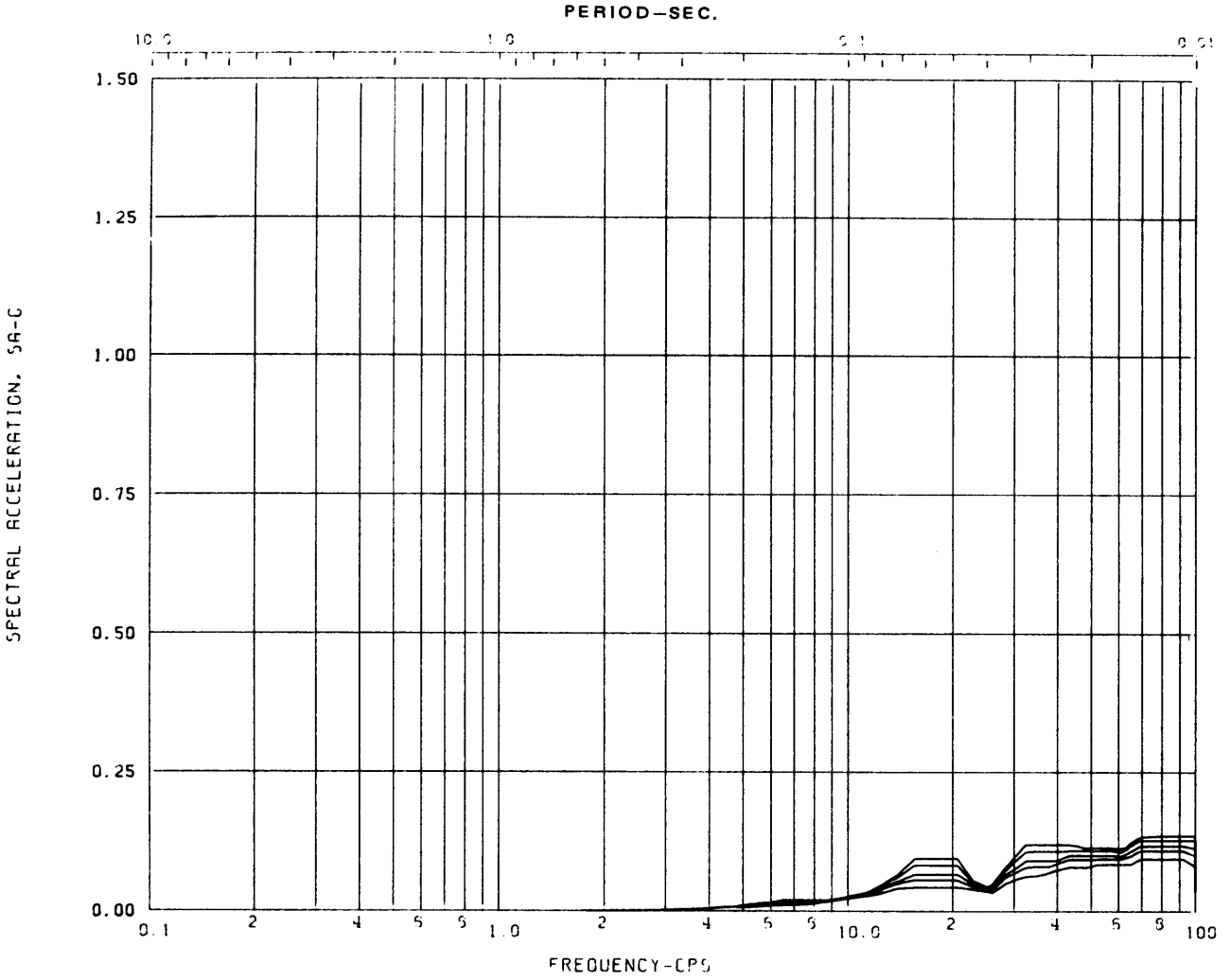
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-250



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 159 Direction: VERTICAL Elev: 177'

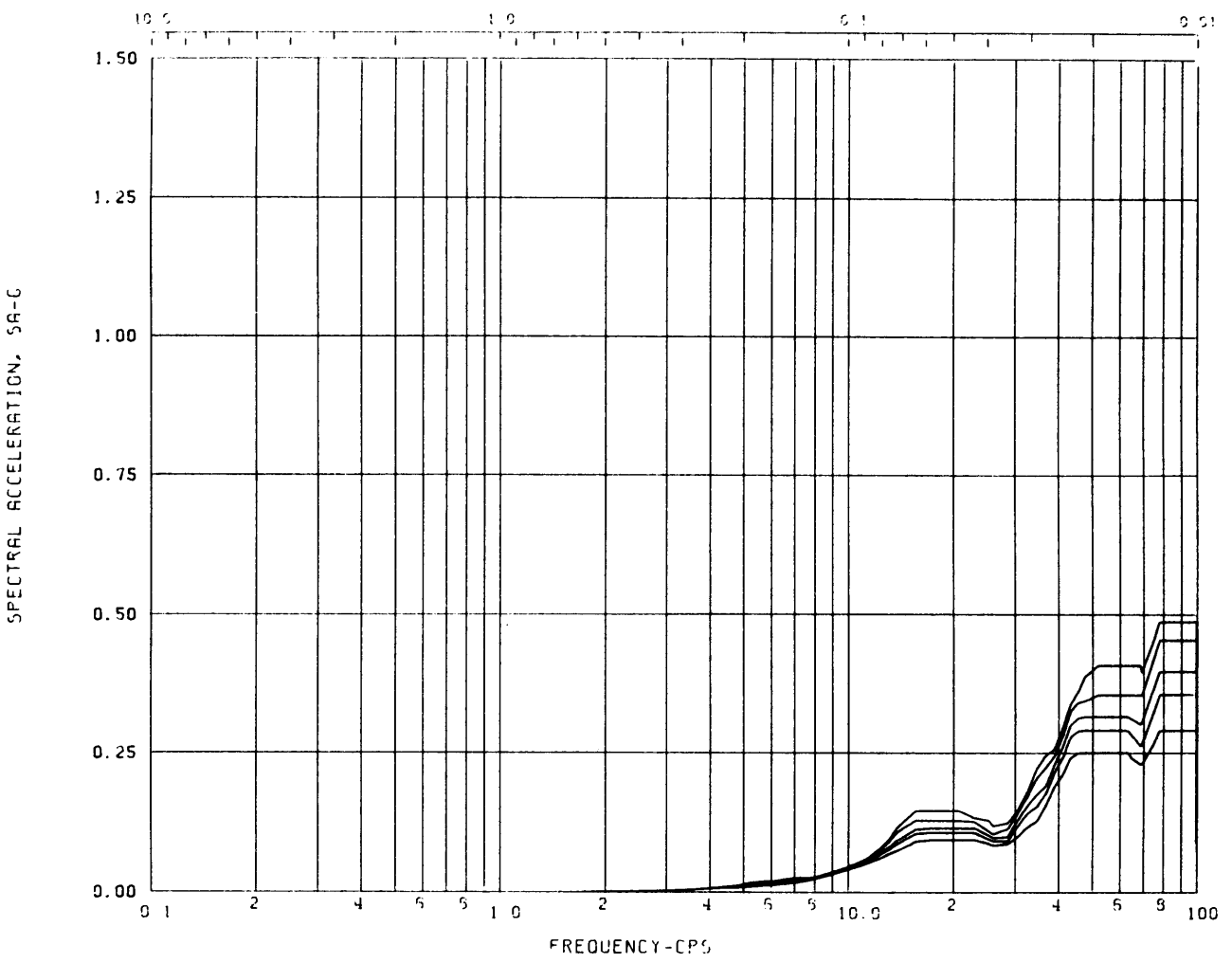
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-251



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 154 Direction: VERTICAL Elev: 177'

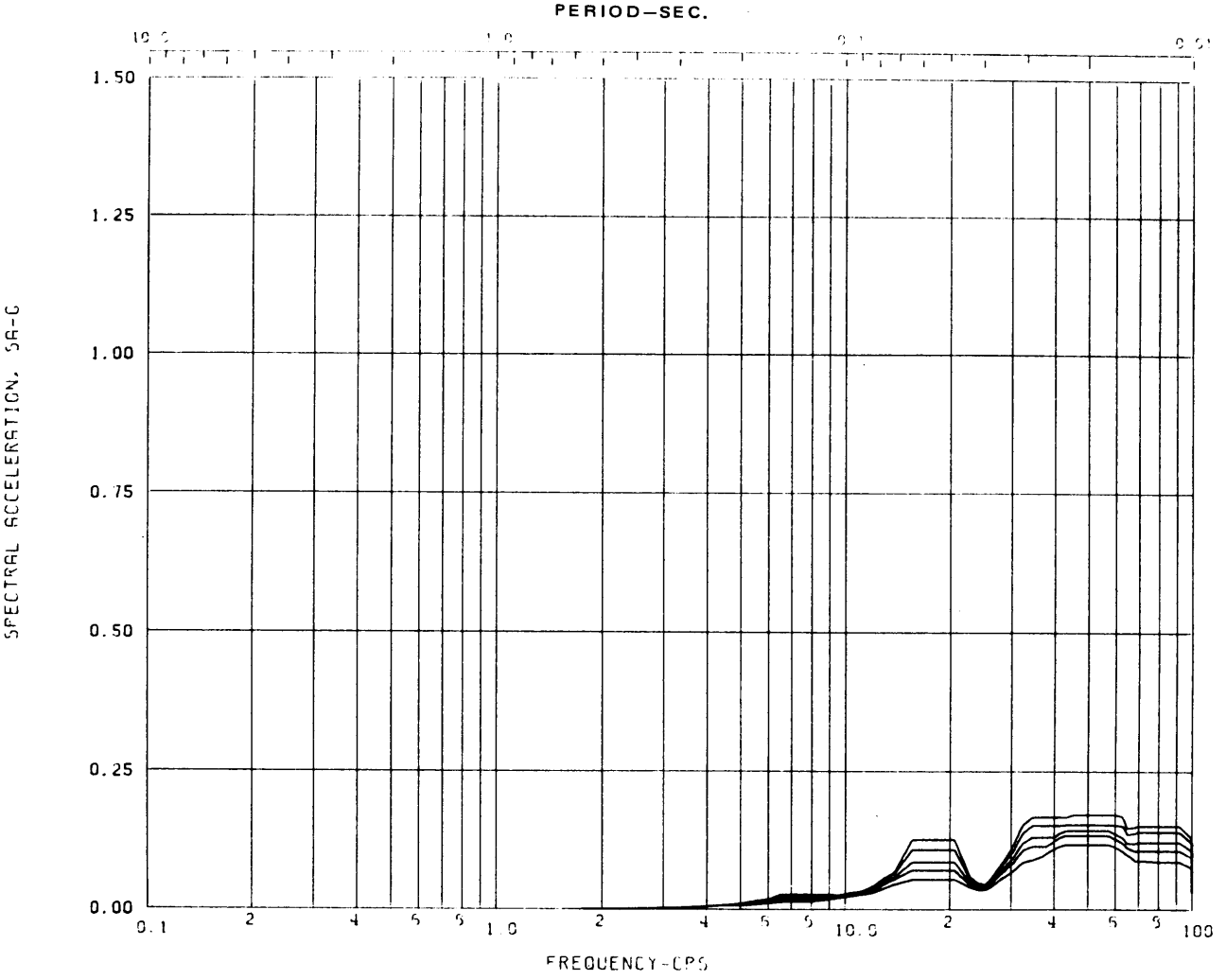
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-252



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 128 Direction: VERTICAL Elev: 201'

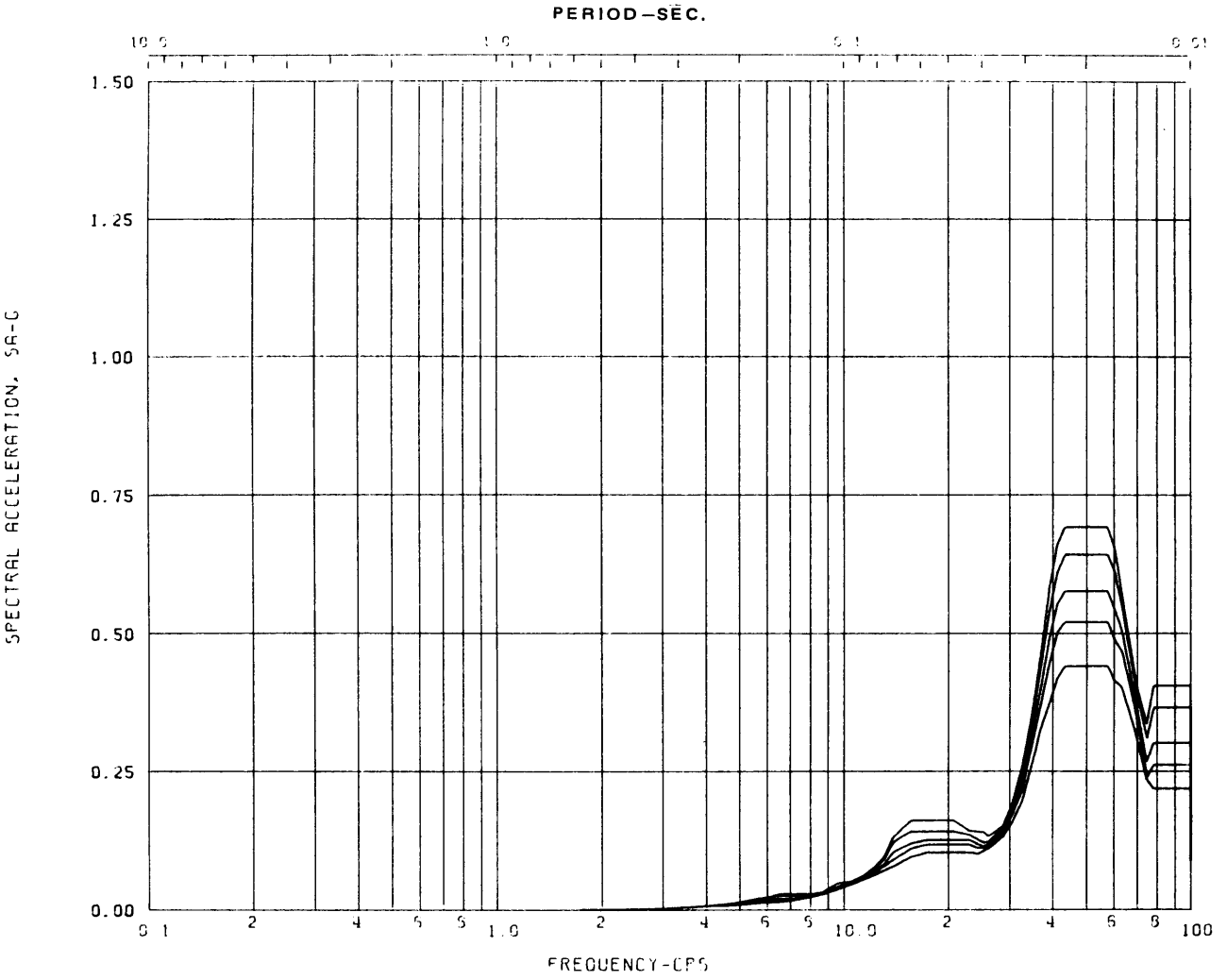
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-253



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIFS ENVELOPE (WIDENED - 15%)

Node: 130 Direction: VERTICAL Elev: 201'

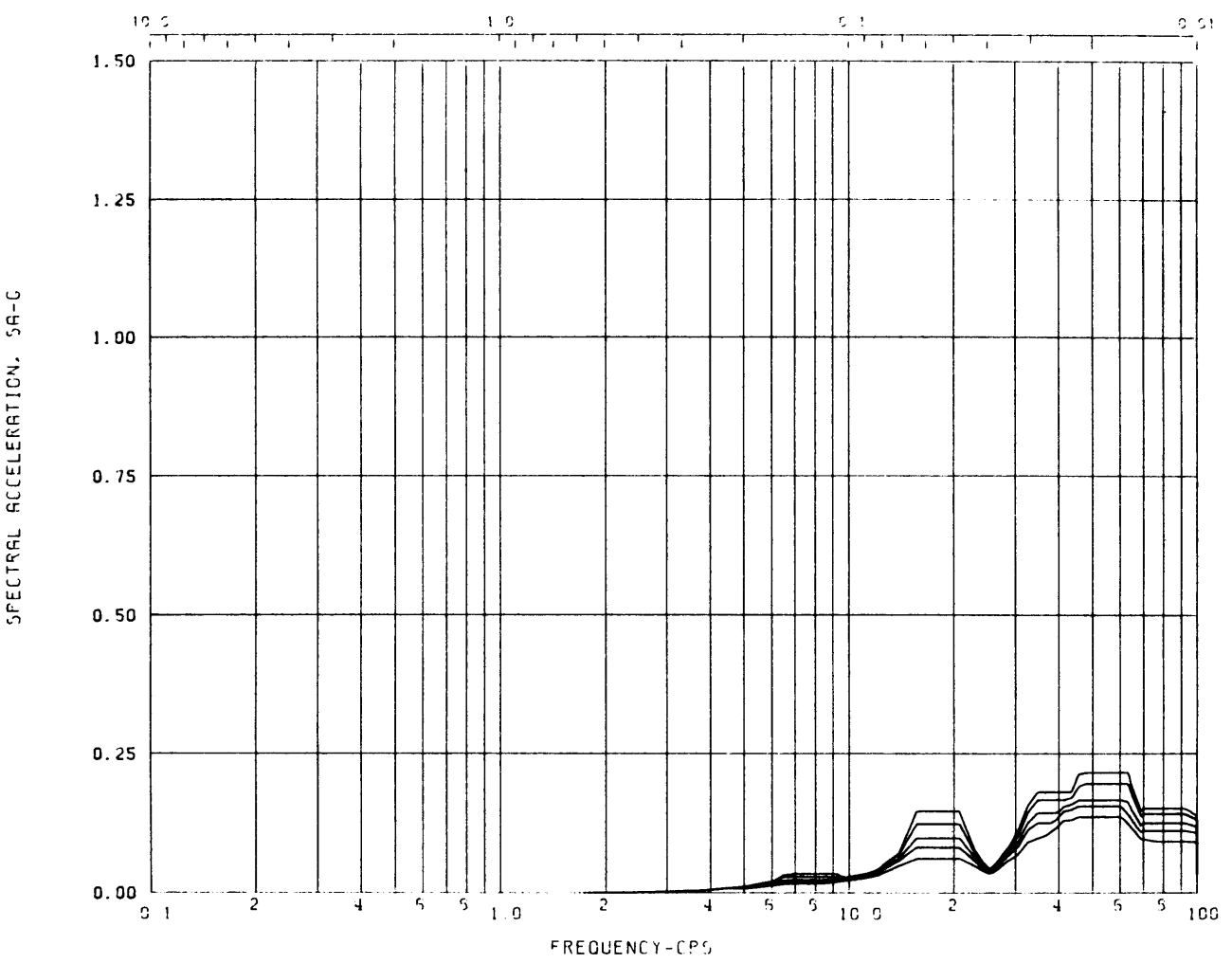
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-254



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 106 Direction: VERTICAL Elev: 217'

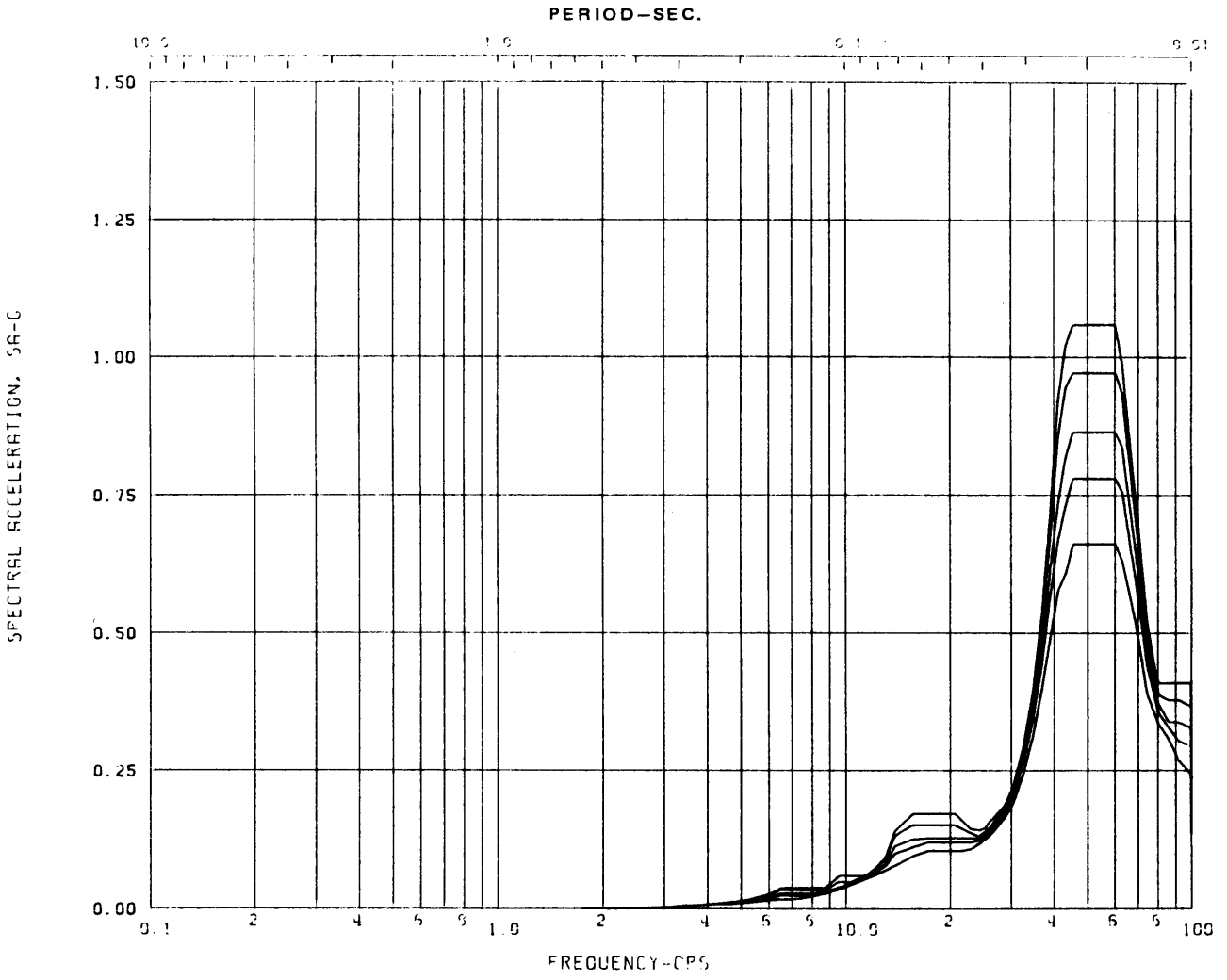
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-255



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

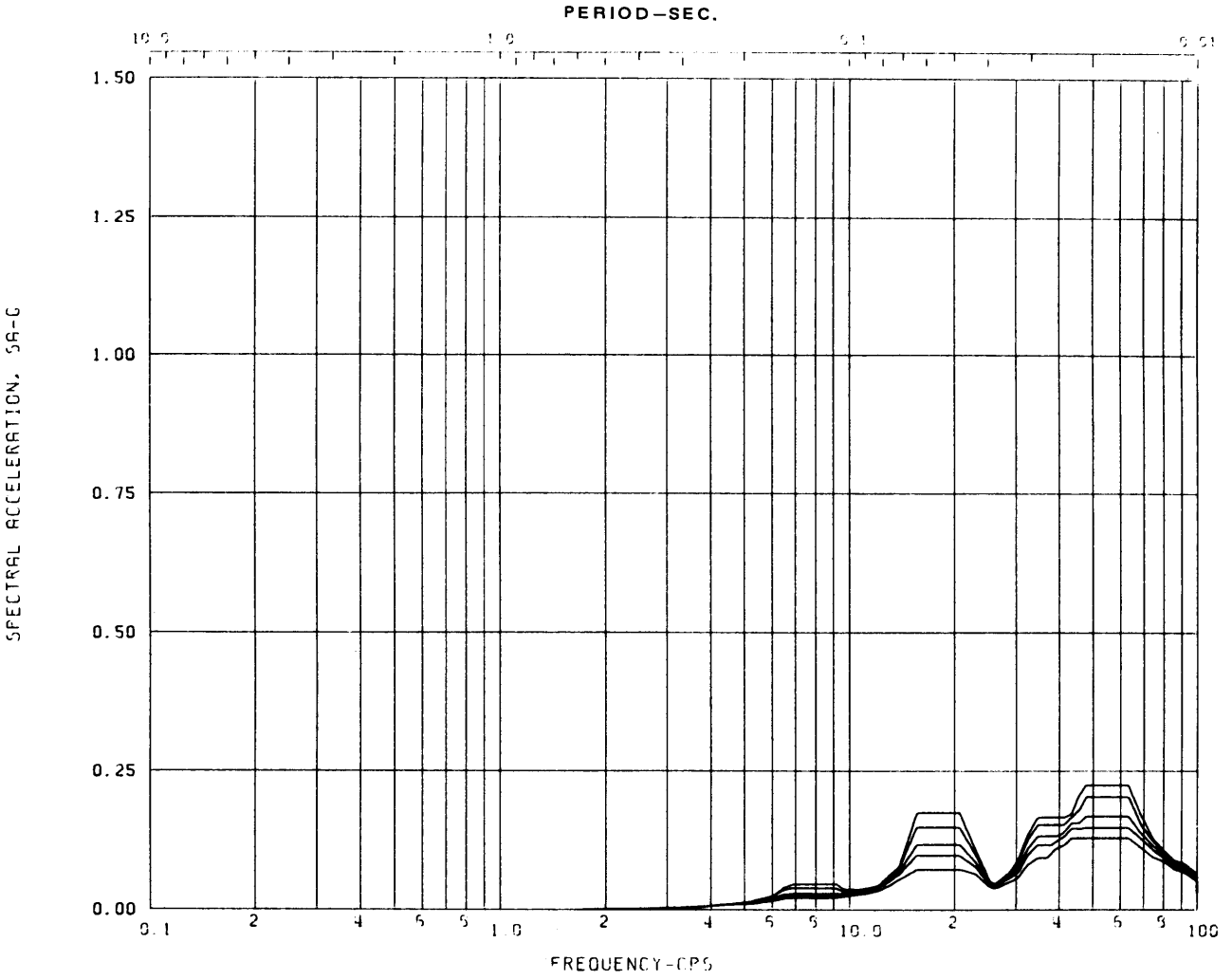
Node: 108 Direction: VERTICAL Elev: 217'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-256



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 104 Direction: VERTICAL Elev: 239'

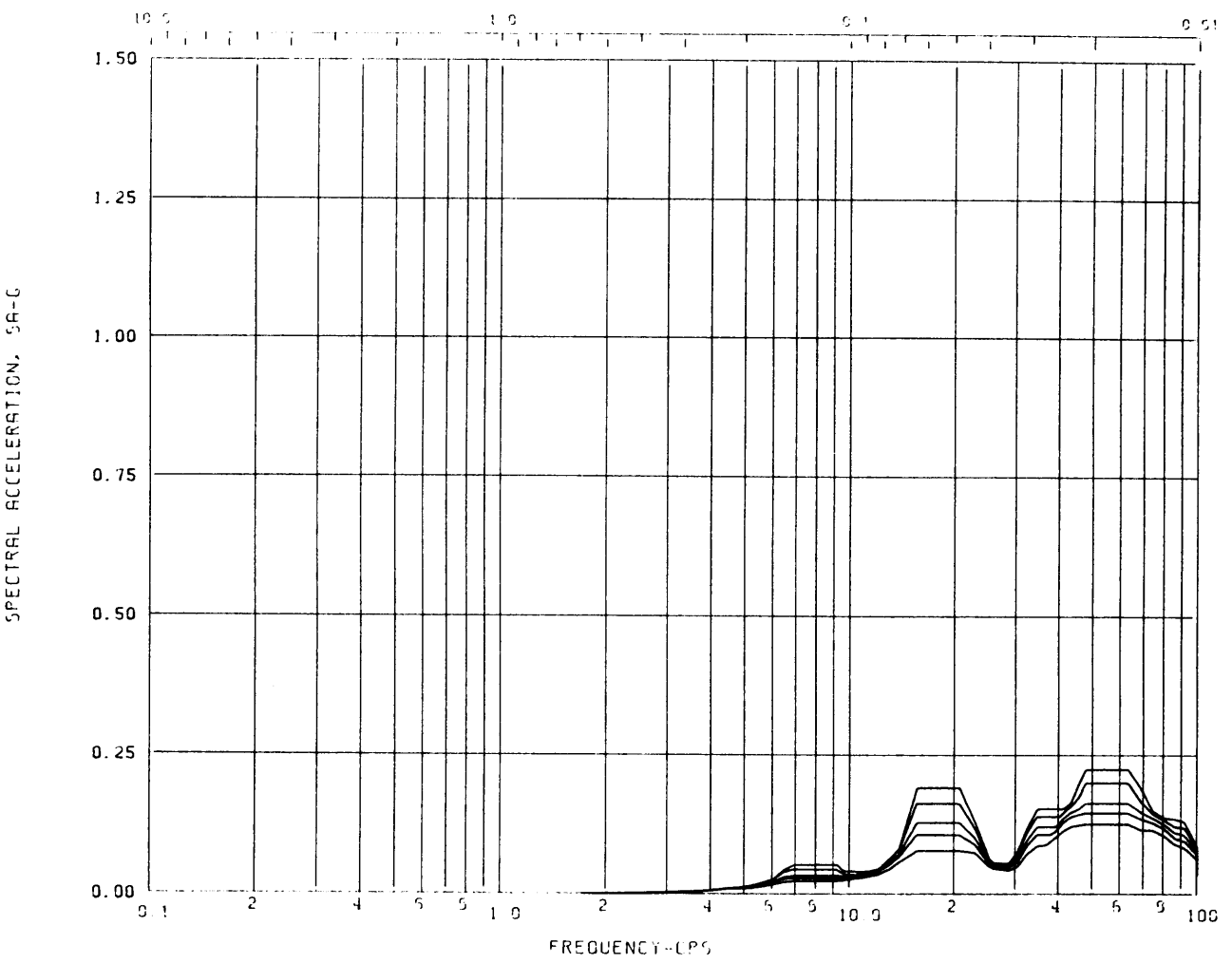
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-257



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIFS ENVELOPE (WIDENED - 15%)

Node: 79 Direction: VERTICAL Elev: 253'

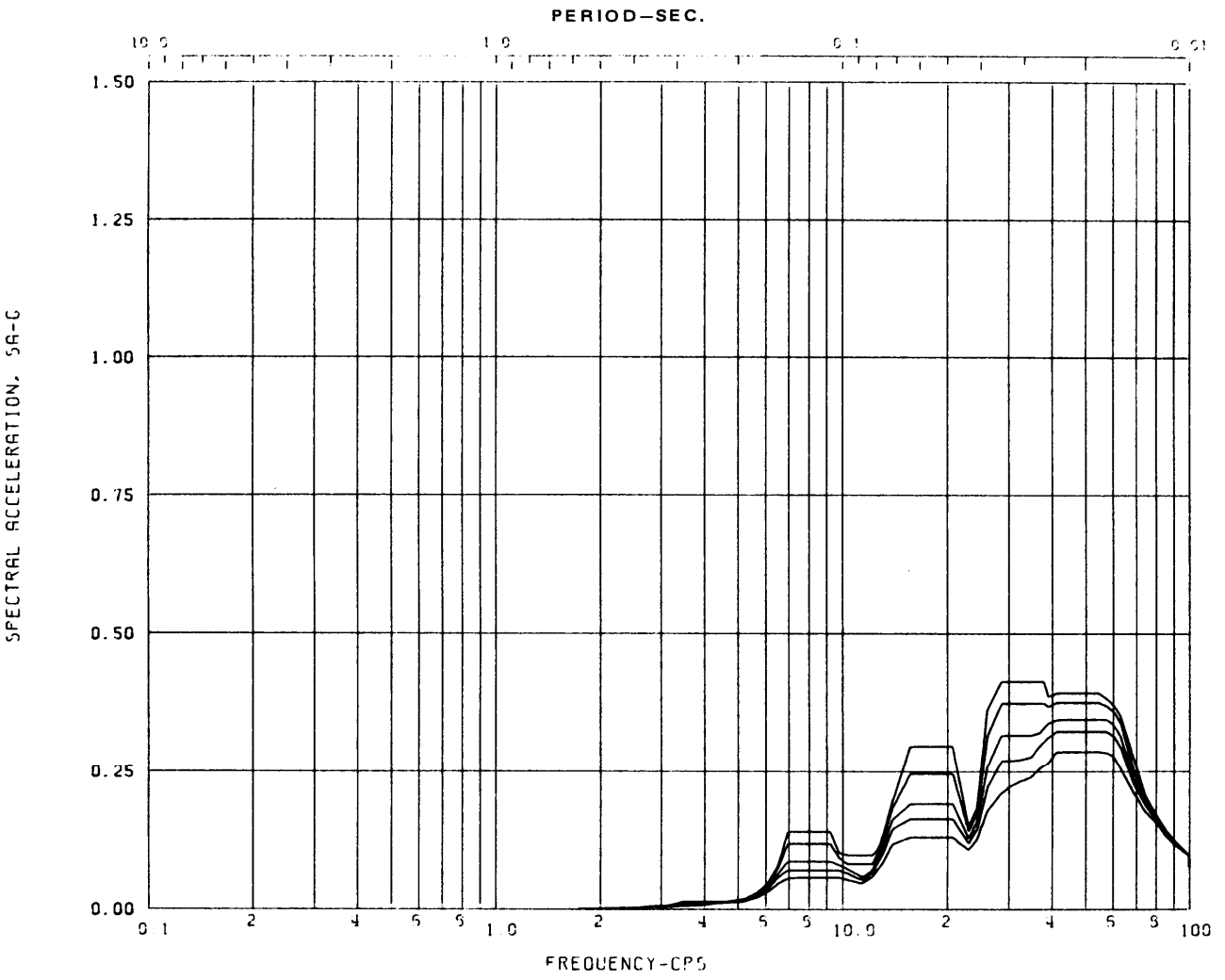
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-258



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 81 Direction: VERTICAL Elev: 253'

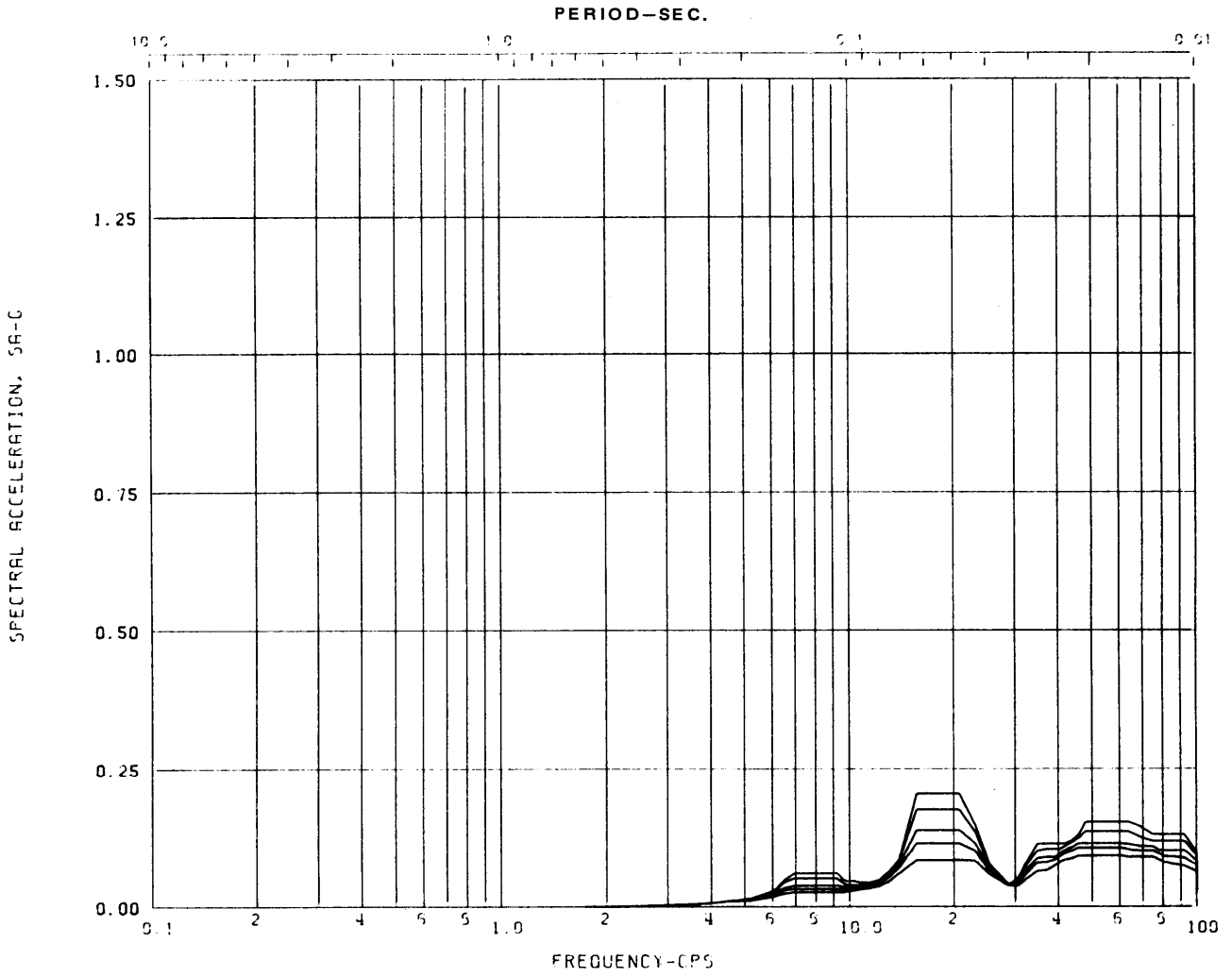
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-259



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 77 Direction: VERTICAL Elev: 269'

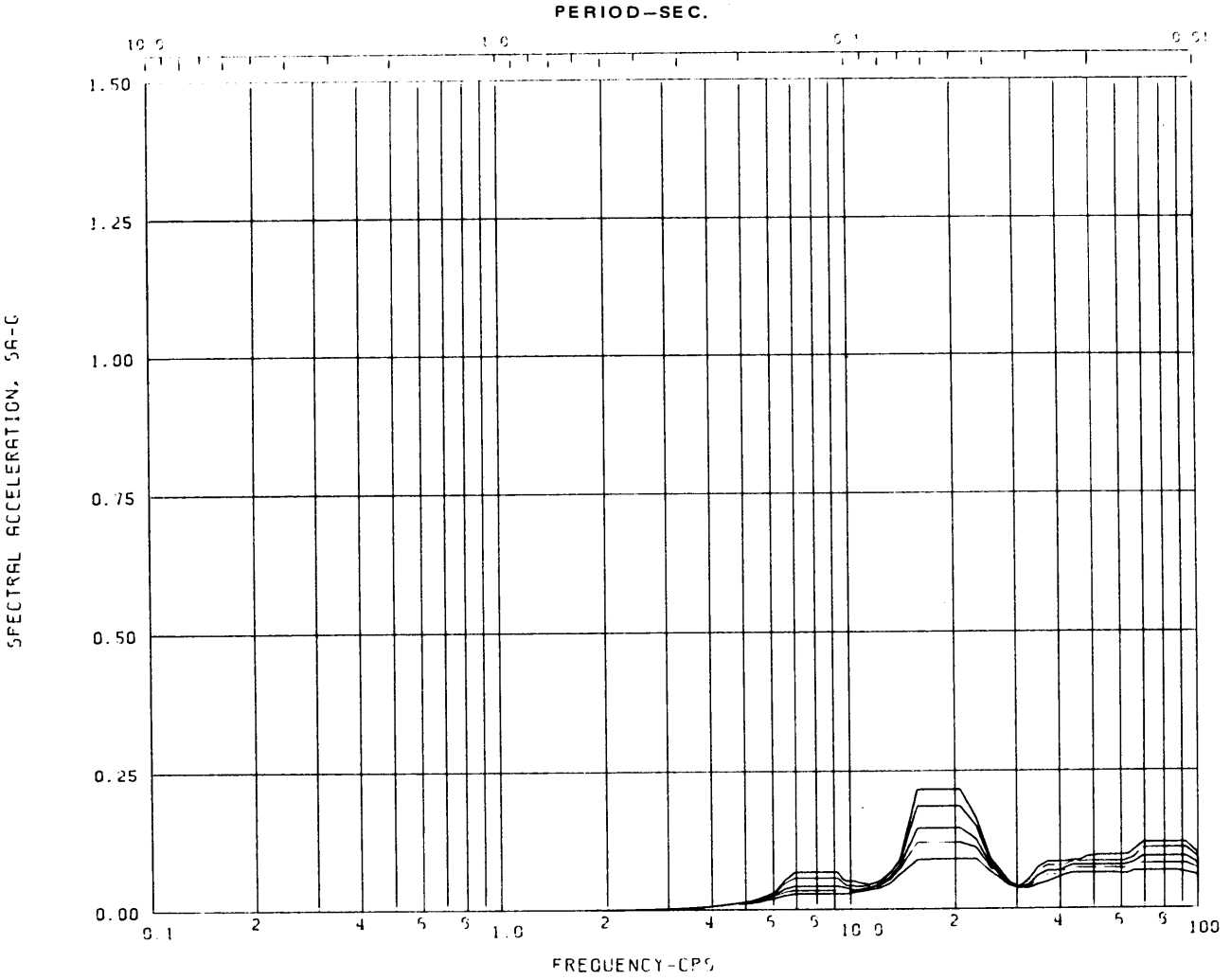
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-260



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 58 Direction: VERTICAL Elev: 283'

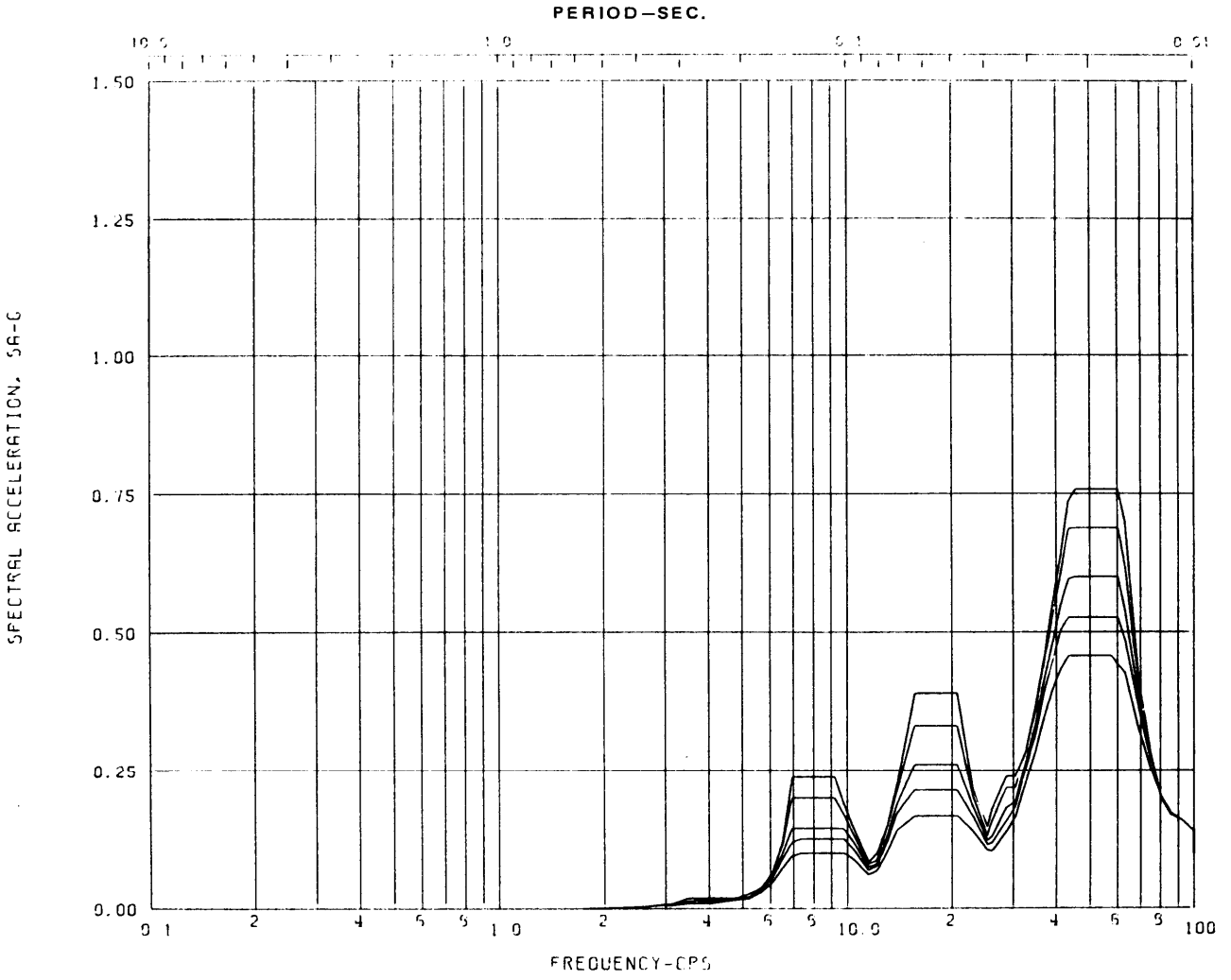
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-261



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 60 Direction: VERTICAL Elev: 283'

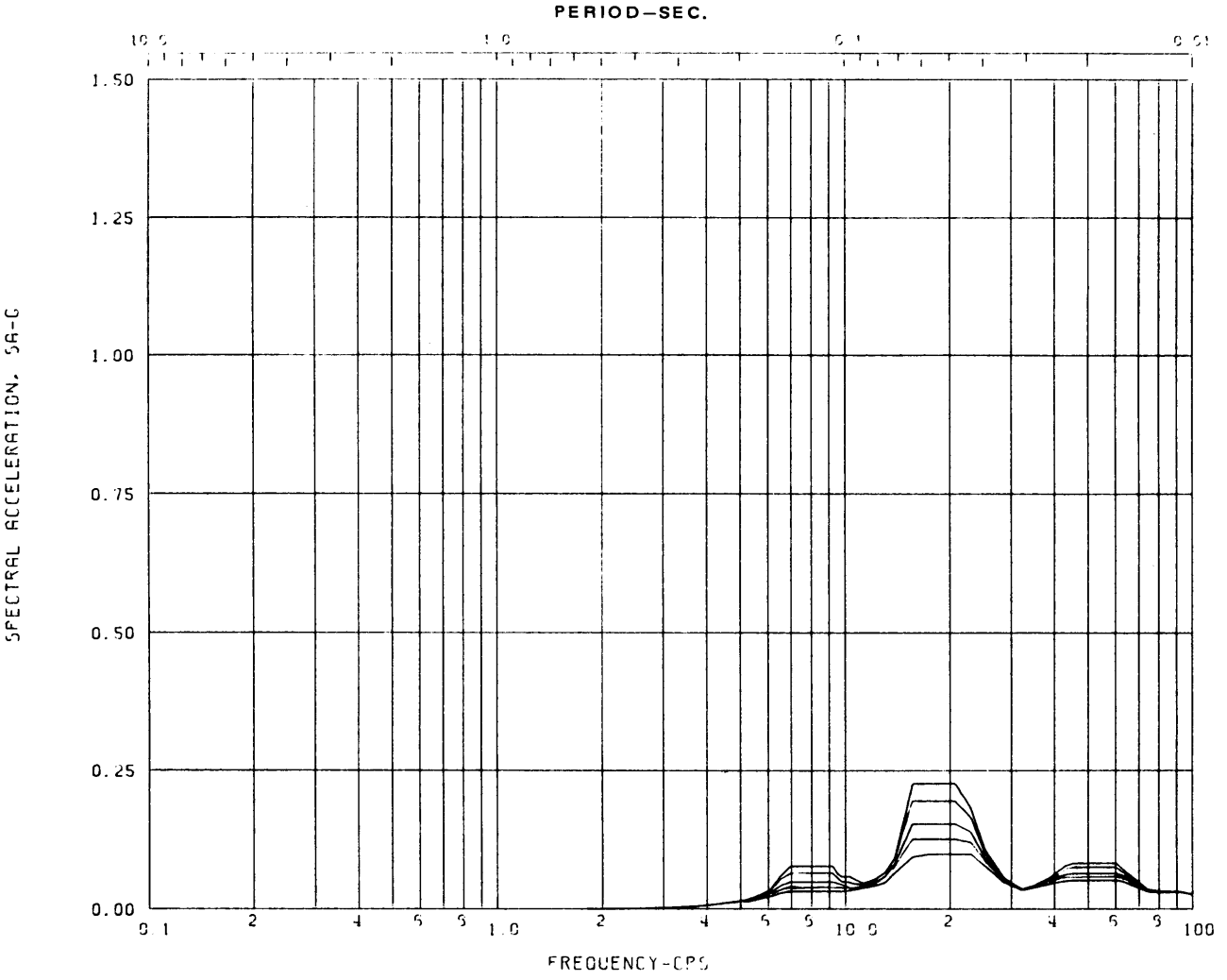
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-262



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 56 Direction: VERTICAL Elev: 304'

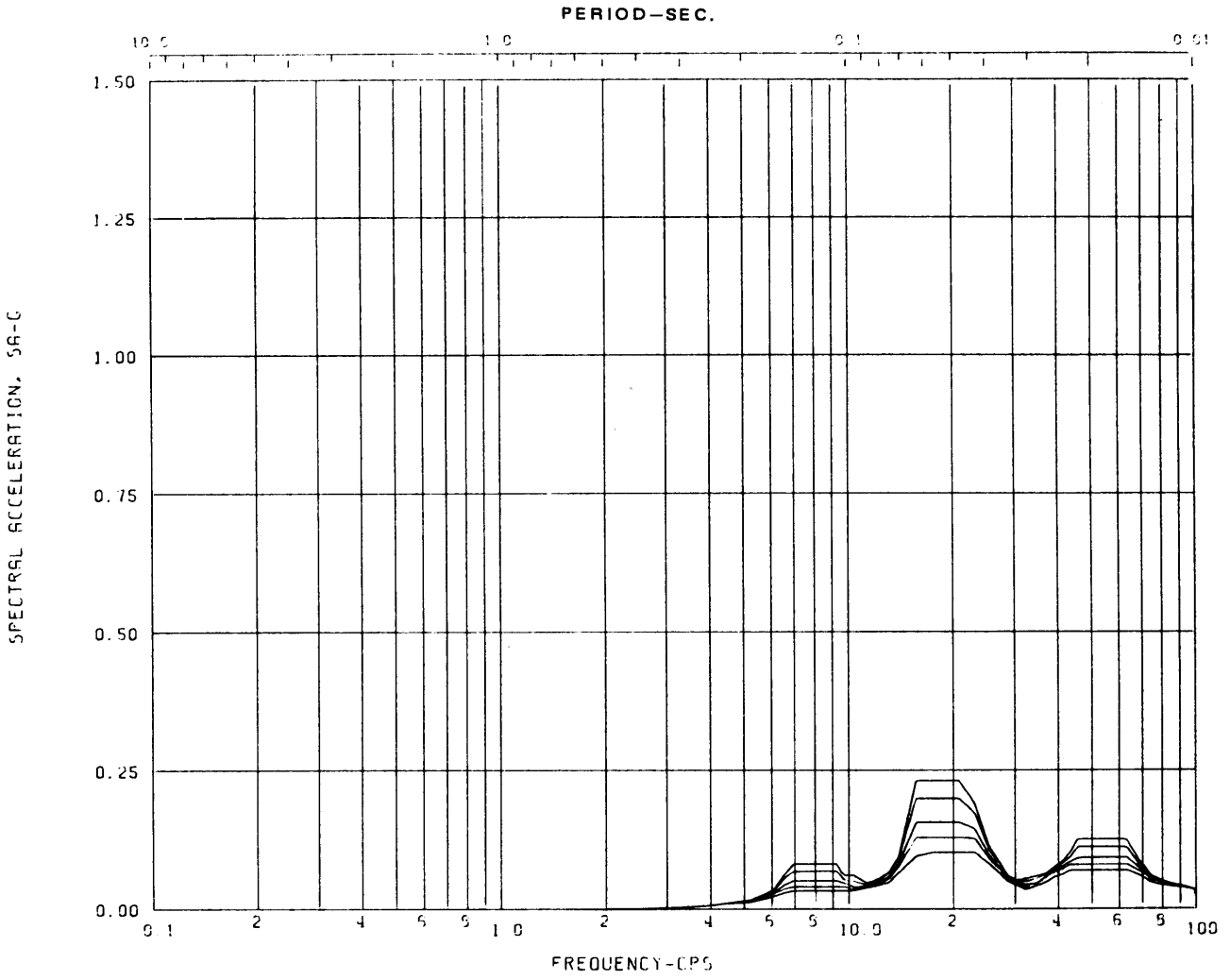
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-263



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 35 Direction: VERTICAL Elev: 313'

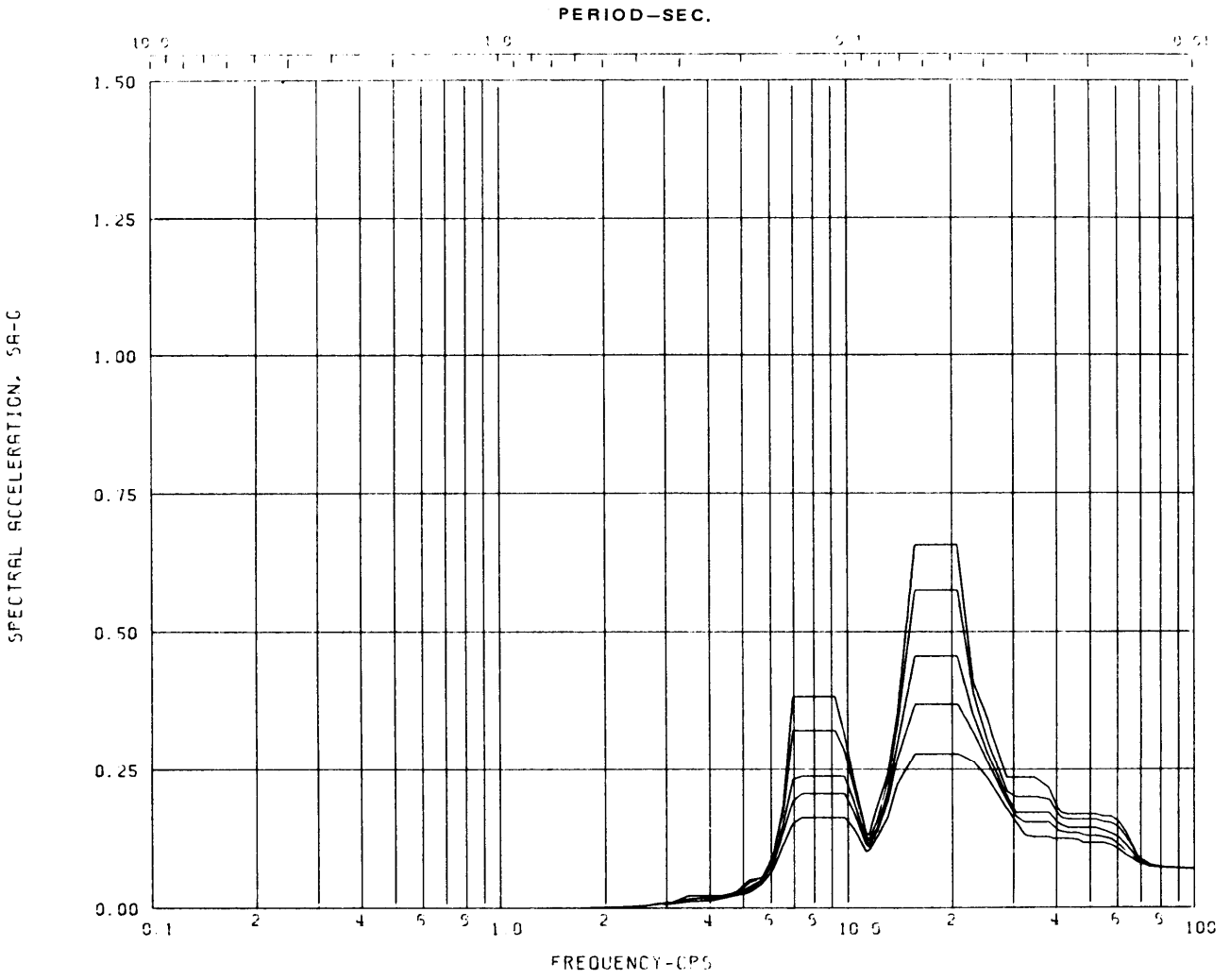
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-264



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 43 Direction: VERTICAL Elev: 313'

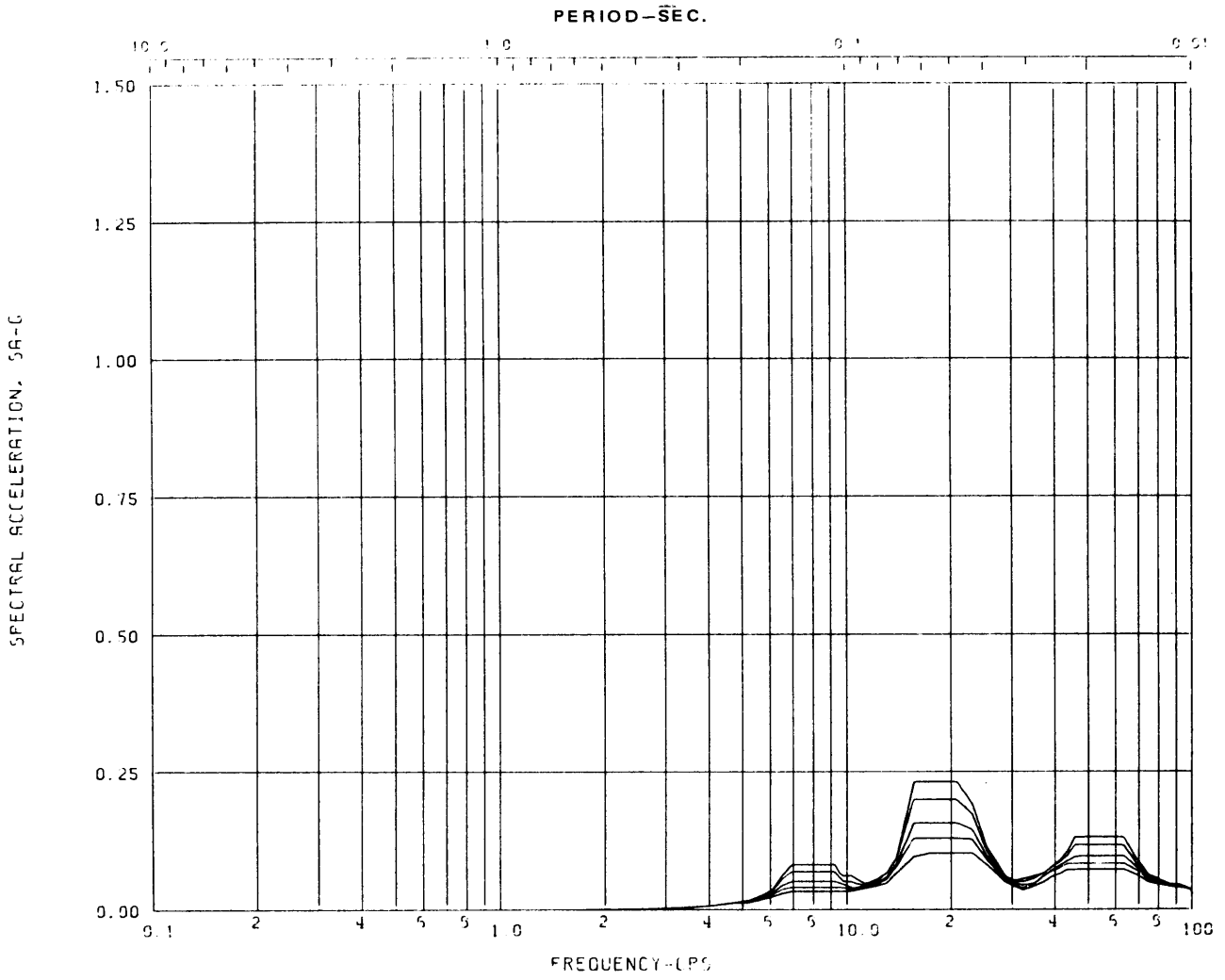
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-265



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIFS ENVELOPE (WIDENED - 15%)

Node: 21 Direction: VERTICAL Elev: 333'

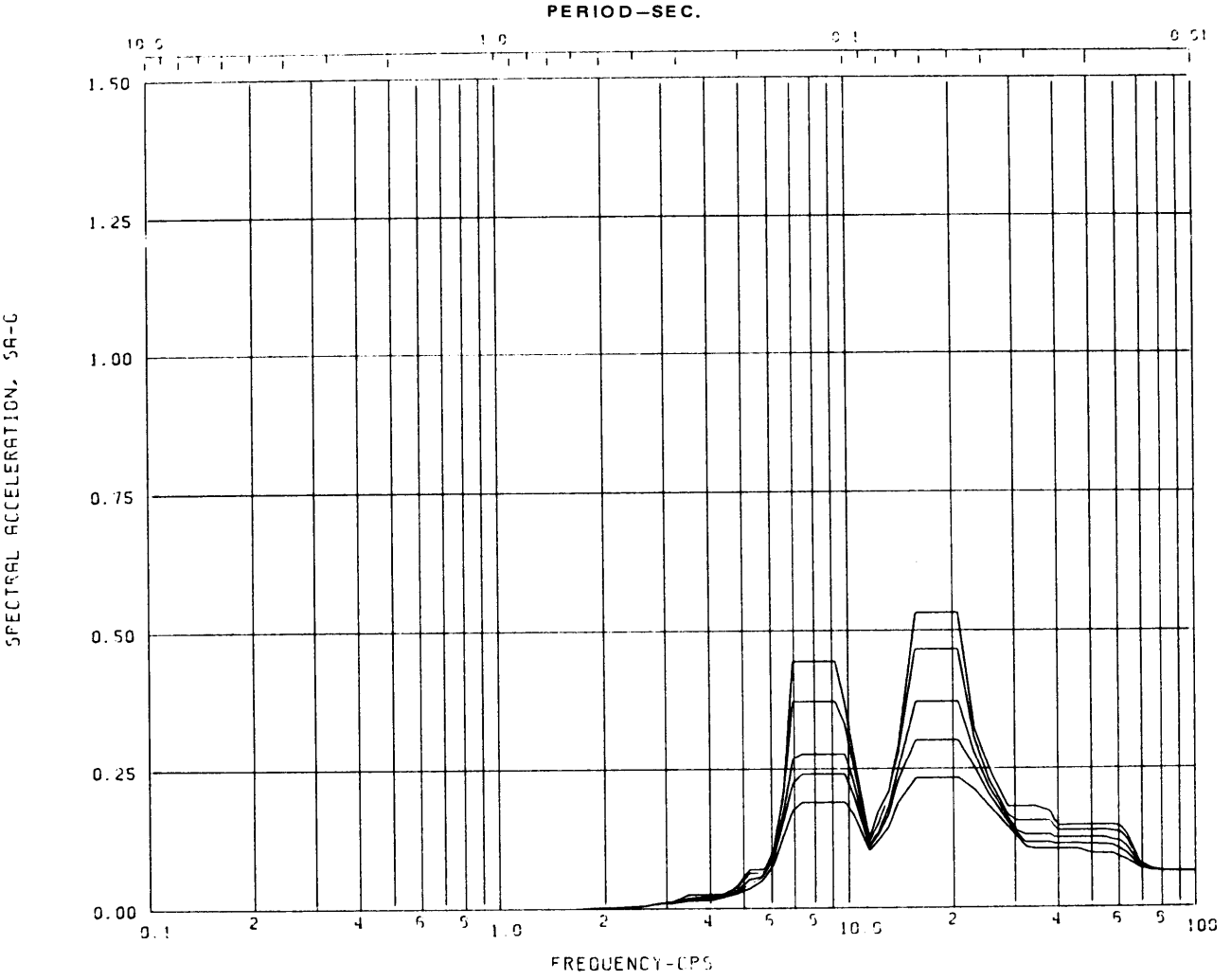
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-266



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIFS ENVELOPE (WIDENED - 15%)

Node: 33 Direction: VERTICAL Elev: 333'

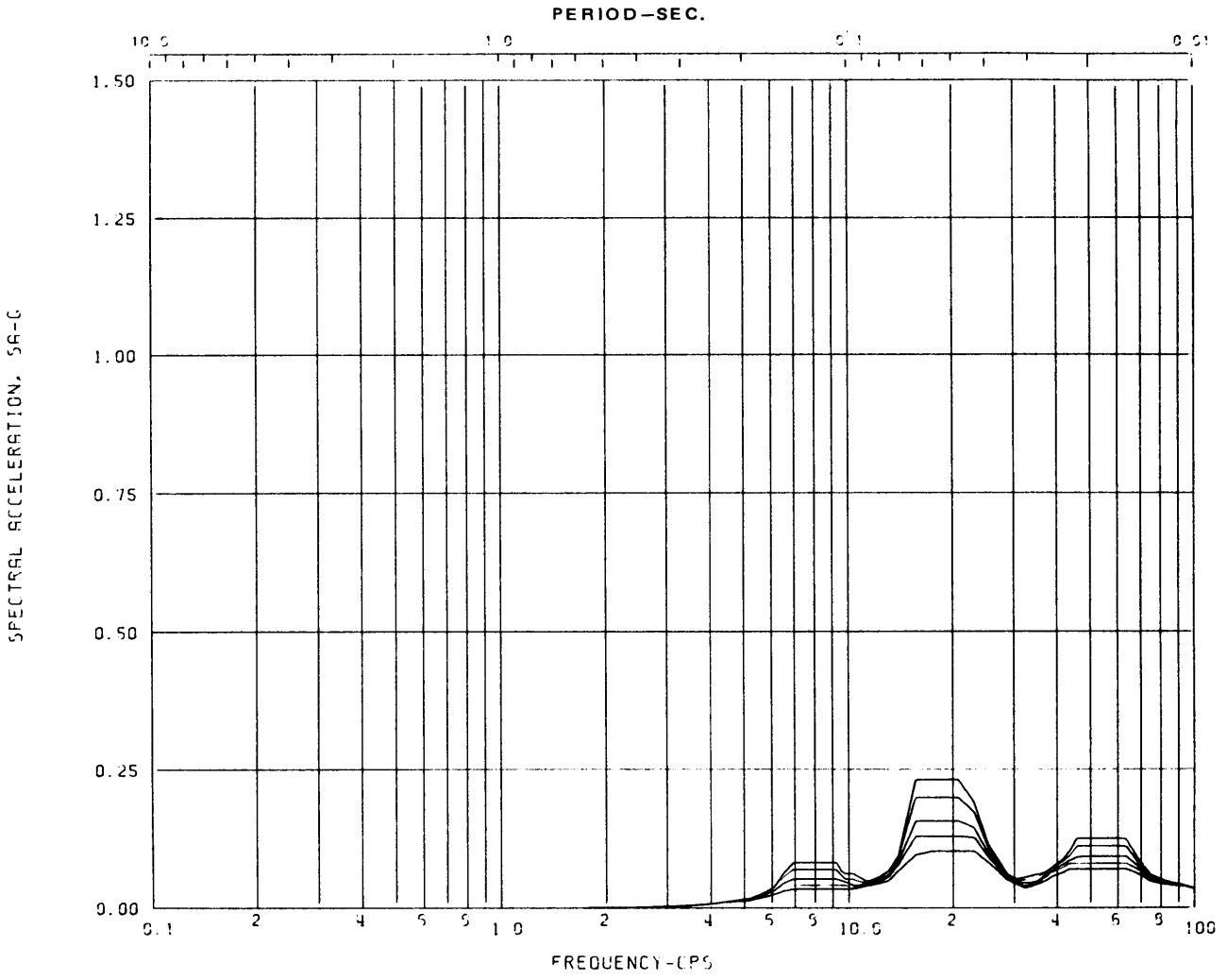
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-267



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 9 Direction: VERTICAL Elev: 352'

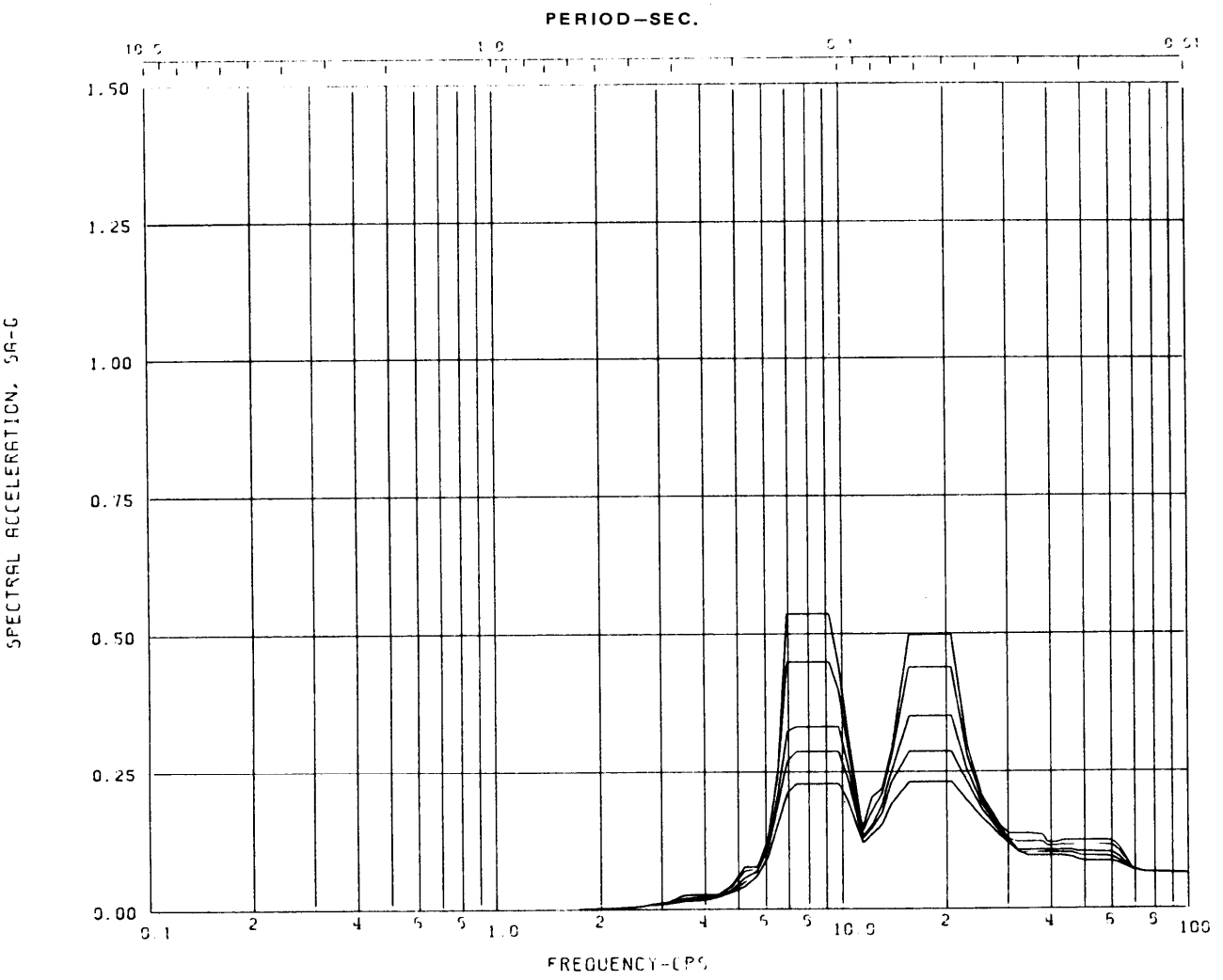
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-268



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 13 Direction: VERTICAL Elev: 352'

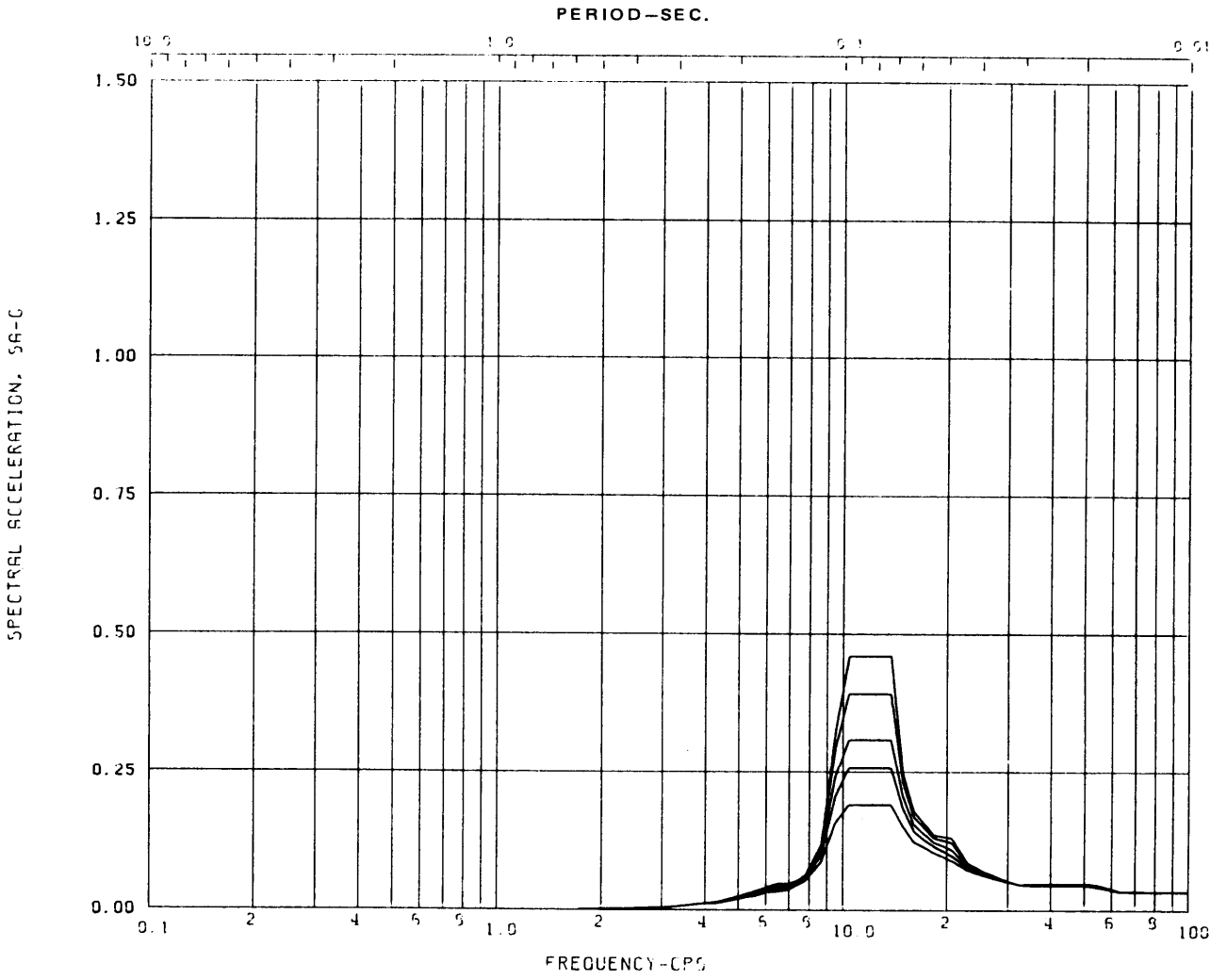
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-269



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 129 Direction: VERTICAL Elev: 201'

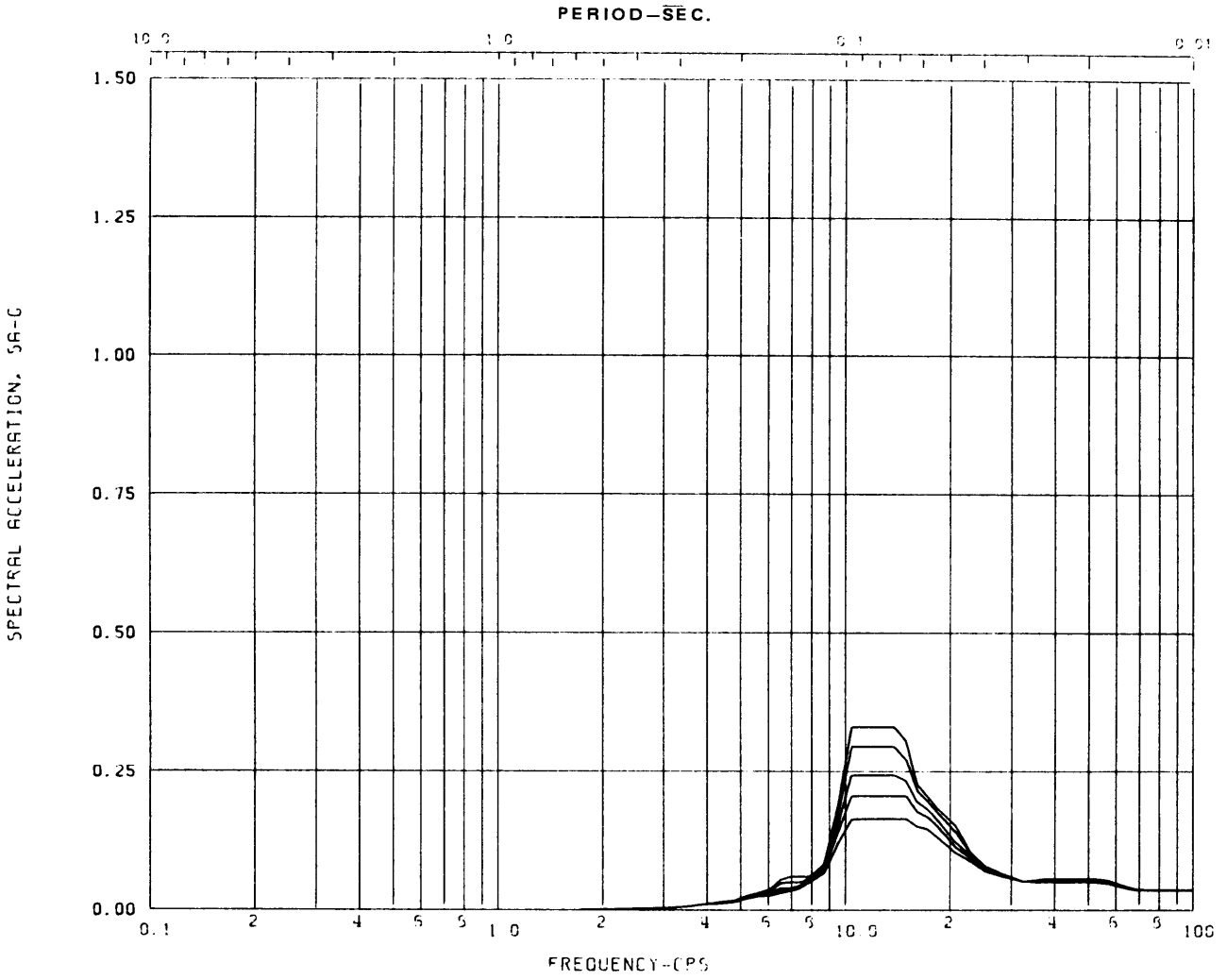
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-270



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 107 Direction: VERTICAL Elev: 217'

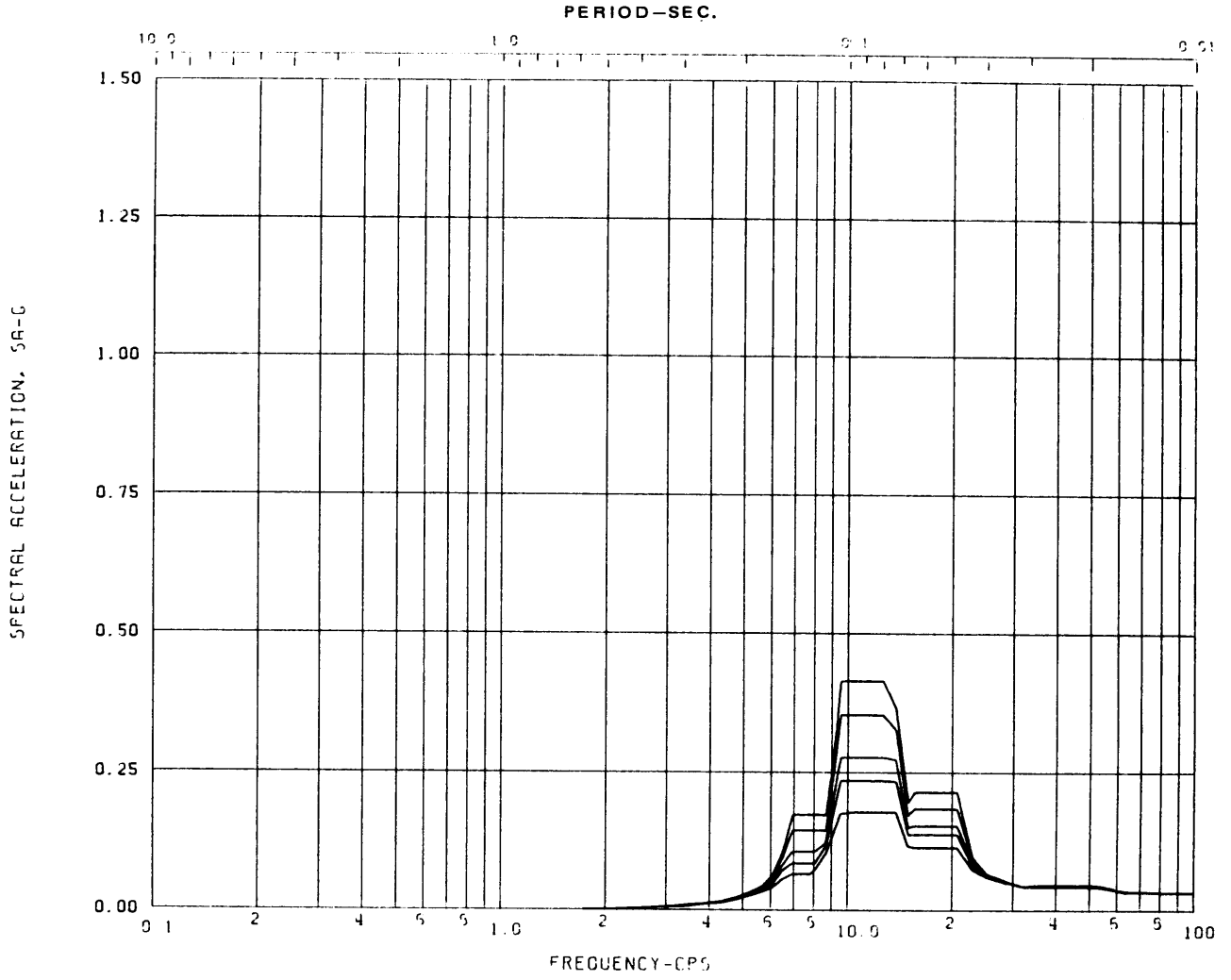
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-271



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 80 Direction: VERTICAL Elev: 253'

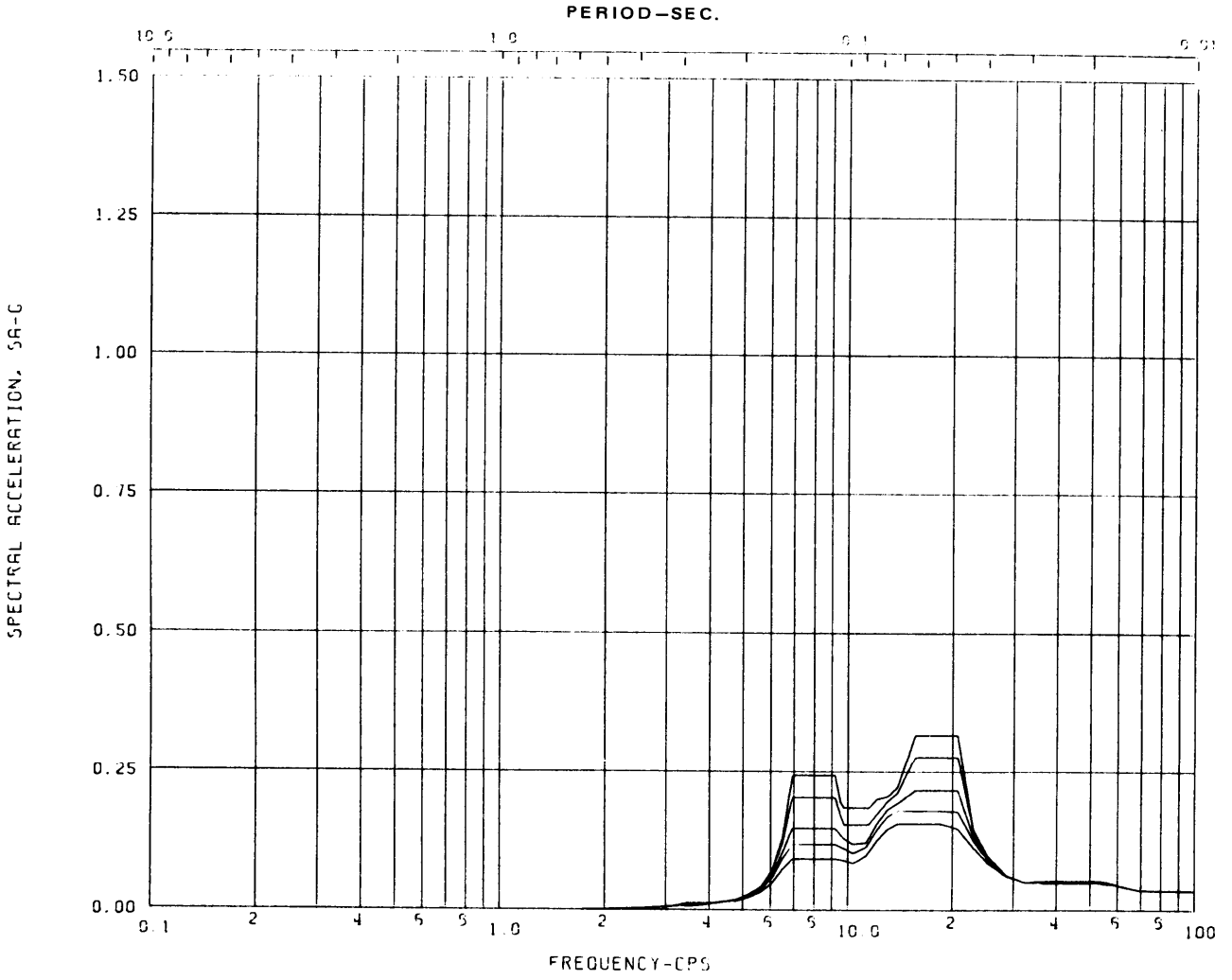
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-272



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 59 Direction: VERTICAL Elev: 283'

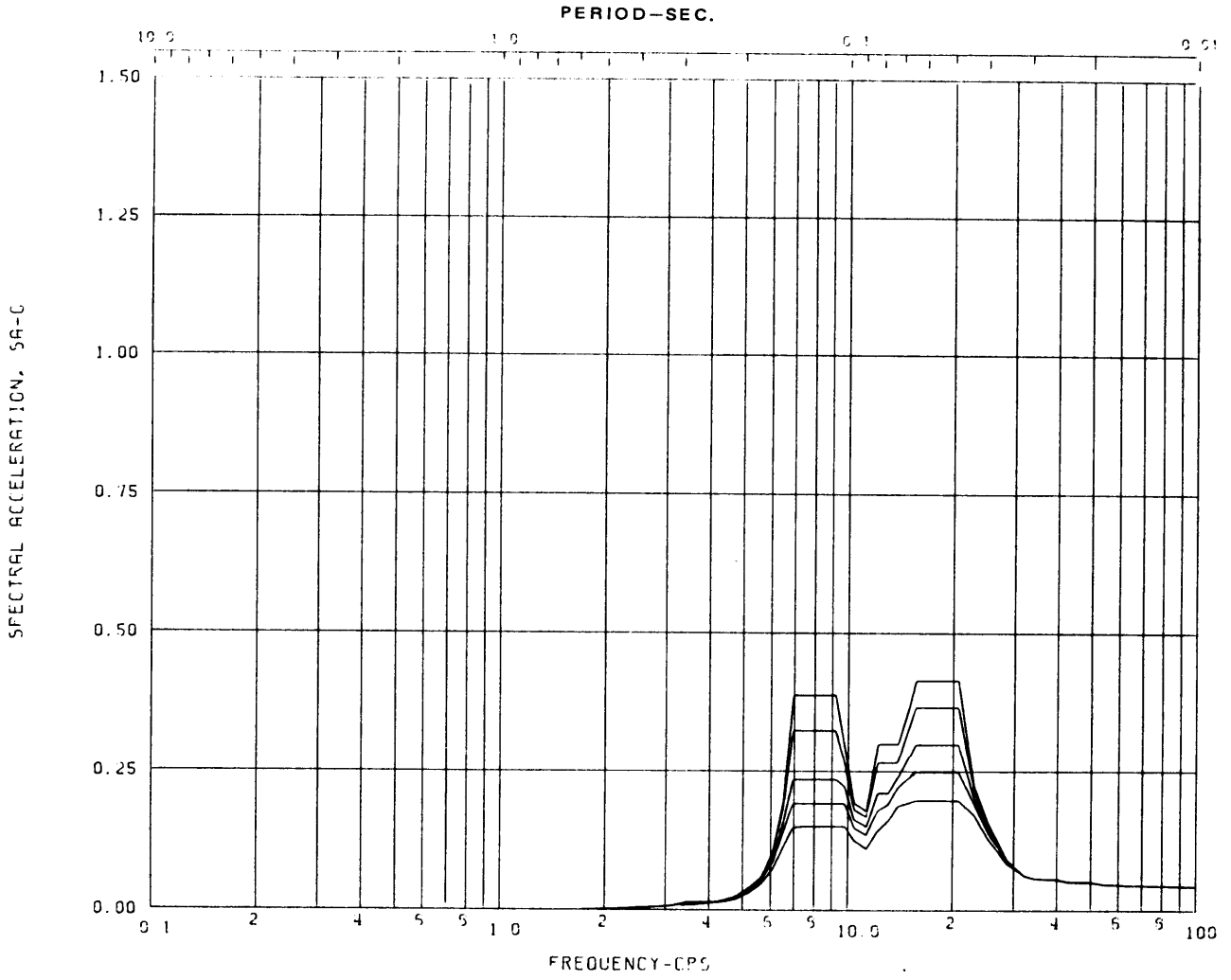
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-273



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

Node: 54 Direction: VERTICAL Elev: 313'

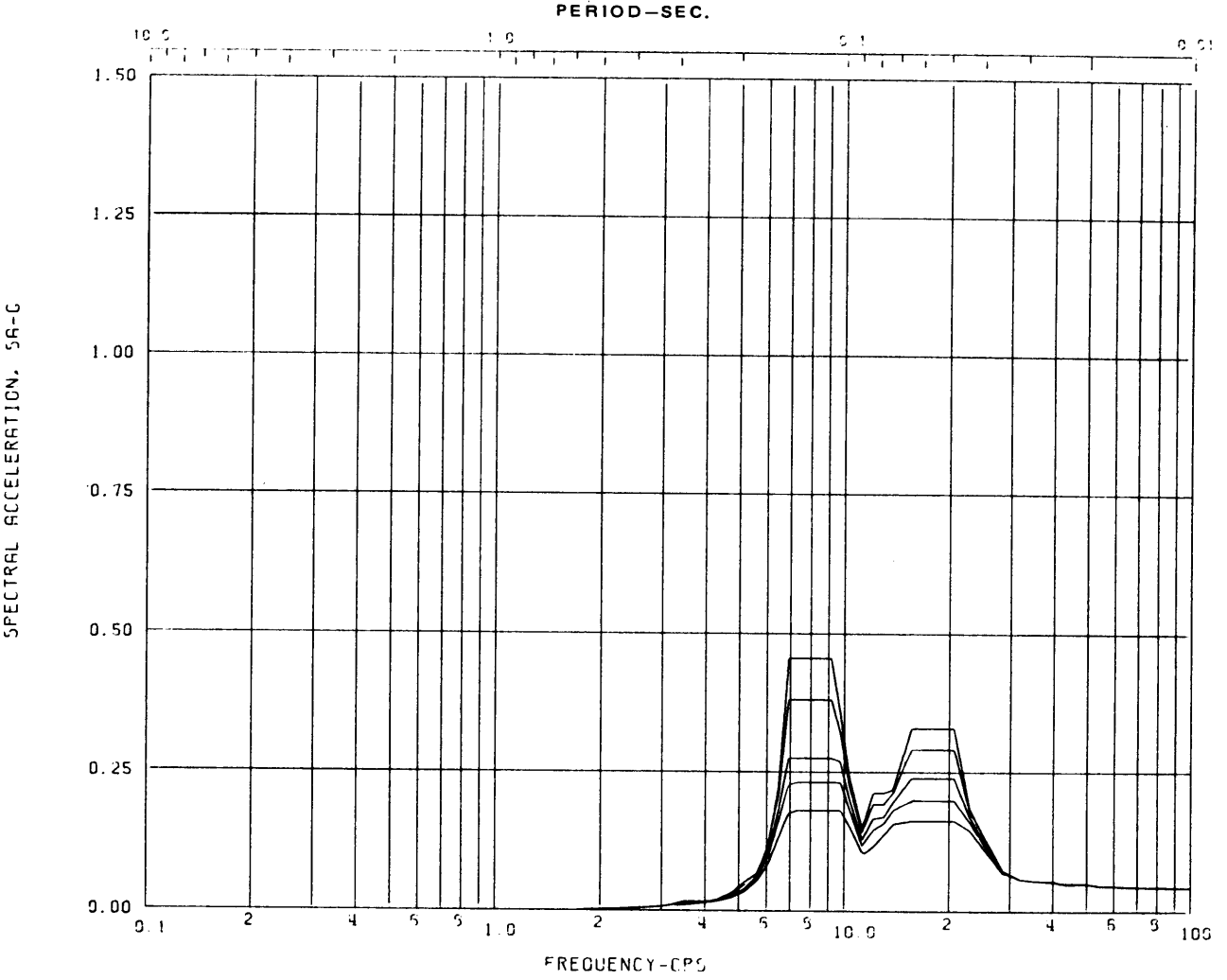
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-274



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIFS ENVELOPE (WIDENED - 15%)

Node: 32 Direction: VERTICAL Elev: 333'

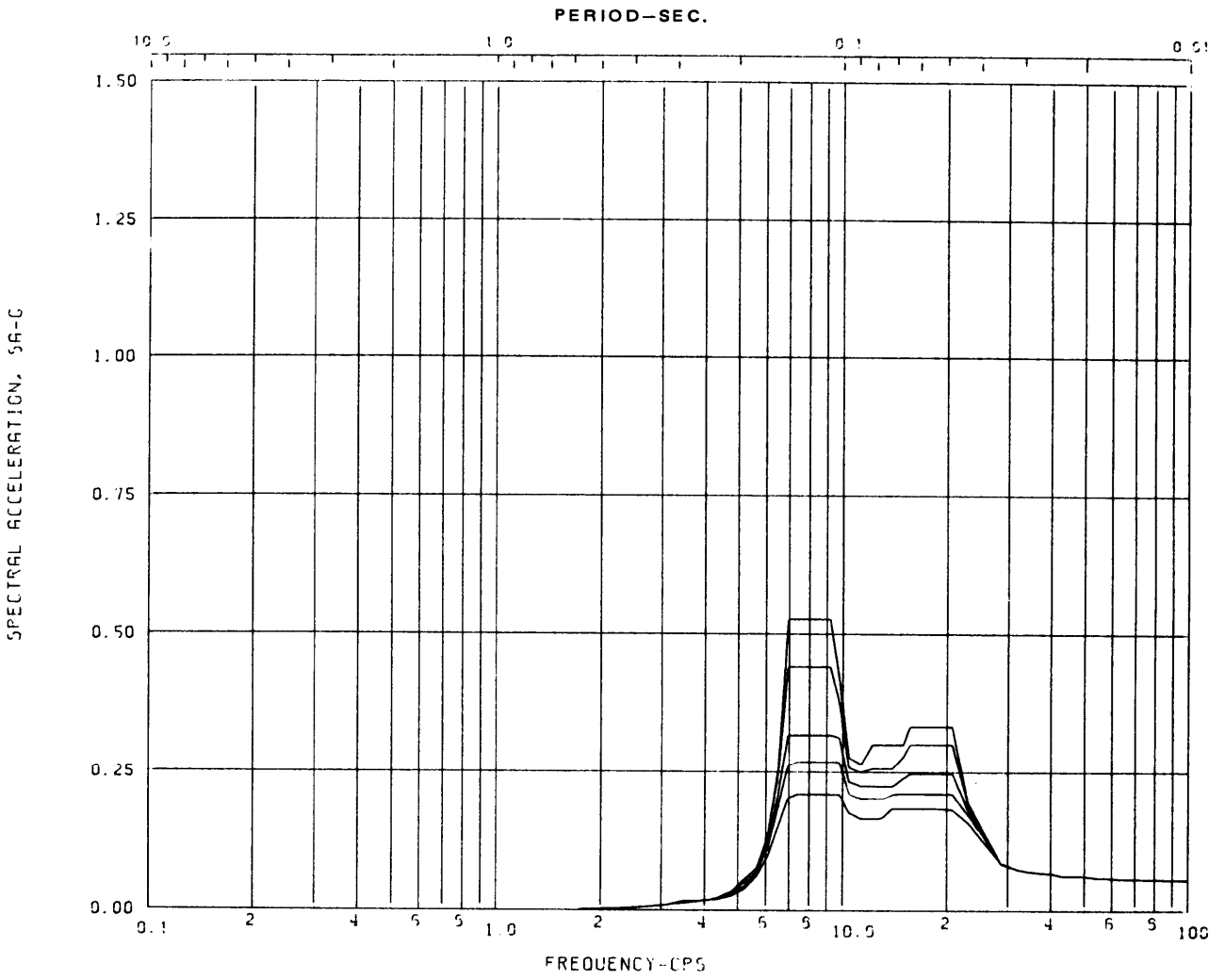
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-275



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIFS ENVELOPE (WIDENED - 15%)

Node: 12 Direction: VERTICAL Elev: 352'

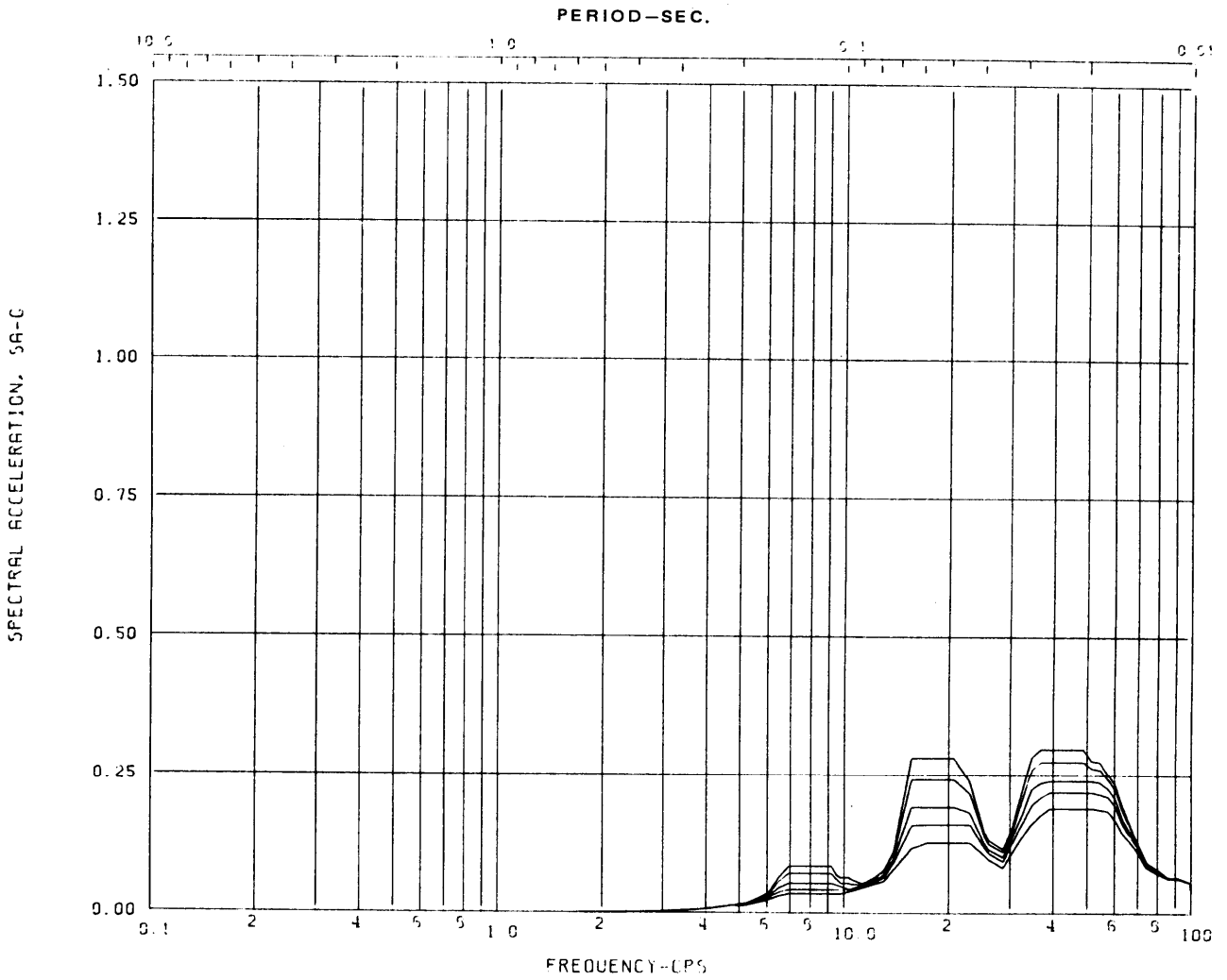
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-276



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC CHUGGING GE700 SERIES ENVELOPE (WIDENED - 15%)

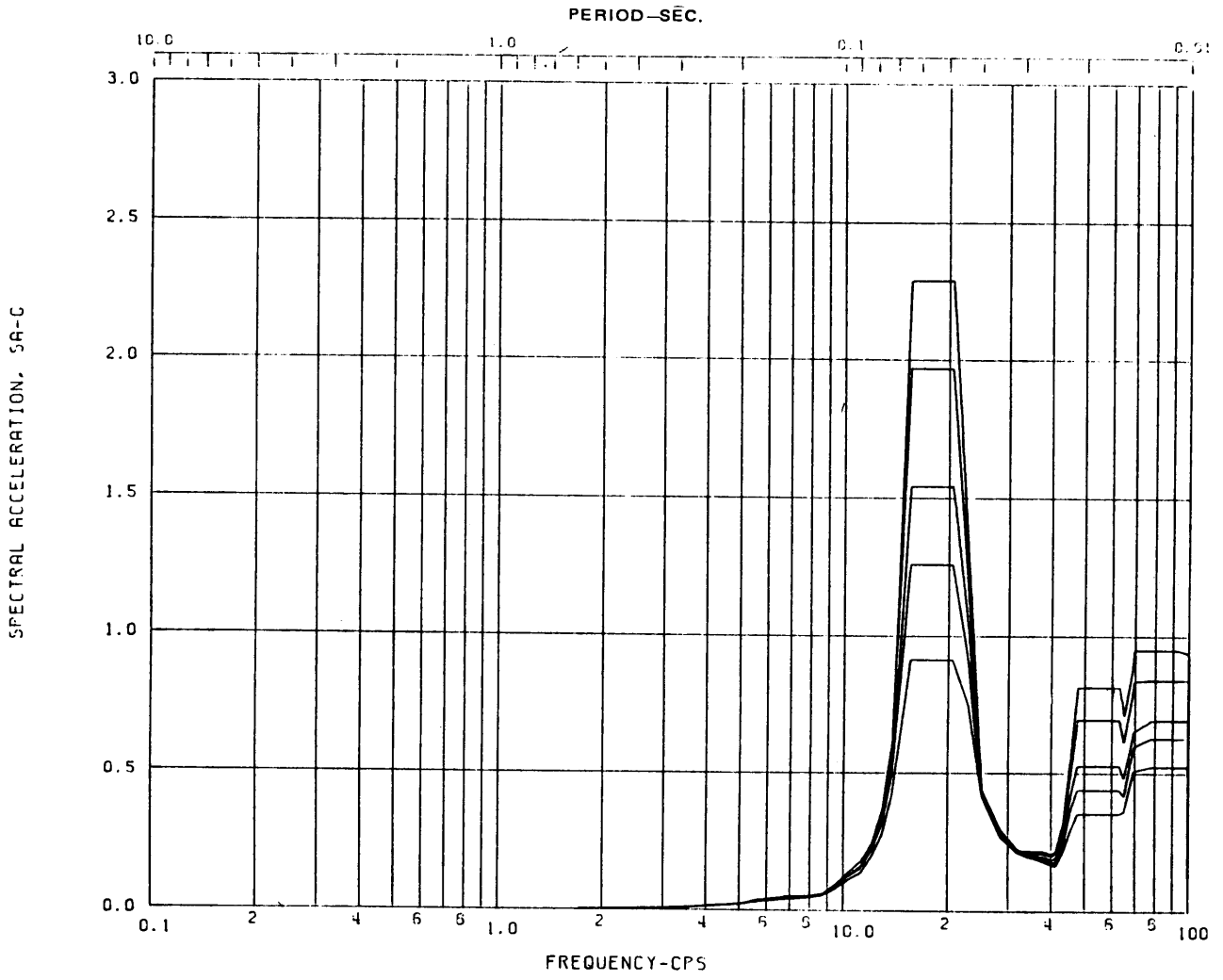
Node: 6 Direction: VERTICAL Elev: 410'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-277



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 19 Direction: VERTICAL Elev: 217'

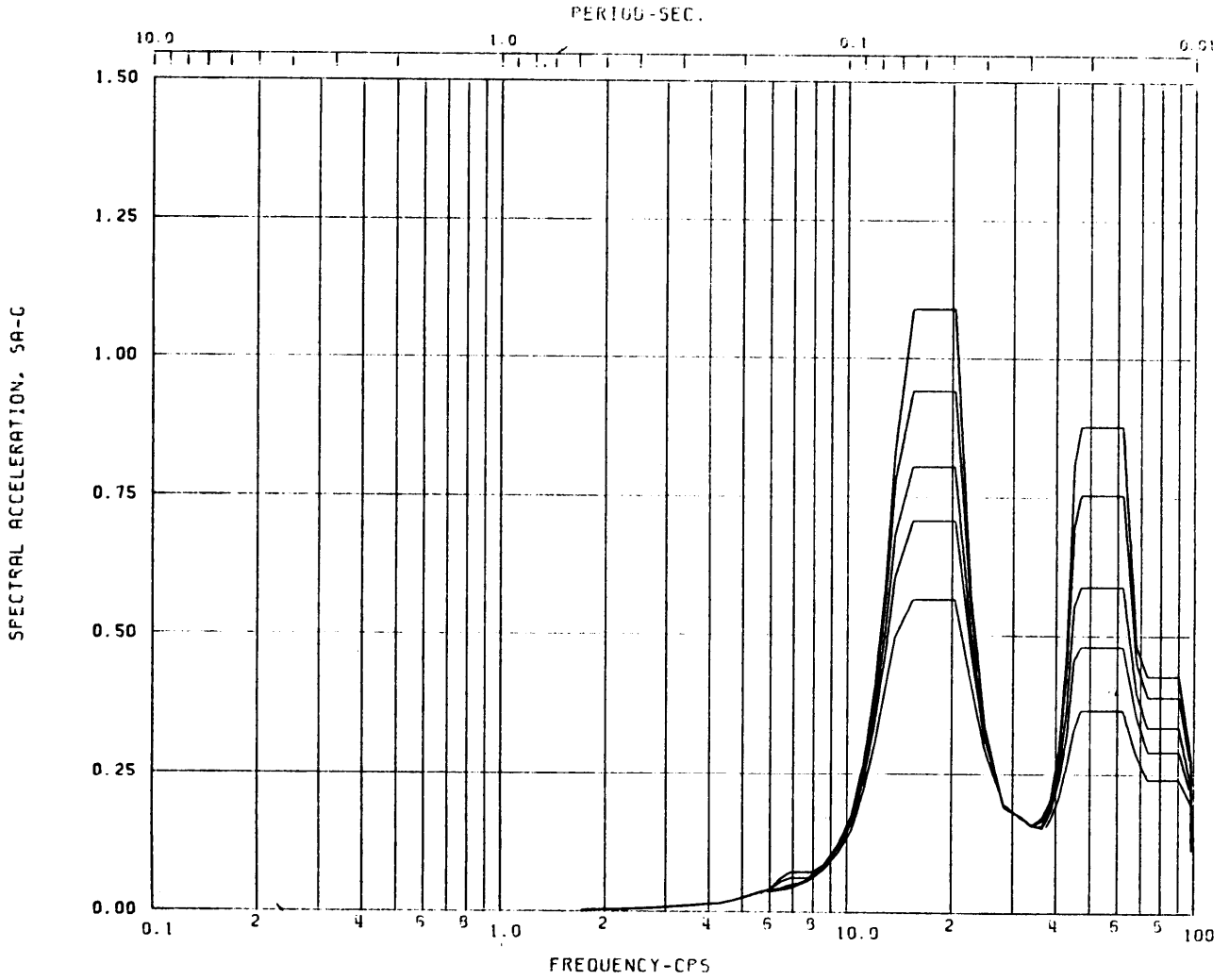
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-278



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 19 Direction: VERTICAL Elev: 239'

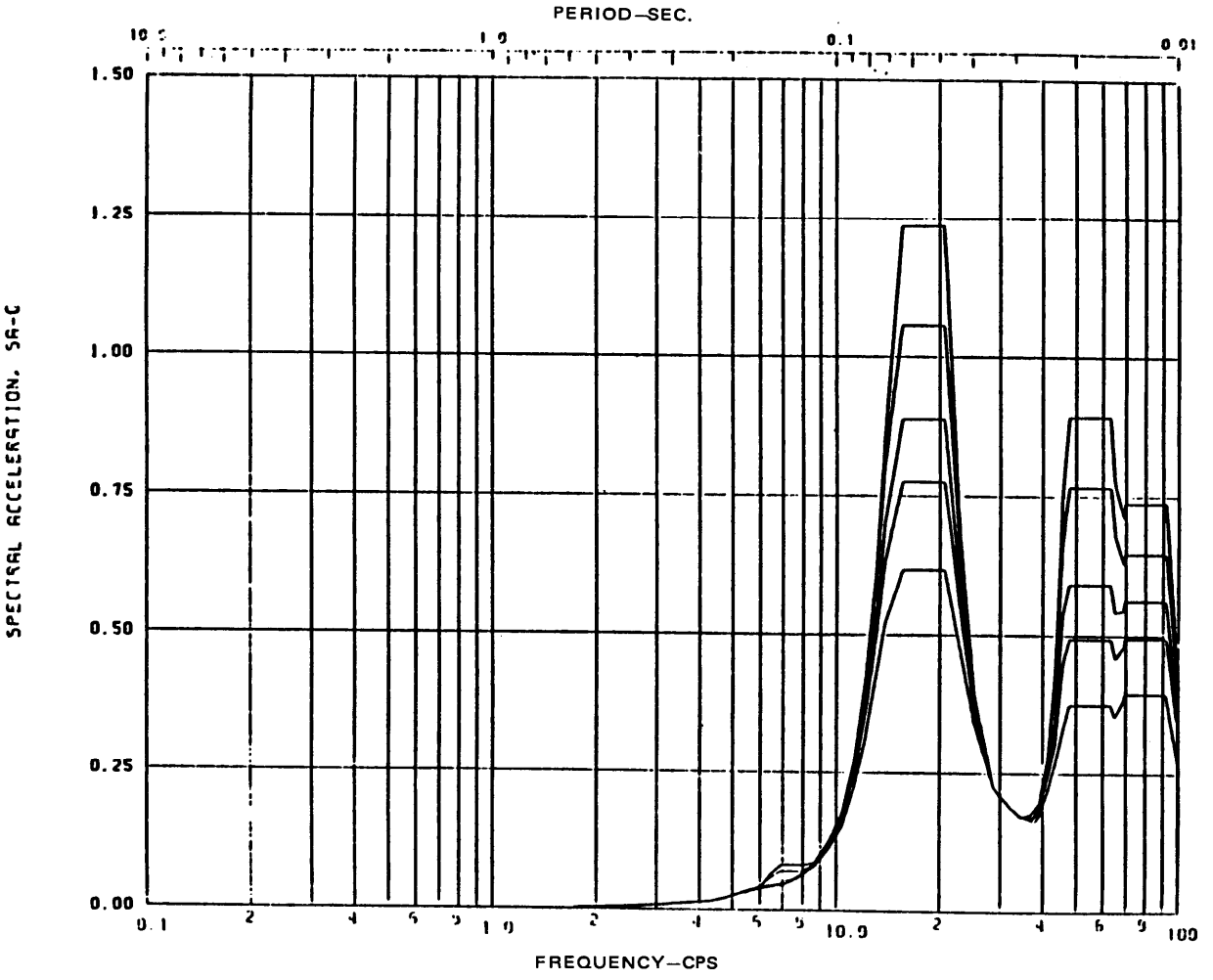
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-279



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

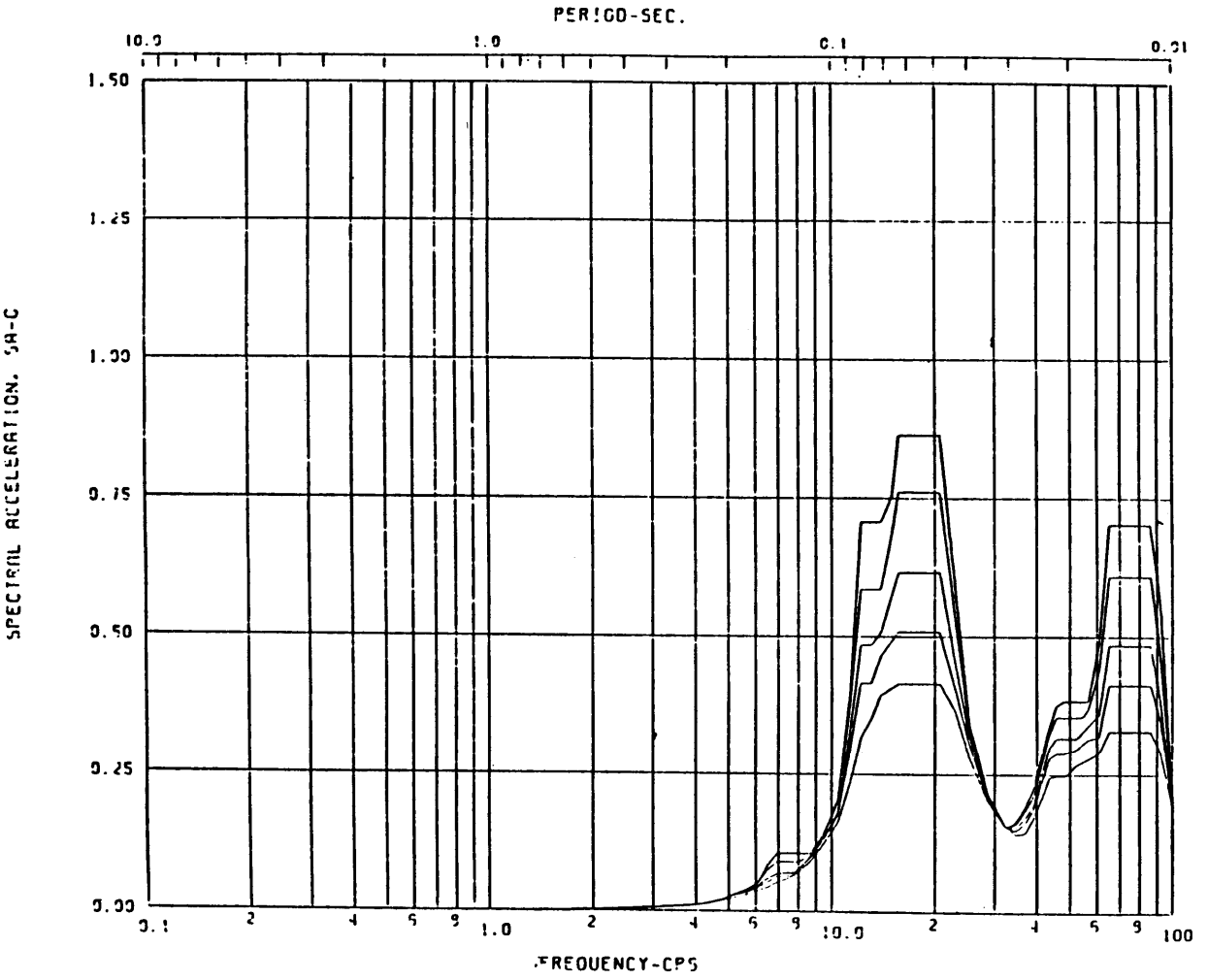
Node: 19 Direction: VERTICAL Elev: 254'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-280



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 19 Direction: VERTICAL Elev: 269'-0

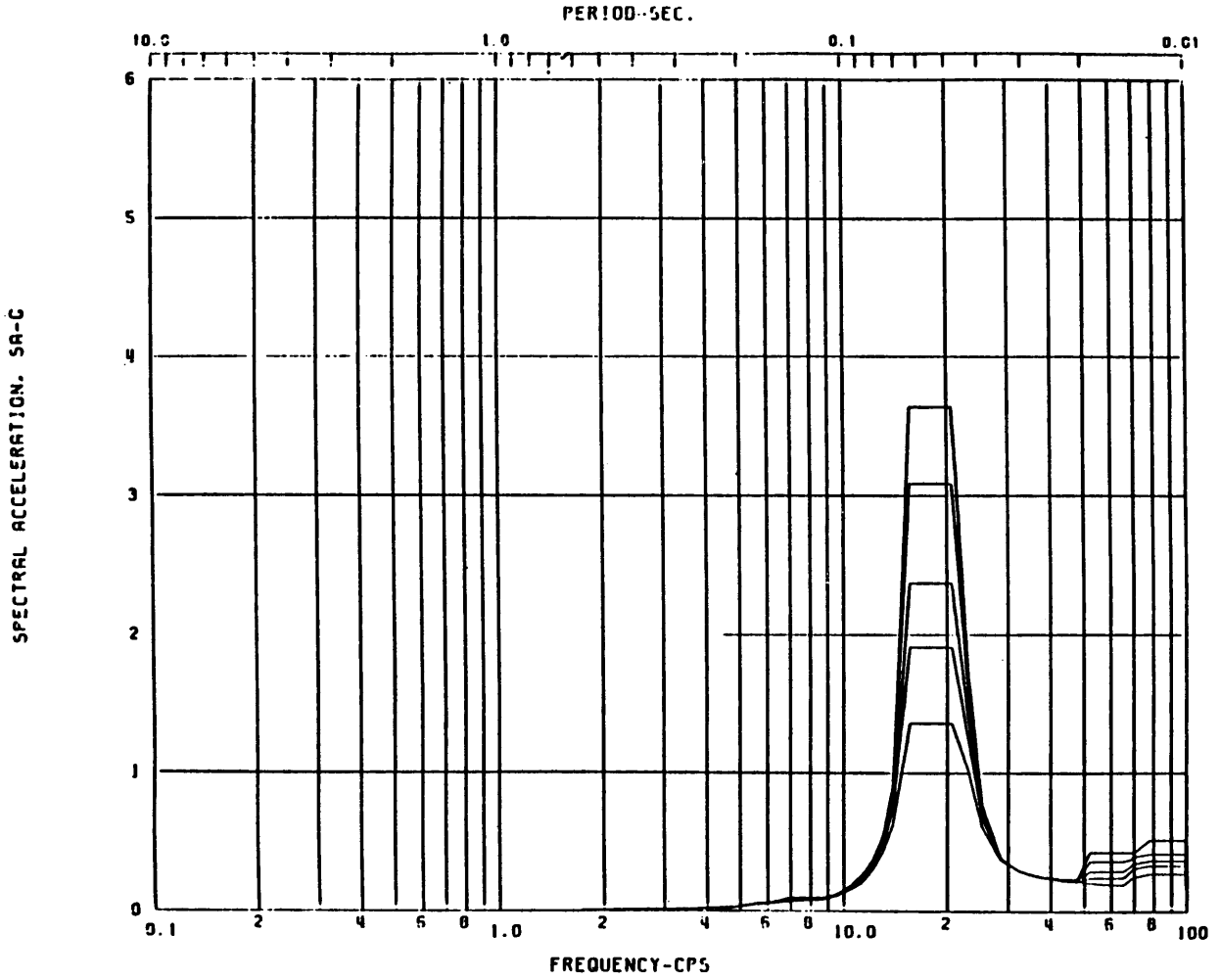
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-281



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 19 Direction: VERTICAL Elev: 289'

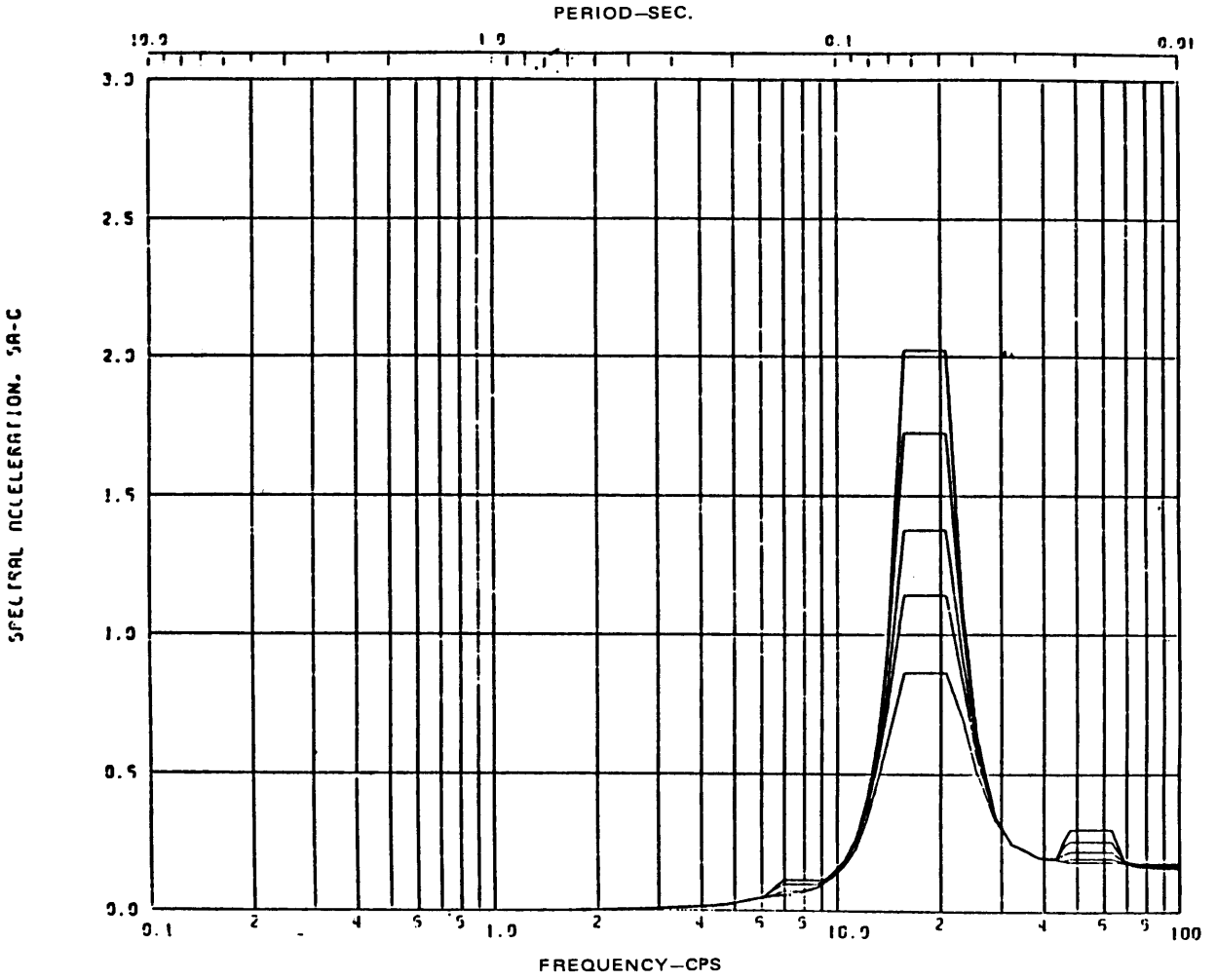
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-282



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 19 Direction: VERTICAL Elev: 304'-0

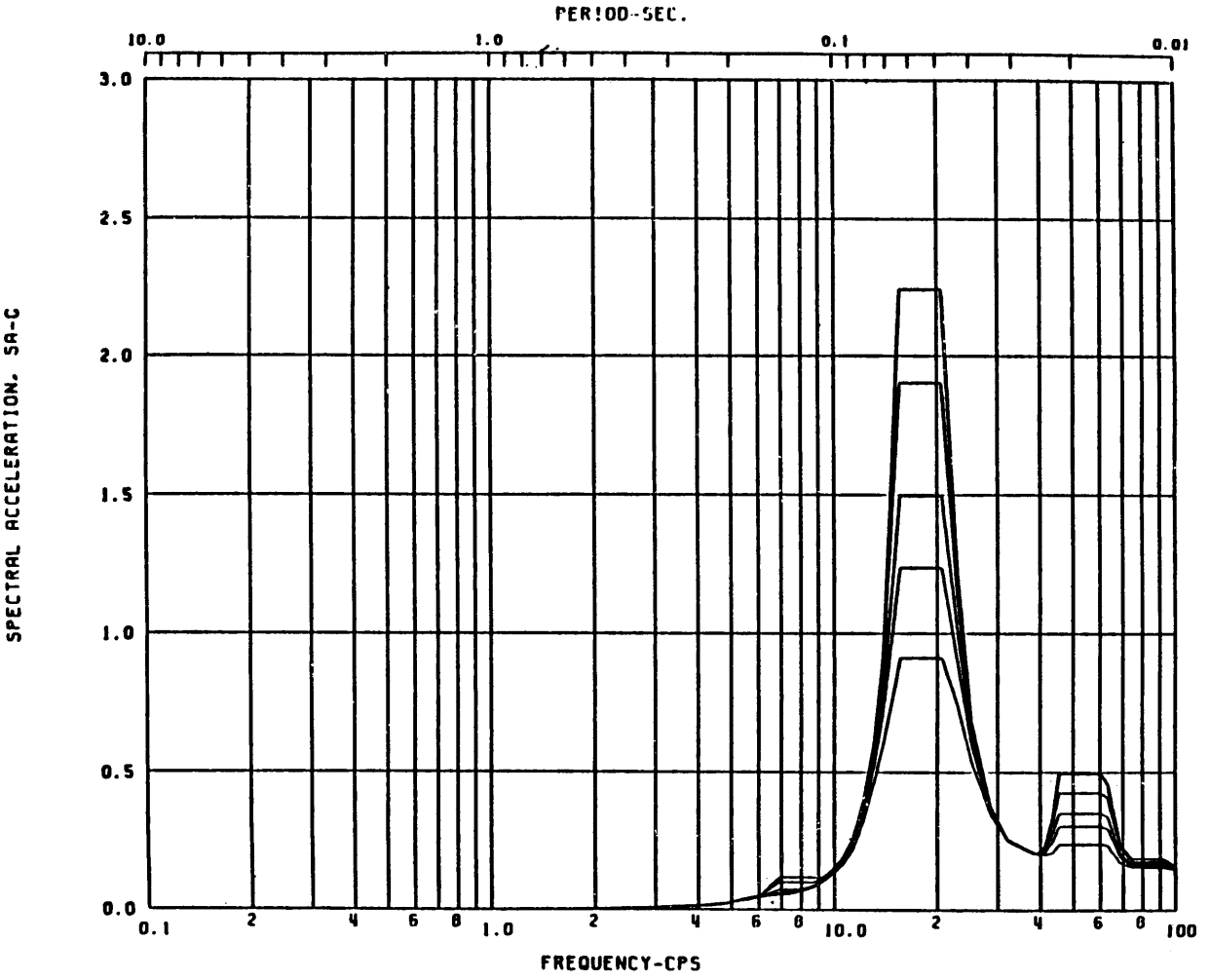
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-283



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC CHUGGING GE 700 SERIES ENVELOPE (WIDENED - 15%)

Node: 19 Direction: VERTICAL Elev: 332'

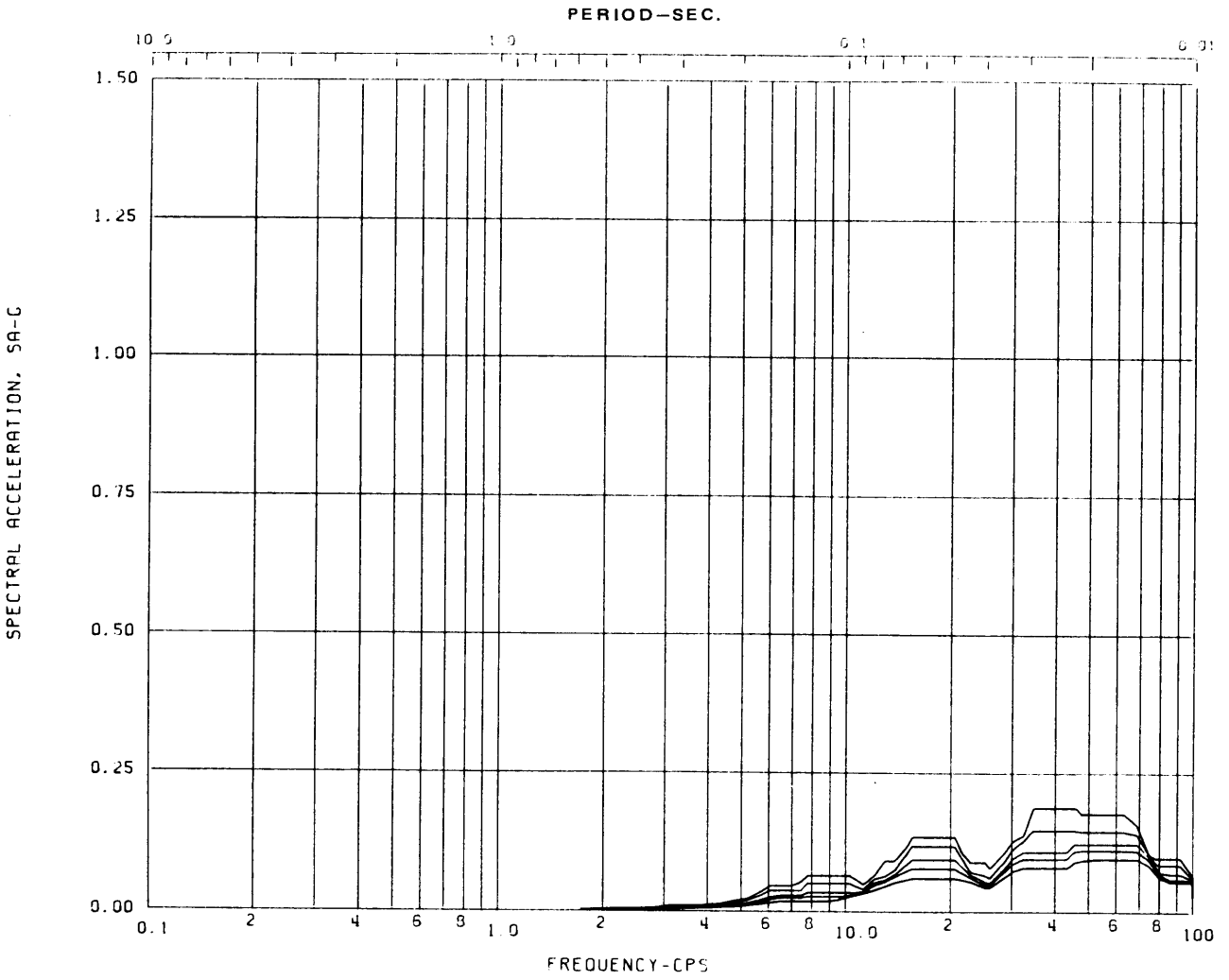
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-284



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPF (WIDENED - 15%)

Node: 159 Direction: VERTICAL Elev: 177'-0

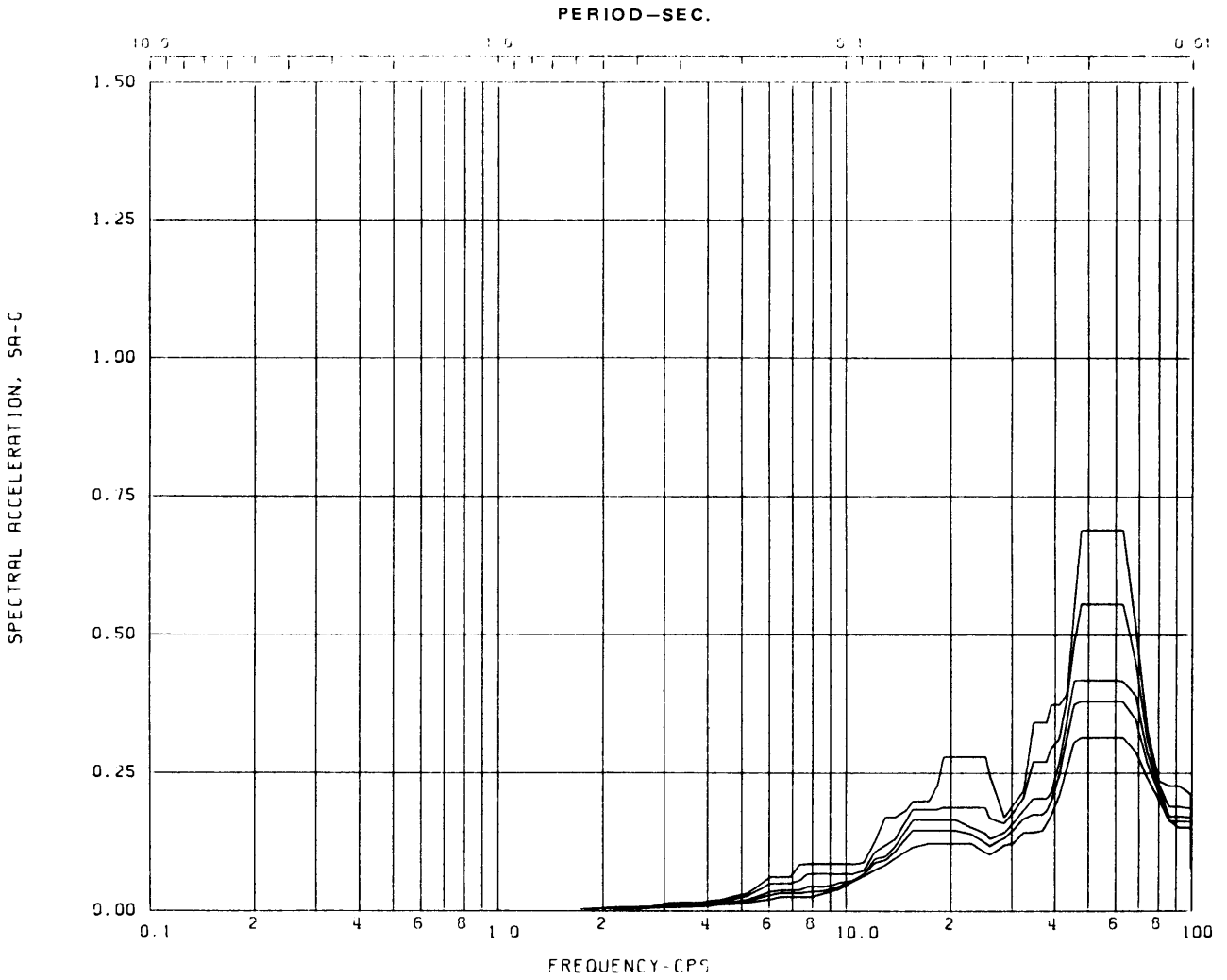
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-285



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 154 Direction: VERTICAL Elev: 177'-0

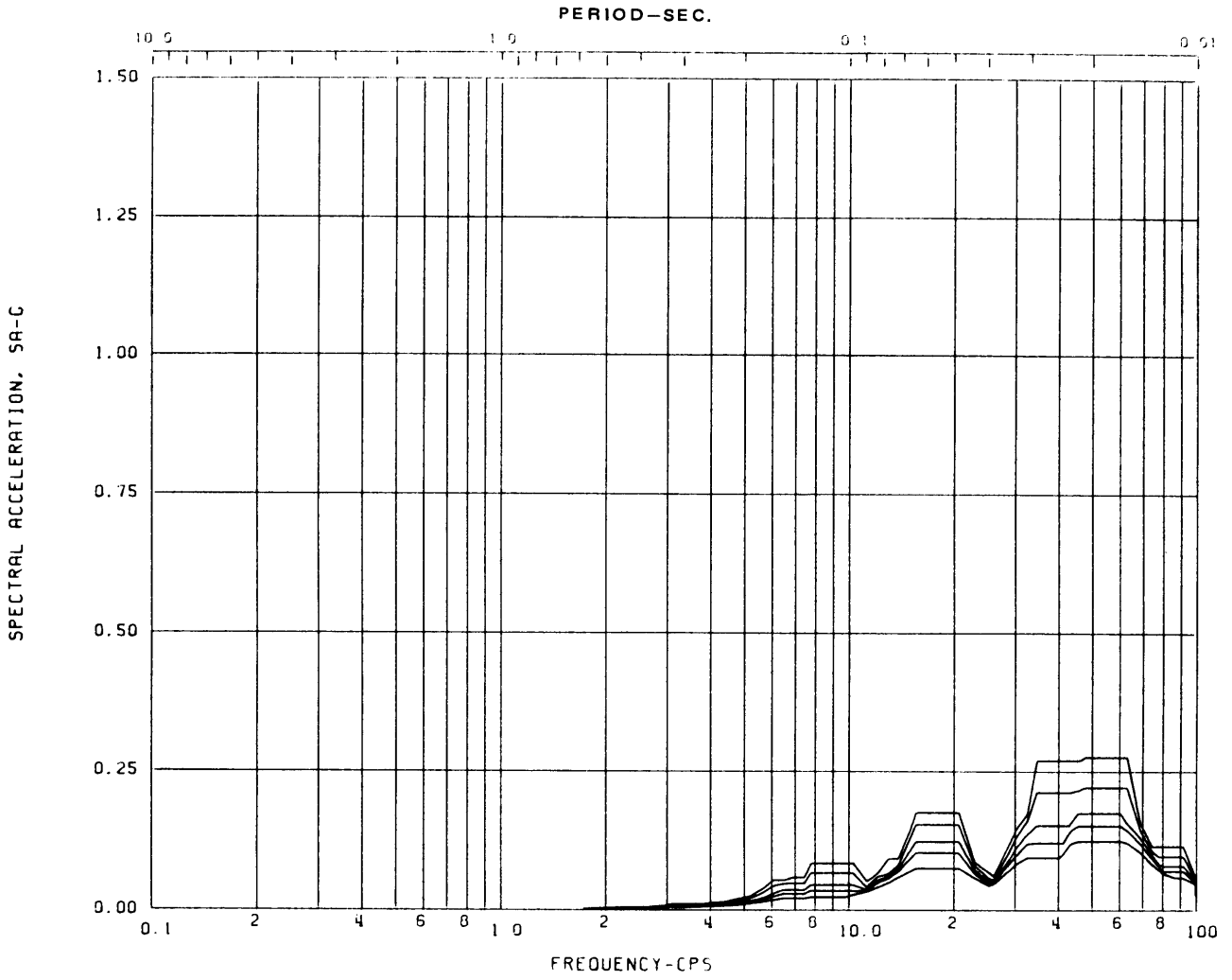
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-286



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

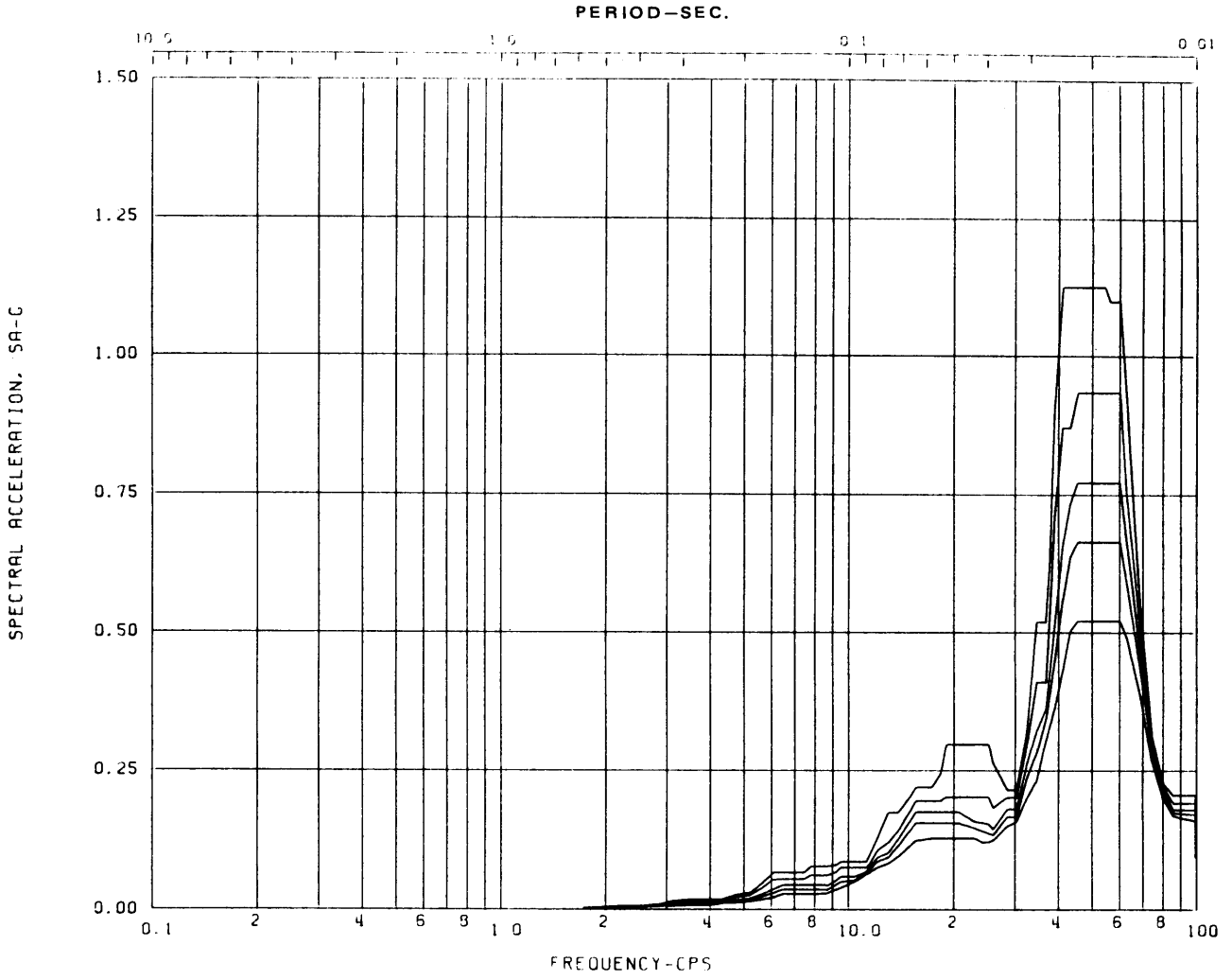
Node: 128 Direction: VERTICAL Elev: 201'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-287



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPF (WIDENED - 15%)

Node: 130 Direction: VERTICAL Elev: 201'-0

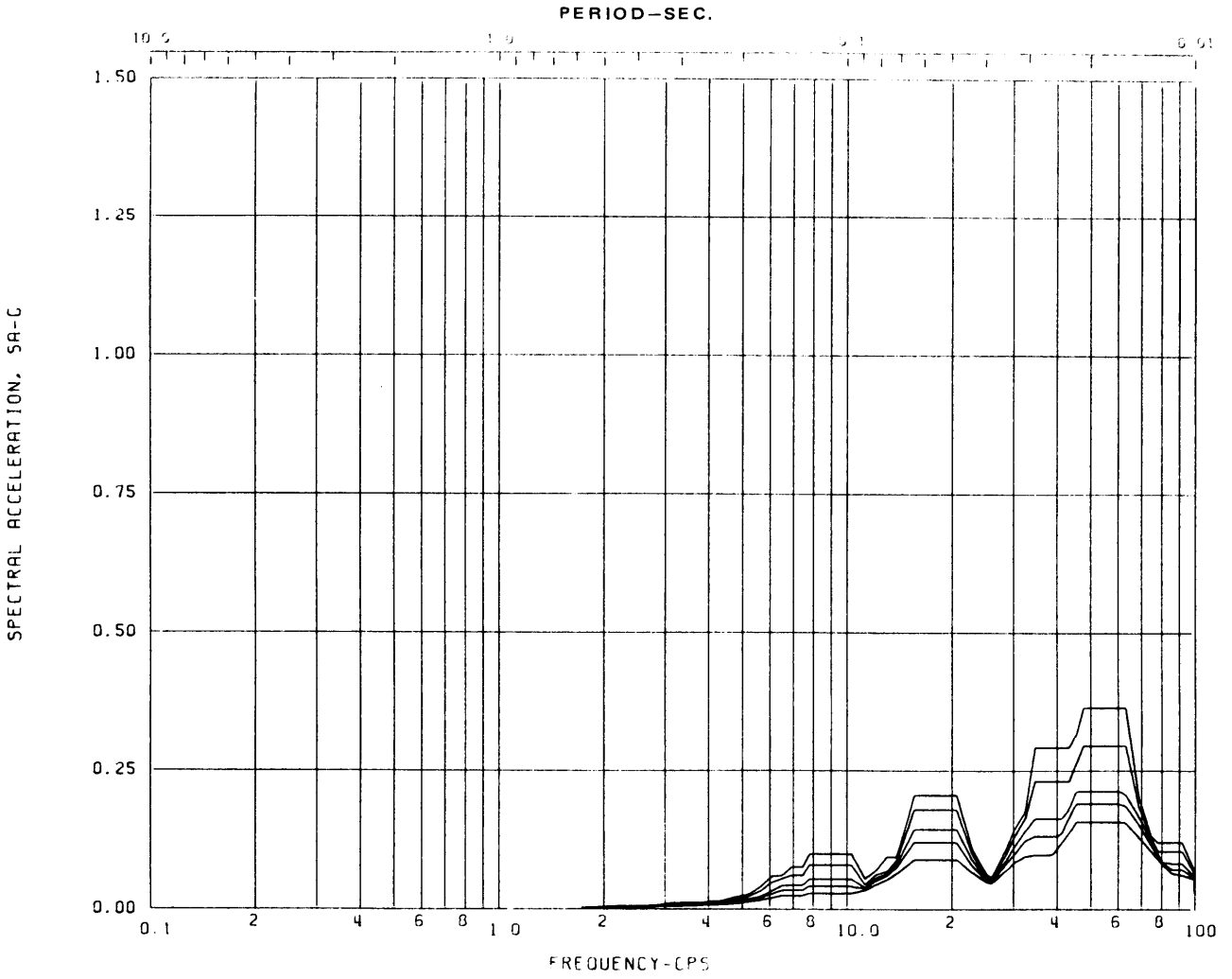
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-288



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 106 Direction: VERTICAL Elev: 217'-0

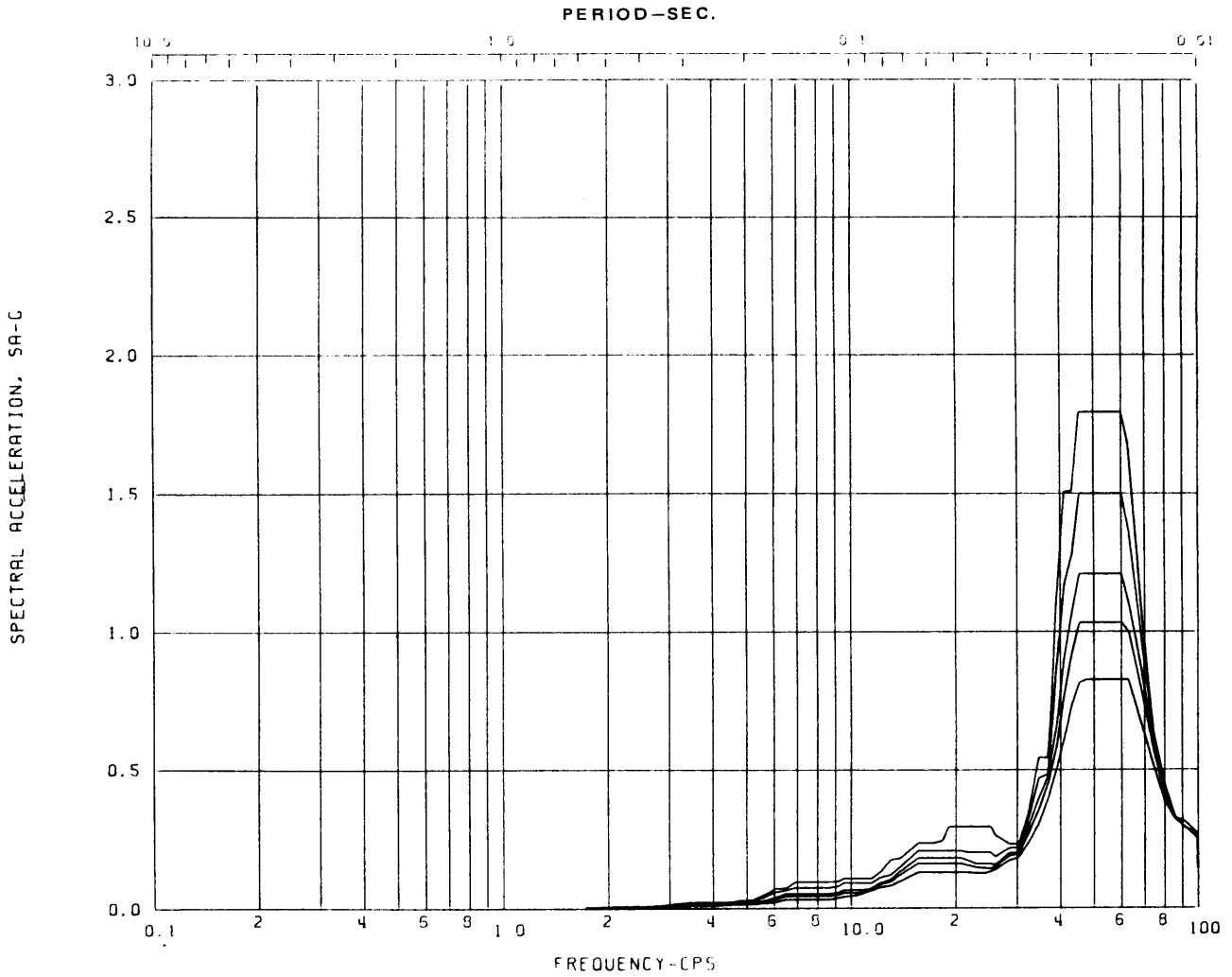
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-289



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 108 Direction: VERTICAL Elev: 217'-0

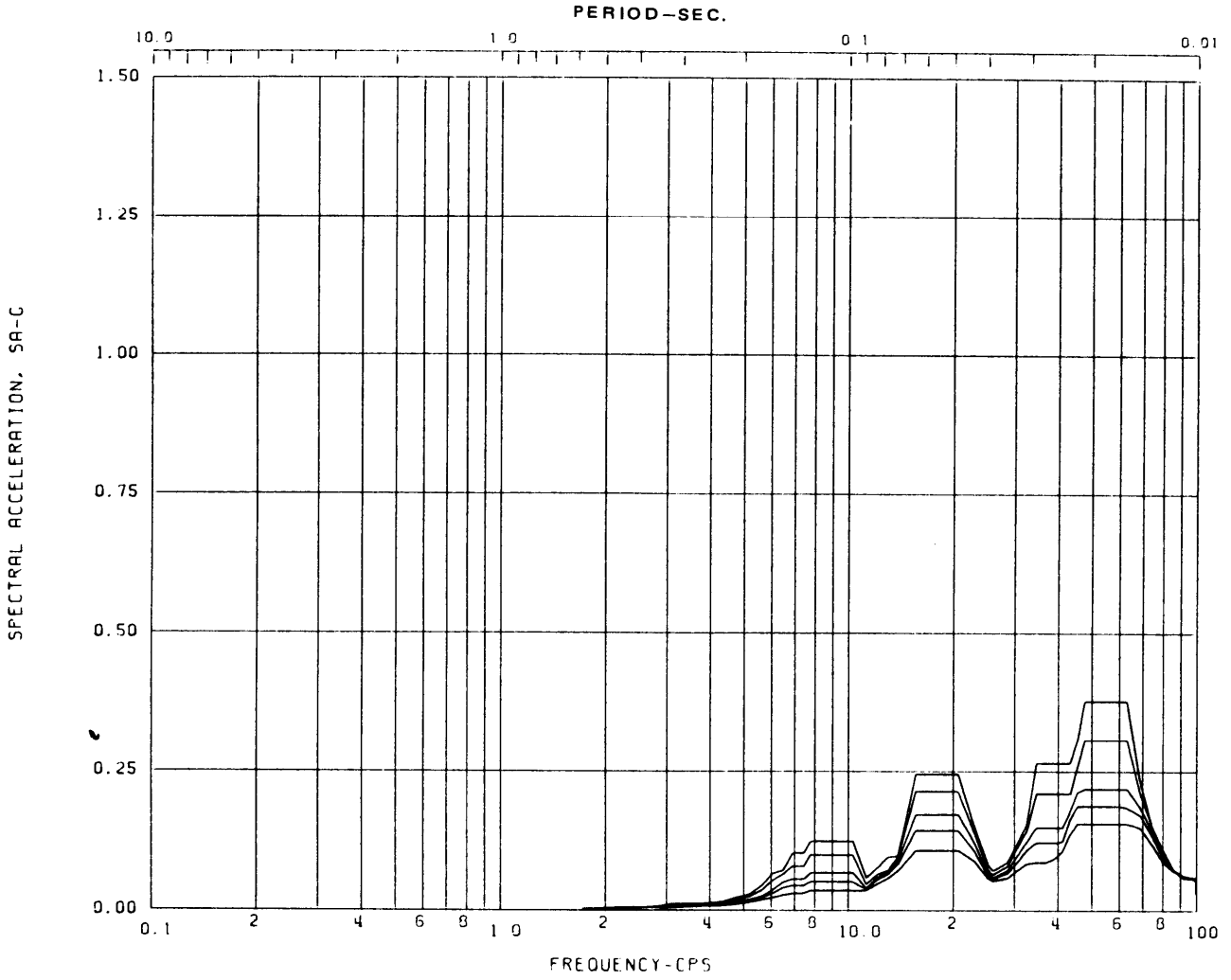
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-290



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPF (WIDENED - 15%)

Node: 104 Direction: VERTICAL Elev: 239'-0

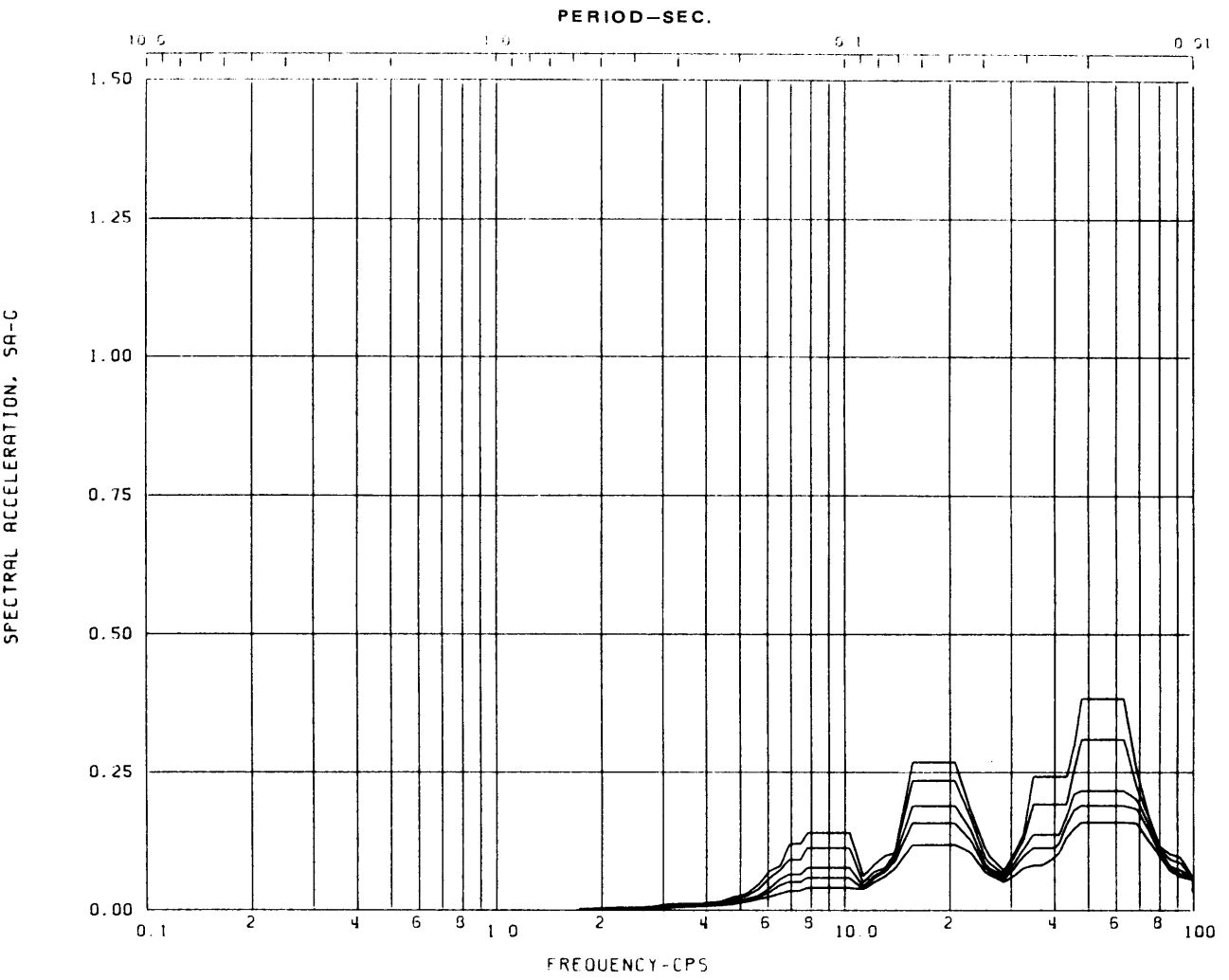
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-291



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 79 Direction: VERTICAL Elev: 253'-0

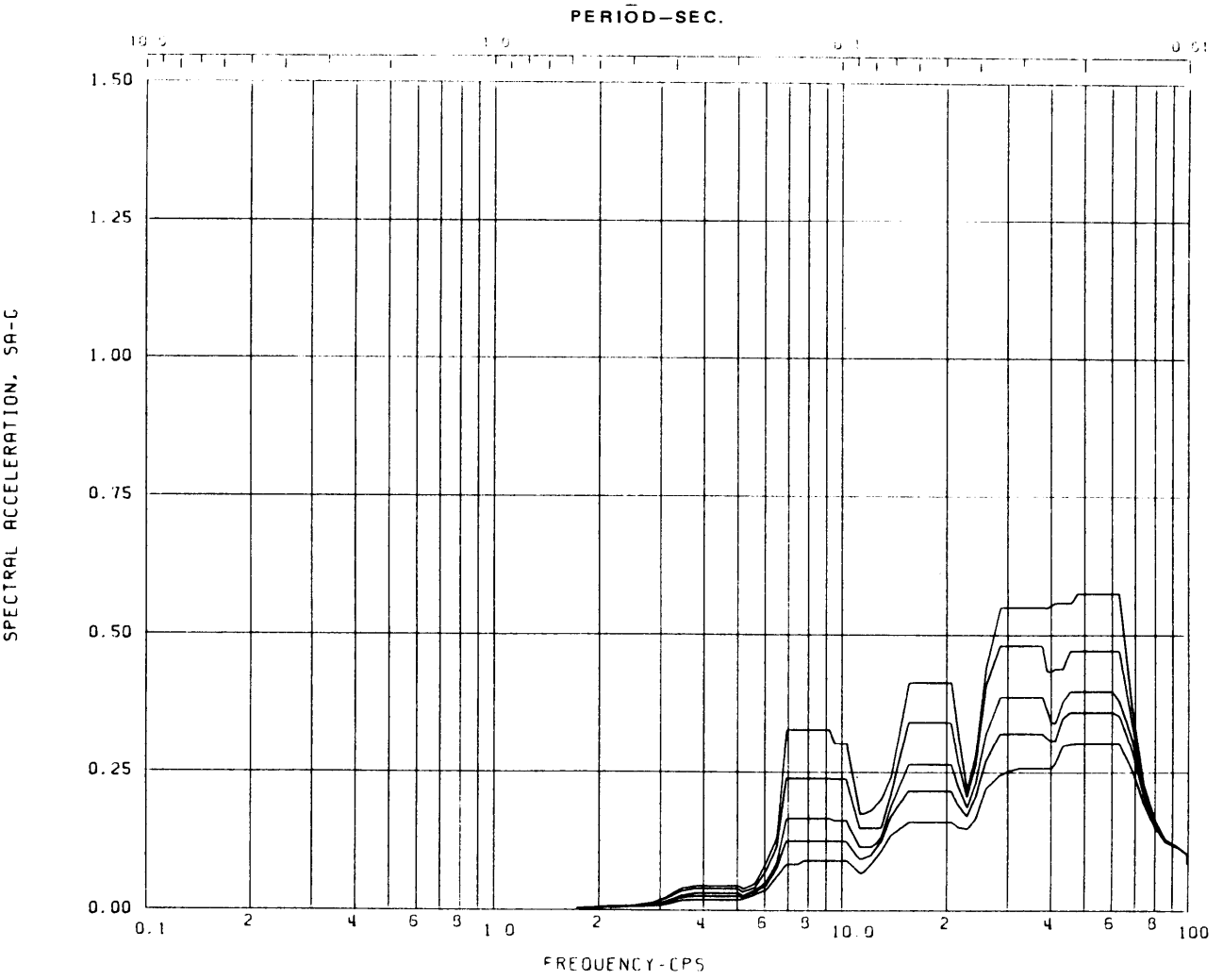
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-292



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 81 Direction: VERTICAL Elev: 253'-0

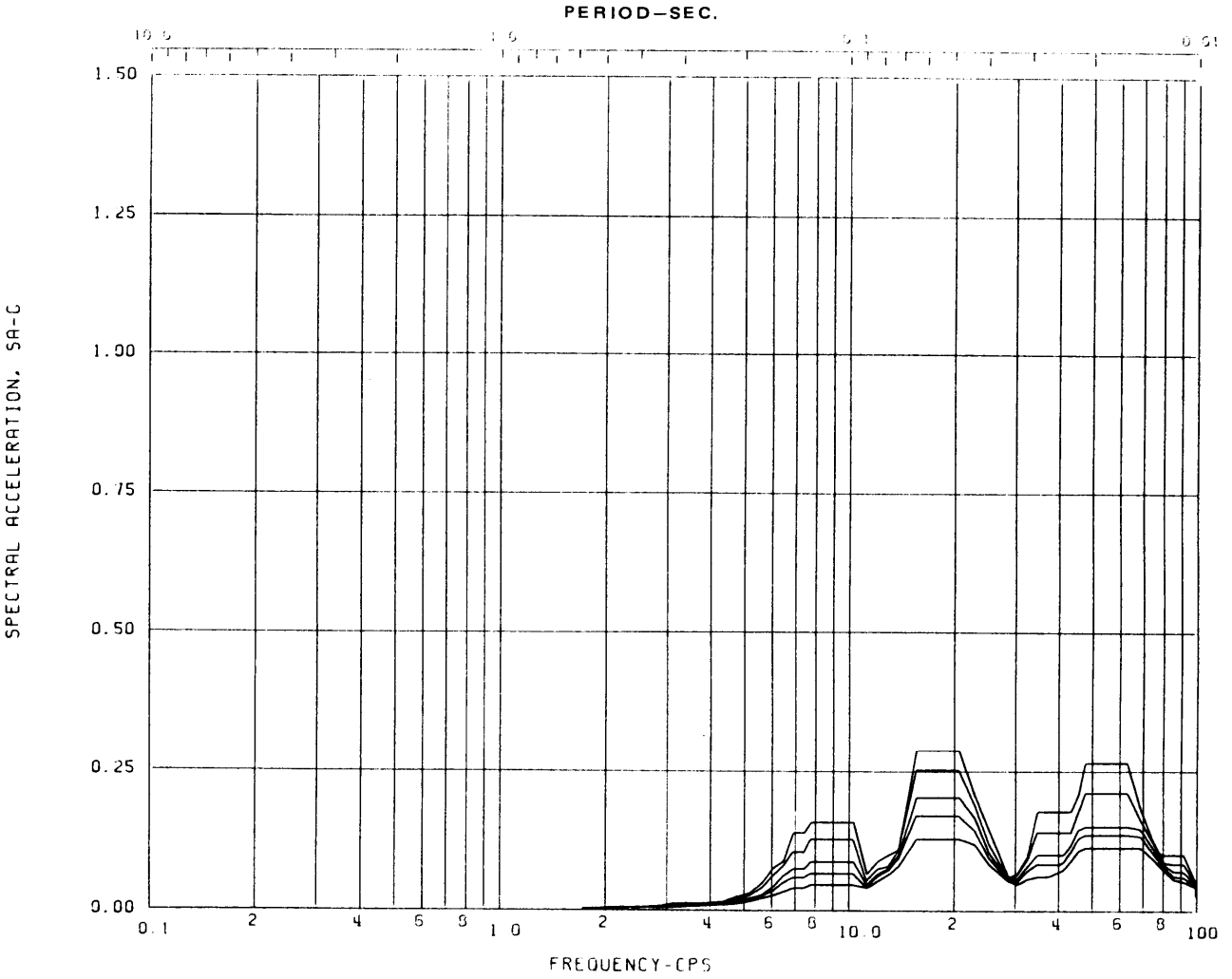
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-293



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 77 Direction: VERTICAL Elev: 269'-0

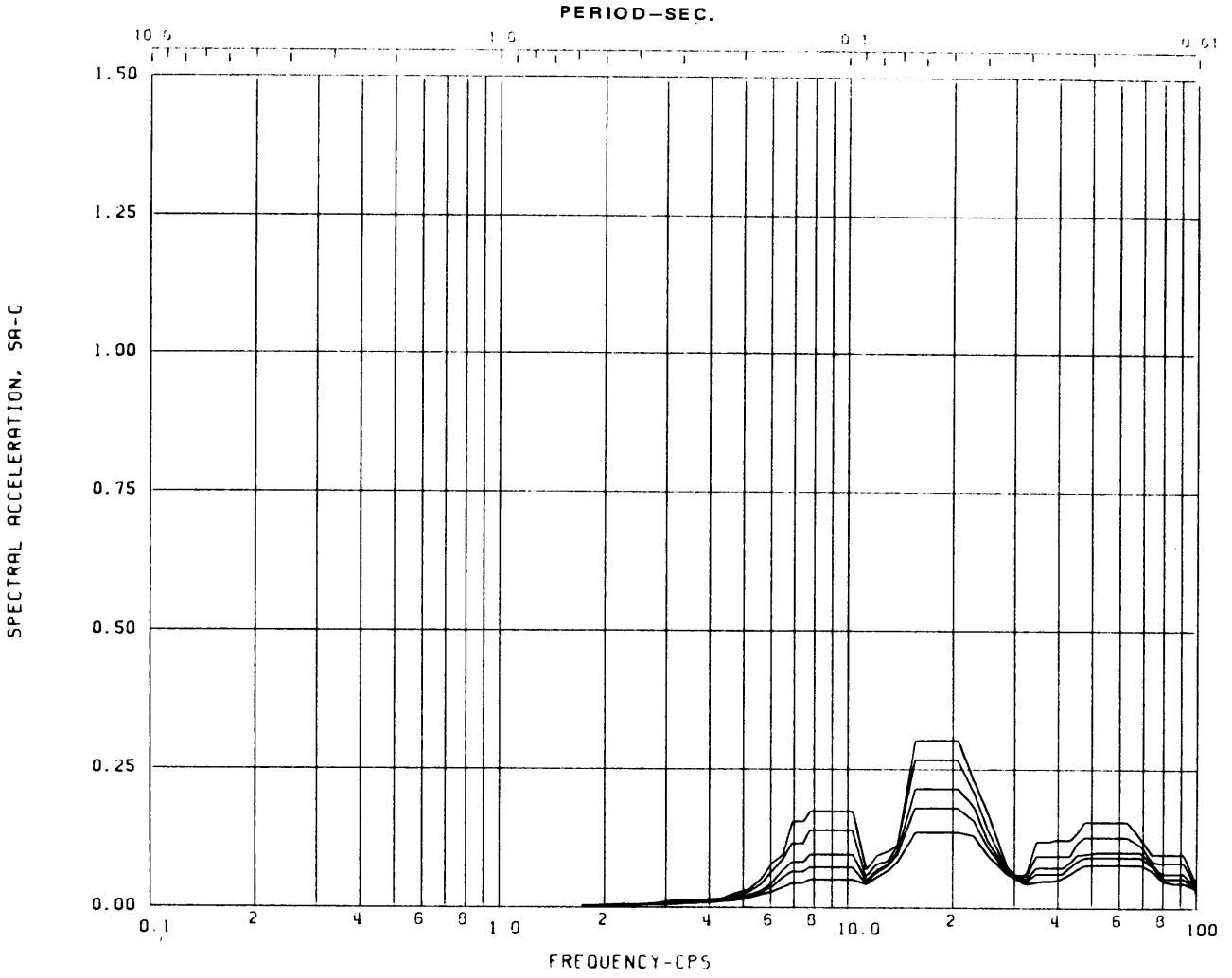
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-294



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 58 Direction: VERTICAL Elev: 283'-0

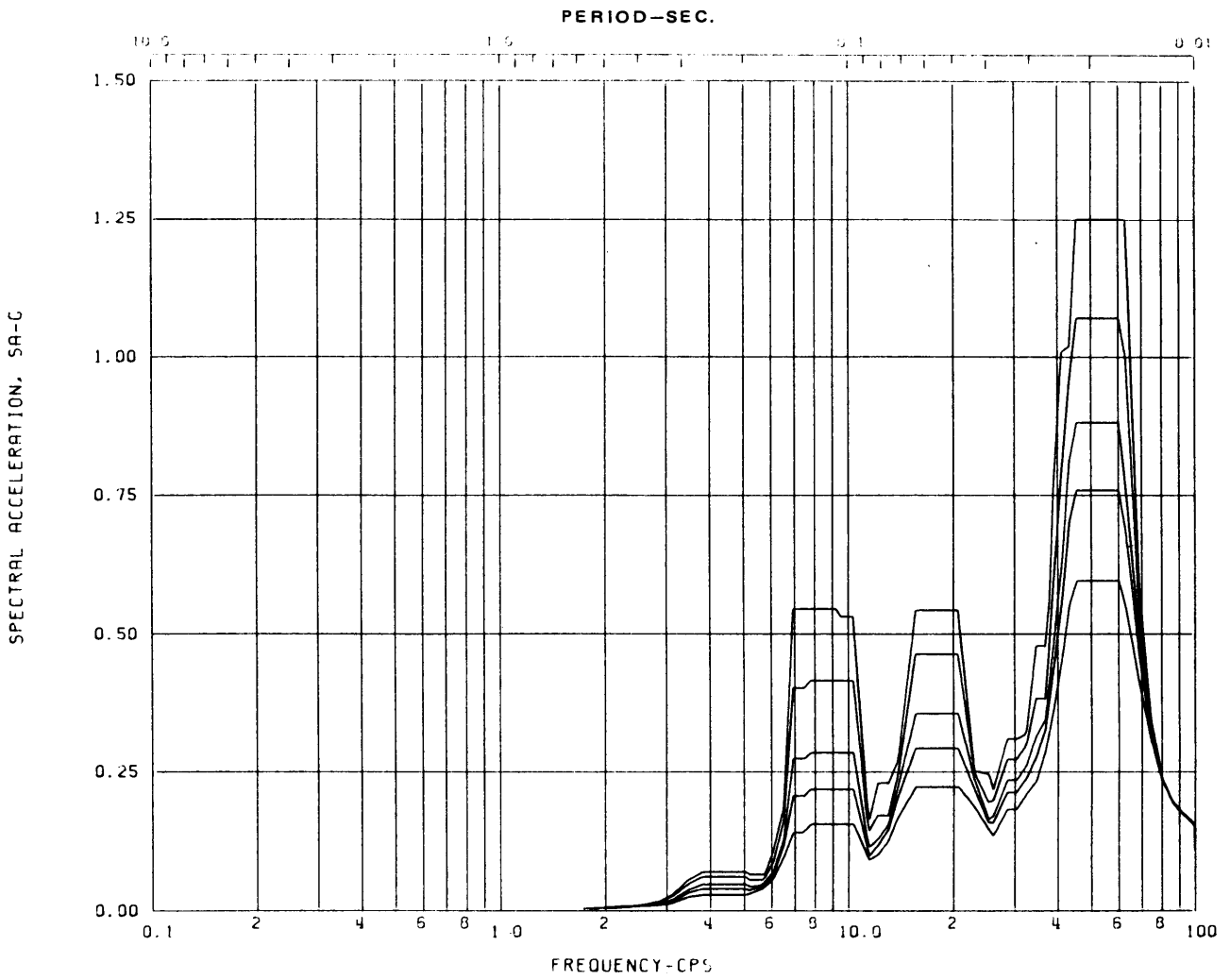
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-295



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 60 Direction: VERTICAL Elev: 283'-0

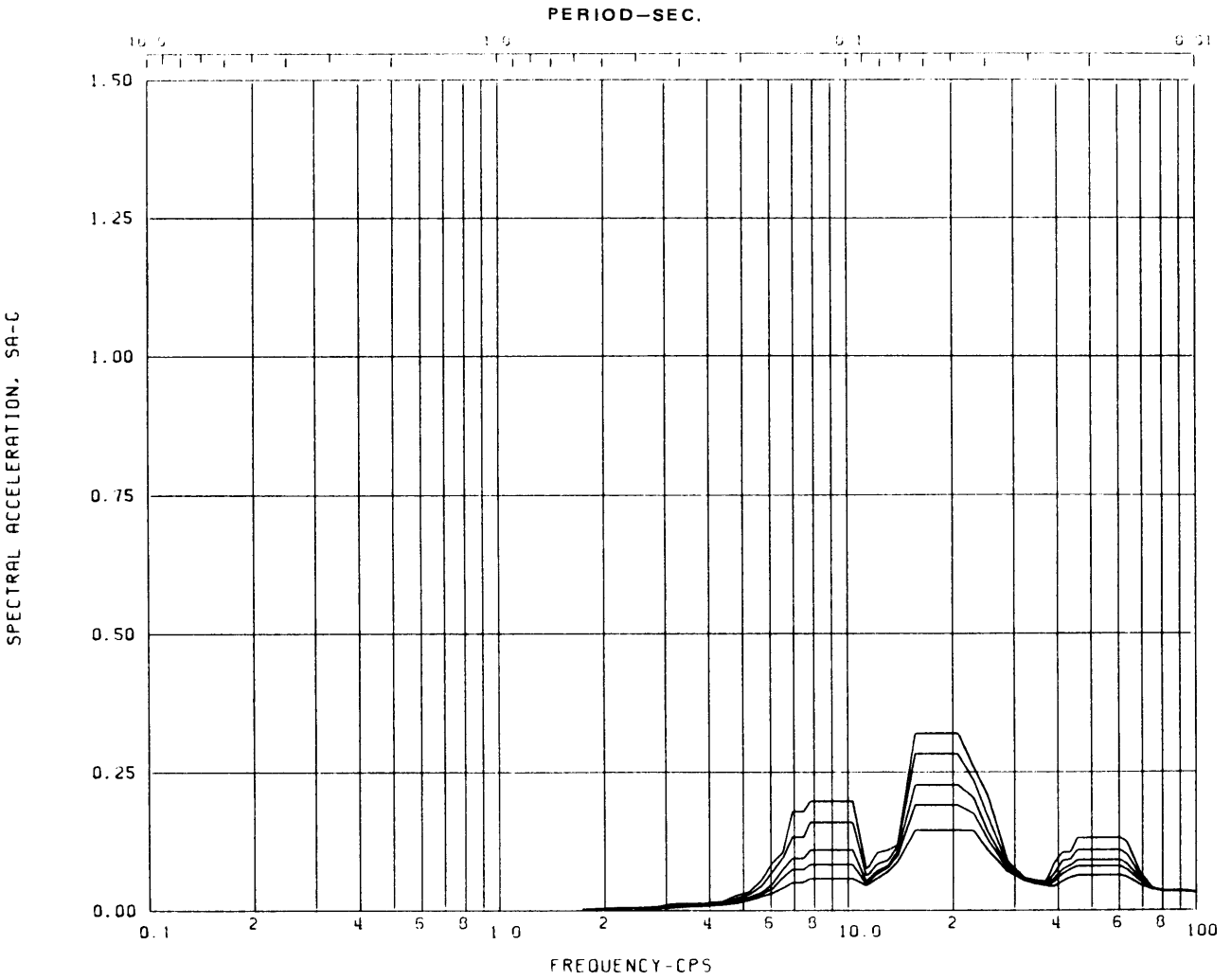
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-296



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 56 Direction: VERTICAL Elev: 304'-0

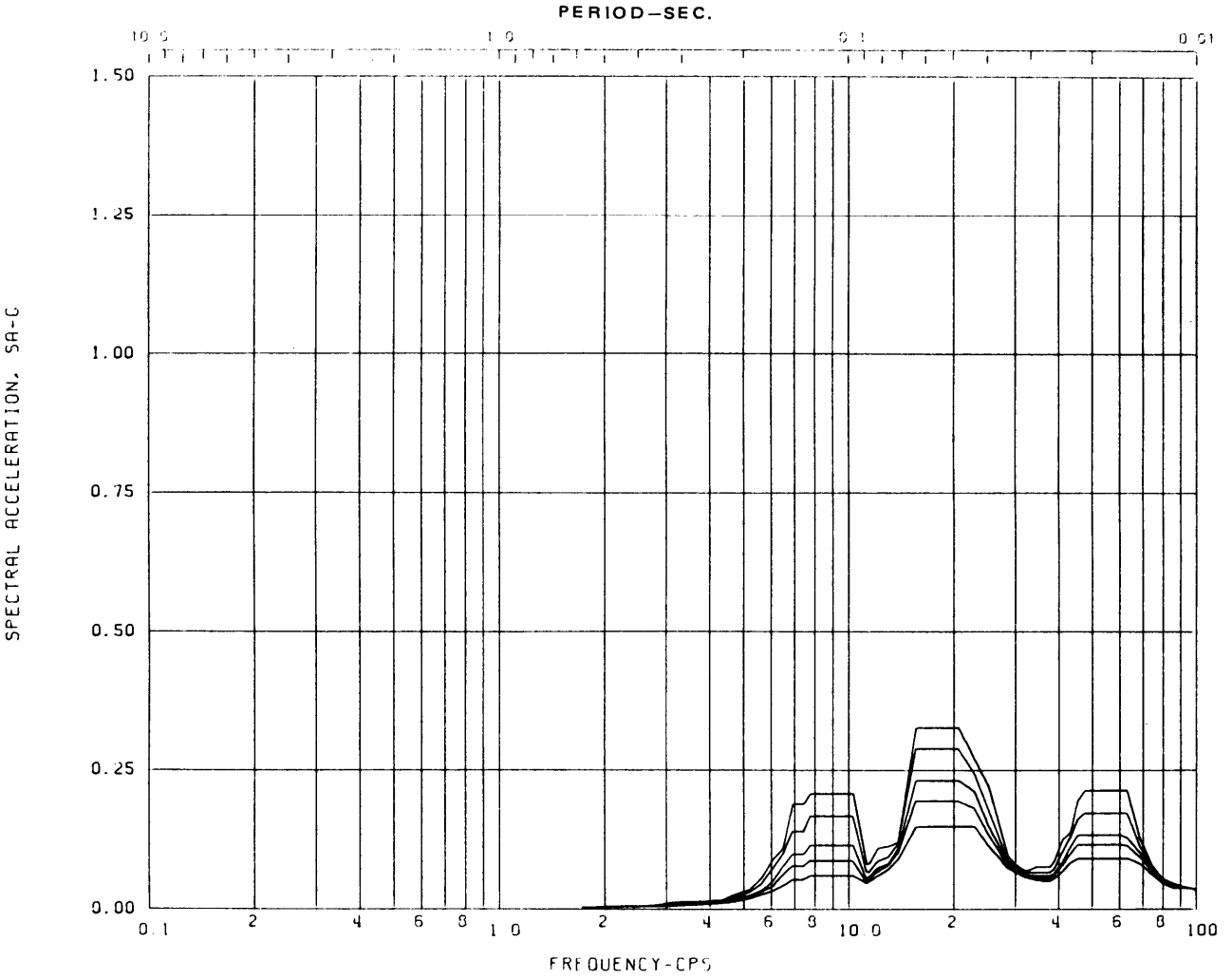
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-297



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 35 Direction: VERTICAL Elev: 313'-0

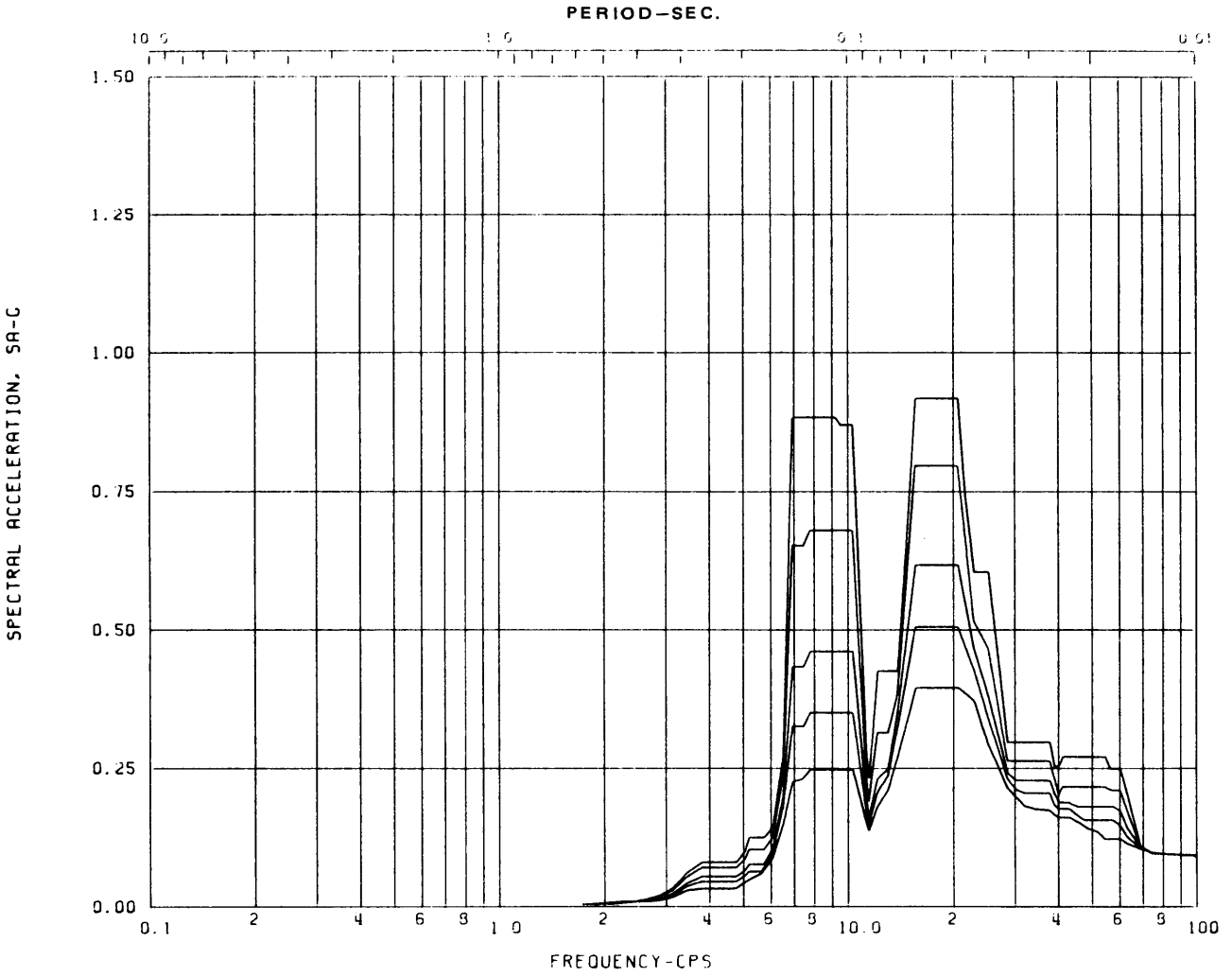
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-298



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 43 Direction: VERTICAL Elev: 313'-0

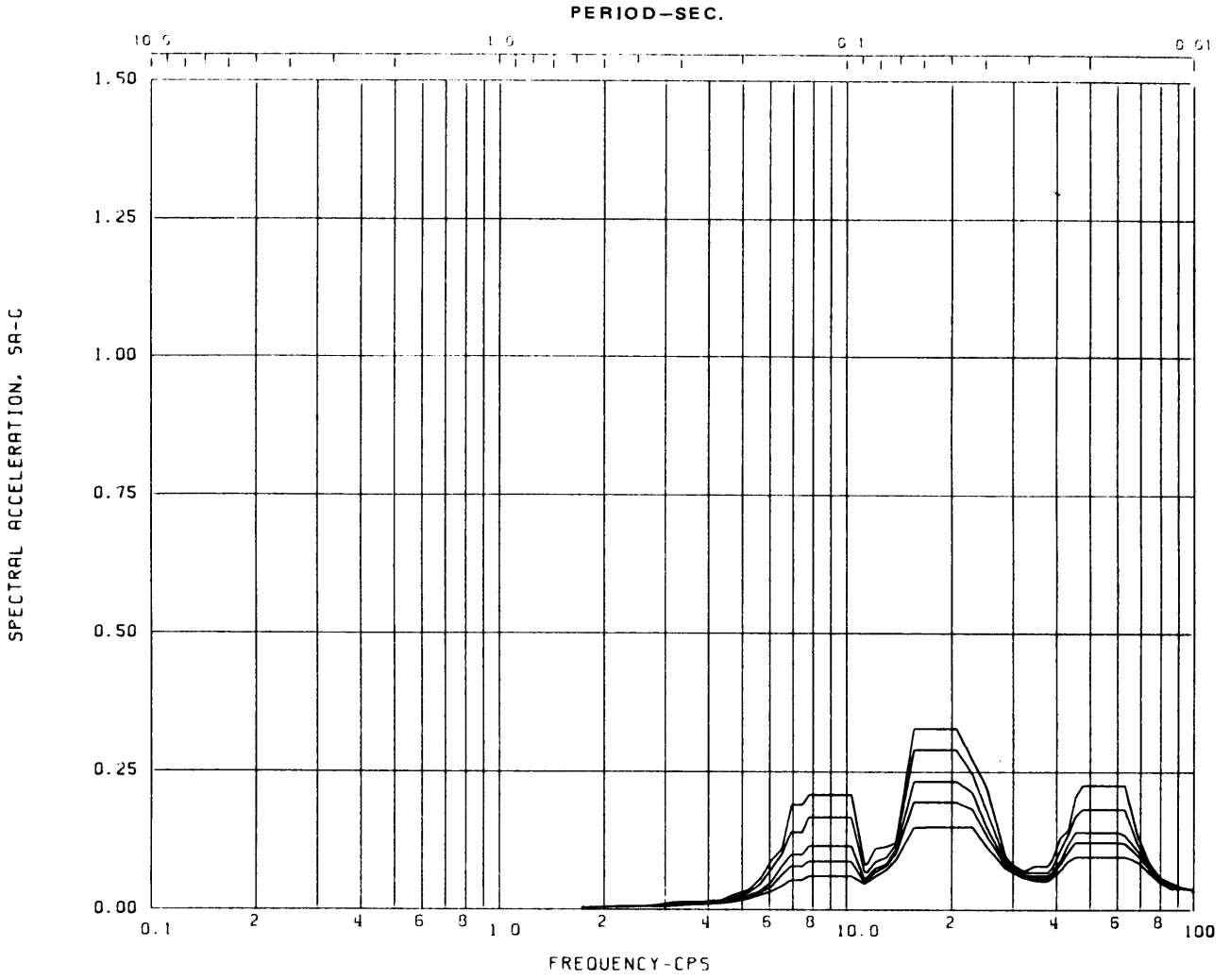
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-299



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 21 Direction: VERTICAL Elev: 333'-0

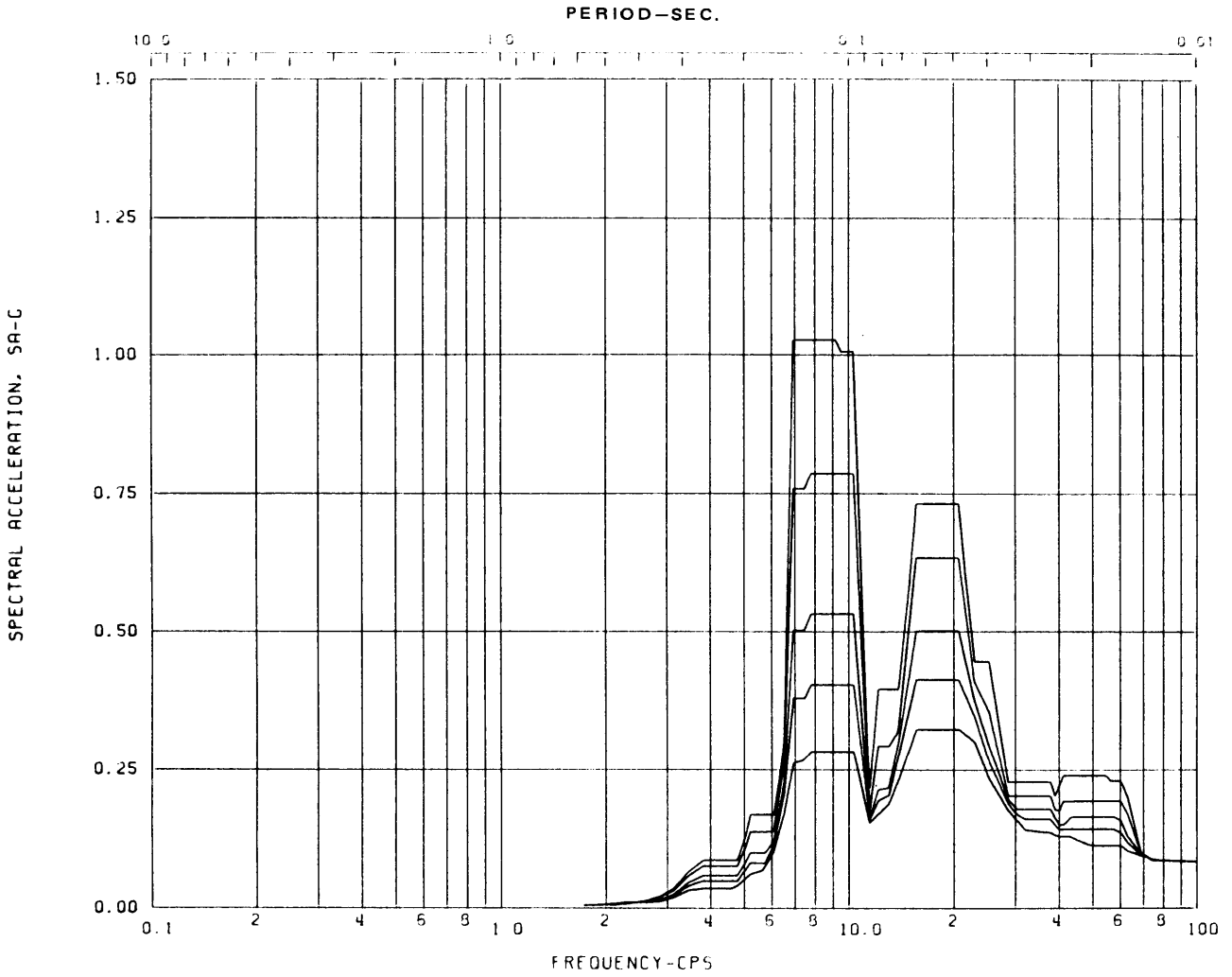
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-300



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 33 Direction: VERTICAL Elev: 333'-0

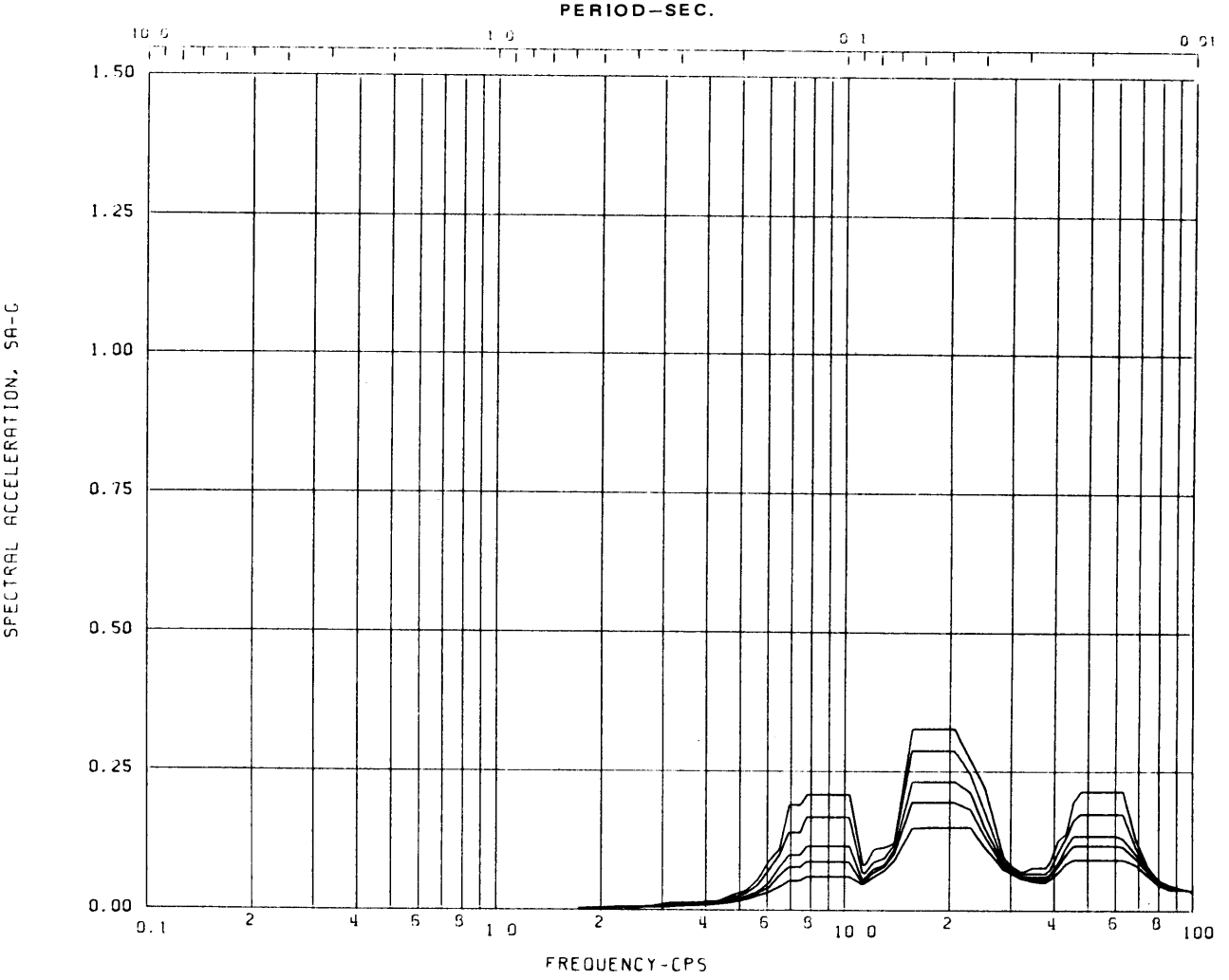
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-301



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 9 Direction: VERTICAL Elev: 352'-0

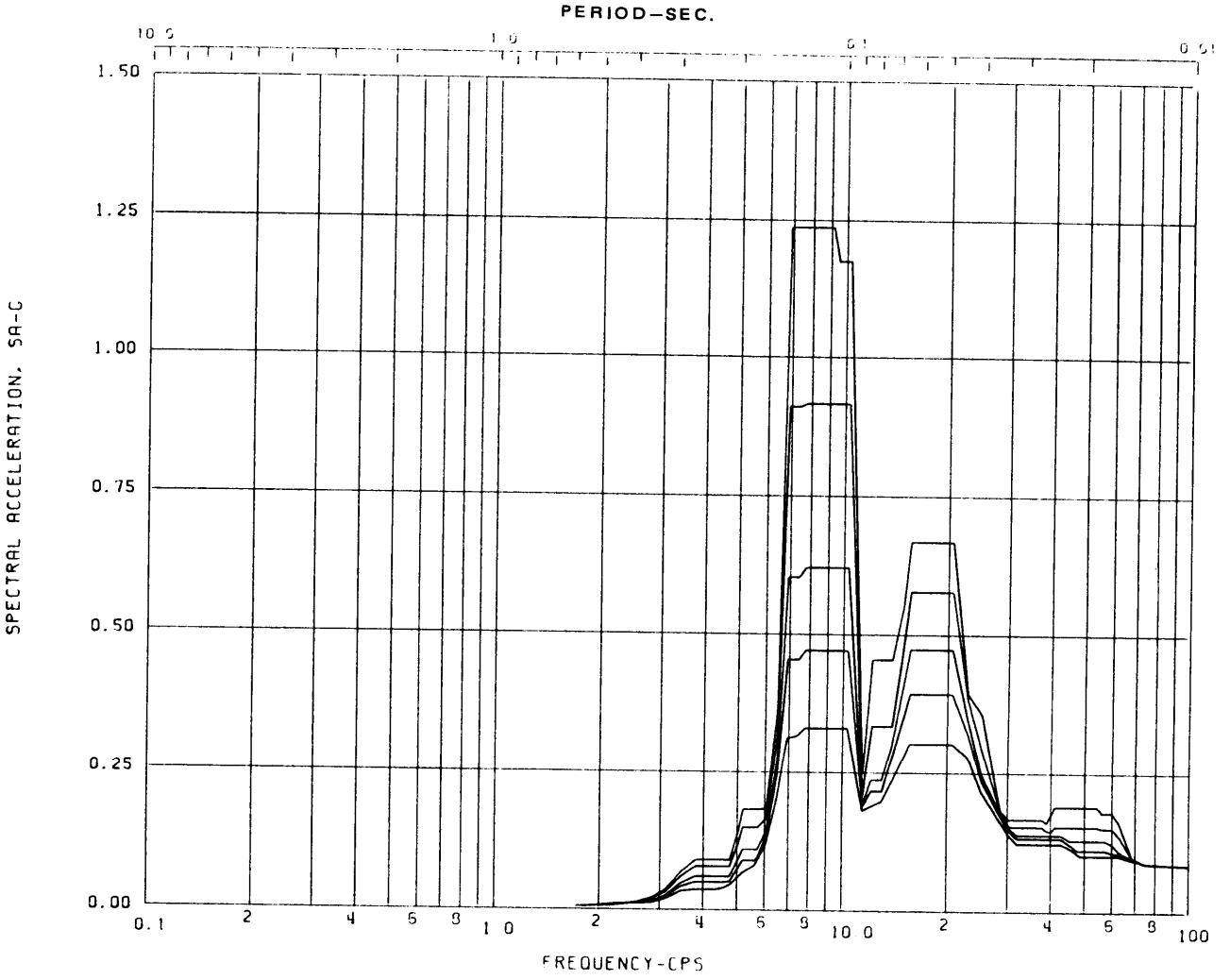
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-302



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 13 Direction: VERTICAL Elev: 352'-0

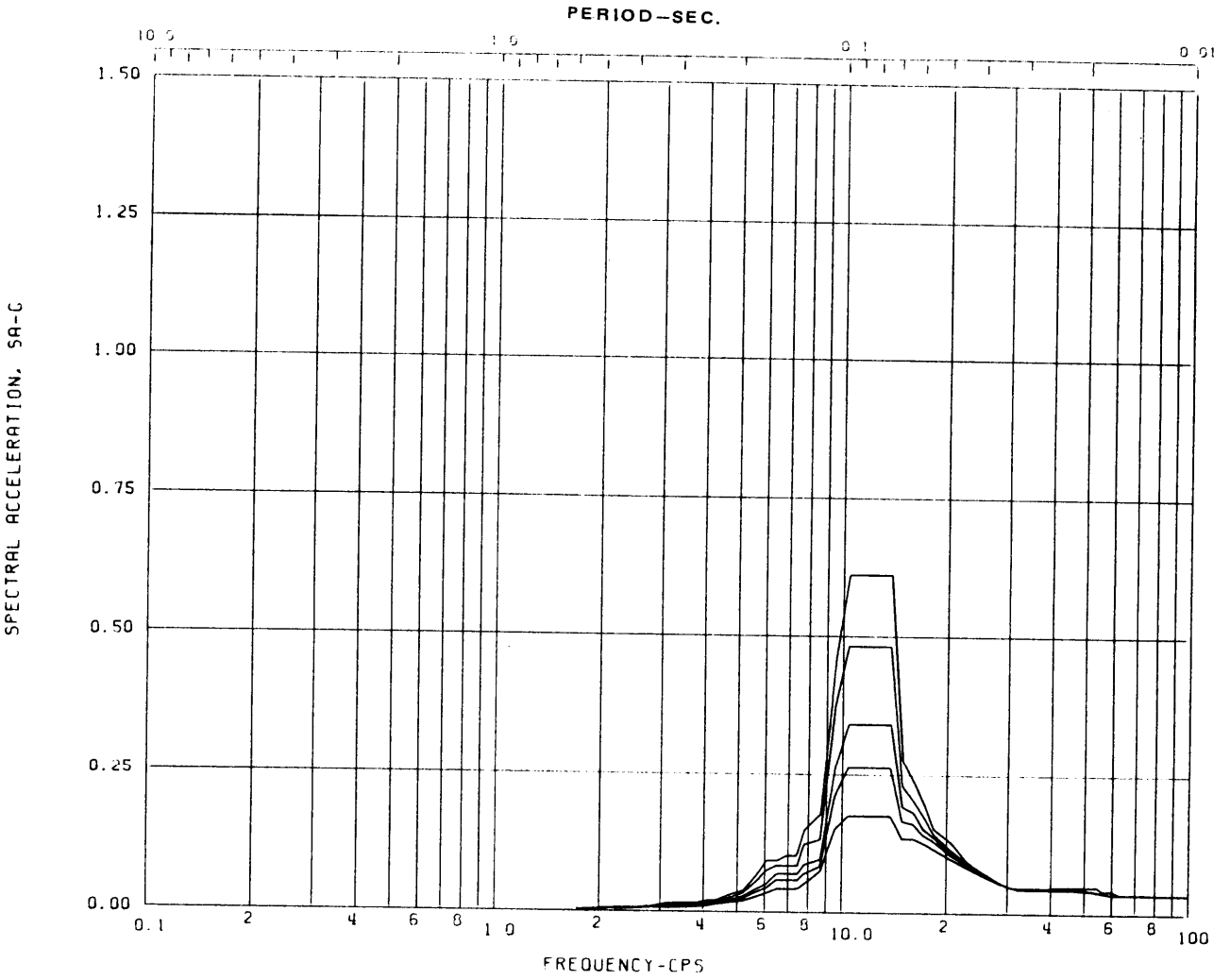
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-303



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPF (WIDENED - 15%)

Node: 129 Direction: VERTICAL Elev: 201'-0

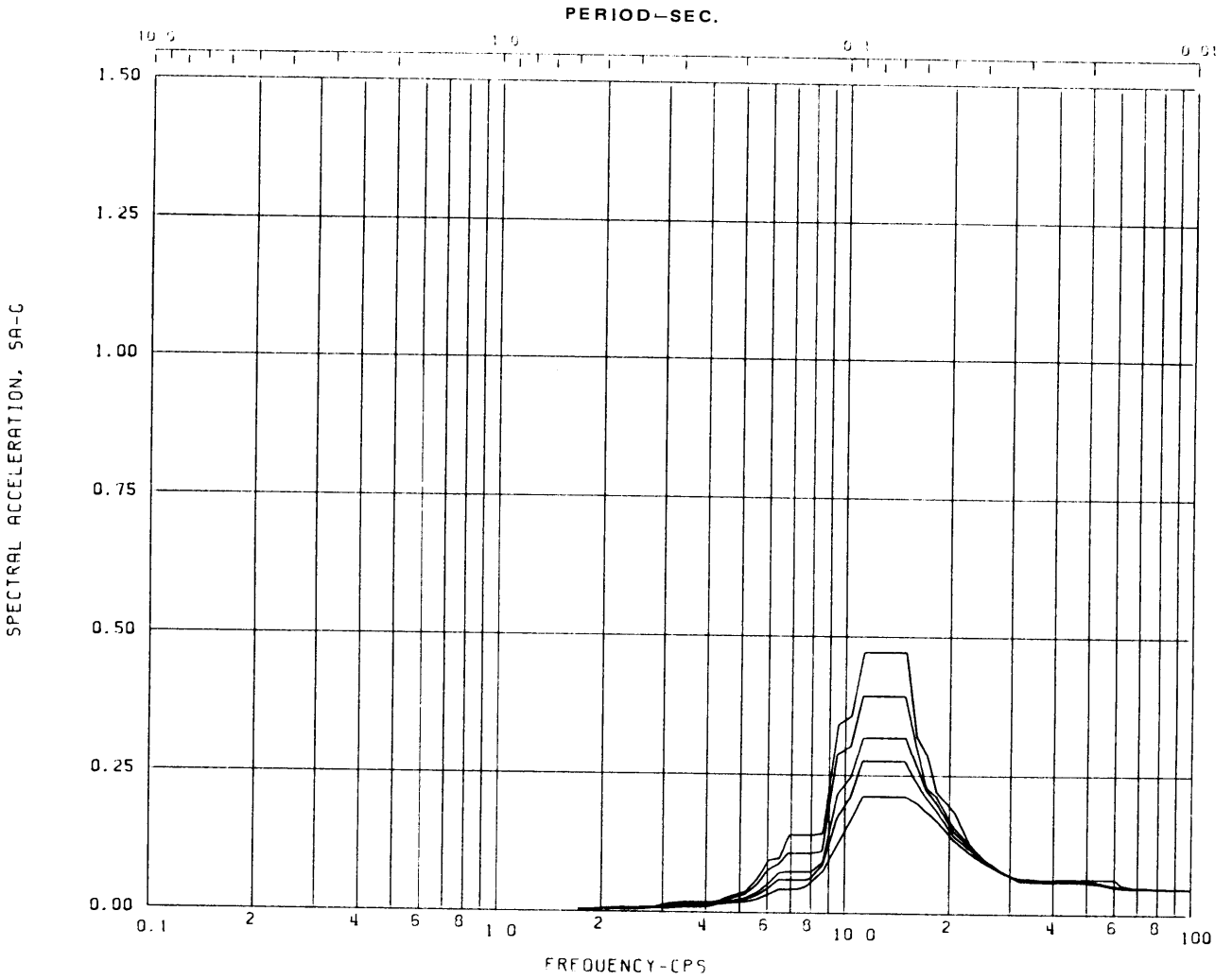
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-304



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 107 Direction: VERTICAL Elev: 217'-0

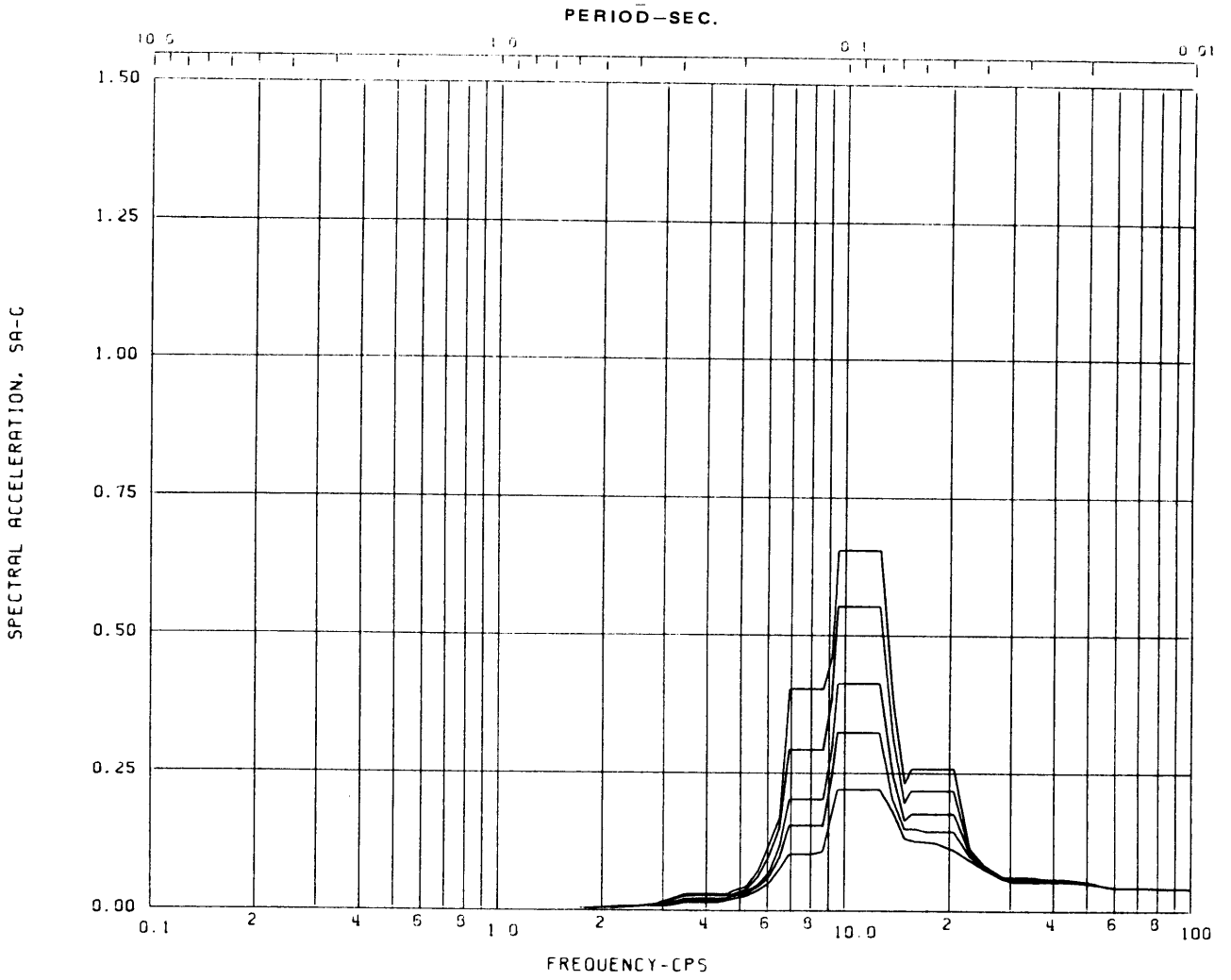
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – BASIC AXISYMMETRIC

FIGURE 3A-305



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 80 Direction: VERTICAL Elev: 253'-0

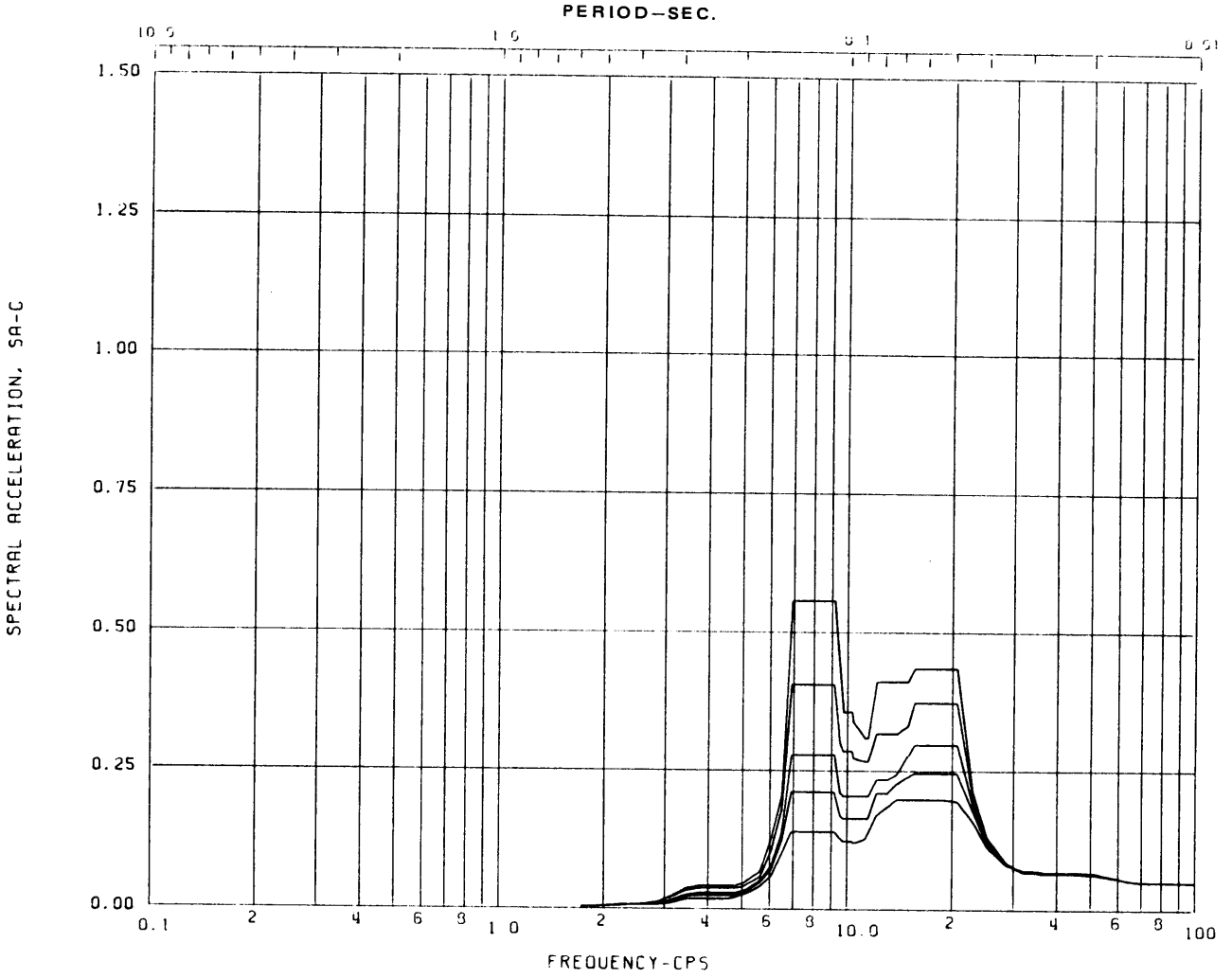
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – BASIC AXISYMMETRIC

FIGURE 3A-306



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 59 Direction: VERTICAL Elev: 283'-0

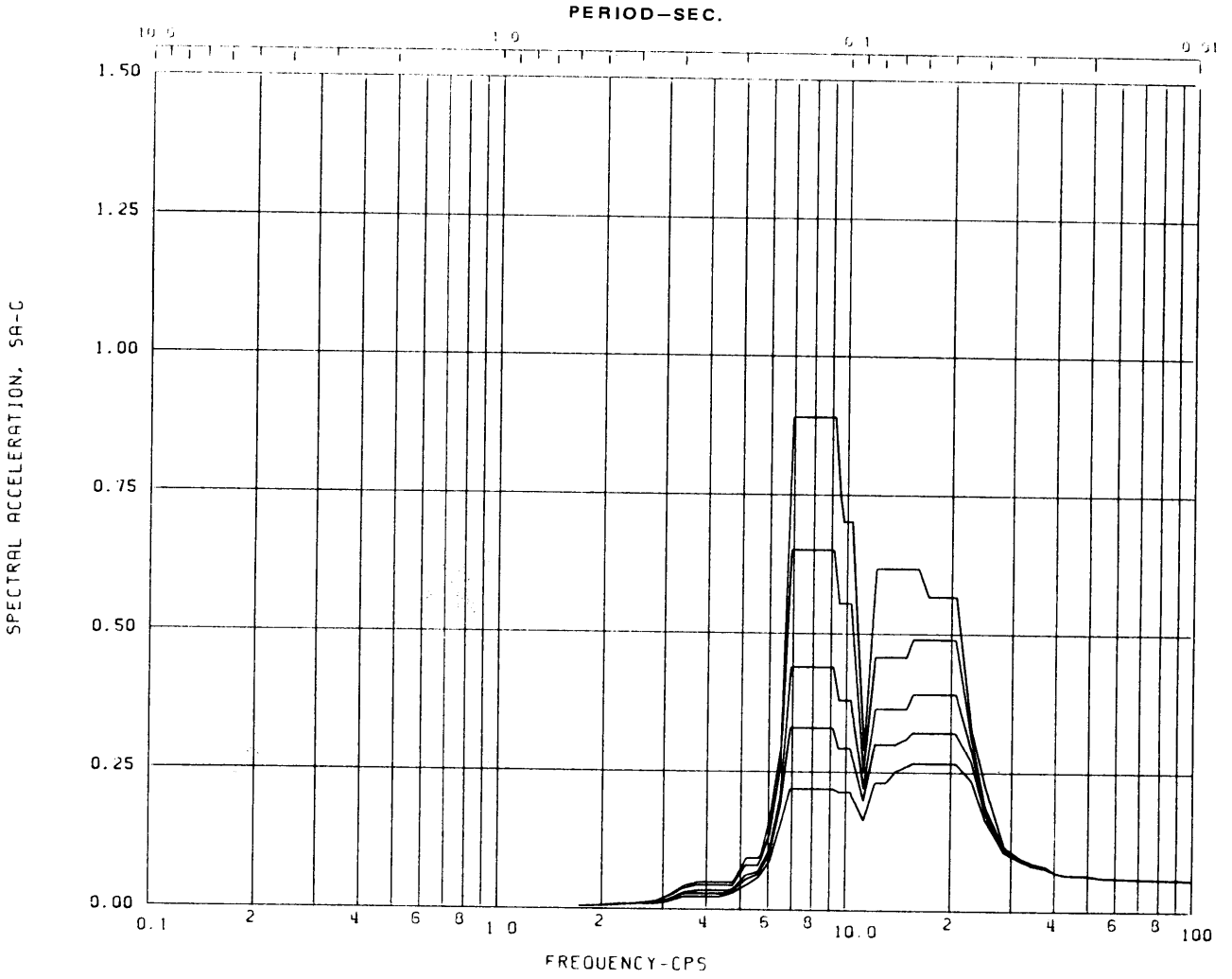
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-307



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 54 Direction: VERTICAL Elev: 313'-0

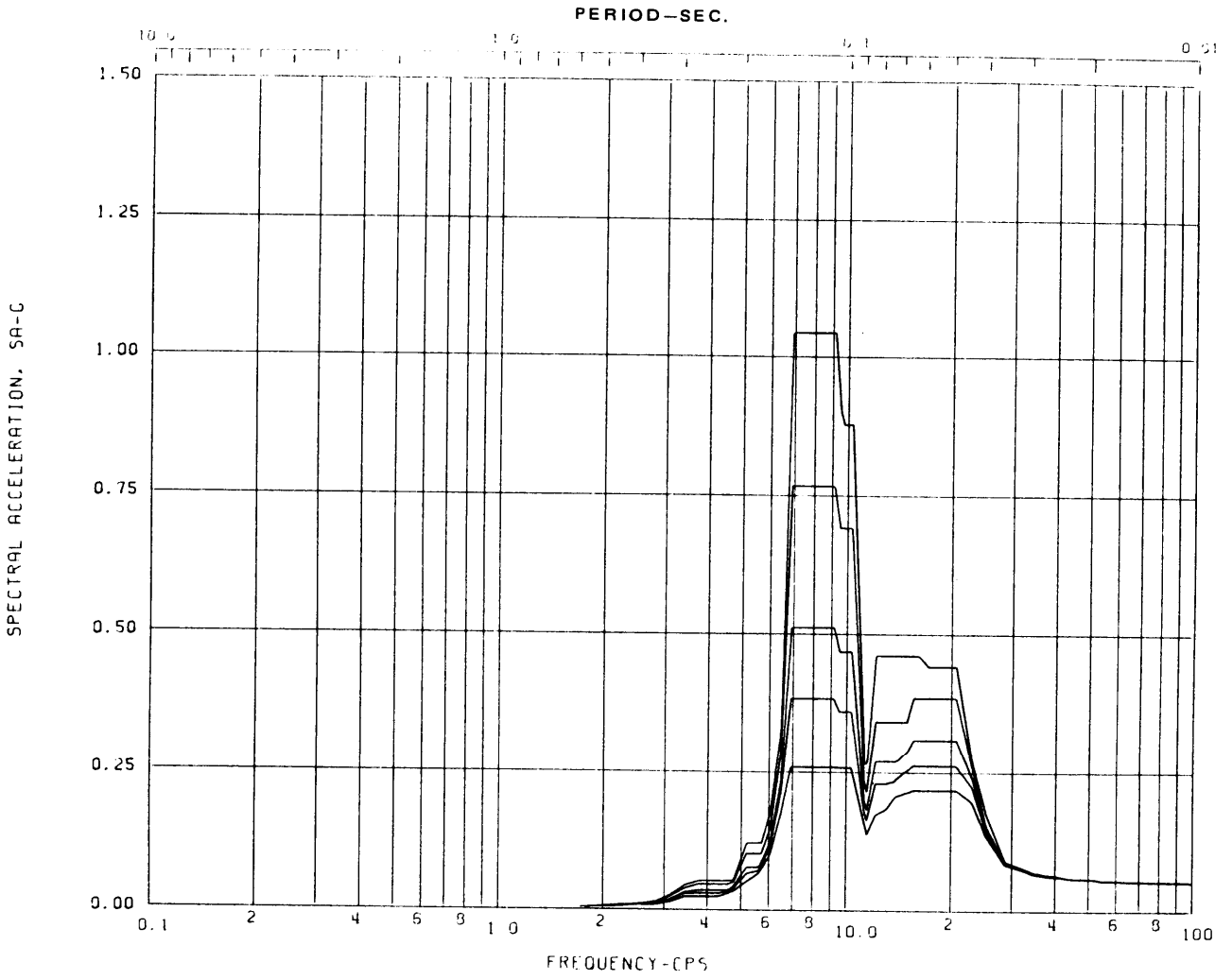
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-308



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 32 Direction: VERTICAL Elev: 333'-0

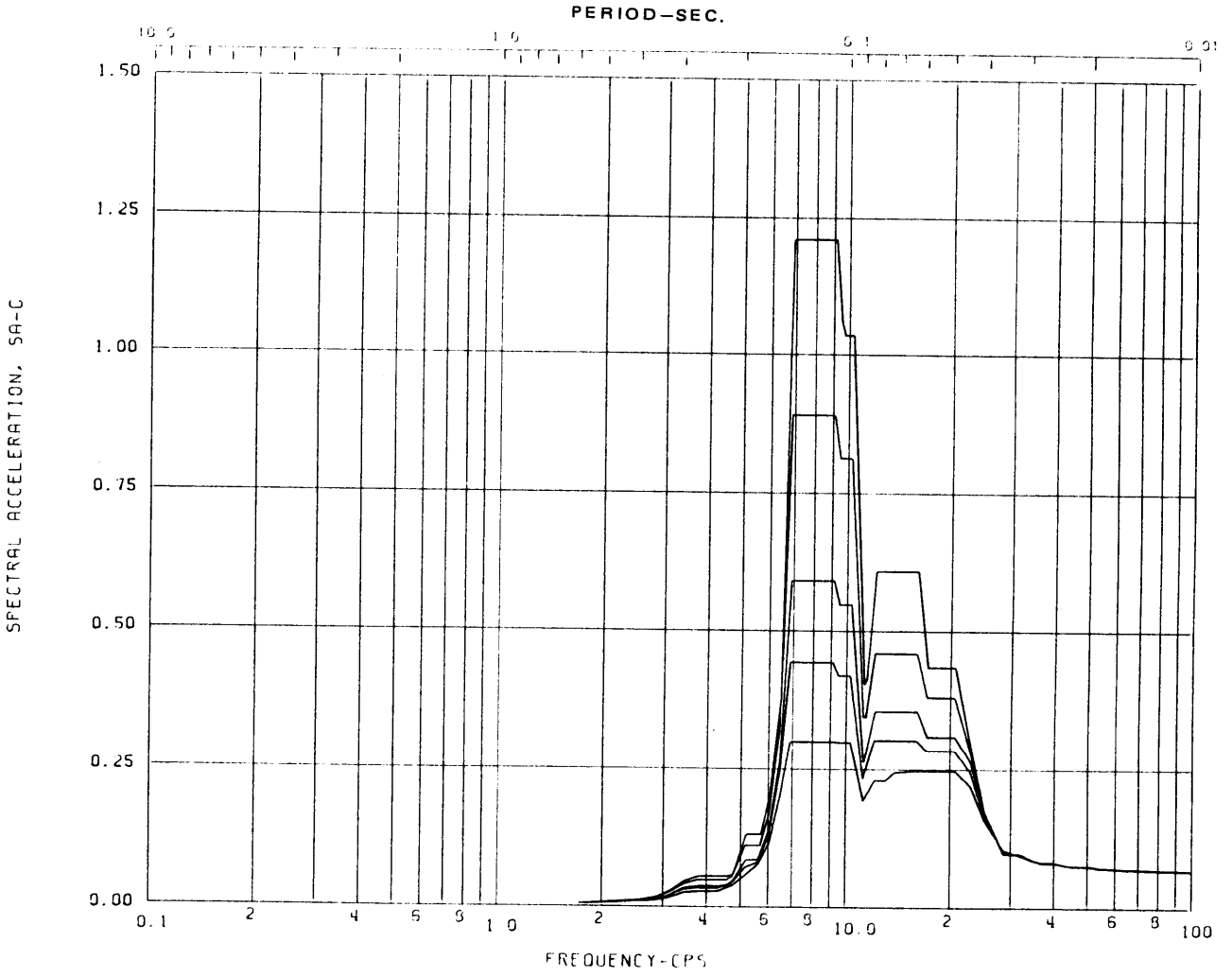
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-309



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 12 Direction: VERTICAL Elev: 352'-0

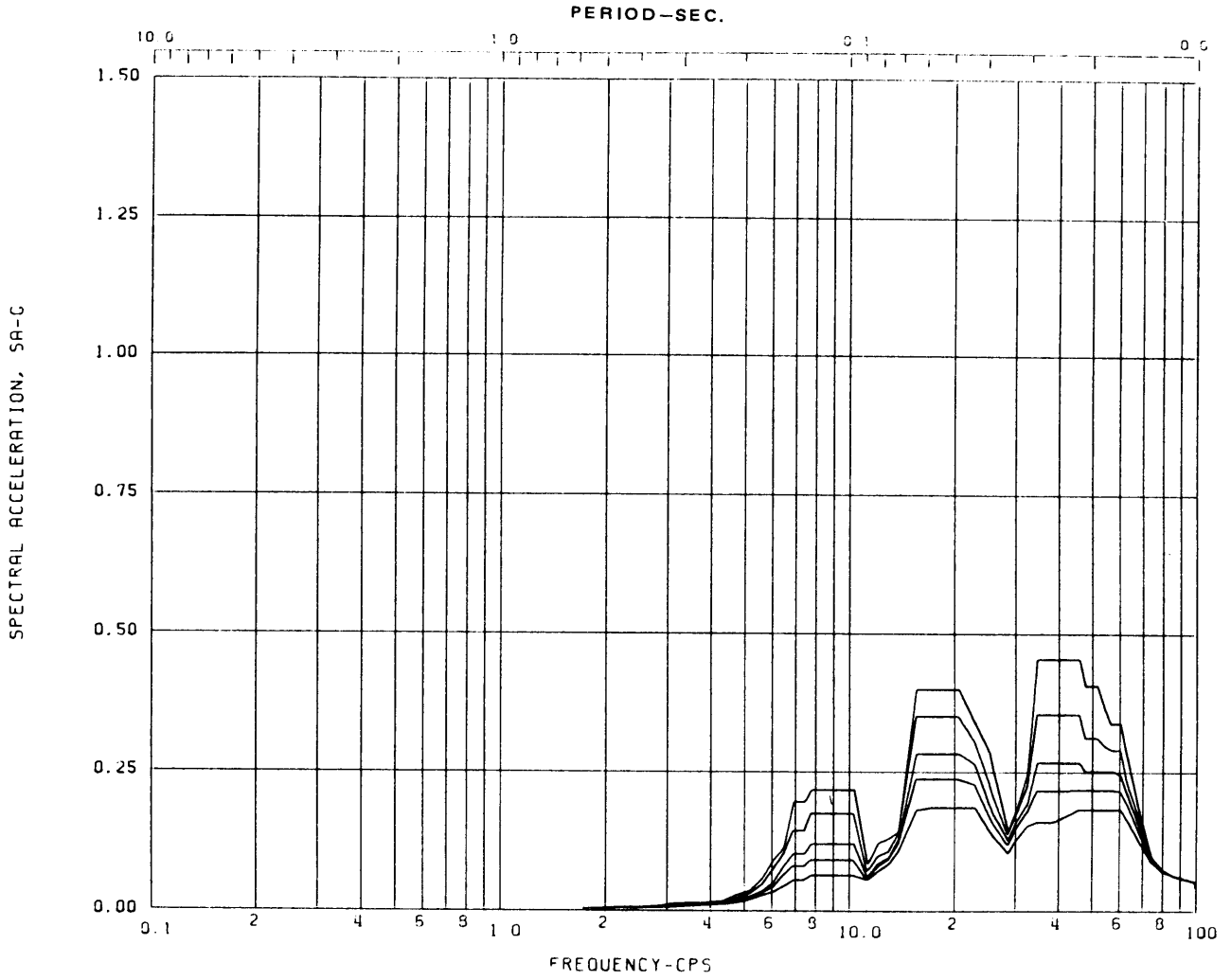
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-310



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 6 Direction: VERTICAL Elev: 410'-0

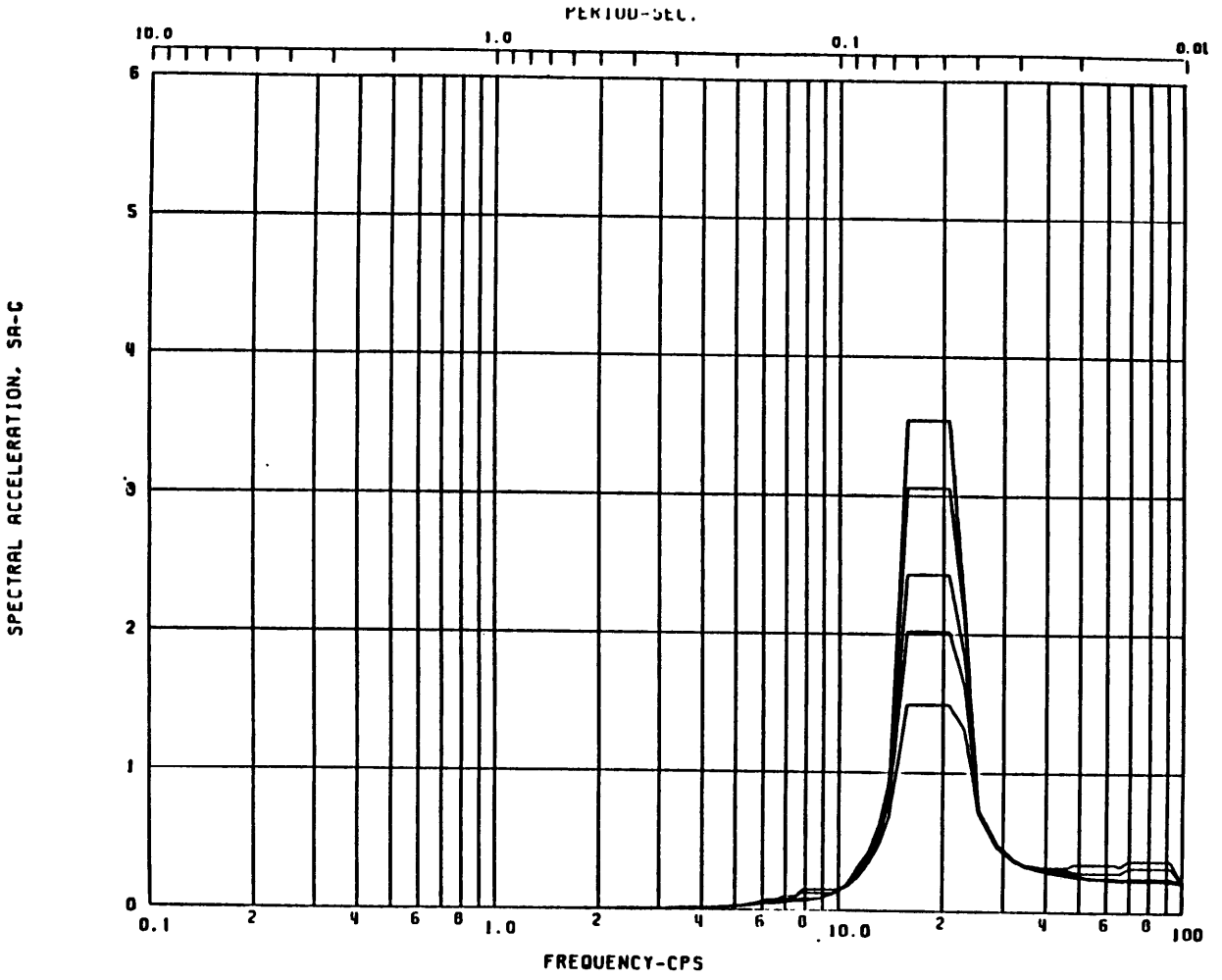
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – BASIC AXISYMMETRIC

FIGURE 3A-311



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPF (WIDENED - 15%)

Node: 7 Direction: VERTICAL Elev: 217'

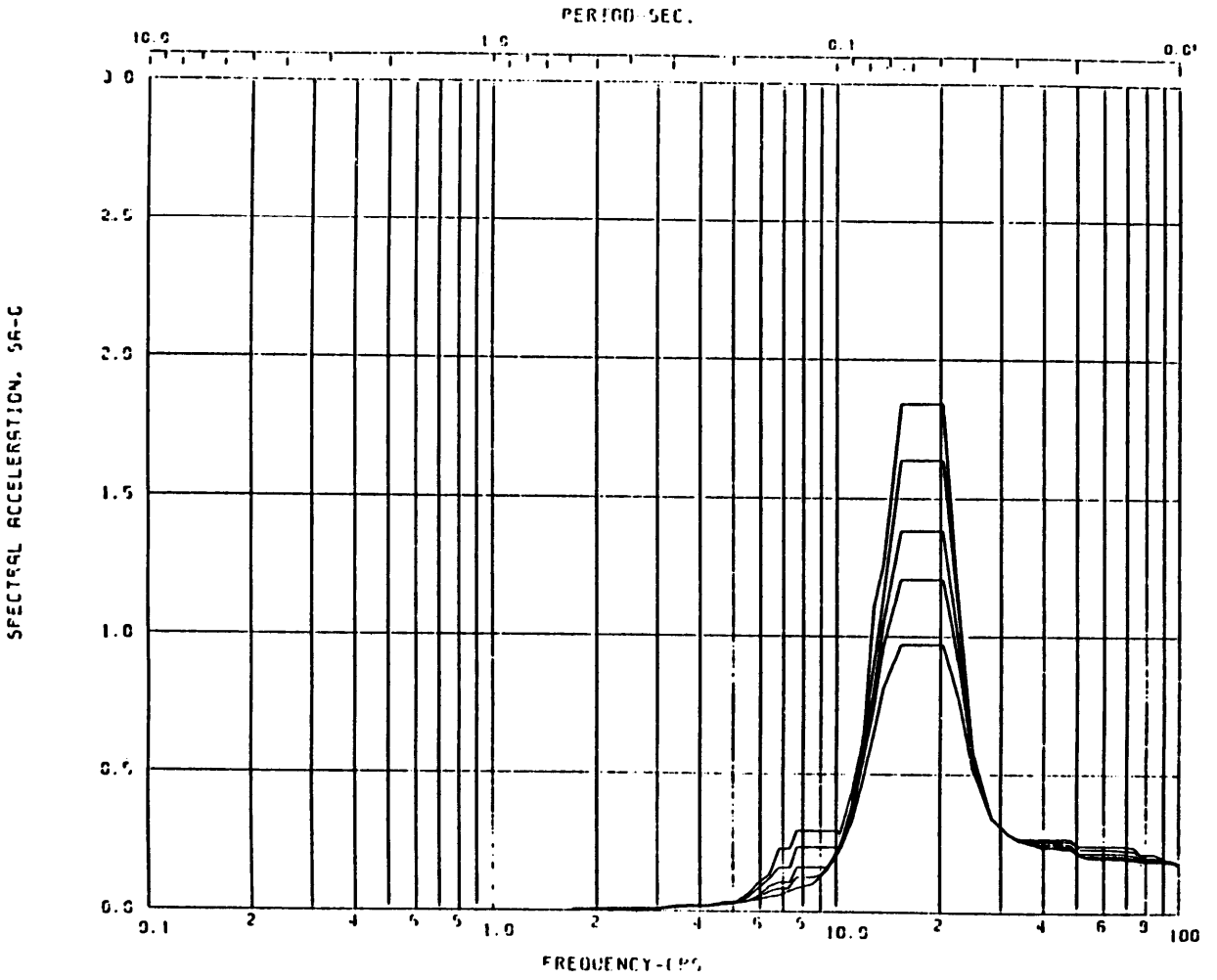
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-312



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 7 Direction: VERTICAL Elev: 239'

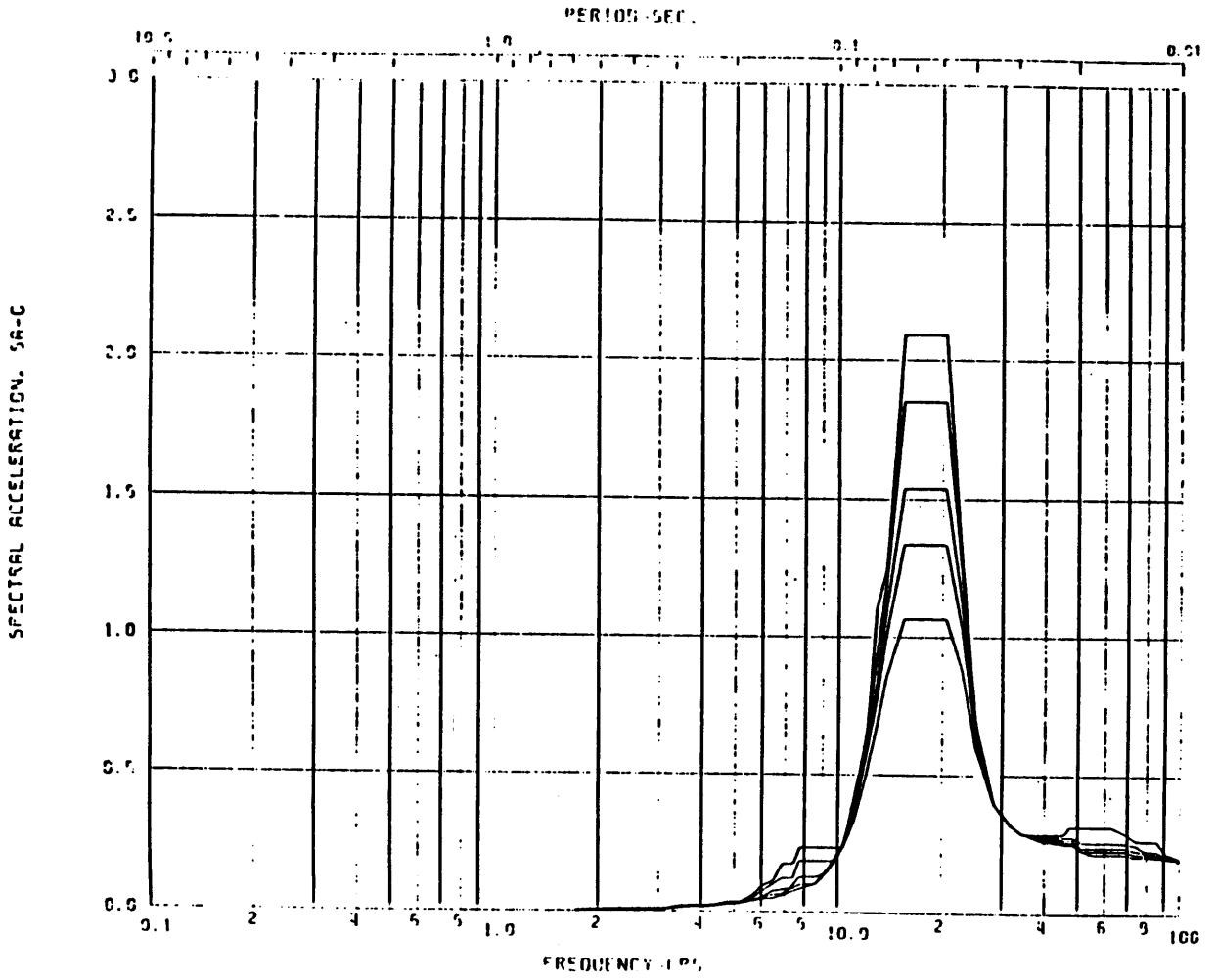
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-313



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 7 Direction: VERTICAL Elev: 254'

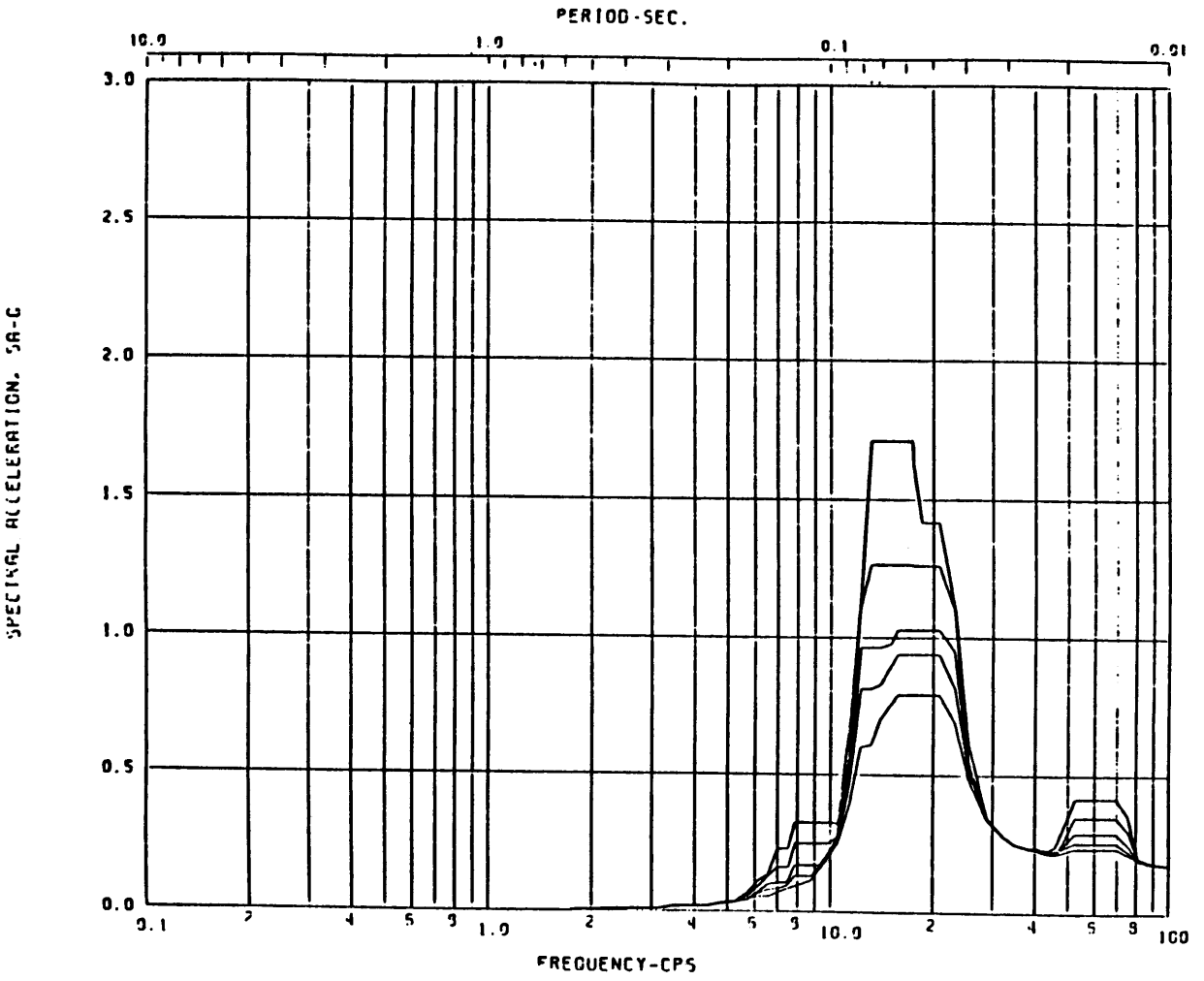
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-314



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

Node: 7 Direction: VERTICAL Elev: 269'-0

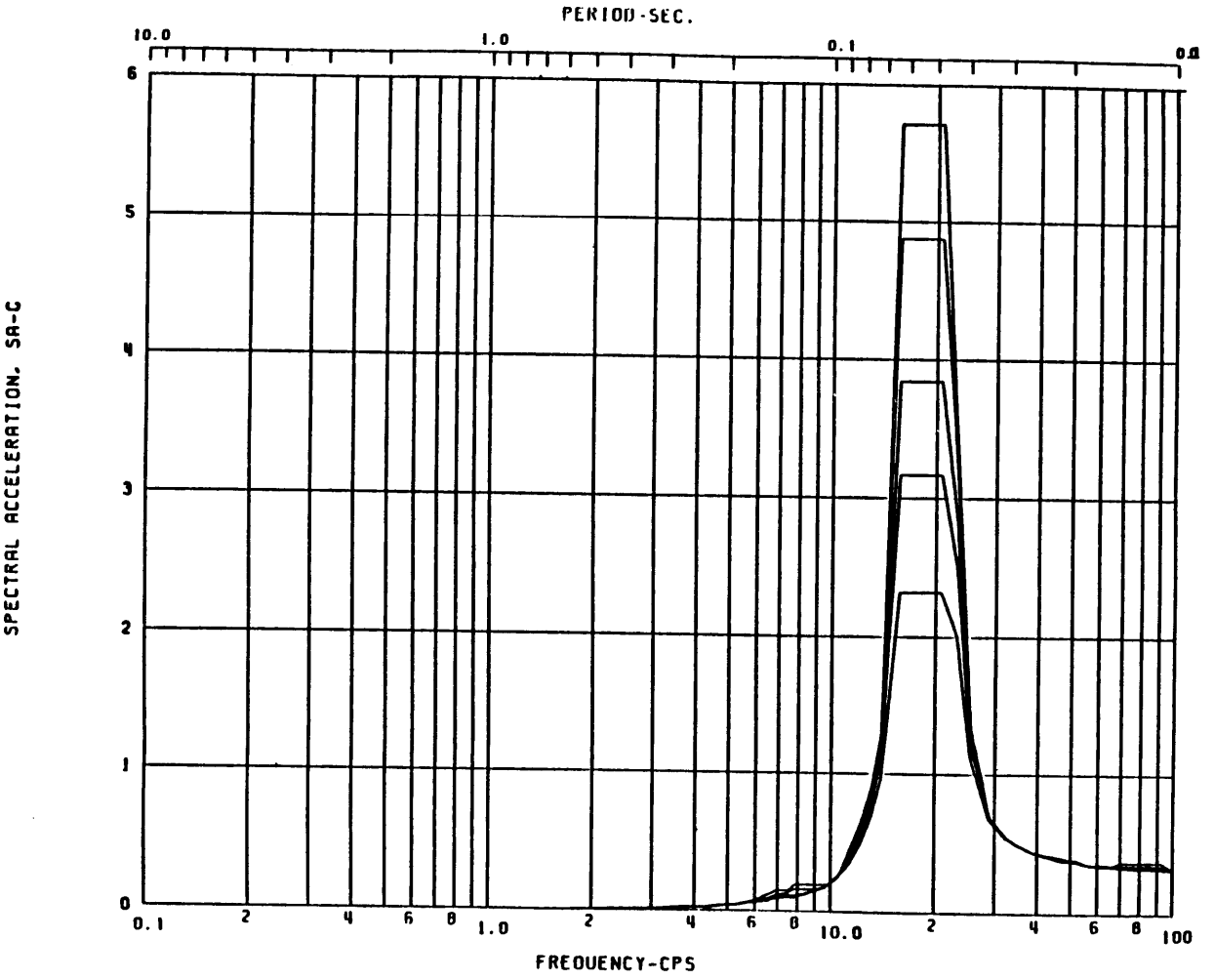
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-315



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

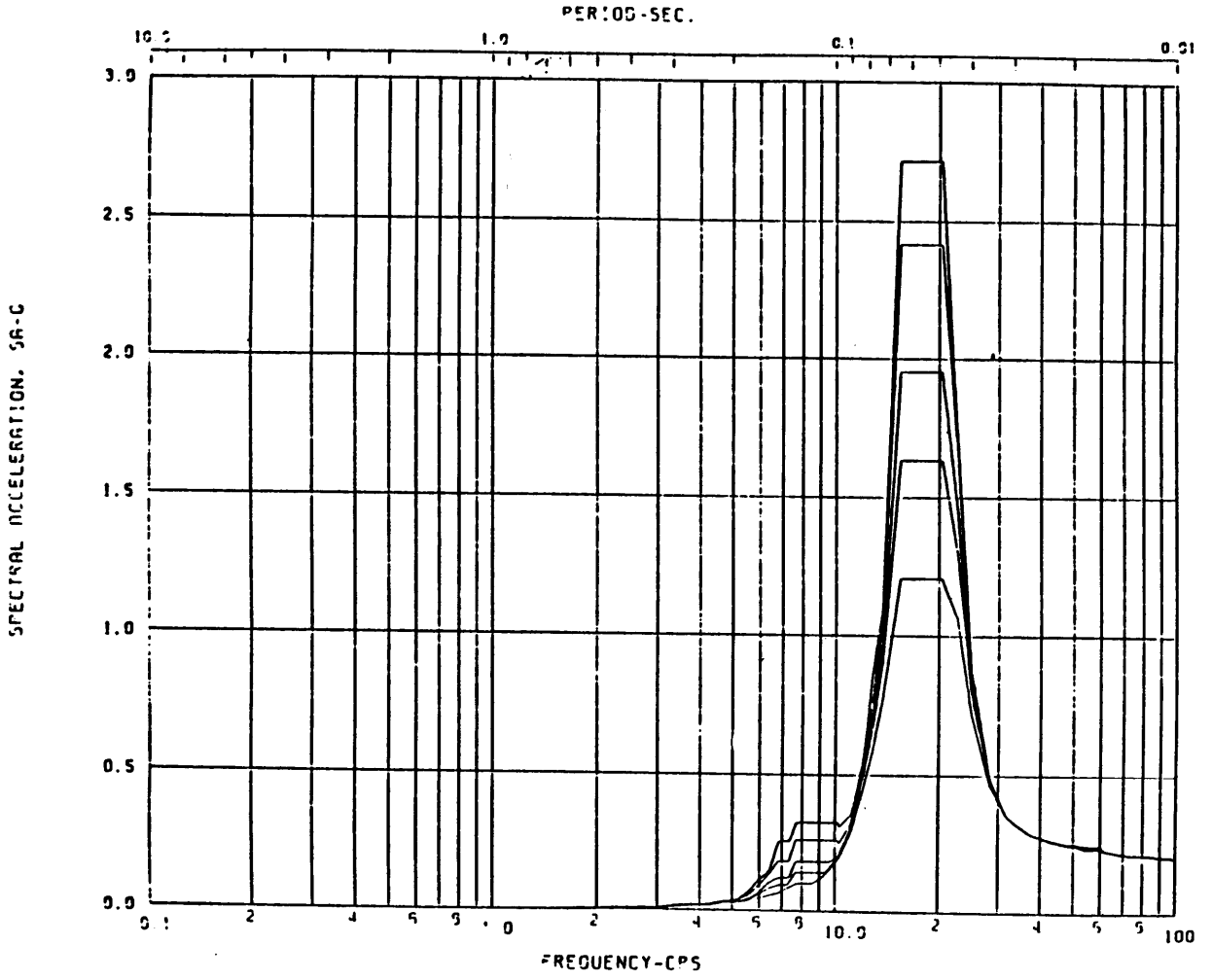
Node: 7 Direction: VERTICAL Elev: 289'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-316



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

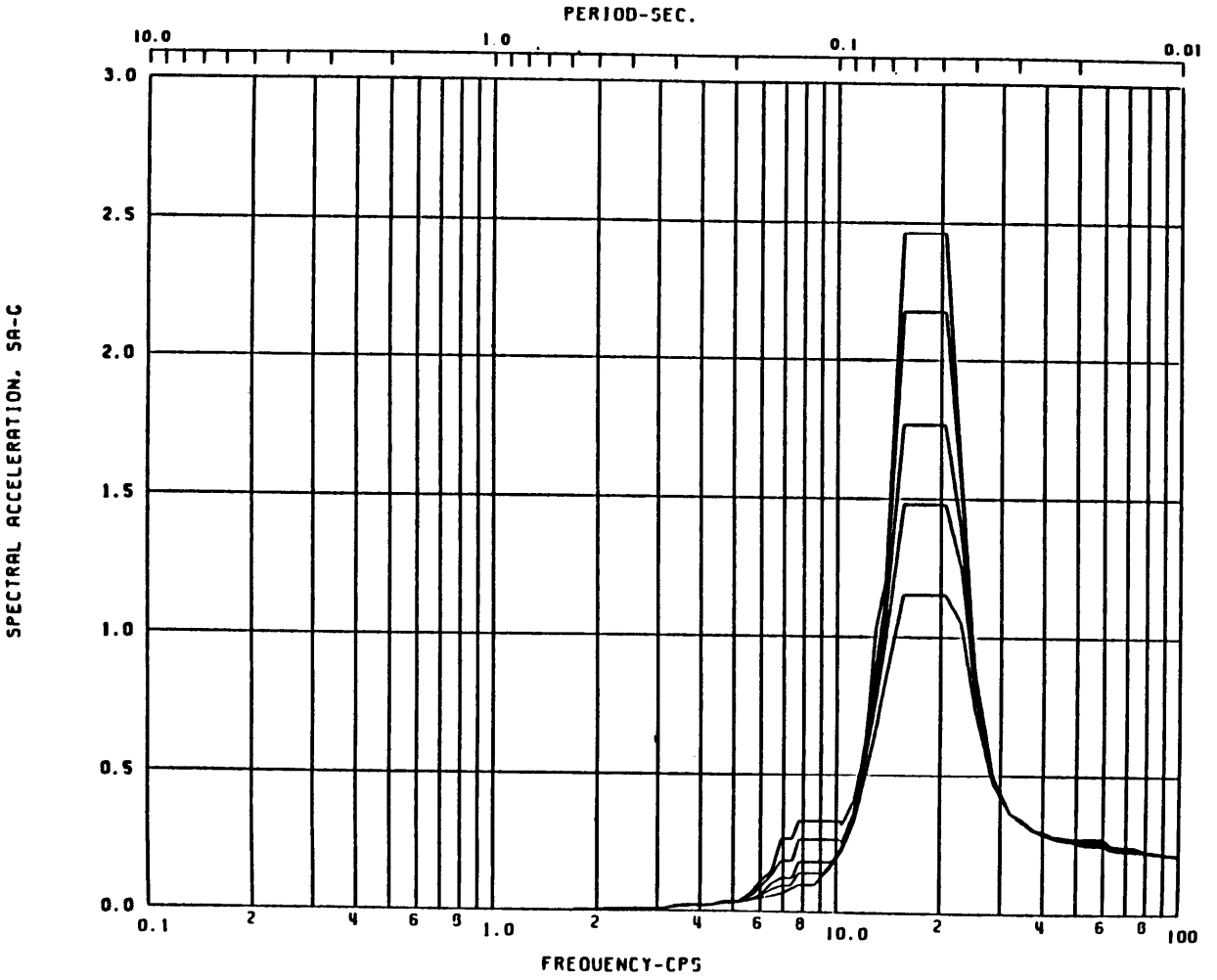
Node: 7 Direction: VERTICAL Elev: 304'-0

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-317



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC GE CO-BASIC ENVELOPE (WIDENED - 15%)

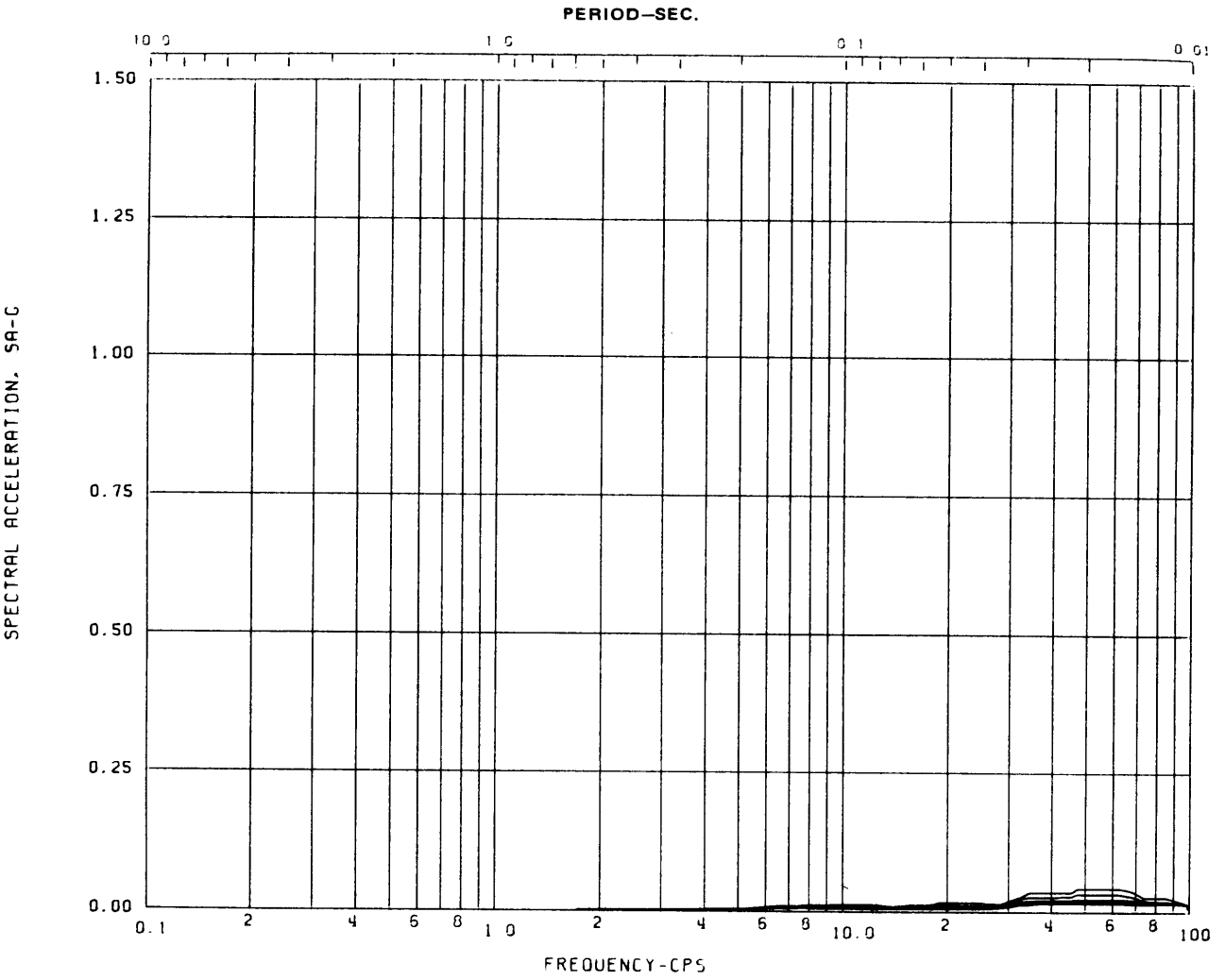
Node: 7 Direction: VERTICAL Elev: 332'

Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-318



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 159 Direction: VERTICAL Elev: 177'-0

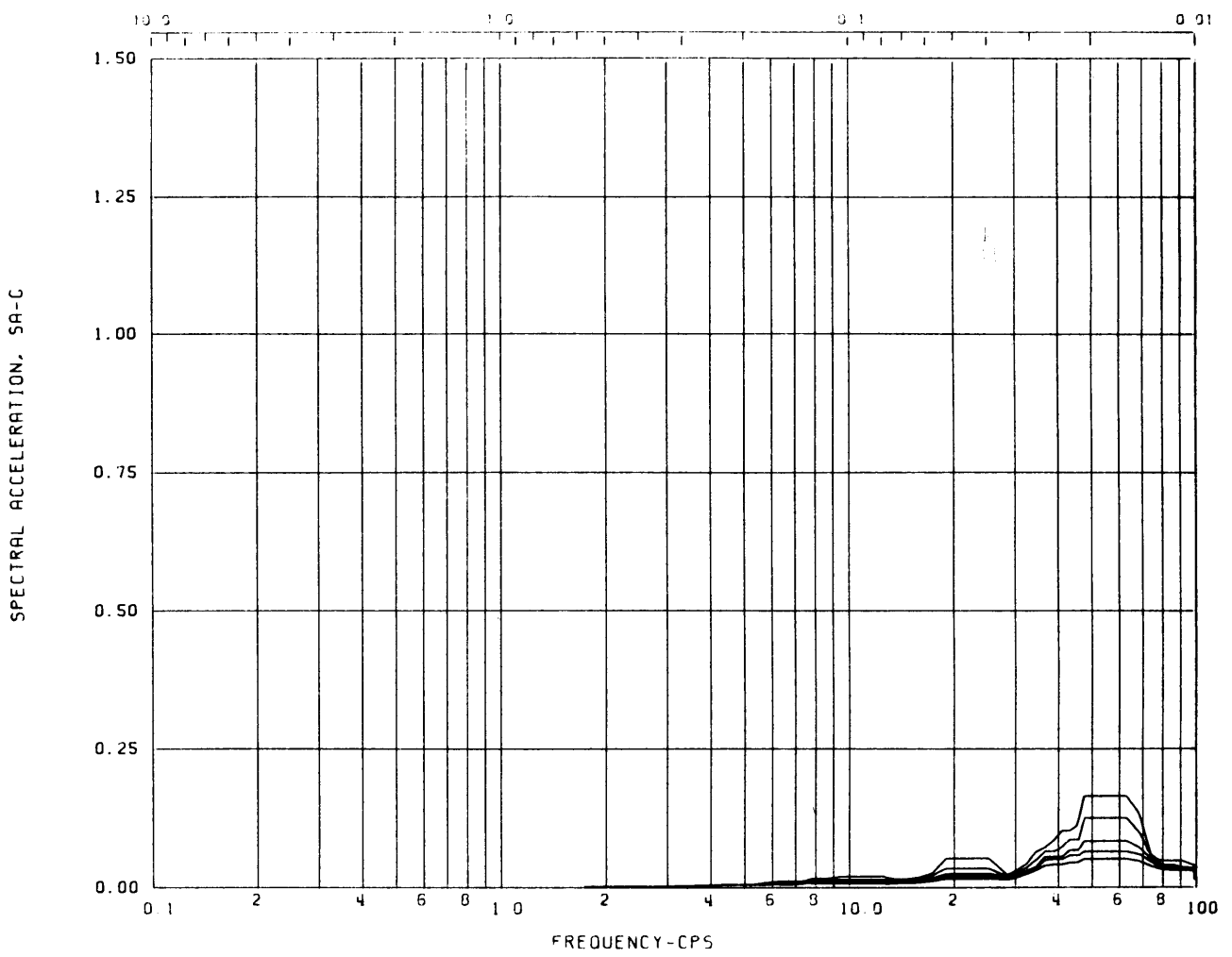
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-319



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 154 Direction: VERTICAL Elev: 177'-0

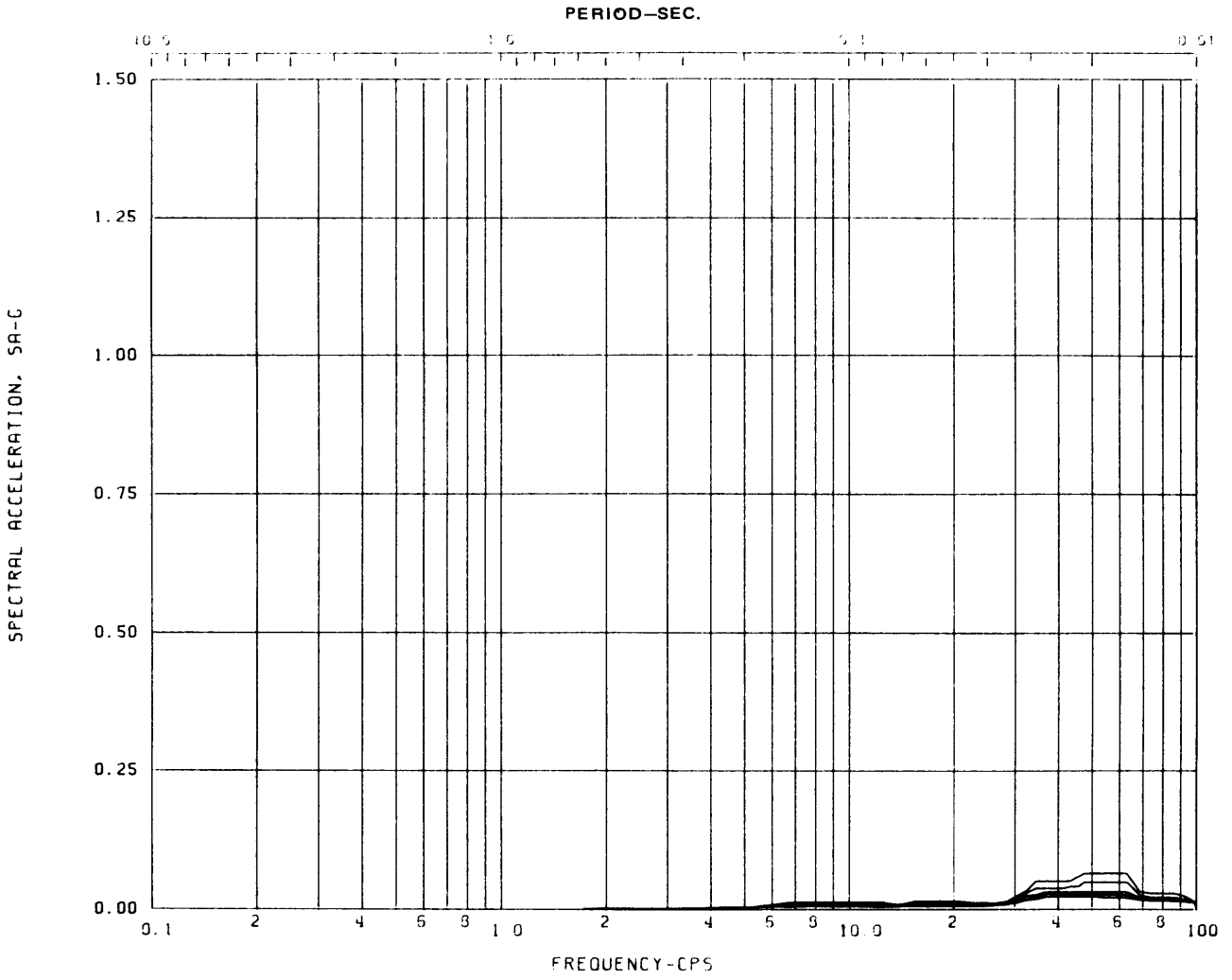
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-320



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 128 Direction: VERTICAL Elev: 201'-0

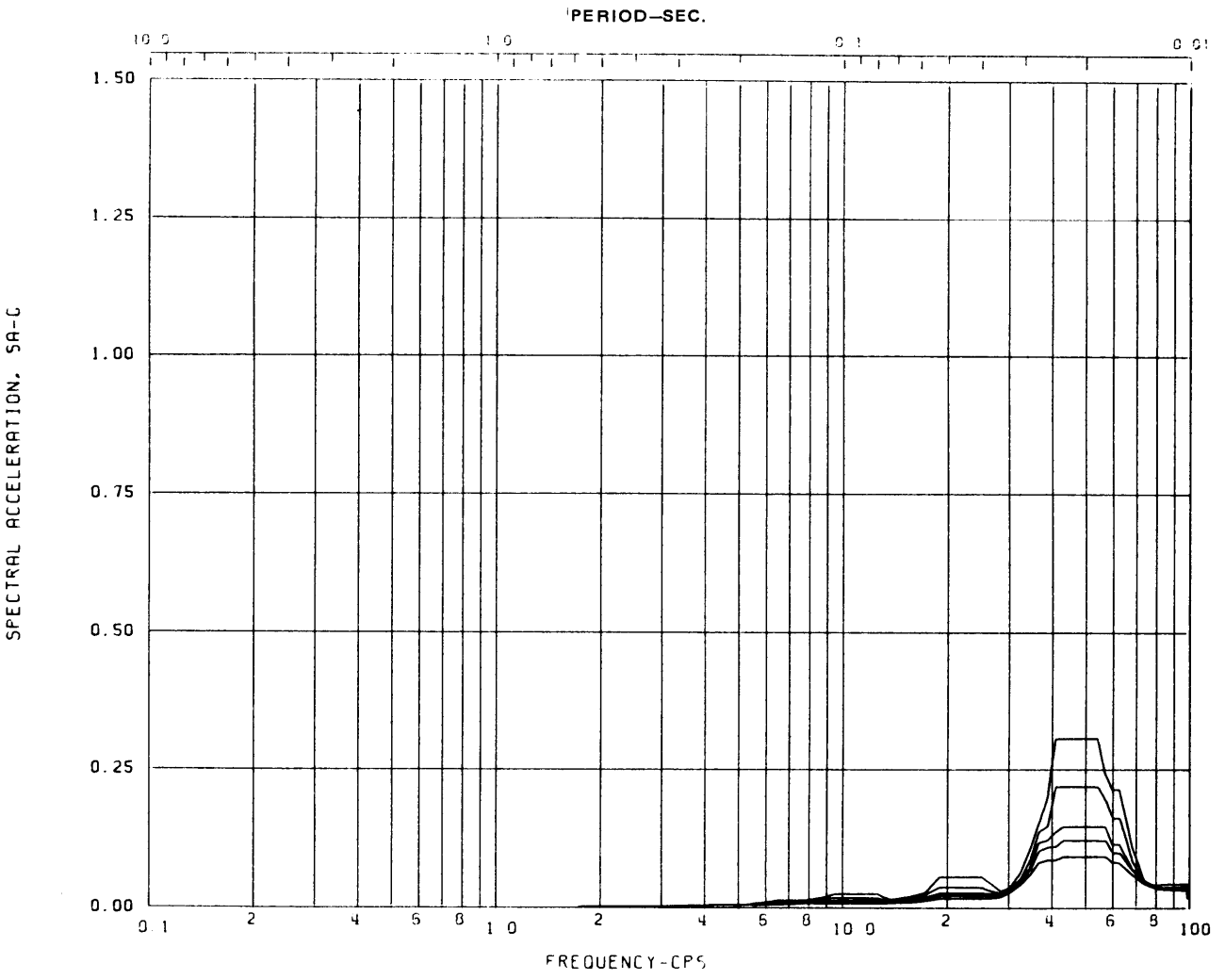
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-321



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 130 Direction: VERTICAL Elev: 201'-0

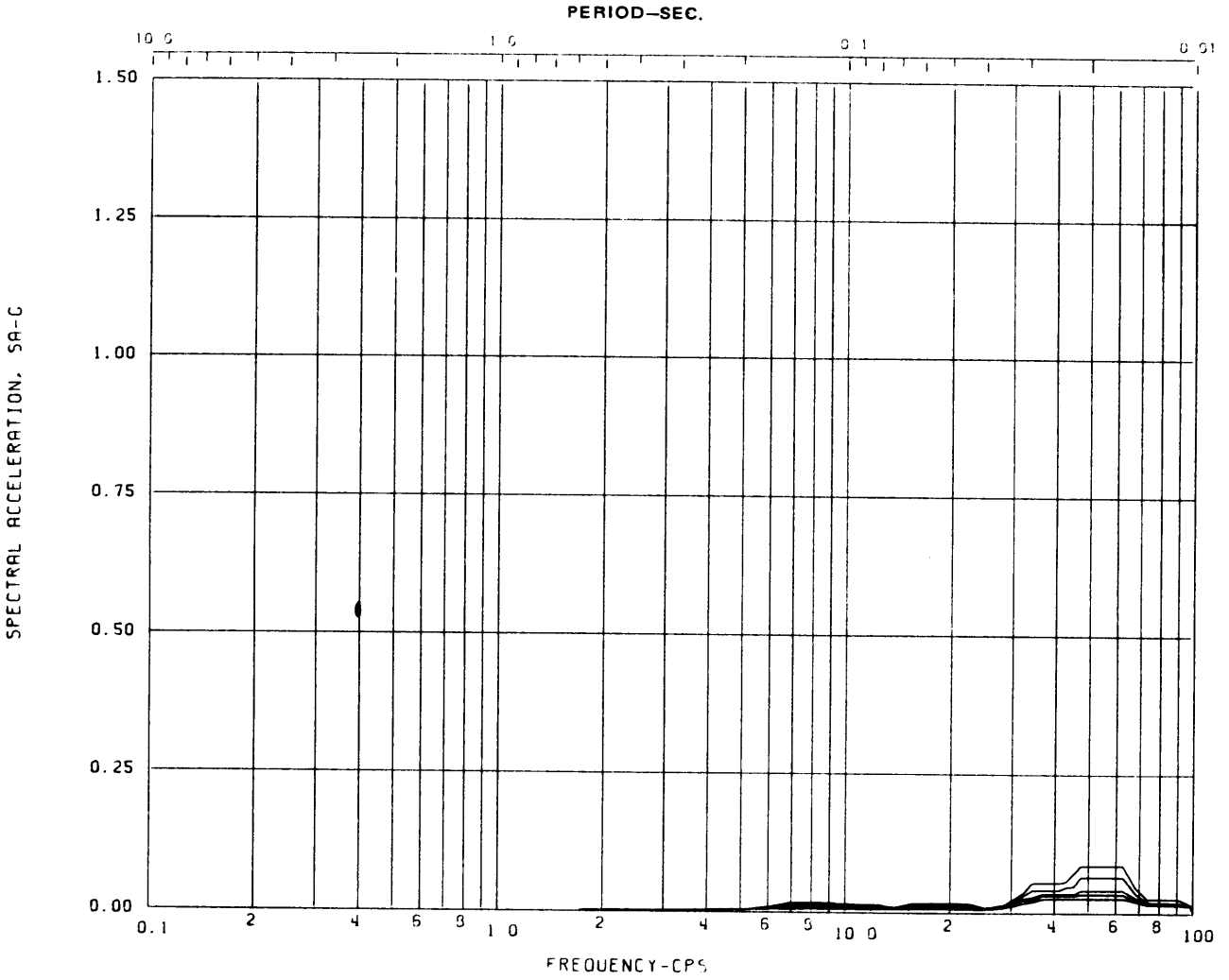
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-322



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 106 Direction: VERTICAL Elev: 217'-0

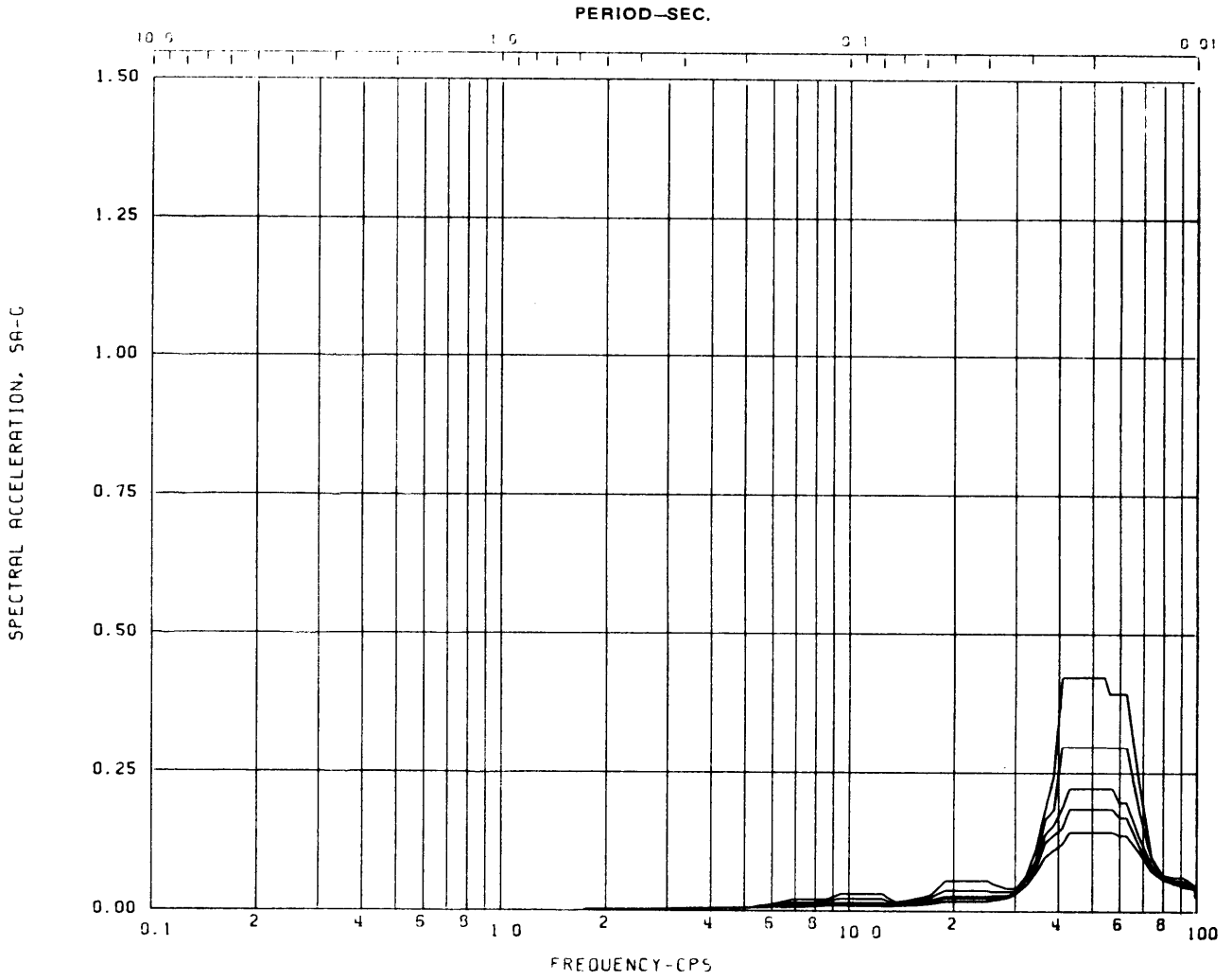
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-323



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 108 Direction: VERTICAL Elev: 217'-0

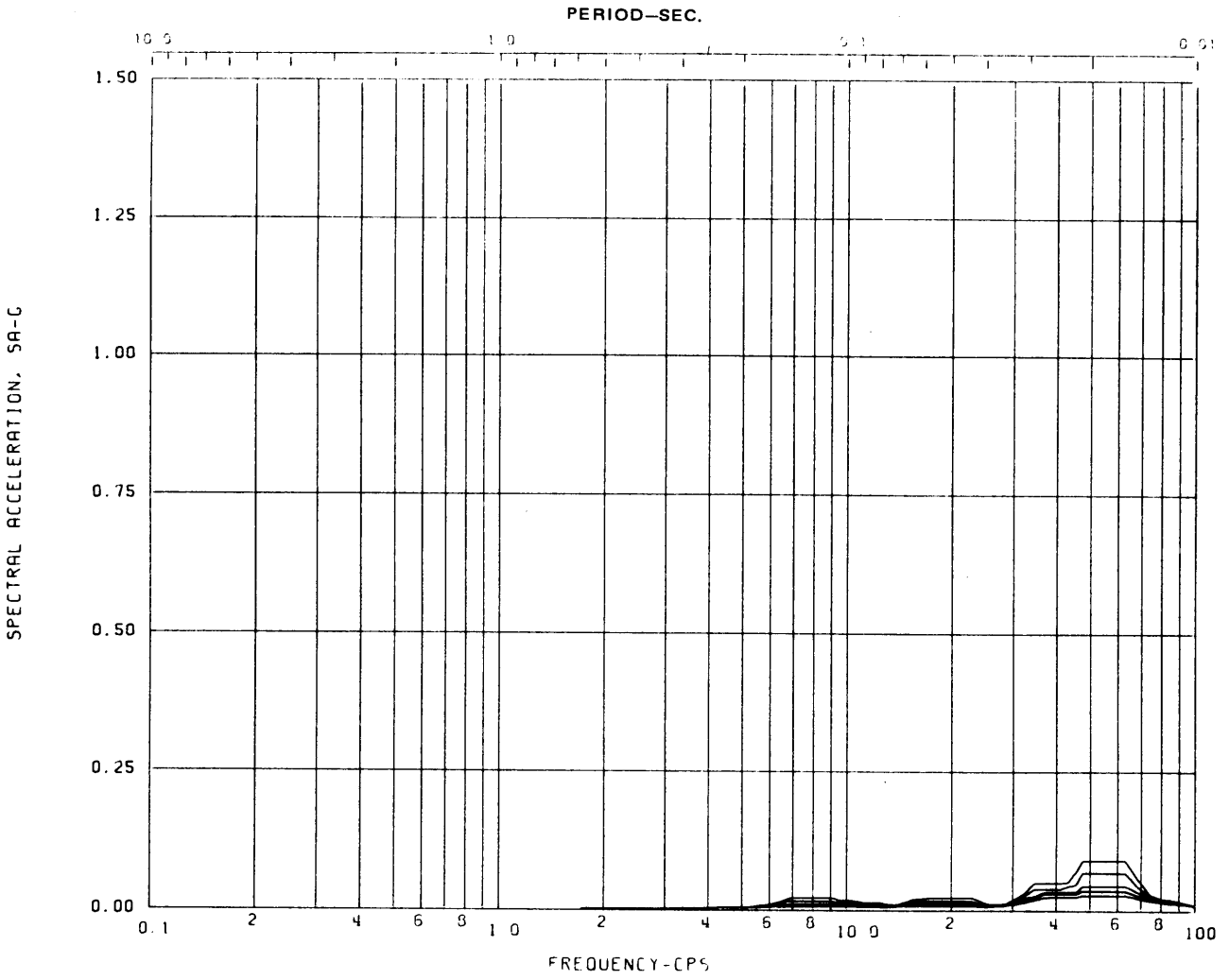
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-324



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 104 Direction: VERTICAL Elev: 239'-0

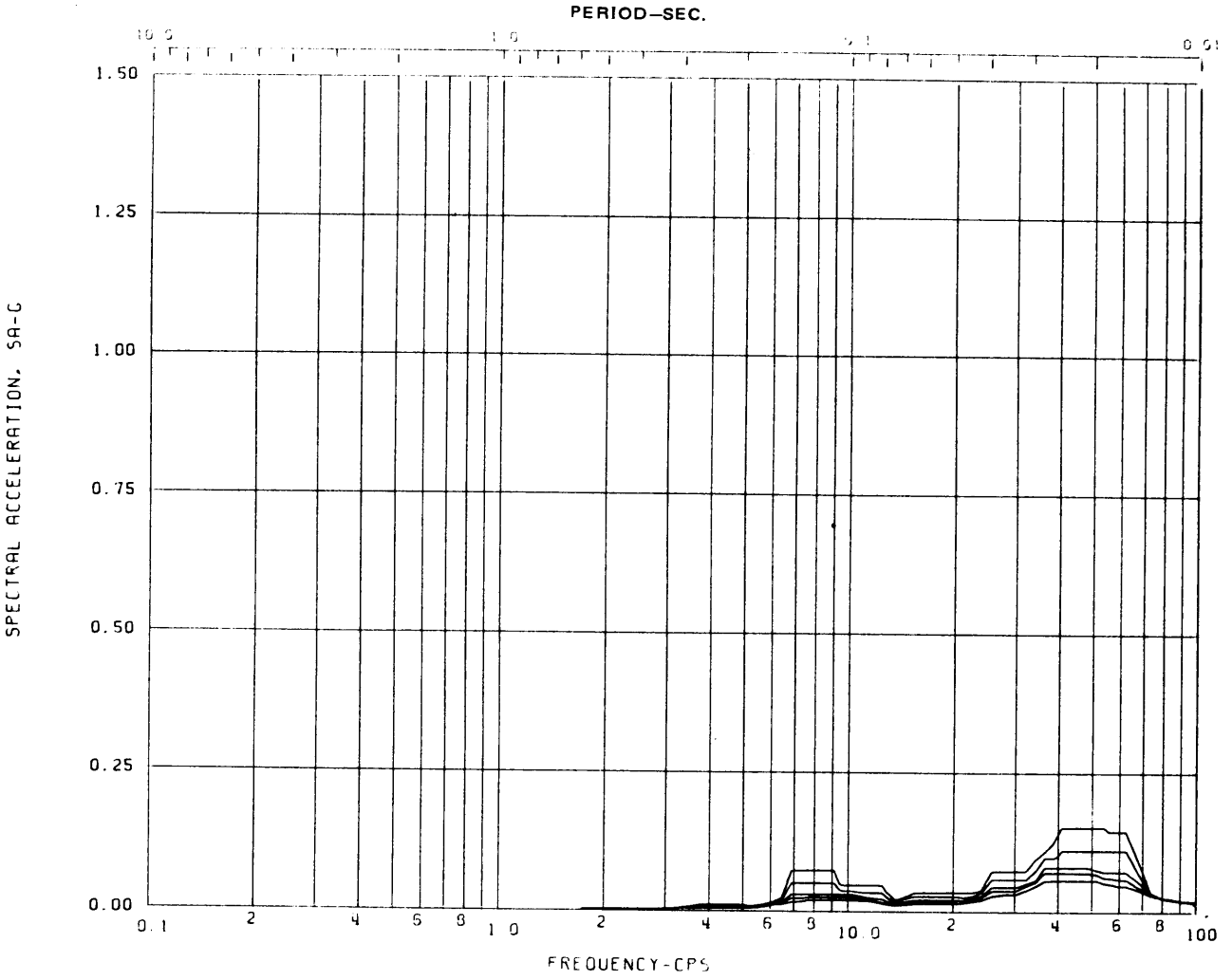
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-325



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 81 Direction: VERTICAL Elev: 253'-0

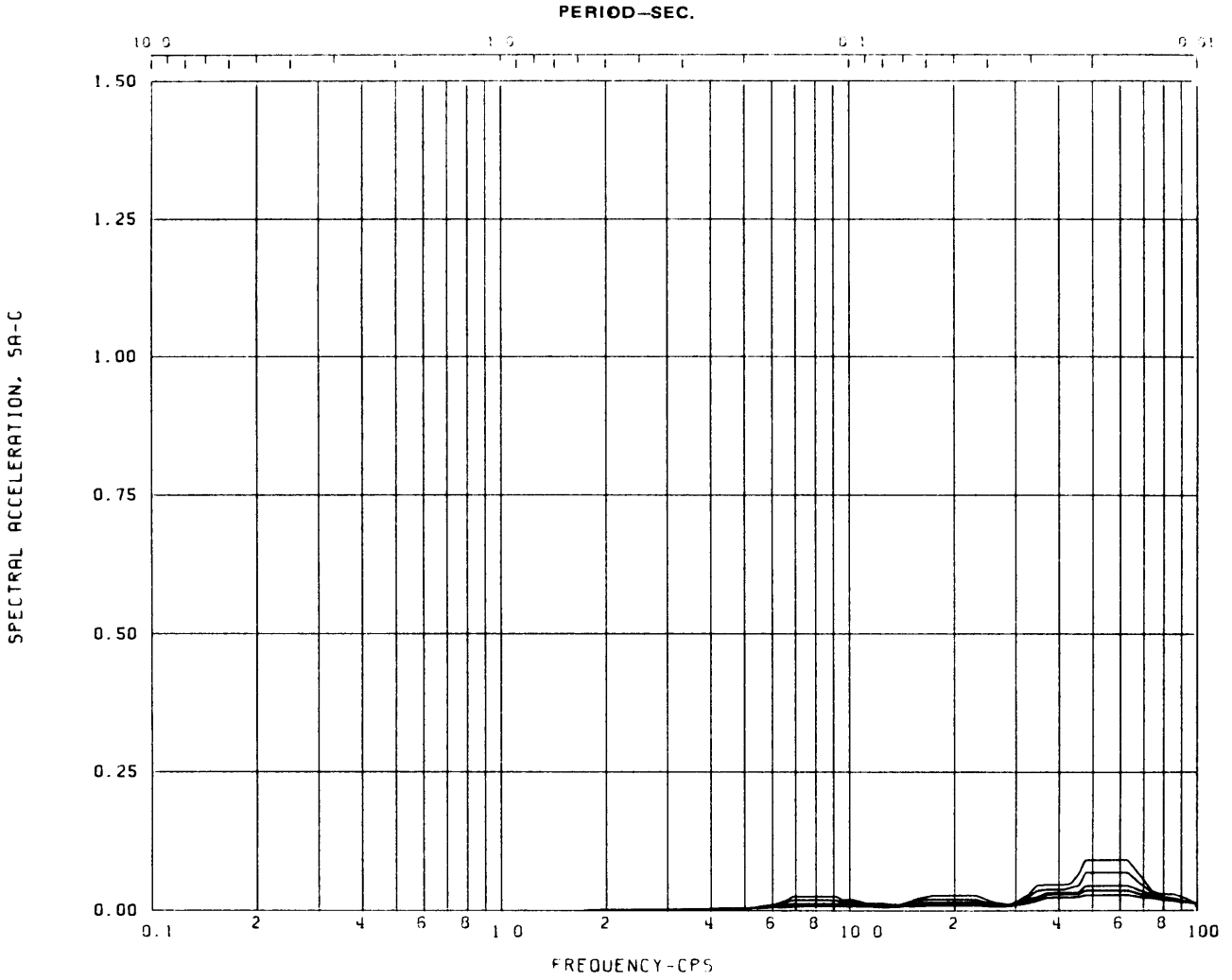
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-326



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 19 Direction: VERTICAL Elev: 253'-0

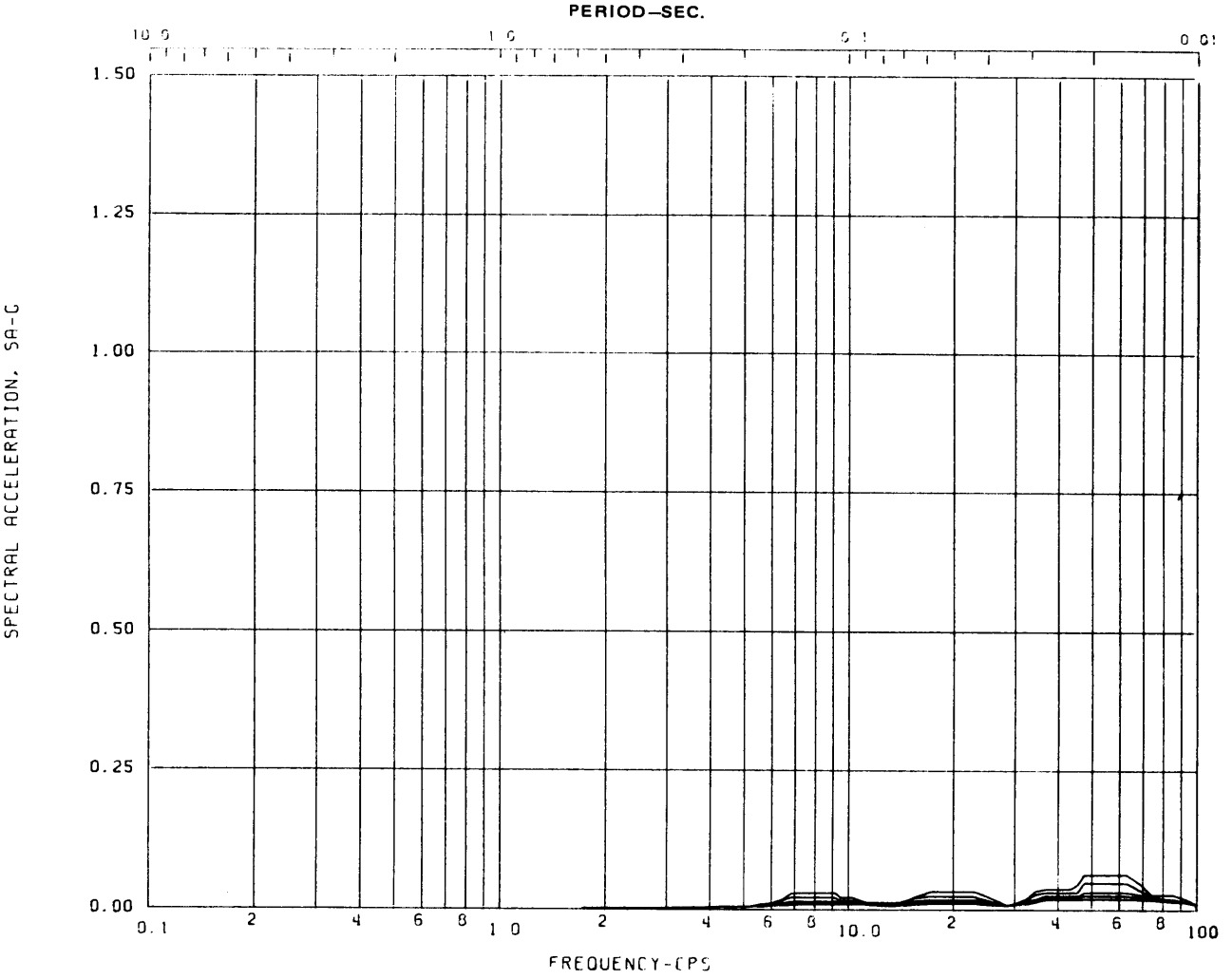
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-327



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 77 Direction: VERTICAL Elev: 269'-0

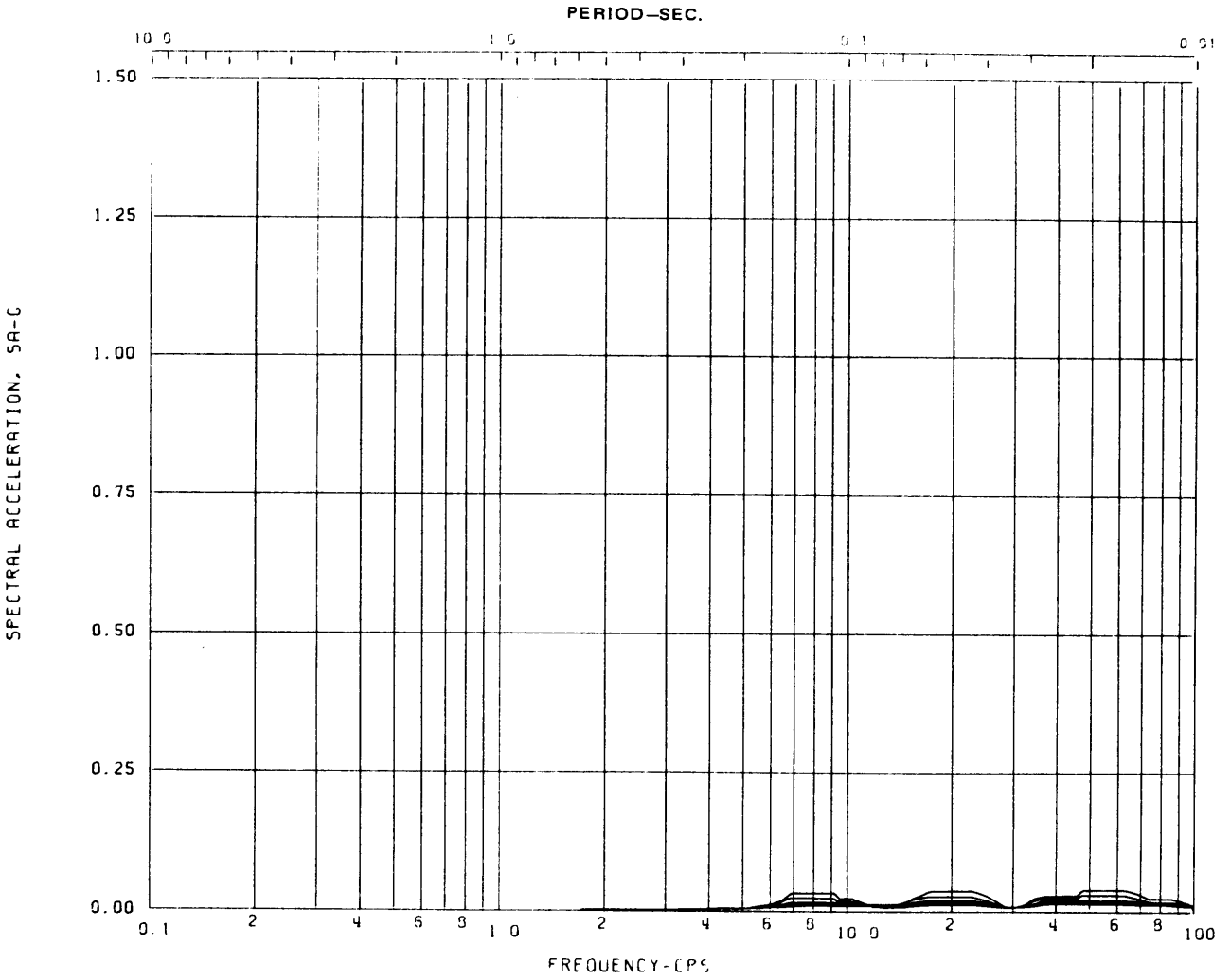
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-328



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 58 Direction: VERTICAL Elev: 283'-0

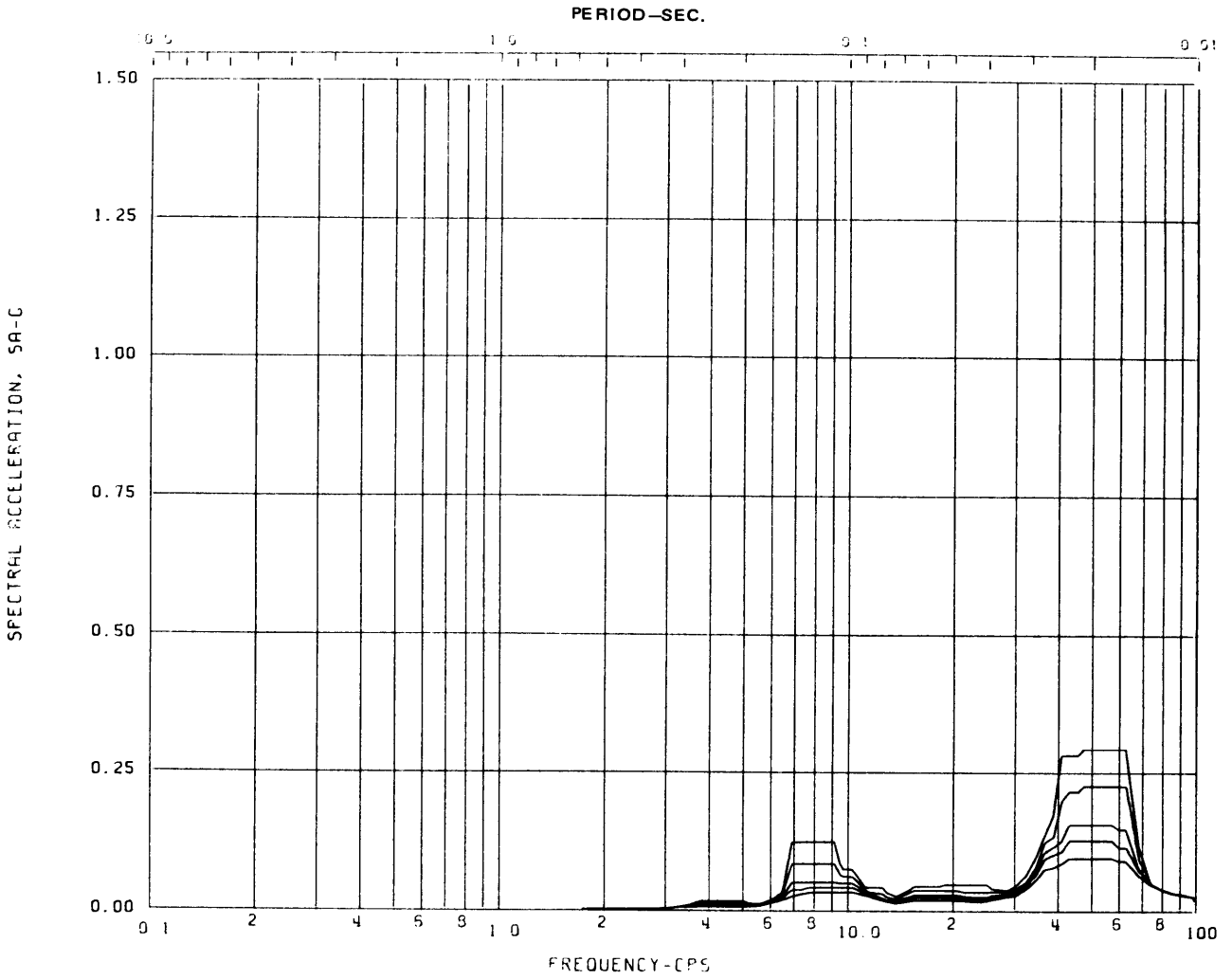
Damping: 0.005,0.01,0.02,0.03,0.05

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FIGURE 3A-329



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 60 Direction: VERTICAL Elev: 283'-0

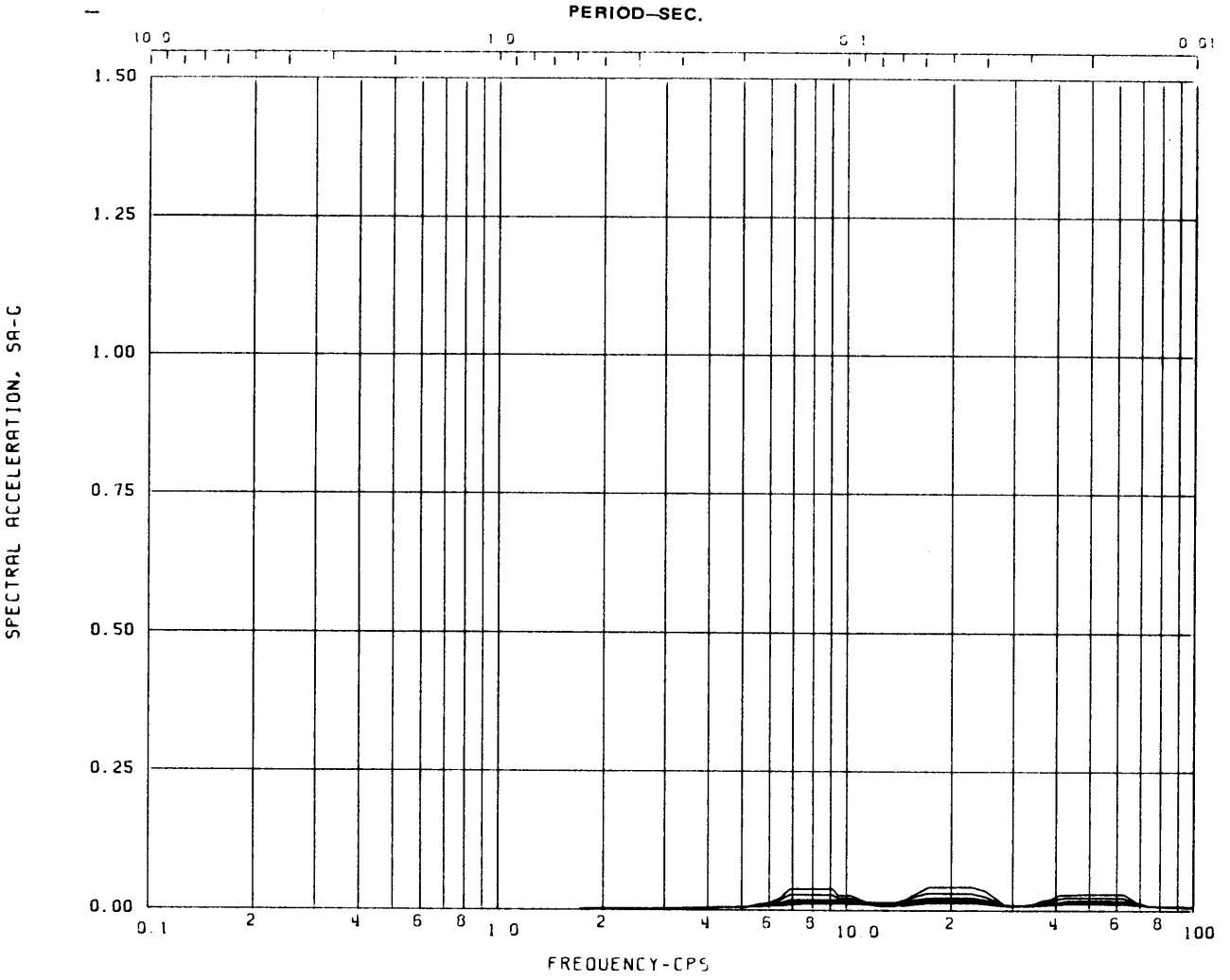
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-330



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 56 Direction: VERTICAL Elev: 304'-0

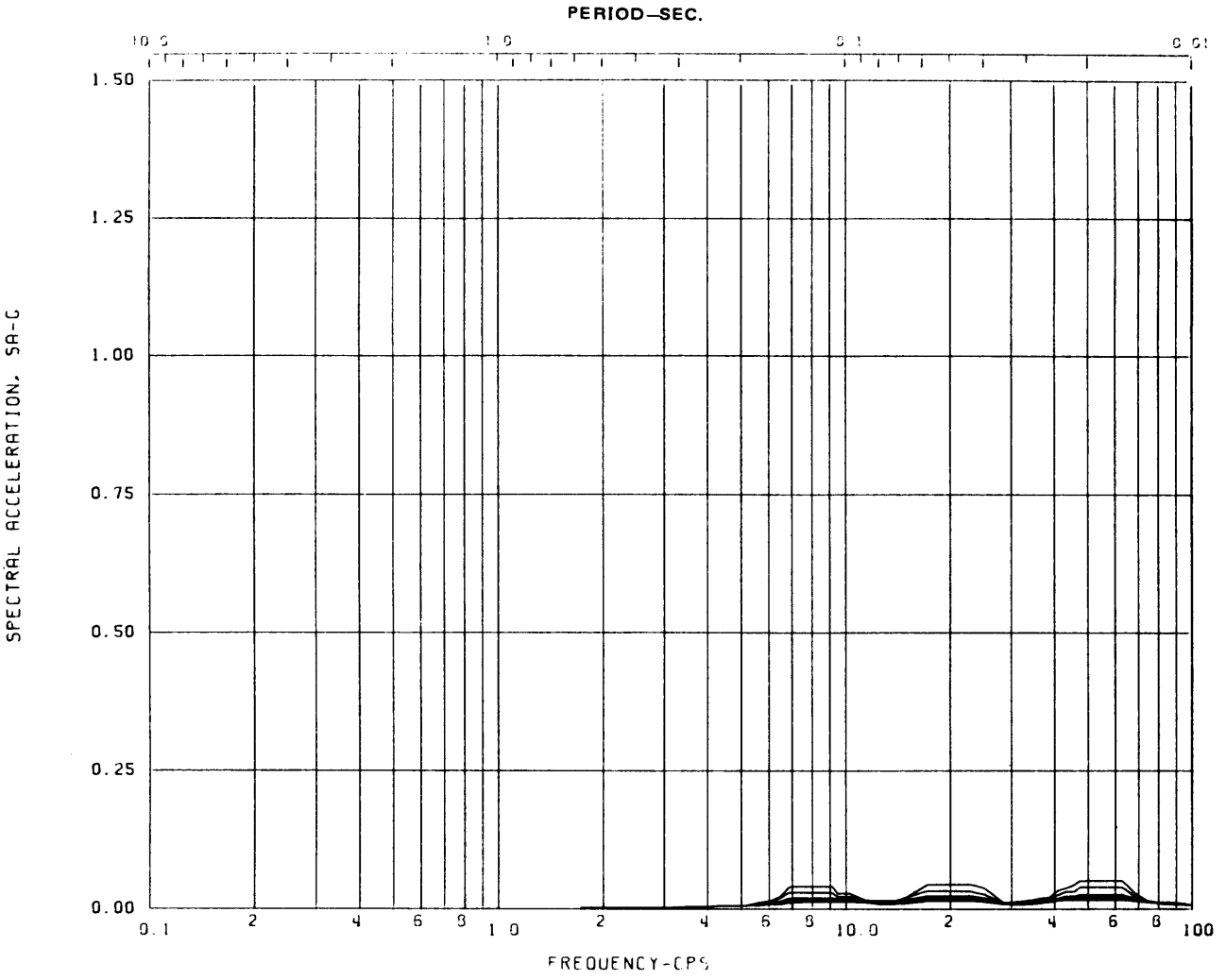
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-331



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 35 Direction: VERTICAL Elev: 313'-0

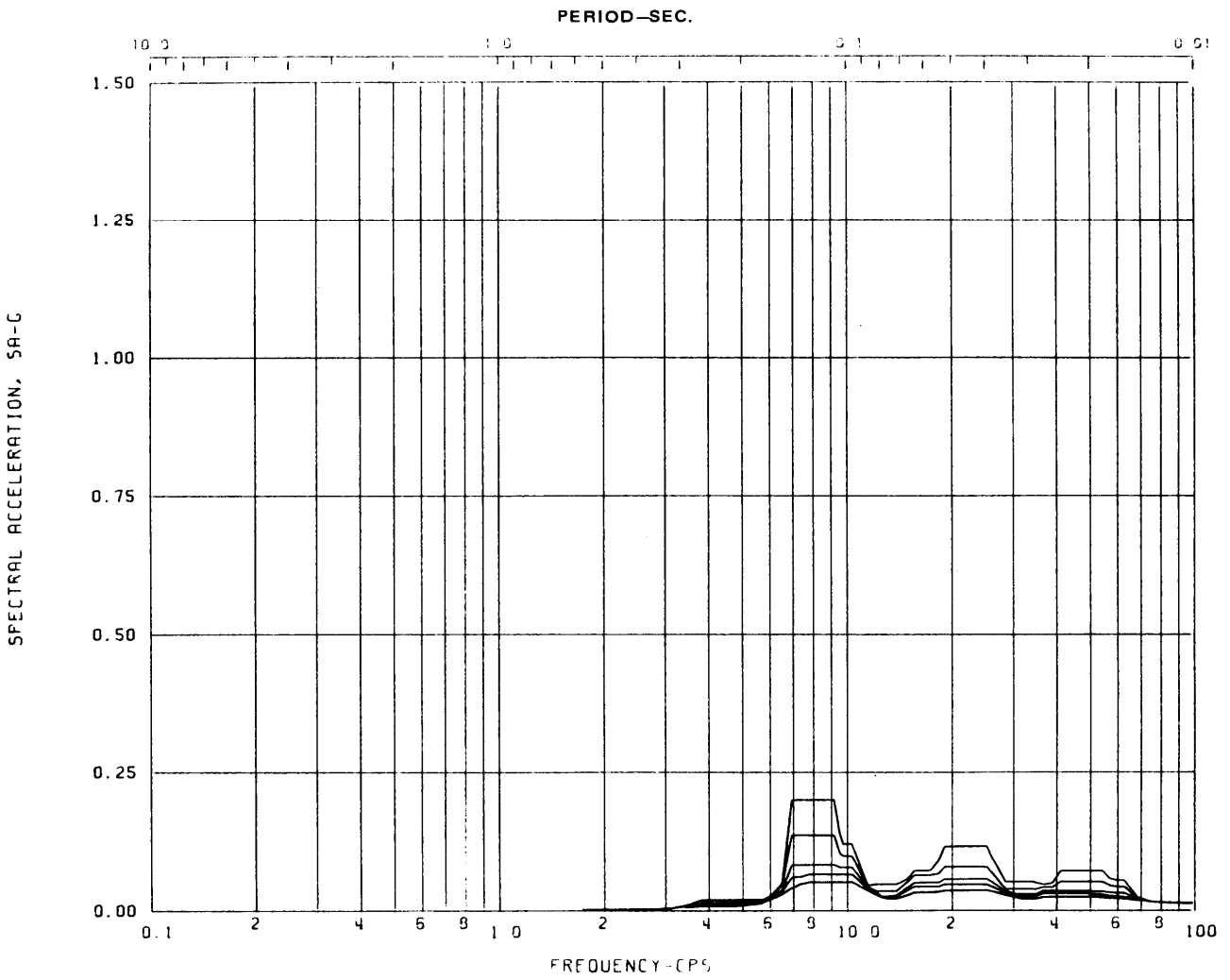
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-332



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 43 Direction: VERTICAL Elev: 313'-0

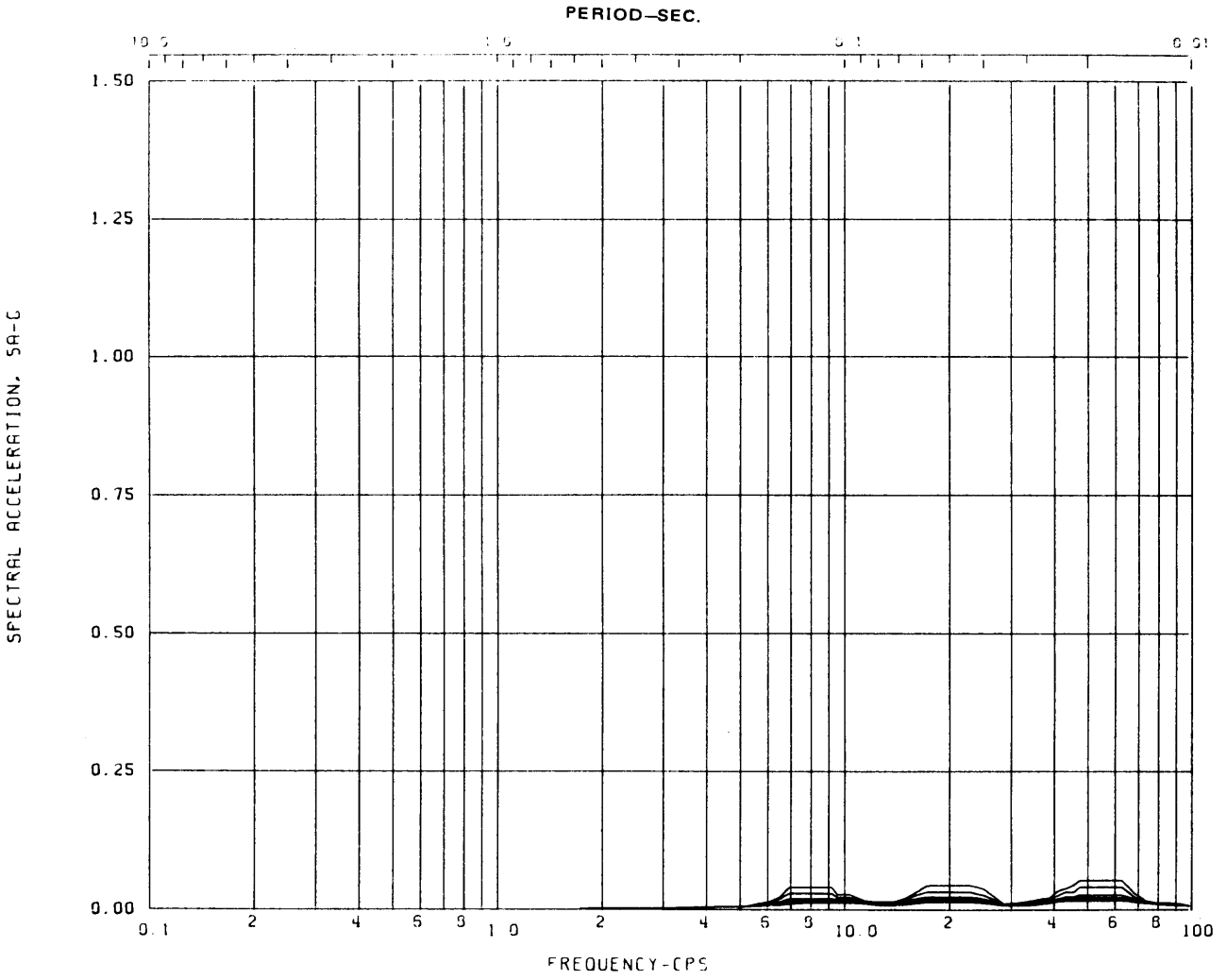
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-333



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 21 Direction: VERTICAL Elev: 333'-0

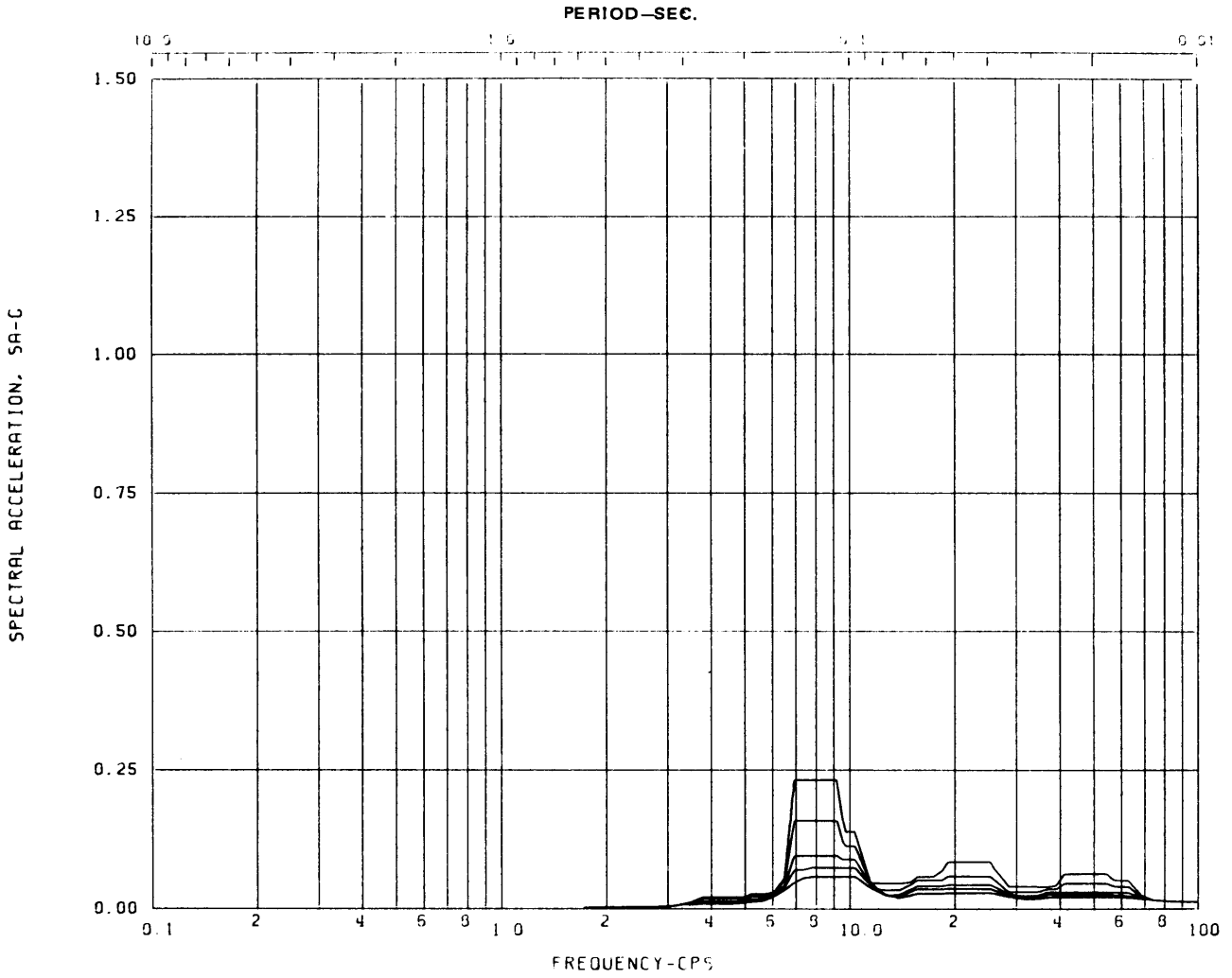
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-334



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 33 Direction: VERTICAL Elev: 333'-0

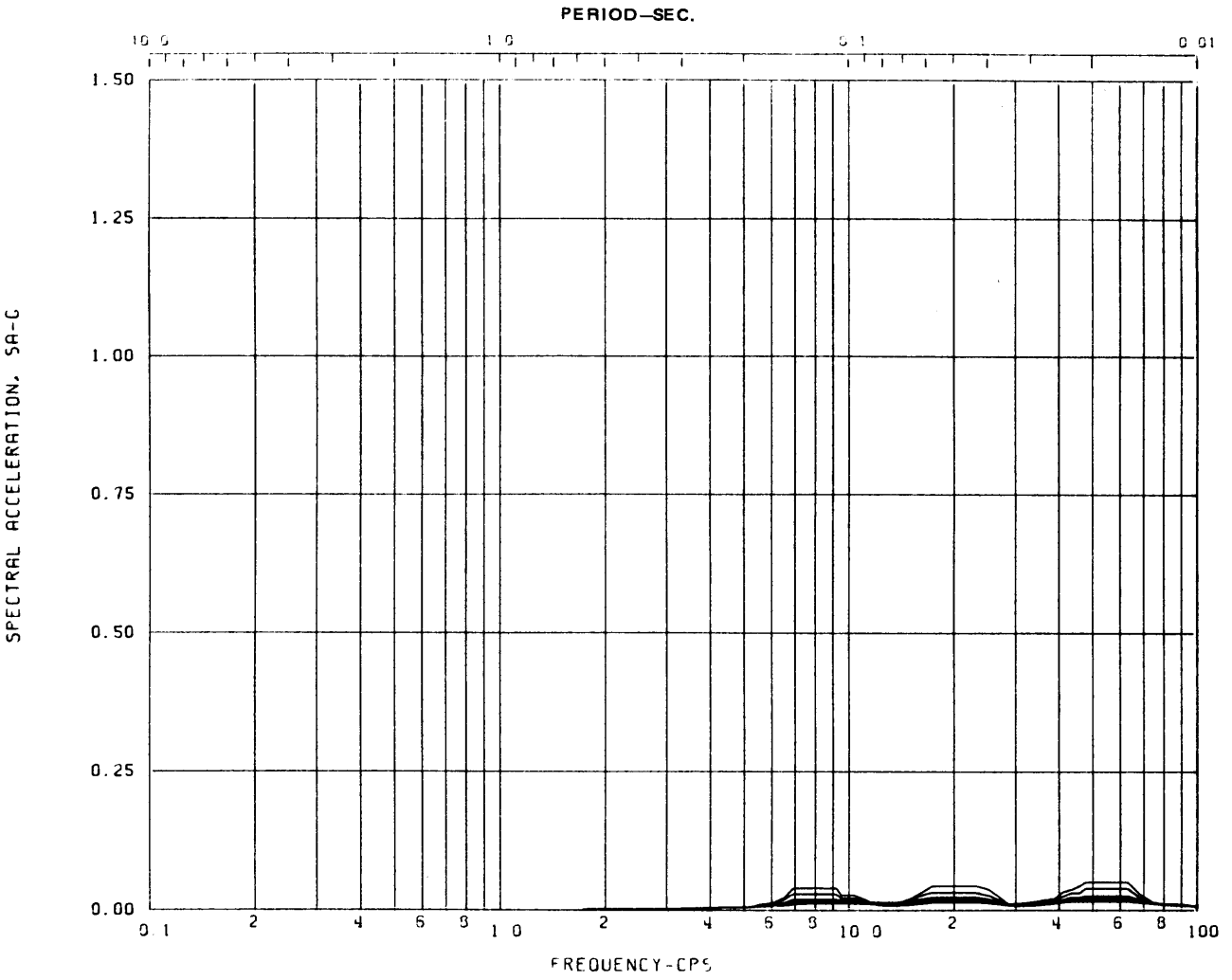
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-335



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 9 Direction: VERTICAL Elev: 352'-0

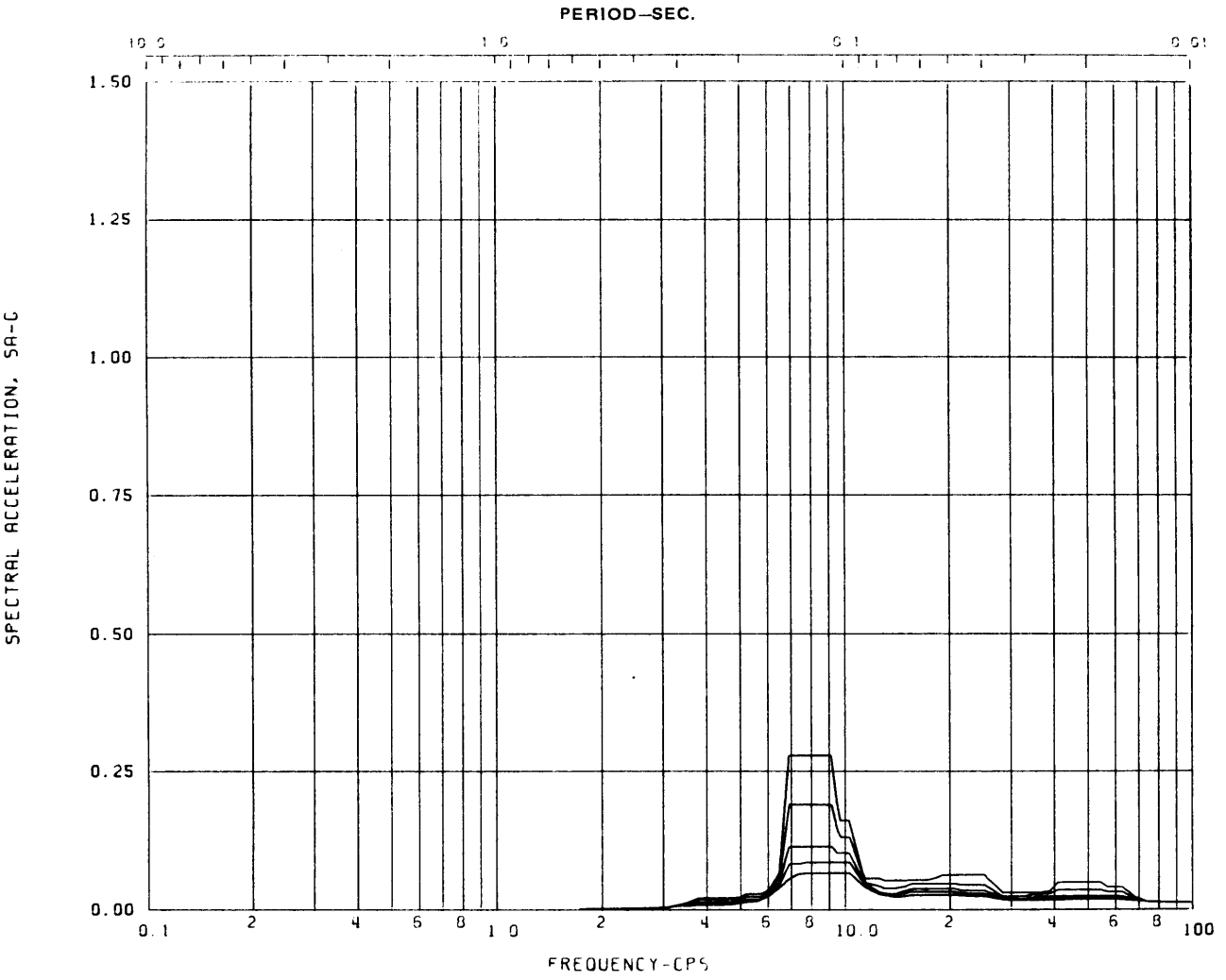
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSUREGLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-336



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 13 Direction: VERTICAL Elev: 352'-0

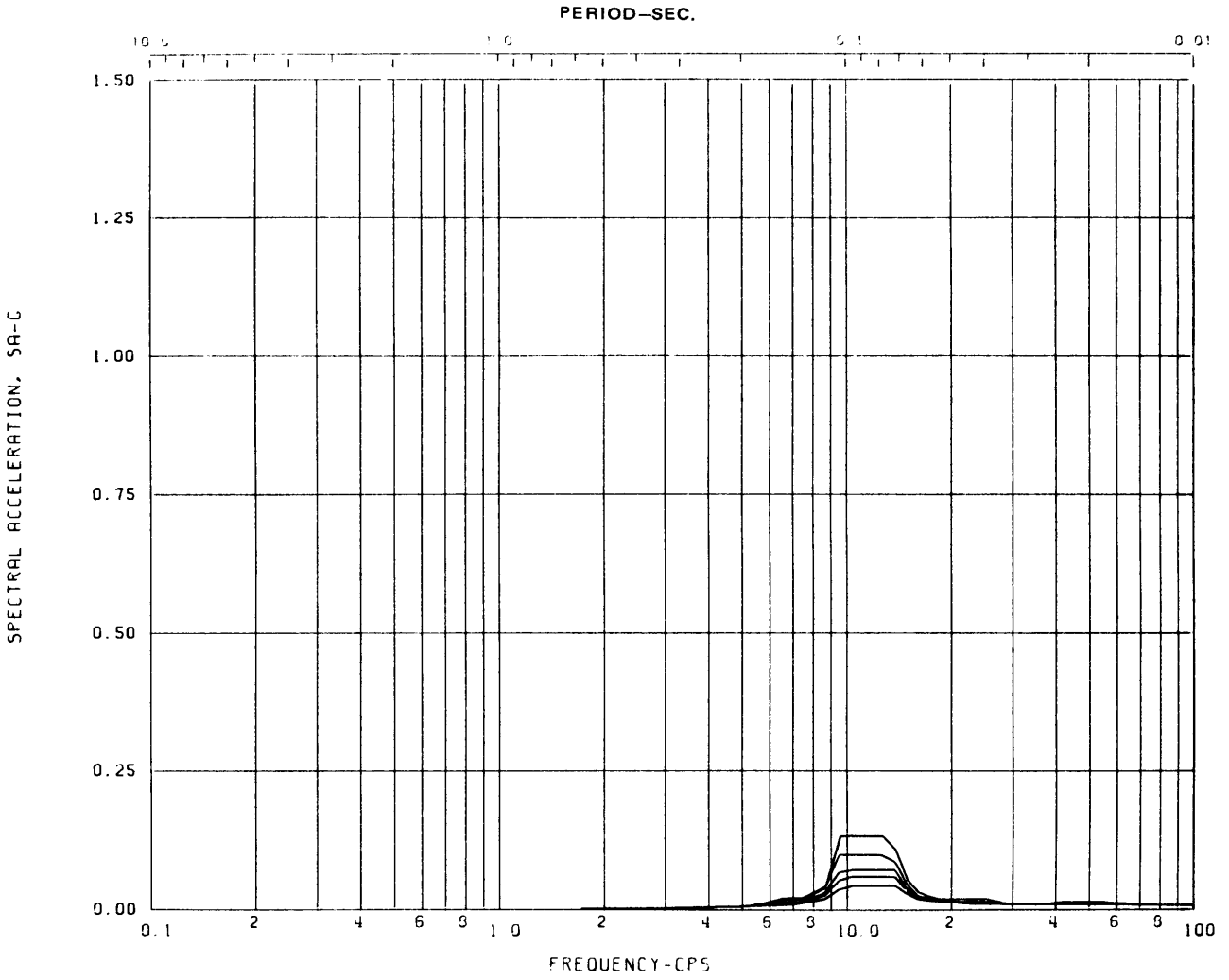
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-337



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 129 Direction: VERTICAL Elev: 201'-0

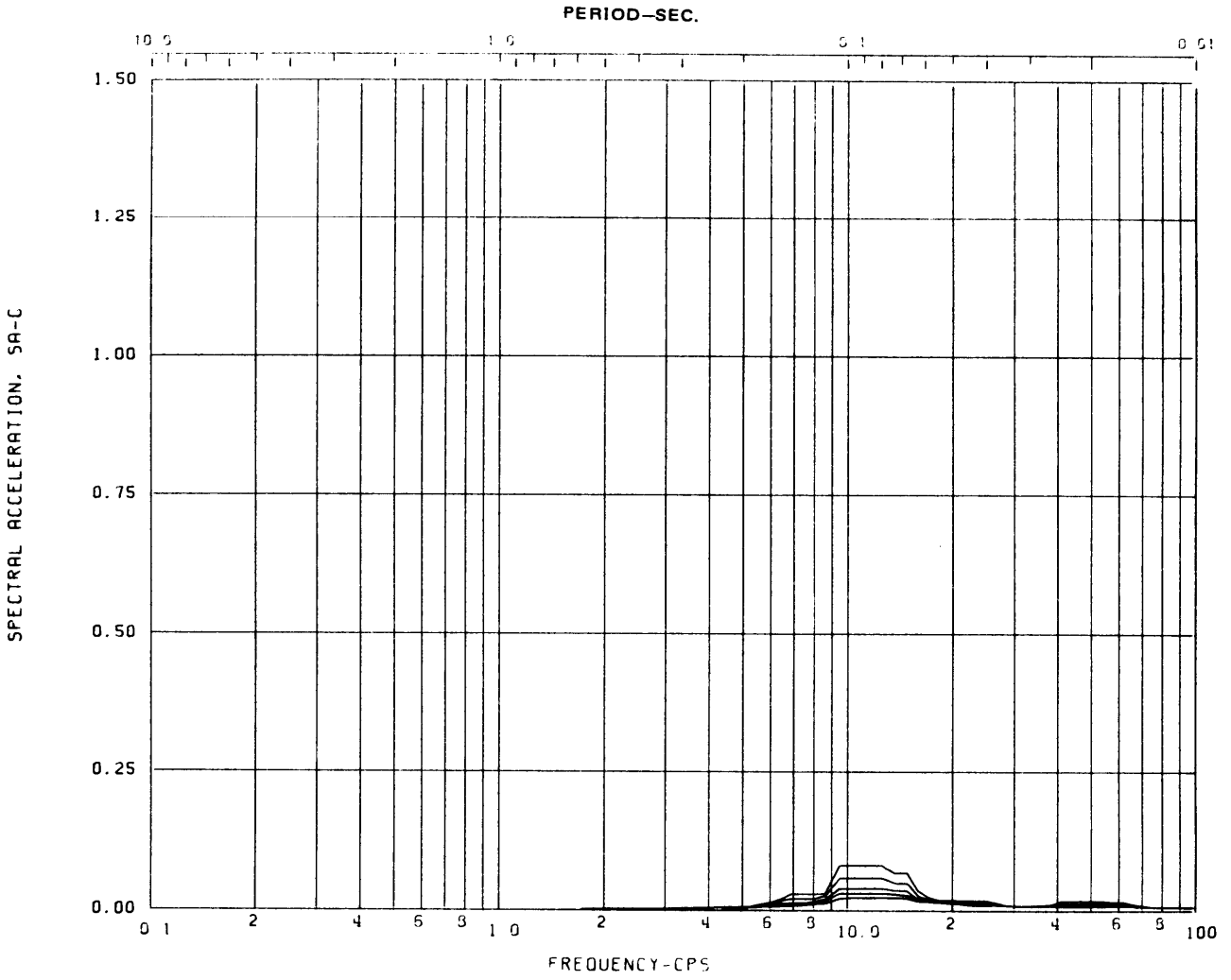
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSUREGLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-338



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 107 Direction: VERTICAL Elev: 217'-0

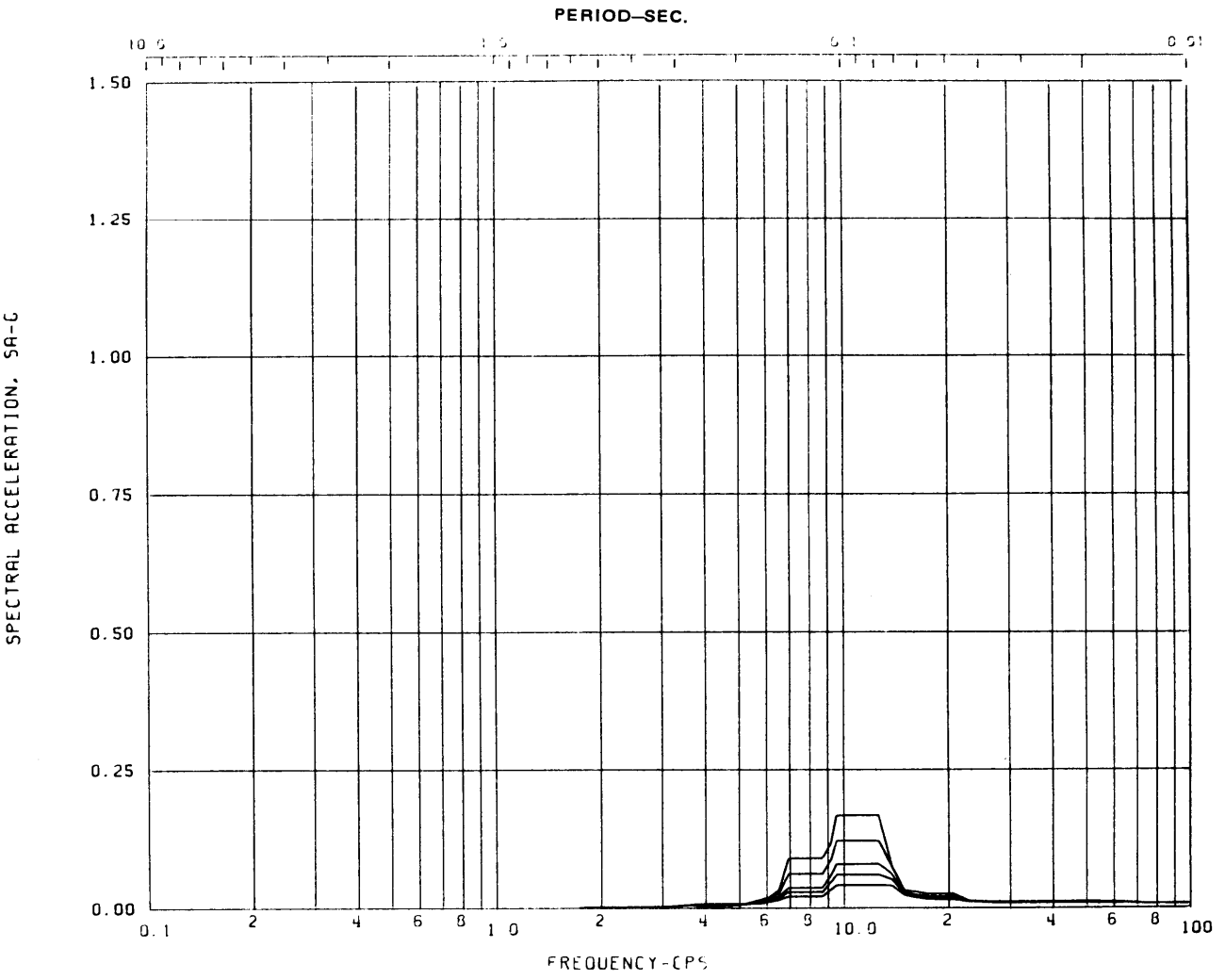
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSUREGLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-339



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 80 Direction: VERTICAL Elev: 253'-0

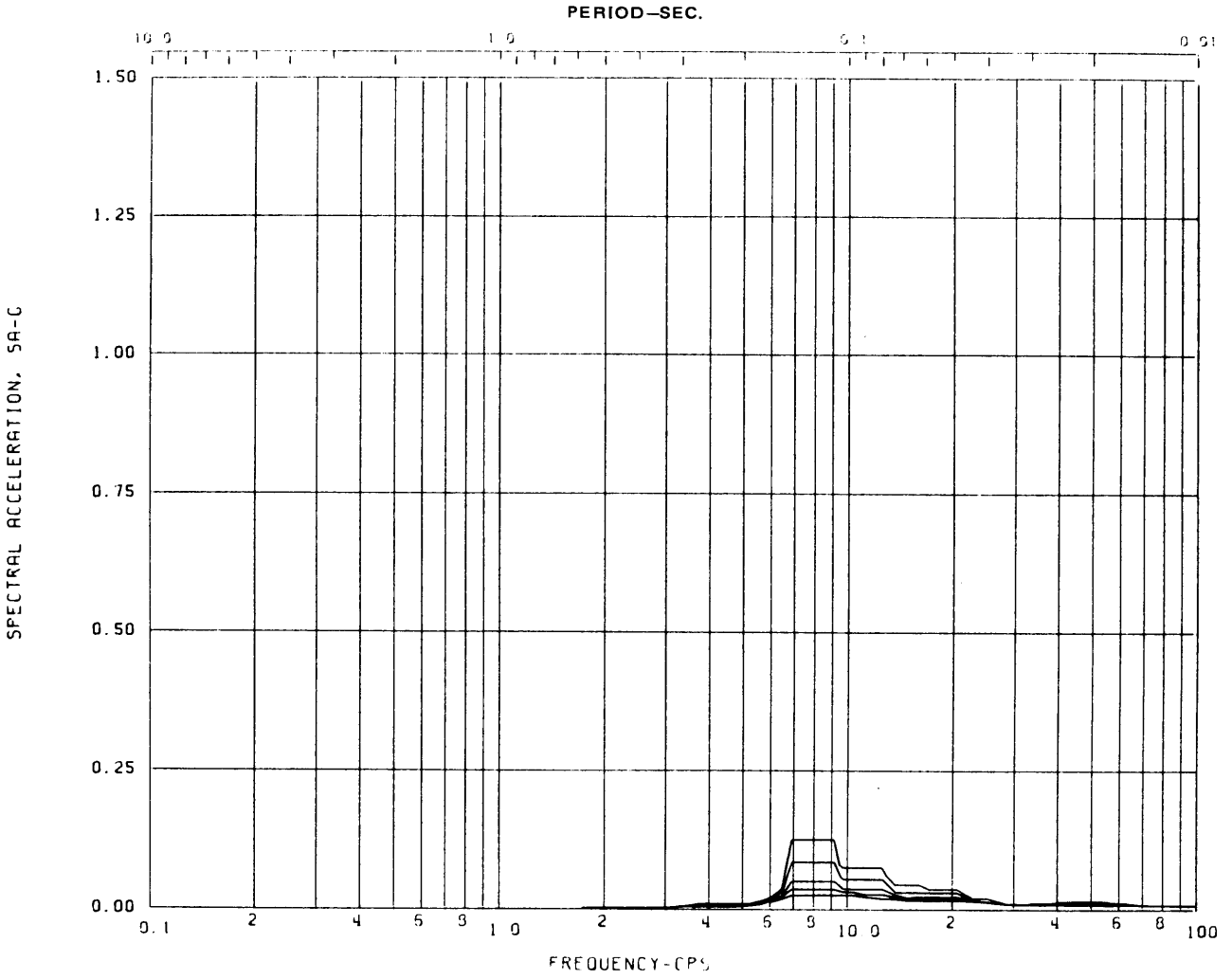
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-340



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 59 Direction: VERTICAL Elev: 283'-0

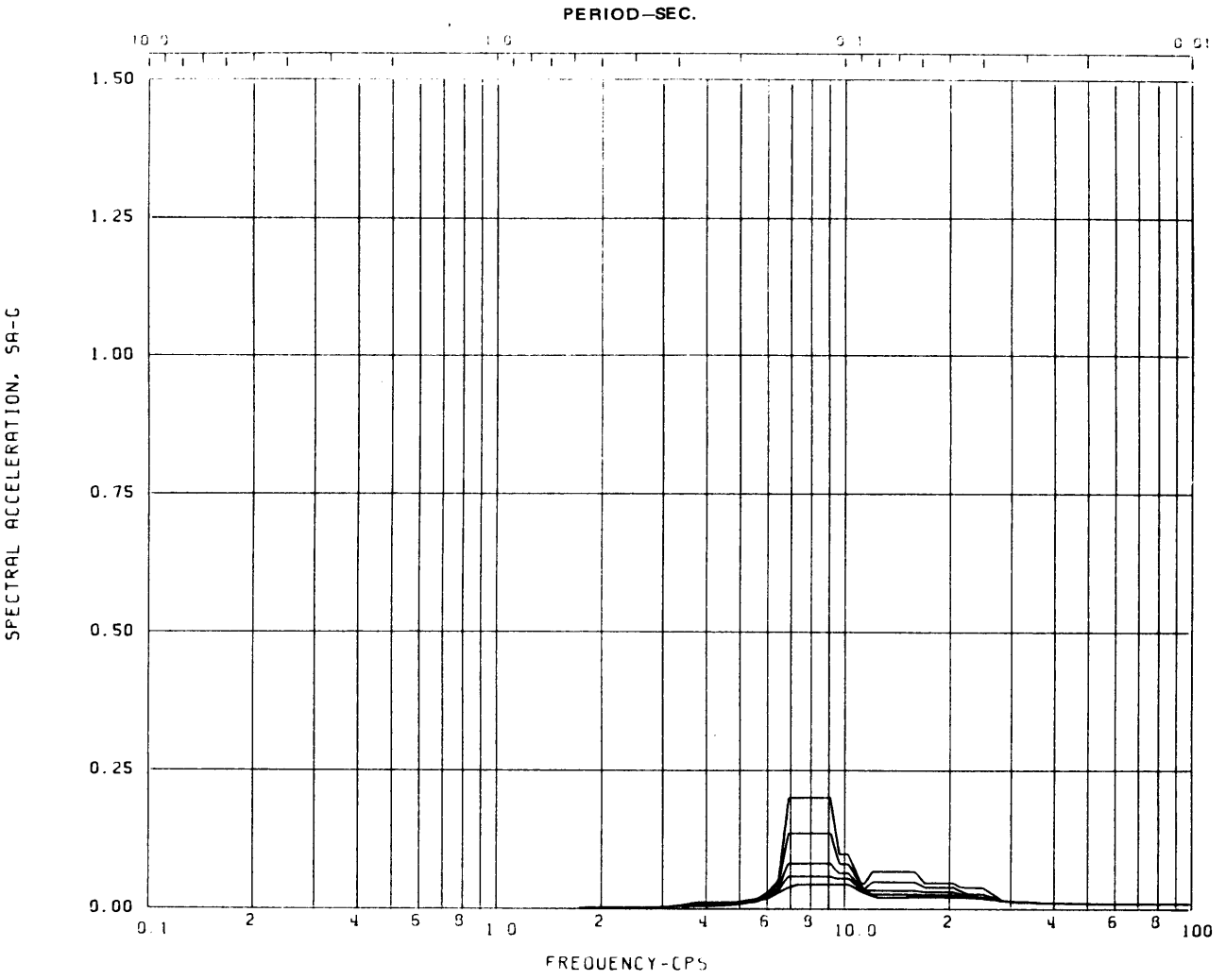
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-341



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 54 Direction: VERTICAL Elev: 313'-0

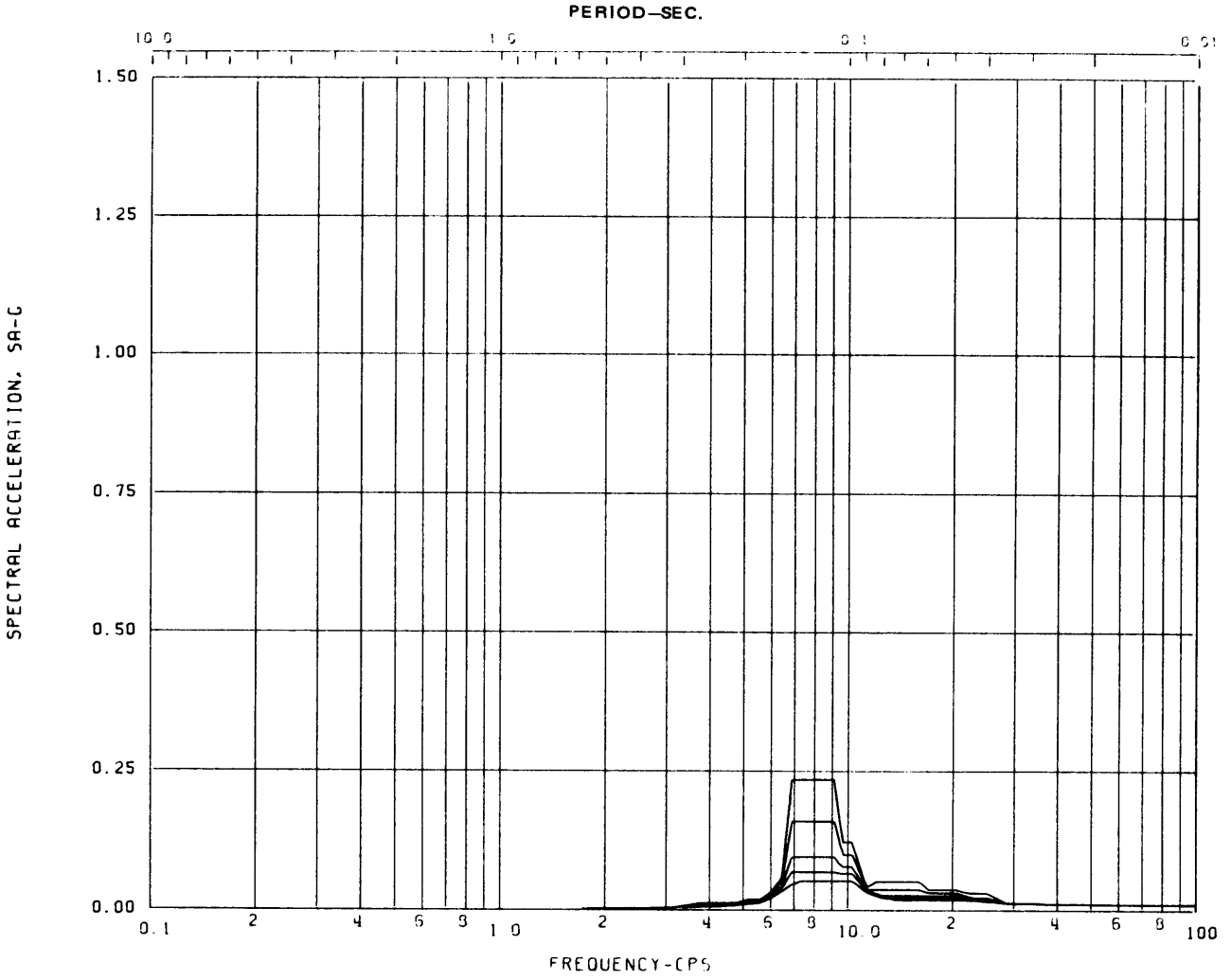
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-342



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 32 Direction: VERTICAL Elev: 333'-0

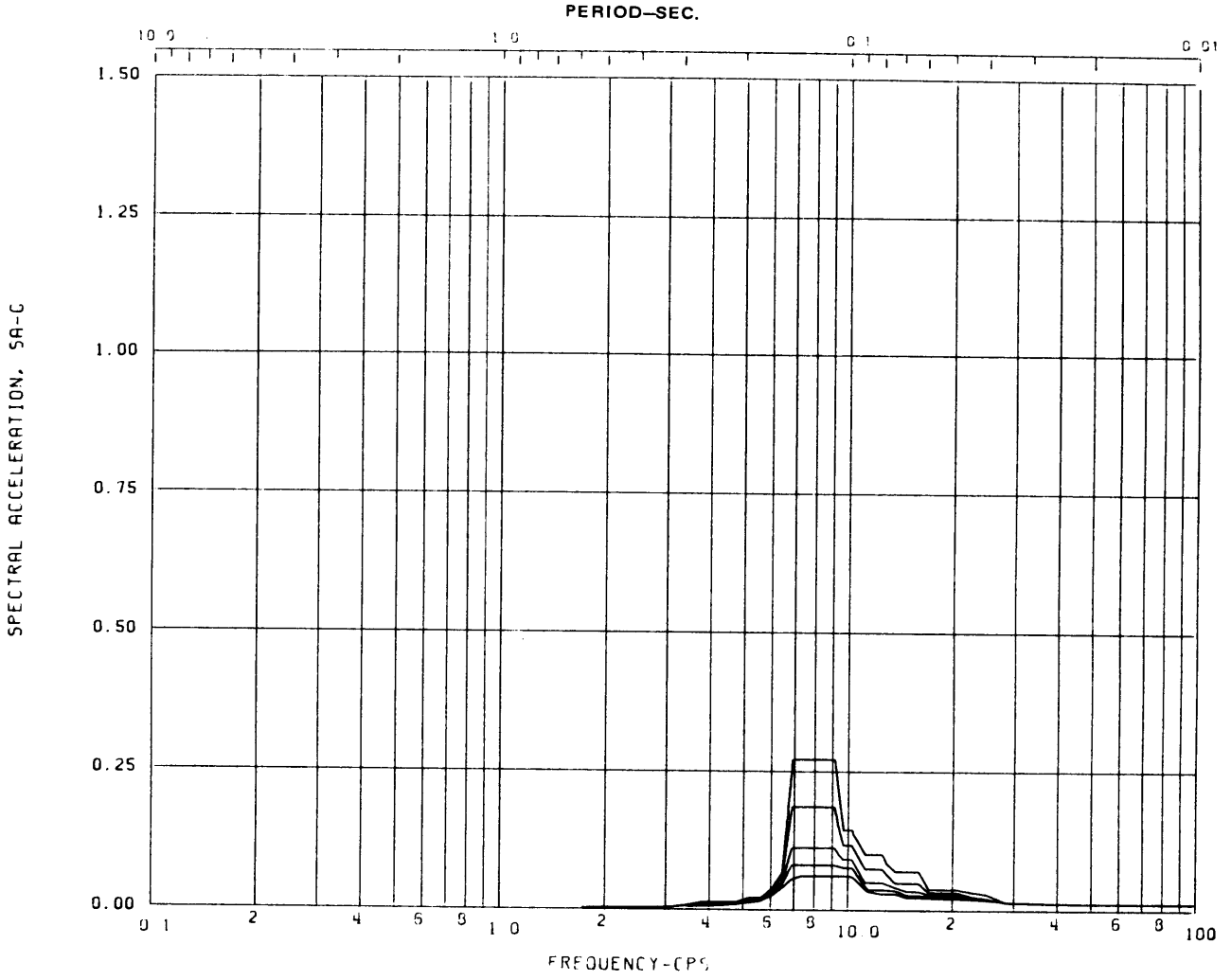
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-343



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 12 Direction: VERTICAL Elev: 352'-0

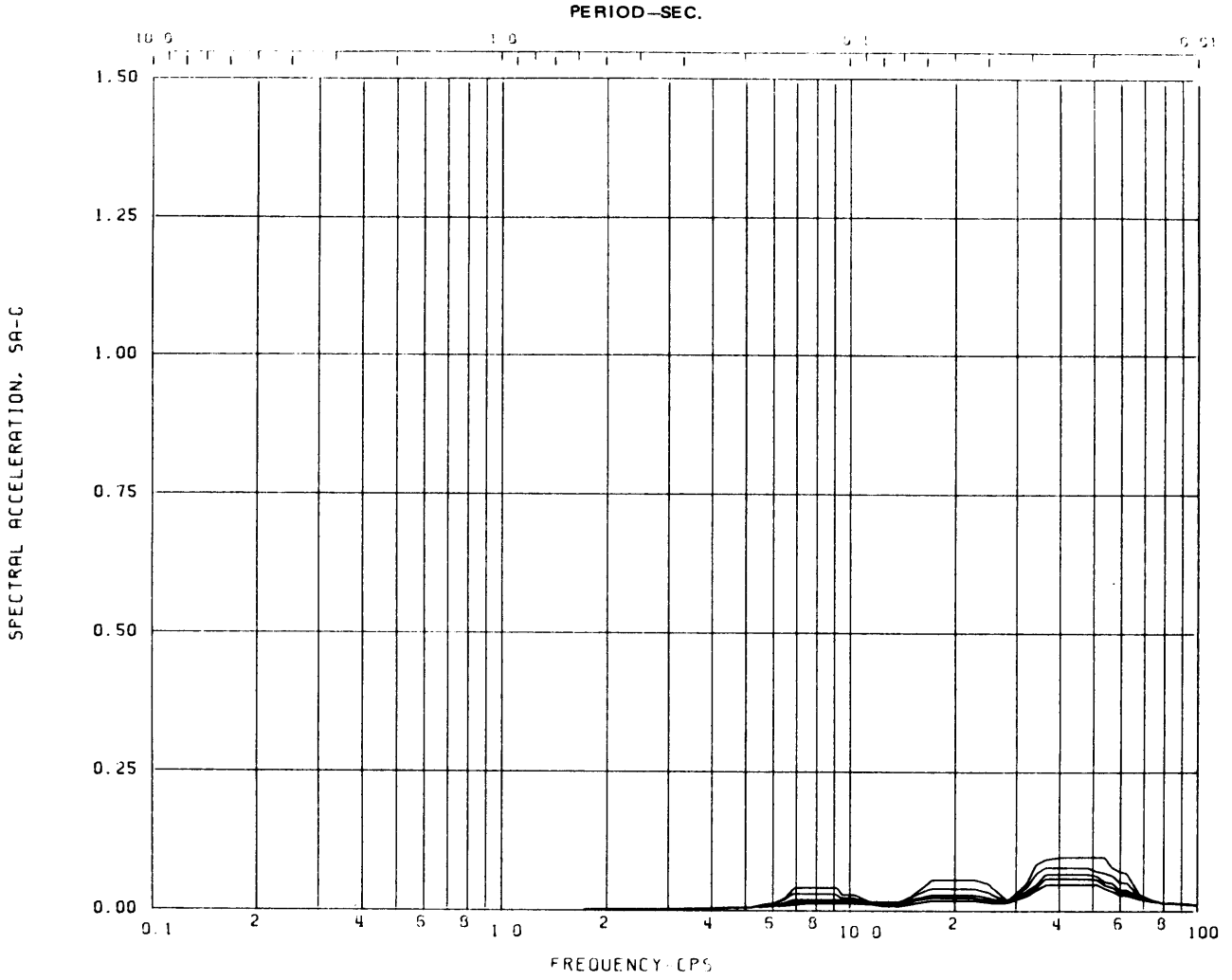
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO – ADS AXISYMMETRIC

FIGURE 3A-344



Acceleration Spectra for REACTOR ENCL.

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 6 Direction: VERTICAL Elev: 410'-0

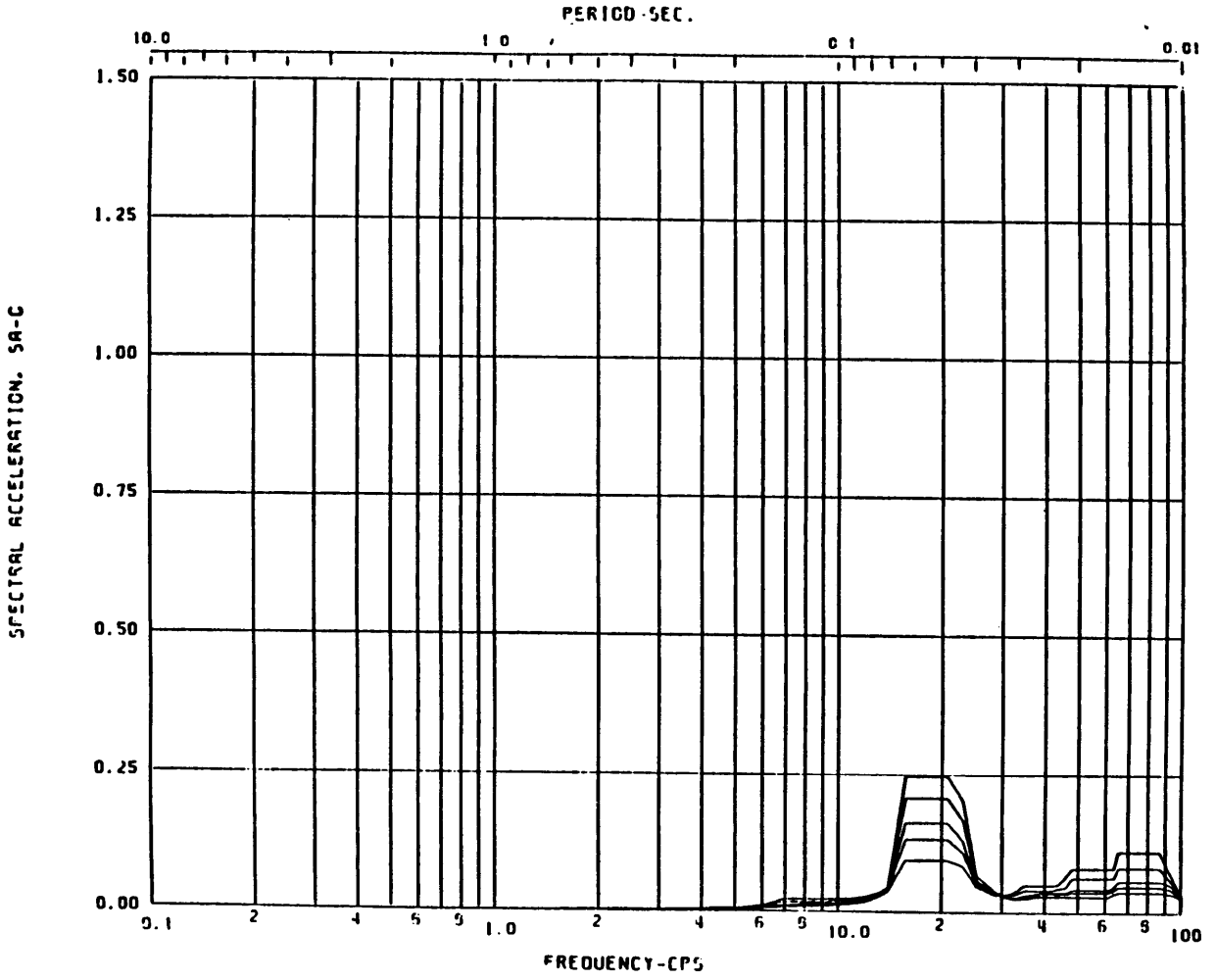
Damping: 0.005,0.01,0.02,0.03,0.05

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REACTOR ENCLOSURE GLOBAL RESPONSE SPECTRA, VERTICAL, CO—ADS AXISYMMETRIC

FIGURE 3A-345



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

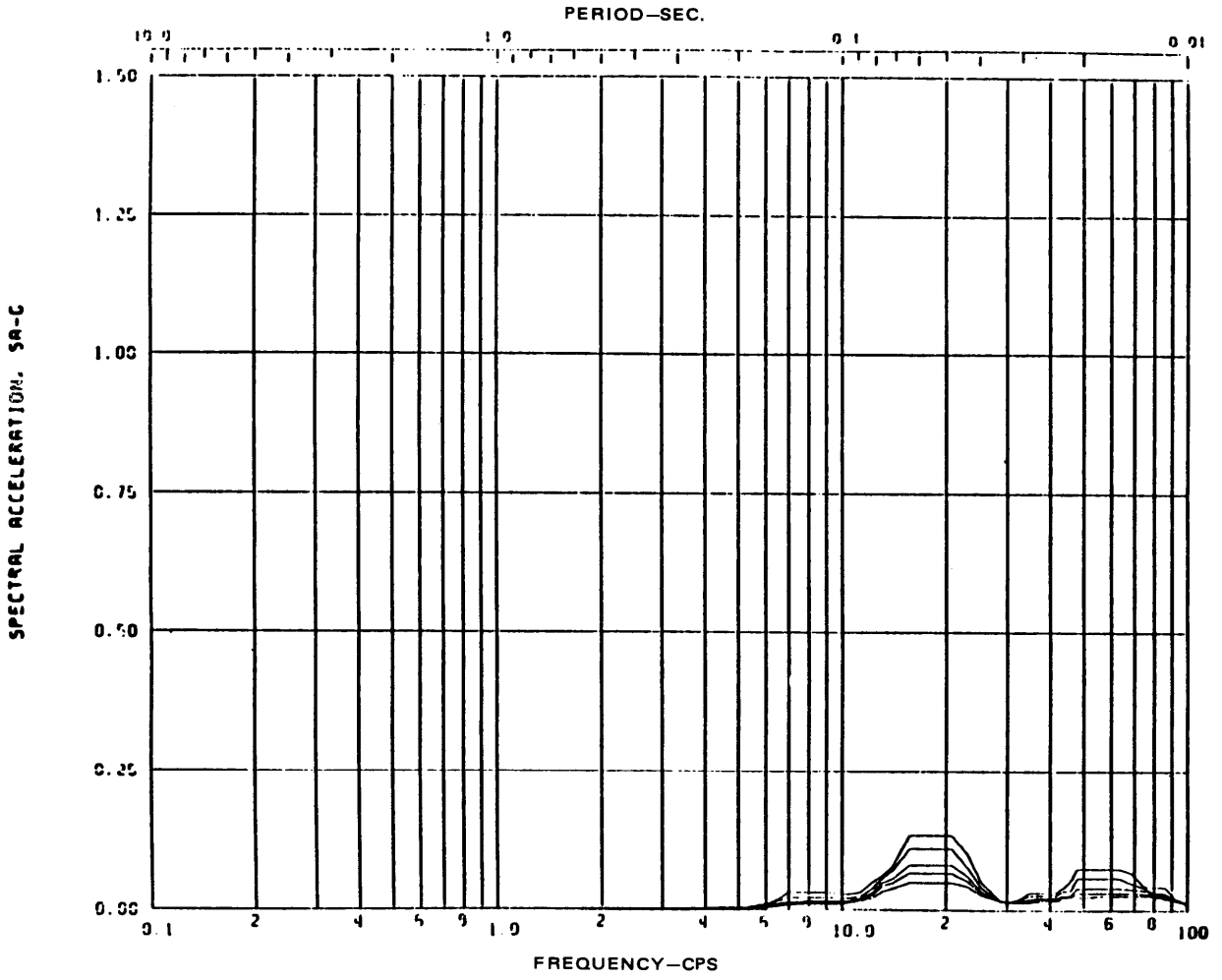
Node: 7 Direction: VERTICAL Elev: 217'

Damping: 0.005,0.01,0.02,0.03,0.05

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CONTROL STRUCTURE
LOCAL RESPONSE SPECTRA, VERTICAL,
CO – ADS AXISYMMETRIC

FIGURE 3A-346



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

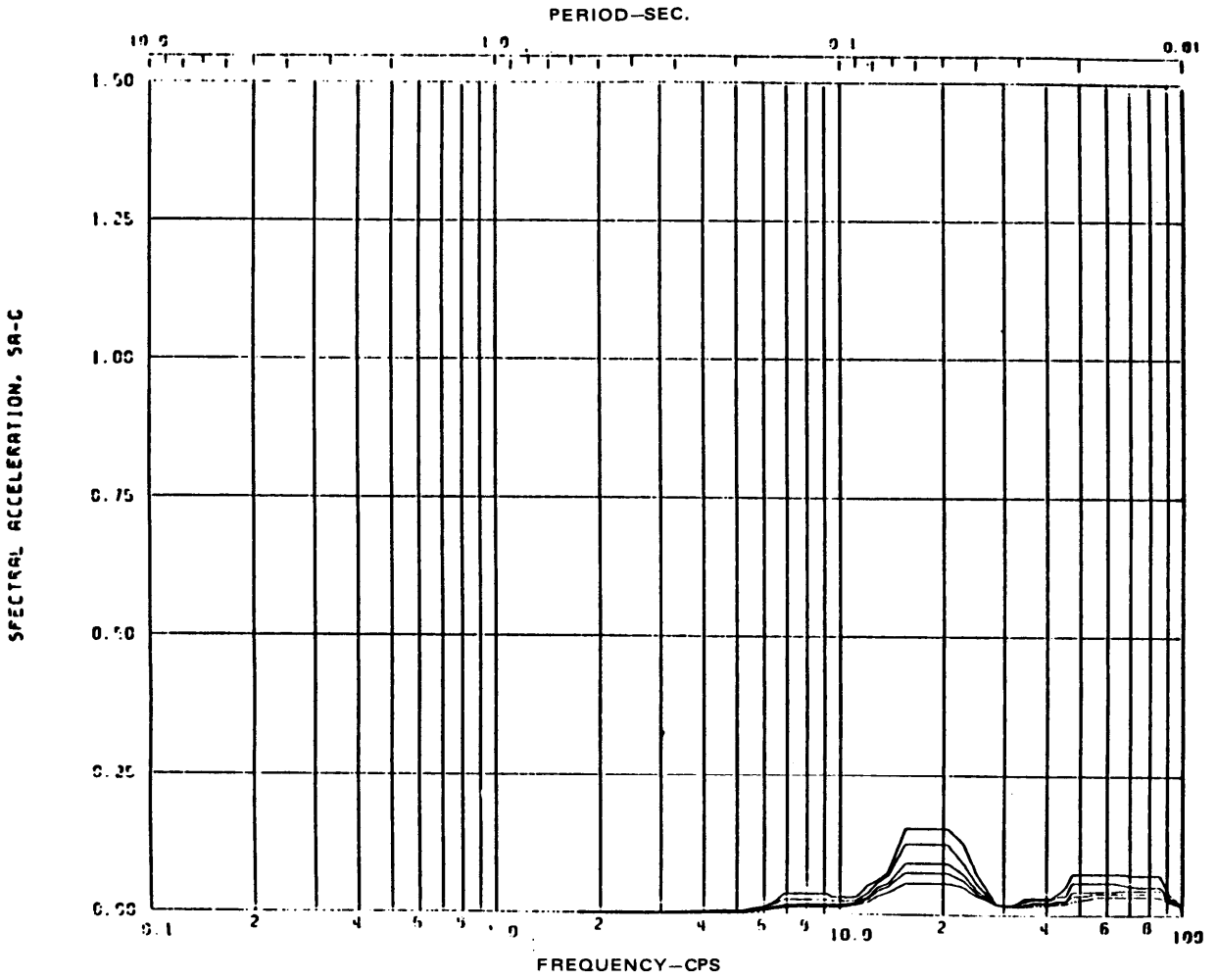
Node: 7 Direction: VERTICAL Elev: 239'

Damping: 0.005,0.01,0.02,0.03,0.05

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CO – ADS AXISYMMETRIC

FIGURE 3A-347



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 7 Direction: VERTICAL Elev: 254'

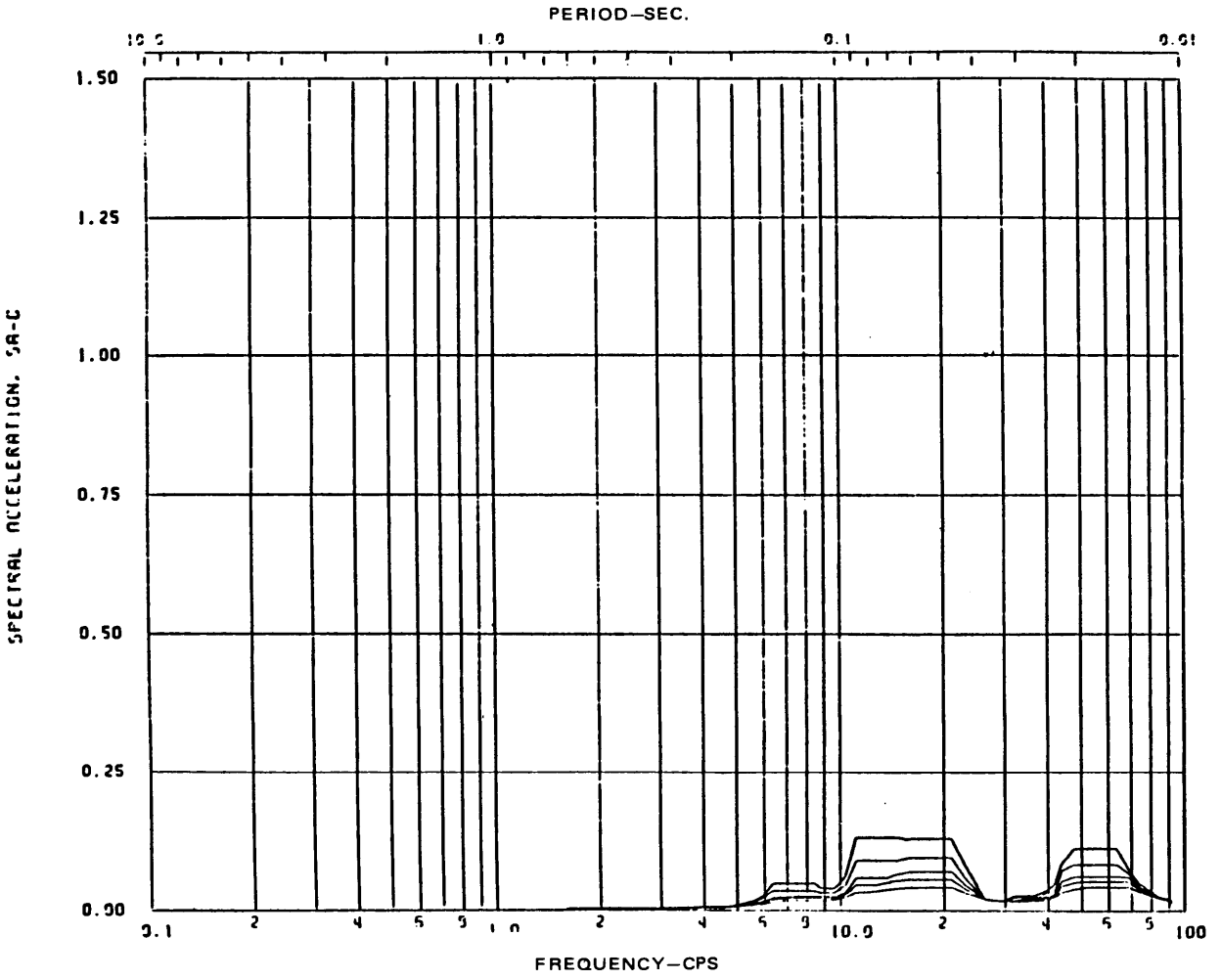
Damping: 0.005,0.01,0.02,0.03,0.05

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CONTROL STRUCTURE
LOCAL RESPONSE SPECTRA, VERTICAL,
CO – ADS AXISYMMETRIC

FIGURE 3A-348



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 7 Direction: VERTICAL Elev: 269'-0

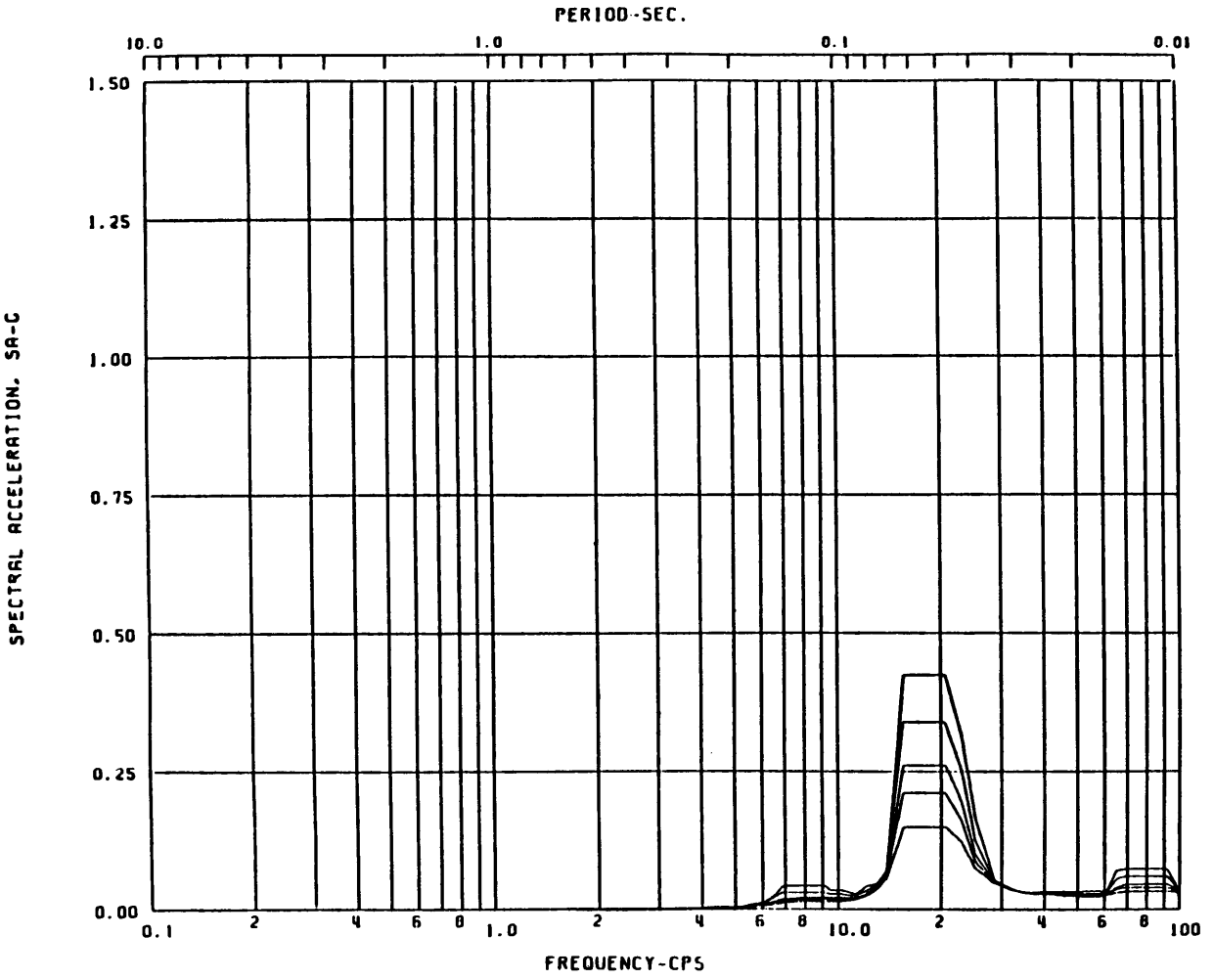
Damping: 0.005,0.01,0.02,0.03,0.05

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CONTROL STRUCTURE
LOCAL RESPONSE SPECTRA, VERTICAL,
CO – ADS AXISYMMETRIC

FIGURE 3A-349



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 7 Direction: VERTICAL Elev: 289'

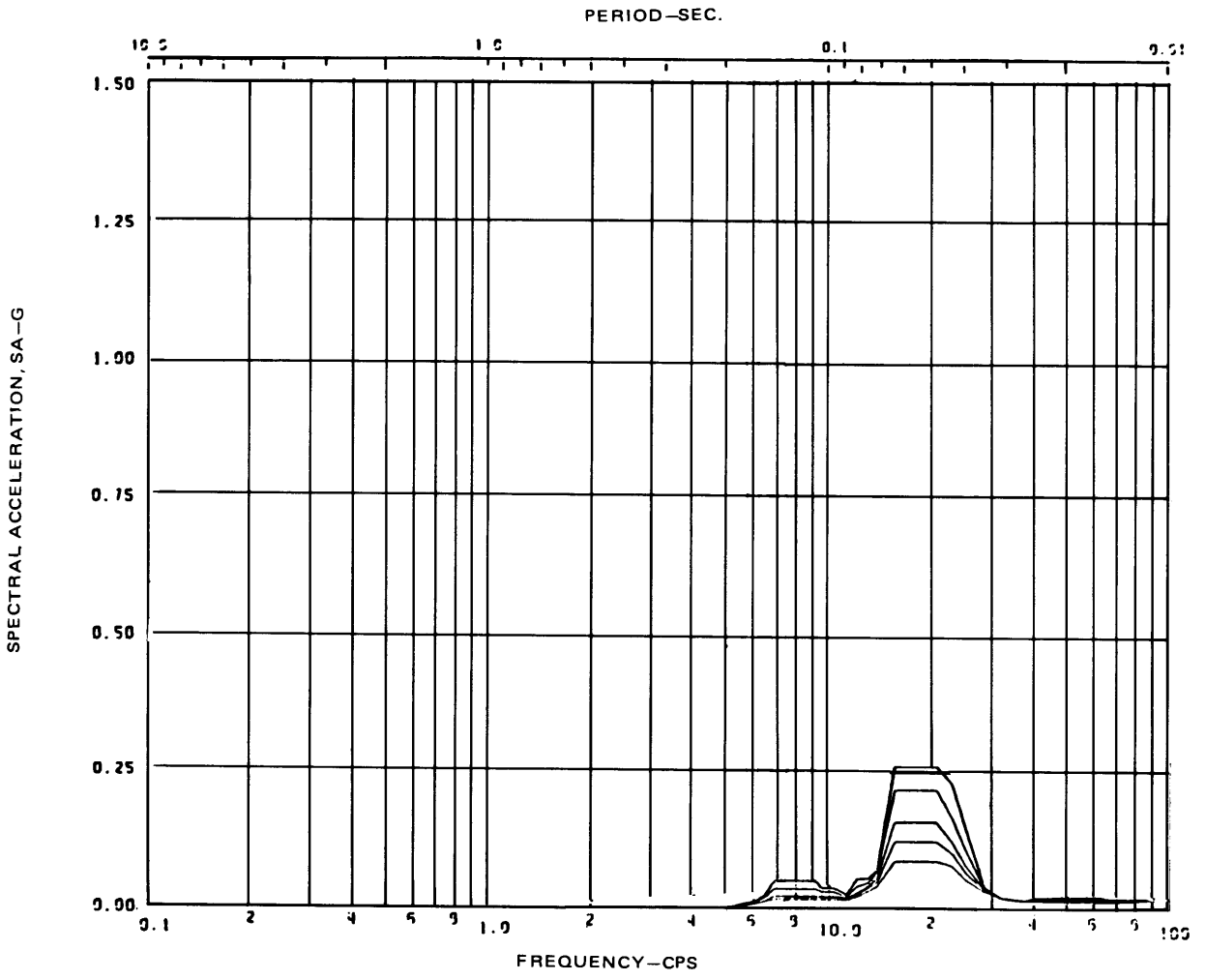
Damping: 0.005,0.01,0.02,0.03,0.05

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CONTROL STRUCTURE
LOCAL RESPONSE SPECTRA, VERTICAL,
CO – ADS AXISYMMETRIC

FIGURE 3A-350



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 7 Direction: VERTICAL Elev: 304'-0

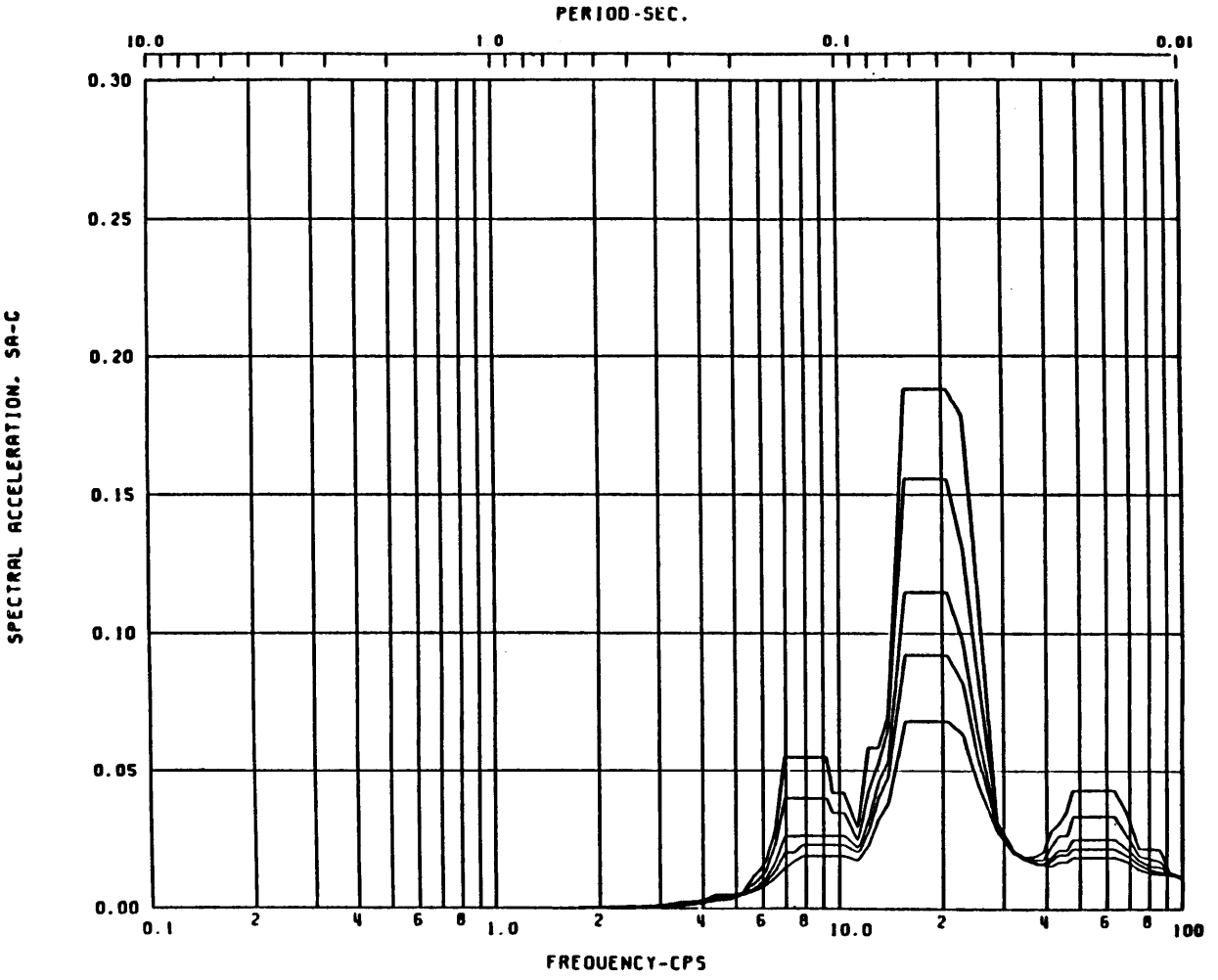
Damping: 0.005,0.01,0.02,0.03,0.05

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CONTROL STRUCTURE
LOCAL RESPONSE SPECTRA, VERTICAL,
CO – ADS AXISYMMETRIC

FIGURE 3A-351



Acceleration Spectra for CONTROL STRUCTURE

Load Case: AXISYMMETRIC GE CO-ADS ENVELOPE (WIDENED - 15%)

Node: 7 Direction: VERTICAL Elev: 332'

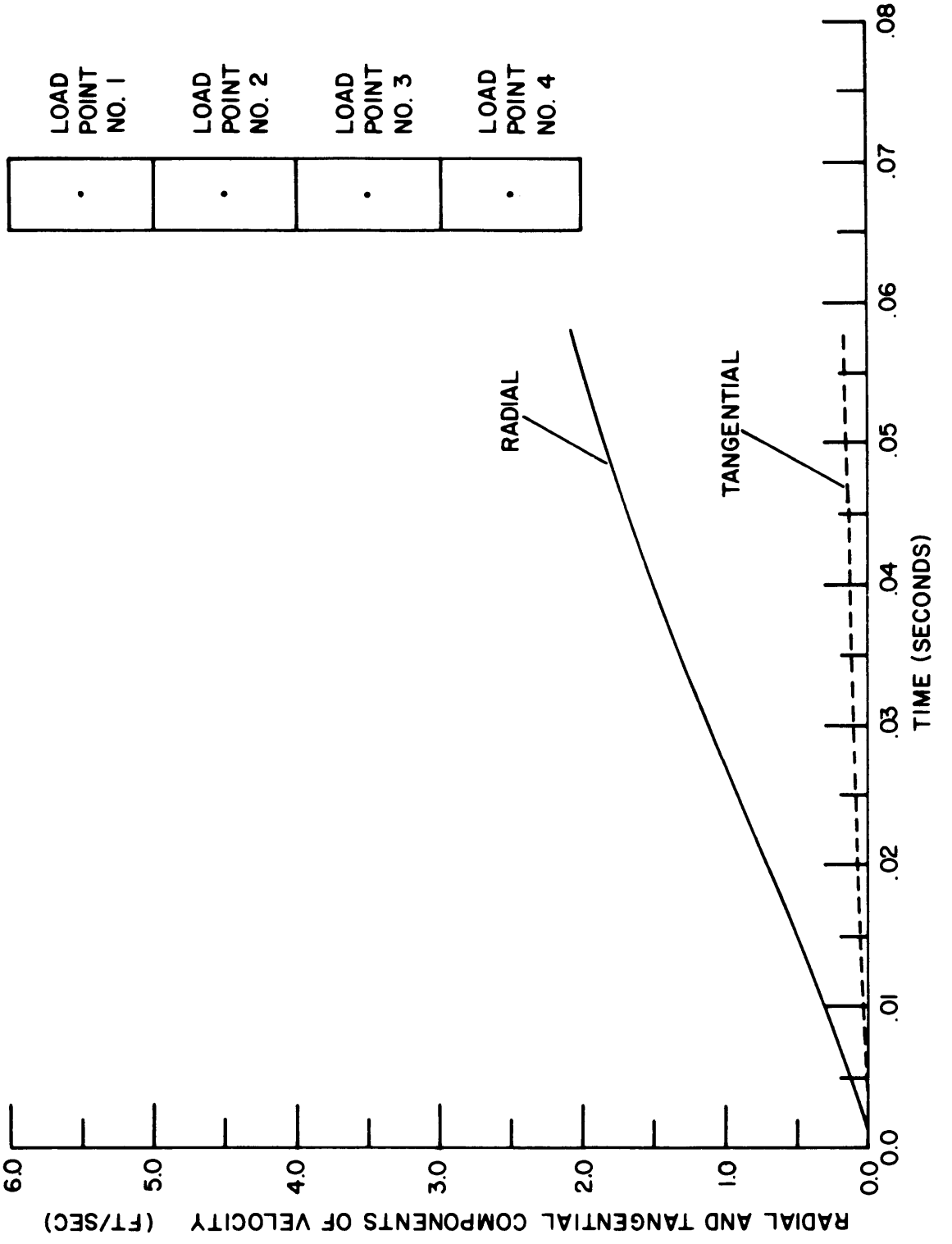
Damping: 0.005,0.01,0.02,0.03,0.05

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CONTROL STRUCTURE
LOCAL RESPONSE SPECTRA, VERTICAL,
CO – ADS AXISYMMETRIC

FIGURE 3A-352



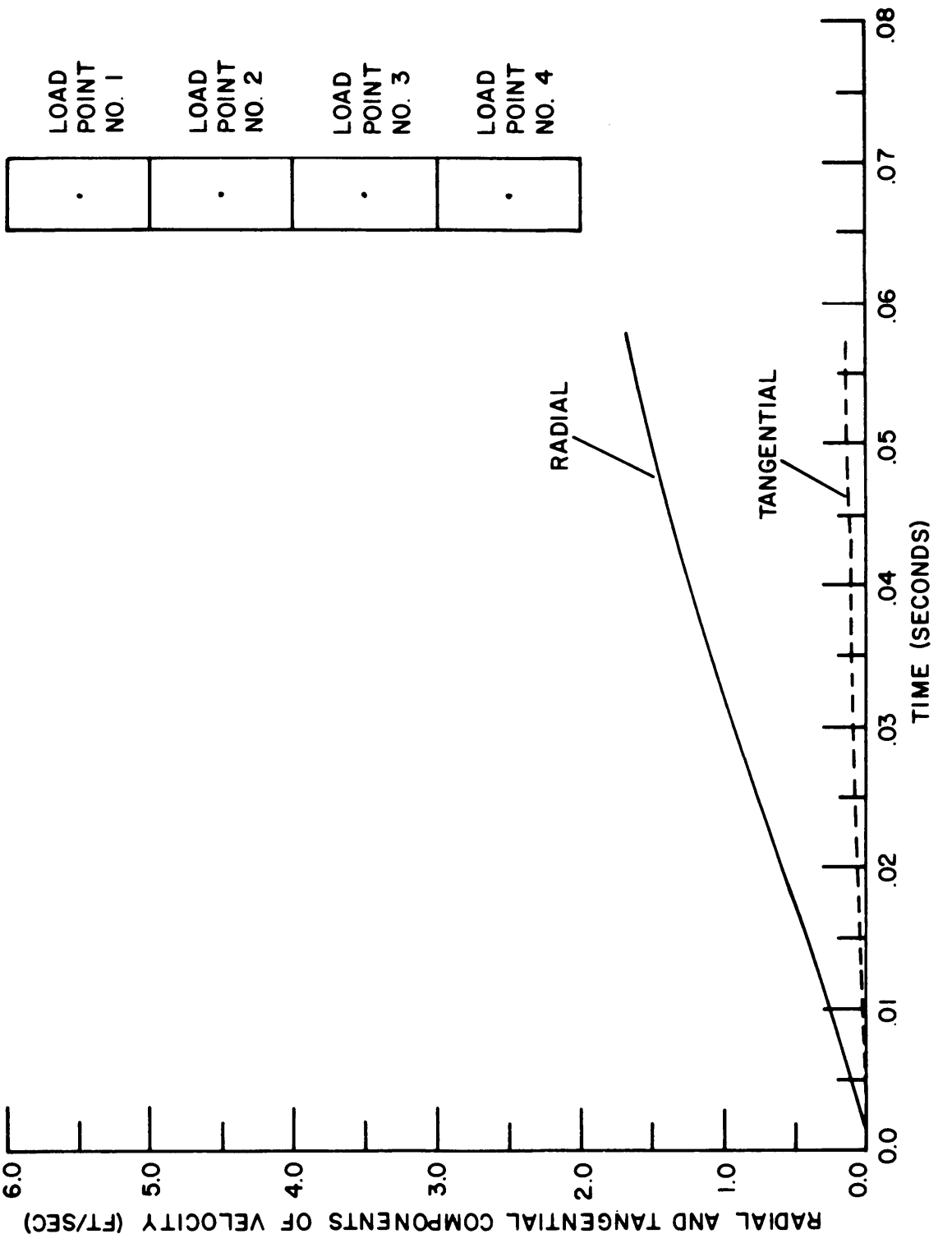
LOAD POINT NO. 1

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DESIGN ASSESSMENT REPORT

LOCA AIR CLEARING VELOCITY
(SHEET 1 OF 4)

FIGURE 3A-353



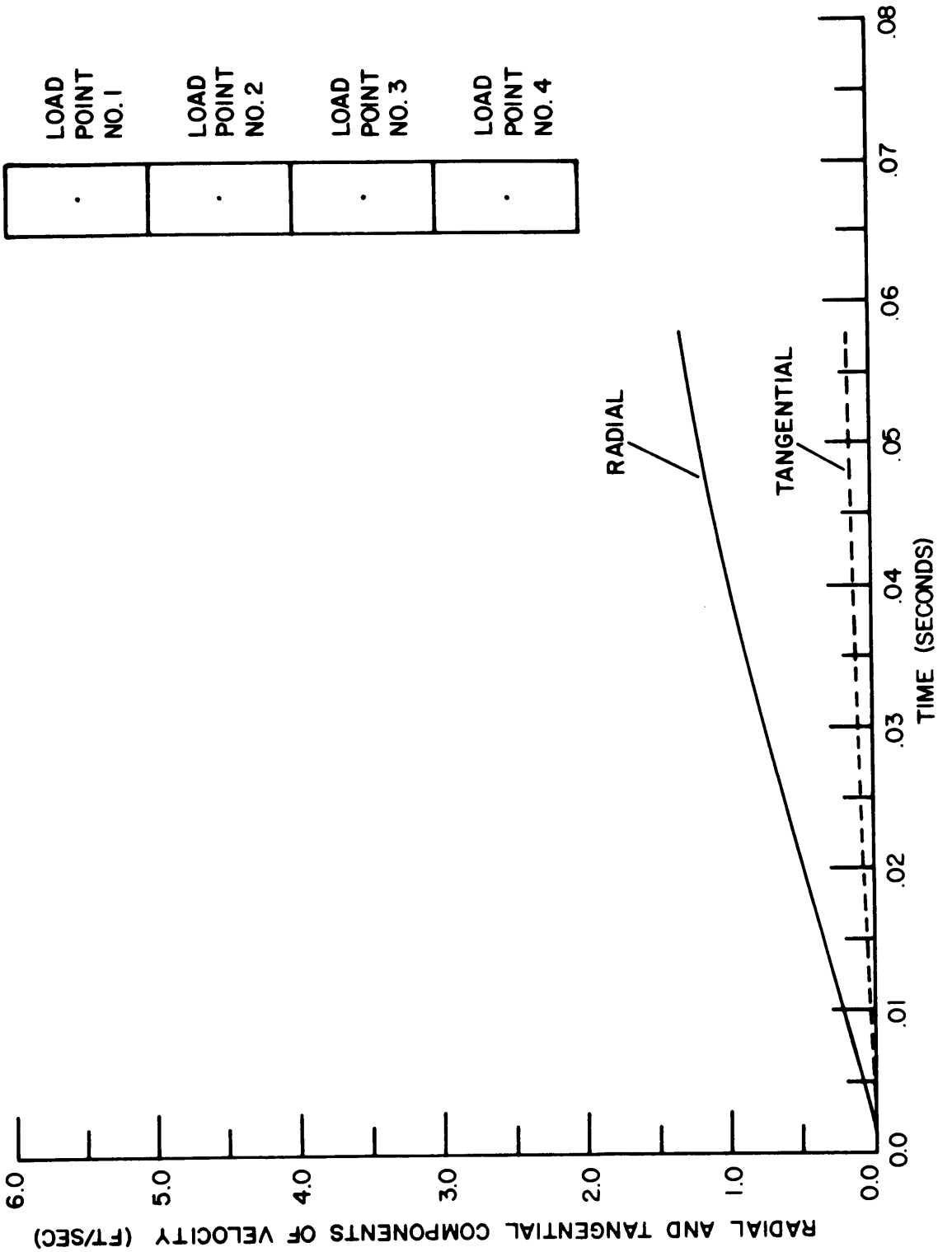
LOAD POINT NO. 2

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LOCA AIR CLEARING VELOCITY (SHEET 2 OF 4)

FIGURE 3A-353



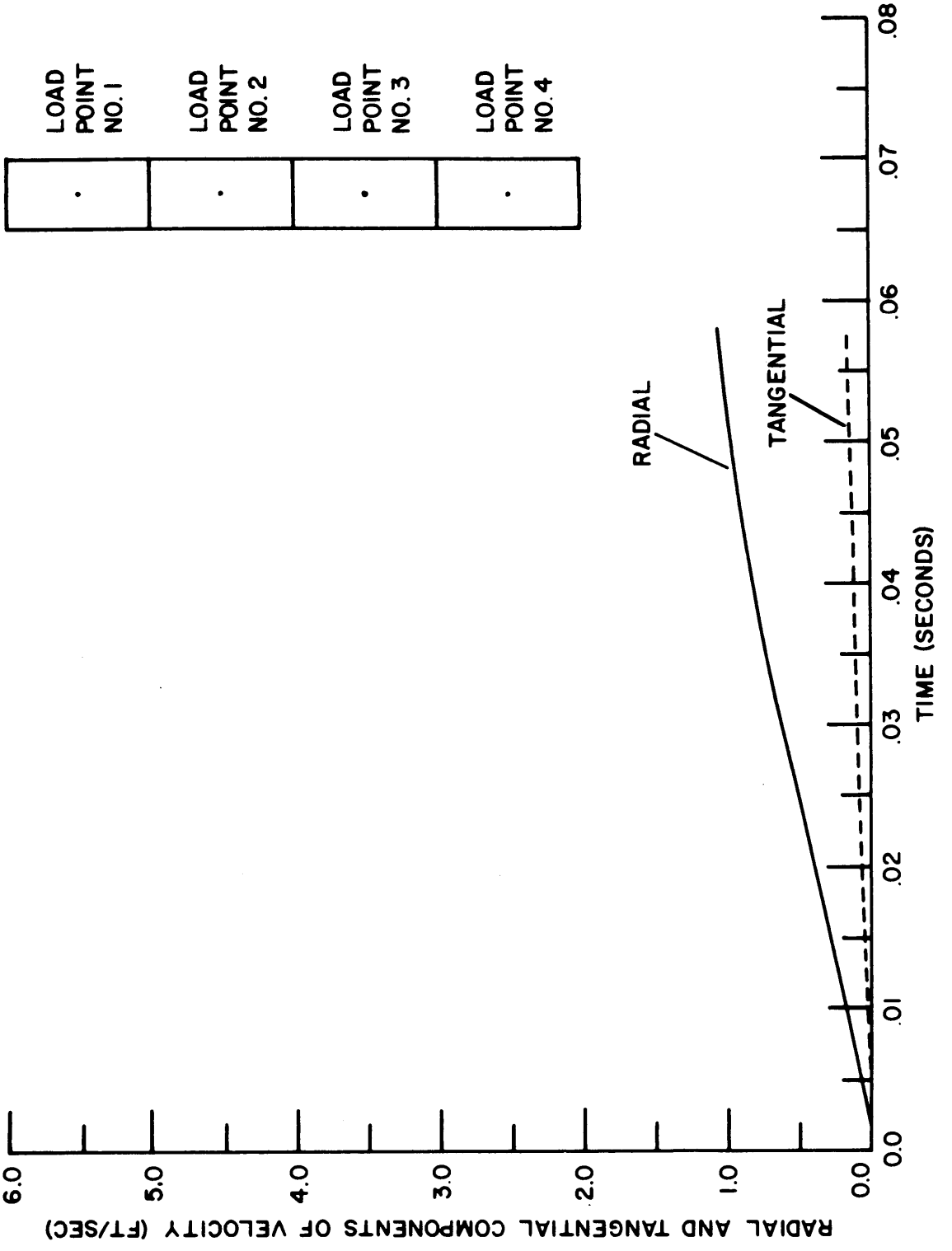
LOAD POINT NO. 3

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LOCA AIR CLEARING VELOCITY (SHEET 3 OF 4)

FIGURE 3A-353



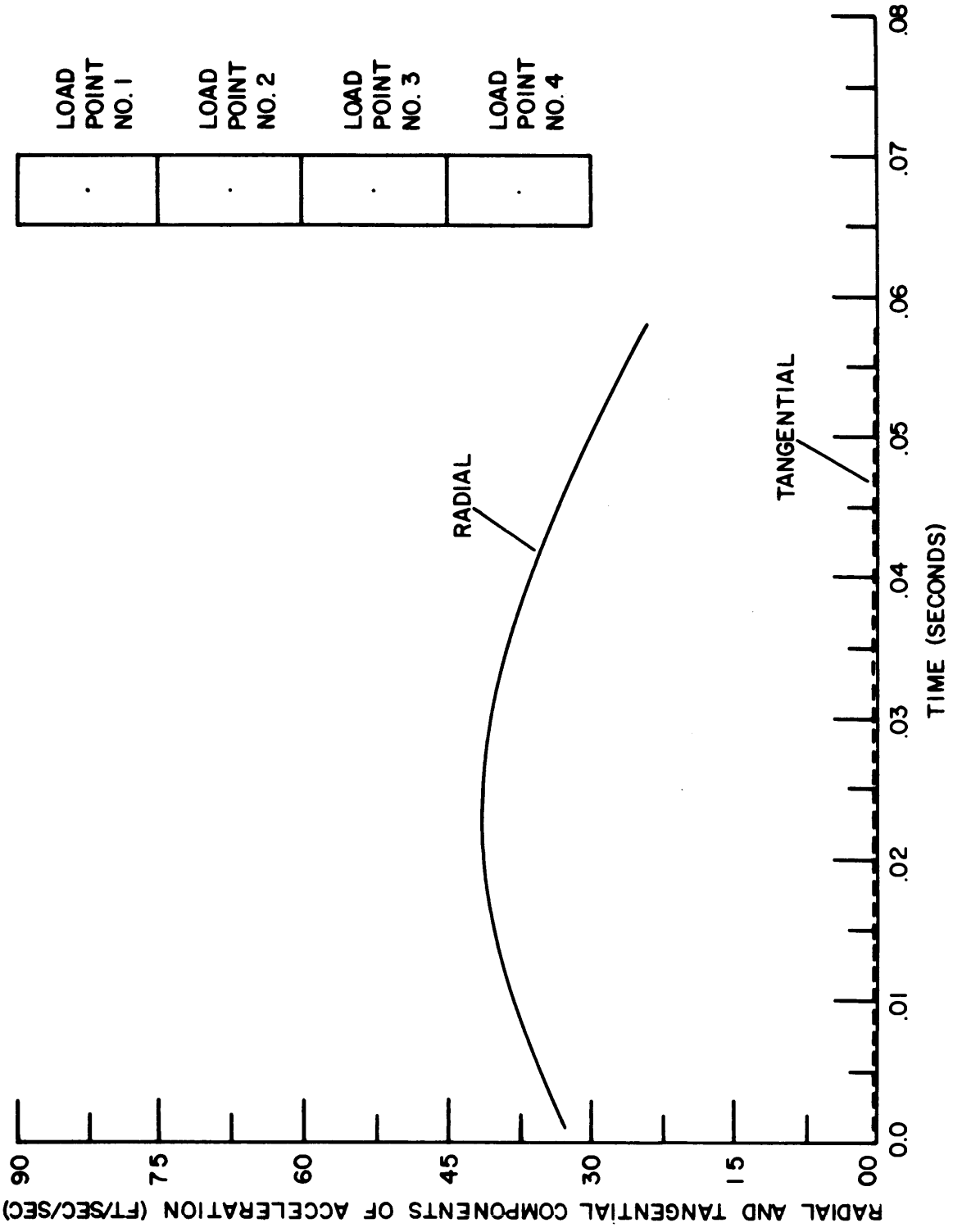
LOAD POINT NO. 4

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LOCA AIR CLEARING VELOCITY (SHEET 4 OF 4)

FIGURE 3A-353

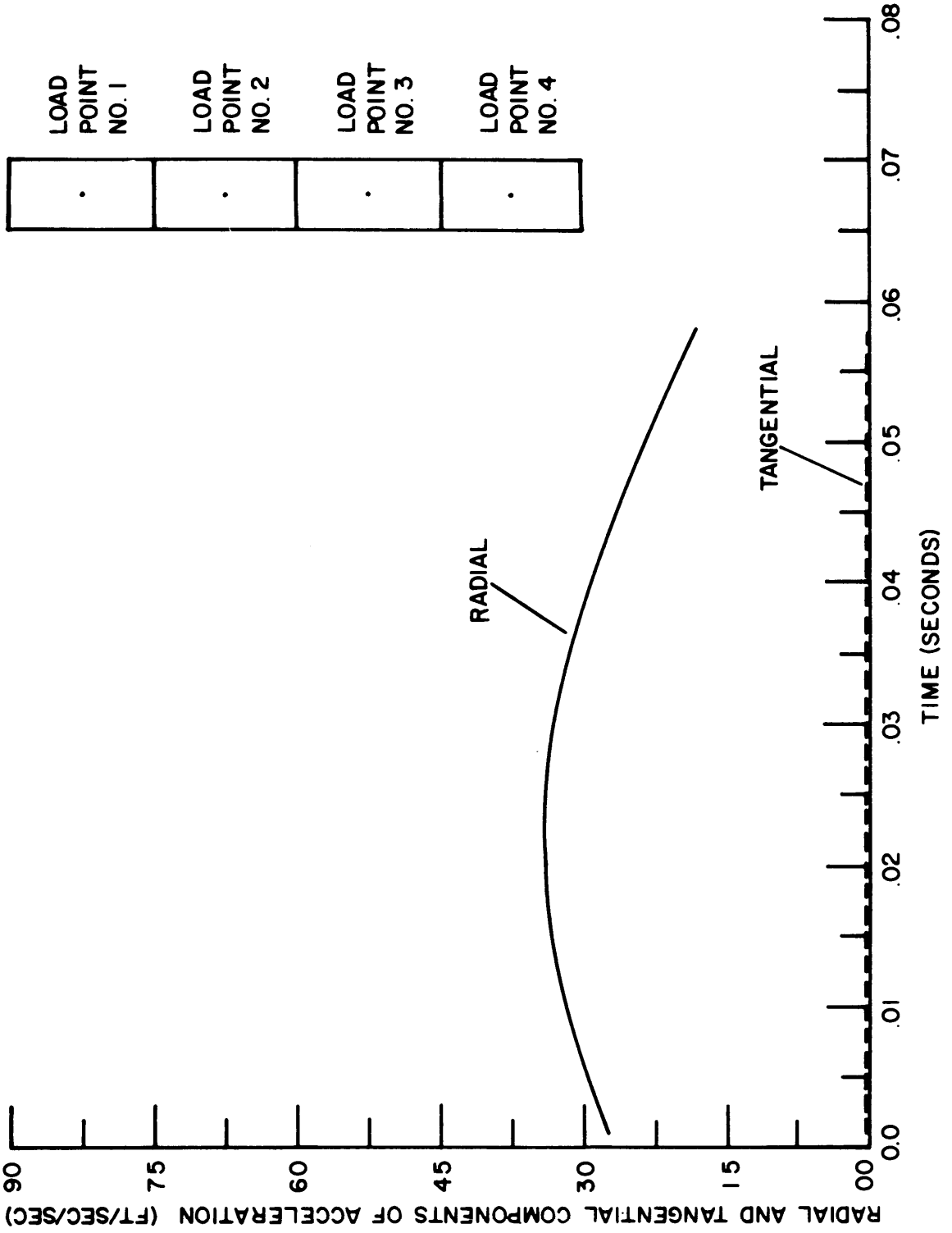


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LOCA AIR CLEARING ACCELERATION (SHEET 1 OF 4)

FIGURE 3A-354



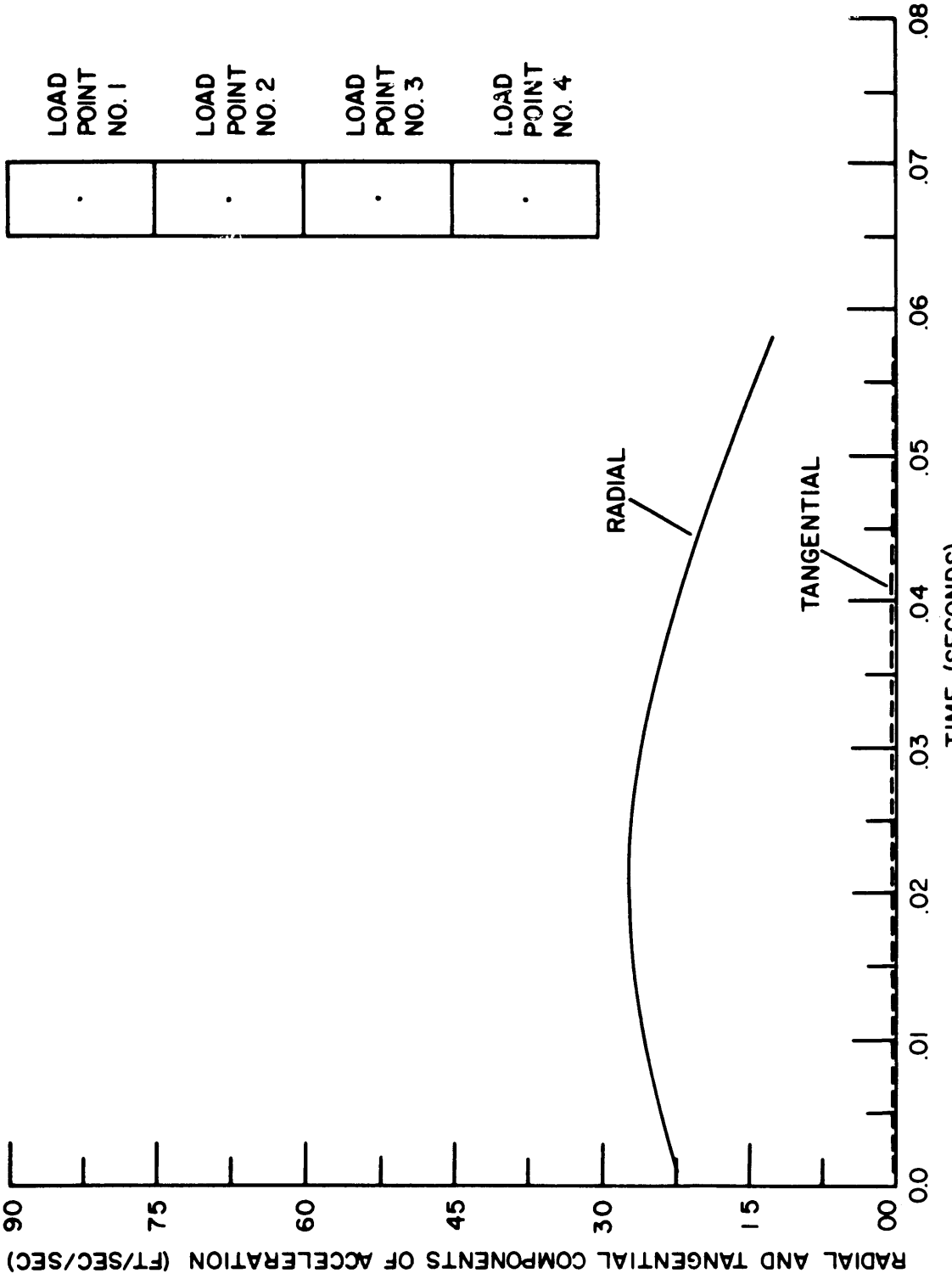
LOAD POINT NO. 2

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LOCA AIR CLEARING ACCELERATION (SHEET 2 OF 4)

FIGURE 3A-354



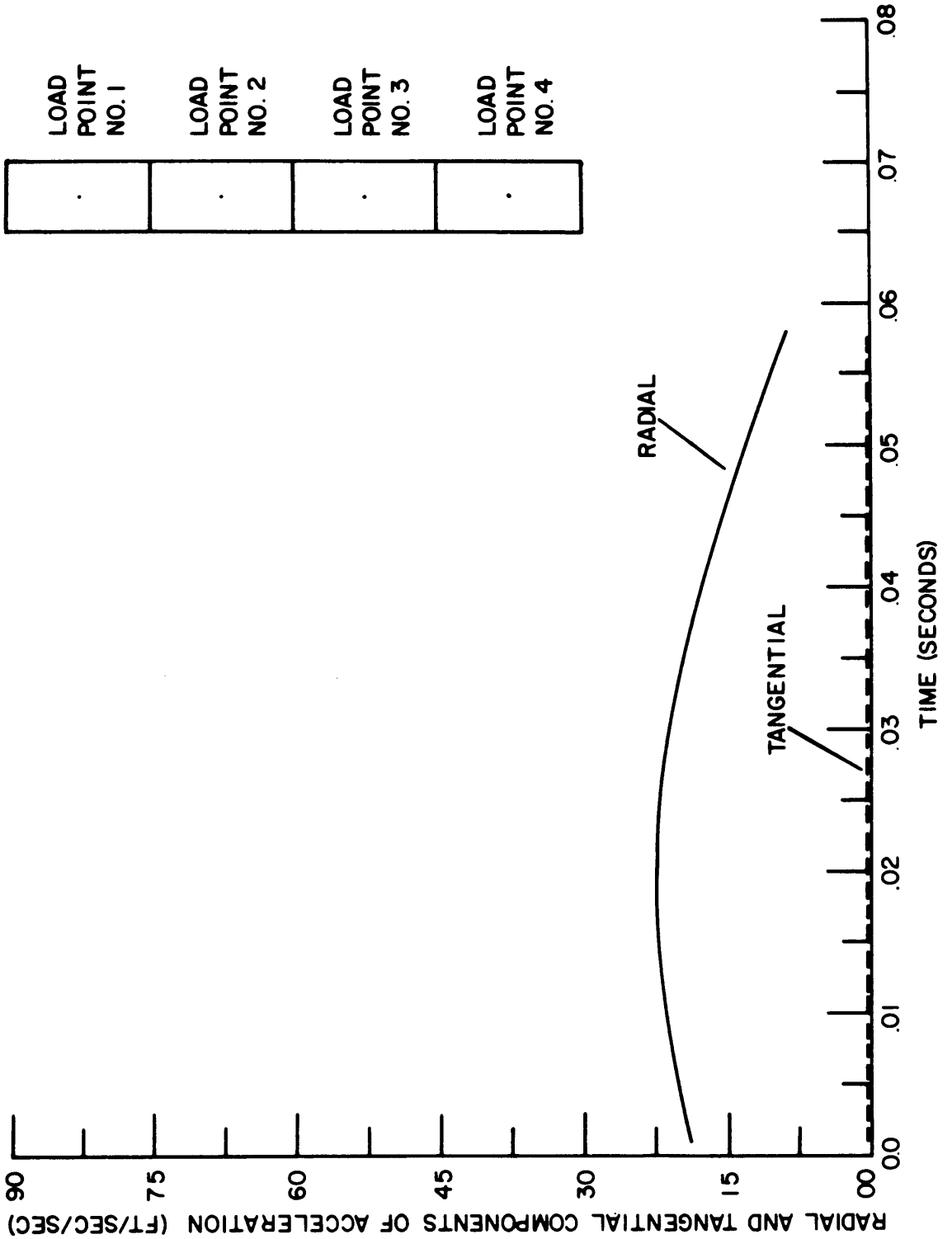
LOAD POINT NO. 3

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

LOCA AIR CLEARING ACCELERATION (SHEET 3 OF 4)

FIGURE 3A-354



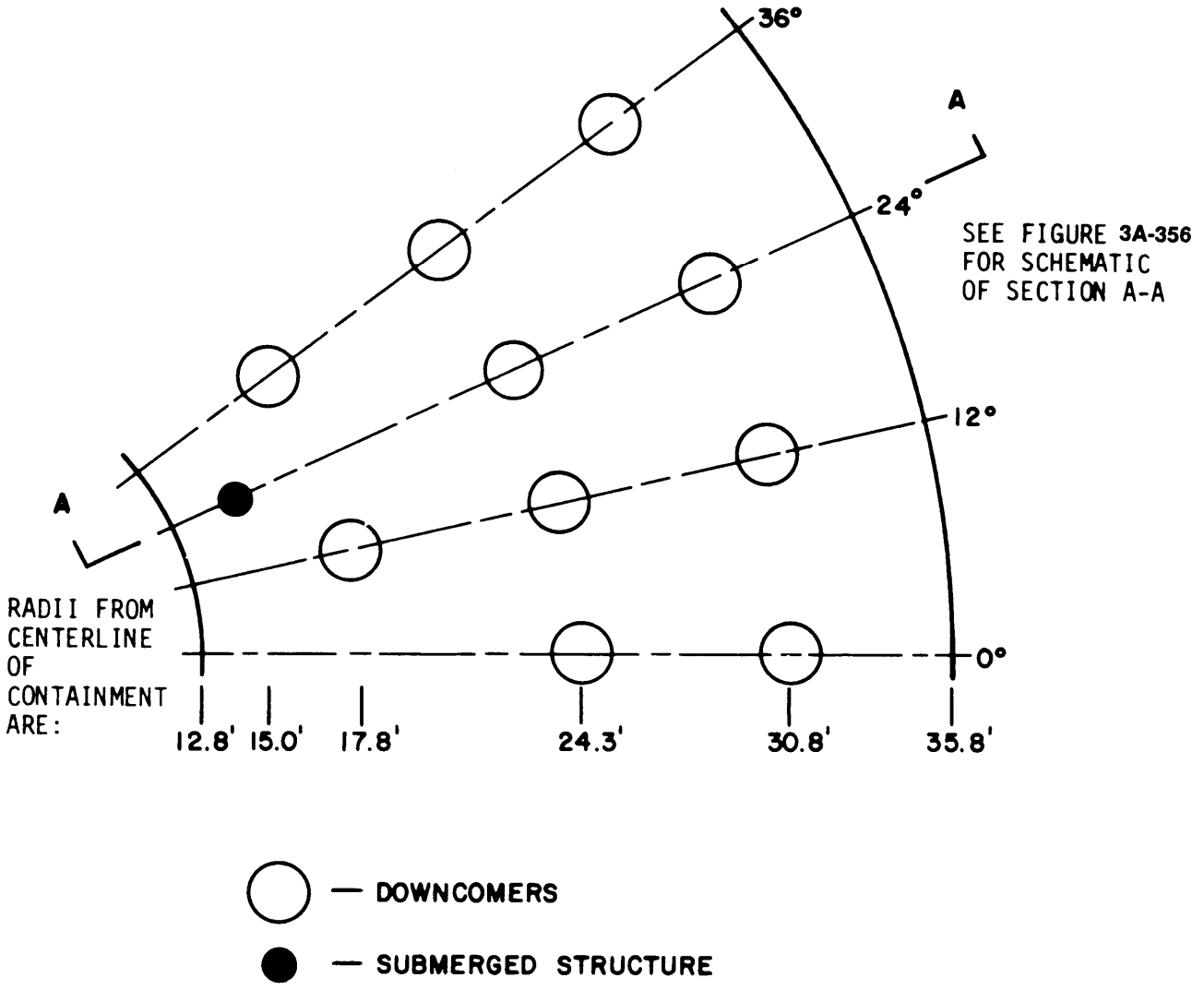
LOAD POINT NO. 4

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

LOCA AIR CLEARING ACCELERATION (SHEET 4 OF 4)

FIGURE 3A-354

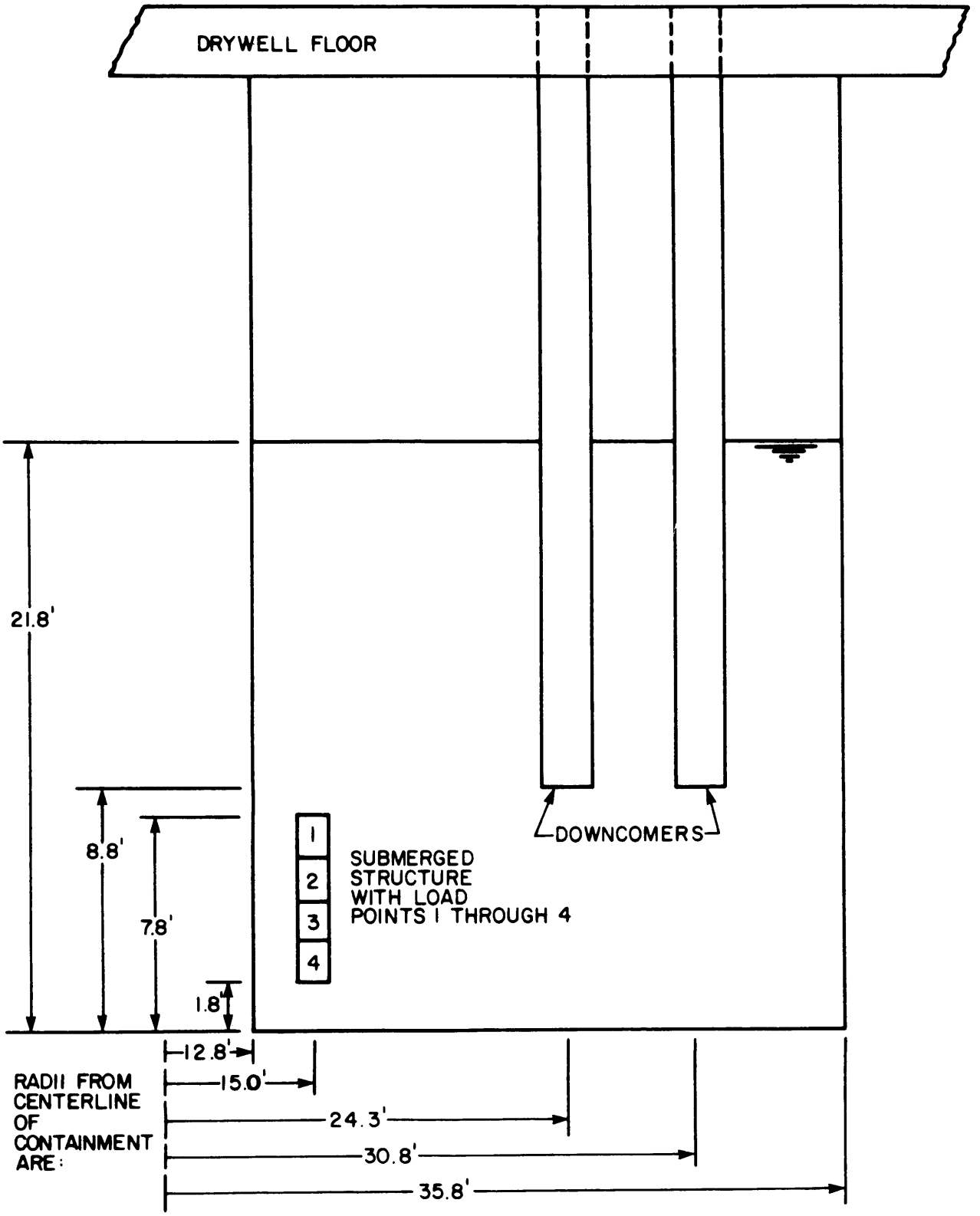


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DESIGN ASSESSMENT REPORT

TOP VIEW OF 36° SECTOR OF A TYPICAL MARK II SUPPRESSION POOL

FIGURE 3A-355

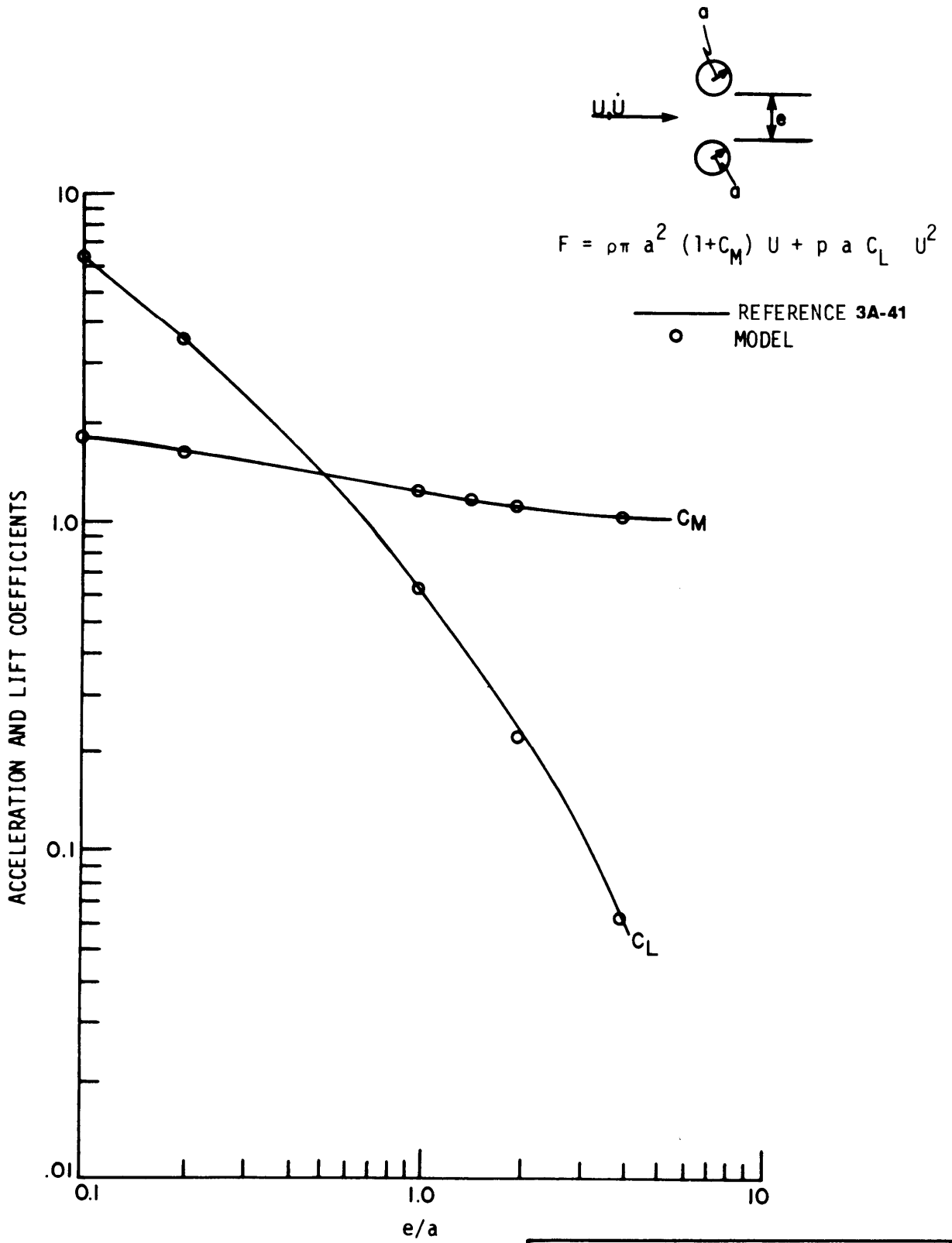


LIMERICK GENERATING STATION
UNITS 1 AND 2
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DESIGN ASSESSMENT REPORT

SCHEMATIC VIEW OF SECTION A-A OF TYPICAL MARK II SUPPRESSION POOL

FIGURE 3A-356



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UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

MODEL/DATA COMPARISONS (SHEET 1 OF 4)

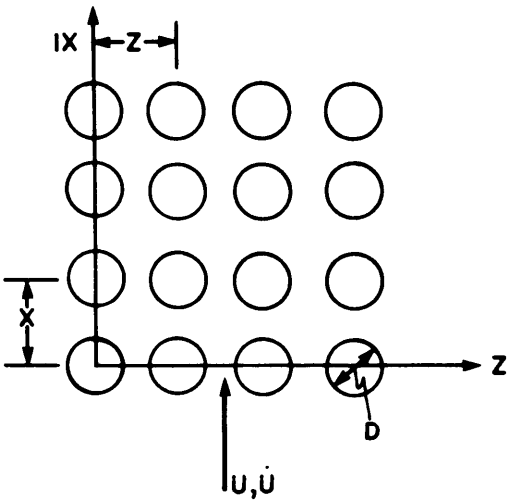
FIGURE 3A-357

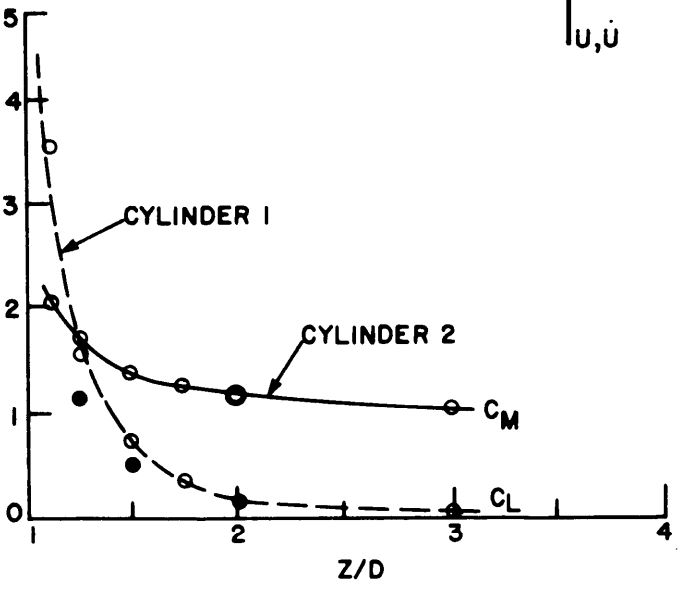
$$F = (1 + C_M)\,\rho\pi\, a^2\, \ddot{U} + \rho a\, C_L\, U\, U$$

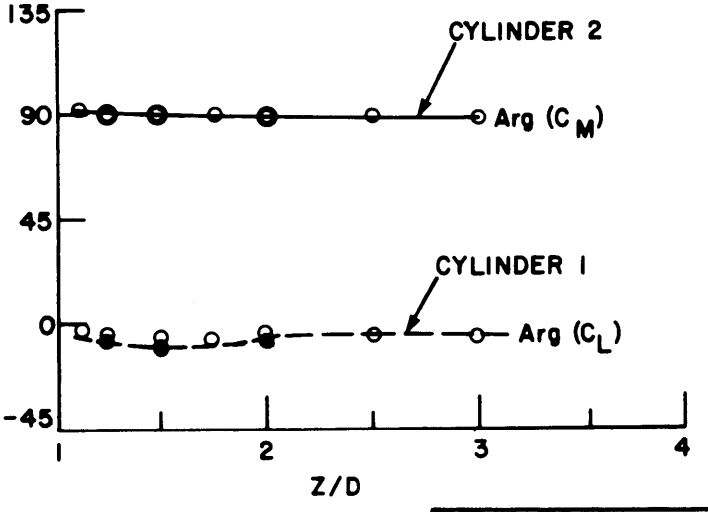
where $a = D/2$

o, O, —, - - - REFERENCE 3A-42

o MODEL





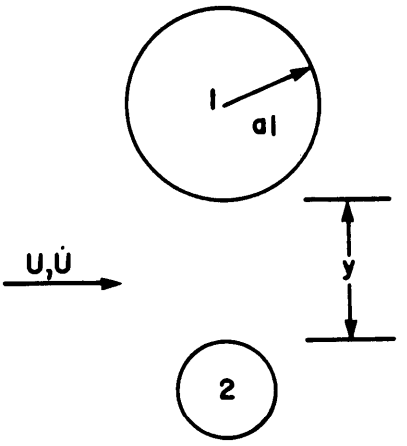


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

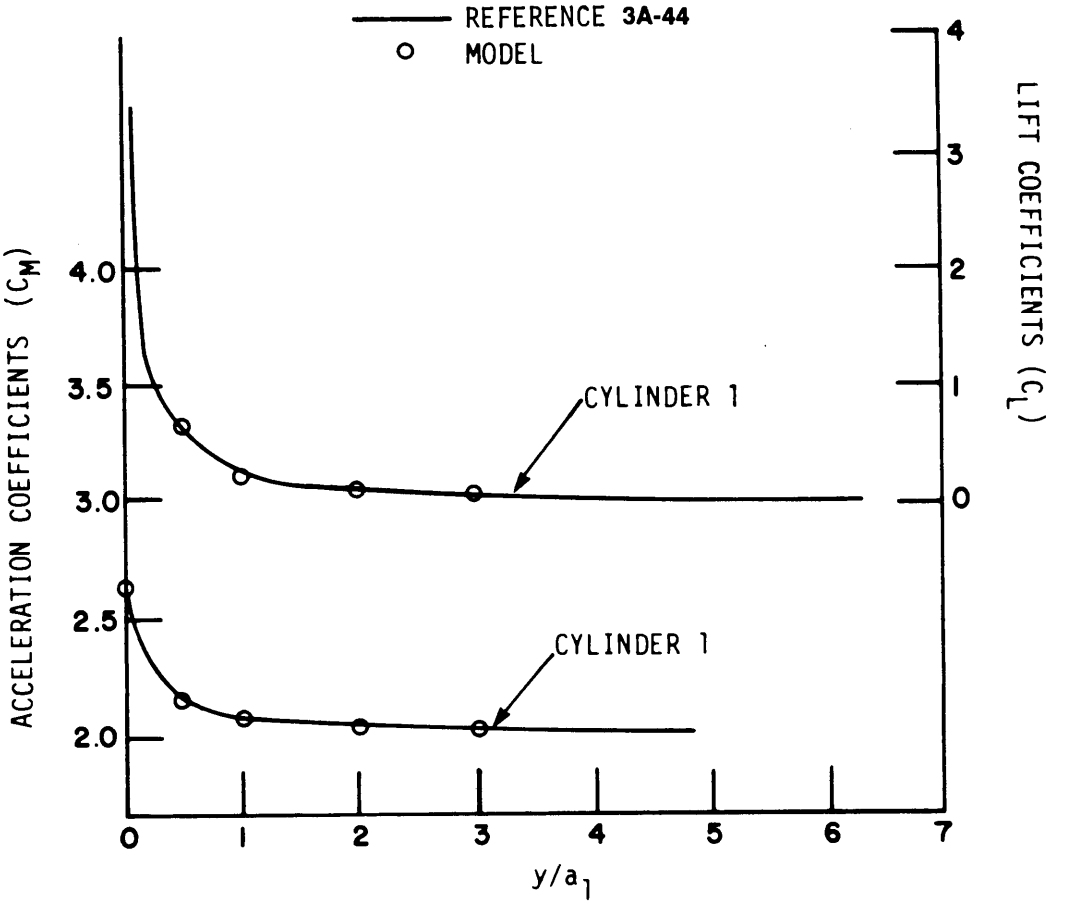
DESIGN ASSESSMENT REPORT

MODEL/DATA COMPARISONS
(SHEET 2 OF 4)

FIGURE 3A-357



$$F = C_M \rho \pi a^2 \dot{U} + C_L \rho a U^2$$

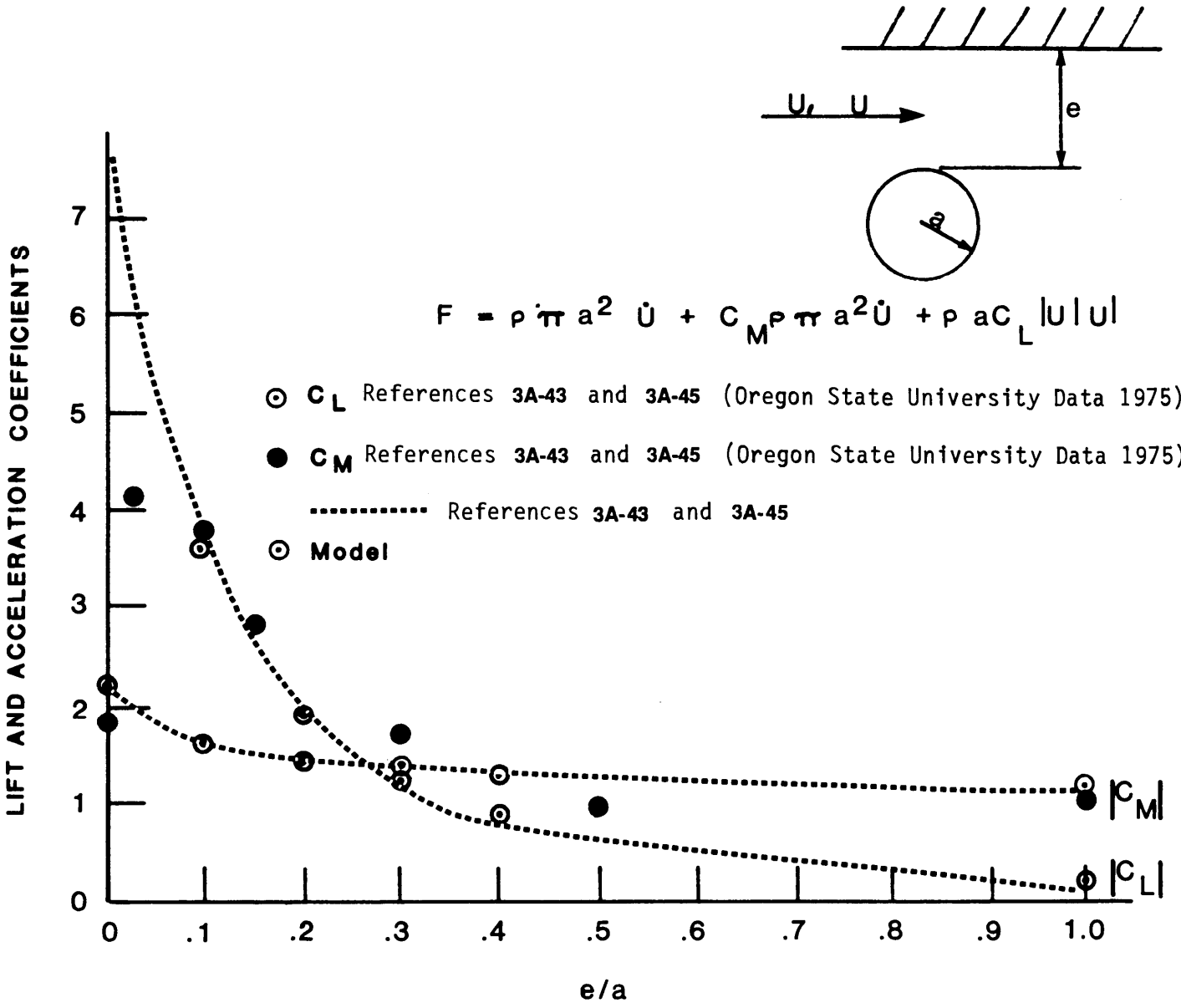


LIMERICK GENERATING STATION
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DESIGN ASSESSMENT REPORT

MODEL/DATA COMPARISONS (SHEET 3 OF 4)

FIGURE 3A-357

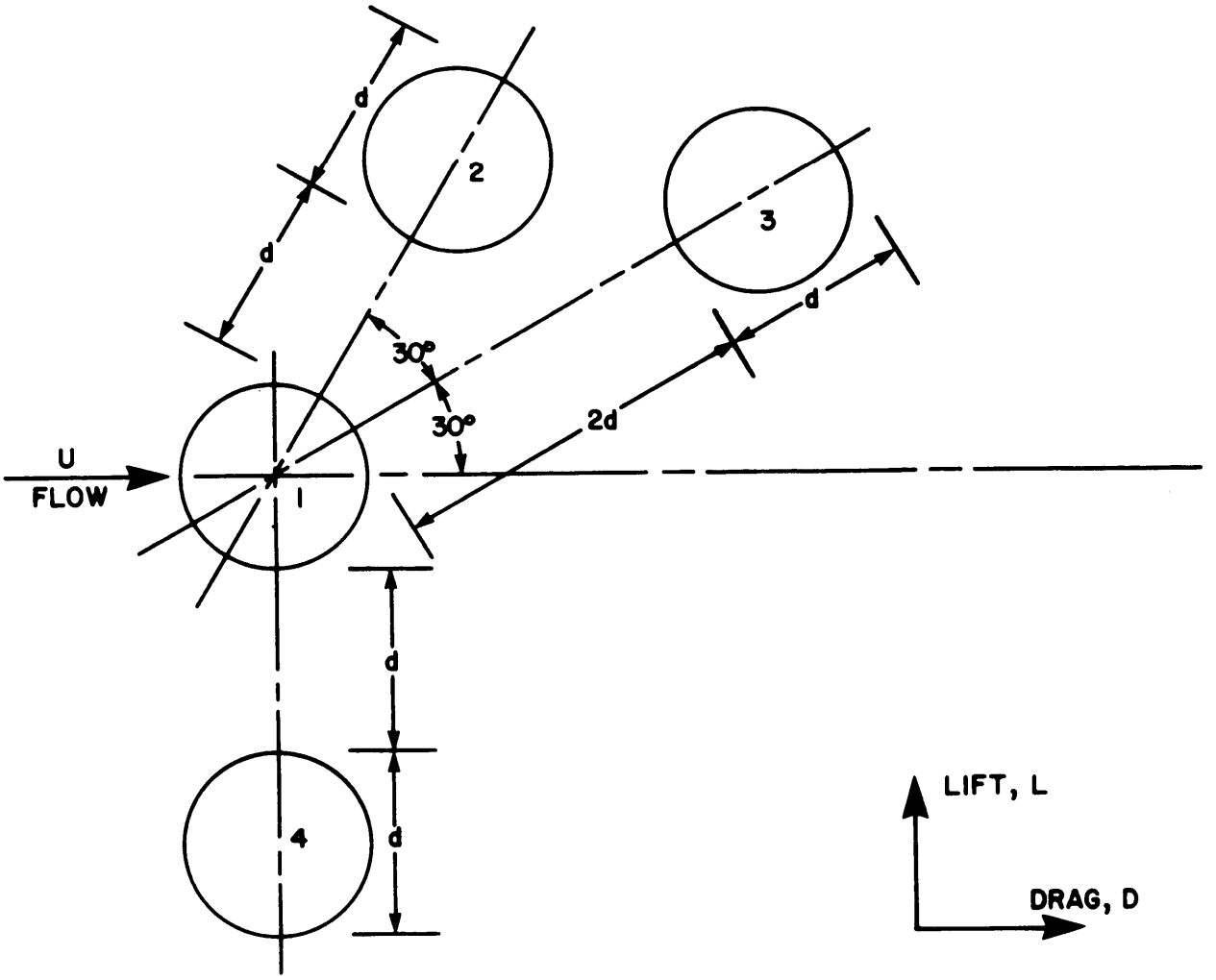


LIMERICK GENERATING STATION
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MODEL/DATA COMPARISONS (SHEET 4 OF 4)

FIGURE 3A-357

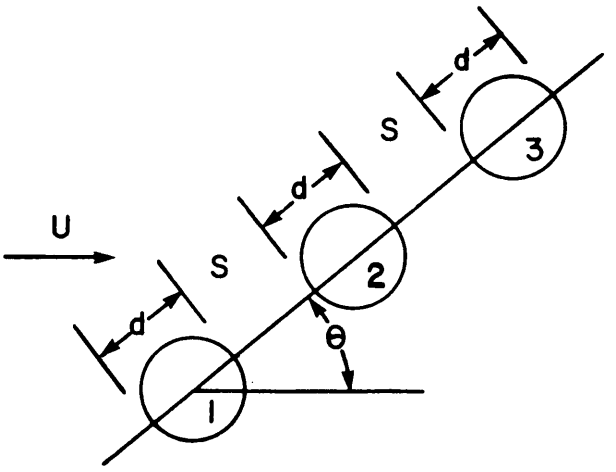


LIMERICK GENERATING STATION
UNITS 1 AND 2
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DESIGN ASSESSMENT REPORT

CYLINDER LOCATIONS

FIGURE 3A-358

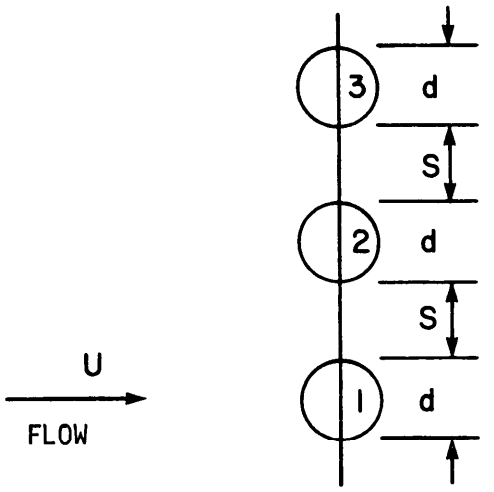


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

INTERFERENCE ON STANDARD DRAG: THREE CYLINDER ARRANGEMENT

FIGURE 3A-359

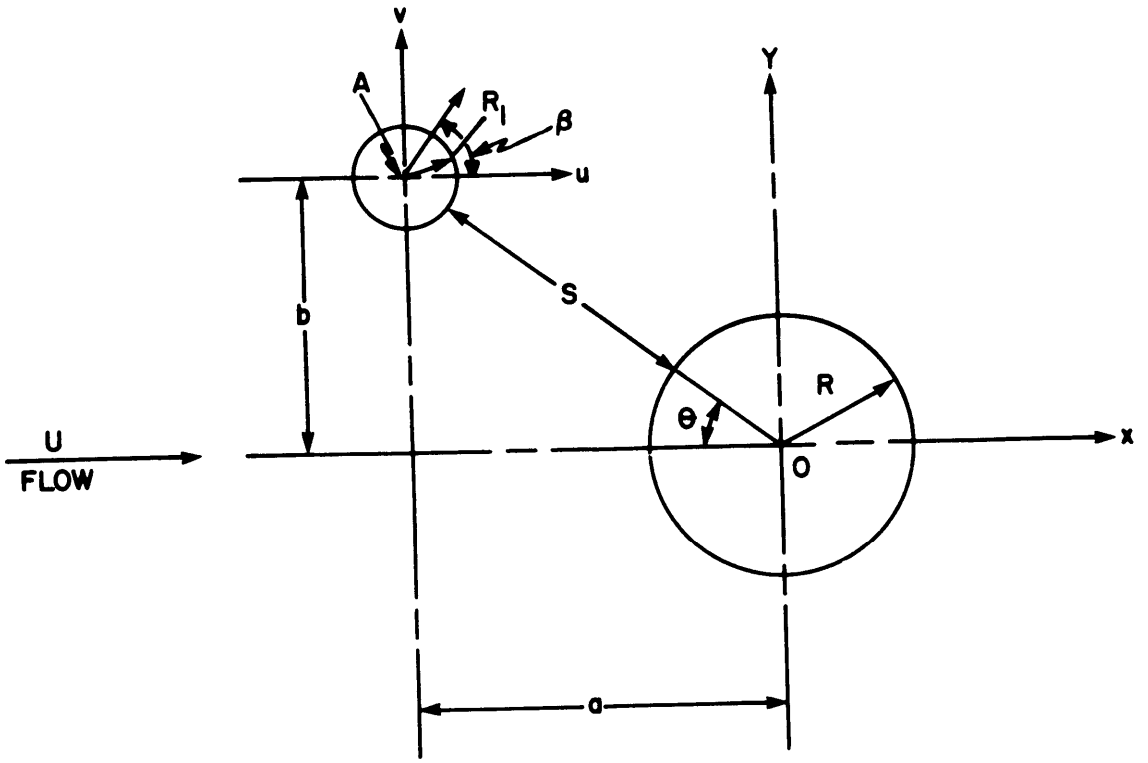


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

INTERFERENCE ON STANDARD DRAG: THREE CYLINDER SIDE-BY-SIDE ARRANGEMENT

FIGURE 3A-360

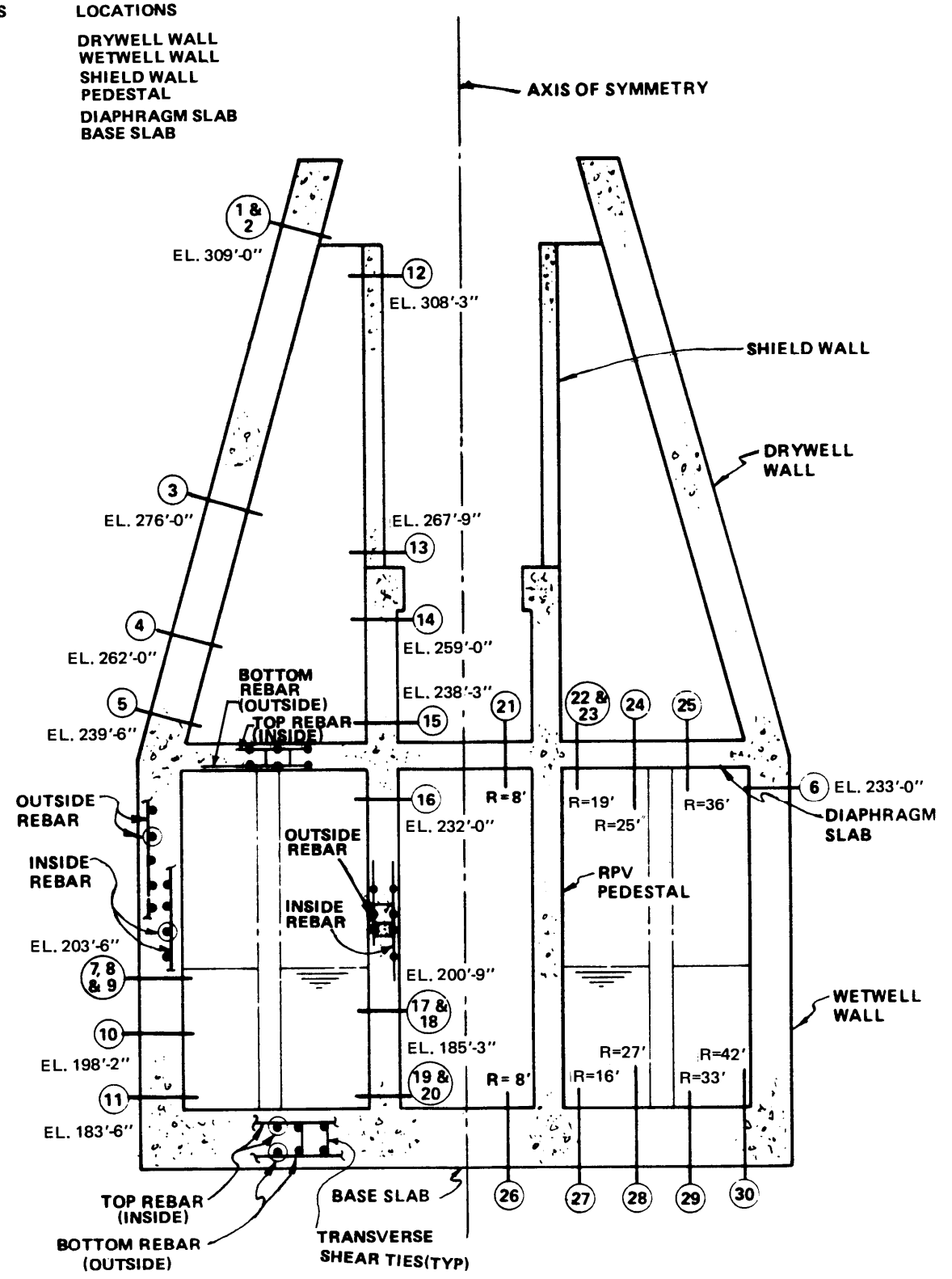


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

FLOW AROUND UNEQUAL CYLINDERS

FIGURE 3A-361



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

CONTAINMENT ASSESSMENT SECTION LOCATION

FIGURE 3A-362

DRYWELL WALL
SECTIONS: 1, 2

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)						Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER			Transverse Ties	
	Vert	Hoop	Vert	Hoop	Diag.		
1	-	-	-	-	-	-	-
3, 6	-	-	-	-	-	-	-
4, 4a 4T, 4aT	18.57 7.14	31.36 6.83	5.82 13.4	13.90 19.75	11.17 16.83	6.50 10.99	-0.233 -0.967
5, 5a, 7, 7a 5T, 5aT, 7T, 7aT	25.66 11.36	30.66 -4.66	9.95 16.34	13.45 24.41	20.82 32.46	4.60 11.67	-0.257 -1.542

NOTES:
(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 3

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)						Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER			Transverse Ties	
	Vert	Hoop	Vert	Hoop	Diag.		
1	-0.46	-0.07	-0.55	-0.04	-0.28	0.12	-0.432
3, 6	11.4	6.26	11.3	4.2	15.7	15.1	-0.200
4, 4a	9.97	43.0	14.8	19.5	17.4	11.4	-0.218
4T, 4aT	3.45	18.7	23.8	28.0	24.5	12.2	-0.926
5, 5a, 7, 7a	21.1	40.2	21.3	17.4	36.9	20.1	-0.460
5T, 5aT, 7T, 7aT	14.9	15.9	34.5	27.4	52.0	17.6	-1.38

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 4

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)						Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER			Transverse Ties	
	Vert	Hoop	Vert	Hoop	Diag.		
1	-0.55	-0.02	-0.69	0.06	-0.35	0.15	-0.097
3, 6	13.0	6.44	13.0	4.2	17.1	20.31	-0.230
4, 4a	8.49	41.7	21.8	20.9	23.2	10.8	-0.202
4T, 4aT	4.43	20.3	29.2	30.2	32.4	11.4	-0.822
5, 5a, 7, 7a	26.3	39.3	28.7	17.5	39.7	24.9	-0.522
5T, 5aT, 7T, 7aT	16.8	16.3	40.6	28.6	48.0	21.8	-1.431

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 5

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)						Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER			Transverse Ties	
	Vert	Hoop	Vert	Hoop	Diag.		
1	-0.73	1.04	-0.80	1.0	-0.35	0.16	-0.106
3, 6	15.5	10.3	14.6	5.5	20.0	18.6	-0.294
4, 4a	31.2	33.7	21.6	6.9	14.6	39.8	-0.671
4T, 4aT	22.6	13.2	24.1	24.4	22.7	36.5	-0.671
5, 5a, 7, 7a	43.6	33.2	32.8	9.5	37.6	54.0	-0.931
5T, 5aT, 7T, 7aT	30.4	9.9	45.5	22.1	47.7	46.2	-1.71

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 6

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)						Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER			Transverse Ties	
	Vert	Hoop	Vert	Hoop	Diag.		
1	-1.2	1.08	-0.76	1.7	0.63	0.161	-0.99
3, 6	16.9	17.7	16.5	4.8	20.6	0.52	-0.361
4, 4a	31.1	39.6	26.8	9.2	18.6	43.7	-0.582
4T, 4aT	26.0	48.7	26.7	8.1	28.2	35.0	-0.718
5, 5a, 7, 7a	50.1	43.1	36.0	12.9	45.7	44.8	-1.009
5T, 5aT, 7T, 7aT	24.9	48.8	53.9	26.7	47.6	27.5	-1.592

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 7, 8, 9

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)						Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER			Transverse Ties	
	Vert	Hoop	Vert	Hoop	Diag.		
1	-1.36	9.7	-1.4	4.8	2.09	0.89	-0.210
3, 6	25.5	20.3	23.3	6.8	28.4	5.3	-0.427
4, 4a	14.8	38.4	26.8	25.5	26.2	13.6	-0.616
4T, 4aT	12.8	46.2	34.6	33.0	33.8	14.0	-1.31
5, 5a, 7, 7a	37.7	37.0	47.9	21.8	48.6	15.2	-0.819
5T, 5aT, 7T, 7aT	33.2	41.0	50.0	46.3	53.9	17.3	-2.12

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 10

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)						Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER			Transverse Ties	
	Vert	Hoop	Vert	Hoop	Diag.		
1	-1.68	15.8	-1.5	7.4	3.35	1.1	-0.254
3, 6	27.5	30.7	25.5	7.58	31.1	0.70	-0.503
4, 4a	16.6	42.4	29.1	35.3	31.4	5.3	-0.744
4T, 4aT	12.2	35.6	38.0	39.7	37.9	8.13	-1.50
5, 5a, 7, 7a	37.5	40.1	43.6	27.5	50.1	6.7	-1.13
5T, 5aT, 7T, 7aT	29.4	46.7	53.8	35.6	52.4	7.4	-2.25

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 11

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)						Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER			Transverse Ties	
	Vert	Hoop	Vert	Hoop	Diag.		
1	-1.57	4.95	-1.5	2.96	1.16	2.81	-0.233
3, 6	29.8	21.2	27.1	8.48	34.3	15.3	-0.527
4, 4a	38.1	35.5	33.2	6.48	20.3	42.9	-0.703
4T, 4aT	36.1	18.5	38.2	11.2	25.1	44.5	-0.990
5, 5a, 7, 7a	53.9	32.9	46.0	9.0	45.0	45.0	-1.04
5T, 5aT, 7T, 7aT	47.2	40.6	51.2	17.0	47.4	45.4	-1.69

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 12

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER PLATE		OUTER PLATE		Transverse Ties	
	Vert	Hoop	Vert	Hoop		
1	0.39	3.6	-0.11	1.2	1.0	-0.071
3, 6	7.1	8.7	2.1	2.9	1.4	-0.293
4, 4a	2.2	9.2	-0.64	3.7	7.5	-0.265
4T, 4aT	2.0	8.8	0.81	3.3	7.5	-0.265
5, 5a, 7, 7a	8.5	12.8	2.7	5.1	9.5	-0.407
5T, 5aT, 7T, 7aT	8.3	12.4	2.5	4.7	9.5	-0.407

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 13

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER PLATE		OUTER PLATE		Transverse Ties	
	Vert	Hoop	Vert	Hoop		
1	-0.28	0.08	-0.57	-0.10	0.128	-0.077
3, 6	9.7	3.5	2.9	1.1	0.63	-0.404
4, 4a	-0.65	0.29	-0.94	-0.15	0.26	-0.128
4T, 4aT	-1.45	-1.73	-0.53	1.03	0.26	-0.128
5, 5a, 7, 7a	10.7	3.6	2.9	1.1	2.4	-0.444
5T, 5aT, 7T, 7aT	9.9	1.9	3.3	2.1	2.4	-0.444

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 14

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER		Transverse Ties	
	Radial	Hoop	Radial	Hoop		
1	-1.0	1.0	-1.2	1.2	0.34	-0.157
3, 6	17.2	13.4	29.2	17.4	3.9	-0.352
4, 4a	-1.3	2.4	-1.7	2.0	0.31	-0.230
4T, 4aT	7.98	7.0	-2.31	4.97	0.31	-0.230
5, 5a, 7, 7a	17.2	14.7	25.6	17.2	3.3	-0.432
5T, 5aT, 7T, 7aT	25.7	19.3	25.0	20.2	3.3	-0.432

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 15

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER		Transverse Ties	
	Radial	Hoop	Radial	Hoop		
1	-1.5	0.94	-2.2	0.32	0.35	-0.290
3, 6	43.9	27.2	52.5	33.6	4.7	-0.649
4, 4a 4T, 4aT	4.5 14.5	32.2 -4.8	6.1 4.9	47.0 -5.9	21.1 48.3	-0.474 -0.910
5, 5a, 7, 7a 5T, 5aT, 7T, 7aT	52.9 49.9	50.1 8.2	52.9 51.9	51.8 -4.0	39.4 27.4	-0.856 -1.017

NOTES:
(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 16

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER		Transverse Ties	
	Radial	Hoop	Radial	Hoop		
1	-1.5	1.1	-2.0	3.1	0.34	-0.266
3, 6	30.3	13.02	39.4	29.1	0.86	-0.526
4, 4a 4T, 4aT	6.9 13.3	12.6 13.3	4.8 5.7	30.4 28.0	7.9 15.0	-0.678 -1.051
5, 5a, 7, 7a 5T, 5aT, 7T, 7aT	45.0 37.3	26.1 16.0	42.7 22.7	36.8 15.5	19.6 27.9	-0.931 -1.249

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 17, 18

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER		Transverse Ties	
	Radial	Hoop	Radial	Hoop		
1	-2.1	5.0	-2.7	12.9	9.0	-0.382
3, 6	9.9	8.5	10.5	17.0	12.9	-0.690
4, 4a	-4.1	11.9	-4.8	28.3	17.0	-0.681
4T, 4aT	4.13	13.8	-4.3	28.9	26.8	-0.635
5, 5a, 7, 7a	18.6	15.7	20.5	29.8	22.5	-1.017
5T, 5aT, 7T, 7aT	23.0	22.1	22.0	32.6	38.9	-0.968

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 19, 20

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER		Transverse Ties	
	Radial	Hoop	Radial	Hoop		
1	-2.01	-0.176	-2.95	0.27	0.59	-0.424
3, 6	17.9	5.26	11.8	5.4	4.7	-0.483
4, 4a	4.86	3.69	-5.2	7.1	5.68	-0.744
4T, 4aT	5.2	-6.1	-5.39	-4.8	5.68	-0.744
5, 5a, 7, 7a	25.9	7.2	32.5	12.8	15.9	-0.851
5T, 5aT, 7T, 7aT	26.2	-5.8	32.3	8.2	15.9	-0.851

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 21

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER		Transverse Ties	
	Radial	Hoop	Radial	Hoop		
1	-	-	-	-	-	-
3, 6	8.5	8.6	6.9	7.7	1.01	-0.073
4, 4a 4T, 4aT	38.8 32.8	30.2 21.6	28.9 35.9	22.7 27.6	8.8 9.5	-0.374 -1.82
5, 5a, 7, 7a 5T, 5aT, 7T, 7aT	35.6 31.7	30.1 21.5	29.3 34.6	23.3 28.0	8.8 8.9	-0.365 -1.83

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 22, 23

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER		Transverse Ties	
	Radial	Hoop	Radial	Hoop		
1	-	-	-	-	-	-
3, 6	7.9	9.5	10.2	13.0	4.46	-0.370
4, 4a 4T, 4aT	14.1 -11.1	21.5 12.3	18.4 26.2	24.2 29.8	16.1 7.0	-0.383 -1.367
5, 5a, 7, 7a 5T, 5aT, 7T, 7aT	16.4 -13.1	23.1 16.0	23.7 25.5	27.9 35.9	18.0 7.2	-0.623 -1.727

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DRYWELL WALL
SECTIONS: 24

Load Combination Equation (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER		Transverse Ties	
	Radial	Hoop	Radial	Hoop		
1	-	-	-	-	-	-
3, 6	10.2	9.6	9.1	8.0	3.0	-0.272
4, 4a 4T, 4aT	22.8 -8.61	22.6 -8.29	30.5 33.2	21.1 29.4	5.9 4.2	-0.842 -1.59
5, 5a, 7, 7a 5T, 5aT, 7T, 7aT	27.9 -10.3	25.4 12.3	33.4 35.5	24.4 30.8	6.2 4.9	-0.931 -1.738

NOTES:

(1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

(5) Values reflect analysis with an initial Drywell air temperature of 135°F. Increasing this temperature to 150°F does not adversely impact the results of this Design Assessment Report.

DIAPHRAGM SLAB
SECTION: 25

Load Combination Equations (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER		Transverse Ties	
	Radial	Hoop	Radial	Hoop		
1	-	-	-	-	-	-
3, 6	13.0	15.5	12.1	14.5	0.66	-.157
4, 4a	26.7	28.0	23.5	30.6	9.9	-.336
4T, 4aT	12.9	24.0	26.1	35.4	6.5	-2.04
5, 5a, 7, 7a	33.6	38.5	28.6	35.9	10.4	-.423
5T, 5aT, 7T, 7aT	19.3	31.8	41.1	42.4	9.5	-2.40

NOTES: (1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

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DESIGN ASSESSMENT REPORT
CONTAINMENT STRESSES
DIAPHRAGM SLAB

FIGURE 3A-381

BASE SLAB
SECTION: 26

Load Combination Equations (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stabs, KSI (2)(3)
	INNER		OUTER		Transverse Ties	
	Radial	Hoop	Radial	Hoop		
1	-	-	-	-	-	-
3, 6	1.7	16.6	5.93	6.22	5.29	-0.318
4, 4a	2.72	1.61	7.10	3.29	0.43	-0.213
4T, 4aT	-5.21	-5.63	15.2	14.9	3.4	-1.21
5, 5a, 7, 7a	10.9	20.7	10.4	9.51	4.03	-0.443
5T, 5aT, 7T, 7aT	-6.36	-4.95	18.4	17.3	3.12	-1.34

NOTES: (1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

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DESIGN ASSESSMENT REPORT
CONTAINMENT STRESSES
BASE SLAB

FIGURE 3A-382

BASE SLAB
SECTION: 27

Load Combination Equations (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER		Transverse Ties	
	Radial	Hoop	Radial	Hoop		
1	-	-	-	-	-	-
3, 6	25.4	26.8	15.5	6.43	24.7	-0.479
4, 4a	10.3	-0.43	11.1	0.65	23.9	-0.309
4T, 4aT	22.4	-7.3	29.8	13.3	33.1	-1.70
5, 5a, 7, 7a	39.8	34.4	29.3	13.9	41.0	-0.540
5T, 5aT, 7T, 7aT	30.0	20.2	29.0	17.1	39.8	-1.79

NOTES: (1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table **3A-14**, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

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DESIGN ASSESSMENT REPORT
CONTAINMENT STRESSES
BASE SLAB

FIGURE 3A-383

BASE SLAB
SECTION: 28

Load Combination Equations (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER		Transverse Ties	
	Radial	Hoop	Radial	Hoop		
1	-	-	-	-	-	-
3, 6	34.0	17.8	11.1	10.6	17.5	-0.910
4, 4a	21.7	9.15	16.9	8.7	12.5	-0.304
4T, 4aT	-8.25	-8.07	17.7	13.4	6.7	-1.59
5, 5a, 7, 7a	42.1	21.2	18.2	16.1	25.2	-0.985
5T, 5aT, 7T, 7aT	25.4	-8.4	23.7	19.8	18.7	-1.72

NOTES: (1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table 3A-14, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

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DESIGN ASSESSMENT REPORT
CONTAINMENT STRESSES
BASE SLAB

FIGURE 3A-384

BASE SLAB
SECTION: 29

Load Combination Equations (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER		Transverse Ties	
	Radial	Hoop	Radial	Hoop		
1	-	-	-	-	-	-
3, 6	12.7	15.6	9.01	8.52	11.1	-0.524
4, 4a	11.8	9.51	17.3	7.95	11.0	-0.243
4T, 4aT	9.32	-6.40	20.6	12.6	12.0	-1.23
5, 5a, 7, 7a	17.7	18.9	19.0	13.3	18.5	-0.508
5T, 5aT, 7T, 7aT	14.4	-6.22	21.5	16.1	18.9	-1.18

NOTES: (1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table **3A-14**, 4T, 4aT, 5T, 5aT, 7T, 7aT include thermal components.

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CONTAINMENT STRESSES
BASE SLAB

FIGURE 3A-385

BASE SLAB
SECTION: 30

Load Combination Equations (4)	MAXIMUM REBAR STRESSES, KSI (1)(3)					Max. Concrete Stress, KSI (2)(3)
	INNER		OUTER		Transverse Ties	
	Radial	Hoop	Radial	Hoop		
1	-	-	-	-	-	-
3, 6	9.32	16.9	9.14	8.54	7.0	-0.414
4, 4a	29.9	33.5	34.1	10.2	25.6	-0.430
4T, 4aT	29.2	5.5	38.5	12.9	27.4	-0.902
5, 5a, 7, 7a	23.9	36.5	32.9	16.6	28.4	-0.688
5T, 5aT, 7T, 7aT	22.5	-6.36	36.5	19.6	28.9	-0.915

NOTES: (1) Allowable Reinforcing Steel Stress = 54 KSI

(2) Allowable Concrete Compressive Stress = 3.4 KSI

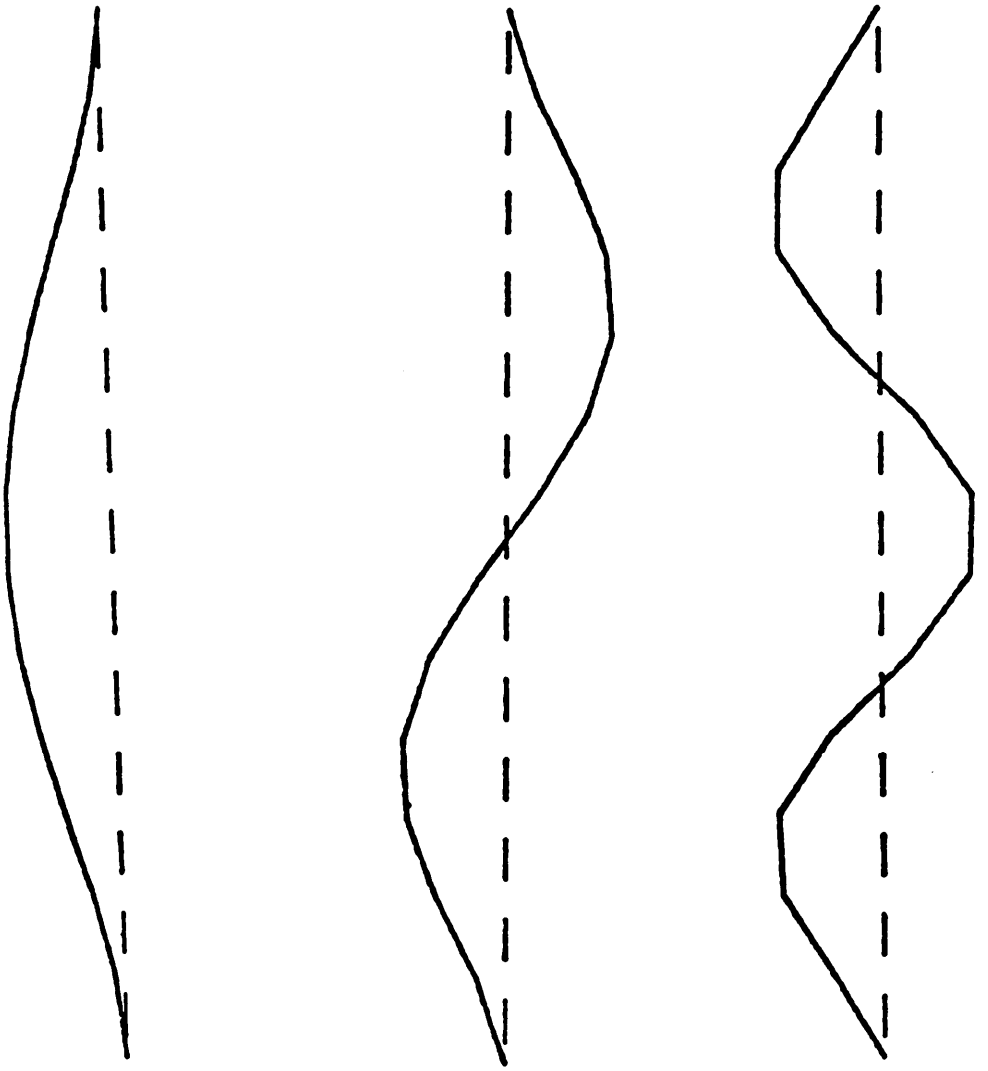
(3) "+" for Tensile Stress; "-" for Compressive Stress

(4) Load Combination Equations are taken from Table **3A-14**, 4T, 4aT, 5T, 5aT, 7T, 7aT include Thermal Components.

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CONTAINMENT STRESSES
BASE SLAB

FIGURE 3A-386



MODE 1
f=20 HZ

MODE 2
f=53 HZ

MODE 3
f=93 HZ

(WITH WATER MASS)

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SUPPRESSION CHAMBER COLUMNS MODE SHAPES

FIGURE 3A-387

SUPPRESSION CHAMBER COLUMNS

COLUMN	MAXIMUM AXIAL STRESS (KSI)	ALLOWABLE AXIAL STRESS (KSI)	MAXIMUM FLEXURAL STRESS (KSI)	ALLOWABLE FLEXURAL STRESS (KSI)	COMBINED STRESS RATIO	STRESS MARGIN %
42" dia pipe (shell element)	11.7	27.3	8.7	28.0	0.74	26
Top Anchorage	22.6	29.9	-	-	0.76	24
Bottom Anchorage	-	-	-	-	-	10

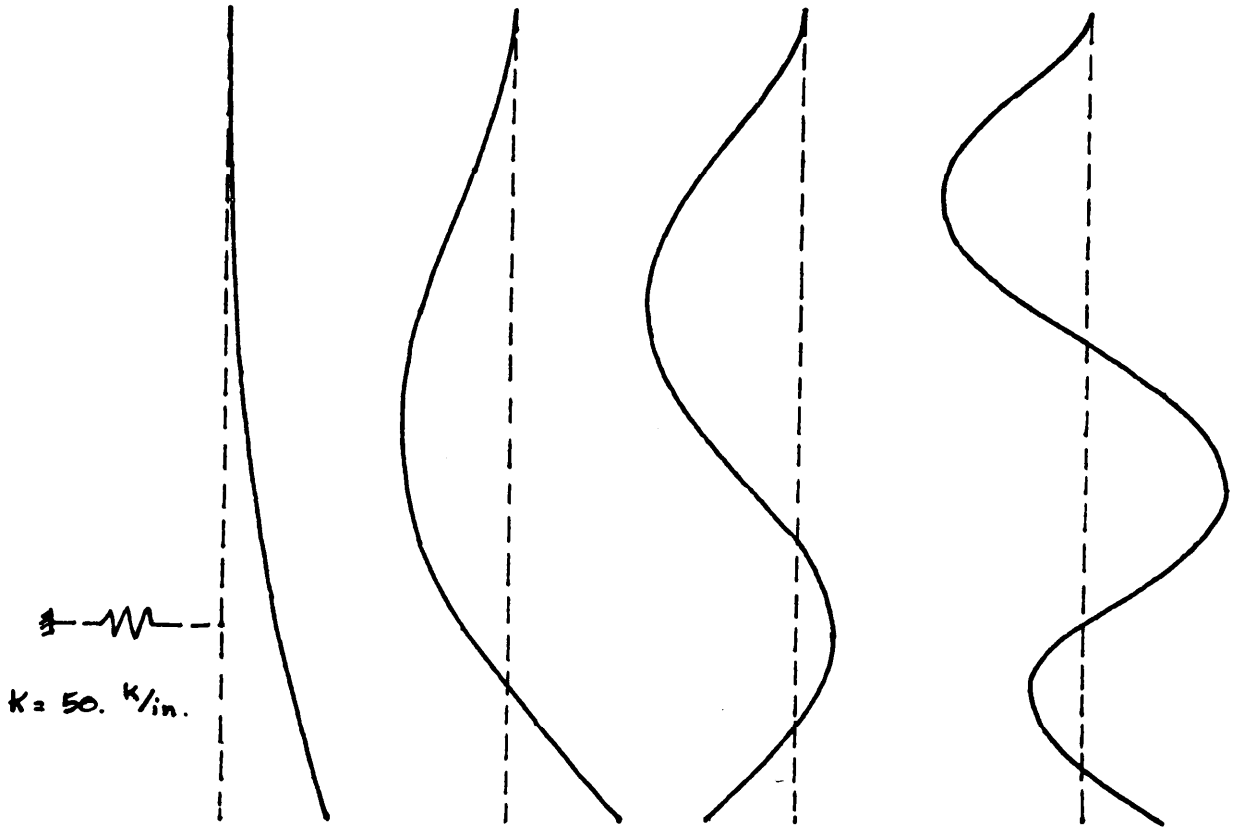
NOTE: These stress margins are based on load combination 7 of Table 3A-15 which is the critical load combination.

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SUPPRESSION CHAMBER COLUMNS DESIGN MARGIN

FIGURE 3A-388

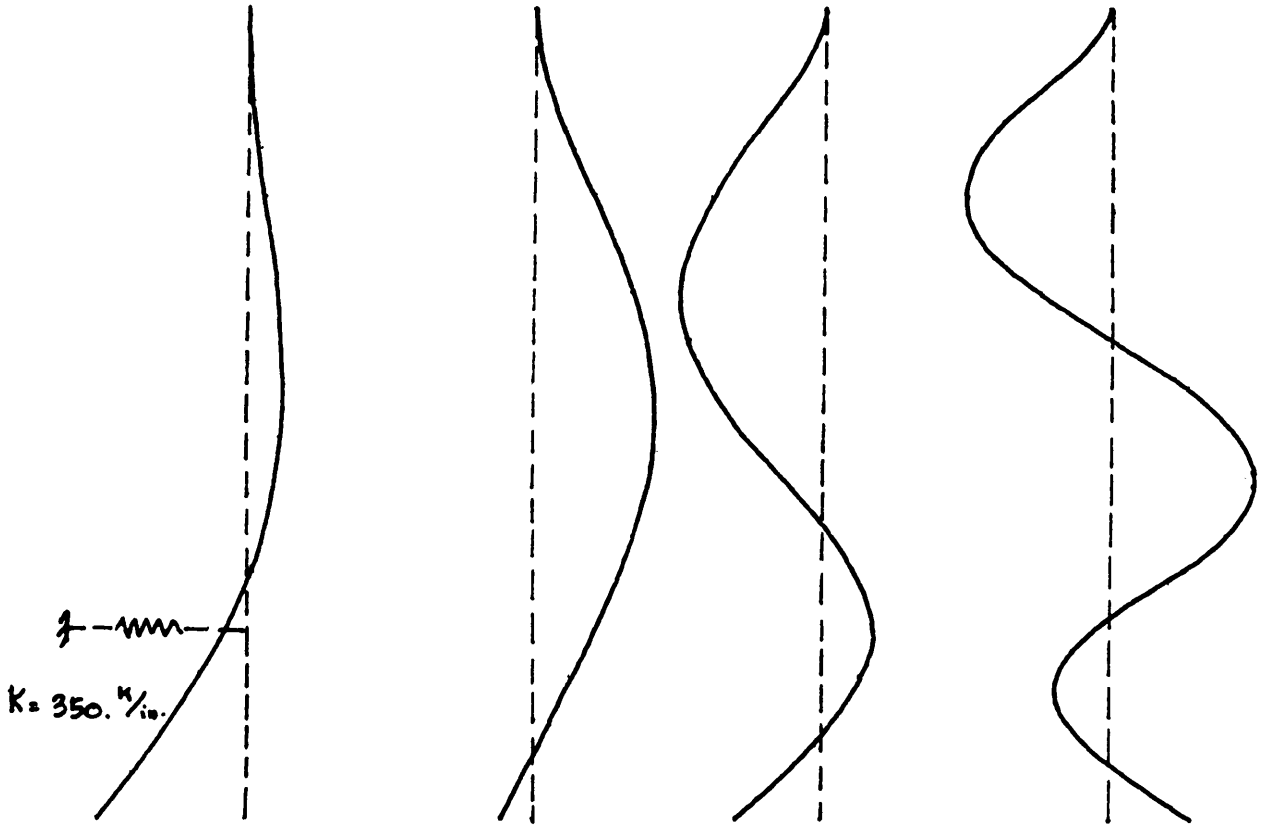


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DOWNCOMER MODE SHAPES, K = 50k/in

FIGURE 3A-389

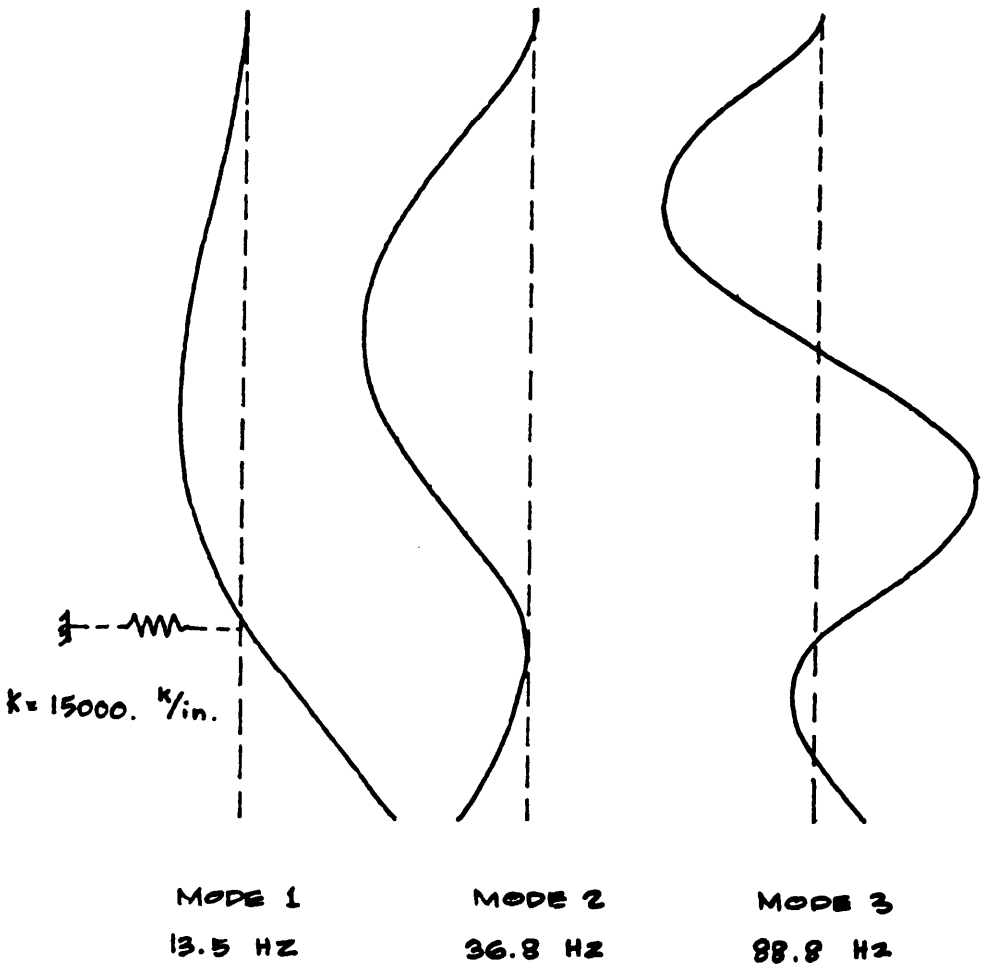


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DOWNCOMER MODE SHAPES, K = 350k/in

FIGURE 3A-390



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DOWNCOMER MODE SHAPES, K = 15000k/in

FIGURE 3A-391

DOWNCOMER - STRESS SUMMARY AND DESIGN MARGINS

LOAD COMBINATION	CONDITION	ALLOWABLE STRESS (KSI)	STRESS (KSI)	DESIGN MARGIN (%)
Equation 1	Upset	28.4	17.5	38.4
Equation 2	Emergency	42.5	19.9	53.2
Equation 3	Emergency	42.5	37.4	12.0
Equation 4	Faulted	56.7	20.0	64.7
Equation 5	Faulted	56.7	37.4	34.0
Equation 6	Faulted	56.7	37.5	33.9
Equation 7	Faulted	56.7	24.5	56.8

NOTE: Equation numbers are based on Table 3A-17.

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DOWNCOMER DESIGN MARGIN

FIGURE 3A-392

USAGE FACTOR SUMMARY OF DOWNCOMERS

LOADS	NORMAL/UPSET CONDITION				EMERGENCY/FAULTED CONDITIONS			CUMULATIVE USAGE
	± OBE ± SRV_1 ± SRV_2	± SRV_1 ± SRV_2 ± CHUG	± SRV_1 ± SRV_2	± SRV_1	SBA o PRESSURE o THERMAL TRANSIENT o STEAM FLOW ± CHUG ± SRV_1 ± SRV_2	IBA OR SBA o PRESSURE o THERMAL TRANSIENT o STEAM FLOW ± CHUG ± SRV_1 ± SRV_2 ± SSE	DBA o PRESSURE o THERMAL TRANSIENT o STEAM FLOW ± CHUG ± SSE	
AT PLATFORM RING	0.001	0.600	0.116	0.080	0.003			0.80
AT 24" x 24" VACUUM BREAKER TEE	0.002	0.194	0.160	0.151	0.001			0.51
AT PIPE ATTACHMENT (1) ELEV. 221'-0"	0.001	0.545	0.078	0.071	0.003			0.70

(1) ORIGINAL LOCATION OF VACUUM BREAKER (ABANDONED)

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DOWNCOMER FATIGUE USAGE FACTOR

FIGURE 3A-393

STRESS CYCLES FOR FATIGUE EVALUATION OF DOWNCOMERS

LOAD TYPE	No. OF CYCLES
N_{SRV1}	14100
N_{SRV2}	7700
N_{OBE}	50
N_{CHUG}	3000
N_{SSE}	10

N_{OBE} = Cycles associated with OBE
N_{SRV1} = Cycles associated with SRV_1 (Submerged Structure Load)
N_{SRV2} = Cycles associated with SRV_2 (Inertia)
N_{CHUG} = Cycles associated with Chugging
N_{SSE} = Cycles associated with SSE

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DOWNCOMER FATIGUE CYCLES

FIGURE 3A-394

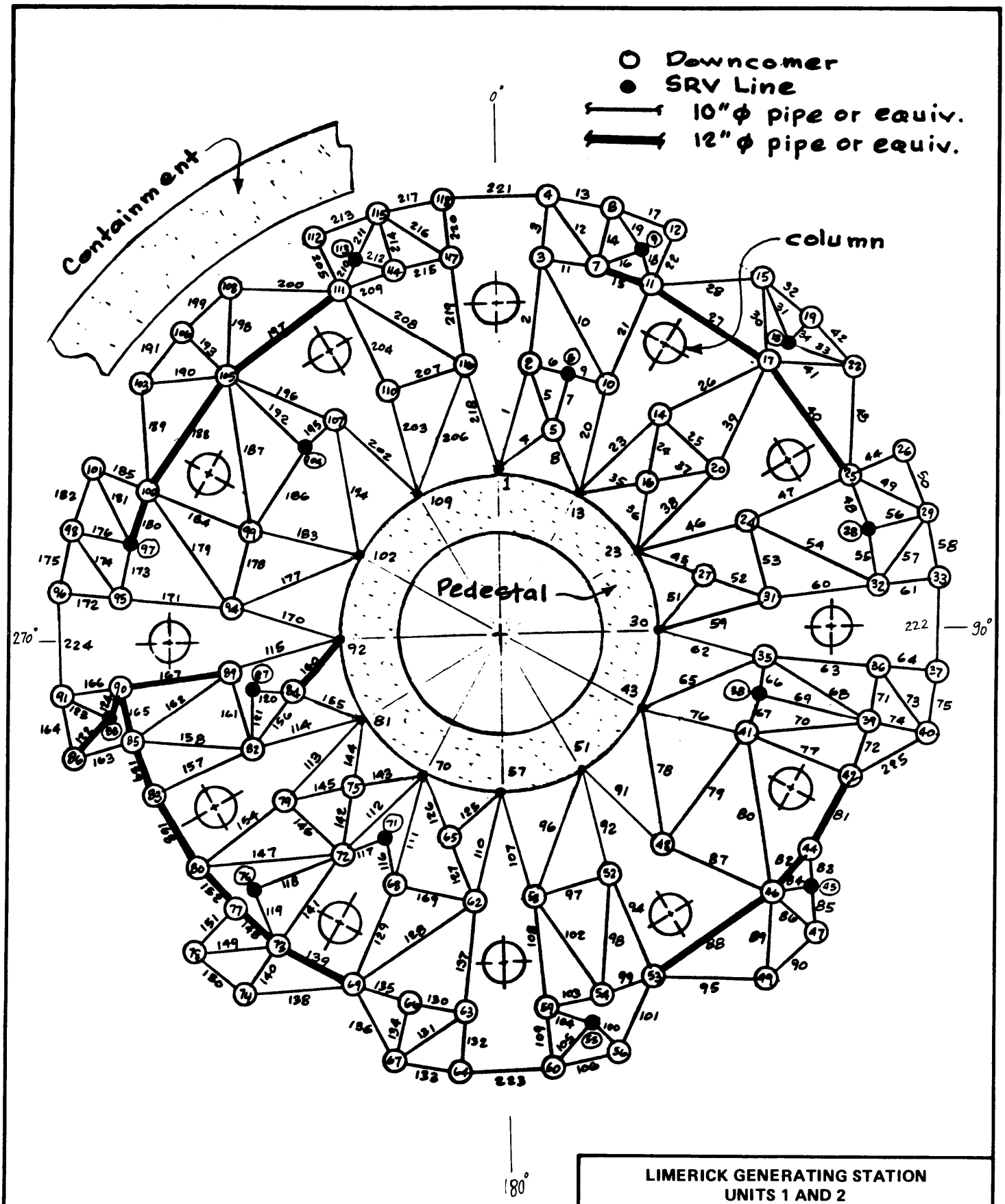
FATIGUE LOAD HISTOGRAM FOR DOWNCOMERS

NORMAL/UPSET CONDITION				EMERGENCY	FAULTED	
				SBA	IBA or SBA	DBA
± OBE ± SRV_1 ± SRV_2	± SRV_1 ± SRV_2 ± CHUG	± SRV_1 ± SRV_2	± SRV_1	° Pressure ° Thermal Transient ° Steam Flow ± CHUG ± SRV_1 ± SRV_2	° Pressure ° Thermal Transient ° Steam Flow ± CHUG ± SRV_1 ± SRV_2 ± SSE	° Pressure ° Thermal Transient ° Steam Flow ± CHUG ± SSE
1 2	3 4	5 6	7 8	9 10	9 10	9 10
50 cycles	3000 cycles	4650 cycles	6400 cycles	Load set pair 9-10 is for one of the three above events which produce the largest combined stress. The cycles associated with oscillatory loads combined with SSE are assumed conservatively to be 10.		

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DOWNCOMER FATIGUE HISTOGRAM

FIGURE 3A-395



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DESIGN ASSESSMENT REPORT

DOWNCOMER BRACING MATHEMATICAL MODEL

FIGURE 3A-396

DOWNCOMER BRACING SYSTEM - STRESS SUMMARY

BRACING MEMBER DESIGN MARGINS FOR CRITICAL MEMBERS AND GOVERNING LOAD COMBINATION

QUADRANT(2)	MEMBER(2)	EQUATION(1)	MARGIN - %
1	58	7	5%
2	75	7	6%
3	126	7	5%
4	217	7	4%
Link between Quadrants	221	7	3%

NOTES: (1) Equation number is based on Table 3A-15

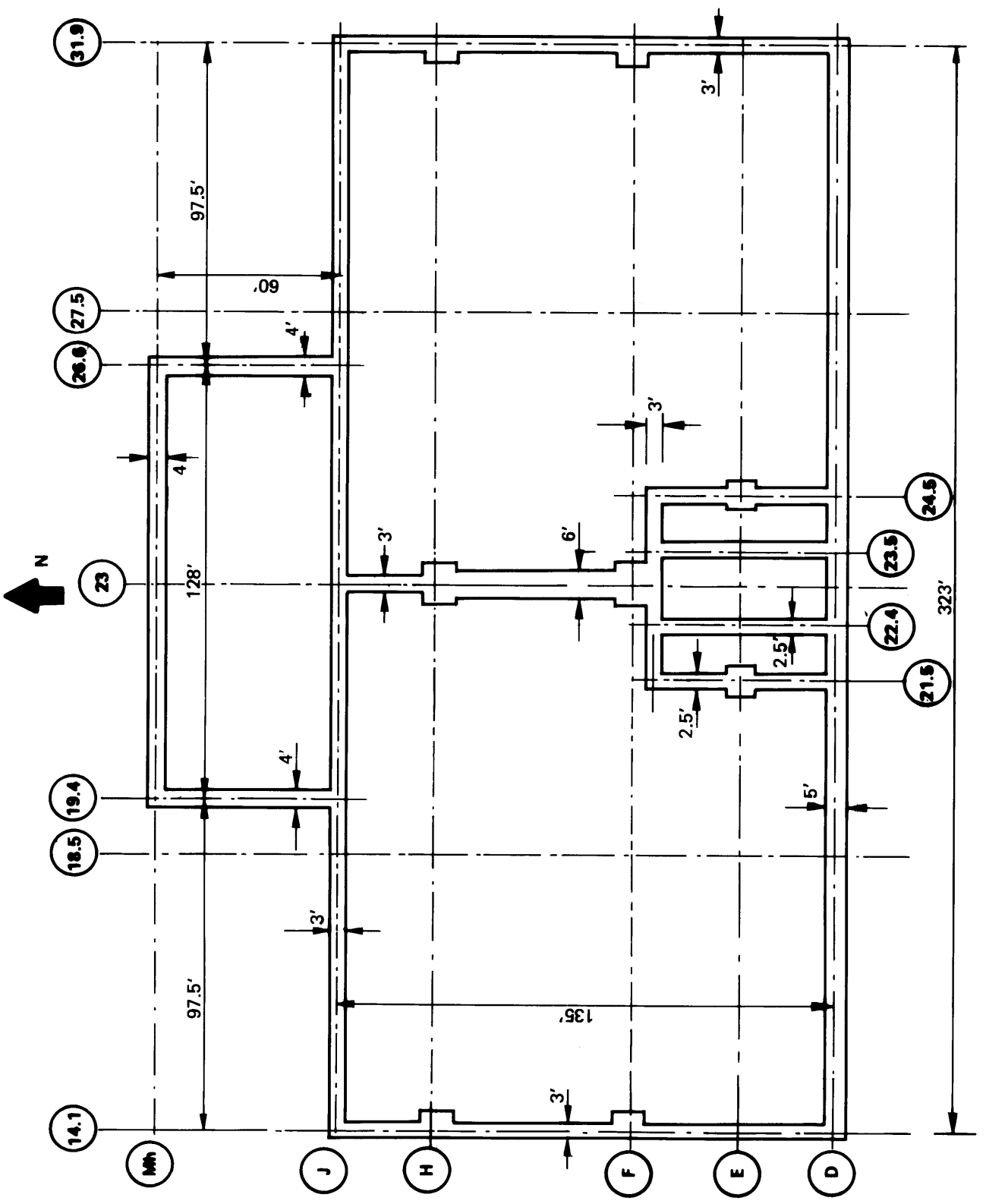
(2) Figure 3A-396 gives location reference

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DOWNCOMER BRACING SYSTEM DESIGN MARGIN

FIGURE 3A-397

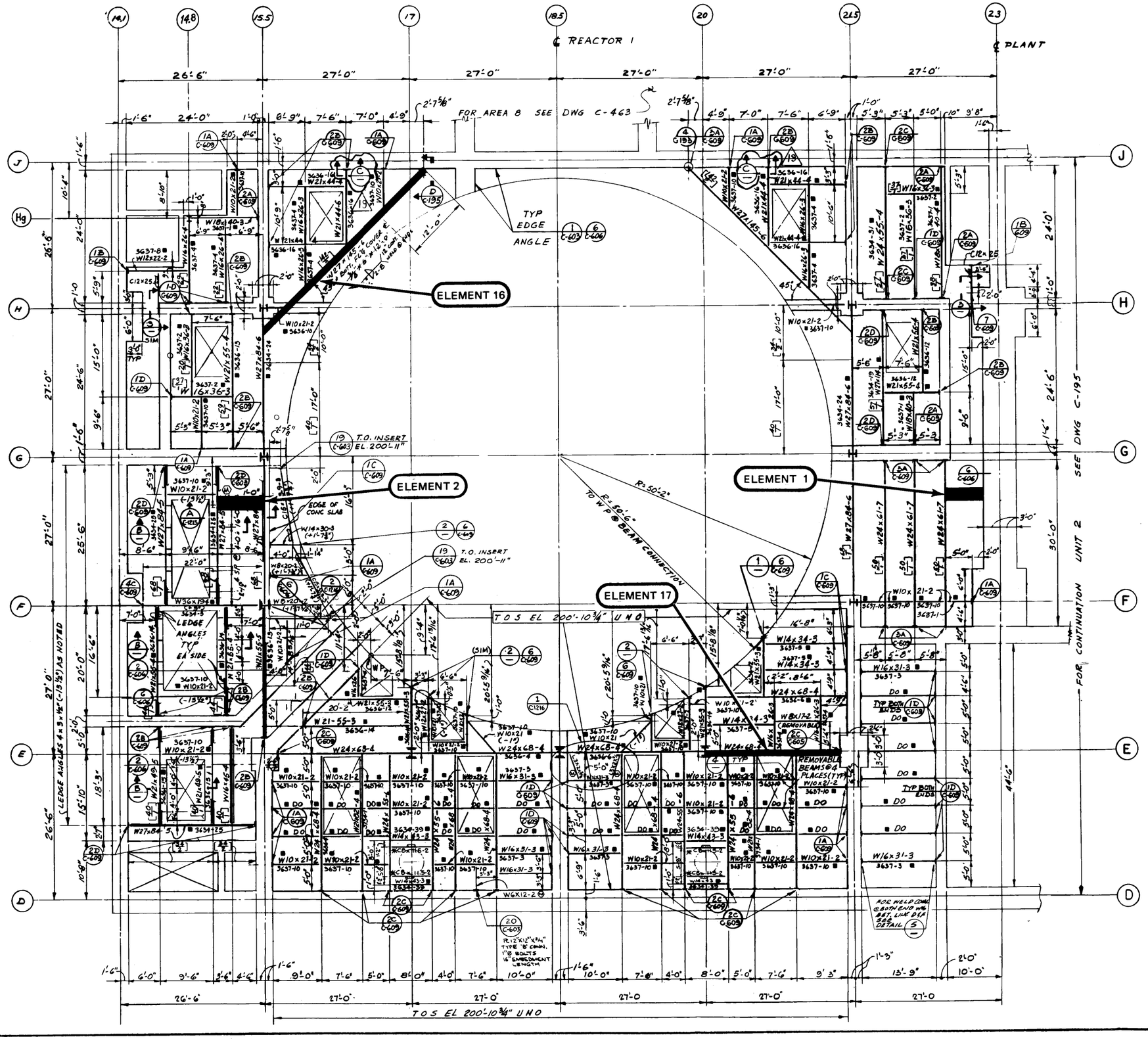


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE & CONTROL STRUCTURE FLOOR PLAN AT ELEVATION 177 FT.

FIGURE 3A-398



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
REACTOR ENCLOSURE
STEEL FRAMING PLAN
EL. 201'

FIGURE 3A-399

REACTOR — UNIT 1

ELEMENT 3

ELEMENT 4

ELEMENT 18

ELEMENT 19

NOTE: DECKING SHALL NOT BE WELDED OR ATTACHED TO THE W27 / W16 IN THIS AREA

LEDGE ANGLE EA. SIDE TYP. SEE DET. 9 C-193

LEDGE ANGLE THIS SIDE ONLY

TYP EDGE ANGLE 1 C-403 6 C-406

INDICATES LEDGE ANGLE EA. SIDE TYP SEE DET. 9 C-193

INDICATES LEDGE ANGLES TYP

SIM TO DET 4 C-193

DET 10 C-193 TYP

PIPE SUPPORT 7 C-216

TYP BOTH ENDS

T.O.S. EL. 215'-3" UNLESS NOTED

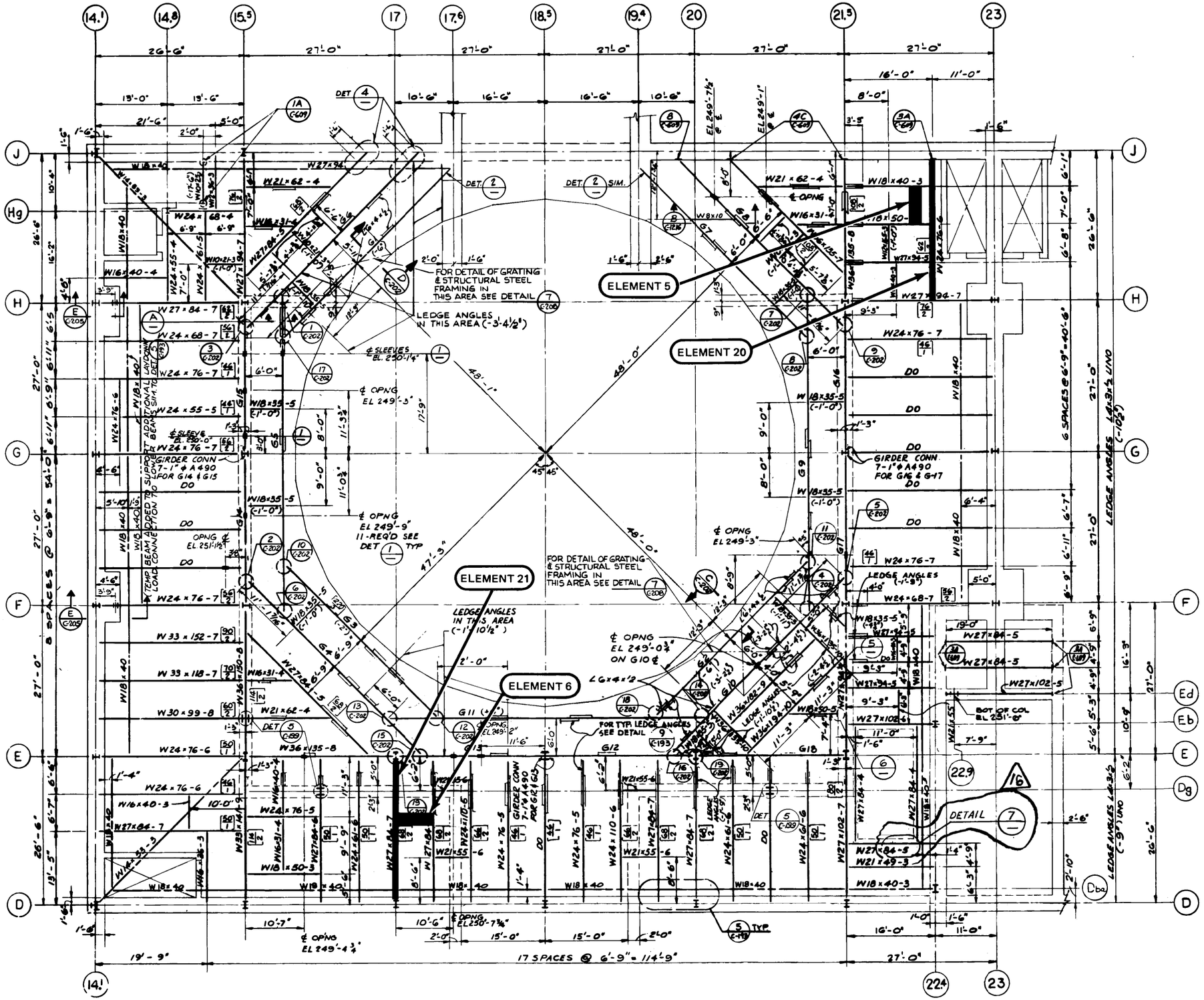
T.O.S. EL. 214'-9" UNLESS NOTED

MATCH LINE FOR UNIT #2 SEE DWG. C-198

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
REACTOR ENCLOSURE
STEEL FRAMING PLAN
EL. 217'

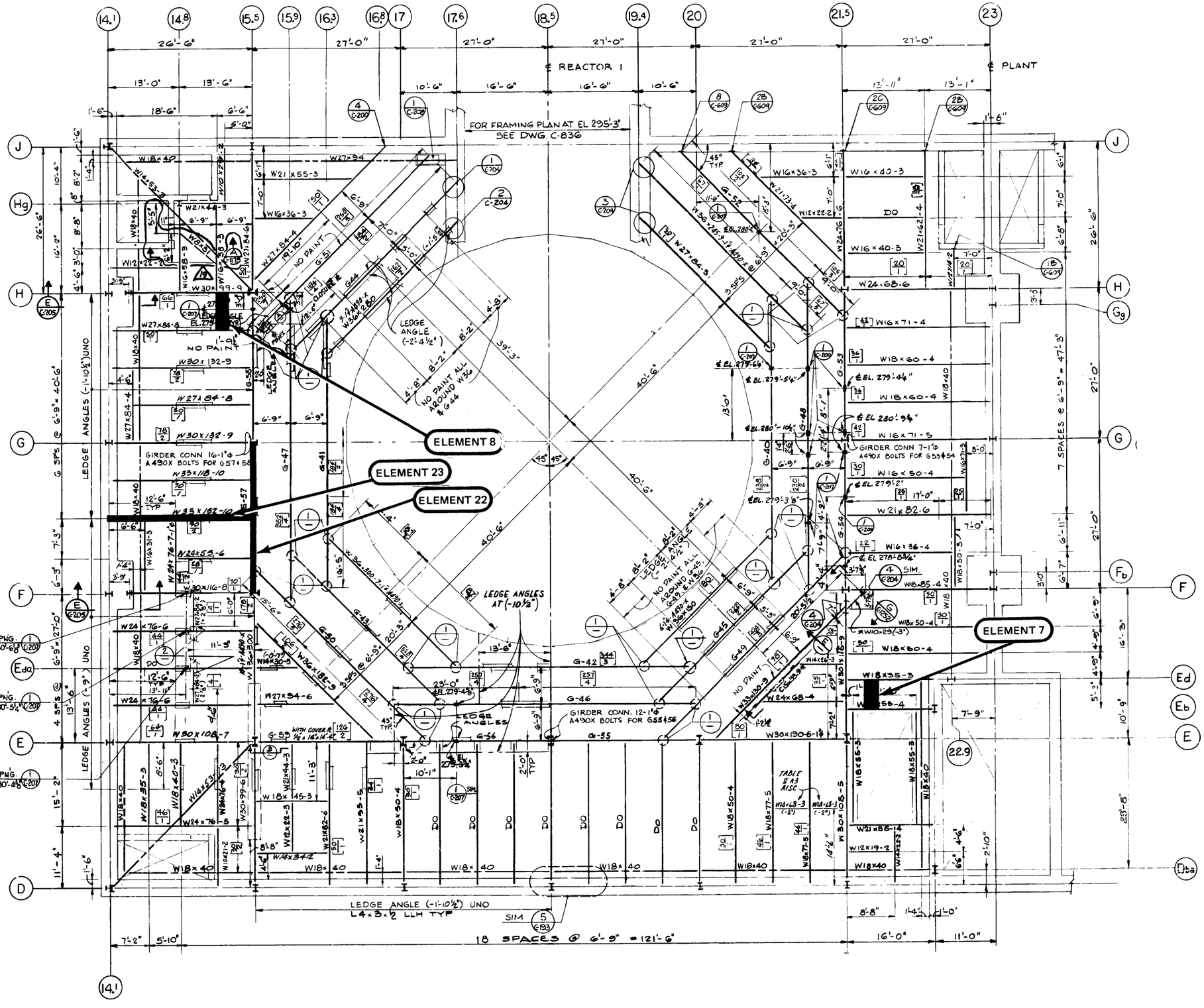
FIGURE 3A-400



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
REACTOR ENCLOSURE
STEEL FRAMING PLAN
EL. 253'

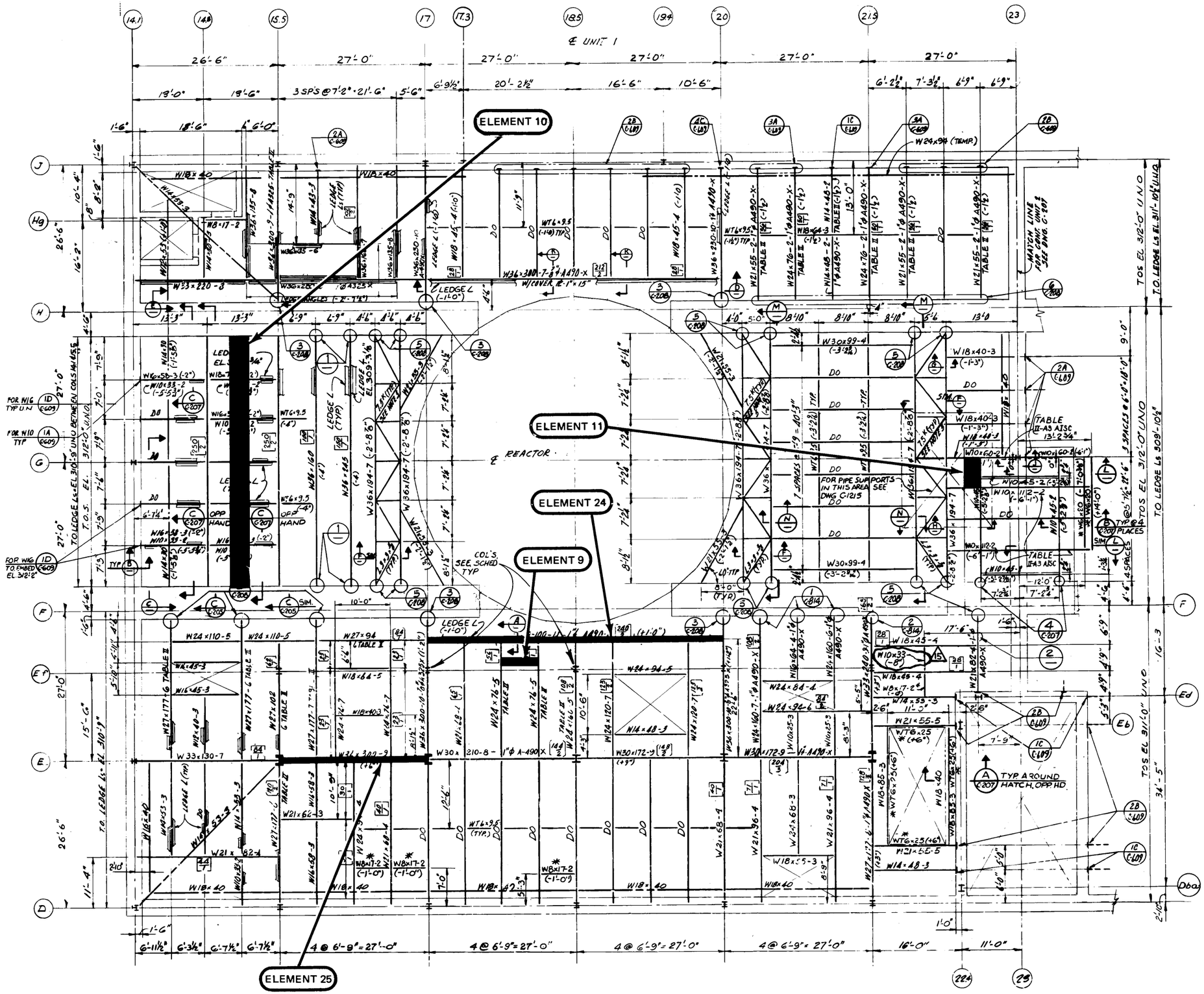
FIGURE 3A-401



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
REACTOR ENCLOSURE
STEEL FRAMING PLAN
EL. 283'

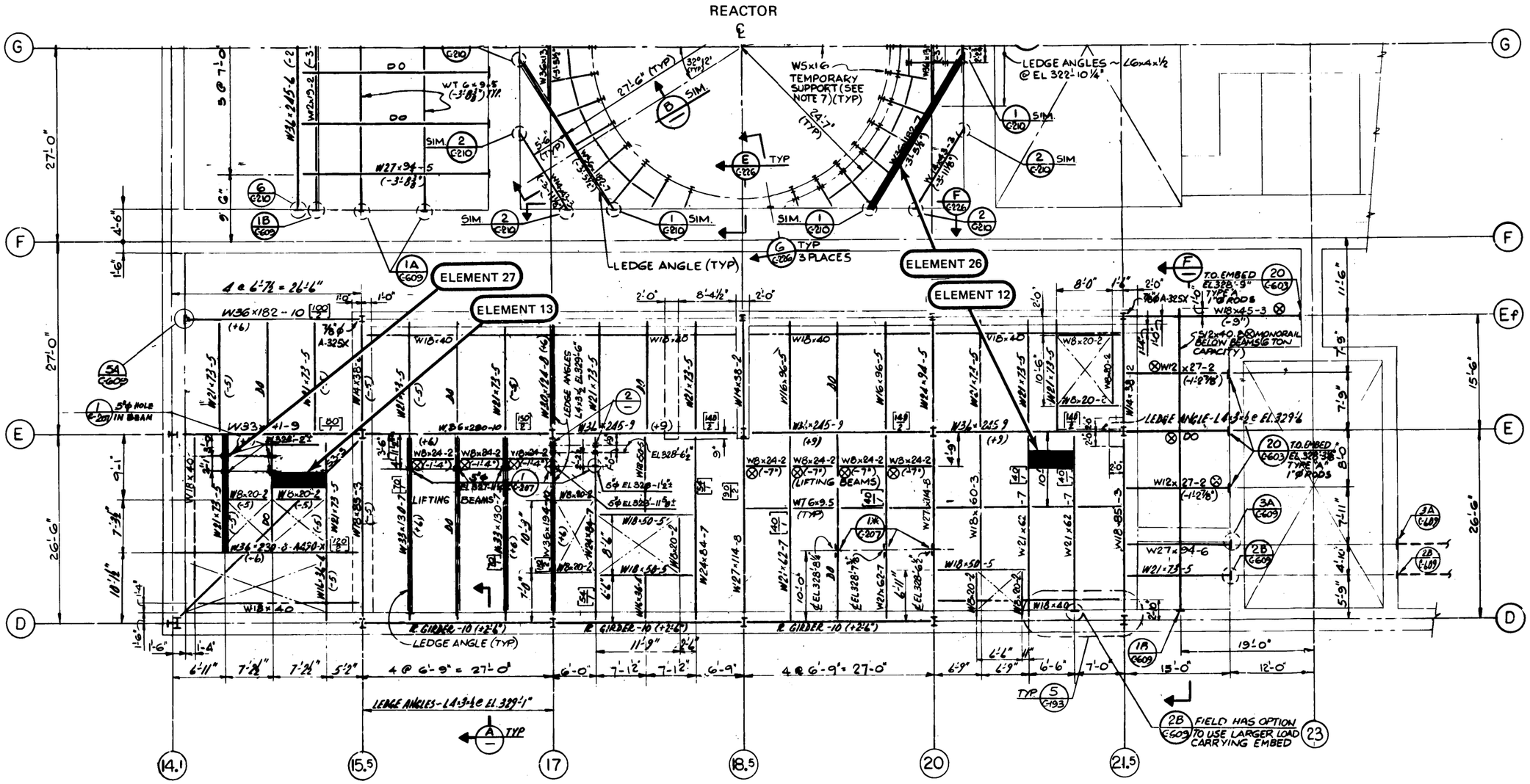
FIGURE 3A-402



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
REACTOR ENCLOSURE
STEEL FRAMING PLAN
EL. 313'

FIGURE 3A-403

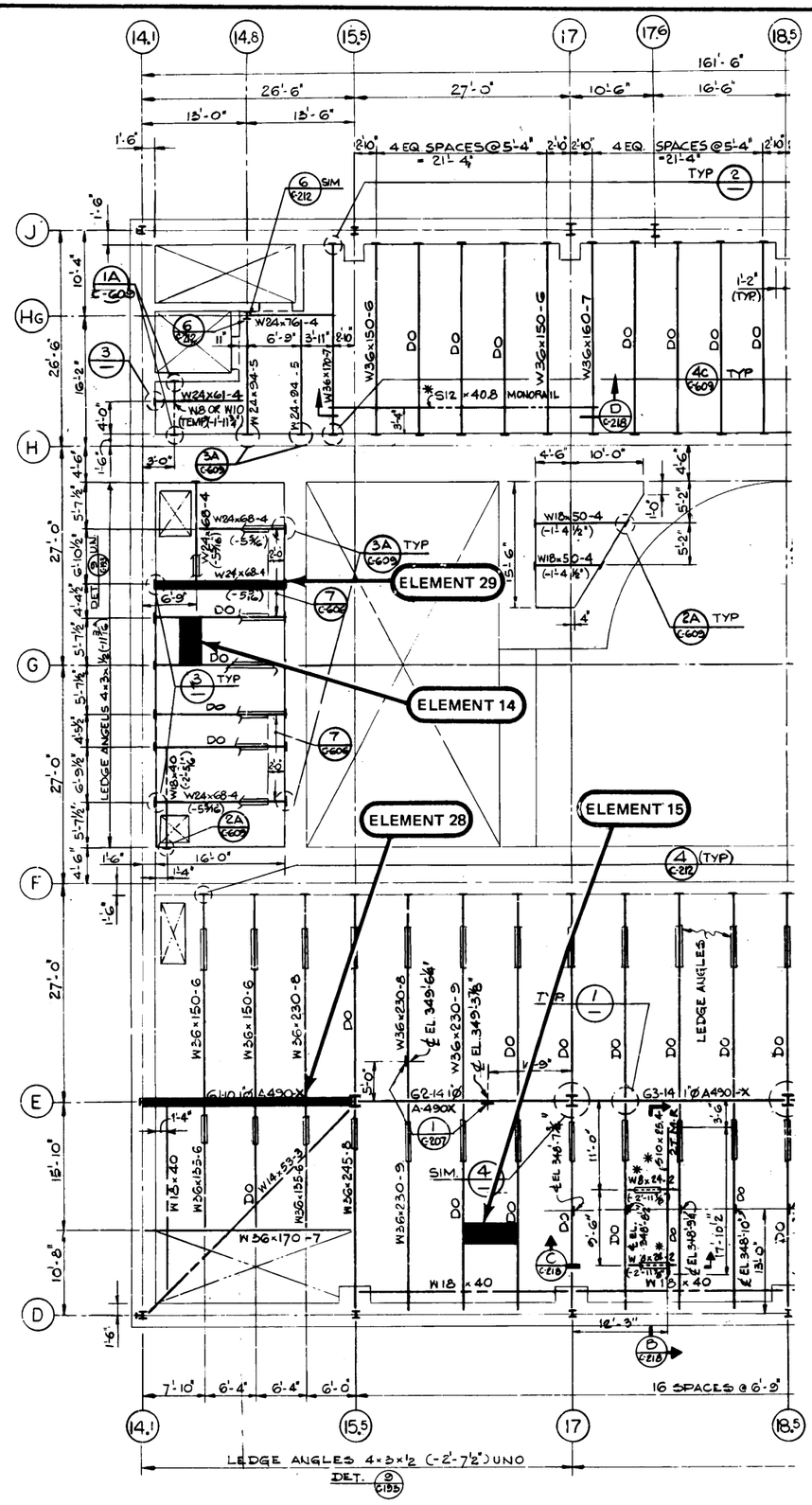


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE STEEL FRAMING PLAN EL. 331'

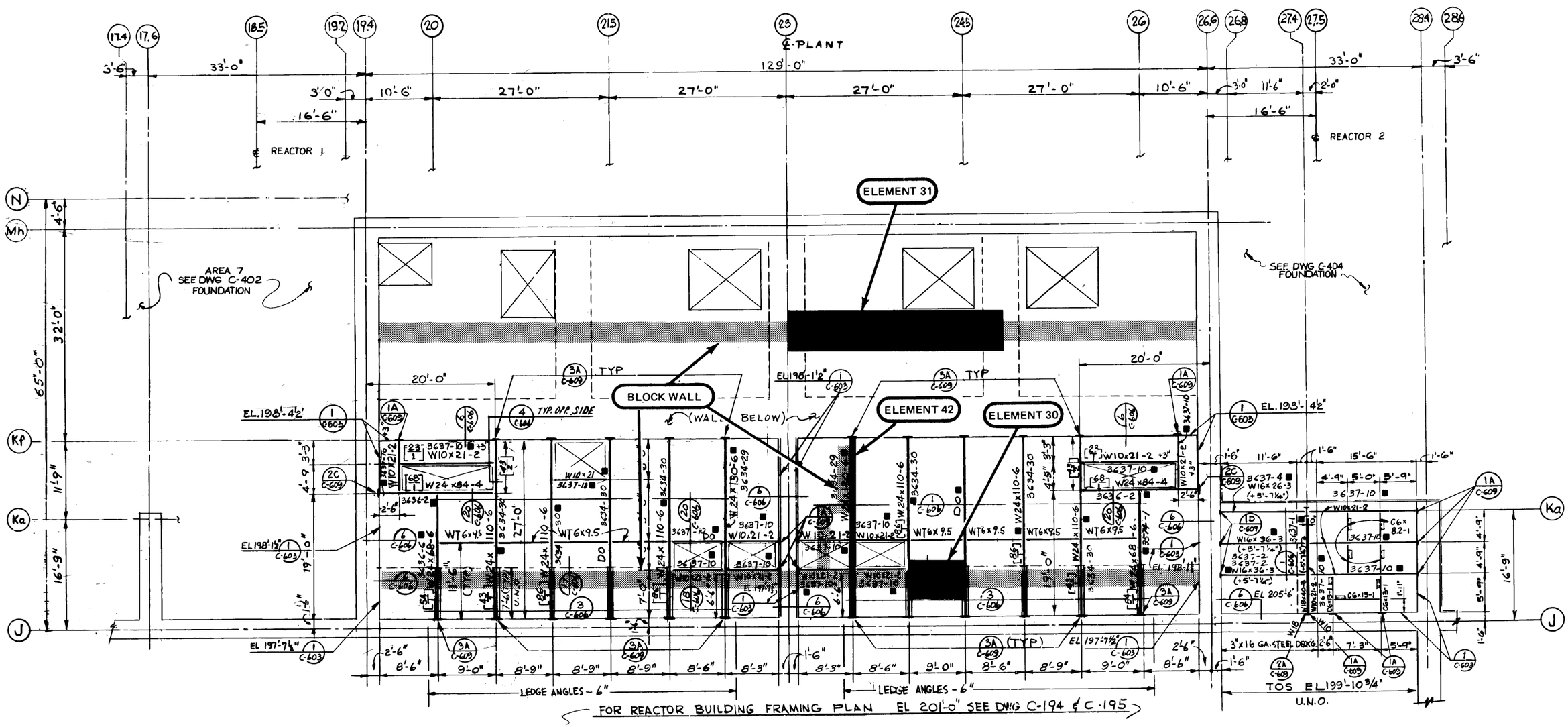
FIGURE 3A-404



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
REACTOR ENCLOSURE
STEEL FRAMING PLAN
EL. 352'

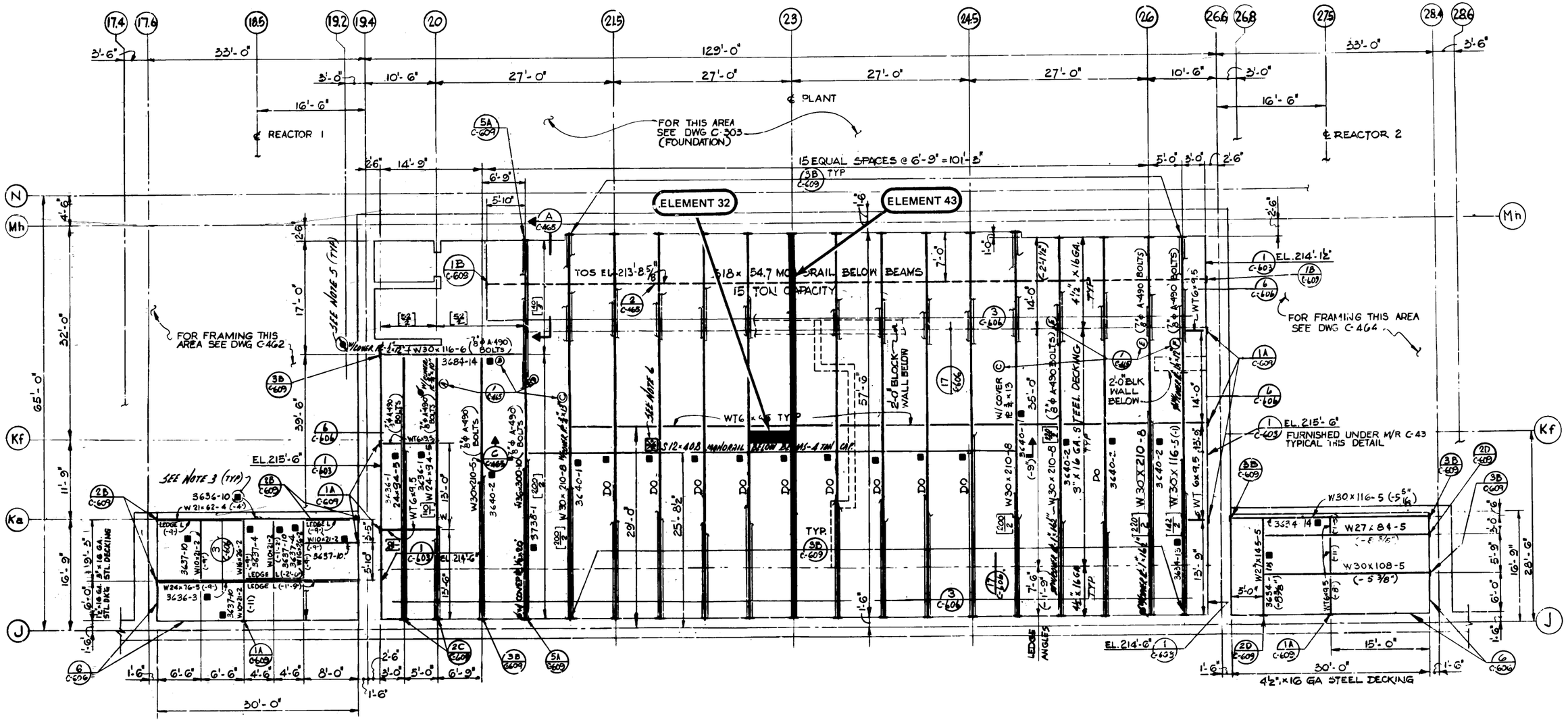
FIGURE 3A-405



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
CONTROL STRUCTURE
STEEL FRAMING PLAN
EL. 200'

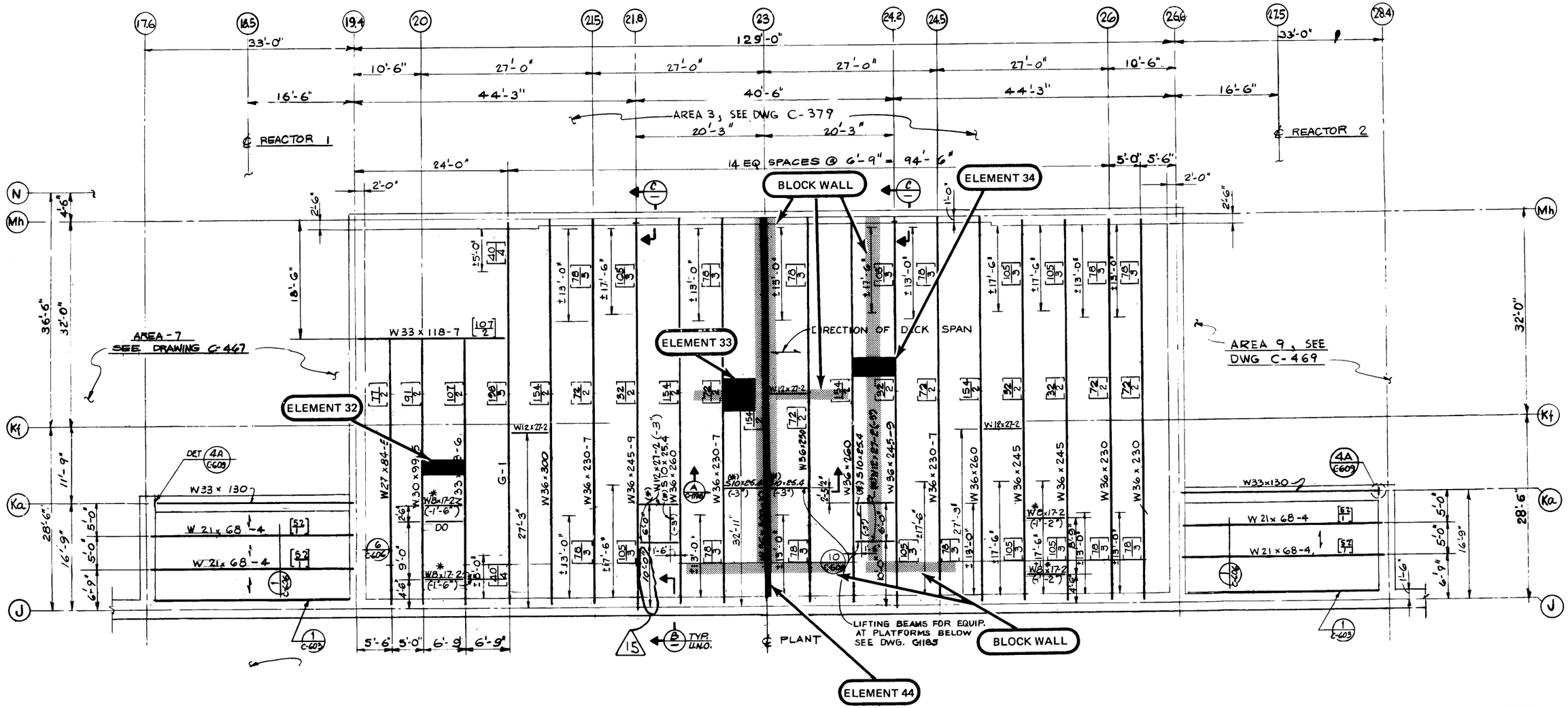
FIGURE 3A-406



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
CONTROL STRUCTURE
STEEL FRAMING PLAN
EL. 217'

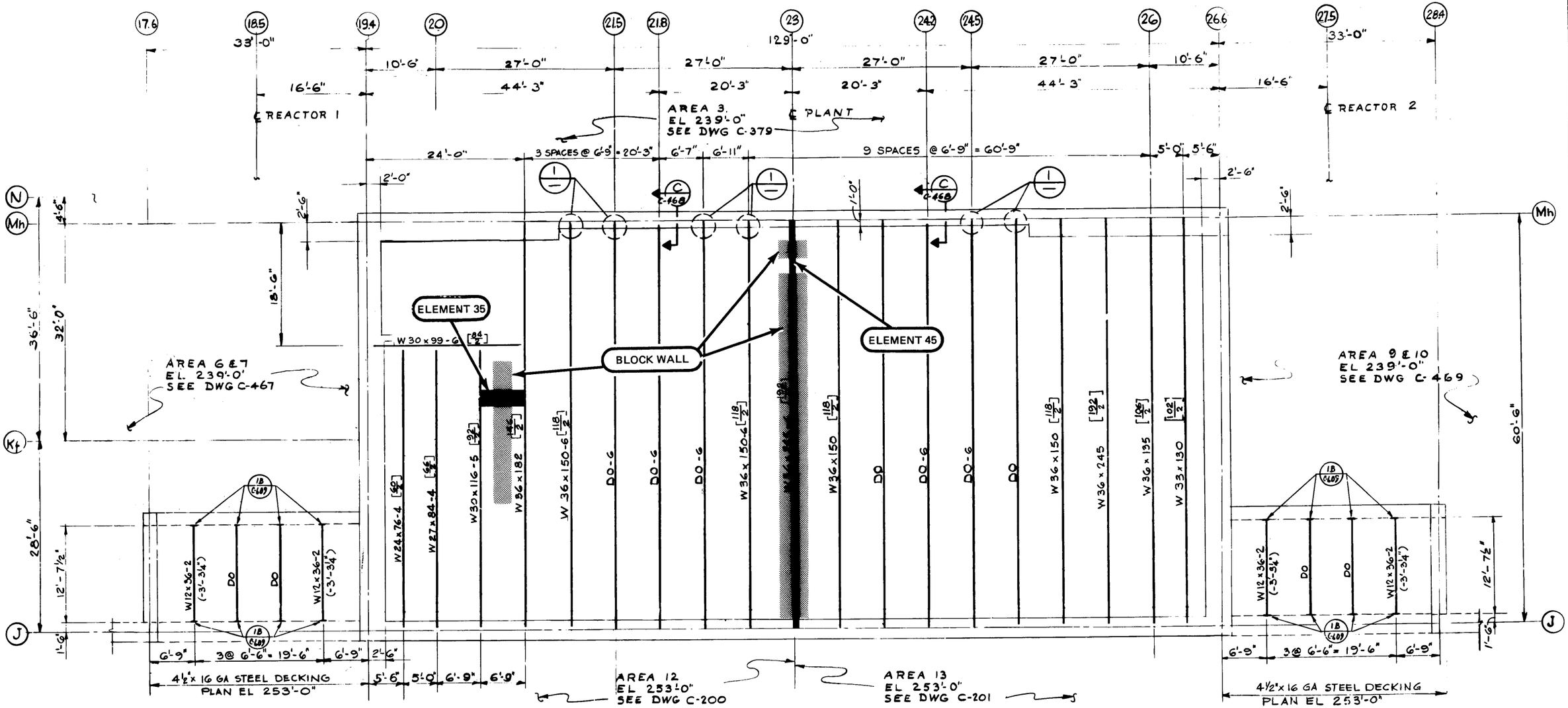
FIGURE **3A-407**



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
CONTROL STRUCTURE
STEEL FRAMING PLAN
EL. 239'

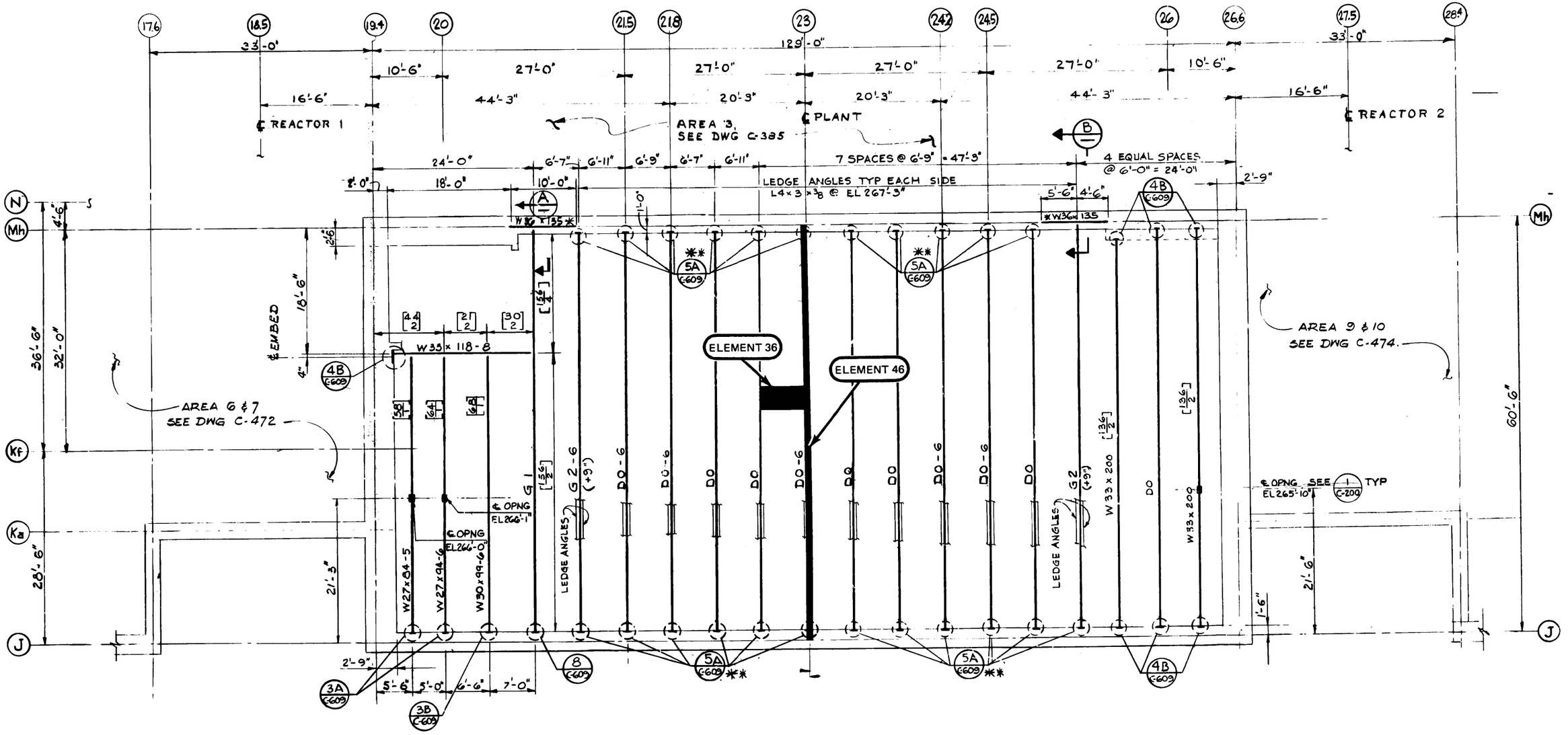
FIGURE 3A-408



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
CONTROL STRUCTURE
STEEL FRAMING PLAN
EL. 254'

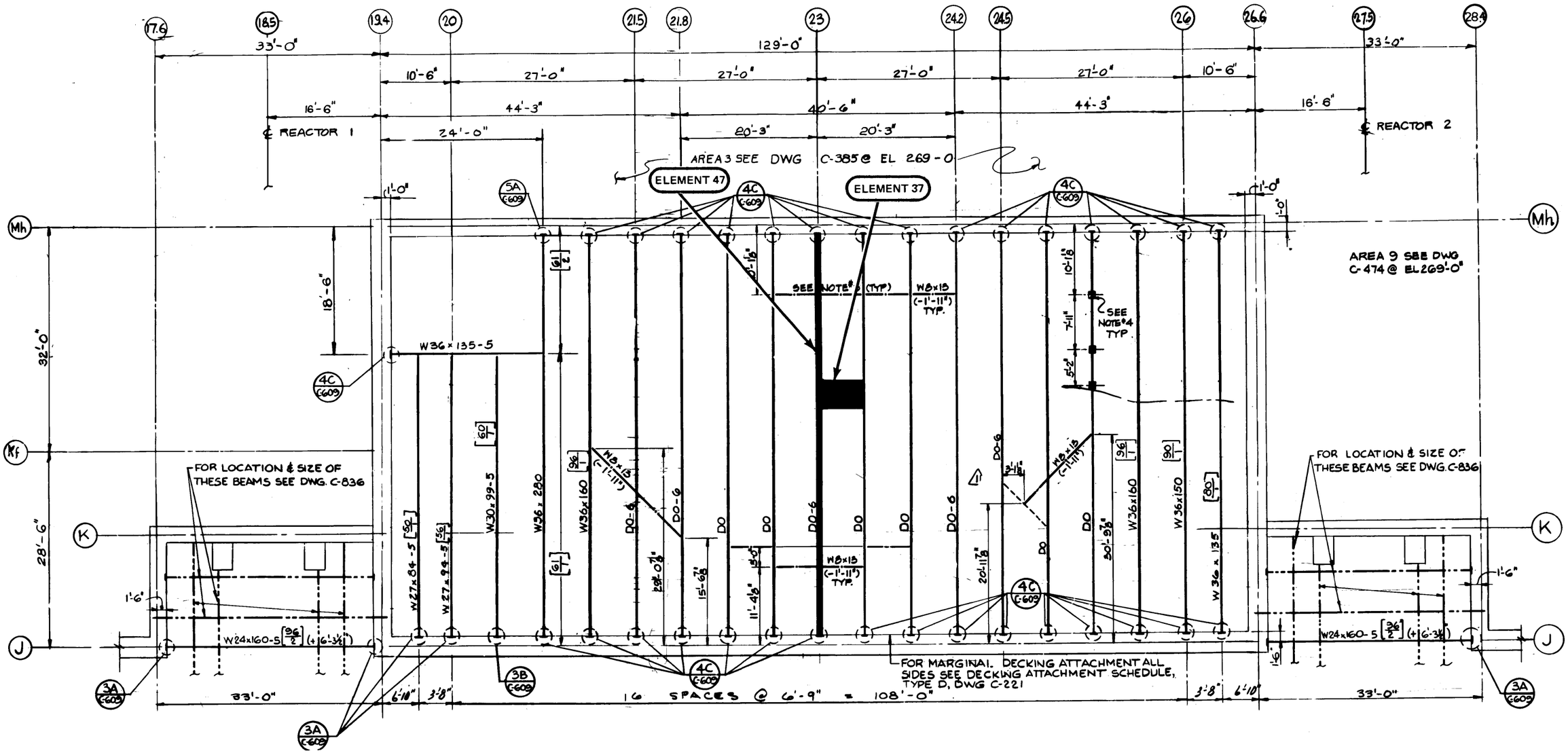
FIGURE 3A-409



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
CONTROL STRUCTURE
STEEL FRAMING PLAN
EL. 269'

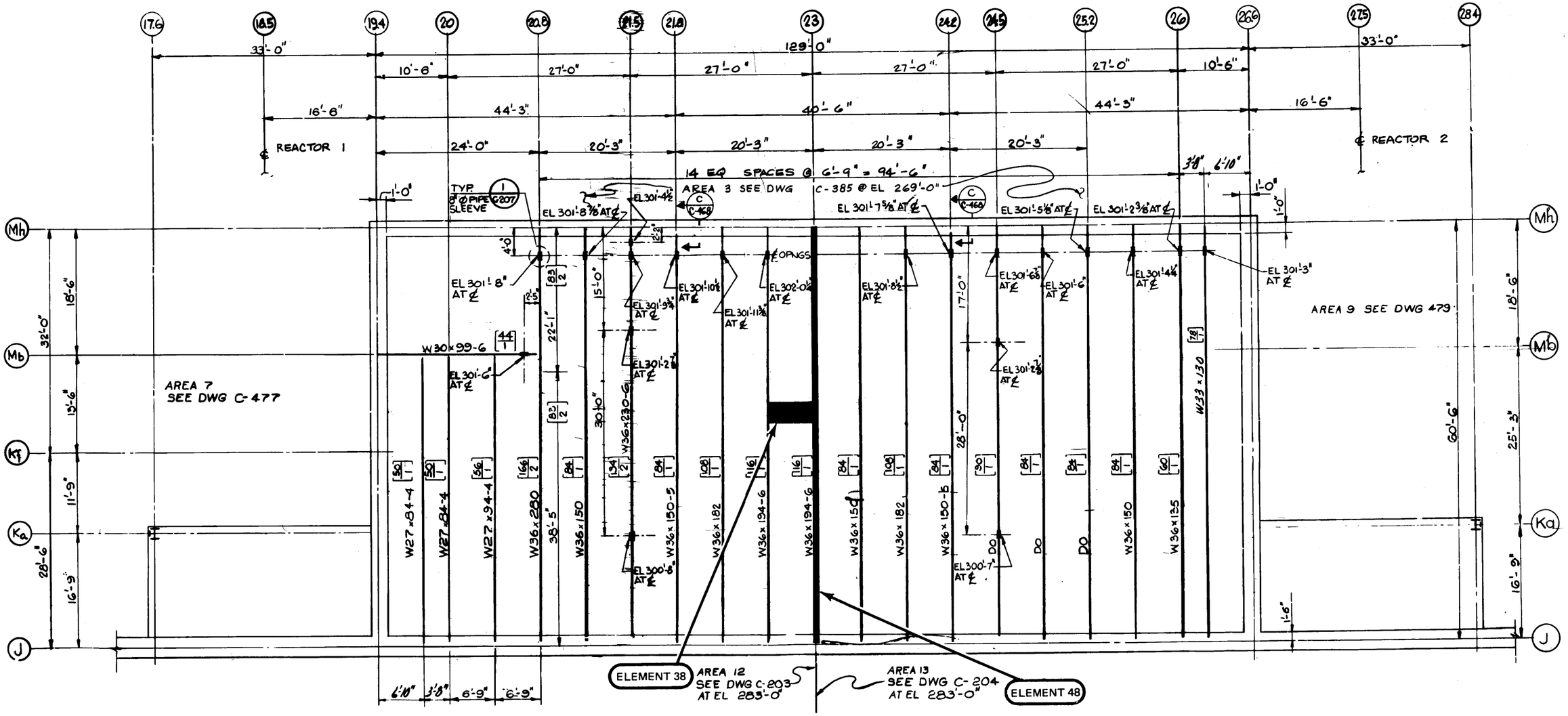
FIGURE 3A-410



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
CONTROL STRUCTURE
STEEL FRAMING PLAN
EL. 289'

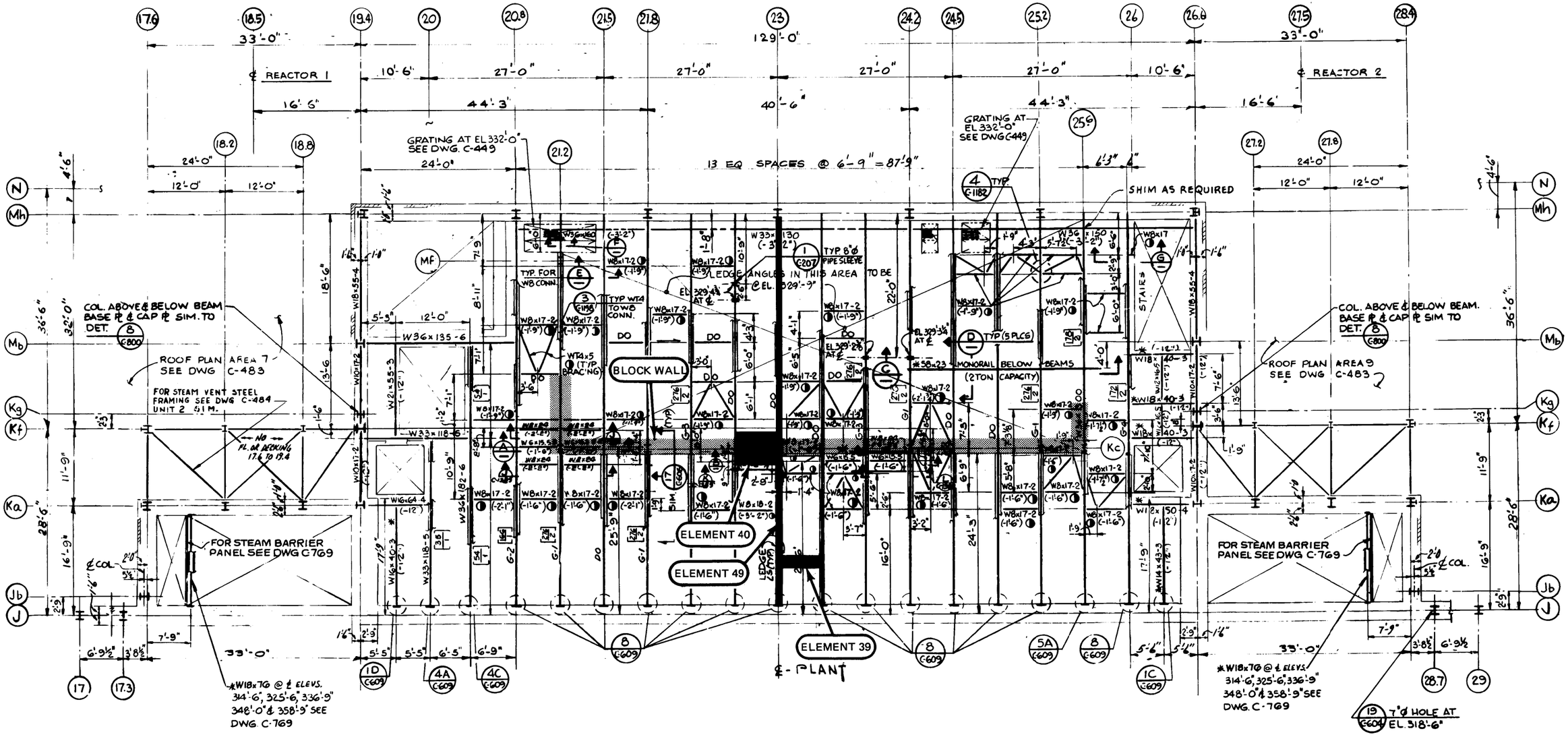
FIGURE 3A-411

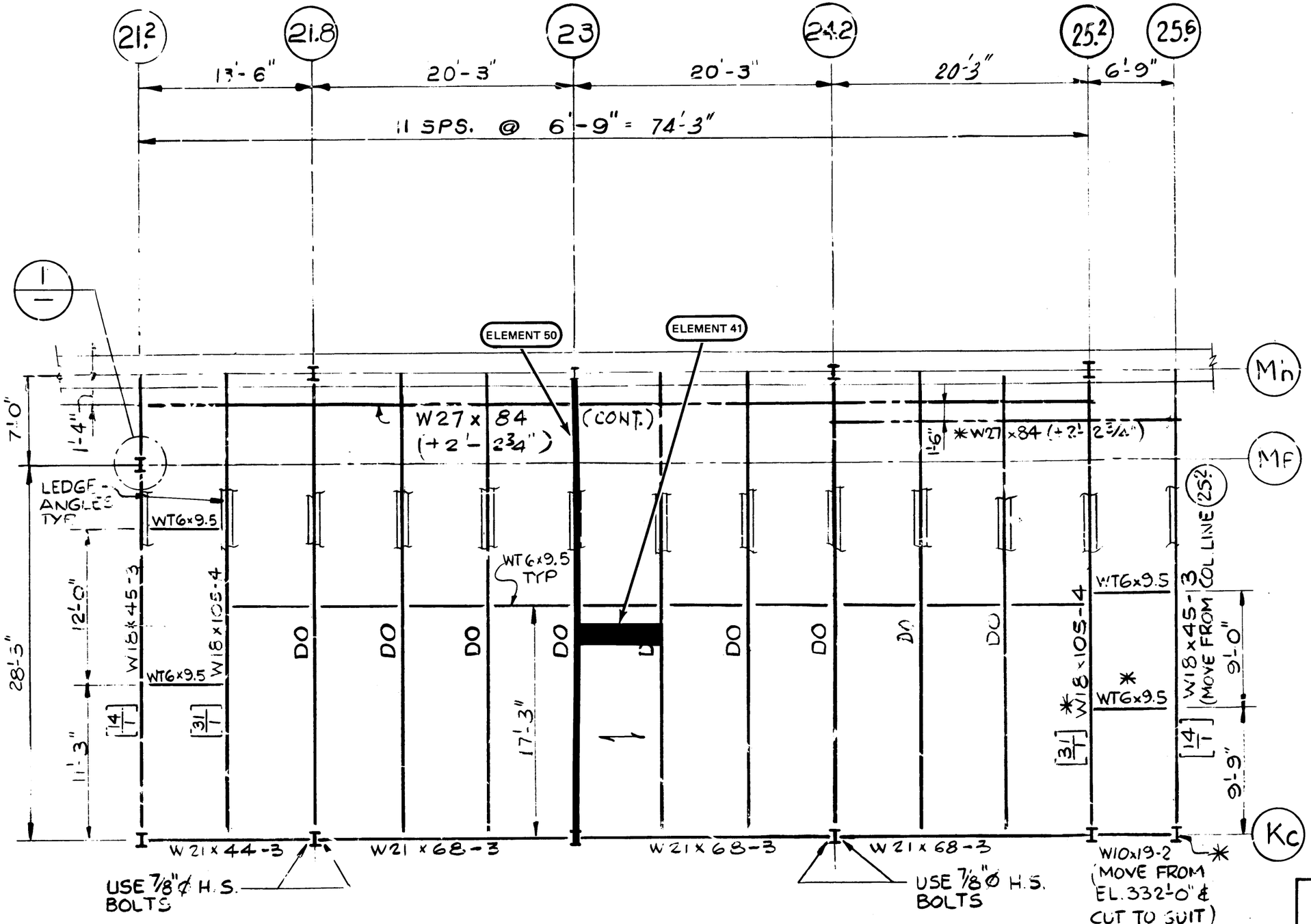


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
CONTROL STRUCTURE
STEEL FRAMING PLAN
EL. 304'

FIGURE 3A-412

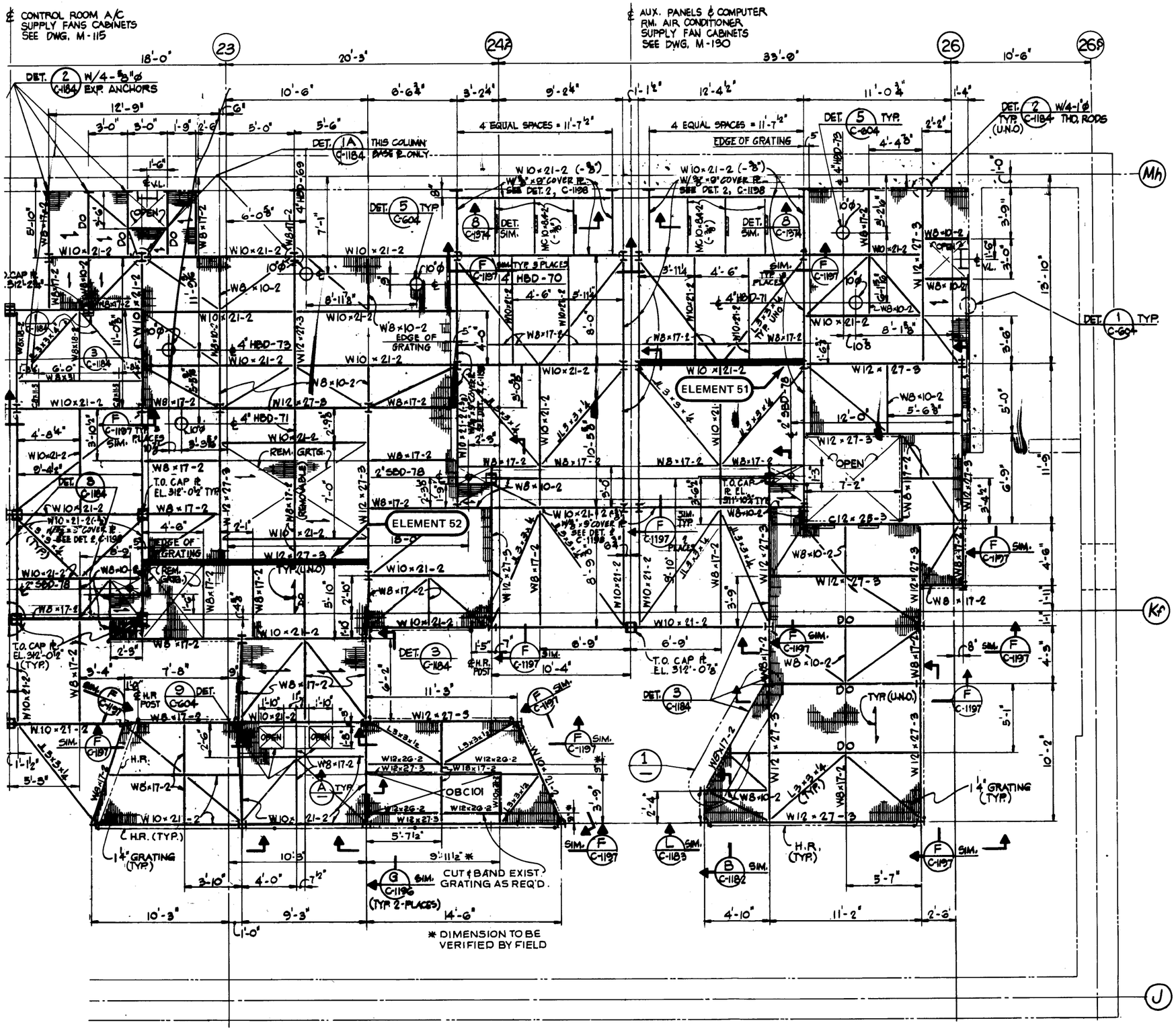

17.6
18.5
19.4
20
20.8
21.5
21.8
23
24.2
24.5
25.2
26
26.6
27.5
28.4
33'-0"
129'-0"
33'-0"
REACTOR 1
REACTOR 2
10'-6"
27'-0"
27'-0"
27'-0"
27'-0"
10'-6"
16'-6"
44'-3"
40'-6"
44'-3"
16'-6"
GRATING AT EL 332'-0" SEE DWG. C-449
GRATING AT EL 332'-0" SEE DWG C449
13 EQ SPACES @ 6'-9" = 87'-9"
24'-0"
24'-0"
24'-0"
24'-0"
12'-0"
12'-0"
12'-0"
12'-0"
6'3"
4"
18.2
18.8
21.2
25.6
27.2
27.8
N
Mh
Mb
Kg
Kf
Ka
Jb
J
MF
SHIM AS REQUIRED
TYP
TYP FOR WB CONN.
TYP WT4 TO WB CONN.
TYP 8"ø PIPE SLEEVE
LEDGE ANGLES IN THIS AREA TO BE @ EL. 329'-9"
TYP (5 PLCS)
MONORAIL BELOW BEAMS (2 TON CAPACITY)
STAIRS
COL. ABOVE & BELOW BEAM BASE PL & CAP PL SIM. TO DET. 8 C-800
ROOF PLAN AREA 7 SEE DWG C-483
FOR STEAM VENT STEEL FRAMING SEE DWG C-484 UNIT 2 SIM.
NO FL. OR DECKING 17.6 TO 19.4
BLOCK WALL
ELEMENT 40
ELEMENT 49
ELEMENT 39
℄ - PLANT
FOR STEAM BARRIER PANEL SEE DWG C-769
ROOF PLAN AREA 9 SEE DWG C-483
W36x135-6
W33x118-6
W36x182-6
W36x150
W18x55-4
W10x17-2
W8x17-2
W8x17
W18x40-3
W14x43-3
W12x50
W16x64-4
W21x55-3
WT4x5 (T/P BRACING)
W35x130 (-3'-2")
W8x18-2 (-5'-2")
W8x20 (-2'-8")
W8x15-5 (-1'-6")
W8x31 (-2'-8")
W8x24 (-2'-2")
W8x28 (-2'-1")
W8x48 (-2'-8")
W8x67 (-2'-8")
W8x58 (-2'-8")
W8x35 (-2'-8")
W8x21 (-2'-8")
W8x40 (-2'-8")
W8x10 (-2'-8")
W8x31 (-2'-8")
W8x28 (-2'-8")
W8x67 (-2'-8")
W8x48



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
CONTROL STRUCTURE
STEEL FRAMING PLAN
EL. 350'

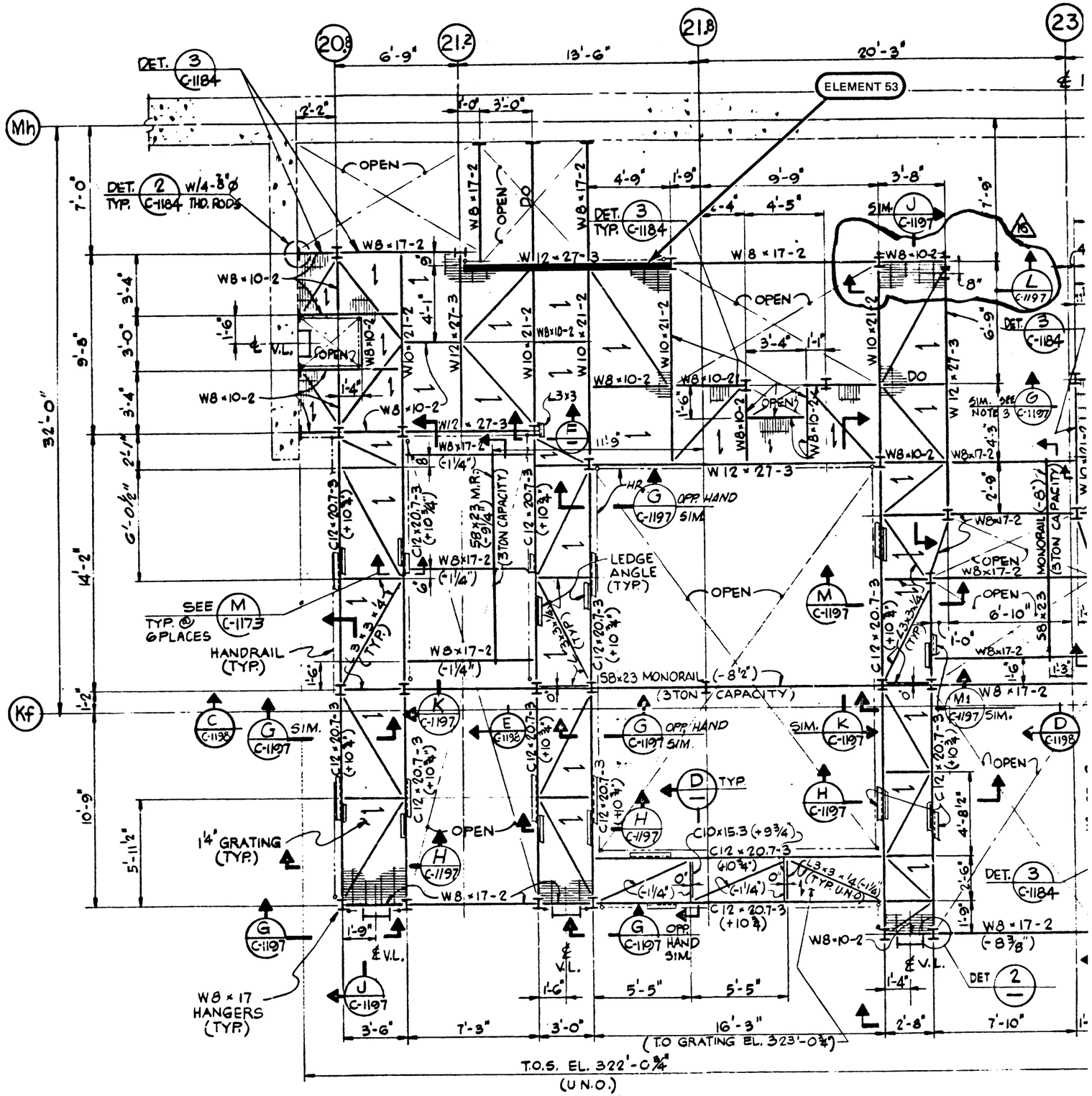
FIGURE 3A-414

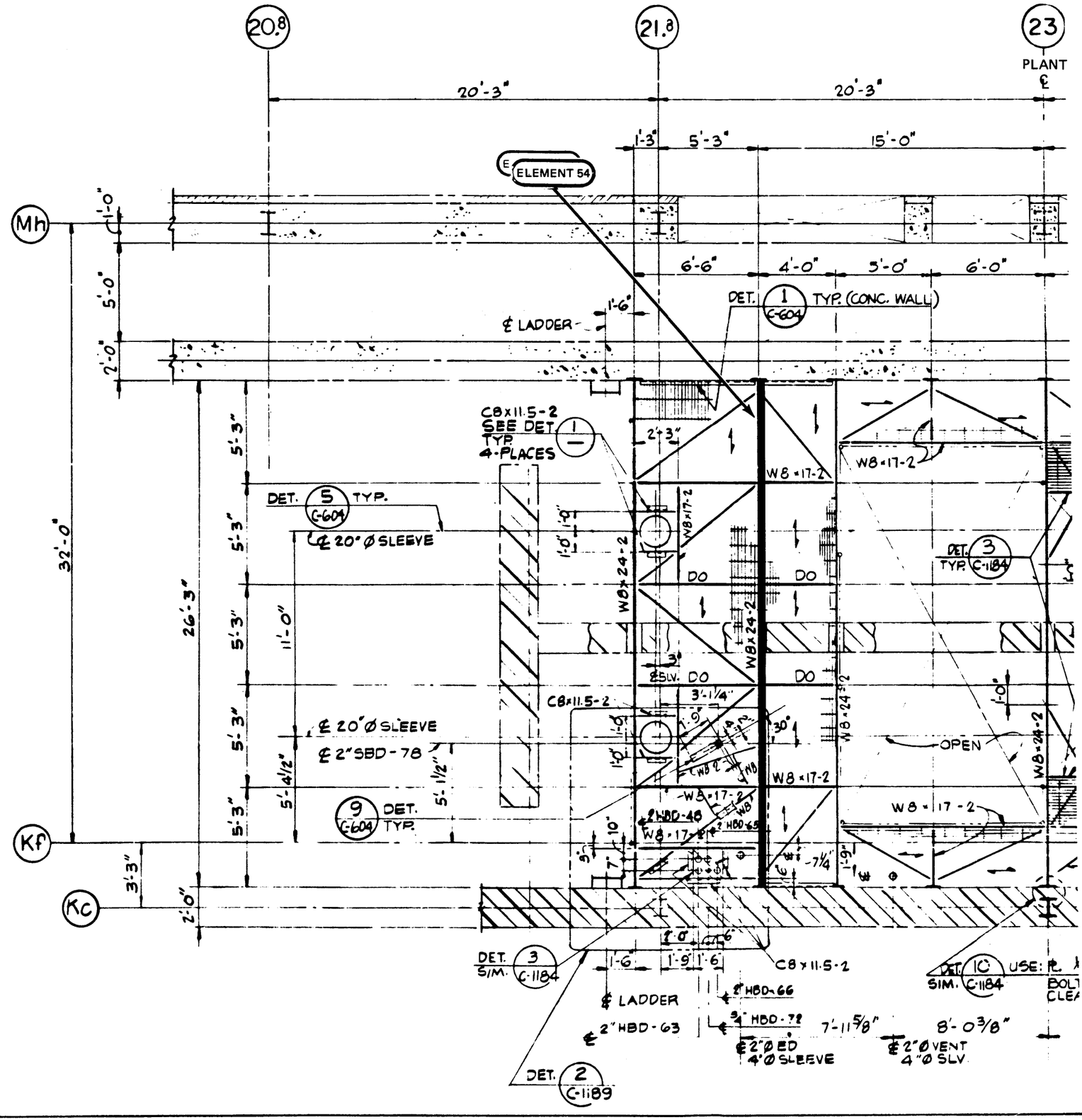


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
CONTROL STRUCTURE PLATFORMS EL. 313'

FIGURE 3A-415

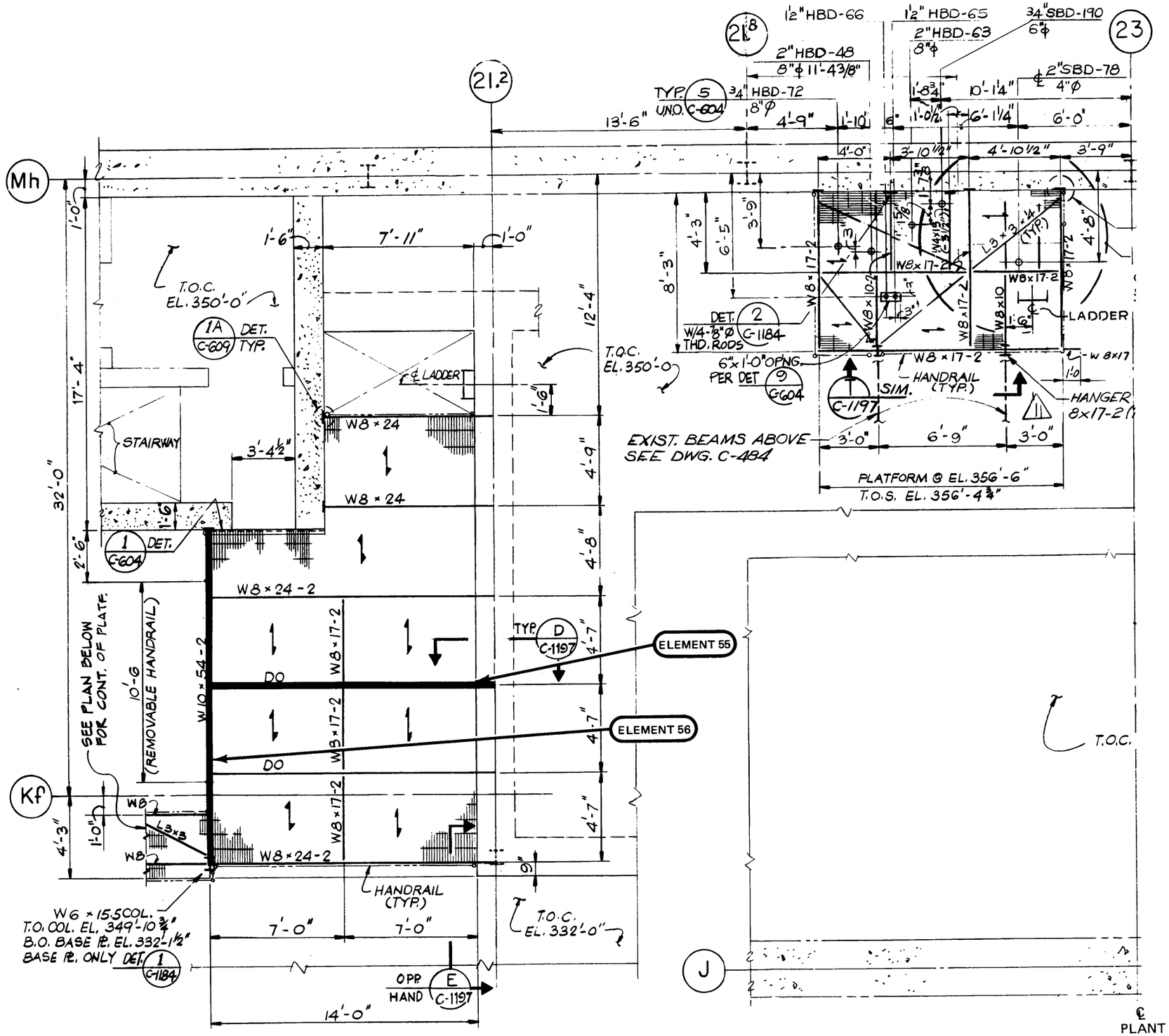

20.8
21.2
21.8
23
Mh
Kf
6'-9"
13'-6"
20'-3"
ELEMENT 53
DET. 3 C-1184
DET. 2 TYP. C-1184 W/4-3/8"ø THD. RODS
OPEN
W8×17-2
W8×10-2
W12×27-3
W10×21-2
W10×21-2
W8×10-2
W8×10-2
W8×10-2
W8×10-2
W8×10-2
W8×10-2
W8×10-2
W8×10-2
W8×17-2
W8×17-2
W8×17



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
CONTROL STRUCTURE
PLATFORMS
EL. 340'

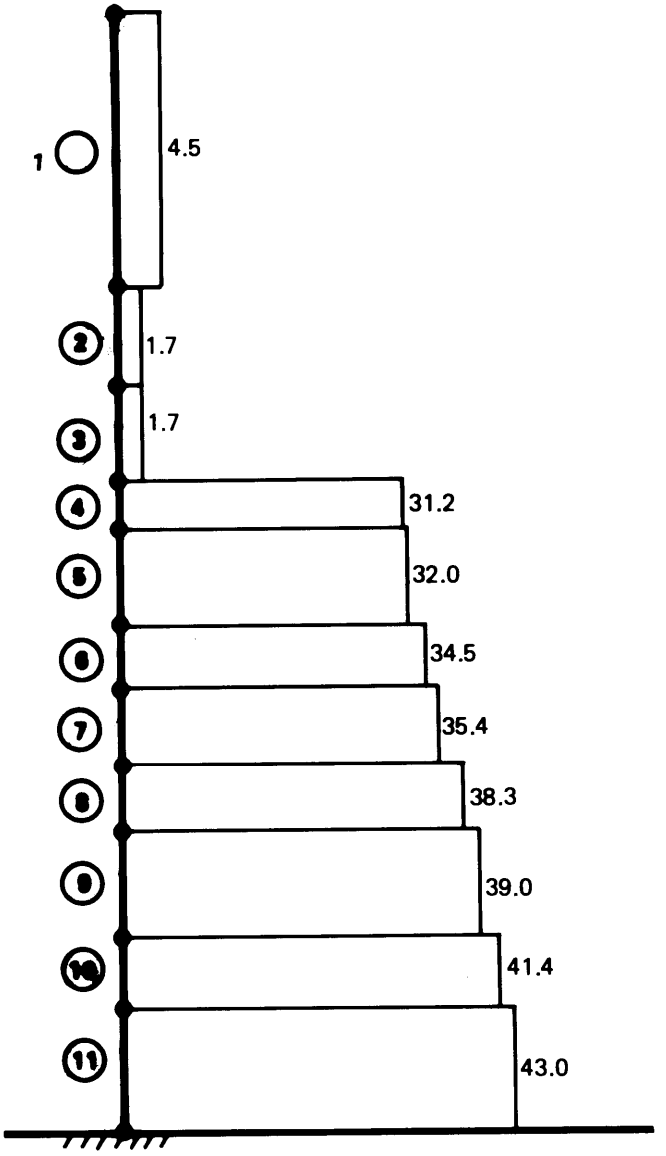
FIGURE 3A-417



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
CONTROL STRUCTURE
PLATFORMS
EL. 350'

FIGURE 3A-418

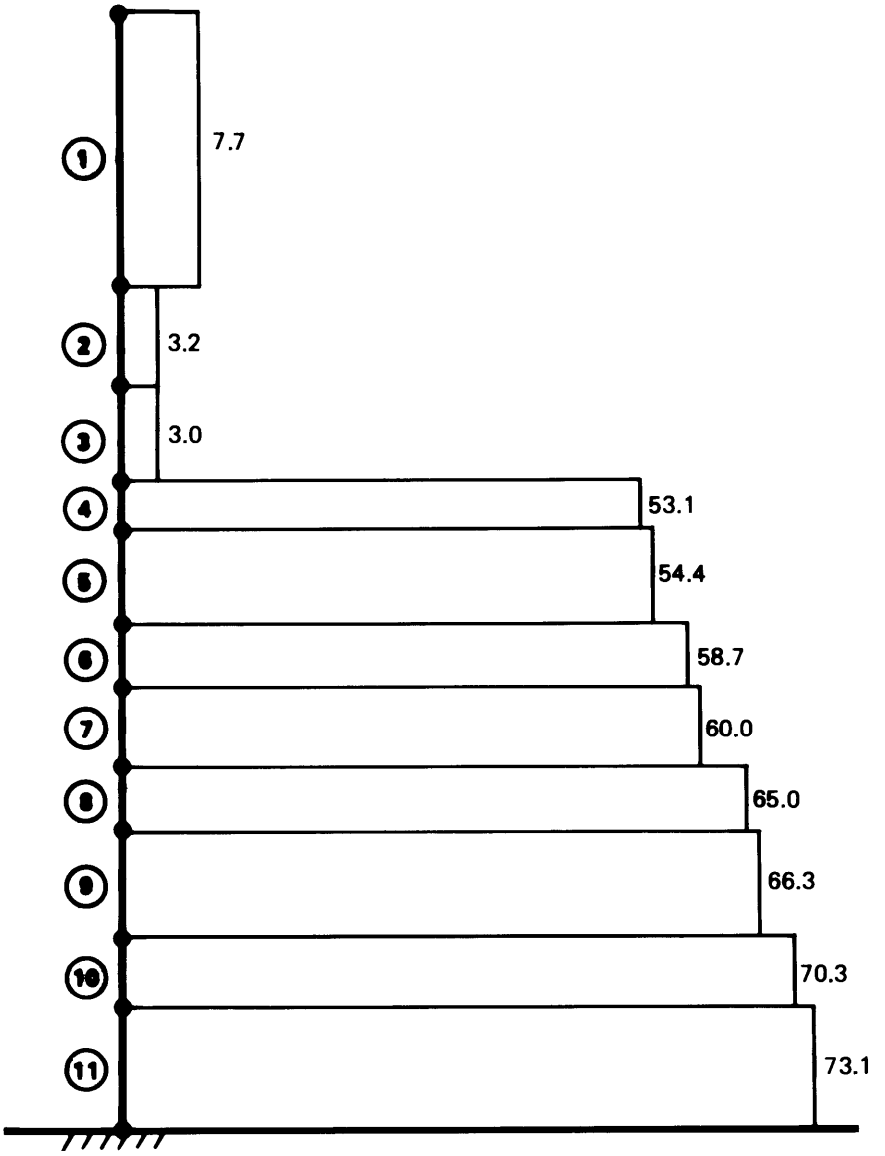


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE & CONTROL STRUCTURE VERTICAL AXIAL FORCES ($X10^3$ KIPS)
OBE+SRV (2% DAMPING)

FIGURE 3A-419

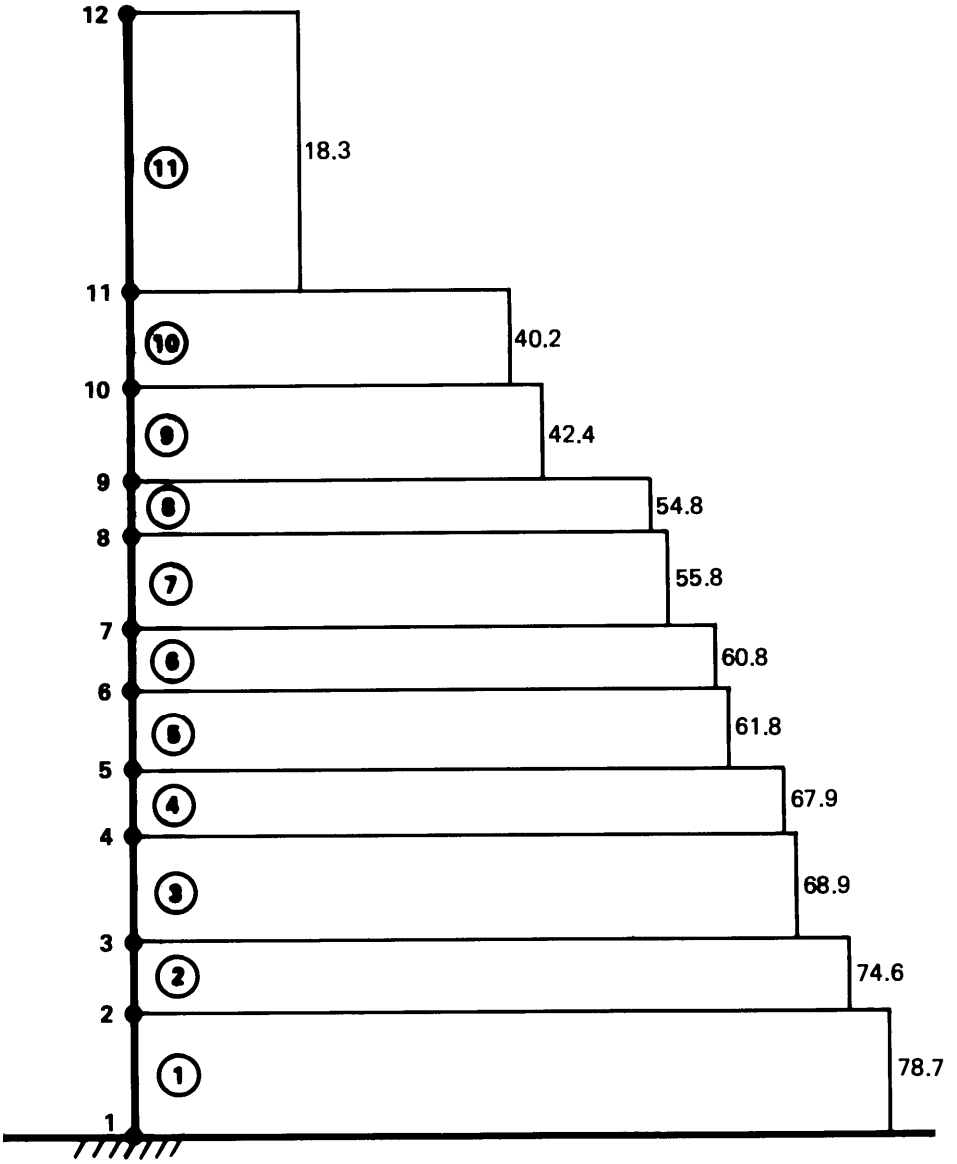


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE & CONTROL STRUCTURE VERTICAL AXIAL FORCES ($X\ 10^3$ KIPS)
DBE+SRV+LOCA (5% DAMPING)

FIGURE 3A-420

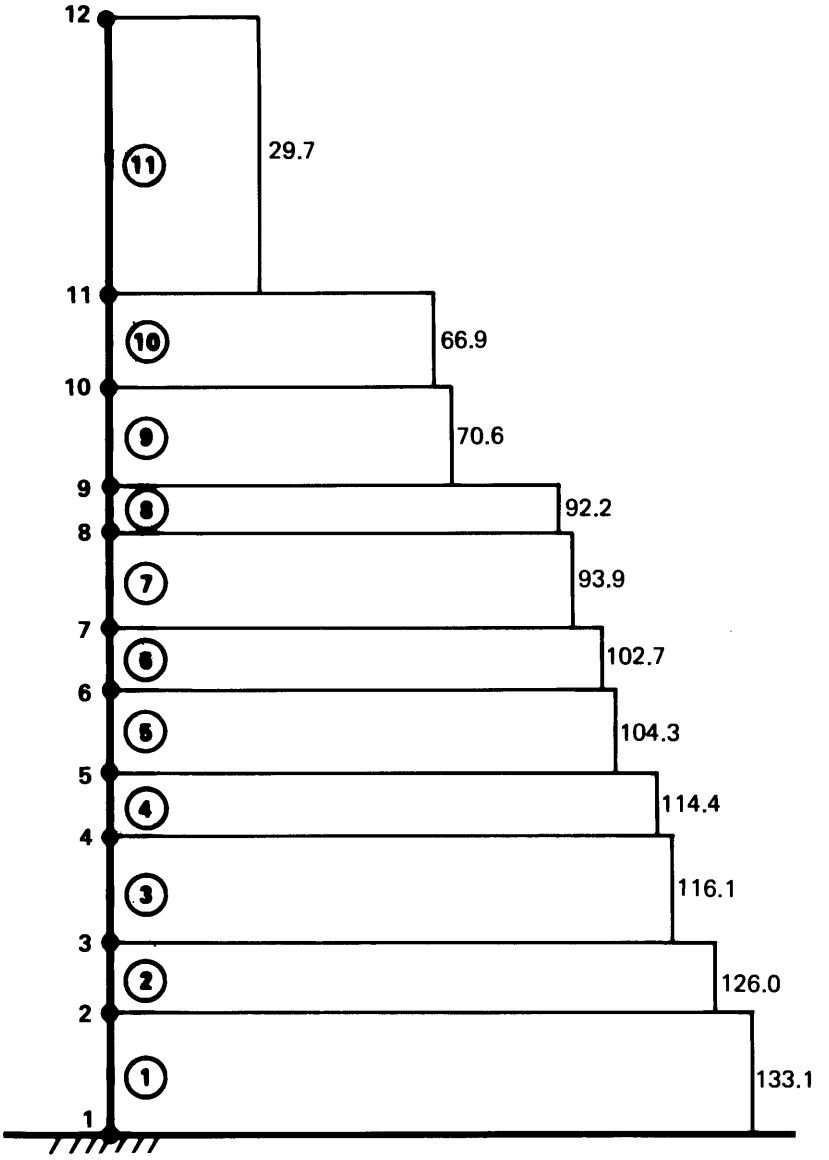


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE & CONTROL STRUCTURE N-S SHEAR FORCES ($X10^3$ KIPS) OBE+SRV (2% DAMPING)

FIGURE 3A-421

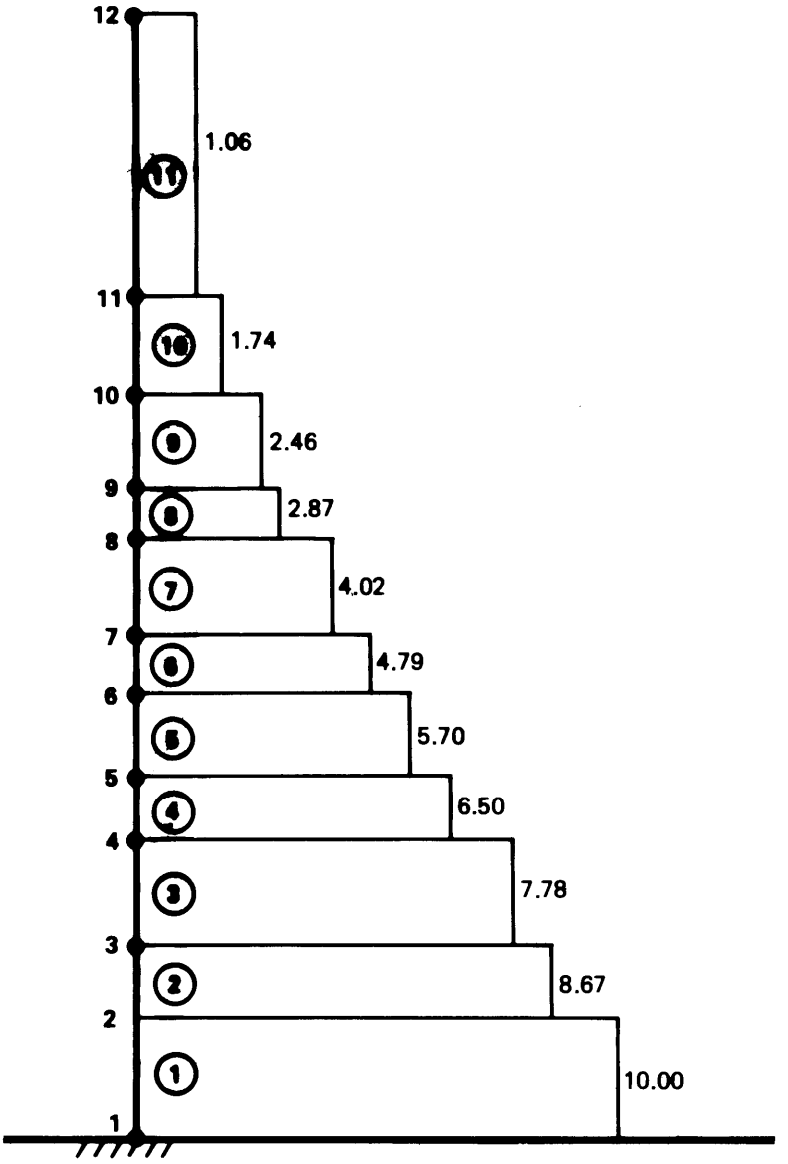


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE & CONTROL STRUCTURE N–S SHEAR FORCES ($X10^3$ KIPS)
DBE+LOCA+SRV (5% DAMPING)

FIGURE 3A-422

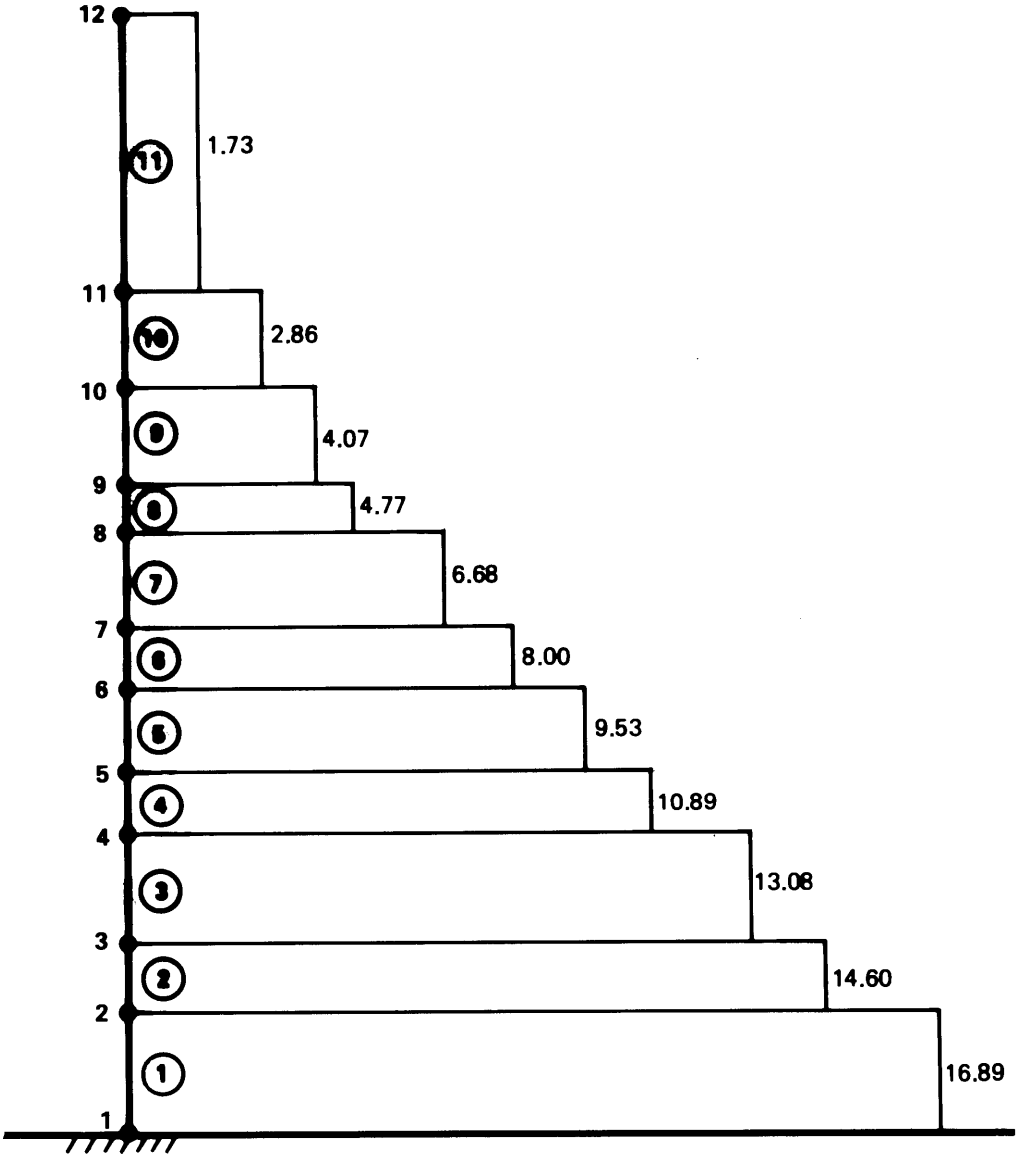


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE & CONTROL STRUCTURE N–S OVERTURNING MOMENTS ($X10^6$ K–FT)
OBE+SRV (2% DAMPING)

FIGURE 3A-423

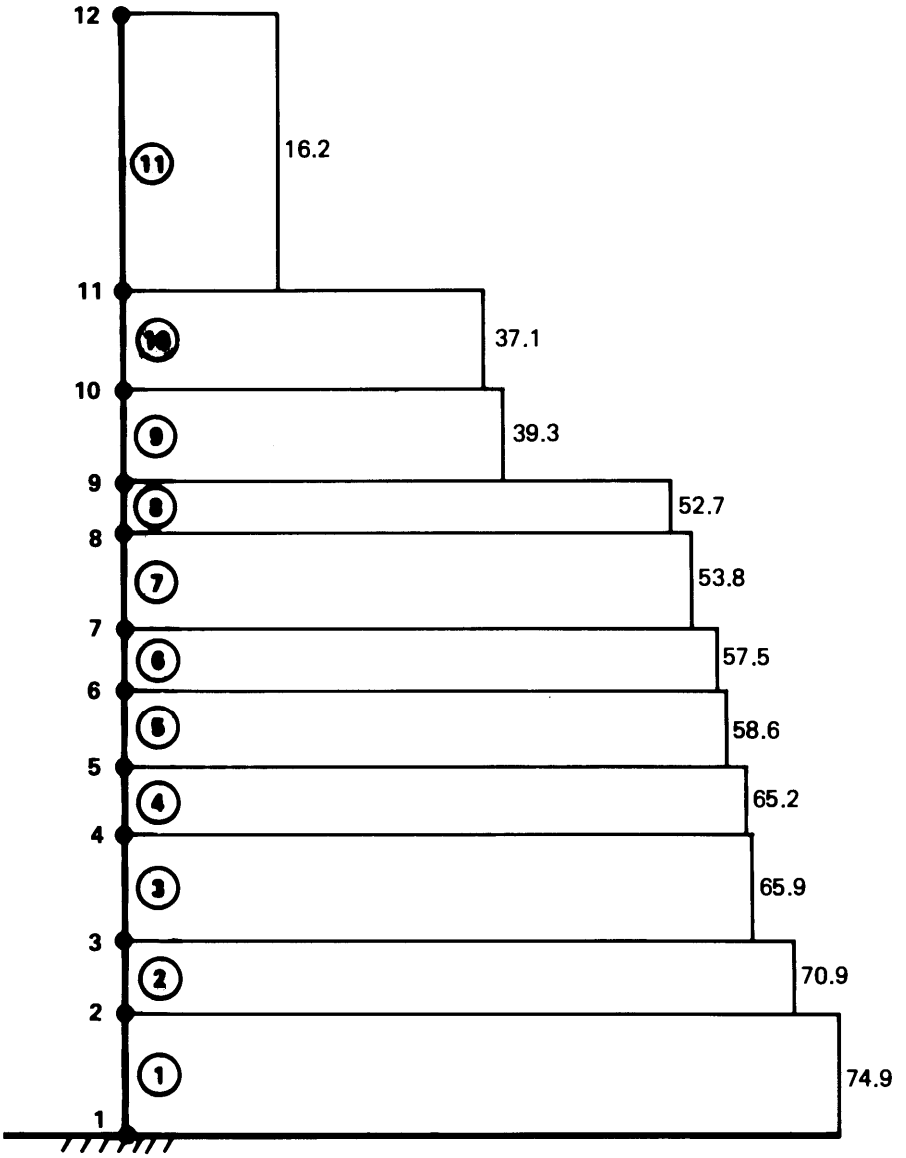


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE & CONTROL STRUCTURE N–S OVERTURNING MOMENTS ($X10^6$ K-FT)
DBE+LOCA+SRV (5% DAMPING)

FIGURE 3A-424

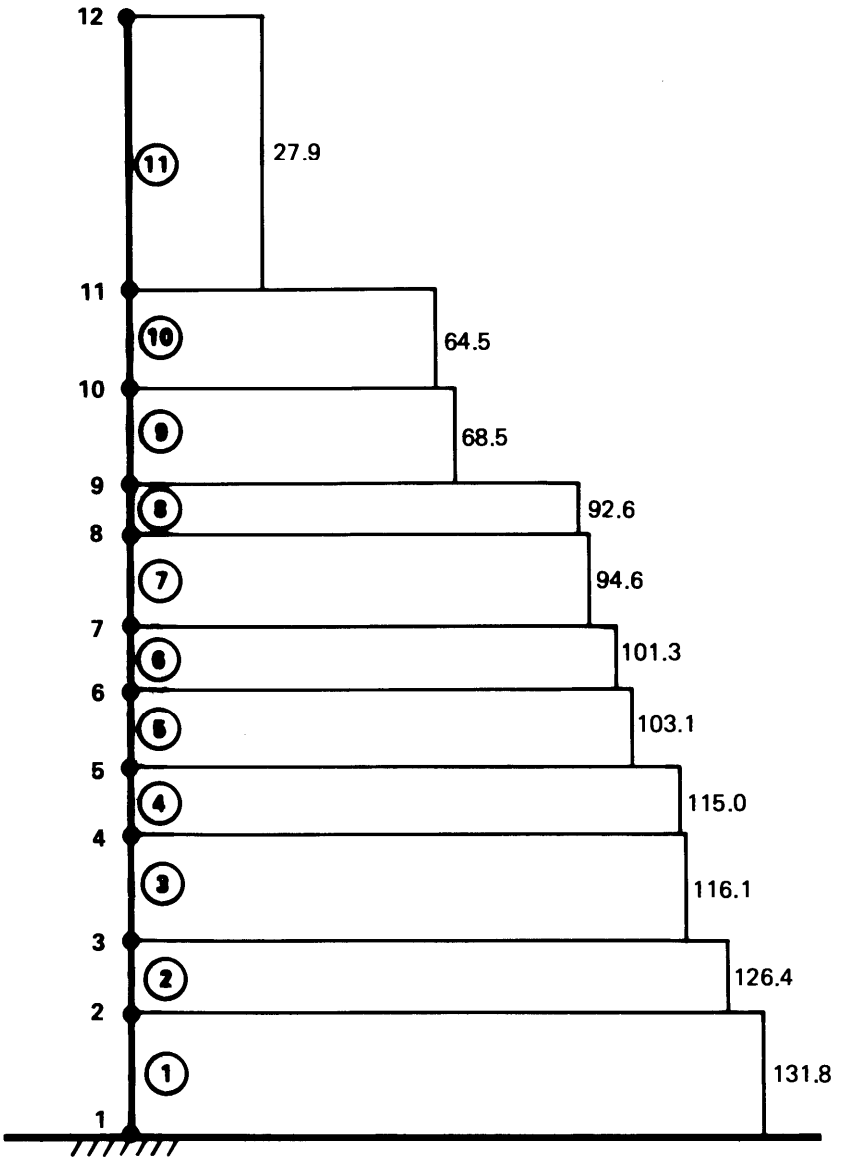


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE & CONTROL STRUCTURE E-W SHEAR FORCES ($X10^3$KIPS) OBE+SRV (2% DAMPING)

FIGURE 3A-425

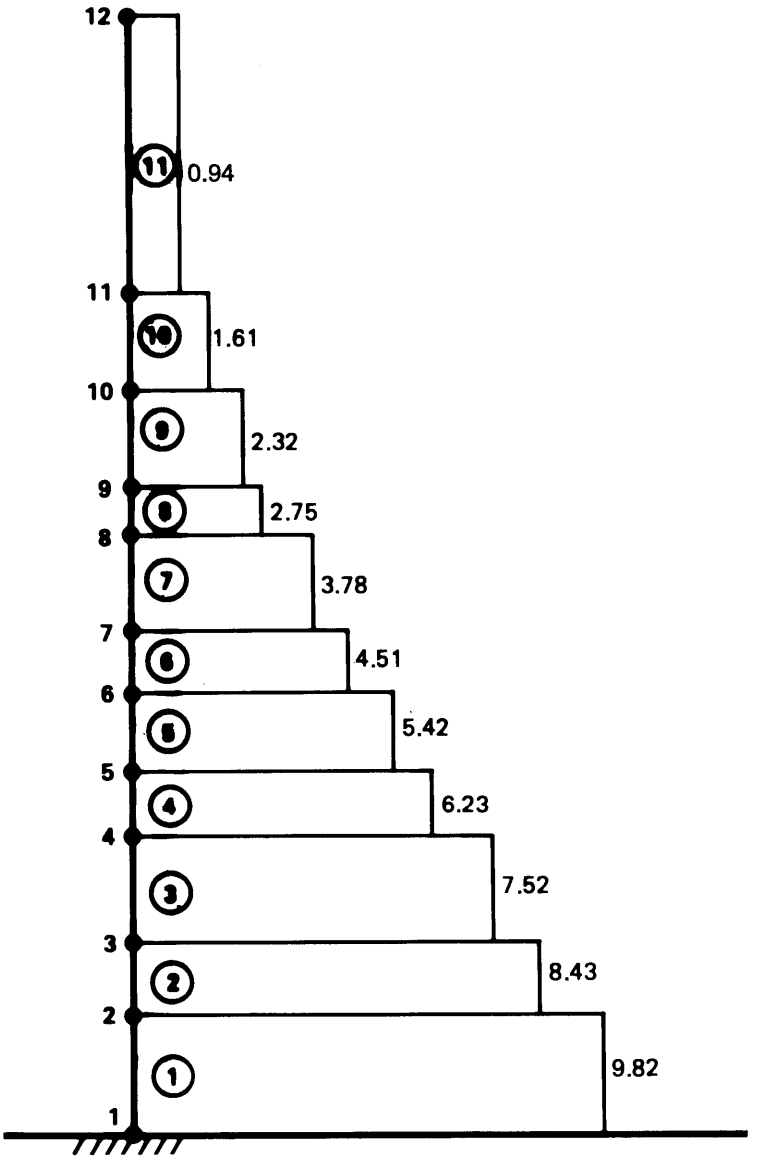


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE & CONTROL STRUCTURE E-W SHEAR FORCES ($X10^3$ KIPS) DBE+LOCA+SRV (5% DAMPING)

FIGURE 3A-426

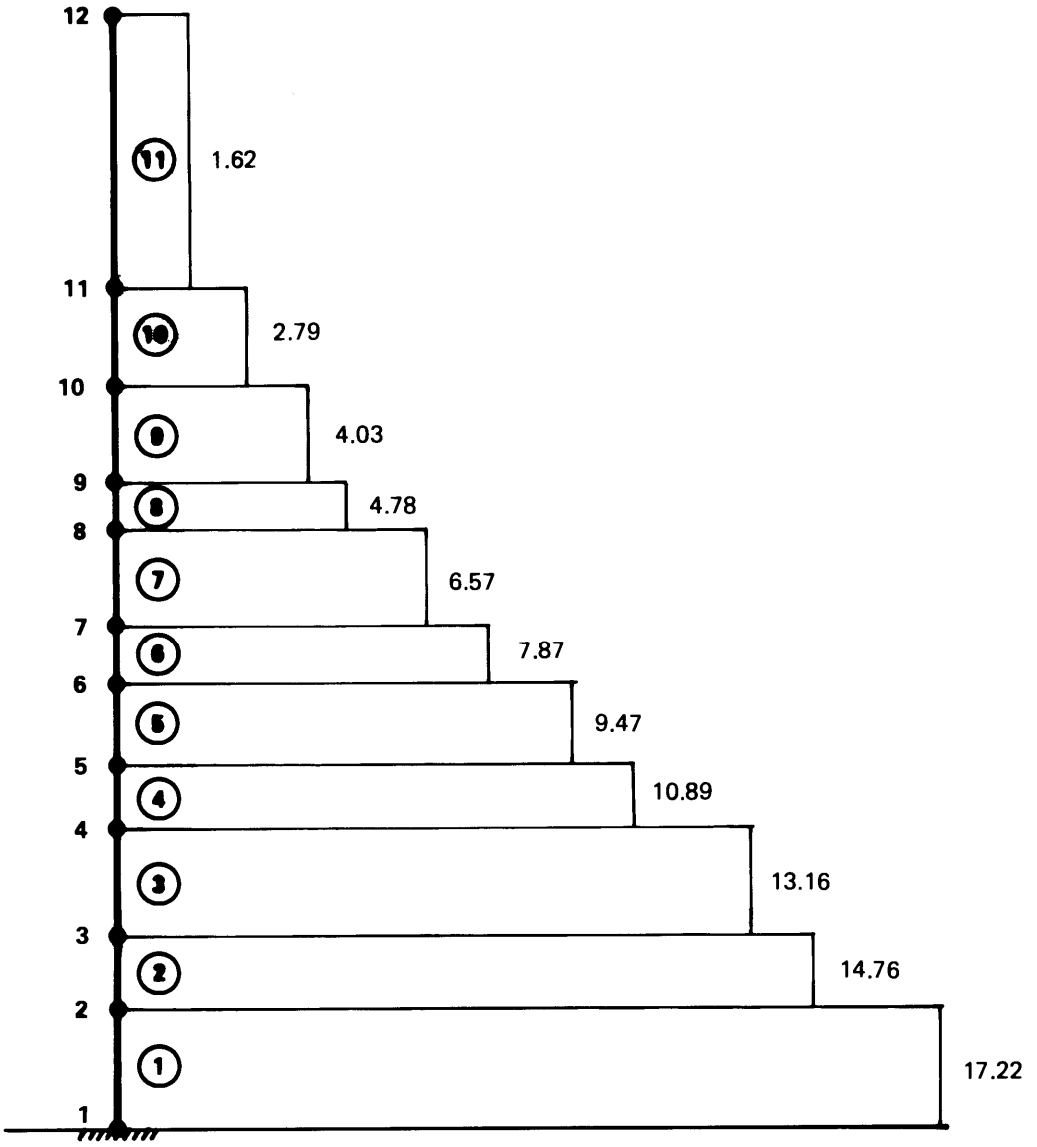


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE & CONTROL STRUCTURE E-W OVERTURNING MOMENTS ($X10^6$ K-FT) OBE+SRV (2% DAMPING)

FIGURE 3A-427



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE & CONTROL STRUCTURE E-W OVERTURNING MOMENTS ($X10^6$K-FT) DBE+LOCA+SRV (5% DAMPING)

FIGURE 3A-428

REACTOR ENCLOSURE FLOOR SLABS

ELEMENT NUMBER	ELEVATION (FT)	SLAB THICKNESS (FT)	GOVERNING EQUATION(1)	REBAR(2) STRESS (KSI)	STRESS MARGIN (%)
1	201	1.5	1	13.13	75.7
2	201	2.5	1	30.55	43.4
3	217	1.5	7a	30.90	42.8
4	217	2.0	7a	27.70	48.7
5	253	1.25	7a	51.26	5.1
6	253	2.0	1	20.40	62.2
7	283	1.25	7a	42.74	20.9
8	283	2.75	1	28.13	47.9
9	313	1.75	1	30.52	43.5
10	313	2.0	7a	23.83	55.9
11	313	3.0	7a	28.16	47.9
12	333	1.25	1	21.22	60.7
13	333	1.67	1	15.47	71.4
14	352	2.0	7a	36.35	32.7
15	352	3.25	7a	11.18	79.3

NOTES: (1) Taken from Table 3A-14 as follows:

Load Combination EQN 1 = 1.4D + 1.7L + 1.5 SRV
Load Combination EQN 7a = 1.0D + 1.0L + 1.0 ESS + 1.0 SRV + 1.0 LOCA

(2) Allowable Reinforcing Steel Stress = 54 KSI

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

REACTOR ENCLOSURE MARGINS
FLOOR SLABS

FIGURE 3A-429

REACTOR ENCLOSURE FLOOR STEEL BEAM(1)

ELEMENT NUMBER	ELEVATION (FT)	STEEL SIZE	GOVERNING EQUATION(2)	BENDING STRESS (KSI)	STRESS MARGIN(3) %
16	201	W27 x 145	1	23.00	4.2
17	201	W24 x 68	1	20.00	16.7
18	217	W33 x 141	1	21.90	8.6
19	217	W33 x 130	7	27.40	15.5
20	253	W24 x 76	1	22.66	5.6
21	253	W27 x 84	1	20.92	12.8
22	283	72" Girder	1	24.00	0.
23	283	W33 x 152	1	19.27	19.7
24	313	56" Girder	7	30.28	6.5
25	313	W36 x 300	7	29.44	9.1
26	331	W36 x 182	7	23.58	27.2
27	331	W21 x 73	7	20.31	37.3
28	352	W36 x 300	7	18.54	42.7
29	352	W24 x 68	7	16.94	47.7

NOTES: (1) All beams are A-36 steel.

(2) Taken from Table 3A-15 as follows:

Load Combination EQN 1 = D + L + SRV
Load Combination EQN 7 = D + L + E^1 + SRV + LOCA

(3) Allowable Bending Stresses for Governing Equations 1 and 7 are 24.0 KSI and 32.4 KSI, respectively.

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REACTOR ENCLOSURE MARGINS
FLOOR STEEL BEAM

FIGURE 3A-430

REACTOR ENCLOSURE SUPPORTING COLUMNS

ELEVATION RANGE	LOCATION(1)	MATERIALS(2)	INTERACTION EQUATION	STRESS MARGIN%
177'-201'	29 & E	Steel	0.77	23
177'-201'	30.5 & E	Reinforced Concrete	-	8
201'-217'	29 & E	Steel	0.78	22
201'-217'	30.5 & E	Reinforced Concrete	-	1
217'-253'	30.5 & E	Steel	1.02	0
253'-283'	30.5 & E	Steel	0.88	12
283'-313'	30.5 & E	Steel	0.78	22
313'-333'	27.5 & E	Steel	0.97	3
313'-333'	30.5 & E	Steel	0.91	9
333'-352'	29 & E	Steel	0.65	35

NOTES: (1) Figure **3A-398** gives location reference

(2) For Steel Supports, Load Combination EQN (7) of Table 5.3-1 is used: D + L + E + LOCA + SRV + P.

For Reinforced Concrete Supports, Load Combination EQN (7) of Table **3A-14** is used:
$D + L + E_O + LOCA + SRV + P_B$

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REACTOR ENCLOSURE MARGINS SUPPORTING COLUMNS

FIGURE 3A-431

REACTOR ENCLOSURE SHEAR WALLS

WALL ELEVATION (FT)	WALL MARK(1)	GOVERNING EQUATION(2)	COMBINED AXIAL & BENDING STRESS MARGIN (%) (3)	SHEAR STRESS MARGIN (%) (4)
177	Line 14.1	7a	67	1
177	Line 31.9	7a	67	1
177	D	7a	48	12
177	Line 23	7a	24	8
177	Line 21.5	7a	29	9

NOTES: (1) Figure **3A-398** gives location reference

(2) Taken from Table **3A-14** as follows:

Load Combination EQN 7a = D + L + Ess + SRV + LOCA

(3) Allowable Reinforcing Steel Stress = 54 KSI

(4) Allowable Reinforcing Steel Stress = 51 KSI

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REACTOR ENCLOSURE MARGINS SHEAR WALLS

FIGURE 3A-432

CONTROL STRUCTURE FLOOR SLABS

ELEMENT NUMBER	ELEVATION (FT)	SLAB THICKNESS (FT)	GOVERNING EQUATION(1)	REBAR STRESS(2) KSI	STRESS MARGIN (%)
30	200	1.5	1	14.47	73.2
31	200	6.0	1	37.64	30.3
32	217	1.25	1	14.15	73.8
33	237	1.0	1	31.10	42.4
34	237	1.0	1	30.89	42.8
35	254	1.0	1	27.86	48.4
36	269	1.5	1	12.15	77.5
37	289	1.5	1	10.26	81.0
38	304	1.0	1	22.95	57.5
39	332	1.5	1	16.92	68.7
40	332	2.0	1	41.4	23.3
41	350	1.5	1	16.65	69.2

NOTES: (1) Taken from Table 3A-14 as follows:

Load Combination EQN 1 = 1.4D + 1.7L + 1.5 SRV

(2) Allowable Reinforcing Steel Stress = 54 KSI

CONTROL STRUCTURE FLOOR STEEL BEAM[1]

ELEMENT NUMBER	ELEVATION (FT)	STEEL SIZE	GOVERNING EQUATION(2)	BENDING STRESS (KSI)	STRESS MARGIN(3) %
42	200	W24 x 130	1	23.78	0.9
43	217	W30 x 210	7	29.90	7.7
44	237	W36 x 300	7	27.60	14.8
45	254	W36 x 245	7	28.80	11.1
46	269	42" Girder	7	25.53	21.2
47	289	W36 x 160	7	27.90	13.9
48	304	W36 x 194	7	30.00	7.4
49	332	38" Girder	7	24.80	23.5
50	350	W18 x 105	7	10.30	68.2

NOTES: (1) All beams are A-36 steel.

(2) Taken from Table **3A-15** as follows:

Load Combination EQN 1 = D + L + SRV
Load Combination EQN 7 = D + L + E' + SRV + LOCA

(3) Allowable bending stresses for governing equations 1 and 7 are 24.0 KSI and 32.4 KSI, respectively.

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CONTROL STRUCTURE MARGINS
FLOOR STEEL BEAM

FIGURE 3A-434

CONTROL STRUCTURE SHEAR WALLS

WALL ELEVATION (FT)	WALL MARK	GOVERNING EQUATION(2)	COMBINED AXIAL & BENDING STRESS MARGIN (%)(3)	SHEAR STRESS MARGIN (%)(4)
177	Mh	7a	2	12
200	Mh	7a	39	2
269	J	1	44	24
239	J	1	48	19
177	Line 19.4	7a	23	0
239	Line 19.4	1	3.4	24
177	Line 26.6	7a	28	0

NOTES: (1) Figure **3A-398** gives location reference.

(2) Taken from Table **3A-14** as follows:

Load Combination EQN 1 = 1.4D + 1.7L + 1.5 SRV
Load Combination EQN 7a = 1.0D + 1.0L + 1.0 E_{SS} + 1.0 SRV + 1.0 LOCA

(3) Allowable Reinforcing Steel Stress = 54 KSI
Allowable Concrete Compressive Stress = 2.8 KSI

(4) Allowable Reinforcing Steel Stress = 51 KSI

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CONTROL STRUCTURE MARGINS SHEAR WALLS

FIGURE 3A-435

CONTROL STRUCTURE STEEL PLATFORM (1)

ELEMENT NUMBER	ELEVATION (FT)	STEEL GRADE	GOVERNING EQUATION(2)	BENDING STRESS (KSI)	STRESS MARGIN(3) (%)
51	313	W10x21	2	14.7	38.8
52	313	W12x27	2	18.9	21.3
53	322	W12x27	2	10.7	55.4
54	340	W8x24	2	10.0	58.3
55	350	W8x24	2	17.6	26.7
56	350	W10x54	2	10.6	55.8

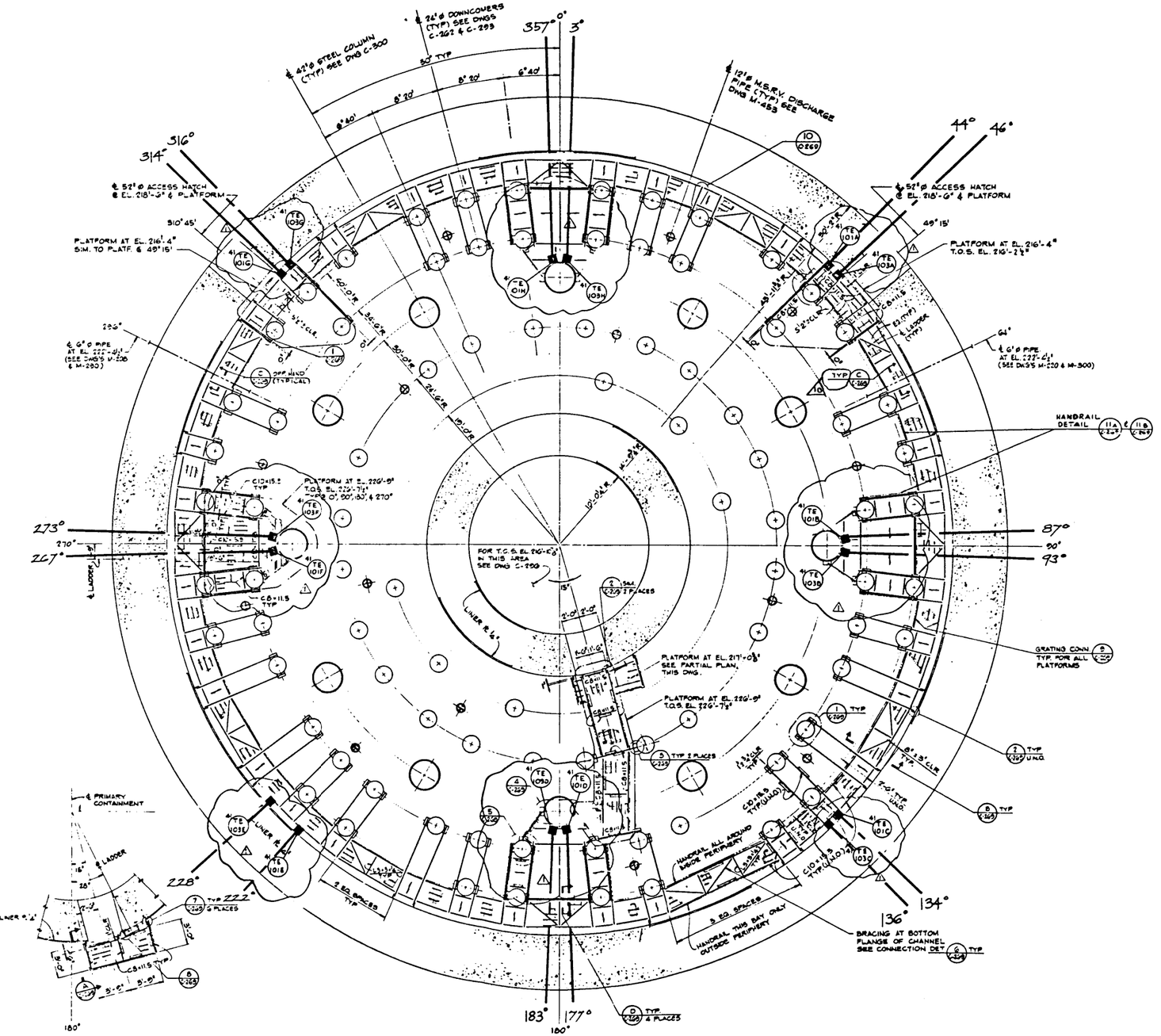
NOTES: (1) All beams are A-36 steel.
(2) Allowable bending stress = 24 KSI
(3) Taken from Table **3A-15** as follows:

Load Combination EQN 2 = D + L + To + SRV

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CONTROL STRUCTURE MARGINS STEEL PLATFORM

FIGURE 3A-436



NOTES:
1. FOR LEGEND AND GENERAL NOTES SEE DWG M-705
2. DISTANCE BETWEEN TWO REDUNDANT SENSORS (E.G. TE-A-101A & TE-A1-102A) SHOULD BE AT LEAST 12' OR MORE.
3. APPROX ELEV OF SUPPRESSION POOL TEs CONN CENTER LINE IS 228'-5". FOR EXACT ELEV SEE INSTALLATION DETAIL 8031-M-830-1029.

PLATFORM AT EL. 217'-0⅜"
T.O.S. EL. 216'-10⅜"
W/ 1½" x ⅜" GRATING

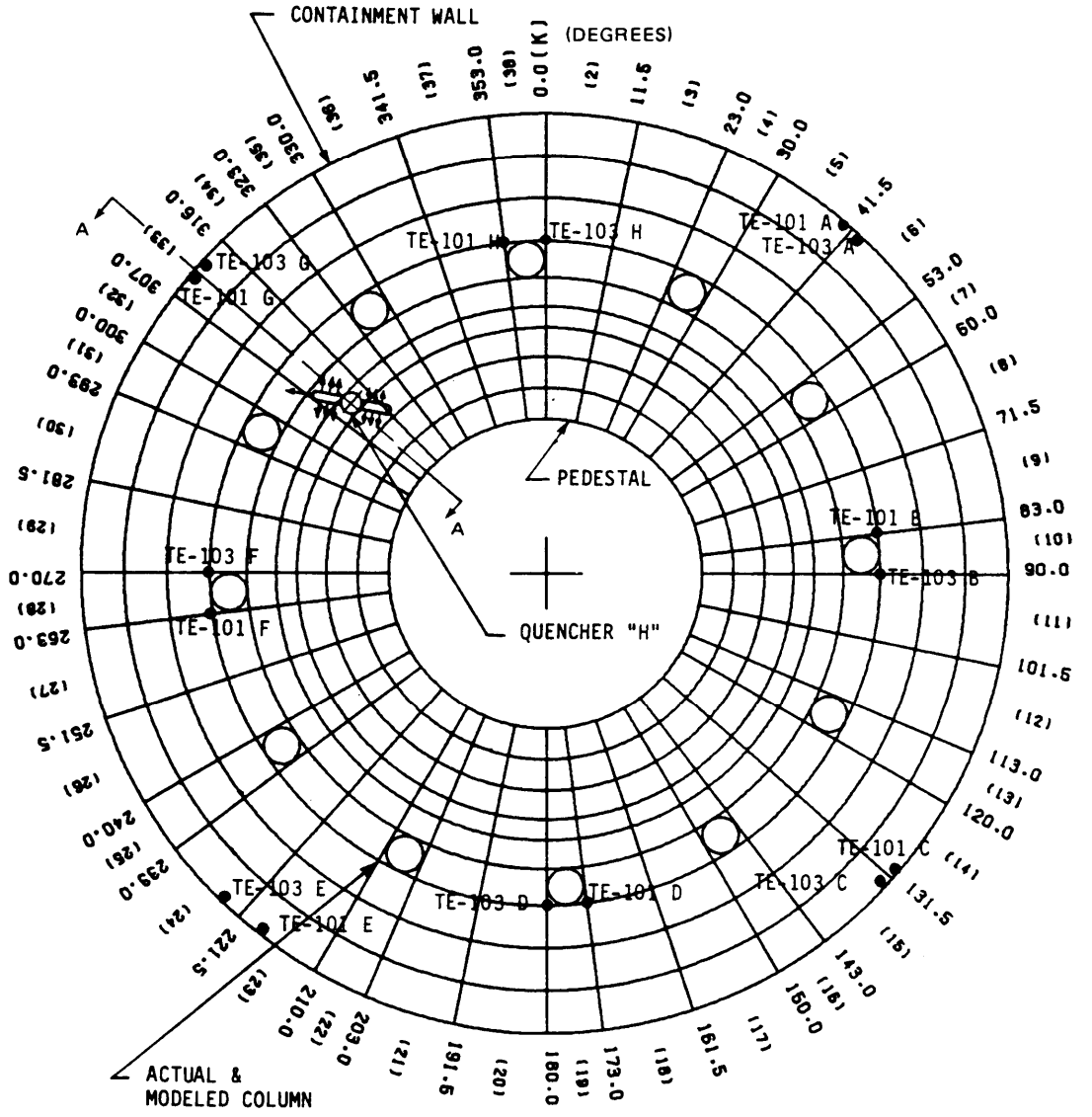
PLATFORM AT EL. 223'-4" U.N.O.
T.O.S. EL. 223'-2½" U.N.O.
W/ 1½" x ⅜" GRATING TYP

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SUPPRESSION POOL TEMPERATURE MONITORING SYSTEM SENSOR LOCATIONS

FIGURE 3A-437



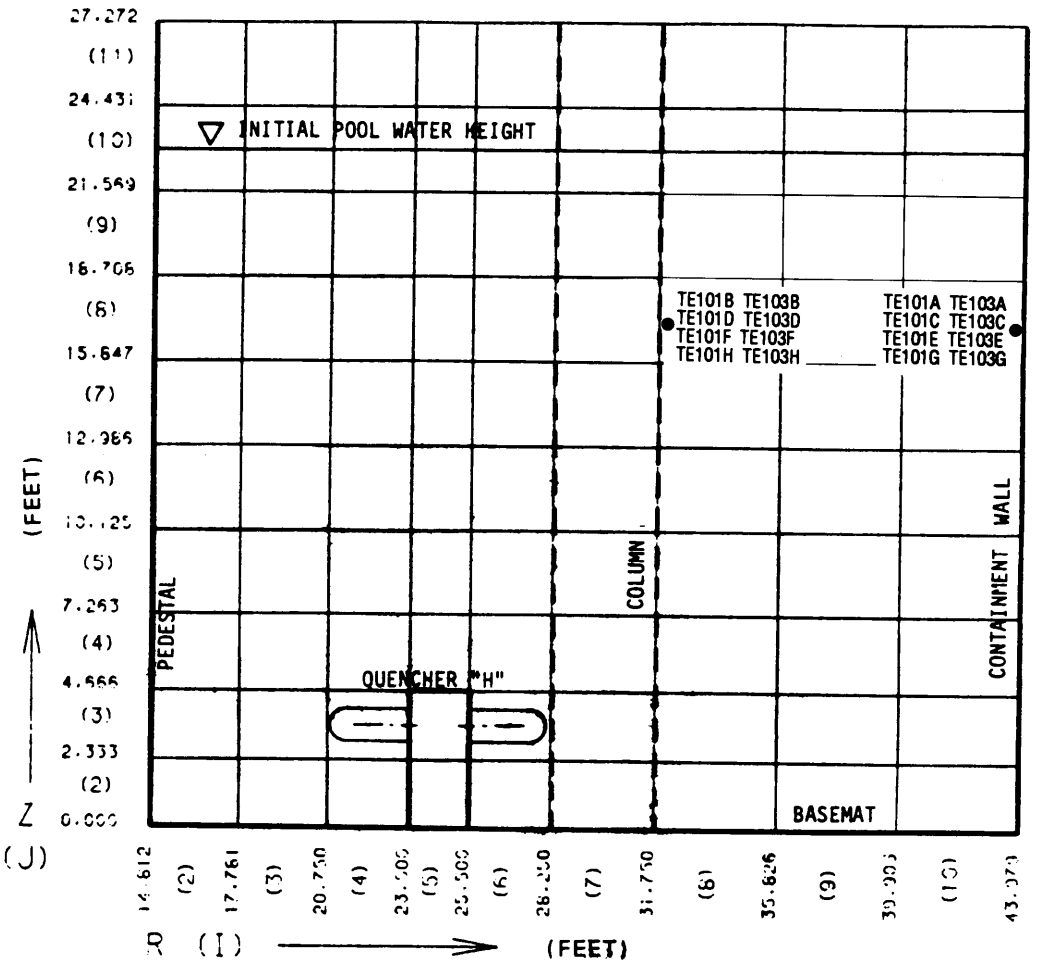
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PLAN VIEW OF MESH SYSTEM MODELING OF SUPPRESSION POOL FOR SRV-H HIGH AND LOW REACTOR PRESSURE BLOWDOWN (WITH SPTMS SENSOR LOCATIONS)

FIGURE 3A-438

VIEW A-A OF FIGURE 3A-438

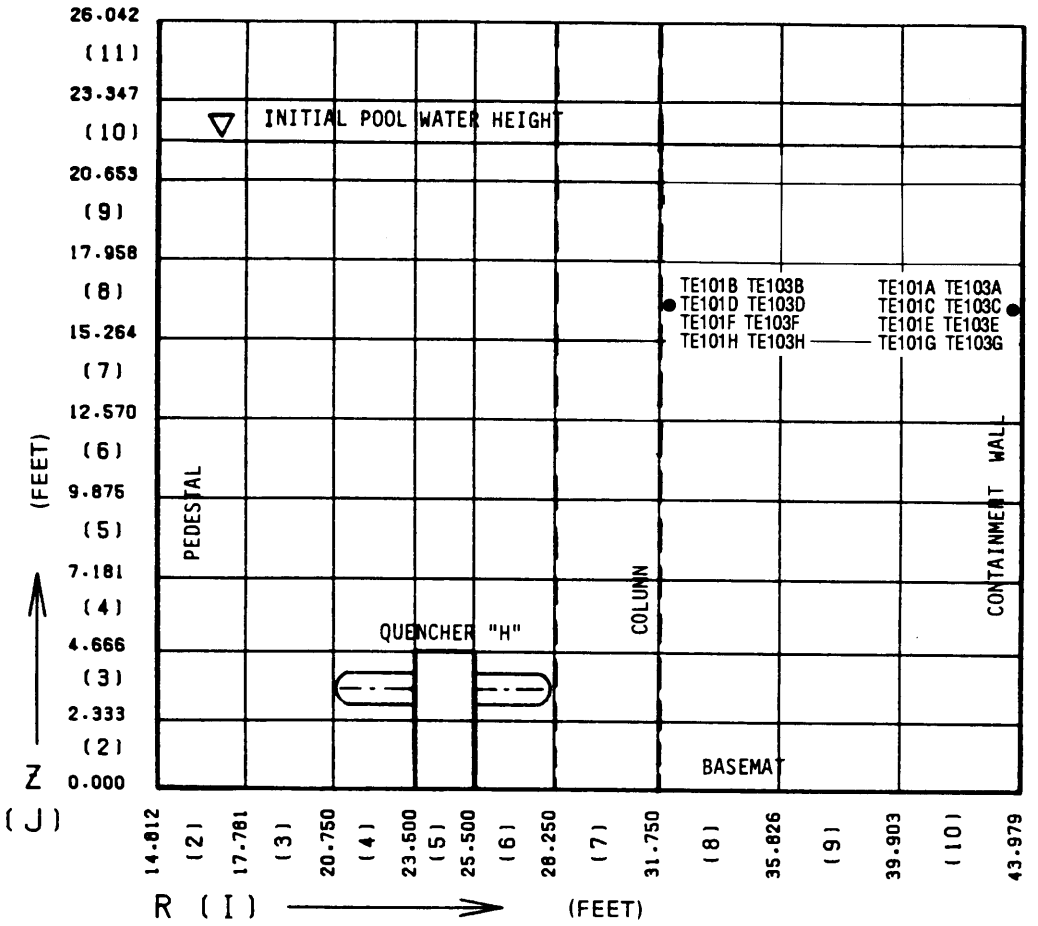


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SECTION VIEW OF MESH SYSTEM MODELING OF SUPPRESSION POOL FOR SRV-H HIGH REACTOR PRESSURE BLOWDOWN (WITH SPTMS SENSOR LOCATIONS)

FIGURE 3A-439

VIEW A-A OF FIGURE 3A-438

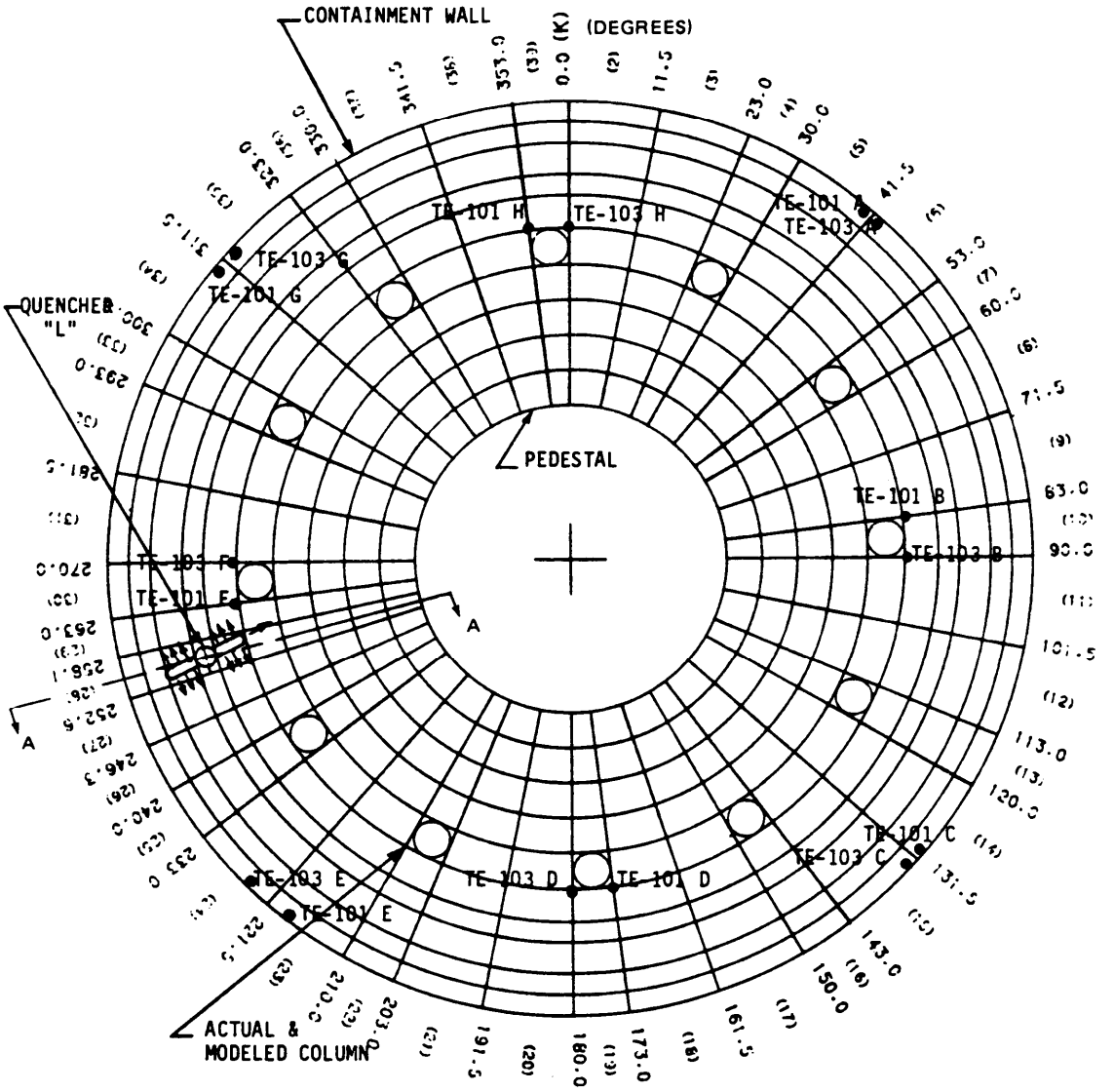


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SECTION VIEW OF MESH SYSTEM MODELING OF SUPPRESSION POOL FOR SRV-H LOW REACTOR PRESSURE BLOWDOWN (WITH SPTMS SENSOR LOCATIONS)

FIGURE 3A-440



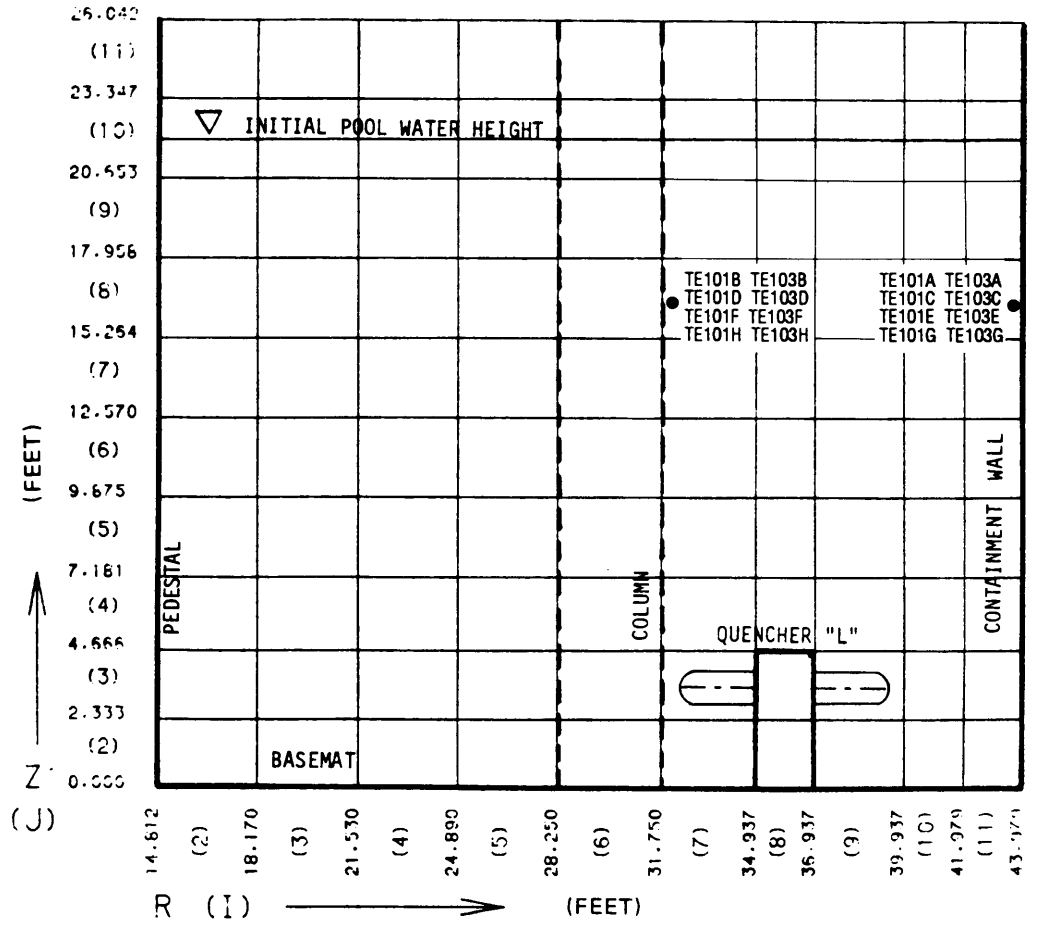
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PLAN VIEW OF MESH SYSTEM MODELING OF SUPPRESSION POOL FOR SRV-L HIGH REACTOR PRESSURE BLOWDOWN (WITH SPTMS SENSOR LOCATIONS)

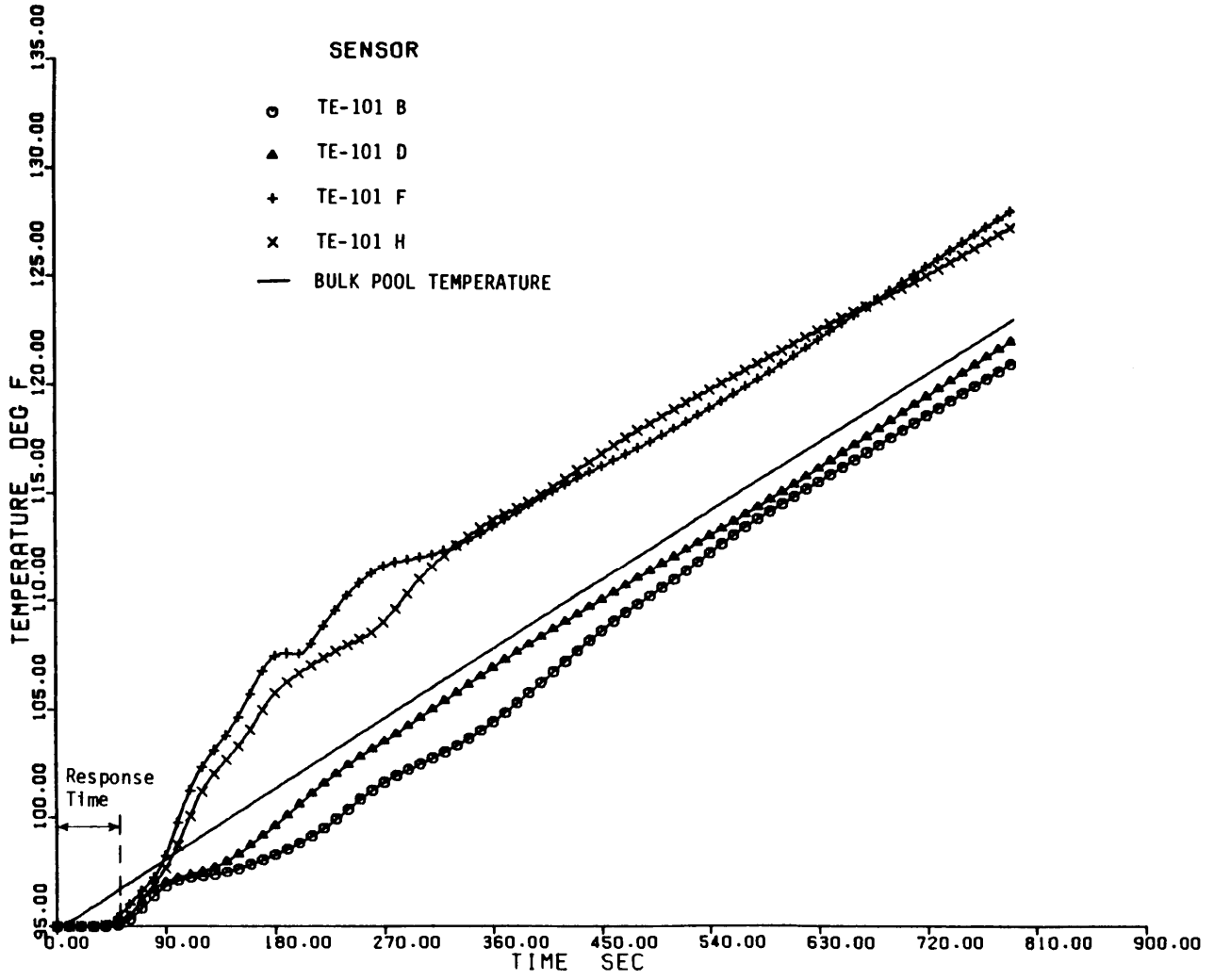
FIGURE 3A-441

VIEW A-A OF FIGURE 3A-441



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SECTION VIEW OF MESH SYSTEM MODELING OF SUPPRESSION POOL FOR SRV-L HIGH REACTOR BLOWDOWN (WITH SPTMS SENSOR LOCATIONS)
FIGURE 3A-442

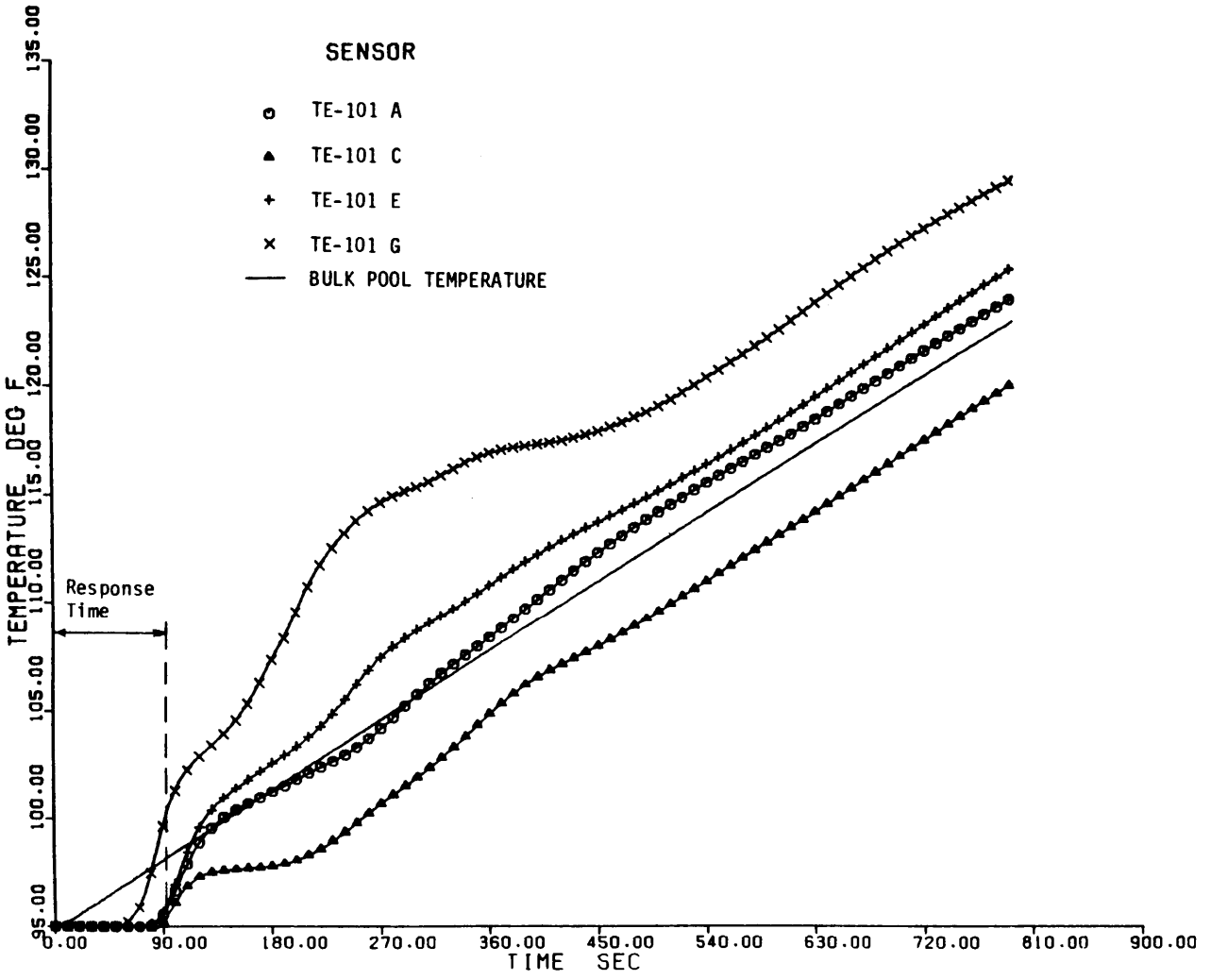


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TEMPERATURE TIME HISTORIES OF COLUMN MOUNTED SPTMS SENSORS (TE-101 B, D, F & H) FOR SRV-H HIGH REACTOR PRESSURE BLOWDOWN

FIGURE 3A-443

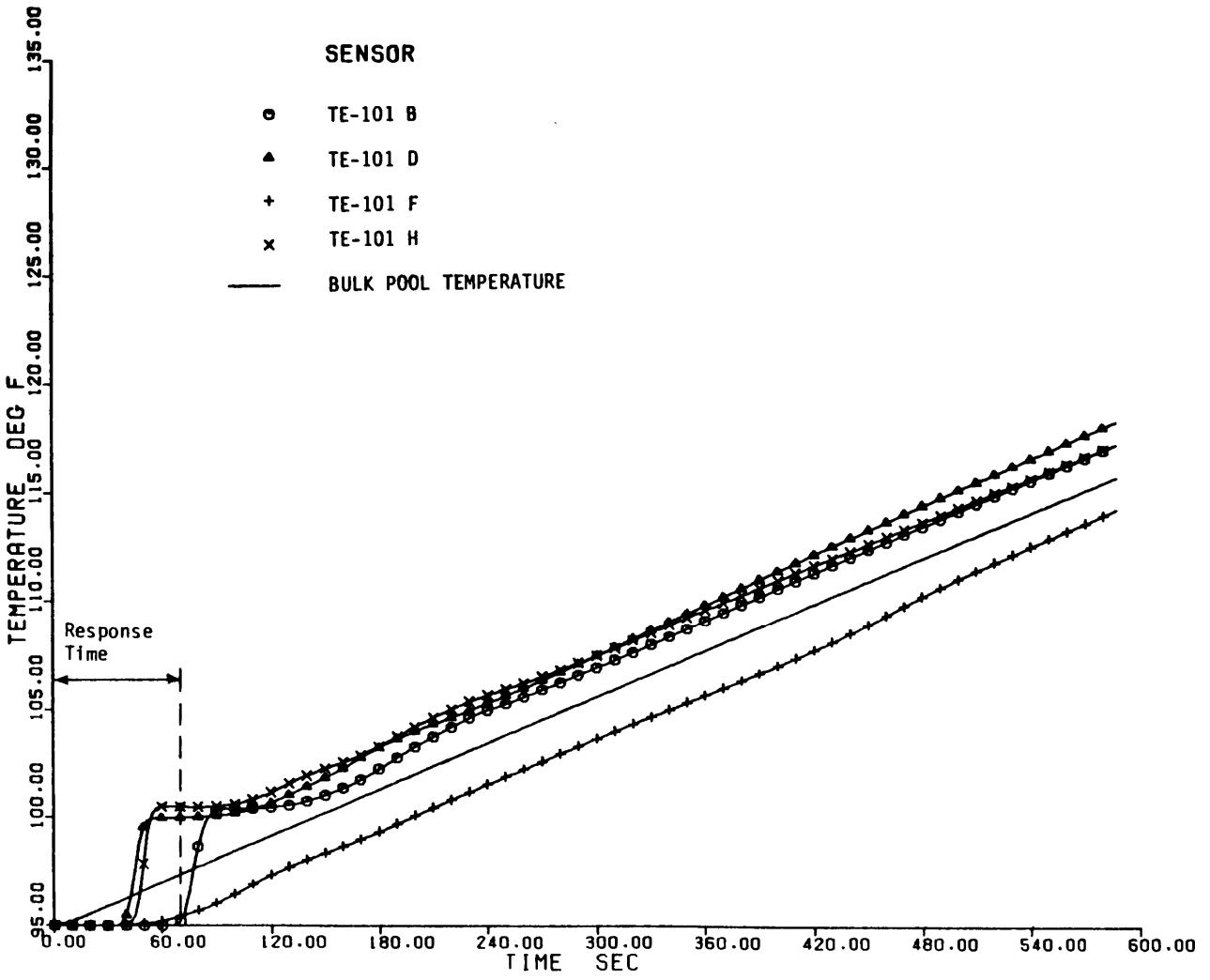


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TEMPERATURE TIME HISTORIES OF CONTAINMENT WALL MOUNTED SPTMS SENSORS (TE-101 A, C, E & G) FOR SRV-H HIGH REACTOR PRESSURE BLOWDOWN

FIGURE 3A-444

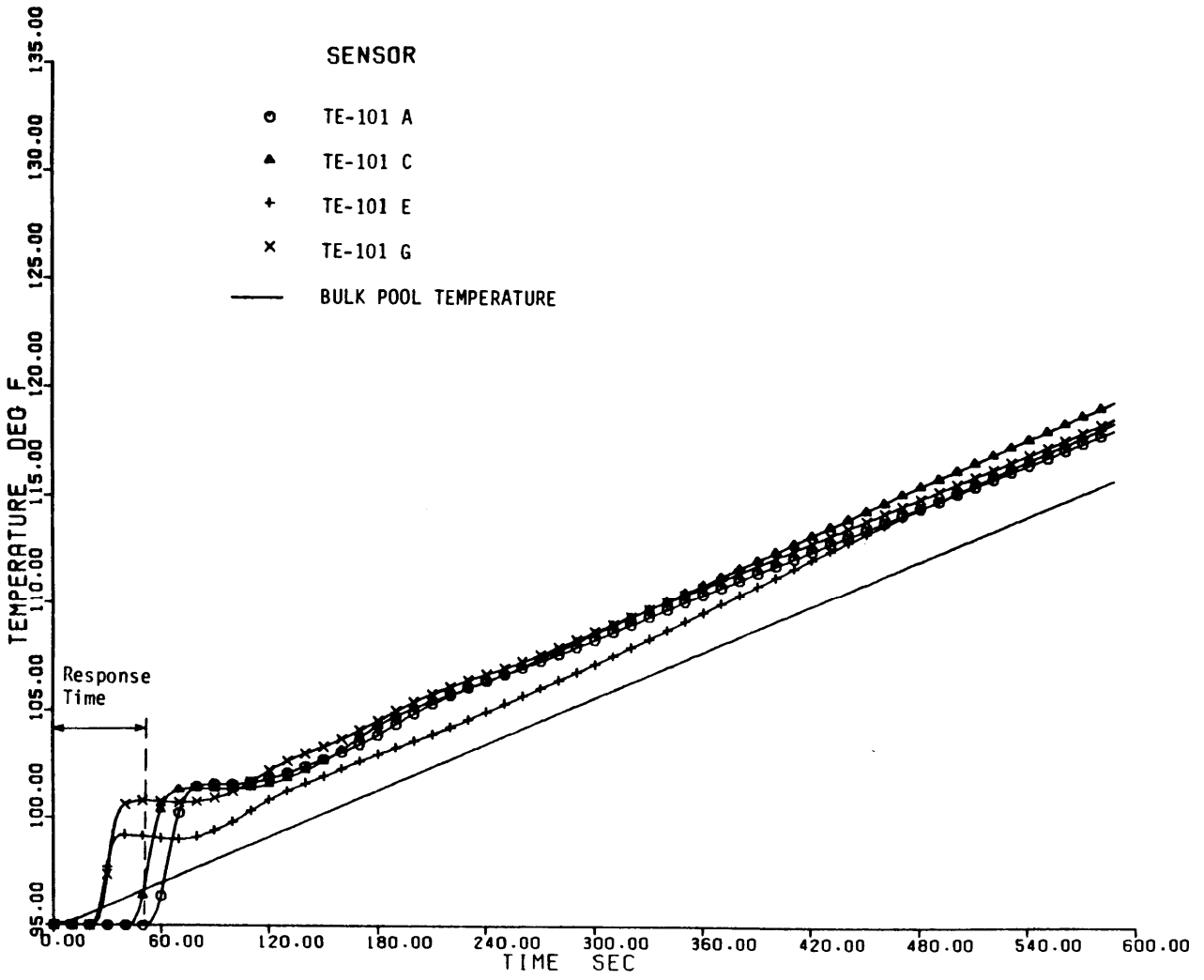


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TEMPERATURE TIME HISTORIES OF COLUMN MOUNTED SPTMS SENSORS (TE-101 B, D, F & H) FOR SRV-L HIGH REACTOR PRESSURE BLOWDOWN

FIGURE 3A-445

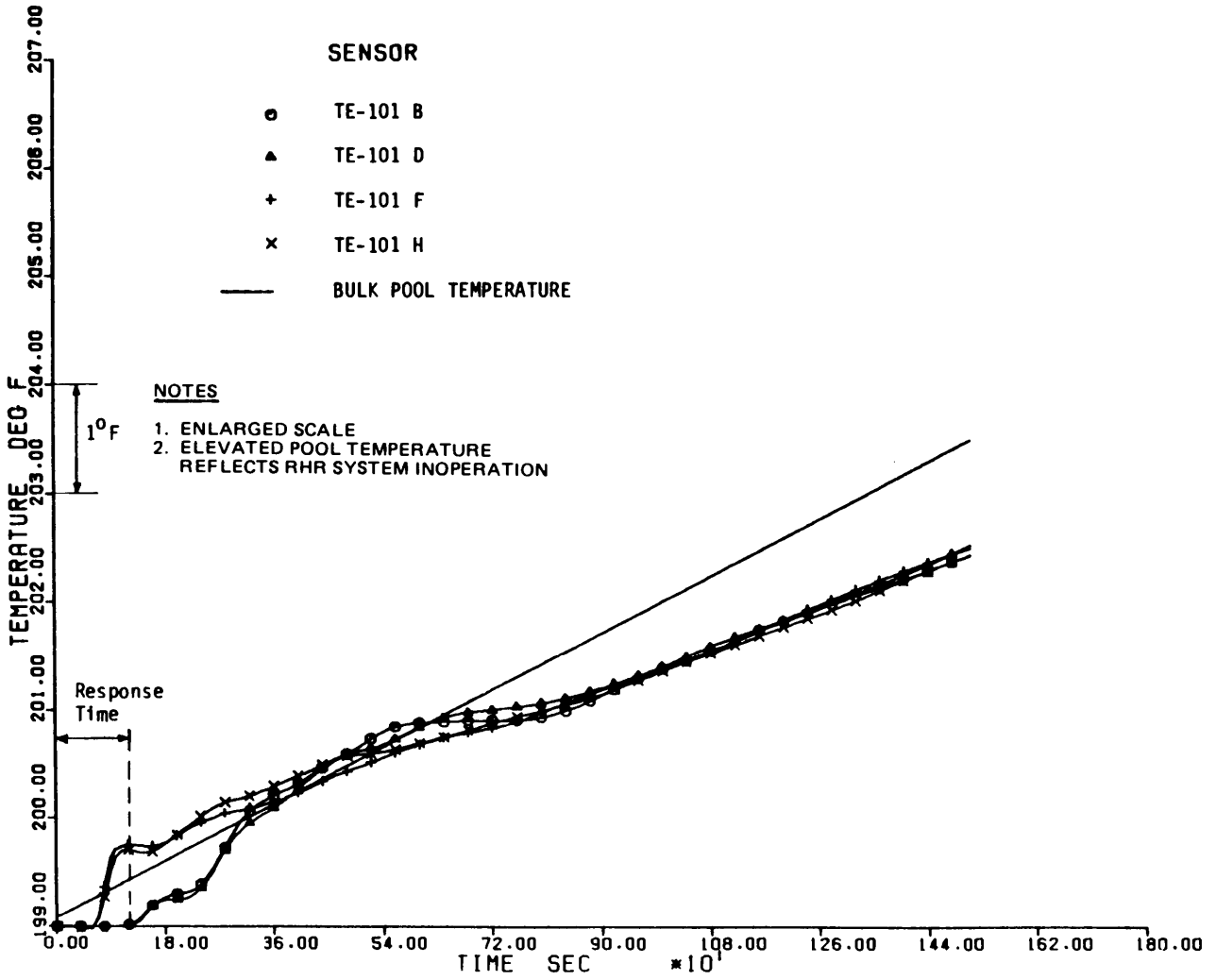


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TEMPERATURE TIME HISTORIES OF CONTAINMENT WALL MOUNTED SPTMS SENSORS (TE-101 A, C, E & G) FOR SRV-L HIGH REACTOR PRESSURE BLOWDOWN

FIGURE 3A-446

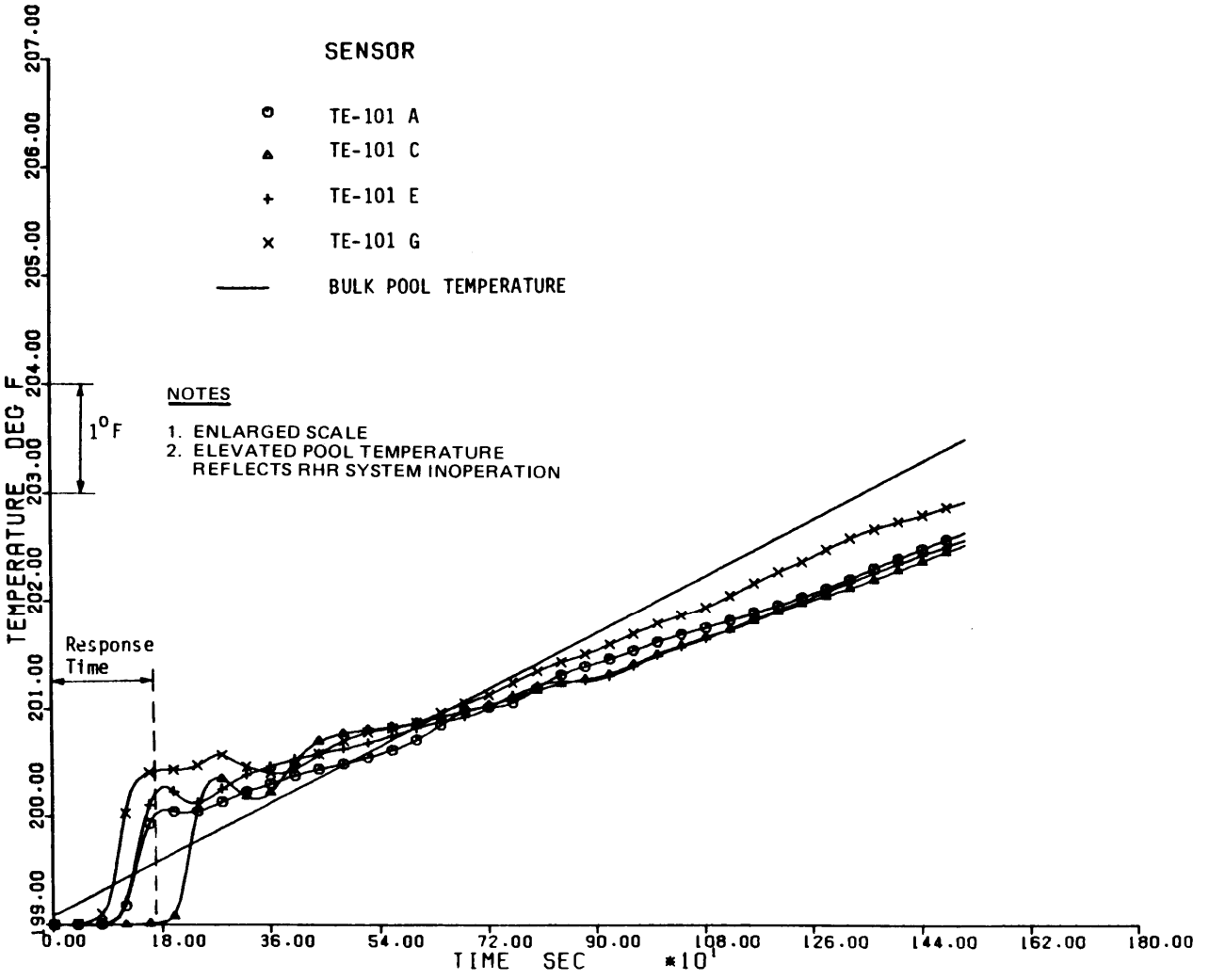


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TEMPERATURE TIME HISTORIES OF COLUMN MOUNTED SPTMS SENSORS (TE-101 B, D, F & H) FOR SRV-H LOW REACTOR PRESSURE BLOWDOWN

FIGURE 3A-447

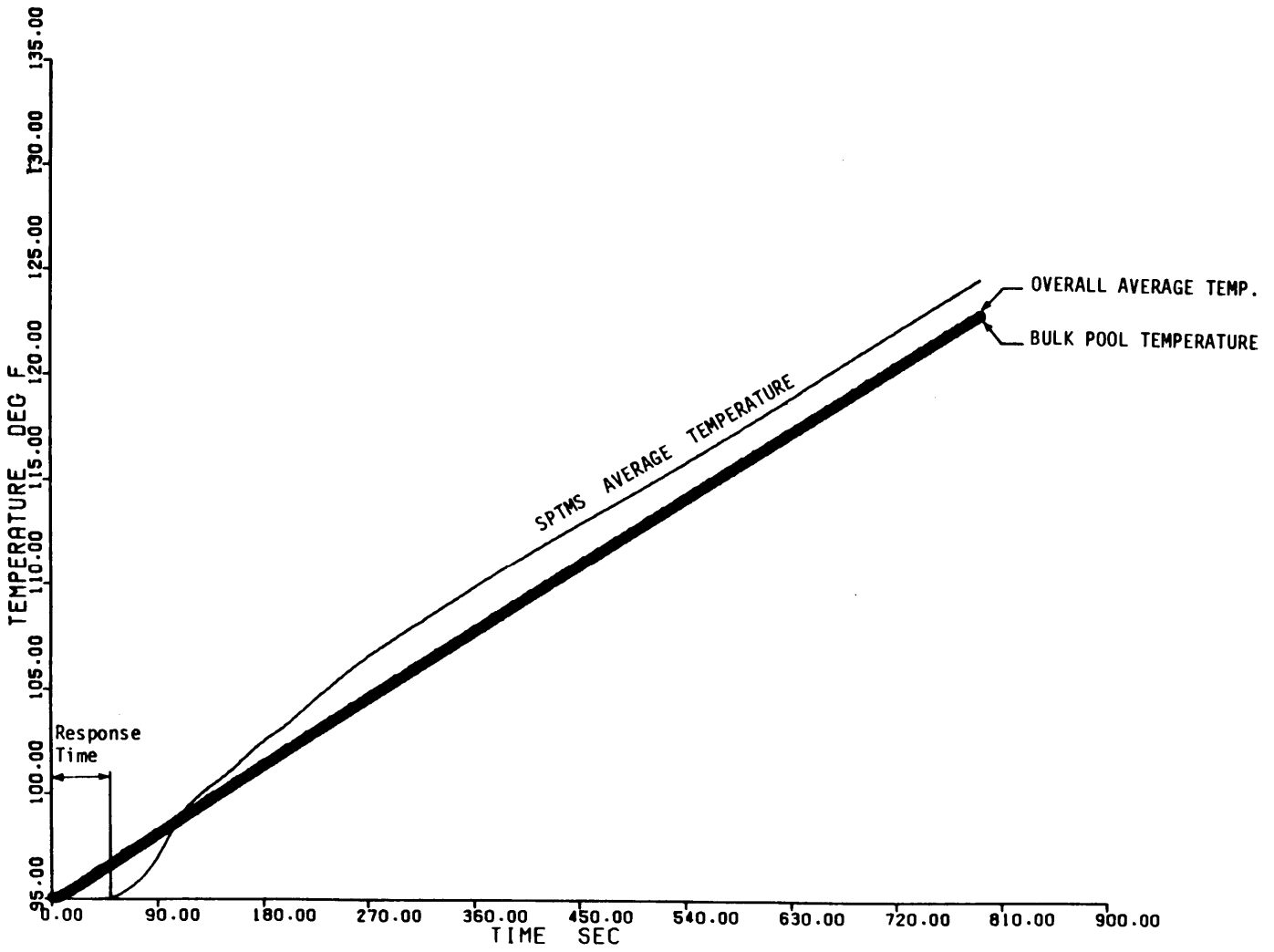


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TEMPERATURE TIME HISTORIES OF CONTAINMENT WALL MOUNTED SPTMS SENSORS (TE-101 A, C, E & G) FOR SRV-H LOW REACTOR PRESSURE BLOWDOWN

FIGURE 3A-448

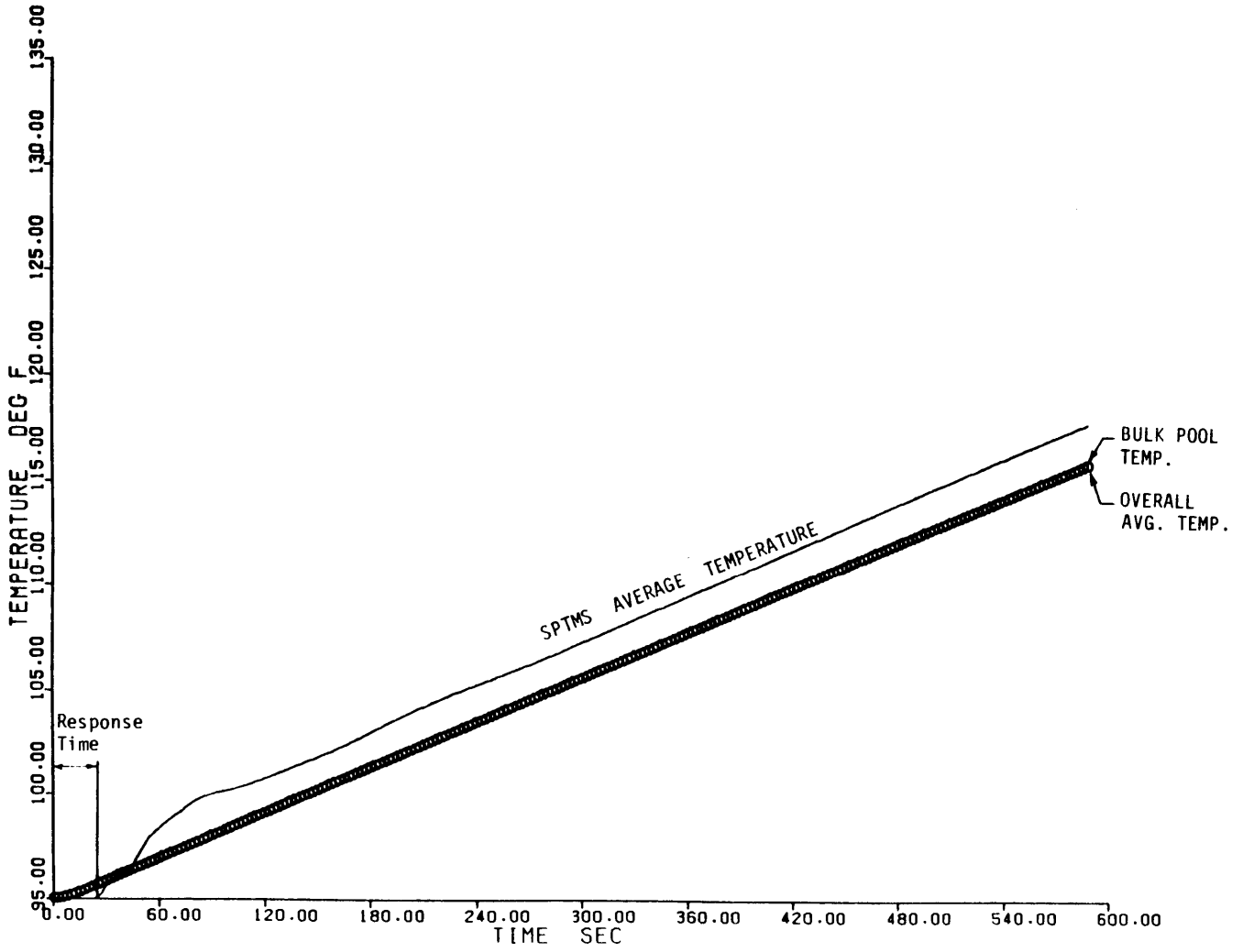


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BULK TEMPERATURE VERSUS AVERAGE TEMPERATURE FROM SPTMS DIVISION 1 (TE 101A...TE-101H) FOR SRV-H HIGH REACTOR PRESSURE BLOWDOWN

FIGURE 3A-449

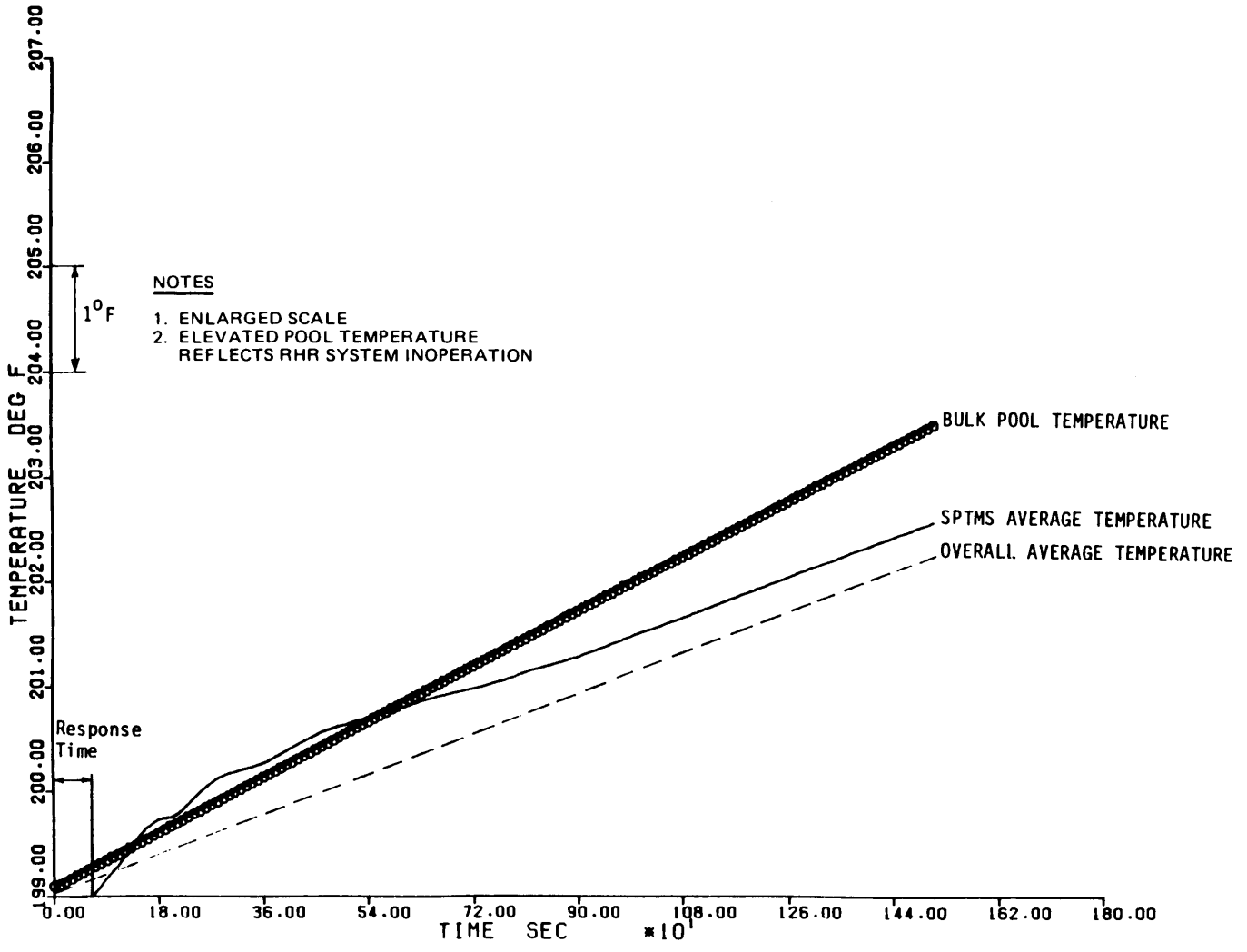


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BULK TEMPERATURE VERSUS AVERAGE TEMPERATURE FROM SPTMS DIVISION 1 (TE 101A...TE-101H) FOR SRV-L HIGH REACTOR PRESSURE BLOWDOWN

FIGURE 3A-450

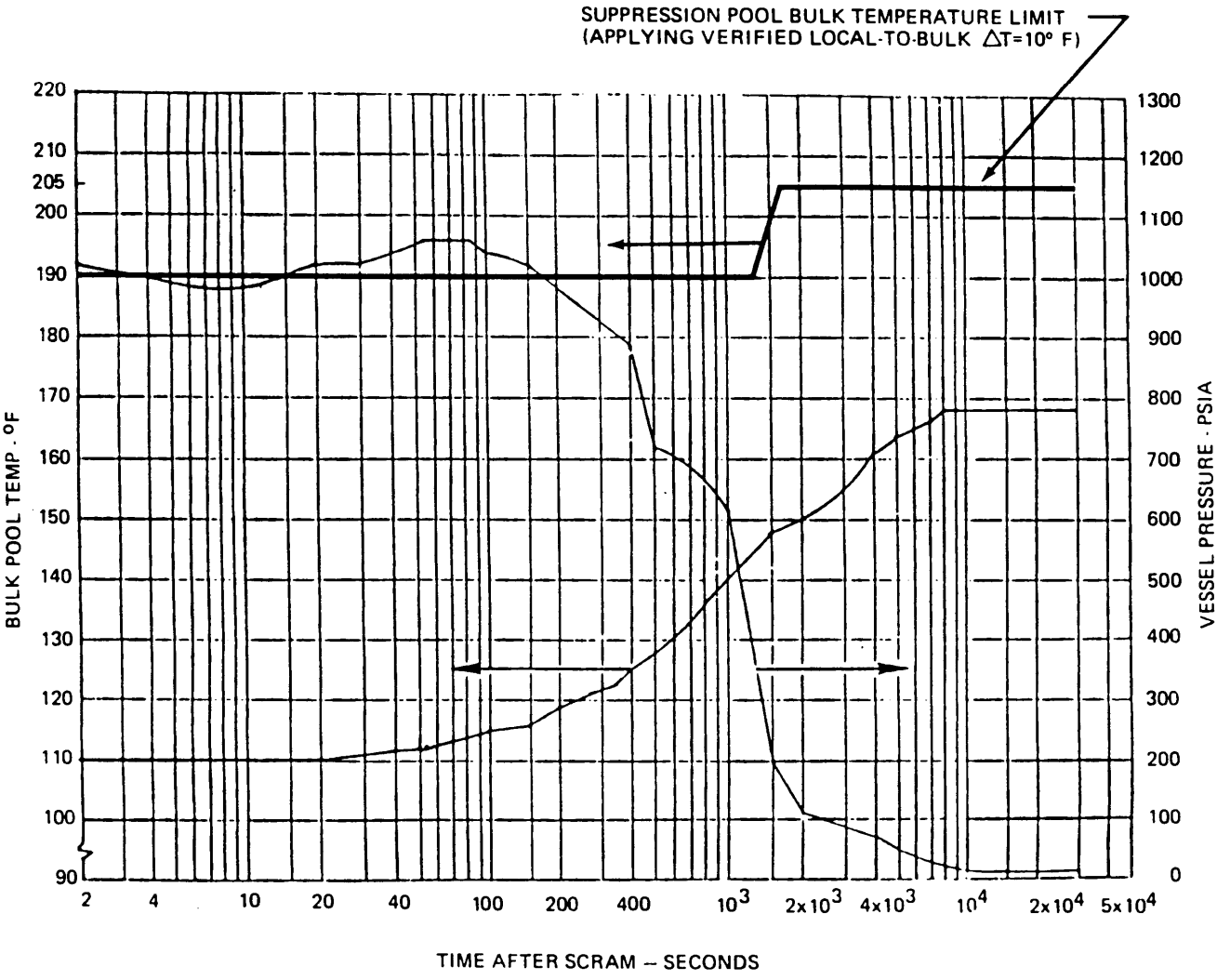


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BULK TEMPERATURE VERSUS AVERAGE TEMPERATURE FROM SPTMS DIVISION 1 (TE 101A...TE-101H) FOR SRV-H LOW REACTOR PRESSURE BLOWDOWN

FIGURE 3A-451



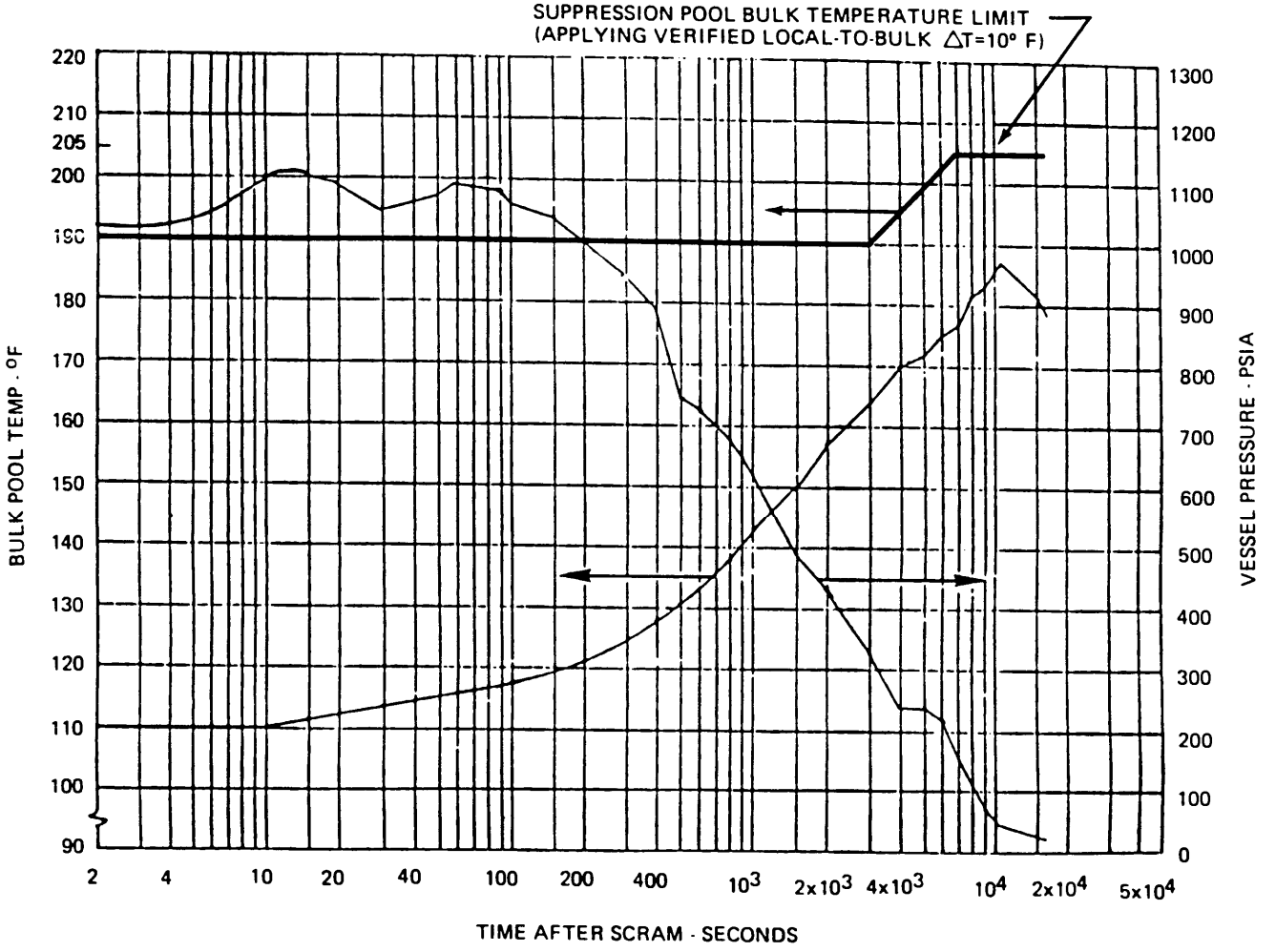
NOTE: The information presented in this figure is based on the original design basis conditions. The current suppression pool temperature response results are discussed in Section 3A.15.2. The results reasonably represent the general characteristics of the suppression pool temperature response.

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SUPPRESSION POOL TEMPERATURE TRANSIENT CASE 1.a

FIGURE 3A-452 Rev. 5, 4/96



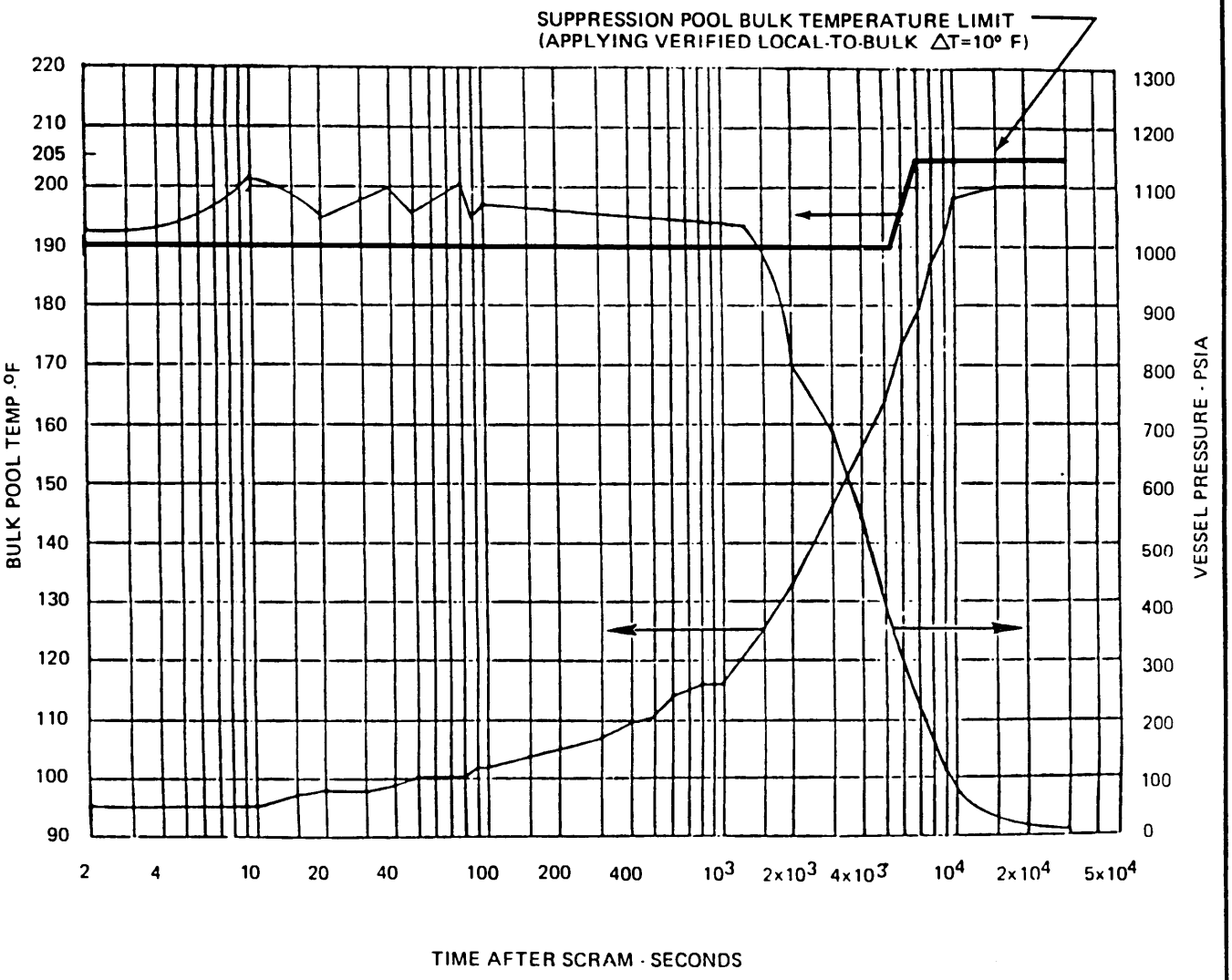
NOTE: The information presented in this figure is based on the original design basis conditions. The current suppression pool temperature response results are discussed in Section 3A.15.2. The results reasonably represent the general characteristics of the suppression pool temperature response.

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SUPPRESSION POOL TEMPERATURE TRANSIENT CASE 1.b

FIGURE 3A-453 Rev. 5, 4/96



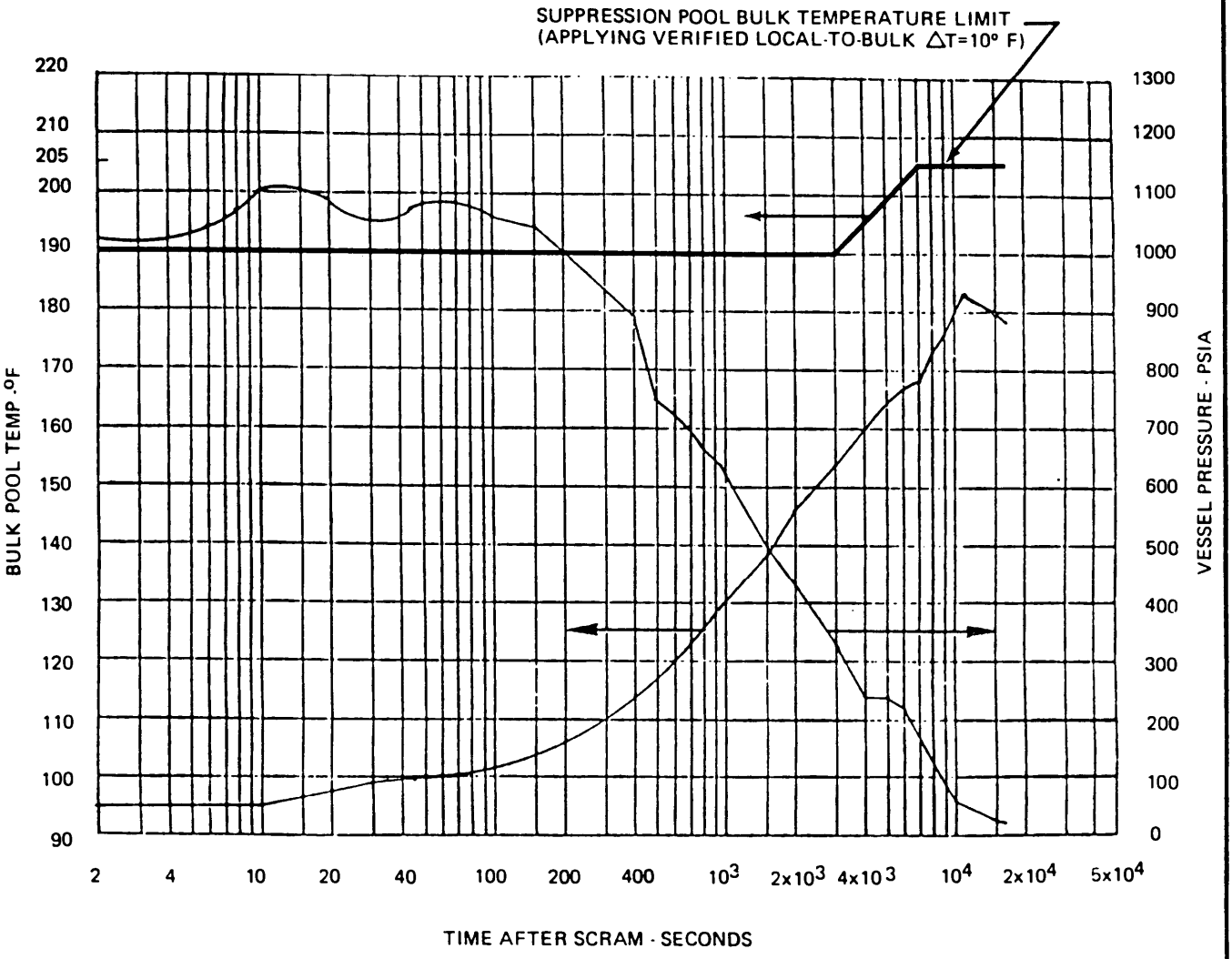
NOTE: The information presented in this figure is based on the original design basis conditions. The current suppression pool temperature response results are discussed in Section 3A.15.2. The results reasonably represent the general characteristics of the suppression pool temperature response.

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SUPPRESSION POOL TEMPERATURE TRANSIENT CASE 2.a

FIGURE 3A-454 Rev. 5, 4/96



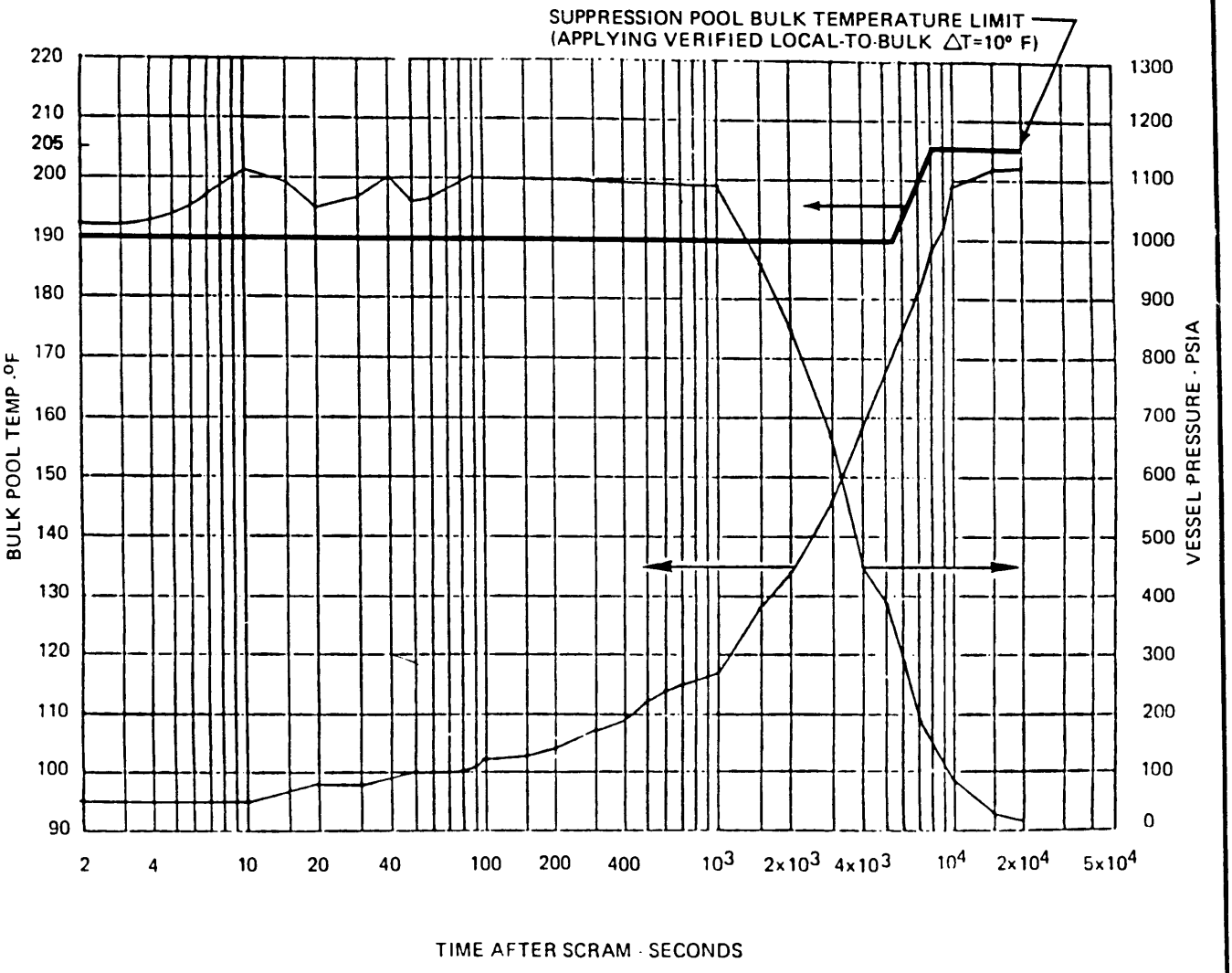
NOTE: The information presented in this figure is based on the original design basis conditions. The current suppression pool temperature response results are discussed in Section 3A.15.2. The results reasonably represent the general characteristics of the suppression pool temperature response.

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SUPPRESSION POOL TEMPERATURE TRANSIENT CASE 2.b

FIGURE 3A-455 Rev. 5, 4/96



NOTE: The information presented in this figure is based on the original design basis conditions. The current suppression pool temperature response results are discussed in Section 3A.15.2 and Table 3A-30. The results reasonably represent the general characteristics of the suppression pool temperature response.

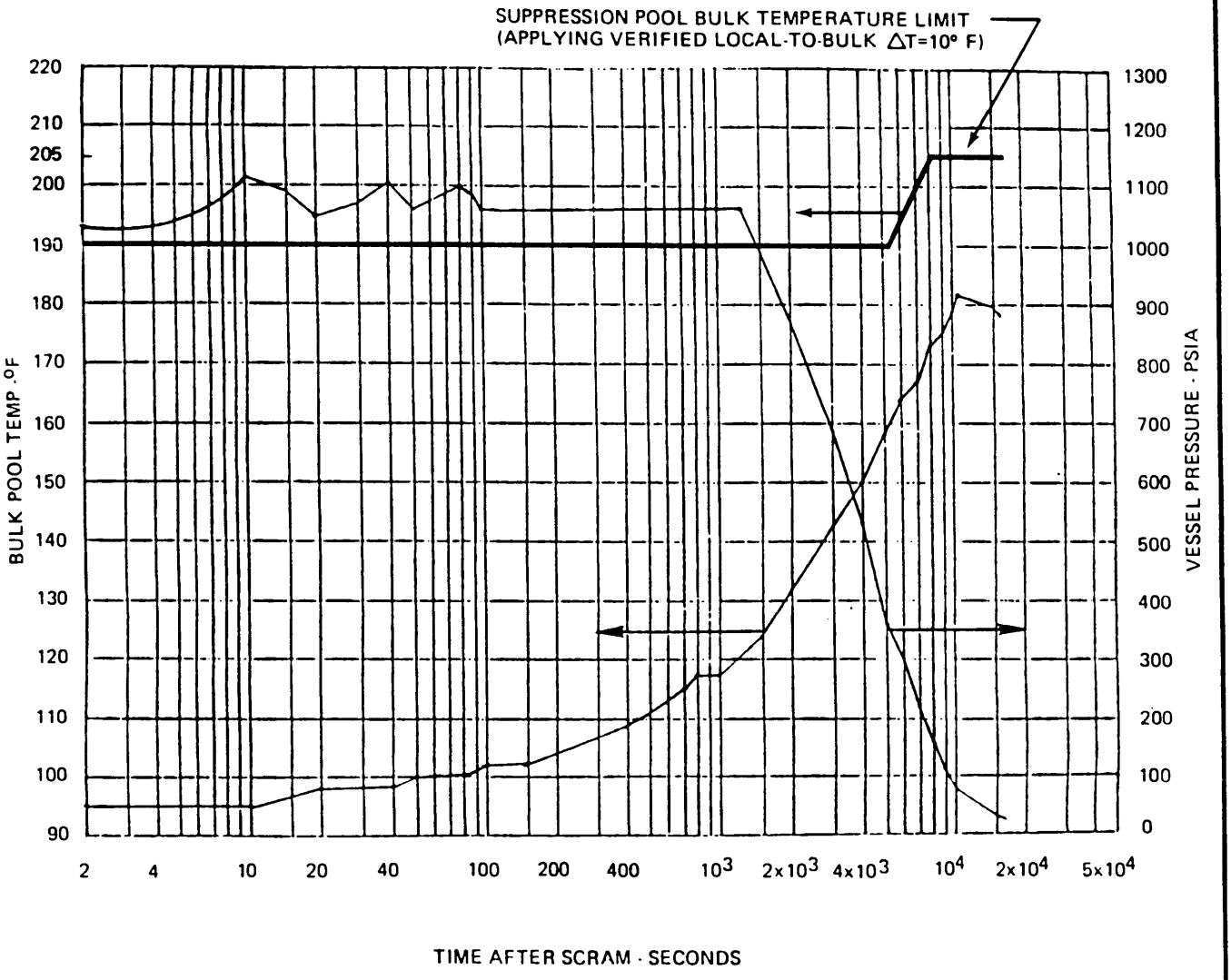
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SUPPRESSION POOL TEMPERATURE TRANSIENT CASE 3.a

FIGURE 3A-456

Rev. 5, 4/96



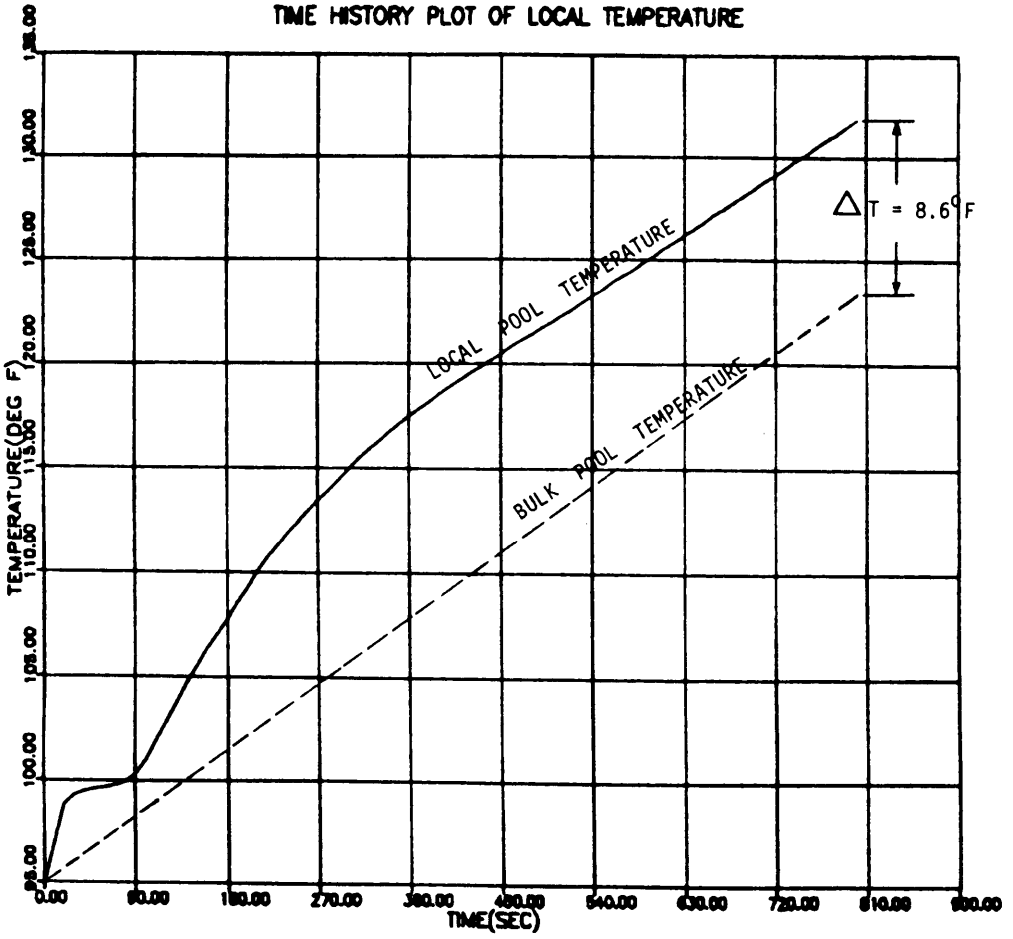
NOTE: The information presented in this figure is based on the original design basis conditions. The current suppression pool temperature response results are discussed in Section 3A.15.2. The results reasonably represent the general characteristics of the suppression pool temperature response.

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SUPPRESSION POOL TEMPERATURE TRANSIENT CASE 3.b

FIGURE 3A-457 Rev. 5, 4/96

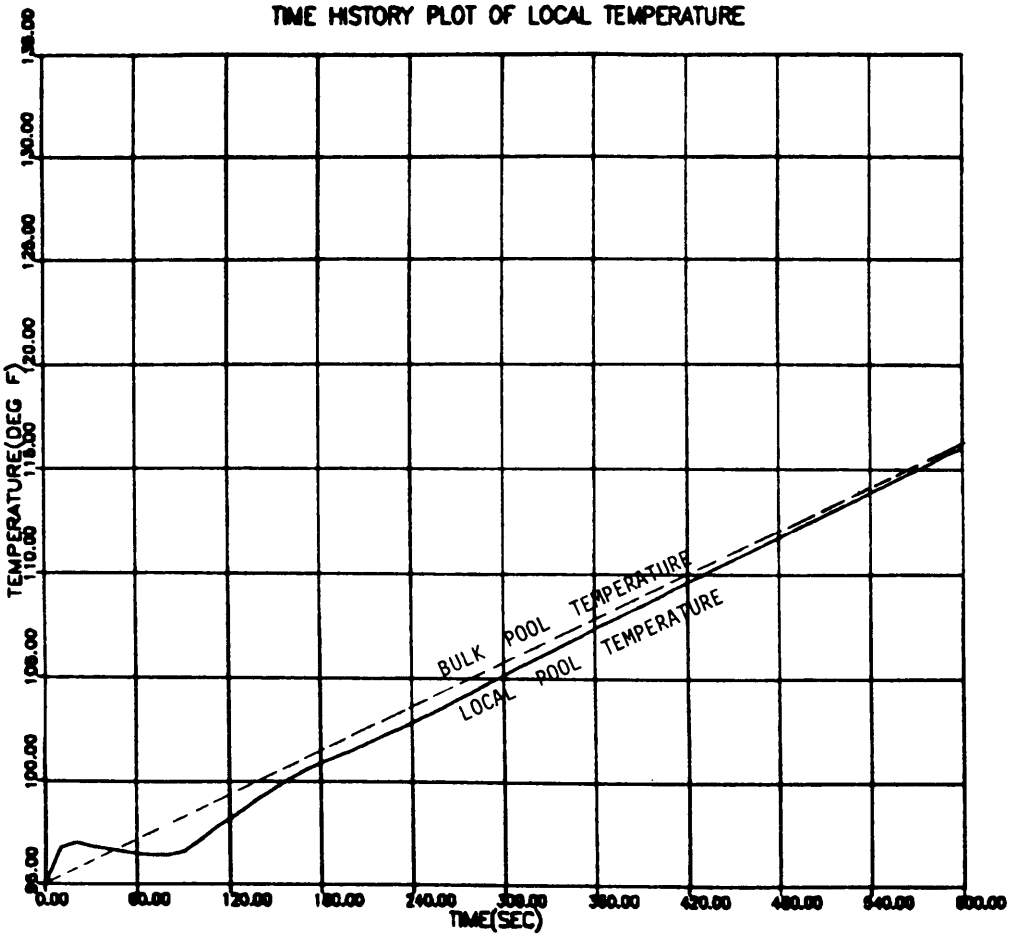


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UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT

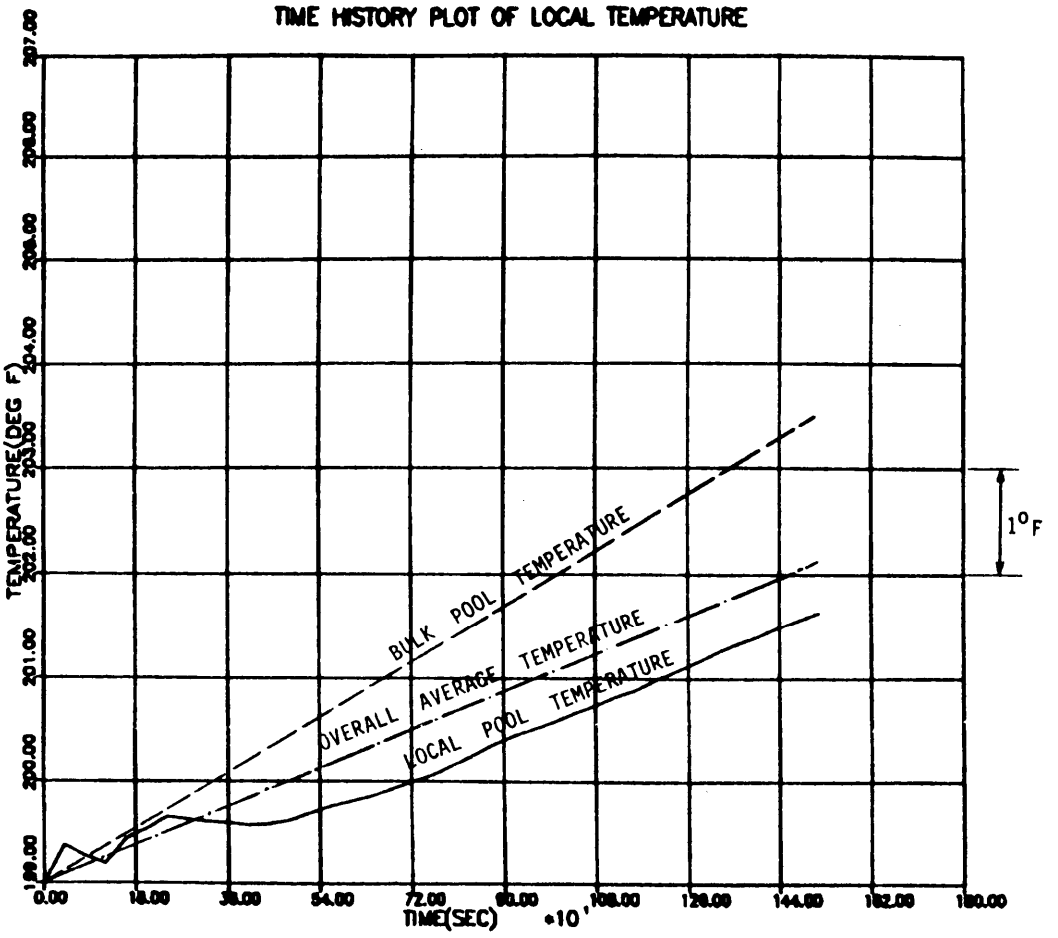
LOCAL-TO-BULK TEMPERATURE DIFFERENCE (ΔT) TRACE FOR SRV-H BLOWDOWN UNDER HIGH REACTOR PRESSURE

FIGURE 3A-458



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DESIGN ASSESSMENT REPORT
LOCAL-TO-BULK TEMPERATURE DIFFERENCE (ΔT) TRACE FOR SRV-L BLOWDOWN UNDER HIGH REACTOR PRESSURE
FIGURE 3A-459

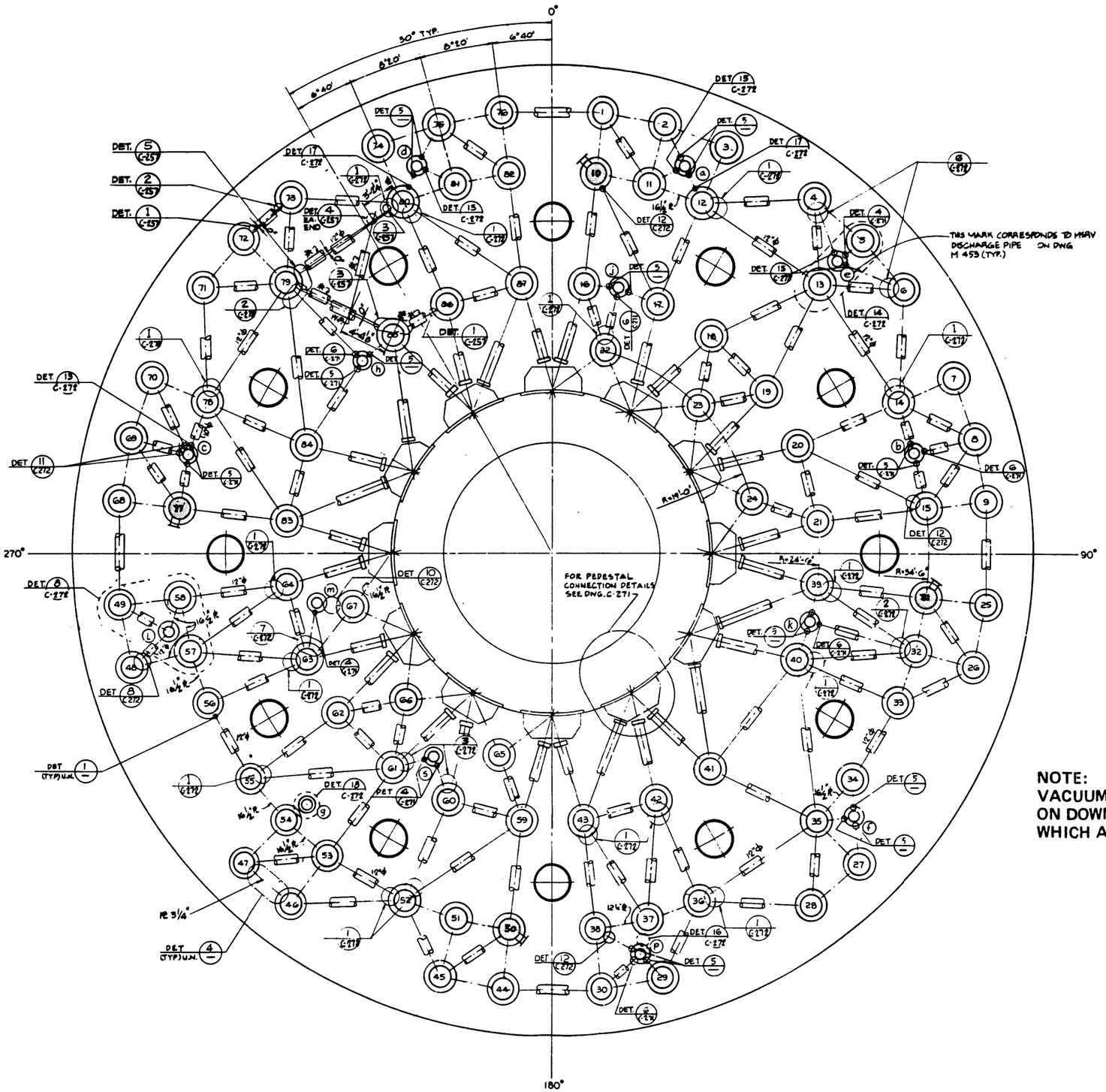


NOTES

1. ENLARGED SCALE
2. ELEVATED POOL TEMPERATURE REFLECTS RHR SYSTEM INOPERATION

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DESIGN ASSESSMENT REPORT
LOCAL-TO-BULK TEMPERATURE DIFFERENCE (ΔT) TRACE FOR SRV-H BLOWDOWN UNDER LOW REACTOR PRESSURE
FIGURE 3A-460



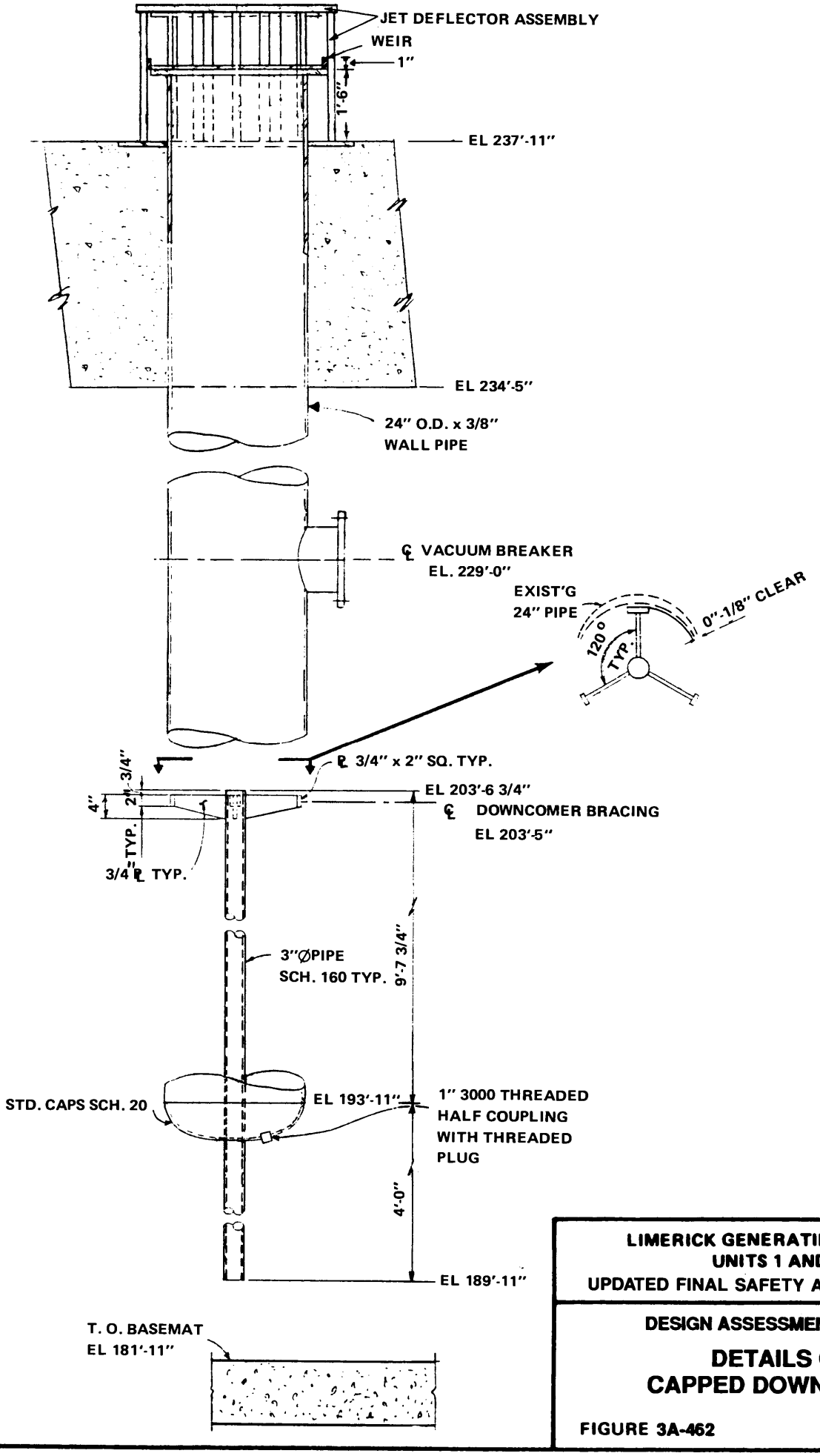
NOTE:
VACUUM BREAKERS ARE INSTALLED ON DOWNCOMERS 10, 31, 50 AND 77 WHICH ARE CAPPED (E.G., ⊗)

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DESIGN ASSESSMENT REPORT

LOCATION OF CAPPED DOWNCOMERS WITH VACUUM BREAKERS

FIGURE 3A-461



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DESIGN ASSESSMENT REPORT

DETAILS OF CAPPED DOWNCOMER

FIGURE 3A-462

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CHAPTER 4 - REACTOR

4.0 INTRODUCTION

This chapter was prepared using topical report, "General Electric Standard Application for Reactor Fuel" (GESTAR-II) including the "United States Supplement," NEDE-24011-P-A-32 and NEDE-24011-P-A-32-US. Applicable sections of this report are referenced as noted in Sections 4.1 through 4.4.

4.1 SUMMARY DESCRIPTION

The reactor assembly consists of the reactor vessel, its internal components of the core, steam separator and dryer assemblies, and jet pumps. Also included in this assembly are the control rods, CRD housings, and the CRDs. Figure 3.9-4 shows the arrangement of reactor assembly components. A summary of the important design and performance characteristics is given in Section 1.3. Loading conditions for reactor assembly components are discussed in Section 3.9.

4.1.1 REACTOR VESSEL

The reactor vessel design and description is discussed in Section 5.3.

4.1.2 REACTOR INTERNAL COMPONENTS

The major reactor internal components are the core (fuel, channels, control blades, and incore instrumentation), core support structure (including the shroud, top guide, and core plate), shroud head and steam separator assembly, steam dryer assembly, feedwater spargers, core spray spargers, and jet pumps. Except for the Zircaloy in the reactor core, these reactor internals are made of stainless steel or other corrosion-resistant alloys. Of the preceding components, the fuel assemblies (including fuel rods and channel), control blades, incore instrumentation, shroud head and steam separator assembly, steam dryers and jet pump subassemblies are removable when the reactor vessel is open.

4.1.2.1 Reactor Core

4.1.2.1.1 General

The design of the BWR core (including fuel) is based on the proper combination of many design variables and operating experience. This contributes to the achievement of high reliability.

Important features of the reactor core arrangement are as follows:

a. The bottom-entry control blades are cruciform-shaped and consist of stainless steel clad neutron absorbing material as described in Section 4.2. The neutron-absorbing material is surrounded by a stainless steel sheath in the conventional designs. In the newer designs, (e.g., GE Marathon Series) the absorber tube and sheath arrangement is replaced with an array of welded square tubes containing the neutron absorbing material.

b. Fixed incore fission chambers provide continuous power range neutron flux monitoring. A guide tube in each incore assembly provides for a traversing ion chamber for calibration and axial detail. Source and intermediate range detectors are located incore and are axially retractable. The incore location of the startup and source range instruments provides coverage of the large reactor core and provides an acceptable signal-to-noise ratio and neutron-to-gamma ratio. All incore instrument leads enter from the bottom. Source and intermediate range instruments are in service during refueling. Incore instrumentation is further discussed in Section 7.6 and 7.7.

c. Experience has shown that the operator, utilizing the incore flux monitoring system, can maintain the desired power distribution within a large core by proper control rod positioning.

d. The reusable channels provide a fixed flow path for the boiling coolant, serve as a guiding surface for the control rods, and protect the fuel during handling operations.

e. Mechanical reactivity control permits criticality checks during refueling and provides maximum plant safety. The core is designed to be subcritical at any time in its operating history, with any one control rod fully withdrawn.

f. The selected control rod pitch represents a practical value of individual control rod reactivity worth, and allows adequate clearance below the pressure vessel, between CRDMs, for ease of maintenance and removal.

4.1.2.1.2 Core Configuration

The reactor core is arranged as an upright circular cylinder containing a large number of fuel cells, and is located within the reactor vessel. The coolant flows upward through the core. The core arrangement (plan view) and the lattice configuration are given in Section 4.3.2.

4.1.2.1.3 Fuel Assembly Description

Descriptions of the fuel assembly and the fuel rods are given in Section 4.2.

4.1.2.1.4 Fuel Assembly Support and Control Rod Location

Twenty four peripheral fuel assemblies and their individual peripheral fuel support pieces are supported by the core plate. Otherwise, individual fuel assemblies in the core rest on fuel support pieces mounted on top of the control rod guide tubes. Each guide tube, with its fuel support piece, bears the weight of four assemblies, and is supported by a CRD penetration nozzle in the bottom head of the reactor vessel. The core plate provides lateral support and guidance at the top of each control rod guide tube.

The top guide, mounted inside the shroud, provides lateral support and guidance for each fuel assembly. The reactivity of the core is controlled by cruciform-shaped control rods (Section 4.2.2) and their associated mechanical-hydraulic drive system. The control rods occupy alternate spaces between fuel assemblies. Each independent CRD enters the core from the bottom, accurately positions its associated control rod during normal operation, and yet exerts approximately ten times the force of gravity to insert the control rod during the scram mode of operation. Bottom-entry allows optimum power shaping in the core, ease of refueling, and convenient CRD maintenance.

4.1.2.2 Shroud

Information on the shroud is contained in Section 3.9.5.

4.1.2.3 Shroud Head and Steam Separator Assembly

Information on the shroud head and steam separators is contained in Section 3.9.5.

4.1.2.4 Steam Dryer Assembly

Information on the steam dryer assembly is contained in Section 3.9.5.

4.1.3 REACTIVITY CONTROL SYSTEMS

4.1.3.1 Operation

The control rods perform dual functions of power distribution shaping and reactivity control. Power distribution in the core is controlled during operation of the reactor by manipulation of selected patterns of rods. The rods, which enter from the bottom of the near-cylindrical reactor core, are positioned to counterbalance steam voids in the top of the core and effect significant power flattening. These groups of control elements, used for power flattening, experience a somewhat higher duty cycle and neutron exposure than the other rods in the control system.

The reactivity control function requires that all rods be designed for both reactor scram and reactivity regulation. Because of this, the control elements are mechanically designed to withstand the dynamic forces resulting from a scram. They are connected to bottom-mounted, hydraulically actuated drive mechanisms which allow either axial positioning for reactivity regulation, or rapid scram insertion. The design of the rod-to-drive connection permits each blade to be attached or detached from its drive, without disturbing the remainder of the control system. The bottom-mounted drives permit the entire control system to be left intact and operable for tests with the reactor vessel open.

4.1.3.2 Description of Control Rods

A description of the control rods is given in Section 4.2.2.1.

4.1.3.3 Supplementary Reactivity Control

The initial and reload core control requirements are met by use of the combined effects of the movable control rods, supplementary burnable poison, and the variation of reactor coolant flow. A description of the supplementary burnable poison is given in Section 4.2.2.

4.1.4 ANALYSIS TECHNIQUES

4.1.4.1 Reactor Internal Components

Computer codes used for the analysis of the internal components are:

a. MASS

b. SNAP (MULTISHELL)

c. GASP

d. NOHEAT

e. FINITE

f. DYSEA

g. SHELL 5

h. HEATER

i. FAP 71

j. CREEP PLAST

k. ANSYS

Detailed descriptions of these programs are given below:

4.1.4.1.1 MASS (Mechanical Analysis of Space Structure)

4.1.4.1.1.1 Program Description

This program, proprietary to GE, is an outgrowth of the PAPA (Plate and Panel Analysis) program originally developed by L. Beitch in the early 1960s. The program is based on the principle of the finite-element method. Governing matrix equations are formed in terms of joint displacements using a "stiffness-influence coefficient" concept originally proposed by L. Beitch (Reference 4.1-2). The program can analyze curved beam, plate, and shell elements. It can accommodate mechanical and thermal loads in a static analysis, and can predict natural frequencies and mode shapes in a dynamic analysis.

4.1.4.1.1.2 Program Version and Computer

GE's Nuclear Energy Division used revision "0" of MASS. The program operated on a Honeywell 6000 computer.

4.1.4.1.1.3 History of Use

Since its development in the early 1960s, the program has been successfully applied to a wide variety of jet engine structural problems, many of which involve extremely complex geometries. The use of the program by GE's Nuclear Energy Division began shortly after its development.

4.1.4.1.1.4 Extent of Application

Besides the Jet Engine and Nuclear Energy Divisions, GE's Missile and Space Division, the Appliance Division, and the Turbine Division have also applied the program to a wide range of engineering problems. The Nuclear Energy Division uses it mainly for piping and reactor internals analyses.

4.1.4.1.2 SNAP (MULTISHELL)

4.1.4.1.2.1 Program Description

The SNAP program, which is also called MULTISHELL, is the GE code which determines the loads, deformations, and stresses of axisymmetric shells of revolution (cylinders, cones, discs, toroids, and rings) for axisymmetric thermal boundary and surface load conditions. Thin-shell theory is inherent in the solution of E. Peissner's differential equations for each shell's influence coefficients. Surface loading capability includes pressure, average temperature, and linear

through-wall gradients; the latter two may be linearly varied over the shell meridian. The theoretical limitations of this program are the same as those of classical theory.

4.1.4.1.2.2 Program Version and Computer

The version used for the Limerick design, was maintained by GE's Jet Engine Division at Evandale, Ohio, and was used on the Honeywell 6000 computer by the Nuclear Energy Division.

4.1.4.1.2.3 History of Use

The initial version of the Shell Analysis Program was completed by the Jet Engine Division in 1961. Since then, a considerable amount of modification and addition has been made to accommodate its broadening area of application. Its application by the Nuclear Energy Division has a history longer than ten years.

4.1.4.1.2.4 Extent of Application

The program has been used to analyze jet engine, space vehicle, and nuclear reactor components. It has been one of the main shell analysis programs in GE's Nuclear Energy Division, because of its efficiency, economy, and reliability.

4.1.4.1.3 GASP

4.1.4.1.3.1 Program Description

GASP is a finite-element program for the stress analysis of axisymmetric, or plane two-dimensional geometries. The element representations can be either quadrilateral or triangular. Axisymmetric or plane structural load inputs can be made at nodal points. Displacements, temperatures, pressure loads, and axial inertia can be accommodated. Effective plastic stress and strain distributions can be calculated using a bilinear stress-strain relationship, by means of an iterative convergence procedure.

4.1.4.1.3.2 Program Version and Computer

The GE version, originally obtained from the developer, Professor E.L. Wilson, operated on the Honeywell 6000 computer.

4.1.4.1.3.3 History of Use

The program was developed in 1965 (Reference 4.1-3). The present version used by GE's Nuclear Energy Division has been in operation since 1967.

4.1.4.1.3.4 Extent of Application

The application of GASP by the Nuclear Energy Division is mainly for elastic analysis of axisymmetric and plane structures, such as the jet pump riser brace, under thermal and pressure loads. The GE version has been extensively tested and used by GE engineers.

4.1.4.1.4 NOHEAT

4.1.4.1.4.1 Program Description

The NOHEAT program is a two-dimensional and axisymmetric transient nonlinear, temperature analysis program. An unconditionally stable numerical integration scheme is combined with an iteration procedure to compute temperature distribution within a body subjected to arbitrary time and temperature-dependent boundary conditions.

This program utilizes the finite-element method. Included in the analysis are the three basic forms of heat transfer (conduction, radiation, and convection) as well as internal heat generation. In addition, cooling pipe boundary conditions are also treated. The output includes the temperature of all the nodal points for the time instants required by the user. The program can accommodate multitransient temperature input.

4.1.4.1.4.2 Program Version and Computer

The version of the program used for the Limerick design was an improvement of the program originally developed by I. Farhoomand and Professor E.L. Wilson (Reference 4.1-4). The program operated on the Honeywell 6000 computer.

4.1.4.1.4.3 History of Use

The program was developed in 1971 and installed in GE's Honeywell computer by one of its original developers, I. Farhoomand, in 1972. A number of heat transfer problems related to the reactor pedestal have been satisfactorily solved using the program.

4.1.4.1.4.4 Extent of Application

The program using finite-element formulation is compatible with the finite-element stress analysis computer program GASP discussed above. Such compatibility simplifies the connection of the two analyses and minimizes error.

4.1.4.1.5 FINITE

4.1.4.1.5.1 Program Description

FINITE is a general purpose finite-element computer program for elastic stress analysis of two-dimensional structural problems including plane stress, plane strain, and axisymmetric structures. It has provision for thermal, mechanical, and body force loads. The materials of the structure may be homogeneous, or nonhomogeneous and isotropic, or orthotropic. The development of the FINITE program is based on the GASP program discussed above.

4.1.4.1.5.2 Program Version and Computer

The present version of the program used for the Limerick design at GE's Nuclear Energy Division was obtained from the developer, J.E. McConnelee of GE's Gas Turbine Department, in 1969 (Reference 4.1-5). The Nuclear Energy Division version operated on the Honeywell 6000 computer.

4.1.4.1.5.3 History of Use

Since its completion in 1969, the program has been widely used in GE's Gas Turbine and Jet Engine Departments for turbine component analysis.

4.1.4.1.5.4 Extent of Usage

The program is used at GE's Nuclear Energy Division in the analysis of axisymmetric, or nearly axisymmetric, BWR internals.

4.1.4.1.6 DYSEA

4.1.4.1.6.1 Program Description

The DYSEA (Dynamic and Seismic Analysis) program is a GE proprietary program developed specifically for seismic and dynamic analysis of RPV/internals and building system. It calculates the dynamic response of linear structural systems by either temporal modal superposition or response spectrum method. The fluid-structure interaction effect in the RPV is taken into account by way of hydrodynamic mass.

DYSEA is based on program SAPIV with added capability to handle the hydrodynamic mass effect. Structural stiffness and mass matrices are formulated similarly to SAPIV. Solution is obtained in time domain by calculating the dynamic response mode by mode. Time integration is performed by using Newmark's Beta method. Response spectrum solution is also available as an option.

4.1.4.1.6.2 Program Version and Computer

The DYSEA version used for the Limerick design on the Honeywell 6000 computer was developed at GE by modifying the SAPIV program. Capability was added to handle the hydrodynamic mass effect due to fluid-structure interaction in the reactor. It could accommodate three-dimensional dynamic problems with beam, trusses, and springs. Both acceleration time histories and response spectra could be used as input.

4.1.4.1.6.3 History of Use

The DYSEA program was developed in 1976. Adopted as a standard production program in 1977, it has been used extensively in all dynamic and seismic analysis of the RPV/internals and building system.

4.1.4.1.6.4 Extent of Application

The current version of DYSEA has been used in all dynamic and seismic analysis since its development. Results from test problems were found to be in close agreement with those obtained from either verified programs or analytic solutions.

4.1.4.1.7 SHELL 5

4.1.4.1.7.1 Program Description

SHELL 5 is a finite-shell-element program used to analyze smoothly curved thin-shell structures with any distribution of elastic material properties, boundary constraints, and mechanical-thermal and displacement loading conditions. The basic element is triangular, whose membrane displacement fields are linear polynomial functions, and whose bending displacement field is a cubic polynomial function (Reference 4.1-6). Five degrees of freedom (three displacements and

two bending rotations) are obtained at each nodal point. Output displacements and stresses are in a local (tangent) surface coordinate system.

Due to the approximation of element membrane displacements by linear functions, the inplane rotation about the surface normal is neglected. Therefore, the only rotations considered are due to bending of the shell cross-section, and application of the method is not recommended for shell intersection (or discontinuous surface) problems where inplane rotation can be significant.

4.1.4.1.7.2 Program Version and Computer

A copy of the source deck of SHELL 5 is retained in GE's Nuclear Energy Division. SHELL 5 was used on the UNIVAC 1108 computer.

4.1.4.1.7.3 History of Use

SHELL 5 is a program developed by Gulf General Atomic Incorporated (Reference 4.1-7) in 1969. The program has been in production status at Gulf General Atomic, GE, and at other major computer operating systems since 1970.

4.1.4.1.7.4 Extent of Application

SHELL 5 has been used at GE to analyze reactor shroud support and torus. Satisfactory results were obtained.

4.1.4.1.8 HEATER

4.1.4.1.8.1 Program Description

HEATER is used in the hydraulic design of feedwater spargers, and their associated delivery header and piping. The program utilizes test data obtained by GE using full-scale mockups of feedwater spargers, combined with a series of models which represent the complex mixing processes obtained in the upper plenum, downcomer, and lower plenum. Mass and energy balances throughout the nuclear steam supply system are modeled in detail (Reference 4.1-8).

4.1.4.1.8.2 Program Version and Computer

This program was developed at GE's Nuclear Energy Division in FORTRAN IV for the Honeywell 6000 computer.

4.1.4.1.8.3 History of Use

The program was developed in the Nuclear Energy Division beginning in 1970. The version used for the Limerick design was in operation since January 1972.

4.1.4.1.8.4 Extent of Application

The program is used in the hydraulic design of the feedwater spargers for each BWR plant, in the evaluation of design modifications, and in the evaluation of unusual operational conditions.

4.1.4.1.9 FAP-71 (Fatigue Analysis Program)

4.1.4.1.9.1 Program Description

The FAP-71 computer code, or Fatigue Analysis Program, is a stress analysis tool used to aid in performing ASME Section III structural design calculations. Specifically, FAP-71 is used in determining the primary plus secondary stress range, and the number of allowable fatigue cycles at points of interest. For structural locations at which the 3 S_m (P+Q) ASME Code limit is exceeded, the program can perform either (or both) of two elastic-plastic fatigue life evaluations: 1) the method reported in ASME Paper 68-PVP-3, 2) the method of paragraph NB-3228.3 of the ASME Section III, 1971 edition. The program can accommodate up to 25 transient stress states of as many as 20 structural locations.

4.1.4.1.9.2 Program Version and Computer

The version of FAP-71 used for the Limerick design was completed by L. Young of GE's Nuclear Energy Division in 1971 (Reference 4.1-9). The program was used on the Honeywell 6000 computer.

4.1.4.1.9.3 History of Use

Since its completion in 1971, the program has been applied to several design analyses of GE BWR vessels.

4.1.4.1.9.4 Extent of Use

The program is used in conjunction with several shell analysis programs in determining the fatigue life of BWR mechanical components subject to thermal transients.

4.1.4.1.10 CREEP/PLAST

4.1.4.1.10.1 Program Description

This finite-element program is used for the analysis of two-dimensional (plane and axisymmetric) problems under the conditions of creep and plasticity. The creep formulation is based on the memory theory of creep in which the constitutive relations are cast in the form of hereditary integrals. The material creep properties are built into the program, and they represent annealed

304 stainless steel. Any other creep properties can be included if required. The plasticity treatment is based on kinematic hardening and von Mises yield criterion. The hardening modulus can be constant or be a function of strain.

4.1.4.1.10.2 Program Version and Computer

The program was developed for elastic-plastic analysis with or without the presence of creep. It was also designed for creep analysis without the presence of instantaneous plasticity. A detailed description of theory is given in Reference 4.1-11. The program was used on the UNIVAC 1108 computer .

4.1.4.1.10.3 History of Use

This program was developed by Y.R. Rashid (Reference 4.1-11) in 1971. It underwent extensive program testing before it was put on production status.

4.1.4.1.10.4 Extent of Application

The program is used at GE's Nuclear Energy Division in the channel cross-section mechanical analysis.

4.1.4.1.11 ANSYS

4.1.4.1.11.1 Program Description

ANSYS is a general purpose finite-element computer program designed to solve a variety of problems in engineering analysis. The ANSYS program features the following capabilities:

a. Structural analysis including the following analyses:

   1. Static Elastic

   2. Plastic and Creep

   3. Dynamic

   4. Seismic and Dynamic Plastic

   5. Large Deflection

   6. Stability

b. One-dimensional fluid flow analyses

c. Transient heat transfer analysis including conduction, convection, and radiation with direct input to thermal-stress analyses

d. An extensive finite-element library, including gaps, friction interfaces, springs, cables (tension only), direct interfaces (compression only), curved elbows, etc. Many of the elements contain complete plastic, creep, and swelling capabilities.

e. Geometry plotting available for all elements in the ANSYS library, including isometric and perspective views of three-dimensional structures

f. Restart Capability - The ANSYS program has restart capability for several types of analyses. An option is also available for saving the stiffness matrix once it is calculated for the structure, and for using it for other loading conditions.

4.1.4.1.11.2 Program Version & Computer

The program used in the Limerick design was maintained current by Swanson Analysis Systems, Inc. of Pittsburgh, Pennsylvania, and was supplied to GE for use on the Honeywell 6000.

4.1.4.1.11.3 History of Use

The ANSYS program has been used for productive analyses since 1970. Users now include nuclear, pressure vessel, piping, mining, structures, bridge, chemical, and automotive industries, as well as many consulting firms.

4.1.4.1.11.4 Extent of Application

ANSYS is used extensively by GE's Nuclear Energy Division for elastic and elastic-plastic analysis of the RPV, core support structures, and reactor internals.

4.1.4.2 Fuel Rod Thermal Analysis

Fuel rod thermal design analyses are referenced in sections A.4.2.1 and A.4.2.3 of GESTAR II (Reference 4.1-1).

4.1.4.3 Reactor Systems Dynamics

The analysis techniques and computer codes used in reactor systems dynamics are described in section 4 of Reference 4.1-10. Section 4.4.4.6 of Reference 4.1-10 also provides a complete stability analysis for the RCS.

4.1.4.4 Nuclear Engineering Analysis

The analysis techniques are described and referenced in section 3 of GESTAR II (Reference 4.1-1).

4.1.4.5 Neutron Fluence Calculations

The original vessel neutron fluence calculations were carried out using a one-dimensional discrete ordinates (S_n) transport code with general anisotropic scattering.

This code is a modification of a widely used discrete ordinates code which solves a wide variety of radiation transport problems. The program solves both fixed source and multiplication problems. Slab, cylinder, and spherical geometry are allowed with various boundary conditions. The fluence calculations were done as a fixed source problem in cylindrical geometry. The fixed source was developed from neutron fission distribution data prepared as a part of the core physics data. Anisotropic scattering was considered for all regions. The cross-sections were prepared with a l/E flux weighted and (P) matrices for anisotropic scattering, but did not include resonance self-shielding factors. Fast neutron fluxes at locations other than the core midplane were calculated using a two-dimensional discrete ordinate code. The two-dimension code is an extension of the one-dimensional code.

This calculational procedure was also used on PBAPS Units 2 and 3. These units are similar in design, and are of the same core size and power rating as the LGS units. The neutron flux at

these units has been measured using a threshold foil technique on the wire samples contained in the vessel surveillance samples. Flux greater than 1 MeV was determined to be $1.3x10^9$ n/cm^2-sec for Unit 2, and $9.8x10^8$ n/cm^2-sec for Unit 3. This is equivalent to a fluence over 40 years of $1.3x10^{18}$ nvt and $9.8x10^{17}$ nvt. The calculated value using these methods is $1.4x10^{18}$ nvt.

Following the original fluence calculations, the NRC issued Regulatory Guide (RG) 1.190, which provides state of the art calculation and measurement procedures that are acceptable to the NRC for determining Reactor Pressure Vessel (RPV) neutron fluence. LGS RPV fluence has been evaluated using a method in accordance with the recommendations of RG 1.190. Future evaluations of RPV fluence will be completed using a method in accordance with the recommendations of RG 1.190 (as noted in Reference 5.3-14).

As part of the plant's extension to 60 years, a fluence calculation has been completed to extend the plant life to 57 EFPY of reactor operation.

The fast neutron fluence was determined in accordance with the guidelines and requirements presented in U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Effluence." Fluence is determined for the 0T, 1/4T and 3/4T depths in the reactor pressure vessel (RPV) plates, welds, and nozzles throughout the RPV extended beltline region determined at 60 years of reactor operation. The damage fluence determined at the 1/4T and 3/4T depths in the RPV wall were determined using the displacements-per-atom (dpa) attenuation method prescribed in U.S. NRC Regulatory Guide 1.99, "Radiation Embrittlement of Reactor Vessel Materials."

The fluence evaluations (Reference 4.1-17 and 4.1-18) are performed based on the RAMA Fluence Methodology (Reference 4.1-14). Under funding from Electric Power Research Institute, Inc. (EPRI) and the Boiling Water Reactor Vessel and Internals Project (BWRVIP), the RAMA Fluence Methodology was developed by TransWare Enterprises Inc. for the purpose of calculating fast neutron fluence in nuclear reactor pressure vessels and reactor vessel internal components. The RAMA Fluence Methodology (hereafter referred to as "RAMA") has received generic approval (Reference 4.1-15) from the U.S. NRC for determining fast neutron fluence in BWRs and PWRs in accordance with the requirements of Regulatory Guide 1.190. Additionally, the U.S. NRC has given conditional approval of the RAMA methodology for determining fast neutron fluence in reactor internals, specifically stating that the staff will "accept RAMA calculated fluence values for BWR core shrouds and top guide for licensing actions provided that the calculation results are supported by sufficient justification that the proposed values are conservative for the intended application." (Reference 4.1-16)

4.1.4.6 Thermal-Hydraulic Calculations

A description of the thermal-hydraulic models is given in section 4 of GESTAR II (Reference 4.1-1).

4.1.5 REFERENCES

4.1-1 "General Electric Standard Application for Reactor Fuel," including the United States Supplement, NEDE-24011-P-A-32 and NEDE-24011-P-A-32-US, August 2024.

4.1-2 L. Beitch, "Shell Structures Solved Numerically by Using a Network of Partial Panels," AIAA Journal, Volume 5, No. 3, (March 1967).

4.1-3 E.L. Wilson, "A Digital Computer Program For the Finite-Element Analysis of Solids With Non-Linear Material Properties", Aerojet General Technical Memo No. 23, Aerojet General, (July 1965).

4.1-4 I. Farhoomand and E.L. Wilson, "Nonlinear Heat Transfer Analysis of Axisymmetric Solids", SESM Report SESM71 6, University of California at Berkeley, Berkeley, California, (1971).

4.1-5 J.E. McConnelee, "Finite-Users Manual", GE TIS Report DF 69SL20 6, (March 1969).

4.1-6 R.W. Clough and C.P. Johnson, "A Finite-Element Approximation for the Analysis of Thin-Shells", International Journal Solid Structures, Vol 4, (1968).

4.1-7 "A Computer Program For the Structural Analysis of Arbitrary Three-Dimensional Thin-Shells", Report No. GA 9952, Gulf General Atomic, (January 1970).

4.1-8 A.B. Burgess, "User Guide and Engineering Description of HEATER Computer Program", NEDE-20371-02, (March 1974).

4.1-9 L.J. Young, "FAP-71 (Fatigue Analysis Program) Computer Code", GE's Nuclear Energy Division Design Analysis Unit R. A. Report No. 49, (January 1972).

4.1-10 L.A. Carmichael and G.J. Scatena, "Stability and Dynamic Performance of the General Electric Boiling Water Reactor", APED 5652, (April 1969).

4.1-11 Y.R. Rashid, "Users Manual for CRPLSO1 Computer Program", NEDO-23538, (December 1976).

4.1-12 DELETED.

4.1-13 “Methodology and Uncertainties for Safety Limit MCPR Evaluations,” NEDC-32601P-A, (August 1999).

4.1-14 BWRVIP-114-A: BWR Vessel and Internals Project, RAMA Fluence Methodology Theory Manual. EPRI, Palo Alto, CA: 2009. 1019049.

4.1-15 U.S. Nuclear Regulatory Commission. Office of Nuclear Reactor Regulation. Safety Evaluation Report with Open Items Related to the License Renewal of Seabrook Station. Docket Number 50-443. Washington, D.C.: Office of Nuclear Reactor Regulation, 2012.

4.1-16 "Safety Evaluation of Proprietary EPRI Report BWR Vessel and Internals Project, Evaluation of Susquehanna Unit 2 Top Guide and Core Shroud Material Samples Using RAMA Fluence Methodology (BWRVIP-145)." Matthew A. Mitchell (U.S. NRC) to Rick Libra (BWRVIP). February 7, 2008.

4.1-17 349-T-VC-00004 R0: "Limerick Generating Station Unit 1 Reactor Pressure Vessel Fluence Evaluation" TransWare Enterprises Inc. 3/21/2020.

4.1-18 349-T-VC-00005 R0: "Limerick Generating Station Unit 2 Reactor Pressure Vessel Fluence Evaluation" TransWare Enterprises Inc. 3/21/2020.

4.2 FUEL SYSTEM DESIGN

The format of this section corresponds to SRP Section 4.2 in NUREG-0800. Most of the information is presented by reference to GESTAR II (Reference 4.1-1).

4.2.1 DESIGN BASES

References to design bases are given in subsection A.4.2.1 of GESTAR II (Reference 4.1-1).

4.2.2 DESCRIPTION AND DESIGN DRAWINGS

References to the fuel system description and design drawings are given in subsections A.1.2.2.3.1 and A.4.2.2 of GESTAR II (Reference 4.1-1). Details of General Electric fuel assembly designs are provided in Reference 4.2-5. For the advanced Nuclear Fuels Corp. 9X9-9, the ABB Atom Inc. SVEA-96, and the General Electric GE11 Qualification Fuel Bundles first used in Limerick 2, Cycle 2, the fuel design description can be found in Reference 4.2-6.

4.2.2.1 Reactivity Control Assembly (Control Rods)

The Unit 1 and Unit 2 cores contain a mix of control rod designs including the standard boron carbide and the advanced long-life hafnium rods. The long-life control rods are inserted in subsequent cycles as the standard rods are depleted. A description of the standard rods is given in subsection 2.2.4 and is shown in figures 2.6a, 2.6b, and 2.7 of NEDE-20944-P-1 (Reference 4.2-1). The advanced long-life control rods are described in subsection 2.1 and shown in figures 2.2 and 2.3 of NEDE-22290-A, Supplement 2 (Reference 4.2-3) and subsection 2.0 and Figures 2-1 and 2-2 of NEDE-31758P-A (Reference 4.2-7).

4.2.2.2 Reactivity Control Assembly Evaluation

The standard boron carbide control rod and the advanced long-life hafnium control rod differ primarily in the type of neutron- absorbing materials. Other minor design differences are described in NEDE-22290-A, Supplement 2 (Reference 4.2-3). The evaluation of the standard control rod is given in subsection 2.3.3 of NEDE-20944-P-1 (Reference 4.2-1). The advanced long-life control rod assemblies are directly interchangeable with the standard assemblies and are compatible with existing hardware.

4.2.3 DESIGN EVALUATION

Compliance with the design bases is discussed in subsection A.4.2.3 of GESTAR II (Reference 4.1-1), with the exceptions as provided below.

4.2.3.1 Exceptions to GESTAR II

PARAGRAPH 4.2.3.2.9 - MECHANICAL FRACTURING EVALUATION

Mechanical adequacy of the fuel assembly is demonstrated by the mechanical design analyses described in section 2.0 of Reference 4.2-4. Corrosion, oxidation, and hydriding effects are specifically addressed in subsection 2.2.1.4 of Reference 4.2-4.

All mechanical breaking under normal operation and abnormal operational transients is bounded by the analysis for LOCA plus SSE given in Section 3.9.1.4.10 and Table 3.9-6(x).

PARAGRAPH 4.2.3.3.5 - STRUCTURAL DEFORMATION EVALUATION

Results of the LGS specific SSE plus LOCA analysis are documented in Section 3.9.1.4.10.

4.2.4 TESTING, INSPECTION, AND SURVEILLANCE PLANS

Descriptions of fuel assembly testing, inspection, and surveillance are referenced in subsection A.4.2.4 of GESTAR II (Reference 4.1-1), with the exception that the following postirradiation fuel surveillance program is intended to conform with the objectives of Regulatory Guide 1.70.

Routine visual inspection of representative (usually discharged) fuel will be performed in accordance with the GE Postirradiation Fuel Surveillance Program (Reference 4.2-2).

4.2.5 REFERENCES

4.2-1 "BWR/4 and BWR/5 Fuel Design," NEDE-20944-P-1 (Proprietary) and NEDO-20944-1, (October 1976 and Amendment 1, January 1977).

4.2-2 Letter from L.S. Rubenstein (NRC) to R.L. Gridley (GE) "Acceptance of GE Proposed Fuel Surveillance Program," (June 27, 1984).

4.2-3 "Safety Evaluation of the General Electric Hybrid 1 Control Rod Assembly", NEDE-22290-A (Proprietary), (September 1983), and NEDE-22290-A, Supplement 2, (August 1985).

4.2-4 "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A-32, August 2024; and U.S. Supplement NEDE-24011-P-A-32-US, August 2024.

4.2-5 "Global Nuclear Fuels Fuel Bundle Designs," NEDE-31152P, Revision 9, May 2007.

4.2-6 G. J. Beck to USNRC, "Limerick Generating Station Unit 2 Qualification Fuel Bundles in Operating Cycle 2", March 11, 1991.

4.2-7 "GE Marathon Control Rod Assembly," NEDE-31758P-A, (October 1991).

4.3 NUCLEAR DESIGN

Most of the information of Section 4.3 is provided in the licensing topical report, GESTAR II (Reference 4.1-1). The subsection numbers in Section 4.3 directly correspond to the subsection numbers of Appendix A of GESTAR II. Any additions or differences are given below for each applicable subsection.

4.3.1 DESIGN BASES

4.3.2 DESCRIPTION

4.3.2.1 Nuclear Design Description

The nuclear design description in GESTAR II is referenced in subsection A.4.3.2.1 of GESTAR II (Reference 4.1-1). The reference loading pattern for the initial core for Limerick 1 and 2 is shown in Figure 4.3-3. The reference loading pattern for subsequent cycle of Limerick 1 and Limerick 2 can be found in the unit and cycle specific Supplemental Reload Licensing Report. The actual as loaded core may be different than the reference loading pattern. The as loaded core can be found in the unit and cycle specific Core Loading Plan.

4.3.2.2 Power Distribution

Power distribution is referenced in subsection A.4.3.2.2 of GESTAR II (Reference 4.1-1).

4.3.2.3 Reactivity Coefficient

Directly corresponds to information in Appendix A of GESTAR II (Reference 4.1-1).

4.3.2.4 Control Requirements

Directly corresponds to information in Appendix A of GESTAR II (Reference 4.1-1).

4.3.2.4.1 Shutdown Reactivity

Information on shutdown reactivity is referenced in subsection A.4.3.2.4.1 of GESTAR II (Reference 4.1-1), except for the cold shutdown margin for the reference initial core loading pattern, which is given in Table 4.3-3.

4.3.2.4.2 Reactivity Variations

Information on reactivity variations is referenced in subsection A.4.3.2.4.2 of GESTAR II (Reference 4.1-1). The combined effects of the individual constituents of reactivity are accounted for in each K_{eff} in Table 4.3-3.

4.3.2.5 Control Rod Patterns and Reactivity Worths

Control rod patterns and reactivity worths are discussed in section 3.2.5 of NEDE-20944-P-1 (Reference 4.2-1). Typical control rod patterns and the associated power distributions are presented in appendix A of NEDE-20944-P-1 (Reference 4.2-1). These control rod patterns are calculated with the BWR Core Simulator. Qualification for this model is discussed and referenced in section 3.1 of GESTAR II (Reference 4.1-1)

4.3.2.5.1 Scram Reactivity

Scram reactivity is calculated as described in section S.2 of GESTAR II (Reference 4.1-1) and is discussed in section 3.2.5.3 of NEDE-20944-P-1 (Reference 4.2-1).

4.3.2.6 Criticality of Reactor During Refueling

Directly corresponds to information in Appendix A of GESTAR II (Reference 4.1-1).

4.3.2.7 Stability

General Design Criterion 12 of 10CFR50 Appendix A states that the reactor core and associated coolant control and protection systems shall be designed to assure power oscillations that can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed. That requirement is met as described in GESTAR II (Reference 4.1-1) and this section.

4.3.2.7.1 Xenon Transients

As documented in GESTAR II (Reference 4.1-1), Xenon transients do not cause instability in BWR reactors.

4.3.2.7.2 Thermal-Hydraulic Stability

LGS has implemented the BWROG Long Term Stability Solution Option III with GEH Simplified Stability Solution (GS3). An OPRM Upscale Function is incorporated into each APRM channel to reliably detect power oscillations in the operating ranges where thermal-hydraulic instability has been determined to be credible. Upon detection of power oscillations, the OPRM Upscale Function generates a trip signal to RPS, which results in an automatic scram to suppress the oscillation before the $MCPR_{99.9\%}$ Safety Limit is reached. The OPRM Upscale Function is described in References 7.6-1 through 7.6-4, Reference 7.6-6, and in Reference 4.3-1.

Stability-based MCPR Operating Limits are calculated for each operating cycle. These calculated values validate the selected OPRM setpoints for a given core configuration. Thus, the core design combined with the OPRM Upscale Function and selected system setpoints for detection and suppression of thermal-hydraulic power oscillation conform to the requirements of General Design Criterion 12 of 10CFR50, Appendix A.

4.3.2.8 Vessel Irradiations

The neutron fluxes at the vessel were originally calculated using the one-dimensional discrete ordinates transport code described in Section 4.1.4.5. The discrete ordinates code was used in a distributed source mode with cylindrical geometry. The geometry described six regions from the center of the core to a point beyond the vessel. The core region was modeled as a single homogenized cylindrical region. The coolant water region between the fuel channel and the shroud was described as containing saturated water at 550°F and 1050 psi. The material compositions for the stainless steel in the shroud and the carbon steel in the vessel contain the mixtures by weight, as specified in the material specifications for ASME SA240, 304L, and ASME SA533 Grade B. In the region between the shroud and the vessel (for conservatism), the presence

of the jet pumps was ignored. A simple diagram showing the regions, dimensions, and weight fractions is shown in Figure 4.3-1.

The distributed source used for this analysis was obtained from the gross radial power description. The distributed source at any point in the core is the product of the power from the power description and the neutron yield from fission. By using the neutron energy spectrum, the distributed source is obtained for position and energy. The integral over position and energy is normalized to the total number of neutrons in the core region. The core region is defined as a 1 cm thick disc with no transverse leakage. The power in this core region is set equal to the maximum power in the axial direction. The radial power distribution is shown in Figure 4.3-2

The neutron fluence is determined from the calculated flux by assuming that the plant is operated 90% of the time at 90% power level for 40 years, or equivalent to $1x10^9$ full power seconds. The calculated fluxes and fluence are shown in Table 4.3-1. The calculated neutron flux leaving the cylindrical core is shown in Table 4.3-2

Following the original fluence calculations, the NRC issued Regulatory Guide (RG) 1.190, which provides state of the art calculation and measurement procedures that are acceptable to the NRC for determining Reactor Pressure Vessel (RPV) neutron fluence. LGS RPV fluence has been evaluated using a method in accordance with the recommendations of RG 1.190. Future evaluations of RPV fluence will be completed using a method in accordance with the recommendations of RG 1.190 (as noted in Reference 5.3-14).

As part of the plant's extension to 60 years, a fluence calculation has been completed to extend the plant life to 57 EFPY of reactor operation.

The fast neutron fluence was determined in accordance with the guidelines and requirements presented in U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Effluence." Fluence is determined for the 0T, 1/4T and 3/4T depths in the reactor pressure vessel (RPV) plates, welds, and nozzles throughout the RPV extended beltline region determined at 60 years of reactor operation. The damage fluence determined at the 1/4T and 3/4T depths in the RPV wall were determined using the displacements-per-atom (dpa) attenuation method prescribed in U.S. NRC Regulatory Guide 1.99, "Radiation Embrittlement of Reactor Vessel Materials."

The fluence evaluations (Reference 4.1-17 and 4.1-18) are performed based on the RAMA Fluence Methodology (Reference 4.1-14). Under funding from Electric Power Research Institute, Inc. (EPRI) and the Boiling Water Reactor Vessel and Internals Project (BWRVIP), the RAMA Fluence Methodology was developed by TransWare Enterprises Inc. for the purpose of calculating fast neutron fluence in nuclear reactor pressure vessels and reactor vessel internal components. The RAMA Fluence Methodology (hereafter referred to as "RAMA") has received generic approval (Reference 4.1-15) from the U.S. NRC for determining fast neutron fluence in BWRs and PWRs in accordance with the requirements of Regulatory Guide 1.190. Additionally, the U.S. NRC has given conditional approval of the RAMA methodology for determining fast neutron fluence in reactor internals, specifically stating that the staff will "accept RAMA calculated fluence values for BWR core shrouds and top guide for licensing actions provided that the calculation results are supported by sufficient justification that the proposed values are conservative for the intended application." (Reference 4.1-16)

4.3.3 ANALYTICAL METHODS

Analytical methods are referenced in section A.4.3.3 of GESTAR II (Reference 4.1-1).

4.3.4 CHANGES

Changes are referenced in section A.4.3.4 of GESTAR II (Reference 4.1-1).

4.3.5 REFERENCES

4.3-1 LEAM-MUR-0042, Rev. 0A, Thermal Hydraulic Stability, dated April 2021.

Table 4.3-1
(Historical)

CALCULATED NEUTRON FLUXES
(USED TO EVALUATE VESSEL IRRADIATION)[1]

NEUTRON ENERGY Mev	AVERAGE FLUX IN THE CORE (n/cm^2-sec)	FLUX AT THE CORE BOUNDARY (n/cm^2-sec)	FLUX AT THE INSIDE SURFACE VESSEL (n/cm^2-sec)
>3.0	1.5×10^{13}	5.4×10^{12}	3.3×10^{8}
1.0 - 3.0	3.3×10^{13}	1.2×10^{13}	2.8×10^{8}
0.1 - 1.0	5.3×10^{13}	1.7×10^{13}	4.9×10^{8}
Maximum Fluence[2]	>1.0 MeV = 1.4×10^{18} n/cm^2		

(1) The calculated flux is a maximum in the axial direction, but is an average over the azimuthal angle.

(2) The maximum fluence is calculated using the flux and a capacity factor of 80% or 1×10^{9} full power seconds. The fluence includes an azimuthal peaking factor and a factor to cover analytical uncertainties.

Table 4.3-2
(Historical)

CALCULATED NEUTRON FLUX AT CORE EQUIVALENT BOUNDARY

GROUP	LOWER ENERGY BOUND (eV)	FLUX (n/cm^2-sec)
1	10.0×10^6	4.6×10^{10}
2	6.065×10^6	6.1×10^{11}
3	3.679×10^6	2.1×10^{12}
4	2.231×10^6	4.2×10^{12}
5	1.353×10^6	4.4×10^{12}
6	8.208×10^5	3.9×10^{12}
7	4.979×10^5	4.0×10^{12}
8	3.020×10^5	2.8×10^{12}
9	1.832×10^5	2.3×10^{12}
10	1.111×10^5	1.8×10^{12}
11	6.732×10^4	1.4×10^{12}
12	4.087×10^4	1.1×10^{12}
13	2.478×10^4	1.0×10^{12}
14	1.503×10^4	1.0×10^{12}
15	9.119×10^3	9.6×10^{11}
16	5.531×10^3	9.4×10^{11}
17	3.355×10^3	9.4×10^{11}
18	2.034×10^3	9.1×10^{11}
19	1.010×10^3	1.3×10^{12}
20	2.492×10^2	2.5×10^{12}
21	5.560×10^1	2.6×10^{12}
22	1.240×10^1	2.5×10^{12}
23	0.625	4.0×10^{12}
24	0.0	2.5×10^{13}

Table 4.3-3

CALCULATED INITIAL CORE EFFECTIVE MULTIPLICATION AND CONTROL SYSTEM WORTH - NO VOIDS, 20°C

Beginning of Cycle-1, K-effective	Unit 1	Unit 2
Uncontrolled	1.1047	1.1051
Fully Controlled	0.9230	0.9330
Strongest Control Rod Out (26-55)	0.9826	0.9799
R, Maximum Increase in Cold Core Reactivity with Exposure Cycle-1, Δk	0.0	0.0

4.4 THERMAL AND HYDRAULIC DESIGN

Most of the information of Section 4.4 is provided in the licensing topic report GESTAR II (Reference 4.1-1). The subsection numbers in Section 4.4 directly correspond to the subsection numbers of Appendix A of GESTAR II. The differences are discussed below.

4.4.1 DESIGN BASIS

The thermal and hydraulic design bases are referenced in GESTAR II (Reference 4.1-1).

The design steady-state initial operating cycle limit for the MCPR and the LHGR are given in Table 4.4-1. The MCPR and LHGR operating limits for subsequent cycles can be found in the unit and cycle specific Core Operating Limits Report.

4.4.2 Description Of Thermal-Hydraulic Design Of The Reactor Core

A description of the thermal-hydraulic design of the reactor core is referenced in GESTAR II (Reference 4.1-1). An evaluation of plant performance from a thermal and hydraulic standpoint is provided in Section 4.4.3.

4.4.2.1 Summary Comparison

A summary comparison of the thermal and hydraulic design parameters of the reactor with reactors of similar design is provided in Table 4.4-1.

4.4.2.2 Critical Power Ratio

Critical power ratio is referenced in GESTAR II (Reference 4.1-1).

4.4.2.3 Linear Heat Generation Rate

LHGR models are referenced in GESTAR II (Reference 4.1-1).

4.4.2.4 Void Fraction Distribution

The core average and maximum exit void fractions in the core at rated condition are given in Table 4.4-1.

4.4.2.5 Core Coolant Flow Distribution and Orificing Pattern

The core coolant flow distribution and orificing pattern are referenced in GESTAR II (Reference 4.1-1).

4.4.2.6 Core Pressure Drop and Hydraulic Loads

Core pressure drop and hydraulic loads are referenced in GESTAR II (Reference 4.1-1).

4.4.2.7 Correlation and Physical Data

GE has obtained substantial amounts of physical data in support of the pressure drop and thermal-hydraulic loads. This information is given in appendix US-B of GESTAR II (Reference 4.1-1) where responses are provided to NRC questions on section 4 of GESTAR II.

4.4.2.8 Thermal Effects of Operational Transients

The evaluation of the core's capability to withstand the thermal effects resulting from anticipated operational transients is covered in Chapter 15.

4.4.2.9 Uncertainties in Estimates

Ultrasonic flow meters have been installed to reduce the uncertainty in the feedwater flow measurements to 0.35%.

The uncertainties in thermal-hydraulic parameters are referenced in GESTAR II (Reference 4.1-1) and NEDC-32601P-A (Reference 4.1-13). The licensing basis power uncertainty for U.S. BWRs is 2.0% as documented in GESTAR II. This power uncertainty is based, in part, on an assumed 1.80% uncertainty in feedwater flow measurement. Feedwater flow uncertainty input to the cycle-specific Safety Limit $MCPR_{99.9\%}$ calculation is 1.80%.

4.4.2.10 Flux Tilt Considerations

The inherent design characteristics of the BWR are particularly well suited to handle perturbations due to flux tilt. The stabilizing nature of the moderator void coefficient effectively damps oscillations in the power distribution. In addition to this damping, the incore instrumentation system and the associated on-line computer provide the operator with prompt and reliable power distribution information. Thus, the operator can readily use control rods or other means to effectively limit the undesirable effects of flux tilting. Because of these features and capabilities, it is not necessary, to allocate a specific peaking factor margin to account for flux tilt. If for some reason the power distribution could not be maintained within normal limits using control rods, then the operating power limits would have to be reduced as prescribed in the Technical Specifications.

4.4.3 DESCRIPTION OF THE THERMAL AND HYDRAULIC DESIGN OF THE REACTOR COOLANT SYSTEM

The thermal and hydraulic design of the RCS is described in this section.

4.4.3.1 Plant Configuration Data

4.4.3.1.1 Reactor Coolant System Configuration

The RCS is described in Section 5.4 and shown in isometric perspective in Figure 5.4-1. The piping sizes, fittings, and valves are listed in Table 5.4-1.

4.4.3.1.2 Reactor Coolant System Thermal-Hydraulic Data

The steady-state distribution of temperature, pressure, and flow rate for each flow path in the RCS is shown in Figure 5.1-1.

4.4.3.1.3 Reactor Coolant System Geometric Data

The volumes of regions and components within the reactor vessel are shown in Figure 5.1-2.

Table 4.4-2 provides the flow path length, height, liquid level, minimum elevations, and minimum flow areas for each major flow path volume within the reactor vessel and recirculation loops of the RCS.

Table 4.4-7 provides the lengths and sizes of all safety injection lines to the RCS.

4.4.3.2 Operating Restrictions on Pumps

Expected recirculation pump performance curves are shown in Figure 5.4-3. These curves are valid for all conditions with a normal operating range varying from approximately 20% to 115% of rated pump flow.

The pump characteristics, including considerations of NPSH requirements, are the same for the conditions of two-pump and one-pump operation as described in Section 5.4.1. Section 4.4.3.3 gives the operating limits imposed on the recirculation pumps by cavitation, pump loads, bearing design flow starvation, and pump speed.

4.4.3.3 Power-Flow Operating Map

4.4.3.3.1 Limits for Normal Operation

A BWR must operate with certain restrictions because of pump NPSH, overall plant control characteristics, core thermal power limits, etc. The general power-flow map characteristics for the power range of operation is shown in Figure 4.4-1. The LGS specific power flow map is discussed in Chapter 15. The nuclear system equipment, nuclear instrumentation, and the RPS, in conjunction with operating procedures, maintain operations within the area of this map for normal operating conditions. The boundaries on this map are as follows:

a. Natural circulation line A: The operating state of the reactor moves along this line for the normal control rod withdrawal sequence in the absence of recirculation pump operation.

b. 20% Recirculation pump constant speed line B: Startup operations of the plant are normally carried out with the recirculation pumps operating at approximately 20% speed. The operating state for the reactor follows this line for the normal control rod withdrawal sequence.

c. Rated flow control line: The rated flow control line (100% rod line) passes through 100% power at 100% flow. The operating state for the reactor follows this line for recirculation flow changes with a fixed control rod pattern. The line is based on constant xenon concentration.

d. Cavitation protection line: This line (minimum power line) results from the recirculation pump and jet pump NPSH requirements. The recirculation pumps are automatically switched to 28% speed when the feedwater flow drops below a preset value.

4.4.3.3.1.1 Performance Characteristics

Other performance characteristics shown on the power-flow operating map are as follows:

a. Recirculation pump constant speed Line C: This line shows the change in flow associated with power changes while maintaining constant recirculation pump speed.

b. Constant rod line: These lines show the change in power associated with flow changes while maintaining constant control rod position, e.g., 50% rod line, etc.

4.4.3.3.2 Regions of the Power-Flow Map

For normal operating conditions, the nuclear system equipment, nuclear instrumentation, and the RPS, in conjunction with operating procedures, maintain operation outside the exclusion areas of the power-flow map. Main regions of the map are discussed below to clarify operational capabilities:

a. Region I: This is the transition region between natural circulation operation and 20% pump speed operation. Steady-state conditions cannot exist in this area because the Adjustable Speed Drive (ASD) has been programmed to limit operator manipulation of pump speed to a minimum of 28%. However, the ASD speed output may drop below 28% momentarily upon a power cell bypass or speed controller swap-over to backup controller but will maintain speed above 20% at all times. Normal startup is along the 20% pump speed boundary of this region.

b. Region II: This region represents the normal operating zone of the map where power changes can be made, either by control rod movement or by core flow changes, by changing recirculation pump drive speed.

c. Region III: This is the low power area of the map where cavitation can be expected in the recirculation pumps and in the jet pumps. Operation within this region is precluded by system interlocks that trip the recirculation pumps to 28% speed whenever feedwater flow is less than a preset value (typically 20% of rated).

4.4.3.4 Temperature-Power Operating Map (PWR)

This section is not applicable to LGS.

4.4.3.5 Load-Following Characteristics

The following simple description of BWR operation with recirculation flow control summarizes the principal modes of normal power range operation. Assuming the plant to be initially hot with the reactor critical, full power operation can be approached following the sequence shown as points 1 to 7 in Figure 4.4-1. The first part of the sequence (1 to 3) is achieved with control rod withdrawal and manual, individual recirculation pump control. Individual pump startup procedures are provided that achieve 28% of full pump speed in each loop. Power, steam flow, and feedwater flow are increased as control rods are manually withdrawn until the feedwater flow has reached approximately 20%. An interlock prevents low power/high recirculation flow combinations that create recirculation pump and jet pump NPSH problems.

Reactor power increases as the operating state moves from point 2 to 3 due to the inherent flow control characteristics of the BWR. Once the feedwater interlock is cleared, the operator can manually increase recirculation flow in each loop until the operating state reaches point 3, the lower limit of the flow control range. At point 3, the operator can switch to simultaneous recirculation pump control. Thermal output can then be increased by either control rod withdrawal or recirculation flow increase. For example, the operator can reach 50% power in the ways indicated by points 4 or 5. With a slight rod withdrawal and an increase of recirculation flow to rated flow, point 4 can be achieved. If, however, it is desired to maintain lowest recirculation flow, 50% power can be reached by withdrawing control rods until point 5 is reached. The operating map, Figure 4.4-1, shows the expected flow control range.

The curve labeled "rated flow control line" represents a typical steady-state power-flow characteristic for a fixed rod pattern. It is slightly affected by xenon, core leakage flow assumptions, and reactor vessel pressure variations; however, for this example, these effects have been neglected.

Normal power range operation is along or below the "rated flow control line." If load-following response is desired in either direction, plant operation near 90% power provides the most capability. If maximum load pickup capability is desired, the nuclear system can be operated near point 6, with fast load response available all the way up to point 7, rated power.

The large negative operating reactivity and power coefficients, which are inherent in the BWR, provide important advantages as follows:

a. Good load-following with well-damped behavior and little undershoot or overshoot in the heat transfer response

b. Load-following with recirculation flow control

c. Strong damping of spatial power disturbances

The reactor power level can be controlled over approximately 45% of the power level on the rated rod line by varying the recirculation flow to the reactor. This method of power level control takes advantage of the reactor negative void coefficient. To increase reactor power, it is necessary to increase the recirculation flow rate that sweeps some of the voids from the moderator, causing an increase in core reactivity. As the reactor power increases, more steam is formed and the reactor stabilizes at a new power level with the transient excess reactivity balanced by the new void formation. No control rods are moved to accomplish this power level change. Conversely, when a power reduction is required, it is necessary only to reduce the recirculation flow rate. When this is done, more voids in the moderator will cause a decrease in the reactor power level to a level commensurate with the new recirculation flow rate. Again, no control rods are moved to accomplish the power reduction.

Varying the recirculation flow rate (flow control) is more advantageous, relative to load-following, than using control rod positioning. Flow variations perturb the reactor uniformly in the horizontal planes and ensure a flatter power distribution and reduced transient allowances. As flow is varied, the power and void distributions remain approximately constant at the steady-state end points for a wide range of flow variations. After adjusting the power distribution by positioning the control rods at a reduced power and flow, the operator can then bring the reactor to rated conditions by increasing flow, with the assurance that the power distribution will remain approximately constant. Section 7.7 describes how recirculation flow is varied.

4.4.3.6 Thermal and Hydraulic Characteristics Summary Table

The thermal-hydraulic characteristics are provided in Table 4.4-1 for the core and in tables of Section 5.4 for other portions of the RCS.

4.4.4 EVALUATION

Refer to GESTAR II (Reference 4.1-1). The results of the cycle-1 stability analysis are given in Table 4.4-8 and Figures 4.4-2 through 4.4-6.

4.4.5 TESTING AND VERIFICATION

The testing and verification techniques to be used to assure that the planned thermal and hydraulic design characteristics of the core have been provided, and will remain within required limits throughout core lifetime, are discussed in Chapter 14 (Initial Test Program).

4.4.6 INSTRUMENTATION REQUIREMENTS

The reactor vessel instrumentation monitors the key reactor vessel operating parameters during planned operations. This ensures sufficient control of the parameters. The reactor vessel sensors are discussed in Sections 7.6 and 7.7.

4.4.6.1 Deleted

Table 4.4-1

THERMAL AND HYDRAULIC DESIGN CHARACTERISTICS
OF THE REACTOR CORE

GENERAL OPERATING CONDITIONS	LGS[2] BWR/4 (251-764)	BWR/4 (218-560)	SSES BWR/4 (251-764)
Reference design thermal output, MWt	3293	2436	3293
Power level for engineered safety features, MWt	3435	2558	3435
Steam flow rate, at 420°F final feedwater temperature, millions lb/hr	14.159	10.5	13.48[1]
Core coolant flow rate, millions lb/hr	100	77.0	100
Feedwater flow rate, millions lb/hr	14.127	10.4	13.44
System pressure, nominal in steam dome, psia	1020	1020	1020
System pressure, nominal core design, psia	1035	1035	1035
Coolant saturation temperature at core design pressure, °F	548	549	549
Average power density, kW/liter	48.7	49.2	48.7
Maximum linear heat generation rate, kW/ft	13.4	13.4	13.4
Average linear heat generation rate, kW/ft	5.3	5.4	5.3
Core total heat transfer area, ft^2	74,871	54,879	74,871
Maximum heat flux, Btu/hr-ft^2	361,600	361,600	361,600
Average heat flux, Btu/hr-ft^2	144,100	145,060	143,700
Design operating MCPR	1.22	1.22	1.25

Table 4.4-1 (Cont'd)

GENERAL OPERATING CONDITIONS	LGS[2] BWR/4 (251-764)	BWR/4 (218-560)	SSES BWR/4 (251-764)
Core inlet enthalpy at 420°F FFWT, Btu/lb	526.1	526.9	521.8[1]
Core inlet temperature, at 420°F FFWT, °F	532	532	528[1]
Core maximum exit voids within assemblies, %	77.1	76.0	76.6
Core average void fraction, active coolant	0.418	0.422	0.410
Maximum fuel temperature, °F	3435	3435	3435
Active coolant flow area per assembly, in^2	15.824	15.824	15.824
Core average inlet velocity, ft/sec	6.44	6.65	6.31
Maximum inlet velocity, ft/sec	7.78	7.1	7.5
Total core pressure drop, psi	21.95	23.89	21.52
Core support plate pressure drop, psi	17.52	19.46	17.08
Average orifice pressure drop			
Central region, psi	5.10	8.0	5.09
Peripheral region, psi	14.32	16.52	14.03
Maximum channel pressure loading, psi	11.63	12.86	11.24
Average-power assembly channel pressure loading (bottom), psi	10.39	11.47	9.96
Shroud support ring and lower shroud pressure loading, psi	23.57	26.46	23.13
Upper shroud pressure loading, psi	6.05	7.0	6.05

(1) At 383°F final feedwater temperature
(2) Based on original licensed operating conditions.

Table 4.4-2

REACTOR COOLANT SYSTEM GEOMETRIC DATA

	FLOW PATH LENGTH (in)	HEIGHT AND LIQUID LEVEL (in)	ELEVATION OF BOTTOM OF EACH VOLUME[1] (in)	MINIMUM FLOW AREAS (ft^2)
Lower plenum	216.5	216.5 216.5	-161.5	92.5
Core	163.0	163.0 163.0	55.0	152.0 (includes bypass)
Upper plenum and separators	185.0	185.0 185.0	217.5	45.0
Dome (above normal water level)	299.5	299.5 0	402.5	352.0
Downcomer area	311.0	311.0 311.0	-30.0	118.0
Recirculation loops and jet pumps	97.0 (one loop)	492.0 492.0	-472.5	77.5 in^2 (one loop)

(1) The reference point is the recirculation nozzle outlet centerline.

Table 4.4-3

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Table 4.4-4

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Table 4.4-5

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Table 4.4-7

SAFETY INJECTION LINE LENGTHS

PRELIMINARY DESIGN DATA – NOT AS-BUILT CONDITIONS

INJECTION LINE	LINE O.D. (in)	LINE LENGTH
High Pressure Coolant Injection[2]		
Pump discharge to valve 108[1]	14/12	337'-8"
Inside containment to RPV	12	42'-3"
Low Pressure Coolant Injection[3]		
Loop A		
Pump A discharge to valve F017A[1]	18	331'-9"
Inside containment to RPV	12	49'
Loop B		
Pump discharge to valve F017B[1]	18	318'-4"
Inside containment to RPV	12	49'-1"
Loop C		
Pump discharge to valve F017C[1]	18	270'-8"
Inside containment to RPV	12	49'-7"
Loop D		
Pump discharge to valve F017D[1]	18	256'-3"
Inside containment to RPV	12	64'-5"

Table 4.4-7 (Cont'd)

INJECTION LINE	LINE O.D. (in)	LINE LENGTH
Core Spray[4]		
Loop A		
Pump A discharge to common discharge	12	57'-5"
Pump B discharge to common discharge	12	23'-4"
Common discharge to valve F005[1]	14	199'-8"
Inside containment to RPV	12	43'-3"
Loop B		
Pump B discharge to common discharge	12	59'-11"
Pump D discharge to common discharge	12	23'-2"
Common discharge to valve 108[1]	14	150'-8"
Inside containment to RPV	12	43'-3"

(1) Valve located as close as possible to outside of containment wall.
(2) See drawings M-55 and M-56.
(3) See drawing M-51.
(4) See drawing M-52.

Table 4.4-8

STABILITY ANALYSIS RESULTS

(Cycle-1 Most Limiting Conditions)

Rod Line Analyzed	
Natural circulation	51.5% rated core flow
Rod pattern	105.0% rated thermal power
Decay Ratio	
Total system stability, x_2/x_o	= See Figure 4.4-2
Reactor core stability, x_2/x_o	= 0.78 (0.32 Hz resonant frequency)
Channel hydrodynamic performance, x_2/x_o	= 0.59 (0.36 Hz resonant frequency)

4.5 REACTOR MATERIALS

4.5.1 CONTROL ROD SYSTEM STRUCTURAL MATERIALS

4.5.1.1 Material Specifications

4.5.1.1.1 Material List

The following material listing applies to the CRDM supplied for this application. The position indicator and minor nonstructural items are omitted.

a. Cylinder, tube, and flange assembly:

Flange	ASME SA182 Grade F304
Plugs	ASME SA182 Grade F304
Cylinder	ASTM A269 Grade TP 304
Outer Tube	ASTM A269 Grade TP 304
Tube	ASTM A269 Grade TP 304
Spacer	ASTM A269 Grade TP 304 or ASTM A511 Grade MT 304

b. Piston tube assembly:

Piston Tube	ASTM A269 Grade TP 304
Stud	ASTM A276 Type 304
Head	ASME SA182 Grade F304
Ind. Tube	ASME SA312 Type 316
Cap	ASME SA182 Grade F304

c. Drive line assembly:

Coupling Spud	Inconel X-750
Index Tube	ASTM A269 Grade TP 304
Piston Head	ARMCO 17-4 PH
Coupling	ASME SA312 Grade TP 304 or ASTM A511 Grade MT 304
Magnet Housing	ASME SA312 Grade TP 304 or ASTM A511 Grade MT 304

d. Collet assembly:

Collet piston	ASTM A269 Grade TP 304 or ASME SA312 Grade TP 304
Finger	Inconel X-750
Retainer	ASTM A269 Grade TP 304 or ASTM A511 Grade MT 304
Guide cap	ASTM A269 Grade TP 304
Collet piston Rings	Haynes 25 Alloy

e. Miscellaneous parts:

Stop piston	ASTM A276 Type 304
Connector	ASTM A276 Type 304
O-Ring spacer	ASME SA240 Type 304
Nut	ASME SA193 Grade B8
Barrel	ASTM A269 Grade TP 304 or ASME SA312 Grade TP 304 or ASME SA240 Type 304
O-Ring seals	Ethylene Propylene
Collet spring	Inconel X-750
Ring flange	ASME SA182 Grade F304
Ball check valve	Haynes, Deloro, or Equivalent Stellite Cobalt-Base Alloy

The materials listed under an ASTM specification number are all in the annealed condition (with the exception of the outer tube in the cylinder, tube, and flange assembly), and their properties are readily available. The outer tube is approximately 1/8 hard and has a tensile strength of 90,000/ 125,000 psi, yield strength of 50,000/85,000 psi, and minimum elongation of 25%.

The coupling spud, collet fingers, and collet spring are fabricated from Inconel X-750 in the annealed or equalized condition and are aged 20 hours at 1300°F to produce a tensile strength of 165,000 psi minimum, yield of 105,000 psi minimum, and elongation of 20% minimum. The piston head is ARMCO 17-4 PH in condition H-1100 (aged 4 hours at 1100°F), with a tensile of 140,000 psi minimum, yield of 115,000 psi minimum, and elongation of 15% minimum.

These are widely used materials whose properties are well-known. The parts are readily accessible for inspection and replacement if necessary.

All materials have been successfully used for the past 10 to 15 years in similar drive mechanisms.

4.5.1.1.2 Special Materials

No cold-worked austenitic stainless steels with a yield strength greater than 90,000 psi are employed in the CRD system. Hardenable martensitic stainless steels are not used. ARMCO 17-4 PH (precipitation-hardened stainless steel) is used for the piston head. This material is aged to the H-1100 condition to produce resistance to stress-corrosion cracking in the BWR environments. ARMCO 17-4 PH (H-1100) has been successfully used for the past 10 to 15 years in BWR drive mechanisms.

4.5.1.2 Austenitic Stainless Steel Components: Processes, Inspections, and Tests

All austenitic stainless steel used in the CRD system is solution annealed material with one exception, the outer tube in the cylinder, tube, and flange assembly (Section 4.5.1.1). Proper solution annealing is verified by testing in accordance with ASTM A262, "Recommended Practices for Detecting Susceptibility to Intergranular Attack in Stainless Steels".

Two special processes are employed that subject selected components to temperatures in the sensitization range.

a. The cylinder (cylinder, tube, and flange assembly) and the retainer (collet assembly) are hard-surfaced with Colmonoy-6.

b. The following components are nitrided to provide a wear-resistant surface:

    1. Tube (cylinder, tube, and flange assembly)

    2. Piston tube (piston tube assembly)

    3. Index tube (drive line assembly)

    4. Collet piston and guide cap (collet assembly)

Colmonoy hard-surfacing is applied by the flame spray process. Parts are preheated to 550°F-800°F and then sprayed with Colmonoy. The sprayed coating is fused at about 2000°F using an oxyacetylene torch followed by air cooling.

Nitriding is accomplished using a proprietary process called New Malcomizing. Components are exposed to a temperature of about 1080°F for about 20 hours during the nitriding cycle.

Colmonoy hard-surfaced components have performed successfully for the past 10 to 15 years in drive mechanisms. Nitrided components have been used in BWR CRDs since 1967. It is normal practice to remove some CRDs at each refueling outage. At this time, both the Colmonoy hard-surfaced parts and nitrided surfaces are accessible for visual examination. In addition, dye penetrant examinations have been performed on nitrided surfaces of the longest service drives. This inspection program is adequate to detect any incipient defects before they can become serious enough to cause operating problems.

Pickling is prohibited on stainless steel components that have been exposed to temperatures in the sensitization range during nitriding or hard-surfacing operations. Pickling of welded stainless steel

is also prohibited unless the welded material has been solution annealed subsequent to all welding operations.

Welding is performed in accordance with ASME Section IX. Heat input for stainless steel welds is restricted to a maximum of 50,000 Joules/in and interpass temperature to 350°F. Heating above 800°F (except for welding) is prohibited unless the welds are subsequently solution annealed. These controls are employed to avoid severe sensitization and comply with the intent of Regulatory Guide 1.44.

Control of Delta Ferrite Content

All type 308 and 308L weld metal is purchased to a specification that requires a minimum of 5% delta ferrite. This amount of ferrite is adequate to prevent any microfissuring (hot-cracking) in austenitic stainless steel welds.

An extensive test program performed by GE, with the concurrence of the regulatory staff, has demonstrated that controlling weld filler metal ferrite at 5% minimum produces production welds that meet the requirements of Regulatory Guide 1.31, "Control of Stainless Steel Welding." A total of approximately 400 production welds in five BWR plants was measured, and all welds met the requirements of BTP MTEB 5-1, "Interim Regulatory Position on Regulatory Guide 1.31".

4.5.1.3 Other Materials

These are discussed in Section 4.5.1.1.2.

4.5.1.4 Cleaning and Cleanliness Control

4.5.1.4.1 Protection of Materials During Fabrication, Shipping, and Storage

All the CRD parts listed above (Section 4.5.1.1) are fabricated under a process specification that limits contaminants in cutting, grinding, and tapping coolants and lubricants. It also restricts all other processing materials (marking inks, tape, etc) to those that are completely removable by the applied cleaning process. All contaminants are then required to be removed by the appropriate cleaning process before any of the following:

a. Any processing that increases part temperature above 200°F

b. Assembly that results in a decrease of accessibility for cleaning

c. Release of parts for shipment

The specification for packaging and shipping the CRD provides the following:

The drive is rinsed in hot deionized water and dried in preparation for shipment. The ends of the drive are then covered with a vapor-tight barrier with desiccant. Packaging is designed to protect the drive and prevent damage to the vapor barrier. The planned storage period considered in the design of the container and packaging is two years. This packaging has been qualified and in use for a number of years. Periodic audits have indicated satisfactory protection.

The degree of surface cleanliness obtained by these procedures meets the requirements of Regulatory Guide 1.37 (Rev 0).

Site or warehouse storage specifications require inside heated storage comparable to level B of ANSI N45.2.2. After the second year, a yearly inspection 2% of the units themselves, or a semi-annual examination of the humidity indicators, where provided, associated with 10% of the units is required to verify that the units are dry and in satisfactory condition. Position indicator probes are not subject to this inspection.

4.5.2 REACTOR INTERNAL MATERIALS

4.5.2.1 Material Specifications

Materials used for the core support structure are as follows:

a. Shroud support: SB168

b. Shroud, core plate, and top guide: ASME SA240, SA193, SA194, SA182, SA479, SA312; ASTM A276, A249, A213, (Types 304L or 304)

c. Peripheral fuel supports: ASTM A269 Grade TP 304, ASTM A312 Grade TP 304, ASTM A511, S1 and S2 Grade MT 304

d. Core plate, studs, and nuts: (all type 304), ASTM A479, ASTM A193 Grade B8A, ASTM A194 Grade 8A

e. CRD housing: ASME SA312 Type 304, SA182 Type 304

f. Control rod guide tube: ASTM A358 Class 2; or ASTM A376 Grade TP 304; or ASTM A312 Grade TP 304; ASTM A351 Grade CF8; ASTM A358 Class 2; or ASTM A213 TP 304; or ASTM A249 TP 304

g. Orificed fuel support: ASME A351 Grade CF8

Materials employed in other reactor internal structures are as follows:

a. Steam separator and steam dryer:

All materials are Type 304 stainless steel:

Plate, Sheet, and Strip	ASTM A240 Type 304
Forgings	ASTM A182 Grade F304 ASTM A182 Grade FXM-19 (Slip-fit joint clamps)
Bars	ASTM A276 Type 304
Pipe	ASTM A312 Grade TP 304
Tube	ASTM A269 Grade TP 304

Castings	ASTM A351 Grade CF8

b. Jet pump assemblies:

The components in the jet pump assemblies are a riser, inlet-mixer, diffuser, adaptor, and riser brace. Materials used for these components are to the following specifications:

Castings	ASTM A351 Grade CF8
Bars	ASTM A276 Type 304
Bolts	ASTM A193 Grade B8 or B8M
Nut	ASTM A194 Grade B8
Sheet and Plate	ASTM A240 Type 304 and 304L
Tubing	ASTM A269 Grade TP 304
Pipe	ASTM A358 Type 304 and ASTM A312 Grade TP 304
Weld Coupling	ASTM A403 Grade WP304
Forgings	ASTM A182 Grade F304 ASTM A182 Grade FXM-19 (slip-fit joint clamps)
Inconel Forgings	ASTM B166

Materials in the jet pump assemblies that are not Type 304 stainless steel are:

1. The inlet-mixer adaptor casting, the wedge casting, bracket casting adjusting screw, and the diffuser collar casting are Type 304 hard-surfaced with Stellite-6 for slip-fit joints. The auxiliary spring wedge assembly and the improved inlet-mixer wedge assembly are made of Iconel X-750, ASTM B-637. The wedge is given a high temperature anneal followed by an aging heat treatment.

2. The adaptor is a bimetallic component made by welding a Type 304 forged ring to a forged Inconel-600 ring, made to Specification ASTM B166.

3. The inlet-mixer contains a pin, insert, and beam made of Inconel X-750 to Specification ASTM A637 Grade 688. The beam is given a high temperature anneal after forging.

4. The jet pump beam bolt is SS316L conforming to ASME SA479.

5. The inlet-mixer to diffuser slip-fit joint clamp, if installed, contains small parts made of precipitation-hardened, heat treated Nickel Alloy to Specification ASTM B-637 (UNS N07750 Type 3).

6. Anti-Vibration Solution (AVS) are made of the following: wedge and spring pad are Nitronic 60, spring components and dowel pin components are X-750, and associated hardware, frame, and body are XM-19.

c. Core spray spargers and core spray lines:

Materials used for these components are as follows: ASME SA240, SA182, SA312, SA351, SA479, SA193, SA194, or ASTM A276, A249, A213, A269, A403, Types 304, 304L, 316, 316L, CF3 or CF8.

d. Feedwater Sparger:

Materials used in this component are: 304, 304L, and 316L.

All core support structures are fabricated from ASME and ASTM specified materials and are designed using ASME Section III as a guide. The other reactor internals are noncoded and are fabricated from ASTM or ASME specification materials. Material requirements in the ASTM specifications are identical to requirements in corresponding ASME material specifications.

4.5.2.2 Controls on Welding

The requirements of the ASME Section IX are followed in fabrication of core support structures and other internals.

4.5.2.3 Nondestructive Examination of Wrought Seamless Tubular Products

Core support structures and other internals for LGS were noncoded because they were fabricated before the issuance of subsection NG of ASME Section III. The only coded tubular parts are the CRD housings and incore housings, which are welded to the reactor vessel. These coded tubular parts were examined by radiographic and/or ultrasonic methods in accordance with the requirements of paragraph NB 2550 of the applicable ASME Section III issue that was in effect at that time.

Other noncoded tubular products were supplied in accordance with the applicable ASTM/ASME material specifications. These specifications require a hydrostatic test on each length of tubing.

4.5.2.4 Regulatory Guide Conformance for Fabrication and Processing of Austenitic Stainless Steel

a. Regulatory Guide 1.31, "Control of Stainless Steel Welding"

Cold-worked stainless steels are not used in the reactor internals. All austenitic stainless steel weld filler materials were supplied with a minimum of 5% delta ferrite. This amount of ferrite is considered adequate to prevent microfissuring in austenitic stainless steel welds.

An extensive test program performed by GE, with the concurrence of the regulatory staff, has demonstrated that controlling the weld filler metal ferrite at 5% minimum produces production welds that meet the requirements of Regulatory Guide 1.31. A total of approximately 400 production welds in five BWR plants was measured, and all welds met the requirements of BTP MTEB 5-1, "Interim Regulatory Position on Regulatory Guide 1.31".

b. Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants"

Exposure to contaminants is avoided by carefully controlling all cleaning and processing materials that contact stainless steel during manufacture and construction. Any inadvertent surface contamination is removed to avoid potential detrimental effects.

Special care is exercised to ensure removal of surface contaminants before any heating operation. Water quality for rinsing, flushing, and testing is controlled and monitored. The water quality meets or exceeds the requirements of ANSI N45.2.1.

The degree of cleanliness obtained by these procedures meets the requirements of Regulatory Guide 1.37.

c. Regulatory Guide 1.44, "Control of the Use of Sensitized Steel"

All wrought austenitic stainless steel was purchased in the solution heat treated condition. Heating above 800°F

was prohibited (except for welding) unless the stainless steel was subsequently solution annealed. For 304 steel with carbon content in excess of 0.035% carbon, purchase specifications restricted the maximum weld heat input to 110,000 Joules/in and the weld interpass temperature to 350°F maximum. Welding was performed in accordance with ASME Section IX. These controls were employed to avoid severe sensitization and comply with the intent of Regulatory Guide 1.44.

d. Regulatory Guide 1.71, "Welder Qualification for Areas of Limited Accessibility"

Welder performance qualification tests are made in accordance with the requirements of ASME Section IX. Performance qualifications require testing of welders under simulated access conditions when the access to nonvolumetrically examined production welds is less than 12 inches in any direction and allow welding from one access only. Requalification is required when significantly more restricted access conditions occur or when any essential welding variable is changed.

4.5.2.5 Other Materials

Hardenable martensitic stainless steels and precipitation hardening stainless steels are not used in the reactor internals.

Materials, other than Type 300 stainless steel, employed in vessel internals are: SB166, 167, and 168 Nickel-Chrome-Iron (Inconel 600); SA637 Grade 688 Inconel X-750.

Inconel 600 tubing, plate, and sheet are used in the annealed condition. Bar may be in the annealed or cold-drawn condition.

Inconel X-750 components are fabricated in the annealed or equalized condition and aged 20 hours at 1300°F.

Stellite 6 hard-surfacing is applied to austenitic stainless steel castings using the gas tungsten arc welding or plasma arc surfacing processes.

All materials have been successfully used for the past 10 to 15 years in BWR applications.

4.5.3 CONTROL ROD DRIVE HOUSING SUPPORTS

All CRD housing support subassemblies are fabricated of ASTM A36 structural steel, except for the following items:

ITEM	MATERIAL
Grid	ASTM A441
Disc springs	Schnorr, Type BS-125-71-8
Hex bolts and nuts	STM A307
6"x4"x3/8" tubes	STM A500 Grade B

For further CRD housing support information, see Section 4.6.1.2.

4.6 FUNCTIONAL DESIGN OF REACTIVITY CONTROL SYSTEMS

The reactivity control systems consist of control rods and the CRD system, supplementary reactivity control for the initial core (Section 4.1.3), and the SLCS (Section 9.3).

4.6.1 CONTROL ROD DRIVE SYSTEM

4.6.1.1 Design

4.6.1.1.1 Safety Design Bases

The CRD mechanical system meets the following safety design bases:

a. The design provides for a sufficiently rapid control rod insertion so that no fuel damage results from any abnormal operating transient.

b. The design includes positioning devices, each of which individually supports and positions a control rod.

c. Each positioning device:

1. Prevents its control rod from initiating withdrawal as a result of a single malfunction,

2. Is individually operated so that a failure in one positioning device does not affect the operation of any other positioning device, and

3. Is individually energized when rapid control rod insertion (scram) is signaled, so that failure of power sources external to the positioning device does not prevent other positioning devices' control rods from being inserted.

4.6.1.1.2 Power Generation Design Basis

The CRD design provides for positioning the control rods to control power generation in the core.

4.6.1.2 Description

The CRD system controls gross changes in core reactivity by incrementally positioning neutron-absorbing control rods within the

reactor core, in response to manual control signals. It is also designed to quickly shut down the reactor (scram) in emergency situations by rapidly inserting withdrawn control rods into the core in response to a manual or automatic signal. The CRD system consists of locking piston CRDMs, and the CRD hydraulic system (including power supply and regulation, HCUs, interconnecting piping, instrumentation, and electrical controls).

4.6.1.2.1 Control Rod Drive Mechanisms

The CRDM (drive) used for positioning the control rod in the reactor core is a double-acting, mechanically latched, hydraulic cylinder using demineralized water as its operating fluid (Figures

4.6-1, 4.6-2, 4.6-3, and 4.6-4). The individual drives are mounted on the bottom head of the RPV. The drives do not interfere with refueling and are operative even when the head is removed from the reactor vessel.

The drives are also readily accessible for inspection and servicing. The bottom location makes maximum utilization of the water in the reactor as a neutron shield, and gives the least possible neutron exposure to the drive components. The use of water from the condensate treatment system, and/or the CST as the operating fluid, eliminates the need for a special hydraulic fluid. The drives utilize simple piston seals whose leakage provides cooling for the CRDMs. This leakage does not contaminate the reactor water.

The drives are capable of inserting or withdrawing a control rod at a slow, controlled rate, in addition to providing rapid insertion when required. A mechanism, on the drive, locks the control rod at 6 inch increments of stroke over the length of the core.

A coupling spud at the top end of the drive index tube (piston rod) engages and locks into a mating socket at the base of the control rod. The weight of the control rod is sufficient to engage and lock this coupling. Once locked, the drive and rod form an integral unit that must be manually unlocked by specific procedures before the components can be separated.

The drive holds its control rod in distinct latch positions until the hydraulic system actuates movement to a new position. Withdrawal of each rod is limited by the seating of the rod in its guide tube. Withdrawal of the drive beyond this position to the overtravel limit can be accomplished only if the rod and drive are uncoupled. Withdrawal to the overtravel limit is annunciated by an alarm.

Individual rod position indicators, grouped in one control panel display, correspond to relative rod locations in the core. A separate, smaller display, located just below the large display presents the positions of the control rod selected for movement and of the other rods in the affected rod group.

For display purposes, the control rods are considered in groups of four adjacent rods centered around a common core volume. Each group is monitored by four LPRM strings (Section 7.6.1.4). Rod groups at the periphery of the core may have less than four rods. The small display shows the positions, in digital form, of the rods in the group to which the selected rod belongs. Backlighting indicates which of the four rods is the one selected for movement.

4.6.1.2.2 Drive Components

Figure 4.6-2 illustrates the operating principle of a CRD. Figures 4.6-3 and 4.6-4 illustrate the drive in more detail. The main components of the drive and their functions are described below.

4.6.1.2.2.1 Drive Piston

The drive piston is mounted at the lower end of the index tube. The function of the index tube is similar to that of a piston rod in a conventional hydraulic cylinder. The drive piston and index tube make up the main moving assembly in the drive. The drive piston operates between positive end stops, with a hydraulic cushion provided at the upper end only. The piston has both inside and outside seal-rings, and operates in an annular space between an inner cylinder (fixed piston tube) and an outer cylinder (drive cylinder). Because the type of inner seal used is effective in only one direction, the lower sets of seal-rings are mounted with one set sealing in each direction.

A pair of nonmetallic bushings prevent metal-to-metal contact between the piston assembly and the inner cylinder surface. The outer piston rings are segmented, step-cut seals with expander springs holding the segments against the cylinder wall. A pair of split bushings on the outside of the piston prevents piston contact with the cylinder wall. The effective piston area for downtravel, or withdrawal, is approximately 1.2 in^2 versus approximately 4.1 in^2 for uptravel, or insertion. This difference in driving area tends to balance the control rod weight and ensures a higher force for insertion than for withdrawal.

4.6.1.2.2.2 Index Tube

The index tube is a long hollow shaft made of nitrided stainless steel. Circumferential locking grooves, spaced every 6 inches along the outer surface, transmit the weight of the control rod to the collet assembly.

4.6.1.2.2.3 Collet Assembly

The collet assembly serves as the index tube locking mechanism. It is located in the upper part of the drive unit. This assembly prevents the index tube from accidentally moving downward. The assembly consists of the collet fingers, a return spring, a guide cap, a collet housing (part of the cylinder, tube, and flange), and the collet piston.

Locking is accomplished by fingers mounted on the collet piston at the top of the drive cylinder. In the locked or latched position, the fingers engage a locking groove in the index tube.

The collet piston is normally held in the latched position by a force of approximately 150 pounds supplied by a spring. Metal piston rings are used to seal the collet piston from reactor vessel pressure. The collet assembly does not unlatch until the collet fingers are unloaded by a short, automatically sequenced drive-in signal. A pressure, approximately 180 psi above reactor vessel pressure, must then be applied to the collet piston to overcome spring force, slide the collet up against the conical surface in the guide cap, and spread the fingers out so they do not engage a locking groove.

A guide cap is fixed in the upper end of the drive assembly. This member provides the unlocking cam surface for the collet fingers and serves as the upper bushing for the index tube.

If reactor water is used during a scram to supplement accumulator pressure, it is drawn through a filter on the guide cap.

4.6.1.2.2.4 Piston Tube

The piston tube is an inner cylinder, or column, extending upward inside the drive piston and index tube. The piston tube is fixed to the bottom flange of the drive and remains stationary. Water is brought to the upper side of the drive piston through this tube. A series of orifices at the top of the tube provides progressive water shutoff to cushion the drive piston at the end of its scram stroke.

4.6.1.2.2.5 Stop Piston

A stationary piston, called the stop piston, is mounted on the upper end of the piston tube. This piston provides the seal between reactor vessel pressure and the space above the drive piston. It also functions as a positive end stop at the upper limit of control rod travel. A stack of spring washers just below the stop piston helps absorb the final mechanical shock at the end of control

rod travel. The piston rings are similar to the drive piston outer rings. A bleed-off passage to the center of the piston tube is located between the two pairs of rings. This arrangement allows seal leakage from the reactor vessel (during a scram) to be bled directly to the discharge line. The lower pair of seals is used only during the cushioning of the drive piston at the upper end of the stroke.

The center tube of the drive mechanism forms a well to contain the position indicator probe. The probe is an aluminum extrusion attached to a cast aluminum housing. Mounted on the extrusion are hermetically sealed, magnetically operated reed switches. The entire probe assembly is protected by a thin-walled stainless steel tube. The switches are actuated by a ring magnet located at the bottom of the drive piston.

The drive piston, piston tube, and indicator tube are all of nonmagnetic stainless steel, allowing the individual switches to be operated by the magnet as the piston passes. One switch is located at each position corresponding to an index tube groove, thus allowing indication at each latching point. An additional switch is located at each midpoint between latching points to indicate the intermediate positions during drive motion. Thus, indication is provided for each 3 inches of travel. Duplicate switches are provided for the full-in and full-out positions. One additional switch (an overtravel switch), is located at a position below the normal full-out position. Because the limit of downtravel is normally provided by the control rod itself as it reaches the back-seat position, the drive can pass this position and actuate the overtravel switch only if it is uncoupled from its control rod. A convenient means is thus provided to verify that the drive and control rod are coupled after installation of a drive and at any time during plant operation.

4.6.1.2.2.6 Flange and Cylinder Assembly

A flange and cylinder assembly is made up of a heavy flange welded to the drive cylinder. A sealing surface on the upper face of this flange forms the seal to the drive housing flange. The seals contain reactor pressure and the two hydraulic control pressures. Teflon-coated, stainless steel rings are used for these seals.

The drive flange contains the integral ball, or two-way check (ball-shuttle) valve. This valve directs either the reactor vessel pressure or the driving pressure, whichever is higher, to the underside of the drive piston. Reactor vessel pressure is admitted to this valve from the annular space between the drive and drive housing through passages in the flange.

Water used to operate the collet piston passes between the inner and outer tubes of the drive cylinder. The inside of the cylinder tube is honed to provide the surface required for the drive piston seals.

Both the cylinder tube and outer tube are welded to the drive flange. The upper ends of these tubes have a sliding fit to allow for differential expansion.

The upper end of the index tube is threaded to receive a coupling spud. The coupling (Figure 4.6-1) accommodates a small amount of angular misalignment between the drive and the control rod. Six spring fingers allow the coupling spud to enter the mating socket on the control rod. A lock plug then enters the spud and prevents uncoupling.

4.6.1.2.2.7 Lock Plug

Two means of uncoupling are provided. With the reactor vessel head removed, the lock plug can be raised against the spring force of approximately 50 pounds by a rod extending up through the center of the control rod to an unlocking handle located above the control rod velocity limiter. The control rod, with the lock plug raised, is then lifted from the drive.

If it is desired to uncouple a drive without removing the reactor vessel head for access, the lock plug can also be pushed up from below. In this case, the piston tube assembly is pushed up against the uncoupling rod assembly, which raises the lock plug and allows the coupling spud to disengage the socket as the drive piston and index tube are driven down.

The control rod is heavy enough to force the spud fingers to enter the socket and push the lock plug up, allowing the spud to enter the socket completely, and the lock plug to snap back into place. Therefore, the drive is coupled to the control rod using only the weight of the control rod.

4.6.1.2.3 Materials of Construction

Factors that determine the choice of construction materials are discussed in the following sections.

4.6.1.2.3.1 Index Tube

The index tube must withstand the locking and unlocking action of the collet fingers. A compatible bearing combination must be provided that is able to withstand moderate misalignment forces. The reactor environment limits the choice of materials suitable for corrosion resistance. The column and tensile loads can be satisfied by an annealed, 300-series stainless steel. The wear and bearing requirements are provided by Malcomizing the completed tube. To obtain suitable corrosion resistance, a carefully controlled process of surface preparation is employed.

4.6.1.2.3.2 Coupling Spud

The coupling spud is made of Inconel X-750 that is aged for maximum physical strength and for the required corrosion resistance. Because misalignment tends to cause chafing in the semispherical contact area, this component is protected by a thin chromium plating (electrolyzed). This plating also prevents galling of the threads attaching the coupling spud to the index tube.

4.6.1.2.3.3 Collet Fingers

Inconel X-750 is used for the collet fingers, which must function as leaf springs when cammed open to the unlocked position. Colmonoy-6 hard-facing provides a long-wearing surface, adequate for design life, for the area contacting the index tube and unlocking the cam surface of the guide cap.

4.6.1.2.3.4 Seals and Bushings

Graphitar-3030 is selected for seals and bushings on the drive piston and stop piston. The material is inert and has a low friction coefficient when water-lubricated. Because some loss of Graphitar-3030 strength is experienced at higher temperatures, the drive is supplied with cooling water to hold temperatures below 250°F. The Graphitar-3030 is relatively soft, which is advantageous when an occasional particle of foreign matter reaches a seal. The resulting

scratches in the seal reduce sealing efficiency until worn smooth, but the drive design can tolerate considerable water leakage past the seals into the reactor vessel.

4.6.1.2.3.5 Summary

All drive components exposed to reactor vessel water are made of austenitic stainless steel except the following:

a. Seals and bushings on the drive piston and stop piston are Graphitar-3030.

b. All springs and members requiring spring action (collet fingers, coupling spud, and spring washers) are made of Inconel X-750.

c. The ball check valve is a Haynes Stellite cobalt-base alloy.

d. Elastomeric O-ring seals are ethylene propylene.

e. Metal piston rings are Haynes-25 alloy.

f. Certain wear surfaces are hard-faced with Colmonoy-6.

g. Nitriding by a proprietary new Malcomizing process and chromium plating are used in certain areas where resistance to abrasion is necessary.

h. The drive piston head is made of ARMCO 17-4PH.

Pressure-containing portions of the drives are designed and fabricated in accordance with requirements of ASME Section III.

4.6.1.2.4 Control Rod Drive Hydraulic System

The CRD hydraulic system supplies and controls the pressure and flow to and from the drives through HCUs. The water discharged from the drives during a scram flows through the HCUs to the scram discharge volume. The water discharged from a drive during a normal control rod positioning operation flows through the HCU, the exhaust header, and is returned to the reactor vessel via the HCUs of nonmoving drives. There are as many HCUs as the number of CRDs. The design criterion for the LGS CRD hydraulic system requires that no single failure of a component, structure, or service function shall prevent a reactor shutdown. Each CRD acts somewhat independently, and reactor shutdown can be achieved assuming failure of a single rod to insert. In addition, the CRD scram hydraulic system is designed to be fail-safe (i.e., to scram on loss of electrical or pneumatic power.)

4.6.1.2.4.1 Hydraulic Requirements

The CRD hydraulic system piping and instrumentation diagram is shown in drawings M-46 and M-47, and the process diagrams are shown in drawings C11-1020-G-004, C11-1020-G-005, C11-1020-G-006, and C11-1020-G-007. The hydraulic requirements, identified by the function they perform, are as follows:

a. An accumulator hydraulic charging pressure of approximately 1400-1500 psig is required. Flow to the accumulators is required only during scram reset or system startup.

b. Drive pressure of 260 psi (minimum) above reactor vessel pressure is required. A flow rate of approximately 4 gpm to insert a control rod and 2 gpm to withdraw a control rod is required.

c. Cooling water to the drives is required at approximately 15 psi above reactor vessel pressure and at a flow rate of approximately 0.2-0.34 gpm per drive unit.

d. The scram discharge volume is sized to receive, and contain, all the water discharged by the drives during a scram; a minimum volume of 3.34 gallons per drive is required (excluding the instrument volume).

4.6.1.2.4.2 System Description

The CRD hydraulic system provides the required functions with the pumps, filters, strainers, valves, instrumentation, and piping shown in drawings M-46 and M-47, listed in Table 4.6-1, and described in the following paragraphs.

Duplicate components are included, where necessary, to ensure continuous system operation if an inservice component requires maintenance. The scram system design for LGS provides numerous indications and alarms in the control room to inform the operator of the condition of vital components, including the following:

1. SDV water level
2. Low scram accumulator pressure alarm
3. Scram accumulator H_2O leakage alarm
4. Scram air header supply low/high pressure alarm
5. SDV vent and drain valve position indication.

4.6.1.2.4.2.1 Supply Pump

One supply pump pressurizes the system with water from the condensate treatment system and/or CST. One spare pump is provided for standby. A discharge check valve prevents backflow through the nonoperating pump. During normal operation, a portion of the pump discharge flow is diverted through a minimum flow bypass line to the CST. This flow is controlled by an orifice and is sufficient to prevent pump damage if the pump discharge is inadvertently closed. An alternative alignment allows pump operation with the minimum flow bypass line closed for the purpose of CRD hydraulic system maintenance, testing or trouble shooting.

Condensate water is processed by two filters. The pump suction filter is a disposable element-type with a 25 micron absolute rating. A differential pressure indicator and control room alarm monitor the filter element as it collects foreign material. A 250 micron strainer, downstream of the suction filter at each pump suction protects the pumps when the suction filter is being serviced. The drive water filter downstream of the pump is a cleanable-element-type with a maximum 50 micron absolute rating. One spare drive water filter is provided for standby service. A 250 micron strainer in each drive water filter/discharge line guards the hydraulic system if there is a filter element failure.

4.6.1.2.4.2.2 Accumulator Charging Pressure

Accumulator charging pressure is established by precharging the nitrogen accumulator to a precisely controlled pressure at known temperature. During a scram, the scram inlet (and outlet) valves open and permit the stored energy in the accumulators to discharge into the drives. The resulting pressure decrease in the charging water header allows the CRD supply pump to "run-out" (i.e., flow rate to increase substantially) into the CRDs via the charging water header. The flow element, upstream of the accumulator charging water header, senses high flow and provides a signal to the manual auto-flow control station, which in turn closes the system flow control valve. This action maintains increased flow through the charging water header, while avoiding prolonged pump operation at run-out conditions.

Pressure in the charging water header is monitored in the control room with a pressure indicator and a low pressure alarm.

During normal operation, the flow control valve maintains a constant system flow rate. This flow is used for drive flow and drive cooling.

4.6.1.2.4.2.3 Drive Water Pressure

Drive water pressure required in the drive water header is maintained by the drive/cooling pressure control valve, which is manually adjusted from the control room. A flow rate of approximately 6 gpm (the sum of the flow rate required to insert and withdraw a control rod) normally passes from the drive water header through two solenoid-operated stabilizing valves (arranged in parallel) into the cooling water header. The flow through one stabilizing valve equals the drive insert flow; that through the other stabilizing valve equals the drive withdrawal flow. When operating a drive, the required flow is diverted to that drive by closing the appropriate stabilizing valve, and at the same time opening the drive and exhaust directional control solenoid valves. Thus, flow through the drive pressure control valve is always constant.

Flow indicators in the drive water header and in the line downstream from the stabilizing valves allow the flow rate through the stabilizing valves to be adjusted when necessary. Differential pressure between the reactor vessel and the drive header is indicated in the control room.

On Unit 2, a permanent CRD friction test facility is connected to the drive water header and to a reactor vessel pressure instrument line. The device measures the friction of the control rods during rod movement. This facility eliminates the need for repetitive instrumentation setups while testing the CRDs during startup testing, refueling outages, and power plant operation. The friction test facility will be isolated from the CRD hydraulic system except when it is being used for friction testing or diagnostics.

4.6.1.2.4.2.4 Cooling Water Header

The cooling water header is located downstream from the drive/cooling pressure valve. The drive/cooling pressure control valve is manually adjusted from the control room to produce the required drive water/cooling water pressure balance.

The flow through the flow control valve is virtually constant. Therefore, once adjusted, the drive/cooling pressure control valve maintains the required drive pressure and cooling water pressure, independent of reactor vessel pressure. Changes in setting of the pressure control valves are required only to adjust for changes in the cooling requirements of the drives, as the drive

seal characteristics change with time. A flow indicator in the control room monitors cooling water flow. A differential pressure indicator in the control room indicates the difference between reactor vessel pressure and drive cooling water pressure. Although the drives can function without cooling water, seal life is shortened by long-term exposure to reactor temperatures. The temperature of each drive is indicated and recorded, and excessive temperatures are annunciated in the control room.

4.6.1.2.4.2.5 Exhaust Water Header

The exhaust water header connects to each HCU and provides a low pressure plenum and discharge path for the fluid expelled from the drives during control rod insert and withdraw operations. The fluid injected into the exhaust water header during rod movements is discharged back up to the RPV via reverse flow through the insert exhaust directional solenoid valves of adjoining HCUs. The pressure in the exhaust water header is, therefore, maintained at essentially reactor pressure. To ensure that the pressure in the exhaust water header is maintained near reactor pressure during the period of vessel pressurization, redundant pressure equalizing valves connect the exhaust water header to the cooling water header.

4.6.1.2.4.2.6 Scram Discharge Volume

The SDV consists of header piping which connects to each HCU and drains into an instrument volume. The header piping is sized to receive and contain all the water discharged by the drives during a scram, independent of the instrument volume. A minimum SDV of 3.34 gallons per drive is specified through the system design specifications. This minimum SDV is based on conservative assumptions such that scram performance is not adversely affected.

The LGS CRD scram discharge header is connected to the instrument volume by piping of the same diameter as the SDV and is sloped towards the instrument volume, which monitors any water accumulation in the header. As the instrument volume starts to fill, the instrumentation triggers an alarm and initiates a scram when the instrument volume is full, but before the scram header begins to fill. This ensures that the scram header is able to accept the scram discharge water. The instrumentation for the instrument volume is located on the vertical instrument volume, and not on connecting piping.

There are two sets of headers, each with its own directly connected SDIV attached to the low point of the header piping. The large diameter pipe of the instrument volume thus serves as a vertical extension of the SDV that monitors water accumulation in the header piping. There is no reduction in the pipe size of the header piping going from the HCUs to the scram discharge instrument volume. This volume in turn is directly connected to the SDV without restriction.

The LGS design provides for redundant and diverse level sensing instrumentation. Two float switches and differential pressure (level) transmitters with level indicating switches provide high water level input to RPS from each SDIV. (There are two SDIVs which are hydraulically coupled via the common drain line). Each device provides an input to one channel. The devices are arranged so that no single failure prevents a reactor scram caused by high water level. These level instruments are connected to the instrument volume and trigger alarms in the control room on SDV High Level Trip.

In addition to the redundant and diverse devices which input to the RPS, there are two level switches for the instrument volume to provide operator warning. At the lowest level, a level switch actuates to indicate that the volume is not completely empty during postscram draining, or to indicate that the volume starts to fill through leakage accumulation at other times during reactor

operation. At the second level, a level switch produces a rod withdrawal block to prevent further withdrawal of any control rod when leakage accumulates to half the capacity of the instrument volume.

The instrumentation on the LGS instrument volume is designed so that no more than half of the scram trip level instruments shall be of the same manufacture, design, and operating principle to minimize the potential for common mode failure.

The SDV level instruments are located on the large diameter SDIV piping to minimize hydrodynamic forces associated with water flow following a scram.

During normal plant operation, the SDV is empty and vented to the atmosphere through its open vent and drain valves. When a scram occurs, upon a signal from the RPS, these vent and drain valves are closed to conserve reactor water. The position of the SDV vent and drain valves is continuously monitored. Lights in the control room indicate the position of these valves.

Redundant scram discharge system vent and drain valves are provided on LGS to ensure that no single failure can result in an uncontrolled loss of reactor coolant. Redundant solenoid-operated pilot valves control the vent and drain valves. The vent and drain system is therefore sufficiently redundant to avoid a failure to isolate the SDV single active failures. In addition, the solenoid-operated pilot valves are fail-safe (i.e., SDV isolates) on loss of electric or pneumatic power. The SDV drain line discharges to the equipment drain collection tank, and the vent line discharges to dirty radwaste. Vent lines are protected by vacuum breakers. The redundant isolation valves on the vent and drain lines are normally open during power operation and would not prevent draining of those lines in the nonscrammed condition. The position of these valves is indicated in the control room. Neither the vent and drain functions would be adversely affected by other system interfaces. Because of the redundant vent and drain valves, repair operations on any one valve will not prevent isolation of the vent and drain lines when scramming.

The operation of the scram discharge system is either automatic or remote manual, thus minimizing the time in which an operator would be in close contact with system components. The instrument volumes and level instruments are installed in corner locations to take advantage of shielding provided by concrete structures and to permit the installation of about two feet of temporary shielding for personnel protection. The scram discharge volume drain valves are located one floor below the instrument volumes which minimize the need for temporary shielding.

The SDV and associated vent and drain piping are classified as important to safety and required to meet the ASME Section III, Class 2 and seismic Category I requirements. Design parameters such as temperature, pressure, and frequency for limiting modes of operation provide a design basis for supply of equipment as well as the interfacing piping design and analysis.

During a scram, the SDV partly fills with water discharged from above the drive pistons. After scram is completed, the CRD seal leakage from the reactor continues to flow into the SDV until the discharge volume pressure equals the reactor vessel pressure. A check valve in each HCU prevents reverse flow from the scram discharge header volume to the drive. When the initial scram signal is cleared from the RPS, the SDV signal is overridden with a key-lock override switch, and the SDV is drained and returned to atmospheric pressure.

Remote manual switches in the pilot valve solenoid circuits allow the discharge volume vent and drain valves to be tested without disturbing the RPS. Closing the SDV valves, allows the outlet scram valve seats to be leak tested by timing the accumulation of leakage into the SDV.

System operating conditions that are required for scram are continuously monitored. Four liquid level switches and two level transmitters, connected to each instrument volume, monitor the volume for abnormal water level. They are set at three different levels. They provide redundant and diverse inputs to the RPS scram function, control room annunciation function, and control rod withdrawal block function (drawing M-47). At the lowest level, a level switch actuates to indicate that the volume is not completely empty during postscram draining, or to indicate that the volume starts to fill through leakage accumulation at other times during reactor operation. At the second level, a level switch produces a rod withdrawal block to prevent further withdrawal of any control rod when leakage accumulates to half the capacity of the instrument volume. The remaining two switches and two transmitters are interconnected with the trip channels of the RPS, and initiate a reactor scram on high water level in the SDIV. Electronic switches are actuated by level transmitters to provide diversity of signals to the RPS.

The SDIV scram level instrumentation arrangement and trip logic allows instrument adjustment or surveillance without bypassing the scram function or directly causing a scram. Each level instrument can be individually isolated without bypassing the scram function. For the repair or replacement of scram level instrumentation the "one-out-of-two-twice" logic could be temporarily modified to "one-out-of-two". Thus, the single failure criterion would not be violated and the scram function is available when needed. Provisions are included in the system design for functional testing and calibration of SDIV level instrumentation.

The SDV piping system leak rates, loading conditions and material properties are bounded by the limiting value for these parameters identified in the BWROG letter of May 10, 1984 (BWROG-8420) and accepted by the NRC in Generic Letter 86-01 (January 3, 1986). Leak tests and inspections are performed per the criterion for Class 2 piping contained in ASME Section XI. Also, the CRD Scram Discharge System is in the Leakage Reduction Program described in UFSAR Section 6.2.8

The LGS EOP for secondary containment control, which is based on the BWROG EPGs, includes an entry condition for secondary containment sump water level being above the normal operating level. In the event of a break in the scram discharge piping system, the normal plant procedures call for a reset of the scram. If, however, the affected system cannot be isolated or the isolation proves ineffective in mitigating temperature or radiation increases, rapid depressurization of the reactor is required per the EOP if the condition causes a widespread problem in the reactor enclosure. Rapid depressurization of the reactor is accomplished by safety valve discharge into the suppression pool. This reduces the leakage into the reactor building. The EOP also specifies the operator actions for achieving isolation and reactor depressurization should they be needed to mitigate leak consequences.

4.6.1.2.4.3 Hydraulic Control Units

Each HCU furnishes pressurized water, on signal, to a drive unit. The drive then positions its control rod as required. Operation of the electrical system that supplies scram and normal control rod positioning signals to the HCU is described in Section 7.7.1.2.

The basic components in each HCU are manual, pneumatic, and electrical valves; an accumulator; related piping; electrical connections; filters; and instrumentation (drawings M-46, M-47, and Figure 4.6-8). The components and their functions are described in the following paragraphs.

4.6.1.2.4.3.1 Insert Drive Valve

The insert drive valve is solenoid-operated and opens on an insert signal. The valve supplies drive water to the bottom side of the main drive piston.

4.6.1.2.4.3.2 Insert Exhaust Valve

The insert exhaust solenoid valve also opens on an insert signal. The valve discharges water from above the drive piston to the exhaust water header.

4.6.1.2.4.3.3 Withdraw Drive Valve

The withdraw drive valve is solenoid-operated and opens on a withdraw signal. The valve supplies drive water to the top of the drive piston.

4.6.1.2.4.3.4 Withdraw Exhaust Valve

The solenoid-operated withdraw exhaust valve opens on a withdraw signal, and discharges water from below the main drive piston to the exhaust header. It also serves as the settle valve which opens, following any normal drive movement (insert or withdraw), to allow the control rod and its drive to settle back into the nearest latch position.

4.6.1.2.4.3.5 Speed Control Units

The insert drive valve and withdraw exhaust valve have a speed control unit. The speed control unit regulates the control rod insertion and withdrawal rates during normal operation. The manually adjustable flow control unit is used to regulate the water flow to and from the volume beneath the main drive piston. A correctly adjusted unit does not require readjustment except to compensate for changes in drive seal leakage.

4.6.1.2.4.3.6 Scram Pilot Valve

The scram pilot valve is operated from the RPS. The single scram pilot valve with two solenoids, controls both the scram inlet valve and the scram exhaust valve. The valve is solenoid-operated and normally energized. On loss of electrical signal to the solenoids, such as the loss of external ac power, the inlet port closes and the exhaust port opens. The scram pilot valve is designed so that the trip system signal must be removed from both solenoids before air pressure can be discharged from the scram valve operators. This prevents inadvertent scram of a single drive if one of the scram pilot valve solenoids fails.

4.6.1.2.4.3.7 Scram Inlet Valve

The scram inlet valve opens to supply pressurized water to the bottom of the drive piston. This quick-opening globe valve is operated by an internal spring and system pressure. It is closed by air pressure applied to the top of its diaphragm operator. A position indicator switch on this valve and on the scram exhaust valve energizes a light in the control room as soon as the valve starts to open.

4.6.1.2.4.3.8 Scram Exhaust Valve

The scram exhaust valve opens slightly before the scram inlet valve, exhausting water from above the drive piston. The exhaust valve opens faster than the inlet valve because of the higher air pressure spring setting in the valve operator.

4.6.1.2.4.3.9 Scram Accumulator

The scram accumulator stores sufficient energy to fully insert a control rod at lower vessel pressures. At higher vessel pressures the accumulator pressure is assisted or supplanted by reactor vessel pressure. The accumulator is a hydraulic cylinder with a free-floating piston. The piston separates the water on top from the nitrogen below. A check valve in the accumulator charging line prevents loss of water pressure if supply pressure is lost.

During normal plant operation, the accumulator piston is seated at the bottom of its cylinder. Loss of nitrogen decreases the nitrogen pressure which actuates a pressure switch which sounds an alarm and actuates an indicating light in the control room.

To ensure that the accumulator is able to produce a scram, it is monitored for water leakage. A float-type level switch actuates an alarm and an indicating light in the control room if water leaks past the piston barrier and collects in the accumulator instrumentation block.

4.6.1.2.5 Control Rod Drive System Operation

The CRD system performs rod insertion, rod withdrawal, and scram. These operational functions are described below.

4.6.1.2.5.1 Rod Insertion

Rod insertion is initiated by a signal from the operator to the insert valve solenoids. This signal causes both insert valves to open. The insert drive valve applies reactor pressure plus approximately 90 psi to the bottom of the drive piston. The insert exhaust valve allows water from above the drive piston to discharge to the exhaust header.

As is illustrated in Figure 4.6-3, the locking mechanism is a ratchet-type device and does not interfere with rod insertion. The speed at which the drive moves is determined by the flow through the insert speed control valve, which is set for approximately 4 gpm for a shim speed (nonscram operation) of 3 in/sec. During normal insertion, the pressure on the downstream side of the speed control valve is 90-100 psi above reactor vessel pressure. However, if the drive slows for any reason, the flow through and the pressure drop across the insert speed control valve decreases; the full differential pressure (260 psi) is then available to cause continued insertion. With 260 psi differential pressure acting on the drive piston, the piston exerts an upward force of 1040 pounds.

4.6.1.2.5.2 Rod Withdrawal

Rod withdrawal is, by design, more involved than insertion. The collet fingers (latch) must be raised to reach the unlocked position (Figure 4.6-3). The notches in the index tube and the collet fingers are shaped so that the downward force on the index tube holds the collet fingers in place. The index tube must be lifted before the collet fingers can be released. This is done by opening the drive insert valves (in the manner described in the preceding paragraph) for approximately one second. The withdraw valves are then opened, applying driving pressure above the drive piston,

and opening the area below the piston to the exhaust header. Pressure is simultaneously applied to the collet piston. As the piston raises, the collet fingers are cammed outward, away from the index tube, by the guide cap.

The pressure required to release the latch is set and maintained at a level high enough to overcome the force of the latch return spring, plus the force of reactor pressure opposing movement of the collet piston. When this occurs, the index tube is unlatched and free to move in the withdraw direction. Water displaced by the drive piston flows out through the withdraw speed control valve, which is set to give a rod shim speed of approxiately 3 in/sec. The entire valving sequence is automatically controlled, and is initiated by a single operation of the rod withdraw switch.

Rod withdrawal will not occur without permissive operator action. Following a deliberate operator withdrawal action, a rod drift could occur due to failure of its collet assembly to return to the locked position. The operator can interrupt this withdrawal with a scram or an insert signal. No single failure can of itself initiate a rod withdrawal.

4.6.1.2.5.3 Scram

During a scram, the scram pilot valves and scram valves are operated as previously described. With the scram valves open, accumulator pressure is admitted under the drive piston, and the area over the drive piston is vented to the SDV.

The large differential pressure (approximately 1500 psi initially, and always several hundred psi, depending on reactor vessel pressure) produces a large upward force on the index tube and control rod. This force gives the rod a high initial acceleration and provides a large margin of force to overcome friction. After the initial acceleration is achieved, the drive continues at a nearly constant velocity. This characteristic provides a high initial rod insertion rate. As the drive piston nears the top of its stroke, the piston seals close off the large passage (buffer orifices) in the stop piston tube, providing a hydraulic cushion at the end of travel.

Prior to a scram signal, the accumulator in the HCU has approximately 1450-1510 psig on the water-side and 1050-1150 psig on the nitrogen side. As the inlet scram valve opens, the full water-side pressure is available at the CRD acting on a 4.1 in^2 area. As CRD motion begins, this pressure drops to the gas-side pressure, less line losses between the accumulator and the CRD. At low vessel pressures, the accumulator completely discharges with a resulting gas-side pressure of approximately 575 psi. The CRD accumulators are required to scram the control rods when the reactor pressure is low, and the accumulators retain sufficient stored energy to ensure the complete insertion of the control rods in the required time.

The ball check valve in the drive flange allows reactor pressure to supply the scram force whenever reactor pressure exceeds the supply pressure at the drive. This occurs, due to accumulator pressure decay and inlet line losses, during all scrams at higher vessel pressures. When the reactor is close to, or at, full operating pressure, reactor pressure alone inserts the control rod in the required time, although the accumulator does provide additional margin at the beginning of the stroke.

The CRD system, with accumulators, provides the following scram performances at full power operation, in terms of average elapsed time after the opening of the RPS trip actuator (scram signal) for the drives to attain the scram strokes listed (See Figure 15.0-2):

% of full stroke	5	20	50	90
Stroke, in	7.2	28.8	72.0	129.6
Average time, sec	0.375	0.90	2.0	3.5

4.6.1.2.5.4 Alternate Rod Insertion

The ARI feature of the RRCS is designed to increase the reliability of the CRD system. ARI provides for rod insertion by actuating valves that are redundant and diverse from the RPS scram pilot valves.

The RRCS signal to insert control rods results in energizing the eight ARI dc solenoid valves shown in drawings M-46, M-47, C11-1020-G-004, C11-1020-G-005, C11-1020-G-006, and C11-1020-G-007. Two of these valves, in series with the backup scram valves, also have parallel functioning check valves to ensure venting of air from the air supply line in the event that an ARI valve fails. Four ARI valves provide for venting of the HCU scram valve pilot air headers to atmosphere. Depressurizing the headers actuates rod insertion. The remaining two ARI valves vent the scram air header that supplies the air pressure to keep the vent and drain lines open, thereby resulting in isolation of the SDV.

4.6.1.2.6 Instrumentation

The instrumentation, for both the CRDMs and HCUs, is defined by that given for the RMCS. The objective of the RMCS is to provide the operator with the means to make changes in nuclear reactivity so that reactor power level and power distribution can be controlled. The system allows the operator to manipulate control rods.

The design bases and further discussion are discussed in Chapter 7. Section 7.6 lists the leak detection systems provided. Operator action is relied on to determine possible break locations based on these and plant system observations as discussed in GE report NEDO-24342 for CRD system breaks.

The licensee participated in the development of NEDO-22209, which was transmitted to the NRC by the BWROG on August 23, 1982. The results of NEDO-22209 show a probability of failure of the SDV too small to warrant exclusive monitoring devices.

4.6.1.3 Control Rod Drive Housing Supports

4.6.1.3.1 Safety Objective

The CRD housing supports prevent any significant nuclear transient from occurring if a drive housing breaks or separates from the bottom of the reactor vessel.

4.6.1.3.2 Safety Design Bases

The CRD housing supports meet the following safety design bases:

a. Following a postulated CRD housing failure, control rod downward motion is limited, so that any resulting nuclear transient could not be sufficient to cause fuel damage.

b. The clearance between the CRD housings and the supports is sufficient to prevent vertical contact stresses caused by thermal expansion during plant operation.

4.6.1.3.3 Description

The CRD housing supports are shown in Figure 4.6-9. Horizontal beams are installed immediately below the bottom head of the reactor vessel, between the rows of CRD housings. The beams are welded to brackets which are welded to the steel form liner of the drive room in the reactor support pedestal.

Hanger rods, approximately 10 feet long and 1¾ inches in diameter, are supported from the beams on stacks of disc springs. These springs compress approximately 2 inches under the design load.

The support bars are bolted between the bottom ends of the hanger rods. The spring pivots at the top, and the beveled, loose-fitting ends on the support bars prevent substantial bending moment in the hanger rods if the support bars are overloaded.

Individual grids rest on the support bars between adjacent beams. Because a single-piece grid would be difficult to handle in the limited work space and because it is necessary that CRDs, position indicators, and incore instrumentation components be accessible for inspection and maintenance, each grid is designed for in-place assembly or disassembly. Each grid assembly is made from two grid plates, a clamp, and a bolt. The top part of the clamp guides the grid to its correct position, directly below the respective CRD housing that it would support in the postulated accident.

When the support bars and grids are installed, a gap of approximately l inch at room temperature (approximately 70°F) is provided between the grid and the bottom contact surface of the CRD flange. During system heatup, this gap is reduced by a net downward expansion of the housings with respect to the supports. In the hot operating condition, the gap is approximately ¾ inch.

In the postulated CRD housing failure, the CRD housing supports are loaded when the lower contact surface of the CRD flange contacts the grid. The resulting load is then carried by two grid plates, two support bars, four hanger rods, their disc springs, and two adjacent beams.

The AISC Manual of Steel Construction, "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings" is used in designing the CRD housing support system. However, to provide a structure that absorbs as much energy as practical without yielding, the allowable tension and bending stresses used are 90% of yield, and the shear stress used is 60% of yield. These design stresses are 1.5 times the AISC allowable stresses (60% and 40% of yield, respectively).

For purposes of mechanical design, the postulated failure resulting in the highest forces is an instantaneous circumferential separation of the CRD housing from the reactor vessel, with the reactor at an operating pressure of 1086 psig (at the bottom of the vessel) acting on the area of the separated housing. The weight of the separated housing, CRD, and blade, plus the pressure of 1086 psig acting on the area of the separated housing, gives a force of approximately 32,000 pounds. This force is used to calculate the impact force, conservatively assuming that the housing travels through a 1 inch gap before it contacts the supports. The impact force (109,000 lb) is then

treated as a static load in design. The CRD housing supports are designed as seismic Category I equipment as discussed in Section 3.2. Loading conditions and examples of stress analysis results and limits are shown in Table 3.9-6. A safety evaluation is provided in Section 4.6.2.3.3.

4.6.2 EVALUATIONS OF THE CRD SYSTEM

4.6.2.1 Failure Mode and Effects Analysis

This subject is discussed in Section 15.9.

4.6.2.2 Protection from Common Mode Failures

This subject is discussed in Section 15.9.

4.6.2.3 Safety Evaluation

Safety evaluation of the control rods, CRDs, and CRD housing supports is described below. Further description of control rods is contained in Section 4.2.

4.6.2.3.1 Control Rods

4.6.2.3.1.1 Materials Adequacy Throughout Design Lifetime

The adequacy of the materials throughout the design life is evaluated in the mechanical design of the control rods. The primary materials, boron carbide (B_4C) powder, solid hafnium, and 304 austenitic stainless steel, have been found suitable in meeting the demands of the BWR environment.

4.6.2.3.1.2 Dimensional and Tolerance Analysis

Layout studies are done to ensure that, given the worst combination of part tolerance ranges at assembly, no interference exists that will restrict the passage of control rods. In addition, preoperational verification is made on each control blade system to show that the acceptable levels of operational performance are met.

4.6.2.3.1.3 Thermal Analysis of the Tendency to Warp

The various parts of the control rod assembly remain at approximately the same temperature during reactor operation, negating the problem of distortion or warpage. What little differential thermal growth that could exist is allowed for in the mechanical design. A minimum axial gap is maintained between absorber rod tubes and the control rod frame assembly for this purpose. Use of dissimilar metals (stainless steel and hafnium) is evaluated to ensure that any effects due to thermal expansion or irradiation growth are acceptable.

4.6.2.3.1.4 Forces for Expulsion

An analysis has been performed which evaluates the maximum pressure forces which could tend to eject a control rod from the core. The results of this analysis are given in Section 4.6.2.3.2.2.2. In summary, if the collet were to remain open, which is unlikely, calculations indicate that the steady-state control rod withdrawal velocity would be 2 ft/sec for a pressure-under line break, the limiting case for rod withdrawal.

4.6.2.3.1.5 Functional Failure of Critical Components

The consequences of a functional failure of critical components have been evaluated and the results are covered in Section 4.6.2.3.2.2.

4.6.2.3.1.6 Precluding Excessive Rates of Reactivity Addition

In order to preclude excessive rates of reactivity addition, analysis has been performed both on the velocity limiter device, and the effect of probable control rod failures (Section 4.6.2.3.2.2).

4.6.2.3.1.7 Effect of Fuel Rod Failure on Control Rod Channel Clearances

The CRD mechanical design ensures a sufficiently rapid insertion of control rods to preclude the occurrence of fuel rod failures, which could hinder reactor shutdown by causing significant distortions in channel clearances.

4.6.2.3.1.8 Mechanical Damage

Analysis has been performed for all areas of the control system, showing that system mechanical damage does not affect the capability to continuously provide reactivity control.

In addition to the analysis performed on the CRDs (Sections 4.6.2.3.2.2 and 4.6.2.3.2.3) and the control rod blade, the following discussion summarizes the analysis performed on the control rod guide tube.

The guide tube can be subjected to any or all of the following loads:

a. Inward load due to pressure differential

b. Lateral loads due to flow across the guide tube

c. Dead Weight

d. Seismic (Vertical and Horizontal)

e. Vibration

In all cases, the analysis considers both a recirculation line break and a steam line break. These events result in the largest hydraulic loadings on a control rod guide tube.

Two primary modes of failure are considered in the guide tube analysis; exceeding allowable stress, and excessive elastic deformation. It was found that the allowable stress limit is not exceeded, and that the elastic deformations of the guide tube are never great enough to cause the free movement of the control rod to be jeopardized.

4.6.2.3.1.9 Evaluation of Control Rod Velocity Limiter

The control rod velocity limiter limits the free fall velocity of the control rod to a value that cannot result in nuclear system process barrier damage. This velocity is evaluated in the rod-drop accident analysis in Chapter 15.

4.6.2.3.2 Control Rod Drives

4.6.2.3.2.1 Evaluation of Scram Time

The rod scram function of the CRD system provides the negative reactivity insertion required by safety design basis as stated in Section 4.6.1.1.1. The scram time shown in the description is adequate as shown by the transient analyses of Chapter 15.

4.6.2.3.2.2 Analysis of Malfunction Relating to Rod Withdrawal

There are no known single malfunctions that cause the unplanned withdrawal of even a single control rod. However, if multiple malfunctions are postulated, studies show that an unplanned rod withdrawal can occur at withdrawal speeds that vary with the combination of malfunctions postulated. In all cases the subsequent withdrawal speeds are less than that assumed in the rod-drop accident analysis as discussed in Chapter 15. Therefore, the physical and radiological consequences of such rod withdrawals are less than those analyzed in the rod-drop accident.

4.6.2.3.2.2.1 Drive Housing Failure at Attachment Weld

The bottom head of the reactor vessel has a penetration for each CRD location. A drive housing is raised into position inside each penetration and is fastened by welding. The drive is raised into the drive housing and bolted to a flange at the bottom of the housing. The housing material is seamless, Type 304 stainless steel pipe with a minimum tensile strength of 75,000 psi. The basic failure considered here is a complete circumferential crack through the housing wall at an elevation just below the J-weld.

Static loads on the housing wall include the weight of the drive and the control rod, the weight of the housing below the J-weld, and the reactor pressure acting on the 6 inch diameter cross-sectional area of the housing and the drive. Dynamic loading results from the reaction force during drive operation.

If the housing were to fail as described, the following sequence of events is foreseen:

a. The housing would separate from the reactor vessel.

b. The CRD and housing would be blown downward against the support structure, by reactor pressure acting on the cross-sectional area of the housing and the drive.

c. The downward motion of the drive and associated parts would be determined by the gap between the bottom of the drive and the support structure, and by the deflection of the support structure under the load.

    1. In the current design, maximum deflection is approximately 3 inches.

    2. If the collet remains latched, no further control rod ejection would occur (Reference 4.6-1); the housing would not drop far enough to clear the reactor vessel penetration.

d. Reactor water would leak at a rate of approximately 180 gpm, through the 0.03 inch diameter clearance between the housing OD and reactor vessel penetration ID.

If the basic housing failure were to occur while the control rod is being withdrawn (this is a small fraction of the total drive operating time) and if the collet were to stay unlatched, the following sequence of events is foreseen:

a. The housing would separate from the reactor vessel.

b. The control rod, CRD, and housing would be blown downward against the CRD housing support.

c. Calculations indicate that the steady-state rod withdrawal velocity would be 0.3 ft/sec.

d. During withdrawal, pressure under the collet piston would be approximately 250 psi greater than the pressure over it; therefore, the collet would be held in the unlatched position until driving pressure was removed from the pressure-over port.

4.6.2.3.2.2.2 Rupture of Hydraulic Line(s) to Drive Housing Flange

There are three types of possible rupture of hydraulic lines to the drive housing flange: pressure-under (insert) line break; pressure-over (withdrawn) line break; and coincident breakage of both of these lines.

4.6.2.3.2.2.2.1 Pressure-Under (Insert) Line Break

For the case of a pressure-under (insert) line break, a partial or complete circumferential opening is postulated at or near the point where the line enters the housing flange. Failure is more likely to occur after another basic failure, wherein the drive housing or housing flange separates from the reactor vessel. Failure of the housing, however, does not necessarily lead directly to failure of the hydraulic lines.

If the pressure-under (insert) line were to fail and if the collet were latched, no control rod withdrawal would occur. There would be no pressure differential across the collet piston and, therefore, no tendency to unlatch the collet. Consequently, the associated control rod could not be withdrawn, but if reactor pressure is greater than 600 psig, it will insert on a scram signal.

The ball check valve is designed to seal off a broken pressure-under line by using reactor pressure to shift the check ball to its upper seat. If the ball check valve were prevented from seating, reactor water would leak to the reactor enclosure or containment. Because of the broken line, cooling water could not be supplied to the drive involved. Loss of cooling water would cause no immediate damage to the drive. However, prolonged exposure of the drive to temperatures at or near reactor temperature could lead to deterioration of material in the seals. High temperature would be indicated to the operator by the thermocouple in the position indicator probe, by high cooling water flow, and by operation of the containment sump pump.

If the basic line failure were to occur while the control rod is being withdrawn, the hydraulic force would not be sufficient to hold the collet open, and spring force normally would cause the collet to latch and stop rod withdrawal. However, if the collet were to remain open, calculations indicate that the steady-state control rod withdrawal velocity would be 2 ft/sec.

4.6.2.3.2.2.2.2 Pressure-Over (Withdrawn) Line Break

The case of the pressure-over (withdrawn) line breakage considers the complete breakage of the line at or near the point where it enters the housing flange. If the line were to break, pressure over the drive piston would drop from reactor pressure to atmospheric pressure. Any significant reactor pressure (approximately 600 psig or greater) would act on the bottom of the drive piston and fully insert the drive. Insertion would occur regardless of the operational mode at the time of the failure. After full insertion, reactor water would leak past the stop piston

seals. This leakage would exhaust to the atmosphere through the broken pressure-over line. The leakage rate at 1000 psi reactor pressure is estimated to be 1-3 gpm; however, with the Graphitar seals of the stop piston removed, the leakage rate could be as high as 10 gpm, based on experimental measurements. If the reactor were hot, drive temperature would increase. This situation would be indicated to the reactor operator by the drift alarm, by the fully inserted drive, by a high drive temperature (annunciated in the control room), and by operation of the drywell sump pump.

4.6.2.3.2.2.2.3 Simultaneous Breakage of the Pressure-Over (Withdrawn) Pressure-Under (Insert) Lines

For the simultaneous breakage of the pressure-over (withdrawn) and pressure-under (insert) lines, pressures above and below the drive piston would drop to zero, and the ball check valve would close the broken pressure-under line. Reactor water would flow from the annulus outside the drive, through the vessel ports, and to the space below the drive piston. As in the case of pressure-over line breakage, the drive would then insert (at reactor pressure approximately 600 psi or greater) at a speed dependent on reactor pressure. Full insertion would occur regardless of the operational mode at the time of failure. Reactor water would leak past the drive seals and out the broken pressure-over line to the reactor enclosure or containment, as described above. Drive temperature would increase. Indication in the control room would include the drift alarm, the fully inserted drive, the high drive temperature annunciated in the control room, and the operation of the drywell sump pump.

4.6.2.3.2.2.3 All Drive Flange Bolts Fail in Tension

Each CRD is bolted to a flange at the bottom of a drive housing. The flange is welded to the drive housing. Bolts are made of AISI-4140 steel or AISI-4340 steel, with a minimum tensile strength of 125,000 psi. Each bolt has an allowable load capacity of at least 15,200 pounds. Capacity of the 8 bolts is at least 121,600 pounds. As a result of the reactor design pressure of 1250 psig, the major load on all 8 bolts is 30,400 pounds.

If a progressive or simultaneous failure of all bolts occurs, the drive separates from the housing. The control rod and the drive would be blown downward against the support structure. Impact velocity and support structure loading would be slightly less than that for drive housing failure, because reactor pressure would act on the drive's cross-sectional area only and the housing would remain attached to the reactor vessel. The drive would be isolated
from the cooling water supply. Reactor water would flow downward past the velocity limiter piston, through the large drive filter, and into the annular space between the thermal sleeve and the drive. For worst case leakage calculations, the large filter is assumed to be deformed or swept out of the way so it would offer no significant flow restriction. At a point near the top of the annulus, where pressure would have dropped to 350 psi, the water would flash to steam and cause choke flow conditions. Steam would flow down the annulus and out the space between the housing and the

drive flanges to the drywell. Steam formation would limit the leakage rate to approximately 840 gpm.

If the collet were latched, control rod ejection would be limited to the distance the drive can drop before coming to rest on the support structure. There would be no tendency for the collet to unlatch, because pressure below the collet piston would drop to zero. Pressure forces, in fact, exert 1435 pounds to hold the collet in the latched position.

If the bolts failed during control rod withdrawal, pressure below the collet piston would drop to zero. The collet, with 1650 pounds return force, would latch and stop rod withdrawal.

4.6.2.3.2.2.4 Weld Joining Flange-to-Housing Failure in Tension

The failure considered is a crack in or near the weld that joins the flange to the housing. This crack extends through the wall and completely around the housing. The flange material is forged, Type 304 stainless steel, with a minimum tensile strength of 75,000 psi. The housing material is seamless, Type 304 stainless steel pipe, with a minimum tensile strength of 75,000 psi. The conventional, full penetration weld of Type 308 stainless steel has a minimum tensile strength approximately the same as that for the parent metal. The design pressure and temperature are 1250 psig and 575°F. Reactor pressure acting on the cross-sectional area of the drive; the weight of the control rod, drive, and flange; and the dynamic reaction force during drive operation result in a maximum tensile stress at the weld of approximately 6000 psi.

If the basic flange-to-housing joint failure occurred, the flange and the attached drive would be blown downward against the support structure. The support structure loading would be slightly less than that for drive housing failure, because reactor pressure would act only on the drive cross-sectional area. Lack of differential pressure across the collet piston would cause the collet to remain latched and limit control rod motion to approximately 3 inches. Downward drive movement would be small; therefore, most of the drive would remain inside the housing. The pressure-under and pressure-over lines are flexible enough to withstand the small

displacement and remain attached to the flange. Reactor water would follow the same leakage path described above for the flange bolt failure, except that exit to the drywell would be through the gap between the lower end of the housing and the top of the flange. Water would flash to steam in the annulus surrounding the drive. The leakage rate would be approximately 840 gpm.

If the basic failure were to occur during control rod withdrawal (a small fraction of the total operating time) and if the collet were held unlatched, the flange would separate from the housing. The drive and flange would be blown downward against the support structure. The calculated steady-state rod withdrawal velocity would be 0.13 ft/sec. Because pressure-under and pressure-over lines remain intact, driving water pressure would continue to the drive, and the normal exhaust line restriction would exist. The pressure below the velocity limiter piston would drop below normal as a result of leakage from the gap between the housing and the flange. This differential pressure across the velocity limiter piston would result in a net downward force of approximately 70 pounds. Leakage out of the housing would greatly reduce the pressure in the annulus surrounding the drive. Thus, the net downward force on the drive piston would be less than normal. The overall effect of these events would be to reduce rod withdrawal to approximately one-half of normal speed. With a 560-psi differential across the collet piston, the collet would remain unlatched; however, it should relatch as soon as the drive signal is removed.

4.6.2.3.2.2.5 Housing Wall Ruptures

This failure is a vertical split in the drive housing wall just below the bottom head of the reactor vessel. The flow area of the hole is considered equivalent to the annular area between the drive and the thermal sleeve. Thus, flow through this annular area, rather than flow through the hole in the housing, would govern leakage flow. The housing is made of Type 304 stainless steel seamless pipe, with a minimum tensile strength of 75,000 psi. The maximum hoop stress of 11,900 psi results primarily from the reactor design pressure (1250 psig) acting on the inside of the housing.

If such a rupture were to occur, reactor water would flash to steam, and leak through the hole in the housing to the drywell at approximately 1030 gpm. Choke flow conditions would exist, as described previously for the flange bolt failure. However, leakage flow would be greater because flow resistance would be less, that is, the leaking water and steam would not have to flow down the length of the housing to reach the drywell. A critical pressure of 350 psi causes the water to flash to steam.

There would be no pressure differential acting across the collet piston to unlatch the collet; but the drive would insert as a result of loss of pressure in the drive housing causing a pressure drop in the space above the drive piston.

If this failure occurred during control rod withdrawal, drive withdrawal would stop, but the collet would remain unlatched. The drive would be stopped by a reduction of the net downward force action on the drive line. The net force reduction would occur when the leakage flow of 1030 gpm reduces the pressure in the annulus outside the drive to approximately 540 psig, thereby reducing the pressure acting on top of the drive piston to the same value. A pressure differential of approximately 710 psi would exist across the collet piston and holds the collet unlatched as long as the operator holds the withdraw signal.

4.6.2.3.2.2.6 Flange Plug Blows Out

To connect the vessel ports with the bottom of the ball check valve, a hole of 0.75 inch diameter is drilled in the drive flange of this hole is sealed with a plug of 0.812 inch diameter and 0.25 inch thickness. A full penetration, Type 308 stainless steel weld holds the plug in place. The postulated failure is a full circumferential crack in this weld and subsequent blowout of the plug.

If the weld were to fail, the plug were to blow out, and the collet remained latched, there would be no control rod motion. There would be no pressure differential acting across the collet piston to unlatch the collet. Reactor water would leak past the velocity limiter piston, down the annulus between the drive and the thermal sleeve, through the vessel ports and drilled passage, and out the open plug hole to the drywell at approximately 320 gpm. Leakage calculations assume only liquid flows from the flange. Actually, hot reactor water would flash to steam, and choke flow conditions would exist. Thus, the expected leakage rate would be lower than the calculated value. Drive temperature would increase and initiate an alarm in the control room.

If this failure were to occur during control rod withdrawal and if the collet were to stay unlatched, calculations indicate that control rod withdrawal speed would be approximately 0.24 ft/sec. Leakage from the open plug hole in the flange would cause reactor water to flow downward past the velocity limiter piston. A small differential pressure across the piston would result in an insignificant driving force of approximately 10 pounds, tending to increase withdraw velocity.

A pressure differential of 295 psi across the collet piston would hold the collet unlatched as long as the driving signal was maintained.

Flow resistance of the exhaust path from the drive would be normal because the ball check valve would be seated at the lower end of its travel by pressure under the drive piston.

4.6.2.3.2.2.7 Ball Check Valve Plug Blows Out

As a means of access for machining the ball check valve cavity, a 1.25 inch diameter hole has been drilled in the flange forging. This hole is sealed with a plug with a 1.31 inch diameter and 0.38 inch thickness. A full penetration weld, utilizing Type 308 stainless steel filler, holds the plug in place. The failure postulated is a circumferential crack in this weld leading to a blowout of the plug.

If the plug were to blow out while the drive was latched, there would be no control rod motion. No pressure differential would exist across the collet piston to unlatch the collet. As in the previous failure, reactor water would flow past the velocity limiter, down the annulus between the drive and thermal sleeve, through the vessel ports and drilled passage, through the ball check valve cage and out the open plug hole to the drywell. The leakage calculations indicate that the flow rate would be 350 gpm. This calculation assumes liquid flow, but flashing of the hot reactor water to steam would reduce this rate to a lower value. Drive temperature would rapidly increase and initiate an alarm in the control room.

If the plug failure were to occur during control rod withdrawal, (it would not be possible to unlatch the drive after such a failure) the collet would relatch at the first locking groove. If the collet were to stick, calculations indicate the control rod withdrawal speed would be 11.8 ft/sec. There would be a large retarding force exerted by the velocity limiter due to a 35 psi pressure differential across the velocity limiter piston.

4.6.2.3.2.2.8 Drive/Cooling Water Pressure Control Valve Closure (Reactor Pressure, 0 psig)

The pressure to move a drive is generated by the pressure drop of practically the full system flow through the drive/cooling water pressure control valve. This valve is either a MOV or a standby manual valve; either one is adjusted to a fixed opening. The normal pressure drop across this valve develops a pressure 260 psi in excess of reactor pressure.

If the flow through the drive/cooling water pressure control valve were to be stopped, as by a valve closure or flow blockage, the drive pressure would increase to the shutoff pressure of the supply pump. The occurrence of this condition during withdrawal of a drive at zero vessel pressure will result in a drive pressure increase from 260 psig to no more than 1750 psig. Calculations indicate that the drive accelerates from 3 in/sec to approximately 6.5 in/sec. A pressure differential of 1670 psi across the collet piston would hold the collet unlatched. Flow would be upward, past the velocity limiter piston, but retarding force would be negligible. Rod movement would stop as soon as the driving signal was removed.

4.6.2.3.2.2.9 Ball Check Valve Fails to Close Passage to Vessel Ports

Should the ball check valve sealing the passage to the vessel ports be dislodged and prevented from reseating following the insert portion of a drive withdrawal sequence, water below the drive piston would return to the reactor through the vessel ports and the annulus between the drive and the housing rather than through the speed control valve. Because the flow resistance of this return path would be lower than normal, the calculated withdrawal speed would be 2 ft/sec. During

withdrawal, differential pressure across the collet piston would be approximately 40 psi. Therefore, the collet would tend to latch and would have to stick open before continuous withdrawal at 2 ft/sec could occur. Water would flow upward past the velocity limiter piston, generating a small retarding force of approximately 120 pounds.

4.6.2.3.2.2.10 Hydraulic Control Unit Valve Failures

Various failures of the valves in the HCU can be postulated, but none could produce differential pressures approaching those described in the preceding paragraphs, and none alone could produce a high velocity withdrawal. Leakage through either one or both of the scram valves produces a pressure that tends to insert the control rod rather than to withdraw it. If the pressure in the SDV should exceed reactor pressure following a scram, a check valve in the line to the scram discharge header prevents this pressure from operating the drive mechanisms.

4.6.2.3.2.2.11 Collet Fingers Fail to Latch

The failure is presumed to occur when the drive withdraw signal is removed. If the collet fails to latch, the drive continues to withdraw at a fraction of the normal speed. This assumption is made because there is no known means for the collet fingers to become unlocked without some initiating signal. Because the collet fingers will not cam open under a load, accidental application of a down signal does not unlock them. (The drive must be given a short insert signal to unload the fingers and cam them open before the collet can be driven to the unlock position.) If the drive withdrawal valve fails to close following a rod withdrawal, the collet would remain open and the drive would continue to move at a reduced speed.

4.6.2.3.2.2.12 Withdrawal Speed Control Valve Failure

Normal withdrawal speed is determined by differential pressures in the drive and is set for a nominal value of 3 in/sec. Withdrawal speed is maintained by the pressure regulating system and is independent of reactor vessel pressure. Tests show that accidental opening of the speed control valve to the fully open position produces a velocity of approximately 6 in/sec.

The CRD system prevents unplanned rod withdrawal, and it has been shown above that only multiple failures in a drive unit and in its control unit could cause an unplanned rod withdrawal.

4.6.2.3.2.3 Scram Reliability

High scram reliability is the result of a number of features of the CRD system. For example:

a. Two reliable sources of scram energy are used to insert each control rod: individual accumulators at low reactor pressure, and the reactor vessel pressure itself at power.

b. Each drive mechanism has its own scram valves and one scram pilot valve with two pilot solenoids, so only one drive can be affected if a scram valve fails to open. Both pilot solenoids must be de-energized to initiate a scram.

c. The RPS and the HCUs are designed so that the scram signal and mode of operation override all others.

d. The collet assembly and index tube are designed so they do not restrain or prevent control rod insertion during scram.

e. The SDV is monitored for accumulated water and the reactor scrams before the volume is reduced to a point that could interfere with a scram.

4.6.2.3.2.4 Control Rod Support and Operation

As described above, each control rod is independently supported and controlled as required by safety design bases.

4.6.2.3.3 Control Rod Drive Housing Supports

Downward travel of the CRD housing and its control rod following the postulated housing failure equals the sum of these distances: the compression of the disc springs under dynamic loading, and the initial gap between the grid and the bottom contact surface of the CRD flange. If the reactor were cold and pressurized, the downward motion of the control rod would be limited to the spring compression (approximately 2 inches) plus a gap of approximately 3/4" ± 1/4". If the reactor were hot and pressurized, the gap would be approximately 1/2" ± 1/4" and the spring compression would be slightly less than in the cold condition. In either case, the control rod movement following a housing failure is substantially limited below one drive "notch" movement (6 inches). Sudden withdrawal of any control rod, through a distance of one drive notch at any position in the core, does not produce a transient sufficient to damage any radioactive material barrier.

The CRD housing supports are in place during power operation and when the nuclear system is pressurized. If a control rod is ejected during shutdown, the reactor remains subcritical because it is designed to remain subcritical with any one control rod fully withdrawn at any time.

At plant operating temperature, a gap of approximately 1/2" ± 1/4" exists between the CRD housing and the supports. At lower temperatures the gap is greater. Because the supports do not contact any of the CRD housing, except during the postulated accident condition, vertical contact stresses are prevented. Inspection and testing are discussed in Section 4.6.3.2.

4.6.2.3.4 Loss of Scram Discharge Valve Air Pressure

Slow or partial loss of air pressure to the scram discharge valves will not result in rapid filling of both the SDV and the SDIV, with consequent loss of adequate discharge volume. This is assured by the physical arrangement of this piping. This SDIV has a cross-sectional area greater than that of the SDV and is connected directly to the SDV, without restriction. In addition, the SDV piping slopes continuously toward the SDIV. Because of this arrangement, both volumes will not fill concurrently but rather the SDIV will fill, causing a reactor scram on high instrument volume level, prior to any filling of the SDV.

Likewise, a loss of reactor coolant will not occur for this event because the scram signal described above will also cause the SDV vent and drain valves to go closed.

4.6.3 TESTING AND VERIFICATION OF THE CONTROL ROD DRIVES

4.6.3.1 Control Rod Drives

4.6.3.1.1 Testing and Inspection

4.6.3.1.1.1 Development Tests

The initial development drive (prototypes of the standard locking piston design) testing included more than 5000 scrams and approximately 100,000 latching cycles. One prototype was exposed to simulated operating conditions for 5000 hours. These tests demonstrated the following:

a. The drive easily withstands the forces, pressures, and temperatures imposed.

b. Wear, abrasion, and corrosion of the nitrided stainless steel parts are negligible. Mechanical performance of the nitrided surface is superior to that of materials used in earlier operating reactors.

c. The basic scram speed of the drive has a satisfactory margin above minimum plant requirements at any reactor vessel pressure.

d. Usable seal lifetimes in excess of 1000 scram cycles can be expected.

4.6.3.1.1.2 Factory Quality Control Tests

Quality control of welding, heat treatment, dimensional tolerances, material verification, and similar factors is maintained throughout the manufacturing process to ensure reliable performance of the mechanical reactivity control components. Some of the quality control tests performed on the control rods, CRDMs, and HCUs are listed below:

a. CRDM tests:

1. Pressure welds on the drives are hydrostatically tested in accordance with ASME codes.

2. Electrical components are checked for electrical continuity and resistance to ground.

3. Drive parts that cannot be visually inspected for dirt are flushed with filtered water at high velocity. No significant foreign material is permitted in effluent water.

4. Seals are tested for leakage to demonstrate correct seal operation.

5. Each drive is tested for shim motion, latching, and control rod position indication.

6. Each drive is subjected to cold scram tests at various reactor pressures to verify correct scram performance.

b. HCU tests:

1. Hydraulic systems are hydrostatically tested in accordance with the applicable code.

2. Electrical components and systems are tested for electrical continuity and resistance to ground.

3. Correct operation of the accumulator pressure and level switches is verified.

4. The unit's ability to perform its part of a scram is demonstrated.

5. Correct operation and adjustment of the insert and withdrawal valves is demonstrated.

c. Control rod tests:

1. Absorber rods are examined by nondestructive methods to ensure correct B_4C density and weld integrity.

2. The absorber rod process control rod is inspected to ensure correct assembly.

3. The envelope of each control rod is inspected to ensure correct assembly.

4.6.3.1.1.3 Operational Tests

After installation, all control rods and drive mechanisms are tested through their full stroke for operability.

During normal operation, each time a control rod is withdrawn a notch, the operator can observe the incore monitor indications to verify that the control rod is following the drive mechanism. All control rods that are partially withdrawn from the core can be tested for rod following by inserting or withdrawing the rod one notch and returning it to its original position, while the operator observes the incore monitor indications.

To make a positive test of control rod-to-CRD coupling integrity, the operator can withdraw a control rod to the end of its travel and then attempt to withdraw the drive to the overtravel position. Failure of the drive to overtravel demonstrates rod-to-drive coupling integrity.

Hydraulic supply subsystem pressures can be observed from instrumentation in the control room. Scram accumulator pressures can be observed on the nitrogen pressure gauges.

4.6.3.1.1.4 Acceptance Tests

Criteria for acceptance of the individual CRDMs and the associated control and protection systems are incorporated in specifications and test procedures covering three distinct phases: preinstallation; after installation prior to startup; and during startup testing.

The preinstallation specification will define criteria and acceptable ranges of such characteristics as seal leakage, friction, and scram performance under fixed test conditions which must be met before the component can be shipped.

The after installation, prestartup tests (Chapter 14) include normal and scram motion, and are primarily intended to verify that piping, valves, electrical components, and instrumentation are properly installed. The test specifications will include criteria and acceptable ranges for drive

speed, timer settings, scram valve response times, and control pressures. These are tests intended more to document system condition rather than to test performance.

As fuel is placed in the reactor, the startup test procedure (Chapter 14) is followed. The tests in this procedure are intended to demonstrate that the initial operational characteristics meet the limits of the specifications over the range of primary coolant temperatures and pressures from ambient to operating. The detailed specifications and procedures follow the general pattern established for such specifications and procedures in BWRs presently under construction and in operation.

4.6.3.1.1.5 Surveillance Tests

The surveillance requirements for the CRD system are described below:

a. Sufficient control rods are withdrawn, following a refueling outage when core alterations are performed, to demonstrate with a margin of 0.25% Δk that the core can be made subcritical at any time in the subsequent fuel cycle with the most reactive operable control rod fully withdrawn and all other operable rods fully inserted.

b. Each partially or fully withdrawn control rod is exercised one notch periodically in accordance with the Technical Specifications.

   In the event that operation is continuing with three or more rods valved out of service as a result of rod or drive system problems, this test shall be performed at least once each day.

   The periodic control rod exercise test serves as a periodic check against deterioration of the control rod system, and also verifies the ability of the CRD to scram. If a rod can be moved with drive pressure, it may be expected to scram, since higher pressure is applied during scram. The frequency of exercising the control rods, under the conditions of three or more control rods valved out of service as a result of rod or drive system problems, provides even further assurance of the reliability of the remaining control rods.

c. The coupling integrity is verified for each withdrawn control rod as follows:

   1. When the rod is first withdrawn, observe discernible response of the nuclear instrumentation.

   2. When the rod is fully withdrawn the first time, observe that the drive does not go to the overtravel position.

   Observation of a response from the nuclear instrumentation during an attempt to withdraw a control rod indicates indirectly that the rod and drive are coupled. The overtravel position feature provides a positive check on the coupling integrity, for only an uncoupled drive can reach the overtravel position.

d. During operation, accumulator pressure and level at the normal operating value is verified.

Experience with CRD systems of the same type indicates that weekly verification of accumulator pressure and level is sufficient to ensure operability of the accumulator portion of the CRD system.

A channel functional test of the accumulator water leak detectors and a channel calibration of the accumulator pressure detectors, including alarm setpoint $\geq$ 955 psig on decreasing pressure is performed at least once per 24 months.

e. At the time of each major refueling outage, each operable control rod is subjected to scram time tests from the fully withdrawn position.

Experience indicates that the scram times of the control rods do not significantly change over the time interval between refueling outages. A test of the scram times at each refueling outage is sufficient to identify any significant increase in the scram times.

f. The LGS Technical Specifications require periodic testing of the vent and drain valves.

g. The LGS Technical Specifications include periodic testing and acceptance criteria to demonstrate SDV operability

The operability of the entire system as an integrated whole shall be demonstrated periodically and during each operating cycle.

4.6.3.1.1.6 Functional Tests

The functional testing program of the CRDs consists of the 5 year maintenance life and the 1.5 times design life test programs as described in Section 3.9.4.4.

There are a number of failures that can be postulated on the CRD, but it would be very difficult to test all possible failures. A partial test program with postulated accident conditions and imposed single failures is available.

The following tests with imposed single failures have been performed to evaluate the performance of the CRDs under these conditions:

a. Simulated ruptured scram line test

b. Stuck ball check valve in CRD flange

c. HCU drive down inlet flow control valve (V122) failure

d. HCU drive down outlet flow control valve (V120) failure

e. CRD scram performance with V120 malfunction

f. HCU drive up outlet control valve (V121) failure

g. HCU drive up inlet control valve (V123) failure

h. Cooling water check valve (V138) leakage

i. CRD flange check valve leakage

j. CRD stabilization circuit failure

k. HCU filter restriction

l. Air trapped in CRD hydraulic system

m. CRD collet drop test

n. Control rod qualification velocity limiter drop test

Additional postulated CRD failures are discussed in Sections 4.6.2.3.2.2.1 through 4.6.2.3.2.2.12.

4.6.3.2 Control Rod Drive Housing Supports

4.6.3.2.1 Testing and Inspection

CRD housing supports are removed for inspection and maintenance of the CRDs. The supports for one control rod can be removed during reactor shutdown, even when the reactor is pressurized, because all control rods are then inserted. When the support structure is reinstalled, it is inspected for correct assembly with particular attention to maintaining the correct gap between the CRD flange lower contact surface and the grid.

4.6.4 INFORMATION FOR COMBINED PERFORMANCE OF REACTIVITY SYSTEMS

4.6.4.1 Vulnerability to Common Mode Failures

The two reactivity control systems, CRD and SLCS, do not share any instrumentation or components. Thus, a common mode failure of the reactivity systems would be limited to an accident event which could damage essential equipment in the two independent systems.

A seismic event or the postulated accident environments (Section 3.11) are not considered potential common mode failures since the essential (scram) portions of the CRD system are designed to seismic Category I standards and to operate as required under postulated accident environmental conditions. The SLCS system is also designed to seismic Category I standards.

No common mode power failure is considered possible. The scram function of the CRD system is "fail-safe" on a loss of power and is designed to override any other CRD function. The SLCS system has three independent power supplies to its essential redundant pumps and valves. The power supplies to the SLCS system are considered vital and as such are switched to the onsite standby diesels on a loss of normal power sources.

4.6.4.2 Accidents Taking Credit for Multiple Reactivity Systems

There are no postulated accidents evaluated in Chapter 15 that take credit for two or more reactivity control systems preventing or mitigating each accident.

4.6.5 EVALUATION OF COMBINED PERFORMANCE

As indicated in Section 4.6.4.2, credit is not taken for multiple reactivity control systems for any postulated accidents in Chapter 15.

4.6.6 REFERENCES

4.6-1 J.E. Benecki, "Impact Testing on Collet Assembly for Control Rod Drive Mechanism 7RD B144A", GE, Atomic Power Equipment Department, APED 5555, (November 1967).

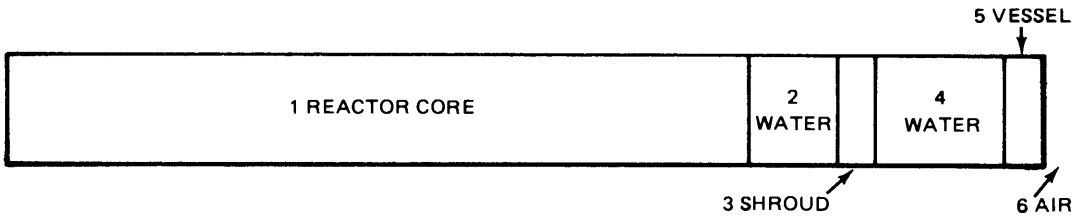
Table 4.6-1

IDENTIFICATION OF SCRAM DISCHARGE SYSTEM COMPONENTS[1]

Component	Component No.
SDV Vent Valve	F010
SDV Vent Valve	F180
SDV Drain Valve	F181
SDV Drain Valve	F011
Instrument Volume Level Switch (Alarm Only)	LS-N013-F
Instrument Volume Level Switch (Rod Block)	LS-N013-E
Instrument Volume Level Switches (Input to RPS)	LS-N013-A LS-N013-B LT-N012-C LT-N012-D
Level Ind Switch	LIS-N601-A LIS-N601-B LIS-N601-C LIS-N601-D

(1) See drawing M-47.

Historical



MATERIAL		RADIUS INCHES	MATERIAL	MATERIAL DENSITY
NO.	NAME			
			WATER	0.274g/cm^3
1	REACTOR CORE	93.56	UO_2	2.642 g/cm^3
			ZIRCONIUM	0.896 g/cm^3
2	WATER	101.4	WATER	0.74 g/cm^3
3	SHROUD	103.4	304L STAINLESS STEEL	FROM ASME SA 240
4	WATER		WATER	0.74 g/cm^3
		125.5		
5	VESSEL	131.68	CARBON STEEL	FROM ASME 533
6	AIR		AIR	1.3 X 10^{-3} g/cm^3

Historical

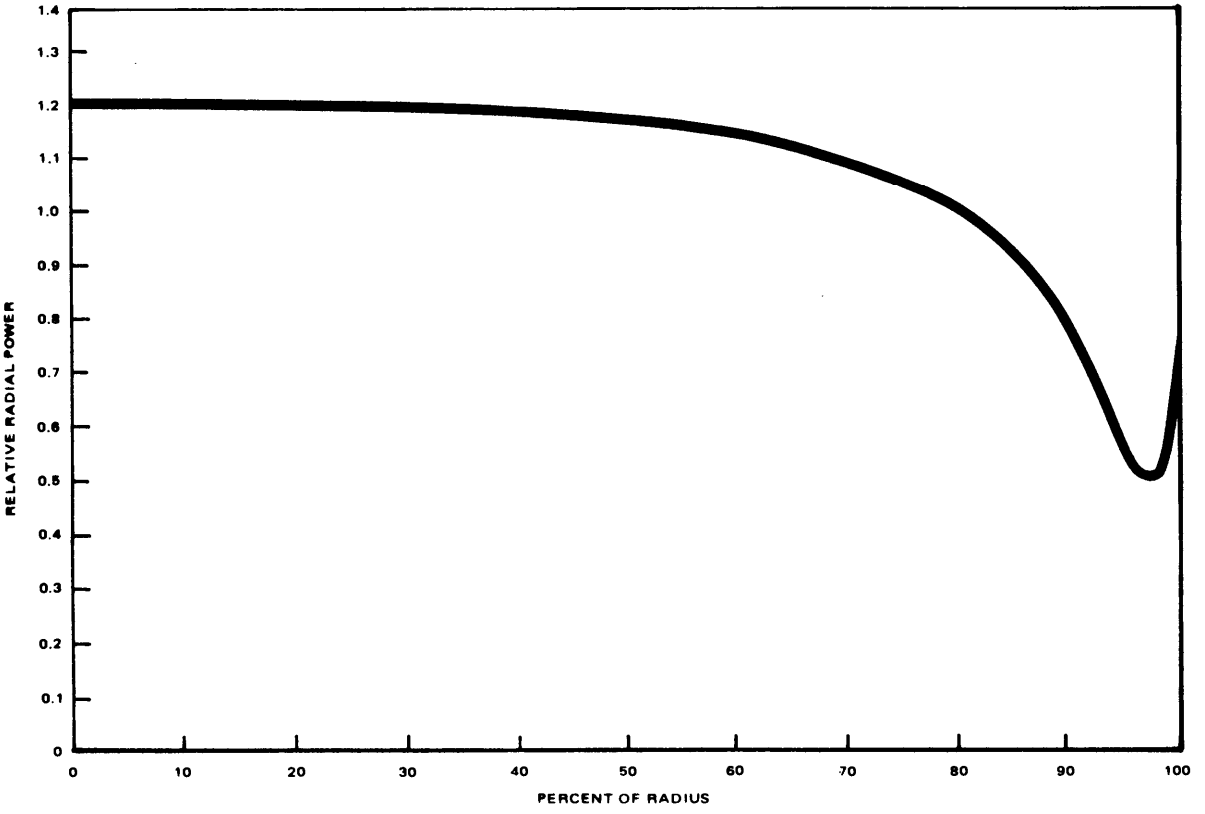
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UPDATED FINAL SAFETY ANALYSIS REPORT

MODEL FOR ONE-DIMENSIONAL TRANSPORT ANALYSIS OF VESSEL FLUENCE
(Historical)

FIGURE 4.3-1

Rev. 21 09/22

Historical

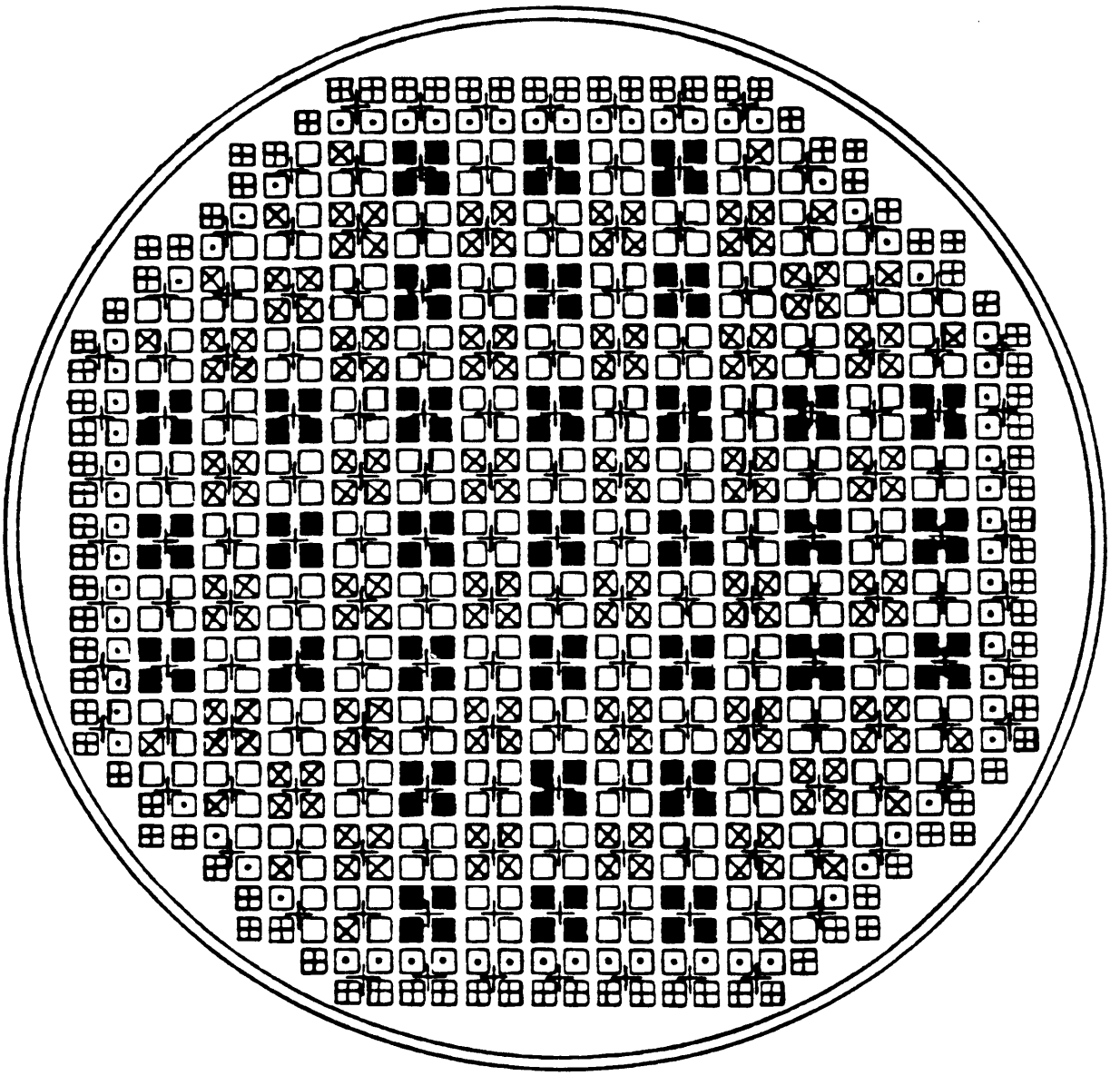


Historical

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RADIAL POWER DISTRIBUTIONS USED IN THE VESSEL FLUENCE CALCULATION
(Historical)

FIGURE 4.3-2 Rev. 21 09/22



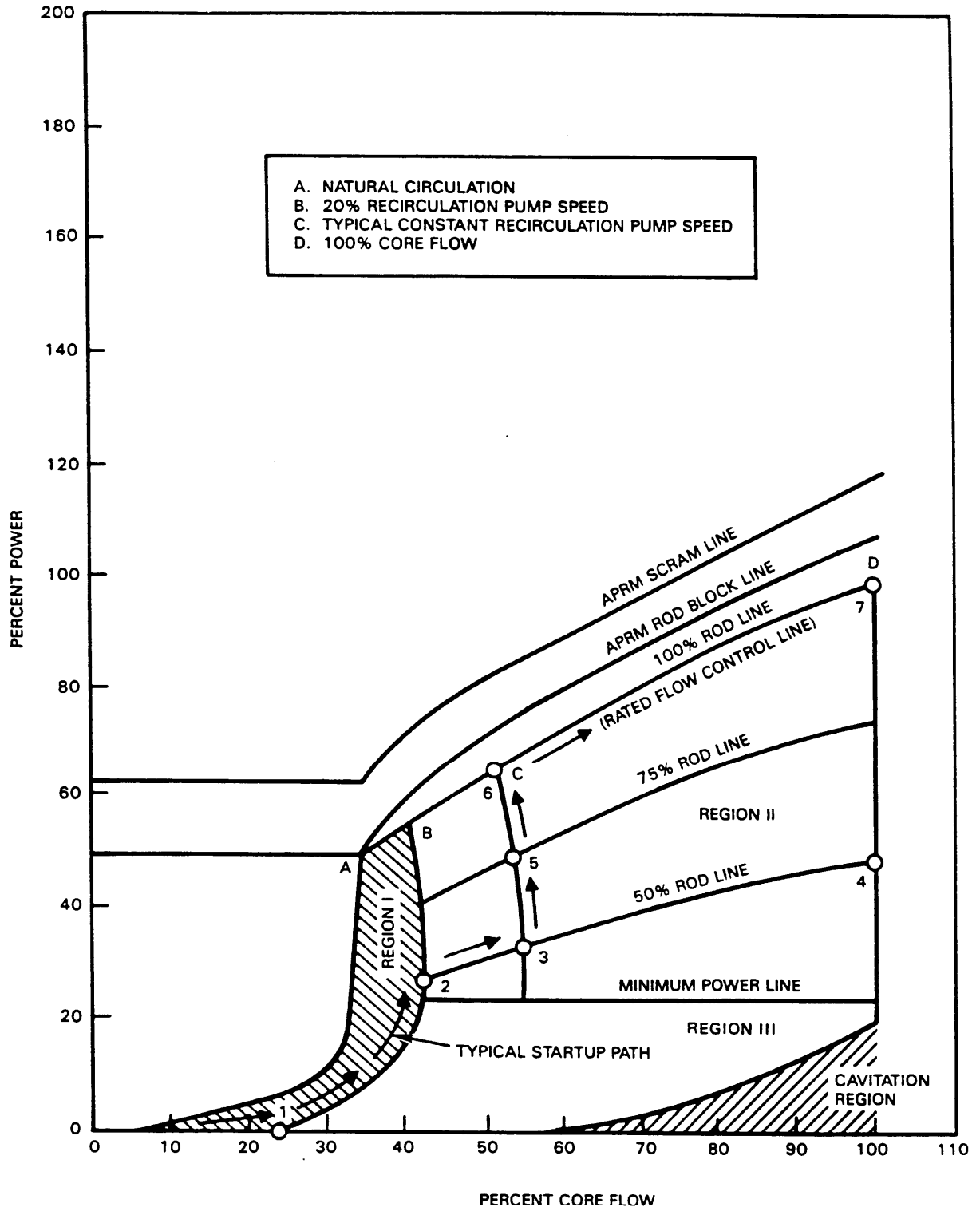
		GESTAR II Nomenclature
⊞	= 0.71 wt% U235 (92)*	P8CRB071
■	= 0.94 wt% U235 (132)	P8CRB094
⊠	= 1.63 wt% U235 (160)	P8CRB163
□	= 2.48 wt% U235 (308)	P8CRB248
⊡	= 2.78 wt% U235 (72)	P8CRB278

* = number of bundles

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REFERENCE LOADING PATTERN

FIGURE 4.3-3

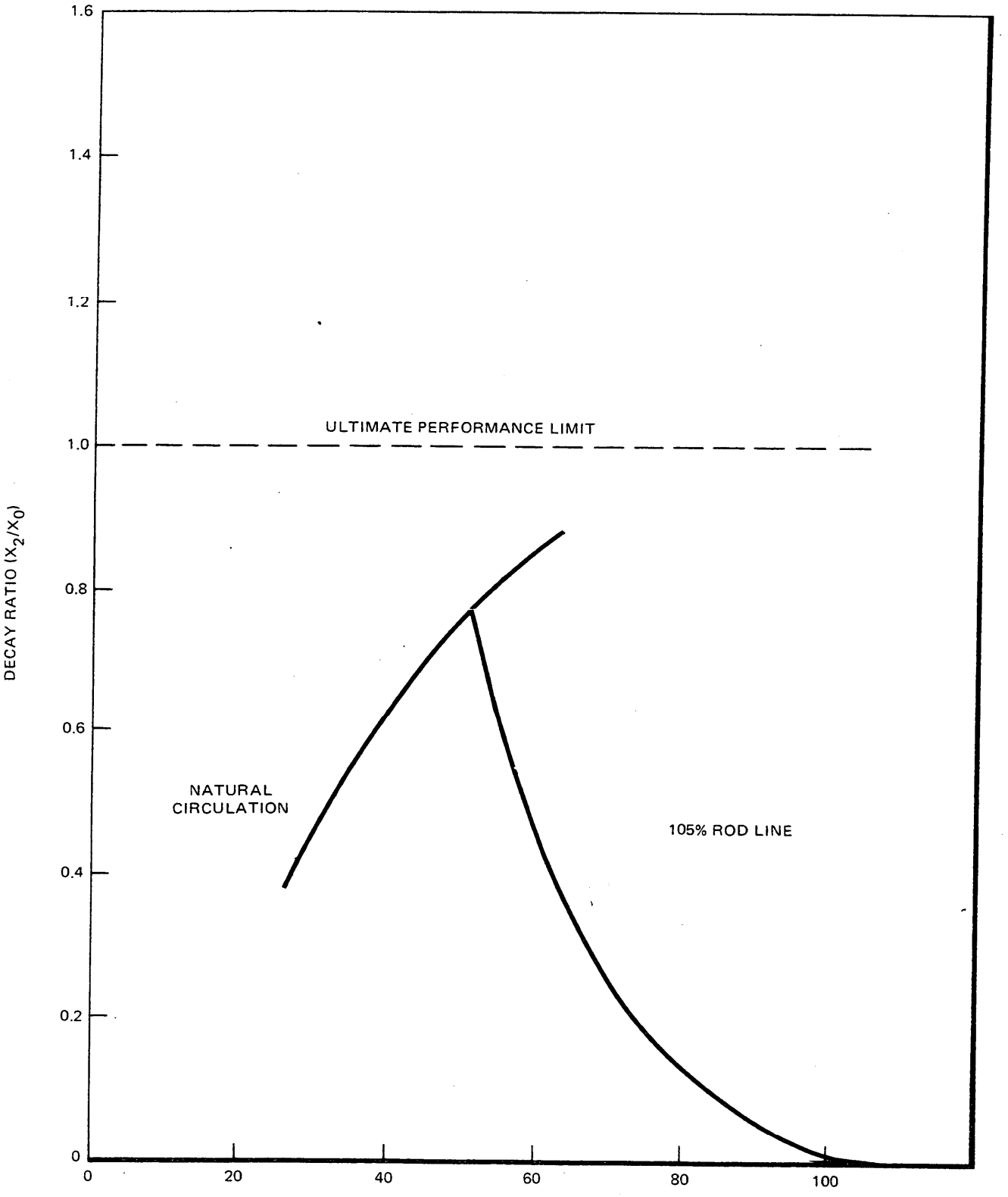


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TYPICAL
POWER-FLOW OPERATING MAP

Rev. 5, 4/96

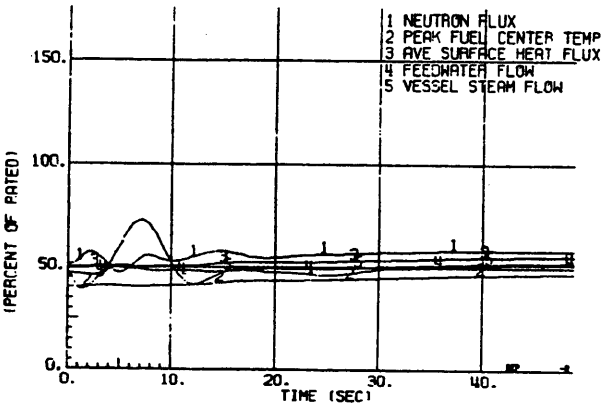
FIGURE 4.4-1

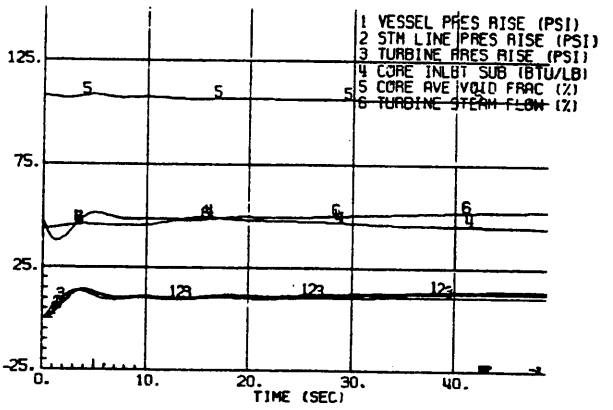


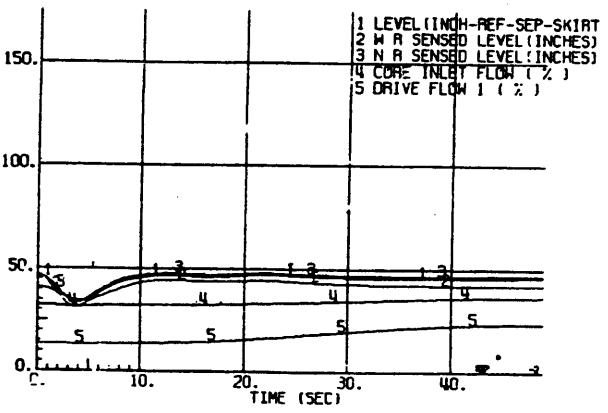
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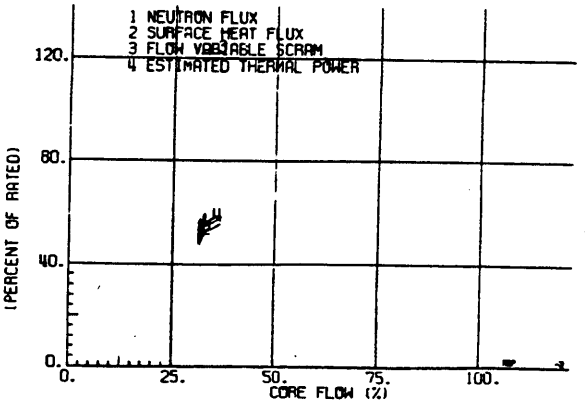
TOTAL CORE STABILITY
CYCLE - 1 STABILITY ANALYSIS

FIGURE 4.4-2 Rev. 10 10/00





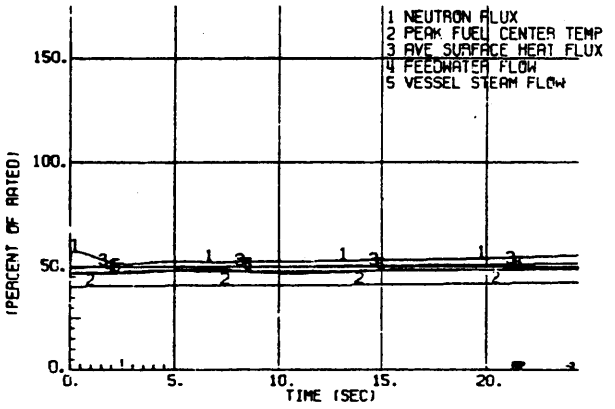


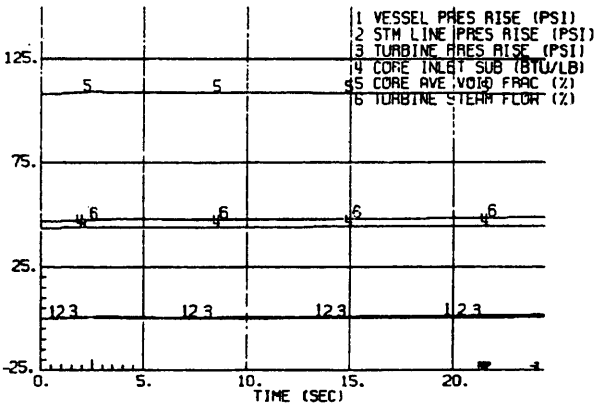


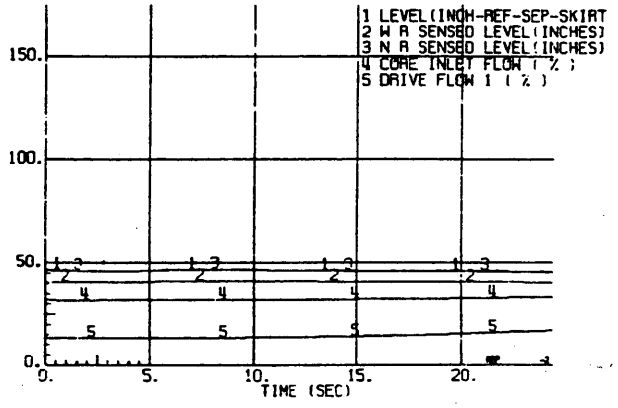
LIMERICK GENERATING STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

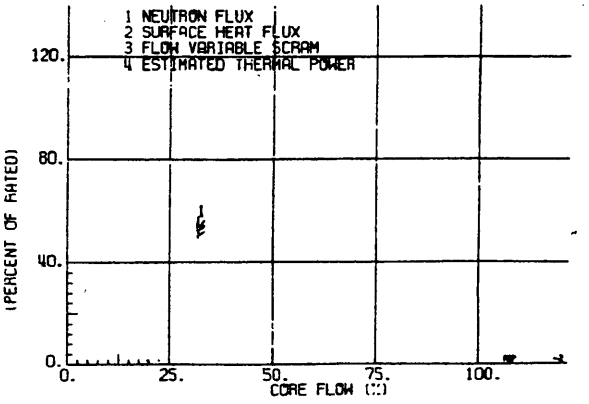
10 PSI PRESSURE REGULATOR SETPOINT STEP AT 51.5% RATED POWER (NATURAL CIRCULATION) CYCLE - 1 STABILITY ANALYSIS

FIGURE 4.4-3 Rev. 10 10/00





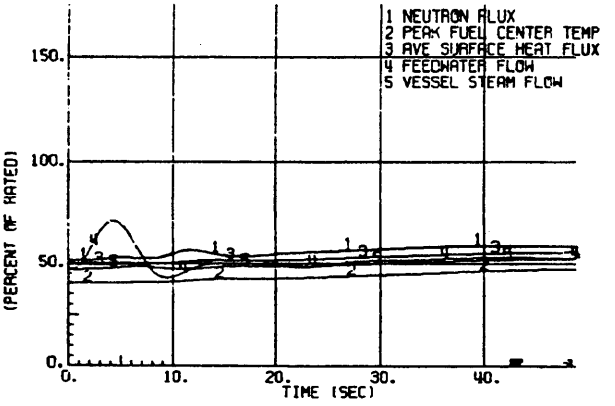


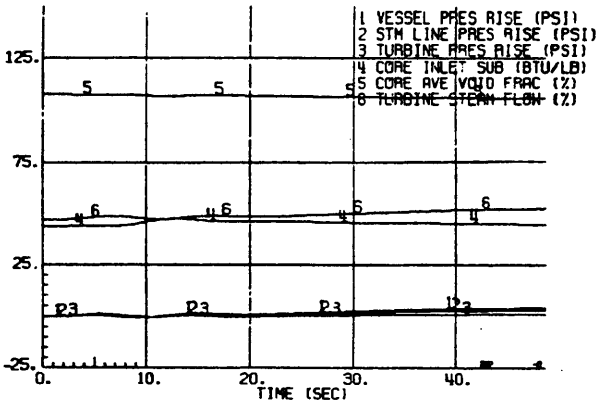


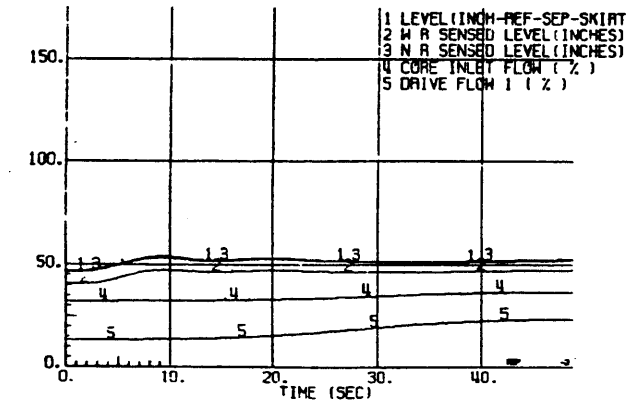
LIMERICK GENERATING STATION
UNITS 1 & 2
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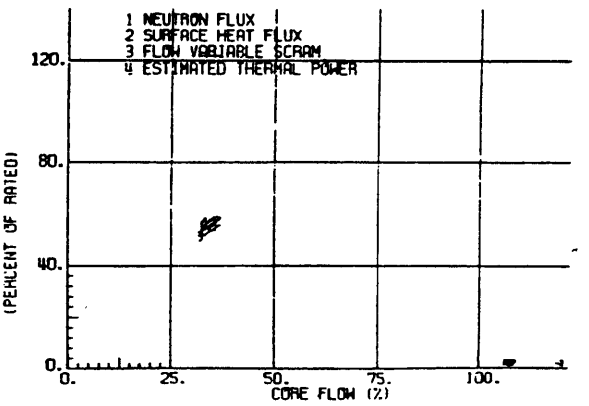
10 CENT ROD REACTIVITY STEP
51.5% RATED POWER
(NATURAL CIRCULATION)
CYCLE - 1 STABILITY ANALYSIS

FIGURE 4.4-4 **Rev. 10 10/00**





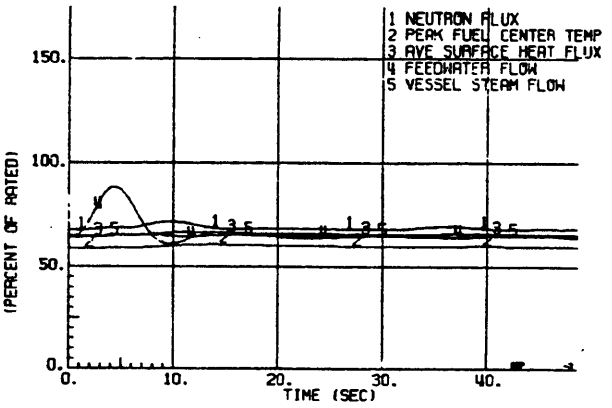


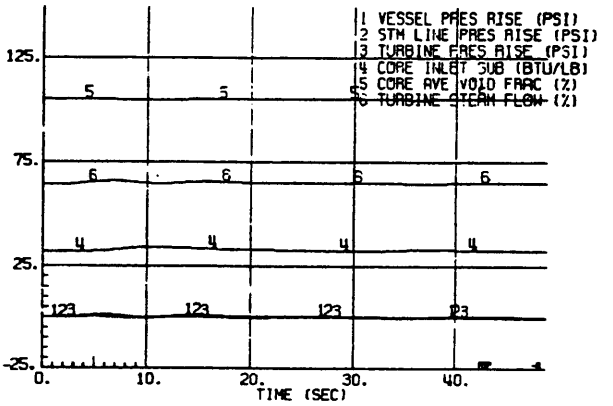


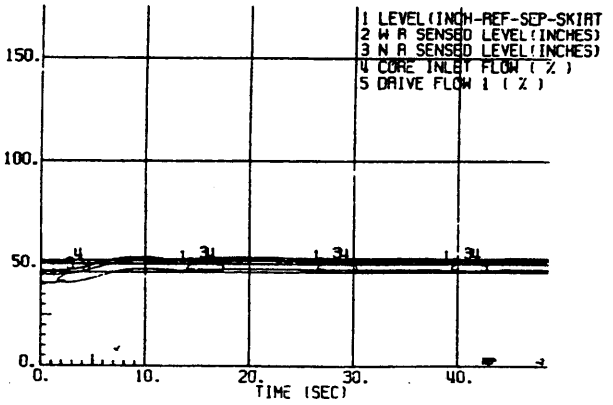
LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

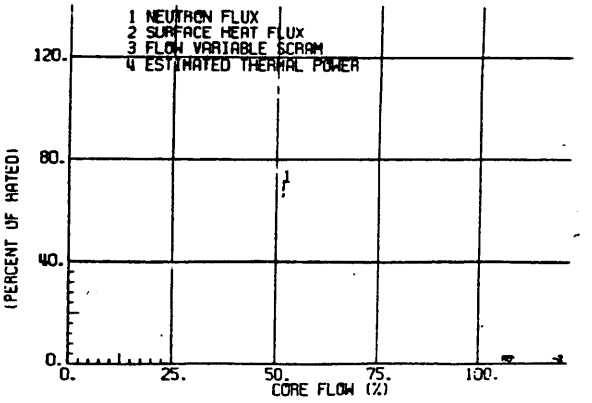
6 INCH WATER LEVEL SETPOINT STEP AT 51.5% RATED POWER (NATURAL CIRCULATION) CYCLE - 1 STABILITY ANALYSIS

FIGURE 4.4-5 Rev. 10 10/00









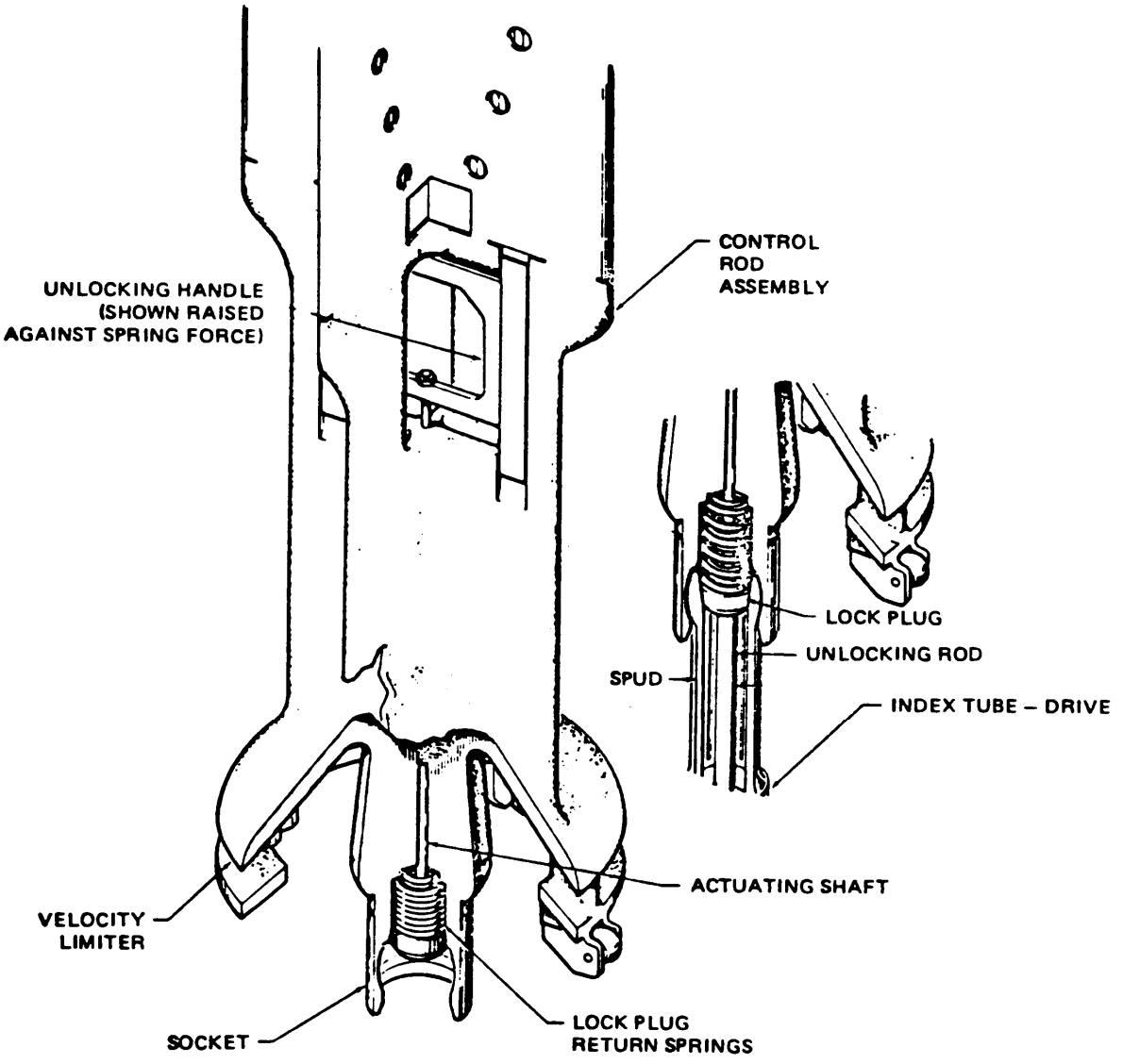
LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

6 INCH WATER LEVEL SETPOINT STEP AT 68% RATED POWER AND 51.5% RATED FLOW CYCLE - 1 STABILITY ANALYSIS

FIGURE 4.4-6 Rev. 10 10/00

Figure 4.4-7

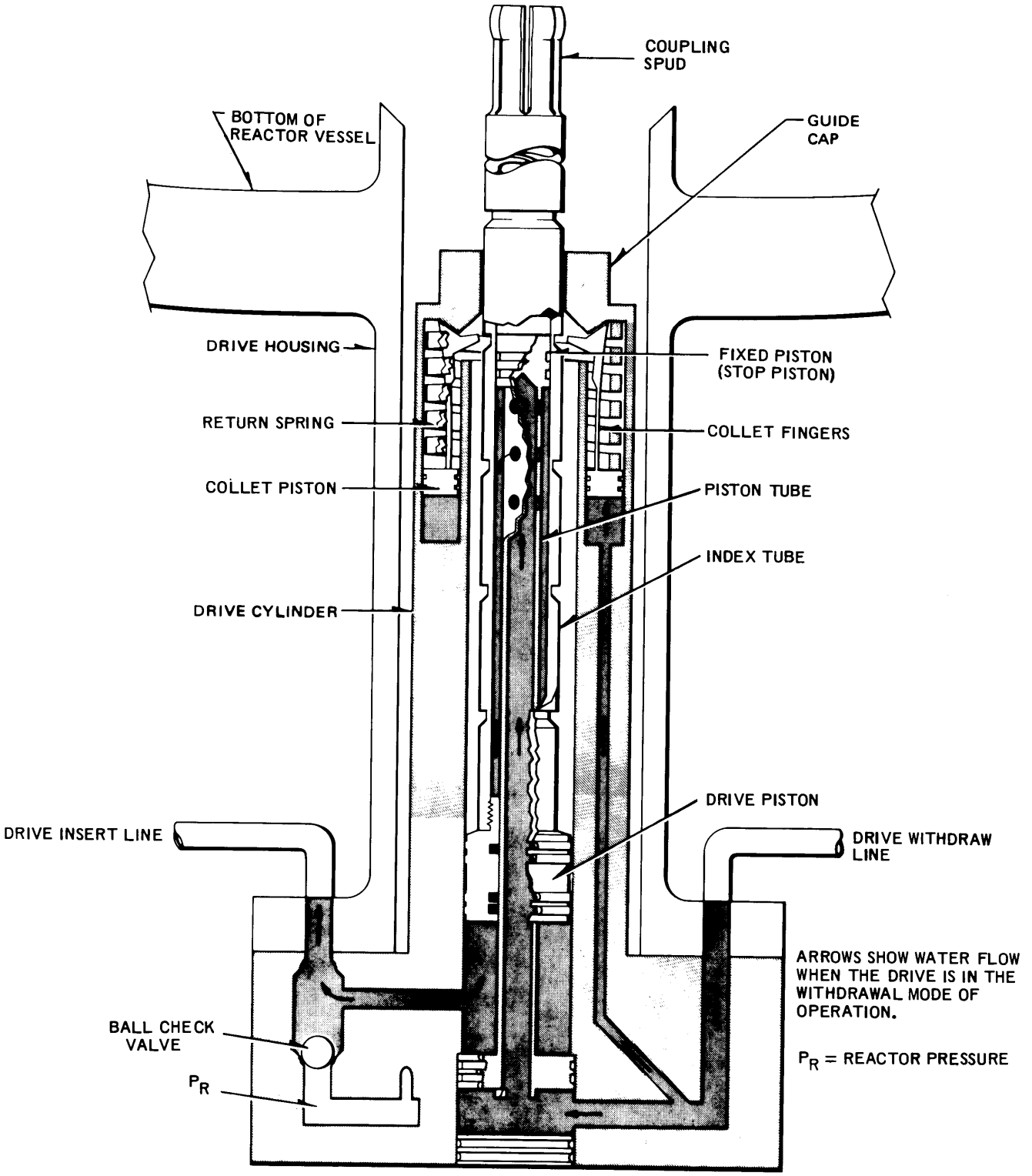
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LIMERICK GENERATING STATION
UNITS 1 AND 2
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CONTROL ROD TO CONTROL ROD DRIVE COUPLING

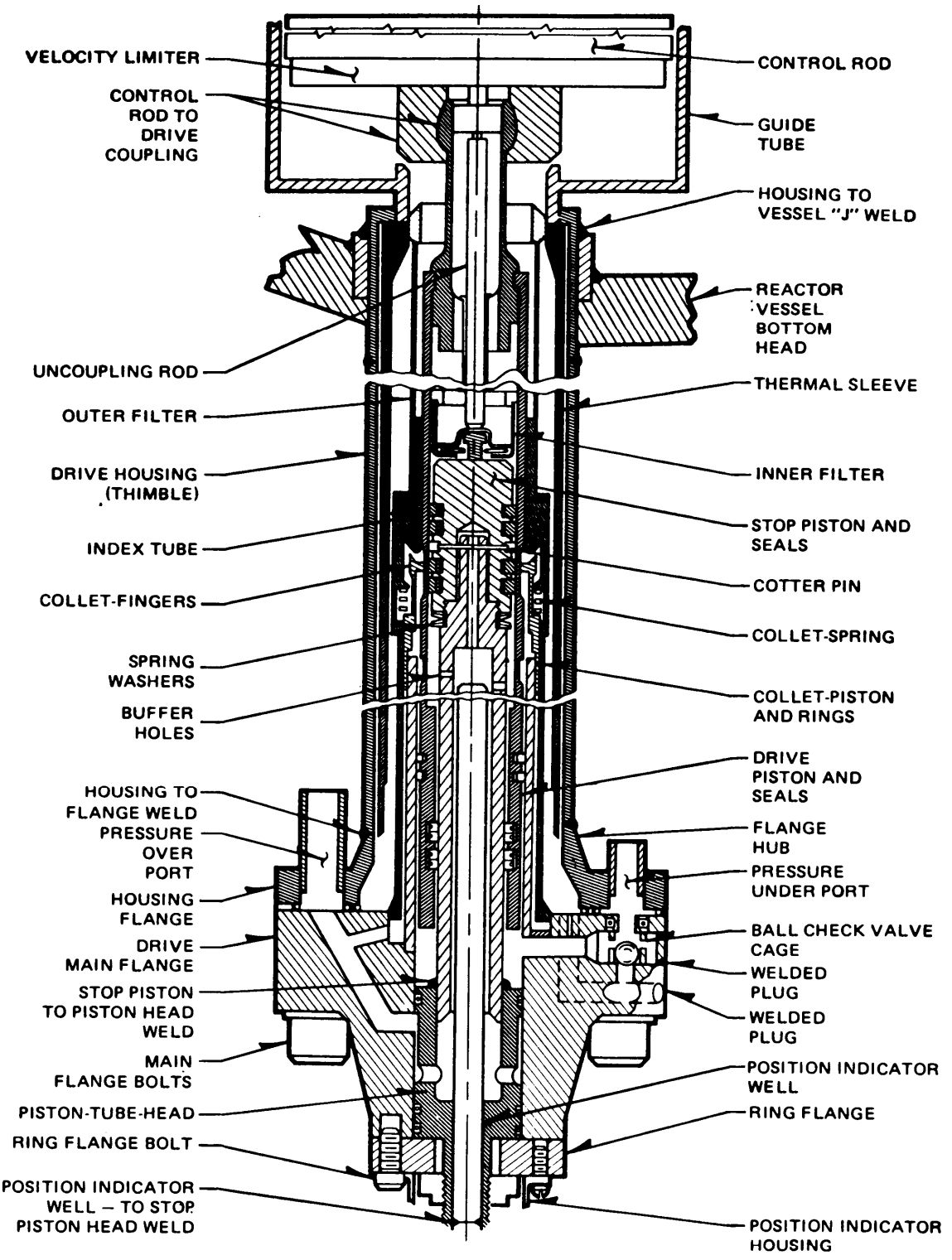
FIGURE 4.6-1



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CONTROL ROD DRIVE UNIT

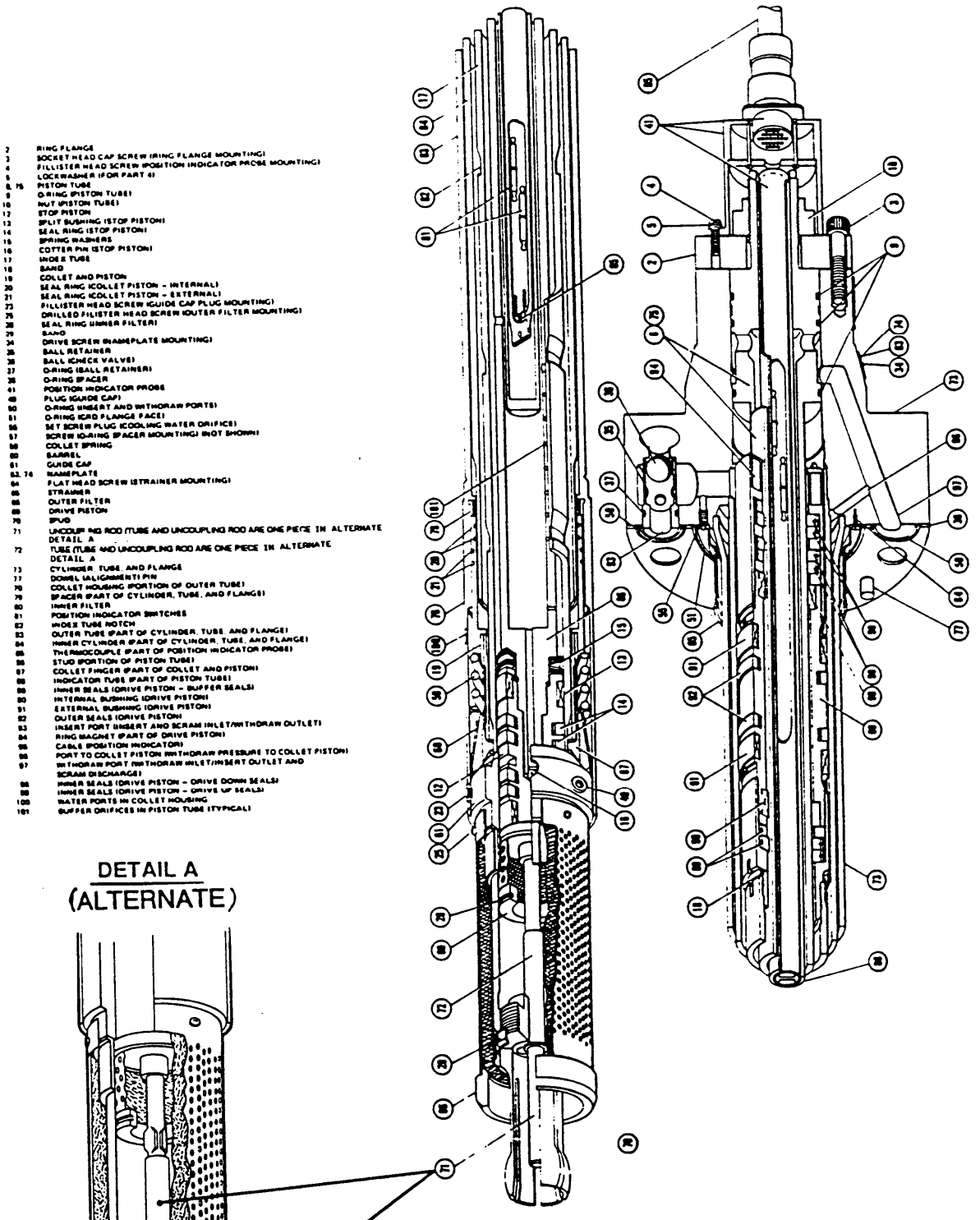
FIGURE 4.6-2



LIMERICK GENERATING STATION
UNITS 1 AND 2
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CONTROL ROD DRIVE SCHEMATIC BWR/4 & 5

FIGURE 4.6-3



SINGLE PIECE UNCOUPLING ROD (ITEM # 71)
WITHOUT SEPARATE TUBE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

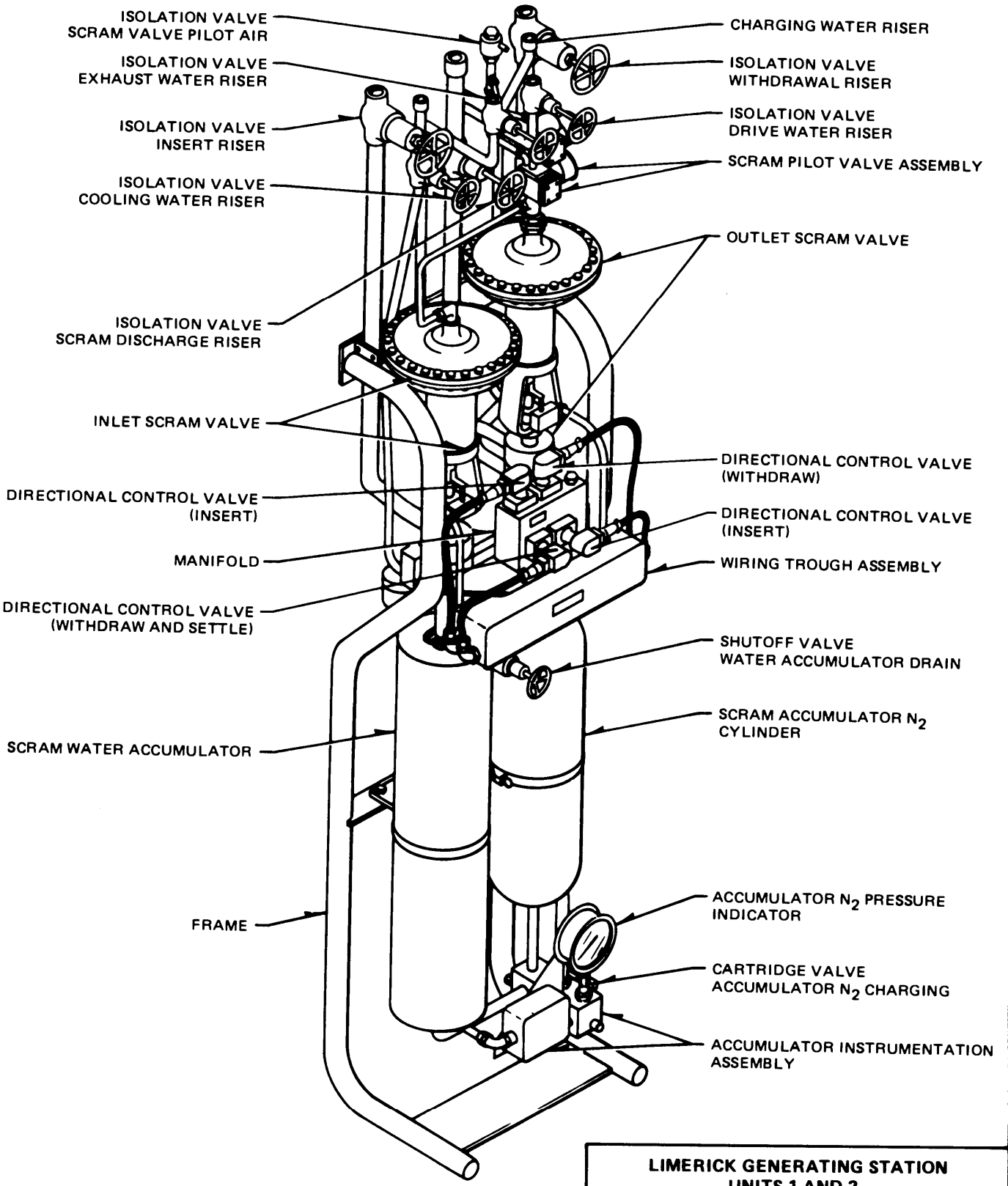
CONTROL ROD DRIVE

Rev. 5, 4/96

FIGURE 4.6-4

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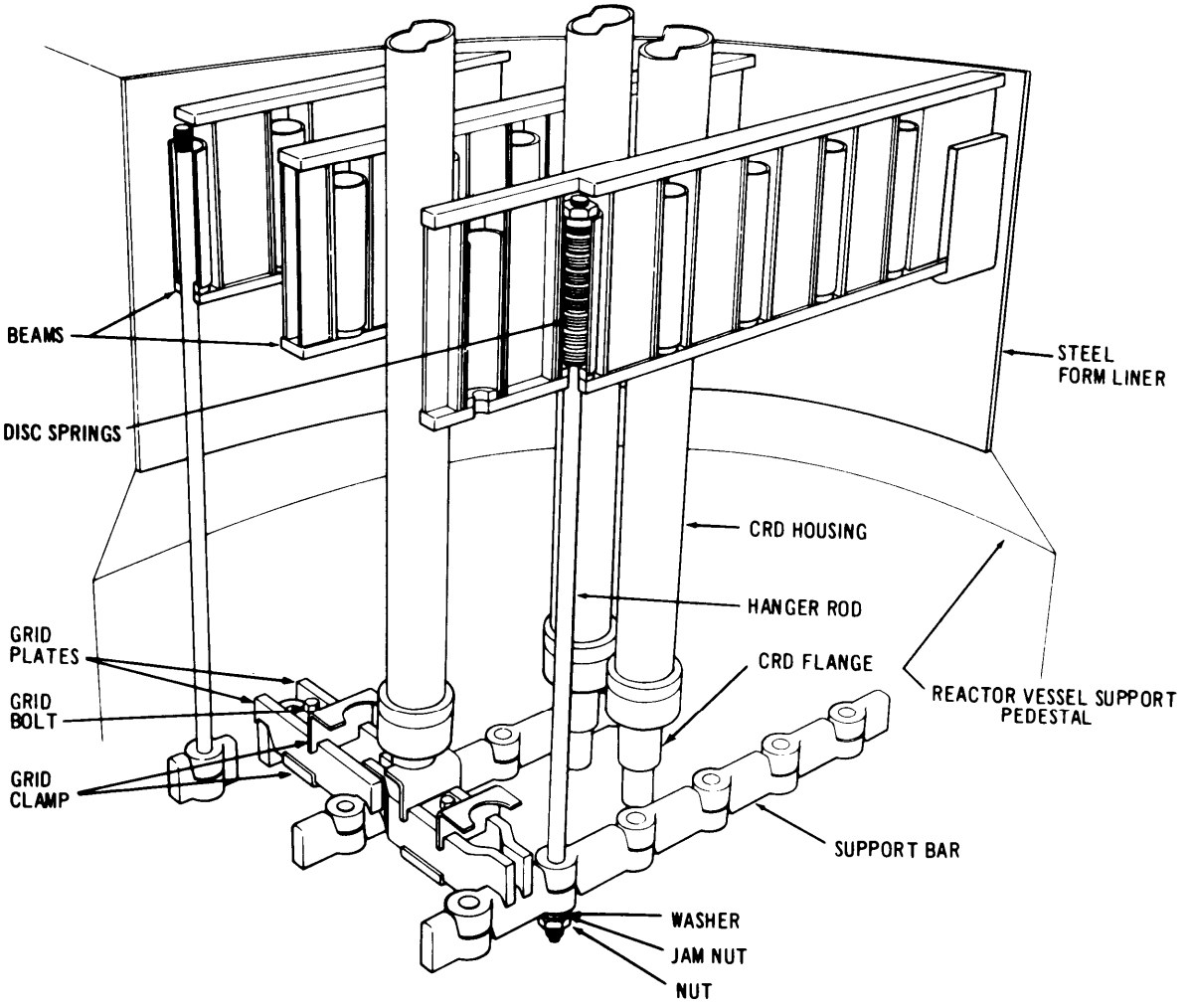
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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTROL ROD DRIVE HYDRAULIC CONTROL UNIT

FIGURE 4.6-8



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

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CHAPTER 5 - REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 SUMMARY DESCRIPTION

The RCS includes those systems and components that contain or transport fluids to or from the reactor core. These systems form a major portion of the nuclear system process barrier. This chapter provides information regarding the RCS and pressure-containing appendages out to and including isolation valves. This group of components is defined as the RCPB in 10CFR50.2(v) as follows:

"Reactor coolant pressure boundary means all those pressure-containing components of boiling and pressurized water-cooled nuclear power reactors, such as pressure vessels, piping, pumps, and valves, which are:

a. Part of the reactor coolant system, or

b. Connected to the reactor coolant system, up to and including any and all of the following:

   1. The outermost containment isolation valve in system piping which penetrates primary reactor containment

   2. The second of two valves normally closed during normal reactor operation in system piping which does not penetrate primary reactor containment

   3. The reactor coolant system safety and relief valves."

Section 5.4 of this chapter also deals with various subsystems to the RCPB that are closely allied to it. These are briefly reviewed below.

The nuclear pressure relief system protects the RCPB from damage due to overpressure. To protect against overpressure, pressure-operated relief valves are provided to discharge steam from the NSSS to the suppression pool. The nuclear pressure relief system also acts to automatically depressurize the NSSS if there is a LOCA in which the HPCI system fails to maintain RPV water level. Depressurization of the NSSS allows the low pressure core cooling systems to supply enough cooling water to adequately cool the fuel.

The RCPB leak detection system, described in Section 5.2.5, detects system leakage inside the primary containment so that appropriate action can be taken before the integrity of the nuclear system process barrier is impaired.

The RPV and appurtenances are described in Section 5.3. The major safety functions of the RPV are to maintain water over the core and to act as a radioactive material barrier. The RPV meets the requirements of applicable codes and criteria. The possibility of brittle fracture is considered, and suitable design and operational limits are established that avoid conditions in which brittle fracture is possible.

The reactor recirculation system provides coolant flow through the core. Adjustment of the core coolant flow rate changes reactor power output, thus providing a means of following plant load demand without adjusting the control rods. The reactor recirculation system is designed to provide a slow coast-down of flow so that fuel thermal limits cannot be exceeded as a result of recirculation system malfunctions. The arrangement of the reactor recirculation system piping is such that a piping

failure cannot compromise the integrity of the floodable inner volume of the reactor vessel, thereby helping to ensure adequate core cooling following a LOCA.

The main steam line flow restrictors are venturi-type flow devices. One restrictor is installed in each main steam line inside the primary containment. The restrictors are designed to limit the loss of coolant resulting from a main steam line break outside the primary containment. The coolant loss is limited so that RPV water level remains above the top of the core during the time required for the MSIVs to close. This action maintains the integrity of the fuel cladding (fuel barrier).

The MSIVs automatically close to isolate the nuclear system process barrier if a pipe break occurs downstream of the isolation valves, thereby limiting the loss of coolant and the release of radioactive materials from the NSSS. Two MSIVs are installed on each main steam line, one inside and the other outside the primary containment. Closure of either of the two MSIVs acts to seal the primary containment if a main steam line break occurs inside the primary containment.

The RCIC system provides makeup water to the core during a reactor shutdown when feedwater flow is not available. The system is started either automatically on receipt of a low reactor water level signal or manually by the operator. Water is pumped to the core by a turbine-driven pump using reactor steam.

The RHR system includes a number of pumps and heat exchangers that can be used to cool the NSSS in a variety of situations. During normal shutdown and reactor servicing, the RHR system removes residual and decay heat. The RHR system allows decay heat to be removed whenever the main heat sink (main condenser) is not available (e.g., hot standby). Another operational mode of the RHR system is LPCI. LPCI operation is an ESF system for use during a postulated LOCA. This operation is described in Section 6.3. Another mode of RHR system operation allows heat to be removed from the primary containment following a LOCA.

The RWCU system functions to maintain the required quality of reactor coolant by circulating coolant through a system of filter/ demineralizers.

Design and performance characteristics of the RCS and its various components are shown in Table 5.4-1.

5.1.1 SCHEMATIC FLOW DIAGRAM

A flow diagram and process information for the reactor vessel and recirculation loops under normal steady-state full power operating conditions is presented in Figure 5.1-1. Coolant volumes in the reactor vessel and recirculation loops under full power conditions are presented in Figure 5.1-2.

5.1.2 PIPING AND INSTRUMENTATION DIAGRAMS

Piping and instrumentation diagrams covering the systems included within the RCS and connected systems are presented in the following:

a. Nuclear boiler shown in drawing M-41

b. Nuclear boiler vessel instrumentation shown in drawing M-42

c. Main steam shown in drawing M-01

d. Feedwater system shown in drawing M-06

e. Recirculation system shown in drawing M-43

f. RCIC system shown in drawing M-42 and M-50

g. RHR system shown in drawing M-51

h. RWCU system shown in drawing M-44.

5.1.3 ARRANGEMENT DRAWINGS

A section drawing of the reactor enclosure and primary containment is shown in drawings M-123 and M-138. The routing of reactor recirculation, feedwater, main steam, and RHR piping inside the primary containment is shown in Figure 5.1-5. Piping layout drawings for the reactor recirculation piping and main steam piping inside primary containment are presented in Figures 5.1-6 and 5.1-7, respectively.

5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY

This section discusses measures employed to provide and maintain the integrity of the RCPB for the plant design lifetime.

5.2.1 COMPLIANCE WITH CODES AND CODE CASES

5.2.1.1 Compliance with 10CFR50.55a

A table that shows compliance with the rules of 10CFR50, "Codes and Standards", is included in Section 3.2. As stated in Table 3.2-1, note 7, alternative codes to those required by 10CFR50.55a were used for primary pressure boundary components.

5.2.1.2 Applicable Code Cases

The RPV and appurtenances and the RCPB piping, pumps, and valves have been designed, fabricated, and tested in accordance with the applicable edition of the ASME Code, including addenda that were mandatory at the order date for the applicable components. 10CFR50.55a requires code case approval only for Class 1 components. These code cases contain requirements or special rules that may be used for the construction of pressure-retaining components of Quality Group Classification A. The various ASME code case interpretations that were applied to components in the RCPB are listed in Table 5.2-1. The listed code cases are either in accordance with the recommendations of Regulatory Guide 1.84 and Regulatory Guide 1.85 or special written acceptance has been obtained for their use. Conformance to Regulatory Guide 1.84 and Regulatory Guide 1.85 for other than Class 1 components is discussed in Section 1.8.

5.2.2 OVERPRESSURE PROTECTION

Overpressure protection for the RCPB is provided by the nuclear pressure relief system. The nuclear pressure relief system includes 14 MSRVs, which are dual-function safety/relief valves.

5.2.2.1 Design Basis

Overpressure protection is provided in conformance with GDC 15. Preoperational and startup instructions are given in Chapter 14.

5.2.2.1.1 Safety Design Bases

The nuclear pressure relief system is designed to perform the following functions:

a. Prevent overpressurization of the nuclear system that could lead to the failure of the RCPB

b. Provide automatic depressurization for small breaks in the nuclear system occurring with misoperation of the HPCI system so that the LPCI and the core spray systems can operate to protect the fuel barrier

c. Permit verification of its operability

d. Withstand adverse combinations of loadings and forces resulting from normal, upset, emergency, or faulted conditions

5.2.2.1.2 Power Generation Design Bases

The nuclear pressure relief system MSRVs are designed to meet the following power generation bases:

a. Discharge to the containment suppression pool

b. Correctly reclose following operation so that maximum operational continuity can be obtained

5.2.2.1.3 Discussion

The ASME B&PV Code requires that each vessel designed to meet Section III be protected from overpressure under upset conditions as discussed in subsection S.2.3 of GESTAR II (Reference 4.1-1). The MSRV setpoints satisfy the ASME Code specifications for safety valves, because all valves open at less than the nuclear system design pressure of 1250 psig.

The automatic depressurization capability of the nuclear pressure relief system is evaluated in Sections 6.3 and 7.3.

The following detailed criteria are used in the selection of MSRVs:

a. Meet the requirements of ASME Section III

b. Qualify for 100% of nameplate capacity credit for the overpressure protection function

c. Meet other performance requirements such as response time, etc. as necessary to provide relief functions

The MSRV discharge piping is designed, installed, and tested in accordance with the ASME Section III, Class 3. Fatigue evaluation of the unsubmerged portion of the MSRV discharge piping and downcomers in the wetwell has been performed in accordance with ASME Section III, Class 1 fatigue rules.

5.2.2.1.4 Main Steam Safety/Relief Valve Capacity

The MSRV capacity is adequate to limit the primary system pressure, including transients, to the requirements of the ASME Section III, "Nuclear Vessels", up to and including the Summer 1969 Addenda for LGS. The essential ASME requirements that are all met by this analysis are as follows.

It is recognized that the protection of vessels in a nuclear power plant is dependent on many protective systems to relieve or terminate pressure transients. Installation of pressure-relieving devices may not independently provide complete protection. The MSRV sizing evaluation assumes credit for operation of the RPS, which may be tripped by either of two sources: a direct position switch signal or an indirect high neutron flux trip signal. The direct scram trip signal is derived from position switches mounted on the MSIVs or the turbine stop valves or from pressure switches mounted on the dump valve of the turbine control valve hydraulic actuation system. The position switches are actuated when the respective valves are closing prior to 10% travel of full stroke. The pressure switches are actuated when a fast closure of the turbine control valves is initiated. Credit is taken for the SRVs in their ASME Code qualified self-actuating mode.

The rated capacity of the pressure-relieving devices is sufficient to prevent a rise in pressure within the protected vessel of more than 110% of the design pressure (1.10 x 1250 psig = 1375 psig) for events defined in Section 15.2.

Full account is taken of the pressure drop on both the inlet and discharge sides of the valves. Each MSRV discharges into the suppression pool through a separate discharge pipe that is designed to achieve sonic flow conditions through the valve, thus providing flow independence to discharge piping losses.

Table 5.2-5 lists the systems that could initiate during the design basis overpressure event.

5.2.2.2 Design Evaluation

5.2.2.2.1 Method of Analysis

The nuclear boiler system pressure protection was designed using an analytical model representing all essential dynamic characteristics of the system. This model include the hydrodynamics of the flow loop, the reactor kinetics, the thermal characteristics of the fuel and its transfer of heat to the coolant, and all the principal controller features, such as feedwater flow, recirculation flow, reactor water level, pressure, and load demand. These are represented with all their principal nonlinear features in models that have evolved through extensive experience and favorable comparison of analysis with actual BWR test data.

Detailed descriptions of the one-dimensional kinetics model (ODYN) is and the three-dimensional kinetics model (TRACG) are documented in References 5.2-7 and 5.2-34 respectively. MSRVs are simulated in a nonlinear representation, and the models thereby allow full investigation of the various valve response times, valve capacities, and actuation setpoints that are available in applicable hardware systems.

Further descriptions of these models are given in GESTAR II (Reference 4.1-1).

5.2.2.2.2 System Design

An analysis was conducted to demonstrate that the steam flow capacity of the MSRVs is sufficient for power rerate operation.

5.2.2.2.2.1 Operating Conditions

a. Operating power = 3527 MWt

b. Vessel dome pressure P =1068 psia

c. Steam flow = 15.35×10^6 lb/hr

These conditions are the most severe because maximum stored energy exists at these conditions. At lower power conditions the transients would be less severe.

5.2.2.2.2.2 Transients

The overpressure protection system must accommodate the most severe pressurization transient. There are two major transients, the closure of all MSIVs and a turbine-generator trip with a coincident closure of the turbine steam bypass system valves, that represent the most severe abnormal operational transients resulting in a nuclear system pressure rise. The evaluation of transient behavior with final plant configuration has shown that the isolation valve closure is slightly more severe when credit is taken only for indirectly derived scrams; therefore, it is used as the overpressure protection basis event.

The setpoint values used for the overpressure analysis have been reviewed to ensure that both instrument uncertainties and drift allowance are included in the transient simulation of the highest attainable transient pressures. The Technical Specification values for reactor steam dome pressure will be established consistent with the initial dome pressure of 1068 psia used for the analysis. The effect of an ATWS recirculation pump trip on reactor pressure was simulated using an analytical trip setpoint value of 1164 psia. This trip occurs approximately 4.5 seconds after the transient is initiated.

5.2.2.2.2.3 Scram

a. Scram reactivity curve - Figure 5.2-2

b. CRD scram motion Figure 5.2-3

5.2.2.2.2.4 MSRV Transient Analysis Specifications

a. Valve groups: 3

b. Pressure setpoint (maximum safety limit):

group 1 - 1205 psig

group 2 - 1215 psig

group 3 - 1226 psig

The setpoints are assumed at a conservatively high level above the nominal setpoints as shown by Table 5.2-2. This is to account for initial setpoint errors and any instrument setpoint drift that might occur during operation. Typically the assumed setpoints in the analysis are 3% above the actual nominal setpoints. Highly conservative MSRV response characteristics are also assumed.

5.2.2.2.2.5 MSRV Capacity

Sizing of MSRV capacity is based on establishing an adequate margin from the peak vessel pressure to the vessel code limit (1375 psig) in response to the reference transients (Section 5.2.2.2.2.2).

5.2.2.2.3 Evaluation of Results

5.2.2.2.3.1 MSRV Capacity

The design pressure of the reactor vessel and reactor coolant boundary is 1250 psig, and the ASME allowable overpressure limit is 1375 psig. The Main Steam Isolation Valve Closure with Flux Scram (MSIVF) event is the design basis event to demonstrate compliance to the ASME vessel

overpressure protection criteria and is analyzed during every cycle-specific reload licensing process. The rerate analysis conservatively assumes that the position scram fails and the event terminates on a high neutron flux scram signal. The closure of all MSIVs causes an abrupt pressure increase in the RPV, which is mitigated by the actuation of the SRVs. The MSIVF event was analyzed at dome pressure of 1068 psia, 2% overpower for initial power, 110% of rated core flow and normal feedwater temperature. The MSIVF event was analyzed with all SRVs in service, 110% of rated core flow and normal feedwater temperature. The MSIVF event was analyzed with three (3) SRVs out of service (OOS) (3% setpoint tolerance), and two (2)SRVs out of service (3% setpoint tolerance).

The calculated reactor dome pressures (psig) for these cases are as follows:

three (3) SRVs OOS	1329
two (2) SRVs OOS	1318

The calculated reactor vessel bottom head pressures (psig) for these cases are as follows:

three (3) SRVs OOS	1348
two (2) SRVs OOS	1338

Since the analysis for three (3) SRVs OOS with 3% SRV setpoint tolerance exceeds the Technical Specification reactor dome pressure safety limit of 1325 psig, the number of SRVs allowed OOS by the Technical Specifications has been changed from three (3) to two (2). The reactor vessel bottom head pressures remain below the ASME overpressure limit of 1375 psig.

Under the "General Requirements for Protection Against Overpressure" as given in ASME Section III, credit can be allowed for a scram from the RPS. In addition, credit is also taken for the protective circuits that are indirectly derived when determining the required MSRV capacity. The backup reactor high neutron flux scram is conservatively applied as a design basis in determining the required capacity of the MSRVs. Application of the direct position scrams in the design basis could be used, since they qualify as acceptable pressure protection devices when determining the required SRV capacity of nuclear vessels under the provisions of the ASME Code.

5.2.2.2.3.2 Pressure Drop in Inlet and Discharge

Pressure drop on the piping from the reactor vessel to the MSRV is taken into account in calculating the maximum vessel pressures. Pressure drop in the discharge piping to the suppression pool is limited by proper discharge line sizing to prevent the back pressure on each MSRV from exceeding 40% of the valve inlet pressure, thus ensuring choked flow in the valve orifice and no reduction of valve capacity due to the discharge piping. Each MSRV has its own separate discharge line.

5.2.2.3 Piping & Instrument Diagrams

Drawing M-41 and Figure 5.2-6 show the schematic location of pressure-relieving devices for the following:

a. The RCS

b. The primary side of the auxiliary or emergency systems interconnected with the primary system

c. Any blowdown or heat dissipation system connected to the discharge side of the pressure-relieving devices

The schematic arrangement of the MSRVs is shown in Figures 5.2-6 and 5.2-7. Drawings M-41 and M-59 are the P&IDs of the nuclear boiler and PCIG systems.

5.2.2.4 Equipment and Component Description

5.2.2.4.1 Description

The nuclear pressure relief system consists of dual-function safety/relief valves (the MSRVs) located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. These valves protect against overpressure of the nuclear system.

The MSRVs provide two main protection functions:

a. Overpressure safety/relief operation. The valves open to limit a pressure rise.

b. Depressurization operation. The ADS valves open automatically as part of the ECCS if HPCI fails for events involving small breaks in the nuclear system process barrier (Sections 6.3 & 7.3).

Chapter 15 discusses the events that are expected to activate the MSRVs. Chapter 15 also summarizes the number of valves expected to operate during the initial blowdown of the valves and the expected duration of this first blowdown. For several of the events, it is expected that the lowest set MSRV will reopen and reclose as generated heat drops into the decay heat characteristics. The pressure increase and relief cycle will continue with lower frequency and shorter relief discharges as the decay heat drops off and until the RHR system can dissipate this heat. Remote manual actuation of the valves from the control room is recommended to minimize the total number of these discharges, with the intent of achieving extended valve seat life.

A schematic of the MSRV is shown in Figure 5.2-8. It is opened by either of two modes of operation:

a. The safety mode of operation involves extension of the pressure sensing bellows which engages the first stage pilot disc when reactor pressure approaches the valve setpoint. Once the pilot valve starts to open, the upstream seating force is eliminated, resulting in a net increase in the force tending to open the pilot valve. Opening of the first stage pilot valve admits fluid to the operating piston of the second stage valve, causing it also to open. Opening of the second stage pilot valve vents the chamber over the main valve piston to the downstream side of the valve. This venting action creates a differential pressure across the main valve piston almost equal to the system pressure and in a direction tending to open the valve.

b. The relief, or power-actuated mode of operation uses an auxiliary actuating device that directly opens the second stage valve, which vents the chamber over the main valve piston, causing the main valve to open.

The pneumatic operator is so arranged that, if it malfunctions, it will not prevent the pilot disc from lifting if steam inlet pressure reaches the set pressure.

The MSRVs can be operated in the power-actuated mode by remote manual controls from the control room.

The MSRVs are designed to operate to the extent required for overpressure protection in the following accident environments:

a. 340°F for 3 hours at drywell pressure ≤ 45 psig

b. 320°F for an additional 3 hour period, at drywell pressure ≤ 45 psig

c. 250°F for an additional 18 hour period, at 25 psig

d. 200°F at 20 psig for an additional 24 hour period, following which the valves remain fully open or closed for the remainder of a 100 day period, provided that an air and a power supply are available. No power/air supply is required to keep the valve closed.

The ADS uses selected MSRVs for depressurization of the reactor, as described in Sections 6.3 and 7.3. Each of the MSRVs used for automatic depressurization is equipped with an air accumulator and check valve arrangement. Each ADS accumulator is sized to provide two ADS valve actuations at 70% of drywell design pressure because that is the maximum pressure for which rapid reactor depressurization through the ADS valves is required. For large breaks that result in higher drywell pressure, sufficient reactor depressurization occurs due to the break to preclude the need for ADS. One ADS actuation at 70% of drywell design pressure is sufficient to depressurize the reactor and allow inventory makeup by the low pressure ECCS. However, for conservatism, the ADS accumulators are sized to allow two ADS actuations at 70% of drywell design pressure. This design provides sufficient gas to the ADS valves to permit depressurization until the RHR shutdown cooling mode can be initiated (short-term).

An allowable leakage criteria is applied only to the short-term ADS SRV operations because backup nitrogen bottles provide a longer term supply and provision is made for an infinite long-term supply through the use of external connections. An allowable leakage criteria of 164 scc/min was established to ensure that there would be sufficient pneumatic pressure to depressurize the RPV from the HPCI/RCIC operating pressure to the RHR shutdown cooling operating pressure range using two ADS SRV actuations over a period of 6 hours. Calculations indicate that this leakage criteria will ensure ADS operability for periods in excess of 6 hours for a range of containment conditions that might accompany the need for ADS operation. This short-term duration is sufficient to ensure that the ADS valves can perform their functions as described in Chapter 15, Accident Analyses.

To account for any possible increase in leakage due to a harsh environment and/or seismic event, a surveillance test leakage limit of 78 scc/min was established to provide additional margin as compared to the allowable leakage criteria of 164 scc/min.

The pneumatic components that make up the ADS accumulator system were designed for low leakage in a harsh environment and seismic event. A safety-grade pneumatic supply of nitrogen bottles is available to provide a backup supply if the ADS accumulator system leakage rate should exceed its allowable limit. These bottles are part of the long-term ADS gas supply subsystem of the Containment Instrument Gas System described in Section 9.3.1.3.2.

It should be understood that “short-term” and “long-term” as used here to describe the gas supplies for the ADS valves are not synonymous with the same terms when used to describe ECCS functions. In the context of ADS valve gas supplies, short-term is the first 6 hours of postulated events requiring power operation of ADS valves. This is the timeframe during which the plant would typically be brought to cold shutdown conditions following postulated events. In the context of ECCS functions, short-term refers to a shorter time period of ECCS operation after postulated reactor coolant pressure boundary breaks. A coolable core geometry is assured for subsequent long term cooling. Thus, the long-term gas supply subsystem is not required to support short-term ADS valve ECCS functions nor is it, typically, required to support the first few hours of ADS valve ECCS long-term cooling functions.

Testing and/or analysis has been performed, as described below, to verify that a harsh environment and/or seismic event would not increase the leakage rate of the ADS pneumatic supply system.

The pneumatic system solenoid valves have been qualified under the qualification program for electrical equipment to remain functional under conditions simulating the environment following a postulated design basis LOCA. The pneumatic system spring-loaded, soft-seated valves have been qualified to remain leak-tight after a seismic event. A materials and design review was performed to ensure that the check valves would not experience a significant increase in leakage due to post-LOCA environmental conditions. The functional capability of the check valves was further reviewed as part of the mechanical equipment qualification program. In any event, the long-term safety-grade pneumatic supply will provide the motive force for ADS valve operation.

Each MSRV discharges steam through a discharge line to a point below the minimum water level in the suppression pool. MSRV discharge line piping from the valve to the suppression pool consists of two parts. The first part is attached at one end to the valve and at its other end to a pipe anchor. The main steam piping, including this portion of the MSRV discharge piping, is analyzed as a complete system.

The second part of the MSRV discharge piping extends from the anchor to the suppression pool. Because of the upstream anchor on this part of the line, it is physically decoupled from the main steam header and is therefore analyzed as a separate piping system.

The MSRV discharge piping is designed to limit valve outlet pressure to 40% of maximum valve inlet pressure with the valve wide open at steady-state flow. Water in the line more than a few feet above the suppression pool water level would cause excessive pressure at the valve discharge when the valve is again opened. For this reason, a vacuum relief valve is provided on each MSRV discharge line to prevent the drawing of an excessive amount of water up into the line as a result of steam condensation following termination of relief operation. The MSRVs are located on the main steam line piping, rather than on the reactor vessel top head, primarily to simplify the discharge piping to the pool and to avoid the necessity of having to remove sections of this piping when the reactor head is removed for refueling. In addition, valves located on the steam lines are more accessible during a shutdown for valve maintenance.

The nuclear pressure relief system automatically depressurizes the nuclear system sufficiently to permit the LPCI and CS systems to operate as a backup for the HPCI system. Further descriptions of the operation of the automatic depressurization feature are found in Sections 6.3 and 7.3.

MSRV's A, C and N, controlled from the RSP, are provided with accumulators and check valves, which enhance the power-actuated mode of operation of these MSRV's. The accumulators and check valves are shown in drawing M-41, Sheet 2.

5.2.2.4.2 Design Parameters

The specified operating transients for components within the RCPB are given in Table 5.2-9. See Section 3.7 for a discussion of the input criteria for design of seismic Category I structures, systems, and components.

The design requirements established to protect the principal components of the RCS against environmental effects are discussed in Section 3.11.

The complete ADS accumulator system and associated equipment and control circuitry are included in the LGS Environmental Qualification Program for electrical and mechanical equipment and are qualified to accommodate the effects of, and be compatible with, the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents as stated in GDC 2 and 4 of 10CFR50, Appendix A.

5.2.2.4.2.1 Main Steam Safety/Relief Valve

The discharge area of each MSRV is 20.63 in^2, and the coefficient of discharge K_D is equal to 0.8 ($K = 0.9\ K_D$).

The design pressure and temperature of the valve inlet and outlet are 1250 psig @ 575°F and 500 psig @ 470°F, respectively.

The valves are designed to achieve the maximum practicable number of actuations consistent with state-of-the-art technology.

See Figure 5.2-8 for a schematic cross-section of the valve.

5.2.2.5 Mounting of Main Steam Relief Valves

The MSRVs are located on the main steam piping header. The mounting consists of a special contour nozzle and an oversized flange connection. This provides a high integrity connection that withstands the thrust, bending, and torsional loadings to which the main steam pipe and MSRV discharge pipe are subjected. This includes the following:

a. The thermal expansion effects of the connecting piping

b. The dynamic effects of the piping due to an SSE

c. The reactions due to transient unbalanced wave forces exerted on the MSRVs during the first few seconds after the valve is opened and before the time when steady-state flow is established (with steady-state flow, the dynamic flow reaction forces are self-equilibrated by the valve discharge piping)

d. The dynamic effects of the piping and branch connection due to the turbine stop valve closure

In no case are allowable valve flange loads exceeded, nor does the stress at any point in the piping exceed code allowables for any specified combination of loads. The design criteria and analysis methods for considering loads due to MSRV discharge are in Section 3.9.3.3.

5.2.2.6 Applicable Codes and Classification

The vessel overpressure protection system is designed to satisfy the requirements of ASME Section III. The general requirements for protection against overpressure of ASME Section III recognize that reactor vessel overpressure protection is one function of the reactor protection systems and allows the integration of pressure relief devices with the reactor protection systems of the nuclear reactor.

Hence, credit is taken for the reactor protection system as a complementary pressure protection device. The NRC has also adopted the ASME Codes as part of its requirements in 10CFR50.55a.

5.2.2.7 Material Specification

Material specifications of pressure-retaining components of MSRVs are listed in Table 5.2-3.

5.2.2.8 Process Instrumentation

Overpressure protection process instrumentation is listed in drawing M-42.

ADS valve gas supply instrumentation is described in Sections 7.6 and 9.3.1.3.

5.2.2.9 System Reliability

The system is designed to satisfy the requirements of ASME Section III; therefore, it has high reliability. The consequences of failure are discussed in Section 15.1.4.

5.2.2.10 Inspection and Testing

The MSRVs are tested at the vendor's shop in accordance with quality control procedures to detect defects and prove operability before installation. The following tests are conducted:

a. Hydrostatic test at specified test conditions

b. Pneumatic seat leakage test at 90% of set pressure, with maximum permitted leakage of 30 bubbles per minute being emitted from a 0.250 inch diameter hole submerged ½ inch below a water surface or an equivalent test using an approved test medium

c. Set pressure test: valve pressurized with saturated steam, with the pressure rising to the valve set pressure. Valve must open at nameplate set pressure ±1%.

d. Response time test: each valve is tested to demonstrate acceptable response time

The valves are installed as received from the factory. The GE equipment specification requires certification from the valve manufacturer that design and performance requirements have been met. This includes capacity and blowdown requirements. The setpoints are adjusted, verified, and

indicated on the valves by the vendor. The specified manual and automatic actuation relief mode of each MSRV is verified during the preoperational test program.

It is not feasible to test the MSRV setpoints while the valves are in place. The valves are mounted on 1500 pound primary service rating flanges. They can be removed for maintenance or bench checks and reinstalled during normal plant shutdowns. The valves are tested to check set pressure in accordance with the requirements of the Technical Specifications. The external surface and seating of all MSRVs are 100% visually inspected when the valves are removed for maintenance or bench checks. Valve operability is verified during the preoperational test program as discussed in Chapter 14.

A surveillance test of the ADS accumulator system will be conducted every refueling cycle under the LLRT program. Although the accumulator system is not considered to be a part of the primary containment boundary, this test under the LLRT program ensures completion of the surveillance test. Two tests will be performed at 90 psig. For the first test, the isolation boundaries will be the normal supply check valve, the seismic supply check valve, and the de-energized actuation solenoid. Vents are provided on the upstream side of the isolation check valves to meet the single isolation valve criteria. For the second test, the solenoid will be energized so that the SRV actuator and the solenoid valve vent port become part of the boundaries. In both tests, the leakage criteria will be 78 scc/min. as discussed in Section 5.2.2.4.1.

ADS valves gas supply pressure is monitored periodically by Operators in accordance with ECCS Technical Specifications.

5.2.3 Reactor Coolant Pressure Boundary Materials

5.2.3.1 Material Specifications

Table 5.2-3 lists the principal pressure-retaining materials and the appropriate material specifications for the RCPB components.

5.2.3.2 Compatibility with Reactor Coolant

5.2.3.2.1 PWR Chemistry of Reactor Coolant

Not applicable to BWRs.

5.2.3.2.2 BWR Chemistry of Reactor Coolant

Materials in the primary system are primarily austenitic stainless steel and Zircaloy cladding. Reactor water chemistry limits are established to provide an environment favorable to these materials. Limits are placed on conductivity, pH, and chloride concentrations. Conductivity is limited because it can be continuously and reliably measured and gives an indication of abnormal conditions and the presence of unusual materials in the coolant. Chloride limits are specified to mitigate stress-corrosion cracking of stainless steel. Other controls and limits are implemented which would further reduce stress-cracking or decrease crack growth rates, for example: Hydrogen Water Chemistry: Noble Metals as applicable based on industry experience and optimal water chemistry guidelines for BWRs. For further information, see Reference 5.2-2.

Several investigations have shown that in neutral solutions some oxygen is required to cause stress-corrosion cracking of stainless steel, while in the absence of oxygen no cracking occurs. One of

these is the chloride-oxygen relationship of Reference 5.2-3, where it is shown that at high chloride concentration little oxygen is required to cause stress-corrosion cracking of stainless steel, and at high oxygen concentration little chloride is required to cause cracking. These measurements were determined in a wetting and drying situation using alkaline-phosphate treated boiler water and, therefore, are of limited significance to BWR conditions. They are, however, a qualitative indication of trends.

When conductivity is in its normal range, pH, chloride, and other impurities affecting conductivity may be assumed to be within their normal range. When conductivity becomes abnormal, chloride measurements are made to determine whether or not they are also out of their normal operating values. This would not necessarily be the case. Conductivity could be high due to the presence of a neutral salt that would not have an effect on pH or chloride. In such a case, high conductivity alone is not a cause for shutdown. In some types of water-cooled reactors, conductivities are high because of the purposeful use of additives. In BWRs, however, where high purity water chemistry at near-neutral pH is maintained, conductivity provides a good and prompt measure of the quality of the reactor water. Significant changes in conductivity provide a warning mechanism so the operator can investigate and remedy the condition before reactor water limits are reached. Methods available to the operator for correcting the off-standard condition include operating the RWCU system, reducing the input of impurities, and placing the reactor in the cold shutdown condition. The major benefit of cold shutdown is to reduce the temperature-dependent corrosion rates and provide time for the cleanup system to reestablish the purity of the reactor coolant.

The following is a summary and description of BWR water chemistry for various plant conditions.

a. Normal plant operation

The BWR system water chemistry is conveniently described by following the system cycle as shown in Figure 5.2-9. Reference to Table 5.2-4 is made as numbered on the diagram and correspondingly in the table.

For normal operation starting with the condenser/ hotwell, condensate water is processed through condensate cleanup system, resulting in effluent water quality represented in Table 5.2-4. As the effluent is pumped through the feedwater heater train, zinc may be injected into the feedwater stream by the Zinc Injection Passivation (PZIP) Skid to adjust feedwater chemistry. The additions to feedwater are used to adjust the final water chemistry in the reactor vessel and primary loop.

On Unit 1 the GEZIP skid is used to suspend components in demineralized water and to dilute the suspension with additional demineralized water during injection. The addition of soluble zinc oxide is used to reduce the levels of corrosion products and cobalt deposits in the primary piping and components. This reduces the radioactive contamination buildup and dose levels. Iron oxide is added to maintain feedwater iron levels within the industry recommended range of 0.5-1.5 ppb. This reduces the redistribution of radioactive cobalt crud and dose levels. Impurity limits are placed on the compounds added to the GEZIP tank to limit the impact on reactor chemistry to a maximum increase of 0.5 ppb sulfates and 0.5 ppb halogens. The chloride and oxygen levels in the demineralized water and GEZIP tank have a negligible impact on the chloride and oxygen levels in feedwater due to the small quantity injected when compared to the total feedwater flow.

The PZIP uses the pressure drop between a tap on the downstream side of the feedwater pumps and a corresponding tap upstream of the feedwater pumps to inject zinc ions into the reactor water. Actual flowrate is controlled by throttling of a skid mounted flow control valve. The injection rate is manually adjusted in order to maintain zinc concentration in the reactor and feedwater at predetermined levels.

The effluent from the condensate cleanup system is pumped through the feedwater heater train and enters the reactor vessel at an elevated temperature and typically with a chemical composition as shown in Table 5.2-4.

During normal plant operation, boiling occurs in the reactor, decomposition of water takes place due to radiolysis, and oxygen and hydrogen gas are formed. Due to steam generation, stripping of these gases from the water phase takes place, and the gases are carried with the steam through the turbine to the condenser. The oxygen level in the steam, resulting from this stripping process, is typically observed to be about 20 ppm (Table 5.2-4). Deaeration takes place at the condenser, and the gases are removed from the process by SJAEs. The deaeration is completed to a level of approximately 20 ppb (0.02 ppm) oxygen in the condensate. The capability exists for adding oxygen to condensate water to maintain oxygen at levels which protect system piping from corrosion when needed.

The dynamic equilibrium in the reactor vessel water phase, established by the steam-gas stripping and the radiolytic formation (principally) rates, corresponds to a nominal value of approximately 200 ppb (0.2 ppm) of oxygen at rated operating conditions. Slight variations around this value have been observed as a result of differences in neutron flux density, core flow, and recirculation flow rate.

The RWCU system is provided for removal of impurities in the primary system. The cleanup process consists of filtration/ demineralization and serves to maintain a high level of water purity in the reactor coolant.

Typical chemical parametric values for the reactor water are listed in Table 5.2-4 for various plant conditions.

Additional water input to the reactor vessel originates from the CRD cooling water. The CRD water is of approximately feedwater quality. Separate filtration for purification and removal of insoluble corrosion products takes place within the CRD system before the water enters the drive mechanisms and reactor vessel.

During plant conditions other than normal operation, additional inputs and mechanisms are present, some of which are outlined in the following discussion.

b. Plant conditions outside normal operation

During periods of plant conditions other than normal power production, transients take place, particularly with regard to the oxygen levels in the primary coolant. Oxygen levels in the primary coolant vary from the normal during plant startup, plant shutdown, hot standby, and when the reactor is vented and depressurized. The hotwell condensate absorbs oxygen from the air when vacuum is broken on the condenser. Before the startup and input of feedwater to the reactor, vacuum is established in the condenser and deaeration of the condensate takes place by

mechanical vacuum pump, SJAE operation, and condensate recirculation. During these plant conditions, continuous input of CRD cooling water takes place as described previously.

1. Plant depressurized and reactor vented

   During certain periods, such as refueling and maintenance outages, the reactor is vented to the condenser or to the atmosphere. Under these circumstances the reactor cools, and the oxygen concentration increases to a maximum value of 8 ppm. Equilibrium between the atmosphere above the reactor water surface, the CRD cooling water input, residual radiolytic effects, and the bulk water is established after some time .

2. Plant startup/shutdown

   During these conditions, significant changes in oxygen concentration take place.

   (a) Plant startup

   Depending on the duration of the plant shutdown before startup and whether the reactor has been vented, the oxygen concentration could be that of air-saturated water: i.e., 8 ppm oxygen.

   Following nuclear heatup initiation, the oxygen level in the reactor water decreases rapidly as a function of water temperature increase and corresponding oxygen solubility in water. The oxygen level reaches a minimum of about 20 ppb (0.02 ppm) at a coolant temperature of about 380°F, at which point an increase takes place due to significant radiolytic oxygen generation. For the elapsed process up to this point, the oxygen is degassed from the water and is displaced to the steam dome above the water surface.

   A further increase in nuclear power increases the oxygen generation as well as the temperature. The solubility of oxygen in the reactor water at the prevailing temperature controls the oxygen level in the coolant until rated temperature (540°F) is reached. Thus, gradual increase from the minimum level of 20 ppb to a maximum value of about 200 ppb oxygen takes place. At and after this point (540°F), steaming and the radiolytic process control the coolant oxygen concentration to a level of around 200 ppb.

   (b) Plant shutdown

   On plant shutdown following power operation, the radiolytic oxygen generation essentially ceases as the fission process is terminated. Because oxygen is no longer generated, while some steaming still takes place due to residual energy, the oxygen concentration in the coolant decreases to a minimum value determined by the steaming rate temperature. If venting is performed, a gradual increase to essentially oxygen saturation at coolant temperature takes place, reaching a maximum value of <8 ppm oxygen.

(c) Oxygen in piping and in parts other than the reactor vessel proper

As can be concluded from the preceding descriptions, the maximum possible oxygen concentration in the reactor coolant and any other directly related or associated parts is that of air saturation at ambient temperature. At no time or location in the water phase do oxygen levels exceed the nominal value of 8 ppm. As temperature is increased and oxygen solubility is thus decreased accordingly, the oxygen concentration is maintained at this maximum value or reduced below it, depending on available removal mechanisms: i.e., diffusion, steam stripping, flow transfer, or degassing.

Depending on the location, configuration, etc., such as dead legs or stagnant water, inventories may contain less than the maximum limitation of 8 ppm dissolved oxygen.

Conductivity of the reactor coolant is continuously monitored. These measurements provide reasonable assurance of adequate surveillance of the reactor coolant.

Grab samples may be taken from the locations shown in Table 5.2-6 for special and noncontinuous measurements such as pH, oxygen, chloride, and radiochemical measurements.

The relationship of chloride concentration to specific conductance measured at 25°C is shown in Figure 5.2-10. The values essentially bracket the values of common chloride salts or mixtures at the same chloride concentration. Surveillance requirements are based on these relationships.

In addition to this program, limits, monitoring, and sampling requirements are imposed on the condensate, condensate cleanup system, and feedwater to detect and correct off-specification conditions.

The sampling frequency when reactor water has a low specific conductance is adequate for calibration and routine audit purposes. When specific conductance increases and higher chloride concentrations are possible or when continuous conductivity monitoring is unavailable, increased sampling is provided (see plant Technical Specifications).

For the higher than normal limits of <1 μmho/cm, more frequent sampling and analyses are invoked by the coolant chemistry surveillance program.

The primary coolant conductivity monitoring instrumentation, ranges, accuracy sensor, and indicator locations are shown in Table 5.2-6.

3. Water purity during a condenser leakage

To protect against a major condenser tube leak, sufficient instrumentation and monitoring is provided so that there is adequate demineralizer capacity margin available to permit orderly shutdown of the reactor in case of a serious condenser leak. Details are discussed in Section 10.4.1.

5.2.3.2.2.1 Conformance with Regulatory Guide 1.56 (July 1978) - Maintenance of Water Purity in Boiling Water Reactors

Conformance with Regulatory Guide 1.56 of the design and associated instrumentation and operating procedures for the RWCU and condensate cleanup systems is discussed in Sections 5.4.8 and 10.4.6, respectively.

Maintenance of coolant chemistry at a level comparable to the recommendations of Regulatory Guide 1.56 is discussed in Section 10.4.1 and Technical Specifications.

5.2.3.2.3 Compatibility of Construction Materials with Reactor Coolant

The construction materials exposed to the reactor coolant consist of the following:

a. Solution annealed austenitic stainless steels (both wrought and cast) Types 304, 304L, 316, and 316L

b. Nickel base alloys - Inconel 600 and Inconel 750X

c. Carbon steel and low alloy steel

d. Some 400 series martensitic stainless steel (all tempered at a minimum of 1100°F)

e. Colmonoy and Stellite hard-facing material

General corrosion on all materials, except carbon and low alloy steel, is negligible. Conservative corrosion allowances are provided for all exposed surfaces of carbon and low alloy steels.

Contaminants in the reactor coolant are controlled to very low limits per the reactor water quality specifications. The reactor coolant monitoring and control programs are based on industry guidelines for BWR water chemistry and are designed to protect construction materials from adverse affects.

5.2.3.2.4 Compatibility of Construction Materials with External Insulation and Reactor Coolant

The construction materials exposed to external insulation are:

a. Solution annealed austenitic stainless steels, Types 304, 304L, 316, and 316L

b. Carbon and low alloy steel

Two types of external insulation are employed on BWRs. The reflective metal insulation used does not contribute to any surface contamination and has no effect on construction materials. The nonmetallic insulation used on stainless steel piping and components is in accordance with

Regulatory Guide 1.36 (February 1973) and complies with the requirements of the following industry standards:

a. ASTM C692-71, Standard Methods for Evaluating Stress- Corrosion Effects of Wicking-Type Thermal Insulation on Stainless Steel (Dana Test)

b. RDT-Ml2-1T, Test Requirements for Thermal Insulating Materials for Use on Austenitic Stainless Steel, Section 5 (KAPL Test)

Chemical analyses are required to verify that the leachable sodium, silicate, and chloride are within acceptable levels. Insulation is packaged in waterproof containers to prevent damage or contamination during shipment and storage.

These same construction materials may be exposed to external penetration seals. Those penetration seals that could contribute to surface contamination of the construction materials are in accordance with Reg. Guide 1.36 (February 1973) as discussed above, or any similar standard which is at least as stringent as Reg. Guide 1.36 (February 1973).

Because of the high purity water quality of the BWR coolant, leakage exposes materials to essentially the same effects as that of demineralized water which is negligible.

5.2.3.3 Fabrication and Processing of Ferritic Materials

5.2.3.3.1 Fracture Toughness of Ferritic Materials

The ferritic materials of the containment pressure boundary were purchased and impact-tested prior to the issuance of the Summer 1977 Addenda to ASME Section III. These materials have been reviewed and found to be acceptable within the context of GDC 51 based on the following information.

Materials for AE-supplied pipe, valves, and flued heads for systems that are part of the containment pressure boundary are approved impact quality materials as listed in ASME Section III. The impact test requirements were derived from ASME Section III, 1971 Edition, including Winter 1972 Addenda. All materials required to be tested were tested satisfactorily and documented. Records for all AE-supplied containment pressure boundary piping, valves, and flued heads are available for inspection.

The material used for the fabrication of the penetration assemblies, personnel air locks, hatches, and drywell head of the containment pressure boundary are impact quality materials conforming to ASME Section III, subsection B, article 12. All materials required to be tested in accordance with paragraph NC2311 of the Summer 1977 Addenda to ASME Section III were impact-tested satisfactorily in accordance with the requirements of ASME Section III, 1968 Edition, including Winter 1969 Addenda, or later addenda or editions. Records for tested materials of the containment pressure boundary penetration assemblies, personnel air locks, hatches, and drywell head are available for inspection.

The materials of the containment pressure boundary used for the NSSS flued head fittings, main steam piping, and MSIVs, which are also part of the RCPB, meet the GDC 51 requirements for fracture toughness as demonstrated by their conformance to 10CFR50, Appendix G, which is discussed below.

The materials used for the NSSS flued head fittings and main steam piping were satisfactorily impact-tested at 0°F and 70°F, respectively, in accordance with ASME Section III, 1971 Edition with Summer 1972 Addenda. The materials used for the NSSS MSIVs were exempted from toughness testing, but have been reviewed against the criteria of 10CFR50, Appendix G and are considered to be acceptable based on the information provided in Section 5.2.3.3.1.4 below.

5.2.3.3.1.1 Piping

Toughness testing of the main steam piping is in compliance with 10CFR50, Appendix G, since it was tested at +70°F in accordance with ASME Section III, 1971 edition with Summer 1972 Addenda.

5.2.3.3.1.2 Safety/Relief Valves

The SRVs are exempted by the ASME Code from toughness testing because of their 6 inch size. This is consistent with 10CFR50, Appendix G.

5.2.3.3.1.3 Flued Head Fittings

Testing of the flued head fittings is in compliance with 10CFR50, Appendix G. These materials were impact-tested in accordance with ASME Section III, 1971 Edition with Summer 1972 Addenda. The test temperature was 0°F.

5.2.3.3.1.4 Main Steam Isolation Valves

The MSIVs were procured to meet the requirements of the 1968 ASME Nuclear Draft for Pumps and Valves Code, which did not require toughness testing for the subject valve materials. These were exempted because they are subjected to less than 20% of design pressure at temperatures less than 250°F.

The LGS Units 1 and 2 MSIV body materials are A216 Grade WCB carbon steel castings. Table 5.2-12 shows the typical chemical composition and heat treatment of these castings. Although impact tests were not run, these materials are considered to have adequate toughness to meet the current code requirements (i.e., 25 mil lateral expansion). Evidence of this design adequacy is provided in Table 5.2-13 which presents similar MSIV body material data from other BWR projects identified as Projects A through F. These materials received heat treatments equivalent to those experienced in LGS Units 1 and 2.

The bonnet (i.e., cover) materials are A105 Grade 2 forgings. Table 5.2-11 lists available information for the materials used to fabricate the valve covers. These materials were normalized at 1650°F for 12 hours and air cooled. Evidence of toughness for SA105 forgings is given in the July 1978 issue of "Metal Progress", (pages 35-39). This article (Reference 5.3-1) shows charpy V-notch in excess of 25 mils lateral expansion at +40°F and NDTT values no greater than -10°F for SA105 material normalized at 1565°F for 4 hours and air cooled after forging. Similar results would be expected for the LGS MSIV bonnet materials. MSIVs modified with nose guided poppets have bonnets made from SA105 forgings which are equivalent to the original material.

Additional toughness data for SA105 forging materials obtained from fittings in another BWR plant is presented in Table 5.2-10. These materials were normalized at 1650°F for 4 hours and air cooled. The toughness data given is for longitudinally oriented specimens whereas the code requirements are for transverse specimens. However, prior GE impact test experience with carbon steel material indicates it is appropriate to approximate transverse properties at about 40% of the corresponding

longitudinal properties. On this basis, the data given in Table 5.2-10 demonstrates that the transverse properties meet the 25 mil lateral expansion code requirements.

5.2.3.3.2 Control of Welding

5.2.3.3.2.1 Regulatory Guide 1.50 (May 1973) - Control of Preheat Temperature Employed for Welding of Low Alloy Steel

This guide delineates preheat temperature control requirements and welding procedure qualifications supplementing those in ASME Sections III and IX.

For the GE scope of supply, Regulatory Guide 1.50 is not employed as a design basis for LGS. However, the procedures in use either conform with the guide or are evaluated as satisfying the guide through the use of alternate approaches.

Preheat temperatures employed for the welding of low alloy steel meet or exceed the recommendations of ASME Section III, Subsection NA. Either components were held for an extended time at preheat temperature to ensure removal of hydrogen, or preheat was maintained until postweld heat treatment. The minimum preheat and maximum interpass temperatures were specified and monitored.

All welds were nondestructively examined by radiographic methods. In addition, a supplemental ultrasonic examination was performed.

For the Bechtel scope of supply, this guide is followed except for the following alternate approaches:

a. With respect to the position in Paragraph C.1.a of the guide that the procedure qualification should require that a minimum preheat and a maximum interpass temperature be specified, there is conformance when impact testing in accordance with Subarticle 2300 of ASME Section III, Division 1, is required. The maximum interpass temperature shall be 500°F unless otherwise specified. When impact testing is not required, specification of a maximum interpass temperature in the welding procedure is not necessary to ensure that the required mechanical properties are met. The minimum preheat temperatures of ASME Section III, Appendix D are required to be met regardless of whether impact testing is required.

b. Regarding the position in Paragraph C.1.b of the guide that the procedure qualification should require that the welding procedure be qualified at the minimum preheat temperature, the welding procedure qualification requirements of ASME Sections III and IX are considered to be more than adequate.

c. Regarding the position of Paragraph C.2 of the guide that, for production welds, the preheat temperature should be maintained until a postweld heat treatment has been performed, the position is conformed with for Class 1 pressure vessels with nominal thickness greater than 1 inch. Maintenance of preheat beyond completion of welding until postweld heat treatment is not required for thinner sections since experience has indicated that delayed cracking in the weld or heat-affected zone is not a problem.

   Current usage of low alloy steel in piping, pumps and valves is minimal and normally is limited to Class 3 construction. When low alloy steel piping, pumps and valves are

used, preheat is maintained until welding is complete but not until postweld heat treatment is performed, since the conditions which cause delayed cracking in the weld or heat-affected zone are not present.

When the regulatory guide positions or above alternate approaches are not met, the weld is subject to rejection; however, the soundness of the weld may be verified by an acceptable examination procedure.

5.2.3.3.2.2 Regulatory Guide 1.34 - Control of Electroslag Weld Properties

No electroslag welding was performed on BWR components.

5.2.3.3.2.3 Regulatory Guide 1.71 - Welder Qualification for Areas of Limited Accessibility

The qualification for areas of limited accessibility is discussed in Section 5.2.3.4.2.3.

5.2.3.3.2.4 Regulatory Guide 1.43 - Control of Stainless Steel Weld Cladding of Low Alloy Steel Components

This guide applies to welding of cladding to low alloy steels made to coarse grain practice. LGS vessel plate and nozzle forgings are made to fine grain practice and a low heat input process is used. Other components are not clad. Therefore, the guide is not applicable.

5.2.3.3.3 Nondestructive Examination of Ferritic Tubular Products - Regulatory Guide 1.66 (October 1973)

This regulatory guide was withdrawn on September 28, 1977, by the NRC because the additional requirements imposed by the guide were satisfied by the ASME Code. The following discussion applies only to activities performed prior to that time.

This guide described a method of implementing requirements acceptable to the NRC regarding nondestructive examination requirements of tubular products used in the RCPB.

For the GE scope of supply, wrought tubular products were supplied in accordance with applicable ASTM/ASME material specifications. Also, the specification for the tubular product used for CRD housings specified ultrasonic examination to paragraph NB-2550 of ASME Section III.

These RCPB components met the requirements of the ASME Codes existing at the time of the placement of the order that predated Regulatory Guide 1.66. At the time of the placement of the orders, the 10CFR50, Appendix B requirements and ASME code requirements ensure adequate control of quality for the products.

For the Bechtel scope of supply, there was partial conformance with the guide in that tubular products used for Class 1, 2, and 3 components were ultrasonically examined in accordance with the requirements of ASME Section III, Division 1, 1971 Edition with Addenda through Winter 1971. In addition, the ultrasonic examination procedures were in accordance with ASTM E213-68.

5.2.3.3.4 Moisture Control for Low Hydrogen, Covered Arc Welding Electrodes

All low hydrogen covered welding electrodes are stored in controlled storage areas, and only authorized persons are permitted to release and distribute electrodes. Electrodes are received in hermetically sealed canisters. After removal from the sealed containers, electrodes which are not immediately used are placed in storage ovens which are maintained at about 250°F (generally 200°F minimum).

Electrodes are distributed from sealed containers or ovens as required. At the end of each work shift, unused electrodes are returned to the storage ovens. Electrodes which are damaged, wet, or contaminated are discarded. If any electrodes are inadvertently left out of the ovens for more than one shift, they are discarded or reconditioned in accordance with the manufacturer's instructions.

5.2.3.4 Fabrication and Processing of Austenitic Stainless Steels

5.2.3.4.1 Avoidance of Stress-Corrosion Cracking

5.2.3.4.1.1 Avoidance of Significant Sensitization - Regulatory Guide 1.44 (May 1973) - Control of the Use of Sensitized Stainless Steel

The purpose of Regulatory Guide 1.44 is to address 10CFR50, Appendix A, GDC 1 and 4, and the Appendix B requirements to control "the application and processing of stainless steel to avoid severe sensitization that could lead to stress-corrosion cracking."

This guide is not used by GE as a design basis for LGS. However, the procedures used either conform with the guides or are evaluated as satisfying the guide through the use of alternate approaches.

All austenitic stainless steel was purchased in the solution heat treated condition in accordance with applicable ASME and ASTM specifications. Cooling rates from solution heat treating temperatures were required to be rapid enough to prevent sensitization. Non-sensitization was verified using ASTM A262, Practice A or E methods.

Material changes have been made to minimize the possibility of IGSCC. Except certain valves, for which alternate means of mitigating IGSCC or inspection procedures were employed to comply with the intent of Regulatory Guide 1.44, wrought austenitic stainless steel in the RCPB was changed to low carbon (0.025% maximum) material. Piping in the following systems, from the reactor vessel to the first isolation valve, is manufactured from low carbon austenitic stainless steel (AISI 316L, maximum carbon content of 0.02%): the core spray system and the RHR system (shutdown cooling suction line, shutdown cooling return line, LPCI). The RWCU system uses 316L from the recirculation system connection through the containment penetration. The recirculation system piping is manufactured from low carbon high strength austenitic stainless steel (316K). Thus, there is no piping that is nonconforming and service sensitive, as defined in NUREG-0313 (Rev 1). 316L seamless small-bore piping and forged fittings (2 inch and smaller) are not subject to the 0.02% maximum carbon content requirement.

For manual welds with gas tungsten arc and shielded metal arc welding processes, heat input was limited by weaving and welding technique restrictions. Nonweaving (stringer bead) techniques were used where possible. Where required, weaving was controlled to meet the following bead width limits:

a. For gas tungsten arc, the lesser of 5 times the filler wire diameter or 7/8 inch

b. For shielded metal arc, the lesser of 4 times the electrode core wire diameter or 5/8 inch.

For machine, automatic, and manual welding with processes except gas tungsten arc and shielded metal arc, heat input for piping was restricted to 50,000 joules/in. Interpass temperature was restricted to 350°F for all stainless steel welds. High heat welding processes such as block welding and electroslag welding were not permitted. All weld filler metal and castings were required by specification to have a minimum of 5% ferrite.

For welding of short sections of 316L pipe to forged 316 LPCI and core spray valves adjacent to the reactor, heat was controlled by use of a demineralized water heat sink. The 316L pipe sections were welded to the valves with a gas tungsten arc root pass with argon backing. Subsequent welds were made with a demineralized water backing heat sink as a means of mitigating IGSCC.

Whenever any wrought austenitic stainless steel was heated to temperatures over 800°F by means other than welding or thermal cutting, the material was re-solution heat treated.

These controls were used to avoid severe sensitization and to conform with the intent of Regulatory Guide 1.44.

For the Bechtel scope of supply, the guide is followed except for the following alternate approaches:

a. Regarding the position in Paragraph C.3 of the guide which discusses testing for non-sensitization, there is partial conformance in that all austenitic stainless steels are furnished in accordance with applicable ASME or ASTM material specifications. Testing to determine susceptibility to intergranular attack is performed only when required by the material specification.

b. Regarding the position of Paragraph C.6 of the guide which discusses intergranular corrosion testing, welding practices are controlled to avoid severe sensitization, and heat treatment in the temperature range 800°F to 1500°F is not permitted. Since severe sensitization is avoided, testing to determine susceptibility to intergranular attack is not performed.

5.2.3.4.1.2 Process Controls to Minimize Exposure to Contaminants

Exposure to contaminants capable of causing stress-corrosion cracking of austenitic stainless steel components is avoided by carefully controlling all cleaning and processing materials that contact the stainless steel during manufacture and construction.

Special care is exercised to ensure the removal of surface contaminants before any heating operations. Water quality for cleaning, rinsing, flushing, and testing is controlled and monitored. Suitable packaging and protection is provided for components to maintain cleanliness during shipping and storage.

The degree of surface cleanliness achieved by the GE procedures meets the requirements of Regulatory Guide 1.44 and Regulatory Guide 1.37.

Regulatory Guide 1.37 and the associated ANSI N45.2.1 are not specifically applied in the Bechtel scope of work. However, the procedures in use are generally equivalent to the regulatory guide and standard.

5.2.3.4.1.3 Cold-Worked Austenitic Stainless Steels

Austenitic stainless steels with a yield strength greater than 90,000 psi are not used.

5.2.3.4.1.4 Noble Metals Chemical Addition

Noble Metals added to the wetted surfaces of the reactor vessel and internals in combination with low rates of feedwater hydrogen injection (Hydrogen Water Chemistry), provides improved mitigation of Stress Corrosion Cracking of the Noble Metals treated components and associated piping.

5.2.3.4.2 Control of Welding

5.2.3.4.2.1 Avoidance of Hot-Cracking - Regulatory Guide 1.31 - Control of Ferrite Content in Stainless Steel Weld Metal

Regulatory Guide 1.31 describes an acceptable method of implementing requirements with regard to the control of welding when fabricating and joining austenitic stainless steel components and systems.

Per the implementation section of Regulatory Guide 1.31 (Rev 3), April 1978, of the guide, the guide is not applicable to LGS. Nevertheless, for explanatory purposes, LGS procedures with reference to the guide are discussed below.

GE employs Regulatory Guide 1.31 (Rev 1), June 1973, as a design basis for LGS, with certain alternate approaches:

> Written welding procedures which are approved by GE are required for all primary pressure boundary welds. These procedures comply with the requirements of ASME Sections III and IX and applicable regulatory guides.
>
> All austenitic stainless steel weld filler materials were required by specification to have a minimum of 5% ferrite. Prediction of ferrite content was made by using the chemical composition in conjunction with the Schaeffler diagram. The use of the 5% minimum limit for ferrite content determined by the Schaeffler diagram has been shown to be adequate to prevent hot-cracking in austenitic stainless steel welds. An extensive test program performed by GE, with the concurrence of the NRC, demonstrated that controlling weld filler metal ferrite at 5% minimum (by Schaeffler diagram) resulted in production welds which met the requirements of Regulatory Guide 1.31 "Control of Stainless Steel Welding." A total of approximately 400 production welds in five BWR plants were measured and all welds met the requirements of BTP MTEB 5-1 "Interim Regulatory Position on Regulatory Guide 1.31, Control of Stainless Steel Welding."

Bechtel employs an alternate approach to the guide:

> With respect to Paragraph C.1 of the guide, the delta ferrite determination for consumable inserts, electrodes, rod or wire filler metal used with gas tungsten arc welding process and

the plasma arc welding process is predicted from a chemical analysis of as-manufactured material using the constitutional diagram in ASME Section III, figure NX-2433.1-1.

As an alternate to the magnetic method of determining the ferrite content of an undiluted weld deposit as specified in Paragraph C.1, C.2 and C.3, the chemical analysis method specified in ASME Section III, NX-2430 may be used.

5.2.3.4.2.2 Regulatory Guide 1.34 - Electroslag Welds

Electroslag welding was not employed for RCPB components.

5.2.3.4.2.3 Regulatory Guide 1.71 (December 1973) - Welder Qualification for Areas of Limited Accessibility

Regulatory Guide 1.71 recommends that weld fabrication and repair for wrought low alloy and high alloy steels, or other materials such as static and centrifugal castings and bimetallic joints, should comply with the fabrication requirements of ASME Sections III and IX. It also recommends additional performance qualifications for welding in areas of limited access.

For the GE scope of supply, Regulatory Guide 1.71 is not employed as a design basis for LGS. However, the procedures in use either conform with the guide or alternate approaches are used that are evaluated as satisfying the intent of the guide.

All ASME Section III welds were fabricated in accordance with the requirements of ASME Sections III and IX. There are few restrictive welds involved in the fabrication of BWR components. The welder qualification for welds with the most restrictive access was accomplished by mockup welding. Mockups were examined by radiography or sectioning.

For the Bechtel scope of supply, alternate approaches are employed:

Performance qualifications for personnel who weld under conditions of limited access, as defined in Regulatory Position C.1, are maintained in accordance with the applicable requirements of ASME Sections III and IX. Additionally, responsible site supervisors are required to assign only the most highly skilled welders to limit access welding. Of course, welding conducted in areas of limited access is subjected to the required nondestructive testing and no waiver or relaxation of examination methods or acceptance criteria because of the limited access is permitted.

Requalification is required when any of the essential variables of ASME Section IX are changed or when any authorized inspector questions the ability of the welder to perform satisfactorily the requirements of ASME Sections III or IX.

Production welding is monitored and welding qualifications are certified in accordance with the alternate approaches discussed above.

5.2.3.4.3 Nondestructive Examination of Tubular Products - Regulatory Guide 1.66

For GE scope of supply, wrought tubular products were supplied in accordance with applicable ASTM/ASME material specifications. The specification for the tubular product used for CRD housings requires ultrasonic examination in compliance with ASME Section III, paragraph NB-2550.

All tubular products meet the requirements of ASME Codes existing at time of placement of order which predated Regulatory Guide 1.66.

Bechtel conformance with Regulatory Guide 1.66 is discussed in Section 5.2.3.3.3.

5.2.4 PRESERVICE/INSERVICE INSPECTION, EXAMINATION AND TESTING OF THE REACTOR COOLANT PRESSURE BOUNDARY

The construction permits for LGS Units 1 and 2 were issued in June 1974. Based on this date, 10CFR50.55a requires that the preservice inspection program for the RCPB meet the examination requirements set forth in ASME Section XI, 1971 edition with addenda through Winter 1972 or, alternatively, the examination requirements of subsequent editions and addenda, subject to the limitations and modifications listed in 10CFR50.55a. The LGS preservice inspection programs follow the alternative requirement.

Specifically, the Unit 1 PSI program (with the exception of the RPV and the operability testing of safety-related pumps and valves) meets the requirements of ASME Section XI, 1974 edition with addenda through Summer 1975, as modified by Appendix III of the Winter 1975 Addenda and paragraph IWA-2232 of the Summer 1976 Addenda.

At the time the LGS PSI program commenced, the latest edition of the code permissible for use was the Summer 1975 Addenda. In an effort to take advantage of improved UT methods, Appendix III of the Winter 1975 Addenda and paragraph IWA-2232 of the Summer 1976 were used. Although these items were not specifically referenced by 10CFR50.55a, they are equivalent to the comparable portions of the Summer 1978 Addenda (which was subsequently approved by 10CFR50.55a) as long as Section XI Appendix III indications greater than 50% DAC are recorded. The LGS ISI procedures do record such indications.

Supplement 7 of Appendix III permits the use of Appendix III for austenitic piping welds with certain modifications. It is our position, consistent with the PSI/ISI industry, that Appendix III (at 50% DAC recording) is more appropriate for austenitic piping weld examination than article 5 of ASME Section V. Thus for austenitic piping welds:

a. All of the Supplement 7 modifications are being used.

b. Examination sensitivity is ensured through the calibration process.

c. Where one-sided access only occurs and penetrations cannot be confirmed, a one-sided access limitation is noted in the data package for that weld.

When using Section XI, Appendix III for either ferritic or austenitic piping welds, the following applies:

a. All indications showing signal amplitudes equal to or in excess of 20% of the reference response are evaluated to the extent that the level II or III examiner can determine their true nature.

b. The owner evaluates and takes corrective action for the disposition of any indication investigated and found to be other than geometrical or metallurgical in nature.

The Unit 1 RPV PSI program meets the requirements of ASME Section XI, 1980 edition with addenda through Winter 1980. The Unit 2 preservice inspection program and Units 1 and 2

programs for the preservice testing of safety-related pumps and valves meet the requirements of ASME Section XI, 1980 edition with addenda through Winter 1981.

For certain ASME Section XI requirements that have been determined to be impractical in the course of inspecting the components, the licensee has submitted and will submit requests for relief from the requirements to the NRC in accordance with the provisions of 10CFR50.55a.

In accordance with 10CFR50.55a, throughout the service life, RCPB components (including supports) will meet the ISI requirements, except design and access provisions and preservice examination requirements, set forth in the ASME Section XI edition and addenda that become effective, to the extent practical within the limitations of design, geometry, and materials of construction

of the components. In accordance with 10CFR50.55a, inservice examination of components, inservice tests to verify operational readiness of safety-related pumps and valves, and system pressure tests conducted during the initial 10 year inspection interval will comply with the ASME Section XI edition and addenda in effect 12 months prior to the date of issuance of the operating license. In accordance with 10CFR50.55a(g)(4)(ii), the initial 10 year inspection interval commences with commercial operation. The successive 10 year inspection intervals will comply with the ASME Section XI edition and addenda in effect 12 months prior to the start of the 10 year inspection interval.

5.2.4.1 System Boundary

LGS piping was originally designed to ANSI B31.7. For the purpose of inservice inspection, ANSI B31.7, Class I is considered equivalent to ASME Section III, Class 1. The PSI/ISI program includes figures showing the systems or portions of systems within the scope of ASME Section XI. The applicable PSI/ISI programs are described in References 5.2-8 through 5.2-18. Any necessary requests for relief are addressed in these documents.

5.2.4.2 Accessibility

The access provided for the various components and parts is in accordance with ASME Section XI, Subarticle IWA-1500.

a. Sufficient space has been provided for personnel and equipment to perform examinations of the RCPB, as follows:

    1. Piping welds - The access provided depends on whether ultrasonic, surface, or visual examinations are performed.

    2. Pumps and valves - Space has been provided to disassemble and reassemble pump and valves. For visual examination, space for lighting and access sufficient to permit examination of the inner surface has been provided. For ultrasonic examination and depending on the specific design of the weld, access to equipment has been provided.

    3. Supports - Access provisions for supports requiring examination has been made and depends on the specific type and design detail of the supports.

    4. Reactor vessel - The reactor vessel insulation has been designed to allow access for examination, by a remotely operated scanning device, of the

vessel longitudinal and circumferential welds, nozzle-to-vessel inside radiused sections, and nozzle-to-safe-end welds.

The vessel-to-flange weld and flange ligaments are accessible during refueling. The closure head-to-flange weld and closure head circumferential and meridional welds are accessible from the outside.

The vessel-to-skirt weld is accessible during refueling.

Closure studs, nuts, and washers can be removed when the vessel head is removed. This provides adequate access.

Portions of the vessel cladding and interior are accessible by removal of components. Portions of the interior attachments and core support structures are accessible by removal of components.

Only the peripheral CRD housings are accessible for volumetric examination.

b. Capability for removal and storage of structural members, shielding components, and insulation is provided.

c. Hoists and other handling machinery necessary to support inservice inspection are provided.

d. Equipment, personnel, and procedures for alternative examinations that may be required will be provided.

e. Repair and replacement procedures are provided for system components and parts, when necessary.

5.2.4.3 Examination Techniques and Procedures

a. The techniques and procedures for surface, visual, and volumetric examinations are in compliance with ASME Section XI, Subarticle IWA-2200.

b. Alternate examination methods are acceptable provided the results are equal or superior to the methods of Subarticle IWA-2220. The acceptance criteria for alternate examination methods shall be in accordance with Subarticle IWB-3100.

5.2.4.4 Inspection Intervals

Inservice inspection is performed according to the schedule outlined in Subarticle IWB-2400; all required examinations being completed within a nominal 10 year period, hereafter referred to as the inspection interval. Inspections will be scheduled to coincide with normal plant or system outages.

5.2.4.5 Examination Categories and Requirements

The PSI/ISI program provides a listing of the Class 1 components or parts, the corresponding ASME Section XI item number, examination category, the required method of examination, and the extent and frequency of examination. The applicable PSI/ISI programs are identified in References 5.2-8 through 5.2-18.

5.2.4.6 Evaluation of Examination Results

a. The standards for evaluation of examination results are in accordance with Article IWB-3000.

b. The repair procedures are in agreement with Article IWA-4000.

c. Flaw indications are characterized in accordance with the requirements of IWB-3420 and compared with the acceptance standards specified in IWB-3410.

d. The replacement procedures are in agreement with Article IWA-4000.

e. Summary reports for the RPV and piping PSI will be submitted in accordance with subarticles IWA-6000.

5.2.4.7 System Leakage and Hydrostatic Pressure Tests

The Class 1 leakage and hydrostatic pressure test program meets the requirements of ASME Section XI, Article IWB-5000, "System Leakage and Hydrostatic Pressure Tests." The Technical Specification requirements for operating limitations for heatup, cooldown, and system hydrostatic pressure testing will be met during such testing.

5.2.4.8 Augmented Inservice Inspection

Class 1 components will receive augmented inservice inspections in accordance with the documents listed below to the extent specified in the applicable PSI/ISI programs identified in References 5.2-8 through 5.2-18.

a. Regulatory Guide 1.150 (Rev 1), February 1983, with Appendix A, Alternate Method. "Ultrasonic Testing of Reactor Vessel Welds During Preservice and Inservice Examinations" and NRC Generic Letter 83-15 dated March 23, 1983.

b. NUREG-0619, November 1980, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking. Resolution of Generic Technical Activity A-10"

   The LGS feedwater nozzle has been modified. The new configuration is the triple-sleeve with two sister ring seals and an unclad nozzle. This ensures the longest ISI intervals in accordance with NUREG-0619.

c. IE Bulletin 80-07, April 4, 1980, "BWR Jet Pump Assembly Failure" (NUREG/CR-3052)

d. IE Bulletin 80-13, May 12, 1980, "Cracking in Core Spray Spargers"

e. NUREG-0313 (Rev 1), July 1980, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping. Resolution of Generic Technical Activity A-42," applicable prior to issuance of Generic Letter 88-01.

   Following issuance of Generic Letter 88-01, the criteria of NUREG-0313 (Rev 2), January 1988 become applicable for both LGS Units 1 and 2, with full implementation

effective for both units by the second refueling outage at Unit 1. The ISI program for weldments in piping shall conform with the NRC staff positions identified in Generic Letter 88-01 and BWRVIP-75-A, "BWR Vessel and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedule," as documented in the licensee's responses to Generic Letter 88-01 (References 5.2-19,20,21,23 and 25), approved by the NRC (References 5.2-24 and 5.2-26), and required by amended Technical Specifications for Units 1 and 2 (Reference 5.2-28 and 5.2-33). Details for schedule, methods, personnel, and sample expansion shall be included as augmented inspection requirements. Correspondence relating to Generic Letter 88-01 is specified in References 5.2-19 through 5.2-28.

f. BTP MEB 3-1 (NUREG-0800) for high energy piping between containment isolation valves and first outboard restraint for which no breaks are postulated.

In addition, high energy fluid system piping between containment isolation valves will receive an augmented examination as follows:

a. Protective measures and structures are located, to the greatest extent possible, so as not to prevent access for inservice inspections.

b. High energy fluid system piping between containment isolation valves is required to be either 100% volumetrically examined (circumferential welds) during each examination interval or examined in accordance with the Risk Informed Inservice Inspection Program as applied to these welds.

c. High energy piping requiring ISI receives a baseline (preservice) examination to establish the integrity of the original condition of the welds.

d. Augmented examination for high energy piping is maintained out to outboard restraints.

e. Welds between outboard containment isolation valves and piping restraints will be included in the PSI and the ISI plans.

5.2.5 Reactor Coolant Pressure Boundary Leak Detection System

5.2.5.1 Design Bases

The leak detection system is designed to:

a. Detect the occurrence of and alert operating personnel to abnormal leakage from the RCPB.

b. Detect leakage from selected portions of systems located outside the primary containment, and not a part of the RCPB.

c. Remain functional following a SSE, except as discussed in Sections 5.2.5.2.1.4 and 5.2.5.2.1.5.

5.2.5.2 Description

The RCPB leak detection system consists of temperature, pressure, flow, and radiation sensors, and associated instrumentation and alarms. The system detects, annunciates, and, in certain cases, isolates abnormal leakage in the following systems:

a. Main steam lines

b. RWCU system

c. RHR system

d. RCIC system

e. Feedwater system

f. HPCI system

g. Reactor recirculation system

h. Core spray system

A summary of isolation and/or alarms of affected systems and the methods used appears in Table 5.2-7. The table shows those leak detection methods which detect gross leakage and initiate immediate automatic isolation. Those methods which are capable of detecting small leaks initiate an alarm in the control room, at which time the operator can either manually isolate the leaking system or take other appropriate action.

5.2.5.2.1 Detection of Abnormal Leakage Within the Primary Containment

Leaks within the primary containment are detected by continuously monitoring for:

a. Abnormally high pressure and temperature within the primary containment

b. Rapid level increase in drywell equipment and floor drain sumps

c. A decrease in the reactor vessel water level

d. High gaseous radiation level in the primary containment atmosphere

e. High containment air cooler condensate flow.

In addition to these leak detection methods, selected RCPB components within the primary containment are provided with their own leak detection devices. While some of the methods provided for detecting leakage within the primary containment are not redundant in themselves, it is not postulated that any one event could render all means of leak detection inoperable. Each of the leak detection methods are discussed below. The systems and equipment provided at LGS meet or exceed the requirements and recommendations of ANSI/ISA S67.03 (1982).

5.2.5.2.1.1 Drywell Temperature Monitoring

Drywell temperature monitoring provides an indirect method of detecting RCPB leakage.

The drywell area unit coolers circulate and cool the drywell atmosphere to maintain the drywell at its design operating temperature. Cooling water is supplied to the unit coolers by the DCWS (Section 9.2.10). A temperature rise in the drywell will indicate the presence of reactor coolant or steam leakage and is detected by the drywell temperature monitors located at various elevations and at the inlet and outlet of the air coolers. A discussion of indications and alarms for drywell temperature in accordance with Regulatory Guide 1.45 is given in Section 7.5.

5.2.5.2.1.2 Drywell Pressure Monitoring

Drywell pressure monitoring provides an indirect method of detecting RCPB leakage.

The drywell normally ranges from slightly below to slightly above atmospheric pressure during reactor operation. The pressure typically fluctuates slightly as a result of barometric pressure changes and/or outleakage. A pressure rise above the normally indicated value indicates leakage within the drywell. Drywell pressure monitoring is shown in drawings M-42 and M-57. A discussion of indications, alarms, and protective functions for drywell pressure in accordance with Regulatory Guide 1.45 is given in Sections 7.2, 7.3, 7.4, and 7.5.

5.2.5.2.1.3 Drywell Sump Level Monitoring

All leakage from RCPB components inside the drywell, with the exception of leakage from the MSRVs (Section 5.2.5.2.1.8), flows directly to either the drywell equipment drain sump or the drywell floor drain sump. There are no other reservoirs in the drywell of sufficient capacity to prevent leakage from draining directly to either of these sumps. Both drain sumps are identically sized, horizontal cylindrical tanks located inside the reactor vessel pedestal below the diaphragm slab and vented to the drywell atmosphere. The liquid radwaste collection system piping and instrumentation diagram is given in drawing M-61. These drain sumps are discussed below:

a. Drywell equipment drain sump - Certain RCPB components within the drywell are, by the nature of their design, normally subject to a limited amount of leakage. These components include pump seals, valve stem packings, and other equipment that cannot practicably be made to be completely leak-tight. These leakages are piped directly to the drywell equipment drain sump. All of the various drains are open only to the equipment they serve, thereby receiving leakage only from identified sources. Background leakage to this sump is determined during initial plant operation. Rates of leakage collection in excess of background indicates abnormal RCPB leakage.

b. Drywell floor drain sump - Leakage from RCPB components inside the primary containment which are not normally subject to leakage is collected by the drywell floor drain sump. This leakage, which may originate from any number of sources within the drywell, is transported to the sump via the floor drain network within the drywell. Thus, separation of unidentified leakage from the identifiable leakage routed to the equipment drain sump ensures that a small unidentified leakage that is of concern will not be masked by a larger, acceptable, identified leakage.

c. Each sump tank has its own level transmitter which is monitored by a dedicated processing unit. Normally closed drain valves are provided, enabling the level in each tank to increase as leakage drains into them. The processing unit calculates an average leak rate for a given measurement period by establishing the amount of increase in level that occurred during the period, and converting that value into

volumetric terms (gpm). The processing units provide an alarm in the main control room each time the average leak rate changes by a predetermined valve since the last time that alarm was reset. The setpoint is a 1 gpm change in unidentified leakage collected in the drywell floor drain sump tank, and a 2 gpm change in identified leakage collected in the drywell equipment drain tank.

Alarms are also generated in the main control room for high total average leak rate. The high total average leak rate alarm setpoints can be adjusted at the processing unit, which is located in the main control room, as the amount of acceptable identified leakage changes during operation. Indication of the leakage rates is provided in the main control room on panel-mounted indicators. Sump tank levels (in gallons) are provided on CRT displays from the ERFDS system.

An alternative method to quantify RCPB leakage in the drywell is used when the Drywell floor drain sump monitoring system in unavailable. The alternate method allows the Drywell floor drain sump to overflow, through installed piping, to the Drywell equipment drain monitoring system to verify that RCPB leakage is within allowable limits. In this condition, all input into the Drywell equipment drain sump will be considered unidentified drywell leakage.

Level switches, which are independent of the level transmitters, open the sump tank drain valves when the level increases to an upper setpoint value and keep them open until the level decreases to lower setpoint value. The level switches then close the drain valves and reset the processing units to start a new measurement period. The measurement period must be long enough to ensure that the level transmitter loop can adequately detect the increase in level that would correspond to the 1 gpm and 2 gpm changes in leak rates described above, and yet short enough to ensure that such a leak rate will be detected within an hour. The measurement period will be less than 1 hour.

The transmitters which are located in the reactor enclosure and the processing units which are located in the main control room, are accessible during normal plant operation for calibration. The transmitters can be isolated from the sump tanks by existing bypass manifolds. Zero and span adjustments can be made using portable test equipment. The processing unit functions can be calibrated by applying known input levels at the unit and observing the response.

The DSLMS is comprised of the processing units, level transmitters, control room leakage flow indicators and interconnecting raceway and cables. The DSLMS has been demonstrated to remain operational after an SSE. The DSLMS is energized by Class 1E power. The Class 1E power to the panel is provided with a Class 1E fuse and circuit breaker in series to meet separation requirements. The DSLMS is automatically shed from the Class 1E power in the event of a LOCA (the load shedding relay, however, is not qualified for Class 1E service). Drawing M-61 shows the piping and instrument diagram for this system.

In addition to the sump level monitoring system described above, the discharge from each sump is monitored by a flow element. The measured flow rate is integrated and recorded in the control room. A control room alarm is also provided to indicate excessive discharge rates. These indications and alarms are provided in accordance with Regulatory Guide 1.45.

5.2.5.2.1.4 Drywell Air Cooler Condensate Drain Flow Monitoring

The drywell air cooler condensate drain flow monitoring system consists of six flow sensors and their associated flow transmitters that provide inputs to a separate flow monitoring device. The flow sensors are mounted in the drywell air cooler drain lines located in the drywell. There are a total of eight coolers. Two flow sensors measure the flow from two air cooler drain line headers. Four additional flow sensors measure the drain flow from each of the remaining coolers which are piped separately to the drywell floor drain sump tank. The outputs from the six flow transmitters which receive their input from the flow sensors are added to provide a total continuous drain flow rate by the use of two summing units. The continuous drain flow rate is monitored by a flow switch, located in the main control room, which will alarm if the rate exceeds 1 gpm over the preset identified leak rate. The plant operator establishes the acceptable identified drain flow rate and adjusts the setpoint of this flow switch accordingly (i.e., if the identified flow rate is established at 5 gpm, the system will be set to alarm at 6 gpm). The requirement to detect a 1 gpm increase in unidentified leakage within an hour is met by monitoring the continuous flow rate. Indication of the total continuous drain flow rate is provided in the main control room on panel-mounted indicators and CRT displays from the ERFDS system.

The calibration and test interval for the flow sensors, transmitters, and processing units is in accordance with the manufacturer's recommendation.

The drywell air cooler condensate drain flow monitoring system is qualified to withstand an OBE. The system is energized by Class 1E power. Drawing M-87 shows the piping and instrument diagram for this system.

5.2.5.2.1.5 Containment Airborne Radioactivity Monitoring

The primary containment is continuously monitored for airborne gaseous radioactivity. A drywell air sample is extracted via sample line through containment penetration X-117B at el 292', area 16. Air flow through the monitoring system is assured by the suction created by a vacuum pump. The air sample is surveyed by the GM tubes in the sampling chamber for its radioactivity content. The air sample is returned to the drywell through the same containment penetration. The level of radioactivity is recorded in the main control room in counts per minute. The range is from 10 cpm to 10^6 cpm. The corresponding concentration is 10^{-6} μCi/cc to 10^{-1} μCi/cc. Particulate and iodine monitors are not provided due to the substantial limitations of their usefulness as described below.

The noble gas monitoring equipment is shown in drawing M-26. It is not designed to be operable following an SSE.

Radioactivity level indication and alarms for loss of sample flow, high radiation, and down-scale are provided locally and in the main control room. Activity level indication in the control room is provided on a strip-chart recorder to provide trend information.

The operability of the sensor and the electronic circuitry can be verified during operations from the auxiliary equipment room. A check source is supplied with the monitor. Sample connections are also provided to facilitate additional sampling for laboratory analysis.

The radiation monitor is capable of being calibrated during power operation and will be calibrated in accordance with Technical Specifications requirements (Chapter 16).

The reliability, sensitivity, and response times of radiation monitors to detect 1 gpm in 1 hour of RCPB leakage will depend on many complex factors. The major limiting factors are discussed below.

5.2.5.2.1.5.1 Source of Leakage

a. Location of Leakage - The amount of activity that would become airborne following a 1 gpm leak from the RCPB will vary depending on the leak location and the coolant temperature and pressure. For example, a feedwater pipe leak may have concentration factors of 100 to 1000 lower than a recirculation line leak. A steam line leak may be a factor of 50 to 100 lower in iodine and particulate concentrations than the recirculation line leak, but the noble gas concentrations may be comparable. An RWCU leak upstream of the demineralizers and heat exchangers may be a factor of 10 to 100 higher than downstream, except for noble gases. Differing coolant temperatures and pressures will affect the flashing fraction and partition factor for iodines and particulates. Thus, an airborne concentration cannot be directly correlated to a quantity of leakage without knowing the source of the leakage.

b. Coolant Concentrations - Variations in coolant concentrations during operation can be as much as two orders of magnitude within a time frame of several hours. These effects are mainly due to spiking during power transients or changes in the use of the RWCU system. Examples of these transients for I-131 are given in Reference 5.2-6. An increase in the coolant concentrations could give increased containment concentrations when no increase in unidentified leakage occurs.

c. Other Sources of Leakage - Because the unidentified leakage is not the sole source of activity in the containment, changes in other sources will result in changes in the containment airborne concentrations. For example, identified leakage is piped to the equipment drain tank in the drywell, but the tank is vented to the drywell atmosphere allowing the release of noble gases and some small quantities of iodines and particulates from the drain tank.

5.2.5.2.1.5.2 Drywell Conditions Affecting Monitor Performance

a. Equilibrium Activity Levels - During normal operation, the activity release from acceptable quantities of identified and unidentified leakage will build up to significant amounts in the drywell air. Due to these high equilibrium activity levels, the activity increase due to a small increase in leakage may be difficult to detect within a short period of time.

b. Purge and Pressure Release Effects - Changes in the detected activity levels have occurred during containment venting operations. These changes are of the same order of magnitude as approximately a 1 gpm leak and are sufficient to invalidate the results from iodine and particulate monitors.

c. Plateout, Mixing, Condensation, Fan Coolant Depletion - Plateout effects on measured iodine and particulate levels will vary with the distance from the coolant release point to the detector. Larger travel distances would result in more plateout. In addition, the pathway of the leakage will influence the plateout effects. For example, a leak from a pipe with insulation will have greater plateout than a leak from an uninsulated pipe. Although the drywell air will be mixed by the fan coolers, it may be possible for a leak to develop in the vicinity of the radiation detector sample lines. In addition, condensation in the coolers and sample lines will remove iodines and particulates from the air. Variations in flow, temperature, and number of coolers will

affect the plateout fractions. Plateout within the detector sample chamber will also add to the reduction of the iodine and particulate activity levels. The uncertainties in any estimate of plateout effects could be as much as one or two orders of magnitude.

5.2.5.2.1.5.3 Physical Properties and Capabilities of the Detector

a. Detector Range - The detector was chosen to ensure that the operating range covered the concentrations expected in the drywell. The operating range of the noble gas monitor is: 10^{-6} μCi/cc to 10^{-1} μCi/cc.

b. Sensitivity - In the absence of background radiation and equilibrium drywell activity levels, the detector has the following minimum sensitivity: 10^{-6} μCi/cc for Xe-133.

c. Counting Statistics and Monitor Uncertainties - In theory, this radioactivity monitor is statistically able to detect increases in concentration as small as 2 or 3 times the square root of the count rate, i.e., at $1x10^6$ cpm an increase of $2x10^3$ or 0.2% is detectable; at 100 cpm an increase of 20, or 20% is detectable. In addition, at high count rates the monitors have dead-time uncertainties and the potential for saturating the monitor or the electronics. Uncertainties in calibration (±5%), sample flow (±10%), and other instrument design parameters tend to make the uncertainty in a count rate closer to 20% to 40% of the equilibrium drywell activity.

d. Monitor Setpoints - Due to the uncertainty and extreme variability of the radioactivity concentrations to be measured in the containment, the use of tight alarm setpoints on the radioactivity monitor would not be practical or useful. The setpoint, which would be required to alarm at 1 gpm, would be well within the bounds of uncertainty of the measurements. The use of such setpoints would result in many unnecessary alarms and the frequent resetting of setpoints. The alarm setpoints for the radiation monitors are set significantly above normal readings to prevent nuisance alarms.

e. Operator Action - There is no direct correlation or known relationship between the detector count rate and the leakage rate because the coolant activity levels, source of leakage, and background radiation levels (from leakage alone) are not known and cannot be cost-effectively determined in existing reactors. There are also several other sources of containment airborne activity (e.g., SRV leakage) that further complicate the correlation.

Thus, the procedure for the control room operator is to set an alarm setpoint at 1 gpm in 1 hour on the sump level monitor (measuring water collected in the sump that may not exactly correspond to water leaking from an unidentified source). When the alarm is actuated, the operator will review all other monitors (e.g., noble gas, containment temperature and pressure, air cooler condensate flow, etc.) to determine if the leakage is from the primary coolant pressure boundary and not from an SRV or cooling water system, etc. Appropriate actions will then be taken in accordance with Technical Specifications. The review of other monitors will consist of comparisons of the increases and rates of increase in the values previously recorded. Increases in all parameters except sump level will not be correlated to a RCPB leakage rate. Instead, the increases will be compared to normal operating limits and limitations, and abnormal increases will be investigated.

Because the Technical Specification limit for leakage is allowed to be averaged over 24 hours, quick and accurate responses are not necessary unless the leakage is large and indicative of a pipe break. In this case, the containment pressure and reactor vessel water level monitors will alarm within seconds, and the sump level monitor would alarm within minutes or tens of minutes.

Radiation monitor alarms are not set to levels that are intended to correspond to the RCPB leakage levels because such correlations are not valid. Because the containment airborne activity levels vary by orders of magnitude during operation due to power transients, spiking, steam leaks, and outgassing from sumps, an appropriate alarm setpoint is determined by the operator based on experience with the specific plant. A setpoint level of 10 times the level during full power steady-state operation may be useful for alarming large leaks and pipe breaks, but it would not always alarm for 1 gpm in one hour and therefore could not be considered as any more than a qualitative indication of the presence of abnormal leakage.

Due to the sum total of the uncertainties identified in the previous paragraphs, iodine and particulate monitors are not relied upon for immediate leak detection purposes. The noble gas monitor is used to give supporting information to that supplied by the sump discharge monitoring, and it would be able to give an early warning of a major leak, especially if equilibrium containment activity levels are low. However, the uncertainties and variations in noble gas leaks and concentrations would preclude the setting of a meaningful alarm setpoint. Grab sampling and laboratory analyses of airborne particulate, noble gas, and iodine may be used to characterize leakage detected by other means.

5.2.5.2.1.6 Reactor Vessel Head Seal Leak Detection

The reactor vessel head is provided with two concentric metallic seals, with a leak-off connection between the seals to permit detection of leakage through the inner seal. The connection is piped to a local pressure indicator and pressure switch. High pressure in this leak-off connection is annunciated in the control room, alerting the operator to failure of the inner seal. This system is shown in drawing M-41.

5.2.5.2.1.7 Reactor Recirculation Pump Seal Leak Detection

Each of the reactor recirculation pumps is provided with a system for monitoring leakage through each of its two mechanical seals. Two types of monitoring are provided for each pump.

Instrumentation is provided to monitor the pressure within each of the pump seal cavities. Changes in seal cavity pressure from that normally expected alerts the operator to possible reactor recirculation pump seal damage or excessive wear.

Instrumentation is also provided to monitor the flow rate in the drain line from each seal. A limited amount of leakage is expected past each of the mechanical seals. Flow instrumentation in each seal drain line actuates an annunciator in the control room wherever the leakage flow in the line becomes excessive. The instrumentation is shown in drawing M-43.

5.2.5.2.1.8 MSRV Leak Detection

Temperature sensors connected to a multipoint recorder are provided to detect MSRV leakage during reactor operation. Using a thermo-well, temperature elements are mounted, in the MSRV discharge piping downstream of the valve body. Normally, all MSRVs are in the shut-tight condition and remain at approximately the same temperature. Steam leakage past an MSRV elevates the sensed temperature in its discharge line. High discharge line temperature is annunciated in the control room, alerting the operator to MSRV leakage. The temperature sensors are shown in drawing M-41.

5.2.5.2.1.9 RPV Water Level

Under conditions of normal reactor operation at constant power, reactor water level should remain fairly constant at its programmed level since the rate of steam mass flow leaving the boiler is matched by the feedwater mass flow rate into the reactor vessel. However, given a condition of continued steam leakage from the closed system, the CST level and the reactor water level decreases.

Reactor water level is monitored by the level indicating switches associated with the containment isolation system in addition to the normal complement of process monitoring instruments. Reactor water level falling below the predetermined minimum allowable level results in switch actuation and subsequent containment isolation. Section 7.3 gives a complete description of this isolation function. The level instrumentation is shown in drawing M-42.

5.2.5.2.2 Detection of Abnormal Leakage Outside the Primary Containment

The various methods utilized for detecting leakage from components outside the primary containment are discussed below.

5.2.5.2.2.1 Main Steam Line Leak Detection Outside Primary Containment

The main steam lines are continuously monitored for leaks by the main steam line leak detection system. Steam line leaks will cause changes in at least one of the following monitored operating parameters: air temperature adjacent to the main steam lines, main steam line flow rate, or water level in the reactor vessel. If a leak is detected, the detection system actuates an annunciator in the control room and, depending upon the activating parameter, initiates steam line isolation action. The following methods are used for monitoring the above operating parameters:

a. Air temperature of the space adjacent to the main steam lines (both inside the steam tunnel and from the steam tunnel exit to the inlet of the main turbine) is monitored by a set of temperature sensors located along the length of each main steam line (drawing M-25). The temperature sensors are located or shielded so as to be sensitive to air temperature only and not to the radiated heat from hot equipment. These temperature sensors are connected to nonindicating temperature switches which initiate an alarm in the control room on abnormally high temperature. In order to prevent excessive loss of reactor coolant and the release of significant amounts of radioactive material from the RCPB, these temperature switches initiate isolation of the following lines on abnormally high temperature in the area adjacent to the main steam lines:

    1. All 4 main steam lines

    2. Main steam line drain

In addition to the above temperature sensors and switches used for detecting gross leakage, temperature sensors are also provided to detect possible small leaks in the main steam lines by monitoring (1) the ambient temperature within the main steam line tunnel, and (2) the temperature difference between the supply and return ventilation air for the main steam line tunnel. These sensors are also located or shielded so as to be sensitive to air temperature only and not to radiated heat from hot equipment. A rise in either the ambient temperature or the ventilation air differential temperature above the values normally indicated is alarmed in the control room, alerting the operator to possible main steam line leakage.

The heat balance for the area under consideration for the temperature sensor location is established for normal load, and that area is evaluated for various leak rates. The alarm and isolation setpoints are computed and checked by this method. The alarms and isolation setpoints associated with the above temperature devices are selected to be high enough to avoid spurious alarms and isolations, yet low enough to provide timely detection and isolation of a main steam line break.

b. Main steam flow rate within each of the main steam lines is monitored by the main steam flow restrictors and their associated differential pressure transducers and indicating switches. The outputs of the differential pressure indicating switches initiate an alarm in the control room and isolation of the following lines whenever the flow in a single steam line exceeds 140% of the line rated flow:

   1. All 4 main steam lines

   2. Main steam line drain

   The main steam line high flow alarm and isolation setpoint is set to be high enough to permit the isolation of one main steam line for test at rated power without causing an automatic isolation of the rest of the steam lines, yet low enough to provide timely detection and isolation of a gross main steam line break.

c. Reactor water level monitoring is described in Section 5.2.5.2.1.8.

5.2.5.2.2.2 RWCU System Leak Detection

Leakage in the high temperature process flow of the RWCU system external to the primary containment is detected by temperature sensors located within the RWCU equipment compartments and in the supply and return ventilation air ducts for the compartments (drawing M-25). The temperature sensors are located or shielded so as to be sensitive to air temperature only and not to the radiated heat from hot equipment. These temperature sensors are connected to nonindicating temperature switches which initiate an alarm in the control room whenever the ambient temperature or the ventilation air differential temperature of an RWCU system equipment compartment exceeds the value normally indicated. In order to prevent excessive loss of reactor coolant and the release of significant amounts of radioactive material from the RCPB, these temperature switches also initiate isolation of the RWCU system. The alarm and isolation setpoints associated with the above temperature devices are selected to be high enough to avoid spurious isolation, yet low enough to provide timely detection and isolation of a break in the RWCU system.

In addition to the temperature detection method above, leakage from the RWCU system is also detected by means of a RWCU system inlet and outlet flow comparison. If the inlet flow exceeds the

outlet flow by at least 54.9 gpm for a minimum of 45 seconds, an alarm is actuated in the control room and the RWCU system is automatically isolated.

5.2.5.2.2.3 RHR System Leak Detection

RHR system leakage external to the primary containment is detected by temperature sensors in the RHR compartments (drawing M-25).

The temperature sensors are located or shielded so as to be sensitive to air temperature only and not to the radiated heat from hot equipment. These temperature sensors are connected to nonindicating temperature switches which initiate an alarm in the control room whenever the ambient temperature or the ventilation air differential temperature of a RHR system compartment exceeds the value normally expected.

5.2.5.2.2.4 RCIC and HPCI Systems Leak Detection

Leak detection components are provided for monitoring, annunciation, and, in certain cases, isolation of steam supply line leakage in the RCIC and HPCI equipment compartments and pipe-ways. Steam line leaks cause changes in air temperature adjacent to the steam lines or steam line flow rate (drawing M-25). If a leak is detected, the detection system actuates an annunciator in the control room and, depending upon the activating parameter, initiates steam line isolation action. The following methods are used for monitoring the above operating parameters:

a. As are provided for the RWCU and RHR equipment compartments, temperature sensors are located in each of the RCIC and HPCI equipment compartments and in the supply and return ventilation air ducts for the compartments. The temperature sensors are located or shielded so as to be sensitive to air temperature only and not to the radiated heat from hot equipment. These temperature sensors are connected to nonindicating temperature switches which initiate alarms in the control room whenever the ambient temperatures or the ventilation air differential temperatures of the compartments exceed the values normally indicated. In order to prevent excessive loss of reactor coolant and the release of significant amounts of radioactive material from the RCPB, the temperature switches associated with ventilation air differential temperatures of the RCIC and HPCI compartments initiate isolation of the corresponding RCIC or HPCI steam lines.

   Temperature sensors are also located along the length of the RCIC and HPCI steam lines between the primary containment and the respective equipment compartments and in the equipment compartments for monitoring air temperature adjacent to the steam lines. The temperature sensors are located or shielded so as to be sensitive to air temperature only and not to the radiated heat from hot equipment. These temperature sensors are connected to nonindicating temperature switches which initiate an alarm in the control room on abnormally high temperature. In order to prevent excessive loss of reactor coolant and the release of significant amounts of radioactive material from the RCPB, the switches also initiate isolation of the corresponding RCIC or HPCI steam lines.

   The alarms and isolation setpoints associated with the above temperature devices in the RCIC and HPCI equipment compartments and pipe-ways are selected to be high enough to avoid spurious isolation, yet low enough to provide timely detection and isolation of a RCIC or HPCI steam line break.

b. Steam flow rates in the RCIC and HPCI steam supply lines are monitored by venturi-type flow elements and their associated differential pressure transducers and indicating switches. The outputs of the differential pressure indicating switches initiate an alarm in the control room and isolation of the corresponding steam supply line whenever the flow in a single steam line exceeds 300% of the line rated flow.

The RCIC and HPCI steam supply line high flow alarm and isolation setpoints are selected to provide timely detection and isolation of an RCIC or HPCI steam supply line break. Spurious isolations due to short-term flow peaks are precluded by a predetermined time delay feature.

5.2.5.2.2.5 Other Leakage Detection Methods

Instrumentation associated with the plant drainage system (Section 9.3.3) can provide indication of leakage of systems outside containment.

The RHR, CS, HPCI, and RCIC compartments are equipped with level switches to sense and alarm in the main control room if excessive leakage or flooding occurs in the compartment.

Excessive leakage outside the containment can also be detected by observation of abnormal reactor enclosure sump pump operating times and by sump high level alarms. This instrumentation is provided in the radwaste control room.

5.2.5.2.2.6 Intersystem Leak Detection

Radiation monitors are used to detect reactor coolant leakage into the RHRSW system, ESW system, and the RECW system from the RHR heat exchangers, ESW cooled compartment and the RWCU nonregenerative heat exchangers, respectively. These radiation monitoring channels are part of the PRMS (drawing M-26), and monitor for leakage into the cooling water flows downstream of the RHR heat exchangers and the RWCU system nonregenerative heat exchangers and the ESW return flow.

High radiation levels in the monitored cooling water systems is annunciated in the control room. Associated trips and interlocks for the RHRSW system pumps and the design basis and the associated instrumentation for PRMS are discussed in Section 11.5.

5.2.5.3 Indication in Control Room

Details of the leakage detection system indications are included in Section 7.6.

5.2.5.4 Limits for Reactor Coolant Leakage Inside the Containment

The total leakage inside containment consists of all leakage, both identified and unidentified, which flows to the drywell floor and equipment drain sumps. The total leakage rate limit is well within the makeup capability of the RCIC system. This limit is 30 gpm of which a limit of 5 gpm is set for unidentified leakage, and 25 gpm is allowed for identified sources.

The unidentified leakage rate limit must be low because of the possibility that most of the unidentified leakage might emanate from a single crack in the nuclear system process barrier that could be large enough to propagate rapidly.

The unidentified leakage rate limit is established at 5 gpm to allow time for corrective action before the process barrier could be significantly compromised. This 5 gpm unidentified leakage rate is adequate since it is a small fraction of the calculated flow from a critical crack in a primary system pipe as discussed in Section 5.2.5.6. Safety limits and safety limit settings are discussed in Chapter 16.

5.2.5.5 Sensitivity and Response Time

Sensitivity, including sensitivity tests, and response times of the leak detection system components are discussed in Section 7.6. As indicated therein, the sensitivity and response time of the sump leak detection system is adequate to detect an increase in unidentified leakage inside the containment of 1 gpm in less than 1 hour. The airborne radiation monitors are capable of detecting a 1 gpm coolant leak in 1 hour in a containment atmosphere free from airborne radioactivity (zero background). However, during normal plant operation (i.e. operation within technical specification limits), the normal levels of containment airborne activity coupled with normal changes in coolant activity concentrations may mask an increase in coolant leakage to the extent that its detection, by this method alone, is not possible within 1 hour.

5.2.5.6 Crack Length and Through-Wall Flow

Experiments conducted by GE and BMI permit an analysis of critical crack length and crack opening displacement (Reference 5.2-4). This analysis relates to axially oriented through-wall cracks.

a. Critical Crack Length

Both the GE and BMI test results indicate that theoretical fracture mechanics formulas do not predict critical crack length, but that satisfactory empirical expressions may be developed to fit test results. A simple equation which fits the data in the range of normal design stresses (for carbon steel pipe) is:

$$L_c = \frac{15000\ D}{h} \qquad \text{(EQ. 5.2-1)}$$

where:

L_c = critical crack length (in)

D = mean pipe diameter (in)

h = nominal hoop stress (psi)

Data correlation for Equation (EQ. 5.2-1) is shown in Figure 5.2-13.

b. Crack Opening Displacement

The theory of elasticity predicts a crack opening displacement of:

$$W = \frac{2\ L\sigma}{E} \qquad \text{(EQ. 5.2-2)}$$

where:

W = crack opening displacement (in)

L = crack length (in)

σ = applied nominal stress (psi)

E = Young's Modulus

Measurements of crack opening displacement made by BMI show that local yielding greatly increases the crack opening displacement as the applied nominal stress (σ) approaches the failure stress (σ_f). A suitable correction factor for plasticity effects is:

$$C = \sec\left(\frac{\pi\sigma}{2\sigma_f}\right) \qquad \text{(EQ. 5.2-3)}$$

The crack opening area is given by,

$$A = \frac{C\pi WL}{4} = \frac{\pi L^2\sigma}{2E}\sec\left(\frac{\pi\sigma}{2\sigma_f}\right) \qquad \text{(EQ. 5.2-4)}$$

For a given crack length L:

σ_f = 15000 D/L

c. Leakage Flow Rate

The maximum flow rate for blowdown of saturated water at 1000 psi is 55 lb/sec-in^2, and for saturated steam the rate is 14.6 lb/sec-in^2, (Reference 5.2-5). Friction in the flow passage reduces this rate, but for cracks leaking at 5 gpm (0.7 lb/sec) the effect of friction is small. The required leak size for 5 gpm flow is:

A = 0.0126 in^2 (saturated water)
A = 0.0475 in^2 (saturated steam)

From this mathematical model, the critical crack length and the 5 gpm crack length have been calculated for representative BWR pipe size (Schedule 80) and pressure (1050 psi). Results are tabulated as follows:

Nominal Pipe Size (Sch 80) (in)	Avg. Wall Thickness (in)	5 gpm Crack Length (in)		Critical Crack Length (in)	
		Steam Line	Wtr Line	Steam Line	Wtr Line
4	0.337	7.2	4.9	9.7	9.6
12	0.687	8.5	4.8	19.7	19.8
24	1.218	8.6	4.6	34.8	34.8

The ratios of crack length (L) to the critical length (L_c) as a function of nominal pipe size are:

Nominal Pipe Size (Sch 80) (in)	Ratio/L/L	
	Steam Line	Water Line

4	0.745	0.510
12	0.432	0.243
24	0.247	0.132

It is important to recognize that the failure of ductile piping with a long, through-wall crack is characterized by large crack opening displacements which precede unstable rupture. Judging from observed crack behavior in the GE and BMI experimental programs involving both circumferential and axial cracks, it is estimated that leak rates of hundreds of gallons per minute will precede crack instability. Measured crack opening displacements for the BMI experiments were in the range of 0.1-0.2 inches at the time of incipient rupture, corresponding to leaks of the order of 1 in^2 in size for plain carbon steel piping. For austenitic stainless steel piping, ever larger leaks are expected to precede crack instability, although there is insufficient data to permit quantitative prediction.

The results given are for a longitudinally oriented flaw at normal operating hoop stress. A circumferentially oriented flaw could be subjected to stress as high as the 550°F yield stress, assuming high thermal expansion stresses exist. A good mathematical model which is supported by test data is not available for the circumferential crack. Therefore, it is assumed that the longitudinal crack, subject to a stress as high as 30,000 psi, constitutes a "worst case" with regard to leak rate versus critical size relationships. Given the same stress level, differences between the circumferential and longitudinal orientations are not expected to be significant in this comparison.

Figure 5.2-12 shows general relationships between crack length, leak rate, stress, and line size, using the mathematical model described above. The asterisks denote conditions at which the crack opening displacement is 0.1 inch, at which time instability is imminent. This provides a realistic estimate of the leak rate to be expected from a crack of critical size. In every case, the leak rate from a crack of critical size is greater than the 5 gpm unidentified leakage rate limit.

5.2.5.7 Margins of Safety

The margins of safety for a detectable flaw to reach critical size are presented in Section 5.2.5.6. Figure 5.2-12 shows general relationships between crack length, leak rate, stress, and line size using the mathematical model presented in Section 5.2.5.6.

5.2.5.8 Criteria to Evaluate the Adequacy and Margin of the Leak Detection System

For process lines that are normally open, there are at least two different methods of detecting abnormal leakage from the reactor system process barrier located in the primary containment and reactor enclosure (Table 5.2-7). The instrumentation can be set to provide alarms at established leakage rate limits and isolate an affected system when necessary. The alarm setpoints are determined

analytically or, where appropriate, based on measurements of appropriate parameters made during startup and preoperational tests.

The primary containment unidentified leakage rate limit of 5 gpm is based, with an adequate margin for contingencies, on the crack size large enough to propagate rapidly. The established limit is sufficiently low so that, even if the entire unidentified leakage rate were coming from a single crack in the nuclear system process barrier, corrective action could be taken before the integrity of the barrier would be threatened with significant compromise.

5.2.5.9 Differentiation Between Identified and Unidentified Leakage

Section 5.2.5.2 describes the systems that are monitored by the leak detection system. The ability of the leak detection system to differentiate between identified, and unidentified leakage is discussed in Section 5.2.5.2.

5.2.5.10 Sensitivity and Operability Tests

Testability of the leak detection system is discussed in Section 7.6.

5.2.5.11 Testing and Calibration

The leak detection system is preoperationally tested in accordance with the requirements of Chapter 14 and is periodically tested in accordance with the requirements of Chapter 16.

5.2.6 REFERENCES

5.2-1 R.Linford, "Analytical Methods of Plant Transient Evaluations for the General Electric Boiling Water Reactor," NEDO-10802, (February 1973).

5.2-2 J.M. Skarpelos and J.W. Bagg, "Chloride Control in BWR Coolants," NEDO-10899, (June 1973).

5.2-3 W.L. Williams, "Corrosion", Vol 13, p. 539t, (1957).

5.2-4 M.B. Reynolds, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flows", GEAP-5620, (April 1968).

5.2-5 "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants," NUREG 75-067, (October 1975).

5.2-6 "Behavior of Iodine in Reactor Water during Plant Shutdown and Startup," NEDO-10585, (August 1972).

5.2-7 "Qualification of the One-dimensional Core Transient Model for BWRs", NEDO-24154, (October 1978)

5.2-8 Document 8031-M246B-19, "Preservice Inspection Program Plan for the LGS Unit 1 Reactor Pressure Vessel"

5.2-9 Document 8031-M246AQA-59, "Preservice Inspection Program Plan for the LGS Unit 1 Nuclear Piping Systems"

5.2-10 Program Document ML-008 Limerick Generating Station Units 1 and 2, “IST Program Plan” and “IST Basis Document”

5.2-11 ER-LG-330-1001 through 1006, Limerick ISI Program Documents

5.2-12 Deleted

5.2-13 Document 8031-M246B-129, "LGS Units 1 and 2 Reactor Pressure Vessel Examination Plan for Inservice Inspection"

5.2-14 DELETE (Document 8031-P-502, "LGS Unit 1 and Common Plant First 10 year Interval Inservice Inspection Examination Plan")

5.2-15 Document 8031-P-504, "LGS Unit 2 Preservice Inspection Program"

5.2-16 Document 8031-M-246B-227, "LGS Unit 2 Reactor Pressure Vessel Preservice Inspection Examination Plan"

5.2-17 Document 8031-P-505, "LGS Unit 2 Preservice Inspection Examination Plan for Nuclear Piping Systems"

5.2-18 Document 8031-P-507, "LGS Unit 2 (Baseline) Testing Plan for Safety-Related Pumps and Valves"

5.2-19 Letter from PECo to the NRC, "Response to NRC Generic Letter 88-01, 'NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping,' for Limerick Generating Station," dated August 2, 1988.

5.2-20 Letter from PECo to the NRC, "Limerick Generating Station, Units 1 and 2, Revised Response to Generic Letter 88-01, 'NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping,'" dated April 28, 1989.

5.2-21 Letter from PECo to the NRC, "Limerick Generating Station, Units 1 and 2, Revised Response to Generic Letter 88-01, 'NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping,'" dated May, 1989.

5.2-22 Letter from the NRC to PECo, "Request for Additional Information on Response to Generic Letter 88-01 on IGSCC in Materials (TAC Nos. 69143 and 69144)," dated July 10, 1989.

5.2-23 Letter from PECo to the NRC, "Limerick Generating Station, Units 1 and 2, NRC Request for Additional Information on Generic Letter 88-01, 'NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping,'" dated September 11, 1989.

5.2-24 Letter from the NRC to PECo, "Generic Letter 88-01 (TAC Nos. 69143 and 69144)," dated March 6, 1990.

5.2-25 Letter from PECo to the NRC, "Limerick Generating Station, Units 1 and 2, Response to NRC Letter Dated March 6, 1990, Results of NRC Review of Submittals Responding to NRC Generic Letter 88-01, 'NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping,'" dated June 8, 1990.

5.2-26 Letter from the NRC to PECo, "Generic Letter 88-01 (TAC Nos. 69143 and 69144)," dated October 22, 1990.

5.2-27 Letter from PECo to the NRC, "Limerick Generating Station, Units 1 and 2, Technical Specifications Change Request," dated December 21, 1990.

5.2-28 Letter from the NRC to PECo, "Generic Letter 88-01, Limerick Generating Station, Units 1 and 2 (TAC Nos. 77293 and 79294)," dated March 5, 1991.

5.2-29 Power Rerate Safety Analysis Report for Limerick Generating Station Units 1 and 2, NEDC-22225P, GE, September 1993.

5.2-30 Deleted

5.2-31 Deleted

5.2-32 “Limerick Generating Station, Units 1 and 2, SRV Setpoint Tolerance Relaxation Licensing Report,” NEDC-32645P (December 1998).

5.2-33 Letter from NRC to Exelon, "Limerick Generating Station, Units 1 and 2 - Issuance of Amendment RE: Generic Letter 88-01 Requirements (TAC Nos. MB9884 and MB9885)," dated April 20, 2004, LAR No. 171 (Unit 1) and 133 (Unit 2).

5.2-34 “Migration to TRACG04 / PANAC11 from TRACG02 / PANAC10 for TRACG AOO and ATWS Overpressure Transients,” NEDE-32906P Supplement 3-A, Revision 1, April 2010

Table 5.2-1

APPLICABLE CODE CASES FOR REACTOR COOLANT
PRESSURE BOUNDARY COMPONENTS

1332-5	Requirements for Steel Forgings, Section III and VIII
1361-1	Socket Welds, Section III
1441-1	Waiving of 3 S_m Limit for Section III Construction
1464	Requirements for Stamping, Section III
1492	Postweld Heat Treatment Sections I, III, and VIII
1516-2	Welding of Seats in Valves for Section III Applications

Table 5.2-2

NUCLEAR SYSTEM SAFETY/RELIEF VALVE SETPOINTS

NO. OF VALVES[1]	SPRING SET PRESSURE (psig)	ASME RATED CAPACITY AT 103% REFERENCE PRESSURE OF 1090 psig (lb/hr each)
4	1170	870,000
5	1180	870,000
5	1190	870,000

(1) Five of the SRVs serve in the automatic depressurization function.

Table 5.2-3

REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
12" 900# TESTABLE CHECK VALVE (E21-F006/E11-F041)			
Body	Cast	Steel	SA352 LCB
Disc	Cast	Steel	SA352 LCB
Cover	Forged	Steel	SA350 LF1
Bearing cover	Forged	Steel	SA350 LF1
Stud	Bar	Alloy steel	SA540 B23 Class 5
Nut	Bar	Steel	SA540 B23 Class 5
MAIN STEAM FLOW ELEMENT B21-N051 thru N054			
Inst nozzle	Forging	Carbon steel	SA105
Pipe spool	Pipe	Carbon steel	SA105 Grade B
SLCS VALVE HV-048-F006A/F006B			
Body	Bar	304 SST	QQ-S-763 (Cond A)
Fitting	Bar	304 SST	QQ-S-763 (Cond A)
Trigger body	Bar	304 SST	QQ-S-763 (Cond A)
Ram	Bar	17-4PH Cond H900	
Q-ring	Liquid	ARP 568-116	

Table 5.2-3 (Cont'd)

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
RCIC PUMP			
E51-C001			
Barrel, outer	Forged	Carbon steel	ASTM, A105 Grade II
Nozzle, disch	Forged	Carbon steel	ASTM, A105 Grade II
Nozzle, suction	Forged	Carbon steel	ASTM, A105 Grade II
Elbow, suction	Forged	Carbon steel	ASTM, A105 Grade II
Connection branches, vents & drains	Forged	Carbon steel	ASTM, A105 Grade II
Flange, bypass	Forged	Carbon steel	ASTM, A105 Grade I
Cover, drive end	Forged	Carbon steel	ASTM, A105 Grade II
Cover, thrust end	Forged	Carbon steel	ASTM, A105 Grade II
Pipe, bypass	Cold drawn	Carbon steel	ASTM, A106 Grade B
Bolting	Rolled	Alloy steel	ASTM, A193-B7
Nuts	Rolled	Alloy steel	ASTM, A194-2H
Piping-seal	Cold drawn	Carbon steel	ASTM, A106 Grade B
Circulation union pipe 6000#	Forged	Carbon steel	ASTM, A181 Grade II
Tee, pipe 6000#	Forged	Carbon steel	ASTM, A181 Grade II
Coupling, pipe	Forged	Carbon steel	ASTM, A181 Grade II
Nipple, pipe	Cold drawn	Carbon steel	ASTM, A106 Grade B
Separator, cyclone	Cast	Carbon steel	ASTM, A216 Grade WCB
CONTROL ROD	Pipe	Austenitic stainless steel	SA312 Type 304L
DRIVE HOUSING	Welds	Stainless steel	SFA5.9 Type 308 or 316 SFA5.4 Type 308 or 316
	Forging	Stainless steel	SA182 Type 304
INCORE HOUSING	Tube	Austenitic stainless steel	SA213 Type 304
	Weld	Stainless steel	SFA5.9 Type 308 or SFA5.4
	Forging	Stainless steel	SA182 Type 304
REACTOR VESSEL	Rolled plate	Low alloy steel	SA533 Grade B
Heads, shells	Forgings		SA508 Class 2
	Welds	Low alloy steel	SFA5.5
Closure flange	Forged ring	Low alloy steel	SA508 Class 2
	Welds	Low alloy steel	SFA5.5
Large Nozzles	Forged shapes	Low alloy steel	SA508 Class 2
	Welds	Low alloy steel	SFA5.5
Nozzles (Water Level Instrumentation)	Forgings	Inconel Alloy 600/690	SB166 or SB167
Cladding	Weld overlay	Austenitic stainless steel	SFA5.9 or SFA5.4 Type 309 with carbon content on final surface limit to 0.08% maximum

Table 5.2-3 (Cont'd)

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
Control rod	Pipe	Austenitic stainless steel	SA312 Type 304
Drive housing	Forgings	Stainless steel	SA182 Type 304
	Welds	Stainless steel	SFA5.9 or SFA5.4 Type 308
Incore	Tube	Austenitic stainless steel	SA213 Type 304
Housings	Welds	Stainless steel	SFA5.9 or 5.4 Type 308
MAIN STEAM ISOLATION VALVE B21-F022/F028			
Valve body	Cast	Carbon steel	ASTM A216 WCB
Cover	Forged steel	Steel	ASTM A105 Grade II
Poppet	Forged	Steel	ASTM A105 Grade II
Valve stem	Bar	Stainless steel	ASME/ASTM SA/A564 Grade 630
Body bolts	Bar	Steel	ASTM A193 Grade B7
Hex nuts	Bar	Steel	ASTM A194 Grade 2H
MAIN STEAM SAFETY RELIEF VALVE (B21-F013)			
Main Valve Body	Forging	Carbon Steel	ASME SA105
Base	Forging	Inconel 600	ASME SB564
Disc	Forging	Stainless Steel	ASME SA182
Seat	Bar or Forging	Carbon Steel	ASME SA105 OR SA696, Grade C
Studs	Bar	Alloy Steel	ASME SA193, Grade B7 and Grade B16
Nuts	Bar	Alloy Steel	ASME SA194, Grade 7
Pilot body	Bar	Inconel 600	ASME SB166, Grade 600
RECIRCULATION PUMP B32-C001			
Pump case	Cast	Stainless steel	SA351 Grade CF8M
Pump cover	Cast	Stainless steel	SA351 Grade CF8M
Seal flange	Forging	Stainless steel	SA351 Grade CF8M
Studs cover/case	Bar	Alloy steel	SA540 Grade B23 Class 4
Cap screw seal flg	Bar	Alloy steel	SA540 Grade B23 Class 4
Drive mount bottom flg	Forging	Carbon steel	A216 WCB
Coil heat exch	Tube	Stainless steel	SA213 Type 304 SMLS.
Fitting heat exch	Forging	Stainless steel	SA351 Grade CF8
	Forging	Stainless steel	SA479 Type 304
CONTROL ROD DRIVE	Forging	Austenitic stainless steel	ASME SA182 Type 304
	Pipe	Austenitic stainless steel	ASME SA312 Type 316

Table 5.2-3 (Cont'd)

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
12" TESTABLE CHECK VALVE (E11-F050)			
Body	Cast	Stainless steel	SA351 CF8M
Disc	Cast	Stainless steel	SA351 CF8M
Cover	Forging	Stainless steel	SA182 F316
Bearing cover	Forging	Stainless steel	SA182 F316
Studs	Bar	Alloy steel	SA540 B23 Class 5
Hex nuts	Bar	Steel	SA540 B23 Class 5
12" 900# VALVE (E11-F015)			
Body	Cast	Stainless steel	SA351 CF8M
Bonnet	Cast	Stainless steel	SA351 CF8M
Disc	Cast	Stainless steel	SA351 CF8M
Stud	Bar	Alloy steel	SA193 B7
Nut	Bar	Carbon steel	SA194 2H
12" 900# GATE VALVE (E21-F005)			
Body	Cast	Carbon steel	SA352 LCB
Bonnet	Cast	Carbon steel	SA352 LCB
Disc	Cast	Carbon steel	SA352 LCB
Stud	Bar	Alloy steel	SA193 B7
Nut	Bar	Steel	SA194 2H
RECIRCULATION GATE VALVE B32-F023/F031			
Body	Cast	Stainless steel	SA351 Grade CF8M
Bonnet	Cast	Stainless steel	SA351 Grade CF8M
Disc	Cast	Stainless steel	SA351 Grade CF3A
Stud	Bar	Alloy steel	A193 Grade B7
Nut	Bar	Steel	ASTM 194 Grade 2H

Table 5.2-3 (Cont'd)

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
Depending on whether impact tests are required and depending on the lowest service metal temperature when impact tests are required, the following ferritic materials and specifications are used in the piping system:			
Pipe		Carbon steel	SA106 Grade B, SA333 Grade 6, SA155 KCF70
Fittings		Carbon steel	SA105 Grade II, SA350 Grade LF1, SA234 Grade B, SA420 Grade WPL1
Bolting		Carbon steel	SA193 Grade B7, SA194 Grades 7 and 2H
For those systems or portions of systems, except for the reactor recirculation system, that require austenitic stainless steel, the following materials and specifications are used in the piping system:			
Pipe		Austenitic stainless steel	SA376 Type 304, SA312 Type 304, SA358 Type 304
Flanges		Austenitic stainless steel	SA182 Grade F316
Bolting		Austenitic stainless steel	SA193 Grade B7, SA194 Grades 7 and 2H
Fittings		Austenitic stainless steel	SA182 Grade F304, SA403 Grades WP304, 304W
For the recirculation system (inside containment) the following materials and specifications are used in the piping system:			
Pipe		Austenitic stainless steel	B50 YP166 Type A1
Fittings		Austenitic stainless steel	B50 YP193 Type B2

Table 5.2-4

NOMINAL BWR WATER CHEMISTRY FOR NORMAL OPERATION

	CONCENTRATIONS - PARTS PER BILLION (ppb)				CONDUCTIVITY	
	Iron	Copper	Chloride	Oxygen	(μmho/cm @ 25°C)	pH @ 25°C
1. Condensate (1)[1]	15-30	3-5	≤20	20-50	~0.1	~7
2. Condensate cleanup effluent (2)[1]	<5.0	<1	~0.2	20-50	<0.1	~7
3. Feedwater (3)[1]	<5.0	<1	~0.2	20-50	<0.1	~7
4. Reactor water (4)[1]						
(a) Normal operation	10-50	<20	<20	100-300 See note [2]	0.2-0.5	~7
(b) Shutdown	-	-	<20	See note [2]	<1	~7
(c) Hot standby	--	<20	See note [2]	<1	~7	
(d) Depressurized	-	-	<20	8000	<2	6-6.5
5. Steam (5)[1]	0	0	0	10000-30000	~0.1	-
6. CRD cooling water (6)[1]	50-500	-	<20	≤50	≤0.1	~7

(1) The numerals in parentheses refer to locations delineated in Figure 5.2-9.

(2) See Section 5.2.3.2.2.

Table 5.2-5

SYSTEMS THAT MAY INITIATE DURING OVERPRESSURE EVENT

SYSTEM	INITIATING/TRIP SIGNALS(S)[1]
RPS	Reactor trips "Off" on high flux
RCIC	"On" when reactor water level at L2 "Off" when reactor water level at L8
HPCI	"On" when reactor water level at L2 "Off" when reactor water level at L8
Recirculation system	"Off" when reactor water level at L2 "Off" when reactor pressure at 1125 psig
RWCU	"Off" when reactor water level at L2

(1) Vessel level trip settings are shown in Figure 5.3-2.

Table 5.2-6

WATER SAMPLE LOCATIONS

SAMPLE ORIGIN	SENSOR LOCATION	INDICATOR LOCATION	RECORDER LOCATION
Reactor water recirculation loop	Sample Line	Sample Station	_
RWCU System inlet	Sample Line	Sample Station	Control room
RWCU system outlets	Sample Line	Sample Station	Control room
Stored condensate CRD System	Sample Line	Sample Station	Control room
RHR heat exchanger Outlets	Sample Line	Sample Station	_
Main steam from reactor	Sample Line	Sample Station	_
Feedwater to reactor	Sample Line	Sample Station	_

Table 5.2-7

LEAK DETECTION METHODS USED AND SYSTEM ALARMS AND INTERLOCKS PROVIDED

SOURCE OF LEAKAGE		VARIABLE MONITORED[5]												
		A	A	A	A/I	A/I	A/I	A/I	A/I	A/I	A	A/I	A	A
SYSTEM[1]	LOCATION[5]	PC HIGH TEMPERATURE	PC HIGH PRESSURE	PC SUMP HIGH FLOW RATE	EQUIPMENT AREA HIGH T & ΔT	RWCU HIGH FLOW	PIPE ROUTING AREA HIGH T & ΔT	HIGH FLOW RATE[4]	RWCU HIGH ΔFLOW	REACTOR LOW WATER LEVEL	HIGH FISSION PRODUCT RADIOACTIVITY	RE FLOOR DRAIN SUMP MONITORING[6]	COMPARTMENT WATER LEVEL[6]	PC AIR COOLER CONDENSATE DRAIN FLOW
MAIN STEAM	PC RE	X	X	X	X[2]		X[2]	X X		X X	X	X		X
RHR	PC RE	X	X	X	X					X X	X	X	X	X
RCIC STEAM	PC RE	X	X	X	X		X	X X		X X	X	X		X
RCIC WATER	PC RE											X	X	
HPCI STEAM	PC RE	X	X	X	X		X	X X		X X	X	X		X
HPCI WATER	PC RE											X	X	
RWCU WATER	PC RE RE	X Hot Cold	X	X	X	X X X			X X X	X X X	X	X X		X
FEEDWATER	PC RE	X	X	X							X	X		X
CORE SPRAY	PC RE	X	X	X								X	X	X

Table 5.2-7 (Cont'd)

(1) All systems within the drywell share a common leak detection system.

(2) Isolation and alarm occur on high temperature in the main steam line Outboard MSIV room. Alarm occurs on high temperature in the main steam line steam tunnel in the turbine enclosure.

(3) Alarm only.

(4) Leakage downstream of the flow element will cause isolation of the steam line.

(5) The following notations are used:

A - alarm
I - isolation
PC - primary containment
RE - reactor enclosure

(6) Plant drainage system instrumentation.

Table 5.2-8

SEQUENCE OF EVENTS

(REDY, ODYN, and TRACG)

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Table 5.2-8 (Cont'd)

SEQUENCE OF EVENTS

(3 SRV Out-Of-Service)*

TIME-SEC	EVENT
0	Initiate closure of all MSIVs.
0.3	MSIVs reach 90% open and initiate reactor scram. However, hypothetical failure of this position scram is assumed in this analysis.
1.64	Neutron flux reaches the high APRM flux scram setpoint and initiates reactor scram.
2.35	Recirculation pump drive motors trip due to high vessel pressure.
2.75	Steam line pressure reaches the relief valve pressure setpoint and valves start to open.
3.01	All SRVs opened.
3.0	The MSIVs completely closed.
4.41	Vessel bottom pressure at its peak value.

* General Electric performed a re-analysis to increase the allowable SRV as-found setpoint tolerance to ± 3% of the SRV setpoint (ref. 3.9-26). The results of this analysis require that the number of SRVs allowed out-of-service, be limited to 2. An assessment of the data given in Table 5.2-8 indicates that the effect from the re-analysis on the time sequence is not significant. The change to ± 3% of the SRV setpoint tolerance is effective after 2R05 for Unit 2, and after 1R08 for Unit 1.

Table 5.2-9

RCPB OPERATING THERMAL CYCLES

NORMAL, UPSET, AND TESTING CONDITIONS	NUMBER OF CYCLES
1. Bolt-up[1]	123
2. Design hydrostatic test	130
3. Startup (100°F/hr heatup rate)[2]	117
4. Daily reduction to 75% power[1]	10,000
5. Weekly reduction to 50% power[1]	2,000
6. Control rod pattern change[1]	400
7. Loss of feedwater heaters (80 cycles total)	80
8. OBE event	1[4]
9. Scram:	
a. Turbine-generator trip, feedwater on, isolation valves stay open	40
b. Other scrams	140
10. Reduction to 0% power, hot standby, shutdown (100°F/hr cooldown rate)[2]	111
11. Unbolt	123
12. Natural circulation startup	3
13. Loss of AC power natural circulation restart	5
EMERGENCY CONDITIONS	
14. Scram:	
a. Reactor overpressure with delay scram, feedwater stays on, isolation valves stay open	1[3]

Table 5.2-9 (Cont'd)

	NUMBER OF CYCLES
b. Loss of feedwater pumps, isolation valves closed	5
c. Automatic blowdown	1(3)
d. Turbine trip with single SRV blowdown	8
15. Improper start of cold recirculation loop	1(3)
16. Sudden start of pump in cold recirculation loop	1(3)
17. Improper startup with reactor drain shutoff followed by turbine roll and increase to rated power	1(3)
FAULTED CONDITION	
18. SSE (at rated operating conditions)	1(3)
19. Pipe rupture and blowdown	1(3)

(1) Applies to RPV only
(2) Bulk average vessel coolant temperature change in any 1 hour period, excluding flooding
(3) The 40 year encounter probability of these one-cycle events is $<10^{-1}$ for emergency and $<10^{-3}$ for faulted events
(4) Includes 10 maximum load cycles per event – 1 event = 10 cycles

Table 5.2-10

MAIN STEAM SWEEPOLET MATERIAL DATA FROM OTHER BWRs

PROJECT A

Applicable Code:	ASME Section III, 1974 Edition, S74 Addendum
Vendor:	Bonney Forge Division, Gulf Western Manufacturing
Material Vendor:	Sharon Steel
Material Spec:	SA105N
Heat No.:	631218 (Sharon Steel)

	C	Mn	Si	P	S
Chemical Composition (wt%)	0.28	0.98	0.22	0.014	0.015

Heat Treatment: Normalize 1650°F (12 hr) - Air Cooled

Charpy V-Notch Impact Toughness (Longitudinal)

Test Temperature:	+70°F
Energy (ft-lb)	68.2, 83.5, 76.0
Lat. Exp. (mil)	64, 71, 69
% Shear:	80, 80, 80

PROJECT B

Applicable Code:	ASME Section III, 1974 Edition, S74 Addendum
Vendor:	Bonney Forge Division, Gulf Western Manufacturing
Material Vendor:	Sharon Steel
Material Spec:	SA105N
Heat No.:	630614 (Sharon Steel)

Table 5.2-10 (Cont'd)

	C	Mn	Si	P	S
Chemical Composition (wt%)	0.26	0.86	0.16	0.022	0.017
Heat Treatment:	Normalize 1650°F (4 hr) - Air Cooled				
Charpy V-Notch Impact Toughness (Longitudinal)					
Test Temperature:	+70°F				
Energy (ft-lb)	76.6, 74.9, 62.0		107.7, 108.5, 109.3		
Lat. Exp. (mil)	68, 69, 63		75, 84, 85		
% Shear:	80, 90, 80		100, 100, 100		

Table 5.2-11

MSIV BONNET COVER MATERIAL

	UNIT 1					
Applicable Code:	1968 ASME Nuclear Pump and Valve Code					
Valve Vendor:	Atwood & Morrill Company					
Material Vendor:	Cann & Saul Steel Company					
Material Specification:	ASTM A105, Grade 2					
Heat No.	219222					
	C	Mn	Si	P	S	
Chemical Composition (wt%)	0.30	0.68	0.19	0.009	0.014	
Heat Treatment:	Normalize 1650°F (12 hr) - Air Cooled					
	UNIT 2					
Applicable Code:	1968 ASME Nuclear Pump and Valve Code					
Valve Vendor:	Atwood & Morrill Company					
Material Vendor:	Cann & Saul Steel Company					
Material Specification:	ASTM A105, Grade 2					
Heat No.	221398/69D018					
	C	Mn	Si	P	S	
Chemical Composition (wt%)						
(221398)	0.28	0.79	0.23	0.010	0.020	
(69D018)	0.34	0.82	0.18	0.009	0.024	
Heat Treatment:	Normalize 1650°F (12 hr) - Air Cooled					

MSIVs modified with nose guided poppet kits have bonnets made from SA105 forgings which have equivalent properties.

Table 5.2-12

MSIV BODY DATA

UNIT 1

Applicable Code:	ASME Section III, W68, Draft Pump & Valve Code
Valve Vendor:	Atwood & Morrill Company
Material Vendor:	Quaker Alloy Casting Company
Material Spec:	ASTM A216 Grade WCB
Heat Number:	F8304-1

	C	Mn	Si	P	S
Chemical Composition (wt%):	0.26	0.90	0.30	0.019	0.012

Heat Treatment: Normalize 1700°F (7 hr 10 min) air cool

+Temperature 1340°F (7 hr) air cool

+Postweld heat treatment/stress relieve 140°F/1170°F (5 hr 10 min) air cool

UNIT 2

Applicable Code:	ASME Section III, W68, Draft Pump & Valve Code
Valve Vendor:	Atwood & Morrill Company
Material Vendor:	Quaker Alloy Casting Company
Material Spec:	ASTM A216 Grade WCB
Heat Number:	F3034

	C	Mn	Si	P	S
Chemical Composition (wt%):	0.25	0.63	0.38	0.016	0.014

Heat Treatment: Normalized @ 1690°F - 1770°F, 8 hr 5 min

+Temperature 1360°F, 6 hr 40 min.

+Postweld heat treatment/stress relieve 1100°F - 1125°F, 6 hr 45 min.

Table 5.2-13

MSIV BODY DATA FROM OTHER BWRs

PROJECT A

Applicable Code: ASME Section III, 1974

Valve Vendor: Atwood & Morrill Company

Material Vendor: Quaker Alloy Casting Company

Material Spec: ASME SA216 Grade WCB

Heat Number: F6406

	C	Mn	Si	P	S
Chemical Composition (wt%):	0.23	0.89	0.53	0.019	0.012

Heat Treatment: 1680°F/1710°F (5 hr, 30 min) air cool

+Temperature 1350°F (5 hr, 30 min) air cool

+Postweld 1200°F (6 hr) air cool

Charpy V-Notch Impact Toughness

Test Temperature: +60°F

Energy (ft-lb): 32, 31, 34

Exp. (mil): 33, 32, 31

% Shear: 40, 40, 40

PROJECT B

Applicable Code: ASME Section III, 1974

Valve Vendor: Atwood & Morrill Company

Material Vendor: Atwood & Morrill Company

Material Spec: ASME SA216 Grade WCB

Heat Number: 35

Table 5.2-13 (Cont'd)

	C	Mn	Si	P	S
Chemical Composition (wt%):	0.24	0.82	0.46	0.022	0.013

Heat Treatment: 1650°F/1800°F (8 hr), air cool to 400°F

+Temperature 1150°F/1250°F (8 hr), air cool

+Postweld 1095°F/1195°F (18 hr) furnace cool to 800°F (100°F/hr) air cool

Charpy V-Notch Impact Toughness

Test Temperature: +60°F

Energy (ft-lb) 31.5, 37.5, 39.5

Exp. (mil): 33, 41, 40

% Shear: 10, 10, 10

PROJECT C

Applicable Code: ASME Section III, 1974 with Summer 1975 Addenda

Valve Vendor: Atwood & Morrill Company

Material Vendor: Quaker Alloy Casting Company

Material Spec: ASME SA216 Grade WCB

Heat Number: F3547

	C	Mn	Si	P	S
Chemical Composition (wt%):	0.23	0.88	0.38	0.016	0.015

Heat Treatment: 1700°F/1725°F (6 hr, 20 min) air cool

+Temperature 1345°F (6 hr, 45 min) air cool

+Postweld 1200°F/1225°F (6 hr, 20 min) air cool

Table 5.2-13 (Cont'd)

Charpy V-Notch Impact Toughness

Test Temperature:	+60°F
Energy (ft-lb):	66, 56, 54
Exp. (mil):	53, 50, 53
% Shear:	40, 40, 40

PROJECT D

Applicable Code:	ASME Section III, 1971 with Summer 1973 Addenda
Valve Vendor:	Rockwell International
Material Vendor:	Rockwell International
Material Spec:	ASME SA216 Grade WCC
Heat Number:	1750262

Chemical Composition (wt%):	C	Mn	Si	P	S	Al
	0.21	1.19	0.43	0.011	0.009	0.043

Heat Treatment: 1700°F (10 hr) normalize

+1225°F (7.5 hr) temperature

+1100°F (6 hr) postweld

Charpy V-Notch Impact Toughness

Test Temperature:	+40°F
Energy (ft-lb):	29.0, 33.0 35.0
Exp. (mil):	25.0, 26.0, 30.0
% Shear:	15, 15, 15

Table 5.2-13 (Cont'd)

PROJECT E

Applicable Code: ASME Section III, 1971 with Summer 1973 Addenda

Valve Vendor: Rockwell International

Material Vendor: Rockwell International

Material Spec: ASME SA216 Grade WCC

Heat Number: 3760171

Chemical Composition (wt%):

C	Mn	Si	P	S	Al
0.17	1.09	0.50	0.008	0.011	0.060

Heat Treatment: 1700°F (8 hr) normalize

+1275°F (8 hr) temperature

+1100°F (6 hr) postweld

Charpy V-Notch Impact Toughness

Test Temperature:	+40°F
Energy (ft-lb):	35, 38, 29
Exp. (mil):	32, 36, 29
% Shear:	20, 20, 20

PROJECT F

Applicable Code: ASME Section III, 1974

Valve Vendor: Atwood & Morrill Company

Material Vendor: Quaker Alloy Casting Company

Material Spec: ASME SA216 Grade WCB

Heat Number: F7516

Table 5.2-13 (Cont'd)

	C	Mn	Si	P	S
Chemical Composition (wt%):	0.25	0.78	0.53	0.018	0.013

Heat Treatment: 1690°F/1710°F (6 hr, 5 min) air cool

+Temperature 1350°F/1360°F (6 hr) air cool

+Postweld 1200°F (6 hr, 5 min) air cool

Charpy V-Notch Impact Toughness

Test Temperature:	+60°F
Energy (ft-lb):	30, 24, 34
Exp. (mil):	37, 27, 33
% Shear:	40, 40, 40

5.3 REACTOR VESSEL

5.3.1 REACTOR VESSEL MATERIALS

5.3.1.1 Materials Specifications

The materials used in the RPV and appurtenances are shown in Table 5.2-3 together with the applicable specifications.

5.3.1.2 Special Processes Used for Manufacturing and Fabrication

The RPV is primarily constructed from low alloy, high strength steel plate and forgings. Plates are ordered to ASME SA533, Grade B, Class 1, and forgings to ASME SA508, Class 2. These materials are melted to fine grain practice and are supplied in the quenched and tempered condition. Further restrictions include a requirement for vacuum degassing to lower the hydrogen level and improve the cleanliness of the low alloy steels.

Studs, nuts, and washers for the main closure flange are ordered to ASME SA540, Grade B23, or Grade B24. Welding electrodes are low hydrogen-type ordered to ASME SFA5.5.

All plate, forgings, and bolting are 100% ultrasonically tested and surface examined by magnetic particle methods or liquid penetrant methods in accordance with ASME Section III standards. Fracture toughness properties are also measured and controlled in accordance with ASME Section III requirements.

All fabrication of the RPV is performed in accordance with GE approved drawings, fabrication procedures, and test procedures. The shells and vessel heads are made from formed plates, and the flanges and nozzles from forgings. Welding performed to join these vessel components is in accordance with procedures qualified in accordance with ASME Sections III and IX requirements. Weld test samples are required for each procedure for major vessel full penetration welds. Tensile and impact tests are performed to determine the properties of the base metal, heat-affected zone, and weld metal.

Submerged arc and manual stick electrode welding processes are employed. Electroslag welding is not permitted. Preheat and interpass temperatures employed for welding of low alloy steel meet or exceed the requirements of ASME Section III. Postweld heat treatment at 1100°F minimum is applied to all low alloy steel welds.

Radiographic examination is performed on all pressure-containing welds in accordance with requirements of ASME Section III, Paragraph N-624 including Summer 1975 Addenda. In addition, all welds are given a supplemental ultrasonic examination.

The materials, fabrication procedures, and testing methods used in the construction of BWR RPVs meet or exceed requirements of ASME Section III, Class I vessels.

The Unit 2 N16D repair was performed using Machine and Manual Gas Tungsten Arc Welding with the Ambient Temperature Temper Bead weld technique in accordance with the rules of ASME Section XI Code Case N-638-4.

5.3.1.3 Special Methods for Nondestructive Examination

The materials and welds on the RPV were examined in accordance with methods prescribed, and met the acceptance requirements specified by ASME Section III. In addition, the pressure-retaining welds were ultrasonically examined using manual techniques. The ultrasonic examination method, including calibration, instrumentation, scanning sensitivity, and coverage is based on the requirements imposed by ASME Section XI, Appendix I. Acceptance standards are equivalent to, or more restrictive than, those required by ASME Section XI.

5.3.1.4 Special Controls For Ferritic and Austenitic Stainless Steels

5.3.1.4.1 Compliance With Regulatory Guides

5.3.1.4.1.1 Regulatory Guide 1.31, Control of Ferrite Content in Stainless Steel Weld Metal

Controls on stainless steel welding are discussed in Section 5.2.3.4.2.1.

5.3.1.4.1.2 Regulatory Guide 1.34, Control of Electroslag Weld Properties

Electroslag welding is not employed for the RPV fabrication.

5.3.1.4.1.3 Regulatory Guide 1.43, Control of Stainless Steel Weld Cladding of Low Alloy Steel Components

This guide applies to welding of cladding to low alloy steels made to coarse grain practice. LGS vessel plate and nozzle forgings are made to fine grain practice and a low heat input process is used. Other components are not clad. Therefore, the guide is not applicable.

5.3.1.4.1.4 Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel

Controls to avoid severe sensitization are discussed in Section 5.2.3.4.1.1.

5.3.1.4.1.5 Regulatory Guide 1.50, Control of Preheat Temperature for Welding Low Alloy Steel

Preheat controls are discussed in Section 5.2.3.3.2.1.

5.3.1.4.1.6 Regulatory Guide 1.71, Welder Qualification for Areas of Limited Accessibility

Welder qualification for areas of limited accessibility is discussed in Section 5.2.3.4.2.3.

5.3.1.4.1.7 Regulatory Guide 1.99, Effects of Residual Elements on Predicted Radiation Damage to Reactor Pressure Vessel Materials

Predictions for changes in transition temperature and upper-shelf energy are made in accordance with the guidelines of Regulatory Guide 1.99 (Rev 2).

5.3.1.5 Fracture Toughness

This section is supplemented by Sections 5.3.1.7 and 5.3.1.8 in discussing the compliance to the intent of 10CFR50, Appendix G.

5.3.1.5.1 Assessment of 10CFR50, Appendix G

A major condition necessary for full compliance to 10CFR50, Appendix G is satisfaction of the requirements of the Summer 1972 Addenda to ASME Section III. This is not possible with components that were purchased to earlier code requirements. For the extent of compliance see Table 5.3-1.

Ferritic materials complying with 10CFR50, Appendix G must have both drop weight tests and Charpy V-notch tests with the CVN specimens oriented transverse to the maximum material working direction to establish the RT_{NDT}. The CVN tests must be evaluated against both an absorbed energy and a lateral expansion criteria. The maximum acceptable RT_{NDT} must be determined in accordance with the analytical procedures of ASME Section XI, Appendix G. 10CFR50, Appendix G, requires an initial minimum of 75 ft-lb upper-shelf CVN energy for beltline material. It also requires at least 45 ft-lb CVN energy and 25 mils lateral expansion for bolting material at the lower of the preload or lowest service temperature.

By comparison, materials for the LGS Units 1 and 2 reactor vessels are qualified by drop weight tests and/or in most cases longitudinally oriented CVN tests (both not required), confirming that the material NDTT is at least 60°F below the lowest service temperature. When the longitudinal CVN test was applied, a 30 ft-lb energy level was used in defining the NDTT. There was no upper-shelf CVN energy requirement on the LGS Units 1 and 2 beltline material. The bolting material was qualified to a 30 ft-lb CVN energy requirement at 60°F below the minimum preload temperature.

To determine operating limits in accordance with 10CFR50, Appendix G, estimates of the beltline material RT_{NDT} and the highest RT_{NDT} of all other material were made, as explained in Section 5.3.1.5.3. The method for developing these operating limits is also described therein.

5.3.1.5.2 Method of Compliance

The method of compliance is based on the last paragraph on page 19013 of the July 17, 1973 Federal Register.

The intent of the proposed special method of compliance with Appendix G for this vessel is to provide operating limitations on pressure and temperature based on fracture toughness. These operating limits ensure that a margin of safety against a nonductile failure of this vessel is very nearly the same as a vessel built to the Summer 1972 Addenda.

The specific temperature limits for all modes of plant operation when the core is critical are based on 10CFR50, Appendix G.

5.3.1.5.3 Methods of Obtaining Operating Limits Based on Fracture Toughness

Operating limits that define minimum metal temperatures versus reactor pressure during normal heatup and cooldown, and during inservice hydrostatic testing, are established using the methods of ASME Section XI, Appendix G, 2007 Edition with addenda through 2008. (Reference 5.3-11 and 5.3-12). The results are shown in Figures 5.3-4 (LGS Unit 1) and 5.3-5 (LGS Unit 2).

Estimated RT_{NDT} values and temperature limits are given in this section for the limiting locations in the reactor vessel.

All the vessel shell and head areas remote from discontinuities were evaluated and the operating limit curves are based on the limiting location. The bolt-up limits for the flange and adjacent shell regions are based on a minimum metal temperature of RT_{NDT} + 60°F. The maximum through-wall temperature gradient from continuous heating and cooling at 100°F per hour was considered. The safety factors applied were as specified in ASME Section XI, Appendix G.

For the purpose of setting these operating limits the reference temperature, RT_{NDT}, is determined from the toughness test data taken in accordance with requirements of the Code to which the vessels are designed and manufactured. These toughness test data, CVN and/or drop-weight NDT are analyzed to permit compliance with the intent of 10CFR50, Appendix G. Because all toughness testing needed for strict compliance with Appendix G was not required at the time of vessel procurement some toughness results are not available. For example, longitudinal CVNs, instead of transverse, were tested, usually at a single test temperature of +10°F or +40°F, for absorbed energy. Also, at the time, either CVN or drop-weight testing was permitted; therefore, in many cases both tests were not performed as is currently required. To substantiate the design adequacy, toughness property correlations are derived for the vessel materials to give a conservative estimate of RT_{NDT}, compliant with the intent of Appendix G criteria.

These toughness correlations vary, depending on the specific material analyzed, and are derived from the results of Bulletin 217, "Properties of Heavy Section Nuclear Reactor Steels," and from toughness data from the LGS Unit 1 and 2 vessels and other reactors. In the case of vessel plate material (SA533, Grade B, Class 1), the predicted limiting toughness property is either NDT or transverse CVN 50 ft-lb temperature minus 60°F. NDT values are available for all beltline and some other LGS 1 and 2 vessel plates. Where NDT results are missing, NDT is estimated as the longitudinal CVN 35 ft-lb transition temperature. The transverse CVN 50 ft-lb transition temperature is estimated from longitudinal CVN data in the following manner. The lowest longitudinal CVN ft-lb value is adjusted to derive a longitudinal CVN 50 ft-lb transition temperature by adding 2°F per ft-lb to the test temperature. If the actual data equals or exceeds 50 ft-lb, the test temperature is used. Once the longitudinal 50 ft-lb temperature is derived, an additional 30°F is added to account for orientation effects and to estimate the transverse CVN 50 ft-lb temperature minus 60°F, estimated in the preceding manner.

For forgings (SA508, Class 2), the predicted limiting property is the same as for vessel plates. CVN and drop-weight values are available for the vessel flange, closure head flange, and feedwater and LPCI nozzle materials for LGS Units 1 and 2. RT_{NDT} is estimated in the same way as for vessel plate.

For the vessel weld metal the predicted limiting property is the CVN 50 ft-lb transition temperature minus 60°F, as the NDT values are -50°F or lower for these materials. This temperature is derived in the same way as for the vessel plate material, except the 30°F addition for orientation effects is omitted since there is no principal working direction. When NDT values are available, they are also considered and the RT_{NDT} is taken as the higher of NDT or the 50 ft-lb temperature minus 60°F. When NDT is not available, the RT_{NDT} shall not be less than -50°F, since lower values are not supported by the correlation data.

For vessel weld heat-affected zone material the RT_{NDT} is assumed the same as for the base material, since ASME Code weld procedure qualification test requirements and postweld heat treatment indicates this assumption is valid.

Closure bolting material (SA540, Grade B24) toughness test requirements for LGS Units 1 and 2 are for 30 ft-lb at 60°F below the bolt-up temperature. Current Appendix G requirements are for 45 ft-lb

and 25 MLE at the preload or lowest service temperature, including bolt-up. All LGS Units 1 and 2 closure stud materials meet current requirements at +10°F.

Using this general approach, an initial RT_{NDT} of 20°F is established for the core beltline region for LGS Unit 1 and 40°F for LGS Unit 2.

The effect of the main closure flange discontinuity is considered by adding 60°F and 90°F to the RT_{NDT} to establish the minimum temperature for bolt-up and pressurization respectively. The minimum bolt-up temperature of 80°F for LGS Unit 1, which is shown in Figure 5.3-4 is based on an initial RT_{NDT} of +20°F for the shell plate which connects to the closure flange. The minimum bolt-up temperature of +70°F for LGS Unit 2, which is shown in Figure 5.3-5, is based on an initial RT_{NDT} of +10°F for the closure flange forgings. A flange region flaw size less than 0.24 inch critical flaw depth can be detected at the outside surface of the flange to shell and head junctions where stresses due to bolt-up are most limiting.

These values are consistent with the minimum temperature limits and minimum bolt-up temperature in the previous docketed P-T curves (Reference 5.3-18 and 5.3-19) (approved by the NRC in Reference 5.3-20 and 5.3-21). These values also bound the minimum temperature in the first set of P-T limits approved for initial operation (thereby addressing the NRC condition in Reference 5.3-17, Section 4.0).

The composite P-T curves are extended below 0 psig to -14.7 psig based on the evaluation in Reference 5.3-11 and 5.3-12, which demonstrates that the P-T curves are applicable to negative gauge pressures. A pressure of -14.7 psig bounds the maximum expected vacuum pressure as well as externally applied pressures the RPV may experience.

The reactor vessel closure studs have a minimum Charpy impact energy of 48 ft-lb and a 27 MLE at 10°F for LGS Unit 1. The studs for LGS Unit 2 have a minimum Charpy impact energy of 25 MLE and 46 ft-lb at 10°F. The lowest service temperature for bolt-up of LGS Unit 2 is 10°F. Charpy test results are discussed in Sections 5.3.1.7 and 5.3.1.8.

5.3.1.6 Material Surveillance

5.3.1.6.1 Compliance with "Reactor Vessel Material Surveillance Program Requirements"

The materials surveillance program monitors changes in the fracture toughness properties of ferritic materials in the reactor vessel beltline region resulting from their exposure to neutron irradiation and thermal environment.

Materials for the original surveillance program were selected to represent materials used in the reactor beltline region. The specimens were manufactured from a plate actually used in the beltline region, and a weld typical of those in the beltline region, and thus represent base metal, weld metal, and the transition zone between base metal and weld. The plate and weld were heat treated in a manner that simulates the actual heat treatment performed on the core region shell plates of the completed vessel.

The original surveillance program included three capsule holders per reactor vessel.

Information on the specimen arrangement is given in Table 5.3-12, referenced in Section 5.3.1.10.

A set of out-of-reactor baseline CVN specimens is provided with the surveillance test specimens.

Charpy impact specimens for the original reactor vessel surveillance programs are of the longitudinal orientation consistent with the ASME requirements prior to the issue of the 1972 Addenda and ASTM E185-73. Based on GE experience, the amount of shift measured by these irradiated longitudinal test specimens is essentially the same as the shift in an equivalent transverse specimen.

For LGS Units 1 and 2, each set of surveillance specimens is loaded in 6 small capsules rather than one large capsule. Therefore, each capsule holder which contains all 6 small capsules can be considered to be the same as one surveillance capsule as defined in 10CFR50, Appendix H. Three capsule holders are included in each reactor vessel. Since the predicted adjusted increase in reference temperature of the beltline region, estimated at the time of design, was less than 100°F at EOL and the calculated peak neutron fluence is less than $5x10^{18}$ n/cm^2, the use of three capsule holders meets the requirements of 10CFR50, Appendix H, and ASTM E185-73.

For the extent of compliance of the original surveillance program to 10CFR50, Appendix H, see Table 5.3-2.

In 2003, the NRC approved LGS participation in the BWR Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (ISP) as described in BWRVIP-78 and BWRVIP-86 (Reference 5.3-13). The NRC approved the ISP for the industry in Reference 5.3-13 and approved LGS participation in Reference 5.3-14. The ISP meets the requirements of 10 CFR 50 Appendix H and provides several advantages over the original program. The surveillance materials in many plant-specific programs do not represent the best match with the limiting vessel beltline materials since some were established prior to 10 CFR 50 Appendix H requirements. Also, the ISP allows for better caparison to unirradiated material data to determine actual shifts in toughness. Finally, for many plants, ISP data will be available sooner to factor into plant operations since there are more sources of data.

The current withdrawal schedule for both units is based on the latest NRC-approved revision of BWRVIP-86 (Reference 5.3-13). Based on this schedule, LGS is not scheduled to withdrawal any additional material specimens. Per Reference 5.3-15, the schedule is not changed due to MUR power uprate.

The Unit 2 surveillance capsule and holder at Azimuth 120° was removed from the vessel during the 2M54 maintenance outage due to the failure of the holder. This surveillance capsule and holder was not reinstalled in the vessel. A letter was sent to the NRC (LG-17- 172) for notification in accordance with the Integrated Surveillance Program (ISP).

5.3.1.6.2 Neutron Flux and Fluence Calculations

A description of the methods of analysis is contained in Sections 4.1.4.5 and 4.3.2.8.

5.3.1.6.3 Predicted Irradiation Effects on Vessel Beltline Materials

Estimated maximum changes in RT_{NDT} (initial reference temperature) and upper shelf fracture energy as a function of the EOL fluence at the ¼ depth of the vessel beltline materials are provided in Section 5.3.1.7. The predicted peak EOL maximum neutron irradiation fluences for the 110% power rerate condition at the ¼ of the vessel beltline are $1.3x10^{18}$ n/cm^2 after 32 EFPY (where an EFPY is based on the rerated power level). For conservative flux calculations, 251 inches is used as the inside diameter of the beltline region with a wall thickness of 6-3/16 inches. Transition temperature changes and variations in upper-shelf energy were calculated in accordance with the rules of Regulatory Guide 1.99 (Rev 2). Reference temperatures were established in accordance with 10CFR50, Appendix G and NB-2330 of the ASME Code. Per Reference 5.3-15, the rerate fluence bounds the requirements for operation at the MUR power uprate.

As part of the license renewal, the adjusted reference temperature (ART) and upper shelf energy (USE) values are calculated for fluence values corresponding to 57 effective full power years (EFPY), representative of the end of extended operation (60 years). The ART values and predicted EOL USE reductions calculated in accordance with RG 1.99 (Rev. 2) for all LGS Unit 1 and 2 RPV beltline materials exposed to fluence greater than $1x10^{17}$ n/cm^2 for 57 EFPY. The re-evaluation demonstrates that the EOL USE values for all LGS Units 1 and 2 beltline materials are expected to satisfy the requirements of 10 CFR 50, Appendix G, through 57 EFPY.

5.3.1.6.4 Positioning of Surveillance Capsules and Method of Attachment

Surveillance specimen capsules are located at three azimuths at a common elevation in the core beltline region. The sealed capsules are not attached to the vessel but are in welded capsule holders. The capsule holders are mechanically retained by capsule holder brackets welded to the vessel cladding as shown in Figure 5.3-3. The capsule holder brackets allow the capsule holder to be removed at any desired time in the life of the plant for specimen testing. These brackets are designed, fabricated, and analyzed to the requirements of ASME Section III. A positive spring-loaded locking device is provided to retain the capsules in position throughout any anticipated event during the lifetime of the vessel.

The Unit 2 surveillance capsule and holder at Azimuth 120° was removed from the vessel during the 2M54 maintenance outage due to the failure of the holder. This surveillance capsule and holder was not reinstalled in the vessel. A letter was sent to the NRC (LG-17- 172) for notification in accordance with the Integrated Surveillance Program (ISP).

5.3.1.6.5 Dosimetry Measurements

Each surveillance capsule contains iron and copper flux wires. These wires can be used to determine the relationship between reactor power and neutron fluence.

5.3.1.7 Vessel Beltline Plates and Welds

This section supplements Section 5.3.1.5 in discussing the compliance to the intent of 10CFR50, Appendix G.

5.3.1.7.1 Test Data

Available Charpy V-notch and drop-weight impact test data are presented in Tables 5.3-3 and 5.3-4. The sample test welds are prepared in accordance with the ASME Code and do not include base material from the beltline. There are two categories of belt-line welds identified "shop" welds and "field" welds. The shop welds represent vessel vertical seams which were made prior to shipment of preassembled ring segments to the LGS Unit 1 and Unit 2 plant site. The flux material for the submerged arc weld is LINDE 124. The field welds (i.e., girth welds) were made at the plant site. However, exact identification of weld materials used in the beltline girth weld seam is not available. Therefore, a conservative assumption is made to consider all electrodes which were released for field welding the vessel shells.

Figure 5.3-7 shows the vessel beltline layouts. They give plate heat numbers and locations, as well as weld seam locations and identifications.

5.3.1.7.2 Effects of Irradiation

Copper, nickel, and phosphorus values used to estimate the effects of irradiation on toughness are presented in Table 5.3-5.

Estimated starting (i.e., unirradiated) RT_{NDT} values for the beltline plate and weld materials are presented in Table 5.3-5. These values were calculated using the data in Tables 5.3-3 and 5.3-4 in accordance with ASME Section III, NB2300.

Estimated EOL RT_{NDT} values including the influence of power rerate and MUR power uprate for (for ¼ thickness location from the vessel ID) are also given in Table 5.3-5. The EOL RT_{NDT} values are estimated in accordance with Regulatory Guide 1.99 (Rev 2).

As part of the license renewal, RT_{NDT} corresponding to 57 effective full power years (EFPY) are also given in Table 5.3-5. The EOL values have been estimated in accordance with RG 1.99 (Rev. 2) and meet the requirements of 10 CFR 50, Appendix G, through 57 EFPY.

5.3.1.7.3 Upper-Shelf Toughness Testing

Charpy V-notch upper-shelf toughness testing was not required when the LGS vessels were manufactured. 10CFR50, Appendix G requires a minimum of 75 ft-lb transverse upper-shelf CVN energy for beltline material. BTP MTEB 5-2 indicates that 70 ft-lb is adequate for fluence levels less than $1x10^{19}$ n/cm^2.

All of the LGS Units 1 and 2 beltline plates were CVN impact- tested as longitudinal specimens at only one temperature, +40°F. For Unit 1, the lowest CVN value obtained for beltline plate was 45 ft-lb with 50% shear, and the highest was 104 ft-lb with 70% shear. For Unit 2, the lowest value obtained for beltline plate was 35 ft-lb with 30% shear, and the highest was 97 ft-lb with 50% shear. The 50% and 30% shear values suggest there is a considerable margin remaining before the upper-shelf (i.e., 100% shear) level is reached.

Table 5.3-6 summarizes the test certificates for representative LGS Units 1 and 2 beltline plate. Similar data are also documented for all other plates. Supporting data from representative plate materials in other BWR plants are provided in Table 5.3-7. Compatibility of the supporting data from other BWRs, Plants A through E, with respect to LGS is based on criteria such as similarity in material, fabrication, vendor source, welding procedure, etc. All listed plate materials were produced by Luken's Steel Co. These data show that plates with as low as 36 ft-lb (Plant E, Heat No. C9570-1) of absorbed energy with 30% shear at +40°F can have longitudinal upper-shelf energies in excess of 100 ft-lb.

BTP MTEB 5-2 states that longitudinal values should be reduced to 65% of the test value to estimate transverse upper-shelf. To account for the power rerate end-of-life fluence of $1.3x10^{18}$, a further shift in upper-shelf toughness can be made using Regulatory Guide 1.99, resulting in a maximum reduction of approximately 12.5% for the highest Cu content of 0.12 wt% for Unit 1 and 15% for the highest Cu content of 0.15 wt% for Unit 2 as shown in Table 5.3-5. Using these conservative assumptions with a goal of achieving at least 50 ft-lb transverse toughness at EOL, the following equations are derived:

Unit 1: $50 = .65(L) - (.125)[.65(L)]$

Unit 2: $50 = .65(L) - (.15)[.65(L)]$

(where L is unirradiated longitudinal upper-shelf value.)

These equations predict a minimum required unirradiated longitudinal upper-shelf toughness requirement of 88 ft-lb for Unit 1 and 91 ft-lb for Unit 2. Table 5.3-7 indicates that toughness in excess of 91 ft-lb is to be expected for longitudinal upper- shelf of this material.

Although upper-shelf testing was not required for the beltline welds, Table 5.3-4 shows that the majority of the weld materials, both field and shop, meet the 75 ft-lb minimum upper-shelf requirement.

Weld materials that do not meet the 75 ft-lb minimum upper-shelf requirement were impact-tested exclusively at +10°F. The upper-shelf level (i.e., the absorbed energy corresponding with 100% shear) is not expected at this temperature. For Unit 1, Heat No. 07L857, Lot No. B101A27A evidenced the lowest toughness properties exhibiting a minimum of 28 ft-lbs and 20% shear at +10°F T_{CV}. For Unit 2, Heat No. 432A2671, Lot No. H019A27A evidenced the lowest toughness properties exhibiting a minimum of 31 ft-lbs and 30% shear at +10°F T_{CV}. Again, the 20% and 30% shear values indicate that there is considerable margin for improved properties at higher test temperatures.

For these welds where the minimum upper-shelf energy was not established, the Cu content does not exceed 0.05 wt.%. Based on power rerate EOL fluence of 1.3×10^{18} n/cm^2, Regulatory Guide 1.99 predicts a maximum decrease in upper-shelf energy of approximately 12% for weld material containing .05% Cu. With a goal of achieving at least 50 ft-lbs upper-shelf at EOL, the following equation is derived:

$$50 = (U.V.) - .12 (U.V.)$$

where:

U.V. = the unirradiated upper-shelf value for weld metal.

This equation predicts a minimum required unirradiated upper-shelf level of only 57 ft-lbs.

Further upper-shelf toughness data for representative welds, made by the same vendor as LGS Units 1 and 2, are given in Table 5.3-8. Tables 5.3-9 and 5.3-10 present the weld procedures typical for the data base in Table 5.3-8. These tables represent surveillance program weld procedures and some corresponding baseline data, along with other vessel material data which are considered representative of LGS Units 1 and 2 beltline welds. These data are in excess of 75 ft-lbs at the upper-shelf.

5.3.1.7.4 Upper Shelf Energy Equivalent Margin Analysis

10CFR50 Appendix G requires that 50 ft-lb upper shelf energy be maintained in the vessel beltline low alloy steel material throughout operation. It further requires, if 50 ft-lb USE cannot be demonstrated, that methods to show equivalent margin be provided. Since initial USE data is not available to demonstrate 50 ft-lb USE per NCR methods, an equivalent margin analysis was performed (Reference 5.3-6). This analysis has been approved by the NRC and confirms that, even in the absence of initial USE data, adequate margin of safety against fracture equivalent to 10CFR50 Appendix G requirements does exist. For the MUR power uprate, all materials that did not demonstrate 50 ft-lb USE were qualified in Reference 5.3-15 by the equivalent margin analysis methodology of Reference 5.3-6.

However, the equivalent margin analysis methodology defined in Reference 5.3-6 does not specifically identify that forging materials were included in the statistical calculations. Therefore, the LPCI nozzle forgings and the water level instrumentation (WLI) nozzles were assessed in a plant

specific evaluation (Reference 5.3-16). The evaluation concluded that the LPCI nozzle forgings in the RPV meet the margin of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME code. The WLI nozzles were not evaluated further because the forging material is less than 2.5 inches thick. The evaluation for the WLI nozzle in Reference 5.3-15, based on the plate material in the shell where the nozzles are located, is appropriate.

5.3.1.8 Nonbeltline Region and Ferritic Piping and Valves

This section supplements Section 5.3.1.5 in discussing the compliance to the intent of 10CFR50, Appendix G.

Table 5.3-11 lists the estimated reference temperature (RT_{NDT}) for various components in the LGS Units 1 and 2 vessel nonbeltline region. These values were derived in accordance with the intent of ASME Section III, Paragraph NB-2300.

5.3.1.9 Assessment to Appendix G, 1983 Revision

This section addresses the latest requirements of Appendix G, 1983 Revision.

a. The 1983 revision of Appendix G has redefined the adjusted reference temperature by stating "change from the 50 ft-lb level to the 30 ft-lb level of Charpy energy at which the transition temperature shift is to be measured as an indicator of radiation damage." This change does not impact the current reference temperature RT_{NDT} shift information provided in Table 5.3-5. Those shift values were estimated in accordance with Regulatory Guide 1.99 (Rev 2). The data base to establish the procedures for shift prediction in this regulatory guide was given in terms of the 30 ft-lb level; therefore, the predicted reference temperature shifts meet the latest Appendix G requirement.

b. The 1983 revision of Appendix G requires that reactor vessel beltline materials "must maintain upper-shelf energy throughout the life of the vessel of no less than 50 ft-lbs." Section 5.3.1.7.4 describes the equivalent margin analysis which was performed to demonstrate compliance with this requirement.

c. The 1983 revision of Appendix G changes the definition of the "adjacent regions" by stating "beltline region of reactor vessel means the region of the reactor vessel (shell material including welds, heat-affected zones, and plates or forgings) that directly surrounds the effective height of the active core and adjacent regions of the reactor vessel that are predicted to experience sufficient neutron radiation damage to be considered in the selection of the most limiting material with regard to radiation damage." The active fuel region for the LGS vessels is contained by shell courses 1 and 2. The design elevation of the fuel assemblies indicates there remains approximately 36 inches of vessel steel above, and 90 inches of vessel steel below, the fuel elevation before reaching any additional girth welds/shell courses. Therefore, the "adjacent regions" of vessel shell are considered to represent material from shell courses 1 and 2 as well. For this reason, no additional considerations of beltline plates or welds are warranted. Moreover, the effect of radiation on the low pressure coolant injection nozzles and their related welds has been included in the current Appendix G analysis. No other components are near enough to the fuel to be significantly affected by radiation.

5.3.1.10 RPV Surveillance Program

This section supplements Section 5.3.1.6 in discussing the compliance to the intent of 10CFR50, Appendix H.

5.3.1.10.1 LGS Unit 1 Surveillance Program

The base-plate and weld materials used to fabricate the surveillance test plate are identified in Table 5.3-5. The base metal from a core beltline plate Heat No. C7689-1 was used for surveillance test material. With respect to initial RT_{NDT} and percent of copper by weight, this material is considered equivalent to other beltline plates and its utilization for test plate fabrication is in compliance with current recommendations for selection of surveillance materials. The test plate weld, like the core beltline vertical weld seams, was made using both SMAW and SAW welding processes. The test plate weld procedure is presented in Table 5.3-10. For each of the two welding processes, only one heat of weld material was used. The SAW material Heat/Flux No. 1P4218/3929-989, which was also used for beltline seams BE, BA, and BB (Figure 5.3-7), is considered suitable for surveillance monitoring because it represents the most limiting SAW material in terms of shift and predicted EOL RT_{NDT}. The SMAW material Heat/Lot No. 421A6811/F022A27A which was used for surveillance material was not used for production beltline welds; however, the weight percentages of copper and nickel which it contains (0.09% Cu and 0.81% Ni) are generally greater than those for actual belt-line material. Moreover, the unirradiated RT_{NDT} of this material is equivalent to the initial RT_{NDT} of the beltline weld materials. The Chicago Bridge and Iron weld procedure for test plate fabrication involves utilizing stick electrode to fuse backup bars and completing the major volume of the weld with SAW. This includes back-gouging of the backup bar to complete the back side of the weld. Therefore, the test plate weld metal is essentially SAW welded material. Table 5.3-5 indicates that all beltline materials, both plate and weld, are highly resistant to irradiated degradation of notch toughness.

5.3.1.10.2 LGS Unit 2 Surveillance Program

The base-plate and weld materials used to fabricate the surveillance test plate are identified in Table 5.3-5. The base metal used was plate from Heat No. C9569-2; this material was also used for one of the core beltline plates, and its use in RPV surveillance is consistent with the requirements at the time of vessel fabrication.

The test plate weld, like the core beltline vertical weld seams, was made using SMAW and SAW welding processes. The test plate weld procedure is presented in Table 5.3-10. The SAW material Heat No. 3P4000, Lot No. 3933 (both single and tandem wire) was also used for fabrication of beltline seams BA, BB, BC, BD, BE, and BF, and is considered suitable for surveillance monitoring.

Two heats of SMAW material were used for test plate fabrication. One weld material, Heat/Lot No. CTY538/A027A27A, was not used for production beltline welds; however, the weight percentages of Cu and Ni (0.03% Cu and 0.83% Ni) are equivalent to the concentrations of these elements for actual beltline material. The other SMAW material, Heat/Lot No. 03R728/L910A27A, was used in production beltline seam fabrication and is considered suitable for surveillance monitoring.

Table 5.3-5 indicates that all beltline materials, both plate and weld, are acceptably resistant to irradiation degradation of notch toughness.

For Units 1 and 2, Table 5.3-12 lists the actual number of specimens and their orientations in each surveillance capsule (including tensile specimens). The number and orientation of the Charpy impact specimens are consistent with the ASME requirements prior to the issuance of the Summer 1972 Addenda and ASTM 185-73.

Prior surveillance experience indicates the amount of radiation-induced shift in properties measured by longitudinally oriented specimens is applicable to equivalent transverse oriented specimens (Reference 5.3-2). Therefore, the shift when determined can be used for the transverse RT_{NDT} values for the beltline materials. Referring to Table 5.3-12, the longitudinal orientation of the base metal heat-affected zone specimens are such that they simulate beltline vertical seams in this manner.

5.3.1.11 Reactor Vessel Fasteners

The reactor vessel closure head (flange) is fastened to the reactor vessel shell flange by multiple sets of threaded studs and nuts. The lower end of each stud is installed in a threaded hole in its vessel shell flange. A nut and washer are installed on the upper end of each stud. The proper amount of preload can be applied to the studs by a sequential tensioning using hydraulic tensioners. The design and analysis of this area of the vessel is in full compliance with all ASME Section III, Class I, code requirements. The material for studs, nuts, and washers is SA540, Grade B23 or Grade B24. The maximum reported ultimate tensile stresses for the bolting material are 164,000 psi for Unit 1 and 169,000 psi for Unit 2 which are less than the 170,000 psi limitation in Regulatory Guide 1.65. Also, the Charpy impact test recommendations of paragraph IV.A.4 of 10CFR50, Appendix G were not specified in the vessel order since the order was placed prior to issuance of 10CFR50, Appendix G. However, impact data from the certified materials report shows that all bolting materials meet the Appendix G impact properties.

A phosphate coating is applied to threaded areas of studs and nuts and bearing areas of nuts and washers to act as a rust inhibitor and to assist in retaining lubricant on these surfaces.

5.3.2 PRESSURE -TEMPERATURE LIMITS

5.3.2.1 Limit Curves

The basis for setting operational limits on pressure and temperature for normal, upset, and test conditions for the RPV is described in Section 5.3.1.5.

5.3.2.1.1 Temperature Limits for Bolt-Up

A minimum temperature of 20°F is required on LGS Unit 1 and 10°F on LGS Unit 2 for the closure studs. A sufficient number of studs can be tensioned at a temperature between 20°F and 80°F for Unit 1 and 10°F and 70°F for Unit 2 to seal the closure flange O-rings for the purpose of raising reactor water level above the closure flanges in order to assist in warming them. The flanges and adjacent shell are required to be warmed to minimum temperatures of 80°F (Unit 1) and 70°F (Unit 2) before they are stressed by the full intended bolt preload (all bolts tensioned). The fully preloaded bolt-up limits are shown on Figures 5.3-4 and 5.3-5.

5.3.2.1.2 Temperature Limit for Preoperational Tests and Inservice Inspection

Based on the NRC general revision to 10CFR50, Appendix G, Document No. [7590-1], paragraph IV.A.4, the preoperational system hydrostatic test at 1563 psig prior to fuel loading was performed at a minimum temperature of 100°F for Unit 1 without fuel in the reactor, and 100°F for Unit 2. These limits were established by the 40°F maximum RT_{NDT} of the reactor vessel materials.

The fracture toughness analysis for system pressure tests with fuel in the reactor yields the curves labeled A shown in Figures 5.3-4 and 5.3-5. The curves labeled "core beltline" are based on an initial RT_{NDT} of 20°F for Unit 1 and 40°F for Unit 2. The predicted shift in the RT_{NDT} based on the power rerate neutron fluence at ¼ of the vessel wall thickness, has been added to the belt-line curve to account for the effect of fast neutrons. (References 5.3-11 and 5.3-12)

5.3.2.1.3 Operating Limits During Heatup, Cooldown, and Core Operation

The fracture toughness analysis is done for the normal heatup or cooldown rate of 100°F/hour. The temperature gradients and thermal-stress effects corresponding to this rate are included. The results of the analyses are a set of operating limits for non-nuclear heatup or cooldown shown as curves labeled B in Figures 5.3-4 and 5.3-5. Curves labeled C in these figures apply whenever the core is critical. The predicted shift in the RT_{NDT}, based on the power rerate neutron fluence at ¼ of the vessel wall thickness, has been added to the belt-line curve to account for the effect of fast neutrons. As part of the plant's extension to 60 years, a pressure temperature curve has been re-evaluated to extend the plant life to 57 EFPY of reactor operation (References 5.3-11 and 5.3-12).

5.3.2.1.4 Reactor Vessel Annealing

Inplace annealing of the reactor vessel because of radiation embrittlement is not anticipated to be necessary because the predicted value of adjusted reference temperature does not exceed 200°F (10CFR50, Appendix G), even for the power rerate condition or the MUR power condition.

5.3.2.2 Operating Procedures

By comparison of the pressure versus temperature limits in Section 5.3.2.1 with intended normal operating procedures for the most severe upset transient, it is shown that the limits are not exceeded during any foreseeable upset condition. Reactor operating procedures are established so that actual transients are not more severe than those for which the vessel design adequacy has been demonstrated. Of the design transients, the upset condition producing the most adverse temperature and pressure condition anywhere in the vessel head and/or shell areas yields a minimum fluid temperature of 250°F and a maximum power rerate pressure peak of 1233 psig. Scram automatically occurs with initiation of this event, prior to the reduction in fluid temperature, so the applicable operating limits are given by curve B in Figures 5.3-4 and 5.3-5. For a temperature of 250°F, the maximum allowable pressure exceeds 1233 psig for the intended margin against nonductile failure. The maximum transient pressure is therefore within the specified allowable limits.

5.3.3 REACTOR VESSEL INTEGRITY

The reactor vessels are fabricated for GE's Nuclear Energy Division by Chicago Bridge and Iron Company; and are subject to the requirements of GE's Quality Assurance program.

Measures are established to ensure that purchased material, equipment, and services associated with the reactor vessels and appurtenances conform to the requirements of the purchase documents. These measures include provisions, as appropriate, for source evaluation and selection, objective evidence of quality furnished, inspection at the vendor source, and examination of the completed reactor vessels.

GE provides inspection surveillance of the reactor vessel fabricator's in-process manufacturing, fabrication, and testing operations in accordance with GE's Quality Assurance program and approved inspection procedures. The reactor vessel fabricator is responsible for the first level inspection of his manufacturing, fabrication, and testing activities and GE is responsible for the first level of audit and surveillance inspection.

Adequate documentary evidence that the reactor vessel material, manufacture, testing, and inspection conform to the specified quality assurance requirements contained in the procurement specification is available at the fabricator's plant site.

5.3.3.1 Design

5.3.3.1.1 Description

5.3.3.1.1.1 Reactor Vessel

The reactor vessel shown in Figure 5.3-1 is a vertical, cylindrical pressure vessel of welded construction. The vessels for LGS are designed, fabricated, tested, inspected, and stamped in accordance with the ASME Section III, Class A including the Summer Addenda 1969. Design of the reactor vessel and its support system meets seismic Category I requirements.

The materials used in the RPV are shown in Table 5.2-3.

The cylindrical shell and bottom head sections of the reactor vessel are fabricated of low alloy steel, the interior of which is clad with stainless steel weld overlay. Nozzle and nozzle weld zones are unclad except for those mating to stainless steel piping systems.

Inplace annealing of the reactor vessel is unnecessary because shifts in transition temperature caused by irradiation during the 40 year life can be accommodated by raising the minimum pressurization temperature. Radiation embrittlement is not a problem outside of the vessel beltline region because the irradiation in those areas is less than $1x10^{18}$ nvt with neutron energies in excess of 1 MeV.

Quality control methods used during the fabrication and assembly of the reactor vessel and appurtenances ensure that design specifications are met.

The vessel top head is secured to the reactor vessel by studs and nuts. These nuts are tightened with a stud tensioner. The vessel flanges are sealed with two concentric metal seal-rings designed to permit no detectable leakage through the inner or outer seal at any operating condition, including heating to operating pressure and temperature at a maximum rate of 100°F/hr in any one hour period. To detect seal failure, a vent tap is located between the two seal-rings. A monitor line is attached to the tap to provide an indication of leakage from the inner seal-ring seal.

5.3.3.1.1.2 Shroud Support

The shroud support is a circular plate welded to the vessel wall. This support is designed to carry the weight of the shroud, shroud head, peripheral fuel elements, neutron sources, core plate, top guide, the steam separators, the jet pump diffusers, and to laterally support the fuel assemblies. Design of the shroud support also accounts for pressure differentials across the shroud

support plate, for the restraining effect of components attached to the support, and for earthquake loadings. The shroud support design is specified to meet appropriate ASME code stress limits.

5.3.3.1.1.3 Protection of Closure Studs

The BWR does not use borated water for reactivity control. This section is therefore not applicable.

5.3.3.1.2 Safety Design Basis

The design of the reactor vessel and appurtenances meets the following safety design bases:

a. The reactor vessel and appurtenance will withstand adverse combinations of loading and forces resulting from operation under abnormal and accident conditions

b. To minimize the possibility of brittle fracture of the nuclear system process barrier, the following are required:

1. Impact properties at temperatures related to vessel operation are specified for materials used in the reactor vessel

2. Expected shifts in transition temperature during design life as a result of environmental conditions, such as neutron flux, are considered in the design. Operational limitations ensure that RT_{NDT} temperature shifts are accounted for in reactor operation.

3. Operational margins to be observed with regard to the transition temperature are specified for each mode of operation.

5.3.3.1.3 Power Generation Design Basis

The design of the reactor vessel and appurtenances meets the following power generation design bases:

a. The reactor vessel has been designed for a useful life of 40 years.

b. External and internal supports that are integral parts of the reactor vessel are located and designed so that stresses in the vessel and supports that result from reactions at these supports are within ASME Code limits.

c. Design of the reactor vessel and appurtenances allows for a suitable program of inspection and surveillance.

5.3.3.1.4 Reactor Vessel Design Data

The reactor vessel design pressure is 1250 psig and the design temperature is 575°F. The maximum installed test pressure is 1656 psig (1563 psig plus the ASME Code tolerance of 6%).

5.3.3.1.4.1 Vessel Support

The reactor vessel support assembly consists of a ring girder and the various bolts and shims necessary to position and secure the assembly between the reactor vessel support skirt and the support pedestal. The concrete and steel support pedestal is constructed as an integral part of the structure-foundation. Steel anchor bolts are set in the concrete with their threads extending above the surface. The anchor bolts extend through the ring girder bottom flange. High strength bolts are used to secure the flange of the reactor vessel support skirt to the top flange of the ring girder. The ring girder is fabricated of ASTM A-36 structural steel according to AISC specifications.

5.3.3.1.4.2 Control Rod Drive Housings

The CRD housings are inserted through the CRD penetrations in the reactor vessel bottom head and are welded to the reactor vessel. Each housing transmits loads to the bottom head of the reactor. These loads include the weights of a control rod, a CRD, a control rod guide tube, a four-lobed fuel

support piece, and the four fuel assemblies that rest on the fuel support piece. The housings are fabricated of Type 304 austenitic stainless steel.

5.3.3.1.4.3 Incore Neutron Flux Monitor Housings

Each incore neutron flux monitor housing is inserted through the incore penetrations in the bottom head and is welded to the inner surface of the bottom head.

An incore flux monitor guide tube is welded to the top of each housing and either a SRM/IRM drive unit or a LPRM is bolted to the seal/ring flange at the bottom of the housing (Sections 7.6 and 7.7).

5.3.3.1.4.4 Reactor Vessel Insulation

The reactor vessel top head insulation is designed to permit complete submersion in water during shutdown without loss of insulating material, contamination of the water, or adverse effect on the insulation efficiency after draining. Most of the reactor vessel insulation is of the stainless steel, reflective type. The insulation used for many of the large reactor vessel nozzles is fiberglass-type, in blanket form. The top head insulation framework is designed to seismic Category I requirements and is used as an anchor point for reactor vessel vent piping.

The insulation above the reactor vessel stabilizer brackets is close-fitting, freestanding insulation designed to be 100% removable for inservice inspection of the reactor vessel.

The insulation below the stabilizer brackets is suspended from the brackets to allow a minimum of 8 inches annular clearance between the reactor vessel and the insulation for remote inservice inspection of the reactor vessel. Some of the suspended insulation is removable to permit access for manual inspection in locations where remote inspection may not be feasible. The suspended insulation is also equipped with removable access ports.

Reactor vessel bottom head insulation includes horizontal flat panels connected to a cylindrical shell covering the inside of the reactor support skirt. The top row of the cylindrical shell panels are removable to expose the bottom head for inservice inspection.

Quick removable insulation is provided around all reactor vessel nozzles to allow manual or remote automatic examination of nozzle-to-vessel and nozzle-to-piping welds.

5.3.3.1.4.5 Reactor Vessel Nozzles

All piping connected to the reactor vessel nozzles is designed to not exceed the allowable loads on any nozzle.

The vessel top head nozzles are provided with a flange with small groove facings. The drain nozzle is of the full penetration weld design. The recirculation inlet nozzles (located as shown in Figure 5.3-1), feedwater inlet nozzles, the RHR LPCI inlet nozzles, and the core spray inlet nozzles all have thermal sleeves.

With the exception of the Unit 2 N16D nozzle (ASME Section III, SB-167), nozzles connecting to stainless steel piping have safe ends made of stainless steel or Inconel (ASME Section III, SB-166). These safe ends are welded to the nozzles after the pressure vessel has been heat treated to avoid furnace sensitization of the stainless steel safe ends. The material used is compatible with the material of the mating pipe.

5.3.3.1.4.6 Materials and Inspections

The reactor vessel is designed and fabricated in accordance with the appropriate ASME Code as defined in Section 5.2.1. Table 5.2-3 defines the materials and specifications. Section 5.3.1.6 defines the compliance with reactor vessel material surveillance program requirements.

5.3.3.1.4.7 Reactor Vessel Schematic (BWR)

The reactor vessel schematic is contained in Figure 5.3-1. Trip system water levels are indicated as shown in Figure 5.3-2.

5.3.3.2 Materials of Construction

All materials used in the construction of the RPV conform to the requirements of ASME Section II materials. The vessel heads, shells, flanges, and nozzles are fabricated from low alloy steel plate and forgings purchased in accordance with ASME SA533, Grade B, Class 1 and ASME SA508, Class 2. Special requirements for the low alloy steel plate and forgings are discussed in Section 5.3.1.2. Cladding employed on the interior surfaces of the vessel consists of austenitic stainless steel weld overlay.

These materials are selected because they provide adequate strength, fracture toughness, fabricability, and compatibility with the BWR environment. Their suitability is demonstrated by long-term successful operating experience in reactor service.

5.3.3.3 Fabrication Methods

The RPV is a vertical, cylindrical pressure vessel of welded construction fabricated in accordance with ASME Section III, Class I requirements. All fabrication of the RPV is performed in accordance with GE approved drawings, fabrication procedures, and test procedures. The shell and vessel head are made from formed low alloy steel plates, and the flanges and nozzles from low alloy steel forgings. Welding performed to join these vessel components is in accordance with procedures qualified in ASME Sections III and IX requirements. Weld test samples are required for each procedure for major vessel full penetration welds.

Submerged arc and manual stick electrode welding processes are employed. Electroslag welding is not permitted. Preheat and interpass temperatures employed for welding of low alloy steel meet or exceed the requirements of ASME Section III, subsection NA. Postweld heat treatment of 1100°F minimum is applied to all low alloy steel welds.

All previous BWR pressure vessels employed similar fabrication methods. These vessels have operated for periods of up to 16 years and their service history is excellent.

The vessel fabricator, Chicago Bridge and Iron Co., has had extensive experience with GE reactor vessels dating back to 1966. Chicago Bridge and Iron Nuclear Co. was formed in 1972 from a merger agreement between Chicago Bridge and Iron Co. and GE and has continued as the primary supplier for GE domestic reactor vessels.

5.3.3.4 Inspection Requirements

All plate, forgings, and bolting were 100% ultrasonically tested and surface examined by magnetic particle methods or liquid penetrant methods in accordance with ASME Section III requirements. Welds on the reactor pressure vessel were examined in accordance with methods prescribed and

meet the acceptance requirements specified by ASME Section III. In addition, the pressure-retaining welds were ultrasonically examined in accordance with ASME Section XI requirements prior to shipping.

5.3.3.5 Shipment and Installation

The LGS reactor vessels were assembled at the site. Methods and procedures are discussed in the PSAR, Appendix G. Suitable measures were taken during installation to ensure that vessel integrity was maintained; for example, access controls were applied to personnel entering the vessel, weather protection was provided, and periodic cleanings were performed.

5.3.3.6 Operating Conditions

Procedural controls on plant operation are implemented to hold thermal-stresses within acceptable ranges. These restrictions on coolant temperature are:

a. The average rate of change of reactor coolant temperature during normal heatup and cooldown shall not exceed 100°F during any 1 hour period.

b. If the coolant temperature difference between the dome (inferred from PSAT) and the bottom head drain exceeds 145°F, the reactor recirculation pumps shall not be started, and neither reactor power nor recirculation pump flow shall be increased.

c. The pump in an idle reactor recirculation loop shall not be started unless the coolant temperature in that loop is within 50°F of average reactor coolant temperature.

The limit regarding the normal rate of heatup and cooldown (item a) ensures that the vessel closure, closure studs, vessel support skirt, and CRD housing and stub tube stresses and usage remain within acceptable limits. The limit regarding a vessel temperature limit on recirculation pump operation and power level increase restriction (item b) augments the item a. limit in further detail by ensuring that the vessel bottom head region is not warmed at an excessive rate caused by rapid sweep out of cold coolant in the vessel lower head region by recirculation pump operation or natural circulation (cold coolant can accumulate as a result of control drive inleakage and/or low recirculation flow rate during startup or hot standby). The item c. limit further restricts operation of the recirculation pumps to avoid high thermal-stress effects in the pumps and piping, while also minimizing thermal-stresses on the vessel nozzles.

The above operational limits are maintained to ensure that the stress limits within the reactor vessel and its components are within the thermal limits to which the vessel is designed for normal operating conditions. To maintain the integrity of the vessel if these operational limits are exceeded, the reactor vessel is also designed to withstand a limited number of transients caused by operator error. Also, for abnormal operating conditions where safety systems or controls provide an automatic temperature and pressure response in the reactor vessel, the reactor vessel integrity is maintained since the severest anticipated transients are included in the design conditions. Therefore, it is concluded that vessel integrity is maintained during the most severe postulated transients, since all such transients are evaluated in the design of the reactor vessel.

5.3.3.7 Inservice Surveillance

The vessel is examined once prior to startup to satisfy the preoperational requirements of ASME Section XI. Subsequent ISI is scheduled and performed in accordance with the requirements of 10CFR50.55a .

The materials surveillance program monitors changes in the fracture toughness properties of ferritic materials in the reactor vessel beltline region resulting from their exposure to neutron irradiation and the thermal environment. Specimens of actual reactor beltline material are exposed in the reactor vessel and periodically withdrawn for impact testing. Operating procedures are modified in accordance with test results to ensure adequate brittle fracture control.

Material surveillance programs and ISI programs are in accordance with applicable ASME code requirements, and provide assurance that brittle fracture control and pressure vessel integrity are maintained throughout the service life of the RPV.

Inservice inspection and testing of the RCPB is discussed in detail in Section 5.2.4.

5.3.4 REFERENCES

5.3-1 "Metal Progress", pp. 35-39, (July 1978).

5.3-2 "Radiation Effects in BWR Pressure Vessel Steels", GE Licensing Topical Report, NEDO-21708.

5.3-3 Letter MFN-414-77, G.G. Sherwood (GE) to Edson G. Case (NRC), (October 17, 1977).

5.3-4 Letter, Robert B. Minogue (NRC) to G.G. Sherwood (GE), (February 14, 1978).

5.3-5 NEDO-21778A, Transient Pressure Rise Affecting Fracture Toughness for BWR's, GE Licensing Topical Report (December 1978).

5.3-6 NEDO-32205-A, Revision 1, 10CFR50 Appendix G Equivalent Margin Analysis for Low Upper Shelf Energy in BWR/2 Through BWR/6 Vessels.

5.3-7 Reference no longer used

5.3-8 General Electric Co. Report GE-NE-B1100786-01R1, “Surveillance Specimen Program Evaluation for Limerick Generating Station Unit 1”, dated December 1997.

5.3-9 General Electric Co. Report GE-NE-B1100786-02, “Surveillance Specimen Program Evaluation for Limerick Generating Station Unit 2”, dated June 1998.

5.3-10 “Limerick Generating Station, Units 1 and 2, SRV Setpoint Tolerance Relaxation Licensing Report”, NEDC-32645P (December 1998).

5.3-11 Structural Integrity Associates, Inc., 00018973-VC-00006, Exelon Corporation Limerick Generating Station Unit 1 Pressure and Temperature Limits Report (PTLR) for 57 Effective Full-Power Years (EFPY).

5.3-12 Structural Integrity Associates, Inc., 00018973-VC-00008, Exelon Corporation Limerick Generating Station Unit 2 Pressure and Temperature Limits Report (PTLR) for 57 Effective Full-Power Years (EFPY).

5.3-13 BWRVIP-86, Revision 1-A: BWR Vessel and Internals Project Updated BWR Integrated Surveillance Program (ISP) Implementation Plan," dated October 2012.

5.3-14 Letter from S. P. Wall (U.S. NRC) to J. L. Skolds (Exelon Generation Company, LLC), "Limerick Generating Station Units 1 and 2 - Issuance of Amendment Re: Revision to the Reactor Pressure Vessel Material Surveillance Program (TAC Nos. MB7003 and MB7004)," dated November 4, 2003."

5.3-15 Design Analysis LEAM-MUR-0043, Revision 2, T0301, "RPV Fracture Toughness Evaluation"

5.3-16 "Upper Shelf Energy Evaluation for LPCI Nozzle Forging Material," GEH-0000-0114-0580-R0, Revision, August 2010.

5.3-17 U.S. NRC Letter to BWROG dated May 16, 2013, "Final Safety Evaluation for Boiling Water Reactor Owners' Group Topical Report BWROG-TP-11-022, Revision 1, November 2011, 'Pressure-Temperature Limits Report Methodology for Boiling Water Reactors'" (TAC NO. ME7649, ADAMS Accession No. ML13277A557).

5.3-18 PECO Nuclear Letter dated November 20, 2000, GE Nuclear Energy Report No. GENE-B11-00836-00-02a NP, Revision 0, "Pressure-Temperature Curves For PECO Energy Company, Limerick Unit 2," July 2000 (ADAMS Accession No. ML003772248).

5.3-19 PECO Nuclear Letter dated May 19, 2000, GE Nuclear Energy Report No. GE-NE-B11-00836-00-01a NP, Revision 0, "Pressure-Temperature Curves For PECO Energy Company, Limerick Unit 1," April 2000 (ADAMS Accession No. ML003718786).

5.3-20 Limerick Generating Station, Unit 2, License Amendment No. 111, Issuance of Amendment Re. Update The Pressure-Temperature Limit Curves (TAC No. MB0590, ADAMS Accession No. ML010540068), March 23, 2001.

5.3-21 Limerick Generating Station, Unit 1, License Amendment No. 145, Issuance of Amendment Re. Update Pressure-Temperature (P-T) Limit Curves (TAC No. MA8953, ADAMS Accession No. ML003745510), September 15, 2000.

Table 5.3-1

APPENDIX G MATRIX FOR LGS
(Unit 1)

APPENDIX G PARA. NO.	TOPIC	COMPLY YES/NO OR N/A	ALTERNATE ACTIONS OR COMMENTS
I, II	Introduction; definitions	-	-
III.A	Compliance With ASME Section III NB-2300	Yes	See Section 5.3.1.5.1.2 for discussion
III.B.1	Location and orientation of impact test specimens	Yes	See III A above
III.B.2	Materials used to prepare test specimens	No	Compliance except for CVN orientation and CVN upper shelf
IIII.B.3	Calibration of temperature, instrumentation, and Charpy test machines	No	Paragraph NB-2360 of the ASME Section III was not in existence at the time of purchase of the Unit 1 RPV. However the requirements of the 1971 edition of ASME Section III, Summer 1971 addenda are met. For the discussions of the GE interpretations of compliance and NRC acceptance, see References 5.3-3 and 5.3-4. The temperature instruments and Charpy test machines calibration data are retained until the next calibration. This is accordance with Regulatory Guide 1.88 (Section 1.8) and ANSI N45.2.9 (1974). Therefore, the instrument calibration data for Unit 1 are not currently available.
III.B.4	Qualification of testing personnel	No	No written procedures were in existence as now required by the regulation; however individuals were qualified by on-the-job training and past experience. For a discussion of the GE interpretation of compliance and NRC acceptance see References 5.3-3 and 5.3-4.
III.B.5	Test results recording and certification	Yes	See References 5.3-3 and 5.3-4.
III.C.1	Test condtions	No	See III.A, III.B.2, above
III.C.2	Materials used to prepare test specimens for reactor vessel beltline	Yes	Compliance on base metal and weld metal tests. Test welds were not necessarily made on the same heat as that of the base plate.

Table 5.3-1 (Cont'd)

(UNIT 1)

APPENDIX G PARA. NO.	TOPIC	COMPLY YES/NO OR N/A	ALTERNATE ACTIONS OR COMMENTS
IV.A.1	Acceptance standard of materials	-	-
IV.A.2.a	Calculated stress intensity factor	Yes	-
IV.A.2.b	Requirements for nozzles, flanges and shell region near geometric discontinuities	No	Plus 60°F added to the RT_{NDT} for the reactor vessel flanges. For feedwater nozzles, the results of the BWR/6 analysis are adjusted to LGS Unit 1 RT_{NDT} conditions.
IV.A.2.c	RPV metal temperature requirement when core is critical	No	Regulation change in process (See Reference 5.3-5)
IV.A.2.d	Minimum permissible temperature during hydro test	Yes	
IV.A.3	Materials for piping, pumps, and valves	No	See section 5.2.3.3.1
IV.A.4	Materials for bolting and other fasteners	Yes	Meet requirements for closure studs at 10°F.
IV.B	Minimum upper-shelf energy for RPV beltline	No	See Section 5.3.1.7.4 and Reference 5.3-6 for discussion on equivalent margin analysis.
IV.C	Requirement for annealing when RT_{NDT} > 200°F	NA	
V.A	Requirements for material surveillance program	-	See Table 5.3-2
V.B	Conditions for continued operation	Yes	Meet requirements of IV.A.2

Table 5.3-1 (Cont'd)

(UNIT 1)

APPENDIX G PARA. NO.	TOPIC	COMPLY YES/NO OR N/A	ALTERNATE ACTIONS OR COMMENTS
V.C	Alternate if V.B cannot be satisfied	NA	
V.D.	Requirement for RPV thermal annealing if V.C. cannot be met	NA	
V.E.	Reporting requirement for V.C. and V.D.	NA	

COMPLY

Table 5.3-1 (Cont'd)

APPENDIX G MATRIX FOR LGS

(UNIT 2)

APPENDIX G PARA. NO.	TOPIC	COMPLY YES/NO OR N/A	ALTERNATE ACTIONS OR COMMENTS
I, II	Introduction; definitions	-	-
III.A	Compliance With ASME Section NB-2300	Yes	See Section 5.3.1.5.1.2 for discussion
III.B.1	Location and orientation of impact test specimens	Yes	See III A above
III.B.2	Materials used to prepare test specimens	No	Compliance except for CVN orientation and CVN upper shelf
IIII.B.3	Calibration of temperature, instrumentation, and Charpy test machines	No	Paragraph NB-2360 of the ASME Section III was not in existence at the time of purchase of the Unit 2 RPV. However the requirements of the 1971 edition of ASME Section III, Summer 1971 Addenda are met. For the discussions of the GE interpretations of compliance and NRC acceptance, see References 5.3-3 and 5.3-4. The temperature instruments and Charpy test machines calibration data are retained until the next recalibration. This is accordance with Regulatory Guide 1.88 (Section 1.8) and ANSI N45.2.9 (1974). Therefore, the instrument calibration data for Unit 2 are not currently available.
III.B.4	Qualification of testing personnel	No	No written procedures were in existence as now required by the regulation; however individuals were qualified by on-the-job training and past experience. For a discussion of the GE interpretation of compliance and NRC acceptance see References 5.3-3 and 5.3-4.
III.B.5	Test results recording and certification	Yes	See References 5.3-3 and 5.3-4.

Table 5.3-1 (Cont'd)

(UNIT 2)

APPENDIX G PARA. NO.	TOPIC	COMPLY YES/NO OR N/A	ALTERNATE ACTIONS OR COMMENTS
III.C.1	Test condtions	No	See III.A, III.B.2, above
III.C.2	Materials used to prepare test specimens for reactor vessel beltline	Yes	Compliance on base metal and weld metal tests. Test welds were not necessarily made on the same heat as that of the base plate.
IV.A.1	Acceptance standard of materials	-	-
IV.A.2.a	Calculated stress intensity factor	Yes	-
IV.A.2.b	Requirements for nozzles, flanges and shell region near geometric discontinuities	No	Plus 60°F added to the RT_{NDT} for the reactor vessel flanges. For feedwater nozzles, the results of the BWR/6 analysis were adjusted to LGS Unit 2 RT_{NDT} conditions.
IV.A.2.c	RPV metal temperature requirement when core is critical	No	Regulation change in process (See Reference 5.3-5)
IV.A.2.d	Minimum permissible temperature during hydro test	Yes	
IV.A.3	Materials for piping, pumps, and valves	No	See section 5.2.3.3.1
IV.A.4	Materials for bolting and other fasteners	Yes	See Section 5.2.3.3.1.1 for discussion.
IV.B	Minimum upper-shelf energy for RPV beltline	No	See Section 5.3.1.7.4 and Reference 5.3-6 for discussion on equivalent margin analysis.
IV.C	Requirement for annealing when RT_{NDT} > 200°F	NA	
V.A	Requirements for material surveillance program	-	See Table 5.3-2
V.B	Conditions for continued operation	Yes	Meet requirements of IV.A.2

Table 5.3-1 (Cont'd)

(UNIT 2)

APPENDIX G PARA. NO.	TOPIC	COMPLY YES/NO OR N/A	ALTERNATE ACTIONS OR COMMENTS
			EOL upper-shelf values (100% shear) are predicted to be in excess of 50 ft-lb, based upon preceding data and Regulatory Guide 1.99.
IV.C	Requirement for annealing when RT_{NDT} > 200°F	NA	
V.A	Requirements for material surveillance program		See Table 5.3-2
V.B	Conditions for continued operation	Yes	Meet requirements of IV.A.2
V.C	Alternate if V.B cannot be satisfied	NA	
V.D.	Requirement for RPV thermal annealing if V.C. cannot be met	NA	
V.E.	Reporting requirement for V.C. and V.D.	NA	

Table 5.3-2

APPENDIX H MATRIX FOR LGS

APPENDIX H PARA. NO.	TOPIC	COMPLY YES/NO OR N/A	ALTERNATE ACTIONS OR COMMENTS
I	Introduction	NA	
II.A	Fluence $<10^{17}$ n/cm^2 - surveillance program not required	NA	
II.B	Standards requirements (ASTM) for surveillance	No	Noncompliance with ASTM E185-73 in that the surveillance specimens are not necessarily from the limiting beltline material. Specimens are from representative beltline material, however, and can be used to predict behavior of the limiting material. Heat and heat/lot numbers for surveillance specimens are to be supplied.
II.C.1	Surveillance specimen is taken from locations alongside the fracture test specimens (Section III.B of Appendix G)	No	Noncompliance in that specimens are not necessarily taken from alongside specimens required by Section III fo Appendix G and transverse CVNs are employed. However, representative materials are used, and RT_{NDT} shift appears to be independent of specimen orientation.
II.C.2	Locations of surveillance capsules in RPV	Yes	Code basis is used for the attachment of brackets to vessel cladding (Section 5.3.1.6.4).
II.C.3.a	Withdrawal schedule of capsules, $RT_{NDT} \leq 100°F$	Yes	Three capsules planned. Starting RT_{NDT} of limiting material is based on alternative action (see paragraph III.A of Appendix G).
II.C.3.b	Withdrawal schedule of capsules, $100°F < RT_{NDT} \leq 200°F$	NA	
II.C.3.c	Withdrawal schedule of capsules, $RT_{NDT} > 200°F$	NA	
III.A	Fracture toughness testing requirements of specimens	No	CVN tests only

Table 5.3-2 (Cont'd)

(UNIT 1)

APPENDIX H PARA. NO.	TOPIC	COMPLY YES/NO OR N/A	ALTERNATE ACTIONS OR COMMENTS
III.B	Method of determining adjusted reference temperature for base metal, heat affected zone and weld metal	No	II.B and II.C.1 above.
IV.A	Reporting requirements of test results	Yes	
IV.B	Requirement for dosimetry measurement	Yes	
IV.C	Reporting requirements of pressure/temperature limits	Yes	

Table 5.3-2 (Cont'd)

APPENDIX H MATRIX FOR LGS

(UNIT 2)

APPENDIX H PARA. NO.	TOPIC	COMPLY YES/NO OR N/A	ALTERNATE ACTIONS OR COMMENTS
I	Introduction	NA	
II.A	Fluence $<10^{17}$ n/cm^2 - surveillance program not required	NA	
II.B	Standards requirements (ASTM) for surveillance	No	Noncompliance with ASTM E185-73 in that the surveillance specimens are not necessarily from the limiting beltline material. Specimens are from representative beltline material, however, and can be used to predict behavior of the limiting material. Heat and heat/lot numbers for surveillance specimens are to be supplied. (Section 5.3.1.10)
II.C.1	Surveillance specimen is taken from locations alongside the fracture test specimens (Section III.B of Appendix G)	No	Noncompliance in that specimens are not necessarily taken from alongside specimens required by Section III fo Appendix G and transverse CVNs are not employed. However, representative materials are used, and RT_{NDT} shift appears to be independent of specimen orientation.
II.C.2	Locations of surveillance capsules in RPV	Yes	Code basis is used for the attachment of brackets to vessel cladding (Section 5.3.1.6.4).
II.C.3.a	Withdrawal schedule of capsules, $RT_{NDT} \leq 100°F$	Yes	Three capsules planned. Starting RT_{NDT} of limiting material is based on alternative action (see paragraph III.A of Appendix G).
II.C.3.b	Withdrawal schedule of capsules, $100°F < RT_{NDT} \leq 200°F$	No	Material with , RT_{NDT} shift > 100° F is not limiting material; shift was predicted < 100° F at time of surveillance program design,
II.C.3.c	Withdrawal schedule of capsules, $RT_{NDT} > 200°F$	NA	
III.A	Fracture toughness testing requirements of specimens	No	CVN tests only

Table 5.3-2 (Cont'd)

(UNIT 2)

APPENDIX H PARA. NO.	TOPIC	COMPLY YES/NO OR N/A	ALTERNATE ACTIONS OR COMMENTS
III.B	Method of determining adjusted reference temperature for base metal, heat affected zone and weld metal	No	II.B and II.C.1 above.
IV.A	Reporting requirements of test results	Yes	
IV.B	Requirement for dosimetry measurement	Yes	
IV.C	Reporting requirements of pressure/temperature limits	Yes	

Table 5.3-3

LGS BELTLINE PLATE TOUGHNESS DATA

(UNIT 1)

SHELL COURSE	HEAT NO./ SLAB NO.	NDT (°F)	ORIENTATION	CHARPY TEST TEMP (°F)	ENERGY (FT-LB)			LAT. EXPANSION (MIL)			% SHEAR		
NO. 1													
I. D. 14-1	C7688-1	TOP –10	L	+40	84	78	58	62	48	64	40	50	50
		BOTTOM –10	L	+40	78	58	85	78	58	85	40	50	50
I.D. 14-3	C7688-2	TOP –10	L	+40	69	84	79	75	67	58	50	50	50
		BOTTOM –10	L	+40	104	90	86	66	72	78	70	70	70
I. D. 14-2	C7698-2	TOP –10	L	+40	77	88	73	75	66	52	50	50	70
		BOTTOM –10	L	+40	100	98	87	79	72	64	50	60	60
NO. 2													
I. D. 17-3	C7698-1	TOP –10	L	+40	82	84	84	61	63	61	50	50	50
		BOTTOM –10	L	+40	85	96	80	69	63	66	50	50	50
I. D. 17-1	C7689-1	TOP –10	L	+40	87	93	77	73	69	62	50	60	60
		BOTTOM –10	L	+40	75	86	81	61	71	78	50	60	60
I. D. 17-2	C7677-1	TOP –10	L	+40	71	71	61	52	48	56	40	40	40
		BOTTOM –10	L	+40	71	45	65	54	58	55	40	50	50

Table 5.3-3 (Cont'd)

LGS BELTLINE PLATE TOUGHNESS DATA

(UNIT 2)

SHELL COURSE	HEAT NO./ SLAB NO.	NDT (°F)	ORIENTATION	CHARPY TEST TEMP (°F)	ENERGY (FT-LB)			LAT. EXPANSION (MIL)			% SHEAR		
NO. 1													
I. D. 14-1	B3312-1	TOP –20	L	+40	73	69	78	53	53	61	50	50	50
		BOTTOM –20	L	+40	58	63	68	44	48	47	60	60	60
I.D. 14-3	C9621-2	TOP 0	L	+40	44	47	60	35	35	44	30	30	30
		BOTTOM –20	L	+40	77	89	79	60	69	60	30	30	30
I. D. 14-2	B3416-1	TOP +10	L	+40	51	42	55	32	39	48	40	40	50
		BOTTOM 0	L	+40	61	35	37	45	32	36	50	30	30
NO. 2													
I. D. 17-3	C9526-2	TOP –40	L	+40	71	74	87	57	52	50	50	50	50
		BOTTOM –30	L	+40	83	84	97	65	58	62	50	50	50
I. D. 17-1	C9569-2	TOP –20	L	+40	68	62	68	45	50	47	30	30	30
		BOTTOM –30	L	+40	83	87	66	62	50	64	40	40	40
I. D. 17-2	C9526-1	TOP –40	L	+40	65	60	66	47	49	55	30	30	30
		BOTTOM –40	L	+40	73	63	89	68	50	56	40	40	40

(1) Longitudinal or transverse

Table 5.3-4

BELTLINE WELD TOUGHNESS DATA

(UNIT 1)

BELTLINE SHOP WELD TOUGHNESS

IDENTITY	PROCESS	HEAT NO.	FLUX LOT	CHARPY IMPACT TOUGHNESS									
				CV TEMP (°F)	ABSORBED ENERGY (ft-lb)			LATERAL EXP. (mil)			% SHEAR		
Weld B-E	SMAW	411A3531	H004A27A	+10	60	60	68	51	52	54	60	50	60
				-20	41	68	48	39	53	41	35	35	25
Welds, B-A, B-B, B-D, B-F	SMAW	06L165	F017A27A	+10	60	61	62	40	52	46	70	60	70
				-20	46	53	32	34	39	24	25	25	25
Welds B-A B-D, B-E, B-F	SMAW	662A746	H013A27A	+10	35	38	47	35	31	43	50	50	50
				-20	89	82	95	69	64	68	45	40	65
Welds B-A, B-B, B-C	SAW	3P4000	3932-989	+10	97	95	88	85	82	64	80	80	70
Weld B-F	SAW	S3986	Run #934	+10	46	51	49	38	44	43	40	40	40
Welds B-A, B-B, B-E	SAW	1P4218	3929-989	+10	98	100	102	72	65	83	82	65	83
					94	91	90	58	66	77	98	95	95
Surveillance Test Plate Weld	SAW	421A6811	F022A27A	+10	80	85	91	64	73	72	70	75	75
N-17 Nozzle	SMAW	07L669	K004A27A		73 (Note 2)								
N-17 Nozzle	SMAW	411A3531	H004A27A		73 (Note 2)								
N-17 Nozzle	SMAW	401Z9711	A022A27A		73 (Note 2)								
N-17 Nozzle	SMAW	662A746	H013A27A		73 (Note 2)								
N-17 Nozzle	SMAW	S3986	RUN #934		73 (Note 2)								

Table 5.3-4 (Cont'd)

UNIT 1

BELTLINE FIELD WELD TOUGHNESS DATA

Test No.	983
Trade Name:	Atom Arc 8018NM
Diameter Size:	1/8 in 1,400 lb
Lot No.:	B101A27A
Heat No.:	07L857

CHEMICAL TEST RESULTS

Carbon	0.060
Manganese	1.20
Nickel	0.97
Silicon	0.42
Molybdenum	0.55
Copper	0.03
Phosphorus	0.012
Sulfur	0.017

MECHANICAL TEST RESULTS

Test Specimen PW ht @ 1100°F to 1150°F for 62½ hr

TENSILE PROPERTIES

Specimen Type: 0.505 in
UTS: 89,600 psi
YKP: 76,200 psi
Elongation in 2 in: 30%
Red of Area: 71.7%

IMPACT PROPERTIES

Specimen Type: Charpy V-Notch
Test Temp: +10°F
Energy (ft-lb): 28, 36, 39
Lateral Expansion (mil): 27, 41, 45
% Shear: 20, 40, 50

OTHER TESTS

Concentricity: 4%
Moisture @ 1800°F: 0.18%

Table 5.3-4 (Cont'd)

(UNIT 1)

		MECHANICAL TESTS
Test No.:	38	Test Specimen PW @ 1100°F to 1150°F for 62½ hr
Trade Name:	Atom Arc 8018NM	
Diameter Size:	5/32 in 6,750 lb	
Lot No.:	C115A27A	
Heat No.:	402C4371	TENSILE PROPERTIES
		Specimen Type: 0.505 in UTS: 94,000 psi YLP: 87,000 psi Elongation in 2 in: 26% Red of Area: 71.3%
CHEMICAL TEST RESULTS		
Carbon	0.033	
Manganese	1.22	
Nickel	0.92	
Silicon	0.49	
Molybdenum	0.57	
Copper	0.02	IMPACT PROPERTIES
Phosphorus	0.009	
Sulfur	0.014	Specimen Type Charpy V-Notch Test Temp: +10°F Energy (ft-lb): 82, 81, 92 Lateral Expansion (mil): 62, 61, 66 % Shear Area: 80, 70, 70
		OTHER TESTS
		Concentricity: 5% Moisture @ 1800°F: 0.18%

Table 5.3-4 (Cont'd)

(UNIT 1)

Test No.:	WO #11-D
Type Electrode:	E8018NM
Trade Name:	Atom Arc 8018NM
Electrode Diameter:	3/16 in
Lot No.:	H004A27A
Heat No.:	411A3531

CHEMICAL TEST RESULTS

Carbon	0.066
Manganese	1.13
Nickel	0.96
Silicon	0.51
Molybdenum	0.47
Copper	0.02
Phosphorus	0.018
Sulfur	0.017

MECHANICAL TESTS

Heat Treatment 1100°F to 1150°F for 62½ hr

TENSILE PROPERTIES

Specimen Type: 0.505 in
UTS: 84,500 psi
YLP: 71,500 psi
Elongation in 2 in: 29%
Red of Area: 72.5%

IMPACT PROPERTIES

Specimen Type: Charpy V-Notch
Test Temperature: -20°F
Energy (ft-lb): 41, 68, 48
Lateral Expansion (mil): 39, 53, 41
% Shear: 35, 35, 25

Table 5.3-4 (Cont'd)

(UNIT 1)

Test No.:	27
Trade Name:	Atom Arc 8018NM
Diameter Size:	7/32 in 13,800 lb
Lot No.:	C109A27A
Heat No.:	09M057

CHEMICAL TEST RESULTS

Carbon	0.063
Manganese	1.18
Nickel	0.89
Silicon	0.47
Molybdenum	0.53
Copper	0.03
Phosphorus	0.009
Sulfur	0.021

MECHANICAL TESTS

Test Specimen PW ht @ 1100°F to 1150ºF for 62½ hr

TENSILE PROPERTIES

Specimen Type: 0.505 in
UTS: 94,500 psi
YLP: 85,000 psi
Elongation in 2 in: 27%
Red of Area: 69.8%

IMPACT PROPERTIES

Specimen Type: Charpy V-Notch
Test Temp: +10ºF
Energy (ft-lb): 43, 43, 44
Lateral Expansion (mil): 40, 41, 41
% Shear: 50, 60, 50

OTHER TESTS

Concentricity: 4%
Moisture @ 1800ºF: 0.18%

Table 5.3-4 (Cont'd)

(UNIT 1)

Test No.:	346
Trade Name:	Atom Arc 8018NM
Diameter Size:	3/16 in 7,950 lb
Lot No.:	J417B27AF
Heat No.:	412P3611

CHEMICAL TEST RESULTS

Carbon	0.07
Manganese	1.10
Chromium	0.03
Nickel	0.93
Silicon	0.36
Molybdenum	0.47
Copper	0.03
Phosphorus	0.016
Sulfur	0.019
Vanadium	0.02
Aluminum	<0.01

MECHANICAL TESTS

Stress relieved 50 hr @ 1150°F

TENSILE PROPERTIES

UTS: 87,500 psi
YLP: 75,000 psi
Elongation in 2 in: 28%
Red of Area: 71.2%

IMPACT PROPERTIES

See page 5.3-38 for impact values

OTHER TESTS

Concentricity: 3%
Moisture @ 1800°F: 0.2%

Table 5.3-4 (Cont'd)

(UNIT 1)

DROP-WEIGHT TESTS	SPECIMEN	TEST TEMPERATURE (°F)	RESULTS
MATERIAL: 8018NM	1	-90	Break
LOT: J417B27AF	2	-80	Break
HEAT: 412P3611	3	-70	No Break
	4	-70	No Break

NDT TEMPERATURE = -80°F

CVN IMPACT TESTS

SPECIMEN	TEST TEMPERATURE (°F)	ENERGY (ft-lb)	LATERAL EXP. (mil)	% SHEAR
1	-100	8	6	3
2	-100	12	10	5
3	-80	15	13	10
4	-80	16	14	10
5	-80	19	15	10
6	-20	52	41	30
7	-20	65	54	50
8	-20	69	53	45
9	+40	100	80	90
10	+40	103	68	80
11	+72	133	91	90
12	+72	138	92	90
13	+130	136	89	100
14	+130	137	95	100
15	+130	146	97	100

T_{cv} = -20°F

REFERENCE TEMPERATURE

Material	T_{NDT} (Drop-Weight)	T_{CV} (Charpy V-Notch)	RT_{NDT} (References)
Weld Metal	-80°F	-20°F	-80°F

Table 5.3-4 (Cont'd)

(UNIT 1)

Test No.:	46
Trade Name:	Atom Arc 8018NM
Diameter Size:	3/16 in 7,900 lb
Lot No.:	C118A27A
Heat No.:	03M014

CHEMICAL TEST RESULTS

Carbon	0.041
Manganese	1.23
Nickel	0.94
Silicon	0.53
Molybdenum	0.58
Copper	0.01
Phosphorus	0.012
Sulfur	0.015

MECHANICAL TEST RESULTS

Test Specimen PW ht @ 1100°F to 1150°F for 62½ hr

TENSILE PROPERTIES

Specimen Type: 0.505 in
UTS: 92,500 psi
YLP: 82,500 psi

Elongation in 2 in: 26%
Red of Area: 69.5%

IMPACT PROPERTIES

Specimen Type: Charpy V-Notch
Test Temp: +10°F
Energy (ft-lb): 42, 44, 47
Lateral Expansion (mil): 37, 37, 51
% Shear: 40, 40, 40

OTHER TESTS

Concentricity: 5%
Moisture @ 1800°F: 0.16%

Table 5.3-4 (Cont'd)

(UNIT 1)

Test No.:	242
Trade Name:	Atom Arc 8018NM
Diameter Size:	1/8 in
	2,100 lb
Lot No.:	S411B27AD
Heat No.:	L83355

CHEMICAL TEST RESULTS

Carbon	0.07
Manganese	1.25
Chromium	0.03
Nickel	1.08
Silicon	0.38
Molybdenum	0.53
Copper	0.03
Phosphorus	0.017
Sulfur	0.018
Vanadium	0.02
Aluminum	<0.01

MECHANICAL TEST RESULTS

Stress relieved 50 hr @1150°F

TENSILE PROPERTIES

UTS: 87,600 psi
YLP: 77,900 psi
Elongation in 2 in: 25%
Red of Area: 71.4%

IMPACT PROPERTIES

See page 5.3-41 for impact values

OTHER TESTS

Concentricity: 4%
Moisture @ 1800°F: 0.2%

Table 5.3-4 (Cont'd)

(UNIT 1)

DROP-WEIGHT TESTS	SPECIMEN	TEST TEMPERATURE (°F)	RESULTS
MATERIAL:8018NM	1	-90	Break
LOT: S411B27AD	2	-80	No Break
HEAT: L83355	3	-80	No Break

NDT TEMPERATURE = -90°F

CVN IMPACT TESTS

SPECIMEN	TEST TEMPERATURE (°F)	ENERGY (ft-lb)	LATERAL EXP. (mil)	% SHEAR
1	-105	7	6	5
2	-105	8	7	5
3	-90	19	11	8
4	-90	21	11	10
5	-90	21	13	10
6	-30	27	25	25
7	-30	30	24	25
8	-30	34	29	25
9	-20	31	26	30
10	-20	36	29	30
11	-20	45	37	30
12	-10	51	39	40
13	-10	52	37	40
14	-10	63	52	50
15	+40	112	83	80
16	+40	126	79	80
17	+130	150	91	100
18	+130	154	83	100
19	+130	154	83	100

T_{cv} = -10°F

REFERENCE TEMPERATURE

Material	T_{NDT} (Drop-Weight)	T_{CV} (Charpy V-Notch)	RT_{NDT} (References)
Weld Metal	-90°F	-10°F	-70°F

Table 5.3-4 (Cont'd)

(UNIT 1)

Test No.:	374
Trade Name:	Atom Arc 8018NM
Diameter Size:	5/32 in 2,000 lb
Lot No.:	J424B27AE
Heat No.:	640892

CHEMICAL TEST RESULTS

Carbon	0.08
Manganese	1.20
Chromium	0.04
Nickel	1.00
Silicon	0.44
Molybdenum	0.55
Copper	0.09
Phosphorus	0.015
Sulfur	0.018
Vanadium	0.02
Aluminum	0.01

MECHANICAL TEST RESULTS

Stress relieved 50 hr @ 1150°F

TENSILE PROPERTIES

UTS: 90,000 psi
YLP: 76,500 psi
Elongation in 2 in: 27%
Red of Area: 71%

IMPACT PROPERTIES

See page 5.3-43 for impact values

OTHER TESTS

Concentricity: 3%
Moisture @ 1800°F: 0.2%

Table 5.3-4 (Cont'd)

(UNIT 1)

DROP-WEIGHT TESTS	SPECIMEN	TEST TEMPERATURE (°F)	RESULTS
MATERIAL: 8018NM	1	-70	Break
LOT: J424B27AE	2	-60	No Break
HEAT: 640892	3	-60	No Break

NDT TEMPERATURE = -70°F

CVN IMPACT TESTS

SPECIMEN	TEST TEMPERATURE (°F)	ENERGY (ft-lb)	LATERAL % EXP. (mil)	SHEAR
1	-108	14	3	3
2	-108	16	3	3
3	-70	15	8	5
4	-70	20	9	10
5	-70	27	15	10
6	-10	38	26	30
7	-10	42	31	30
8	-10	45	31	30
9	0	55	38	35
10	0	62	44	40
11	0	62	48	40
12	+40	56	42	50
13	+40	75	55	60
14	+130	118	87	100
15	+130	122	89	100
16	+130	130	82	100

T_{cv} = -10°F

REFERENCE TEMPERATURE

Material	T_{NDT} (Drop-Weight)	T_{CV} (Charpy V-Notch)	RT_{NDT} (References)
Weld Metal	-70°F	0°F	-60°F

Table 5.3-4 (Cont'd)

(UNIT 1)

RESULTS

Test No.:	261
Trade Name:	Atom Arc 8018NM
Diameter Size:	7/32 in 2,400 lb
Lot No.:	S419B27AG
Heat No.:	401P6741

CHEMICAL TEST RESULTS

Carbon	0.06
Manganese	1.16
Chromium	0.03
Nickel	0.92
Silicon	0.34
Molybdenum	0.47
Copper	0.03
Phosphorus	0.013
Sulfur	0.014
Vanadium	0.02
Aluminum	<0.01

MECHANICAL TEST

Stress relieved 50 hr @ 1150°F

TENSILE PROPERTIES

UTS: 85,000 psi
YLP: 78,000 psi
Elongation in 2 in: 30%
Red of Area: 73%

IMPACT PROPERTIES

See page 5.3-45 for impact values

OTHER TESTS

Concentricity: 3%
Moisture @ 1800°F: 0.2%

Table 5.3-4 (Cont'd)

(UNIT 1)

DROP-WEIGHT TESTS	SPECIMEN	TEST TEMPERATURE (°F)	RESULTS
MATERIAL: 8018NM	1	-70	Break
LOT: S419B27AG	2	-60	No Break
HEAT: 401P6741	3	-60	No Break
	NDT TEMPERATURE = -70°F		

CVN IMPACT TESTS

SPECIMEN	TEST TEMPERATURE (°F)	ENERGY (ft-lb)	LATERAL EXP. (mil)	% SHEAR
1	-90	13	8	5
2	-90	14	8	5
3	-70	11	12	10
4	-70	13	14	8
5	-70	16	16	15
6	-10	31	24	25
7	-10	44	30	30
8	-10	76	57	40
9	0	51	37	45
10	0	57	44	40
11	0	68	50	40
12	+40	83	61	50
13	+40	100	80	70
14	+130	136	93	100
15	+130	139	94	100
16	+130	146	94	100

T_{cv} = 0°F

REFERENCE TEMPERATURE

Material	T_{NDT} (Drop-Weight)	T_{CV} (Charpy V-Notch)	RT_{NDT} (References)
Weld Metal	-70°F	0°F	-60°F

Table 5.3-4 (Cont'd)

(UNIT 1)

		MECHANICAL TEST RESULTS
Test No.:	CN-165	Heat Treatment: 1150°F for 50 hr
Electrode Specification:	WMS-444F, (Rev 1)	
Electrode Type:	CBI 1NMM	
Trade Name:	Raco 1NMM	TENSILE PROPERTIES
Electrode Diameter: 3/32 in		Specimen Type: 0.505 in UTS: 90,500 psi
Heat No.:	5P6756	YLP: 84,000 psi Elongation in 2 in: 25% Red of Area: 64.1%

CHEMICAL TEST RESULTS

Carbon	0.13
Manganese	1.89
Chromium	0.08
Nickel	0.96
Silicon	0.07
Molybdenum	0.48
Copper	0.08
Phosphorus	0.008
Sulfur	0.012
Vanadium	0.006
Aluminum	0.02

IMPACT PROPERTIES

Specimen Type: Charpy V-Notch
Orientation: Perpendicular to weld direction
See page 5.3-47 for impact values

Table 5.3-4 (Cont'd)

(UNIT 1)

DROP-WEIGHT TESTS	SPECIMEN	TEST TEMPERATURE (°F)	RESULTS
MATERIAL: C BI 1NMM	1	-40	No Break
HEAT: 5P6756	2	-60	Break
	3	-50	No Break
	4	-50	No Break
	NDT TEMPERATURE = -60°F		

CVN IMPACT TESTS (@ 1/2T LOCATION)

SPECIMEN	TEST TEMPERATURE (°F)	ENERGY (ft-lb)	LATERAL EXP. (mil)	% SHEAR
1	-20	97	60	60
2	-20	115	75	75
3	-20	105	45	70
4	-20	107	74	65
5	-20	94	65	65
6	0	134	55	100
7	0	121	78	100
8	0	124	75	100
	T_{cv} = 0°F			

REFERENCE TEMPERATURE

Material	T_{NDT} (Drop-Weight)	T_{CV} (Charpy V-Notch)	RT_{NDT} (References)
Weld Metal	-60°F	0°F	-60°F

Table 5.3-4 (Cont'd)

BELTLINE WELD TOUGHNESS DATA

(UNIT 2)

BELTLINE SHOP WELD TOUGHNESS DATA[1]

WELD IDENTITY	PROCESS	HEAT NO.	FLUX LOT	NDT (°F)	CV TEMP (°F)	CHARPY IMPACT TOUGHNESS ABSORBED ENERGY (ft-lbs)			LATERAL EXP. mil			% SHEAR		
Seams BA,BB,BD,BE,BF	SMAW	432A2671	H019A27A	N/A	+10	31	31	33	30	32	30	30	30	30
					-20	64	42	32	53	34	31	40	35	30
Seams BA, BC	SMAW	03R728	L910A27A	N/A	+10	64	61	72	50	55	56	60	70	70
Seams BA,BB,BC,BD,BE,BF	SAW (SINGLE WIRE)	3P4000	3933	N/A	+10	92,92,95,82,80			81,62,60,72,66			80,80,80,75,80		
Seams BA,BB,BC,BD,BE,BF	SAW (TANDEM WIRE)	3P4000	3933	N/A	+10	90,86,91,87,79			78,73,58,76,71			95,90,98,90,80		
Seam BB	SMAW	401Z9711	A022A27A	N/A	+10	98	99	104	70	69	73	80	70	80
Seam BC	SMAW	662A746	H013A27A	N/A	+10	35	38	47	35	31	43	50	50	50
					-20	89	82	95	69	64	68	45	40	65
Seam BC	SMAW	402A0462	B023A27A	N/A	+10	75	77	86	60	70	60	60	60	62
Seams BD, BE	SMAW	09L853	A111A27A	N/A	+10	78	78	79	60	62	62	70	80	60
Seams BC,BD,BE,BF	SMAW	07L669	K004A27A	N/A	+10	50	50	54	44	44	46	50	50	54
					-20	49, 60, 55, 61, 54			41, 54, 46, 50, 49			40, 40, 35, 35, 35		
Seam AB	SMAW	07L857	B101A27A	N/A	+10	28	36	39	27	41	45	20	40	50
N-17 Nozzle	SMAW	432A2671	H019A27A			73 (Note 2)								
N-17 Nozzle	SMAW	09L853	A111A27A			73 (Note 2)								
N-17 Nozzle	SMAW	07L669	K004A27A			73 (Note 2)								
N-17 Nozzle	SMAW	C3L46C	J020A27A			73 (Note 2)								
N-17 Nozzle	SMAW	422B7201	L030A27A			73 (Note 2)								
N-17 Nozzle	Single/ Tandem	4P4784	3930			97/95								

Table 5.3-4 (Cont'd)

(UNIT 2)

WELD IDENTITY	PROCESS	HEAT NO.	FLUX LOT	NDT (°F)	CHARPY IMPACT TOUGHNESS									
					CV TEMP (°F)	ABSORBED ENERGY (ft-lbs)			LATERAL EXP. mil			% SHEAR		
Seam AB	SMAW	402C4371	C115A27A	N/A	+10	82	84	92	62	61	66	80	70	70
Seam AB	SMAW	03M014	C118A27A	N/A	+10	42	44	47	37	37	51	40	40	40
Seam AB	SMAW	411A3531	H004A27A	N/A	+10	60	60	68	51	52	54	60	50	60
					-20	41	68	48	39	53	41	35	35	25
Seam AB	SMAW	09M057	C109A27A	N/A	+10	43	43	44	40	41	41	50	60	50
Seam AB	SMAW	L83355	S411B27AD	N/A	See page 5.3-50									
Seam AB	SMAW	640892	J424B27AE	N/A	See page 5.3-52									
Seam AB	SMAW	401P6741	S419B27AG	N/A	See page 5.3-53									
Seam AB	SMAW	412P3611	J417B27AF	N/A	See page 5.3-51									

Table 5.3-4 (Cont'd)

(UNIT 2)

DROP-WEIGHT TESTS	SPECIMEN	TEST TEMPERATURE °F	RESULTS
MATERIAL: 8018NM	1	-90	Break
LOT: S411B27AD	2	-80	No Break
HEAT: L83355	3	-80	No Break
	NDT TEMPERATURE = -90°F		

CVN IMPACT TESTS

SPECIMEN	TEST TEMPERATURE (°F)	ENERGY (ft-lb)	LATERAL EXP. (mil)	% SHEAR
1	-105	7	6	5
2	-105	8	7	5
3	-90	19	11	8
4	-90	21	11	10
5	-90	21	13	10
6	-30	27	25	25
7	-30	30	24	25
8	-30	34	29	25
9	-20	31	26	30
10	-20	36	29	30
11	-20	45	37	30
12	-10	51	39	40
13	-10	52	37	40
14	-10	63	52	50
15	+40	112	83	80
16	+40	126	79	80
17	+130	150	91	100
18	+130	154	83	100
19	+130	154	83	100
		T_{cv} = -10°F		

REFERENCE TEMPERATURE

Material	T_{NDT} (Drop-Weight)	T_{CV} (Charpy V-Notch)	RT_{NDT} (References)
Weld Metal	-90°F	-10°F	-70°F

Table 5.3-4 (Cont'd)

(UNIT 2)

DROP-WEIGHT TESTS	SPECIMEN	TEST TEMPERATURE °F	RESULTS
MATERIAL: 8018NM	1	-90	Break
LOT: J417B27AF	2	-80	Break
HEAT: 412P3611	3	-70	No Break
	4	-70	No Break
	NDT TEMPERATURE = -80°F		

CVN IMPACT TESTS

SPECIMEN	TEST TEMPERATURE (°F)	ENERGY (ft-lb)	LATERAL EXP. (mil)	% SHEAR
1	-100	8	6	3
2	-100	12	10	5
3	-80	15	13	10
4	-80	16	14	10
5	-80	19	15	10
6	-20	52	41	30
7	-20	65	54	50
8	-20	69	53	45
9	+40	100	80	90
10	+40	103	68	80
11	+72	133	91	90
12	+72	138	92	90
13	+130	136	89	100
14	+130	137	95	100
15	+130	146	97	100
		T_{cv} = -20°F		

REFERENCE TEMPERATURE

Material	T_{NDT} (Drop-Weight)	T_{CV} (Charpy V-Notch)	RT_{NDT} (References)
Weld Metal	-80°F	-20°F	-80°F

Table 5.3-4 (Cont'd)

(UNIT 2)

DROP-WEIGHT TESTS	SPECIMEN	TEST TEMPERATURE °F	RESULTS
MATERIAL: 8018NM	1	-70	Break
LOT: J424B27AE	2	-60	No Break
HEAT: 640892	3	-60	No Break
	NDT TEMPERATURE = -70°F		

CVN IMPACT TESTS

SPECIMEN	TEST TEMPERATURE (°F)	ENERGY (ft-lb)	LATERAL EXP. (mil)	% SHEAR
1	-108	14	3	3
2	-108	16	3	3
3	-70	15	8	5
4	-70	20	9	10
5	-70	27	15	10
6	-10	38	26	30
7	-10	42	31	30
8	-10	45	31	30
9	0	55	38	35
10	0	62	44	40
11	0	62	48	40
12	+40	56	42	50
13	+40	75	55	60
14	+130	118	87	100
15	+130	122	89	100
16	+130	130	82	100
		T_{cv} = -10°F		

REFERENCE TEMPERATURE

Material	T_{NDT} (Drop-Weight)	T_{CV} (Charpy V-Notch)	RT_{NDT} (References)
Weld Metal	-70°F	0°F	-60°F

Table 5.3-4 (Cont'd)

(UNIT 2)

DROP-WEIGHT TESTS	SPECIMEN	TEST TEMPERATURE °F	RESULTS
MATERIAL: 8018NM	1	-70	Break
LOT: S419B27AG	2	-60	No Break
HEAT: 401P6741	3	-60	No Break
	NDT TEMPERATURE = -70°F		

CVN IMPACT TESTS

SPECIMEN	TEST TEMPERATURE (°F)	ENERGY (ft-lb)	LATERAL EXP. (mil)	% SHEAR
1	-90	13	8	5
2	-90	14	8	5
3	-70	11	12	10
4	-70	13	14	8
5	-70	16	16	15
6	-10	31	24	25
7	-10	44	30	30
8	-10	76	57	40
9	0	51	37	45
10	0	57	44	40
11	0	68	50	40
12	+40	83	61	50
13	+40	100	80	70
14	+130	136	93	100
15	+130	139	94	100
16	+130	146	94	100
		T_{cv} = 0°F		

REFERENCE TEMPERATURE

Material	T_{NDT} (Drop-Weight)	T_{CV} (Charpy V-Notch)	RT_{NDT} (References)
Weld Metal	-70°F	0°F	-60°F

Table 5.3-4 (Cont'd)

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(1) This table is complemented by Table 5.3-5.

Note 2: An initial Upper Shelf Energy (USE) of 73 ft-lb has been applied for the N-17 nozzle welds. The Safety Evaluation Report for the Measurement Uncertainty Recapture Power Uprate, Section 3.9.3, states that the NRC reviewed the CMTR CVN data for LGS Units 1 and 2, LPCI nozzle (N-17) weld materials and concluded that it would be conservative to assume an initial USE value of 73 ft-lb for the LGS Units 1 and 2 SMAW materials instead of the initial USE values resulting from testing performed at temperatures lower than 40 degrees F.

Table 5.3-5

LGS BELTLINE PLATE WELDS AND FORGINGS EOL RT_{NDT} Based on 57 EFPY

(Unit 1)

(PEAK EOL FLUENCE = 7.35×10^{18} n/cm^2 @ ¼T)

A. Plates

I.D.	Heat	Wt % Cu	Wt % P	Wt % Ni	Wt % S	ASME NB-2300 Start RT_{NDT} (°F)	Estimated 57 EFPY EOL RT_{NDT} (°F)
14-1	C7688-1	0.12	0.011	0.51	0.015	+10	59.9
14-2	C7698-2	0.11	0.010	0.48	0.014	+10	55
14-3	C7688-2	0.12	0.011	0.51	0.015	+10	59.9
17-1(1)	C7689-1	0.11	0.007	0.48	0.014	+10	62.3
17-2	C7677-1	0.11	0.016	0.50	0.016	+20	72.3(3)
17-3	C7698-1	0.11	0.010	0.48	0.014	+10	62.3

B. Welds

1 Shop Welds (i.e., Vertical Seams)

Heat/Lot	Seams Used In	Wt % Cu	Wt % P	Wt % Ni	Wt % S	ASME NB-2300 Start RT_{NDT} (°F)	Estimated 57 EFPY EOL RT_{NDT} (°F)
411A3531/H004A27A	BE	0.02	0.018	0.96	0.017	-50	-32.5
06L165/F017A27A	BA, BB BD, BF	0.03	0.021	0.99	0.017	-50	-23.4
662A746/H013A27A	BA, BD BE, BF	0.03	0.021	0.88	0.017	-20	6.6
3P4000/(2) 3932-989	BC, BB BA	0.02	0.015	0.935	0.012	-50	-34.2
S3986/(2) Run #934	BF	0.058	0.019	0.949	0.016	-42	6.2
1P 4218/(1)(2) 3929-989	BA, BB BE	0.058	0.010	0.865	0.011	-50	1.2
421A6811/(1) F022A27A	Weld Test Plate	0.09	0.018	0.81	0.016	-50	37.4

Table 5.3-5 (Cont'd)

LGS BELTLINE PLATE WELDS AND FORGINGS EOL RT_{NDT} Based on 57 EFPY

(Unit 1)

Heat/Lot	Wt % Cu	Wt % P	Wt % Ni	Wt % S	ASME NB-2300 Start RT_{NDT} (°F)	Estimated 57 EFPY EOL RT_{NDT} (°F)
2. Field Welds (i.e., Girth)						
07L857/B101A27A	0.03	0.012	0.97	0.017	-6	19.3[3]
402C4371/C115A27A	0.02	0.009	0.92	0.014	-50	-33.4
411A3531/H004A27A	0.02	0.018	0.96	0.017	-50	-33.4
09M057/C109A27A	0.03	0.009	0.89	0.021	-36	-10.7
412P3611/J417B27AF	0.03	0.016	0.93	0.019	-80	-54.7
03M014/C118A27A	0.01	0.012	0.94	0.015	-34	-21.7
L83355/S411B27AD	0.03	0.017	1.08	0.018	-70	-44.7
640892/J424B27AE	0.09	0.015	1.00	0.018	-60	15.2[3]
401P6741/S419B27AG	0.03	0.013	0.92	0.014	-60	-34.7
5P6756	0.08	0.008	0.936	0.012	-60	6.5
3. LPCI Nozzle Welds[4]						
07L669/K004A27A	0.03	0.014	1.02	0.016	-50	-31.0
401Z9711/A022A27A	0.02	0.021	0.83	0.017	-50	-37.5
411A3531/H004A27A	0.02		0.96		-50	
662A746/H013A27A	0.03		0.88		-20	
3P4000/3932-989 S3986/Run #934	0.02 0.058		0.935 0.949		-50 -42	
C. Forgings[6]						
Water Level Instrumentation (SB166)	0.11		0.50		20	47.6
LPCI Nozzle forging:						
110L-1(45°) & 110L-2(225°) (Q2Q25W)	0.18		0.85		-6	59.9
110L-4(135°) & 110L-3(315°) (Q2Q35W)	0.18		0.78		-8	57

Table 5.3-5 (Cont'd)

LGS BELTLINE PLATE WELDS AND FORGINGS EOL RT_{NDT} Based on 57 EFPY

(Unit 2)

(PEAK EOL FLUENCE = 7.08×10^{17} n/cm^2 @ ¼T)

A. Plates

I.D.	Heat	Wt % Cu	Wt % P	Wt % Ni	Wt % S	ASME NB-2300 Start RT_{NDT} (°F)	Estimated 57 EFPY EOL RT_{NDT} (°F)
14-1	B3312-1	0.13	0.009	0.58	0.016	+10	64.0
14-2	B3416-1	0.14	0.009	0.65	0.015	+40	100.6(3)
14-3	C9621-2	0.15	0.006	0.60	0.020	+22	88.0
17-1(1)	C9569-2	0.11	0.009	0.51	0.018	+10	61.3
17-2	C9526-1	0.11	0.012	0.56	0.018	+10	62.0
17-3	C9526-2	0.11	0.012	0.56	0.018	+10	62.0

B. Welds

1. Shop Welds (i.e., Vertical Seams)

Heat/Lot	Seams Used In	Wt % Cu	Wt % P	Wt % Ni	Wt % S	ASME NB-2300 Start RT_{NDT} (°F)	Estimated 57 EFPY EOL RT_{NDT} (°F)
432A2671/H019A27A	BA,BB,BD BE,BF	0.04	0.019	1.08	0.014	-12	22.6(3)
03R728/L910A27A	BA,BC	0.03	0.020	0.92	0.016	-50	-26.4
3P4000/3933(1) Single and/or Tandem Wire	BA,BB,BC BD,BE,BF	0.02	0.014	0.935	0.012	-50	-32.7
401Z9711/A022A27A	BB	0.02	0.021	0.83	0.017	-50	-36.2
662A746/H013A27A	BC	0.03	0.021	0.88	0.017	-20	3.6
402A0462/B023A27A	BC	0.02	0.021	0.90	0.018	-50	-34.5
07L669/K004A27A	BC,BD BE,BF	0.03	0.014	1.02	0.016	-50	-23.8
09L853/A111A27A	BD,BE	0.03	0.018	0.86	0.023	-50	-23.8

Table 5.3-5 (Cont'd)

LGS BELTLINE PLATE WELDS AND FORGINGS EOL RT_{NDT} Based on 57 EFPY

(Unit 2)

Heat/Lot	Wt % Cu	Wt % P	Wt % Ni	Wt % S	ASME NB-2300 Start RT_{NDT} (°F)	Estimated 57 EFPY EOL RT_{NDT} (°F)
2. Field Welds (i.e., Girth)						
07L857/B101A27A	0.03	0.012	0.97	0.017	-6	18.6
402C4371/C115A27A	0.02	0.009	0.92	0.014	-50	-33.8
411A3531/H004A27A	0.02	0.018	0.96	0.017	-50	-33.8
09M057/C109A27A	0.03	0.009	0.89	0.021	-36	-11.4
412P3611/J417B27AF	0.03	0.016	0.93	0.019	-80	-55.4
03M014/C118A27A	0.01	0.012	0.94	0.015	-34	-22.0
L83355/S411B27AD	0.03	0.017	1.08	0.018	-70	-45.4
640892/J424B27AE	0.09	0.015	1.00	0.018	-60	13.2
401P6741/S419B27AG	0.03	0.013	0.92	0.014	-60	-35.4
3. LPCI Nozzle Welds[4]						
07L669/K004A27A	0.03	0.014	1.02	0.016	-50	-31.3
432A2671/H019A27A	0.04	0.019	1.08	0.014	-12	12.6
C3L46C/J020A27A	0.02	0.019	0.87	0.017	-20	-7.7
422B7201/L030A27A	0.04	0.013	0.90	0.018	-40	-15.4
09L853/A111A27A	0.03	0.018	0.86	0.023	-50	-31.3
4P4784/3930[5]	0.06	0.012	0.87	0.013	-50	-12.7
4P4784/3930 Tandem Wire	0.06	0.012	0.87	0.013	-20	17.3
4. Surveillance Welds						
CTY538/A027A27A	0.03	0.020	0.83	0.018	-50	-21.2

Table 5.3-5 (Cont'd)

LGS BELTLINE PLATE AND FORGINGS WELDS EOL RT_{NDT} Based on 57 EFPY

(Unit 2)

Heat/Lot	Wt % Cu	Wt % P	Wt % Ni	Wt % S	ASME NB-2300 Start RT_{NDT} (°F)	Estimated 57 EFPY EOL RT_{NDT} (°F)
C. Forgings[7]						
Water Level Instrumentation[8]						
N16A - 0° (SB-166)	0.11		0.51		10	37.7
N16C - 100° (SB-166)	0.11		0.51		10	37.7
N16B - 200° (SB-166)	0.11		0.51		10	37.7
N16D - 280° (SB-167)	0.11		0.51		10	37.3
LPCI Nozzle forging:						
892L-1 (Q2Q33W) (45°)	0.18		0.83		-20	44.2
892L-2 (Q2Q33W) (135°)	0.18		0.81		-6	58.2
892L-3 (Q2Q33W) (225°)	0.18		0.82		-4	60.2[3]
892L-4 (Q2Q33W) (315°)	0.18		0.82		-20	44.2

(1) Surveillance Program Material.

(2) Submerged arc welding.

(3) The most limiting value.

(4) Deleted.

(5) Single wire or tandem wire with submerged arc welding.

(6) The Unit 1 RPV design results in this component experiencing a predicted EOL fluence of 3.30×10^{17} n/cm^2 at ¼ of the thickness. This fluence, based on an assumed Cu content of 0.18% and a measured nickel content of 0.85%, yields an estimated EOL RT_{NDT} of +59.9°F. The EOL estimate is in accordance with Regulatory Guide 1.99 (Rev. 2).

(7) The Unit 2 RPV design results in this component experiencing a predicted EOL fluence of 3.19×10^{17} n/cm^2 at ¼ of the thickness. This fluence, based on an assumed Cu content of 0.18% and a measured nickel content of 0.82%, yields an estimated EOL RT_{NDT} of +60.2°F. The EOL estimate is in accordance with Regulatory Guide 1.99 (Rev. 2).

(8) The N16 nozzle is evaluated using the fluence and the limiting material properties (chemistry and initial RT_{NDT}) of the adjoining shell ring #2.

Table 5.3-6

LGS TYPICAL BELTLINE PLATE
(SURVEILLANCE PLATE)

(Unit 1)

Mill Order No: 27265-1

Requirements: SA533 Grade B
Class 1

Melt No: 7689

TEST RESULTS CHEMICAL
(Wt%)

Carbon	0.20
Manganese	1.33
Nickel	0.48
Silicon	0.23
Molybdenum	0.48
Phosphorous	0.007
Sulfur	0.014

MECHANICAL TEST RESULTS

Tensile Properties

UTS: 84,600 psi
85,100 psi

YLP: 63,900 psi
64,400 psi

% Elongation in 2 in: 26
28

Impact Properties

Specimen Type: Charpy V-Notch
Test Temp: +40°F
Energy (ft-lb): 87, 93, 77
75, 86, 81
Lateral Exp. (mil) 73, 69, 62
61, 71, 78
% Shear: 50, 60, 60
50, 60, 60

Drop-weight Test

TEST TEMP (°F)	TOP/BOTTOM RESULTS
+30	1 No Break
+20	1 No Break
+10	1 No Break
0	2 No Break
-10	1 Break
-20	1 Break
-30	1 Break

NDT=-10°F

Table 5.3-6 (Cont'd)

(Unit 1)

Test Location

Drop-Weights - Top and Bottom - Longitudinal
Bend - Top Middle - Transverse
Tensions - Top and Bottom - Transverse
Impacts - Top and Bottom - Longitudinal
Tests ¼T from rolled surface
No closer than "T" from quenched and tempered edge

Specification

ASME SA533 Grade B CL-1 Pressure Vessel Quality

Ultrasonic Testing

Per Procedure LS-UT-4

Heat Treatment

Procedure LS-102 Revision 5

Plates

Austenitized at 1650°F held ½ hr/in (min), and water quenched.
Tempered at 1260°F held ½ hr/in (min), and air cooled.
Stress relieved at 1075°F held 1 hr (min) and air cooled.
Test coupons then cut from plate.

Tests only

Stress relieved @ 1150°F held 50 hr and furnace cooled to below 600°F, then air cooled.

Maximum Heating Rate	Maximum Cooling Rate
100°F/hr	100°F/hr

Mechanical Property Requirements

Tensile:	80/100,000 psi
Yield:	50 min 0.2% offset
Elong:	18% in 2 in (min)
Impacts	30 ft-lb @ +40°F. Lateral Expansion and % Shear Fracture for information only.
Drop-Weights:	Type P-3 specimens with a NDT temperature no higher than +40°F.
Grain-Size:	Final Plate Grain-Size #5 or finer determined on a fully heat treated test coupon.

Table 5.3-6 (Cont'd)

LGS TYPICAL BELTLINE PLATE
(SURVEILLANCE PLATE)

(Unit 2)

Mill Order No: 51090-2

Requirements: SA533 Grade B
Class 1

Melt No: 0569

TEST RESULTS CHEMICAL
(Wt%)

Carbon	0.20
Manganese	1.26
Nickel	0.51
Silicon	0.23
Molybdenum	0.49
Phosphorous	0.009
Sulfur	0.018

MECHANICAL TEST RESULTS

Tensile Properties

UTS: 85,600 psi
88,500 psi

YLP: 65,100 psi
68,100 psi

% Elongation in 2 in: 26
24

Impact Properties

Specimen Type: Charpy V-Notch
Test Temp: +40°F
Energy (ft-lb): 68, 62, 68
83, 87, 66
Lateral Exp. (mil): 45, 50, 47
62, 50, 64

% Shear: 30, 30, 30
40, 40, 40

Drop-weight Test

TEST TEMP (°F)	TOP RESULTS	BOTTOM RESULTS
+10	No Break	No Break
0	No Break	No Break
-10	2	No Break -
-20	Break	2 No Break
-30	-	Break
	NDT = -20°F	NDT = -30°F

Table 5.3-6 (Cont'd)

(Unit 2)

Test Location

Drop-Weights - Top and Bottom - Longitudinal
Bend - Top Middle - Transverse
Tensions - Top and Bottom - Transverse
Impacts - Top and Bottom - Longitudinal
Tests ¼T from rolled surface
No closer than "T" from quenched and tempered edge

Specification

ASME SA533 Grade B CL-1 Pressure Vessel Quality

Ultrasonic Testing

Per Procedure LS-UT-4

Heat Treatment

Procedure LS-102 Revision 5

Plates

Austenitized at 1650°F held ½ hr/in (min), and water quenched.
Tempered at 1260°F held ½ hr/in (min), and air cooled.
Stress relieved at 1150°F held 1 hr (min) and air cooled.
Test coupons then cut from plate.

Tests only

Stress relieved @ 1150°F held 50 hr and furnace cooled to below 600°F, then air cooled.

Maximum Heating Rate	Maximum Cooling Rate
100°F/hr	100°F/hr

Mechanical Property Requirements

Tensile:	80/100,000 psi
Yield:	50 min 0.2% offset
Elong:	18% in 2 in (min)
Impacts:	30 ft-lb @ +40°F. Lateral Expansion and % Shear Fracture for information only.
Drop-Weights:	Type P-3 specimens with a NDT temperature no higher than +40°F.
Grain-Size	Final Plate Grain-Size #5 or finer determined on a fully heat treated test coupon.

Table 5.3-7

SA533 GRADE B, CLASS 1 PLATE TOUGHNESS DATA BASE INCLUDING UPPER-SHELF
(VENDOR - LUKENS STEEL CO.)

Heat No.	NDT (°F)	Charpy Temp (°F)	Orientation (L or T)	Energy (ft-lb)	Lateral Expansion (mil)	% Shear
I. PLANT A						
C5978-1	+10	-40	L	7.0, 7.0, 11.0	5, 3, 7	0, 0, 0
		+10		25.0, 33.0, 30.0	23, 25, 23	10, 10, 10
		+40		53.0, 48.0, 48.0	40, 35, 36	20, 20, 20
		+110		118.0, 116.0, 109.0	79, 76, 74	80, 80, 80
		+160		123.0, 136.0, 136.0	82, 84, 84	90, 95, 95
C5978-2	-10	-40	L	22.0, 24.0, 24,0	17, 18, 19	0, 0, 0
		+10		49.0, 46.0, 42.0	38, 36, 33	25, 25, 25
		+40		62.0, 60.0, 41.0	46, 44, 34	35, 35, 35
		+110		98.0, 90.0, 100.0	73, 67, 75	80, 70, 80
		+160		119.0, 120.0, 118.0	88, 86, 82	99, 100, 100
C5979-1	-10	-40	L	9.0, 11.0, 19.0	5, 7, 13	0, 0, 0
		+10		61.0, 57.0, 43.0	45, 41, 32	30, 30, 20
		+40		73.0, 92.0, 65.0	51, 63, 43	35, 45, 35
		+110		117.0, 116.0, 100.0	78, 76, 68	80, 80, 70
		+116		134.0, 136.0, 134.0	87, 86, 85	99, 99, 100
C6345-1	-40	-80	L	8, 6	4, 4	0, 0
		-40		29, 15, 23	21, 13, 16	5, 0, 1
		+10		109, 88, 77	76, 58, 56	50, 35, 35
		+40		103, 96, 122	68, 65, 77	45, 40, 60
		+110		147, 147	84, 82	100, 100
		+160		151, 165	87, 94	100, 100
C6318-1	-20	-40	L	25, 17, 14	18, 11, 9	1, 0, 0
		+10		80, 66, 72	57, 47, 50	35, 30, 30
		+40		85, 95, 112	64, 68, 75	40, 40, 50
		+110		126, 145, 117	81, 89, 76	90, 100, 90
		+160		140, 140, 139	86, 89, 88	100, 100, 100
C6345-2	-40	-80	L	10, 12	7, 9	0, 0
		-40		32, 16, 49	20, 11, 33	10, 0, 20
		+10		93, 94, 67	69, 66, 48	40, 40, 25
		+40		109, 125, 128	70, 72, 82	50, 60, 70
		+110		127, 165	81, 82	85, 100

+160	153, 161	86, 88	100, 100

Table 5.3-7 (Cont'd)

Heat No.	NDT (°F)	Charpy Temp (°F)	Orientation (L or T)	Lateral Energy (ft-lb)	Expansion (mil)	% Shear
C5979-2	-10	-80	L	8.0, 11.0	5, 9	0, 0
		-40		28.0, 17.0, 18.0	20, 16, 14	15, 10, 10
		+10		64.0, 63.0, 49.0	44, 44, 34	30, 30, 20
		+40		72.0, 76.0, 79.0	47, 49, 50	35, 35, 35
		+110		107.0, 102.0	77, 74	85, 80
		+160		134.0, 141.0	79, 83	100, 100
C5996-1	-10	-40	L	12.0, 53.0, 12.0	10, 20, 11	0, 15, 0
		+10		65.0, 60.0, 77.0	46, 42, 54	30, 30, 40
		+40		88.0, 113.0, 78.0	56, 70, 54	40, 60, 40
		+110		111.0, 126.0, 134.0	74, 85, 83	80, 90, 90
		+160		146.0, 148.0, 143.0	86, 89, 86	100, 100, 100
C6318-1	-40	T	7.5	5.0	1	
		-10		32.5, 31.0	27.0, 28.5	5, 5
		+10		41.5, 42.0	36.0, 37.0	25, 25
		+40		31.5, 60, 49, 63	26.0, 44.0, 34.0, 49.0	35, 30, 40, 40
		+61		70, 71.0	57.2, 57.5	50, 50
		+120		95	70.5	99
		+200		100.0, 91.0, 90.0	75.0, 63.5, 69.5	99, 100, 100
A5333-1	-10	-40	L	21, 13, 11	17, 11, 9	5, 0, 0
		+10		56, 67, 53	41, 47, 40	20, 30, 20
		+40		82, 100, 84	56, 70, 60	40, 50, 40
		+110		126, 120, 133	87, 81, 84	80, 80, 80
		+160		155, 155, 145	92, 90, 89	100, 100, 100
B-0078-1	-10	-40	L	10, 14, 25	10, 13, 21	0, 0, 5
		+10		73, 49, 70	54, 39, 53	40, 30, 40
		+40		94, 100, 100	65, 68, 70	60, 60, 60
		+110		118, 128, 140	82, 86, 89	90, 90, 100
		+160		151, 136, 143	90, 84, 88	100, 100, 100
C6123-2	-10	-80	L	11, 8	9, 7	0, 0
		-40		28, 38, 10	22, 28, 9	10, 10, 0
		+10		77, 60, 73	56, 45, 53	40, 35, 40
		+40		113, 108, 122	73, 71, 75	65, 60, 75
		+110		120, 149	89, 91	90, 100
		+160		149, 151	91, 93	100, 100

Table 5.3-7 (Cont'd)

Heat No.	NDT (°F)	Charpy Temp (°F)	Orientation (L or T)	Lateral Energy (ft-lb)	Expansion (mil)	% Shear
C5987-1	-10	-40	L	19, 13, 14	14, 10, 13	0, 0, 0
		+10		63, 55, 35	47, 41, 26	35, 35, 30
		+40		80, 99, 87	59, 68, 61	50, 70, 55
		+110		122, 134, 122	84, 86, 84	100, 100, 100
		+160		122, 134, 127	86, 86, 84	100, 100, 100
C5987-2	-10	-40	L	15.0, 8.0, 10.0	7, 7, 7	0, 0, 0
		+10		76.0, 79.0, 51.0	54, 59, 57	35, 35, 30
		+40		57.0, 76.0, 75.0	42, 57, 54	30, 35, 35
		+110		106.0, 102.0, 113.0	72, 68, 76	80, 80, 80
		+160		140.0, 133.0, 138.0	87, 81, 84	100, 100, 100
C6003-2	-10	-40	L	10.0, 7.0, 8.0	7, 4, 3	0. 0. 0
		+10		37.0, 31.0, 51.0	28, 22, 37	20, 20, 30
		+40		65.0, 49.0, 50.0	44, 34, 36	35, 30, 30
		+110		81.0, 95.0, 82.0	60, 67, 61	60, 70, 60
		+160		121.0, 107.0, 120.0	82, 78, 87	100, 99, 100
C5996-2	-10	-80	L	7.0, 10.0	5, 8	0, 0
		-40		18.0, 25.0, 25.0	14, 20, 19	10, 10, 10
		+10		62.0, 71.0, 66.0	45, 50, 47	20, 30, 25
		+40		81.0, 100.0, 91.0	52, 71, 64	35, 50, 40
		+110		124.0, 130.0	83, 88	90, 90
		+160		149.0, 151.0	89, 91	100, 100
II. PLANT B						
C4882-1	-60	-80	L	16,0, 14.0	15, 11	0, 0
		-40		41.0, 32.0, 54.0	28, 22, 38	20, 20, 25
		+10		75.0, 68.0, 48.0	52, 49, 35	30, 30, 25
		+40		83.0, 95.0, 100.0	59, 65, 70	45, 50, 60
		+110		104.0, 116.0	75, 82	85, 90
		+160		130.0, 131.0	86, 84	100, 100
C4882-2	-40	-80	L	10.0, 7.0	10, 8	0, 0
		-40		46.0, 43.0, 30.0	36, 35, 26	10, 10, 10
		+10		75.0, 50.0, 66.0	58, 44, 52	30, 20, 20
		+40		90.0, 80.0, 88.0	71, 62, 63	40, 35, 40
		+110		120.0, 107.0	84, 82	85, 80
		+160		137.0, 129.0	94, 90	100, 100

Table 5.3-7 (Cont'd)

Heat No.	NDT (°F)	Charpy Temp (°F)	Orientation (L or T)	Energy (ft-lb)	Lateral Expansion (mil)	% Shear
C4882-2		-80	T	19.0	15.5	1
		-50		41.0, 25.0, 37.5	29.0, 16.5, 26.0	20, 10, 20
		-30		41.0, 40.0	30.0, 29.5	20, 20
		+10		61.0, 68.0	45.0, 49.5	30, 30
		+39		77.0, 71.0	54.0, 54.5	50, 30
		+70		91.0, 71.0	62.0, 53.0	75, 40
		+121		113.0	79.0	95
		+200		115.5, 113.5	82.5, 74.0	95, 95
III. PLANT C						
C9481-1	-30	+40	L	74, 74, 81	61, 58, 60	50, 50, 50
		+40		103, 61, 85	48, 66, 72	40, 50, 50
C9481-1		-40	T	17.0	15.0	5
		+10		23.5, 22.0	21.0, 20.5	10, 10
		+25		36.0	31.0	20-25
		+40		45.0, 35.0, 42.0	42.0, 34.2, 38.0	30-35, 30, 30-35
		+51		40.5	35.0	30
		+70		51.0, 50.0	44.5, 42.5	40, 40
		+93		71.0	58.5	70
		+120		93.0	69.5	90-95
		+200		93.5, 100.0, 93.0	74.0, 72.0, 69.0	95, 95, 95
IV. PLANT D						
C4574-2	-30	-80	L	8.0, 16.0	6, 13	0, 0
		-40		34.0, 32.0, 27.0	25, 24, 20	10, 10, 5
		+10		48.0, 49.0, 60.0	36, 37, 43	15, 15, 20
		+40		76.0, 63.0, 69.0	56, 47, 51	30, 20, 25
		+110		98.0, 103.0	72, 76	95, 95
		+160		121.0, 119.0	85, 82	100, 100
C4574-2		-20	T	22.0	17.5	1
		+10		32.0, 35.0	22.5, 27.5	5, 5
		+40		50.0, 52.5	35.5, 41.5	10, 10
		+65		64.0, 55.0	47.0, 42.5	30, 30
		+102		75.0	60.5	50
		+119		108.0, 88	75.0, 66.0	100, 85
		+201		112.5	83.5	100
		+202		108.5	79.0	100

Table 5.3-7 (Cont'd)

Heat No.	NDT (°F)	Charpy Temp (°F)	Orientation (L or T)	Energy (ft-lb)	Lateral Expansion (mil)	% Shear
V. PLANT E						
C9533-2	0/10	-50	L	7-12	7-4	1-1
		-30		9-7	7-4	1-1
		-20		9-14[1]/19-40[1]	11-7[1]/5-30[1]	10-10/20-20
		+10		34-26/45-47	28-23/36-35	20-20/30-30
		+70		48-64/70-76	48-40/57-60	40-40/40-40
		+100		82-62/82-71	53-65/63-61	60-60/60-60
		+130		72-68/92-86	60-57/72-69	60-60/80-80
		+212		88-81/110-99	75-73/87-81	99-99/99-99
C9570-2 (top)	-40	-70	L	6-4	5-4	1-1
		-50		10-13	20-20	10-10
		-20		14-27	23-14	20-20
		+10		30-42	29-39	30-30
		+70		70-64	56-54	40-40
		+100		76-79	64-63	60-60
		+212		106-108	66-81	90-90
C9570-2 (Bottom)	-50	-70	L	5-7	3-5	1-1
		-40		12-12	16-18	10-10
		-20		36-45	30-36	20-20
		+10		35-46	29-34	30-30
		+40		48-56	47-49	50-50
		+70		79-81	74-75	70-70
		+100		90-110	70-82	80-80
		+130		114-112	86-85	99-99
9570-1	-20	-20	L	11-8[1]/13-12[1]	8-10[1]/12-12[1]	1-1/10-10
	-10					
		-10		20-21/15-14	20-20/15-14	10-10/10-10
		+10		19-19/43-43	18-18/34-33	10-10/30-30
		+40		36-44	37-41	30-30
		+72		60-62/69-70	52-50/56-56	40-40/40-40
		+100		72-75/79-80	65-62/64-65	50-50/60-60
		+130		84-83/94-88	69-71/74-71	70-70/80-80
		+212		96-110/105-103	82-78/81-80	90-90/90-90

[1] Top/Bottom

Table 5.3-8

UPPER-SHELF TOUGHNESS FOR BELTLINE WELDS

Heat No./Flux Lot	NDT (°F)	Charpy Temp (°F)	Wire (S or T)[1]	Energy (ft-lb)			Lateral Expansion (mil)			% Shear		
I. PLANT A												
INMM ELECTRODE (TRADE NAME - TECHALLOY) LINDE 124 FLUX, SUBMERGED ARC POSTWELD 1150°F FOR 50 HR TYPICAL												
KN203/0171	-80	-130	S	7	6		7	7		5	5	
		-80		34	18	22	32	16	21	40	35	40
		-20		68	70	62	61	57	56	80	70	75
		+10		75	72		64	64		90	90	
		+40		94	82		81	71	100	95		
		+212		94	92	86	76	80	80	100	100	100
	-80	-130	T	7	5		6	5		5	5	
		-100		25	16		24	19		10	10	
		-80		24	22	25	21	19	25	25	20	30
		-20		48	49	54	44	42	46	45	45	60
		-10		59	54	54	48	49	46	60	45	60
		+10		78	67		65	56		95	80	
		+40		80	79		68	68		95	95	
		+212		86	89	87	87	86	85	100	100	100
E8018-G WELD ELECTRODE, SHIELDED METAL ARC (TRADE NAME - ATOM ARC 8018 NM) POSTWELD 1150°F FOR 50 HR TYPICAL												
640967/D502B27AF	-80	-105		13	14		4	4		5	5	
		-80		16	22	28	11	13	18	10	12	15
		-20		58	76	86	18	42	56	15	50	50
		+40		102	106	119	69	74	86	90	80	90
		+72		119	127			86	82		90	90
		+130		130	140	150	90	92	80	100	100	100

Table 5.3-8 (Cont'd)

Heat No./Flux Lot	NDT (°F)	Charpy Temp (°F)	Wire (S or T)[1]	Energy (ft-lb)			Lateral Expansion (mil)			% Shear		
II. PLANT B												
INMM ELECTRODE (TRADE NAME - RACO) LINDE 124 FLUX, SUBMERGED ARC POSTWELD 1150°F FOR 50 HR TYPICAL												
5P7397/[2]	-70	-70	T	22	16	36	22	18	28	5	5	5
0342		-10		58	68	61	54	50	47	25	20	20
		+10		76	73	75	60	65	60	30	45	50
		+10		75	69		58	56		35	35	
		+40		91	84		75	63		80	85	
		+70		79	75	77	73	63	74	90	95	95
		+212		84	81	87	69	67	75	100	100	100
	-70	-70	S	20	34	27	16	32	22	5	5	5
		-10		54	50	59	47	47	53	25	20	20
		+10		65	59	69	60	56	65	50	25	75
		+10		70	75		56	61		45	55	
		+40		71	78		65	68		75	90	
		+70		92	101	94	82	65	69	95	95	100
		+212		100	95	96	88	58	82	100	100	100
E8018-G WELD ELECTRODE, SHIELDED METAL ARC (TRADE NAME - E8018 NM) POSTWELD 1150°F FOR 50 HR TYPICAL												
401P2871/H430B27AF	-50	-90		7	10		7	11		3	5	
		-70		15	16	16	14	15	16	8	8	10
		-20		66	76	64	58	61	58	15	15	15
		-20		63	81		50	61		15	15	
		-10		27	39	54	25	35	46	35	35	35
		0		27	50	56	25	42	46	40	45	45
		+10		75	76	107	60	62	74	60	50	80
		+40		90	100		71	76		70	80	
		+130		130	140	142	91	94	93	100	100	100
402P3162/H426B27AE	-70	-70		11	7	14	9	6	8	5	5	5
		-40		33	52	32	27	42	22	10	15	10
		-20		65	62	37	52	48	30	20	10	20
		-20		52	55		36	38		15	15	
		-10		60	54	53	44	37	--	40	30	30
		+40		96	99		57	68		60	60	
		+212		119	122	124	93	90	68	100	100	100

Table 5.3-8 (Cont'd)

Heat No./Flux Lot	NDT (°F)	Charpy Temp (°F)	Wire (S or T)[1]	Energy (ft-lb)			Lateral Expansion (mil)			% Shear		
III.PLANT C												
INMM ELECTRODE (TRADE NAME - RACO) LINDE 124 FLUX, SUBMERGED ARC POSTWELD 1150°F FOR 50 HR TYPICAL												
02R486/J404B27AG	-70	-100		12	13		3	5		3	5	
		-90		16	17	19	6	8	7	8	8	10
		-30		17	30	31	15	24	23	15	20	20
		-20		41	42	44	33	34	35	30	30	30
		-10		52	64	66	39	45	46	40	40	40
		+40		84	87		63	68		60	60	
		+130		121	124	129	91	96	95	100	100	100
L83978/J414B27AD	-80	-100		10	12		6	7		4	5	
		-80		14	15	24	10	12	18	10	10	12
		-20		51	52	81	37	40	63	35	50	40
		-20		64	63	69	51	47	55	15	15	15
		-20		67	56		53	45		15	10	
		+40		120	123		72	73		80	80	
		+72		128	140		78	81		90	90	
		+130		148	156	168	90	81	87	100	100	100
5P7397/0156	-50	-70		25	21		18	15		5	5	
		-50		42	27	19	33	25	20	10	15	10
		+10		64	67	55	53	53	52	30	35	40
		+10		64	70		53	54		40	45	
		+40		91	84	85	78	68	79	85	90	95
		+212		103	92	94	59	66	59	100	100	100
3P4966/0342	-80	-80		51	27	9	45	25	12	5	5	5
		-20		71	66	54	57	57	45	30	25	20
		+10		85	84	71	68	72	61	70	80	65
		+10		83	76		67	64		65	55	
		+40		87	91		71	60		75	80	
		+70		100	101	97	82	89	71	90	95	90
		+212		108	111	108	66	84	86	100	100	100

Table 5.3-8 (Cont'd)

Heat No./Flux Lot	NDT (°F)	Charpy Temp (°F)	Wire (S or T)[1]	Energy (ft-lb)			Lateral Expansion (mil)			% Shear		
4P7465/0751	-60	-80		27	14		21	12		5	0	
		-70		48	43	26	42	36	22	15	15	5
		0		63	57	68	54	45	63	30	25	35
		+10		56	58	90	62	62	86	30	25	45
		+10		87	55		83	42		40	30	
		+40		67	97		71	90		45	50	
		+212		118	102	112	88	71	72	100	100	100
1P6484/0156	-20	-80		5	8		6	11		5	5	
		-60		22	16	12	23	13	10	10	10	10
		0		17	36	30	20	27	28	25	20	25
		+10		30	38	17	25	38	12	15	15	15
						34	38	28	30		15	20
		+30		34	46	42	29	37	45	25	50	35
		+40		72	60	72	54	47	49	50	45	50
		+212		93	81	83	65	66	69	100	100	100
5P5657/0931	-60	-80		39	39		27	37		5	5	
		-60		19	20	32	18	22	28	10	10	10
		0		51	55	58	50	50	63	30	30	55
		+10		69	69	66	61	65	59	50	50	40
		+10		62	57		60	63		60	40	
		+40		77	66		73	72		70	80	
		+212		88	91	85	86	75	83	100	100	100
E8018NM WELD ELECTRODE (TRADE NAME - ATOM ARC E8018NM) SHIELDED METAL ARC POSTWELD 1150°F FOR 50 HR TYPICAL												
492L4871/A421B27AE	-60	-108		10	11		5	4		4	4	
		-90		25	30	32	6	6	6	8	10	10
		-30		19	28	31	19	23	25	20	25	25
		-20		22	26	30	23	21	27	25	25	30
		-10		38	41	43	28	32	30	30	30	30
		0		50	51	57	36	38	40	30	40	45
		+40		135	137		84	80		90	80	
		+130		151	160	161	80	82	81	100	100	100

Table 5.3-8 (Cont'd)

Heat No./Flux Lot	NDT (°F)	Charpy Temp (°F)	Wire (S or T)[1]	Energy (ft-lb)			Lateral Expansion (mil)			% Shear		
422K8511/G313A27AD	-80	-90		14	17		15	16		5	5	
		-80		14	16	20	15	16	20	10	10	10
		-40		26	26	40	26	24	33	30	30	30
		-20		65	74	127	44	48	76	40	50	60
		+25		107	108		74	80		80	70	
		+40		125	125	140	84	89	82	100	100	90
		+50		153	143	156	95	81	91	90	80	90
		+68		153	143	165	85	96	91	100	100	100
640892/J424B27AE	-60	-108		14	16		3	3		3	3	
		-70		15	20	27	8	9	15	5	10	10
		-10		38	42	45	26	31	31	30	30	30
		0		55	62	62	38	44	48	35	40	40
		+40		56	75		42	55		50	60	
		+130		118	122	130	87	89	82	100	100	100
40150371/B504B27AE	-60	-60	42	45	23	35	36	20	5	5	5	
		-20		61	84	77	48	66	62	30	25	25
		-20		68	67		51	52		25	25	
		0		80	85	82	63	62	60	35	50	35
		+40		95	97		71	76		40	75	
		+70		111	107	109	87	85	77	80	90	80
		+212		122	114	130	92	92	69	100	100	100
402P3162/H426B27AE	-70	-70		11	7		9	6		5	5	
		-40		33	52	32	27	42	22	10	15	10
		-20		65	62	37	52	48	30	20	10	20
		-20		52	55		36	38		15	15	
		-10		60	54	68	44	37	53	40	30	30
		+40		96	99		57	68		60	60	
		+212		119	122	124	93	90	68	100	100	100

Table 5.3-8 (Cont'd)

Heat No./Flux Lot	NDT (°F)	Charpy Temp (°F)	Wire (S or T)[1]	Energy (ft-lb)			Lateral Expansion (mil)			% Shear		
401P2871/H430B27AE	-50	-90		7	10		7	11		3	5	
		-70		15	16	16	14	15	16	8	8	10
		-10		27	39	54	25	35	46	35	35	35
		0		27	50	56	25	42	46	40	45	45
		+10		75	76	107	60	62	74	60	50	80
		+40		90	100		71	76		70	80	
		+130		130	140	142	91	94	93	100	100	100
07R458/S403B27AG	-60	-70		9	9		7	7		5	5	
		-60		10	11	13	9	9	11	15	10	10
		0		59	61	70	51	52	58	50	50	60
		+40		99	101		77	78		80	75	
		+72		106	110		85	87		80	80	
		+130		129	131	132	81	78	81	100	100	100
03L048/B525B27AF	-60	-105		8	9		2	3		3	3	
		-80		10	16	19	7	10	11	10	10	10
		-20		31	50	65	22	37	50	30	30	30
		-10		36	53	58	34	43	45	40	40	40
		0		61	75	79	44	58	59	50	60	60
		+40		104	108		75	77		80	80	
		+130		122	123	126	89	83	91	100	100	100

[1] Single or Tandem
[2] This material is in Plant B's vessel surveillance program.

Table 5.3-9

WELD PROCEDURE SPECIFICATION FOR VESSEL MATERIAL
REPRESENTATIVE OF LGS BELTLINE WELDS(1)

(Unit 1)

Reference Specifications

General WPS 800 Latest Revision
General WPS 820 Latest Revision

Procedure Qualification

No.	Position	Thickness Range (inches)
1890 (SMA)	V	3/16 to 8
1891 (SMA)	H	3/16 to 8
1892 (SMA)	OH, F	3/16 to 8
1893 (SA1)	F	3/16 to 8
2200 (SA2)	F	3/16 to 8

Postheat Treatment

Procedure qualified with 50 hours at 1150°F + 25°F/-50°F.

Postweld heat treatment of the weldment shall be in accordance with a Chicago Bridge and Iron approved procedure.

Base Metal

ASME SA533 Grade B Class 1 or SA508 Class 2
ASME Group No. P12B Subgroup 1

Shielding Gas: None

Backup Gas: None

Flux: Linde 124

Preheat Requirements

Minimum preheat of 300°F shall be applied uniformly to the full thickness of the weld joint and adjacent base material for a minimum distance of "T" or 6 inches, whichever is least, where "T" is the material thickness.

Maintain 300°F min preheat temperature until start of postweld heat treatment except for longitudinal and circumferential shell and head seams, preheat may be dropped to 250°F min 8 hours after completion of welding. All turnoff tabs and flux dams must be removed prior to dropping preheat below 300°F.

Table 5.3-9 (Cont'd)

Interpass Temperature Requirements

The interpass temperature shall not exceed 500°F maximum.

Filler Metal

Submerged Arc

Specification - N.A.
Classification - N.A.
Analysis - A3 (except Ni 0.50 to 1.25)
Usability - F6
Trade Name - CBI 1NMM (1% Nickel) or equal

Shielded Metal Arc

Specification - SFA5.5
Classification - E8018-G
Analysis - A3 (except Ni 0.50 to 1.25)
Usability - F4
Trade Name - Alloy Rods E8018NM

Electrical Characteristics

SMA - DCRP
Submerged Arc
  Tandem Wire
    Lead Wire - DCRP
    Trail Wire - AC
  Single Wire - DCRP

(1) This specification is extracted from the surveillance program of another BWR plant with similar beltline weld material.

Table 5.3-10

TYPICAL SURVEILLANCE PROGRAM WELD PROCEDURE FOR
LGS AND OTHER BWRs

Reference Specifications

General WPS 800 Latest Revision
General WPS 820 Latest Revision

Procedure Qualification

No.	Position	Thickness Range (in)
963 (TW)	F (Sub Arc) F,V,H (SMA)	4½ to 9.9
1261 (SW)	F (Sub Arc) F,V (SMA)	2¾ to 8

Postheat Treatment

Procedure qualified with 50 hours at 1150°F + 25°F/-50°F.

Postweld heat treatment of the weldment shall be in accordance with Chicago Bridge and Iron approved procedure.

Base Metal

ASME SA533 Grade B Class 1 or SA508 Class 2
ASME Group P12B Subgroup 1

Shielding Gas: None

Backup Gas: None

Flux: Linde 124

Table 5.3-10 (Cont'd)

Preheat Requirements

Minimum preheat of 300°F shall be applied uniformly to the full thickness of the weld joint and adjacent base material for a minimum distance of "T" or 6 inches, whichever is less where "T" is the material thickness.

Maintain preheat temperature until start of postweld heat treatment.

Interpass Temperature Requirements

The interpass temperature shall not exceed 500°F maximum.

Filler Metal

Submerged Arc

Specification - NA
Classification - NA
Analysis - A3 (except Ni 0.50 to 1.25)
Usability - F6
Trade Name - Adcom 1NMM (1% nickel) or equal

Shielded Metal Arc

Specification - SA316
Classification - E8018-G
Analysis - A3 (except Ni 0.50 to 1.25)
Usability - F4
Trade Name - Alloy Rods E8018NM

Electrical Characteristics

SMA - DCRP

Submerged Arc
Tandem Wire
Lead Wire - DCRP
Trail Wire - AC
Single Wire - DCRP

Table 5.3-10 (Cont'd)

GENERAL WELDING TECHNIQUE

Operation Description	Beads Layer	Weld Proc.	Electrode Size (in)	Current Type	Voltage (Amps)	(volts)	Travel
SMA	As Req'd	SMA	1/8 5/32 3/16 7/32 1/4	E8018NM	90-135 110-160 150-220 250-350 300-400	23-25 24-26 24-26 25-27 25-27	
Submerged Arc Single Wire (DCRP)	As Req'd	(1)		Adcom 1NMM or Equal	550-650	28-32	10-18
Tandem Wire	As Req'd	Lead Trail	(1) (1)		650-750 550-650	32-36 34-37	24 min
GROOVES(2)							
SMA	As Req'd	SMA	1/8 5/32 3/16 7/32 1/4	E8018NM	90-135 110-160 150-220 250-350 300-400	23-25 24-26 24-26 25-27 25-27	
Submerged Arc Single Wire (DCRP)	As Req'd		(1)	Adcom 1NMM or Equal	450-700	28-35	8-18

(1) 5/32 or 3/16 inches
(2) See Figure 5.3-8

Table 5.3-10 (Cont'd)

Unit 2 N16D Nozzle Weld Pad

Operation Description	Beads Layer	Weld Proc.	Electrode Size (in)	Current Type	Voltage (Amps)	(volts)	Travel
Machine Temper Bead GTAW	As Req'd	GTAW	1/16 3/32	DCSP	210-310 (primary) 115-130 (background)	9.5-10	

Heat Input Requirements/Allowable Wire Feed Speed Ranges

PARAMETER	LAYER 1	LAYER 2	LAYER 3	BALANCE
Primary Volts	9.5	9.8	10.0	10.0
Background Volts*	N/A	N/A	N/A	N/A
Primary Amps	210	280	280	310
Background Amps	115	120	120	130
Primary Wire (IPM)	36-44	54-66	54-66	54-66
Background Wire (IPM)	27-33	45-55	45-55	45-55
Primary Pulse Width (PPW)	40%	40%	40%	40%
Travel Speed (IPM)	4.5	4.0	4.0	3.8
Pulse Frequency (PPS)	2	2	2	2
Recommended Parameters Heat Input (J/in)	19,380	27,048	27,600	31,895 Max***
**MAX. Heat Input +10% (J/in)	21,318	29,752	30,360	N/A
**MIN. Heat Input -10% (J/in)	17,442	24,343	24,840	N/A

* Background Voltage is not applicable in the SAMP mode.
** Minimum and maximum heat input values are based on actual PQR parameters.
*** Maximum heat input used on the PQR balance of welding.

FORMULA FOR CALCULATING HEAT INPUT:
AVGAVC = PRIVOLT when in SAMP mode.
AVGAMP = (PRIAMP * PPW) + (BCKAMP * (1-PPW)
HEAT INPUT (J/in) = (AVGAVC * AVGAMP * 60) / TRAVEL SPEED

Unit 2 N16D J-Groove Weld

Operation Description	Beads Layer	Weld Proc.	Electrode Size (in)	Current Type	Voltage (Amps)	(volts)	Travel
Machine Temper Bead GTAW	As Req'd	GTAW	0.030-0.045 1/16 3/32 1/8	DCSP	20-90 50-100 60-170 85-180		

Table 5.3-11

ESTIMATED RT_{NDT} FOR COMPONENTS IN LGS VESSEL NONBELTLINE REGION

Component	Material	RT_{NDT}(°F)
I. Unit 1		
1. Vessel Flange	SA508 Class 2	-20
2. Top Head Flange	SA508 Class 2	+10
3. Top Head Torus	SA533 Grade B, Class 1	+10
4. Plate Connecting to Vessel Flange	SA533 Grade B, Class 1	+20
5. Feedwater Nozzle	SA508 Class 2	-20
6. Vessel Main Closure Stud(2)	SA540 Grade B 24	--
II. Unit 2		
1. Vessel Flange	SA508 Class 2	+10
2. Top Head Flange	SA508 Class 2	+10
3. Top Head Torus	SA533 Grade B, Class 1	-20
4. Plate Connecting to Vessel Flange	SA533 Grade B, Class 1	-16
5. Feedwater Nozzle	SA508 Class 2	0
6. Vessel Main Closure Stud(2)	SA540 Grade B 24	--

Table 5.3-11 (Cont'd)

(1) Deleted

(2) This component meets the CVN test requirements of 45 ft-lb absorbed energy and 25 mil lateral expansion at +10°F.

(3) Deleted

Table 5.3-12

SURVEILLANCE CAPSULE[1]

Capsule	Tensile	Charpy V-Notch
No. 1 (Azimuth 300°)	3 Base Metal (BM) 4 Weld Metal (WM) 3 Heat Affected Zone (HAZ)	8 BM, Long. 8 WM 8 HAZ
No. 2(2) (Azimuth 120°)	3 BM 4 WM 3 HAZ	8 BM, Long. 8 WM 8 HAZ
No. 3 (Azimuth 30°)	3 BM 4 WM 3 HAZ	20 BM, Long. 16 WM 12 HAZ

(1) Each capsule also includes Fe and Cu flux wires.

(2) The Unit 2 surveillance capsule and holder at Azimuth 120° was removed from the vessel in October 2017 and was not reinstalled due to the failure of the holder.

5.4 COMPONENT AND SUBSYSTEM DESIGN

5.4.1 REACTOR RECIRCULATION PUMPS

5.4.1.1 Safety Design Bases

The reactor recirculation system is designed to meet the following safety design bases:

a. An adequate fuel barrier thermal margin is ensured during postulated transients.

b. A failure of piping integrity does not compromise the ability of the reactor vessel internals to provide a refloodable volume.

c. The system maintains pressure integrity during adverse combinations of loadings and forces occurring during abnormal, accident, and special event conditions.

5.4.1.2 Power Generation Design Bases

The reactor recirculation system meets the following power generation design bases:

a. The system provides sufficient flow to remove heat from the fuel.

b. The system provides for changing reactor power without control rod movement over the range of approximately 55% to 100% rated power.

c. The system design minimizes maintenance situations that would require core disassembly and fuel removal.

5.4.1.3 Description

The reactor recirculation system consists of the two recirculation pump loops external to the reactor vessel. These loops provide the piping path for the driving flow of water to the reactor vessel jet pumps (Figure 5.4-1 and drawing M-43). Each external loop contains one high capacity, variable-speed, motor-driven recirculation pump and two motor-operated gate valves (for pump maintenance). Each loop contains a flow-measuring system. The recirculation loops are part of the RCPB and are located inside the drywell structure. The jet pumps are reactor vessel internals. Their location and mechanical design are discussed in Section 3.9.5. However, certain operational characteristics of the jet pumps are discussed in this section. The important design and performance characteristics of the reactor recirculation system are shown in Table 5.4-1. The head, NPSH, flow, and efficiency curves are shown in Figure 5.4-3. An instrumentation and control description is provided in Section 7.1.2.

The recirculated coolant consists of saturated water from the steam separators and dryers that has been subcooled by incoming feedwater. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pumps within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the driven flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The flows, both driving and driven, are mixed in the jet pump throat section and result in partial pressure recovery. The balance of

recovery is obtained in the jet pump diffuser (Figure 5.4-4). The adequacy of the total flow to the core is discussed in Section 4.4.

The allowable heatup rate for the recirculation pump casing is the same as for the reactor vessel. If one loop is shut down, it can be kept hot by leaving the discharge and suction gate valves open; this permits the reactor pressure plus the active jet pump head to cause reverse flow in the idle loop.

Because the removal of the reactor recirculation gate valve internals would require unloading the core due to the resulting draining of reactor coolant, the objective of the valve trim design is to minimize the need for maintenance of the valve internals. The valves are provided with high quality back-seats that permit renewal of stem packing while the system is full of water.

The feedwater flowing into the reactor vessel annulus during operation provides subcooling for the fluid passing to the recirculation pumps and jet pumps, thus providing additional NPSH available beyond that provided by the pump location below the reactor vessel water level. If feedwater flow is less than the minimum value necessary for adequate NPSH for full speed recirculation pump operation, the pump speed is automatically limited.

When preparing for hydrostatic tests, the nuclear system temperature must be raised above the vessel NDTT limit. The vessel is heated by operating the recirculation pumps and/or by core decay heat.

Each recirculation pump is a single-stage, variable-speed, vertical, centrifugal pump equipped with mechanical shaft seal assemblies. The pump is capable of stable and satisfactory performance while operating continuously at any speed corresponding to a power supply frequency range of 11.5 Hz to 57.5 Hz for 60 Hz power supply.

The recirculation pump shaft seal assembly consists of two individual seals built into a cartridge or cartridges that can be readily replaced without removing the motor from the pump. The seal assembly is designed to require minimum maintenance over a long period of time, regardless of whether the pump is stopped or is operating at various speeds with water at various pressures and temperatures. Each seal is designed for a life of one year, based on a 90% probability factor (original design). Each individual seal in the cartridge is capable of sealing against pump operating pressure so that any one seal can adequately limit leakage if the other seal fails. A breakdown orfice is provided in the pump casing to reduce leakage if there is a gross failure of both shaft seals. Provision is made for monitoring the pressure drop across each individual seal as well as the cavity temperature of each seal. Provision is also made for piping the seal leakage to a flow-measuring device. It should be noted that the original seals have been replaced with an improved design prone to less leakage in the event of a seal failure.

Each recirculation pump motor is a vertical, variable-speed, ac electric motor that can drive the pump over a controlled range of 28% to 99.2% of rated pump speed. The motor is designed to operate continuously at any speed within the power supply frequency range of 15.7 Hz to 55.6 Hz from 60 Hz power supply. Electrical equipment is designed, constructed, and tested in accordance with the applicable sections of the NEMA standards.

A variable-frequency ac ASD located outside the drywell supplies power to a recirculation pump motor. Each unit has two variable-frequency ac ASDs (one per recirculation pump motor). The pump motor is electrically connected to the ASD 4kV output generated by digitally controlled solid-state power electronics.

The ASD has no rotational inertia to add to the recirculation pump and motor to slow down the coast-down rate. However, per the GEH Transient Analysis Report (SDOC G-080-VC-00467 and SDOC G-080-VC-00470), it is determined that this lack of rotational inertia was either 1) not a factor in the transient, 2) had low consequence in the analysis or 3) was otherwise analyzed as not being a significant contributor to the event. The lack of additional coast-down inertia is not a concern for flow into the core.

Pump casing and valve bodies are designed for a 40 year life and are welded into the piping system with no plans to remove them from the system for maintenance or overhaul. Removable parts of the pump such as wear rings, impellers, bearings, etc, are designed for as long a life as practicable, and as a design objective they should have a life between overhaul or major maintenance cycle of more than five years. Pump seals and valve packings are expected to have a useful service life in excess of a refueling cycle, to afford convenient replacement during the refueling outage.

The recirculation system piping is of all-welded construction and is designed and constructed to meet the requirements of the ASME Code. The reactor recirculation system pressure boundary equipment is designed as seismic Category I. Design codes and standards are discussed in detail in Section 3.2.

Snubbers located at the top of the motor and at the bottom of the pump casing are designed to resist seismic reactions.

The recirculation piping, valves, and pumps are supported by hangers to avoid the use of piping expansion loops that would be required if the pumps were anchored. In addition, the recirculation loops are provided with a system of restraints designed so that reaction forces associated with the postulated pipe breaks do not jeopardize primary containment integrity. This restraint system provides adequate clearance for normal thermal expansion movement of the loop. Because possible pipe movement is limited to slightly more than the clearance required for thermal expansion movement, no impact loading on limit stops is considered. A more detailed discussion of the recirculation piping restraints is in Section 3.6.

The recirculation system piping, valves, and pump casings are covered with fiberglass-type thermal insulation and stainless steel jacketing. This insulation is removable for the purpose of inservice inspection.

5.4.1.4 Safety Evaluation

Postulated reactor recirculation system malfunctions that could lead to damage to the fuel barrier are described and evaluated in Chapter 15. It is shown in Chapter 15 that none of the malfunctions could result in significant fuel damage. The recirculation system has sufficient flow coast-down characteristics to maintain fuel thermal margins during abnormal operational transients.

The core flooding capability of a jet pump design plant is discussed in detail in the ECCS topical report (Reference 5.4-1). The ability to reflood the BWR core to the top of the jet pumps is shown schematically in Figure 5.4-5 and is discussed in Reference 5.4-1.

Piping and pump design pressures for the reactor recirculation system are based on peak steam pressure in the reactor dome, appropriate pump head allowances, and the elevation head above the lowest point in the recirculation loop. Piping and related equipment pressure-retaining components are chosen in accordance with applicable codes (Section 3.2). Use of the code design criteria ensures that a system designed, built, and operated within design limits has an extremely low probability of failure caused by any known failure mechanism.

GE purchase specifications require that the recirculation pump's first critical speed be not less than 130% of operating speed. Calculations were verified by GE design engineering.

GE purchase specifications require that the integrity of the pump case be maintained through all transients and that the pump remain operable through all normal and upset transients. The design of the pump and motor bearings is required to be such that the dynamic load capability at rated operating conditions is not exceeded during the SSE. Calculation submittal is required.

Pump overspeed occurs during the course of a postulated LOCA due to blowdown through the broken loop pump. Design studies determined that the overspeed is not sufficient to cause destruction of the motor, and consequently no provision is made to decouple the pump from the motor for such an event.

5.4.1.5 Inspection and Testing

Quality control methods were used during fabrication and assembly of the reactor recirculation system to ensure that design specifications are met. Inspection and testing were carried out as described in Section 3.9. The RCS was thoroughly cleaned and flushed before fuel was loaded initially.

During the preoperational test program, the reactor recirculation system was hydrostatically tested in accordance with the codes listed in Section 5.2.1. Preoperational tests on the reactor recirculation system also include checking the operation of the pumps, flow control system, and gate valves and are discussed in Chapter 14.

During the startup test program, horizontal and vertical motions of the reactor recirculation system piping and equipment were observed; supports were adjusted, if necessary, to ensure that components are free to move as designed. Nuclear system responses to recirculation pump trips at rated temperatures and pressure were evaluated during the startup tests, and plant power response to recirculation flow control was determined.

5.4.2 STEAM GENERATORS (PWR)

Section 5.4.2 is not applicable to LGS.

5.4.3 REACTOR COOLANT PIPING

The reactor coolant piping is discussed in Sections 3.9.3 and 5.4.1. The recirculation loops are shown in Figure 5.4-1 and drawing M-43, and the design characteristics are presented in Table 5.4-1.

5.4.4 MAIN STEAM LINE FLOW RESTRICTORS

5.4.4.1 Safety Design Bases

The main steam line flow restrictors are designed to:

a. Limit the loss of coolant from the reactor vessel following a steam line rupture outside the containment to the extent that the reactor vessel water level remains high enough to provide cooling within the time required to close the MSIVs

b. Withstand the maximum pressure difference expected across the restrictor, following complete severance of a main steam line

c. Limit radioactive release outside of the drywell before MSIV closure

d. Provide a trip signal for MSIV closure

5.4.4.2 Description

A main steam line flow restrictor (Figure 5.4-6) is provided for each of the four main steam lines. The restrictor is a complete assembly welded into the main steam line, and it is located in the drywell.

If a main steam line break occurs outside the containment, the restrictor limits the coolant blowdown rate from the reactor vessel to the maximum (choke) flow of 7.08×10^6 lb/hr at 1000 psig upstream pressure. The restrictor assembly consists of a venturi-type nozzle insert welded, in accordance with applicable code requirements, into the main steam line. The flow restrictor is designed and fabricated in accordance with ASME "Fluid Meters," 5th edition, 1959.

The flow restrictor has no moving parts. Its mechanical structure can withstand the velocities and forces associated with a main steam line break. The maximum differential pressure is conservatively assumed to be 1375 psi, the reactor vessel ASME Code limit pressure.

The ratio of venturi throat diameter to steam line inside diameter of approximately 0.55 results in a maximum pressure differential (unrecovered pressure) of about 11 psi at 105% of rated flow. This design limits the steam flow in a severed line to less than 200% rated flow, yet it results in negligible increase in steam moisture content during normal operation. The restrictor is also used to measure steam flow to initiate closure of the MSIVs when the steam flow exceeds preselected operational limits.

5.4.4.3 Safety Evaluation

If a main steam line breaks outside the containment, the critical flow phenomenon would restrict the steam flow rate in the venturi throat to 200% of the rated value. Before isolation valve closure, the total coolant losses from the vessel are not sufficient to cause core uncovering, and the core is thus adequately cooled at all times.

Analysis of a steam line rupture accident (Chapter 15) shows that the core remains covered with water and that the amount of radioactive materials released to the environment through the main steam line break does not exceed the guideline values of published regulations.

Tests on a scale model determined the final design and performance characteristics of the flow restrictor. The characteristics include maximum flow rate of the restrictor corresponding to the accident conditions, unrecoverable losses under normal plant operating conditions, and discharge moisture level. The tests showed that flow restriction at critical throat velocities is stable and predictable.

The steam flow restrictor is exposed to steam of about 0.2% moisture flowing at velocities of 150 ft/sec (steam piping ID) to 600 ft/sec (steam restrictor throat). ASTM A351 (Type 304) cast stainless steel is used for the steam flow restrictor material because it has excellent resistance to erosion/corrosion in a high velocity steam atmosphere. The excellent performance of stainless steel in high velocity steam appears to be due to its resistance to corrosion. A protective surface film forms on the stainless steel, which prevents any surface attack, and this film is not removed by the steam.

Hardness has no significant effect on erosion/corrosion. For example, hardened carbon steel or alloy steel erodes rapidly in applications where soft stainless steel is unaffected.

Surface finish has a minor effect on erosion/corrosion. If very rough surfaces are exposed, the protruding ridges or points erode more rapidly than a smooth surface. Experience shows that a machined or a ground surface is sufficiently smooth and that no detrimental erosion occurs.

5.4.4.4 Inspection and Testing

Because the flow restrictor forms a permanent part of the main steam line piping and has no moving components, no testing program is planned. Only very slow erosion occurs with time, and such a slight enlargement has no safety significance. Stainless steel resistance to corrosion has been substantiated by turbine inspections at the Dresden Unit 1 facility, which have revealed no noticeable effects from erosion on the stainless steel nozzle partitions. The Dresden inlet velocities are about 300 ft/sec, and the exit velocities are 600-900 ft/sec. However, calculations show that, even if the erosion rates are as high as 0.004 inch per year, after 40 years of operation the increase in restrictor choked flow rate would be no more than 5%. A 5% increase in the radiological dose calculated for the postulated main steam line break accident is not significant.

5.4.5 MAIN STEAM LINE ISOLATION SYSTEM

5.4.5.1 Safety Design Bases

The MSIVs, individually or collectively, perform the following functions:

a. Close the main steam lines within the time established by DBA analysis to limit the release of reactor coolant.

b. Close the main steam lines slowly enough that simultaneous closure of all steam lines does not induce transients that exceed the nuclear system design limits.

c. Close the main steam line when required despite single failure in either a valve or in the associated controls, to provide a high level of reliability for the safety function.

d. Use separate energy sources as the motive force to close independently the redundant isolation valves in the individual steam lines.

e. Use local stored energy (compressed air and springs) to close at least one isolation valve in each steam pipeline without relying on the continuity of any variety of electrical power to furnish the motive force to achieve closure.

f. Close the steam lines, either during or after seismic loadings, to ensure isolation if the nuclear system is breached.

g. Have capability for testing, during normal operating conditions, to demonstrate that the valves will function.

5.4.5.2 Description

Two isolation valves are welded in a horizontal run of each of the four main steam pipes; one valve is as close as possible to the inside of the drywell, and the other is just outside the primary containment.

Figure 5.4-7 shows an MSIV. Each is a 26 inch Y-pattern, globe valve. The rated steam flow rate through each valve is 3.543×10^6 lb/hr. The main disc or poppet is attached to the lower end of the

stem. Normal steam flow tends to close the valve, and higher inlet pressure tends to hold the valve closed. The bottom end of the valve stem closes a small pressure balancing hole in the poppet. When the hole is open, it acts as a pilot valve to relieve differential pressure forces on the poppet. Valve stem travel is sufficient to permit flow areas past the wide open poppet that are greater than the seat port area. The poppet travels approximately 90% of the valve stem travel to close the main seat port area; approximately the last 10% of valve stem travel closes the pilot valve. The gas (air for MSIVs outside containment, nitrogen for MSIVs inside containment, as described in Section 9.3) can open the poppet with a maximum differential pressure of 200 psi across the isolation valve in a direction that tends to hold the valve closed.

A 45° angle permits the inlet and outlet passages to be streamlined; this minimizes pressure drop during normal steam flow and helps prevent blockage by debris. The pressure drop at 105% of rated flow is 7 psi maximum.

Attached to the upper end of the stem is a gas cylinder that opens and closes the valve and a hydraulic dashpot that controls its speed. The speed is adjusted by a valve in the hydraulic return line bypassing the dashpot piston. Valve closing time is adjustable to between 3 seconds and 10 seconds.

The gas cylinder is supported on the valve bonnet by actuator support and spring guide shafts. Helical springs around the spring guide shafts close the valve on loss of pneumatic pressure to the gas cylinder. The motion of the spring seat member actuates switches in the 10% open, 90% open valve positions.

The valve is operated by pneumatic pressure and by the action of compressed springs. The control unit is attached to the gas cylinder. This unit contains three types of control valves (pneumatic, dc, and ac from another source) that open and close the main valve and exercise it at slow speed. Remote manual switches in the control room enable the operator to operate the valves.

Operating gas is supplied to the valves from the Instrument Air (outboard valves) and Primary Containment Instrument Gas (inboard valves) systems. A gas accumulator between the control valve and a check valve provides backup operating gas. The actuator and seals act as extensions of the accumulator and as such have specific leakage limits.

Each valve is designed to accommodate saturated steam at plant operating conditions, with a moisture content of approximately 0.25%, an oxygen content of 30 ppm, and a hydrogen content of 4 ppm. The valves are furnished in conformance with a design pressure and temperature rating in excess of plant operating conditions to accommodate plant overpressure conditions.

In the worst case, if the main steam line ruptures downstream of the valve, the steam flow would quickly increase to 200% of rated flow. Further increase is prevented by the venturi flow restrictor inside the containment.

During approximately the first 75% of closing, the valve has little effect on flow reduction, because the flow is choked by the venturi restrictor. After the valve is approximately 75% closed, flow is reduced as a function of the valve area versus travel characteristic.

The design objective for the valve is a minimum of 40 years' service at the specified operating conditions. Operating cycles (excluding exercise cycles) are estimated to be 50 cycles per year during the first year and 20 cycles per year thereafter.

In addition to the minimum wall thickness required by applicable codes, a 0.120 inch (minimum) corrosion allowance is added to provide for 40 years' service.

Design specification ambient conditions for normal plant operation are 150°F maximum temperature and 100% relative humidity, in a radiation field of 15 rad/hr gamma and 25 rad/hr neutron plus gamma, continuous for design life. The inside valves are not continuously exposed to maximum conditions, particularly during reactor shutdown, and valves outside the primary containment and shielding are in ambient conditions that are considerably less severe.

The MSIVs are designed to close under accident environmental conditions of 340°F for one minute at drywell design pressure. In addition, they are designed to remain closed under the following postaccident environment conditions:

a. For the balance of the first 3 hours; 340°F at a drywell pressure of 45 psig maximum

b. 320°F for an additional 3 hours at 45 psig maximum

c. 250°F for an additional 24 hours at 25 psig maximum

d. 200°F during the next 100 days at 20 psig maximum

To resist sufficiently the response motion from the SSE, the MSIV installations are designed as seismic Category I equipment. The valve assembly is manufactured to withstand the SSE forces applied at the mass center of the extended mass of the valve operator, assuming that the cylinder/spring operator is cantilevered from the valve body and the valve is located in a horizontal run of pipe. The stresses caused by horizontal and vertical seismic forces are assumed to act simultaneously. The stresses in the actuator supports caused by seismic loads are combined with the stresses caused by other live and dead loads, including the operating loads. The allowable stress for this combination of loads is based on a percentage of the allowable yield stress for the material. The parts of the MSIVs that constitute a process fluid pressure boundary are designed, fabricated, inspected, and tested as required by the ASME Section III. Design codes and standards are discussed in detail in Section 3.2.

5.4.5.3 Safety Evaluation

In a direct cycle nuclear power plant, the reactor steam goes to the turbine and to other equipment outside the containment. Radioactive materials in the steam are released to the environment through process openings in the steam system, or they can escape from accidental openings. A large break in the steam system can drain the water from the reactor core faster than it is replaced by feedwater.

The analysis of a complete, sudden steam line break outside the containment is described in Chapter 15. The analysis shows that the fuel barrier is protected against loss of cooling if MSIV closure is within specified limits, including instrumentation delay to initiate valve closure after the break. The calculated radiological effects of the radioactive material assumed to be released with the steam are shown to be well within the guideline values for such an accident.

The shortest closing time (approximately 3 seconds) of the MSIVs is also shown to be satisfactory in Chapter 15. The switches on the valves initiate reactor scram when specific conditions (extent of valve closure, number of pipelines included, and reactor power level) are exceeded (Section 7.2.1). The pressure rise in the system from stored and decay heat may cause the nuclear system relief

valves to open briefly, but the rise in fuel cladding temperature is insignificant. No fuel damage results.

The ability of this 45°, Y-design globe valve to close in a few seconds after a steam line break, under conditions of high pressure differentials and fluid flows with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of dynamic tests. A full-size, 20 inch valve was tested in a range of steam-water blowdown conditions simulating postulated accident conditions (Reference 5.4-2).

The following specified hydrostatic, leakage, and stroking tests, as a minimum, are performed by the valve manufacturer in-shop tests:

a. To verify its capability to close at settings between 3 seconds and 10 seconds, each valve is tested at a pressure of 1000 psig and no flow (response time for full closure is set before plant operation at 3 seconds minimum, 5 seconds maximum). The valve is stroked several times, and the closing time is recorded. The valve is closed by springs only and by the combination of air cylinder and springs. The closing time is slightly greater when closure is by springs only.

b. Leakage is measured with the valve seated and back-seated. The specified maximum seat leakage, using cold water at design pressure, is 2 cm^3/hr/in of nominal valve size. In addition, an air seat leakage test is conducted using 50 psi pressure upstream. Maximum permissible leakage is 0.1 scfh/in of nominal valve size. There must be no visible leakage from either set of stem packing at hydrostatic test pressure. The valve stem is operated a minimum of three times from the closed position to the open position, and the packing leakage still must be zero by visual examination. (Valve stem backseat feature and valve packing leak off feature has been eliminated on all of the MSIVs by modification.)

c. Each valve is hydrostatically tested in accordance with the requirements of the applicable edition and addenda of the ASME Code. During valve fabrication, extensive nondestructive tests and examinations are conducted. The tests include radiographic, liquid penetrant, or magnetic particle examinations of casting, forgings, welds, hard-facings, and bolts.

d. The spring guides, the guiding of the spring seat member on support shafts, and rigid attachment of the seat member ensure correct alignment of the actuating components. Binding of the valve poppet in the internal guides is prevented by making the poppet in the form of a cylinder longer than its diameter and by applying stem force near the bottom of the poppet.

Each valve is tested after installation as discussed in Chapter 14.

Two isolation valves provide redundancy in each steam line so that either can perform the isolation function and either can be tested for leakage after the other is closed. The inside valve, the outside valve, and their respective control systems are separated physically.

The design of the MSIV has been analyzed for earthquake loading. The cantilevered support of the air cylinder, hydraulic cylinder, springs, and controls is the key area. The increase in loading caused by the specified earthquake loading does not result in stresses exceeding ASME allowable stresses or prevent the valve from closing as required.

Electrical equipment that is associated with the MSIVs and operates in an accident environment is limited to the wiring, solenoid valves, and position switches on the valves. The expected pressure and temperature transients following an accident are discussed in Chapter 15.

5.4.5.4 Inspection and Testing

The MSIVs can be functionally tested for operability during plant operation. The test provisions are listed below. During refueling outages the MSIVs can be functionally tested, leak tested, and visually inspected.

During plant operation the MSIVs can be tested and exercised individually to the 90% open position, because the valves still pass rated steam flow when 90% open.

During prestartup tests following an extensive shutdown, the valves receive the same hydro tests (approximately 400 psi) that are imposed on the primary system.

The MSIVs can also be tested and exercised individually to the fully closed position if reactor power is reduced sufficiently to avoid scram from reactor overpressure or high flow through the steam line flow restrictors in the remaining steam lines. Continued operation with one or both MSIV's closed on one Main Steam Line is permitted provided that reactor thermal power is maintained at or below 75% of rated (ref. 5.4-3).

Leakage from the valve stem packing can be detected during reactor operation from measurements of leakage into the drywell or from observations or similar measurements in the steam tunnel.

The leak rate through the valve seats (pilot and poppet seats) is measured accurately as a part of the 10CFR50, Appendix J LLRT program during shutdown.

Leak rates are determined by typical Appendix J, Type C, leak rate procedures which use a combination of flow-in, flow-out, pressure decay, and pressure differential elimination across valves to determine valve leakage at its test pressure required by technical specifications.

Such a test and leakage measurement program ensures that the valves are operating correctly and that any leakage trend is detected.

5.4.6 REACTOR CORE ISOLATION COOLING SYSTEM

5.4.6.1 Design Bases

The RCIC system is a safety system that consists of a turbine, pump, piping, valves, accessories, and instrumentation designed to ensure that sufficient reactor water inventory is maintained in the reactor vessel to permit adequate core cooling to take place. This prevents reactor fuel overheating during the following conditions:

a. The vessel is isolated and maintained in the hot standby condition.

b. The vessel is isolated, accompanied by loss of coolant flow from the reactor feedwater system.

c. A complete plant shutdown under conditions of loss of normal feedwater system is started before the reactor is depressurized to a level at which the shutdown cooling system can be placed into operation.

Following a reactor scram, steam generation continues at a reduced rate due to the core fission product decay heat. At this time the turbine bypass system diverts the steam to the main condenser, and the feedwater system supplies the makeup water required to maintain the reactor vessel inventory.

If the reactor vessel is isolated and the feedwater supply is unavailable, relief valves are provided to automatically (or remote manually) maintain vessel pressure within desirable limits. The water level in the reactor vessel drops due to continued steam generation by decay heat. On reaching a predetermined low level, the RCIC system is initiated automatically. The system then functions to restore adequate vessel water levels. On reaching a predetermined high level, the RCIC steam admission valve (F045) automatically closes, resulting in turbine shutdown. RCIC will automatically restart if the level returns to the low level trip point. The turbine-driven pump supplies makeup water from the CST to the reactor vessel. If the CST level falls below a predetermined low level, an alternate source of water is automatically made available from the suppression pool. The turbine is driven with a portion of the decay heat steam from the reactor vessel, and exhausts to the suppression pool. Suppression pool water may not be of condensate quality and hence it is preferred that it only be used if sources of condensate quality water are not available.

During RCIC operation, the suppression pool acts as the heat sink for steam generated by reactor decay heat. This results in a rise in pool water temperature. The RHR system heat exchangers are used to maintain pool water temperature within acceptable limits by cooling the pool water.

For design basis events RCIC needs to operate for a maximum of six hours in order to fulfill its safety functions.

5.4.6.1.1 Residual Heat and Isolation

5.4.6.1.1.1 Residual Heat

The RCIC system is designed to initiate and discharge, within 55 seconds, a specified constant flow into the reactor vessel over a specified pressure range. The temperature of the RCIC water discharged into the reactor vessel varies between 40°F and 140°F. Station Blackout (SBO) procedures directs the operation of the RCIC System for Reactor Pressure Level Control for the SBO 4-hour coping duration with water supply from the Suppression Pool. During the SBO event, the Suppression Pool water may reach up to 180 degrees F. The mixture of the cool RCIC water and the hot steam accomplishes the following:

a. Quenches the steam

b. Removes reactor residual heat by reducing the heat level (enthalpy) due to the temperature difference between the steam and water

c. Replenishes reactor vessel inventory

The HPCI system performs the same function, thereby providing single failure protection. Both systems use different electrical power sources of high reliability, which permits operation with either onsite or offsite power. Additionally, the RHR system performs a residual heat removal function.

The RCIC system design includes interfaces with redundant leak detection devices:

a. A high pressure drop across a flow device in the steam supply line equivalent to 300% of the steady-state steam flow at 1197 psia

b. A high area temperature, using temperature switches as described in the leak detection system; high area temperature is alarmed in the control room

c. A high pressure between the turbine exhaust rupture diaphragms

d. Reactor low pressure

These devices, activated by the redundant power supplies, automatically isolate the steam supply to the RCIC turbine.

Other isolation bases are defined below. Again, HPCI provides redundancy for RCIC if RCIC becomes isolated, thus providing single failure protection.

5.4.6.1.1.2 Isolation

Isolation valve arrangements include the following (additional information about containment isolation is given in Section 6.2.4):

a. Two RCIC lines penetrate the primary containment and form a part of the RCPB. The first is the RCIC steam supply line, which branches off the B main steam line between the reactor vessel and the inboard MSIV. This line has two automatic motor-operated isolation valves F007 and F008, which are key-locked open. One is located inside and the other outside primary containment. An automatic MOV, F076, is provided in the bypass line around the outboard RCIC isolation valve. The isolation signals noted earlier close these valves. The isolation signal is automatic and bypasses the key-lock when the valves must be closed in the case of an RCIC line break. For other accidents, it is more desirable to have steam available for RCIC operation than to preclude its operation because of a containment automatic isolation valve closure signal. If the isolation valves were closed, operator action would be required to reopen the valves to avoid water hammer and thermal shock. An isolation signal is given for a large pipe break by detecting flow rates greater than 300% of the steady-state steam flow. For leakage with flow rates less than 300% of steady-state steam flow, an isolation signal is signaled by use of area temperature sensors provided by the leak detection system.

   The RCIC pump discharge line is the other line that forms a part of the RCPB; however, it indirectly connects to the RPV. Outside containment, this line enters the feedwater line, which provides required isolation valves inside the primary containment. The RCIC system has an automatic MOV F013 outside primary containment for isolation. The above arrangements satisfy GDC 55 for RCPB lines penetrating containment.

b. The RCIC turbine exhaust line vacuum breaker system line has two automatic MOVs (F080, F084) and four check valves. This line runs between the suppression pool air space and the turbine exhaust line downstream of the exhaust line check valve.

Isolation is automatic via a combination of low reactor pressure and high drywell pressure. This design satisfies GDC 56 for primary containment isolation.

The vacuum breaker valve complex is placed outside primary containment, due to a more desirable environment. In addition, the valves are then readily accessible for maintenance and testing.

c. The RCIC pump suction line, minimum flow pump discharge line, turbine gland seal system vacuum pump discharge, and turbine exhaust line all penetrate the primary containment and terminate below the suppression pool water level. The isolation valves (F031, F019, F002 and F060, respectively) for the lines are all outside primary containment and require remote manual operation, except for the minimum flow valves, which operate automatically. This arrangement satisfies GDC 56 for primary containment isolation.

5.4.6.1.2 Reliability, Operability, and Manual Operation

5.4.6.1.2.1 Reliability and Operability

The RCIC system as shown in Table 3.2-1 is designed commensurate with the safety importance of the system and its equipment. Each component is individually tested to confirm compliance with system requirements. The system as a whole is tested during both the startup and preoperational phases of the plant to set a base-mark for system reliability. To confirm that the system maintains this mark, functional and operability testing is periodically performed.

A design flow functional test of the RCIC system may be performed during normal plant operation by drawing suction from the CST and discharging through a full flow test return line to the condensate storage tank. The discharge valve to the feedwater line remains closed during the test, and reactor operation remains undisturbed. All components of the RCIC system are capable of undergoing individual functional testing during normal plant operation. The system automatically aligns from test to operating mode if system initiation is required, but operator action is needed in the following instances:

a. Auto/manual switch is in manual on the flow controller. This feature is provided for operator flexibility during system operation.

b. Steam inboard/outboard isolation valves closed. Closure of either or both of these valves requires operator action to properly sequence their opening. An alarm sounds when either of these valves leaves the fully open position.

c. Parts of the system have been bypassed or otherwise deliberately rendered inoperable. These conditions are automatically indicated in the control room at the system level. Capability for manual initiation of system level indication exists for items not readily automated.

See also Section 5.4.6.2.4.

Four RCIC lines have a low design pressure and could possibly be overpressurized: the turbine exhaust line, the turbine leak-off to the barometric condenser, the cooling water line from PCV-1F015 to the barometric condenser, and the vacuum pump discharge line. These lines are shown on drawings M-49 and M-50. The turbine exhaust line is protected from overpressurization by two

rupture discs, PSE-1D001 and PSE-1D002. Pressure relief valves are provided to protect the other three lines from overpressurization.

5.4.6.1.2.2 Manual Operation

Provisions are included for remote manual startup, operation, and shutdown of the RCIC system.

As discussed in Section 5.4.7.1.1.5, the steam condensing mode of the RHR system has been removed from the plant.

See also Section 5.4.6.2.4.

5.4.6.1.3 Loss of Offsite Power

The RCIC system electrical power is derived from a highly reliable source that is maintained by either onsite or offsite power. See Section 5.4.6.1.1.

5.4.6.1.4 Physical Damage

The system is designed to the requirements shown in Table 3.2-1, which are commensurate with the safety importance of the system and its equipment. The RCIC system is located in a different area of the reactor enclosure and uses different divisional power (with separated electrical routings) than its redundant system (HPCI), as discussed in Sections 5.4.6.1.1 and 5.4.6.2.3.

5.4.6.1.5 Environment

The RCIC suction line that is exposed to the outdoor environment is provided with non-Class 1E heat tracing. Indication is provided in the control room if this heat tracing should become inoperative. Condensate level instrumentation for control room monitoring is located in the reactor enclosure and therefore is not exposed to the outdoor environment.

5.4.6.2 System Design

5.4.6.2.1 General

5.4.6.2.1.1 Description

A summary description of the RCIC system is presented in Section 5.4.6.1, which defines in general the system functions and components. The detailed description of the system, its components, and its operations is presented in the following sections.

5.4.6.2.1.2 Diagrams

The following diagrams are included for the RCIC system:

a. A P&ID (drawings M-49 and M-50) shows all components, piping, points where interface system and subsystems tie together, and instrumentation and controls associated with subsystem and component actuation.

b. A schematic process diagram (drawing E51-1020-G-002) shows temperature, pressures, and flows for RCIC operation and system process data hydraulic requirements.

5.4.6.2.1.3 Interlocks

The following electrical interlocks are provided:

a. There are four key-locked valves (F007, F008, F060, and F002) and two key-locked resets (the isolation resets).

b. Limit switches on valves F029 and F031 activate such that when both valves are fully open, F010 closes.

c. A limit switch on valve F060 activates when fully open and clears a permissive so valve F045 can open.

d. The limit switch on valve F045 actuates when F045 is partially open. The limit switch causes the valve to stop at the partially open position and also initiates a time delay relay. The valve remains in the partially open position until the time delay relay times out and activates the opening of the F045 valve. The time delay relay also initiates the ramp generator.

e. A limit switch on valve F045 activates when F045 is not fully closed, initiates startup ramp function and acts to lock out the following alarms for 15 seconds: RCIC pump low flow, RCIC low oil pressure, and RCIC vacuum tank low vacuum. This ramp resets each time F045 is closed.

f. The F045 limit switch activates when fully closed to permit valves F004, F005, F025, and F026 to open and causes valves F013 and F019 to close.

g. The turbine trip throttle valve (part of the turbine assembly) limit switch activates when fully closed and causes valves F013 and F019 to close.

h. The combined pressure switches at reactor low pressure and high drywell pressure, when activated, close valves F080 and F084.

i. High turbine exhaust pressure, low pump suction pressure, or an isolation signal, actuate to close the turbine trip throttle valve; when the signal is cleared, the trip throttle valve must be reset from the control room.

j. 124% overspeed trips both the mechanical trip at the turbine and the trip throttle valve; the former is reset at the turbine, and then the latter is reset in the control room

k. An isolation signal closes valves F007, F008, F076, and other valves, directly or indirectly, as noted in items f and h above.

l. An initiation signal opens valves F010 (if closed), F013, and F046; starts the barometric condenser vacuum pump; and causes valve F022 to close, if open.

m. A high RCIC steam line drain pot level signal causes valve F054 to open. The valve recloses when the high level signal clears.

n. The combined signal of low flow plus pump discharge pressure opens and, with increased flow, closes valve F019. See also items e and f above.

o. The switches for reactor low pressure, high turbine exhaust diaphragm pressure, steam line high differential pressure, or high area temperature, when activated, close valves F007, F008 and F076.

p. Limit switches on valves F029 and F031 activate such that when either valve is open, F022 closes.

q. High water level in the reactor vessel (level 8) initiates closure of the F045 and FO46 valves.

5.4.6.2.2 Equipment and Component Description

5.4.6.2.2.1 Design Conditions

The RCIC system components are as follows:

a. One 100% capacity turbine and accessories

b. One 100% capacity pump assembly and accessories

c. Piping, valves, and instrumentation for the following:

1. Steam supply to the turbine

2. Turbine exhaust to the suppression pool

3. Makeup supply from the CST to the pump suction

4. Makeup supply from the suppression pool to the pump suction including pump suction strainers described in Section 6.2.2.2.

5. Deleted

6. Pump discharge to the feedwater line, a test line to the CST, a minimum flow bypass line to the suppression pool, and a coolant water supply to accessory equipment.

5.4.6.2.2.2 Applicable Codes and Classifications

The RCIC system components within the drywell up to and including the outer isolation valve are designed in accordance with the ASME Section III, Class 1. The RCIC system is also designed as seismic Category I equipment. The RCIC electrohydraulic system integrated with the turbine governing valve is a safety-grade design, specified for seismic Category I design.

Other RCIC system component classifications are given in Table 3.2-1.

5.4.6.2.3 System Reliability Considerations

To ensure that the RCIC operates when necessary and in time to prevent inadequate core cooling, the power supply for the system is taken from immediately available energy sources of high reliability. Added assurance is given in the capability for periodic testing during station operation. The instrumentation design for the RCIC system is such that no failure of a single initiating sensor either prevents or falsely starts the system.

To ensure HPCI or RCIC availability for the operational events noted previously, certain design considerations are used in the design of both systems:

a. Physical independence. The two systems are located in separate rooms in the secondary containment. Piping runs are separated, and the water delivered from each system enters the reactor vessel via different nozzles.

b. Prime mover diversity and independence. Prime mover independence is achieved by using separate steam lines to drive the HPCI and RCIC steam turbines. Additionally, separate divisions of electrical power are used for HPCI and RCIC.

c. Control independence. Control independence is obtained by using different battery systems to provide control power to each system. Separate detection initiation logics are also used for each system.

d. Environmental independence. The safety-related equipment in the RCIC compartment does not rely upon auxiliary system support.

e. Periodic testing. A design flow functional test of the RCIC system is performed during plant operation by taking suction from the CST and discharging through the full flow test return line back to the CST. The discharge valve to the reactor feedwater line remains closed during the test, and reactor operation is undisturbed. Control system design provides automatic alignment from test to operating mode if system initiation is required during testing.

f. General. Periodic inspections and maintenance of the turbine-pump units are conducted in accordance with manufacturers' instructions. Valve position indication and instrumentation alarms are provided in the control room.

5.4.6.2.4 System Operation

Manual actions required for the various modes of RCIC are discussed in system operating and test procedures.

5.4.6.2.4.1 Automatic Operation

Automatic startup of the RCIC system due to an initiation signal from reactor low water level requires no operator action. Preparation of the system for the standby mode and manual actions required during operation and shutdown are defined by system operating procedures.

5.4.6.2.4.2 Test Loop Operation

This operating mode is manually initiated by the operator. Operator action is required as defined by surveillance test procedures and system operating procedures.

During all modes of manual MOV operation using the handswitch from the main control room, a "dead zone" is present for a portion of the valve travel. The "dead zone" is present when the valve is not fully closed and green light only indication exists. If the valve is stopped in the "dead zone", operator action is required to restart the valve.

5.4.6.2.4.1 Deleted

5.4.6.2.4.2 Deleted

5.4.6.2.4.3 Steam Condensing (Hot Standby) Operation

As discussed in Section 5.4.7.1.1.5, all the components which make up the steam condensing mode of the RHR system with the exception of an isolated vent line off each of the 2 Unit 2 RHR heat exchangers have either been abandoned in place or physically removed from the plant. Therefore, the mode is no longer functional.

5.4.6.2.4.4 Limiting Single Failure

The most limiting single failure of the high pressure recovery systems, HPCI and RCIC, is the failure of HPCI. If the capacity of the RCIC system is adequate to maintain reactor water level, the operator follows the station operating procedures. However, if the RCIC capacity is inadequate, the station operating procedures still apply, but additionally the ADS may be initiated as described in Section 6.3.2.

5.4.6.3 Performance Evaluation

The analytical methods and assumptions used in evaluating RCIC system performance are presented in Chapter 15. The RCIC system provides the flows required from the analysis (drawing E51-1020-G-002) within a 55 second interval based on considerations noted in Section 5.4.6.2.3.

5.4.6.4 Preoperational Testing

The preoperational and initial startup test program for the RCIC system is presented in Chapter 14.

5.4.6.5 Safety Interfaces

The BOP/NSSS safety interfaces for the RCIC system are:

a. Preferred water supply from the CST.

b. All associated wire, cable, piping, sensors, and valves that are outside the NSSS scope of supply.

c. Air supply for testable check and solenoid-actuated valves.

5.4.7 RESIDUAL HEAT REMOVAL SYSTEM

5.4.7.1 Design Bases

The RHR system is comprised of four independent loops. Each loop contains a motor-driven pump, piping, valves, instrumentation, and controls. Each loop takes suction from the suppression pool and is capable of discharging water to the reactor for low pressure coolant injection vessel via a separate vessel nozzle or back to the suppression pool via a full flow test line. In addition, loops A and B have heat exchangers that are cooled by RHRSW. These two loops can also take suction from the reactor recirculation system suction or from the spent fuel pool during refueling and can discharge into the reactor recirculation system discharge for residual heat removal. One of these two loops can be aligned to cool the spent fuel pool. The pumps in loops C and D can be aligned via crossties for use as alternates to the pumps in loops A and B, respectively. During cold shutdown and refueling operation condition, this results in the availability of four shutdown cooling subsystems (A heat exchanger with A RHR pump; A heat exchanger with C RHR pump; B heat exchanger with B RHR pump; and B heat exchanger with D RHR pump).

The Fire Protection system can be cross-tied to Loop B (Unit 1) and Loop A (Unit 2) RHR to provide an alternate source of water for the containment (drywell) spray mode of RHR. This cross-tie can only be used when there is no other method of injection to containment spray. Also, the cross-ties can provide an alternate source of water that can be injected through the LPCI injection line.

As discussed in Section 5.4.7.1.1.5, all the components comprising steam condensing mode of the RHR system have ether been abandoned in place or physically removed from the plant. Therefore, the mode is no longer functional.

5.4.7.1.1 Functional Design Basis

Each of the RHR modes has it's own functional requirements. Each subsystem is discussed separately below.

5.4.7.1.1.1 Residual Heat Removal Mode (Shutdown Cooling Mode)

a. The functional design basis of the shutdown cooling mode is to have the capability to remove decay and sensible heat from the reactor primary system so that the reactor outlet temperature is reduced to 125°F, approximately 20 hours after the control rods have been inserted, and to permit refueling when the RHRSW temperature is 85°F, assuming that the core is "mature" and the RHR heat exchanger tubes are completely fouled (see Section 5.4.7.2.2 for exchanger design details). The capacity of the heat exchangers is such that the time to reduce the vessel outlet water temperature to 212°F results in a cooldown rate in excess of 100°F per hour with both loops in service. However, the flushing operation associated with shutdown prevents the attainment of 212°F coolant temperature at a continuous 100°F per hour rate.

   Assuming 2 hours are used for flushing the system before operation, with all systems available the minimum time required to reduce vessel coolant temperature to 212°F is depicted by Figure 5.4-11.

b. The plant can be shut down using the capacity of a single RHR heat exchanger and related RHRSW system capability. Figure 5.4-12 shows the minimum time required to reduce vessel coolant temperature to 212°F using one RHR heat exchanger in the shutdown cooling mode and allowing 2 hours for flushing.

c. Each RHR heat exchanger can be aligned to one of two associated RHR pumps, constituting a shutdown cooling subsystem comprised of a heat exchanger, pump,

and piping flow path. This results in the availability of four shutdown cooling subsystems since each subsystem can be considered operable for shutdown cooling if it can be aligned (remote or local) for removal of decay heat.

d. The RHR heat exchangers can be aligned in the RHR Alternate Decay Heat Removal (ADHR) method when flooded-up during refueling. The heat exchangers are aligned to the spent fuel pool skimmer surge tanks and flow is returned to the reactor vessel. The functional design basis is to maintain the reactor and fuel pool water temperatures below 140°F while providing greater maintenance flexibility. In addition, the FPCC system(s) and the RHR fuel pool assist mode can be used for decay heat removal. See Section 9.1.3.1 for further details.

5.4.7.1.1.2 Low Pressure Coolant Injection Mode

The functional design basis for the LPCI mode is to pump 10,000 gpm of water per loop, using the separate loop pumps from the suppression pool into the core region of the vessel when the vessel pressure is 20 psid over drywell pressure. Injection flow commences at 295 psid vessel pressure above drywell pressure.

The initiating signals are reactor vessel low water level (level 1) or high drywell pressure coincident with low reactor pressure. The pumps attain rated speed in less than 40 seconds after their initiation signal, and the injection valves are in their fully open position in less than 40 seconds after the initiation signal.

The LPCI mode is discussed in greater detail in Section 6.3.

5.4.7.1.1.3 Suppression Pool Cooling Mode

The functional design basis for the suppression pool cooling mode is that it has the capacity to maintain the suppression pool temperature immediately after a blowdown below 170°F when the reactor pressure is above 135 psig.

5.4.7.1.1.4 Containment Spray Cooling Mode

The functional design basis for the containment spray cooling mode is that there are two (redundant) means to spray into the drywell and suppression pool vapor space to maintain internal pressure below the design limits.

5.4.7.1.1.5 Reactor Steam Condensing Mode

The reactor steam condensing mode is no longer functional. With the exception of an isolated vent line off each Unit 2 heat exchanger, components required for reactor steam condensing mode have been either abandoned in place or physically removed from the plant.

5.4.7.1.2 Design Basis for Isolation of RHR System from Reactor Coolant System

In the absence of a valid LOCA signal, the low pressure portions of the RHR system are isolated from full reactor pressure whenever the primary system pressure is above the RHR system design pressure (see Section 5.4.7.1.3 for further details). In addition, automatic isolation may occur for reasons of vessel water inventory retention, which is unrelated to piping pressure rating (see Section 5.2.5 for an explanation of the LDS and the isolation signals).

The RHR pumps are protected against damage from a closed discharge valve by the automatic minimum flow valves in the recirculation lines, which open on low main line flow and close on high main line flow. The minimum flow valve opens at main line flows of less than approximately 15% of pump rated flow (1500 gpm); this allows flow to return to the suppression pool through the low resistance low flow bypass line which branches off the main line upstream of the flow element.

The minimum flow valve closes at main line flows greater than approximately 1500 gpm; this closes the low resistance low flow bypass to the suppression pool and forces the entire pump discharge flow through the main line.

Under certain preplanned valve test scenarios, it is necessary and permissible to temporarily operate the RHR pumps at shutoff without minimum flow protection. These preplanned tests are conducted under explicit administrative controls. Continuous RHR pump operation at shutoff would eventually result in pump damage.

The minimum flow valve, valve control meets IEEE 279 requirements on the ECCS network level.

The minimum flow line restricting orifice is Quality Group B (i.e. seismic Category I, ASME Section III). The piping is rated at 300 lb (ANSI Primary Rating).

5.4.7.1.3 Design Basis for Pressure Relief Capacity

The relief valves in the RHR system are sized on one of two bases:

a. Thermal relief

b. Valve leakage

Transients are treated by item a; item b results from an excessive leak past isolation valves. Valves F025, F029 and F030 are set at or below the design pressure of the associated piping.

An interlock prevents the opening of valves to the low pressure suction piping when the reactor pressure is above the shutdown range. The same interlock initiates valve closure on increasing reactor pressure.

An additional interlock is provided for valve F008 to prevent a fire-induced valve open signal from causing both valves to open simultaneously while the reactor pressure is greater than the design capabilities of the RHR low-pressure piping.

In addition, check valves in the discharge lines to the vessel prevent reverse flow from the reactor if the reactor pressure increases above the RHR system pressure. Relief valves in the discharge piping are sized to account for leakage past the check valves.

5.4.7.1.4 Design Basis with Respect to GDC 5

With the exception of the fuel pool structures as discussed below, the RHR system for one unit does not share equipment or structures with the other unit. The RHRSW and ESW systems that provide cooling water to the RHR heat exchangers, and pump motor oil coolers, respectively, are common to both units. During OPCON 5, the spent fuel pools can be cross-tied with RHR on the shutdown unit taking suction from the reactor cavity or fuel pool. However, as discussed in Sections 3.1,

9.1.3.2.3, 9.2.2, and 9.2.3, this cannot compromise the ability of the RHR system to perform its safety-related functions.

5.4.7.1.5 Design Basis for Reliability and Operability

The shutdown cooling mode of the RHR system can be controlled by the operator from the control room. The only operations required to be performed outside of the control room for a normal shutdown are manual operation of keep fill valves (condensate transfer) to prevent addition to the reactor, and local alignment of the C and D RHR pumps to the respective A and B RHR heat exchangers for operation of the C and D subsystems of shutdown cooling.

The use of the RHR ADHR method will require the installation of the RHR/FPC spool piece, the manual alignment of several valves, and adjustment of the fuel pool overflow weirs.

Two separate shutdown cooling heat exchanger loops are provided, each with two alignable RHR pumps, and although both heat exchanger loops may be employed for shutdown, the reactor coolant can be brought to 212°F in approximately 20 hours with only one heat exchanger loop in operation. Interties are provided between the suction and discharge lines of the RHR pump in the direct injection LPCI loop (C and D pumps) and the suction and discharge lines of the associated RHR pump in the heat exchanger loop (A and B pumps, respectively) to allow use of the C and D pumps in the shutdown cooling mode, thus providing greater maintenance flexibility. During the cold shutdown and refueling operation conditions, this results in the existence of four shutdown cooling subsystems, each comprised of one of the two heat exchangers with one of its two alignable RHR pumps (A heat exchanger with A RHR pump; A heat exchanger with C RHR pump; B heat exchanger with B RHR pump; and B heat exchanger with D RHR pump). With the exception of the shutdown suction and shutdown return lines, the entire RHR system is part of the ECCS and containment cooling systems and is therefore required to be designed with the redundancy, flooding protection, piping protection, power separation, etc., required of such systems (see Section 6.3 for an explanation of the design bases for ECCS systems). Shutdown suction and discharge valves are powered from both offsite and onsite emergency power for isolation and shutdown following a LOOP. If either of the two shutdown supply valves fails to

operate, the design basis states that an operator is sent to open the valve by hand. If this is not feasible, the shutdown line is isolated using manual valve F077 and repairs are made to the shutdown valves so that they can be opened to supply shutdown suction to the RHR pumps. Residual heat is absorbed by the main condenser or by the suppression pool with pool cooling by the RHR system while repairs are in process (see Section 5.4.7.5 for a discussion of an alternate shutdown cooling flow path).

To increase the reliability of RHR shutdown cooling mode during refueling outages, the automatic isolation function of the RHR shutdown cooling mode supply and return valves are typically bypassed provided that automatic isolation is not required by the Technical Specifications or Technical Requirements Manual. Manual isolation capability is retained.

The RHR ADHR block valve (051-1193 and 051-2193) will be normally locked open to provide additional assurance that the valve is not inadvertently closed. Closure of this valve has no impact on ESF functions but could delay the start of shutdown cooling mode.

A non-limiting single active failure is a loss of a shutdown cooling return valve or testable check valve. In this case the other RHR heat exchanger loop is used, or if two required operable shutdown cooling subsystems are on the same heat exchanger loop and manual actions to restore valve operability are not successful, cooling water flow may be returned to the vessel through the LPCI injection line.

5.4.7.1.6 Design Basis for Protection from Physical Damage

Evaluation of the RHR system with respect to the following areas is discussed in the indicated sections:

a.	Protection from wind and tornado effects	Section 3.3
b.	Flood design	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Seismic events	Section 3.7
f.	Environmental design	Section 3.11
g.	Fire protection	Section 9.5

5.4.7.2 Systems Design

5.4.7.2.1 System Diagrams

All of the components of the RHR system are shown in the P&ID (drawing M-51). A description of the controls and instrumentation is presented in Section 7.3 and 7.4.

The RHR process diagram (drawing E11-1020-G-002) contains both the process diagram and process data. All of the sizing modes of the system are shown in the process data. The FCD for the RHR system is provided in Section 7.3.

Interlocks are provided to prevent:

a. Draining the vessel water to the suppression pool during shutdown.

b. Opening the vessel suction valves above the suction line design pressure or the discharge line design pressure, with the pumps at shutoff head.

c. Inadvertent opening of the drywell spray valves while in shutdown.

d. A pump start when the suction valve(s) is not open.

NOTE: The pump start interlock when the suction valve(s) is not open is defeated during operation of certain modes of RHR.

5.4.7.2.2 Equipment and Component Description

a. System pumps:

The RHR pumps are motor-driven deep-well pumps with mechanical seals and cyclone separators. The motors are air cooled by the ventilating system and by lube oil coolers. The pumps are sized on the basis of the LPCI mode (Mode A) and the minimum flow mode (Mode G) in drawing E11-1020-G-002. Design pressure for the pump suction is 220 psig, with a temperature range from 40°F to 360°F. Design pressure for the pump discharge is 500 psig. The bases for the design temperature and pressure are maximum shutdown cut-in pressures and temperature, minimum ambient temperature, and maximum shutoff head. The pump pressure vessel is carbon steel, and the shaft and impellers are stainless steel. Available NPSH is calculated according to Regulatory Guide 1.1 and is greater than the required NPSH for all operating modes. NPSH calculations for the LPCI mode are provided in Section 6.3.2.2.4.1.

The reliability of the RHR pumps at LGS is enhanced by their "deep draft" design, which is based on many years of experience in industrial and power plant application. While their use in nuclear power plant application is more recent, the same proven design principles have been used in successful industrial applications.

The RHR pumps are designed for the life of the plant (40 years) and are tested for operability assurance and performances as follows:

i. In-shop tests including: (1) hydrostatic tests of pressure-retaining parts at 150% of the design pressure; (2) performance tests while the pump is operated with flow to determine the total developed head at zero flow and design flow; and (3) NPSH requirements.

ii. After the pump is installed in the plant, it undergoes the: (1) system hydro tests; (2) functional tests; and (3) required periodic inservice inspection of approximately once every three months for approximately an hour during normal plant operation, and approximately one month of operation each year for shutdown.

iii. In addition, the pumps are designed for a postulated single operation of 100 days for one accident during the unit's 40 year life.

The following shows the maximum expected accumulated operating time for the life of the plant (40 years):

Mode of Operation	RHR (days)
In-Shop Test	1
Preoperation	3
Monthly Testing	9.2
Yearly Testing	1.7
Post-LOCA	365
Shutdown	2520
	2899.9*

Furthermore, Ingersoll-Rand pumps similar to the ones installed at LGS have been installed in operating plants and have accumulated significant successful operating experience.

* The above information provided on maximum accumulated RHR pump operating time for the life of the plant is historical and is based on original plant design conditions. The evaluation did not include any expected RHR pump operating time to maintain Suppression Pool temperature within specified operating limits during plant operation. Suppression Pool cooling operation to offset heat addition (such as HPCI runs or SRV leakage) up to 10% cumulative RHR runtime per unit per year is evaluated as acceptable use and is offset by shutdown usage (due to shorter outage lengths than the original evaluation).

A summary of experience of Ingersoll-Rand RHR pumps currently available to GE through 1981 is as follows:

			RHR (hours)
Hatch	RHR Pump	2A	864
		2B	1112
		2C	629
		2D	569
Chinshan 1	RHR Pump		100
Chinshan 2	RHR Pump		75

Maintenance was not required or performed during the running times listed above.

No problems have been reported on these pumps.

A comparison of the pumps cited for operating experience and the LGS pumps is as follows:

		HATCH	CHINSHAN	LGS
Column Length	RHR	241"	187"	138"

RPM	RHR	1800	1800	1200

Thus, it may be noted that the LGS pumps are conservatively represented by the operating experience in that they are shorter than the operating pumps and run at a slower speed. Both of these features are conservative because they make the pump less susceptible to vibration that causes degradation and wear. In this context, it should also be noted that the LGS pumps are much shorter than the deep draft pumps that have experienced vibration problems in the past.

b. Heat exchangers:

The RHR system heat exchangers are sized on the basis of the duty for the shutdown cooling mode (Mode E of the process data). All other uses of these exchangers require less cooling surface.

Flow rates are 10,000 gpm (rated) on the shell side and 9,000 gpm (rated) on the tube side (service water side). The rated inlet temperature is 125°F shell side and 85°F tube side for the shutdown cooling mode. The overall heat transfer coefficient is 225 Btu/hr-ft^2-°F. The exchangers contain 6,281 ft^2 (Unit 1 and Unit 2A) and 6,073.56 ft^2 (Unit 2B) of effective surface. The design temperature range of both shell and tube sides is 40°F to 470°F. The design pressure is 450 psig on both sides, and original design fouling factors are .0005 (Unit 1 & 2) shell side and 0.0018 (Unit 1), and 0.002 (Unit 2A) and 0.001 (Unit 2B) tube side. The construction materials are carbon steel for the pressure vessel with stainless steel tubes and stainless steel clad tube sheet. The condition of the heat exchangers is controlled by administrative and test procedures to assure that the required heat removal capability is maintained. Refer to Section 6.2 for heat removal requirements.

c. Valves:

All of the directional valves in the system are conventional gate, globe, butterflies and check valves designed for nuclear service. The injection valves and reactor coolant isolation valves are high speed valves, as operation for LPCI injection or vessel isolation requires. Valve pressure ratings are, as necessary, to provide the control or isolation function; i.e., all vessel isolation valves are rated as Class 1 nuclear valves rated at the same pressure as the primary system.

d. ECCS portions of the RHR system:

The ECCS portions of the RHR system include those sections described through Mode A-1 of drawing E11-1020-G-002.

The route includes suppression pool suction strainers, suction piping, RHR pumps, discharge piping, injection valves, and drywell piping into the vessel nozzles and core region of the reactor vessel.

Pool cooling components include pool suction strainers, suction piping, pumps, heat exchangers, and pool return lines. The suction strainers are described in Section 6.2.2.2.

Containment spray components are the same as pool cooling except that the spray headers replace the pool return lines.

5.4.7.2.3 Controls and Instrumentation

Controls and instrumentation for the RHR system are described in Chapter 7. The RHR system incorporates relief valves to prevent the components and piping from inadvertent overpressure conditions. The relief valve setpoint, capacity, and method of collection are shown in Table 5.4-3.

5.4.7.2.4 Applicable Codes and Classifications

a. Piping, pumps, and valves:

1.	Process side	ASME III	Class 2
2.	Service water side	ASME III	Class 3

b. Heat exchangers

1.	Process side	ASME III (Refer to Table 3.2-3)	Class C
2.	Service water side	ASME VIII	Division 1

c. Electrical portions

1. IEEE 279

2. IEEE 308

5.4.7.2.5 Reliability Considerations

The ECCS portion of the RHR system includes the redundancy requirements of Section 5.4.7.1.5. Two redundant heat exchanger loops are provided to remove residual heat, each with two alignable RHR pumps powered from separate emergency buses. Either heat exchanger loop is capable of cooling down the reactor within a reasonable length of time. During cold shutdown and refueling operation conditions, this results in the availability of four shutdown cooling subsystems. The shutdown cooling suction line from the recirculation suction piping is common to all four shutdown cooling subsystems, and each heat exchanger and its associated discharge piping is common to its two alignable RHR pumps (A and C RHR pumps for the A heat exchanger, B and D RHR pumps for the B heat exchanger). When aligned in the shutdown cooling mode of operation, each heat exchanger and its discharge piping are passive components that are assumed not to fail.

5.4.7.2.6 Manual Action

a. Residual heat removal (shutdown cooling mode)

To align a loop of the RHR system for shutdown cooling, the minimum flow and suppression pool suction valves are closed to prevent inadvertent drainage of reactor water to the suppression pool. The RHRSW pump on the selected loop is started. A preoperational flush of the RHR suction and most of the discharge piping is performed to prewarm piping and reactor cavity water clarity by flushing reactor water through it. During flushing the reactor water is discharged to the suppression pool

through the test return line in a controlled manner. After verifying that the discharge lines are full, the RHR pump is started. The operator controls the cooldown rate by regulating the reactor coolant flow through the heat exchanger by using the heat exchanger outlet bypass valve, the heat exchanger bypass valve, and the heat exchanger outlet valve in various combinations. The total flow can be throttled with the shutdown cooling return outboard isolation valve. All of these operations except initial alignment of a LPCI dedicated RHR pump (C or D pump) for shutdown cooling use can be performed from the control room.

The operator determines the cooldown rate by monitoring temperature change with time. When the process computer is available, the operator can assign the process computer points to use in the trend function. The computer then drives a strip-chart recorder with the data from the computed points. The operator can display temperature/time information graphically by calling up information on the process computer and manually plotting the temperature information versus time. The operator can monitor temperature directly on recorders that provide a permanent record of cooldown transient information.

The manual actions required for the most limiting failure are discussed in Section 5.4.7.1.5.

b. Steam condensing mode

As discussed in Section 5.4.7.1.1.5, all components comprising the steam condensing mode of the RHR system have either been abandoned in place or physically removed from the plant. Therefore, the mode is no longer functional.

5.4.7.3 Performance Evaluation

The thermal performance of the RHR heat exchangers is based on the residual heat generated at 20 hours after rod insertion, a 125°F vessel outlet (exchanger inlet) temperature, and the flow of two loops in operation. Because shutdown is usually a controlled operation, maximum service water temperature (95°F) less 10°F is used as the service water inlet temperature (i.e., 85°F). These are nominal design conditions; if the service water temperature is higher, the exchanger capabilities are reduced and the shutdown time may be longer, and vice-versa.

5.4.7.3.1 Shutdown with All Components Available

No typical curve is included here to show vessel cooldown temperatures versus time due to the infinite variety of such curves that may be generated due to the following:

a. Clean steam systems that may allow the main condenser to be used as the heat sink when nuclear steam pressure is insufficient to maintain steam-air ejector performance

b. The fouling condition of the exchangers

c. Operator use of one or two cooling loops

d. Service water temperature

e. System flushing time

Since the exchangers are designed for the fouled condition with relatively high service water temperature, the heat exchangers have excess capability to cool when first cut-in at high vessel temperatures. The total flow and mix temperature must be controlled to avoid exceeding a 100°F per hour cooldown rate. See Section 5.4.7.1.1.1 for the minimum shutdown time to reach 212°F.

5.4.7.3.2 Shutdown with Most Limiting Failure

Shutdown under conditions of the most limiting failure is discussed in Section 5.4.7.1.1.1. The capability of the heat exchanger for any time period is balanced against residual heat, pump heat, and sensible heat. The excess over residual heat and pump heat is used to reduce the sensible heat.

5.4.7.4 Preoperational Testing

The preoperational test program and startup test program as discussed in Chapter 14 are used to generate data to verify the operational capabilities of each piece of equipment in the system: each instrument, each setpoint, each logic element, each pump, each heat exchanger, each valve, and each limit switch. In addition these programs verify the capabilities of the system to provide the flows, pressures, condensing rates, cooldown rates, and reaction times required to perform all system functions as specified for the system or component in the system data sheets and process data. Logic elements are tested electrically; valves, pumps, controllers, and relief valves are tested mechanically; finally, the system is tested for total system performance against the design requirements as specified above using both the offsite power and standby emergency power. Preliminary heat exchanger performance can be evaluated by operating in the pool cooling mode, but a vessel shutdown is required for the final check due to the small temperature difference available with pool cooling.

5.4.7.5 Conformance to Regulatory Guide 1.139

Although the LGS design was completed before the issuance of this guide, which provides guidance on shutdown cooling mode design, the LGS design satisfies the intent of the guide, subject to the following clarifications:

a. Provisions of shutdown cooling, assuming the most limiting single active failure (loss of the common suction line due to valve failure to open), as discussed in paragraph C.1 of the regulatory guide, is accomplished by an alternate flow path. In the alternate method the RHR pump pumps from the suppression pool to the reactor vessel via the RHR heat exchanger. Flow returns from the vessel to the suppression pool via manually opened ADS valves. The LGS ADS valves are three-stage Target Rock valves. Their operability under the fluid conditions expected to occur during the alternate shutdown cooling mode has been demonstrated by generic testing described in topical report NEDE-24988-P/NEDO-24988.

   The test results documented in the topical report verify the adequacy of the LGS valve operation and integrity under the expected liquid discharge conditions. The loads on the valve and piping induced by the liquid discharge were shown to be lower than the high pressure steam discharge loads for which the system is designed. The test results also provide flow capacity information, which shows that sufficient shutdown cooling flow is provided through 1 or 2 valves.

A safety-grade pneumatic supply is available for ADS valve actuation, as discussed in Section 9.3.1. A variation of this method is to pump to the vessel with a Core Spray Loop and operate the RHR system in the suppression pool cooling mode.

b. Regarding paragraph C.2.a of the regulatory guide, which discusses reactor high pressure interlocks and alarms, LGS conforms with the intent in that the two suction valves are interlocked with reactor pressure; two out of two low reactor pressure signals must be present to permit opening. On a high pressure signal, the valves close and the pump trips. A pump trip activates an "RHR system out of service" alarm that annunciates in the main control room. There is no high pressure alarm per se. Loss of power to the valve control logic causes suction valve closure and pump trip.

   An additional interlock is provided for valve F008 to prevent a fire-induced valve open signal from causing both valves to open simultaneously while the reactor pressure is greater than the design capabilities of the RHR low-pressure piping.

c. Pressure relief is not provided for a pressure transient during operation as discussed in paragraph C.3 of the regulatory guide; however, no rapid pressurization mechanism is known for a BWR. Pressure may increase gradually, and the automatic high pressure valve interlocks (closed on high pressure) are considered adequate for this case.

d. The RHR design is considered to conform to the pump protection discussion in paragraph C.4 of the regulatory guide, in that the pump motor is equipped with thermal overload protection and the stator and bearing temperatures are monitored on the plant computer. Cavitation can be detected by the vibration.

   Pump cavitation/NPSH protection is provided by automatic pump trip if any of the three suction valves leaves the fully open position. Automatic valve closure and pump trip occurs at low reactor water level (level 3), which protects the pump from inadequate NPSH.

e. On-line testing capability of isolation valve operability and interlock circuits, as discussed in paragraph C.5 of the regulatory guide, is not provided. However, the system is periodically tested as discussed in Chapter 16.

5.4.8 REACTOR WATER CLEANUP SYSTEM

The RWCU system is classified as a primary power generation system (not an engineered safeguard feature), a small part of which is part of the RCPB up to and including the second isolation valve. The other portions of the system are not part of the RCPB and are isolatable from the reactor. The RWCU system may be operated at any time during reactor operations, or it may be shut down if water quality is within the Technical Specification limits.

5.4.8.1 Design Basis

5.4.8.1.1 Safety Design Basis

The RCPB portion of the RWCU system meets the requirements of Regulatory Guide 1.26 and Regulatory Guide 1.29 (Section 3.2) to:

a. Prevent excessive loss of reactor coolant

b. Prevent the release of radioactive material from the reactor

c. Isolate the major portion of the RWCU system from the RCPB

5.4.8.1.2 Power Generation Design Basis

The RWCU system performs the following functions:

a. Removes solid and dissolved impurities from reactor coolant, maintains reactor water purity, and measures the reactor water conductivity in accordance with Regulatory Guide 1.56.

b. Discharges excess reactor water during startup, shutdown, and hot standby conditions to the main condenser, condensate storage tank (CST), or radwaste system.

c. Minimizes temperature gradients in the main recirculation piping and RPV during periods when the main recirculation pumps are unavailable.

d. Minimizes the RWCU system heat loss.

e. Enables the major portion of the RWCU system to be serviced during reactor operation.

f. Prevents the standby liquid reactivity control material from being removed by the RWCU system when required for shutdown.

g. Provide a means for monitoring the effectiveness of the Noble Metals Chemical Addition. An ECP monitor measures the electrochemical corrosion potential of the reactor water with respect to the Noble Metals treated piping. A Durability Monitor provides a source of tubing samples which can be analyzed to determine the surface density and wear rate of the deposition of the Noble Metals. A Data Acquisition System collects and stores the flow, temperature and ECP data from the Noble Metals Monitoring System.

5.4.8.2 System Description

The system takes its suction from the inlet of the "B" reactor main recirculation pump and from the RPV bottom head. The process fluid is circulated with the cleanup pump(s) through a regenerative and nonregenerative heat exchanger for cooling, through filter/ demineralizers for cleanup, and back through the regenerative heat exchanger for reheating. The processed water is returned to the RPV and/or the main condenser, CST, or radwaste (drawings M-44 and G31-1030-G-001).

The major equipment of the RWCU system is located outside the drywell. This equipment includes pumps, regenerative and nonregenerative heat exchangers, and filter/demineralizers with precoat equipment. Flow rate capacities for the major pieces of equipment are presented in Table 5.4-2.

The temperature of the filter/demineralizer units is limited by the resin operating temperature. Therefore the reactor coolant is cooled before being processed in the filter/demineralizer units. The regenerative heat exchanger transfers heat from the tube side (hot process inlet) to the shell side

(cold process inlet). The shell side flow returns to the reactor. The nonregenerative heat exchanger cools the process further by transferring heat to the reactor enclosure closed cooling water system.

The filter/demineralizer units (drawing M-45) are pressure precoat-type filters using filter aid and powdered, mixed ion exchange resins. Spent resins are nonregenerative and are sluiced from the filter/demineralizer unit to a backwash receiving tank from which they are transferred to the radwaste system for processing and disposal. To limit resins from entering the reactor recirculation system if there is failure of a filter/demineralizer resin support, a strainer is installed on the filter/demineralizer unit. Each strainer and filter/demineralizer vessel has a control room alarm that is energized by high differential pressure. On further increase in differential pressure from the alarm point, the filter/demineralizer automatically isolates.

The backwash and precoat cycle for a filter/demineralizer unit is entirely automatic to prevent human operational errors, such as inadvertent opening of valves, that would initiate a backwash or contaminate the reactor water with resins. The filter/demineralizer piping configuration is arranged to ensure that transfers are complete and crud traps are eliminated. A bypass line is provided around the filter/demineralizer units.

If there is low flow or loss of flow in the system, flow is maintained through each filter/demineralizer by its own holding pump.

Sample points are provided in the common influent header and in each effluent line of the filter/demineralizer units for continuous indication and recording of system conductivity to ensure that the reactor coolant quality is within limits, and as a check of filter/ demineralizer effectiveness. High conductivity is annunciated in the control room. The control room alarm setpoints for conductivity at the inlet and outlet of the filter/demineralizers are 1.0 μmho/cm and 0.1 μmho/cm, respectively. The effluent setpoint indicates impending resin exhaustion and, therefore, forestalls breakthrough of solubles, usually chlorides. The influent sample point is also used as the normal source of reactor coolant grab samples. Reactor water chloride content and pH will be determined from grab samples taken and analyzed in accordance with approved plant procedures. Additional water quality limits and corrective actions to be taken will be specified in the Technical Specifications.

A Noble Metals Monitoring System sample bypasses the RWCU system from the Regenerative Heat Exchanger Tube Side Inlet Piping to the Shell Side Outlet. An ECP Monitor, measures the electrochemical corrosion potential of the reactor water with respect to the piping. A Durability Monitor provides a source of tubing samples which can be analyzed to determine the surface density and wear rate of the deposition of the Noble Metals. A Data Acquisition System collects and stores the flow, temperature and ECP data from the Noble Metals Monitoring System.

The suction line (RCPB portion) of the RWCU system contains two motor-operated isolation valves, which automatically close in response to signals from reactor low water level, leak detection system, actuation of the SLCS, and nonregenerative heat exchanger high outlet temperature. Section 7.6 describes the leak detection requirements, and they are summarized in Table 5.2-7. This isolation prevents the loss of reactor coolant and release of radioactive material from the reactor, prevents removal of liquid reactivity control material by the cleanup system if the SLCS is in operation, and prevents damage of the filter/demineralizer resins due to high temperature. The RCPB isolation valves may be remotely manually operated to isolate the system equipment for maintenance or servicing. The requirements for the RCPB are specified in Section 5.2.

A remote manually operated spring assisted check valve and a simple check valve in the RWCU return line to feedwater provides instantaneous reverse flow isolation. The spring assisted check

valve is a containment isolation valve and is remote manually closed for long term leakage control as described in Section 6.2.4.

A motor operated globe valve in the return line to the reactor is provided for system flow control (throttling) and system isolation for maintenance.

The operation of the RWCU system is controlled from the control room. Resin changing operations, which include backwashing and precoating, are controlled from a local control panel. The time required to remove a unit from the line, backwash, and precoat is approximately 1 hour.

A FCD is provided in Section 7.7.

5.4.8.3 System Evaluation

The RWCU system in conjunction with the condensate cleanup system, and the FPCC system, maintains reactor water quality during all reactor operating modes (normal, hot standby, startup, shutdown, and refueling).

This type of "pressure precoat" cleanup system was first put into operation in 1971 and is used in all operating BWR plants that have been placed in operation since. Operating plant experience has shown that the RWCU system as designed in accordance with these criteria provides the required BWR water quality. The nonregenerative heat exchanger is sized to maintain the required process temperature for filter demineralization even when the cooling capacity of the regenerative heat exchanger is reduced due to bypassing a portion of the return flow to the main condenser, CST, or radwaste. The control requirements of the RCPB isolation valves are designed to the requirements of Section 7.3.1. The component design data (flow rates, pressure, and temperature) are presented in Table 5.4 2. All components are designed to the requirements listed in Section 3.2, according to the requirements of the P&IDs (drawings M-44 and M-45).

5.4.9 MAIN STEAM LINE AND FEEDWATER PIPING

The main steam piping is described in Section 10.3. The feedwater piping is described in Section 10.4.7. Additional design information concerning these lines is found in Sections 3.6, 3.9, and 5.2.

5.4.10 PRESSURIZER

Not applicable to BWRS

5.4.11 PRESSURIZER RELIEF DISCHARGE SYSTEM

Not applicable to BWRS

5.4.12 VALVES

5.4.12.1 Safety Design Bases

Line valves such as gate, globe, and check valves are located in the fluid systems to perform a mechanical function. Valves are components of the system pressure boundary and, having moving parts, are designed to operate efficiently to maintain the integrity of this boundary.

The valves operate under the internal pressure/temperature loading as well as the external loading experienced during the various system transient operating conditions. The design criteria, the design loading, and acceptability criteria are as discussed in Section 3.9.3 for ASME Class 1, 2, and 3 valves. Compliance with ASME Codes is discussed in Section 5.2.1.

5.4.12.2 Description

Line valves furnished are manufactured standard types, designed and constructed in accordance with the requirements of ASME Section III for Class 1, 2, and 3 valves. All materials exclusive of seals, packing, and wearing components are designed to endure the 40 year plant life under the environmental conditions applicable to the particular system when appropriate maintenance is periodically performed.

Power operators have been sized to operate successfully under the maximum differential pressure determined in the design specification.

5.4.12.3 Safety Evaluation

Line valves are shop tested by the manufacturer for performability. Pressure-retaining parts are subject to the testing and examination requirements of ASME Section III. To minimize internal and external leakage past seating surfaces, maximum allowable leakage rates are stated in the design specifications for the back-seat as well as the main seat for gate and globe valves.

Valve construction materials are compatible with the maximum anticipated radiation dose for the service life of the valves.

5.4.12.4 Inspection and Testing

Valves that serve as containment isolation valves and must remain closed or open during normal plant operation may be partially exercised during this period to ensure their operability at the time of an emergency or faulted conditions. Other valves, serving as a system block for throttling valves, may be exercised when appropriate.

Leakage from critical valve stems is monitored by the use of double-packed stuffing boxes with an intermediate lantern leak-off connection for detection and measurement of leakage rates.

Motors used with valve actuators are furnished in accordance with applicable industry standards. Each motor actuator is assembled, factory tested, and adjusted on the valve for proper operation, position and torque switch setting, position transmitter function (where applicable), and speed requirements. Valves are additionally tested to demonstrate adequate stem thrust (or torque) capability to open (or close) the valve within the specified time at specified differential pressure. Tests verify that there is no mechanical damage to valve components during full stroking of the valve. Suppliers are required to furnish assurance of acceptability of the equipment for the intended service based on any combination of the following:

a. Test stand data

b. Prior field performance

c. Prototype testing

d. Engineering analysis

Preoperational and operational testing performed on the installed valves consists of total circuit checkout and performance tests to verify speed requirements for specified differential pressure.

5.4.13 SAFETY AND RELIEF VALVES

5.4.13.1 Safety Design Bases

Overpressure protection is provided at isolatable portions of systems in accordance with the rules set forth in ASME Section III, for Class 1, 2, and 3 components.

5.4.13.2 Description

Pressure relief valves are designed and constructed in accordance with the same code class as that of the line valves in the system.

Table 3.2-1 lists the applicable code classes for valves, and system design pressures and temperatures are given in Section 5.2.2.4.2.1. The design criteria, design loadings, and design procedures are described in Section 3.9.3.

5.4.13.3 Safety Evaluation

The use of pressure-relieving devices ensures that overpressure does not exceed 10% above the design pressure of the system. The number of relieving devices on a system or portion of a system is determined on this basis.

5.4.13.4 Inspection and Testing

No provisions are to be made for in-line testing of pressure relief valves. Certified set pressures and relieving capacities are stamped on the body of the valves by the manufacturer, and further examinations would necessitate removal of the component.

5.4.14 COMPONENT SUPPORTS

Support elements are provided for the components included in the RCPB and the connected systems.

5.4.14.1 Design Bases

Design loading combinations, design procedures, and acceptability criteria are described in Section 3.9.3. Stress analysis calculations for ASME Section III, Class 1, 2, and 3, and ANSI B31.1 piping conform to the requirements of the appropriate code.

The spacing and size of pipe support elements are based on piping stress analyses performed in accordance with the appropriate codes and as further described in Section 3.7.

Materials, fabrication, and inspection of pipe supporting elements for nuclear piping are in accordance with the USAS B31.7 "Nuclear Power Piping" code, the 1969 issue through the 1971 addenda. Pipe supporting elements for conventional steam and service piping are in accordance with the Code for Power Piping, ANSI B31.1 through the Winter 1974 addenda.

5.4.14.2 Description

The use of rigid-type supports, variable or constant spring-type supports, snubbers, and anchors is determined by stress analysis performed on the piping system. Component support elements are generally manufacturers' standard items.

5.4.14.3 Safety Evaluation

Design loadings used for the determination of component support systems included transient loading conditions expected by each component. Provisions are made to prevent damage to the piping system and the spring-type supports during initial deadweight loading due to hydrostatic testing.

5.4.14.4 Inspection and Testing

After completion of the installation of a support system, component support elements are visually examined to ensure that they are in correct adjustment to their cold setting positions. Verification of satisfactory component support performance is made in accordance with the requirements of Chapter 14.

5.4.15 REFERENCES

5.4-1 P.W. Ianni, "Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors," APED-5458 (March, 1968).

5.4-2 "Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves," APED-5750, GE, Atomic Power Equipment Department (March, 1969).

5.4-3 “Evaluation of Limiting Transients with MSIV/TCV/TSV Closed for Peach Bottom and Limerick at Power,” General Electric Nuclear Energy Letter A096-0013 (J.L. Casillas to G.C. Storey), Sept. 23, 1996.

5.4-4 Deleted.

Table 5.4-1

REACTOR RECIRCULATION SYSTEM DESIGN CHARACTERISTICS

EXTERNAL LOOPS

Number of Loops 2

SINGLE-LOOP PIPING DESCRIPTION	QUANTITY	APPROX LENGTH (feet)	NOMINAL SIZE (inches)
Pump suction line			
Straight pipe	-	0	28
Elbows	3	-	28
Gate valves	1	-	28
Discharge line			
Straight pipe	-	22	28
Elbows	1	-	28
Gate valves	1	-	28
Discharge manifold			
Pipe	-	38	22
Reducer cross	1	-	28x22
Contour nozzle	4	-	22x12
Caps	2	-	22
Concentric reducer	1	-	28x12
External risers			
Straight pipe	5	12/riser	12
Elbows	5	-	12

Design Pressure (psig)/Design Temperature (^{o}F)

Suction piping and valve up to and including pump suction nozzle	1250/575
Pump, discharge valves, and piping Between	1500/575
Piping after discharge blocking valve up to vessel	1500/575
Pump auxiliary piping and cooling water piping	150/212
Vessel bottom drain	1275/575

Table 5.4-1 (Cont'd)

Operation at Rated Conditions

Recirculation Pump

Flow, gpm	45,200
Flow, lb/hr	17.1×10^6
Total developed head, ft	710
Suction pressure (static), psia	1070
Required NPSH, ft	138
Water temperature (max), °F	537
Pump brake hp (min)	7050
Flow velocity at pump suction, fps	28

Jet Pumps

Number	20
Total jet pump flow, 10^6 lbs/hr	102.6
Throat I.D., in	8.18
Diffuser I.D., in	19.0
Nozzle I.D. (representative), in	3.14
Diffuser exit velocity, fps	15.4
Jet pump head, ft	81.5

Recirculation Block Valve, Discharge

Type	Gate
Actuator	Motor-operated
Material	Austenitic stainless steel
Valve size diameter, in	28

Recirculation Block Valve, Suction

Type	Gate
Actuator	Motor-operated
Material	Austenitic stainless steel
Valve size diameter, in	28

Pump Motor

Voltage rating	3920
Speed, rpm	1668
Meter rating, hp	7500
Phase	3
Frequency, Hz	56
Rotational inertial (lb-ft^2)	14,710

Table 5.4-1 (Cont'd)

Drive Motor and Power Supply	
Frequency Hz (at rated)	55.6
Frequency Hz (operating range)	15.7 - 55.6
Total Required Power to ASD	
kW/ASD Unit	6146
kW Total	12,293

Table 5.4-2

REACTOR WATER CLEANUP SYSTEM EQUIPMENT DESIGN DATA

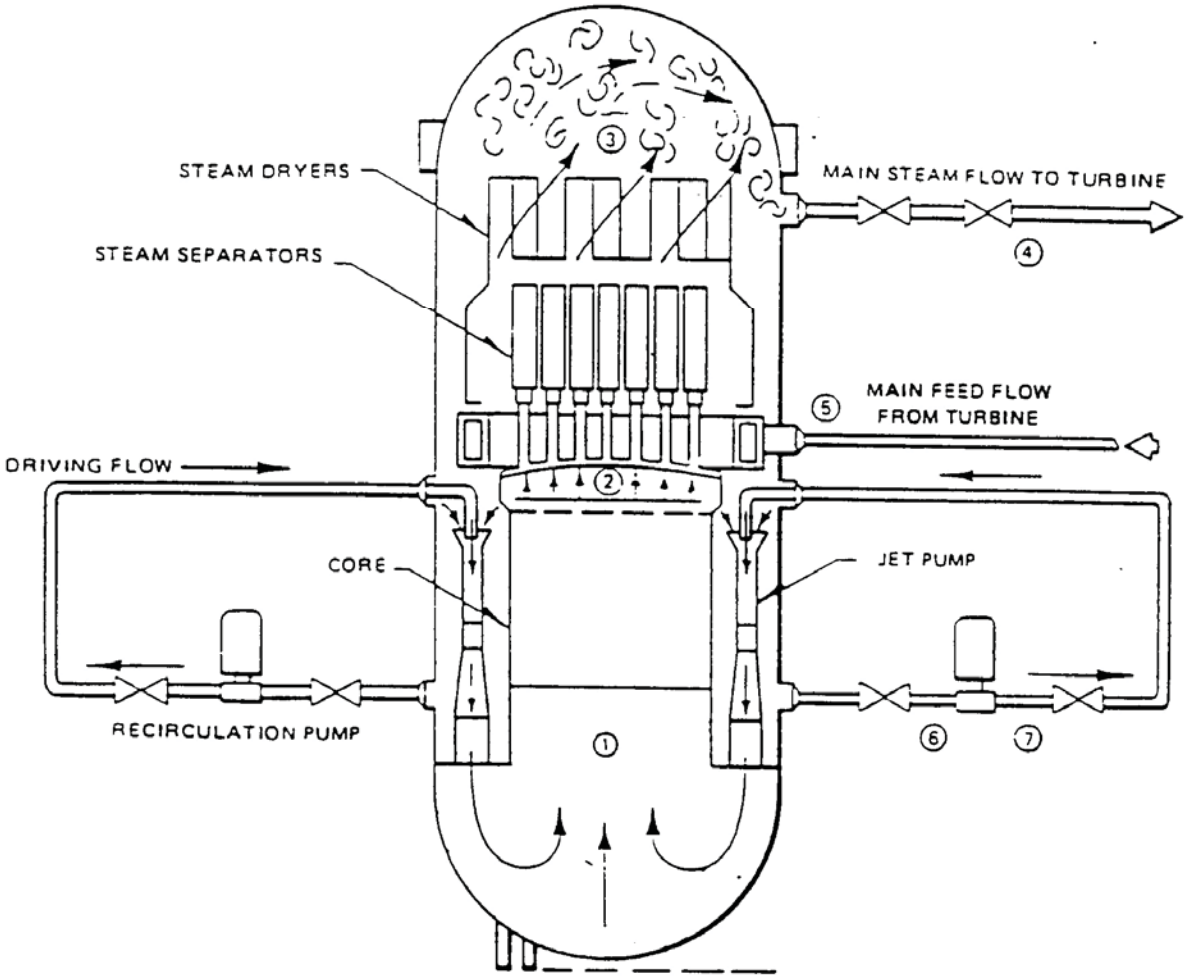
System flow rate (lbs/hr)		
Normal operation "A" pump		133,000
Normal operation "B" plus "C" pump		133,000
Maximum operation (cold operation only)		180,000
MAIN CLEANUP RECIRCULATION PUMPS	"A" Pump	"B" & "C" Pumps
Number required	1	2
Capacity, % (each)	100	50
Design temperature, °F	582	575
Design pressure, psig	1400	1400
Discharge head at shutoff, ft	650	650
Required NPSH, ft	15.5	6.5
HEAT EXCHANGERS	Regenerative	Nonregenerative
Rated capacity, %	100	100
Shell side pressure, psig	1425	150
Shell side temperature, °F	575	370
Tube side pressure, psig	1425	1425
Tube side temperature, °F	575	575
FILTER/DEMINERALIZERS		
Number required	2	
Capacity, % each	50	
Design temperature, °F	150	
Design pressure, psig	1425	

Table 5.4-3
RHR SYSTEM RELIEF VALVE DATA

VALVE LOCATION	VALVE NO.	SETPOINT (psig)	CAPACITY (gpm)[1]	METHOD OF COLLECTION[3]
Shutdown supply line (outside containment)	PSV-1F029	140	10	RW
Pump suction line	PSV-1F030 A,B,C&D	170	10	Suppression pool
Pump discharge line	PSV-1F025 A,B,C,D	420	10	RW
Heat exchanger (shell side)[2]	PSV-106 A,B	450	Thermal relief only	Suppression pool
Heat exchanger (tube side)[2]	PSV-105 A,B	450	Thermal relief only	RW
Thermal relief valve on shutdown cooling suction line (inside containment)	PSV-155	1200	2	RW
Thermal relief valve on head spray line, Unit 1 only (ABANDONED)	PSV-122	1200	2	RW

(1) Capacity is based on setpoint plus 10% accumulation
(2) GE supplied valves
(3) RW = liquid radwaste collection system

Figure Marked *"Historical"*
Reference Figure 1.2-84, "Reactor System Heat Balance," for current operating conditions



	Pressure (psai)	Flow (lb/hr)	Temperature (° F)	Enthalpy (Btu/lb)
1. Core Inlet	1091	100.0×10^6	535	530.7
2. Core Outlet	1071	100.0×10^6	553	650.0
3. Separator Outlet (Steam Dome)	1060	14.986×10^6	552	1190.7
4. Steam Line (Turbine Inlet)	1005	14.986×10^6	545	1190.7
5. Feedwater Inlet (includes RWCU)	1088	15.087×10^6	425	403.3
6. Recirculation Pump Suction	1066	33.0×10^6	535	530.6
7. Recirculation Pump Discharge	1248	33.0×10^6	536	531.4

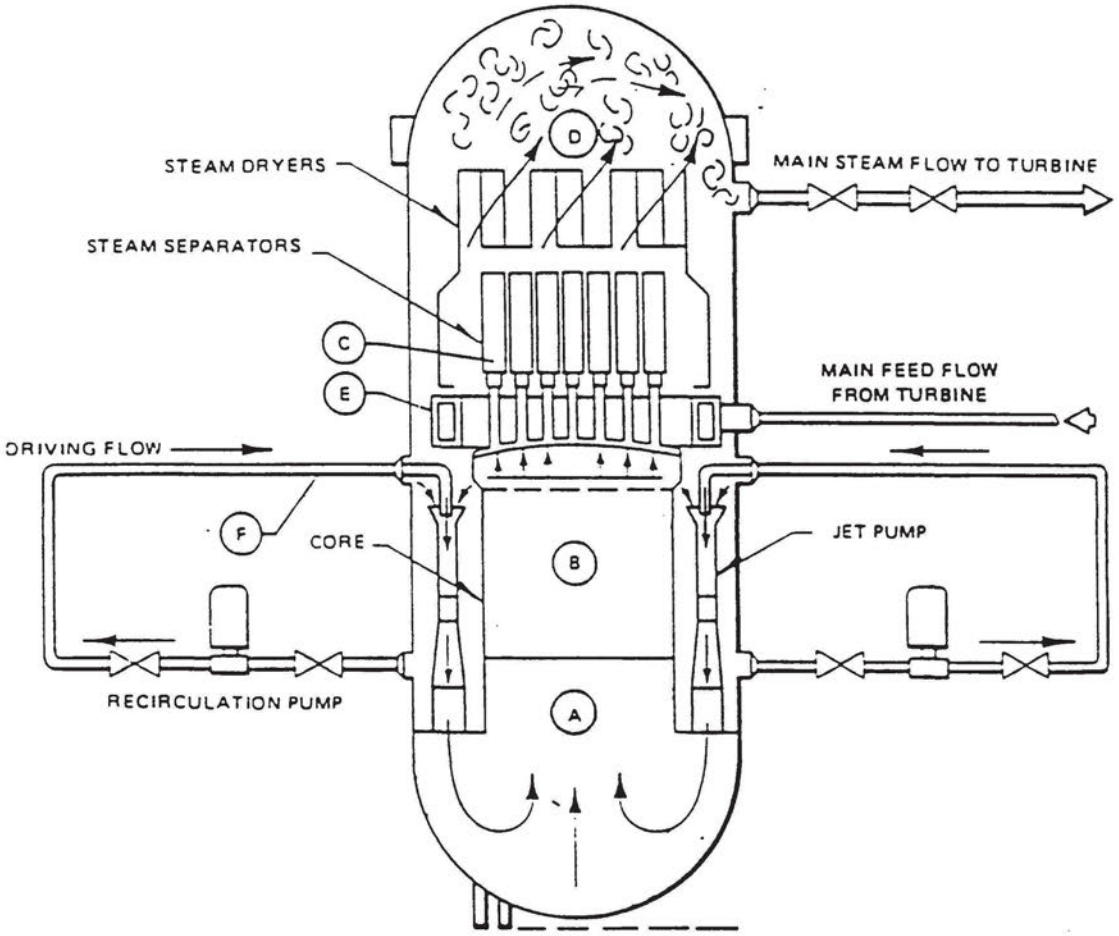
CHANNEL BYPASS – NORMALLY 10%

* BASED ON 100% DRY STEAM IN THE STEAM DOME

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RATED OPERATING CONDITIONS
[3458 MWt]

FIGURE 5.1-1 *Historical* **Rev. 16 09/12**



	VOLUME OF FLUID (ft^3)
A LOWER PLENUM	3887
B CORE	2054
C UPPER PLENUM AND SEPARATORS	1321
D DOME (ABOVE NORMAL WATER LEVEL)	7934
E DOWNCOMER REGION	5817
F RECIRC LOOPS AND JET PUMPS	1411

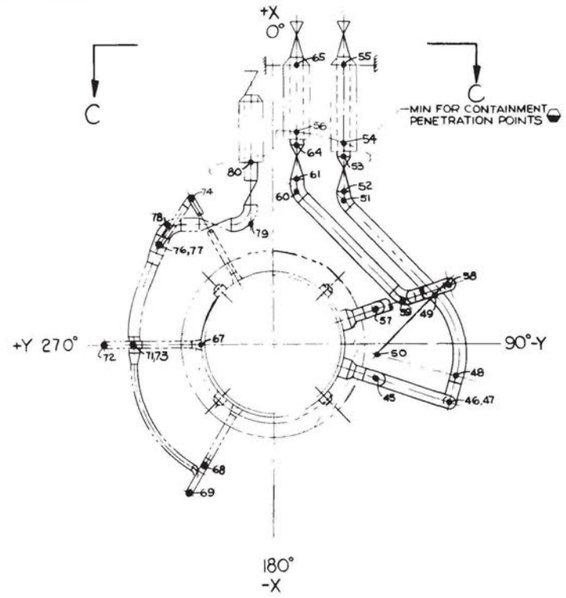
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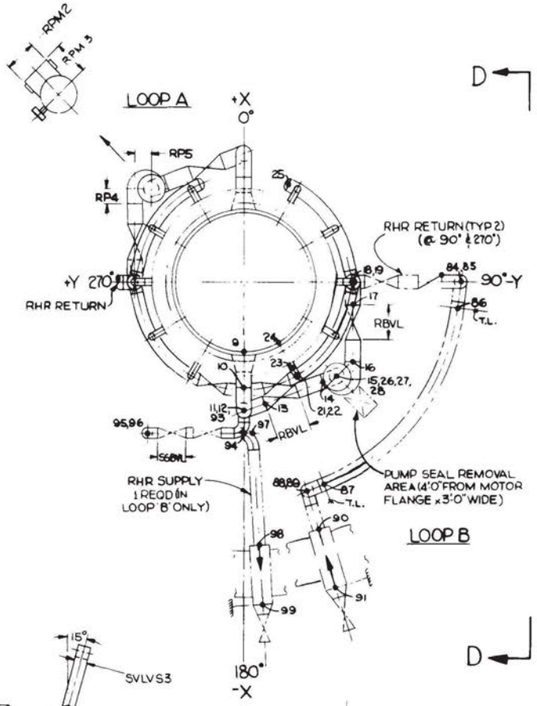
(TYPICAL)
COOLANT VOLUMES OF THE
REACTOR VESSELS AND RECIRC LOOPS

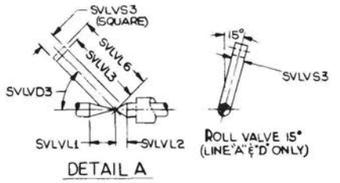
FIGURE 5.1-2 Rev. 5, 4/96

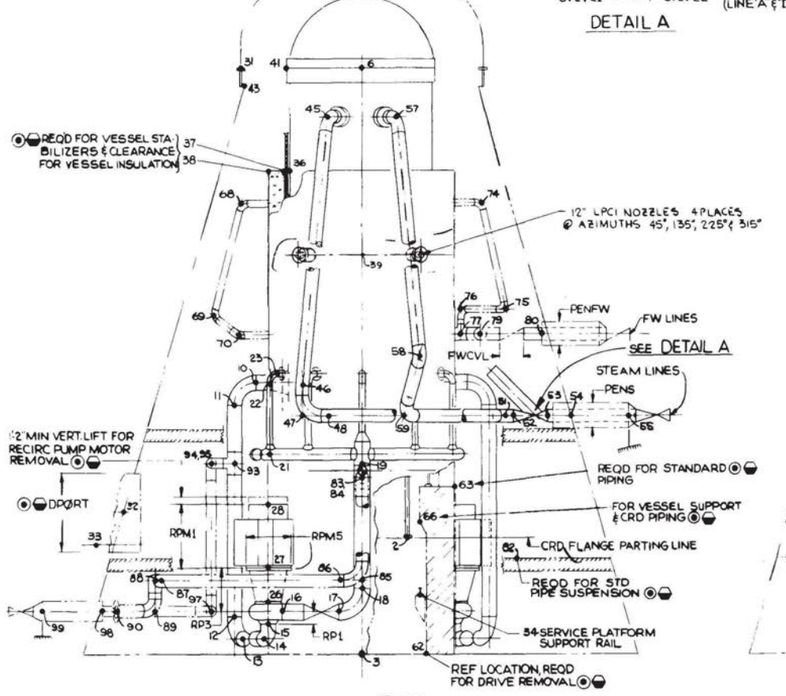
Figures 5.1-3 and 5.1-4

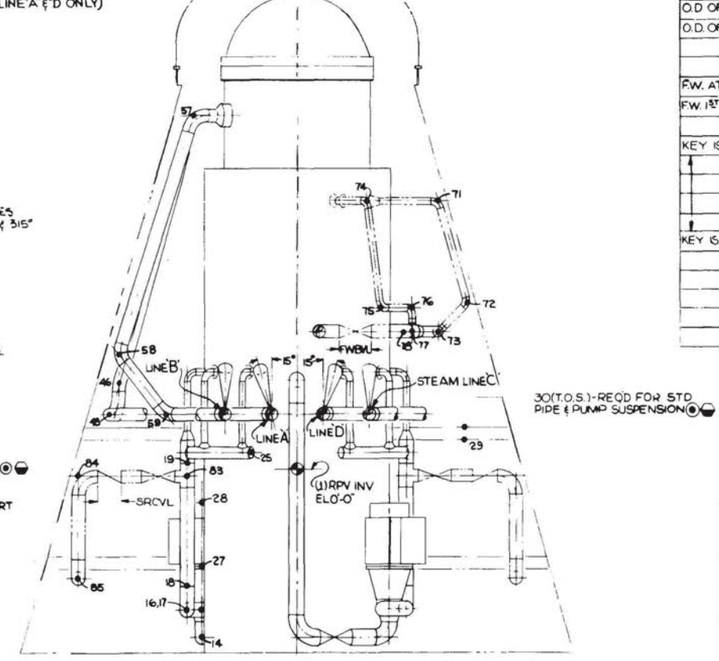
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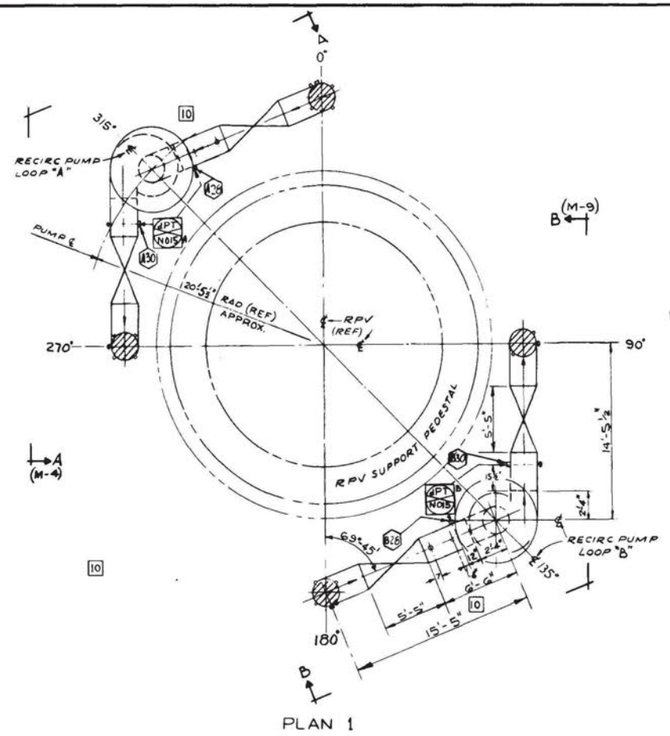


REFERENCE EQUIPMENT DATA			
RECIRC SYSTEM		SYMBOL	
RECIRC PUMP SUCTION LINE			28"
PUMP DISCHARGE LINE			28"
RING HEADER			22"
RECIRC RISER LINE (5 PER LOOP)			12"
RHR/SHUTDOWN SUPPLY LINE			20"
RHR/SHUTDOWN RETURN LINE			12"
HPCI SUPPLY LINE			10"
KEY MOTOR DIM.	MAX	RPM5	85"
-MOTOR OVERALL HEIGHT	MAX	RPM1	117"
	MAX	RPM2	79"
KEY MOTOR DIM.	MAX	RPM3	42"
KEY PUMP DIM - PUMP ℄ TO DISCHARGE ℄		RP5	30"
- PUMP DISCH ℄ TO PED FLG FACE	(MIN)	RP3	80"
- PUMP ℄ TO SUCTION WELD POINT		RP1	24"
KEY PUMP DIM - PUMP ℄ TO DISCHARGE WELD POINT		RP4	28"
KEY SUCTION & DISCH VLV. DIM. - TOTAL VALVE LENGTH		RBVL	65"
KEY RHR/SHUTDOWN RETURN LINE VALVE LENGTH		SRCVL	61"
KEY RHR/SHUTDOWN SUCTION LINE VALVE LENGTH		SSBVL	52"
STEAM & FEEDWATER SYSTEMS			
MAIN STEAM LINE			26"
KEY F.W. VLV DIM. - CHECK VLV LENGTH		FWCVL	61"
KEY F.W. VLV DIM. - BLOCK VLV LENGTH		FWBVL	61"
O.D. OF PENETRATION FOR STEAM LINES		PENS	42"
O.D. OF PENETRATION FOR F.W. LINES		PENFW	42"
F.W. AT VESSEL (6 REQD PER PLANT)			12"
F.W. 1ST INCREASE & 2ND INCREASE			20" & 24"
KEY ISOL. VLV DIM. - LENGTH UPSTREAM	(MAX)	SVLVL1	45"
- LENGTH DOWNSTREAM	(MAX)	SVLVL2	20"
- SQUARE OPERATOR DIM	(MAX)	SVLVS3	22"
- ANGLE OF OPERATOR		SVLVD3	45°
- OPERATOR LENGTH	(MAX)	SVLVL3	134"
KEY ISOL VLV DIM - OPERATOR PULL SPACE	(MAX)	SVLVL6	142"

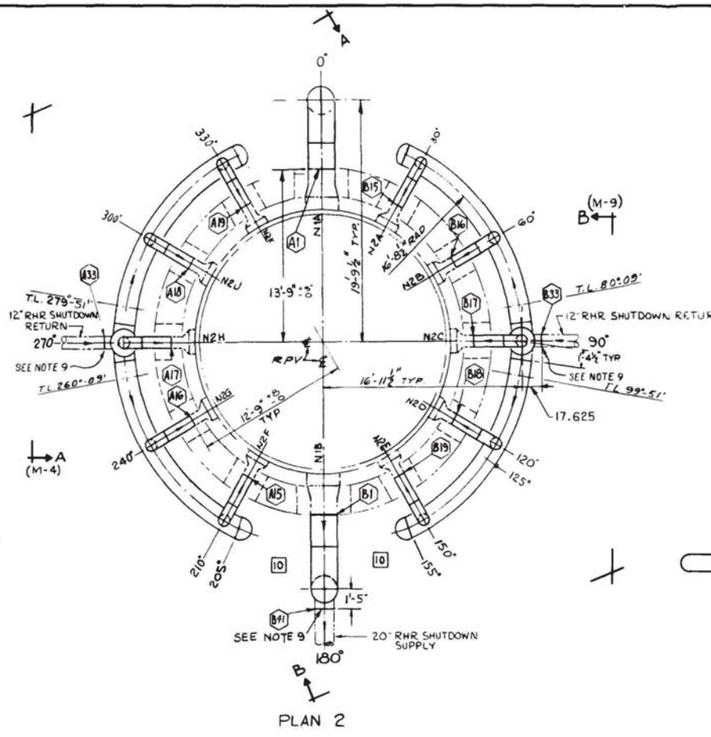
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PIPE ROUTING OF REACTOR COOLANT SYSTEM AND ASSOCIATED SYSTEMS

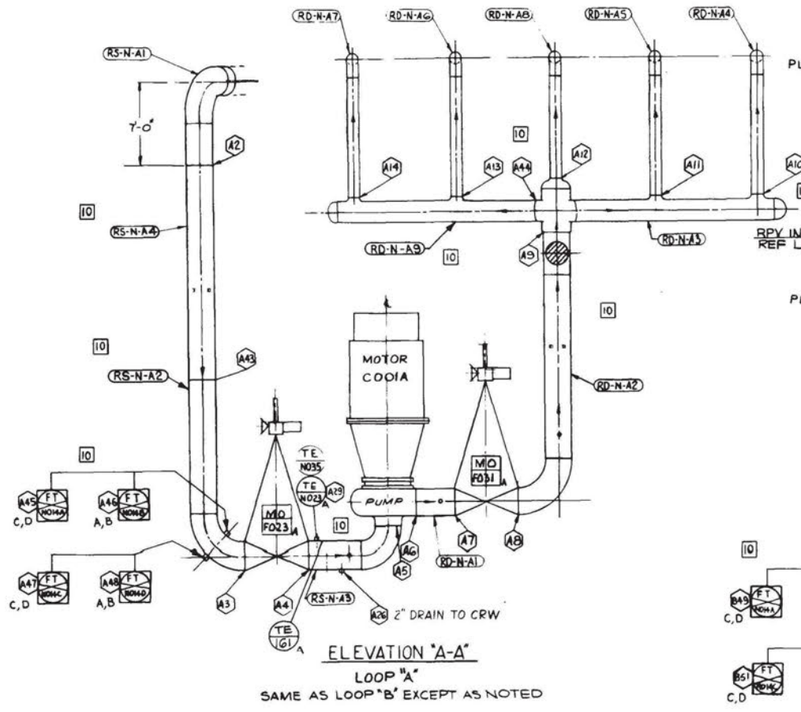
FIGURE 5.1-5



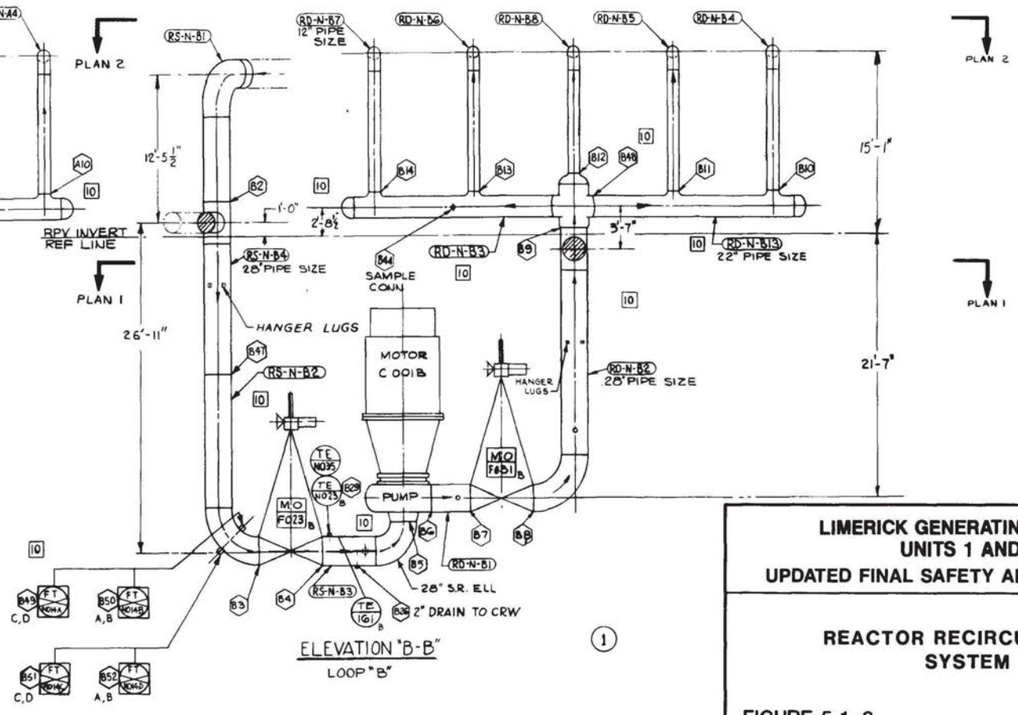
PLAN 1



PLAN 2



ELEVATION "A-A"
LOOP "A"
SAME AS LOOP "B" EXCEPT AS NOTED



ELEVATION "B-B"
LOOP "B"

LEGEND:

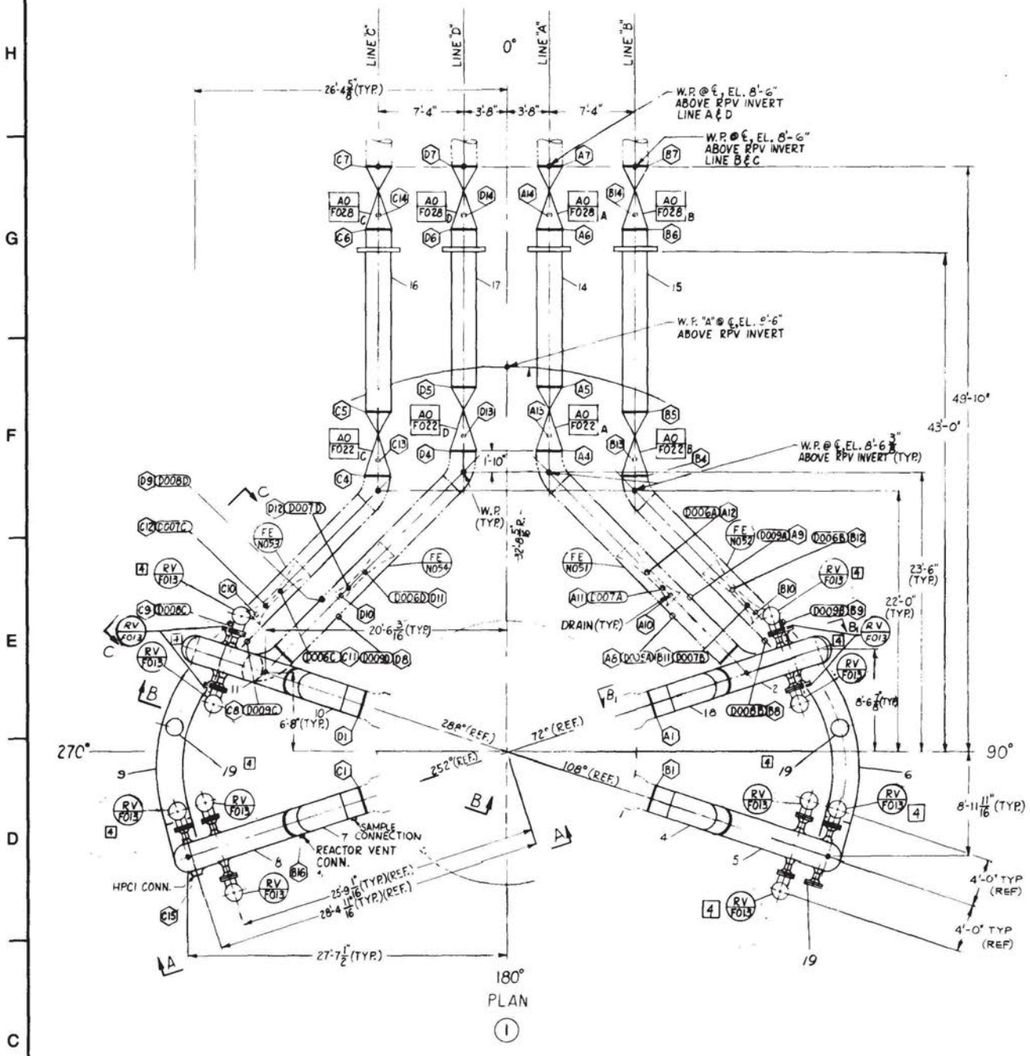
- T.L. INDICATES TANGENT LINE
- RS RECIRCULATION SYSTEM SUCTION PIPING
- RD RECIRCULATION SYSTEM DISCHARGE PIPING
- INDICATES PIPE SPOOL NUMBER
- INDICATES FIELD WELD (DESIGNATIONS ARE TO BE USED FOR NON-DESTRUCTIVE EXAMINATION RECORDS)

(1)

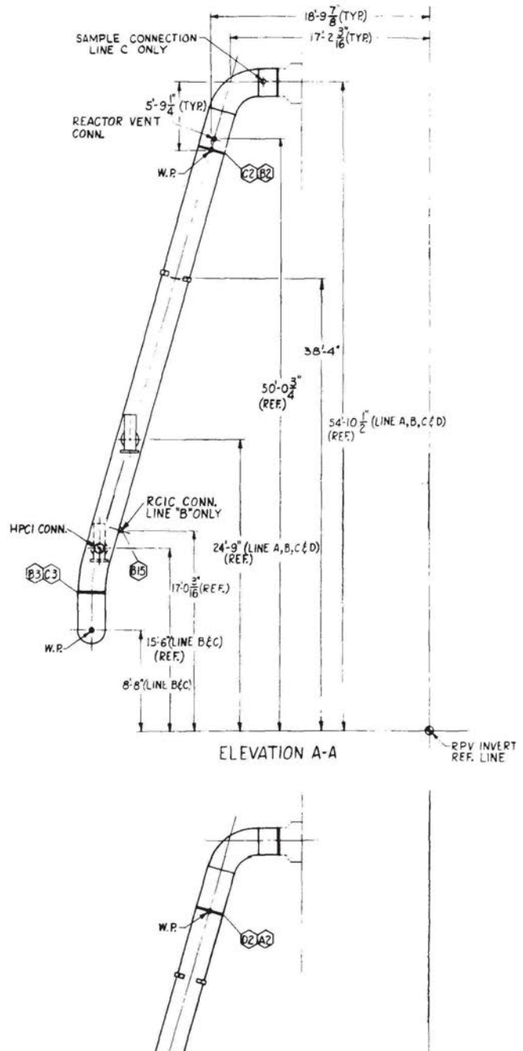
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REACTOR RECIRCULATION SYSTEM

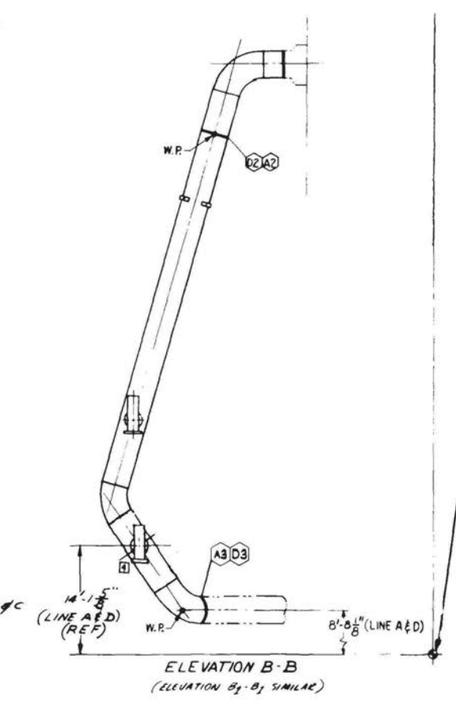
FIGURE 5.1-6



ELEVATION C-C



ELEVATION A-A



ELEVATION B-B
(ELEVATION B_1-B_1 SIMILAR)

LEGEND:

⬡ - INDICATES FIELD WELD (DESIGNATIONS ARE TO BE USED FOR NON-DESTRUCTIVE EXAMINATION RECORDS).

RPV - REACTOR PRESSURE VESSEL.

W.P. - WORK POINT

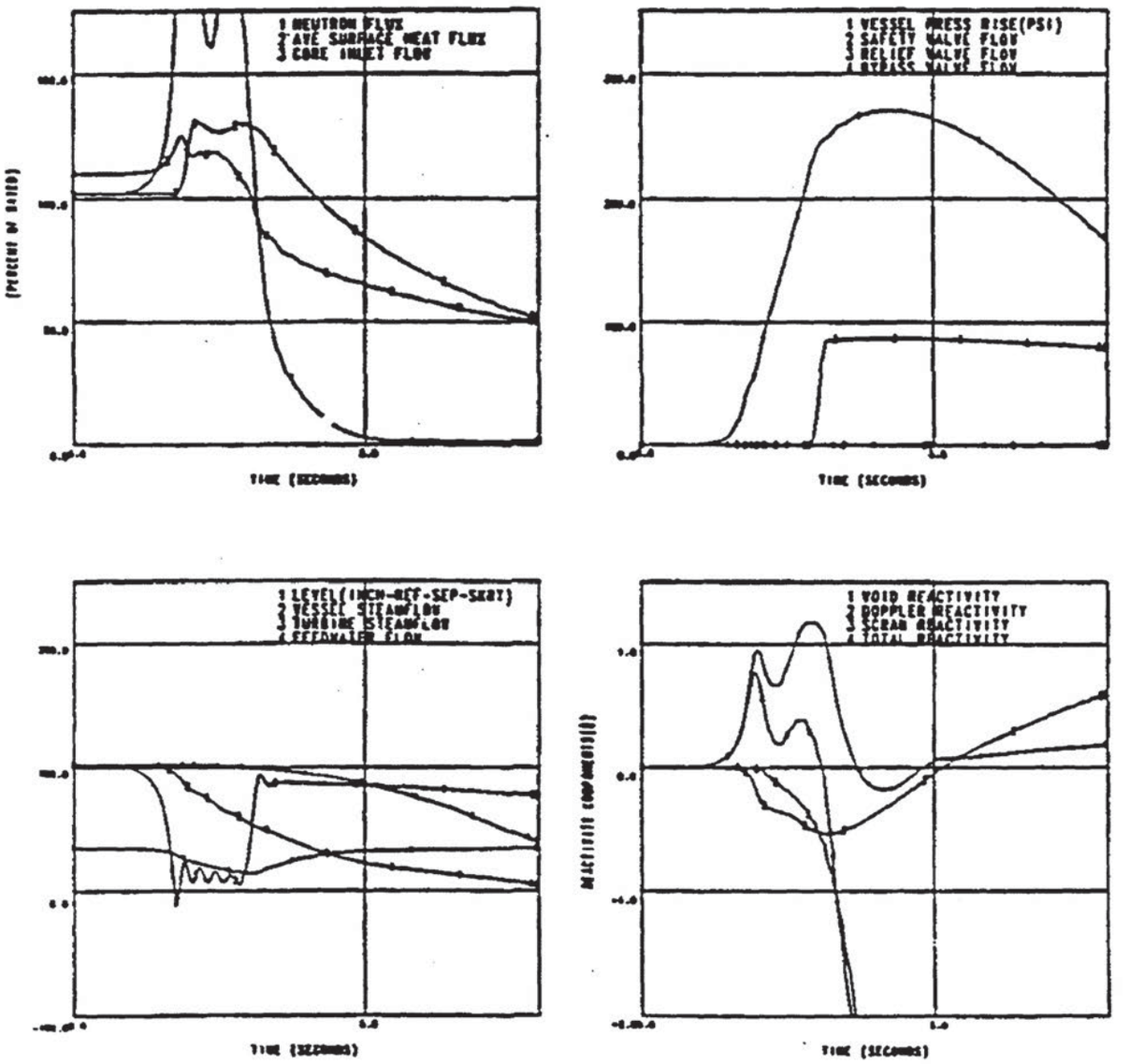
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MAIN STEAM PIPING LAYOUT INSIDE PRIMARY CONTAINMENT

FIGURE 5.1-7

Figure 5.2-1

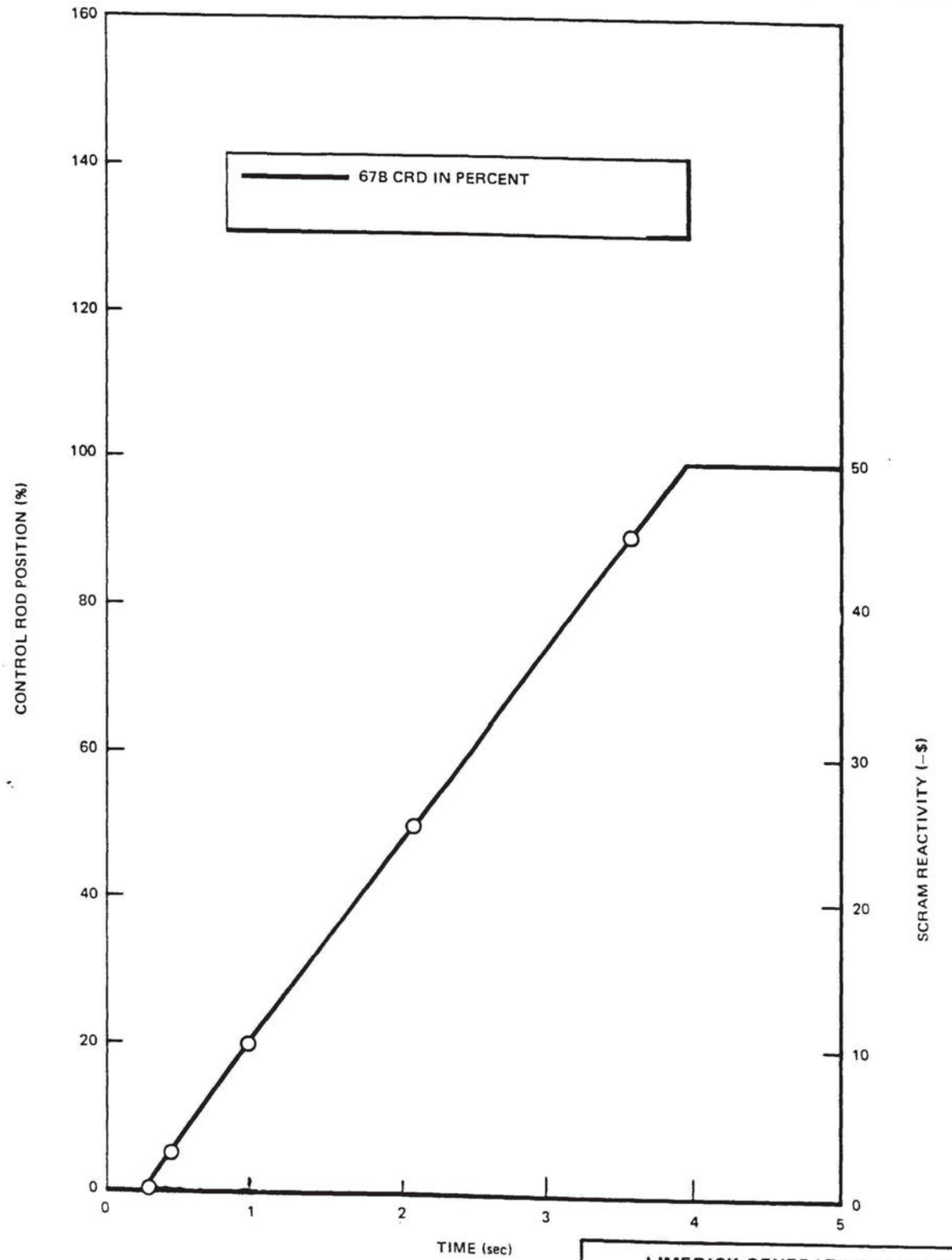
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OVERPRESSURE TRANSIENT RESPONSE TO MSIV CLOSURE WITH FLUX SCRAM (ODYN)
(2 SRVS OOS)

FIGURE 5.2-2 Rev. 16 09/12



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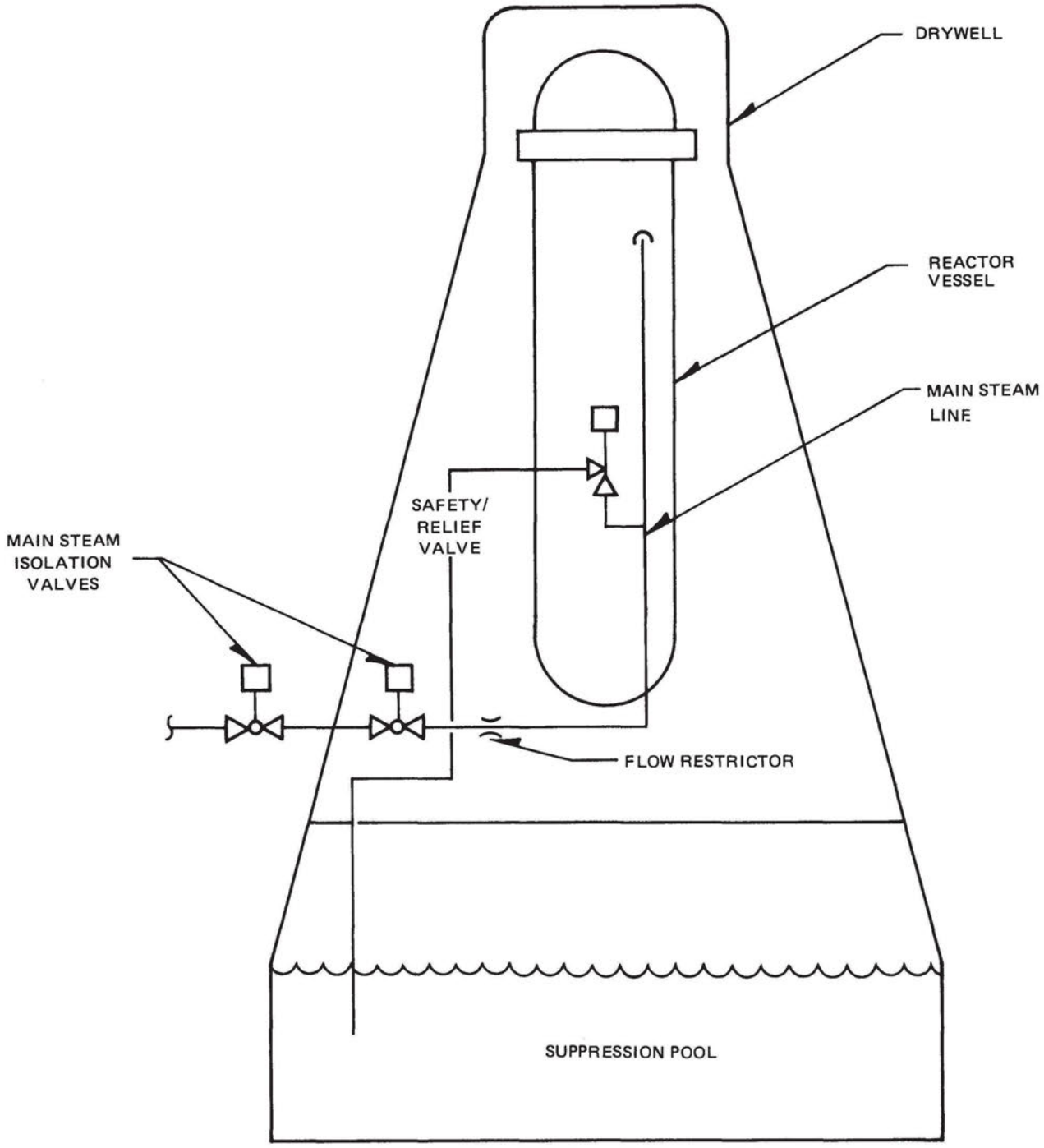
CONTROL ROD POSITION
VERSUS TIME CHARACTERISTICS

FIGURE 5.2-3

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Figures 5.2-4 and 5.2-5

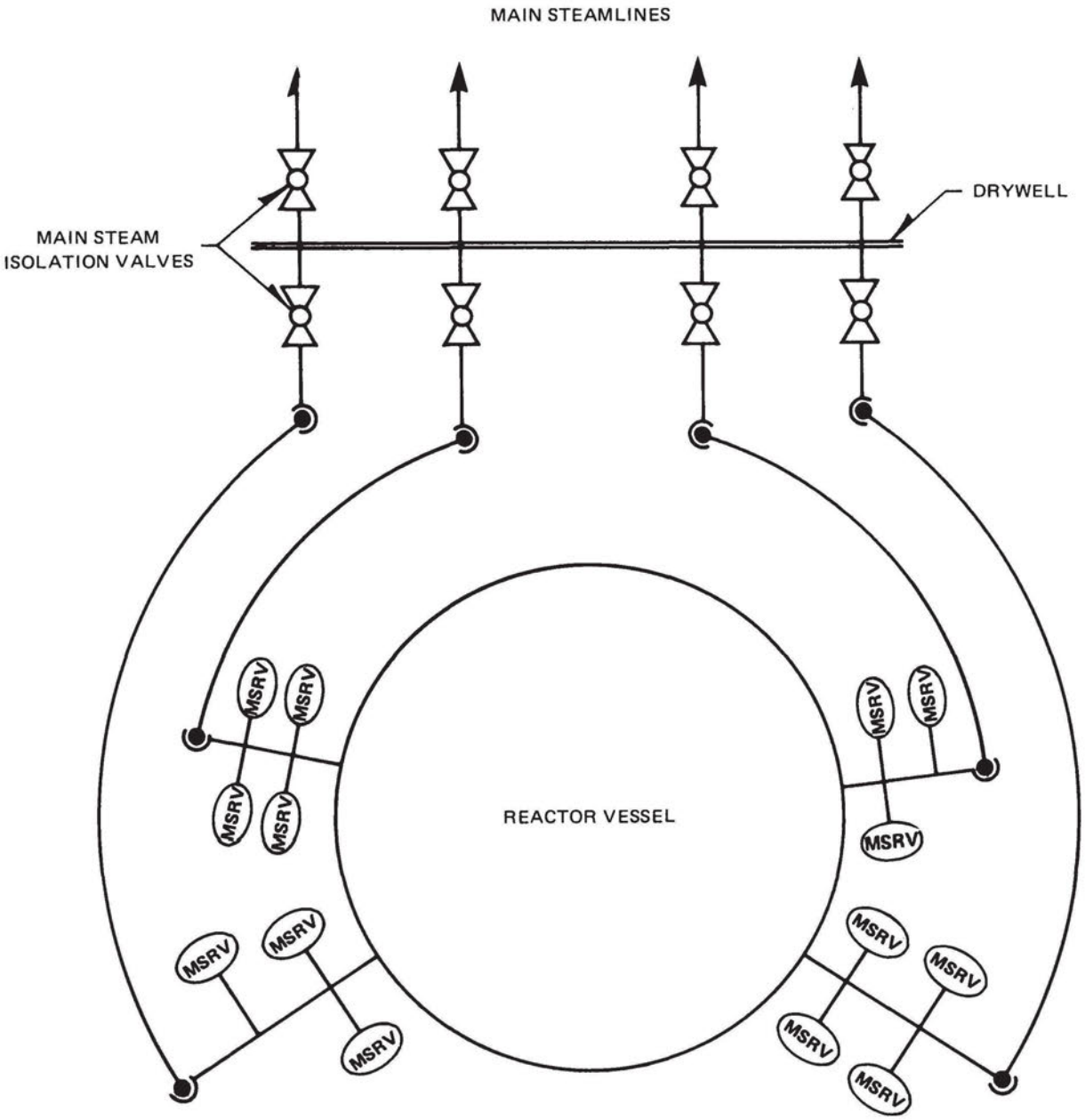
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SAFETY/RELIEF VALVE SCHEMATIC ELEVATION

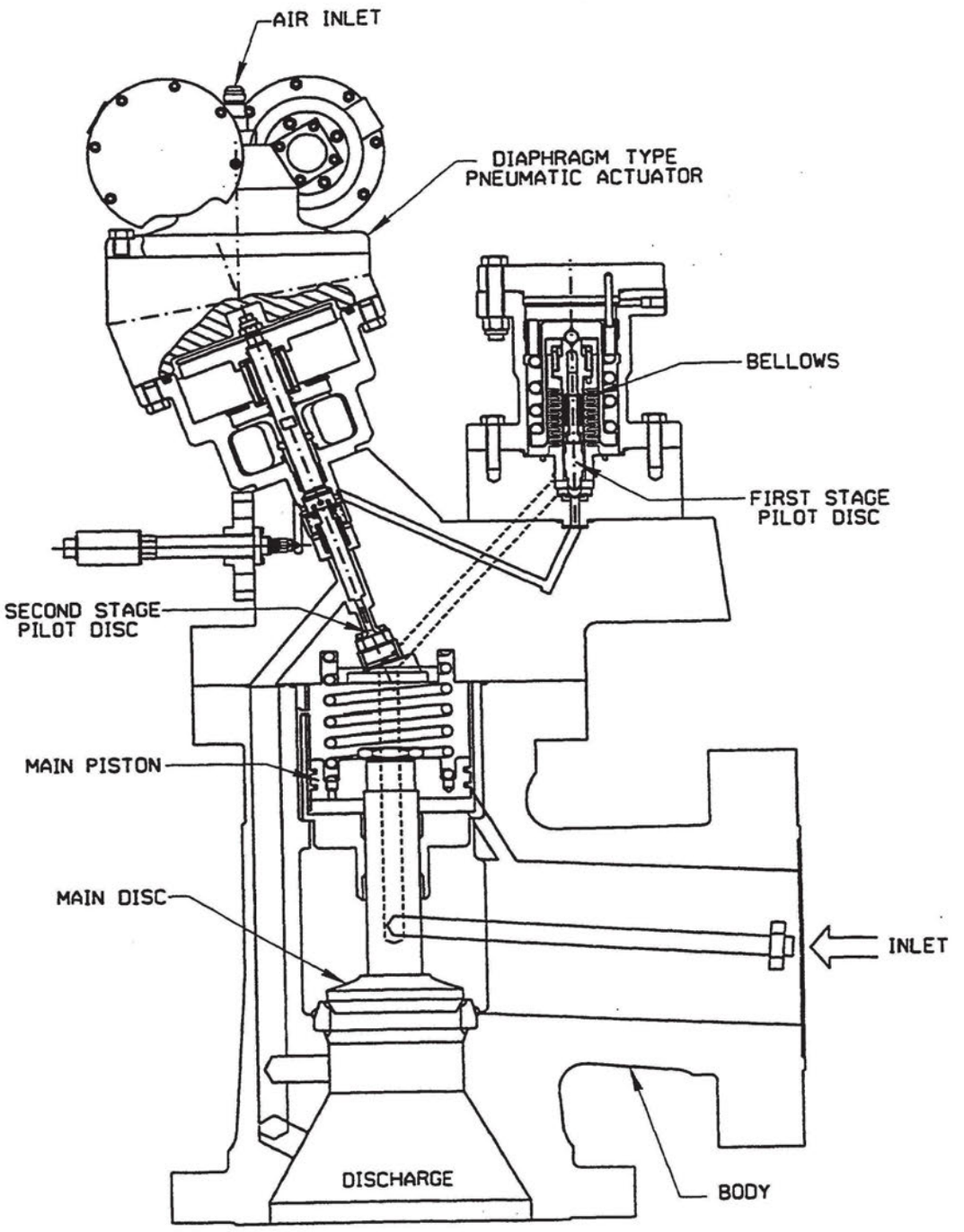
FIGURE 5.2-6



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MSRV AND STEAMLINE SCHEMATIC

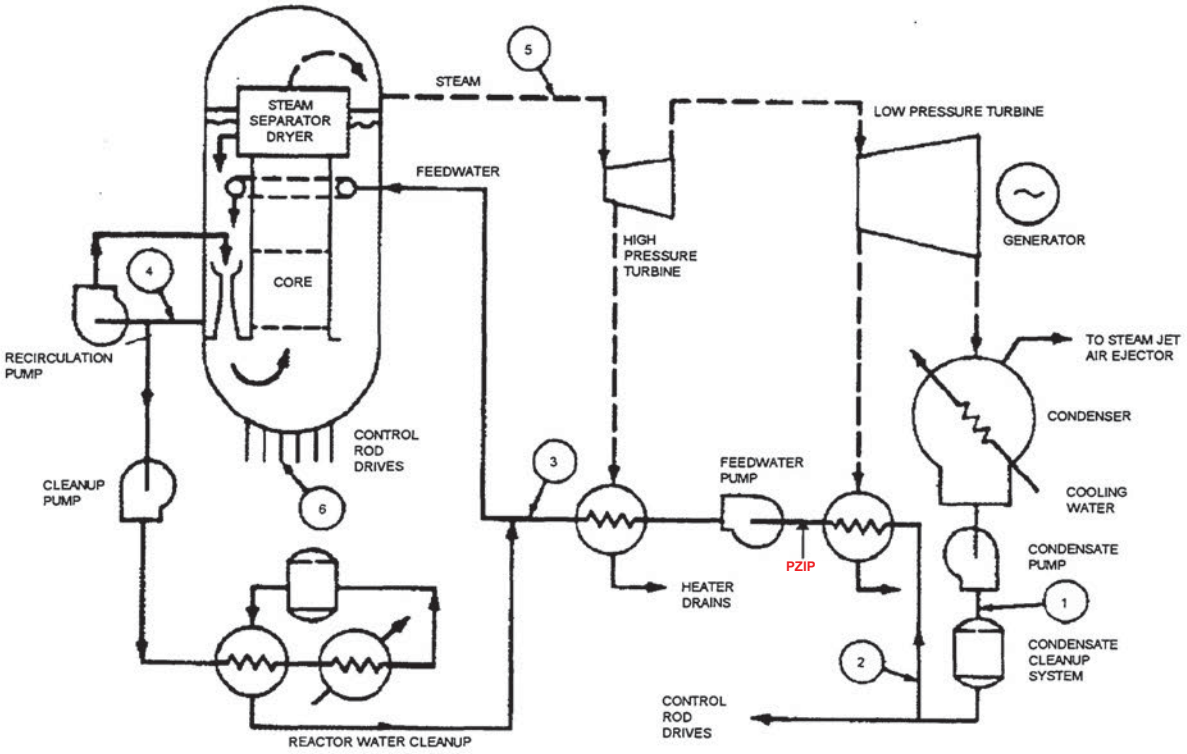
FIGURE 5.2-7



PECO ENERGY COMPANY
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THREE-STAGE, PILOT ACTUATED, SAFETY RELIEF VALVE (VERTICAL DISCHARGE)

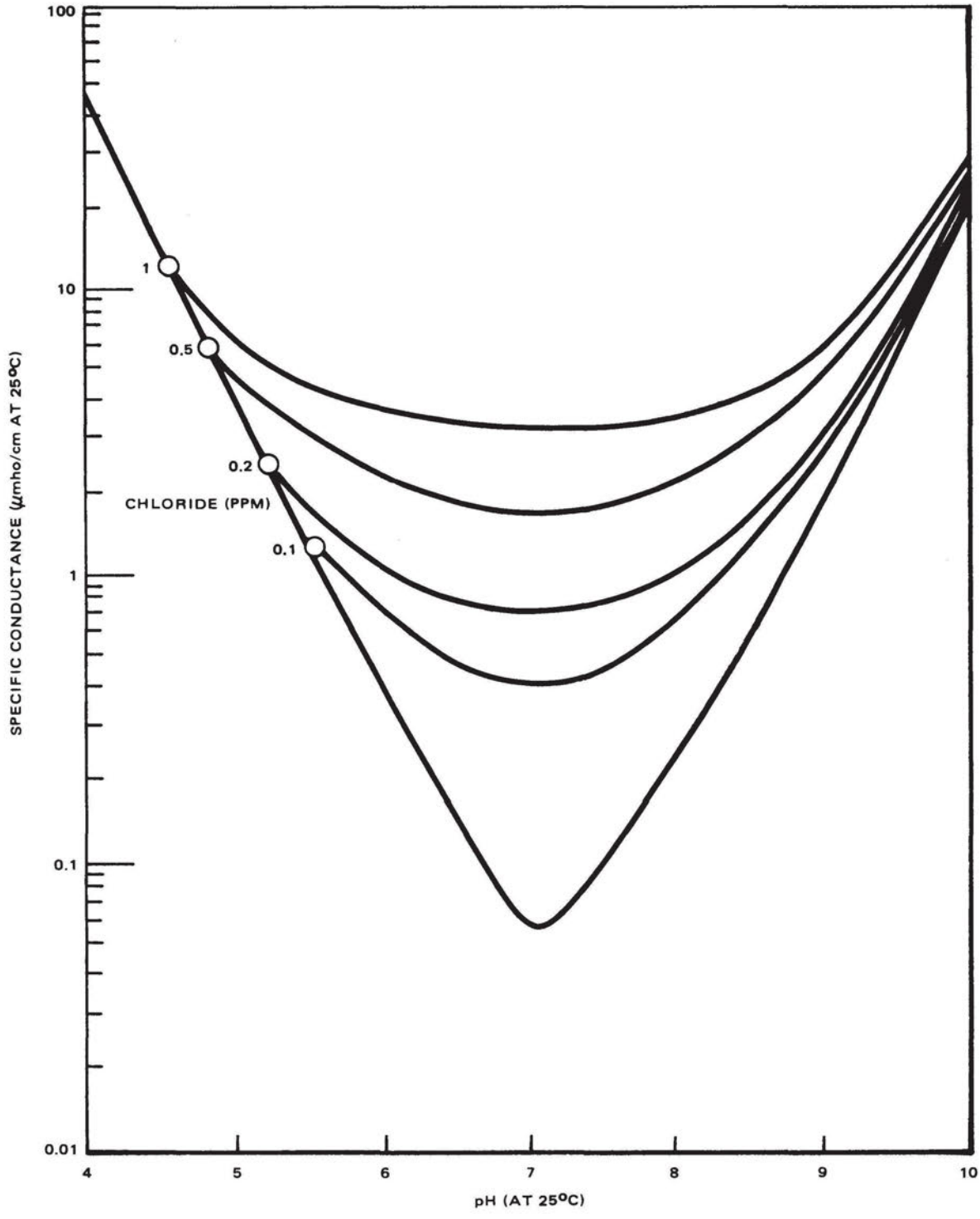
FIGURE 5.2-8 **Rev. 10 10/00**



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TYPICAL BWR FLOW DIAGRAM

FIGURE 5.2-9 Rev. 21 09/22



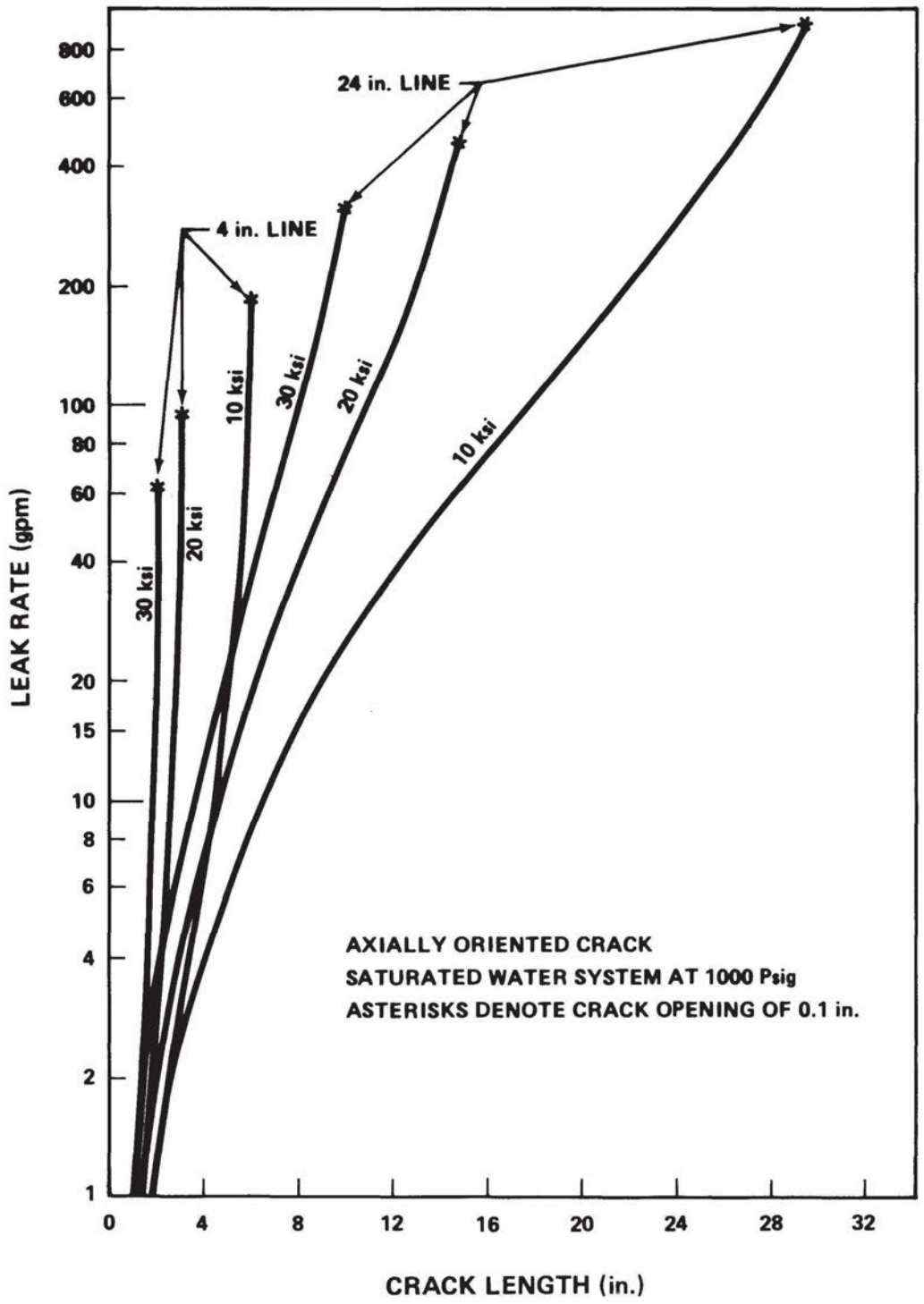
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CONDUCTANCE VS pH AS A FUNCTION OF CHLORIDE CONCENTRATION OF AQUEOUS SOLUTION AT 25°C

FIGURE 5.2-10

Figure 5.2-11

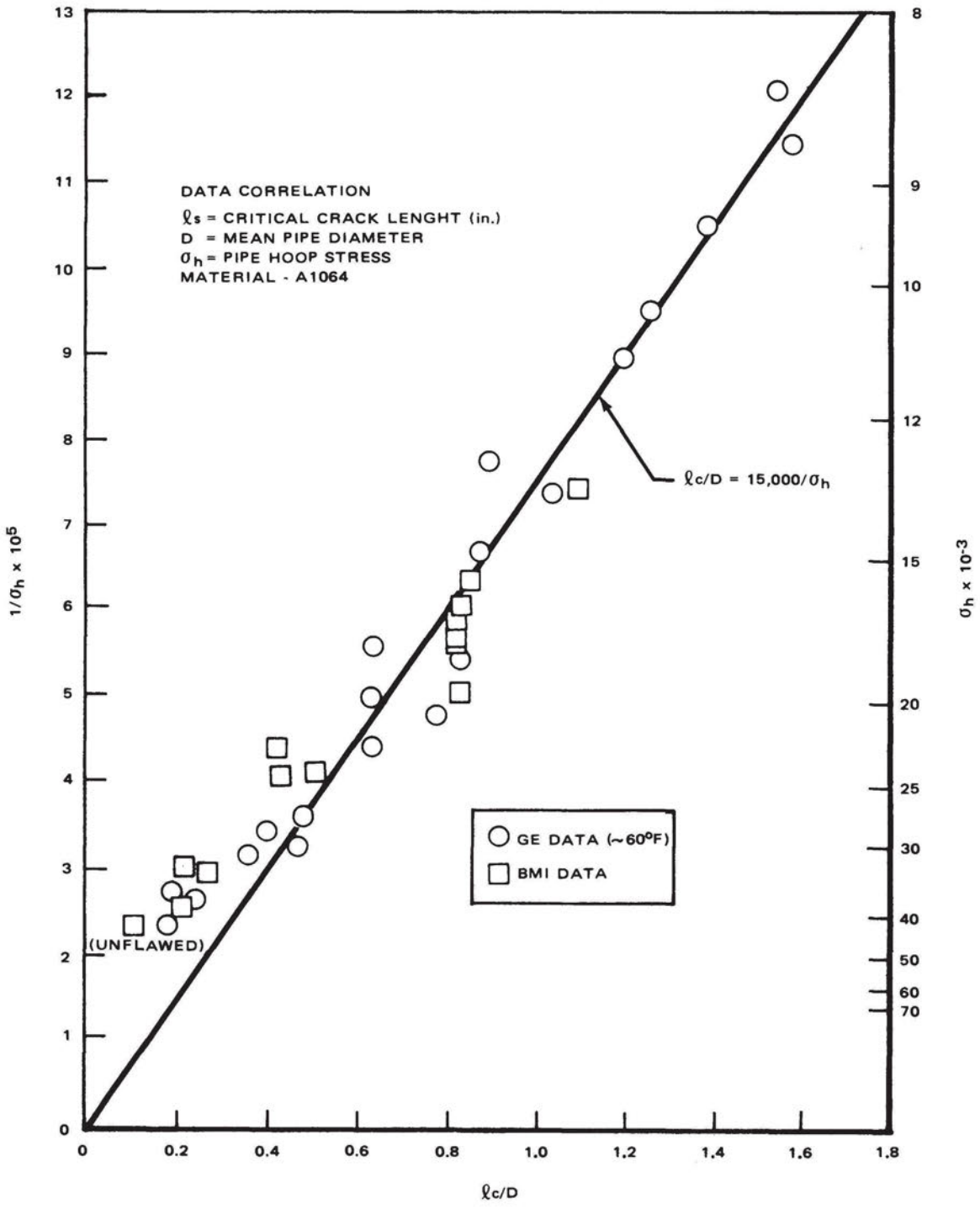
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CALCULATED LEAK RATE AS A FUNCTION OF CRACK LENGTH & APPLIED HOOP STRESS

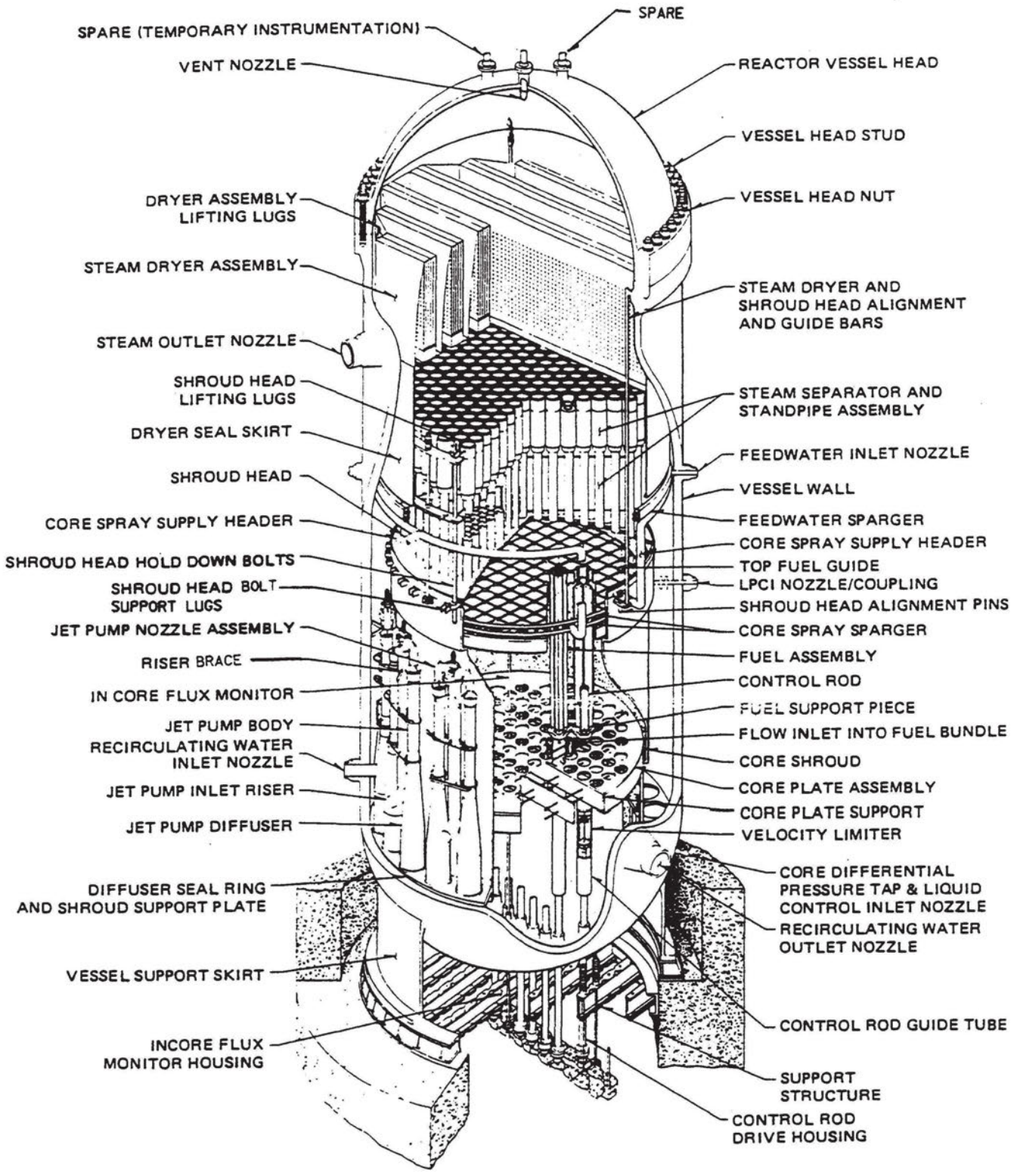
FIGURE 5.2-12



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AXIAL THROUGH-WALL CRACK LENGTH DATA CORRELATION

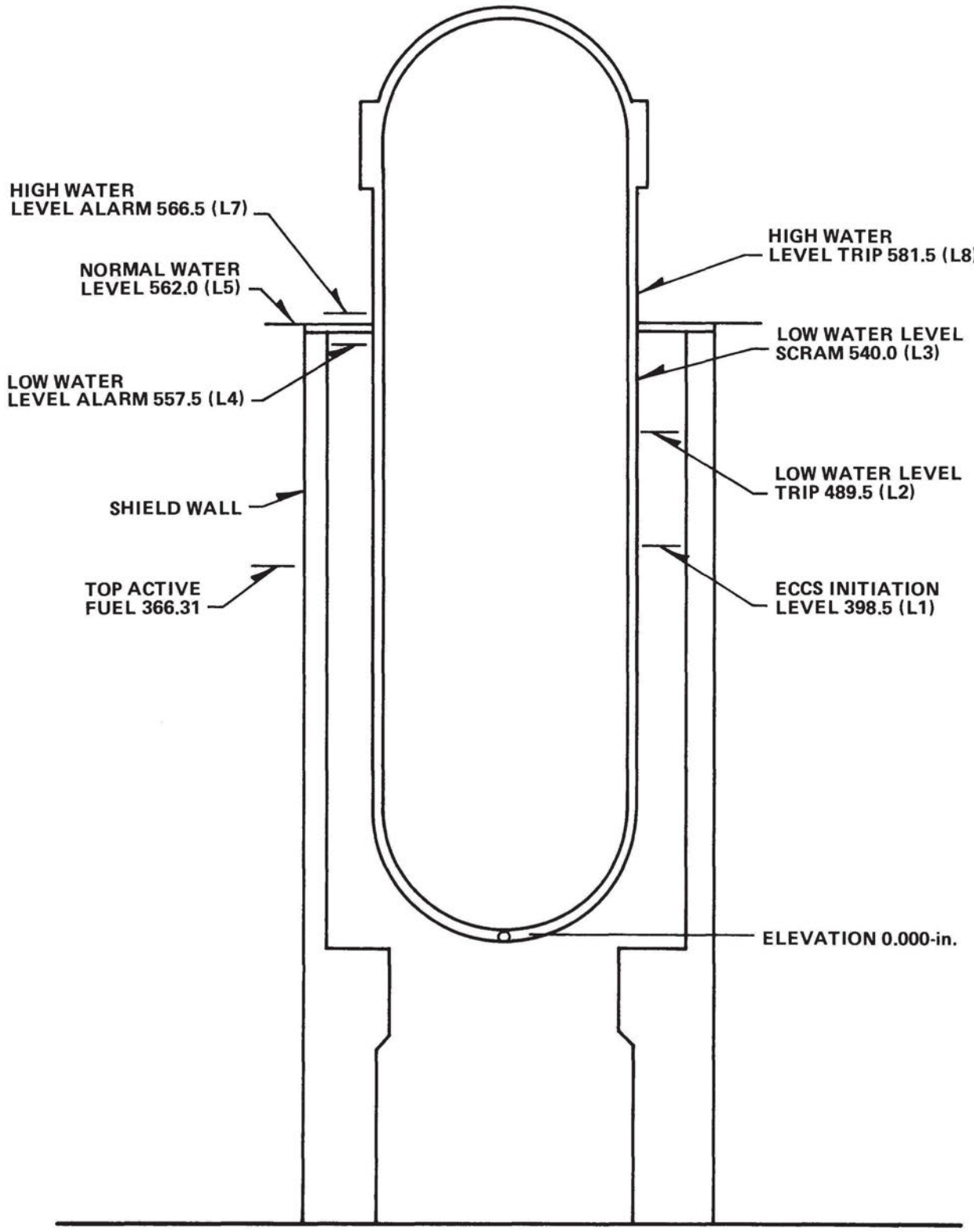
FIGURE 5.2-13



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REACTOR VESSEL CUTAWAY DIAGRAM

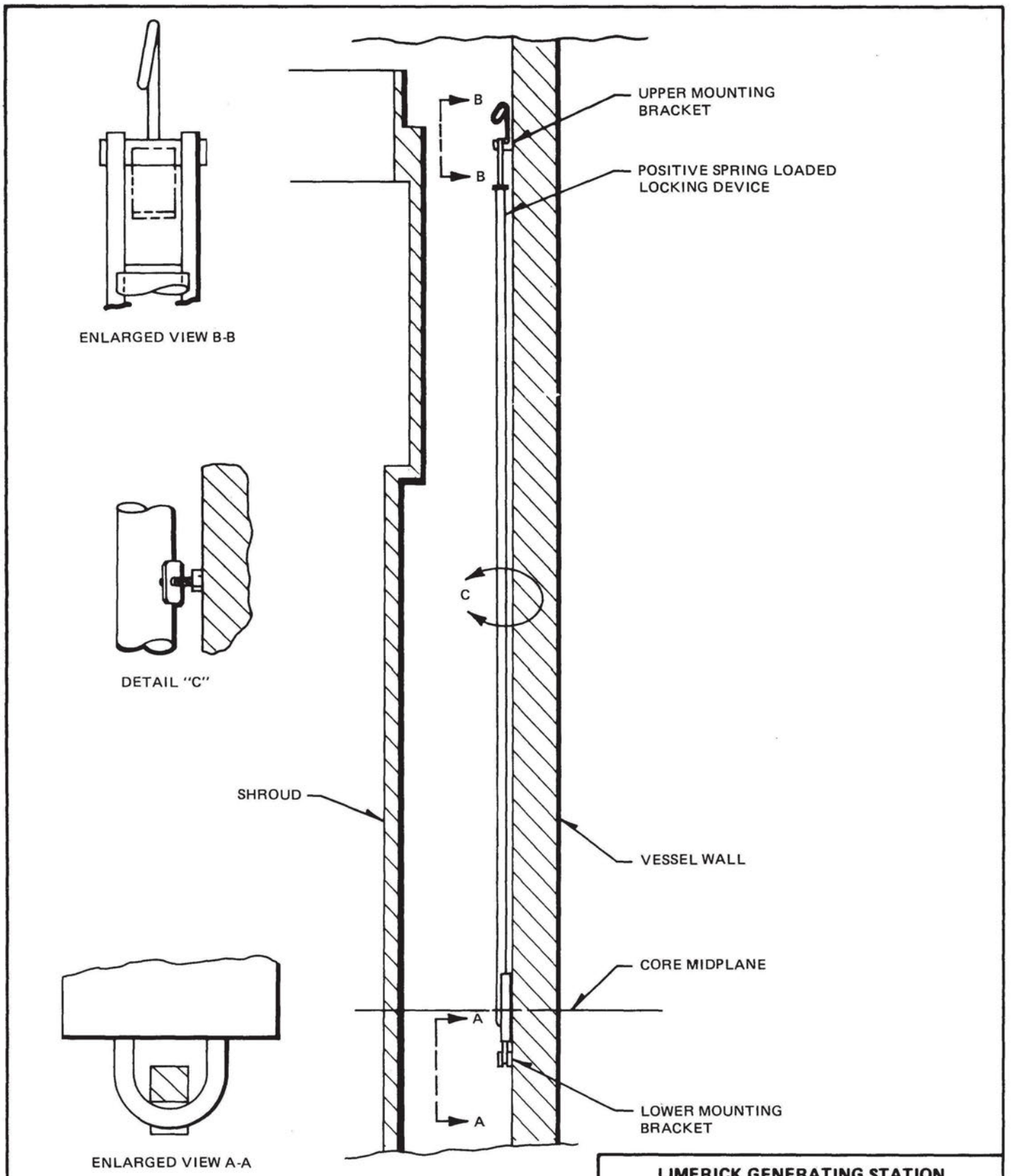
FIGURE 5.3-1 Rev 08 11/98



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NOMINAL REACTOR VESSEL WATER LEVEL TRIP AND ALARM ELEVATION SETTINGS

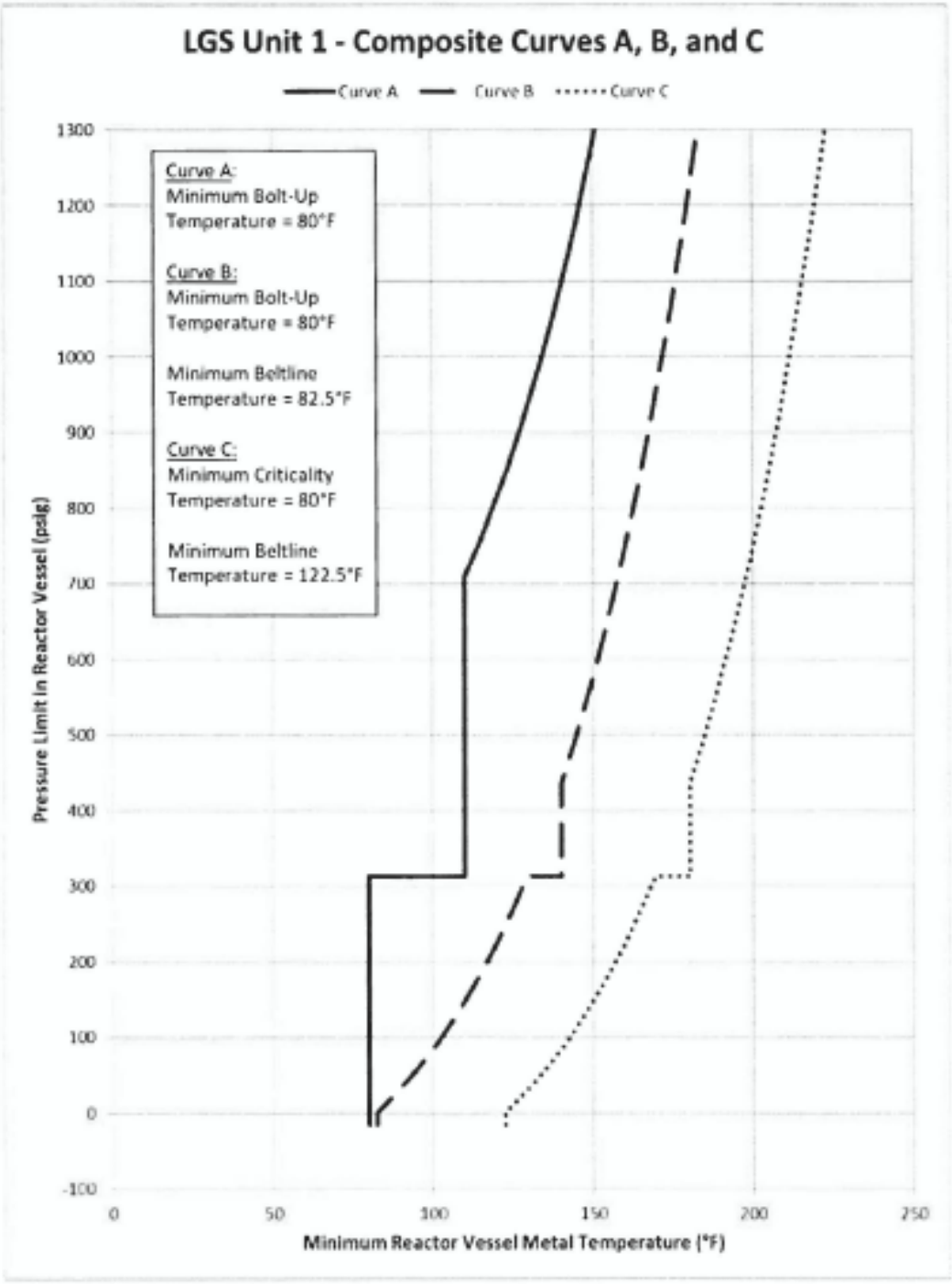
FIGURE 5.3-2



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SURVEILLANCE CAPSULE

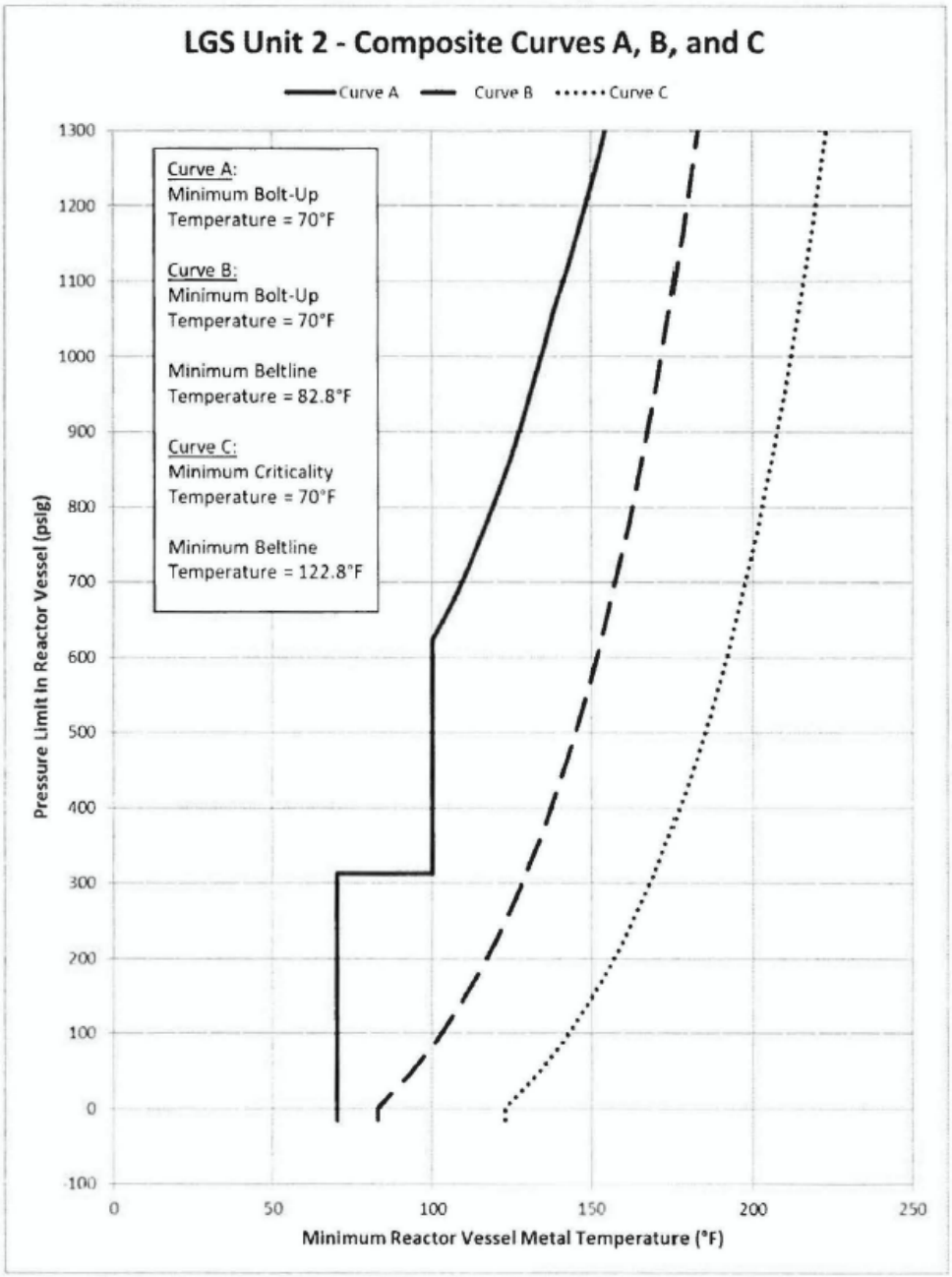
FIGURE 5.3-3



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MINIMUM TEMPERATURE REQUIRED
VERSUS REACTOR PRESSURE
(UNIT 1)

FIGURE 5.3-4 Rev. 21 09/22



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MINIMUM TEMPERATURE REQUIRED
VERSUS REACTOR PRESSURE
(UNIT 2)
Sheet 1 of 1

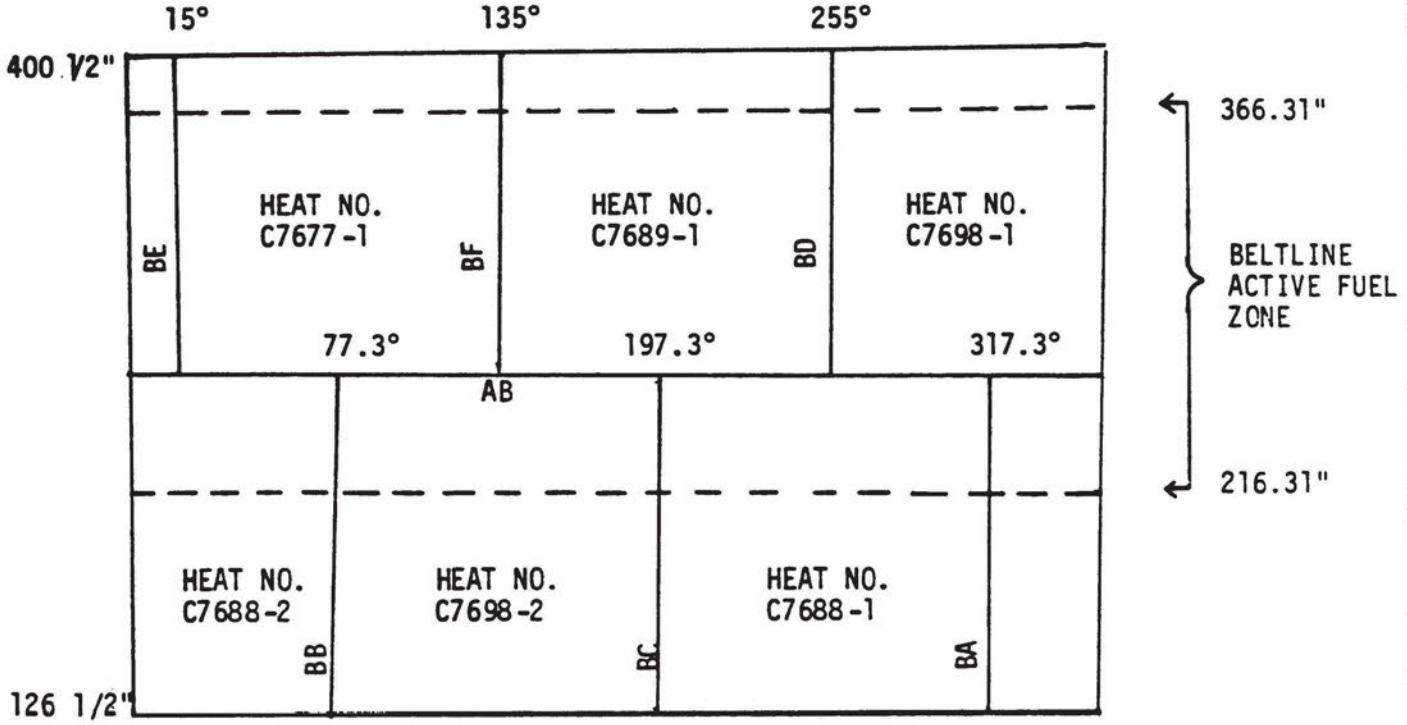
FIGURE 5.3-5 Rev. 21 09/22

Figures 5.3.5 Sheet 2 of 2

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Figure 5.3-6

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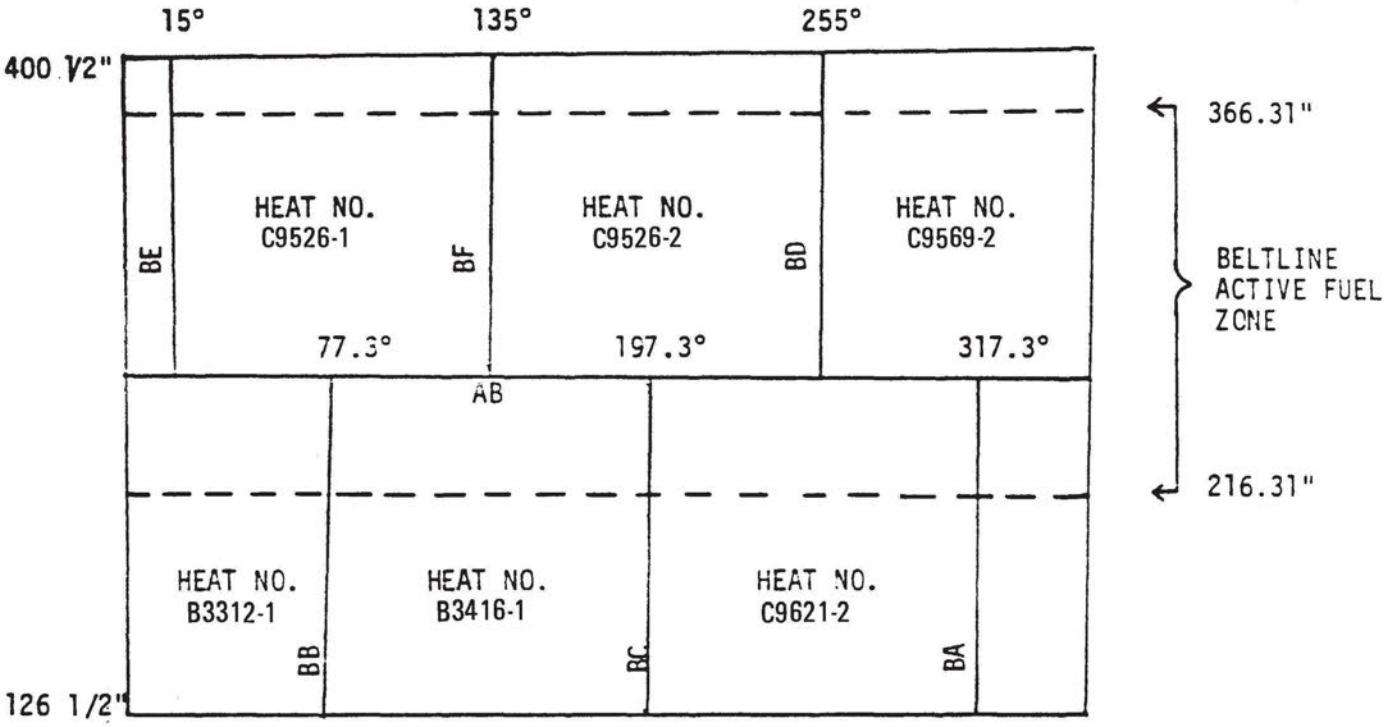
SHOP WELDS: SEAMS BA, BB, BC, BD, BE, BF

FIELD WELDS: SEAM AB

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

BELTLINE PLATE AND WELD SEAM LOCATIONS (UNIT 1) SHEET 1 OF 2

FIGURE 5.3-7



SHOP WELDS: SEAMS BA, BB, BC, BD, BE, BF

FIELD WELDS: SEAM AB

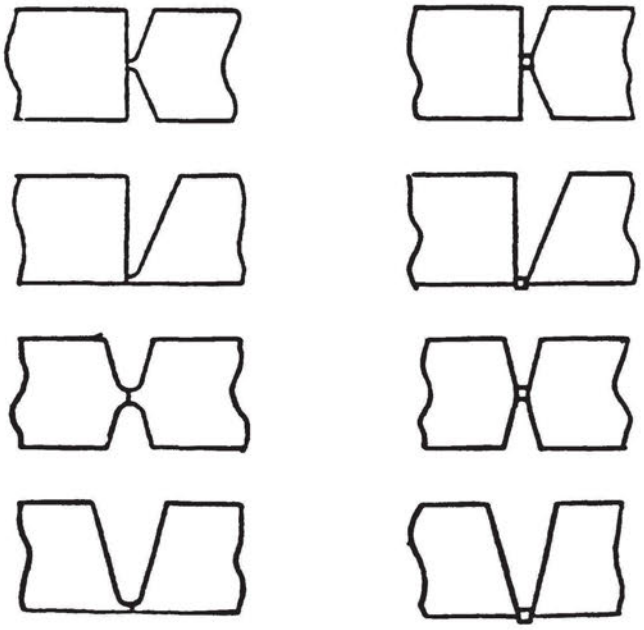
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

BELTLINE PLATE AND WELD SEAM LOCATIONS (UNIT 2) SHEET 2 OF 2

FIGURE 5.3-7

GROOVES

Submerged Arc - Flat
SMA - Flat & Vertical



The spacer bar shall be of the same material as the base material.

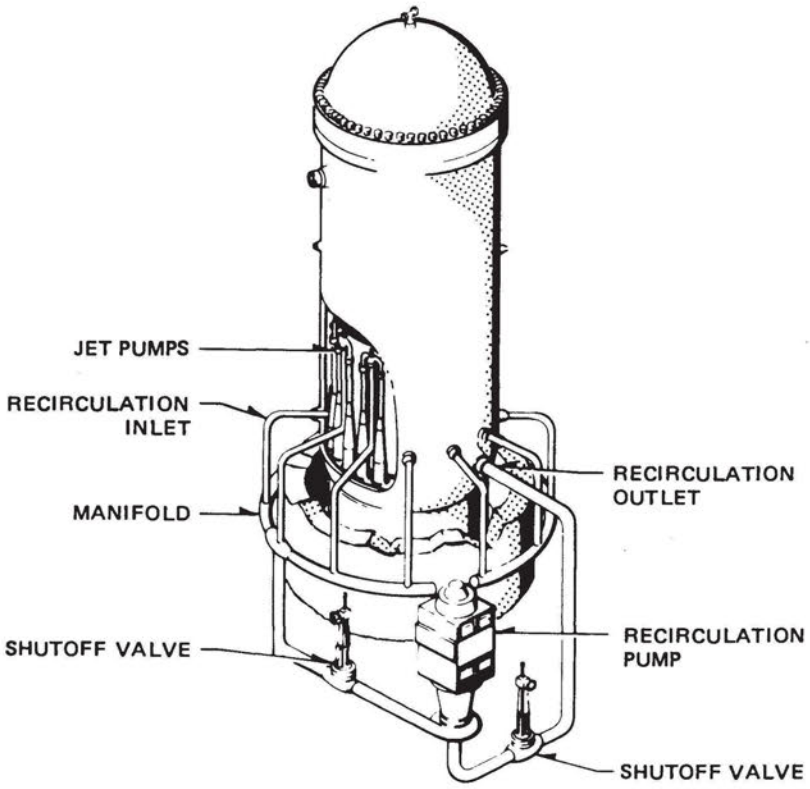
WELD BUILDUP



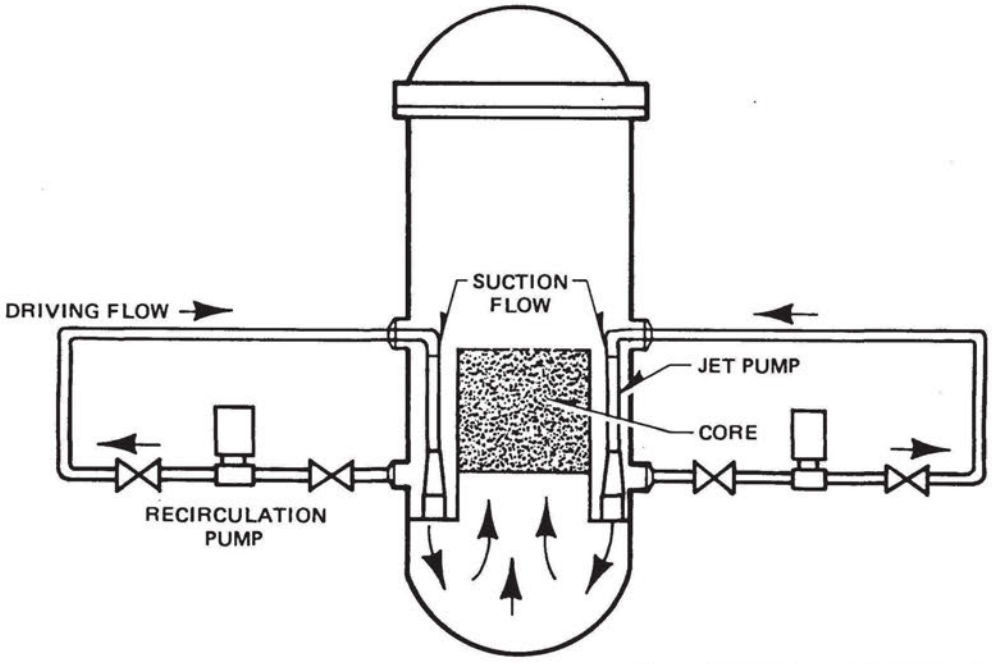
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GENERAL WELDING TECHNIQUES

FIGURE 5.3-8



ISOMETRIC

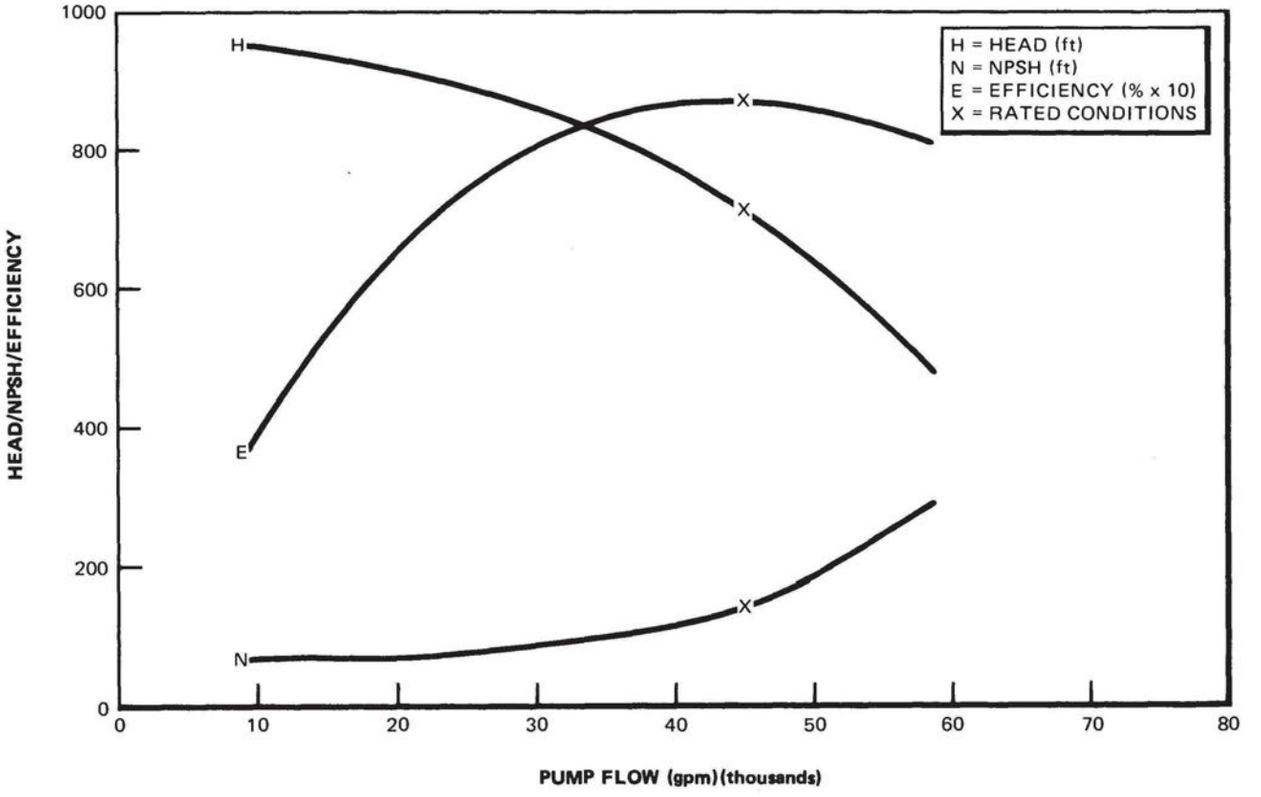


ELEVATION

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RECIRCULATION SYSTEM ELEVATION AND ISOMETRIC (SHEET 1 OF 2)

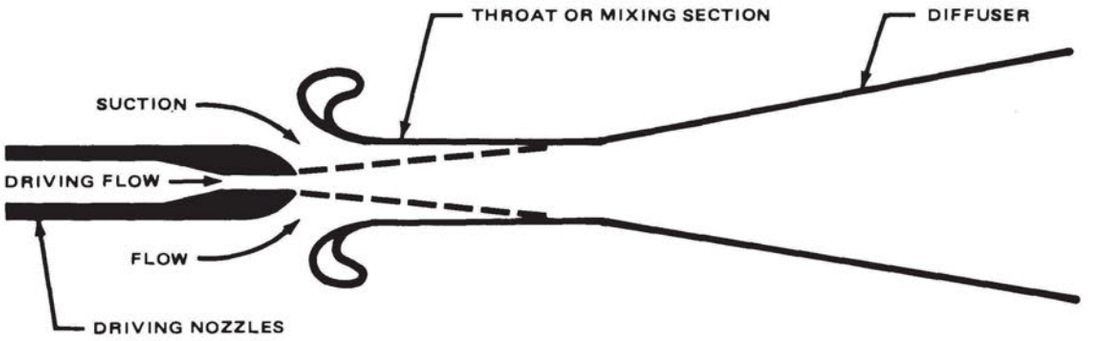
FIGURE 5.4-1

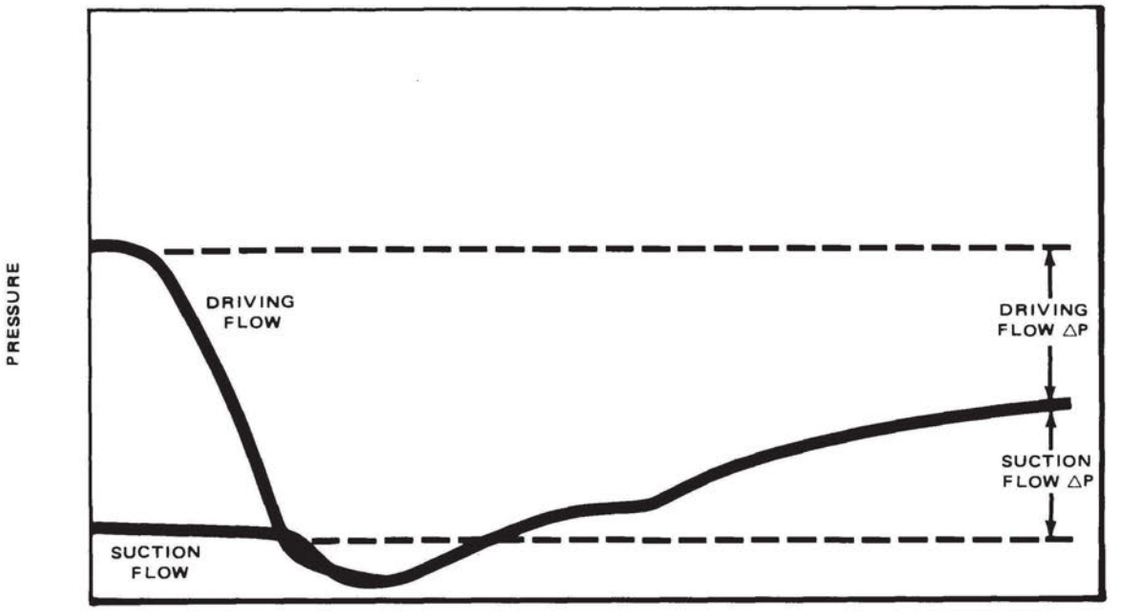


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RECIRCULATION PUMP HEAD, NPSH, AND EFFICIENCY CURVES

FIGURE 5.4-3

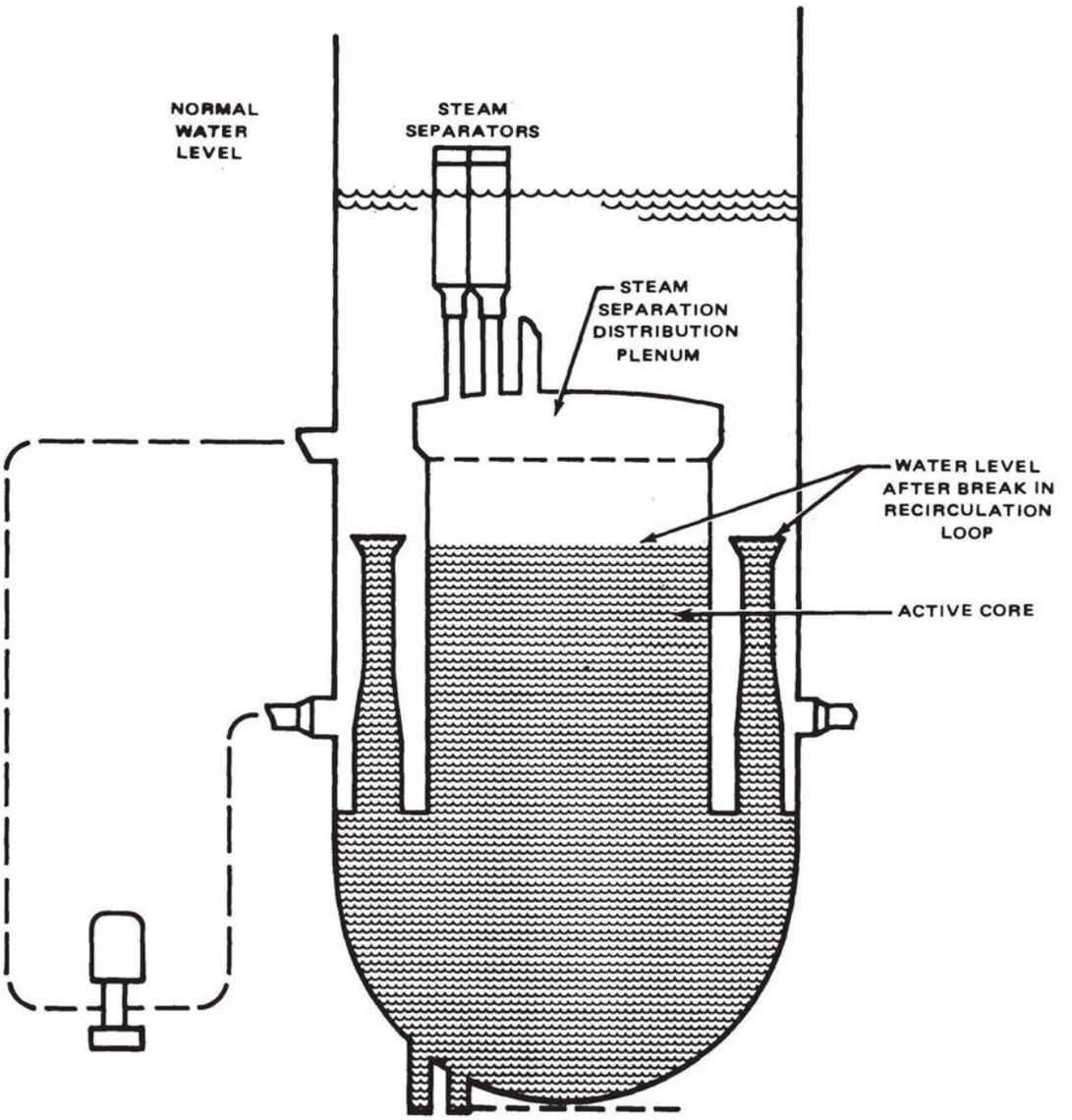




LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

OPERATING PRINCIPLE OF JET PUMP

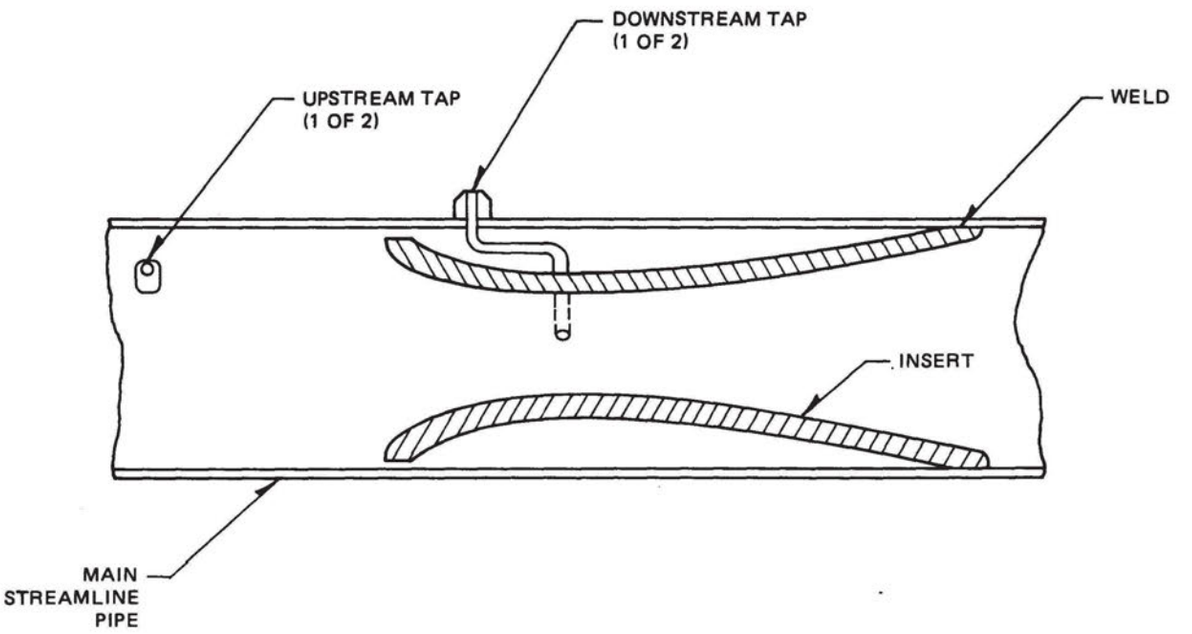
FIGURE 5.4-4



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CORE FLOODING CAPABILITY
OF RECIRCULATION SYSTEM

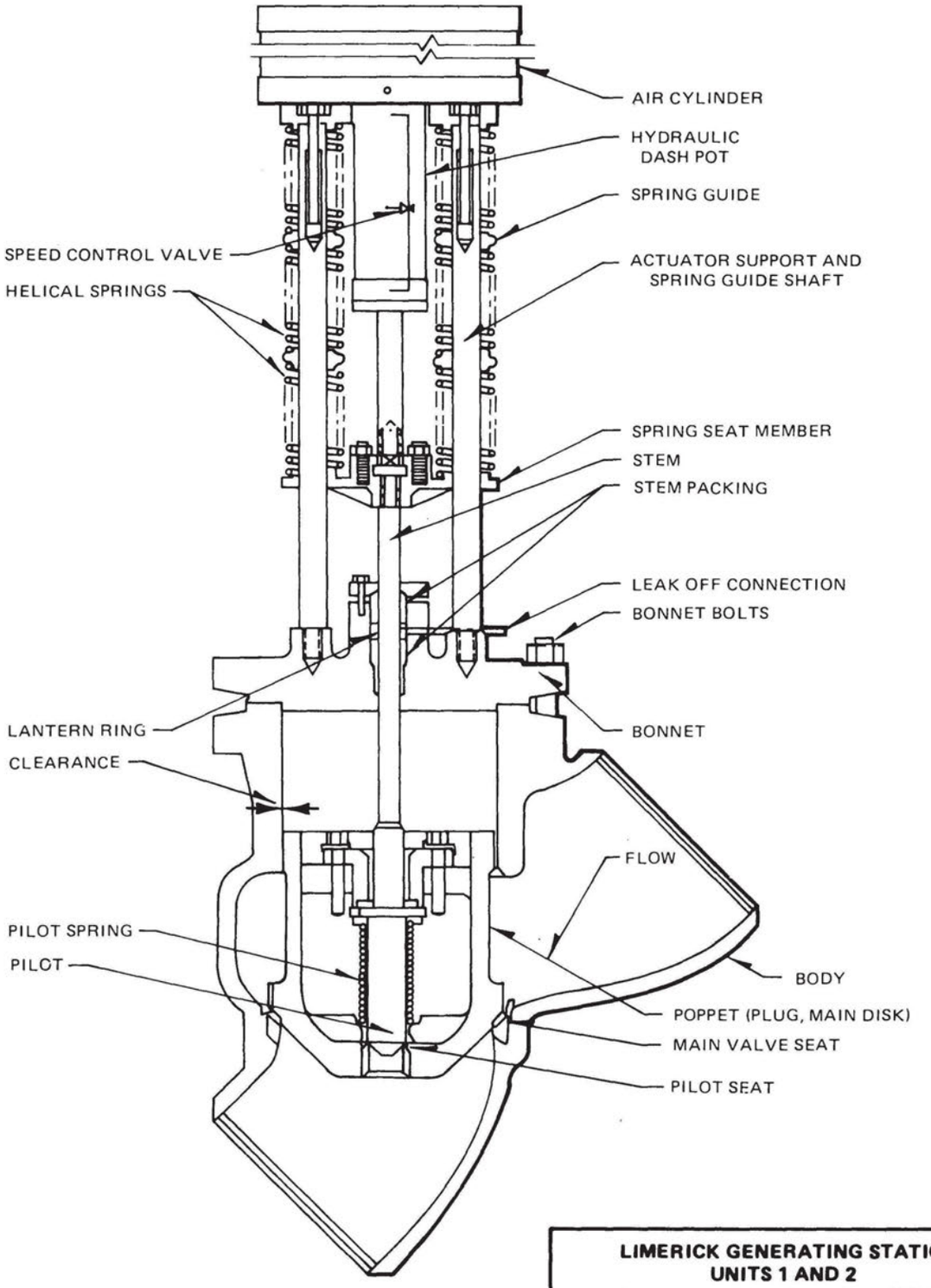
FIGURE 5.4-5



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAMLINE FLOW RESTRICTOR

FIGURE 5.4-6



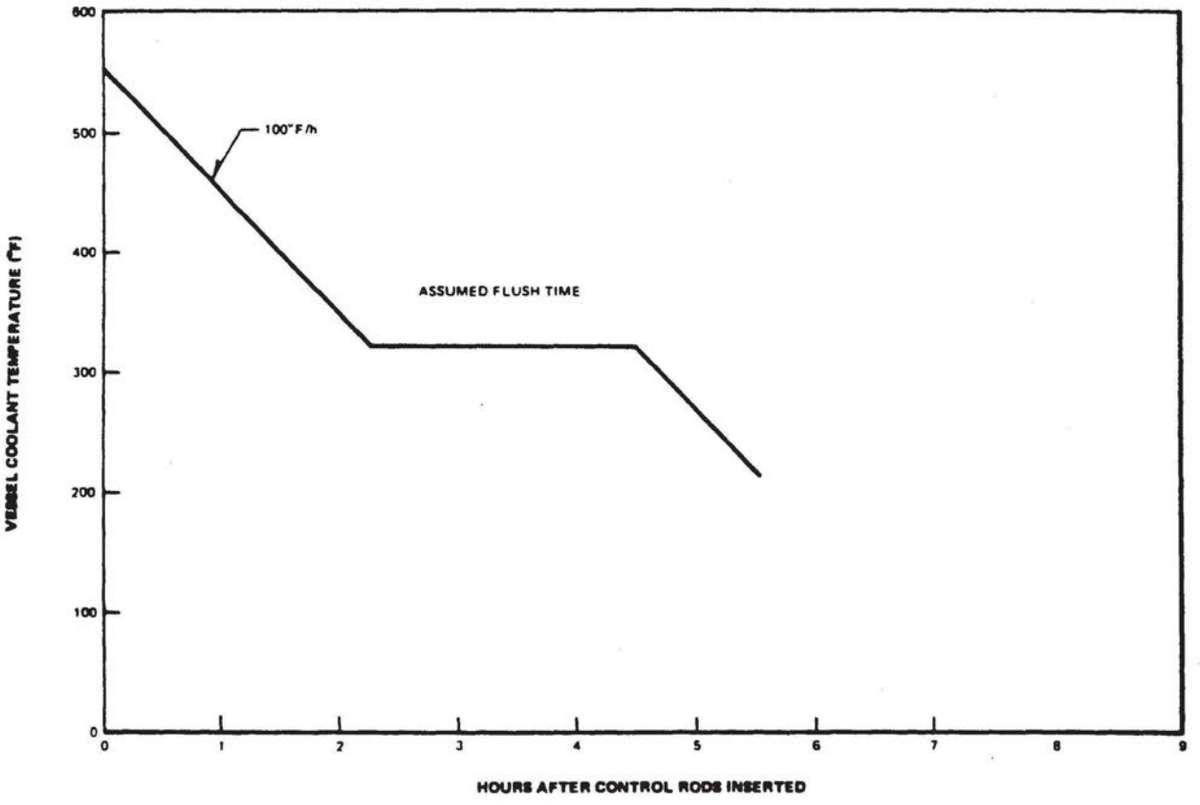
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM ISOLATION VALVE

FIGURE 5.4-7

Figures 5.4-8 through 5.4-10

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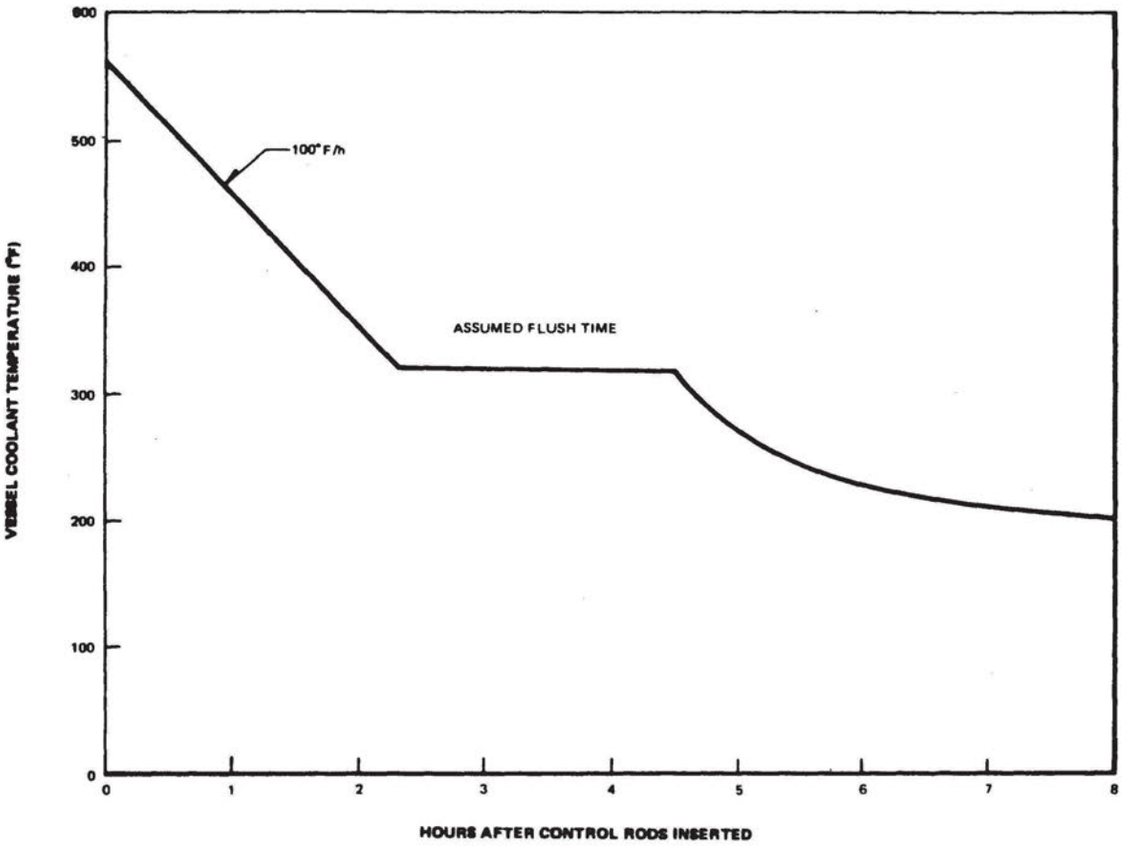


NOTE: This curve is based on original plant design conditions. Actual cooldown rate will vary depending on system flowrates, cooling water temperature, and RHR heat exchanger fouling.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

VESSEL COOLANT TEMPERATURE VERSUS TIME (TWO HEAT EXCHANGERS AVAILABLE)

FIGURE 5.4-11 REV. 13 09/06



NOTE: This curve is based on original plant design conditions. Actual cooldown rate will vary depending on system flowrates, cooling water temperature, and RHR heat exchanger fouling.

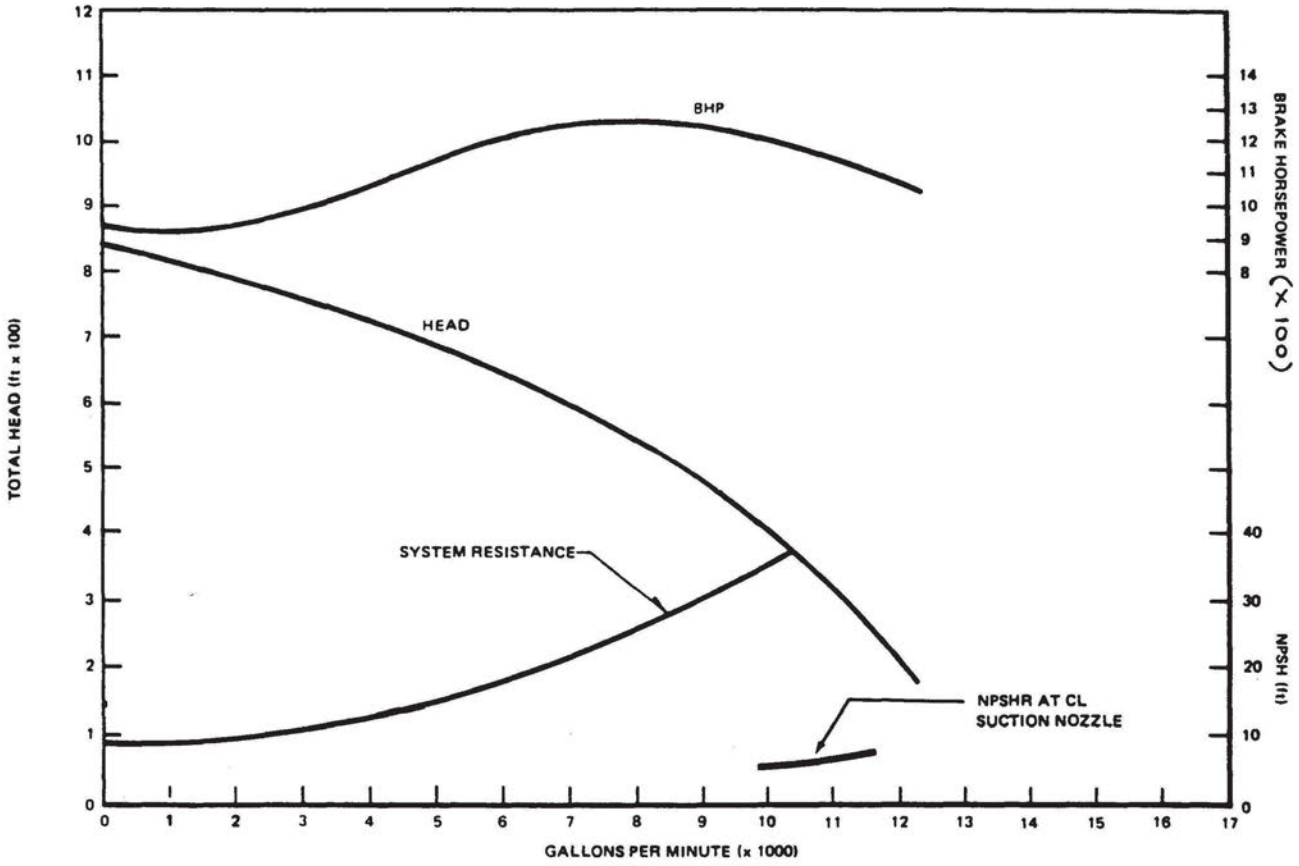
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

VESSEL COOLANT TEMPERATURE VERSUS TIME (ONE HEAT EXCHANGER AVAILABLE)

FIGURE 5.4-12 REV. 13 09/06

Figures 5.4-13 thru 5.4-14

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LIMERICK GENERATING STATION UNITS 1 AND 2 UPDATED FINAL SAFETY ANALYSIS REPORT
RHR PUMP CHARACTERISTIC CURVES
FIGURE 5.4-15 Rev. 6,12/96

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CHAPTER 6 - ENGINEERED SAFETY FEATURES

6.0 INTRODUCTION

Engineered safety features are provided to mitigate the consequences of postulated serious accidents, even though these accidents are very unlikely. The following ESFs are discussed in this chapter:

a. Containment systems (Section 6.2)

1. Primary containment
2. Secondary containment
3. Containment heat removal system
4. Containment isolation system
5. Containment atmospheric control system

b. ECCS (Section 6.3)

1. HPCI system
2. ADS
3. Core spray system
4. LPCI system

c. Control room habitability system (Section 6.4)

d. Fission product removal and control systems (Section 6.5)

In addition to the ESFs discussed in this chapter, other ESF systems discussed elsewhere are provided to limit the consequences of postulated accidents. The ESF systems are described in the sections of Chapter 6 and those sections referenced in Table 6.1-1; therefore, no optional sections are required.

The information provided herein demonstrates the following:

a. The concepts on which the operation of each system is predicated have been proven by tests under simulated accident conditions and/or by conservative extrapolations from present knowledge and experience.

b. Component reliability, system interdependency, redundancy, and separation of components or portions of systems, etc., ensure that the ESF accomplishes its intended purpose and functions for the period required.

c. Provisions for testing, inspection, and surveillance are made to ensure that the ESF is dependable and effective on demand.

d. The material used can withstand the postulated accident environment, including radiation levels, and the radiolytic decomposition products that may occur cannot interfere with any ESF.

6.1 ENGINEERED SAFETY FEATURE MATERIALS

The materials used in the LGS ESF systems have been selected on the basis of an engineering review and evaluation for compatibility with:

a. The normal and accident service conditions of the ESF system

b. The normal and accident environmental conditions associated with the ESF system

c. The maximum expected normal and accident radiation levels to which the ESF system will be subjected

d. Other materials to preclude material interactions that could potentially impair the operation of the ESF systems

The materials selected for the ESF systems are expected to function satisfactorily in their intended service without adverse effects on the service, performance, or operation of any ESF.

6.1.1 METALLIC MATERIALS

In general, metallic materials used in ESF systems comply with the material specifications of ASME Section II. Pressure-retaining materials of the ESF systems comply with the quality requirements of their applicable quality group classification and ASME Section III classification. Adherence to these requirements ensures that materials for the ESF systems are of the highest quality. Where it is not possible to adhere to the ASME material specifications, metallic materials have been selected in compliance with other nationally recognized standards, e.g., ASTM, where practicable, or chosen in compliance with current industry practice.

6.1.1.1 Materials Selection and Fabrication

Metallic materials in ESF systems have been selected for a service life of 40 years, with due consideration of the effects of the service conditions on the properties of the material, as required by ASME Section III, Articles NB-2160, NC-2160, and ND-2160.

Pressure-retaining components are designed with appropriate corrosion allowances, considering the service conditions to which the material will be subjected, in accordance with the general requirements of ASME Section III, Articles NB-3120, NC-3120, and ND-3120.

6.1.1.1.1 NSSS Supplied Components

6.1.1.1.1.1 NSSS Material Specifications

Table 6.1-2 lists the principal pressure-retaining materials and the appropriate material specifications for the NSSS supplied ESF components.

6.1.1.1.1.2 Compatibility of NSSS Construction Materials with Core Cooling Water and Containment Sprays

Section 5.2.3.2.3 discusses compatibility of the reactor coolant with construction materials exposed to the reactor coolant. These same construction materials are found in other ESF components.

6.1.1.1.1.3 Controls for Austenitic Stainless Steel

a. Control of the use of sensitized stainless steel

   Where practicable, stainless steel with a carbon content of less than 0.02% is used.

   Controls to avoid severe sensitization are discussed in Section 5.2.3.4.1.1. Compliance with Regulatory Guide 1.44 is discussed in Section 5.2.3.4.

b. Process controls to minimize exposure to contaminants

   Process controls for austenitic stainless steel and compliance with Regulatory Guide 1.37 are discussed in Section 5.2.3.4.

c. Use of cold-worked austenitic stainless steel

   Cold-worked austenitic stainless steel with a yield strength greater than 90,000 psi is not used in ESF systems.

d. Avoidance of hot-cracking of stainless steel

   Process controls to avoid hot-cracking and compliance with Regulatory Guide 1.31 are discussed in Section 5.2.3.4.

6.1.1.1.2 Non-NSSS Supplied Components

6.1.1.1.2.1 Non-NSSS Material Specifications

Material specifications for the principal pressure-retaining ferritic, austenitic, and nonferrous metals for non-NSSS supplied components are listed in Table 6.1-3.

6.1.1.1.2.2 Compatibility of Non-NSSS Construction Materials with Core Cooling Water and Containment Sprays

Materials that would be exposed to the core cooling water and containment sprays if there is a LOCA are identified in Table 6.1-3. The metallic materials of the ESF systems have been evaluated for their compatibility with core cooling water and containment sprays. Demineralized water, with no additives, is employed for core cooling water and containment sprays. No radiolytic or pyrolytic decomposition of ESF material can occur during accident conditions, and the integrity of the containment or function of any other ESF cannot be affected by the action of core cooling water or containment spray systems.

6.1.1.1.3 Controls for Austenitic Stainless Steel

a. Control of the use of sensitized stainless steel

Design specifications call for ASME material, which is to be supplied in the solution annealed condition. Design specifications prohibit the use of materials that have been exposed to sensitizing temperatures in the range of 800°F to 1500°F unless they are subsequently solution annealed and water quenched or bright annealed. Where practicable, stainless steel with a carbon content of less than 0.02% is used. Compliance with Regulatory Guide 1.44 is discussed in Section 5.2.3.4.

b. Process controls to minimize exposure to contaminants

Design specifications for austenitic stainless steel components require that the material be cleaned using low halide cleaning solutions and that special care be exercised in the fabrication, shipment, storage, and construction to avoid contaminants. Conformance with Regulatory Guide 1.37 is discussed in Section 5.2.3.4.

c. Use of cold-worked austenitic stainless steel

Cold-worked austenitic stainless steels with yield strengths greater than 90,000 psi are not used in ESF systems. Therefore, there are no compatibility problems with core cooling water or the containment sprays.

d. Use of nonmetallic thermal insulation for austenitic stainless steel

Austenitic stainless steel piping inside the primary containment is insulated with nonmetallic thermal insulating materials. These nonmetallic insulating materials are either jacketed or encapsulated in stainless steel to protect against water entry. (Nukon insulation is not required to be jacketed or encapsulated since it meets all G.E. specifications requirements for leachable chlorides, fluorides, sodium and silicates without jacketing.) Leachable concentrations of chlorides, fluorides, sodium, and silicates for all nonmetallic insulation on austenitic stainless steel inside the primary containment meet the positions of Regulatory Guide 1.36. Conformance with Regulatory Guide 1.36 is discussed in Section 5.2.3.2.

e. Avoidance of hot-cracking of stainless steel

Process controls to avoid hot-cracking and compliance with Regulatory Guide 1.31 are discussed in Section 5.2.3.4.

6.1.1.2 Composition, Compatibility, and Stability of Containment and Core Spray Coolants

The HPCI system is supplied from either the CST or the suppression pool. The core spray and LPCI are supplied from the suppression pool only. The containment spray mode of the RHR system, which uses the suppression pool as its source of supply, does not induce radiolytic or pyrolytic decomposition of ESF materials.

The Suppression Pool and CST water chemistry is normally maintained within the following guidelines:

a. pH: 5.3 to 8.6 at 25°C

b. Chloride: <0.5 ppm

c. Conductivity: <10 μmho/cm at 25°C

No corrosion inhibitors or other additives are present in either the CST water or the suppression pool water.

The makeup water for the SLCS (SLCS is not an ESF system but does have a safety-related function and is described in Section 9.3.5), is supplied from the demineralized water storage tank. The makeup water for the CST is supplied from both the demineralized water storage tank and treated liquid radwaste. The makeup water to the suppression pool can be supplied from either the CST or the Refueling Water Storage Tanks. Water supplied to the demineralized water storage tank and the CST is continuously monitored by conductivity measuring devices that initiate alarms and divert flow to waste on high conductivity. Treated liquid radwaste is sampled and analyzed prior to transfer to the CST. This ensures water quality.

Chloride concentration in the SLCS tank is controlled by specifications on the sodium pentaborate and the demineralized water that is added to the tank.

Water quality is maintained in the CST by using the "A" condensate filter/demineralizer to remove impurities from the water. CST water is processed from the CST with the refueling water transfer pump and refueling water transfer system. Water quality is maintained in the suppression pool by a bleed and feed method. Water is drained from the suppression pool with the suppression pool cleanup pump. This water goes to the hotwell for cleanup with the condensate cleanup system. Makeup water comes from the CST.

6.1.2 ORGANIC MATERIALS

Tables 6.1-4 and 6.1-5, respectively, list the significant organic materials and coatings that exist within the primary containment. These materials in ESF components have been evaluated with regard to the expected service conditions and have been found to have no adverse effects on service, performance, or operation.

6.1.2.1 NSSS Supplied Components

The only significant organic materials on NSSS equipment are the protective coatings used on carbon steel components. Most of the equipment is painted with a primer coat of inorganic zinc. The quality assurance requirements in Regulatory Guide 1.54 were not imposed on painting material and paint application, because most equipment was ordered before the issuance of the guide.

Equipment specifications in place at the time of ordering much of the LGS equipment specified a primer coat of inorganic zinc. These coatings are not considered qualified under the guide because the specifications did not require the near white blasted surface needed to meet nuclear qualification.

The total amount of unqualified paint in the containment on NSSS equipment is estimated to be less than 12 kg. Equipment tightly covered with thermal insulation is not included in this total because potential paint debris could not escape to the suppression pool during a LOCA.

6.1.2.2 Non-NSSS Supplied Components

The drywell liner is coated with modified phenolic epoxy, and exposed metal surfaces inside the drywell are coated with an inorganic zinc compound. These coatings have been qualified in accordance with ANSI N101.2. No radiolytic or pyrolytic decomposition or interaction with other ESF materials can occur.

The suppression pool liner is coated with an inorganic zinc compound that has been qualified in accordance with ANSI N101.2. Since the failure mode of inorganic zinc coatings is particulate rather then flaking in nature, this amount is not considered significant. No radiolytic or pyrolytic decomposition or interaction with other ESF materials can occur.

Non-NSSS coating practice and procedures are in conformance with ASTM D3843-93 as discussed in the Quality Assurance Topical Report (NO-AA-10).

6.1.2.3 Insoluble Debris

Insoluble debris formed under DBA conditions inside containment, from unqualified organic paint surfaces and from corrosion products from galvanized steel and zinc paints without qualified organic top coats, will not adversely affect the performance of the LGS RHR or the containment spray systems which take suction from the suppression pool.

a. The total amount of unqualified paint on both non-NSSS and NSSS supplied components has been reviewed and is summarized below. All coatings on non-NSSS equipment within the primary containment are qualified with the following exceptions:

    1. Unqualified primers and mill coats have been applied to pipe, inside the drywell, that has insulation covering the coating. The insulation will prevent any potential debris from entering the suppression pool.

NOTE: The information presented above regarding the quality of unqualified coatings in the primary containment is historical and is based on an original design estimate and does not represent the current unqualified coatings inventory. Unqualified coatings in the primary containment are administratively controlled to ensure that the design basis limits for debris are not exceeded.

    2. Heavy support steel in the drywell is coated with an inorganic zinc coating that passed DBA testing and is fully documented. Unqualified coatings on NSSS equipment have been reviewed and found to be less than 11.7 kg in total, as identified in Table 6.1-6. NSSS equipment has either 2-5 mils coating of inorganic zinc or 3-6 mils organic coating. The major equipment, the recirculation pump motors, have two coats of epoxy paint at 3-6 mils per coat.

b. The following discussion explains why insoluble debris from unqualified organic paints and corrosion products from galvanized steel and zinc paints without qualified organic top coat will not adversely affect the performance of the RHR or containment spray systems.

    As discussed above, the only unqualified organic paints that could reach the suppression pool are on NSSS equipment. Due to the limited supply of NSSS unqualified paint noted in Table 6.1-6, it is not expected that the ECCS suction strainers would be sufficiently plugged so as to impair ECCS or containment spray

performance. The redundant pair of suction strainers on each HPCI and RCIC suction line are sized to provide the design flow rate with each of the strainers 50% plugged and are centered approximately midway between the suppression pool surface and wetwell floor. The RHR and Core Spray strainers are designed based on debris loading and zone of influence of the worst case pipe location. The suction strainers are discussed in detail in Section 6.2.2.2.

Galvanized steel and zinc paints without qualified organic top coats were used for various applications in the primary containment. The demineralized suppression pool water, which is used for containment spray, is maintained near-neutral and the containment atmosphere is inerted during plant operating conditions to reduce the corrosion of exposed galvanized steel or zinc paints to the lowest possible rate. Typical zinc corrosion products produced in a neutral or near-neutral environment are zinc oxide and zinc carbonate. They are loosely adherent fluffy white substances. Because the zinc corrosion products are loosely adherent, they will not plug the ECCS suction strainers, containment spray nozzles, or ECCS pump seal flushing water circuits.

6.1.3 POST-ACCIDENT CHEMISTRY

This section is not applicable to BWR plants.

NOTE: The information presented above regarding the quality of unqualified coatings in the primary containment is historical and is based on an original design estimate and does not represent the current unqualified coatings inventory. Unqualified coatings in the primary containment are administratively controlled to ensure that the design basis limits for debris are not exceeded.

Table 6.1-1

ENGINEERED SAFETY FEATURES DISCUSSED IN
OTHER CHAPTERS OF THE UFSAR

ENGINEERED SAFETY FEATURE	UFSAR LOCATION
Chapter 4	
Control rod velocity limiter	4.6.2
Control rod drive housing supports	4.6
Chapter 5	
Overpressure protection	5.2.2
Main steam line flow restrictors	5.4.4
Main steam line isolation valves	5.4.5
Chapter 7	
Instrumentation and controls for ESF systems	7.3
Chapter 8	
Standby ac power system	8.3.1
Dc power system	8.3.2
Chapter 9	
ESW system	9.2.2
RHRSW system	9.2.3
UHS	9.2.6
CSCWS	9.2.10
Primary containment HVAC	9.4.5
Diesel generator enclosure HVAC	9.4.6
Spray pond pump structure HVAC	9.4.7
Diesel generator systems	9.5.4-9.5.8

Table 6.1-2

NSSS SUPPLIED ENGINEERED SAFETY FEATURES COMPONENT MATERIALS

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
RHR Heat Exchanger			
Shell, head, and channel	Plate	SA516, Grade 70	ASME
Tube sheet	Plate	SA516, Grade 70	ASME
Nozzles	Forging	SA105-II (Unit 2) SA105 (Unit 1)	ASME
Flanges	Forging	SA105-II (Unit 2) SA105 (Unit 1)	ASME
Tubes	Tube	SA249, Type 304L (Unit 2A) SB676, Type AL-6XN (Unit 1 and Unit 2B)	ASME
Bolts	Bar	SA193, Grade B7	ASME
Nuts	Forging	SA194, Grade 2H	ASME
RHR and CS Pumps			
Bowl	Casting	A536, Grade 65-45-12	ASTM
Discharge head shell	Plate	A516, Grade 70	ASTM
Discharge head cover	Plate	A516, Grade 70	ASTM
Suction barrel shell and dished head	Plate	A516, Grade 70	ASTM
Suction flange	Forging	A516, Grade 70	ASTM
Discharge flange	Forging	A350, LF1 or LF2	ASTM
Shaft	Bar	A276, Type 410	ASTM
Impeller	Forging	A296, CA15	ASTM
Studs	Bolting	A193, Grade B7	ASTM
Nuts	Nut	A194, Grade 7	ASTM
Cyclone separator body and cover		A351, Grade CF8M	ASTM

Table 6.1-2 (Cont'd)

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
HPCI Pump			
Case	Casting	A216	ASTM
Bearing housing	Casting	A278	ASTM
Impeller	Casting	A276	ASTM
Shaft	Forging	A276	ASTM
Studs	Forging	A193	ASTM
SLCS Pump			
Fluid cylinder	Forging	A182, F304	ASTM
Cylinder head, valve cover, and stuffing box flange plate	Plate	A285, Grade C	ASTM
Cylinder head extension, valve stop, and stuffing box	Bar	A479, Type 304A	ASTM
Stuffing box gland and plungers	Bar	A564, Type 630	ASTM
Studs	Bar	A193, Grade B7	ASTM
Nuts	Forging	A194, Grade 7	ASTM
SLCS Tank			
Tank	Plate	SA240, Type 304	ASME
Fittings	Forging	SA782, Grade F304	ASME
Pipe	Pipe	SA312, Type 304	ASME
Welds	Electrodes	SFA5.4 & SFA5.9, Types 308,308L, 316,316L	ASME

Table 6.1-2 (Cont'd)

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
Control Rod Velocity Limiter	Casting	A351, Grade CF8	ASTM

Table 6.1-3

PRINCIPAL PRESSURE-RETAINING MATERIALS FOR ESF COMPONENTS

SYSTEM/COMPONENT	MATERIAL
Containment Systems	
Primary containment:	
Containment walls	4000 psi concrete
Drywell and suppression chamber liner[1]	SA285, Grade A
Drywell head[1]	SA516, Grade 60
Penetrations[1]	SA333, Grade 1; A120
Equipment hatches[1]	SA516, Grade 60 or 70; SA537, Grade B
Personnel access hatches[1]	SA516, Grade 60 or 70; SA537, Grade B
Suppression vent downcomers[1]	SA333, Grade 6; SA516, Grade 60
Vacuum relief valve assemblies[1]	SA105
Pressure-retaining bolting[1]	SA194, Grade 4 or 7; SA320, Grade L43; SA540, Grade B23, Class 5
Flued heads	SA105; SA350, Grade LF2; SA182; Grade 316, 316L
Secondary containment:	
Ducts	A526, A527, A36
Dampers	A526, A157, A36

Table 6.1-3 (Cont'd)

SYSTEM/COMPONENT	MATERIAL
Containment heat removal system:	
Equipment(1)	(2)
Piping(1)	SA106, Grade B; SA155, Grade KC-70, Class 1; SA155, Grade C55, Class 1; SA53, Grade B
Valves(1)	SA216, Grade WCB; SA105
Pressure-retaining bolting(1)	SA193, Grade B7; SA194, Grade 2H
Welding material(1)	E70-S2, E7018, E7016
Containment isolation system:	
Valves(1)	SA351, Grade CF8M; SA182, Grade F316; SA352, Grade LCB; SA350, Grade LF2; SA216, Grade WCB; SA182, Grade F316L; SA105
Pressure-retaining bolting(1)	SA193, Grade B7; SA194, Grade 2H
Welding material(1)	E70-S2, E7018, E7016, ER308, ER308L, ER316, E308-16, E308L-16, E316-16
Combustible gas control system:	
Piping	SA106, Grade B; SA155, Grade KC-70, Class 1; SA358, Type 304, Class 1; SA312, Type 304; SA376, Type 304
Valves	SA216, Grade WCB; SA105; SA351, Grade CF8M; SA182, Grade F316

Table 6.1-3 (Cont'd)

SYSTEM/COMPONENT	MATERIAL
Recombiner	SA182, SA240, SA312 or SA376
Blower	SA234 WPB CS
Pressure-retaining bolting	SA193, Grade B7; SA194, Grade 2H
Welding material	E70-S2, E7018, E7016, ER308, ER308L, ER316, E308-16, E308L-16, E316-16
Emergency Core Cooling Systems	
HPCI:	
Equipment(1)	(2)
Piping(1)	SA106, Grade B; SA155, Grade KC-70, Class 1; SA106, Grade C; A155, Grade KC-70 or KC-65 Class II
Valves(1)	SA216, Grade WCB SA105; A216, Grade WCB; A105
Pressure-retaining bolting(1)	A193, Grade B7; SA193, Grade B7; SA194, Grade 2H; A194, Grade 2H
Welding materials(1)	E70-S2, E7018, E7016
Core spray:	
Equipment(1)	(2)
Piping(1)	SA106, Grade B; SA155, Grade KC-70, Class 1; SA106, Grade C; SA312, Type 316L; SA333, Grade 6; A358, Type 304, Class II; A376 or A312, Type 304 SA358, Type 316L, Class 1 with 0.02% C max

Table 6.1-3 (Cont'd)

SYSTEM/COMPONENT	MATERIAL
Valves[1]	SA351, Grade CF8M; SA182, Grade F316; SA352, Grade LCB; SA350, Grade LF2; SA216, Grade WCB; SA105; A216, Grade WCB; A105
Pressure-retaining bolting[1]	SA193, Grade B7; SA194, Grade 2H
Welding materials[1]	E70-S2, E7018, E7016, ER308, ER308L, ER316, E308-16, E308L-16, E316-16
LPCI:	
Equipment[1]	[2]
Piping[1]	SA358, Type 316L, Class 1 with 0.02% C max.; SA358, Type 304, Class 1; SA312, Type 304; SA376, Type 304; SA333, Grade 6; SA106, Grade B; SA155, Grade KC-70, Class 1; SA155, Grade C55, Class 1; SA53, Grade B
Valves[1]	SA351, Grade CF8M; SA182, Grade F316; SA352, Grade LCB; SA350, Grade LF2, SA216, Grade WCB; SA105
Pressure-retaining bolting[1]	SA193, Grade B7; SA194, Grade 2H

Table 6.1-3 (Cont'd)

SYSTEM/COMPONENT	MATERIAL
Welding materials(1)	E70-S2, E7018, E7016, ER308, ER308L, ER316, E308-16, E308L-16, E316-16
ADS:	
Piping(1)	SA106, Grade B
Pressure-retaining bolting(1)	SA193, Grade B7
Welding materials(1)	E70-S2, E7018, E7016
Control Room Habitability System	
Blowers	A283; B26 Alloy 356
Dampers	A36; A526; A527
Ducts	A526; A527; A36
Housing	A36
Fission Product Removal and Control Systems	
SGTS:	
Ducts	A526; A527; A36
Housing	A36
Valves	A36; A516, Type 304
Dampers	A526; A151, 1008/1018
Blowers	A283; A242
Pressure-retaining bolting	A307-74
Welding materials	E70-S3, E70-S6
CREFAS:	
Ducts	A526; A527; A36
Dampers	A526; A527; A36

Table 6.1-3 (Cont'd)

SYSTEM/COMPONENT	MATERIAL
Housing	A36; A240, Type 304; A193-87; A193-88; A276, Type 304; A312, Type 304; A182, Type 304
Blower	A283; B26 Alloy
RERS:	
Ducts	A526; A527; A36
Dampers	A526; A527, A36
Housing	A36; A240, Type 304; A193-87; A193-88; A276, Type 304; A312, Type 304; A182, Type 304
Blower	A283; B26 Alloy 356 A108, Grade 1040; A575; A510, Grade 1010; A569; B209 Alloy 6061; A307

(1) Material may be subjected to containment spray or core cooling water if there is a LOCA.
(2) See Table 6.1-2 for material designations.

Table 6.1-4

ORGANIC MATERIALS WITHIN THE PRIMARY CONTAINMENT

MATERIAL	USE	QUANTITY
Kerite Type FR-HT/ Kerite Type FR	Low voltage electrical power cable jacketing and insulation material	Throughout drywell
EPR/hypalon	Medium voltage electrical power cable jacketing and insulation material	Throughout drywell
XLPE	Instrumentation cable insulation/jacketing material	Throughout drywell
XLPE/neoprene	Instrumentation cable insulation/jacketing material	Throughout drywell
Cross-linked polyolefin/ alkaneimide polymer	Instrumentation coaxial and triaxial insulation/ jacketing material	Throughout drywell
Lube oil	Reactor recirculation pump motor (two motors per unit)	120 gal Unit 1 208 gal Unit 2
Gear lube	Valve motor operators	206 lbs per unit
Silicone rubber	Drywell duct-work and damper gaskets and seals	Throughout drywell
Cross-linked polyethylene/ chlorinated polyethylene	480VAC and 120VAC outage power cable insulation/ jacketing material	Throughout drywell (396 lbs per Unit)
Cross-linked polyethylene (XLPE) and polyvinyl chloride (PVC)	Armored coaxial cable for video signals from drywell video cameras, also armored multiconductor cable for drywell video camera control and audio signals. XLPE is used as insulating material, PVC as jacketing material.	Throughout drywell

Table 6.1-5

COATINGS USED INSIDE THE PRIMARY CONTAINMENT

		COATING TYPE				INITIAL APPLICATION			
CATEGORY	ITEM DESCRIPTION	Special Coating	Mfr Std Coating	Uncoated	GENERIC TYPE[1]	Total Film Thickness	Shop Applied	Field Applied	TOTAL COATING THICKNESS AFTER 40 YEARS
Carbon Steel Liner Plate	Containment dome	X			Modified phenolic epoxy	8-12 mils		X	8-12 mils
	Containment walls	X			Modified phenolic epoxy	8-12 mils		X	8-12 mils
	Containment floor	X			Modified phenolic epoxy	8-12 mils		X	8-12 mils
	Suppression chamber	X			Inorganic zinc	6-8 mils		X	6-8 mils
Structural Steel	Heavy support steel	X			Inorganic zinc	3-5 mils	X		3-5 mils
	Miscellaneous steel	X			Inorganic zinc	3-5 mils	X		3-5 mils
	Handrails and gratings			[3]					
	Exposed surface of steel inserts	X			Inorganic zinc	3-5 mils		X	3-5 mils
	Hatches (equipment and personnel)	X			Modified phenolic epoxy	8-10 mils	X or	X	8-10 mils
Steel Tubes	Downcomer caps	X			Modified phenolic epoxy	8-12 mils	X		8-12 mils
Carbon Steel Pipe	Uninsulated	X			Inorganic zinc silicate	3-5 mils	X		3-5 mils
Valve Operators	2 inches and smaller	X			Inorganic zinc silicate	3±0.5 mils	X		3±0.5 mils

Table 6.1-5 (Cont'd)

CATEGORY	ITEM DESCRIPTION	COATING TYPE: Special Coating	COATING TYPE: Mfr Std Coating	COATING TYPE: Uncoated	GENERIC TYPE[1]	INITIAL APPLICATION: Total Film Thickness	INITIAL APPLICATION: Shop Applied	INITIAL APPLICATION: Field Applied	TOTAL COATING THICKNESS AFTER 40 YEARS
	2½ inches and larger	X			Epoxy polyamide or modified epoxy phenolic inorganic zinc silicate	4.5 mils (total)	X		4.5 mils total
Valves[7]	2 inches and smaller	X			Inorganic zinc silicate	3-5 mils	X		3-5 mils
Pipe Hangers	2½ inches and larger	X			Inorganic zinc	3 mils	X		3 mils
	2 inches and smaller	X			Inorganic zinc	3 mils	X		3 mils
Mechanical Equipment	Reactor recirculation pump			[5]					
	Reactor recirculation pump motor	X			Modified phenolic epoxy	8-12 mils		X	16-20 mils
	Fan cabinet (carbon steel)		X		Epoxy polyamide or modified phenolic epoxy	7 mils (minimum)	X		7 mils (minimum)
	Fan housing		X		Primer: inorganic zinc; finish: Phenoline 305	7 mils		X	11 mils
	HVAC ducts			[3]					
Concrete[2] and Masonry	RPV concrete pedestal	X			Sand-filled epoxy surfacing	65-250 mils		X	65-250 mils

Table 6.1-5 (Cont'd)

CATEGORY	ITEM DESCRIPTION	COATING TYPE: Special Coating	COATING TYPE: Mfr Std Coating	COATING TYPE: Uncoated	GENERIC TYPE	INITIAL APPLICATION: Total Film Thickness	INITIAL APPLICATION: Shop Applied	INITIAL APPLICATION: Field Applied	TOTAL COATING THICKNESS AFTER 40 YEARS
Electrical Equipment	Terminal and junction boxes[8]				[4]				
	Cable trays			[4]					
	Conduits			[4]					
	Cables			[4]					

(1) Generic coating systems acceptable for containment use have been selected from suppliers who are prequalified to project standards and test criteria. Systems other than those listed are acceptable for specific units based on analysis of requirements.
(2) Concrete coating limited to minimum area required for decontamination purposes.
(3) No coating needed since material is galvanized.
(4) No coating needed since aluminum is used.
(5) No coating needed since material is stainless steel.
(6) Cables are insulated (EPR insulation and polyolefin insulation).
(7) Exterior coating system is identical to the pipe system in which the valve is installed.
(8) Bakelite is used inside terminal boxes.

Table 6.1-6

ESTIMATED WEIGHT OF UNQUALIFIED PAINT
ON NSSS CONTAINMENT EQUIPMENT

COMPONENT	WEIGHT (lbs)
Nuclear Boiler System	3.8
Reactor Recirculation System	6.9
CRD System	6.7
In-Vessel Service Equipment	<0.1
Under-Vessel Servicing Equipment	6.0
RWCU System	<0.4
RWCU Filter/Demineralizer System	1.9
TOTAL	25.8
	(11.7 kg)

NOTE: The information presented above regarding the quality of unqualified coatings in the primary containment is historical and is based on an original design estimate and does not present the current unqualified coatings inventory. Unqualified coatings in the primary containment are administratively controlled to ensure that the design basis limits for debris are not exceeded.

6.2 CONTAINMENT SYSTEMS

6.2.1 CONTAINMENT FUNCTIONAL DESIGN

6.2.1.1 Pressure-Suppression Containment

6.2.1.1.1 Design Bases

The pressure-suppression containment system is designed to have the following functional capabilities:

a. The containment has the capability to maintain its functional integrity during and following the peak transient pressures and temperatures which would occur following any postulated LOCA. The design basis LOCA includes the worst single active failure (which leads to maximum containment pressure and temperature) and is further postulated to occur simultaneously with LOOP and a SSE. A discussion of the LOCA events is contained in Section 6.2.1.1.3.3.

b. The containment, in combination with other accident mitigation systems, limits fission product leakage during and following the postulated DBA to values less than leakage rates that would result in offsite doses greater than those set forth in 10CFR50.67.

c. The containment system can withstand coincident fluid jet forces associated with the flow from the postulated rupture of any pipe within the containment.

d. The containment is designed to accommodate flooding up to the refueling floor elevation to permit removal of fuel assemblies from the reactor core after the postulated LOCA.

e. The containment system is protected from and designed to withstand missiles from internal sources and excessive motion of pipes that could directly or indirectly endanger the integrity of the containment.

f. The containment system provides the means to channel the flow from postulated pipe ruptures in the drywell to the pressure-suppression pool.

g. The containment system is designed to allow for periodically conducted tests at the peak pressure calculated to result from the postulated DBA in order to confirm the leak-tight integrity of the containment and its penetrations.

h. The containment system is provided with pressure relief capability for use following a postulated accident accompanied by the loss of containment heat removal capability when high containment radiation levels do not exist.

6.2.1.1.2 Design Features

Section 3.8 describes the design features of the containment structure and internal structures. Figures 3.8-1 through 3.8-8 show the general arrangement of the containment and internal structures.

6.2.1.1.2.1 Protection from Dynamic Effects

The containment structure and ESF system functions are protected from dynamic effects of postulated accidents as described in Sections 3.5 and 3.6.

6.2.1.1.2.2 Codes, Standards, and Guides

Table 3.8-1 lists the applicable codes, standards, guides, and specifications for the containment structure and internal structures.

6.2.1.1.2.3 Functional Capability Tests

The functional capability of the containment structure is verified by:

a. Pressure testing the containment structure to 1.15 times the design pressure as required by Regulatory Guide 1.18 (Rev 1), and

b. Leak rate testing the containment structure to the design accident pressure as required by 10CFR50, Appendix J.

Refer to Sections 3.8.1.7, 3.8.2.7, 3.8.3.7, and 6.2.6 for a description of the structural integrity test and the integrated leak rate test.

6.2.1.1.2.4 External Pressure Loading Conditions

The containment structure is designed for an external to internal differential pressure of 5 psid.

6.2.1.1.2.5 Trapped Water that Cannot Return to Containment Sump

Not applicable to pressure-suppression containment.

6.2.1.1.2.6 Containment and Subcompartment Atmosphere

Sections 9.4.5 and 3.11 describe the pressure, temperature, and humidity limits within which all the Class 1E equipment located inside the containment structure is qualified to operate. Section 9.4.5 also describes the system that maintains these limits during normal plant operation.

6.2.1.1.3 Design Evaluation

The information presented in this section is historical and is based on the original design basis conditions and does not represent current plant conditions or current methodology used to analyze the containment response following a LOCA. The methods and results that bound current plant conditions are described in Section 6.2.1.8. Table 6.2-4A provides the plant conditions used for the current analysis. The results presented here, however, do provide the basis for determining which events are limiting. They also demonstrate the relationship of the containment response to different input assumptions.

The limiting cases were reanalyzed in Section 6.2.1.8 for the current plant conditions using the current analysis methodology. The current reactor power and RPV pressure have been increased over the original design basis conditions. The short-term containment pressure and pool swell load response is dependent on the initial reactor pressure. The double-ended guillotine recirculation line break was reanalyzed for the current plant conditions because this break results in the limiting peak containment pressures and pool swell loads. The long-term containment pool temperature response is dependent on the initial reactor power. Case C (loss of offsite power with no containment spray)

was reanalyzed for the current plant conditions because this case results in the highest suppression pool temperature. The intermediate and small line breaks result in the highest peak drywell temperature however, these breaks were not reanalyzed at the current operating conditions. As described in Section 6.2.1.1.3.3.5.4, the limiting drywell temperature response is determined by steam enthalpy properties and is not sensitive to the increase in reactor operating pressure or power level. The main steam line break was not reanalyzed for the current plant operating conditions. The containment pressure and pool swell load response for the main steam break is bounded by the recirculation line break results. The drywell temperature response for the main steam line break is bounded by the small and intermediate line break results.

6.2.1.1.3.1 Summary Evaluation

The key design values and the maximum calculated accident values of these parameters for the pressure-suppression containment are as follows:

Parameter	Design Value	Calculated Accident Value
Drywell design pressure	55 psig	44.0 psig*
Drywell design temperature	340°F	340°F
Suppression chamber design pressure	55 psig	30.57 psig*
Suppression chamber design temperature	220°F	212.5°F*
Peak drywell deck downward differential pressure	30 psid	25.995 psid*

*NOTE: The calculated values presented in this table are based on the original design basis conditions. The calculated results for current plant conditions as shown in Table 6.2-5A.

The foregoing design and maximum calculated accident parameters are not determined from a single accident event but from an envelope of accident conditions. As a result, there is no single DBA for this containment system.

A maximum drywell and suppression chamber pressure occurs near the end of the blowdown phase of a LOCA. Approximately the same peak pressure occurs for the break of either a recirculation line or a main steam line. Both accidents are evaluated.

The most severe drywell temperature condition (peak temperature and duration) occurs for a small primary system rupture above the reactor water level that results in the blowdown of reactor steam to the drywell (small steam break). In order to demonstrate that breaks smaller than the rupture of the largest primary system pipe do not exceed the containment design parameters, the containment system responses to an intermediate size liquid break and a small size steam break are evaluated. The results show that the containment design conditions are not exceeded for these smaller break sizes.

All of the analyses assume that the primary system and containment are initially at the maximum normal operating conditions. References are provided that describe relevant experimental verification of the analytical models used to evaluate the containment system response.

6.2.1.1.3.2 Containment Design Parameters

Table 6.2-1 provides a listing of the key design parameters of the primary containment system including the design characteristics of the drywell, suppression pool, and the pressure-suppression vent system.

A diagram showing the geometric configuration of the downcomer is shown in Figure 6.2-1.

As described in Section 9.4.5, vacuum relief valve assemblies are provided to limit the degree to which suppression chamber pressure can exceed drywell pressure, and to prevent the drywell design negative pressure from being exceeded as described in Section 6.2.1.1.4. There are four assemblies, each mounted on the side of a downcomer on the flanges shown in Figure 6.2-1. Each assembly consists of two vacuum relief valves mounted in series. A schematic diagram of a single vacuum relief valve is shown in Figure 9.4-6. The required number and size of the vacuum relief valve assemblies was determined as described in Section 6.2.1.1.3.3.1.5.

Table 6.2-2 provides the performance parameters of the related ESF systems that supplement the design conditions of Table 6.2-1 for containment cooling purposes during postblowdown long-term accident operation. Performance parameters given include those applicable to full capacity operation and those applicable to the conservatively reduced capacities assumed for containment analyses.

6.2.1.1.3.2.1 Downcomer Vent Flow Loss Coefficient

The downcomer vent flow loss coefficient, K, is defined by:

$$K = \frac{\Delta P}{\rho V^2 / 2g_c} \qquad \text{(EQ. 6.2-1)}$$

and is calculated from standard references (References 6.2-1 and 6.2-2). In the above equation ΔP is the total pressure drop across the downcomer, ρ is the fluid density, and V is the flow velocity.

The total downcomer flow loss coefficient is modeled as the sum of three contributors: an entrance loss (K_1), a length loss (K_2), and an exit loss (K_3). The entrance loss coefficient (K_1) is calculated from Reference 6.2-1 using a hooded duct entrance geometry that very nearly approximates the standoff jet deflector shield feature of the LGS downcomer and (K_1) is calculated to be 0.90. The length loss (K_2) is represented by a resistance coefficient (fL/D) loss with (f) calculated from Reference 6.2-2 and (K_2) calculated to be 0.33. The exit loss coefficient (K_3) is calculated to be 1.0 from Reference 6.2-2, which when combined with the above yields an overall loss coefficient value of K = 2.23.

6.2.1.1.3.3 Accident Response Analysis

The containment functional evaluation is based on the consideration of several postulated accident conditions resulting in the release of reactor coolant to the containment. These accidents include the following:

a. An instantaneous guillotine rupture of a recirculation line

b. An instantaneous guillotine rupture of a main steam line

c. An intermediate size liquid line rupture

d. A small size steam line rupture

Energy release from these accidents is discussed in Section 6.2.1.3.

6.2.1.1.3.3.1 Recirculation Line Break

NOTE: The information presented in this section is historical and is based on the original design basis conditions. See the explanation at the beginning of Section 6.2.1.1.3.

Immediately following the rupture of the recirculation line, the flow out both sides of the break is limited to the maximum allowed by critical flow considerations. The total effective flow area is given in Figure 6.2-2. In the side adjacent to the suction nozzle, the flow corresponds to critical flow in the pipe cross-section. In the side adjacent to the injection nozzle, the flow corresponds to critical flow at the ten jet pump nozzles associated with the broken loop. Table 6.2-3 provides a summary of the break areas.

6.2.1.1.3.3.1.1 Assumptions for Reactor Blowdown

The response of the RCS during the blowdown period of the accident is analyzed using the following assumptions:

a. The initial conditions for the recirculation line break accident are such that the system energy is maximized and the system mass is minimized. That is:

   1. The reactor is operating at 105% of rated steam flow. This maximizes the postaccident decay heat.

   2. The service water temperature is at the maximum normal value.

   3. The suppression pool mass is at the low water level.

   4. The suppression pool temperature is at the maximum normal value.

b. The recirculation line is considered to be severed instantly. This results in the most rapid coolant loss and depressurization of the vessel, with coolant being discharged from both ends of the break.

c. Reactor power generation ceases at the time of accident initiation because of void formation in the core region. Scram occurs in less than one second from receipt of

the high drywell pressure signal. The difference in time between accident initiation and shutdown is negligible.

d. The vessel depressurization flow rates are calculated using Moody's critical flow model (Reference 6.2-3) assuming "liquid only" outflow, since this assumption maximizes the energy release to the drywell. "Liquid only" outflow implies that all vapor formed in the RPV by bulk flashing rises to the surface instead of being entrained in the existing flow. Actually, some of the vapor would be entrained in the break flow which would significantly reduce the RPV discharge flow rates. Further, Moody's critical flow model which assumes annular, isentropic flow, thermodynamic phase equilibrium, and maximized slip ratio, accurately predicts vessel outflows through small diameter orifices. Actual rates through larger flow areas, however, are less than the model indicates because of the effects of a near homogeneous two-phase flow pattern and phase nonequilibrium. These effects are conservatively neglected in the analysis.

e. The core decay heat and the sensible heat released in cooling the fuel to initial average coolant temperature are included in the RPV depressurization calculation. The rate of energy release is calculated using a conservatively high heat transfer coefficient throughout the depressurization period. The resulting high energy release rate causes the RPV to maintain nearly rated pressure for approximately 20 seconds. The high RPV pressure increases the calculated blowdown flow rates, which is again conservative for analysis purposes. The sensible energy of the fuel stored at temperatures below the initial average coolant temperature is released to the vessel fluid along with the stored energy in the vessel and internals as vessel fluid temperatures decrease during the remainder of the transient calculation.

f. The MSIVs start closing 0.5 seconds after the accident. They are fully closed in the shortest possible time of three seconds following closure initiation. In actuality, the closure signal for the MSIVs occurs from low-low-low reactor water level (level 1), so the valves do not receive a signal to close for greater than four seconds, and the closing time may be as long as five seconds. By assuming rapid closure of these valves, the RPV is maintained at a high pressure, which maximizes the calculated discharge of high energy water into the drywell.

g. Reactor feedwater flow is assumed to stop instantaneously at time t = zero. Since feedwater flow tends to depressurize the RPV, thereby reducing the discharge of steam and water into the drywell, this assumption is conservative for the short-term analysis.

h. A complete LOOP occurs simultaneously with the pipe break. This condition results in the loss of power conversion system equipment and also requires that all vital systems for long-term cooling be supported by onsite power supplies.

6.2.1.1.3.3.1.2 Assumptions for Containment Pressurization

The pressure response of the containment during the blowdown period of the accident is analyzed using the following assumptions:

a. Thermodynamic equilibrium exists in the drywell and suppression chamber. The analysis assumes complete mixing and the error introduced by this assumption is negligible.

b. The fluid flowing through the downcomers is formed from a homogeneous mixture of the fluid in the drywell. The use of this assumption results in complete carryover of the drywell air and a higher positive flow rate of liquid droplets that conservatively minimizes downcomer pressure losses.

c. The fluid flow in the downcomers is compressible except for the liquid phase.

d. No heat loss occurs from the gases inside the primary containment. Actually condensation of some steam on the drywell surfaces would occur.

6.2.1.1.3.3.1.3 Assumptions for Long-Term Cooling

Following the blowdown period, the ECCS (discussed in Section 6.3) provides water for core flooding, containment spray, and long-term decay heat removal. The containment pressure and temperature responses during this period are analyzed using the following assumptions:

a. The RHR pumps are used to flood the core within 600 seconds after the accident (LPCI mode).

b. After 600 seconds, flow from one RHR pump can be diverted from the RPV to the containment cooling. This is a manual operation. Containment spray need not be actuated at all to keep the containment pressure below the containment design pressure. Analytically, no credit may be assumed for containment cooling earlier than 600 seconds after the accident and cooling is assumed to begin at 600 seconds. However, containment cooling will be initiated in accordance with plant emergency operating procedures based on plant conditions.

c. The effects of decay energy, stored energy, sensible energy, energy added by ECCS pumps, and energy from the metal-water reaction on the suppression pool temperature are considered.

d. The suppression pool is the only heat sink available in the containment system prior to initiation of the RHRSW system.

e. After 600 seconds, the RHR heat exchangers are activated to remove energy from the containment via the RHR suppression pool cooling mode in conjunction with RHRSW system.

The performance of the ECCS equipment during the long-term cooling period is evaluated in Section 6.2.1.1.3.3.1.6 for each of the three cases of interest.

6.2.1.1.3.3.1.4 Initial Conditions for Accident Analyses

Table 6.2-4 provides the initial RCS and containment conditions used in all the accident response evaluations. The tabulation includes parameters for the reactor, the drywell, and the suppression chamber.

Table 6.2-3 provides the initial conditions and numerical values assumed for the recirculation line break accident as well as the sources of energy considered prior to the postulated pipe rupture. The assumed conditions for the reactor blowdown are also provided.

The mass and energy release sources and rates for the containment response analyses are given in Section 6.2.1.3.

6.2.1.1.3.3.1.5 Short-Term Accident Response

The calculated containment pressure and temperature responses for the recirculation line break are shown in Figures 6.2-3 and 6.2-4, respectively.

The suppression chamber is pressurized by the carryover of noncondensables from the drywell and by heatup of the suppression pool. As the vapor formed in the drywell is condensed in the suppression pool, the temperature of the suppression pool water peaks and the suppression chamber pressure stabilizes. The drywell pressure stabilizes at a slightly higher pressure, the difference being equal to the downcomer submergence. During the RPV depressurization phase, most of the noncondensable gases initially in the drywell are forced into the suppression chamber. However, following depressurization the noncondensables redistribute between the drywell and suppression chamber via the vacuum relief valve system. This redistribution takes place as steam in the drywell is condensed by the relatively cool ECCS water which is beginning to cascade from the break causing the drywell pressure to decrease.

In the early design phase of the plant, conservative hand calculations were performed to establish the minimum number of operating vacuum breaker assemblies required. Two cases leading to potentially rapid drywell depressurization were considered for wetwell-to-drywell vacuum breaker sizing:

a. The inadvertent actuation of one drywell spray train (10,000 gpm @ 90°F, assumed)

b. Maximum ECCS spillage (7750 lb_m/sec @ 140°F exit temperature, assumed) during the depressurization phase of the large recirculation outlet line break LOCA

Each case was to determine the number of vacuum breaker valve assemblies required to ensure that the maximum differential pressure across the diaphragm slab in the upward direction does not exceed allowables. For the analyses, a conservatively low 3 psid across the diaphragm slab was used, well below the present design allowable of 20 psid upward.

In the analyses done for both cases, a. and b., it was conservatively assumed that all noncondensables have been removed to the wetwell vapor region prior to drywell depressurization. In addition to this, for the Case a. accident a 100% spray efficiency, together with a drywell temperature of 273°F, combine with the assumptions regarding spray rate and inlet temperature noted above, to render this analysis conservative. This results in a net drywell energy removal rate of approximately 321,000 Btu/sec.

The analysis for Case b. assumes a drywell saturation temperature of 262°F, an ECCS drop fall height of 42 feet, an average drop diameter of 1 inch (for calculating condensation heat transfer to the falling ECCS spillage), and an average heat transfer coefficient of 2300 Btu/hr-ft^2-°F (for calculating heat transfer from the drywell vapor region to the pool of ECCS spillage collected on the drywell floor). These considerations, combined with the assumptions regarding noncondensables and ECCS spillage rate and temperature, yield a net drywell energy removal rate of approximately 318,000 Btu/sec for an ECCS spillage spray effectiveness of 34%.

The two cases yield drywell energy removal rates of the same order of magnitude, with the inadvertent containment spray case being the larger, 321,000 Btu/sec. As such, this inadvertent spray actuation case controls the vacuum breaker sizing. The hand calculation established that three operable vacuum breaker valve assemblies each having a seat inner diameter of 18 inches, were required.

Subsequently, the inadvertent spray actuation (ISA) case was reanalyzed using a dynamic computer model, described in Section 6.2.1.1.4. This analysis was performed to verify that vacuum relief valve capacity is sufficient to prevent drywell depressurization below the design value of -5 psig. For purposes of vacuum relief valve sizing, primary containment negative pressure is more limiting than diaphragm slab differential pressure. The computer model conservatively approximated vacuum relief valve flow characteristics based on actual test data. Additional conservative assumptions were made to maximize the negative pressure in the drywell. The results confirmed that two operable vacuum relief valve assemblies were sufficient to prevent excessive drywell depressurization, as discussed in Section 6.2.1.1.4.

The ECCS supplies sufficient core cooling water to control core heatup and limit metal-water reaction to less than 1%. After the RPV is flooded to the height of the jet pump nozzles, the excess flow discharges through the recirculation line break into the drywell. This flow of water (steam flow is negligible), in the form of hot water which flows into the suppression chamber via the downcomers, transports the core decay heat out of the RPV through the broken recirculation line. This flow provides a heat sink for the drywell atmosphere, and thereby causes the drywell to depressurize.

Table 6.2-5 provides the peak pressure, temperature, and time parameters for the recirculation line break as predicted for the conditions of Table 6.2-4 and as correspond with Figures 6.2-3 and 6.2-4. Figure 6.2-5 shows the time-dependent response of the drywell floor (diaphragm slab) differential pressure.

During the blowdown period of the LOCA, the downcomers conduct the flow of the steam-water gas mixture in the drywell to the suppression pool for condensation of the steam. The pressure differential between the drywell and suppression pool controls this flow. Figure 6.2-6 provides the mass flow versus time relationship through the downcomers for this accident.

6.2.1.1.3.3.1.6 Long-Term Accident Responses

NOTE: The information in this Section is based on the original design basis conditions. Only case C (Loss of Offsite Power with no Containment Spray) was reanalyzed for the current plant conditions because this case results in the highest suppression pool temperature. The methods and results that bound current plant conditions are described in Section 6.2.1.8.

In order to assess the adequacy of the containment following the initial blowdown transient, an analysis was made of the long-term temperature and pressure responses following the accident for each of three cases. The results of these analyses are described below. The analyses assumptions

for these cases are those discussed in Section 6.2.1.1.3.3.1.3. The initial pressure response of the containment (the first 600 seconds after the break) is the same for each case.

CASE A: All ECCS equipment operating - with containment spray

This case assumes that offsite ac power is available to operate all cooling systems. During the first 600 seconds following pipe break, the HPCI, core spray, and all LPCI pumps are assumed to operate. All flow is injected directly into the reactor vessel.

After 600 seconds, RHRSW pumps are started and both RHR heat exchangers are aligned to remove energy from the containment. During this mode of operation the flow from two RHR pumps is routed through their associated RHR heat exchanger where it is cooled before being discharged into the drywell and suppression chamber spray headers. The CS system continues operation during this mode with both loops injecting into the vessel.

The containment pressure response to this set of conditions is shown as curve A in Figure 6.2-7. The corresponding drywell and suppression pool temperature responses are shown as curve A in Figures 6.2-8 and 6.2-9. After the initial blowdown and subsequent depressurization due to CS and LPCI core flooding, energy addition due to core decay heat results in a gradual pressure and temperature rise in the containment.

When the energy removal rate of the RHR system equals the energy addition rate from the decay heat, the containment pressure and temperature reach a second peak value and decrease gradually. Table 6.2-6 summarizes the equipment operation, the peak long-term containment pressure following the initial blowdown peak, and the peak suppression pool temperature.

CASE B: LOOP - with containment spray

This case assumes that no offsite power is available following the accident with only minimum diesel power. The RHR system and the drywell and suppression chamber sprays are in operation after 600 seconds. During this mode of operation the RHR system flows through only one RHR heat exchanger and is directed to the spray headers while one LPCI pump and one CS loop continue to inject water into the vessel. The containment pressure response to this set of conditions is shown as curve B in Figure 6.2-7. The corresponding drywell and suppression pool temperature responses are shown as curve B in Figures 6.2-8 and 6.2-9. A summary of this case is given in Table 6.2-6.

CASE C: LOOP - no containment spray

This case assumes that no offsite power is available following the accident with only minimum diesel power. After 600 seconds the sprays may be manually activated to further reduce containment pressure if desired. This analysis assumes that the drywell and suppression chamber sprays are not activated.

After 600 seconds, the RHRSW system and one RHR heat exchanger are activated to remove energy from the containment. The flow from one RHR pump is cooled by the RHR heat exchanger before being discharged into the reactor vessel while another RHR pump and one CS loop inject directly into the vessel.

The containment pressure response to this set of conditions is shown as curve C in Figure 6.2-7. The corresponding drywell and suppression pool temperature responses are shown as curve C in Figures 6.2-8 and 6.2-9. A summary of this case is given in Table 6.2-6.

When comparing the "spray" case B with the "no spray" case C, the same RHR heat exchanger duty is obtained since the suppression pool temperature response is approximately the same, as shown in Figure 6.2-9. Thus, the same amount of energy is removed from the pool whether the exit flow from the RHR heat exchanger is injected into the reactor vessel, into the suppression pool, or into the drywell as spray. However, the peak containment pressure is higher for the "no spray" case, but the pressure is still much less than the containment design pressure.

Figure 6.2-10 shows the rate at which the RHR system heat exchanger removes heat from the suppression pool following a LOCA (Section 6.2.2 describes the containment cooling mode of the RHR system). The heat removal rate is shown for the three cases of interest (A, B and C). The first assumes that all the ECCS equipment is available, in addition to both RHR heat exchangers and their associated RHRSW pumps. The second and third cases are for the very degraded minimum cooling condition that limits the heat removal capacity to one heat exchanger. For all cases, it is conservatively assumed that at the time of the accident the RHRSW is at its maximum design temperature, as defined in Table 6.2-2.

6.2.1.1.3.3.1.7 Energy Balance During Accident

In order to establish an energy distribution in the containment as a function of time (short-term or long-term) for this accident, the following energy sources and sinks are required:

a. Blowdown energy release rates

b. Decay heat rate and fuel relaxation sensible energy

c. Sensible heat rate (vessel and internals)

d. Pump heat rate

e. Heat removal rate from suppression pool (Figure 6.2-10)

f. Metal-water reaction heat rate

Items a, b, c, d, and f are discussed in Section 6.2.1.3. A complete energy balance for the recirculation line break accident is given in Table 6.2-7 for the reactor system, the containment and the containment cooling systems at time zero, at the time of peak drywell pressure, at the end of reactor blowdown, and at the time of the long-term peak pressure in the containment.

6.2.1.1.3.3.1.8 Chronology of Accident Events

A complete description of the containment response to the recirculation line break has been given in Sections 6.2.1.1.3.3.1.5 through 6.2.1.1.3.3.1.7. Results for this accident are shown in Figures 6.2-3 through 6.2-10. A chronological sequence of events for this accident from time zero is provided in Table 6.2-8.

6.2.1.1.3.3.2 Main Steam Line Break

NOTE: The information in this section for the main steam line break is based on the original design basis conditions. See explanation at the beginning of Section 6.2.1.1.3. The main steam line break was not reanalyzed for current plant conditions. The containment pressure and pool swell load response for the main steam line break is bounded by the small and intermediate line break results and remains unchanged by the change in plant operating conditions. The information presented in this section reasonably represents the general characteristics of the main steam line break analysis.

The assumed sudden rupture of a main steam line between the reactor vessel and the flow restricting orifice results in the maximum flow rate of primary system fluid and energy to the drywell. This would in turn result in the maximum drywell differential pressure. The sequence of events immediately following the rupture of a main steam line between the reactor vessel and the flow restricting orifice has been determined. The flow on both sides of the break accelerates to the maximum allowed by the critical flow considerations. On the side adjacent to the reactor vessel, the flow corresponds to critical flow in the steam line break area. Blowdown through the other side of the break occurs because the steam lines are all interconnected at a point upstream of the turbine by the bypass header. This interconnection allows primary system fluid to flow from the three unbroken steam lines through the header and back into the drywell via the broken line. Flow is limited by critical flow in the steam line flow restricting orifice. The total effective flow area is given in Figure 6.2-11. The MSIVs are assumed to start closing at 0.5 seconds and are fully closed in the maximum time of 5 seconds following closure initiation. By assuming slow closure of these valves, a large effective break area is maintained for a longer period of time. The peak drywell floor differential pressure occurs before the reduction in effective break area and is therefore insensitive to any additional delay in closure of the isolation valves. An MSIV closure time longer than the 5 second maximum closure time would increase the break flow rate from the inventory side of the break (break to MSIV valve). However, this is offset by a lower flow rate from the vessel side of the break due to a decreasing vessel pressure. The net effect on the peak drywell pressure would be on the order of 1 psi. Section 6.2.1.3 provides the mass and energy release rates.

Immediately following the break, the total steam flow rate leaving the vessel exceeds the steam generation rate in the core, causing an initial depressurization of the RPV. Void formation in the reactor vessel water causes a rapid rise in the water level. It is conservatively assumed that the water level reaches the vessel steam nozzles one second after the break occurs. The water level rise time of one second is the minimum that can occur under any reactor operating condition. From that time on, a two-phase mixture is discharged from the break. During the first second of the blowdown, the blowdown flow consists of saturated steam. This steam enters the containment in a superheated condition at approximately 330°F.

Figures 6.2-12 and 6.2-13 show the pressure and temperature responses of the drywell and suppression chamber during the primary system blowdown phase of the steam line break accident.

Figure 6.2-13 shows that the drywell atmosphere temperature approaches a peak after approximately one second of primary system steam blowdown. At that time, the water level in the vessel reaches the steam line nozzle elevation and the blowdown flow changes to a two-phase mixture. This increased flow causes a more rapid drywell pressure rise. The peak differential pressure occurs shortly after the vent clearing transient. As the blowdown proceeds, the primary system pressure and fluid inventory decrease and this results in reduced break flow rates. As a consequence, the flow rate in the downcomers and the differential pressure between the drywell and suppression chamber begin to decrease.

Table 6.2-5 presents the peak pressures, peak temperatures and corresponding times of this accident as compared to the recirculation line break.

After the primary system pressure has dropped to the drywell pressure, the blowdown is over. At this time the drywell contains saturated steam, and the drywell and suppression chamber pressures stabilize. The pressure difference corresponds to the hydrostatic pressure of downcomer submergence.

The drywell and suppression pool remain in this equilibrium condition until the reactor vessel refloods. During this period, the ECCS pumps inject cooling water from the suppression pool into the reactor. This injection of water eventually floods the reactor vessel to the level of the steam line nozzles and the ECCS flow spills into the drywell. The water spillage condenses the steam in the drywell and thus reduces the drywell pressure. As soon as the drywell pressure drops below the suppression chamber pressure, the primary containment vacuum breakers open and noncondensable gases from the suppression chamber flow back into the drywell until the pressures in the two regions equalize.

6.2.1.1.3.3.3 Hot Standby Accident Analysis

This section is not applicable to BWR 4.

6.2.1.1.3.3.4 Intermediate Size Breaks

The information presented in this section for the intermediate size break is based on the original design basis conditions. As described in Section 6.2.1.1.3.5.4, the limiting drywell temperature response is determined by steam enthalpy properties and is not sensitive to the change in plant operating conditions. These breaks were not reanalyzed at the current operating conditions. The information presented in this section reasonably represents the general characteristics of the intermediate size break analysis. (See explanation at beginning of Section 6.2.1.1.3.)

An intermediate size break is analyzed as part of the containment performance evaluation to demonstrate that the consequences are no more severe than from a rupture of the largest primary system pipe. This classification covers those breaks for which the blowdown results in reactor depressurization and operation of the ECCS. This section describes the consequences to the containment of a 0.1 ft^2 break below the RPV water level. This break area is chosen as being representative of the intermediate size break area range. These breaks can involve either reactor steam or liquid blowdown.

The 0.1 ft^2 break was assumed to occur below the vessel water level to maximize the mass and energy release rates to the drywell. Based on the Moody slip flow model for the same-sized break, the total mass and energy release is greater for liquid break than for a steam break.

The initial reactor and containment conditions used in the analysis were the same as those used for the design basis accident as presented in Tables 6.2-1 and 6.2-4 and discussed in Section 6.2.1.1.3.3.1.

Following the 0.1 ft^2 break, the drywell pressure increases at approximately 1 psi/sec. This drywell pressure transient is sufficiently slow so that the dynamic effect of the water in the downcomers is negligible and the downcomers clear when the drywell-to-suppression chamber differential pressure is equal to the downcomer submergence hydrostatic pressure.

Figures 6.2-14 and 6.2-15 show the short-term drywell and suppression chamber pressure and temperature response, respectively. The ECCS response is discussed in Section 6.3. Approximately 5 seconds after the 0.1 ft^2 break occurs, air, steam, and water start to flow from the drywell to the suppression pool; the steam is condensed and the air enters the suppression chamber free space. The continual purging of drywell air to the suppression chamber results in a gradual pressurization of both the wetwell and drywell. The containment continues to gradually increase in pressure due to the long-term pool heatup.

The ECCS is initiated as a result of the 0.1 ft^2 break as described in Section 7.3.1 and Table 6.3-2 and provides emergency cooling of the core. The operation of these systems is such that the reactor is depressurized in approximately 600 seconds. This terminates the blowdown phase of the transient.

In addition, the suppression pool temperature at the end of blowdown is the same as that of the recirculation line break because essentially the same amount of primary system energy is released during the blowdown. After reactor depressurization and reflood, water from the ECCS begins to flow out the break. This flow condenses the drywell steam and eventually causes the drywell and suppression chamber pressures to equalize in the same manner as happens following a recirculation line break.

The subsequent long-term suppression pool and containment heatup transient is essentially the same as for the recirculation line break.

In comparison to the short-term drywell pressure and temperature responses for a large recirculation line break, it can be concluded that the consequences of an intermediate size break are less severe than those of a recirculation line break. The comparison of the short-term wetwell pressure and temperature responses shows that the intermediate size break is not significantly more severe than the large recirculation line break.

6.2.1.1.3.3.5 Small Size Breaks

The information presented in this section for the small size break is based on the original design basis conditions. As described in Section 6.2.1.1.3.3.5.4, the limiting drywell temperature response is determined by steam enthalpy properties and is not sensitive to the change in plant operating conditions. These breaks were not reanalyzed at the current operating conditions. The information presented in this section reasonably represents the general characteristics of the small size break analysis. (See explanation at beginning of Section 6.2.1.1.3.)

6.2.1.1.3.3.5.1 Reactor System Blowdown Considerations

This section discusses the containment transient associated with small primary system line breaks. The sizes of primary system ruptures in this category are those that do not result in reactor depressurization due either to loss of reactor coolant or automatic operation of the ECCS equipment. Following the occurrence of a break of this size, it is assumed that the reactor operators will initiate an orderly plant shutdown and depressurization of the reactor system. The thermodynamic process associated with the blowdown of primary system fluid from such a break is one of constant enthalpy. If the primary system break is below the water level, the blowdown flow will consist of reactor water. Blowdown from reactor pressure to the drywell pressure will flash approximately one-third of this water to steam and two-thirds will remain as liquid. Both phases of the blowdown flow will be at saturation conditions corresponding to the drywell pressure. Thus, if the drywell is at atmospheric pressure (for example) the steam and liquid associated with the liquid blowdown would be at 212°F.

If the primary system rupture is located above the RPV water level so that the blowdown flow consists of reactor steam only, the resultant steam temperature in the containment is significantly higher than the temperature associated with liquid blowdown. This is because the constant enthalpy depressurization of high pressure, saturated steam results in superheated conditions.

A small reactor steam leak (resulting in superheated steam) imposes the most severe temperature conditions on the drywell structures and the safety equipment in the drywell. For larger steam line breaks, the superheat temperature is nearly the same as for small breaks, but the duration of the high temperature condition is less for the larger break. This is because the larger breaks depressurize the reactor more rapidly than the orderly reactor shutdown that is assumed to be initiated for the small break.

6.2.1.1.3.3.5.2 Containment Response

For drywell design considerations, the following sequence of events is assumed to occur. With the reactor and containment operating at the maximum normal conditions, a small break occurs that allows blowdown of reactor steam to the drywell. The resulting pressure increase in the drywell leads to a high drywell pressure signal that scrams the reactor and activates the containment isolation system. The drywell pressure continues to increase at a rate dependent upon the size of the steam leak. The pressure increase lowers the water level in the downcomers until the level reaches the bottom of the downcomers. At this time, air and steam start to enter the suppression pool. The steam is condensed and the air carried over to the suppression chamber free space. The air carryover results in a gradual pressurization of the suppression chamber at a rate dependent upon the size of the steam leak. Once all the drywell air is carried over to the suppression chamber, short-term pressurization of the suppression chamber ceases and the system reaches an equilibrium condition. The drywell contains only superheated steam, and continued blowdown of reactor steam condenses in the suppression pool. The suppression pool temperature continues to increase until the RHR heat exchanger heat removal rate is equal to the decay heat release rate.

6.2.1.1.3.3.5.3 Recovery Operations

The reactor operators are alerted to the incident by the high drywell pressure signal and the reactor scram. For the purpose of evaluating the duration of the superheat condition in the drywell, it is assumed that their response is to shut the reactor down in an orderly manner using the main condenser while limiting the reactor cooldown rate to 100°F per hour. This results in the reactor primary system being depressurized within 6 hours. At this time, the blowdown flow to the drywell ceases and the superheat condition is terminated. If the plant operators elect to cool down and depressurize the reactor primary system more rapidly than at 100°F per hour, then the drywell superheat condition will be shorter.

6.2.1.1.3.3.5.4 Drywell Design Temperature Considerations

For drywell design purposes, it is assumed that there is a blowdown of reactor steam for the 6 hour cooldown period. The design temperature is determined by finding the combination of primary system pressure and drywell pressure that produces the maximum steam temperature. The maximum steam temperature occurs when the primary system is at approximately 450 psia and the drywell pressure is maximum. Thus, for design purposes, it is assumed that the drywell is at 35 psig; this results in a conservative temperature of 340°F for the first 3 hours. After the first 3 hours of blowdown of reactor steam, the primary system pressure is reduced to a level that results in a temperature which is conservatively bounded by 320°F for the remaining 3 hours.

6.2.1.1.3.4 Accident Analysis Models

NOTE: The information presented in this section for the accident analysis models is based on the original analysis models and does not represent the current methodology used to analyze the containment response following a LOCA. See explanation at the beginning of Section 6.2.1.1.3.

6.2.1.1.3.4.1 Short-Term Pressurization Model

The analytical models, assumptions, and methods used to evaluate the containment response during the reactor blowdown phase of a LOCA are described in References 6.2-4 and 6.2-5.

6.2.1.1.3.4.2 Long-Term Cooling Mode

Once the RPV blowdown phase of the LOCA is over, a fairly simple model of the drywell and suppression chamber may be used. During the long-term, postblowdown transient, the RHR containment cooling system flow path (Section 6.2.2.2) is a closed-loop and the suppression pool mass is constant. Schematically, the cooling loop mode used for analysis is shown in Figure 6.2-16. Since there is no change in mass storage in the system (the RPV is reflooded during the blowdown phase of the accident), the mass flow rates shown in the figure are equal, thus:

$$\dot{m}_{Do} = \dot{m}_{So} = \dot{m}_{eccs} \qquad \text{(EQ. 6.2-2)}$$

where:

$\dot{m}_{Do}$ = mass flow rate out of RPV, lb_m/sec

$\dot{m}_{So}$ = mass flow rate out of suppression pool, lb_m/sec

$\dot{m}_{eccs}$ = mass flow rate into RPV, lb_m/sec

6.2.1.1.3.4.3 Analytical Assumptions

The key assumptions employed in the model are as follows:

a. The drywell and suppression chamber atmospheres are both saturated (100% relative humidity).

b. The drywell atmosphere temperature is equal to the temperature of the coolant spilling from the RPV, or to the spray temperature if the sprays are activated.

c. The suppression chamber atmosphere temperature is equal to the suppression pool temperature or to the spray temperature if the sprays are activated.

d. No credit is taken for heat losses from the primary containment or to the containment internal structures.

6.2.1.1.3.4.4 Energy Balance Considerations

The rate of change of energy in the suppression pool, (E_p) , is given by:

$$\frac{dE_p}{dt} = \frac{d}{dt}(M_{wS} \cdot u_S) = u_S \cdot \frac{dM_{wS}}{dt} + M_{wS} \frac{du_s}{dt} \quad \text{(EQ. 6.2-3)}$$

where:

M_{wS} = mass of water in suppression pool, lb_m

u_S = internal energy of water in suppression pool, Btu/lb_m

Since $\frac{dM_{wS}}{dt} = 0$ (because there is no change in mass storage), and at the conditions existing in the containment:

$$\frac{du_S}{dt} = C_v \cdot \frac{dT_S}{dt} \quad \text{(EQ. 6.2-4)}$$

where:

C_v = 1.0 for the constant volume specific heat of water, Btu/lb_m-°F

T_S = suppression pool temperature, °F

The pool energy balance yields:

$$M_{wS} \cdot C_v \cdot \frac{dT_S}{dt} = \dot{M}_{Do} \cdot h_D - \dot{M}_{So} \cdot h_S \quad \text{(EQ. 6.2-5)}$$

where:

h_D = enthalpy of water leaving RPV, Btu/lb_m

h_S = enthalpy of water in suppression pool, Btu/lb_m

This equation can be rearranged to yield:

$$\frac{dT_S}{dt} = \frac{\dot{M}_{Do} \cdot h_D - \dot{M}_{So} \cdot h_s}{C_v \cdot M_{wS}} \quad \text{(EQ. 6.2-6)}$$

An energy balance on the RHR heat exchanger yields:

$$h_c = h_s - \frac{\dot{q}_{HX}}{\dot{M}_{So}} \qquad \text{(EQ. 6.2-7)}$$

where:

h_c = enthalpy of water entering RPV, Btu/lb_m

q_{HX} = heat removal rate of heat exchanger, Btu/sec

Similarly, an energy balance on the RPV yields:

$$h_D = h_c + \frac{\dot{q}_D + \dot{q}_e}{\dot{M}_{eccs}} \qquad \text{(EQ. 6.2-8)}$$

where:

q_D = core decay and pump heat rate, Btu/sec

q_e = sensible energy release rate, Btu/sec

Combining Equations 6.2-2, 6.2-6, 6.2-7 and 6.2-8 gives:

$$\frac{dT_S}{dt} = \frac{\dot{q}_D + \dot{q}_e - \dot{q}_{HX}}{C_v M_{wS}} \qquad \text{(EQ. 6.2-9)}$$

This differential equation is integrated by finite-difference techniques to yield the suppression pool temperature transient.

6.2.1.1.3.4.5 Containment Thermodynamic Conditions

Once the energy equations are solved, the drywell and suppression chamber atmospheric temperatures can be calculated.

For the case in which no containment spray is operating, the suppression chamber temperature, (T_W), will, at any time, be equal to the current temperature of the pool, (T_S), and the drywell temperature, (T_D), will be equal to the temperature of the fluid leaving the RPV. Thus:

$$T_D = T_S + \frac{\dot{q}_D + \dot{q}_e - \dot{q}_{HX}}{C_p \dot{M}_{eccs}} \text{ and } T_W = T_S \qquad \text{(EQ. 6.2-10)}$$

where:

C_p = constant pressure specific heat of water, Btu/lb_m-°F

For the case in which the containment spray is assumed to be operating, both the drywell and suppression chamber atmosphere will be at the spray temperature, T_{sp}, where:

$$T_{sp} = T_S - \frac{\dot{q}_{HX}}{C_p \dot{M}_{eccs}} \text{ and } T_D = T_W = T_{sp} \qquad \text{(EQ. 6.2-11)}$$

Using the suppression chamber and drywell atmosphere temperatures, and assumption (a) of Section 6.2.1.1.3.4.3 (drywell and suppression chamber saturated), it is possible to solve for the containment total pressures, since:

$$P_D = P_{aD} + P_{vD} \qquad \text{(EQ. 6.2-12)}$$

$$P_S = P_{aS} + P_{vS} \qquad \text{(EQ. 6.2-13)}$$

where:

P_D = drywell total pressure, psia

P_{aD} = partial pressure of air in drywell, psia

P_{vD} = partial pressure of water vapor in drywell, psia

P_S = suppression chamber total pressure, psia

P_{aS} = partial pressure of air in the suppression chamber, psia

P_{vS} = partial pressure of water vapor in the suppression chamber, psia

and, from the Ideal Gas Law:

$$P_{aD} = \frac{M_{aD} \cdot RT_D}{V_D \cdot 144} \qquad \text{(EQ. 6.2-14)}$$

$$P_{aS} = \frac{M_{aS} \cdot RT_W}{V_S \cdot 144} \qquad \text{(EQ. 6.2-15)}$$

where:

M_{aD} = mass of air in the drywell, lb_m

M_{aS} = mass of air in the suppression chamber, lb_m

R = gas constant for air, $ft\text{-}lb_f/lb_m\text{-}°R$

V_D = drywell free volume, ft^3

V_S = suppression chamber free volume, ft^3

With known values of T_D and T_W Equations 6.2-12, 6.2-13, 6.2-14, and 6.2-15 can be solved by transient analysis and iteration. This iteration procedure is also used to calculate the unknown quantities M_{aD} and M_{aS}.

6.2.1.1.3.4.6 Solution of Equations

The transient analysis is based on successive time step integration of the suppression pool temperature. When this integration has been performed and the value of T_S at the end of a time step has been calculated, a pressure balance is made. Using values of M_{aD} and M_{aS} from the end of the previous time step and the updated values of T_D and T_S, a check is made to determine if P_S is greater than or equal to P_D using equations 6.2-12, 6.2-13, 6.2-14 and 6.2-15. If P_S is greater than or equal to P_D , then the two values are made equal. The vacuum breakers between the drywell and suppression chamber ensure that P_S cannot be greater than P_D.

Hence, with $P_D = P_S$ and knowing that:

$$M_{aD} + M_{aS} = \text{constant;} \qquad \text{(EQ. 6.2-16)}$$

where the constant is the known total initial mass of air in the suppression chamber and drywell prior to the accident, Equations 6.2-12, 6.2-13, 6.2-14, and 6.2-15 can be solved for M_{aS}, M_{aD}, and P_a. It is conservatively assumed that the total mass of air remains constant, which ignores any containment leakage that might occur during the transient.

If, as a result of the end-of-time step pressure check,

$$P_S \leq P_D \leq P_S + \frac{H \cdot g}{V_W \cdot 144 \cdot g_c} \qquad \text{(EQ. 6.2-17)}$$

where:

g = acceleration of gravity, ft/sec^2

g_c = constant of proportionality ft-lb$_m$/lb$_f$-sec^2

H = submergence of downcomers, feet

V_W = specific volume of fluid in downcomer, ft^3/lb$_m$

then the pressure in the drywell is higher than the pressure in the suppression chamber but not sufficiently so to depress the water to the bottom of the downcomers and thus permit air to flow from the drywell to the suppression chamber. Under these circumstances, no air transfer is assumed to have occurred during the time step, and Equations 6.2-12, 6.2-13, 6.2-14, and 6.2-15 are solved during the time step, and Equations 6.2-12, 6.2-13, 6.2-14, and 6.2-15 are solved using the updated temperatures with the same M_{aS} and M_{aD} values from the previous time step.

If the end-of-time step pressure check shows:

$$P_D > P_S + \frac{H \cdot g}{V_W \cdot 144 \cdot g_c} \qquad \text{(EQ. 6.2-18)}$$

then the drywell pressure is set to the value:

$$P_D = P_S + \frac{H \cdot g}{V_W \cdot 144 \cdot g_c} \qquad \text{(EQ. 6.2-19)}$$

This requires that the drywell pressure can never exceed the suppression chamber pressure by more than the hydrostatic head associated with the submergence of the downcomers. To maintain this condition, some transfer of drywell air to the suppression chamber is required. The amount of air transfer is calculated by using Equation 6.2-16 and combining Equations 6.2-12, 6.2-13, 6.2-14, 6.2-15, and 6.2-19 to give:

$$P_{vD} + \frac{M_{aD} \cdot RT_D}{144V_D} = P_{vS} + \frac{M_{aS} \cdot RT_W}{144V_S} + \frac{H \cdot g}{144V_W g_c} \qquad \text{(EQ. 6.2-20)}$$

which can be solved for the unknown air masses. The total pressures can then be determined.

6.2.1.1.4 Negative Pressure Design Evaluation

The primary containment has been designed for a negative pressure of -5 psig. The worst case for this consideration results from actuation of the drywell sprays. During such a transient, cold spray water is passed through the drywell atmosphere resulting in a drop in vapor region temperature and a corresponding drop in vapor region pressure. This condition was analyzed for LGS and a peak negative pressure of -4.85 psig was obtained for actuation of one drywell spray network. With three operable vacuum relief valve assemblies (two operating and one redundant), a sensitivity study indicates that actuation of both drywell spray networks concurrently results in a pressure below -5 psig if the suppression pool temperature is below approximately 105°F, assuming worst case conditions for all other variables. Actuation of both drywell spray networks is administratively controlled whenever the suppression pool temperature is below 105°F.

Operation of the drywell sprays at LGS will be governed by appropriate EOPs, which will be written and revised to implement the BWROG EPGs. There will be no other procedural requirements or administrative directives that will cause drywell sprays to be used. In accordance with the EOPs, prior to initiating drywell sprays, the operators will be directed first to determine if the present combination of drywell temperature and drywell pressure fall below the drywell spray initiation limit. If the combination of parameters is below the limit, the operator is directed to initiate drywell spray with a flow rate as specified in the EOPs. The drywell spray initiation limit and minimum drywell spray flow rate are calculated in accordance with the BWROG EPGs. These limits prevent the generation of drywell negative pressures relative to secondary containment and suppression pool that could be damaging to the containment vessel.

The inadvertent actuation of both drywell spray trains is also prevented by the type and location of the control room switches. The outboard valves are normally closed and have key-locked switches that are approximately 8 feet apart.

To determine the temporal pressure and temperature of the primary containment the conservation equations of mass and energy, along with the state equations for steam and air (noncondensable), were written for the drywell and wetwell regions. A schematic of these two regions is presented in Figure 6.2-17. The various terms for the mass and energy transfer mechanisms are also presented in this figure. The systems of differential equations for each region are presented in the following sections (definition of nomenclature is provided below):

A_{cond} = suppression pool free surface area, ft^2

A_{VB} = vent area through vacuum breakers, ft^2

C_{VB} = vacuum breaker flow coefficient

C_P = specific heat at constant pressure for H_2O, 1 Btu/lb_m-°F

C_P^* = specific heat at constant pressure for N_2, O.247 Btu/lb_m-°R

C_V = specific heat at constant volume for H_2O, 1 Btu/lb_m-°F

C_v^* = specific heat at constant volume for N_2, 0.176 Btu/lb_m-°R

E = energy content, Btu

g_c = gravitational constant, 32.174 $ft\text{-}lb_m/lb_f\text{-}sec^2$

h = specific enthalpy, Btu/lb_m

k = ratio of specific heats

M = mass, lb_m

M_{nc} = noncondensable mass, lb_m

M_{cond} = condensate mass, lb_m

M_{drop} = dropout mass, lb_m

M_{evap} = evaporated steam mass, lb_m

M_{stm} = steam mass, lb_m

P = pressure, psi

R = gas constant, $lb_f\text{-}ft/lb_m$-°R

Q = transferred energy, Btu

T = temperature, °F

T^* = absolute temperature, °R

t = time, sec

U_{stm} = steam specific energy, Btu/lb_m

V = volume, ft^3

v = specific volume, ft^3/lb_m

Greek Symbols

ξ	=	heat exchanger effectiveness
ε	=	spray efficiency
ϕ	=	minimum heat exchanger flow rate, lb_m/sec
ρ	=	density, lb_m/ft^3

Subscripts

D	-	drywell region
f	-	final, saturated liquid
g	-	saturated vapor
S	-	suppression pool liquid region, sump
sat	-	saturated conditions
spray	-	spray
sv	-	suppression pool vapor region
VB	-	vacuum breaker

6.2.1.1.4.1 Drywell Region

As indicated in Figure 6.2-17, there are several mass transfer terms for the drywell region. These are: drywell spray rate ($\dot{m}_{spray}$), drywell vapor region condensation rate (or "rainout" due to dropping saturation temperature) ($\dot{m}_{cond}$), and wetwell-to-drywell vacuum breaker flow rate ($\dot{m}_{VB}$). A mass balance on the drywell vapor region yields:

$$\frac{dM_D}{dt} = \frac{dM_{nc}}{dt} + \frac{dM_{stm}}{dt} \qquad \text{(EQ. 6.2-21)}$$

$$= (\dot{M}_{VB} + \dot{M}_{spray})_{in} - (\dot{M}_{cond} + \dot{M}_{spray})_{out}$$

The spray water is assumed to be removed directly to the wetwell liquid region to disallow any potential for re-evaporation to the drywell, as well as to maintain a larger drywell vapor region volume, both of which serve to induce conservatism in the analysis. The requirement of maintaining saturation conditions for the steam component is imposed and results in the following relationship:

$$M_{stm} = \frac{V_D}{v_g(T_D)} \quad \text{or} \quad \frac{dM_{stm}}{dt} = -\frac{V_D}{v_g^2(T_D)} \cdot \frac{dv_g}{dT_D} \cdot \frac{dT_D}{dt} \qquad \text{(EQ. 6.2-22)}$$

The energy balance for this region is:

$$\frac{dE_D}{dt} = (\dot{M}_{spray} C_p (T_{out} - 32) + \dot{Q}_{VB})_{in} \qquad \text{(EQ. 6.2-23)}$$

$$-(\dot{M}_{spray}\, C_p (T_f - 32) + \dot{M}_{cond}\, h_f (T_f))_{out}$$

$$= \dot{M}_{spray}\, C_p (T_{out} - T_f) - \dot{M}_{cond}\, h_f (T_f) + \dot{Q}_{VB}$$

But,

$$\frac{dE_D}{dt} = \left[C_V^* \, T_D^* \, \frac{dM_{nc}}{dt} + u_g \, (T_D) \, \frac{dM_{stm}}{dt} \right] + \left[M_{nc} C_V^* + M_{stm} \, \frac{du_g}{dT_D} \right] \frac{dT_D}{dt} \qquad \text{(EQ. 6.2-24)}$$

so,

$$\left[C_V^* \, T_D^* \, \frac{dM_{nc}}{dt} + u_g \, (T_D) \, \frac{dM_{stm}}{dt} \right] + \left[M_{nc} C_V^* + M_{stm} \, \frac{du_g}{dT_D} \right] \frac{dT_D}{dt} \qquad \text{(EQ. 6.2-25)}$$

The spray efficiency, ε, is defined as follows:

$$\varepsilon = \frac{T_f - T_{out}}{T_D - T_{out}} = f\left(\frac{M_{stm}}{M_{nc}}\right) \qquad \text{(EQ. 6.2-26)}$$

The functional relationship is determined in the work of Reference 6.2-4 and is illustrated in Figure 6.2-18.

6.2.1.1.4.2 Wetwell Region

The wetwell region is modeled in much the same way as the drywell region except that, due to the presence of the suppression pool, two subregions are identified: one to represent the wetwell vapor region, and one to represent the wetwell liquid region (suppression pool). The vapor region is denoted by subscript (sv). Mass and energy balances on this subregion yield the following:

$$\frac{dM_{sv}}{dt} = \frac{d(M_{nc})_{sv}}{dt} + \frac{d(M_{stm})_{sv}}{dt}$$

$$= (\dot{M}_{evap})_{in} - (\dot{M}_{VB} + \dot{M}_{cond})_{sv} + \dot{M}_{drop})_{out} \qquad \text{(EQ. 6.2-27)}$$

As was the case in the drywell region, the wetwell vapor region is assumed to maintain saturated conditions. Therefore,

$$(M_{stm})_{sv} = \frac{V_{sv}}{v_g(T_{sv})} \quad \text{or} \qquad \text{(EQ. 6.2-28)}$$

$$\frac{d(M_{stm})_{sv}}{dt} = \frac{1}{v_g(T_{sv})} \cdot \frac{dV_{sv}}{dt} - \frac{V_{sv}}{v^2 g(T_{sv})} \cdot \frac{dv_g}{dT_{sv}} \cdot \frac{dT_{sv}}{dt}$$

From volume considerations, V_{sv} can change less than 2% and does so gradually throughout the transient. Therefore, the approximation is made that,

$$\frac{dV_{sv}}{dt} \sim 0 \qquad \text{(EQ. 6.2-29)}$$

The suppression pool represents a large surface for condensation and evaporation, thus resulting in a net mass transfer between the liquid and vapor subregions. This effect serves to maintain the wetwell vapor region in a saturated state and is therefore modeled with the terms $\dot{m}_{evap}$ and $\dot{m}_{drop}$. The kinetic theory of condensation (Reference 6.2-5) is used to determine these mass transfer rates. This results in the following expressions:

$$(\dot{M}_{cond})_{sv} = 144\ \Gamma\ A_{cond} \left(\frac{g_c}{2\pi R_{stm}} \right)^{1/2} \frac{(P_{stm})_{sv}}{(T_{sv})^{1/2}} \qquad \text{(EQ. 6.2-30)}$$

$$\dot{M}_{evap} = 144\ A_{cond} \left(\frac{g_c}{2\pi R_{stm}} \right)^{1/2} \cdot \frac{(P_{sat})_s}{(T_s^*)^{1/2}} \qquad \text{(EQ. 6.2-31)}$$

where:

$$\Gamma = -w\ (\pi)^{1/2}\ (1 + \text{erf}(w)) - e^{-w^2} \qquad \text{(EQ. 6.2-32)}$$

$$w = \frac{G_{net}}{G_{std}} = \frac{(\dot{M}_{evap} + (\dot{M}_{cond})_{sv})}{-A_{cond}\ \rho_{stm}\ (2g_c R_{stm} T^*_{sv})^{1/2}} \qquad \text{(EQ. 6.2-33)}$$

$$\text{erf}(w) = \frac{2}{(\pi)^{1/2}} \int_0^w e^{-z^2}\ dz \qquad \text{(EQ. 6.2-34)}$$

For the energy balance,

$$\frac{dE_{sv}}{dt} = C_v^* T_{sv}^* \frac{d(M_{nc})_{sv}}{dt} + (M_{nc})_{sv}\ C_v^* \frac{dT_{sv}^*}{dt} + u_g(T_{sv}) \frac{d(M_{nc})_{sv}}{dt} \qquad \text{(EQ. 6.2-35)}$$

$$= (M_{stm})_{sv} \frac{du_g}{dT_{sv}^*} \cdot \frac{dT_{sv}}{dt}$$

$$= (\dot{M}_{evap}\ h_g(T_S))_{in} - (\dot{Q}_{VB} + (\dot{M}_{cond})_{sv} h_f(T_{sv}) + \dot{M}_{drop}\ h_g(T_{sv}))_{out}$$

The suppression pool region is denoted by subscript (S). Mass and energy balances on this subregion yield the following:

$$\frac{dM_s}{dt} = (\dot{M}_{drop} + \dot{M}_{cond} + (\dot{M}_{cond})_{sv})_{in} - (\dot{M}_{evap})_{out} \qquad \text{(EQ. 6.2-36)}$$

$$\frac{dE_s}{dt} = C_v\ (T_s - 32)\ \frac{dM_s}{dt} + M_s C_v\ \frac{dT_s}{dt} \qquad \text{(EQ. 6.2-37)}$$

$$= (\dot{M}_{cond}\ h_f(T_f) + (\dot{M}_{cond})_{sv} h_f(T_{sv}) + \dot{M}_{drop}\ h_f(T_{sv})$$

$$+ (\dot{M}_{spray}\ C_p(T_f - T_s))_{in} - (\dot{M}_{evap} h_g(T_s))_{out}$$

Two additional mass and energy transfer mechanisms need further definition. These are vacuum breaker flows and RHR heat exchangers, discussed in the next two sections.

6.2.1.1.4.3 Vacuum Breakers Flows

When sufficient differential pressure has built up across the diaphragm slab, the wetwell-to-drywell vacuum breaker assemblies open, allowing for transfer of mass and energy between these two regions. This transfer is described as follows:

$$\dot{M}_{VB} = \begin{cases} C^*_{VB} A_{VB} \left(\dfrac{2 g_c K_{sv}}{K_{sv} - 1}\ r_{sv} P_{sv}\ \left(\left(\dfrac{P_D}{P_{sv}} \right)^{2/Ksv} - \left(\dfrac{P_D}{P_{sv}} \right)^{(Ksv+1)/Ksv} \right) \right)^{1/2} \\ \quad \text{For } \left(\dfrac{P_D}{P_{sv}} \right) > \left(\dfrac{2}{K_{sv}+1} \right)^{K_{sv}/(K_{sv}-1)} \\ C^*_{VB}\ A_{VB} \left(g_c K_{sv} P_{sv} r_{sv} \left(\dfrac{2}{K_{sv}+1} \right)^{(Ksv+1)/(Ksv-1)} \right)^{1/2} \\ \quad \text{For } \left(\dfrac{P_D}{P_{sv}} \right) \le \left(\dfrac{2}{K_{sv}+1} \right)^{Ksv/(Ksv-1)} \end{cases} \qquad \text{(EQ. 6.2-38)}$$

$$(\dot{M}_{VB})_{stm} = \left(\frac{M_{stm}}{M_{stm} + M_{nc}} \right)_{sv} \bullet \dot{M}_{VB} \qquad \text{(EQ. 6.2-39)}$$

$$(\dot{M}_{VB})_{nc} = \left(\frac{M_{nc}}{M_{stm}+M_{nc}}\right)_{sv} \cdot \dot{M}_{VB} \qquad \text{(EQ. 6.2-40)}$$

$$K_{sv} = \left(\frac{P_{NC}}{P_{tot}}\right)_{sv} \cdot K_{nc} + \left(\frac{P_{stm}}{P_{tot}}\right)_{sv} \cdot K_{stm} \qquad \text{(EQ. 6.2-41)}$$

and,

$$\dot{Q}_{VB} = (\dot{M}_{VB})_{stm} h_g(T_{sv}) + (\dot{M}_{VB})_{nc} C_p^* T_{sv}^* \qquad \text{(EQ. 6.2-42)}$$

6.2.1.1.4.4 RHR Heat Exchangers

In the drywell spray mode, the RHR system draws water from the suppression pool, passes it through the RHR heat exchangers, and injects it into the drywell vapor region. As such, the RHR heat exchangers must be modeled to reflect this condition. Therefore,

$$\dot{Q}_{HX} = \dot{M}_{spray} C_p (T_S - T_{out}) = \phi\xi C_p (T_S - T_{sw}) \qquad \text{(EQ. 6.2-43)}$$

where:

$$\phi = \min(\dot{M}_{spray}, \dot{M}_{sw}) \qquad \text{(EQ. 6.2-44)}$$

Combining these yields,

$$T_{out} = T_S - \frac{\phi\xi}{\dot{M}_{spray}}(T_S - T_{sw}) \qquad \text{(EQ. 6.2-45)}$$

6.2.1.1.4.5 Summary

The preceding equations, combined with the state equations for steam and air, yield a set of coupled equations which, when reduced and solved simultaneously, determine the dynamic response of the primary containment system to the postulated drywell spray accident.

The inherent conservatisms of this model are: to neglect transfer of sensible heat energy from equipment and structures to the drywell vapor region, to disallow re-evaporation of the condensed drywell steam, to maintain a large volume for the drywell region by transferring condensed steam mass directly to the suppression pool, and to require saturated conditions in the primary containment vapor regions.

In addition to the modeling conservatisms, initial conditions for the primary containment are also chosen to induce conservatism in the analysis. The presence of any noncondensables in the drywell tends to hold-up the depressurization rate of this region following spray actuation. Thus, a condition is postulated wherein a small break occurs within the drywell serving to pressurize this region and drive all the noncondensables from the drywell vapor space. This sets the initial pressure distribution

and, along with the assumptions regarding saturated conditions for the steam phase, the temperature distribution for all three regions - drywell, wetwell vapor region, and suppression pool. Normally the noncondensables are driven from the drywell to the wetwell. However, when evaluating the reduction from 4 operable vacuum breakers to 3 operable vacuum breakers, it was assumed for a worst case analysis that a small amount of noncondensables is discharged to the reactor enclosure, prior to purge valve closure, and the remainder are driven to the wetwell vapor space. These initial conditions are presented under the heading "t_o" in Table 6.2-9.

The results of this analysis are illustrated in Figures 6.2-19 and 6.2-20. These results indicate a maximum negative drywell pressure of -4.85 psig.

6.2.1.1.5 Steam Bypass of the Suppression Pool

NOTE: The information in this section for the steam bypass of the suppression pool is based on the original basis conditions. See explanation at the beginning of Section 6.2.1.1.3.

6.2.1.1.5.1 Protection Against Bypass Paths

The pressure boundary penetrations between drywell and suppression chamber include the downcomers, which are fabricated, erected, and inspected in accordance with ASME Section III, Subsection NC, 1971 Edition with the exception of the tees supporting the primary containment vacuum relief valves. This special construction, inspection, and quality control ensures the integrity of this boundary. The design pressure differential and temperature for this boundary are defined in Table 6.2-1. Actual peak accident differential pressure and temperature for this boundary are provided in Table 6.2-5.

All penetrations of this boundary are welded except the vacuum relief valves supported by four tees and the blinds closing 10 spare nozzles in the downcomers. All penetrations are available for periodic visual inspection.

All potential bypass leakage paths have been considered. Every path has at least two isolation valves in the potential leakage path. These valves are high quality leak-tight containment isolation valves that are all normally closed and receive an isolation signal to close. All AOVs in these paths are failed closed.

6.2.1.1.5.2 Reactor Blowdown Conditions and Operator Response

In the highly unlikely event of a primary system leak in the drywell accompanied by the existence of an open bypass path leakage between the drywell and suppression chamber, the suppression chamber is pressurized by the steam that enters through the leakage path (bypassing the suppression pool). For a given primary system break area, the maximum leakage that can be allowed is the amount that results in the containment pressure just reaching the design pressure at the end of reactor blowdown. The most limiting conditions, in terms of the smallest allowable leakage flow path area, occur for those primary system break sizes that do not cause rapid reactor depressurization, but do have a long leakage duration. This corresponds to break sizes less than approximately 0.4 ft^2, which require some operator action to terminate the reactor blowdown.

Immediately after the postulated conditions given for a small primary system break, there is a fairly rapid rise in containment pressure as the noncondensable gases in the drywell are carried over to the suppression chamber. During this portion of the transient, it is assumed that the plant operators are unaware that a leakage path exists. For the maximum allowable leakage calculations, it is assumed that the plant operators become aware of a potential leakage only when the drywell

pressure reaches 30 psig. For conservatism, an additional 30 minute delay is assumed to occur before any corrective action to terminate the transient takes effect. At that time, the drywell pressure would be equal to the design pressure if the allowable leakage had occurred. The operator will be alerted to the existence of significant steam bypass leakage by the attendant drywell pressure increase which the operator will be monitoring as part of the EOPs. The operator will initiate the wetwell spray in accordance with the EOPs which will be based on the BWROG EPGs. The BWROG EPGs explicitly consider the possibility of suppression pool bypass leakage in determining spray initiation points.

Termination of the wetwell (and drywell) pressure increase is assured by the operation of only one of the two wetwell sprays.

6.2.1.1.5.3 Analytical Assumptions

When calculating the allowable leakage capacities for a spectrum of break sizes, the following assumptions are made:

a. Flow through the postulated leakage path is pure steam. For a given leakage path, if the leakage flow consists of a mixture of liquid and vapor, the total leakage mass flow rate is higher but the steam flow rate is less than for the case of pure steam leakage. Since only the steam entering the suppression chamber free space results in the additional containment pressurization, this is a conservative assumption.

b. There is no condensation of the leakage flow on either the suppression pool surface or the containment and vent system structures. Since condensation acts to reduce the suppression chamber pressure, this is a conservative assumption. For an actual containment there is condensation, especially for the larger primary system break where vigorous agitation at the pool surface occurs during blowdown.

The following assumptions were made in performing the small break bypass leakage computations to demonstrate that operator action is not required for at least 30 minutes.

a. The steam that leaks into the wetwell air space does not mix with the air already there.

b. No portion of the steam that has leaked into the wetwell air space condenses.

c. Only steam leaks into the wetwell; any air moving from the drywell into the wetwell goes through the vents.

d. All of the air initially in the drywell is cleared into the wetwell before the moment when the operator is alerted.

e. The vents do not refill with water during the time span considered in this procedure.

f. The flow of steam through leakage paths is treated as being incompressible.

g. The pressure difference across the leakage path is assumed to be constant and equal to the vent submerged hydrostatic pressure difference.

h. The drywell pressure at which the operator is alerted is 30 psig.

i. The wetwell air temperature when the operator is alerted to the occurrence of bypass leakage is assumed to be equal to the initial wetwell temperature (95°F). Later, when

the drywell pressure is reduced due to operator action, the wetwell air temperature is assumed to be 50°F greater than the initial wetwell temperature, i.e., 145°F.

j. Maximum allowable leakage area $A/(k)^{½}$ = 0.05 ft^2.

k. The wetwell air space is saturated at the time of spray initiation.

The initial conditions assumed were:

Drywell Temperature	135°F ①
Drywell Pressure	15.45 psia
Drywell Relative Humidity	20%
Wetwell Temperature	95°F
Wetwell Relative Humidity	100%
Drywell Volume	248390 ft^3 (HWL)*
Wetwell Volume	149425 ft^3 (HWL)*
Vent Submergence	12.25 ft (HWL)

Using the above assumptions and initial conditions, a small break LOCA in the drywell produces a constant drywell-to-wetwell pressure differential equivalent to the vent submergence static head (5.28 psid). The resulting bypass steam flow through the leakage path of $A/(k)^{½}$ = 0.05 ft^2 is 3.76 lb_m/sec. The operator becomes alerted to the existence of bypass leakage when the drywell pressure reaches 30 psig. For the drywell pressure to increase from 30 psig to 55 psig (design pressure), the corresponding wetwell pressure rise is from 24.72 to 49.72 psig. Therefore, based on the amount of bypassed steam needed to produce this pressure rise, the operator has about 31 minutes to complete an action that will terminate the pressure increase.

The following shows the minimum required spray efficiency as a function of spray temperature. Because the wetwell airspace is saturated when the spray is initiated (this conservative assumption maximizes pressurization at a given temperature), no net evaporation from hot downcomer surfaces will occur to counteract the spray depressurization effect. The mass flow rate of one spray system is 500 gpm. With two spray systems in operation, the required efficiency would be halved. The spray efficiency is typically on the order of 0.7 and, therefore, even with a single system is operation, the termination of the wetwell (and drywell) pressure increase is assured.

① The assumed initial condition for Drywell temperature of 135°F conservatively bounds an initial Drywell Temperature of 150°F.

* See Table 6.2-1 for final design volumes.

Spray Temperature	Required Efficiency of 1 Wetwell Spray System
70°F	0.22
90°F	0.24
120°F	0.28

6.2.1.1.5.4 Analytical Results

The containment has been analyzed to determine the allowable leakage between the drywell and suppression chamber. Figure 6.2-21 shows the allowable leakage capacity ($A/(k)^{½}$) as a function of the primary system break area. (A) is the area of the leakage flow path and (K) is the total geometric loss coefficient associated with the leakage flow path.

Figure 6.2-21 is a composite of two curves. If the break area is greater than approximately 0.4 ft^2, natural reactor depressurization rapidly terminates the transient and maximum allowable leakage is correspondingly high. For break areas less than approximately 0.4 ft^2, however, reactor blowdown is of long duration and the maximum allowable leakage is limited to small values. The smallest maximum allowable leakage capacity is at $A/(K)^{½}$ = .046 ft^2.

6.2.1.1.5.5 Tests and Inspections

A visual inspection will be conducted at each refueling outage to detect possible drywell-to-suppression bypass leakage paths. A visual inspection of each primary containment vacuum relief valve assembly will be conducted during each refueling outage to verify that it is clear of foreign matter.

Vacuum breakers will be tested for operability at an interval specified by the Technical Specifications. This surveillance testing will be in accordance with the Technical Specifications.

6.2.1.1.5.6 Instrumentation

The vacuum relief valve position indicator system has adequate sensitivity to detect a total valve opening, for all valves, that is less than the bypass capability for a small break. Outboard valve opening is detectable at a disk lift of 0.050 inch or greater off the valve seat. Inboard valve opening is detectable at a disk lift of 0.120 inch or greater off the valve seat. Even assuming that one outboard valve is in the fully open position and all other

valves are open to their minimum detectable position, the total $A/(k)^{½}$ is below 0.05 ft^2. Therefore, the valve leakage, which is based on the assumption that the valve opening is evenly divided among all the vacuum breakers assemblies with one outboard valve in the fully open position, is well within the limits of acceptable bypass leakage.

6.2.1.1.6 Suppression Pool Dynamic Loads

Hydrodynamic loads due to MSRV discharge and a LOCA are described in Appendix 3A.

6.2.1.1.7 Asymmetric Loading Conditions

Asymmetric loads considered for the design of the containment structure include horizontal seismic and localized missile and pipe rupture loads. Refer to Section 3.7 for a description of the seismic analysis methods. Refer to Sections 3.6 and 3.8 for descriptions of the analytical methods used for pipe rupture and missile loads.

6.2.1.1.8 Containment Environment Control

The functional capability of the containment ventilation system to maintain the temperature, pressure, and humidity of the containment and subcompartments is discussed in Section 9.4.5.

6.2.1.1.9 Postaccident Monitoring

A description of the postaccident monitoring systems is provided in Section 7.5.

6.2.1.2 Containment Subcompartments

The containment subcompartments considered for LGS are the biological shield annulus and the drywell head region. The modeling procedures and considerations are presented in Appendix 6A.

6.2.1.3 Mass and Energy Release Analyses for Postulated LOCAs

The information presented in this section for the mass and energy release analyses for postulated LOCAs is based on the original design basis conditions. The information presented in this section reasonably represent the general characteristics for the mass and energy release following a postulated LOCA. (See explanation at beginning of Section 6.2.1.1.3.)

This section presents information concerning the transient energy release rates from the reactor primary system to the containment system following a LOCA. Where the ECCS enter into the determination of energy released to the containment, the single failure criterion has been applied in order to maximize the energy release to the containment following a LOCA. Long-term responses and single failure analyses are discussed in Section 6.2.1.1.3.3.1.6.

6.2.1.3.1 Mass and Energy Release Data

Table 6.2-10 provides the mass and enthalpy release data for the recirculation line break. Blowdown steam and liquid flow rates approach zero in approximately 40 seconds and do not change significantly during the remainder of the 24 hour period following the accident. Figures 6.2-22 and 6.2-23 show the blowdown flow rates for the recirculation line break graphically. These data were employed in the containment pressure-temperature transient analyses reported in Section 6.2.1.1.3.3.1.

Table 6.2-11 provides the mass and enthalpy release data for the main steam line break. Blowdown steam and liquid flow rates approach zero in approximately 60 seconds and do not change significantly during the remainder of the 24 hour period following the accident. Figure 6.2-24 shows the vessel blowdown flow rates for the main steam line break as a function of time after the postulated rupture. This information has been employed in the containment response analyses presented in Section 6.2.1.1.3.3.2.

6.2.1.3.2 Energy Sources

The RCS conditions prior to the line break are presented in Tables 6.2-3 and 6.2-4. Reactor blowdown calculations for containment response analyses are based on these conditions during a LOCA.

The energy released to the containment during a LOCA is comprised of the following:

a. Energy stored in the reactor system

b. Energy generated by fission product decay

c. Energy from fuel relaxation

d. Sensible energy stored in the reactor structures

e. Energy being added by the ECCS pumps

f. Metal-water reaction energy

These energy additions are discussed or referenced in this section. The pump heat rate used in evaluating the containment response to the LOCA is conservatively selected as a constant input of $.00434 \times 10^6$ Btu/sec to the system. The pump heat rate is added to the decay heat rate for inclusion in the analysis.

Following each postulated accident event, the stored energy in the reactor system and the energy generated by fission product decay are released. The rate of release of core decay heat for the evaluation of the containment response to a LOCA is provided in Table 6.2-12 as a function of time after accident initiation.

Following a LOCA, the sensible energy stored in the reactor primary system metal is transferred to the recirculating ECCS water and thus contributes to the suppression pool and containment heatup.

Figure 6.2-25 shows the temperature transients of the various primary system structures that contribute to this sensible energy transfer. Figure 6.2-26 shows the variation of the sensible heat content of the reactor vessel and internal structures during a recirculation line break accident based on the temperature transient responses.

6.2.1.3.3 Reactor Blowdown Model Description

NOTE: The reactor blowdown model description provided below is for the original analysis models and do not represent the methods used to analyze current plant conditions. Refer to the explanation provided at the beginning of Section 6.2.1.1.3.

The reactor primary system blowdown flow rates are evaluated with the model described in References 6.2-4 and 6.2-5.

6.2.1.3.4 Effects of Metal-Water Reaction

The containment systems are designed to accommodate the effects of metal-water reactions and other chemical reactions that may occur following a LOCA. The amount of metal-water reaction that can be accommodated is consistent with the performance objectives of the ECCS. Section 6.2.5.3 provides a discussion on the generation of hydrogen within the containment by metal-water reaction. In evaluating the containment response, 0.002077×10^6 Btu/sec of heat from metal-water reaction is included for the first 120 seconds. The containment response is insensitive to the reaction time, even for the extremely conservative case where all of the energy is included prior to the occurrence of peak drywell pressure.

6.2.1.3.5 Thermal-Hydraulic Data for Reactor Analysis

Sufficient data to perform confirming thermodynamic evaluations of the containment are provided in Section 6.2.1.1.3.3 and associated tables, in particular, Table 6.2-4.

6.2.1.4 Pressurized Water Reactor - Not Applicable

6.2.1.5 Pressurized Water Reactor - Not Applicable

6.2.1.6 Testing and Inspection

Preoperational containment testing and inspection programs are described in Section 3.8 and Chapter 14. Operational containment leakage rate testing and inspection programs are described in Section 6.2.6. The requirements and bases for acceptability are described in Chapter 16.

6.2.1.7 Instrumentation Requirements

Containment pressure and temperature sensing and the associated actuating input to the ESF systems are discussed in Section 7.3. Refer to Section 7.5 for a discussion of the display instrumentation.

Containment airborne radioactivity monitoring is described in Section 12.3.4. Containment hydrogen monitoring is described in Section 6.2.5.

6.2.1.8 Containment System Performance at Power Rerate

The UFSAR provides the results of analyses of the containment response to various postulated accidents that constitute the design basis for the containment. Operation with power rerate changes some of the conditions for the containment analyses. For example, the short-term DBA-LOCA containment response during the blowdown is governed by the blowdown flow rate. This blowdown flow rate is dependent on the reactor initial thermal-hydraulic conditions, such as vessel dome pressure and the mass and energy of the vessel fluid inventory, which change slightly with power rerate. Also, the long-term heat up of the suppression pool following a LOCA or a transient is governed by the ability of the RHR to remove decay heat. Since the decay heat depends on the initial reactor power level, the long-term containment response is affected by power rerate. The LGS containment response has been conservatively re-analyzed to demonstrate the plant's capability to operate at 110% of the original rated power.

The analyses were performed in accordance with Regulatory Guide 1.49 and Reference 6.2-25 using GE codes and models. The M3CPT code was used to model the short-term containment pressure and temperature response. The modeling used in M3CPT is described in References 6.2-26 through 6.2-28. Reference 6.2-26 and 6.2-27 describe the basic containment analytical models used in GE codes. Reference 6.2-28 describes the more detailed RPV model used in the containment analyses for power rerate. The SHEX code was used to model the long-term containment pressure and temperature response. The key models in SHEX are based on models described in References 6.2-26 and 6.2-27. The GE models and methods have been reviewed by the NRC (Reference 6.2-29). The

NRC has approved the use of SHEX on a plant-specific basis, as described in Reference 6.2-30. The significant input parameters and initial conditions for the power rerate containment analyses are shown in the Table 6.2-4A.

The effects of power rerate on the containment dynamic loads due to a LOCA or SRV discharge have also been evaluated as described in Section 6.2.1.8.2. These loads were previously defined generically during the Mark II Containment Program as described in Reference 6.2-31 and accepted by the NRC in Reference 6.2-32 and 6.2-33. Plant-specific dynamic loads were also defined for the plant (Section 3A), which were accepted by the NRC in Reference 6.2-34. The evaluation of the LOCA containment dynamic loads is based primarily on the results of the short-term analysis described in Section 6.2.1.8.1.3. The SRV discharge load evaluation considers the change in the SRV opening setpoints with power rerate.

6.2.1.8.1 Containment Pressure and Temperature Response

The short-term analysis is directed primarily at determining the containment pressure response during the initial blowdown of the reactor vessel inventory to the containment following a large break inside the drywell. The long-term analysis is directed primarily at the pool temperature response, considering the decay heat addition to the pool. The impact of power rerate on the events which yield the limiting containment pressure and temperature response is provided below.

6.2.1.8.1.1 Long-Term Suppression Pool Temperature Response

6.2.1.8.1.1.1 Bulk Pool Temperature

The long-term bulk suppression pool temperature response for LGS with power rerate was evaluated for the DBA LOCA and includes the increased decay heat loads from SIL 636. The analysis was performed at 3528 MWt (Ref. 6.2-40, 6.2-41). Table 6.2-5A compares the calculated peak values for LOCA bulk pool temperature. The suppression pool temperature response is shown in Figure 6.2-9A. The peak bulk suppression pool temperature calculated is 203.4°F. This temperature is within the suppression pool water temperature structural design value (220°F), and does not exceed the low pressure ECCS pump limit of 212°F.

6.2.1.8.1.1.2 Steam Bypass Case

A concern during a LOCA event is steam bypass of the suppression pool due to leakage between the drywell and the wetwell airspace. Excess leakage could result in overpressurization of the primary containment. A steam bypass analysis was performed at 3694 MWt to ensure that there is sufficient time for a manual actuation of the containment spray to prevent the containment pressure from exceeding the design limit of 55 psig. The evaluation shows that power rerate has negligible impact on the suppression pool steam bypass effects. Reference 6.2-41 qualitatively equates the steam bypass event at 3458 MWt with the decay heat rates of SIL 636. At these conditions, it is expected that sufficient time for manual equation of containment spray is available to prevent containment pressure from exceeding 55 psig.

6.2.1.8.1.2 Containment Gas Temperature Response

The drywell design temperature (340°F) has been determined based on a bounding analysis of the superheated gas temperature which can be reached with blowdown of steam to the drywell during a LOCA. A small reactor steam leak (resulting in superheated steam) imposes the most severe temperature conditions on the drywell structures and the safety-related equipment in the drywell. For larger steam line breaks, the superheat temperature is nearly the same as for the small breaks, but the duration of the high temperature condition is less for the large break. This is because the larger breaks depressurize the reactor more rapidly than the orderly reactor shutdown that is assumed to be initiated for the small breaks. The changes in the reactor vessel conditions with power rerate will increase the calculated long-term peak drywell gas temperature during a small break LOCA by a

maximum of a few degrees. However, it has been evaluated that the small break drywell gas temperature response with power rerate will not exceed the drywell design value. The short-term drywell and wetwell gas temperature response is shown in Figure 6.2-4A. The long-term drywell gas temperature response is shown in Figure 6.2-8A.

The wetwell gas space peak temperature response is calculated assuming short-term thermal equilibrium between the pool and wetwell gas space. For the long term containment response, the heat and mass transfer between the suppression pool and the wetwell air space is mechanically calculated. Table 6.2-5A shows the peak bulk pool temperature is 203.4°F due to power rerate and SIL 636 (Reference 6.2-41). The peak wetwell gas space temperature is 210.7°F. These temperatures are well below the design temperature of 220°F.

6.2.1.8.1.3 Short-Term Containment Pressure Response

Short-term containment pressure response analyses were performed for the limiting DBA LOCA which assumes a double-ended guillotine break of a recirculation suction line to demonstrate that operation with power rerate will not result in exceeding the containment design limits. The short-term analysis covers the blowdown period during which the maximum drywell pressure, wetwell pressure, and differential pressure between the drywell and wetwell occur. This analysis was conservatively performed at 102% of 110% of original rated power. The results of this short-term analysis are summarized in Table 6.2-5A. The short-term containment pressure response for power rerate is shown in Figure 6.2-3A. The long-term containment pressure response is shown in Figure 6.2-7A. Table 6.2-5A also includes comparisons of the pressure values calculated with power rerate to the design pressures values from previous calculations reported in the UFSAR. As shown by these results, the peak pressure values are below the design values.

6.2.1.8.2 Containment Dynamic Loads

6.2.1.8.2.1 LOCA Containment Dynamic Loads

The LOCA containment dynamic loads analysis for power rerate is based primarily on the short-term LOCA analyses described in Section 6.2.1.8.1.3. These analyses provide calculated values for the controlling parameters for the dynamic loads throughout the blowdown. The key parameters are drywell and wetwell pressure, vent flow rate and suppression pool temperature. The LOCA dynamic loads which are considered in the power rerate evaluation include pool swell, condensation oscillation (CO), and chugging.

The short-term containment response conditions with power rerate are within the conditions used to define the pool swell loads. The initial drywell pressurization rate used to define the pool swell load is negligibly affected by rerated power. The short-term containment response conditions for vent flow rate and pool temperature with power rerate are negligibly affected by power rerate. In addition, the containment conditions with power rerate in which CO and chugging would occur are within the range of test conditions used to define the CO and chugging loads. Therefore, the LOCA dynamic loads are not affected by power rerate.

6.2.1.8.2.2 SRV Containment Dynamic Loads

Hydrodynamic loads generated by the actuation of Safety/Relief Valve (SRV) include both internal and external hydrodynamic loads. Internal loads include SRV discharge line loads and load on the quencher discharge device. External hydrodynamic loads include the suppression pool boundary pressure loads and the submerged structure loads. These loads are influenced by SRV opening

setpoint pressure, SRVDL geometry and submergence, initial air volume in SRVDL, quencher design and suppression pool geometry. The only parameter change introduced by power rerate which can affect SRV loads is the increase in SRV opening setpoint pressure which results in higher SRV flow rates and, therefore higher SRV loads.

The SRV analytical limits for setpoints show a 3.5% increase in the analytical values of the SRV opening pressure with power rerate. The increase in SRV setpoint pressure results in a corresponding 3.5% increase in flow rate and hydrodynamic loads. However, the original SRV external hydrodynamic load specification and the load specification on quenchers are defined based on a reference RPV pressure of 1276 psig. Comparison shows that the rerate increased SRV setpoint pressure and flow rate are still bounded by the referenced flow rate used to define the LGS T-quencher hydrodynamic loads (Reference 6.2-35). Therefore, the original containment dynamic and submerged structure loads remain bounding for power rerate. The same conclusion is also valid for the hydrodynamic loads on the quencher. The SRV discharge piping loads are included in the evaluation discussed in Appendix 3A and 3B.

6.2.1.8.2.3 Subcompartment Pressurization

The design loads on the shield wall due to a postulated pipe break in the annulus between this wall and the reactor vessel are acceptable for the higher reactor pressure at rerated conditions. The shield wall design remains adequate because the original analyzed loads were based on mass and energy releases which bound the rerated conditions. The subcompartment pressurization evaluations for power rerate are provided in Appendix 6A.

6.2.2 Containment Heat Removal System

6.2.2.1 Design Bases

The containment heat removal system (containment cooling system) prevents excessive containment temperatures following a LOCA so that containment integrity is maintained. To fulfill this purpose, the containment cooling system meets the following design bases:

a. The system is designed to limit the long-term bulk temperature of the suppression pool without spray operation when considering the energy additions to the containment following a LOCA (see Reference 6.2-4). These energy additions, as a function of time, are provided in Section 6.2.1.3.2.

b. The system is designed with sufficient capacity and redundancy so that a single failure of any active component, assuming a LOOP, cannot impair its capability to perform its safety-related function. The system is designed to remain operable following an SSE.

c. The system is designed to operate under any of the following conditions: LOOP, adverse natural phenomena (such as tornadoes, hurricanes, earthquakes, floods, etc.), and site related events (such as high and moderate energy pipe breaks, externally generated missiles, and transportation accidents).

d. Each active component of the system is testable during normal operation of the nuclear power plant.

6.2.2.2 System Design

The containment cooling system is an integral part of the RHR system as described in Section 5.4.7 and designed to seismic Category I requirements. The system is designed, fabricated, erected, and tested to quality Group B standards with the exception of the drywell and wetwell spray headers which were originally designed, fabricated, and erected to quality Group C standards but have been upgraded to quality Group B (Table 3.2-1). In the containment cooling mode, water is drawn from the suppression pool through redundant suction strainers, pumped through one or both RHR heat exchangers, and delivered to the vessel, the suppression pool, the drywell spray header, and/or the suppression pool vapor space spray header. Water from the RHRSW system is pumped through the heat exchanger tube side to remove heat from the suppression pool water. Two 100% capacity cooling loops are provided; each being mechanically and electrically separate from the other to achieve redundancy (Section 9.2.3). Power is supplied from the safeguard buses (Section 8.3). A P&ID and process diagram, including the process data, are provided in Section 5.4 for all design operating modes and conditions.

All ECCS and RCIC suction piping originating in the suppression pool is designed based on the following criteria:

a. The allowable pressure drop across the redundant pair of strainers for each RCIC and HPCI suction line is 2 psi maximum at the design flow rate with each of the strainers 50% plugged in order to exceed the minimum required NPSH provided to the associated pump.

b. The allowable dirty pressure drop across the redundant strainers for each of the RHR and Core Spray suction lines is 5 psi and 3.8 psi maximum, respectively, at the design flow rate in order to satisfy the minimum required NPSH provided to the associated pump. The dirty strainer pressure drop is based on the entire amount of fibrous debris generated in the drywell during a design basis LOCA (within the zone of influence of the worst case pipe break location) transported to the suppression pool and all fibrous debris is available to clog the strainer.

c. The strainer mesh openings are sized to allow foreign particles of no greater than 0.0625 inches to pass through in order to prevent plugging of the containment spray nozzles and pump seal flushing water circuits.

d. Each strainer is designed to withstand all seismic and hydrodynamic loads postulated to occur in the suppression pool. A dynamic loading analysis has been performed for the ECCS suction strainers that demonstrates their capability to adequately accommodate inertial loads (earthquake, SRV discharge, and LOCA condensation oscillation and chugging), operational loads (pressure and temperature), dead weight loads, and direct hydrodynamic loads. The latter loads are due to direct hydrodynamic SRV discharge (SRV air bubble loads) and downcomer discharges (LOCA air bubble, CO, chugging, water jet, and pool-swell loads). The mentioned loads are combined in accordance with Table 3A-20. Figure 3A-27 presents elevations, dimensions, and orientations of the piping systems inside containment that are associated with the ECCS suction strainers.

e. The RHR suction piping is arranged in the suppression pool considering the locations of the discharge piping, so that when operating in the suppression pool cooling mode the suppression pool is uniformly cooled.

Each pump suction line penetrates the vertical wall of the suppression pool, leading directly to a "T" arrangement. The "T"s for the RCIC line and HPCI line are oriented vertically. The remaining "T"s are horizontal. The centerline of this "T" is 23 inches maximum from the suppression pool wall and 11'-11" below the minimum Technical Specification suppression pool water level. Each arm of the "T" is the same nominal pipe size as the suction line. The strainers are bolted to the arms of each "T" except Core Spray strainers which are attached to one arm of each "T". Each of the two strainers for each suction line provides more than 100% of the cross-sectional area of the suction line. The design drawing for the RCIC and HPCI strainers is shown in Figure 6.2-51. The design drawings for the RHR and Core Spray strainers are shown in Figure 6.2-51.

In the unlikely event of a high energy pipe break within the primary containment, debris created might migrate to the suppression pool and build-up on the RCIC and HPCI pump suction strainers, impairing operation of these pumps. Such debris considerations are part of USI A-43, "Containment Emergency Sump Performance." The manufacturer has addressed this concern on a generic basis in a topical report which has been reviewed and accepted by the NRC (Reference 6.2-23). A plant specific review of this concern was made.

The only credible sources of LOCA generated debris inside the primary containment that have the potential to clog pump suction strainers are the thermal insulation materials on piping and equipment. There are four types of insulation materials used inside the primary containment:

a. Metallic reflective - used on reactor vessel.

b. Fiberglass (Nukon) - used on piping, valves, and pumps.

c. Fiberglass (antisweat) - used on chilled water piping.

d. Stainless steel encapsulated low conductivity insulation - used on piping at the pipe whip restraints.

Fiberglass insulation inside primary containment is protected with stainless steel jackets except where it is not practical (pipe hangers, supports) or where shapes are not suitable (some valves and reactor nozzles). Insulation added in the Unit 1 drywell during power ascension testing was installed without jackets to simplify installation.

Insulation debris can enter the suppression pool only through the wetwell downcomers (Figure 6.2-1). There are several physical barriers that will minimize the amount and size of debris that enters the downcomers, as described below:

a. Floor grating, walkways, stairs, structural steel, piping, etc., located above the drywell floor will trap the majority of dislodged insulation pieces before they can reach the drywell floor where the downcomers are located.

b. Covers over downcomer openings will prevent debris from falling directly into a downcomer.

c. Downcomer openings are above the floor. The downcomer pipes extend 18 inches above the drywell floor. This feature prevents entry of all heavier insulation debris due to the specific gravity of the debris and low velocity of the water converging on the downcomer rims. Floating debris, in most cases, will be partially submerged, which will prevent them from passing over the downcomer rim.

d. The clearances around the jet deflector assembly covering the downcomer openings are such that debris with dimensions larger than 10 inches will be blocked from entering the downcomer.

In the case of metallic reflective insulation, it will immediately sink to the bottom of the drywell floor pool, where the flow velocities are too low to transport this insulation over the downcomer rims into the suppression pool.

In the case of permanently installed antisweat insulation, the jacketing subjected to jet forces of a high energy line break is susceptible to being blown away along with the underlying fiberglass panels. The stainless steel jacketing is too dense to be transported to the wetwell. Loose fiberglass panels that fall to the floor float due to their low specific gravity and therefore could be carried over with the emergency core cooling water and be transported to the suppression pool. However, due to the minimal quantity of antisweat insulation provided on piping in the drywell, and the filtering effect of the physical barriers noted above, it is improbable that sufficient antisweat insulation materials would be available to plug the pump suction strainers.

In the case of stainless steel encapsulated low conductivity insulation, the steel jackets are welded around the low conductivity insulation and would therefore be expected to stay intact even if the entire assembly is blown away from the piping due to jet forces of a high energy line break. If the low conductivity insulation remained dry within the steel jackets, the assembly would have a lower specific gravity than water, thus allowing the assembly to float. However, vent holes are provided in each assembly for pressure equalization, so the low conductivity insulation would become wet, in which case the assembly would have a higher specific gravity than water and would sink. If the low conductivity insulation remained dry long enough to allow it to float to the downcomer openings, the size of most individual insulation assemblies would be too large to pass through the downcomer jet deflector assemblies. Also, the submergence of most smaller assemblies will be too deep to pass over the downcomer rims. Thus, due to the minimal quantity of low conductivity insulation provided on piping in the drywell, and the low probability of any dislodged insulation assemblies being transported to the suppression pool, it is improbable that these insulation materials would plug the pump suction strainers.

There is a potential for some quantity of fiberglass insulation to travel to the suppression pool. An evaluation was made to estimate the maximum quantity of fiberglass insulation debris that might be generated by a LOCA, the amount of such debris that might enter the suppression pool and cover the ECCS strainers, the attendant pressure losses and resulting effect on the ECCS pump NPSH margins.

In this review, no credit was taken for the protective effect of stainless steel jackets on the fiberglass insulation. The head loss due to 50% plugging of the suction strainers concurrent with minimum postaccident NPSH conditions does not cause the available NPSH to drop below that required by the RCIC and HPCI pumps. Using more realistic considerations, it has been determined that other transport mechanisms will significantly reduce the actual amount of fibrous insulation debris that could migrate to the suppression pool and cover the pump strainers.

Large capacity passive pump suction strainers have been installed on each RHR and Core Spray suction line in the suppression pool via plant modification, in response to NRC I.E. Bulletin 96-03, “Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactors”. The assumptions used in sizing these new strainers are consistent with the guidance specified in Regulatory Guidance 1.82, Revision 2, “Water Sources for Long-Term Recirculation

Cooling Following a Loss-of Coolant Accident" and NUREG/CR-6224, "Parametric Study of the Potential for BWR ECCS Strainer Blockage Due to LOCA Generated Debris" as described in PECO Energy's letter from G. A. Hunger, Jr., Director Licensing, to USNRC, dated October 6, 1997, "Request for Licensing Amendment Associated with ECCS Pump Suction Strainer Plant Modification".

It has been determined that the amount of fiberglass insulation debris generated by a LOCA jet impinging on nearby insulation will not jeopardize ECCS pump operation at LGS Units 1 & 2.

The containment cooling system is designed to withstand operating loads and loads resulting from natural phenomena. Components required to operate can be tested during normal plant operation so that reliability can be ensured. Construction codes and standards are covered in Section 5.4.7.

The containment cooling system is started manually. There are no signals that automatically initiate the system. Rather, the LPCI mode of RHR operation is automatically initiated from ECCS signals. The RHR system is realigned for containment cooling by the plant operator after the reactor vessel water level has been restored (Section 6.2.1). The RHR pumps are already operating. Containment cooling is initiated in loop A or B by manually starting the RHRSW pump; closing the heat exchanger bypass valve; opening the service water valves at the heat exchanger; closing the LPCI injection valve; and opening the pool return valve, not necessarily in this order. If a single failure has occurred that prevents system initiation, the other totally redundant system is placed into operation by following the same initiation procedure. If the operator chooses to use the containment spray to reduce containment pressure, he must close the LPCI injection valve and open the spray valves. An interlock prevents the operator from opening the drywell spray valves unless a containment high pressure signal is present.

The containment cooling system equipment is located in the reactor enclosure and protected from both internal and external floods. The equipment is located in separate compartments, the walls and doors of which are steam-tight and water-tight so that flooding due to leakage from piping in an adjacent containment cooling system or other ECCS compartment does not affect the redundant containment cooling system equipment. Flood design of the reactor enclosure is discussed in Section 3.4.

6.2.2.3 Design Evaluation

If there is a postulated LOCA, the short-term energy release from the reactor primary system is dumped to the suppression pool. Subsequent to the accident, fission product decay heat results in a continuing energy input to the pool. The containment cooling system removes this energy that is input to the primary containment system, thus resulting in acceptable suppression pool temperatures and containment pressures.

To evaluate the adequacy of the containment cooling mode of the RHR system, the following sequence of events is assumed to occur:

a. With the reactor initially operating at 3528 MWt, a LOCA occurs.

b. A LOOP occurs and one emergency diesel fails to start and remains out of service during the entire transient. This is the worst single active failure.

c. Only three LPCI pumps are activated and operated as a result of no offsite power and minimum onsite power. Section 6.3 describes the ECCS equipment.

d. No credit may be taken for manual actions within 10 minutes of a design basis accident. Analytically, it is assumed that containment heat removal begins at 10 minutes following a design basis LOCA. However, containment heat removal by activating an RHR heat exchanger for suppression pool cooling will be initiated in accordance with plant emergency operating procedures based on plant conditions. Once containment cooling has been established, no further operator actions are required.

When calculating the long-term post-LOCA pool temperature transient, it is assumed that the initial suppression pool temperature and the RHRSW temperature are at their maximum values. This assumption maximizes the heat sink temperature to which the containment heat is rejected and thus maximizes the containment temperature. All heat sources in the containment are considered with no credit taken for any heat losses other than through the RHR heat exchanger. These heat sources are discussed in Section 6.2.1.3. In addition, the RHR heat exchanger is assumed to be in a fully fouled condition at the time the accident occurs. This conservatively minimizes the heat exchanger heat removal capacity.

Figure 6.2-10 shows the actual heat removal rate of the RHR heat exchanger. The resultant suppression pool temperature transient is described in Section 6.2.1.1.3.3.1 and is shown in Figure 6.2-9. Even with the degraded conditions outlined above, the maximum suppression pool temperature is maintained below the design limit of 220°F.

The conservative evaluation procedure described above clearly demonstrates that the RHR system in the containment cooling mode meets its design objective of limiting the post-LOCA containment temperature transients safely.

6.2.2.4 Tests and Inspections

The Suppression Pool floor and low pressure ECCS (RHR and Core Spray) suction strainers shall be visually inspected for sludge accumulation and foreign material. The visual inspection allows use of a remote camera in lieu of divers. The interval of these inspections shall be every other refueling outage.

Preoperational tests are performed to verify individual component operation, individual logic element operation, and system operation up to the drywell spray spargers. A sample of the sparger nozzles is bench-tested for flow rate versus pressure drop to evaluate the original hydraulic calculations. Finally, the spargers are tested by air to verify that all nozzles are clear.

The preoperational test program of the containment cooling system is described in Chapter 14.

A design flow functional test of the RHR pumps is performed for each pump during normal plant operation by taking suction from and returning to the suppression pool. The discharge valves to the reactor recirculation system loops remain closed during this test, and reactor operation is undisturbed.

An operational test of the discharge valves is performed by shutting the downstream valve after it has been satisfactorily tested, thereby establishing the RCPB at the downstream valve, and then operating the upstream valve. The discharge valves to the drywell spray headers are checked in a similar manner by operating the upstream and downstream valves individually. All these valves can

be actuated from the control room by using remote manual switches. Control system design provides automatic return from the test to the operating mode if LPCI initiation is required during testing.

The surveillance frequency for testing and inspection is discussed in Chapter 16.

6.2.2.5 Instrumentation Requirements

The containment spray and suppression pool cooling modes of the RHR system are manually initiated from the control room. Once initiated, containment cooling performance is monitored by suppression pool temperature, flow, and containment pressure instrumentation. Details of the instrumentation are provided in Section 7.3.1.

6.2.3 SECONDARY CONTAINMENT FUNCTIONAL DESIGN

The secondary containment consists of three distinct isolatable zones. Zones I and II are the Unit 1 and Unit 2 reactor enclosures, respectively. Zone III is the common refueling area. Each zone has an independent normal ventilation system which is capable of providing secondary containment zone isolation as required.

Each reactor enclosure (Zones I or II) completely encloses and provides secondary containment for its corresponding primary containment and reactor auxiliary or service equipment, including the RCIC system, RWCU system, SLCS, CRD system equipment, the ECCS, and electrical equipment components.

The common refueling area (Zone III) completely encloses and provides secondary containment for the refueling servicing equipment and spent fuel storage facilities for Units 1 and 2.

When a unit's primary containment is open, as it is during the refueling period, the associated reactor enclosure and common refueling area provide primary containment for the unit being refueled.

The ability to procedurally combine each of the reactor enclosure secondary containment zones to the common refueling area secondary containment zone exists. The combining of the associated isolation zones is accomplished via an interlock switch located on the auxiliary equipment room panels. Table 6.2-29 identifies the associated secondary containment ventilation system automatic isolation valves that are required for the combined zone alignment.

6.2.3.1 Design Bases

a. The conditions that could exist following a LOCA or fuel handling accident require the establishment of a method of controlling any fission products that may leak into the secondary containment.

b. The functional capability of the ventilation system to maintain negative pressure in the secondary containment with respect to the outdoors is discussed in Sections 6.5.1.1 and 9.4.2.

c. The seismic design, leak-tightness, and internal and external design pressures of the secondary containment structure are discussed in Section 6.2.3.2 and Chapter 3.

d. The surveillance requirements for periodic inspection and functional testing of the secondary containment structure is discussed in the Technical Specifications.

6.2.3.2 System Design

6.2.3.2.1 Secondary Containment Design

The secondary containment is designed and constructed in accordance with the design criteria outlined in Chapter 3. All of the major structural walls are constructed of reinforced concrete. All of the major structural floor slabs and roof slabs are constructed of reinforced concrete supported by structural steel framing.

The reactor enclosure secondary containment (Zones I and II) are designed to limit the inleakage to 200% of their zone free volume per day, and the refueling area secondary containment (Zone III) is designed to limit the inleakage to 50% of its zone free volume per day. These inleakage rates are based on a negative interior pressure of 0.25 in wg, while operating the SGTS. Following a LOCA the affected zone is maintained at this negative pressure by operation of the SGTS. The secondary containment zones are identified in Figures 6.2-27 through 6.2-35.

An analysis of the post-LOCA pressure transient in the Unit 1/2 reactor enclosure secondary containment was performed (Figure 6.2-52). The length of time following isolation signal initiation of the SGTS that the pressure in the secondary containment would exceed -0.25 in wg. is 15.5 minutes based on drawing down both reactor enclosures and the common refueling area simultaneously.

In addition to the pressure transient analysis, a detailed review has been performed to identify potential leakage paths from either the primary containment or the secondary containment to the common refueling area. This review resulted in the following changes which ensure that no leakage paths exits:

a. A vent path from the reactor well to the reactor enclosure was added. When blind flanges are attached, the vent path will be through the associated opened drain lines or through a 1.5 inch hole in the blind flange.

b. Normally closed valves on the reactor well skimmer drain lines were added.

c. Provisions have been made to ensure that there is no flow path through the drain system between the refueling area and the reactor enclosure secondary containment.

Periodic tests are performed in accordance with the plant Technical Specifications to verify that the reactor enclosure secondary containment inleakage is less than 200% of its free volume per day at a negative interior pressure of 0.25 in wg.

The time line of events for actuating the SGTS is as follows:

Event	Time (sec)
Start of accident	0
Signal to start diesel	3
Diesel ready to load	13
Apply power to 480 V block 1 load	16
SGTS fans at rated speed	18

A maximum SGTS flow rate of 2800 cfm from a single reactor enclosure zone was used for the drawdown analysis.

The guidelines stated in the SRP 6.2.3 have been followed in calculating the drawdown time as noted:

a.

1. The heat transfer coefficients found in BTP CSB 6-1 apply to an atmosphere with high-energy blowdown where condensation on the primary containment surface is expected. Because the drawdown analysis was only 15.5 minutes long, the primary containment heat load was calculated as the steady-state load during normal operation when there are no condensation effects. This is accurate because LOCA conditions inside the primary containment will not affect the exterior surface temperature of the 6 foot containment wall significantly in 15.5 minutes. For steady-state heat load a conservative value was assumed.

2. Steady-state conduction and convection was calculated.

3. Radiant heat transfer was considered.

b. Adiabatic boundary conditions were used.

c. There will be negligible expansion of the 6 foot thick primary containment concrete walls in 15.5 minutes.

d. Inleakage was considered.

e. No credit was taken for outleakage.

f. The analysis was based on the assumptions and delays indicated in the acceptance criteria.

g. Heat loads generated within the secondary containment were considered.

h. Fan performance characteristics were considered.

Information that demonstrates the external design pressure of the secondary containment structure ensures an adequate margin above the maximum expected external pressure for wind loadings, tornado loadings, and explosion loadings. This information is provided in Sections 3.3 and 2.2.3.

The openings provided for gaining access to the secondary containment are listed in Table 6.2-13, and are shown in Figures 6.2-27 through 6.2-33.

Personnel Access Doors:

At each secondary containment personnel access opening there are two doors, which are designated the inner door and the outer door. Each door is equipped with a door position switch to provide monitoring. The monitoring circuitry consists of local indicating lights, local audible alarms, and control room annunciator lights and alarms. The monitoring operation is as follows:

a. Both doors closed - the blue indicating lights located on both sides above each door are de-energized

b. One door opened (either inner or outer) - the blue indicating lights above the door that is still closed are energized to warn against opening. The blue indicating lights above the opened door are still de-energized.

c. Both doors opened - the blue indicating lights above each door are energized; an instantaneous audible local alarm is energized; a time delay relay is energized and, after a preset time, it energizes a control room annunciator to identify that secondary containment access has been breached.

Closure of one of the doors returns the system condition to the same status as in paragraph B, above.

Equipment Access Doors:

All equipment access doors are kept locked. Each door is equipped with a door position switch to provide constant monitoring. The monitoring circuitry consists of a blue light indication on both sides of each door; instantaneous audible local alarm; and time delayed alarm in the main control room. The monitoring operation is the same as for the Personnel Access Doors described above.

Entrances to the reactor enclosure are provided with air locks for separation. Access doors between reactor enclosure ventilation zones are provided with airlocks.

The railroad access shaft, located between Unit 1 and Unit 2, is accessible through airlocks to the reactor enclosures and through the refueling floor ventilation duct-work and access hatch to the refueling floor. The railroad access door position is constantly monitored and alarmed (in the plant security system), under the requirements defined in the Physical Security Plan. Administrative procedures require that the access shaft outside door be closed and locked unless the access shaft is sealed closed from the refueling area and the ventilation duct-work is blocked whenever the refueling area secondary containment is required to be maintained.

Each door and section of the hatch is equipped with a position switch to provide constant monitoring. The monitoring circuitry consists of a blue light indication on both sides of the railroad access door and the top of the refueling floor access hatch; instantaneous audible local alarm; and time delayed alarm in the main control room. The monitoring operation is the same as for the Personnel Access Doors described above.

The boundaries of the secondary containment are shown in Figures 6.2-27 through 6.2-35.

The secondary containment design data are in Table 6.2-14.

6.2.3.2.2 Secondary Containment Isolation System

Isolation dampers and the plant protection signals that activate the secondary containment isolation system are described in Section 9.4.2.1.3.

6.2.3.2.3 Containment Bypass Leakage

Upon receipt of a reactor enclosure isolation signal, the RERS and the SGTS are automatically activated and begin to process all air flow streams from the reactor enclosure ventilation system. Therefore, if a LOCA occurs, radioactivity that exfiltrates the steel-lined primary containment or piping systems containing radioactive fluids is collected and passed through the RERS and SGTS as described in Section 6.5.

The potential paths by which leakage from the primary containment can bypass the areas serviced by the SGTS have been evaluated. Table 6.2-15 identifies all primary containment penetrations, the termination region of all lines penetrating primary containment, and the bypass leakage barriers in each line. It has been determined that no potential bypass leakage paths exist except for the feedwater line following a feedwater line break inside containment and the TIP purge nitrogen supply line. No significant amounts of radioactivity will be released to the environment in either case, as discussed below.

Leakage through the containment isolation valves of the TIP purge line could be released from a break or equipment failure into the reactor enclosure, radwaste enclosure, or outdoors. Leakage into the reactor enclosure would not constitute a bypass leakage path because the reactor enclosure is serviced by the SGTS. Any leakage into the radwaste enclosure would not result in a significant release of radioactivity because of plateout, deposition, and transport delay within the TIP purge piping. The long lines within the reactor enclosure (>240 feet of 1 inch pipe and >220 feet of 6 inch pipe) and the presence of numerous valves in these lines (2 containment isolation valves, a ¼ inch check valve, a ¼ inch solenoid valve, a ¼ inch metering valve, a 1 inch check valve, and a 1 inch globe valve) provide a long and tortuous route between the primary containment and the radwaste enclosure. Any leakage through the reactor enclosure and radwaste enclosure piping would be into the liquid nitrogen facility (tanks, vaporizers, control valves, etc.) located adjacent to the radwaste enclosure. The liquid nitrogen facility maintains system pressure at 50 psig.

A water seal cannot be maintained in the broken feedwater line by the feedwater fill system (Section 6.2.3.2.3.2) for the case of a feedwater line break inside containment. For this case, containment leakage may travel past the broken feedwater line's containment isolation valves into the portion of the feedwater line located in the turbine enclosure. However, a water seal in this portion of the feedwater line would be maintained by water from the CST as discussed in Section 6.2.3.2.3.1.

When designating the termination region, if either the system line that penetrates primary containment or any branch lines connecting to it penetrate the reactor enclosure, the termination region is listed in Table 6.2-15 as outside reactor enclosure. The types of bypass leakage barriers employed by these lines are:

1. Redundant primary containment isolation valves

2. Closed piping system inside primary containment

3. A water seal maintained for 30 days following a LOCA

4. The line beyond the outboard primary containment isolation valve is vented to the reactor enclosure by use of a vent line located upstream of the two block valves.

5. A MSIV alternate drain pathway is provided.

6. The line contains a temporary spool piece that is removed during normal operation and replaced by blind flanges so that any leakage through the flange is into the reactor enclosure.

7. A closed seismic Category I piping system outside primary containment.

8. The line contains a spectacle flange with the blind side installed during normal operation. Any leakage through the flange will be into the reactor enclosure.

9. The line contains two spring loaded check valves and two manual stop valves.

Type 1 and Type 2 leakage barriers are considered to limit but not eliminate bypass leakage. Leakage barriers of Type 3 through Type 9 are considered to effectively eliminate any bypass leakage.

Leakage from those lines terminating in the reactor enclosure is collected during the LOCA because the reactor enclosure is restored to and maintained at subatmospheric pressure and all exhaust is processed by the RERS and SGTS during these modes (Section 6.5). Therefore, lines terminating within the reactor enclosure are not considered potential bypass leakage paths.

Lines penetrating primary containment are isolated following a LOCA as described in Section 6.2.4. All containment isolation valves and penetrations are designed to seismic Category I requirements.

The primary containment and penetration leakage is monitored during periodic tests as discussed in Section 6.2.6. Those penetrations for which credit is taken for water seals as a means of eliminating bypass leakage (Table 6.2-15) are preoperationally leak tested with water and Technical Specification leakage rates are given as water leak rates.

6.2.3.2.3.1 Water Seals

In each case where water seals are used to eliminate the potential of reactor enclosure bypass leakage, a 30 day water seal is assured because either a loop seal is present or the water for the seal is provided from a large reservoir. The water seals for all of these lines will be maintained at a pressure greater than the peak containment accident pressure. Each of the water seals listed in Table 6.2-15 is discussed below (some penetrations may be listed more than once due to the presence of multiple types of water seals).

a. Penetrations 9A, 9B, and 44:

   The feedwater fill system (Section 6.2.3.2.3.2) is used to maintain a water seal in the lines downstream of these penetrations. The feedwater fill system cannot maintain a water seal in the feedwater lines (penetrations 9A and 9B) following a feedwater line break inside containment. However, for this case, a water seal will be maintained in the piping and equipment between the CST and the feedwater penetrations because:

   1. The elevation of the primary containment penetrations is 287 ft.

   2. The elevation of the minimum CST water level is 246 ft.

   3. The low point of the makeup water line is at elevation 220 ft.

   Therefore, the water seal will be maintained in that portion of the piping system below el 246'. This water seal will be able to withstand the containment pressure resulting from a feedwater line break as discussed below.

Immediately after the line break, when containment pressure will be at its peak, the feedwater line will still have a pressure greater than the pressure in primary containment. The feedwater will flash into steam at the break until the line pressure matches the containment pressure, thus preventing any containment atmosphere from entering the line during this period. In addition, there are several valves in the feedwater line between the primary containment and the water seal. A pressure decrease will occur across each valve, reducing the pressure that the water seal will encounter. Figures 6.2-3 and 6.2-7 show the primary containment pressure transient following a recirculation line break. These figures show that the maximum long-term pressure post-LOCA is approximately 17 psig. The difference in elevation between the lowest point of the water seal and the minimum CST water level indicates a head of 20 psig, which is greater than the pressure that the primary containment will exert on the water seal.

The piping and equipment that comprise this potential bypass leakage flow path is continuously inspected during normal operation when pressures are more than ten times greater than post-LOCA pressures. Even considering liquid leakage from the components in the water seal, the volume of water contained in the CST is sufficiently large to ensure that a water seal is maintained for at least 30 days.

b. Penetrations 204A, 204B, 207A, 207B, 208B, 210, 212, 215, 216, 217, 226A, 226B, 235, 236, 238, 239, and 240:

The lines associated with these penetrations all penetrate the wetwell above the suppression pool water level and terminate at least 4 feet below the minimum suppression pool water level. A 30 day water seal is therefore assured on the submerged portion of line.

c. Penetrations 13A, 13B, 16A, 16B, 17, 39A, 39B, 45A-D, 205A, and 205B:

Piping connected to these penetrations is normally full of water and will be kept full after a LOCA due to operation of the ECCS and/or safeguard piping fill system. The suppression pool is the water source for the ECCS and fill system, and therefore a 30 day water supply is assured.

d. Penetrations 203A-D, 206A-D, 209, 214, and 237:

The lines associated with these penetrations all penetrate the wetwell at least 11 feet below the minimum water level of the suppression pool, and therefore a 30 day water seal is assured.

e. Penetrations 231A and 231B:

The line to the containment isolation valves from the drywell floor drain sump is maintained full of water by an elevation difference between the sump and the valves. The line to the containment isolation valves from the drywell equipment drain tank is maintained full of water by an elevation difference between the tank and the valves.

f. Penetrations 10, 11, 12, 44, 228D, and 241:

Lines associated with these penetrations that pass through the secondary containment boundary and take credit for water seals are provided with loop seals inside secondary containment, which eliminates the possibility of bypass leakage. The HPCI and RCIC steam supply line connections to Auxiliary Steam contain spectacle flanges. After testing, the blind portion of the spectacle flange shall be installed. These spectacle flanges are shown on drawing M-55 (lines 4" GBD-137 and GBD-237) and on drawing M-50 (lines 3" GBD-136 and GBD-236).

g. Penetration 14:

The minimum piping height inside primary containment of the RWCU supply line that branches off the recirculation loop is at el 267'. The primary containment penetration is at el 297' and the RPV penetration is at el 280'. This elevation difference ensures that a water seal is maintained in the line from the RPV to the containment isolation valves. The RWCU supply branch line that connects to the bottom of the vessel is normally full of water, and the water will be maintained in this line because it connects directly to, and below, the vessel.

h. Penetrations 37A-D and 38A-D:

The CRD insert and withdraw lines are normally full of water. A water seal will be maintained in these lines after a LOCA due to the elevation difference between the containment penetrations (el 265') and the connections to the control rod drives (el 215').

i. Penetrations 23, 24, 53, 54, 55, and 56:

Both the drywell chilled water system and the RECW system have a system vent in the refueling area. A 30 day water seal is provided between the system vent and the containment penetrations. These systems are normally full of water and are inspected during normal operation, when system pressure is greater than post-LOCA containment pressure, to ensure that leakage is minimized. These systems have an interconnecting line between them which decreases the possibility of depleting their water seals. The systems each contain a head tank with a water-retaining boundary qualified to LOCA (hydrodynamic) loads. These tanks increase the system water inventory and maintain the head of water in the system piping greater than the maximum containment pressure following a LOCA.

j. Penetration 61:

The recirculation pump seal purge lines are vented to secondary containment by use of vent lines located before two block valves and the secondary containment (drawings M-43 and M-46). The normally open block valves (HV127 and HV128) receive an automatic containment isolation signal to close, which is shown as Reference 18 on drawing M-46. It is not necessary for the containment isolation signal to also automatically open the (normally closed) vent valves. The seal lines are normally filled with water, which will spill into secondary containment when the vent valves open. To preclude the possibility of this happening in the event of a false LOCA, the vent valves will be manually actuated to open when the operator has verified that isolation and venting of these lines is required. The water in the lines will provide a temporary seal to prevent bypass leakage until the vent valves are opened.

6.2.3.2.3.2 Feedwater Fill System

The feedwater fill system prevents the release of fission products through the feedwater containment isolation valves after a LOCA by providing a water seal downstream of the valves.

6.2.3.2.3.2.1 Safety Design Bases

The feedwater fill system is designed with sufficient capacity and capability to prevent leakage through the feedwater lines under the conditions associated with the entire spectrum of LOCAs except for a feedwater line break inside containment.

The feedwater fill system conforms to seismic Category I requirements. Quality group classifications are shown in Table 3.2-1, Item XI.A. The system meets the intent of Regulatory Guide 1.96, where applicable.

The feedwater fill system is capable of performing its safety function considering the effects resulting from a LOCA, including missiles that may result from equipment failures, dynamic effects associated with pipe whip and jet forces, and normal operating and accident-caused local environmental conditions consistent with the design basis event. Furthermore, any portion of the feedwater fill system that is quality Group A and is located outside the primary containment structure is protected from missiles, pipe whip, and jet force effects originating outside the containment so that containment integrity is maintained.

The feedwater fill system is capable of performing its safety function following a LOCA and an assumed single active failure.

The feedwater fill system is designed so that effects resulting from a single active component failure do not affect the integrity or operability of the feedwater lines or the feedwater containment isolation valves.

The feedwater fill system is capable of performing its safety function following a LOOP coincident with a postulated design basis LOCA.

The feedwater fill system is designed to prevent leakage from the feedwater lines consistent with maintaining containment integrity for up to 30 days.

The feedwater fill system is manually actuated and is not required to be actuated sooner than 30 minutes after a LOCA.

The feedwater fill system, including instrumentation and circuits necessary for the functioning of the system, is designed in accordance with standards applicable to an ESF.

The plant is designed to permit testing of the operability of the feedwater fill system controls and actuating devices during power operation, to the extent practicable, and to permit testing of the complete functioning of the system during plant shutdowns.

6.2.3.2.3.2.2 System Description

The feedwater fill system is a subsystem of the safeguard piping fill system. The safeguard piping fill pumps provide suppression pool water as the water seal source for the feedwater lines (Section

6.3.2.2.6 and drawing M-52). The feedwater fill system consists of two fill trains, one from each fill pump. Each train is routed to both feedwater lines (drawing M-41).

Following a LOCA, the feedwater fill system is manually initiated from the control room. A water seal is provided by the fill system in both feedwater lines for all line breaks other than a feedwater line break inside containment. For this case, the feedwater fill system can be isolated from the broken feedwater line so that a water seal can be maintained in the intact feedwater line. A water seal inside the broken feedwater line cannot be maintained by the fill system for the case of a feedwater line break inside containment because the water escapes out the broken pipe into primary containment.

The sealing water to the valves eventually fills the feedwater lines up to the reactor vessel, and the water returns to the suppression pool through the LOCA break. Because the source of sealing water is the suppression pool, a 30 day water supply is assured. Operation of the feedwater fill system will not affect the function of the suppression pool because the seal water is eventually returned to the pool when the drywell is flooded back through the downcomers.

6.2.3.2.3.2.3 Safety Evaluation

The feedwater fill system is designed to prevent the release of radioactivity through the feedwater line isolation valves by providing a continuous flow of water through the feedwater lines following a LOOP coincident with the postulated design basis LOCA. The two redundant fill trains are physically separated, except where the lines are interconnected, to minimize the exposure to missiles and to the effects of pipe whip or jet impingement from high energy line breaks.

The feedwater fill system is seismic Category I and is capable of performing its intended function following an active component failure. Each fill train is powered from a different division of the Class 1E power supply. Double series isolation valves are provided to ensure that no single active failure will affect the integrity of the feedwater lines.

Feedwater line pressure is indicated in the control room so that the operator can determine if there has been a feedwater line break inside containment. If so, the operator can isolate the system from the broken line and still provide fill system water to the intact line.

6.2.3.2.3.2.4 Instrumentation and Controls

The instrumentation necessary for control and status indication of the feedwater fill system is classified as essential and, as such, is designed and qualified in accordance with applicable IEEE standards to function under seismic Category I and LOCA environmental loading conditions appropriate to its installation, with the control circuits designed to satisfy the mechanical and electrical separation criteria. Section 7.6 gives a control and instrumentation description.

6.2.3.2.3.2.5 Inspection and Testing

Preoperational tests for the safeguard piping fill system are discussed in Chapter 14. During plant operation, valves, piping, instrumentation, electrical circuits, and other components outside the steam tunnel can be inspected visually at any time. Complete system functional testing or isolation valve testing from fully closed-to-open and the return open-to-closed position is performed during reactor shutdown.

6.2.3.3 Design Evaluation

The design evaluation of the secondary containment ventilation systems are given in Sections 6.5.1 and 9.4.2. The high energy lines within the secondary containment are identified and pipe ruptures analyzed in Section 3.6. The leak-off system on the nitrogen purge lines has two outboard block valves in series downstream of the leak-off vent valves and the secondary containment boundary. The liquid nitrogen facility is located outside of secondary containment. Therefore, a failure of one of the outboard block valves does not prevent a negative pressure from being maintained in the secondary containment structure or result in leakage from the primary containment across the inboard valve to the environment.

6.2.3.4 Tests and Inspections

The program for initial performance testing is described in Chapter 14. The program for periodic functional testing of the secondary containment structures including SGTS drawdown time and the secondary containment isolation system and system components is described in Chapter 16. The leak rate testing program and provisions are discussed in Section 6.5.1, as part of the SGTS tests.

6.2.3.5 Instrumentation Requirements

The control systems to be employed for the actuation of the reactor enclosure ESF air handling systems are described in Section 7.3.

The control and monitoring instrumentation for the above systems is discussed in Sections 6.5.1 and 9.4.2. Design details and instrumentation logic are discussed in Section 7.3.

6.2.4 CONTAINMENT ISOLATION SYSTEM

The containment isolation system is designed to prevent or limit the release of radioactive materials that may result from postulated accidents. This is accomplished by providing isolation barriers in all fluid lines that penetrate primary containment.

6.2.4.1 Design Bases

a. The containment isolation system is designed to allow the normal or emergency passage of fluids through the containment boundary while preserving the ability of the boundary to prevent or limit the escape of radioactive materials that can result from postulated accidents.

b. The containment isolation system is designed to either automatically isolate fluid penetrations or provide the capability for remote manual isolation from the control room.

c. The arrangement of containment isolation valves for fluid systems that penetrate the primary containment conforms to GDC 54, 55, 56, and 57 to the greatest extent practicable.

d. Fluid instrument lines that penetrate primary containment conform to the isolation criteria of Regulatory Guide 1.11 to the greatest extent practicable.

e. Containment isolation provisions are designed to withstand the most severe natural phenomenon or site-related event (e.g., earthquake, tornado, wind, flood, or transportation accident) without impairing their functions.

f. The containment isolation system is designed with provisions for periodic operability and leak rate testing.

g. Valve closure times are selected to limit the release of containment atmosphere to the environs, to mitigate offsite radiological consequences, and to ensure that ECCS effectiveness is not degraded.

h. Design provisions are made to detect possible leakage from lines provided with remote manually controlled isolation valves.

i. Isolation valves, actuators, and controls are protected against loss of functional capability from missiles and accident environments for which they are designed.

j. Redundancy and physical separation are provided in the electrical and mechanical design to ensure that no single failure in the containment isolation system can prevent the system from performing its intended function (except as described in this section).

k. The design of the control systems for automatic containment isolation valves is such that resetting the isolation signal does not result in the automatic reopening of containment isolation valves (except as described in this section).

6.2.4.2 System Design

Table 6.2-17 lists the fluid system and instrument line containment penetrations and presents design information about each. Accompanying this table is Figure 6.2-36, which consists of diagrams for the various isolation valve arrangements. Cross references are provided between the diagrams and the table.

The plant protection signals and instrumentation that initiates containment isolation are discussed in Section 7.3.1.1.2.

Evaluation of the containment isolation system with respect to the following areas is discussed in separate sections as indicated:

a.	Code class and seismic design	Section 3.2
b.	Missile protection	Section 3.5
c.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
d.	Environmental design	Section 3.11

Debris transported to the suppression pool by the emergency core cooling water is prevented from entering the ECCS suction lines by suction strainers. The suction strainers are described in Section 6.2.2.

Assurance of the operability of valves and valve operators in the containment atmosphere under normal plant operating conditions and postulated accident conditions is discussed in Section 3.9.3.

Provisions for detecting leakage from systems connected to the RCPB which are provided with manual isolation valves are discussed in Section 5.2.5.

The design provisions for testing the operability of the isolation valves and the leakage rate of the containment isolation barriers are discussed in Section 6.2.6.

An alternate drain pathway is provided for the MSIVs, and is discussed in Section 6.7. A seismic Category I fill system provides a water seal for the feedwater lines, as discussed in Section 6.2.3.2.3.

Containment isolation valve closure times are selected to ensure rapid isolation of the containment following postulated accidents. The isolation valves, in lines that provide an open path from the containment to the environs, have closure times that limit the release of containment radioactivity to the environs to below 10CFR50.67 dose limits, mitigate the offsite radiological consequences, and ensure that ECCS effectiveness is not degraded. These valve closure times are identified with a double asterisk in Table 6.2-17. The isolation valves for lines in which HELBs can occur have closure times that limit the resultant pressure and temperature transients as well as the radiological consequences. These valve closure times are identified with a single asterisk in Table 6.2-17.

All of the isolation valve closure times listed in Table 6.2-17 are the actual closure times that the isolation valves were purchased with, which in all cases are equal to or lower than the closure times necessary to meet the aforementioned design requirements. The given valve closure times are the maximum time it takes for a valve to move to its fully closed position after power has reached the operator assembly. Those closure times which are required to be met to satisfy isolation valve closure time design requirements are identified by a single or double asterisk in Table 6.2-17.

The essential/nonessential classification of containment isolation valves, as listed in Table 6.2-17, was based on the following: those systems identified as essential are regarded as indispensable or are backup systems in the event of an accident; nonessential systems have been judged to not be required after an accident. The classification of essential and nonessential systems is given in Table 6.2-27.

Isolation valves are designed to be operable under environmental conditions such as maximum differential pressures, seismic occurrences, steam atmosphere, high temperature, and high humidity. The normal and accident environmental conditions are described in Section 3.11.

Refer to Table 6.2-17 for isolation valve power supplies.

Motor-operated isolation valves remain in their last position upon failure of electrical power to the motor operator. Air operated containment isolation valves are spring-loaded to close upon loss of air or electrical power.

The design of the isolation valve system gives consideration to the possible adverse effects of sudden isolation valve closure when the plant systems are functioning under normal operation.

Reopening of the containment isolation valves requires deliberate operator action. The HPCI and RCIC steam line isolation valves are exceptions as discussed in Section 7.1.2.11. Control systems for the automatic containment isolation valves are discussed in Section 7.3.1.1.2.

The LGS containment purge valves have been designed to function if a LOCA should occur while the purge valves were open. The valve manufacturer has completed an extensive program of tests

and analyses to demonstrate the operability of the valves in accordance with all published NRC guidelines and criteria. The following is a brief summary of the factors addressed in the valve operability qualification report (Reference 6.2-8):

a. Valves are supplied in accordance with ASME Section III, Class 2 requirements

b. Finite-element analyses have been used to determine valve component stress levels for limiting combinations of loads

c. The impact of dynamic loadings is addressed by analysis and static load testing

d. All valves are located outside containment, thus eliminating concern over the effects of containment pressure on pneumatic operator performance

e. Air operators are equipped with springs to facilitate valve closure; accumulators or other pneumatic systems are not used for valve closure or sealing

f. Valve dynamic torque coefficients have been determined by reduced-scale and full-scale testing

g. The effects of installation geometry and arrangement have been fully considered

h. Containment pressure has been conservatively assumed to be constant at its maximum pressure for all valve angles

i. Back pressure caused by flow through downstream piping has been conservatively neglected

j. Elastomeric materials are not used for valve seating surfaces

k. Valve operators and pilot solenoids have been qualified to IEEE 323 (1974) and NUREG-0588 Category I requirements

l. Motor operator performance has been demonstrated at minimum available voltage levels

m. Motor operators are equipped with hand wheels which automatically disengage upon electric activation

6.2.4.3 Design Evaluation

The main objective of the containment isolation system is to provide protection by limiting release to the environment of radioactive materials. This is accomplished by isolation of system lines penetrating the primary containment. Redundancy is provided so that the active failure of any single valve or component does not prevent containment isolation.

The arrangements of isolation valves are described in Table 6.2-17 and Figure 6.2-36. In general, isolation valves have redundancy in the mode of actuation as indicated in Table 6.2-17. A program of testing, described in Section 6.2.4.4, is maintained to ensure valve operability and leak-tightness.

The design specifications require each isolation valve to be operable under the most severe environmental conditions that it might experience. Protection from potential missiles is discussed in Section 3.5.

Provisions for administrative control of the proper position of all nonpowered isolation valves, including valves in test, vent, drain, and similar types of branch lines that serve as containment isolation barriers, are maintained. The test taps, vents, drains, and similar types of branch lines that constitute containment isolation barriers are equipped with manually closed isolation valves.

Administrative controls will ensure that the valves are locked closed after use.

All power-operated isolation valves have position indicators in the control room. Discussion of instrumentation and controls for the isolation valves is included in Chapter 7.

6.2.4.3.1 Evaluation Against General Design Criteria

6.2.4.3.1.1 Evaluation Against GDC 54

All piping systems penetrating containment, other than instrument lines, are designed in accordance with GDC 54.

6.2.4.3.1.2 Evaluation Against GDC 55

GDC 55 requires that lines which penetrate the primary containment and form a part of the RCPB must have two isolation valves; one inside the containment and one outside, unless it can be demonstrated that the containment isolation provisions for a specific class of lines are acceptable on some other basis.

The RCPB, as defined in 10CFR50, Section 50.2 (v), consists of the RPV, pressure-retaining appurtenances attached to the vessel, and valves and pipes that extend from the RPV up to and including the outermost isolation valve.

6.2.4.3.1.2.1 Influent Lines

All influent lines that penetrate the primary containment and connect directly to the RCPB are equipped with at least two isolation valves, one inside the drywell, and the other outside the drywell and as close to the external side of the containment as practicable.

6.2.4.3.1.2.1.1 Feedwater Line

The feedwater lines are part of the RCPB as they penetrate the drywell to connect with the RPV. Each of the two feedwater penetrations is provided with a series arrangement of three isolation valves:

a. A check valve is provided inside the drywell as close to the containment wall as practicable. For a worst case break of a feedwater line inside containment, it would be impossible to ensure the operability of the inboard check valve due to pipe whip forces.

b. A spring assisted check valve is provided outside the drywell as close to the containment wall as practicable. The spring forces the valve flapper in the closed

direction, thus providing added assurance of valve seating in the event of low pressure in the supply piping. The spring will not prevent flow in the downstream (toward the vessel) direction but does create some flow restriction. An air operator is provided with the check valve assembly. This air operator is normally pressurized, thus compressing the spring and reducing the flow restriction.

c. A third check valve is provided in the feedwater line outboard of the above described spring assisted check valve. The function of these valves is to:

1. Prevent HPCI, RCIC, and RWCU water from flowing upstream in the feedwater line, thus ensuring flow into the reactor vessel.

2. Provide isolation in the event of a feedwater line break upstream of this valve.

This third check valve includes a motor operator to seal the disc closed for long-term leakage control.

Additional isolation valves are provided on each of the lines connecting to the feedwater lines inboard of the check valve :

1. MOVs are provided on the HPCI, RCIC, and long path recirculation lines.

2. A spring assisted check valve is provided on the RWCU supply line. This valve is of a design similar to the outboard spring assisted feedwater check valves described above. This RWCU check valve is spring assisted to seal the disc closed for long-term leakage control.

In the Limerick SER Section 6.2.4, licensee committed to administrative procedures that will require isolation of the main feedwater, RWCU, RCIC, and HPCI system lines following an accident if these systems are not providing reactor coolant makeup. The NRC included this commitment in the SER to satisfy SRP 6.2.4.6.b criteria. Instead of using a leakage detection system in conjunction with a remote manual containment isolation valve, to satisfy SRP criteria, these valves would be procedurally controlled and remotely closed from the control room to provide long term leakage protection after a postulated LOCA to satisfy SRP criteria.

Plant procedures will require remote manual closure of the remote manual containment isolation valves in the main feedwater and RWCU systems, if reactor coolant makeup is no longer required. The containment isolation valves in the RCIC and HPCI system automatically reposition closed, if reactor coolant makeup is no longer required from these systems. Therefore, plant procedures will not be required to remote manually close the RCIC and HPCI containment isolation valves.

Limerick SER Section 6.2.4 also states that a remote-manual motor-operated valve upstream of the air-operated check valve on the RWCU branch line that can also be utilized to isolate this line. This non-safety related remote-manual motor-operated valve upstream of the air-operated check valve is not capable of, or required to support a safety related long-term leakage control function as described in the SER.

6.2.4.3.1.2.1.2 Core Spray (CS) Loop B

The CS loop B line penetrates the drywell to inject directly into the RPV. Isolation is provided by two valves in the CS line, a pneumatic testable check valve inside the containment, and a spring assisted check valve outside the containment, with positions of both indicated in the main control room. The

core spray loop B line is also provided with a normally closed pneumatic operated globe valve which bypasses the inboard isolation valve for equalization during testing.

Although not a containment isolation valve, a MOV is provided outboard of the spring assisted check valve to provide isolation of this flow path for long-term leakage control.

One branch of the HPCI line connects to the CS loop B upstream of the outboard spring assisted check valve. Although not a containment isolation valve, the HPCI line also contains a MOV outboard of the spring assisted check valve to provide isolation of this flow path for long-term leakage control.

6.2.4.3.1.2.1.3 LPCI and CS Loop A

The LPCI lines and CS loop A line are provided with remote manually controlled gate valves outside and pneumatic testable check valves inside containment. Both types of valves are normally closed with the gate valves receiving an automatic signal to open at the appropriate time. The check valves are located as close as practicable to the RPV. The normally closed check valves limit containment pressurization if there is a pipe rupture between the check valve and containment wall. The core spray loop A line and the LPCI lines are also each provided with a normally closed pneumatic operated globe valve which bypasses the inboard isolation valve for testing purposes.

6.2.4.3.1.2.1.4 Deleted

6.2.4.3.1.2.1.5 Recirculation Pump Seal Purge Line

The recirculation pump seal purge line extends from the CRD supply line outside primary containment, penetrates primary containment through an excess flow check valve outside and a check valve inside containment, and connects to the recirculation pump seal housing. The 1 inch recirculation pump seal purge line is Quality Group Classification A from the pump up to and including the excess flow check valve outside containment. Should this line be postulated to fail and either one of the check valves is assumed to fail open, the flow rate through a broken line outside containment is calculated to be substantially less than that permitted for a broken instrument line. Therefore, the two check valves in series provide sufficient isolation capability for the postulated failure of this line.

6.2.4.3.1.2.1.6 Standby Liquid Control System Lines

The SLCS line penetrates the drywell and connects to the Core Spray loop B line. In addition to a simple check valve inside the drywell, a globe stop-check valve is located outside the drywell. Since the SLCS line is a normally closed, nonflowing line, rupture of this line is of extremely remote probability. The globe stop check includes a motor operator to seal the valve closed for long-term leakage control.

6.2.4.3.1.2.1.7 RWCU System

The RWCU pumps, heat exchangers, and filter/demineralizers are located outside the drywell. The return line branches into three separate lines outside the drywell. One line connects to the RCIC line that connects to the B feedwater line penetrating the drywell and injecting directly into the RPV. The second branch connects directly to the A feedwater line that penetrates the drywell and injects directly into the RPV.

Isolation of both these lines is provided by the feedwater system check valves inside and outside the containment and a spring assisted check valve in the connecting RWCU return line.

Following a LOCA, it is desirable to maintain reactor coolant makeup. For this reason, the above remote manual containment isolation valves are not provided with automatic isolation signals. However, plant procedures will require remote manual closure of the remote manual containment isolation valves, if reactor coolant makeup is no longer required.

The third line penetrates the drywell and then connects to the A feedwater line that injects directly into the RPV. This line is only used during outages. Isolation is provided by one locked closed globe valve inside containment and one locked closed globe valve outside containment. A 3/4 inch relief valve is provided outside containment between the two isolation valves for thermal relief.

6.2.4.3.1.2.1.8 RCIC Line

The RCIC line connects to the B feedwater line outside containment that penetrates the drywell to inject directly into the RPV. The feedwater line has a check valve both inside and outside the drywell. In addition to these two isolation valves, a motor- operated gate valve is located in the RCIC line that is normally closed and receives an automatic signal to open. Following a LOCA, plant procedures will require remote manual closure of this isolation valve unless RCIC is providing reactor coolant makeup.

6.2.4.3.1.2.1.9 RHR Shutdown Cooling Return

Each RHR shutdown cooling return line penetrates primary containment and discharges into a recirculation pump discharge line that injects directly into the RPV. Isolation is provided by an automatically actuated motor-operated globe valve outside containment and a pneumatic testable check valve and a spring-assist check valve inside containment. A normally closed pneumatic operated globe valve is provided which bypasses the inboard isolation testable check valve for equalization during testing. To increase the reliability of RHR shutdown cooling mode during refueling outages, the automatic isolation function of the RHR shutdown cooling mode return motor-operated valves is typically bypassed provided that automatic isolation is not required by the Technical Specifications or Technical Requirements Manual and the reactor cavity is flooded up. Manual isolation capability is retained.

6.2.4.3.1.2.2 Effluent Lines

Effluent lines that form part of the RCPB and penetrate containment are equipped with at least two isolation valves; one inside the drywell and the other outside, located as close to the containment as practicable or justified on an alternate basis.

6.2.4.3.1.2.2.1 Main Steam, RCIC and HPCI Steam Lines, and RHR Shutdown Cooling Supply Line

The main steam lines extend from the RPV to the main turbine and condenser system, and penetrate the primary containment. For these lines, isolation is provided by automatically actuated globe valves, one inside the containment and one just outside the containment. The MSIVs are spring-loaded, pneumatic, piston- operated globe valves designed to fail closed on loss of pneumatic pressure or loss of power to the solenoid-operated pilot valves. Each valve has two independent pilot valves supplied from independent power sources. Each MSIV has an accumulator to assist in its closure upon loss of normal supply. The springs and accumulator provide a local stored energy source dedicated to closure of an MSIV under all conditions which requires MSIV closure.

The main steam line drain connects to the main steam lines inside containment and extends through containment to the condenser. This line is provided with motor-operated gate valves inside and

outside containment that receive an automatic isolation signal to close when the reactor water level drops below Level 1.

The RCIC turbine steam supply line from main steam line B is provided with two motor-operated, normally open globe valves, one inside and one outside the containment. These valves are closed on receipt of an RCIC isolation signal. The HPCI system turbine steam supply line from main steam line C is provided with motor-operated, normally open globe valves, one inside and one outside containment. These valves are closed on receipt of a HPCI isolation signal.

The RCIC and HPCI steam lines are each also provided with a normally closed motor-operated globe valve that bypasses the outboard isolation valve for steam supply line warmup purposes only. The valve in the RCIC steam line is closed upon receipt of an RCIC isolation signal, and the HPCI steam line valve is closed upon receipt of an HPCI isolation signal. The isolation signals are considered adequate because there is no consequence if the valves open or leak while the system is in operation and appropriate isolation signals are provided to secure the line when system isolation is required.

The RHR shutdown cooling supply line is provided with motor- operated gate valves, one inside and one outside containment, that receive an automatic isolation signal when isolation is required. To increase the reliability of RHR shutdown cooling mode during refueling outages, the automatic isolation function of the RHR shutdown cooling mode supply motor-operated valves is typically bypassed provided that automatic isolation is not required by the Technical Specifications or Technical Requirements Manual and the reactor cavity is flooded up. Manual isolation capability is retained.

6.2.4.3.1.2.2.2 Main Steam and Recirculation System Sample Lines

Sample lines from the main steam and recirculation lines penetrate the primary containment. These lines are provided with air operated globe valves, one inside and one outside containment, that receive an automatic isolation signal if there is an accident, or fail closed on loss of air or electrical power.

6.2.4.3.1.2.3 CRD Lines

The CRD system has multiple lines, the insert and withdraw lines, that penetrate primary containment.

The classification of these lines is Quality Group B, and they are designed in accordance with ASME Section III, Class 2. The basis on which the CRD insert and withdraw lines are designed is commensurate with the safety importance of maintaining the pressure integrity of these lines.

The CRD insert and withdrawal lines are not provided with automatic containment isolation valves in order to maximize the reliability of the scram function. A ball check valve located in the CRD flange housing automatically seals the insert line in the event of a line break. The insert and withdrawal lines terminate in HCUs which contain multiple valves (manual, solenoid, air operated, and check valves) to control CRD movement, and limit leakage. The isolation function is provided by two redundant simple check valves outboard of the HCUs on each main water header (charging, cooling, drive and exhaust). All automatic valves in the HCUs are normally closed and are open only during rod movement. Because the scram valves in the HCU are normally open after a scram, the scram discharge volume is provided with redundant automatic vent and drain valves.

6.2.4.3.1.2.4 Conclusion on GDC 55

In order to ensure protection against the consequences of accidents involving the release of radioactive material, pipes that form the RCPB are shown to provide adequate isolation capabilities on a case-by-case basis. In all cases, a minimum of two barriers are shown to limit the release of radioactive materials.

The pressure-retaining components that comprise the RCPB are designed to meet other appropriate requirements that limit the probability or consequences of an accidental pipe rupture. The quality requirements for these components ensure that they are designed, fabricated, and tested to the highest quality standards of all reactor plant components. The classification of components that comprise the RCPB are designed in accordance with ASME Section III, Class 1, with the exception of the CRD insert and withdrawal lines as discussed in Section 6.2.4.3.1.2.3 above.

It is therefore concluded that the design of piping systems that comprise the RCPB and penetrate containment either meet the explicit requirements of, or are acceptable alternatives to the explicit requirements of GDC 55.

6.2.4.3.1.3 Evaluation Against GDC 56

GDC 56 requires that lines which penetrate the containment and communicate with the containment interior must have two isolation valves; one inside the containment and one outside, unless it can be demonstrated that the containment isolation provisions for a specific class of lines are acceptable on some other basis.

6.2.4.3.1.3.1 Influent and Effluent Lines to Suppression Pool

Typically, lines which connect directly to the suppression pool are provided with a single remote manual or automatic isolation valve. These valves are attached to lines which are an extension of the containment and are enclosed in a pump-room adjacent to the containment which has provisions for environmental control of any fluid leakage. The lines to the suppression pool are always submerged so no containment atmosphere can impinge upon the valves.

The systems which the lines from the suppression pool connect to outside containment are closed systems meeting the appropriate requirements of closed systems, except for the suppression pool cleanup line and the RCIC vacuum pump discharge line. Both of these lines have redundant containment isolation valves.

The valves provide a barrier outside containment to prevent loss of suppression pool water should a leak develop downstream of the valves in the lines from the suppression pool. (The valves are either remotely closed from the control room or automatically closed to accomplish this. Leak detection is provided for the lines outside containment so that the operator can determine which valve is to be closed.) Should a leak develop outside containment, the fluid will be contained within compartments that have provisions for the environmental control of any fluid leakage. The configuration of the connection of the lines to the suppression pool assures that the connections are always submerged, and prevents escape of containment atmosphere.

6.2.4.3.1.3.1.1 CS, HPCI, and RHR Test Lines and Minimum Flow Bypass Lines

The CS, HPCI, and RHR test and minimum flow bypass lines have isolation capabilities commensurate with the importance to safety of isolating these lines.

The RHR pump test lines connect to the associated minimum flow bypass lines outside primary containment and penetrate containment through normally open, remote manually controlled gate valves located directly on the containment. This reduces the number of penetrations through the primary containment, thus minimizing the potential pathways for radioactive material release.

The CS pump test lines have a normally closed, motor-operated globe valve located directly on the containment that receives an automatic isolation signal if there is an accident. The CS minimum flow bypass lines have a normally open motor-operated globe valve that receives an automatic isolation signal when adequate flow is established in the pump discharge lines.

The HPCI pump test line has a normally closed motor-operated gate valve located directly on the containment that receives an automatic isolation signal if there is an accident. The minimum flow bypass line has a normally closed motor-operated globe valve located directly on the containment that receives an automatic isolation signal when adequate flow is established in the pump discharge lines.

The CS, HPCI and RHR pump test and minimum flow bypass lines discharge below the surface of the suppression pool. Thus the lines are not directly open to the containment atmosphere.

6.2.4.3.1.3.1.2 RCIC Turbine Exhaust, Vacuum Pump Discharge, and RCIC Pump Minimum Flow Bypass Lines

The lines that penetrate the containment and discharge to the suppression pool are equipped with a remote manually actuated valve. The RCIC turbine exhaust isolation valve is a normally open motor-operated gate valve. The vacuum pump discharge isolation valve is a normally open globe stop-check valve. The RCIC pump minimum flow bypass isolation valve is a normally closed motor-operated globe valve. In addition, there is a check valve upstream of each valve that provides positive actuation for immediate isolation if there is a break upstream of this valve. The gate valve in the RCIC turbine exhaust is designed to be key-locked open in the control room and interlocked to preclude opening of the inlet steam valve to the turbine when the turbine exhaust valve is not in a fully open position. The RCIC vacuum pump discharge line is also normally key-locked open but has no requirement for interlocking with the steam inlet to the turbine. The RCIC vacuum pump discharge line is provided with a stop-check valve at the containment to automatically prevent flow out of the containment. This valve functions as both a check valve and a remote manually actuated globe valve. A remote manually actuated motor operator ensures the long-term positive closure of the stop-check valve. This arrangement ensures that the essential RCIC pump-turbine will be ready to operate in the event of a reactor vessel isolation occurrence accompanied by loss of feedwater flow. The RCIC pump minimum flow bypass line is isolated by a normally closed remote manually actuated valve that is automatically isolated when adequate flow is obtained in the pump discharge line, with a check valve installed upstream. These lines discharge below the surface of the suppression pool. Thus, the lines are not directly open to containment atmosphere.

6.2.4.3.1.3.1.3 RHR Heat Exchanger Vent Lines and Relief Valve Discharge Lines

The Unit 2 RHR heat exchanger vent lines discharge to the suppression chamber via relief valve discharge lines and are provided with two normally closed, remotely controlled motor-operated globe valves. The inboard valves receive an automatic isolation signal if there is a LOCA. The Unit 1 and Unit 2 relief valve discharge lines are isolated by the relief valves themselves in a fashion similar to a check valve, and the relief setting on these valves is more than 1.5 times the containment design pressure. The lines discharge below the surface of the suppression pool. Thus, the lines are not directly open to containment atmosphere.

6.2.4.3.1.3.1.4 HPCI Turbine Exhaust Line

The HPCI turbine exhaust line that penetrates the primary containment and discharges to the suppression pool is equipped with a remote manually operated gate valve located directly on the containment. In addition, there is a stop-check upstream of the gate valve that provides positive actuation for immediate isolation if there is a break upstream of this valve. The gate valve is designed to be key-locked open and interlocked to preclude opening of the inlet steam valve to the turbine while the turbine exhaust valve is not fully open. This line discharges below the surface of the suppression pool. Thus, the line is not directly open to containment atmosphere.

6.2.4.3.1.3.1.5 RHR, RCIC, CS, and HPCI Pump Suction Lines

The RHR, RCIC, CS, and HPCI suction lines contain motor-operated, remote manually actuated gate valves that provide assurance of isolating these lines if there is a break. These valves also provide long-term leakage control. In addition, the suction piping from the suppression chamber is considered an extension of containment since it must be available for long-term usage following a design basis LOCA, and as such, is designed to the same quality standards as the containment. System reliability is greater with only one isolation valve in the line because the ECCS pumps must have the capability to take suction from the suppression pool in order to mitigate the consequences of an accident. The RHR suction lines are also provided with a relief valve that discharges back into the suppression pool through the suction line penetration. The relief valve discharge lines are isolated by the relief valves themselves in a fashion similar to a check valve.

6.2.4.3.1.3.1.6 Suppression Pool Cleanup Line

The suppression pool cleanup line is isolated by two normally closed motor-operated gate valves that close on receipt of a containment isolation signal and a relief valve (PSV-52-127) whose setting is more than 1.5 times the containment design pressure.

6.2.4.3.1.3.2 Influent and Effluent Lines from Drywell and Suppression Pool Free Volume

6.2.4.3.1.3.2.1 Containment Atmosphere Sampling Lines

The sampling system lines that penetrate the containment and connect to the drywell and suppression chamber air volume are equipped with two normally open solenoid-operated isolation valves in series, located outside and as close to the containment as possible. These valves ensure isolation of these lines if there is a break; they also provide long-term leakage control. In addition, the piping is considered an extension of the containment boundary since it must be available for long-term usage following a design basis LOCA, and, as such, is designed to the same quality standards as the primary containment. The following containment atmosphere sampling isolation valves have ganged controls for reopening:

a. Inboard drywell sample and return isolation valves SV-132, SV-134, and SV-150 are ganged on HS-132

b. Inboard suppression pool sample and return valves SV-183 and SV-191 are ganged on HS-183

c. Outboard drywell sample and return isolation valves SV-141, SV-142, SV-143, SV-144, SV-145, and SV-159 are ganged on HS-153

d. Outboard suppression pool sample and return isolation valves SV-184, SV-185, SV-186, SV-190, and SV-195 are ganged on HS-187.

6.2.4.3.1.3.2.2 Drywell Equipment and Floor Drain Lines

The drywell equipment and floor drain lines are each provided with two air operated spring-closed valves located outside the primary containment. One of these valves is normally open and one normally closed. The inner valve (normally open) is located directly on the containment. Both valves are automatically closed upon receipt of a containment isolation signal.

6.2.4.3.1.3.2.3 Containment Purge and Hydrogen Recombiner Lines

The high volume purge lines for the drywell and suppression chamber are each provided with two isolation valves located outside the primary containment. The inboard valve in each line is a normally closed, air operated butterfly valve located as close as practical to the primary containment penetration. The outboard valve in each line is a normally closed, motor-operated butterfly valve. A nonsafety-related north stack effluent high radiation isolation signal is also provided for the containment purge valves (HV-104, 109, 114, 115, 112, 121, 124, 123, 131, 135, 147). A description of the type and the arrangement of containment isolation valves used in the low volume purge exhaust lines is provided in Section 9.4.5.1.2. Each of these valves receives automatic isolation signals.

The hydrogen recombiner lines connect to the high volume purge lines between the containment penetration and the inboard isolation valve. Each of the recombiner lines is provided with two normally closed MOVs that can be manually actuated from the control room. These isolation valves each receive automatic isolation signals. For operation of the recombiners after a LOCA, the isolation signals to these valves are overridden by using key-locked bypass switches. All four isolation valves on each recombiner train are powered from the same channel of electrical power in order to minimize the impact on system reliability.

The ESF recombiner system (Section 6.2.5) is designed as a closed system outside containment in addition to the isolation valves described above. The containment isolation provisions for the recombiner lines meet all of the relevant design criteria in Regulatory Guide 1.141, ANSI N-271, and SRP 6.2.4, as described below:

a. The closed system does not communicate with either the secondary containment atmosphere or the environment.

b. The closed system has been designed, fabricated, installed, and stamped in accordance with ASME Section III, Class 2 requirements.

c. The closed system has a design temperature and pressure at least equal to the containment design conditions. The design temperatures and pressures are as follows:

    1. Nonoperating modes: 55 psig / 340°F for stainless steel and carbon steel components

    2. Operating conditions: stainless steel components (30 psig / 1400°F)

d. The closed system is designed as seismic Category I.

e. The system is designed to withstand the loads and environmental conditions accompanying a LOCA.

f. High energy and moderate energy pipe break effects will not affect hydrogen recombiner system continuity when the closed system is needed for containment isolation (Section 3.6.2).

g. The recombiner system is designed to be leak-tight and will be periodically leak tested at the containment peak accident pressure.

h. Any leakage from the system will be confined within the secondary containment and will be diluted and filtered prior to release.

i. The closed system is protected from missiles (Section 3.5).

The high volume purge lines are provided with debris screens located at the point where each purge line terminates inside the primary containment. The debris screens are designated as seismic Category I and are designed to withstand the maximum differential pressure across the screen that could result from a LOCA.

6.2.4.3.1.3.2.4 RCIC and HPCI Turbine Exhaust Vacuum Breaker Lines

These lines are provided with two normally open motor-operated remote manually actuated gate valves. The valves are automatically closed on receipt of an RCIC or HPCI isolation signal.

6.2.4.3.1.3.2.5 Traversing Incore Probe

The TIP system purge line is equipped with a normally open air operated globe valve outside containment and a check valve inside containment. The TIP system purge line air operated valve is normally open in order to provide a continuous supply of dry gas to the indexing mechanisms. Upon receipt of a containment isolation signal, the TIP system purge line AOV is automatically closed. TIP drive cables are normally retracted except during calibration of the power range neutron detectors or when an actual TIP mapping operation is in progress. Under normal operating conditions, the TIP system guide tubes do not communicate with the containment atmosphere because purge air supplied to the box surrounding the indexing mechanism effectively precludes such communication. However, following a LOCA or containment pressurizing event, a check valve on the box will open resulting in direct communication between the containment atmosphere and the TIP guide tubes. Because the TIP system lines can be considered instrument lines, the isolation provisions for the TIP system are described in the evaluation of compliance with Regulatory Guide 1.11, Section 6.2.4.3.1.5.

6.2.4.3.1.3.2.6 Containment Spray

The containment spray lines are provided with two normally closed, remote manually operated isolation valves outside the containment. The inner isolation valve is located directly on the containment.

6.2.4.3.1.3.2.7 Suppression Pool Spray

The suppression pool spray lines are provided with normally closed isolation valves outside containment, located directly on the containment. The valves automatically close upon receipt of an isolation signal. The external pipe, designed to Quality Group B and seismic Category I requirements, provides the second isolation barrier. Because of the desired use of this system after a LOCA, the system reliability is greater with only one isolation valve in the line.

6.2.4.3.1.3.2.8 Drywell Radiation Sampling Lines

The sampling system lines that penetrate the containment and connect to the drywell and suppression chamber air volume are equipped with two normally open solenoid-operated isolation valves in series, located outside and as close to the containment as possible. These valves ensure isolation of these lines if there should be a break; they also provide long-term leakage control.

In addition, the piping is considered an extension of the containment boundary and, as such, is designed to the same quality standards as the primary containment. The drywell radiation sampling isolation valves have ganged controls for reopening. Inboard sample and return isolation valves SV-190A and SV-190C are ganged on HS-190A. Outboard sample and return isolation valves SV-190B and SV-190D are ganged on HS-190B.

6.2.4.3.1.3.2.9 Primary Containment Instrument Gas

The influent lines are provided with a normally open power-operated globe valve outside the containment and a check valve inside the containment. MOVs are used on the influent lines that contain the ADS gas supply. These are essential lines that provide a long-term backup to the ADS accumulators inside containment. The valves on these essential lines are remote manually operated and automatically isolate only when flow out of containment through these lines would be possible (i.e., low differential pressure between the containment and the instrument gas line). The remaining influent lines are nonessential lines that use AOVs that are automatically closed on receipt of a containment isolation signal. The effluent line is provided with a normally open air operated globe valve outside and a motor-operated globe valve inside the containment that close automatically on receipt of a containment isolation signal.

6.2.4.3.1.3.2.10 Reactor Enclosure Cooling Water

Each influent and effluent line is provided with two gate valves located outside containment. The inboard valves are motor- operated. The outboard valves on the ESW intertie lines are locked closed and the motor operators are not connected to any power supply. The outboard valves on the RECW lines (HV-108 and HV-111) are motor-operated and their controls are ganged on HS-108. Each of the MOVs can be remote manually closed from the control room. Automatic, diverse isolation signals are also provided to these valves. In addition, the containment isolation signals to these valves can be overridden by using key-locked bypass switches.

6.2.4.3.1.3.2.11 Drywell Chilled Water

Each influent and effluent line is provided with two motor-operated gate valves located outside containment. The controls for these valves are ganged as follows:

a. Loop A inboard influent and effluent isolation valves HV-128 and HV-129 are ganged on HS-128.

b. Loop B inboard influent and effluent isolation valves HV-122 and HV-123 are ganged on HS-122.

c. Loop A outboard influent and effluent isolation valves HV-120A, 121A, 124A and 125A are ganged on HSS-121A.

d. Loop B outboard influent and effluent isolation valves HV-120B, 121B, 124B and 125B are ganged on HSS-121B.

The inboard valves are provided with automatic isolation signals as indicated in Table 6.2-17. The outboard isolation valves are normally aligned to the drywell chilled water system. Outboard valves HV-120A, HV-120B, HV-121A and HV-121B are provided with diverse, automatic isolation signals. In addition, the containment isolation signals to these valves can be overridden by using key-locked bypass switches. The other outboard isolation valves, HV-124A, HV-124B, HV-125A, and HV-125B were motor operated valves converted to normally closed passive manual valves using the existing actuator. These valves may be aligned to the RECW system as allowed by the Primary Containment Isolation Valve Technical Specification LCO/Action requirements. These valves have administrative controls because they are passive locked closed manual valves with the associated breakers locked open when primary containment integrity is required.

6.2.4.3.1.3.3 Conclusion on GDC 56

In order to ensure protection against the consequences of accidents involving release of significant amounts of radioactive materials, pipes that penetrate the containment have been demonstrated to provide isolation capabilities on a case-by-case basis in accordance with GDC 56.

In addition to meeting isolation requirements, the pressure- retaining components of these systems are designed to the same quality standards equivalent to those used for the primary containment.

6.2.4.3.1.4 Evaluation Against GDC 57

This GDC was not used in the design of containment penetrations for LGS.

6.2.4.3.1.5 Evaluation Against Regulatory Guide 1.11

Instrument lines that penetrate the containment from the RCPB conform to Regulatory Guide 1.11 in that they are equipped with a restricting orifice located inside the drywell and an EFCV located outside and as close as practicable to the containment. Should an instrument line that forms part of the reactor pressure boundary develop a leak outside the containment, a flow rate that results in a differential pressure across the valve of 3-10 psi causes the EFCV to close automatically. Should an EFCV fail to close when required, the main flow path through the valve has a resistance to flow at least equivalent to a sharp-edged orifice of 0.375 inch diameter. Valve position indication is provided in the reactor enclosure. Those instrument lines that do not connect to the RCPB conform to Regulatory Guide 1.11 in that they are either equipped with an EFCV or an isolation valve capable of remote operation from the control room, and are sized or orificed to meet the criteria outlined in Regulatory Guide 1.11. The drywell pressure, suppression pool level, suppression chamber pressure, and drywell sump level instrument lines are:

a. Provided with isolation valves capable of remote operation from the control room.

b. Q-listed, as discussed in Section 3.2.

c. Designed to seismic Category I standards.

d. Designed to withstand containment design pressure and temperature.

e. Terminate in the reactor enclosure, which is served by the SGTS.

The status of the isolation valves capable of remote operation from the control room is indicated in the control room.

The TIP system lines as shown in drawing M-59 and described below are considered instrument lines because:

a. they function as instrument lines or support the operation of instrument lines, and

b. they are small diameter lines.

TIP system isolation valves are provided on each guide tube immediately outside the containment. Dual barrier protection is provided by a solenoid-operated ball valve and an explosive actuated cable shearing valve. The ball valve is closed except when a TIP is inserted. These valves prevent loss of reactor coolant in the event that an incore guide tube ruptures inside the reactor vessel and prevents the escape of primary containment atmosphere.

The guide tube ball valve solenoid is normally de-energized and the valve is in the closed position. When the TIP starts forward, the valve solenoid is energized and the valve is held open against its spring. As the valve opens, it actuates a set of contacts which provide position indication at the TIP control panel and a permissive signal for TIP motion. Upon receipt of a containment isolation signal (reactor low water level or high drywell pressure), the TIP drive mechanism is signalled to retract the TIP. As the TIP is withdrawn into its shield chamber outside containment, a position switch signals the ball valve to close.

The shear valve is provided as a backup in the event that a TIP cannot be retracted or a ball valve sticks open when containment isolation is required. In this event, the shear valve would be operated from the control room to cut the cable and seal the guide tube. Continuity of the shear valve squib firing circuits is continuously monitored by front panel indicator lights in the control room.

The guidelines of Regulatory Guide 1.11, section 1.b are met for the TIP system as discussed below.

An analysis of the maximum leakage rate from the TIP system and the offsite radiological effects under normal reactor operating conditions was performed. The analysis conservatively assumed that all TIP system lines suffered guillotine breaks just outside the containment boundary. Specific activity inside the primary containment was assumed to be at the maximum Technical Specification limit for iodine in the primary coolant. (This is an extreme conservatism because a primary coolant rather than drywell atmosphere source term was assumed.) To characterize maximum flow through the TIP system lines, the drywell was assumed to be at its maximum normal pressure (2.0 psig) and normal temperature (135°F ①). It was also conservatively assumed that all TIP probes are fully retracted. Under these conditions, total flow from the TIP system lines would be only 0.105 lb_m/sec as compared to 2.2 lb_m/sec for an instrument line which penetrates the reactor primary coolant

boundary. The corresponding 24 hour site boundary dose for this flow rate (using worst case average annual meteorology) would be less than 0.03 rem thyroid. The conservatively calculated leak rate is extremely low and the offsite dose is a small fraction of 10CFR50.67 limits.

The TIP guide tubes are equipped with dual isolation valves located as close to containment as practical; a solenoid-actuated ball valve and an explosively actuated shear valve acting in series. The ball valves are normally de-energized (in a closed position). Consequently, during normal operation, the containment isolation function for the TIP system is accomplished without the need for any action. Therefore, requirement of Regulatory Guide 1.11, section 1.C.1 is met. In the unlikely event of a LOCA while the TIP system is in operation, containment isolation is automatically accomplished as follows. Upon receipt of a containment isolation signal (reactor low water level or high drywell pressure), the TIP drive mechanism is automatically signaled to retract the TIP. As the TIP is withdrawn into its shield chamber, a position switch signals the ball valve to close. All TIP line ball valves open against a spring and will close on loss of power. The cable shearing valves are equipped with redundant explosive actuating devices increasing the isolation reliability of the system and are remote manually operated from the control room. The ball and shear valves are instrumented to indicate position (i.e., open or closed).

Accidental closure of the TIP line isolation valves does not create a safety hazard, nor is the TIP system required to operate during an accident to mitigate the consequences of that accident. Therefore, the isolation provisions of the TIP system comply with the requirements of Regulatory Guide 1.11, section 1.C.2. When the TIP starts forward, the ball valve solenoid is energized and the valve is held open against its spring. This satisfies the requirement of section 1.C.3, and therefore satisfies all the requirements of Regulatory Guide 1.11, section 1.C.

The design of the TIP isolation system is commensurate with the importance to safety of isolating that system. It recognizes that the TIP system design is such that the TIP guide tube isolation ball valve is normally closed. Typically, a TIP scan requires insertion of the TIP probes into the reactor vessel for a period of approximately 4 hours per month. Over a one year period, this amounts to a total of 120 hours per year, or less than 2% of the time.

① This evaluation bounds the effects of operating at a normal temperature of 150°F, since total mass flow would be reduced.

Because of the normally closed state of the TIP ball valves, the probability of a release of radioactivity through the TIP guide tubes following a LOCA is extremely low. Even in the event of a LOCA, the TIP system design will reliably provide automatic isolation of any open TIP guide tubes by providing for automatic retraction of the TIP cable followed by automatic closure of the TIP ball valve. Should the ball valve fail to automatically close, that condition would be indicated to the operator in the control room. The operator could then manually actuate the shear valve in the control room to isolate that line.

The design of the TIP system isolation provisions is based on the low probability that the system will be called upon to isolate the containment following a significant fission product release to the containment atmosphere. Consequently, the power supplies and the controls for the TIP isolation valves are not safety-grade. However, the overall system reliability for isolation is high because: (1) the ball and shear valves are powered from separate power supplies, (2) the shear valves are powered from an onsite dc power source, (3) the ball, shear, and purge check valves, and the line from the containment to the outermost isolation valve are mechanically safety-grade, (4) upon loss of power the ball valves close, and (5) the TIP system receives automatic LOCA signals to retract and isolate.

In considering the potential magnitude of a fission product release through the TIP guide tubes as a result of a design basis LOCA event, it is appropriate to consider the event probability. There are several sequences of events which could lead to a fission product release through the TIP guide tubes. Any sequence which leads to a release must involve: (1) a design basis LOCA, and (2) a degraded core. The probability of this combination of events alone is on the order of 10^{-7} per reactor year. Additional failure(s) in the TIP isolation system have to be assumed for the release through the TIP guide tubes to occur. These failures would involve the ball and shear valves not closing as designed for various reasons such as a hot short causing the ball valves to fail open and the shear valve not closing after the cable is retracted. The inclusion of the additional failures would lower the probability of occurrence of the event by several orders of magnitude below the 10^{-7} per reactor year figure discussed above. This analysis assumes the proper functioning of nonsafety-grade power supplies and circuits for the TIP isolation valves in determining overall system reliability. The low probability of a fission product release to the environment through the TIP guide tubes demonstrates the adequacy of the current TIP isolation system design basis.

Although the above discussion indicates an extremely low likelihood of a fission product release through the TIP guide tubes or purge lines, the consequence of that release has been evaluated for the most probable event. That event would involve the failure of all five TIP guide tubes to isolate following a degraded core event. In this instance, the TIP probe substantially reduces the flow area in the TIP guide tube which provides a pathway for fission product release unless some other unlikely event (i.e., earthquake) were to occur at the same time and cause further equipment failures. The pathway for an atmospheric fission product release would be through the check valve in the indexer box (open due to a positive internal containment pressure), down the long and narrow annulus between the TIP probe/cable assembly and the guide tube, and out through the end of the guide tube located in the reactor enclosure. The probe/cable assembly are never completely withdrawn from the guide tube, so the annular flow restriction is maintained. For the radiological analysis, Regulatory Guide 1.183 source terms and accident meteorology were assumed.

The results of the radiological evaluation show that the site boundary and low population zone doses for this limiting event using Regulatory Guide 1.183 assumptions are below 10CFR50.67 limits.

The low probability of fission product release and the results of the radiological evaluation satisfy the intent of Regulatory Guide 1.11, section 1.d.

6.2.4.3.1.6 Evaluation Against Regulatory Guide 1.141

The containment isolation system conforms to Regulatory Guide 1.141 except as discussed below:

> Section 3.6.4 Single Valve and Closed System Both Outside Containment...
>
> The single valve and piping between the containment and the valve shall be enclosed in a protective leak-tight or controlled leakage housing to prevent leakage to the atmosphere.

LGS Design:

For systems that fall into this category except for the ECCS pump suction lines, the single valve outside primary containment is not enclosed in a protective leak-tight or controlled leakage housing. Moderate energy lines that fall into this category do not connect to the RCPB and are not postulated to break concurrent with a LOCA. Therefore, neither reactor coolant nor post-LOCA containment atmosphere are released. However, any leakage is contained within the secondary containment

and is diluted and filtered prior to release. The ECCS pump suction isolation valves are enclosed in pump rooms adjacent to the containment that have provisions for the environmental control of any fluid leakage.

The existing isolation provisions for the above lines meet the criteria set forth by ANSI N271 (1976). These isolation provisions consist of a line submerged in the suppression pool (except for the suppression pool spray line) and a valve outside containment. In addition, a closed system is provided as another containment isolation barrier. For each of the lines, the closed system outside containment is protected from missiles, designed to seismic Category I standards, classified safety class 2, and is designed to the temperature and pressure conditions that the system will encounter after an accident. Justification for the design of the valve nearest containment and any piping between containment and the valve is provided in the following discussion.

> Section 3.6.5 Two Valves Outside Containment...
>
> The valve nearest the containment wall and piping between the containment and that valve shall be enclosed in a protective leak-tight or controlled leakage housing to prevent leakage to the atmosphere.

LGS Design:

The lines listed below, which have containment isolation provisions that consist of two valves in series located outside primary containment, are moderate energy lines that do not connect to the RCPB. These lines are not postulated to experience a guillotine break. Locating the valves on these lines outside the primary containment is more practical than locating the valves inside containment because of the adverse environment that is experienced when most of the valves may be needed (post-LOCA) and because this location allows inspections and maintenance to be performed on these valves during normal operation. The existing isolation provisions for all these lines meet the criteria set forth by ANSI N271 (1976).

The design of the valve nearest containment and any piping between the containment and the valve, for the following penetrations, is discussed below:

Penetration	Line	Valve
X-25	Drywell purge supply	122
X-26	Drywell purge exhaust	113
X-28A	Drywell $H_2/0_2$ sample	134, 132
X-28B	Drywell $H_2/0_2$ sample	133
X-39A,B	Containment Spray	F021A,B
X-35C-G	TIP Drive	140A-E, 141A-E
X-40G	ILRT data acquisition	1057, 1071
X-117B	Drywell radiation sampling	190A,B, 190C,D

X-62	$H_2/0_2$ sample return; drywell purge makeup	150
X-201A	Suppression pool purge supply	125
X-202	Suppression pool purge exhaust	103
X-203A,B,C,D	RHR pump suction	F004A,B,C,D
X-204A,B	RHR pump test and minimum flow	125A,B
X-205A,B	Suppression pool spray	F027A,B
X-206A,B,C,D	CS pump suction	F001A,B,C,D
X-207A,B	CS pump test and flush	F015A,B
X-208B	CS pump minimum flow	F031B
X-209	HPCI pump suction	F042
X-210	HPCI turbine exhaust	F072
X-212	HPCI pump test and flush	F071
X-214	RCIC pump suction	F031
X-215	RCIC turbine exhaust	F060
X-216	RCIC minimum flow	F019
X-217	RCIC vacuum pump discharge	F002
X-220A	$H_2/0_2$ sample return; wetwell purge makeup	190
X-221A	Wetwell $H_2/0_2$ sample	181
X-221B	Wetwell $H_2/0_2$ sample	183
X-226A,B	RHR minimum flow	105A,B
X-227	ILRT data acquisition	1073
X-228D	HPCI vacuum relief	F095
X-231A,B	Drywell sump drains	110, 130
X-235	CS pump minimum flow	F031A
X-236	HPCI pump minimum flow	F012

X-238	RHR relief valve discharge	106B
X-239	RHR relief valve discharge	106A
X-241	RCIC vacuum relief	F084

These moderate energy lines are not postulated to break concurrent with a LOCA. Therefore, neither reactor coolant nor post-LOCA containment atmosphere are released. Analyses have been performed to ensure that the effects of postulated moderate energy line breaks will not prevent the safe shutdown of the plant. The results of these analyses are provided in Section 3.6.1.2.

Section 4.4.2 Method of Valve Actuation...

It should not be possible for remote manual operation to override the automatic isolation signal until the sequence of automatic events following a isolation signal is completed...

LGS Design:

This guideline is met for all remote manually operable valves with the exception of valves in systems that must be operated after an accident and that have been provided with a key-locked override switch for this purpose.

Section 5.3.2 - Leakage Rate Testing

Provisions and Methods. Provisions shall be made for leakage rate testing of containment isolation valves.

LGS Design:

Individual leakage rate tests are performed for containment isolation valves as indicated in Table 6.2-25.

6.2.4.3.2 Failure Mode and Effects Analyses

A single failure can be defined as a failure of some component in any safety system that results in a loss or degradation of the system's capability to perform its safety function. Active components are defined as components that must perform a mechanical motion during the course of accomplishing a system safety function. 10CFR50, Appendix A requires that electrical systems be designed against passive single failures as well as active single failures. Section 3.1 describes the implementation of these requirements as well as GDC 17, 21, 35, 41, 44, 54, 55, and 56.

In single failure analysis of electrical systems, no distinction is made between mechanically active or passive components; all fluid system components, such as valves, are considered electrically active whether or not mechanical action is required.

6.2.4.4 Tests and Inspections

The containment isolation system undergoes periodic testing during reactor operation. The functional capabilities of power-operated isolation valves are remotely tested manually from the main control room. During all modes of manual MOV operation using the handswitch from the main control room, a "dead zone" is present for a portion of the valve travel. The "dead zone" is present when the valve is not fully closed and green light only indication exists. If the valve is stopped in the "dead

zone", operator action is required to restart the valve. By observing position indicators and changes in the affected system operation, the closing ability of a particular isolation valve is demonstrated.

A discussion of testing and inspection pertaining to isolation valves is provided in Section 6.2.1.6 and in Chapter 16. Table 6.2-17 lists all isolation valves.

Instruments are periodically tested and inspected. Test and/or calibration points are supplied with each instrument.

EFCVs are periodically tested to verify proper operation. As these valves are outside the containment and accessible, periodic visual inspection is performed in addition to the operational check.

Leak rate testing for the containment isolation system is discussed in Section 6.2.6.

6.2.5 COMBUSTIBLE GAS CONTROL IN CONTAINMENT

Limerick license amendment numbers 173/135 for Unit 1 and 2, respectively approved the removal of the hydrogen recombiner and hydrogen and oxygen monitoring controls from Technical Specifications. The following items were committed to as part of license amendment numbers 173/135.

1. Limerick will maintain the hydrogen monitors within the Emergency and Operating procedures and the Maintenance Program.

2. Limerick will maintain the oxygen monitors within the Emergency and Operating Procedures and the Maintenance Program.

The revised Technical Specifications are based on the NRC revision to 10CFR50.44 (Combustible gas control for nuclear power reactors), which eliminated the design basis LOCA hydrogen release based on risk significance; eliminated the requirements for hydrogen control systems to mitigate such releases; and maintained the requirements for containment inerting, containment atmosphere mixing, monitoring of oxygen to verify the status of the inert containment, and monitoring of hydrogen for diagnosing beyond design basis accidents. Based on the revised rule removing the design basis requirements for beyond design basis accidents, the hydrogen recombiners can be eliminated in the future and the H2/O2 analyzers are downgraded to non-safety related and non-redundant. However, the recombiners and analyzers are currently being maintained as described in the UFSAR, except for removal of the system requirements from the Technical Specifications. The analyzer system requirements removed from the Technical Specifications have been transferred to the Technical Requirements Manual (TRM).

Following a postulated LOCA, hydrogen gas may be generated within the primary containment as a result of the following processes:

a. Metal-water reaction involving the Zircaloy fuel cladding and the reactor coolant

b. Radiolytic decomposition of water in the reactor vessel and the suppression pool (oxygen also evolves in this process)

c. Corrosion of metals and paints in the primary containment

d. Release of free hydrogen already in the reactor coolant at the time of the LOCA.

To preclude the possibility of a combustible mixture of hydrogen and oxygen accumulating in the primary containment, the containment atmosphere is inerted with nitrogen gas during power operation of the reactor. The means provided for inerting the containment is described in Section 9.4.5.1. With the concentration of oxygen being controlled to below the lower flammability limit, the level of hydrogen buildup in the primary containment following a postulated LOCA is of no particular concern for combustible gas control.

To ensure that the oxygen concentration in the primary containment is maintained below the lower flammability limit, the following features are provided:

a. A containment hydrogen recombiner subsystem

b. A combustible gas analyzer subsystem

c. The capability to mix the primary containment atmosphere to prevent the local accumulation of hydrogen and oxygen (accomplished by the drywell air cooling system, which is discussed in Section 9.4.5.2)

d. The capability for a controlled purge of the primary containment following a LOCA (accomplished by the CAC system, which is discussed in Section 9.4.5.1)

Both the containment hydrogen recombiner subsystem and the combustible gas analyzer subsystem are part of the CAC system, which is shown in drawing M-57.

6.2.5.1 Design Bases

a. The containment hydrogen recombiner subsystem is designed to maintain the oxygen concentration in the primary containment below the lower flammability limit of 5% by volume.

b. The combustible gas analyzer is designed to operate either in standby or continuous mode during normal operation. However, the combustible gas analyzer is required to continuously monitor hydrogen and oxygen concentrations in the primary containment following a LOCA.

c. Those lines that penetrate the primary containment and are associated with the containment hydrogen recombiner subsystem and the combustible gas analyzer subsystem are provided with automatic isolation valves to ensure the integrity of the containment boundary during accident conditions. Two isolation valves in series are provided on the recombiner lines.

d. The controls for containment isolation valves on lines associated with post-LOCA combustible gas control and monitoring are designed so that the valves may be reopened by utilizing key-locked bypass switches to override the isolation signals.

e. The containment hydrogen recombiner subsystem and the safety-related portions of the drywell air cooling system are designed to remain functional after an SSE.

f. The containment hydrogen recombiner subsystem, the combustible gas analyzer subsystem, and the safety-related features of the drywell air cooling system are designed so that a single failure of an active component, assuming a LOOP, cannot result in the loss of a safety function.

g. The CAC system is designed to permit a controlled purge of the primary containment atmosphere following a LOCA, as a backup means of combustible gas control and as an aid in cleanup.

h. The containment hydrogen recombiner subsystem, the combustible gas analyzer subsystem, and the portions of the CAC system that are related to post-LOCA purging are designed to facilitate periodic inspection and testing of safety-related features.

i. The containment hydrogen recombiner subsystem, the combustible gas analyzer subsystem, and the safety-related portions of the drywell air cooling system are designed to remain operable in the environments existing in their respective areas following a LOCA.

6.2.5.2 System Description

6.2.5.2.1 Containment Hydrogen Recombiner Subsystem

The containment hydrogen recombiner subsystem is part of the CAC system, which is discussed in Section 9.4.5.1 and shown schematically in drawing M-57. The recombiner subsystem consists of two redundant hydrogen recombiner packages, each of which has adequate processing capacity to control the quantity of oxygen postulated to be generated in the primary containment after a LOCA. The recombiners are of the thermal recombination type, manufactured by the Atomics International Division of Rockwell International. The recombiners are similar in design and construction to those described in Reference 6.2-9 and are identical to those described in Reference 6.2-10.

A schematic diagram of one recombiner package is shown in drawing M-58. Each hydrogen recombiner package consists of three modules: the recombiner skid assembly, the power cabinet, and the control cabinet. The recombiner skid assembly, which is shown in Figure 6.2-38, consists of the process components. The process components include valves, canned motor/blower assembly, gas heater pipe, reaction chamber, water spray cooler, and water separator. The gas heater pipe and the reaction chamber are located within an insulated enclosure that also contains electric heater elements. The recombiner skid assembly is located outside the primary containment in the reactor enclosure.

The power cabinet houses the power distribution components for the recombiner package. The cabinet is located adjacent to its associated recombiner skid assembly and contains the 480 V power supply, control transformer, blower motor starter, circuit breakers, control relays, and the silicon-controlled rectifiers that control electrical power to the heater elements.

The control cabinet contains all of the instrumentation, annunciators, lights, and switches necessary for operation of the recombiner package. The control cabinet is located in the control room.

Each recombiner package is designed to process 60 scfm of gas (inlet flow) containing 5% oxygen, or up to about 150 scfm of gas (inlet flow) containing 2% oxygen, with the balance consisting of unlimited amounts of hydrogen, nitrogen, and water vapor. Each recombiner package will also process up to about 150 scfm of air containing 4% hydrogen. As containment pressure decreases

following an accident, recombiner flow may decrease below the 150 scfm nominal operating value, as discussed in Section 6.2.5.3. The recombination process is accomplished by increasing the temperature of the process stream to approximately 1300°F, at which temperature the hydrogen and oxygen combine spontaneously to form water vapor by the reaction $2H_2 + O_2 \rightarrow 2H_2O$. Virtually complete recombination occurs, so that the concentration of the limiting gas in the effluent from the recombiner package is negligible.

During recombiner operation, gas from the drywell flows through the high volume purge piping of the CAC system to the gas inlet piping of the recombiner package. The effluent from the recombiner package flows through the gas outlet piping to the high volume purge piping associated with the suppression chamber, and then into the suppression chamber. By taking suction from the drywell and discharging to the suppression chamber, a differential pressure is created between these two volumes. This differential pressure is limited to 1.0 psid by the primary containment vacuum relief valve assemblies (described in Section 9.4.5.1), that open to allow air to flow from the suppression chamber back into the drywell.

The recombiner gas inlet and outlet lines are each provided with two normally closed valves for containment isolation. These valves can be operated by hand switches in the control room, and are automatically closed upon receipt of a containment isolation signal. The isolation signals can be overriden by using key-locked bypass switches. The recombiner outlet lines are each provided with pressure relief valves to protect the outlet piping from overpressurization in the event of recombiner cooling water line isolation valve leakage from the RHR system during recombiner isolation. Containment isolation is discussed further in Section 6.2.4.

Blank flanges will be installed on the outboard side of the isolation valves for pressure boundary maintenance.

The process stream entering the recombiner skid assembly flows first through a valve that is used to regulate the flow rate through the recombiner. Next along the process path is the blower, that provides sufficient head to overcome the system flow losses and also the 1.0 psid differential pressure between the drywell and the suppression chamber. From the blower, the gas flows through the gas heater pipe that spirals around the reaction chamber.

The gas is heated as it flows through the gas heater pipe, due to radiated heat from the electric heater elements and the reaction chamber. Next, the gas flows into the reaction chamber, where the exothermic recombination of hydrogen and oxygen occurs. The flow field in the reaction chamber is highly turbulent, with sufficient mixing to rapidly bring the inlet gas temperatures to a level where virtually complete recombination occurs. Reaction chamber temperature is not critical, and considerable deviation from the nominal operating temperature of 1300°F may be tolerated without seriously affecting recombiner performance. The geometric configuration and volume of the reaction chamber provide gas flow movement and transport times so that recombination is completed over a varied range of hydrogen-oxygen concentrations. Recombined gas flows from the reaction chamber to the water spray cooler where it is cooled to less than 250°F. The hot process gas is mixed with water spray in the throat region of a venturi, and the hot gas is cooled by vaporization of the water and by direct contact with the water droplets. The cooling water is supplied to the recombiners from the RHR system. Cooled gas flowing from the cooler is passed through a water separator that prevents any remaining water droplets from entering the gas recirculation line. The separated water drains down to the suppression pool through the recombiner gas outlet piping. Recirculation (dilution) gas is drawn from the top of the water separator and is routed to the recombiner gas inlet piping.

Operation of the hydrogen recombiner package is initiated manually from the control cabinet. When gas flow has been established and the water inlet valve is fully open, the heater elements are energized. Less than 2 hours are required for the system to reach operating temperature. As the temperature of the heated enclosure increases, the gas being circulated through the recombiner is heated. The recombination reaction begins to occur at the outlet of the gas heater pipe when the temperature at that location reaches approximately 1150°F. When the temperature at the gas heater pipe outlet reaches 1300°F, power to the heater elements is automatically turned off. When the gas heater pipe cools to the point at which it can no longer sustain the reaction, the reaction moves into the reaction chamber. When the temperature at the gas heater pipe outlet falls below 1300°F, an interlock is cleared and power is returned to the heater elements at a lower level than during startup. Temperatures in the gas heater pipe stay below those required for reaction, so the reaction stays in the reaction chamber. A temperature controller located in the control cabinet is used to maintain reaction chamber temperature at about 1300°F.

6.2.5.2.2 Combustible Gas Analyzer Subsystem

The combustible gas analyzer subsystem is part of the CAC system, which is discussed in Section 9.4.5.1 and shown schematically in drawing M-57. The combustible gas analyzer subsystem consists of two analyzer packages, each of which contains a hydrogen sensor and an oxygen sensor. The analyzer packages are provided with sufficient sample points so that both analyzer packages can take samples from either the drywell or the suppression chamber.

Each analyzer package consists of a sample cabinet located in the reactor enclosure and a remote control panel located in the control room. Sample points in the primary containment are located as follows:

a. Drywell

   1. el 291', azimuth 10°; 15' from containment centerline
   2. el 255', azimuth 215°; 25' from containment centerline
   3. el 242', azimuth 214°; 1.5' from inside wall of reactor pedestal.

b. Suppression chamber

   1. el 222', azimuth 70°; at inside of containment wall
   2. el 222', azimuth 250°; at inside of containment wall.

The sample suction and return lines are each provided with two normally open solenoid-operated valves for containment isolation. These valves are operated by hand switches in the control room, and are automatically closed upon receipt of a containment isolation signal. The isolation signals to the valves can be overridden by using key-locked bypass switches. Containment isolation is discussed further in Section 6.2.4.

Sample location is controlled by a touchscreen at remote control panel. Gases from the sample point thus selected are routed through a hydrogen sensor and an oxygen sensor located in the sample cabinet.

The operation of the hydrogen and oxygen sensors is based on the measurement of the partial pressure of the oxygen and/or hydrogen in the gas sample. The partial pressure sensors are galvanic in nature and consist of two electrodes; a catalytic sensing electrode and metal oxide

counter electrode for the hydrogen sensor and gold electrode and metal counter electrode for the oxygen sensor. The electrodes for the sensors are immersed in an electrolyte. The electrodes are externally connected by a resistive load. When the ambient atmosphere contains hydrogen and/or oxygen, the gas is ionized at the sensing electrode. The end result is an exchange of electrons through the resistive load connecting the electrodes that is in proportion to the amount of hydrogen (or oxygen). The voltage developed across the external resistance or load, is a mVDC signal, directly proportional to the partial pressure of hydrogen (or oxygen). Note that each sensor is designed to respond only to hydrogen or only to oxygen and is insensitive to other gasses. The total pressure is measured so the partial pressures can be converted to a concentration of hydrogen or oxygen.

The hydrogen sensor has a range of 0% to 10% (by volume) and the oxygen sensor has a range of 0% to 25% (by volume). The calibrated range of each analyzer is 0% to 7%. The sensors are capable of providing oxygen and hydrogen measurement under ambient pressure and up to 73 PSI for components exposed to containment sample under accident conditions. The hydrogen and oxygen concentrations are indicated at the remote control panel.

Sample gases are drawn through the sensors by a positive displacement pump located in the sample cabinet. Sample gases discharged from the pump are routed back to the primary containment.

6.2.5.2.3 Containment Atmosphere Mixing

The capability is provided to maintain the primary containment atmosphere in a thoroughly mixed condition following a LOCA in order to prevent nonuniform distributions of oxygen from occurring. This function is performed by the drywell air cooling system, which is discussed in Section 9.4.5.2. One fan in each of the unit coolers of the drywell air cooling system runs continuously during normal reactor operation and at least one fan in each of two of the safety-related coolers (1AV-212 or 1BV-212 and 1GV-212 or 1HV-212) continues to run after a LOCA to maintain containment in a thoroughly mixed condition.

The design of the primary containment is such that compartmentalization is minimized. The only regions of the drywell that are segregated to some extent from the remainder of the drywell are the drywell head area above the containment seal plate and the CRD area inside the reactor pedestal. Oxygen is prevented from accumulating in a concentration in excess of 5% (volume) in these areas during normal and post-LOCA operation by the operation of the drywell air cooling system.

Following a LOCA, containment oxygen would be mixed by several mechanisms in addition to the operation of the drywell air cooling system. Sprays and natural convective mixing would contribute significantly to maintaining all gases at nearly uniform concentrations (Reference 6.2-20). The boiling mechanism associated with the radiolysis responsible for the release of oxygen from irradiated water (Reference 6.2-21) would also create a significant amount of turbulent mixing, steam condensation effects, and a temperature gradient. These effects would cause oxygen to be well mixed with steam as it entered the drywell from the line break.

6.2.5.2.4 Post-LOCA Purging

The capability to purge the primary containment in order to control oxygen concentration and aid in cleanup after a LOCA is provided.

The BWROG EPGs make specific recommendations for Post-LOCA purging based on the hydrogen levels in containment. Post-LOCA purging using the low volume purge mode of CAC (discussed in section 9.4.5.1) is recommended when containment hydrogen levels are greater than a specific level in the BWROG EPGs, no deflagration can occur, and the containment can be purged without exceeding the normal release rate limits in the Technical Specifications or ODCM. Post-LOCA low volume purging continues until the containment hydrogen levels fall below the recommended value specified in the BWROG EPGs. Gases exhausted from the containment during post-LOCA purging are processed through the RERS and SGTS in order to remove radioactive particulate and halogen contaminants prior to release to the environment.

If containment hydrogen levels continue to increase a high volume purge of the containment can be performed using nitrogen, depending on the potential for the hydrogen and oxygen concentration to result in a deflagration. Depending on the plant conditions at the time of the high volume purge, RERS and SGTS may or may not be available. Depending on the specific concentrations of hydrogen in containment at the time, offsite release rates are limited to those in the Technical Specifications or ODCM. The high volume purge can be used in accordance with BWROG EPG recommendations to prevent containment failure due to a deflagration and to minimize the consequences of the accident. Post-LOCA high volume purging continues until the containment hydrogen levels fall below the recommended value specified in the BWROG EPGs. The BWROG EPG recommendations regarding purging of the containment are incorporated in the EOPs.

6.2.5.2.5 Venting of Combustible Gases from the Reactor Vessel

Combustible gases generated within the reactor vessel or its connected piping can accumulate in the steam space of the vessel following certain types of accidents. Several means are available to vent these gases from the reactor vessel into the primary containment, where they can be processed by the hydrogen recombiner subsystem.

Operation of either the HPCI or RCIC system provides one such means for combustible gas venting. Both of these systems utilize steam-driven turbines that take steam from the reactor vessel and discharge it to the suppression chamber. Any combustible gases present in the reactor vessel steam space are carried along in the steam driving the HPCI or RCIC turbines.

Combustible gases can also be vented from the reactor vessel through the use of the ADS. The ADS utilizes five of the MSRVs to discharge steam and any other gases present in the reactor vessel to the suppression chamber.

A third means that is available for combustible gas venting involves the RPV head vent line that runs from the top of the reactor vessel head to the drywell equipment drain sump. MOVs in this line can be opened to allow steam and other gases to be discharged to the drywell equipment drain sump. Any gases not condensed in the drain sump are released into the drywell through the drain sump's vent line.

6.2.5.3 Hydrogen and Oxygen Generation Analysis

In establishing the design and assessing the capability of the hydrogen recombiner subsystem and the post-LOCA purge, an analysis was performed to determine the hydrogen and oxygen concentrations in the primary containment (drywell and suppression chamber) as a function of time following a postulated LOCA. The assumptions and design parameters used in this analysis are listed in Tables 6.2-18 and 6.2-19, respectively. These assumptions are in accordance with Regulatory Guide 1.7 (Reference 6.2-12). The computer program used to conduct these primary containment hydrogen and oxygen analyses is the Bechtel in-house computer code, HYDROGEN,

which incorporates the models from Regulatory Guide 1.7, SRP 6.2.5, and the NRC Code COGAP. The analysis considered the generation of hydrogen gas from the following sources:

a. Metal-water reaction involving the Zircaloy fuel cladding and the reactor coolant

b. Radiolytic decomposition of water in the reactor vessel and the suppression pool

c. Corrosion of metals and paints in the primary containment

d. Release of free hydrogen already in the reactor coolant at the time of the LOCA

Radiolytic decomposition of water is considered to be the only source of oxygen gas generation after a LOCA.

Metal-Water Reaction

As a result of a LOCA, fuel cladding temperatures rise beginning after blowdown and continuing until core reflood. Zirconium reacts with steam according to the following reaction (Reference 6.2-11):

$$Zr + 2H_2O \rightarrow ZrO_2 + 2H_2$$

Thus, for each mole of zirconium that reacts, 2 moles of free hydrogen are produced. The extent of the metal-water reaction and associated hydrogen generation depends strongly on the course of events assumed for the accident and on the effectiveness of emergency cooling systems, since the metal-water reaction is highly temperature-dependent. Regulatory Guide 1.7 (Reference 6.2-12) conservatively states that the amount of hydrogen assumed to be generated by metal-water reaction in determining the performance requirements for combustible gas control systems should be five times the maximum amount calculated in accordance with 10CFR50, Appendix K, but no less than the amount that would result from reaction of all the metal in the outside surfaces of the cladding cylinders surrounding the fuel (excluding the cladding surrounding the plenum volume) to a depth of 0.00023 inch.

In accordance with Appendix K, calculations have determined that the maximum core wide metal-water reaction is 0.09% (weight). Five times this calculated value is 0.45% (weight). Based on the fuel design, a reaction that results in a cladding penetration depth of 0.00023 inch is well in excess of the Appendix K value. Therefore, since the metal-water reaction based on 0.00023 inch penetration depth is greater than five times the value calculated in accordance with Appendix K, the value based on 0.00023 inch cladding penetration reaction is used as the basis for determining the amount of hydrogen generated by the metal-water reaction.

The analysis assumes that the hydrogen from the metal-water reaction is generated during the first 2 minutes after the beginning of the accident. The hydrogen thus evolved is assumed to mix homogeneously with the drywell atmosphere.

Radiolysis

Water is decomposed into free hydrogen and oxygen by the absorption of energy emitted by fission products contained in fuel and those mixed with the LOCA water. The quantities of hydrogen and oxygen that are produced by radiolysis are functions of both the energy of ionizing radiation absorbed by the LOCA water and the net hydrogen and oxygen radiolysis yields, $G(H_2)$ and $G(O_2)$, pertaining to the particular physical-chemical state of the irradiated water. As recommended in Regulatory

Guide 1.7 (Reference 6.2-12), the net yields of hydrogen and oxygen from radiolysis of all LOCA water are conservatively assumed to be 0.5 molecule/100 eV for hydrogen and 0.25 molecule/100 eV for oxygen.

The total fission product decay power is taken from Reference 6.2-13, conservatively assuming a 730 day[1] reactor operating time for fission product buildup. The results are comparable to those of proposed Standard ANS 5.1. The fission product distribution after the accident and the fractions of fission product radiation energy assumed to be absorbed by the LOCA water are listed in Table 6.2-18. The rates of energy absorption by the LOCA water are shown in Figure 6.2-39 and the integrated energy absorption is shown in Figure 6.2-40.

Corrosion

The corrosion of zinc and aluminum located either in the drywell or the suppression chamber is evaluated as a potential source of hydrogen after a LOCA. One factor that affects the rate of corrosion of either of these metals is the pH of the water with which the metal is in contact. Since no chemicals are added to the containment spray water, the pH of water in the primary containment after a LOCA should be approximately 7 (neutral).

Zinc in the primary containment is in two forms: zinc-based paint and galvanized steel. The masses and exposed areas of zinc-based paint and galvanized steel are listed in Table 6.2-19.

Corrosion of zinc in contact with water at a nominal pH of 7 is caused by two processes:

1. A one time cycle length of 27 months for Unit 1 cycle 7 and Unit 2 cycle 5 was evaluated to have a negligible impact on total fission product decay power.

   a. $Zn + 2\ H_2O \rightarrow Zn(OH)_2 + H_2$

   b. $2\ Zn + 2\ H_2O + O_2 \rightarrow 2\ Zn(OH)_2$

Both reactions occur in the post-LOCA atmosphere of the containment, and the relative amount of corrosion due to reaction a. as compared to reaction b. depends on the availability of oxygen. Galvanized steel and zinc-based paint surfaces that are not submerged are in contact with atmospheric oxygen along with the spray water; therefore, reaction b. is a major contributor to the corrosion of zinc. For the submerged surfaces, the oxygen present depends on the solubility of oxygen, which decreases with increasing temperature. For this situation, reaction a. dominates zinc corrosion.

A search of the literature available on the subject of zinc corrosion at a pH of 7 gives data for corrosion as a weight loss of zinc (References 6.2-14, 6.2-15, and 6.2-16) and also as hydrogen evolved (References 6.2-17 and 6.2-18). Van Rooyen (Reference 6.2-19) surveyed the available literature and formulated a corrosion rate. The data given as weight loss of zinc should be viewed carefully to determine which corrosion reaction is involved.

Other data are available for corrosion in water at higher pH levels or in water with NaOH additives. However, these data are not applicable to a BWR.

Baylis (Reference 6.2-17) determined the hydrogen generated from a sample of zinc submerged in distilled water for different time periods. This study was performed for temperatures of 100°F and lower. Therefore, the lower temperature corrosion domain can be inferred from this data.

The Franklin Institute Research Laboratories (Reference 6.2-18) performed a study of hydrogen evolution from zinc under simulated LOCA conditions and gave corrosion data for 2 hour and 24 hour periods. These data show that corrosion is faster for the 2 hour period than for the 24 hour period for different temperatures, except at the high temperature end (260°F-300°F) where the corrosion rates are comparable. This effect is due to the buildup of a corrosion-resistant zinc hydroxide protective layer that inhibits corrosion after an extended period of time.

Burchell (Reference 6.2-15) and Cox (References 6.2-14 and 6.2-16) present corrosion as a weight loss of zinc. In both cases, the corrosion rate is higher at the lower temperature domain, peaking at approximately 110°F and then decreasing with increasing temperature. Since the solubility of oxygen decreases with increasing temperature, the decrease in the corrosion rates can be attributed to the depletion of oxygen available. Thus, these corrosion rates show that reaction b. is dominant in the oxygen-rich lower temperature water, and reaction a. becomes dominant with increasing temperature.

Van Rooyen (Reference 6.2-19) determined the corrosion rate of zinc from the available data, but did not differentiate whether the corrosion was due to reaction a. or b. Thus, Van Rooyen's calculated corrosion rate does not accurately present the hydrogen generated from the corrosion of zinc.

The data of References 6.2-17 and 6.2-18 on hydrogen generation from zinc corrosion are bounded by the following corrosion rate:

$$H\,(Zn) = 3.76 \times 10^{-9}\, e^{(0.0218T)} \text{ lb-moles/ft}^2\text{-hr} \qquad \text{(EQ. 6.2-46)}$$

where:

T = temperature in degrees Fahrenheit

This rate equation is used to calculate the hydrogen released due to zinc corrosion and corrosion of zinc paint by conservatively assuming that all corrosion is caused by reaction a.

Since containment spray water does not contain any chemical additives, the pH of the LOCA water is approximately 7. At this pH, the corrosion rate of aluminum is negligible even at high temperatures (References 6.2-14 and 6.2-15). Therefore, aluminum in the containment is not assumed to be the source of any hydrogen generation.

Hydrogen Existing in Reactor Coolant

During normal operation of the reactor, free hydrogen exists in the coolant water in concentrations of 10-50 scc/kg of coolant. Although it is unlikely, it is assumed that all of this hydrogen is stripped from the coolant at the time of the LOCA. The total amount added to the containment atmosphere (corresponding to a concentration of 30 scc/kg of coolant) is listed in Table 6.2-19.

Results

The curves of drywell pressure and temperature as a function of time after a LOCA, which are used in the analysis to adjust for the mass of steam in the drywell atmosphere, are shown in Figures 6.2-3, 6.2-4, 6.2-7, and 6.2-8.

Figure 6.2-41 shows the integrated production of hydrogen from all sources as a function of time after the postulated LOCA. The hydrogen concentrations in a noninerted containment over the short-term and long-term periods after a LOCA are shown in Figures 6.2-42 and 6.2-43, respectively. These figures show hydrogen concentrations for three cases: no hydrogen control, recombiner operation at 150 scfm, and a 150 scfm purge. The analysis shows that hydrogen concentration in the drywell reaches 4% (volume) at about 25 hours after the LOCA, if no control measures are taken. If operation of one recombiner package is started so that recombination begins when the hydrogen concentration reaches 3.5% (volume) (at 19 hours after the LOCA), the concentration peaks at 3.57% (volume) and then decreases as long as the recombiner remains in operation. This analysis assumes a flow rate of 150 scfm. As containment pressure decreases following an accident, recombiner flow may decrease below this value. Field tests show that the system resistance can limit flow to less than 150 scfm when the containment is at atmospheric pressure and normal temperature. Sensitivity calculations have been performed which demonstrate that the hydrogen concentration will not exceed 4 volume percent with a single recombiner operating at a flow rate as low as 95 scfm. Actual recombiner flow rates exceed this requirement by a significant margin. For a 150 scfm purge beginning at 19 hours, the hydrogen concentration continues to increase to a maximum of about 3.8% (volume), occurring at about 45 hours after the LOCA. The purge mode used as a basis for this calculation involves supply and exhaust evenly divided between the drywell and suppression chamber, without repressurization of the primary containment.

The oxygen concentrations in an inerted containment over the short-term and long-term periods after a LOCA are shown in Figures 6.2-44, 6.2-45, and 6.2-46. These figures show oxygen concentration for three cases: no oxygen control, recombiner operation at 60 scfm, and a 60 scfm purge. The oxygen concentration (volume percent) initially drops in both the drywell and suppression chamber because, following a LOCA, the blowdown and subsequent increases in containment temperature and pressure result in significant fractions of other gases, primarily steam. To account for the additional constituents, the volume percent of oxygen decreases. The analysis shows that oxygen concentration in the drywell reaches 5% (volume) at about 54 hours after the LOCA, if no control measures are taken. If operation of one recombiner package is started so that recombination begins when the oxygen concentration reaches 4.5% (volume) (at about 39 hours after the LOCA), the concentration will peak at 4.92% (volume) and will then decrease as long as the recombiner remains in operation. For a 60 scfm purge beginning at 39 hours, the oxygen concentration increases to a maximum of 4.61% (volume), occurring at about 54 hours after the LOCA. The purge mode used as a basis for this calculation involves supply and exhaust evenly divided between the drywell and suppression chamber, without repressurization of the primary containment.

6.2.5.4 Safety Evaluation

The containment hydrogen recombiner subsystem (including supporting structures) is designed to seismic Category I requirements as defined in Section 3.7. Except for tubing internal to the sample cabinets of the combustible gas analyzer subsystem, piping and tubing associated with both subsystems, except for some piping and the hydrogen cylinders of the gas analyzer subsystem, are designed, fabricated, inspected, and tested in accordance with the requirements of the ASME Section III, Class 2. All portions of the two subsystems are located within the reactor enclosure and control structure, which are designed to seismic Category I requirements as discussed in Section 3.8.4. H_2 span gas cylinders are seismically supported in a location outside the reactor enclosure (and other safety-related areas) as required by BTP CMEB 9.5-1. Evaluation with respect to the following areas is discussed in sections as indicated:

a.	Protection from wind and tornado effects	Section 3.3
b.	Flood design	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11

The containment hydrogen recombiner subsystem and the combustible gas analyzer subsystem both consist of two separate packages that are fully redundant and independent. The redundant packages are powered from different divisions of Class 1E power. A single failure in either subsystem would only render the affected package unavailable, with the redundant package fully capable of performing the required function at full capacity. Failure modes and effects analyses for the containment hydrogen recombiner subsystem and the combustible gas analyzer subsystem are provided in Tables 6.2-20 and 6.2-21, respectively.

Each combustible gas analyzer sample line penetrating the primary containment is provided with redundant isolation valves powered from different divisions of Class 1E power. Since the isolation valves are of a type that fail closed upon loss of power, loss of power to any individual valve or to all valves powered from the same division does not disable the containment isolation function. In the event of a failure of any single valve to close when required, the redundant valve on the same line provides the isolation function. The bypass of an isolation signal to any valve is annunciated in the control room.

Containment isolation provisions for piping used in conjunction with hydrogen recombination and post-LOCA purging are discussed in Section 9.4.5.1.

The design pressures and temperatures for process components of the hydrogen recombiner packages are as follows:

a.	Nonoperating conditions: entire system	55 psig/340°F
b.	Operating conditions:	
	Stainless steel components (gas heater pipe, reaction chamber, and water spray cooler)	30 psig/1400°F
	Carbon steel components (inlet piping, water separator, and outlet piping)	55 psig/340°F

Since the post-LOCA primary containment pressure-temperature transient stays well below these design parameters for the time period greater than 6 hours after the LOCA (Section 6.2.1), no restrictions exist on recombiner operation after this 6 hour period.

As shown in Figures 6.2-44, 6.2-45, and 6.2-46, the operation of one hydrogen recombiner package is sufficient to maintain post-LOCA oxygen concentrations in the containment below 5% (volume). The analysis to determine post-LOCA oxygen concentrations assumes that hydrogen-oxygen recombination begins at 39 hours after the LOCA. Since the recombiner requires a maximum 2 hour heatup period (verified by surveillance testing) before complete recombination of oxygen in the process stream occurs, one recombiner package is activated at or prior to 37 hours after a LOCA.

In the extremely unlikely event that a LOCA occurs and both recombiner packages fail to function properly, purging may be utilized to control the oxygen concentration inside the containment. The oxygen generation analysis shows that the oxygen concentration reaches 4.5% (volume) at 39 hours after the LOCA, and that a 60 scfm purge initiated at that time ensures that the oxygen concentration remains below the 5% level. The effect of the purge on oxygen concentration is shown in Figures 6.2-44, 6.2-45, and 6.2-46.

The BWROG EPGs make specific recommendations for Post-LOCA purging based on the hydrogen levels in containment. Post-LOCA purging using the low volume purge mode of CAC (discussed in section 9.4.5.1) is recommended when containment hydrogen levels are greater than a specific level in the BWROG EPGs, no deflagration can occur, and the containment can be purged without exceeding the normal release rate limits in the Technical Specifications or ODCM. Post-LOCA low volume purging continues until the containment hydrogen levels fall below the recommended value specified in the BWROG EPGs. Gases exhausted from the containment during post-LOCA purging are processed through the RERS and SGTS in order to remove radioactive particulate and halogen contaminants prior to release to the environment.

If containment hydrogen levels continue to increase a high volume purge of the containment can be performed using nitrogen, or air depending on the potential for the hydrogen and oxygen concentration to result in a deflagration. Depending on the plant conditions at the time of the high volume purge, RERS and SGTS may or may not be available. Depending on the specific concentrations of hydrogen in containment at the time, offsite release rates are limited to those in the Technical Specifications or ODCM. The high volume purge can be used in accordance with BWROG EPG recommendations to prevent containment failure due to a deflagration and to minimize the consequences of the accident. Post-LOCA high volume purging continues until the containment hydrogen levels fall below the recommended value specified in the BWROG EPGs. The BWROG EPG recommendations regarding purging of the containment are incorporated in the EOPs.

6.2.5.5 Tests and Inspections

The containment hydrogen recombiner subsystem and the combustible gas analyzer subsystem are preoperationally tested in accordance with the requirements of Chapter 14 and periodically tested in accordance with the requirements of the maintenance program and the Technical Requirements Manual (TRM), respectively. Inservice inspection of the subsystems will be in accordance with the ASME Section XI, for ASME Section III, Class 2 components.

6.2.5.6 Instrumentation Applications

6.2.5.6.1 Containment Hydrogen Recombiner Subsystem

The control cabinet for each hydrogen recombiner package contains the following devices (on the front side of the cabinet) that control and monitor the operation of the recombiner:

a. Operate switch (HS-3)

b. Inlet valve flow control switch (HS-1)

c. Recirculation valve flow control switch (HS-2)

d. Reaction chamber temperature controller (TIC-7)

e. Flow/pressure recorder (XR-1)

f. Temperature recorders (TRS-2 and TRS-4)

g. Annunciator assembly

Also located on the control cabinet, but on the rear of the cabinet, are eight hand switches (HS-6 through HS-10 and HS-14 through HS-16).

The hydrogen recombiner packages have three basic modes of operation: standby, ready, and operate. The recombiner is kept in the "ready" mode when not being tested or otherwise operated. Initially, when the recombiner subsystem is first energized or during maintenance, the system is placed in the "standby" mode. The trickle heaters are energized in order to keep the insulated enclosure warm in the "standby" and "ready" modes. The temperature controller is set at the value that will be used during initial operation of the recombiner. The recombiner is placed in the "ready" mode by actuating the service disconnect switches (HS-6 through HS-9) to the "on" position. The recombiner is left in the "ready" mode for approximately one hour, to allow circuits to stabilize before proceeding to the "operate" mode. Since the recombiner is normally in the "ready" mode, the one hour stabilization time is not a concern prior to going to the "operate" mode. The recombiner is placed in the "operate" mode by actuating switch HS-3, at which time the blower starts and the water inlet valve opens. Interlocks are provided to prevent the heater elements from being energized until the water inlet valve is fully open and the blower inlet gas flow rate exceeds the low flow setpoint. Recombiner inlet flow control and recirculation flow control is achieved using hand switches HS-1 and HS-2 in conjunction with flow/pressure recorder XR-1.

While the recombiner is in the "operate" mode, the "startup" light is on while the reaction chamber gas temperature remains below 1150°F, and the "operate" light is on when this temperature has been exceeded.

The following process alarms are displayed on the annunciator:

a. Blower inlet gas pressure (high)

b. Blower inlet gas flow (low)

c. Blower inlet gas temperature (high)

d. Heater wall temperature (high)

e. Reaction chamber gas temperature (high and low)

f. Reaction chamber shell temperature (high)

g. Return gas temperature (high)

Automatic shutdown of the recombiners (interruption of power to the blower and the heater elements) results if setpoints are exceeded for variables a, c, d, f, and g as listed above. If the setpoint is exceeded for variable b or heater temperature two-thirds through heater (high), heater outlet temperature (high), or the water inlet control valve is not fully open, power to the heater elements is interrupted but the blower continues to run.

The recombiner process alarms listed above are annunciated by a general trouble alarm external to the recombiner control cabinet, as well as by the annunciator on each recombiner control cabinet. Failure of the recombiner trickle heat is also annunciated by this general trouble alarm.

The gas outlet piping from each recombiner package is provided with a level switch to detect (and annunciate in the control room) the accumulation of water in the outlet piping. Such an occurrence could result from leakage of the recombiner cooling water inlet valve while the recombiner is not in operation.

The following process variables are recorded on XR-1:

a. Blower inlet pressure

b. Recombiner inlet flow

c. Blower inlet flow

Separate modules provide alarm and trip outputs for variables a and c. These modules are mounted on an instrument rack located on the front side of the control cabinet.

The following process temperatures are recorded on TRS-2:

a. Blower inlet temperature

b. Reaction chamber shell temperature

c. Return gas temperature

The following process temperatures are recorded on TRS-4:

a. Heater temperature two-thirds through heater

b. Heater outlet temperature

c. Heater wall temperature

Process temperature alarm and trip outputs are provided by the temperature recorders.

The annunciator assembly is a backlighted legend plate, flasher, sequential type annunciator with a common horn. The annunciator, along with the TEST, ACKNOWLEDGE, and RESET push buttons are mounted on the front side of the control cabinet.

During normal conditions, the legend plate is dark and the horn is off. During abnormal conditions, the annunciator indicates an alarm by a fast flashing legend plate and by a horn. The operator can acknowledge the alarm by pressing the ACKNOWLEDGE push button. This causes the horn to stop

sounding and the legend to stop flashing but remain lighted. When conditions return-to-normal, the legend changes from steady to slow flashing and the horn sounds. The operator can clear the alarm by pressing the RESET push button. This causes the window to become dark again.

The alarm sequence is different if the abnormal condition returns to normal before acknowledgement by the operator. In that case, pushing the ACKNOWLEDGE push button causes the legend to change from fast flashing to slow flashing. The horn remains on until the RESET push button is pressed.

The operator can functionally test the entire annunciator system by pressing the TEST push button. After testing, the operator returns the annunciator to the ready condition by pressing the ACKNOWLEDGE and RESET push buttons in sequence.

6.2.5.6.2 Combustible Gas Analyzer Subsystem

The combustible gas analyzer packages are designed to be operable from the remote control panel and includes hydrogen and oxygen concentration indicators. Also provided in the control room are annunciation of high oxygen concentration and high hydrogen concentration, and analyzer package malfunction. Those malfunctions that are annunciated include out of range signal from the partial or total pressure sensors, calibration errors, system configuration errors, low flow, over pressurization, and module hardware faults.

Instrumentation and controls for the containment hydrogen recombiner subsystem and the combustible gas analyzer subsystem are discussed further in Section 7.3.1.1.6.

6.2.6 PRIMARY REACTOR CONTAINMENT LEAKAGE RATE TESTING

This section presents the testing program for the primary reactor containment ILRTs (Type A tests), primary containment penetration leakage rate tests (Type B tests), and primary containment isolation valve leakage rate tests (Type C tests). This program complies with 10CFR50, Appendix A, General Design Criteria, and Performance Based Option B of 10CFR50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors", to the greatest extent practicable. The details of the program are defined in the Primary Containment Leak Rate Testing Program (PCLRTP) as identified in Chapter 16.

6.2.6.1 Primary Reactor Containment Integrated Leakage Rate Tests

Upon completion of construction of the primary reactor containment, including installation of all portions of the mechanical, fluid, electrical, and instrumentation systems penetrating the containment associated with containment integrity; and upon satisfactory completion of the structural integrity tests as described in Section 3.8, the preoperational containment ILRT was performed in accordance with the requirements of Chapter 14 to verify that the actual containment leakage rate did not exceed the design limit.

Type A tests are conducted at intervals as described in PCLRTP. A general inspection of the accessible interior and exterior surfaces of the primary containment structure and components is performed in accordance with the PCLRTP, to uncover any evidence of structural deterioration that could affect either the containment structural integrity or leak-tightness. If there is evidence of structural deterioration, corrective action is taken. The structural deterioration and corrective action are reported in accordance with 10CFR50, Appendix J. Repairs or adjustments made to the

containment boundary prior to the conduct of the Type A test shall be accounted for in the determination of the As-Found Type A test.

The ILRT (Type A) is performed to determine that the total leakage from the containment does not exceed the maximum allowable leakage rate (La) at the design basis LOCA maximum peak containment pressure (Pa), as defined in Chapter 16. Typical piping and instrumentation are shown in drawing M-60. Acceptance criteria and frequency are defined in the PCLRTP.

The Type A test is conducted in accordance with 10 CFR 50, Appendix J, Option B and the PCLRTP.

A typical data acquisition system is shown in drawing M-60. Prior to commencement of any Type A test the pretest requirements of ANSI/ANS N56.8-2002 are met with specifics as follows:

a. Those portions of fluid systems that are part of the RCPB, and are open directly to the primary containment atmosphere under postaccident conditions and become an extension of the boundary of the primary containment, are opened or vented to the containment atmosphere prior to and during the Type A test, except as noted in Table 6.2-24. Portions of closed systems inside the containment that penetrate primary containment and can rupture as a result of a LOCA are vented to the containment atmosphere, except as noted in Table 6.2-24.

b. All systems not designed to remain water-filled post-LOCA are drained of water to the extent necessary to ensure exposure of the system primary containment isolation valves to containment air test pressure.

c. Those portions of fluid systems that penetrate the primary containment, that are external to the containment and are not designed to provide a containment isolation barrier, are vented to the outside atmosphere, as applicable, to ensure that full postaccident differential pressure is maintained across the containment isolation barrier.

d. Systems that are required to maintain the plant in a safe condition during the Type A test are operable in their normal mode and are not vented, as noted in Table 6.2-24.

e. Systems that are normally filled with water and operating under postaccident conditions are not vented. However, the measured leakage rates (Type C) for containment isolation valves in these systems identified in Table 6.2-24 are reported in the Type A test final report.

f. For planning and scheduling purposes, or ALARA considerations, pathways that are Type B or C tested within the previous 24 calendar months need not be vented or drained during the Type A test.

6.2.6.2 Primary Containment Penetration Leakage Rate Tests

Containment penetrations with designs incorporating resilient seals, gaskets or sealant compounds, air locks and lock door seals, equipment and access hatch seals, and electrical canisters receive preoperational and periodic Type B leakage rate tests in accordance with 10CFR50, Appendix J, Option B and the PCLRTP. A list of all containment penetrations subject to Type B tests is provided in Table 6.2-25.

All Type B tests are conducted at pressure (Pa) as defined in Chapter 16. The acceptance criteria are given in the PCLRTP. Test methods are described in Section 6.2.6.3 below.

Penetrations with threaded caps are provided in the air lock to permit pressure testing of the door seals and the entire lock.

Penetrations for equalizing valves as described in Section 3.8.2.1.2 are provided in the air lock. Figure 6.2-48 shows the locations of all mechanical and electrical penetrations in the air lock. Figure 6.2-49 shows details of the door seals and the pressure test connection.

The personnel air lock volume is pressurized to primary containment peak accident pressure and tested periodically as described in Chapter 16 and the PCLRTP. During the air lock test, tie-downs are installed from inside the lock on the inner door, since normal locking mechanisms are not designed to withstand a differential pressure across the door in the reverse direction in excess of 5 psig. See Figure 6.2-50 for details of the tie-downs for the inner door. The tie-downs are installed from within the air lock. The force exerted by the tie-downs on the inner door is not monitored. Pressurizing the lock barrel also tests the lock mechanical and electrical penetrations, and the door seals.

The door seals are periodically tested at Pa as indicated in Chapter 16. Additionally, the door seals are tested after each opening at 10 psig without installing tie-downs as indicated in Chapter 16 and the PCLRTP.

6.2.6.3 Primary Containment Isolation Valve Leakage Rate Tests

The containment isolation valves that are Type C tested are listed in Table 6.2-25.

Type B and C tests are performed by local pressurization, using either the pressure-decay or flowmeter method. For the majority of isolation valves, the test pressure is applied in the same direction that the valve would see when required to perform its safety function. There are a few exceptions where the test pressure is applied in the reverse direction. Further explanation is provided in Table 6.2-25. For the pressure decay method, the test volume is pressurized with air or nitrogen to at least Pa. The rate of decay of pressure of the known free air test volume is monitored to calculate leakage rate. For the flowmeter method, pressure is maintained in the test volume by making up air, nitrogen, or water (if applicable) through a calibrated flowmeter. The flowmeter fluid flow rate is the isolation valve leakage rate.

All isolation valve seats that are exposed to containment atmosphere subsequent to a LOCA are tested with air or nitrogen at pressure (Pa) as defined in Chapter 16.

Those valves which are in lines designed to be, or remain, filled with a liquid for at least 30 days subsequent to a LOCA are leakage rate tested with that liquid. The liquid leakage measured is neither converted to equivalent air leakage nor added to the Type B and C test totals. Isolation valves tested with liquid are identified in Table 6.2-25 and designated under note (15).

The acceptance criteria for all penetrations and isolation valves subject to Type B and C tests are given in Chapter 16 and the PCLRTP.

6.2.6.4 Scheduling and Reporting of Periodic Tests

The periodic leakage rate test schedules for Types A, B and C tests are given in the PCLRTP.

Type B and C tests can be conducted at any time during normal plant operations or during shutdown periods, so long as the time interval between tests for any individual Type B or C test does not exceed the maximum allowable interval specified in the PCLRTP. Each time a Type B or C test is completed, the overall total leakage rate for all required Type B and C tests is corrected for any differences noted.

Provisions for reporting test results are given in the PCLRTP.

6.2.6.5 Special Testing Requirements

6.2.6.5.1 Drywell Steam Bypass Test

Following the drywell structural integrity test, described in Section 3.8.1.7, a preoperational drywell-to-wetwell leakage rate test is performed at the peak drywell-to-wetwell differential pressure. Table 14.2-4 gives the test descriptions. Also, drywell to wetwell leakage rate tests at a reduced differential pressure corresponding approximately to the submergence of the vents, defined in Chapter 16, are performed following the preoperational Type A test and periodically thereafter. These drywell leakage rate tests verify, over the design life of the plant, that no paths for gross leakage from the drywell to the suppression chamber air space bypassing the pressure-suppression feature exist. The combination of the design pressure and reduced pressure leakage rate tests also verifies that the drywell performs adequately for the full range of postulated primary system break sizes. The drywell leakage rate limits specified in Chapter 16 for the above tests are based on a value of 10% of the allowable bypass $A/(K)^{1/2}$ for small breaks that are described in Section 6.2.1.1.5.4.

Drywell leakage rate tests are performed with the drywell isolated from the suppression chamber. Valves and system lineups are the same as for the Type A test except any paths for equalizing drywell and suppression chamber pressure open during the Type A test are isolated. The drywell atmosphere is allowed to stabilize for a period of 1 hour after attaining test pressure. Leakage rate test calculations, using the wetwell pressure rise method on Unit 1 and the wetwell pressure rise method on Unit 2, commence after the stabilization period.

The pressure rise method (Unit 1) is based on containment atmosphere pressure and temperature observations and the known wetwell free air volume specified in Table 6.2-1. Leakage rate is calculated from the pressure and temperature data, wetwell free air volume, and elapsed time.

The pressure rise method (Unit 2) is based on containment atmosphere pressure and temperature observations and the known wetwell volume specified in Table 6.2-1. Leakage rate is calculated from the pressure and temperature data, wetwell free air volume, and elapsed time.

When the drywell leakage rate test described above is not performed, an alternate test is performed to verify that each set of downcomer vacuum breaker valves does not provide a path for gross leakage from the drywell to the suppression chamber.

The periodic drywell leakage rate test and downcomer vacuum breaker valve leakage rate test pressures, test duration, and acceptance criteria are specified in Chapter 16. Periodic drywell leakage rate tests and downcomer vacuum breaker valve leakage tests are performed at the intervals specified in Chapter 16. This surveillance testing will be in accordance with the Technical Specifications.

6.2.6.5.2 Risk Informed Alternative Treatment Due to 10 CFR 50.69

There is a Risk Informed Categorization and Treatment Program at Limerick which is based on 10 CFR 50.69. This regulation provides an alternative approach for establishing requirements for treatment of SSCs using a risk-informed method of categorizing SSCs according to their safety significance. Specifically, for SSCs categorized as low safety significant, alternate treatment requirements may be implemented rather than treatments chosen by the Appendix J program. Refer to Section 13.5.5 for further information.

6.2.7 POSTACCIDENT SYSTEM ISOLATION

Following an accident in which significant fuel damage is postulated to occur, a number of plant systems whose piping penetrates the primary containment may contain highly radioactive fluids. Adequate system isolation features exist to ensure that the integrity of these systems will be maintained.

6.2.7.1 System Isolation Provisions

The boundaries of potentially contaminated systems are adequately isolated by one of the following:

a. Two normally closed manual valves

b. One normally closed manual valve (low pressure piping)

c. One or two normally closed manual valves and a cap

d. One SRV or one rupture disc

e. Two check valves

f. One remotely actuated valve and one check valve

g. Two remotely actuated valves

In cases where a remotely actuated valve is required to change position to provide system isolation, the valve receives an auto isolation signal. In some cases a system isolation valve does not receive a direct isolation signal but is interlocked to close when a containment isolation valve or other valve opens to permit fluid flow from the containment.

Table 6.2-26 lists remotely actuated system isolation valves, their normal and required accident positions and their actuation signals. Containment isolation valves that also provide postaccident system isolation are not included in this table but are listed in Table 6.2-17.

6.2.7.2 Potentially Contaminated Systems

The following systems whose piping penetrates primary containment may contain highly radioactive fluids after an accident. Other systems have been excluded from this list for the reasons discussed in Section 6.2.8.2.

a. RHR System (drawing M-51)

b. Core Spray System (drawing M-52)

c. HPCI System (drawing M-55)

d. RCIC System (drawing M-49)

e. CRD Hydraulic System (SDV, drawings M-46 and M-47).

f. Safeguard Piping Fill System (drawing M-52)

g. PASS (drawing M-30)

h. CAC System (drawing M-57)

6.2.8 LEAKAGE REDUCTION PROGRAM

To ensure that leakage from systems that may be expected to handle highly radioactive fluids during or after an accident is maintained as-low-as-practical, a leakage reduction program will be established. System isolation provisions have been reviewed in conjunction with this effort and are discussed in Section 6.2.7.

6.2.8.1 Systems to be Leak Tested

The following systems will be leak tested at 24-month intervals. The test conditions will simulate the expected operating conditions during an accident or transient:

a. RHR System

b. Core Spray System

c. HPCI System

d. RCIC System

e. CRD Scram Discharge System

f. Safeguard Piping Fill System

g. PASS (including portions of the Process Sampling System)

h. CAC System (recombiner and sample loops only)

6.2.8.2 Systems Excluded from the Program

The following systems are excluded from the leakage reduction program for the reasons given below:

a. Reactor Recirculation System - The interfaces between the recirculation system and the systems outside containment (other than RHR) are isolated by containment isolation valves.

b. RWCU - The RWCU system is isolated from the recirculation system by containment isolation valves.

c. Main Steam System - The main steam system is isolated by containment isolation valves.

d. Feedwater System - The feedwater system is isolated by containment isolation valves.

e. Process Sampling System - Sample lines from potentially contaminated sources inside the containment are isolated by containment isolation valves. Potentially

contaminated sample lines from the RHR system, associated with postaccident sampling, will be leak tested with the postaccident sample system.

f. Suppression Pool Cleanup System - The suppression pool cleanup system is isolated by containment isolation valves.

g. RERS and SGTS - The reactor enclosure HVAC supply and exhaust valves will isolate the reactor enclosure upon receipt of high radiation isolation signal. The RERS and SGTS will then filter and exhaust air from the reactor enclosure and maintain a subatmospheric pressure. Because the source of radioactivity in these systems is airborne contamination resulting from previous leakage from the containment or contaminated systems, a leakage reduction program for the low pressure RERS/SGTS ducting would not significantly reduce the airborne radioactivity concentrations in the secondary containment. The recirculation and SGTS filters will be tested as described in Sections 6.5.1.3.4 and 6.5.1.1.4.

h. Containment Radiation Sampling System - The containment radiation sampling system, used to provide an indication of primary leakage during normal operation, is isolated by containment isolation valves.

6.2.8.3 Leak Testing Method

System leak test conditions will simulate the expected operating conditions during an accident. Each component in the system will be inspected for leakage. Water leakage will be collected and measured. Steam leakage will be estimated and converted to an equivalent water leak rate. Gas systems will be bubble leak tested with a zero leakage acceptance criteria or leakage will be quantified by means of a pressure decay or helium leak test.

Leakage rate goals will be established for each system based on baseline data from the first tests. Components whose leakage contributes significantly to the total leak rate or increases substantially between tests will be repaired to maintain total leakage as-low-as-practical.

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Table 6.2-1 (See Note)

CONTAINMENT DESIGN PARAMETERS*

DRYWELL AND SUPPRESSION CHAMBER	DRYWELL	SUPPRESSION CHAMBER
Internal design pressure, psig	55	55
External to internal design differential pressure, psid	5	5
Drywell deck design differential pressure, psid	30 downward	20 upward
Design temperature, °F	340	220
Drywell net free air volume, ft^3		
Low level(4)		243,580(1)(2)
High level(4)		242,860(1)(2)
Design leak rate, % by weight/day	0.5	0.5
Maximum allowable leak rate, % by weight/day	0.5	0.5
Suppression chamber free air volume, ft^3		
Low level(4)		159,540(2)(3)
High level(4)		147,670(2)(3)
Suppression pool water volume, ft^3		
Low level(4)		122,120(2)(3)
High level(4)		134,600(2)(3)
Suppression pool surface area, ft^2		
Outside pedestal		4974(2)
Inside pedestal		293
Suppression pool depth, ft		
Low level		22'
High level		24'-3"

Table 6.2-1 (Cont'd)

	DRYWELL	SUPPRESSION CHAMBER
VENT SYSTEM		
Number of downcomers		83(5)
Nominal downcomer diameter, ft		2
Total vent area, ft^2		244.7(5)
Downcomer submergence, ft		
Low water level		10'
High water level		12'-3"
Downcomer loss coefficient		2.23(2)

(1) Drywell volume includes downcomer air volume.
(2) These values vary slightly from those actually used in the analysis. The difference in analysis results is negligible.
(3) Including pedestal volume.
(4) Low level and high level refer to suppression pool water level.
(5) The original containment analysis included a total vent area of 256.5 square feet, equivalent to all 87 downcomers. Four of the downcomers have been capped. The impact of capping four downcomers on analysis results is negligable.

*NOTE: The information presented in this table was used for the original containment analysis and such should be considered historical. Refer to Table 6.2-4a for the parameters used in the current containment response analysis.

Table 6.2-2

ENGINEERED SAFETY FEATURE SYSTEMS INFORMATION
FOR CONTAINMENT RESPONSE ANALYSES*

	FULL CAPACITY	CONTAINMENT ANALYSIS VALUE CASE A	CASE B	CASE C
DRYWELL SPRAY				
Number of RHR pumps	2	2	1	0
Number of lines	2	2	1	0
Number of headers	2	2	1	0
Spray flow rate, gpm/pump	9,500	9,500	9,500	0
Spray thermal efficiency, %	See Section 6.2.1.1.3.4.3			
SUPPRESSION CHAMBER SPRAY				
Number of RHR pumps	2	2	1	0
Number of lines	2	2	1	0
Number of headers	1	1	1	0
Spray flow rate, gpm/pump	500	500	500	0
Spray thermal efficiency, %	See Section 6.2.1.1.3.4.3			
SUPPRESSION POOL COOLING SYSTEM				
Number of RHR pumps	2	2	1	1
Pump capacity, gpm/pump	10,000	10,000	10,000	10,000
RHR heat exchangers				
Type - Inverted U-tube, single pass shell, multipass tubes, vertical mounting	-	-	-	-
Number	2	2	1	1

Table 6.2-2 (Cont'd)

	FULL CAPACITY	CONTAINMENT ANALYSIS VALUE CASE A	CASE B	CASE C
Heat transfer area, ft^2/unit	6,281*	-	-	-
Overall heat transfer coefficient, Btu/hr-ft^2-°F/unit	228 *	-	-	-
RHRSW flow rate, gpm/unit	8000	5570	5570	5570
RHRSW temperature, °F	-	95	95	95
Minimum design	40	-	-	-
Maximum design	95	-	-	-
Containment heat removal capability per unit, using 95°F RHRSW and 212°F pool temperature, Btu/hr	128.5 $x10^6$	-	-	-
Peak Containment Heat removal rate Btu/hr at peak suppression pool temperature of 203.4°F	119.9 $x10^6$	-	-	-

* Actual heat transfer surface area and heat transfer coefficient vary with the condition of the heat exchanger (e.g. plugged or fouled tubes). Acceptance criteria are administratively controlled by plant surveillance procedures to assure that the RHR heat exchangers can provide the required Peak Containment Heat Removal Rate at the peak suppression pool water temperature.

** For two-unit operation with one RHRSW loop in service, the RHRSW design minimum required flow rate under accident conditions is 8000 gpm to the LOCA unit and between 5570 and 8000 gpm to the unit under normal shutdown conditions. An evaluation has been performed, however, to confirm that a RHRSW flow rate as low as 5570 gpm is sufficient to meet the design heat removal requirements of the unit with the LOCA under certain conditions.

Table 6.2-3

ACCIDENT ASSUMPTIONS AND INITIAL CONDITIONS
FOR CONTAINMENT RESPONSE ANALYSES*

Components of effective break area (recirculation line break), ft^2	
Recirculation line	3.538
Jet pumps	0.537
Primary steam energy distribution(1), 10^6 Btu	
Steam energy	26.7
Liquid energy	365.0
Sensible energy	
Reactor vessel	93.97
Reactor internals (less core)	59.08
Primary system piping	23.2
Fuel(2)	6.299
Other assumptions used in analysis	
Feedwater valve closure time, sec	Instantaneous
MSIV closure time, sec	
Recirculation line break (includes 0.5 second delay)	3.0
Main steam line break (includes 0.5 second delay)	5.0
Scram time, sec	<1

(1) All energy values except fuel are based on a 32°F datum.
(2) Fuel energy is based on a datum of 285°F.

*NOTE: The information presented in this table was used for the original containment analysis and such should be considered historical. Refer to Table 6.2-4a for the parameters used in the current containment response analysis.

Table 6.2-4

INITIAL CONDITIONS FOR CONTAINMENT RESPONSE ANALYSES*

REACTOR COOLANT SYSTEM[1]	
Reactor power level, MWt	3,435
Average coolant pressure, psia	1,055
Average coolant temperature, °F	551.1
Mass of RCS liquid, lb	669,900
Mass of RCS steam, lb	24,100
Volume of liquid in vessel, ft^3	11,922.3
Volume of steam in vessel, ft^3	10,122
Volume of liquid in recirculation loops, ft^3	1,320.4
Volume of steam in steam lines, ft^3	1,218.0
Volume of liquid in feedwater line, ft^3	1,232.5
Volume of liquid in miscellaneous lines, ft^3	Insignificant
Total reactor coolant volume, ft^3	25,815.2

CONTAINMENT	DRYWELL	SUPPRESSION CHAMBER
Pressure, psig	0.75	0.75
Air temperature, °F	150	95
Relative humidity, %	20%	100%
Suppression pool water temperature, °F	-	95
Suppression pool water volume, ft^3	-	118,655
Vent submergence, ft	-	12'-3"

(1) 105% of rated steam flow and normal liquid levels

*NOTE: The information presented in this table was used for the original containment analysis and such should be considered historical. Refer to Table 6.2-4a for the parameters used in the current containment response analysis.

Table 6.2-4A

THE LGS POWER RERATE CONTAINMENT ANALYSIS

I. Short-Term Analysis

A. Drywell and Vent System

Variable	Units	Value Used for Analysis
Drywell Internal Design Pressure	psig	55
Drywell Internal Design Temperature	°F	340
Drywell Deck Design Differential Pressure	psid	30 (downward)
Drywell Free Volume (including vent system)	ft^3	243,580
Drywell Pressure	psia	15.45
Drywell Temperature	°F	150
Drywell Relative Humidity	%	20
Number of Downcomers		83 (1)
Downcomer Inside Diameter	ft	1.9375
Downcomer Length	ft	45.5
Downcomer Area (each)	ft^2	2.95
Total Downcomer Discharge Area	ft^2	244.7 (1)
Downcomer Submerge (HWL)	ft	12.25
Total Downcomer Flow Loss Coefficient (including exit loss)		2.23

B. Wetwell and Suppression Pool

Variable	Units	Value Used for Analysis
Wetwell Internal Design Pressure	psig	55
Wetwell Deck Design Differential Pressure	psid	20 (upward)
Wetwell Airspace Volume at high water level (including vent system)	ft^3	147,670
Suppression Pool Volume (HWL)	ft^3	134,600
Suppression Pool Surface Area (outside pedestal)	ft^2	4,974
Suppression Pool Surface Area (inside pedestal	ft^2	293
Wetwell Pressure	psia	15.45
Wetwell Airspace Temperature	°F	95
Suppression Pool Temperature	°F	95
Wetwell Relative Humidity	%	100

(1) The original containment analysis included a total vent area of 256.5 square feet, equivalent to all 87 downcomers. Four of the downcomers have been capped. The impact of capping four downcomers on analysis results is negligable.

Table 6.2-4A

THE LGS POWER RERATE CONTAINMENT ANALYSIS

I. Short-Term Analysis (cont'd)

C. Reactor Initial Conditions

Rerated Power*/Flow Operating Point	RPV Dome Pressure (psia)	Saturation Enthalpy (Btu/lbm)	Downcomer Enthalpy (Btu/lbm)	Downcomer Subcooling Btu/lbm
62RP/40F	1017	545.2	503.0	42.2
102RP/81F**	1068	552.8	526.1	26.7
102RP/87F	1068	552.8	527.7	25.1
102RP/100F	1068	552.8	531.3	21.5
102RP/110F	1068	552.8	533.4	19.4
62RP/40F - FFWTR	1009	543.9	487.9	56.0
102RP/81F - FFWTR**	1051	550.3	509.0	41.3
102RP/87F - FFWTR	1049	550.0	510.6	39.4
102RP/100F - FFWTR	1049	550.0	516.0	34.0
102RP/110F - FFWTR	1049	550.0	519.3	30.7

* RP (Rerate Power) is defined as 3458 MWt
** RP (Rerate Power) is defined here as 3622 MWt

Table 6.2-4A

THE LGS POWER RERATE CONTAINMENT ANALYSIS

II. Long-Term Analysis*

A. Reactor Coolant System

Variable	Units	Value Used for Analysis
Reactor Power	MWt	3528 (102% of 100%P)
Core Flow Rate	lbm/hr	100.0E6 (100%F)
RPV Dome Pressure	psia	1068
RPV Temperature	°F	552.5
Core Inlet Enthalpy	Btu/lbm	531.3
RPV Inlet Feedwater Enthalpy (upstream of RWCU inlet)	Btu/lbm	411.4
Initial Steam Flow	lbm/hr	15.451E6
Coolant System Total Free Volume	ft^3	23,492
Coolant System Liquid Volume	ft^3	13,108

B. Drywell and Vent System

Variable	Units	Value Used for Analysis
Drywell Free Volume (including vents)	ft^3	243,580
Drywell Pressure	psia	15.45
Drywell Temperature	°F	150
Drywell Relative Humidity	%	20
Number of Downcomers		83
Downcomers Inside Diameter (Nominal)	ft	1.9375
Total Vent Area	ft^2	244.7
Maximum Downcomer Submerge	ft	10.0
Total Downcomer Flow Loss Coefficient (including exit loss)		2.23

* The Long term containment analysis is performed for rerated conditions including the additional head load from SIL 636. (Reference 6.2-41)

Table 6.2-4A

THE LGS POWER RERATE CONTAINMENT ANALYSIS

II. Long-Term Analysis(cont'd)

C. Suppression Chamber and Suppression Pool

Variable	Units	Value Used for Analysis
Suppression Chamber Airspace Volume	ft^3	147,670 (HWL) 159,540 (LWL)
Suppression Pool Volume	ft^3	134,300 (HWL) 118,655 (LWL)
Suppression Pool Surface Area	ft^2	5267
Suppression Chamber Airspace Pressure	psia	15.45
Suppression Chamber Airspace Temperature	°F	95
Suppression Chamber Relative Humidity	%	100
Suppression Pool Temperature	°F	95

D. RHR System

Variable	Units	Value Used for Analysis
Service Water Temperature	°F	95
Heat Exchanger K-Factor	Btu/sec-°F	305
RHR Pump Heat per Pump	Hp	1250

Table 6.2-4A

THE LGS POWER RERATE CONTAINMENT ANALYSIS

II. Long-Term Analysis(cont'd)

E. ECCS

Variable	Units	Value Used for Analysis
HPCI		
Minimum Rated Flow at 0 to 200 psid	gpm	5600
LPCS		
Minimum Rated Flow at 105 psid (2 pumps)	gpm	6250
Pump Heat per pump	Hp	658
LPCI		
Minimum Rated Flow at 20 psid (per pump)	gpm	10000
Pump Heat per pump	Hp	1250

F. Containment Spray

Variable	Units	Value Used for Analysis
Drywell Spray		
Flow Rate Per Pump	gpm	9500
Pump Heat per Pump	Hp	1187.5
HX K-Factor	Btu/sec-°F	289.8
Wetwell Spray		
Flow Rate Per Pump	gpm	500
Pump Heat per Pump	Hp	62.5
HX K-Factor	Btu/sec-°F	15.2

Table 6.2-5

SUMMARY OF SHORT-TERM CONTAINMENT RESPONSES TO RECIRCULATION LINE AND MAIN STEAM LINE BREAKS

	RECIRCULATION LINE BREAK	MAIN STEAM LINE BREAK
Peak drywell pressure, psig	44.0	36.20
Peak drywell deck downward differential pressure, psid	25.995	19.5
Time of peak pressures, sec	13.66	20.12
Peak drywell temperature, °F	290.9	330
Peak suppression chamber pressure, psig	30.57	30.55
Time of peak suppression chamber pressure, sec	34.75	50
Peak suppression pool temperature during blowdown, °F	135.7	136
Calculated drywell pressure margin, %	20	34
Calculated suppression chamber pressure margin, %	44	44
Calculated deck differential pressure margin, %	13	35
Energy released to containment at time of peak pressure, 10^6 Btu	262.23	-
Energy absorbed by passive heat sinks at time of peak pressure, 10^6Btu	0	0

NOTE: The information presented in this table for the recirculation line break results is based on the original design basis conditions. Refer to Table 6.2-5A for the recirculation line break results for current plant conditions.

The information presented in this table for the main steam line break results is based on the original design basis conditions. As described in Section 6.2.1.1.3, the main steam line break was not reanalyzed for the current conditions; however, the results presented here reasonably represent the general characteristics of the main steam line break analysis results. See explanation at the beginning of Section 6.2.1.1.3.

Table 6.2-5A

CONTAINMENT LOCA RESPONSE AT RERATE POWER

Parameter	Analysis	Design Limit
Peak Drywell Pressure (psig)	42.1 (1)	55
Peak Wetwell Pressure (psig)	39.0 (2)	55
Peak Drywell-to-Wetwell Pressure Difference (psid)	28.5 (3)	30
Peak Bulk Pool Temperature (°F) (LOCA)	203.4 (4)	220* 212**

* Structural
** Low pressure ECCS pump NPSH @ 0 psig in the suppression chamber

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(1) Short Term Analysis performed for: Power=3694 MWt; Core Flow=110%; FWTR=105°F

(2) Short Term Analysis performed for: Power=3527 MWt; Core Flow=81%; FWTR=105°F

(3) Short Term Analysis performed for: Power=3694 MWt; Core Flow=100%; FWTR=0°F

(4) Long Term Analysis performed for: Power = 3528 MWt; Core Flow = 100%; FWTR = 0°F

(Initial Reactor pressure assumed to be 1053 psig)

Table 6.2-6

SUMMARY OF LONG-TERM CONTAINMENT RESPONSES TO RECIRCULATION LINE AND MAIN STEAM LINE BREAKS

	CASE A	CASE B	CASE C
Secondary peak suppression chamber pressure, psig	6.56	14.19	16.7
Peak suppression pool temperature, ^{o}F	173.6	211.3	212.5
HPCI flow rate, gpm		Not Used	
CS flow rate, gpm	12,500	6,250	6,250
RHR flow rate, gpm/pump	10,000	10,000	10,000

NOTE: The information presented in this table is based on the original design basis conditions. Refer to Table 6.2-5A for the Case C results for current plant conditions and methodology. The results for Cases A, B, and C shown is this table reasonably represent the general characteristics and relative differences between the three cases.

Table 6.2-7

ENERGY BALANCE FOR RECIRCULATION LINE BREAK ACCIDENT

	Energy, 10^6 Btu			
	INITIAL	DRYWELL PEAK PRESSURE	END OF BLOWDOWN	LONG-TERM PEAK PRESSURE
Reactor coolant	392.3	139.5	12.325	58.1
Fuel and cladding[1]	6.299	6.296	6.116	-
Core internals and primary primary system piping	82.29	82.99	82.26	28.097
Reactor vessel metal	93.97	93.97	93.97	32.56
Pump heat added	0	0	0.38045	185.3
Blowdown enthalpy[2]	0	262.23	409.6	409.6
Decay heat[3]	0	23.28	35.82	1,563.0
Metal-water reaction heat	0	0.02838	0.085	0.25
Drywell structures	0	0	0	0
Drywell air	[4]	[4]	[4]	1.98
Drywell steam	2.236	56.33	42.06	9.79
Suppression chamber air	1.005	2.622	2.7233	1.097
Suppression chamber steam	0.3849	0.7054	1.0749	5.6238
Suppression pool water	64.3	666.4	823.8	1,382.7
Energy transferred by heat exchangers	0	0	0	1,304.0
Passive heat sinks	0	0	0	0

(1) Does not include sensible energy in the fuel above initial reactor vessel saturation temperature (this energy is accounted for in decay heat as fuel relaxation energy)
(2) Blowdown is accounted for in drywell condition, and should not be used to sum the total energy
(3) Includes fuel relaxation energy
(4) Included in drywell steam

NOTE: The information presented in this table is based on the original design basis conditions. The current recirculations line break results are discussed in Section 6.2.1.8. The results presented here reasonably represent the general characteristics of the current recirculation line break analysis results.

Table 6.2-8

ACCIDENT CHRONOLOGY FOR
RECIRCULATION LINE BREAK ACCIDENT [1]

	TIME (SEC) ALL ECCS IN OPERATION	MINIMUM ECCS AVAILABLE
Vents cleared	0.733	0.733
Drywell reaches peak pressure	12.66	13.66
Maximum positive differential pressure occurs	0.85	0.85
Suppression chamber reaches pressure peak	33.72	34.75
Initiation of the ECCS	30	30
End of blowdown	36.35	37.69
Vessel reflooded	72.03	91.03
Initiation of RHR heat exchanger	600[2]	600[2]
Suppression chamber reaches secondary pressure peak	7,047	42,854

NOTE: (1) The information presented in this table is based on the original design basis conditions. The current recirculation line break results are discussed in Section 6.2.1.8. The results presented here reasonably represent the general characteristics of the current recirculation line break analysis results.

(2) Initiating time for analysis only. Containment heat removal will be initiated in accordance with emergency operating procedures based on plant conditions.

Table 6.2-9

INITIAL AND BOUNDARY CONDITIONS FOR
DRYWELL SPRAY ACTUATION ANALYSIS
(Used in Reference 6.2 - 24 Analysis)

TABLE A[5]

		t_{oo}[1]	t_o[2]
Drywell			
Volume[3], ft^3		242,860	242,860
Pressure, psia		13.7	35.61
Temperature, °F		135	260.3
Relative humidity, %		90	100
Spray rate, gpm/number of trains		0/0	9,500/1
Wetwell			
Volume - Vapor region[3], ft^3		137,132	137,132
- Suppression pool[3], ft^3		127,507	127,507
Pressure, psia		13.7	31.28
Temperature, °F		50	50
Relative humidity, %		100	100
Suppression pool free surface area, ft^2		4,974	4,974
Wetwell-to-Drywell Vacuum Breakers			
Number of valve assemblies operable (three required to operate and one redundant)		4 of 4	
Flow area per assembly, ft^2		2.05	
Flow coefficient[4]		0.495	
Vacuum breaker full open pressure[4] (psid)		4.48	
RHR System - Drywell Spray Mode			
Service water flow rate, gpm		9,000	
Service water temperature, °F		40	
Heat exchanger effectiveness		0.249	
Spray Temperature:	(Initially)	47.6°F	
	(at 300 seconds)	49.7°F	

Table 6.2-9

INITIAL AND BOUNDARY CONDITIONS FOR
DRYWELL SPRAY ACTUATION ANALYSIS
(Used in Reference 6.2 - 24 Analysis)

TABLE B[5]

	t_{oo}[1]	t_o[2]
Drywell		
Volume[3], ft^3	248,950	248,950
Pressure, psia	14.8	34.4
Temperature, °F	150	258.3
Relative humidity, %	100	100
Spray rate, gpm/number of trains	0/0	9,500/1
Wetwell		
Volume - Vapor region[3], ft^3	146,283	146,283
- Suppression pool[3], ft^3	127,507	127,507
Pressure, psia	14.8	29.1
Temperature, °F	50	50
Relative humidity, %	100	100
Suppression pool free surface area, ft^2	4,983	4,983
Wetwell-to-Drywell Vacuum Breakers		
Number of valve assemblies operable (two required to operate and one redundant)	3 of 4	
Flow area per assembly, ft^2	2.05	
Flow coefficient[4]	0.495	
Vacuum breaker full open pressure[4] (psid)	4.48	
RHR System - Drywell Spray Mode		
Service water flow rate, gpm	9,000	
Service water temperature, °F	40	
Heat exchanger effectiveness	0.249	
Spray Temperature: (Initially)	47.6°F	
(at 300 seconds)	49.7°F	

(1) Initial conditions prior to small break as discussed in Section 6.2.1.1.4.4
(2) Conditions after small break, preceding drywell spray actuation (see Section 6.2.1.1.4.5).
(3) High water level

Table 6.2-9

INITIAL AND BOUNDARY CONDITIONS FOR
DRYWELL SPRAY ACTUATION ANALYSIS
(Used in Reference 6.2 - 24 Analysis)

(4) Value given is for total flow path. Actual test results indicate that full open pressure differential across the vacuum breaker assembly only is 2.89 psid. For the ISA computer analysis, the following different pressures were used for opening the valves:

dp (across two valves) at which VB assembly starts to open equals 2.81 psid

dp (from wetwell to drywell) at which VB assembly is fully open equals 4.48 psid

(5) The initial conditions and parameters differ slightly from those indicated in UFSAR Table 6.2-1; however, the use of the conditions and assumptions such as the loss of noncondensables through the purge lines, which were used in the ISA Analysis (reference 6.2-24) produces a more severe transient for purposes of comparing the performance of two vs three operating vacuum breaker valve assemblies. Table A provides the initial conditions used in the original analysis which assumes that the purge valves are closed. The assumptions that are shown in Table B were used to created a worst case analysis to justify reducing the number of operable vacuum breakers from 4 to 3. This scenario assumes that the purge valves are open at the time of a small break LOCA.

Table 6.2-10

REACTOR BLOWDOWN DATA FOR RECIRCULATION LINE BREAK[1][2][3][4]

REACTOR VESSEL TEMPERATURE (°F)	TIME (sec)	REACTOR VESSEL PRESSURE (psia)	LIQUID FLOW (lb_m/sec)	LIQUID ENTHALPY (Btu/lb_m)	STEAM FLOW (lb_m/sec)	STEAM ENTHALPY (Btu/lb_m)
551.1	-	1055	47620	550.1	-	1190.3
550.4	0.733	1048	47620	549.4	-	1190.5
549.9	1.03	1045	47620	549.1	-	1190.6
549.3	1.53	1040	47620	549.0	-	1190.65
548.5	3.16	1032	32290	547.5	-	1191.0
549.3	4.16	1040	32380	549.0	-	1190.65
550.2	5.16	1047	32470	549.3	-	1190.5
550.1	6.16	1055	32560	550.1	-	1190.3
552.5	8.16	1067	32700	552.1	-	1189.9
553.3	10.16	1074	32790	553.5	-	1189.5
552.8	13.66	1069	32720	552.2	-	1189.9
542.0	15.16	979.2	14160	538.5	4895	1192.8
518.7	18.16	803.2	10480	509.2	4438	1199.4
500.7	20.16	685.5	8518	487.7	4054	1202.5
454.3	25.00	441.6	4788	435.8	2919	1205.6
403.4	30.00	257.0	2387	387.53	1851	1202.4
328	35.00	100.7	2673	298.76	609.2	1187.9
294.6	37.5	61.78	2505	263.8	265.8	1178.2
292.8	37.69	60.06	-	262.5	277.7	1178.1
282.6	38.6	51.26	-	252.2	121	1175.1
281.0	38.75	49.98	-	250.2	-	1174.4

(1) The volume of the primary system below the elevation of the recirculation line break is 4641 ft^3.

(2) The maximum diameter for the 251 sized vessel is 254 in corresponding to an inside cross-sectional vessel area of 352 ft^2. (The actual flow area is a function of elevation due to the varying amount of space occupied by the vessel internals).

(3) The surface area and maximum depth of the liquid pool formed on the drywell floor following a DBA LOCA and/or containment spray actuation are approximately 4800 ft^2 and 18 inches, respectively.

(4) The blowdown data provided includes the effect of ECCS additions prior to the end of blowdown. The amount of water in the vessel at the end of blowdown for the DBA is 1559 ft^3.

NOTE: The information presented in this table is histroical and is based on the original design basis conditions. The current recirculation line break results are discussed in Section 6.2.1.8.

Table 6.2-11

REACTOR BLOWDOWN DATA FOR MAIN STEAM LINE BREAK[1][2][3]

REACTOR VESSEL TEMPERATURE (°F)	TIME (sec)	REACTOR VESSEL PRESSURE (psia)	LIQUID FLOW (lb_m/sec)	LIQUID ENTHALPY (Btu/lb_m)	STEAM FLOW (lb_m/sec)	STEAM ENTHALPY (Btu/lb_m)
551.1	-	1055	-	550.1	11650	1190.3
547.4	0.73	1023	-	546.1	8464.0	1191.6
546.5	1.0	1016	28250	544.2	1023.0	1191.3
547.0	1.499	1020	28120	545.7	1084.0	1191.7
547.2	2.06	1022	27950	545.7	1148.0	1191.7
547.3	2.56	1022	27730	545.7	1223.0	1191.7
547.3	3.06	1023	27600	545.7	1267.0	1191.7
547.3	4.06	1023	23960	545.7	1220.0	1191.7
547.8	5.18	1027	20710	546.8	1169.0	1191.6
548.2	8.18	1030	19880	546.0	1452.0	1191.5
547.2	10.1	1022	19190	545.7	1637.0	1191.7
540.7	15.1	968.8	16960	536.6	2069.0	1193.7
526.1	20.18	868.5	14130	518.0	2355.0	1197.5
509.0	25.18	737.7	11080	499.4	2431.0	1201.0
487.6	30.01	608.1	8285	473.0	2294.0	1203.4
460.7	35.03	470.2	5777	441.4	2046.0	1205.5
432.0	40.01	350.9	3695	410.5	1686.0	1204.4
395.3	45.18	234.4	2536	369.6	1164.0	1201.3
350.1	50.06	134.7	2570	321.8	604.9	1193.1
308.0	55.01	75.42	2442	278.0	237.9	1182.5
282.9	58.62	51.54	1126	252.28	58.74	1175.1
281.6	58.87	50.5	404.2	251.23	20.2	1174.7
280.5	59.12	49.56	-	249.18	-	1174.1

(1) The volume of the primary system below the elevation of the main steam line break is 16,148 ft^3.

(2) The maximum diameter for the 251 sized vessel is 254 in corresponding to an inside cross-sectional vessel area of 352 ft^2. (The actual flow area is a function of elevation due to the varying amount of space occupied by the vessel internals).

(3) The surface area and maximum depth of the liquid pool formed on the drywell floor following a DBA LOCA and/or containment spray actuation are approximately 4800 ft^2 and 18 inches, respectively.

NOTE: The information presented in this table is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the main steam line break was not reanalyzed for the current conditions; however, the results reasonably represent the general characteristics of the main steam line break analysis results.

Table 6.2-12

CORE DECAY HEAT FOLLOWING LOCA
FOR CONTAINMENT ANALYSES

TIME (Sec)	NORMALIZED CORE HEAT[1]
0.0	1.00288
0.2	0.98188
0.6	0.74628
1.0	0.58218
2.0	0.54548
4.0	0.57113
6.0	0.53537
10.0	0.37232
20.0	0.11244
40.0	0.04215
60.0	0.03789
80.0	0.03575
100.0	0.03436
150.0	0.03197
220.0	0.02990
220.1	0.02702
300.0	0.02547
400.0	0.02408
600.0	0.02212
800.0	0.02069
1000.0	0.01956
2000.0	0.01599
3000.0	0.01400
$1x10^4$	0.01012
$2x10^4$	0.00850
$4x10^4$	0.00705
$1X10^5$	0.00546

(1) Normalized to include fuel relaxation energy, pump heat, and metal-water reaction

The information presented in this table is historical and was used in the original design basis for containment analysis. The current design basis analysis uses the decay heat model presented in ANSI/ANS 5.1-1979, as approved by the NRC (Ref. 6.2-30), including SIL 636 (Ref. 6.2-40)

Table 6.2-13

SECONDARY CONTAINMENT ACCESS OPENINGS

ACCESS OPENING ROOM NUMBER	ELEVATION (feet)	TYPE OF ACCESS OPENING
201	201	Personnel access air lock
282	201	Personnel access air lock
300	217	Personnel access air lock
310	217	Railroad access air lock
301	217	Equipment access air lock
303	217	Personnel access air lock
308	217	Personnel access air lock
366	217	Personnel access air lock
367	217	Equipment access air lock
369	217	Personnel access air lock
377	217	Personnel access air lock
402A	253	Personnel access air lock
408	269	Personnel access air lock
481	269	Personnel access air lock
608	313	Personnel access air lock
606	313	Personnel access air lock
614	331	Personnel access air lock
642	313	Personnel access air lock
635	313	Personnel access air lock
650	331	Personnel access air lock
655	352	Personnel access air lock
703	352	Personnel access air lock
707	352	Personnel access air lock
654	352	Personnel access air lock
591(1)	360	Personnel access air lock
711(1)	360	Personnel access air lock

(1) These are access openings to the refueling area containment rather than the secondary containment.

Table 6.2-14

SECONDARY CONTAINMENT
DESIGN DATA

REACTOR ENCLOSURE VENTILATION ZONES I AND II, AND
REFUELING AREA VENTILATION ZONE III

Free volume, ft^3:	Zones I and II	1,800,000 each
	Zone III	2,200,000

Pressure

Normal operation: Negative 0.25 in wg.

Postaccident: Negative 0.25 in wg.

Leak rate at postaccident pressure: 0.5 air change/day (Zone III)
2.0 air changes/day
(Zones I and II)

SGTS Exhaust fans - common

Number: 2

Type: centrifugal, single inlet single width

Secondary containment atmosphere filtration prior to release to outdoors via SGTS fans

Number: 2

Type:	Zone I and II	prefilter, HEPA, charcoal, HEPA in RERS followed by HEPA, charcoal, HEPA in SGTS
	Zone III	prefilter, HEPA, charcoal, HEPA in SGTS

TRANSIENT ANALYSIS

Initial Conditions

Pressure: negative 0.25 in wg.

Temperature: 104°F

Outside air temperature: 95°F

Thickness of secondary containment wall: 36 in

Thickness of primary containment wall: 72 in

Table 6.2-14 (Cont'd)

Thermal Characteristics

Primary containment wall

Thermal conductivity: 0.5 Btu/hr-ft-°F
Thermal capacitance: 25 Btu/ft^3-°F

Secondary containment wall

Thermal conductivity: 0.5 Btu/hr-ft-°F
Thermal capacitance: 25 Btu/ft^3-°F

Heat transfer coefficients

Primary containment atmosphere to primary containment wall: 1.46 Btu/hr-ft^2-°F

Primary containment wall to secondary containment atmosphere: 1.46 Btu/hr-ft^2-°F

Secondary containment wall to secondary containment atmosphere: 1.46 Btu/hr-ft^2-°F

Primary containment emissivity: 0.9 Btu/hr-ft^2-°F

Secondary containment emissivity: 0.9 Btu/hr-ft^2-°F

Table 6.2-15

EVALUATION OF POTENTIAL SECONDARY CONTAINMENT BYPASS LEAKAGE PATHS

CONTAINMENT PENETRATION	SYSTEM	TERMINATION REGION[1]	BYPASS LEAKAGE BARRIERS[2]	POTENTIAL BYPASS PATH
1	Equipment access door	IRE	Double O-Ring	No
2	Equipment access door and personnel lock	IRE	Double O-Ring	No
2	Service air supply to personnel lock	ORE	1,8	No
3A	Main steam line D flow instrumentation	IRE	-	No
3B	Instrument gas supply	ORE	1,4	No
3C	HPCI steam flow instrumentation	IRE	-	No
3D	Main steam line A flow instrumentation	IRE	-	No
3D	Instrument gas supply	ORE	1,4	No
4	Head access manhole	IRE	Double O-Ring	No
5	Spare	-	-	-
6	CRD removal hatch	IRE	Double O-Ring	No
7A-D	Primary steam	ORE	1,5	No
8	Primary steam line drain	ORE	1,4	No
9A&B	Feedwater	ORE	1,3	No[3][4]
10	Steam to RCIC turbine	ORE	1,3,8	No
11	Steam to HPCI turbine	ORE	1,3,8	No
12	RHR shutdown cooling supply	ORE	1,3	No
13A&B	RHR shutdown return	ORE	1,3	No
14	RWCU supply	ORE	1,3	No
15	Spare	-	-	-
16A&B	Core spray pump discharge	ORE	1,3	No
17	RPV head spray (Unit 1 only) (ABANDONED)	ORE	7	No
17	Spare (Unit 2 only)	-	-	-
18	Spare	-	-	-
19	Spare	-	-	-
20A	RPV level instrumentation	IRE	-	No
20A	LPCI ΔP instrumentation	IRE	-	No
20B	LPCI ΔP instrumentation	IRE	-	No
20B	RPV level instrumentation	IRE	-	No
21	Spare	-	-	-
22	Drywell pressure instrumentation	IRE	-	No
23	Closed cooling water supply	ORE	1,2,3	No
24	Closed cooling water return	ORE	1,2,3	No
25	Drywell purge supply	ORE	1,4,8	No
26	Drywell purge exhaust	IRE	-	No
27A	Instrument gas supply	ORE	1,4	No
27B	HPCI flow instrumentation	IRE	-	No
28A	Recirculation loop sample	IRE	-	No
28A	Drywell H_2/O_2	ORE	1,7	No
28B	LPCI ΔP instrumentation	IRE	-	No
28B	Drywell air sample	ORE	1,7	No
29A	RPV flange leakage instrumentation	IRE	-	No
29B	Core spray ΔP instrumentation	IRE	-	No
30A	Main steam line D flow instrumentation	IRE	-	No
30B	Drywell pressure instrumentation	IRE	-	No
30B	Main steam line C flow instrumentation	IRE	-	No
31A&B	Jet pump flow instrumentation	IRE	-	No
32A&B	Jet pump flow instrumentation	IRE	-	No
33A	Pressure above core plate instrumentation	IRE	-	No
33A	Pressure below core plate instrumentation	IRE	-	No

Table 6.2-15 (Cont'd)

CONTAINMENT PENETRATION	SYSTEM	TERMINATION REGION[1]	BYPASS LEAKAGE BARRIERS[2]	POTENTIAL BYPASS PATH
33B	RCIC steam flow instrumentation	IRE	-	No
34A	Main steam line C flow instrumentation	IRE	-	No
34B	Recirculation flow instrumentation	IRE	-	No
X-35A	Spare	-	-	-
35B	Instrumentation gas to TIP indexing mechanism	ORE	1	No[4]
35C-G	TIP drives	IRE	-	No
36	Spare	-	-	-
37A-D	CRD insert	ORE	1,3	No
38A-D	CRD withdraw	ORE	1,3	No
39A&B	Drywell spray	ORE	1,3	No
40A-C	Jet pump flow instrumentation	IRE	-	No
40D	Pressure below core plate instrumentation	IRE	-	No
40E	Drywell pressure instrumentation	IRE	-	No
40F	RCIC steam flow instrumentation	IRE	-	No
40F	Instrumentation gas suction	ORE	1,4	No
40G	ILRT data acquisition system (2 lines)	ORE	1,8	No
40H	Instrument gas supply	ORE	1,4	No
40H	Recirculation pump cooler flow instrumentation	IRE	-	No
41	LPCI ΔP instrumentation	IRE	-	No
41	RWCU flow instrumentation	IRE	-	No
42	SLCS	IRE	-	No
43A	Recirculation loop A ΔP instrumentation	IRE	-	No
43A	Recirculation pump seal pressure instrumentation	IRE	-	No
43B	Main steam sample	IRE	-	No
44	CRD/RWCU return	ORE	1,3	No
45A-D	LPCI	ORE	1,3	No
46	Spare	-	-	-
47	RWCU flow instrumentation	IRE	-	No
48A	RPV level instrumentation	IRE	-	No
48A	Core spray ΔP instrumentation	IRE	-	No
48B	RPV level instrumentation	IRE	-	No
49A&B	Main steam line A&B flow instrumentation	IRE	-	No
50A	Drywell pressure instrumentation	IRE	-	No
50A	Recirculation flow instrumentation	IRE	-	No
50B	Recirculation pump seal pressure instrumentation	IRE	-	No
50B	Recirculation pump cooler flow instrumentation	IRE	-	No
51A	Recirculation line flow instrumentation	IRE	-	No
51B	Jet pump flow instrumentation	IRE	-	No
52A	Main steam line B flow instrumentation	IRE	-	No
52B	Recirculation line flow instrumentation	IRE	-	No
53	Drywell chilled water supply	ORE	1,2,3	No
54	Drywell chilled water return	ORE	1,2,3	No
55	Drywell chilled water supply	ORE	1,2,3	No
56	Drywell chilled water return	ORE	1,2,3	No
57	RWCU flow instrumentation	IRE	-	No

Table 6.2-15 (Cont'd)

CONTAINMENT PENETRATION	SYSTEM	TERMINATION REGION(1)	BYPASS LEAKAGE BARRIERS(2)	POTENTIAL BYPASS PATH
58A	Recirc loop B ΔP instrumentation	IRE	-	No
58B	Spare	-	-	-
59A&B	Spare	-	-	-
60	Spare	-	-	-
61	Recirculation pump seal purge	ORE	1,4	No
62	H_2/O_2 sample return	ORE	1,4	No
63	Recirculation loop ΔP instrumentation; recirculation pump seal pressure instrumentation	IRE	-	No
64	Spare	-	-	-
65A&B	RPV pressure instrumentation	IRE	-	No
65A&B	RPV instrumentation reference leg backfill system	ORE	9	No
66A	RPV level instrumentation	IRE	-	No
66A	LPCI ΔP instrumentation	IRE	-	No
66B	RPV level instrumentation	IRE	-	No
66B	LPCI ΔP instrumentation	IRE	-	No
67A&B	RPV level and pressure instrumentation	IRE	-	No
67A&B	RPV instrumentation reference leg backfill system	ORE	9	No
100A-D	Neutron monitoring system	-	-	-
101A-D	Recirculation pump power	-	-	-
102A&B	Electrical spare	-	-	-
103A&B	Temperature and low level signals	-	-	-
104A-D	CRD position indicator	-	-	-
105A-E	Miscellaneous low voltage power	-	-	-
106A-C	Low voltage control	-	-	-
107	Electrical spare	-	-	-
108	Electrical spare	-	-	-
109	Electrical spare	-	-	-
110	Electrical spare	-	-	-
111	Electrical spare	-	-	-
112	Electrical spare	-	-	-
113	Electrical spare	-	-	-
114	Electrical spare	-	-	-
115	Electrical spare	-	-	-
116	SLCS	IRE	-	No
117A	Electrical spare	-	-	-
117B	Drywell radiation monitoring	IRE	-	No
118A&B	Electrical spare	-	-	-
200A&B	Access hatch	-	-	-
201A	Suppression pool purge supply	ORE	1,4,8	No
201A (Unit 2)	Hardened containment vent	ORE	1,11	No
	Argon purge supply	IRE	1,4	No
201B (Unit 1)	Hardened containment vent Unit 1	ORO	1,11	No
	Argon purge supply	IRE	1,4	No
201B (Unit 2)	Spare	-	-	-
202	Suppression pool purge exhaust	IRE	-	No
203A-D	RHR pump suction	ORE	3	No
204A&B	RHR pump test	ORE	3	
205A&B	Suppression pool spray	ORE	3	No
206A-D	CS pump suction	ORE	3	No
207A&B	CS pump test and flush	ORE	3	No
208A	Spare	-	-	-
208B	CS pump minimum recirculation	ORE	3	No
209	HPCI pump suction	ORE	3	No
210	HPCI turbine exhaust	ORE	3	No
211	Spare	-	-	-
212	HPCI pump test and flush	ORE	3	No
213	Spare	-	-	-
214	RCIC pump suction	ORE	3	No
215	RCIC turbine exhaust	ORE	3	No
216	RCIC minimum flow	ORE	3	No
217	RCIC vacuum pump discharge	ORE	3	No
218	Instrument gas to vacuum relief valves	ORE	1,4	No

Table 6.2-15 (Cont'd)

CONTAINMENT PENETRATION	SYSTEM	TERMINATION REGION[1]	BYPASS LEAKAGE BARRIERS[2]	POTENTIAL BYPASS PATH
219A&B	Suppression pool level instrumentation	IRE	-	No
220A	H_2/O_2 sample return	ORE	1,4	No
220B (Unit 1)	Suppression pool pressure instrumentation	IRE	-	No
220B (Unit 2)	Spare	-	-	-
221A	Wetwell H_2/O_2 sample	ORE	1,7	No
221B	Suppression pool air sample	ORE	1,7	No
222	Indication and control	-	-	-
223	Spare	-	-	-
224	Spare	-	-	-
225	Spare	-	-	-
226A&B	RHR minimum recirculation	ORE	3	No
227	ILRT data acquisition system	ORE	1,8	No
228A-C	Spare	-	-	-
228D	HPCI vacuum relief	ORE	1,3,8	No
229A (Unit 1)	Spare	-	-	-
229A (Unit 2)	Suppression pool pressure instrumentation	IRE	-	No
229B	Spare	-	-	-
230A	Strain gauge instrumentation	IRE	-	No
230B	Drywell sump level instrumentation	IRE	-	No
231A&B	Drywell sump drains	ORE	1,3	No
232A-S	MSRV discharge	-	-	-
235	CS pump minimum recirculation	ORE	3	No
236	HPCI pump minimum recirculation	ORE	3	No
237	Suppression pool cleanup pump suction	ORE	1,3	No
238	RHR relief valve discharge	ORE	3	No
239	RHR relief valve discharge	ORE	3	No
240	RHR relief valve discharge	ORE	3,10	No
241	RCIC vacuum relief	ORE	1,3,8	No

(1) The termination regions are: IRE - Inside reactor enclosure
ORE - Outside reactor enclosure

(2) The bypass leakage barriers are defined as follows (Section 6.2.3.3.3):

1. Redundant primary containment isolation valves.
2. Closed piping system inside containment.
3. A water seal maintained for 30 days following a LOCA.
4. The line beyond the outboard primary containment isolation valve is vented to the reactor enclosure by use of a vent line.
5. A MSIV alternate drain pathway (Section 6.7) is provided.
6. The line contains a temporary spool piece that is removed during normal operation and replaced by blind flanges so that any leakage through the flange is into the reactor enclosure.
7. Closed seismic Category I piping system outside containment.
8. The line contains a spectacle flange with the blind side installed during normal operation. Any leakage through the flange will be into the reactor enclosure.
9. The line contains two spring loaded check valves and two manual stop valves.
10. Blind flange permanently installed in line in the reactor enclosure.
11. Rupture disc installed downstream of primary containment isolation valves with burst pressure greater than maximum LOCA pressure.

(3) The feedwater fill system will provide a water seal in the feedwater lines for all line breaks other than a feedwater line break inside containment. For a feedwater line break inside containment, a water seal is maintained by the CST water supply as discussed in Section 6.2.3.2.3.1.a.

(4) No significant amounts of radioactivity will be released to the environment as discussed in Section 6.2.3.2.3.

Table 6.2-16

ACCIDENT CHRONOLOGY FOR MAIN STEAM LINE BREAK ACCIDENT

Time	Event
0	Break occurs
0	Scram assumed to occur
0	Isolation signal
0.5	MSIV start to close
1.0	Vessel water level reaches main steam line elevation
5.5	MSIV fully closed
30	ECCS flows start
59	End of blowdown
430	Vessel refloods

NOTE: The information presented in this table is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the main steam line break was not reanalyzed for the current conditions; however, the results reasonably represent the general characteristics of the main steam line break analysis results.

Table 6.2-17

CONTAINMENT PENETRATION DATA

CONTAINMENT PENETRATION NUMBER	LINE ISOLATED	FLUID	LINE SIZE (in)	NRC GENERAL DESIGN CRITERION	ESF SYSTEM	ESSENTIAL SYSTEM	VALVE NUMBER	VALVE TYPE (1)	VALVE LOCATION	VALVE ARRANGEMENT (2)	TYPE C TEST	LENGTH OF PIPE FROM CONT. TO OUTSIDE VALVES	PRIMARY METHOD OF ACTUATION (3)	SECONDARY METHOD OF ACTUATION	NORMAL VALVE POSITION (4)	SHUTDOWN VALVE POSITION	POST-ACCIDENT POSITION	POWER FAILURE VALVE POSITION	ISOLATION SIGNAL(5)	DIVERSE ISOLATION SIGNAL(12)	VALVE CLOSURE TIME(6)	POWER SOURCE (7)	REMARKS
X-3A-1	Instrumentation - main steam line D flow	Water/ steam	1	55	-	-	F070D	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F073D	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
X-3A-2	Instrumentation - recirc pump seal pressure	Water	1	55	-	-	F003A	XFC	Outside	(40)	No	2'-3"	Flow	-	0	0	0	-	-	-	-	-	
X-3B	Instrument gas supply	Gas	1	56	No	No	1005B	CK	Inside	(22)	Yes	-	Flow	-	0	0	C	-	-	-	-	-	
					No	No	129B	GB	Outside			6"	Comp air	Spring	0	0	C	C	C,H,S	Yes	4.4 sec	B	
X-3C-1	Instrumentation - HPCI steam flow	Steam	1	55	-	-	F024A	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-3C-2	Instrumentation - HPCI steam flow	Steam	1	55	-	-	F024C	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-3D-1	Instrumentation - main steam line A flow	Steam/ water	1	55	-	-	F070A	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F073A	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
X-3D-2	Instrument gas supply	Gas	1	56	No	Yes	1112	CK	Inside	(48)	Yes	-	Flow	-	0	0	C	-	-	-	-	-	
					No	Yes	151B	GB	Outside			7"	AC motor	Manual	0	0	C	As is	M	NA	30 sec	D	
X-7A-D	Main steam	Steam	26	55	No	No	F022A-D	GB	Inside	(1)	Yes	-	Instr gas	Spring	0	C	C	C	C,D,E,F,P,Q	Yes	3-5*sec	A/W	
					No	No	F028A-D	GB	Outside			0"	Comp air	Spring	0	C	C	C	C,D,E,F,P,Q	Yes	3-5*sec	B/X	
X-8	Main steam drain	Steam/ water mix	3	55	No	No	F016	GT	Inside	(33)	Yes	-	AC motor	Manual	C	0	C	As is	C,D,E,F,P,Q	Yes	30 sec	A	
					No	No	F019	GT	Outside			0"	AC motor	Manual	C	0	C	As is	C,D,E,F,P,Q	Yes	Standard	B	
X-9A,B	Feedwater	Water	24	55	Yes	Yes	F010A	CK	Inside	(2)	Yes	-	Flow	-	0	C	0	-	-	-	-	-	
					No	Yes	F010B	CH	Inside			-	Flow	-	0	C	0	-	-	-	-	-	
					Yes	Yes	F074A	SLPACK	Outside			0"	Flow	Spring	0	C	0	-	-	-	-	D	
					No	Yes	F074B	SLPACK	Outside			0"	Flow	Spring	0	C	0	-	-	-	-	D	
					No	No	F032A,B	CK	Outside			22'-2"	Flow	AC motor	0	C	0	As is	-	-	-	D	
					No	No	109A,B	GT	Outside			31'-6"	AC motor	Manual	C	C	C	As is	RM	No	Standard	D	
					No	No	F039	SLPACK	Outside			29'-6"	Flow	Spring	0	C	C	-	-	-	-	N	
					No	Yes	F013	GT	Outside			20'-1"	DC motor	Manual	C	C	0	As is	LFCC	NA	23 sec	A	
					No	Yes	1036A,B	CK	Outside			2'-6"	Flow	-	C	C	0	-	-	-	-	-	
					No	Yes	130A,B	GB	Outside			124'-6"	AC motor	Manual	C	C	C	As is	RM	NA	30 sec	A,B	
					No	Yes	133A,B	GB	Outside			70'-1"	AC motor	Manual	C	C	0	As is	RM	NA	30 sec	A,B	
					No	No	1016	GB	Outside			83'-2"	Manual	-	C	C	C	C	-	-	-	-	
					Yes	Yes	F105	GT	Outside			22'-8"	DC motor	Manual	C	C	0	As is	RM	NA	30 sec	B	(19)
X-10	Steam to RCIC turbine	Steam	3	55	No	Yes	F007	GB	Inside	(3)	Yes	-	AC motor	Manual	0	C	0	As is	K,KA	NA	7.2* sec	C	
					No	Yes	F008	GB	Outside			0"	AC motor	Manual	0	C	0	As is	K,KA	NA	7.2* sec	A	(14)
					No	No	F076	GB	Outside			3'-3"	AC motor	Manual	C	C	C	As is	K,KA	No	30 sec	A	
X-11	Steam to HPCI turbine	Steam	10	55	No	Yes	F002	GB	Inside	(3)	Yes	-	AC motor	Manual	0	C	0	As is	L,LA	NA	12* sec	D	
					No	Yes	F003	GB	Outside			0"	AC motor	Manual	0	C	0	As is	L,LA	NA	12* sec	B	(14)
					No	No	F100	GB	Outside			6'-9"	AC motor	Manual	C	C	C	As is	L,LA	No	30 sec	B	
X-12	RHR shutdown cooling supply	Water	20	55	No	No	F009	GT	Inside	(21)	Yes	-	AC motor	Manual	C	0	C	As is	A,V	Yes	Standard	A	(15)
					No	No	F008	GT	Outside			17"	AC motor	Manual	C	0	C	As is	A,V	Yes	Standard	B	(15)
					No	-	155	PSV	Inside			-	Water	-	C	C	C	As is	-	-	-	-	
X-13A&B	RHR shutdown cooling return	Water	12	55	No	No	F050A,B	TCK	Inside	(11)	Yes	-	Flow	Inst gas	C	0	0	-	A,V	-	-	A,B	(15)
					No	No	151A,B	GB	Inside			-	Inst gas	Spring	C	C	C	C	A,V	Yes	20 sec	A	(15)
					No	No	F015A,B	GB	Outside			11"	AC motor	Manual	C	0	C	As is	A,V	Yes	29 sec	B	
					No	No	1200A, B	CK	Inside			-	Flow	Spring	C	C	C	C	-	-	-	-	
X-14	RWCU supply	Water	6	55	No	No	F001	GT	Inside	(20)	Yes	-	AC motor	Manual	0	0	C	As is	B,J,Y	Yes	10* sec	A	
					No	No	F004	GT	Outside			0"	AC motor	Manual	0	0	C	As is	B,J,Y	Yes	10* sec	B	
X-16A	CS discharge	Water	12	55	Yes	Yes	F006A	TCK	Inside	(11)	Yes	-	Flow	Inst gas	C	C	0	-	-	-	-	A	(9)
					Yes	Yes	F039A	GB	Inside			-	Inst gas	Spring	C	C	C	C	-	-	4.4 sec	A	
					Yes	Yes	F005	GT	Outside			0"	AC motor	Manual	C	C	0	As is	RM	NA	12 sec	A	
X-16B	CS discharge	Water	12	55	Yes	Yes	F006B	TCK	Inside	(11)	Yes	-	Flow	Inst gas	C	C	0	-	-	-	-	B	(9)
					Yes	Yes	F039B	GB	Inside			-	Inst gas	Spring	C	C	C	C	-	-	4.4 sec	B	
					Yes	Yes	108	SLPACK	Outside			0"	Flow	Spring	C	C	0	C	-	-	-	B	(9)
X-17	RPV head spray (Unit 1 only) (ABANDONED)				-	-	-	-	-	(21A)	-	-	-	-	-	-	-	-	-	-	-	-	
X-17	Spare (Unit 2 only)				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
X-20A-1	Instrumentation - RPV level	Water	1	55	-	-	F045B	XFC	Outside	(37)	No	14"	Flow	-	0	0	0	-	-	-	-	-	
X-20A-2	Instrumentation - LPCI `B' dp	Water	1	55	-	-	102B	XFC	Outside	(40)	No	14"	Flow	-	0	0	0	-	-	-	-	-	
X-20A-3	Instrumentation - LPCI `D' dp	Water	1	55	-	-	103B	XFC	Outside	(40)	No	14"	Flow	-	0	0	0	-	-	-	-	-	
X-20B-1	Instrumentation - RPV level	Water	1	55	-	-	F045C	XFC	Outside	(37)	No	2'-2"	Flow	-	0	0	0	-	-	-	-	-	
X-20B-2	Instrumentation - LPCI `C' dp	Water	1	55	-	-	102C	XFC	Outside	(40)	No	13"	Flow	-	0	0	0	-	-	-	-	-	

Table 6.2-17 (Cont'd)

CONTAINMENT PENETRATION NUMBER	LINE ISOLATED	FLUID	LINE SIZE (in)	NRC GENERAL DESIGN CRITERION	ESF SYSTEM	ESSENTIAL SYSTEM	VALVE NUMBER	VALVE TYPE (1)	VALVE LOCATION	VALVE ARRANGEMENT (2)	TYPE C TEST	LENGTH OF PIPE FROM CONT. TO OUTSIDE VALVES	PRIMARY METHOD OF ACTUATION (3)	SECONDARY METHOD OF ACTUATION	NORMAL VALVE POSITION (4)	SHUTDOWN VALVE POSITION	POST-ACCIDENT POSITION	POWER FAILURE VALVE POSITION	ISOLATION SIGNAL(5)	DIVERSE ISOLATION SIGNAL(12)	VALVE CLOSURE TIME(6)	POWER SOURCE (7)	REMARKS
X-21	Service air	Gas	3	56	No	No	1140	GT	Inside	(8)	Yes	-	Manual	-	C	C	C	-	-	-	-	-	
	air				No	No	1139	GT	Outside			0"	Manual	-	C	C	C	-	-	-	-	-	
X-22	Instrumentation - drywell pressure	Gas	1	56	-	-	147C	GB	Outside	(41)	No	8"	AC motor	Manual	0	0	0	As is	RM	-	30 sec	C	
X-23	Recirc pump	Water	4	56	No	No	106	GT	Outside	(13)	Yes	0"	AC motor	Manual	0	0	C	As is	C,H	Yes	Standard	C	
	cooling water				No	No	108	GT	Outside			3'-11"	AC motor	Manual	0	0	C	As is	C,H	Yes	Standard	D	
	supply				No	No	109	GT	Outside			5'-2"	Manual	-	C	C	C	-	-	-	-	-	
X-24	Recirc pump	Water	4	56	No	No	107	GT	Outside	(13)	Yes	0"	AC motor	Manual	0	0	C	As is	C,H	Yes	Standard	C	
	cooling water				No	No	111	GT	Outside			3'-8"	AC motor	Manual	0	0	C	As is	C,H	Yes	Standard	D	
	return				No	No	110	GT	Outside			5'-0"	Manual	-	C	C	C	-	-	-	- -		
X-25	Drywell purge	Gas	24	56	No	No	HV-57-135	BF	Outside	(5)	Yes	16'-7"	AC motor	Manual	C	0	C	As is	B,H,W,U,S,R,T	Yes	6** sec	B	(19)
	supply				Yes	Yes	HV-57-121	BF	Outside			3'-11"	Comp air	Spring	C	C	C	C	B,H,W,U,S,R,T	NA	5** sec	A	(23)
					No	No	HV-57-123	BF	Outside			3'-4"	Comp air	Spring	C	0	C	C	B,H,W,U,S,R,T	Yes	5** sec	A	
					Yes	Yes	HV-57-131	BF	Outside			60'-7"	Comp air	Spring	C	C	C	C	B,H,W,U,S,R,T	NA	5** sec	A	(19), (23)
					Yes	Yes	HV-57-163	BF	Outside			3'-8"	AC motor	Manual	C	C	0	As is	B,H,R,S	NA	6 sec	D	(24)
					No	No	HV-57-109	BF	Outside			42'-2"	AC motor	Manual	C	C	C	As is	B,H,W,U,S,R,T	Yes	6** sec	B	(19)
					Yes	Yes	FV-DO-101B	GB	Outside			251-1"	AC motor	Manual	C	C	0	As is	B,H,R,S	NA	80 sec	D	(19)
X-26	Drywell purge	Gas	24	56	No	No	HV-57-115	BF	Outside	(27)	Yes	53'-7"	AC motor	Manual	C	0	C	As is	B,H,W,U,S,R,T	Yes	6** sec	A	(19)
	exhaust				Yes	Yes	SV-57-145	GB	Outside			66'-9"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	D	(19)
					No	No	HV-57-111	GB	Outside			6'-6"	AC motor	Manual	C	C	C	As is	B,H,U,S,R,T	Yes	15** sec	B	(20)
					No	No	HV-57-114	BF	Outside			49'-7"	Comp air	Spring	C	0	C	C	B,H,W,U,S,R,T	Yes	5** sec	B	(19)
					Yes	Yes	HV-57-161	BF	Outside			47'-11"	AC motor	Manual	C	C	0	As is	B,H,R,S	NA	6 sec	C	(19)
					No	No	HV-57-117	GB	Outside			60'-3"	Comp air	Spring	C	C	C	C	B,H,U,S,R,T	Yes	5** sec	A	(19)
					-	-	SV-57-139	GB	Outside		No	35'-5"	AC coil		0	0	0	C	RM	-	2 sec	A	(19)
					Yes	Yes	FV-DO-101A	GB	Outside			78'-3"	AC motor	Manual	C	C	0	As is	B,H,R,S	NA	80 sec	C	(19)
X-27A	Instrument gas	Gas	1	56	No	Yes	1128	CK	Inside	(48)	Yes	-	Flow	-	0	0	C	-	-	-	-	-	
	supply				No	Yes	151A	GB	Outside			7"	AC motor	Manual	0	0	C	As is	M	NA	30 sec	C	
X-27B-1	Instrumentation - HPCI	Steam	1	55	-	-	F024B	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-27B-2	Instrumentation - HPCI flow	Steam	1	55	-	-	F024D	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-28A-1	Recirc loop	Water	3/4	55	No	No	F019	GB	Inside	(9)	Yes	-	Instr gas	Spring	C	C	C	C	B,D	Yes	7 sec	A	(14)
	sample				No	No	F020	GB	Outside			4'-3"	Comp air	Spring	C	C	C	C	B,D	Yes	7 sec	B	(14)
X-28A-2	Drywell H_2O_2	Gas	1	56	Yes	Yes	132	GB	Outside	(23)	Yes	20"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	B	
	sample				Yes	Yes	142	GB	Outside			3'-0"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	D	
X-28A-3	Drywell H_2O_2	Gas	1	56	Yes	Yes	134	GB	Outside	(23)	Yes	20"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	B	
	sample				Yes	Yes	144	GB	Outside			3'-0"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	D	
X-28B	Drywell H_2O_2	Gas	1	56	Yes	Yes	133	GB	Outside	(23)	Yes	17"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	A	
	sample				Yes	Yes	143	GB	Outside			2'-11"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	D	
					Yes	Yes	195	GB	Outside			2'-11"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	C	
X-29A	Instrumentation - RPV flange leakage	Water	1	55	-	-	F009	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-29B	Instrumentation - CS WP	Water	1	55	-	-	F018A	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-30A	Instrumentation -	Water	1	55	-	-	F071D	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
	main steam line D flow				-	-	F072D	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
X-30B-1	Instrumentation - drywell pressure	Gas	1	56	-	-	147A	GB	Outside	(41)	No	7"	AC motor	Manual	0	0	0	As is	RM	-	30 sec	A	
X-30B-2	Instrumentation -	Water	1	55	-	-	F071C	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
	main steam line C flow				-	-	F072C	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
X-31A,B	Instrumentation -	Water	1	55	-	-	F059B,F,H	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
	jet pump flow				-	-	F059D	XFC	Outside			4'-7"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F051B	XFC	Outside			3'-4"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F053B	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
X-32A,B	Instrumentation -	Water	1	55	-	-	F059M,S,U	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
	jet pump flow				-	-	F051D	XFC	Outside			3'-4"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F053D	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F059P	XFC	Outside			4'-6"	Flow	-	0	0	0	-	-	-	-	-	
X-33A-1	Instrumentation - pressure above core plate	Water	1	55	-	-	F055	XFC	Outside	(37)	No	2'-5"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F076	XFC	Outside			4'-2"	Flow	-	0	0	0	-	-	-	-	-	
X-33A-2	Instrumentation - pressure below core plate	Water	1	55	-	-	F061	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-33B	Instrumentation - RCIC steam flow	Water	1	55	-	-	F044A,C	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-34A	Instrumentation -	Water	1	55	-	-	F070C	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
	main steam line C flow				-	-	F073C	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
X-34B-1	Instrumentation -	Water	1	55	-	-	F009C	XFC	Outside	(40)	No	18"	Flow	-	0	0	0	-	-	-	-	-	
	recirc flow				-	-	F010D	XFC	Outside			3'-6"	Flow	-	0	0	0	-	-	-	-	-	

Table 6.2-17 (Cont'd)

CONTAINMENT PENETRATION NUMBER	LINE ISOLATED	FLUID	LINE SIZE (in)	NRC GENERAL DESIGN CRITERION	ESF SYSTEM	ESSENTIAL SYSTEM	VALVE NUMBER	VALVE TYPE (1)	VALVE LOCATION	VALVE ARRANGEMENT (2)	TYPE C TEST	LENGTH OF PIPE FROM CONT. TO OUTSIDE VALVES	PRIMARY METHOD OF ACTUATION (3)	SECONDARY METHOD OF ACTUATION	NORMAL VALVE POSITION (4)	SHUTDOWN VALVE POSITION	POST-ACCIDENT POSITION	POWER FAILURE VALVE POSITION	ISOLATION SIGNAL(5)	DIVERSE ISOLATION SIGNAL(12)	VALVE CLOSURE TIME(6)	POWER SOURCE (7)	REMARKS
X-34B-2	Instrumentation - recirc flow	Water	1	55	-	-	F009D	XFC	Outside	(40)	No	2'-9"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F010C	XFC	Outside			2'-9"	Flow	-	0	0	0	-	-	-	-	-	
X-35B	TIP purge	Gas	1	56	No	No	131	GB	Outside	(46)	Yes	0"	Comp air	Spring	0	C	C	C	B,H,S	Yes	4.4 sec	B	
					No	No	1056	CK	Inside			-	Flow	-	0	C	C	C	-	-	-	-	
X-35C-G	TIP drives	Gas	3/8	56	No	No	140A-E	XP	Outside	(6)	Yes	16"	Explosion	-	0	0	0	As is	RM	-	-	N	(10)
					No	No	141A-E	BL	Outside			8"	AC coil	Spring	C	C	C	C	B,H	Yes	-	N	(10)
X-37A-D	CRD insert	Water	1	55	Yes	Yes	-	BLCK	Inside	(47)	No	-	-	-	-	-	-	-	-	-	-	-	(11)
					Yes	Yes	46-1101 46-1102 46-1108 46-1109	CK	Outside	-	Yes	-	Flow	-	0	0	C	-	-	-	-	-	(11)
X-38A-D	CRD withdraw	Water	3/4	55	Yes	Yes	46-1115 46-1116 46-1122 46-1123	CK	Outside	(47)	Yes	-	Flow	-	0	0	C	-	-	-	-	-	(11)
					Yes	Yes	F180	GB	Outside		Yes	Varies	Comp air	Spring	0	0	C	C	-	NA	30	N	(11)
					Yes	Yes	F181	GB	Outside			(input	Comp air	Spring	0	0	C	C	-	NA	30	N	(11)
					Yes	Yes	F010	GB	Outside			from	Comp air	Spring	0	0	C	C	-	NA	25	N	(11)
					Yes	Yes	F011	GB	Outside			185 HCUs with max. of approx. 320')	Comp air	Spring	0	0	C	C	-	NA	25	N	(11)
X-39A,B	Containment spray	Water	16	56	Yes	Yes	F021A,B	GT	Outside	(25)	Yes	12"	AC motor	Manual	C	C	C	As is	RM	NA	Standard	A,B	
					Yes	Yes	F016A,B	GT	Outside			8'-0"	AC motor	Manual	C	C	C	As is	RM	NA	Standard	A,B	
X-40A	Instrumentation - jet pump flow	Water	1	55	-	-	F059L,R	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F059N	XFC	Outside			4'-7"	Flow	-	0	0	0	-	-	-	-	-	
X-40B	Instrumentation - jet pump flow	Water	1	55	-	-	F059G	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F051A	XFC	Outside			3'-4"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F053A	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
X-40C	Instrumentation - jet pump flow	Water	1	55	-	-	F059A,E	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F059C	XFC	Outside			4'-7"	Flow	-	0	0	0	-	-	-	-	-	
X-40D-1	Instrumentation - pressure below core plate	Water	1	55	-	-	F057	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-40D-2	Instrumentation - RWCU flow	Water	1	55	-	-	170	XFC	Outside	(37)	No	1'-10"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	171	XFC	Outside			1'-10"	Flow	-	0	0	0	-	-	-	-	-	
X-40E	Instrumentation - drywell pressure	Gas	1	56	-	-	147D	GB	Outside	(41)	No	12"	AC motor	Manual	0	0	-	As is	RM	-	30 sec	D	
X-40F-1	Instrumentation - RCIC pressure	Steam	1	56	-	-	F044B,D	XFC	Outside	(40)	No	12"	Flow	Manual	0	0	0	-	-	-	-	D	
X-40F-2	Instrument gas suction	Gas	1	56	No	No	101	GB	Inside	(4)	Yes	-	AC motor	Manual	0	0	C	As is	C,H,S	Yes	30 sec	A	
					No	No	102	GB	Outside			8"	Comp air	Spring	0	0	C	C	C,H,S	Yes	4.4 sec	B	
X-40G-1	ILRT data acquisition	Gas	3/4	56	No	No	1057	GB	Outside	(31)	Yes	7"	Manual	-	C	C	C	-	-	-	-	-	
					No	No	1058	GB	Outside			23"	Manual	-	C	C	C	-	-	-	-	-	
X-40G-2	ILRT data acquisition	Gas	3/4	56	No	No	1071	GB	Outside	(31)	Yes	7"	Manual	-	C	C	C	-	-	-	-	-	
					No	No	1070	GB	Outside			2'-10"	Manual	-	C	C	C	-	-	-	-	-	
X-40H-1	Instrument gas supply	Gas	1	56	No	No	1005A	CK	Inside	(22)	Yes	-	Flow	-	0	0	C	-	-	-	-	-	
					No	No	129A	GB	Outside			13"	Comp air	Spring	0	0	C	C	C,H,S	Yes	4.4 sec	A	
X-40H-2	Instrumentation - recirc pump cooler	Water	1	56	-	-	156B	XFC	Outside	(44)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	157B	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
X-41-1	Instrumentation - RWCU flow	Water	1	55	-	-	102A	XFC	Outside	(40)	No	2'-5"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	102B	XFC	Outside			13"	Flow	-	0	0	0	-	-	-	-	-	
X-41-2	Instrumentation - LPCI `A' dp	Water	1	55	-	-	103A	XFC	Outside	(40)	No	13"	Flow	-	0	0	0	-	-	-	-	-	
X-42	Standby liquid control	Sodium pentaborate solution	2	55 Yes	Yes Yes	Yes F006A	F007 SCK	CK Outside	Inside	(10)	Yes 8"	- Flow	Flow AC motor	- 0	C 0	C 0	C -	- RM	- NA	- Standard	- A	-	
X-43A	Instrumentation - recirc loop A WP	Water	1	55	-	-	F040A,C	XFC	Outside	(40)	No	2'-3"	Flow	-	0	0	0	-	-	-	-	-	
X-43B	Main steam sample	Steam	3/4	55	No	No	F084	GB	Inside	(9)	Yes	-	Inst gas	Spring	C	C	C	C	B,D	Yes	7 sec	A	
					No	No	F085	GB	Outside			2'-6"	Comp air	Spring	C	C	C	C	B,D	Yes	7 sec	B	
X-44	Alternate RWCU return	Water	4	55	No	No	1017	GB	Inside	(14)	Yes	-	Manual	-	C	0	C	-	-	-	-	-	
					No	No	1016	GB	Outside			20"	Manual	-	C	0	C	-	-	-	-	-	
					No	-	112	PSV	Outside			7'-6"	Water pres	-	C	C	C	-	-	-	-	-	
X-45A-D	LPCI	Water	12	55	Yes	Yes	142A,B,C,D	GB	Inside	(11)	Yes	-	Inst gas	Spring	C	C	C	C	-	-	4.4 sec	A,B,C,D	
					Yes	Yes	F041A,B,C,D	TCK	Inside			-	Flow	Inst gas	C	C	0	-	-	-	-	A,B,C,D	
					Yes	Yes	F017A,B,C,D	GT	Outside			0"	AC motor	Manual	C	C	0	As is	RM	NA	24 sec	A,B,C,D	
X-47	Instrumentation - RWCU flow	Water	1	55	-	-	102D	XFC	Outside	(40)	No	11"	Flow	-	0	0	0	-	-	-	-	-	
X-48A-1	Instrumentation - RPV level	Water	1	55	-	-	F065B	XFC	Outside	(37)	No	2'-6"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F047B	XFC	Outside			21"	Flow	-	0	0	0	-	-	-	-	-	
X-48A-2	Instrumentation - core spray WP	Water	1	55	-	-	F018B	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	

Table 6.2-17 (Cont'd)

CONTAINMENT PENETRATION NUMBER	LINE ISOLATED	FLUID	LINE SIZE (in)	NRC GENERAL DESIGN CRITERION	ESF SYSTEM	ESSENTIAL SYSTEM	VALVE NUMBER	VALVE TYPE (1)	VALVE LOCATION	VALVE ARRANGEMENT (2)	TYPE C TEST	LENGTH OF PIPE FROM CONT. TO OUTSIDE VALVES	PRIMARY METHOD OF ACTUATION (3)	SECONDARY METHOD OF ACTUATION	NORMAL VALVE POSITION (4)	SHUTDOWN VALVE POSITION	POST-ACCIDENT POSITION	POWER FAILURE VALVE POSITION	ISOLATION SIGNAL(5)	DIVERSE ISOLATION SIGNAL(12)	VALVE CLOSURE TIME(6)	POWER SOURCE (7)	REMARKS
X-48B	Instrumentation - RPV Level	Water	1	55	- -	- -	F065A F047A	XFC XFC	Outside Outside	(37)	No	21" 2'-6"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-49A,B	Instrumentation - main steam line A&B flow	Water/ steam	1	55	- -	- -	F071A,B F072A,B	XFC XFC	Outside Outside	(40)	No	12" 12"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-50A-1	Instrumentation - drywell pressure	Gas	1	56	-	-	147B	GB	Outside	(41)	No	7"	AC motor	Manual	0	0	0	As is	RM	-	30 sec	B	
X-50A-2	Instrumentation - recirc flow	Water	1	55	- -	- -	F011A F012B	XFC XFC	Outside Outside	(40)	No	2'-9" 18"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-50A-3	Instrumentation - recirc flow	Water	1	55	- -	- -	F011B F012A	XFC XFC	Outside Outside	(40)	No	18" 2'-9"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-50B	Instrumentation - recirc pump seal pressure	Water	1	55	-	-	F004A	XFC	Outside	(45)	No	4'-11"	Flow	-	0	0	0	-	-	-	-	-	
X-50B	Instrumentation - recirc pump cooler flow	Water	1	56	- -	- -	156A 157A	XFC XFC	Outside Outside	(44)	No	22" 20"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-51A	Instrumentation - recirc line flow	Water	1	55	- -	- -	F009A,B F010A,B	XFC XFC	Outside Outside	(40)	No	18" 18"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-51B	Instrumentation - jet pump flow	Water	1	55	- - -	- - -	F059T F051C F053C	XFC XFC XFC	Outside Outside Outside	(37)	No	12" 3'-4" 12"	Flow Flow Flow	- - -	0 0 0	0 0 0	0 0 0	- - -	- - -	- - -	- - -	- - -	
X-52A	Instrumentation - main steam line B flow	Water	1	55	- -	- -	F070B F073B	XFC XFC	Outside Outside	(40)	No	12" 12"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-52B-1	Instrumentation - recirc line flow	Water	1	55	- -	- -	F011C F011D	XFC XFC	Outside Outside	(40)	No	2'-9" 18"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-52B-2	Instrumentation - recirc line flow	Water	1	55	- -	- -	F012C F012D	XFC XFC	Outside Outside	(40)	No	2'-3" 18"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-53	Chilled water supply A	Water	8	56 No	No No	No No 125A	128 120A GT	GT GT Outside	Outside Outside	(13)	Yes 63'-10"	0" 63'-10" AC motor	AC motor AC motor Manual	Manual Manual C	0 0 C	0 0 C	C C As is	As is As is -	C,H C,H -	Yes Yes -	Standard Standard -	B A (21)	(19)
X-54	Chilled water return "A"	Water	8	56 No	No No No	No No 124A	129 121A GT	GT GT Outside	Outside Outside	(13)	Yes 67'-0"	0" 67'-0" AC motor	AC motor AC motor Manual	Manual Manual C	0 0 C	0 0 C	C C As is	As is As is -	C,H C,H -	Yes Yes -	Standard Standard -	B A (21)	(19)
X-55	Chilled water supply "B"	Water	8	56	No No No	No No No	122 120B 125B	GT GT GT	Outside Outside Outside	(13)	Yes	0" 46'-10" 46'-10"	AC motor AC motor AC motor	Manual Manual Manual	C 0 C	C 0 C	C C C	As is As is As is	C,H C,H -	Yes Yes -	Standard Standard -	B A -	(19) (21)
X-56	Chilled water return "B"	Water	8	56	No No No	No No No	123 121B 124B	GT GT GT	Outside Outside Outside	(13)	Yes	0" 37'-2" 37'-2"	AC motor AC motor AC motor	Manual Manual Manual	C 0 C	C 0 C	C C C	As is As is As is	C,H C,H -	Yes Yes -	Standard Standard -	B A -	(19) (21)
X-57	Instrumentation - RWCU flow	Water	1	55	-	-	102C	XFC	Outside	(40)	No	11"	Flow	-	0	0	0	-	-	-	-	-	
X-58A	Instrumentation - recirc loop B WP	Water	1	55	-	-	F040B	XFC	Outside	(40)	No	14"	Flow	-	0	0	0	-	-	-	-	-	
X-61-1	Recirc pump seal purge	Water	1	55	No -	No -	1004A 103A	CK XFC	Inside Outside	(45)	Yes	- 20"	Flow Flow	-	0 0	C 0	C 0	-	-	-	-	-	
X-61-2	Recirc pump seal purge	Water	1	55	No -	No -	1004B 103B	CK XFC	Inside Outside	(45)	Yes	- 20"	Flow Flow	-	0 0	C 0	C 0	-	-	-	-	-	
X-62	H_2/O_2 sample return; drywell purge makeup	Gas	1	56	Yes No Yes Yes Yes	Yes No Yes Yes Yes	150 116 159 190 191	GB GB GB GB GB	Outside Outside Outside Outside Outside	(12)	Yes	3'-3" 6'-6" 15'-9" 255'-8" 253'-1"	AC coil AC motor AC coil AC coil AC coil	- Manual - - -	0 C 0 0 0	0 C 0 0 0	0 C 0 0 0	C As is C C C	B,H,R,S B,H,R,S B,H,R,S B,H,R,S B,H,R,S	NA Yes NA NA NA	2 sec 30** sec 2 sec 2 sec 2 sec	B D D C A	(19)
X-63-1	Instrumentation - recirc loop "B" dp	Water	1	55	-	-	F040D	XFC	Outside	(40)	No	3'-4"	Flow	-	0	0	0	-	-	-	-	-	
X-63-2	Instrumentation - recirc pump seal pressure	Water	1	55	- -	- -	F004B F003B	XFC XFC	Outside Outside	(45)	No	12" 12"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-65A,B	Instrumentation - RPV pressure	Water	1	55	- -	- -	F043B F049A	XFC XFC	Outside Outside	(37)	No	14" 14"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-66A-1	Instrumentation - RPV level	Water	1	55	-	-	F045D	XFC	Outside	(37)	No	13"	Flow	-	0	0	0	-	-	-	-	-	
X-66A-2	Instrumentation - LPCI "B" dp	Water	1	55	- -	- -	102D 103D	XFC XFC	Outside Outside	(40)	No	13" 13"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-66B-1	Instrumentation - RPV level	Water	1	55	-	-	F045A	XFC	Outside	(37)	No	14"	Flow	-	0	0	0	-	-	-	-	-	
X-66B-2	Instrumentation - LPCI "A" dp	Water	1	55	-	-	102A	XFC	Outside	(37)	No	14"	Flow	-	0	0	0	-	-	-	-	-	

Table 6.2-17 (Cont'd)

CONTAINMENT PENETRATION NUMBER	LINE ISOLATED	FLUID	LINE SIZE (in)	NRC GENERAL DESIGN CRITERION	ESF SYSTEM	ESSENTIAL SYSTEM	VALVE NUMBER	VALVE TYPE (1)	VALVE LOCATION	VALVE ARRANGEMENT (2)	TYPE C TEST	LENGTH OF PIPE FROM CONT. TO OUTSIDE VALVES	PRIMARY METHOD OF ACTUATION (3)	SECONDARY METHOD OF ACTUATION	NORMAL VALVE POSITION (4)	SHUTDOWN VALVE POSITION	POST-ACCIDENT POSITION	POWER FAILURE VALVE POSITION	ISOLATION SIGNAL(5)	DIVERSE ISOLATION SIGNAL(12)	VALVE CLOSURE TIME(6)	POWER SOURCE (7)	REMARKS
X-67A	Instrumentation - RPV pressure	Water	1	55	-	-	F049B	XFC	Outside	(37)	No	13"	Flow	-	0	0	0	-	-	-	-	-	
X-67B-1	Instrumentation - RPV pressure	Water	1	55	-	-	F043A	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-67B-2	Instrumentation - RPV level	Water	1	55	-	-	F041	XFC	Outside	(37)	No	11"	Flow	-	0	0	0	-	-	-	-	-	
X-102A	Instrumentation - jet pump flow	Water	1	55	-	-	185A	XFC	Outside	(37)	No	18"	Flow	-	0	0	0	-	-	-	-	-	
X-107	Instrumentation - jet pump flow	Water	1	55	-	-	185B	XFC	Outside	(37)	No	18"	Flow	-	0	0	0	-	-	-	-	-	
X-116	Standby liquid control	Sodium pentaborate solution	2	55	Yes Yes	Yes Yes	F007 F006B	CK SCK	Inside Outside	(10)	Yes	- 16"	Flow Flow	- AC motor	C 0	C 0	C 0	- As is	- RM	- NA	- Standard	- B	
X-117B-1	Drywell radiation sample supply and return	Gas	1	56	No	No	190-A,B	GB	Outside	(23)	Yes	9'-4"	AC coil	-	0	C	C	C	B,H,R,S	Yes	2 sec	C,B	
X-117B-2	Drywell radiation sample supply and return	Gas	1	56	No	No	190-C,D	GB	Outside	(23)	Yes	10'-2"	AC coil	-	0	C	C	C	B,H,R,S	Yes	2 sec	C,B	(19)
X-201A	Suppression pool purge supply	Gas	20	56	No No No Yes Yes Yes Yes	No No No Yes Yes Yes Yes	HV-57-109 HV-57-147 HV-57-124 HV-57-131 HV-57-164 HV-57-121 HV-57-169	BF BF BF BF BF BF BF	Outside Outside Outside Outside Outside Outside Outside	(7)	Yes	42'-9" 17'-5" 13'-5" 7'-9" 8'-2" 69'-11" 9'-6"	AC motor AC motor Comp air Comp air AC motor Comp air AC motor	Manual Manual Spring Spring Manual Spring Manual	C C C C C C C	C 0 0 C C C C	C 0 C C 0 C 0	As is As is C C As is C As is	B,H,W,U,S,R,T B,H,W,U,S,R,T B,H,W,U,S,R,T B,H,W,U,S,R,T B,H,R,S B,H,W,U,S,R,T B,H,R,S	Yes Yes Yes NA NA NA NA	6** sec 6** sec 5** sec 5** sec 6 sec 5** sec 6 sec	B B A A D A D	(19) (19) (19) (23) (24) (19), (23) (24)
X-201A (Unit 2)	Hardened Containment Vent	Steam/ Non-Cond Gas	12	56	No	No	HV-57V-280	BF	Outside	(7)	Yes	13'-2"	Comp Air	Spring	C	C	C	C	-	NA	Standard**	N	(19), (21)
		Steam/ Non-Cond Gas	12	56	No	No	HV-57V-281	BF	Outside	(7)	Yes	22'-1"	Comp Air	Spring	C	C	C	C	-	NA	Standard**	N	(19), (21)
X-201B	Hardened Containment Vent	Steam/20 Non-Cond Gas	56	No	No	HV-57V-180	BF	Outside	(7)	Yes	16'-7"	Comp Air	Spring	C	C	C	C	-	NA	Standard**	N	(19), (21)	
		Steam/20 Non-Cond Gas	56	No	No	HV-57V-181	BF	Outside	(7)	Yes	23'-5"	Comp Air	Spring	C	C	C	C	-	NA	Standard**	N	(19), (21)	
X-202	Suppression pool purge exhaust	Gas	18	56	Yes Yes Yes No No No Yes	No Yes Yes No No No Yes	HV-57-112 HV-57-185 HV-57-162 HV-57-105 HV-57-104 HV-57-118 HV-57-166	BF GB BF GB BF BF BF	Outside Outside Outside Outside Outside Outside Outside	(15)	Yes	18'-6" 24'-6" 3'-10" 6'-10" 4'-0" 32'-11" 5'-9"	AC motor AC coil AC motor AC motor Comp air Comp air AC motor	Manual - Manual Manual Spring Spring Manual	C 0 C C C C C	0 0 C C 0 C C	0 0 0 C C C 0	As is C As is As is C C As is	B,H,W,U,S,R,T B,H,R,S B,H,R,S B,H,U,S,R,T B,H,W,U,S,R,T B,H,U,S,R,T B,H,R,S	NA NA NA Yes Yes Yes NA	6** sec 2 sec 6 sec 15** sec 5** sec 5** sec 6 sec	A C C B B A C	(19) (19) (24) (20) (19)
X-203A-D	RHR pump suction	Water	24	56	Yes Yes Yes	Yes - -	F004A,B,C,D F030A,B F030C,D	GT PSV PSV	Outside Outside Outside	(16)	No	0" 46'-6" 35'-6"	AC motor Water pres Water pres	Manual - -	0 C C	0 C C	0 C C	As is - -	RM - -	NA - -	Standard - -	A,B,C,D - -	(22) (19) (19)
X-204A,B	RHR pump test and min flow	Water	6	56	Yes	Yes	125A,B	GT	Outside	(36)	No	0"	AC motor	Manual	0	0	0	As is	RM	NA	Standard	A,B	(22)
X-205A,B	Suppression pool spray	Water	6	56	Yes	Yes	F027A,B	GB	Outside	(43)	Yes	0"	AC motor	Manual	0	0	0	As is	C,G	NA	30 sec	A,B	
X-206A-D	CS pump suction	Water	16	56	Yes	Yes	F001A,B,C,D	GT	Outside	(42)	No	0"	AC motor	Manual	0	0	0	As is	RM	NA	Standard	A,B	(22)
X-207A,B	CS pump test and flush	Water	10	56	Yes	No	F015A,B	GB	Outside	(24)	No	0"	AC motor	Manual	C	C	C	As is	C,G	Yes	15 sec	A,B	(22)
X-208B	CS pump min flow	Water	4	56	Yes	Yes	F031B	GB	Outside	(24)	No	0"	AC motor	Manual	0	C	C	As is	LFCH	NA	30 sec	B	(22)
X-209	HPCI pump suction	Water	16	56	Yes	Yes	F042	GT	Outside	(42)	No	0"	DC motor	Manual	0	0	0	As is	L,LA	NA	Standard	B	(22)
X-210	HPCI turbine exhaust	Water	12	56	Yes	Yes	F072	GT	Outside	(24)	No	0"	DC motor	Manual	0	0	0	As is	RM	NA	Standard	B	(22)
X-212	HPCI pump test and flush	Water	4	56	Yes	No	F071	GT	Outside	(24)	No	0"	DC motor	Manual	C	C	C	As is	B,H	Yes	Standard	B	(22)
X-214	RCIC pump suction	Water	6	56	Yes	Yes	F031	GT	Outside	(42)	No	0"	DC motor	Manual	C	C	0	As is	RM	NA	Standard	A	(22)
X-215	RCIC turbine	Water exhaust	8	56	Yes	Yes	F060	GT	Outside	(24)	No	0"	DC motor	Manual	0	0	0	As is	RM	NA	Standard	A	(22)
X-216	RCIC min flow	Water	2	56	Yes	Yes	F019	GB	Outside	(24)	No	0"	DC motor	Manual	C	C	C	As is	LFRC	NA	8 sec	A	(22)
X-217	RCIC vacuum discharge (Unit 1)	Air	2	56	No No	No No	F002 F028	SCK CK	Outside Outside	(34)	No	11" 6'-2"	Flow Flow	DC motor -	0 C	0 C	0 C	- -	RM -	No -	Standard -	A -	(14)
X-217	RCIC vacuum discharge (Unit 2)	Air	2	56	No No	No No	F002 F028	SCK CK	Outside Outside	(34)	No	17" 6'-2"	Flow Flow	DC motor -	0 C	0 C	0 C	- -	RM -	No -	Standard -	A -	(14)
X-218	Instrument gas supply	Air	1	56	No No	No No	1001 135	CK GB	Inside Outside	(22)	Yes	-" 3"	Flow Comp air	- Manual	0 0	0 0	C C	- -	- C,H,S	- Yes	- 4.4 sec	- B	
X-219A,B	Instrumentation - suppression pool level	Water	2	56	- -	- -	120 121	GB GB	Outside Outside	(38)	No	0" 0"	AC motor AC motor	Manual Manual	0 0	0 0	0 0	As is As is	RM RM	- -	30 sec 30 sec	B B	

Table 6.2-17 (Cont'd)

CONTAINMENT PENETRATION NUMBER	LINE ISOLATED	FLUID	LINE SIZE (in)	NRC GENERAL DESIGN CRITERION	ESF SYSTEM	ESSENTIAL SYSTEM	VALVE NUMBER	VALVE TYPE (1)	VALVE LOCATION	VALVE ARRANGEMENT (2)	TYPE C TEST	LENGTH OF PIPE FROM CONT. TO OUTSIDE VALVES	PRIMARY METHOD OF ACTUATION (3)	SECONDARY METHOD OF ACTUATION	NORMAL VALVE POSITION (4)	SHUTDOWN VALVE POSITION	POST-ACCIDENT POSITION	POWER FAILURE VALVE POSITION	ISOLATION SIGNAL(5)	DIVERSE ISOLATION SIGNAL(12)	VALVE CLOSURE TIME(6)	POWER SOURCE (7)	REMARKS
X-220A	H_2/O_2 sample return; wet-well purge makeup	Air	2	56	Yes	Yes	190	GB	Outside	(12)	Yes	10'-5"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	C	(19)
					Yes	Yes	191	GB	Outside			8'-5"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	A	
					Yes	Yes	116	GB	Outside			14'-8"	AC motor	Manual	C	C	C	As is	B,H,R,S	NA	30** sec	D	
					Yes	Yes	150	GB	Outside			247'-9"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	B	
					Yes	Yes	159	GB	Outside			255'-3"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	D	
X-220B	Instrumentation - suppression pool pressure (Unit 1 only)	Air	2	56	-	-	101	GB	Outside	(39)	No	0"	AC coil	-	0	0	0	C	RM	-	2 sec	A	
X-221A	Wetwell H_2/O_2 sample	Air	1	56	Yes	Yes	181	GB	Outside	(29)	Yes	2'-2"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	B	
					Yes	Yes	141	GB	Outside			3'-11"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	D	
					Yes	Yes	184	GB	Outside			3'-11"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	C	
X-221B	Wetwell H_2/O_2 sample	Air	1	56	Yes	Yes	183	GB	Outside	(23)	Yes	2'-5"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	A	
					Yes	Yes	186	GB	Outside			3'-5"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	C	
X-226A,B	RHR min flow	Water	4	56	Yes	Yes	105A,B	GT	Outside	(35)	No	0"	AC motor	Manual	0	0	0	As is	RM	NA	Standard	C,D	(22)
X-227	ILRT data acquisition	Air	3/4	56	No	No	1073	GB	Outside	(31)	Yes	18"	Manual	-	C	C	C	-	-	-	-	-	
					No	No	1074	GB	Outside			2'-9"	Manual	-	C	C	C	-	-	-	-	-	
X-228D	HPCI vacuum relief	Air	4	56	Yes	Yes	F095	GT	Outside	(17)	Yes	0"	AC motor	Manual	0	0	C	As is	H,LA	NA	Standard	D	(17)
					Yes	Yes	F093	GT	Outside			12'-6"	AC motor	Manual	0	0	C	As is	H,LA	NA	Standard	B	(17), (19)
X-229A	Instrumentation - suppression pool pressure (Unit 2 only)	Air	2	56	-	-	201	GB	Outside	(39)	No	0"	AC coil	-	0	0	0	C	RM	-	2 sec	A	
X-230B	Deactivated Instrumentation - drywell sumps	Water	1-1/2	56	-	-	102	GB	Outside	(32a)	No	3'-0"	AC motor	Manual	C	C	C	As is	-	-		A	(18)
					-	-	112	GB	Outside	(32)		4"	AC motor	Manual	0	0	0	As is	RM	-	30 sec	A	
					-	-	132	GB	Outside			4"	AC motor	Manual	0	0	0	As is	RM	-	30 sec	A	
X-231A,B	Drywell sump drains	Water	4	56	No	No	110	GT	Outside	(28)	No	0"	Comp air	Spring	0	C	C	C	B,H	Yes	30 sec	A	
					No	No	130	GT	Outside			0"	Comp air	Spring	0	C	C	C	B,H	Yes	30 sec	A	
					No	No	111	GT	Outside			3'-5"	Comp air	Spring	C	C	C	C	B,H	Yes	30 sec	B	
					No	No	131	GT	Outside			3'-5"	Comp air	Spring	C	C	C	C	B,H	Yes	30 sec	B	
X-235	CS pump min flow (Unit 1)	Water	4	56	Yes	Yes	F031A	GB	Outside	(24)	No	0"	AC motor	Manual	0	C	C	As is	LFCH	NA	30 sec	A	(22)
X-235	CS pump min flow (Unit 2)	Water	4	56	Yes	Yes	F031A	GB	Outside	(24)	No	6"	AC motor	Manual	0	C	C	As is	LFCH	NA	30 sec	A	
X-236	HPCI pump min flow	Water	4	56	Yes	Yes	F012	GB	Outside	(24)	No	0"	DC motor	Manual	C	C	C	As is	LFHP	NA	15 sec	B	(22)
X-237	Suppression pool clean-up pump suction; level instrumentation	Water	6	56	No	No	127	GT	Outside	(26)	No	(U1)12" (U2)18"	AC motor	Manual	C	C	C	As is	B,H	Yes	Standard	A	
					No	No	128	GT	Outside			(U1)15'-11" (U2)16'-5"	AC motor	Manual	C	C	C	As is	B,H	Yes	Standard	C	(19)
					No	-	127	PSV	Outside			(U1)4'-0" (U2)8'-3"	Water pres	-	C	C	C	-	-	-	-	-	
					-	-	HV-139	GB	Outside		No	(U1)4'-11" (U2)4'-11"	AC motor	Manual	0	0	0	As is	RM	-	30 sec	B	
					-	-	SV-139	GB	Outside		No	(U1)3'-7" (U2)2'-2"	AC coil	-	0	0	0	C	RM	-	4 sec	A	
X-238	RHR relief valve discharge (Unit 1)	Water	10	56	Yes	-	106B	PSV	Outside	(18)	No	38'-4"	Water pres	-	C	C	C	-	-	-	-	-	(19), (22)
					Yes	No	F104B	GB	Outside			34'-10"	Manual	-	C	C	C	-	-	-	-	-	(19), (22)
X-238	RHR relief valve discharge (Unit 2)	Water	10	56	Yes	-	206B	PSV	Outside	(18)	No	38'-4"	Water pres	-	C	C	C	-	-	-	-	-	(19), (22)
X-239	RHR relief valve discharge (Unit 1)	Water	10	56	Yes	-	106A	PSV	Outside	(18)	No	47'-0"	Water pres	-	C	C	C	-	-	-	-	-	(19), (22)
					Yes	No	F103A	GB	Outside			36'-3"	Manual	-	C	C	C	-	-	-	-	-	(19), (22)
X-239	RHR relief valve discharge (Unit 2)	Water	10	56	Yes	-	206A	PSV	Outside	(18)	No	47'-0"	Water pres	-	C	C	C	-	-	-	-	-	(19), (22)
					Yes	No	F203A	GB	Outside			36'-3"	AC motor	Manual	C	C	C	As is	C,G	Yes	12 sec	A	(19), (22)
X-241	RCIC vacuum relief	Water	3	56	Yes	Yes	F084	GT	Outside	(17)	Yes	0"	AC motor	Manual	0	0	C	As is	H,KA	NA	25 sec	A	(17)
					Yes	Yes	F080	GT	Outside			5'-6"	AC motor	Manual	0	0	C	As is	H,KA	NA	25 sec	B	(17)

Table 6.2-17 (Cont'd)

(1) Valve Type:

Ball	BL
Butterfly	BF
Check	Ck
Gate	GT
Globe	GB
Pressure relief	PSV
Stop-check	SCK
Testable check	TCK
Spring load piston-actuated check	SLPACK
Explosive (shear)	XP
Excessive flow check	XFC
Ball check	BLCK
Hydraulic control unit	HCU

(2) See Figure 6.2-36. Numbers in this column refer to details in the figure.

(3) Ac MOVs required for isolation functions are powered from the ac standby power buses. Dc operated isolation valves are powered from the station batteries.

(4) Normal valve position (open or closed) is the position during normal power operation of the reactor.

(5) Isolation Signal Codes

Signal	Description
A*	Reactor vessel level 3 trip (a scram occurs at this level also)
B*	Reactor vessel level 2 trip
C*	Reactor vessel level 1 trip (main steam line isolation occurs at this level)
D*	High radiation in main steam lines and vicinity
E*	Main steam line high flow
	Deleted
F*	High temperature in Outboard MSIV room

Table 6.2-17 (Cont'd)

Signal	Description
G*	High drywell pressure and low reactor vessel pressure
H*	High drywell pressure
J*	Line break in RWCU system (high differential flow, high temperature in RWCU compartments)
K*	Break in RCIC steam line (high temperature in pipe routing area, high temperature or high differential temperature in RCIC compartment, high steam flow), or high RCIC turbine exhaust diaphragm pressure
KA	Low RCIC steam supply pressure
L*	Break in HPCI steam line (high temperature in pipe routing area, high temperature or high differential temperature in HPCI compartment, or high steam flow), or high HPCI turbine exhaust diaphragm pressure
LA	Low HPCI steam supply pressure
LFHP	With HPCI pumps running, opens on low flow in associated pipe, closes when flow is above setpoint
LFRC	With RCIC pump running, opens on low flow in associated pipe, closes when flow is above setpoint
LFCH	With CS pump running, opens on low flow in associated pipe, closes when flow is above setpoint.
LFCC	Steam supply valve fully closed or RCIC turbine stop valve fully closed
M*	Low differential pressure between the instrument gas line and the primary containment
P*	Low main steam line pressure at inlet to turbine (RUN mode only)
Q*	Low condenser vacuum and turbine stop valve in bypass mode or more than 90% open

Table 6.2-17 (Cont'd)

Signal	Description
R*	High radioactivity in refueling floor ventilation exhaust ducts
S*	High radiation in the reactor enclosure
T	Low differential pressure between the outside atmosphere and the refueling area
U	Low differential pressure between the outside atmosphere and the reactor enclosure
V*	High reactor pressure (shutdown cooling mode only)
W*	North stack effluent high radiation
Y	SLCS actuated or RRCS actuated
RM*	Remote manual switch from control room (all power-operated isolation valves are capable of being operated remote manually from the control room)

* These are the isolation functions of the primary containment and reactor vessel isolation control system; other functions are given for information only.

(6) The standard closing rate for automatic isolation gate valves is based on a nominal line size of 12 inches. Using the standard closing rate, a 12 inch line is isolated in 60 seconds. Conversion to closing time can be made on this basis using the actual size of the line in which the gate valve is installed.

The closure times for isolation valves in lines in which HELBs could occur are identified with a single asterisk. The closure times for isolation valves in lines which provide an open path from the containment to the environs are identified with a double asterisk. Closure times for the valves identified by a single or double asterisk are considered maximum closure times. Closure times for all other valves are nominal times.

The closure time for F105 is a maximum closure time.

Table 6.2-17 (Cont'd)

(7) Power Source

Electrical Separation Source:

A - Class 1E electrical channel
B - Class 1E electrical channel
C - Class 1E electrical channel
D - Class 1E electrical channel
W - RPS electrical separation channel
X - RPS electrical separation channel
Y - RPS electrical separation channel
Z - RPS electrical separation channel
N - non-Class 1E

For explanation of electrical separation channels, refer to Section 8.1.

(8) Deleted

(9) The spring-loaded piston, which is actuated by an isolation signal or a loss of power, will not close this valve against normal flow on loss of power from the normal direction.

(10) The TIP drive guide tubes provide a path for the flexible drive cable of the TIP probes. The drive cable is automatically retracted on an isolation signal. When the drive cable is fully retracted, the ball valve closes. The shear valves is provided to isolate the guide tubes by cutting the cable if the drive cable cannot be withdrawn.

(11) The CRD insert and withdraw lines can be isolated outside containment. Upstream of the HCUs, two redundant simple check valves are provided on each main water header (i.e. charging, cooling, drive and exhaust). Air operated scram inlet and outlet valves are also provided. Leakage may occur through the scram outlet valves. A low leakage flowrate will be treated by the clean radwaste system. Excessive leakage will result in either automatic scram or operator initiated scram. When scram is complete, the SDV system is automatically isolated by the redundant vent and drain valves.

(12) Only nonessential systems require diverse signals for automatic isolation. Therefore, this column is not applicable, (NA), for essential systems.

Table 6.2-17 (Cont'd)

(13) These valves are sealed closed whenever the reactor is critical and reactor pressure is greater then 600 psig. The valves are expected to be opened only in the following instances:

a. Flushing of the condensate and feedwater systems during plant startup.

b. RPV hydrostatic testing, which is conducted following each refueling outage prior to commencing plant startup.

(14) Diverse isolation signals are not sensed as discussed in Section 6.2.4.3.1.

(15) These valves are normally closed, will be open only during reactor shutdown, are interlocked to open only on low reactor pressure, and connect to a closed system outside containment. Therefore, closure times less then 60 seconds are not required.

(16) Deleted

(17) Both isolation signals required for valve closure.

(18) Valve HV-61-102 is locked closed, the motor operator is normally de-energized and the valve position is controlled procedurally. The valve remains closed during 10 CFR50, Appendix J, Type A testing, and type C testing is not required. Valve HV-61-202 has been deleted from the Unit 2 design.

(19) All outside containment isolation valves have been located as close to containment as practical. Examples of containment isolation valve locations greater than 10 feet from containment are identified and justified below.

a. Deleted

b. Valves HV-F032A-B, HV-109A-B, HV-F039, HV-F013, HV-130A-B, HV-F105, HV-133A-B (Penetrations X-9A-B) provide a third isolation barrier for the feedwater lines. These valves are located at distances from the penetration dictated by equipment accessibility considerations.

c. Valve 1016 (penetrations X-9A-B, X-44) also provides a third isolation barrier for the feedwater lines and an outboard isolation barrier for the alternate RWCU return penetration (X-44). The valve is located in closer proximity to the latter penetration.

Table 6.2-17 (Cont'd)

d. Valves HV-121 & 131 (penetrations X-25, X-201A) are isolation valves for both drywell and wetwell penetrations. They have been located nearer to one penetration and therefore at some distance from the other.

e. Relief valves F030A-D (penetrations X-203A-D) are located as close to the RHR pumps as possible in order to perform their intended function of providing overpressure protection for the pumps. These valves are part of a closed system outside containment.

f. Relief valve 106B and globe valve F104B, (penetration X-238) have been located as close as practical to the RHR heat. Their location is dictated by functionality and pipe stress considerations. Valves 106A and F103A, (penetration X-239) are located similarly.

g. DELETED

h. Valves HV-114, HV-115 (penetration X-26) are restricted to their location because of necessary piping interties and for valve accessibility.

i. Valve 109 (penetration X-25, X-201A) provides the outboard barrier for both the drywell penetration and the wetwell penetration. Physical separation of the penetrations and the resulting piping arrangement prohibits a closer placement to either penetration.

j. Valves HV-57V-180 and HV-57V-181 (Unit 1 penetration X-201B) are associated with the hardened containment vent and located at distances from the penetration dictated by equipment located in the compartment. Valves HV-57V-280 and HV-57V-281 (Unit 2 penetration X-201A) are associated with the hardened containment vent and located at distances from the penetration dictated by equipment located in the compartment.

(20) Closure times of 6 seconds or less are provided for all isolation valves on the purge lines, with the exception of valves HV-57-105 and HV-57-111. Valves HV-57-105 and HV-57-111 are 2 inch MOVs in the low volume purge lines with closure times of 15 seconds or less. This closure time has been justified by an analysis of the radiological consequences of a LOCA that occurs during purging, as discussed in Section 9.4.5.1.2.

(21) 124A, 124B, 125A, and 125B (penetrations X-53, X-54, X-55 and X-56) do not receive an automatic isolation signal. Valves HV-57V-180 and HV-57V-181 associated with Unit 1 penetration X-201B also do not receive automatic isolation signals and are not normally powered. Valves HV-57V-280 and HV-57V-281 associated with penetration X-201A (Unit 2) also do not receive automatic isolation signals and are not normally powered.These valves are administratively controlled such that these valves are treated as locked closed valves. Therefore, these valves do not have a required closure time.

(22) These lines are below the minimum water level in the suppression pool, the system is a closed system outside primary containment, and will maintain a water seal following an accident. Therefore, 10CFR50 Appendix J, Type C testing is not required.

Table 6.2-17 (Cont'd)

(23) There are electrical interlocks between HV-057-121 and HV-057-131 and in between HV-057-221 and HV-057-231, which prevent both interlocked valves from being open at the same time. This interlock is consistent with requirements of UFSAR Section 9.4.5.1.2.2 to limit the number of high volume purge lines in use during the operational modes of startup, power operation and hot shutdown to one supply line and one exhaust line.

(24) Valves HV-57-262, HV-57-263, HV-57-1(2)64, HV-57-269 (penetrations X-25, X-201A, and X-202) are administratively controlled such that these valves are treated as seal closed barriers. Therefore, these valves do not have a required closure time.

Table 6.2-18

ASSUMPTIONS USED IN EVALUATING THE PRODUCTION
OF COMBUSTIBLE GASES FOLLOWING A LOCA

PARAMETER	VALUE
Fraction of fission product radiation energy absorbed by the coolant:	
Betas from fission products in fuel rods	0.0
Betas from fission products mixed with coolant	1.0
Gammas from fission products in fuel rods	0.1
Gammas from fission products mixed with coolant	1.0
Hydrogen yield rate $G(H_2)$	0.5 molecule/100 eV
Oxygen yield rate $G(0_2)$	0.25 molecule/100 eV
Extent of initial core metal-water reaction involving cladding surrounding the fuel	0.00023 inch depth into original cladding
Evolution time of hydrogen produced from metal-water reaction	2 minutes
Corrosion rate for zinc and zinc paint	3.76×10^{-9} exp(0.0218T) lb-moles/ft^2-hr (where T = temperature in degrees Fahrenheit)
Fission product distribution model:	
Coolant water	1% of solids + 50% of halogens
Containment atmosphere	100% of noble gases
Fuel rods	All other fission products

Table 6.2-19

PARAMETERS USED IN EVALUATING THE PRODUCTION OF HYDROGEN FOLLOWING A LOCA

PARAMETER	VALUE
Reactor thermal power:	3,527 MWt (1)
Drywell free volume:	248,700 ft^3
Suppression chamber free volume:	149,000 ft^3
Zircaloy cladding surrounding active fuel:	
Mass	67,700 lb (1)
Surface area	89,210 ft^2 (1)
Zinc (as galvanized steel) in drywell:	
Mass	1,850 lb
Surface area	32,055 ft^2
Zinc paint in drywell:	
Volume of paint	1.92 ft^3
Surface area	7,692 ft^2
Zinc content of zinc paint	87%
Zinc paint in suppression chamber:	
Volume of paint	39.67 ft^3
Surface area	68,000 ft^2
Zinc content of zinc paint	87%
Volume of free hydrogen normally in reactor coolant (at 60°F and atmospheric pressure):	195 ft^3

(1) Reference 6.2-42 accounts for GNF3 fuel at 3527 MWt.

Table 6.2-20

CONTAINMENT HYDROGEN RECOMBINER SUBSYSTEM FAILURE MODES AND EFFECTS ANALYSIS

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (LOCA)	Power supply	LOOP	Loss of both recombiner packages	Alarm in the control room	None. The recombiner packages are powered from the Class 1E buses. When standby power becomes available, the recombiner packages resume operation.
Emergency (LOCA or LOCA + LOOP)	Power supply	Loss of one Class 1E bus or the associated diesel generator	Loss of one recombiner package	Alarm in the control room	None. The redundant recombiner package is unaffected and is activated manually by the operator.
Emergency (LOCA or LOCA + LOOP)	Containment isolation valve in one gas inlet or gas outlet line	Failure of valve to reopen after containment isolation signal is bypassed	No flow through recombiner package	Flow indication and low flow alarm in the control room	None. The redundant recombiner package is unaffected and is activated manually by the operator.
Emergency (LOCA or LOCA + LOOP)	Blower in one recombiner package	Abnormally low blower speed or complete failure to operate	Insufficient flow through recombiner package	Flow indication and low flow alarm in the control room	None. The redundant recombiner package is unaffected and is activated manually by the operator.
Emergency (LOCA or LOCA + LOOP)	Heater elements or SCRs in one recombiner package	Abnormally low heater output	Reaction chamber temperature too low for complete recombination	Alarm in the control room	None. The redundant recombiner package is unaffected and is activated manually by the operator.

Table 6.2-20 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (LOCA or LOCA + LOOP)	Water inlet valve in one recombiner package	Failure to open fully	Abnormally high return gas temperature	Alarm in the control room	None. The redundant recombiner package is unaffected and is activated manually by the operator.
Emergency (LOCA or LOCA + LOOP)	Gas inlet valve in one recombiner package	Case 1: Excessive valve opening	High flow through the recombiner package, with the possibility of excessive temperatures in the reaction chamber	Flow indication and high temperature alarm in the control room	None. The redundant recombiner package is unaffected and is activated manually by the operator.
		Case 2: Insufficient valve opening	Insufficient flow through the recombiner package	Flow indication and low flow alarm in the control room	None. The redundant recombiner package is unaffected and is activated manually by the operator.

Table 6.2-21

COMBUSTIBLE GAS ANALYZER SUBSYSTEM FAILURE MODES AND EFFECTS ANALYSIS

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Normal or Emergency	Power supply	LOOP	Closure of containment isolation valves on all sample lines. Loss of both analyzer packages.	Alarm in the control room	None. The analyzer packages are powered from the Class 1E buses. When standby power becomes available, the containment isolation valves reopen and the analyzer packages resume operation.
Normal or Emergency	480V Fuses	Loss of one fuse.	A/B phase fuse failure would cause loss of one analyzer package. C phase fuse failure would cause pump not to start and analyzer package would not be able to perform function.	A/B phase fuse failure would cause alarm in the control room. C phase fuse failure would be detected upon use or during testing every month.	None. The redundant analyzer package is unaffected and continues to operate.
Emergency (LOCA or LOCA + LOOP)	Power supply	Loss of one Class 1E bus or the associated diesel Generator.	Loss of one analyzer package. Closure of containment isolation valves on associated sample lines.	Alarm in the control room	None. The redundant analyzer package is unaffected and continues to operate.
Emergency (LOCA or LOCA + LOOP)	Sample pump in one analyzer package.	Failure of the operating pump.	Loss of sample flow through the affected analyzer package.	Alarm in the control room	None. The redundant analyzer package is unaffected and continues to operate.
Emergency (LOCA or LOCA + LOOP)	Hydrogen analyzer cell in one analyzer package,	Analyzer cell failure.	Incorrect hydrogen concentration for the affected analyzer package.	Alarm in the control room	None. The redundant analyzer package is unaffected and continues to operate.
Emergency (LOCA or LOCA + LOOP)	Oxygen analyzer cell in one analyzer package.	Analyzer cell. failure.	Incorrect oxygen concentration for the affected analyzer package.	Alarm in the control room	None. The redundant analyzer package is unaffected and continues to operate.

Table 6.2-21 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (LOCA or LOCA + LOOP)	Sample line containment isolation valves.	Failure of one valve to reopen when containment isolation signal is bypassed.	Case A, a sample suction line: inability to draw sample through affected line only.	Case A: alarm in the control room due to low flow when the affected line is selected.	None. The redundant analyzer package is unaffected and continues to operate.
			Case B, a sample return line: blockage of all flow through affected analyzer package.	Case **B**: alarm in the control room due to low flow Immediately.	
Emergency (LOCA or LOCA + LOOP)	Sample line containment isolation valves.	Failure of one valve to close when containment isolation signal is received.	Reduction in containment isolation barriers from two valves to one valve in the affected line.	Indicating lights in the control room.	None. The redundant valve provides isolation.
Normal or Emergency	Other electrical components and cables.	Open circuits and shorted circuits or loss of input / output due to various failure mechanisms or errors.	Loss of functions associated with failure of specific component (indication, alarms, controls, etc.	Depending on failed component alarm indication in control room or failure will be self-revealing.	None. The redundant analyzer package is unaffected and continues to operate.
Normal or Emergency	MCR Signal Conditioner and PLC Assembly	Failure to provide indication or control function.	Unable to obtain Combustible gas concentration readings.	Depending on failed component alarm indication in control room or failure will be self-revealing.	None. The redundant analyzer package is unaffected and continues to operate.

Table 6.2-22

The information in this table has been deleted

Table 6.2-23

The information in this table has been deleted

Table 6.2-24

SYSTEM VENTING AND DRAINING EXCEPTIONS FOR PRIMARY CONTAINMENT INTEGRATED LEAKAGE RATE TEST

I. The drywell chilled water system, located inside the primary containment, is required to maintain the plant in a stabilized condition during the Type A test and is not vented and operates in its normal mode.

II. Portions of systems that are normally filled with water and operating under post-LOCA conditions are not specifically vented to the containment atmosphere or to the outside atmosphere. They remain water-filled during the Type A test. These systems are listed below. (Note: Venting to the primary containment atmosphere does occur for these systems, since the reactor vessel is vented to the primary containment atmosphere and/or system penetrations are open to the suppression pool or containment atmospheres.)

III. For planning and scheduling purposes, or ALARA considerations, pathways that are Type B or C tested within the previous 24 calendar months need not be vented or drained during the Type A test.

System
RCIC
RHR
CS
HPCI

Table 6.2-25

CONTAINMENT PENETRATIONS
COMPLIANCE WITH 10CFR50, APPENDIX J

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
-	Drywell head flange	M-60	B	Double O-Ring	-	2
1	Equipment access door	M-60	B	Double O-Ring	-	2
2	Equipment access door and personnel lock	M-60	B	Double O-Ring	-	2
3A	Instrumentation - main steam line D flow	M-41	A	-	XFC-F070D XFC-F073D	1
3A	Instrumentation - recirculation pump seal pressure	M-43	A	-	XFC-F003A	1
3B	Instrument gas supply	M-59	C	CK-1005B	HV-129B	-
3C	Instrumentation - HPCI steam flow	M-55	A	-	XFC-F024A	1
3C	Instrumentation - HPCI steam flow	M-55	A	-	XFC-F024C	1
3D	Instrumentation - main steam line A flow	M-41	A	-	XFC-F070A XFC-F073A	1
3D	Instrument gas supply	M-59	C	CK-1112	MO-151B	-
4	Head access manhole	M-60	B	Double O-Ring	-	2
5	Spare	-	A	-	-	-
6	CRD removal hatch	M-60	B	Double O-Ring	-	2
7A-D	Primary steam	M-41	C	AO-F022A-D	AO-F028A-D	6
8	Primary steam line drain	M-41	C	MO-F016	MO-F019	4

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
9A,B	Feedwater	M-41	C	CK-F010A,B	CK-F074A,B CK-F032A,B MO-109A,B CK-F039 MO-F013 MO-F105 CK-1036A,B MO-130A,B MO-133A,B 1016	7(MO-F105 only), 18, 24
10	Steam to RCIC turbine	M-49	C	MO-F007	MO-F008 MO-F076	5
11	Steam to HPCI turbine	M-55	C	MO-F002	MO-F003 MO-F100	5
12	RHR shutdown cooling supply	M-51	C	MO-F008	Closed system	33
13A,B	RHR shutdown return	M-51	C	MO-F015A,B	Closed system	33
14	RWCU supply	M-44	C	MO-F001	MO-F004	-
15	Spare	-	A	-	-	-
16A	CS pump discharge	M-52	C	MO-F005	Closed system	33
16B	CS pump discharge	M-52	C	CK-108	Closed system	33
17	RPV head spray (Unit 1 only) (ABANDONED)	M-51	A		Welded Plate	-
17	Spare (Unit 2 only)	M-51	A	-	-	-
18	Spare	-	A	-	-	-
19	Spare	-	A	-	-	-

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
20A	Instrumentation - RPV level	M-42	A	-	XFC-F045B	1
20A	Instrumentation - LPCI ΔP	M-51	A	-	XFC-102B	1
20A	Instrumentation - LPCI ΔP	M-51	A	-	XFC-103B	1
20B	Instrumentation - RPV level	M-42	A	-	XFC-F045C	1
20B	Instrumentation - LPCI ΔP	M-51	A	-	XFC-102C	1
21	Service air	M-15	C	1140	1139	-
22	Instrumentation - drywell pressure	M-42	A	-	MO-147C	11
23	Closed cooling water supply	M-13	C	MO-106	MO-108 MO-109	12
24	Closed cooling water return	M-13	C	MO-107	MO-111 MO-110	12
25	Drywell purge supply	M-57	C B	AO-121 MO-163 AO-123 Double O-Ring Seal Assembly (3)	MO-109 FV-DO-101B AO-131 MO-135	3, 12, 25
26	Drywell purge exhaust	M-57	C B	SV-139 MO-161 MO-111 AO-114 Double O-Ring Seal Assembly (2)	SV-145 FV-DO-101A AO-117 MO-115	3, 1 (SV-139 only) 12, 25
27A	Instrument gas supply	M-59	C	CK-1128	MO-151A	-
27B	Instrumentation - HPCI flow	M-55	A	-	XFC-F024B	1
27B	Instrumentation - HPCI flow	M-55	A	-	XFC-FO24D	1
28A	Recirc loop sample	M-43	C	AO-F019	AO-F020	-

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
28A	Drywell H_2/O_2 sample	M-57	C	SV-134	SV-144	12
28A	Drywell H_2/O_2 sample	M-57	C	SV-132	SV-142	12
28B	Drywell H_2/O_2 sample	M-57	C	SV-133	SV-143 SV-195	12
28B	Spare	-	A	-	-	-
29A	Instrumentation - RPV flange leakage	M-41	A	-	XFC-F009	1, 28
29B	Instrumentation - CS ⧅P	M-52	A	-	XFC-F018A	1
30A	Instrumentation - main steam line D flow	M-41	A	-	XFC-F071D XFC-F072D	1
30B	Instrumentation - drywell pressure	M-42	A	-	MO-147A	11
30B	Instrumentation - main steam line C flow	M-41	A	-	XFC-F071C XFC-F072C	1
31 A,B	Instrumentation - jet pump flow	M-42	A	-	XFC-F059B,D,F,H XFC-F051B XFC-F053B	1
32 A,B	Instrumentation - jet pump flow	M-42	A	-	XFC-F059M,P,S,U XFC-F051D XFC-F053D	1
33A	Instrumentation - pressure above core plate	M-42	A	-	XFC-F055 XFC-F076	1
33A	Instrumentation - pressure below core plate	M-42	A	-	XFC-F061	1
33B	Instrumentation - RCIC steam flow	M-49	A	-	XFC-FO44A,C	1
34A	Instrumentation - main steam line C flow	M-41	A	-	XFC-F070C XFC-F073C	1

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
34B	Instrumentation - recirculation flow	M-43	A	-	XFC-F009C,D XFC-F010C,D	1
35A	Spare	-	A	-	-	-
35B	Instrument gas to TIP indexing mechanisms	M-59	C B	CK-1056 Double O-Ring Seal	AO-131	27
35C-G	TIP drives	M-59	C B	XV-141A-E Double O-Ring Seal (5)	XV-140A-E	12, 20, 27
36	Spare	-	A	-	-	-
37A-D	CRD insert	M-47	A C	Ball check -	- CK46-1101 CK46-1102 CK46-1108 CK46-1109	- 13,15
38A-D	CRD withdraw	M-47	C	-	CK46-1115 CK46-1116 CK46-1122 CK46-1123	13,15
			C		F010, F011 F180, F181	
39A,B	Drywell spray	M-51	C	MO-F021 A,B	Closed system	4, 12, 33
40A	Instrumentation - jet pump flow	M-42	A	-	XFC-F059L,N,R	1
40B	Instrumentation - jet pump flow	M-42	A	-	XFC-F059G XFC-F051A XFC-F053A	1
40C	Instrumentation - jet pump flow	M-42	A	-	XFC-F059A,C,E	1
40D	Instrumentation - pressure below core plate	M-42	A	-	XFC-F057	1
40D	Instrumentation - bottom drain flow	M-44	A	-	XFC-170 XFC-171	1
40E	Instrumentation - drywell pressure	M-42	A	-	MO-147D	11

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
40F	Instrumentation - RCIC steam flow	M-49	A	-	XFC-F044B,D	1
40F	Instrument gas suction	M-59	C	MO-101	AO-102	5
40G	ILRT data acquisition system	M-60	C	1057	1058	12, 30
40G	ILRT data acquisition system	M-60	C	1071	1070	12, 30
40H	Instrument gas supply	M-59	C	CK-1005A	AO-129A	-
40H	Instrumentation - recirculation pump cooler flow	M-87	A	-	XFC-156B XFC-157B	21
41	Instrumentation - RWCU flow	M-44	A	-	XFC-102A,B	1
41	Instrumentation - LPCI ⍁P	M-51	A	-	XFC-103A	1
42	SLCS	M-48	C	CK-F007	MO-F006A	-
43A	Instrumentation - recirculation loop A ⍁P;	M-43	A	-	XFC-F040A,C	1
43B	Main steam sample	M-41	C	AO-F084	AO-F085	-
44	RWCU alternate return	M-41	C	1017	1016 PSV-112	5, 24
45A-D	LPCI	M-51	C	MO-F017A-D	Closed system	33
46	Spare	-	A	-	-	-
47	Instrumentation - RWCU flow	M-44	A	-	XFC-102D	1
48A	Instrumentation - RPV level	M-42	A	-	XFC-F065B XFC-F047B	1
48A	Instrumentation - CS ⍁P	M-52	A	-	XFC-F018B	1

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
48B	Instrumentation - RPV level	M-42	A	-	XFC-F065A XFC-F047A	1
49A,B	Instrumentation - main steam line A & B flow	M-41	A	-	XFC-F071A,B XFC-F072A,B	1
50A	Instrumentation - drywell pressure	M-42	A	-	MO-147B	11
50A	Instrumentation - recirculation flow	M-43	A	-	XFC-F011A,B XFC-F012A,B	1
50B	Instrumentation - recirculation pump seal pressure	M-43	A	-	XFC-F004A	1
50B	Instrumentation - recirculation pump cooler flow	M-87	A	-	XFC-156A XFC-157A	21
51A	Instrumentation - recirculation line flow	M-43	A	-	XFC-F009A,B XFC-F010A,B	1
51B	Instrumentation - jet pump flow	M-42	A	-	XFC-F059T XFC-F051C XFC-F053C	1
52A	Instrumentation - main steam line B flow	M-41	A	-	XFC-F070B XFC-F073B	1
52B	Instrumentation - recirculation line flow	M-43	A	-	XFC-F011C,D XFC-F012C,D	1
53	Drywell chilled water supply	M-87	C	MO-128	MO120A, MO125A	12
54	Drywell chilled water return	M-87	C	MO-129	MO121A, MO124A	12
55	Drywell chilled water supply	M-87	C	MO-122	MO120B, MO125B	12
56	Drywell chilled water return	M-87	C	MO-123	MO121B, MO124B	12

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
57	Instrumentation - RWCU flow	M-44	A	-	XFC-102C	1
58A	Instrumentation - recirculation loop B ΔP	M-43	A	-	XFC-F040B	1
58B	Spare	-	A	-	-	-
59A,B	Spare	-	A	-	-	-
60	Spare	-	A	-	-	-
61	Recirculation pump seal purge	M-43	C	CK-1004A, B	XFC-103A,B	1, 19
62	H_2/O_2 sample return	M-57	C	SV-150	MO-116 SV-159 SV-190 SV-191	12
63	Instrumentation - recirculation loop ΔP; recirc pump Seal pressure	M-43	A	-	XFC-F003B XFC-F004B XFC-F040D	1
64	Spare	-	A	-	-	-
65A,B	Instrumentation - RPV pressure	M-42	A	-	XFC-F043B XFC-F049A	1
66A	Instrumentation - RPV level	M-42	A	-	XFC-F045D	1
66A	Instrumentation - LPCI ΔP	M-51	A	-	XFC-102D XFC-103D	1
66B	Instrumentation - RPV level	M-42	A	-	XFC-F045A	1
66B	Instrumentation - LPCI ΔP	M-51	A	-	XFC-102A XFC-103C	1
67A,B	Instrumentation - RPV level; RPV pressure	M-42	A	-	XFC-F041 XFC-F043A XFC-F049B	1

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
100 A-D	Neutron monitoring system	M-60	B	Canister	-	8
101 A-D	Recirculation pump power	M-60	B	Canister	-	8
102A	Instrumentation - Jet pump flow	M-42	A	-	XFC-185A	1
102B	Electrical spare	-	A	-	-	-
103A,B	Temperature and low level signals	M-60	B	Canister	-	8
104 A-D	CRD position indicator	M-60	B	Canister	-	8
105 A-E	Miscellaneous low voltage power	M-60	B	Canister	-	8
106 A-C	Low voltage control	M-60	B	Canister	-	8
107	Instrumentation - Jet pump flow	M-42	A	-	XFC-185B	1
108	Electrical spare	-	A	-	-	-
109	Electrical spare	-	A	-	-	-
110	Electrical spare	-	A	-	-	-
111	Electrical spare	-	A	-	-	-
112	Electrical spare	-	A	-	-	-
113	Electrical spare	-	A	-	-	-
114	Electrical spare	-	A	-	-	-
115	Electrical spare	-	A	-	-	-
116	SLCS	M-48	C	CK-F007	MO-F006B	-

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
117A	Electrical spare	-	A	-	-	-
117B	Drywell radiation monitoring supply and return	M-26	C	SV 190-A SV 190-C	SV 190-B SV 190-D	12
118 A,B	Electrical spare	-	A	-	-	-
200 A,B	Access hatch	M-60	B	Double O-Ring	-	2
201A	Suppression pool purge supply	M-57	C B	AO-131 MO-164 AO-124 Double O-Ring Seal Assembly (3)	AO-121 MO-169 MO-147 MO-109	3, 12, 25
201A	Hardened containment vent (Unit 2)	M-57	C B	AO-280 Double O-Ring Seal Assembly (3)	AO-281	3, 12, 25
201B	Hardened containment vent (Unit 1)	M-57	C B	AO-180 Double O-Ring Seal Assembly (2)	AO-181	3, 12, 25
202	Suppression pool purge Exhaust	M-57	C B	MO-162 MO-105 AO-104 Double O-Ring Seal Assembly (2)	MO-166 AO-118 SV-185 MO-112	3, 5 (MO-105) (Unit 1 only), 12, 25
203 A-D	RHR pump suction	M-51	A	Water seal	MO-F004A-D PSV-F030A-D	14
204 A,B	RHR pump test line and containment cooling	M-51	A	Water seal	MO-125A,B	14
205 A,B	Suppression pool spray	M-51	C	-	MO-F027A,B	10, 12
206 A-D	CS pump suction	M-52	A	Water seal	MO-F001A-D	14
207 A,B	CS pump test and flush	M-52	A	Water seal	MO-F015A,B	14

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
208A	Spare	-	A	-	-	-
208B	CS pump minimum recirc	M-52	A	Water seal	MO-F031B	14
209	HPCI pump suction	M-55	A	Water seal	MO-F042	14
210	HPCI turbine exhaust	M-55	A	Water seal	MO-F072	14
211	Spare	-	A	-	-	-
212	HPCI pump test and flush	M-55	A	Water seal	MO-F071	14
213	Spare	-	A	-	-	-
214	RCIC pump suction	M-49	A	Water seal	MO-F031	14
215	RCIC turbine exhaust	M-49	A	Water seal	MO-F060	14
216	RCIC minimum flow	M-49	A	Water seal	MO-F019	14
217	RCIC vacuum pump discharge	M-49	A	MO-F002	CK-F028	34
218	Instrument - gas to vacuum relief valves	M-59	C	CK-1001	AO-135	-
219 A,B	Instrumentation - suppression pool level	M-55	A	-	MO-120 MO-121 MO-126	11 31
220A	H_2/O_2 sample return	M-57	C	SV-191	SV-190 MO-116 SV-150 SV-159	12
220B	Instrumentation - suppression pool pressure; suppression pool level (Unit 1 only)	M-57	A	-	SV-101	11
220B	Spare (Unit 2 only)	-	A	-	-	-
221A	Wetwell H_2/O_2 sample	M-57	C	SV-181	SV-141 SV-184	12

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
221B	Wetwell H_2/O_2 sample	M-57	C	SV-183	SV-186	12
222	Indication and control	M-60	B	Canister	-	8
223	Spare	-	A	-	-	-
224	Spare	-	A	-	-	-
225	Spare	M-51	A	-	-	2 (Unit 2 Only)
226A,B	RHR minimum recirc	M-51	A	Water seal	MO-105A,B	14
227	ILRT data acquisition system	M-60	C	1073	1074	12
228A,B	Spare	-	A	-	-	-
228C	Spare	-	A	-	-	-
228D	HPCI vacuum relief	M-55	C	MO-F095	MO-F093	4, 12
229A	Spare (Unit 1 only)	-	A	-	-	-
229A	Instrumentation - suppression pool pressure; suppression pool level (Unit 2 only)	M-57	A	-	SV-201	11
229B	Spare	-	A	-	-	-
230A	Strain gauge instrumentation	-	B	Canister	-	8
230B	Instrumentation - drywell sump level	M-61	A	-	MO-102 MO-112 MO-132	29
231A	Drywell sump drains	M-61	A	AO-110	AO-111	12, 34
231B	Drywell sump drains	M-61	A	AO-130	AO-131	12, 34
232 A-S	MSRV discharge	M-41	-	-	-	16

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
235	CS pump minimum recirc	M-52	A	Water Seal	MO-F031A	14
236	HPCI pump minimum recirc	M-55	A	Water Seal	MO-F012	14
237	Suppression pool cleanup pump suction	M-52	A	MO-127	MO-128 PSV-127	12, 34
237	Level instrumentation	M-52	A	-	SV-139 MO-139	11
238	RHR relief valve discharge	M-51	A	Water Seal	PSV-106B MO-F104B Double O-ring Seal Assembly (4)	14, 23
239	RHR relief valve discharge	M-51	A	Water Seal	MO-F103A PSV-106A Double O-ring Seal Assembly (4)	14, 23
240	RHR relief valve discharge	M-51	A	Water Seal	Double O-ring Seal Assembly (3)	32
241	RCIC vacuum relief	M-49	C	MO-F084	MO-F080	4, 12

NOTES

1. Seismic Category I, Quality Group A instrument line with an orifice and excess flow check valve or remote manual isolation valve. The excess flow check valve is subjected to operability testing except as discussed in Note 28, but no Type C test is performed or required. The line does not isolate during a LOCA and can leak only if the line or instrument should rupture. Leak-tightness of the line is verified during the integrated leak rate test (Type A test) by conducting the test with these valves open.

2. Penetration is sealed by a blind flange or door with double O-ring seals. These seals are leakage rate tested by pressurizing between the O-rings. For more detail, see Section 6.2.6.2.

3. Inboard butterfly valve installed such that testing in the reverse direction is equivalent to testing in the forward direction.

4. Inboard gate valve tested in the reverse direction. Valve seating forces are greater than unseating forces due to post-LOCA containment pressure by at least a factor of 3.

5. Inboard globe valve installed such that testing in the reverse direction is conservative.

6. The primary steam penetrations are tested by pressurizing between the valves. Testing of the inboard MSIV in the reverse direction tends to unseat the valve and is therefore conservative. The valves are Type C tested at a test pressure of 22 psig.

7. Gate valve tested in the reverse direction. Valve seating forces are greater than unseating forces due to post-LOCA containment pressure by at least a factor of 3.

8. Electrical penetrations are tested by pressurizing between the seals

Table 6.2-25 (Cont'd)

9. The isolation provisions for this penetration consist of two isolation valves and a closed system outside containment. Because a water seal is maintained in these lines by the safeguard piping fill system, the inboard valve may be tested with water. The outboard valve will be pneumatically tested.

10. The isolation provisions for this line consist of one isolation valve outside containment and a closed system outside containment. A single active failure can be accommodated. The closed system is missile-protected, seismic Category I, quality group B and designed to the temperature and pressure conditions that the system will encounter post-LOCA.

    System leakage will be minimized in accordance with NUREG-0737, Item III.D.1.1. Any leakage out of the closed system will be into the reactor enclosure, thus facilitating collection and treatment.

11. The valve does not receive an isolation signal but remains open to measure containment conditions post-LOCA. Leak-tightness of the penetration is verified during the Type A test by conducting the test with these valves open.

12. All isolation barriers are located outside containment.

13. Isolation provisions for the CRD insert and withdrawal lines are described in Section 6.2.4.3.1.2.3. The SDV vent and drain valves are Type C tested. Redundant check valves are provided on each main water header (i.e. charging, cooling, drive and exhaust). These valves are Type C tested with water.

14. The isolation provisions for this line consist of a suppression pool water seal, at least one isolation valve outside containment, and a closed system outside containment. The isolation valve is not exposed to the primary containment atmosphere because the line terminates below the minimum water level of the suppression pool. The closed system is missile-protected, seismic Category I, quality group B, and designed to the temperature and pressure conditions that the system will encounter post-LOCA. Because these valves will remain water covered following a LOCA, 10CFR50 Appendix J, Type C testing is not required. System leakage is minimized in accordance with NUREG-0737, Item III.D.1.1. Any leakage out of the closed system will be into the reactor enclosure, thus facilitating collection and treatment.

15. The isolation barrier remains water-filled post-LOCA and may be tested with water.

16. These lines penetrate the diaphragm slab and are not subject to Appendix J leakage rate testing.

17. Table 1.8-2 contains a cross-reference to figure numbers.

18. Feedwater penetrations will remain water-filled post-LOCA as described in Section 6.2.3.2.3.

19. Check valve used instead of flow orifice.

20. The ball valves (XV-141A-E) are Type C tested. It is not practical to leak test the shear valves (XV-140A-E) because squib detonation is required for closure; however, the following tests will be conducted to ensure that these valves will perform their intended function:

    a. The continuity of the explosive charge will be verified at least once per 31 days.

    b. One of the squib charges will be initiated at least once per 24 months. The replacement charge for the shear valve will be from the same manufacturing batch as the one fired, or from another batch that has been certified by having one sample from that batch successfully fired.

       In addition, all charges will be replaced at the manufacturer's recommended intervals. These requirements will be incorporated into the plant administrative procedures and surveillance test procedures.

21. Seismic Category I, Quality Group B instrument line with an excess flow check valve. Because the instrument line is connected to a closed cooling water system inside containment, no flow orifice is provided. The excess flow check valve is subject to operability testing, but no Type C test is performed or required. The line does not isolate during a LOCA and can leak only if the line or instrument should rupture. Leak-tightness of the line is verified during the integrated leak rate test (Type A test) by conducting the test with these valves open.

22. Deleted

Table 6.2-25 (Cont'd)

23. The RHR system safety pressure relief valves will be exempted from the initial LLRT. The relief valves in these lines will be exposed to containment pressure during the initial ILRT and all subsequent ILRTs. In addition, modifications will be performed at the first refueling to facilitate local testing or removal and bench testing of the relief valves during subsequent LLRTs. Justification for exclusion from separate testing of these valves as part of the initial LLRT program is based on the substantial containment isolation barriers provided by the design of the relief valves and the RHR system:

    a. The relief valves are maintained normally closed by their springs.

    b. The relief valves are oriented such that containment pressure would tend to seat the valve disc and enhance sealing.

    c. The relief valves are not exposed to the primary containment atmosphere because the lines terminate below the minimum water level of the suppression pool.

    d. The lines outside containment are part of a closed system which is missile-protected, Seismic Category I, quality group B, and designed to the temperature and pressure conditions that the system will encounter.

    e. System leakage will be minimized in accordance with NUREG-0737 Item III.D.1.1.

    f. Any leakage out of the system will be into the reactor enclosure, thus facilitating collection and treatment.

    g. Those relief valves that are flanged to facilitate removal will be equipped with double O-ring seal assemblies on the flange closest to primary containment.

24. Valve 41-1016 is an outboard isolation barrier for penetrations X-9A, B and X-44. Leakage through valve 41-1016 is included in the total for penetration X-44 only.

25. Butterfly valves are flanged. Those that serve as inboard isolation valves are equipped with double O-ring seal assemblies on the flange closest to primary containment. These seals are leak rate tested by pressurizing between the O-rings.

26. Relief valves PSV-51-1F030A, B, and C are flanged to facilitate removal and ISI testing. PSV-51-1F030D will be flanged prior to the end of the first refueling outage. In all cases, the flanges closest to primary containment will be equipped with double O-ring seal assemblies prior to the end of the first refueling outage. The seals will be leak rate tested by pressurizing between the O-rings. In the interim, the flanged valves are equipped with gasketed connections. The connections are exposed to suppression pool water and are tested during the integrated leak rate test. In addition, they are inspected as part of the system leakage reduction program (Section 6.2.8).

27. Penetration is sealed by a flange with double O-ring seals. Both the TIP purge supply (Penetration X-35B) and the TIP drive tubes (Penetration X-35C through G) are welded to their respective flanges. The seals are leak rate tested by pressurizing between the O-rings.

28. The reactor vessel head seal leak detection line (Penetration X-29A) excess flow check valve is not subject to operability testing. This valve will not be exposed to primary system pressure except under the unlikely conditions of a seal failure where it could be partially pressurized by reactor pressure. Any leakage path is restricted at the source; therefore, this valve need not be operability tested.

29. Valve HV-61-102 is locked closed, the motor operator is normally de-energized and the valve position is controlled procedurally. The valve remains closed during 10 CFR 50, Appendix J Type A testing, and Type C testing is not required. Valve HV-61-202 has been deleted from the Unit 2 design.

30. Inboard valve will be tested from the containment side using a temporary test connection at the open pipe end inside the drywell.

31. Valve HV-55-126 has been used for Unit 1 only.

32. The isolation provisions for this line consist of a suppression pool water seal, blind flange, and a closed system outside containment. The flange is not exposed to the primary containment atmosphere because the line terminates below the minimum water level in the suppression pool. The line is not used to support the system's functions. Because the line will maintain a water seal following a LOCA, 10 CFR 50 Appendix J, Type B testing is not required.

33. The isolation provisions for this line consist of one isolation valve outside containment and a closed system outside containment. A single active failure can be accommodated. The closed system does not communicate with the outside atmosphere, meets Seismic Category I and Safety Class 2 design requirements, designed to temperature and pressure conditions that the system will encounter post-LOCA, is protected from a HELB, is missile-protected, and is capable of being leak tested.

34. Type C testing of these valves is not required. A water seal for these lines will be maintained for 30 days.

Table 6.2-26

REMOTELY ACTUATED VALVES REQUIRED FOR POSTACCIDENT SYSTEM ISOLATION[1]

System	Boundary Valve	Location	Normal Valve Position[2]	Postaccident Position[3]	Actuation Signal[4]
HPCI	HV-F008	HPCI to CST (Test Bypass)	Closed	Closed	B, H
	HV-F011	HPCI/RCIC Test Return to CST	Closed	Closed	B, H, IA
	HV-F025	HPCI Vacuum Tank Drain	Open	Closed	IB
	HV-F026	HPCI Vacuum Tank Drain	Closed	Closed	IB
	HV-F028	HPCI Steam Line Drain	Open	Closed	IB
	HV-F029	HPCI Steam Line Drain	Open	Closed	IB
RCIC	HV-F004	RCIC Vacuum Tank Drain	Closed	Closed	IC
	HV-F005	RCIC Vacuum Tank Drain	Open	Closed	IC
	HV-F022	RCIC to CST (Test Bypass)	Closed	Closed	B, ID
	HV-F025	RCIC Steam Line Drain	Open	Closed	1C
	HV-F026	RCIC Steam Line Drain	Open	Closed	IC
RHR					
	HV-F040	RHR to Liquid Radwaste	Closed	Closed	H, A
	HV-F049	RHR to Liquid Radwaste	Closed	Closed	H, A

Table 6.2-26 (Cont'd)

System	Boundary Valve	Location	Normal Valve Position[2]	Postaccident Position[3]	Actuation Signal[4] [6]
RHR	HV-F079A, B	RHR Sample Isolation	Closed	Closed	H, A
	HV-F080A, B	RHR Sample Isolation	Closed	Closed	H, A
Containment Atmospheric Control	HV-116	Nitrogen Purge Supply	Closed	Closed	B, H
Reactor Enclosure HVAC	HV-030/031	Drywell Purge Exhaust	Closed	Closed	B, H, R, T
	HV-107/108	Reactor Enclosure Air Supply	Open	Closed	B, H, R, T
	HV-117/118	Refueling Floor Air Supply	Open	Closed	R, T
	HV-141/142	Reactor Enclosure Equipment Comp. Exhaust	Open	Closed	B, H, R, T
	HV-157/158	Reactor Enclosure Exhaust	Open	Closed	B, H, R, T
	HV-167/168	Refueling Floor Exhaust	Open	Closed	R, T
CRD Scram Discharge	XV-F010	Scram Discharge Piping Vent	Open	Closed	RPS
	XV-F180	Scram Discharge Piping Vent	Open	Closed	RPS
	XV-F011	Scram Discharge Piping Drain	Open	Closed	RPS
	XV-F181	Scram Discharge Piping Drain	Open	Closed	RPS

Table 6.2-26 (Cont'd)

(1) Closure of these valves establishes a redundant boundary for potentially contaminated systems. Containment isolation valves that also provide system isolation are not included in this table (see Table 6.2-17). Where Unit 1 valves are listed, the design is typical for Unit 2.

(2) Normal valve position (open or closed) is the position during normal power operation of the reactor.

(3) Postaccident position is the required position of the valve during DBA conditions.

(4) Actuation signal codes

Signal	Description
A	Reactor vessel level 3 trip (a scram occurs at this level also)
B	Reactor vessel level 2 trip
C	Reactor vessel level 1 trip (main steam line isolation occurs at this level)
G	High drywell pressure and low reactor vessel pressure
H	High drywell pressure
IA	Interlocked to close when any of the HPCI (F041) or RCIC suppression pool suction valves (HV49-F029 or HV49-F031) open
IB	Interlocked to close when the HPCI turbine steam supply isolation valve (F001) opens
IC	Interlocked to close when the RCIC turbine steam supply isolation valve (F045) opens
ID	Interlocked to close when the RCIC suppression pool suction valves (F029 or F031) open
R	High radioactivity in reactor enclosure or refueling floor ventilation exhaust ducts, as applicable
T	Low differential pressure between the outside atmosphere and either the secondary containment or refueling area, as applicable
RPS	Reactor Protection System Scram Signal

(5) DELETED

(6) With the Reactor Enclosure Secondary Containment Zones I or II interlocked with Refuel Area Secondary Containment Zone III, The Reactor Enclosure HVAC valve isolation signals are combined for all associated valves as follows: B, H, R, T. In addition, the same valves isolate on RE Vent. Exh. High Rad (S) and Outside Atmos. to RE - Low DP (U).

Table 6.2-27

ESSENTIAL/NONESSENTIAL SYSTEMS

	ESSENTIAL	COMMENTS
SLCS	Yes	Should be available as backup to CRD system.
LPCI	Yes	Safety System
HPCI	Yes	Safety System
Core Spray	Yes	Safety System
Service Water	No	Not required for shutdown.
CAC	Yes	Combustible gas control function necessary to monitor and control containment hydrogen/oxygen levels.
ADS	Yes	Safety System/control RPV pressure
SGTS	Yes	Necessary to control emissions to environment.
RECW	No	Not required for DBA, but necessary for the recirculation cleanup system operation and fuel pool heat exchangers.
RCIC	Yes	Necessary for core cooldown following isolation from the turbine condenser and feedwater makeup.
ESW	Yes	Necessary to remove heat following accident. Includes the UHS.
RHRSW	Yes	Necessary to remove heat following accident. Includes the UHS.
PCIG	No	Not required for shutdown.
Compressed Air	No	Not required for shutdown.
Main Steam	No	Not required for shutdown.
Feedwater Line	No	Not required for shutdown, except for the portion to which the RCIC and HPCI systems connects.
Sampling Systems	No	Not required for shutdown. Some sampling capability will be provided for postaccident assessment in accordance with NUREG-0737 Item II.B.3.

Table 6.2-27 (Cont'd)

	ESSENTIAL	COMMENTS
CRD System	Yes	Parts of system are necessary for reactor shutdown.
RWCU	No	Not required for shutdown.
Radwaste Collection	No	Not required for shutdown.
Recirculation System	No	Not required for shutdown.
RHR Heat Exchangers	Yes	Main heat sink during isolation.
RHR Shutdown Cooling	Yes	Not essential, but desirable to use if available. Not redundant, but safety-grade.
RHR Containment/Suppression Spray	Yes	Necessary to control pressure.
RHR - Suppression Pool Cooling	Yes	Main heat sink during isolation.
Drywell Chilled Water	No	Not required for shutdown, but desirable to keep running.
Clarified Water	No	Not required for shutdown.
Condensate	No	Not required for shutdown.
Fuel Pool Cooling	No	Not required for shutdown but continuous pool cooling is desired. Seismic Category I makeup line is provided.
Control Drywell Purge	Yes	Backup to hydrogen control.
MSIV Alternative Drain Pathway	Yes	Ensures that highly radioactive fluids are confined to the reactor building.
TIP System	No	Not required for shutdown.
Fire Protection System	Yes	Availability is essential for shutdown following a fire.
Makeup Demineralizer	No	Not required for shutdown.
ECCS Fill System	Yes	Required to ensure ECCS operability.
Feedwater Fill System	Yes	Required to mitigate radiological consequences.

Table 6.2-27 (Cont'd)

	ESSENTIAL	COMMENTS
Primary Containment Leak Test System	No	Not required for shutdown.
Suppression Pool Cleanup System	No	Not required for shutdown.
Long-Term ADS Gas Supply	Yes	Long-term backup to ADS accumulators inside containment.

Table 6.2-28

REACTOR ENCLOSURE AND REFUELING AREA SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION VALVES-SEPERATE ZONE SYSTEM ALIGNMENT

REACTOR ENCLOSURE (ZONE I) VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS [a]
1. Reactor Enclosure Ventilation Supply Valve HV-76-107	5	B,H,S,U
2. Reactor Enclosure Ventilation Supply Valve HV-76-108	5	B,H,S,U
3. Reactor Enclosure Ventilation Exhaust Valve HV-76-157	5	B,H,S,U
4. Reactor Enclosure Ventilation Exhaust Valve HV-76-158	5	B,H,S,U
5. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-141	5	B,H,S,U
6. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-142	5	B,H,S,U
7. Drywell Purge Exhaust Valve HV-76-30	5	B,H,S,U,R,T
8. Drywell Purge Exhaust Valve HV-76-31	5	B,H,S,U,R,T
9. Drywell Purge Exhaust Inboard Valve HV-57-214 (Unit 2)	5	B,H,S,U,W,R,T
10. Drywell Purge Exhaust Outboard Valve HV-57-215 (Unit 2)	6	B,H,S,U,W,R,T
11. Suppression Pool Purge Exhaust Inboard Valve HV-57-204 (Unit 2)	5	B,H,S,U,W,R,T
12. Suppression Pool Purge Exhaust Outboard Valve HV-57-212 (Unit 2)	6	B,H,S,U,W,R,T

TABLE 6.2-28 (Cont'd)

REACTOR ENCLOSURE (ZONE II)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS [a]
1. Reactor Enclosure Ventilation Supply Valve HV-76-207	5	B,H,S,U
2. Reactor Enclosure Ventilation Supply Valve HV-76-208	5	B,H,S,U
3. Reactor Enclosure Ventilation Exhaust Valve HV-76-257	5	B,H,S,U
4. Reactor Enclosure Ventilation Exhaust Valve HV-76-258	5	B,H,S,U
5. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-241	5	B,H,S,U
6. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-242	5	B,H,S,U
7. Drywell Purge Exhaust Valve HV-76-30	5	B,H,S,U,R,T
8. Drywell Purge Exhaust Valve HV-76-31	5	B,H,S,U,R,T
9. Drywell Purge Exhaust Inboard Valve HV-57-114 (Unit 1)	5	B,H,S,U,W,R,T
10. Drywell Purge Exhaust Outboard Valve HV-57-115 (Unit 1)	6	B,H,S,U,W,R,T
11. Suppression Pool Purge Exhaust Inboard Valve HV-57-104 (Unit 1)	5	B,H,S,U,W,R,T
12. Suppression Pool Purge Exhaust Outboard Valve HV-57-112 (Unit 1)	6	B,H,S,U,W,R,T

(a) See LGS Technical Specification 3.3.2, Table 3.3.2-1 for isolation signals that operate each automatic isolation valve.

Table 6.2-28 (Cont'd)

REFUELING AREA (ZONE III)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS [a]
1. Refueling Area Ventilation Supply Valve HV-76-117 (Unit 1)	5	R,T
2. Refueling Area Ventilation Supply Valve HV-76-118 (Unit 1)	5	R,T
3. Refueling Area Ventilation Exhaust Valve HV-76-167 (Unit 1)	5	R,T
4. Refueling Area Ventilation Exhaust Valve HV-76-168 (Unit 1)	5	R,T
5. Refueling Area Ventilation Supply Valve HV-76-217 (Unit 2)	5	R,T
6. Refueling Area Ventilation Supply Valve HV-76-218 (Unit 2)	5	R,T
7. Refueling Area Ventilation Exhaust Valve HV-76-267 (Unit 2)	5	R,T
8. Refueling Area Ventilation Exhaust Valve HV-76-268 (Unit 2)	5	R,T
9. Drywell Purge Exhaust Valve HV-76-030	5	B,H,S,U,R,T
10. Drywell Purge Exhaust Valve HV-76-031	5	B,H,S,U,R,T
11. Drywell Purge Exhaust Inboard Valve HV-57-114 (Unit 1)	5	B,H,S,U,W,R,T
12. Drywell Purge Exhaust Outboard Valve HV-57-115 (Unit 1)	6	B,H,S,U,W,R,T
13. Suppression Pool Purge Exhaust Inboard Valve HV-57-104 (Unit 1)	5	B,H,S,U,W,R,T
14. Suppression Pool Purge Exhaust Outboard Valve HV-57-112 (Unit 1)	6	B,H,S,U,W,R,T
15. Drywell Purge Exhaust Inboard Valve HV-57-214 (Unit 2)	5	B,H,S,U,W,R,T
16. Drywell Purge Exhaust Outboard Valve HV-57-215 (Unit 2)	6	B,H,S,U,W,R,T
17. Suppression Pool Purge Exhaust Inboard Valve HV-57-204 (Unit 2)	5	B,H,S,U,W,R,T,
18. Suppression Pool Purge Exhaust Outboard Valve HV-57-212 (Unit 2)	6	B,H,S,U,W,R,T

(a) See UFSAR Table 6.2-17, note 5 for isolation signals that operate each automatic isolation valve.

Table 6.2-29

REACTOR ENCLOSURE AND REFUELING AREA SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION VALVES-COMBINED ZONE SYSTEM ALIGNMENT

RX / REFUEL ENCL. (ZONE I & III)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS [a]
1. Reactor Enclosure Ventilation Supply Valve HV-76-107	5	B,H,S,U,R,T
2. Reactor Enclosure Ventilation Supply Valve HV-76-108	5	B,H,S,U,R,T
3. Reactor Enclosure Ventilation Exhaust Valve HV-76-157	5	B,H,S,U,R,T
4. Reactor Enclosure Ventilation Exhaust Valve HV-76-158	5	B,H,S,U,R,T
5. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-141	5	B,H,S,U,R,T
6. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-142	5	B,H,S,U,R,T
7. Drywell Purge Exhaust Valve HV-76-30	5	B,H,S,U,R,T
8. Drywell Purge Exhaust Valve HV-76-31	5	B,H,S,U,R,T
9. Drywell Purge Exhaust Inboard Valve HV-57-214 (Unit 2)	5	B,H,S,U,W,R,T
10. Drywell Purge Exhaust Outboard Valve HV-57-215 (Unit 2)	6	B,H,S,U,W,R,T
11. Suppression Pool Purge Exhaust Inboard Valve HV-57-204 (Unit 2)	5	B,H,S,U,W,R,T
12. Suppression Pool Purge Exhaust Outboard Valve HV-57-212 (Unit 2)	6	B,H,S,U,W,R,T
13. Refueling Area Ventilation Supply Valve HV-76-117	5	B,H,S,U,R,T
14. Refueling Area Ventilation Supply Valve HV-76-118	5	B,H,S,U,R,T
15. Refueling Area Ventilation Exhaust Valve HV-76-167	5	B,H,S,U,R,T
16. Refueling Area Ventilation Exhaust Valve HV-76-168	5	B,H,S,U,R,T
17. Refueling Area Ventilation Supply Valve HV-76-217 (Unit 2)	5	B,H,S,U,R,T
18. Refueling Area Ventilation Supply Valve HV-76-218 (Unit 2)	5	B,H,S,U,R,T
19. Refueling Area Ventilation Exhaust Valve HV-76-267 (Unit 2)	5	B,H,S,U,R,T
20. Refueling Area Ventilation Exhaust Valve HV-76-268 (Unit 2)	5	B,H,S,U,R,T

TABLE 6.2-29 (Cont'd)

ZONE I & III (Cont'd)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS [a]
21. Drywell Purge Exhaust Inboard Valve HV-57-114	5	B,H,S,U,W,R,T
22. Drywell Purge Exhaust Outboard Valve HV-57-115	6	B,H,S,U,W,R,T
23. Suppression Pool Purge Exhaust Inboard Valve HV-57-104	5	B,H,S,U,W,R,T
24. Suppression Pool Purge Exhaust Outboard Valve HV-57-112	6	B,H,S,U,W,R,T

Table 6.2-29 (Cont'd)

RX / REFUEL ENCL.(ZONE II & III)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS [a]
1. Reactor Enclosure Ventilation Supply Valve HV-76-207	5	B,H,S,U,R,T
2. Reactor Enclosure Ventilation Supply Valve HV-76-208	5	B,H,S,U,R,T
3. Reactor Enclosure Ventilation Exhaust Valve HV-76-257	5	B,H,S,U,R,T
4. Reactor Enclosure Ventilation Exhaust Valve HV-76-258	5	B,H,S,U,R,T
5. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-241	5	B,H,S,U,R,T
6. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-242	5	B,H,S,U,R,T
7. Drywell Purge Exhaust Valve HV-76-30	5	B,H,S,U,R,T
8. Drywell Purge Exhaust Valve HV-76-31	5	B,H,S,U,R,T
9. Drywell Purge Exhaust Inboard Valve HV-57-114 (Unit 1)	5	B,H,S,U,W,R,T
10. Drywell Purge Exhaust Outboard Valve HV-57-115 (Unit 1)	6	B,H,S,U,W,R,T
11. Suppression Pool Purge Exhaust Inboard Valve HV-57-104 (Unit 1)	5	B,H,S,U,W,R,T
12. Suppression Pool Purge Exhaust Outboard Valve HV-57-112 (Unit 1)	6	B,H,S,U,W,R,T
13. Refueling Area Ventilation Supply Valve HV-76-117 (Unit 1)	5	B,H,S,U,R,T
14. Refueling Area Ventilation Supply Valve HV-76-118 (Unit 1)	5	B,H,S,U,R,T
15. Refueling Area Ventilation Exhaust Valve HV-76-167 (Unit 1)	5	B,H,S,U,R,T
16. Refueling Area Ventilation Exhaust Valve HV-76-168 (Unit 1)	5	B,H,S,U,R,T
17. Refueling Area Ventilation Supply Valve HV-76-217	5	B,H,S,U,R,T
18. Refueling Area Ventilation Supply Valve HV-76-218	5	B,H,S,U,R,T
19. Refueling Area Ventilation Exhaust Valve HV-76-267	5	B,H,S,U,R,T
20. Refueling Area Ventilation Exhaust Valve HV-76-268	5	B,H,S,U,R,T

Table 6.2-29 (Cont'd)

ZONE II & III (Cont'd)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS [a]
21. Drywell Purge Exhaust Inboard Valve HV-57-214	5	B,H,S,U,W,R,T
22. Drywell Purge Exhaust Outboard Valve HV-57-215	6	B,H,S,U,W,R,T
23. Suppression Pool Purge Exhaust Inboard Valve HV-57-204	5	B,H,S,U,W,R,T
24. Suppression Pool Purge Exhaust Outboard Valve HV-57-212	6	B,H,S,U,W,R,T

(a) See UFSAR Table 6.2-17, note 5 for isolation signals that operate each automatic isolation valve.

6.3 EMERGENCY CORE COOLING SYSTEMS

6.3.1 DESIGN BASES AND SUMMARY DESCRIPTION

Section 6.3.1 provides the design basis for the Emergency Core Cooling System (ECCS) systems and a brief summary design description. Detailed system descriptions are provided in Section 6.3.2. Section 6.3.3 contains the results of the performance analysis.

The current ECCS-LOCA analysis was performed using the SAFER/GESTR-LOCA methodology described in References 6.3-5 and 6.3-7 and supplemented by the implementation of the PRIME methodology described in Reference 6.3-15 with updates as discussed in Reference 6.3-16 and Reference 4.1-1. The SAFER/GESTR analysis was performed assuming the thermal power listed in Table 6.3-1 (which bounds the current plant conditions). The results of the original SAFER/GESTR-LOCA are provided in Reference 6.3-6.

This analysis addressed the fuel types that were in operation at the time. However, those 8x8 (e.g., GE9) and 9x9 (e.g., GE11/GE13) fuel designs are no longer in operation and therefore are not considered when evaluating the limiting peak cladding temperature.

For the implementation of GNF3 fuel (10x10 fuel design) an updated SAFER/PRIME analysis has been performed and documented in Reference 6.3-16. Reference 6.3-18 provides updates to Figures 1-d, 2-d, 3-d, and 4-d of Reference 6.3-16. The input parameters used for the current ECCS-LOCA analysis are listed in Table 6.3-1. Table 6.3-2 summarizes the revised operational sequence of ECCS for the design basis LOCA. The licensing basis peak cladding temperature values for GNF3 fuel are provided in Table 6.3-5.

There exist changes or errors that affect the analysis of record PCT calculation. These changes or errors are documented via 10 CFR 50.46 reporting. After accounting for all changes or errors, the licensing basis PCT remains below the 2,200°F limit. Refer to the docketed annual or thirty-day 10 CFR 50.46(a)(3) report for details.

The original ECCS-LOCA analysis was performed using the methodology described in reference 6.3-1. The input parameters used for the original ECCS-LOCA are listed in Table 6.3-1A. Table 6.3-2A contains the operational sequence of ECCS assumed in the original ECCS-LOCA analysis. Tables 6.3-1A and 6.3-2A are retained for historical purposes, because they provide the basis for most of the ECCS performance parameters specified in the current plant Technical Specifications.

6.3.1.1 Design Bases

6.3.1.1.1 Performance and Functional Requirements

The ECCS is designed to provide protection against postulated LOCA's caused by ruptures in primary system piping. The functional requirements (e.g., coolant delivery rates), specified in Table 6.3-1 for the current ECCS-LOCA analysis and in Table 6.3-1A for the original LOCA analysis, are such that the system performance under all LOCA conditions postulated in the design satisfies the requirements of 10CFR50.46, "Acceptance Criteria for Emergency Core Cooling System for Light-Water-Cooled Nuclear Power Reactors." These requirements are summarized in Section 6.3.3.2. In addition, the ECCS is designed to meet the following requirements:

a. Protection is provided for any primary system line break up to and including the double-ended break of the largest line.

b. Two independent phenomenological cooling methods (flooding and spraying) are provided to cool the core.

c. One high pressure cooling system is provided, which is capable of maintaining the water level above the top of the core and preventing Automatic Depressurization System (ADS) actuation for breaks of lines less than 1-inch nominal diameter.

d. No operator action is required until 10 minutes after an accident, to allow for operator assessment and decision.

e. The ECCS is designed to satisfy all criteria specified in this section for any normal mode of reactor operation.

f. A sufficient water source and the necessary piping, pumps, and other hardware are provided so that the containment and reactor core can be flooded for possible core heat removal following a LOCA.

6.3.1.1.2 Reliability Requirements

The following reliability requirements apply:

a. The ECCS conforms to all licensing requirements and to good design practices of isolation, separation, and common mode failure considerations.

b. In order to meet the above requirements, the ECCS network has built-in redundancy so that adequate cooling can be provided, even in the event of specified failures. As a minimum, the following equipment makes up the ECCS:

1. One HPCI system
2. Two Core Spray (CS) loops
3. Four Low Pressure Coolant Injection (LPCI) loops
4. One ADS

c. The ECCS is designed so that a single active or passive component failure, including power buses, electrical and mechanical parts, cabinets, and wiring, cannot disable the ADS.

d. If there is a break in a pipe that is not a part of the ECCS, no single active component failure in the ECCS, including all common and support components, prevents automatic initiation and successful operation of less than one of the following combinations of ECCS equipment:

1. Three LPCI loops, one CS loop and the ADS and HPCI (i.e., single diesel generator failure). If the single failure occurs in a diesel generator that supplies power to an ESW pump, the diesel generator in the other unit is needed to support the other ESW pump that supplies that loop.

2. Four LPCI loops, two CS loops and the ADS (i.e., HPCI failure)

e. If there is a break in a pipe that is a part of the ECCS, no single active component failure in the ECCS, including all common and support components, prevents automatic initiation and successful operation of less than one of the following combinations of ECCS equipment:

1. Three LPCI loops and the ADS
2. Two LPCI loops, one CS loop, and the ADS and HPCI

These are the minimum ECCS combinations which result after assuming any failure (from d. above), and assuming that the ECCS line break disables the affected loop/system.

f. Long-term (later than 10 minutes after initiation signal) cooling requirements call for the removal of decay heat via the RHRSW system. In addition to the break which initiated the loss-of-coolant event, the system can sustain one failure, either active or passive, and have at least one low pressure ECCS pump (LPCI or CS) operating for makeup, one RHR pump with a heat exchanger, and 100% RHRSW flow to the heat exchanger operating for heat removal.

g. Offsite ac power is the preferred source of ac power for the ECCS network, and every reasonable precaution is made to assure its high availability. However, onsite safeguard ac power has sufficient diversity and capacity to meet all the above requirements, even if offsite ac power is not available.

h. The onsite diesel fuel reserve is in accordance with IEEE 308 (1974) criteria.

i. The diesel load configuration is one LPCI pump and one CS pump, connected to a single diesel generator (4 sets per unit).

j. Electrical systems which interface with, but are not part of, the ECCS are designed and operated so that failure(s) in the interfacing systems do not propagate to, and/or affect the performance of, the ECCS.

k. 1. Nonsafety-related electrical systems in the accident unit interfacing with the Class 1E buses are automatically shed from the Class 1E buses when a LOCA signal exists.

2. Nonsafety-related electrical systems in the nonaccident unit will remain connected to the Class 1E buses when a LOCA signal exists in the other unit.

l. No more than one storage battery is connectable to a dc power bus.

m. Each fluid loop/system of the ECCS network, including flow rate and sensing networks, is capable of being tested during shutdown. All active components are capable of being tested during plant operation, including logic required to automatically initiate component action.

n. Provisions for testing the ECCS network components (electronic, mechanical, hydraulic and pneumatic, as applicable) are installed in such a manner that they are an integral and nonseparable part of the design.

o. While a break in a non-ECCS or ECCS pipe concurrent with a single active component failure in an ECCS or support component will result in remaining combinations of ECCS as described in items d. and e. above, certain technical specification limiting conditions for operation (LCOs) are based on ECCS requirements as given in NEDO-24708A. This document, prepared in response to NRC questions arising from licensee responses to I. E. Bulletin 79-08 (Events relevant to boiling water power reactors identified during Three Mile Island incident), specifies the minimum ECCS system requirements to successfully terminate a transient or LOCA initiating event (with scram) assuming multiple failures with realistic conditions. For the postulated suction line breaks (including DBA), one low pressure ECCS (one LPCI pump or one CS loop) and ADS to depressurize thereby allowing the low-pressure ECCS to inject is adequate to reflood the vessel and maintain core cooling sufficient to preclude fuel damage. NEDC-30936P-A, specifically applicable to LGS and supplemented by 006N4699, references NEDO-24708A and reaffirms that one low pressure ECCS will reflood the vessel and maintain core cooling. It adds the advisory that for a large break LOCA, following 2 hours of LPCI injection, an alternate cooling path may be necessary for long term core cooling. This is because LPCI injecting directly into the core shroud could possible keep the body of water around the core substantially subcooled, quenching any steam cooling effects.

6.3.1.1.3 ECCS Requirements for Protection from Physical Damage

The ECCS piping and components are protected against damage from the effects of movement, thermal-stresses, the effects of the LOCA, and the SSE.

The ECCS is protected against the effects of pipe whip, which might result from piping failures up to, and including, the design basis event LOCA. This protection is provided by separation, pipe whip restraints, or energy-absorbing materials if required. One of these three methods is applied to provide protection against damage to piping and components of the ECCS, which otherwise could reduce ECCS effectiveness to an unacceptable level.

For the purpose of mechanical separation ECCS components are divided into two divisions. The Division 1 ECCS components include the following:

a. Core spray loop A

b. RHR loop A and RHR-LPCI loop C

c. ADS

The Division 2 ECCS components include the following:

a. Core spray loop B

b. RHR loop B and RHR-LPCI loop D

c. HPCI

With the exception of the RHR pumps, each of the ECCS pumps and its associated components are located in individual compartments within the reactor enclosure. The two RHR pumps in each division are located in a common compartment. This compartmentalization ensures that

environmental disturbances such as fire, pipe rupture, flooding, etc., affecting one system do not affect the remaining systems. For ECCS mechanical components located outside the pump compartments, such as the outboard containment isolation valves, separation between the different divisions is provided by distance or by locating the components in different compartments.

Electrical separation is described in Sections 7.1 and 8.3.

6.3.1.1.4 ECCS Environmental Design Basis

Each loop/system of the ECCS injection network, except the HPCI system, has a safety-related injection/isolation testable check valve located in piping within the drywell. The HPCI system injects through one of the core spray spargers and through the feedwater sparger, and the (non-ECCS) RCIC system injects through the feedwater system. However, both systems have isolation valves in the drywell portion of their steam supply piping. No portion of the ECCS and RCIC piping is subject to drywell flooding, since water drains into the suppression chamber through the downcomers. The valves are qualified for the following environmental conditions:

a. Normal and upset plant operating ambient temperatures, relative humidities, and pressures as discussed for each area of the drywell in Section 3.11.

b. Envelope-of-accident conditions for temperature, relative humidity, and pressure within the drywell for various time periods following the accident as discussed in Section 3.11.

c. Normal and envelope-of-accident radiation environment (gamma and neutron) as discussed in Section 3.11.

The portions of ECCS and RCIC piping and equipment located outside the drywell and within the secondary containment are qualified for the following environmental conditions:

a. Normal and upset plant operating ambient temperatures, relative humidities, and pressures as discussed in Section 3.11.

b. Envelope-of-accident conditions for temperature, relative humidity, and pressure for various time periods following the accident as discussed in Section 3.11.

c. Normal and envelope-of-accident radiation environment (gamma and neutron) as discussed in Section 3.11.

6.3.1.2 Summary Descriptions of ECCS

The ECCS injection network is comprised of a HPCI system, a low pressure CS system, and the LPCI mode of the RHR system. These systems are briefly described here as an introduction to the more detailed system design descriptions provided in Section 6.3.2. The ADS, which assists the injection network under certain conditions, is also briefly described. BWRs with the same ECCS design are listed in Table 1.3-2.

6.3.1.2.1 High Pressure Coolant Injection System

The HPCI system pumps water into the reactor vessel through one of the CS spargers and through one of the feedwater sparger. The primary purpose of HPCI is to provide sufficient coolant to the reactor vessel following a small break LOCA until reactor pressure is below the pressure at which

CS operation or LPCI mode of RHR system operation maintains core cooling. The HPCI system is also required to provide sufficient coolant to the reactor vessel to prevent the actuation of the ADS and maintain reactor level above the top of the reactor core in the event of a small pipe break with a break size of one-inch diameter or less.

6.3.1.2.2 Core Spray System

The two CS system loops pump water into peripheral ring spray spargers, mounted above the reactor core. The primary purposes of the CS loops are to provide inventory makeup and spray cooling during large breaks in which the core is calculated to uncover. Following ADS initiation, CS provides inventory makeup following a small break.

6.3.1.2.3 Low Pressure Coolant Injection Subsystem

LPCI is an operating mode of the RHR system. Four pumps deliver water from the suppression pool to separate vessel nozzles, which lead to direct discharge inside the core shroud region (four loops). The primary purpose of LPCI is to provide vessel inventory makeup following large pipe breaks. Following ADS initiation, LPCI provides inventory makeup following a small break.

6.3.1.2.4 Automatic Depressurization System

The ADS utilizes five of the reactor SRVs to reduce reactor pressure during small breaks or after containment isolation, in the event of HPCI failure. When the vessel pressure is reduced to within the design of the low pressure systems (CS and LPCI), these systems provide inventory makeup so that acceptable postaccident temperatures are maintained.

6.3.1.2.5 Management of Gas Accumulation in Fluid Systems

On January 11, 2008, the NRC issued Generic Letter 2008-01, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray (Reference 6.3-12). Generic Letter 2008-01 requested licensees to evaluate the licensing basis, design, testing, and corrective action programs for the Emergency Core Cooling, Decay Heat Removal, and Containment Spray systems to ensure that gas accumulation is maintained less than the amount that challenges operability of these systems, and that appropriate action is taken when conditions adverse to quality are identified. As a consequence, Limerick performed in-depth system reviews for the RHR, HPCI, Cores Spray, and RCIC systems in accordance with the criteria of GL 2008-01, investigating whether the existing Licensing Basis, Design Basis, actual field configuration, system restoration processes, and operational procedures would introduce or allow the accumulation of a gas (air) void in system piping. Piping locations in each system that are susceptible to air accumulation are periodically monitored to ensure that the piping systems are maintained sufficiently filled with water. The piping systems addressed in the response to Generic Letter 2008-01 have the potential to develop voids and pockets of entrained gases. Maintaining the pump suction and discharge piping sufficiently full of water is necessary to ensure that the system will perform and will inject the flow assumed in the safety analyses into the Reactor Coolant System or containment upon demand. This will also prevent damage from pump cavitation or water hammer, and pumping of unacceptable quantities on non-condensable gas (e.g., air, nitrogen, hydrogen) into the reactor vessel following an ECCS start signal or during shutdown cooling.

6.3.2 SYSTEM DESIGN

More detailed descriptions of the individual systems, including individual design characteristics of the systems, are covered in detail in Sections 6.3.2.2.1 through 6.3.2.2.4. The following discussion provides details of the combined systems, and in particular, those design features and characteristics which are common to all systems.

6.3.2.1 Piping and Instrumentation and Process Diagrams

The P&IDs for the ECCS and the process diagrams which identify the various operating modes of each system are identified in Section 6.3.2.2.

6.3.2.2 Equipment and Component Descriptions

The starting signal for the ECCS comes from at least two independent and redundant sensors of high drywell pressure and low reactor water level. The ECCS is actuated automatically, and is designed to require no operator action during the first 10 minutes following the accident. A time sequence for starting of the systems is provided in Table 6.3-2 for the current ECCS-LOCA analysis, and in Table 6.3-2A for the original ECCS-LOCA analysis.

Electric power for operating the ECCS (except the dc powered HPCI and ADS systems) is from the preferred offsite ac power supply.

Upon loss of the preferred source, operation is from the onsite standby diesel generators. Four diesel generators supplying individual ac buses in a unit have sufficient diversity and capacity so that any three units satisfy minimum ECCS requirements, which are stated in Section 6.3.1.1.2.b. One CS pump (2 loop) and one LPCI loop are powered by each ac bus. Section 8.3 contains a more detailed description of the power supplies for the ECCS.

Regulatory Guide 1.1

Regulatory Guide 1.1 prohibits design reliance on pressure and/or temperature transients expected during a LOCA for assuring adequate NPSH. The requirements of this guide are applicable to the HPCI, CS, and LPCI pumps.

The BWR design conservatively assumes 0 psig containment pressure and maximum expected temperatures of the pumped fluids. Thus, no reliance is placed on pressure and/or temperature transients to ensure adequate NPSH.

Requirements for NPSH at the centerline of the pump suction nozzles for each pump are given in drawings E41-1020-G-002 (HPCI), E21-1020-G-001 (CS), and E11-1020-G-002 (LPCI).

6.3.2.2.1 High Pressure Coolant Injection System

The HPCI system consists of a steam turbine-driven, constant flow pump assembly and associated system piping, valves, controls, and instrumentation. The P&IDs for the HPCI, drawings M-55 and M-56, show the system components and their arrangement. The HPCI process diagram, drawing E41-1020-G-002, shows the design operating modes of the system.

The principal HPCI equipment is installed in the reactor enclosure. Suction piping comes from both the CST and the suppression pool. Injection water is piped to the reactor via the CS Loop B sparger pipe and through the Loop A feedwater sparger. The steam supply for the turbine is piped from a main steam

line in the primary containment. This piping is provided with an isolation valve on each side of the primary containment. Remote controls for valve and turbine operation are provided in the main control room. The controls and instrumentation of the HPCI system are described, illustrated, and evaluated in detail in Section 7.3.

The HPCI system provides coolant to the reactor vessel following a small break LOCA until reactor vessel pressure is below the pressure at which CS operation or LPCI operation maintains core cooling. The HPCI system is also capable of providing sufficient coolant to the reactor vessel to prevent the actuation of the ADS and ensure that the reactor core remains covered in the event of a small pipe break with a break size of one-inch diameter or less. This permits the plant to be shut down, while maintaining sufficient reactor vessel inventory until the reactor is depressurized. For design basis events HPCI needs to operate for a maximum of six hours in order to fulfill its safety functions.

The HPCI system is designed to pump water into the reactor vessel for a wide range of pressures in the reactor vessel. The normal alignment of the HPCI system initially injects water from the CST instead of water from the suppression pool. An alternate alignment to the suppression pool is also available during periods whan the CST is not available. This provides reactor grade water to the reactor vessel. Water is pumped into the reactor vessel through a core spray sparger and a feedwater sparger; this flow split is provided by orificing.

The pump assembly is located below the water levels of the CST and the suppression pool, to ensure positive suction head to the pumps. Pump NPSH requirements are met by providing adequate suction head and adequate suction line size.

The HPCI turbine-pump assembly and piping are protected from the detrimental physical effects of pipe whip, flooding, and high temperature.

The HPCI turbine is driven by steam from the reactor vessel, generated by decay and residual heat. The steam is extracted from a main steam line upstream of the MSIVs. Inboard and outboard HPCI isolation valves in the steam line to the HPCI turbine are normally open. This keeps the piping to the turbine at an elevated temperature to permit rapid startup of the HPCI system. Signals from the HPCI control system open or close the turbine control valve adjacent to the turbine. The outboard isolation valve has a bypass line containing a normally closed valve. This bypass line permits pressure equalization and drainage around the isolation valve, and downstream line warmup prior to opening of the isolation valve.

A condensate drain pot is provided upstream of the turbine stop valve to prevent the HPCI steam supply line from filling with water. The drain pot normally routes the condensate to the main condenser, but upon receipt of a HPCI initiation signal and subsequent opening of the steam supply valve, or a loss of control air pressure signal, isolation valves on the condensate line automatically close.

The turbine power is controlled by a flow controller that senses pump discharge flow and provides a variable signal to the turbine governor to maintain constant pump discharge flow over the pressure range of operation. The turbine control system is capable of limiting speed overshoot to 15% of maximum operating speed on a quick start, while driving only the pump inertia load.

Limit switches are provided on the turbine control (governor) valves(s) to indicate fully open and closed positions. Both lights are "on" in midposition.

As reactor steam pressure decreases, the HPCI turbine throttle valves open further to pass the steam flow required to provide the necessary pump flow. The capacity of the system is selected to provide sufficient core cooling to prevent clad temperatures in excess of the limits (10CFR50.46) while the pressure in the reactor vessel is above the pressure at which CS and LPCI become effective.

Exhaust steam from the HPCI turbine is discharged to the suppression pool. A drain pot at the low point in the exhaust line collects moisture present in the steam. Collected moisture is discharged through an orifice to the barometric condenser.

The HPCI turbine gland seals are vented to the barometric condenser for cooling. Noncondensable gases from the barometric condenser are pumped to the reactor enclosure equipment compartment exhaust filter during normal plant operation and to the RERS during reactor enclosure isolation.

A redundant system of check valves and isolation valves is installed as a vacuum breaker line, which connects the air space in the suppression chamber with the HPCI turbine exhaust line. This eliminates any possibility of water from the suppression pool being drawn into the HPCI turbine exhaust line. The isolation valves in this vacuum breaker line automatically close via a combination of low HPCI steam supply pressure and high drywell pressure. Test connections are provided on either side of the two check valves.

Potential damage from water hammer in the HPCI turbine supply and exhaust lines is prevented by the use of design features such as exhaust line vacuum breakers, drain pots upstream and downstream of the turbine, and a sparger in the turbine exhaust line in the suppression pool. Further discussion of water hammer is provided in Section 1.12.3.

Startup of the HPCI system is completely independent of ac power. Only dc power from the station battery and steam extracted from the nuclear system are necessary.

The various operations of the HPCI components are summarized below.

The HPCI controls automatically start the system and bring it to design flow rate within 60 seconds from receipt of a RPV low water level signal, or a primary containment (drywell) high pressure signal. Refer to Chapter 15 for more analysis details.

The HPCI turbine is directly shut down by any of the following signals:

a. Turbine overspeed: this prevents damage to the turbine.

b. RPV high water level: this indicates that core cooling requirements are satisfied.

c. HPCI pump low suction pressure: this prevents damage to the pump due to loss of flow.

d. HPCI turbine exhaust high pressure: this indicates a turbine or turbine control malfunction.

e. Isolation of either inboard or outboard HPCI isolation valves.

f. Low steam supply pressure.

If an initiation signal is received after the turbine is shut down, the system restarts automatically, if no shutdown signal exists.

Because the steam supply line to the HPCI turbine is part of the RCPB, certain signals automatically isolate this line, causing shutdown of the HPCI turbine. Automatic shutoff of the steam supply is described in Section 7.3. However, automatic depressurization and the low pressure systems of the ECCS act as backup; and automatic shutoff of the steam supply does not negate the ability of the ECCS to satisfy the safety objective.

In addition to the automatic operational features of the system, provisions are included for remote manual startup, operation, and shutdown (provided automatic initiation or shutdown signals do not exist).

HPCI operation automatically actuates the following valves:

a. HPCI pump discharge shutoff valve, if closed (F007)

b. HPCI steam supply shutoff valve (F001)

c. HPCI turbine stop valve

d. HPCI turbine control valves

e. HPCI steam line drain isolation valve (F028, F029)

f. HPCI test valves, if open (F008, F011, F071)

g. Minimum flow bypass valve (F012)

h. HPCI pump discharge injection valves (F006, F105)

i. HPCI lube oil cooling water valve (F059)

j Condensate pump discharge isolation valves, if open (F025, F026)

Startup of the auxiliary oil pump and proper functioning of the hydraulic control system are required to open the turbine stop and control valves. Operation of the barometric condenser components is required to prevent out-leakage from the turbine shaft seals. Startup of the condenser equipment is automatic, but its failure does not prevent the HPCI system from fulfilling its core cooling objective. Prior to startup of the HPCI turbine, the turbine control system is set to maintain the turbine at the low speed design condition. Upon receipt of an initiation signal, a speed ramp generator module automatically runs the control system toward its high speed design point, thereby controlling the transient acceleration of the turbine. The flow controller then automatically overrides the speed ramp generator, and when rated flow is established, the flow controller signal adjusts the setting of the turbine control so that rated flow is maintained as nuclear system pressure decreases.

A minimum flow bypass is provided for pump protection. The bypass valve automatically opens on low flow, provided pump discharge pressure is above a pressure permissive setpoint (indicates pump is running) and automatically closes on high flow, stop valve closure or steam supply valve closure. When the bypass is open, flow is directed to the suppression pool. A line used for system testing

leads from the HPCI pump discharge line to the CST. The shutoff valves in this line are sequenced to close by the signal that actuates system operation, and valve F011 is interlocked closed when the F041 valve, suppression pool to pump suction valve, is open. All automatically operated valves are capable of remote manual operation.

The normal alignment of the HPCI system is to initially inject water from the CST. An alternate alignment to the suppression pool is also available when the CST is not available. When the water level in the tank falls below a predetermined level or the suppression pool level is high, the pump suction is automatically transferred to the suppression pool. A vortex breaker is located at the suction nozzle of the CST to prevent vortex formation. A calculation has been performed to demonstrate that air core vortex formation will not occur with the CST level at the transfer level, and with the HPCI pumps operating at 5600 gpm. This transfer may also be made from the main control room using remote controls. When the pump suction has been transferred to the suppression pool, a closed-loop is established for recirculation of water escaping from a break.

To ensure continuous core cooling, general containment isolation signals do not operate any HPCI valves. The HPCI system incorporates a relief valve in the pump suction line to protect the components and piping from inadvertent overpressure conditions.

Level instrumentation for the CST and the HPCI suction line are protected from the effects of cold weather. The HPCI suction line and the CST instrument sensing lines that are exposed to the outdoor environment are provided with heat tracing. Indication is provided in the control room if this heat tracing should become inoperative. The CST level instrumentation for control room monitoring is located in the reactor enclosure. The level instrumentation used to automatically transfer the HPCI pump suction from the CST to the suppression pool is located on the portion of the HPCI line in the reactor enclosure and is not subject to the effects of cold weather.

The HPCI pump and piping are designed and located to avoid damage from the physical effects of DBAs, such as pipe whip, missiles, temperature, pressure, and humidity.

The HPCI equipment and support structures are designed in accordance with seismic Category I criteria (Section 3.9). The system is assumed to be filled with water for seismic analysis.

Provisions are included in the HPCI system which permit the HPCI system to be tested. These provisions are:

a. A full flow test line is provided to route water from and to the CST, without entering the RPV.

b. A bypass flow test line is provided to route water from and to the suppression pool, without entering the RPV.

c. Instrumentation is provided to indicate system performance during normal test operations.

d. All MOVs are capable of manual operation for test purposes. During all modes of manual MOV operation using the handswitch from the main control room, a "dead zone" is present for a portion of the valve travel. The "dead zone" is present when the valve is not fully closed and green light only indication exists. If the valve is stopped in the "dead zone", operator action is required to restart the valve.

e. Drains are provided to leak test the major system valves.

Interlocks for the HPCI system are described in Chapter 7. The operating requirement parameters for the components of the HPCI system, listed below, are shown on the process diagram (drawing E41-1020-G-002).

a. One 100% capacity booster and main pump assembly with accessories

b. Piping, valves, and instrumentation for:

1. Steam supply to the turbine

2. Turbine exhaust to the suppression pool

3. Makeup supply from the CST to the pump suction

4. Makeup supply from the suppression pool to the pump suction including pump suction strainers described in Section 6.2.2.2.

5. Pump discharge to the core spray sparger and feedwater line, including a test line to the CST, a minimum flow bypass line to the suppression pool, and a coolant water supply to accessory equipment

The basis for the design conditions is the ASME Section III, "Nuclear Power Plant Components."

A design flow functional test of the HPCI is performed during plant operation by taking suction from the CST, and discharging through the full flow test return line back to the CST. The discharge valve to the core spray and feedwater lines remain closed during the test, and reactor operation is undisturbed. All components of the HPCI system are capable of individual functional testing during normal plant operation. Control system design provides automatic alignment from test to operating mode if system initiation is required. The three exceptions are as follows:

a. The auto/manual station is in "manual" on the flow controller. This feature is required for operator flexibility during system operation.

b. Steam inboard/outboard isolation valves: closure of either or both of these valves requires operator action to properly sequence their opening. An alarm sounds when either of these valves leaves the fully open position.

c. Parts of the system which are bypassed or deliberately rendered inoperable. This is automatically indicated in the control room.

Periodic inspection and maintenance of the turbine-pump unit are conducted in accordance with plant programs and procedures. Other than surveillances required by technical specifications, the types of inspection and maintenance are based on manufacturer’s recommendations and industry guidelines and the frequency is based on industry and site specific experience. Valve position indications and instrumentation alarms are displayed in the control room.

6.3.2.2.1.1 NPSH Available with Suction from the CST

The available NPSH is calculated in accordance with Regulatory Guide 1.1. The following data were used in the calculation:

a. Condensate water level is at el 191'- 7.25" at the bottom of the 34 inch section of pipe HCB-105. This level is approximately 27 ft below the static transfer level (i.e. 0 gpm HPCI flow), which is within the CST nozzle.

b. CST water is at 120°F.

c. Atmospheric pressure is assumed above the condensate water level.

d. $NPSH = h_s - h_{vp} - h_f + h_a$

where:

h_s	=	static head above pump suction nozzle centerline	
	=	191.6 ft to 182.25 ft	= 9.3 ft
h_f	=	friction head loss	= 4.0 ft
h_{vp}	=	vapor pressure (head loss)	= 3.9 ft
h_a	=	atmospheric head	= 34.3 ft
NPSH	=	35.7 ft	

6.3.2.2.1.2 NPSH Available with Suction from the Suppression Pool

The available NPSH is calculated in accordance with Regulatory Guide 1.1. The following data were used in the calculation:

a. Suppression pool is at the minimum postaccident level reached while the pump is running of el 201'-5.64".

b. Suppression pool water is at its maximum temperature for the given operating mode, 170°F.

c. Atmospheric pressure is assumed over the suppression pool.

d. $NPSH = h_s - h_{vp} - h_f + h_a$

where:

h_s	=	static head above pump suction nozzle centerline	
	=	201.47 ft to 182.25 ft	= 19.2 ft
h_f	=	friction head loss (including 2 psi loss across suction strainers)	= 11.7 ft

h_{vp}	=	vapor pressure (head loss)	= 14.2 ft
h_a	=	atmospheric head	= 34.8 ft
NPSH	=	28.1 ft	

6.3.2.2.2 Automatic Depressurization System

If the RCIC system or the HPCI system cannot maintain the reactor water level, the ADS reduces the reactor pressure so that flow from LPCI and/or CS systems enters the reactor vessel in time to cool the core and limit fuel cladding temperature.

The ADS employs five of the nuclear system SRVs to relieve high pressure steam to the suppression pool. The design, number, location, description, operational characteristics, and evaluation of the SRVs and their pneumatic accumulators are discussed in detail in Section 5.2.2. The instrumentation and controls for the ADS are discussed in Section 7.3. Gas supplies for long term operation of ADS are described in Sections 9.3.1.3 and 7.6.

6.3.2.2.3 Core Spray System

Each of the two redundant CS system loops consists of: two 50% capacity centrifugal pumps powered from Class 1E buses; a spray sparger in the reactor vessel above the core (a separate sparger for each CS loop); piping and valves to convey water from the suppression pool to the sparger; and associated controls and instrumentation. A connection to the HPCI system is provided to allow HPCI injection through the CS Loop B vessel connection. The CS P&ID (drawing M-52) presents the system components and their arrangement. The CS process diagram (drawing E41-1020-G-001) shows the design operating modes of the system. A simplified system flow diagram showing system injection into the reactor vessel is included in drawing E41-1020-G-001.

When low water level in the reactor vessel and/or high pressure in the drywell is sensed, and if reactor vessel pressure is low enough, the CS system automatically starts and sprays water into the top of the fuel assemblies to cool the core. The time sequence assumed in the current ECCS-LOCA analysis for CS system operation is given in Table 6.3-2. The time sequence assumed in the original ECCS-LOCA analysis for CS system operation is given in Table 6.3-2A. The CS injection piping enters the vessel, divides, and enters the core shroud at two points near the top of the shroud. A semicircular sparger is attached to each outlet. Nozzles are spaced around the sparger to spray the water radially over the core and into the fuel assemblies.

The CS system is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. However, when CS operates in conjunction with the ADS, the effective core cooling capability of CS is extended to all break sizes because the ADS rapidly reduces the reactor vessel pressure to the CS operating range.

The CS pumps and all MOVs can be operated individually by manual switches located in the control room. Operating indication is provided in the control room by a flowmeter, and valve and pump indicator lights.

To assure continuity of core cooling, signals to isolate the containment do not operate any CS system valves. Suppression pool test return valves isolate on an automatic CS initiation signal.

Loop A and B injection lines are each provided with two isolation valves. One of these valves is a pneumatically-testable check valve located inside the drywell, as close as practical to the reactor vessel. CS injection flow causes this valve to open during LOCA conditions (i.e., no power is required for valve actuation during the LOCA). If the CS line should break outside the containment, the check valve in the line inside the drywell prevents loss of reactor water.

The outer isolation valve on Loop A is a motor-operated gate valve, and the outer isolation valve on Loop B is a pneumatically-testable check valve. These valves are located as close as practicable to the CS discharge line containment penetration. The pneumatically-testable check valve is designed so that air failure will not close the valve against normal flow. Upstream of the HPCI injection connection on Loop B is a motor-operated gate valve which isolates CS Loop B upstream of the valve from HPCI injection pressure. This valve, and the Loop A outer isolation valve are also referred to as the CS injection valves. These valves are capable of opening with the maximum differential pressure across the valve expected for any system operating mode. These valves are normally closed. The containment isolation design of the CS system is discussed in detail in Section 6.2.4.

The CS system piping and components are designed and arranged to avoid unacceptable damage from the physical effect of pipe whip, missiles, high temperature, pressure or humidity. All principal active CS equipment is located outside the primary containment.

A check valve (one per CS pump), flow element, and restricting orifice are provided in the CS discharge line from the pump to the injection valve. The check valve is located below the minimum suppression pool water level, and is provided so that the piping downstream of the valve can be continuously filled with water by the condensate transfer or safeguard piping fill systems (Section 6.3.2.2.6). The flow element is provided to measure system flow rate during LOCA and test conditions, and for automatic control of

the minimum low flow bypass valve. The flow rate is indicated in the main control room. The restricting orifice is sized during preoperational testing of the system to limit system flow to acceptable values, as described on the CS system process diagram.

A low flow bypass line with a motor-operated globe valve connects to the CS discharge line upstream of the check valve on the pump discharge line. The line bypasses water to the suppression pool preventing pump damage when other discharge line valves are closed, or when reactor pressure is greater than the CS system discharge pressure following system initiation. The valve automatically closes when flow in the main discharge line is sufficient.

A normally open motor-operated pump suction valve is provided that can be remote-manually closed to isolate the CS system from the suppression pool should a leak develop in the system. This valve is located as close to the suppression pool penetration as practical. Because the CS system conveys water from the suppression pool, a closed-loop is established for the spray water escaping from the break.

The design pressure and temperature of the system components are based on ASME Section III. The design pressures and temperatures at various points in the system can be obtained from the miscellaneous information blocks on the CS process diagram (drawing E41-1020-G-001).

The CS pumps are located in the reactor enclosure below the water level in the suppression pool, assuring positive pump suction. Pump NPSH requirements are met with the containment at atmospheric pressure. Each CS Pump has a local pressure gauge to indicate the suction head. The pump suction strainers are described in Section 6.2.2.2.

The CS system incorporates relief valves to prevent the components and piping from inadvertent overpressure conditions.

For the CS “A” loop:

- One relief valve located on the pump discharge is set at 500 psig at a capacity of 16 gpm – 10% accumulation to 1340 psig at a capacity of 24 gpm – 10% accumulation.
- One relief valve is located on the suction side of each pump in the “A” loop and is set for 100 psig at a capacity of 10 gpm – 10% accumulation.

For the CS “B” loop:

- One relief valve located on the pump discharge is set at 500 psig at a capacity of 16 gpm – 10% accumulation to 1340 psig at a capacity of 24 gpm – 10% accumulation.
- One relief valve is located on the suction side of each pump in the “B” loop and is set for 100 psig at a capacity of 10 gpm – 10% accumulation.

The CS system piping and support structures are designed in accordance with seismic Category I criteria (Section 3.9). The system is assumed to be filled with water for seismic analysis. The CS system has the capability to be lined up to the CST, with the plant shutdown, to provide a clean water source for pipe flushes, cavity flood-up and as an alternate ECCS make-up volume.

Provisions are included in the design which permit the CS system to be tested. These provisions are:

a. All active CS components are testable during normal plant operation.

b. A full flow test line is provided in each loop of CS to route water to and from the suppression pool without entering the RPV.

c. A suction test line supplying water from the CST is provided to allow the capability to test pump discharge into the RPV during normal plant shutdown.

d. Instrumentation is provided to indicate system performance during normal and test operations.

e. All motor-operated and check valves are capable of operation for test purposes. During all modes of manual MOV operation using the handswitch from the main control room, a "dead zone" is present for a portion of the valve travel. The "dead zone" is present when the valve is not fully closed and green light only indication exists. If the valve is stopped in the "dead zone", operator action is required to restart the valve.

6.3.2.2.4 Low Pressure Coolant Injection Subsystem

The LPCI subsystem is an operating mode of the RHR system. The LPCI subsystem is automatically actuated by low water level in the reactor and/or high pressure in the drywell coincident with low reactor pressure. It uses four motor-driven RHR pumps to draw suction from the suppression pool and inject cooling water flow into the reactor core via separate vessel nozzles and core shroud penetrations.

The LPCI subsystem, like the CS system, is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. However, when LPCI operates in conjunction with the ADS, the effective core cooling capability of LPCI is extended to all break sizes because the ADS rapidly reduces the reactor vessel pressure to the LPCI operating range.

Drawing E41-1020-G-002 shows a process diagram and process data for the RHR system, including the LPCI mode. The RHR system P&ID is shown in drawing M-51.

LPCI operation includes using associated valves, control, instrumentation, and pump accessories. LPCI is normally powered from the preferred ac power source, and from the standby ac power source upon a loss of preferred ac power.

If there is a LOCA, the four loops of the LPCI subsystem inject water into the reactor vessel. Separate power sources are provided for the LPCI injection valves, so that the failure of a single electrical division does not prevent the valves in other divisions from opening.

To ensure continuity of core cooling, signals to isolate the primary containment do not operate any RHR system valves which interfere with the LPCI mode of operation.

The process diagram (E11-1020-G-002) and the P&ID (drawing M-51) indicate that a great many flow paths are available other than the LPCI injection line. However, the low water level and/or high drywell pressure coincident with low reactor pressure signals which automatically initiate the LPCI mode are also used to isolate all other modes of operation and revert other system valves to the LPCI lineup. Inlet and outlet valves from the heat exchangers receive no automatic signals, as the system is designed to provide rated flow to the vessel whether they are open or not. Further discussion of valve logic is provided in Section 7.3.1.1.

A check valve in the pump discharge line is used, together with a discharge line fill system (Section 6.3.2.2.6), to prevent water hammer resulting from starting the pump with a partially drained discharge line.

Further discussion of water hammer is provided in Section 1.12.3.

A flow element in the pump discharge line originates automatic signals for control of the pump minimum flow valve. The minimum flow valve permits a small flow to the suppression pool if sufficient system flow is not available.

There is sufficient system resistance to preclude RHR pump damage due to pump run-out in the LPCI and containment spray operating modes. A combination of valve throttling and flow orifices prevents pump run-out during suppression pool cooling and test modes.

Using the suppression pool as the source of water for LPCI establishes a closed-loop for recirculation of water escaping from a pipe break inside containment.

The design pressures and temperatures at various points in the system, during each LPCI subsystem mode of operation can be obtained from the miscellaneous information blocks on the RHR process diagram (drawing E11-1020-G-002).

LPCI pumps and equipment are described in detail in Section 5.4.7, which also describes the other functions served by the same pumps in other modes of RHR system operation. The RHR heat exchangers are not associated with the emergency core cooling function. The heat exchangers are discussed in Section 5.4.7.2.2. Portions of the RHR system required for accident protection, including support structures, are designed in accordance with seismic Category I criteria (Section 3.9). The LPCI pump characteristic curves are shown in Figure 5.4-15.

The LPCI subsystem incorporates a relief valve on each of the pump discharge lines, which protects the components and piping from inadvertent overpressure conditions. These valves are set as shown in Table 5.4-3.

Provisions are included in the LPCI subsystem to permit testing of the LPCI loops. These provisions are:

a. All active LPCI components are designed to be testable during normal plant operation.

b. A discharge test line is provided for the four pumps to route suppression pool water back to the suppression pool without entering the RPV.

c. Instrumentation is provided to indicate system performance during normal and test operations.

d. All MOVs, AOVs, and check valves are capable of manual operation for test purposes. During all modes of manual MOV operation using the handswitch from the main control room, a "dead zone" is present for a portion of the valve travel. The "dead zone" is present when the valve is not fully closed and green light only indication exists. If the valve is stopped in the "dead zone", operator action is required to restart the valve.

e. Shutdown cooling lines taking suction from the recirculation system permit testing of the pump discharge into the RPV after normal plant shutdown.

f. All relief valves are or will be removable for bench testing during plant shutdown.

6.3.2.2.4.1 NPSH for LPCI Mode

The available NPSH is calculated in accordance with Regulatory Guide 1.1. The following data are used for a typical NPSH calculation:

a. Suppression pool is at its minimum post accident depth, el 199'-11.5".

b. Centerline of pump suction is at el 174'-10.5".

c. Suppression pool water is at its maximum temperature for the given operating mode.

d. Pressure is atmospheric above the suppression pool.

e. Maximum suction strainer losses are 5.0 psi at 11,000 gpm.

$$NPSH = h_{ATM} + h_S - h_{VAP} - h_F$$

where:

h_{ATM} = atmospheric head

h_S = static head

h_{VAP} = vapor pressure head

h_F = frictional head

Operating modes and conditions are given on the process flow diagram (drawing E11-1020-G-002). NPSH requirements are given on the pump curve (Figure 5.4-15).

Case 1 LPCI Pump Run-out (Mode A-2)

Maximum suppression pool temperature is 180°F.

h_{ATM} = 34.94'

h_S = 25.08'

h_{VAP} = 17.85'

h_F = 4.61’

Strainer head loss = 11.85’

NPSH available = 34.94 + 25.08 - 17.85 - 4.61 - 11.85
= 25.71

Case 2 RHR Accident Mode B

Maximum suppression pool temperature assumed is 212°F

h_{ATM} = 35.4'

h_S = 25.08'

h_{VAP} = 35.4'

h_F = 3.8’

Strainer head loss at 10,000 gpm = 10.67’

NPSH available = 35.4 + 25.08 - 35.4 - 3.8’ - 10.67’
= 10.61’

6.3.2.2.5 ECCS NPSH Margin and Vortex Formation

NPSH calculations for ECCS pumps, such as that in the previous section, have shown adequate margin to ensure capability of proper pump operation under accident conditions. This capability will be verified during preoperational testing by verifying expected pump operating parameters at specific operating conditions. The absence of air entrainment and vortex formation in the flow approaching the suction strainers in the suppression pool during ECCS pump operation will also be verified during preoperational testing. Pump performance and pump noise will be monitored during these tests to determine if pumps are sensitive to suction flow conditions in the suppression pool.

6.3.2.2.6 Safeguard Piping Fill System

A requirement of the core cooling systems is that cooling water flow to the RPV be initiated rapidly when the system is called upon to perform its function. This quick-start system capability is provided by quick-opening valves, quick-start pumps, and standby ac power sources. The lag between the signal to start the pump and the initiation of flow into the RPV can be minimized by keeping the core cooling pump discharge lines full. Additionally, if these lines are empty when the systems are called for, the large momentum forces associated with accelerating fluid into a dry pipe could cause physical damage to the piping. Therefore, the safeguard piping fill system is designed to maintain the pump discharge lines in a filled condition.

Since the ECCS discharge lines are elevated above the suppression pool, check or stop-check valves are provided near the pumps to prevent backflow from emptying the lines into the suppression pool. Past experience shows that these valves may leak slightly, producing a small backflow that eventually empties the discharge piping. To ensure that the leakage from the discharge lines is replaced and the lines are always kept filled, suppression pool water is provided for each system of the ECCS by the safeguard piping fill system. There are two safeguard fill pump trains, as shown in drawing M-52. Each fill train and its associated ECCS lines are powered from separate Class 1E electrical divisions. Each fill train also provides water to both of the feedwater lines after a LOCA to prevent bypass leakage, as described in Section 6.2.3.2.3.

During normal plant operating conditions, the safeguard piping fill system (SPFS) is on standby and water from the condensate transfer system is used through different connections to keep the ECCS lines full.

The fill system is a safety-related system and is designed to seismic Category I criteria, as described in Section 3.7. Quality group classification is discussed in Section 3.2. A single failure of an active component in one fill system train will prevent that train from performing its intended function, but will not affect the operation of the other train. When the SPFS is in use, the fill pumps operate continuously, with recirculation back to the suppression pool via two core spray pump suction lines. The pumps are powered from the diesel generators during a LOOP. The pumps are operated from the control room and alarms in the control room indicate low fill pump discharge pressure.

As discussed in Section 5.4.7.1.1.5, all of the components comprising the steam condensing mode of the RHR system have either been abandoned in place or physically removed from the plant. Therefore, the mode is no longer functional.

6.3.2.3 Applicable Codes and Classification

The applicable codes and classification of the ECCS are specified in Section 3.2. All piping systems and components (pumps, valves, etc.) for the ECCS comply with applicable codes, addenda, code cases, and errata in effect at the time the equipment is procured. The equipment and piping of these systems are designed to the requirements of seismic Category I. This seismic designation applies

to all structures and equipment essential to the core cooling function. IEEE standards applicable to the controls and power supplies are specified in Section 7.1.

6.3.2.4 Materials Specifications and Compatibility

Materials specifications and compatibility for the ECCS are presented in Section 6.1. Nonmetallic materials, such as lubricants, seals, packings, paints and primers, insulation, as well as metallic materials are selected as a result of an engineering review and evaluation for compatibility with other materials in the system and the surroundings, with concern for chemical, radiolytic, mechanical and nuclear effects. Materials used are reviewed and evaluated with regard to radiolytic and pyrolytic decomposition, and attendant effects on safe operation of the ECCS.

6.3.2.5 System Reliability

A single failure analysis shows that no single failure prevents the starting of the ECCS and/or the delivery of coolant to the reactor vessel. The most severe effects of single failures with respect to loss of equipment occur if a LOCA occurs in an ECCS pipe coincident with a LOOP. The consequences of the most severe single failures are shown in Table 6.3-3.

Certain technical specification LCO periods are justified based on NEDO-24708A which states that for postulated LOCAs, one low pressure ECCS (one LPCI pump or one CS loop) and ADS to depressurize is adequate to reflood the vessel and maintain core cooling sufficient to preclude fuel damage. NEDC-30936P-A, specifically applicable to LGS references NEDO-24708A and reaffirms this conclusion, with the advisory regarding the possible necessity of an alternate cooling path following 2 hours of post large-break LOCA LPCI injection into the core shroud.

6.3.2.6 Protection Provisions

Protection provisions are included in the design of the ECCS. Protection is afforded against missiles, pipe whip, and flooding. Also accounted for in the design are thermal-stresses, loadings from a LOCA, and seismic effects.

The ECCS piping and components located outside the primary containment are protected from internally and externally generated missiles by the reinforced concrete structure of the ECCS pump rooms. The layout and protection of the pump rooms are covered in Section 6.2.3.

The ECCS is protected against the effects of pipe whip which might result from piping failures up to, and including, the design basis event LOCA. This protection is provided by separation, pipe whip restraints, and energy-absorbing materials. These three methods are applied to provide protection against damage to piping and components of the ECCS which otherwise could result in a reduction of ECCS effectiveness to an unacceptable level. See Section 3.6 for criteria on pipe whip.

The component supports, which protect against damage from movement and from seismic events, are discussed in Section 5.4.14. The methods used to provide assurance that thermal-stresses do not cause damage to the ECCS are described in Section 3.9.3.

The ECCS relief valves discharge lines that penetrate the primary containment and that have outlets below the surface of the suppression pool are designed to protect against the possibility of water hammer. RHR system valves in this category are: PSV-1(2)06A and PSV-1(2) 06B (Dwg. M-51). Each PSV discharge line connects to a 10 inch line which has been designed and installed with a continuous slope to the suppression pool to preclude water pockets from forming. These design

features prevent the occurrence of excessive dynamic loads resulting from water hammer during relief valve actuation, and thereby preclude line cracking or rupture. The dynamic loadings have been included in the piping stress analysis. Supports are designed to ensure that they are capable of withstanding the normal plus dynamic loading resulting from the relief valve opening. Section 1.12.3 contains further discussion of water hammer.

6.3.2.7 Provisions for Performance Testing

Periodic system and component testing provisions for the ECCS are described in Section 6.3.2.2 as part of the individual system descriptions.

6.3.2.8 Manual Actions

The ECCS is actuated automatically, and is designed to require no operator action during the first 10 minutes following the accident. Only limited operator action is required before 20 minutes following a LOCA.

During the long-term cooling period (after 10 minutes), the operator takes action, as specified in Section 6.2.2.2, to place the containment cooling system into operation. This action will ensure that suppression pool temperature limits are not exceeded. This is the only manual action that the operator needs to accomplish for the ECCS during the course of the LOCA.

The operator has multiple instrumentation available in the control room to assist him in assessing the post-LOCA conditions. This instrumentation provides reactor vessel pressure and water level, and containment pressure, temperature, and radiation levels, as well as indicating the operation of the ECCS. ECCS flow indication is the primary parameter available to assess proper operation of the system. Other indications, such as position of valves, status of circuit breakers, and essential power bus voltage are also available to assist in determining system operating status.

All controls required to perform the above manual actions are located in the control room. If the RHRSW radiation monitors are inoperable either due to loss of power or component malfunction/failure, the RHRSW pump trip bypass can also be accomplished from the Control Room. The EOPs written in accordance with the BWROG EPGs have been incorporated into LGS training and procedures. The EOPs, with main sections on reactor control and containment control, specify operator actions based on the symptoms that are occurring. Implementation of these training and procedural measures will ensure that LGS operators are adequately equipped to deal with plant emergencies consistent with the design bases assumptions.

The instrumentation and controls for the ECCS are discussed in detail in Section 7.3. Monitoring instrumentation available to the operator is discussed in more detail in Chapter 5 and Section 6.2.

6.3.2.9 Correct Positioning of Manual Valves

Consideration has been given to the possibility that manual valves in the ECCS might be left in the wrong position when an accident occurs. Remote indication in the control room is not required for all critical ECCS manual valves unless they are located in primary containment and therefore are not accessible for survey during normal plant operation. (Critical ECCS manual valves are those that provide system isolation, other than vent, drain, or test connection valves, or are located in the main flow paths.) The positions of those critical valves that are not provided with remote position indication in the control room are administratively controlled and have the following additional protection features:

a. Manual valves in the main ECCS flow paths and manual system isolation valves for ECCS pump suction piping are physically locked in their normal position; access to the keys is controlled administratively.

b. All other manual ECCS isolation valves are redundant to provide double isolation.

The only manual valves in the RHR system that were evaluated are those associated with LPCI mode. The boundary of the LPCI mode piping also includes all piping associated with the suppression pool cooling mode.

Vent, drain, and test connection valves are valves which are not critical to the ECCS function, and administrative controls such as prestartup valve lineup checks suffice to reasonably ensure that such valves will not degrade ECCS performance. In addition, many of these valves are redundant or locked in position, and test connections are capped.

The position of each manually operated valve will be identified in a valve checkoff list. When verification of system operability is required, performance of the valve checkoff list in conjunction with the applicable lineup procedure is one method which may be used. When operability is verified in this manner, an independent verification of valve lineup will be accomplished by redundant performance of each valve checkoff list used. Use of a lineup procedure with its associated valve checkoff lists will not be the exclusive method available for verification of operability, but can be used in any circumstance and supersedes the other methods discussed below. If valve positions are to be changed for surveillance or maintenance purposes, the procedure or other administrative control will have steps requiring return-to-normal valve lineup prior to completion. The shift supervisor will not consider the system operable until all valves identified within the boundaries of the surveillance/maintenance activities have been returned to the position specified in the valve checkoff list. If valve positions in the ECCS are changed for operational purposes, these changes will be made in accordance with procedures having similar administrative controls.

6.3.3 ECCS Performance Evaluation

The performance of the ECCS is determined through application of the 10CFR50, Appendix K evaluation models, and by conformance to the acceptance criteria of 10CFR50.46. The analytical models are documented in GESTAR II (Reference 4.1-1).

The ECCS performance is evaluated for the entire spectrum of break sizes for postulated LOCAs. The accidents, as listed in Chapter 15, for which ECCS operation is required are located in the following sections:

a.	Feedwater piping breaks outside primary containment	15.6.6
b.	Spectrum of BWR steam system piping failures outside of containment	15.6.4
c.	LOCAs inside primary containment	15.6.5

6.3.3.1 ECCS Bases for Technical Specifications

The maximum average planar linear heat generation rates calculated in this performance analysis provide the bases for Technical Specifications designed to ensure conformance with the acceptance criteria of 10CFR50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water-Cooled Nuclear Power Reactors." Minimum ECCS functional requirements are specified in Sections 6.3.3.4 and 6.3.3.5; and testing requirements are discussed in Section 6.3.4. Limits on minimum suppression pool water level are discussed in Section 6.2.

Certain technical specification LCO periods are justified based on the results of NEDO-24708A, NEDC-30936P-A and 006N4699 which state that one low pressure ECCS (one LPCI pump or one CS loop) and ADS is adequate to reflood the vessel and maintain core cooling sufficient to preclude fuel damage following a suction line break (including DBA). NEDC-30936P-A adds an advisory about the possible necessity of an alternate cooling path following 2 hours of post large-break LOCA LPCI injection into the core shroud. The justification provided by these documents is required to provide a basis for the maximum period specified to restore equipment or systems declared inoperable to operable status.

6.3.3.2 Acceptance Criteria for ECCS Performance

The applicable acceptance criteria, extracted from 10CFR50.46, are listed below. For each criterion, applicable parts of Section 6.3.3 (where conformance is demonstrated) are indicated. A description of the methods used to show compliance is contained in GESTAR II (Reference 4.1-1).

Criterion 1, Peak Cladding Temperature:

"The calculated maximum fuel element cladding temperature shall not exceed 2200°F." Conformance to Criterion 1 is demonstrated in Table 6.3-5.

Criterion 2, Maximum Cladding Oxidation:

"The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation." Conformance to Criterion 2 is shown in Table 6.3-5.

Criterion 3, Maximum Hydrogen Generation:

"The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all the metal in the cladding cylinder surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react." Conformance to Criterion 3 is shown in References 6.3-6, 6.3-9, and 6.3-16.

Criterion 4, Coolable Geometry:

"Calculated changes in core geometry shall be such that the core remains amenable to cooling." As described in section III of Reference 6.3-6, conformance to Criterion 4 is demonstrated by conformance to Criteria 1 and 2.

Criterion 5, Long-Term Cooling:

"After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core." Conformance to Criterion 5 is

demonstrated generically for GE BWRs in section III.A of Reference 6.3-1 and confirmed in References 6.3-6, 6.3-9, and 6.3-16. Briefly summarized, the core remains covered to at least the jet pump suction elevation, and the uncovered region is cooled by spray cooling.

The LGS equipment for long-term cooling following a postulated LOCA includes two complete core spray systems and two RHR systems. System components required for long-term coolant recirculation and decay heat removal are designed to remain operable during and following a LOCA. The redundancy provided is such that maintenance is not expected to be required during the long-term core cooling period (180 days) following a LOCA. However, the RHR and core spray systems are designed with provisions for flushing as shown in drawings M-51 and M-52.

6.3.3.3 Single Failure Considerations

The functional consequences of single failures (including operator errors which might cause any manually controlled electrically operated valve in the ECCS to move to a position which could adversely affect the ECCS) are discussed in Section 6.3.2. All potential single failures are no more severe than one of the single failures identified in Table 6.3-3.

It is therefore only necessary to consider each of these single failures in the ECCS performance analyses. For the original Reference 6.3-1 methodology, failure of one of the diesel generators is, in general, the most severe failure for large break; and a loss of the HPCI system is the most severe failure for small break. For the ECCS analysis performed with SAFER/GESTR-LOCA method (References 6.3-5 and 6.3-7) the limiting failure for all breaks is the division 2 dc (battery) failure.

The worst failure of an ECCS pump seal or valve packing during the long-term cooling mode would produce a leak of less than 50 gpm. The ECCS equipment compartments, located on the lowest elevation of the reactor enclosure, are watertight and equipped with flood alarms. Any passive failure including pump seal or valve packing failure occurring in an ECCS long-term cooling loop can be isolated by turning off the pump and shutting the suction isolation valve. If the packing of the suction isolation valve should fail, the leak could still be isolated because all of the suction isolation valves are gate valves.

6.3.3.4 System Performance During the Accident

In general, the system response to an accident can be described as the following:

a. Receiving an initiation signal

b. A small lag time (to open all valves and have the pumps up to rated speed)

c. Finally, the ECCS flow entering the vessel

Key ECCS actuation setpoints and time delays for all the ECCS are provided in Table 6.3-1 for the current ECCS-LOCA analysis and in Table 6.3-1A for the original ECCS-LOCA analysis. The minimization of the delay from the receipt of signal until the ECCS pumps have reached rated speed is limited by the physical constraints on accelerating the diesel generators and pumps. The delay time due to valve motion in the case of the high pressure system provides a suitably conservative allowance for valves available for this application. In the case of the low pressure system, the time delay for valve motion is such that the pumps are at rated speed prior to the time the vessel pressure reaches the pump shutoff pressure.

The operational sequence of ECCS for the DBA is shown in Table 6.3-2 for the current ECCS-LOCA analysis and in Table 6.3-2A for the original ECCS-LOCA analysis.

Operator action is not required, except as a monitoring function, during the short-term cooling period following the LOCA. The HPCI system is designed to inject water into the reactor vessel for small breaks that do not depressurize the vessel.

If a small break occurs and the HPCI system does not function, the ADS will cause vessel blowdown, and the low pressure systems will then act to restore vessel water level. In either case, no operator action is required to restore reactor water level. To establish decay heat removal, the operator will realign the RHR system to the suppression pool cooling mode. The necessary operator actions are described in Section 6.2.2.2.

If a small break occurs and the HPCI system functions properly, reactor vessel water level will be maintained, and no automatic depressurization will occur. The operator must then manually depressurize the vessel, using a minimum number of ADS valves, and establish long-term cooling as above.

All control switches necessary for ADS operation and realignment of the RHR system are located in the control room. The instrumentation available to monitor RHR pressure and flow, reactor vessel pressure, level and temperature, suppression pool temperature, pump status and relevant valve positions are discussed in Chapter 7.

Direction for accomplishing the above actions are available to the operator in the EOPs and appropriate system operating procedures.

The preceding discussion of operator actions in response to a small break LOCA is applicable even when single active failures and LOOP are assumed.

The available NPSH for the pumps in the HPCI system has been calculated based on minimum postaccident suppression pool level, maximum suppression pool temperature, 50% plugged strainers, and no credit for wetwell pressurization. The available NPSH for the RHR and Core Spray pumps has been calculated based on the same assumptions used for the HPCI except for the criteria for the determination of the dirty strainer pressure drop. The dirty strainer pressure drop for these strainers is based on the entire amount of fibrous debris generated in the drywell during a design basis LOCA (within the zone of influence of the worst case pipe break location) transported to the suppression pool and all debris is available to clog the strainer. The results of these calculations show that available NPSH is greater than the required NPSH by a margin of at least 10 feet for RHR, at least 7 feet for Core Spray, and at least 4 feet for HPCI.

6.3.3.5 Use of Dual-Function Components for ECCS

With the exception of the LPCI and ADS systems, the systems of the ECCS are designed to accomplish only one function: to cool the reactor core following a loss of reactor coolant. To this extent, components or portions of these systems (except for pressure relief) are not required for the operation of other systems which have emergency core cooling functions, or vice-versa. Because either the ADS initiating signal or the overpressure signal opens the SRV, no conflict exists.

The LPCI subsystem, however, uses the RHR pumps, and some of the RHR valves and piping. When the reactor water level is low, the LPCI subsystem has priority, through the valve control logic,

over the other RHR modes of operation. Immediately following a LOCA, the RHR system is aligned to the LPCI mode. Further discussion of valve logic is provided in Section 7.3.1.1.

6.3.3.6 Limits on ECCS System Parameters

Refer to GESTAR II (Reference 4.1-1).

6.3.3.7 ECCS Analyses for LOCA

6.3.3.7.1 LOCA Analysis Procedures and Input Variables

Refer to GESTAR II (Reference 4.1-1).

The significant input variables used by the LOCA codes are listed in Table 6.3-1 and Figure 6.3-11, for the current ECCS-LOCA. The significant input variables used for the original ECCS-LOCA analysis are shown in Table 6.3-1A and Figure 6.3-11A.

6.3.3.7.2 Accident Description

The original methodology for analysis of the LOCA is reflected in Reference 6.3-1. Reference 6.3-5 provides a detailed description of the current methodology for analysis of the LOCA. The results of the Reference 6.3-5 and 6.3-7 methods are detailed in References 6.3-6, 6.3-9, and 6.3-16.

6.3.3.7.3 Break Spectrum Calculations

A complete spectrum of postulated break sizes and locations is considered in the evaluation of ECCS performance.

A summary of the results of the break spectrum calculations is shown in tabular form in Table 6.3-5. Conformance to the acceptance criteria (PCT $\leq$2200°F, local oxidation <17%, and core-wide metal-water reaction <1%) is demonstrated in the above paragraphs. Details of calculations for specific breaks are included in subsequent paragraphs.

6.3.3.7.4 Large Recirculation Line Break Calculations

The characteristics that determine which is the most limiting large break are:

a. the calculated hot node reflooding time,

b. the calculated hot node uncovery time, and

c. the time of calculated boiling transition.

The time of calculated boiling transition increases with decreasing break size, since jet pump suction uncovery (which leads to boiling transition) is determined primarily by the break size for a particular plant. The calculated hot node uncovery time also generally increases with decreasing break size, as it is primarily determined by the inventory loss during the blowdown. The hot node reflooding time is determined by a number of interacting phenomena such as depressurization rate, counter current flow limiting, and a combination of available ECCS.

The period between hot node uncovery and reflooding is the period when the hot node has the lowest heat transfer. Hence, the break that results in the longest period during which the hot node remains uncovered results in the highest calculated PCT. If two breaks have similar times during which the hot node remains uncovered, then the larger of the two breaks will be limiting as it would have an earlier boiling transition time (i.e., the larger break would have a more severe LAMB/SCAT blowdown heat transfer analysis).

The DBA was determined to be the break that results in the highest calculated PCT in the 1.0 ft^2 to DBA region.

The component areas that comprise the suction and discharge break areas in the LOCA analysis are as follows:

a. Suction Break

Recirculation Suction Line Nozzle/Safe End	3.541 ft^2	
Jet Pump Discharge Nozzles - One Bank	0.548 ft^2	
	Total	4.089 ft^2

b. Discharge Break

Recirculation Pump Minimum Area	1.736 ft^2	
Jet Pump Discharge Nozzles - One Bank	0.548 ft^2	
	Total	2.284 ft^2

6.3.3.7.5 Steam Flow Induced Process Measurement Error

The impact on the ECCS-LOCA analysis of a Steam Flow Induced Error (SFIE) in the Level 3 scram has been evaluated. SFIE is a process measurement error in Reactor vessel level measurement induced by steam flowing in the annulus region between the dryer and vessel wall across the mouth of the instrument reference leg tap during a loss of coolant inventory event. For Limerick, SFIE can result in a level measurement error up to 4.67 inches at extended (20%) Power Uprate (3952 MWt). This error adversely impacts the timing of the Level 3 (L3) scram Analytical Limit (AL) for events resulting in a decrease in coolant inventory. Reference 6.3-13 provides an evaluation of this process error for ECCS-LOCA analysis.

For Limerick, the limiting LOCA analysis (and Licensing Basis PCT) is limited by large breaks. Therefore, the Limiting PCT is not affected by the reduction in the L3 analytical limit.

6.3.3.8 LOCA Analysis Conclusions

Having shown compliance with the applicable acceptance criteria of Section 6.3.3.2, it is concluded that the ECCS will perform its function in an acceptable manner and meet all of the 10CFR50.46 acceptance criteria.

6.3.4 TESTS AND INSPECTIONS

6.3.4.1 ECCS Performance Tests

All systems of the ECCS are tested for their operational ECCS function during the preoperational and/or startup test program. Each component is tested for power source, range, direction of rotation, setpoint, limit switch setting, torque switch setting, etc., as applicable. Each pump is tested for flow capacity for a comparison with vendor data (this test is also used to verify flow-measuring capability). The flow tests involve the same suction and discharge source; i.e., the suppression pool or CST.

All logic elements are tested individually and as a system to verify complete system response to emergency signals, including the ability of valves to revert to the ECCS alignment from other positions.

Finally, the entire system is tested for response time and flow capacity, taking suction from its normal source and delivering flow into the reactor vessel. This last series of tests is performed with power supplied from both offsite power and onsite emergency power.

See Chapter 14 for a thorough discussion of preoperational testing for these systems.

6.3.4.2 Reliability Tests and Inspections

The average reliability of a standby (nonoperating) safety system is a function of the duration of the interval between periodic functional tests. The factors considered in determining the periodic test interval of the ECCS are: the desired system availability (average reliability), the number of redundant functional system success paths, the failure rates of the individual components in the system, and the schedule of periodic tests (simultaneous versus uniformly staggered versus randomly staggered). For the ECCS, the above factors are used to determine safe test intervals, utilizing the methods described in Reference 6.3-2.

All of the active components of HPCI, CS, and LPCI are designed so that they may be tested during normal plant operation. Full flow test capability of each ECCS injection system is provided by test lines back to their suction sources. The full flow test is used to verify the capacity of each ECCS pump loop while the plant remains undisturbed in the power generation mode. In addition, each individual valve may be tested during normal plant operation. Input jacks are provided, and by racking out the injection valve breaker, each ECCS loop can be tested for response time.

The ADS logic is designed so that it may be tested during normal plant operation. The SRVs and associated solenoid valves are all tested at least once during the plant startup following each refueling outage. Those SRVs and their associated solenoid valves, which are overhauled during a plant outage, are tested during the startup following that outage.

Testing of the initiating instrumentation and controls portion of the ECCS is discussed in Section 7.3. The safeguard power system, which supplies electrical power to the ECCS if offsite power is unavailable, is tested as described in Section 8.3. Testing is specified in the Technical Specifications. Visual inspections of all the ECCS components located outside the primary containment can be made at any time during power operation. Components inside the primary containment can be visually inspected only during periods of access to the primary containment. When the reactor vessel is open, the spargers and other reactor vessel internals can be inspected.

6.3.4.2.1 HPCI Testing

The HPCI system can be tested at full flow with CST water at any time during plant operation, except when the reactor vessel water level is low, when the condensate level in the CST is below the reserve level, or when the HPCI F041 valve from the suppression pool to the pump are open. If an initiation signal occurs while the HPCI system is being tested, the system aligns automatically to the operating mode.

A design flow functional test of the HPCI system over the operating pressure and flow range is performed by pumping water from the CST and back through the full flow test return line to the CST. The HPCI system turbine-pump is driven at its rated output by steam from the reactor. The HPCI F041 valve, suction valve from the suppression pool, and the discharge valves to the core spray line remain closed. The HPCI F042 valve, suppression pool to pump suction PCIV remains open. These valves are tested separately to ensure their operability.

The HPCI test conditions are tabulated on the HPCI process flow diagram (drawing E41-1020-G-002).

6.3.4.2.2 ADS Testing

The ADS valves are tested once per fuel cycle. This testing includes simulated automatic actuation of the system throughout its emergency operating sequence, but excludes actual valve actuation.

During plant operation the ADS system can be checked as discussed in Section 7.3.

6.3.4.2.3 CS Testing

The CS pumps and valves can be tested during reactor operation. The injection valve and injection line check valve for the A-loop and the outboard and inboard injection line check valves for the B-loop are normally tested with the reactor shutdown. The injection lines to the reactor can be tested when the reactor is shutdown and the CS suction is lined up to the CST. With the injection valve closed and the return line open to the suppression pool, full flow pump capability is demonstrated. The system test conditions during reactor shutdown are shown on the CS system process diagram (drawing E41-1020-G-001. The portion of the CS system outside the drywell may be inspected for leaks during tests.

If an initiation signal occurs during the test, the CS System aligns to the operating mode. The test return line valves close automatically to ensure that CS pump discharge is correctly routed to the RPV.

6.3.4.2.4 LPCI Testing

Each LPCI loop can be tested during reactor operation. The test conditions are tabulated in drawing E11-1020-G-002. During plant operation, this test does not inject cold water into the reactor, because the injection line check valve is held closed by vessel pressure, which is higher than the pump pressure. The injection line portion can be tested with reactor water when the reactor is shut down, and when a closed system loop is created. This prevents unnecessary thermal-stresses.

To test a LPCI pump at rated flow, the test line valve to the suppression pool is opened, the pump suction valve from the suppression pool is opened (this valve is normally open), and the pumps are started using the remote manual switches in the control room. Correct operation is determined by observing instruments locally and in the control room.

If an initiation signal occurs during the test, the LPCI subsystem aligns to the operating mode. The valves in the test bypass lines close automatically to ensure that the LPCI pump discharge is correctly routed to the RPV.

6.3.5 Instrumentation Requirements

Design details, including redundancy and logic of the ECCS instrumentation, are discussed in Section 7.3.

All instrumentation required for automatic and manual initiation of HPCI, CS, LPCI, and ADS is discussed in Section 7.3.2, and is designed to meet the requirements of IEEE 279 and other applicable standards.

Long-term ADS gas supply instrumentation is addressed in Section 7.6.

The HPCI system is automatically initiated on low reactor water level and/or high drywell pressure. The CS and LPCI loops are automatically initiated on low reactor water level, and/or high drywell pressure (in combination with low reactor pressure). The ADS is automatically actuated by sensed variables for reactor vessel low water level and drywell high pressure plus the indication that at least one CS loop or LPCI pump is operating. HPCI, CS, and LPCI automatically realign from system flow test modes to the emergency core cooling mode of operation following receipt of an automatic initiation signal. The CS and LPCI injection into the RPV begins when reactor pressure decreases to loop discharge shutoff pressure.

HPCI injection begins as soon as the HPCI turbine-pump is up to speed and the injection valve is open, since the HPCI is capable of injecting water at full flow into the RPV at pressures up to the reactor pressure specified in Mode A of drawing E41-1020-G-002.

6.3.6 REFERENCES

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6.3-2 H.M. Hirsch, "Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems," NEDO-10739, (January 1973).

6.3-3 General Electric Company, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors", NEDO-24708A, Revision 1, (December 1980).

6.3-4 General Electric Company, "BWR Owner's Group Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Activation Instrumentation)", NEDC-30936P-A, (December 1988).

6.3-5 General Electric Company Analytical Model for Loss of Coolant Analysis in Accordance with 10CFR50, Appendix K, NEDO-20566A, General Electric Company, September 1986.

6.3-6 GE Nuclear Energy, Limerick Generating Station Units 1 and 2, SAFER/GESTR-LOCA, Rev. 2 Loss-of-Coolant Accident Analysis, NEDC-32170P, Rev. 2, May 1995

6.3-7 General Electric Company, "The GESTR-LOCA and SAFER models for the evaluation of the Loss-of-Coolant Accident, Volume III, SAFER/GESTR Application Methodology," NEDE-23785-1 PA, Rev. 1, (Oct 1984).

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6.3-9 Limerick Generating Station Units 1 and 2 ECCS-LOCA Evaluation for GE-14, GE-NE-J1103793-09-01P, DFR J11-03793-09, March 2001.

6.3-10 Deleted.

6.3-11 Deleted.

6.3-12 Generic Letter 2008-01, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems,” dated January 11, 2008.

6.3-13 GE-Hitachi Nuclear Energy, 0000-0077-4603-R1, "BWR Owners Group Evaluation of Steam Flow Induced Error (SFIE) Impact on the L3 Setpoint Analytic Limit," October 2008.

6.3-14 Letter Report for Exelon, Summary of GEH Transient Anticipated Operational Occurrences (AOO) and Loss of Coolant Accident (LOCA) Analyses with Respect to ASD Modification in Limerick Generating Station Units 1 and 2, 0000-0129-8688-R1, Revision 1, May 2011.

6.3-15 GE Hitachi Nuclear Energy, "Implementation of PRIME Models and Data in Downstream Methods," NEDO-33173, Supplement 4-A, Revision 1, November 2012.

6.3-16 GE Hitachi Nuclear Energy, "Limerick Generating Station Units 1 and 2 GNF3 ECCS-LOCA Evaluation," 005N3990, Revision 0, December 2020.

6.3-17 GE Hitachi Nuclear Energy, "Limerick Supplemental ECCS Flow Reduction LOCA Analysis for NEDC-30936," 006N4699, Revision 0, July 2021.

6.3-18 GE Hitachi Nuclear Energy, "Corrected HTC Plots for ECCS-LOCA Reports," 007N3418, Revision 0, October 2022.

Table 6.3-1

SIGNIFICANT INPUT VARIABLES USED IN THE LOCA ANALYSIS

VARIABLE		VALUE	
		GNF3	
A. PLANT PARAMETERS		NOMINAL	APPENDIX K
•	Core thermal power (MWt)	3515	3528
•	Vessel steam output (lbm/hr)	15.8×10^6	N/A
•	Vessel steam dome pressure (psia)	1060	1063(1)
•	Maximum recirculation line break area (ft^2)	4.174	4.174
B. ECCS PARAMETERS			
B.1	LPCI System		
•	Vessel pressure at which flow may commence	<295 psid (vessel to drywell)	
•	Minimum rated flow at vessel Pressure	32,000 gpm (4 pumps) 20 psid (vessel to drywell)	
•	Initiating signals		
	Low water level (level 1), or	≥366.5 inches above vessel zero	
	High drywell pressure	≤2.0 psig	
•	Maximum allowable time delay from initiating signal to power at injection valves	13 sec	
•	Maximum allowable time delay from initiating signal to injection valves full open	≤64 sec	
B.2	Core Spray System		
•	Vessel pressure at which flow may commence	<289 psid (vessel to drywell)	
•	Minimum rated flow at vessel pressure	5000 gpm/loop 105 psid (vessel to drywell)	

(1) The conclusions of the Limerick GNF3 LOCA analysis for 1063 psia dome pressure remain valid for TS LCO of 1068 psia dome pressure.

Table 6.3-1 (Cont'd)

VARIABLE		VALUE
		GNF3
•	Initiating signals	
	Low water level (level 1), or	≥366.5 inches above vessel zero
	High drywell pressure	≤2.0 psig
•	Minimum allowed run-out flow	6250 gpm/loop
•	Maximum allowed delay time from initiating signal to power at injection valves	13 sec
•	Maximum allowed delay time from initiating signal to injection valve full open	48.0 sec
B.3	HPCI/Core Spray Flow Split Characteristics	
•	Minimum flow rate (independent of vessel pressure)	5400 gpm
•	Initiating signals	
	Low water level (level 2), or	≥457.5 inches above vessel zero
	High drywell pressure	≤2.0 psig
•	Maximum allowed delay time from initiating signal to rated flow available and injection valve wide open	≤60.0 sec
•	Maximum HPCI flow rate injected through core spray sparger	2890 gpm
B.4	Automatic Depressurization System	
•	Total number of relief valves with ADS function	5
•	Total minimum flow capacity at a vessel pressure	4.35×10^6 lbs/hr 1090 x 1.03 psig

Table 6.3-1 (Cont'd)

VARIABLE	VALUE
	GNF3
• Initiating signals	
a) Low water level (level 1), and	≥366.5 inches above vessel zero
High drywell pressure(1)	≤2.0 psig
b) Low water level (level 1), and	≥366.5 inches above vessel zero
High drywell pressure bypass timer timed out(2)	≤8 minutes
• Delay time from all initiating signals completed to the time valves are open	≤120 seconds

(1) Designed to actuate for breaks inside the drywell.
(2) Designed to actuate ADS when needed for events which do not result in drywell pressurization.

Table 6.3-1A

SIGNIFICANT INPUT VARIABLES USED IN THE LOCA ANALYSIS
BASED ON ORIGINAL REFERENCE 6.3-1 METHODOLOGY

VARIABLE		VALUE
A.	PLANT PARAMETERS	
•	Core thermal power	3430 MWt
•	Vessel steam output	14.86×10^6 lb_m/hr
•	Corresponding percent of rated steam flow	105%
•	Vessel steam dome pressure	1055 psia
•	Maximum recirculation line break area	4.1 ft^2
B.	ECCS PARAMETERS	
	B.1 LPCI System	
•	Vessel pressure at which flow may commence	<295 psid (vessel to drywell)
•	Minimum rated flow at vessel pressure	40,000 gpm (4 pumps) 20 psid (vessel to drywell)
•	Initiating signals	
	Low water level (level 1), or	≥1.0 feet above top of active fuel
	High drywell pressure	≤2.0 psig
•	Maximum allowable time delay from initiating signal to pumps at rated speed	≤40 sec
	B.2 Core Spray System	
•	Vessel pressure at which flow may commence	<289 psid (vessel to drywell)
•	Minimum rated flow at vessel pressure	6250 gpm/loop 105 psid (vessel to drywell)

Table 6.3-1A (Cont'd)

VARIABLE		VALUE
•	Initiating signals	
	Low water level (level 1), or	≥1.0 feet above top of active fuel
	High drywell pressure	≤2.0 psig
•	Minimum allowed run-out flow	7000 gpm/loop
•	Maximum allowed delay time from initiating signal to pump at rated speed	≤27.0 sec
B.3	HPCI/Core Spray Flow Split Characteristics	
•	Minimum flow rate (independent of vessel pressure)	5600 gpm
•	Initiating signals	
	Low water level (level 2), or	≥8.6 feet above top of active fuel
	High drywell pressure	≤2.0 psig
•	Maximum allowed delay time from initiating signal to rated flow available and injection valve wide open	≤30.0 sec
•	Maximum HPCI flow rate injected through core spray sparger	3000 gpm
B.4	Automatic Depressurization System	
•	Total number of relief valves with ADS function	5
•	Total minimum flow capacity at a vessel pressure of	4.0×10^6 lbs/hr 1125 psig

Table 6.3-1A (Cont'd)

VARIABLE		VALUE
•	Initiating signals	
	a) Low water level (level 1), and	≥1.0 feet above top of active fuel
	High drywell pressure(1)	≤2.0 psig
	b) Low water level (level 1), and	≥1.0 feet above top of active fuel
	High drywell pressure bypass timer timed out(2)	≤8 minutes
•	Delay time from all initiating signals completed to the time valves are open	≤120 seconds
C.	FUEL PARAMETERS	
•	Fuel type	Initial Core
•	Fuel bundle geometry	8x8
•	Lattice	C
•	Number of fueled rods per bundle	62
•	Peak Technical Specification LHGR	13.4 kW/ft
•	Initial minimum critical power ratio	1.2
•	Design axial peaking factor	1.4

(1) Designed to actuate for breaks inside the drywell.
(2) Designed to actuate ADS when needed for events which do not result in drywell pressurization.

Table 6.3-2

OPERATIONAL SEQUENCE OF ECCS FOR DESIGN BASIS LOCA[1]

TIME (sec)	EVENTS
0	Design basis LOCA is assumed to start; normal auxiliary power is assumed to be lost.
<1	Drywell high pressure is reached. Scram initiated; HPCI is signaled to start, and containment isolates, except for the MSIVs.
Approx 1	Reactor Low Water Level (Level 3) is reached [2]. The second scram initiation signal is received.
Approx 4	Reactor low-low water level (level 2) is reached. HPCI receives the second signal to start.
Approx 5	The reactor low-low-low water level (level 1) is reached; MSIVs are signaled to close; the signal to start LPCI and CS is given.
Approx 25	Reactor low pressure is reached. CS and LPCI receive the second signal to start. CS injection valve receives pressure permissive signal to open.
≤54	The CS pumps are at rated flow and the CS injection valves are open, which completes the CS system startup.
≤70	The LPCI pumps are at rated flow and the LPCI injection valves are open, which completes the LPCI system startup.
Approx 130	The core is effectively reflooded, assuming the worst single failure; heatup is terminated.
>10 min	The operator shifts to containment cooling.

[1] For the purpose of all but the next to the last entry on this table, all ECCS equipment is assumed to function as designed. Performance analysis calculations consider the effects of single equipment failures (Sections 6.3.2.5 and 6.3.3.3).

[2] The Level 3 Analytical value in this table may be slightly different for various events due to a steam flow induced process measurement error. However, the impact of the change is not significant and the event descriptions or conclusions need not be modified (Section 6.3.3.7.5).

Table 6.3-2A

OPERATIONAL SEQUENCE OF ECCS FOR DESIGN BASIS LOCA [1]
BASED ON THE ORIGINAL REFERENCE 6.3-1 METHODOLOGY

TIME (sec)	EVENTS
0	Design basis LOCA is assumed to start; normal auxiliary power is assumed to be lost.
<1	Drywell high pressure [2] and reactor low water level (level 3) are reached [3]. All diesel generators are signaled to start; scram initiated; HPCI is signaled to start, and containment isolates, except for the MSIVs.
Approx 2	Reactor low-low water level (level 2) is reached [3]. HPCI receives the second signal to start.
Approx 5	The reactor low-low-low water level (level 1) is reached; MSIVs are signaled to close; the signal to start LPCI and CS is given.
Approx 22	Reactor low pressure is reached. CS and LPCI receive the second signal to start. CS injection valve receives pressure permissive signal to open.
Approx 26	LPCI injection valve receives ΔP permissive signal to open.
Approx 32	The HPCI injection valve opens and the pump is at design flow, which completes the HPCI startup.
≤34	The CS pumps are at rated flow and the CS injection valves are open, which completes the CS system startup.
≤50	The LPCI pumps are at rated flow and the LPCI injection valves are open, which completes the LPCI system startup.
Approx 165	The core is effectively reflooded, assuming the worst single failure; heatup is terminated.
>10 min	The operator shifts to containment cooling.

(1) For the purpose of all but the next to the last entry on this table, all ECCS equipment is assumed to function as designed. Performance analysis calculations consider the effects of single equipment failures (Sections 6.3.2.5 and 6.3.3.3).

(2) No credit taken in the DBA LOCA analysis for ECCS system initiation on the high drywell pressure signal.

(3) The Level 3 Analytical value in this table may be slightly different for various events due to a steam flow induced process measurement error. However, the impact of the change is not significant and the event descriptions or conclusions need not be modified (Section 6.3.3.7.5).

Table 6.3-3

SINGLE FAILURE EVALUATION[1][4]

No potential single failure has been identified as more severe than one of the following single failures:

ASSUMED FAILURE	SUCTION BREAK[2] SYSTEMS REMAINING
Division 2 dc source	1 CS loop + 3 LPCI + All ADS
Diesel generator[3]	1 CS loop + HPCI + 3 LPCI + All ADS
LPCI injection valve	2 CS loop + HPCI + 3 LPCI + All ADS
HPCI	2 CS loop + 4 LPCI + All ADS
One ADS valve	2 CS loop + 4 LPCI + HPCI + All ADS minus one

(1) Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the above designated failures.

(2) Systems remaining, as identified in this table, are applicable to all non-ECCS line breaks. For a LOCA from an ECCS line break, the systems remaining are those listed, less the ECCS system in which the break is assumed.

(3) If the single failure occurs in a diesel generator that supplies power to an ESW pump, the diesel generator in the other unit is needed to support the other ESW pump that supplies that loop.

(4) This table demonstrates the performance of safety systems under the single failure criteria. For the minimum system requirements to successfully terminate a transient or LOCA initiating event (with scram), assuming multiple failures with realistic conditions, refer to NEDO-24708.

Table 6.3-4 has been deleted

Table 6.3-5

SUMMARY OF RESULTS OF LOCA
ANALYSIS USING TABLE 6.3-1 INPUTS

Parameter	Value	10 CFR 50.46 Acceptance Criteria
1. Fuel Type	GNF3	N/A
2. Limiting Break	Large Recirc suction DBA(1)	N/A
3. Limiting Single Failure	Division 2 dc source	N/A
4. Licensing Basis Peak Cladding Temperature	≤ 1940 °F	≤ 2200 °F
5. Maximum Local Oxidation	< 3.0 %	≤ 17 %
6. Core-Wide Metal-Water Reaction	< 0.1 %	≤ 1.0 %
7. Coolable Geometry	Item 4 AND Item 5 satisfied.	Maintain coolable geometry, which is satisfied by meeting PCT ≤ 2200 °F AND Maximum Local Oxidation ≤ 17 %.
8. Long-Term Cooling	Satisfied by EITHER: Core reflooded above TAF OR Core reflooded to the elevation of jet pump suction and one core spray system in operation.	Core Temperature acceptably low AND long-term decay heat removed.

(1) Includes the area of the bottom head drain line.

Table 6.3-5A has been deleted

Table 6.3-6 has been deleted

Table 6.3-7 has been deleted

6.4 HABITABILITY SYSTEMS

The control room habitability systems are designed to provide safety and comfort for operating personnel during normal operations and during postulated accident conditions. These habitability systems for the control room include radiation shielding, charcoal filter systems, HVAC, storage for food and water, kitchen and sanitary facilities, and fire protection. The habitability systems are designed to meet GDC 19 of 10CFR50, Appendix A.

6.4.1 DESIGN BASES

The design bases of the habitability systems, upon which the functional design is established, are summarized as follows:

a. The control room environmental envelope is designed for continuous occupation on a year-round basis. The occupancy of the operating personnel is ensured for a minimum of 30 days after a DBA.

b. The habitability systems are designed to support 5 people during normal and abnormal station operating conditions. A 5 day emergency supply of food and water is provided within the control room habitability envelope. Supplies of potassium iodide adequate to protect 30 people are maintained onsite.

c. Kitchen and sanitary facilities and medical supplies for minor injuries are provided within the boundary of the control room habitability systems for the use of control room personnel during normal and accident conditions.

d. The radiological effects on the control room personnel that could exist as a consequence of the postulated DBAs described in Chapter 15 do not exceed the guidelines set by GDC 19 of 10CFR50, Appendix A, or the dose limits of 10CFR50.67.

e. The design includes provisions to preclude the effects of a chlorine release accident onsite or offsite from affecting the habitability of the control room.

f. The design includes provisions to preclude the effects of an offsite toxic chemical release from affecting the habitability of the control room.

g. Respiratory and skin protection and emergency breathing apparatus are provided within the control room envelope for control room operators.

h. The control room ventilation system is capable of automatic transfer from its normal operational mode to its accident or isolation mode upon detection of conditions which could result in the introduction of airborne radioactivity into the control room.

i. The control room ventilation system is designed to remain functional during and after an OBE and an SSE.

j. The habitability systems are designed to remain functional following a failure of any one of the HVAC system components.

k. Radiation monitors and offsite toxic chemical detectors continuously monitor the outside air at the control room envelope outside air intake. The detection of high radiation or offsite toxic chemical release is alarmed in the control room, and related protection functions are simultaneously initiated.

l. The control room HVAC system design bases are discussed in Section 9.4.1.

m. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the habitability systems are discussed in Section 3.2.

n. The guidelines of Regulatory Guide 1.52, Regulatory Guide 1.78, and Regulatory Guide 1.95 apply to the design of habitability systems. Conformance for the analyses associated with Regulatory Guide 1.78 is discussed in Section 2.2.3. Conformance to design aspects of the guides is as follows:

    1. There is partial conformance with Regulatory Guide 1.52 as discussed in Section 6.5.1

    2. The habitability system design for offsite toxic chemical protection conforms with Regulatory Guide 1.78. Differences from the analytic models are discussed in Section 2.2.3.

    3. Regulatory Guide 1.95 (Rev 1), which discusses protection from accidental chlorine release, does not apply to LGS per its implementation section. Nevertheless, the LGS design is in conformance.

The design of the habitability systems with respect to the following areas is discussed in separate sections as indicated:

a.	Protection from wind and tornado effects	Section 3.3
b.	Flood Design	Section 3.4
c.	Missile Protection	Section 3.5
d.	Protection against dynamic effects associated with postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11

6.4.2 SYSTEM DESIGN

6.4.2.1 Definition of Control Room Envelope

The control room envelope maintained under habitable conditions following an accident is shown on Figure 6.4-1. The envelope consists of the control room, peripheral offices at the west and east ends, toilet room, and utility room; all on el 269'-0". Steam and air tight doors are provided for ingress and egress.

The volume of the emergency zone served by the HVAC system in the accident mode or the isolation mode is approximately 126,000 cubic feet.

6.4.2.2 Ventilation System Design

The control room HVAC system is discussed in detail in Section 9.4.1. The system is shown schematically in drawing M-78, and major system components are described in Table 9.4-1.

Figure 6.4-2 shows the plant layout, including the location of plant facilities, with respect to the control room outside air intake. The control room arrangement is shown in Figure 6.4-1. The seismic category and quality group classification of components, instrumentation, and ducts are listed in Section 3.2 and shown in drawing M-78.

The control room is common for Units 1 and 2. The principal equipment in the system includes:

a. Two 100% capacity air handling units which include cooling coils, and fans for use during normal plant operation and following a DBA, a chlorine accident, or an offsite toxic chemical accident. Electric humidifiers, electric heaters, and roll filters are provided for use during normal plant operation, during a chlorine accident, or during an offsite chemical accident.

b. Two 100% capacity return air fans for use during normal plant operation and following a DBA, chlorine or offsite toxic chemical accident.

c. Two banks of high efficiency air filtration units consisting of a prefilter, HEPA filter, an electric heating coil, a carbon adsorber, and a second HEPA filter for treatment of recirculated air or outside supply air following a DBA, chlorine, or offsite toxic chemical accident. Two filtration unit fans are provided; one for each filtration unit.

d. A single outside air intake for use during normal plant operation and following a DBA.

6.4.2.3 Leak-Tightness

Control room envelope construction joints and penetrations for cable, pipe, HVAC duct, HVAC equipment, dampers, and steam-tight doors have been designed specifically for leak-tightness. A list of potential leak paths to the control room is provided in Table 6.4-2, along with the type of material, joint, or penetration.

For the onsite chlorine storage discussed in Section 2.2.3, a control room design with a maximum allowable control room isolated air exchange rate of 0.25 air changes per hour is provided. The analysis discussed in Section 2.2.3.1.3 demonstrates that this air exchange rate allows the operators more than 2 minutes to put on their breathing masks.

6.4.2.4 Interaction with Other Zones and Pressure-Containing Equipment

a. Design of the control room envelope boundaries, duct-work and isolation valves minimizes interchange of exterior radioactive gases or toxic vapors into the control room envelope.

The control room is surrounded by the turbine enclosure, the reactor enclosure, and the cable spreading room and auxiliary equipment room. Each of these areas is separated from the control room by shield walls, floors, and leak-tight doors and is served by the independent HVAC systems described in Section 9.4.

The HVAC equipment room at el 304' is a part of the control structure. The negative pressure control room duct-work system in the HVAC equipment room is of welded construction and tested for leak-tightness. Dampers on the negative pressure duct-work are of gas-tight construction.

b. Steam lines and central carbon dioxide fire prevention system tanks are not located within the control room envelope.

6.4.2.5 Shielding Design

Control room shielding is discussed in Section 12.3. The shielding is designed for continuous occupancy during a DBA and meets GDC 19 and 10CFR50.67.

6.4.3 System Operational Procedures

6.4.3.1 Normal Operation

During normal operation, one of the two air handling units and one of the two return fans recirculate the control room air. Approximately 2100 cfm of fresh outside air is taken in at the control room ventilation system intake located on the north wall of the control enclosure. By balancing the exhaust and makeup flow rates, the control room is normally maintained at a slightly positive pressure with respect to the surrounding areas. The outside makeup air and recirculated air pass through a roll filter at the inlet of the air handling unit fans. The supply air is cooled or heated by the air handling units as required to maintain the desired temperature. Upon loss of supply or return air flow, the respective standby fans automatically start; the associated fan dampers reposition; and an alarm annunciates in the main control room. The start of standby equipment may also be manually initiated.

The control room is fully air conditioned and will be maintained between 65 and 78°F and between 30 and 90% relative humidity. Control room temperature is sensed by a temperature transmitter which transmits a signal to a temperature indicating controller. The temperature controller maintains the proper temperature by controlling an electric heating coil or cooling coil valve as necessary. Control room minimum humidity is maintained by a return air duct moisture sensor and transmitter, which transmits a signal to the humidity controller which in turn controls an electric humidifier. Excessive humidity is precluded by the cooling coil which condenses excessive moisture.

6.4.3.2 Postaccident Operation

The control room HVAC system is designed to ensure habitability after any of the design basis radiological accidents or a chemical release accident. To provide adequate operator protection in the unlikely event of one of these accidents, three distinct accident modes of operation are included. These modes are referred to as the chlorine isolation mode, the toxic chemical isolation mode, and the radiation isolation mode.

The mode of system operation after each of the individual accidents of concern with the control room HVAC system initially in the normal mode of operation is as follows:

Chlorine accident - Chlorine isolation mode

High radiation accident - Radiation isolation mode

Offsite toxic chemical accident - Toxic chemical isolation mode

In the event of a radiation accident, the control room will be automatically isolated. In the event of an offsite toxic chemical accident, the control room will be remote manually isolated when the predetermined toxic chemical concentrations are detected in the control room air intake plenum and alarmed in the control room.

Note: the possibility exists for a chlorine accident to occur while the control room HVAC system is operating in the radiation isolation mode for testing purposes or as required by the Action statement of an associated Technical Specifications Limiting Condition of Operation, and likewise, a high radiation accident could occur while the control room HVAC system is operating in the chlorine isolation mode for the same purposes. The mode of system operation with the control room HVAC system in these initial system configurations is described in Sections 6.4.3.2.1 and 6.4.3.2.2 below.

The high radiation accident is discussed in detail in Chapter 15 and identification of design basis toxic chemicals including chlorine is discussed in Section 2.2.3.

6.4.3.2.1 Chlorine Isolation Mode

Upon detection or notification of an off-site chlorine spill, operators will initiate a manual chlorine isolation of the control room HVAC system. The following events occur (drawing M-78) to isolate the control room from the outside air when the control room HVAC system is initially in the normal mode of operation.

a. Redundant outside air intake isolation valves close in 3-5 seconds to prevent outside air from entering the control room supply air handling units.

b. For a manual chlorine isolation only, outside air intake isolation valves to the charcoal filter inlets close, if open, in 8-12 seconds to provide isolation to the charcoal filter trains.

c. Control room exhaust isolation valves and control room toilet exhaust isolation valves close in 3-5 seconds.

d. The emergency fresh air charcoal filter recirculation inlet isolation valve opens in 8-12 seconds.

e. The emergency fresh air fan for charcoal filter train A or B starts to establish filtered recirculation of the control room environment.

f. Manual chlorine isolation concentration is indicated and alarmed in the control room.

In the chlorine isolation mode approximately 3000 cfm of the control room atmosphere is recirculated through the charcoal filter train for cleanup.

The normal air handling units continue to recirculate approximately 26,200 cfm of the control room atmosphere, including the charcoal filter train discharge.

Once initiated, the system remains in the isolation mode until the trip switch is manually reset.

6.4.3.2.2 Radiation Isolation Mode

The radiation isolation mode of operation is intended to protect the control room operators if there are design basis radiological accidents.

Upon receipt of an initiating signal, the following automatic functions occur (drawing M-78) when the control room HVAC system is initially in the normal mode of operation:

a. The control room outside air exhaust is isolated.

b. The control room outside air intake, charcoal filter trains, and normal air handling units are aligned, so that all outside air must pass through the charcoal filter trains before it enters the control room.

c. The control room is maintained at a positive pressure (approximately 1/8 inch wg) with respect to the surrounding areas.

d. High radiation is alarmed in the control room.

The control room is now positively pressurized with respect to the surrounding areas. The quantity of outside air taken in at the normal ventilation intake on the north wall of the control structure is mixed with recirculated control room air, and a total of 3000 cfm is passed through the charcoal adsorber filter train for removal of airborne radioactivity.

If the control room HVAC system is initially in the chlorine isolation mode as described in Section 6.4.3.2.1 for any purpose, the system will remain in this mode of operation upon receipt of a high radiation signal, i.e., automatic transfer from the chlorine isolation mode to the radiation isolation mode will not occur. This design recognizes that the infiltration of chlorine into the main control room is a more immediate threat to the operations personnel.

If the control room HVAC system is initially in the chlorine isolation mode as result of maintenance or surveillance testing, the HVAC system can be manually switched to the radiation isolation mode once the operators determine that no chlorine is present.

6.4.3.2.3 Toxic Chemical Isolation Mode

The toxic chemical isolation mode is identical to the chlorine isolation mode as described in Section 6.4.3.2.1, with the exception that toxic chemical detection does not automatically initiate control room isolation.

Upon receipt of a high toxic chemical concentration alarm indicated by the toxic chemical detectors located in the control room outside air intake plenum, the operator manually initiates control room isolation utilizing controls available in the control room in accordance with plant procedures.

High toxic chemical concentration is indicated and alarmed in the control room and the system remains in the isolation mode until the high toxic chemical concentration condition is no longer present and the system is manually reset.

6.4.4 Design Evaluations

The control room habitability system is designed with redundancy and separation of active components to provide reliable operation under normal conditions and to ensure operation under accident conditions. A failure analysis of the system components is shown in Table 6.4-1.

6.4.4.1 Radiological Protection

A detailed discussion of the dose calculation model for control room operators following the postulated DBA is discussed in Section 15.10. The analysis considers both conditions in which the control room HVAC system is initially in the normal mode of operation and the chlorine isolation mode prior to the high radiation accident. The resulting calculated doses for control room ingress, egress, and occupancy (on a rotating shift basis) are less than 5 rem total effective dose equivalent (TEDE). These doses are within the dose limits specified in GDC 19 and 10CFR50.67. The analysis also assumes the installation of a MCR door seal, which ensures zero direct inleakage from the Turbine Enclosure through the MCR doors. Following the DBA LOCA, after the MSIV Leakage Alternate Drain Pathway has been aligned and when a Turbine Enclosure Area Radiation Monitor alarms, a temporary MCR door seal will be erected, to prevent the direct inleakage to the MCR. This action is necessary to prevent a relatively high calculated concentration of Iodine from entering the MCR directly from the Turbine Enclosure.

Control room shielding design, based on the most limiting radiological accident (design basis LOCA) is discussed in Section 12.3. The evaluations in Chapter 12 demonstrate that radiation exposures to control room personnel originate from containment shine, external cloud shine, and containment airborne radioactivity sources. Total exposures resulting from the worst radiological accident are below the dose limits specified by GDC 19 and 10CFR50.67; the portion contributed by containment shine and external cloud shine is reduced to a small fraction of the total by means of the walls which surround the control room.

Two radiation detector units are located in the control room fresh air inlet duct, and another two radiation detector units are located in the auxiliary equipment room HVAC system fresh air inlet duct. All four radiation detectors are situated in duct-work that is directly below the floor penetration level at el 332'. A description of the radiation detector units is provided in Section 7.1.2.1.11.

6.4.4.2 Toxic Gas Protection

The control room HVAC system is designed to satisfy the guidelines of Regulatory Guide 1.78 for toxic chemical protection, and Regulatory Guide 1.95 for chlorine protection (except as discussed in Section 6.4.1). Detection systems are provided for both offsite toxic chemical accidental release and onsite chlorine container accidental release.

Detector design criteria and descriptions and respiratory protection are discussed below.

6.4.4.2.1 Chlorine

The chlorine release accident analysis is described in Section 2.2.3. The control room and isolation system are designed to meet the requirements of a control room that has a maximum allowable isolated air exchange rate of 0.25 air changes per hour.

The analysis considers both conditions in which the control room HVAC system is initially in the normal mode of operation and the radiation isolation mode prior to the chlorine accident.

6.4.4.2.2 Offsite Toxic Chemical System

Three toxic chemical detection systems are provided to detect the offsite toxic chemicals identified in Section 2.2.3, to provide annunciation in the control room, and identification of the chemical and concentration to a control room console.

Each toxic chemical detection system consists of a microcomputer built around a microprocessor and integrated with an infrared spectrometer and a multipoint sampling manifold. Each system is designed to measure and record the concentration of toxic chemicals at one sample location. Each system, located in the control enclosure, monitors the control room outside air intake plenum.

The microcomputer controls the spectrometer, signal averages the infrared transmission measurements at each programmed wavelength, calculates absorbance, and uses a stored coefficient matrix to calculate the concentration of components in the air sample.

During factory calibration, each system is programmed to monitor the toxic gases listed in Table 2.2-6. Calibration coefficients for each gas are stored in the system hard drive.

The sampling program begins with a nitrogen zero gas cycle. Ambient air is collected from the air intake plenum and pumped into the sample cell of the analyzer. The analyzer passes an infrared beam through the sample and measures the amount of light absorbed at each of the analytical wavelengths of a programmed sequence. The computer uses the stored calibration coefficients to calculate the concentration of sample components.

If the concentration of any monitored gas should exceed the selected limits, alarms will be automatically triggered at the analyzer. The toxic chemical high concentration alarm in the control room will be energized when two-out-of-three analyzers alarm. In addition to the concentration alarms, the system will indicate any malfunction related to electronics, optical system, loss of flow by local indication, or a single toxic chemical high concentration alarm.

Three “Inop/Operate” selector switches are installed on the Relay Logic Panel 00-C734, one for each analyzer. Each selector switch allows the associated analyzer, when inoperable, to be placed in the tripped condition. The switch when placed in the "Inop" position bypasses the toxic analyzer trouble annunciator for the affected analyzer and interrupts the data sent to the remote computer and PMS. With one analyzer in the tripped condition, only one of the two operable analyzers are required to alarm to satisfy the two-out-of-three alarm criteria.

A computer display console in the control room can provide an indication of the toxic chemical and its concentration at any given time.

The equipment has built-in test features. A part of the self-test program is automatically performed each time the analyzer is zeroed.

This system has self calibrated features that are always running when the analyzers are in service to keep them within specification or to activate the control room “Trouble” annunciator if any critical parameter is outside its specified range.

Test points are provided on the Relay Logic Panel for each analyzer to facilitate testing of the toxic chemical high concentration alarm relays.

No special maintenance is required.

6.4.4.2.3 Respiratory Protection

Full-faced pressure demand self-contained breathing apparatus rated for 1 hour per cylinder and protective clothing are available for control room operators.

A 6 hour onsite bottled air supply is provided by charged cylinders maintained for backup fire protection and health physics use. Offsite replenishment is provided by compressors (fill capacity greater than 30 cylinders per hour) owned by an offsite vendor, fire company, or another offsite entity.

The number of respiratory devices shall, as a minimum, provide a 6 hour air supply for 6 individuals. Consistent with the provisions of Regulatory Guide 1.95, one extra respiratory device will be provided for every 3 devices needed to meet the minimum capacity.

See Section 13.2 for discussion on Respiratory Protection.

A program for periodic inspection of control room operator respiratory equipment will be established. The program will address inspection for defects, storage conditions, and, as found to be necessary, cleaning, disinfecting, and repairing. In addition, the equipment will be cleaned, disinfected, and inspected after each use. Replacements and repairs will be done only by trained personnel using parts designed for that equipment. The equipment will be stored to protect against dust, sunlight, extreme heat or cold, excessive moisture, and damaging chemicals.

6.4.5 TESTING AND INSPECTION

The control room HVAC emergency system filtration components are tested in a program consisting of the following classifications:

a. Predelivery tests and factory component qualification tests to ensure the quality of the manufactured product.

b. Preoperational tests in accordance with the requirements of Chapter 14.

c. Periodic tests in accordance with the requirements of Chapter 16.

The frequency of tests and inspections is selected to ensure the continued integrity of the system. Charcoal testing frequency is in accordance with Regulatory Guide 1.52 for the efficiency claimed and the bed depth specified. Except that in-place testing and laboratory testing is performed at least once per 48 months as discussed in Table 6.5-2.

Written test procedures establish minimum acceptable values for all tests. Test results are recorded as a matter of performance records, thus permitting early detection of faulty performance.

The predelivery and factory component qualification tests are in accordance with the recommendations and guidelines presented in section C-3 of Regulatory Guide 1.52. HEPA filters have a minimum efficiency of 99.97% when measured with a 0.3 micron DOP aerosol. Carbon lot

testing is required and certified by a qualified testing agency to establish gas adsorption efficiency, uniformity of density, ignition temperature, hardness, and impregnate content.

Filter plenums are tested for leakage under positive pressure. Plenums are pressurized to the design pressure with soap bubble tests made at all welds. The maximum permissible leakage rate is 0.05% of the filter plenum rated flow in cubic feet per minute at 125% of the negative design plenum pressure.

Preoperational tests are conducted in accordance with the requirements of Chapter 14. In general, the tests include:

a. Visual inspection

b. Verification of ability to maintain control room pressurization without exceeding outside air makeup design flow rate

c. Airflow capacity verification test

d. Airflow distribution verification test

e. Air/aerosol uniformity test

f. Inplace HEPA test

g. Inplace adsorber test

h. Laboratory test of adsorbent

i. Electric heater test

Periodic tests of the makeup airflow to the control room HVAC system from the emergency fresh air intake are performed in accordance with the requirements of Chapter 16.

Periodic inplace testing of HEPA filters and charcoal adsorbers and laboratory testing of charcoal adsorbers are performed in accordance with the requirements of Chapter 16.

6.4.6 Instrumentation Requirement

Differential pressure indicators are provided locally to measure the pressure drop across each filter element. The overall pressure drop across each filter train is measured and indicated on the local panel and alarmed in the computer on high differential pressure.

Each charcoal adsorber is provided with three temperature switches that actuate alarms in the control room. The alarms provide information to allow the operator to discontinue operation in the event of fire or radioactivity release due to charcoal desorption. The temperature is also indicated in the control room.

The electric heating coils upstream of the filters are controlled by a minimum temperature control and a humidity control to maintain less than 70% relative humidity. In the recirculation mode, the

filters are supplied with recirculated control room air at approximately 78°F dry-bulb, 50% relative humidity. Thus, in this mode, if the charcoal adsorber is subjected to less than 70% relative humidity, the heater does not operate, and no additional heat load is imposed upon the control room HVAC system.

Radiation and offsite toxic chemical monitors are provided in the outside air intake duct. Radiation monitors are also provided in the main control room. The monitors alarm in the control room upon detection of high radiation or high toxic chemical conditions.

Differential pressure transmitters are provided which sense the differential pressure between the control room and the outside air and indicate positive pressure differential in the control room.

The hand switches for HVAC equipment required for control room habitability are located in the control room.

The flow of control room air recirculating through the emergency fresh air filter system is indicated in the control room.

Section 9.4 addresses instrumentation requirements for the control room supply and return air systems.

The instrumentation used to provide the initiating signals for control room pressurization are discussed in Sections 7.3 and 7.6.

Table 6.4-1

CONTROL ROOM EMERGENCY HVAC SYSTEM
FAILURE ANALYSIS

COMPONENT	MALFUNCTION	COMMENTS
Emergency fresh air fan	Failure of fan resulting in reduction of air flow	If the operating fan fails, the resultant reduction of air flow actuates an alarm in the control room, automatically starts the standby fan, and opens the standby filter train isolation valves.
Electric heating coil	Failure of coil control resulting in constant coil operation	Maximum capacity of the electric heating coil is not sufficient to cause damage.
	Failure of coil resulting in no heat	The heating coil is not required during emergency operation because the humidity will not exceed 70% relative humidity.
Filter train	Failure resulting in high differential pressure across the filter train	High differential pressure across the filter train is indicated on the local panel and automatically actuates an alarm in the computer. The defective filter train is manually isolated and the standby train is manually placed in service. If the high differential pressure results in low flow the standby fan and filter train will start.
	Failure resulting in high radiation at the discharge	The defective filter train is manually isolated and the redundant filter train is manually placed into operation upon receiving a high radiation signal.
Charcoal Adsorber	High temperature in charcoal bed	Temperature sensors are provided on the leaving air side of each charcoal bed to alarm in the control room

Table 6.4-1 (Cont'd)

COMPONENT	MALFUNCTION	COMMENTS
		on rising charcoal temperature. The charcoal temperature is also indicated in the control room. The deluge fire protection system is manually initiated if required.
Isolation Valve	Failure to close or failure to close completely	A series redundant isolation valve and a closed and capped test port connection provide the required isolation.
Operational Damper	Failure to open	Low flow switch actuates standby fan and filter train.
Air handling units and return air fans	All postulated failures	See Table 9.4-3.

Table 6.4-2

CONTROL ROOM POTENTIAL LEAK PATHS

	POTENTIAL LEAK PATHS	TYPE OF MATERIAL JOINT, OR PENETRATION
a.	Control room walls	3' thick reinforced concrete
b.	Control room ceiling	1½' thick reinforced concrete poured on 16 gauge galvanized steel metal decking
c.	Control room floor	1½' thick reinforced concrete poured on 16 gauge galvanized steel metal decking
d.	Control room construction joints - floor to wall, wall to wall, wall to ceiling, slab to slab	All are poured concrete cold joints
e.	Doors - personnel access	2 each - 3'x7' steam-tight metal doors with elastomer seals and sealing mechanism
f.	Electrical cable penetrations	Kaowool fiber and silicone expansion foam - 9" deep Dow-Corning 36548 RTV and Sylgard 170
g.	HVAC duct penetrations	Embedded metal sleeves through concrete walls - flanged and welded to ducts
h.	Control room HVAC ducts (negative pressure) exterior to control room	Welded galvanized steel
i.	Dampers (frames, shaft penetrations, flanges) in control room ducts (negative pressure) exterior to control room	Gas-tight construction maximum 0.1 cfm/damper from ambient into duct-work.
j.	HVAC isolation valves	Pneumatic or electrohydraulic butterfly valves - bubble-tight
k.	Piping penetrations	Bellows-type expansion joint

Table 6.4-2 (Cont'd)

	POTENTIAL LEAK PATHS	TYPE OF MATERIAL JOINT, OR PENETRATION
l.	Emergency fresh air supply system (filter assembly and fans)	Welded filter - leak tested; welded fan housing-bolted; and gasketed access doors; inlet and discharge connections
m.	Control room supply air fan cabinets	Welded cabinet construction; vaneaxial fan and coil connections - bolted; and gasketed inlet and discharge connections
n.	Test port connection and isolation valve	Capped test port connection and closed globe valve. Pneumatic or electrohydraulic butterfly valve - bubble-tight.

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 ENGINEERED SAFETY FEATURE FILTER SYSTEMS

The following filtration systems, required to perform postaccident safety-related functions are provided:

a. SGTS: In its safety-related mode of operation, this system is used to reduce halogen and particulate concentrations in gases potentially present in the reactor enclosure following a LOCA, and gases present following a postulated fuel handling accident in the refueling area before the gases are discharged to the environment (Section 6.5.1.1). The system exhausts a controlled filtered flow to the atmosphere during isolation to restore and maintain a negative pressure in the affected secondary containment zone. In addition, this system performs the nonsafety-related function of reducing halogen and particulate concentrations in gases purged from the primary containment.

b. CREFAS filter units: This system is used to clean the outside air of halogens and particulates that are potentially present in the air following a postulated accident before introducing the air into the control room HVAC system (Section 6.5.1.2).

c. RERS filter units: This system is used to reduce halogen and particulate concentrations in gases in the reactor enclosures following a LOCA. The RERS is the initial cleanup system (the SGTS is the final cleanup system) before discharge of the gases from the reactor enclosures (Section 6.5.1.3).

6.5.1.1 Standby Gas Treatment System

6.5.1.1.1 Design Bases

As described in Section 9.4.2.1, the secondary containment consists of three ventilation zones. Zones I and II surround the primary containment of Units 1 and 2, respectively, below the floor at el 352'. Zone III consists of the common refueling area above the floor at el 352'.

The SGTS is designed to accomplish the following objectives:

a. Exhaust sufficient filtered air from the reactor enclosure and/or refueling area to maintain a negative pressure of about 0.25 inch wg. in the affected volumes during secondary containment isolation (see Section 9.4.2 for discussion of the secondary containment isolation signals)

b. Filter the air exhausted to remove radioactive particulates and both radioactive and nonradioactive forms of iodine from the following areas:

   1. Reactor enclosure (Zone I and Zone II)

   2. Refueling area (Zone III)

   3. Deleted

   4. Primary containment during purging and ventilating

5. Discharge from the HPCI barometric condenser, following filtration by the RERS when the reactor enclosure is isolated

c. Ensure that the failure of any component of the filtration train, assuming LOOP, cannot impair the ability of the system to perform its safety function

d. Remain intact and functional in the event of a SSE

e. Automatically start in response to any one of the following signals:

1. LOCA signal as described in Section 9.4.2.

2. High radiation level in refueling area exhaust air

3. High radiation level in reactor enclosure (Zone I or Zone II) exhaust air

4. Low differential pressure in the reactor enclosure (Zone I or Zone II)

5. Low differential pressure in refueling area (Zone III)

(The SGTS fans can also be started manually in the control room by tripping the refueling area isolation system or the reactor enclosure isolation system.)

f. The design bases employed for sizing the filters, fans, and associated duct-work are as follows:

1. Each filter train is sized and specified for treating the incoming air-steam mixture at 11,000 cfm maximum and 135°F ① for drywell purge (drywell purge is discussed in Section 9.4.5). The SGTS fans are sized for 8400 cfm maximum flow at 20 inches wg. static pressure.

2. The system capacity is maintained with all filters fully loaded (dirty).

3. For HEPA filters, maximum free velocity does not exceed 300 fpm with maximum airflow resistance of 1 inch wg. when clean and minimum efficiency of 99.97% by DOP test method.

4. The charcoal adsorber is rated for 99.0% trapping of radioactive iodine as elemental iodine (I_2) and 99.0% trapping of radioactive iodine as methyl iodide (CH_3I) when passing through charcoal (8 inch bed depth) at 70% relative humidity. The air residence time in the 8 inch charcoal bed is 0.68 seconds considering a maximum total after drawdown leakage rate from Zones I, II, and III of 5764 cfm.

① This information is based on original design conditions. Further evaluation has validated this design for a drywell operating temperature of 150°F.

5. Relative humidity at the charcoal adsorber is limited to 70% by the appropriate heating of air.

6. The SGTS maximum fan capacity is based on the calculated inleakage into secondary containment with the secondary containment maintained at a negative pressure of 0.25 inches of water with reference to the outside atmosphere. The maximum capacity includes an allowance for thermal expansion of the secondary containment air volume due to equipment residual heat transfer to the air during SGTS operation.

6.5.1.1.2 System Description

The SGTS is common to both Units 1 and 2. Each of the two redundant SGTS filter trains consists of an electric air heater, two banks of HEPA filters (upstream and downstream of charcoal adsorber), a vertical 8 inch deep charcoal adsorber bed (with temperature detection sensors and a water flooding system for fire protection), and associated dampers, ducts, instruments, valves, and controls.

For its safety-related mode of operation (Section 6.5.1.a), two redundant 100% capacity SGTS fans are provided for use in conjunction with the SGTS filter trains. Each fan has a controllable capacity of 500 cfm to 8400 cfm, which is sufficient to restore and maintain both reactor enclosures and the common refueling area at the required negative pressure in relation to atmospheric pressure during secondary containment isolation. The air flow varies in response to secondary containment differential pressure controls, which modulate the fan inlet vanes and control dampers in the run-around bypass and discharge ducts provided for each fan. Slide gate dampers with position switches are closed to isolate the SGTS from any secondary containment zone which cannot be isolated and drawn down.

The SGTS is actuated automatically in its safety-related mode of operation. Both SGTS filter trains are maintained in the open position. Upon receipt of a secondary containment isolation signal (Section 6.5.1.1.1.e), both of the SGTS fans are started and the associated controls are activated to open or modulate appropriate dampers and valves so that the system function is accomplished. Following the initial fan start, the operators may elect to place one of the SGTS fans in the standby position.

For its nonsafety-related mode of operation (Section 6.5.1.a), two redundant 100% capacity drywell purge fans are provided for use in conjunction with the SGTS filter trains. Each fan has a capacity of 11,000 cfm which is sufficient for the drywell purge operation.

The SGTS is manually actuated for its nonsafety-related mode of operation.

If one of the SGTS filter train isolation valves fails closed during its safety-related mode of operation, the redundant filter train is automatically placed into service. If one of the SGTS fans fails to establish flow, because of either fan or fan damper failure, the standby SGTS fan automatically starts.

The SGTS is shown schematically on drawing M-76. Specific SGTS component design parameters are shown in Table 6.5-1.

The equipment and materials conform to the applicable requirements and recommendations of the guides, codes, and standards listed in Section 3.2. Conformance with Regulatory Guide 1.52 is discussed in Table 6.5-2.

Components for each SGTS train are designed as discussed in the following paragraphs.

A prefilter is not included in the SGTS filter trains because the SGTS intake is downstream of the recirculation filter system fans so that the air is prefiltered before entering the SGTS filters after RERS start during reactor enclosure isolation. A prefilter is provided in the SGTS duct for air drawn from the refueling area during refueling area isolation. The drywell purge air supply is prefiltered by the reactor enclosure supply air system during the drywell purge mode.

The SGTS fan performance and motor selection are based on the maximum system pressure drop resulting from dirty SGTS filters. The SGTS filter banks are sized for 11,000 cfm drywell purge flow, (see Table 6.5-1 for filter pressure drops).

The charcoal adsorber is a gasketless, welded seam type filled with impregnated activated charcoal that meets the requirements in table 5-1 of ANSI N509 (1980) and Regulatory Guide 1.52 except that laboratory analysis of carbon samples is performed in accordance with ASTM D3803-1989. The bank holds a total of approximately 2400 pounds of charcoal having an ignition temperature of not less than 626°F. The charcoal adsorber is capable of removing not less than 99.0% of elemental iodine and 99.0% of methyl iodide at 70% relative humidity. The maximum loading is 2.5 milligrams of iodine per gram of activated charcoal.

A demister is not required for the SGTS filters. The absence of water droplets in the air stream entering the SGTS filters during post-LOCA isolation, refueling area isolation, and primary containment purging is assured based on the following:

a. The SGTS intake is downstream of the RERS filters and normally exhausts air which has been prefiltered by the RERS filters. However, prior to RERS fan operation (up to 3 minutes post-LOCA), the SGTS can draw air directly through a pressure relief vent located between the RERS and SGTS ducts. This vent is located in an access area on el 283' where there are no significant sources of humidity which can form water droplets. After the RERS fan starts, the vent is maintained at a slight positive pressure with air which has been prefiltered by the RERS filters. The absence of water droplets in the RERS air stream during reactor enclosure isolation is discussed in Section 6.5.1.3.2.

b. There are no sources of water droplets in the refueling area that could enter the duct connection to the SGTS. As discussed below, water droplets from condensation will not reach the SGTS filters during refueling area isolation because of the tortuous flow path and low velocities through the ducts, and low point drains in the ducts. The duct from the refueling area to the SGTS filters passes the Unit 1 reactor enclosure for approximately 260 feet and includes at least 20 bends and turns. If condensation does occur, the amount of condensation would be minor, based on the potential amount of water vapor in the air stream. One inch diameter low point drain is provided for the portion of duct-work in the reactor enclosure to ensure that any condensation will be drained from the duct. When refueling area drawdown begins, the flow rate could reach 2400 cfm or more for a short period of time. As water vapor accumulates in the refueling area, the flow rate will be decreasing. During the period when any significant condensation could occur in the ducts, the flow rate in the duct will be no more than 800 cfm. The air velocity during this period varies from approximately 162 fpm to 325 fpm (1.8 mph to 3.7 mph) for the majority of the duct-work.

c. Water droplets will not reach the SGTS filters during drywell containment purging because of the reasons discussed below.

It is highly unlikely that water droplets will enter the purge lines during drywell purging. As discussed in Section 6.5.1.3.3, the licensee's preventive maintenance program will maintain normal plant leaks to low flow dripping type leakages. Any leakage with spraying water droplets (such as those due to failed seals in pumps and valves) will be identified and corrected as part of the maintenance program. It can be shown that any droplets formed will travel less than 20 feet. There are no potential sources of water droplets within 20 feet of the suppression chamber purge exhaust opening. There are no pumps, and only few valves, within 20 feet of the drywell purge exhaust opening. The closest valve is 8 feet away from the opening. Because the purge system is used during only a limited period of power operation (only open for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open), it is highly unlikely that a valve seal would fail and spray water into the drywell purge exhaust opening during purge system operation.

If water droplets are hypothetically assumed to enter the purge exhaust ducts, or if condensation within the duct-work occurs, the water droplets would not reach the SGTS filters because of the tortuous flow path, the insulated duct-work in the control structure, and the SGTS heaters. Purge air exhausted from the drywell flows approximately 215 feet in the reactor enclosure through three valves, two vertical upward turns, and four additional bends and turns with a flow rate of 11,000 cfm at a velocity of 2240 fpm (25.5 mph) in the duct, and 3731 fpm in the pipe. The purge air from the suppression chamber flows more than 160 feet in the reactor enclosure through valves and six bends and turns with a flow rate of 9750 cfm and a velocity of 1986 fpm (22.6 mph) in the duct, and 6008 fpm in the pipe. At these velocities, if condensation occurs within the duct-work, it is possible for some water droplets to be entrained in the air-steam. Condensation within the reactor enclosure duct-work could occur while purging the suppression chamber, but no significant condensation would occur while purging the drywell because the drywell is maintained at a low relative humidity by the drywell coolers. No significant condensation would occur in the control enclosure duct-work for either purge mode because it is insulated.

The environmental conditions within the reactor enclosure duct-work will be such that only surface type condensation could occur. Droplets will coalesce on the inside surface of the duct creating larger droplets, forming condensate flow on the bottom of the duct. Much of this flow will drain to low points in the duct-work and be removed via drains, and therefore never enters the air stream. Much of the condensate that does become entrained in the air stream is subsequently removed from the air stream due to the any bends and turns in the duct. Water droplets greater than 20 microns in size are removed by the bends and turns, including a square elbow with turning vanes, which act as course moisture separators (Reference 6.5-2). Water droplets less than 20 microns in size may reach the SGTS heaters. However, analyses have been performed to demonstrate that the SGTS heaters can evaporate all water droplets less than 25 microns in size. Thus, no water droplets will reach the SGTS filters.

The effects of water droplets on the SGTS HEPA filters were evaluated, even though there is no credible way for water droplets to reach the HEPA filters. (Effects on the charcoal filters were not evaluated because the HEPA filters are upstream of the charcoal filters and would collect any water droplets postulated to be in the air

stream). When HEPA filters are exposed to high concentrations of liquid, plugging could occur that would decrease air flow through them. Decreased efficiency in collecting particulate matter would not occur unless plugging is severe enough to rupture the HEPA filter. Based on Reference 6.5-2, if the maximum water delivery rate is kept below 0.18 gpm per 1000 cfm of air flow, plugging will not occur. Analyses have been performed to demonstrate that, even if all of the condensation that forms in the duct during the worst case condition of suppression pool purging is hypothetically assumed to reach the HEPA filters in the form of water droplets, the condensate loading is only 8.33×10^{-3} gpm/1000 cfm, which is well below 0.18 gpm/1000 cfm. Thus, plugging of the filters would not occur.

Analyses were performed to demonstrate that the SGTS heaters are capable of reducing the relative humidity of the air during suppression pool purging (9750 cfm for this mode) from 100% relative humidity, with entrained droplets, to less than 70% relative humidity, with no entrained droplets. The SGTS heaters are also capable of reducing the relative humidity of the air during drywell purging (11,000 cfm for this mode), from 100% relative humidity to less than 70% relative humidity.

A water flooding system within the charcoal bed is provided. The water system is connected to the station fire protection system. Valves are mounted outside the charcoal adsorber. Two continuous type thermistors are provided on the leaving air side of the charcoal bed. A rise in the charcoal bed area temperature results in the following:

a. The first temperature setpoint (200°F) actuates an alarm in the control room. The filter train is removed from service until the cause of the alarm has been determined. The operator shall investigate to determine if a fire has occurred and introduce the fire protection water to the charcoal plenum, if necessary, as listed in Item c.

b. The second temperature setpoint (250°F) also actuates an alarm in the control room. The operator shall continue to investigate to determine if a fire has occurred and introduce the fire protection water, if necessary, as listed in Item c. The SGTS charcoal temperature sensor system power trouble alarm is allied with this alarm window.

c. The third temperature setpoint (550°F) actuates an alarm in the control room. The operator shall investigate to determine if a fire has occurred and introduce the fire protection water to the charcoal plenum, if necessary, as follows: The operator manually opens the valves, thus introducing the fire protection water to the charcoal plenum. A drain valve is provided to drain the water from the filter plenum.

Four test canisters are provided for each charcoal adsorber. These canisters contain the same depth of the same charcoal that is in the adsorber. The canisters are mounted so that a parallel flow path is created between each canister and the adsorber. Periodically one of the canisters can be removed and laboratory tested to verify the adsorbent efficiency. Alternate means of sampling (slotted-tube method) may also be used for obtaining representative samples of used activated charcoal per the requirements specified in ANSI N509-1980.

Permanently installed injection and sampling ports are provided for all ESF atmosphere cleanup systems to permit accurate testing in accordance with ANSI N510. Providing fewer charcoal test canisters on the ESF atmosphere cleanup systems than specified in ANSI N509 (1980) section 4.11 results in equal or more frequent replacement of activated carbon. Regulatory Guide 1.52 states that testing of representative samples should be performed (1) initially, (2) at least once per 18

months thereafter for systems in a standby status, or after 720 hours of system operation and (3) following painting, fire, or chemical release in any ventilation zone communicating with the system. However, representative samples of the SGTS are tested at least once per 48 months as discussed in Table 6.5-2. More frequent replacement may result because Regulatory Guide 1.52 further states that when no representative samples are available for testing, the activated carbon should be replaced with new activated carbon.

Access doors, with 30x68 inch openings, to each HEPA filter compartment are provided. An 18 inch access hatch is provided for the charcoal filter compartment.

The HEPA filter and charcoal filter housings are of all-welded construction.

Interior lights with external light switches are provided in the HEPA filter plenums to facilitate inspection, testing, and replacement of components.

The SGTS has been designed to continuously purge the filter plenums with dry instrument air when the filters are not in use. Any amount of dry air continuously purged through the adsorbers and HEPA filters will entrain moisture and maintain moisture levels at a minimum because the duct-work is gas-tight and there is no internal humidity source. (The periodic operation of the ESF atmosphere cleanup (SGTS) train could introduce additional moisture into the system and increase moisture levels above those normally maintained.)

The electric heater maintains the relative humidity below 70% for charcoal adsorber operation by maintaining a constant temperature rise of 15°F across the heater. An analysis of heater capabilities for various entering saturated air conditions up to 150°F (which exceeds any inlet conditions the SGTS system will experience) yields a peak heating requirement of 135,000 Btu/hr, at maximum 11,000 cfm airflow. A 55 kW heater is provided.

The automatic reset cutout (setpoint 260°F) is located inside the heater where the sensed temperature is higher than the actual air temperature downstream of the heater. This heater protection device that was selected and installed by the heater manufacturer. The automatic reset cutout (setpoint 180°F), which is located downstream of the heater, senses the actual temperature of air leaving the heater and causes an alarm signal in the control room when the air temperature exceeds 180°F. Because the SGTS electric heaters operate with a fixed temperature differential of 15°F between the inlet and outlet air temperatures and the maximum inlet temperature is 150°F, the maximum air temperature downstream of the heater should not exceed 165°F. In the event of a heater malfunction, the discharge air automatic reset cutout will shut off the heater when the downstream air temperature exceeds 180°F. The conservatively selected 180°F heater cutout temperature, and an alarm annunciation in the control room to notify the operator if this condition should occur are considered to be equivalent to the 225°F manual heater cutout required by section 5.5 of ANSI N509-76.

6.5.1.1.3 Design Evaluation

The SGTS is designed to preclude direct exfiltration of contaminated air from the secondary containment following a postulated accident or an abnormal occurrence which could result in abnormally high airborne radiation in the secondary containment. Equipment is powered from Class 1E buses, and all power circuits meet IEEE 279 and IEEE 308 requirements to ensure power availability from the standby diesel generator sets in the event of loss of normal offsite ac power. Redundant components are provided where necessary to ensure that a single failure does not impair or preclude system operation. The SGTS is designed to seismic Category I requirements as discussed in Section 3.7 to ensure that the system remains intact and functional in the event of an SSE. Components and materials of the SGTS system have been selected to assure availability of the system under postulated accident conditions. An SGTS failure mode and effect analysis is presented in Table 6.5-3.

6.5.1.1.4 Tests and Inspections

Except for Items D.2 and D.3 of Table 9.4-4, all tests and inspections described in the table apply to the SGTS. Conformance with Regulatory Guide 1.52 is discussed in Table 6.5-2.

ESF atmosphere cleanup systems are accessible during normal operation and during anticipated transients. ESF atmosphere cleanup systems are designed to operate after an accident or during drywell purge. Periodic tests are performed during normal operation on all ESF atmosphere cleanup systems, to ensure that prefilters and HEPA filters are either changed on high pressure readings or checked on abnormal readings.

The system will be preoperationally tested in accordance with the requirements of Chapter 14 and periodically tested in accordance with the requirements of Chapter 16.

6.5.1.1.5 Instrumentation

The SGTS can be actuated manually from the control room. Each SGTS train is designed to function automatically upon receipt of a secondary containment isolation signal. The status of system equipment, which is an indication of pertinent system temperatures and flow rates, is displayed in the control room during both normal and accident operation.

All instrumentation required during and after accident conditions is qualified to meet seismic Category I requirements. Instrumentation conformance with Regulatory Guide 1.52 is discussed in Tables 6.5-2 and 6.5-8.

The following alarms are annunciated in the control room:

a. Fan trouble

b. Heater failure (low temperature rise across the heater)

c. Charcoal filter high temperature alarms

d. Filter system trouble (including valve circuit trouble, charcoal temperature detection system trouble and electric heater trouble)

e. Low pressure differential, referenced to the outside ambient pressure, in the secondary containment ventilation zones being isolated

6.5.1.1.6 Materials

The materials of construction used in or on the SGTS are given in Table 6.5-4.

Materials used in or on the SGTS are selected to ensure that system operability is not affected by radiation, temperature, or other environmental effects. Environmental qualification of the SGTS is discussed in Section 3.11.

By being located in the control structure, the SGTS is protected from extremes of radiation and temperature that could potentially produce radiolytic or pyrolytic decomposition of filter materials. Thus, filter system decomposition products would not be generated.

6.5.1.2 Control Room Emergency Fresh Air Filter Units

6.5.1.2.1 Design Bases

The design bases for the control room emergency fresh air filter units are described in Sections 6.4 and 9.4.1 and as given below.

The design bases employed for sizing the filters, fans, and associated duct-work are as follows:

a. Each filter train is sized and specified for treating incoming air at 3000 cfm at design outdoor temperature.

b. The system capacity is maintained with all filters fully loaded (dirty).

c. For HEPA filters, maximum free velocity does not exceed 300 fpm with maximum airflow resistance of 1 inch wg. when clean and minimum efficiency of 99.97% by the DOP test method.

d. The charcoal adsorber is rated 95.0% for trapping of radioactive iodine as elemental iodine (I_2) and 95.0% trapping of radioactive iodine as methyl iodide (CH_3I) when passing through charcoal (2 inch bed depth) at 70% relative humidity. The air residence time in the 2 inch charcoal bed is not less than 0.25 seconds.

6.5.1.2.2 System Description

The control room emergency fresh air filter system is described in Sections 6.4 and 9.4.1. Conformance with Regulatory Guide 1.52 is discussed in Table 6.5-2.

6.5.1.2.3 Design Evaluation

The control room emergency fresh air filter units work in conjunction with the control room HVAC system to maintain habitability in the control room. The design evaluation is given in Sections 6.4 and 9.4.1. Control room emergency fresh air filter system failure analysis is given in Section 6.4.

6.5.1.2.4 Tests and Inspections

Tests and inspections are described in Sections 6.4 and 9.4.1.

6.5.1.2.5 Instrumentation

Instrumentation requirements are discussed in Section 6.4. Conformance with Regulatory Guide 1.52 is discussed in Tables 6.5-2 and 6.5-8.

6.5.1.2.6 Materials

The materials of construction used in or on the control room emergency fresh air filter systems are given in Table 6.5-5.

Materials used in or on the emergency fresh air filter systems are selected to ensure that system operability is not affected by radiation, temperature, or other environmental effects. Environmental qualification of the system is discussed in Section 3.11.

By being located in the control structure, the emergency fresh air filter systems are protected from extremes of radiation and temperature that could potentially produce radiolytic or pyrolytic decomposition of filter materials. Thus, filter system decomposition products would not be generated.

6.5.1.3 Reactor Enclosure Recirculation System Filter Units

6.5.1.3.1 Design Bases

The RERS is designed to accomplish the following objectives:

a. Filter the air in the reactor enclosures following a LOCA to reduce the concentration of radioactive halogens and particulates potentially present in the reactor enclosures

b. Ensure that failure of any component of the filtration train, assuming loss of offsite power, cannot impair the ability of the system to perform its safety function

c. Remain intact and functional in the event of an SSE

d. Automatically start in response to any one of the following signals (the RERS fans can also be started manually in the control room by tripping the reactor enclosure isolation system):

    1. LOCA signal as described in Section 9.4.2

    2. High radiation level in the reactor enclosure (Zone I or Zone II) exhaust air of the respective unit

    3. Low differential pressure in the reactor enclosure (Zone I or Zone II)

e. The design bases employed for sizing the filters, fans, and associated duct-work are:

    1. Each filter train is sized and specified for treating incoming air at 60,000 cfm and 150°F, which exceeds the accident temperature service requirements.

2. The system capacity is maintained with all filters fully loaded (dirty).

3. For HEPA filters, maximum free velocity does not exceed 375 fpm, with maximum airflow resistance of 1 inch wg. when clean and minimum efficiency of 99.97% by DOP test method.

4. The charcoal adsorber is rated for 95.0% trapping of radioactive iodine as elemental iodine (I_2) and 95.0% trapping of radioactive iodine as methyl iodide (CH_3I) when passing through charcoal (2 inch bed depth) at 70% relative humidity. The air residence time in the 2 inch charcoal bed is not less than 0.25 seconds.

6.5.1.3.2 System Description

There are two redundant RERS trains in each reactor enclosure. Each of the RERS trains consists of a bank of prefilters, two banks of HEPA filters (upstream and downstream of the charcoal adsorber), a vertical two inch deep charcoal adsorber bed (with fire detection temperature sensors and a water spray system for fire protection), and associated dampers, ducts, instruments, and controls. The RERS is shown schematically on drawing M-76. Specific RERS component design parameters are provided in Table 6.5-1.

The equipment and materials conform to the applicable requirements and recommendations of the guides, codes, and standards listed in Section 3.2. Conformance with Regulatory Guide 1.52 is discussed in Table 6.5-2.

Each redundant RERS train has a constant capacity of 60,000 cfm, and each is capable of treating the required amount of air from the Unit 1 or Unit 2 reactor enclosure volume being recirculated. Components for each RERS are designed as discussed in the following paragraphs.

The fan performance and motor selection are based on maximum system pressure drop, that is, a pressure drop based on maximum pressure drops across the component filters (3 inches wg. for the first bank of HEPA filters and 4 inches wg. for the second bank). The air flow is maintained at a constant rate by flow control dampers.

The charcoal adsorber is a gasketless, welded seam type filled with impregnated activated charcoal that meets the requirements in table 5-1 of ANSI N509 (1980) and Regulatory Guide 1.52 except that laboratory analysis of carbon samples is performed in accordance with ASTM D3803-1989. The bank holds a total of approximately 13,000 pounds of charcoal having an ignition temperature of not less than 626°F. The charcoal adsorber is capable of removing not less than 95.0% of elemental iodine and 95.0% of methyl iodide at 70% relative humidity.

There are no demisters provided for the RERS. The absence of water droplets in the RERS air stream during reactor enclosure isolation is assured based on the following:

a. The reactor enclosure relative humidity will not exceed 77% during normal operation. This relative humidity will decrease to below 70% post-LOCA due to the increase in heat to the structure.

b. ESF system leakage will be held to a minimum because LGS will follow the guidelines of NUREG-0737 Item III.D.1.1, i.e., provide periodic surveillance tests to minimize system leakage.

c. The RERS is not required to mitigate the consequences of a HELB or a moderate energy line break. Therefore this line break is not considered a source of water that could enter the RERS air stream.

d. The RERS will not communicate with the refueling area during reactor enclosure isolation or refueling area isolation. Therefore humidity from the fuel pool is not considered a source of water that could enter the RERS air stream. As indicated in Table 6.5-2, the SGTS, which will drawdown the refueling area upon refueling area isolation, will be provided with a prefilter in accordance with Regulatory Guide 1.52.

A water spray system within the charcoal bed is provided. The spray system is connected to the fire protection system. A valve is mounted outside the charcoal adsorber. A continuous type thermistor is provided on the leaving air side of the charcoal bed. A rise in the charcoal bed area temperature results in the following:

a. The first temperature setpoint (200°F) actuates an alarm in the control room. The filter train is removed from service until the cause of the alarm has been determined. The operator shall investigate to determine if a fire has occurred and introduce the fire protection water to the charcoal plenum, if necessary, as listed in item c.

b. The second temperature setpoint (250°F) also actuates an alarm in the control room. The operator shall continue to investigate to determine if a fire has occurred and introduce the fire protection water, if necessary, as listed in item c. The RERS charcoal temperature sensor system power trouble alarm is allied with this alarm window.

c. The third temperature setpoint (550°F) actuates an alarm in the control room. The operator shall investigate to determine if a fire has occurred and introduce the fire protection water to the charcoal plenum, if necessary, as follows: The operator manually opens the valve, thus introducing the fire protection water to the charcoal plenum. A drain valve is provided to drain the water from the filter plenum.

Six test canisters are provided for each charcoal adsorber. These canisters contain the same depth of the same charcoal that is in the adsorber. The canisters are mounted so that a parallel flow path is created between each canister and the adsorber. Periodically one of the canisters can be removed and laboratory tested to verify the adsorbent efficiency. Alternate means of sampling (slotted-tube method) may also be used for obtaining representative samples of used activated charcoal per the requirements specified in ANSI N509-1980.

Access doors, with 20x50 inch openings, are provided in each filter compartment in the RERS plenum.

The RERS filter plenum housing is of all-welded construction.

Interior lights with external light switches are provided between all train components to facilitate inspection, testing, and replacement of components.

Each charcoal train is continuously purged with 1 cfm of dry instrument air; however, any amount of dry air continuously purged through the adsorbers and HEPA filters will entrain moisture and maintain moisture levels at a minimum because the duct-work is gas-tight and there is no internal humidity

source. (The periodic operation of the ESF atmosphere cleanup train could introduce additional moisture into the system and increase moisture levels above those normally maintained.)

The RERS is actuated either automatically (safety-related mode) or manually for routine system operability testing (nonsafety-related mode). The automatic actuation is originated by the reactor enclosure isolation signal (Section 6.5.1.3.1.d).

During normal operation the RERS trains are maintained in a lead/lag mode of operation. Upon receipt of an automatic isolation signal the RERS train in lead will automatically start to accomplish the system functions. The RERS train in lag will remain in standby. In the event of a single active failure associated with the operating RERS train, the RERS train in standby will automatically start, following a time delay, to perform the system functions and will operate for the duration of the Design Bases Event.

6.5.1.3.3 Design Evaluation

The RERS is designed for filtration of contaminated air in the reactor enclosure following a postulated accident or abnormal occurrence which could result in abnormally high airborne radiation in the reactor enclosure. Equipment is powered from Class 1E buses and all power circuits meet IEEE 279 and IEEE 308 requirements to ensure uninterruptible operation in the event of loss of normal offsite ac power. Redundant components are provided where necessary to ensure that a single failure will not impair or preclude system operation. Operating the RERS trains in a lead/lag mode will assure compliance with the design bases since a single RERS train is sufficient to perform all of the required RERS safety functions and the time delay associated with the shutdown of the lead RERS train and standby start of the lag RERS train will have a negligible effect on the Reactor Enclosure differential pressure, the post-LOCA mixing function and the on-site/off-site dose analyses. The RERS is designed to seismic Category I requirements as discussed in Section 3.7 to ensure that the system remains intact and functional if there is an SSE. Components and materials of the RERS have been selected to assure availability of the system under postulated accident conditions. A RERS failure mode and effect analysis is presented in Table 6.5-6.

An analysis was conducted to calculate the maximum post-LOCA time period for which the relative humidity at the inlet of the RERS charcoal filters could exceed 70%. It was found that within 15 minutes after isolation of the reactor enclosure secondary containment, the relative humidity will decrease from an initial maximum condition of 76.2% to below 70%. The following conservative rationale was used for this analysis:

a. The reactor enclosure supply air system uses unconditioned outdoor air to provide once-through ventilation to cool the reactor enclosure during normal plant operation.

b. On a design basis summer day of 95°F (Db), the reactor enclosure ventilation system is designed to maintain the reactor enclosure at a nominal 104°F. The outdoor air is sensibly heated from 95°F to 104°F as it passes through the reactor enclosure supply fans and from internal reactor enclosure heat loads such as the primary containment, MCCs, load control centers, motors, lights, cable trays, and piping.

c. Assuming outdoor air conditions of 95°F (Db) and 95°F (Wb) (100% relative humidity) exist, the same air when heated to 104°F (Db) will have a relative humidity of 76.2%. This is the basis for the initial reactor enclosure relative humidity conditions when isolation occurs due to a LOCA.

d. Based on the ASHRAE 1981 Handbook of Fundamentals, less than 1% of the total hours during the months of June through September will exceed a 93°F (Db) or 77°F (Wb) in Philadelphia. Therefore the outdoor air conditions used in this analysis are improbable.

e. Other outdoor air conditions at lower dry-bulb and wet-bulb temperatures, which are more probable from a meteorological standpoint, can also result in an initial reactor enclosure relative humidity condition exceeding 70%. However, the initial relative humidity for these cases will be less than 76.2% because cooler air contains less moisture and the 9°F temperature rise from operating equipment has a greater effect on lowering the relative humidity.

f. After isolation occurs, an increase in the bulk reactor enclosure temperature from 104°F to 107°F will lower the relative humidity to 70% in accordance with basic psychrometric principles. At lower reactor enclosure temperatures, the initial relative humidity is closer to 70%, and a smaller temperature rise after isolation is needed to lower the relative humidity to 70%.

g. Only internal reactor enclosure heat loads that were determined to exist for the duration of the transient were considered to provide air heat-up. The heat load from seismic Category II motors was considered to decay instantly because loss of their internal motor ventilating fans would prevent efficient residual heat removal from the motor casings. The lighting load was also considered to decay to zero instantly because the small mass and therefore residual heat stored in this equipment would be small.

h. The heat loss of the air into the cooler exterior and interior walls and floor slabs of the reactor enclosure was calculated using a conservative heat transfer model.

i. The cooling effect of outdoor air inleakage into the reactor enclosure due to SGTS operation was considered.

j. Because the bulk reactor enclosure temperature 15 minutes post-LOCA will always exceed any outdoor air temperature by at least 12°F (107°F versus 95°F for worst case analysis), the relative humidity will not rise above 70% for the duration of RERS operation.

k. Internal sources of moisture resulting from operation of the ECCS pumps were evaluated. The additional moisture was found to be small and will not have a significant effect on relative humidity.

The RERS charcoal filter efficiency is not expected to be adversely affected by this temporary condition. Although the initial relative humidity of the reactor enclosure is 76.2% at the time of the LOCA, the RERS does not operate for the first 3 minutes. Therefore, the time period in which the relative humidity exceeds 70% and the RERS operates is between 3 minutes and 15 minutes when the average relative humidity will be approximately 73%. Reference 6.5-2 recommends a charcoal efficiency for methyl iodine removal of 95% for relative humidities of 85% and less as a conservative design basis. It also states that "Trapping of elemental radioiodine involves physical adsorption only, and the efficiency of nearly any good grade of activated carbon, impregnated or not, will be at least 99% (DF = 100) under any combination of temperature and humidity that would be encountered in

a nuclear air cleaning system." Evidence that these efficiency values are realistic and conservative has been identified in the following sources:

a. The ANSI N509 (1980) activated carbon performance test requirements and acceptance values are more stringent than the recommended efficiency values of Reference 6.5-2. LGS RERS charcoal is being supplied in accordance with the ANSI N509 requirements.

b. Figure 4.6 of Reference 6.5-3 plots the test results of 65 different methyl iodine penetration tests as a function of relative humidity. In no cases was the penetration found to be greater than 4% when the relative humidity was less than 85%. Figure 4.7 of Reference 6.5-3, based on 7 different tests, indicates a generally low penetration (less than 1%) for elemental iodine for all relative humidity conditions.

It was also determined that demisters were not necessary for the RERS. This conclusion is based on the following analysis of a postulated situation in which water droplets are assumed to be formed from system leakage and the possible migration paths of this leakage to the RERS filters.

The estimated leakage from the drywell/suppression pool to the reactor enclosure is limited by several mechanisms. These are:

a. The limit of 0.5% per day air leakage imposed by the containment leak test Technical Specification, the periodic integrated leak rate test, and individual valve leak tests. The 0.5% per day leak rate corresponds to approximately 1.4 cfm, which dictates only pinhole-size leak paths. These small leak paths serve to condense moisture and preclude droplet formation.

b. The programs of preventive maintenance implemented by NUREG-0737, Item III.D.1.1 to minimize system leakage. This program includes helium leak detection for gaseous systems and liquid detection/inspection for liquid-containing systems.

c. The postulated passive failure of an RHR pump seal and resulting release of liquid. The licensee’s preventive maintenance program will maintain normal plant leaks to low flow dripping type leakages. Any leakages with spraying water droplets will be identified and corrected as part of the maintenance program. However, for the purpose of this discussion, a postulated passive failure of an RHR pump seal is assumed (SRP 15.6.5, Appendix B). This assumption results in a 5 gpm leak of suppression water at less than 212°F (Figure 6.2-9) and may produce water spray into the air. Because the water is below the boiling point, the airborne water will fall to the floor and subsequently into the floor drains with little or no flashing.

   If water should be sprayed from the passive failure, it can be shown that any droplets formed travel less than 20 feet, based on analyses of spray systems where the nozzles are designed to maximize the development of water droplets (Reference 6.5-1). These analyses have shown that 1000 micron droplets would travel no more than 20 feet in a horizontal direction with an initial velocity of 3000 ft/sec. The travel distance from the RHR pump seal to the local RERS exhaust vents is approximately 29 feet vertically and 10 feet horizontally. No droplets will reach the exhaust duct.

   Another factor virtually eliminating the potential for water droplets to travel as far as 20 feet is the effect of the unit coolers in the ECCS rooms. These coolers have flow

rates of 9000 cfm to 22,000 cfm. The major objective of the unit coolers is to ensure cool ambient air in the RHR room and to condense excess water vapor. The RHR pump rooms have unit coolers, each operating at 21,800 cfm. The unit cooler air flow competes with the 310 cfm RERS exhaust air flow. Over 95% of the moisture in the air will go through the unit coolers and not into the duct-work.

If it is hypothetically and nonmechanistically assumed that airborne droplets are available, those water droplets entering the exhaust duct must make an immediate 90° turn. A 155 fpm (1.8 mph) RERS exhaust air velocity is not sufficient to overcome the force of gravity to impart a vertical upward velocity to any water droplets. Over 400 feet of RERS ducting containing valves and dampers and numerous bends and turns (at least 15) exist between the exhaust and the prefilters. This tortuous path results in droplets either falling back or impacting on the walls of the ducting where it will evaporate due to the less than 100% humidity in the air flow.

Furthermore, any water droplets suspended in the small air flow (310 cfm) from the RHR room are diluted by 59,700 cfm entering the RERS from other parts of the reactor enclosure. Because the calculated maximum humidity is less than 76.2%, water droplets carried with the air stream would be evaporated.

Even if water droplets were to reach the RERS filters, the droplets must first pass through the prefilter and the HEPA filters before impacting the charcoal medium. Both of these filters are more efficient at removing water droplets from air than demisters. Water removed would be evaporated in the air due to the maximum humidity being less than 76.2%.

Given these physical conditions and the lack of a significant source of water droplets, there is no need to install a demister on the RERS.

These contributions to the DBA/LOCA are considered in the Section 15.6.5 analysis and in SRP 15.6.5, Appendices A and B.

d. Deleted

6.5.1.3.4 Tests and Inspections

Tests and inspections are described in the applicable items (2, 3, and 7 through 13) in Table 9.4-4. Conformance with Regulatory Guide 1.52 is discussed in Table 6.5-2. The system is preoperationally tested in accordance with the requirements of Chapter 14 and periodically tested in accordance with the requirements of Chapter 16.

6.5.1.3.5 Instrumentation

The RERS can be actuated manually from the control room by tripping the reactor enclosure isolation system. Each RERS train is designed to function automatically upon receipt of a reactor enclosure isolation signal. The status of system equipment, which is an indication of pertinent system pressure drops and temperatures, is displayed in the control room during both normal and accident operation.

All instrumentation required during and after accident conditions is designed to seismic Category I requirements. Instrumentation conformance with Regulatory Guide 1.52 is discussed in Tables 6.5-2 and 6.5-8.

The following alarms are annunciated in the control room:

a. Fan trouble (including valve circuit trouble and charcoal temperature detection system trouble)

b. Charcoal filter high temperature alarms

ESF atmosphere cleanup systems are accessible during normal operation and during anticipated transients. ESF atmosphere cleanup systems operate only after an accident or during drywell purge. This allows operation on all ESF atmosphere cleanup systems, which ensures that prefilters and HEPA filters are either changed on high pressure readings or checked on abnormal readings.

6.5.1.3.6 Materials

The materials of construction used in or on the RERS are given in Table 6.5-7.

Materials used in or on the RERS are selected to ensure that system operability is not affected by radiation, temperature, or other environmental effects. Environmental qualification of the RERS is discussed in Section 3.11.

Filter materials used will not decompose due to radiation during the specified useful life of the filter.

6.5.2 CONTAINMENT SPRAY SYSTEM

The containment spray cooling subsystem, which is one of the five modes of operation of the RHR system, is not designed to perform a fission product removal function following a DBA. The containment cooling subsystem is described in Section 6.2.2.

6.5.3 FISSION PRODUCT CONTROL SYSTEMS

6.5.3.1 Primary Containment

The primary containment structure is in the form of a truncated cone (the drywell) over a cylindrical section (the suppression chamber). Its pressure-suppression concept is the GE Mark II design. The primary containment is made of reinforced concrete, and it is lined with welded steel plate and provided with a steel domed head. The structural design of the primary containment is discussed in Section 3.8. Plan and elevation views of the primary containment are shown in Figures 3.8-1 through 3.8-8.

The primary containment walls, liner plate, mechanical penetrations, isolation valves, hatches, and locks function to limit release of radioactive materials, subsequent to postulated accidents, so that the resulting offsite doses are less than the dose limits of 10 CFR 50.67. Primary containment parameters affecting fission product release accident analyses are given in Section 6.2.1. Fission product removal systems are discussed in Section 6.5.1. Operation of the primary containment purge system during normal conditions is described in Section 9.4.5.1. This system isolates as described in Section 6.2.4. As discussed in Section 6.2.5, a low volume containment purge capability is provided as a backup to the containment hydrogen recombiner system. If placed into operation, the ESF filtration systems (RERS and SGTS) would process the low volume purge exhaust flow prior to its release.

6.5.3.2 Secondary Containment

The secondary containment completely encloses both primary containments and is provided to contain leakage from the primary containments so that any such leakage can be processed by filtration systems prior to release to the environment. The secondary containment boundary is formed by the exterior walls of the reactor enclosures and the refueling area, with the exception of the fan rooms on el 313' and el 331'. These fan rooms are not within the secondary containment, and the interior walls which separate them from the remainder of the reactor enclosure form a portion of the secondary containment boundary. The design of the secondary containment is discussed in Section 3.8.4, and plan and elevation views of the reactor enclosure are shown in drawings M-116, M-117, M-118, M-119, M-120, M-121, M-122, M-123, M-131, M-132, M-133, M-134, M-135, M-136, M-137, and M-138.

Two systems are provided for removal of fission products from reactor enclosure air following a DBA. These systems are the RERS and the SGTS, both of which are described in Section 6.5.1. Drawdown of the reactor enclosures by the SGTS following a postulated accident to establish a negative relative pressure with respect to the outside is discussed in Section 6.2.3.

The SGTS also provides for the drawdown of the refueling area to a negative relative pressure with respect to the outside following a fuel handling accident. As described in the LGS Technical Specifications, SGTS is only required to be aligned to the refueling area during handling of recently irradiated fuel and during water inventory control actions.

Section 9.4.2.1.3 gives details of secondary containment isolation modes (REIS, RAIS) versus the various secondary containment isolation signal inputs.

6.5.4 ICE CONDENSER AS A FISSION PRODUCT CLEANUP SYSTEM

LGS does not have an ice condenser system.

6.5.5 REFERENCES

6.5-1 Sprayco Co., Catalog "1713A Nozzle for Nuclear Containment Vessels," Spray Engineering Co., Burlington, MA, includes: Article from Nuclear Technology Vol. 1, "Droplet Size Distribution and Spray Effectiveness," W.F. Pasedag and J.I. Gallagher, (April 10, 1971).

6.5-2 ERDA 76-21, "Nuclear Air Cleaning Handbook", pp. 64-65.

6.5-3 "American Air Filter Topical Report", AAF-TR-7102, (September 1, 1972).

Table 6.5-1

ENGINEERED SAFETY FEATURE FILTER SYSTEMS DESIGN PARAMETERS

ITEM	SGTS[1]	RERS[1]
Type	Built-up unit	Built-up unit
Number of units	2	2
Flow rate, each (cfm)	SGTS: 500 to 8400; Drywell purge: 11,000 max	60,000
COMPONENTS		
Fan	SGTS/Drywell purge	
Type	Centrifugal	Vaneaxial
Drive	Direct	Direct
No. of fans per unit	1/1	1
No. of running fans	1/1	1
Total pressure (in wg.)	20/28	15.3
Motor power each (hp)	40/100	200
Air Heater		
No. of coils per unit	1	-
Heating capacity (kW)	55	-
Prefilters	Refueling Area	
Quantity, per unit	4	40
Size, each (in)	24x24x12	24x24x12
Pressure drop (in wg.)		
Clean	0.17 @ 2400 cfm	0.55
Dirty	0.25 @ 2400 cfm	1
Efficiency [2](%)	80	80
HEPA filter, upstream[3]	SGTS/Drywell Purge	
Size, each (in)	24x24x12	24x24x12
Pressure drop (in wg.)		
Clean	0.77/1.0	1.0
Dirty	1.53/2.0	3.0
Efficiency [4] %	99.97	99.97
Charcoal filter	SGTS/Drywell Purge	
Type	Vertical bed	Vertical bed
Depth (in)	8	2

Table 6.5-1 (Cont'd)

ITEM	SGTS(1)	RERS(1)
Filter media	Impregnated Activated charcoal	Impregnated activated charcoal
Pressure drop (in wg.)	6.0/10.5	1.2
Assigned efficiency(5), 70% relative humidity		
Removing elemental iodine (%)	99.0	95.0
Removing organic iodine (%)	99.0	95.0
Residence time (sec)	0.68 (when using SGTS fans at 3 zone maximum leakage rate of 5764 cfm)	0.25

(1) SGTS: Standby gas treatment system
RERS: Reactor enclosure recirculation system

(2) Dust spot test on atmospheric dust in accordance with ASHRAE 52-68

(3) All design parameters for the downstream HEPA filter are the same as the upstream HEPA filter, except in the drywell purge mode, the pressure drop when dirty is 4 in wg.

(4) By MIL Standards 282 DOP test method on 0.3 micron particles

(5) Efficiency designated by Regulatory Guide 1.52 for use in release analyses.

Table 6.5-2

COMPLIANCE WITH REGULATORY GUIDE 1.52
OF LIGHT-WATER-COOLED NUCLEAR POWER PLANTS (REV 2)(1)

REGULATORY POSITION		(SGTS)	(RERS)	CREFAS
C.1.	Environmental Design Criteria			
	Position a	Conforms	Conforms	Conforms
	Position b	Conforms The LGS system design is based on a total integrated dose over the 40 year plant life. The magnitude of the dose is dependent on location and includes the effect of a DBA. The design is more stringent than the regulatory guide guideline.	Conforms	Conforms
		Conforms with the shielding requirement: The system is shielded from other engineered safeguard features or components. There is no essential service located near the filters.	(Same as SGTS)	(Same as SGTS)
	Position c	Conforms	Conforms	Conforms
	Position d	Not applicable. There is no primary containment atmospheric cleanup system for LGS.	(Same as SGTS)	(Same as SGTS)
	Position e	Conforms	Conforms	Conforms

Table 6.5-2 (Cont'd)

REGULATORY POSITION	(SGTS)	(RERS)	CREFAS
C.2. System Design Criteria			
Position a	Partially conforms. Demisters are not included; there are no water droplets in the air stream. Air heaters are included to control humidity.	Partially conforms. Demisters are not included; there are no water droplets in the air stream. Air heaters are not included to control humidity.	Partially conforms. Demisters are not included; there are no water droplets in the air stream.
	Filter trains and fans are redundant, but duct-work is not: These systems are designed on a single active component failure basis.	(Same as SGTS)	(Same as SGTS)
Position b	Partially conforms. The filters are physically separated, but the fans are not: There will be no missiles from equipment failure or natural phenomenon.	(Same as SGTS)	Does not conform. There will be no missiles from equipment failure or natural phenomenon.
Position c	Conforms	Conforms	Conforms
Position d	Not applicable to systems outside the primary containment.	(Same as SGTS)	(Same as SGTS)
Position e	Conforms	Conforms	Conforms
Position f	Partially conforms. HEPA filters are arranged 3 wide by 4 high and are serviced by a stepladder. The plenum design provides easy access to the HEPA filters.	Does not conform. Due to space restrictions(1), recirculation system filter train is rated at 60,000 cfm. HEPA filters are arranged 8 wide by 5 high. Platforms are provided in the plenums to service the filters.	Conforms

Table 6.5-2 (Cont'd)

REGULATORY POSITION	(SGTS)	(RERS)	CREFAS
Position g	Partially conforms. Instruments are provided to indicate and alarm overall pressure drop across the entire filter train. Local pressure indicators are provided for each filter component. No recorders are provided, because the filters are able to be changed on high pressure readings.	(Same as SGTS)	(Same as SGTS)
	Flow rate is indicated in the control room.	Flow rate is indicated locally. Low flow activates alarm in control room.	Flow rate is indicated locally. Low flow activates alarm in control room.
Position h	Conforms	Conforms	Conforms
Position i	Conforms	Conforms	Conforms
Position j	Conforms	Partially conforms. Design meets intent of this paragraph. Because of space restrictions(1), filter plenum cannot be removed as a complete module or segmented sections.	Conforms
Position k	Not applicable. No outdoor air intake	Not applicable. No outdoor air intake	Conforms

Table 6.5-2 (Cont'd)

REGULATORY POSITION	(SGTS)	(RERS)	CREFAS
Position l	Does not conform. Allowable leak rate: (1) filter housing, 0.1% of rated flow at 125% negative pressure, which complies with the 1973 original version of Regulatory Guide 1.52; (2) fan discharge gas-tight duct-work, 0.1% scheduled air flow, multiplied by ratio of the volume of duct being tested to the total volume of the duct run; (3) fan suction duct, 1% of scheduled air flow, multiplied by ratio of the volume of duct being tested to the total volume of the duct run. The system is considered not to be in a high radiation zone.	Does not conform. Allowable leak rate: (1) filter housing, 0.05% of rated flow at 125% negative design pressure, which complies with the 1973 original version of Regulatory Guide 1.52; (2) gas-tight duct-work, 0.1% of scheduled air flow, multiplied by ratio of volume of duct being tested to the total volume of the duct run; (3) standard duct, 1% of scheduled air flow, multiplied by ratio of the volume of duct being tested to the total volume of the duct run. The system is considered not to be in a high radiation zone.	Does not conform. Allowable leak rate: (1) filter housing, 0.05% of rated flow at 125% negative pressure, which complies with the 1973 original version of Regulatory Guide 1.52; (2) duct-work, 0.1% of scheduled air flow, multiplied by ratio of the volume of duct being tested to the total volume of the duct run. The system is considered not to be in a high radiation zone.
C.3. Component Design Criteria and Qualification Testing			
Position a	Not applicable. Demisters are not included.	(Same as SGTS)	(Same as SGTS)
Position b	Partially conforms. Two automatic reset cut-outs set at 180°F and 260°F.	Not applicable. Heaters are not included.	Conforms
Position c	Conforms[3]	Conforms	Conforms

Table 6.5-2 (Cont'd)

REGULATORY POSITION	(SGTS)	(RERS)	CREFAS
Position d	Partially conforms. HEPA filters meet requirements in this paragraph. However, testing will not be performed in ERDA test facilities. Shop tests and field tests are considered adequate.	(Same as SGTS)	(Same as SGTS)
Position e	Conforms	Conforms	Conforms
Position f	Partially conforms. HEPA filters are arranged 3 wide by 4 high and are serviced by a stepladder.	Does not conform. Because of space restrictions(1), the system is rated at 60,000 cfm. HEPA filters are arranged 8 wide by 5 high. Platforms are provided in the plenum to service the filter.	Partially conforms. Filter arrangement meets general guideline, except that service aisles between filter banks are narrower than recommended.
Position g	Partially conforms. Housing design generally conforms with ANSI N509 (1976) section 5.6, except that view ports are not included.	(Same as SGTS)	(Same as SGTS)
Position h	Conforms	Conforms	Conforms
Position i	Partially Conforms(2) (5)	Conforms(2)	Conforms(2)
Position j	Conforms	Conforms	Conforms
Position k	Conforms	Conforms	Conforms
Position l	Conforms	Conforms	Conforms
Position m	Conforms	Conforms	Conforms

Table 6.5-2 (Cont'd)

REGULATORY POSITION		(SGTS)	(RERS)	CREFAS
	Position n	Conforms	Conforms	Conforms
	Position o	Conforms	Conforms	Conforms
	Position p	Conforms	Conforms	Conforms
C.4.	Maintenance			
	Position a	Conforms	Conforms	Conforms
	Position b	Conforms	Does not conform. Because of space restrictions(1), distance between filter banks is less than recommended.	(Same as RERS)
	Position c	Partially conforms. There are 4 charcoal test canisters provided rather than 6.	Conforms	Conforms
	Position d	Does not conform. SGTS trains continuously purged when the filters are not in use with dry instrument air to prevent build-up of moisture.	(Same as SGTS)	(Same as SGTS)
	Position e	Conforms	Conforms	Conforms
C.5.	In-Place Testing Criteria			
	Position a	Conforms(4)	Conforms(4)	Conforms(4)
	Position b	Conforms(4)	Conforms(4)	Conforms(4)
	Position c	Partially conforms. (4) HEPA filters are tested to re-quirements of this paragraph. However, testing will be performed at least once per 48 months rather than 18 months.	(Same as SGTS)	(Same as SGTS)
	Position d	Partially conforms.(4) Acti-vated carbon adsorber sections are tested to re-quirements of this paragraph. However, testing will be performed at least once per 24 months rather than 18 months.	(Same as SGTS)	(Same as SGTS)

Table 6.5-2 (Cont'd)

REGULATORY POSITION		(SGTS)	(RERS)	CREFAS
C.6.	Laboratory Testing Criteria for Activated Carbon[2]			
	Position a	Partially conforms. The Laboratory analysis of new and used carbon samples is performed in accordance with ASTM D3803-1989.	(Same as SGTS)	(Same as SGTS)
	Position b	Partially conforms. Activated carbon adsorber sections are tested to requirements of this paragraph. However, testing will be performed at least once per 24 months rather than 18 months. Additionally, the laboratory analysis of carbon samples is performed in accordance with ASTM D3803-1989.	(Same as SGTS)	(Same as SGTS)

(1) The LGS air filter systems were designed before the issuance of Regulatory Guide 1.52 in 1973. The filter design details have been studied in accordance with the regulatory guide and it was found that the filter performs satisfactorily although the design is not in strict conformance with the regulatory guide.

(2) Each original or replacement batch of impregnated activated charcoal used in the adsorber section meets the qualification and batch test results of ANSI N509 (1980). Laboratory tests of charcoal samples meeting the requirements of Position C.6 of Regulatory Guide 1.52 can be performed in accordance with ANSI N509 (1980) except that the laboratory analysis of carbpon samples is performed in accordance with ASTM D3803-1989.

(3) The prefilters in the RERS act as prefilters for the SGTS during reactor enclosure isolation. The prefilters in the SGTS duct from the refueling area act as prefilters for the SGTS during refueling area isolation.

(4) To ANSI/ASME N510 (1980) testing criteria.

(5) The air residence time in the 8 inch bed is 0.68 seconds considering a maximum total post inleakage rate from Zones I, II, and III of 5764 cfm.

Table 6.5-3

STANDBY GAS TREATMENT SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency	Power supply	Total LOOP	None. All units are powered from separate standby diesel generators.	Alarm in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Exhaust fans	Loss of one fan	The standby fan automatically starts.	Low flow indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Electric heaters	Loss of electric heater	Efficiency of of charcoal adsorber may decrease if the relative humidity is above 70%. The operator may manually switch to the standby train.	Temperature indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Upstream & downstream HEPA filters	High differential pressure across the filter bank.	The fan recirculation dampers modulate in sequence to maintain airflow. However, if the system flow rate drops below the setting of the fan flow switch, the standby fan automatically starts and the filter train is manually switched to standby train	Low flow indication in the control room	No loss of safety function

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Table 6.5-3 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (LOCA or LOCA & LOOP)	Charcoal adsorbers	High-high-high temperature	At ignition temperature setting the fire protection system is manually actuated.	Temperature indication in the control room.	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	RERS to SGTS transfer valves	Valve fails to open	None. Valves are redundant and parallel. Normally closed valves fail open.	SGTS flow indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Fans inlet dampers	Damper fails closed	None. These dampers are redundant - standby unit will operate.	Flow indication and damper position indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Charcoal filter inlet valves and outlet valves	Valve fails closed	None. The valves are redundant - the standby unit will operate.	Flow indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Fans recirculation dampers	Dampers fail closed	None. These dampers are designed to fail closed. If the damper fails, this will increase a demand for more makeup air, and fans will attempt to deliver maximum flow.	Flow indication in the control room.	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Refueling Area to SGTS transfer valve	Valve fails open[1]	None. The refueling area is automatically isolated. The SGTS will drawdown both the reactor enclosure and refueling area.	Flow indication in the control room	No loss of safety function
Emergency (Fuel Handling Accident)	Refueling Area to SGTS transfer valve	Valve fails to open	None.Valves are redundant and parallel. Normally closed valves fail open.	SGTS flow indication in the control room	No loss of safety function

Table 6.5-3 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (Fuel Handling Accident)	RERS to SGTS transfer valve	Valve fails open[1]	None. The corresponding reactor enclosure is automatically The SGTS will drawdown the refueling area and that Unit's reactor enclosure.	Flow indication in the Control isolated.	No loss of safety function Room
Emergency (Unit LOCA or LOOP)	The other Unit RERS to SGTS transfer valve	Valve fails open[1]	None. The other Unit reactor enclosure is automatically isolated. The SGTS will drawdown both reactor enclosures.	Flow indication in the Control Room	No loss of safety function

Note: The SGTS is a common system.

(1) Any combination of valve failures which result in either a 2 or 3 zone isolation will not affect SGTS operation. The SGTS has a design flow of 8400 cfm which is adequate to restore and maintain the required pressure in both reactor enclosures and common refueling area.

Table 6.5-4

MATERIALS USED IN THE STANDBY GAS TREATMENT FILTER SYSTEM

COMPONENT	MATERIAL
Housing	
Structural steel	
Channel	CS ASTM A36
Plate	CS ASTM A36 SS ASTM A240 304 CS ASTM A36
Angle	CS ASTM A106 Grade B
Piping	CS ASTM A53 Grade B CS ASTM A105 Grade 1 or 2 CI ASTM A126 SS ASTM A312 TP304 CS ASTM A197
Internal structure	
Filter supports	
Plate	SS ASTM A240 304 CS ASTM A36
Angle	SS ASTM A276 304 CS ASTM A36
Fasteners	CS ASTM A307 CS ASTM A325 CS ASTM A449
Gaskets	ASTM D1056
Filter elements	
HEPA	
Frame	Cadmium Plated or Stainless Steel per ASME AG-1
Filter media	Glass Fiber per MIL-F-51079A or ASME AG-1
Electric heating coil	Nickel-chrome alloy wire with metal sheathing

Table 6.5-4 (Cont'd)

COMPONENT	MATERIAL
Carbon adsorber filter media	Activated impregnated coconut base charcoal per ANSI N509 (1980), table 5-1 and Regulatory Guide 1.52 except that laboratory analysis of carbon samples is performed in accordance with ASTM D3803-1989
Prefilter	(1)
Paint	
Interior Carboline CarboZinc 11 primer	with Carboline 3912 finish coat
Exterior	PPG 6-205 primer with PPG Lavax Machinery Enamel No. 23-61

(1) Prefilters for the refueling area to SGTS alignment are installed in the refueling area duct-work. The filter elements consist of galvanized carbon steel frames and fiberglass media. Each filter has a UL Class I flame retardant rating. Prefiltering for the reactor enclosure to SGTS alignment is provided by the RERS filter train.

Table 6.5-5

MATERIALS USED IN THE CONTROL ROOM
EMERGENCY FRESH AIR FILTER SYSTEM

COMPONENT	MATERIAL
Housing	
Structural steel	
Plate	CS ASTM A36
Angle	CS ASTM A36
Bar-stock	CS ASTM A36
Piping	CS ASTM A120 SS ASTM A312 TP304 CS ASTM A105 SS ASTM A182 F304
Internal structure	
Filter supports	
Plate	SS ASTM A240 304
Sheet	SS ASTM A240 304
Angle	SS ASTM A240 304
Bar-stock	SS ASTM A276 304
Studs	CS ASTM A108 SS AISI 166 304
Filter elements	
Prefilter	
Frame	Fire retardant particle board
Filter media	Glass fiber
HEPA	
Frame	Chromized or Stainless Steel per ASME AG-1
Filter media	Glass Fiber per MIL-F-51079A or ASME AG-1
Carbon adsorber filter media	Activated impregnated coconut base charcoal per table 5-1 of ANSI N509 (1980), and Regulatory Guide 1.52 except that laboratory analysis of carbon samples is performed in accordance with ASTM D3803-1989.

Table 6.5-5 (Cont'd)

COMPONENT	MATERIAL
Paint	
Interior	Carboline Carbo Zinc 11
Exterior	Mobil Val-Chem Zinc Chromate Primer, red base 13-R-56B with finish coat Mobil Val-Chem Hi-Build Epoxy 89 Series.

Table 6.5-6

REACTOR ENCLOSURE RECIRCULATION SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Typical for Zone I or Zone II)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency	Power supply	Total LOOP	None; each of the redundant fans and associated dampers is powered from separate standby diesel generators.	Alarm in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Recirculation fans	Loss of one fan	The standby fan automatically starts.	Pressure differential indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Valves on duct from recirculation system to SGTS	One valve failed closed	None; the other valve installed in parallel remains open.	SGTS flow indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Valves on duct from reactor enclosure equipment compartment exhaust system to supply plenum of recirculation system	One valve failed closed	None; the other valve installed in parallel remains open.	Valve position indication on local panel C101	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Valves on duct from reactor enclosure exhaust system to supply plenum of recirculation	One valve failed at last position	None; the other valve installed in parallel remains open.	Valve position indication on local panel C101	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Valves on duct from discharge plenum of recirculation system to reactor enclosure supply system	One valve failed closed	None; the other valve installed remains open.	Valve position indication on local panel C101	No loss of safety function

Table 6.5-6 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (LOCA or LOCA & LOOP)	Upstream & downstream HEPA filters	High differential pressure across the filter bank	None; the filter discharge flow control dampers will modulate to maintain constant airflow. However, if the pressure differential rises above a selected maximum value the operator may manually switch to the standby filter train.	Filter bank pressure differential indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Charcoal absorbers	High-high-high temperature	At ignition temperature setting the fire protection system is manually actuated.	Temperature indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Filter train inlet & outlet dampers	Damper fail close	Low flow on the flow switch will cause automatic switch-over to the standby train.	Filter differential pressure indication in the control room. Damper position indication in the control room	No loss of safety function

Table 6.5-7

MATERIALS USED IN THE REACTOR ENCLOSURE
RECIRCULATION FILTER SYSTEM

COMPONENT	MATERIAL
Housing	
Structural Steel	
Plate	CS ASTM A36
Angle	CS ASTM A36
I-Beams	CS ASTM A36
Bar-stock	CS ASTM A36
Piping	CS ASTM A105 SS ASTM A312 TP304 SS ASTM A182 F304
Internal Structure	
Filter Supports	
Plate	SS ASTM A240 304
Sheet	SS ASTM A240 304
Angle	SS ASTM A276 304
Studs	CS ASTM A193 B7 CS ASTM 193 B8
Filter elements	
Prefilter	
Frame	Fire retardant particle board
Filter media	Glass fiber
HEPA	
Frame	Chromized or Stainless Steel per ASME AG-1
Filter media	Glass Fiber per MIL-F-51079A or ASME AG-1
Carbon adsorber filter media	Activated impregnated coconut base charcoal per table 5-1 of ANSI N509 (1980), and Regulatory Guide 1.52

Table 6.5-7 (Cont'd)

COMPONENT	MATERIAL
Paint	
Interior	Carboline Carbo Zinc 11
Exterior	Mobil Val-Chem Zinc Chromate Primer, red base 13-R-56B with finish coat Mobil Val-Chem Hi-Build Epoxy 89 Series.

Table 6.5-8

INSTRUMENTATION FOR ESF ATMOSPHERE CLEANUP SYSTEMS

GUIDELINES PER SRP Table 6.5.1-1			INSTRUMENTATION PROVIDED IN LGS DESIGN[1]		
SENSING LOCATION	LOCAL READOUT/ALARM	CONTROL ROOM PANEL	SGTS	RERS	CREFAS
Unit inlet or outlet	Flow rate (indication)	-	Not provided[2]	Flow rate indication at outlet	Flow Rate indication at outlet
Unit inlet or outlet	-	Flow rate (recorded indication, high and low alarms	Flow indication at outlet Low flow alarm [2][3][4]	Low flow alarm[3][5]	Low flow alarm [3][6]
Electrical heater	Status indication	-	Status indication in the control room	N/A	Not provided (Trouble alarm in the control room)[7]
Space between heater and prefilter	Temperature (indication high and low alarm signals)	-	Indication only[8]	N/A	Indication only[8]
Space between heater and prefilter	-	Temperature (indication high and low alarms, trip alarm signals)	Provided	N/A	Not provided[9]
Prefilter	Pressure drop (indication, high alarm signal)	-	Indication only [8][10]	Indication only[8][10]	Indication only[8][10]
First HEPA	Pressure drop (indication, high alarm signal)	-	Indication only[8][10]	Same as SGTS[8][10]	Same as SGTS[8][10]
First HEPA	-	Pressure drop (recorded indication)	Not provided[10]	Not provided [10]	Not provided[10]
Space between adsorber and second HEPA	Temperature (two-stage high alarm signal)	-	Not provided[8]	Not provided [8]	Not provided[8]
Space between adsorber and second HEPA	-	Temperature (two-stage high alarm signal)	Three-stage high alarm and indication	Same as SGTS	Same as SGTS

Table 6.5-8 (Cont'd)

GUIDELINES PER SRP Table 6.5.1-1			INSTRUMENTATION PROVIDED IN LGS DESIGN[1]		
SENSING LOCATION	LOCAL READOUT/ALARM	CONTROL ROOM PANEL	SGTS	RERS	CREFAS
Second HEPA	Pressure drop (indication, high alarm signal)	-	Indication only [8][10]	Same as SGTS[8][10]	Same as SGTS[8][10]
Fan	(Optional hand switch and status indication)	-	Not provided	Not provided	Not provided
Fan	-	Hand switch, status indication	Provided	Provided	Provided
Valve/damper operator	(Optional status indication)	-	Not provided	Not provided	Not provided
Valve/damper	-	Status indication	Provided	Provided	Provided
Deluge valves	-	-	Manual valves Indication only	Same as SGTS	Same as SGTS
Deluge valves	-	-	Alarm[11]	Same as SGTS[11]	Same as SGTS[11]
System inlet to outlet	-	Summation of pressure drop across total system, high alarm signal.	Provided	Provided	Provided

(1) Regulatory Guide 1.52, ANSI-N509, and SRP Table 6.5.1-1 were originally issued after the LGS system design and therefore were not specifically considered in the design.

(2) The SGTS flow rate is variable to draw down and maintain the reactor enclosure/refueling area at a negative 0.25 in wg. Local flow indication does not provide meaningful information in terms of system operability. Flow indication is provided in the control room where this information, in addition to the reactor enclosure/refueling area pressure differential indicators, is available for operator evaluation of system performance.

(3) Low flow switch operates on loss of flow only.

Table 6.5-8 (Cont'd)

(4) Maximum SGTS flow occurs only during drawdown. As thermodynamic equilibrium is approached within the reactor enclosure and/or refueling area during isolation, the SGTS flow decreases to the design inleakage rate.

(5) The RERS does not operate during normal plant operation. The RERS flow is recirculated within the reactor enclosure during isolation and is not directly released to the environment.

(6) Outdoor air requirements are governed by the control room leak-tightness needed to maintain a positive pressure. High flow through the filtration system due to the failure of FD-C-78-011A in an open position will result in additional recirculation flow rather than additional unfiltered outdoor air. Control room pressure differential is indicated in the control room.

(7) Electric heater does not operate continuously during EFA system operation. Local temperature and humidity indicator controllers are provided to assess system operation.

(8) Local panels are not continuously manned to observe alarm signals.

(9) The Emergency Fresh Air system air is made up of approximately 90% recirculation air from the control room and 10% outdoor air to maintain the control room at a positive pressure. If the heater fails to operate, the temperature of the resultant air mixture will be similar to the control room even during winter conditions. Therefore, a low temperature alarm is not essential. The Emergency Fresh Air heaters are provided with automatic and manual high temperature cutouts to prevent overheating of the heater elements. Radiation monitors are provided downstream of the Emergency Fresh Air system filters and will alarm on high radiation in the event of unacceptable air quality.

(10) ESF systems do not operate continuously, and routine system testing will ensure that filter changeout requirements will be met.

(11) General trouble alarm for local panel OOC926 when any deluge valve is opened.

6.6 PRESERVICE/INSERVICE INSPECTION OF CLASS 2 AND 3 COMPONENTS

The construction permits for the LGS Units 1 and 2 were issued in June 1974. Based on this date, 10CFR50.55a required that the PSI program for the Class 2 and 3 components meet the examination requirements set forth in ASME Section XI, 1971 edition with addenda through Winter 1972 or alternatively, the examination requirements of the subsequent editions and addenda, subject to the limitations and modifications listed in 10CFR50.55a. The LGS PSI programs followed the alternative requirements.

Specifically, the Unit 1 Class 2 and 3 component PSI program (except operability testing of safety-related pumps and valves) meets the requirements of ASME Section XI, 1974 edition with addenda through Summer 1975, as modified by Appendix III of the Winter 1975 Addenda and paragraph IWA-2232 of the Summer 1976 Addenda.

At the time the LGS PSI program commenced, the latest edition of the code permissible for use was the Summer 1975 Addenda. In an effort to take advantage of improved UT methods, Appendix III of the Winter 1975 Addenda and paragraph IWA-2232 of the Summer 1976 were used. Although these items are not specifically referenced by 10CFR50.55a, they are equivalent to the comparable portions of the subsequently approved ASME Section XI of Summer 1978 Addenda as long as Section XI Appendix III indications greater than 50% DAC are recorded. The LGS ISI procedures do record such indications.

Supplement 7 of Appendix III permits the use of Appendix III for austenitic piping welds with certain modifications. It is our position, consistent with the PSI/ISI industry, that Appendix III (at 50% DAC recording) is more appropriate for austenitic piping weld examination than Article 5 of ASME Section V. Thus for austenitic piping welds:

a. All of the Supplement 7 modifications are being used.

b. Examination sensitivity is ensured through the calibration process.

c. Where one-sided access only occurs and penetrations cannot be confirmed, a one-sided access limitation is noted in the data package for that weld.

When using Section XI, Appendix III for either ferritic or austenitic piping welds, the following applies:

a. All indications showing signal amplitudes equal to or in excess of 20% of the reference response are evaluated to the extent that the level II or level III examiner can determine their true nature.

b. The owner evaluates and takes corrective action for the disposition of any indication investigated and found to be other than geometrical or metallurgical in nature.

The Unit 2 Class 2 and 3 component PSI program and Units 1 and 2 programs for the preservice testing of safety-related pumps and valves meet the requirements of the Section XI Code, 1980 edition with addenda through Winter 1981.

For certain ASME Section XI requirements that have been determined to be impractical in the course of inspecting the components, the licensee has submitted and will submit requests for relief from the requirements to the NRC in accordance with the provisions of 10CFR50.55a.

In accordance with 10CFR50.55a, throughout the service life, Class 2 and 3 components (including supports) will meet the ISI requirements, except design and access provisions and preservice examination requirements, set forth in the ASME Section XI edition and addenda that become effective, to the extent practical within the limitations of design, geometry, and materials of construction of the components. In accordance with 10CFR50.55a, inservice examinations of components, inservice tests to verify operational readiness of safety-related pumps and valves, and system pressure tests conducted during the initial 10 year inspection interval will comply with ASME Section XI edition and addenda in effect 12 months prior to the date of issuance of the operating license. In accordance with 10CFR50.55a, the initial 10 year inspection interval commences with commercial operation. The successive 10 year inspection intervals will comply with ASME Section XI edition and addenda in effect 12 months prior to the start of the 10 year inspection interval.

6.6.1 COMPONENTS SUBJECT TO EXAMINATION

LGS piping was originally designed to ANSI B31.7. For inservice inspection, ANSI B31.7 Classes II and III are considered equivalent to ASME Section III, Classes 2 and 3. The PSI/ISI program includes figures showing the systems or portions of systems within the scope of the Section XI Code. The applicable PSI/ISI programs are described in References 6.6-1 through 6.6-7. Any necessary requests for relief are addressed in these documents.

There is a Risk Informed Categorization and Treatment Program at Limerick which is based on 10 CFR 50.69. This regulation provides an alternative approach for establishing requirements for treatment of SSCs using a risk-informed method of categorizing SSCs according to their safety significance. Specifically, for SSCs categorized as low safety significant, alternate treatment requirements may be implemented rather than treatments chosen by the ISI program. Refer to Section 13.5.5 for further information.

6.6.2 ACCESSIBILITY

a. Sufficient space is provided for personnel and equipment so that examinations of Class 2 and Class 3 piping and components can be performed, as required by the Code.

   1. Piping welds - The access provided for Class 2 system components depends on whether ultrasonic, surface, or visual examinations are performed.

   2. Pumps and valves - Space is provided to disassemble and reassemble the pump or valve. For visual examination, sufficient lighting and access space is provided to permit examination of the inner surface. For ultrasonic examination, access for equipment is provided, depending on the specific design of the weld.

   3. Supports - Access provisions for supports requiring examination are provided and depend on the specific type and design detail of the support.

   4. Pressure welds - Access is provided for the inspection of pressure-retaining welds, vessel supports, and pressure-retaining bolting.

b. Capability for the removal and temporary storage of structural members, shielding components, and insulation is provided.

c. Hoists and other handling machinery necessary to support ISI are provided.

d. Equipment and personnel for alternative examinations that may be required will be provided.

e. Repair and replacement operations are provided for system components and parts, where necessary.

6.6.3 EXAMINATION TECHNIQUES AND PROCEDURES

a. The techniques and procedures for surface, visual, and volumetric examinations are in compliance with IWA-2200 of the Section XI Code.

b. Alternate examination methods are acceptable, provided that the results are equal or superior to the methods of IWA-2200. The acceptance criteria for alternate examination methods are in accordance with IWA-3100 of the Section XI Code.

6.6.4 INSPECTION INTERVALS

The examinations required by IWC-2400 for Class 2 system components and by IWD-2400 for Class 3 system components will be performed on the basis of a 10 year interval, hereafter known as the inspection interval.

6.6.5 EXAMINATION CATEGORIES AND REQUIREMENTS

The PSI/ISI program provides a listing of the Class 2 and 3 components or parts including the Section XI Code item number, examination category, the required method of examination, and the extent and frequency of examination. The applicable PSI/ISI programs are identified in References 6.6-1 through 6.6-7.

6.6.6 EVALUATION OF EXAMINATION RESULTS

The standards for evaluation of results and repair procedures are in accordance with Articles IWB-3000 and IWA-4000. Where acceptance standards are still in preparation, IWA-3100 shall apply. The ISI program for the first and successive inspection intervals will use the articles in IWC and IWD as they are issued and approved. Summary reports for the RPV and piping PSI were submitted 90 days after commercial operation, in accordance with subarticle IWA-6220.

6.6.7 SYSTEM PRESSURE TESTS

The system pressure tests will be performed in accordance with the general requirements of IWA-5000 and the specific requirements of IWC-5000 and IWD-5000 for Class 2 and 3 components, respectively.

6.6.8 AUGMENTED INSERVICE INSPECTION TO PROTECT AGAINST POSTULATED PIPING FAILURES

Class 2 and 3 components will receive augmented inservice inspection in accordance with the documents listed below to the extent specified in the applicable PSI/ISI programs identified in References 6.6-1 through 6.6-7.

a. NUREG-0313, Revision 1, July 1980, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping" (see resolution of USI A-42, Section 1.12.2). Revision 1 of this NUREG is applicable prior to issuance of Generic Letter 88-01.

   In accordance with Generic Letter 88-01, the criteria of NUREG-0313, Revision 2, January 1988 are applicable for LGS Units 1 and 2. The ISI Program for weldments in piping shall be performed in accordance with the NRC staff positions and criteria addressed in Generic Letter 88-01 and BWRVIP-75-A, "BWR Vessel and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedule." Details for schedule, methods, personnel, and sample expansion shall be included as augmented inspection requirements. Response to the Generic Letter 88-01 was provided per letter from S.J. Kowalski (PECo) to F.J. Miraglia, Jr. (NRC), dated August 2, 1988. The ISI Program for weldments in piping shall be performed in accordance with the NRC staff positions and criteria addressed in Generic Letter 88-01. Details for schedule, methods, personnel, and sample expansion shall be included as augmented inspection requirements.

b. BTP MEB 3-1 (NUREG-0800) addresses high energy piping between containment isolation valves and first outboard restraint for which no breaks are postulated

In addition, high energy fluid system piping between containment isolation valves will receive an augmented examination as follows:

a. Protective measures and structures are located, to the greatest extent possible, so as not to prevent access for inservice inspections.

b. High energy fluid system piping between containment isolation valves is required to be either 100% volumetrically examined (both circumferential and longitudinal welds) during each examination interval or examined in accordance with the Risk Informed Inservice Inspection Program as applied to these welds.

c. High energy piping requiring ISI receives a baseline (preservice) examination to establish the integrity of the original condition of the welds.

d. Augmented examination for high energy piping is maintained out to outboard restraints.

e. Welds between outboard containment isolation valves and piping restraints will be included in the PSI and the ISI plans.

6.6.9 REFERENCES

6.6-1 Document 8031-M246AQA-59, Preservice Inspection Program Plan for the LGS Unit 1 Nuclear Piping Systems

6.6-2 Program Document ML-008, Limerick Generating Station Units 1 and 2, “IST Program Plan” and “IST Basis Document”

6.6-3 ER-LG-330-1001 through 1006, Limerick ISI Program Documents

6.6-4 Deleted

6.6-5 Document 8031-P-504, LGS Unit 2 Preservice Inspection Program

6.6-6 Document 8031-P-505, LGS Unit 2 Preservice Inspection Examination Plan for Nuclear Piping Systems

6.6-7 Document 8031-P-507, LGS Unit 2 Testing Plan for Safety-Related Pumps and Valves

6.7 MSIV LEAKAGE ALTERNATE DRAIN PATHWAY

The MSIV Leakage Alternate Drain Pathway prevents a direct release of fission products that could leak through the closed MSIVs after a LOCA. The pathway provides control by providing a hold-up volume for the MSIV leakage before release to the atmosphere. This is accomplished by directing the leakage through existing Main Steam Drain Lines to the High Pressure Shell of the Main Condenser.

6.7.1 DESIGN BASES

6.7.1.1 Safety Criteria

The following criteria represent pathway design, safety, and performance requirements imposed on the MSIV Leakage Alternate Drain Pathway.

a. The MSIV Leakage Alternate Drain Pathway is evaluated to have sufficient capacity and capability to control the leakage from the MSIVs, consistent with containment leakage limits imposed for the conditions associated with a postulated design basis LOCA. Specifically, a complete severance of a recirculation line does not permit an offsite dose to exceed the requirements of 10CFR50.67.

b. The MSIV Leakage Alternate Drain Pathway has been evaluated to demonstrate that the main system piping and equipment are seismically rugged and meet the requirements of 10CFR Part 100, Appendix A.

c. The MSIV Leakage Alternate Drain Pathway is capable of performing its safety function following a LOCA with Loss of Offsite Power. The Pathway is not single failure proof, but there are alternate unanalyzed pathways which will serve to direct any MSIV leakage to allow for reducing the offsite dose.

d. The MSIV Leakage Alternate Drain Pathway is manually actuated, and designed to permit actuation within about 20 minutes, but no earlier than 10 minutes, after a postulated design basis LOCA. This time period is considered to be consistent with loading requirements of the Class 1E electrical buses and with reasonable times for operator action.

6.7.1.2 Regulatory Acceptance Criteria

The piping and the components of the MSIV Leakage Alternate Drain Pathway have been evaluated to confirm the capability of the main steam piping and condenser to serve as an alternate leakage pathway. Seismic verification walkdowns have been performed to assure that the MSIV, the steam drain lines, the condenser and interconnecting piping and equipment that are not seismically analyzed fall within the bounds of the design characteristics of the seismic experience database as discussed in reference 1.

6.7.2 SYSTEM DESCRIPTION

The MSIV Leakage Alternate Drain Pathway is credited in the Radiological Dose Calculations for Limerick Generating Station. The pathway serves as a "hold-up" volume for processing of a potential release of fission products that could leak through the closed MSIV's during a Loss of Coolant Accident (LOCA). This pathway limits the calculated doses from the MSIV Leakage to within the requirements of 10CFR50.67 for offsite releases and GDC 19 for local area access. The system has been evaluated to adequately handle the Technical Specification allowed MSIV leakage.

The design boundaries of the MSIV Leakage Alternate Drain Pathway are defined as follows. The designated boundary (block) valves (HV-1(2)08, HV-1(2)09, HV-1(2)11, HV-1(2)50, Main Turbine Stop Valves (MSTV), and Main Turbine Bypass Valves (MTBV)) will function to contain the MSIV leakage in the drain pathway. The boundary valves also identify the functional and design boundary of the "MSIV Leakage Alternate Drain Pathway." All other lines which interface with the designated drain pathway are shown in the applicable drawings and UFSAR Figures (drawings M-01, M-41, M-49, M-55, and Figure 10.4-4) will either be described below as a drain pathway, or lead back through Seismic Category I/IIA piping back into containment (primary or secondary) and as such do not represent potential leakage pathways.

There are three potential leakage pathways. These pathways are as follows:

1) Flow from all four Main Steam lines directly after the outboard MSIVs, through 2 inch EBB-1(2)05, into 3 inch EBB-1(2)05, into 3 inch EBD-1(2)08, into 4 inch EBD-1(2)08, discharging into the H.P. Condenser.

2) Flow from the above seat drain on the Main Stop Valves through 1 inch EBD-*, into 2 inch EBD-1(2)15, into 4 inch EBD-1(2)08, discharging into the H.P. Condenser.

3) Flow from all four Main Steam lines directly before the Main Stop Valves through 1 inch EBB-1(2)01(2,3,4), into 2 inch EBD-1(2)14, into 2 inch EBD-1(2)15, into 4 inch EBD-1(2)08, discharge into the H.P. Condenser.

Although all three drain pathways are capable of directing leakage to the H.P. Condenser the only credited drain line is item 1). This is based on the fact that the other drain lines are either not sized properly to ensure adequate flow or require the opening of non-class 1E valves. The primary drain pathway has one normally closed valve in the line (HV-041-1(2)F021). This valve is required to be opened to establish the drain pathway.

The remainder of the system shown in attachment 1 of reference 2, identifies the total scope of the potential pathways which was evaluated during a seismic walkdown, and was in a Design Analysis contained in reference 1 for "Seismic Ruggedness" specified in reference 2.

6.7.3 SYSTEM EVALUATION

An evaluation of the capability of the MSIV Leakage Alternate Drain Pathway to control the release of radioactivity from the MSIVs during and following a LOCA has been conducted. A summary of the evaluation is contained in reference 2. In addition, the results of the radiological evaluations are contained in section 15.6.5.

6.7.4 INSTRUMENTATION REQUIREMENTS

There are no specific instrumentation requirements for this pathway since there are no automatic actions required. The operational requirements of the pathway only require the capability to reposition one valve identified in section 6.7.2 .

6.7.5 Inspection And Testing

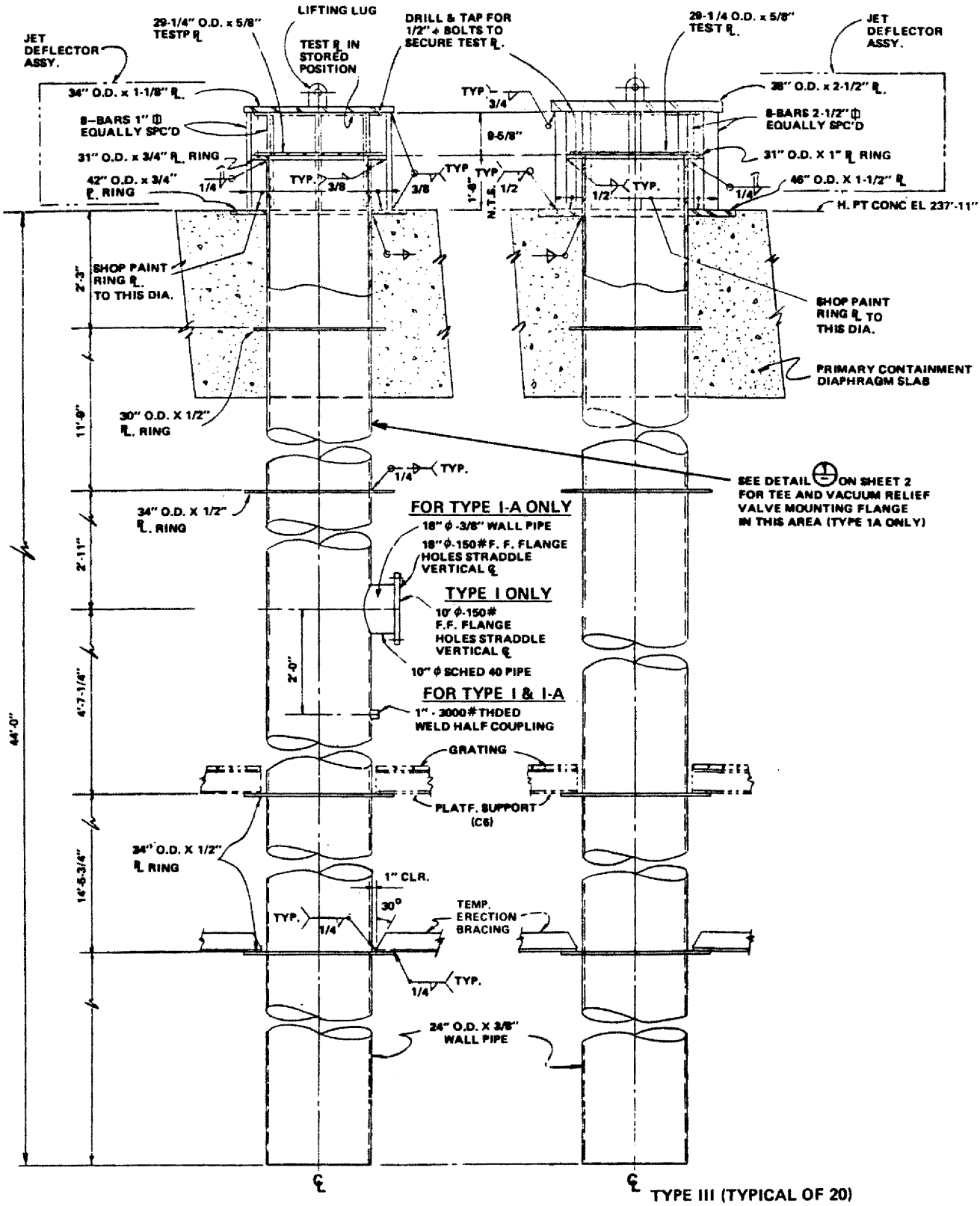
The valves required to be repositioned are tested in accordance with the requirements of the Inservice Testing Program.

6.7.6 REFERENCES

1. NEDC-31585P, Revision 2, BWROG Report for Increasing MSIV Leakage Rate Limits and Elimination of Leakage Control System, dated September 1993.

2. 10CFR50.90 Technical Specification Change Request 93-18-0, for removal of MSIV-LCS, dated January 14, 1994.

Table 6.7-1 has been deleted



TYPE I (TYPICAL OF 6)
TYPE IA (TYPICAL OF 4)
TYPE II (TYPICAL OF 57)

TYPE III (TYPICAL OF 20)

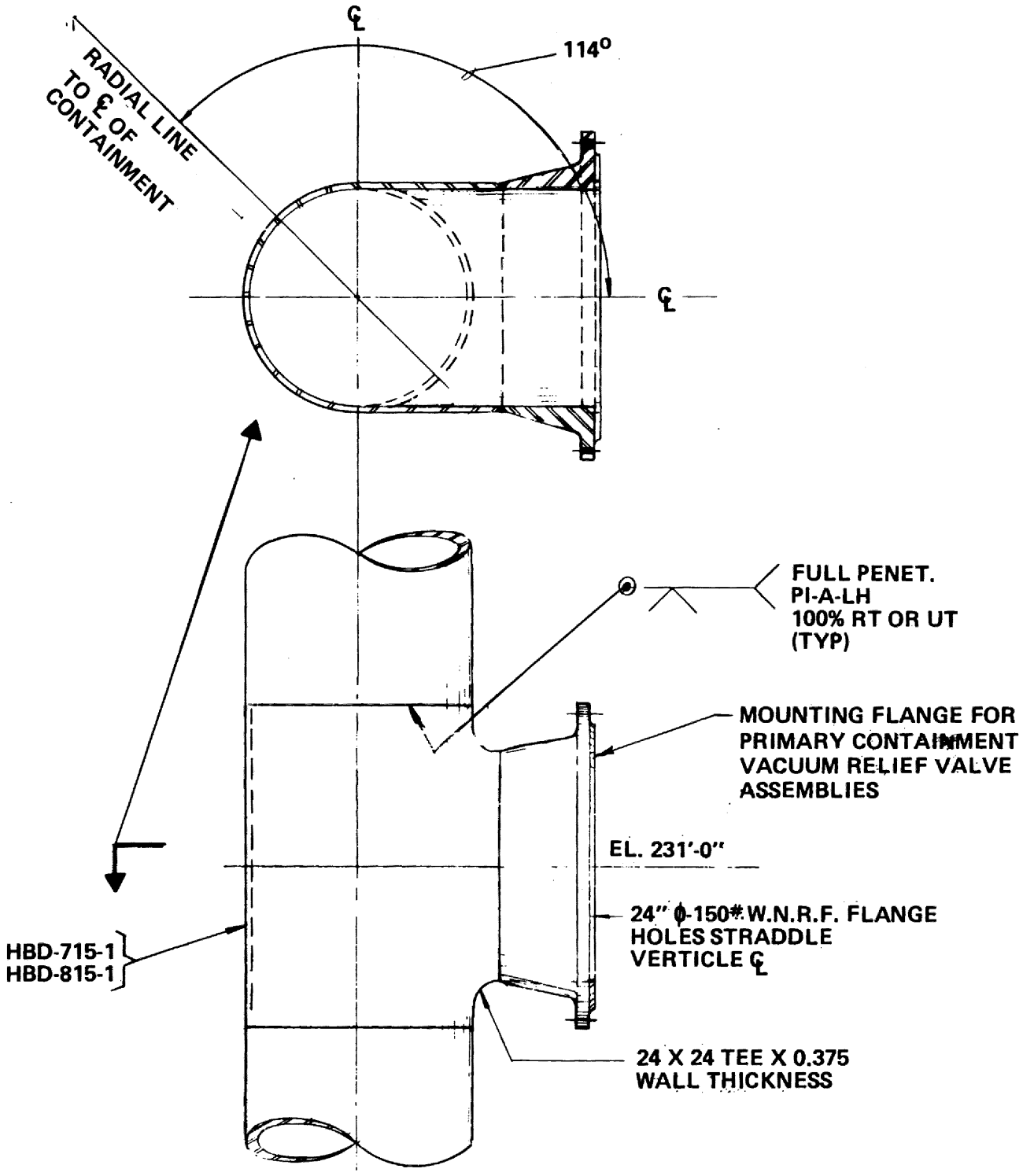
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-293.

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DOWNCOMER DESIGN DETAILS
(SHEET 1 OF 2)

FIGURE 6.2-1



ELEVATION

FOR TYPE IA ONLY DETAIL (1/—)

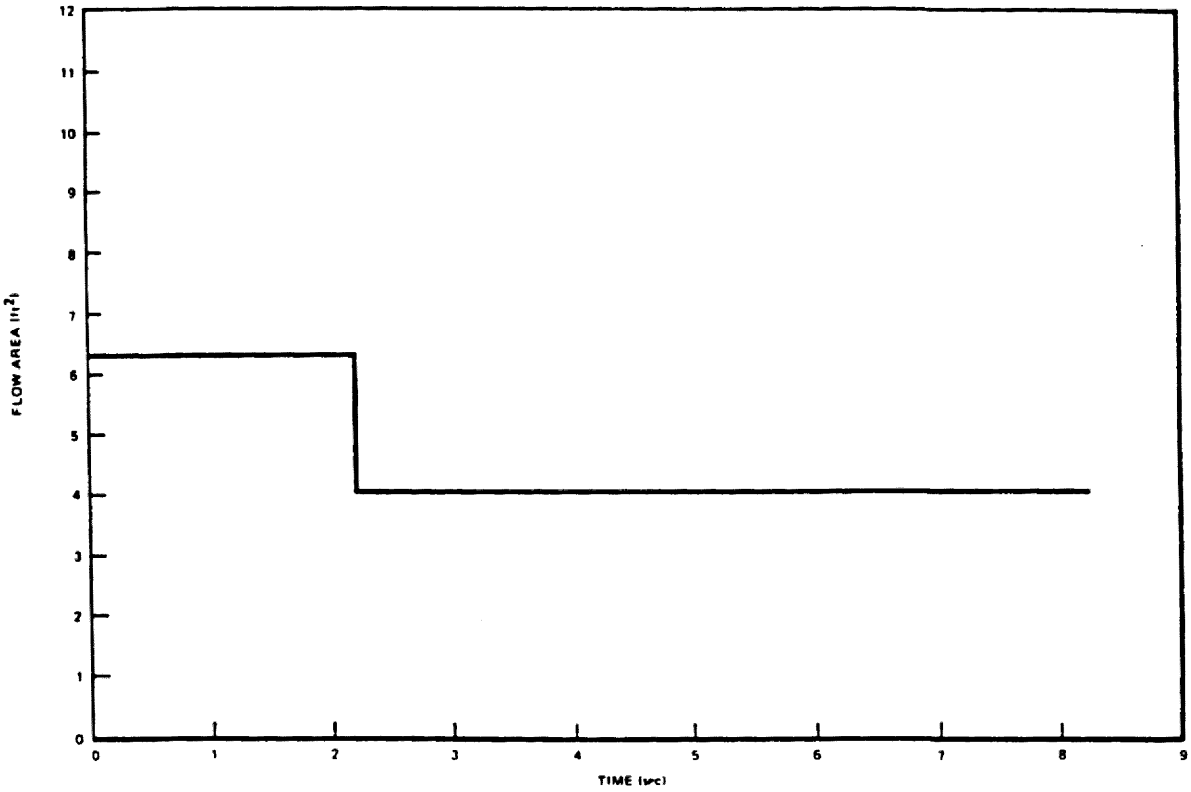
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-293.

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DOWNCOMER DESIGN DETAILS
(SHEET 2 OF 2)

FIGURE 6.2-1



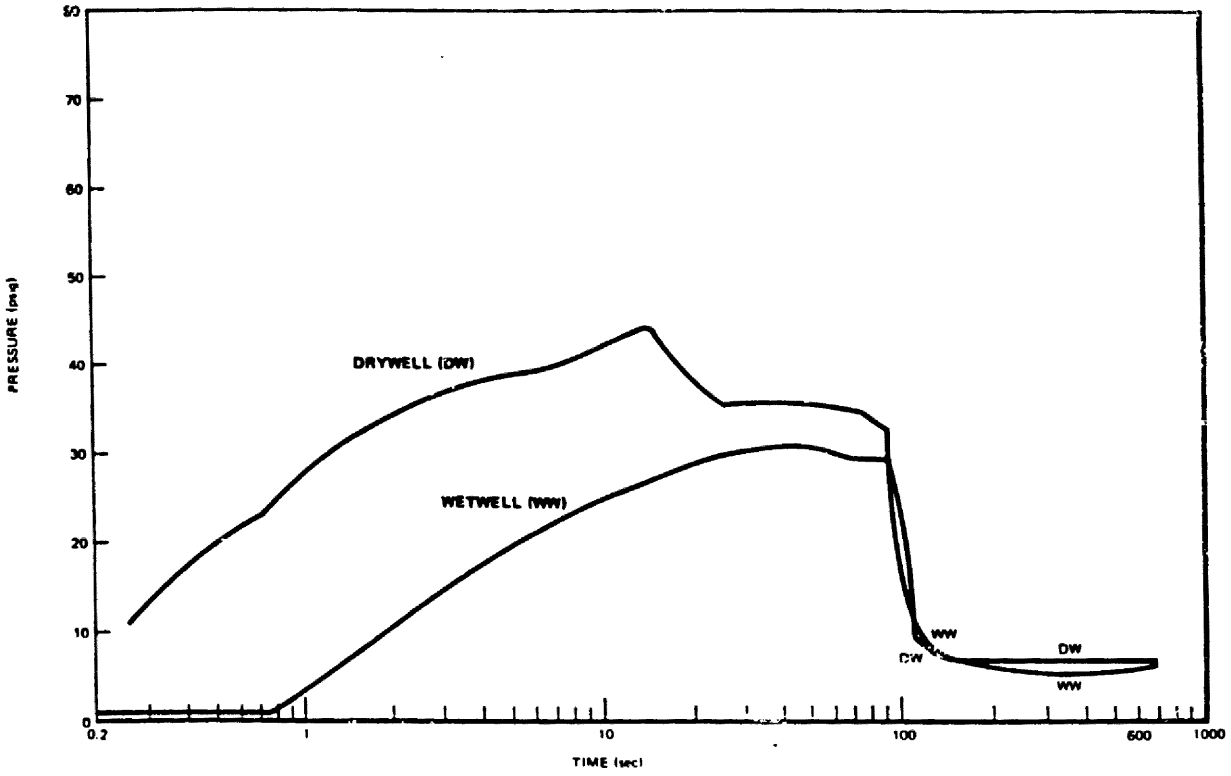
NOTE: The information presented in this figure is historical and is based on the original design basis conditions and does not represent current plant conditions or methodology used to analyze the containment response following a LOCA. Refer to Section 6.2.1.8 for the current analysis results and methodology.

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EFFECTIVE BLOWDOWN AREA FOR RECIRCULATION LINE BREAK

FIGURE 6.2-2

Rev. 5, 4/96

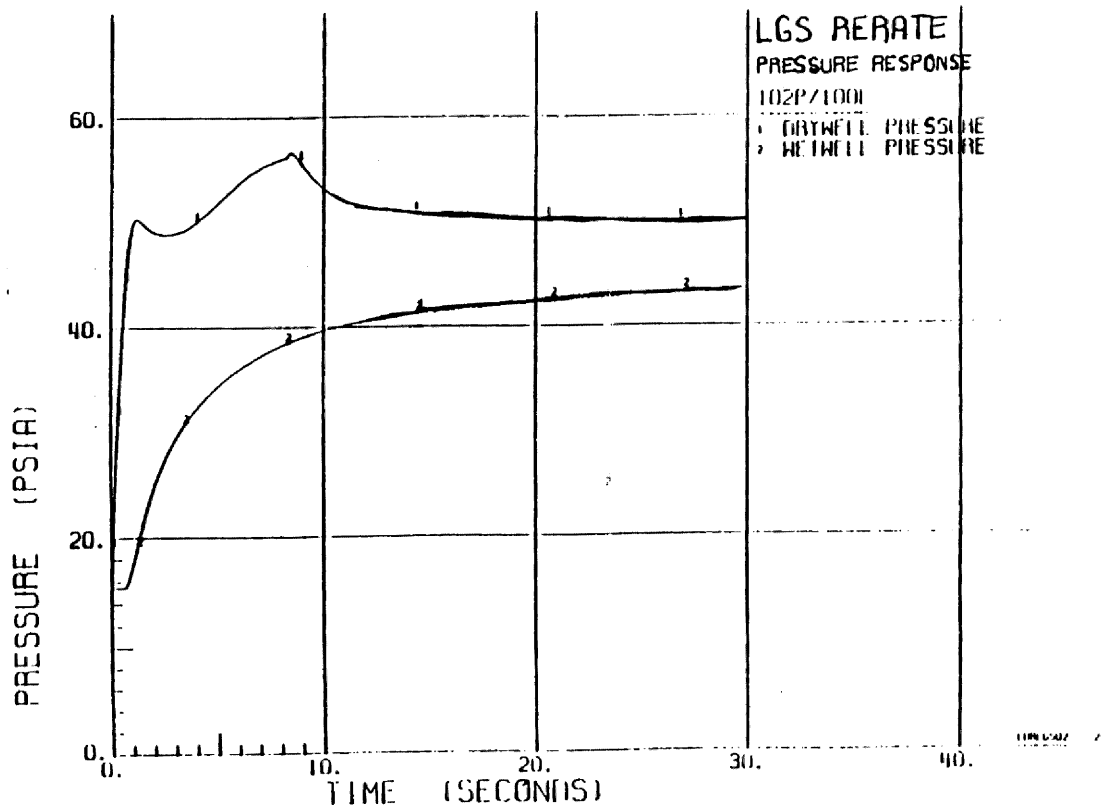


NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Figure 6.2-3A for the recirculation line break results for current plant conditions.

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SHORT-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK

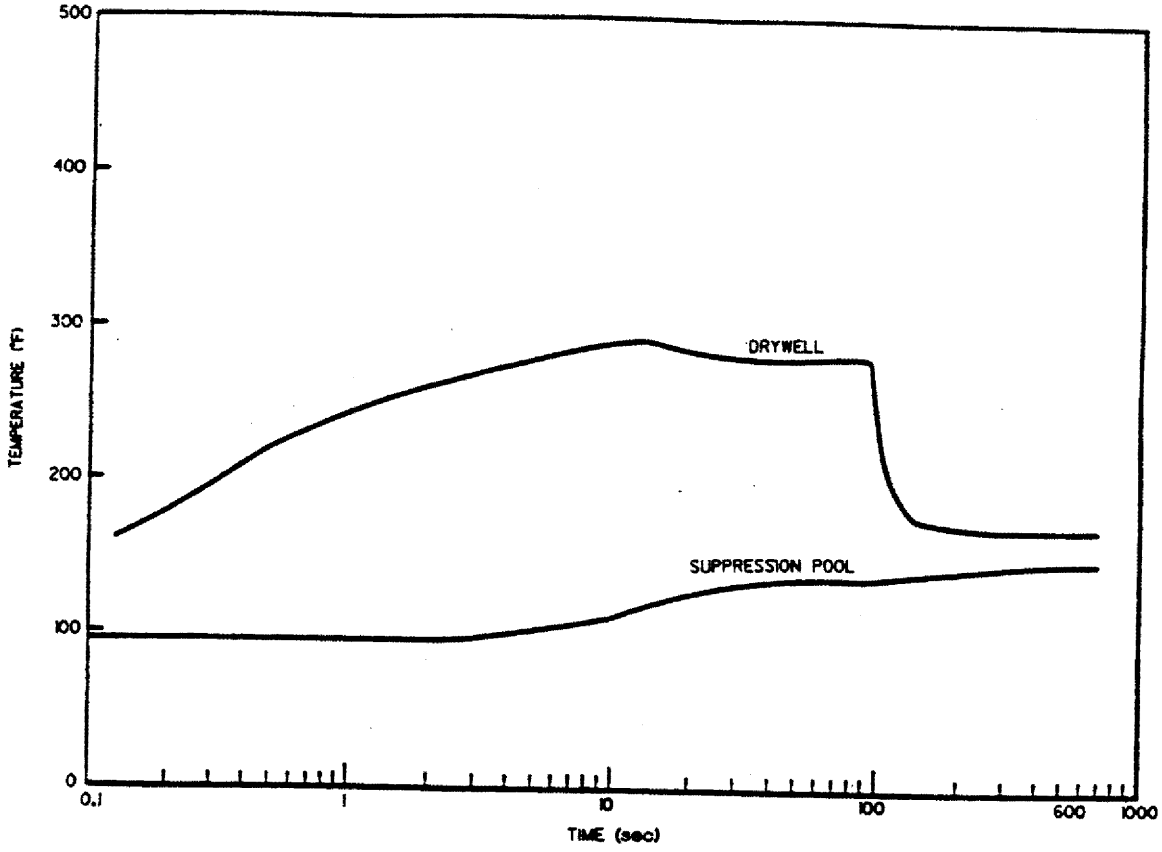
FIGURE 6.2-3 Rev. 5, 4/96



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UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PRESSURE RESPONSE AS A FUNCTION OF TIME

FIGURE 6.2-3A REV. 5, 4/96

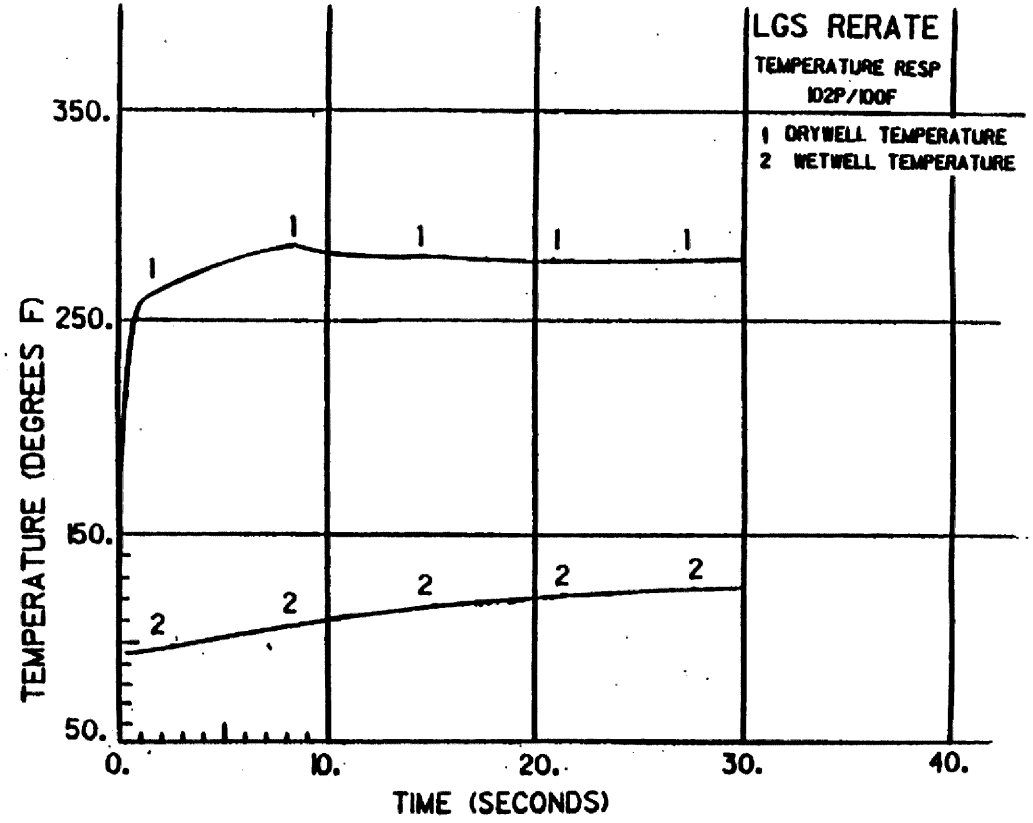


NOTE: The information presented in this figure is historical and is based on the original design basis conditions and to analyze the containment response following a LOCA. Refer to Figure 6.2-4A for the recirculation line break results for current plant conditions.

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SHORT-TERM CONTAINMENT TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK

FIG 6.2-4 Rev 08 11/98

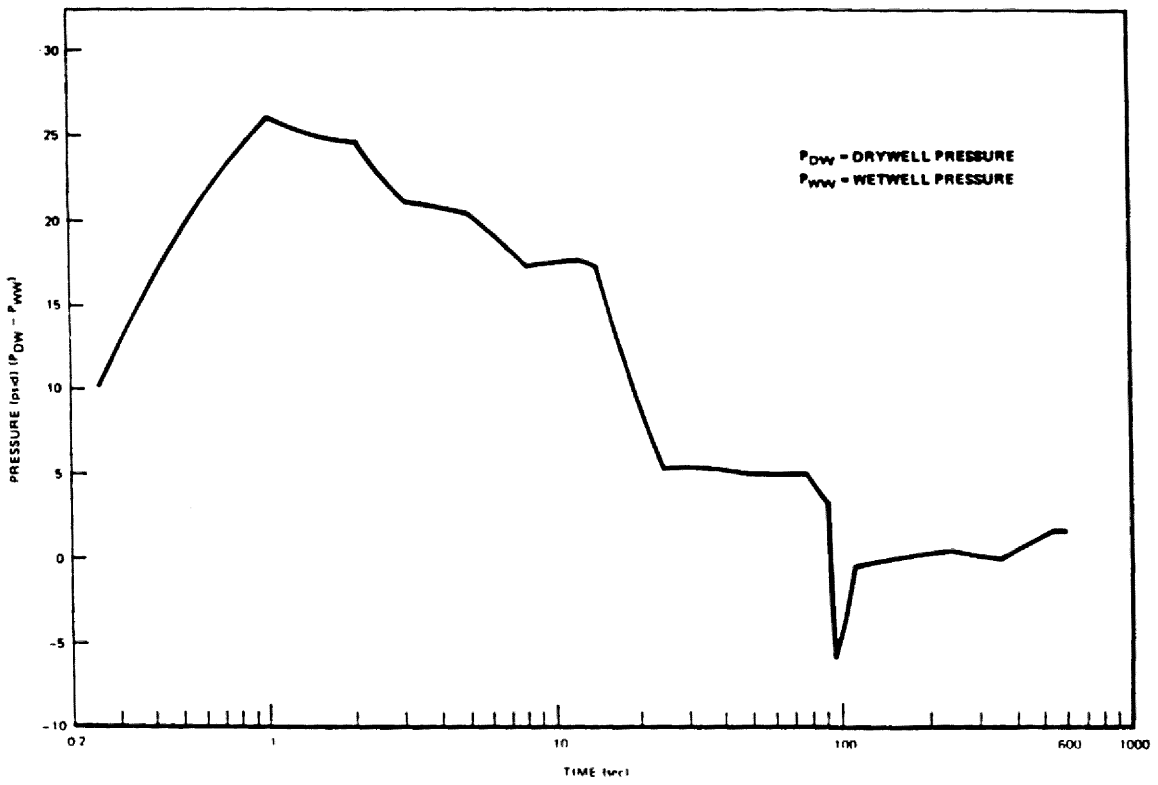


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TEMPERATURE RESPONSE AS A
FUNCTION OF TIME
(at Rerate Power Conditions)

FIGURE 6.2-4A

Rev 08 11/98



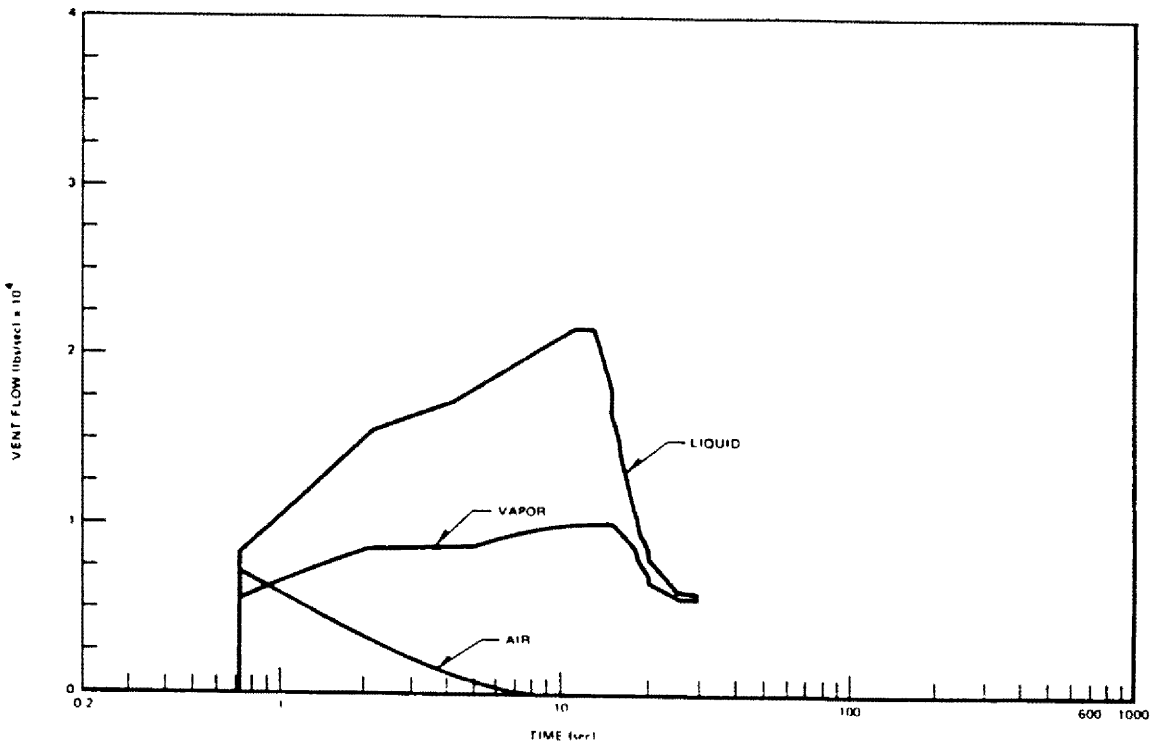
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The current recirculation line break results are discussed in Section 6.2.1.8. The results presented here reasonably represent the general characteristics of the current recirculation line break analysis results.

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SHORT-TERM DIFFERENTIAL PRESSURE ACROSS DIAPHRAM SLAB FOLLOWING RECIRCULATION LINE BREAK

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FIGURE 6.2-5



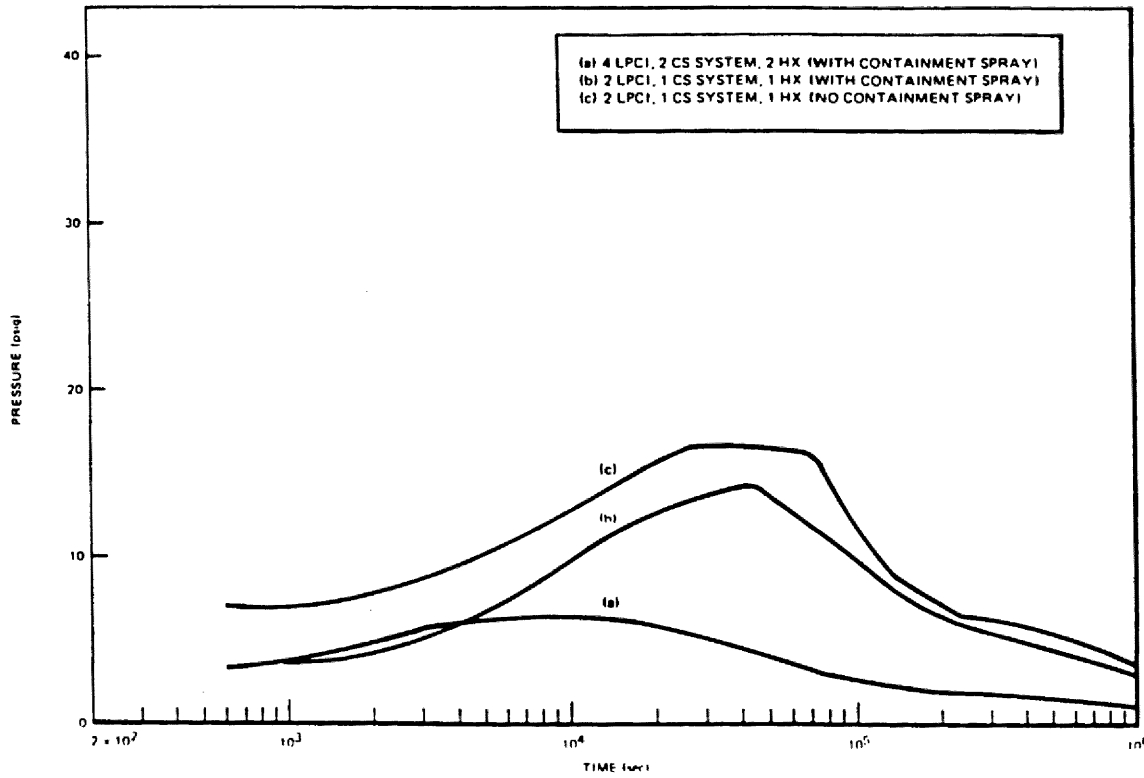
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The current recirculation line break results are discussed in Section 6.2.1.8. The results presented here reasonably represent the general characteristics of the current recirculation line break analysis results.

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SHORT-TERM DOWNCOMER FLOW FOLLOWING RECIRCULATION LINE BREAK

Rev. 5, 4/96

FIGURE 6.2-6

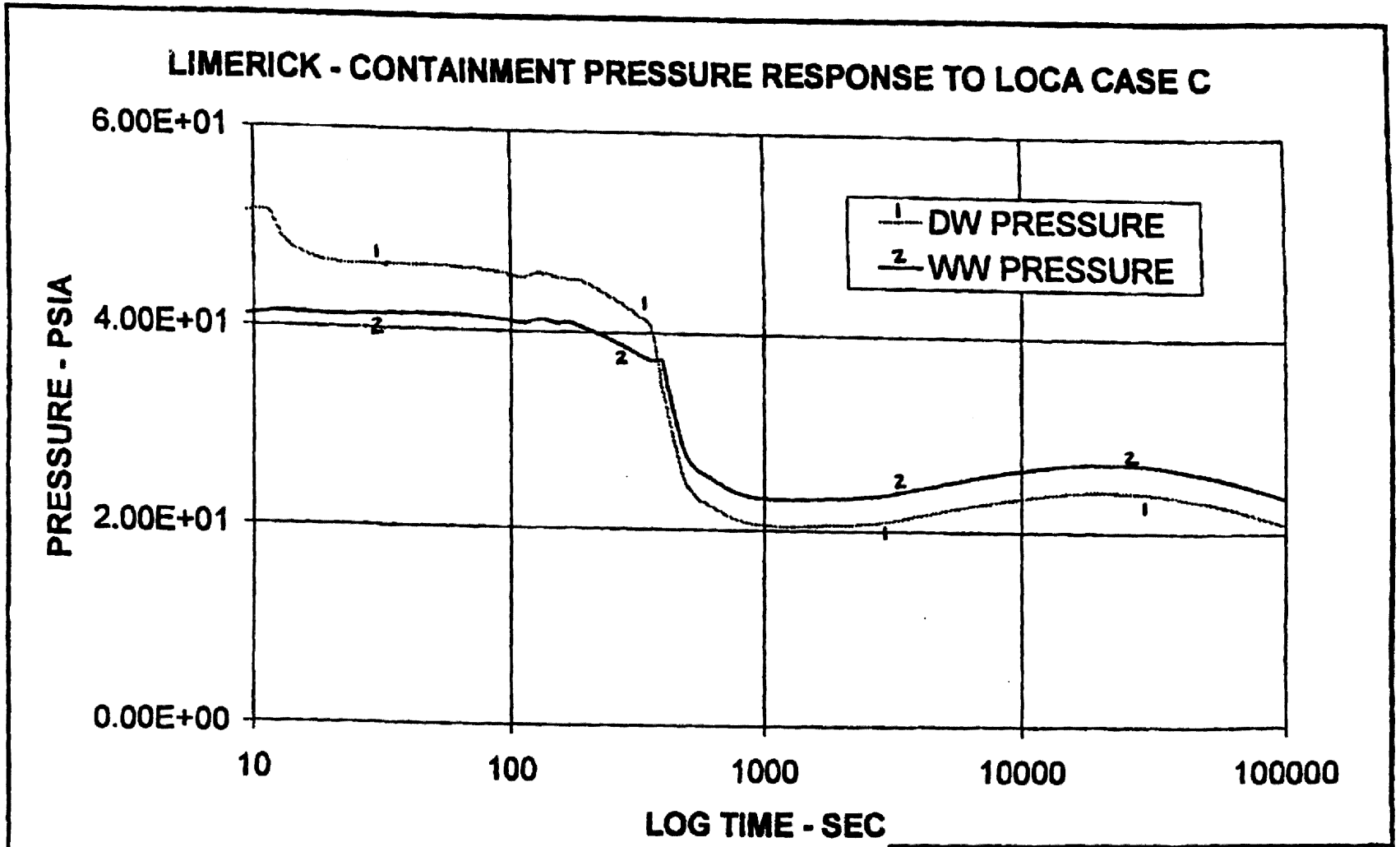


NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Figure 6.2-7A for the Case C results for current plant conditions. The results for Cases A, B, and C shown in this figure do not reflect the current containment analysis, but reasonably represent the general characteristics and relative differences between the three cases.

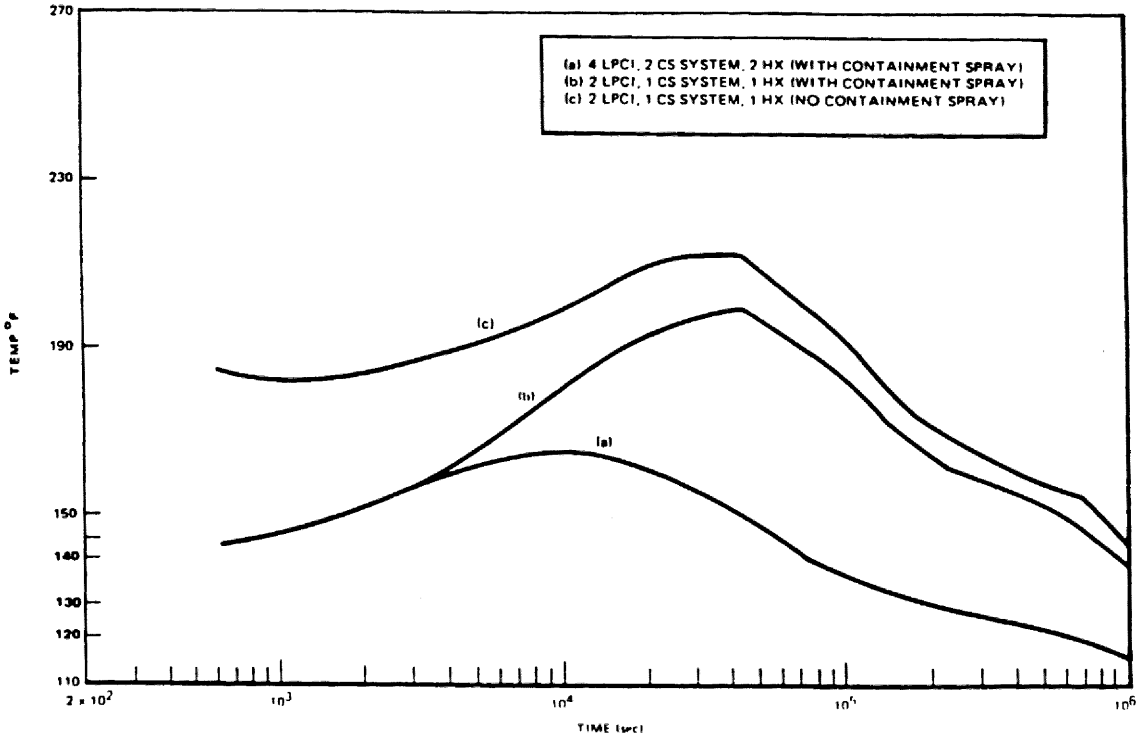
LIMERICK GENERATING STATION
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LONG-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING RECIRCULATION LINE OR MAIN STEAM LINE BREAK

FIGURE 6.2-7 Rev. 5, 4/96



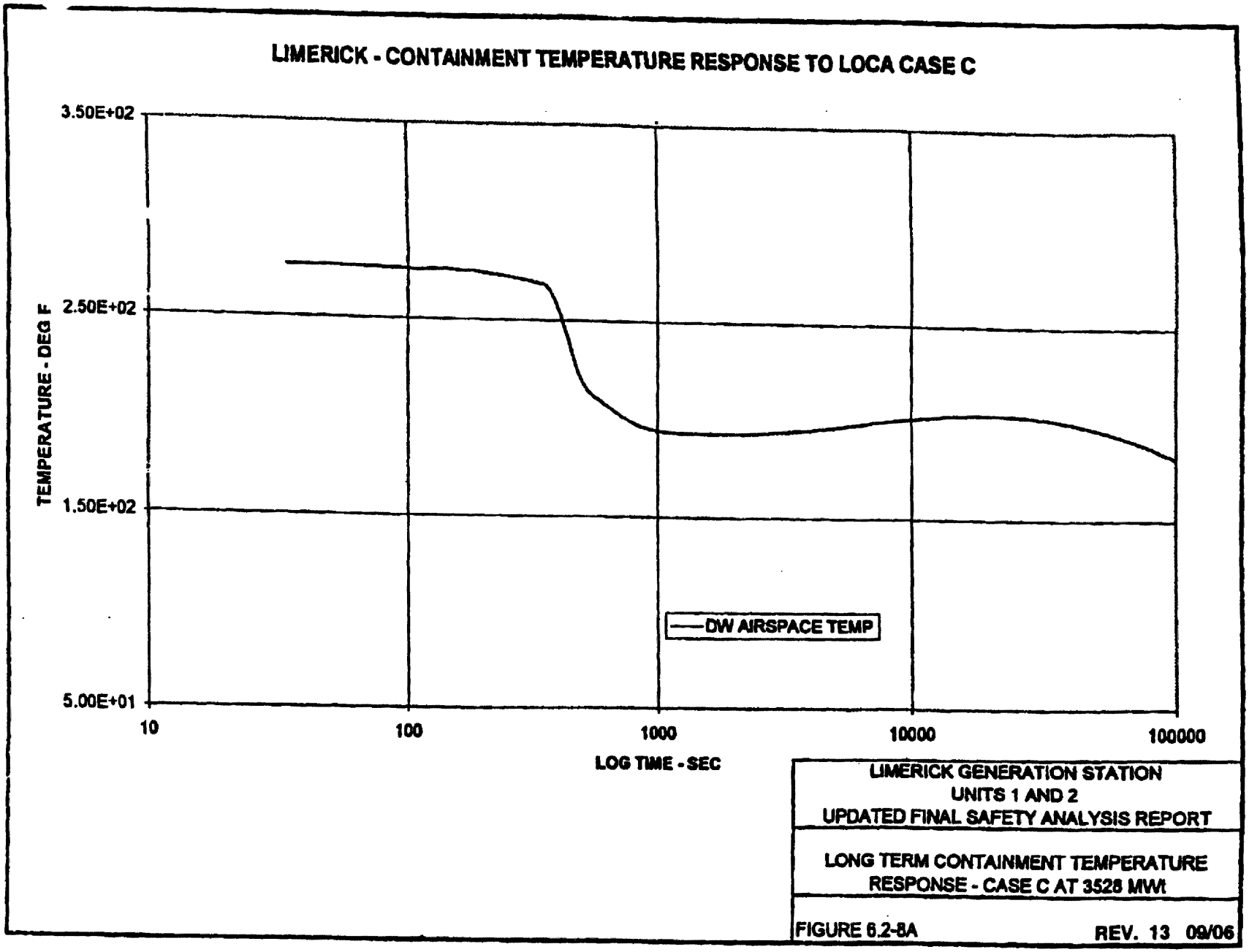
LIMERICK GENERATION STATION UNITS 1 AND 2 UPDATED FINAL SAFETY ANALYSIS REPORT
LONG TERM CONTAINMENT PRESSURE LOCA RESPONSE - CASE C AT 3528 MWt
FIGURE 6.2-7A REV. 13 09/06

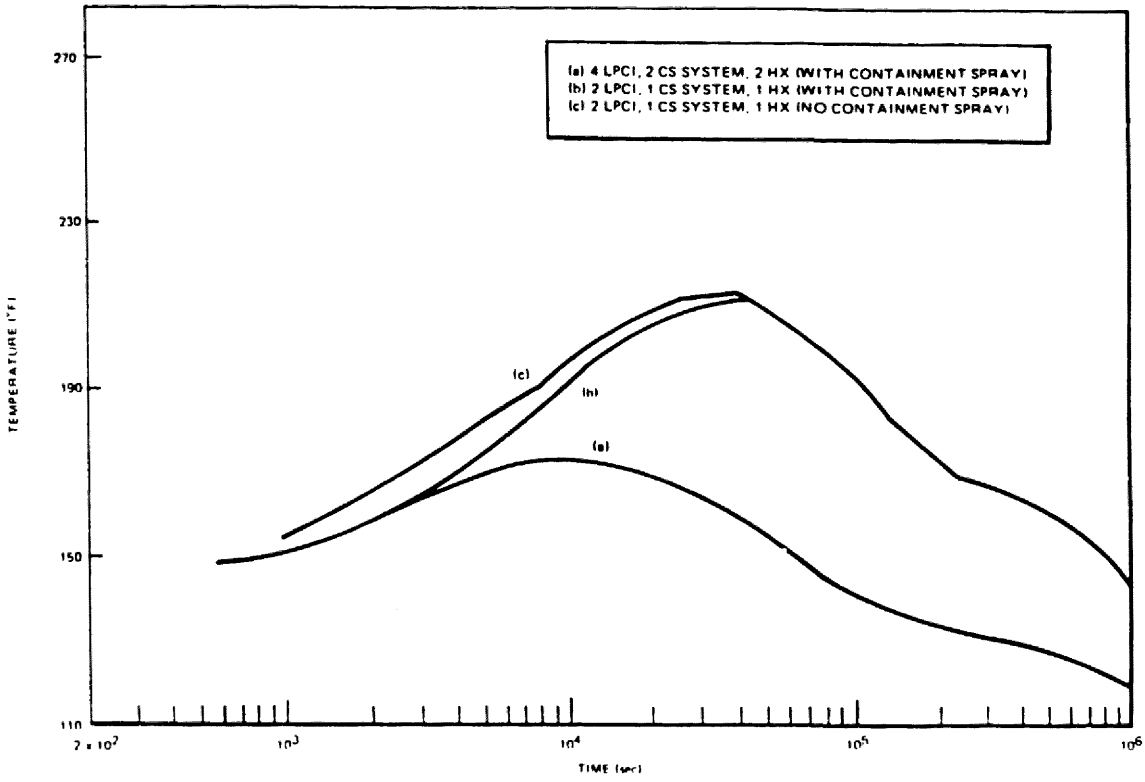


NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Figure 6.2-8A for the Case C results for current plant conditions. The results for Cases A, B, and C shown in this figure do not reflect the current containment analysis, but reasonably represent the general characteristics and relative differences between the three cases.

LONG-TERM DRYWELL TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE OR MAIN STEAM LINE BREAK

FIGURE 6.2-8 Rev. 5, 4/96


LIMERICK - CONTAINMENT TEMPERATURE RESPONSE TO LOCA CASE C
3.50E+02
2.50E+02
1.50E+02
5.00E+01
TEMPERATURE - DEG F
10
100
1000
10000
100000
LOG TIME - SEC
DW AIRSPACE TEMP
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LONG TERM CONTAINMENT TEMPERATURE RESPONSE - CASE C AT 3528 MWt
FIGURE 6.2-8A
REV. 13 09/06

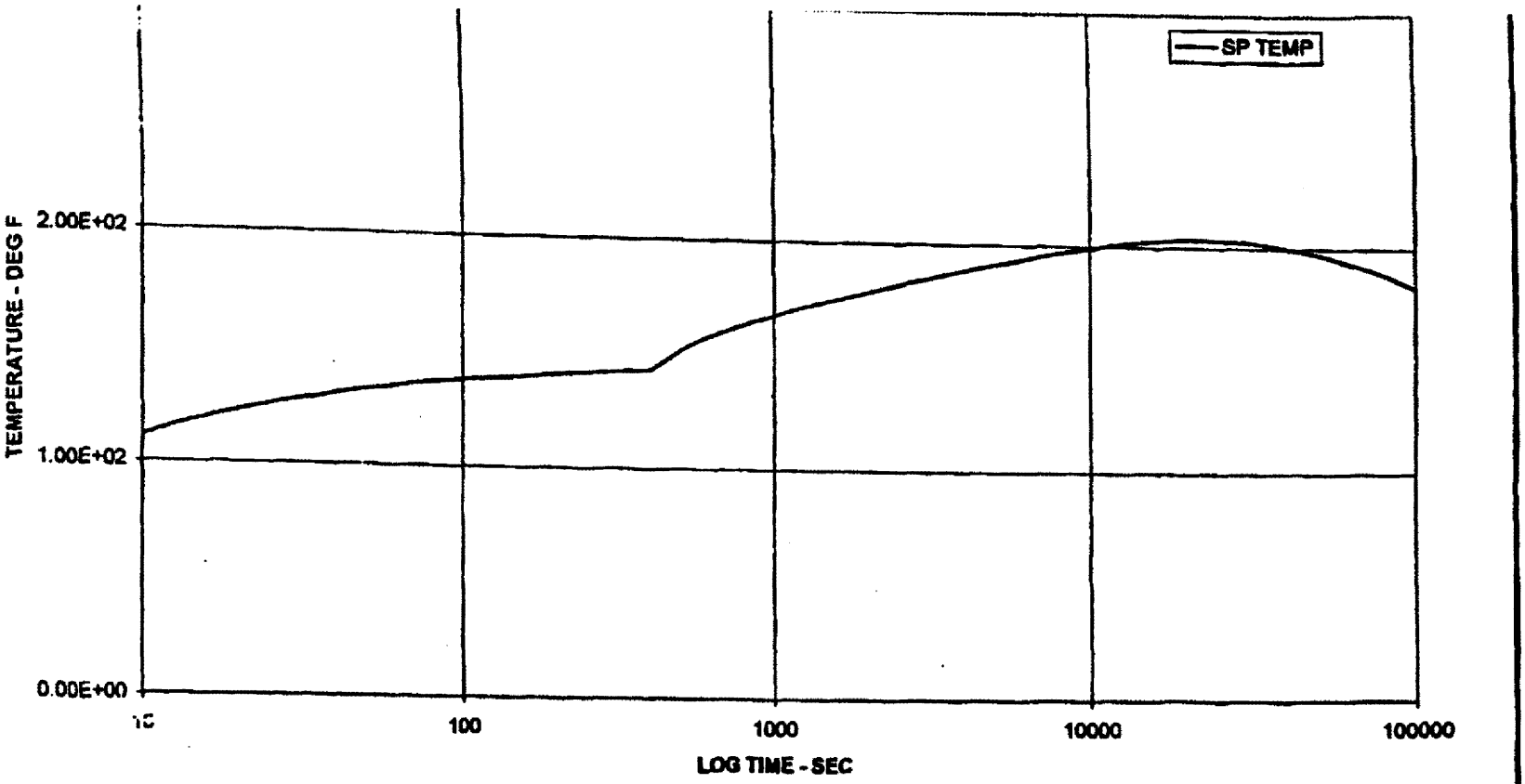


NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Figure 6.2-9A for the Case C results for current plant conditions. The results for Cases A, B, and C shown in this figure do not reflect the current containment analysis, but reasonably represent the general characteristics and relative differences between the three cases.

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LONG-TERM SUPPRESSION POOL TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE OR MAIN STEAM LINE BREAK

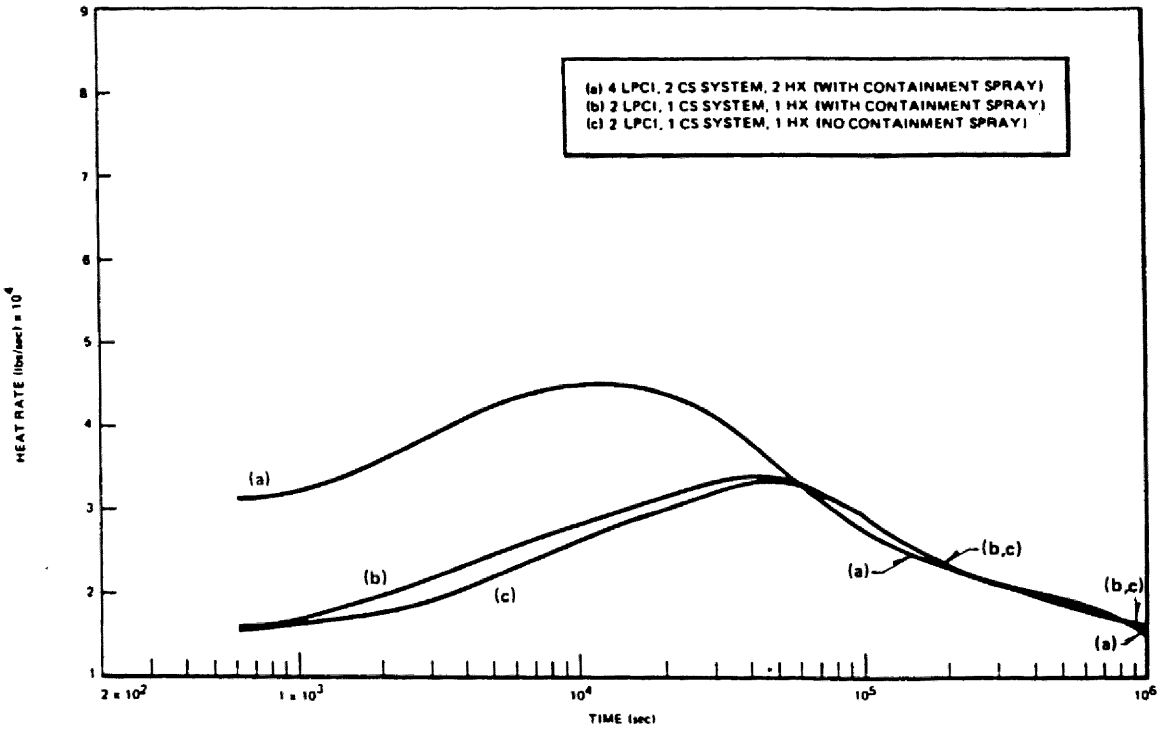
FIGURE 6.2-9 Rev. 5, 4/96



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LONG TERM SUPPRESSION POOL
TEMPERATURE RESPONSE - CASE C AT 3528 MWt

FIGURE 6.2-9A REV. 13 09/06

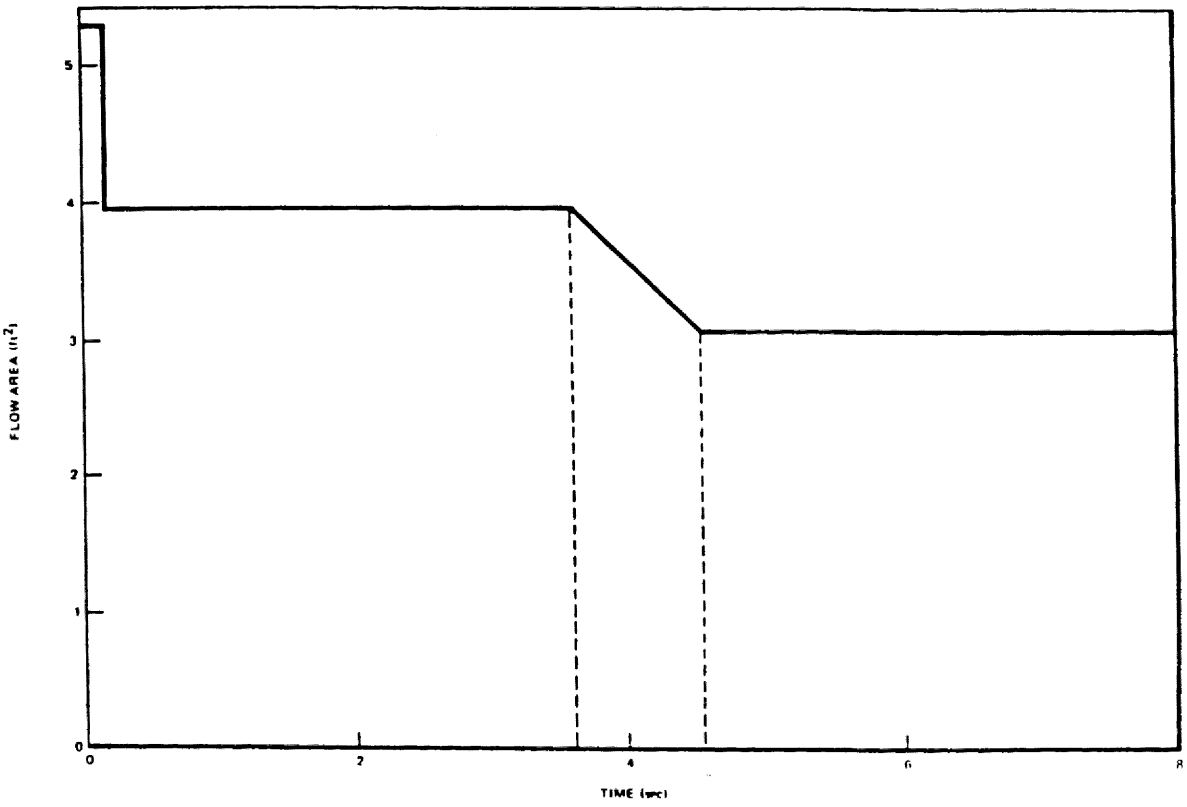


NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Section 6.2.1.1.3, only Case C was reanalyzed for current plant conditions. The results for Cases A, B, and C shown in this figure do not reflect the current containment analysis, but reasonably represent the general characteristics and relative differences between the three cases.

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RHR HEAT REMOVAL RATE
FOLLOWING RECIRCULATION
LINE OR MAIN STEAM LINE BREAK

FIGURE 6.2-10 Rev. 5, 4/96

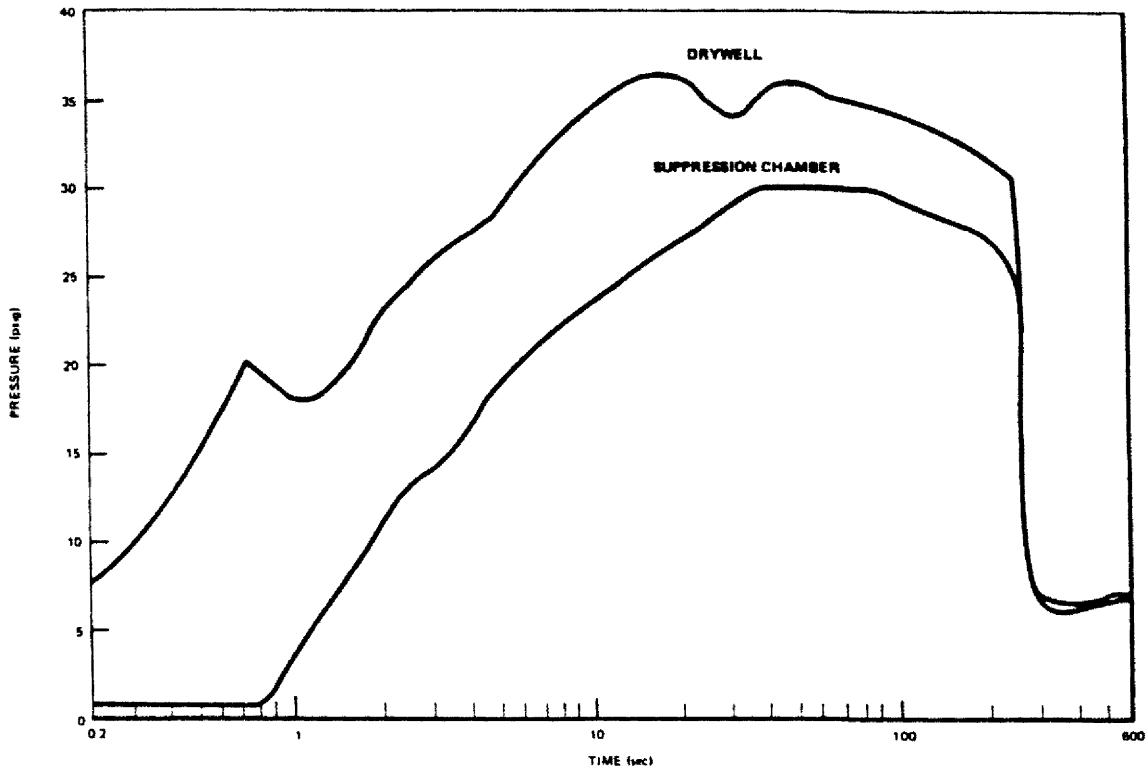


NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Section 6.2.1.8 for the current analysis results and methodology. The results shown here reasonably represent the general characteristics of the event.

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EFFECTIVE BLOWDOWN AREA
FOR MAIN STEAM LINE BREAK

FIGURE 6.2-11 Rev. 5, 4/96



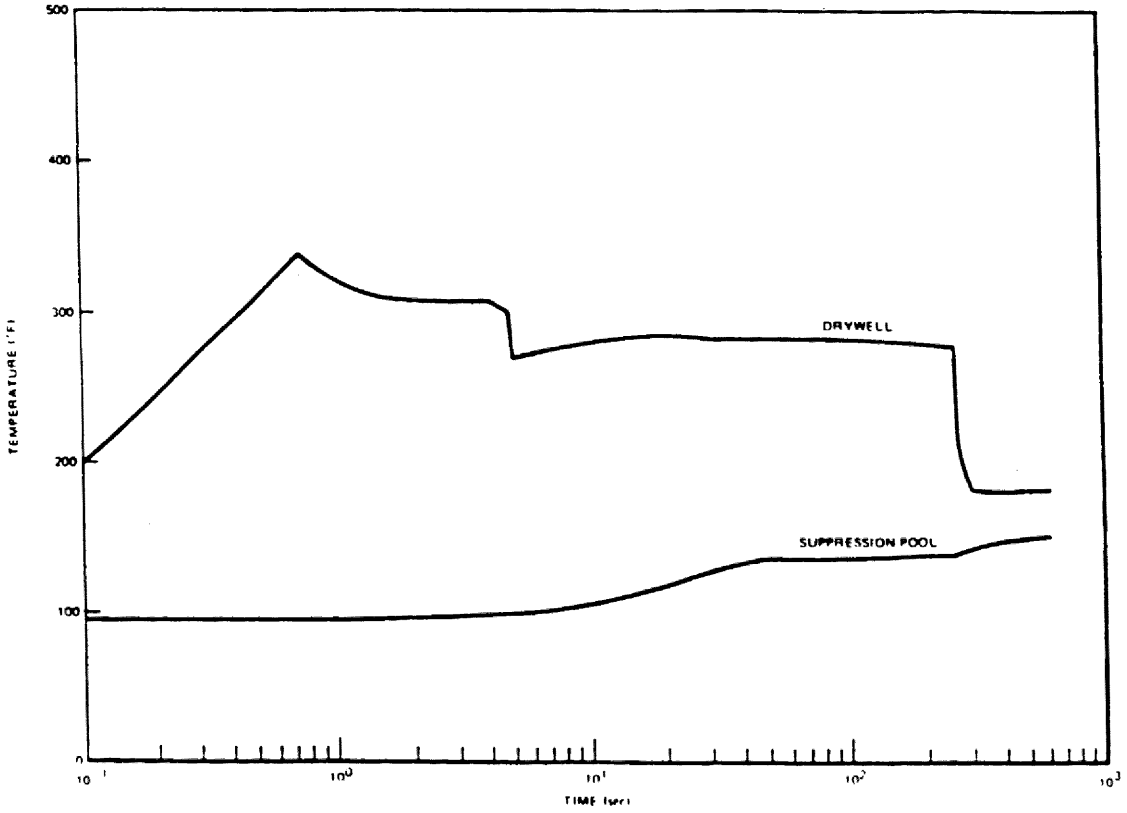
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the main steam line break was not reanalyzed for the current conditions; however, the results reasonably represent the general characteristics of the main steam line break.

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SHORT-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING MAIN STEAM LINE BREAK

FIGURE 6.2-12

Rev. 5, 4/96



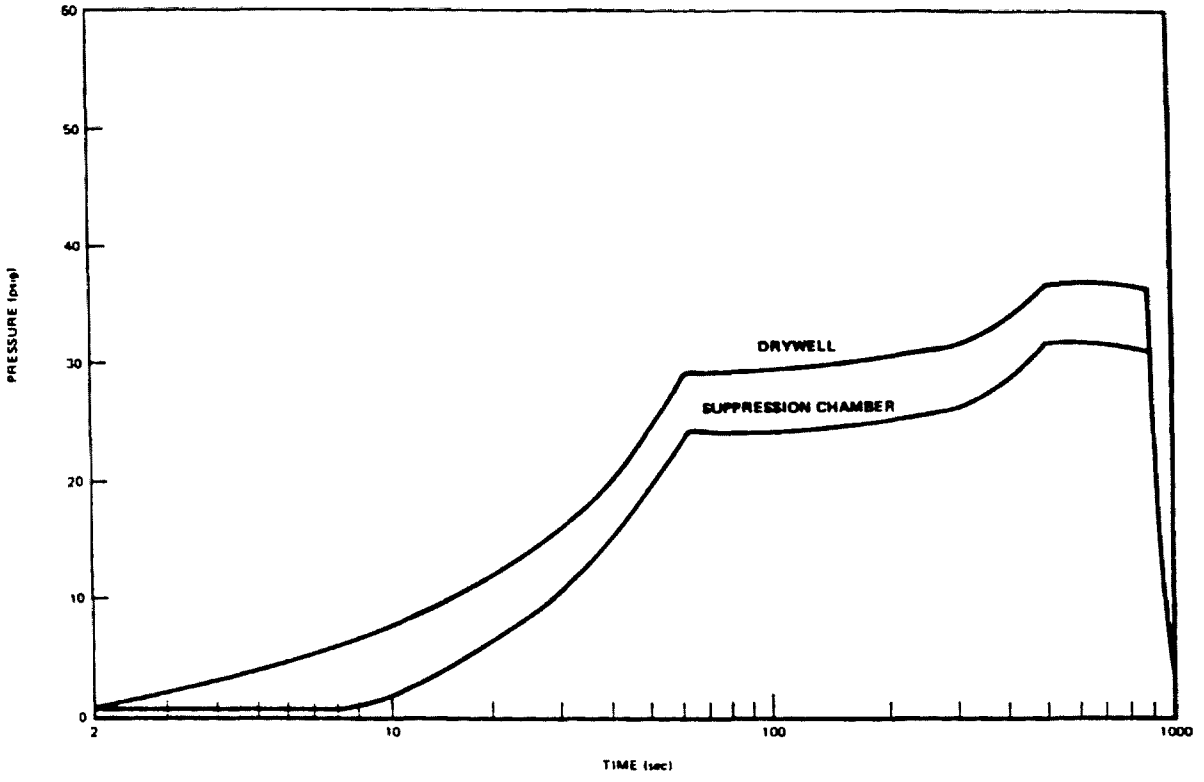
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the main steam line break was not reanalyzed for the current conditions; however, the results reasonably represent the general characteristics of the main steam line break.

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UPDATED FINAL SAFETY ANALYSIS REPORT

SHORT-TERM CONTAINMENT TEMPERATURE RESPONSE FOLLOWING MAIN STEAM LINE BREAK

Rev. 5, 4/96

FIGURE 6.2-13



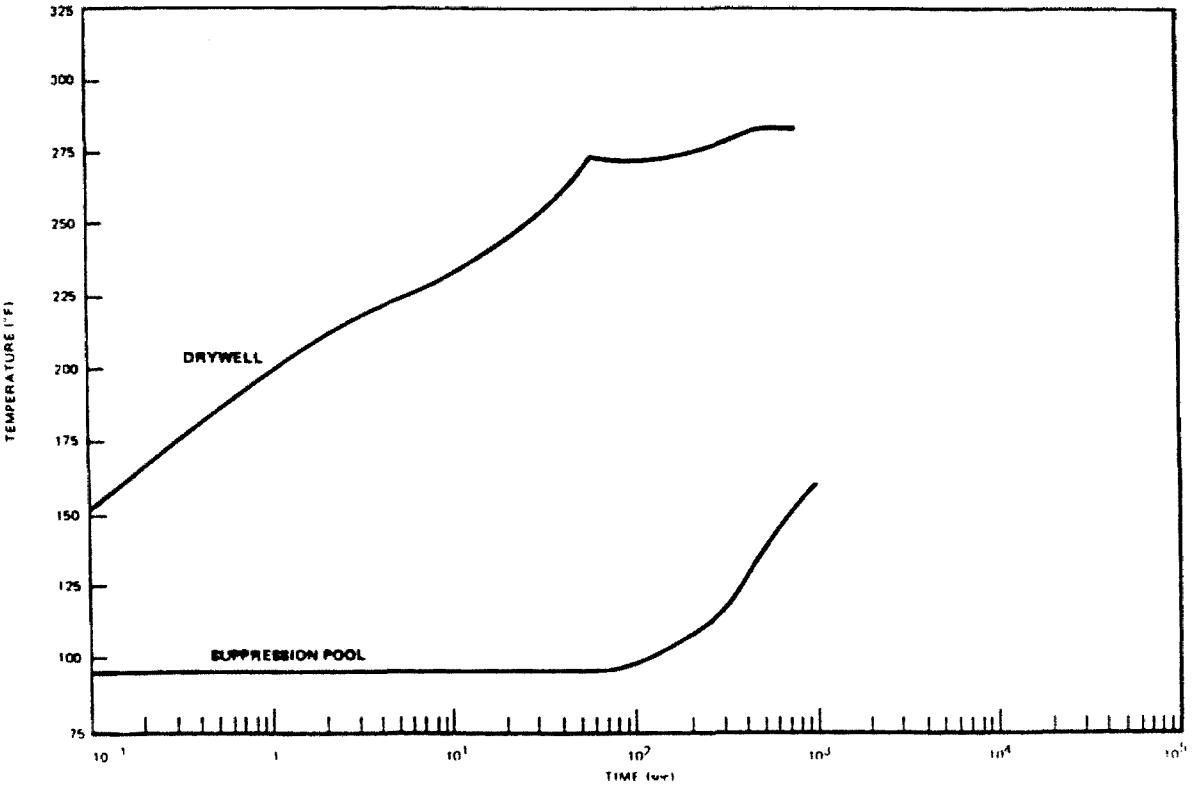
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the pipe break was not reanalyzed for the current conditions; however, the results reasonably represent the general characteristics of the pipe break analysis results.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SHORT-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING AN INTERMEDIATE SIZE BREAK (0.1 ft^2 LIQUID BREAK)

Rev. 15, 09/10

FIGURE 6.2-14



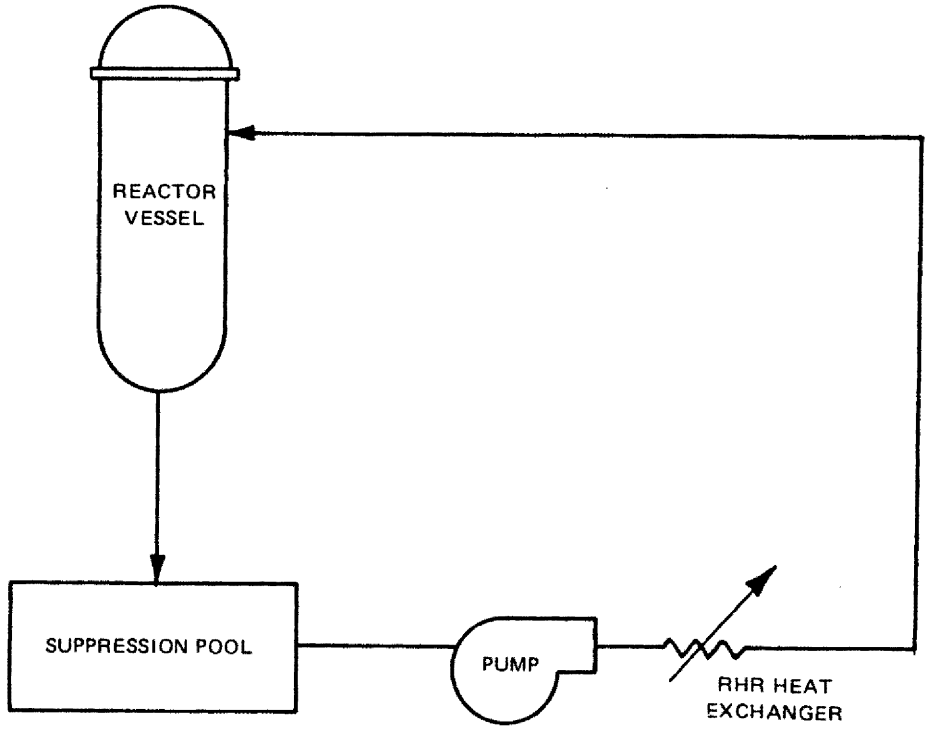
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the pipe break was not reanalyzed for the current conditions; however, the results reasonably represent the general characteristics of the pipe break analysis results.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SHORT-TERM CONTAINMENT TEMPERATURE RESPONSE FOLLOWING AN INTERMEDIATE SIZE BREAK (0.1 ft^2 LIQUID BREAK)

FIGURE 6.2-15

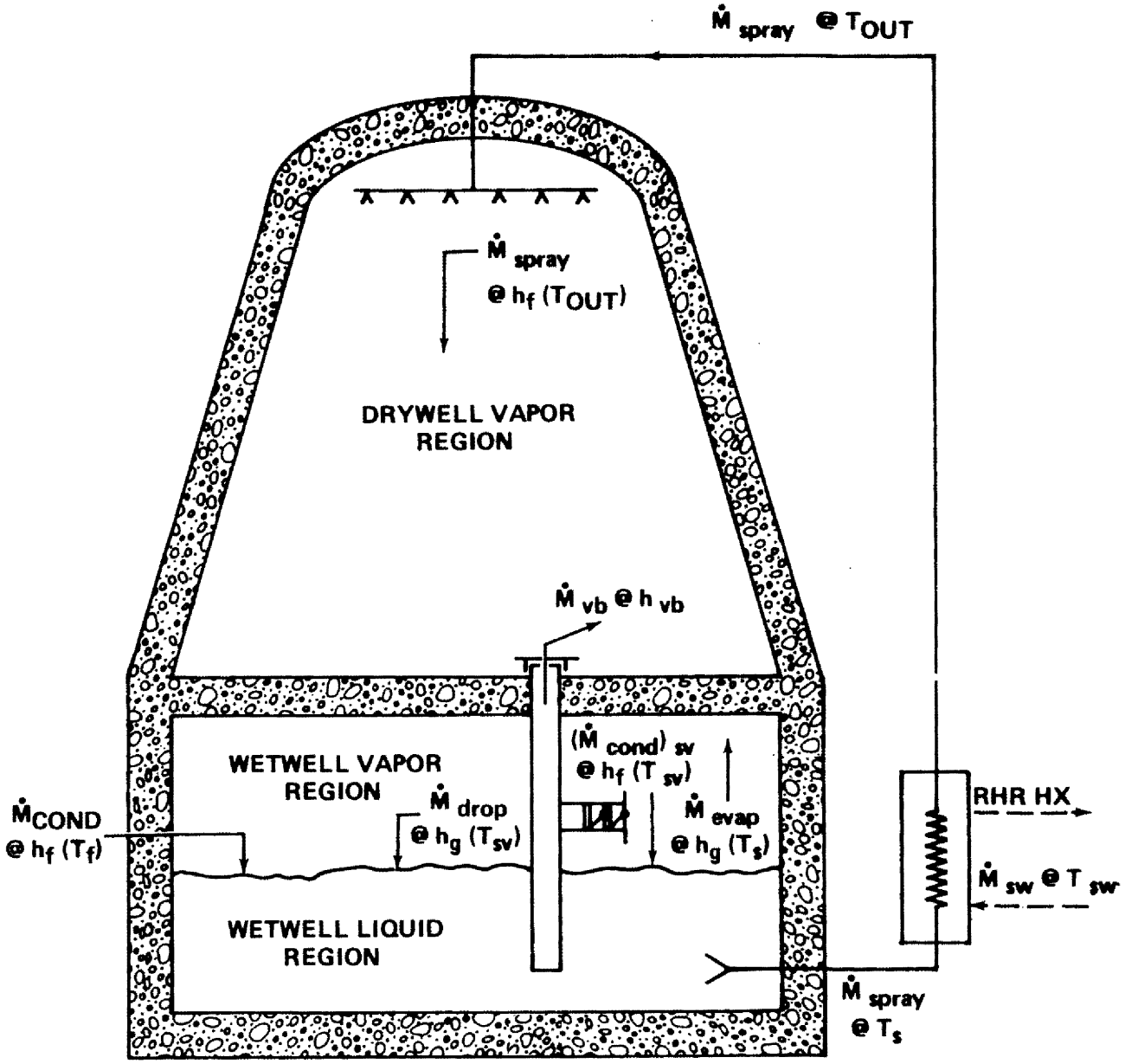
Rev. 15, 09/10



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SCHEMATIC OF ANALYTICAL MODEL FOR RHR CONTAINMENT COOLING SYSTEM

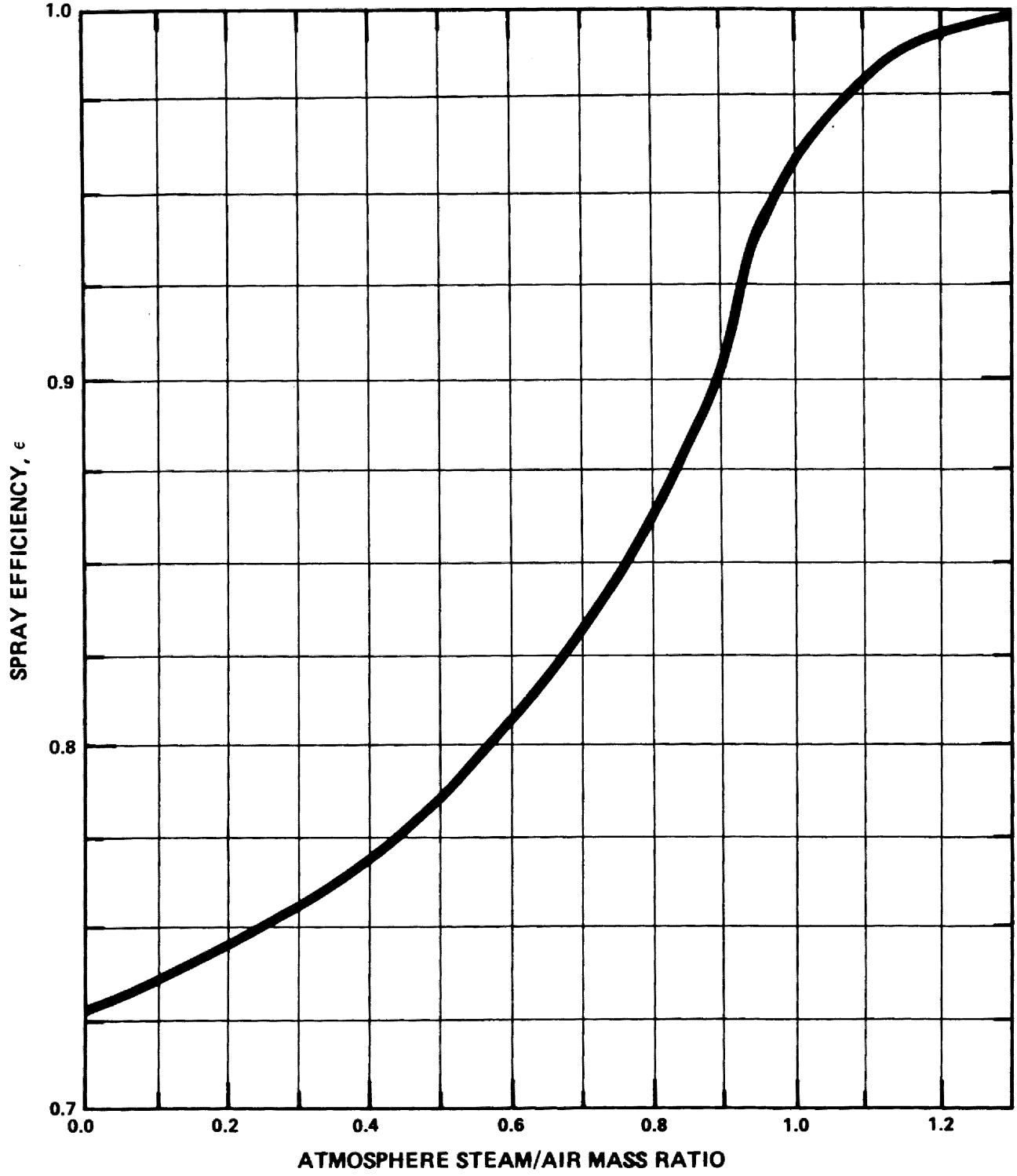
FIGURE 6.2-16



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MODEL FOR ANALYSIS OF INADVERTANT DRYWELL SPRAY ACTUATION

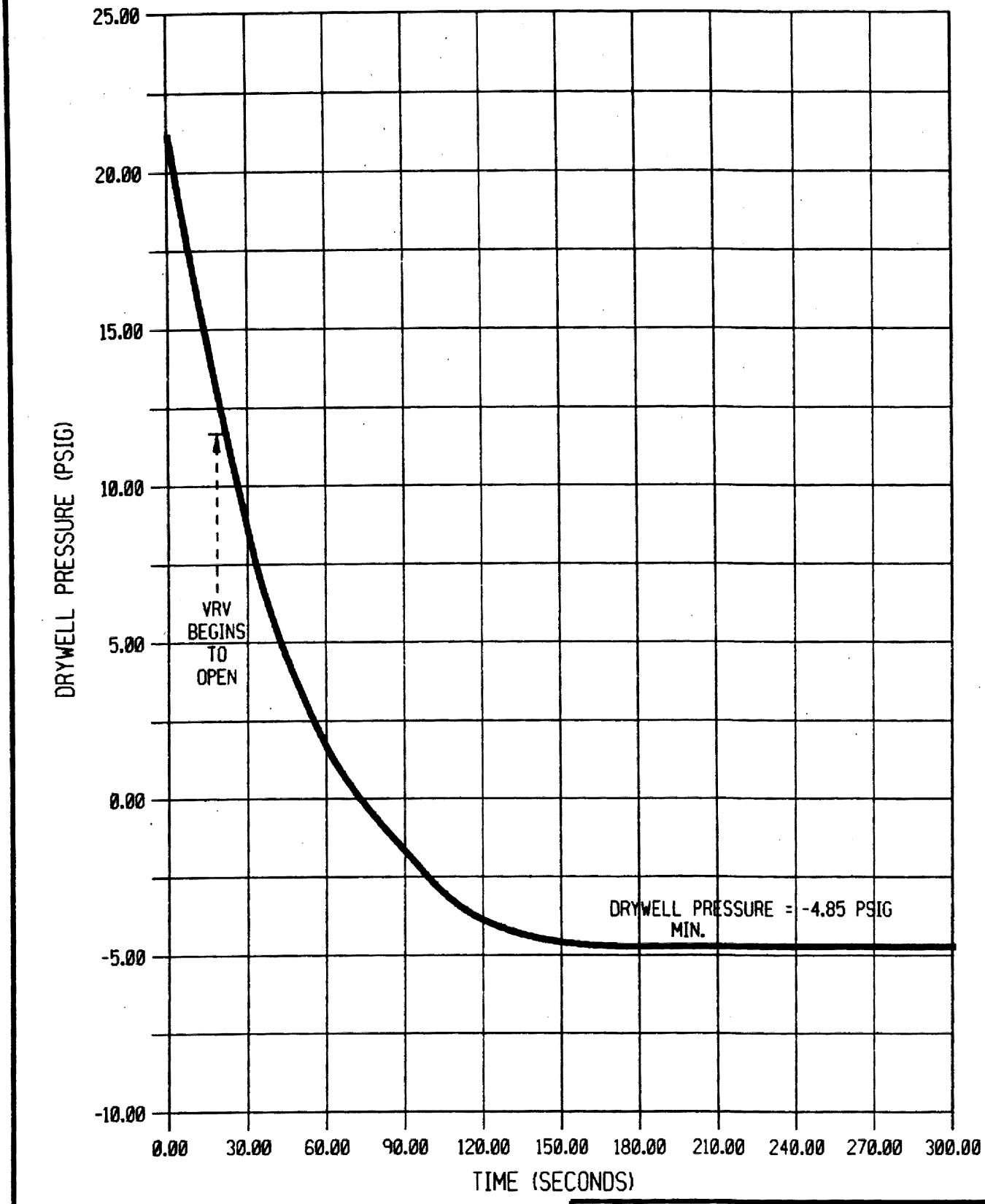
FIGURE 6.2-17



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

THERMAL HEAT
REMOVAL EFFICIENCY
OF DRYWELL SPRAY

FIGURE 6.2-18

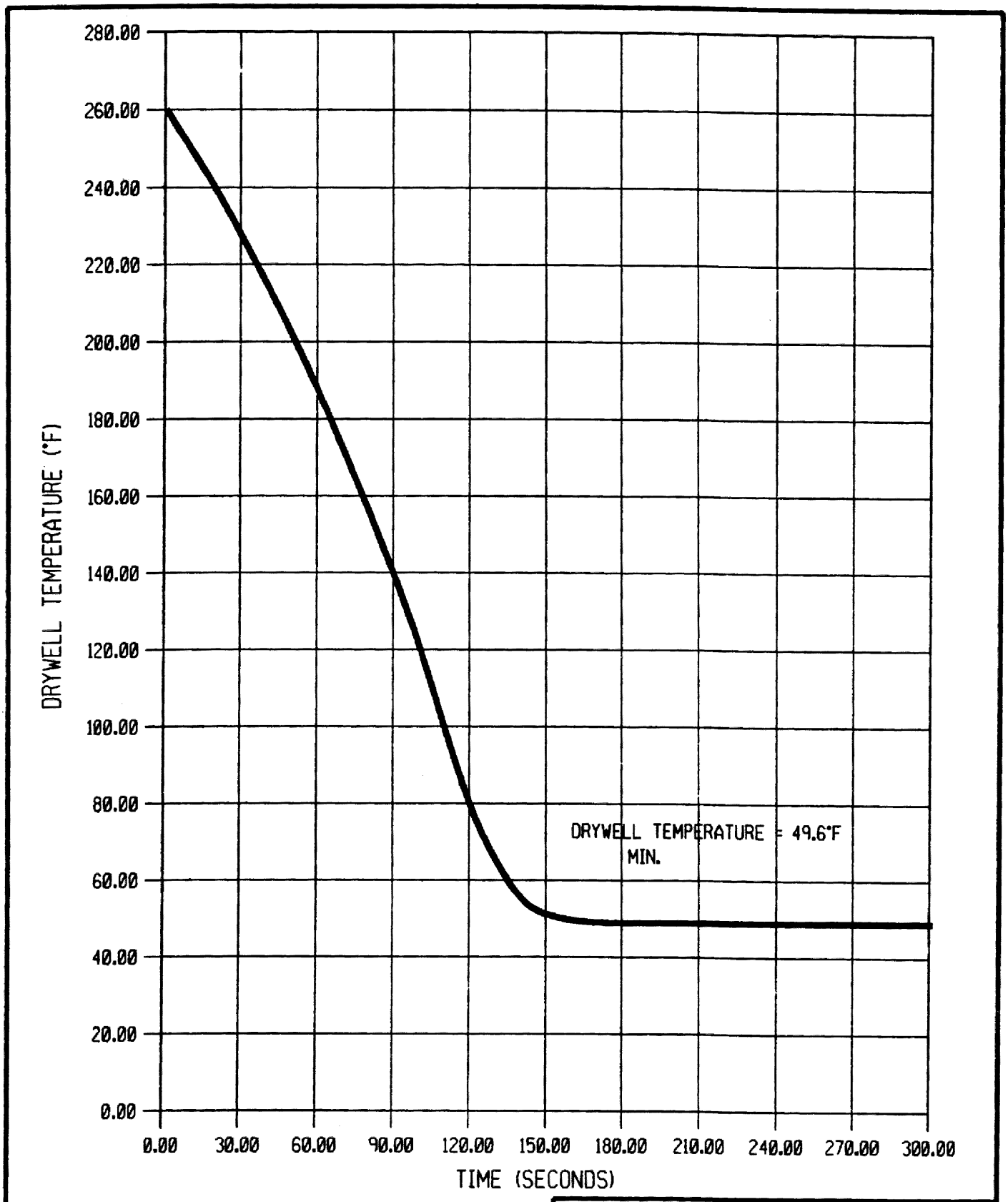


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL PRESSURE
RESPONSE TO
SPRAY ACTUATION

FIGURE 6.2-19 Rev. 1 July/91

7:\MECH\ 0602019.DGN

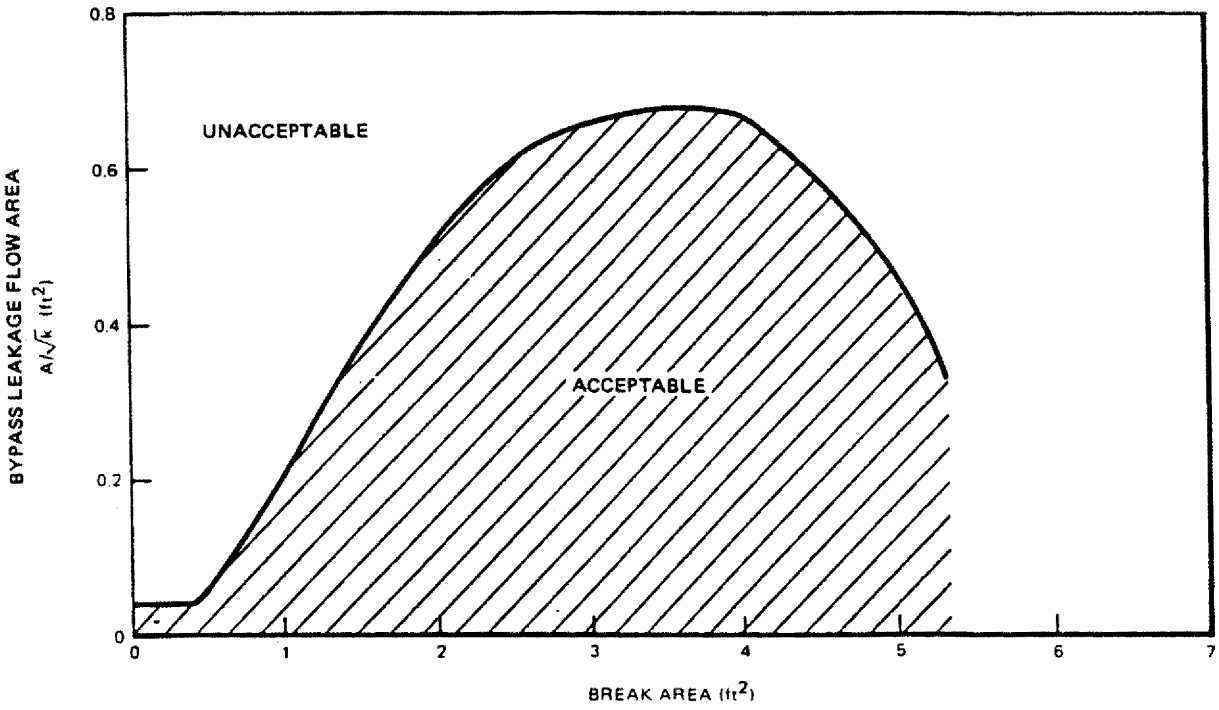


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL TEMPERATURE
RESPONSE TO
SPRAY ACTUATION

FIGURE 6.2-20 Rev. 1 July/91

Z:\MECH\ 0602020.DGN



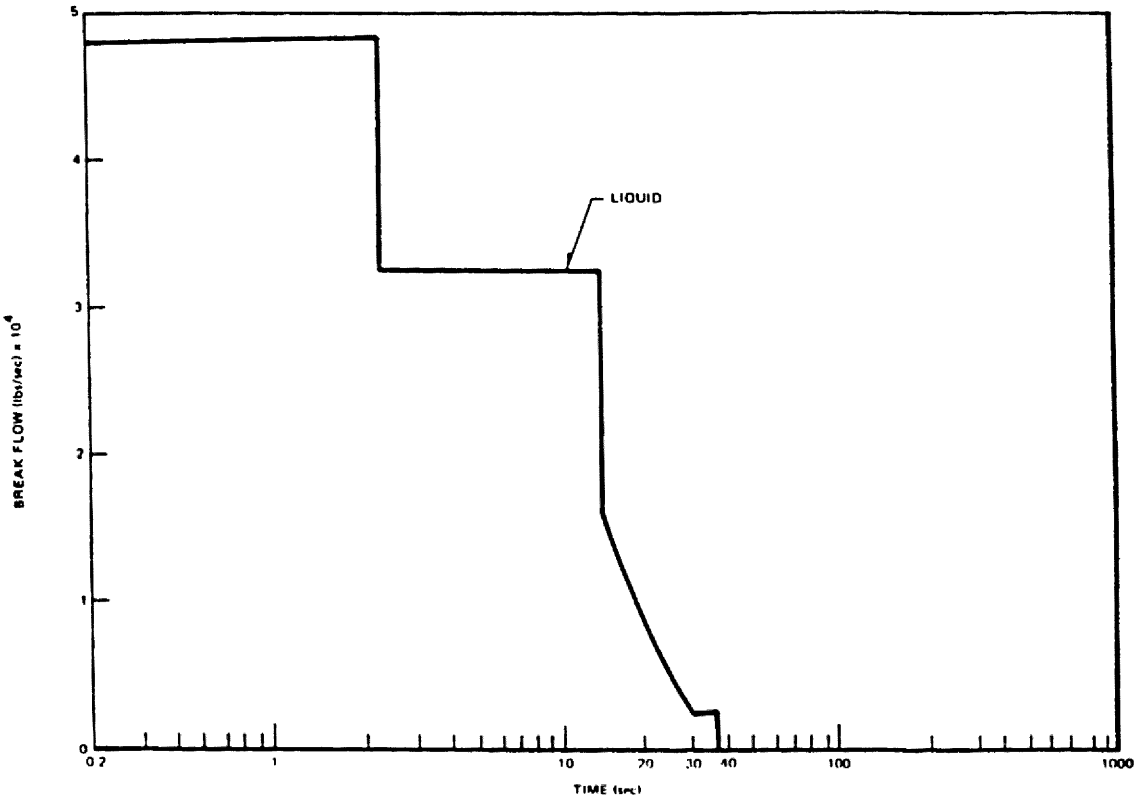
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the main steam line break was not reanalyzed for the current conditions; however, the results reasonably represent the general characteristics of the main steam line break analysis results.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAXIMUM ALLOWABLE STEAM
BYPASS LEAKAGE
FLOW AREA

FIGURE 6.2-21

Rev. 5, 4/96

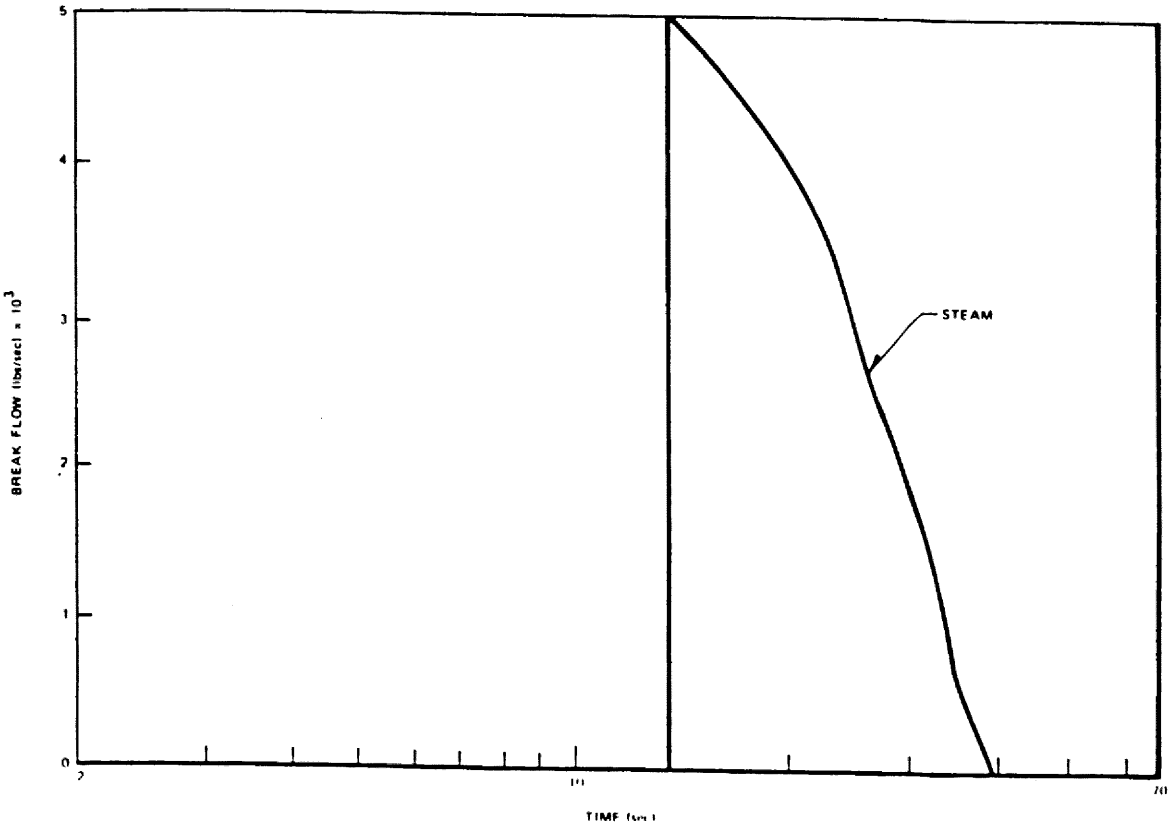


NOTE: The information presented in this figure is historical and is based on the original design basis conditions and does not represent current plant conditions or methodology used to analyze the containment response following a LOCA. Refer to Section 6.2.1.8 for the current analysis methodology.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL LIQUID BLOWDOWN FLOW RATE FOLLOWING RECIRCULATION LINE BREAK

FIGURE 6.2-22 Rev. 5, 4/96

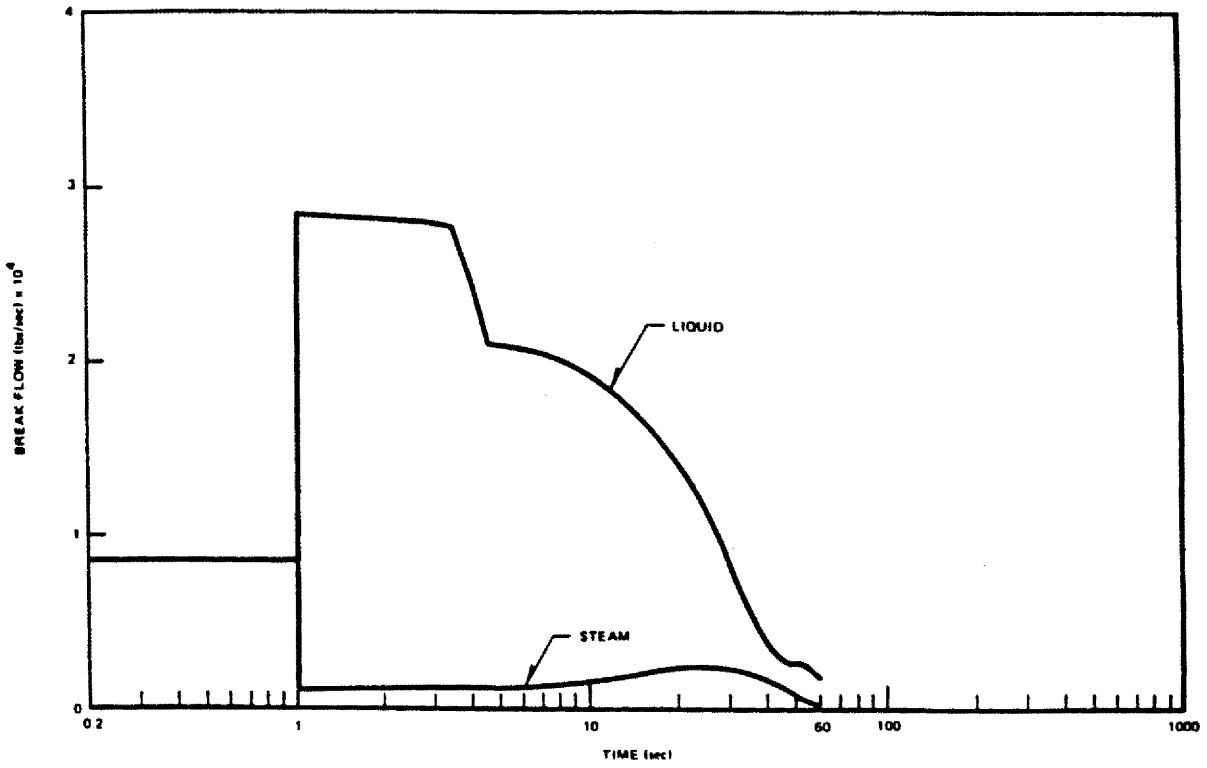


NOTE: The information presented in this figure is historical and is based on the original design basis conditions and does not represent current plant conditions or methodology used to analyze the containment response following a LOCA. Refer to Section 6.2.1.8 for the current analysis methodology.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL STEAM BLOWDOWN FLOW RATE FOLLOWING RECIRCULATION LINE BREAK

FIGURE 6.2-23 Rev. 5, 4/96

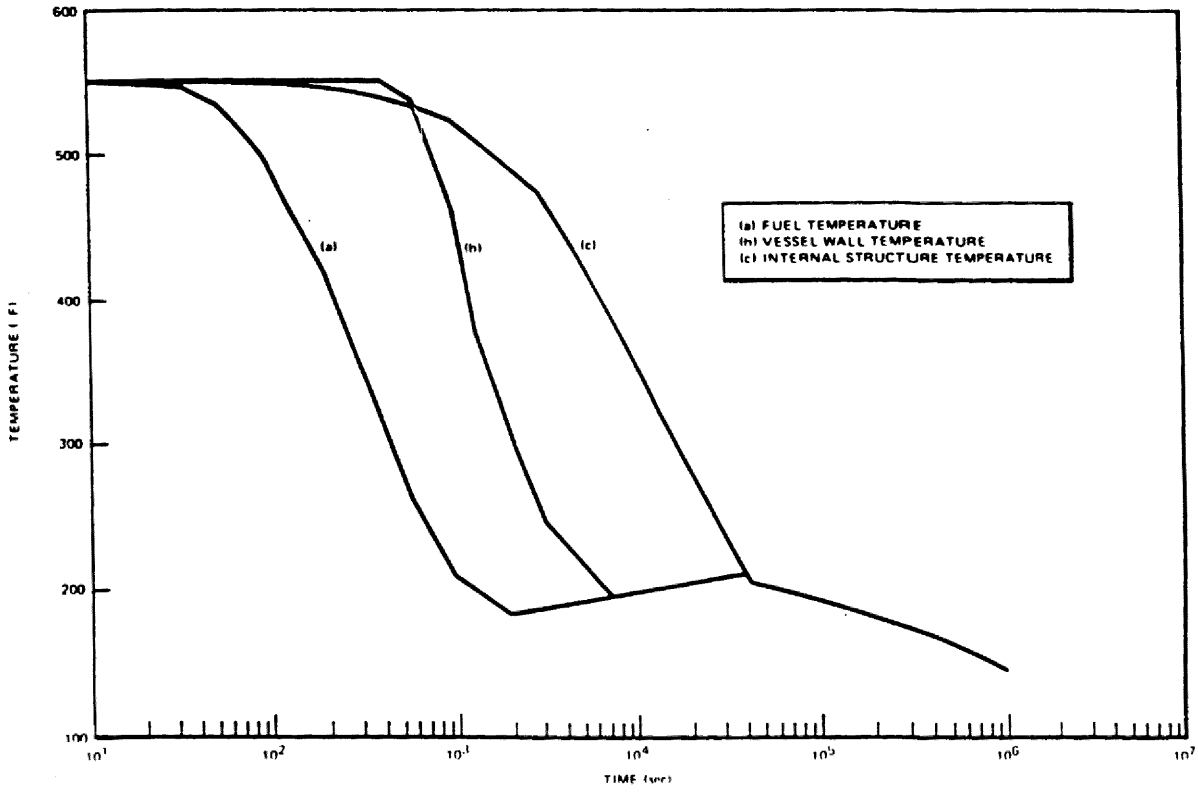


NOTE: The information presented in this figure is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the main steam line break was not reanalyzed for the current conditions.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL BLOWDOWN
FLOW RATE FOLLOWING
MAIN STEAM LINE BREAK

FIGURE 6.2-24 Rev. 5, 4/96



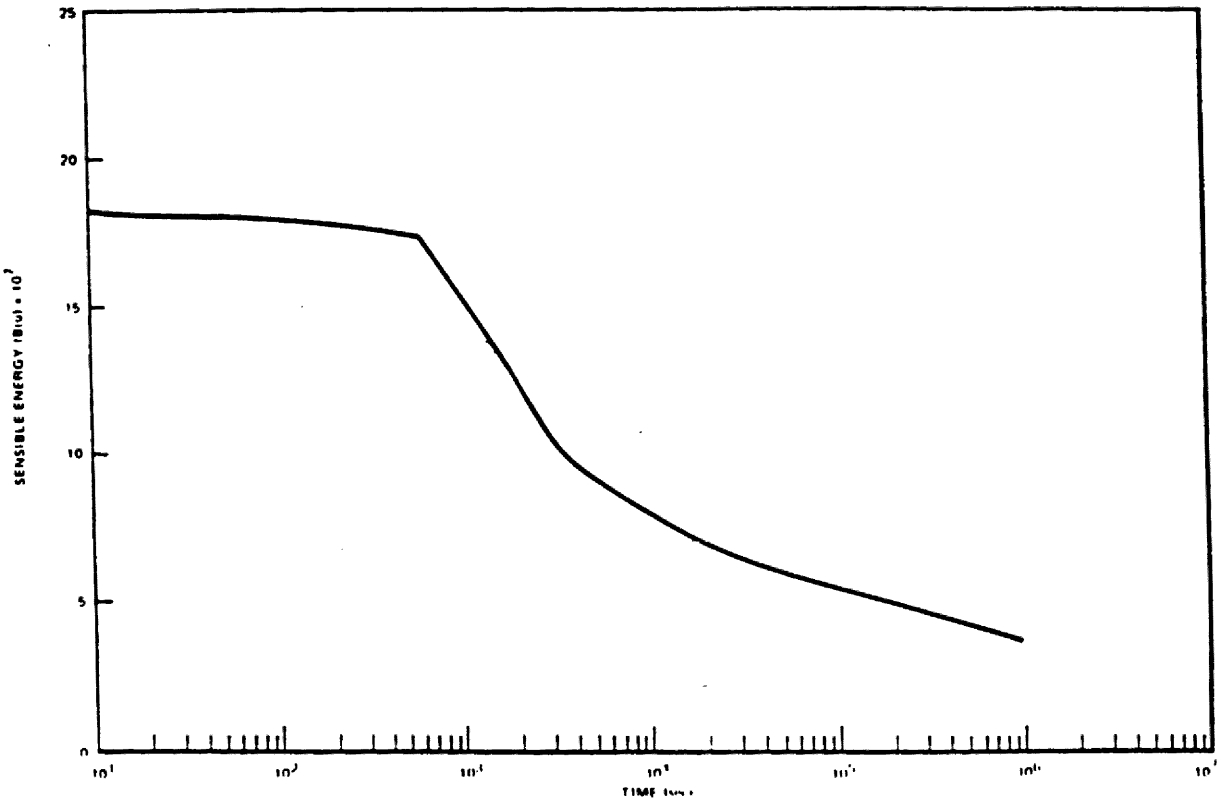
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The current recirculation line break results are discussed in Section 6.2.1.8. The results presented here reasonable represent the general characteristics of the current recirculation line break analysis results.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK

FIGURE 6.2-25

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NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The current recirculation line break results are discussed in Section 6.2.1.8. The results presented here reasonable represent the general characteristics of the current recirculation line break analysis results.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SENSIBLE ENERGY IN REACTOR VESSEL AND INTERNAL STRUCTURE METALS FOLLOWING RECIRCULATION LINE BREAK

FIGURE 6.2-26

Rev. 5, 4/96



[redacted]

[redacted]

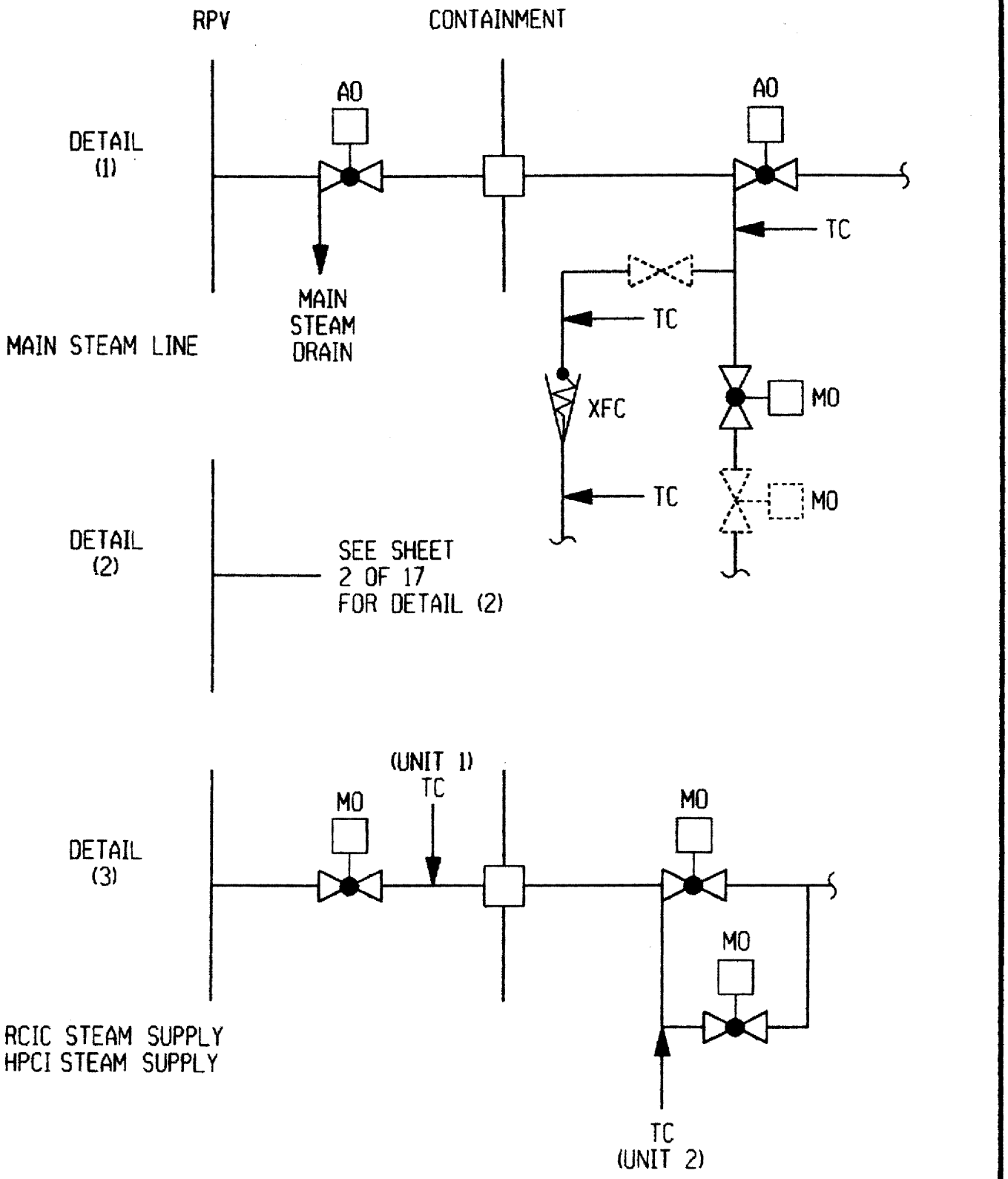
[redacted]



[redacted]

[redacted]

[redacted]



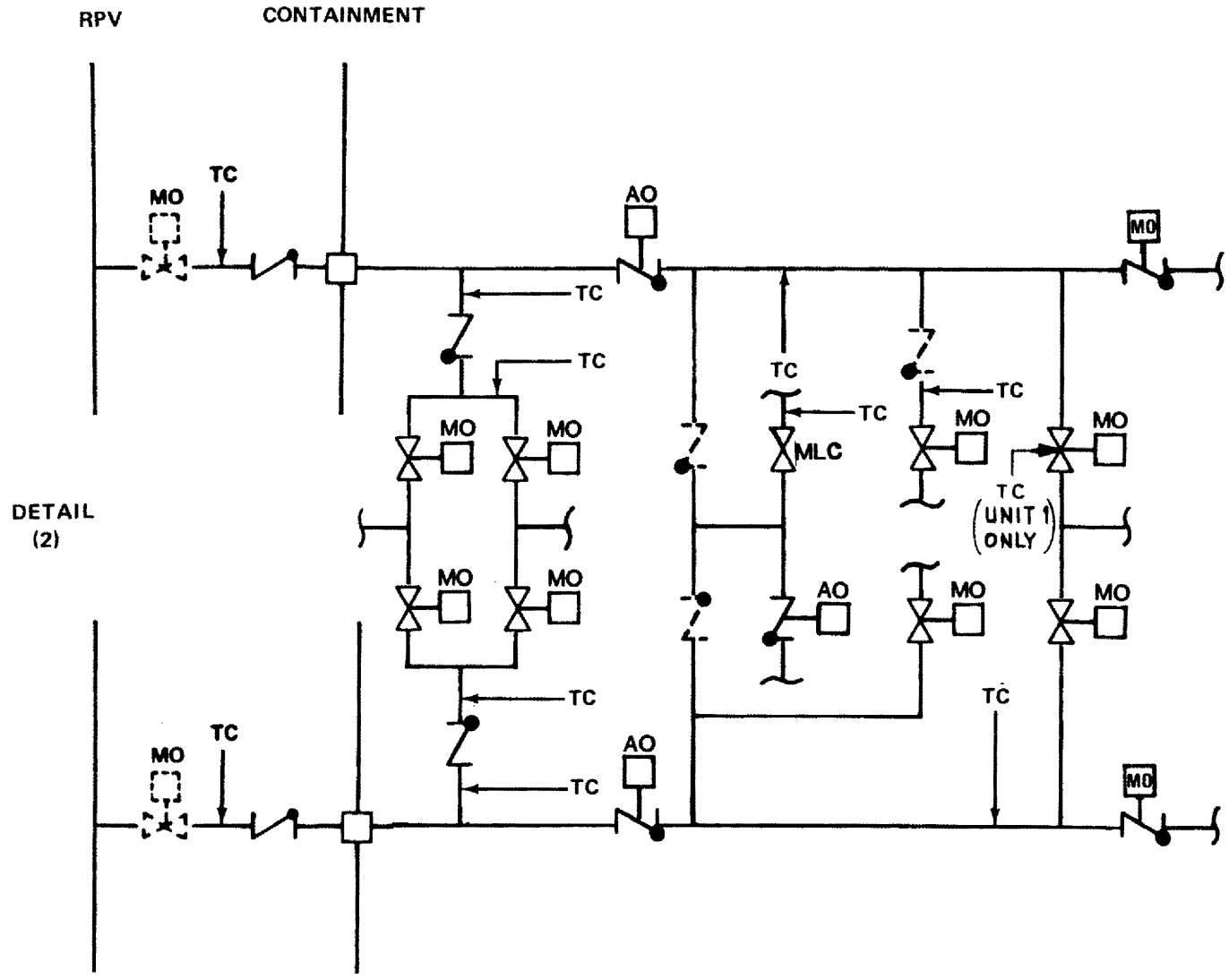
MO - MOTOR OPERATED
TC - TEST CONNECTION
AO - AIR OPERATED
XFC - EXCESS FLOW CHECK VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS (SHEET 1 OF 17)

FIGURE 6.2-36 Rev. 1 July/91

Z:\MECH\ 0602036.S1

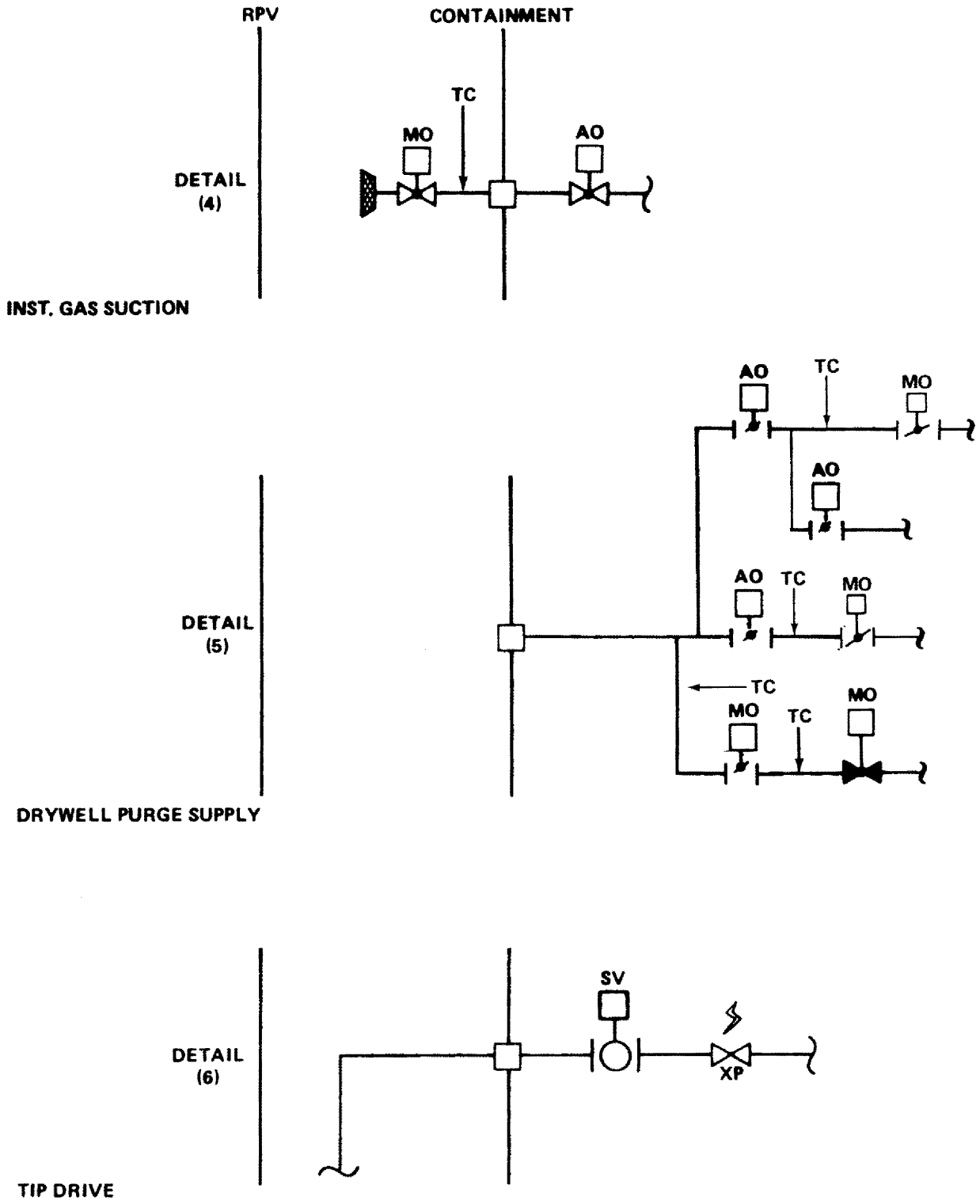


MO–MOTOR OPERATED
TC–TEST CONNECTION
AO–AIR OPERATED
XFC–EXCESS FLOW CHECK VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 2 OF 17)

FIGURE 6.2-36

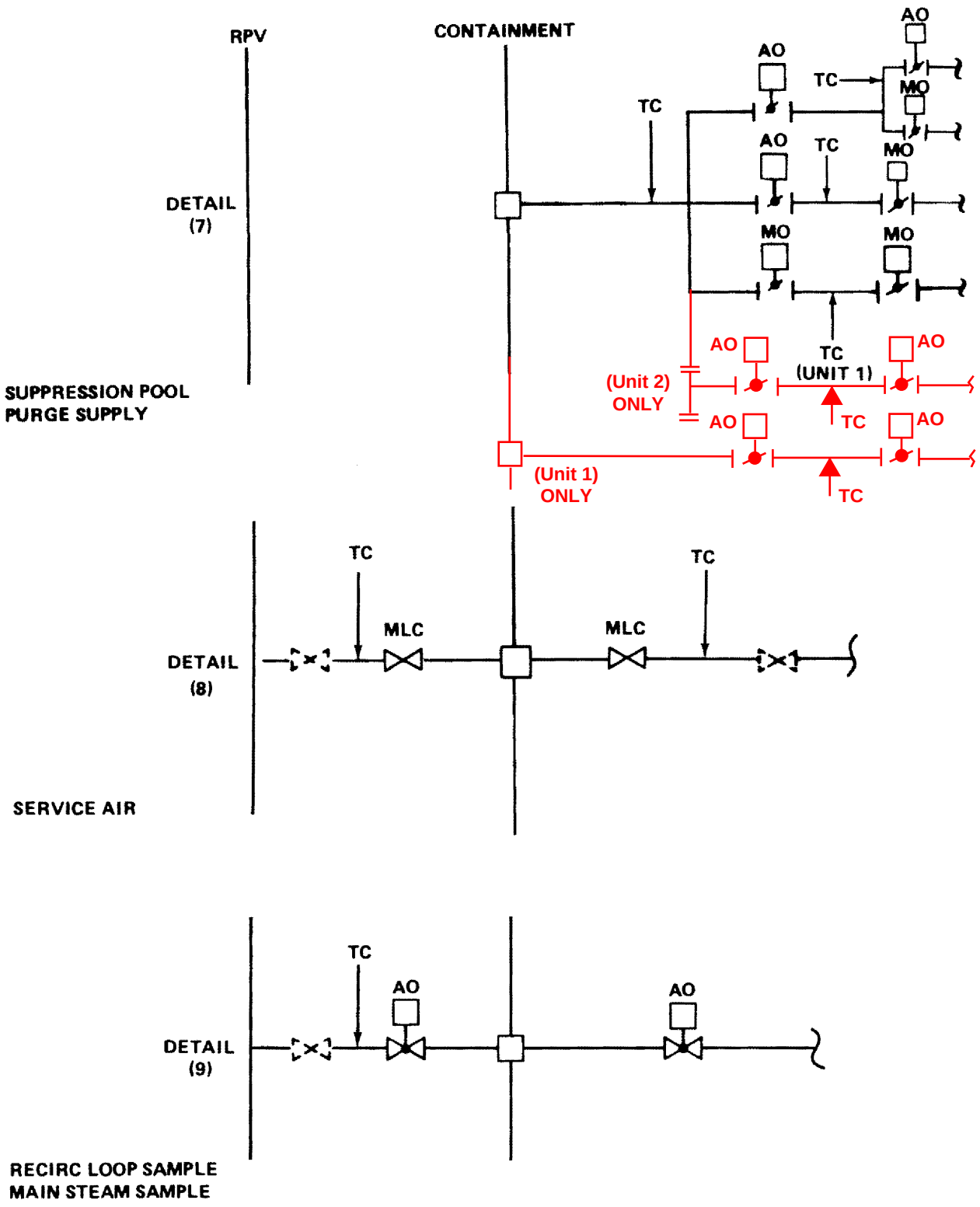


SV–SOLENOID VALVE
MO–MOTOR OPERATED
TC–TEST CONNECTION
AO–AIR OPERATED
XP–EXPLOSIVE (SHEAR) VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 3 OF 17)

FIGURE 6.2-36



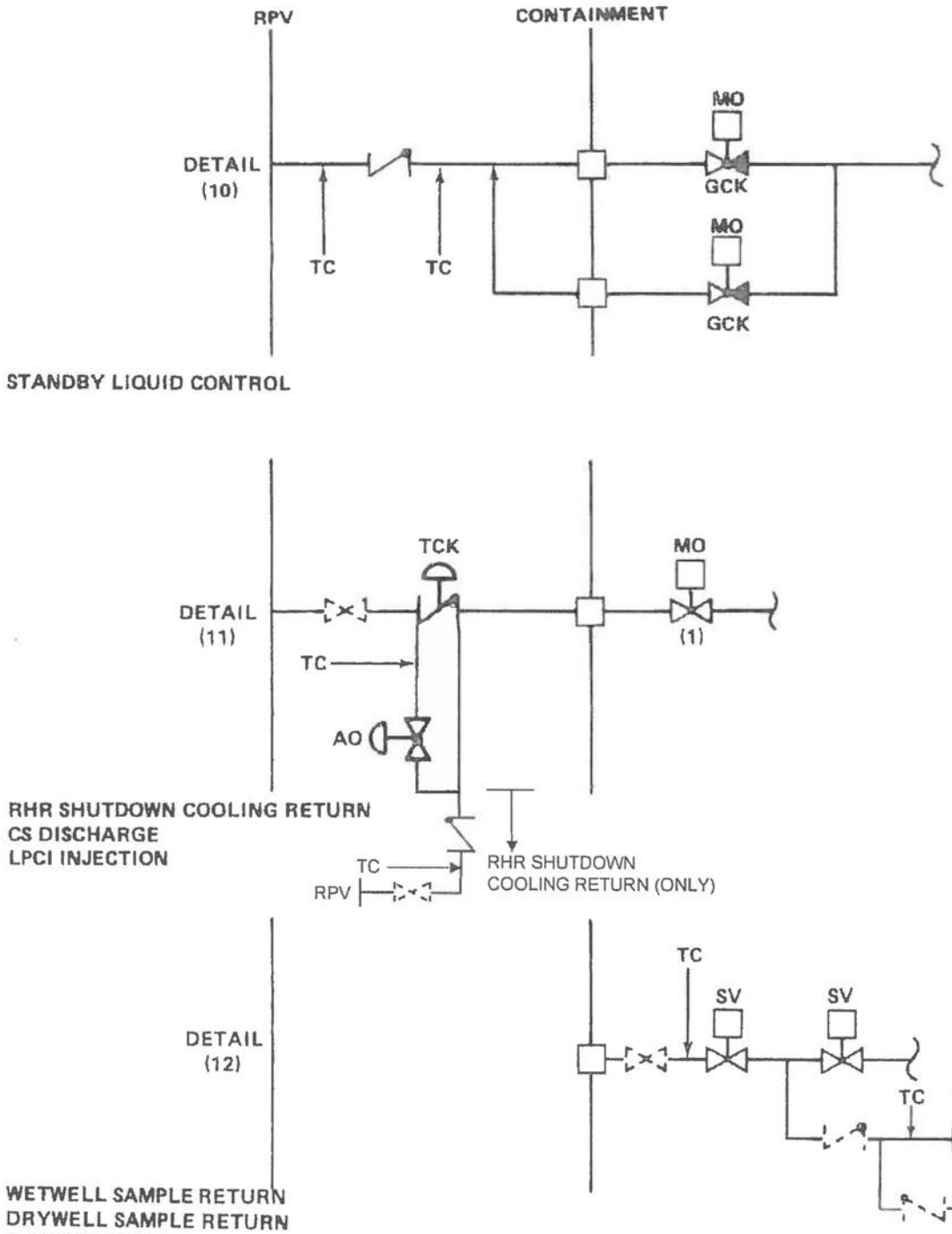
MO–MOTOR OPERATED
SV–SOLENOID VALVE
TC–TEST CONNECTION
AO–AIR OPERATED
TCK–TESTABLE CHECK VALVE
MLC–MANUAL LOCKED CLOSED

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 4 OF 17)

FIGURE 6.2-36

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MO–MOTOR OPERATED
SV–SOLENOID VALVE
TC–TEST CONNECTION
GCK–GLOBE STOP CHECK
TCK–TESTABLE CHECK VALVE
AO–AIR OPERATED

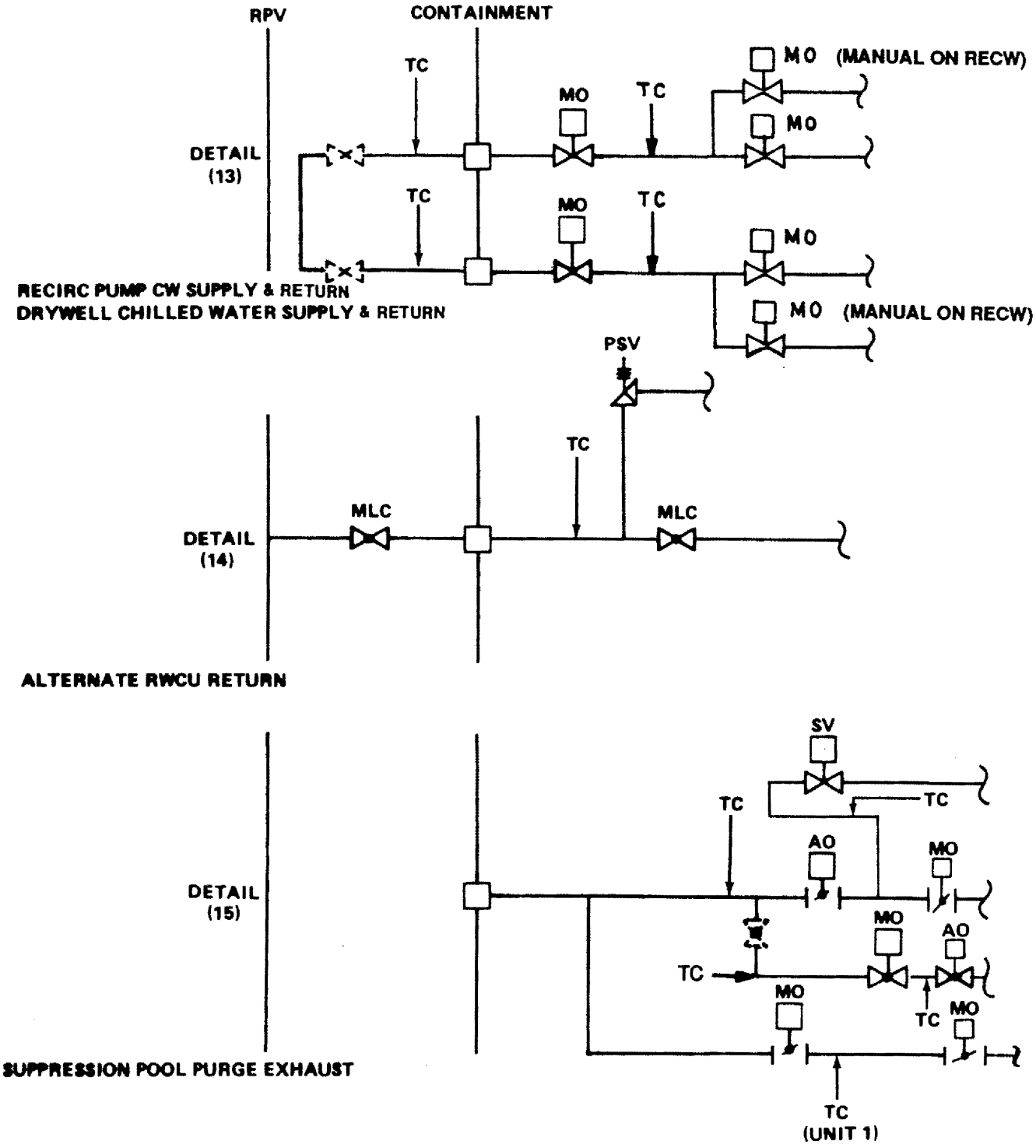
(1) THIS IS A GLOBE VALVE FOR RHR SHUTDOWN COOLING RETURN AND A SPRING LOADED PISTON ACTUATED CHECK VALVE FOR CS LOOP B.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 5 OF 17)

FIGURE 6.2-36

REV. 15, 09/10

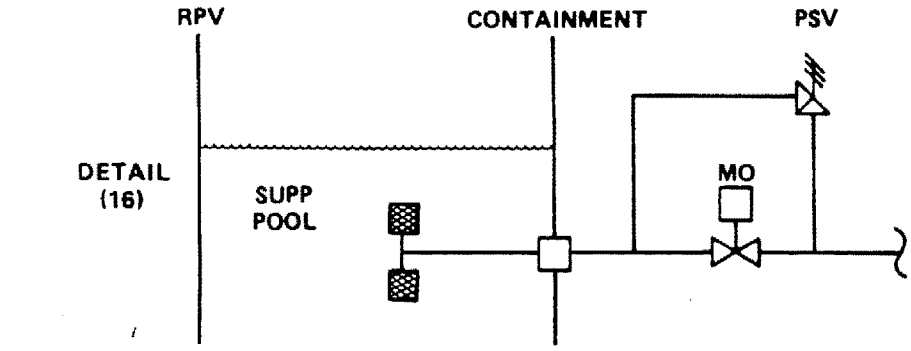


MO–MOTOR OPERATED
AO–AIR OPERATED
TC–TEST CONNECTION
MLC–MANUAL LOCKED CLOSED
SV–SOLENOID VALVE
PSV–PRESSURE SAFETY VALVE

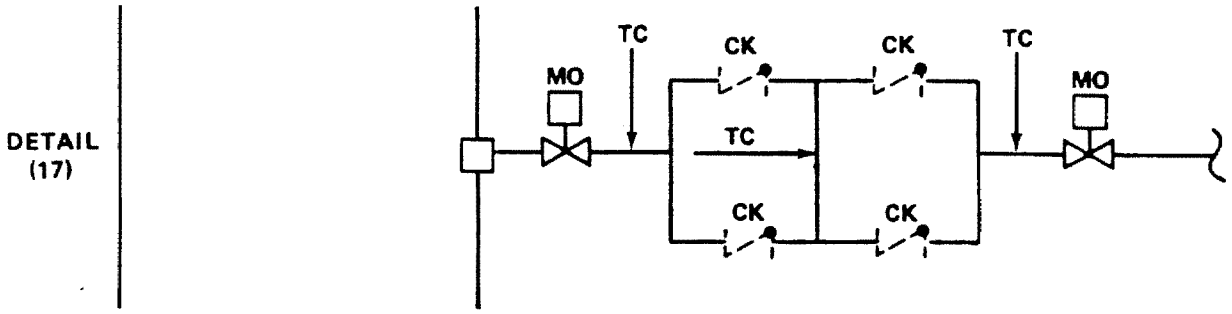
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 6 OF 17)

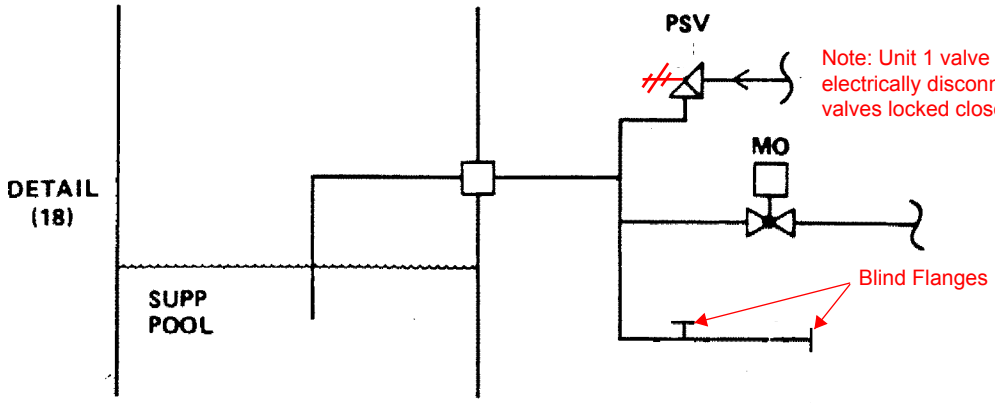
FIGURE 6.2-36



RHR PUMP SUCTION



HPCI VACUUM RELIEF
RCIC VACUUM RELIEF



RHR RELIEF VALVE DISCHARGE

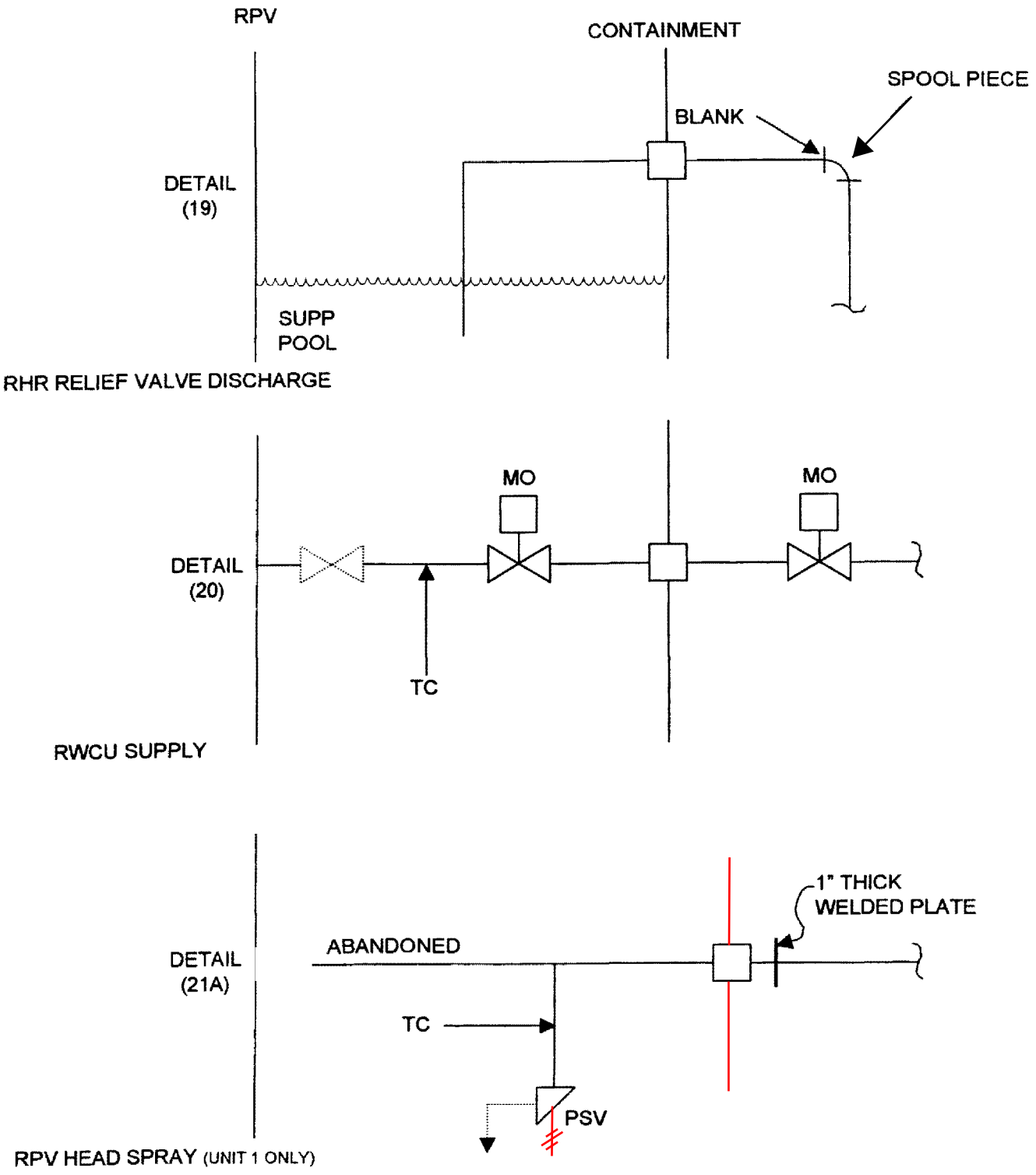
PSV–PRESSURE SAFETY VALVE
MO–MOTOR OPERATED
TC–TEST CONNECTION
CK–CHECK VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 7 OF 17)

FIGURE 6.2-36

Rev. 15, 09/10

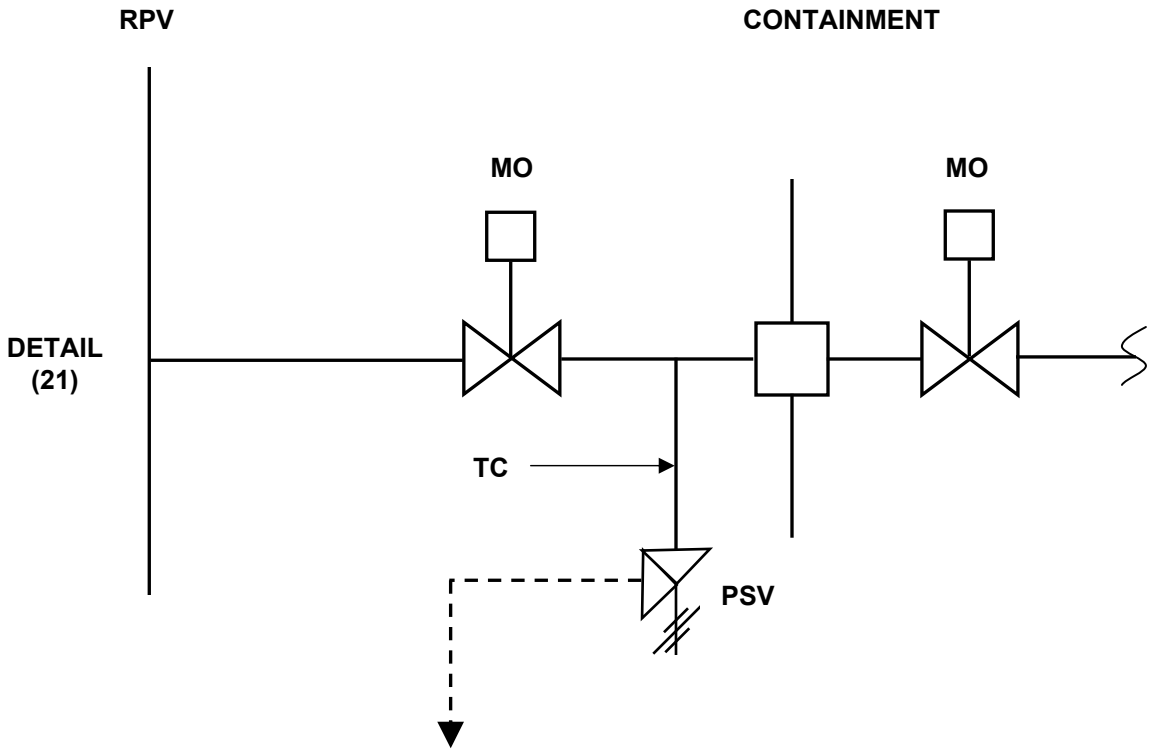


MO – MOTOR OPERATED
TC – TEST CONNECTION
PSV – PRESSURE SAFETY VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 8 of 17)

FIGURE 6.2-36 Rev. 15, 09/10



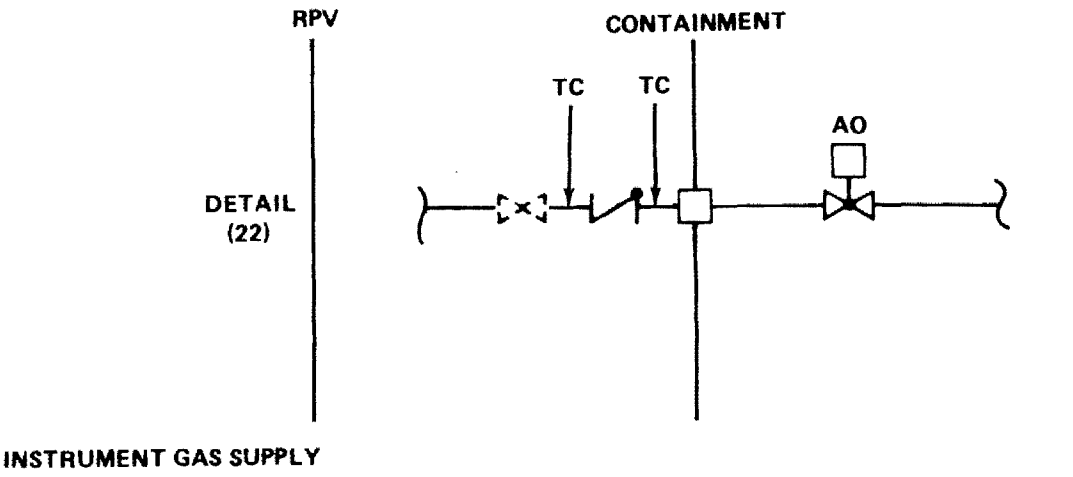
RHR SHUTDOWN COOLING SUPPLY

MO – MOTOR OPERATED
TC – TEST CONNECTION
PSV – PRESSURE SAFETY VALVE

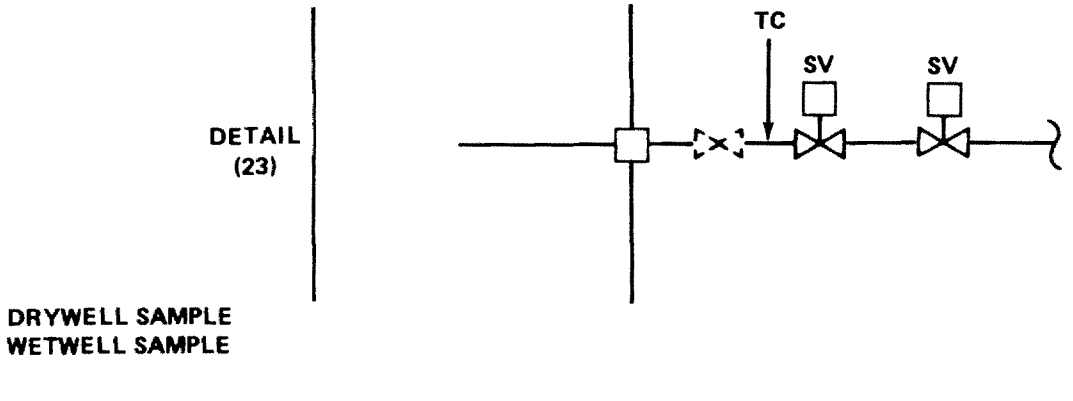
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS
(Sheet 8a of 17)

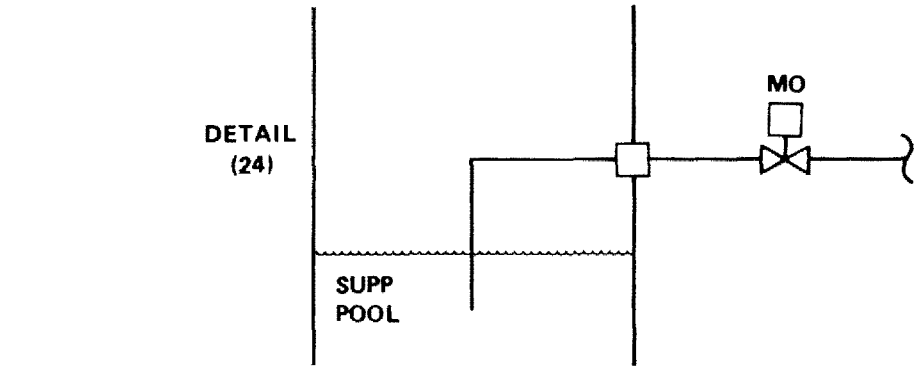
FIGURE 6.2-36 Rev. 15, 09/10



INSTRUMENT GAS SUPPLY



DRYWELL SAMPLE
WETWELL SAMPLE



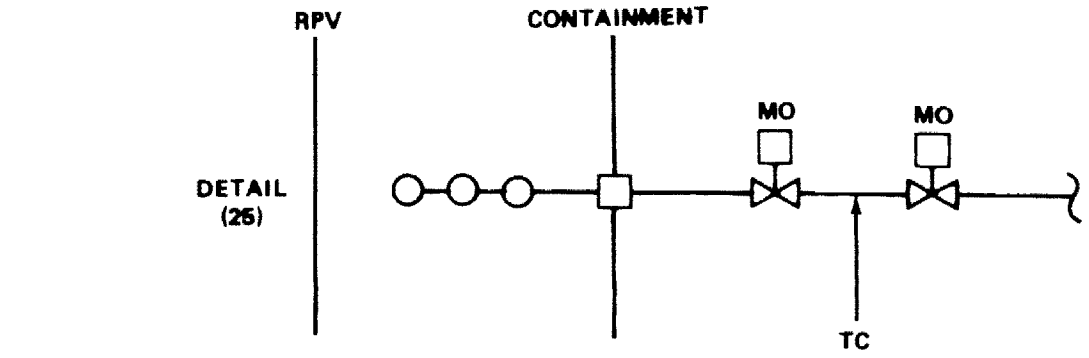
HPCI TURBINE EXHAUST
HPCI PUMP FLUSH
HPCI PUMP MIN FLOW
CS PUMP MIN FLOW
CS PUMP TEST & FLUSH
RCIC TURBINE EXHAUST
RCIC MIN FLOW
RHR PUMP MIN FLOW

AO–AIR OPERATED
MO–MOTOR OPERATED
SV–SOLENOID VALVE
TC–TEST CONNECTION

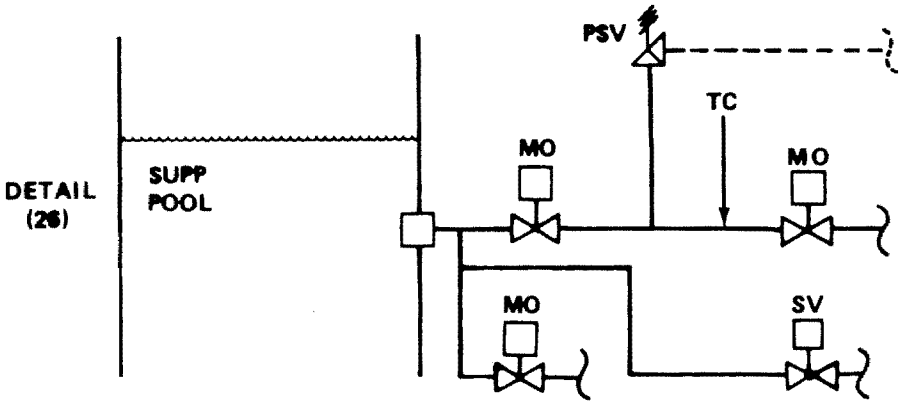
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 9 OF 17)

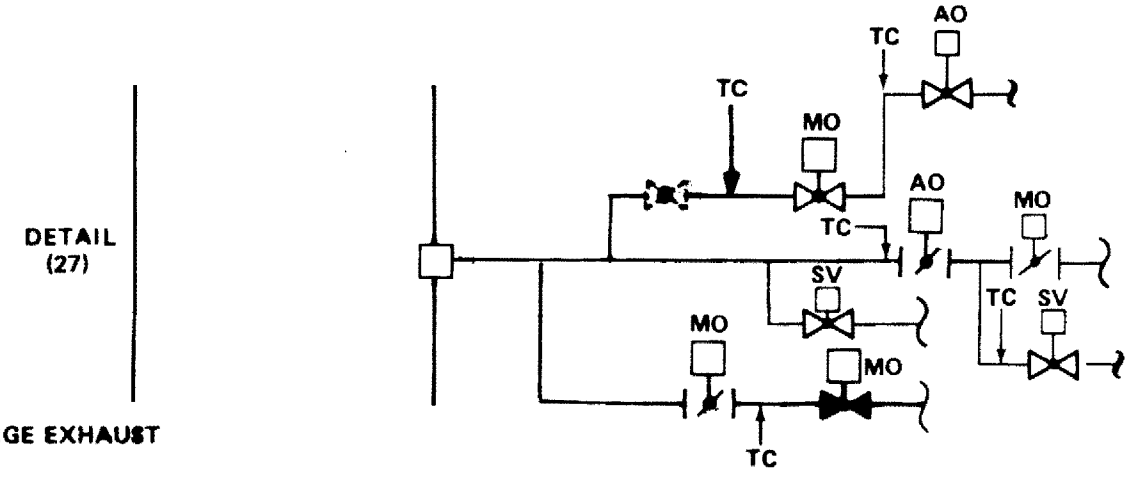
FIGURE 6.2-36



CONTAINMENT SPRAY



SUPPRESSION POOL
CLEANUP PUMP SUCTION
AND LEVEL
INSTRUMENTATION



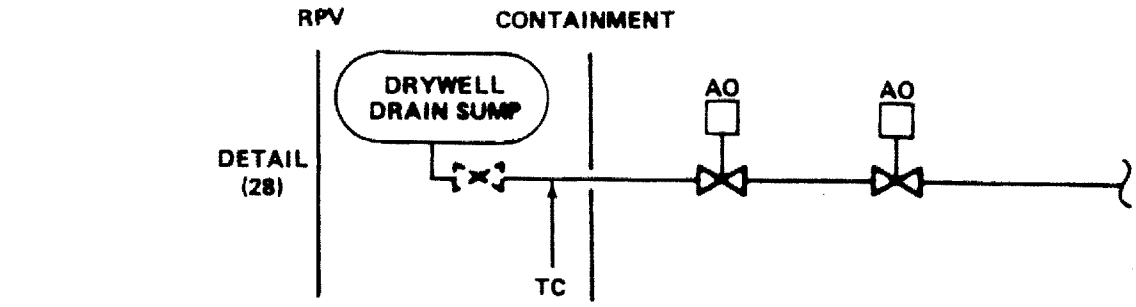
DRYWELL PURGE EXHAUST

MO–MOTOR OPERATED
AO–AIR OPERATED
TC–TEST CONNECTION
PSV–PRESSURE SAFETY VALVE
SV–SOLENOID VALVE

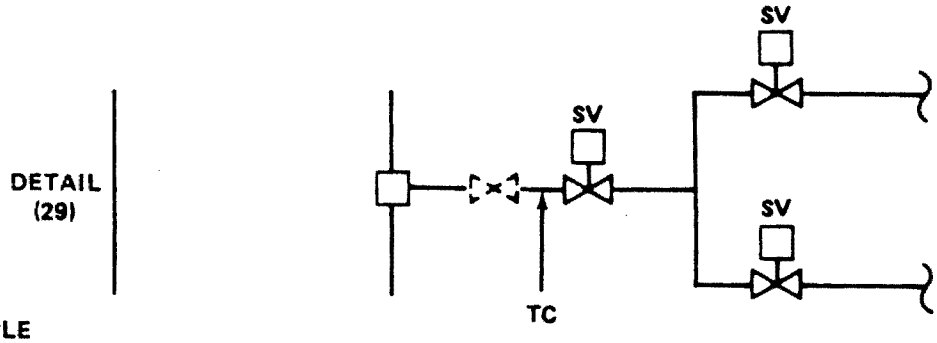
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS
(SHEET 10 OF 17)

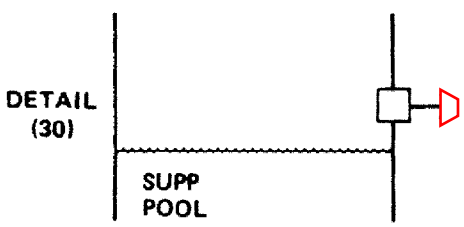
FIGURE 6.2-36



DRYWELL DRAIN SUMP DISCHARGE

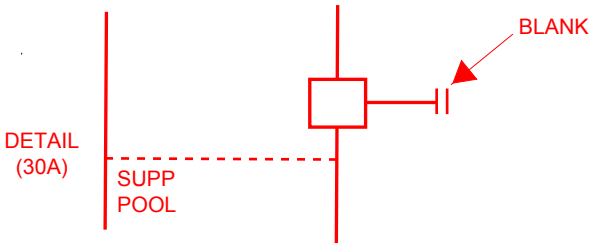


DRYWELL SAMPLE
WETWELL SAMPLE



RHR VACUUM RELIEF

UNIT 1 ONLY



UNIT 2 ONLY

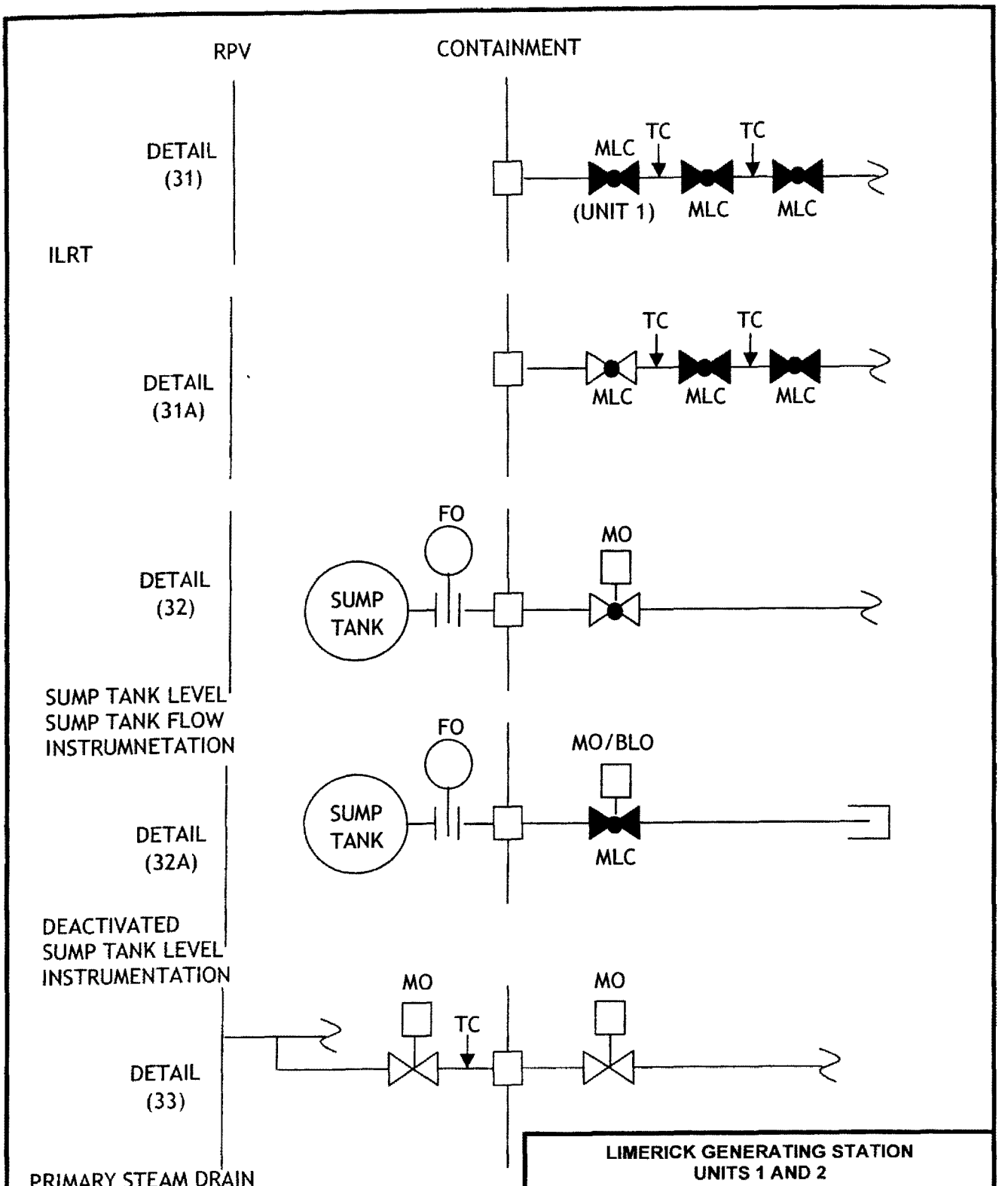
MO–MOTOR OPERATED
TC–TEST CONNECTION
SV–SOLENOID VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS
(SHEET 11 OF 17)

FIGURE 6.2-36

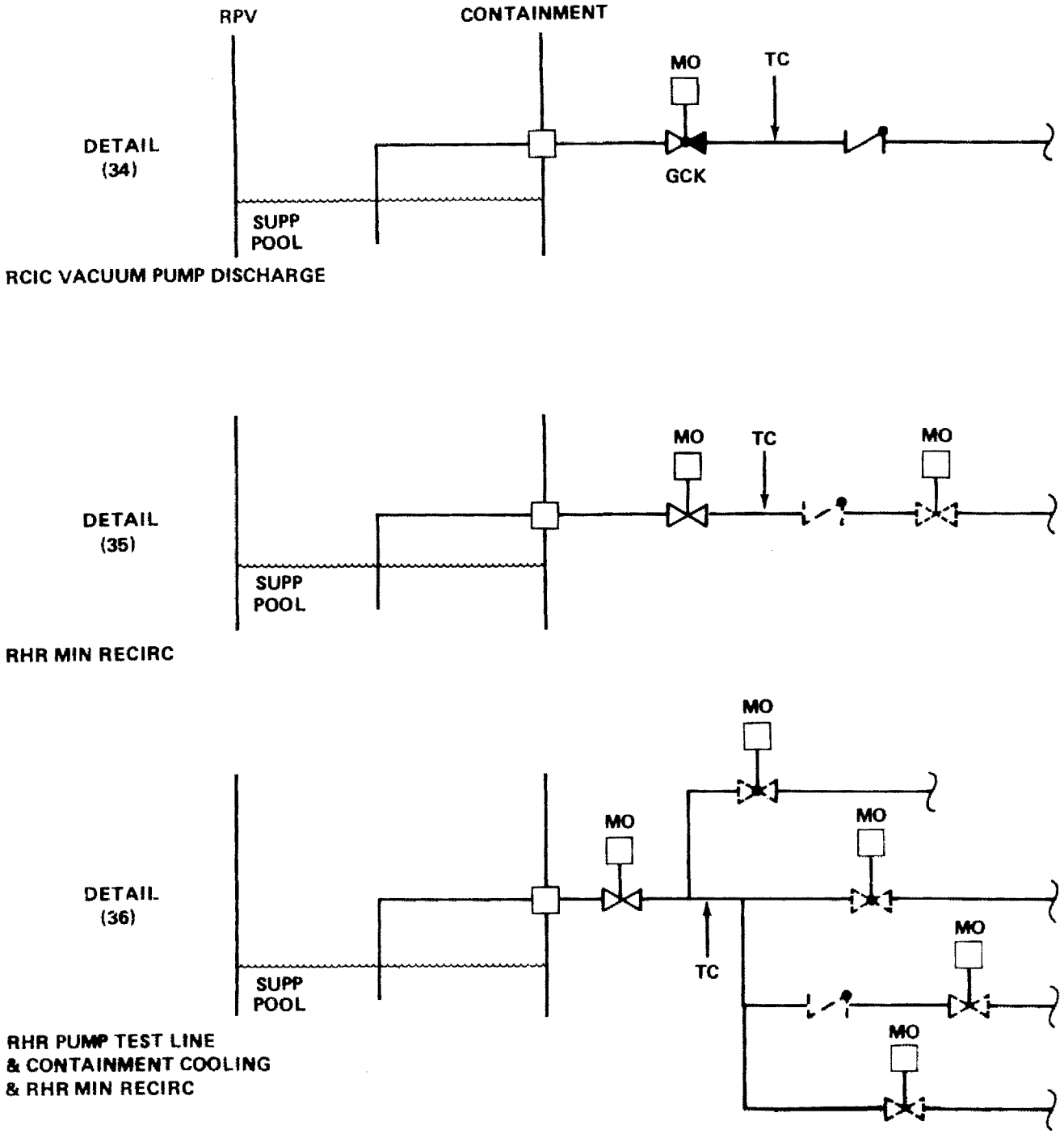
Rev. 15, 09/10



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 12 OF 17)

FIGURE 6.2-36 **Rev. 12 9/04**

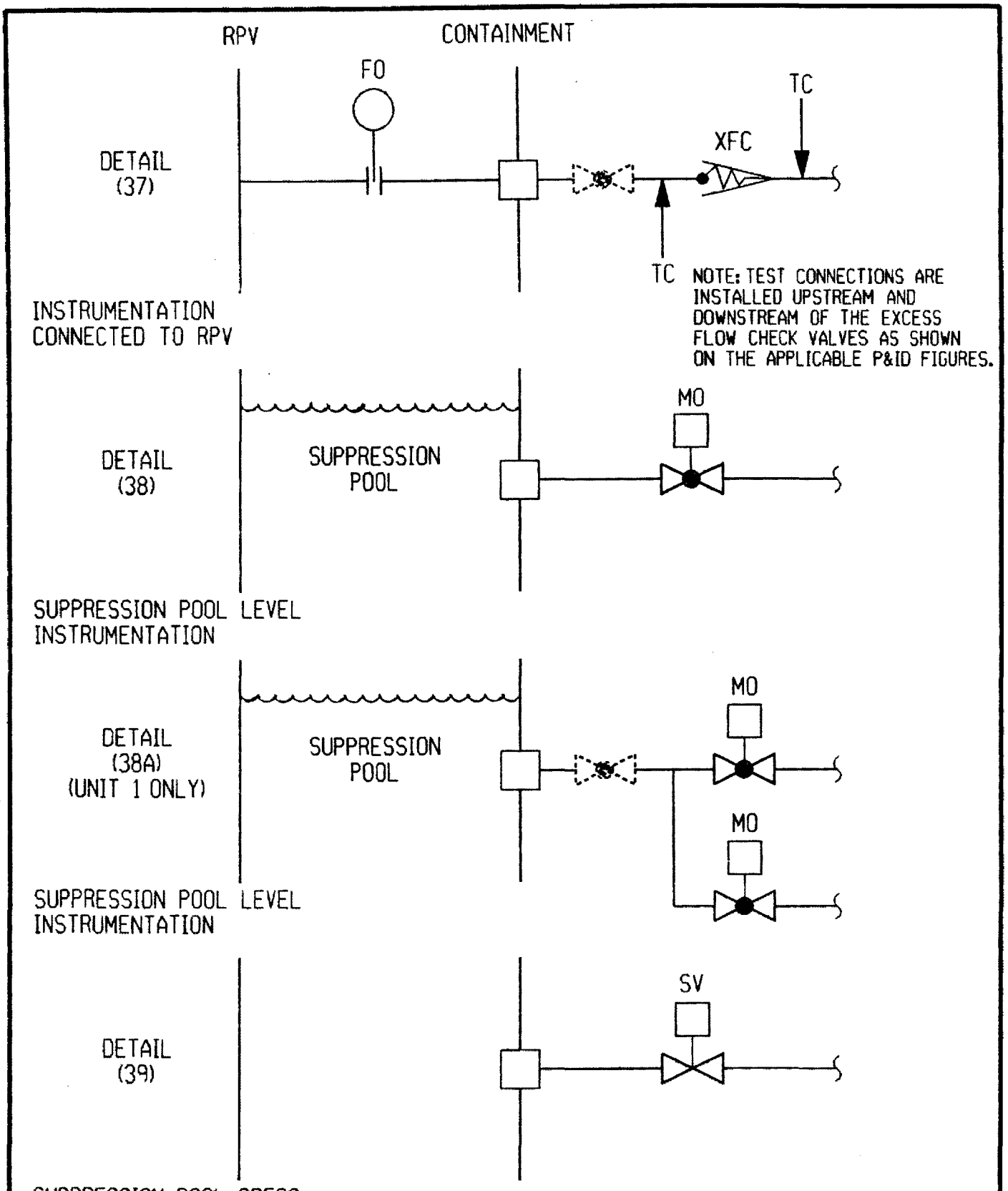


MO—MOTOR OPERATED
TC—TEST CONNECTION
GCK—GLOBE STOP CHECK

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS
(SHEET 13 OF 17)

FIGURE 6.2-36



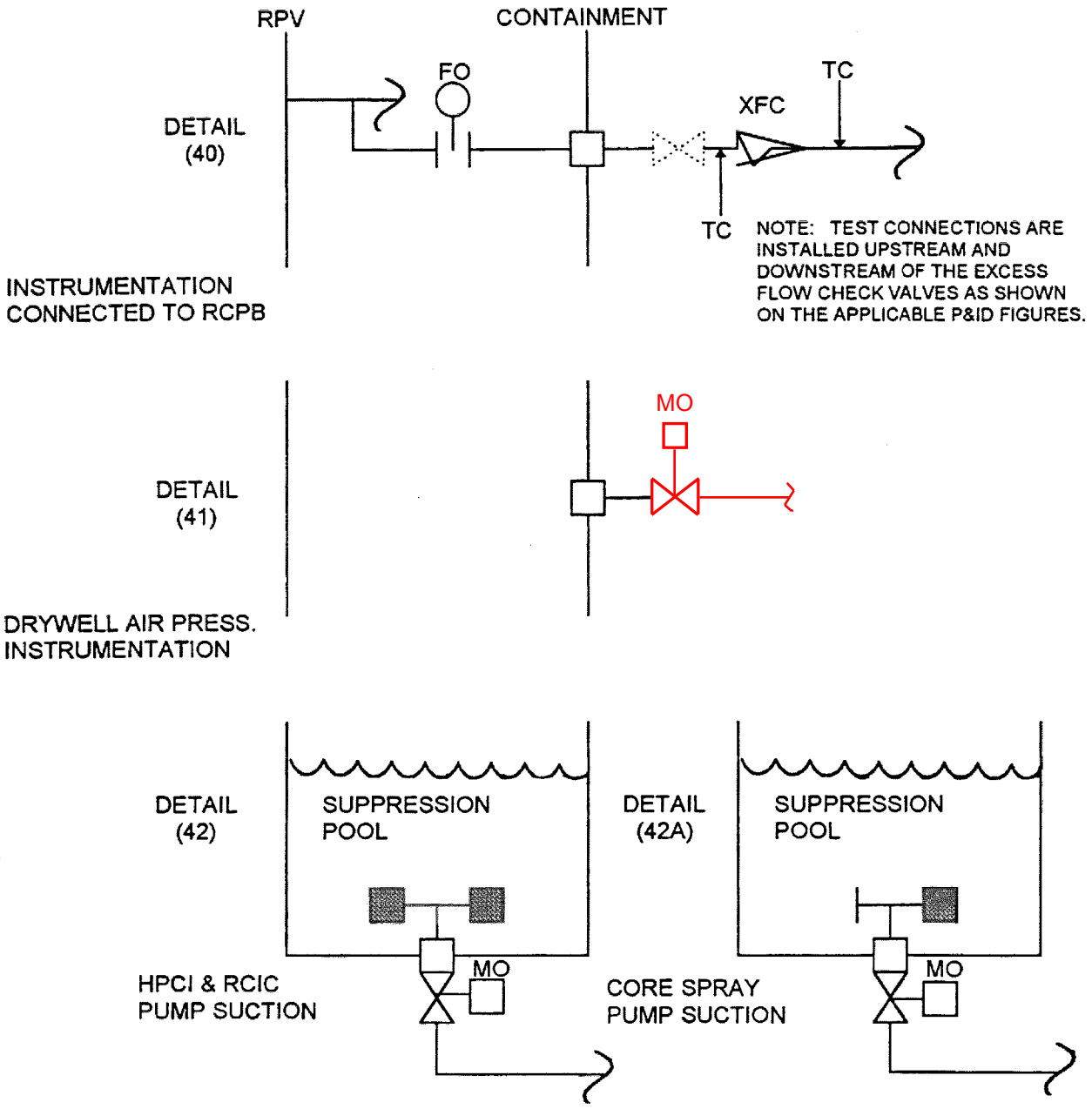
XFC - EXCESS FLOW CHECK VALVE
FO - FLOW ORIFICE
MO - MOTOR OPERATED
TC - TEST CONNECTION
SV - SOLENOID VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 14 OF 17)

FIGURE 6.2-36 Rev. 1 July/91

Z:\MECH\ 0602036.DGN



FO - FLOW ORIFICE
MO - MOTOR OPERATED
TC - TEST CONNECTION
XFC - EXCESS FLOW CHECK VALVE

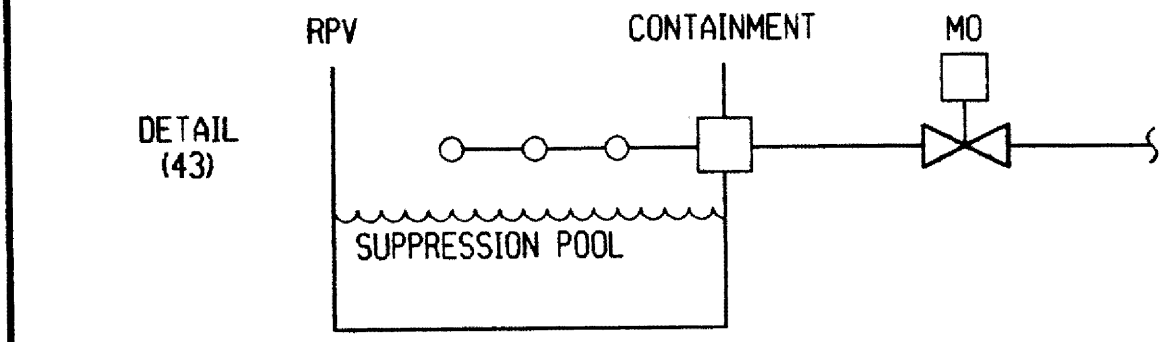
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS

(SHEET 15 OF 17)

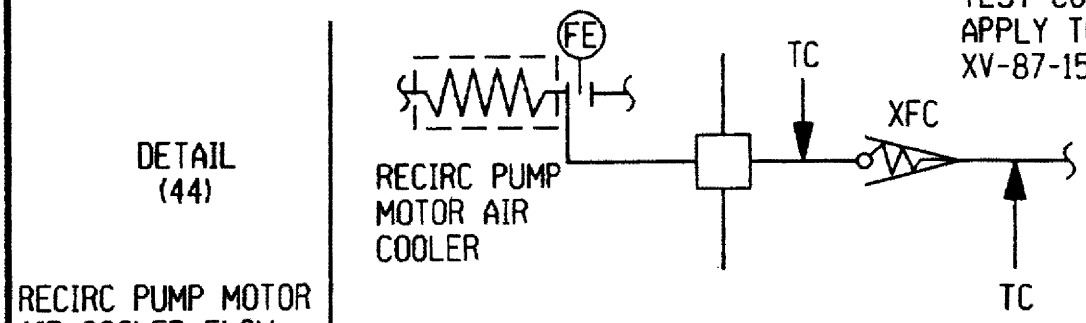
FIGURE 6.2-36

Rev. 15, 09/10

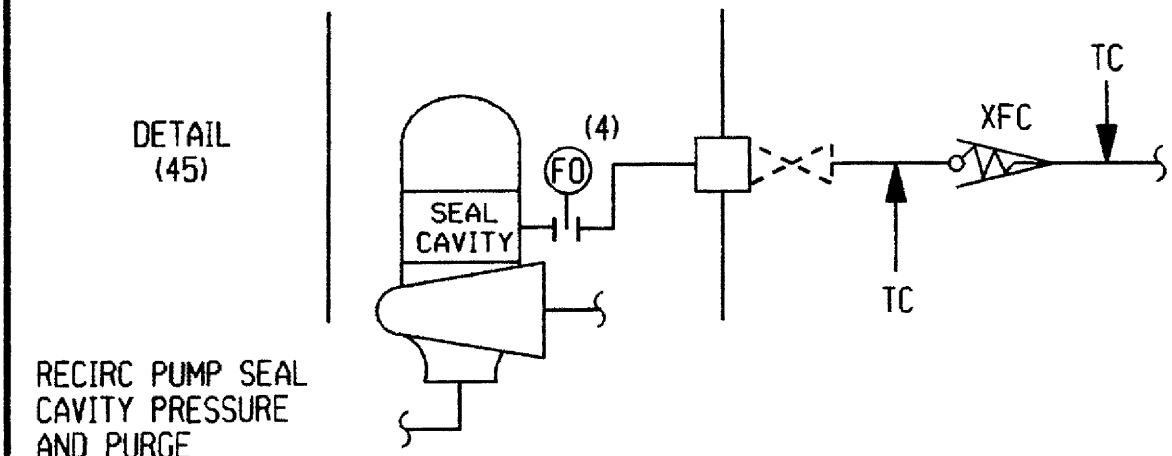


SUPPRESSION POOL SPRAY

NOTE:
TEST CONNECTIONS DO NOT APPLY TO UNIT 1 VALVES XV-87-156A AND XV-87-157A.



RECIRC PUMP MOTOR AIR COOLER FLOW INSTRUMENTATION



RECIRC PUMP SEAL CAVITY PRESSURE AND PURGE

XFC - EXCESS FLOW CHECK VALVE
FE - FLOW ELEMENT
TC - TEST CONNECTION
MO - MOTOR OPERATED
FO - FLOW ORIFICE

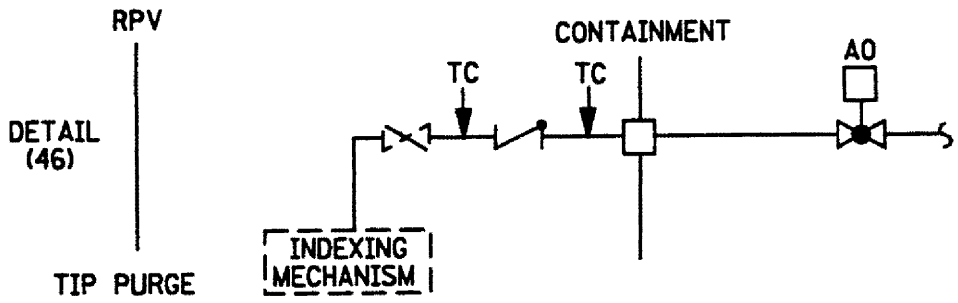
(3) DELETED

(4) CHECK VALVE INSTEAD OF FO FOR PURGE LINES

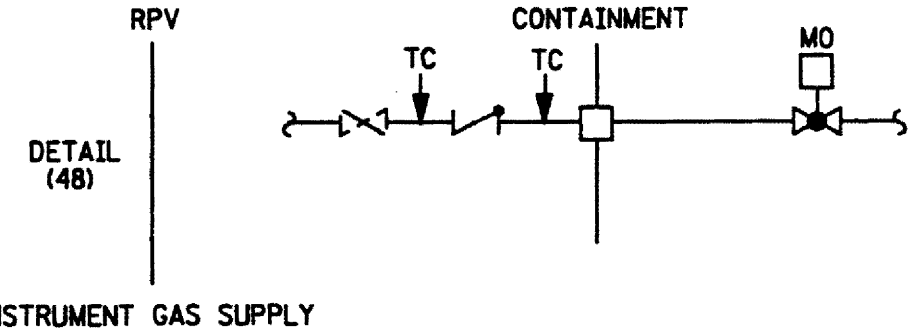
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 16 OF 17)

FIGURE 6.2-36 Rev. 1 July/91



CRD INSERT AND
WITHDRAWAL LINES



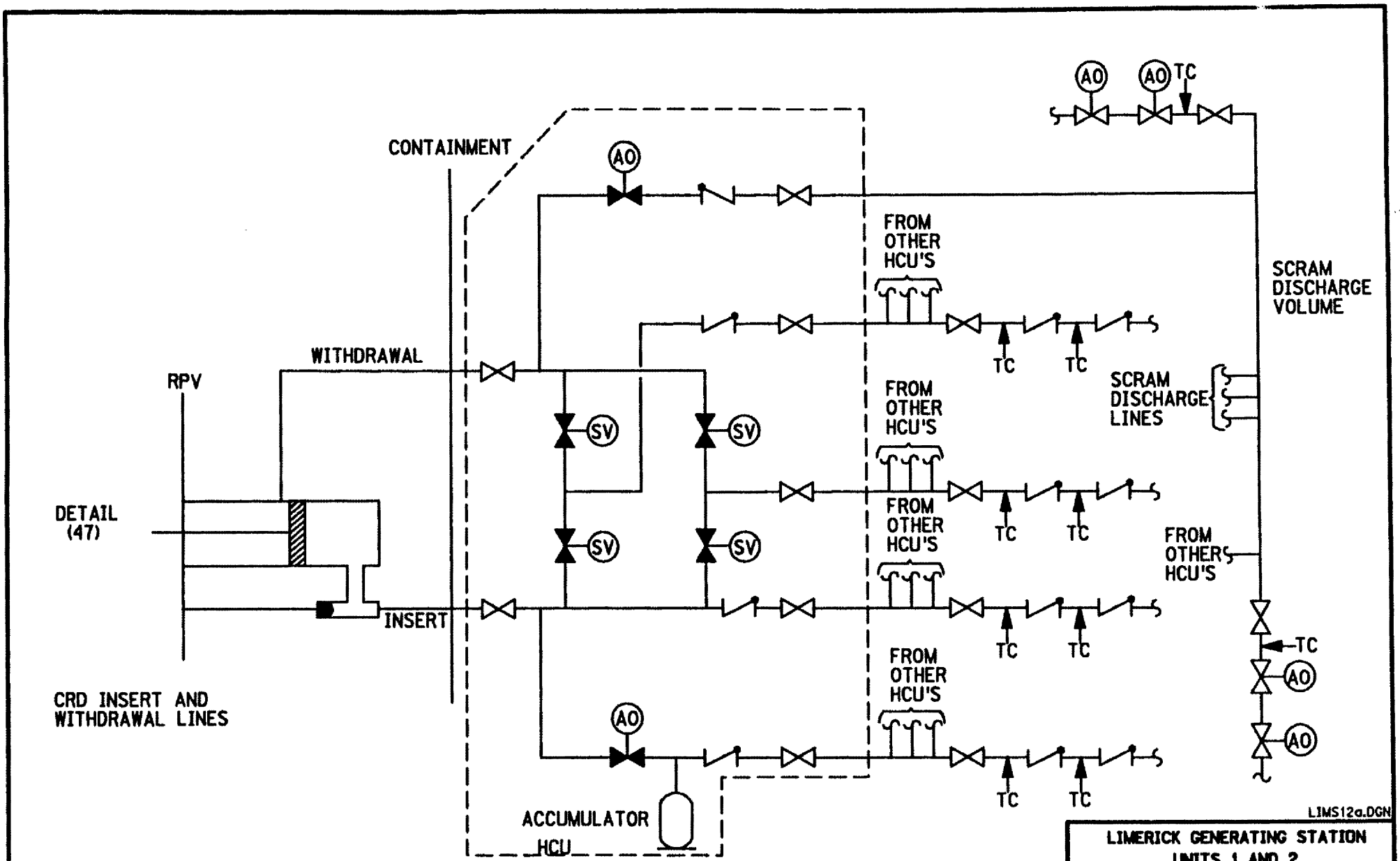
TC=TEST CONNECTION
MO= MOTOR OPERATED
AO= AIR OPERATED
SV=SOLENOID VALVE

LIMS12.DGN

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS
(SHEET 17 OF 17)

FIGURE 6.2-36 Rev. 3 Nov./93



TC=TEST CONNECTION
MO= MOTOR OPERATED
AO= AIR OPERATED
SV=SOLENOID VALVE

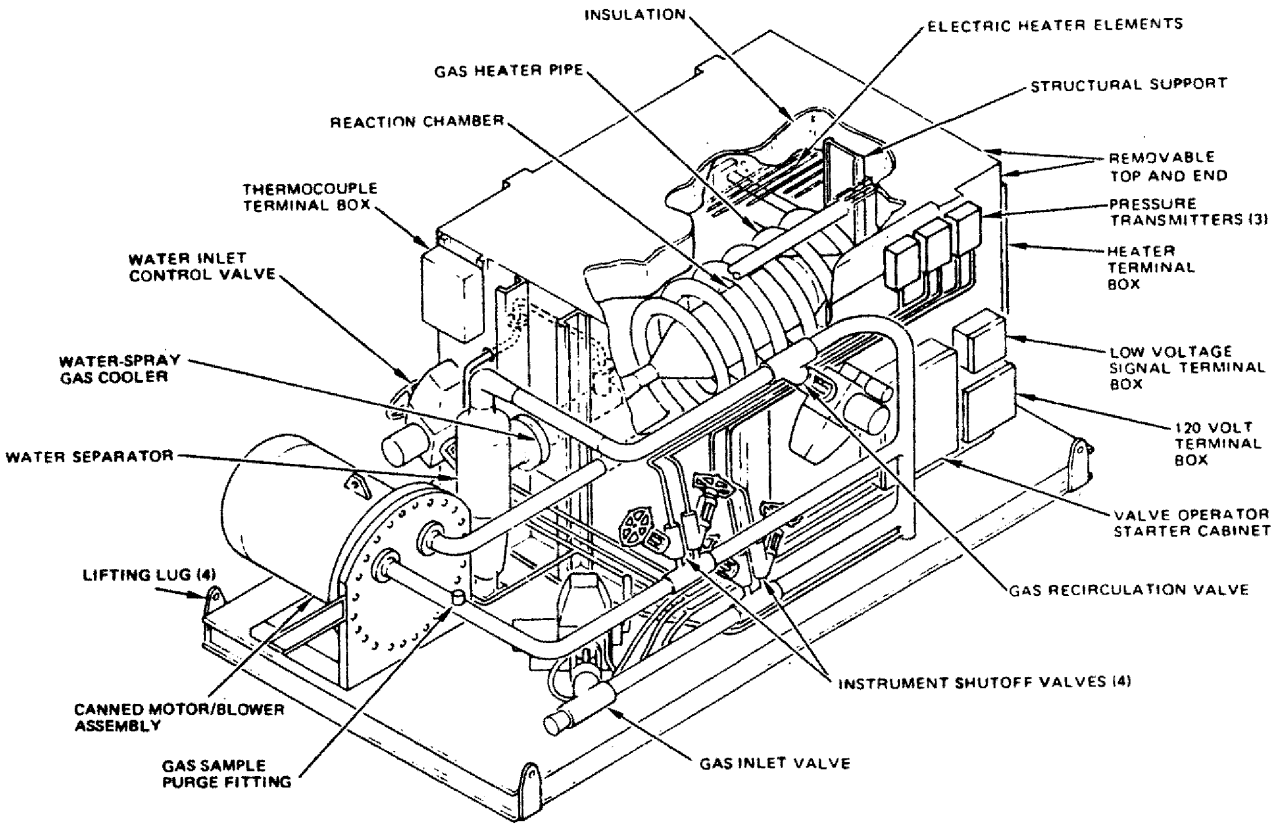
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 17a OF 17)

FIGURE 6.2-36 Rev. 3 NOV./93

Figure 6.2-37

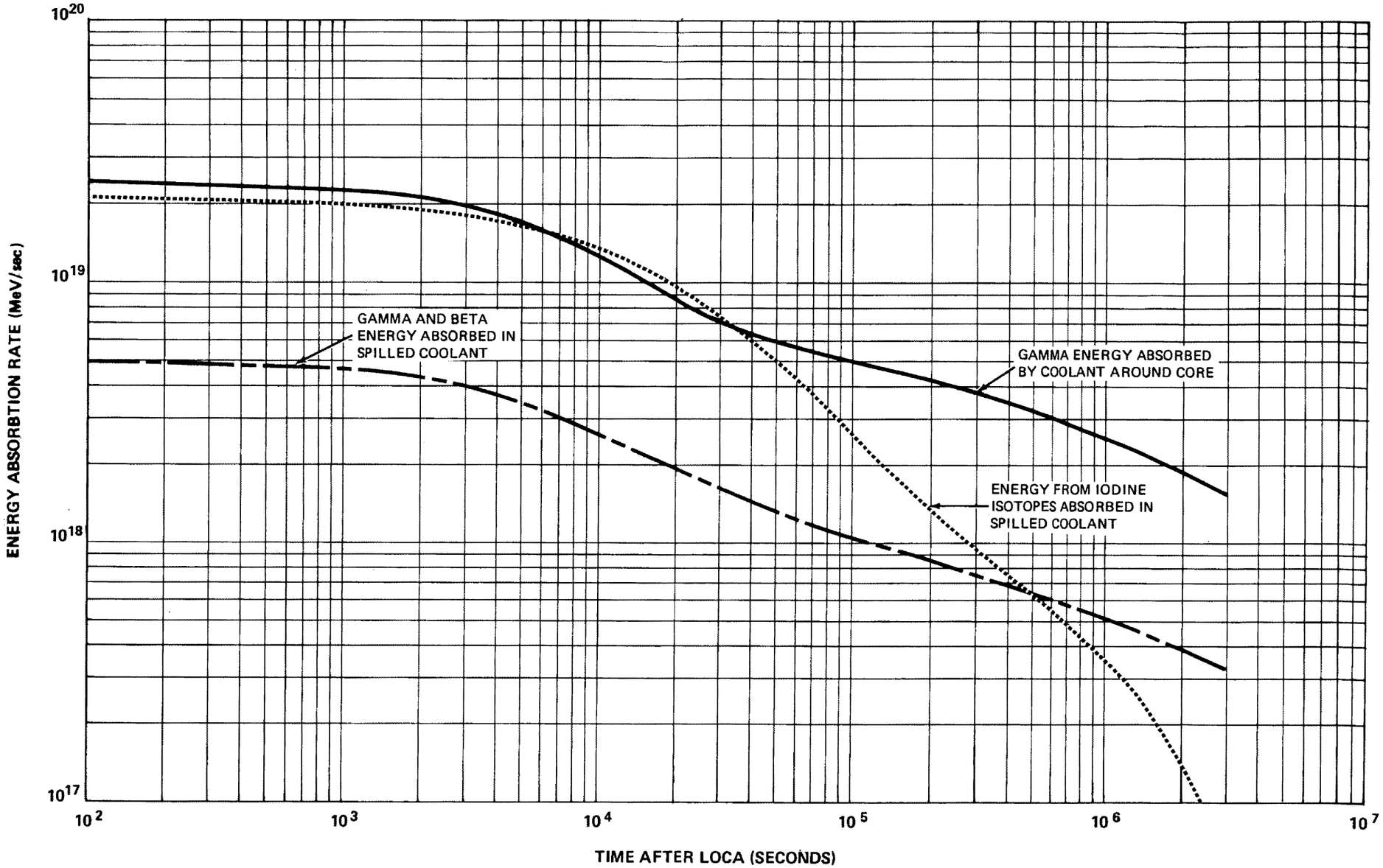
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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT HYDROGEN RECOMBINER SKID, CUTAWAY VIEW

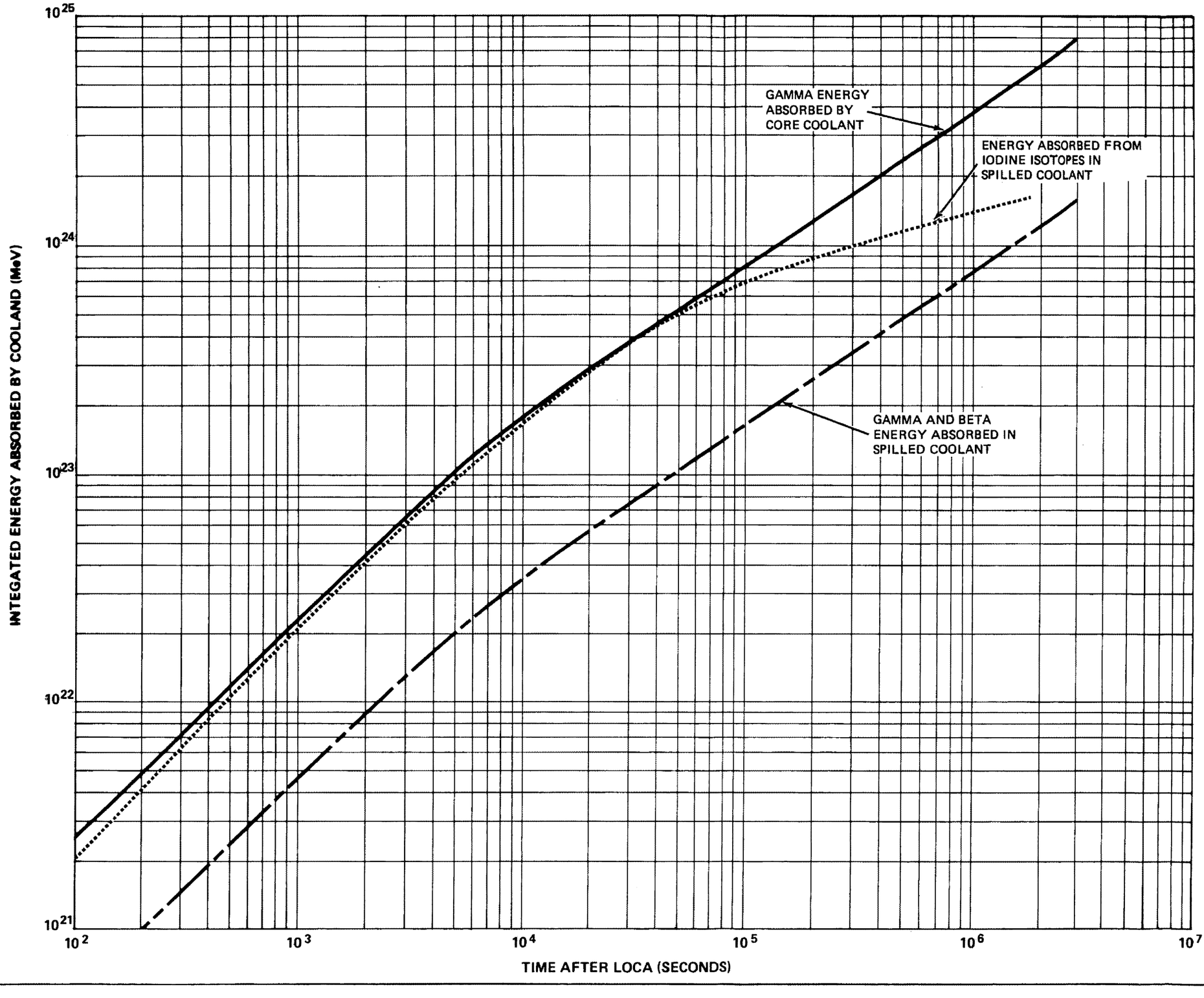
FIGURE 6.2-38



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RATE OF ENERGY ABSORPTION BY LOCA WATER AS A FUNCTION OF TIME AFTER LOCA

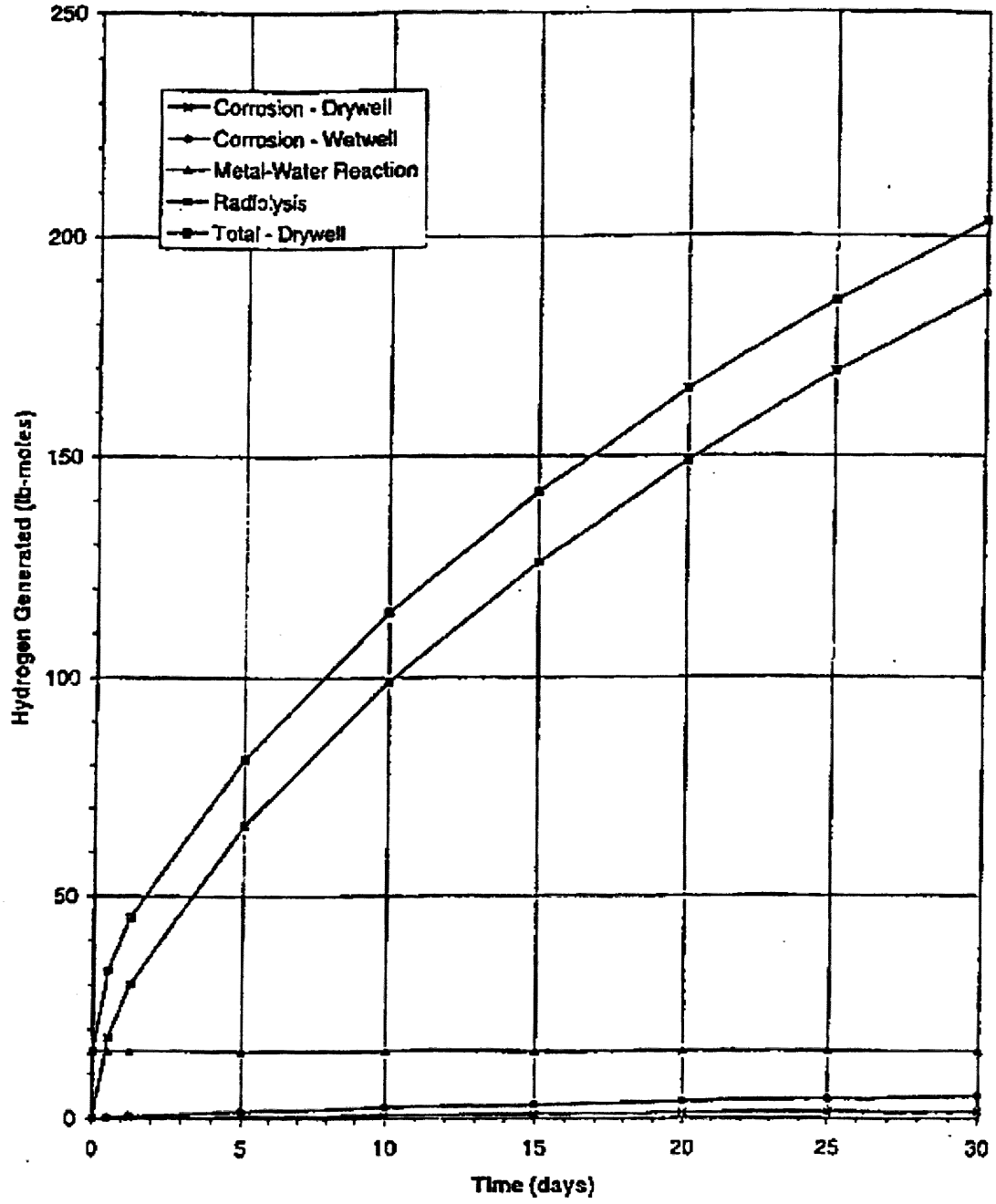
FIGURE 6.2-39



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

INTEGRATED ENERGY ABSORPTION BY LOCA WATER AS A FUNCTION OF TIME AFTER LOCA

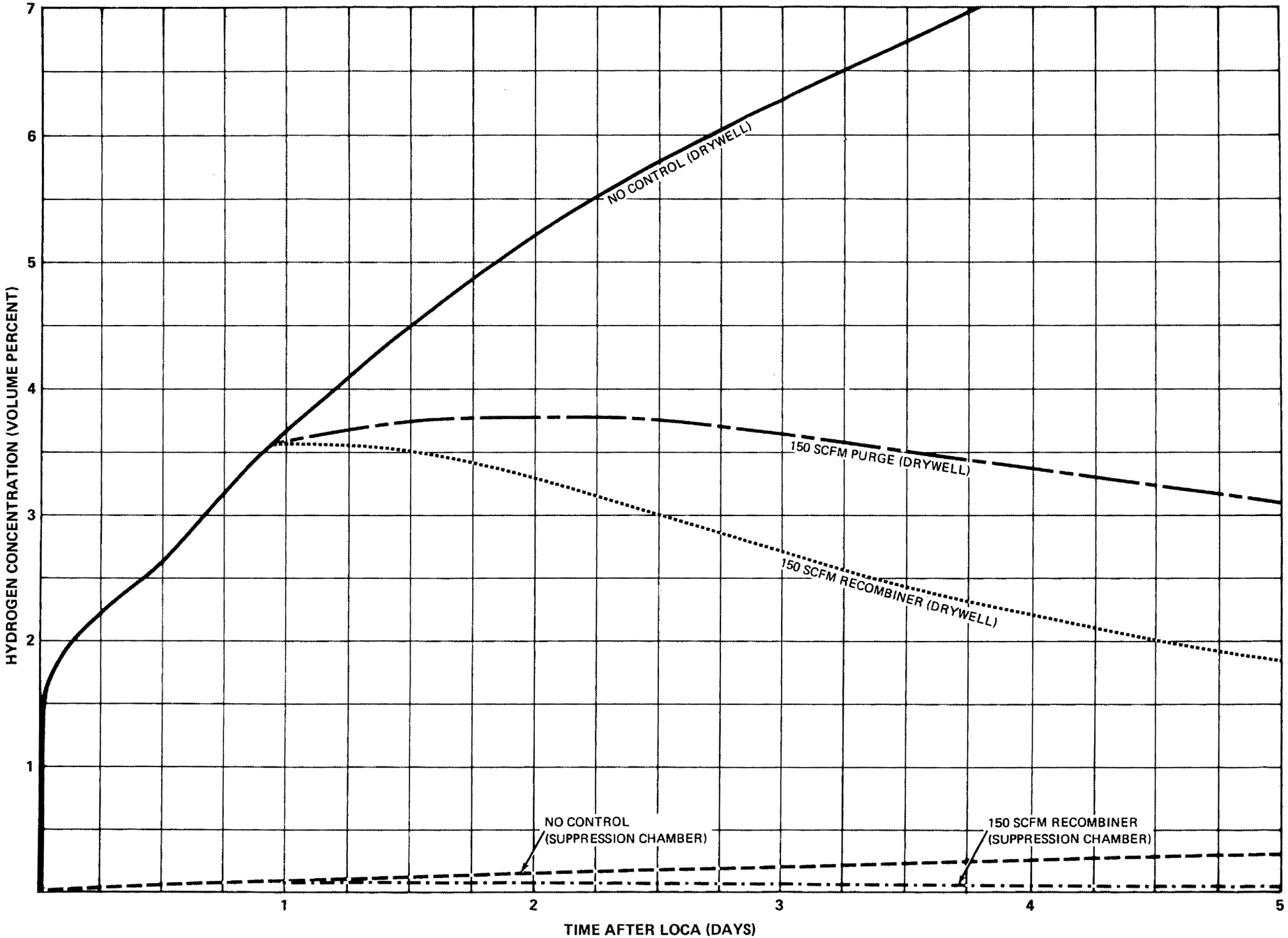
FIGURE 6.2-40



LIMERICK GENERATING STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

INTIGRATED HYDROGEN PRODUCTION AS A FUNCTION OF TIME AFTER LOCA

FIGURE 6.2-41 Rev. 11 9/02



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SHORT TERM CONTAINMENT
HYDROGEN CONCENTRATION
AFTER LOCA

FIGURE 6.2-42

NOTE: 150 SCFM RECOMBINER WILL KEEP H_2 CONCENTRATION BELOW 0.08 V% IN THE SUPPRESSION CHAMBER.
150 SCFM PURGE WILL KEEP H_2 CONCENTRATION BELOW 0.09 V% IN THE SUPPRESSION CHAMBER.

HYDROGEN CONCENTRATION (VOLUME PERCENT)

20
18
16
14
12
10
8
6
4
2

NO CONTROL (DRYWELL)

150 SCFM PURGE (DRYWELL)

150 SCFM RECOMBINER (DRYWELL)

NO CONTROL (SUPPRESSION CHAMBER)

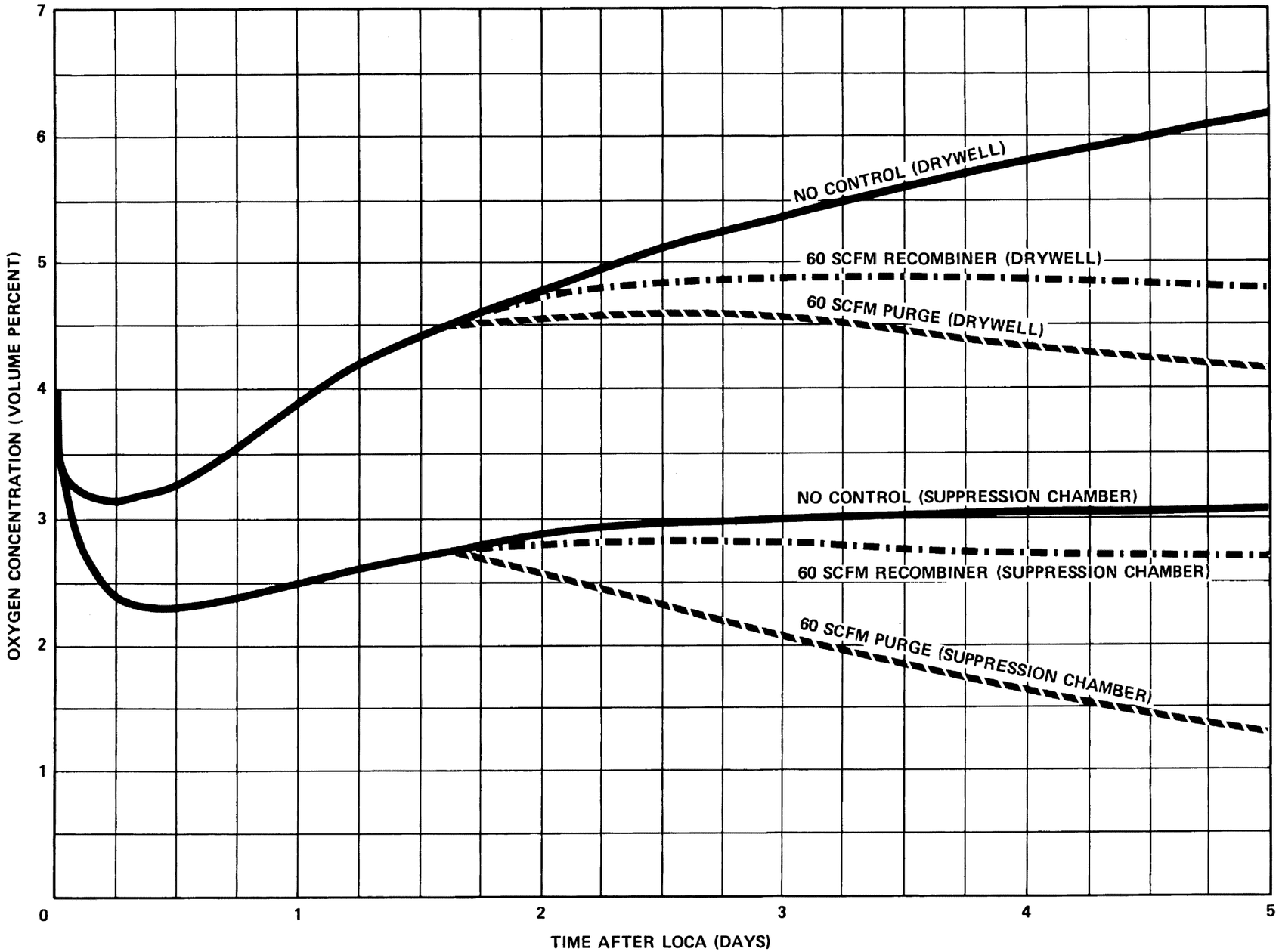
0 5 10 15 20 25 30

TIME AFTER LOCA (DAYS)

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LONG TERM CONTAINMENT HYDROGEN CONCENTRATION AFTER LOCA

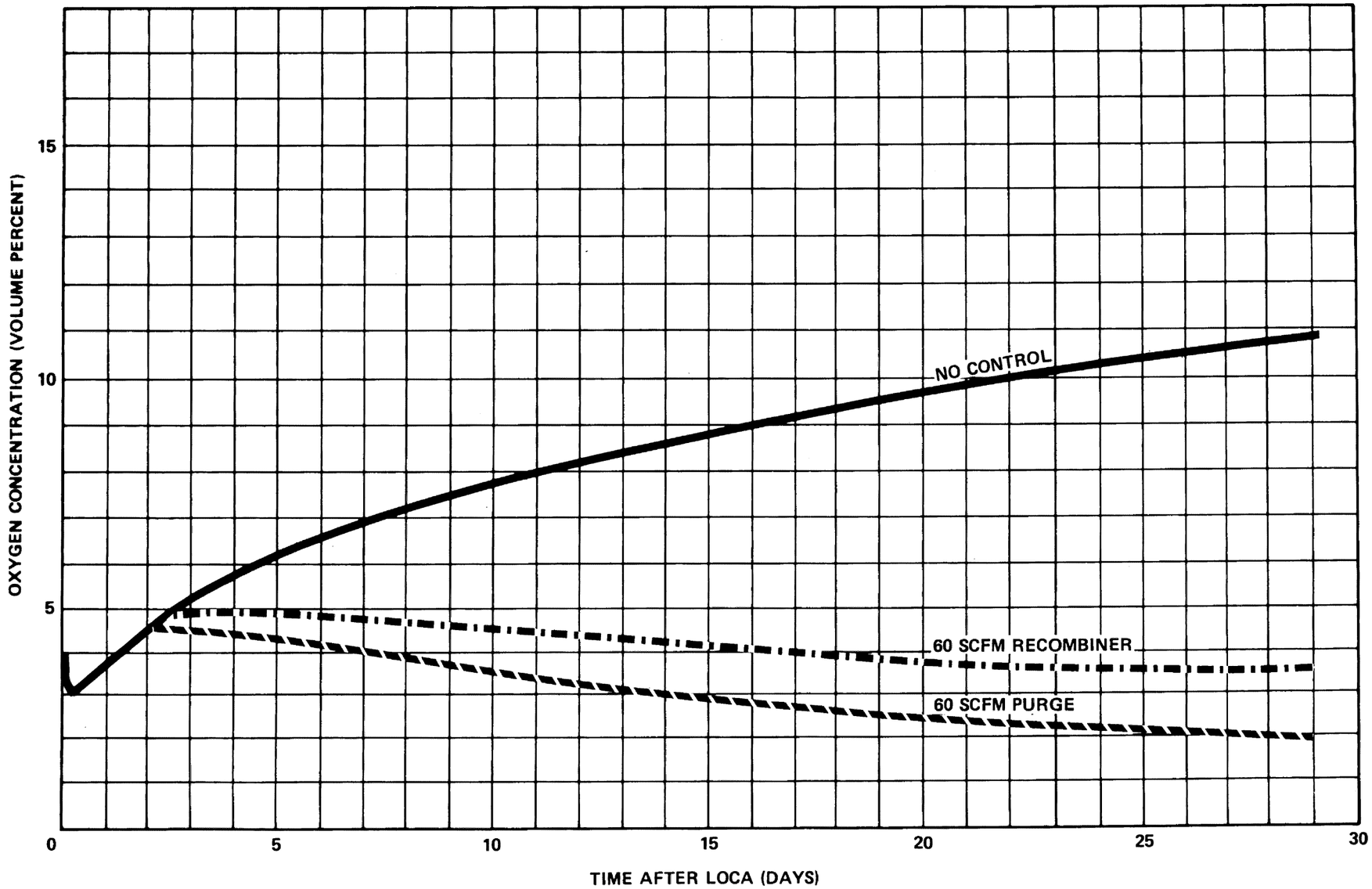
FIGURE 6.2-43



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SHORT TERM CONTAINMENT
OXYGEN CONCENTRATION
AFTER LOCA

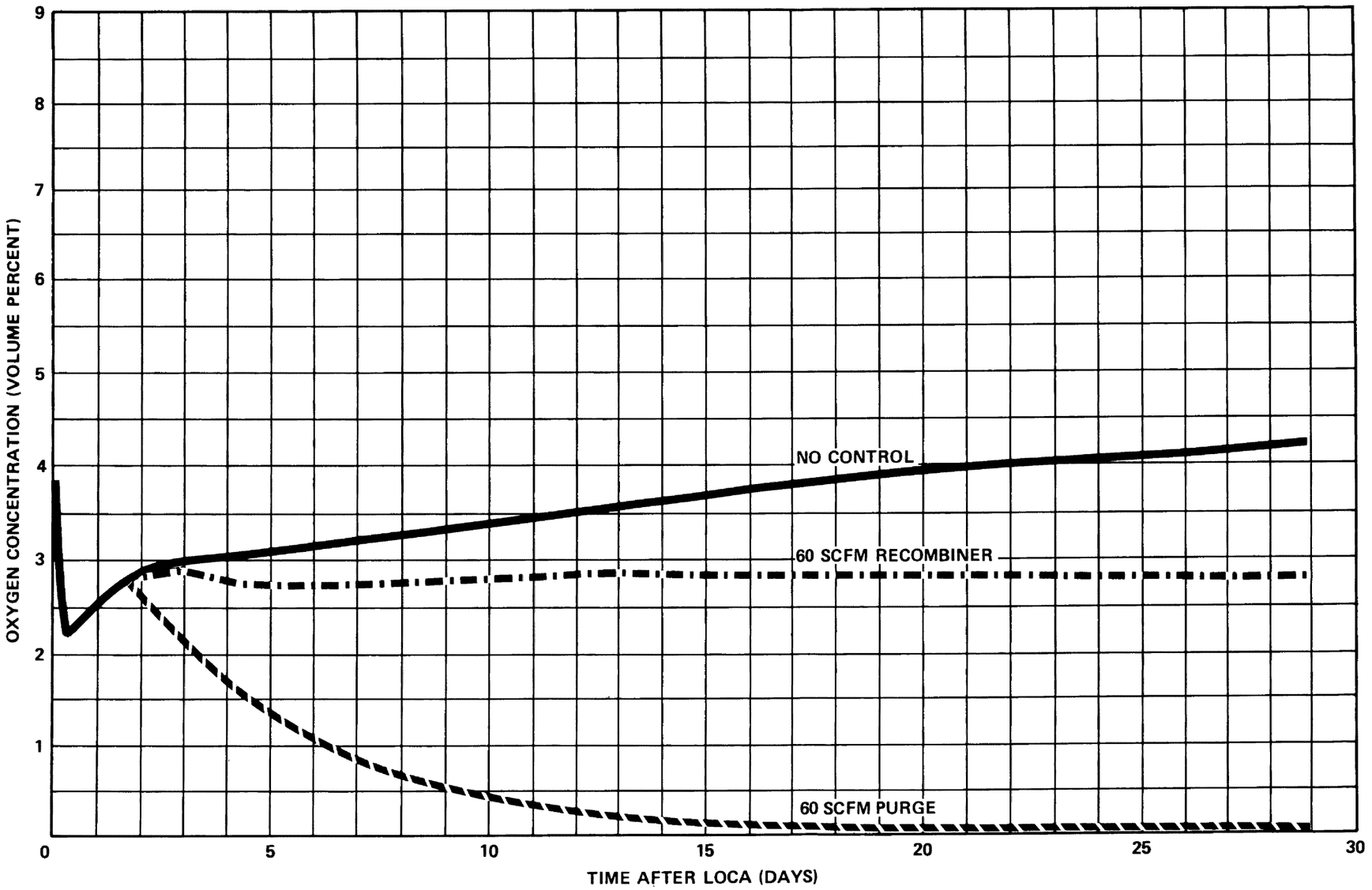
FIGURE 6.2-44



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LONG TERM DRYWELL OXYGEN CONCENTRATION AFTER LOCA

FIGURE 6.2-45



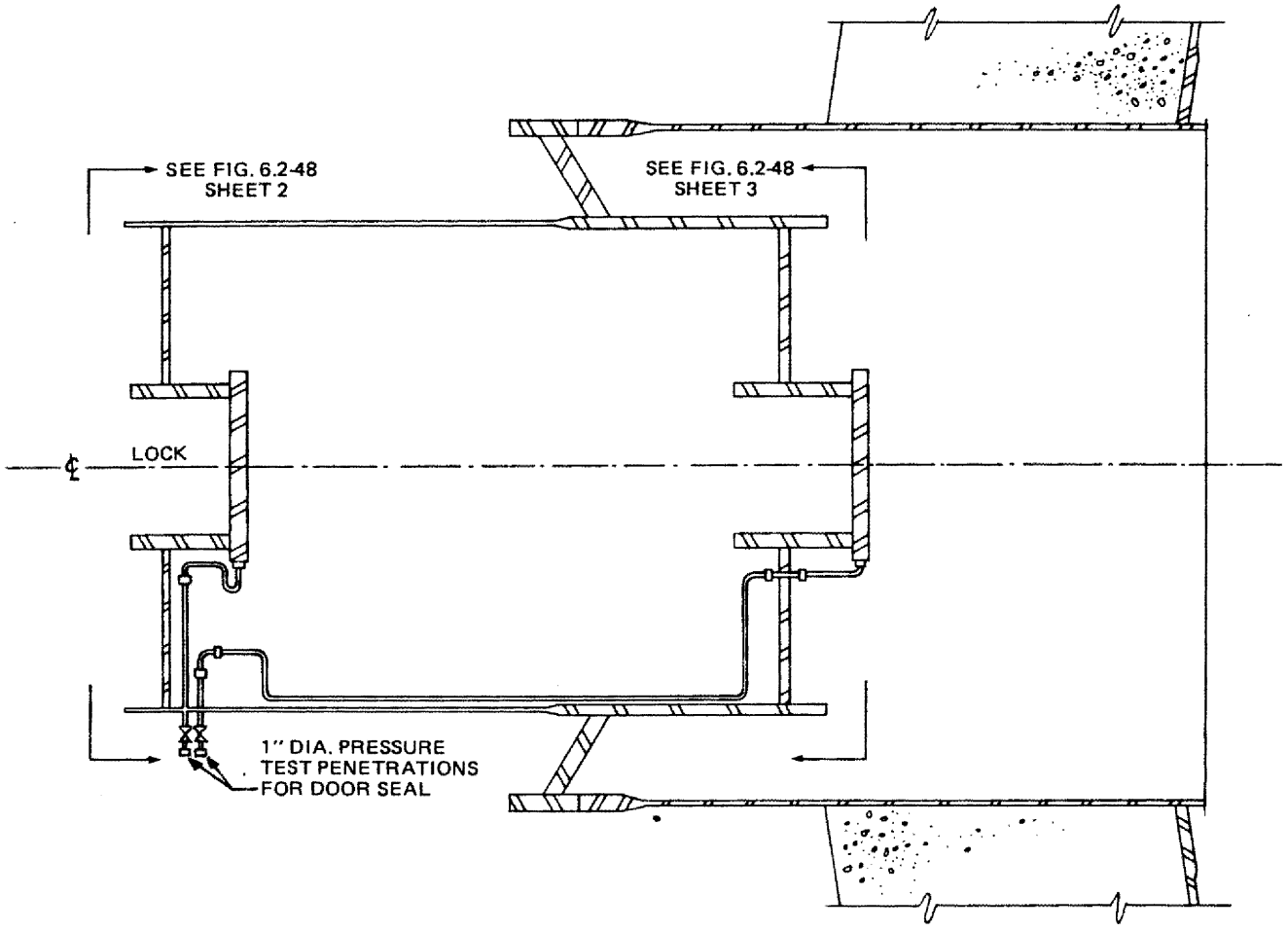
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LONG TERM SUPPRESSION CHAMBER OXYGEN CONCENTRATION AFTER LOCA

FIGURE 6.2-46

Figure 6.2-47

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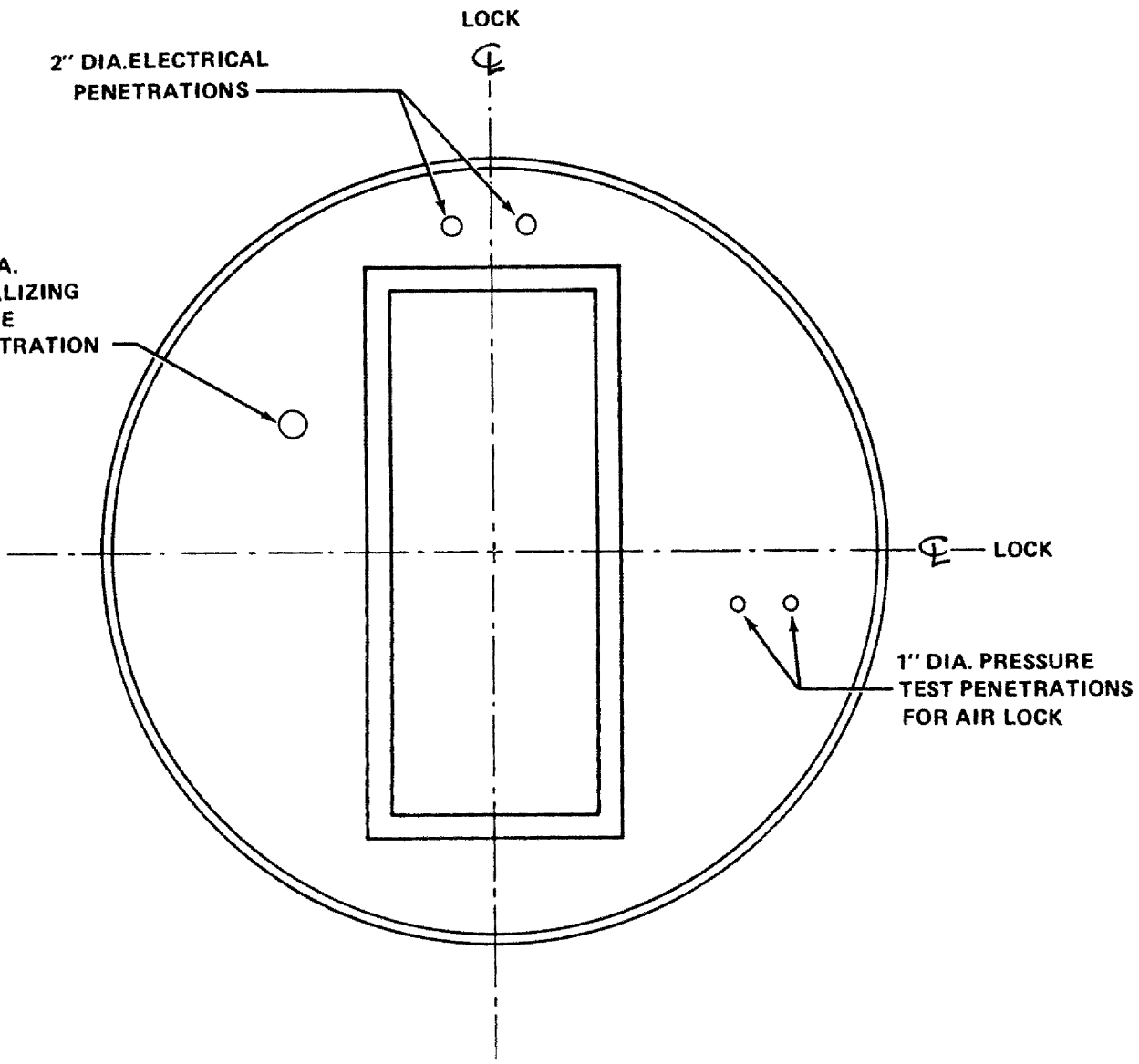


PLAN VIEW OF PERSONNEL LOCK

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL LOCK PENETRATIONS
(SHEET 1 OF 3)

FIGURE 6.2-48

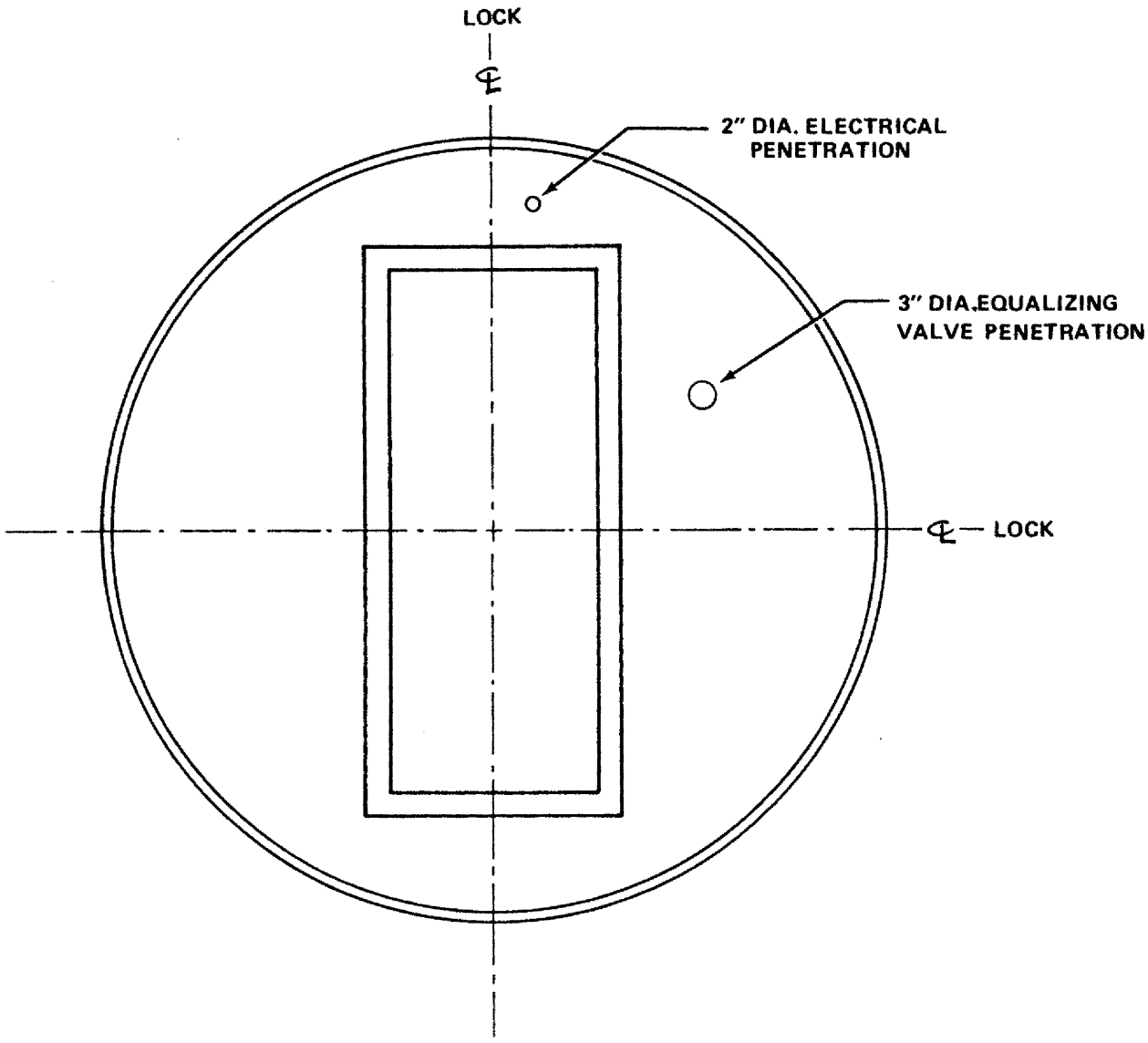


ELEVATION VIEW OF
EXTERIOR BULKHEAD

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL
LOCK DOOR PENETRATIONS
(SHEET 2 0F 3)

FIGURE 6.2-48

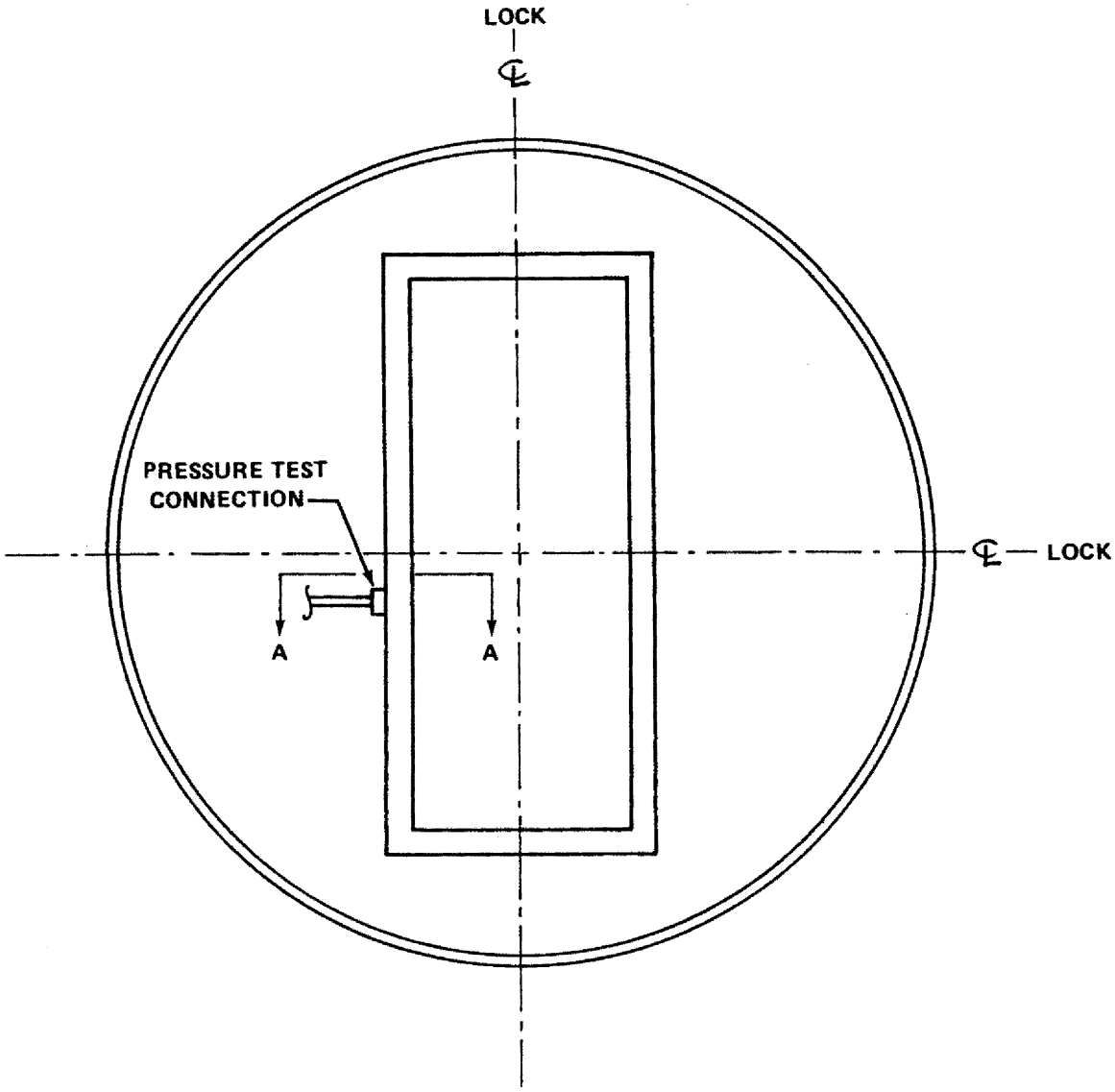


ELEVATION VIEW OF INTERIOR BULKHEAD

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL LOCK PENETRATIONS
(SHEET 3 OF 3)

FIGURE 6.2-48

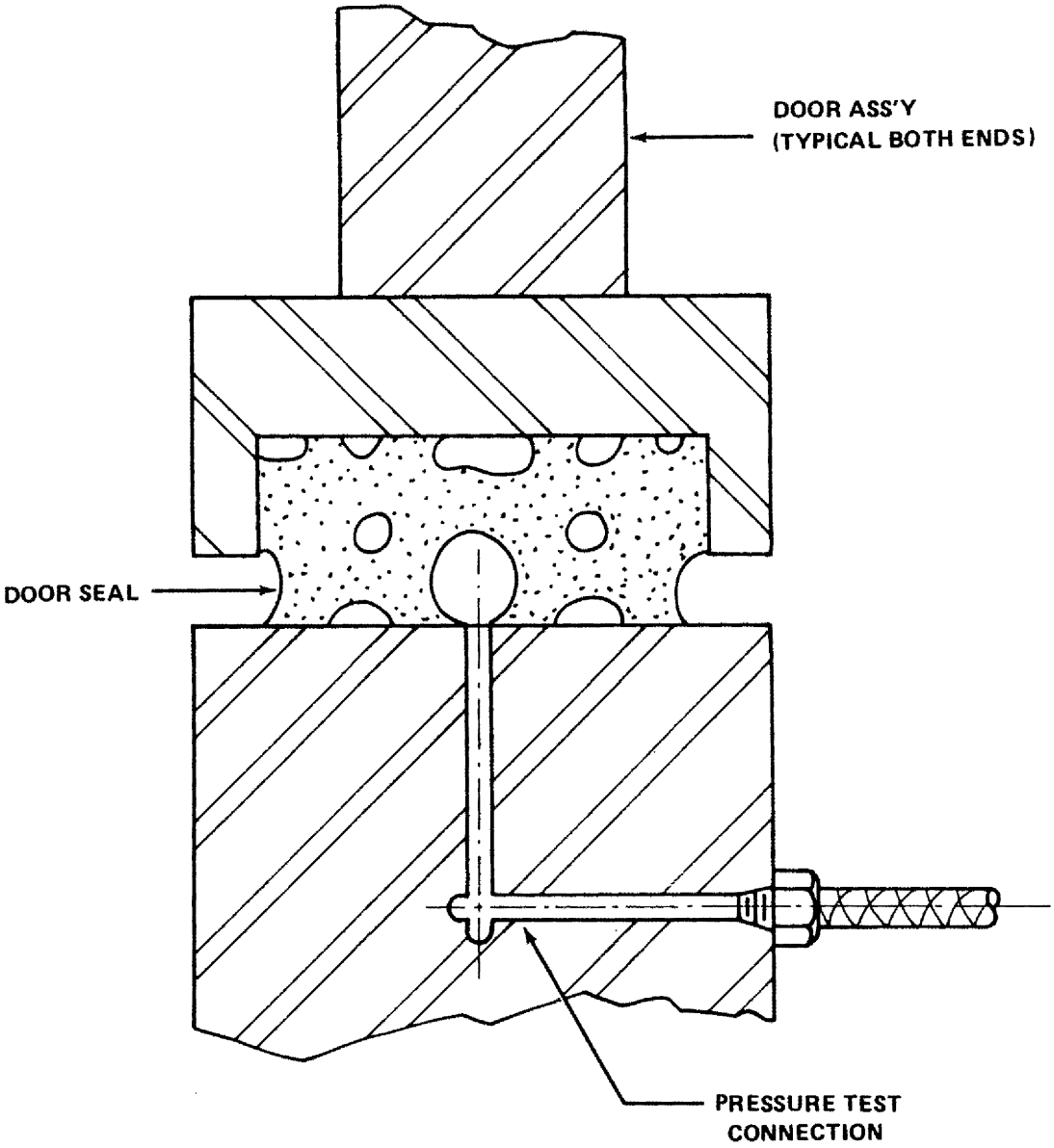


ELEVATION VIEW OF INTERIOR
OR EXTERIOR BULKHEAD

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL
LOCK DOOR SEALS
(SHEET 1 OF 2)

FIGURE 6.2-49

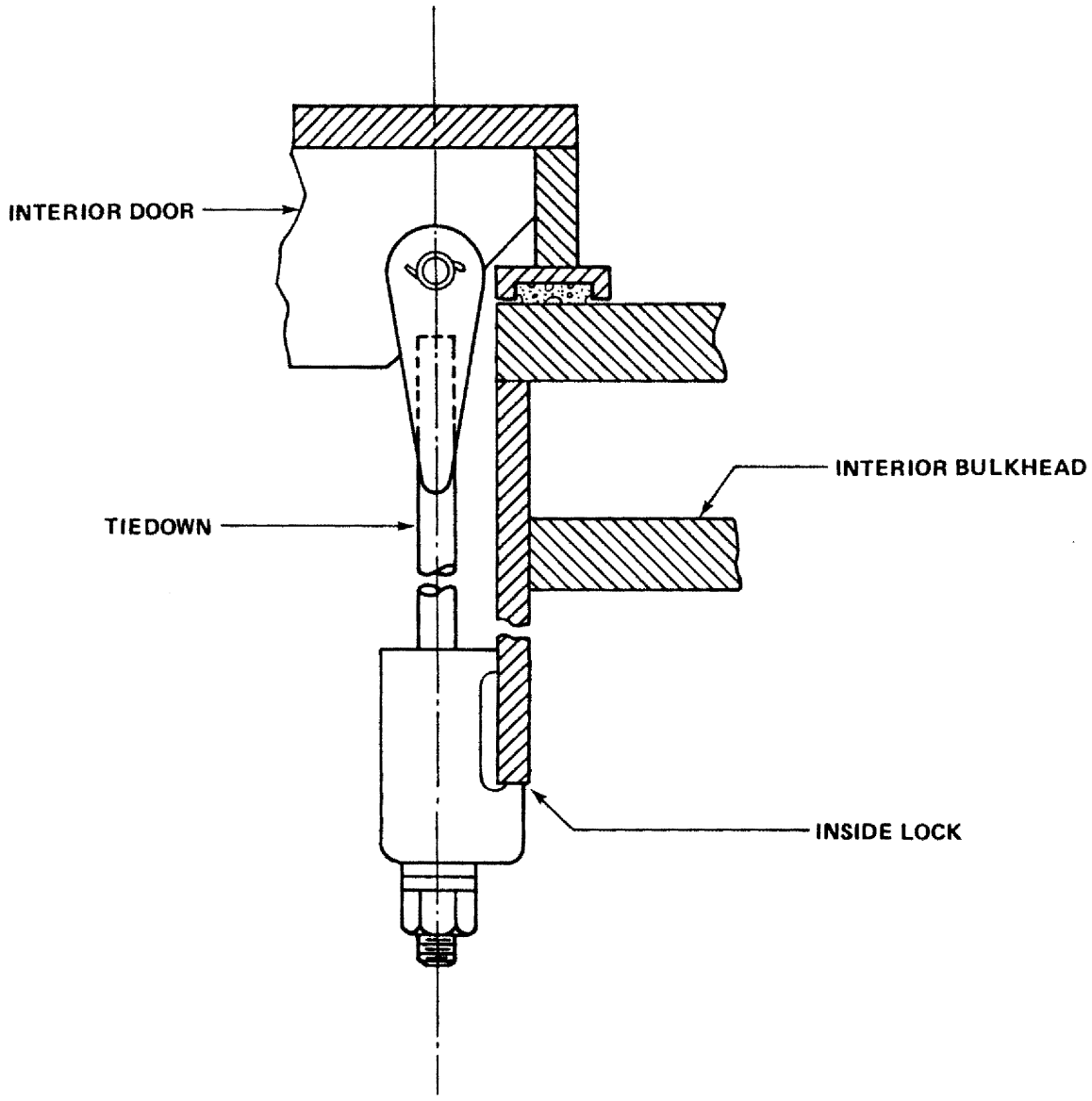


SECTION A–A

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL
LOCK DOOR SEALS
(SHEET 2 OF 2)

FIGURE 6.2-49



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL
LOCK INNER DOOR
TIEDOWNS

FIGURE 6.2-50

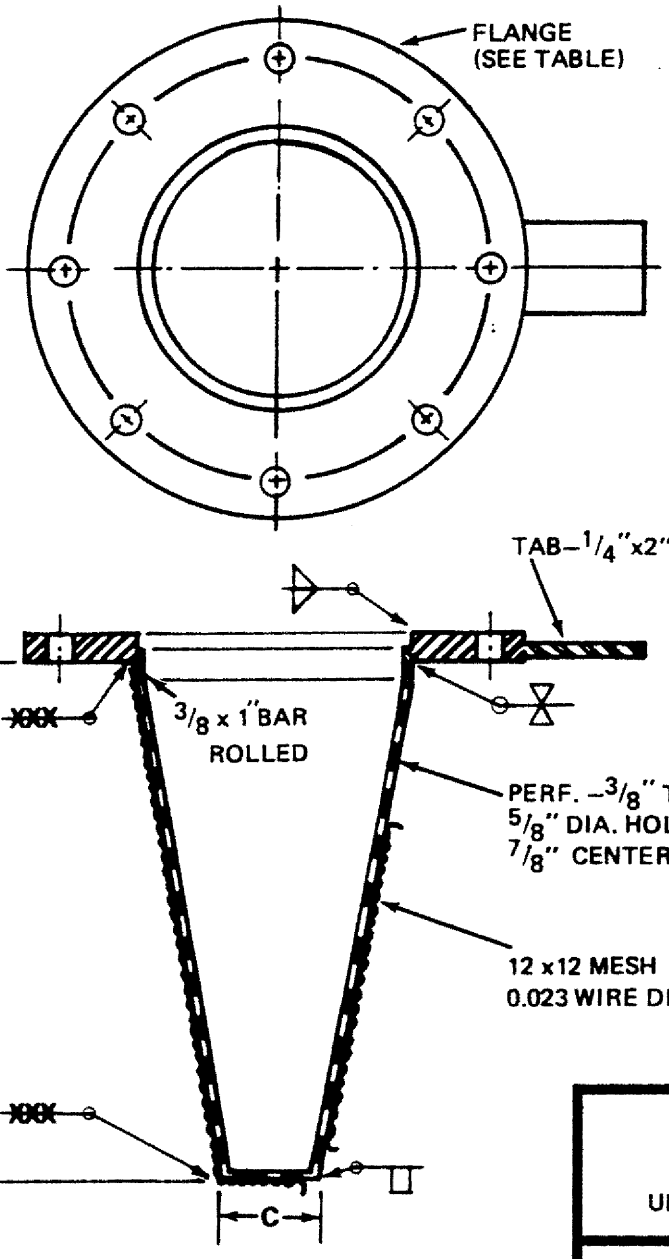
QUANTITY	NPS	A LENGTH	FLANGE O.D. I.D. THK.	NO. OF HOLES	DIA. OF HOLES	BOLT CIRCLE	C DIA.
4	6	$14\ ^{3}/_{16}$	11" - 6.07" - $^{3}/_{8}$"	8	$^{7}/_{8}$"	$9\ ^{1}/_{2}$"	$2\ ^{1}/_{2}$"
4	16	$30\ ^{3}/_{4}$	$23\ ^{1}/_{2}$" - $15\ ^{1}/_{4}$" - $^{1}/_{2}$"	16	$1\ ^{1}/_{8}$"	$21\ ^{1}/_{4}$"	4"

NOTES:

(1) THERE ARE TWO LONGITUDINAL ARC WELDS ON THE PERFORATED PLATE.

(2) THERE IS ONE LONGITUDINAL RESISTANCE WELD ON THE 12 MESH CLOTH.

(3) MATERIAL OF CONSTRUCTION IS STAINLESS STEEL; 304L FOR THE MESH.

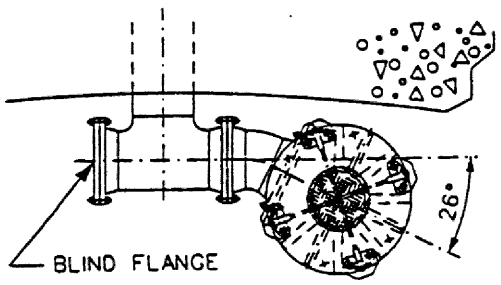


RCIC AND HPCI
STRAINER ARRANGEMENT

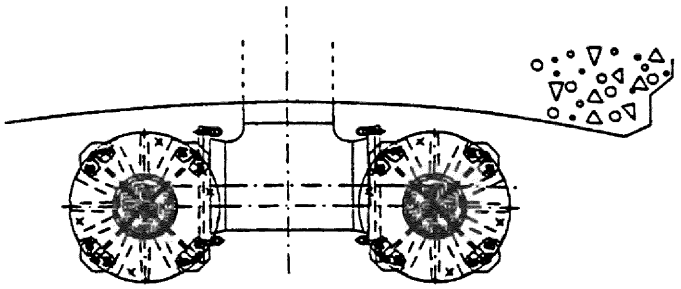
PECO ENERGY COMPANY
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION POOL
SUCTION STRAINERS
(SHEET 1 OF 2)

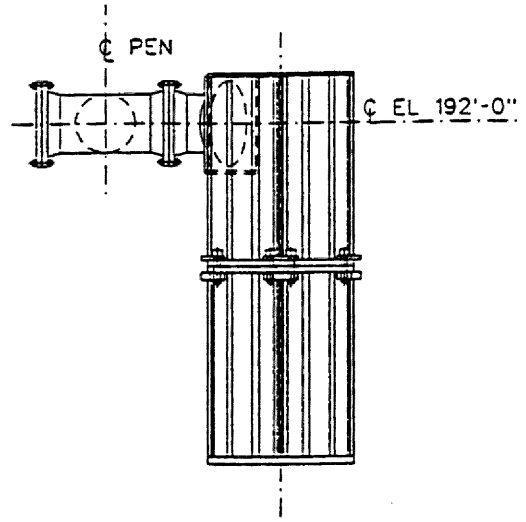
FIGURE 6.2-51 Rev. 09 11/99



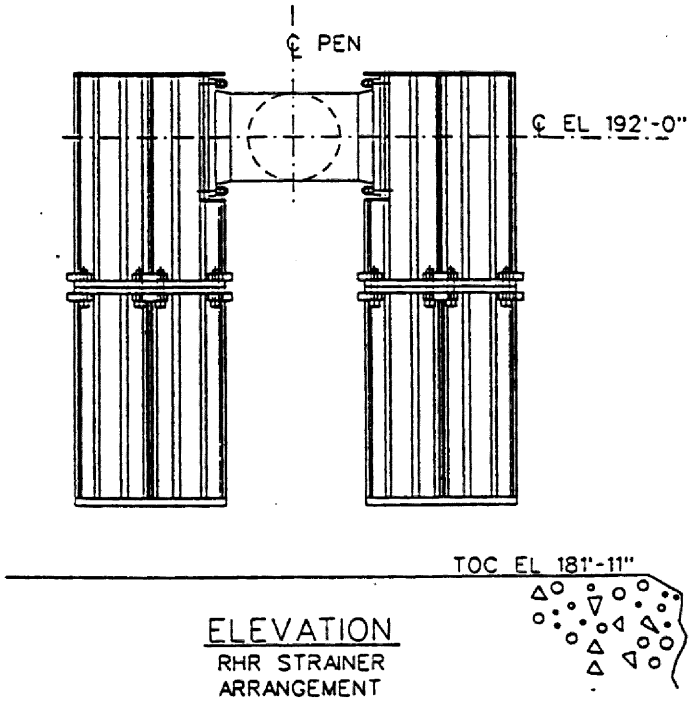
PLAN



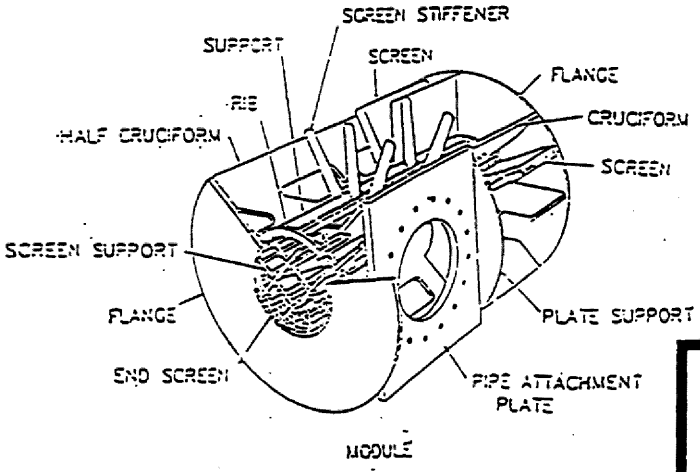
PLAN



ELEVATION
CS STRAINER
ARRANGEMENT



ELEVATION
RHR STRAINER
ARRANGEMENT

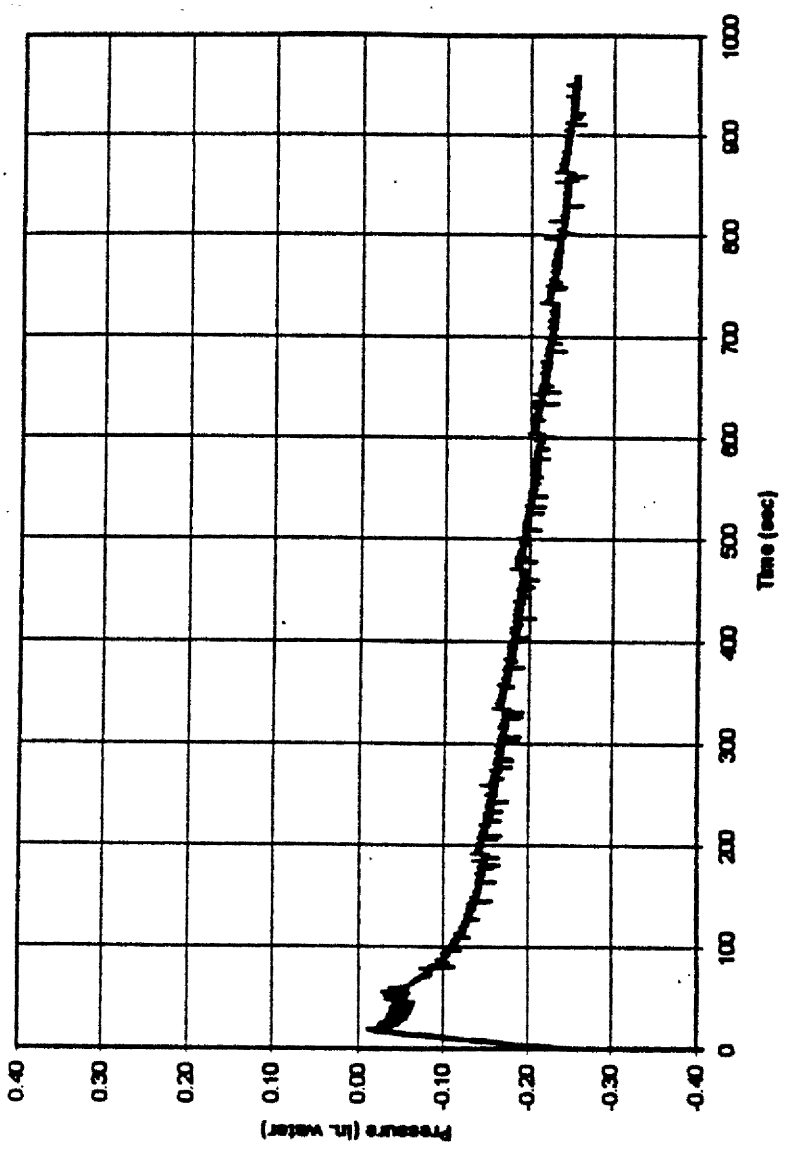


MODULE

PECO ENERGY COMPANY
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION POOL
SUCTION STRAINERS
(SHEET 2 OF 2)

FIGURE 6.2-51 Rev. 09 11/99



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE DRAWDOWN

FIGURE 6.2-52 REV. 7 12/97

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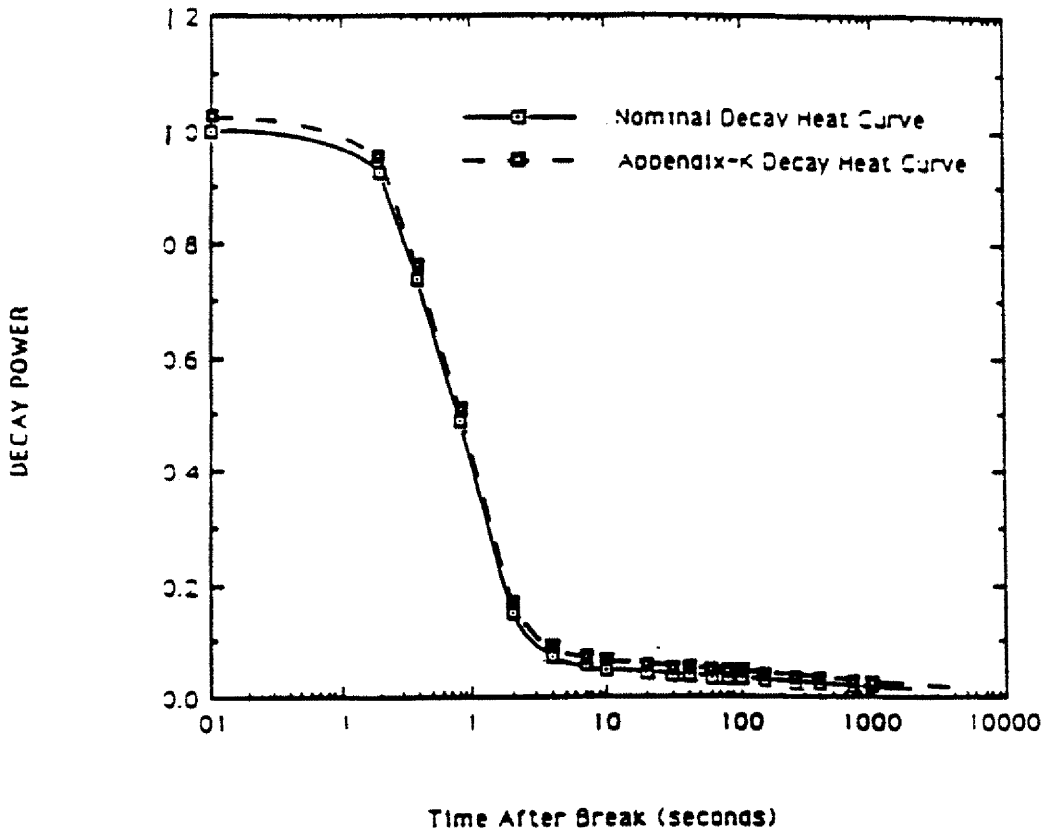
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

EVENT TREE FOR TIP SYSTEM
LINE ISOLATION

FIGURE 6.2-53 Rev. 1 July/91

Figures 6.3-1 through 6.3-10

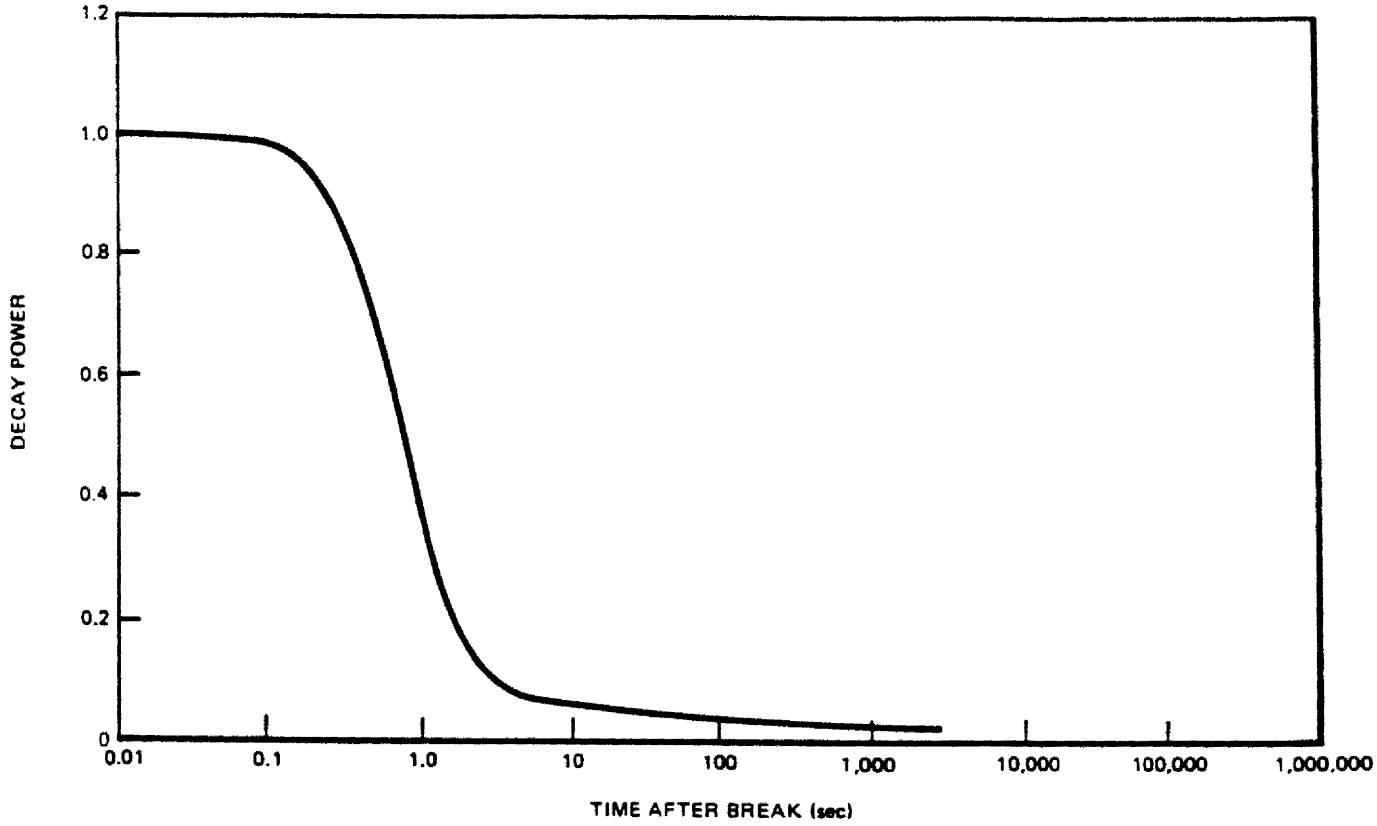
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LIMERICK GENERATING STATION
UNITS 2 AND 3
UPDATED FINAL SAFETY ANALYSIS REPORT

NORMALIZED POWER
VS TIME AFTER BREAK
(SAFER/GESTR METHODOLOGY)

FIGURE 6.3-11 **Rev. 07 12/97**



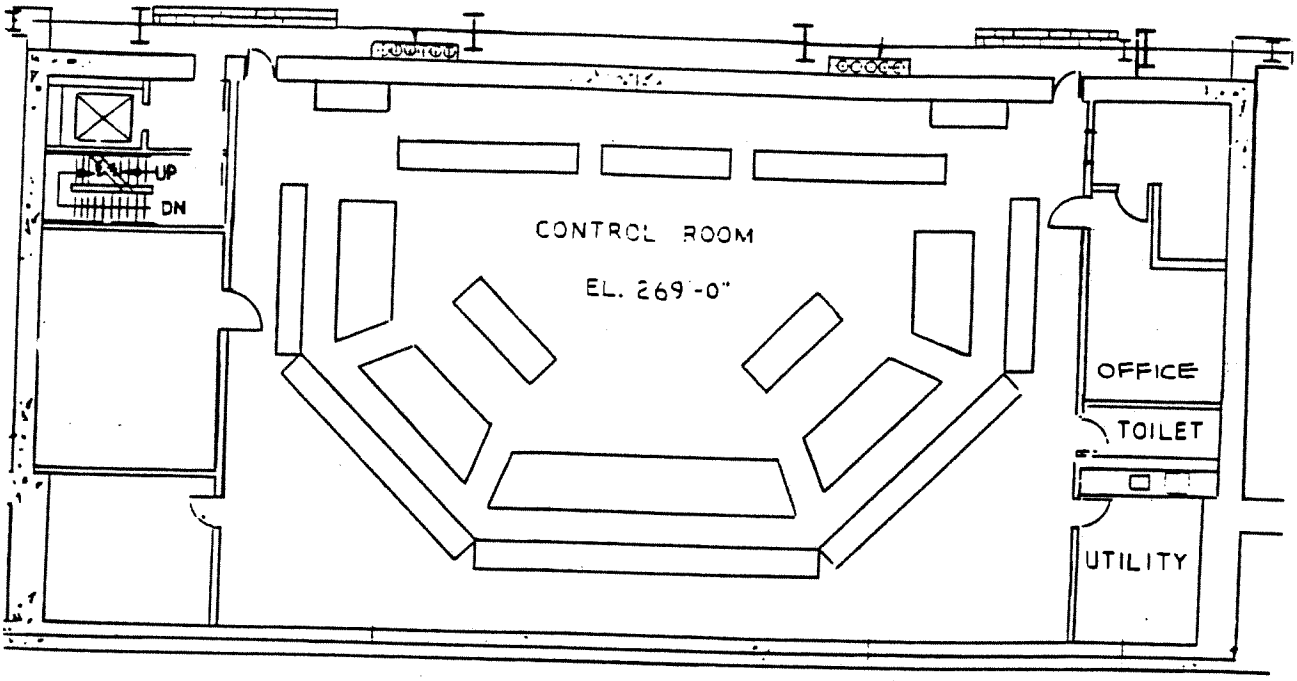
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

NORMAL POWER
VS TIME AFTER BREAK
(ORIGINAL 6.3-1 METHOD)

FIGURE 6.3-11A **Rev. 07 12/97**

Figures 6.3-12 through 6.3-74

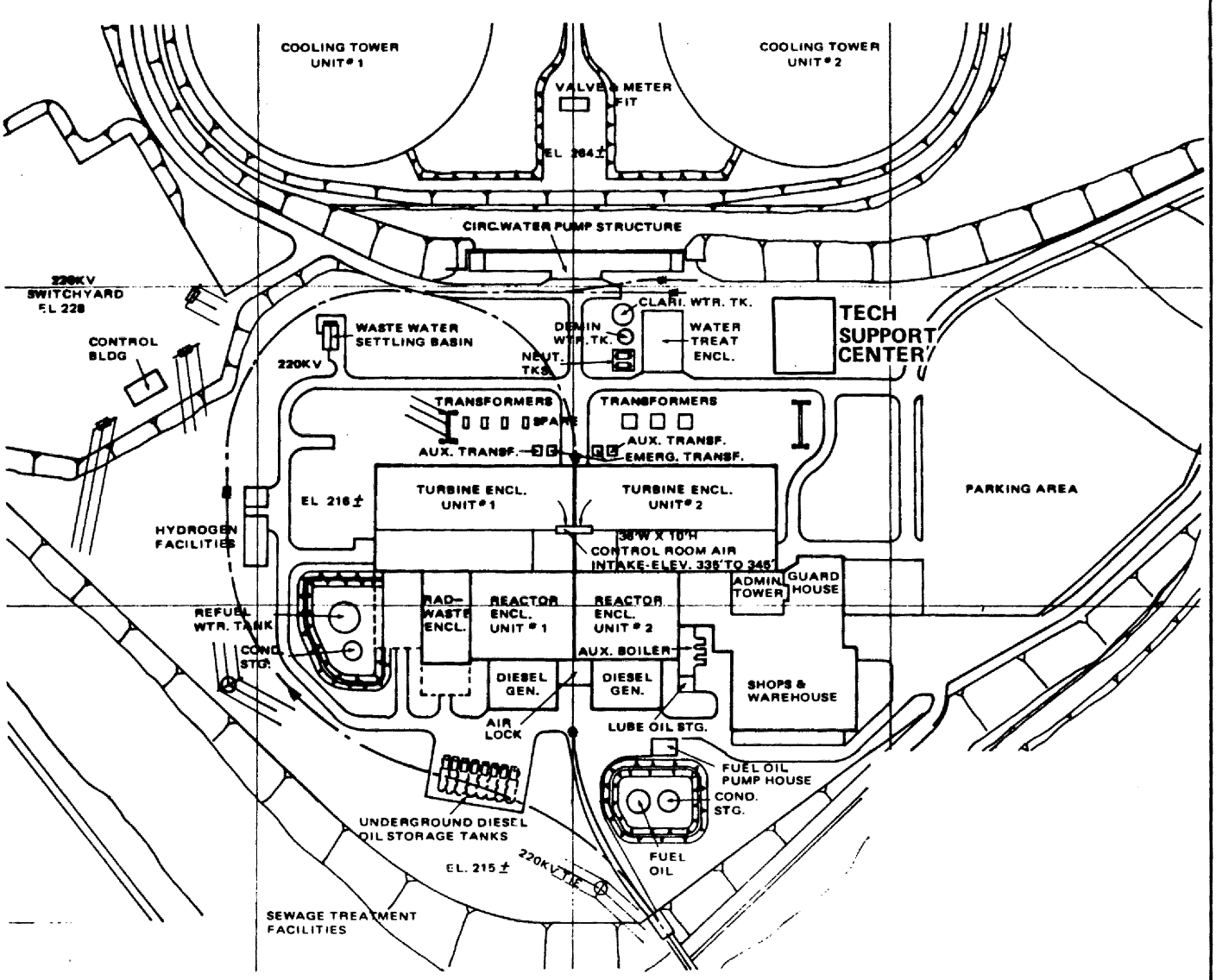
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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTROL ROOM ARRANGEMENT

FIGURE 6.4-1 REV. 13 09/06



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PLANT LAYOUT WITH RESPECT
TO CONTROL ROOM INTAKE

FIGURE 6.4-2

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APPENDIX 6A -SUBCOMPARTMENT DIFFERENTIAL PRESSURE CONSIDERATIONS

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6A-2	Recirculation Outlet Line Break Blowdown Mass Flux Time History
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APPENDIX 6A -SUBCOMPARTMENT DIFFERENTIAL PRESSURE CONSIDERATIONS

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APPENDIX 6A - SUBCOMPARTMENT DIFFERENTIAL PRESSURE CONSIDERATIONS

6A.0 INTRODUCTION

NOTE: The subcompartment differential pressure inputs values and analysis results presented in this section for the recirculation line and feedwater line breaks are based on the original design basis conditions. The blowdown mass and energy releases for the recirculation line and feedwater line breaks were reanalyzed at power rerate conditions. Based on the power rerate analyses, the original analyzed load bounds rerate conditions. Therefore, the shield wall design is not affected by power rerate. The drywell head region pressurization analysis presented in this section was reanalyzed for power rerate conditions. The resulting pressure differential at power rerate conditions is well below pressure differential for the drywell head region.

Differential pressure analyses were performed for the RPV shield annulus and the drywell head region.

The RPV shield annulus, which is 48.95 feet high and 1.70 feet wide at the top, has the 28 inch recirculation pumps suction lines passing through it. The mass and energy release rates from a postulated recirculation outlet line break constitute the most severe transient in the reactor shield annulus. Therefore, this pipe break is selected when analyzing loading of the shield wall and the RPV support skirt for pipe breaks causing annulus pressurization. The estimation of mass and energy release is based on the guidelines set forth in GE's "Generic Annulus Pressurization Mass-Energy Release Methodology" (MFN178-78) and "Technical Description Annulus Pressurization Load Adequacy Evaluation" (NEDO-24548/78NED302). Table 6A-1 presents the full mass and energy release data estimated by applying the finite break opening time/instantaneous break opening time approaches. Because the break location is more than three-fourths of the distance through the penetration, it is conservatively assumed that 50% of the blowdown is released into the annulus, and the remaining 50% is vented to the drywell atmosphere. Table 6A-2 provides, as a function of time, the mass flux and areas used for each side of the break. Physical parameters pertinent to the blowdown rate estimation are noted in the table.

In addition to the analyses for the recirculation outlet line break in the annulus, similar analyses using the same methodology for blowdown rate estimation are performed for a postulated feedwater line break in the annulus. Table 6A-3 presents the mass and energy release rates generated by only applying the very conservative instantaneous break opening time method. Also, it is conservatively assumed in the analyses that the full blowdown is completely released into the annulus. The mass flux as a function of time and areas used for each side of the break are presented in Table 6A-4. Pertinent physical parameters are noted in the table.

Because the main steam lines are not inside the annulus and the recirculation inlet lines are smaller than the outlet lines, the annulus pressurization analyses for these two cases are not needed.

In considering the drywell head region, the maximum blowdown rate stems from a break in the RHR head spray line. The blowdown mass and energy release rates for this line are calculated using Moody Critical Flow of 2800 $lb_m/sec\text{-}ft^2$ and an enthalpy of 1192 Btu/lb_m for the original power level. Pressurization consequences at 3527 MWt are based on the original effects and a multiplier. This multiplier is calulated from the effects of the 3527 MWt on the blowdown mass and energy release rates.. Table 6A-5 shows the blowdown schedule for a 6 inch Schedule 80 line break with an effective break area of 0.181 ft^2. Since this line could singularly pressurize the drywell head region, it is chosen for analysis in a postulated break. The head spray line does not

exist for Unit 2 and has been removed from Unit 1. However, the analysis is still applicable since it envelopes loads from rupture of any other pipe in this region.

All differential pressure analyses were performed according to the analytical techniques described in Reference 6A-1. These adjusted pressures are combined with the other appropriate loads (e.g., seismic and jet impingement) to develop design loads for the affected structures and components. Subcompartment venting is used to ensure that the differential pressures developed will remain below the structural capability of compartment walls.

Mass and energy release rates using the NEDO-20533 methodology for a recirculation line break are shown in Table 6.2-10. Short-term release rates based on NEDO-24548 are shown in Table 6A-1. Comparison of these two tables indicates that mass flow rates and enthalpy calculated using NEDO-24548 are less than the conservative values produced using assumptions consistent with NEDO-20533.

Recirculation line break blowdown data used for containment analysis are based on assumptions and calculations made specifically for the LGS units. These assumptions and calculations are discussed in NEDO-10320 (Reference 6.2-5), which follows the methodology outlined in NEDO-20533. This model has been shown to be quite conservative for long-term containment analysis.

However, for the special cases required to analyze pressurization of the annulus due to a recirculation line or feedwater line break, a more detailed model is used. The NEDO-24548 model for short-term mass and energy release includes the effects of inventory and subcooling for flow rates during the first 5 seconds. Credit may also be taken for a finite break opening time. Blowdown rates from NEDO-24548, which calculates the maximum quasi-steady mass flux based on the Moody steady slip flow model with subcooling, are also considered to be conservative estimates of the mass and energy released from the vessel.

6A.1 BIOLOGICAL SHIELD ANNULUS SUBCOMPARTMENT MODELING PROCEDURES AND ANALYSIS

NOTE: The subcompartment differential pressure inputs values and analysis results presented in this section for the recirculation line and feedwater line breaks are based on the original design basis conditions. The blowdown mass and energy releases for the recirculation line and feedwater line breaks were reanalyzed at power rerate conditions. Based on the power rerate analyses, the original analyzed loads bound rerate conditions. Therefore, the shield wall design is not affected by power rerate. The drywell head region pressurization analysis presented in this section was reanalyzed for power rerate conditions. The resulting pressure differential at power rerate conditions is well below pressure differential for the drywell head region.

An analysis was performed of the pressure distribution around the RPV after a recirculation line break. The general layout of the shield annulus is shown in Figures 3.8-1 through 3.8-8 and in 6A-1. Figure 6A-2 is a schematic of the RPV shield annulus model. The model consists of six major levels. Each level is subdivided into twelve 30° segments to form a total of 72 nodes inside the annulus plus an additional node for the rest of the drywell.

The guidelines of GE's "Generic Annulus Pressurization Load Adequacy Evaluation" (NEDO-24548/78NED302) were followed in treating the entire drywell region (volume number 73) as a single compartment in the RPV shield annulus subcompartment analysis. Treating the drywell region as a single compartment reduces the drywell pressure response due to venting from the annulus, resulting in the greatest ΔP across the shield wall.

The 235,200 ft^3 size of the drywell region used in the analysis is a "free volume." The volume occupied by equipment, structures, and floors (i.e.; obstructions) contained within the drywell was excluded from the "free volume" estimate.

In general, the arrangement of the pipes in the annulus determines the most representative level division, since they constitute the only significant flow restrictions. This 73 node model is considered detailed enough to conservatively predict the maximum pressure loads on the compartment structure. Therefore, a nodalization sensitivity study is not needed.

For the purpose of determining peak pressure in the reactor vessel shield annulus, all insulation is assumed to move flush against the biological shield wall while still maintaining its original thickness. The volume of the insulation is excluded from the net volume of each subcompartment, and the projected area of the insulation that blocks the venting path is also excluded from the free venting area used in the analysis.

Venting to the drywell atmosphere is achieved only through the top of the biological shield annulus. For conservatism, venting through the reactor shield wall is not considered.

Initial conditions used in this analysis are 15.45 psia, 135°F, and 30% relative humidity. Bases for these initial conditions are discussed in the drywell head region subcompartment analysis (Section 6A.2).

Tables 6A-6 and 6A-7 give the subcompartment volumes, flow areas, length/area (L/A) ratio, and flow coefficients (including origins) used in the analysis.

The resultant pressure distributions are shown in Figure 6A-3 for the recirculation outlet line break and Figure 6A-4 for the feedwater line break. The subcompartment pressures existing in each subcompartment at the time of peak differential pressure across the RPV are also shown in these figures. Additionally, the load forcing functions that include both peak and transient loadings on the RPV and the reactor shield wall are presented in Figures 6A-5 and 6A-6 for the recirculation outlet break and in Figures 6A-7 and 6A-8 for the feedwater line break. This forcing function represents the time-dependent resultant force on the structure and originates from the vector sum of the product of compartment pressure and area for each of the many nodes used to represent the surface.

The components of these nodal areas are calculated in the following manner:

$$(A_x)_i = R_i H_i \operatorname{Sin}(\theta_{1_i} - \theta_{2_i}) \qquad \text{(EQ. 6A-1)}$$

$$(A_y)_i = R_i H_i \operatorname{Cos}(\theta_{2_i} - \theta_{1_i}) \qquad \text{(EQ. 6A-2)}$$

where:

R_i = Radius of the ith geometry node, in

H_i = Height of the ith geometry node, in

$\theta_{1_i} + \theta_{2_i}$ = Swept angle of geometry node i

Therefore, the force generated by a pressure, (P), acting on a nodal area (A) has the following components:

$(F_x)_i = P_j (A_x)_i$ (EQ. 6A-3)

$(F_y)_i = P_j (A_y)_i$ (EQ. 6A-4)

The compartment pressure transients resulting from a break in the reactor shield annulus generate a nodal force distribution over exposed surfaces. The resultant of this nodal force distribution is presented in Figures 6A-5, 6A-6, 6A-7 and 6A-8. This nodal force distribution is included in the analysis of nonaxisymmetric loadings on the containment internal structures, which is discussed in Sections 3.8.3.3 and 3.8.3.4.

Blowdown jet loads that include jet impingement and reaction forces against the reactor vessel are also analyzed for the feedwater line break for reference and comparison. Note that these analyses are based on the very conservative assumptions that the first pipe restraint nearest the nozzle fails. For this break, approximately 9.5" pipe center line offset limited by the shield plug opening produces a net break area of 88.53 in^2, which consequently results into a total maximum jet load against the vessel and a maximum reaction force of 158,500 lb_f and 93,230 lb_f, respectively. Note that this blowdown jet load is relatively small compared with the peak load contributed by the unbalanced reactor annulus pressurization due to the same break.

6A.2 DRYWELL HEAD REGION SUBCOMPARTMENT ANALYSIS

The design basis pressure differential between the drywell head region and the rest of the containment is a structural requirement of the drywell head. A pressure analysis of the drywell head region for a postulated head spray line break was performed. The effects of a 6 inch RHR head spray line break bound those of a 2 inch core vent line, which is the only other line that runs through the drywell head region.

Figure 6A-9 illustrates the basic arrangement of the head region. Venting from the head region is accomplished through ventilation openings as shown in Figure 6A-9. These vent openings provide a total of 18.64 ft^2 of vent area with a flow coefficient of 0.64 to relieve pressure buildup caused by the postulated break. Figure 6A-10 is the schematic flow diagram with vent flow areas and discharge coefficient used in the drywell head venting analysis.

For the drywell head region subcompartment analysis, the possibility that insulation from the RPV could break loose and block the vent paths was not considered because the postulated rupture of the RHR head spray line is outside the insulation above the top of the RPV. The jet from the vessel side of the break is above the top of the insulation, which precludes the metallic insulation sections from breaking loose due to the outward flow of the jet. Forces on the insulation from flow from the other side of the break as well as from the subsequent pressurization in the drywell head region would be inward toward the RPV, rather than outward toward the vent paths.

There is only a small amount of insulation on the drywell head region lines. In the event that this insulation should fail to remain on the pipe due to direct jet impingement, the vent paths leading from the drywell region would not become blocked for the following reasons. The openings of each of the six vents and two exhaust lines from the drywell head region are above the floor and have a ¾ inch mesh screen installed over them. To block the vent paths, a substantial amount of insulation would need to fall directly onto the vent path opening and break through the screen. This is considered improbable because there is only a small amount of pipe insulation in this region and not all of the failed insulation would fall on any one vent path opening.

To determine peak pressure in the drywell head, all insulation is assumed to remain in place. Initial conditions of 15.4 psia, 135°F, and 20% relative humidity are used in this analysis.

The initial conditions used for both the RPV shield annulus and drywell head region analyses reflect conservative assumptions to minimize the total heat capacity of the subcompartment, which satisfies SRP Section 6.2.1.2, Item II.B.1. The COPDA (NE699/D2) subcompartment analysis code is designed to handle realistic conditions. Recommended minimum relative humidity for COPDA, which is described in Reference 6A-1, is in the range of 25% to 30%. The available heat capacity at P=15.45 psia, T=135°F, and RH=30% is less than 3% greater than the heat capacity at 14.8 psia, 135°F, and RH=0%, and will not significantly affect the results of the analysis.

The initial pressure of 15.45 psia (0.75 psig) is the nominal drywell pressure under normal operating conditions for this unit. The pressure alarm setpoints are at 14.8 psia (0.1 psig) and 16.2 psia (1.5 psig). The heat capacity gain due to the higher initial pressure of 0.75 psig is less than 0.2% compared to the heat capacity available for T=135°F, RH=30%, and P=14.8 psia.

The drywell air cooling system is designed to limit the maximum average bulk temperature in the drywell to 135°F, with local maxima not exceeding 150°F (Section 9.4.5.2). For a given relative humidity, an increase in the initial temperatures is accompanied by an increase in the steam partial pressure. Consequently, the heat capacity in the compartment increases due to a greater steam mass. For this reason, the maximum bulk temperature of 135°F is used rather than the 150°F local maximum.

For the RPV shield annulus subcompartment analysis, it should be noted that Reference 6A-2 concludes that loads from such annulus pressurization analyses are insensitive to minor variations in initial (P), (T), and (ϕ).

The pressure transient of this analysis is presented in Figure 6A-11. It can be seen that the maximum pressure in the drywell head region is 25.91 psia and occurs 0.82 seconds after the head spray line break. The maximum pressure of 25.91 psia includes an increase of 2.61 psia as a result of power rerate. Considering the containment pressure to be atmospheric (no drywell air displaced into the rest of containment), a differential of 11.2 psid is obtained between the drywell head and the rest of containment. This pressure differential is well below the design pressure differential of 16.0 psid.

6A.3 REFERENCES

6A-1 "Subcompartment Pressure Analyses," BN-TOP-4, Rev 1, Bechtel Power Corporation, San Francisco, California, (November 1972).

6A-2 NUREG/CR-2633, "Containment Reactor Cavity Subcompartment Analysis Procedures for a Boiling Water Reactor", (May 1982).

Table 6A-1

REACTOR PRIMARY SYSTEM BLOWDOWN FLOW RATES AND FLUID ENTHALPY - RECIRCULATION LINE BREAK

TIME (s)	MASS (lb_m/s)	ENTHALPY (Btu/lb_m)
0.000	0.0000	0.000
2.5500×10^{-3}	1.3400×10^{3}	527.9
3.9000×10^{-3}	2.6750×10^{3}	527.9
4.9600×10^{-3}	4.0100×10^{3}	527.9
5.8600×10^{-3}	5.3500×10^{3}	527.9
7.3700×10^{-3}	8.0200×10^{3}	527.9
9.2400×10^{-3}	1.2025×10^{4}	527.9
1.1800×10^{-2}	1.9285×10^{4}	527.9
1.3800×10^{-2}	2.6560×10^{4}	527.9
1.5800×10^{-2}	3.2355×10^{4}	527.9
1.8000×10^{-2}	4.5975×10^{4}	527.9
2.0800×10^{-2}	4.5975×10^{4}	527.9
2.0800×10^{-2}	2.2400×10^{4}	527.9
2.1800×10^{-2}	2.4130×10^{4}	527.9
2.2800×10^{-2}	2.5840×10^{4}	527.9
2.3800×10^{-2}	2.7520×10^{4}	527.9
2.5800×10^{-2}	3.0780×10^{4}	527.9
2.7800×10^{-2}	3.3880×10^{4}	527.9
3.0800×10^{-2}	3.8170×10^{4}	527.9
3.5800×10^{-2}	4.4220×10^{4}	527.9
3.7000×10^{-2}	4.5975×10^{4}	527.9
4.1400×10^{-1}	4.5975×10^{4}	527.9
4.1400×10^{-1}	3.4370×10^{4}	527.9
1.0000	3.4370×10^{4}	527.9

NOTE: The information presented in this table is based on original plant conditions. The values in the table do provide a reasonable representation of the general blowdown characteristics.

Table 6A-2

RECIRCULATION OUTLET LINE BREAK BLOWDOWN
MASS FLUX TIME HISTORY[1][2]

TIME (s)	MASS FLUX ($lb_m/s/ft^2$)	EFFECTIVE BREAK AREA (ft^2)
VESSEL SIDE:		
0.00255	21200	0.0316
0.00496	21200	0.0964
0.00737	21200	0.1892
0.01180	21200	0.4548
0.01580	21200	0.7631
0.02080	21200	1.0843
0.02081	8410	1.3317
0.02180	8410	1.4346
0.02380	8410	1.6361
0.02780	8410	2.0142
0.03580	8410	2.6280
0.03700	8410	2.7333
0.41400	8410	3.6440
0.41410	8410	3.6440
1.0	8410	3.6440
PUMP SIDE:		
0.00255	21200	0.0316
0.00496	21200	0.0964
0.00737	21200	0.1892
0.01180	21200	0.4548
0.01580	21200	0.7631
0.02080	21200	1.0843
0.02081	8410	1.3317
0.02180	8410	1.4346
0.02380	8410	1.6361
0.02780	8410	2.0142
0.03580	8410	2.6290
0.03700	8410	2.7333
0.41400	8410	1.8220
0.41410	8410	0.4420
1.0	8410	0.4420

NOTE: The information presented in this table is based on original plant conditions. The values in the table do provide a reasonable representation of the general blowdown characteristics.

Table 6A-2 (Cont'd)

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(1) Listed below are pertinent physical parameters used in the blowdown estimation:

A	=	3.644	ft^2	Minimum cross-sectional area between vessel and break
D	=	2.154	ft	Pipe I.D. at the break location
h_o	=	527.85	Btu/lb_m	Vessel enthalpy
L_I	=	2.917	ft	Inventory length
P_o	=	1031.2	psia	Vessel pressure
P_{sat}	=	908	psia	Saturation pressure
ν	=	0.02127	ft^3/lb_m	Specific volume of the fluid initially in the pipe
V	=	135	ft^3	Inventory volume

(2) The postulated break location is at the nozzle safe-end to the pipe weld, which is located about 4.5 inches from the drywell side of the shield wall. A double-ended guillotine break was assumed. This is conservative because there is insufficient clearance for complete separation of the pipe and nozzle.

NOTE: The information presented in this table is based on original plant conditions.

Table 6A-3

REACTOR PRIMARY SYSTEM BLOWDOWN FLOW RATES AND
FLUID ENTHALPY - FEEDWATER LINE BREAK

TIME (s)	MASS FLOW (lb_m/s)	ENTHALPY (Btu/lb_m)
0.0	0	404.5
0.0001	20348	404.5
0.0217	20348	404.5
0.0218	18454	404.5
1.0	18454	404.5

NOTE: The information presented in this table is based on original plant conditions. The values in the table do provide a reasonable representation of the general blowdown characteristics.

Table 6A-4

FEEDWATER LINE BREAK BLOWDOWN MASS FLUX TIME HISTORY[1]

TIME (s)	MASS FLUX ($lb_m/s/ft^2$)	EFFECTIVE BREAK AREA (ft^2)
VESSEL SIDE:		
0.0001	18250	0.3717
0.0217	18250	0.3717
0.0218	18250	0.2679
1.0	18250	0.2679
SUPPLY PIPE SIDE[2]		
0.0001	18250	0.7433
1.0	18250	0.7433

(1) Listed below are some pertinent physical parameters used in the blowdown estimation

A	=	0.7433 ft^2		Minimum cross-sectional area between vessel and break
D	=	0.9728 ft		Pipe I.D. at the break location
h_o	=	404.5		Btu/lb_m Vessel enthalpy
L_l	=	12	ft	Inventory length
P_o	=	1053	psia	Vessel pressure
P_{sat}	=	326	psia	Saturation pressure
ν	=	0.01888	ft^3/lb_m	Specific volume of the feedwater
V	=	2.79	ft^3	Inventory volume

(1) The most restricted flow area on the feedwater supply pipe side is the break area itself. Full break area steady-state blowdown from this side is conservatively assumed to be reached immediately after the pipe rupture.

NOTE: The information presented in this table is based on original plant conditions. The values in the table do provide a reasonably represent the general characteristics of the blowdown mass flux time history.

Table 6A-5

HEAD SPRAY LINE BREAK[1][2]

TIME (s)	STEAM FLOW lb_m/s	STEAM ENTHALPY (Btu/lb)
0.0	506.8	1192
20.0	506.8	1192

(1) Head spray line break is based on 6 inch Schedule 80 pipe with Moody Blowdown corresponding to 2800 $lb_m/sec\text{-}ft^2$. Overall containment response is that of a "small break accident."

(2) This table is based on the original design basis power. the effects of rerate power conditions blowdown are shown in Figure 6A-11.

Table 6A-6

COMPARTMENT VOLUMES USED IN REACTOR VESSEL SHIELD ANNULUS SUBCOMPARTMENT ANALYSIS

COMPARTMENT NO.	DESIGNATION	VOLUME, ft^3
1	V1	54
2	V2	54
3	V3	54
4	V4	54
5	V5	54
6	V6	54
7	V7	54
8	V8	54
9	V9	54
10	V10	54
11	V11	54
12	V12	54
13	V13	69
14	V14	76
15	V15	75
16	V16	76
17	V17	76
18	V18	69
19	V19	69
20	V20	76
21	V21	75
22	V22	76
23	V23	76
24	V24	69
25	V25	59
26	V26	57
27	V27	57
28	V28	57
29	V29	57
30	V30	57
31	V31	57
32	V32	57
33	V33	57
34	V34	57
35	V35	57
36	V36	59
37	V37	60
38	V38	58
39	V39	60
40	V40	76
41	V41	58

Table 6A-6 (Cont'd)

COMPARTMENT NO.	DESIGNATION	VOLUME, ft^3
42	V42	60
43	V43	76
44	V44	58
45	V45	60
46	V46	76
47	V47	58
48	V48	60
49	V49	77
50	V50	71
51	V51	73
52	V52	77
53	V53	75
54	V54	77
55	V55	77
56	V56	74
57	V57	77
58	V58	73
59	V59	71
60	V60	77
61	V61	34
62	V62	34
63	V63	34
64	V64	34
65	V65	34
66	V66	34
67	V67	34
68	V68	34
69	V69	34
70	V70	34
71	V71	34
72	V72	34
73	V73	235200

Table 6A-7

FLOW AREA AND COEFFICIENTS USED IN
REACTOR VESSEL SHIELD ANNULUS SUBCOMPARTMENT ANALYSIS

FLOW PATHS	FLOW AREA (ft^2)	K FACTOR	DESCRIPTION	L/A (ft^{-1})	FLOW COEFFICIENT
1-2,1-12, 2-3,3-4, 4-5,5-6, 6-7,7-8, 8-9,9-10,		0.13	30° turn		
10-11,11-12	10	1.0	Final expansion	0.62	0.94
1-13,2-14, 3-15,4-16, 5-17,6-18, 7-19,8-20, 9-21,10-22,		0.05	Friction		
11-23,12-24	8.5	1.0	Final expansion	1.01	0.97
2-73,3-73, 5-73,6-73, 8-73,9-73,		0.42	Contraction		
11-73,12-73	2	1.0	Final expansion	0.73	0.83
		0.13	30° turn		
13-24,		1.12	Around pipe		
18-19	9.5	1.0	Final expansion	0.54	0.66
13-14,15-16, 16-17,17-18, 19-20,20-21,		0.13	30° turn		
		0.1	Around pipe		
22-23,23-24	13	1.0	Final expansion	0.43	0.9
		0.1	Around pipe		
		0.1	Around instrument pipe		
14-15,		0.13	30° turn		
21-22	12	1.0	Final expansion	0.43	0.86
		1.35	Around pipe		
13-25,18-30,		0.28	Around pipe		
19-31,24-36	4.5	1.0	Final expansion	1.57	0.61
14-26,16-28,		0.28	Around pipe		
17-29,20-32,		0.28	Around pipe		
22-34,23-35,	5.5	1.0	Final expansion	1.17	0.8

Table 6A-7 (Cont'd)

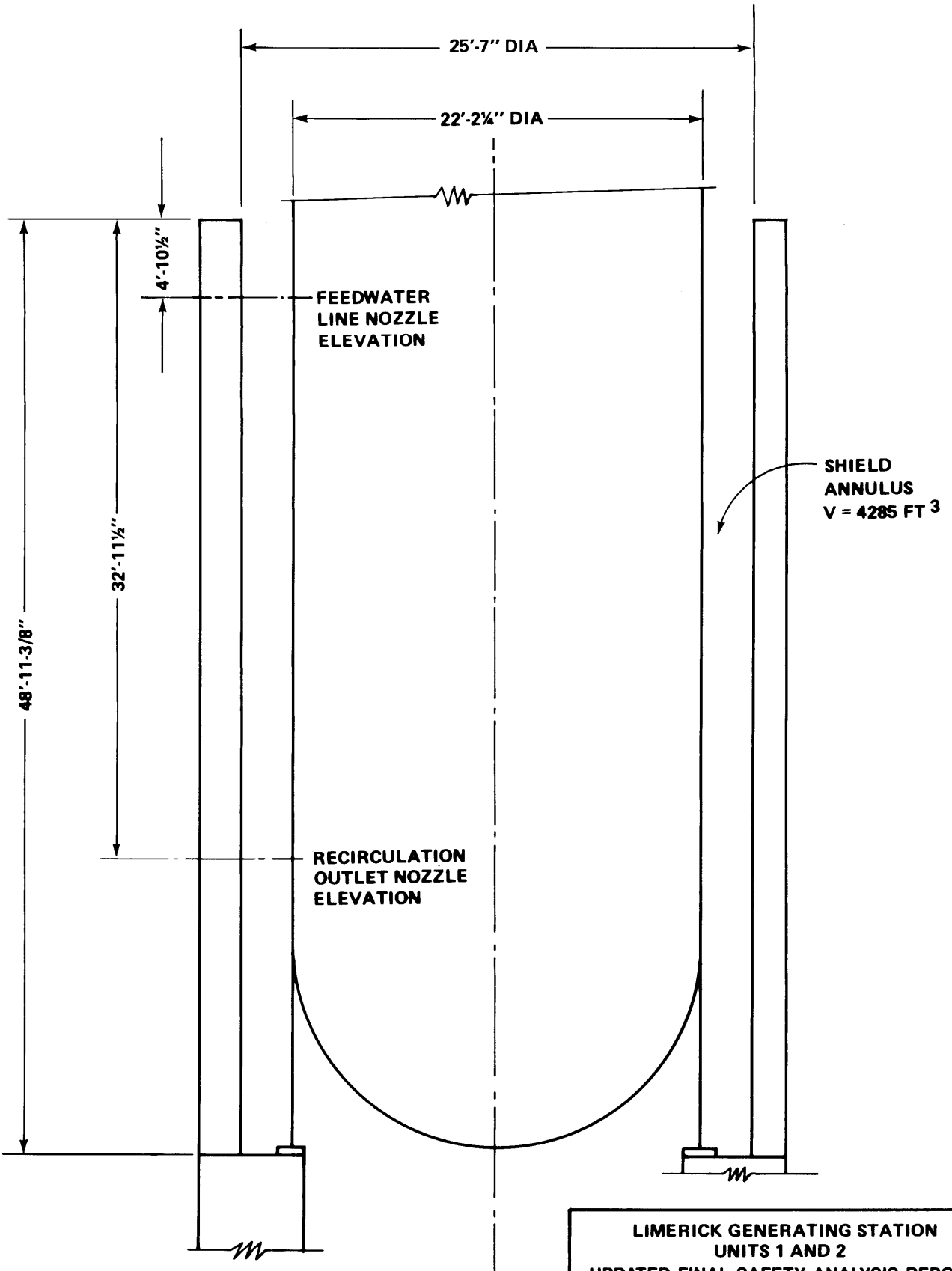
FLOW PATHS	FLOW AREA (ft^2)	K FACTOR	DESCRIPTION	L/A (ft^{-1})	FLOW COEFFICIENT
		0.28	Around pipe		
		0.28	Around pipe		
15-27,		0.31	Around pipe		
21-33	4.5	1.0	Final expansion	1.31	0.73
25-36,		0.13	30° turn		
30-31	11	1.0	Final expansion	0.55	0.94
25-26,26-27, 27-28,28-29, 29-30,31-32,		0.13	30° turn		
32-33,33-34,		0.16	Around pipe		
34-35,35-36,	9.5	1.0	Final expansion	0.58	0.88
25-37,26-38, 27-39,28-40, 29-41,30-42, 31-43,32-44, 33-45,34-46,		0.07	Friction		
33-47,36-48	8.5	1.0	Final expansion	0.92	0.96
		0.13	30° turn		
37-48,38-39		0.01	Around instrument pipe		
41-42,45-46	10.5	1.0	Final expansion	0.55	0.93
		0.13	30° turn		
37-38,40-41,		0.16	Around pipe		
44-45,47-48	9.5	1.0	Final expansion	0.57	0.88
39-40,42-43,		0.13	30° turn		
43-44,46-47	11	1.0	Final expansion	0.55	0.94
		0.01	Around instrument pipe		
37-49,		0.07	Friction		
48-60	8	1.0	Final expansion	1.07	0.96
38-50,41-53,		1.11	Around pipe		
44-56,47-59	6	1.0	Final expansion	1.14	0.68
39-51,42-54,		0.08	Around instrument pipe		
45-57	8	1.0	Final expansion	1.07	0.96

Table 6A-7 (Cont'd)

FLOW PATHS	FLOW AREA (ft^2)	K FACTOR	DESCRIPTION	L/A (ft^{-1})	FLOW COEFFICIENT
40-52,43-55		0.07	Around pipe		
46-58	8.5	1.0	Final expansion	1.06	0.96
		0.13	30° turn		
		0.15	Around pipe		
49-50		0.15	Around pipe		
59-60	11.5	1.0	Final expansion	0.46	0.83
		0.125	30° turn		
		0.01	Around instrument pipe		
49-60	14	1.0	Final expansion	0.42	0.93
		0.13	30° turn		
		0.01	Around instrument pipe		
		0.47	Around pipe		
50-51	10.5	1.0	Final expansion	0.48	0.78
		0.13	30° turn		
51-52,52-53,		0.15	Around pipe		
56-57	13	1.0	Final expansion	0.44	0.88
		0.13	30° turn		
		0.01	Around instrument pipe		
		0.15	Around pipe		
53-54,57-58	12.5	1.0	Final expansion	0.45	0.88
		0.13	30° turn		
54-55	14.5	1.0	Final expansion	0.42	0.94
		0.13	30° turn		
		0.15	Around pipe		
		0.12	Around CRD		
		0.15	Around pipe		
55-56	10.5	1.0	Final expansion	0.5	0.8
		0.13	30° turn		
		0.47	Around pipe		
58-59	11	1.0	Final expansion	0.47	0.79
49-61,52-64,					
53-65,55-67,		0.49	Around pipe		
57-69	6.5	1.0	Final expansion	0.96	0.81

Table 6A-7 (Cont'd)

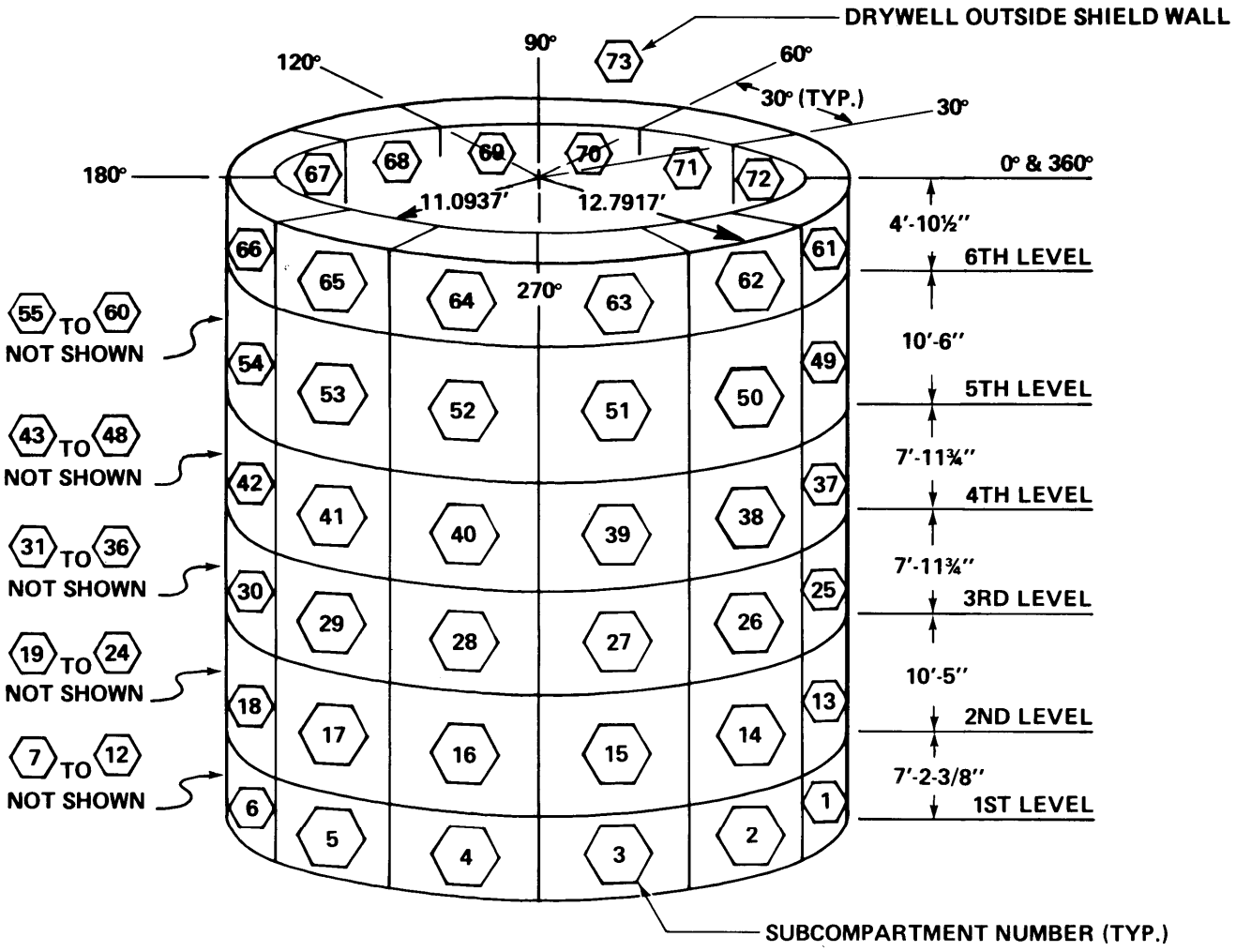
FLOW PATHS	FLOW AREA (ft^2)	K FACTOR	DESCRIPTION	L/A (ft^{-1})	FLOW COEFFICIENT
		0.49	Around pipe		
54-66,		0.08	Around instrument pipe		
60-72	6	1.0	Final expansion	1.0	0.79
		0.49	Around pipe		
		0.17	Around CRD		
56-68	5.5	1.0	Final expansion	1.07	0.77
		0.11	30° turn		
61-62,63-64		0.96	Around pipe		
67-68,69-70	5	1.0	Final expansion	1.03	0.69
61-72,62-63					
64-65,66-67		0.11	30° turn		
68-69,70-71	6.5	1.0	Final expansion	0.9	0.94
		0.11	30° turn		
		0.96	Around pipe		
65-66,		0.1	Around instrument pipe		
71-72	4.5	1.0	Final expansion	1.1	0.67
61-73,63-73					
64-73,66-73					
67-73,69-73		0.12	Contraction		
70-73,72-73	6	1.0	Final expansion	0.28	0.94
62-73,65-73		0.05	Contraction		
68-73,71-73	7.5	1.0	Final expansion	0.28	0.97
		0.49	Around pipe		
50-62,51-63,		0.49	Around pipe		
58-70,59-71	5	1.0	Final expansion	1.28	0.71



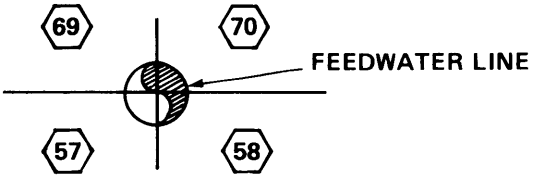
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR SHIELD ANNULUS ARRANGEMENT

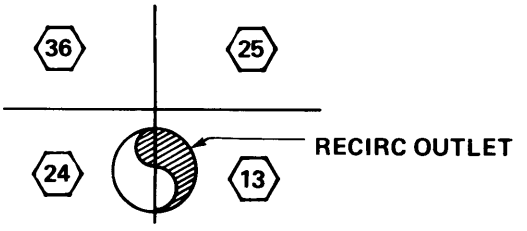
FIGURE 6A-1



FEEDWATER PIPE BREAK IN SUBCOMPARTMENTS 57, 58, 69 AND 70



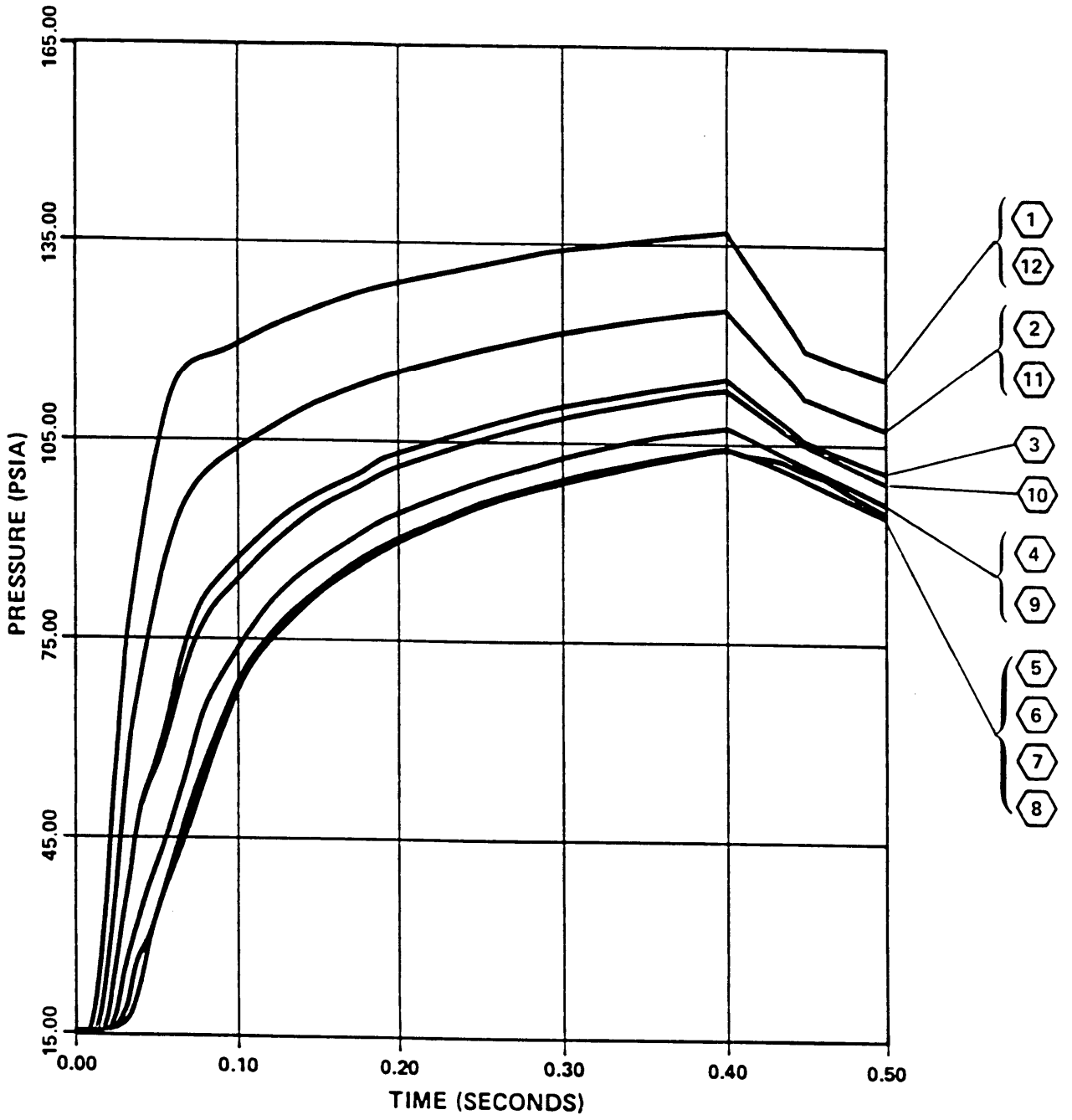
RECIRCULATION OUTLET PIPE BREAK IN SUBCOMPARTMENTS 13 AND 24



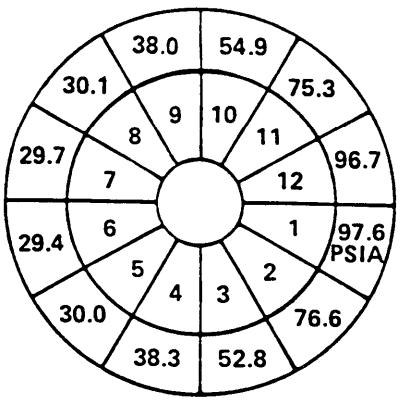
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UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR SHIELD ANNULUS SUBCOMPARTMENT MODEL SCHEMATIC

FIGURE 6A-2



NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the pressure transient.



1ST LEVEL

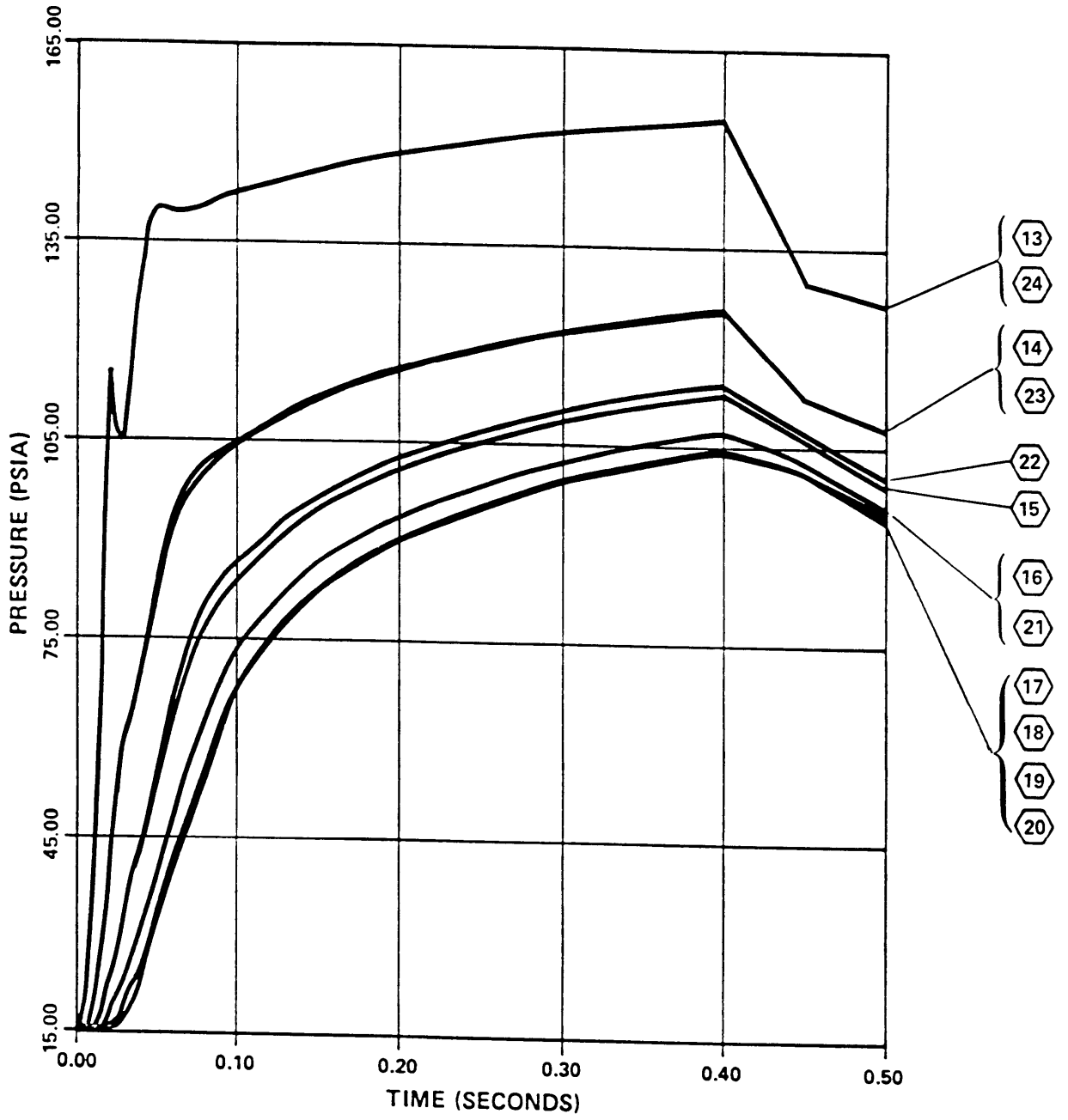
THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC, PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

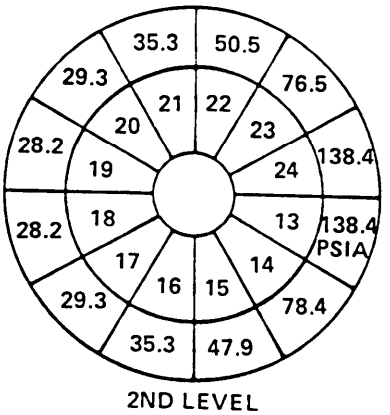
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE SAFE END

SHEET 1 OF 6

FIGURE 6A-3 Rev. 5, 4/96



NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the pressure transient.



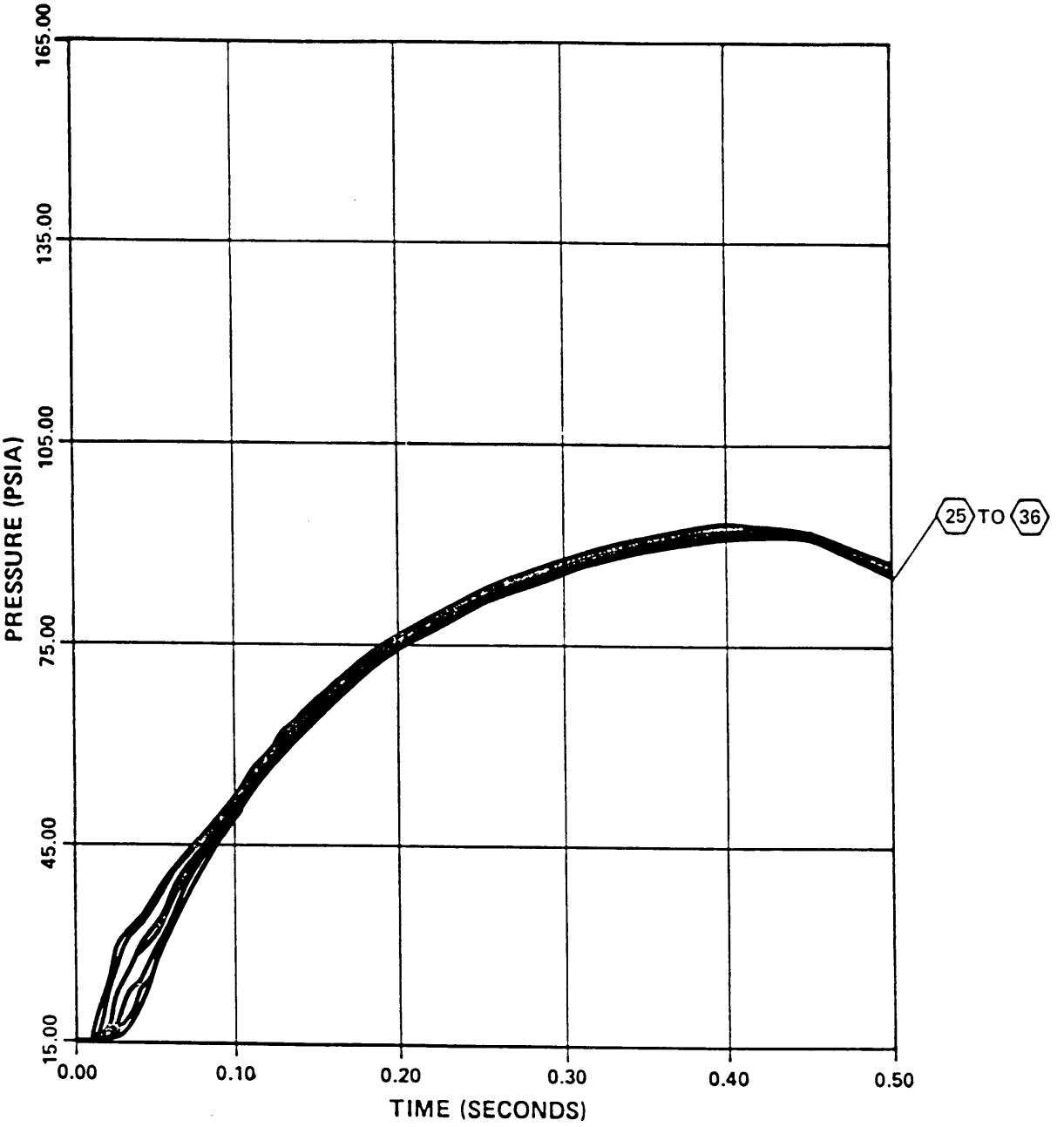
THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC, PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

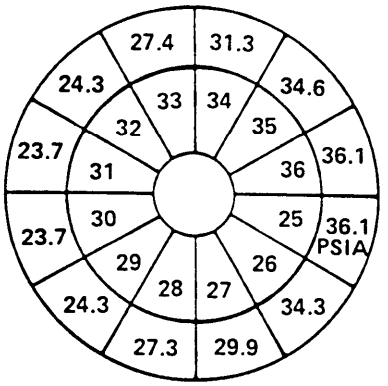
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE SAFE END

SHEET 2 OF 6

FIGURE 6A-3 Rev. 5, 4/96



NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the pressure transient.



3RD LEVEL

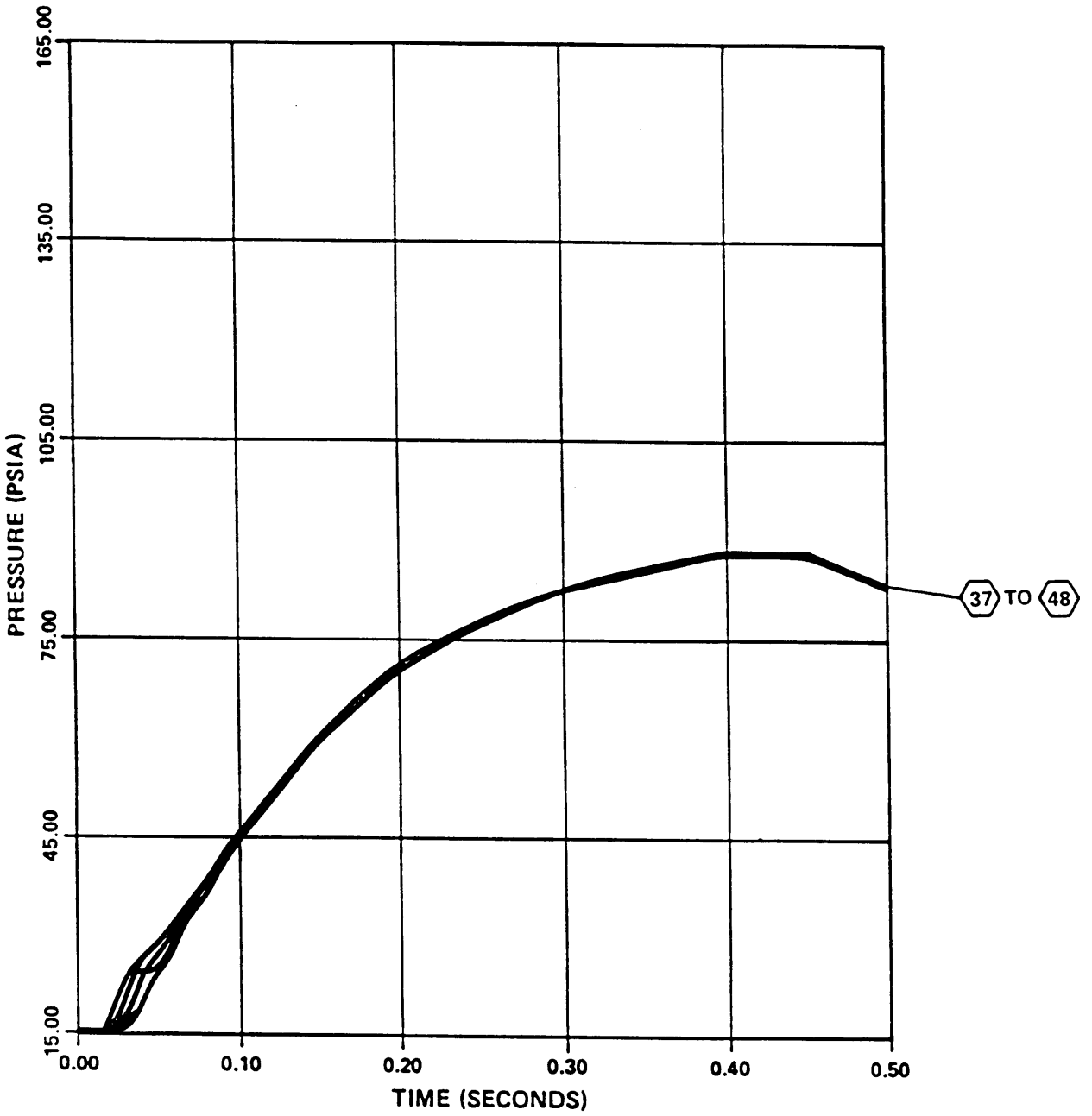
THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC, PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

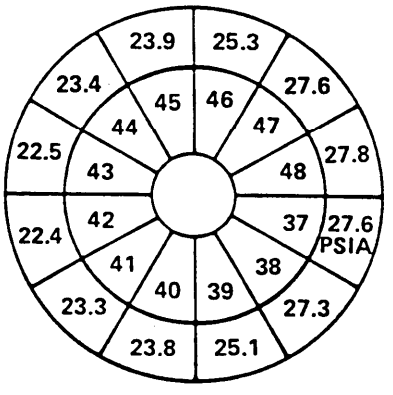
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE SAFE END

SHEET 3 OF 6

FIGURE 6A-3 Rev. 5, 4/96



NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the pressure transient.



4TH LEVEL

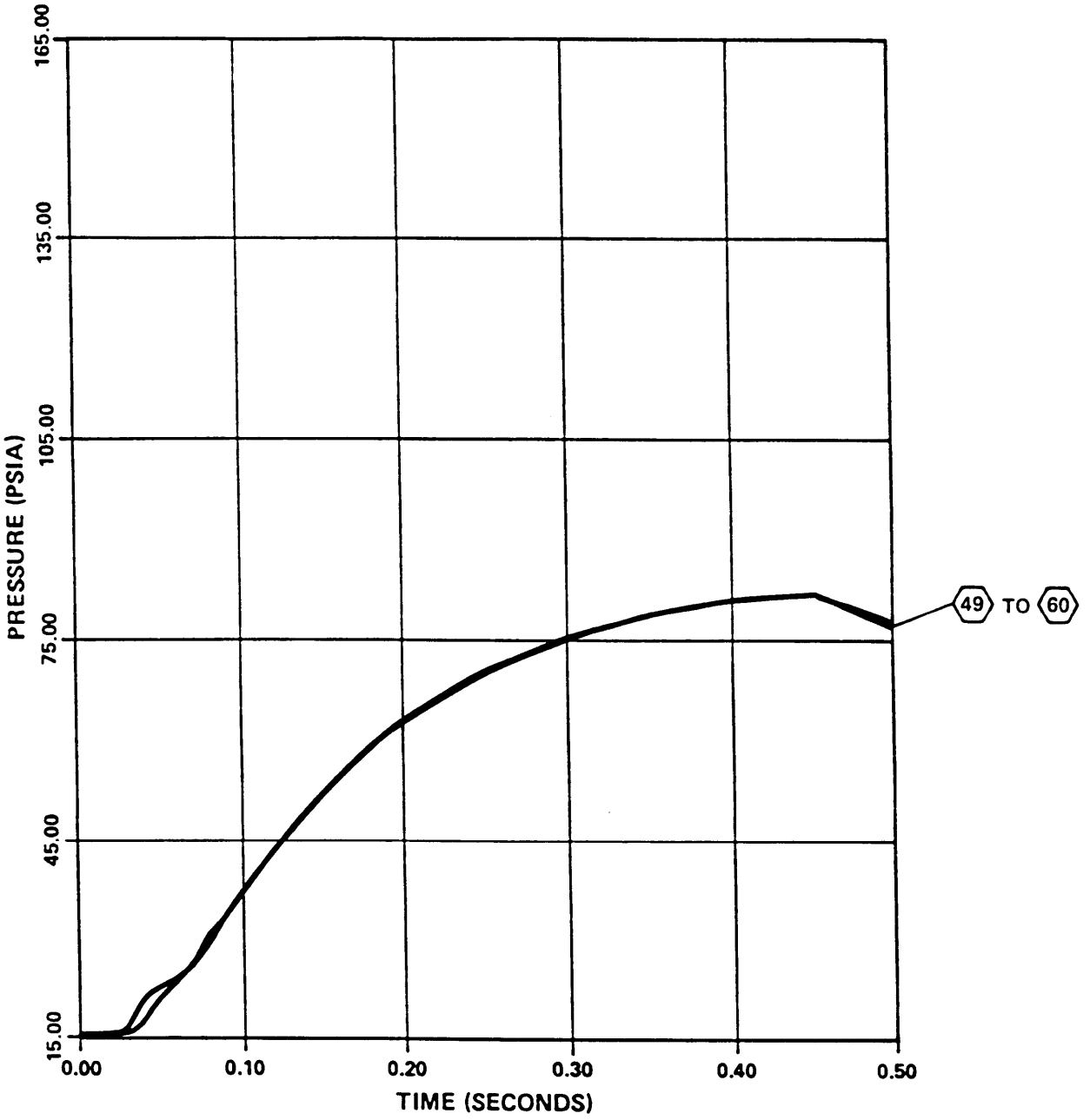
THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC, PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

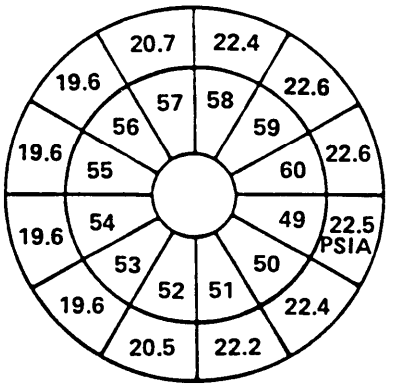
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE SAFE END

SHEET 4 OF 6

FIGURE 6A-3 Rev. 5, 4/96



NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the pressure transient.



5TH LEVEL

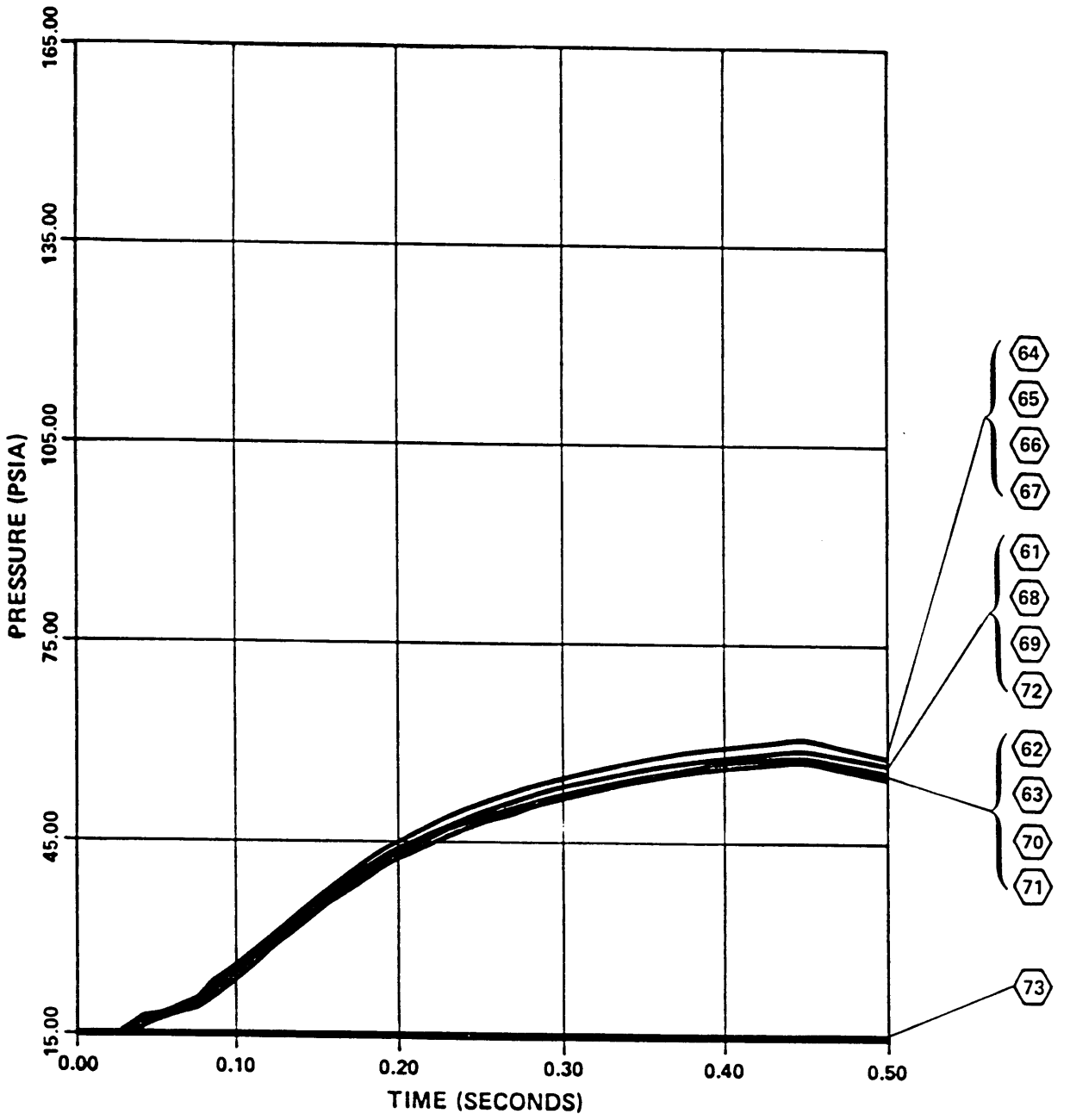
THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC, PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

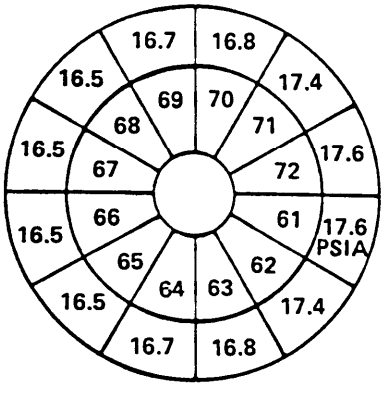
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE SAFE END

SHEET 5 OF 6

FIGURE 6A-3 Rev. 5, 4/96



NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the pressure transient.



6TH LEVEL

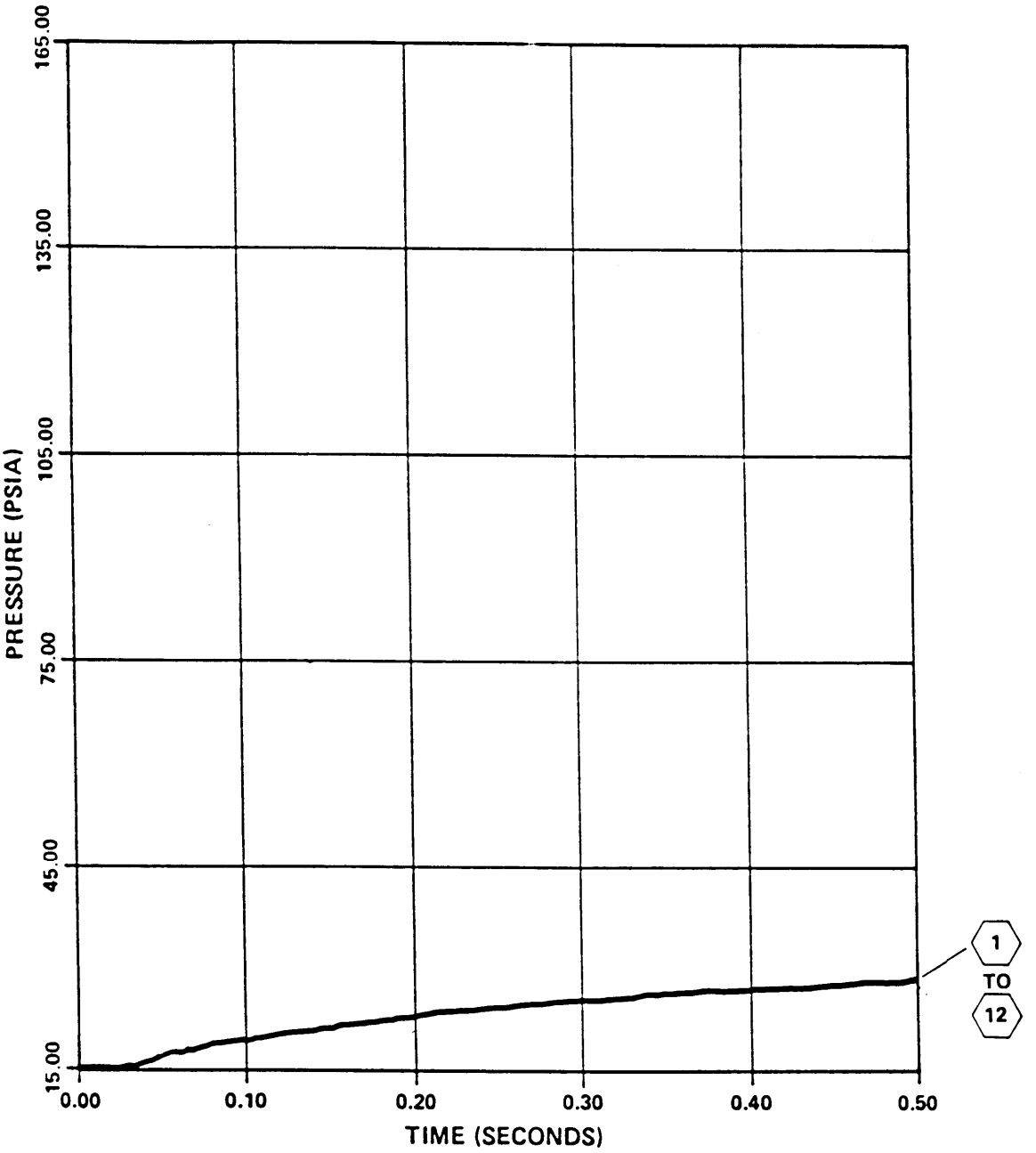
THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC, PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

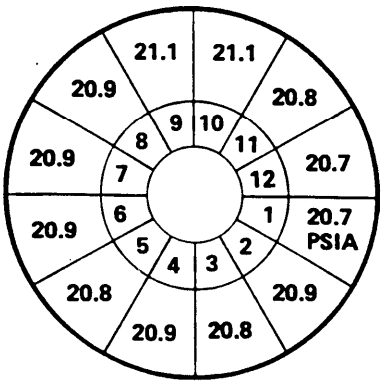
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE SAFE END

SHEET 6 OF 6

FIGURE 6A-3 Rev. 5, 4/96



NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the pressure transient.



1ST LEVEL

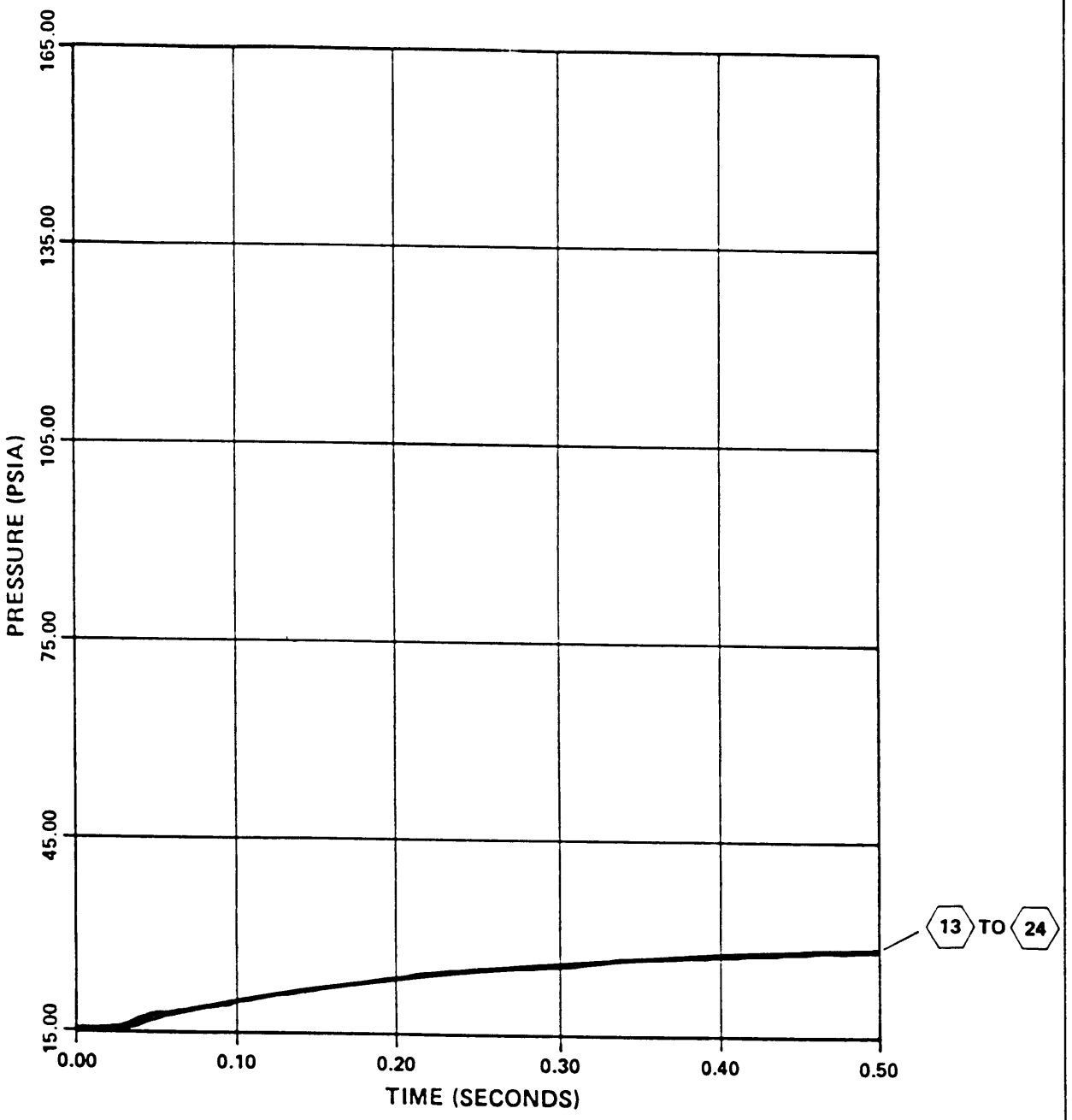
THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.14 SECONDS, PRODUCING THE MAX DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

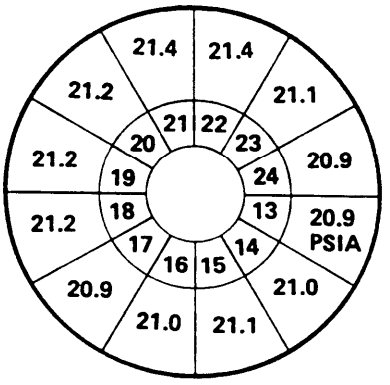
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE SAFE END

SHEET 1 OF 6

FIGURE 6A-4 Rev. 5, 4/96





NOTE:

2ND LEVEL

THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.14 SECONDS, PRODUCING THE MAX DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the pressure transient.

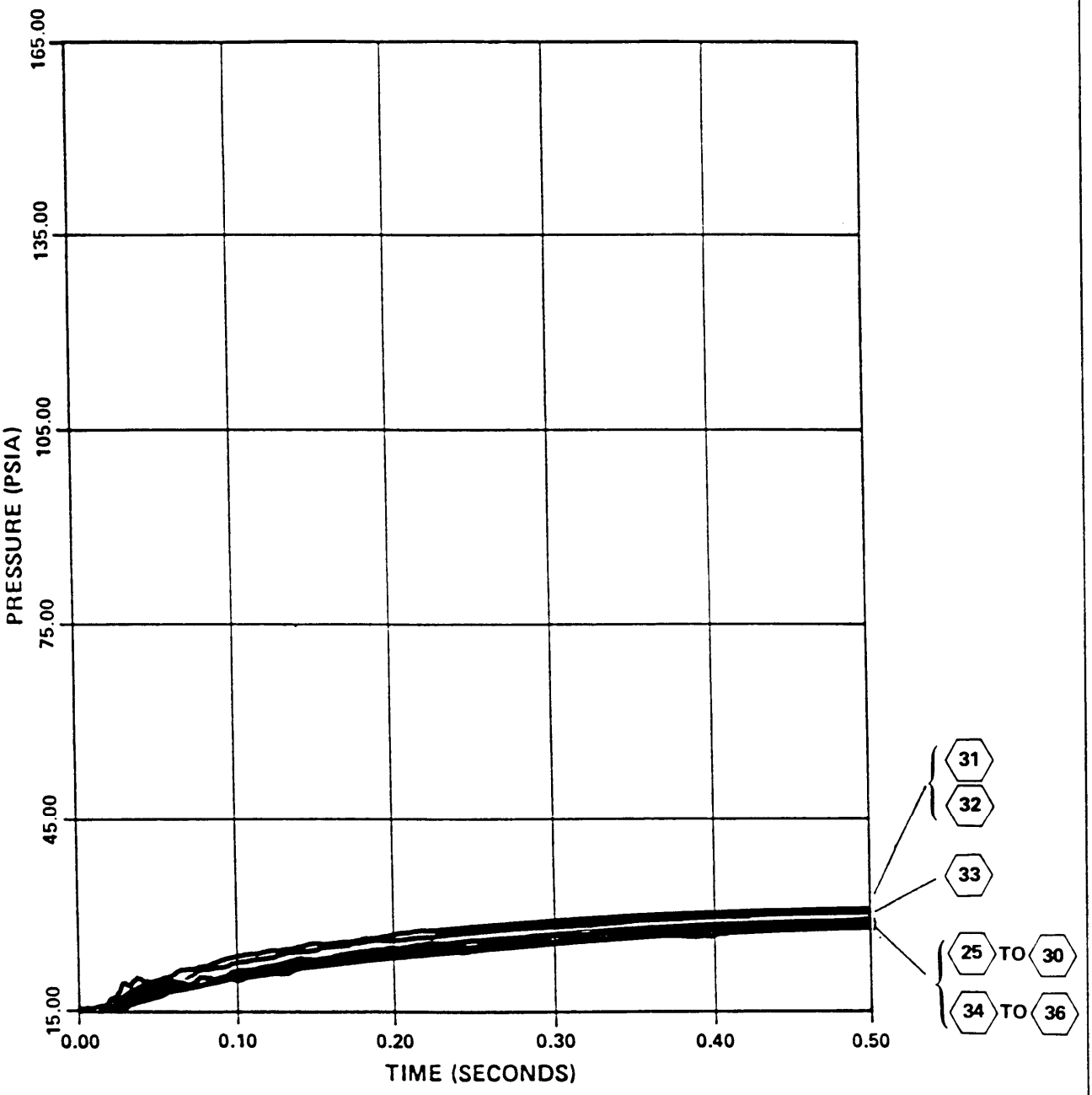
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE SAFE END

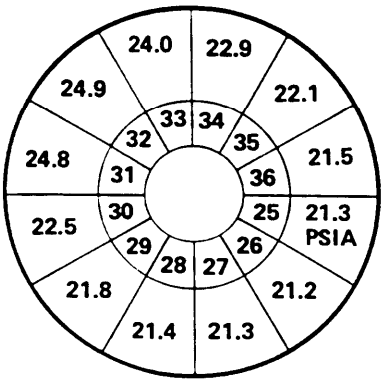
SHEET 2 OF 6

FIGURE 6A-4

Rev. 5, 4/96



NOTE: The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the pressure transient.



3RD LEVEL

THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.14 SECONDS, PRODUCING THE MAX DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

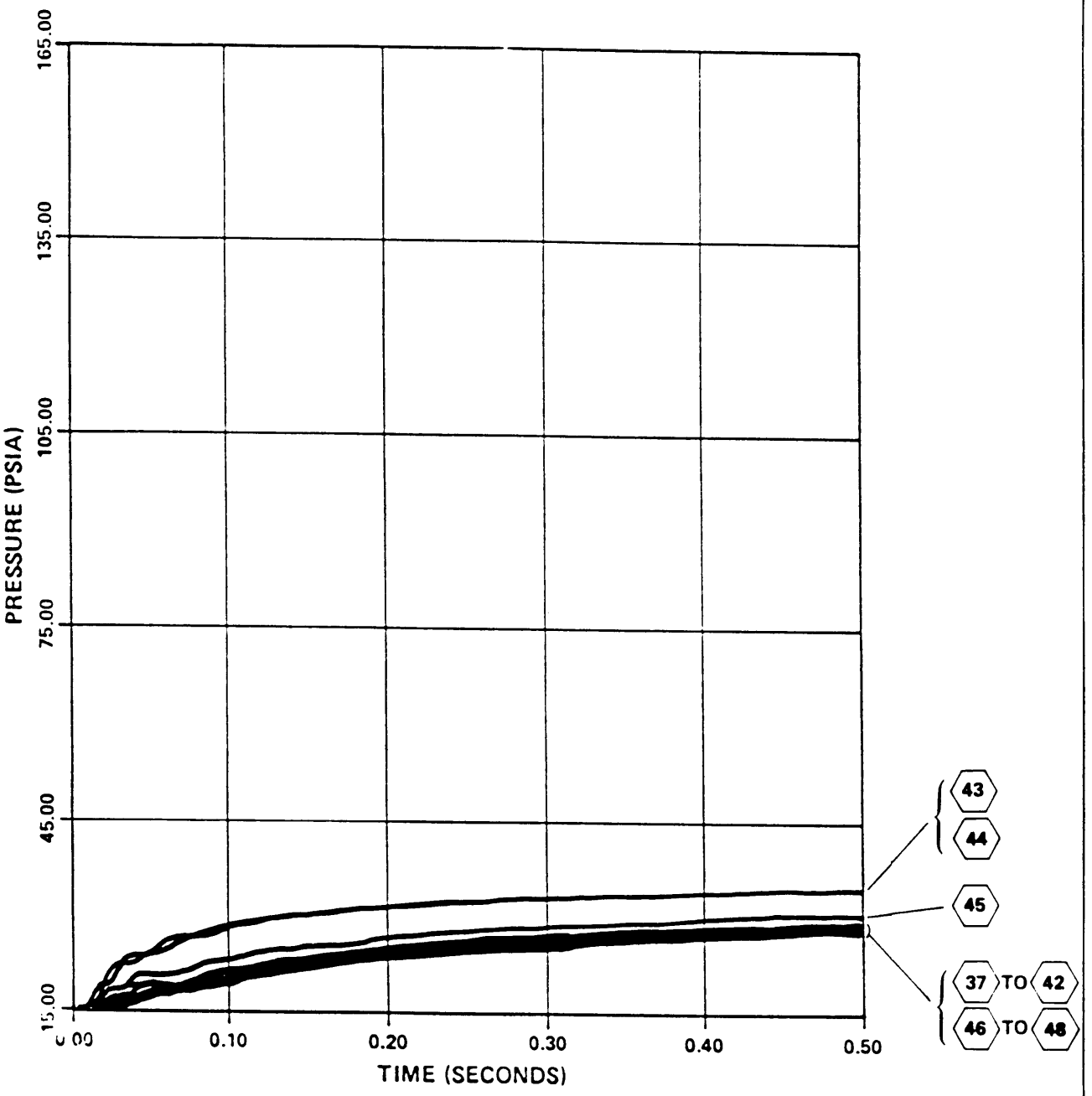
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE SAFE END

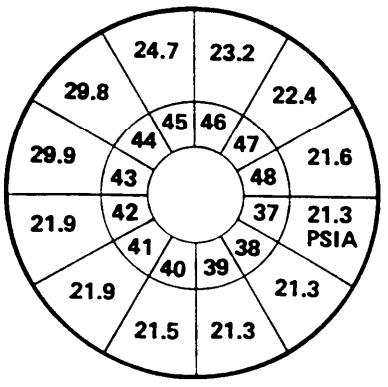
SHEET 3 OF 6

FIGURE 6A-4

Rev. 5, 4/96



NOTE: The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the pressure transient.



FOURTH LEVEL

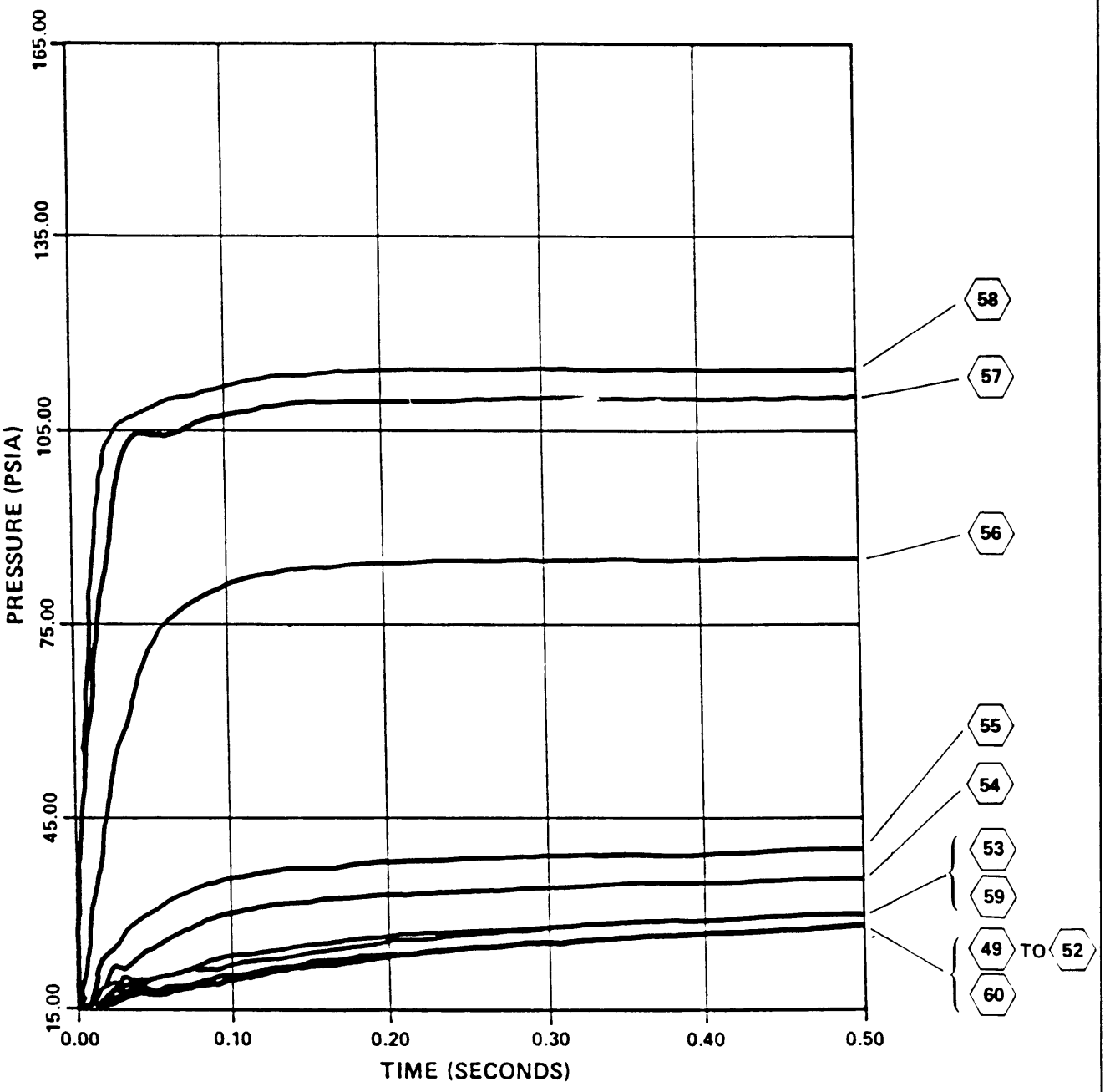
THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.14 SECONDS, PRODUCING THE MAX DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

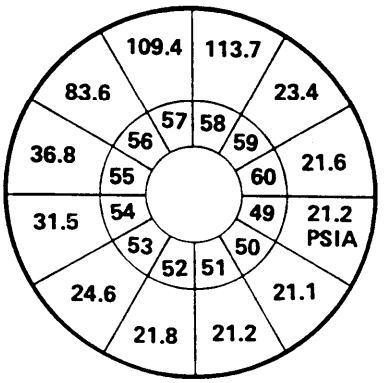
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE SAFE END

SHEET 4 OF 6

FIGURE 6A-4 Rev. 5, 4/96



NOTE: The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the pressure transient.



5TH LEVEL

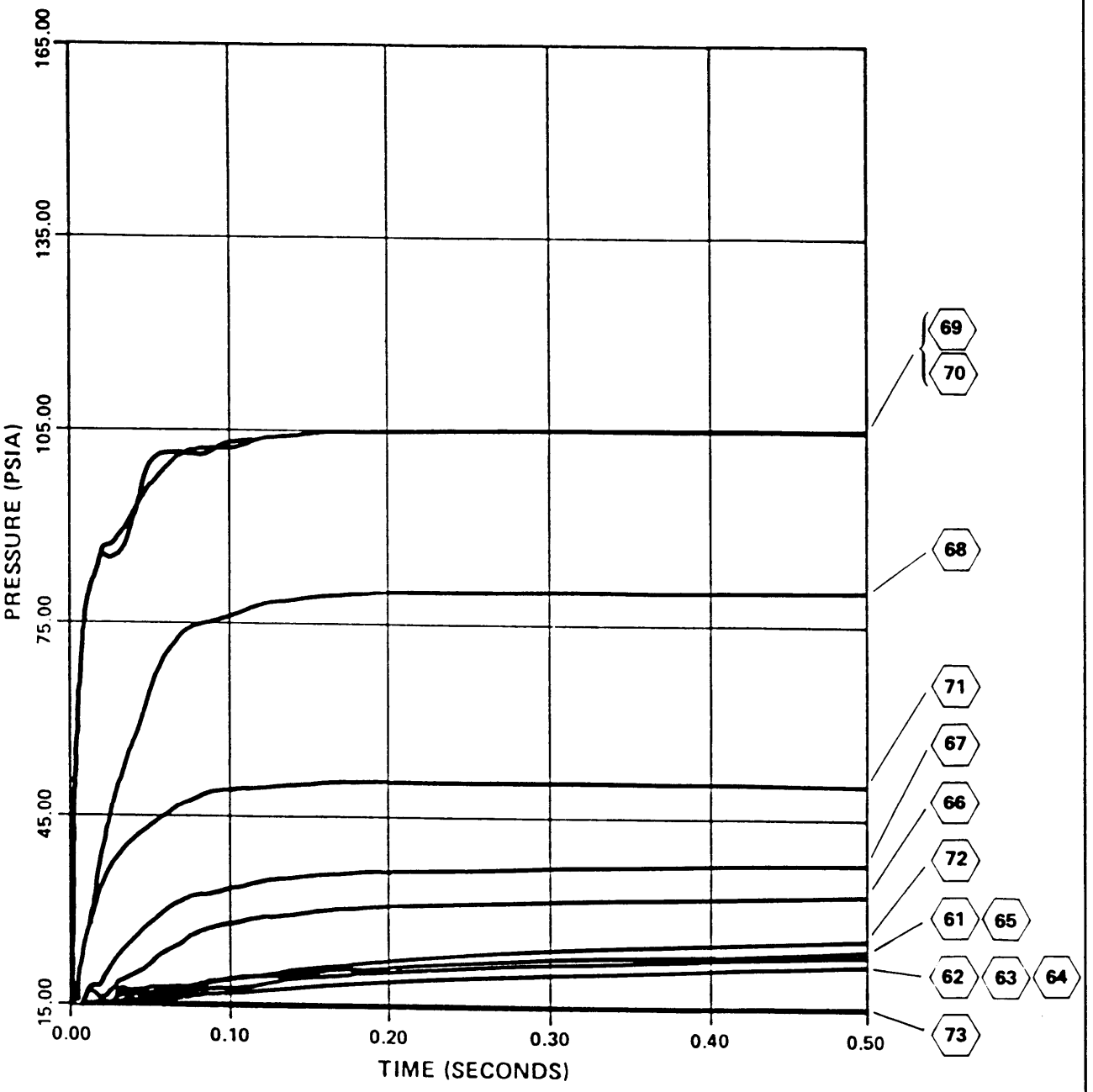
THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.14 SECONDS, PRODUCING THE MAX DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

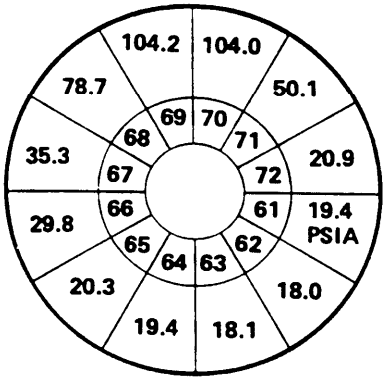
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE SAFE END

SHEET 5 OF 6

FIGURE 6A-4 Rev. 5, 4/96



NOTE: The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the pressure transient.



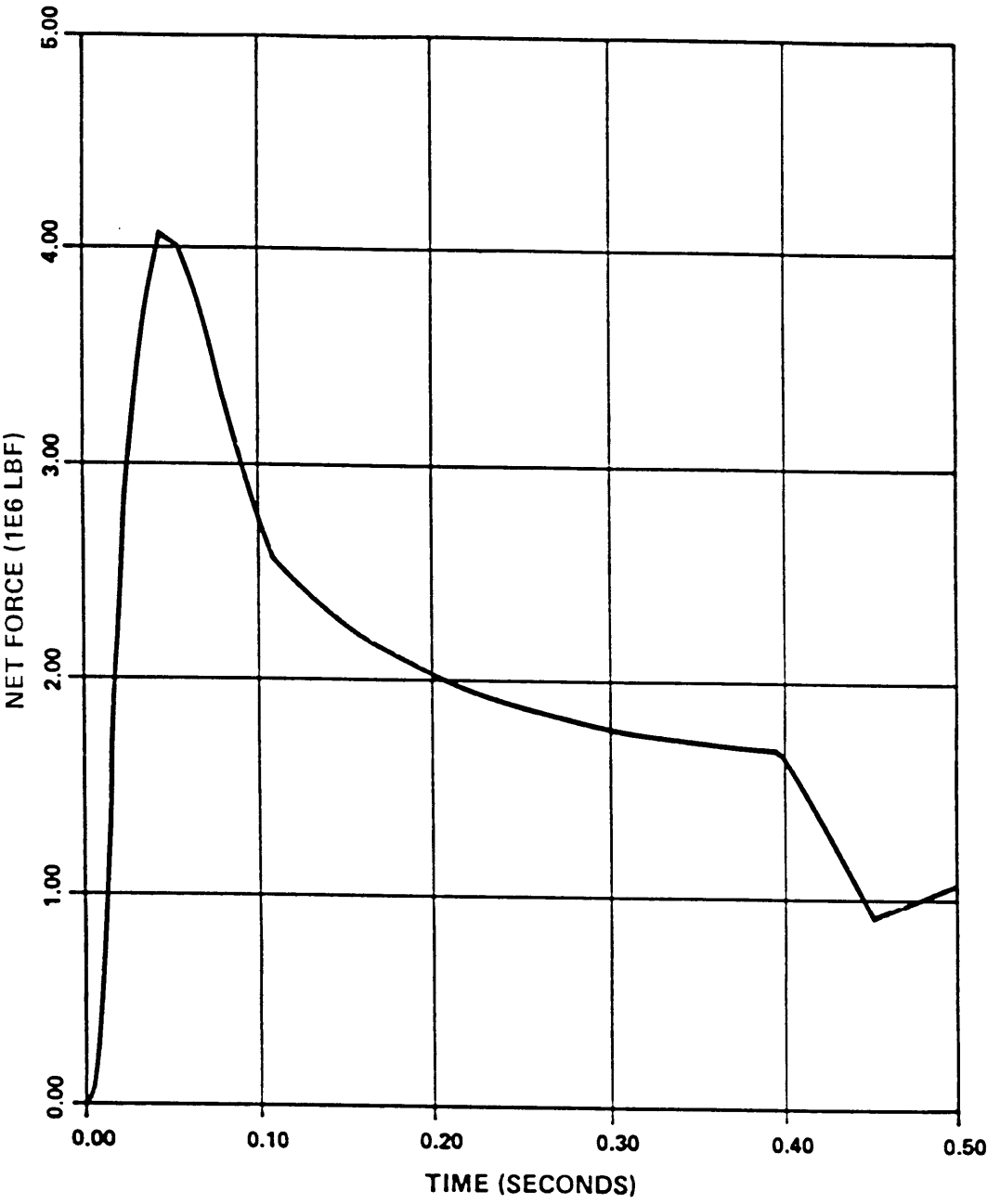
THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.14 SECONDS, PRODUCING THE MAX DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

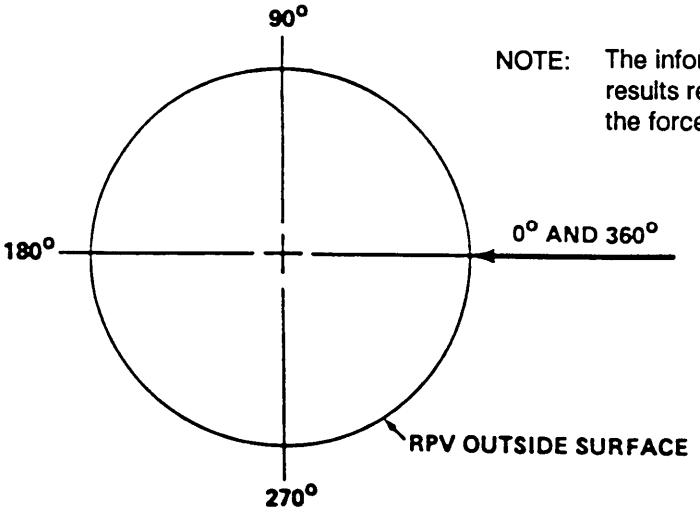
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE SAFE END

SHEET 6 OF 6

FIGURE 6A-4 Rev. 5, 4/96



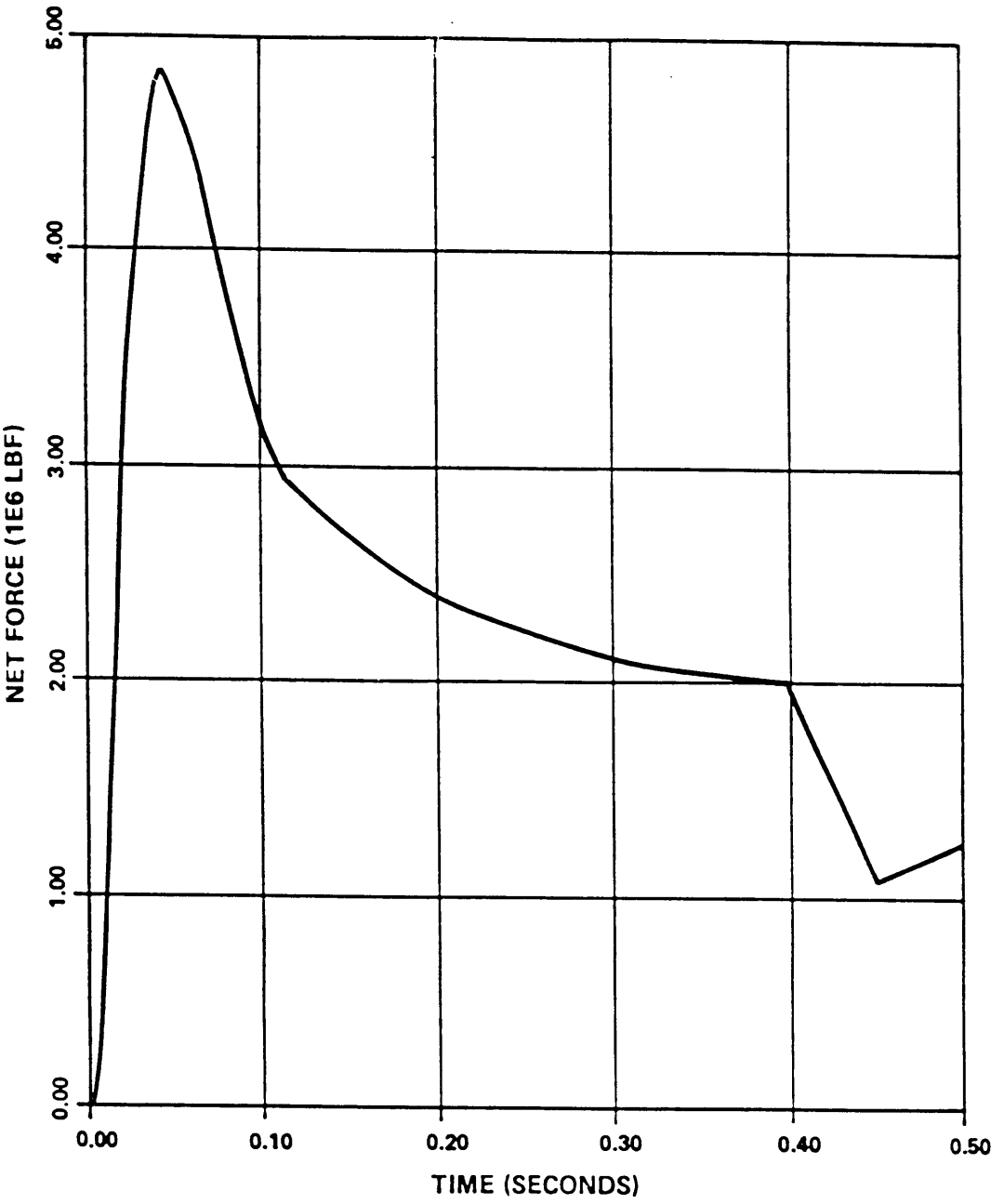


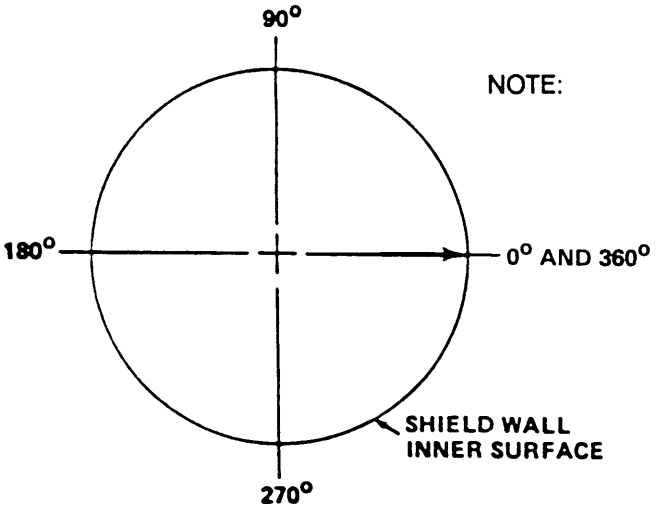
NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the force transient.

LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

FORCE TRANSIENT ON REACTOR VESSEL FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE

FIGURE 6A-5 Rev. 5, 4/96





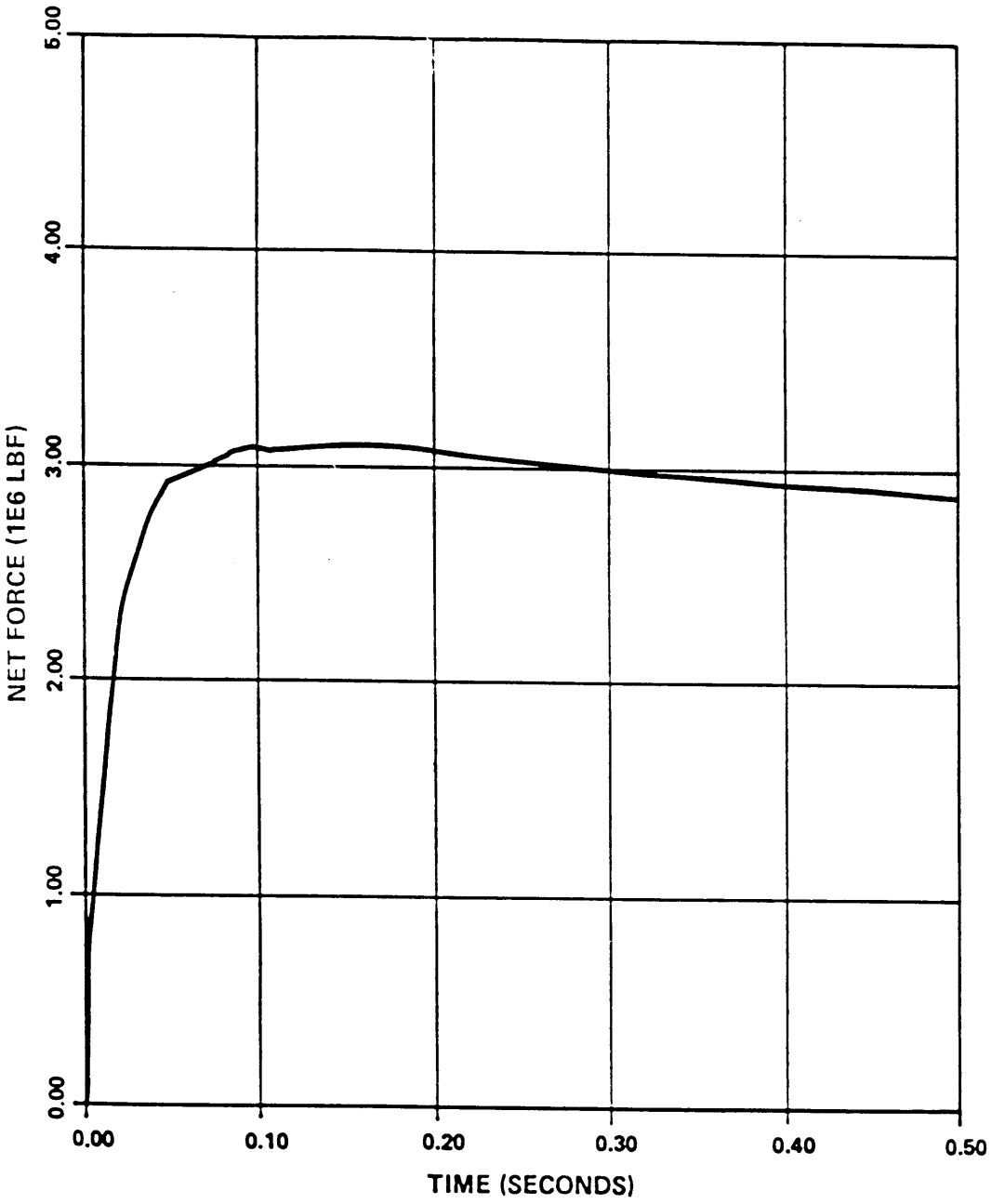
NOTE: The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the force transient.

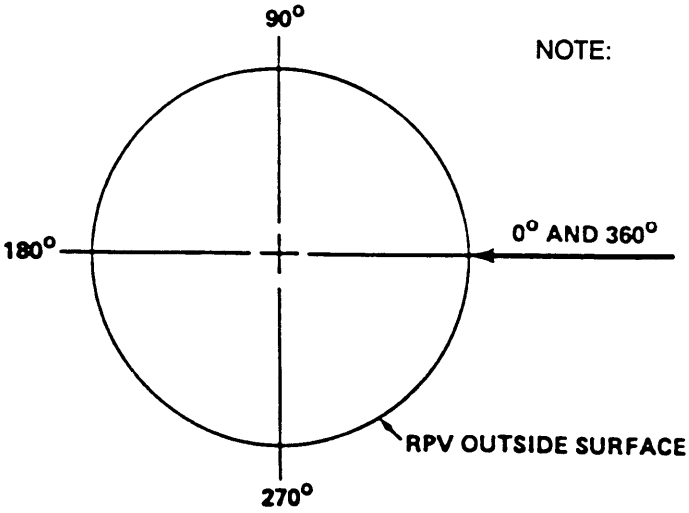
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FORCE TRANSIENT ON REACTOR SHIELD WALL FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE

FIGURE 6A-6

Rev. 5, 4/96



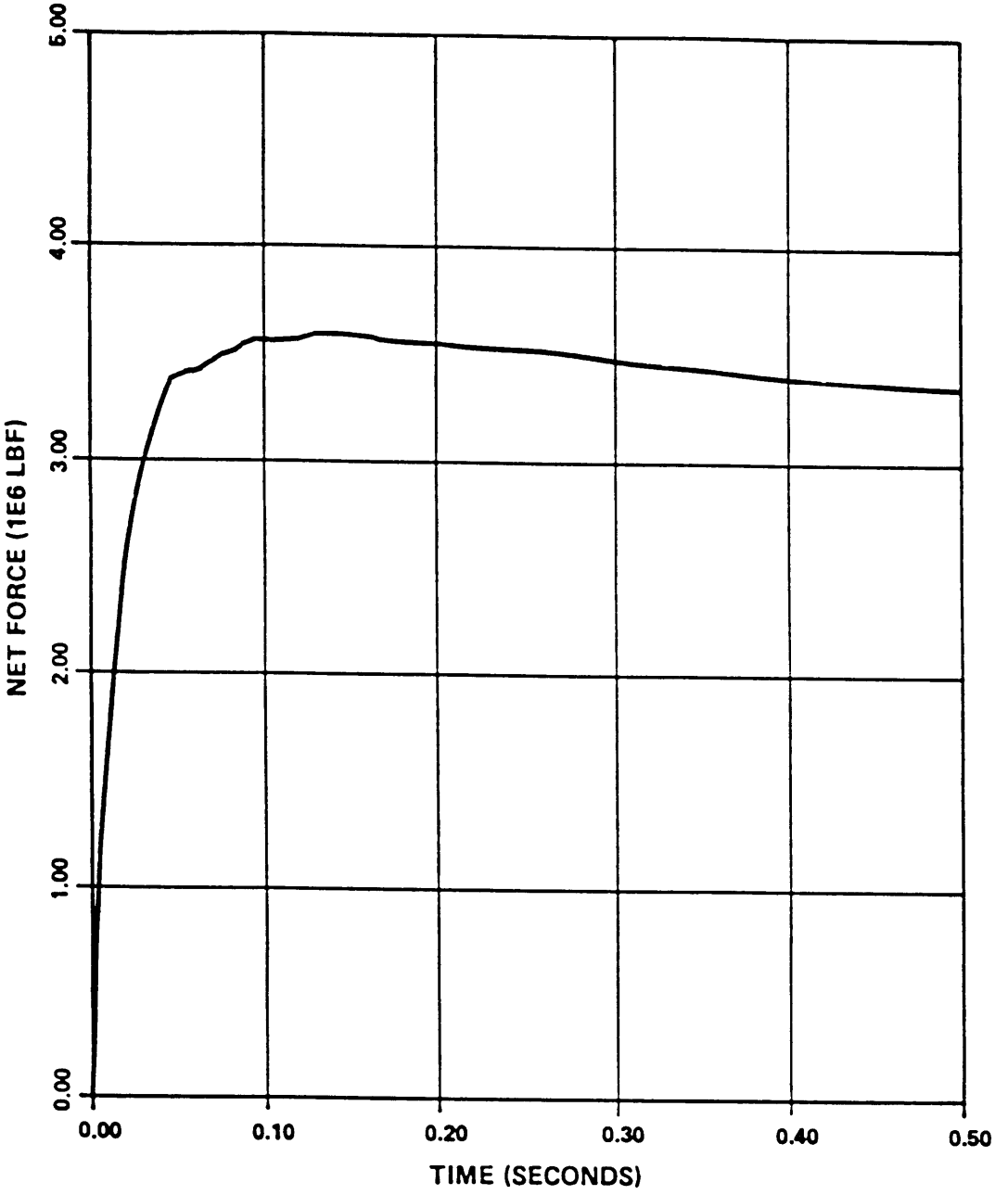


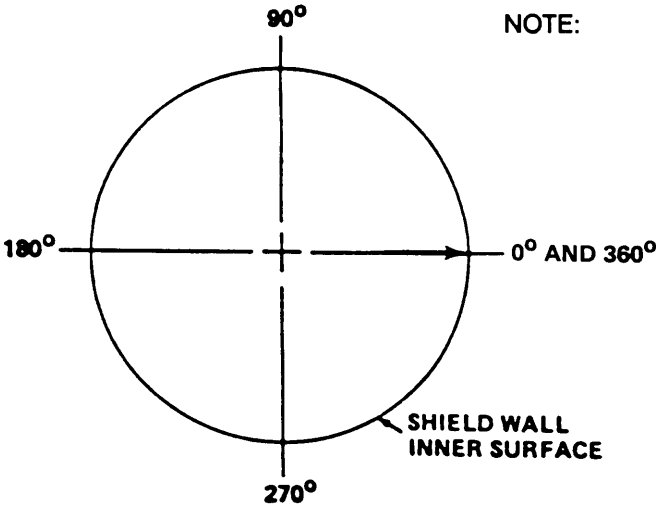
NOTE: The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the force transient.

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FORCE TRANSIENT ON REACTOR VESSEL FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE

FIGURE 6A-7 Rev. 5, 4/96





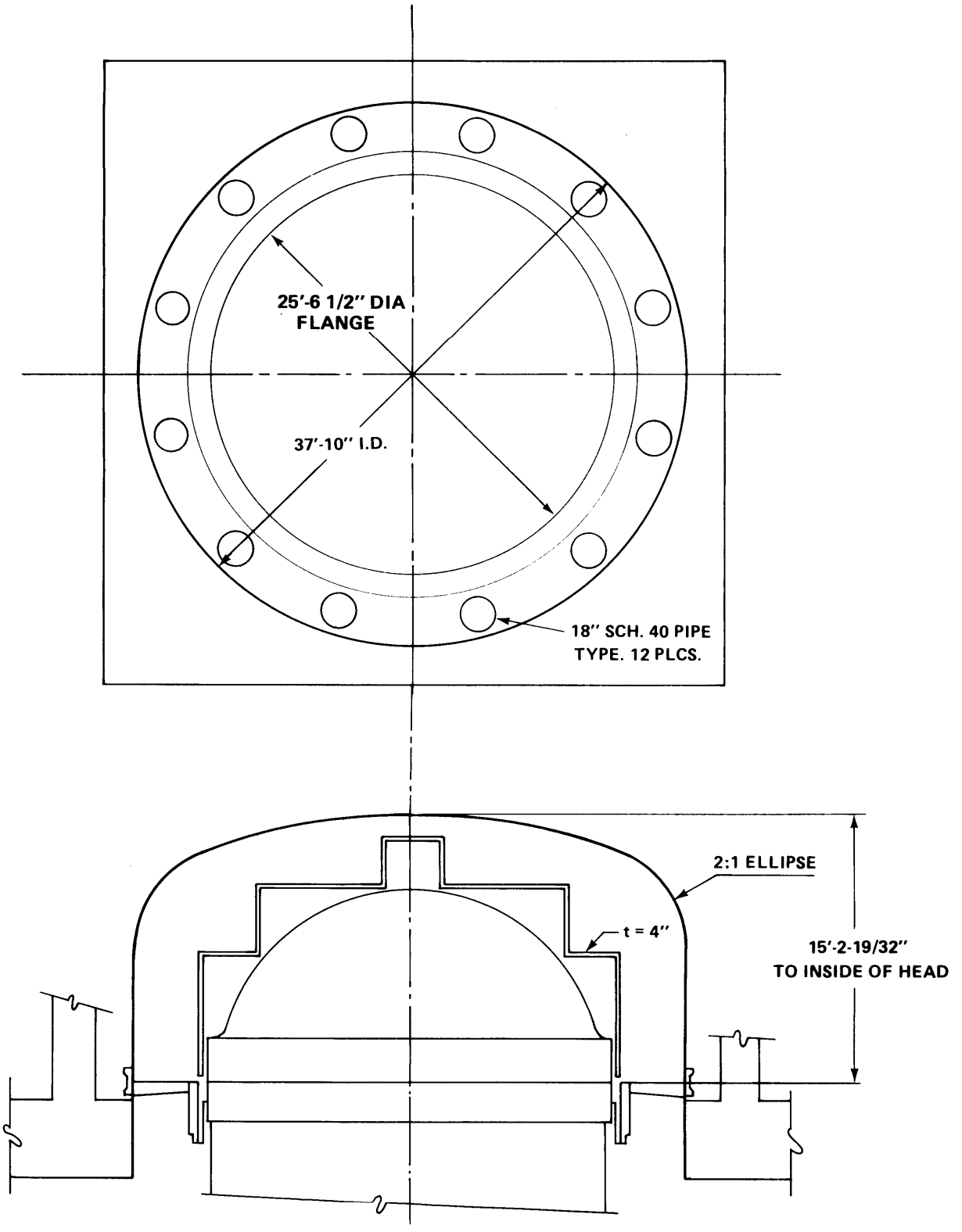
NOTE: The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the force transient.

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FORCE TRANSIENT ON REACTOR SHIELD WALL FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE

FIGURE 6A-8

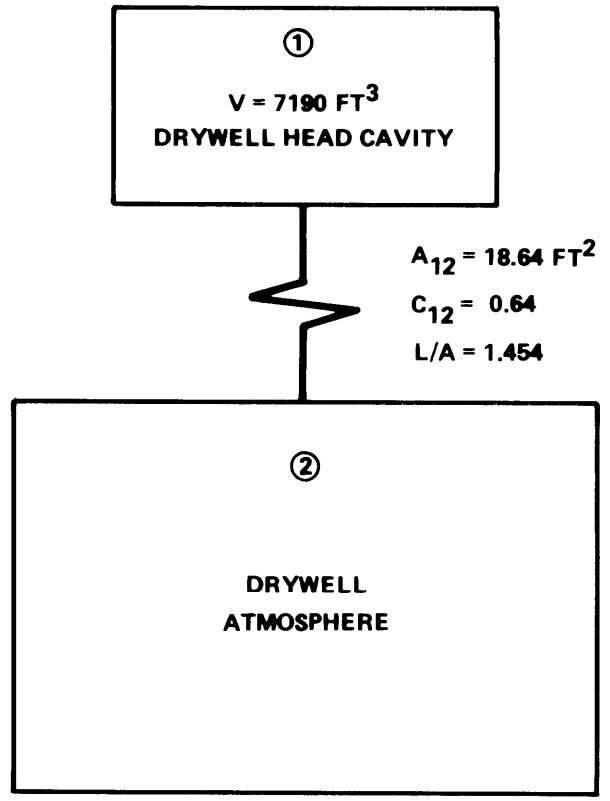
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DRYWELL HEAD ARRANGEMENT

FIGURE 6A-9

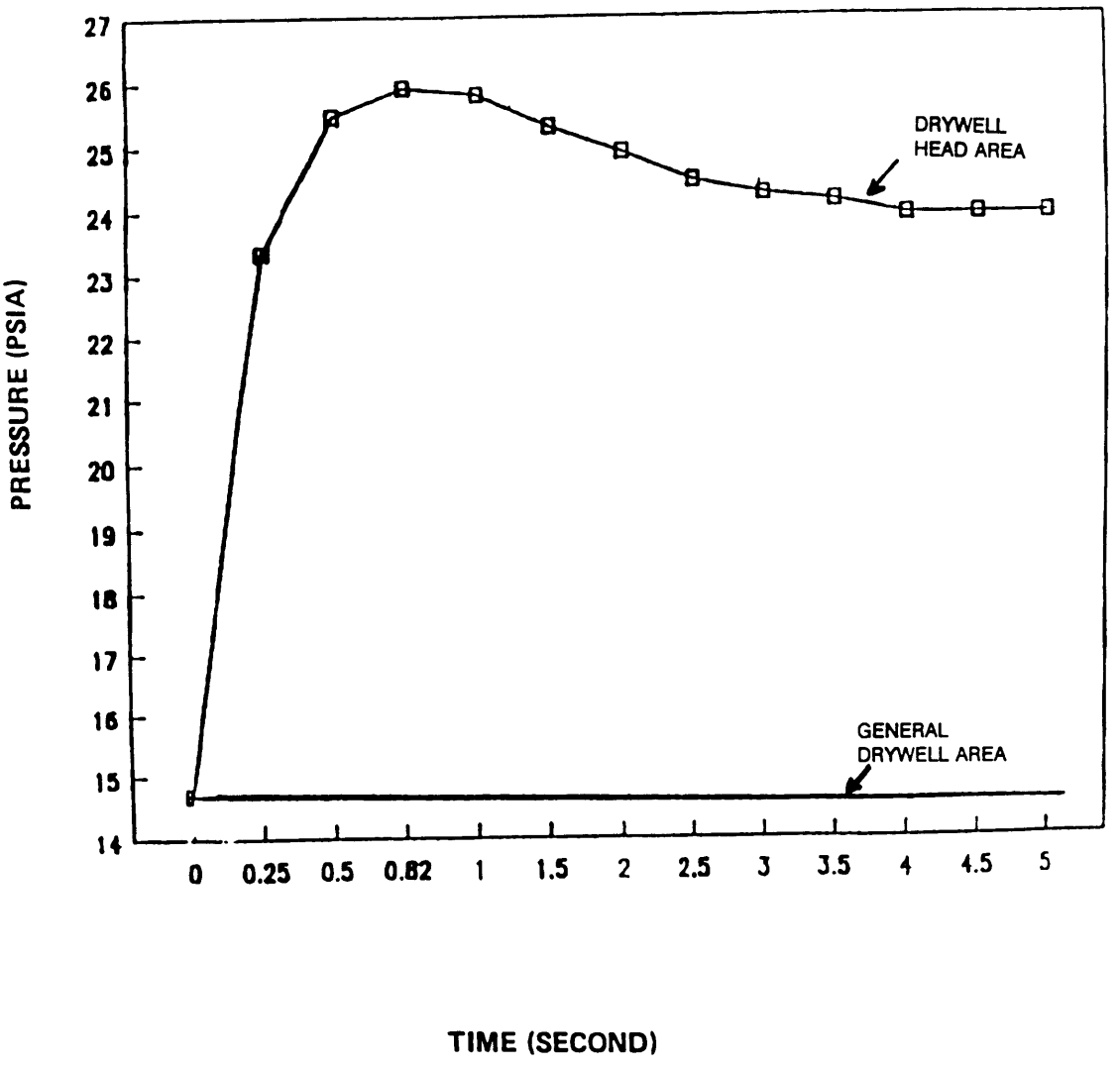


(HEAD SPRAY LINE BREAK IN COMPARTMENT ①)

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HEAD SPRAY LINE
BREAK GEOMETRY

FIGURE 6A-10



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PRESSURE TRANSIENT IN
DRYWELL HEAD AREA FOR
HEAD SPRAY LINE BREAK

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FIGURE 6A-11

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CHAPTER 7 - INSTRUMENTATION AND CONTROL SYSTEMS

7.1 INTRODUCTION

This chapter presents the specific detailed design and performance information relative to the instrumentation and control aspects of the safety-related and power generation systems used throughout the plant. The design and performance considerations relative to these systems' safety function and their mechanical aspects are described elsewhere in this UFSAR.

See Section 1.7 for a listing of elementary diagrams and schematic diagrams and Section 1.2 for equipment layout drawings.

7.1.1 IDENTIFICATION OF SAFETY-RELATED SYSTEMS

7.1.1.1 General

Instrumentation and control systems supplied by GE are designated as either power generation systems or safety-related systems, depending on their function. Some portions of a system may have a safety function while other portions of the same system may be classified as power generation. A description of the system of classification can be found in Section 15.9.2.2.2.

The systems presented in Chapter 7 are also classified according to Regulatory Guide 1.70 (Rev 3), namely, RPS, ESF systems, safe shutdown systems, safety-related display instrumentation, other systems required for safety, and control systems not required for safety. Table 7.1-1 lists the systems under each of these classifications and identifies the designer and/or the supplier. Table 7.1-2 identifies instrumentation and control systems that are identical to those of a nuclear power plant of similar design that has recently received NRC design or operation approval through the issuance of either a construction permit or an operating license. Differences and their effect on safety-related systems are also identified in Table 7.1-2. "First-of-a-kind" instruments including any microprocessors, multiplexers or computer systems used in or providing inputs to safety-related systems are identified in Table 7.1-8.

7.1.1.2 Identification of Individual Systems

A brief descriptive statement is given for each system.

1. The RPS instrumentation and controls initiate an automatic reactor shutdown via control rods (scram) if monitored system variables exceed pre-established limits. This action prevents fuel damage and limits system pressure, thus restricting the release of radioactive material.

2. The PCRVICS instrumentation and controls initiate closure of various automatic isolation valves if monitored system variables exceed pre-established limits. This action limits the loss of coolant from the RCPB and the release of radioactive materials from the RCPB, the primary containment, and the reactor enclosure.

3. The ECCS instrumentation and controls provide initiation and control of systems that provide core cooling. These systems are the HPCI system, the ADS, the core spray system, and the LPCI mode of the RHR system.

4. The NMS instrumentation and controls use incore neutron detectors to monitor core neutron flux. The NMS provides logic signals to the RPS when a condition necessitating a reactor shutdown is detected. Average neutron flux and Simulated Thermal Power are used as the overpower indicator during power operation and intermediate range detectors are used as overpower indicators during startup and shutdown. Oscillations in the local neutron flux are used as the indicator of thermal-hydraulic instability caused power oscillations**.** The NMS also provides power level indication during planned operation. Source range detectors are used to provide neutron flux information during reactor startup and low flux level operations. The TIP system gathers axial neutron flux information via a gamma-sensitive detector and uses this data to calibrate the LPRMS. The RBM system provides a signal to prevent control rod movement when local high neutron flux is sensed by the LPRMs.

   The NMS consists of the following six major systems:

   a. SRM system

   b. IRM system

   c. LPRM system

   d. APRM system (includes OPRM function)

   e. TIP system

   f. RBM system

5. The RI instrumentation and controls serve as a backup to procedural core reactivity control during refueling operation. These interlocks prevent the withdrawal of control rods and the movement of refueling equipment when permissive conditions are not satisfied.

6. The RMCS instrumentation and controls allow the operator to manipulate control rods and determine their positions. Various interlocks are provided in the control circuitry to prevent multiple operator errors or equipment malfunctions from requiring the action of the RPS.

7. The RVI monitors and transmits information to the reactor operator concerning key reactor vessel operating variables.

8. The RFCS instrumentation and controls regulate the speed of the reactor recirculation pumps (through ASDs) to vary the coolant flow rate through the core.

9. The FCS instrumentation and controls regulate the feedwater system flow rate so that proper reactor vessel water level is maintained. The system is arranged to permit single-element (reactor vessel water level only), three-element (reactor vessel water level, main steam flow, and feedwater flow), or manual operation.

10. The PRTGS instrumentation and controls work together to allow proper generator and reactor response to load demand changes. If the generator electrical load is lost, the turbine-generator speed-load controls initiate rapid closure of the turbine

governor valves (coincident with fast opening of the bypass valves) to prevent excessive turbine overspeed.

11. The PRMS instrumentation and controls:

The process radiation monitoring systems are those radiation monitoring systems other than the area monitoring system, the portable monitors, and the offsite monitors. The PRMS serve one or more of the following purposes:

a. Maintain surveillance over process liquid and gas lines that may serve as discharge routes for radioactive materials for the monitoring and/or controlling radioactive releases from the plant.

b. Maintain surveillance and/or control of ventilation systems for either maintaining the habitability of area that are vital for safe plant operation and shutdown or monitoring the quantity of radioactive effluents released to the environment.

c. Maintain surveillance and/or control of those process lines of power generating equipment whose malfunction is indicated by an abnormal increase in radiation levels.

The following is a listing of the safety-related PRMS:

a. Main steam line radiation monitoring system

b. Reactor enclosure ventilation exhaust radiation monitoring system

c. Refueling area ventilation exhaust radiation monitoring system

d. Control room ventilation radiation monitoring system

e. Control room emergency fresh air radiation monitoring system

f. Primary containment post-LOCA radiation monitoring system

g. Residual heat removal service water radiation monitoring system

The following is a listing of the nonsafety-related PRMS:

a. South stack effluent radiation monitoring system

b. Radwaste equipment rooms ventilation radiation monitoring system

c. Charcoal treatment system process exhaust radiation monitoring system

d. Recombiner rooms, hydrogen analyzer compartments, and equipment drain sump vent radiation monitoring system

e. Steam exhaust discharge and vacuum pump exhaust radiation monitoring system

f. Radwaste enclosure ventilation exhaust radiation monitoring system

g. Air ejector/holdup pipe discharge radiation monitoring system

h. Primary containment leak detection radiation monitoring system

i. Hot maintenance shop ventilation exhaust radiation monitoring system

j. Liquid radwaste discharge radiation monitoring system

k. Service water radiation monitoring system

l. Reactor enclosure cooling water radiation monitoring system

m. North stack effluent radiation monitoring system

Some of the above safety and nonsafety-related PRMSs provide postaccident monitoring capabilities in accordance with Regulatory Guide 1.97. These systems are identified in Section 7.5.

12. Area radiation monitoring system:

The purpose of the ARMS is to indicate and record gamma radiation levels in areas where radioactive materials might be present, stored, handled, or inadvertently introduced. Alarm capability is provided in case these radiation levels rise above permissible limits.

13. Deleted

14. The HCRIS instrumentation and controls provide means to isolate the control room from radiation or chlorine entering through the control room ventilation system. The emergency fresh air system provides a means for pressurizing the control room with clean air during radiation isolation. The control room HVAC system provides the proper environment for the control room and adjacent areas.

15. The service water systems instrumentation and controls provide cooling water to vital equipment as follows:

a. ESW to the diesel generators, RHR pumps, ECCS room coolers, and control room chillers

b. RHRSW to the RHR heat exchangers

16. CAC system instrumentation and controls:

a. The CGCS monitors and controls the concentration of combustible gases (hydrogen and oxygen) in the containment during normal operation and after a LOCA.

b. The PCVR subsystem monitors the drywell and suppression chamber pressure to limit the amount by which suppression chamber pressure can exceed drywell pressure.

17. The RCIC system instrumentation and controls provide initiation and control of a system that provides makeup water to the reactor vessel to remove decay heat from the reactor core in the event of reactor isolation from the main condenser system and loss of coolant flow from the reactor feedwater system.

18. The SLCS instrumentation and controls provide initiation of a reactivity control system that can shut the reactor down from rated power if all withdrawn control rods cannot be inserted to achieve reactor shutdown. The SLCS instrumentation and controls also support the manual initiation of SLCS to control suppression pool pH post LOCA.

19. The radwaste system instrumentation and controls support the manual processing and disposing of the radioactive process wastes generated during power operation. The radwaste control system includes liquid, gaseous, and solid radwaste subsystems.

20. The RWCU system instrumentation and controls support manual operation of system equipment to maintain high reactor water purity and reduce concentrations of fission products in the reactor water.

21. The Class 1E power system instrumentation and controls provide for reliable operation of the Class 1E power systems during normal and accident conditions. These power systems consist of:

    a. 4 kV ac power system fed from offsite source with diesel generator backup

    b. dc power system fed from offsite source with battery backup

22. The LDS instrumentation and controls use various temperature, pressure, level, and flow sensors to detect and indicate water and steam leakage in selected reactor systems and to annunciate and provide isolation signals (in certain cases) to limit leakage from the RCPB when limiting leakage conditions exist.

23. The RHR-SCM instrumentation and controls provides manual initiation of cooling to remove the decay and sensible heat from the reactor vessel during shutdown so that the reactor can be refueled and serviced.

24. The FPCC system instrumentation and controls support manual operation of the system that cools the fuel pool.

25. The RERS instrumentation and controls provide initiation and control of a system which filters and mixes the reactor enclosure and refueling floor ventilation air during isolation conditions.

26. The SGTS instrumentation and controls provide the means to control reactor enclosure and refueling floor pressure at a negative value with reference to the outside atmosphere during an isolation of the reactor enclosure.

27. Deleted

28. The SRDI is provided to inform the reactor operator when a manual safety action should be taken or is required. Instrumentation is also provided to give the reactor operator the capability to track process variables pertinent to safety during expected operational perturbations and following postulated accidents.

29. The CIGS instrumentation and controls support a system that provides the necessary compressed gas for the operation of the ADS SRVs, and for the operation of pneumatic devices located inside the drywell and suppression chamber.

30. The RHR-CSM instrumentation and controls support the manual initiation of the portion of the RHR system that is provided to condense steam in the containment under postaccident conditions.

31. The RSS instrumentation and controls provide the capability to ensure safe shutdown of the reactor when the control room is uninhabitable.

32. The RHR-SPCM instrumentation and controls support the manual initiation of the portion of the RHR system that is provided to effect post-LOCA cooling of the suppression pool water.

33. The safety-related equipment area cooling ventilation systems are as follows:

    a. The SGTS filter room and access area unit coolers instrumentation and controls provide support to the system that provides cooling to SGTS filter room and access areas.

    b. The DGEVS instrumentation and controls provide support to the system that provides ventilation to the diesel generator enclosures and equipment.

    c. The SPPSVS instrumentation and controls provide support to the system that provides ventilation for the ESW pumps and RHRSW pumps located in the spray pond pump house.

    d. The ESBRCS instrumentation and controls provide support to the system that provides ventilation and cooling to the emergency switchgear rooms, inverter rooms, battery rooms, and the chiller equipment rooms in the control structure.

    e. The ECCS and RCIC pump compartment unit coolers instrumentation and controls provide support to the system that provides cooling to the core spray, HPCI, RHR, and RCIC pump rooms.

f. The AERVS instrumentation and controls provides support to the system that provides ventilation and cooling to the auxiliary equipment room, computer room, remote shutdown room, and control enclosure fan rooms.

34. The DUC instrumentation and controls provide support to the system that provides atmosphere mixing in the primary containment after a LOCA and cooling during normal operation.

35. The CECWS instrumentation and controls provide support to the system that provides chilled water to the control room air supply fan cabinets, the auxiliary equipment room air supply fan cabinets, the SGTS room and access area unit coolers, and emergency switchgear and battery room air supply fan cabinets.

36. HPLPSI instrumentation and controls prevent over pressurization of the low pressure systems that interface with the RCPB.

37. SRVPI system instrumentation and controls use acoustic sensors to provide the operator with reliable OPEN/NOT-OPEN status of the SRVs.

38. The FPSS instrumentation and controls provide fire protection and suppression for the cable area of the PGCC and adjacent areas in the auxiliary equipment room.

39. The REIS instrumentation and controls provide signals to isolate the reactor enclosure secondary containment and starts the RERS and SGTS under emergency conditions.

40. Nonsafety-related equipment area cooling ventilation systems:

a. Reactor enclosure ventilation system instrumentation and controls provide support to the system that provides ventilation to the reactor enclosure during normal plant operation.

b. Turbine enclosure ventilation system instrumentation and controls provide support to the system that provides ventilation to the turbine enclosure and to el 180', el 200', el 217', and el 254' in the control structure.

c. Radwaste enclosure ventilation system instrumentation and controls provide support to the system that provides ventilation to the radwaste enclosure.

d. Chemistry laboratory expansion ventilation system instrumentation and control provided to the system that provides ventilation to the chemical laboratories.

e. Hot maintenance shop ventilation system instrumentation and controls provide support to the system that provides ventilation to the hot maintenance shop.

e. Miscellaneous enclosure ventilation systems instrumentation and controls provide support to the systems that provide ventilation to the circulating water pump structure, water treatment enclosure, Schuylkill River pump structure, Perkiomen Creek pump structure, sewage treatment enclosure,

auxiliary boiler enclosure, boiler fuel transfer enclosure, lube oil structure, chlorine and acid feed enclosure, and the administration building.

41. The SPFS instrumentation and controls provide support to a system which ensures that the ECCS and RCIC piping is maintained full of water when the systems are in standby mode. The SPFS also discharges to the feedwater lines to provide a seal on the isolation valves in the event of a feedwater line break outside containment.

42. The RRCS is a system designed to mitigate the potential consequences of an anticipated transient without scram event. The system consists of control panels, detection and actuation logic, and the necessary interface logic for input to the recirculation system, feedwater system, SLCS, RWCU system, and the ARI function of the CRD.

43. The RAIS instrumentation and controls provide signals to isolate the refueling area and start the SGTS under emergency conditions.

44. The RWM monitors and enforces adherence to established rod insert and withdraw sequences at low power levels. This function prevents the operator from establishing control rod patterns that are not consistent with the prescribed sequence by initiating the appropriate rod insert block and rod withdrawal block. When RWM is inoperable both insert and withdraw rod blocks are enforced unless the RWM is bypassed.

45. The PMS is a centralized, integrated system which performs the process monitoring and calculations that are necessary for the effective evaluation of normal and emergency power plant operation. The PMS acquires and records process data (e.g., temperatures, pressures, flows, status indicators) to produce displays, logs, and plots of current or historical plant performance.

46. The ERFDS is a part of the PMS and performs the process monitoring and calculations defined as being necessary for the effective evaluation of normal and emergency power plant operation. The PMS acquires and records process data for ERFDS including temperatures, pressures, flows, and status indicators. This data is processed to produce meaningful displays, logs, and plots of current or historical plant performance and is presented to plant personnel in the plant main control room or other user definable locations.

7.1.1.3 Classification

7.1.1.3.1 Safety-Related Systems

Safety-related systems provide actions necessary to ensure safe shutdown, protect the integrity of radioactive material barriers, or prevent the release of radioactive material in excess of allowable limits. These safety-related systems may consist of components, groups of components, systems, or groups of systems. ESF systems are included in this category. ESF systems function to mitigate the consequences of DBAs.

7.1.1.3.2 Power Generation Systems

Power generation systems are not required to ensure safe shutdown, protect the integrity of radioactive material barriers, or prevent the release of radioactive material in excess of allowable limits. The instrumentation and control portions of these systems, may, by their actions, prevent the plant from exceeding preset limits that would otherwise initiate action of the safety-related systems.

7.1.1.3.3 General Functional Requirements of Design Basis

Plant systems may have both a safety design basis and a power generation design basis, depending on their function. The safety design basis states in functional terms the unique design requirements that establish limits for the operation of the system. The general functional requirements portion of the safety design basis presents those requirements that have been determined to be sufficient to ensure the adequacy and reliability of the system from a safety viewpoint. Many of these requirements have been incorporated into various codes, criteria, and regulatory requirements.

7.1.1.3.4 Specific Regulatory Requirements

The plant systems have been examined with respect to specific regulatory requirements that are applicable to the subject instrumentation and controls systems. These regulatory requirements include:

a. Conformance to regulatory guides

b. Conformance to 10CFR50, Appendix A, "General Design Criteria"

c. Conformance to industry codes and standards

The specific regulatory requirements applicable to each system's instrumentation and controls are specified in Table 7.1-3.

7.1.2 IDENTIFICATION OF SAFETY CRITERIA

7.1.2.1 General

Design bases and criteria for instrumentation and control equipment design are based on the need to have the system perform its intended function while meeting the requirements of applicable general design criteria, regulatory guides, industry standards, and other documents.

7.1.2.1.1 Reactor Protection System - Instrumentation and Controls

7.1.2.1.1.1 RPS Safety Design Bases

The RPS is designed to meet the following functional requirements:

a. The RPS initiates a reactor scram with precision and reliability to prevent or limit fuel damage following abnormal operational transients.

b. The RPS initiates a scram with precision and reliability to prevent damage to the RCPB as a result of excessive internal pressure, that is, to prevent nuclear system pressure from exceeding the limit allowed by applicable industry codes.

c. To limit the uncontrolled release of radioactive materials from the RCPB, the RPS precisely and reliably initiates a reactor scram on gross failure of this barrier.

d. To detect conditions that threaten the fuel assembly or RCPB, the RPS inputs are derived from variables that are true, direct measures of operational conditions.

e. The RPS responds correctly to the sensed variables over the expected range of magnitudes and rates of change.

f. A sufficient number of sensors are provided to monitor essential variables that have spatial dependence.

g. The following bases ensure that the RPS is designed with sufficient reliability:

1. If failure of a control or regulating system causes a plant condition that requires a reactor scram but also prevents action by necessary RPS channels, the remaining portions of the RPS meet safety design basis (g.6).

2. The loss of one or both power supplies does not prevent a reactor scram.

3. Once initiated, an RPS action goes to completion. The return-to-normal operation requires deliberate operator action.

4. There is sufficient physical separation between redundant instrumentation and control equipment monitoring the same variable to prevent environmental factors, electrical transients, or physical events from impairing the ability of the system to respond correctly.

5. Ground motions of a SSE magnitude as amplified by building and supporting structures do not impair the ability of the RPS to initiate a reactor scram.

6. No single failure within the RPS prevents proper RPS action, when required, to satisfy safety design bases (a), (b), and (c) above.

7. Any one intentional bypass, maintenance operation, calibration operation, or test to verify operational availability does not impair the ability of the RPS to respond correctly.

8. The system is designed so that the required number of sensors for any monitored variable exceeding the scram setpoint initiates an automatic scram.

h. The following bases reduce the probability that RPS operational reliability and precision are degraded by operator error:

1. Access to trip settings, component calibration controls, test points, and other terminal points is under the control of plant procedures.

2. Manual bypass of instrumentation and control equipment components is under the control of the control room operator. If the ability to trip some

essential part of the system has been manually bypassed, this fact is continuously annunciated in the control room.

7.1.2.1.1.2 RPS Specific Regulatory Requirements

The specific requirements applicable to the RPS instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.1.3 RPS Power Generation Design Bases

The RPS has one objective, which is availability. The setpoints, power sources, and controls and instrumentation are arranged so as to preclude spurious scrams.

7.1.2.1.2 Primary Containment and Reactor Vessel Isolation Control System - Instrumentation and Controls

7.1.2.1.2.1 PCRVICS Safety Design Bases

The following safety design bases are implemented in the PCRVICS:

a. To limit the release of radioactive materials to the environment, the PCRVICS precisely and reliably initiates timely isolation of penetrations through the primary containment whenever the values of monitored variables exceed preselected operational limits.

b. To provide assurance that important variables are monitored with a precision sufficient to fulfill safety design basis requirements (a), the PCRVICS responds correctly to the sensed variables over the expected design range of magnitudes and rates of change.

c. To ensure that important variables are monitored to fulfill safety design basis (a), a sufficient number of sensors is provided for monitoring essential variables.

d. To ensure that conditions indicative of a failure of the RCPB are detected to fulfill safety design basis (a), PCRVICS inputs are derived from variables that are accurate, direct measures of existing plant conditions.

e. The time required to close the MSIVs is short, to limit the radiological consequences and loss of coolant from a steam line break outside containment. However, the time required to close the MSIVs is long enough so that inadvertent isolation of steam lines does not cause a transient as severe as that resulting from closure of the turbine stop valves coincident with failure of the turbine bypass system. This ensures that the MSIV closure speed is compatible with the ability of the RPS to protect the fuel assemblies and the RCPB.

f. The following safety design bases are specified for the systems controlling automatic isolation valves to ensure that the closure of automatic isolation valves is initiated when required to fulfill safety design basis (a):

1. Any single failure, maintenance operation, calibration operation, or test to verify operational availability does not impair the functional ability of the isolation control system.

2. The system is designed so that a specified number of sensors for any monitored variable exceeding the isolation setpoint initiate automatic isolation.

3. Where a plant condition that requires isolation can be caused by a failure or malfunction of a control or regulating system, and the same failure or malfunction prevents action by one or more isolation control system channels designed to provide protection against the unsafe condition, the remaining portions of the isolation control system meet the requirements of safety design bases (a), (b), (c), and (f.1).

4. The power supplies for the PCRVICS are arranged so that the loss of one supply cannot prevent automatic isolation when required.

5. The system is designed so that, once initiated, automatic isolation action goes to completion. The return-to-normal operation after isolation action requires deliberate operator action.

6. There is sufficient electrical and physical separation of wiring and piping between instrument channels monitoring the same essential variable to prevent environmental factors, electrical faults, and physical events from impairing the ability of the system to respond correctly.

7. Earthquake ground motions of SSE magnitude do not impair the ability of the primary containment and reactor vessel isolation control system to initiate automatic isolation.

g. The following safety design basis is specified to ensure that the isolation of main steam lines is accomplished:

   The isolation valves in each of the main steam lines do not rely on electrical power to achieve closure. Valve closure power is from diverse stored energy sources.

h. To reduce the probability that the operational reliability of the PCRVICS is degraded by operator error, the following safety design bases are specified for automatic isolation valves:

   1. Access to all trip settings, component calibration controls, test points, and other terminal points for equipment associated with essential monitored variables is under the control of the plant procedures.

   2. The means for bypassing instrument channels, trip logics, or system components are under the control of the control room operator. If the ability to trip some essential part of the system has been bypassed, this fact is continuously annunciated in the control room.

i. The system provides the operator with a means to take manual isolation action that is independent of the automatic isolation. If there is a failure of the RCPB, it is possible for the operator to manually initiate isolation of the primary containment and reactor vessel from the control room.

j. The following bases are specified to provide the operator with the means to assess the condition of the PCRVICS and to identify conditions indicative of a failure of the RCPB.

1. The PCRVICS is designed to provide the operator with information pertinent to the status of the system.

2. Means are provided for prompt identification of instrument channel and trip system responses.

k. It is possible to check the operational availability of each instrument channel and trip logic during reactor operation.

7.1.2.1.2.2 PCRVICS Specific Regulatory Requirements

The specific regulatory requirements applicable to the PCRVICS instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.2.3 PCRVICS Power Generation Design Bases

There are no power generation design bases for the PCRVICS.

7.1.2.1.3 Emergency Core Cooling System - Instrumentation and Controls

7.1.2.1.3.1 ECCS Safety Design Bases

The ECCS control and instrumentation is designed to meet the following functional safety design bases:

a. Automatically initiate and control the ECCS to prevent fuel cladding temperatures from reaching 2200°F.

b. Respond to a need for emergency core cooling, regardless of the physical location of the malfunction or break that causes the need.

c. The following safety design bases are specified to limit dependence on operator judgement in times of stress:

1. The ECCS responds automatically so that no action is required of plant operators within 10 minutes after a LOCA.

2. The performance of the ECCS is indicated by control room instrumentation.

3. Facilities for manual control of the ECCS are provided in the control room.

7.1.2.1.3.2 ECCS Specific Regulatory Requirements

The specific regulatory requirements applicable to the controls and instrumentation for the ECCS are shown on Table 7.1-3.

7.1.2.1.3.3 ECCS Power Generation Design Bases

There are no power generation design bases for this system.

7.1.2.1.4 Neutron Monitoring System - Instrumentation and Controls

7.1.2.1.4.1 Source Range Monitor Subsystem

7.1.2.1.4.1.1 SRM Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.4.1.2 SRM Specific Regulatory Requirements

There are no specific regulatory requirements for this system.

7.1.2.1.4.1.3 SRM Power Generation Design Bases

The SRM subsystem meets the following power generation design bases:

a. Neutron sources and neutron detectors together result in a signal-to-noise ratio of at least 2:1 and a count rate of at least three counts per second with all control rods fully inserted before initial power operation.

b. The SRM is able to perform the following functions:

    1. Indicate a measurable increase in output signal from at least one detecting channel before reactor period reaches 20 seconds duration during the worst possible startup rod withdrawal conditions

    2. Indicate substantial increases in output signals with the maximum permitted number of SRM channels out of service during normal reactor startup operations

    3. Ensure that the SRM channels are on scale when the IRM first indicates neutron flux during a reactor startup

    4. Provide a measure of the time rate of change of the neutron flux (reactor period) for operational convenience

    5. Generate interlock signals to block control rod withdrawal if the count rate exceeds a preset value or falls below a preset limit (if the IRMs are not above the second range) or if certain electronic failures occur

c. Perform its function in the maximum normal thermal and radiation environment

d. Ensure that loss of a single power bus does not disable the monitoring and alarming functions of all the available monitors

7.1.2.1.4.2 Intermediate Range Monitor Subsystem

7.1.2.1.4.2.1 IRM Safety Design Bases

The IRM generates a trip signal that can be used while operating in the intermediate range to prevent fuel damage resulting from anticipated or abnormal operational transients that occur. The independence and redundancy incorporated in the design of the IRM is consistent with the safety design bases of the RPS.

7.1.2.1.4.2.2 IRM Specific Regulatory Requirements

The specific regulatory requirements applicable to the controls and instrumentation for the IRM are given in Table 7.1-3 for the NMS.

7.1.2.1.4.2.3 IRM Power Generation Design Bases

The IRM generates an interlock signal to block rod withdrawal if the IRM reading exceeds a preset value or if the IRM is not operating properly. The IRM is designed so that overlapping neutron flux indications exist with the SRM and APRM subsystems.

7.1.2.1.4.3 Local Power Range Monitor Subsystem

7.1.2.1.4.3.1 LPRM Safety Design Bases

The LPRM is designed to provide a sufficient number of LPRM signals to satisfy the APRM safety design bases.

7.1.2.1.4.3.2 LPRM Specific Regulatory Requirements

The specific regulatory requirements applicable to the controls and instrumentation for the LPRM are given in Table 7.1-3 for the NMS.

7.1.2.1.4.3.3 LPRM Power Generation Design Bases

The LPRM supplies the following:

a. Signals to the APRM that are proportional to the local neutron flux at various locations within the reactor core

b. Signals to alarm high or low local neutron flux

c. Signals proportional to the local neutron flux to drive indicating meters and auxiliary devices to be used for operator evaluation of power distribution, local heat flux, minimum critical power ratio, and fuel burnup rate

d. Signals to the RBM to indicate changes in local relative neutron flux during the movement of control rods

7.1.2.1.4.4 Average Power Range Monitor Subsystem

7.1.2.1.4.4.1 APRM Safety Design Bases

Under the worst permitted input LPRM bypass conditions, the APRM is capable of generating a trip signal in response to average neutron flux increases or thermal-hydraulic instability caused power oscillations in time to prevent fuel damage. The independence and redundancy incorporated into the design of the APRM are consistent with the safety design bases of the RPS.

7.1.2.1.4.4.2 APRM Specific Regulatory Requirements

The specific regulatory requirements applicable to the controls and instrumentation for the APRM are given in Table 7.1-3 for the NMS.

7.1.2.1.4.4.3 APRM Power Generation Design Bases

The APRM provides the following functions:

a. A continuous indication of average reactor power (neutron flux) from a few percent to 125% of rated reactor power

b. Interlock signals for blocking further rod withdrawal to avoid an unnecessary scram actuation

c. A reference power level for the RBM subsystem

7.1.2.1.4.5 Traversing Incore Probe Subsystem

7.1.2.1.4.5.1 TIP Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.4.5.2 TIP Specific Regulatory Requirements.

There are no specific regulatory requirements applicable to this system.

7.1.2.1.4.5.3 TIP Power Generation Design Bases

The TIP subsystem meets the following power generation design bases:

a. It provides a signal proportional to the axial neutron flux distribution at the radial locations of the LPRM detectors. This signal is of high precision to allow reliable calibration of LPRM gains.

b. It provides an accurate indication of the position of the flux measurement to allow pointwise or continuous measurement of the axial neutron flux distribution.

7.1.2.1.4.6 Rod Block Monitor Subsystem

7.1.2.1.4.6.1 RBM Safety Design Bases

There are no safety design bases for the RBM subsystem.

7.1.2.1.4.6.2 RBM Specific Regulatory Requirements

Specific regulatory requirements applicable to this subsystem are given in Table 7.1-3.

7.1.2.1.4.6.3 RBM Power Generation Design Bases

The RBM subsystem meets the following power generation design bases:

a. Prevents local fuel damage that may result from a single rod withdrawal error under the worst permitted conditions of RBM bypass

b. Provides a signal used by the operator to evaluate the change in the local relative power level during control rod movement

7.1.2.1.5 Refueling Interlocks - Instrumentation and Controls

7.1.2.1.5.1 RI Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.5.2 RI Specific Regulatory Requirements

The specific regulatory requirements applicable to the controls and instrumentation for refueling interlocks are given in Table 7.1-3.

7.1.2.1.5.3 RI Power Generation Design Bases

Refueling interlocks meet the following power generation design bases:

a. During fuel movements in or over the reactor core, they prevent control rod withdrawal.

b. No more than one control rod is withdrawn from its fully inserted position at any time when the reactor is in the refueling mode.

c. They prevent the operation of fuel loaded refueling equipment over the core whenever any control rod is withdrawn.

When fuel is being moved from the core to the spent fuel pool during refueling, the refueling interlocks may be disabled for core cells from which the four fuel assemblies have been removed if the conditions contained in Technical Specifications 3.9.10.2 are met and compensating administrative controls are established.

7.1.2.1.6 Reactor Manual Control System - Instrumentation and Controls

7.1.2.1.6.1 RMCS Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.6.2 RMCS Specific Regulatory Requirements

The specific regulatory requirements applicable to the controls and instrumentation for the RMCS are given in Table 7.1-3.

7.1.2.1.6.3 RMCS Power Generation Design Basis

The RMCS is designed to meet the following power generation design basis:

a. Enforce adherence to predetermined control rod withdrawal and insertion sequences

b. Provide the operator with the means to achieve prescribed control rod patterns

c. Inhibit control rod motion following receipt of rod block trip signals

d. Provide information pertinent to the position and motion of the control rods to the control room.

7.1.2.1.7 Reactor Vessel Instrumentation

7.1.2.1.7.1 RVI Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.7.2 RVI Specific Regulatory Requirements

There are no specific regulatory requirements applicable to this system.

7.1.2.1.7.3 RVI Power Generation Design Bases

RVI is designed to provide the reactor operator with sufficient indication of reactor vessel coolant temperature, reactor vessel water level, reactor vessel pressure, and nuclear system leakage to maintain proper normal operating conditions. These instruments augment safety-related information so that the operator can startup, operate, shutdown, and service the reactor in an efficient manner.

7.1.2.1.8 Recirculation Flow Control System - Instrumentation and Controls

7.1.2.1.8.1 RFCS Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.8.2 RFCS Specific Regulatory Requirements

The specific regulatory requirements applicable to the RFCS are given in Table 7.1-3.

7.1.2.1.8.3 RFCS Power Generation Design Bases

The RFCS is designed to allow manual recirculation flow rate adjustment of reactor power level.

7.1.2.1.9 Feedwater Control System - Instrumentation and Controls

7.1.2.1.9.1 FCS Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.9.2 FCS Specific Regulatory Requirements

The specific regulatory requirements applicable to the FCS are given in Table 7.1-3.

7.1.2.1.9.3 FCS Power Generation Design Bases

The reactor FCS regulates the feedwater flow over the entire power range of the reactor to maintain adequate water level in the reactor vessel and to prevent unnecessary initiation of safety-related systems due to low water level.

7.1.2.1.10 Pressure Regulator and Turbine-Generator System - Instrumentation and Controls

7.1.2.1.10.1 PRTGS Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.10.2 PRTGS Specific Regulatory Requirements

The specific regulatory requirements applicable to this system are given in Table 7.1-3.

7.1.2.1.10.3 PRTGS Power Generation Design Bases

The operation of the reactor demands that a pressure regulator concept be applied to maintain a constant turbine inlet pressure.

The turbine pressure regulator, to maintain constant turbine inlet pressure, operates the steam bypass valves so that a portion of nuclear boiler rated flow can be bypassed for transient steam flow loads above that which can be accepted by the turbine and for the startup and shutdown phase. The PRTGS accomplishes the following control functions:

a. Control turbine speed and turbine acceleration

b. Operate the steam bypass system to keep reactor pressure within limits and avoid large power transients

c. Control main turbine control valve pressure within the proportional band setting of the pressure regulator

7.1.2.1.11 Process Radiation Monitoring System - Instrumentation and Controls

7.1.2.1.11.1 Main Steam Line Radiation Monitoring System

7.1.2.1.11.1.1 MSL-RMS Safety Design Bases

The MSL-RMS is designed to meet the following safety design bases:

a. Detect a gross release of fission products from the fuel under any anticipated operating combination of main steam lines

b. Promptly indicate a gross release of fission products from the fuel

7.1.2.1.11.1.2 MSL-RMS Specific Regulatory Requirements

The specific regulatory requirements applicable to this subsystem are shown in Table 7.1-3.

7.1.2.1.11.1.3 MSL-RMS Power Generation Design Bases

The MSL-RMS is designed to display in the control room an indication of gross gamma radiation level at the main steam tunnel.

7.1.2.1.11.2 Reactor Enclosure Ventilation Exhaust Radiation Monitoring System

7.1.2.1.11.2.1 REVE-RMS Safety Design Bases

This system is designed to meet the following design bases:

a. Detect a gross release of radioactive material into the reactor enclosure ventilation duct

b. Promptly indicate a gross release of radioactive material

c. Provide, on detection of a gross release of radioactive material:

1. A trip signal for the reactor enclosure fans and closure of the valves to the vent exhaust system

2. A trip signal to isolate the primary containment atmosphere purge and vent lines and start the SGTS

3. An annunciation alarm signal in the control room

7.1.2.1.11.2.2 REVE-RMS Specific Regulatory Requirements

The specific regulatory requirements applicable to this system are shown in Table 7.1-3.

7.1.2.1.11.2.3 REVE-RMS Power Generation Design Bases

The system provides the following:

a. Recorder indication in the control room of the gross gamma radiation level

b. An alarm annunciation in the control room

7.1.2.1.11.3 Refueling Area Ventilation Exhaust Radiation Monitoring System

7.1.2.1.11.3.1 RAVE-RMS Safety Design Bases

This system is designed to meet the following design bases:

a. Detect a gross release of radioactive material into the refueling area ventilation duct

b. Promptly indicate a gross release of radioactive material

c. Provide on detection of a gross release of radioactive material:

1. A trip signal for the refueling area fans and closure of the valves to the ventilation exhaust system

2. A trip signal to isolate the primary containment atmosphere purge and vent lines and start the SGTS

3. An alarm annunciation in the control room

7.1.2.1.11.3.2 RAVE-RMS Specific Regulatory Requirements

The specific regulatory requirements applicable to this system are shown in Table 7.1-3.

7.1.2.1.11.3.3 RAVE-RMS Power Generation Design Bases

This system is designed to display an alarm in the control room and record gross releases of radioactive material from the refueling area duct. The control trip capability is stated above.

7.1.2.1.11.4 Control Room Ventilation Radiation Monitoring System

7.1.2.1.11.4.1 CRV-RMS Safety Design Bases

This system is designed to meet the following design bases:

a. Detect the presence of a hazardous quantity of radioactive material infiltrating the control room ventilation duct

b. Promptly indicate the presence of hazardous amounts of radioactivity

c. Provide, on detection of hazardous amounts of radioactive material:

1. A trip signal to close the control room ventilation intake dampers

2. A trip signal to start the control room emergency fresh air system

7.1.2.1.11.4.2 CRV-RMS Specific Regulatory Requirements

The specific regulatory requirements applicable to this system are given in Table 7.1-3.

7.1.2.1.11.4.3 CRV-RMS Power Generation Design Bases

The system provides continuous indication and recording of the concentration of radioactive material entering the control room under all conditions of plant operation, including accidents. It provides annunciation alarms in the control room.

7.1.2.1.11.5 Control Room Emergency Fresh Air Radiation Monitoring Systems

7.1.2.1.11.5.1 CREFA-RMS Safety Design Bases

This system is designed to detect the presence of residual radiation in the effluent from the HEPA/charcoal filters during operation of the CREFAS.

7.1.2.1.11.5.2 CREFA-RMS Specific Regulatory Requirements

This system satisfies the requirement that the control room ventilation system is monitored at all times for radioactivity. If there is closure of the control room ventilation intake dampers, the control room radiation monitoring system becomes inoperative, so it becomes necessary to transfer surveillance to an active station. The specific regulatory requirements of this system are shown in Table 7.1-3.

7.1.2.1.11.5.3 CREFA-RMS Power Generation Design Bases

During operation of the CREFAS, the monitoring system provides continuous indication and recording of the concentration of radioactive material entering the control room. It provides annunciation alarms in the control room.

7.1.2.1.11.6 Primary Containment Post-LOCA Radiation Monitoring System

7.1.2.1.11.6.1 PCPL-RMS Safety Design Bases

This system is designed to maintain surveillance of the gross gamma radioactivity of the primary containment atmosphere under postaccident conditions.

7.1.2.1.11.6.2 PCPL-RMS Specific Regulatory Requirements

The specific regulatory requirements applicable to this system are shown in Table 7.1-3.

7.1.2.1.11.6.3 PCPL-RMS Power Generation Design Bases

This monitoring system becomes operational during and after accident conditions when shutdown occurs. As such, it does not serve any power generation design basis. However, indications of radiation levels are transmitted to the control room for readout, recording, and alarm annunciation at preset levels.

7.1.2.1.11.7 Residual Heat Removal Service Water Radiation Monitoring System

7.1.2.1.11.7.1 RHRSW-RMS Safety Design Bases

This system is designed to meet the following safety design bases:

a. Detect the presence of significant amounts of radioactivity in the RHRSW downstream of the RHR heat exchangers

b. Promptly indicate the release of radioactive material to the spray pond

c. Provide a trip signal to the RHRSW Pumps on detection of the presence of significant amounts of radioactive material.

7.1.2.1.11.7.2 RHRSW-RMS Specific Regulatory Requirements

The specific regulatory requirements applicable to this system are given in Table 7.1-3.

7.1.2.1.11.7.3 RHRSW-RMS Power Generation Design Bases:

This system provides the following:

a. Recorder indication in the control enclosure of the radioactivity level in the RHRSW

b. Annunciates alarms in the control room.

7.1.2.1.11.8 Nonsafety-Related Radiation Monitoring Systems

The following process radiation monitoring systems are classified as power generation systems in that they do not serve safety-related functions. The postaccident monitoring functions of some of these systems are discussed in Section 7.5.

a. South stack effluent (ventilation)

b. Radwaste equipment rooms ventilation

c. Charcoal treatment system process exhaust (gas)

d. Recombiner rooms, hydrogen analyzer compartments, and equipment drain sump vent (ventilation)

e. Steam exhauster discharge and vacuum pump exhaust (gas)

f. Radwaste enclosure ventilation exhaust (ventilation)

g. Air ejector offgas

h. Primary containment leak detector (gas)

i. Hot maintenance shop ventilation exhaust (ventilation)

j. Liquid radwaste discharge (liquid)

k. Service water (liquid)

l. Reactor enclosure cooling water (liquid)

m. North stack effluent (ventilation)

With the exception of items (g) and (j), these monitoring systems have no control functions. The above systems are described in Section 11.5.

7.1.2.1.11.8.1 Nonsafety-Related RMS Safety Design Bases

There are no safety design bases for these systems. The postaccident design bases of some of the systems are described in Section 7.5.

7.1.2.1.11.8.2 Nonsafety-Related RMS Specific Regulatory Requirements

The specific regulatory requirements applicable to these systems are shown in Table 7.1-3.

7.1.2.1.11.8.3 Nonsafety-Related RMS Power Generation Design Bases

These systems provide the following:

a. Except for the hot maintenance shop monitor, the systems provide an indication in the control room of the radiation levels measured in each application. All indications of the hot maintenance shop monitor are local.

b. Except for the hot maintenance shop monitor, the systems provide recorder signals to the control room.

c. Alarm annunciation is provided if high or downscale trip signals are transmitted to the control room. Alarm annunciator signals from the hot maintenance shop monitor are local.

d. The liquid radwaste discharge monitor trip signal closes the liquid radwaste discharge valve if there is a high signal. Data from this monitor are transmitted to the radwaste enclosure control room rather than to the main control room.

7.1.2.1.12 Area Radiation Monitoring System

7.1.2.1.12.1 ARMS Safety Design Bases

The ARMS is not a safety-related system and provides no control function.

7.1.2.1.12.2 ARMS Specific Regulatory Requirements

The specific regulatory requirements applicable to this system are given in Table 7.1-3.

7.1.2.1.12.3 ARMS Power Generation Design Bases

The system provides continuous indication and recording of gamma radiation intensities in those areas where radioactive materials may be present, handled, or inadvertently introduced. It provides annunciation alarms both locally and in the control room if preset limits of radiation are exceeded. Local alarms and readouts are located either adjacent to the detectors or at the entrance-ways to those areas that might prove hazardous to personnel.

7.1.2.1.13 Deleted

7.1.2.1.14 Habitability and Control Room Isolation System - Instrumentation and Controls

7.1.2.1.14.1 HCRIS Safety Design Bases

The system is designed to meet the following safety design bases:

a. During a radiation accident, isolate the main air intake and pressurize the control room with clean, filtered air

b. During a chlorine accident, isolate the control room and provide cleanup of the control room atmosphere by recirculation

7.1.2.1.14.2 HCRIS Specific Regulatory Requirements

The specific regulatory requirements applicable to the system instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.14.3 HCRIS Power Generation Design Bases

This system is designed to provide a safe and comfortable environment for the control room personnel.

7.1.2.1.15 Service Water Systems - Instrumentation and Controls

7.1.2.1.15.1 Emergency Service Water - Instrumentation and Controls

7.1.2.1.15.1.1 ESW Safety Design Bases

The system is designed to meet the following safety design bases:

a. During and after transient and accident conditions, the system provides cooling for the control room chillers and diesel generators, serves safety-related pump-motor units needing water cooling, and maintains cooling of safety-related equipment via space coolers.

b. During loss of fuel pool cooling, the system provides makeup water to maintain the water level in the fuel pool.

7.1.2.1.15.1.2 ESW Specific Regulatory Requirements

The specific regulatory requirements applicable to the ESW system are shown in Table 7.1-3.

7.1.2.1.15.1.3 ESW Power Generation Design Bases

The system is designed to provide cooling for recirculation pump motors and oil coolers and the RECW system heat exchangers.

7.1.2.1.15.2 Residual Heat Removal Service Water System - Instrumentation and Controls

7.1.2.1.15.2.1 RHRSW Safety Design Bases

The system is designed to meet the following safety design bases:

a. During normal shutdown, the RHRSW system provides cooling for the RHR system heat exchangers.

b. During and after transient and accident conditions, the system provides cooling for the RHR system heat exchangers.

c. After an accident, the RHRSW system provides water for flooding the reactor core, and spraying the primary containment, if required.

7.1.2.1.15.2.2 RHRSW Specific Regulatory Requirements

The specific regulatory requirements applicable to the RHRSW system are shown in Table 7.1-3.

7.1.2.1.15.2.3 RHRSW Power Generation Design Bases

There are no power generation design bases for this system.

7.1.2.1.16 Containment Atmospheric Control System - Instrumentation and Controls

7.1.2.1.16.1 Combustible Gas Control System

7.1.2.1.16.1.1 CGCS Safety Design Bases

The system provides the means to measure and control the concentration of hydrogen and oxygen in the primary containment atmosphere following postulated accidents to ensure that the primary containment integrity is maintained.

The system monitors the concentration of hydrogen and oxygen in the primary containment atmosphere during normal operation and following postulated accidents. Limits are established on abnormal concentrations of hydrogen and oxygen so that corrective action can be taken before unacceptable results occur. The unacceptable results are as follows:

a. A threat of significant compromise to the primary containment structure

b. A threat of significant compromise to the equipment inside the primary containment

7.1.2.1.16.1.2 CGCS Specific Regulatory Requirements

The specific regulatory requirements applicable to the CGCS instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.16.1.3 CGCS Power Generation Design Bases

The system is designed to provide the means to measure and control the amount of oxygen to ensure containment inerting.

7.1.2.1.16.2 Primary Containment Vacuum Relief System - Instrumentation and Controls

7.1.2.1.16.2.1 PCVR Safety Design Bases

The PCVR is designed to meet the following safety design bases:

a. Operate automatically to allow air from the suppression chamber to enter the drywell when a differential pressure exceeds a pre-established limit

b. Check the operational availability of each valve and the disc position indication system for each valve during reactor operation

7.1.2.1.16.2.2 PCVR Specific Regulatory Requirements

The specific regulatory requirements applicable to the system instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.16.2.3 PCVR Power Generation Design Bases

This system has no power generation design bases.

7.1.2.1.17 Reactor Core Isolation Cooling System - Instrumentation and Controls

7.1.2.1.17.1 RCIC Safety Design Bases

The system is designed to meet the following safety design bases:

a. Sufficient coolant can be maintained in the reactor vessel in case of an isolation with a loss of main feedwater flow.

b. Provisions are made for automatic and remote manual operation of the system.

c. Components of the RCIC system are designed to satisfy seismic Category I design requirements.

d. The power supply for the system is from immediately available energy sources of high reliability.

e. Provision is made so that periodic testing can be performed during plant operation.

7.1.2.1.17.2 RCIC Specific Regulatory Requirements

The specific regulatory requirements applicable to this system are given in Table 7.1-3.

7.1.2.1.17.3 RCIC Power Generation Design Bases

There are no power generation design bases for this system.

7.1.2.1.18 Standby Liquid Control System - Instrumentation and Controls

7.1.2.1.18.1 SLCS Safety Design Bases

This system is capable of shutting the reactor down from full power to cold shutdown and maintaining the reactor in a subcritical state at atmospheric temperature and pressure conditions by pumping sodium pentaborate, a neutron absorber, into the reactor. This system is also capable of maintaining suppression pool pH at a level of 7.0 or greater following a LOCA.

7.1.2.1.18.2 SLCS Specific Regulatory Requirements

The specific regulatory requirements applicable to the system instrumentation and controls are given in Table 7.1-3.

7.1.2.1.18.3 SLCS Power Generation Design Bases

This system has no power generation design bases.

7.1.2.1.19 Radwaste Systems - Instrumentation and Controls

7.1.2.1.19.1 Liquid Radwaste System

7.1.2.1.19.1.1 LRS Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.19.1.2 LRS Specific Regulatory Requirements

Specific regulatory requirements applicable to the system are listed in Table 7.1-3.

7.1.2.1.19.1.3 LRS Power Generation Design Bases

The instrumentation and control system is designed to provide dependable measurement and control for the various liquid processing systems during normal and expected occurrence conditions.

7.1.2.1.19.2 Gaseous Radwaste System

7.1.2.1.19.2.1 GRS Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.19.2.2 GRS Specific Regulatory Requirements

Specific regulatory requirements applicable to the system are listed in Table 7.1-3.

7.1.2.1.19.2.3 GRS Power Generation Design Bases

The instrumentation and control system is designed to perform the following:

a. Monitor and control the GRS

b. Detect, indicate, and alarm a system upset to provide sufficient time for corrective action

7.1.2.1.19.3 Solid Radwaste System

7.1.2.1.19.3.1 SRS Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.19.3.2 SRS Specific Regulatory Requirements

No specific regulatory requirements are imposed on the SRS.

7.1.2.1.19.3.3 SRS Power Generation Design Bases

The instrumentation and control system is designed to:

a. Monitor and control the SRS

b. Detect, indicate, and alarm a system upset to provide sufficient time for corrective action

7.1.2.1.20 Reactor Water Cleanup System - Instrumentation and Controls

7.1.2.1.20.1 RWCU Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.20.2 RWCU Specific Regulatory Requirements

The specific regulatory requirements applicable to this system are provided in Table 7.1-3.

7.1.2.1.20.3 RWCU Power Generation Design Bases

The purpose of the RWCU system is to provide continuous processing of the reactor water to maintain the purity within specified limits. The system also provides the means for removal of reactor water. Although the RWCU system is of importance to startup and long-term operation, the reactor may operate while the RWCU is out of service.

7.1.2.1.21 Class 1E Power Systems

7.1.2.1.21.1 Class 1E Power Systems Safety Design Bases

The safety design bases for the electrical power systems required to support the safety-related systems are described in Sections 8.1 and 8.3.

7.1.2.1.21.2 Class 1E Power Systems Specific Regulatory Requirements

The specific regulatory requirements applicable to the standby power systems are given in Sections 8.1 and 8.3.

7.1.2.1.21.3 Class 1E Power Systems Power Generation Design Bases

The power generation design bases for the standby power systems are described in Sections 8.1 and 8.3.1.

7.1.2.1.22 Leak Detection Systems - Instrumentation and Controls

7.1.2.1.22.1 LDS Safety Design Bases

The safety design bases for the LDS are as follows:

a. Signals are provided that initiate automatic isolation (or permit manual isolation) of abnormal leakage before the results of this leakage become unacceptable.

b. The unacceptable results of failure to detect leakage are as follows:

1. The potential for degradation of the RCPB in excess of specified limits

2. The potential for release of primary coolant fluid sufficient to cause unacceptable offsite radiological doses

3. The potential for a leakage rate in excess of the capability of operating equipment to maintain reactor vessel water level

4. A threat of significant compromise to the steam and power conversion system boundary

5. The potential for a leakage rate in excess of radiological limits

6. The potential for a leakage rate that negates the safety equipment function

7.1.2.1.22.2 LDS Specific Regulatory Requirements

The specific regulatory requirements applicable to this system are given in Table 7.1-3.

7.1.2.1.22.3 LDS Power Generation Design Bases

A means is provided to detect and indicate in the control room abnormal leakage from the RCPB, steam, and the power conversion system boundary.

7.1.2.1.23 Reactor Shutdown Cooling Mode of the RHR System - Instrumentation and Controls

7.1.2.1.23.1 RHR-SCM Safety Design Bases

The RHR-SCM is designed to meet the following functional design bases:

a. Instrumentation and controls are provided that enable the system to remove the residual heat (decay heat and sensible heat) from the reactor vessel during normal shutdown.

b. Manual controls of the RHR-SCM are provided in the control room, and manual controls for one loop are provided at the remote shutdown panel.

c. Performance of the RHR-SCM is indicated by control room instrumentation and instrumentation on the remote shutdown panel.

7.1.2.1.23.2 RHR-SCM Specific Regulatory Requirements

The specific requirements applicable to the RHR-SCM are shown in Table 7.1-3.

7.1.2.1.23.3 RHR-SCM Power Generation Design Bases

The RHR-SCM meets the following power generation design bases:

a. Cooling is provided for the reactor during the shutdown operation when the vessel pressure is below the prescribed limit.

b. The reactor water is cooled to a temperature that is practicable for refueling and servicing operation.

7.1.2.1.24 Fuel Pool Cooling and Cleanup System - Instrumentation and Controls

7.1.2.1.24.1 FPCC Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.24.2 FPCC Specific Regulatory Requirements

The specific regulatory requirements applicable to the FPCC are given in Table 7.1-3.

7.1.2.1.24.3 FPCC Power Generation Design Bases

The purpose of the FPCC instrumentation and controls is to maintain the shielding water in the spent fuel and equipment storage pools and the reactor water well below a desired temperature and at a degree of clarity necessary to refuel and service the reactor.

7.1.2.1.25 Reactor Enclosure Recirculation System - Instrumentation and Controls

7.1.2.1.25.1 RERS Safety Design Bases

During an isolation of the reactor enclosure the RERS filters and mixes the air in this area.

7.1.2.1.25.2 RERS Specific Regulatory Requirements

The specific regulatory requirements applicable to the RERS instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.25.3 RERS Power Generation Design Bases

This system has no power generation design bases.

7.1.2.1.26 Standby Gas Treatment System - Instrumentation and Controls

7.1.2.1.26.1 SGTS Safety Design Bases

This system is designed to meet the following safety design bases:

a. During an isolation of the reactor enclosure and/or refueling area, the SGTS restores and maintains these areas at a negative pressure with reference to the outside atmosphere

b. Further filter the air drawn from the reactor enclosure recirculation system before exhausting it to the atmosphere

7.1.2.1.26.2 SGTS Specific Regulatory Requirements

The specific regulatory requirements applicable to the SGTS instrumentation and control are shown in Table 7.1-3.

7.1.2.1.26.3 SGTS Power Generation Design Bases

This system has no power generation design bases.

7.1.2.1.27

Deleted

7.1.2.1.28 Safety-Related Display Instrumentation

7.1.2.1.28.1 SRDI Safety Design Bases

The necessary display instrumentation is available to the reactor operator in the control room for determining when conditions exist that require specified manual control actions and to monitor the results of these and automatic actions, and to identify and follow the source of the accident to the degree necessary for the operator to perform his/her role and to verify adequate core cooling and containment integrity.

7.1.2.1.28.2 SRDI Specific Regulatory Requirements

The specific regulatory requirements applicable to the SRDI are given in Table 7.1-3.

7.1.2.1.28.3 SRDI Power Generation Design Bases

The safety-related instruments that are also used for power generation are designed so that all the expected power operation actions and maneuvers can be reasonably accomplished by the reactor operator.

7.1.2.1.29 Containment Instrument Gas System - Instrumentation and Controls

7.1.2.1.29.1 CIGS Safety Design Bases

The CIGS is designed to provide a compressed gas supply for the ADS SRVs.

7.1.2.1.29.2 CIGS Specific Regulatory Requirements

The specific regulatory requirements applicable to the system instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.29.3 CIGS Power Generation Design Bases

See Section 9.3.

7.1.2.1.30 Containment Spray Mode of the RHR System - Instrumentation and Controls

7.1.2.1.30.1 RHR-CSM Safety Design Bases

The RHR-CSM is designed to meet the following safety design bases:

a. Instrumentation and controls are provided to sense drywell pressure and to enable the system to condense steam in the drywell and the suppression pool air volume during a transient or accident event.

b. All manual controls for the containment spray mode of the RHR system are provided in the control room.

c. Performance of the RHR-CSM is indicated by control room instrumentation.

7.1.2.1.30.2 RHR-CSM Specific Regulatory Requirements

Specific regulatory requirements applicable to the RHR-CSM are listed in Table 7.1-3.

7.1.2.1.30.3 RHR-CSM Power Generation Design Bases

This system has no power generation design bases.

7.1.2.1.31 Remote Shutdown System - Instrumentation and Controls

7.1.2.1.31.1 RSS Safety Design Bases

The capability to remotely shutdown the reactor is designed to meet the following functional design bases:

a. Instrumentation and controls are provided outside the control room to allow prompt hot shutdown of the reactor and to maintain safe conditions during hot shutdown.

b. Suitable procedures provide the capability for subsequent cold shutdown of the reactor.

7.1.2.1.31.2 RSS Specific Regulatory Requirements

Specific regulatory requirements applicable to the RSS are listed in Table 7.1-3.

7.1.2.1.31.3 RSS Power Generation Design Bases

This system has no power generation design bases.

7.1.2.1.32 Suppression Pool Cooling Mode of the RHR System - Instrumentation and Controls

7.1.2.1.32.1 RHR-SPCM Safety Design Bases

Instrumentation and controls are provided to allow the reactor operator to manually initiate suppression pool cooling to ensure that the pool temperature does not exceed the pre-established pool temperature limit.

7.1.2.1.32.2 RHR-SPCM Specific Regulatory Requirements

The specific regulatory requirements applicable to this mode of operation are the same as listed in Table 7.1-3 for the RHR-SCM.

7.1.2.1.32.3 RHR-SPCM Power Generation Design Bases

This system has no power generation design bases.

7.1.2.1.33 Safety-Related Equipment Area Cooling Ventilation Systems

7.1.2.1.33.1 Standby Gas Treatment System Filter Room and Access Area Unit Coolers - Instrumentation and Controls

7.1.2.1.33.1.1 SGTS-UC Safety Design Bases

Instruments and controls are provided to enable the unit coolers to provide cooling to the areas around the SGTS filter to keep ambient conditions within the prescribed limits.

7.1.2.1.33.1.2 SGTS-UC Specific Regulatory Requirements

The specific regulatory requirements applicable to the system instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.33.1.3 SGTS-UC Power Generation Design Bases

This system has no power generation design bases.

7.1.2.1.33.2 Diesel Generator Enclosure Ventilation System - Instrumentation and Controls

7.1.2.1.33.2.1 DGEVS Safety Design Bases

Instruments and controls are provided to enable the diesel generator fans to provide ventilation to the diesel generator cells to keep the ambient conditions within the prescribed limits.

7.1.2.1.33.2.2 DGEVS Specific Regulatory Requirements

The specific regulatory requirements applicable to the DGEVS instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.33.2.3 DGEVS Power Generation Design Bases

This system has no power generation design bases.

7.1.2.1.33.3 Spray Pond Pump Structure Ventilation System - Instrumentation and Controls

7.1.2.1.33.3.1 SPPSVS Safety Design Bases

Instruments and controls are provided to enable the fan systems to maintain the environment of the spray pond pump structure within the prescribed limits.

7.1.2.1.33.3.2 SPPSVS Specific Regulatory Requirements

This specific regulatory requirements applicable to the SPPSVS instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.33.3.3 SPPSVS Power Generation Design Bases

This system has no power generation design bases.

7.1.2.1.33.4 Emergency Switchgear and Battery Rooms Cooling System - Instrumentation and Controls

7.1.2.1.33.4.1 ESBRCS Safety Design Bases

Instruments and controls are provided to enable the cooling units to keep the ambient conditions of the affected areas within the prescribed limits and provide exhaust recirculation from the battery rooms.

7.1.2.1.33.4.2 ESBRCS Specific Regulatory Requirements

The specific regulatory requirements applicable to the system instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.33.4.3 ESBRCS Power Generation Design Bases

Instruments and controls are provided to enable the cooling units to keep the ambient conditions of the affected areas within the prescribed limits and provide exhaust from the battery rooms.

7.1.2.1.33.5 Emergency Core Cooling Systems (ECCS and RCIC) Pump Compartment Unit Coolers - Instrumentation and Controls

7.1.2.1.33.5.1 ECCS-UC Safety Design Bases

Instruments and controls are provided to enable the unit coolers to keep the ambient conditions of the affected areas, except for HPCI and RCIC within the prescribed limits.

7.1.2.1.33.5.2 ECCS-UC Specific Regulatory Requirements

The specific regulatory requirements applicable to the system instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.33.5.3 ECCS-UC Power Generation Design Bases

This system has no power generation design bases.

7.1.2.1.33.6 Auxiliary Equipment Room Ventilation System - Instrumentation and Controls

7.1.2.1.33.6.1 AERVS Safety Design Bases

Instruments and controls are provided to enable the fan systems to maintain the environment in the auxiliary equipment room within the prescribed limits.

7.1.2.1.33.6.2 AERVS Specific Regulatory Requirements

The specific regulatory requirements applicable to the system instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.33.6.3 AERVS Power Generation Design Bases

Instruments and controls are provided to ensure adequate ventilation for the equipment in the auxiliary equipment room.

7.1.2.1.34 Drywell Unit Coolers - Instrumentation and Controls

7.1.2.1.34.1 DUC Safety Design Bases

Instruments and controls are provided to enable the unit coolers to provide atmosphere mixing in the primary containment.

7.1.2.1.34.2 DUC Specific Regulatory Requirements

The specific regulatory requirements applicable to the system instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.34.3 DUC Power Generation Design Bases

Instruments and controls are provided to enable the unit coolers to provide cooling in the primary containment.

7.1.2.1.35 Control Enclosure Chilled Water System - Instrumentation and Controls

7.1.2.1.35.1 CECWS Safety Design Bases

Instruments and controls are provided to enable the chiller and its circulating pumps to supply chilled water to the cooling coils of the associated equipment.

7.1.2.1.35.2 CECWS Specific Regulatory Requirements

The specific regulatory requirements applicable to the system instrumentation and controls are shown in Table 7.1-3.

7.1.2.1.35.3 CECWS Power Generation Design Bases

Instruments and controls are provided to enable the chiller and its circulating pumps to supply chilled water to the cooling coils of the associated equipment.

7.1.2.1.36 High Pressure/Low Pressure System Interlocks

7.1.2.1.36.1 HPLPSI Safety Design Bases

HPLPSI is not a system, but provides interlocks between pressure in the reactor coolant and pressure in the RHR system. Therefore safety design bases do not apply directly to HPLPSI.

7.1.2.1.36.2 HPLPSI Specific Regulatory Requirements

There are no specific regulatory requirements for the HPLPSI.

7.1.2.1.36.3 HPLPSI Power Generation Design Bases

There are no power generation design bases for the HPLPSI.

7.1.2.1.37 Safety/Relief Valve Position Indication System - Instrumentation and Controls

7.1.2.1.37.1 SRVPI Safety Design Bases

Indication and alarms, provided in the control room, alert the operator to, and identifies, OPEN/NOT-OPEN SRVs.

7.1.2.1.37.2 SRVPI Specific Regulatory Requirements

The specific regulatory requirements applicable to the SRVPI are shown in Table 7.1-3.

7.1.2.1.37.3 SRVPI Power Generation Design Bases

There are no power generation design bases for this system.

7.1.2.1.38 Fire Protection and Suppression System

7.1.2.1.38.1 FPSS Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.38.2 FPSS Specific Regulatory Requirements

There are no specific regulatory requirements for this system.

7.1.2.1.38.3 FPSS Power Generation Design Bases

There are no power generation design bases for this system.

7.1.2.1.39 Reactor Enclosure Isolation System

7.1.2.1.39.1 REIS Safety Design Bases

The system is designed to meet the following safety design bases:

a. Instruments and controls are provided that enable the system to isolate the reactor enclosure secondary containment.

b. Manual controls for the isolation system are provided in the control room.

c. Performance of the isolation is indicated by control room instrumentation.

7.1.2.1.39.2 REIS Specific Regulatory Requirements

The specific regulatory requirements applicable to the system instrumentation and control are shown in Table 7.1-3.

7.1.2.1.39.3 REIS Power Generation Design Bases

This system has no power generation design bases.

7.1.2.1.40 Nonsafety-Related Equipment Area Cooling Ventilation Systems

7.1.2.1.40.1 Safety Design Bases

There are no safety design bases for the instrumentation and controls for these systems.

7.1.2.1.40.2 Specific Regulatory Requirements

There are no specific regulatory requirements for these systems' instruments and controls.

7.1.2.1.40.3 Power Generation Design Bases

Instruments and controls are provided to ensure adequate ventilation for equipment and personnel located in the areas serviced by the nonsafety-related equipment area cooling ventilation systems during normal plant operation.

7.1.2.1.41 Safeguard Piping Fill System

7.1.2.1.41.1 SPFS Safety Design Bases

The SPFS is designed to perform two functions:

a. Provide a safety-related backup source of makeup water to the ECCS and RCIC pump discharge lines to prevent drainage of the lines from back leakage through the discharge check valves in the event of failure of the primary source (condensate transfer system)

b. Provide a water seal in the feedwater lines to forestall the possibility of drainage of the feedwater lines and subsequent bypass leakage of containment atmosphere

7.1.2.1.41.2 SPFS Specific Regulatory Requirements

The specific regulatory requirements for this system are listed in Table 7.1-3.

7.1.2.1.41.3 SPFS Power Generation Design Bases

This system has no power generation design bases.

7.1.2.1.42 Refueling Area Isolation System

7.1.2.1.42.1 RAIS Safety Design Bases

The system is designed to meet the following safety design bases:

a. Instruments and controls are provided that enable the system to isolate the refueling floor.

b. Manual controls for the isolation system are provided in the control room.

c. Performance of the isolation is indicated by control room instrumentation.

7.1.2.1.42.2 RAIS Specific Regulatory Requirements

The specific regulatory requirements applicable to the system instrumentation and control are shown in Table 7.1-3.

7.1.2.1.42.3 RAIS Power Generation Design Bases

There are no power generation design bases for this system.

7.1.2.1.43 Redundant Reactivity Control System

7.1.2.1.43.1 RRCS Safety Design Basis

The RRCS is designed to mitigate the potential consequences of an ATWS event. The RRCS provides signals to mitigate an ATWS event by:

a. Initiating an ARI which is redundant and diverse from the normal RPS

b. Tripping the recirculation pump

c. Providing feedwater runback function

d. Automatically initiating the SLCS.

7.1.2.1.43.2 RRCS Specific Regulatory Requirements

The regulatory requirements applicable to the RRCS are given in Table 7.1-3.

7.1.2.1.43.3 RRCS Power Generation Design Bases

This system has no power generation design bases.

7.1.2.1.44 Rod Worth Minimizer

7.1.2.1.44.1 RWM Safety Design Bases

There are no safety design bases for the RWM.

7.1.2.1.44.2 RWM Specific Regulatory Requirements

The specific regulatory requirements applicable to the system instrumentation and control are listed in Table 7.1-3.

7.1.2.1.44.3 RWM Power Generation Design Basis

The RWM monitors and enforces operator adherence to established startup, shutdown, and low power level control rod sequences.

7.1.2.1.45 Plant Monitoring System

7.1.2.1.45.1 PMS Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.45.2 PMS Specific Regulatory Requirements

The specific regulatory requirements applicable to this system are listed in Table 7.1-3.

7.1.2.1.45.3 PMS Power Generation Design Bases

The PMS is a centralized, integrated system which performs the process monitoring and calculations defined as being necessary for the effective evaluation of power plant operation. The PMS acquires and records process data (e.g., temperatures, pressure, flows, and status indicators) to produce meaningful displays, logs, and plots of current and historical plant performance. The PMS has the following major functions:

a. Provide real-time and historical emergency response information necessary to meet and support SPDS requirements; that is, information to maintain adequate core cooling, shut down the reactor, cool the RPV to cold shutdown conditions, maintain primary containment integrity, and protect equipment in the primary containment.

b. Provide functions, such as scan, log, and alarm, certain NSSS programs, SOE, trend recorder, and BOP programs.

c. Provide information to personnel in the control room, the TSC, and the EOF.

d. Provide real-time and historical information during normal, startup, and emergency operation at high resolution recording speeds for event monitoring and analyses.

7.1.2.1.46 Emergency Response Facility Data System

7.1.2.1.46.1 ERFDS Safety Design Bases

There are no safety design bases for this system.

7.1.2.1.46.2 ERFDS Specific Regulatory Requirements

The specific regulatory requirements applicable to this system are listed in Table 7.1-3.

7.1.2.1.46.3 ERFDS Power Generation Design

The ERFDS is a part of the PMS and performs the process monitoring and calculations defined as being necessary for the effective evaluation of normal and emergency power plant operation. The PMS acquires and records process data for ERFDS including temperatures, pressures, flows, and status indicators. This data is processed to produce meaningful displays, logs, and plots of current or historical plant performance and is presented to plant personnel in the plant main control room or other user definable locations.

7.1.2.2 Independence of Redundant Safety-Related Systems

7.1.2.2.1 Introduction

This section defines separation criteria for safety-related mechanical and electrical equipment. Safety-related equipment to which the criteria apply is that equipment that is necessary to mitigate the effects of DBAs and is identified in Section 7.1.1. The objective of the criteria is to delineate the separation requirements necessary to achieve independence of safety-related equipment.

7.1.2.2.2 Mechanical Systems Separation Criteria

7.1.2.2.2.1 General

a. Separation of the affected mechanical systems and equipment is accomplished so that the substance and intent of the General Design Criteria of 10CFR50, Appendix A are fulfilled.

b. Consideration is given to the redundant and diverse requirements of the affected systems.

c. Consideration is given to the type, size, and orientation of possible breaks of the RCPB specified in Section 3.6.

d. A single active component failure is an occurrence which results in the loss of capability of a component to perform its intended safety functions. Multiple failures resulting from a single occurrence are considered to be part of the single failure. Fluid systems are considered to be designed against an assumed single failure if a single failure of any active component (assuming passive components function properly) does not result in a loss of capability of the system to perform its safety function.

e. The affected mechanical systems and equipment, along with their associated structures, are appropriately separated so that they are adequately protected against:

    1. The design basis LOCA dynamic effects outlined in Section 3.6

    2. Missiles as defined in Section 3.5

3. Fires and floods capable of damaging redundant mechanical safety equipment (Sections 9.5.1 and 3.4)

The need for and the adequacy of separation are determined in conjunction with the criteria specified in Sections 3.5 and 3.6.

7.1.2.2.2.2 Mechanical Systems Separation

a. Piping for a redundant safety system is run independently of its counterpart. Redundant piping supports, restraints, and mechanical components of the same system are not shared unless it can be shown that such sharing does not impair their ability to perform their safety functions.

b. Entrance penetrations to the containment are separated so that damage to or failure of one branch of a system does not render its redundant counterpart(s) inoperable.

c. Equipment for redundant safety systems or redundant groups of safety systems is separated so that damage to or failure of one division of a system does not render its redundant counterpart inoperable.

7.1.2.2.2.3 Mechanical Systems Physical Separation

a. Mechanical equipment, piping, and tubing for safety-related systems are separated so that no single credible event is capable of disabling sufficient equipment to prevent reactor shutdown, removal of decay heat from the core, long-term suppression pool cooling, isolation, and integrity of the containment. Separation is accomplished either by distance or by physical barriers such as walls and intervening structural components.

   A representation of the separation is shown in Tables 7.1-4, 7.1-5, and 7.1-6.

b. The equipment in each group is separated from that in the other group by the required practical distance.

c. Separation barriers are constructed between the functional groups as required to ensure that the environmental disturbances (such as fire, flood, pipe rupture phenomena, falling objects, etc.) affecting one functional group do not affect the remaining groups.

7.1.2.2.3 Electrical Systems Separation Criteria

7.1.2.2.3.1 General

The electrical separation criteria are described in Section 8.1.6.1.14, compliance with Regulatory Guide 1.75. In addition to the criteria described there, the following applies:

a. Panels and Racks

Panels and racks associated with the RPS or ESF are labeled with marker plates which distinctively identify the equipment as being in the protective system; the difference may be in color, or color of engraving-fill. The marker plates include identification of the proper division of the equipment included.

b. Junction or Pullboxes

Junction and/or pullboxes enclosing wiring for the RPS or ESF have identification similar to and compatible with the panels and racks.

c. Cables

Refer to Section 8.1.6.1.14.

d. Raceways

Refer to Section 8.1.6.1.14.

e. Sensory Equipment Grouping and Designation Letters

Redundant sensory equipment is identified by suffix letters in accordance with Table 7.1-4 for all de-energized-to-operate systems, including the RPS, and in accordance with Table 7.1-5 for the NMS. These tables also show the allocation of sensors to their separated divisions.

f. Isolation Devices

Three types of isolation devices are used in control and instrumentation circuits:

a. Auxiliary relays and control switches

b. Fiber optic couplers

c. Solid-state signal isolators

Auxiliary relays are the most widely used type of isolation device. Several relay types are used with both contact-to-contact and coil-to-contact isolation being used in both BOP and NSSS circuits. Relays and control switches are considered to be acceptable isolation devices if they have a minimum breakdown voltage of at least 600 V RMS between adjacent contacts. This level was chosen because the maximum credible voltage that could be impressed on a control circuit is 530 V ac based on a hot short occurring between a power and control cable in a cable tray.

To confirm the suitability of relays as isolation devices, tests were performed on the several relay types that are mort widely used at LGS. These tests are documented in PECo Test Report 48503, dated September 1, 1982. This test report was submitted to the NRC by letter from J.S. Kemper (PECo) to A. Schwencer (NRC) dated November 20, 1982 and shows that these relays perform satisfactorily in preventing a postulated failure in a non-Class 1E circuit from adversely affecting a Class 1E circuit.

Fiber optic couplers are used to isolate the inputs to the PMS, which is non-safety related, from certain safety-related instrument loops that it monitors. The fiber optic transducers are part of the input modules of the PMS, some of which are Class 1E. The safety related modules are mounted in panels that contain cables of only one division. These panels are located in the control structure from which the multiplexer output is transmitted via fiber optic cable to the TSC where the PMS CPUs are located. Any failure of the PMS would not be reflected back into the safety systems through the fiber optic link because this fiber optic cable has a typical dielectric breakdown of 1.4 MV per inch.

Fiber optic isolators are also used between the Class 1E postaccident radiation monitors and the computer-based RMMS.

The RRCS also uses fiber optic isolators for logic interface between Class 1E divisions and Class 1E/non-Class 1E inputs. Test data for the isolators in these systems was transmitted to the NRC by letter from J.S. Kemper (PECo) to A. Schwencer (NRC) dated December 14, 1983.

Solid-state isolators are used to provide isolation of Class 1E analog inputs to the Plant Monitoring System. Because the computer input cables are routed in raceways that contain only instrumentation cables, it can be shown by analysis that these isolators adequately prevent any failure in the computer or the instrumentation raceways from adversely affecting any safety-related system.

Solid-state isolators are used to isolate inputs from the NMS (except PRNM) and from the dc battery bus to the Plant Monitoring System.

The NMS (except PRNM) isolators consist of an operational amplifier with a 10 volt maximum output which is reduced to 160 mV maximum by a resistive network. A 30 mA fuse is then provided in series prior to taking the signal to the computer. The dc voltage transducer/isolator has been tested to ensure that either a short circuit, open circuit, or short to ground on the output terminals would not cause an unacceptable effect on the dc system.

The PRNM uses fiber optic isolators between divisions and to the Plant Monitoring System, optically coupled relays for isolation of outputs to non-divisional circuits, and magnetically coupled analog isolators for isolation of analog outputs. It has been shown by analysis that these methods in combination with the wire and cable routing within the system assure adequate isolation between redundant channels of the safety-related functions.

Solid-state analog isolators are also used in several HVAC analog control loops to provide isolation of cross-division signals. Test data for all solid-state isolators was transmitted to the NRC by letter from J.S. Kemper (PECo) to A. Schwencer (NRC) dated December 14, 1983.

7.1.2.2.3.2 Electrical Systems Separation Requirements

7.1.2.2.3.2.1 RPS and Normally Energized Portions of PCRVICS

The following general rules apply to RPS wiring. Portions of the NMS wiring are considered as part of the RPS.

a. RPS cable in raceways outside of the main protection system cabinets run in enclosed raceways used only for the RPS. Under-vessel neutron monitoring cables are not placed in any enclosure that unduly restricts their flexibility. Neutron monitoring cables (SRM, IRM, and APRM) may be run in the same raceway, provided that divisional separation is maintained.

b. Wiring to redundant sensors on a common process tap is run in separate raceways to separate destinations to meet the single failure criterion.

c. Wiring for sensors of more than one variable in the same trip channel may be run in the same raceway.

d. Wires from both RPS trip systems that trip actuators to a single group of scram solenoids may be run in a single conduit; however, a single conduit does not contain wires to more than one group of scram solenoids or any other wiring. Wiring for two solenoids on the same control rod may be run in the same conduit.

e. Cables through the primary containment penetrations are so grouped that failure of all cabling in a single penetration cannot prevent a scram (this applies specifically to the neutron monitoring cables and the MSIVs position switch cables).

f. Power supplies to systems that de-energize to operate (so-called "fail-safe" power supplies) require only separation that is deemed prudent to give reliability (continuity of operation). Therefore, the protection system power supplies and load circuit breakers are not required to comply with the separation requirements for safety reasons, even though the load circuits go to separated panels.

g. Wiring providing power for the movement of each RPS backup scram valve and the solenoids for the SDV vent and drain valves is routed in rigid conduit, and wires are separated from one another and from all other cables.

h. The RPS wiring is run and/or protected so that no common source or potentially damaging energy (e.g., electrical fire in non-RPS wireways, malfunction, misoperation of plant equipment, pipe rupture, etc.) could reasonably result in a loss of ability to scram when required.

7.1.2.2.3.2.2 <u>All Other Safety-Related Systems Electrical Systems Separation Criteria</u>

a. Separation is designed so that no single failure can prevent the performance of any safety-related function. Redundant (even dissimilar) systems may be required to perform the required function to satisfy the single failure criterion. Figures 7.1-1 through 7.1-4, and Table 7.1-6 show equipment separation into divisions and the allowable interconnections through isolating devices.

b. The inboard and outboard NSSS system isolation valves are backups for each other, so they must be independent of and protected from each other, to the extent that no single failure can prevent the operation of at least one valve of an inboard/outboard pair. Figure 7.1-3 illustrates the MSL isolation valve separation concept.

c. Isolation valve circuits require special attention because of their function in limiting the consequences of a pipe break outside the primary containment. Isolation valve

control and power circuits are protected from the pipelines that they are responsible for isolating, as follows:

1. Essential isolation valve wiring in the vicinity of the outboard valve (or downstream from the valve) is installed in conduit and routed to take advantage of the mechanical protection afforded by the valve operator or other available structural barriers not susceptible to disabling damage from the pipeline break. Additional mechanical protection (barriers) is interposed as necessary.

2. Isolation valve control and/or power wiring run in a raceway with other cables is protected from secondary effects of damage to those cables that might result from a pipe break in a line requiring isolation (i.e., short circuits that might overheat cables in an ESF raceway).

3. When the downstream piping from the containment is not seismic Category I, the isolation valve wiring in the vicinity of the inboard valve is in rigid conduit and routed so as to take advantage of the mechanical protection afforded by the valve operator or other available structural barriers not susceptible to disabling damage from a pipe line break. Additional mechanical protection (barriers) are interposed as necessary between wiring and potential sources of disabling mechanical damage consequential to a pipe break. Except for the requirements of this paragraph, wiring near the inboard valve does not require special treatment discussed in paragraphs (1) and (2) above.

4. MOVs that have a mechanical check valve backup for their isolation function are included in the division that embraces the system in which the valves are located rather than adhering strictly to the inboard/outboard divisional classification.

d. Steam Leakage Zone

Electrical equipment and raceways for systems listed in Section 7.1.1.2 are not located in a steam leakage zone insofar as is practicable, or they are designed for short-term exposure to the high temperature and humidity associated with a steam leak.

e. Suppression Pool Level Swell Zone

Any electrical equipment and/or raceways for the RPS or ESF located in this zone are designed to complete their function satisfactorily before being rendered inoperable due to exposure to the environment created by the level swell phenomena.

7.1.2.3 Physical Identification of Safety-Related Equipment

The physical identification of equipment is described in Section 8.1.

7.1.2.4 Instrument Errors

The design considers instrument performance, as well as engineering judgment and historical practices in the selection of instrumentation and controls and in the determination of setpoints. An adequate margin between safety limits and Limiting Safety System Settings is provided based on the appropriate combination of engineering judgment, historical practice, and allowances for instrument performance. The Limiting Safety System Settings are contained in the Technical Specifications. When computational techniques are employed, nominal trip setpoints and allowable values are determined by combining allowances for instrument channel performance, such as accuracy (e.g., reference accuracy, pressure effects, temperature affects, radiation effects, etc.), process measurement accuracy, primary element accuracy, instrument drift, calibration accuracies and other uncertainties as appropriate. The specific performance allowance and the environmental and process conditions used, are based on the design, application, functional and calibration requirements of the instrument channel. The surveillance frequency is factored into time based instrument performance parameters.

Process instrument setpoints for LGS Units 1 and 2 are controlled in plant documentation and logs. The setpoints include automatic trip, indication, interlock and alarm setpoints for plant instruments such as analog and digital switches, time delays and similar devices.

The setpoint values shown on the logic diagrams in Chapter 7 are intended to assist the reader in the understanding of the document.

Administrative process control and document instrument setpoints for LGS Units 1 & 2. The scope of these processes include trip, alarm, and initiation setpoints for plant instruments such as analog and digital switches, time delays and similar devices.

The setpoint values shown on the logic diagrams in Chapter 7 are intended to assist the reader in the understanding of the document.

7.1.2.5 Conformance to Regulatory Guides

The statements on the degree of conformance to various regulatory guides which follow are intended to demonstrate an overall safety system level of compliance. The applicability of the conformance statements to each system is found in Table 7.1-3. Each individual system analysis discussion defines any difference in the degree of conformance to a particular regulatory guide.

7.1.2.5.1 Regulatory Guide 1.6 (March 1971) - Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems (Safety Guide 6)

Independence is maintained between redundant standby (onsite) sources and between their distribution systems in compliance with Regulatory Guide 1.6. Further discussion is presented in Section 8.1.6.1.

7.1.2.5.2 Regulatory Guide 1.7 (November 1978) - Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident

Conformance with Regulatory Guide 1.7 is discussed in Section 6.2.5.4.

7.1.2.5.3 Regulatory Guide 1.9 (March 1971) - Selection of Diesel Generator Set Capacity for Standby Power Supplies (Safety Guide 9)

See Section 8.1.6.1 for a complete discussion of conformance with Regulatory Guide 1.9.

7.1.2.5.4 Regulatory Guide 1.11 (March 1971) - Instrument Lines Penetrating Primary Reactor Containment (Safety Guide 11)

Conformance to Regulatory Guide 1.11 is discussed in Section 6.2.4.

7.1.2.5.5a Regulatory Guide 1.21 (June 1974) - Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants

The LGS process and effluent radiological monitoring and sampling systems are designed to allow conformance to this guide, as discussed in Sections 11.5, 7.6 and 7.7. Evaluation and reporting procedures during operation will conform to this guide.

7.1.2.5.5b Regulatory Guide 1.22 (February 1972) – Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The LGS design is in conformance with this guide. With respect to paragraph D.3 of the guide, administrative controls are considered "positive means" to limit the expansion of a bypass to redundant or diverse systems. Collective annunciation of bypassing by manual means is considered to satisfy the guidelines. Additional details are provided below:

D.3a The indications of system inoperability provided under the guidelines of Regulatory Guide 1.47 are used by the operator to prevent, through administrative procedures, the bypassing of a redundant channel of a protection system. The conditions that render the system inoperable during test are annunciated. The conditions that automatically bring up the out-of-service alarm are identifiable to the operator in the control room by means of the out-of-service status light.

D.3b A manual out-of-service switch is provided to annunciate any bypass condition that does not automatically energize the system out-of-service annunciator. A single status light indicates that the annunciator has been manually actuated. Individual indication for each manually induced inoperability is not provided.

Details for each system are discussed in Sections 7.2, 7.3, 7.4 and 7.6.

7.1.2.5.6 Regulatory Guide 1.29 (September 1978) - Seismic Design Classification

LGS is in conformance with this Guide with respect to instrumentation and controls.

The instrumentation and control equipment required to meet seismic Category I requirements is identified in general in Table 3.2-1, and specifically in the system piping and instrumentation drawings.

7.1.2.5.7 Regulatory Guide 1.30 (August 1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

Conformance to this guide is discussed in Section 8.1.6.1.

7.1.2.5.8 Regulatory Guide 1.32 (February 1977) - Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants

Refer to Section 8.1.6.1 for a discussion of this guide.

7.1.2.5.9 Regulatory Guide 1.40 (March 1973) - Qualification Tests of Continuous-Duty Motors Installed Inside the Containment of Water-Cooled Nuclear Power Plants

There are no continuous-duty motors installed inside the containment that are part of the instrumentation and control systems.

7.1.2.5.10 Regulatory Guide 1.45 (May 1973) - Reactor Coolant Pressure Boundary Leakage Detection Systems

The RCPB leakage detection systems are provided to detect and, to the extent practical, identify the location(s) of the source of reactor coolant leakage.

Conformance to Regulatory Guide 1.45 is discussed in Section 5.2.

7.1.2.5.11 Regulatory Guide 1.47 (May 1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

In accordance with the requirements of Regulatory Guide 1.47, bypassed and inoperable status indication has been provided for all plant protection systems. These systems are listed below. Also listed are the conditions that cause annunciation of system inoperability.

Equipment monitored within a protection system is that equipment which, when bypassed on removed from service, will cause inoperability of a redundant portion of the protection system. Bypass or removal of equipment will automatically initiate the system level out-of-service annunciator and illuminate a status light on the system control panel indicating the cause of the out-of-service condition.

All auxiliary and supporting systems to protection systems are monitored as part of the protection system availability in accordance with Regulatory Guide 1.47. The inoperability of these support systems causes the actuation of the out-of-service annunciator for the protection systems that these systems support. A status light is provided to indicate that the inoperability of the support system is the cause of inoperability of the protection system.

The bypass indication system is designed and installed in a manner which precludes the possibility of adverse affects on the plant safety system. The bypass indication system is electrically isolated from the protection circuits so that the failure or bypass of a protective function is not a credible consequence of failures in the bypass indication system and the bypass indication system cannot reduce the independence between redundant safety systems.

Equipment that is bypassed or removed from service not more than once per year is not monitored. A manual out-of-service switch is provided for this equipment and for other equipment that cannot be monitored.

Regulatory Positions C.1, C.2, and C.3:

Automatic indication is provided in the main control room to inform the operator that a system is inoperable. Annunciation is provided to indicate that a system or part of a system is not operable. Individual lights indicate what part of the system is out of service. Manual actuation is provided to cover situations which cannot be automatically annunciated. For example, the reactor protection (trip) system, and the containment and reactor vessel isolation system have annunciators lighting

and sounding whenever one or more channels of an input variable are bypassed. Bypassing is not allowed in the trip logic or actuation logic.

Instruments which form part of a one-out-of-two-twice logic system can be removed from service for calibration. Removal of the instrument from service is indicated in the main control room by manual actuation of the system out-of-service annunciator.

Regulatory Position C.4:

All the annunciators can be tested by depressing the annunciator test switches on the control room bench boards and can be brought up by manual switches as discussed in Regulatory Positions C.1, C.2, and C.3.

The following discussion expands the explanation of conformance to Regulatory Guide 1.47 to reflect the importance of providing accurate information for the operator and of reducing the possibility for the indicating equipment to adversely affect its monitored safety system.

a. Individual indicator lights are arranged together on a control room panel to indicate what function of the system is out of service, bypassed or otherwise inoperable. All bypass and inoperability indicators both at a system level and component level are grouped only with items that will prevent a system from operating if needed.

b. As a result of design, preoperational testing, and startup testing, no erroneous bypass indication is anticipated.

c. These indication provisions serve to supplement administrative controls and aids the operator in assessing the availability of component and system level protective actions. This indication does not perform a safety function.

d. All circuits are electrically independent of the plant safety systems to prevent the possibility of adverse effects.

e. Each indicator is provided with dual lamps and can be periodically tested.

The individual out-of-service condition that initiates a system level out-of-service alarm is listed below.

a. Pump breaker control power undervoltage

b. Pump breaker not connected

c. Pump breaker locked out

d. Loss of power to relay logic

e. Loss of power to control valve or valve motor overload

f. System logic in test

g. Trip unit in calibration or failure

h. Loss of power to trip unit or trip unit out of file

i. Manual out of service

j. Loss of system support HVAC

k. Valves operated from the control room that are not automatically positioned by the initiation signal

l. Transfer switch out of position

For the specific alarms that are associated with a system, refer to the functional control diagram for that system as listed in Chapter 7 figures and to the schematics E-648 as listed in Table 1.7-1.

Systems monitored as discussed above are as follows:

a.	RPS	Drawings C71-1010-F-002, C71-1010-F-003, C71-1010-F-004, and C71-1010-F-005
b.	CS System	Figure 7.3-9
c.	PCRVICS	Figure 7.3-8
d.	HPCI System	Figure 7.3-7
e.	RHR System	Drawings E11-1030-F-001, E11-1030-F-002, and E11-1030-F-003
f.	ESW System	Table 1.7-1
g.	Standby ac Power System	Table 1.7-1
h.	RCIC	Drawings E51-1030-F-004, E51-1030-F-005, E51-1030-F-006, E51-1030-F-007, E51-1030-F-008, and E51-1030-F-009
i.	RHR-SCM	Drawings E11-1030-F-001, E11-1030-F-002, and E11-1030-F-003
j.	REIS	Drawings B21-1030-F-002, B21-1030-F-002, B21-1030-F-003, B21-1030-F-004, B21-1030-F-005 and M-76FD
k.	SGTS	Drawing M-76FD
l.	RERS	Drawing M-76FD
m.	Control Enclosure HVAC Systems	Drawing M-78FD
n.	NMS	Figure 7.6-1

o. SLCS Table 1.7-1

p. CGCS Table 1.7-1

Regulatory Guide 1.47 compliance for Items (k), (l), and (m) above is through the use of a trouble alarm in the control room that will direct the operator to a local control panel in the control enclosure for more information. For Items (n) through (p), alarms are provided in the control room that provide the cause of the out-of-service condition. No status lights are provided.

The following three systems do not have system level out-of-service alarms in the control room: NMS, SLCS, and CGCS. The following conditions which can make these systems out of service are specifically annunciated in the control room:

a. NMS (Drawing E-620)

SRM	Downscale
SRM	Upscale/Inoperable
SRM	Retracted When Not Permitted
IRM	Upscale/Inoperable
IRM	Downscale
IRM	Upscale
RBM	Downscale/Trouble
APRM/RBM	Flow Reference Off-Normal
RBM	Upscale/Inoperable
APRM	Downscale
APRM	Upscale
LPRM	Downscale
LPRM	Upscale
APRM	Upscale Trip/Inoperable
OPRM/APRM	Trouble
OPRM	Upscale Trip
OPRM	Trips Enabled

b. SLCS (Drawing E-620)

SLCS	Pump A/B/C Overload/Loss of Power
SLCS	Tank High/Low Level
SLCS	Tank High/Low Temperature
SLCS	Squib Valve Loss of Continuity
SLCS	Isolation Valves Not Fully Open

c. CGCS (Drawing E-622)

Drywell H_2 Recombiner System Trouble 1A
Drywell H_2 Recombiner System Trouble 1B
The following alarms are provided on the recombiner control panels which are located in the control room behind the main control boards:

Return Gas Temperature High
Reaction Chamber Shell Temperature High

Blower Inlet Gas Pressure High
Reaction Chamber Gas Temperature High
Blower Inlet Temperature High
Blower Inlet Gas Flow Low
Reaction Chamber Gas Temperature Low
Heater Wall Temperature High

The above alarms for these four systems represent all conditions which can prevent the system from performing its safety function. The requirements of Regulatory Guide 1.47 for these systems are therefore satisfied. Any other conditions can be annunciated by manually causing one of the above annunciators to light.

Details of the administrative procedures that control access as a means for bypassing are contained in Section 7.2.2.1.1.1.8.

7.1.2.5.12 Regulatory Guide 1.53 (June 1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

LGS is in conformance with this guide which provides that protection systems meet section 4.2 of IEEE 279 (1971), in that any single failure within the protection systems will not prevent proper protective action at the system level when required. Conformance is achieved by specifying, designing, and constructing the ESFs to meet the single failure criterion, section 4.2 of IEEE 279 (1971), "Criteria for Protection Systems for Nuclear Power Generating Stations," and IEEE 379 (1972), "IEEE Trial Use Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems." See Sections 7.2, 7.3, 7.4, and 7.6 for a discussion of conformance for each system.

7.1.2.5.13 Regulatory Guide 1.56 (July 1978) - Maintenance of Water Purity in Boiling Water Reactors

The RWCU instrumentation is in conformance with Regulatory Guide 1.56. Further discussion is provided in Sections 7.7.2.8.2.3 and 5.4.8. Conformance of the deep bed condensate demineralizer system is discussed in Section 10.4.6.

7.1.2.5.14 Regulatory Guide 1.62 (October 1973) - Manual Initiation of Protective Actions

LGS is in conformance with this guide which provides that manual initiation of each protective action at the system level be provided, that such initiation accomplish all actions performed by automatic initiation, and that protective action at the system level goes to completion once manually initiated. In addition, manual initiation is by switches readily accessible in the control room, and a minimum of equipment should be used in common with automatically initiated protective action.

Means are provided for manual initiation of the PCRVICS, the ECCS, and for RPS scram at the system level through the use of armed push buttons, as described below:

ACTION INITIATED	NUMBER OF SWITCHES
PCRVICS	Four
ADS	Four: two in Division 1 and two in Division 3
HPCI	One in Division 2

RHR A/CS A*	One in Division 1
RHR B/CS B*	One in Division 2
RHR C/CS C*	One in Division 3
RHR D/CS D*	One in Division 4
RPS	Four

The note "*" indicates that pumps A and C are for one CS injection system, and the B and D pumps are for the other system.

The operation of these switches initiates all actions performed by the automatic initiation circuitry.

For a detailed discussion on Regulatory Guide 1.62 compliance, refer to the following UFSAR Sections:

PCRVICS	Section 7.3.2.2.2.1.7
ADS	Section 7.3.2.1.2.1.9
HPCI	Section 7.3.2.1.2.1.9
RHR/CS	Section 7.3.2.1.2.1.9
RPS	Section 7.3.2.1.2.1.9

7.1.2.5.15 Regulatory Guide 1.63 (July 1978) - Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants

Conformance to this guide is discussed in Section 8.1.6.1.

7.1.2.5.16 Regulatory Guide 1.68 (August 1978) - Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors

Conformance to this guide is discussed in Section 14.2.

7.1.2.5.17 Regulatory Guide 1.70 (November 1978) - Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants

Chapter 7 conforms to the format of Regulatory Guide 1.70.

7.1.2.5.18 Regulatory Guide 1.73 (January 1974) - Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants

Conformance to this guide is discussed in Sections 8.1.6.1 and 3.11.2.2.

7.1.2.5.19 Regulatory Guide 1.75 (September 1978) - Physical Independence of Electric Systems

Conformance is discussed in Section 8.1.6.1.14.

7.1.2.5.20 Regulatory Guide 1.80 (June 1974) - Preoperational Testing of Instrument Air Systems

Conformance to this guide is discussed in Section 14.2.

7.1.2.5.21 Regulatory Guide 1.89 (November 1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

Discussion of degree of conformance to Regulatory Guide 1.89 is given in Section 3.11.2 for NSSS equipment and in Section 8.1.6.1 for non-NSSS equipment.

7.1.2.5.22 Regulatory Guide 1.96 (May 1975) - Design of Main Steam Isolation Valve Leakage Control Systems for Boiling Water Reactor Nuclear Power Plants

In 1994, LGS received approval to remove the MSIV-LCS and replace it with the MSIV Leakage Alternate Drain Pathway discussed in Section 6.7.

7.1.2.5.23 Regulatory Guide 1.97 (December 1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

See Section 7.5 for a discussion of the degree of conformance.

7.1.2.5.24 Regulatory Guide 1.100 (August 1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

The degree of conformance to this guide is discussed in Section 3.10.

7.1.2.5.25 Regulatory Guide 1.105 (November 1976) - Instrument Setpoints

Although this guide does not apply to LGS per its implementation section except for the RRCS, the following is an assessment of the design supplied.

The nominal trip setpoint and allowable value for Limiting Safety System Settings are contained in the Technical Specifications. These parameters are determined based on the appropriate combination of engineering judgment, historical practice, and allowances for instrument performance (7.1.2.4). The setpoints are within the operating capability of the associated instruments. The established setpoints provide sufficient margin to satisfy both safety requirements, and plant availability objectives.

Related setpoint methodology concerns have been addressed by Reference 7.1-1. In a May 15, 1984 submittal, LGS endorsed the work scope and schedule proposed by Reference 7.1-1, which was accepted by the NRC staff in Reference 7.1-2. The licensee agreed to show compliance with the methodology within 6 months of NRC approval of the methodology. The methodology was submitted by GE on November 19, 1986. This methodology has been accepted by the NRC by virtue of issuance of an SSER for the Power Re-Rate for LGS.

7.1.2.5.26 Regulatory Guide 1.118 (June 1978) - Periodic Testing of Electric Power and Protection Systems

This guide, which endorses/modifies IEEE 338 (1977), is not applicable to LGS per its implementation section except for the RRCS. Discussion of IEEE 338 is presented on a system-by-system basis in the analysis portion of Section 7.2, 7.3, 7.4, and 7.6 with the following clarification of the regulatory guide requirements:

Position C.2 - Insofar as is practical and safe, response time testing will be performed from sensor inputs (at the sensor input connection for process instruments) to and including the actuated device.

Sensor response time testing for pressure sensors for the RPS will be performed in accordance with Regulatory Guide 1.118 (June, 1978). Response of the sensor output and the final actuation device will be measured. Response time testing for the differential pressure (level) sensors is not required based on the analysis performed in NEDO-32291-A. Response time testing of the trip unit and relay logic are required. Neutron detectors are exempt from response time testing; response time will be measured from the input of the first electronic component in the channel. Except for the MSIVs, individual sensor response times and logic system response times are not required for isolation systems because the signal delay (sensor response) is concurrent with the 13 second diesel startup. (Refer to LGS Technical Specification Bases 3/4.3.2 "Isolation Actuation Instrumentation" and 3/4.3.3 "ECCS Actuation Instrumentation.")

Position C.6b - Trip of an associated protective channel or actuation of an associated Class 1E load group is required on removal of fuses or opening of a breaker only for the purpose of deactivating instrumentation and control circuits.

Evaluation of the systems to be surveillance tested has determined that the actions required will include opening of circuit breakers. This action is required in a limited number of cases. The circuit breakers will be opened during monthly testing but will also bring up an out-of-service alarm that will not clear with the breaker open.

A review of safety-related control circuits that may be affected by racking-out their individual circuit breakers reveals that disabling of one component does not render redundant components inoperable. All modes of test, operation, and failure were considered; specifically, a study was conducted to identify safety systems with crossover interlocks. The effects of disabling of these components and their associated interlocks were then analyzed. The review identified that several crossover interlocks exist in the ESW and RHRSW systems and in several of the NSSS fail-safe logic circuits. However, the analysis did not disclose any cases where disabling the component or the associated interlocks would adversely affect the redundant safety circuit or components.

Response to Information Notice 84-37 – Lifting of leads will be required to perform a limited number of the surveillance tests. Each of these tests, however, will follow the guidance provided by Information Notice 84-37, dated May 10, 1984.

The procedure for these tests will include instructions requiring the reconnecting of the lifted leads following the completion of the surveillance. This procedural step will be documented by a sign-off sheet to be initialed by the tester when the lifted leads have been reconnected. An independent or double verification will be performed and documented in the procedure to verify that the lifted leads have been returned to service. If permitted by existing plant design, functional tests designed to verify the restoration of proper system configuration will be performed.

The lifting of leads will be limited to surveillance tests that fall into one of the four categories below:

a. Test that involve thermocouples

b. Test that require the introduction of test equipment into the instrument channel being tested

c. Tests on extensive systems that would otherwise become unnecessarily large and complex

d. Tests on systems or components for which the plant design permits no other reasonable alternative.

7.1.2.5.27 Regulatory Guide 1.139 (May 1978) - Guidance for Residual Heat Removal

Conformance to this guide is discussed in Section 5.4.

7.1.2.6 Conformance to 10CFR50, Appendix A, General Design Criteria

The statements which follow on the degree of conformance to various GDC are intended to demonstrate an overall safety system level of compliance. The applicability of the conformance statements to each system is found in Table 7.1-3. Each individual system analysis discussion defines any difference in the degree of conformance to a particular GDC.

7.1.2.6.1 GDC 1 - Quality Standards and Records

All systems required for safety are designed and built in accordance with an established quality assurance program.

7.1.2.6.2 GDC 2 - Design Bases for Protection Against Natural Phenomena

All systems required for safety are designed to withstand the effects of natural phenomena without loss of capability to perform their safety functions.

7.1.2.6.3 GDC 3 - Fire Protection

All systems and components required for safety are designed and located to minimize the probability and effect of fires and explosions. Materials that are heat-resistant and noncombustible have been chosen wherever practicable.

7.1.2.6.4 GDC 4 - Environmental and Dynamic Effects Design Bases

Systems and components required for safety are designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operations maintenance testing and postulated accidents, including LOCAs. These systems and components are appropriately protected against dynamic events such as missiles and pipe whipping.

7.1.2.6.5 GDC 5 - Sharing of Structures, Systems, and Components

Systems and components required for safety are not shared with any other nuclear power unit, except for the RHRSW, the ESW, the SGTS and the control structure ventilation systems, which are common systems.

7.1.2.6.6 GDC 10 - Reactor Design

The reactor core and associated coolant, control, and protection systems are designed with appropriate margins to ensure that specified acceptable fuel design limits will not be exceeded

during any condition of normal operation, including the effects of anticipated operational occurrences.

7.1.2.6.7 GDC 12 - Suppression of Reactor Power Oscillations

The instrumentation and control systems are designed to readily detect and initiate action to suppress reactor power oscillations.

7.1.2.6.8 GDC 13 - Instrumentation and Control

Instrumentation is provided to monitor variables and systems over their anticipated ranges for normal operation, anticipated operational occurrences, and accident conditions and to control these variables and systems to ensure adequate safety.

7.1.2.6.9 GDC 15 - Reactor Coolant System Design

The RCS instrumentation and control systems are designed to ensure that the design conditions of the RCPBs are not exceeded.

7.1.2.6.10 GDC 19 - Control Room

A control room is provided where actions can be taken to operate the nuclear power unit under normal and abnormal conditions. A remote shutdown capability is also provided.

7.1.2.6.11 GDC 20 - Protection System Functions

The protection systems are designed to sense accident conditions and automatically initiate the operation of appropriate systems important to safety to ensure that specified fuel design limits are not exceeded.

7.1.2.6.12 GDC 21 - Protection System Reliability and Testability

The conformance discussion of this GDC is presented on a system-by-system basis in the analysis portions of Sections 7.2, 7.3, 7.4, and 7.6.

7.1.2.6.13 GDC 22 - Protection System Independence

The protection systems are designed with independence through redundancy or functional diversity to prevent loss of the protection function.

7.1.2.6.14 GDC 23 - Protection System Failure Modes

The protection systems are designed to be fail-safe during anticipated operational occurrences including postulated adverse environments.

7.1.2.6.15 GDC 24 - Separation of Protection and Control Systems

The protection systems are separated from control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection

system component or channel which is common to both, leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system.

7.1.2.6.16 GDC 25 - Protection System Requirements for Reactivity Control Malfunctions

The protection system is designed so that fuel design limits are not exceeded even with any single malfunction of the reactivity control system.

7.1.2.6.17 GDC 26 - Reactivity Control System Redundancy and Capability

The conformance discussion of this GDC is presented on a system-by-system basis in the analysis portions of Sections 7.4, 7.6, and 7.7.

7.1.2.6.18 GDC 27 - Combined Reactivity Control Systems Capability

The conformance discussion of this GDC is presented on a system-by-system basis in the analysis portions of Sections 7.4, and 7.7.

7.1.2.6.19 GDC 28 - Reactivity Limits

The conformance discussion of this GDC is presented on a system-by-system basis in the analysis portions of Sections 7.6 and 7.7.

7.1.2.6.20 GDC 29 - Protection Against Anticipated Operational Occurrences

The protection and reactivity control systems are designed to ensure an extremely high probability of accomplishing their safety function in the event of an anticipated operational occurrence.

7.1.2.6.21 GDC 30 - Quality of Reactor Coolant Pressure Boundary

The conformance discussion of this GDC is presented in the analysis portions of Sections 7.3, 7.4, and 7.6.

7.1.2.6.22 GDC 33 - Reactor Coolant Makeup

Reactor coolant makeup is provided to ensure that specified acceptable fuel design limits are not exceeded because of reactor coolant losses in the RCPB.

7.1.2.6.23 GDC 34 - Residual Heat Removal

A system is provided to remove reactor residual heat to ensure that the specified acceptable fuel design limits are not exceeded even assuming a single failure.

7.1.2.6.24 GDC 35 - Emergency Core Cooling

An ECCS is provided to ensure cooling of the reactor following any loss of reactor coolant at undesirable rates even assuming a single failure.

7.1.2.6.25 GDC 37 - Testing of Emergency Core Cooling System

The ECCS is designed to permit appropriate periodic pressure and functional testing including the controls which bring the system into operation.

7.1.2.6.26 GDC 38 - Containment Heat Removal

A system is provided to ensure heat removal from the reactor containment following any LOCA even assuming a single failure.

7.1.2.6.27 GDC 40 - Testing of Containment Heat Removal System

The containment heat removal system is designed to permit appropriate periodic and functional testing including the controls which bring the system into operation.

7.1.2.6.28 GDC 56 - Primary Containment Isolation

Each line that connects directly into the containment atmosphere and penetrates the primary reactor containment is provided with isolation valves that comply with the requirements of this criterion.

7.1.2.6.29 GDC 57 - Closed System Isolation Valves

See GDC 56.

7.1.2.6.30 GDC 60 - Control of Releases of Radioactive Materials to the Environment

The nuclear power unit is designed to control the release of radioactive material and from gaseous, liquid, and solid effluents to within prescribed limits, through monitoring the release points and processing the effluent.

7.1.2.6.31 GDC 61 - Fuel Storage and Handling and Radioactivity Control

The conformance discussion of this GDC is presented in the analysis portion of Section 7.7.

7.1.2.6.32 GDC 63 - Monitoring Fuel and Waste Storage

The conformance discussion of this GDC is presented in the analysis portion of Section 7.7.

7.1.2.6.33 GDC 64 - Monitoring Radioactivity Releases

The conformance discussion of this GDC is presented in the analysis portion of Section 7.6.

7.1.2.7 Conformance to Industry Codes and Standards

The statements which follow on the degree of conformance to various industry standards are intended to demonstrate an overall safety system level of compliance. The applicability of the conformance statements to each system is found in Table 7.1-3. Each individual system analysis discussion will define any difference in the degree of conformance to a particular industry standard.

Reference 7.1-3 discusses the conformance of the sensors to industry standards and regulatory guides.

Conformance other than that discussed in NEDO-21617-A is discussed in Section 7.1.2.5 and 7.1.2.6 and also on a system-by-system basis in Sections 7.2, 7.3, and 7.4.

7.1.2.7.1 IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

This discussion is presented on a system-by-system basis in the analysis portions of Sections 7.2, 7.3, 7.4, and 7.6.

7.1.2.7.2 IEEE 308 (1971 and 1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Conformance to IEEE 308 as described in Section 8.3 is applicable to safety-related instrumentation and control equipment.

7.1.2.7.3 IEEE 317 (1972) - Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations

Penetration assemblies meet the requirements of IEEE 317 (1972) and GDC 50 of 10CFR50, Appendix A.

All containment electrical penetration assemblies used for Class 1E and non-Class 1E circuits are designed to withstand, without loss of containment integrity, the maximum postulated overcurrent versus time conditions, assuming a single failure of the circuit primary overcurrent protection apparatus.

7.1.2.7.4 IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

Written procedures and responsibilities are developed for the design and qualification of Class 1E electric equipment. This includes preparation of specifications, qualification procedures, and documentation. Whenever possible qualification testing or analysis is accomplished before release of the engineering design for production. Standards manuals are maintained containing specifications, practices, and procedures for implementing qualification requirements. The environmental qualification of this equipment is being evaluated to the criteria of NUREG-0588 Category II. An Environmental Qualification Report will be provided to present the results of this evaluation.

See Sections 3.11.2 and 8.1.6.1 for a conformance discussion of IEEE 323 and Regulatory Guide 1.89 for NSSS and non-NSSS equipment, respectively.

7.1.2.7.5 IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

See Section 8.1.6.1 for a conformance discussion of Regulatory Guide 1.30 which endorses/modifies IEEE 336 (1971).

7.1.2.7.6 IEEE 338 (1971, 1975, and 1977) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

This discussion is presented on a system-by-system basis in the analysis portion of Sections 7.2, 7.3, 7.4, and 7.6.

See Section 7.1.2.5.26 for a conformance discussion of Regulatory Guide 1.118, which endorses/modifies this standard.

7.1.2.7.7 IEEE 344 (1971 or 1975) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

All safety-related instrumentation and control equipment is classified as seismic Category I and designed to withstand the effects of an SSE, and function before, during and after such a seismic event. Equipment required to function after an SSE is also qualified for such service. Qualification and documentation procedures used for seismic Category I equipment and systems meet the provisions of IEEE 344 as identified in Section 3.10.

7.1.2.7.8 IEEE 379 (1972 or 1977) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The extent to which the single failure criteria of IEEE 379 are satisfied is specifically covered for each system in the analysis of IEEE 279, paragraph 4.2.

7.1.2.7.9 IEEE 382 (1972) - Trial Use Guide for Type Test of Class 1 Electric Valve Operators for Nuclear Power Generating Stations

The extent of conformance to this standard is given in Sections 3.11.2 and 8.1.6.1.13.

7.1.2.7.10 IEEE 383 (1974) - Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations

The extent of conformance to this standard is given in Section 7.7.2.21.2.2.1.

7.1.2.7.11 IEEE 384 (1974 or 1977) - Criteria for Separation of Class 1E Equipment and Circuits

The safety-related systems described in Sections 7.2, 7.3, 7.4, and 7.6 meet the independence and separation criteria for redundant systems in accordance with IEEE 279, paragraph 4.6 (Section 7.1.2.5.1).

The electrical power supply, instrumentation, and control wiring for redundant portions of safety-related systems have physical separation to preserve redundancy and ensure that no single credible event prevents operation of the associated function. Credible events include, but are not limited to, the effects of short circuits, pipe rupture, pipe whip, high pressure jets, missiles, fire, earthquake, and falling objects, and are considered in the basic plant design.

The independence of tubing, piping, and control devices for safety-related controls and instrumentation is achieved by physical space or barriers between separation groups of the same protective function. In locations where a specific hazard exists (missile, jet, etc.) that could produce damage to safety-related controls and instrumentation, the physical separation or structural protection provided is adequate to ensure that no multiple failures can result from a single common event.

The criteria and bases for the independence of electrical cable, including routing, marking, and cable derating, are discussed in Section 8.1. Fire detection and protection in the areas where wiring is installed are discussed in Section 9.5.1.

Regulatory Guide 1.75, which endorses/modifies this standard, is discussed in Section 7.1.2.5.19.

7.1.2.8 Conformance to Branch Technical Positions

7.1.2.8.1 BTP ICSB 3

The HPLPSI conform to BTP ICSB 3 as discussed in Section 7.6.1.2.

7.1.2.8.2 BTP ICSB 21

Conformance to BTP ICSB 21 is discussed below, by position:

B1. Individual indicator lights are arranged together on a control room panel to indicate what function of the system is out-of-service, bypassed, or otherwise inoperable. All bypass and inoperability indicators both at a system level and component level are grouped only with items that will prevent a system from operating if needed.

B2. LGS has only one control room. When a protective function of a shared system is bypassed, it is annunciated on the annunciator panel for the shared system, and status indication for the system is provided on the control panel for the shared system.

B3. As a result of design, preoperational testing, and startup testing, no erroneous bypass indication is anticipated. Capability for cancelling bypass indications is not provided.

B4. These indication provisions serve to supplement administrative controls and to aid the operator in assessing the availability of component and system level protective actions. This indication does not perform a safety function.

B5. All circuits are electrically independent of the plant safety systems to prevent the possibility of adverse effects.

B6. The out-of-service annunciators can be tested by depressing the annunciator test switches on the control room bench boards. Each status indicating light can be tested by depressing the light assembly.

The bypass and inoperable status indicators are further discussed in Section 7.1.2.5.11.

7.1.2.8.3 BTP ICSB 22

The conformance to the provisions of D.4 of Regulatory Guide 1.22 for actuated equipment not tested during power operation is discussed in Section 7.3.2.1.2.3.1.10 for the ADS valves and Sections 7.4.2.2.2.3.1.9 and 7.4.2.2.2.3.1.10 for the SLCS explosive valves.

7.1.2.8.4 BTP ICSB 26

Anticipating or backup trips for the system comply with the requirements of IEEE 279 (1971) as discussed in Section 7.2.2.1.2.3.1.

7.1.2.9 Technical Design Bases

The technical design bases appear as follows:

RPS	Section 7.2.1
ESFs	Section 7.3.1
Systems required for safe shutdown	Section 7.4.1
Other systems required for safety	Section 7.6.1

7.1.2.10 Safety System Settings

The Limiting Safety System Settings are listed in the Technical Specifications discussions for each safety system. The settings are determined based on operating experience and conservative analyses. The settings are set to preclude inadvertent initiation of the safety action, while ensuring that a sufficient margin is maintained to satisfy safety requirements. The appropriate combination of engineering judgment, historical practice, and allowances for instruments performance are considered in the setpoint determination (Section 7.1.2.4). The margin between the limiting safety system settings and the actual safety limits includes consideration of the design basis transients in the process being measured, expected for the time the specific functions are required.

7.1.2.11 Operating Experience Assessment

Review of operating experiences and assessment of their applicability to LGS is conducted as discussed in Section 13.4.5. The actions taken by the licensee for LGS for some specifically requested NRC Bulletins, Circulars and Information Notices is provided in Table 7.1-7. Specific actions taken for some of these is provided below.

7.1.2.11.1 Bulletin 80-06, Engineered Safety Feature Reset Controls

Bulletin 80-6 requires that safety-related equipment remain in its emergency mode on reset of an ESF actuation signal.

To determine whether or not all safety-related equipment remains in its emergency mode on isolation signal reset, schematic drawings for all LGS systems serving safety-related functions were reviewed. The review showed that a number of valves were subject to reverting to their normal mode on isolation signal reset. All continuous-duty loads were found to remain in their emergency mode on isolation signal reset.

In general, control schemes of safety-related valves found not to remain in their emergency mode on reset of an isolation signal were revised to provide a control switch interlock with the isolation signal reset circuit (Figure 7.1-5). To reset an isolation signal, every valve subject to reverting to normal mode on reset of the isolation signal must have its control switch placed in the closed position. A normally open contact of each of the valve control switches is wired in series with the

isolation signal reset contact. On manual placement of all of the subject control switches in the closed position, the permissive series of control switch contacts will all be closed, thus allowing the isolation signal reset contact to complete the reset circuit.

On the bases of the design review, the following systems and valve control schemes were modified as described above:

System	Valve No.	
CAC System	HV57-117	SV57-133
	HV57-118	SV57-183
	HV57-104	SV57-191
	HV57-114	SV57-181
	HV57-123	SV57-132
	HV57-124	SV57-134
	HV57-121	SV57-150
	HV57-131	SV57-141
	SV57-184	SV57-142
	SV57-185	SV57-143
	SV57-186	SV57-144
	SV57-190	SV57-145
	SV57-195	SV57-159
PCIG System	HV59-129A	SV59-131
	HV59-102	SV59-135
	HV59-129B	
NSSSS	HV41-1F084	HV51-1F079A
	HV41-1F085	HV51-1F079B
	HV43-1F019	HV51-1F080A
	HV43-1F020	HV51-1F080B

In addition to the foregoing valves, drywell purge exhaust fan inlet isolation valves HV76-030 and HV76-031 were found to revert to their normal mode on isolation signal reset. Thus, if the valves were in their open purge mode on receipt of an isolation signal, the valves would revert to the open purge mode isolation signal reset. To ensure that these valves remain in their closed emergency mode on isolation signal reset, the valve control schemes were modified to the configuration shown on Figure 7.1-6. The auxiliary relay (95-2) is picked up by the normally closed isolation signal contacts and by the placement of the valve control switch in the "CLOSE" position. Once picked up, the auxiliary seals itself in with a contact around the valve control switch "CLOSE" contact. The valves are placed in the "OPEN" purge position through a contact from the auxiliary relay and the placement of the valve control switch in the "OPEN" position. On receipt of an isolation signal, the normally closed isolation signal contacts open, thus dropping out the auxiliary relay, which in turn opens the auxiliary relay seal-in circuit and de-energizes the valve "OPEN" circuit, thus closing the valve. Resetting the isolation signal will not re-energize the auxiliary relay because the valve control switch is in the "OPEN" position. Thus, the valve "OPEN" circuit will remain de-energized and the valves will remain closed.

The liquid radwaste collection isolation valves, HV61-110, HV61-111, HV61-130 and HV61-131 were found to revert to normal mode on isolation signal reset. To ensure that these valves

remained in their emergency mode, seal-in relays were added in their control circuit. Because these valves are a part of the drywell sump tank level control system and the primary containment leakage detection system, these valves have been excluded from the system logic reset and are provided with individual reset circuits.

The following are exceptions to Bulletin 80-06 guidance:

a. RCIC

All actuated equipment remains in its abnormal condition, except for the RCIC system inboard and outboard steam line isolation valves, E51-F007 and E51-F008.

b. HPCI

All actuated equipment remains in its abnormal condition, except for the HPCI system inboard and outboard steam line isolation valves, E41-F002 and E41-F003.

The reset control for the HPCI/RCIC isolation logics do not strictly meet the intent of Bulletin 80-06. If the isolation logic is reset with the valve control switches in the open position, the isolation valves will open, but we believe the design is acceptable. There are two completely independent isolation logics for the HPCI and RCIC. Each of these logics consists of two logic channels, one for the inboard valves and one for the outboard valves. Each of these logic channels is sealed in until a reset switch in that logic is depressed. Therefore activation of the reset switch only affects one logic channel and will only cause the inboard or outboard valves to open on the system being reset. The line will remain isolated, i.e., in its safe mode, until both the isolation logics for each system are reset. In addition, the logic reset has no effect if the initiation signal is still present. Administrative Procedures will instruct the operator to place the control switches in the closed position before resetting the isolation logic. In addition to this procedural caution, a caution tag will be added to the control board next to the reset switch. This tag will instruct the operator to place the control switches for the associated valves in the closed position before resetting the logic.

Even if the HPCI of RCIC isolation valves were inadvertently reopened before the pipe break condition was corrected, due to both isolation logics being reset after the isolation parameters have cleared, the pipe break condition would be detected again and the isolation valves would reclose. The offsite radiological doses due to the released steam would be a small fraction of the 10CFR50.67 limits.

The results of this review will be verified as part of the system preoperational testing.

7.1.2.11.2 Information Notice 79-22, Qualification of Control Systems

Information Notice 79-22 discusses the effects of a HELB on nonsafety-related control systems to determine whether any adverse effects initiated by a HELB could result in an event more severe than the transient and accident events analyzed in Chapter 15.

In response, a comprehensive, systematic study has been conducted to determine the consequences of postulated HELBs and their effects on adjacent, nonsafety-related, control systems components. In most cases, the effects of the postulated HELB (control systems failures) events are less severe than the Unacceptable Results for Incidents of Moderate Frequency -

Anticipated Operational Transients presented in Chapter 15. In all cases, the effects of the postulated events are bounded by the Unacceptable Results for Limiting Faults - Design Basis (Postulated) Accidents presented in Chapter 15. It is concluded that safe reactor shutdown is assured for all events postulated therein, and the consequences of these postulated events do not result in any significant risk to the health and safety of the public.

Details of the LGS Unit 1 analysis were submitted on May 4, 1984. The report was later updated to confirm its applicability to Unit 2 and submitted on February 17, 1989.

7.1.2.11.3 Bulletin 79-27, Loss of Non-Class 1E Instrumentation and Control Power Systems Bus During Operation

Bulletin 79-27 discussed a failure of a bus supplying power to control systems and vital instrumentation resulting in a malfunction of the control systems and a simultaneous loss to the operator of information required for a safe shutdown. In response, an analysis has been conducted to demonstrate that the control systems used to achieve a hot shutdown are designed to perform their intended function with a loss of any single power source. Subsequent cooldown to cold shutdown conditions will be accomplished using diverse means. One method utilizes the shutdown cooling mode of the RHR system. An alternate method utilizes the ADS to depressurize, core spray for make up, and RHR in the suppression pool cooling mode.

An analysis has also been conducted to demonstrate that for a loss of power to an instrument there is another instrument available, fed from an independent bus, that monitors the same parameter or a diverse parameter that will provide sufficient information to achieve cold shutdown.

From these reviews we conclude that there exists sufficient diversity and redundancy of the plant's power supplies and that the capability to place the plant in a cold shutdown condition would not be compromised by a loss of Class 1E or non-Class 1E instrument and/or control system power supply and that for all instrumentation and controls needed for safe shutdown a loss of power is annunciated directly or indirectly in the control room.

Details of the LGS Unit 1 analysis were submitted on December 14, 1983 and supplementation on June 5, 1984. The report was later updated to confirm its applicability to Unit 2 and submitted on February 17, 1989.

7.1.3 PROTECTION SYSTEM INSERVICE TESTABILITY

Testability provisions for each system are discussed in Sections 7.2, 7.3, 7.4, and 7.6.

7.1.4 REFERENCES

7.1-1 Letter from J.F. Carolan (Chairman, LRG Instrumentation Setpoint Methodology Group) to T.M. Novak (NRC), "Action Plan to Answer the NRC Staff concerns on Setpoint Methodology for General Electric Supplied Protection System Instrumentation," (June 29, 1984).

7.1-2 Letter from B.J. Youngblood (NRC) to J.F. Carolan (Chairman, LRG Instrumentation Setpoint Methodology Group), "Acceptance of Action Plan to Answer NRC Staff Concerns on Setpoint Methodology for General Electric Supplied Protection System Instrumentation," (July 23, 1984).

7.1-3 "Analog Transmitter/Trip Unit Systems for Engineered Safeguard Sensor Trip Inputs," Licensing Topical Report, NEDO-21617-A.

Table 7.1-1

DESIGN AND SUPPLY RESPONSIBILITY

	GE Design	GE Supply	Others
Reactor Trip System			
Reactor protection system	x	x	x
Engineered Safety Feature Systems			
Emergency core cooling systems HPCI system ADS CS system LPCI mode of the RHR system	x	x	
Primary containment and reactor vessel isolation control system	x	x	x
Service water systems RHRSW ESW			x
Containment atmosphere control system, combustible gas control system, primary containment vacuum relief system			x
Class 1E power system			x
Suppression pool cooling mode of RHR system	x		x
Containment spray mode of RHR system	x	x	
SGTS			x
Reactor enclosure recirculation system			x
Reactor enclosure isolation system			x
Habitability, control room isolation			x
SGTS filter room and access area unit coolers			x
Diesel generator enclosure ventilation system			x
Spray pond pump structure ventilation system			x
Emergency switchgear and battery rooms cooling system			x
ECCS pump compartment unit coolers			x

Table 7.1-1 (Cont'd)

	GE Design	GE Supply	Others
Engineered Safety Feature Systems			
Drywell unit coolers			x
Control enclosure chilled water system			x
Auxiliary equipment room ventilation system			x
Refueling area isolation system			x
Systems Required for Safe Shutdown			
RCIC system	x	x	
SLCS	x	x	
Shutdown cooling mode at the RHR system	x	x	
Remote shutdown system	x	x	
Safety-Related Display Instrumentation	x	x	x(1)
All Other Systems Required for Safety			
Process radiation monitoring system			
Main steam line radiation monitoring system	x	x	
Reactor enclosure ventilation exhaust radiation monitoring system	x	x	
Refueling floor ventilation exhaust radiation monitoring system	x	x	
Control room ventilation radiation monitoring system			x
Control room emergency fresh air radiation monitoring system			x
Primary containment post-LOCA radiation monitoring system			x
RHRSW radiation monitoring system	x	x	
High pressure/low pressure systems interlocks	x	x	
SRV position indication system			x
Containment instrument gas system-ADS control			x
Safeguard piping fill system			x
Neutron monitoring system	x	x	
Intermediate range monitor			
Local power range meter			
Average power range monitor			
Redundant reactivity control system	x	x	

Table 7.1-1 (Cont'd)

	GE Design	GE Supply	Others
Leak detection systems	x		x
Main steam line leak detection subsystem			
RCIC system leak detection subsystem			
RWCU system leak detection subsystem			
HPCI system leak detection subsystem			
Control Systems Not Required for Safety			
Fuel pool cooling and cleanup system			x
RPV instrumentation	x	x	
Reactor manual control system	x	x	
Rod movement control			
Rod block trips			
Recirculation flow control systems			x
Feedwater control system	x	x	x
Pressure regulator & turbine-generator system			x
Process Radiation Monitoring Systems			
South stack effluent radiation system			x
North stack effluent radiation monitoring system			x
Charcoal offgas treatment ventilation radiation monitoring system	x	x	
Charcoal offgas treatment effluent radiation monitoring system	x	x	
Recombiner compartments, hydrogen/oxygen analyzers compartments, and equipment drain sump vent radiation monitoring system	x	x	
Steam seal effluent radiation monitoring system	x	x	
Radwaste enclosure ventilation exhaust radiation monitoring system	x	x	
Air ejector offgas effluent radiation monitoring system	x	x	
Primary containment leak detection radiation monitoring system	x	x	
Hot maintenance shop ventilation exhaust radiation monitoring system			x
Liquid radwaste discharge radiation monitoring system	x	x	
Service water radiation monitoring system	x		

Table 7.1-1 (Cont'd)

	GE Design	GE Supply	Others
Reactor enclosure cooling water radiation monitoring system	x	x	
Neutron monitoring system	x	x	
Traversing incore probe			
Rod block monitor			
Source range monitor			
Reactor water cleanup system	x	x	
Refueling interlocks	x	x	
Radwaste system			x
Gaseous radwaste system			x
Liquid radwaste system			x
Solid radwaste system			x
Area radiation monitoring system	x	x	
Leak detection system			
Recirculation pump seal leak detection	x	x	
RHR system leak detection	x	x	
Drywell leak detection			x
SRV leak detection			x
Reactor vessel head leak detection	x	x	
CS system leak detection	x	x	
Containment instrument gas system			x
Fire protection and suppression system			
Nonsafety-related equipment area cooling ventilation systems			
Plant monitoring system (PMS)			x(2)
Rod worth minimizer	x	x	
Emergency Response Facility Data System	x	x	

(1) The software specifications used for non-NSSS calculations are supplied by others.
(2) Designed and Supply by Scientech

Table 7.1-2

SIMILARITY TO LICENSED REACTORS

	INSTRUMENTATION AND CONTROLS (SYSTEM)	PLANTS APPLYING FOR OR HAVING CONSTRUCTION PERMIT OR OPERATING LICENSE	SIMILARITY OF DESIGN
(1)	Reactor protection system	SSES	(1)(2)
(2)	Primary containment, and reactor vessel isolation control system	SSES	(1)(3)
(3)	Emergency core cooling system	SSES	(1)
(4)	Neutron monitoring system	SSES	(16)
(5)	Refueling interlocks	SSES	Identical
(6)	Reactor manual control system	SSES	(4)
(7)	Reactor vessel instrumentation	SSES	(5)
(8)	Recirculation flow control system	SSES	(13)
(9)	Feedwater control system	LASALLE	Identical
(10)	Pressure regulator and turbine-generator system	SSES	Identical
(11)	Process radiation monitoring systems	SSES	(6)
(12)	Area radiation monitoring system	PBAPS	(6)
(13)			
(14)	Habitability and control room isolation system	None	
(15)	Service water system	SSES	Identical
(16)	RHR service water system	SSES	Identical
(17)	Containment atmosphere control system	None	
(18)	Reactor core isolation cooling system	SSES	(1)(8)

Table 7.1-2 (Cont'd)

	INSTRUMENTATION AND CONTROLS (SYSTEM)	PLANTS APPLYING FOR OR HAVING CONSTRUCTION PERMIT OR OPERATING LICENSE	SIMILARITY OF DESIGN
(19)	Standby liquid control system	None	
(19a)	Liquid radwaste systems	None	
(19b)	Gaseous radwaste systems	SSES	
(19c)	Solid radwaste systems	-	
(20)	Reactor water cleanup system	None	
(21)	Class 1E power systems	PBAPS	(12)
(22)	Leak detection systems	SSES	(1)(7)
(23)	Reactor shutdown cooling mode of RHR system	SSES	(1)
(24)	Fuel pool cooling and cleanup system	None	
(25)	Reactor enclosure recirculation system	None	
(26)	Standby gas treatment system	None	
(27)	Safety-related display instrumentation	SSES	(1)(10)
(28)	Containment instrument gas system	None	
(29)	Containment spray mode of RHR system	SSES	(1)
(30)	Remote shutdown system	Shoreham	(9)
(31)	Suppression pool cooling mode of RHR system	SSES	(1)

Table 7.1-2 (Cont'd)

	INSTRUMENTATION AND CONTROLS (SYSTEM)	PLANTS APPLYING FOR OR HAVING CONSTRUCTION PERMIT OR OPERATING LICENSE	SIMILARITY OF DESIGN
(32)	Safety-related equipment area cooling ventilation systems	SSES	
(32.1)	SGTS filter room and access area unit coolers	Hope Creek	
(32.2)	Diesel generator enclosure ventilation system	None	
(32.3)	Spray pond pump structure ventilation system	None	
(32.4)	Emergency switchgear and battery rooms cooling system	None	
(32.5)	Emergency core cooling systems unit coolers	SSES	
(32.6)	Auxiliary equipment room ventilation system	Hope Creek	
(33)	Drywell unit coolers	SSES	
(34)	Control enclosure chilled water system	SSES	
(35)	High pressure/low pressure system interlocks	SSES	
(36)	Safety/relief valve position indication	PBAPS	
(37)	Fire protection and suppression system	None	
(38)	Reactor enclosure isolation system	Hope Creek	

Table 7.1-2 (Cont'd)

	INSTRUMENTATION AND CONTROLS (SYSTEM)	PLANTS APPLYING FOR OR HAVING CONSTRUCTION PERMIT OR OPERATING LICENSE	SIMILARITY OF DESIGN
(39)	Nonsafety-related equipment area cooling ventilation systems	None	
(40)	Safeguard piping fill system	None	
(41)	Redundant reactivity control system	None	
(42)	Refueling area isolation system	None	
(43)	Rod worth minimizer	Millstone	(14)
(44)	Plant monitoring system	Hatch	
(45)	Emergency Response Facility Data System	Hatch	

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(1) LGS and SSES designs are very similar; however, there are differences common to all systems that refer to this note. The differences are that LGS uses transmitter/trip unit system for testability, four divisions of separation, and uninterruptible power supplies for the RPS.

(2) The RPS logics are the same, however, LGS uses a single relay contact for trip functions.

(3) The PCRVICS logics are the same, however, LGS utilizes more sensors for the leak detection system.

(4) The RMCS for LGS and SSES are designed to perform the same. The differences that exists are due to SSES's use of the advanced control room. The advanced control room layout full core display is on the console rather than a wall panel. The differences in the control rooms change the panel location of RMCS modules. These changes don't change the module functions.

Table 7.1-2 (Cont'd)

(5) Instrumentations used for SSES and LGS are of similar design, they both use testability and four division separation. The setpoints, instrument numbering, quantity of instruments, and division assignments are different for LGS. LGS uses excess flow checks and orificing on instrument lines connected to the reactor vessel. Nonessential vessel instrumentation is functionally identical to SSES, except LGS has added gauge pressure transmitters for measurement of shutdown and upset range water level during refueling.

(6) LGS uses more detectors.

(7) The leak detection system for LGS uses 94 sensors as compared to 51 for SSES. This increases the redundant instruments available. The power for sensors not supplied by RPS bus are powered from four instrument ac buses. LGS uses meters rather than a recorder for the spare thermocouple in each location.

(8) RCIC is identical except as indicated in note (1).

(9) LGS and Shoreham shutdown systems are designed to provide all of the same control functions. The differences are due to divisional separation and device numbering related to this. LGS has four divisions of separation making divisional assignment of valves different.

(10) The safety-related display instruments for LGS and SSES are designed to provide the same types of indications to the operator. LGS provides more redundant indication and utilizes four divisions of separation. SSES has the advanced control room making differences in location of the display to the operator.

(11) Deleted

(12) PBAPS uses 4 diesel generators and batteries shared between 2 units. LGS has 8 diesel generators and batteries which are not shared between units.

(13) The LGS recirculation system does not have a bypass valve at the discharge block valve; the SSES system does. The SSES recirculation pumps are provided with decontamination connections; these connections are not required for LGS.

(14) The rod worth minimizers are functionally identical. The differences are in plant interfaces. Millstone Unit 1 is a BWR, 660 MWe, 145 control rods. Each LGS Unit is a BWR, 1055 MWe, 185 control rods.

(15) Deleted

(16) The neutron monitoring system is identical to SSES's except for the TIP system, which uses a gamma-measuring probe instead of a thermal neutron-measuring probe.

(17) Deleted

Note: Historical Information - Comparative plant data provided to support original plant licensing.

Table 7.1-3

CODES AND STANDARDS APPLICABILITY MATRIX

	REGULATORY GUIDES[1]																										IEEE STANDARDS[2]									
	1.6	1.7	1.9	1.11	1.21	1.22	1.29	1.30	1.32	1.40	1.45	1.47	1.53	1.56	1.62	1.63	1.68	1.70	1.73	1.75	1.80	1.89	1.96	1.97	1.100	1.105	1.118	1.139	279	308	317	323	336	338	344	379	382	384
REACTOR PROTECTION SYSTEM				X		X	X	X				X	X		X	X	X	X		X		X		X	X	X	X		X	X	X	X	X	X	X	X		X
ENGINEERED SAFETY FEATURE SYSTEMS																																						
Emergency Core Cooling	X			X		X	X	X	X			X	X		X		X	X	X	X		X		X	X	X	X		X	X	X	X	X	X	X	X	X	X
Primary Containment and Reactor Vessel Isolation Control				X		X	X	X				X	X		X		X	X	X	X		X		X	X	X	X		X	X		X	X	X	X	X	X	X
Residual Heat Removal Service Water	X					X	X		X			X	X		X			X		X				X		X	X		X	X		X		X	X	X		X
Emergency Service Water	X					X	X		X			X	X		X			X		X				X		X	X		X	X		X		X	X	X		X
Containment Atmospheric Control		X				X									X			X		X				X	X	X	X		X	X		X		X	X	X		X
Primary Containment Vacuum Relief						X						X	X			X		X						X	X	X	X			X		X		X	X			
Suppression Pool Cooling Mode (RHR)						X	X	X	X			X	X		X	X	X	X		X		X		X	X	X	X		X	X		X	X	X	X	X		X
Containment Spray Mode (RHR)				X		X	X	X	X			X	X		X		X	X		X		X		X	X	X	X		X	X		X	X	X	X	X		X
Standby Gas Treatment						X	X	X				X	X		X			X		X		X			X	X	X		X	X		X	X	X	X	X		X
Reactor Enclosure Recirculation						X	X	X				X	X		X			X		X		X			X	X	X		X	X		X	X	X	X	X		X
Reactor Enclosure Isolation						X	X	X				X	X		X			X		X		X			X	X	X		X	X		X	X	X	X	X		X
Habitability and Control Room Isolation						X	X	X				X	X		X			X		X		X			X	X	X		X	X		X	X	X	X	X		X
Safety-Related Equipment Area Cooling/Vent						X	X	X				X	X		X			X		X		X			X	X	X		X	X		X	X	X	X	X		X
Drywell Unit Coolers						X	X	X				X	X		X	X		X		X		X			X	X	X		X	X	X	X	X	X	X	X		X
Control Enclosure Chilled Water System						X	X	X				X	X		X			X		X		X			X	X	X		X	X		X	X	X	X	X		X
Refueling Area Isolation						X	X	X				X	X		X			X		X		X			X	X	X		X	X		X	X	X	X	X		X
SYSTEMS REQUIRED FOR SAFE SHUTDOWN																																						
Reactor Core Isolation Cooling				X		X	X	X				X	X		X		X	X	X	X		X			X	X	X		X	X		X	X	X	X	X	X	X
Standby Liquid Control						X	X	X				X	X		X		X	X		X		X			X	X	X		X	X		X	X	X	X	X		X
Reactor Shutdown Cooling Mode (RHR)						X	X	X				X	X		X		X	X	X	X		X			X	X	X		X	X		X	X		X	X	X	X
Remote Shutdown							X	X				X	X				X	X		X		X			X	X	X		X	X		X	X	X	X			X
Shutdown Ventilation						X	X	X					X		X			X		X		X			X	X	X		X	X		X	X	X	X	X		X
SAFETY-RELATED DISPLAY INSTRUMENTATION	X			X			X	X				X	X			X	X	X		X		X		X	X	X	X		X	X	X	X	X	X	X	X		X

Table 7.1-3 (Cont'd)

	GENERAL DESIGN CRITERIA[3]																																		
	1	2	3	4	5	10	12	13	15	19	20	21	22	23	24	25	26	27	28	29	30	33	34	35	37	38	40	54	56	57	60	61	63	64	10CFR50 APP I
REACTOR PROTECTION SYSTEM		X	X	X		X	X	X	X	X	X	X	X	X	X	X				X															
ENGINEERED SAFETY FEATURE SYSTEMS																																			
Emergency Core Cooling		X	X	X				X		X	X	X	X	X	X					X		X		X	X										
Primary Containment and Reactor Vessel Isolation Control	X	X	X	X		X		X		X	X	X	X	X	X					X			X												
Residual Heat Removal Service Water	X	X	X	X	X			X		X	X	X	X	X	X					X			X												
Emergency Service Water	X	X	X	X	X			X		X	X	X	X	X	X					X															
Containment Atmospheric Control	X	X	X	X				X		X		X	X	X	X					X								X	X						
Primary Containment Vacuum Relief	X	X	X	X						X		X	X																						
Suppression Pool Cooling Mode (RHR)	X	X	X	X				X		X		X	X	X	X					X						X	X								
Containment Spray Mode (RHR)	X	X	X	X				X		X		X	X	X	X					X						X	X								
Standby Gas Treatment	X	X	X	X	X			X		X	X	X	X	X	X					X											X				
Reactor Enclosure Recirculation	X	X	X	X				X		X	X	X	X	X	X					X											X				
Reactor Enclosure Isolation	X	X	X	X				X		X	X	X	X	X	X					X											X				
Habitability and Control Room Isolation	X	X	X	X	X			X		X	X	X	X	X	X					X															
Safety-Related Equipment Area Cooling/Vent	X	X	X	X	X			X		X	X																								
Drywell Unit Coolers	X	X	X	X				X																											
Control Enclosure Chilled Water System	X	X	X	X	X			X																											
Refueling Area Isolation	X	X	X	X				X		X	X	X	X	X	X					X											X				
SYSTEMS REQUIRED FOR SAFE SHUTDOWN																																			
Reactor Core Isolation Cooling	X	X	X	X		X		X	X	X										X															
Standby Liquid Control	X	X	X	X				X		X																									
Reactor Shutdown Cooling Mode (RHR)	X	X	X	X		X		X	X	X																									
Remote Shutdown	X	X	X	X				X		X																									
Shutdown Ventilation	X	X	X	X				X																											
SAFETY-RELATED DISPLAY INSTRUMENTATION	X	X	X	X				X		X																									

Table 7.1-3 (Cont'd)

	REGULATORY GUIDES[1]																										IEEE STANDARDS[2]									
	1.6	1.7	1.9	1.11	1.21	1.22	1.29	1.30	1.32	1.40	1.45	1.47	1.53	1.56	1.62	1.63	1.68	1.70	1.73	1.75	1.80	1.89	1.96	1.97	1.100	1.105	1.118	1.139	279	308	317	323	336	338	344	379	382	383	384
ALL OTHER SYSTEMS REQUIRED FOR SAFETY																																							
Process Radiation Monitoring					X	X	X	X				X	X		X			X				X		X	X	X	X		X			X	X	X	X	X			X
High Pressure/Low Pressure System Interlocks						X	X	X				X	X					X		X		X			X	X	X		X	X		X	X	X	X	X			X
Leak Detection						X	X	X			X	X	X					X		X		X		X	X	X	X		X			X	X	X	X	X			X
Neutron Monitoring						X	X	X				X	X					X		X		X			X	X	X		X			X	X	X	X	X			X
Safety Relief Valve Position Indication							X	X								X		X				X		X	X	X						X		X	X				
Containment Instrument Gas System-ADS							X	X				X	X					X				X			X	X			X			X	X	X	X	X			X
Safeguard Piping Fill						X	X	X					X					X				X							X			X	X	X	X	X			X
Redundant Reactivity Control System	X					X	X	X	X			X	X		X		X	X		X		X			X	X	X		X	X				X	X	X			X
CONTROL SYSTEMS NOT REQUIRED FOR SAFETY																																							
Reactor Pressure Vessel Instrumentation				X		X	X	X					X					X																					
Reactor Manual Control																		X																					
Recirculation Flow Control				X														X																					
Feedwater Control				X														X																					
Pressure Regulator and Turbine Generator																		X																					
Neutron Monitoring																		X																					
Reactor Water Cleanup														X				X	X																		X		
Process Radiation Monitoring				X							X							X																					
Area Radiation Monitoring																		X																					
Radwaste																		X																					
Fuel Pool Cooling and Cleanup																		X																					
Refueling Interlocks																		X																					
Leak Detection				X							X							X																	X				
Containment Instrument Gas System								X										X	X																	X			X
Fire Protection and Suppression																		X																					
Nonsafety-Related Equipment Area Cooling/Vent																		X																					
Plant Monitoring System																																	X		X			X	X
Rod Worth Minimizer							X																															X	
Emergency Response Facility Data System																																	X		X			X	X

Table 7.1-3 (Cont'd)

	GENERAL DESIGN CRITERIA[3]																																				
	1	2	3	4	5	10	12	13	15	19	20	21	22	23	24	25	26	27	28	29	30	33	34	35	37	38	40	54	56	57	60	61	63	64	10CFR50 APP I
ALL OTHER SYSTEMS REQUIRED FOR SAFETY																																			
Process Radiation Monitoring	X	X	X	X	X	X		X		X	X	X	X	X	X					X	X		X			X	X				X			X	X
High Pressure/Low Pressure System Interlocks																																			
Leak Detection	X	X	X	X		X		X		X	X	X		X						X	X		X	X				X							
Neutron Monitoring	X	X	X	X		X	X	X		X	X	X		X		X				X															
Safety Relief Valve Position Indication	X	X	X	X				X																											
Containment Instrument Gas System-ADS	X	X	X	X				X			X	X	X	X	X					X															
Safeguard Piping Fill	X	X	X	X				X			X	X	X	X						X															
Redundant Reactivity Control System	X	X	X	X						X	X	X	X		X					X															
CONTROL SYSTEMS NOT REQUIRED FOR SAFETY																																			
Reactor Pressure Vessel Instrumentation								X							X																				
Reactor Manual Control								X							X		X																		
Recirculation Flow Control								X	X								X																		
Feedwater Control								X	X																										
Pressure Regulator and Turbine Generator																																			
Neutron Monitoring								X																											
Reactor Water Cleanup								X																											
Process Radiation Monitoring								X																				X			X			X	X
Area Radiation Monitoring								X																								X			
Radwaste																																			
Fuel Pool Cooling and Cleanup																																			
Refueling Interlocks																																			
Leak Detection								X													X		X					X							
Containment Instrument Gas System								X																											
Fire Protection and Suppression																																			
Nonsafety-Related Equipment Area Cooling/Vent																																			
Plant Monitoring System																																			
Rod Worth Minimizer																																			
Emergency Response Facility Data System																																			

(1) See Section 7.1.2.5 for degree of conformance.

(2) See Section 7.1.2.7 for degree of conformance.

(3) See Section 7.1.2.6 for degree of conformance.

Table 7.1-4

RPS AND PCRVICS (DE-ENERGIZE-TO-OPERATE PORTIONS) SEPARATION[1]

	DIVISION IA	DIVISION IB	DIVISION IIA	DIVISION IIB
RPS	Trip Logic A1	Trip Logic B1	Trip Logic A2	Trip Logic B2
SENSORS	A, E, J, N, T, AA	B, F,K, P	C, G, L, R	D, H, M, S, W, DD
	Part of Trip System A	Part of Trip System B	Part of Trip System A	Part of Trip System B
PCRVICS	Trip Logic A	Trip Logic B	Trip Logic C	Trip Logic D
	MSIV inboard valve ac logic and solenoid	MSIV outboard valve ac logic and solenoid		

(1) This separation does not apply to the NMS. Reference Table 7.1-5 for NMS separation.

Table 7.1-5

DIVISIONAL GROUPING OF NEUTRON MONITORING SYSTEM IN DRYWELL PENETRATIONS

Drywell[(1)(2)(3)(4)] Penetration Designations	A	B	C	D
Instrument Channels	IRM A & E APRM 1 (SRM A)	IRM B & F APRM 2 (SRM B)	IRM C & G APRM 3 (SRM C)	IRM D & H APRM 4 (SRM D)
Wireway	NA	NB	NC	ND
Neutron monitoring channel				
APRM	1	2	3	4
IRM	A & E	B & F	C & G	D & H
RPS trip logic	A1	B1	A2	B2
APRM flow reference	A	B	C	D

(1) Penetrations across top of table for 4 penetration grouping carry cables for neutron monitoring channels shown, and each channel serves RPS trip logic directly below it.

(2) Horizontal zoning represents LPRM cable distribution to APRMs from various penetrations, e.g., penetration B carries cables for LPRMs going to APRM channel 2 (Figure 7.1-1).

(3) Designations for penetrations and wireways are arbitrary and may be deviated from provided that an equivalent separation is maintained.

(4) Routing of SRM channels has been chosen for convenience and not for safeguard separation reasons.

Table 7.1-6

SYSTEM AND SUBSYSTEM SEPARATION

DIV 1	DIV 2	DIV 3	DIV 4
Sensors A, E, J, N, T, X	Sensors B, F, K, P, U, Y	Sensors C, G, L, R, V	Sensors D, H, M, S, W
RCIC[(1)] Controls	HPCI Controls		
RCIC OBV[(2)]	HPCI OBV	RCIC IBV	HPCI IBV
ADS A	-	ADS C	-
RHR A Pump and Valves	RHR B Pump and Valves	RHR C Pump and Valves	RHR D Pump and Valves
CS A Pump and Suction Valve and inject A	CS B Pump and Suction Valve and inject B	CS C Pump and Suction Valve	CS D Pump and Suction Valve
ESW Pumps and Valves	ESW Pumps and Valves	ESW Pumps and Valves	ESW Pumps and Valves
RHRSW Pumps and Valves	RHRSW Pumps and Valves	RHRSW Pumps and Valves	RHRSW Pumps and Valves
PCRVICS Inboard Valves & Logic	PCRVICS Outboard Valves & Logic	-	-
MSIV Inboard Valve dc Logic and Solenoid	MSIV Outboard Valve dc Logic and Solenoid	-	-
SPPSVS A	SPPSVS B	SPPSVS C	SPPSVS D
-	-	ESBRCS A	ESBRCS B
Drywell Unit Coolers A, E	Drywell Unit Coolers B, F	Drywell Unit Coolers C, G	Drywell Unit Coolers D, H
-	-	CECWS A	CECWS B
-	-	AERVS A	AERVS B
RRCS I	RRCS II		

Table 7.1-6 (Cont'd)

DIV 1	DIV 2	DIV 3	DIV 4
-	-	Control Room HVAC A	Control Room HVAC B
-	-	Emergency Fresh Air Fan & Filter A	Emergency Fresh Air Fan & Filter B
Control Room Isolation A	Control Room Isolation B	Control Room Isolation C	Control Room Isolation D
RERS A	RERS B	-	-
SGTS A	SGTS B	-	-
REIS A	REIS B	-	-
SGTS Unit Coolers A	SGTS Unit Coolers B	-	-
DGEVS A	DGEVS B	DGEVS C	DGEVS D
-	-	Containment Hydrogen Recombiner A Isolation Valves	Containment Hydrogen Recombiner B Isolation Valves
Class 1E power Channel A	Class 1E power Channel B	Class 1E power Channel C	Class 1E power Channel D
RCIC pump-room unit coolers	HPCI pump-room unit coolers	-	-
A&E RHR pump-room unit coolers	B&F RHR pump-room unit coolers	C&G RHR pump-room unit coolers	D&H RHR pump-room unit coolers
A&E CS pump-room unit coolers	B&F CS pump-room unit coolers	C&G CS pump room unit coolers	D&H CS pump-room unit coolers

Table 7.1-6 (Cont'd)

DIV 1	DIV 2	DIV 3	DIV 4
-	-	SLCS A pump & valves	SLCS B pump & valves
Control Room Radiation Monitor A	Control Room Radiation Monitor B	Control Room Radiation Monitor C	Control Room Radiation Monitor D
-	-	Control Room Emergency Fresh Air Radiation Monitor A	Control Room Emergency Fresh Air Radiation Monitor B
RHRSW loop A Radiation	RHRSW loop B Radiation		
SGTS discharge radiation	-	-	-
RHR Loops A/C Differential Pressure	RHR Loops B/D Differential Pressure	-	-
Core Spray Loops A/B Differential Pressure	-	-	-
Containment Atmosphere Sampling System Inboard Isolation Valves	Containment Atmosphere Sampling System Inboard Isolation Valves	Containment Atmosphere Sampling System Outboard Isolation Valves	Containment Atmosphere Sampling System Outboard Isolation Valves
CIGS Inboard Isolation Valve and A Line Header Outboard Isolation Valve	CIGS Suction Line, B Line Header and Tip Purge Outboard Isolation Valves	-	-

Table 7.1-6 (Cont'd)

DIV 1	DIV 2	DIV 3	DIV 4
Refueling area isolation A	Refueling area isolation B		

(1) RCIC is not part of ESF

(2) OBV = Outboard isolation valve and logic

IBV = Inboard isolation valve and logic

Table 7.1-7
NRC BULLETINS, CIRCULARS, AND INFORMATION NOTICES

Bulletin #	Description	LGS Response
78-01	Flammable contact arm retainers in GE relays	GE performed an inspection to verify that all CR120A relays have proper fire resistant retainers.
78-05	Malfunction of CR105 relay auxiliary contacts	It was confirmed by review that no auxiliary contacts from these relays are used in safety related circuits.
79-09	Failures of GE type AK-2 circuit breakers	None of these type breakers are used in safety related circuits.
79-12	Short period scrams at BWR	Station staff to prepare procedure and review with operators during training. This Bulletin applied to operating plants. No modifications required.
79-24	Frozen instrument lines	A review of the ECCS minimum flow lines was made as well as the criteria for application and design of heat tracing and freeze protection on instrument, process and sample lines. No modifications were made as existing design was deemed adequate.
79-27	Loss of Instrument ac	Study complete and submitted to NRC. No modifications needed.
79-28	Failure of Namco limit switches	No switches of this type were found. Some Namco switches are being replaced with qualified models due to environmental qualification concerns.
80-06	Engineered safety feature control reset	Study completed. Modifications to circuitry completed. Detailed discussion provided in Section 7.1.2.11.1.
80-09	Failure of ITT actuators	Vendor reviews and testing determined that several actuators required spring replacements. Corrective actions have been completed.

Table 7.1-7 (Cont'd)

Bulletin #	Description	LGS Response
80-14	Degradation of Scram Discharge Volume Capability	Diverse means of measuring SDV capacity have been added to the LGS design.
80-16	Misapplication of Rosemount transmitters	Transmitters to be replaced have been identified. Unit 1 replacements completed. Unit 2 was completed prior to fuel load.
80-17	Failure of control rods to insert	Modification made as part of ATWS fix.
80-23	Failure of Valcor solenoid valves	Review indicated that no Valcor valves of the type described are used in safety related applications.
Circular #	**Description**	**LGS Response**
79-07	Recirculation pump speed increase	Maintenance procedures to include recommended actions.
79-24	Calibration of pipe detection equipment	Problem not applicable as design is different at LGS than Duane Arnold.
80-08	RPS Response time	Start up test program will verify adequate response time on as-built system.
81-01	Honeywell push button switches	Review shows that no switches of this type are used in any safety related systems.
81-03	Inoperable seismic monitoring equipment	Maintenance procedure to include lessons learned.
81-06	Foxboro transmitter defects	Review indicated that this type transmitter is not used in any safety related systems.
81-11	Inadequate decay heat removal	Preliminary review of calculations showed flow rates to be adequate. Shutdown procedures will address this concern.

Table 7.1-7 (Cont'd)

Circular #	Description	LGS Response
81-13	MOV torque switch bypass circuit	MOV rework program on all safety related MOVs includes rewiring and checking connections internal to the operator.
81-14	MSIV Failures	Reviewed operating experience at PBAPS and other plants. Causes of failures were identified. Based on analyses no modifications to LGS valve or air supply design are required.

Notice #	Description	LGS Response
79-13	Water Level Instrumentation	Review indicated LGS will not experience problem due to different design.
79-22	Environmental Effects on non-Class 1E control systems	Study indicated no potential problems. Analysis and rationale provided in Section 7.1.2.11.2.
79-32	Separation of HPCI and ADS cables	Review of LGS design shows this problem does not exist.
80-11	ASCO valve problems	Review showed that ASCO valves are not used in the conditions described.
80-13	SBM Switch defects	All SBM switches have been inspected. Defective switches have been replaced.
80-30	Control air-CRD interactions	Review shows that LGS design precludes this problem
80-31	Defective K600 circuit breakers	These breakers are used at LGS. Each breaker is inspected and tested to procedures before installation and acceptance. Any corrective work if needed is completed before final acceptance.
80-34	SDV water level instrumentation failure	Problem not applicable to LGS due to different design.

LGS UFSAR

Table 7.1-7 (Cont'd)

Notice #	Description	LGS Response
80-39	Valcor solenoid valve malfunction	This type valve is not used in safety systems at LGS.
80-45	Failure of backup scram capability	Not applicable to LGS RPS Design.
81-01	HFA relay failures	All Class 1E HFA relays have been replaced. All non-Class 1E relay coils are being replaced.
81-06	Failure of ITE K600 circuit breakers	Inspections completed to find and fix loose connections.
81-11	ARI design	This concern will be addressed by GE in the LGS ATWS modifications.
81-16	CRD system possible malfunctions	Operator training and plant procedures to be used to avoid problem.
81-25	P-transmitter valve misalignment	Plant procedures to be used to avoid problem.

Table 7.1-8

"FIRST-OF-A-KIND" INSTRUMENTS AND CONTROLS

Instruments

Type	Manufacturer	Model	Use
Pressure Switch	ITT Barton	580A2	Various

Microprocessors, Multiplexers, Computer Systems [3]

Type	Manufacturer	Model
Radiation Monitor Process	General Atomic	RM-80
Radiation Monitor Digital High Range	General Atomic	RM-80
Radiation Display	General Atomic	RM-23
Radiation Monitor[1]	Digital Equip. Corp.	PDP-11-34
Radiation Monitor[2]	Digital Equip. Corp.	VAX-11-780
ERFDS	RTP Corp.	Series 3000
ERFDS	RTP Corp.	Series 3000
RWM (Unit 2)	GE	NUMAC
Plant Monitoring System	Scientech and HP	DL38OP Gen8

(1) Radiation monitoring display system

(2) Meteorological monitoring display and reporting subsystem

(3) These systems are used for monitoring and display only, not for control of any system. Microprocessors (which incorporate ROMs) are used in the RRCS. The RRCS does not perform any reactor control functions. It does provide signals to trip the recirculation system, to run back the feedwater system, to initiate SLCS, and to initiate ARI to mitigate an ATWS event. No plant control is implemented by microprocessors, multiplexers, or computers.

7.2 REACTOR TRIP SYSTEM (REACTOR PROTECTION SYSTEM) - INSTRUMENTATION AND CONTROLS

7.2.1 DESCRIPTION

7.2.1.1 System Description

7.2.1.1.1 RPS Identification

The RPS includes sensors, relays, bypass circuitry, and switches that cause rapid insertion of control rods (scram) to shut down the reactor. The RPS also includes outputs to the process computer system and annunciators, which are not part of the RPS. Trip signals are received from the NMS; other portions of this system are treated in Sections 7.5, 7.6, and 7.7.

A completely separate and diverse system, the RRCS, is provided to mitigate the potential consequences of an ATWS event (Section 7.6.1.8).

7.2.1.1.2 RPS Classification

The RPS is classified as Safety Class 2, seismic Category I, Quality Group B, and electric Class 1E.

7.2.1.1.3 RPS Power Sources

Power to each of the two RPS trip systems is supplied by separate buses powered by independent static inverter sets. Each static inverter set is designed to provide uninterruptible ac power to the loads. Each static inverter set is supplied by two electrical sources, one from the plant auxiliary electrical source (alternate) and the other from the class 1E 250 V dc system (preferred). The inverter output and the plant auxiliary electrical source are connected to a static transfer switch within the inverter set and ahead of the loads. The switch will normally connect the load to the preferred source. Upon failure or undervoltage of the preferred source, the switch will automatically transfer the load to the alternate source. Additionally, if an overload occurs while the load is supplied from the inverter, the switch will automatically transfer the load to the ac source. If, while being fed from the alternate supply the inverter recovers, and the static transfer switch is in auto, the transfer switch will automatically transfer the load to the inverter. Alternatively, if the static transfer switch is in manual, the load transfer requires manual action. Refer to Section 7.6.1.4.5 for independent powering of APRMs.

The static inverter sets are not part of the RPS and are not Class 1E devices. Two Class 1E circuit breakers are located between each static transfer switch and its respective RPS distribution panel (Drawing E-32) to isolate the RPS from the inverter and the bypass ac source if there is an overvoltage, undervoltage, or underfrequency condition. The trip points of the overvoltage, undervoltage, and frequency relays are set to ensure that the power supplied to the RPS is within the limits to which the RPS equipment has been designed and qualified.

A bypass disconnect test switch is installed in parallel with the two class IE circuit breakers. The test switch allows for testing of the breakers without loss of power to the RPS distribution panels. During the test, when the breakers are bypassed, the AC source is monitored for overvoltage, undervoltage, or underfrequency conditions as determined by the trip points. When not in test, the disconnect test switch is locked open.

Dc power is supplied to the backup scram valve solenoids from the Class 1E station batteries.

The power source used to drive the control rods during scram is pressurized water contained in the scram accumulator furnished as part of each HCU, as described in Section 4.6.1.

7.2.1.1.4 RPS Equipment Design

7.2.1.1.4.1 General

Trip systems are designated A and B. Trip system A is comprised of instrument channels A, C, E, and G; trip logics A1 and A2; and the scram contactors A, E, C and G. Trip system B comprises of instrument channels B, D, F and H; trip logics B1 and B2; and the scram contactors B, D, F and H. During normal operation, all sensor and trip contacts essential to safety and corresponding trip logic channel contacts are closed, and the scram contactors are energized. Trip channel bypass contacts are normally open.

Table 7.2-1 lists the instruments that provide signals for the system. Figure 7.2-2 summarizes the RPS signals that cause a scram.

The functional arrangement of channels that constitute trip system A is shown in Figure 7.2-5. When a channel sensor contact opens, its sensor relay de-energizes, opening its contacts and thereby de-energizing its associated scram contactors. Trip system B is similar to that shown on Figure 7.2-5 for trip system A. Scram contactors and scram contactor logics for trip systems A and B are shown in Figure 7.2-4. When a scram contactor is de-energized, its contacts associated with the pilot solenoids open and those associated with the backup scram valves close. As seen on Figure 7.2-4, tripping A1 or A2 or both A1 and A2 trip logics will open the circuits associated with the trip system A pilot solenoids and close corresponding contacts in both trip system A and B backup scram valve circuits. When both trip systems A and B have tripped, all pilot solenoids are de-energized and both backup scram valves are energized, either of which will cause a reactor scram.

There is one scram pilot valve and two scram valves for each control rod, arranged as shown in Drawing C71-1010-F-002. Each scram pilot valve is solenoid-operated with two normally energized pilot solenoids. The scram pilot valve control the air supply to the scram valves for each control rod. With either pilot solenoid energized, air pressure holds the scram valves closed. The scram valves control the supply and discharge paths for CRD water. As shown in Figure 7.2-4, one of the pilot solenoids for each control rod is controlled by trip system A logic A1 and A2, and the other solenoid is controlled by trip system B logic B1 and B2.

When trip system A, logic A1 or A2, and trip system B, logic B1 or B2, are tripped, air is vented from the scram valves, allowing CRD water to act on the CRD piston. Thus, all control rods are scrammed. The water displaced by the movement of each rod piston is exhausted into a SDV.

To restore the RPS to normal operation following any single trip of the trip logic or a scram, the trip logic must be reset manually. Reset is possible only if the conditions that caused the trip have been cleared. Reset after a scram is permissible only after a 10 second delay. The trip systems are reset by a three-position switch in the control room. Figure 7.2-5 shows the functional arrangement of reset contacts for trip system A.

There are two dc solenoid-operated backup scram valves that provide a second means of controlling the air supply to the scram valves for all control rods. When the solenoid for either backup scram valve is energized, the backup scram valve vents the air supply for the scram

valves. This action initiates insertion of any withdrawn control rods regardless of the action of the scram pilot valves. The backup scram valve solenoids are energized (initiate scram) when trip logic A1 or A2 and trip logic B1 or B2 are tripped.

7.2.1.1.4.2 RPS Initiating Circuits

The RPS scram functions, shown in Figure 7.2-2, are discussed in the following paragraphs.

a. Neutron Monitoring System

NMS instrumentation is described in Section 7.6.1.4. Figure 7.2-6 clarifies the relationship between NMS channels and the trip system logics. The NMS channels are considered to be part of the NMS; however, the NMS logics are considered to be part of the RPS. Each NMS logic receives signals from one IRM channel and one APRM voter channel. The position of the reactor mode switch determines which input signals affect the output signal from the logic.

The NMS logics are arranged so that failure of any one logic cannot prevent the initiation of a high neutron flux scram. As shown in Drawings C51-1020-F-009, C51-1020-F-010, C51-1020-F-011, C51-1020-F-012, C51-1020-F-013, C51-1020-F-014, C51-1020-F-015, and C51-1020-F-016, there are eight NMS logics associated with the RPS. Each trip system logic receives inputs from two NMS logics.

For the initial fuel load, and during shutdown margin demonstration testing performed as a special test, trip contacts from each SRM are combined with IRM trips to produce a noncoincident reactor NMS trip via removal of the RPS "shorting links".

Note that during the routine shutdown margin demonstra-tion testing performed during the first startup following refueling operations, the RPS "shorting links" remain installed and the SRMS do not contribute to the SCRAM function.

1. IRM System Logic

The IRMs monitor neutron flux between the upper portion of the SRM range to the lower portion of the APRM range. The IRM detectors can be positioned in the core by remote control. The detectors are inserted into the core for a reactor startup and are withdrawn after the reactor reaches a predetermined power level within the power range.

The IRM is able to generate a trip signal that can be used to prevent fuel damage resulting from abnormal operational transients that occur while operating in the intermediate power range. The IRM is divided into two groups of IRM channels arranged in the core as shown in Drawings C51-1010-F-002, C51-1010-F-003, and C51-1010-F-0023. Four IRM channels are associated with one of the two trip systems of the RPS. Two IRM channels and their trip auxiliaries from each group are installed in one bay of a cabinet; the remaining two channels are installed in a separate bay of the cabinet. Full-length side covers separate the cabinet bays. The arrangement of IRM channels allows one IRM channel in each group to be bypassed without compromising intermediate range neutron monitoring.

Each IRM channel includes four trip circuits as standard equipment. One trip circuit is used as an instrument trouble trip. It operates on four conditions: when the high voltage drops below a preset level; when one of the modules is not plugged in; when the negative 20 V dc supply is lost: or when the operate-calibrate switch is not in the operate position. Each of the other trip circuits can be specified to trip when preset downscale or upscale levels are reached.

The trip functions actuated by the IRM trips are indicated in Table 7.6-2. The reactor mode switch determines whether IRM trips are effective in initiating a rod block or a reactor scram (Figure 7.2-6). Section 7.7.1.2.3.2.3.3 describes the IRM rod block trips. With the reactor mode switch in refuel or startup, an IRM upscale or inoperative trip signal actuates an NMS trip of the RPS. Only one of the IRM channels must trip to initiate an NMS trip of the associated trip system of the RPS.

2. APRM System Logic

The APRM channels receive input signals from the LPRM detectors and provide a continuous indication of average reactor power from a few percent to greater than rated reactor power.

The APRM subsystem has sufficient redundant channels to meet industry and regulatory safety criteria. Even with the permitted APRM bypasses, the subsystem is capable of generating a scram trip signal before the average neutron flux or the magnitude of any thermal-hydraulic instability caused power oscillations increases to the point that fuel damage is probable.

The digital electronics for each APRM channel, via APRM interface hardware, provides trip signals directly to the Reactor Manual Control System (RMCS) and Redundant Reactivity Control System (RRCS) and via the APRM 2-out-of-4 voter channels to the Reactor Protection System (RPS). An APRM upscale trip or inoperative in any two unbypassed APRM channels can initiate an RPS trip in both RPS trip systems. Similarly, an OPRM upscale trip from any two unbypassed APRM channels can initiate an RPS trip in both RPS trip systems if the reactor mode switch is in the RUN position, and the plant is operating within the OPRM trip enabled region of the power-flow map. Any single APRM upscale trip or inoperative or OPRM upscale trip will not initiate an NMS trip in the RPS. Table 7.6-4 itemizes the APRM system trip functions. Any one unbypassed APRM can initiate a rod block, depending upon the position of the reactor mode switch. Section 7.7.1.2.3.2.3.3 describes in detail the APRM rod block interlock functions. The APRM Simulated Thermal Power - Upscale rod block and the APRM Simulated Thermal Power - Upscale scram trip setpoints vary as a function of reactor recirculation loop flow. The OPRM upscale trip output to the RPS is automatically bypassed when the reactor is operating below the lower power limit or above the upper flow limit of the OPRM trip enabled region.

Manually moving the reactor mode switch out of the RUN position to any other position causes the APRM rod block and APRM neutron flux scram

setpoints to be lowered. The manual positioning of the reactor mode switch is governed by the standard reactor startup (shutdown) procedure. The operator can bypass the trips from any one APRM channel, but only one APRM channel may be bypassed at any time. No APRM voter channels may be bypassed.

A simplified circuit arrangement is shown in Figure 7.6-7.

NMS scram operating bypasses are described in Section 7.2.1.1.4.4.6. Diversity of trip initiation for unusual excursions in reactor power is provided by the NMS trip signals and reactor vessel high pressure trip signals. An increase in reactor power initiates protective action from the NMS discussed in the above paragraphs. The increase in power causes reactor pressure to increase because of a higher rate of steam generation with no change in turbine control valve position resulting in a trip from reactor vessel high pressure. These variables are independent of one another and provide diverse initiation of protective action for this condition.

b. Reactor Pressure (RPS Initiating Circuits)

Reactor pressure is measured at four physically separated locations. A pipe from each location is routed through the drywell and terminates in the reactor enclosure. One locally mounted pressure sensor monitors the pressure in each pipe. Cables from these sensors are routed to the RPS logic cabinets. Each sensor provides a high pressure signal to one channel as shown in Figure 7.2-3. The physical separation and the signal arrangement ensure that no single physical event can prevent a scram caused by nuclear system high pressure.

The environmental conditions for the RPS are described in Section 3.11. The piping arrangement of the reactor pressure sensors is shown in Drawing M-41.

The discussion of diversity for reactor vessel high pressure is provided in Section 7.2.1.1.4.6.

c. Reactor Vessel Water Level (RPS Initiating Circuits)

Reactor vessel low water level signals are initiated from level sensors that sense the difference between the pressure that is due to a constant reference column of water and the pressure that is due to the actual water level in the vessel. The level sensors (A, B, C and D) have separate RPV reference leg taps; however, sensors A and B share the same variable leg tap and common piping to the outside of the primary containment where the piping is split for these and other sensors as shown in Drawing M-42. Sensors C and D are of a similar configuration with their tap and piping physically separated from that used by sensors A and B. A break (or blockage) in either of the common piping runs will result in a reactor scram because the one-out-of-two-twice logic is arranged with sensors A and C in trip logic A and sensors B and D in trip logic B. The physical separation of redundant sensors and the signal arrangement ensure that no single physical event can prevent a scram that is due to reactor vessel low water level.

Diversity of trip initiation for breaks in the RCPB is provided by reactor vessel low water level trip signals and high drywell pressure trip signals. If a break in the primary system boundary occurs, a volume of primary coolant is released to the drywell in the form of steam. This release causes reactor vessel water level to decrease and drywell pressure to increase, resulting in protective action initiation. These variables are independent of one another and provide diverse initiation of protective action for this condition.

The locations of the reactor vessel low water level sensors are shown in Drawings C71-1010-F-002, C71-1010-F-003, C71-1010-F-004, and C71-1010-F-005, and the environmental conditions for the RPS are described in Section 3.11. The piping arrangement of the reactor vessel low water level sensors is shown in Drawing M-42.

d. Turbine Stop Valve (RPS Initiating Circuits)

Turbine stop valve closure inputs to the RPS come from valve stem position switches mounted on the four turbine stop valves. Each of the double-pole, single-throw switches opens before the valve is more than 7% closed to provide the earliest positive indication of closure (Technical Specification - Setpoint <= 5%, Allowable Value <= 7%). Either of the two channels associated with one stop valve, can signal valve closure, as shown in Figure 7.2-7. The logic is arranged so that closure of three or more valves initiates a scram.

Turbine stop valve closure trip channel operating bypasses are described in Section 7.2.1.1.4.4.1.

Diversity of trip initiation for increases in reactor vessel pressure that are due to termination of steam flow by turbine stop valve or control valve closure is provided by reactor vessel high pressure and high power trip signals. A closure of the turbine stop valves or control valves at steady-state conditions would result in an increase in reactor vessel pressure. If a scram were not initiated from these closures, a scram would occur from high reactor vessel pressure or power. Reactor vessel high pressure and power are independent variables for this condition and provide diverse initiation of protective action.

The locations of the turbine stop valve closure position switches are shown in the instrument location drawing provided in Drawing E-1112. The environmental conditions for the RPS are described in Section 3.11.

e. Turbine Control Valve (RPS Initiating Circuits)

Turbine control valve fast closure inputs to the RPS are from oil line pressure sensors on each of four fast-acting control valve hydraulic mechanisms. These hydraulic mechanisms are part of the turbine control, and they are used to effect fast closure of the turbine control valves. These pressure switches provide signals to the RPS. If hydraulic oil line pressure is lost, a turbine control valve fast closure scram is initiated.

Turbine control valve fast closure trip channel operating bypasses are described in Section 7.2.1.1.4.4.1.

The discussion of diversity for turbine control valve fast closure is the same as that for turbine stop valve closure provided in Sections 7.2.1.1.4.2.d and 7.2.1.1.4.6.

The locations of the turbine control valve fast closure pressure switches are shown in the instrument location drawings provided in Drawing M-677. The environmental conditions for the RPS are described in Section 3.11. The piping arrangement of the turbine control valve fast closure pressure switch is shown in Drawing M-01.

f. Main Steam Isolation Valves (RPS Initiating Circuits)

Position switches mounted on the eight MSIVs signal MSIV closure to the RPS. Each of the double-pole, single- throw switches is arranged to open before the valve is more than 12% closed to provide the earliest positive indication of closure (Technical Specification - Setpoint <= 8%, Allowable Value <= 12%). Either of the two channels associated with one isolation valve can signal valve closure. To facilitate the description of the logic arrangement, the position-sensing channels for each valve are identified and assigned to RPS logics as follows:

Valve Identification	Position-Sensing Channels	Feeds Trip Logic
Main steam line A, inboard valve	F022A	A1, B1
Main steam line A, outboard valve	F028A	A1, B1
Main steam line B, inboard valve	F022B	A1, B2
Main steam line B, outboard valve	F028B	A1, B2
Main steam line C, inboard valve	F022C	A2, B1
Main steam line C, outboard valve	F028C	A2, B1
Main steam line D, inboard valve	F022D	A2, B2
Main steam line D, outboard valve	F028D	A2, B2

Thus, each logic receives signals from the valves associated with two steam lines (Figure 7.2-8). The arrangement of signals within each logic requires closing of at least one valve in each of the two steam lines associated with that logic to cause a trip of that logic. For example, closure of the inboard valve of steam line A and the outboard valve of steam line C causes a trip of logic B1. This in turn causes trip system B to trip.

No scram occurs, because no trips occur in trip system A. In no case does closure of two valves or isolation of two steam lines cause a scram that is due to valve closure. Closure of at least one valve in three or more steam lines causes a scram. The wiring for the position-sensing channels from one position switch is physically separated in the same way that wiring to duplicate sensors on a common process tap is separated. The wiring for position-sensing channels feeding the different trip logics of one trip system is also separated.

MSIV closure trip channel operating bypasses are described in Section 7.2.1.1.4.4.2.

Diversity of trip initiation that is due to main steam isolation is provided by reactor vessel high pressure and power trip signals. A closure of the MSIVs at steady-state conditions would cause an increase in reactor vessel pressure and power. If a scram were not initiated from MSIV closure, a scram would occur from high reactor vessel pressure or high power. These variables are independent and provide diverse initiation of protective action for this condition.

The locations of the MSIV closure position switch are shown in the instrument location drawing in Figures 7.2-12 and 7.2-13. The environmental conditions for the RPS are described in Section 3.11.

g. Scram Discharge Volume (RPS Initiating Circuits)

Four nonindicating float switches (one for each channel) provide SDV high water level inputs to the four RPS channels. In addition, a trip unit, with a level transmitter, in each channel provides diversity with the float-type level switch in that channel. This arrangement provides diversity, as well as redundancy, to ensure that no single event can prevent a scram caused by SDV high water level. With the predetermined scram setting, a scram is initiated when sufficient capacity still remains in the tank to accommodate a scram.

SDV water level trip channel operating bypasses are described in Section 7.2.1.1.4.4.3.

The SDV function is to receive water that is discharged from the CRD during a scram. If at the completion of the scram the level of water in the SDV is greater than the trip setting, the RPS cannot be reset until the discharge volume has been drained or the discharge volume level switch is in the bypass position and the reactor mode switch is in the shutdown or refuel mode. In addition, the SDV water level scram setting has been selected so that the CRD water discharged because of a scram can fit in the volume, along with prior leakage that would have initiated the scram.

The locations of the SDV water level sensors are shown in the instrument location drawing in Drawings E-1164 and E-1165. The environmental conditions for the RPS are described in Section 3.11. The piping arrangement of the SDV level sensors is shown in Drawings C11-1030-F-008,C11-1030-F-009,C11-1030-F-010,C11-1030-F-011,C11-1030-F-012,C11-1030-F-013, and C11-1030-F-014.

h. Drywell Pressure (RPS Initiating Circuits)

Drywell pressure is monitored by four pressure sensors mounted on instrument racks outside the drywell in the secondary containment. Pipes that terminate in the secondary containment connect the sensors with the drywell interior. The sensors are physically separated and electrically connected to the RPS so that no single event prevents a scram caused by drywell high pressure. Cables are routed from the sensors to the RPS logic cabinets. Each sensor provides an input to one channel (Figure 7.2-3).

The discussion of diversity for high drywell pressure is provided in Sections 7.2.1.1.4.2 and 7.2.1.1.4.6.

The drywell pressure sensors are located on instrument racks outside the drywell. Instrument location drawings listed in Table 1.7-3 show the rack locations. The environmental conditions of the RPS are described in Section 3.11.

i. Deleted

j. Manual Scram (RPS Initiating Circuits)

A scram can be initiated manually. There are four scram buttons, one for each trip logic (A1, A2, B1, and B2). To initiate a manual scram, at least one button in each trip system must be depressed. The manual scram logic is the same as the automatic scram logic. The manual scram buttons are arranged in two groups of two switches. One group contains the A1 and B1 switches. The A2 and B2 switches are in the other group. The switches in each group are located close enough to permit one hand motion to initiate a scram. By operating the manual scram button for one trip logic at a time and then resetting that logic, each actuator logic can be tested for manual scram capability. The reactor operator can also scram the reactor by placing the mode switch in its shutdown position.

k. Mode Switch in Shutdown (RPS Initiating Circuits)

A scram is initiated whenever the mode switch is placed in the shutdown position. The mode switch has four electrically separated banks of gear-driven contacts. Each bank provides inputs into a separate RPS trip logic. The mode switch is located on the reactor control console in the control room. The environmental conditions for the control room are described in Section 3.11. The discussion of mode switch in shutdown operating bypass is discussed in Section 7.2.1.1.4.4.4.

The discussion of mode switch interlocks is given in Sections 7.2.1.1.4.5 and 7.2.1.1.6.2.1.

The mode switch in shutdown does not require diversity as discussed in Section 7.2.1.1.4.4.4.

7.2.1.1.4.3 RPS Logic

The basic one-out-of-two-twice logic arrangement of the RPS is illustrated in Drawings C71-1010-F-002, C71-1010-F-003, C71-1010-F-004, and C71-1010-F-005. The system is arranged as two separately powered trip systems. Each trip system has two redundant logics, as shown in Figures

7.2-4 and 7.2-5. Each logic receives input signals from at least one channel for each monitored variable. Each variable is monitored by at least four channels.

Channel and logic relays are fast response, high reliability relays. Power relays for interrupting the scram pilot valve solenoids have high current carrying capabilities and are highly reliable. All RPS relays are selected so that the continuous load will not exceed 50% of the continuous-duty rating.

The time response for the RPS sensor and sensor trip to actuators de-energized is provided in Chapter 16. The time requirements for control rod movement are discussed in Section 4.6.3.

Each trip logic provides inputs into each of the actuator logics of one trip system, as shown in Figures 7.2-4 and 7.2-5. Thus, either of the two logics associated with one trip system can produce a trip system trip. The arrangement is a one-out-of-two-twice logic. To produce a scram, the actuator logics of both trip systems must be tripped.

Diversity of variables is provided for the RPS but not in the logic. One-out-of-two-twice logic is used, but the logic channels are identical.

The RPS reset switch is used to momentarily bypass the seal-in contacts of the final actuators of the RPS. The reset is effected in conjunction with auxiliary relays. If a single channel is tripped, the reset is accomplished immediately upon operation of the reset switch. On the other hand, if a reactor scram condition is present, manual reset is prohibited for a 10 second period to permit the control rods to achieve their fully inserted position.

7.2.1.1.4.4 RPS Scram Operating Bypasses

A number of manual and automatic scram bypasses are provided to accommodate the varying protection requirements that depend on reactor conditions. These are automatically removed when the permissives conditions are not present. In addition, individual channels can be bypassed under administrative control for test and maintenance.

All manual bypass switches are in the control room, under the direct control of the control room operator.

7.2.1.1.4.4.1 Turbine Stop Valve and Turbine Control Valve Fast Closure

Turbine stop valve closure and turbine control valve fast closure trip bypass is effected by four pressure sensors associated with the turbine first stage.

Two physically separate and redundant pressure taps located in the turbine steam supply lines upstream of the high pressure turbine first stage are each piped to two non-redundant pressure sensors that sense first stage pressure. Redundancy has been achieved by connecting one pressure transmitter output to each of the four divisional trip logics so that at least two divisions must be bypassed, by action of the turbine first-stage pressure scram bypass trip units, to prevent a scram from turbine stop valve closure or turbine control valve fast closure.

The turbine stop valve closure scram and turbine control valve fast closure scram are automatically bypassed if the turbine first-stage pressure is less than a predetermined value. Closure of these turbine valves below a low initial power level does not threaten the integrity of any radioactive material release barrier. Any one channel in a bypass state produces a control room annunciation. The sensors are arranged so that no single failure can prevent a turbine stop valve closure scram

or turbine control valve fast closure scram. In addition, this bypass is automatically removed when the turbine first-stage pressure exceeds the setpoint corresponding to 29.5% of rated power.

7.2.1.1.4.4.2 MSIV Closure (RPS Scram Bypass)

At plant shutdown and during initial plant startup, a bypass is required for the MSIV closure scram trip to properly reset the RPS. This bypass is in effect when the reactor mode switch is in the SHUTDOWN, REFUEL, or STARTUP position. The bypass allows plant operation when the MSIVs are closed during low power operation. The operating bypass is removed when the mode switch is placed in the run position.

The discussion of diversity for MSIV closure is provided in Section 7.2.1.1.4.2.f.

7.2.1.1.4.4.3 Scram Discharge Volume Level (RPS Scram Bypass)

The SDV high water level trip bypass is controlled by the manual operation of two key-locked switches, a bypass switch, and the mode switch. The mode switch must be in the shutdown or refuel position to allow manual bypass of this trip. This bypass allows the operator to reset the RPS scram relays so that the SDV may be drained. Resetting the trip actuators opens the SDV vent and drain valves. An annunciator in the control room indicates the bypass condition.

The discussion of diversity of the SDV level trip is provided in Section 7.2.1.1.4.2.g.

7.2.1.1.4.4.4 Mode Switch in Shutdown (RPS Scram Bypass)

The scram initiated by placing the mode switch in shutdown is automatically bypassed after a short time delay. The bypass allows the CRD hydraulic system valve lineup to be restored to normal. An annunciator in the control room indicates the bypassed condition.

Diversity of variables is not provided for this function because the placing of the mode switch in shutdown is part of the normal method for shutting down the reactor and requires only operator action for initiation. The mode switch in shutdown is not a safety function and does not require diversity.

7.2.1.1.4.4.5 Maintenance, Calibration, or Test RPS Scram Bypasses

Each reactor scram sensor can be tested and calibrated. When an instrument is valved out for test or calibration, the administratively controlled system out-of-service annunciation is manually actuated.

Individual channels for drywell high pressure, reactor vessel high pressure, reactor vessel low water level, CRD SDV high water level, and main steam line high radiation are tripped when any one sensor is physically removed for maintenance. The bypass of the turbine stop valve closure and turbine control valve fast closure trip remains in the unbypassed state when the one turbine first-stage pressure sensors are physically removed for maintenance.

7.2.1.1.4.4.6 NMS (RPS Scram Bypass)

Bypasses for the NMS channels are described below.

The neutron monitoring scram logic trip outputs for IRM and APRM can be bypassed, during any mode of operation by hand operated selector switches located on the reactor control bench board in the control room. The bypasses for APRM channels 1, 2, 3, and 4 are controlled by one fiber-optic selector switch. None of the four APRM 2-out-of-4 voter channels can be bypassed. The bypasses for IRM channels A, C, E, and G are controlled by one selector switch and the bypasses for IRM channels B, D, F, and H are controlled by a second selector switch.

The APRM and IRM bypass switches can bypass only one NMS channel at a time. Each APRM and IRM bypass is indicated by a light in the control room.

Bypassing one APRM channel with the APRM selector switch does not inhibit the NMS from providing protective action when required. Bypassing one IRM channel with each IRM selector switch does not inhibit the NMS from providing protective action when required. Bypass indication is discussed in Section 7.2.2.1.2.1.7.

The operating bypasses of the NMS are controlled by the reactor mode switch located on the control room reactor control bench board. When the reactor mode switch is in the RUN mode, the IRM trips are bypassed; protection is provided by the APRM trips. When the reactor mode switch is not in the RUN mode, the IRM trips are active. As reactor power is increased and the APRM system reaches its operating range, by procedure the IRM detectors are withdrawn from the reactor core. When reactor power is decreased to the IRM operating range, by procedure the IRM detectors are inserted into the reactor core.

Plant administration procedures manuals specify the administrative controls used during maintenance, test, and calibration.

7.2.1.1.4.5 RPS Interlocks

The SDV high water level trip bypass signal interlocks with the RMCS to initiate a rod block. The interlock is isolated by relay contacts so that no failure in the control system can prevent a scram.

Reactor vessel low water level, reactor vessel pressure, main steam line radiation, turbine stop valve closure, and drywell high pressure signals are shared with the PCRVICS. The sensors operate relays in the RPS whose contacts interlock with the PCRVICS.

A discussion of the NMS interlocks to rod block functions is provided in Section 7.6.1.4.

Each APRM and IRM bypass is indicated by a light in the control room. The reactor mode switch has interlocks to systems other than the RPS. These interlocks are discussed in Section 7.6.1.4.

7.2.1.1.4.6 RPS Redundancy and Diversity

Redundant portions of the RPS have physically separated sensor taps, sensing lines, sensors, sensor racks, cable routing, and logic. By the use of redundant sensors for each RPS variable and separate redundant logic and wiring, the RPS system has been protected from the credible single failures. For additional information on redundancy of RPS subsystems, see Section 7.2.1.1.4.2.

Redundancy of the fail-safe RPS power supply is not required. There are two uninterruptible power supplies for continuity of service only.

Diversity is provided by monitoring diverse sets of independent reactor vessel variables. MSIV closure, turbine stop valve closure, and turbine control valve fast closure are anticipatory of a reactor vessel high pressure and power scram trip. Therefore reactor high pressure and power are diverse scram inputs to main steam line closure. Drywell high pressure and reactor low water level are diverse scram variables for a steam or water line break inside the containment. Diversity of variables for main steam line breaks outside the drywell, which initiate main steam line isolation and in turn reactor trip initiation, is covered in Section 7.3.1.1.2.8.1.

Additional discussion of diversity of RPS variables is provided in Section 7.2.1.1.4.2.

7.2.1.1.4.7 RPS Actuated Devices

The trip system logic opens when a trip signal is received and de-energizes the scram pilot valve solenoids. There are two pilot solenoids per control rod. Both solenoids must de-energize to bleed the instrument air from, and open, the inlet and outlet scram valves to allow drive water to scram a control rod. One solenoid receives its signal from trip system A, and the other receives it from trip system B. The control rods are arranged in four groups. Within each trip system, each group of control rods has its own scram contactor logic as shown in Figure 7.2-4. The failure of one control rod group to scram does not prevent a complete shutdown. The instrument air system provides support to the RPS by keeping the air operated scram valve closed until a scram is required.

The individual control rods and their controls, the scram valves, and the pilot solenoids are not part of the RPS; however, the RPS does interface with these devices by controlling the pilot solenoids. The pilot solenoids for the scram pilot valves are part of the HCU (C11-D001) of the associated control rod in the CRD system. The backup scram valves (C11-F110A & B), classified as nonessential, are also not part of the RPS, but are part of the CRD system. The valves are supplied with 125 V dc safeguard power from separate supplies. For further information on the scram valves and control rods, see Section 4.6.1.2.4.3.

The pilot solenoid valves are supplied from the RPS uninterruptible power sources.

In addition to the two scram valves for each CRD, there are two backup scram valves that are used to vent the common header for all control rods. Both backup scram valves are energized to initiate venting and are individually supplied with 125 V dc power from the Class 1E plant batteries. In any auxiliary use of the plant instrument air system, a failure of the air system causes a safe direction actuation of the safety device.

7.2.1.1.4.8 RPS Separation

Four independent sensor channels monitor the various process variables listed in Section 7.2.1.1.4.2. The redundant sensor devices are separated so that no single failure can prevent a scram. All RPS wiring outside the control system cabinets is run in totally enclosed metallic raceways or in embedded PVC conduits. Physically separated cabinets or cabinet bays are provided for the four trip logics. The rack number for RPS sensors is shown in Drawing M-01 and M-42. The locations for local RPS racks and panels are shown on the instrument location drawings listed in Table 1.7-3. Cable routing from sensor to panel is shown in raceway plans listed in Section 1.7. The criteria for separation of sensing lines and sensors are discussed in Section 7.1.2.2.

The mode switch, SDV high water level trip bypass switch, scram reset switch, and manual scram switches are all mounted on one control console. Each device is mounted in a metal enclosure

and has a sufficient number of barrier devices when required to maintain adequate separation between redundant portions of the RPS. Within the panel, conduit is provided from the metal enclosures to the point where adequate physical separation can be maintained without barriers.

The outputs from the logic cabinets to the pilot solenoids are run in four separate raceway systems to match the four scram groups shown in Drawings C71-1010-F-002 and C71-1010-F-003. The groups are selected so that the failure of one group to scram does not prevent a reactor shutdown.

RPS inputs to annunciators and the computer are arranged so that no malfunction of the annunciating or computing equipment can functionally disable the RPS. Direct signals from RPS sensors are not used as inputs to annunciating or data logging equipment. Isolation is provided between the primary signal and the information output.

7.2.1.1.4.9 RPS Testability

The RPS has components that are not activated or tested during normal operation with an integrated testing procedure. These components are tested using manual test methods which allow for independent checking of individual system components. This testing includes verification of each channel trip, including scram contactors, by using the associated installed sensors and circuits to verify proper operation. The frequency of these tests and parameters to be verified are identified in the Technical Specifications.

The RPS can be tested during reactor operation by an overlapping series of tests.

a. The manual scram test is as follows: By depressing the manual scram button for one trip channel, appropriate scram contactors are de-energized, opening contacts in the scram contactor logics. After the first trip channel is reset, the second trip channel is tripped manually and so forth for the four manual scram buttons. The total test verifies the ability to de-energize the scram pilot valve solenoids without scram by using the manual scram push button switches. In addition to control room and computer printout indications, scram group indicator lights verify that the scram contractor contacts have opened and interrupted power in these pilot solenoids.

b. Calibration of the NMS is by simulated inputs from calibration signal generators. Calibration and test controls for the NMS are located in the auxiliary equipment room. Their physical location places them under control of the operating shift management. Section 7.6.1.4 describes the calibration procedure of the NMS.

c. The single rod scram test verifies the capability of each rod to scram. It is accomplished by operating two toggle switches on the hydraulic control unit for the particular CRD. Timing traces can be made for each rod scrammed. Before the test, a physics review must be conducted to ensure that the rod pattern during scram testing does not create a rod of excessive reactivity worth.

d. MSIV position switches, turbine control valve fast closure sensors, and turbine stop valve position switches can be checked for operability.

e. The process computer verifies the correct operation of many sensors during plant startup and shutdown. The verification provided by the process computer is not considered in the selection of test and calibration frequencies and is not required for plant safety.

f. The overall RPS response time from sensor trip to channel relay de-energization and scram contactor de-energization is verified by test.

g. The fourth test involves one of two methods for applying test signals to each RPS channel in turn and observing that a logic trip results. This test also verifies the independence of the channel circuitry. The test signals can be applied to the process-type sensing instruments (pressure and differential pressure) through calibration taps, or a calibration input may be applied to each instrument trip unit by use of a built-in calibrator. Calibration and test controls for pressure sensors and differential pressure sensors are located in the turbine enclosure and secondary containment. Calibration controls for the trip units are located in the auxiliary equipment room. To gain access to the setting controls for each sensor, a cover plate or sealing device must be removed. The control room operator is responsible for granting access to the setting controls. Only properly qualified plant personnel are granted access for testing or calibration adjustments.

   In addition to the above test, the operability of the pressure and level sensors may be verified by cross-checking instrument readouts in the auxiliary equipment room at any time during operations.

The CRD SDV level sensors are tested by valving the sensor out of service and injecting and varying a test source to the level sensor.

7.2.1.1.5 RPS Environmental Considerations

Electrical modules for the RPS are located in the drywell, control structure, secondary containment, and turbine enclosure. The environmental conditions for these are discussed in Section 3.11.

7.2.1.1.6 RPS Operational Considerations

7.2.1.1.6.1 Reactor Operator Information

7.2.1.1.6.1.1 Indicators

Scram group indicators extinguish when trip logic opens.

Recorders in the control room also provide information regarding reactor vessel water level, reactor vessel pressure, drywell pressure, and reactor power level.

7.2.1.1.6.1.2 Annunciators (RPS Operator Information)

Each manual and/or automatic RPS input is annunciated in the control room by isolated relay contacts. Trip logic trips also actuate the annunciator system.

When an RPS sensor channel trips, a corresponding red annunciator window on the reactor control panel in the control room indicates the out-of-limit variable. Each trip logic also initiates a corresponding red annunciator window that indicates the trip logic that has tripped. An RPS channel trip also actuates an annunciator system horn, which can be silenced by the operator. The annunciator window lights latch-in until reset manually. Reset is not possible until the condition that

caused the trip has been cleared. The location of alarm windows permits the operator to quickly identify the cause of RPS trips and to evaluate the threat to the fuel or RCPB.

7.2.1.1.6.1.3 Computer Alarms (RPS Operator Information)

A computer printout identifies each tripped channel. All RPS trip events are recorded by the NSSS process computer system. This permits subsequent analysis of an operational transient that occurs too rapidly for operator comprehension of events as they occur. The first 80 events are recorded in chronological sequence; events occurring within 4 milliseconds of one another are treated as having occurred simultaneously. The use of the computer is not required for plant safety. The printout of trips is particularly useful in routinely verifying the correct operation of pressure, level, and valve position switches as trip points are passed during startup, shutdown, and maintenance operations.

7.2.1.1.6.2 RPS Reactor Operator Controls

7.2.1.1.6.2.1 Mode Switch

A conveniently located, multiposition mode switch is provided to select the necessary scram functions for various plant conditions. The mode switch selects the appropriate sensors for scram functions and provides appropriate bypasses. The switch also interlocks such functions as control rod blocks and refueling equipment restrictions, which are not considered here as part of the RPS. The switch is designed to provide separation between the four trip channels. The mode switch positions and their related scram functions are as follows:

a. Shutdown

   Initiates a reactor scram; bypasses main steam line isolation scram.

b. Refuel

   Selects the IRM trips for low neutron flux level operation (disables the OPRM upscale trip but does not disable the APRM upscale and inoperative trips); bypasses main steam line isolation scram.

c. Startup

   Selects the IRM trips for low neutron flux level operation (disables the OPRM upscale trip but does not disable the APRM upscale and operative trips); bypasses main steam line isolation scram.

d. Run

   Selects the APRM trips, including the OPRM upscale trip, for power range operation.

7.2.1.1.6.3 Setpoints (RPS Operational Considerations)

Instrument ranges are chosen to cover the range of expected conditions for the variable being monitored. Additionally, the range is chosen to provide the necessary accuracy for any required setpoints and to meet the overall accuracy requirements of the channel.

a. NMS Trip

To protect the fuel against high heat generation rates, neutron flux is monitored and used to initiate a reactor scram. The NMS setpoints and their bases are discussed in Section 7.6.1.4.

b. Reactor Vessel High Pressure

Excessively high pressure within the reactor vessel threatens to rupture the RCPB. A reactor vessel pressure increase during reactor operation compresses the steam voids and results in a positive reactivity insertion; this causes increased core heat generation that could lead to fuel failure and system overpressurization. A scram counteracts a pressure increase by quickly reducing core fission heat generation. The reactor vessel high pressure scram setting selected is slightly above the reactor vessel maximum normal operation pressure, to permit normal operation without a spurious scram and yet provide a wide margin to the maximum allowable reactor vessel pressure. The location of the pressure measurement, as compared to the location of the highest nuclear system pressure during transients, was also considered in the selection of the high pressure scram setting. The reactor vessel high pressure scram works in conjunction with the pressure relief system to prevent reactor vessel pressure from exceeding the maximum allowable pressure. The reactor vessel high pressure scram setting also protects the core from exceeding thermal-hydraulic limits resulting from pressure increases during events that occur when the reactor operates below rated power and flow.

c. Reactor Vessel Low Water Level (RPS Setpoints)

Low water level in the reactor vessel indicates that the reactor is in danger of being inadequately cooled. Decreasing water level while the reactor operates at power decreases the reactor coolant inlet subcooling. The effect is the same as raising feedwater temperature. If the water level decreases further, fuel damage could result as steam forms around fuel rods. A reactor scram protects the fuel by reducing the fission heat generation within the core. The reactor vessel low water level scram setting was selected to prevent fuel damage following abnormal operational transients caused by single equipment malfunctions or single operator errors that result in a decreasing reactor vessel water level. The scram setting is far enough below normal operational levels to prevent spurious scrams. The setting is high enough above the top of the active fuel to ensure that enough water is available to account for evaporation, loss, and displacement of coolant following the most severe abnormal operational transient involving a level decrease.

d. Turbine Stop Valve Closure (RPS Setpoints)

Closure of the turbine stop valve with the reactor operating at power can result in a significant addition of positive reactivity to the core as the reactor vessel pressure rise causes steam voids to collapse. The turbine stop valve closure scram initiates a scram earlier than either the NMS or reactor vessel high pressure. It is required to provide a satisfactory margin below core thermal-hydraulic limits for this category of abnormal operational transients. By inserting

negative reactivity with control rods, the scram counteracts the addition of positive reactivity caused by increasing pressure. Although the reactor vessel high pressure scram, in conjunction with the pressure relief system, is adequate to preclude overpressurizing the nuclear system, the turbine stop valve closure scram provides additional margin to the reactor vessel pressure limit. The turbine stop valve closure scram setting provides the earliest positive indication of valve closure.

e. Turbine Control Valve Fast Closure (RPS Setpoints)

With the reactor and turbine-generator at power, fast closure of the turbine control valves can result in a significant addition of positive reactivity to the core as nuclear system pressure rises. The turbine control valve fast closure scram initiates a scram earlier than either the NMS or reactor vessel high pressure. It is required to provide a satisfactory margin to core thermal-hydraulic limits for this category of abnormal operational transients. By inserting negative reactivity with control rods, the scram counteracts the addition of positive reactivity resulting from increasing pressure. Although the reactor vessel high pressure scram, in conjunction with the pressure relief system, is adequate to preclude overpressurizing the nuclear system, the turbine control valve fast closure scram provides additional margin to the nuclear system pressure limit. The turbine control valve fast closure scram setting is selected to provide timely indication of control valve fast closure.

f. Main Steam Line Isolation (RPS Setpoints)

MSIV closure can result in a significant addition of positive reactivity to the core as nuclear system pressure rises. The main steam line isolation trip initiates a scram earlier than either the NMS or reactor vessel high pressure. By inserting negative reactivity with control rods, the scram counteracts the addition of positive reactivity resulting from increasing pressure. Although the reactor vessel high pressure scram, in conjunction with the pressure relief system, is adequate to preclude overpressurizing the nuclear system, the main steam line isolation scram provides additional margin to the nuclear system pressure limit. The main steam line isolation scram setting is selected to give the earliest positive indication of isolation valve closure. The logic allows functional testing of main steam line isolation trip channels by partially closing an MSIV.

g. SDV High Water Level (RPS Setpoints)

Water displaced by the CRD pistons during a scram goes to the SDV. If the SDV fills with water so that insufficient capacity remains for the water displaced during a scram, control rod movement would be hindered during a scram. To prevent this situation, the reactor is scrammed when the water level in the discharge volume is high enough to verify that the volume is filling up, yet low enough to ensure that the remaining capacity in the volume can accommodate a scram.

h. Drywell High Pressure (RPS Setpoints)

High pressure inside the drywell may indicate a break in the RCPB. It is prudent to scram the reactor in such a situation to minimize the possibility of fuel damage and

to reduce energy transfer from the core to the coolant. The drywell high pressure scram setting is selected to be as low as possible without inducing spurious scrams.

i. Left blank intentionally.

j. Manual Scram (RPS Setpoints)

Push buttons are located in the control room to enable the operator to shut down the reactor by initiating a scram.

k. Mode Switch in Shutdown (RPS Setpoints)

When the mode switch is in shutdown, the reactor is to be shut down with all control rods inserted. This scram is not considered a protective function, because it is not required to protect the fuel or reactor vessel process barrier, and it bears no relationship to minimizing the release of radioactive material from any barrier. The scram signal is removed after a short delay, permitting a scram reset that restores the normal valve lineup in the CRD hydraulic system.

l. Turbine First-Stage Pressure (RPS Setpoints)

The turbine stop valve closure scram and turbine control valve fast closure scram are automatically bypassed if the turbine first-stage pressure is less than a predetermined value. This setpoint is chosen so that closure of these valves below the setpoint does not threaten the integrity of any radioactive material release barrier.

7.2.1.1.7 RPS Containment Electrical Penetration Assignment

See Section 6.2.6.

7.2.1.1.8 RPS Control Room Area

The control room area is divided into three floors, the auxiliary equipment room, the control room, and the cable spreading room. Each floor is divided into a Unit 1 and Unit 2 section. The RPS control board is located in the control room. The bench board for reactor control contains the reactor mode switch, bypass switches, scram solenoid valve status indicating lights, and manual scram switches. The RPS vertical boards are located in the auxiliary equipment room. The RPS vertical boards contain the trip units, trip channel and logic relays, test switches, trip indicating lights, and terminal boards. The vertical boards are installed on PGCC floor sections and are connected to individual termination cabinets by under-floor cable ducts. A general description of the cable spreading in the PGCC floor sections is contained in NEDO-10466A, "Power Generation Control Complex", and a further description is contained in Section 8.1.6.1.14.b.6.

There is no RPS equipment except for cables located in the cable spreading room. In the cable spreading room the RPS cables are routed in identified, totally enclosed metallic raceways. The arrangement of the equipment is shown in Drawings M-602 and M-603.

7.2.1.1.9 Test Methods that Enhance RPS Reliability

Surveillance testing is performed periodically on the RPS during operation and shutdown. This testing includes sensor calibration, response time testing, trip channel actuation, and trip time

measurement with simulated inputs to individual trip units and sensors. The sensors that are transmitters can be checked by comparison of the readings on other channels of the same variable.

7.2.1.1.10 Interlock Circuits to Inhibit Rod Motion as Well as Vary the Protection Function

Section 7.7.1.2.3.2.3.3 describes interlock circuits to inhibit rod motion that are derived from neutron flux and recirculation flow measurements. Electrical isolation is provided between the RBM interlock circuits and the APRM protective action circuits.

There are no interlock circuits that inhibit rod motion as well as vary the protective functions.

7.2.1.1.11 RPS Support Cooling Systems

Operation of the control enclosure chilled water system and associated unit coolers is required to ensure operation of the RPS components within their design requirements. The control enclosure chilled water system is described in Section 7.3.1.1.13.

7.2.1.2 RPS Design Bases

Design basis information requested by IEEE 279 (1971) is discussed in the following paragraphs. These IEEE 279 design bases aspects are considered separately from those more broad and detailed design bases for this system cited in Section 7.1.

7.2.1.2.1 Conditions

The generating station conditions that require reactor trip system protective action are as follows:

a. Generator load rejection above the turbine steam bypass capability

b. Turbine trip above the turbine steam bypass capability

c. MSIV closure during operation in the run mode

d. Turbine pressure regulator failure (valve open) resulting in MSIV closure that is due to dropping line pressure

e. Excess reactor coolant inventory resulting in turbine trip that is due to high reactor water level

f. Loss of feedwater flow

g. Recirculation flow control failure with increasing flow

h. Control rod-drop accident

i. LOCA

j. Main steam line break

k. Feedwater system piping break

7.2.1.2.2 Variables

The generating station variables that require monitoring in order to provide protective actions, are identified in Table 7.2-2.

7.2.1.2.3 Sensors

A minimum number of LPRMs per APRM are required to provide adequate protective action. This is the only variable that has spatial dependence as discussed in IEEE 279, paragraph 3.3. A discussion of these requirements is in Section 7.6.

7.2.1.2.4 Operational Limits

Operational limits for each safety-related variable trip setting are selected with sufficient margin so that a spurious scram is avoided. It is then verified by analysis that the calculated radioactive material releases are kept within acceptable bounds. Design basis operational limits are listed in Chapter 16. Technical Specifications are based on operating experience and constrained by the safety design basis and the safety analyses.

7.2.1.2.5 Margin Between Operational Limits

The margin between operational limits and the levels requiring protective action for the RPS are listed in Chapter 16, Technical Specifications. The margin includes the allowance for instrument accuracy, calibration error, sensor response times, and sensor and setpoint drift.

7.2.1.2.6 Levels Requiring Protective Action

Levels requiring protective action are provided in Chapter 16, Technical Specifications.

7.2.1.2.7 Ranges of Energy Supply and Environmental Conditions

The RPS 120 V ac power is provided by two static inverter sets that are each fed by two electrical sources, one from the plant auxiliary source and the other from the station batteries. The plant auxiliary source is a 480/120 V transformer, which is supplied through a transfer switch either from a non-Class 1E 440 V MCC or from a non-Class 1E 440 V MCC energized by a non-Class 1E UPS. Voltage regulation of the RPS power source is ±2% under steady-state conditions.

Environmental conditions for the RPS components inside and outside the containment are discussed in Section 3.11.

7.2.1.2.8 Unusual Events

Unusual events are defined as malfunctions, accidents, and other events that could cause damage to safety systems. The following accidents and events are considered: floods; storms; tornadoes; earthquakes; fire; LOCA; pipe break outside containment; feedwater line break; and missiles. Each of these events is discussed below for the RPS.

a. Floods

The structures containing RPS components are designed to meet the PMF at the site location as described in Section 3.4. This ensures that the structures remain

water-tight under PMF, including wind-generated wave action and wave run-up. Therefore, none of the RPS functions is affected by flooding.

b. Storms and Tornados (RPS Design Bases Unusual Events)

The structures containing RPS components are designed to withstand all credible meteorological events and tornados as described in Section 3.3.2. Superficial damage may occur to miscellaneous station property during a postulated tornado, but this will not impair the RPS capabilities.

c. Earthquakes (RPS Design Bases Unusual Events)

The structures containing RPS components, except the turbine enclosure, are seismically qualified as described in Sections 3.7 and 3.8. These structures containing RPS components remain functional during and following a SSE. The only RPS components located in the nonseismically qualified turbine enclosure are the sensors and associated cables for turbine stop valve closure, turbine control valve fast closure, turbine stop valve closure, and control valve fast closure bypass. Since reactor pressure and power trips are diverse to these turbine scram variables, locating these sensors in the turbine enclosure does not compromise the ability of the RPS to provide protective action when required.

d. Fires (RPS Design Bases Unusual Events)

To protect the RPS from a fire, the RPS trip logics are divided into four separate sections within two separate RPS panels. The sections within a panel are separated by fire barriers. If a fire were to occur within one of the sections or in the area of one of the panels, the RPS functions would not be prevented by the fire. The use of separation and fire barriers ensures that, even though some portion of the system may be affected, the RPS continues to provide the required protective action.

A nonsafety-related fire detection system using both thermal (rate of temperature rise) and ionization smoke detectors is provided in the PGCC floor sections, termination cabinets, and the space between the slab and the elevated floor in the periphery of the auxiliary equipment room. The entire space, with the exception of the termination cabinets, is protected by a Halon 1301 total flooding fire suppression system. The system is automatically initiated by heat detectors within the protected space. Detection of fire by smoke detectors and automatic initiation of the Halon suppression system are annunciated in the control room.

The control room is provided with ionization smoke detectors. Manual fire fighting capability provided for the control room consists of portable halon fire extinguishers within the control room and carbon dioxide hose stations outside of the control room. Additionally, fire hose stations with hose lines equipped with combination nozzles are installed outside the control room.

These fire protection systems are fully discussed in Section 9.5.1.

e. LOCA (RPS Design Bases Unusual Events)

The following RPS components are located inside the drywell and would be subjected to the effects of a design basis LOCA:

1. NMS cabling from the detectors to the control room

2. MSIV inboard position switches

3. Reactor vessel pressure and reactor vessel water level instrument taps and sensing lines that terminate outside the drywell

4. Drywell pressure instrument taps

These items and all RPS Class 1E components are environmentally qualified to remain functional during and following a LOCA as discussed in Section 3.11.

f. Pipe Break Outside Secondary Containment (RPS Design Bases Unusual Events)

This condition would not affect the reliability of the RPS.

g. Feedwater Break (RPS Design Bases Unusual Events)

This condition would not affect the reliability of the RPS.

h. Missiles (RPS Design Bases Unusual Events)

See Section 3.5.

7.2.1.2.9 Performance Requirements

The minimum performance requirements are referenced in Chapter 16.

A logic combination (one-out-of-two-twice) of instrument channels and their trips, actuated by abnormal or accident conditions, initiates a scram and produces independent logic seal-ins within each of the four logic divisions. The trip conditions are annunciated and recorded on the process computer. The trip seal-in maintains a scram signal condition at the CRD system terminals until the instrument channels have returned within their normal operating range and the seal-in is manually reset by operator action. Thus, once a trip signal is present long enough to initiate a scram, the protective action goes to completion.

7.2.1.3 RPS Final System Drawings

The final RPS drawings are processed at two different levels relative to this UFSAR.

a. System IED and channel logic diagrams are provided in this section.

b. Detailed circuit diagrams, electrical elementary diagrams, and cabinet and panel layout drawings are listed in Section 1.7. This documentation is complementary to discussions and drawings included in this UFSAR.

There are no functional or architectural design basis differences or changes to this system between the approved preliminary PSAR design and the FSAR final design, except for the following changes:

1. 600 psi permissive in MSIV closure trip was deleted.

2. 15% APRM trip was added.

3. Trip units/transmitters were added.

4. Logics A3 and B3 were deleted.

A direct comparison of the PSAR and FSAR verifies these observations.

7.2.2 ANALYSIS

7.2.2.1 Reactor Protection System - Instrumentation and Controls

7.2.2.1.1 RPS General Functional Requirements Conformance

Presented below are analyses to demonstrate how the various general functional requirements and the specific regulatory requirements listed under the RPS design bases (Section 7.1.2.1) are satisfied.

7.2.2.1.1.1 RPS Conformance to Design Bases Requirements

7.2.2.1.1.1.1 Design Basis (Section 7.1.2.1.1.1.a)

The RPS is designed to provide timely protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier. Chapter 15 identifies and evaluates events that jeopardize the fuel barrier. The methods of assessing barrier damage and radioactive material releases, along with the methods by which abnormal events are detected and identified, are presented in that chapter.

The design basis from Section 7.1.2.1.1 requires that the precision and reliability of the initiation of reactor scrams be sufficient to prevent or limit fuel damage.

Table 7.2-1 lists the sensors selected to initiate reactor scrams and delineates the needed accuracy, range, and time response for each sensor. This information, along with the information in the Technical Specifications establishes the precision of the RPS variable sensors.

The reliability of the RPS is ensured by design through the selection of reliable components, configuration of components in redundant logic, the use of components based on previous design, and periodic testing.

The selection of scram trip settings has been developed through analytical modeling, experience, historical use of initial setpoints, and adoption of new variables and setpoints as experience was gained. The initial setpoint selection method provided for settings that were sufficiently above the normal operating levels (to preclude the possibilities of spurious scrams or difficulties in operation) but low enough to protect the fuel. As additional information became available or systems were changed, additional scram variables were provided using the above method for initial setpoint selection. The selected scram settings are analyzed to verify that they are conservative and that

the fuel and fuel barriers are adequately protected. In all cases, previous operating experience and the analytical models have been taken into consideration, so that the specific scram trip point selected is a conservative value that prevents damage to the fuel.

7.2.2.1.1.1.2 RPS Design Basis (Section 7.1.2.1.1.1.b)

The scram initiated by the RCPB high pressure, in conjunction with the pressure relief system, is sufficient to prevent damage to the RCPB as a result of internal pressure. The MSIV closure scram provides a greater margin to the RCPB pressure safety limit than the high pressure scram does. For turbine-generator trips, the stop valve closure scram and turbine control valve fast closure scram provide a greater margin to the nuclear system pressure safety limit than the high pressure scram does. Chapter 15 identifies and evaluates accidents and abnormal operational events that result in nuclear system pressure increases. In no case does pressure exceed the RCPB safety limits.

7.2.2.1.1.1.3 RPS Design Basis (Section 7.1.2.1.1.1.d)

The scram initiated by the reactor vessel low water level satisfactorily limits the radiological consequences of gross failure of the RCPB. Chapter 15 evaluates gross failures of the RCPB; in no case does the release of radioactive material to the environment result in exposures that exceed the guide values of applicable published regulations.

7.2.2.1.1.1.4 RPS Design Basis (Section 7.1.2.1.1.1.d)

Scrams are initiated by variables that are designed to indirectly monitor fuel temperature and protect the RCPB. The NMS monitors fuel temperature indirectly using incore detectors. The incore detectors monitor the reactor power level by detecting the neutron level in the core. Reactor power level is directly proportional to neutron level and the heat generated in the fuel. Although the NMS does not monitor fuel temperature directly, by establishing a correlation between fuel temperature and reactor power level, scram setpoints can be determined for protective action, which prevents fuel damage.

The RCPB is protected by monitoring parameters that indicate reactor pressure directly or anticipate reactor pressure increases. Reactor pressure is monitored directly by pressure sensors that are connected directly to the RPV through sensing lines and pressure taps. In addition, reactor pressure transients are anticipated by monitoring the closure of valves that shut off the flow of steam from the RPV and cause rapid pressure increases. The variables monitored to anticipate pressure transients are MSIV position, turbine stop valve closure, and turbine control valve fast closure. If any of these valves were to close, pressure would rise very rapidly. Therefore, the pressure rise is anticipated, and a trip is initiated to minimize the pressure transient.

Chapter 15 identifies and evaluates the conditions that threaten fuel and RCPB integrity. In no case does the core exceed a safety limit.

7.2.2.1.1.1.5 RPS Design Basis (Section 7.1.2.1.1.1.e)

The scrams initiated by the NMS, drywell pressure, reactor vessel pressure, reactor vessel water level, turbine stop valve closure, and the turbine control valve fast closure prevent fuel damage. The scram setpoints and response time requirements for these variables are referenced in Chapter 16 and have been designed to cover the expected range of magnitude and rates of change during abnormal operational transients without fuel damage. Chapter 15 identifies and evaluates

the conditions that threaten fuel integrity. With the selected variables and scram setpoints, adequate core margins are maintained relative to thermal-hydraulic safety limits.

7.2.2.1.1.1.6 RPS Design Basis (Section 7.1.2.1.1.1.f)

Neutron flux is the only essential variable with spatial dependence that provides inputs to the RPS. Neutron flux is monitored both as an indication of average reactor power (APRM upscale trips) and as indication of thermal-hydraulic instability caused power oscillations (OPRM upscale trip).

Two transient analyses are used to determine the minimum number and physical location of required LPRMs for each APRM for average power monitoring.

a. The first analysis is performed with operating conditions of 100% reactor power and 100% recirculation flow using a continuous rod withdrawal of the maximum worth control rod. In the analysis, LPRM detectors are mathematically removed from the APRM channels. This process is continued until the minimum number and locations of detectors needed to provide protective action are determined for this condition.

b. The second analysis is performed with operating conditions of 100% reactor power and 100% recirculation flow using a reduction of recirculation flow at a fixed design rate. Again, LPRM detectors are mathematically removed from the APRM channels. This process is continued until the minimum number and locations of detectors needed to provide protective action are determined for this condition.

The results of the two analyses are evaluated and compared to establish the actual minimum number and location of LPRMs needed for each APRM channel.

The OPRM upscale function monitors LPRMs combined into cells of 4 LPRMs each (see Figure 7.2-17). If more than 2 of the 4 LPRMs in an OPRM cell are bypassed the cell is determined to be inoperable and removed from the logic. The minimum required number of operable OPRM cells per APRM channel is determined by performing an analysis that mathematically removes LPRMs (and OPRM cells when the number of remaining LPRMs in a cell falls below the required minimum) and calculates the hot-bundle MCPR change that will result prior to an OPRM trip due to a power oscillation. That calculated value is compared to the hot-bundle MCPR change calculated with no LPRMs bypassed. The minimum required number of operable OPRM cells is that number that assures that the hot-bundle MCPR change that results prior to an OPRM upscale trip is equal to or less than the corresponding value calculated with no LPRMs bypassed (References 7.6-1 through 7.6-4).

Analyses like those discussed above for APRMs have also been conducted for the IRMs. These analyses have established the actual minimum number and location of IRM sensors and channels (Reference 7.2-1).

7.2.2.1.1.1.7 RPS Design Basis (Sections 7.1.2.1.1.1.g.1 through 7.1.2.1.1.1.g.8)

Sensors, channels, and logics of the RPS are not used directly for automatic control of process systems. Therefore, failure in the controls and instrumentation of process systems cannot induce failure of any portion of the protection system.

The RPS system is a normally energized system. Failure of either RPS power supply results in the de-energization of one of the two pilot solenoids associated with each control rod. Alternate power is available to the RPS buses. A complete loss of electrical power to both power supplies results in a scram. Loss of one or both power supplies does not prevent a reactor scram.

The RPS is designed so that trip variables need only exceed their trip setpoints for a sufficient length of time to de-energize the scram relay contactors and open the seal-in contacts of the associated trip logic. Once this is accomplished, the scram will go to completion, regardless of the state of the variable that initiated the protective action.

When the initiating condition has cleared and a sufficient (10 second) time delay has occurred, the scram logic may be reset only by actuation of the scram reset switches in the control room by the operator.

Reactor protection cabling is routed in separate, totally-enclosed metallic raceways or in embedded PVC conduits for all wiring between sensors, racks, panels, and scram solenoids.

Physical separation and electrical isolation among redundant portions of the RPS are provided by separated process instrumentation, separated racks, separated portions of panels, and separated cabling, as described in Section 7.2.1.1.4.8. This separation ensures that environmental factors, electrical transients, and physical events do not impair the ability of the RPS to respond correctly when required.

The RPS has four divisions housed in two panels in the auxiliary equipment room and one panel in the control room. Each panel has metallic fireproof barriers between divisions. Where equipment from more than one division is in a panel, divisional separation is provided by fire barriers or a physical distance of 6 inches or more where practicable. Where wiring from more than one redundant division is present at a single component, divisional separation is provided by fire barriers on the component, in addition to routing the wiring from the component in separate conduits or by routing wiring in such a way as to prevent any failure within the component from affecting redundant divisions. Separate racks are provided for the reactor protection sensor instrumentation in redundant divisions and they are either installed in different locations or separated by metal barriers.

The ability of the RPS to withstand an SSE is discussed in Section 7.2.2.1.2.1.4.

The ability of the RPS to function properly with a single failure is discussed in Section 7.2.2.1.2.3.1.2.

The ability of the RPS to function properly while any one sensor or channel is bypassed or is undergoing testing or maintenance is discussed in Section 7.2.2.1.2.3.1.11.

The RPS logic circuit is designed so that an automatic scram is initiated when at least one sensor in each trip system for any monitored variable exceeds the scram setpoint.

7.2.2.1.1.1.8 RPS Design Basis (Section 7.1.2.1.1.1.h)

Access to trip settings, component calibration controls, test points, and other terminal points is under the control of plant operations supervisory personnel.

Access control is provided by the use of administration control procedures. These require that approved procedures be used to perform calibration and testing; permission must be obtained before performance of all calibration and testing. It is also required that operations personnel, within the control room, monitor and control access to panels and cabinets within the control room.

Manual bypass of instrumentation and control equipment components is under the control of the control room operator. If the ability to trip some essential part of the system is bypassed during a mode of operation that requires operability of that part of the system, this fact is continuously annunciated in the control room, as described in Section 7.2.2.1.2.1.7.

7.2.2.1.1.1.9 Other RPS Design Basis Requirements

The RPS is a one-out-of-two-twice logic system. Theoretically, its reliability is slightly higher than a two-out-of-three system and slightly lower than a one-out-of-two system. However, because the differences are slight, they can be neglected. The dual trip system is advantageous because it can be tested thoroughly during reactor operation without causing a scram. This capability for a thorough testing program significantly increases reliability.

The environment in which the instruments and equipment of the RPS must operate is discussed in Section 3.11.

The control room maximum environment is predicated on supplying the control room with 100% outside air with no refrigeration. The minimum environment is predicated on a mixture of outside and recirculated air concurrent with minimum equipment heat loss. The RPS components that must function in the environment resulting from a RCPB break inside the drywell are the condensing chambers and the inboard MSIV position switches. Special precautions are taken to ensure their operability after the accident.

The condensing chambers have been qualified by analysis to the applicable ASME Codes. The chamber itself is strictly a mechanical assembly with no moving parts and no active functions. There is no environmental requirement on the condensing chambers, other than that each maintain its integrity under the most severe environmental condition. The results of the seismic qualification of the condensing chambers are documented in the LGS SQRT Program.

The environmental qualification of the existing MSIV limit switches has been evaluated as part of the LGS environmental qualification program. As a result of the licensee's evaluation, the originally supplied limit switches have been replaced with prequalified limit switches. The selection criteria for the replacement switches include qualification levels appropriate for a RCPB break inside the drywell.

Other essential components of the control and electrical equipment are either similar to those that have successfully undergone qualification testing in connection with other projects, or additional qualification testing under simulated environmental conditions has been conducted.

To ensure that the RPS remains functional, the number of operable channels for the essential monitored variables is maintained at or above the minimums referenced in Chapter 16. The minimums apply to any untripped trip system; a tripped trip system may have any number of inoperative channels. Because reactor protection requirements vary with the mode in which the reactor operates, the tables show different functional requirements for the run and startup modes. These are the only modes in which more than one control rod can be withdrawn from the fully inserted position.

In case of a LOCA, reactor shutdown occurs immediately following the accident as process variables exceed their specified setpoint. Operator verification that shutdown has occurred may be made by observing one or more of the following indications:

a. Control rod status lamps indicating each rod fully inserted

b. Control rod scram pilot valve status lamps indicating open valves

c. Neutron monitoring power range channels and recorders downscale

d. Annunciators for RPS variables and trip logic in the tripped state

e. Process computer logging of trips and control rod position log

Following generator load rejection, a number of events occur in the following chronological order:

a. The pressure in the hydraulic oil lines to the control valve fast closure solenoid drops, and the pressure sensors provide a trip signal to RPS. Simultaneously the turbine control logic initiates fast opening of the turbine bypass valves which minimizes the pressure from the transient.

b. The RPS scrams the reactor upon receipt of the turbine control valve fast closure signal, provided that at the time of load rejection the unit load is equal to or greater than 29.5% of rated power output.

   The reactor scram is averted, if at the time of load rejection, the unit load is within the capacity of the turbine bypass system.

c. The APRM Simulated Thermal - Upscale trip setting is automatically reduced from 117% to 97% Simulated Thermal Power, as recirculation flow is run back from 100% to 50% of the rated flow.

The trip settings discussed in Section 7.2.1.1.6.3 are not changed to accommodate abnormal operating conditions. Actions required during abnormal conditions are discussed in Chapter 16. Transients requiring activation of the RPS are discussed in Chapter 15. The discussions there designate which systems and instrumentation are required to mitigate the consequences of these transients.

Operability of the anticipatory signals from the turbine control valve fast closure or turbine stop valve closure following an SSE is not a system design basis. There is no reason to expect concurrent failures of these trips without the SSE. However, if the gross failure of these trips should occur, the reactor would scram on high neutron flux or high reactor pressure. The results of this event would not be more severe than the one caused by closure of all the MSIVs without the MSIV position switch trip. That event is discussed in Section 5.2.2.2.2.4 as the relief valve sized transient.

7.2.2.1.2 RPS Specific Regulatory Requirements Conformance

7.2.2.1.2.1 RPS Conformance to Regulatory Guides

Conformance of the transmitter/trip unit system used in the RPS is discussed in Licensing Topical Report NEDO-21617-A, "Analog Transmitter/Trip Unit System for Engineered Safeguard Sensor Inputs." Conformance of the other features with the regulatory guides is discussed in the following sections.

7.2.2.1.2.1.1 RPS - Regulatory Guide 1.6 (1971) - Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems (Safety Guide 6)

Conformance is discussed in Section 7.1.2.5.1.

7.2.2.1.2.1.2 RPS - Regulatory Guide 1.11 (1971) - Instrument Lines Penetrating Primary Reactor Containment (Safety Guide 11)

Conformance to Regulatory Guide 1.11 is discussed in Section 6.2.4.3.

7.2.2.1.2.1.3 RPS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The system is designed so that it may be tested during plant operation from sensor device to final actuator device. The test must be performed in overlapping portions so that an actual reactor scram does not occur as a result of the testing.

7.2.2.1.2.1.4 RPS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

All electrical and mechanical devices and circuitry between process instrumentation and protection actuators and monitoring of systems important to safety are classified as seismic Category I.

7.2.2.1.2.1.5 RPS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

See Section 8.1.6.1.5 and Chapter 17.

7.2.2.1.2.1.6 RPS - Regulatory Guide 1.32 (1977) - Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants

Although not a design basis, an assessment of the LGS design shows that it meets the guidelines of Regulatory Guide 1.32 (1977) and conforms to IEEE 308 (1971).

7.2.2.1.2.1.7 RPS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

a. Regulatory Positions C.1, C.2, and C.3

Automatic indication is provided in the control room to inform the operator that a system is out-of-service. Indicator lights indicate which part of a system is not operable. System out-of-service annunciators energize whenever one or more of the following conditions occur:

1. Trip units are being tested or a gross failure of a transmitter is detected.

2. Trip units are out of their card file, or there is a loss of power to the transmitters, or trip units.

These are the only conditions expected to occur more than once a year that would cause inoperability of the RPS. In addition, there is a switch in the control room that the operator can use to manually bring up the system out-of-service annunciator.

Instruments that form part of a one-out-of-two-twice logic system can be removed from service for calibration. Removal of the instrument from service is indicated in the control room by manual actuation of the system out-of-service annunciator by the system out-of-service switch.

b. Regulatory Position C.4

All the annunciators can be tested by depressing the annunciator test switches on the control room bench boards.

The following discussion expands the explanation of conformance to Regulatory Guide 1.47 to reflect the importance of providing accurate information for the operator and reducing the possibility for the indicating equipment to adversely affect its monitored safety system.

1. Individual indicator lights are arranged together on the control room console to indicate what function of the system is out-of-service, bypassed, or otherwise inoperable. All bypass and inoperability indicators both at a system level and component level are grouped only with items that prevent a system from operating if needed.

2. A manual switch is provided for manual actuation to cover out-of-service conditions that could not be automatically annunciated.

3. These indication provisions serve to supplement administrative controls and to aid the operator in assessing the availability of component and system level protective actions. This indication does not perform a safety function.

4. All system out-of-service annunciator circuits are electrically independent of the plant safety systems to prevent the possibility of adverse effects.

5. Each indicator light is provided with dual lamps. These are tested periodically, along with the other devices in the circuit.

7.2.2.1.2.1.8 RPS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 is obtained by specifying, designing, and constructing the RPS to meet the single failure criterion, section 4.2 of IEEE 279 (1971), "Criteria for Protection Systems for Nuclear Power Generating Stations," and IEEE 379 (1972), "IEEE Trial Use Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems." Redundant instrument tubing, sensors, wiring, logic, and actuators are separated to ensure that a single failure in any portion of the RPS does not prevent protective action.

Facilities for testing are provided so that the equipment can be operated in various test modes to confirm that it operates properly when required. Testing incorporates all elements of the system under one test mode or another, including sensors, logic, actuators, and actuated equipment. The testing is planned to be performed at intervals so that there is an extremely low probability of failure in the periods between tests. During testing, there are always enough channels and systems available for operation to provide proper protection action.

7.2.2.1.2.1.9 RPS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Means are provided for manual initiation of reactor manual scram at the system level through the use of four, armed push button switches, one for each trip logic. Operation of these switches accomplishes the initiation of all actions performed by the automatic initiation circuitry. These switches are located on the control room bench board and are easily accessible to the operator so that action can be taken expeditiously.

The amount of equipment common to the initiation of both manual scram and automatic scram is kept to a minimum through the implementation of manual scram as close to the final devices (scram contactor) as practicable. No single failure in the manual, automatic, or common portions of the protection system prevents initiation of reactor scram by manual or automatic means.

The "minimum of equipment" objective is accomplished for the initiation of manual scram through its implementation "as close as practicable to" the final actuating devices (scram contactor) of the protection system.

Manual initiation of reactor scram, once initiated, goes to completion as required by IEEE 279 (1971), section 4.16.

7.2.2.1.2.1.10 RPS - Regulatory Guide 1.63 (1978) - Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants

Conformance to Regulatory Guide 1.63 is discussed in Section 8.1.6.1.12.

7.2.2.1.2.1.11 RPS - Regulatory Guide 1.68 (1978) - Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors

Conformance to Regulatory Guide 1.68 is discussed in Section 14.2.

7.2.2.1.2.1.12 RPS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

Conformance is discussed in Section 8.1.6.14.

7.2.2.1.2.1.13 RPS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

Conformance is discussed in Sections 3.11 and 8.1.6.1.16.

7.2.2.1.2.1.14 RPS - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Conformance to this guide is discussed in Section 7.5.2.5.1.1.2.

7.2.2.1.2.1.15 RPS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

General compliance for Regulatory Guide 1.100 is found in Section 3.10.2.

7.2.2.1.2.1.16 RPS - Regulatory Guide 1.105 (November 1976) - Instrument Setpoints

RPS conformance to this guide is discussed in Section 7.1.2.5.25.

7.2.2.1.2.1.17 RPS - Regulatory Guide 1.118 (June 1978) - Periodic Testing of Electric Power and Protection Systems

RPS conformance to this guide is discussed in Section 7.1.2.5.26.

Position C.5 for APRM:

With respect to conformance to position C.5, the inherent time response of the incore sensors used for APRM (fission detectors operated in the ionization chamber mode) is many orders of magnitude faster than the APRM channel response time requirements and the signal conditioning electronics. The sensors cannot be tested without disconnecting and reconnecting to special test equipment.

7.2.2.1.2.2 RPS Conformance to 10CFR50, Appendix A, General Design Criteria

7.2.2.1.2.2.1 RPS - GDC 1 - Quality Standards and Records

The QA program for the system ensures sound engineering in all phases of design and construction through conformity to regulatory requirements and design bases described in the license application. The QA program is discussed in Chapter 17.

Documents are maintained that demonstrate that all the requirements of the QA program are being satisfied. These records are maintained during the life of the operating licenses.

7.2.2.1.2.2.2 RPS - GDC 2 - Design Bases for Protection Against Natural Phenomena

Wind and tornado loadings are discussed in Section 3.3, flood design is described in Section 3.4, and seismic qualification of instrumentation and electrical equipment is discussed in Section 3.10.

7.2.2.1.2.2.3 RPS - GDC 3 - Fire Protection

The fire protection system and its design basis are discussed in Section 9.5.1. Fire protection for cable systems is described in Sections 8.3.1.1.7 and 8.3.1.1.8.

7.2.2.1.2.2.4 RPS - GDC 4 - Environmental and Dynamic Effects Design Bases

The system is designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including LOCAs.

The system is appropriately protected against dynamic effects including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures. Missile protection is discussed in Section 3.5, pipe whip in Section 3.6, and environmental qualification of equipment in Section 3.11.

7.2.2.1.2.2.5 RPS - GDC 10 - Reactor Design

The RPS is designed to monitor certain reactor parameters, to sense abnormalities, and to scram the reactor, thereby preventing fuel design limits from being exceeded when trip points are exceeded. Scram trip setpoints are selected based on operating experience and by the safety design basis. There is no case in which the scram trip setpoints allow the core to exceed the thermal-hydraulic safety limits. Power for the RPS is supplied by two independent uninterruptible ac power supplies.

The system is designed to ensure that the specified fuel and RCPB design limits are not exceeded during conditions of normal or abnormal operation.

7.2.2.1.2.2.6 RPS - GDC 12 - Suppression of Reactor Power Oscillations

The system design provides protection from excessive fuel cladding temperatures and protects the RCPB from excessive pressures that threaten the integrity of the system. An OPRM Upscale Function BWROG Long Term Stability Solution Option III is incorporated into each APRM channel to detect power oscillations in the operating ranges where thermal-hydraulic instability has been determined to be credible. Upon detection of power oscillations, the OPRM Upscale Function generates a trip signal to RPS which results in an automatic scram to suppress the oscillation before the MCPR Safety Limit is reached. High reliability of the reactor protection system is achieved through the combination of redundant sensors, logic, trip channel actuators, and physical separation of these redundant portions of the RPS.

7.2.2.1.2.2.7 RPS - GDC 13 - Instrumentation and Control

Instrumentation is provided to monitor the variables identified in Table 7.2-1 over their anticipated ranges for normal operation, anticipated operational occurrences, and accident conditions. If these variables exceed a predetermined setpoint, the RPS automatically takes action to ensure the integrity of the reactor core and the RCPB.

7.2.2.1.2.2.8 RPS - GDC 15 - Reactor Coolant System Design

The RPS acts to provide sufficient margin to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including anticipated operational occurrences. If the monitored variables exceed their predetermined settings, the RPS automatically responds to maintain the variables and systems within allowable design limits.

7.2.2.1.2.2.9 RPS - GDC 19 - Control Room

Controls and instrumentation for the RPS are provided in the control room to allow the operator to safely shut down the plant. The reactor can also be shut down in an orderly manner from outside the control room as described in Section 7.4.1.4.

7.2.2.1.2.2.10 RPS - GDC 20 - Protection System Functions

The RPS constantly monitors the appropriate plant variables to maintain the fuel barrier and primary coolant pressure boundary and initiates a scram automatically when the variables exceed the established setpoints.

7.2.2.1.2.2.11 RPS - GDC 21 - Protection System Reliability and Testability

The system is designed with four redundant, independent, and separated channels. No single failure can prevent a scram. Removal from service of any component or channel does not result in loss of the required minimum redundancy. The system can be tested during plant operation to ensure its reliability.

7.2.2.1.2.2.12 RPS - GDC 22 - Protection System Independence

The redundant portions of the RPS are separated so that no single failure or credible natural disaster can prevent a scram. Even though the turbine scram inputs originate from the nonseismic turbine enclosure, reactor pressure and power are diverse to these turbine scram variables to ensure protective action during and following a seismic event. Diversity is used to the extent practicable in the monitoring of other variables as described in Section 7.2.1.1.4.6 to prevent loss of the protective function.

7.2.2.1.2.2.13 RPS - GDC 23 - Protection System Failure Modes

The RPS is fail-safe. A loss of electrical power, a loss of air supply, or postulated adverse environments do not prevent a scram.

7.2.2.1.2.2.14 RPS - GDC 24 - Separation of Protection and Control Systems

The RPS has no control function and no components common to any control systems. There are interlocks to control systems through isolation devices. Failure of any single control system component or channel leaves the integrity of the RPS system intact, without compromising any reliability, redundancy, or independence requirements of the RPS.

7.2.2.1.2.2.15 RPS - GDC 25 - Protection System Requirements for Reactivity Control Malfunctions

The system provides protection against the onset and consequences of conditions that threaten the integrity of the fuel barrier. Any monitored variable that exceeds the scram setpoint initiates an automatic scram and does not prevent the remaining variables from being monitored. Fuel design limits are not exceeded for any single malfunction of the reactivity control system.

7.2.2.1.2.2.16 RPS - GDC 29 - Protection Against Anticipated Operational Occurrences

The RPS is highly reliable so that it causes a scram if there are anticipated operational occurrences where any of the RPS trip setpoints are exceeded.

7.2.2.1.2.3 RPS Conformance to Industry Codes and Standards

Conformance of the transmitter/trip unit system, used in the RPS, is discussed in Licensing Topical Report NEDO-21617-A, "Analog Transmitter/Trip Unit System for Engineered Safeguard Sensor Inputs." Conformance of the other features with the industry standards is discussed in the following sections.

7.2.2.1.2.3.1 RPS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

7.2.2.1.2.3.1.1 RPS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The following RPS trip variables provide automatic initiation of protective action in compliance with this requirement:

a. SDV high water level trip

b. MSIV closure trip

c. Turbine stop valve closure trip

d. Turbine control valve fast closure trip

e. Reactor vessel low water level trip

f. Left blank intentionally.

g. Neutron monitoring (APRM) system trip (including OPRM trip)

h. Neutron monitoring (IRM) system trip

i. Drywell high pressure trip

j. Reactor vessel high pressure trip

The reactor system mode switch selects appropriate operating bypasses for various RPS variables in the shutdown, refuel, startup, and run modes of operation. Other manual controls, such as the SDV high water level bypass, the manual scram push button switches, and the three-position RPS reset switch are arranged to ensure that the process variables providing automatic initiation of protective action continue to remain in compliance with this requirement.

The three-position RPS reset switch is under the administrative control of the reactor operator. Since the reset switch does not connect redundant circuits in parallel with the trip logic, failure of the reset switch cannot prevent initiation of protective action.

Manual reset by the operator bypasses the seal-in contact to permit a trip system to be reset to its normally energized state when all process sensor trip channels are within their normal (untripped) range of operation.

The trip system logic, scram contactors, and scram contactor logic are designed to comply with this requirement through automatic removal of electric power to the CRD scram solenoids when one or more RPS variables exceed the specified trip setpoint.

7.2.2.1.2.3.1.2 RPS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The following RPS trip variables are individually implemented with four physically separated, redundant channels in compliance with this requirement:

a. MSIV closure trip

b. Turbine stop valve closure trip

c. Turbine control valve fast closure trip

d. Reactor vessel low water level trip

e. Drywell high pressure trip

f. Reactor vessel high pressure trip

g. SDV high water level trip

The APRM and IRM trips comply with the single failure criterion through the use of physical panel barriers and electrical isolation provisions to provide independence among the two redundant APRM 2-out-of-4 voter channels and four redundant IRM channels in either trip system A or B. Four redundant APRM channels provide inputs to both trip system A and trip system B.

Redundant sensors, wiring, logic, and actuators are physically separated to prevent a single failure from preventing the protective action. Wiring between redundant portions of the RPS and between RPS and non-Class 1E circuitry is configured to eliminate a possible single failure.

Wiring to each group of scram solenoids is routed in individual raceways separated from wiring to the other groups of scram solenoids.

Wiring from each sensor to the relay cabinets is run in a separate, totally enclosed metallic raceway or embedded PVC conduit to maintain electrical isolation and physical separation among redundant sensor trip channels.

RPS manual controls also comply with the single failure criterion. Four manual scram push buttons are arranged into two groups on one control room panel. The switch contact blocks are physically separated by metal barriers.

The reactor mode switch consists of a single manual actuator connected to four separated switch banks. Each bank is housed within a fire-retardant cover. Contacts from each bank are wired in conduit to a metallic terminal box with separation barriers.

Although the SDV high water level trip bypass is controlled by only one switch, the design of the bypass circuit complies with the single failure criteria. This bypass requires manual operation of a bypass switch and the mode switch to establish four bypass channels; the design of the bypass function complies with this design requirement. For the bypass switch, a single operator connects to two physically and electrically separated blocks of switch contacts within the switch body that separates redundant trip channels. Wiring from the contacts is routed in conduit to separate metallic terminal boxes. One set of switch contacts in conjunction with separated mode switch contacts is used to energize each trip channel bypass relay when the bypass condition is desired. There is no single failure of this bypass function that could establish a spurious bypass condition of more than one channel. Hence, this function complies with the single failure criterion.

The main steam line valve closure trip operating bypass is implemented with separated mode switch contacts.

The turbine stop valve closure trip and control valve fast closure trip operating bypass complies with the single failure criterion. Nonredundant pairs of pressure sensors are mounted at each of two, physically separated pressure taps located in the turbine steam supply lines upstream of the high pressure turbine first stage. Wiring from the metallic raceway or embedded PVC conduit

sensors is routed in a TEMR or to the RPS cabinets in the auxiliary equipment room. A single bypass is associated with a single trip channel for stop valve closure and for control valve fast closure. The worst case single failure could result in the bypass of the turbine stop valve closure and turbine control valve fast closure for the A and B trip logics or the C and D trip logics. The logic is arranged so that this failure does not interfere with the normal protective action of the RPS.

The three-position RPS reset switch and associated logic comply with this design requirement. The reset switch is constructed with a single operator and two physically and electrically separated contact blocks. The wires from the contact blocks go through conduit to metallic terminal boxes.

Since the opening of the process sensor trip channel contact is the initiating event for reactor scram, failure of the reset switch does not prevent de-energization of the trip actuators during the time interval that the process actually exceeds the trip setpoint.

Those portions of the RPS downstream of the trip channels also comply with this design requirement. Any postulated single failure of a given trip logic does not affect the remaining three trip logics. Similarly, any single failure of a scram contactor does not affect the remaining scram contactors, and any single failure of one trip logic does not affect the other trip logics. The cabling associated with one control rod group is routed in conduit that is physically separated from similar cabling associated with the other control rod groups. Cabling from the scram contactor logic to the scram solenoid groups is routed in individual, totally-enclosed, metallic raceway or in PVC conduits when embedded in concrete to comply with this design requirement. Because both the "A" or "B" solenoid valves must de-energize to scram, the wiring of these two solenoids for one control rod group is routed together within a single raceway, separate from all other wiring.

7.2.2.1.2.3.1.3 RPS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All RPS trip variables are implemented with components and modules used on previous GE BWR plants and that exhibit high quality and high reliability characteristics.

The selected RPS manual switches are also of high quality and reliability.

The four pressure sensors selected for the turbine stop valve closure and control valve fast closure operating bypass are of high quality and reliability.

The RPS trip system logic consists of series-connected relay contacts from the trip channel output relays. The relays are of high quality and reliability.

The RPS scram contactor logic consists of interconnecting trip logics to form a trip system by means of scram contactor contacts. The scram contactors are of high quality and reliability.

7.2.2.1.2.3.1.4 RPS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

Qualification tests of RPS equipment are conducted to confirm their adequacy. Details of this testing are contained in Section 3.10 and 3.11. In addition, the vendor is required to certify that the sensors associated with each of the RPS trip variables, manual switches, and trip logic components perform in accordance with the requirements listed on the purchase specification as well as in the intended application. This certification, in conjunction with the qualification tests and existing field experience with these components in this application, serves to qualify these components.

Qualification tests of the panels are conducted to confirm their adequacy. Details of this testing are contained in Sections 3.10 and 7.1.2.7.4.

7.2.2.1.2.3.1.5 RPS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

All the components of the RPS trip variables are specified to operate under normal and abnormal conditions of environment, energy supply, and accidents, except as follows:

a. Turbine stop valve closure trip (not guaranteed to operate under an SSE design basis event)

b. Turbine control valve fast closure trip (not guaranteed to operate under an SSE design basis event)

c. Turbine stop valve bypass circuit (not guaranteed to operate under an SSE design basis event)

The RPS trip systems, trip logics, and scram contactors are designed to be operable under normal and abnormal conditions of environment, energy supply, malfunctions, and accidents.

The cables for the turbine stop valves and fast closure valves are run in protective conduit from the sensor to the seismic Category I qualified auxiliary equipment room. Each channel is run in its own conduit which provides the required separation. Starting at the sensor is a flexible metallic conduit section which is connected to a rigid steel conduit section leading to the flooring. The cables are routed in PVC conduit embedded in the floor from the turbine enclosure to the auxiliary equipment room, which contains the reactor trip system.

Table 7.3-6 shows these and other sensors and circuits located in nonseismically qualified structures. Drawings showing the cable routing are E-1112, E-1121, E-1124, E-1125, and E-1183. The applicable sensors shown on E-1112 are ZS01-104A through D and PS01-102A through D.

The routing of the four cables, each in its own separate run, to the trip sensors in the turbine enclosure for the turbine stop valve and turbine valve fast closure trips is such that the only credible failures that will challenge the system are: 1) a SSE, 2) a turbine missile, and 3) a HELB. The expected failure mode caused by these events would be loss of the sensors due to opening or loss of continuity, which would result in a reactor trip.

If the trip sensors failed closed or shorted due to the fault, the reactor pressure and reactor power trips, which are diverse, will still function to prevent damage to the reactor. Shorting of a single sensor would not prevent protective action by the other sensors. Each of the inputs is isolated from the remainder of the RPS logic by the use of interposing relays. If a sensor circuit opened, the signal would be a trip from that input.

7.2.2.1.2.3.1.6 RPS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The four redundant trip channels for the following RPS trip variables are physically separated from one another to meet this design requirement:

a. SDV high water level trip

b. Turbine stop valve closure trip

c. Turbine control valve fast closure trip

d. Reactor vessel low water level trip

e. Left blank intentionally.

f. Drywell high pressure trip

g. Reactor vessel high pressure trip.

The individual switch boxes for the turbine variables are physically separated.

The MSIV closure trip is derived from 8 individual channels. Two channels associated with each trip logic are separated as shown in Figure 7-2.8.

The 8 IRM and 4 APRM channels and 4 APRM 2-out-of-4 voter channels are electrically isolated and physically separated from one another so as to comply with this design requirement.

The redundant scram push buttons are physically separated and electrically isolated to comply with this design requirement.

The mode switch banks are physically separated and electrically isolated to comply with this design requirement.

The circuitry for the RPS operating bypasses complies with this design requirement. Sufficient physical separation and electrical isolation of redundant circuits exists to ensure that the operating bypass channels are satisfactorily independent.

The four RPS reset channels to the trip logics are physically separated and electrically isolated. Similarly, the four RPS trip logics and scram contactors are physically separated. The wiring to each rod group scram schedules A and B is routed in TEMRs with module wiring. The details of the physical independence provided between redundant channels are in Section 7.1.2.2.3.2.1.

7.2.2.1.2.3.1.7 RPS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The RPS is electrically isolated from the plant control systems in compliance with this design requirement.

Each trip channel output relay uses one contact within the RPS trip logic. One additional contact on each relay is wired to a common annunciator in the control room, and another contact on each relay is wired to the process computer cabinets to provide a written log of the channel trips. There is no single failure that prevents proper functioning of any protective function when it is required.

The MSIV and turbine stop valve limit switch contacts for RPS use are routed through TEMRs separated from the other limit switches used for indicator lights in the control room. After the cabling emerges from the limit switch junction box associated with each MSIV or turbine stop valve, it is routed in Class 1E raceway to the RPS panels in the auxiliary equipment room.

Turbine control valve fast closure pressure sensor outputs for RPS use are routed separately relative to other outputs used for indicator lights and turbine control purposes. After the cabling

emerges from the junction boxes, it is routed in Class 1E raceway to the logic cabinets in the auxiliary equipment room.

Within the IRM modules (i.e., before their output trip unit driving the RPS), analog outputs are derived for use with control room meters, recorders, and the process computer. Electrical isolation is incorporated into the design at this interface to prevent any single failure from influencing the protective output from the trip unit. The trip unit outputs are physically separated and electrically isolated from other plant equipment in their routing to the RPS panels.

Within the APRM equipment (i.e., before their output trip driving the RPS), analog outputs are derived for use with control room meters and recorders. Electrical isolation is incorporated into the design at this interface to prevent any single failure from influencing the protective trip output. The trip outputs are physically separated and electrically isolated from other plant equipment in their routing to the RPS panel.

The manual scram push buttons have no control interaction.

The reactor system mode switch is used for protective functions and restrictive interlocks on control rod withdrawal and refueling equipment movement. Additional contacts of the mode switch are used to disable certain computer inputs when the alarms would represent incorrect information for the operator. No control functions are associated with the mode switch. Hence, the switch complies with this design requirement. The system interlocks to control systems only through isolation devices so that no failure or combination of failures in the control system has any effect on the RPS.

The RPS SDV high water level trip operating bypass complies with this design requirement. For each trip channel, one contact is used in the bypass logic. One contact of each relay is also wired to a common annunciator in the control room. One contact from A1 and one contact from B1 trip systems are wired to the control rod block circuitry to prevent rod withdrawal whenever the trip channel bypass is in effect. The system interlocks for control rod block are through isolation devices so that no failure or combination of failures in the control system has any effect on the RPS.

The MSIV closure trip bypass has no interaction with any control system in the plant. Two contacts of each relay are used to initiate a control room annunciator for this bypass function.

Turbine stop valve and control valve trip bypasses have no interaction with any control system in the plant. One output relay contact is used in the RPS trip logic, one output relay contact is used in the Recirc Pump Trip circuitry, and one additional contact from each relay is used to initiate a control room annunciator for this bypass function.

Switch contacts of the three-position reset switch are used only to control auxiliary relays. Contacts from the relays are used only in the scram contactor coil circuits. Consequently, this RPS function has no interaction with any other system in the plant.

The four RPS trip logics are totally separate from all other plant systems. The RPS trip logics use the power contacts of the scram contactors to provide the scram contactor logic and the seal-in contact of the trip logics, and use auxiliary contacts for control room annunciation, the process computer inputs, and initiation of the backup scram valves. Because of the design of this output

and separation of the cabling, there is no interaction with control systems of the plant. The scram solenoids are physically separate and electrically isolated from the other portions of the CRD HCU.

In summary, the transmission of signals from the RPS to control systems is through isolation devices that are part of the RPS. No credible failure at the output of these isolation devices can prevent the RPS from meeting its minimum performance requirements. No single random failures can cause a control system action that results in a condition requiring action by the RPS that can also disable a portion of the RPS designed to protect against that condition.

An SSE is the only single credible event that can cause a control system action resulting in a condition requiring protective action and that can concurrently prevent operation of a portion of the RPS. In an SSE, the turbine stop valve closure trip and the turbine control valve fast closure trip may be disabled. The reactor vessel high pressure and high power trips provide diverse protection for this event.

7.2.2.1.2.3.1.8 RPS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

The following RPS trip variables are direct measures of a reactor overpressure condition, a reactor overpower condition, a gross fuel damage condition, or abnormal conditions within the RCPB:

a. Reactor vessel low water level trip

b. Left blank intentionally.

c. Neutron monitoring (APRM) system trip

    1. Neutron flux trip

    2. Simulated thermal power trip

    3. OPRM upscale trip

d. Neutron monitoring (IRM) system trip

e. Drywell high pressure trip

f. Reactor vessel high pressure trip

The measurement of SDV water level is an appropriate variable for this protective function. The desired variable is "available volume" to accommodate a reactor scram. However, the measurement of consumed volume is sufficient to infer the amount of remaining available volume, because the total volume is a fixed, predetermined value established by the design.

The measurement of MSIV position and turbine stop valve position is an appropriate variable for the RPS. The desired variable is "loss of the reactor heat sink"; however, isolation or stop valve closure is the logical variable from which to infer that the steam path has been blocked between the reactor and the heat sink.

Because of the normal throttling action of the turbine control valves with changes in the plant power level, measurement of control valve position is not an appropriate variable from which to infer the desired variable, which is "rapid loss of the reactor heat sink." Consequently, a measurement of valve closure rate is necessary.

Protection system design practice has discouraged the use of rate sensing devices for protective purposes. In this instance, it was determined that detection of hydraulic actuator operation would be a more positive means of determining fast closure of the control valves.

Loss of hydraulic pressure in the EHC oil lines, which initiates fast closure of the control valves, is monitored. These measurements indicate that fast closure of the control valves is imminent.

This measurement is adequate and a proper variable for the protective function, taking into consideration the reliability of the chosen sensors relative to other available sensors and the difficulty in making direct measurements of control valve fast closure rate.

Since the mode switch is used to bypass certain RPS trips depending on the operating state of the reactor, the selection of particular contacts to perform this logic operation is an appropriate means for obtaining the desired function.

The turbine stop valve closure trip and control valve fast closure trip operating bypass permits continued reactor operation at low power levels when the turbine stop or control valves are closed. The selection of turbine first-stage pressure is an appropriate variable for this bypass function. In the power range of reactor operation, turbine first-stage pressure is essentially linear with increasing reactor power. Consequently, this variable provides the desired measurement of power level.

7.2.2.1.2.3.1.9 RPS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

During reactor operation, the analog outputs of each of the four redundant transmitters for the following RPS trip variables may be directly cross-compared to meet this requirement:

a. Reactor vessel low water level trip

b. Drywell high pressure trip

c. Reactor vessel high pressure trip

During reactor operation, one transmitter of each of these variables may also be valved out of service at a time to perform calibration. During this test, operation of the sensor and the RPS trip unit and relay may be confirmed. At the conclusion of the test, administrative control must be used to ensure that the sensor has been properly returned to service.

In addition, the trip unit associated with these variables may be tested by injecting an electronic calibration signal into the trip unit input.

During reactor operation, the sensors associated with the SDV high water level trip may be valved out of service to perform a functional test. During the test, one RPS trip logic is tripped and produces both control room annunciation and computer logging of the trip. At the conclusion of the test, administrative control is used to ensure that the sensors have been returned to service.

The MSIV position switches are tested during valve movements that cause the limit switches to operate at the setpoint value of the valve position.

The eight MSIV isolation channels are combined into the four RPS logics as follows:

a. A1 (tripped) = inboard or outboard valve partially closed in main steam line A, and inboard or outboard valve partially closed in main steam line B

b. A2 (tripped) = inboard or outboard valve partially closed in main steam line C, and inboard or outboard valve partially closed in main steam line D

c. B1 (tripped) = inboard or outboard valve partially closed in main steam line A, and inboard or outboard valve partially closed in main steam line C

d. B2 (tripped) = inboard or outboard valve partially closed in main steam line B, and inboard or outboard valve partially closed in main steam line D

For any test of a single valve closure, two of the eight instrument channels are placed in a tripped condition, but none of the channel logics is tripped, and no RPS annunciation or NSSS computer logging occurs. This arrangement permits single valve testing without corresponding tripping of the RPS. At full power operation the main steam line closure logic test switch for one main steam line may be opened, and the other MSIV may be closed to produce a channel trip with annunciation and computer output.

At reduced power levels, two valves may be tested in sequence to produce RPS trips, annunciation of the trips, and computer printout of the trip channel identification. For example, closure of one valve in main steam line A and another valve in main steam line B produces an A1 logic trip and does not produce trips in A2, B1, or B2 channel logic circuits. These observations are another important test result that confirms proper RPS operation.

In sequence, each possible combination of single valve closure and switch operation is performed to confirm proper operation of all eight instrument channels.

The turbine stop valve position switches are also tested during valve movements that cause the limit switches to operate at the setpoint value.

The eight turbine stop valve isolation channels are combined into the four RPS logics as follows:

a. A1 (tripped) = turbine stop valve 3 partially closed, and turbine stop valve 4 partially closed

b. A2 (tripped) = turbine stop valve 1 partially closed, and turbine stop valve 2 partially closed

c. B1 (tripped) = turbine stop valve 1 partially closed, and turbine stop valve 3 partially closed

d. B2 (tripped) = turbine stop valve 2 partially closed, and turbine stop valve 4 partially closed

For any test of a single stop valve closure, two of the eight instrument channels are placed in a tripped condition, but none of the RPS trip logics is tripped, and no RPS annunciation or NSSS computer logging occurs. This arrangement permits single valve testing without corresponding tripping of the RPS, and the observation that no RPS trips result is a valid and necessary test

result. At full power, the stop valve logic test switch can be activated and the other stop valve in the same logic can be closed, causing a logic trip with annunciation and computer logging.

At reduced power levels, but greater than 29.5% of rated power, two valves may be tested in sequence to produce RPS trips, annunciation of the trips, and computer printout of the trip channel identification. These observations are another important test result that confirms proper RPS operation.

In sequence, each possible combination of single valve closure and test switch operation is performed to confirm proper operation of all eight instrument channels.

The turbine control valve fast closure EHC oil pressure sensors may be tested during the routine turbine system tests. During any control valve fast closure test, one RPS trip logic is tripped and produces both control room annunciation and computer logging of the trip.

The four RPS instrument logics are arranged as follows, assuming initial operation above 29.5% of rated power:

a. A1 (tripped) = pressure switch A loss of oil pressure

b. A2 (tripped) = pressure switch B loss of oil pressure

c. B1 (tripped) = pressure switch C loss of oil pressure

d. B2 (tripped) = pressure switch D loss of oil pressure

During reactor operation in the run mode, the IRM detectors are stored below the reactor core in a low flux region. Movement of the detectors into the core permits the operator to observe the instrument response from the different IRM channels and confirms that the instrumentation is operable.

Each APRM instrument channel may also be calibrated with a simulated signal introduced into the amplifier input, and each IRM instrument channel may be calibrated by introducing an external signal source into the amplifier input.

During these tests, proper instrument response may be confirmed by observation of instrument lights in the control room and trip annunciators.

Proper operation of the mode switch may be verified by the operator during plant operation by performing certain sensor tests to confirm proper RPS operation. Movement of the mode switch from one position to another is not required for these tests, since the connection of appropriate sensors to the RPS logic as well as the bypass of inappropriate sensors may be confirmed from the sensor tests.

7.2.2.1.2.3.1.10 RPS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The following RPS trip variable sensors may be tested by cross-comparison of channels. They also have provisions for sensor test and calibration during reactor operation in compliance with this design requirement. See Section 7.1.3.

a. Reactor vessel low water level trip

b. Neutron monitoring (APRM) system trip (including OPRM trip)

c. Neutron monitoring (IRM) system trip

d. Drywell high pressure trip

e. Reactor vessel high pressure trip.

A test of individual SDV water level switches can be performed during full power operation by valving out the sensor and injecting water into a test tap. At plant shutdown, the level switches may be calibrated by introducing a fixed volume of water into the discharge volume and observing that all level switches operate at the specified capacity.

During plant operation the operator can set the turbine stop valve or main steam line closure logic test switch in a test position and actuate the other valve, which results in a logic trip, with annunciation and computer logging. The operator can confirm that the MSIV and turbine stop valve limit switches operate during valve motion, from fully open to fully closed and vice-versa, by comparing the time that the RPS channel trip occurs with the time that the valve position indicator lights in the control room signal that the valve is fully open and fully closed. This test does not confirm the exact setpoint but does provide the operator with an indication that the limit switch operates between the limiting positions of the valve. During reactor shutdown, calibration of the MSIV and turbine stop valve limit switch setpoint is possible by physical observation of the valve stem.

During reactor operation, the operability of the individual EHC oil line pressure sensors associated with turbine control valve fast closure is confirmed during each test of the turbine control valve closure. Calibration of the sensor may be accomplished by valving one sensor out-of-service at a time and introducing a test pressure input during shutdown.

The APRMs are calibrated to reactor power by using a reactor heat balance and the TIP system to establish the relative local flux profile. LPRM gain settings are determined from the local flux profiles measured by the TIP system once the total reactor heat balance has been determined.

The gain adjustment factors for the LPRMs are produced as a result of the process computer nuclear calculations involving the reactor heat balance and the TIP flux distributions. These adjustments, when incorporated into the LPRMs, permit the nuclear calculations to be completed for the next operating interval and establish the APRM calibration relative to reactor power.

During reactor operation, one manual scram push button may be depressed to test the proper operation of the switch and trip logic relay. Once the RPS has been reset, the other switches may be depressed to test their operation one at a time. For each such operation, a control room annunciation is initiated and the process computer logs the trip.

Operation of the reactor mode switch from one position to another may be employed to confirm certain aspects of the RPS trip channels during periodic test and calibration at shutdown only. During tests of the trip channels, proper operation of the mode switch contacts may be easily verified by noting that certain sensors are connected into the RPS logic and that other sensors are bypassed in the RPS logic in an appropriate manner dependent on the position of the mode switch.

In the startup and run modes of plant operation, tests confirm that SDV high water level trip channels cannot be bypassed as a result of the operating bypass switches. In the shutdown and refuel modes of plant operation, tests may be used to bypass all four scram discharge volume trip channels. Because of the discrete on-off nature of the bypass function, calibration is not meaningful.

Administrative control must be exercised to valve one turbine first-stage pressure sensor out-of-service for the periodic test. During this test, a variable pressure source may be introduced to operate the sensor at the setpoint value. When the condition for bypass has been achieved on an individual sensor under test, the control room annunciator for this bypass function is initiated. If the RPS trip channel associated with this sensor has been in its tripped state, the process computer logs the return-to-normal state for the RPS trip logic. When the plant is operating above the switch setpoint, testing of the turbine stop valve and control valve fast closure trip channels confirms that the bypass function is not in effect.

Operation of the three-position RPS reset switch following a trip of one RPS trip system confirms that the switch is performing its intended function. Operation of the reset switch following trip of both RPS trip systems confirms that all portions of the switch and relay logic are functioning properly, since half of the scram contactors are returned to a normal state for each actuation of the switch.

The manual scram switches permit each trip logic, scram contactor, and scram contactor logic to be tested on a periodic basis. Testing of each process sensor of the protection system affords an opportunity to verify proper operation of these components. Calibration of the time response of the trip channel relays and trip logics may be accomplished by the connection of external test equipment.

7.2.2.1.2.3.1.11 RPS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

The following RPS trip variables have no provision for sensor removal from service because of the use of valve position limit switches as the channel sensor:

a. MSIV closure trip

b. Turbine stop valve closure trip

During periodic testing of any one of the following trip channels, a sensor may be valved out of service and returned to service under administrative control procedures. Since only one sensor is valved out-of-service at any given time during the test interval, protective capability for the following RPS trip variables is maintained through the remaining redundant instrument channels:

a. SDV high water level trip

b. Turbine control valve fast closure trip

c. Reactor vessel low water level trip

d. Drywell high pressure trip

e. Reactor vessel high pressure trip

A sufficient number of IRM channels are provided to permit any one IRM channel in a given trip system to be manually bypassed and still ensure that the remaining operable IRM channels comply with the IEEE 279 single failure design requirements.

One IRM manual bypass switch is provided for each RPS trip system. The mechanical characteristics of this switch permit only one of the four IRM channels of that trip system to be bypassed at any time. To accommodate a single failure of this bypass switch, electrical interlocks are incorporated into the bypass logic to prevent the bypassing of more than one IRM in that trip system at any time. Consequently, with any IRM bypassed in a given trip system, three IRM channels remain in operation to satisfy the protection system requirements.

One manual APRM bypass switch is provided for all four APRM channels. This is a mechanical/optical switch which allows only one APRM channel to be bypassed at any time. This interlock is accomplished independently in each of the APRM 2-out-of-4 voter channels. With any one APRM channel bypassed, the three remaining operating channels provide the necessary protection of the reactor.

None of the APRM 2-out-of-4 voter channels may be bypassed.

7.2.2.1.2.3.1.12 RPS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

The following RPS trip variables have no provision for an operating bypass:

a. Reactor vessel low water level trip

b. Left blank intentionally.

c. Neutron monitoring (APRM) system trip

d. Drywell high pressure trip

e. Reactor vessel high pressure trip

An operating bypass of the SDV high water level trip is provided in the control room for the operator to use to bypass the trip outputs in the shutdown and refuel modes of operation. Control of this bypass is achieved through administrative means, and its only purpose is to permit reset of the RPS following reactor scram. The bypass is manually initiated and must be manually removed to commence withdrawal of control rods after a reactor shutdown.

An operating bypass is provided for the MSIV closure trip. The bypass requires that the reactor system mode switch, which is under the administrative control of the operator, be placed in the shutdown, refuel, or startup positions. The only purpose of this bypass is to permit the RPS to be placed in its normal energized state for operation at low power levels with the MSIVs closed or not fully open.

The operating bypasses of the NMS are controlled by the reactor mode switch located on the control room reactor control bench board. When the reactor mode switch is in the RUN mode, the IRM trips are bypassed; protection is provided by the APRM and OPRM trips. When the reactor mode switch is not in the RUN mode, the IRM and APRM flux trips are active, but the OPRM trip is bypassed. As reactor power is increased and the APRM system reaches

its operating range, by procedure the IRM detectors are withdrawn from the reactor core. When reactor power is decreased to the IRM operating range, by procedure the IRM detectors are inserted into the reactor core.

For each of these operating bypasses, four independent bypass channels are provided through the mode switch to ensure that all of the protection system criteria are satisfied.

An operating bypass of the turbine stop valve and control valve fast closure trip is provided whenever the turbine is operating at a low initial power level. The purpose of the bypass is to permit the RPS to be placed in its normal energized state for operation at low power levels with the turbine stop valves not fully open.

During normal plant operation above the switch setpoint, the bypass is automatically removed. Under these conditions, removal of the bypass for periodic testing is permitted, since it has no effect on plant safety. Under plant conditions below the switch setpoint, one bypass channel may be removed from service at a time without initiating protective action or affecting plant safety. This removal from service is accomplished under administrative control of plant personnel.

7.2.2.1.2.3.1.13 RPS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

The mode switch produces operating bypasses that need not be annunciated, because they are numbered by manual reactor operating sequence.

The control room operator must exercise administrative control over the valving out-of-service of one RPS trip variable sensor at a time. The out-of-service condition is manually alarmed as described in Section 7.2.2.1.2.1.7. Once a sensor is removed from service and a simulated test signal is introduced in excess of the setpoint, a control room annunciator indicates the tripped condition, and the process computer provides a typed record of the channel identification. The trip unit in calibration also causes actuation of the system out-of-service annunciator.

When any IRM or APRM instrument channel output to the RPS is bypassed, this fact is indicated by lights for each channel located on the control room panels.

Operating bypasses are annunciated in the control room. The SDV high water level trip operating bypass, the MSIV closure trip operating bypass, and the turbine stop valve closure and control valve fast closure trips operating bypass are individually annunciated to the operator.

When the conditions for any single bypass channel are satisfied, the control room operator is notified by an annunciator for the particular set of bypass conditions. Bypassing is not allowed in the trip logic or scram contactor logic.

7.2.2.1.2.3.1.14 RPS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

All instrumentation valves associated with the periodic testing of individual RPS trip variable sensors are under administrative control.

During periodic testing, administrative control procedures must be followed to remove one main steam line high radiation monitor from service and subsequently return it to service.

Manual bypassing of any IRM or APRM channel is accomplished with control room selector switches under the administrative control of the operator.

Manual controls for the SDV high water level trip operating bypass and the MSIV closure trip operating bypass are located in the control room and are under the direct administrative control of the operator. Manual key-lock switches are used to control these operating bypasses.

The mode switch is a key-lock switch under the administrative control of plant personnel. Since other controls must be operated or other sensors must be in an appropriate state to complete the operating bypass logic, the mode switch itself satisfies this requirement.

Under normal operating conditions, all four channels of the turbine stop valve closure trip and control valve fast closure trip operating bypass are in operation and are automatically removed from service as reactor power is increased above the switch setpoint and are automatically reinstated as reactor power is reduced below this same setpoint. During periodic testing of each bypass channel, one sensor is removed from service under administrative control.

7.2.2.1.2.3.1.15 RPS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

The design requirement is not applicable to the following RPS trip variables, because the setpoint values are fixed and do not vary with other reactor or plant parameters:

a. SDV high water level trip

b. MSIV closure trip

c. Turbine stop valve closure trip

d. Turbine control valve fast closure trip

e. Reactor vessel low water level trip

f. Left blank intentionally.

g. Neutron monitoring neutron flux and OPRM trips

h. Drywell high pressure trip

i. Reactor vessel high pressure trip

The trip setpoint of each IRM channel is established at a fixed percentage of full-scale for each range of IRM operation. The IRM is a linear, half decade per range instrument. Therefore, as the operator switches an IRM from one range to the next, the trip setpoint tracks the operator's selection. In the startup mode the APRM Neutron Flux - Upscale trip setpoint is reduced to 15% of Rated Thermal Power.

In the run mode, the APRM Simulated Thermal Power - Upscale trip varies automatically with recirculation flow. For further discussion, see Section 7.6.1.4.

Each of these multiple setpoint provisions is a portion of the RPS and complies with the design requirements of IEEE 279.

Operation of the mode switch from one position to another bypasses various RPS trip channels in accordance with the reactor conditions implied by the given position of the mode switch. This action does not influence the established setpoint of any given RPS trip channel, but merely connects one set of channels as another set is disconnected. Consequently, the mode switch meets this design requirement.

7.2.2.1.2.3.1.16 RPS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

It is only necessary that the instrument channel remain in a tripped condition for a sufficient length of time to de-energize the scram contactors and open their seal-in contacts.

Once the manual scram push buttons are depressed, it is only necessary to maintain them in that condition until the scram contactors have de-energized and opened their seal-in contacts.

The function of the mode switch is to provide appropriate RPS trip channels for the RPS trip logic on a steady-state basis for each of four given reactor operating states: shutdown, refuel, startup, and run. Protective action, in terms of the needed transient response, is derived from the other portions of the trip channels independent of the mode switch. Hence, the mode switch does not influence the completion of protective action in any manner.

The turbine operating bypass is put into effect only when the turbine first-stage pressure is at or below a preset level. For plant operation above this setpoint, the trip channels initiate protective action once the scram contactors have de-energized and opened the seal-in contact.

The interface of the RPS trip logic and the scram contactors ensures that this design requirement is accomplished. The trip logic is normally energized and is sealed in by one of the contacts of the scram contactor. Once the trip logic has been open-circuited as a result of a process sensor trip channel becoming tripped or the depression of a manual scram push button, the scram contactor seal-in contact opens, and completion of protective action is directed without regard to the state of the initiating process sensor trip channel.

Reset of the RPS logic is permissible only after a 10 second time delay and requires deliberate operator action.

7.2.2.1.2.3.1.17 RPS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

Four manual scram push button controls are provided on one control room panel to permit manual initiation of reactor scram at the system level. Failure of an automatic RPS function cannot prevent the manual portions of the system from initiating the protective action. The manual scram push buttons are wired as close as is practicable to the scram contactor coil circuits to minimize the dependence of manual scram capability on other equipment.

Additional backup to these manual controls is provided by the shutdown position of the reactor system mode switch.

No single failure in the manual or automatic portions of the system can prevent either a manual or automatic scram.

7.2.2.1.2.3.1.18 RPS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

During reactor operation, access to setpoint or calibration control is not possible for the SDV high water level trip. (The instrument is accessible, but the setpoint is not adjustable).

Access to setpoint adjustments, calibration controls, and test points for the following RPS trip variables is under the administrative control of plant personnel:

a. Main steam line isolation valve closure trip (accessible with radiation exposure)

b. Turbine stop valve closure trip (accessible with radiation exposure)

c. Turbine control valve fast closure trip (accessible with radiation exposure)

d. Turbine stop valve closure and turbine control valve fast closure trip bypass (accessible with radiation exposure)

e. Reactor vessel low water level trip

f. Left blank intentionally.

g. Neutron monitoring (APRM) system trip (including OPRM trip)

h. Neutron monitoring (IRM) system trip

i. Drywell high pressure trip

j. Reactor vessel high pressure trip

7.2.2.1.2.3.1.19 RPS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

When any one of the redundant sensors exceeds its setpoint value for the following RPS trip variables, a control room annunciator is initiated to identify the particular variable:

a. SDV high water level trip

b. Turbine control valve fast closure trip

c. Reactor vessel low water level trip

d. Left blank intentionally.

e. Neutron monitoring (APRM) system trip (including OPRM trip)

f. Neutron monitoring (IRM) system trip

g. Drywell high pressure trip

h. Reactor vessel high pressure trip

Identification of the particular trip channel exceeding its setpoint is accomplished as a typed record from the process computer or visual observation of the annunciators.

When any manual scram push button is depressed, a control room annunciation is initiated and a process computer record is produced to identify the tripped RPS trip logic.

Identification of the mode switch in shutdown position scram trip is provided by the manual scram annunciator and the process computer trip logic identification printout.

Partial or full closure of any MSIV or turbine stop valve causes a change in the status of position indicator lights in the control room. These indications are not a part of the RPS, but they do provide the operator with valid information pertinent to the valve status. Partial or full closure of one or both valves in a particular set of two main steam lines initiates a control room annunciator when the trip setpoint has been exceeded. A turbine stop valve closure trip will be indicated if an RPS channel is tripped by a two-out-of-four valve closure combination. This information is displayed on panel 1AC803 (reactor control annunciator panel) and on the main turbine annunciator panel (1BC807). The closed position of each turbine stop valve is also indicated in the control room using a position switch independent of those used in the RPS logic and powered from a separate electrical power source. This same condition permits identification of the tripped channels in the form of a typed record from the process computer or by visual observation of the valve position indicator lights.

NMS annunciators provided in the control room indicate the NMS RPS trip. The process computer provides a typed record of the tripped NMS channel as well as identification of individual IRM and APRM channel trips.

Two control room annunciators are provided to identify the tripped portions of the RPS in addition to the previously described trip channel annunciators:

a. A1 or A2 trip logics tripped

b. B1 or B2 trip logics tripped

These same functions are connected through independent auxiliary contacts of the scram contactors to the process computer to provide a typed record of the relay operations.

7.2.2.1.2.3.1.20 RPS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The data presented to the control room operator for each of the RPS trip variables complies with this design and provide accurate, complete, and timely information pertinent to the status of the RPS. The design minimizes the development of conditions that would cause anomalous indications that are confusing to the operator.

7.2.2.1.2.3.1.21 RPS - IEEE 279 (1971), Paragraph 4.21 - System Repair

During periodic testing of the sensor channels for the following RPS trip variables, the operator can determine any defective component and replace it during plant operation:

a. SDV high water level trip

b. Reactor vessel low water level trip

c. Drywell high pressure trip

d. Reactor vessel high pressure trip

During periodic testing of the sensor channels for the trip variables listed below, all defective components can be identified. Replacement and repair of failed sensors can only be accomplished during reactor shutdown. All other components can be replaced, repaired, or adjusted during plant operation.

a. MSIV closure trip

b. Turbine stop valve closure trip

c. Left blank intentionally.

d. Neutron monitoring (APRM) system trip (including OPRM trip)

e. Neutron monitoring (IRM) system trip

f. Turbine control valve fast closure trip

Replacement of IRM and LPRM detectors must be accomplished during plant shutdown. Repair of the remaining portions of the NMS may be accomplished during plant operation by appropriate bypassing of the defective instrument channel. The design of the system facilitates rapid diagnosis and repair.

7.2.2.1.2.3.1.22 RPS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each system logic cabinet is identified distinctively as being in the protection system, and the particular redundant portion is listed on a distinctive marker plate. Cabling outside the cabinets is identified specifically as RPS wiring. An identification scheme is used to distinguish between redundant cables and raceways. Redundant racks are identified by the identification marker plates of instruments on the racks. Control room devices are identified by tags on the panels. These tags indicate the function of the device.

7.2.2.1.2.3.2 RPS - IEEE 308 (1971) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

The RPS is a fail-safe logic system, and its power supplies are non-Class 1E. The backup scram circuitry is powered by Class 1E power. The backup scram circuitry is designed to meet the requirements of IEEE 308 (1971).

7.2.2.1.2.3.3 RPS - IEEE 317 (1972) - Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations

See the discussion of Regulatory Guide 1.63 in Section 8.1.6.1.12.

7.2.2.1.2.3.4 RPS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

IEEE 323 (1971) is satisfied by complete qualification testing and certification of all essential components. Records covering all essential components are maintained.

7.2.2.1.2.3.5 RPS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

See Chapter 17.

7.2.2.1.2.3.6 RPS - IEEE 338 (1971) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

IEEE 338 (1971) is satisfied by being able to test the RPS from sensors to the scram contactors at any time during plant operation. The tests are performed in overlapping portions.

7.2.2.1.2.3.7 RPS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Station

IEEE 344 (1971) is satisfied by all Class 1 RPS equipment as described in Section 3.10.

The above does not apply to turbine stop valve and control valve fast closure trips during or after an SSE, as discussed in Section 7.2.1.2.8.

7.2.2.1.2.3.8 RPS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

IEEE 379 (1972) requirements are satisfied by considering the different single failure modes and carefully designing all potential violations of the single failure criterion out of the system.

7.2.2.1.2.3.9 RPS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

See Section 7.1.2.7.11.

The standard requires that redundant sensors and their connections to the process system be sufficiently separated to ensure that functional capability of the protection system is maintained despite any single design basis event or resulting effect.

The RPS conforms to IEEE 384 except for the requirement that redundant sensors and their connections to the process system be sufficiently separated to ensure that functional capability of the protection system is maintained despite any single design basis event or resulting effect. The above does not apply to the turbine stop valve and control valve fast closure trips in a nonseismic turbine enclosure during or after an SSE, as discussed in Section 7.2.1.2.8.

Additional details of the separation criteria used for the RPS are provided in Sections 8.1.6.1.14 and 7.1.2.2.

7.2.2.1.2.4 RPS Power Generation Design Bases

The RPS is a one-out-of-two-twice logic system, which inherently provides both reliability of action and availability of function. This permits testing during reactor operation without causing a scram.

7.2.2.1.3 RPS Additional Design Considerations Analyses

7.2.2.1.3.1 RPS Spurious Rod Withdrawals

Spurious control rod withdrawals do not normally cause a scram.A control rod withdrawal block may occur, however. Rod block is discussed in Section 7.6.1.4 and is not part of the RPS. A scram does occur, however, if the spurious control rod withdrawal causes the average flux to exceed the trip setpoint.

7.2.2.1.3.2 Loss of Plant Instrument Air System

Loss of plant instrument air causes opening of the scram valves on the hydraulic control units, resulting in a scram.

7.2.2.1.3.3 Loss of Cooling Water to Vital Equipment

There is no loss of cooling water that affects the RPS.

7.2.2.1.3.4 Plant Load Rejection

Electrical grid disturbances could cause a significant loss of load that would initiate a turbine-generator overspeed trip and control valves fast closure, resulting in a reactor scram. The reactor scram occurs to anticipate an increase in reactor vessel pressure that is due to shutting off the path of steam flow to the turbine. Any additional increase in pressure is prevented by the SRVs that open to relieve reactor pressure and close as pressure is reduced. The RCIC or HPCI systems automatically actuate and provide vessel makeup water if required.

The fuel temperature or pressure boundary thermal-hydraulic limits are not exceeded during the event, as described in Chapter 15.

7.2.2.1.3.5 Turbine Trip

Initiation of turbine trip by the turbine system closes the turbine stop valves initiating a reactor scram. The stop valve scram anticipates a reactor pressure or power scram that is due to the closure of turbine stop valves. Any additional increase in reactor vessel pressure is prevented by the SRVs that open to relieve reactor vessel pressure and close as pressure is reduced. The RCIC and HPCI automatically actuate and provide vessel makeup water if a low water level occurs.

Initiation of turbine trip by loss of condenser vacuum causes simultaneous closure of the turbine stop valves and MSIVs initiating a reactor scram.

The fuel temperature, pressure boundary, and thermal-hydraulic limits are not exceeded during these events, as described in Chapter 15.

7.2.3 REFERENCES

7.2-1 W.R. Morgan, "Incore Neutron Monitoring System for General Electric Boiling Water Reactors", APED-5706, (November 1968, Revised April 1969).

Table 7.2-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SPECIFICATIONS

SCRAM FUNCTION	INSTRUMENT	INSTRUMENT RANGE
Reactor vessel high pressure	Pressure sensor	0-1500 psi
Drywell high pressure	Pressure sensor	0-10 psig
Reactor vessel low water level	Level sensor	0-60 inches(1)
SDV high water level	Level switch Level transmitter	(2) 0-100 in H_2O
Turbine stop valve closure	Position switch	0-100%
Turbine control valve fast closure	Pressure sensor	250-3000 psig
MSIV closure	Position switch	0-100%
Neutron monitoring system trips	IRM APRM Neutron Flux-Upscale trip	0-125 divisions 10%-125% rated thermal power
	APRM Simulated Thermal Power-Upscale trip	10%-125% rated thermal power
	OPRM Upscale Trip	Period Based Detection Algorithm – Confirmation Count: 2-25 Amplitude: 1.00-1.30 Amplitude Based Algorithm: 1.05-1.50 Growth Rate Algorithm: 1.00-1.50
SDV high water level trip bypass	Bypass switch	--

Table 7.2-1
(Continued)

SCRAM FUNCTION	INSTRUMENT	INSTRUMENT RANGE
Turbine stop valve and control valve fast closure trip bypass	Pressure sensor	0-1000 psi
MSIV closure trip bypass	Reactor mode switch	--

(1) Instrument zero equal to 527.5 inches above vessel zero.
(2) Instrument range dependent on installation.

Table 7.2-2

TRIP SYSTEM CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE OF RPS

This table shows the normal and minimum number of trip system channels required for the functional performance of the RPS. The "normal" column lists the normal number of channels provided per trip system. The "minimum" column lists the minimum number of trip system operable channels required to maintain functional performance.

Channel Description	Normal	Minimum
Neutron monitoring system (APRM)(4)(5)	4	3
Neutron monitoring system APRM 2-out-of-4 voter (5)	2	2
Neutron monitoring system (IRM)(1)	4	3
Nuclear system high pressure	2	2
Drywell high pressure	2	2
Reactor vessel low water level	2	2
SDV high water level	2	2
Manual scram	2	2
Each MSIV position(2)	1/valve	1/valve
Each turbine stop valve position(3)	1/valve	1/valve
Turbine control valve fast closure, trip oil pressure low (3)	2	2
Reactor mode switch shutdown position	2	2

(1) Not required in run and shutdown modes
(2) Not required in shutdown, refuel and startup modes
(3) Not required when reactor power is less than 29.5% of rated power
(4) APRM channels, including OPRM trip, provide input to both RPS trip systems via the 2-out-of-4 voters.
(5) Not required in shutdown and refuel modes.

7.3 ENGINEERED SAFETY FEATURE SYSTEMS

Safety-related instrumentation and controls for ESF systems are described in this section. Instrumentation and controls for systems that support ESF systems are also described.

7.3.1 DESCRIPTION

The following systems are part of the ESF:

a. Emergency core cooling systems

b. Primary containment and reactor vessel isolation control system

c. Deleted

d. RHR containment spray mode

e. RHR suppression pool cooling mode

f. Containment atmospheric control system

g. Standby gas treatment system

h. Reactor enclosure recirculation system

i. Reactor enclosure isolation system

j. Habitability and control room isolation

k. Emergency service water system

l. RHR service water system

m. Control enclosure chilled water system

n. Class 1E power system

o. Safety-related equipment area cooling ventilation systems:

    1. SGTS filter room and access area unit coolers

    2. Diesel generator enclosure ventilation system

    3. Spray pond pump structure ventilation system

    4. ESF switchgear and battery rooms cooling system

    5. ECCS pump compartment unit coolers

    6. Auxiliary equipment room ventilation system

p. Drywell Unit Coolers

7.3.1.1 System Description

7.3.1.1.1 Emergency Core Cooling Systems - Instrumentation and Controls

The ECCS is a network of the following systems:

a. HPCI system

b. ADS

c. Core spray system

d. LPCI mode of the RHR system

The purpose of ECCS instrumentation and controls is to initiate appropriate responses from the system to ensure that the fuel is adequately cooled if there is a DBA. The cooling provided by the system restricts the release of radioactive materials from the fuel by preventing or limiting the extent of fuel damage following situations in which coolant is lost from the RCPB.

The ECCS instrumentation detects a need for core cooling systems operation, and the trip systems initiate the appropriate response. The ECCS instrumentation and controls are classified as Safety Class 2, seismic Category I, Quality Group B, and electric Class 1E.

Not included in this section is a discussion of measures that are taken to protect the low pressure ECCS from the high pressure RCS. The high pressure/low pressure interlocks are examined in Section 7.6.

The instrumentation and controls of the ECCS network system are powered by the 125 V dc and 120 V ac systems. The redundancy and separation of these systems are consistent with the redundancy and separation of the ECCS functional requirements. The power sources for the ECCS network systems are described in detail in Chapter 8.

7.3.1.1.1.1 High Pressure Coolant Injection System - Instrumentation and Controls

7.3.1.1.1.1.1 HPCI System Identification

When actuated, the HPCI system pumps water from either the CST or the suppression pool to the reactor vessel via a core spray line and a feedwater line. The HPCI system includes a turbine-driven pump, a dc motor-driven auxiliary oil pump, a gland seal condenser condensate pump, a gland seal condenser vacuum pump, automatic valves, control devices, sensors, and logic circuitry. The arrangement of equipment and control devices is shown in drawings M-55 and M-56. These drawings identify both nonsafety-related and safety-related parts of this system.

7.3.1.1.1.1.2 HPCI Equipment Design

Pressure and level transmitters used in the HPCI system are located on racks in the reactor enclosure. The only active component for the HPCI system located inside the primary containment is the inboard HPCI system turbine steam supply line isolation valve. The rest of the HPCI system control and instrumentation is located outside the primary containment. A full flow functional test of the system can be conducted during normal reactor power operation; however, the controls are

configured such that the system can be realigned automatically to fulfill its safety function regardless of the test being conducted.

There are three exceptions:

a. The HPCI flow controller auto/manual feature in the manual mode sets the HPCI system at selected flow rate; the operator can select auto if required. This feature is for operator flexibility during system operation.

b. Steam inboard/outboard isolation valves. Closure of either or both of these valves requires operator action to properly sequence their opening. An alarm sounds when either of these valves leaves the fully open position.

c. HPCI test switch in F006 and F007 position and test plug J1 or J10 inserted results in the HPCI system being inoperable. Depending on whether the test switch is in F006 or F007 position, one of the two series discharge valves are interlocked closed, preventing high pressure core injection. If the test switch is in F006, it disables both the F006 (discharge to core spray) and F105 (discharge to feedwater). HPCI OUT-OF-SERVICE annunciator sounds in the control room in indicate HPCI in test.

7.3.1.1.1.1.3 HPCI Initiating Circuits

Reactor vessel low water level is monitored by four level sensors that sense the difference between the pressure due to a constant reference leg of water and the pressure due to the actual height of water in the vessel as shown in drawing M-42. Each level sensor provides an input to a trip unit. Refer to Figure 7.3-26 for a diagram of level sensor connections. The four trip units are connected in a one-out-of-two-twice logic to provide an automatic HPCI initiation signal. Two lines, attached to taps above and below the water level on the reactor vessel, are required for the differential pressure measurement for each pair of level sensors. The lines terminate outside the primary containment and inside the reactor enclosure. The sensors are physically separated from the ADS sensors and tap off the reactor vessel at points widely separated from the ADS sensors. These same lines are also used for pressure and water level instruments for other systems. A similar arrangement of the ADS instrumentation initiates the ADS system. The arrangement ensures that no single event can prevent reactor vessel low water level from initiating both the HPCI system and the ADS.

Primary containment pressure is monitored by four pressure sensors that are mounted on an instrument rack outside the drywell, but inside the reactor enclosure. Pipes from the drywell interior to the sensors provide the sensing lines. Each drywell high pressure sensor provides an input into a trip unit. The four trip units are connected in a one-out-of-two-twice logic to provide an automatic HPCI initiation signal. The relay contacts from the trip units are arranged so no single event can prevent containment high pressure from initiating the HPCI system and ADS. The sensors are physically separated from the ADS pressure sensors and tap off the containment at points widely separated from the ADS pressure sensors.

The HPCI system controls automatically start the HPCI system from the receipt of a reactor vessel low water level signal (level 2) or primary containment drywell high pressure signal and bring the system to its design flow rate within 60 seconds. The system can also be initiated by use of a system-level remote manual switch or an individual remote manual switch for each valve and the auxiliary oil pump which provides the initial hydraulic fluid for the turbine stop and governor valves. In all initiation modes, the system is prevented from operating above high water level (level 8) using one-out-of-two-twice logic. The controls then function to provide design makeup water flow to the

reactor vessel until the amount of water delivered to the reactor vessel is adequate (level 8), at which time the HPCI system automatically shuts down. The system is designed to automatically cycle between these two levels. The controls are arranged to allow remote manual startup, operation, and shutdown.

The HPCI turbine is functionally controlled as shown in drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. A speed governor limits the turbine speed to its maximum operating level. A control governor receives a HPCI system flow signal and adjusts the turbine steam control valve so that the design HPCI system pump discharge flow rate is obtained. drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009 shows the various modes of turbine control. The flow signal used for automatic control of the turbine is derived from a differential pressure measurement across a flow element in the HPCI system pump discharge line. The governor controls the pressure applied to the hydraulic operator of the turbine control valve, which in turn controls the steam flow to the turbine. Hydraulic pressure is supplied for both the turbine control valve and the turbine stop valve by the dc-powered auxiliary oil pump during startup and then by the shaft-driven hydraulic oil pump when the turbine reaches operating speed.

Upon receipt of an initiation signal, the auxiliary oil pump starts, providing hydraulic pressure for the turbine stop valve and turbine control valve hydraulic operator. Because there is no flow in the HPCI system, the flow signal runs the control governor to the high speed stop. As hydraulic oil pressure is developed, the turbine stop valve and the turbine control valve open, and the turbine accelerates toward the speed setting of the control governor. As HPCI system flow increases, the flow signal adjusts the control governor setting so that design flow is maintained. The turbine is automatically shut down by tripping the turbine stop valve closed if any of the following conditions are detected:

a. High turbine exhaust pressure (one-out-of-two)

b. Low HPCI pump suction pressure (one-out-of-one)

c. High reactor water level (one-out-of-two-twice)

d. Turbine overspeed signal (one-out-of-one mechanical)

e. Low steam supply pressure (two-out-of-two)

f. HPCI autoisolation signals (one-out-of-two logic for turbine trip, for isolation one channel closes the inboard valve and one channel closes the outboard valve).

g. Remote manual trip

In each division, an auto isolation signal is initiated by any of the following:

a. Steam supply line - high flow (one-out-of-one logic trip)

b. High turbine exhaust diaphragm pressure (two-out-of-two logic trip)

c. High equipment or piping area temperature or high equipment area delta temperature (one-out-of-six logic trip)

d. Low steam supply pressure (two-out-of-two logic trip)

Precautions taken to preclude spurious HPCI system turbine isolation are:

a. Using coincident logic isolation trip circuits for low steam supply and high turbine exhaust diaphragm pressure.

b. Using trip time delay circuits (Reference NUREG-0737, Item II.K.3.15).

c. Using safety-grade instrumentation and control equipment.

d. Selecting trip settings far enough from normal operating values to avoid spurious trips, yet close enough to protect equipment.

The HPCI test return to condensate storage line valve HV-55-*F011 is normally kept closed except during HPCI or RCIC system flow testing. If during testing either a low reactor water level (level 2) or high drywell pressure condition initiates HPCI system operation, valve HV-55-*F011 and in series test return valve HV-55-*F008 are automatically closed. In addition, HPCI valve HV-55-*F011 is automatically closed if one of the HPCI or RCIC pump suppression pool suction valves HV-55-*F041, HV-49-*F029 or F031 fully opens. The *F011 is not automatically closed if the suppression pool to pump suction PCIV, HV-055 *F042 is open.

The preferred source of water for the HPCI is the CST. The HPCI system will realign to suppression pool suction upon receipt of a CST low level or suppression pool high level signal. Either of these signals open the HPCI suppression pool suction valves HV-55-*F041 and F042, if closed, which in turn sends a signal to close the CST suction valve HV-55-*F004 when both are fully open.

Turbine overspeed indicates a malfunction of the turbine control mechanism. High turbine exhaust pressure indicates a condition that threatens the physical integrity of the turbine casing. Low pump suction pressure warns that cavitation and lack of cooling can cause damage to the pump, which could place it out-of-service. A turbine trip is initiated for abnormal conditions so that, if the causes of the abnormal condition can be found and corrected, the system can be restored to service. The trip settings are selected far enough from normal values so that a spurious turbine trip is unlikely, but not so close that damage occurs before the turbine is shut down. Turbine overspeed is detected by a standard turbine overspeed electronic device for indication and a mechanical-hydraulic device for tripping the turbine. Two pressure sensors are used to detect high turbine exhaust pressure; either sensor can initiate turbine shutdown. One pressure sensor is used to detect low HPCI system pump suction pressure.

High water level in the reactor vessel indicates that the HPCI system has performed satisfactorily in providing makeup water to the reactor vessel. Further increase in level could result in HPCI system turbine damage caused by gross carryover of moisture. The reactor vessel high water level setting that trips the turbine (level 8) is near the top of the steam separators and is sufficient to prevent gross moisture carryover to the turbine. Four level 8 trip units, connected to appropriate sensors, arranged in a one-out-of-two-twice configuration, are required to initiate a turbine shutdown. Refer to Figure 7.3-26 for a diagram of level sensor connections.

Low steam supply pressure is detected by two pressure sensors, both of which must trip to initiate a turbine shutdown. This low pressure indicates that there is insufficient energy in the steam for the turbine to function.

The control scheme for the turbine auxiliary oil pump is shown in drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. System controls are arranged for automatic or manual control. Upon receipt of an HPCI system initiation

signal, the auxiliary oil pump starts and provides hydraulic pressure to open the turbine stop valve and the turbine control valve. As the turbine gains speed, the shaft-driven oil pump begins to supply hydraulic pressure. When the pressure supply by the shaft-driven oil pump is sufficient, the auxiliary oil pump automatically stops. Should the shaft-driven oil pump malfunction, causing oil pressure to drop, the auxiliary oil pump restarts automatically.

The operation of the gland seal condenser components (gland seal condenser condensate pump (dc), gland seal condenser vacuum pump (dc), and gland seal condenser water level instrumentation) prevents outleakage from the turbine shaft seals. Startup of this equipment is automatic, as shown in drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. Failure of this equipment does not prevent the HPCI system from providing water to the reactor vessel.

7.3.1.1.1.1.4 HPCI Logic and Sequencing

Either reactor vessel low water level (level 2) or primary containment (drywell) high pressure can automatically start the HPCI system as indicated in drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. Reactor vessel low water level is an indication that reactor coolant is being lost and that the fuel is in danger of being overheated. Primary containment high pressure is an indication that a breach of the nuclear system process barrier has occurred inside the drywell.

The scheme used for initiating the HPCI system is shown in drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. The components required for HPCI system initiation are powered by dc buses.

Instrument settings for the HPCI system controls and instrumentation are listed in Table 7.3-1. The reactor vessel low water level setting for HPCI system initiation is selected high enough above the active fuel to start the HPCI system in time both to prevent excessive fuel cladding temperatures and to prevent more than a small fraction of the core from reaching the temperature at which gross fuel failure occurs. The water level setting is sufficiently below normal levels so that spurious HPCI system startups are avoided. The primary containment high pressure setting is selected to be as low as possible without inducing a spurious HPCI system startup. The logic diagram for BOP portions of the HPCI system is shown in drawing M-55FD.

7.3.1.1.1.1.5 HPCI Bypasses and Interlocks

To prevent the turbine-pump from being damaged by overheating at reduced HPCI pump discharge flow, a pump discharge minimum flow line is provided to route the water being discharged from the pump to the suppression pool. The minimum flow is controlled by an automatic, dc MOV whose control scheme is shown in drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. On high HPCI flow, stop valve closure, or steam supply valve closure, the valve is closed, and on low flow, provided pump discharge pressure is above a pressure permissive setpoint (indicates pump is running) the valve is opened. The flow transmitter and trip units that measure the pressure difference across a flow element in the HPCI pump discharge pipeline provide the control signal for this valve.

To prevent the HPCI steam supply pipeline from filling up with water and cooling, a condensate drain pot, steam line drain, and appropriate valves are provided in a drain pipeline arrangement just upstream of the turbine supply valve. The control scheme is shown in drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. The controls position valves so that during normal operation steam line drainage is routed to the

main condenser. Upon receipt of a HPCI initiation signal and subsequent steam supply valve opening, the drainage path is isolated. The water level in the steam line condensate drain pot is controlled by a level switch, a flow orifice, and an air-operated steam trap bypass drain valve that allows condensate to flow out of the pot.

During test operation, the HPCI pump discharge is routed to the CST. Two dc MOVs are installed in the pump discharge to the CST pipeline. The piping arrangement is shown in drawing M-55. The control scheme for the two valves is shown in drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. Upon receipt of an HPCI system initiation signal, the two valves close and remain closed. Valve F011 is interlocked closed if the HPCI F041 or RCIC F029 or F031 valves are fully open. Numerous indications pertinent to the operation and condition of the HPCI system are available to the control room operator. Drawings M-55, M-56, E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009 show the various indications provided.

Suction is normally taken from the CST. If the level in the CST falls to a low level or the nonseismic pipeline from the CST breaks, a level sensor in the vertical run of pipe from the grade down to the HPCI pump compartment initiates an automatic realignment of pump suction piping to the suppression pool. The logic for automatic operation of the suction valves is shown by drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. Also, high suppression pool level will cause an automatic realignment of the suction source from the CST to the suppression pool.

7.3.1.1.1.1.6 HPCI Redundancy and Diversity

The HPCI system is actuated either by reactor vessel low water level (level 2) or by primary containment (drywell) high pressure. Both of these conditions could result from a LOCA. The redundancy of the HPCI system initiating circuits is consistent with the design of the HPCI system.

7.3.1.1.1.1.7 HPCI Actuated Devices

The HPCI actuated devices are automatically controlled by logic circuitry or manually controlled by switches in the control room. MOVs are provided with appropriate limit and/or torque switches to turn off the motors when the fully open or fully closed positions are reached. Valves that are automatically closed on isolation signals are equipped with remote manual reset devices so that they cannot be reopened without operator action. All essential components of the HPCI system controls operate on dc power or ac power supplied by an inverter that is part of the ECCS.

To ensure that the HPCI system can be brought to design flow rate within 60 seconds from receipt of the initiation signal, the following maximum operating times for essential HPCI system valves are provided by the valve operation mechanisms:

a.	HPCI system turbine steam supply valve	20 sec
b.	HPCI system pump discharge valves (except F105 valve	20 sec 40 sec)
c.	HPCI system pump minimum flow bypass valve	15 sec

The operating time is the time required for the valve to travel from the fully closed to the fully open position or vice-versa. Because the two HPCI system steam supply line isolation valves are normally open and because they are intended to isolate the HPCI system steam line if there is a break in that line, their operating time requirements are based on isolation requirements. These are described in Section 7.3.1.1.2.4.1.2. A normally closed dc MOV is located in the turbine steam supply line just upstream of the turbine stop valve. The control scheme for this valve is shown in

drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. Upon receipt of an HPCI system initiation signal, this valve opens and remains open until closed by operator action from the control room.

Two normally open isolation valves are provided in the steam supply line to the turbine. The control diagram is shown in drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. The valves automatically close upon receipt of an HPCI system turbine steam line high flow signal, an HPCI system turbine steam supply low pressure signal, high turbine exhaust diaphragm pressure, high steam line space temperature, HPCI equipment room ventilation inlet/outlet high differential temperature, or high area temperature.

Three pump suction valves are provided in the HPCI system. One valve provides pump suction from the CST; the other two provide suction from the suppression chamber. The CST is the preferred source. All valves are operated by dc motors. The control arrangement is shown in drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. Although the CST suction valve is normally open, an HPCI system initiation signal opens it if it is closed. If the water level in the CST falls below a preselected level, the suppression chamber suction valves automatically open. When both suppression chamber valves are fully open, the CST suction valve automatically closes. Two level sensors are used to detect the CST low water level condition. Either sensor can cause the suppression chamber suction valve to open. The suppression chamber suction valve also automatically opens, and the CST suction valve closes if a high water level is detected in the suppression chamber.

Two level sensors monitor the suppression pool water level. Either sensor can initiate the opening of the suppression chamber suction valves. If open, the suppression chamber suction valves automatically close upon receipt of the signals that initiate HPCI system steam line isolation.

Two dc motor-operated HPCI system pump discharge injection valves (F006, F105) are downstream of a single pump discharge shutoff valve (F007). The control scheme for these valves is shown in drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009and is arranged to open upon receipt of HPCI system initiation signals. The injection valves close following a turbine trip signal.

To prevent damage by overheating at reduced HPCI system pump flow, a pump discharge minimum flow bypass is provided by an automatic, dc MOV whose control scheme is shown in drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. On HPCI system high flow, stop valve closure or steam supply valve closure, the valve is closed; on low flow, provided pump discharge pressure is above a pressure permissive setpoint (indicates pump is running), the valve is opened. Flow sensors that measure the pressure difference across a flow element in the HPCI system pump discharge line provide the signals to control this valve. There is also an interlock provided to shut the minimum flow bypass whenever the turbine is tripped due to the subsequent stop valve closure. This is necessary to prevent drainage of the CST into the suppression pool.

To prevent the HPCI system steam supply line from filling up with water and cooling, a condensate drain pot, steam line drain, and appropriate valves are provided in a drain line arrangement just upstream of the turbine supply valve. The control scheme is shown in drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. The controls position valves so that, during normal operation, steam line drainage is routed to the main condenser. Upon receipt of an HPCI system initiation signal, the drainage path is isolated. The water level in the steam line condensate drain pot is controlled by a steam trap and secondarily by a level switch and an AOV that opens to allow condensate to flow out of the pot.

During test operation, the HPCI system pump discharge can be routed to the CST. The dc MOVs are installed in the pump discharge test line. The piping arrangement is shown in drawing M-55. The control scheme for the valves is shown in drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. Upon receipt of an HPCI system initiation signal, the valves close and remain closed. The F011 is interlocked closed if the HPCI F041 or RCIC F029 or F031 valves are fully open. Indications pertinent to the operation and condition of the HPCI system are available to the plant operator. Drawings M-55, M-56, E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009 show the indications provided.

7.3.1.1.1.1.8 HPCI Separation

Separation within the ECCS is designed so that no single occurrence can prevent core cooling when required. Control and instrumentation equipment wiring is segregated into separate divisions designated 1, 2, 3, and 4. Similar separation requirements are also maintained for the control and motive power required. Separation is as follows:

Division 1	Division 2	Division 3	Division 4
Core spray A	Core spray B	Core spray C	Core spray D
RHR "A" (including	RHR "B" HPCI outboard isolation valve)	RHR "C" inboard isolation	RHR "D" HPCI (including valves)
ADS "A"		ADS "C"	

The ADS, combined with the low pressure ECCS (CS and RHR), is considered a backup for HPCI. A complete description of the physical independence between divisions is given in Section 7.1.2.2.

7.3.1.1.1.1.9 HPCI Testability

The HPCI system has components that are not activated or tested during normal operation with an integrated testing procedure. These components are tested using manual test methods which allow for independent checking of individual system components. This testing includes verification of flow using the installed return piping such that the turbine and pump are operated. A system functional test, including simulated automatic actuation of the system, with verification that automatic valves in the injection flow path move to the correct position, is also performed. Associated sensors and circuits are monitored to verify proper operation. The frequency of these tests and the parameters to be verified are identified in the Technical Specifications.

The HPCI instrumentation and control system is capable of being tested during normal unit operation to verify the operability of each system component. Testing of the initiation sensors that are located outside the drywell is accomplished by valving out each sensor, one at a time, and applying a test pressure source. This verifies the operability of the sensor. Trip units located in the auxiliary equipment room are calibrated individually by a calibration source with verification of setpoint by a digital readout located on the calibration module.

a. Calibration and test controls for the sensors are located in the reactor enclosure. Calibration and test controls for the trip units are located in the auxiliary equipment room. To gain access to the calibration points of each sensor, a cover plate must be removed. The control room operator is responsible for granting access to the calibration points. Only properly qualified plant personnel are granted access for testing or calibration adjustments.

   In addition to the above tests, operability of the sensors can be verified by cross-checking instrument readouts in the auxiliary equipment room at any time during operation.

b. Test jacks are provided to test the logic. Annunciation is provided in the control room whenever a test plug is inserted in a jack to indicate to the control room operator that the HPCI system is in the test status. Operation of the test plug switches can initiate or isolate the HPCI system. Injection into the reactor on an initiation signal is prevented by an interlock, actuated only when the test plug is inserted, which prevents the opening of one of the HPCI discharge valves. The test can be repeated with the other discharge valve interlocked closed. The manual initiation switch can also be tested at this time. This sequence of tests ensures that all components are tested. A logic test of the HPCI does not interfere with the operation of other ECCS equipment if required by an initiation signal.

c. The functional performance of the HPCI system can be verified by pumping water from the CST, through the full flow test lines, and back to the CST. If a LOCA were to occur during this mode of operation, the valve line-up would automatically be changed so that water can be pumped to the reactor.

During the above testing, the operation of the HPCI system can be observed in the control room by panel lamps, indicators, recorders, annunciators, and computer printout.

7.3.1.1.1.1.10 HPCI Environmental Considerations

The only HPCI system control component located inside the primary containment that must remain functional in the environment resulting from a LOCA is the control mechanism for the inboard isolation valve on the HPCI system turbine steam line. The environmental capabilities of this valve are discussed in Section 7.3.1.1.2.12. The HPCI system control and instrumentation equipment located outside the primary containment is selected in consideration of the normal and accident environments in which it must operate. These conditions are discussed in Section 3.11.

7.3.1.1.1.1.11 HPCI Operational Considerations

7.3.1.1.1.1.11.1 HPCI General Information

The HPCI system is not required for normal operations. Under abnormal or accident conditions, initiation and control are automatically provided for at least 10 minutes if required. After that time, operator action can assist the automatic controls to sustain core cooling.

7.3.1.1.1.1.11.2 HPCI Reactor Operator Information

A detection system continuously confirms the integrity of the HPCI injection piping to the reactor vessel. The HPCI discharge to the reactor vessel is through a CS system line and sparger and feedwater line. A differential pressure sensor measures the pressure difference between the two CS system injection lines. If the CS piping is sound, the pressure difference is very small between these lines. If integrity is lost, increasing differential pressure initiates an alarm in the main control room. Pressure in the HPCI pump suction line is monitored by pressure transmitters, which initiate

alarms in the control room on high or low suction pressure and also provide signals to indicators in the control room. Sufficient level, flow, pressure, and valve position information is available in the control room for the operator to assess the HPCI system operation as shown in drawings M-55, M-56, E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009.

7.3.1.1.1.1.11.3 HPCI Setpoints

See Chapter 16 for safety setpoints.

7.3.1.1.1.2 Automatic Depressurization System - Instrumentation and Controls

7.3.1.1.1.2.1 ADS Identification

The ADS automatically controls five of the SRVs that are installed on the main steam lines inside the primary containment. Table 1 in drawing M-41 identifies which SRVs are controlled by the ADS. The valves are dual-purpose in that they relieve pressure by normal mechanical action or by automatic action of an electric-pneumatic control system. The relief by normal mechanical action is intended to prevent overpressurization of the RCPB. The depressurization by automatic action of the control system is intended to reduce the pressure during a LOCA in which the HPCI system is not available so that the CS system and/or LPCI system can inject water into the reactor vessel.

7.3.1.1.1.2.2 ADS Equipment Design

The control system consists of pressure and water level sensors arranged in trip systems that control dual solenoid valves. The dual solenoid valves control the pneumatic pressure applied to an actuator that controls the SRV directly. An accumulator is included with the control equipment to store pneumatic energy for SRV operation. Cables from the sensors lead to the control structure, where the logic arrangements are formed in cabinets. The electrical control circuitry is powered by dc from the plant safeguard batteries. The power supplies for the redundant control circuits are selected and arranged to maintain tripping ability if there is an electrical power circuit failure. Electrical elements in the control system energize to cause the opening of the SRV. The instrument gas supply to the accumulators is furnished from a seismic Category I gas supply if the normal supply is lost. Seismic Category I backup gas supply is required to be connected at all times during normal operation.

7.3.1.1.1.2.3 ADS Initiating Circuits

The pressure and level sensors used to initiate ADS are separated from those used to initiate the HPCI system. Drawing M-42 lists sensors with common transmitters. The ADS function is initiated automatically by low reactor water level and high drywell pressure signals or low reactor water level with the high drywell pressure bypass timer timed out. The ADS function can also be initiated by system-level remote manual switches. In either mode, the ADS valves are prevented from opening unless both pumps in either of the two CS loops, or any of the four RHR pumps, are running. In addition, each individual ADS valve can be opened manually without restriction from permissive sensors.

Reactor vessel low water level (level 1) is monitored by four level sensors that sense the difference between the pressure due to a constant reference leg of water and the pressure due to the actual height of water in the vessel as shown in drawing M-42. Each level sensor provides an input to a trip unit. Two pairs of lines, attached to taps above and below the water level on the reactor vessel, are required for the differential pressure measurement for the level sensors. The lines terminate outside the primary containment and inside the reactor enclosure. They are physically

separated from the HPCI sensors and tap off the reactor vessel at points widely separated from the HPCI sensors. These same lines are also used for pressure and water level instruments for other systems. Two additional level sensors are piped individually to confirm reactor vessel low water level (level 3) so that an instrument line break inside containment does not inadvertently initiate autoblowdown. The relay contacts from the trip units are arranged so that a set of sensors sensing low water level initiates the ADS system and a separate pair of sensors initiates the HPCI. This arrangement ensures that no single event due to reactor vessel low water level can prevent the initiation of both the HPCI system and the ADS.

Primary containment pressure is monitored by four pressure sensors that are mounted on instrument racks outside the drywell, but inside the reactor enclosure as shown in drawing M-42. Pipes from the drywell interior to the sensors provide the sensing lines. Each drywell high pressure sensor provides an input into a trip unit. The sensors are grouped in a manner similar to the level sensors and are electrically arranged so that no single event due to primary containment high pressure can prevent the initiation of both the HPCI and the ADS systems.

Discharge pressure on the CS and RHR pumps is monitored by twelve pressure sensors; one sensor is at the discharge of each CS pump as shown in drawing M-52 and two sensors are at the discharge of each RHR pump as shown in drawing M-51. Each pressure sensor provides an input to a trip unit.

The primary containment high pressure signals are arranged to seal-in the control circuitry; they must be manually reset to clear. The level sensing logic and the pump discharge pressure signals do not seal-in.

A timer is used in each of the two ADS trip systems. The time delay setting before actuation of the ADS is long enough so that the HPCI system has time to operate, yet not so long that the LPCI and CS systems are unable to adequately cool the fuel if the HPCI system fails to start. An alarm in the control room is annunciated when either of the timers is timing. Resetting the ADS initiating signals recycles the timers. A manual reset switch is provided in each trip system to reset the timer to delay ADS initiation.

Within each trip system, if the reactor level is restored before the timer times out, the timer automatically resets, and autodepressurization is aborted. Should additional reactor level dips occur below the setpoints, the timer is again initiated.

7.3.1.1.1.2.4 ADS Logic and Sequencing

Two initiation signals and one permissive signal are used for the ADS: reactor vessel low water level; drywell high pressure; and RHR and/or CS pumps running. If all signals are present, the ADS SRVs will open after the ADS timer runs out. If the high drywell pressure signal is not present, the ADS SRVs can open after the high drywell pressure bypass timer and ADS timer run out (Figure 7.3-4). There are two reactor vessel low water level signals associated with the ADS system; one (level 3) prevents undesired system operation, and the other (level 1) initiates the ADS. Primary containment high pressure indicates a breach in the RCPB inside the drywell. A permissive signal indicating RHR or CS pump discharge pressure is also required. Discharge pressure on any one of the RHR pumps or both pumps of either CS loop is sufficient to give the permissive signal, which permits automatic depressurization when the LPCI or CS systems are operating.

The ADS is composed of four logics, arranged with the A and E logics in ADS trip system A and the C and G logics in ADS trip system C. Each trip system controls one of the two solenoid valves

associated with each SRV. As shown in Figure 7.3-4, both logics in a trip system must be enabled to energize the solenoid valves associated with that trip system.

After receipt of the initiation signals and a delay provided by timers, one or both of the solenoid valves are energized. This allows pneumatic pressure from the accumulator to act on the cylinder operator. The pneumatic cylinder operator holds the relief valve open. Lights in the control room indicate when the solenoid valves are energized to open an SRV.

Manual reset circuits are provided in the ADS initiation logic. By manually resetting the initiation signal, the delay timers are recycled. The operator can use the reset push buttons to delay or prevent the automatic opening of the relief valves if such delay or prevention is prudent.

The operator's decision to use the manual reset circuits is based on the following criteria:

a. ADS logic shall not be reset prior to system initiation unless spurious initiation is verified.

b. ADS logic may be reset after system initiation if reactor vessel level is greater than Level 1 and sufficient water delivery capability exists to maintain this level.

The EOPs written in accordance with the BWROG EPGs further address operator intervention concerning the ADS function.

A manual inhibit switch is provided in each division of the ADS initiation logic. By placing this switch in the inhibit position, the automatic depressurization will be inhibited, and it will be indicated by a white status light and annunciator window in the control room. If the ADS has already begun and is sealed-in, the inhibit switch does not break the seal-in and does not terminate the ADS.

A manual initiation switch is provided in the control room for each ADS logic. The design minimizes the components that are common to both the manual and automatic logics. The manual initiation signal is sealed-in until reset by the operator.

Once opened by an ADS initiation, the ADS SRVs will return to their normal (closed) position if both ADS reset buttons dedicated to valve closure are depressed. If, however, the ADS initiating signal has not reset or the signal recurs, a subsequent time-delayed ADS trip and valve opening logic sequence will commence.

Activating both ADS divisional reset circuits is an acceptable operating method to prevent or limit inadvertent ADS valve actuation. This is considered to be a deliberate operator action and the only expedient means to close the ADS valves.

Control switches are available in the control room for manual operation of each SRV.

Two ADS trip systems are provided as shown in Figure 7.3-4. Division 1 sensors for low reactor water level and high drywell pressure initiate ADS A, and Division 3 sensors initiate ADS C.

The dual solenoids 'A' and 'B', on the pilot valve for each ADS SRV are individually controlled by ADS trip systems A and C, respectively.

The reactor vessel low water level initiation setting for the ADS is selected to depressurize the reactor vessel in time to allow adequate cooling of the fuel by the LPCI system or CS system following a LOCA in which the HPCI system fails to perform its function adequately. The primary containment high pressure setting selected is as low as possible without inducing a spurious

initiation of the ADS. This provides timely depressurization of the reactor vessel if the HPCI system fails to start or fails after it successfully starts following a LOCA.

The pump discharge pressure setting used as a permissive for depressurization is selected to ensure that at least one of the RHR pumps, or both pumps of either CS loop, have received electrical power, have started, and are capable of delivering water into the vessel. The setting is high enough to ensure that the pump or pump pair delivers at near-rated flow, yet not so low as to provide an erroneous signal that the pump or pump pair is running when it actually is not.

7.3.1.1.1.2.5 ADS Bypasses and Interlocks

It is possible for the operator to manually delay the depressurizing action by the trip system reset switches. This would reset the timers to zero seconds and prevent depressurization until the timers have timed out. The operator would make this decision based on an assessment of other plant conditions. ADS is interlocked with the CS and RHR systems by pressure sensors located on the discharge of these pumps. This interlock ensures that at least one of the RHR pumps or both pumps of either CS loop are capable of delivering water into the vessel. Although the ac interlock is common to both the automatic and manual ADS initiation circuits, ADS initiation is not compromised because each of the trip systems is duplicated (ADS A and ADS C). For a failure of the ADS to occur, this interlock would have to fail in each of the ADS trip systems.

The high drywell pressure bypass timer is actuated on low water level (level 1). When this timer runs out, the high drywell pressure trip is bypassed, and the ADS timer is initiated on low water level alone. If the low water level signal clears before the high drywell pressure bypass timer runs out, the bypass timer will automatically reset.

7.3.1.1.1.2.6 ADS Redundancy and Diversity

The ADS has two independent and redundant trip systems. Each trip system controls one of the two independent and redundant solenoid valves associated with each ADS valve. The initiating circuits for each trip system are redundant, as verified by the circuit description of this section.

7.3.1.1.1.2.7 ADS Actuated Devices

The five SRVs associated with the ADS are equipped with remote manual switches so that the entire system can be operated manually as well as automatically. The valves also prevent RCPB overpressurization by their built-in mechanical action.

7.3.1.1.1.2.8 ADS Separation

ADS is a Division 1 (ADS A) and Division 3 (ADS C) system except that only one set of relief valves is supplied. Each relief valve can be actuated by either of two solenoid valves supplying gas to the relief valve operator. One of the solenoid valves is actuated by trip system A and the other by trip system C. Logic relays, manual controls, and instrumentation are mounted so that Division 1 and Division 3 separation is maintained. A complete description of the physical independence between divisions is given in Section 7.1.2.2.

7.3.1.1.1.2.9 ADS Testability

The ADS has two divisional trip systems, and either one can initiate automatic depressurization. Each trip system has two trip logics, both of which must trip to initiate ADS. Four test jacks are provided, one in each trip logic. During testing, only one trip logic is actuated at a time to prevent spurious ADS operation. The test plug switch disables one trip logic of a trip system while the other

is undergoing test. Actuation of appropriate trip units in the trip logic being tested closes one of the two series relay contacts in the valve solenoid circuit. This causes a panel light to come on, indicating proper trip logic operation and also continuity of the solenoid electrical circuit. Testing of the other trip logic and trip system is similar. Annunciation is provided in the control room whenever a test plug is inserted in a jack to indicate to the reactor operator that the ADS is in a test status. Testing in one division of the ADS does not interfere with automatic operation of the other division if required by an initiation signal.

Integrated testing of the ADS solenoid valves and circuitry is not performed with the plant operating at power, which is consistent for safety systems where the final actuating device(s) would cause temporary modification of plant processes such as fluid injection or discharge. The Technical Specifications provide for a functional partially integrated test without valve actuation. The transmitter/ trip units that provide sensory inputs to the ADS are checked by station personnel. The logic chain up to the solenoid is tested by manually inserting a trip signal and observing the trip logic lights which indicate both continuity of the solenoid circuit and proper trip logic operation

7.3.1.1.1.2.10 ADS Environmental Considerations

The signal cables, solenoid valves, and SRV operators are the only essential control and instrumentation equipment for the ADS located inside the primary containment. These items operate in the most severe environment resulting from a design basis LOCA (Section 3.11). Gamma and neutron radiation have been considered in the selection of these items. Equipment located outside the primary containment operates in an appropriate environment. The environmental conditions for these areas are discussed in Section 3.11.

7.3.1.1.1.2.11 ADS Operational Considerations

7.3.1.1.1.2.11.1 ADS General Information

The instrumentation and controls of the ADS are not required for normal plant operations. When automatic depressurization is required, it is initiated automatically or manually by the circuits described in this section.

7.3.1.1.1.2.11.2 ADS Reactor Operator Information

Recorders and indicators in the control room provide information regarding reactor water level and drywell pressure.

Each manual and automatic ADS input is provided to the annunciator system. Annunciation is also provided on initiation of the ADS timers, tripping of each logic, and system out-of-service indication. All interface with the annunciator system is through isolated contacts.

7.3.1.1.1.2.11.3 ADS Setpoints

See Chapter 16 for safety setpoints.

7.3.1.1.1.3 Core Spray System - Instrumentation and Controls

7.3.1.1.1.3.1 CS System Identification

The CS system consists of two independent and redundant spray loops as illustrated in drawing M-52.

7.3.1.1.1.3.2 CS Equipment Design

The two spray loops are physically and electrically separated so that no single physical or electrical event makes both loops inoperable. Each loop includes two ac motor-driven pumps, each with a separate suction path from the suppression pool, necessary control and instrumentation devices and valves, and a discharge path connected directly to the reactor which is common to both pumps. Each pump supplies 50% of the required core spray flow so either loop can satisfy 100% of the core spray design requirements. The controls and instrumentation for the CS system include the sensors, relays, wiring, and valve operating mechanisms used to start, operate, and test the system. Except for the testable check valve and the bypass valve in each spray loop that are inside the primary containment, the sensors and valve operating mechanisms for the CS system are located in the reactor enclosure. Testable check valves are described in Chapter 6. Cables from the sensors are routed to the control structure, where the logic circuitry is assembled in electrical panels. Each pump, associated suction valve, instrumentation, control and motive devices are assigned to separate electrical safety divisions. Each division is fully separated (including instrumentation, control, and power cables) from each of the other divisions as required by the LGS electrical separation criteria. Logic and motive power for each division is supplied from safeguard power sources within the division. The remaining devices and valves in each loop are assigned to the same safety divisions as the pumps in that loop to provide adequate separation between the redundant loops. Control power for each of the CS pumps comes from separate dc buses. The electrical equipment in the control room for one CS loop is separated from that used for the other loop.

7.3.1.1.1.3.3 CS Initiating Circuits

Trip units associated with two reactor vessel low water level sensors and two drywell high pressure sensors in conjunction with two reactor low pressure sensors are electrically connected in a one-out-of-two-twice arrangement for each CS pump as shown in Figure 7.3-9, so that no single event can prevent initiation of CS.

The following discussion describes the initiation and operation of the 'A' core spray loop. The 'B' loop is initiated and operated similarly and independently of the 'A' loop. The 'A' loop is automatically initiated when a LOCA condition (low reactor vessel level or high drywell pressure coincident with low reactor vessel pressure) exists. The 'A' core spray loop can also be manually initiated by arming and depressing the 'A' and 'C' core spray initiation switches ('B' & 'D' switches for B loop).

Upon receipt of either of the above loop initiation signals in their respective divisions of initiation logic, the 'A' and 'C' core spray pumps start automatically, the core spray test return line to the suppression pool is automatically isolated, and a signal to open the inboard and outboard loop injection valves is initiated. However the normally-closed inboard injection valve (also refereed to as the injection valve) and the normally-open outboard injection valves are interlocked to prevent opening if reactor pressure is greater than the pressure permissive setpoint (determined by monitoring reactor pressure) or if power is not available at the 4 kV bus to which the 'A' core spray pump is connected.

When the 4 kV bus is energized and reactor pressure has decreased to below the pressure permissive setpoint the injection valves will automatically open. The pressure permissive setpoint prevents overpressurizing the low pressure portions of core spray.

Each of the components in the core spray flow path can also be manually operated from the control room by means of the component's individual control switch. The inboard injection valve is interlocked to prevent opening unless; either its respective loop initiation signal with 4kV power and

pressure permissive is present (as described above), or the associated outboard injection valve is closed.

Reactor vessel low water level is monitored by eight level sensors that sense the difference between the pressure that is due to a constant reference leg of water and the pressure that is due to the actual height of water in the vessel. Each level sensor provides an input to a trip unit located in the control structure. Refer to Figure 7.3-26 for a diagram of level sensor connections. The lines terminate outside the primary containment and inside the reactor enclosure.

Drywell pressure is monitored by eight sensors mounted on instrument racks in the reactor enclosure. Four sensing lines that terminate in the reactor enclosure allow the sensors to measure the drywell interior. Each drywell high pressure sensor provides an input to a trip unit located in the control structure.

Reactor pressure is monitored by twelve pressure sensors mounted on racks in the reactor enclosure. Four of the pressure sensors are used to develop system initiation signals, four are used in development of injection value open-permissive interlocks, four provide inputs to both system initiation and injection valve open-permissive interlock logic. Four sensing lines that terminate in the reactor enclosure allow the sensors to measure the reactor vessel. Each pressure sensor provides an input to a trip unit located in the control structure.

The CS initiation signal also initiates the corresponding diesel generator.

7.3.1.1.1.3.4 CS Logic and Sequencing

The control scheme for the CS system is illustrated in Figure 7.3-9. The logic of BOP portions of the CS system is shown in drawing M-52FD. Trip settings are given in Chapter 16. The overall operation of the system following the receipt of an initiating signal is as follows:

a. Test bypass valves are closed and interlocked to prevent opening.

b. If offsite ac power is available, the CS pumps in one loop start after a 10 second delay, and the CS pumps in the other loop start after a 15 second delay.

c. If offsite ac power is not available, the CS pumps in both spray loops start 7 seconds after standby power becomes available for loading.

d. The pump minimum flow bypass valves open as soon as the core spray pumps start.

e. When reactor vessel pressure drops to a preselected value, valves open in the pump discharge lines, allowing water to be sprayed over the core.

f. When pump discharge flow is greater than a preselected value, the pump minimum flow bypass valves shut, directing full flow into the reactor vessel.

Three initiating variables are used for the CS system: reactor vessel low water level; drywell high pressure; and reactor vessel low pressure.

The CS initiation logic is a one-out-of-two-twice network using level and pressure sensors. The initiation signal is generated when:

a. Both level sensors are tripped.

b. Four pressure sensors are tripped (two high drywell pressure and two low reactor vessel).

c. Either of two combinations of one level sensor and two pressure sensors (one high drywell and one low reactor vessel) are tripped.

The CS system can also be manually initiated.

Once an initiation signal is received by the CS control circuitry, the signal is sealed-in until manually reset. The seal-in feature is shown in Figure 7.3-9.

The pressure permissive signal for opening the respective injection valve is provided by four division (1) or four division (2) pressure sensors that monitor reactor vessel pressure. Two of these sensors are the ones described in Section 7.3.1.1.1.3.3, to initiate the CS system in conjunction with high drywell pressure. The other two sensors are located on the same sensing lines and provide signals to trip units located in the control structure. These pressure signals are arranged in a one-out-of-two-twice logic.

7.3.1.1.1.3.5 CS Bypasses and Interlocks

The CS pump motors and inboard injection valves are provided with manual override controls that allow the operator to control the system following automatic initiation.

A pressure transmitter is installed upstream of each pump discharge check valve. These pressure signals are used in the ADS to indicate that core spray pumps are running, allowing actuation of the ADS.

The CS initiation signal also initiates the corresponding diesel generator and is used to trip the drywell chillers.

7.3.1.1.1.3.6 CS Redundancy and Diversity

As described in Section 7.3.1.1.1.3.4, sufficient redundancy and diversity of initiation signals is provided to prevent a single failure from preventing initiation of the CS system. Core spray is a four-pump, two-loop system that is backed up by the four-loop LPCI mode of the RHR system. Each of the two CS loops is independent.

Each loop of either core spray or LPCI in itself is not designed to sustain a single failure and still perform its design functions. Single failures such as: loss of one division of safeguard power, logic failure in one division, or an instrument failure in one division can disable one loop of core spray and/or one loop of LPCI including both manual and automatic operation of those loops. For a DBA coincident with a worst case single failure, the most demanding and limiting scenarios on low pressure ECCS are:

a. A pipe break that is not part of the low pressure ECCS and a single diesel generator failure. Three LPCI loops and one core spray loop would remain.

b. A low pressure ECCS pipe break and a single diesel generator failure. If the pipe break is in core spray, three LPCI loops would remain. If the pipe break is in LPCI, one core spray loop and two LPCI would remain.

For either scenario, the remaining low pressure ECCS loops are more than sufficient to satisfy the low pressure coolant flow requirements to the reactor.

The above scenarios are more demanding on the low pressure ECCS than the failure of any one core spray or LPCI instrument. Hence, the consequences of a single core spray or LPCI instrument failure are bounded by the consequences for the above scenarios. Because the low pressure ECCS is designed with sufficient redundancy and separation to perform their design functions in the worst case single failure scenarios, no design changes are required to reduce the consequence of a single failure of a core spray or LPCI instrument.

7.3.1.1.1.3.7 CS Actuated Devices

The control arrangements for the CS pumps are shown in Figure 7.3-9. The circuitry provides for detection of normal power available, so that all pumps are automatically started in sequence. Each pump can be manually controlled by a control room remote switch or the automatic control system. The CS pump motors are provided with overload and undervoltage protection. Overload relays are sized so as to maintain power as long as possible without immediate damage to the motors or emergency power system.

Flow-measuring instrumentation is provided in the discharge line of each set of core spray pumps. This instrumentation provides flow indication in the control room.

Except where otherwise specified, the remainder of the description of the CS system refers to one spray loop. The second CS loop is identical. The control arrangements for the various automatic valves in the CS system are indicated in Figure 7.3-9. All MOVs can be controlled from the control room and are equipped with limit and torque switches to turn off the valve motor when the valve reaches the limits of movement and provide control room indication for valve position.

Each automatic valve can be operated from the control room. Overload protection is provided to valve motors in accordance with Section 8.1.6.1.19. The valves in the suction paths from the suppression pool are key-locked open and require no automatic action to line-up CS suction.

Upon receipt of an initiation signal, the test bypass valve is automatically closed and interlocked shut. The injection valves are automatically opened when reactor vessel pressure drops to a preselected value; the setting selected is low enough so that the low pressure portions of the CS system are not overpressurized, yet is high enough to open the valves in time to provide adequate cooling for the fuel. The full stroke operating times of the MOVs are selected to be rapid enough to ensure proper delivery of water to the reactor vessel following a DBA.

A flow sensor on the discharge of each set of pumps provides a signal to operate the minimum flow bypass line valve for each loop. When the flow reaches the value required to prevent pump overheating, the valves close and all flow is directed into the sparger.

7.3.1.1.1.3.8 CS Separation

The CS system consists of four pumps, each with its own independent logic and control power source. The sensors used to initiate one core spray pump are separated from those used to initiate the other core spray pumps. The locations of the instrumentation and controls components are provided in Table 1.7-3.

Logics for the A and B loop valves are powered by the 125 V dc buses A and B, respectively.

A complete description of the physical independence between divisions is given in Section 7.1.2.2.

7.3.1.1.1.3.9 CS Testability

The CS System has components that are not activated or tested during normal operation with an integrated testing procedure. The components are tested using manual test methods which allow for independent checking of individual components. This testing includes verification of flow using the installed test piping such that the motors and pumps are operated. A system function test, including automatic actuation of the system, with verification that automatic valves in the injection flow path move to the correct position, is also performed. Associated sensors and circuits are monitored to verify proper operation. The frequency of these tests and the parameters to be verified are identified in the Technical Specifications.

The CS system is capable of being tested during normal operation by an overlapping series of tests. All sensors are individually valved out of service and subjected to a test pressure. This verifies the operability of the sensors as well as the calibration range. The trip units mounted in the auxiliary equipment room are calibrated individually by a calibration source with verification of setpoint by a digital readout located on the calibration module.

a. Calibration and test controls for the sensors are located in the reactor enclosure. Calibration and test controls for the trip units are located in the auxiliary equipment room. To gain access to the calibration points of each sensor, a cover plate must be removed. The control room operator is responsible for granting access to the calibration points. Only properly qualified plant personnel are granted access for testing or calibration adjustments.

   In addition to the above tests, the operability of the sensors can be verified by cross-checking instrument readouts in the auxiliary equipment room at any time during operation.

b. Test jacks are provided to test the logic. Annunciation is provided in the control room whenever a test plug is inserted in a jack to indicate to the control room operator that the CS system is in the test status. Operation of the test plug switches initiates the system. Injection into the reactor is prevented by an interlock actuated when the test plug is inserted. This will prevent the automatic opening of either the inboard or the outboard injection valve, depending on the position of the test switch that is used to select which valve to test. The manual initiation switches can also be tested. This sequence of tests ensures that all components are tested. A logic test of one CS loop does not interfere with the operation of the other CS loop if required by an initiation signal.

c. The functional performance of CS components can be verified by pumping water to the suppression pool through the full flow test line. If a LOCA were to occur during this mode of operation, the valve line-up would automatically be changed so that water can be pumped to the reactor.

During the above testing, CS operation can be observed in the control room by panel lamps, indicators, recorders, annunciators, and computer printout.

7.3.1.1.1.3.10 CS Environmental Considerations

The testable check valves are the only control and instrumentation components for the CS system that are located inside the primary containment that must operate in the environment resulting from a LOCA. All other components of the CS system that are required for system operation are outside

the drywell and are selected in consideration of the normal and accident environments in which they must operate. The environmental conditions for the areas where the equipment is located are provided in Section 3.11.

7.3.1.1.1.3.11 CS Operational Considerations

7.3.1.1.1.3.11.1 CS General Information

The CS system is not required for normal plant operation. When it is required for accident conditions it is automatically initiated by the circuitry described in this section. No operator action is required for at least 10 minutes following initiation. After this time, operator action can assist the automatic controls to sustain core cooling.

7.3.1.1.1.3.11.2 CS Reactor Operator Information

Sufficient temperature, flow, pressure, and valve position indications are available in the control room for the operator to accurately assess CS system operation. Valves have indications of fully open, intermediate, and fully closed position. The pump has indications for pump running and pump stopped. Alarm and indication devices are shown in drawing M-52 and Figure 7.3-9. A detection system continuously confirms the integrity of the CS A and B injection line piping to the reactor vessel. A differential pressure sensor measures the pressure difference between the two injection lines. If the CS A and B piping is sound, the pressure difference will be very small between these lines. If integrity is lost, an increase in differential pressure initiates an alarm in the control room. Pressure in each CS pump suction line is monitored by a local pressure indicator to determine suction head and pump performance. Pressure in the discharge line of each CS loop is monitored by a pressure indicator in the control room to determine pump performance.

7.3.1.1.1.3.11.3 CS Setpoints

See Chapter 16 for safety setpoints.

7.3.1.1.1.4 LPCI Mode of the RHR System - Instrumentation and Controls

7.3.1.1.1.4.1 LPCI System Identification

LPCI is an operating mode of the RHR system. The RHR system and its operating modes are discussed in Sections 5.4 and 6.3. Because the LPCI mode of the RHR system is designed to provide water to the reactor vessel following the design basis LOCA, the controls and instrumentation for it are discussed herein.

7.3.1.1.1.4.2 LPCI Equipment Design

Drawing M-51 shows the entire RHR system, including the equipment used for LPCI operation. This drawing identifies nonsafety-related parts of this system. Control and instrumentation required for the operation of the LPCI mode are electric Class 1E and seismic Category I.

The instrumentation for LPCI operation controls other valves in the RHR. This ensures that the water pumped from the suppression pool by the main system pumps is routed directly to the reactor. These interlocking features are described in this section.

LPCI, an operating mode of the RHR system, consists of four independent and redundant loops. Each loop contains a separate suction path from the suppression pool, a motor-driven pump, necessary control and instrumentation devices and valves, and a separate injection path that

discharges directly into the reactor. Drawing M-51 shows the locations of instruments, control equipment, and LPCI components. Except for the LPCI testable check valves, the components pertinent to LPCI operation are located outside the primary containment.

Each loop is assigned to a separate electrical safety division. Logic and motive power for each division is supplied from safeguard power sources within that division. Each safety division is fully separated (including instrumentation, control, and power cables) from each of the other safety divisions as required by the LGS electrical separation criteria. Each LPCI pump will supply 100% of the loop design flow. Power for the main system pumps is supplied from ac buses that can receive standby ac power. Motive power for each of the injection valves, one in each loop, used during LPCI operation comes from a separate bus that can be automatically connected to standby power sources. Control power for all LPCI components, except valves, comes from the dc buses. Redundant trip systems are powered from different dc buses.

LPCI is arranged for automatic operation and for remote manual operation from the control room. The equipment provided for manual operation of the system allows the operator to take action independent of the automatic controls if there is a LOCA.

7.3.1.1.1.4.3 LPCI Initiating Circuits

Two automatic initiation signals are provided for the LPCI mode of operation of the RHR systems: reactor vessel low water level and drywell high pressure with a reactor vessel low pressure permissive. Either will initiate the LPCI mode of operation. The same sensors and trip units used for initiation of the CS system are used to initiate LPCI.

The low water level or high drywell pressure coincident with reactor low pressure initiation signal for LPCI is a one-out-of-two-twice arrangement as described in Section 7.3.1.1.1.3.3 for the CS system.

Drawing M-42 can be used to identify the instrument rack used for the sensors. Table 1.7-3 can be used to determine the location of the sensors, and drawings E11-1030-F-001, E11-1030-F-002, and E11-1030-F-003 can be used to determine the functional use of each sensor in the control circuitry for LPCI components. Instrument characteristics are given in Table 7.3-4.

The following discussion describes the initiation and operation of the 'A' LPCI loop only. The three remaining loops are initiated and operated similarly and each loop is initiated and operated independently of the other loops. The 'A' LPCI loop is automatically initiated when LOCA condition (reactor vessel low level or containment high pressure coincident with reactor low pressure) exists. LPCI can be manually initiated from the control room by arming and depressing the loop initiation switch.

Upon receipt of the LOCA or manual initiation signal, the 'A' RHR pump is automatically started. The necessary valves required to isolate non-LPCI portions of the RHR system from the LPCI flow path are automatically closed. A signal to open the 'A' LPCI injection valve is initiated, however the valve is interlocked to prevent opening if reactor pressure is greater than the RHR piping design maximum pressure (determined by monitoring the ΔP across the injection valve) or if power is not available at the 4 kV bus to which the 'A' RHR pump motor is connected. When the 4 kV bus is energized and reactor pressure has decreased to below the RHR piping design maximum pressure, the injection valve will automatically open and allow low pressure coolant injection.

Each of the components in the LPCI flow path can also be manually operated from the control room by means of each component's individual control switch. Again the LPCI valve is interlocked to prevent opening if reactor pressure is greater than the RHR piping design maximum pressure.

The interlocks and control devices used in this manner are the same as those used for automatic operation.

7.3.1.1.1.4.4 LPCI Logic and Sequencing

The control scheme for LPCI operation is illustrated in drawings E11-1030-F-001, E11-1030-F-002, and E11-1030-F-003. The logic for BOP portions of the LPCI system is shown in drawing M-51FD.

Three variables are used for LPCI: reactor vessel low water level, drywell high pressure, and reactor vessel low pressure.

The LPCI initiation logic is a one-out-of-two-twice network using appropriately connected trip units from level and pressure sensors. The initiation signal is generated when:

a. Both level sensor trip units are tripped.

b. Four pressure sensor trip units are tripped (two high drywell pressure and two low reactor vessel pressure).

c. Either of two other combinations of one level sensor trip unit and two pressure sensor (one high drywell and one low reactor vessel) trip units are tripped.

LPCI operation can also be manually initiated.

Once an initiation signal is received by the RHR control circuitry, the signal is sealed-in until manually reset. The seal-in feature is shown in drawings E11-1030-F-001, E11-1030-F-002, and E11-1030-F-003.

The overall LPCI operating sequence following the receipt of an initiation signal is as follows:

a. If offsite ac power is available, the C and D RHR pumps start immediately, taking suction from the suppression pool. The other two pumps start after a 5 second delay to limit the loading of the power sources. If offsite ac power is lost, standby power sources become available, and all pumps start immediately.

b. Valves used in other RHR modes are automatically positioned so that the water pumped from the suppression pool is routed correctly.

c. The LPCI injection valves automatically open when the differential pressure across the valves decreases to less than a pre-established value.

d. When reactor vessel pressure has dropped to a value at which the RHR pumps are capable of injecting water into the reactor, water is delivered to the reactor vessel via four independent loops.

e. An open signal is applied to the RHR heat exchanger bypass valves for the first 3 minutes following LPCI initiation to ensure that full injection flow is available, then it is removed to permit the operator to manually throttle flow for other modes of operation.

f. The valves in the suction paths from the suppression pool are key-locked open and require no automatic action to line-up LPCI suction.

g. The valves at the primary containment penetration in the pump minimum flow recirculation return lines to the suppression pool and in the full flow test return line to the suppression pool are normally open. These valves can be repositioned only by a key-locked switch in the control room. The logic for these valves is shown in drawing M-51FD.

7.3.1.1.1.4.5 LPCI Bypasses and Interlocks

Two pressure transmitters are installed in each pump discharge pipeline to verify that the pumps are operating following an initiation signal. The pressure signal is used in the ADS to verify availability of low pressure core cooling. The pressure instruments are located upstream of the pump discharge check valves. Limit switches from the system suction valves are used to trip the RHR pump motors if a suction flow path is not established. The system pump motors are provided with overload protection. The overload relays maintain power on the motors as long as possible without harming the motors or jeopardizing the emergency power system.

The RHR pump motors and injection valves are provided with manual override controls that allow the operator to control the system following automatic initiation.

The valves that allow the diversion of water for suppression pool spray are automatically closed upon receipt of an LPCI initiation signal. The manual controls for these valves are interlocked so that opening the valves by manual action is not possible unless the reactor vessel injection valve in its respective RHR loop is closed or the LPCI initiation signal is not present. The valves that allow diversion of water for containment spray are normally closed. The manual controls for these valves are interlocked so that opening both valves in one drywell spray loop by manual action is not possible unless an LPCI initiation signal is present, the reactor vessel injection valve in its respective RHR loop is closed, and drywell pressure is high. The sensors used to monitor drywell pressure for LPCI initiation are also used in the drywell spray logic. The trip setting is selected to be as low as possible yet provide indication of abnormally high drywell pressure. The drywell pressure switches are arranged in a one-out-of-two logic arrangement as shown in drawings E11-1030-F-001, E11-1030-F-002, and E11-1030-F-003.

7.3.1.1.1.4.6 LPCI Redundancy and Diversity

The LPCI is redundant in that four separate loops are provided. Failure of any one loop still allows three pumps to supply water to the reactor.

The LPCI mode of operation is initiated by either reactor vessel low water level or primary containment high pressure coincident with low reactor vessel pressure. These two initiating signals are diverse indications of a LOCA. Diversity for LPCI is provided by the CS system.

7.3.1.1.1.4.7 LPCI Actuated Devices

The functional control arrangement for the RHR pumps is shown in drawings E11-1030-F-001, E11-1030-F-002, and E11-1030-F-003. The circuitry provides for detection of normal power available so that all pumps are automatically started in sequence. The operator can manually control the pumps from the control room, thus permitting the operator to use the pumps for other purposes such as containment cooling. Controls for the pumps are discussed in Section 7.3.1.1.1.4.5.

All automatic valves used in the LPCI function are equipped with remote manual test capability. The entire system can be operated from the control room. All MOVs are equipped with limit and

torque switches to turn off the motors when the valve reaches the limits of movement and to provide control room indication. Valves that have vessel and containment isolation requirements are described in Section 7.3.1.1.2. Overload protection is provided to valve motors in accordance with Section 8.1.6.1.19.

The RHR pump suction valves from the suppression pool are normally open. To reposition the valves, a key-lock switch must be turned in the control room. On receipt of an LPCI initiation signal, other RHR system valves are signaled to open or close, as required, even though they may normally be left in the proper position to ensure that the RHR pump discharge is correctly routed. Included in this set of valves are the valves that, if not closed, would permit the RHR system pumps to take suction from the reactor recirculation loops and pump water to the reactor during normal shutdown cooling operation.

A timer similar to that used in the LPCI system pump control circuitry cancels the LPCI open signal to the heat exchanger bypass valves after a 3 minute delay, which is time enough to permit satisfactory start of the LPCI system. The signal cancellation allows the operator to control the flow through the heat exchangers for other postaccident purposes. Cancelling the open signal does not cause the bypass valves to close.

A flow sensor on the discharge of each pump provides a signal to operate the minimum flow bypass valve in that loop. When the flow has been established above the value required to prevent pump overheating, the valves close and all flow is directed into the reactor.

7.3.1.1.1.4.8 LPCI Separation

Four separate logics located in separate panels and powered by four 125 V dc buses are used. Control power for pumps A through D is from the corresponding 125 V dc buses A through D. AC power for A through D pump motors is supplied from the corresponding A through D 4160 V buses.

A complete description of the physical independence between divisions is given in Section 7.1.2.2.

7.3.1.1.1.4.9 LPCI Testability

The LPCI mode of the RHR system has components that are not activated or tested during normal operation with an integrated testing procedure. These components are tested using manual test methods which allow for independent checking of individual system components. This testing includes verification of flow using the installed test piping such that the motors and pumps are operated. A system function test, including automatic actuation of the system, with verification that automatic valves in the injection flow path move to the correct position, is also performed. Associated sensors and circuits are monitored to verify proper operation. The frequency of these tests and the parameters to be verified are identified in the Technical Specifications.

The RHR system is capable of being tested during normal plant operation by an overlapping series of tests:

a. All sensors can be individually valved out-of-service and subjected to a test pressure. This verifies the operability of the sensors as well as the calibration range. The trip units mounted in the auxiliary equipment room can be calibrated individually by a calibration source with verification of setpoint by a digital readout located on the calibration module.

   Calibration and test controls for the sensors are located in the reactor enclosure. Calibration and test controls for the trip units are located in the auxiliary equipment

room. To gain access to the calibration points of each sensor, a cover plate must be removed. The control room operator is responsible for granting access to the calibration points. Only properly qualified plant personnel are granted access for testing or calibration adjustment.

In addition to the above tests, the operability of the sensors can be verified by cross-checking instrument readouts in the auxiliary equipment room at any time during operation.

b. Test jacks are provided to test the logic. Annunciation is provided in the control room whenever a test plug is inserted in a jack to indicate to the control room operator that the RHR system is in the test status. Operation of the test plug switches initiates LPCI. Injection into the reactor is prevented by an interlock, actuated only when the test plug is inserted, which prevents the opening of the LPCI discharge valve. After the RHR pump is tripped, the LPCI discharge valve can be opened to ensure its operability. The manual initiation switches can also be tested. This sequence of tests ensures that all components are tested. A logic test of one LPCI loop does not interfere with the operation of the other LPCI loops if required by an initiation signal.

c. Functional performance of LPCI components can be verified by pumping water to the suppression pool through the full flow test line. If a LOCA were to occur during this mode of operation, the valve line-up would automatically be changed so that water can be pumped to the reactor.

During the above testing, LPCI operation can be observed in the control room by panel lamps, indicators, recorders, annunciators, and computer printout.

7.3.1.1.1.4.10 LPCI Environmental Considerations

The only control components pertinent to LPCI operation that are located inside the drywell are those controlling the air-operated testable check valves on the injection lines. Other equipment, located outside the primary containment, is selected in consideration of the normal and accident environments in which it must operate. The environmental conditions for the areas where the equipment is located are provided in Section 3.11.

7.3.1.1.1.4.11 LPCI Operational Considerations

7.3.1.1.1.4.11.1 LPCI General Information

LPCI is a mode of the RHR system. The pumps, valves, piping, etc., used for LPCI are also used for other modes of the RHR system. The LPCI mode is not required for normal operation. When it is required for accident conditions, it is initiated automatically by the circuitry described in this section. No operator action is required for at least 10 minutes following initiation. The operator may manually control the RHR system after a 3 minute delay (for the RHR heat exchanger bypass valve open command timers) to use its capabilities in the other modes of the RHR system, provided the core is being cooled by other portions of the ECCS.

7.3.1.1.1.4.11.2 LPCI Reactor Operator Information

Sufficient temperature, flow, pressure, and valve position indications are available in the control room for the operator to accurately assess the LPCI system operation. A detection system continuously confirms the integrity of the injection line piping to the reactor vessel. Differential

pressure sensors sense the pressure differential between injection lines of RHR A and C loops and between the B and D loops. If the piping is sound, the pressure differential is very small between these lines. If integrity is lost, an increase in differential pressure initiates an alarm in the control room. Valves have indications of fully open, intermediate, and fully closed positions. Pumps have indications for pump running and pump stopped. Alarm and indication devices are shown in drawings M-51, E11-1030-F-001, E11-1030-F-002, and E11-1030-F-003.

7.3.1.1.1.4.11.3 LPCI Setpoints

See Chapter 16 for safety setpoints.

7.3.1.1.1.5 Manual Shutdown of ECCS Pumps

Design provisions in the ECCS allow the operator to manually shut down the ECCS pumps after they have been automatically started.

The HPCI pump-turbine driver can be stopped after starting automatically, and in the presence of an automatic signal, by: (1) closing the system supply isolation valves or (2) pressing the isolation push button, which closes the steam supply valves, the pump discharge valve, and the pump suction valve (from the suppression pool) and trips the HPCI turbine.

Provisions in the core spray and RHR systems allow the operator to stop any of the pumps after an automatic start signal. There are also provisions in both systems to allow the operator to close the injection valves after they have been signalled open. Operator action is required to reopen the injection valve or to restart the stopped pump as long as the original accident signal is still present and has not been reset.

7.3.1.1.2 Primary Containment and Reactor Vessel Isolation Control System - Instrumentation and Controls

7.3.1.1.2.1 PCRVICS Identification

The PCRVICS includes the instrument channels, trip logics, and actuation circuits that activate valve closing mechanisms associated with the valves that, when closed, effect isolation of the primary containment or reactor vessel or both. The following description of the PCRVICS instrument channels and logic circuits are applicable to the Nuclear Steam Supply Shutoff System, and the Plant Leak Detection System unless noted otherwise.

PCRVICS provides initiation to the following systems:

a. SGTS (Section 7.3.1.1.7)

b. REIS and HVAC support system (Section 7.3.1.1.9)

The purpose of the system is to prevent the gross release of radioactive materials to the environment from the fuel or a break in the RCPB. The PCRVICS automatically isolates the appropriate pipelines that penetrate the primary containment whenever monitored variables exceed preselected setpoints. All other pipelines that penetrate primary containment are manually isolated. The power generation objective of this system is to prevent spurious closure of isolation valves as a result of single failure. A list of valves closed by PCRVICS is provided in Table 6.2-17.

7.3.1.1.2.2 PCRVICS Power Sources

Power for the system instrument channels except for the Leak Detection System (Refer to Section 7.6.1.3.2) are supplied from the two nonessential electrical buses that supply the RPS trip systems.

Power for the isolation logics of the isolation control system and MSIVs are supplied from the two nonessential electrical buses that supply the RPS trip systems. Each bus has its own inverter and can receive alternate power from an alternate power source. Each bus can be supplied from only one of its power sources at any given time. Additional details of these power sources are given in Section 7.2.1.1.3.

The MSIV electrical control power is supplied as follows:

	Inboard (Div 1)	Outboard (Div 2)
Solenoid 1	RPS Bus A	RPS Bus B
Solenoid 2	125 V dc Bus A	125 V dc Bus B

A pressurized pneumatic supply is required for motive power to open the MSIVs. The power to close these valves is provided by pneumatic and spring force .

Motor-operated isolation valves and solenoid pilot valves for air-operated isolation valves receive power from essential emergency buses. Power for the operation of any two valves mounted in series is supplied from independent essential sources.

Direct solenoid-operated main steam, RHR and reactor water sample valves are energized open against spring pressure by essential 120 vac instrument power. Spring pressure provides closure force.

7.3.1.1.2.3 PCRVICS Equipment Design

The isolation valve arrangement for pipelines that penetrate containment is discussed in Section 6.2.4. The general valve arrangements are as follows:

a. Pipelines that penetrate primary containment and communicate directly with the reactor vessel have two isolation valves: one inside primary containment and one outside primary containment.

b. Pipelines that connect directly to the containment atmosphere and penetrate the primary containment have two valves outside the containment.

The MSIV controls include pneumatic piping and an accumulator for the AOVs as the isolation motive power source in addition to the springs. Pressure, temperature, and water level sensors are mounted on instrument racks or locally in either the reactor enclosure or the turbine enclosure. Valve position switches are mounted on MOVs and AOVs. Switches are encased to protect them from environmental conditions. All signals transmitted to the control room are electrical (no pipe from the nuclear system penetrates the control room). The sensor cables and logic power supply cables are routed to cabinets in the auxiliary equipment room, where the system logic is located.

All instrument line penetrations of the containment are equipped with automatic isolation valves. These excess flow check valves automatically isolate due to high flow if there is a break in the instrument line downstream of the valve.

7.3.1.1.2.4 PCRVICS Initiating Isolation Signals

The isolation trip settings of primary containment and reactor vessel isolation control system are listed in Chapter 16. The FCDs (drawings B21-1030-F-002, B21-1030-F-002, B21-1030-F-003,

B21-1030-F-004, B21-1030-F-005, E11-1030-F-001, E11-1030-F-002, E11-1030-F-003, E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, E41-1030-F-009, E51-1030-F-004, E51-1030-F-005, E51-1030-F-006, E51-1030-F-007, E51-1030-F-008, E51-1030-F-009, and G31-1020-F-001) and the P&IDs (drawings M-41, M-42, M-44, M-49, M-51, and M-55) illustrate how these signals initiate closure of isolation valves. Additional logic is shown in drawings M-51FD, M-52FD, M-55FD, M-57FD, M-59FD, and M-61FD.

7.3.1.1.2.4.1 PCRVICS - Reactor Vessel Low Water Level

7.3.1.1.2.4.1.1 Subsystem Identification

A low water level in the reactor vessel could indicate that reactor coolant is being lost through a breach in the RCPB and that the core is in danger of becoming overheated as the reactor coolant inventory diminishes.

Three reactor vessel low water level isolation trip settings are used to complete the isolation of the primary containment and the reactor vessel.

The first (and highest) low water level isolation setting (level 3) is the same water level setting as the RPS scram setting. This setting initiates selected isolations at the earliest indication of a possible breach in the RCPB, yet the setting is far enough below normal operational levels to prevent spurious isolation. RHR shutdown cooling piping is isolated when reactor vessel low water level falls to level 3.

The second (middle) reactor vessel low water level isolation setting (level 2) is the same water level setting at which the RCIC and HPCI systems are initiated. The setting selected is low enough to allow the removal of heat from the reactor for a predetermined time following the scram and high enough to complete isolation in time for the operation of ECCS if there is a large break in the RCPB. The pipelines that are isolated when the reactor vessel water level falls to this second setting are listed below.

a. RWCU

b. CAC including H_2O_2 sample lines

c. TIP

d. Main steam sample

e. HPCI pump flush (isolation signal generated by the HPCI system logic circuits)

f. Deleted

g. Drywell sump drains

h. Suppression pool cleanup

i. Drywell radiation sample

j. Recirculation loop sample

The third (and lowest) of the reactor vessel low water level isolation settings (level 1) is the water level setting used to initiate RHR, core spray, and ADS, and to start the diesel generators. The

pipelines that are isolated when the reactor vessel water level falls to this third setting are the main steam, main steam line drain, containment instrument gas, RHR heat exchanger vent valves (Unit 2 only), suppression pool spray, drywell chilled water, and core spray pump test and flush.

Reactor vessel low water level signals used by NSSS and RPS are initiated from eight differential pressure sensors, four sensors for the level 1 and level 2 trip and four sensors for the level 3 trip, as shown in drawing M-42. They sense the difference between the pressure caused by a constant reference leg of water and the pressure caused by the actual water level in the vessel.

Four of the eight sensors are used in the measurement of level 1 and 2. Signals from these sensors are used by NSSS only. Each sensor is connected to different reference leg. Sensors A and B share a common variable leg. Sensors C and D share a common variable leg. The remaining four sensors are used in the measurement of level 3 and are used by both NSSS and RPS. Each of these sensors is connected to different reference and variable legs. The variable legs are different from those used by the level 1 and 2 sensors. Refer to Figure 7.3-26 for a diagram of level sensor connections. This arrangement ensures that no single physical event can prevent isolation, if required.

7.3.1.1.2.4.2 PCRVICS

7.3.1.1.2.4.3 PCRVICS - Main Steam Line Temperature in Outboard MSIV Room and Turbine Enclosure Main Steam Tunnel High Ambient Temperature

High ambient temperature in the areas in which the main steam lines are located outside of the primary containment could indicate a leak in a main steam line. The automatic closure of various valves prevents the excessive loss of reactor coolant and the release of a significant amount of radioactive material from the RCPB. Turbine Enclosure Main Steam Tunnel High Ambient Temperature will alarm and subsequently be monitored by Operations and manual action will be taken as needed per T.S. 3/4.7.9.

See Section 7.6.1.3.3.2.2 for a detailed description of this system.

7.3.1.1.2.4.4 PCRVICS - Main Steam Line High Flow

Main steam line high flow could indicate a breach in a main steam line. Automatic closure of isolation valves prevents excessive loss of reactor coolant and release of significant amounts of radioactive material from the RCPB.

The main steam line high flow trip setting selected is high enough to permit isolation of one main steam line for testing at rated power without causing an automatic isolation of the other steam lines, yet low enough to permit detection of a steam line break.

High flow in each main steam line is sensed by four differential pressure sensors that sense the pressure difference across the flow element in that line.

Refer to Section 7.6.1.3.3.2.3 for a detailed description of this system.

7.3.1.1.2.4.5 PCRVICS - Main Steam Line Low Pressure

7.3.1.1.2.4.5.1 Subsystem Identification

Low steam pressure at the turbine inlet while the reactor is operating could indicate a malfunction of the steam pressure controller in which the turbine control valves or turbine bypass valves

become fully open and cause rapid depressurization of the reactor vessel. From part-load operating conditions, the rate of decrease of saturation temperature could exceed the allowable rate of change of vessel temperature. A rapid depressurization of the reactor vessel while the reactor is near full power could result in undesirable differential pressures across the channels around some fuel bundles of sufficient magnitude to cause mechanical deformation of channel walls. Such depressurizations, without adequate preventive action, could require thorough vessel analysis or core inspection before returning the reactor to power operation.

The steam pressure at the turbine inlet is monitored to forestall these effects and thus preclude the necessity of requiring analysis and/or inspection.

The low steam pressure isolation setting selected is far enough below normal turbine inlet pressures to prevent spurious isolation, yet high enough to provide timely detection of a pressure controller malfunction. Although this isolation function is not required to satisfy any of the safety design bases for this system, the discussion is included to complete the listing of isolation functions.

Main steam line low pressure is monitored by four pressure sensors that sense pressure downstream of the outboard MSIVs. The sensing point is located at the header that connects the four steam lines upstream to the turbine stop valves. Each sensor provides a signal to one isolation logic.

7.3.1.1.2.4.5.2 Subsystem Power Supplies

See Figures 7.3-1 and 7.3-2.

Logic channels A and C and one pilot solenoid of the inboard (Division 1) MSIVs are supplied from RPS bus A 120 V ac. The second pilot solenoid of the inboard MSIV is supplied from a Division I, Class 1E 125 V dc station battery.

Logic channels B and D and one pilot solenoid of the outboard (Division 2) MSIVs are supplied from RPS bus B 120 V ac. The second pilot solenoid of the outboard MSIV is supplied from a Division II, Class 1E 125 V dc station battery.

7.3.1.1.2.4.5.3 Subsystem Initiating Circuits

Four pressure channels, one for each main steam line, monitor main steam line pressure. Each channel is associated with one of four trip logics. The locations of the pressure sensors provide the earliest practicable detection of low main steam line pressure.

7.3.1.1.2.4.5.4 Subsystem Logic and Sequencing

When a predetermined decrease in main steam line pressure is detected, trip signals are transmitted to the PCRVICS. The PCRVICS initiates closure of all main steam line isolation drain valves.

Four instrumentation channels are provided to ensure protective action when required and to prevent inadvertent isolation resulting from instrumentation malfunctions. The output trip signal of each instrumentation channel initiates a trip logic. The output trip signals of the trip logics are combined in one-out-of-two-twice configuration for the MSIVs and two-out-of-two configuration for the drain valves as shown in Figures 7.3-1 and 7.3-2. Trip logics A or C and B or D are required to initiate main steam line isolation. Trip logics A and B or C and D are required to initiate main steam line drain isolation. Failure of any one trip logic does not result in inadvertent action.

7.3.1.1.2.4.5.5 Subsystem Redundancy and Diversity

Redundancy of trip initiation signals for low pressure is provided by four pressure sensors, one for each main steam line. Each pressure sensor is associated with one of four trip logics. Two pressure trip channels are supplied from one 120 V ac bus A and the other two are supplied from 120 V ac bus B.

7.3.1.1.2.4.5.6 Subsystem Bypasses and Interlocks

The main steam line low pressure trip is bypassed by the reactor mode switch in the shutdown, refuel, and startup modes of reactor operation. In the run mode, the low pressure trip function is operative.

There are no interlocks to other systems for main steam line low pressure trip signals.

7.3.1.1.2.4.5.7 Subsystem Testability

Testability is discussed in Sections 7.3.2.2.2.3.1.9 and 7.3.2.2.2.3.1.10.

7.3.1.1.2.4.5.8 Environmental Considerations

This subsystem is designed and has been qualified to meet the environmental conditions indicated in Section 3.11. The seismic qualification of this subsystem in discussed in Section 7.3.2.2.2.3.1.5.

7.3.1.1.2.4.6 PCRVICS - Drywell High Pressure

7.3.1.1.2.4.6.1 Subsystem Identification

High pressure in the drywell could indicate a breach of the RCPB inside the drywell. The automatic closure of various valves prevents the release of significant amounts of radioactive material from the primary containment.

The drywell high pressure isolation setting selected is as low as possible without inducing spurious isolation trips. Based on a BWROG generic analysis, the containment isolation pressure setpoint is based on an analytic limit of approximately 2 psig (drywell pressure).

Fluctuations in the atmospheric barometric pressure as well as heat inputs (from such sources as pumps) during normal operation can result in containment pressure increases on the order of 1 psi. Consequently, the analytic limit of 2 psig provides a 1 psi margin above the maximum expected operating pressure. The 1 psi margin to isolation has proved to be a suitable value to minimize the possibility of spurious containment isolation. At the same time, it is such a low value (particularly in view of the small drywell volume) that it provides a sensitive and positive means of detecting and protecting against breaks and leaks in the RCS.

7.3.1.1.2.4.6.2 Subsystem Power Supplies

Logic channels A and C and one pilot solenoid of the inboard (Division 1) MSIVs are supplied from RPS bus A 120 V ac. The second pilot solenoid of the inboard MSIV is supplied from a Division I, Class 1E 125 V dc station battery.

Logic channels B and D and one pilot solenoid of the outboard (Division 2) MSIVs are supplied from RPS bus B 120 V ac. The second pilot solenoid of the outboard MSIV is supplied from a Division II, Class 1E 125 V dc station battery.

See Figures 7.3-1 and 7.3-2.

7.3.1.1.2.4.6.3 Subsystem Initiating Circuits

Drywell pressure is monitored by four pressure sensors that are mounted on instrument racks outside the primary containment. Instrument sensing lines that terminate in the reactor enclosure connect the sensors with the drywell interior. Redundant sensors are physically separated and electrically connected to the isolation control systems so that no single event prevents isolation because of primary containment high pressure.

7.3.1.1.2.4.6.4 Subsystem Logic and Sequencing

When a predetermined increase in drywell pressure is detected, trip signals are transmitted to the PCRVICS for generation of isolation signals. The following lines are isolated for a high drywell pressure condition.

a. Drywell and drywell sump drain discharge toradwaste

b. Containment purge and vent

c. TIP system

d. Containment atmosphere sampling

e. Containment instrument gas

f. HPCI pump flush (isolation signal generated by the HPCI system logic circuits)

g. HPCI vacuum relief (isolation signal generated by the HPCI system logic circuits if low steam pressure condition exists)

h. RCIC vacuum relief (isolation signal generated by the RCIC system logic circuits if low steam pressure condition exists)

i. Suppression pool cleanup

j. Drywell radiation sample

k. Drywell chilled water

l. Reactor enclosure cooling water

Four instrumentation channels are provided to ensure protective action when required and to prevent inadvertent isolation resulting from instrumentation malfunctions. The output trip signals of the instrumentation channels are combined in two-out-of-two logics. Instrumentation channels A and B or C and D are required to initiate isolation of either inboard or outboard valves, respectively. Thus, failure of any one channel does not result in inadvertent action.

7.3.1.1.2.4.6.5 Subsystem Redundancy and Diversity

Redundancy of trip initiation signals for drywell high pressure is provided by pressure switches installed at different locations around the drywell. Wiring from redundant instruments is separated.

Each pressure switch is associated with one logic. Two pressure sensors are supplied from RPS bus A, and the other two are supplied from RPS bus B.

Diversity of trip initiation signals for line breaks inside the primary containment is provided by drywell high pressure and reactor low water level. An increase in drywell pressure or a decrease in reactor water level initiates isolation.

7.3.1.1.2.4.6.6 Subsystem Bypasses and Interlocks

There are no bypasses or interlocks for drywell high pressure trip signals.

7.3.1.1.2.4.6.7 Subsystem Testability

Testability is discussed in Section 7.3.1.1.2.11.

7.3.1.1.2.4.6.8 Environmental Considerations

This subsystem is designed and has been qualified to meet the environmental conditions indicated in Section 3.11. In addition, this subsystem has been seismically qualified as described in Section 3.10.

7.3.1.1.2.4.7 PCRVICS - Reactor Enclosure Ventilation Exhaust Radiation Monitoring System - Instrumentation and Controls

The purpose of this system is to indicate when excessive amounts of radioactivity exist in the reactor enclosure ventilation exhaust and to provide signals for initiation of appropriate action so that the release of radioactive gases to the environment is limited to levels below the guidelines of published regulations. The radiation monitoring system is described in Section 11.5. The system consists of four independent channels monitoring the reactor zone.

See Section 7.6.1.1.2 for a detailed description of this system.

7.3.1.1.2.4.8 PCRVICS - Refueling Area Ventilation Exhaust Radiation Monitoring System - Instrumentation and Controls

The purpose of this system is to indicate when excessive amounts of radioactivity exist in the refueling area ventilation exhaust and to provide signals for initiation of appropriate action so that the release of radioactive gases to the environment is limited to levels below the guidelines of published regulations. The radiation monitoring system is described in Section 11.5. The system consists of independent channels, monitoring the refueling area.

See Section 7.6.1.1.3 for a detailed description of this system.

7.3.1.1.2.4.9 PCRVICS - RWCU System High Differential Flow

High differential flow in the RWCU system could indicate a breach of the RCPB in the cleanup system. The flow at the inlet to the system (suction from "B" recirculation line and bottom head drain) is compared with the flow at the outlets of the system (discharge to feedwater, main condenser, radwaste and CST). High differential flow initiates isolation of the cleanup system.

See Section 7.6.1.3.3.4.2 for a detailed description of this system.

7.3.1.1.2.4.10 PCRVICS - RWCU System Area High Temperature and Differential Temperature

High temperature in the equipment room areas of the RWCU system could indicate a breach in the RCPB in the cleanup system. High ambient temperature and high differential temperature in the equipment area ventilation system initiates isolation of the RWCU system.

See Section 7.6.1.3.3.4.3 for a detailed description of this system.

7.3.1.1.2.4.11 PCRVICS - Main Condenser Low Vacuum Trip

7.3.1.1.2.4.11.1 Subsystem Identification

A main steam line isolation valve trip from a low condenser vacuum instrumentation system is provided.

The main turbine condenser low vacuum signal could indicate a leak in the condenser. Initiation of automatic closure of selected valves will prevent excessive loss of reactor coolant and the release of significant amounts of radioactive material from the RCPB.

The turbine condenser low vacuum trip setting selected is far enough above the normal operating vacuum to prevent spurious isolation, yet low enough to provide an isolation signal before the rupture of the condenser and subsequent loss of reactor coolant and release of radioactive material. There are four main condenser sensors that provide an isolation trip signal to the main steam line isolation valve logic channels.

7.3.1.1.2.4.11.2 Subsystem Power Supplies

See Figures 7.3-1 and 7.3-2.

7.3.1.1.2.4.11.3 Subsystem Initiating Circuits

Four vacuum sensors monitor the main condenser vacuum. Each vacuum sensor is associated with one of four separate trip logics. Four vacuum sensors are installed to provide the earliest practicable detection of a main condenser leak.

7.3.1.1.2.4.11.4 Subsystem Logic and Sequencing

When a predetermined decrease in main condenser vacuum is detected, trip signals are transmitted to the PCRVICS. The PCRVICS initiates closure of all main steam line isolation and drain valves.

Four vacuum sensors with associated trip units are provided to ensure protective action when required and to prevent inadvertent isolation resulting from instrumentation malfunctions. The output signals of the trip logics are combined in one-out-of-two-twice logic for the MSIVs and two-out-of-two logics for the main steam line drain valves. Trip logics A or C and B or D are required to initiate main steam line isolation. Trip logics A and B or C and D are required to initiate main steam line drain isolation. Failure of any one trip logic does not result in inadvertent isolation action.

7.3.1.1.2.4.11.5 Subsystem Redundancy and Diversity

Redundancy of trip initiation signals for low condenser vacuum is provided by four vacuum sensors. Each pressure signal is associated with one of four logics. Two vacuum sensors are supplied by one power source, and the other two are supplied from a different power source.

Diversity of trip initiation signals is not required or provided.

7.3.1.1.2.4.11.6 Subsystem Bypasses and Interlocks

Main condenser low vacuum trip can be bypassed manually when the turbine stop valve is less than 90% open.

There are no interlocks to other systems from the main condenser low vacuum trip signals.

7.3.1.1.2.4.11.7 Subsystem Testability

Testability is discussed in Section 7.3.2.2.2.3.1.10.

7.3.1.1.2.4.11.8 Environmental Considerations

This subsystem is designed and has been qualified to meet the environmental conditions indicated in Section 3.11. The seismic qualification for this subsystem is discussed in Section 7.3.2.2.2.3.1.5.

7.3.1.1.2.4.12 PCRVICS - HPCI System Isolation Signals

The HPCI system is constantly monitored for leaks by the following types of monitoring circuits:

a. Equipment area and pipe chase area ambient and differential temperature monitoring

b. HPCI steam flow rate monitoring

c. HPCI turbine exhaust diaphragm pressure monitoring

When limiting conditions are attained an HPCI autoisolation signal is initiated and an annunciator activated in the control room.

Refer to Section 7.6.1.3.3.5 for a description of the leak detection functions of these subsystems.

HPCI area temperatures are monitored by instrumentation of the LDS. Monitored temperatures include the following.

a. HPCI pipe chase area ambient temperatures

b. HPCI emergency area cooler ambient temperature

c. HPCI area vent air differential temperature.

The common HPCI/RHR steam line connecting the reactor vessel main steam line and the HPCI turbine is monitored by differential pressure sensors which signal a high steam flow rate condition.

The HPCI turbine exhaust diaphragm is monitored by pressure sensors which signal a high pressure condition.

For a detailed discussion see Section 7.6.1.3.3.5.5.

7.3.1.1.2.4.13 PCRVICS - RCIC System Isolation Signals

The RCIC system is constantly monitored for leaks by the following types of monitoring circuits:

a. Equipment area and pipe chase area ambient and differential temperature monitoring

b. RCIC steam flow rate monitoring

c. RCIC steam line pressure monitoring

d. RCIC turbine exhaust diaphragm pressure monitoring

When limiting conditions are attained an RCIC autoisolation signal is initiated and an annunciator activated in the control room.

Refer to Section 7.6.1.3.3.3 for a description of the leak detection functions of these subsystems.

RCIC area temperatures are monitored by instrumentation of the LDS. Monitored temperatures include the following:

a. RCIC pipe chase area temperatures

b. RCIC emergency area cooler ambient temperature

c. RCIC area vent air differential temperature

The RCIC steam line connecting the reactor vessel main steam line and the RCIC turbine is monitored by differential pressure sensors which signal a high steam flow rate condition.

The RCIC steam line connecting the nuclear boiler and the RCIC turbine is monitored by two pressure sensors which signal a low steam supply pressure condition.

The RCIC turbine exhaust diaphragm is monitored by pressure sensors which signal a high pressure condition.

For a detailed discussion see Section 7.6.1.3.3.3.6.

7.3.1.1.2.5 PCRVICS Instrumentation

Sensors providing inputs to the PCRVICS are not used for the automatic control of the process system, thereby achieving separation of the protection and process systems. Redundant channels are physically separated and electrically independent to reduce the probability that a single physical event would prevent isolation. Redundant channels for each monitored variable provide inputs to different isolation trip systems. The functions of the sensors in the isolation control system are shown in Figures 7.3-1 and 7.3-2. Table 7.3-5 lists instrument characteristics.

7.3.1.1.2.6 PCRVICS Initiating Circuits

Solenoid valves which are controlled by the PCRVICS for automatic isolation generally utilize actuator solenoids which are energized during normal service. The logic circuitry signalling automatic isolation is generally arranged such that when a monitored parameter reaches its trip setpoint, the associated trip logic contact opens. When the proper combination of logic trips occur, the actuator trip relay de-energizes, de-energizing the valve actuator solenoid. The system also has system level manual initiation switches that isolate all automatically controlled isolation valves. This general arrangement is applicable to the following valve discussions.

The MSIV actuators each have two actuator solenoids. For automatic valve closure, both solenoids must be de-energized. Each solenoid receives inputs from two separate trip logics, either of which can de-energize the solenoid.

Four RPS instrument channels are provided for each monitored parameter used in the MSIV trip logic. The redundant instrument channels are independent and separate. A and C trip logic relays control one solenoid in each of the inboard and outboard MSIVs on each main steam line. Channels B and D trip logic relays control the other solenoid in the inboard and outboard MSIVs.

Closure of the inboard and outboard main steam line drain isolation MOVs is initiated by the MSIV trip logic relays, utilizing two-out-of-two logic. Logic relays A and B initiate closure of the inboard isolation valve and relays C and D initiate closure of the outboard isolation valve.

Closure of the inboard and outboard RHR discharge to radwaste isolation valves and RHR process sampling isolation valves is initiated by low reactor vessel water level and high drywell pressure signals, utilizing two-out-of-two logic. Logic trip A closes the inboard valves, and logic trip B closes the outboard valves.

Closure of the inboard RHR shutdown cooling suction valves, as well as the RHR shutdown cooling injection-testable check valve and bypass valve is initiated by logic trip A. Closure of the outboard RHR shutdown cooling suction, and RHR shutdown cooling injection outboard throttling MOVs is initiated by logic trip B. Tripping requires two-out-of-two logic for low reactor vessel water level signal or the one-out-of-two logic for reactor high pressure (low pressure permissive to open) signals.

Closure of outboard drywell chiller water isolation valves HV-87-120A&B, 121A&B, 220A&B and 221A&B, and the inboard drywell chilled water isolation valves is initiated by any one of the following conditions in a two-out-of-two logic: reactor level below level 1 trip; high drywell pressure. Outboard drywell chilled water isolation valves HV-87-124A&B, 125A&B, 224A&B, and 225A&B do not receive isolation signals. These valves are normally closed in accordance with the Technical Specifications and Technical Requirements Manual.

Closure of the inboard and outboard reactor water sample AOVs and reactor steam sample AOVs is initiated by low reactor vessel water level utilizing two-out-of-two logic. Logic trip A closes the inboard valves and logic trip B closes the outboard valves.

Retraction of the TIP drives is initiated by low reactor vessel water level 2 and high drywell pressure in a two-out-of-two logic. Logic trip A initiates retraction of the TIP system drives.

Closure of the primary containment purge valves is initiated by any one of the following conditions in a two-out-of-two logic: reactor level below level 2; high drywell pressure; high radiation in the reactor enclosure ventilation exhaust duct; high radiation in the refueling floor ventilation exhaust duct.

Closure of the inboard and outboard RWCU isolation MOVs is initiated by low reactor vessel water level utilizing two-out-of-two logic or by high area temperature or high differential RWCU flow. Logic trip A closes the inboard valve and logic trip B closes the outboard valves.

Closure of the inboard PCIG suction valve is initiated by any one of the following conditions in a two-out-of-two logic: Reactor level below level 1 trip; high drywell pressure; high radiation in the reactor enclosure ventilation exhaust duct.

Closure of the primary containment atmosphere sample isolation valves and the post-LOCA hydrogen recombiner isolation valves is initiated by any one of the following conditions: Reactor level below level 2 trip; high drywell pressure; high radiation in the reactor enclosure ventilation exhaust duct; high radiation in the refueling floor ventilation exhaust duct.

Closure of outboard PCIG isolation valves not on ADS gas supply lines is initiated by any one of the following conditions in a two-out-of-two logic: Reactor level below level 1 trip; high drywell pressure; high radiation in the reactor enclosure ventilation exhaust duct.

Closure of the RHR suppression pool spray line, the core spray pump test and flush line, and the RHR heat exchanger vent valve discharge lines (Unit 2 only) is initiated by high drywell pressure and low reactor vessel pressure or low reactor vessel water level in a two-out-of-two logic.

Closure of the suppression pool cleanup pump suction valves is initiated by high drywell pressure or low reactor vessel water level in a two-out-of-two logic. The HPCI system logic circuits also initiate closure of the HPCI Pump Flush valve for high drywell pressure or low reactor vessel water level in a one-out-of two-twice logic.

Closure of the drywell equipment drain sump and floor drain sump isolation valves is initiated by any one of the following conditions in a two-out-of-two logic: reactor level below level 2; high drywell pressure.

The circuitry controlling isolation of the HPCI and RCIC systems differs from the general arrangement of the systems previously discussed in that the logic trip relays must be energized to initiate valve isolation.

The sensors which monitor leakage in the HPCI system and the common HPCI/RHR steam line and associated logic circuitry are discussed in subsections 7.3.1.1.2.4.12 and 7.6.1.3.3.5. Closure of the outboard HPCI steam supply isolation MOV is controlled by logic trip B (division 2) and the inboard steam supply isolation MOV by logic trip D (division 4).

The sensors and logic circuits which monitor leakage in the RCIC system and signal the automatic isolation logic circuitry are discussed in Sections 7.3.1.1.2.4.13 and 7.6.1.3.3.3. Closure of the outboard RCIC steam supply line isolation and steam line warm-up isolation MOVs is controlled by logic trip A and the inboard steam supply line isolation MOV by logic trip C.

7.3.1.1.2.7 PCRVICS Bypasses and Interlocks

An automatic bypass of the main steam line low pressure signal is effected in all modes of operation except run mode (Section 7.3.1.1.2.4.5.6). The low condenser vacuum trip can be manually bypassed when the turbine stop valves are less than 90% open to allow the condenser vacuum to be established.

Key locked switches in the control room provide bypass of isolation signals to the CAC and PCIG containment isolation valves which may be bypassed. Any time a bypass switch is moved to a position that would cause an isolation signal bypass, this condition is annunciated.

Interlocks initiate the SGTS, isolate the reactor building ventilation system, and trip the drywell purge valves and purge fan units. There are no interlocks involved in manual operation of the PCRVICS.

7.3.1.1.2.8 PCRVICS Redundancy and Diversity

7.3.1.1.2.8.1 Main Steam Lines

Redundancy is provided by instruments monitoring each essential variable as follows:

a. Four differential pressure transmitters and associated switches, one set in each of four trip logics, monitor low reactor vessel level.

b. Left blank intentionally.

c. Sixteen differential pressure transmitters and associated switches, one set of four in each of four trip logics, monitor high steam line flow.

d. Thirty-six temperature sensors and associated switches, one in each of the four trip logics, monitor high temperature along the main steam line in the Outboard MSIV room. Eight sets in each of the four alarm logics, monitor high temperature along the main steam line in the turbine building main steam tunnel.

e. Four pressure transmitters and associated switches, one set in each of four trip logics, monitor low pressure in the main steam lines.

f. Four pressure transmitters and associated switches, one set in each of four trip logics, monitor low condenser vacuum.

Diversity in main steam line monitoring is provided by main steam line high flow and low reactor vessel level, for the gross release of RCPB fluid.

7.3.1.1.2.8.2 RWCU

Redundancy is provided by instruments monitoring each essential variable as follows:

a. Four differential pressure transmitters and associated switches, one set of two in each of two trip logics, monitor low reactor vessel level.

b. Two instrument channels, one in each of two trip logics, monitor differential flow in the RWCU system.

c. Two instrument channels, one in each of two trip logics, monitor high ambient and differential temperature in the area of the RWCU system.

Diversity in RWCU system monitoring is provided by differential flow, and high ambient or differential temperature. Low reactor vessel level monitoring provides additional diversity for gross release of RCPB fluid.

7.3.1.1.2.8.3 RHR

Redundancy is provided by instruments monitoring each essential variable as follows:

a. Four differential pressure transmitters and associated switches, one set of two in each of two trip logics, monitor low reactor vessel level.

b. Four pressure transmitters and associated switches, one set of two in each two trip logics, monitor high drywell pressure.

Diversity in RHR system monitoring is provided by low reactor vessel level and high drywell pressure.

7.3.1.1.2.8.4 HPCI

Redundancy is provided by instruments monitoring each essential variable as follows:

a. Two instrument channels, one in each of two trip logics, monitor high temperature in HPCI equipment area and in the vicinity of the steam line.

b. Two differential pressure transmitters and associated switches, one set in each of two trip logics, monitor high steam line flow.

c. Four pressure transmitters and associated switches, two sets in each of two trip logics, monitor high turbine diaphragm exhaust pressure.

d. Four pressure transmitters and associated switches, two sets in each of two trip logics, monitor low steam supply pressure.

e. Four pressure transmitters and associated switches, two sets in each of two trip logics, monitor high drywell pressure.

Diversity in HPCI monitoring is provided as follows: the steam lines by area and steam line space temperature; the vacuum relief line by high drywell pressure, and low reactor pressure.

7.3.1.1.2.8.5 RCIC

Redundancy is provided by instruments monitoring each essential variable as follows:

a. Two instrument channels, one in each of two trip logics, monitor high temperature in RCIC equipment area and in the vicinity of the steam line.

b. Two differential pressure transmitters and associated switches, one set in each of two trip logics, monitor high steam line flow.

c. Four differential pressure transmitters and associated switches, two sets in each of two trip logics, monitor high turbine exhaust diaphragm pressure.

d. Four pressure transmitters and associated switches, two sets in each of two trip logics, monitor low reactor pressure.

e. Four pressure transmitters and associated switches, two sets in each of two trip logics monitor high drywell pressure.

Diversity in RCIC monitoring is provided as follows: the steam lines by area and steam line space temperature; the vacuum relief line by high drywell pressure, and low reactor pressure.

7.3.1.1.2.8.6 Core Spray

There are no core spray isolation signals.

7.3.1.1.2.8.7 Containment Atmospheric Control System

Redundancy is provided by instruments monitoring each essential variable as follows:

a. Four differential pressure transmitters and associated switches, one set of two in each of two trip logics, monitor low RPV water level.

b. Four pressure transmitters and associated switches, one set of two in each of two trip logics, monitor high drywell pressure.

c. Four radiation monitors, two in each of two trip logics, monitor high refueling floor exhaust duct radiation.

d. Four radiation monitors, two in each of two trip logics, monitor high reactor building exhaust duct radiation.

Diversity in CAC system is provided by RPV water level, and drywell pressure.

7.3.1.1.2.8.8 Containment Instrument Gas

Redundancy is provided by instruments monitoring each essential variable as follows:

a. Four radiation monitors, two in each of two trip logics, monitor high reactor enclosure radiation.

b. Four differential pressure transmitters and associated switches, two sets in each of two trip logics, monitor low RPV water level.

c. Four pressure transmitters and associated switches, two sets in each of two trip logics, monitor high drywell pressure.

Diversity in monitoring these lines is provided by RPV water level, and drywell pressure.

7.3.1.1.2.8.9 Recirculation Loop Sample

Redundancy is provided by instruments monitoring each essential variable as follows:

a. Four differential pressure transmitters and associated switches, two sets in each of two trip logics, monitor low RPV water level.

There is no diverse isolation signal for this line.

7.3.1.1.2.8.10 Other Lines That Penetrate Containment

Redundancy is provided by instruments monitoring each essential variable as follows:

a. Four differential pressure transmitters and associated switches, one set of two in each of two trip logics, monitor RPV low water level.

b. Four pressure transmitters and associated switches, one set of two in each of two trip logics, monitor drywell pressure.

Diversity in monitoring these lines is provided by RPV water level, and drywell pressure.

7.3.1.1.2.9 PCRVICS Actuated Devices

To limit the radiological consequences and reduce reactor vessel water inventory loss as a result of a pipeline break, the valve closing mechanisms are designed to meet the minimum closing rates specified in Table 6.2-17.

The MSIVs are spring and pneumatic closing, piston-operated valves. They close on loss of pneumatic pressure to the valve operator. This is a fail-safe design. The control arrangement is shown in Figure 7.3-3. Closure time for the valves is adjustable between 3 seconds and 10 seconds. Each valve is piloted by two three-way, solenoid-operated valves, one powered by 120 V ac and the other powered by 125 V dc. An accumulator located close to each isolation valve provides pneumatic pressure for valve closing if there is failure of the normal air supply system. The spring is capable of closing the valve without the aid of the pneumatic pressure if accumulator integrity is lost. The logic channel and trip logic relays for the instrumentation used in the systems described are high reliability relays. The relays are selected so that the continuous load does not exceed 50% of the continuous-duty rating. For the minimum number of channels required for functional performance, see Chapter 16, Technical Specifications.

The MOVs used in the PCRVICS are operated by energizing the valve operator motor windings so as to cause motor rotation in the desired direction. Typically, manual valve operation is controlled using a three-position spring return-to-normal switch.

The valves close automatically on receipt of a safety signal. Valve closure is permitted when the valve is fully open or when the seating torque is below the setpoint. A seal-in feature is provided which ensures that autoclosure is completed once initiated. The closure signal also inhibits valve opening.

Valve opening is permitted when the open/inhibit signal is removed and if either the valve is fully closed or if the valve is not fully open and the seating torque is below the setpoint.

Overload protection is provided to valve motors in accordance with Section 8.1.6.1.19.

7.3.1.1.2.10 PCRVICS Separation

Redundant sensor devices are separated physically so that no single failure (open, closure, or short) can prevent the safety action. By the use of separated raceways, the single failure criterion is met from the sensors to the logic cabinets in the auxiliary equipment room. The logic cabinets are so arranged that redundant equipment and wiring are not present in the same bay of a cabinet. Redundant equipment and wiring can be present in control room panels where separation is achieved by surrounding redundant wire and equipment in metal encasements. A bay is a cabinet section separated from other cabinet sections by a fire barrier. Normally the barrier is of full cabinet height and depth. From the logic cabinets to the isolation valves, separated cable trays or a conduit) are employed to complete adherence to the single failure criterion. A complete description of the physical independence between divisions is given in Section 7.1.2.2.

7.3.1.1.2.11 PCRVICS Testability

Portions of PCRVICS are not activated or tested during normal operation with an integrated testing procedure. These portions of the system are tested using manual test methods which allow for independent checking of individual components. This testing includes monitoring of installed sensors and circuits to verify proper operation, to assure that isolation will occur when needed. The frequency of these tests and the parameters to be verified are identified in the Technical Specifications.

PCRVICS is capable of complete testing in overlapping portions during power operation. Operation of the level, pressure, flow, differential flow, and vacuum sensors may be verified by cross-comparison of instrument channels. In addition, these transmitters may be valved out of service one at a time and functionally tested using a test pressure source. The channel trip units and trip relays can be calibrated and tested by injecting a calibration signal.

The operation of the isolation temperature sensors can be verified by cross-comparison of instrument channels. They can also be functionally tested by applying a heat source to the temperature sensing elements. Control room indications of logic trip include annunciation, panel lights, and computer printout. The condition of each sensor is indicated by at least one of these methods in addition to annunciators common to sensors of one variable.

The MSIV logic relays can be tested either by tripping a transmitter or trip unit or by actuating the manual isolation switch in a given logic division. The MSIV indicator lights and trip annunciators indicate a logic trip. Other isolation valve logic can be likewise tested in conjunction with logic test switches provided for this purpose. Indicator lights will indicate a logic trip.

The MSIVs mechanical components can be tested manually to any position at full power in a "slow test" mode. This "slow test" is used to exercise the valve mechanical components, one valve at a time. Full closure, simulating actual autoisolation conditions, can be performed on individual MSIVs when shutdown or at reduced power level by placing the MSIV selector switch in the closed position. This tests the isolation solenoids and valve mechanical components at full isolation speed. In either test, the valve closure can be verified by valve position indicator lights.

Other PCRVICS valve testing must be split into two sections. The motor controls and mechanical components for MOVs that are isolated under normal reactor conditions may be tested only at shutdown. Motor controls and valves that are not normally isolated can be tested by tripping the control logic and verifying valve closure by valve position indicator lights.

7.3.1.1.2.12 PCRVICS Environmental Considerations

The physical and electrical arrangement of the PCRVICS was selected so that no single physical event can prevent achievement of isolation functions. Motor operators for valves inside the drywell are of the totally-enclosed type; those outside the containment have weatherproof-type enclosures. Solenoid valves, whether used for direct valve isolation or as an air pilot, are provided with watertight enclosures. All cables and operators are capable of operation in the most unfavorable ambient conditions anticipated for normal operations. Temperature, pressure, humidity, and radiation are considered in the selection of equipment for the system. Cables used in high radiation areas have radiation-resistant insulation. Shielded cables are used where necessary to eliminate interference from magnetic fields.

Special consideration has been given to isolation requirements during a LOCA inside the drywell. Components of the PCRVICS that are located inside the drywell and must operate during a LOCA

are the cables, control mechanisms, and valve operators of isolation valves inside the drywell. These isolation components are required to be functional in a LOCA environment Section 3.11. Electrical cables are selected with insulation designed for this service. Closing mechanisms and valve operators are considered satisfactory for use in the PCRVICS only after completion of environmental testing under LOCA conditions or submission of evidence from the manufacturer describing the results of suitable prior tests.

7.3.1.1.2.13 PCRVICS Operational Considerations

7.3.1.1.2.13.1 PCRVICS General Information

The PCRVICS is not required for normal operation. This system automatically isolates the appropriate pipeline when one of the monitored variables exceeds preset limits. No operator action is required for at least 10 minutes following automatic initiation. The operator can manually close all other isolation valves.

All automatic isolation valves can be closed by manual operation of switches in the control room.

7.3.1.1.2.13.2 PCRVICS Reactor Operator Information

In general, once isolation is initiated, the valve continues to close even if the condition that caused isolation is restored to normal. The reactor operator must manually reset the tripped logic and operate switches in the control room to reopen a valve that has been automatically closed. The HPCI and RCIC steam line isolation valves are exceptions as discussed in Section 7.1.2.11. Unless a manual bypass under administrative control is provided, the operator cannot reopen the valve until the conditions that initiated isolation have cleared.

A trip of a PCRVICS channel is annunciated in the control room so that the reactor operator is immediately informed of the condition. All motor-operated and air-operated isolation valves have open/ closed indicating lights.

In addition, isolation of any excess flow check valve is annunciated in the control room.

Inputs to annunciators and the process computer are electrically and physically isolated from safety circuits so that no malfunction of the annunciating or computing equipment can functionally disable the system. Direct signals from the isolation system sensors are not used as inputs to annunciating or data logging equipment.

7.3.1.1.2.13.3 PCRVICS Setpoints

See Chapter 16 for the safety setpoint information.

7.3.1.1.3 Main Steam Isolation Valve Leakage Control System - Instrumentation and Controls

7.3.1.1.3.1 Information in this section has been deleted.

7.3.1.1.4 RHR Containment Spray Mode - Instrumentation and Controls

7.3.1.1.4.1 RHR-CSM System Identification

Containment spray is an operating mode of the RHR system. It is designed to condense steam in the suppression pool air volume and/or the drywell atmosphere. The system is manually initiated when necessary.

The RHR system including containment spray is shown in drawing M-51.

7.3.1.1.4.2 RHR-CSM Classification

The RHR containment spray mode is classified as safety Class 3, seismic Class I, and electrical Class 1E.

7.3.1.1.4.3 RHR-CSM Power Sources

Power for the two RHR system pumps used for containment spray is supplied from two independent ac buses that can receive standby ac power. Motive and control power for the two loops of containment spray instrumentation and control equipment are the same as those used for LPCI A and LPCI B (Section 7.3.1.1.1.4.2).

7.3.1.1.4.4 RHR-CSM Equipment Design

Control and instrumentation for the following equipment is required for this mode of operation:

a. Two RHR system pumps

b. Pump suction valves

c. Containment spray discharge valves

d. Valves used to shut off flow paths used for other modes of RHR system operation

The controls and instrumentation for containment spray operation ensure that water is routed from the suppression pool to the containment spray system for use in the drywell and/or suppression pool air volumes.

Containment spray operation uses two pump loops, each loop with its own separate discharge valves. All components pertinent to containment spray operation are located outside of the drywell. The system can be operated so that the spray can be directed to the drywell and/or suppression pool air volume.

7.3.1.1.4.5 RHR-CSM Initiating Circuits

a. Containment Spray A

Drywell spray is initiated manually by means of two remote manual switches, one for each injection valve. Both injection valves may be opened if drywell pressure exceeds the setpoint, the LPCI injection valve is fully closed, and either a LOCA signal is present or the LPCI mode of operation has been manually started.

If any of these required permissives is missing, one of the two injection valves can be opened (for testing) only if the other injection valve is closed. Suppression pool spray is manually initiated from the control room if the LPCI injection valve is fully closed.

Drywell pressure (permissive for manual initiation) is monitored by two pressure sensors mounted in instrument racks outside the primary containment.

Cables from these sensors are routed to trip units in the control structure.

The two drywell pressure sensors are electrically connected so that no single sensor failure can prevent initiation of containment spray A. The drywell pressure sensors and trip units used in the containment spray initiating circuits are the same ones used for LPCI initiation. Additional details concerning these instruments are in Section 7.3.1.1.1.4.3 and Table 7.3-4.

b. Containment Spray B

Initiation of containment spray B is identical to that of "A".

7.3.1.1.4.6 RHR-CSM Logic and Sequencing

Containment spray is manually initiated provided that certain permissive conditions are satisfied as shown in drawings E11-1030-F-001, E11-1030-F-002, and E11-1030-F-003.

The operating sequence of containment spray following receipt of the necessary initiating signals is as follows:

a. The containment spray discharge valves open.

b. The RHR system pumps continue to operate.

c. Valves in other RHR modes are manually positioned or remain as positioned during LPCI.

The containment spray system continues to operate until the operator closes the containment spray injection valves. The operator can then initiate another mode of RHR.

7.3.1.1.4.7 RHR-CSM Bypasses and Interlocks

No bypasses are provided for the containment spray system.

The drywell spray injection valves are interlocked such that the system cannot be manually initiated unless drywell pressure exceeds the setpoint, the LPCI injection valve is fully closed, and either a LOCA signal is present or the LPCI mode of operation has been manually initiated. The open circuit of each drywell spray injection valve has an interlock that permits opening one valve for testing if the other valve in its respective loop is closed.

Since the outboard suppression pool spray injection valves may be open for several modes of RHR system operation, the injection valves are signaled to close on a LOCA signal. Once closed, the valves can be opened manually to initiate suppression pool spray as described in Section 7.3.1.1.4.5. The manual opening signal is interlocked with the LOCA signal to keep the valve open until the LPCI signal is manually reset.

7.3.1.1.4.8 RHR-CSM Redundancy and Diversity

Redundancy is provided for the containment spray function by two separate logics, one for each loop. Redundancy of initiation permissive sensors is described in Section 7.3.1.1.4.5 under "Initiating Circuits."

No diversity is provided for the initiation sensors.

7.3.1.1.4.9 RHR-CSM Actuated Devices

Drawings E11-1030-F-001, E11-1030-F-002, and E11-1030-F-003 shows the functional control arrangement of the containment spray system.

The RHR A and RHR B loops are used for containment spray. Therefore, the pump and valves are the same for LPCI and containment spray function except that each has its own discharge valve. See Section 7.3.1.1.1.4.7 for specific information.

7.3.1.1.4.10 RHR-CSM Separation

Separation is as discussed for LPCI mode in Section 7.3.1.1.1.4.8.

Containment spray uses Division I (RHR A) and Division II (RHR B) equipment. Manual controls, logic circuits, cabling, and instrumentation for containment spray are mounted so that Division I and Division II separation is maintained.

7.3.1.1.4.11 RHR-CSM Testability

The containment spray mode of the RHR system has components that are not activated or tested during normal operation with an integrated testing procedure. These components are tested using manual test methods which allow for independent checking of individual system components. This testing includes verification of suppression chamber spray flow such that the motors, pumps and valves are operated. Associated sensors and circuits are monitored to verify proper operation. Drywell spray injection valves are checked independently and separately by manual initiation. The frequency of these tests and the parameters to be verified are identified in the Technical Specifications.

The containment spray mode is capable of being tested up to the last discharge valve during normal operation. During testing, only one of the drywell spray discharge valves is opened at a time to prevent discharging water into the drywell. Each valve can be individually opened to verify operability.

7.3.1.1.4.12 RHR-CSM Environmental Considerations

See Section 3.11 for environmental qualifications of the system equipment.

7.3.1.1.4.13 RHR-CSM Operational Considerations

7.3.1.1.4.13.1 RHR-CSM General Information

Containment spray is a mode of the RHR and is not required during normal operation.

7.3.1.1.4.13.2 RHR-CSM Reactor Operator Information

Sufficient pressure, temperature, flow, and valve position indications are provided in the control room for the operator to accurately assess containment spray operation. Alarms and indications are shown in drawings M-51, E11-1030-F-001, E11-1030-F-002, and E11-1030-F-003.

All valves necessary for proper containment spray mode operation have indications of fully open, intermediate, and fully closed positions. Numerous RHR system performance parameters are

monitored, including pump discharge pressure, heat exchanger inlet and outlet temperatures, and system flow.

Annunciators are provided to indicate an out-of-service condition, pump running or pump stopped, and abnormal system performance.

7.3.1.1.4.13.3 RHR-CSM Setpoints

The setpoint for the drywell pressure permissive is in the Technical Specifications.

7.3.1.1.5 RHR Suppression Pool Cooling Mode - Instrumentation and Controls

7.3.1.1.5.1 RHR-SPCM System Identification

Suppression pool cooling is an operating mode of the RHR system. It is designed to provide the capability of removing heat from the suppression pool water volume. The system is manually initiated when necessary.

7.3.1.1.5.2 RHR-SPCM Power Sources

Control, instrumentation, and logic power for the two loops of the suppression pool cooling mode of the RHR are the same as those used for LPCI A and LPCI B (Section 7.3.1.1.1.4.2).

7.3.1.1.5.3 RHR-SPCM Equipment Design

Control and instrumentation for the following equipment is required for this mode of operation:

a. Two RHR pumps

b. Pump suction valves

c. Suppression pool discharge valves

d. Two RHR heat exchangers

Suppression pool cooling uses two pump loops, each loop with its own separate discharge valve. All components pertinent to suppression pool cooling operation are located outside of the drywell.

The suppression pool cooling mode is manually initiated from the control room. This mode is put into operation to maintain the water temperature in the suppression pool within specified limits.

7.3.1.1.5.4 RHR-SPCM Initiating Circuits

Initiation of either suppression pool cooling loop is performed manually by the control room operator by activating the manual override to clear any LOCA signal.

7.3.1.1.5.5 RHR-SPCM Logic and Sequencing

There is no engineering safety feature logic or sequencing associated with the suppression pool cooling mode. It is initiated manually. A discussion of suppression pool cooling mode is provided in Section 6.2.2.2.

7.3.1.1.5.6 RHR-SPCM Bypasses and Interlocks

No bypasses are provided for the suppression pool cooling mode. The MOVs isolating suppression pool cooling flow are interlocked to close when the reactor low water level setpoint is reached, or when the drywell high pressure and reactor low pressure setpoints are reached. This action automatically lines up the RHR system for coolant injection.

7.3.1.1.5.7 RHR-SPCM Redundancy and Diversity

Redundancy is provided for the suppression pool cooling function by two separate logics, one for each loop. There is no diversity provided.

7.3.1.1.5.8 RHR-SPCM Actuated Devices

Drawings E11-1030-F-001, E11-1030-F-002, and E11-1030-F-003 (RHR FCD) shows the functional control arrangement of the suppression pool cooling mode.

The RHR A and RHR B loops are utilized for suppression pool cooling. Therefore, the pump and valves are the same for LPCI and suppression pool cooling except that each has its own discharge valves.

7.3.1.1.5.9 RHR-SPCM Separation

Suppression pool cooling is a Division I (RHR A) and a Division II (RHR B) system. Manual control, logic circuits, cabling, and instrumentation for suppression pool cooling are mounted so that Division I and Division II separation is maintained.

7.3.1.1.5.10 RHR-SPCM Testability

Suppression pool cooling is capable of being tested during normal operation; however, the suppression pool cooling mode of the RHR system is a manually actuated mode whose components are operated during normal plant operation. In addition, the associated system components are tested using manual test methods which allow for independent checking of individual system components. This testing includes verification of flow such that the motors, pumps and valves are operated. Associated sensors and circuits are monitored to verify proper operation. The frequency of these tests and the parameters to be verified are identified in the Technical Specifications.

Testing for functional operability can be accomplished by manual testing of each loop. Adequate indication in the form of panel lamps and annunciators is provided in the control room. Testing of instrumentation and equipment shared by the core spray system and LPCI mode of RHR is discussed in Sections 7.3.1.1.1.3.9 and 7.3.1.1.1.4.9.

7.3.1.1.5.11 RHR-SPCM Environmental Conditions

Refer to Sections 3.10 and 3.11 for identification and environmental qualification of the systems' components.

7.3.1.1.5.12 RHR-SPCM Operational Considerations

7.3.1.1.5.12.1 RHR-SPCM General Information

Suppression pool cooling is a mode of the RHR and may be operated during normal operation to maintain the suppression pool temperature within specified operating limits.

7.3.1.1.5.12.2 RHR-SPCM Reactor Operator Information

Sufficient temperature, flow, pressure, and valve position indications are available in the control room for the operator to accurately assess suppression pool cooling operation. Alarms and indications are shown in drawings E11-1030-F-001, E11-1030-F-002, and E11-1030-F-003.

The temperature of the suppression pool is continuously monitored by the SPTMS as described in Appendix 3A.15.1.

7.3.1.1.5.12.3 RHR-SPCM Setpoints

There are no operating setpoints for this manually initiated mode of RHR; however, there are setpoints associated with other modes of RHR which will take precedence over the operation of this mode.

7.3.1.1.6 Containment Atmospheric Control System - Instrumentation and Controls

7.3.1.1.6.1 CAC System Description

The CAC system incorporates features for accomplishing a number of functions, including purging and venting of the primary containment, limitation of the differential pressure between drywell and wetwell, monitoring of hydrogen and oxygen concentrations in the primary containment, and control of hydrogen concentration in the primary containment after a LOCA.

The purging and venting function of the CAC system is accomplished by a high volume purge. The purging and venting function of the CAC system is not safety-related. This function is accomplished by the reactor enclosure HVAC system discussed in Section 7.7.

The monitoring of hydrogen and oxygen concentrations in the primary containment and control of hydrogen concentrations in the primary containment after a LOCA is accomplished by the CGCS, which is discussed in Section 7.3.1.1.6.1.2.

The limitation of the differential pressure between drywell and wetwell function is accomplished by the PCVR subsystem, which is discussed in Section 7.3.1.1.6.1.1.

7.3.1.1.6.1.1 Primary Containment Vacuum Relief System - Instrumentation and Controls

7.3.1.1.6.1.1.1 PCVR System Identification

The PCVR system consists of four PCVR valve assemblies that are provided to limit the degree to which suppression chamber pressure can exceed drywell pressure. The assemblies are located in the suppression chamber, each assembly being mounted on the side of a downcomer. Each assembly consists of two 24 inch (nominal diameter) vacuum relief valves mounted in series. When suppression chamber pressure exceeds drywell pressure by a specified amount, the vacuum relief valves open automatically and allow air from the suppression chamber to enter the

downcomer and flow upward into the drywell, thereby equalizing pressure above and below the diaphragm slab. The PCVR system is shown in Figure 9.4-6.

7.3.1.1.6.1.1.2 PCVR System Power Sources

The PCVR valves are check valves and do not require electrical power to perform their safety function and therefore are not supplied with safeguard power. Since the solenoid valves are used for remote actuation of the primary containment vacuum relief valves for testing purposes only, the solenoid valves are powered from a non-Class 1E bus. The separation criteria for the test circuitry is given in Section 8.1.

7.3.1.1.6.1.1.3 PCVR Equipment Design

Equipment design is described in Section 9.4.5.

7.3.1.1.6.1.1.4 PCVR Initiating Circuits

There are no initiating circuits.

7.3.1.1.6.1.1.5 PCVR Logic and Sequencing

No sequencing is provided for this system.

7.3.1.1.6.1.1.6 PCVR Bypasses and Interlocks

No bypasses or interlocks are provided for this system.

7.3.1.1.6.1.1.7 PCVR Redundancy and Diversity

Redundancy is given by the divisionalized system design. Four independent PCVR valve assemblies are provided. Each assembly consists of two vacuum relief valves mounted in series. Diversity is not required for this system.

7.3.1.1.6.1.1.8 PCVR Actuated Devices

The vacuum relief valves are the only actuated devices.

7.3.1.1.6.1.1.9 PCVR Separation

The test circuitry for each valve is separated from the other valves.

7.3.1.1.6.1.1.10 PCVR Testability

The system is designed to allow periodic testing of all four pairs of PCVR valves to ensure their functional capability. This is accomplished by opening each valve by remote actuation of the solenoid valve. One test selector switch per solenoid valve permits the independent testing of each relief valve. A momentary test push button causes a selective opening of the valve. The valve closes again when the selector switch is returned to the normal position.

Lights indicating the status of the relief valve position verify the operation.

The primary containment vacuum relief valves are tested from the vacuum breaker test panel located in the reactor enclosure.

7.3.1.1.6.1.1.11 PCVR Environmental Considerations

See Table 3.11 for environmental considerations.

7.3.1.1.6.1.1.12 PCVR Operational Considerations

7.3.1.1.6.1.1.12.1 PCVR General Information

This system functions automatically during normal operation. The ability to test during normal operation is not a requirement.

7.3.1.1.6.1.1.12.2 PCVR Reactor Operator Information

Initiation of the system is annunciated in the control room.

7.3.1.1.6.1.1.12.3 PCVR Setpoints

Refer to Chapter 16 for the opening set pressure of the valves.

7.3.1.1.6.1.2 Combustible Gas Control Subsystem - Instrumentation and Controls

7.3.1.1.6.1.2.1 CGCS Identification

The CGCS is described in Section 6.2.5. The safety-related function of this system is to control the oncentration of combustible gases (hydrogen, oxygen) in the containment after a LOCA. Two redundant thermal hydrogen recombiners are provided for this purpose. In the following discussion, when CGCS is used, it refers to the hydrogen recombiner, H_2/O_2 analyzers, and the isolation valves in the piping to and from the recombiners.

7.3.1.1.6.1.2.2 CGCS Power Sources

The CGCS power is provided from Class 1E ac buses.

7.3.1.1.6.1.2.3 CGCS Equipment Design

Equipment design is described in Section 6.2.5.

7.3.1.1.6.1.2.4 CGCS Initiating Circuits

The CGCS is manually initiated from the control room. There is no automatic system initiation. The combustible gas analyzer is designed to operate either in standby or continuous mode during normal operation. However, the combustible gas analyzer is required to continuously monitor hydrogen and oxygen concentrations in the primary containment following a LOCA. The combustible gas analyzers will automatically trip on a LOCA. Following the LOCA, the analyzers are realigned to continuously sample the concentration of combustible (Hydrogen & Oxygen) gases.

7.3.1.1.6.1.2.5 CGCS Logic and Sequencing

See the recombiner and isolation valve logic shown in drawing M-57FD and electrical schematics listed in Table 1.7-1.

The recombiner is manually started and continues to run until manually shut down by the operator or until tripped by one of the following conditions:

a. System inlet pressure high

b. Blower inlet temperature high

c. Heater wall temperature very high

d. Reaction chamber shell temperature very high

e. Return gas temperature high

The recombiner heaters are energized by interlock when the blower is started, and continues to run until the blower is shutdown by the operator or until tripped by one of the following conditions:

a. High gas temperature two-thirds through heater

b. High heater outlet gas temperature

c. Blower inlet gas flow low

d. Spray water inlet valve not full open

The Post-LOCA Recombiners also receive a trip signal from the PCIS upon actuation of containment isolation.

There is no sequencing for this system since it is manually initiated.

7.3.1.1.6.1.2.6 CGCS Bypasses and Interlocks

When in standby, an indicating light in the control room indicates that the recombiner is ready for operation. The light goes out and an alarm sounds if any condition arises that would prevent the recombiner from starting. In addition, a trickle heater keeps the blower and heater section warm during standby. If the trickle heater fails, the general recombiner trouble alarm annunciates.

A level switch is provided in the containment hydrogen recombiner outlet piping that alerts the operator in the control room if the level exceeds a preset value. This alarm is to protect the recombiner from flooding that is due to a leak in the associated cooling water piping.

The recombiners are not interlocked with any other system. However, the recombiners shutdown automatically, and the drywell isolation valves and recombiner isolation valves close on a containment isolation signal. This signal can be bypassed in the control room. The valves can be reopened to permit recombiner operation by key-lock switch (bypass is alarmed). The isolation signal is described in Section 7.3.1.1.2.

7.3.1.1.6.1.2.7 CGCS Redundancy and Diversity

The two hydrogen recombiners are identical, physically and functionally. They feed from independent electrical sources and use different piping for connection to the containment.

7.3.1.1.6.1.2.8 CGCS Actuated Devices

No devices are actuated by this system.

7.3.1.1.6.1.2.9 CGCS Separation

The controls and instrumentation circuits are physically and electrically separated for each recombiner and associated isolation valves. The A recombiner, isolation valves to the A recombiner, and the A water supply valve are in Division III. The B recombiner, isolation valves to the B recombiner, and B water supply valve are in Division IV.

7.3.1.1.6.1.2.10 CGCS Testability

The CGCS tested in accordance with the test requirements of the maintenance program and the Technical Requirements Manual (TRM).

7.3.1.1.6.1.2.11 CGCS Environmental Considerations

The sensors and transmitters of the CGCS are located in the reactor building. Remaining controls and instrumentation are located on the control panel in the control room. See Section 3.11 for environmental considerations.

7.3.1.1.6.1.2.12 CGCS Operational Considerations

7.3.1.1.6.1.2.12.1 CGCS General Information

The combustible gas control function of the CAC system is not required for normal plant operation. It is manually initiated after a LOCA to control the amount of combustible gases (hydrogen, oxygen) in the containment.

7.3.1.1.6.1.2.12.2 CGCS Reactor Operator Information

The operator is provided with sufficient indication to assess accurately the condition of the CGCS. Alarms for both the recombiners and the analyzers alert the operator of abnormal conditions. CGCS instrumentation is discussed in Section 6.2.5.6

7.3.1.1.6.1.2.12.3 Deleted

7.3.1.1.7 Standby Gas Treatment System - Instrumentation and Controls

7.3.1.1.7.1 SGTS Identification

The SGTS provides the means to control reactor enclosure and refueling floor pressure at a negative value with reference to the outside atmosphere. For description and operation of the SGTS, see Section 6.5.1.

7.3.1.1.7.2 SGTS Power Sources

The power for the instruments and controls associated with the SGTS is supplied from the Class 1E 120 V ac system. See Chapter 8 for a description of the electrical system.

7.3.1.1.7.3 SGTS Equipment Design

Equipment design is described in Section 6.5.1.

7.3.1.1.7.4 SGTS Initiating Circuits

The initiating circuits of the SGTS are the reactor enclosure isolation system and the refueling area isolation system. Section 7.3.1.1.9 and 7.3.1.1.17 gives a discussion of the isolation systems.

7.3.1.1.7.5 SGTS Logic and Sequencing

The two SGTS subsystems are normally set up with both sets of filter valves open. When an isolation signal exists, both of the SGTS fans are started and the associated controls are activated to open or modulate appropriate dampers and valves. The flow control of the operating SGTS uses the lowest appropriate reactor enclosure zone pressure to atmospheric pressure differential as a setpoint to ensure that the reactor enclosure pressure is less than atmospheric. This prevents reactor enclosure exhaust to the outside other than through the SGTS. See drawing M-76FD for the logic diagram.

7.3.1.1.7.6 SGTS Bypasses and Interlocks

The hand switch of each SGTS fan when in the off position and the hand switch of each filter train when in the close position provide input to a control room alarm. The SGTS fans are interlocked with the respective reactor enclosure and refueling floor isolation system.

7.3.1.1.7.7 SGTS Redundancy and Diversity

Controls and instrumentation are provided on a one-to-one basis with the mechanical equipment they serve to maintain the redundancy of the equipment. Diversity is not applicable.

7.3.1.1.7.8 SGTS Actuated Devices

No additional devices or systems are actuated by the SGTS.

7.3.1.1.7.9 SGTS Separation

The controls, instrumentation, and power supplies of the SGTS are physically and electrically separated for each of the filter and fan systems. See Section 8.1.6.1 for a discussion of electrical system separation.

7.3.1.1.7.10 SGTS Testability

The SGTS initiating circuits do not employ specific test features. SGTS initiating testing requirements are defined by Technical Specifications, and are implemented in conjunction with testing of the reactor enclosure and refueling floor isolation logics, and employ overlap with NSSSS testing to verify SGTS operability for all initiating conditions.

7.3.1.1.7.11 SGTS Environmental Consideration

The controls for the SGTS equipment are located in the control enclosure. The environmental consideration for this area and a qualification summary is provided in Section 3.11.

7.3.1.1.7.12 SGTS Operational Considerations

7.3.1.1.7.12.1 SGTS General Information

The SGTS is required to maintain the reactor enclosure and the refueling area at negative pressure under isolation conditions and to filter reactor enclosure exhaust taken from the RERS and the refueling area exhaust. Section 6.5.1 gives system function.

7.3.1.1.7.12.2 SGTS Reactor Operator Information

The operator is provided with fan motor status, a fan system trouble annunciator, filter heater inlet and outlet temperatures, carbon filter outlet air temperature, heater trouble alarm, two carbon filter preignition alarms and carbon filter fire alarm.

7.3.1.1.7.12.3 Deleted

7.3.1.1.8 Reactor Enclosure Recirculation System - Instrumentation and Controls

7.3.1.1.8.1 RERS Identification

The recirculation system filters and mixes the air in the reactor enclosure during isolation conditions. For description and operation of the recirculation system, see Sections 6.5.1 and 9.4.2.

7.3.1.1.8.2 RERS Power Sources

The power for the instruments and controls associated with the recirculation system is supplied from the Class 1E 120 V ac system. See Chapter 8 for a description of the electrical system.

7.3.1.1.8.3 RERS Equipment Design

Equipment design is described in Section 6.5.1.

7.3.1.1.8.4 RERS Initiating Circuits

The initiating circuit of the recirculation system is the REIS. Section 7.3.1.1.9 gives a discussion of the isolation systems. An operating train is stopped by low air flow, and the standby train is initiated.

7.3.1.1.8.5 RERS Logic and Sequencing

Two redundant systems are set up in auto-standby fashion. When an initiation signal exists, the lead (auto-selected) system automatically starts and the other system remains on standby. An air flow switch in the discharge duct monitors the operation of the lead fan. If the lead fan fails and the system loses air flow, the lead fan is tripped, the standby fan starts, after a time delay, to eliminate transient response. See drawing M-76FD for the logic diagram.

7.3.1.1.8.6 RERS Bypasses and Interlocks

The hand switch of each recirculation system, when in the off position, provides input to a control room alarm.

7.3.1.1.8.7 RERS Redundancy and Diversity

To maintain the redundancy of the mechanical equipment, controls and instrumentation are provided on a one-to-one basis with the mechanical equipment they serve. Diversity is not applicable.

7.3.1.1.8.8 RERS Actuated Devices

Recirculation exhaust isolation valves HV-76-109 and HV-76-110 are actuated when their respective recirculation system starts. See Sections 6.5.1 and 9.4.2 for a description of operation.

7.3.1.1.8.9 RERS Separation

The controls, instrumentation, and power supplies of the recirculation system are physically and electrically separated for each of the fan systems. See Section 8.1.6.1.14 for a discussion of electrical system separation.

7.3.1.1.8.10 RERS Testability

The RERS initiating circuits do not employ specific test features. RERS initiation testing requirements are defined by Technical Specifications, and are implemented in conjunction with testing of the reactor enclosure isolation logic, and employ overlap with NSSSS testing to verify RERS operability for all initiating conditions.

7.3.1.1.8.11 RERS Environmental Considerations

The controls for the recirculation system are located in the reactor enclosure and the control enclosure. The environmental considerations for these areas and a control qualification summary is provided in Section 3.11.

7.3.1.1.8.12 RERS Operational Considerations

7.3.1.1.8.12.1 RERS General Information

The recirculation system is required to filter and mix the air in the reactor enclosure under isolation conditions. See Section 6.5.1.3 for system function.

7.3.1.1.8.12.2 RERS Reactor Operator Information

The operator is provided with fan motor status, a charcoal temperature detection failure alarm, carbon filter inlet air temperature, filter system differential, two carbon filter preignition alarms, and carbon filter fire alarm.

7.3.1.1.8.12.3 Deleted

7.3.1.1.9 Reactor Enclosure Isolation System - Instrumentation and Controls

7.3.1.1.9.1 REIS Identification

The REIS provides signals to isolate the reactor enclosure and start the recirculation and SGTS systems under emergency conditions. For description and operation of the isolation system, see Section 9.4.2.

7.3.1.1.9.2 REIS Power Sources

The power for the instruments and controls associated with the isolation system is supplied from the Class 1E 120 V ac system. See Chapter 8 for a description of the electrical system.

7.3.1.1.9.3 REIS Equipment Design

Equipment design is described in Section 9.4.2.

7.3.1.1.9.4 REIS Initiating Circuits

Each trip logic of the reactor enclosure isolation system may be manually initiated or automatically initiated in a protective function mode as follows:

a. A trip logic may be initiated on low reactor water level (level 2) or high drywell pressure.

b. A trip logic may be initiated by high radiation sensed by both of the two gamma sensors located in the reactor enclosure exhaust duct. (Section 7.6.1.1.2)

c. A trip logic may be initiated by loss of reactor enclosure differential pressure with respect to pressure external to the building.

7.3.1.1.9.5 REIS Logic and Sequencing

Each trip logic of the redundant isolation system is normally held in an energized (fail-safe) mode so that an initiating signal or loss of power de-energizes the trip logic and starts all the related systems. The isolation signal seals-in upon initiation, and removal of the initiating signal does not deactivate the channel. The trip logic may be reset to a normal condition only if the initiating condition, other than low building differential pressure, is no longer present. A key-lock reset is provided to bypass low building differential pressure to re-establish it with the normal ventilation system. See drawing M-76FD for the logic diagram.

7.3.1.1.9.6 REIS Bypasses and Interlocks

The hand switch of each isolation system, when in the RESET position, provides input to a control room alarm. The isolation system is interlocked with the SGTS and the RERS.

7.3.1.1.9.7 REIS Redundancy and Diversity

To maintain the redundancy of the mechanical equipment, controls and instrumentation are provided on a one-to-one basis with the mechanical equipment they serve.

The diversity of the NSSS-furnished LOCA signal is used.

7.3.1.1.9.8 REIS Actuated Devices

The SGTS, RERS, and the reactor enclosure isolation valves are actuated by this system. See Sections 7.3.1.1.7 and 7.3.1.1.8, respectively, for descriptions of the actuated systems.

7.3.1.1.9.9 REIS Separation

The controls, instruments, and power supplies of the isolation system are physically separated and electrically independent for each of the redundant trip channels. See Section 8.1.6.1 for a discussion of electrical system separation.

7.3.1.1.9.10 REIS Testability

Verification of the operability of the initiating circuits may be made as follows:

a. By tripping the individual radiation monitor circuits

b. By tripping the differential pressure input circuits

c. By manually initiating the channels with hand switches located in the control room

d. By tripping the LOCA signal circuits (REIS only)

The REIS system may be tested as discussed above during plant operation.

7.3.1.1.9.11 REIS Environmental Considerations

The controls for the isolation systems are located in the reactor enclosure and the control enclosure. The environmental considerations for these areas are in Section 3.11.

7.3.1.1.9.12 REIS Operational Considerations

7.3.1.1.9.12.1 REIS General Information

The isolation systems are required to provide for reactor enclosure isolation during emergency conditions. See Sections 6.5.1 and 9.4.2 for system function.

7.3.1.1.9.12.2 REIS Reactor Operator Information

The operator is provided with an isolation initiation alarm and an isolation incomplete alarm in the control room for each of the two redundant isolation system logics. In addition, a common system (REIS and RAIS) "armed/bypassed" alarm is provided in the control room.

7.3.1.1.9.12.3 REIS Setpoints

Refer to Technical Specifications for REIS radiation setpoints.

7.3.1.1.10 Habitability and Control Room Isolation System - Instrumentation and Controls

7.3.1.1.10.1 HCRIS Identification

The control room isolation system provides means to isolate the control room from radiation or chlorine entering through the control room ventilation system. The emergency fresh air system

provides a means of pressurizing the control room during radiation isolation. The control room HVAC system provides the proper environment for the control room and adjacent areas. For description and operation, see Sections 9.4.1.1 and 6.4.

7.3.1.1.10.2 HCRIS Power Sources

Power for the instruments and controls associated with the isolation system, the emergency fresh air system, and the control room HVAC system is supplied from the Class 1E 120 V ac system. See Chapter 8 for a description of the electrical system.

7.3.1.1.10.3 HCRIS Equipment Design

Equipment design is described in Section 9.4.

7.3.1.1.10.4 HCRIS Initiating Circuits

The control room isolation system is initiated by outside air high-high radiation (Section 11.5) or a high concentration of chlorine gas (manual initiation). The control room supply and return fans initiate identically to the auxiliary equipment room ventilation system (Section 7.3.1.1.15.6). The CREFAS is initiated by the isolation signals.

7.3.1.1.10.5 HCRIS Logic and Sequencing

Two modes of isolation are provided: complete intake and exhaust isolation of the control room upon chlorine detection (manual initiation), and intake air diverted through the emergency fresh air supply system upon radiation detection and control room isolation. See Sections 9.4 and 6.4 for details. The control room supply and return fans operate identically to the auxiliary equipment room ventilation system (Section 7.3.1.1.15.6), except the control room supply fans do not trip on high fan discharge temperature. See drawing M-78FD for the HCRIS control logic diagram.

7.3.1.1.10.6 HCRIS Bypasses and Interlocks

The hand switch of each fan in the emergency fresh air system and the control room HVAC system, when in the OFF position, provides input to a control system alarm. One hand switch of each isolation channel, when in the TEST position, provides input to a control system alarm. The isolation system is interlocked with the emergency fresh air system to maintain ventilation within the control room during isolation. The control room HVAC supply fans are interlocked with the purge system, and the chilled water pumps in a way identical to the auxiliary equipment room ventilation system (Section 7.3.1.1.15.6).

7.3.1.1.10.7 HCRIS Redundancy and Diversity

To maintain the redundancy of the mechanical equipment, controls and instrumentation are provided on a one-to-one basis with the mechanical equipment they serve.

7.3.1.1.10.8 HCRIS Actuated Devices

The associated control enclosure chilled water system pumps are actuated by the control room HVAC supply fans (Section 7.3.1.1.13).

7.3.1.1.10.9 HCRIS Separation

The controls, instrumentation, and power supplies of the isolation system, emergency fresh air system, and control room HVAC are physically separated and electrically independent for each of the redundant trip channels. See Section 8.1.6.1.14 for a discussion of the electrical system separation.

7.3.1.1.10.10 HCRIS Testability

Verification of the operability of the initiating circuits of the isolation system may be made as follows:

a. By tripping the individual radiation monitor circuits

b. By manually initiating the channels by hand switches located in the control room. Verification of the operability of the initiating circuits of the emergency fresh air system may be made as follows:

   1. By putting each fan in the AUTO mode and tripping the isolation channel

   2. By putting each fan in the STANDBY mode and tripping the isolation channel when the other fan is shut down

   Verification of the operability of the initiating circuits of the control room HVAC fans may be made by putting each fan in the AUTO mode when the other fan of the pair is shut down. In addition, all fans may be manually tested by hand switches from the control room.

The HCRIS may be tested as discussed above during plant operation.

7.3.1.1.10.11 HCRIS Environmental Consideration

The controls for these systems are located in the control enclosure. The environmental consideration for this area and the control qualification summary is provided in Section 3.11.

7.3.1.1.10.12 HCRIS Operational Considerations

7.3.1.1.10.12.1 HCRIS General Information

The control room HVAC system is required for normal operation of the control room. The isolation system and the emergency fresh air system are required for emergency operation of the control room.

7.3.1.1.10.12.2 HCRIS Reactor Operator Information

Alarms that are common to all four redundant trip channels are provided in the control room for Chlorine Isolation Initiated, Radiation Isolation Initiated, Isolation System Armed, Isolation Not Complete, and Isolation Circuit In Test.

The information provided for the control room HVAC system is identical to the auxiliary equipment room ventilation system (Section 7.3.1.1.15.6).

The following safety-related information is provided for the emergency fresh air system:

a. Fan motor status and damper position status.

b. System flow rate indication

c. Carbon filter leaving air temperature

7.3.1.1.10.12.3 HCRIS Setpoints

For setpoints, see Chapter 16.

7.3.1.1.11 Emergency Service Water System - Instrumentation and Controls

7.3.1.1.11.1 ESW Identification

The ESW system is described in Section 9.2.2. This system provides cooling water to the diesel generator units, RHR pumps, and room coolers required during emergency conditions to safely shut down the plant. The ESW system is shown in drawing M-11.

7.3.1.1.11.2 ESW Power Sources

The power for the ESW pump motors and its associated loop MOVs is supplied from Class 1E ac buses. Control power for the ESW pumps is supplied from Class 1E dc buses. Instrumentation power is supplied from Class 1E ac buses.

7.3.1.1.11.3 ESW Equipment Design

Equipment design is described in Section 9.2.2.

7.3.1.1.11.4 ESW Initiating Circuits

Start signals from both the Unit 1 and Unit 2 diesel generators in the same electrical division initiate the auto start of the associated ESW pump. The diesel generator that supplies power to the ESW pump in a loop provides two start signals. The first signal monitors bus voltage and diesel generator speed. The second signal monitors bus voltage and diesel generator output breaker position. The diesel generator in the same division that does not supply power to the associated ESW pump only provides the start signal associated with bus voltage and diesel generator speed. The start signals have different time delays to ensure proper load sequencing. Diesel generators D11 and D21 start ESW pump A (Division I); D12 and D22 start ESW pump B (Division II); D13 and D23 start ESW pump C (Division III); and D14 and D24 start ESW pump D (Division IV).

A start signal from each ESW pump initiates the associated loop valve action.
Manual control for all four pumps and remote-operated loop configuration control valves is available in the control room. Manual control of ESW pump A and specific A ESW and A RHRSW return header valves is available on the remote shutdown panel. In addition, the "B" and "C" ESW pump can be operated using local controls located at the "B" and "C" ESW pump motor circuit breaker cubicles.

7.3.1.1.11.5 ESW Logic and Sequencing

See drawing M-11FD for the logic diagram and Table 1.7-1 for reference to the electrical schematic diagrams.

See Chapter 8 for the diesel generator control circuits.

Automatic start of each pump is initiated on the following conditions:

a. Forty-five seconds after the associated diesel generator bus breaker is in and closed and the bus voltage is available

b. Fifty-three seconds after the associated diesel generator is operating (i.e. speed detection) and the bus voltage is available

The time delay is for bus loading considerations.

The starting of an ESW pump automatically opens or closes the associated cooling water loop configuration valves. Also, the start signal closes the cooling tower inlet to the associated pump wet pit and opens the sluice gate from the spray pond. The return valve from the ESW system to the cooling tower is closed, and the associated return valves to the spray pond are opened.

Once an ESW pump is started, it continues to operate until any of the following conditions occurs:

a. Manually stopped by the operator in the control room or, for pump A, from the remote shutdown room, or for pumps B and C, from the local circuit breaker cubicle.

b. Bus lockout

c. Phase overcurrent

d. Ground fault

e. Bus undervoltage

During Unit 1 operation and Unit 2 construction, ESW supplies and returns to Unit 2 were valved off. During this period ESW pumps "C" and "D" were temporarily powered from safeguard buses D13 and D14, respectively.

7.3.1.1.11.6 ESW Bypasses and Interlocks

An interlock is provided so that if an ESW pump is running and a LOCA signal is initiated the pump trips and restarts automatically after a time delay on the signals described in Section 7.3.1.1.11.5. This interlock is for diesel generator loading considerations.

7.3.1.1.11.7 ESW Redundancy and Diversity

To maintain the redundancy of the mechanical equipment described in Section 9.2.2, controls are provided on a one-to-one basis with the mechanical equipment.

MCR instrumentation of each process loop is redundant to the other process loop.

7.3.1.1.11.8 ESW Actuated Devices

The devices actuated by the initiation of the ESW pumps are the loop valving and the water source and return valving and/or sluice gates.

7.3.1.1.11.9 ESW Separation

The controls and instrumentation are physically and electrically separated for each of the four ESW pumps. ESW pump A controls and instruments are in Division I; ESW pump B is in Division II; ESW pump C is in Division III; and ESW pump D is in Division IV.

The controls for the ESW valves are assigned to various divisions so that a single active failure cannot disable a complete ESW loop. In cases where two valves are in series to shut off a flow path, the valves are assigned to two different divisions. Likewise, in cases where two valves are used to provide redundant flow paths in a single loop, the valves are assigned to two different divisions.

Loop A valves are in Divisions I and III, and loop B valves are in Divisions II and IV. The manual control loop selection valves for each diesel generator are in the same division as the associated diesel generator.

Loop A pressure and differential flow indication are in Division I, and the Loop B instruments are in Division II.

7.3.1.1.11.10 ESW Testability

Verification of operability of initiation circuits is made when the associated diesel generator is tested. Circuits that are actuated by ESW pump starts are tested by manipulating the associated components to the nonsafety-related positions, starting the ESW pump and verifying the proper safety-related position is obtained.

7.3.1.1.11.11 ESW Environmental Considerations

The control equipment for the ESW system is located in the reactor enclosure, diesel generator enclosures, spray pond pump house, control enclosure, and the control room. See Section 3.11 for environmental considerations.

7.3.1.1.11.12 ESW Operational Considerations

7.3.1.1.11.12.1 ESW General Information

The ESW system is not required for normal operation. The system is initiated automatically on a signal based on the status of the diesel generators.

7.3.1.1.11.12.2 ESW Reactor Operator Information

The operator is provided with pump motor status and valve position indicators for the ESW system in the control room. An indicator is provided for each loop to show the differential between the loop inflow and the loop return flow. Also, pump A status and position indication for certain loop A valves is provided in the remote shutdown room.

In addition, the following nonsafety-related instrumentation and alarms are provided in the main control room:

a. ESW loop A discharge header pressure indication

b. ESW loop B discharge header pressure indication

c. Control room annunciators:

1. ESW loop A(B) high differential flow
2. Pump discharge pressure low (one/pump)
3. Diesel generator compartment flooding (one/diesel generator)
4. Pump control transferred to remote shutdown panel (pump A only)
5. Pump motor overcurrent (one/pump)
6. Pump autostart (one/pump)
7. ESW system out of service (one/pump)
8. Division I (II, III, and IV) any ESW auto initiated valve not fully open/closed
9. Division I (II, III, and IV) ESW MOVs overload or loss of power

d. Plant computer alarms

1. ESW pump motor high bearing temperature
2. ESW pump motor high stator temperature

See Section 7.4.1.4 for a description of the indications provided on the remote shutdown panel.

7.3.1.1.11.12.3 ESW Setpoints

There are no safety setpoints for the ESW system.

7.3.1.1.12 RHR Service Water System - Instrumentation and Controls

7.3.1.1.12.1 RHRSW Identification

The RHRSW system is described in Section 9.2.3. This system provides cooling water to the RHR heat exchangers of both units. The RHRSW system is shown in drawing M-12.

7.3.1.1.12.2 RHRSW Power Sources

The power for the RHRSW pump motors and cooling water loop MOVs is supplied from Class 1E ac buses. Control power for the RHRSW pump motors is supplied from Class 1E dc buses. Instrumentation power is supplied from Class 1E ac buses.

7.3.1.1.12.3 RHRSW Equipment Design

Equipment design is described in Section 9.2.3.

7.3.1.1.12.4 RHRSW Initiating Circuits

The RHRSW system is a manually initiated system. However, as noted in Section 7.3.1.1.12.5, the common ESW and RHRSW supply and return valves and the spray pond sluice gates are automatically oriented to the spray pond on a start signal from the ESW system.

Manual controls for the RHRSW pumps, cooling water loop valves, and the spray pond sluice gate are available in the control room. Also, manual control of the "A" and "C" RHRSW pumps and the cooling water loop A valves and associated sluice gates is available in the remote shutdown room. In addition, the "B and D" RHRSW pumps can be operated using local controls located at "B and D" RHRSW pumps motor circuit breaker cubicle.

7.3.1.1.12.5 RHRSW Logic and Sequencing

See drawings M-12FD and M-51FD for the RHRSW and the RHR heat exchanger inlet and outlet valve logic diagrams and Table 1.7-1 for reference to electrical schematic diagrams.

The RHRSW pumps are started manually. Once a pump is started, it continues to operate until any of the following conditions occurs:

a. Manually stopped by the operator in the control room, or, for pumps A and C, from the remote shutdown room

b. Bus lockout

c. Phase overcurrent

d. Ground fault

e. Bus undervoltage

f. Associated cooling water loop heat exchanger return line high radiation signal

g. High pump discharge pressure

Each RHR heat exchanger inlet and outlet valve is opened manually from the control room. The loop A RHR heat exchanger inlet and outlet valves can also be manually operated from the remote shutdown room.

The system is normally aligned to the spray pond for cooling water source and loop return. However, the system can be manually aligned to the cooling towers, if available. The starting of the ESW system, the cooling water source, and return for the ESW and RHRSW system automatically aligns to the spray pond if the systems are not already in that mode. Manual alignment of the loop A valve to the cooling tower or the spray pond is also available in the remote shutdown room.

7.3.1.1.12.6 RHRSW Bypasses and Interlocks

A key-locked manual switch bypass is provided to inhibit the ESW signal that automatically aligns the ESW and RHRSW system from the cooling tower mode to the spray pond mode. This bypass is provided to permit alignment to the cooling tower if available. A control room alarm indicates that the ESW system is out-of-service whenever this bypass is activated.

A key-locked manual bypass switch is provided to inhibit the high radiation signal of the monitor in the associated cooling water loop return to provide the capability to restart the pumps. The bypass switch will also bypass the high discharge pressure trip of the pumps. A control room alarm indicates that the high radiation and high discharge pressure trips are bypassed.

7.3.1.1.12.7 RHRSW Redundancy and Diversity

Controls are provided on a one-to-one basis with the mechanical equipment described in Section 9.2.3.

Instrumentation of each process loop is redundant to the other process loop.

7.3.1.1.12.8 RHRSW Actuated Devices

Starting an RHRSW pump does not actuate any associated components. The actuation of loop valving, the water source and return valving, and/or sluice gates is limited by ESW pump start.

7.3.1.1.12.9 RHRSW Separation

The controls and instrumentation are physically and electrically separated for each RHRSW loop. The controls for the loop A RHR heat exchanger inlet valves and for RHRSW pumps A and C are in Division I, and controls for RHRSW pumps B and D, and the loop B RHR heat exchanger inlet valves are in Division II. Controls for the loop A RHR heat exchanger outlet valve are Division III and the controls for loop BRHR heat exchanger are in Division IV.

The controls of the RHRSW Loop A valves that are common with the ESW system are in either Division I or III, and the Loop B valves that are common with the ESW system are in either Division II or IV as described in Section 7.3.1.1.11.9.

Similarly the Loop A instrumentation for pressure, flow, and radiation is in either Division I or III, and the Loop B instrumentation is in either Division II or IV.

7.3.1.1.12.10 RHRSW Testability

The RHRSW system is capable of being tested during normal plant operation by the manual testing of each RHRSW loop component. Manual control switches with status lights are provided in the control room for the system pumps and valves.

7.3.1.1.12.11 RHRSW Environmental Considerations

The control equipment for the RHRSW system is located in the spray pond pump house, and control structure. See Section 3.11 for environmental considerations.

7.3.1.1.12.12 RHRSW Operational Considerations

7.3.1.1.12.12.1 RHRSW General Information

The RHRSW system is not required for normal plant operations. The RHRSW system is required for normal plant shutdowns. The system is manually initiated to supply cooling water to the RHR heat exchangers.

7.3.1.1.12.12.2 RHRSW Reactor Operator Information

The operator is provided with pump motor status and valve position indication for the RHRSW system components in the control room. A recording of the radiation level of each of the RHRSW return loops is provided.

In addition, the following nonsafety-related instrumentation and alarms are provided in the control room:

a. RHRSW pumps A and C discharge header pressure indicator. This pressure indication is also provided in the remote shutdown room.

b. RHR heat exchanger service water outlet pressure indicator (one/heat exchanger). This pressure indication is also provided in the remote shutdown room.

c. RHR heat exchanger service water outlet temperature recording (one/heat exchanger)

d. Control room annunciators:

1. RHRSW pump discharge low pressure (one/pump)

2. RHRSW pump discharge high pressure (one/pump)

3. RHRSW header low pressure (two/loop)

4. RHRSW pump motor high bearing or stator temperature alarms. Alarms are via the plant computer (three/pump motor).

5. RHRSW pump control transferred to the remote shutdown panel (pumps A and C only)

6. RHRSW pump motor overcurrent (one/motor)

7. RHRSW high radiation trip signal bypassed (one/loop)

8. RHR heat exchanger service water valves not open (one/loop)

9. RHR out-of-service (input from each RHRSW loop)

10. DELETED

11. RHRSW drain high/low level

12. Spray pond MOVs overload on loss of power (one/ division)

7.3.1.1.12.12.3 RHRSW Setpoints

There are no safety setpoints for the RHRSW system.

7.3.1.1.13 Control Enclosure Chilled Water System - Instrumentation and Controls

7.3.1.1.13.1 CECWS Identification

The CECWS provides chilled water to the control room air supply fan cabinets, the auxiliary equipment room air supply fan cabinets, the emergency switchgear and battery room air supply fan cabinets, and the SGTS room and access area unit coolers. For description and operation, see Section 9.4.1.

7.3.1.1.13.2 CECWS Power Sources

The power for the instruments and controls associated with the CECWS is supplied from the Class 1E 120 V ac system. See Chapter 8 for a description of the electrical system.

7.3.1.1.13.3 CECWS Equipment Design

Equipment design is described in Section 9.4.1.

7.3.1.1.13.4 CECWS Initiating Circuits

The CECWS chillers and pumps may be manually started from hand switches in the control room. The circulating water pumps, when in the auto mode, can be started by any one of the five fan units served by the CECWS. The chiller can be automatically started, when in the auto mode, by the starting of its circulating water pump.

7.3.1.1.13.5 CECWS Logic and Sequencing

One circulating water pump and its associated chiller are started manually to correspond with the cooling coils in use. The other pump and chiller remain in a standby mode. If a fan unit fails or is shut down, its standby unit starts and sends a signal to its corresponding circulating water pump and chiller to start. If a pump or chiller shuts down, the corresponding fan units shut down due to high temperature, except for the main control room fan unit(s). The operating main control fan unit can be manually shut down if required, which causes the standby fan unit to start and send a signal to the corresponding circulating water pump and chiller to start.

Upon receipt of a LOCA signal the operating chiller is automatically tripped, and the operating circulating pump continues to run. The standby circulating pump automatically starts approximately 116 seconds (126 sec if LOOP/LOCA) later. Both chillers automatically start approximately 167 seconds (117 if LOOP/LOCA) later. See drawing M-90FD for the control logic diagram.

7.3.1.1.13.6 CECWS Bypasses and Interlocks

The hand switch of each pump, when in the "off" position, provides input to a computer alarm. The hand switch of each chiller, when in the off position, provides input to a control system alarm. Each safeguard channel pump and chiller is interlocked with each other and with the 5 fan/coil units that are serviced by it.

7.3.1.1.13.7 CECWS Redundancy and Diversity

To maintain the redundancy of the mechanical equipment, the controls and instrumentation are provided on a one-to-one basis with the mechanical equipment they serve. Diversity is not applicable.

7.3.1.1.13.8 CECWS Actuated Devices

The pump and chiller can be actuated by each other under certain circumstances as described in Section 7.3.1.1.13.4.

7.3.1.1.13.9 CECWS Separation

The controls, instrumentation, and power supplies of the CECWS are physically and electrically separated for each of the redundant systems. See Section 8.1.6.1 for the electrical system separation.

7.3.1.1.13.10 CECWS Testability

Verification of the operability of the initiating circuits may be made as follows:

a. By manually testing the pumps and chillers by hand switches located in the control room.

b. By putting the chiller and pump pair in the automatic mode and starting one of the 5 fan units interlocked with that pair.

7.3.1.1.13.11 CECWS Environmental Consideration

The controls for the CECWS are located in the control enclosure; the environmental consideration for this area and control qualification summary is provided Section 3.11.

7.3.1.1.13.12 CECWS Operational Considerations

7.3.1.1.13.12.1 CECWS General Information

The CECWS is required for normal and emergency operation of its service areas.

7.3.1.1.13.12.2 CECWS Reactor Operator Information

The operator is provided with pump motor status and flow indication for the pumps. Chiller motor status, and entering and leaving chilled water temperature indication is provided for the chillers. A chilled water return high temperature alarm is also provided to the computer.

7.3.1.1.13.12.3 Deleted

7.3.1.1.14 Class 1E Power System

Descriptions of the standby power system and supporting system can be found in the following:

a. See Section 8.3.1 for a description of the onsite Class 1E ac power systems.

b. See Section 8.3.2 for a description of the onsite Class 1E dc power system.

c. See Section 9.5.5 for the diesel generator cooling water system.

d. See Section 9.5.6 for the diesel generator starting system.

e. See Section 9.5.7 for the diesel generator lubrication system.

f. See Section 9.5.8 for the diesel generator combustion air intake and exhaust system.

7.3.1.1.15 Safety-Related Equipment Area Cooling Ventilation Systems - Instrumentation and Controls

7.3.1.1.15.1 SGTS Filter Room and Access Area Unit Coolers - Instrumentation and Controls

7.3.1.1.15.1.1 SGTS-UC System Identification

The SGTS unit coolers provide cooling to the SGTS filter room and access areas. For description and operation, see Section 9.4.1.

7.3.1.1.15.1.2 SGTS-UC Power Sources

The power for the instruments and controls associated with the SGTS unit coolers is supplied from the Class 1E 120 V ac system. See Section 8 for a description of the electrical system.

7.3.1.1.15.1.3 SGTS-UC Equipment Design

Equipment design is described in Section 9.4.1.

7.3.1.1.15.1.4 SGTS-UC Initiating Circuits

Each of the unit coolers may be initiated as follows:

a. The tripping of the high temperature switch in auto mode

b. The tripping of the high-high temperature switch in the standby mode

7.3.1.1.15.1.5 SGTS-UC Logic and Sequencing

When the temperature of the area exceeds the high temperature setting, the lead fan starts. If the temperature continues to rise, the standby fan starts. When a fan starts, air flow is sensed by differential pressure instrumentation which sends a signal to start the associated control structure chilled water pump and chiller and opens the chilled water coil inlet valve. Once started, a fan runs until the area temperature drops below the low temperature setting. See drawings M-78FD for the control logic diagram.

7.3.1.1.15.1.6 SGTS-UC Bypasses and Interlocks

The hand switch of each unit, when in the off position, provides input to a computer alarm. The unit coolers are interlocked with the control enclosure chilled water pumps.

7.3.1.1.15.1.7 SGTS-UC Redundancy and Diversity

To maintain the redundancy of the mechanical equipment, controls and instrumentation are provided on a one-to-one basis with the mechanical equipment they serve. Diversity is not applicable.

7.3.1.1.15.1.8 SGTS-UC Actuated Devices

The associated control enclosure chilled water system pumps are actuated by the unit coolers. See Section 7.3.1.1.13 for a description of CECWS controls.

7.3.1.1.15.1.9 SGTS-UC Separation

The controls, instrumentation, and power supplies of the SGTS unit coolers are physically and electrically separated for each of the units. See Section 8.1.6.1 for a discussion of electrical system separation.

7.3.1.1.15.1.10 SGTS-UC Testability

Verification of the operability of the initiating circuits may be made as follows:

a. The fans can be manually tested by hand switches from the local control panel.

b. In the auto mode, the unit can be started by tripping the high temperature switch.

c. In the standby mode, the unit can be started by tripping the high-high temperature switch.

7.3.1.1.15.1.11 SGTS-UC Environmental Considerations

The controls for the subject equipment are located in the control enclosure. The environmental considerations for this area and the control qualification summary is provided in Section 3.11.

7.3.1.1.15.1.12 SGTS-UC Operational Considerations

7.3.1.1.15.1.12.1 SGTS-UC General Information

The SGTS unit coolers are required to maintain environmental conditions in their service areas when the SGTS fan is operating.

7.3.1.1.15.1.12.2 SGTS-UC Reactor Operator Information

The following safety-related information is provided on a local control panel:

a. Fan motor status for each unit cooler

b. Area temperature for each unit cooler

In addition, a fan trouble alarm is relayed to the computer alarm for each unit cooler.

7.3.1.1.15.1.12.3 Deleted

7.3.1.1.15.2 Diesel Generator Enclosure Ventilation System - Instrumentation and Controls

7.3.1.1.15.2.1 DGEVS System Identification

The diesel generator enclosure ventilation system cools the diesel generator cells and equipment. For description and operation, see Section 9.4.6.

7.3.1.1.15.2.2 DGEVS Power Sources

The power for the instruments and controls associated with the diesel generator enclosure ventilation system is supplied from the Class 1E 120 V ac system. See Chapter 8 for a description of the electrical system.

7.3.1.1.15.2.3 DGEVS Equipment Design

Equipment design is described in Section 9.4.6.

7.3.1.1.15.2.4 DGEVS Initiating Circuits

Each of the four diesel generators has its own corresponding ventilation system which may be initiated in a protective function mode as follows:

a. The starting of an associated diesel and the receipt of a temperature permissible (temperature >36°F)

b. The initiation of the high temperature switch will start the standby fan if the diesel is running.

c. With the diesel not running, the initiation of the high- high temperature switch will start both the lead and standby fans.

7.3.1.1.15.2.5 DGEVS Logic and Sequencing

When the diesel start signal is initiated and the cell temperature exceeds the thermostat setting, the lead fan starts. If the temperature continues to rise, the standby fan starts.

Once started, a fan runs until the cell temperature drops below the low temperature switch setting. The fan blades modulate to maintain the discharge air temperature setting. See drawings M-81FD for the control logic diagram.

7.3.1.1.15.2.6 DGEVS Bypasses and Interlocks

The hand switch of each ventilation fan, when in the off position, provides input to a local panel alarm that is relayed to the control room.

The diesel generator enclosure fans are interlocked with their respective diesel start signal.

7.3.1.1.15.2.7 DGEVS Redundancy and Diversity

To maintain the redundancy of the mechanical equipment, controls and instrumentation are provided on a one-to-one basis with the mechanical equipment they serve. Diversity is not applicable.

7.3.1.1.15.2.8 DGEVS Actuated Devices

No additional devices or systems are actuated by the diesel generator enclosure ventilation system.

7.3.1.1.15.2.9 DGEVS Separation

The controls, instrumentation, and power supplies of the diesel generator enclosure ventilation fans are physically and electrically separated for each of the fan systems. See Section 8.1.6.1 for a discussion of electrical system separation.

7.3.1.1.15.2.10 DGEVS Testability

Verification of the operability of the initiating circuits may be made as follows:

a. By manually testing the fans by hand switches from the local panel

b. In the auto mode, by tripping the diesel start signal or the cell high-high temperature switch

c. In the standby mode, by tripping the diesel start signal and cell high temperature switch or by tripping the cell high-high temperature switch

7.3.1.1.15.2.11 DGEVS Environmental Consideration

The controls for the subject equipment are located in the diesel generator enclosure. The environmental consideration for these areas and a control qualification summary is provided in Section 3.11.

7.3.1.1.15.2.12 DGEVS Operational Considerations

7.3.1.1.15.2.12.1 DGEVS General Information

The diesel generator enclosure ventilation system is required for normal operation and testing of the diesel generators when the plant is in operation.

7.3.1.1.15.2.12.2 DGEVS Reactor Operator Information

The operator is provided with a fan system trouble alarm.

7.3.1.1.15.2.12.3 Deleted

7.3.1.1.15.3 Spray Pond Pump Structure Ventilation System - Instrumentation and Controls

7.3.1.1.15.3.1 SPPSVS System Identification

The spray pond pump structure ventilation system provides ventilation and heating for the ESF pumps located in the spray pond pump structure. For description and operation, see Section 9.4.7.

7.3.1.1.15.3.2 SPPSVS Power Sources

The power for the instruments and controls associated with the spray pond pump structure ventilation system is supplied from the Class 1E 120 V ac system.

7.3.1.1.15.3.3 SPPSVS Equipment Design

Equipment design is described in Section 9.4.7.

7.3.1.1.15.3.4 SPPSVS Initiating Circuits

Each of the fans may be initiated or stopped in a protective function mode as follows:

a. The initiation of a high temperature switch (for cooling)

b. The initiation of a low temperature switch (for heating)

c. The tripping of a low temperature switch (for cooling)

d. The tripping of a high temperature switch (for heating)

7.3.1.1.15.3.5 SPPSVS Logic and Sequencing

Each train of the SPPSVS may be operated in either the Run or Standby mode. See drawings M-81FD for control logic diagrams and Table 1.7-1 for reference to electrical schematic diagrams. Fans in the run mode operate continuously and structure temperature is controlled automatically by a temperature controller that modulates dampers which mix outside and recirculated air. If temperature drops below setpoint, heaters will be energized automatically.

As the SPPSVS temperature rises;

a. Fans in Run mode run continuously. Dampers are energized and modulated when structure temperature exceeds a high temperature setpoint.

b. Fans in the Standby mode have a higher setpoint, and will start if the temperature rises above the automatic setpoint.

As the SPPSVS temperature decreases;

a. Fans in the Run mode will operate continuously. Dampers are deenergized when structure temperature exceeds a low temperature setpoint, and the associated heaters will be energized.

b. Fans in the Standby mode also have a lower setpoint; they will start if the temperature falls below the automatic setpoint, and the associated heaters will be energized.

c. In all modes of operation, if structure temperature continues to decrease, the SPPSVS will be automatically tripped before reaching the freezing point.

Fans that have started in the Run mode will operate continuously. Fans that have started in the standby mode will stop after the initiating temperature switch has reset.

7.3.1.1.15.3.6 SPPSVS Bypasses and Interlocks

The hand switch of each fan, when in the off position, provides input to a control room alarm.

The electric heating coils are interlocked with the LOCA signals and trip off upon receipt of these signals.

7.3.1.1.15.3.7 SPPSVS Redundancy and Diversity

To maintain the redundancy of the mechanical equipment, controls and instrumentation are provided on a one-to-one basis with the mechanical equipment they serve. Diversity is not applicable.

7.3.1.1.15.3.8 SPPSVS Actuated Devices

No additional devices or systems are actuated by the spray pond pump structure ventilation system.

7.3.1.1.15.3.9 SPPSVS Separation

The controls, instrumentation, and power supplies for the spray pond pump structure ventilation fans are physically and electrically separated for each of the fan systems. See Section 8.1.6.1.14 for a discussion of the electrical system separation.

7.3.1.1.15.3.10 SPPSVS Testability

Verification of operability of the cooling modes initiation circuits may be made when the applicable pumps are operationally tested. Verification of operability of the heating mode initiating circuits may be made by tripping the low temperature switch. The units may be manually tested by hand switches located in the control room.

7.3.1.1.15.3.11 SPPSVS Environmental Consideration

The controls for the subject equipment are located in the control enclosure and the spray pond pump structure. The environmental consideration for these areas and the control qualification summary is provided in Section 3.11.

7.3.1.1.15.3.12 SPPSVS Operational Considerations

7.3.1.1.15.3.12.1 SPPSVS General Information

The spray pond pump structure ventilation system is required for normal heating and cooling of the pump structure as well as for safeguard cooling of the pumps enclosed therein.

7.3.1.1.15.3.12.2 SPPSVS Reactor Operator Information

The operator is provided with fan motor status, building high temperature annunciator, and a fan system trouble annunciator.

7.3.1.1.15.3.12.3 Deleted

7.3.1.1.15.4 Emergency Switchgear and Battery Rooms Cooling System - Instrumentation and Controls

7.3.1.1.15.4.1 ESBRCS System Identification

The ESBRCS provides ventilation and cooling to the emergency switchgear rooms, inverter rooms, battery rooms, and the chiller equipment rooms in the control structure. For description and operation, see Section 9.4.1. See Chapter 8 for a description of the electrical system.

7.3.1.1.15.4.2 ESBRCS Power Sources

The power for the instruments and controls associated with the ESBRCS is supplied from the Class 1E 120 V ac system.

7.3.1.1.15.4.3 ESBRCS Equipment Design

Equipment design is described in Section 9.4.1.

7.3.1.1.15.4.4 ESBRCS Initiating Circuits

Each of the fans may be initiated in a protective function mode as follows: a standby fan may be automatically started by a low flow signal.

7.3.1.1.15.4.5 ESBRCS Logic and Sequencing

See drawings M-78FD for the control logic diagram.

One fan is started manually, and the other is placed on standby. An operating fan may be shut down automatically due to the following:

a. Loss of flow

b. Discharge temperature exceeding setpoint

c. Discharge temperature below setpoint

The standby fan starts upon detection of a loss of flow in the primary fan system and sends a signal to start the associated control structures chilled water pump and chiller. When a fan is operating, its temperature controls operate its cooling coil to maintain a constant environment in its service area.

7.3.1.1.15.4.6 ESBRCS Bypasses and Interlocks

The hand switch of each fan, when in the off position, provides input to a local panel alarm that is relayed to the control room. The fans are interlocked with the control enclosure chilled water pumps. Operation of a fan initiates operation of the associated chilled water pump.

7.3.1.1.15.4.7 ESBRCS Redundancy and Diversity

To maintain the redundancy of the mechanical equipment, controls and instrumentation are provided on a one-to-one basis with the mechanical equipment they serve. Diversity is not applicable.

7.3.1.1.15.4.8 ESBRCS Actuated Devices

The associated control enclosure chilled water system pumps are activated by the emergency switchgear and battery rooms supply fan units. These pumps are described in Section 7.3.1.1.13.4.

7.3.1.1.15.4.9 ESBRCS Separation

The controls, instrumentation, and power supplies of the emergency switchgear and battery rooms supply fans are physically and electrically separated for each of the fan systems. See Section 8.1.6.1 for a discussion of the electrical system separation.

7.3.1.1.15.4.10 ESBRCS Testability

Verification of the operability of the initiating circuits may be made as follows:

a. By putting each fan in the auto mode when the complementary fan of the pair is shut down

b. By manually testing the fans by hand switches located in the control room

7.3.1.1.15.4.11 ESBRCS Environmental Consideration

The controls for the subject equipment are located in the control enclosure. The environmental consideration for these areas and the control qualification summary is provided in Section 3.11.

7.3.1.1.15.4.12 ESBRCS Operational Considerations

7.3.1.1.15.4.12.1 ESBRCS General Information

The emergency switchgear and battery rooms HVAC system is required for normal operation of its service areas.

7.3.1.1.15.4.12.2 ESBRCS Reactor Operator Information

The operator is provided with a relayed fan system trouble alarm.

7.3.1.1.15.4.12.3 Deleted

7.3.1.1.15.5 ECCS Pump Compartment Unit Coolers - Instrumentation and Controls

7.3.1.1.15.5.1 ECCS-UC System Identification

The ECCS pump compartment unit coolers provide cooling to the core spray, HPCI, and RHR pump rooms. For description and operation, see Section 9.4.2.

7.3.1.1.15.5.2 ECCS-UC Power Sources

The power for the instruments and controls associated with the ECCS pump compartment unit coolers is supplied from the Class 1E 120 V ac system. See Chapter 8 for a description of the electrical system.

7.3.1.1.15.5.3 ECCS-UC Equipment Design

Equipment design is described in Section 9.4.2.

7.3.1.1.15.5.4 ECCS-UC Initiating Circuits

Each of the fans may be initiated in a protective function mode as follows:

a. A unit cooler will start when the respective pump starts.

b. A unit cooler may be manually started from the local control panel.

c. A fan may be started by the initiation of a high temperature switch.

7.3.1.1.15.5.5 ECCS-UC Logic and Sequencing

See drawings M-76FD for the control logic diagram.

When each pair of unit coolers is set up in a lead lag mode, automatic start is initiated under the following conditions:

a. When the area temperature exceeds 100°F, the lead fan starts.

b. When the area temperature exceeds 110°F, the standby fan starts.

The starting of a fan automatically opens a valve in the ESW system to supply cooling water to the unit.

The fan shuts down when the area temperature drops to 80°F.

7.3.1.1.15.5.6 ECCS-UC Bypasses and Interlocks

The hand switch of each fan, when in the off position, provides input to a local panel alarm that is relayed to the control room.

7.3.1.1.15.5.7 ECCS-UC Redundancy and Diversity

To maintain the redundancy of the mechanical equipment, controls and instrumentation are provided on a one-to-one basis with the mechanical equipment they serve. Diversity is not applicable.

7.3.1.1.15.5.8 ECCS-UC Actuated Devices

No additional devices or systems are actuated by the ECCS pump compartment unit coolers.

7.3.1.1.15.5.9 ECCS-UC Separation

The controls, instrumentation, and power supplies are physically and electrically separated for each of the ECCS unit coolers. See Section 8.1.6.1 for a discussion of the electrical system separation.

7.3.1.1.15.5.10 ECCS-UC Testability

Verification of operability of initiation circuits may be made when the applicable pumps are operationally tested. The units may be manually tested by hand switches located on local control cabinets.

7.3.1.1.15.5.11 ECCS-UC Environmental Consideration

The controls for the subject equipment are located in the reactor enclosure. The environmental consideration for this area and the control qualification summary is provided in Section 3.11.

7.3.1.1.15.5.12 ECCS-UC Operational Considerations

7.3.1.1.15.5.12.1 ECCS-UC General Information

The ECCS pump compartment unit coolers are not required for normal cooling of these areas when the ECCS pumps are not operating.

7.3.1.1.15.5.12.2 ECCS-UC Reactor Operation Information

The operator is provided with a relayed unit cooler system trouble alarm.

7.3.1.1.15.5.12.3 ECCS-UC Setpoints

For setpoints, see Section 7.3.1.1.15.5.5 (logic and sequencing).

7.3.1.1.15.6 Auxiliary Equipment Room Ventilation System - Instrumentation and Controls

7.3.1.1.15.6.1 AERVS System Identification

The auxiliary equipment room ventilation system provides ventilation and cooling to the auxiliary equipment room, computer room, remote shutdown room, control enclosure fan room, SGTS access area, and SGTS room. For description and operation, see Section 9.4.1.

7.3.1.1.15.6.2 AERVS Power Sources

The power for the instruments and controls associated with the auxiliary equipment room ventilation system is supplied from the Class 1E 120 V ac system.

7.3.1.1.15.6.3 AERVS Equipment Design

Equipment design is described in Section 9.4.1.

7.3.1.1.15.6.4 AERVS Initiating Circuits

Each of the supply fans can be initiated in a protective function mode as follows: a standby fan can be started by a low condition sensed in the other fan's INTAKE.

Each of the return fans can be initiated in a protective function mode as follows: a standby fan can be started by a low condition sensed in the other fan's INTAKE.

7.3.1.1.15.6.5 AERVS Logic and Sequencing

See drawings M-78FD for the control logic diagram. One supply and one return fan are started manually. The other fan in each pair is put on standby. An operating supply fan can be shut down automatically, due to the following:

a. Loss of flow

b. Discharge temperature exceeding setpoint

c. Discharge temperature below setpoint

The standby supply fan starts upon detection of loss of flow in the primary fan system and sends a signal to start the associated control structure chilled water pump and chiller. A return fan shuts down upon detection of loss of flow in its own system. When a supply fan is operating, its temperature controls operate its cooling and Class II heating and humidifying equipment to maintain a constant environment in its service area.

7.3.1.1.15.6.6 AERVS Bypasses and Interlocks

The hand switch of each fan, when in the off position, provides input to a control system alarm. The supply fans are interlocked with the control enclosure chilled water pumps and the supply fan low temperature cut-out is interlocked with the control enclosure purge system. The purge system, described in Section 9.4.1, is not an ESF. It has been upgraded to safeguard power status for convenience in interfacing with the control enclosure HVAC systems.

7.3.1.1.15.6.7 AERVS Redundancy and Diversity

To maintain the redundancy of the mechanical equipment, controls and instrumentation are provided on a one-to-one basis with the mechanical equipment they serve. Diversity is not applicable.

7.3.1.1.15.6.8 AERVS Actuated Devices

The associated control enclosure chilled water pumps are actuated by the supply fans.

7.3.1.1.15.6.9 AERVS Separation

The controls, instrumentation, and power supplies of the AERVS are physically and electrically separated for each of the fan systems. See Section 8.1.6.1 for a discussion of the electrical system separation.

7.3.1.1.15.6.10 AERVS Testability

Verification of the operability of the initiating circuits can be made as follows:

a. By putting each fan in the auto mode when the complementary fan of the pair is shut down

b. By manually testing the fans by hand switches located on local control cabinets

7.3.1.1.15.6.11 AERVS Environmental Consideration

The controls for the subject equipment are located in the control enclosure. The environmental consideration for this area and the control qualification summary is provided in Section 3.11.

7.3.1.1.15.6.12 AERVS Operational Considerations

7.3.1.1.15.6.12.1 AERVS General Information

The auxiliary equipment room ventilation system is required for normal operation of its service areas.

7.3.1.1.15.6.12.2 AERVS Reactor Operator Information

The following safety-related information is provided on a local control panel that has a trouble alarm relayed to the control room:

a. Fan motor status and damper position status for the supply and return fans

b. Supply fan electric heater leaving air temperatures

c. Supply fan leaving air temperature

The following nonsafety-related information is also provided on the local control panel:

a. Supply fan mixed air entering temperature

b. Auxiliary equipment room humidity level

c. Return fan leaving air temperature

7.3.1.1.15.6.12.3 Deleted

7.3.1.1.16 Drywell Unit Coolers - Instrumentation and Controls

7.3.1.1.16.1 DUC System Identification

The drywell unit coolers provide cooling and atmosphere mixing in the primary containment. For description and operation, see Section 9.4.5. Atmosphere mixing is the only safety-related function of this system.

7.3.1.1.16.2 DUC Power Sources

The power for the instruments and controls associated with the drywell unit coolers is supplied from the Class 1E 120 V ac system.

7.3.1.1.16.3 DUC Equipment Design

Equipment design is described in Section 9.4.5.

7.3.1.1.16.4 DUC Initiating Circuits

Each of the fans can be initiated or stopped in a protective function mode as follows:

a. A fan can be manually started from the control room.

b. A standby fan can be automatically started by a low flow signal.

7.3.1.1.16.5 DUC Logic and Sequencing

See drawings M-77FD for the control logic diagram.

Each pair of fans is set up in a run/auto mode.

The run fan is manually started and normally operates continuously. If loss of flow is detected by the flow switch, the unit is shut down and the autofan starts. Each fan may be manually stopped from the control room.

7.3.1.1.16.6 DUC Bypasses and Interlocks

The hand switch of each fan, when in the off position, provides input to a computer alarm.

7.3.1.1.16.7 DUC Redundancy and Diversity

To maintain the redundancy of the mechanical equipment, controls and instrumentation are provided on a one-to-one basis with the mechanical equipment they serve. Diversity is not applicable.

7.3.1.1.16.8 DUC Actuated Devices

No additional devices or systems are actuated by the drywell unit coolers.

7.3.1.1.16.9 DUC Separation

The controls, instrumentation, and power supplies of the drywell unit coolers are physically and electrically separated for each redundant pair of fans. See Section 8.1.6.1 for discussion of electrical system separation.

7.3.1.1.16.10 DUC Testability

Verification of operability of the initiation circuits may be made by putting each fan in the auto mode when the complementary fan of the pair is shut down. The units may be manually tested by hand switches located in the control room.

7.3.1.1.16.11 DUC Environmental Considerations

The controls for the subject equipment are located in the control enclosure, the reactor enclosure, and primary containment. The environmental considerations for these areas and the control qualification summary is provided in Section 3.11.

7.3.1.1.16.12 DUC Operational Considerations

7.3.1.1.16.12.1 DUC General Information

The drywell unit coolers are required to maintain uniform mixing of combustible gases in the drywell.

7.3.1.1.16.12.2 DUC Reactor Operator Information

The operator is provided with fan motor status and a fan system trouble alarm. In addition, the following nonsafety-related instrumentation and alarms are provided in the control room for each pair of fans:

a. Drywell area temperature (unit cooler inlet temperature) indicator

b. Unit cooler supply temperature indicator

c. Unit cooler temperature trouble

7.3.1.1.16.12.3 Deleted

7.3.1.1.17 Refueling Area Isolation System - Instrumentation and Controls

7.3.1.1.17.1 RAIS Identification

The RAIS provides signals to isolate the refueling area and start the SGTS under emergency conditions. A description and operation of the isolation system are given in Section 9.4.2.

7.3.1.1.17.2 RAIS Power Sources

The power for the instruments and controls associated with the isolation system is supplied from the Class 1E 120 V ac system. Chapter 8 gives a description of the electrical system.

7.3.1.1.17.3 RAIS Equipment Design

Equipment design is described in Section 9.4.2.

7.3.1.1.17.4 RAIS Initiating Circuits

Each channel of the isolation system may be manually initiated or automatically initiated in a protective function mode as follows:

a. A channel may be initiated by high radiation sensed by both of the two gamma sensors located in the refueling area exhaust duct.

b. A channel may be initiated by loss of refueling area differential pressure with respect to outside pressure.

7.3.1.1.17.5 RAIS Logic and Sequencing

Each channel of the redundant isolation system is normally held in an energized (fail-safe) mode so that an initiating signal or loss of power activates the channel and starts all the related systems. The isolation signal seals-in upon initiation, and removal of the initiating signal does not deactivate the channel. The channel may be reset to a normal condition only if the initiating condition, other than low building differential pressure, is no longer present. A key-lock reset is provided to bypass low building differential pressure to re-establish it with the normal ventilation system. Drawings M-76FD shows the logic diagram.

7.3.1.1.17.6 RAIS Bypasses and Interlocks

The hand switch of each isolation system, when in the RESET position, provides input to a control room alarm. The isolation system is interlocked with the SGTS exhaust fan start and SGTS filter valves auto change-over circuit.

7.3.1.1.17.7 RAIS Redundancy and Diversity

To maintain the redundancy of the mechanical equipment, controls and instrumentation are provided on a one-to-one basis with the mechanical equipment they serve.

7.3.1.1.17.8 RAIS Actuated Devices

The SGTS and the refueling area isolation are actuated by this system. Section 7.3.1.1.7 gives a description of the actuated system.

7.3.1.1.17.9 RAIS Separation

The controls, instruments, and power supplies of the isolation system are physically separated and electrically independent for each of the redundant trip channels. Section 8.1.6.1 gives a discussion of electrical system separation.

7.3.1.1.17.10 RAIS Testability

Verification of the operability of the initiating circuits may be made as follows:

a. By tripping the individual radiation monitor circuits

b. By tripping the differential pressure input circuits

c. By manually initiating the channels with hand switches located in the control room

The RAIS system may be tested as discussed above during plant operation.

7.3.1.1.17.11 RAIS Environmental Considerations

The controls for the isolation system are located in the refueling area, reactor enclosure, and the control enclosure. The environmental considerations for these areas are in Section 3.11.

7.3.1.1.17.12 RAIS Operational Considerations

7.3.1.1.17.12.1 RAIS General Information

The isolation systems are required to provide for refueling area isolation during emergency conditions. Sections 6.5.1 and 9.4.2 give system function.

7.3.1.1.17.12.2 RAIS Reactor Operator Information

The operator is provided with an isolation initiation alarm and an isolation incomplete alarm in the control room for each of the two channels. In addition, a common system (REIS and RAIS) "armed/bypassed" alarm is provided in the control room.

7.3.1.1.17.12.3 RAIS Setpoints

Refer to Technical Specifications for RAIS radiation setpoints.

7.3.1.2 IEEE 279 (1971) Design Basis Information

IEEE 279 (1971) defines the requirements for design bases. Using the IEEE 279 format, the following nine paragraphs fulfill the requirement for systems and equipment described in this section. Additional design basis information is given in Section 7.1.

7.3.1.2.1 IEEE 279 Design Basis Information - Conditions

The plant conditions that require protective action involving the systems of this section and other sections are examined and presented in Chapter 15.

7.3.1.2.2 IEEE 279 Design Basis Information - Variables

The plant variables that require monitoring to provide protective action are:

a. HPCI (Section 7.3.1.1.1.1.)

1. Reactor vessel water level
2. Primary containment pressure

b. ADS (Section 7.3.1.1.1.2.)

1. Reactor vessel water level
2. Primary containment pressure
3. Core spray and RHR pump discharge pressure

c. Core Spray (Section 7.3.1.1.1.3)

1. Reactor vessel water level
2. Primary containment pressure
3. Reactor vessel pressure

d. LPCI (Section 7.3.1.1.1.4)

1. Reactor vessel water level
2. Primary containment pressure
3. Reactor vessel pressure

e. PCRVICS (Section 7.3.1.1.2)

See Table 7.3-5.

f. Deleted

g. Containment Spray (Section 7.3.1.1.4)

1. Reactor vessel water level
2. Primary containment pressure
3. Reactor vessel pressure

h. CAC System (Section 7.3.1.1.6)

1. Containment hydrogen concentration
2. Containment oxygen concentration

7.3.1.2.3 IEEE 279 Design Basis Information - Number and Location of Sensors with Spatial Dependence Only

For the minimum number of channels required for functional performance, see the Technical Specifications. There are no sensors in the ECCS, PCRVICS, or RHR/containment spray systems that have a spatial dependence. Therefore, location information is not relevant.

7.3.1.2.4 IEEE 279 Design Basis Information - Operational Limits

Prudent operational limits for each safety-related variable trip setting are selected to be far enough above or below normal operating levels so that a spurious ESF initiation is prevented. It is then verified by analysis that the release of radioactive materials, following postulated gross failures of the fuel, or the nuclear system process barrier, is kept within acceptable bounds. Design basis operational limits as referenced in Chapter 16 are based on operating experience and constrained by the safety design basis and the safety analyses.

7.3.1.2.5 IEEE 279 Design Basis Information - Margin Between Operational Limits

The margin between operational limits and the limiting conditions for ESF systems operation are those parameters listed in Chapter 16. The margin includes the consideration of calibration error, sensor accuracy, response times, and sensor and setpoint drift. Annunciators are actuated at the setpoints to alert the reactor operator of the onset of unsafe conditions.

7.3.1.2.6 IEEE 279 Design Basis Information - Levels Requiring Protective Action

Levels requiring protective action for the ESF systems are provided in Chapter 16.

7.3.1.2.7 IEEE 279 Design Basis Information - Range of Energy Supply and Environmental Conditions of Safety Systems

See Section 3.11 for environmental conditions and Chapter 8 for the range of energy supply.

PCRVICS channel, logic, and MSIV 120 V ac power is provided by the RPS uninterruptible power source discussed in Section 7.2.1.1.3.

ECCS 125 V dc power is provided by the station safeguard batteries. ECCS 120 V ac power is provided by the instrument ac system.

ESF system MOV power is supplied from MCCs connected to the safeguard power system.

7.3.1.2.8 IEEE 279 Design Basis Information - Malfunctions, Accidents, and Other Unusual Events That Could Cause Damage to the Safety System

a. Floods

   The structures containing ESF systems components are designed to meet the PMF at the site location. This ensures that the structures remain watertight under PMF conditions, including wind-generated wave action and wave run-up (Section 3.4.1).

b. Storms and tornados

   The structures containing ESF components are designed to withstand the meteorological events described in Section 3.3.2. Superficial damage may occur to

miscellaneous station property during a postulated tornado, but this does not impair the ESF capabilities.

c. Earthquakes

The structures containing ESF components are seismically qualified as described in Section 3.7 and 3.8 and are designed to remain functional during and following a SSE. Seismic qualification of instrumentation and electrical equipment is discussed in Section 3.10.

d. Fires

If there is a fire, the redundant portions of the systems are separated by fire barriers to protect the ESF systems. If a fire were to occur within one of the sections or in the area of one of the panels, the ESF systems functions would not be affected by the fire. The use of separation and fire barriers ensures that, even though some portion of the systems may be affected, the ESF systems continue to provide the required protective action.

The ESFs are protected by different fire detection systems (heat and smoke detectors). The fire detection and the fire suppression systems are not ESF.

For further fire protection discussion, see Section 9.5.1.

e. LOCA

The following ESF components are located inside the drywell and are affected by a design basis LOCA:

1. Reactor vessel pressure, reactor vessel water level instrument taps and sensing lines, and drywell pressure sensing lines

2. Most inboard isolation valves and the SRVs, actuators, actuated equipment, and cables

3. Drywell unit coolers and associated cables

This equipment, which is located outside the containment, and the remainder of the ESF equipment is environmentally qualified to remain functional during and following a LOCA as discussed in Section 3.11

f. Pipe Break Outside Containment

This condition does not prevent ESFs from performing their safety functions (Section 3.6).

g. Feedwater Break

This condition does not prevent the ESFs from performing their safety functions (Section 3.6).

h. Missiles

See Section 3.5.

7.3.1.2.9 IEEE 279 Design Basis Information - Minimum Performance Requirements

The minimum performance requirements are identified in Chapter 16 for each of the ESF systems. These requirements include those for accuracy, which is accounted for in setpoint selection, in addition to the system response times. The instrument ranges of the initiating variables are contained in Tables 7.3-1, 7.3-2, 7.3-3, and 7.3-4 and are selected to accurately span normal, abnormal, and accident conditions. The ESF systems performance has been analyzed to bound the systems instrument capability.

See Table 7.3-5 for PCRVICS performance requirements.

Within ECCS, performance requirements refer only to a system as a whole and not specifically to individual components, except for ECCS instrument accuracy and range.

7.3.1.3 Final System Drawings

The following final system drawings are included in the UFSAR:

a. Piping and instrumentation diagrams

b. Functional control diagrams

c. Instrument and electrical drawings

d. Instrument location drawings

e. Logic diagrams

Electrical schematic diagrams are supplied under separate cover as the regulations allow. A list of the drawings is provided in Section 1.7.

There are no design basis differences for the subject systems between the PSAR and the FSAR. Direct comparison between the PSAR and FSAR verifies this.

Changes in the following areas have been made in the system design between the PSAR and the FSAR:

a. Analog transmitters and trip units replace the switches used in the ESF initiating circuits.

b. Additional testability has been designed into the ESF logic to allow complete testing.

c. Physical separation is maintained by the use of four divisions as opposed to the two divisions described in the PSAR.

d. The LPCI mode of RHR injects directly into the reactor instead of the recirculation piping.

e. The HPCI injects into the core spray sparger instead of the feedwater sparger.

f. The SRVs have dual solenoids. This allows the ADS to meet the single failure criteria.

g. Four additional diesel generators have been added to eliminate the sharing of diesels between units.

h. Additional bypass and inoperable status indication has been provided.

i. MSIV closure on low condenser vacuum has been added.

j. The isolation logic for the reactor water sample lines and the main steam line sample lines have been changed from initiation by low water level.

k. HPCI and RCIC steam line isolation valves no longer receive an automatic opening signal on system initiation.

l. The MSIV-LCS was replaced with the MSIV Leakage Alternate Drain Pathway.

m. CAC - containment recombiners included.

7.3.2 ANALYSIS

Presented below is an analysis to demonstrate how the various general functional requirements and specific regulatory requirements listed under the ESF design bases (Section 7.1.2) are satisfied.

7.3.2.1 Emergency Core Cooling Systems - Instrumentation and Controls

7.3.2.1.1 ECCS General Functional Requirements Conformance

a. Design basis 7.1.2.1.3.1.a

Chapter 15 and Chapter 6 evaluate the individual and combined capabilities of the emergency core cooling systems. For the entire range of the RCPB break sizes, the cooling systems prevent fuel cladding temperatures from exceeding 2200°F.

b. Design basis 7.1.2.1.3.1.b

Instrumentation for the ECCS must respond to the potential inadequacy of core cooling regardless of the location of a breach in the RCPB. Such a breach inside or outside the containment is sensed by reactor low water level. The reactor vessel low water level signal is the only ECCS initiating function that is completely independent of breach location. Consequently, it can actuate HPCI, CS, and LPCI.

The other major initiating function, drywell high pressure, is provided because pressurization of the drywell results from any significant RCPB breach anywhere inside the drywell. Consequently, it can actuate HPCI, CS, and LPCI.

Initiation of the ADS, which employs both reactor vessel low water level and drywell high pressure in coincidence, requires that the RCPB breach be inside the drywell. This control arrangement is satisfactory in view of the automatic isolation of the reactor vessel for breaches outside the drywell.

c. Design basis 7.1.2.1.3.1.c

An evaluation of ECCS controls shows that no operator action is required earlier than 10 minutes after a LOCA to initiate the correct responses of the ECCS. However, the control room operator can manually initiate every essential operation of the ECCS. Alarms and indications in the control room allow the operator to assess situations that require the ECCS and verify the responses of each system. This arrangement limits safety dependence on operator judgment, yet provides sufficient information for operator action when such action is determined to be necessary.

Capability for emergency core cooling following a postulated accident may be verified by observing the following indications:

a. Annunciators for HPCI, CS, LPCI, and ADS sensor and logic trips

b. Flow and pressure indications for each HPCI, CS, and LPCI

c. Valve position lights indicating open or closed valves

d. Relief valve position may also be inferred from reactor pressure indications

e. Process computer logging of trips in the emergency core cooling network

f. Relief valve discharge pipe temperature monitors and alarm

A NSOA is provided for the ECCS in Chapter 15.

7.3.2.1.2 ECCS Specific Regulatory Requirements Conformance

The conformance of the transmitter trip unit system is covered by Licensing Topical Report NEDO-21697A.

7.3.2.1.2.1 ECCS Conformance to Regulatory Guides

7.3.2.1.2.1.1 ECCS - Regulatory Guide 1.6 (1971) - Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems (Safety Guide 6)

See Section 8.1.6.1.1.

7.3.2.1.2.1.2 ECCS - Regulatory Guide 1.11 (1971) - Instrument Lines Penetrating Primary Reactor Containment (Safety Guide 11)

Instrument lines have automatic isolation.

7.3.2.1.2.1.3 ECCS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

Conformance to this regulatory guide is achieved by providing system and component testing capability, either during reactor power operation or shutdown.

Facilities for testing are provided so that the equipment can be operated in various test modes to confirm that it operates properly when called upon. Testing incorporates all elements of the system

under one test mode or another, including sensors, logic, actuators, and actuated equipment. The testing is planned to be performed at intervals so that there is an extremely low probability of failure in the periods between tests. During testing there are always enough channels and systems available for operation to provide proper protection.

7.3.2.1.2.1.4 ECCS - Regulatory Guide 1.29 (1978) – Seismic Design Classification

Instrumentation is classified as seismic Category I and is covered under Section 3.10.

7.3.2.1.2.1.5 ECCS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

See Section 8.1.6.1.5.

7.3.2.1.2.1.6 ECCS - Regulatory Guide 1.32 (1977) - Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants

Conformance is described in the conformance to GDC 17 and industry standard IEEE 308 (1971).

7.3.2.1.2.1.7 ECCS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

Indication is provided in the control room to inform the operator that a system is inoperable. Annunciation is provided to indicate that either a system or a part of a system is not operable. Indicator lights indicate the reason why the system is not operable. Conditions expected to occur more than once per year are automatically alarmed. In addition, there is a switch in the control room that the operator can use to manually bring up the system out-of-service annunciator.

All the annunciators can be tested by depressing the annunciator test switches on the control room bench boards.

The importance of providing accurate information for the reactor operator and reducing the possibility for the indicating equipment to adversely affect its monitored safety system is discussed in the following paragraphs:

a. Individual indicators are arranged together on the control room panel to indicate what function of the system is out-of-service, bypassed, or otherwise inoperable. All bypass and inoperability indicators, both at a system level and component level, are grouped only with those items that prevent a system from operating if needed.

b. As a result of design, preoperational testing, and startup testing, no erroneous bypass indication is anticipated.

c. These indication provisions serve to supplement administrative controls and aid the operator in assessing the availability of component and system level protective actions. This indication does not directly provide safety functions.

d. The annunciator initiation signals are provided by contacts and cannot prevent required protective actions.

e. Each indicator can be individually tested and is provided with dual lamps. Testing of these indicators is accomplished when the associated equipment is periodically tested.

7.3.2.1.2.1.8 ECCS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 (1973) is achieved by specifying, designing, and constructing the ECCS so that it meets the single failure criterion described in section 4.2 of IEEE 279 (1971), "Criteria for Protection Systems for Nuclear Power Generating Stations," and IEEE 379 (1972), "IEEE Trial Use Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems." Redundant sensors, instrument tubing, wiring, logic, actuators, and power supplies are used to ensure that a single failure in any portion of the ESF system does not prevent protective action. Separated divisions are employed, so that a fault affecting one division does not prevent the other division from operating properly.

7.3.2.1.2.1.9 ECCS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Means are provided for manual initiation of emergency core cooling at the system level through the following armed push button switches:

a. HPCI: one switch in Division 2

b. ADS A: two switches in Division 1

c. ADS C: two switches in Division 3

d. CS A: one switch in Division 1

e. CS C: one switch in Division 3

f. CS B: one switch in Division 2

g. CS D: one switch in Division 4

h. RHR A: one switch in Division 1

i. RHR B: one switch in Division 2

j. RHR C: one switch in Division 3

k. RHR D: one switch in Division 4

Operation of these switches accomplishes the initiation of all actions performed by the automatic initiation circuitry.

These switches are located in the control room on the designated ECCS division portions of the reactor core cooling vertical board and are easily accessible to the operator so that action can be taken expeditiously.

The ADS system initiation is interlocked to prohibit the ADS valves from opening unless both pumps in either of the two CS loops, or any of the four RHR pumps are running. However, each individual ADS valve can be remote-manually operated from the control room independent of interlocks. A failure in the automatic, manual, or common portions of the ADS protective function

logic will not prevent the performance of a protective action by redundant system or component level controls located in the control room.

ECCS systems are not required to meet single failure criterion. A failure in the automatic, manual, or common portions of an individual ECCS loop protective function will not prevent the performance of the protective action because ECCS function will be met by a redundant loop.

The HPCI system is not required to meet single failure criteria. ADS and low pressure injection systems, CS and LPCI, provide the HPCI backup safety functions in the event of a HPCI system failure. A failure in the automatic, manual, or common portions of the HPCI protective function logic will not prevent the performance of a protective action by redundant systems or component level controls located in the control room.

7.3.2.1.2.1.10 ECCS - Regulatory Guide 1.63 (1978) - Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants

See Section 8.1.6.1 for a discussion of the degree of conformance.

7.3.2.1.2.1.11 ECCS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

See Section 7.1.2.2.3 for separation criteria.

7.3.2.1.2.1.12 ECCS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

See Section 3.11.

7.3.2.1.2.1.13 ECCS - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

See Section 7.5.2.5.1.1.2 for a discussion of the degree of conformance.

7.3.2.1.2.1.14 ECCS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance with this regulatory guide is discussed in Section 3.10.

7.3.2.1.2.1.15 ECCS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

See Section 7.1.2.5.25 for a discussion of the degree of conformance.

7.3.2.1.2.1.16 ECCS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26 for a discussion of the degree of conformance.

7.3.2.1.2.2 ECCS - Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.1.2.2.1 ECCS - GDC 1 - Quality Standards and Records

The quality assurance program for the system ensures sound engineering in all phases of design and construction through conformity to regulatory requirements and design bases described in the license application. The quality assurance program during construction is discussed in the

document "Limerick Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction," referenced in FSAR Section 17.1.

Documents are maintained that demonstrate that all the requirements of the quality assurance program are being satisfied. These records will be maintained during the life of the operating licenses.

7.3.2.1.2.2.2 ECCS - GDC 2 - Design Bases for Protection Against Natural Phenomena

Wind and tornado loadings are discussed in Section 3.3, flood design is described in Section 3.4, and seismic qualification of instrumentation and electrical equipment is discussed in Section 3.10.

7.3.2.1.2.2.3 ECCS - GDC 3 - Fire Protection

The fire protection system and its design basis are discussed in Section 9.5.1, and fire protection in the cable systems is described in Section 8.3.3.

7.3.2.1.2.2.4 ECCS - GDC 4 - Environmental and Dynamic Effects Design Bases

The system is designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including LOCAs.

The system is appropriately protected against dynamic effects including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures. Missile protection is discussed in Section 3.5, pipe whip in Section 3.6, and environmental qualification of equipment in Section 3.11.

7.3.2.1.2.2.5 ECCS - GDC 10 - Reactor Design

The ECCS has been designed with appropriate margin to ensure that acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrence.

7.3.2.1.2.2.6 ECCS - GDC 13 - Instrumentation and Control

Conformance to this requirement is achieved by monitoring appropriate variables over the range expected and providing emergency core cooling as required to maintain the variables within the prescribed ranges.

7.3.2.1.2.2.7 ECCS - GDC 17 - Electric Power Systems

See Chapters 8.3.1.2.1 and 8.3.2.2.1.

7.3.2.1.2.2.8 ECCS - GDC 18 - Inspection and Testing of Electric Power Systems

See Chapters 8.3.1.2.1 and 8.3.2.2.1

7.3.2.1.2.2.9 ECCS - GDC 19 - Control Room

Controls and instrumentation are provided in the control room.

7.3.2.1.2.2.10 ECCS - GDC 20 - Protection Systems Functions

The system is automatically initiated after a LOCA as evidenced by high drywell pressure or reactor vessel low water level displayed in the control room.

7.3.2.1.2.2.11 ECCS - GDC 21 - Protection System Reliability and Testability

The components used are selected to meet specific requirements to ensure high functional reliability. The system can be tested and failures determined during normal plant operations.

7.3.2.1.2.2.12 ECCS - GDC 22 - Protection System Independence

The four divisions are independent and physically separated with separate instruments and controls to provide assurance that the protective function is not lost.

7.3.2.1.2.2.13 ECCS - GDC 23 - Protection System Failure Modes

The system is designed to tolerate malfunctions. See the NSOA provided for the ECCS in Chapter 15.

7.3.2.1.2.2.14 ECCS - GDC 29 - Protection Against Anticipated Operational Occurrences

The ECCS network is designed to remain functional during anticipated operating occurrences and initiate protective action if accident conditions develop (Section 7.3.2.1.2.3.1.1).

7.3.2.1.2.2.15 ECCS - GDC 33 - Reactor Coolant Makeup

Reactor coolant makeup for small breaks is provided to ensure that specified acceptable fuel design limits are not exceeded.

7.3.2.1.2.2.16 ECCS - GDC 35 - Emergency Core Cooling

The system initiates emergency core cooling (Section 6.3).

7.3.2.1.2.2.17 ECCS - GDC 37 - Testing of Emergency Core Cooling System

Testing the ECCS conforms to the criteria as demonstrated in Sections 6.3.4, 7.3.2.1.2.3.1.9, and 7.3.2.1.2.3.1.10.

7.3.2.1.2.3 ECCS Conformance to Industry Codes and Standards

The conformance of the transmitter trip unit system is covered by Licensing Topical Report NEDO-21617-A.

7.3.2.1.2.3.1 ECCS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

Compliance of the ECCS with IEEE 279 (1971) is detailed below.

7.3.2.1.2.3.1.1 ECCS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The ECCS is automatically initiated by instruments that sense the requirement for the initiation of protective action. The following systems are individually initiated by automatic means:

a. HPCI

b. ADS

c. CS

d. LPCI mode of the RHR system

This automatic initiation is accomplished with precision and reliability commensurate with the overall ECCS objective and is effective over the full range of environmental conditions cited below:

a. Power supply voltages -

ECCS:

Equipment is designed to operate over the voltage ranges specified in Section 8.3.1 for ac power, and Section 8.3.2 for dc power.

HPCI:

Tolerance is provided to complete loss of station ac power, but not loss of the dc source of power for the HPCI system.

ADS:

Tolerance is provided to complete loss of station ac power.

CS:

Tolerance is provided to complete loss of ac or dc power within one division.

LPCI:

Tolerance is provided to ac power supply failure so that failures cannot negate successful low pressure cooling. Dc power supply failure affects only one LPCI division.

b. Power supply frequency -

HPCI:

System control does not depend on ac power sources.

ADS:

No ac controls are used.

CS:

Excessive frequency reduction is indicative of an onsite power supply failure, and equipment shutdown in that division is required. Core spray equipment is designed to operate over the frequency range specified in Section 8.3.1.

LPCI:

Excessive frequency reduction is indicative of an onsite power supply failure, and equipment shutdown in that division is required. LPCI equipment is designed to operate over the frequency range specified in Section 8.3.1.

c. Temperature -

HPCI, ADS, CS, and LPCI:

These are operable at all temperatures that can result from any design basis LOCA. Also see Section 3.11.

d. Humidity -

HPCI, ADS, CS, and LPCI:

These are operable at all humidities, including steam, that can result from a LOCA. Also see Section 3.11.

e. Pressure -

HPCI, ADS, CS, and LPCI:

These are operable at all pressures resulting from a LOCA as required. Also see Section 3.11.

f. Radiation -

HPCI, ADS, CS, and LPCI:

These are designed to operate at all radiation levels expected for any design basis LOCA. Also see Section 3.11.

g. Vibration -

HPCI, ADS, CS, and LPCI:

Tolerance to conditions is stated in Section 3.10.

h. Malfunctions -

Overall ECCS:

Network tolerance to any single component failure to operate on command

i. Accidents -

HPCI, ADS, CS, and LPCI:

Network tolerance to all DBAs without malfunction

j. Fire -

Overall ECCS:

Network tolerance to raceway fires in a single division

k. Explosion -

HPCI, ADS, CS, and LPCI:

Explosions are not defined in design bases.

l. Missiles -

ADS:

Separate routing of the ADS conduits within the drywell reduces to a very low probability the potential for missile damage to more than one conduit to ADS or damage to the pilot solenoid assemblies of ADS valves.

Overall ECCS:

Network tolerance to any single missile destroying pipe, raceway, cabinet, or equipment in one division

m. Lightning -

HPCI, ADS, CS, and LPCI:

Ungrounded dc system not subject to lightning strikes

CS and LPCI:

Tolerance to lightning damage of ac power system is limited to one auxiliary bus system. See comments under (a) and (b).

n. Flood -

HPCI, ADS, CS, and LPCI:

All control equipment is located above level by design or below level in watertight compartments.

o. Earthquake -

HPCI, ADS, and LPCI:

Tolerance to conditions stated in Section 3.10

p. Wind and tornado -

HPCI, ADS, CS, and LPCI:

Seismic Category I structure houses all control equipment. See Section 3.3 for wind loadings.

q. System response time -

HPCI, ADS, CS, and LPCI:

Response times are within the requirements of need to start ECCS.

r. System accuracies -

HPCI, ADS, CS, and LPCI:

Accuracies are within those needed for correct timely action.

s. Abnormal ranges of sensed variables -

HPCI, ADS, CS, and LPCI:

Sensors are designed for the expected ranges and rates of change of variables.

7.3.2.1.2.3.1.2 ECCS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

a. HPCI:

The HPCI system, by itself, is not required to meet the single failure criterion. The single failure criterion is met by providing separation between ADS and HPCI systems. The control logic circuits for the HPCI system initiation and control are housed in a single relay cabinet, and the power supply for the control logic and other HPCI system equipment is from a single dc power source. The control logic for the ADS is housed in cabinets and is powered by sources that are separate from both the HPCI initiation logic and the HPCI isolation logic.

Physical separation of instrument lines is provided so that no single instrument rack destruction or single instrument line or pipe failure can prevent both HPCI and ADS initiation. Wiring separation between divisions also provides tolerance to wireway destruction, including shorts, opens, and grounds of the wireways in a single division.

b. ADS:

The ADS system, comprised of two independent sets of controls consisting of two channels each for the two pilot solenoids, meets the single failure criterion. Tolerance to the following single failures or events has been incorporated into the control system design and installation:

1. Single open circuit

2. Single short circuit

3. Single relay failure to pickup

4. Single relay failure to drop out

5. Single module failure (including multiple shorts, opens, and grounds)

6. Single control relay cabinet destruction (including multiple shorts, opens, and grounds)

7. Single instrument rack destruction (including multiple shorts, opens, and grounds)

8. Single raceway destruction (including multiple shorts, opens, and grounds)

9. Single control power supply failure (any mode)

10. Single control circuit failure

11. Single sensing line (pipe) failure

12. Single electrical component failure

c. CS:

The CS system, comprising two independent sets of controls for the two physically separated pumping systems, meets the single failure criterion. Tolerance to the following single failures or events has been incorporated into the control system design and installation:

1. Single open circuit

2. Single short circuit

3. Single relay failure to pickup

4. Single relay failure to drop out

5. Single module failure (including multiple shorts, opens, and grounds)

6. Single control relay cabinet destruction (including multiple shorts, opens, and grounds)

7. Single instrument rack destruction (including multiple shorts, opens, and grounds)

8. Single raceway destruction (including multiple shorts, opens, and grounds)

9. Single control power supply failure (any mode)

10. Single motive power supply failure (any mode)

11. Single control circuit failure

12. Single sensing line (pipe) failure

13. Single electrical component failure

d. LPCI:

Redundancy in equipment and control logic circuitry is provided so that it is highly unlikely that the complete LPCI subsystem can be rendered inoperative.

Four control logic circuits are provided. Control logic "A" initiates loop A pumps and valves. Control logic "B" initiates loop B pumps and valves. Control logics "C" and "D" initiate pumps C and D, respectively. Tolerance to the following single failures or events is provided in the control system design and installation.

1. Single open circuit

2. Single short circuit

3. Single relay failure to pickup

4. Single relay failure to drop out

5. Single module failure (including multiple shorts, opens, and grounds)

6. Single control relay cabinet destruction (including multiple shorts, opens, and grounds)

7. Single local instrument rack destruction (including multiple shorts, opens, and grounds)

8. Single raceway destruction (including multiple shorts, opens, and grounds)

9. Single control power supply failure

10. Single motive power supply failure

11. Single control circuit failure

12. Single sensing line (pipe) failure

13. Single electrical component failure

7.3.2.1.2.3.1.3 ECCS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

a. HPCI:

The discussion in this section regarding CS system equipment applies equally to the HPCI system.

b. ADS:

Components used in the ADS control system have been carefully selected for the specific application. Ratings have sufficient conservatism to ensure that there is no significant deterioration over the lifetime of the plant.

These components are subjected to the manufacturer's normal quality control and undergo functional testing on the panel assembly floor as part of the integrated module test before shipment of each panel. Only components that have demonstrated a high degree of reliability and serviceability in other functionally similar applications are selected for use in the ADS.

Furthermore, a quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

c. CS:

Components used in the CS control system have been carefully selected on the basis of suitability for the specific application. All of the sensors and logic relays are of the same types used in the RPS discussed in Section 7.2.1.1. Ratings have sufficient conservatism to ensure that there is no significant deterioration during anticipated duty over the lifetime of the plant.

These components are subjected to the manufacturer's normal quality control and undergo functional testing on the panel assembly floor as part of the integrated module test before shipment of each panel. Only components that have demonstrated a high degree of reliability and serviceability in other functionally similar applications are selected for use in the CS control system.

Furthermore, a quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

d. LPCI:

The discussion in this section regarding CS system equipment applies equally to the LPCI subsystem.

7.3.2.1.2.3.1.4 ECCS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

The ECCS safety-related controls and instrumentation have been qualified according to the requirements outlined in IEEE 323-1971 as highlighted in Section 7.1.2.7.4. The conditions for which the equipment has been qualified are those identified in Sections 3.10 and 3.11. The conditions identified cover normal, abnormal, and accident environments both inside and outside the drywell.

7.3.2.1.2.3.1.5 ECCS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The ECCS control system is designed to tolerate the spectrum of failures listed under the general requirements, meets the single failure criterion, and has been qualified for the accident environment and thus satisfies the channel integrity objective of this paragraph.

7.3.2.1.2.3.1.6 ECCS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

a. HPCI, ADS:

Channel independence for the initiation sensor is provided by electrical and mechanical separation of the ADS and HPCI. The ADS sensors A and E for reactor vessel water level, for instance, are located on one local instrument rack identified as Division 1 equipment, and the ADS sensors C and G are located on another instrument rack widely separated from the first and identified as Division 3 equipment. The HPCI sensors B and F are located on an instrument rack widely separated from the ADS instruments and identified as Division 2 equipment. The sensors of each division have a common pair of process taps that are widely separated from the corresponding taps of equipment in other divisions.

The disabling of one or both sensors in one location does not disable the control for both HPCI and ADS initiation. Likewise, HPCI sensors used for the inboard isolation valve logic are identified as Division 4 equipment and are separated from the ADS instruments. This ensures that failures cannot cause a false HPCI isolation at the same time that the ADS is disabled. Channel independence does not strictly apply to the HPCI system when considered alone, since the ADS is redundant to the HPCI.

Logic relays for the ADS are separated into Division 1 and Division 3 located in separate cabinets. ADS controls are separated on the control panels.

b. CS:

Channel independence of the sensors for each variable is provided by electrical isolation and mechanical separation. The sensors used to initiate each core spray pump are located on instrument panels widely separated from each other and are identified as belonging in one of four divisions. Sensor taps for each division are widely separated from each other. The disabling of one or all sensors in one location does not disable the control for both of the two CS loops.

Relay cabinets for each CS division are in separate physical divisions. Each division is complete in itself, with its own station battery, control and instrument power bus, power distribution buses, and MCCs. The divisional split is carried all the way from the process taps to the final control element, and includes both control and motive power supplies. Although there are only two sensors for each variable in each division, the drywell pressure and reactor water level sensors backup each other so that the logic for each division is one-out-of-two-twice, energized to operate.

c. LPCI:

Channel independence of the sensors for each variable is provided by electrical isolation and mechanical separation. The A and E, B and F, C and G, and D and H sensors for reactor vessel low water level, for instance, are located on racks that are identified as division 1, 2, 3, and 4 equipment and are widely separated from each other. The sensors of each division have a common process tap, which is widely separated from the corresponding tap for sensors of other divisions. Disabling of one or all sensors in one location does not disable the control for the other division.

Relay cabinets for each division are in a separate location from that of other divisions, and each division is complete in itself, with its own station battery, control and instrument power bus, power distribution buses, and MCCs. The divisional split is carried all the way from the process taps to the final control element and includes both control and motive power supplies.

Although there are only two sensors for each variable in each division, these sensors back each other up as described in the preceding paragraph describing core spray independence.

7.3.2.1.2.3.1.7 ECCS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The HPCI, ADS, CS, and LPCI systems are designated as safety systems and are designed to be independent of plant control systems.

7.3.2.1.2.3.1.8 ECCS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

a. HPCI:

Inputs that start the HPCI system are direct measures of the variables that indicate the need for high pressure core cooling, i.e., reactor vessel low water level or high drywell pressure. Reactor vessel water level and drywell pressure sensors are described in this section for the CS system and apply equally to the HPCI system.

b. ADS:

Inputs that start the ADS are direct measures of the variables that indicate both the need and acceptable conditions for rapid depressurization of the reactor vessel, i.e., the reactor vessel low water level is verified by high drywell pressure and at least one low pressure core cooling subsystem developing adequate discharge pressure plus adequate time delay to allow HPCI to operate if available. Reactor vessel water level and drywell pressure sensors are described in this section for the CS system and apply equally to the ADS system.

c. CS:

Inputs that start the CS system are direct measures of the variables that indicate the need for low pressure core cooling, i.e., reactor vessel low water level or high drywell pressure, coincident with reactor low pressure. The reactor vessel water level is sensed by level indicating sensors that are operated by the differential pressure between a reference leg and the pressure due to the actual height of water in the vessel.

Drywell high pressure is sensed by transducers on separate sensing lines connected to the four separate penetrations. Each sensing line has its own root valve, and each pressure sensor has its own instrument valve. Eight reactor vessel pressure sensors are used for the low pressure injection valve opening permissive. Four of the sensors used for the open permissive, plus four other reactor pressure sensors, in conjunction with drywell pressure are used in system initiation. These sensors are on four separate instrument lines going through the drywell at four different locations (Refer to Figure 7.3-26 for a diagram of level sensor

connections). Trip units connected to these sensors provide a signal to the logic for the CS system valve opening permissives.

d. LPCI:

Inputs that initiate the LPCI mode are the same as those described above for CS. The permissive for opening the injection valves is derived from ΔP sensors across the injection valves.

7.3.2.1.2.3.1.9 ECCS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

All HPCI, ADS, CS, and LPCI sensors are of the pressure-sensing type and are installed with calibration taps and instrument valves to permit testing during normal plant operation or during shutdown.

The reactor low pressure sensors can be checked for operability during plant operation by closing the instrument valve and bleeding off pressure to the low pressure actuation point to observe channel trip.

The reactor vessel level sensors and the drywell high pressure sensors can be checked by application of gas pressure from a low pressure source (instrument air or inert gas bottle) after closing the instrument valve and opening the calibration valve.

7.3.2.1.2.3.1.10 ECCS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

a. HPCI:

The discussion in this section regarding CS system testing and calibration applies equally to the HPCI system, except that the turbine (rather than the pump) is started by opening the steam inlet valve. One of the injection valves is kept closed during the test. The operability of the closed injection valve can be verified by repeating the test with the other valve interlocked closed or by opening it when the HPCI turbine is not operating.

b. ADS:

The ADS is not tested in its entirety during actual plant operation, but provisions are incorporated so that operability of all elements of the system can be verified at periodic intervals. The system is designed such that there is no isolation between the RPV and the ADS valves which prevents testing without depressurizing the RPV. The operability of each individual MSRV may be verified by the individual control switches on the control room panels, preferably during plant shutdown. Sensor open circuit or short circuit failures are immediately detected and annunciated by action from the trip units. In addition, the analog transmitter outputs can be monitored in the auxiliary equipment room and can be cross-checked by comparison with the other redundant channels that monitor the same parameter. Therefore, transmitters need only be surveillance tested once per operating cycle.

The ADS uses safety-grade instrumentation and control equipment. All parts of the system except the valves can be checked during operation. The entire system can be tested during shutdown. Testing the circuitry is accomplished at the control relay cabinets by test jacks, switches, and indicator lights while exercising one logic at a time. The test method is described in detail in Section 7.3.1.1.1.2.9.

c. CS:

The CS control system is capable of being completely tested during normal plant operation to verify that each element of the system, active or passive, is capable of performing its intended function. Sensors can be exercised by applying test pressures. Logic relays can be exercised by means of plug-in test switches used alone or in conjunction with single sensor tests. Pumps can be started by the appropriate breakers to pump water against system check valves or return it to the suppression pool through test valves, while the reactor is at pressure. MOVs can be exercised by the appropriate control relays and starters, and all indications and annunciations can be observed as the system is tested. Check valves are testable by a remotely operable pneumatic piston. CS water is not actually introduced into the vessel, except initially before fuel loading.

d. LPCI:

The discussion in this section regarding CS system testing and calibration applies equally to the LPCI subsystem.

7.3.2.1.2.3.1.11 ECCS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

a. HPCI:

Calibration of a sensor that introduces a single instrument channel trip does not cause a protective action without the coincident trip of a second channel. Removal of a sensor or trip unit from operation during calibration does not prevent the redundant instrument channel from functioning if accident conditions occur.

b. ADS:

Calibration of each sensor introduces a single instrument channel trip. This does not cause a protective action without the coincident trip of the other channel. Removal of an instrument channel from service during calibration is brief and does not significantly increase the probability of failure to operate. Removal of a sensor or instrument channel from operation during calibration does not prevent the redundant division from functioning if accident conditions occur. The manual reset buttons can interrupt the autodepressurization for a limited time. However, releasing either one of the two reset buttons allows automatic timing and action to restart if the permissives so dictate.

c. CS:

The discussion in this section regarding HPCI channel bypass is equally applicable to the CS system.

d. LPCI:

The discussion in this section regarding HPCI channel bypass is equally applicable to the LPCI mode.

7.3.2.1.2.3.1.12 ECCS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

a. HPCI:

There are no operating bypasses in the HPCI system.

b. ADS:

When the high drywell pressure bypass timer runs out, the high drywell pressure trip is bypassed and ADS is initiated on low water level alone.

c. CS:

There are no operating bypasses in the CS system.

d. LPCI:

There are no operating bypasses in the LPCI mode.

7.3.2.1.2.3.1.13 ECCS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

HPCI, ADS, CS, LPCI:

Automatic indication, accompanied by an audible alarm, is provided in the control room to inform the operator that the ECCS and the systems actuated or controlled by the ECCS are inoperable. Manual capability also exists in the control room to activate each system level indicator provided.

7.3.2.1.2.3.1.14 ECCS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

LPCI, HPCI, ADS, CS:

Access to switchgear, MCCs, and valves is procedurally controlled by the following means:

a. Seals (or locks) on valves, administrative procedure on instrument valves.

b. Lockable breaker control switch handles in the MCCs.

The logic test plugs are under the administrative control of plant supervisory personnel.

7.3.2.1.2.3.1.15 ECCS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

This section is not applicable to the HPCI, ADS, CS, or LPCI systems because all trip setpoints are fixed.

7.3.2.1.2.3.1.16 ECCS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It is Initiated

a. HPCI:

The final control elements for the HPCI system are essentially bistable, i.e., MOVs stay open or closed once they have reached their desired position even though their starter may drop out, which occurs when the limit of valve travel is reached. In the case of the turbine, the autoinitiation signal is electrically sealed-in. Thus protective action, once initiated (i.e, once flow is established), must go to completion

or continue until terminated by deliberate operator action or automatically stopped on vessel high water level or system malfunction trip signals.

b. ADS:

Each of the redundant autodepressurization control subsystems seals-in electrically and remains energized until manually reset by one of the two reset push buttons.

c. CS:

The final control elements for the CS system are essentially bistable, i.e., pump breakers stay closed without control power, and MOVs stay open once they have reached their open position even though the motor starter may drop out, which occurs when the valve open limit is reached. If there is an interruption in ac power, the load sequencing timers recycle, resulting in a time delay for pump restart and completion of the MOVs' motion. Thus, protective action, once initiated, goes to completion or continues until terminated by deliberate operator action.

d. LPCI:

The discussion provided in this section for the CS system is equally applicable to the LPCI mode.

7.3.2.1.2.3.1.17 ECCS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

The emergency core cooling system (HPCI, ADS, CS and LPCI) as a whole meets IEEE 279, paragraph 4.17 because each individual subsystem has a provision for its own manual initiation. In addition, no single failure in the initiation portion of the network of systems will prevent manual or automatic initiation of redundant portions of the network.

a. HPCI:

The HPCI has a manual initiation armed push button in parallel with the automatic initiation logic. In addition, each piece of HPCI system actuation equipment required to operate the pumps and valves is capable of manual initiation from the control panel in the control room, although failures of active components or a control circuit failure that produces a turbine trip may disable the manual actuation of the HPCI system. In no event can failure of the automatic, manual, or common control circuit for the HPCI system disable the ADS, which provides backup to the HPCI system.

b. ADS:

The ADS has four manual initiation switches. One switch is in each of the four logics. Both switches for one trip system have to be closed to manually initiate the ADS. To further preclude inadvertent actuation, each switch is equipped with a collar that must be turned before the electrical contacts of the push button are effective. Thus, to initiate the ADS manually, the operator must turn two collars and depress two push buttons. Whenever a collar is turned, an annunciator is actuated. The switches have the low pressure ECCS pumps running as a permissive interlock.

The ADS automatic initiation delay timer is provided to give HPCI ample time to automatically restore vessel level so that ADS actuation is not needed. This delay timer is not provided for manual initiation since the operator does not initiate ADS

until he/she determines it necessary. No single failure in the automatic, manual, or common portion of the ADS can prevent ADS initiation.

c. CS:

The CS system can be manually initiated at the system level in the control room. Each piece of CS system actuation equipment, such as a pump, valve, breaker, or starter, is capable of individual manual initiation electrically from the control panel in the control room.

Failures within the logic circuitry of a single CS logic may cause the failure of one CS loop. In no event can failure of the automatic, manual, or common portions of the control circuit for one CS loop disable the electrical control circuit for the other CS loop.

d. LPCI:

The discussion provided in this section for the CS system is equally applicable to the LPCI mode.

The HPCI, ADS, CS, and LPCI systems of ECCS share permissive logic between automatic and system level manual initiation logic. The design is acceptable because the individual subsystems of ECCS are not required to meet the single failure criterion. The ECCS function will be met with one of its subsystems inoperative.

7.3.2.1.2.3.1.18 ECCS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

The adjustable setpoint for the HPCI system flow controller is in the control room and is administratively controlled.

Setpoint adjustments for the HPCI, ADS, CS, and LPCI system trip units are integral with the trip units and cannot be changed without removal of a bar key-locked over these adjustments. Access to control relay cabinets is under administrative control.

7.3.2.1.2.3.1.19 ECCS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

For HPCI, ADS, LPCI, and CS, protective actions are directly indicated and identified by annunciator operation or instrument channel trip unit indicating lights.

7.3.2.1.2.3.1.20 ECCS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

a. HPCI:

The HPCI control system is designed to provide the operator with accurate and timely information pertinent to its status. The design minimizes conditions that could cause anomalous indications confusing to the operator. Periodic testing is the means provided for verifying the operability of the components and, by proper selection of test periods compatible with the historically established reliability of the components tested, complete and timely indications are made available. Sufficient information is provided on a continuous basis so that the operator can have a high degree of confidence that the HPCI function is available and/or operating properly.

Annunciators are provided as shown on the functional control diagram, drawings E41-1030-F-004, E41-1030-F-005, E41-1030-F-006, E41-1030-F-007, E41-1030-F-008, and E41-1030-F-009. In addition to these, there are other indications for the HPCI system in the control room. These indications include:

1. Valve position lights
2. Pump suction pressure indicator
3. Pump discharge pressure indicator
4. Pump flow indicator
5. Turbine exhaust line pressure indicator
6. Turbine steam supply pressure indicator
7. Turbine steam supply pipe area temperature indicator
8. Turbine speed indicator
9. Shaft vibration indication
10. Temperature recorder for:
    (a) Oil cooler discharge temperature
    (b) High pressure bearing oil temperature
    (c) Low pressure bearing oil temperature
    (d) Thrust bearing temperature
    (e) Pump oil temperature

b. ADS:

The information provided to the operator pertinent to ADS status is as follows:

1. Annunciators shown in drawings B21-1030-F-002, B21-1030-F-002, B21-1030-F-003, B21-1030-F-004, and B21-1030-F-005
2. Logic command position lights for each valve
3. Recorder for relief valve discharge pipe temperature

From the foregoing it can be seen that the change of state of any active component from its normal condition is called to the operator's attention; therefore, the indication is considered to be complete and timely. The condition of the ADS pertinent to plant safety is also considered to be adequately covered by the indications and alarms delineated above (Section 7.3.1.1.1.2.11.2).

c. CS:

The CS control system is designed to provide the operator with accurate and timely information pertinent to its status. The design minimizes conditions that could cause anomalous indications confusing to the operator. Testing is the means provided for verifying the operation of the components, and the test period is properly selected to be compatible with the historically established reliability of the components tested. In addition, trip units are provided with analog indications that allow operability checks through channel cross-comparisons. Sufficient information is provided on a continuous basis so that the operator can have a high degree of confidence that the CS function is available and/or operating properly. Annunciation is provided as shown in Figure 7.3-9. In addition to those annunciators, other indications are included on the main control panel as follows:

1. Valve position lights for each MOV
2. Pump breaker position lights for each pump
3. Position lights for the locked open valves in the drywell
4. Position lights for the testable check valves
5. Flow indication of loop flow in each loop
6. Indication of pump discharge pressure for each loop
7. CS pump current meter for each pump.

d. LPCI:

The LPCI control mode is designed to provide the operator with accurate and timely indication of its status. Signals are not transmitted to other systems if doing so

could cause indications confusing to the operator. Operability of components is verified by periodic testing. Sufficient information is continuously provided to enable the operator to be confident that the LPCI mode is available and/or operating properly.

Annunciators are provided as shown on the functional control diagram, drawings E11-1030-F-001, E11-1030-F-002, and E11-1030-F-003.

7.3.2.1.2.3.1.21 ECCS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The HPCI, ADS, CS, and LPCI control systems are designed to permit repair or replacement of components.

Recognition and location of a failed component is accomplished during periodic testing. The simplicity of the logic makes the detection and location of the component relatively easy, and components are mounted in such a way that they can be conveniently replaced in a short time.

7.3.2.1.2.3.1.22 ECCS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

The ECCS panels for HPCI, ADS, CS, and LPCI are distinctively identified as being in the protection system. Cables and raceways are distinctively colored according to their divisional assignment.

7.3.2.1.2.3.2 ECCS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Class 1 ac and dc power supply system ECCS loads are physically separated and electrically isolated into independent load groups so that safety actions provided by redundant counterparts are not compromised. See Section 8.1.6.2.

7.3.2.1.2.3.3 ECCS - IEEE 317 (1972) - Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations

See Section 8.1.

7.3.2.1.2.3.4 ECCS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electrical Equipment for Nuclear Power Generating Stations

See Section 3.11.2.

7.3.2.1.2.3.5 ECCS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

See Section 8.1.6.1 and Table 7.1-3.

7.3.2.1.2.3.6 ECCS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

The design of the ECCS permits periodic testing as described in Sections 7.3.1.1.1.1.9, 7.3.1.1.1.2.9, 7.3.1.1.1.3.9, and 7.3.1.1.1.4.9.

7.3.2.1.2.3.7 ECCS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

See Section 3.10.

7.3.2.1.2.3.8 ECCS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 279 (1971), paragraph 4.2, as further defined in IEEE 379 (1972), "Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems," is met as described in Section 7.3.2.1.2.3.1.2.

The redundancy of the control equipment for the ECCS is consistent with the redundancy of the cooling systems themselves, as shown in Figure 7.3-6. The arrangement of the initiating signals for the ECCS is shown in Figures 7.3-4 and 7.3-5.

An evaluation of the control schemes for each ECCS component shows that no single control failure can prevent the combined cooling systems from providing the core with adequate cooling. In performing this evaluation, the redundancy of components and cooling systems was considered.

For the minimum number of channels required for functional performance, see the Technical Specifications. The determinations of these minimums considered the use and redundancy of sensors in control circuitry and the reliability of the controlled equipment in any individual cooling system.

The control arrangement used for the ADS is designed to avoid spurious actuation (Table 7.3-9). The ADS relief valves are controlled by two trip logics per trip system; both trip logics must be in the tripped state to allow system initiation. Low pressure injection system operation must also be verified.

The conditions represented by Tables 7.3-8, 7.3-9, 7.3-10, and 7.3-11, and the Technical Specifications are a result of a functional analysis of each individual ECCS. Because of the redundant methods of supplying cooling water to the fuel in a LOCA and because fuel cooling must be ensured in such a situation, the minimum trip channel conditions in the Technical Specifications exceed those required operationally to ensure core cooling capability.

The only equipment protective devices that can interrupt planned ECCS operation are those that must act to prevent complete failure of the component or system. In no case can the action of a protective device prevent other redundant cooling systems from providing adequate cooling to the core.

Manual controls for the ECCS systems are located in the control room and are under supervision of the control room operator.

Some controls for one LPCI loop are located in the remote shutdown control room. Access to these controls is administratively controlled. Transfer of control to the remote shutdown panel is alarmed in the control room.

Components located inside the drywell and essential to ECCS performance are qualified to operate in the drywell environment resulting from a LOCA. Essential instruments located outside the drywell are qualified for the environment in which they must perform their essential function.

7.3.2.1.2.3.9 ECCS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Refer to Section 7.1.2.7.11.

7.3.2.1.3 ECCS Additional Design Considerations Analyses

As defined in Regulatory Guide 1.70, paragraph 7.3.2, the following considerations are addressed.

a. Loss of the plant instrument air system does not prevent the ECCS from performing its protective function.

b. Loss of cooling water to any single piece of vital equipment does not prevent the ECCS from performing its protective function.

7.3.2.2 Primary Containment and Reactor Vessel Isolation Control System - Instrumentation and Controls

7.3.2.2.1 PCRVICS General Functional Requirements Conformance

The PCRVICS is analyzed in this section. This system is described in Section 7.3.1.1.2, and that description is used as the basis for this analysis. The safety design bases and specific regulatory requirements of the system are stated in Section 7.1.2.1.2. This analysis shows conformance to the requirements given in that section.

The PCRVICS, in conjunction with other safety systems, is designed to provide timely protection against the onset and consequences of the gross release of radioactive materials from fuel and RCPBs. Chapter 15 identifies and evaluates postulated events that can result in gross failure of fuel and RCPB. The consequences of such gross failures are described and evaluated. Chapter 15 also evaluates a gross breach in a main steam line outside the containment during operation at rated power. The evaluation shows that the main steam lines are automatically isolated in time to prevent the loss of coolant from being great enough to allow the uncovering of the core. This is true even if the longest closing time of the valve is assumed.

The shortest possible main steam line valve closure time is 3 seconds. The transient resulting from a simultaneous closure of all MSIVs in 3 seconds during reactor operation at rated power is discussed in Chapter 15.

7.3.2.2.2 PCRVICS Specific Regulatory Requirements Conformance

The conformance of the transmitter/trip unit system is covered by Licensing Topical Report NEDO 21617-A.

7.3.2.2.2.1 PCRVICS Conformance to Regulatory Guides

7.3.2.2.2.1.1 PCRVICS - Regulatory Guide 1.11 (1971) - Instrument Lines Penetrating Primary Reactor Containment (Safety Guide 11)

The PCRVICS system is in conformance with this guide, except that position indication of excess flow check valves is provided locally, rather than in the control room as suggested in paragraph C.1.c. of the regulatory guide. However, annunciation in the control room is provided upon isolation of any excess flow check valve.

7.3.2.2.2.1.2 PCRVICS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

Facilities for testing are provided so that the equipment can be operated in various test modes to confirm that it will operate properly when required. Testing incorporates all elements of the system under one test mode or another, including sensors, logic, actuators, and actuated equipment. The testing is planned to be performed at intervals so that there is an extremely low probability of failure in the periods between tests. During testing there are always enough channels and systems available for operation to provide proper protection.

a. MSIV:

   The MSIVs, associated logic, and sensor devices may be tested from the sensor device to one of the two solenoids required for valve closure. The valve may be exercised closed with a slow-acting test solenoid to verify that there are no obstructions to the valve stem at full power. Before performing a valve closure using two fast-acting, main solenoids, a reduction in power is necessary to avoid reactor scram.

b. Other isolation valves:

   Except for the MSIVs, all isolation valves may be tested from sensor to actuator during plant operation. The test may cause isolation of the process lines involved, but this is tolerable.

c. PRPM subsystem:

This subsystem conforms to Regulatory Guide 1.22 in that provisions that allow periodic testing of individual channels have been built into the monitoring instruments and the trip systems.

7.3.2.2.2.1.3 PCRVICS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

All electrical and mechanical devices and circuitry between process instrumentation and protective actuators and monitoring of systems important to safety are classified as seismic Category I (Section 3.2).

See Section 7.1.2.5.6.

7.3.2.2.2.1.4 PCRVICS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

See Section 8.1.6.1.5.

7.3.2.2.2.1.5 PCRVICS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

a. MSIV and other isolation valves:

Automatic indication is provided in the control room to inform the reactor operator that a system is inoperable. Annunciation is provided to indicate that a system or part of a system is not operable.

Control switches are provided to manually initiate the system out of service annunciator, for situations that are not automatically annunciated.

Instruments that form part of a one-out-of-two-twice logic can be removed from service for calibration. Removal of the instrument from service is indicated in the control room by manual actuation of the "system out-of-service" annunciator.

Bypassing is not allowed in the trip logic or actuator logic. CAC system isolation valves associated with POST-LOCA combustible gas control may be overridden using key-locked bypass switches. Isolation signals to the CIGS isolation valves associated with long term operation of ADS valves may also be overridden using key-locked bypass switches.

b. These indication provisions serve to supplement administrative controls and aid the operator in assessing the availability of component and system level protective actions.

c. Each annunciator can be tested and is provided with dual lamps.

7.3.2.2.2.1.6 PCRVICS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

MSIV and other isolation valves:

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing, and constructing the engineered safeguards systems to meet the single failure criterion, section 4.2 of IEEE 279 (1971), and IEEE 379 (1972). Redundant sensors, wiring, instrument tubing, logic, actuators, and power supplies are used to insure that a single failure in any portion of the PCRVICS does not prevent protective action.

7.3.2.2.2.1.7 PCRVICS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

MSIV and other isolation valves:

Means are provided in the control room for manual initiation of reactor isolation at the system level through the use of four armed push button switches.

Operation of these switches accomplishes the initiation of all actions performed by the automatic initiation circuitry.

The equipment common to initiation of both manual reactor isolation and automatic isolation is kept to a minimum through implementation of manual reactor isolation as close as practicable to the final devices (relays) of the protective system. No single failure in the manual, automatic, or common portions of the protection system prevents initiation of reactor isolation by manual or automatic means.

Manual initiation of reactor isolation, once initiated, goes to completion as required by IEEE 279 (1971), section 4.16.

7.3.2.2.2.1.8 PCRVICS - Regulatory Guide 1.63 (1978) - Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants

See Section 8.1.6.1.12.

7.3.2.2.2.1.9 PCRVICS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

See Section 8.1.6.1.14 for a discussion of the degree of conformance.

7.3.2.2.2.1.10 PCRVICS - Regulatory Guide 1.89 (1974) - Qualification Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the PCRVICS is covered by Section 3.11.

7.3.2.2.2.1.11 PCRVICS - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

See Section 7.5.2.5.1.1.2 for a discussion of the degree of conformance.

7.3.2.2.2.1.12 PCRVICS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance with this regulatory guide is covered by Section 3.10.

7.3.2.2.2.1.13 PCRVICS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

See Section 7.1.2.5.25 for a discussion of the degree of conformance.

7.3.2.2.2.1.14 PCRVICS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26 for a discussion of the degree of conformance.

7.3.2.2.2.2 PCRVICS Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.2.2.2.1 PCRVICS - GDC 1 - Quality Standards and Records

See Section 7.1.2.6.1.

7.3.2.2.2.2.2 PCRVICS - GDC 2 - Design Bases for Protection Against Natural Phenomena

See Section 7.1.2.6.2.

7.3.2.2.2.2.3 PCRVICS - GDC 3 - Fire Protection

See Section 7.1.2.6.3.

7.3.2.2.2.2.4 PCRVICS - GDC 4 - Environmental and Dynamic Effects Design Bases

See Section 7.1.2.6.4.

7.3.2.2.2.2.5 PCRVICS - GDC 10 - Reactor Design

See Section 7.1.2.6.6.

7.3.2.2.2.2.6 PCRVICS - GDC 13 - Instrumentation and Control

a. MSIV and other isolation valves: The integrity of the reactor core and the RCPB is ensured by monitoring the appropriate plant variables and automatically closing various isolation valves if the variables exceed predetermined values.

b. Instrumentation is provided to monitor variables and systems over their anticipated ranges for normal operation, anticipated operational occurrences, and accident conditions.

7.3.2.2.2.2.7 PCRVICS - GDC 19 - Control Room

See Section 7.1.2.6.10.

7.3.2.2.2.2.8 PCRVICS - GDC 20 - Protection System Functions

a. MSIV and other isolation valves: The PCRVICS automatically isolates the appropriate process lines.

b. DELETED

c. PRPM subsystem: The subsystem conforms to GDC 20 in that activation of the trip circuit results in alarm annunciator activation and, depending on the specific trip, a

trip signal being sent to the plant vent system, the SGTS, and the containment system.

7.3.2.2.2.2.9 PCRVICS - GDC 21 - Protection System Reliability and Testability

MSIV, other isolation valves, and PRPM subsystems: The high reliability components are separated into four instrument and logic channels so that no single failure can incapacitate the system. Testing is covered in the discussion on conformance to Regulatory Guide 1.22 (Section 7.3.2.2.2.1.2).

7.3.2.2.2.2.10 PCRVICS - GDC 22 - Protection System Independence

a. MSIV and other isolation valves: Four redundant instrument and logic channels are physically separated so that no single failure can prevent an isolation. Functional diversity of sensed variables is used.

b. PRPM subsystem: This subsystem conforms to GDC 22 in that the effects of natural phenomena and normal operation (including testing) do not result in the loss of protection.

7.3.2.2.2.2.11 PCRVICS - GDC 23 - Protection System Failure Modes

a. MSIV and other isolation valves: The system logic and actuator signals are fail-safe. The MOVs will fail "as-is" on loss of power.

b. PRPM subsystem: This subsystem conforms to GDC 23 in that the trip circuits associated with each channel are specifically designed to fail-safe if there is loss of power.

7.3.2.2.2.2.12 PCRVICS - GDC 24 - Separation of Protection and Control Systems

MSIV, other isolation valves, and PRPM subsystems: The system has no control functions. The equipment is physically separated from the control system equipment to the extent that no single failure in the control system can prevent isolation.

7.3.2.2.2.2.13 PCRVICS - GDC 29 - Protection Against Anticipated Operational Occurrences

MSIV, other isolation valves, and PRPM subsystems: No anticipated operational occurrences prevent this equipment from performing its safety function. No anticipated operational occurrence can prevent an isolation.

7.3.2.2.2.2.14 PCRVICS - GDC 34 - Residual Heat Removal

Isolation signals are provided for the shutdown cooling subsystem of the RHR system.

7.3.2.2.2.3 PCRVICS Conformance to Industry Codes and Standards

The conformance of the transmitters/trip unit system is covered by Licensing Topical Report NEDO-21617.

7.3.2.2.2.3.1 PCRVICS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Systems

7.3.2.2.2.3.1.1 PCRVICS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

a. PCRVICS: The PCRVICS initiates automatic closure of specific isolation valves from trip signals generated by specified process variables and maintains the valves in a closed position without further application of power until a manual reset is permissible.

The control system is capable of initiating appropriate action and accomplishing it in a time commensurate with the need for valve closure. Total time, from the point where a process out-of-limits condition is sensed to the energizing or de-energizing of appropriate valve actuators, is less than 1.0 second. The closure time of valves ranges upward from a minimum of 3 seconds for the MSIVs, depending on the urgency for isolation considering the possible release of radioactivity. Thus it can be seen that the control initiation time is at least one order of magnitude lower than the minimum required valve closure time. The chosen speed of the sensors and valve actuators is compatible with the isolation function considered.

The minimum performance requirements are identified in Chapter 16 for the PCRVICS. These requirements include those for accuracy, which is accounted for in setpoint selection, in addition to the system response times. The instrument ranges of the initiating variables are contained in Table 7.3-5 and are selected to accurately span normal, abnormal, and accident conditions. The PCRVICS performance has been analyzed to bound the system's instrument capability.

The reliability of the isolation control system is compatible with the reliability of the actuated equipment (valves).

The PCRVICS equipment is designed for the full range of environmental conditions enumerated as follows:

1. Power supply voltage - Tolerance exists to any degree of power supply failure in one motive power system or one control power system. The PCRVICS is designed to operate over the range of voltage specified in Sections 8.3.1 and 8.3.2.

2. Power supply frequency - Tolerance exists to any degree of power supply failure in one power system or one control power system. The PCRVICS is designed to operate at the range of frequency specified in Section 8.3.1.

3. Temperature - The system operates within the required time limit at all temperatures that could result from an accident.

4. Humidity - The system operates within the required time limit at humidities (steam) that can result from a LOCA.

5. Radiation - PCRVICS equipment operates at all radiation levels expected and defined in Section 3.11.

6. Pressure - As required, the system operates at all pressures resulting from a LOCA.

7. Vibration - Tolerance to conditions is stated in Section 3.10.

8. Malfunctions - The system is tolerant to any single component malfunction.

9. Accidents - Tolerance exists for any DBA without malfunction of either subsystem.

10. Fire - The system is tolerant to any raceway fire in one division, or fire within a single enclosure.

11. Explosion - Explosions are not defined in design bases.

12. Missiles - The system has tolerances to any single missile destroying no more than one pipe, raceway, or cabinet.

13. Lightning - Tolerance to lightning damage is limited to one auxiliary bus system.

14. Flood - All control equipment is located above flood level by design.

15. Earthquake - Tolerance to conditions is stated in Section 3.10.

16. Wind and tornado - A seismic Class I structure houses all isolation control equipment. See Section 3.3 for wind loadings.

17. System response time - Responses are within the requirements dictated by the need to initiate the PCRVICS.

18. System accuracies - Accuracies are within those needed for correct timely action.

19. Abnormal ranges of sensed variables - Sensors are not subject to saturation when overranged.

b. DELETED

c. Reactor enclosure radiation monitoring system: The subsystem detects and promptly indicates excessive radiation in the reactor enclosure. On detection, an isolation is effected (Section 11.5).

d. Refueling floor radiation monitoring subsystem: The physical location and monitoring characteristics of the refueling floor radiation monitoring channels are adequate to detect abnormal amounts of radioactivity in the refueling floor exhaust duct and to initiate isolation. The redundancy and arrangement of channels ensure that no single failure can prevent isolation when required. During refueling operation (including criticality tests) the monitoring system acts as an engineered safeguard against the consequences of a refueling accident and a rod-drop accident. The response of the refueling floor radiation monitoring subsystem to a refueling accident is presented in Chapter 15.

The purpose of this subsystem is to initiate isolation of potentially contaminated refueling area ventilation effluent paths and initiate SGTS if there are excessive amounts of radioactive gases and particulate in the refueling area. For each of the two channels, two high-high radiation trips perform the following:

1. Close one of the two sets of Refueling Area supply and Refueling Area exhaust isolation valves.

2. Close one of the two sets of drywell and suppression pool purge and vent valves

3. Initiate one of two SGTS fans

Alternative trip functions are achieved by each of the two channels.

7.3.2.2.2.3.1.2 PCRVICS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

a. PCRVICS: Tolerance to the following single failures is incorporated into the isolation control system design and installation:

1. Single open circuit

2. Single short circuit

3. Single relay failure to pickup

4. Single relay failure to drop out

5. Single module failure (including multiple shorts, opens, and ground)

6. Single control cabinet bay destruction (including multiple shorts, opens, and grounds)

7. Single instrument panel destruction (including multiple shorts, opens, and grounds)

8. Single raceway destruction (including multiple shorts, opens, and grounds)

9. Single control power supply failure (any mode)

10. Single motive power supply failure (any mode)

11. Single control circuit failure

12. Single sensing line (pipe) failure

13. Single electrical component failure

b. PRMS: This criterion is met, since there are two independent channels that initiate redundant equipment. One failure affects only one channel.

The single failure criterion is met by the use of redundant sensors and logic to provide isolation functions and by seismic and environmental testing of the subsystem components. A single failure in any portion of the subsystem channel circuitry or trip system logic does not prevent a required isolation function from being accomplished.

Two separate power supplies are provided to ensure that a single power failure does not cause a spurious isolation; however, a complete power failure causes an isolation to occur.

7.3.2.2.2.3.1.3 PCRVICS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

a. PCRVICS: Components used in the isolation system are carefully selected on the basis of suitability for the specific application. All of the sensors and logic relays are of the same types used in the RPS. Ratings are selected with sufficient conservatism to ensure against significant deterioration during anticipated duty over the lifetime of the plant as illustrated below:

1. Switch and relay contacts carry no more than 50% of their continuous current rating.

2. Isolation control is de-energized to trip, instead of energized to trip, and is thus made to call attention to the failures that may occur in coil circuits, connections, or contacts.

3. Instrumentation and controls are heavy duty industrial types that have been subjected to type qualification testing and the manufacturer's normal quality control; components and systems undergo functional testing on the panel assembly floor as part of the integrated module test before shipment of each panel. Only components that have demonstrated a high degree of reliability and serviceability in other functionally similar applications or have been qualified by tests are selected for use in the isolation system.

Furthermore, a quality control and assurance program is required to be implemented and documented by equipment vendors to comply with the requirements set forth in 10CFR50, Appendix B.

b. PRMS: The sensor and converters as well as the indicator and trip units have been used in other BWR power plants.

7.3.2.2.2.3.1.4 PCRVICS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

The PCRVICS safety-related controls and instrumentation have been qualified according to the requirements outlined in IEEE 323 (1971) (as highlighted in Section 7.1.2.7.4.) The conditions for which the equipment has been qualified are those identified in Sections 3.10 and 3.11. The identified conditions cover normal, abnormal, and accident environments both inside and outside the drywell.

7.3.2.2.2.3.1.5 PCRVICS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

a. PCRVICS: The isolation system is designed to withstand the spectrum of failures listed under the general requirements, with the following exceptions. The structures containing PCRVICS components, except the turbine enclosure, are seismic Category I as described in Sections 3.7 and 3.8. The turbine enclosure is designed to withstand an SSE without structural elements

exceeding yield strength. The only PCRVICS components located in the nonseismic Category I turbine enclosure are the sensors and associated cables for the main steam high temperature leak detection MSIV alarm main steam line low

pressure MSIV trip, and low condenser vacuum MSIV trip (Table 7.3-6). Because reactor low level, and main steam line high flow are diverse to these MSIV isolation variables, placing these sensors or cables in the turbine enclosure does not compromise the ability of the PCRVICS to provide protective action when required.

b. PRMS: The channel components are operable under the predetermined normal and abnormal circumstances.

The trip channel components are selected to fulfill these minimum requirements.

7.3.2.2.2.3.1.6 PCRVICS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The redundant trip channels of this protective function are electrically isolated and physically separated to meet this design requirement.

Channel independence for redundant sensors exposed to each process variable is provided by electrical and mechanical separation. Physical separation is maintained between redundant elements of the PCRVICS to ensure that no credible single failure can prevent the safety action.

7.3.2.2.2.3.1.7 PCRVICS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

a. PCRVICS: There is no control function in the system. It is strictly a protection system. There are no transmissions of signals from this protection system equipment to control system equipment, therefore no isolation is required. No single random failure of a control system can prevent the isolation safety function.

b. PRMS: The four monitors for this protective function comply with this design requirement. Isolated contacts are used to provide isolation signals to close appropriate valves. Separation of inboard and outboard circuitry prevents postulated failures from impairing subsystem operation.

7.3.2.2.2.3.1.8 PCRVICS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

a. PCRVICS: The inputs that initiate isolation valve closure are direct measures of loss-of-coolant related variables that indicate a need for isolation, namely, reactor vessel low level, drywell high pressure, and pipe break detection. Pipe break detection is effected by measuring main steam line high flow or main steam line Outboard MSIV room temperature to detect loss of coolant rather than actual physical damage to the pipe itself. Turbine Enclosure Main Steam Tunnel High Ambient Temperature will alarm and subsequently be monitored by Operations and Manual action will be taken as needed per T.S. 3/4.7.9.

b. PRMS: The measurement of radiation of each of the designated exhaust plenums is the appropriate variable to use to determine radioactive releases into the containment.

7.3.2.2.2.3.1.9 PCRVICS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

a. PCRVICS: The RCPB instruments can be checked by cross- comparing instrument channels, or the instruments can be checked one at a time by application of simulated signals. These include level, pressure, temperature, and flow. During operation, radiation sensors are cross-checked, and during shutdowns they may be

bench calibrated. Temperature sensors used for leak detection are cross-checked periodically against other channels to provide assurance of operability.

b. PRMS: Due to the two-out-of-two configuration of the trip logic, one channel at a time may be removed from service to perform periodic tests.

7.3.2.2.2.3.1.10 PCRVICS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

a. PCRVICS: All active components of the PCRVICS can be tested or calibrated during plant operation. Pressure and level instrument channels can be cross-checked or valved out of the system and calibrated with a test signal. The radiation and temperature sensors can be cross-checked for verification or operability, and since they are used with reference to background, they do not require actual sensitivity verification on a frequent basis. The sensors may be bench calibrated during shutdown. The log radiation monitor can be tested by placing the monitor switch out of the "operate" position.

b. PRMS: An internal trip test circuit, adjustable over the full range of the trip circuit, is provided. The test signal is fed into the indicator and trip unit input so that a meter reading is provided in addition to a trip. All trip circuits are the latching-type and must be manually reset at the front panel.

Facilities for calibrating these monitor units are provided. It is a test unit designed for use in the adjustment procedure for the area radiation monitor sensor and converter unit. It provides several gamma radiation levels between 1 mrem/hr and 250 mrem/hr. The calibration unit source is an approved source.

A cavity in the calibration unit receives the sensor and converter unit. Located on the back wall of the cylindrical lower half of the cavity is a window through which radiation from the source emanates. A chart on each unit indicates the radiation levels available from the unit for the various control settings.

7.3.2.2.2.3.1.11 PCRVICS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

a. PCRVICS: Valving out and calibration of each sensor is annunciated by manual activation of the system out-of- service annunciator by the operator as well as individual sensor and channel trip annunciators. Calibration of a single sensor does not cause a protective action.

In the case of the MOVs, automatic or manual closure can be prevented by shutting off electric power to the motor starters. This action is indicated by annunciation in the control room.

b. PRMS: During the periodic testing of any given channel, the controls associated with a monitor permit the monitor to be tested for proper operation, and the two-out-of-two trip system logic prevents system level protective action. The two-out-of-two trip system logic channel, when in the test mode, provides an inoperative trip signal to meet the single failure requirements.

To bypass a channel for calibration, it is switched out of the "operate" position. This results in a downscale alarm and actuation of the upscale trip, thereby making

isolation possible in the vent that high radiation would cause an upscale trip in the remaining channel of the same logic. Whenever instrument trouble occurs, the downscale alarm sounds.

The above discussion is applicable to the RMS in Section 7.6 that initiates protective functions. In all cases, removal of the monitor from service causes actuation of the channel input to the system trip logic. In all cases, except the MSL-RMS, instrument trouble does not actuate the individual channel trip but causes a downscale alarm. The MSL-RMS isolation logic is configured such that either an upscale or downscale trip will cause a channel trip.

Administrative procedures are followed in all cases to remove from service a channel that is alarmed due to instrument trouble to ensure that system protective function is not inhibited.

In all cases, except the RHRSW-RMS, removal from service of one channel does not result in inadvertent actuation of the protective function. The RHRSW-RMS are arranged in a one-out-of-one logic configuration, and their removal from service will initiate protective action. Administrative procedures are followed in all cases to prevent removal from service of more than one channel at a time. For the RHRSW-RMS that trip the RHRSW pumps, bypass switches are provided as described in Section 7.3.1.1.12.6 that allow inhibiting the upscale trips.

7.3.2.2.2.3.1.12 PCRVICS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

a. PCRVICS: The isolation valve control system has two bypasses. One is the main steam line low pressure operating bypass, which is imposed by the mode switch in the other-than-run mode. The mode switch cannot be left in this position above 15% of rated power without initiating a neutron flux scram. Therefore the bypass is removed by the normal operational sequence, in accordance with the intent of IEEE 279 (1971), although it is a manual action that removes it, rather than an automatic one.

The low condenser vacuum bypass is imposed by a manual bypass switch in conjunction with closure of the turbine stop valves. Bypass removal is accomplished automatically by the opening of the turbine stop valves and manually by placing the bypass switch in normal position. Hence, the bypass is considered an operating bypass in accordance with IEEE 279 (1971).

Isolation signals to the CAC system isolation valves associated with POST-LOCA combustible gas control and to the CIGS isolation valves associated with long term operation of the ADS valves may be overridden by key-locked bypass switches by manually placing the switches in the bypass position after an isolation signal. The bypass switches are normally key-locked in the normal position to allow isolation of the applicable valves upon receipt of an isolation signal.

b. PRMS: This design requirement is not applicable to this protective function.

7.3.2.2.2.3.1.13 PCRVICS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

a. PCRVICS: The operating bypasses of the main steam line isolation valve closure trip and main condenser low vacuum trip are indicated in the control room.

The operating bypasses of the CAC system and CIGS valves isolation signal are indicated in the control room by annunciation of the bypassed condition and by valve position indicating lights.

Instrument bypass from calibration and certain other bypass conditions cannot be automatically annunciated. They are manually indicated by operator actuation of the system out-of-service annunciator.

b. PRMS: A downscale annunciation is produced during the monitor tests with the PRMS front panel controls. Substitution of the process input with a simulated input to the monitor produces downscale and upscale annunciation in the control room under specific conditions of the tests.

7.3.2.2.2.3.1.14 PCRVICS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

a. PCRVICS: The mode switch and condenser vacuum bypass switch are centrally located in the control room and are key-locked.

The CAC system and CIGS isolation valves bypass switches are centrally located in the control room and are key-locked.

b. PRMS: During the periodic test, administrative control procedures must be followed to remove one monitor from service and subsequently return it to service.

7.3.2.2.2.3.1.15 PCRVICS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

Paragraph 4.15 of IEEE 179 (1971) is not applicable, because all setpoints are fixed.

7.3.2.2.2.3.1.16 PCRVICS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

a. PCRVICS: All isolation actions are sealed-in by logic, so valves go to the close position completing the protective action. Manual reset action is provided by independent reset switches, so that inboard valves can be reset independently of outboard valves. This feature is incorporated only to augment the electrical separation of the inboard and outboard valves and not because of any need to reset them separately.

b. PRMS: The monitor output trip circuit remains in a tripped state whenever the gamma radiation level exceeds the established setpoint.

7.3.2.2.2.3.1.17 PCRVICS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

a. PCRVICS: The PCRVICS has four divisionally separated manual initiation switches that separately activate four MSIV logics and initiate the isolation system at the system level.

The logic for manual initiation is one-out-of-two-twice for the MSIVs. The manual initiation logic for other isolation valves is one-out-of-one by activating one of the system manual initiation switches (S28A for inboard, S28B for outboard), or two-out-of-two by activating both of the subsystem manual initiation switches.

Redundant manual controls are separated so that a single failure does not inhibit an isolation. The separation of redundant devices is maintained in both the manual and automatic portion of the system so that no single failure in either the manual or automatic portions can prevent an isolation by either manual or automatic means.

b. PRMS: This design requirement is not applicable to this protective function.

7.3.2.2.2.3.1.18 PCRVICS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

a. PCRVICS: Setpoint adjustments for the PCRVICS system sensors are integral with the trip unit located in the auxiliary equipment room, with suitable key-locked barriers, and are therefore under the administrative control of the operator.

b. PRMS: Access to the monitors is under the administrative control of plant personnel.

Operation of the monitor front panel controls, whether for calibration or test purposes, results in a downscale annunciation from the channel in the control room.

7.3.2.2.2.3.1.19 PCRVICS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

a. PCRVICS: Any one of the sensor relays actuates an annunciator, so that no single channel "trip" goes unnoticed. In addition, indicator lights are provided to show instrument channel trip. This combination of annunciation and visible verification relay actuation fulfills the requirements of this criterion.

b. PRMS: Actuation of any radiation monitor to produce a tripped condition initiates a control room annunciation for this protective function.

7.3.2.2.2.3.1.20 PCRVICS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

a. PCRVICS: The information presented to the reactor operator by the isolation control system is as follows:

1. Annunciation of each process variable that has reached a trip point

2. Computer readout of trips on main steam line Outboard MSIV room temperature or main steam line high flow

3. Annunciation of steam leaks in each of the systems monitored, namely, main steam, cleanup, and RHR

4. Open and closed position indicator lights for each isolation valve

5. Annunciation of any excess flow check valve isolation

b. PRMS: Actuation of any radiation monitor to produce a tripped condition initiates a control room annunciation for this protective function.

This information is considered to fulfill the requirements for information readout.

7.3.2.2.2.3.1.21 PCRVICS - IEEE 279 (1971), Paragraph 4.21 - System Repair

a. PCRVICS: The components that are expected to have a moderate need for replacement are designed for convenient removal. These include the temperature signals, amplifier units, and thermocouples. The amplifier units are of the circuit card or replaceable module construction, and the temperature sensors are replaceable units. Pressure, vessel level, flow, and temperature, sensors can be replaced in a reasonable length of time. The pressure, level, and flow devices are considered to be permanently installed although they have nonwelded connections at the instrument, which allows replacement. Failures can be detected during periodic testing, and replacement time is nominal.

   The main steam tunnel temperature sensors are not accessible during normal plant operation because of radiation from the main steam lines. However, duplicate sensors are provided that may be substituted for a failed sensor during operation. The failed sensor can be replaced during shutdown.

b. PRMS: The one-to-one relationship of detector, monitor, and trip circuitry permits the operator to identify a faulty channel and determine the defective component.

   Provisions are made to facilitate repair of the channel components during plant operation.

7.3.2.2.2.3.1.22 PCRVICS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

a. PCRVICS: Panels and racks that house isolation system equipment are identified by a distinctive color marker plate identifying the equipment as being in the protective system and listing the system name and designation of the particular redundant portion of the system. Cables, conduits, and raceways are color coded, displaying the appropriate redundant portion of the system.

b. PRMS: Special identification is provided for these monitors by special colored marker plates that identify the RPS division with which the units are associated. Cables, conduits, and raceways are color coded, displaying the appropriate redundant portion of the system.

   Control room devices are identified by tags on the panels. These tags indicate the functions of the devices.

7.3.2.2.2.3.2 PCRVICS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Station

Class 1E ac power supply systems are physically separated and electrically isolated into redundant load groups so that safety actions provided by redundant counterparts are not compromised (Section 8.3). The fail-safe logic for PCRVICS is powered from a non-Class 1E source.

7.3.2.2.2.3.3 PCRVICS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

Conformance of the components of the PCRVICS are covered by Section 7.1.2.7.4.

7.3.2.2.2.3.4 PCRVICS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

The system is completely testable in overlapping segments during reactor operation. The tests test the sensors through to the final actuators, demonstrate independence of channels, and detect failures.

7.3.2.2.2.3.5 PCRVICS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

The seismic qualification of components of the PCRVICS is covered by Section 3.10. This standard does not apply to the low steam line pressure MSIV trip, high condenser pressure MSIV trip, and high steam line temperature MSIV trip during or after an SSE as discussed in Section 7.3.2.2.2.3.1.5.

7.3.2.2.2.3.6 PCRVICS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 279 as defined by IEEE 379 (1972) is fully complied with in the design of the PCRVICS. All redundant sensors cabling, logic and actuators are physically separated so that any credible single failure cannot incapacitate the safety function. Section 7.3.2.2.2.3.1.2 contains more information.

7.3.2.2.2.3.7 PCRVICS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

See Section 7.1.2.7.11 for discussion of degree of conformance.

7.3.2.2.3 PCRVICS Additional Design Considerations Analyses

As defined in Regulatory Guide 1.70, paragraph 7.3.2, the following considerations are addressed:

a. Loss of the plant instrument air system does not prevent the PCRVICS from performing its protective function.

b. Loss of cooling water to any single piece of vital equipment does not prevent the PCRVICS from performing its protective function.

7.3.2.3 Information in this section has been deleted.

7.3.2.4 RHR - Containment Spray Mode - Instrumentation and Controls

7.3.2.4.1 RHR-CSM General Functional Requirements Conformance

The following analysis shows how the RHR-CSM meets the safety design bases identified in Section 7.1.2.1.30.1. When the RHR system is in the containment spray cooling mode, the pumps take suction from the suppression pool, pass it through the RHR heat exchangers and inject it through spray spargers located in the upper drywell and in the suppression pool air space. Operation of this system condenses steam present in these areas and mixes the drywell atmosphere to prevent pockets of hydrogen accumulation. The system is manually initiated as described in Section 7.3.1.1.4.5.

7.3.2.4.2 RHR-CSM Specific Regulatory Requirements Conformance

7.3.2.4.2.1 RHR-CSM Conformance to Regulatory Guides

7.3.2.4.2.1.1 RHR-CSM - Regulatory Guide 1.11 (1971) - Instrument Lines Penetrating Primary Reactor Containment (Safety Guide 11)

Instrument lines penetrating the primary reactor containment have excess flow check valves to isolate the lines in the event of line rupture.

7.3.2.4.2.1.2 RHR-CSM - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

Conformance to this regulatory guide is achieved by providing system and component testing capability, either during reactor power operation or shutdown.

7.3.2.4.2.1.3 RHR-CSM - Regulatory Guide 1.29 (1978) - Seismic Design Classification

All electrical and mechanical devices and circuitry between process instrumentation, protective actuators, and monitoring of systems important to safety are classified as Seismic Category I.

7.3.2.4.2.1.4 RHR-CSM - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

See Section 8.1.6.1.5.

7.3.2.4.2.1.5 RHR-CSM - Regulatory Guide 1.32 (1977) - Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants

Conformance is described in the conformance to IEEE 308 (1971).

7.3.2.4.2.1.6 RHR-CSM - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

Indication and annunciation is provided in the control room to inform the operator that a system or part of a system is inoperable. See Section 7.3.1.1.4.13.2 for a discussion of the bypass indication capability provided.

7.3.2.4.2.1.7 RHR-CSM - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

The system is designed with two independent and redundant portions to ensure that no single failure can prevent the safety function.

7.3.2.4.2.1.8 RHR-CSM - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

System initiation is manual from the control room. Interlocks are provided to prevent inadvertent manual initiation during normal reactor power operation. The manual controls are easily accessible to the operator so that action can be taken in an expeditious manner. Operation of the manual initiation accomplishes all of the actions performed by the automatic initiation circuitry.

No single failure in the manual, automatic or common portion of the protection system will prevent initiation by manual means. Manual initiation, once initiated, goes to completion as required by IEEE 279 (1971), section 4.16, unless overridden by a higher priority safety function, such as LPCI mode.

7.3.2.4.2.1.9 RHR-CSM - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

See Section 7.1.2.5.19 for a discussion of the degree of conformance.

7.3.2.4.2.1.10 RHR-CSM - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The identification and qualification of Class 1E equipment is discussed in Section 3.11.

7.3.2.4.2.1.11 RHR-CSM - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

See Section 7.5.2.5.1.1.2 for a discussion of the degree of conformance.

7.3.2.4.2.1.12 RHR-CSM - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

See Section 3.10 for a discussion of the degree of conformance.

7.3.2.4.2.1.13 RHR-CSM - Regulatory Guide 1.105 (1976) - Instrument Setpoints

See Section 7.1.2.5.25 for discussion of the degree of conformance.

7.3.2.4.2.1.14 RHR-CSM - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26 for discussion of the degree of conformance.

7.3.2.4.2.2 RHR-CSM Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.4.2.2.1 RHR-CSM - GDC 1 - Quality Standards and Records

All systems required for safety are designed and built in accordance with an established quality assurance program.

7.3.2.4.2.2.2 RHR-CSM - GDC 2 - Design Bases for Protection Against Natural Phenomena

All systems required for safety have been designed to withstand the effects of natural phenomena without losing the capacity to perform their safety functions.

7.3.2.4.2.2.3 RHR-CSM - GDC 3 - Fire Protection

All systems and components required for safety have been designed and are located to minimize the probability and effect of fires and explosions. Materials that are heat-resistant and noncombustible are used wherever practicable.

7.3.2.4.2.2.4 RHR-CSM - GDC 4 - Environmental and Dynamic Effects Design Bases

All safety-related systems and components are designed to withstand and function within the environmental conditions resulting from normal operations, maintenance, testing, and postulated accidents, including LOCAs. These systems and components are appropriately protected against dynamic events such as missiles and pipe whip.

7.3.2.4.2.2.5 RHR-CSM - GDC 13 - Instrumentation and Control

Instrumentation is provided to monitor variables and systems over their anticipated ranges for normal operation, anticipated operational occurrences, and accident conditions to ensure adequate safety.

7.3.2.4.2.2.6 RHR-CSM - GDC 19 - Control Room

A control room is provided where actions can be taken to operate the nuclear power unit under normal and abnormal conditions.

7.3.2.4.2.2.7 RHR-CSM - GDC 22 - Protection System Independence

The protection systems are designed to be redundant and diverse.

7.3.2.4.2.2.8 RHR-CSM - GDC 24 - Separation of Protection and Control Systems

The protection systems are separated from the control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel which is common to both, leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system.

7.3.2.4.2.2.9 RHR-CSM - GDC 29 - Protection Against Anticipated Operational Occurrences

The protection and reactivity control systems are designed to ensure an extremely high probability of fulfilling their safety functions in the event of anticipated operational occurrences.

7.3.2.4.2.2.10 RHR-CSM - GDC 38 - Containment Heat Removal

This mode is provided to assure heat removal from the reactor containment following any LOCA.

7.3.2.4.2.2.11 RHR-CSM - GDC 40 - Testing of Containment Heat Removal System

The containment heat removal system is designed to permit appropriate periodic and functional testing including the controls which bring the system into operation.

7.3.2.4.2.3 RHR-CSM Conformance to Industry Codes and Standards

7.3.2.4.2.3.1 RHR-CSM - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

7.3.2.4.2.3.1.1 RHR-CSM - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

a. Autoinitiation - Containment spray is not automatically initiated, however, its safety function is adequately ensured by manual initiation.

b. Appropriate Action - Appropriate action for the containment spray control system is defined as activating equipment for introducing water into the containment spray spargers.

c. Precision - The term precision does not apply strictly to the containment spray mode because of the wide range of setpoint values that could give the appropriate signal to allow manual initiation.

d. Reliability - Reliability of the control system is compatible with the controlled equipment.

e. Performance Under Adverse Conditions -

1. Power Supply Voltage - Tolerance is provided to any degree of ac power supply voltage fluctuation within one division such that voltage regulation failures in one division cannot prevent successful containment cooling. Dc power supply failure will likewise affect only one of the two containment spray divisions.

2. Power Supply Frequency - Same as Item e.1 above. Excessive frequency reduction is indicative of an onsite power supply failure, and equipment shutdown in that division is required.

3. Temperature - The RHR-CSM is operable at all temperatures that can result from any DBA.

4. Humidity - The RHR-CSM is operable at humidities (steam) that can result from any DBA.

5. Pressure - The RHR-CSM is operable at all pressures resulting from any DBA.

6. Vibration - Tolerance to such conditions is as stated in Section 3.10.

7. Malfunctions - Tolerance to any single component failure is provided.

8. Accidents - Tolerance to all DBAs has been provided.

9. Fire - Tolerance to a single raceway or enclosure fire or mechanical damage has been provided.

10. Explosions - Explosions are not defined in design basis.

11. Missiles - Tolerance to any single missile destroying no more than one pipe, raceway, or electrical enclosure has been provided.

12. Lightning - Tolerance to lightning damage of ac power system limited to one auxiliary bus system has been provided. See comments under Item e.1.

13. Flood - All control equipment is located above flood level by design or protected against flooding.

14. Earthquake - Tolerance has been provided to conditions stated in Section 3.10 and seismic Class 1 structures are used to house all control equipment.

15. Wind and Tornado - The structures containing ESF components have been designed to withstand meteorological events described in Section 3.3.2. Superficial damage may occur to miscellaneous station property during a postulated tornado, but this will not impair ESF capabilities.

16. System Response Time - Responses are within the requirements of the need to start containment spray. Manual initiation has been shown to be acceptable for initiation of this RHR mode.

17. System Accuracies - Accuracies are within those needed for proper system functioning and operational display.

18. Abnormal Ranges of Senses Variables - Sensors do not saturate when overranged.

7.3.2.4.2.3.1.2 RHR-CSM - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

Two 100% capacity systems are provided. Redundancy in equipment and control logic circuitry is provided so that a single failure will not render the complete containment spray system inoperative.

Two division logics are provided. Division 1 logic is provided to initiate loop A equipment and Division 2 logic is provided to initiate loop B equipment.

Tolerance to the following single failures or events is provided in the sensing channels, trip logic, actuator logic, and actuated equipment so that these failures will be limited to the possible disabling of the initiation of only one loop:

a. Single open circuit

b. Single short circuit

c. Single component failure open

d. Single component failure shorted or grounded

e. Single module failure (including multiple shorts, opens, and grounds)

f. Single electrical enclosure involvement (including multiple shorts, opens and grounds)

g. Single raceway destruction (including multiple shorts, opens, and grounds)

h. Single control power supply failure

i. Single motive power supply failure

j. Single control circuit failure

k. Single sensing line (pipe) failure

l. Single electrical component failure.

7.3.2.4.2.3.1.3 RHR-CSM - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

Components used in the containment spray control mode have been carefully selected for their specific application. Ratings have sufficient conservatism to ensure against significant deterioration during anticipated duty over the lifetime of the plant.

These components are subjected to the manufacturers' normal quality control and undergo functional testing on the panel assembly floor as part of the integrated module test prior to shipment of each panel assembly. Only components which have demonstrated a high degree of reliability and serviceability in other functionally similar applications or which have been qualified by tests are selected for use.

Furthermore, a quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.4.2.3.1.4 RHR-CSM - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

No components of the containment spray system are required to operate in the drywell environment. Sensory equipment is located outside the drywell and is capable of accurate operation with wider variations in ambient temperature than results from normal or abnormal (loss of ventilation and LOCA) conditions. All components used in the containment spray system have demonstrated reliable operation in similar nuclear power plant protection systems or industrial operation (Section 3.11.2).

7.3.2.4.2.3.1.5 RHR-CSM - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The containment spray system instrument channels are designed to maintain necessary functional capability under extreme conditions, thus satisfying the objective of channel integrity.

7.3.2.4.2.3.1.6 RHR-CSM - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

Channel independence of the sensors for each variable is provided by electrical isolation and mechanical separation. The A and E sensors for reactor vessel low water levels, for instance, are located on one local instrument panel that is identified as Division 1 equipment, and the B and F sensors are located on a second instrument panel, widely separated from the first and identified as Division 2 equipment. The A and E sensors have a common process tap which is widely separated from the corresponding tap for sensors B and F. Disabling of one or all sensors in one location does not disable the control for the other division.

Relay cabinets for Division 1 are in a separate physical location from that of Division 2. Each division is complete in itself, with its own station battery, control and instrument bus, power distribution buses, and MCCs. The divisional split is carried all the way from the process taps to the final activated equipment, and includes both control and motive power supplies.

Although there are only two sensors for each variable in each division, these sensors back up each other as described in the preceding paragraph.

7.3.2.4.2.3.1.7 RHR-CSM - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The containment spray system is a safety system designed to be independent of plant control systems.

7.3.2.4.2.3.1.8 RHR-CSM - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

The inputs which are permissive for the containment spray system are direct measures of the variables that indicate the need for containment cooling. Drywell high pressure is sensed by drywell pressure sensors. Low reactor vessel water (level 1) is sensed by vessel water level sensors. Reactor low pressure is sensed by vessel pressure sensors.

7.3.2.4.2.3.1.9 RHR-CSM - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

All sensors are of the pressure-sensing type and are installed with calibration taps and instrument valves to permit testing during normal plant operation or during shutdown. The drywell high pressure sensors can be checked only by application of gas pressure from a low pressure source (instrument air or inert gas bottle) after closing the instrument valve and opening the calibration valve.

The trip units mounted in the control structure are calibrated separately by introducing a calibration source and verifying the setpoint through the use of a digital readout on the trip calibration module.

7.3.2.4.2.3.1.10 RHR-CSM - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The containment spray system is capable of being completely tested during normal plant operation to verify that each element of the system, active or passive, is capable of performing its intended function. MOVs can be exercised by the appropriate control logic and starters, and all indications and annunciations can be observed as the system is tested.

The pumps can be started by use of the control switches in the control room. Sensors can be exercised by applying test pressures. Logic relays can be exercised by means of plug-in test switches used alone or in conjunction with single sensor tests.

7.3.2.4.2.3.1.11 RHR-CSM - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

Calibration of each sensor will induce a single instrument channel trip. This does not cause a protective function.

Removal of a sensor from operation during calibration does not prevent the redundant instrument channels from functioning if accident conditions occur. Removal of an instrument channel from service during calibration will be brief.

7.3.2.4.2.3.1.12 RHR-CSM - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

Containment spray has no operating bypasses.

7.3.2.4.2.3.1.13 RHR-CSM - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

See Section 7.1.2.7.1.

7.3.2.4.2.3.1.14 RHR-CSM - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Access to switchgear, MCCs, and instrument valves is procedurally controlled by the following means:

a. Administrative control of access to instrument valves

b. Lockable doors on emergency switchgear rooms

7.3.2.4.2.3.1.15 RHR-CSM - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

There are no multiple trip settings.

7.3.2.4.2.3.1.16 RHR-CSM - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

The final control elements for the containment spray system are essentially bistable, i.e., pump breakers stay closed without control power, and MOVs stay open once they have reached their open position, even though the motor starter may drop out (which will occur when the valve open limit switch is reached.

Thus, once initiated, protective action will go to completion and continue until terminated by deliberate operator action or in the use of the suppression pool spray.

7.3.2.4.2.3.1.17 RHR-CSM - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

Containment spray is a manually initiated system.

7.3.2.4.2.3.1.18 RHR-CSM - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Setpoint adjustments for the containment spray system sensors are integral with the trip units located in the auxiliary equipment room and cannot be changed without removal of covers over these adjustments. Access to test points in the control relay cabinets is under administrative control. Because of these restrictions, compliance with this requirement of IEEE 279 is considered complete.

7.3.2.4.2.3.1.19 RHR-CSM - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

Protective actions are directly indicated and identified by annunciator operation and trip unit indicator lights. This combination of annunciation and visible verification fulfills the requirements of this criterion.

7.3.2.4.2.3.1.20 RHR-CSM - IEEE 279 (1971), Paragraph 4.20 - Information Readout

Sufficient information is provided on a continuous basis so that the operator can have a high degree of confidence that the containment spray function is available and/or operating properly. The design minimizes conditions that could cause inconsistent indications confusing to the operator.

7.3.2.4.2.3.1.21 RHR-CSM - IEEE 279 (1971), Paragraph 4.21 - System Repair

The containment spray control system is designed to permit repair or replacement of components.

All devices in the system are designed for a 40 year lifetime under the imposed duty cycles with periodic maintenance. Since this duty cycle is composed mainly of periodic testing rather than operation, lifetime is more a matter of "shelf life" than active life. However, all components are selected for continuous-duty plus thousands of cycles of operation, far beyond that anticipated in actual service. The pump breakers are an exception to this with regard to the large number of operating cycles available. Nevertheless, even these breakers should not require contact replacement within 40 years, assuming periodic pump starts each 3 months.

Recognition and location of a failed component will be accomplished during periodic testing. The simplicity of the logic will make the detection and location relatively easy, and components are mounted in such a way that they can be conveniently replaced in a short time.

7.3.2.4.2.3.1.22 RHR-CSM - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

A nameplate distinctively identifies the equipment as being in the protective system for each logic cabinet and instrument panel that is part of the containment spray system. The nameplate shows the division to which each panel or cabinet is assigned.

Identification of cables and raceways is discussed in Section 8.3.1.3.

Panels in the control room are identified by tags which indicate the system and logic contained in each panel.

7.3.2.4.2.3.2 RHR-CSM - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Class 1E power supply system containment spray loads are physically separated and electrically isolated into independent load groups so that safety action provided by redundant counterparts are not compromised. Refer to Section 8.1.6.1.6 for details of the Class 1E power system.

7.3.2.4.2.3.3 RHR-CSM - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.4 for a discussion of system compliance to this standard.

7.3.2.4.2.3.4 RHR-CSM - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Station

See Section 8.1.6.1.5.

7.3.2.4.2.3.5 RHR-CSM - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

The design of the containment spray cooling system permits periodic testing as described in Sections 7.3.1.1.4.10 and 7.3.2.4.3.1.10.

7.3.2.4.2.3.6 RHR-CSM - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.7 for a discussion of system compliance to this standard.

7.3.2.4.2.3.7 RHR-CSM - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 279 (1971), paragraph 4.2 as further defined in IEEE 379 (1972), "Application of the Single Failure Criterion to Nuclear Power Generating Station Protection System," is met as described in Section 7.3.2.4.2.3.1.2.

7.3.2.4.2.3.8 RHR-CSM - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Independence of containment spray equipment is demonstrated in the Section on conformance to IEEE 279 (1971), paragraph 4.6 and IEEE 308 (1976). See Sections 7.3.1.1.4.10 and 7.3.2.4.2.3.1.6.

7.3.2.4.3 RHR-CSM Additional Design Considerations Analyses

As defined in Regulatory Guide 1.70, paragraph 7.3.2, the following considerations are addressed:

a. Loss of the plant instrument air system does not prevent the containment spray mode from performing its protective function.

b. Loss of cooling water to any single piece of vital equipment does not prevent the containment spray mode from performing its protective function.

7.3.2.5 RHR - Suppression Pool Cooling Mode – Instrumentation and Controls

7.3.2.5.1 RHR-SPCM General Functional Requirements Conformance

The following analysis shows how the safety design bases identified for the RHR-SPCM in Section 7.1.2.1.32.1 are met. The RHR-SPCM is designed to limit the water temperature in the suppression pool such that the temperature immediately after a blowdown does not exceed the established limit when reactor pressure is above the limit for cold shutdown. During this mode of operation, water is pumped from the suppression pool, through the RHR system heat exchangers, and back to the suppression pool. The RHR-SPCM thus maintains the suppression pool as a heat sink for reactor and containment blowdown and as a source of water for ECCS, containment spray, and shutdown cooling.

7.3.2.5.2 RHR-SPCM Specific Regulatory Requirements Conformance

7.3.2.5.2.1 RHR-SPCM Conformance to Regulatory Requirements

7.3.2.5.2.1.1 RHR-SPCM - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

Conformance to this guide is discussed in Section 7.3.2.4.2.1.2.

7.3.2.5.2.1.2 RHR-SPCM - Regulatory Guide 1.29 (1978) - Seismic Design Classification

Conformance to this guide is discussed in Section 7.3.2.4.2.1.3.

7.3.2.5.2.1.3 RHR-SPCM - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

Conformance to this guide is discussed in Section 7.3.2.4.2.1.4.

7.3.2.5.2.1.4 RHR-SPCM - Regulatory Guide 1.32 (1977) - Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants

Conformance is described in the conformance to IEEE 308 (1971).

7.3.2.5.2.1.5 RHR-SPCM - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

Conformance to this guide is discussed in Section 7.3.2.4.2.1.6.

7.3.2.5.2.1.6 RHR-SPCM - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

The system is designed with two independent and redundant portions to assure that no single failure can prevent the safety function.

7.3.2.5.2.1.7 RHR-SPCM - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

System initiation is manual from the control room. The manual controls are easily accessible to the operator so that required actions can be performed quickly. Once initiated, system initiation goes to completion unless overridden by a higher priority function or interlock.

7.3.2.5.2.1.8 RHR-SPCM - Regulatory Guide 1.63 (1978) - Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants

The electric penetration assemblies are designed so that the containment structure can, without exceeding the design leakage rate, accommodate the calculated pressure, temperature and other environmental conditions resulting from any LOCA.

7.3.2.5.2.1.9 RHR-SPCM - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

Conformance to this guide is discussed in Section 8.1.6.1.14.

7.3.2.5.2.1.10 RHR-SPCM - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

Conformance to this guide is discussed in Section 3.11.

7.3.2.5.2.1.11 RHR-SPCM - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following An Accident

Conformance to this guide is discussed in Section 7.5.2.5.1.1.2.

7.3.2.5.2.1.12 RHR-SPCM - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance to this guide is discussed in Section 3.10.

7.3.2.5.2.1.13 RHR-SPCM - Regulatory Guide 1.105 (1976) - Instrument Setpoints

Conformance to this guide is discussed in Section 7.1.2.5.25.

7.3.2.5.2.1.14 RHR-SPCM - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

Conformance to this guide is discussed in Section 7.1.2.5.26.

7.3.2.5.2.2 RHR-SPCM - Conformance to 10CFR50, Appendix A, General Design Criteria

Conformance to GDC 1, 2, 3, 4, 13, 19, 22, 24, 29, 38, and 40 is described in Section 7.3.2.4.2.2.

7.3.2.5.2.3 RHR-SPCM Conformance to Industry Codes and Standards

7.3.2.5.2.3.1 RHR-SPCM - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

7.3.2.5.2.3.1.1 RHR-SPCM - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

a. Autoinitiation - The suppression pool cooling mode has no autoinitiation feature, but is manually initiated from the control room. Proper and timely system operation is assured with manual initiation, because sufficient time and information is available to the operator. The monitored parameters which would indicate satisfactory system performance, or operator error include fluid temperature, flow, pressure, and valve positions.

b. Appropriate Protective Action - The suppression pool cooling instrumentation and controls allow manual initiation of cooling flow to control suppression pool temperature.

c. Precision - Since suppression pool cooling is manually initiated based on one or more parameters, precision does not strictly apply to this system's control circuitry.

d. Reliability - Reliability of the control system is compatible with controlled equipment.

e. Performance Under Adverse Conditions -

1. Power supply voltage and frequency - An electrical fault in one division cannot impair proper suppression pool cooling mode operation due to the redundant control circuits, each being supplied by different power sources.

2. Temperature - The suppression pool cooling mode is designed to function properly in the high temperature environment expected during DBAs.

3. Humidity - The system is designed to function properly in the high humidity (steam) environment expected during DBAs.

4. Pressure - The system is designed to function properly in the full range of pressures expected during DBAs.

5. Vibration - Tolerance to environmentally induced vibration (earthquake, wind) is discussed in Section 3.10.

6. Accidents - The system is tolerant to any DBA.

7. Fire - The system is tolerant to a fire in a single division raceway or enclosure.

8. Explosions - Explosions are not defined in the design basis.

9. Missiles - The system is tolerant to any single missile destroying no more than one pipe, raceway, or electrical enclosure.

10. Lighting - The system is tolerant to lightning damage to one auxiliary ac bus.

11. Flood - All instrumentation and controls are located above flood level or are protected from flood damage.

12. Earthquake - All control equipment is housed in a seismic Class I structure. Tolerance to earthquake damage is discussed in Section 3.10.

13. Wind and Tornado - The structures containing ESF components have been designed to withstand meteorological events described in Section 3.3.2. Superficial damage may occur to miscellaneous station property during a postulated tornado, but this will not impair ESF capabilities.

14. System Response Time - Manual initiation has been shown to provide adequate response time for initiation of this RHR mode.

15. System Accuracies - Instrumentation accuracy is covered in the Technical Specifications.

16. Ranges of Monitored Parameters - Instrument sensors and processing equipment are capable of displaying the full ranges of parameters expected during DBAs.

7.3.2.5.2.3.1.2 RHR-SPCM - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

Two independent fluid systems are provided, each with the capacity for removing the total design heat load. Two division logic networks are provided: Division 1 logic initiates loop A equipment and Division 2 logic initiates loop B equipment.

Redundancy in equipment and control logic circuitry is provided so that a single failure will not interfere with proper operation of the redundant portions of the system.

Tolerance to specific single failures or events is discussed in Section 7.3.2.4.2.3.1.2.

7.3.2.5.2.3.1.3 RHR-SPCM - IEEE 279 (1971), Paragraph 4.3 - Quality of Component and Modules

Components used in the RHR-SPCM have been carefully selected for their specific applications. Ratings have sufficient conservatism to prevent significant deterioration during expected duty over the lifetime of the plant.

These components are subjected to the manufacturer's normal quality control and undergo functional testing on the panel assembly floor as part of the integrated module test prior to shipment of each panel assembly. Only components which have demonstrated a high degree of

reliability and serviceability in other functionally similar applications, or which have been qualified type testing, are selected for use. Additionally, equipment vendors are required to implement and document a quality control and assurance program in accordance with the requirements of 10CFR50, Appendix B.

7.3.2.5.2.3.1.4 RHR-SPCM - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

Components of the suppression pool cooling mode instrumentation have undergone qualification testing to evaluate their suitability for reliable service in their installed locations, or have demonstrated reliable operation in similar nuclear power plant installations and industrial applications (Section 3.11).

No component of the control system is required to operate in the drywell environment. Sensory equipment is located outside the drywell and is capable of accurate operation in wide variations of environmental conditions.

7.3.2.5.2.3.1.5 RHR-SPCM - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The RHR-SPCM instrumentation and controls are designed to remain operable under extreme environmental conditions as detailed in Section 3.11.

7.3.2.5.2.3.1.6 RHR-SPCM - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

Channel independence is maintained for all suppression pool cooling control circuitry. Channel sensor instrumentation is physically and electrically separated and identified as belonging to the respective divisions. Relay cabinets are physically and electrically separated. Each division has its own battery, control and instrumentation bus, power distribution buses, and MCCs.

7.3.2.5.2.3.1.7 RHR-SPCM - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The RHR-SPCM is a safety function and is independent of plant control systems.

7.3.2.5.2.3.1.8 RHR-SPCM - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

The inputs to the interlock circuit for suppression pool cooling flow control are the same as those used for LPCI (Section 7.3.1.1.1.4.4 and 7.3.1.1.1.4.5)

7.3.2.5.2.3.1.9 RHR-SPCM - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

Discussion of checks on sensors used in the interlock circuit are discussed in Section 7.3.1.1.1.4.9.

7.3.2.5.2.3.1.10 RHR-SPCM - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The RHR-SPCM can be tested completely during normal plant operation to verify that each element of the system, active or passive, is capable of performing its intended function. MOVs can be exercised by the appropriate control logic and starters, and all indications and annunciations can be observed during the test.

7.3.2.5.2.3.1.11 RHR-SPCM - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

The suppression pool cooling controls have no operating bypasses.

7.3.2.5.2.3.1.12 RHR-SPCM - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

The suppression pool cooling controls have no operating bypasses.

7.3.2.5.2.3.1.13 RHR-SPCM - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

The suppression pool cooling controls have no operating bypasses.

7.3.2.5.2.3.1.14 RHR-SPCM - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Since there are no bypasses, this criterion is not strictly applicable. Means of disabling instrumentation and controls is administratively controlled, including control of access to instrument valves and emergency switchgear.

7.3.2.5.2.3.1.15 RHR-SPCM - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

There are no multiple trip settings.

7.3.2.5.2.3.1.16 RHR-SPCM - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

The final control elements for the containment spray mode are essentially bistable; for example, MOVs stay open once they have reached their open position even after the motor starter drops out. Thus, once manually initiated, an action will go to completion and will continue unless deliberately terminated by the operator, or overridden by a higher priority function or interlock.

7.3.2.5.2.3.1.17 RHR-SPCM - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

Suppression pool cooling is manually initiated. Each separated loop is independently controlled by the operator.

7.3.2.5.2.3.1.18 RHR-SPCM - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

The suppression pool cooling mode does not require setpoints.

7.3.2.5.2.3.1.19 RHR-SPCM - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

Suppression pool cooling flow initiation is indicated by the Full Flow Test Return Valve indicating lights and flow indicators on the control panel.

7.3.2.5.2.3.1.20 RHR-SPCM - IEEE 279 (1971), Paragraph 4.20 - Information Readout

Continuous reading indications are provided to enable the operator to verify proper system operation. The design minimizes the possibility of confusion due to inconsistent indications.

7.3.2.5.2.3.1.21 RHR-SPCM - IEEE 279 (1971), Paragraph 4.21 - System Repair

The suppression pool cooling mode is designed for efficient maintainability. Easy recognition of malfunctioning equipment is provided through proper test procedures. Accessibility is provided for the sensors and controls to facilitate repair or adjustment.

7.3.2.5.2.3.1.22 RHR-SPCM - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Nameplates distinctively identify the equipment as being in the protective system for each logic cabinet and instrument panel that is part of the RHR system. The nameplates also indicate the division to which each panel or cabinet is assigned. Panels in the control room are identified by tags which indicate the system and logic contained therein. Identification of cables and raceways is discussed in Section 8.3.1.3.

7.3.2.5.2.3.2 RHR-SPCM - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Class 1E electrical loads in the suppression pool cooling instrumentation and control system are physically separated and electrically isolated into independent load groups. A failure in one group will not interfere with proper operation of the redundant portions of the system. Details of the Class 1E power system are discussed in Section 8.1.6.1.6.

7.3.2.5.2.3.3 RHR-SPCM - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.4 for a discussion of system compliance to this standard.

7.3.2.5.2.3.4 RHR-SPCM - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

See Section 8.1.6.1.5.

7.3.2.5.2.3.5 RHR-SPCM - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

The capability for testing the suppression pool cooling instrumentation and control system is discussed in Sections 7.3.1.1.1.4.9 and 7.3.1.1.5.10.

7.3.2.5.2.3.6 RHR-SPCM - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.7 for a discussion of system compliance to this standard.

7.3.2.5.2.3.7 RHR-SPCM - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 279 (1971), paragraph 4.2 as further defined in IEEE 379 (1972), "Application of the Single Failure Criterion to Nuclear Power Generating Station Protection System," is met as described in Section 7.3.2.5.2.3.1.2.

7.3.2.5.2.3.8 RHR-SPCM - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Independence of suppression pool cooling equipment is demonstrated in the Section on conformance to IEEE 279 (1971), paragraph 4.6 and IEEE 308 (1974) (Sections 7.3.2.5.2.3.1.6 and 7.3.2.5.2.3.2).

7.3.2.5.3 RHR-SPCM Additional Design Considerations Analyses

As defined in Regulatory Guide 1.70, paragraph 7.3.2, the following considerations are addressed:

a. Loss of the plant instrument air system does not prevent the containment spray mode from performing its protective function.

b. Loss of cooling water to any single piece of vital equipment does not prevent the containment spray mode from performing its protective function.

7.3.2.6 Containment Atmospheric Control System – Instrumentation and Controls

7.3.2.6.1 CAC Primary Containment Vacuum Relief System - Instrumentation and Controls

7.3.2.6.1.1 PCVR General Functional Requirements Conformance

The following analysis shows how the PCVR meets the safety design bases identified in Section 7.1.2.1.16.2.1.

The simplicity of design of the primary containment vacuum relief valve assemblies ensures their ability to operate when necessary to limit the differential pressure across the diaphragm slab. The valves are of the swing-check configuration and require no motive power other than the differential pressure across the valve.

The use of two valves in series within each assembly prevents failure of any single valve in the stuck open position from compromising the pressure-suppression capability of the primary containment.

7.3.2.6.1.2 PCVR Specific Regulatory Requirements Conformance

7.3.2.6.1.2.1 PCVR Conformance to Regulatory Guides

7.3.2.6.1.2.1.1 PCVR - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

A valve operator is provided to test the operation of the valve and disc position indication system. Associated switches located on a test panel in the reactor enclosure permit the periodic testing of the valves in accordance with the requirements of Chapter 16.

7.3.2.6.1.2.1.2 PCVR - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The PCVR system is an automatic system and cannot be bypassed. Status indicating lights in the control room, provide indication of valve operability.

7.3.2.6.1.2.1.3 PCVR - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

The PCVR system is an automatic system requiring only a differential pressure across the valve discs to initiate the system.

7.3.2.6.1.2.1.4 PCVR - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

See Section 7.5.2.5.1.1.2 for discussion of the degree of conformance.

7.3.2.6.1.2.1.5 PCVR - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

See Section 3.10 for a discussion of Regulatory Guide 1.100 (1977).

7.3.2.6.1.2.1.6 PCVR - Regulatory Guide 1.105 (1976) - Instrument Setpoints

See Section 7.1.2.5.25 for discussion of the degree of conformance.

7.3.2.6.1.2.1.7 PCVR - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.2.1.5.26 for discussion of the degree of conformance.

7.3.2.6.1.2.2 PCVR Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.6.1.2.2.1 PCVR - GDC 1 - Quality Standards and Records

The PCVR system is designed and built in accordance with an established quality assurance program.

7.3.2.6.1.2.2.2 PCVR - GDC 2 - Design Bases for Protection Against Natural Phenomena

The PCVR system is designed to withstand the effects of natural phenomena without loss of capability to perform its safety functions.

7.3.2.6.1.2.2.3 PCVR - GDC 3 - Fire Protection

Section 7.1.2.6.3 gives compliance with GDC 3.

7.3.2.6.1.2.2.4 PCVR - GDC 4 - Environmental and Dynamic Effects Design Bases

Section 7.1.2.6.4 gives compliance with GDC 4.

7.3.2.6.1.2.2.5 PCVR - GDC 19 - Control Room

The PCVR is automatic, requiring only a differential pressure to operate. Annunciation is provided in the control room to alert the operator when any PCVR valve is not fully closed. Hand switches associated with the valves (and located on a panel in the reactor enclosure) are provided for test and containment purge purposes only.

7.3.2.6.1.2.2.6 PCVR - GDC 21 - Protection System Reliability and Testability

High functional reliability is implemented in the system design by redundant and separate PCVR valve assemblies. Each PCVR valve assembly is capable of being tested during normal plant operation.

7.3.2.6.1.2.2.7 PCVR - GDC 22 - Protection System Independence

There are four redundant PCVR valve assemblies that are physically separate. Operational tests do not affect the operation of the system in any way.

7.3.2.6.1.2.2.8 PCVR - GDC 29 - Protection Against Anticipated Operational Occurrences

No anticipated operational occurrence can prevent this equipment from performing its safety function.

7.3.2.6.1.2.3 PCVR Conformance to Industry Codes and Standards

7.3.2.6.1.2.3.1 PCVR - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

This standard is not applicable to this system because the controls for PCVR are for test purposes only. The PCVR system is a fully independent system and does not require an external power source for actuation. Other requirements such as reliability, testing, and equipment qualification requirements, have been discussed in Section 7.3.2.6.1.2.1 and Section 7.3.2.6.1.2.2. Channel bypass or removal from operation is discussed in Section 7.3.2.6.1.2.1.2.

7.3.2.6.1.2.3.2 PCVR - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

See Section 8.3.2.2.1.12 for a discussion of this standard.

7.3.2.6.1.2.3.3 PCVR - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

See Section 7.1.2.7.4.

7.3.2.6.1.2.3.4 PCVR - IEEE 338 (1971) - Criteria for the Periodic Testing of Nuclear Power Generating Stations Protection Systems

See Section 7.1.2.7.6.

7.3.2.6.1.2.3.5 PCVR - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

See Section 7.1.2.7.7 for seismic qualification.

7.3.2.6.1.2.3.6 PCVR - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

This standard is not applicable as this system does not have an external power supply or wiring to safety-related equipment.

7.3.2.6.2 CAC Combustible Gas Control System - Instrumentation and Controls

7.3.2.6.2.1 CGCS General Functional Requirement Conformance

The containment hydrogen recombiner subsystem and the combustible gas analyzer subsystem both consist of two separate packages that are fully redundant and independent. If there is a LOOP, the redundant packages are powered from different divisions of Class 1E power. A single failure in either subsystem would only render the affected package unavailable, with the redundant package being fully capable of serving the intended function at full capacity. FMEAs for the containment hydrogen recombiner subsystem and the combustible gas analyzer subsystem are provided in Tables 6.2-20 and 6.2-21, respectively. See also the safety design basis identified in Section 7.1.2.1.16.1.1.

Refer to Section 6.2.5 for additional details.

7.3.2.6.2.2 CGCS Specific Regulatory Requirements Conformance

7.3.2.6.2.2.1 CGCS Conformance to Regulatory Guides

7.3.2.6.2.2.1.1 CGCS - Regulatory Guide 1.7 (1978) - Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident

See Section 6.2.5.4 for discussion of this regulatory guide.

7.3.2.6.2.2.1.2 CGCS - Regulatory Guide 1.22 (1972) – Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

Actuation devices are periodically tested in accordance with the requirements of the maintenance program and the Technical Requirements Manual (TRM).

7.3.2.6.2.2.1.3 CGCS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The CGCS is manually actuated and cannot be bypassed. A light for each recombiner in the control room indicates system readiness. The light is extinguished if a recombiner is taken out-of-service.

7.3.2.6.2.2.1.4 CGCS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 (1973) is achieved by specifying, designing, and constructing the CGCS so that it meets the single failure criterion as described in paragraph 4.2 of IEEE 279 (1971).

7.3.2.6.2.2.1.5 CGCS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Controls are provided in the control room to manually initiate the recombiners.

7.3.2.6.2.2.1.6 CGCS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

The electrical separation criteria and degree of conformance to Regulatory Guide 1.75 (1975) are discussed in Sections 7.1.2.2.3 and 8.1.6.1.14.

7.3.2.6.2.2.1.7 CGCS - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

See Section 7.5.2.5.1.1.2 for discussion of the degree of conformance.

7.3.2.6.2.2.1.8 CGCS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

See Section 3.10.2.1.1 for a discussion of Regulatory Guide 1.100 (1977).

7.3.2.6.2.2.1.9 CGCS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

See Section 7.1.2.5.25 for discussion of the degree of conformance.

7.3.2.6.2.2.1.10 CGCS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26 for discussion of the degree of conformance.

7.3.2.6.2.2.2 CGCS Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.6.2.2.2.1 CGCS - GDC 1 - Quality Standards and Records

The CGCS is designed and built in accordance with an established quality assurance program.

7.3.2.6.2.2.2.2 CGCS - GDC 2 - Design Bases for Protection Against Natural Phenomena

The CGCS can withstand an SSE and function after the SSE.

7.3.2.6.2.2.2.3 CGCS - GDC 3 - Fire Protection

The CGCS is designed to minimize the probability and effects of fire and explosions by using noncombustible and heat-resistant materials.

7.3.2.6.2.2.2.4 CGCS - GDC 4 - Environmental and Dynamic Effects Design Bases

See Section 3.11 for environmental conditions and Section 3.10 for dynamic effects.

7.3.2.6.2.2.2.5 CGCS - GDC 13 - Instrumentation and Control

Instrumentation is selected to operate within expected ranges required for the safety of the plant in all anticipated operational considerations. Controls are designed to maintain the system within expected operating ranges.

7.3.2.6.2.2.2.6 CGCS - GDC 19 - Control Room

The CGCS can be controlled from the control room. Instrumentation is provided so that the operator can be assured of correct operation.

7.3.2.6.2.2.2.7 CGCS - GDC 21 - Protection System Reliability and Testability

High functional reliability is implemented in the system design by redundant and separate recombiners. Each recombiner is capable of being tested during normal plant operation.

7.3.2.6.2.2.2.8 CGCS - GDC 22 - Protection System Independence

There are two redundant recombiners, physically and electrically separate. Operational tests, maintenance being performed, or failure of one unit does not affect the other in any way.

7.3.2.6.2.2.2.9 CGCS - GDC 23 - Protection System Failure Modes

On a loss of power, valves in the system fail as-is. The blower and heaters are deactivated, effecting a system shutdown.

7.3.2.6.2.2.2.10 CGCS - GDC 24 - Separation of Protection and Control Systems

See the discussion for GDC 22.

7.3.2.6.2.2.2.11 CGCS - GDC 29 - Protection Against Anticipated Operational Occurrences

No anticipated operational occurrence can prevent this equipment from performing its safety function.

7.3.2.6.2.2.2.12 CGCS - GDC 56 - Primary Containment Isolation

Instrument lines that penetrate containment conform to the requirements of Regulatory Guide 1.11 as discussed in Section 7.3.2.2.2.1.1.

7.3.2.6.2.2.3 CGCS Conformance to Industry Codes and Standards

7.3.2.6.2.2.3.1 CGCS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generation Systems

Compliance of the CGCS with IEEE 279 (1971) is detailed below.

7.3.2.6.2.2.3.1.1 CGCS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The CGCS is manually initiated. The system safety function is adequately ensured by manual initiation.

7.3.2.6.2.2.3.1.2 CGCS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The hydrogen recombiners are fully redundant and physically and electrically separate; therefore, the system meets the single failure criterion.

7.3.2.6.2.2.3.1.3 CGCS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the application. A quality assurance program is required to be implemented.

7.3.2.6.2.2.3.1.4 CGCS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

The CGCS safety-related controls and instrumentation have been qualified according to the requirements outlined in IEEE 323 (1971) as highlighted in Section 7.1.2.7.4. The qualifications that have been met are those identified in Sections 3.10 and 3.11. The parameters identified cover normal, abnormal, and accident environments, both inside and outside the drywell.

7.3.2.6.2.2.3.1.5 CGCS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The CGCS meets the channel integrity objective by using the design features described in the other paragraphs of this section.

7.3.2.6.2.2.3.1.6 CGCS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control, instrumentation, and power circuits to each recombiner are physically and electrically separated.

7.3.2.6.2.2.3.1.7 CGCS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The CGCS has no interaction with the plant control systems. Control room annunciator circuits taking input from this system are electrically isolated from the system and cannot impair its operability.

7.3.2.6.2.2.3.1.8 CGCS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

The CGCS is manually initiated.

7.3.2.6.2.2.3.1.9 CGCS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

Sensors can be checked by cross-checking from the control room between redundant instruments. The sensors can be calibrated by introducing calibration gas to the sensors.

7.3.2.6.2.2.3.1.10 CGCS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The CGCS is capable of being tested during normal plant operation to verify that the system is capable of performing its intended function.

7.3.2.6.2.2.3.1.11 CGCS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

The two recombiners are separate electrically and physically. Removal of a component for maintenance prevents the operation of one recombiner; however, the operation of the other is unaffected. The recombiners cannot be bypassed, because they are manually initiated.

7.3.2.6.2.2.3.1.12 CGCS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

A light in the control room indicates the availability of each redundant package in the CGCS subsystem. The operator can manually initiate the available package. The CGCS is manually initiated and cannot be bypassed.

7.3.2.6.2.2.3.1.13 CGCS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

An indicating light for each recombiner in the control room is lit if the recombiner is ready for operation. If the recombiner is removed from service for maintenance, the light goes out.

7.3.2.6.2.2.3.1.14 CGCS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Access to the recombiners, power cabinets, and control panels is procedurally controlled by administrative means.

7.3.2.6.2.2.3.1.15 CGCS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

This paragraph is not applicable to the CGCS.

7.3.2.6.2.2.3.1.16 CGCS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

The CGCS, once initiated, operates until stopped by the operator.

7.3.2.6.2.2.3.1.17 CGCS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

The CGCS is manually initiated.

7.3.2.6.2.2.3.1.18 CGCS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Access to the recombiners, power cabinets, and control panels is procedurally controlled by administrative procedures.

7.3.2.6.2.2.3.1.19 CGCS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

The status of each recombiner is shown by indicating lights in the control room.

7.3.2.6.2.2.3.1.20 CGCS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout provides information so that the operator can be assured of correct operation. Instrumentation is described in Sections 7.3.1.1.6.1.2.12.2 and 7.5.

7.3.2.6.2.2.3.1.21 CGCS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components is accomplished during periodic testing. The control logic is not complex, so that locating failed components is straightforward. The components are mounted so as to facilitate removal and replacement.

7.3.2.6.2.2.3.1.22 CGCS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

The control cabinets and power cabinets are identified with nameplates that distinctively identify them as being a safety system. Cables and cable trays are identified by a color code and tags that identify them as being a separation channel.

7.3.2.6.2.2.3.2 CGCS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

See Section 8.3.2.2.1.12 for a discussion of IEEE 308 (1974).

7.3.2.6.2.2.3.3 CGCS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

See Section 7.1.2.7.4.

7.3.2.6.2.2.3.4 CGCS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

See Section 7.1.2.7.6.

7.3.2.6.2.2.3.5 CGCS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

See Section 7.1.2.7.7 for seismic qualification.

7.3.2.6.2.2.3.6 CGCS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.6.2.2.3.1.2.

7.3.2.6.2.2.3.7 CGCS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Refer to section 7.1.2.7.11 for the degree of conformance.

7.3.2.6.3 CAC Additional Design Considerations Analyses

As defined in Regulatory Guide 1.70, paragraph 7.3.2, the following considerations are addressed:

a. Loss of the plant instrument air system does not prevent the CAC system from performing its protective function.

b. Loss of cooling water to any single piece of vital equipment does not prevent the CAC system from performing its protective function.

7.3.2.7 Standby Gas Treatment System – Instrumentation and Controls

7.3.2.7.1 SGTS General Functional Requirements Conformance

The SGTS is designed with sufficient capacity and redundancy so that a single active or passive electrical or control component failure does not prevent the system from performing its safety-related functions. The SGTS is automatically initiated by the REIS or RAIS. See Section 7.1.2.1.26.1 for the safety design basis and Sections 7.3.2.9 and 7.3.2.17 for additional details.

7.3.2.7.2 SGTS Specific Regulatory Requirements Conformance

7.3.2.7.2.1 SGTS Conformance to Regulatory Guides

7.3.2.7.2.1.1 SGTS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The SGTS can be manually initiated and is capable of being tested during normal plant operation. Hand switches located in the control room allow periodic testing of emergency fans in accordance with the requirements of Chapter 16.

7.3.2.7.2.1.2 SGTS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The SGTS complies with this regulatory guide as discussed in Section 3.2.

7.3.2.7.2.1.3 SGTS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

See Section 8.1.6.1.5 and Chapter 17.

7.3.2.7.2.1.4 SGTS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The fan motor status and fan system trouble annunciator in the control room provide the required information.

7.3.2.7.2.1.5 SGTS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing, and constructing the SGTS to meet the single failure criterion, section 4.2 of IEEE 279 (1971) and IEEE 379 (1972). Redundant sensors and wiring are separated. The logic components and wiring are separated to ensure that a failure in a sensing element or the decision logic or an actuator does not affect its redundant counterpart and prevent protective action. Separate channels are employed so that a fault affecting one channel does not prevent the redundant channel from operating properly.

7.3.2.7.2.1.6 SGTS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Controls are provided in the main control room to manually initiate the SGTS.

7.3.2.7.2.1.7 SGTS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

See Section 8.1.6.1.14 for compliance with this regulatory guide.

7.3.2.7.2.1.8 SGTS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the SGTS is discussed in Section 8.1.6.1.16.

7.3.2.7.2.1.9 SGTS - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Conformance is discussed in Section 7.5.2.5.1.1.2.

7.3.2.7.2.1.10 SGTS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance with this regulatory guide is covered by Section 3.10.

7.3.2.7.2.1.11 SGTS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

Instrument setpoints are selected to allow for the inaccuracy of the instrument, uncertainties in the calibration, and instrumentation drift likely to occur between calibrations to ensure initiation of the SGTS in conjunction with the isolation of the reactor enclosure or the refueling area before the uncontrolled release of airborne contaminates to the atmosphere.

7.3.2.7.2.1.12 SGTS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26.

7.3.2.7.2.2 SGTS Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.7.2.2.1 SGTS - GDC 1 - Quality Standards and Records

The SGTS is included in an established quality assurance program discussed in Section 7.1.2.6 and Chapter 17.

7.3.2.7.2.2.2 SGTS - GDC 2 - Design Bases for Protection Against Natural Phenomena

See Section 7.1.2.6.

7.3.2.7.2.2.3 SGTS - GDC 3 - Fire Protection

See Section 7.1.2.6.

7.3.2.7.2.2.4 SGTS - GDC 4 - Environmental and Dynamic Effects Design Bases

See Section 7.1.2.6.

7.3.2.7.2.2.5 SGTS - GDC 5 - Sharing of Structures, Systems, and Components

The SGTS is common to LGS Units 1 and 2. There are two independent divisions that are each capable of providing 100% exhaust requirements to maintain either Unit 1 and/or 2 reactor enclosure and/or refueling area at a negative pressure. Therefore, sharing this system does not impair its ability to perform its safety function. The SGTS maintains the reactor enclosures and/or the refueling area at a negative pressure depending on the signal received as discussed in Section 6.5.1.1.

7.3.2.7.2.2.6 SGTS - GDC 13 - Instrumentation and Control

Instrumentation for the SGTS is selected to monitor variables over anticipated ranges during normal and emergency operating conditions.

7.3.2.7.2.2.7 SGTS - GDC 20 - Protection System Functions

See Section 7.3.2.7.1.

7.3.2.7.2.2.8 SGTS - GDC 21 - Protection System Reliability and Testability

The SGTS is designed with redundancy and separation so that a single failure does not result in the loss of the protective function. The system is capable of being tested during normal plant operation.

7.3.2.7.2.2.9 SGTS - GDC 22 - Protection System Independence

The components of the SGTS are designed so that the thermal environment resulting from any potential accident in which the components are required to function does not interfere with that function. The controls for the two SGTS divisions are electrically and physically separated so that a single failure does not result in the loss of both divisions. Power for the components of each division is provided from separate Class 1E power sources.

7.3.2.7.2.2.10 SGTS - GDC 23 - Protection System Failure Modes

Each SGTS division is designed to fail in a safe state, permitting its redundant division to operate.

7.3.2.7.2.2.11 SGTS - GDC 24 - Separation of Protection and Control Systems

The control system for the SGTS does not interact with the plant control systems.

7.3.2.7.2.2.12 SGTS - GDC 29 - Protection Against Anticipated Operational Occurrences

The high functional reliability of the SGTS is achieved through system redundancy, physical and electrical independence, fail-safe design, and inservice testability and equipment suitable for normal and accident environments.

7.3.2.7.2.2.13 SGTS - GDC 60 - Control of Releases of Radioactive Materials to the Environment

The SGTS maintains the reactor enclosures and/or refueling area at a negative pressure with respect to outdoor atmospheric pressure during isolation. This prevents the uncontrolled exfiltration of air within the secondary containment to the environment.

7.3.2.7.2.3 SGTS Conformance to Industry Codes and Standards

7.3.2.7.2.3.1 SGTS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

Compliance of the SGTS with IEEE 279 (1971) is detailed below.

7.3.2.7.2.3.1.1 SGTS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The SGTS is an automatically initiated system as discussed in Section 7.3.2.7.1.

7.3.2.7.2.3.1.2 SGTS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The SGTS consists of redundant exhaust fans, filter trains, isolation valves, and independent sets of controls and power that meet the single failure criterion.

7.3.2.7.2.3.1.3 SGTS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. A quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.7.2.3.1.4 SGTS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

See Section 3.11 for a discussion of equipment qualification.

7.3.2.7.2.3.1.5 SGTS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The SGTS meets the channel integrity by using the design features described in the other paragraphs of this section.

7.3.2.7.2.3.1.6 SGTS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for each SGTS component are physically and electrically separated.

7.3.2.7.2.3.1.7 SGTS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The SGTS has no interaction with other plant control systems. Annunciator circuits using contacts at sensor and logic relays cannot impair the operability of the SGTS control because of electrical isolation.

7.3.2.7.2.3.1.8 SGTS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

Initiation of the SGTS is derived from conditions discussed in Section 7.3.2.7.1.

7.3.2.7.2.3.1.9 SGTS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The SGTS can be tested for operational availability as discussed in Section 7.3.1.1.7.10.

7.3.2.7.2.3.1.10 SGTS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The SGTS is capable of being tested during normal plant operation to verify that the system is capable of performing its intended function.

7.3.2.7.2.3.1.11 SGTS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

A channel bypass or removal of a component of an initiation circuit channel does not prevent the SGTS itself from complying with the single failure criterion.

7.3.2.7.2.3.1.12 SGTS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

SGTS bypasses are discussed in Section 7.3.1.1.7.6.

7.3.2.7.2.3.1.13 SGTS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Each of the bypasses described in Section 7.3.1.1.7.6 is automatically indicated in the control room. In addition, each of these bypasses initiates a system out-of-service annunciator.

7.3.2.7.2.3.1.14 SGTS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Manual bypass of initiating circuits is procedurally controlled by administrative means.

7.3.2.7.2.3.1.15 SGTS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

7.3.2.7.2.3.1.16 SGTS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

Once the SGTS is initiated it continues to operate until the operator terminates system operation by manual override.

7.3.2.7.2.3.1.17 SGTS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a division of the SGTS cannot disable the automatic or manual operation of the other SGTS division.

7.3.2.7.2.3.1.18 SGTS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Access to pressure differential setpoints is restricted by administrative control. See Section 11.5 for access to radiation monitoring setpoints.

7.3.2.7.2.3.1.19 SGTS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

System operation is indirectly indicated and identified by high radiation and low pressure differential alarms.

7.3.2.7.2.3.1.20 SGTS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for the SGTS is described in Section 7.3.1.1.7.12.2.

7.3.2.7.2.3.1.21 SGTS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components is accomplished during periodic testing.

7.3.2.7.2.3.1.22 SGTS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate that identifies the safety system. Cables and cable trays are identified by a color code and tags that identify them as being of a separate channel.

7.3.2.7.2.3.2 SGTS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

See Section 8.3.2.2.1.12.

7.3.2.7.2.3.3 SGTS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

See Section 7.1.2.7.4.

7.3.2.7.2.3.4 SGTS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Station

The requirements of this standard have been met by the quality assurance program for construction of safety-related items.

7.3.2.7.2.3.5 SGTS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

See Section 7.1.2.7.6.

7.3.2.7.2.3.6 SGTS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

See Section 7.1.2.7.7.

7.3.2.7.2.3.7 SGTS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.7.2.3.1.2.

7.3.2.7.2.3.8 SGTS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

See Section 7.1.2.7.11.

7.3.2.8 Reactor Enclosure Recirculation System – Instrumentation and Controls

7.3.2.8.1 RERS General Functional Requirements Conformance

The RERS is designed with sufficient capacity and redundancy so that a single active or passive electrical or control component failure does not prevent the system from performing its safety-related functions. The RERS is automatically initiated by the REIS. See Section 7.1.2.1.25.1 for the safety design basis and Section 7.3.2.9.1 for additional details.

7.3.2.8.2 RERS Specific Regulatory Requirements Conformance

7.3.2.8.2.1 RERS Conformance to Regulatory Guides

7.3.2.8.2.1.1 RERS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The RERS can be manually initiated and is capable of being tested during normal plant operation. Hand switches located in the control room are provided for periodic testing of the recirculation fans in accordance with the requirements of Chapter 16.

7.3.2.8.2.1.2 RERS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The RERS complies with the regulatory guide as discussed in Section 3.2.

7.3.2.8.2.1.3 RERS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

See Section 8.1.6.1.5 and Chapter 17.

7.3.2.8.2.1.4 RERS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indications for Nuclear Power Plant Safety Systems

The fan motor status and filter status information meets the intent of the regulatory guide.

7.3.2.8.2.1.5 RERS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing, and constructing the RERS to meet the single failure criterion, section 4.2 of IEEE 279 (1971) and IEEE 379 (1972). Redundant sensors and wiring are separated. The logic components and wiring are separated to ensure that a failure in a sensing element, the decision logic, or an actuator does not affect its redundant counterpart and prevent protective action. Separate channels are employed so that a fault affecting one channel does not prevent the redundant channel from operating properly.

7.3.2.8.2.1.6 RERS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Controls are provided in the main control room to manually initiate the RERS.

7.3.2.8.2.1.7 RERS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

See Section 8.1.6.1.14 for compliance with this regulatory guide.

7.3.2.8.2.1.8 RERS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the RERS is discussed in Section 8.1.6.1.16.

7.3.2.8.2.1.9 RERS - Regulatory Guide 1.100 (1978) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance with this regulatory guide is covered by Section 3.10.

7.3.2.8.2.1.10 RERS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

The RERS response time is limited by diesel loading criteria rather than instrument error and setpoints.

7.3.2.8.2.1.11 RERS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26.

7.3.2.8.2.2 RERS Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.8.2.2.1 RERS - GDC 1 - Quality Standards and Records

The RERS is included in an established quality assurance program discussed in Section 7.1.2.6 and Chapter 17.

7.3.2.8.2.2.2 RERS - GDC 2 - Design Bases for Protection Against Natural Phenomena

See Section 7.1.2.6.

7.3.2.8.2.2.3 RERS - GDC 3 - Fire Protection

See Section 7.1.2.6.

7.3.2.8.2.2.4 RERS - GDC 4 - Environmental and Dynamic Effects Design Bases

See Section 7.1.2.6.

7.3.2.8.2.2.5 RERS - GDC 13 - Instrumentation and Control

Instrumentation for the RERS is selected to monitor variables over anticipated ranges during normal and emergency operating conditions.

7.3.2.8.2.2.6 RERS - GDC 20 - Protection System Functions

See Section 7.3.2.8.1.

7.3.2.8.2.2.7 RERS - GDC 21 - Protection System Reliability and Testability

The RERS is designed with redundancy and separation so that a single failure does not result in the loss of the protective function. The system is capable of being tested during normal plant operation.

7.3.2.8.2.2.8 RERS - GDC 22 - Protection System Independence

The components of the RERS are designed so that the thermal environment resulting from any potential accident conditions in which the components are required to function does not interfere with that function. The controls for the two RERS divisions are electrically and physically separated so that a single failure does not result in the loss of both divisions. Power for the components of each division is provided from separate Class 1E power sources.

7.3.2.8.2.2.9 RERS - GDC 23 - Protection System Failure Modes

Each RERS division is designed such that a failure in one division will not prevent the redundant division from providing the necessary recirculation and filtration.

7.3.2.8.2.2.10 RERS - GDC 24 - Separation of Protection and Control Systems

The control system for the RERS does not interact with the plant control systems.

7.3.2.8.2.2.11 RERS - GDC 29 - Protection Against Anticipated Operational Occurrences

The high functional reliability of the RERS is achieved through system redundancy, physical and electrical independence, fail-safe design, inservice testability, and equipment suitable for normal and accident environments.

7.3.2.8.2.2.12 RERS - GDC 60 - Control of Releases of Radioactive Materials to the Environment

The RERS filters and mixes the air within the reactor enclosure during isolation.

7.3.2.8.2.3 RERS Conformance to Industry Codes and Standards

7.3.2.8.2.3.1 RERS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

Compliance of the RERS with IEEE 279 (1971) is detailed below.

7.3.2.8.2.3.1.1 RERS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The RERS is an automatically initiated system as discussed in Section 7.3.2.8.1.

7.3.2.8.2.3.1.2 RERS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The RERS consists of redundant recirculation fans, filter trains, isolation valves, and independent sets of controls and power that meet the single failure criterion.

7.3.2.8.2.3.1.3 RERS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. A quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.8.2.3.1.4 RERS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

See Section 3.11 for a discussion of equipment qualification.

7.3.2.8.2.3.1.5 RERS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The RERS meets the channel integrity objective by using the design features described in the other paragraphs of this section.

7.3.2.8.2.3.1.6 RERS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for each RERS component are physically and electrically separated.

7.3.2.8.2.3.1.7 RERS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The RERS has no interaction with other plant control systems. Annunciator circuits using contacts at sensor and logic relays cannot impair the operability of the RERS control because of electrical isolation.

7.3.2.8.2.3.1.8 RERS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

Initiation of the RERS is derived from conditions discussed in Section 7.3.2.8.1.

7.3.2.8.2.3.1.9 RERS - IEEE 279 (1971), Paragraph 4.9 - Capability of Sensor Checks

The RERS can be tested for operational availability as described in Section 7.3.1.1.8.10.

7.3.2.8.2.3.1.10 RERS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The RERS is capable of being tested during normal plant operation to verify that the system is capable of performing its intended function.

7.3.2.8.2.3.1.11 RERS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

A channel bypass or removal of a component of an initiation circuit channel does not prevent the RERS itself from complying with the single failure criterion.

7.3.2.8.2.3.1.12 RERS - IEEE 279 (1971), Paragraph 4.12 - Operation Bypasses

RERS bypasses are discussed in Section 7.3.1.1.8.6.

7.3.2.8.2.3.1.13 RERS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Each of the bypasses described in Section 7.3.1.1.8.6 is automatically indicated in the control room. In addition, each of these bypasses initiates a system out-of-service annunciator.

7.3.2.8.2.3.1.14 RERS - IEEE 279 (1971) - Paragraph 4.14 - Access to Means for Bypassing

Manual bypass of initiating circuits is procedurally controlled by administrative means.

7.3.2.8.2.3.1.15 RERS - IEEE 279 (1971) - Paragraph 4.15 - Multiple Setpoints

The RERS radiation detectors are designed to allow the adjustment of trip setpoints to more stringent settings if required.

7.3.2.8.2.3.1.16 RERS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

Once the RERS is initiated, it continues to operate until the operator terminates system operation by manual override.

7.3.2.8.2.3.1.17 RERS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a division of the RERS cannot disable the automatic or manual operation of the other RERS division.

7.3.2.8.2.3.1.18 RERS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

See Section 11.5 for access to radiation monitoring setpoints.

7.3.2.8.2.3.1.19 RERS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

System operation is indirectly indicated and identified by high radiation alarms.

7.3.2.8.2.3.1.20 RERS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for the RERS is described in Section 7.3.1.1.8.12.2.

7.3.2.8.2.3.1.21 RERS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components is accomplished during periodic testing.

7.3.2.8.2.3.1.22 RERS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate that identifies the safety system. Cables and cable trays are identified by a color code and tags that identify them as being of a separate channel.

7.3.2.8.2.3.2 RERS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

See Section 8.3.2.2.1.12.

7.3.2.8.2.3.3 RERS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

See Section 7.1.2.7.4.

7.3.2.8.2.3.4 RERS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

The requirements of this standard have been met by the quality assurance program for construction for safety-related items.

7.3.2.8.2.3.5 RERS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

See Section 7.1.2.7.6.

7.3.2.8.2.3.6 RERS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

See Section 7.1.2.7.7.

7.3.2.8.2.3.7 RERS - IEEE 379 (1972) - Guide for the Application of Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.8.2.3.1.2.

7.3.2.8.2.3.8 RERS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

See Section 7.1.2.7.11.

7.3.2.9 Reactor Enclosure Isolation System – Instrumentation and Controls

7.3.2.9.1 REIS General Functional Requirements Conformance

The REIS is designed with sufficient capacity and redundancy so that a single active or passive electrical or control component failure does not prevent the system from performing its safety-related functions. The REIS is automatically initiated by detection of high radiation in the reactor enclosure exhaust ducts, low pressure differential between the reactor enclosure and the atmosphere, and/or a LOCA signal. See Section 7.1.2.1.39.1 for the safety design basis and Section 11.5 for information on radiation detectors.

7.3.2.9.2 REIS Specific Regulatory Requirements Conformance

7.3.2.9.2.1 REIS Conformance to Regulatory Guides

7.3.2.9.2.1.1 REIS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Function (Safety Guide 22)

The REIS can be manually initiated and is capable of being tested during normal plant operation. Hand switches located in the control room allow periodic testing of the isolation valves in accordance with the requirements of Chapter 16.

7.3.2.9.2.1.2 REIS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The REIS complies with this regulatory guide as discussed in Section 3.2.

7.3.2.9.2.1.3 REIS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

See Section 8.1.6.1.5 and Chapter 17.

7.3.2.9.2.1.4 REIS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The isolation system armed, initiation, and isolation incomplete alarms meet the intent of this regulatory guide.

7.3.2.9.2.1.5 REIS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing, and constructing the REIS to meet the single failure criterion, section 4.2 of IEEE 279 (1971) and IEEE 379 (1972). Redundant sensors and wiring are separated. The logic components and wiring are separated to ensure that a failure in a sensing element, the decision logic, or an actuator does not affect its redundant counterpart and prevent protective action. Separate channels are employed so that a fault affecting one channel does not prevent the redundant channel from operating properly.

7.3.2.9.2.1.6 REIS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Controls are provided in the main control room to manually initiate the REIS.

7.3.2.9.2.1.7 REIS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

See Section 8.1.6.1.14 for compliance with this regulatory guide.

7.3.2.9.2.1.8 REIS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the REIS is discussed in Section 8.1.6.1.16.

7.3.2.9.2.1.9 REIS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance with this regulatory guide is covered by Section 3.10.

7.3.2.9.2.1.10 REIS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

To ensure initiation of the REIS in conjunction with the SGTS to prevent the uncontrolled release of airborne contaminants to the atmosphere, instrument setpoints are selected to allow for the inaccuracy of the instrument, uncertainties in the calibration, and instrumentation drift likely to occur between calibrations. Refer to Chapter 16 for safety setpoints.

7.3.2.9.2.1.11 REIS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26.

7.3.2.9.2.2 REIS Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.9.2.2.1 REIS - GDC 1 - Quality Standards and Records

The REIS is included in an established quality assurance program discussed in Section 7.1.2.6 and Chapter 17.

7.3.2.9.2.2.2 REIS - GDC 2 - Design Bases for Protection Against Natural Phenomena

See Section 7.1.2.6.

7.3.2.9.2.2.3 REIS - GDC 3 - Fire Protection

See Section 7.1.2.6.

7.3.2.9.2.2.4 REIS - GDC 4 - Environmental and Dynamic Effects Design Bases

See Section 7.1.2.6.

7.3.2.9.2.2.5 REIS - GDC 13 - Instrumentation and Control

Instrumentation for the REIS is selected to monitor variables over anticipated ranges during normal and emergency operating conditions.

7.3.2.9.2.2.6 REIS - GDC 20 - Protection System Functions

See Section 7.3.2.9.1.

7.3.2.9.2.2.7 REIS - GDC 21 - Protection System Reliability and Testability

The REIS is designed with redundancy and separation so that a single failure does not result in the loss of the protective function. The system is capable of being tested during normal plant operation.

7.3.2.9.2.2.8 REIS - GDC 22 - Protection System Independence

The components of the REIS are designed so that the thermal environment resulting from any potential accident conditions in which the components are required to function does not interfere with that function. The controls for the two REIS divisions are electrically and physically separated so that a single failure does not result in the loss of both divisions. Power for the components of each division is provided from separate Class 1E power sources.

7.3.2.9.2.2.9 REIS - GDC 23 - Protection System Failure Modes

Each REIS division is designed to fail in a safe state, permitting its redundant division to provide isolation.

7.3.2.9.2.2.10 REIS - GDC 24 - Separation of Protection and Control Systems

The control system for the REIS does not interact with the plant control systems.

7.3.2.9.2.2.11 REIS - GDC 29 - Protection Against Anticipated Operational Occurrences

The high functional reliability of the REIS is achieved through system redundancy, physical and electrical independence, fail-safe design, inservice testability, and equipment suitable for normal and accident environments.

7.3.2.9.2.2.12 REIS - GDC 60 - Control of Releases of Radioactive Materials to the Environment

The REIS isolates the reactor enclosure from the environment to prevent uncontrolled exfiltration of air to the environment.

7.3.2.9.2.3 REIS Conformance to Industry Codes and Standards

7.3.2.9.2.3.1 REIS - IEEE 279 (1971) - Criteria for Protection for Nuclear Power Generating Stations

Compliance of the REIS with IEEE 279 (1971) is detailed below.

7.3.2.9.2.3.1.1 REIS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The REIS is an automatically initiated system as discussed in Section 7.3.2.9.1.

7.3.2.9.2.3.1.2 REIS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The REIS consists of redundant sets of isolation valves and independent sets of controls and power that meet the single failure criterion.

7.3.2.9.2.3.1.3 REIS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. A quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.9.2.3.1.4 REIS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

See Section 3.11 for a discussion of equipment qualification.

7.3.2.9.2.3.1.5 REIS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The REIS meets the channel integrity objective by using the design features described in the other paragraphs of this section.

7.3.2.9.2.3.1.6 REIS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for each REIS component are physically and electrically separated.

7.3.2.9.2.3.1.7 REIS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The REIS has no interaction with other plant control systems. Annunciator circuits using contact at sensor and logic relays cannot impair the operability of the REIS control because of electrical isolation.

7.3.2.9.2.3.1.8 REIS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

Initiation of the REIS is derived from conditions discussed in Section 7.3.2.9.1.

7.3.2.9.2.3.1.9 REIS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The REIS can be tested for operational availability as described in Section 7.3.1.1.9.10.

7.3.2.9.2.3.1.10 REIS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The REIS is capable of being tested during normal plant operation to verify that the system is capable of performing its intended function.

7.3.2.9.2.3.1.11 REIS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

A channel bypass or removal of a component of an initiation circuit channel does not prevent the REIS itself from complying with the single failure criterion.

7.3.2.9.2.3.1.12 REIS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

REIS bypasses are discussed in Section 7.3.1.1.9.6.

7.3.2.9.2.3.1.13 REIS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Each of the bypasses described in Section 7.3.1.1.9.6 is automatically indicated in the control room. In addition, each of these bypasses initiates a system out-of-service annunciator.

7.3.2.9.2.3.1.14 REIS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Manual bypass of initiating circuits is procedurally controlled by administrative means.

7.3.2.9.2.3.1.15 REIS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

The REIS radiation detectors are designed to allow adjustment of trip setpoints to more stringent settings if required.

7.3.2.9.2.3.1.16 REIS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

Once the REIS is initiated, it continues to operate until the operator terminates system operation by manual override.

7.3.2.9.2.3.1.17 REIS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a division of the REIS cannot disable the automatic or manual operation of the other REIS division.

7.3.2.9.2.3.1.18 REIS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

See Section 11.5 for access to radiation monitoring setpoints.

7.3.2.9.2.3.1.19 REIS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

System operation is indirectly indicated and identified by high radiation alarms.

7.3.2.9.2.3.1.20 REIS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for the REIS system is described in Section 7.3.1.1.9.12.2.

7.3.2.9.2.3.1.21 REIS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components is accomplished during periodic testing.

7.3.2.9.2.3.1.22 REIS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate that identifies the safety system. Cables and cable trays are identified by a color code and tags that identify them as being of a separate channel.

7.3.2.9.2.3.2 REIS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

See Section 8.3.2.2.1.12.

7.3.2.9.2.3.3 REIS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

See Section 3.11.2.

7.3.2.9.2.3.4 REIS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

The requirements of this standard have been met by the quality assurance program for construction of safety-related items.

7.3.2.9.2.3.5 REIS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

See Section 7.1.2.7.6.

7.3.2.9.2.3.6 REIS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

See Section 3.10.

7.3.2.9.2.3.7 REIS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.9.2.3.1.2.

7.3.2.9.2.3.8 REIS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

See Section 7.1.2.7.11.

7.3.2.10 Habitability and Control Room Isolation System - Instrumentation and Controls

7.3.2.10.1 HCRIS General Functional Requirements Conformance

The HCRIS is designed with sufficient capacity and redundancy so that a single active or passive electrical or control component failure will not prevent the system from performing its safety-related functions. The HCRIS is automatically initiated by detection of radiation. See Section 7.1.2.1.14.1 for the safety design basis and Sections 9.4.1 and 6.4.1 for additional details.

7.3.2.10.2 HCRIS Specific Regulatory Requirements Conformance

7.3.2.10.2.1 HCRIS Conformance to Regulatory Guides

7.3.2.10.2.1.1 HCRIS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The HCRIS can be manually initiated and is capable of being tested during normal plant operation. Hand switches located in the control room allow periodic testing of the emergency fans in accordance with the requirements of Chapter 16.

7.3.2.10.2.1.2 HCRIS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The HCRIS complies with this regulatory guide as discussed in Section 3.2.

7.3.2.10.2.1.3 HCRIS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

Refer to Section 8.1.6.1.5 and Chapter 17.

7.3.2.10.2.1.4 HCRIS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indications for Nuclear Power Plant Safety Systems

The isolation system armed, initiation, and isolation incomplete alarms meet the intent of this regulatory guide.

7.3.2.10.2.1.5 HCRIS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing, and constructing the HCRIS to meet the single failure criterion, section 4.2 of IEEE 279 (1971) and IEEE 379 (1972). Redundant sensors and wiring are separated. The logic components and wiring are separated to ensure that a failure in a sensing element of the decision logic or an actuator will not affect its redundant counterpart and prevent protective action. Separate channels are employed so that a fault affecting one channel will not prevent the redundant channel from operating properly.

7.3.2.10.2.1.6 HCRIS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Controls are provided in the main control room to manually initiate the HCRIS.

7.3.2.10.2.1.7 HCRIS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

Refer to Section 8.1.6.1.14 for compliance with this regulatory guide.

7.3.2.10.2.1.8 HCRIS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the HCRIS is discussed in Section 8.1.6.1.16.

7.3.2.10.2.1.9 HCRIS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance with this regulatory guide is covered by Section 3.10.

7.3.2.10.2.1.10 HCRIS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

Instrument setpoints are selected to allow for the inaccuracy of the instrument, uncertainties in the calibration, and instrumentation drift likely to occur between calibrations to assure initiation of the HCRIS degradation of the control room environment. For safety setpoints, refer to Chapter 16.

7.3.2.10.2.1.11 HCRIS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

Refer to Section 8.1.6.1.21.

7.3.2.10.2.2 HCRIS Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.10.2.2.1 HCRIS - GDC 1 - Quality Standards and Records

The HCRIS is included in an established quality assurance program described in Section 7.1.2.6 and Chapter 17.

7.3.2.10.2.2.2 HCRIS - GDC 2 - Design Bases for Protection Against Natural Phenomena

Refer to Section 7.1.2.6.

7.3.2.10.2.2.3 HCRIS - GDC 3 - Fire Protection

Refer to Section 7.1.2.6.

7.3.2.10.2.2.4 HCRIS - GDC 4 - Environmental and Dynamic Effects Design Bases

Refer to Section 7.1.2.6.

7.3.2.10.2.2.5 HCRIS - GDC 5 - Sharing of Structures, Systems, and Components

The HCRIS and control room structure are common to LGS Units 1 and 2. There are two independent divisions of isolation valves, emergency supply fans and filter trains, each capable of providing a safe environment within the control room for the operators to safely shutdown both reactor units. The control room as well as HCRIS components are located inside the control structure, a safety-related structure designed to remain functional during and following the most severe natural phenomena. Hence, sharing of the HCRIS will not impair its ability to perform its safety function.

7.3.2.10.2.2.6 HCRIS - GDC 13 - Instrumentation and Control

Instrumentation for the HCRIS is selected to monitor variables over anticipated ranges during normal and emergency operating conditions.

7.3.2.10.2.2.7 HCRIS - GDC 19 - Control Room

Refer to Sections 3.1 and 7.1.2.6.10.

7.3.2.10.2.2.8 HCRIS - GDC 20 - Protection System Functions

The HCRIS is automatically initiated by detection of radiation in the control room air intake duct.

7.3.2.10.2.2.9 HCRIS - GDC 21 - Protection System Reliability and Testability

The HCRIS is designed with redundancy and separation so that a single failure will not result in the loss of the protective function. The system is capable of being tested during normal plant operation.

7.3.2.10.2.2.10 HCRIS - GDC 22 - Protection System Independence

The components of the HCRIS are designed so that the thermal environment resulting from any potential accident condition, in which the components are required to function, will not interfere with that function. The controls of the two HCRIS are electrically and physically separated so that a single failure will not result in the loss of both divisions. Power for the components of each division is provided from separate Class 1E power sources.

7.3.2.10.2.2.11 HCRIS - GDC 23 - Protection System Failure Modes

Each HCRIS division is designed to fail in a safe state permitting its redundant divisions to isolate and ventilate the control room.

7.3.2.10.2.2.12 HCRIS - GDC 24 - Separation of Protection and Control Systems

The control system for the HCRIS does not interact with the plant control systems.

7.3.2.10.2.2.13 HCRIS - GDC 29 - Protection Against Anticipated Operational Occurrences

The high functional reliability of the HCRIS is achieved through system redundancy, physical and electrical independence, fail-safe design, inservice testability, and equipment suitable for normal and accident environments.

7.3.2.10.2.3 HCRIS Conformance to Industry Codes and Standards

7.3.2.10.2.3.1 HCRIS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

Compliance of the HCRIS with IEEE 279 (1971) is detailed below.

7.3.2.10.2.3.1.1 HCRIS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The HCRIS is an automatically initiated system based upon radiation detection in the control room intake duct as discussed in Section 6.4.1.

7.3.2.10.2.3.1.2 HCRIS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The HCRIS consists of redundant supply fans, filter trains, isolation valves, and independent sets of controls and power which meet the single failure criterion.

7.3.2.10.2.3.1.3 HCRIS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. A quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.10.2.3.1.4 HCRIS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

Refer to Section 3.11 for discussion of equipment qualification.

7.3.2.10.2.3.1.5 HCRIS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The HCRIS meets the channel integrity objective by utilizing the design features described in the other paragraphs of this section.

7.3.2.10.2.3.1.6 HCRIS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for each HCRIS component are physically and electrically separated.

7.3.2.10.2.3.1.7 HCRIS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The HCRIS has no interaction with other plant control systems. Annunciator circuits using contacts at sensor and logic relays cannot impair the operability of the HCRIS control because of electrical isolation.

7.3.2.10.2.3.1.8 HCRIS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

Initiation of the HCRIS is derived from high radiation signals from the control room air supply duct.

7.3.2.10.2.3.1.9 HCRIS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The HCRIS can be tested for operational availability as described in Section 7.3.1.1.10.10.

7.3.2.10.2.3.1.10 HCRIS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The HCRIS is capable of being tested during normal plant operation to verify that the system is capable of performing its intended function.

7.3.2.10.2.3.1.11 HCRIS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

A channel bypass or removal of a component of an initiation circuit channel will not prevent the HCRIS from isolating the control room.

7.3.2.10.2.3.1.12 HCRIS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

HCRIS bypasses are discussed in Section 7.3.1.1.10.6.

7.3.2.10.2.3.1.13 HCRIS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Each of the bypasses described in Section 7.3.1.1.10.6 are automatically indicated in the control room. In addition, each of these bypasses will initiate a system out-of-service annunciator.

7.3.2.10.2.3.1.14 HCRIS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Manual bypass of initiating circuits is procedurally controlled by administrative means.

7.3.2.10.2.3.1.15 HCRIS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

The HCRIS radiation detectors have been designed to allow adjustment of trip setpoints to more stringent settings if required.

7.3.2.10.2.3.1.16 HCRIS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

Once the HCRIS is initiated, it will continue to operate until the operator terminates system operation by manual override.

7.3.2.10.2.3.1.17 HCRIS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a division of the HCRIS cannot disable the automatic or manual operation of the other HCRIS divisions.

7.3.2.10.2.3.1.18 HCRIS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Access to radiation monitor setpoints is restricted by lock and key.

7.3.2.10.2.3.1.19 HCRIS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

System operation is indirectly indicated and identified by high radiation, chlorine, or offsite toxic chemical concentration alarms.

7.3.2.10.2.3.1.20 HCRIS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for the HCRIS is described in Section 7.3.1.1.10.12.2.

7.3.2.10.2.3.1.21 HCRIS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components will be accomplished during periodic testing. Calibration verification of the radiation detectors can be performed at anytime by the use of built-in test circuits.

7.3.2.10.2.3.1.22 HCRIS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate which identifies the safety system. Cables and cable trays are identified by a color code and tags which identify them as being of a separate channel.

7.3.2.10.2.3.2 HCRIS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Refer to Section 8.3.2.2.1.12.

7.3.2.10.2.3.3 HCRIS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.4.

7.3.2.10.2.3.4 HCRIS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Station

The requirements of this standard have been met by the quality assurance program for construction of safety-related items.

7.3.2.10.2.3.5 HCRIS - IEEE 338 (1977) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Refer to Section 7.1.2.7.6.

7.3.2.10.2.3.6 HCRIS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Station

Refer to Section 3.10.

7.3.2.10.2.3.7 HCRIS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.10.2.3.1.2.

7.3.2.10.2.3.8 HCRIS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Refer to Section 7.1.2.7.11.

7.3.2.11 Emergency Service Water System – Instrumentation and Controls

7.3.2.11.1 ESW General Functional Requirements Conformance

The ESW system is designed with sufficient capacity and redundancy so that a single active failure cannot impair the capability of the system to perform its safety-related functions. The system is common to Units 1 and 2 and consists of two independent loops, with two 50% capacity pumps per loop.

Both loops are designed to provide 100% of the ESW requirements. The ESW pumps start automatically on diesel generator operation after speed, voltage, and bus breaker conditions are met.

The ESW system is designed to supply makeup water to the spent fuel pools. The ESW system has an intertie to the spent fuel pools which can be used to supply makeup water by opening the two normally closed manual valves.

7.3.2.11.2 ESW Specific Regulatory Requirements Conformance

7.3.2.11.2.1 ESW Conformance to Regulatory Guides

7.3.2.11.2.1.1 ESW - Regulatory Guide 1.6 (1971) - Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems (Safety Guide 6)

Refer to Section 8.3.2.2.1.7.

7.3.2.11.2.1.2 ESW - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

ESW system actuation circuits can also be tested in conjunction with the periodic testing performed on the associated diesel generator. Testing of an ESW pump will in turn test the actuation circuits to the various loop valving. Bypass indication of the ESW control circuitry is provided in the main control room.

7.3.2.11.2.1.3 ESW - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The ESW system complies with this regulatory guide as discussed in Section 3.2.

7.3.2.11.2.1.4 ESW - Regulatory Guide 1.32 (1977) - Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants

Refer to Section 8.1.6.1.6.

7.3.2.11.2.1.5 ESW - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indications for Nuclear Power Plant Safety Systems

The ESW system complies with this regulatory guide. See Section 7.3.1.1.11.12.2 for alarms.

7.3.2.11.2.1.6 ESW - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 (1973) is achieved by specifying, designing, and constructing the ESW system so that it meets the single failure criterion described in paragraph 4.2 of IEEE 279 (1971). The ESW system consists of two loops which have separate and independent sets of controls and power. Each loop consists of two pumps; all four pumps and controls are assigned to separate divisions. The controls for the ESW valves are assigned to various divisions such that a single active or passive electrical or control failure cannot disable a complete ESW loop. In cases where two valves are in series to shutoff a flow path, the valves are assigned to two different divisions. Likewise, in cases where two valves are used to provide redundant flow paths in a single loop, the valves are assigned to two different divisions.

7.3.2.11.2.1.7 ESW - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Controls are provided in the main control room to manually initiate the ESW system.

7.3.2.11.2.1.8 ESW - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

The electrical separation criteria and degree of conformance to Regulatory Guide 1.75 (1975) are discussed in Sections 7.1.2.2.3 and 8.1.6.1.14.

7.3.2.11.2.1.9 ESW - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

See Section 7.5.2.5.1.1.2 for a discussion of the degree of conformance.

7.3.2.11.2.1.10 ESW - Regulatory Guide 1.105 (1976) - Instrument Setpoints

See Section 7.1.2.5.25 for discussion of the degree of conformance.

7.3.2.11.2.1.11 ESW - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26 for a discussion of the degree of conformance.

7.3.2.11.2.2 ESW Conformance to 10CFR50 Appendix A, General Design Criteria

7.3.2.11.2.2.1 ESW - GDC 1 - Quality Standards and Records

The equipment for ESW and supporting systems is included in an established quality assurance program as discussed in Section 7.1.2.6 and Chapter 17.

7.3.2.11.2.2.2 ESW - GDC 2 - Design Bases for Protection Against Natural Phenomena

Refer to Section 7.1.2.6.

7.3.2.11.2.2.3 ESW - GDC 3 - Fire Protection

The ESW system is designed to minimize the probability and the effects of fire and explosions by using noncombustible and heat-resistant materials. Refer to Section 9.5.1 for a discussion of the fire protection system.

7.3.2.11.2.2.4 ESW - GDC 4 - Environmental and Dynamic Effects Design Bases

Environmental design is discussed in Section 3.11. Missile protection is discussed in Section 3.5.

7.3.2.11.2.2.5 ESW - GDC 5 - Sharing of Structures, Systems, and Components

Refer to Section 3.1 for a general discussion.

The ESW system is common to both Units 1 and 2 and consists of two independent loops, each having two 50% capacity pumps. Both the A and B loops are designed to provide 100% of the ESW requirements for either unit during a LOOP or LOCA. ESW loop A and B pumps and piping are physically separated or protected such that no single event can render both loops inoperable. Power is supplied from four independent divisions. Thus, sharing of the ESW system between Units 1 and 2 does not significantly impair the ability of the ESW system to perform its safety function.

7.3.2.11.2.2.6 ESW - GDC 13 - Instrumentation and Control

Monitoring instrumentation is provided for the ESW system as detailed in Section 7.3.1.1.11.12.2 to provide the operator with information on the operation of the system.

7.3.2.11.2.2.7 ESW - GDC 19 - Control Room

Instrumentation and controls for the ESW system are provided in the main control room. Instrumentation and controls for one pump and cooling water loop are also provided in the remote shutdown panels. In addition, two of the redundant ESW pumps that are not operable from the remote shutdown panel can be operated using local controls.

7.3.2.11.2.2.8 ESW - GDC 20 - Protection System Functions

The ESW system is automatically initiated on the starting of the diesel generators. The diesel generators are automatically started if a LOCA occurs as described in Section 8.3.

7.3.2.11.2.2.9 ESW - GDC 21 - Protection System Reliability and Testability

The ESW system is provided with redundancy and separation so that a single failure will not result in the loss of the protective function. The system is capable of being tested during normal plant operation.

7.3.2.11.2.2.10 ESW - GDC 22 - Protection System Independence

The controls for the two ESW cooling water loops are electrically and physically separated so that a single failure will not result in the loss of both cooling water loops. Power for the components of the two cooling water loops is provided by separate Class 1E power sources.

7.3.2.11.2.2.11 ESW - GDC 23 - Protection System Failure Modes

Refer to Section 9.2.2.

7.3.2.11.2.2.12 ESW - GDC 24 - Separation of Protection and Control Systems

The control system for the ESW system does not interact with the plant control systems. Annunciator circuits using contacts with sensors and logic relays cannot impair the operability of the ESW system control because of electrical isolation.

7.3.2.11.2.2.13 ESW - GDC 29 - Protection Against Anticipated Operational Occurrences

The ESW system is designed to provide cooling water to the components described in Section 9.2.2. The system will start upon the starting of the diesel generators, the diesel generators will start if a LOOP or a LOCA occurs as described in Section 8.3.

7.3.2.11.2.3 ESW Conformance to Industry Codes and Standards

7.3.2.11.2.3.1 ESW - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

Compliance of the ESW system with IEEE 279 (1971) is detailed as follows:

7.3.2.11.2.3.1.1 ESW - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The ESW system is an automatically initiated system based upon a change in status of the components in the diesel generator system as described in Section 7.3.1.1.11.4.

7.3.2.11.2.3.1.2 ESW - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The ESW system consists of two cooling water loops which have separate and independent sets of controls and power and meet the single failure criterion.

7.3.2.11.2.3.1.3 ESW - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. Furthermore, a quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.11.2.3.1.4 ESW - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

The ESW system safety-related controls and instrumentation have been qualified as per the requirements outlined in IEEE 323 (1971) as highlighted in Section 7.1.2.7.4. The conditions for which the equipment has been qualified are those identified in Sections 3.10 and 3.11. The environmental parameters identified cover normal, abnormal, and accident conditions both inside and outside the drywell.

7.3.2.11.2.3.1.5 ESW - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The ESW system meets the channel integrity objective by utilizing the design features described in the other paragraphs of this section.

7.3.2.11.2.3.1.6 ESW - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for each pump and associated loop valving are physically and electrically separated. Divisional assignment is described in Section 7.3.1.1.11.4.

7.3.2.11.2.3.1.7 ESW - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The ESW system has no interaction with other plant control systems. Annunciator circuits using contacts with sensors and logic relays cannot impair the operability of the ESW system control because of electrical isolation.

7.3.2.11.2.3.1.8 ESW - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

Initiation of the ESW system is derived from the status of the diesel generator system. The diesel generators are started on receipt of a LOOP or a LOCA signal. The starting of the diesel generators will in turn start the ESW system. The ESW system is not started concurrently with the diesel generators due to bus loading considerations.

7.3.2.11.2.3.1.9 ESW - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The ESW system has no process sensors in the initiation circuits.

7.3.2.11.2.3.1.10 ESW - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The ESW system is capable of being tested during normal plant operation to verify that the system is capable of performing its intended function. The pumps and loop valves can be tested in conjunction with the diesel generator tests.

7.3.2.11.2.3.1.11 ESW - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removed from Operation

Channel bypass or removal of a component of an initiation circuit channel will inhibit one of the four divisions of the ESW system. Removal of a component will not affect the operation of the other three divisions.

7.3.2.11.2.3.1.12 ESW - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

ESW bypasses are described in Section 7.3.1.1.11.6.

7.3.2.11.2.3.1.13 ESW - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Each of the bypasses described in Section 7.3.1.11.1.6 is automatically indicated in the control room. In addition, each of these bypasses will initiate a system out-of-service annunciator.

7.3.2.11.2.3.1.14 ESW - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Access to the switchgear, motor control centers and relay panels is procedurally controlled by administrative means.

7.3.2.11.2.3.1.15 ESW - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

This paragraph is not applicable to the ESW system.

7.3.2.11.2.3.1.16 ESW - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

Once the system is initiated, it will continue to operate until stopped by the operator. However, it is noted that the system could be temporarily stopped for diesel generator loading considerations as discussed in Section 7.3.1.1.11.6.

7.3.2.11.2.3.1.17 ESW - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a division of the ESW system cannot impair the automatic or manual operation of the other ESW divisions.

7.3.2.11.2.3.1.18 ESW - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

ESW system controls do not contain safety-related process setpoints. Refer to Section 7.3.2.11.2.3.1.14 on access to ESW system controls.

7.3.2.11.2.3.1.19 ESW - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

Protective action indication is provided by indicating lights or the status of the system components. Also, an annunciator is provided to alarm the automatic start of each of the four pumps.

7.3.2.11.2.3.1.20 ESW - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for the ESW system is described in Section 7.3.1.1.11.12.2.

7.3.2.11.2.3.1.21 ESW - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components can be accomplished during periodic testing. The control logic is not complex so that location of failed components should be straight forward. The components are mounted in such a manner as to facilitate removal and replacement.

7.3.2.11.2.3.1.22 ESW - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate which identifies the safety system. Cables and cable trays are identified by a color code and tags which identify them as being of a separate channel.

7.3.2.11.2.3.2 ESW - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Refer to Section 8.3.2.2.1.12 for a discussion of this standard.

7.3.2.11.2.3.3 ESW - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.4.

7.3.2.11.2.3.4 ESW - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating System Protection Systems

Refer to Section 7.1.2.7.6.

7.3.2.11.2.3.5 ESW - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Refer to Section 3.10 for seismic qualification.

7.3.2.11.2.3.6 ESW - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is described in Section 7.3.2.11.2.3.1.2.

7.3.2.11.2.3.7 ESW - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

See Section 7.1.2.7.11 for a discussion of the degree of conformance.

7.3.2.11.3 ESW Additional Design Considerations Analyses

As defined in Regulatory Guide 1.70, paragraph 7.3.2, the following considerations are addressed:

a. Loss of the plant instrument air system does not prevent the ESW system from performing its protective function.

b. Loss of cooling water to any single piece of vital equipment does not prevent the ESW system from performing its protective function.

7.3.2.12 RHR Service Water System - Instrumentation and Controls

7.3.2.12.1 RHRSW General Functional Requirements Conformance

The RHRSW system is designed to provide a reliable source of cooling water for all operating modes of the RHR system including heat removal under postaccident conditions, and also to provide water to flood the reactor core or to spray the primary containment after an accident, should it be necessary.

There are two RHRSW loops, each loop serving one RHR heat exchanger in each unit, to supply cooling water for plant shutdown. Each loop is isolated from the other by barriers, separate trenches, or distance to ensure that simultaneous loss of both loops cannot occur. Failure of either a MOV, a diesel generator, or a pump will not prevent the system from performing its safety

function. This arrangement ensures that the full heat removal capacity required is available after the postulated active or passive electrical or control component failure. Refer to Section 7.1.2.1.15.2.1 for the design basis and Section 9.2.3 for additional details.

7.3.2.12.2 RHRSW Specific Regulatory Requirements Conformance

7.3.2.12.2.1 RHRSW Conformance to Regulatory Guides

7.3.2.12.2.1.1 RHRSW - Regulatory Guide 1.6 (1971) - Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems (Safety Guide 6)

Refer to Section 8.1.6.1.1 and 8.3.2.2.1.7.

7.3.2.12.2.1.2 RHRSW - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The RHRSW system is a manually initiated system and is capable of being tested during normal plant operation. The system is tested by the manual testing of each of the cooling water loop components. Control switches with status lights are provided in the control room for the system pumps and valves. Also, the cooling water loop flow and pressure indicators will provide an indication of proper system operation.

7.3.2.12.2.1.3 RHRSW - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The RHRSW system complies with this regulatory guide as discussed in Section 3.2.

7.3.2.12.2.1.4 RHRSW - Regulatory Guide 1.32 (1977) - Criteria for Safety-Related Electric Systems for Nuclear Power Plants

Refer to Section 8.1.6.1.6.

7.3.2.12.2.1.5 RHRSW - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indications for Nuclear Power Plant Safety Systems

RHRSW system conforms to this regulatory guide as a support system annunciated for status under the RHR system.

7.3.2.12.2.1.6 RHRSW - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 (1973) is achieved by specifying, designing, and constructing the RHRSW system so that it meets the single failure criterion described in paragraph 4.2 of IEEE 279 (1971). The RHRSW system consists of two independent cooling water loops with separate and independent controls and power which are segregated by division.

7.3.2.12.2.1.7 RHRSW - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

The RHRSW system is a manually initiated system. All controls necessary to operate the system are in the main control room.

7.3.2.12.2.1.8 RHRSW - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

The electrical separation criteria and degree of conformance to Regulatory Guide 1.75 (1975) are discussed in Sections 7.1.2.2.3 and 8.1.6.1.14.

7.3.2.12.2.1.9 RHRSW - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

See Section 7.5.2.5.1.1.2 for a discussion of the degree of conformance.

7.3.2.12.2.1.10 RHRSW - Regulatory Guide 1.105 (1976) - Instrument Setpoints

See Section 7.1.2.5.25 for a discussion of the degree of conformance.

7.3.2.12.2.1.11 RHRSW - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26 for a discussion of the degree of conformance.

7.3.2.12.2.2 RHRSW Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.12.2.2.1 RHRSW - GDC 1 - Quality Standards and Records

The equipment for ESF and supporting systems is included in an established quality assurance program as discussed in Section 3.1 and Chapter 17.

7.3.2.12.2.2.2 RHRSW - GDC 2 - Design Bases for Protection Against Natural Phenomena

Refer to Section 3.1.

7.3.2.12.2.2.3 RHRSW - GDC 3 - Fire Protection

The RHRSW system is designed to minimize the probability and the effects of fire and explosions by using noncombustible and heat-resistant materials. Refer to Section 9.5.1 for a discussion of the fire protection system.

7.3.2.12.2.2.4 RHRSW - GDC 4 - Environmental and Dynamic Effects Design Bases

Environmental design is discussed in Section 3.11. Missile protection design is discussed in Section 3.5.

7.3.2.12.2.2.5 RHRSW - GDC 5 - Sharing of Structures, Systems, and Components

Refer to Section 3.1 for a general discussion.

The RHRSW system is common to both Units 1 and 2 and consists of two loops. Each loop services one RHR heat exchanger in each unit and provides sufficient cooling to satisfy its safety function. Each loop has two 50% capacity pumps which are powered from separate power sources. Loss of one loop does not affect the capability of the second loop to safely shutdown either or both units during emergency conditions. Thus, sharing of the RHRSW system between Units 1 and 2 does not significantly impair the ability of the RHRSW system to perform its safety function.

7.3.2.12.2.2.6 RHRSW - GDC 13 - Instrumentation and Control

Monitoring instrumentation is provided as detailed in Section 7.3.1.1.12.12.2 to provide the operator with information on the operation of the system.

7.3.2.12.2.2.7 RHRSW - GDC 19 - Control Room

Instrumentation and controls for the RHRSW system are provided in the main control room. Instrumentation and controls for two RHRSW pumps are also provided in the remote shutdown panel. In addition, both of the two redundant RHRSW pumps that are not operable from the remote shutdown panel, can be operated using local controls.

7.3.2.12.2.2.8 RHRSW - GDC 20 - Protection System Functions

The RHRSW system is a manually initiated system. This system is not required immediately after an accident. The safety function of the system is adequately ensured by manual initiation.

7.3.2.12.2.2.9 RHRSW - GDC 21 - Protection System Reliability and Testability

The RHRSW system is provided with redundancy and separation so that a single failure will not result in the loss of the protective function. The system is capable of being tested during normal plant operation.

7.3.2.12.2.2.10 RHRSW - GDC 22 - Protection System Independence

The controls for the two RHRSW cooling water loops are electrically and physically separated so that a single failure will not result in the loss of both cooling water loops. Power for the components of the cooling water loops is provided by separate Class 1E power sources.

7.3.2.12.2.2.11 RHRSW - GDC 23 - Protection System Failure Modes

The various failure modes of the RHRSW system are described in Section 9.2.3.

7.3.2.12.2.2.12 RHRSW - GDC 24 - Separation of Protection and Control Systems

The control system for the RHRSW system does not interact with the plant control system. Annunciator circuits using contacts of sensors and logic relays cannot impair the operability of the RHRSW system control because of electrical isolation.

7.3.2.12.2.2.13 RHRSW - GDC 29 - Protection Against Anticipated Operational Occurrences

The RHRSW system is designed to provide cooling water to the components described in Section 9.2.3. The redundancy and separation of the two loops and manual initiation of the system ensure its ability to accomplish its safety function in the event of anticipated operational occurrences.

7.3.2.12.2.2.14 RHRSW - GDC 34 - Residual Heat Removal

The RHRSW system provides cooling water to the RHR heat exchangers as described in Section 9.2.3. The RHRSW system is provided with redundancy and separation so that a single failure will not result in the loss of the protective function.

7.3.2.12.2.3 RHRSW Conformance to Industry Codes and Standards

7.3.2.12.2.3.1 RHRSW - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

Compliance of the RHRSW system with IEEE 279 (1971) is detailed as follows:

7.3.2.12.2.3.1.1 RHRSW - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The RHRSW system is not an automatically initiated system. The system's safety function is adequately ensured by manual initiation.

7.3.2.12.2.3.1.2 RHRSW - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The RHRSW system consists of two cooling water loops which have separate and independent controls and power, and therefore meets the single failure criterion.

7.3.2.12.2.3.1.3 RHRSW - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the application. A quality control and assurance program is required to be implemented by the equipment vendors which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.12.2.3.1.4 RHRSW - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

The RHRSW system safety-related controls and instrumentation have been qualified as per the requirements outlined in IEEE 323 (1971) as highlighted in Section 7.1.2.7.4. The conditions for which the equipment has been qualified are those identified in Sections 3.10 and 3.11. The identified parameters cover normal, abnormal and accident conditions both inside and outside the drywell.

7.3.2.12.2.3.1.5 RHRSW - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The RHRSW system meets the channel integrity objective by utilizing the design features described in the other paragraphs of this Section.

7.3.2.12.2.3.1.6 RHRSW - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control, instrumentation, and power circuits for the components of each of the RHRSW cooling water loop are physically and electrically separated. The divisional assignments of the system components are described in Section 7.3.1.1.12.9.

7.3.2.12.2.3.1.7 RHRSW - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The RHRSW system has no interaction with the plant control systems. Annunciator circuits using contacts of circuits of sensors and logic relays cannot impair the operability of the RHRSW system control because of electrical isolation.

7.3.2.12.2.3.1.8 RHRSW - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

The RHRSW system is a manually initiated system.

7.3.2.12.2.3.1.9 RHRSW - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The RHRSW system is a manually initiated system. However, the system includes radiation instrumentation which trips components of the system as described in Section 7.3.1.1.12.5. These radiation sensors have provisions for a check source for testing this instrumentation during normal plant operation.

7.3.2.12.2.3.1.10 RHRSW - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

RHRSW system is capable of being tested during normal plant operation to verify that the system is capable of performing its intended function.

7.3.2.12.2.3.1.11 RHRSW - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal From Operation

Channel bypass or removal of a component for maintenance will inhibit the proper operation of one of the cooling water loops. However, it will not affect the proper operation of the other cooling water loop.

7.3.2.12.2.3.1.12 RHRSW - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

RHRSW bypasses are described in Section 7.3.1.1.12.6.

7.3.2.12.2.3.1.13 RHRSW - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Each of the bypasses described in Section 7.3.1.1.12.6 is automatically indicated in the control room. In addition, each of the bypasses will initiate a system annunciator if required.

7.3.2.12.2.3.1.14 RHRSW - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Access to the switchgear and the relay panels will be procedurally controlled by administrative means.

7.3.2.12.2.3.1.15 RHRSW - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

This paragraph is not applicable to the RHRSW system.

7.3.2.12.2.3.1.16 RHRSW - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

Once the system is started, it will continue to operate until stopped by the operator.

7.3.2.12.2.3.1.17 RHRSW - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

The RHRSW system is a manually initiated system.

7.3.2.12.2.3.1.18 RHRSW - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Access to the switchgear, the relay panels, and setpoint adjustments will be procedurally controlled by administrative means.

7.3.2.12.2.3.1.19 RHRSW - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

The RHRSW system is manually initiated. The status of the system components is shown by indicating lights in the control room.

7.3.2.12.2.3.1.20 RHRSW - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout available for the RHRSW system is described in Section 7.3.1.1.12.12.2.

7.3.2.12.2.3.1.21 RHRSW - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components can be accomplished during periodic testing. The control logic is not complex so that location of failed components should be straight forward. The components are mounted in such a manner as to facilitate removal and replacement.

7.3.2.12.2.3.1.22 RHRSW - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate which identifies the safety system. Cables and cable trays are identified by a color code and tags which identify them as being of separate channels.

7.3.2.12.2.3.2 RHRSW - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Refer to Section 8.3.2.2.1.12 for a discussion on this standard.

7.3.2.12.2.3.3 RHRSW - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.4.

7.3.2.12.2.3.4 RHRSW - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Refer to discussion on Regulatory Guide 1.118 in Section 7.1.2.5.26.

7.3.2.12.2.3.5 RHRSW - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.7 for seismic qualification.

7.3.2.12.2.3.6 RHRSW - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion for Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.12.2.3.1.2.

7.3.2.12.2.3.7 RHRSW - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

See Section 7.1.2.7.11 for a discussion of degree of conformance.

7.3.2.12.3 RHRSW Additional Design Considerations Analyses

As defined in Regulatory Guide 1.70, paragraph 7.3.2 the following considerations are addressed:

a. Loss of the plant instrument air system does not prevent the RHRSW system from performing its protective function.

b. Loss of cooling water to any single piece of vital equipment does not prevent the RHRSW system from performing its protective function.

7.3.2.13 Control Enclosure Chilled Water System – Instrumentation and Controls

7.3.2.13.1 CECWS General Functional Requirements Conformance

The CECWS is designed with sufficient capacity and redundancy so that a single active or passive electrical or control component failure will not prevent the system from performing its safety-related functions. The CECWS is automatically initiated by operation of the control room air supply fan cabinets, the auxiliary equipment room air supply fan cabinets, the emergency switchgear and battery room air supply fan cabinets, and the SGTS room and access area unit coolers. Refer to Section 7.1.2.1.35.1 for the safety design basis.

7.3.2.13.2 CECWS Specific Regulatory Requirements Conformance

7.3.2.13.2.1 CECWS Conformance to Regulatory Guides

7.3.2.13.2.1.1 CECWS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The CECWS can be manually initiated and is capable of being tested during normal plant operation. Hand switches located in the control room allow periodic testing of the chillers and pumps in accordance with the requirements of Chapter 16.

7.3.2.13.2.1.2 CECWS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The CECWS complies with this regulatory guide as discussed in Section 3.2.

7.3.2.13.2.1.3 CECWS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

Refer to Section 8.1.6.1.5 and Chapter 17.

7.3.2.13.2.1.4 CECWS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The CECWS by providing indication in the control room of pump and chiller status meets the intent of this regulatory guide.

7.3.2.13.2.1.5 CECWS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing, and constructing the CECWS to meet the single failure criterion, section 4.2 of IEEE 279 (1971) and IEEE 379 (1972).

Redundant sensors and wiring are separated. The logic components and wiring are separated to ensure that a failure in a sensing element or the decision logic or an actuator will not affect its redundant counterpart and prevent protective action. Separate channels are employed so that a fault affecting one channel will not prevent the redundant channel from operating properly.

7.3.2.13.2.1.6 CECWS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Controls are provided in the main control room to manually initiate the CECWS.

7.3.2.13.2.1.7 CECWS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

Refer to Section 8.1.6.1.14 for compliance with this regulatory guide.

7.3.2.13.2.1.8 CECWS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the CECWS system is discussed in Section 8.1.6.1.16.

7.3.2.13.2.1.9 CECWS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance with this regulatory guide is discussed in Section 3.10.

7.3.2.13.2.1.10 CECWS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

The CECWS is automatically initiated by unit cooler operation. Refer to Section 7.3.2.15.1.2.10.

7.3.2.13.2.1.11 CECWS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

Refer to Section 7.1.2.5.26.

7.3.2.13.2.2 CECWS Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.13.2.2.1 CECWS - GDC 1 - Quality Standards and Records

The CECWS is included in an established quality assurance program discussed in Section 7.1.2.6 and Chapter 17.

7.3.2.13.2.2.2 CECWS - GDC 2 - Design Bases for Protection Against Natural Phenomena

Refer to Section 7.1.2.6.

7.3.2.13.2.2.3 CECWS - GDC 3 - Fire Protection

Refer to Section 7.1.2.6.

7.3.2.13.2.2.4 CECWS - GDC 4 - Environmental and Dynamic Effects Design Bases

Refer to Section 7.1.2.6.

7.3.2.13.2.2.5 CECWS - GDC 5 - Sharing of Structures, Systems, and Components

The CECWS is common to Units 1 and 2. There are two independent divisions, each capable of providing sufficient chilled water for unit cooler operation during safe shutdown conditions. Since the CECWS is designed to remain functional during and after the most severe natural phenomena, sharing this system will not impair its ability to perform its safety function.

7.3.2.13.2.2.6 CECWS - GDC 13 - Instrumentation and Control

Instrumentation for the CECWS is selected to monitor variables over anticipated ranges during normal and emergency operating conditions.

7.3.2.13.2.3 CECWS Conformance to Industry Codes and Standards

7.3.2.13.2.3.1 CECWS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

Compliance of the CECWS with IEEE 279 (1971) is detailed as follows:

7.3.2.13.2.3.1.1 CECWS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The CECWS is automatically initiated by unit cooler operation.

7.3.2.13.2.3.1.2 CECWS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The CECWS consists of redundant chillers, pumps, piping, and independent sets of controls and power which meet the single failure criterion.

7.3.2.13.2.3.1.3 CECWS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. A quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.13.2.3.1.4 CECWS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

Refer to Section 3.11 for discussion of equipment qualification.

7.3.2.13.2.3.1.5 CECWS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The CECWS meets the channel integrity objective by utilizing the design features described in the other paragraphs of this section.

7.3.2.13.2.3.1.6 CECWS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for each CECWS component are physically and electrically separated.

7.3.2.13.2.3.1.7 CECWS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The CECWS interacts with the operation of the unit coolers as discussed in Section 7.3.2.15.1. No single event or failure of the control system can result in a condition requiring protective action and can concurrently prevent the operation of the CECWS.

7.3.2.13.2.3.1.8 CECWS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

Initiation of the CECWS is derived from operation of the control room air supply fan cabinets, the auxiliary equipment room air supply fan cabinets, the emergency switchgear and battery room air supply fan cabinets and/or the SGTS room and access area unit coolers.

7.3.2.13.2.3.1.9 CECWS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The CECWS can be tested for operational availability as per Section 7.3.1.1.13.10.

7.3.2.13.2.3.1.10 CECWS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The CECWS is capable of being tested during normal plant operation to verify that the system is capable of performing its intended function.

7.3.2.13.2.3.1.11 CECWS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

A channel bypass or removal of a component of an initiation circuit channel will prevent the CECWS itself from complying with the single failure criterion.

7.3.2.13.2.3.1.12 CECWS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

CECWS bypasses are discussed in Section 7.3.1.1.13.6.

7.3.2.13.2.3.1.13 CECWS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Each of the bypasses described in Section 7.3.1.1.13.6 are automatically indicated in the control room. In addition, each of these bypasses will initiate a system out-of-service annunciator.

7.3.2.13.2.3.1.14 CECWS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Manual bypass of initiating circuits will be procedurally controlled by administrative means.

7.3.2.13.2.3.1.15 CECWS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

Refer to Section 7.3.2.15.1.2.3.1.15.

7.3.2.13.2.3.1.16 CECWS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once it Is Initiated

Once the CECWS is initiated, it will continue to operate until the operator terminates system operation by manual override.

7.3.2.13.2.3.1.17 CECWS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a division of the CECWS cannot disable the automatic or manual operation of the other CECWS division.

7.3.2.13.2.3.1.18 CECWS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Refer to Section 7.3.2.15.1.2.3.1.18.

7.3.2.13.2.3.1.19 CECWS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

System operation is indirectly indicated and identified by pump motor status and flow indication for the pumps.

7.3.2.13.2.3.1.20 CECWS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for the CECWS is described in Section 7.3.1.1.13.12.2.

7.3.2.13.2.3.1.21 CECWS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components can be accomplished during periodic testing.

7.3.2.13.2.3.1.22 CECWS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate which identifies the safety system. Cables and cable trays are identified by a color code and tags which identify them as being of a separate channel.

7.3.2.13.2.3.2 CECWS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Refer to Section 8.3.2.2.1.12.

7.3.2.13.2.3.3 CECWS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.4.

7.3.2.13.2.3.4 CECWS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

The requirements of this standard have been met by the quality assurance program for construction of safety-related items.

7.3.2.13.2.3.5 CECWS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Refer to Section 7.1.2.7.6.

7.3.2.13.2.3.6 CECWS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Refer to Section 3.10.

7.3.2.13.2.3.7 CECWS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.13.2.1.5.

7.3.2.13.2.3.8 CECWS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Refer to Section 7.1.2.7.11.

7.3.2.13.3 CECWS Additional Design Considerations Analyses

As defined in Regulatory Guide 1.70, paragraph 7.3.2, the following considerations are addressed:

a. Loss of the plant instrument air system does not prevent the CECWS from performing its protective function.

b. Loss of cooling water to any single piece of vital equipment does not prevent the CECWS from performing its protective function.

7.3.2.14 Class 1E Power Systems

For an analysis of the Class 1E power systems refer to the following:

a. Refer to Section 8.3.1.2 for an analysis of the Class 1E ac power system.

b. Refer to Section 8.3.2.2 for an analysis of the Class 1E dc power system.

7.3.2.15 Safety-Related Equipment Area Cooling Ventilation Systems

7.3.2.15.1 SGTS Filter Room and Access Area Unit Coolers - Instrumentation and Controls

7.3.2.15.1.1 SGTS-UC General Functional Requirements Conformance

The SGTS-UC are designed with sufficient capacity and redundancy so that a single or passive electrical or control component active failure will not prevent the system from performing its safety-related functions. The SGTS-UC are automatically initiated by high temperature switches. Refer to Section 7.1.2.1.33.1 for the safety design basis and Section 9.4.1.5.1 for additional details.

7.3.2.15.1.2 SGTS-UC Specific Regulatory Requirements Conformance

7.3.2.15.1.2.1 SGTS-UC Conformance to Regulatory Guides

7.3.2.15.1.2.1.1 SGTS-UC - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The SGTS-UC can be manually initiated and are capable of being tested during normal plant operation. Hand switches located in the control enclosure allow periodic testing of the unit coolers in accordance with the requirements of Chapter 16.

7.3.2.15.1.2.1.2 SGTS-UC - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The unit coolers comply with this regulatory guide as discussed in Section 3.2.

7.3.2.15.1.2.1.3 SGTS-UC - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

Refer to Section 8.1.6.1.5 and Chapter 17.

7.3.2.15.1.2.1.4 SGTS-UC - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The SGTS-UC system meets the intent of this regulatory guide through the use of a fan trouble alarm.

7.3.2.15.1.2.1.5 SGTS-UC - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing and constructing the unit coolers to meet the single failure criterion, section 4.2 of IEEE 279 (1971) and IEEE 379 (1972). Redundant sensors and wiring are separated. The logic components and wiring are separated to ensure that a failure in a sensing element or the decision logic or an actuator will not affect its redundant counterpart and prevent protective action. Separate channels are employed so that a fault affecting one channel will not prevent the redundant channel from operating properly.

7.3.2.15.1.2.1.6 SGTS-UC - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Controls are provided on the SGTS local panel to manually initiate the unit coolers.

7.3.2.15.1.2.1.7 SGTS-UC - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

Refer to Section 8.1.6.1.14 for compliance.

7.3.2.15.1.2.1.8 SGTS-UC - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the SGTS-UC is discussed in Section 8.1.6.1.16.

7.3.2.15.1.2.1.9 SGTS-UC - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance is covered by Section 3.10.

7.3.2.15.1.2.1.10 SGTS-UC - Regulatory Guide 1.105 (1976) - Instrument Setpoints

Instrument setpoints are selected to allow for the inaccuracy of the instrument, uncertainties in the calibration, and instrumentation drift likely to occur between calibrations to assure initiation of the SGTS-UC prior to potential degradation of the control room environment.

7.3.2.15.1.2.1.11 SGTS-UC - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

Refer to Section 7.1.2.5.26.

7.3.2.15.1.2.2 SGTS-UC Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.15.1.2.2.1 SGTS-UC - GDC 1 - Quality Standards and Records

The SGTS unit coolers included in an established quality assurance program discussed in Section 3.1 and Chapter 17.

7.3.2.15.1.2.2.2 SGTS-UC - GDC 2 - Design Bases for Protection Against Natural Phenomena

Refer to Section 3.1.

7.3.2.15.1.2.2.3 SGTS-UC - GDC 3 - Fire Protection

Refer to Section 3.1.

7.3.2.15.1.2.2.4 SGTS-UC - GDC 4 - Environmental and Dynamic Effects Design Bases

Refer to Section 3.1.

7.3.2.15.1.2.2.5 SGTS-UC - GDC 5 - Sharing of Structures, Systems and Components

Refer to Section 3.1 for general discussion. The SGTS-UC are common to Units 1 and 2. There are two independent divisions, each capable of providing 100% of the cooling requirements for either unit. Therefore, sharing these unit coolers will not impair their ability to perform their safety function.

7.3.2.15.1.2.2.6 SGTS-UC - GDC 13 - Instrumentation and Control

Instrumentation for the SGTS-UC is selected to monitor variables over anticipated ranges during normal and emergency operating conditions.

7.3.2.15.1.2.3 SGTS-UC Conformance to Industry Codes and Standards

7.3.2.15.1.2.3.1 SGTS-UC - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

Compliance of the SGTS-UC with IEEE 279 (1971) is detailed as follows:

7.3.2.15.1.2.3.1.1 SGTS-UC - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The SGTS-UC are automatically initiated by high temperature switches.

7.3.2.15.1.2.3.1.2 SGTS-UC - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The SGTS-UC consist of redundant unit coolers, and independent sets of controls and power which meet the single failure criterion.

7.3.2.15.1.2.3.1.3 SGTS-UC - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. A quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.15.1.2.3.1.4 SGTS-UC - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

Refer to Section 3.11 for discussion of equipment qualification.

7.3.2.15.1.2.3.1.5 SGTS-UC - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The SGTS-UC meet the channel integrity by utilizing the design features described in the other paragraphs of this section.

7.3.2.15.1.2.3.1.6 SGTS-UC - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for the unit coolers component are physically and electrically separated.

7.3.2.15.1.2.3.1.7 SGTS-UC - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The SGTS-UC have no interaction with other plant control systems. Annunciator circuits using contacts at sensor and logic relays cannot impair the operability of the control because of electrical isolation.

7.3.2.15.1.2.3.1.8 SGTS-UC - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

Initiation of the SGTS-UC is derived from high temperature signals from the control enclosure.

7.3.2.15.1.2.3.1.9 SGTS-UC - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The SGTS-UC can be tested for operational availability per Section 7.3.1.1.15.1.10.

7.3.2.15.1.2.3.1.10 SGTS-UC - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The SGTS-UC are capable of being tested during normal plant operation to verify that the system is capable of performing its intended function.

7.3.2.15.1.2.3.1.11 SGTS-UC - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

A channel bypass or removal of a component of an initiation circuit channel will prevent the SGTS-UC themselves from complying with the single failure criterion.

7.3.2.15.1.2.3.1.12 SGTS-UC - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

SGTS-UC bypasses are discussed in Section 7.3.1.1.15.1.6.

7.3.2.15.1.2.3.1.13 SGTS-UC - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Each of the bypasses described in Section 7.3.1.1.15.1.6 is automatically indicated in the control room. In addition, each of these bypasses will initiate a system out-of-service annunciator.

7.3.2.15.1.2.3.1.14 SGTS-UC - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Manual bypass of initiating circuits will be procedurally controlled by administrative means.

7.3.2.15.1.2.3.1.15 SGTS-UC - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

The SGTS-UC temperature switches are suitable for adjustment of trip points to more stringent settings if required.

7.3.2.15.1.2.3.1.16 SGTS-UC - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once it is Initiated

Once the SGTS-UC are initiated they will continue to operate until the area temperature drops to the low temperature setting.

7.3.2.15.1.2.3.1.17 SGTS-UC - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a division of the SGTS-UC cannot disable the automatic or manual operation of the other SGTS-UC division.

7.3.2.15.1.2.3.1.18 SGTS-UC - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration and Test Points

Access to temperature switch setpoints is restricted by administrative control.

7.3.2.15.1.2.3.1.19 SGTS-UC - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

System operation is indirectly indicated and identified by high temperature alarms.

7.3.2.15.1.2.3.1.20 SGTS-UC - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for the SGTS-UC is described in Section 7.3.1.1.15.1.12.2.

7.3.2.15.1.2.3.1.21 SGTS-UC - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components will be accomplished during periodic testing.

7.3.2.15.1.2.3.1.22 SGTS-UC - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate which identifies the safety system. Cables and cable trays are identified by a color code and tags which identify them as being of a separate channel.

7.3.2.15.1.2.3.2 SGTS-UC - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Refer to Section 8.3.2.2.1.12.

7.3.2.15.1.2.3.3 SGTS-UC - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.4.

7.3.2.15.1.2.3.4 SGTS-UC - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

The requirements of this standard have been met by the quality assurance program for construction of safety-related items.

7.3.2.15.1.2.3.5 SGTS-UC - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Refer to Section 7.1.2.7.6.

7.3.2.15.1.2.3.6 SGTS-UC - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Station

Refer to Section 3.10.

7.3.2.15.1.2.3.7 SGTS-UC - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.15.1.2.3.1.2.

7.3.2.15.1.2.3.8 SGTS-UC - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Refer to Section 7.1.2.7.11.

7.3.2.15.2 Diesel Generating Enclosure Ventilation System - Instrumentation and Controls

7.3.2.15.2.1 DGEVS General Functional Requirements Conformance

The DGEVS is designed with sufficient capacity and redundancy so that a single active or passive electrical or control component failure will not prevent the diesel generators from performing their safety-related functions. The DGEVS system is automatically initiated by detection of high temperature. For the safety design basis refer to Section 7.1.2.1.33.2.1 and for additional details refer to Section 9.4.6.

7.3.2.15.2.2 DGEVS Specific Regulatory Requirements Conformance

7.3.2.15.2.2.1 DGEVS Conformance to Regulatory Guides

7.3.2.15.2.2.1.1 DGEVS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The DGEVS can be manually initiated and is capable of being tested during normal plant operation. Hand switches located on the local panel allow periodic testing of the exhaust fans in accordance with the requirements of Chapter 16.

7.3.2.15.2.2.1.2 DGEVS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The DGEVS complies with this regulatory guide as discussed in Section 3.2.

7.3.2.15.2.2.1.3 DGEVS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

Refer to Section 8.1.6.1.5 and Chapter 17.

7.3.2.15.2.2.1.4 DGEVS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The DGEVS meets the intent of this regulatory guide by using a fan system trouble alarm in the control room.

7.3.2.15.2.2.1.5 DGEVS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing, and constructing the DGEVS to meet the single failure criterion, section 4.2 of IEEE 279 (1971) and IEEE 379 (1972). Redundant sensors and wiring are separated. The logic components and wiring are separated to ensure that a failure in a sensing element or the decision logic or an actuator will not affect its redundant counterparts and prevent protective action.

The two fans for each diesel cell are on the same channel as its diesel generator.

7.3.2.15.2.2.1.6 DGEVS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Controls are provided locally to manually initiate the DGEVS.

7.3.2.15.2.2.1.7 DGEVS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

Refer to Section 8.1.6.1.14 for compliance with this regulatory guide.

7.3.2.15.2.2.1.8 DGEVS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the DGEVS is discussed in Section 8.1.6.1.16.

7.3.2.15.2.2.1.9 DGEVS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance with this regulatory guide is covered by Section 3.10.

7.3.2.15.2.2.1.10 DGEVS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

Instrument setpoints are selected to allow for the inaccuracy of the instrument, uncertainties in the calibration, and instrumentation drift likely to occur between calibrations to assure initiation of the DGEVS, to prevent overheating of the diesel generators. For safety setpoints refer to Chapter 16.

7.3.2.15.2.2.1.11 DGEVS - Regulatory Guide 1.118 (1978) - Periodic Testing Electric Power and Protection Systems

Refer to Section 7.1.2.5.26.

7.3.2.15.2.2.2 DGEVS Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.15.2.2.2.1 DGEVS - GDC 1 - Quality Standards and Records

The DGEVS is included in an established quality assurance program discussed in Section 3.1 and Chapter 17.

7.3.2.15.2.2.2.2 DGEVS - GDC 2 - Design Bases for Protection Against Natural Phenomena

Refer to Section 3.1.

7.3.2.15.2.2.2.3 DGEVS - GDC 3 - Fire Protection

Refer to Section 3.1.

7.3.2.15.2.2.2.4 DGEVS - GDC 4 - Environmental and Dynamic Effects Design Bases

Refer to Section 3.1.

7.3.2.15.2.2.2.5 DGEVS - GDC 13 - Instrumentation and Control

Instrumentation for the DGEVS is selected to monitor variables over anticipated ranges during normal and emergency operating conditions.

7.3.2.15.2.2.3 DGEVS Conformance to Industry Codes and Standards

7.3.2.15.2.2.3.1 DGEVS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

Compliance of the DGEVS with IEEE 279 (1971) is detailed as follows:

7.3.2.15.2.2.3.1.1 DGEVS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The DGEVS is automatically initiated by high temperature switches.

7.3.2.15.2.2.3.1.2 DGEVS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The DGEVS consists of independent sets of exhaust fans, controls and power which meet the single failure criteria.

7.3.2.15.2.2.3.1.3 DGEVS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. A quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.15.2.2.3.1.4 DGEVS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

Refer to Section 3.11 for discussion of equipment qualification.

7.3.2.15.2.2.3.1.5 DGEVS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The DGEVS meets the channel integrity criterion by utilizing the design features described in the other paragraphs of this section.

7.3.2.15.2.2.3.1.6 DGEVS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for each DGEVS component are physically and electrically separated.

7.3.2.15.2.2.3.1.7 DGEVS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The DGEVS has no interaction with other plant control systems. Annunciator circuits using contacts at sensor and logic relays cannot impair the operability of the DGEVS control because of electrical isolation.

7.3.2.15.2.2.3.1.8 DGEVS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

Initiation of the DGEVS is derived from high temperature signals from the diesel generator enclosure.

7.3.2.15.2.2.3.1.9 DGEVS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The DGEVS can be tested for operational availability as per Section 7.3.1.1.15.2.10.

7.3.2.15.2.2.3.1.10 DGEVS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The DGEVS is capable of being tested during normal plant operation to verify that the system is capable of performing its intended function.

7.3.2.15.2.2.3.1.11 DGEVS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

Removal of an initiation circuit component will not prevent the DGEVS itself from complying with the single failure criterion. The two fans for each diesel cell are on the same channel as its diesel generator.

7.3.2.15.2.2.3.1.12 DGEVS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

DGEVS bypasses are discussed in Section 7.3.1.1.15.2.6.

7.3.2.15.2.2.3.1.13 DGEVS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Each of the bypasses described in Section 7.3.1.1.15.2.6 are automatically indicated in the control room. In addition, each of these bypasses will initiate a system out-of-service annunciator.

7.3.2.15.2.2.3.1.14 DGEVS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Manual bypass of initiating circuits will be procedurally controlled by administrative means.

7.3.2.15.2.2.3.1.15 DGEVS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

The DGEVS temperature switches have been designed to allow adjustment of trip setpoints to more stringent settings if required.

7.3.2.15.2.2.3.1.16 DGEVS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

Once the DGEVS is initiated it will continue to operate until the diesel cell temperature drops below the low temperature setpoint.

7.3.2.15.2.2.3.1.17 DGEVS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a division of the DGEVS cannot disable the automatic or manual operation of the other DGEVS divisions.

7.3.2.15.2.2.3.1.18 DGEVS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration and Test Points

Access to temperature switch setpoints is restricted by administrative control.

7.3.2.15.2.2.3.1.19 DGEVS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

System operation is indirectly indicated and identified by high temperature alarms.

7.3.2.15.2.2.3.1.20 DGEVS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for the DGEVS is described in Section 7.3.1.1.15.2.12.2.

7.3.2.15.2.2.3.1.21 DGEVS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components will be accomplished during periodic testing.

7.3.2.15.2.2.3.1.22 DGEVS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate which identifies the safety system. Cables and cable trays are identified by a color code and tags which identify them as being of a separate channel.

7.3.2.15.2.2.3.2 DGEVS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Refer to Section 8.3.2.2.1.12.

7.3.2.15.2.2.3.3 DGEVS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.4.

7.3.2.15.2.2.3.4 DGEVS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

The requirements of this standard have been met by the quality assurance program for construction of safety-related items.

7.3.2.15.2.2.3.5 DGEVS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Refer to Section 7.1.2.7.6.

7.3.2.15.2.2.3.6 DGEVS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Station

Refer to Section 7.1.2.7.7.

7.3.2.15.2.2.3.7 DGEVS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.15.2.2.3.1.2.

7.3.2.15.2.2.3.8 DGEVS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Refer to Section 7.1.2.7.11.

7.3.2.15.3 Spray Pond Pump Structure Ventilation System - Instrumentation and Controls

7.3.2.15.3.1 SPPSVS General Functional Requirements Conformance

The SPPSVS is designed with sufficient capacity and redundancy so that a single active or passive electrical or control component failure will not prevent the system from performing its safety-related functions. For the safety design basis refer to Section 7.1.2.1.33.3 and for additional details refer to Section 9.4.7.

7.3.2.15.3.2 SPPSVS Specific Regulatory Requirements Conformance

7.3.2.15.3.2.1 SPPSVS Conformance to Regulatory Guides

7.3.2.15.3.2.1.1 SPPSVS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The SPPSVS can be manually initiated and is capable of being tested during normal plant operation. Hand switches located in the control room allow periodic testing of the fan cabinets in accordance with the requirements of Chapter 16.

7.3.2.15.3.2.1.2 SPPSVS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The SPPSVS complies with this regulatory guide as discussed in Section 3.2.

7.3.2.15.3.2.1.3 SPPSVS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

Refer to Section 8.1.6.1.5 and Chapter 17.

7.3.2.15.3.2.1.4 SPPSVS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The SPPSVS meets the intent of this regulatory guide by using a fan system trouble alarm in the control room.

7.3.2.15.3.2.1.5 SPPSVS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing and constructing the SPPSVS to meet the single failure criterion, section 4.2 of IEEE 279 (1971) and IEEE 379 (1972). Redundant sensors and wiring are separated. The logic components and wiring are separated to ensure that a failure in a sensing element or the decision logic or an actuator will not affect its redundant counterpart and prevent protective action. Separator channels are employed so that a fault affecting one channel will not prevent the redundant channel from operating properly.

7.3.2.15.3.2.1.6 SPPSVS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Controls are provided in the main control room to manually initiate the SPPSVS.

7.3.2.15.3.2.1.7 SPPSVS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

Refer to Section 8.1.6.1.14 for compliance with this regulatory guide.

7.3.2.15.3.2.1.8 SPPSVS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the SPPSVS is discussed in Section 8.1.6.1.16.

7.3.2.15.3.2.1.9 SPPSVS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance with this regulatory guide is covered by Section 3.10.

7.3.2.15.3.2.1.10 SPPSVS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

Instrument setpoints are selected to allow for the inaccuracy of the instrument, uncertainties in the calibration, and instrumentation drift likely to occur between calibrations to assure initiation of the SPPSVS to maintain the spray pond pump enclosure within specified temperature limits.

7.3.2.15.3.2.1.11 SPPSVS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

Refer to Section 7.1.2.5.26.

7.3.2.15.3.2.2 SPPSVS Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.15.3.2.2.1 SPPSVS - GDC 1 - Quality Standards and Records

The SPPSVS is included in an established quality assurance program discussed in Section 3.1 and Chapter 17.

7.3.2.15.3.2.2.2 SPPSVS - GDC 2 - Design Bases for Protection Against Natural Phenomena

Refer to Section 3.1.

7.3.2.15.3.2.2.3 SPPSVS - GDC 3 - Fire Protection

Refer to Section 3.1.

7.3.2.15.3.2.2.4 SPPSVS - GDC 4 - Environmental and Dynamic Effects Design Bases

Refer to Section 3.1.

7.3.2.15.3.2.2.5 SPPSVS - GDC 5 - Sharing of Structures, Systems, and Components

The SPPSVS is common to Units 1 and 2. There are four independent divisions, any two of which can provide the required ventilation and heating requirements during and after the most severe natural phenomena to maintain a suitable environment for the other safety-related equipment in this area. Therefore, sharing this system will not impair its ability to perform its safety function.

7.3.2.15.3.2.2.6 SPPSVS - GDC 13 - Instrumentation and Control

Instrumentation for the SPPSVS is selected to monitor variables over anticipated ranges during normal and emergency operating conditions.

7.3.2.15.3.2.3 SPPSVS Conformance to Industry Codes and Standards

7.3.2.15.3.2.3.1 SPPSVS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

Compliance of the SPPSVS with IEEE 279 (1971) is detailed as follows:

7.3.2.15.3.2.3.1.1 SPPSVS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The lead SPPSVS fan will run continuously after the control switch is placed in the run position. The standby fan will automatically start if required. Temperature is controlled automatically by a temperature controller.

7.3.2.15.3.2.3.1.2 SPPSVS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The SPPSVS consists of redundant fan cabinets with electric heaters and independent sets of controls and power which meet the single failure criterion.

7.3.2.15.3.2.3.1.3 SPPSVS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. A quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.15.3.2.3.1.4 SPPSVS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

Refer to Section 3.11 for discussion of equipment qualification.

7.3.2.15.3.2.3.1.5 SPPSVS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The SPPSVS meets the channel integrity criterion by utilizing the design features described in the other paragraphs of this section.

7.3.2.15.3.2.3.1.6 SPPSVS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for each SPPSVS component are physically and electrically separated.

7.3.2.15.3.2.3.1.7 SPPSVS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The SPPSVS has no interaction with other plant control systems. Annunciator circuits using contacts at sensor and logic relays cannot impair the operability of the SPPSVS control because of electrical isolation.

7.3.2.15.3.2.3.1.8 SPPSVS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

Initiation of the SPPSVS is derived from placing the hand switch in the run position for the lead fan. The standby fan will automatically start if required. Temperature is controlled automatically by a temperature controller.

7.3.2.15.3.2.3.1.9 SPPSVS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The SPPSVS can be tested for operational availability per Section 7.3.1.1.15.3.10.

7.3.2.15.3.2.3.1.10 SPPSVS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The SPPSVS is capable of being tested during normal plant operation to verify that the system is capable of performing its intended function.

7.3.2.15.3.2.3.1.11 SPPSVS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

A channel bypass or removal of a component of an initiation circuit channel will not prevent the SPPSVS itself from complying with the single failure criterion.

7.3.2.15.3.2.3.1.12 SPPSVS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

SPPSVS bypasses are discussed in Section 7.3.1.1.15.3.6.

7.3.2.15.3.2.3.1.13 SPPSVS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

The bypasses described in Section 7.3.1.1.15.3.6 are automatically indicated in the control room. In addition, each of these bypasses will initiate a system out-of-service annunciator.

7.3.2.15.3.2.3.1.14 SPPSVS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Manual bypass of initiating circuits will be procedurally controlled by administrative means.

7.3.2.15.3.2.3.1.15 SPPSVS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

The SPPSVS high and low temperature switches have been designed to allow adjustment of trip setpoints to more stringent settings if required.

7.3.2.15.3.2.3.1.16 SPPSVS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

Once the SPPSVS is initiated, it will continue to operate until the area temperature reaches the initiating setpoint.

7.3.2.15.3.2.3.1.17 SPPSVS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a division of the SPPSVS cannot disable the operation of the other SPPSVS divisions.

7.3.2.15.3.2.3.1.18 SPPSVS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration and Test Points

Access to the temperature switch setpoints is restricted by administrative control.

7.3.2.15.3.2.3.1.19 SPPSVS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

System operation is indirectly indicated and identified by high temperature and fan system trouble annunciators.

7.3.2.15.3.2.3.1.20 SPPSVS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for the SPPSVS is described in Section 7.3.1.1.15.3.12.2.

7.3.2.15.3.2.3.1.21 SPPSVS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components will be accomplished during periodic testing.

7.3.2.15.3.2.3.1.22 SPPSVS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate which identifies the safety system. Cables and cable trays are identified by a color code and tags which identify them as being of a separate channel.

7.3.2.15.3.2.3.2 SPPSVS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Refer to Section 8.3.3.2.1.12.

7.3.2.15.3.2.3.3 SPPSVS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.4.

7.3.2.15.3.2.3.4 SPPSVS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

The requirements of this standard have been met by the quality assurance program for construction of safety-related items.

7.3.2.15.3.2.3.5 SPPSVS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Refer to Section 7.1.2.7.6.

7.3.2.15.3.2.3.6 SPPSVS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.7.

7.3.2.15.3.2.3.7 SPPSVS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.15.3.2.3.1.2.

7.3.2.15.3.2.3.8 SPPSVS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Refer to Section 7.1.2.7.11.

7.3.2.15.4 Emergency Switchgear and Battery Rooms Cooling System - Instrumentation and Controls

7.3.2.15.4.1 ESBRCS General Functional Requirements Conformance

The ESBRCS is designed with sufficient capacity and redundancy so that a single active or passive electrical or control component failure will not prevent the system from performing its safety-related functions. The ESBRCS operates continuously during normal and emergency plant operation. For the safety design basis refer to Section 7.1.2.1.33.4.1 and for additional details refer to Section 9.4.1.

7.3.2.15.4.2 ESBRCS Specific Regulatory Requirements Conformance

7.3.2.15.4.2.1 ESBRCS Conformance to Regulatory Guides

7.3.2.15.4.2.1.1 ESBRCS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The ESBRCS can be manually initiated and is capable of being tested during normal plant operation. Hand switches located on the local panel allow periodic testing of the unit coolers in accordance with the requirements of Chapter 16.

7.3.2.15.4.2.1.2 ESBRCS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The ESBRCS complies with this regulatory guide as discussed in Section 3.2.

7.3.2.15.4.2.1.3 ESBRCS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

Refer to Section 8.1.6.1.5 and Chapter 17.

7.3.2.15.4.2.1.3A ESBRCS - Regulatory Guide 1.32 (1977) - Criteria for Safety Related Electric Power Systems for Nuclear Power Plants

Refer to Section 8.3.2.2.1.8.

7.3.2.15.4.2.1.4 ESBRCS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The ESBRCS meets the intent of this regulatory guide by using a fan system trouble alarm in the control room.

7.3.2.15.4.2.1.5 ESBRCS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Protection Systems

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing, and constructing the ESBRCS to meet the single failure criterion, section 4.2 of IEEE 279 (1971) and IEEE 379 (1972). Redundant sensors and wiring are separated. The logic components and wiring are separated to ensure that a failure in a sensing element or the decision logic or an actuator will not affect its redundant counterpart and prevent protective action. Separate channels are employed so that a fault affecting one channel will not prevent the redundant channel from operating properly.

7.3.2.15.4.2.1.6 ESBRCS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Controls are provided locally to manually initiate the ESBRCS.

7.3.2.15.4.2.1.7 ESBRCS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

Refer to Section 8.1.6.1.14 for compliance with this regulatory guide.

7.3.2.15.4.2.1.8 ESBRCS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the ESBRCS is discussed in Section 7.1.2.5.21.

7.3.2.15.4.2.1.9 ESBRCS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance with this regulatory guide is covered by Section 3.10.

7.3.2.15.4.2.1.10 ESBRCS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

Instrument setpoints are selected to allow for the inaccuracy of the instrument, uncertainties in the calibration, and instrumentation drift likely to occur between calibrations to assure initiation of the ESBRCS to maintain the associated room temperatures within the specified units.

7.3.2.15.4.2.1.11 ESBRCS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection System

Refer to Section 7.1.2.5.26.

7.3.2.15.4.2.2 ESBRCS Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.15.4.2.2.1 ESBRCS - GDC 1 - Quality Standards and Records

The ESBRCS is included in an established quality assurance program discussed in Section 3.1 and Chapter 17.

7.3.2.15.4.2.2.2 ESBRCS - GDC 2 - Design Bases for Protection Against Natural Phenomena

Refer to Section 3.1.

7.3.2.15.4.2.2.3 ESBRCS - GDC 3 - Fire Protection

Refer to Section 3.1.

7.3.2.15.4.2.2.4 ESBRCS - GDC 4 - Environmental and Dynamic Effects Design Bases

Refer to Section 3.1.

7.3.2.15.4.2.2.5 ESBRCS - GDC 5 - Sharing of Structures, Systems, and Components

The ESBRCS is common to Units 1 and 2. There are two independent divisions, each capable of maintaining a suitable environment for all safety-related equipment located in the corresponding areas used for the safe shutdown of either unit. Since the ESBRCS and control structure are designed to remain functional during and after the most severe natural phenomena, sharing this system will not impair its ability to perform its safety function.

7.3.2.15.4.2.2.6 ESBRCS - GDC 13 - Instrumentation and Control

Instrumentation for the ESBRCS is selected to monitor variables over anticipated ranges during normal and emergency operating conditions.

7.3.2.15.4.2.2.7 ESBRCS - GDC 19 - Control Room

Refer to Section 3.1

7.3.2.15.4.2.3 ESBRCS Conformance to Industry Codes and Standards

7.3.2.15.4.2.3.1 ESBRCS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

Compliance of the ESBRCS with IEEE 279 (1971) is detailed below:

7.3.2.15.4.2.3.1.1 ESBRCS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

Deliberate operator action after an accident is not required to initiate ESBRCS operation because it operates continuously during normal plant operation.

7.3.2.15.4.2.3.1.2 ESBRCS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The ESBRCS consists of redundant unit coolers and independent sets of controls and power which meet the single failure criterion.

7.3.2.15.4.2.3.1.3 ESBRCS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. A quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.15.4.2.3.1.4 ESBRCS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

Refer to Section 3.11 for discussion of equipment qualification.

7.3.2.15.4.2.3.1.5 ESBRCS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The ESBRCS meets the channel integrity criterion by utilizing the design features described in the other paragraphs of this section.

7.3.2.15.4.2.3.1.6 ESBRCS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for each ESBRCS component are physically and electrically separated.

7.3.2.15.4.2.3.1.7 ESBRCS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The ESBRCS has no interaction with other plant control systems. Annunciator circuits using contacts at sensor and logic relays cannot impair the operability of the ESBRCS control because of electrical isolation.

7.3.2.15.4.2.3.1.8 ESBRCS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

The ESBRCS operates continuously.

7.3.2.15.4.2.3.1.9 ESBRCS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The ESBRCS can be tested for operational availability as per Section 7.3.1.1.15.4.10.

7.3.2.15.4.2.3.1.10 ESBRCS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The ESBRCS is capable of being tested during normal plant operation to verify that the system is capable of performing its intended function.

7.3.2.15.4.2.3.1.11 ESBRCS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

A channel bypass or removal of a component of an initiation circuit channel will prevent the ESBRCS itself from complying with the single failure criterion.

7.3.2.15.4.2.3.1.12 ESBRCS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

ESBRCS bypasses are discussed in Section 7.3.1.1.15.4.6.

7.3.2.15.4.2.3.1.13 ESBRCS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Each of the bypasses described in Section 7.3.1.1.15.4.6 are automatically indicated in the control room. In addition, each of these bypasses will initiate a system out-of-service annunciator.

7.3.2.15.4.2.3.1.14 ESBRCS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Manual bypass of initiating circuits will be procedurally controlled by administrative means.

7.3.2.15.4.2.3.1.15 ESBRCS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

The ESBRCS high temperature switches have been designed to allow adjustment of trip setpoints to more stringent settings if required.

7.3.2.15.4.2.3.1.16 ESBRCS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

Once the ESBRCS is initiated, it will continue to operate until manually terminated by the operator.

7.3.2.15.4.2.3.1.17 ESBRCS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a division of the ESBRCS cannot disable the automatic or manual operation of the other ESBRCS division.

7.3.2.15.4.2.3.1.18 ESBRCS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Access to the temperature switch setpoints is restricted by administrative control.

7.3.2.15.4.2.3.1.19 ESBRCS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

System operation is indirectly indicated and identified by high temperature, filter pressure differential, and low air flow alarms.

7.3.2.15.4.2.3.1.20 ESBRCS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for the ESBRCS is described in Section 7.3.1.1.15.4.12.2.

7.3.2.15.4.2.3.1.21 ESBRCS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components will be accomplished during periodic testing.

7.3.2.15.4.2.3.1.22 ESBRCS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate which identifies the safety system. Cables and cable trays are identified by a color code and tags which identify them as being of a separate channel.

7.3.2.15.4.2.3.2 ESBRCS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Refer to Section 8.3.2.2.1.12.

7.3.2.15.4.2.3.3 ESBRCS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.4.

7.3.2.15.4.2.3.4 ESBRCS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

The requirements of this standard have been met by the quality assurance program for construction of safety-related items.
Refer to Section 7.1.2.7.5.

7.3.2.15.4.2.3.5 ESBRCS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Refer to Section 7.1.2.7.6.

7.3.2.15.4.2.3.6 ESBRCS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.7.

7.3.2.15.4.2.3.7 ESBRCS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.15.4.2.3.1.2.

7.3.2.15.4.2.3.8 ESBRCS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Refer to Section 7.1.2.7.11.

7.3.2.15.5 Emergency Core Cooling Systems Pump Compartment Unit Coolers - Instrumentation and Controls

7.3.2.15.5.1 ECCS-UC General Functional Requirements Conformance

The ECCS-UC are designed with sufficient capacity and redundancy so that a single active or passive electrical or control component failure will not prevent the system from performing its safety-related functions. The ECCS-UC are automatically initiated by high temperature switches.

For the safety design basis refer to Section 7.1.2.1.33.5.1 and for additional details, refer to Section 9.4.2.

7.3.2.15.5.2 ECCS-UC Specific Regulatory Requirements Conformance

7.3.2.15.5.2.1 ECCS-UC Conformance to Regulatory Guides

7.3.2.15.5.2.1.1 ECCS-UC - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The ECCS-UC can be manually initiated and are capable of being tested during normal plant operation. Hand switches located on local control panels allow periodic testing of the unit coolers in accordance with the requirements of Chapter 16.

7.3.2.15.5.2.1.2 ECCS-UC - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The ECCS-UC comply with this regulatory guide as discussed in Section 3.2.

7.3.2.15.5.2.1.3 ECCS-UC - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

Refer to Section 8.1.6.1.5 and Chapter 17.

7.3.2.15.5.2.1.4 ECCS-UC - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The ECCS-UC meets the intent of this regulatory guide by using a unit cooler system trouble alarm in the control room.

7.3.2.15.5.2.1.5 ECCS-UC - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing, and constructing the ECCS-UC to meet the single failure criterion, section 4.2 of IEEE 279 (1971) and IEEE 379 (1972). Redundant sensors and wiring are separated. The logic components and wiring are separated to ensure that a failure in a sensing element or the decision logic will not affect its redundant counterpart and prevent protective action. Separate channels are employed so that a fault affecting one channel will not prevent the redundant channel from operating properly.

7.3.2.15.5.2.1.6 ECCS-UC - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Controls are provided locally to manually initiate the unit coolers.

7.3.2.15.5.2.1.7 ECCS-UC - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

Refer to Section 8.1.6.1.14 for compliance with this regulatory guide.

7.3.2.15.5.2.1.8 ECCS-UC - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the ECCS-UC is discussed in Section 8.1.6.1.16.

7.3.2.15.5.2.1.9 ECCS-UC - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance with this regulatory guide is covered by Section 3.10.

7.3.2.15.5.2.1.10 ECCS-UC - Regulatory Guide 1.105 (1976) - Instrument Setpoints

Instrument setpoints are selected to allow for the inaccuracy of the instrument, uncertainties in the calibration, and instrumentation drift likely to occur between calibrations to assure initiation of the ECCS-UC to maintain the temperature of the emergency pump rooms within the specified limits.

7.3.2.15.5.2.1.11 ECCS-UC - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

Refer to Section 7.1.2.5.26.

7.3.2.15.5.2.2 ECCS-UC Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.15.5.2.2.1 ECCS-UC - GDC 1 - Quality Standards and Records

The ECCS-UC are included in an established quality assurance program discussed in Section 3.1 and Chapter 17.

7.3.2.15.5.2.2.2 ECCS-UC - GDC 2 - Design Bases for Protection Against Natural Phenomena

Refer to Section 3.1.

7.3.2.15.5.2.2.3 ECCS-UC - GDC 3 - Fire Protection

Refer to Section 3.1.

7.3.2.15.5.2.2.4 ECCS-UC - GDC 4 - Environmental and Dynamic Effects Design Bases

Refer to Section 3.1.

7.3.2.15.5.2.2.5 ECCS-UC - GDC 13 - Instrumentation and Control

Instrumentation for the ECCS-UC is selected to monitor variables over anticipated ranges during normal and emergency operating conditions.

7.3.2.15.5.2.3 ECCS-UC Conformance to Industry Codes and Standards

7.3.2.15.5.2.3.1 ECCS-UC - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

Compliance of the ECCS-UC with IEEE 279 (1971) is detailed as follows:

7.3.2.15.5.2.3.1.1 ECCS-UC - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The ECCS-UC are automatically initiated by high temperature switches.

7.3.2.15.5.2.3.1.2 ECCS-UC - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The ECCS-UC include 100% capacity redundant unit coolers and independent sets of controls and power which meet the single failure criterion.

7.3.2.15.5.2.3.1.3 ECCS-UC - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. A quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.15.5.2.3.1.4 ECCS-UC - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

Refer to Section 3.11 for discussion of equipment qualification.

7.3.2.15.5.2.3.1.5 ECCS-UC - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The ECCS-UC meets the channel integrity criterion by utilizing the design features described in the other paragraphs of this section.

7.3.2.15.5.2.3.1.6 ECCS-UC - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for each unit cooler are physically and electrically separated.

7.3.2.15.5.2.3.1.7 ECCS-UC - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The ECCS-UC has no interaction with other plant control systems. Annunciator circuits using contacts at sensor and logic relays cannot impair the operability of the ECCS-UC control because of electrical isolation.

7.3.2.15.5.2.3.1.8 ECCS-UC - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

Initiation of the ECCS-UC is derived from high temperature signals from the corresponding emergency pump rooms.

7.3.2.15.5.2.3.1.9 ECCS-UC - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The ECCS-UC can be tested for operational availability per Section 7.3.1.1.15.5.10.

7.3.2.15.5.2.3.1.10 ECCS-UC - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The ECCS-UC is capable of being tested during normal plant operation to verify that the system is capable of performing its intended function.

7.3.2.15.5.2.3.1.11 ECCS-UC - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

A channel bypass or removal of a component of an initiation circuit channel will prevent the other ECCS-UC from complying with the single failure criterion.

7.3.2.15.5.2.3.1.12 ECCS-UC - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

ECCS-UC bypasses are discussed in Section 7.3.1.1.15.5.6.

7.3.2.15.5.2.3.1.13 ECCS-UC - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Each of the bypasses described in Section 7.3.1.1.15.5.6 are automatically indicated in the control room. In addition, each of these bypasses will initiate a system out-of-service annunciator.

7.3.2.15.5.2.3.1.14 ECCS-UC - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Manual bypass of initiating circuits will be procedurally controlled by administrative means.

7.3.2.15.5.2.3.1.15 ECCS-UC - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

The ECCS-UC temperature switches have been designed to allow adjustment of trip setpoints to more stringent settings, if required.

7.3.2.15.5.2.3.1.16 ECCS-UC - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

Once the ECCS-UC are initiated they will continue to operate until they are shut down by a low temperature switch.

7.3.2.15.5.2.3.1.17 ECCS-UC - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a division of the ECCS-UC cannot disable the automatic or manual operation of the other ECCS-UC division.

7.3.2.15.5.2.3.1.18 ECCS-UC - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Access to temperature switch setpoints is restricted by administrative control.

7.3.2.15.5.2.3.1.19 ECCS-UC - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

System operation is indirectly indicated and identified by unit cooler trouble alarms.

7.3.2.15.5.2.3.1.20 ECCS-UC - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for the ECCS-UC is described in Section 7.3.1.1.15.5.12.2.

7.3.2.15.5.2.3.1.21 ECCS-UC - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components will be accomplished during periodic testing.

7.3.2.15.5.2.3.1.22 ECCS-UC - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate which identifies the safety system. Cables and cable trays are identified by a color code and tags which identify them as being of a separate channel.

7.3.2.15.5.2.3.2 ECCS-UC - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Refer to Section 8.3.2.2.1.12.

7.3.2.15.5.2.3.3 ECCS-UC - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.4.

7.3.2.15.5.2.3.4 ECCS-UC - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

The requirements of this standard have been met by the quality assurance program for construction of safety-related items.

7.3.2.15.5.2.3.5 ECCS-UC - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Refer to Section 7.1.2.7.6.

7.3.2.15.5.2.3.6 ECCS-UC - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.7.

7.3.2.15.5.2.3.7 ECCS-UC - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.15.5.2.3.1.2.

7.3.2.15.5.2.3.8 ECCS-UC - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Refer to Section 7.1.2.7.11.

7.3.2.15.6 Auxiliary Equipment Room Ventilation System - Instrumentation and Controls

7.3.2.15.6.1 AERVS General Functional Requirements Conformance

The AERVS is designed with sufficient capacity and redundancy so that a single active or passive electrical or control component failure will not prevent the system from performing its safety-related functions. The AERVS operates continuously during normal and emergency plant operation. For the safety design basis refer to Section 7.1.2.1.33.6.1 and for additional details refer to Section 9.4.1.

7.3.2.15.6.2 AERVS Specific Regulatory Requirements Conformance

7.3.2.15.6.2.1 AERVS Conformance to Regulatory Guides

7.3.2.15.6.2.1.1 AERVS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The AERVS can be manually initiated and is capable of being tested during normal plant operation. Hand switches located on the local panel allow periodic testing of the unit coolers in accordance with the requirements of Chapter 16.

7.3.2.15.6.2.1.2 AERVS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The AERVS complies with this regulatory guide as discussed in Section 3.2.

7.3.2.15.6.2.1.3 AERVS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for Installation, Inspection, and Testing of Instrumentation and Electric Equipment for Nuclear Power Plants (Safety Guide 30)

Refer to Section 8.1.6.1.5 and Chapter 17.

7.3.2.15.6.2.1 3A AERVS - Regulatory Guide 1.32 (1977) - Criteria for Safety Related Electric Power Systems for Nuclear Power Plants Refer to Section 8.1.6.1.6.

7.3.2.15.6.2.1.4 AERVS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indications for Nuclear Power Plant Safety Systems

The AERVS meets the intent of this regulatory guide by using a system trouble alarm in the control room.

7.3.2.15.6.2.1.5 AERVS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing, and constructing the AERVS to meet the single failure criterion, section 4.2 of IEEE 279 (1971), and IEEE 379 (1972). Redundant sensors and wiring are separated. The logic components and wiring are separated to ensure that a failure in a sensing element or the decision logic or an actuator does not affect its redundant counterpart and prevent protective action. Separate channels are employed so that a fault affecting one channel does not prevent the redundant channel from operating properly.

7.3.2.15.6.2.1.6 AERVS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Controls are provided locally to manually initiate the AERVS.

7.3.2.15.6.2.1.7 AERVS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

Refer to Section 8.1.6.1.14 for compliance with this regulatory guide.

7.3.2.15.6.2.1.8 AERVS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the AERVS is discussed in Section 8.1.6.1.16.

7.3.2.15.6.2.1.9 AERVS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance with this regulatory guide is covered by Section 3.10.

7.3.2.15.6.2.1.10 AERVS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

Instrument setpoints are selected to allow for the inaccuracy of the instrument, uncertainties in calibration, and instrument drift between calibrations to assure initiation of the AERVS to maintain the associated room temperatures within the specified limits.

7.3.2.15.6.2.1.11 AERVS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

Refer to Section 7.1.2.5.26.

7.3.2.15.6.2.2 AERVS Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.15.6.2.2.1 AERVS - GDC 1 - Quality Standards and Records

The AERVS is included in an established quality assurance program discussed in Section 3.1 and Chapter 17.

7.3.2.15.6.2.2.2 AERVS - GDC 2 - Design Bases for Protection Against Natural Phenomena

Refer to Section 3.1.

7.3.2.15.6.2.2.3 AERVS - GDC 3 - Fire Protection

Refer to Section 3.1.

7.3.2.15.6.2.2.4 AERVS - GDC 4 - Environmental and Dynamic Effects Design Bases

Refer to Section 3.1.

7.3.2.15.6.2.2.5 AERVS - GDC 5 - Sharing of Structures, Systems and Components

The AERVS is common to Units 1 and 2. There are two independent divisions, each capable of maintaining a suitable environment for the safety-related equipment used for the safe shutdown of either unit. Since the AERVS and control structure are designed to remain functional during and after the most severe natural phenomena, sharing this system will not impair its ability to perform its safety function.

7.3.2.15.6.2.2.6 AERVS - GDC 13 - Instrumentation and Control

Instrumentation for the AERVS is selected to monitor variables over anticipated ranges during normal and emergency operating conditions.

7.3.2.15.6.2.2.7 AERVS - GDC 19 - Control Room

Refer to Section 3.1

7.3.2.15.6.2.3 AERVS Conformance to Industry Codes and Standards

7.3.2.15.6.2.3.1 AERVS - IEEE 279 (1971), Criteria for Protection Systems for Nuclear Power Generating Stations

Compliance of the AERVS with IEEE 279 (1971) is detailed below.

7.3.2.15.6.2.3.1.1 AERVS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

Deliberate operator action after an accident is not required to initiate AERVS operation because the system operates continuously during normal plant operation.

7.3.2.15.6.2.3.1.2 AERVS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The AERVS consists of redundant unit coolers and independent sets of controls and power which meet the single failure criterion.

7.3.2.15.6.2.3.1.3 AERVS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. A quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.15.6.2.3.1.4 AERVS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

Refer to Section 3.11 for discussion of equipment qualification.

7.3.2.15.6.2.3.1.5 AERVS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The AERVS meets the channel integrity by utilizing the design features described in the other paragraphs of this section.

7.3.2.15.6.2.3.1.6 AERVS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for each AERVS component are physically and electrically separated.

7.3.2.15.6.2.3.1.7 AERVS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The AERVS has no interaction with other plant control systems. Annunciator circuits using contacts at sensor and logic relays cannot impair the operability of the AERVS control because of electrical isolation.

7.3.2.15.6.2.3.1.8 AERVS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

The AERVS operates continuously.

7.3.2.15.6.2.3.1.9 AERVS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The AERVS can be tested for operational availability as per Section 7.3.1.1.15.6.10.

7.3.2.15.6.2.3.1.10 AERVS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The AERVS is capable of being tested during normal plant operation to verify that the system is capable of performing its intended function.

7.3.2.15.6.2.3.1.11 AERVS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

A channel bypass or removal of a component of an initiation circuit channel will prevent the AERVS itself from complying with the single failure criterion.

7.3.2.15.6.2.3.1.12 AERVS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

AERVS bypasses are discussed in Section 7.3.1.1.15.6.6.

7.3.2.15.6.2.3.1.13 AERVS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Each of the bypasses described in Section 7.3.1.1.15.6.6 are automatically indicated in the control room. In addition, each of these bypasses will initiate a system out-of-service annunciator.

7.3.2.15.6.2.3.1.14 AERVS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Manual bypass of initiating circuits will be procedurally controlled by administrative means.

7.3.2.15.6.2.3.1.15 AERVS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

The AERVS high temperature switches have been designed to allow adjustment of trip setpoints to more stringent settings if required.

7.3.2.15.6.2.3.1.16 AERVS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

Once the AERVS is initiated it will continue to operate until manually terminated by the operator.

7.3.2.15.6.2.3.1.17 AERVS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a division of the AERVS cannot disable the automatic or manual operation of the other AERVS division.

7.3.2.15.6.2.3.1.18 AERVS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Access to the temperature switch setpoints is restricted by administrative control.

7.3.2.15.6.2.3.1.19 AERVS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

System operation is indirectly indicated and identified by high temperature, filter pressure differential, and low air flow alarms.

7.3.2.15.6.2.3.1.20 AERVS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for the AERVS is described in Section 7.3.1.1.15.6.12.2.

7.3.2.15.6.2.3.1.21 AERVS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components will be accomplished during periodic testing.

7.3.2.15.6.2.3.1.22 AERVS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate which identifies the safety system. Cables and cable trays are identified by a color code and tags which identify them as being of a separate channel.

7.3.2.15.6.2.3.2 AERVS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Refer to Section 8.3.2.2.1.12.

7.3.2.15.6.2.3.3 AERVS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.4.

7.3.2.15.6.2.3.4 AERVS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

The requirements of this standard have been met by the quality assurance program for construction of safety-related items.
Refer to Section 7.1.2.7.5.

7.3.2.15.6.2.3.5 AERVS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Refer to Section 7.1.2.7.6.

7.3.2.15.6.2.3.6 AERVS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.7.

7.3.2.15.6.2.3.7 AERVS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.15.6.2.3.1.2.

7.3.2.15.6.2.3.8 AERVS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Refer to Section 7.1.2.7.11.

7.3.2.15.7 Safety-Related Equipment Area Cooling Ventilation Systems Additional Design Considerations Analyses

As defined in Regulatory Guide 1.70, paragraph 7.3.2, the following considerations are addressed:

a. Loss of the plant instrument air system does not prevent the safety-related equipment area cooling ventilation systems from performing their protective function.

b. Loss of cooling water to any single piece of vital equipment does not prevent the safety-related equipment area cooling ventilation systems from performing their protective function.

7.3.2.16 Drywell Unit Coolers - Instrumentation and Controls

7.3.2.16.1 DUC General Functional Requirements Conformance

The DUC are designed with sufficient capacity and redundancy so that a single active or passive electrical or control component failure will not prevent the system from performing its safety-related function. The DUC are manually initiated and are used during normal plant operation for cooling and ventilation. During emergency conditions, they perform the safety-related function of mixing the containment atmosphere. For the safety design basis refer to Section 7.1.2.1.34.1 and for additional details refer to Section 9.4.5.

7.3.2.16.2 DUC Specific Regulatory Requirements Conformance

7.3.2.16.2.1 DUC Conformance to Regulatory Guides

7.3.2.16.2.1.1 DUC - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The DUC are manually initiated and are capable of being tested during normal plant operation. Hand switches located in the control room allow periodic testing of the unit coolers in accordance with the requirements of Chapter 16.

7.3.2.16.2.1.2 DUC - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The DUC comply with this regulatory guide as discussed in Section 3.2.

7.3.2.16.2.1.3 DUC - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

Refer to Section 8.1.6.1.5 and Chapter 17.

7.3.2.16.2.1.4 DUC - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The DUC meets the intent of this regulatory guide by using a fan system trouble alarm in the control room.

7.3.2.16.2.1.5 DUC - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing, and constructing the DUC to meet the single failure criterion, section 4.2 of IEEE 279 (1971) and IEEE 379 (1972). The logic components and wiring are separated to ensure that a failure in a sensing element or the decision logic will not affect its redundant counterpart and prevent protective action. Separate channels are employed so that a fault affecting one channel will not prevent the redundant channel from operating properly.

7.3.2.16.2.1.6 DUC - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Action

Controls are provided in the main control room to manually initiate the DUC.

7.3.2.16.2.1.7 DUC - Regulatory Guide 1.63 (1978) - Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants

Refer to Section 8.1.6.1.12.

7.3.2.16.2.1.8 DUC - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

Refer to Section 8.1.6.1.14 for compliance.

7.3.2.16.2.1.9 DUC - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the DUC is discussed in Section 8.1.6.1.16.

7.3.2.16.2.1.10 DUC - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance is discussed in Section 3.10.

7.3.2.16.2.1.11 DUC - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

Refer to Section 7.1.2.5.26.

7.3.2.16.2.2 DUC Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.16.2.2.1 DUC - GDC 1 - Quality Standards and Records

The DUC are included in an established quality assurance program discussed in Section 3.1 and Chapter 17.

7.3.2.16.2.2.2 DUC - GDC 2 - Design Bases for Protection Against Natural Phenomena

Refer to Section 3.1.

7.3.2.16.2.2.3 DUC - GDC 3 - Fire Protection

Refer to Section 3.1.

7.3.2.16.2.2.4 DUC - GDC 4 - Environmental and Dynamic Effects Design Bases

Refer to Section 3.1.

7.3.2.16.2.3 DUC Conformance to Industry Codes and Standards

7.3.2.16.2.3.1 DUC - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

Compliance of the DUC with IEEE 279 (1971) is detailed as follows:

7.3.2.16.2.3.1.1 DUC - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

Deliberate operator action after an accident is not required to initiate DUC operation because they operate continuously during normal plant operation.

7.3.2.16.2.3.1.2 DUC - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The DUC consist of redundant fans within each fan cabinet and independent sets of controls and power which meet the single failure criterion.

7.3.2.16.2.3.1.3 DUC - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. A quality control and assurance program is required to be implemented and documented by equipment vendors which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.16.2.3.1.4 DUC - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

Refer to Section 3.11 for discussion of equipment qualification.

7.3.2.16.2.3.1.5 DUC - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The DUC meet the channel integrity criterion by utilizing the design features described in the other paragraphs of this section.

7.3.2.16.2.3.1.6 DUC - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for each DUC fan is physically and electrically separated.

7.3.2.16.2.3.1.7 DUC - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

No single active failure of the DUC can result in a condition requiring protective action.

7.3.2.16.2.3.1.8 DUC - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

The DUC fans operate continuously during emergency conditions and are not initiated by signals from a monitored variable.

7.3.2.16.2.3.1.9 DUC - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The DUC can be tested for operational availability as per Section 7.3.1.1.16.10.

7.3.2.16.2.3.1.10 DUC - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The DUC are capable of being tested during normal plant operation to verify that they are capable of performing their intended function.

7.3.2.16.2.3.1.11 DUC - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

A channel bypass or removal of a component of an initiation circuit channel will prevent the DUC themselves from complying with the single failure criterion.

7.3.2.16.2.3.1.12 DUC - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

DUC bypasses are discussed in Section 7.3.1.1.16.6.

7.3.2.16.2.3.1.13 DUC - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Each of the bypasses described in Section 7.3.1.1.16.6 is automatically indicated in the control room. In addition, each of these bypasses will initiate a system out-of-service annunciator.

7.3.2.16.2.3.1.14 DUC - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Manual bypass of initiating circuits is procedurally controlled by administrative means.

7.3.2.16.2.3.1.15 DUC - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

The DUC are manually initiated. Flow switches to initiate redundant fan operation are designed to allow adjustment of trip setpoints to more stringent settings if required.

7.3.2.16.2.3.1.16 DUC - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

Once the DUC are initiated, they will continue to operate until the operator terminates system operation by manual override.

7.3.2.16.2.3.1.17 DUC - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a division of the DUC cannot disable the automatic or manual operation of the other DUC division.

7.3.2.16.2.3.1.18 DUC - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

The DUC are manually initiated.

7.3.2.16.2.3.1.19 DUC - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

System operation is indirectly indicated and identified by fan motor status and fan system trouble annunciators.

7.3.2.16.2.3.1.20 DUC - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for the DUC is described in Section 7.3.1.1.16.12.2.

7.3.2.16.2.3.1.21 DUC - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components will be accomplished during periodic testing.

7.3.2.16.2.3.1.22 DUC - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate which identifies the safety system. Cables and cable trays are identified by a color code and tags which identify them as being of a separate channel.

7.3.2.16.2.3.2 DUC - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Refer to Section 8.3.2.2.1.12.

7.3.2.16.2.3.3 DUC - IEEE 317 (1972) - Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations

Refer to Section 8.1.6.1.12.

7.3.2.16.2.3.4 DUC - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

Refer to Section 3.11.

7.3.2.16.2.3.5 DUC - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

The requirements of this standard have been met by the quality assurance program for construction of safety-related items.

7.3.2.16.2.3.6 DUC - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Refer to Section 7.1.2.7.6.

7.3.2.16.2.3.7 DUC - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.7.

7.3.2.16.2.3.8 DUC - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.16.2.3.1.2.

7.3.2.16.2.3.9 DUC - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Refer to Section 7.1.2.7.11.

7.3.2.16.3 DUC Additional Design Considerations Analyses

As defined in Regulatory Guide 1.70, paragraph 7.3.2, the following considerations are addressed:

a. Loss of the plant instrument air system does not prevent the DUC from performing their protective function.

b. Loss of cooling water to any single piece of vital equipment does not prevent the DUC from performing their protective function.

7.3.2.17 Refueling Area Isolation System – Instrumentation and Controls

7.3.2.17.1 RAIS General Functional Requirements Conformance

The RAIS is designed with sufficient capacity and redundancy so that a single active failure does not prevent the system from performing its safety-related functions. The RAIS is automatically initiated by detection of high radiation in the refueling area exhaust ducts or low pressure differential between the refueling area and the atmosphere. For the safety design basis refer to Section 7.1.2.1.42.1. Section 11.5 gives information on radiation detectors.

7.3.2.17.2 RAIS Specific Regulatory Requirements Conformance

7.3.2.17.2.1 RAIS Conformance to Regulatory Guides

7.3.2.17.2.1.1 RAIS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Function (Safety Guide 22)

The RAIS can be manually initiated and is capable of being tested during normal plant operation. Hand switches located in the control room allow periodic testing of the isolation valves in accordance with the requirements of Chapter 16.

7.3.2.17.2.1.2 RAIS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The RAIS complies with this regulatory guide as discussed in Section 3.2.

7.3.2.17.2.1.3 RAIS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment (Safety Guide 30)

See Section 8.1.6.1.5 and Chapter 17.

7.3.2.17.2.1.4 RAIS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The RAIS isolation system armed, initiation, and isolation incomplete alarms meet the intent of this regulatory guide.

7.3.2.17.2.1.5 RAIS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing, and constructing the RAIS to meet the single failure criterion, section 4.2 of IEEE 279 (1971) and IEEE 379 (1972). Redundant sensors and wiring are separated. The logic components and wiring are separated to ensure that a failure in a sensing element, the decision logic, or an actuator does not affect its redundant counterpart and prevent protective action. Separate channels are employed so that a fault affecting one channel does not prevent the redundant channel from operating properly.

7.3.2.17.2.1.6 RAIS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Controls are provided in the main control room to manually initiate the RAIS.

7.3.2.17.2.1.7 RAIS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

See Section 8.1.6.1.14 for compliance with this regulatory guide.

7.3.2.17.2.1.8 RAIS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the RAIS is discussed in Section 8.1.6.1.16.

7.3.2.17.2.1.9 RAIS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance with this regulatory guide is covered by Section 3.10.

7.3.2.17.2.1.10 RAIS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

To ensure initiation of the RAIS in conjunction with the SGTS to prevent the uncontrolled release of airborne contaminants to the atmosphere, instrument setpoints are selected to allow for the inaccuracy of the instrument, uncertainties in the calibration, and instrumentation drift likely to occur between calibrations.

Refer to Chapter 16 for safety setpoints.

7.3.2.17.2.1.11 RAIS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26.

7.3.2.17.2.2 RAIS Conformance to 10CFR50, Appendix A, General Design Criteria

7.3.2.17.2.2.1 RAIS - GDC 1 - Quality Standards and Records

The RAIS is included in an established quality assurance program discussed in Section 3.1 and Chapter 17.

7.3.2.17.2.2.2 RAIS - GDC 2 - Design Bases for Protection Against Natural Phenomena

See Section 3.1.

7.3.2.17.2.2.3 RAIS - GDC 3 - Fire Protection

See Section 3.1.

7.3.2.17.2.2.4 RAIS - GDC 4 - Environmental and Dynamic Effects Design Bases

See Section 3.1.

7.3.2.17.2.2.5 RAIS - GDC 13 - Instrumentation and Control

Instrumentation for the RAIS is selected to monitor variables over anticipated ranges during normal and emergency operating conditions.

7.3.2.17.2.2.6 RAIS - GDC 20 - Protection System Functions

See Section 7.3.2.17.1.

7.3.2.17.2.2.7 RAIS - GDC 21 - Protection System Reliability and Testability

The RAIS is designed with redundancy and separation so that a single failure does not result in the loss of the protective function. The system is capable of being tested during normal plant operation.

7.3.2.17.2.2.8 RAIS - GDC 22 - Protection System Independence

The components of the RAIS are designed so that the thermal environment resulting from any potential accident conditions in which the components are required to function does not interfere with that function. The controls for the two RAIS divisions are electrically and physically separated so that a single failure does not result in the loss of both divisions. Power for the components of each division is provided from separate Class 1E power sources.

7.3.2.17.2.2.9 RAIS - GDC 23 - Protection System Failure Modes

Each RAIS division is designed to fail in a safe state, permitting its redundant division to provide isolation.

7.3.2.17.2.2.10 RAIS - GDC 24 - Separation of Protection and Control Systems

The control system for the RAIS does not interact with the plant control systems.

7.3.2.17.2.2.11 RAIS - GDC 29 - Protection Against Anticipated Operational Occurrences

The high functional reliability of the RAIS is achieved through system redundancy, physical and electrical independence, fail-safe design, inservice testability, and equipment suitable for normal and accident environments.

7.3.2.17.2.2.12 RAIS - GDC 60 - Control of Releases of Radioactive Materials to the Environment

The RAIS isolates the refueling area from the environment to prevent uncontrolled exfiltration of air to the environment.

7.3.2.17.2.3 RAIS Conformance to Industry Codes and Standards

7.3.2.17.2.3.1 RAIS - IEEE 279 (1971) - Criteria for Protection for Nuclear Power Generating Stations

Compliance of the RAIS with IEEE 279 (1971) is detailed below.

7.3.2.17.2.3.1.1 RAIS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The RAIS is an automatically initiated system as discussed in Section 7.3.2.17.1.

7.3.2.17.2.3.1.2 RAIS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The RAIS consists of redundant sets of isolation valves and independent sets of controls and power that meet the single failure criterion.

7.3.2.17.2.3.1.3 RAIS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. A quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.3.2.17.2.3.1.4 RAIS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

See Section 3.11 for a discussion of equipment qualification.

7.3.2.17.2.3.1.5 RAIS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The RAIS meets the channel integrity objective by using the design features described in the other paragraphs of this section.

7.3.2.17.2.3.1.6 RAIS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for each RAIS component are physically and electrically separated.

7.3.2.17.2.3.1.7 RAIS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The RAIS has no interaction with other plant control systems. Annunciator circuits using contact at sensor and logic relays cannot impair the operability of the RAIS control because of electrical isolation.

7.3.2.17.2.3.1.8 RAIS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

Initiation of the RAIS is derived from conditions discussed in Section 7.3.2.17.1.1.

7.3.2.17.2.3.1.9 RAIS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The RAIS can be tested for operational availability as described in Section 7.3.1.1.17.10.

7.3.2.17.2.3.1.10 RAIS - IEEE 279 (1971), Paragraph 4.10 - Capability of Testing and Calibration

The RAIS is capable of being tested during normal plant operation to verify that the system is capable of performing its intended function.

7.3.2.17.2.3.1.11 RAIS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

A channel bypass or removal of a component of an initiation circuit channel does not prevent the RAIS itself from complying with the single failure criterion.

7.3.2.17.2.3.1.12 RAIS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

RAIS bypasses are discussed in Section 7.3.1.1.17.6.

7.3.2.17.2.3.1.13 RAIS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Each of the bypasses described in Section 7.3.1.1.17.6 is automatically indicated in the control room. In addition, each of these bypasses initiates a system out-of-service annunciator.

7.3.2.17.2.3.1.14 RAIS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Manual bypass of initiating circuits is procedurally controlled by administrative means.

7.3.2.17.2.3.1.15 RAIS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

The RAIS radiation detectors are designed to allow adjustment of trip setpoints to more stringent settings if required.

7.3.2.17.2.3.1.16 RAIS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

Once the RAIS is initiated, it continues to operate until the operator terminates system operation by manual override.

7.3.2.17.2.3.1.17 RAIS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a division of the RAIS cannot disable the automatic or manual operation of the other RAIS division.

7.3.2.17.2.3.1.18 RAIS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

See Section 11.5 for access to radiation monitoring setpoints.

7.3.2.17.2.3.1.19 RAIS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

System operation is indirectly indicated and identified by high radiation alarms.

7.3.2.17.2.3.1.20 RAIS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for the RAIS system is described in Section 7.3.1.1.17.12.2.

7.3.2.17.2.3.1.21 RAIS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components is accomplished during periodic testing.

7.3.2.17.2.3.1.22 RAIS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate that identifies the safety system. Cables and cable trays are identified by a color code and tags that identify them as being of a separate channel.

7.3.2.17.2.3.2 RAIS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

See Section 8.3.2.2.1.12.

7.3.2.17.2.3.3 RAIS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations

See Section 7.1.2.7.4.

7.3.2.17.2.3.4 RAIS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

The requirements of this standard have been met by the quality assurance program for construction of safety-related items.

7.3.2.17.2.3.5 RAIS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

See Section 7.1.2.7.6.

7.3.2.17.2.3.6 RAIS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

See Section 3.10.

7.3.2.17.2.3.7 RAIS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criterion of IEEE 379 (1972) is met as described in Section 7.3.2.17.2.3.1.2.

7.3.2.17.2.3.8 RAIS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

See Section 7.1.2.7.11.

Table 7.3-1

HIGH PRESSURE COOLANT INJECTION SYSTEM
INSTRUMENT SPECIFICATIONS[2]

HPCI FUNCTION	INSTRUMENT	RANGE
Reactor vessel high water level turbine trip	Level sensor	-150/0/+60 inches[1]
Turbine exhaust high pressure	Pressure sensor	0-200 psi
HPCI system pump high/low suction pressure	Pressure sensor	0-100 psi 0-25 psi
Reactor vessel low water level	Level sensor	-150/0/+60 inches[1]
Primary containment (drywell) high pressure	Pressure sensor	0-10 psig
Pump minimum flow	Flow sensor	0-700 gpm
HPCI system steam supply low pressure	Pressure sensor	0-200 psig
Pump discharge pressure	Pressure sensor	0-1500 psi
CST low level	Level sensor	-12/0/+45 inches
Suppression pool high water level	Level sensor	23 feet - 25 feet
Turbine overspeed	Centrifugal device	[3]

(1) Instrument zero equal to 527.5 inches above vessel zero.
(2) For instrument accuracy and setpoints, see the Technical Specifications.
(3) Instrument range does not apply to this device.

Table 7.3-2

AUTOMATIC DEPRESSURIZATION SYSTEM
INSTRUMENT SPECIFICATIONS

ADS FUNCTION	INSTRUMENT	INSTRUMENT RANGE	ACCURACY
Reactor vessel low water level Level 1	Level sensor	-150/0/+60	±6 inches inches[1]
Reactor vessel low water level Level 3	Level sensor	0-60 inches	±1.5 inches
Primary containment high pressure	Pressure sensor	0-10 psig	±0.05 psi
LPCI permissive	Pressure sensor	0-500 psi	±2.5 psi
Core Spray permissive	Pressure sensor	0-500 psi	±2.5 psi
Automatic depressurization time delay	Timer	0-180 sec	±18 sec.

(1) Instrument zero equal to 527.5 inches above vessel zero.

Table 7.3-3

CORE SPRAY SYSTEM INSTRUMENT SPECIFICATIONS[2]

CORE SPRAY FUNCTION	INSTRUMENT	RANGE
Reactor vessel low water	Level sensor	-150/0/+60 inches [1]
Primary containment high pressure	Pressure sensor	0-10 psig
Reactor vessel low pressure	Pressure sensor	0-1200 psi
Core spray sparger high differential pressure	Differential pressure sensor	-10/0/+10 psid
Pump discharge flow	Flow sensor	0-8,800 gpm
Pump suction Pressure	Pressure sensor	-30" Hg to 60 psig
Pump discharge pressure	Pressure sensor	0-500 psig

(1) Instrument zero equal to 527.5 inches above vessel zero.

(2) For allowable value of applicable core spray function see technical specifications.

Table 7.3-4

LOW PRESSURE COOLANT INJECTION INSTRUMENT SPECIFICATIONS[2]

LPCI FUNCTION	INSTRUMENT	RANGE
Reactor vessel low water level (LPCI initiation)	Level sensor	-150/0/+60 inches[1]
Drywell high pressure (LPCI initiation)	Pressure sensor	0-10 psig
LPCI pump delay (on loss of normal auxiliary power)	Timer	1.5-15 sec
Injection valve Differential pressure	Differential pressure switch	-200/0/+800 psid
Pump minimum flow bypass	Flow sensor	0-2500 gpm
Pump discharge pressure (signal to ADS)	Pressure sensor	0-500 psig
RHR injection line high differential pressure	Differential pressure sensor	-10/0/10 psi

(1) Instrument zero equal to 527.5 inches above vessel zero.
(2) For instrument accuracy and setpoints, see the Technical Specifications.

Table 7.3-5

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM INSTRUMENT SPECIFICATIONS

ISOLATION FUNCTION	SENSOR	RANGE
Reactor vessel low water level (isolation of primary system valves except main steam line valves) Level 3	Level sensor	0-60 inches(1)
Reactor vessel low water level Level 2	Level sensor	-150/0/+60 inches(1)
Reactor vessel low water level (isolates main steam line valves) Level 1	Level sensor	-150/0/+60 inches(1)
Reactor vessel low water level Level 1	Level sensor	-150/0/+60 inches(1)
Main steam line high flow	Differential pressure sensor	0-150 psid
Main turbine inlet low pressure	Pressure sensor	0-1200 psi
Drywell high pressure	Pressure sensor	0-10 psig
RCIC turbine steam line space high temperature	Differential temperature & ambient temperature sensors	0°F-150°F(3) 50°F-350°F
RCIC turbine steam line high flow	Differential pressure sensor	-500/0/+500 inches

Table 7.3-5 (Cont'd)

ISOLATION FUNCTION	SENSOR	RANGE
RCIC turbine steam line low pressure	Pressure sensor	0-200 psi
HPCI turbine steam line space high temperature	Differential temperature & ambient temperature sensors	0°F-150°F(3) 50°F-350°F
HPCI turbine steam line high flow	Differential pressure sensor	-1000/0/+1000 inches
HPCI turbine line low pressure	Pressure sensor	0-200 psi
Reactor enclosure Ventilation exhaust high radiation	Radiation monitor	0.01-100 mr/hr
Refueling floor Ventilation exhaust high radiation	Radiation monitor	0.01-100 mr/hr
RWCU space high Temperature	Differential temperature & ambient temperature sensors	0°F-150°F(3) 50°F-350°F
Main Steam Line Outboard MSIV room high temperature	Ambient temperature sensor	50°F-350°F
RWCU high Differential flow	Differential flow	0-100 gpm(3)

(1) Instrument zero equal to 527.5 inches above vessel zero.
(2) For instrument accuracy and setpoints, see the Technical Specifications.
(3) The range shown is for the instrument channel trip switch which processes multiple sensor inputs to monitor the differential value between the inputs.

Table 7.3-6

SENSORS OR CIRCUITS IN NONSEISMICALLY QUALIFIED STRUCTURES

SENSOR OR CIRCUIT		STRUCTURE
ZS01-104A->D	Turbine stop valve	Turbine Enclosure
PS01-102A->D	Turbine control valve fast closure	Turbine Enclosure
PT01-1NO52A->D	Turbine stop valve bypass	Turbine Enclosure
PT01-1NO76A->D	MSIV pressure trip input	Turbine Enclosure
PT01-1NO75A->D	Condenser Vacuum	Turbine Enclosure
TE41-1NO10A->D	Leak Detection	Turbine Enclosure
TE41-1NO011A->D	Leak Detection	Turbine Enclosure
TE41-1NO012A->D	Leak Detection	Turbine Enclosure
TE41-1NO14	Leak Detection	Turbine Enclosure
TE41-1NO16	Leak Detection	Turbine Enclosure
TE41-1NO17	Leak Detection	Turbine Enclosure
TE25-115A->D	Leak Detection	Turbine Enclosure
TE25-116A->D	Leak Detection	Turbine Enclosure
TE25-117A->D	Leak Detection	Turbine Enclosure
TE25-118A->D	Leak Detection	Turbine Enclosure
TE25-119A->D	Leak Detection	Turbine Enclosure

Table 7.3-7

INSTRUMENT CHANNELS REQUIRED FOR PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM

I. MSIV ISOLATION(1)

INSTRUMENT CHANNEL DESCRIPTION	NORMAL
Reactor vessel low water level (level 1)	4
Main steam line high flow (each steam line)	4
Main steam line low pressure	4
Main condenser line low vacuum	4
Main Steam Line Outboard MSIV room high temperature	4 ambient

II. MAIN STEAM DRAIN VALVE ISOLATION(1)

INSTRUMENT CHANNEL DESCRIPTION	NORMAL LOGIC CHANNEL PER TRIP SYSTEM
Same as MSIV's instrument channels, however, MSIV logic channels provide inputs to drain valve trip systems.	4

(1) The tables show the number of instrument channels provided to monitor each variable required for the functional performance of PCRVICS (MSIV isolation only). For the minimum number of channels required for functional performance, see the Technical Specifications.

Table 7.3-8

HIGH PRESSURE COOLANT INJECTION SYSTEM
NUMBER OF TRIP CHANNELS FOR FUNCTIONAL PERFORMANCE

COMPONENT AFFECTED	TRIP CHANNEL	INSTRUMENT	CHANNELS PROVIDED[1]
HPCI initiation	Reactor vessel low water level (level 2)	Level sensor	4
HPCI initiation	Primary containment high pressure	Pressure sensor	4
HPCI turbine	HPCI pump discharge Flow	Flow indicator controller	1
HPCI turbine	Reactor vessel high water level (level 8)	Level sensor	4
HPCI turbine	Turbine exhaust high pressure	Pressure sensor	4
HPCI turbine	HPCI pump low suction pressure	Pressure sensor	1
HPCI pump	Minimum flow	Flow sensor	1

Table 7.3-8 (Cont'd)

COMPONENT AFFECTED	TRIP CHANNEL	INSTRUMENT	CHANNELS PROVIDED[1]
HPCI steam supply valve and suppression pool suction valve	HPCI steam supply low pressure	Pressure sensor	4
Suppression pool suction valves	CST low level and/or suppression pool high level	Level sensor	4

(1) For the minimum number of channels required for functional performance, see the Technical Specifications.

Table 7.3-9

AUTOMATIC DEPRESSURIZATION SYSTEM
NUMBER OF TRIP CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE

INITIATING FUNCTION	INSTRUMENT TYPE	NUMBER OF TRIP CHANNELS PROVIDED[1]
Reactor vessel low water level 3	Level sensor	2
Reactor vessel low water level 1	Level sensor	4
Primary containment high pressure	Pressure sensor	4
Time delay (start)	Timer	2
Time delay (bypass)	Timer	4
RHR or core spray pump running interlock	Pressure sensor	4

(1) For the minimum number of channels required for functional performance, see the Technical Specifications.

Table 7.3-10

LOW PRESSURE COOLANT INJECTION SYSTEM
NUMBER OF TRIP CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE

COMPONENT AFFECTED	TRIP CHANNEL	INSTRUMENT TYPE	NUMBER OF TRIP CHANNELS PROVIDED(1)
LPCI/CS Initiation	Reactor vessel low water level (level 1)	Level sensor	2 per trip system
LPCI/CS Initiation	Primary containment high pressure	Pressure sensor	2 per trip system
Minimum flow Valves	LPCI pumps discharge low flow	Flow sensor	1 per trip system
LPCI injection Valves	ΔP across valve low	Δ Pressure sensor	1 per trip system

(1) For the minimum number of channels required for functional performance, see the Technical Specifications.

Table 7.3-11

CORE SPRAY SYSTEM
NUMBER OF TRIP CHANNELS REQUIRED FOR FUNCTIONAL PERFORMANCE

COMPONENT AFFECTED	TRIP CHANNEL	INSTRUMENT TYPE	NUMBER OF TRIP CHANNELS PROVIDED[1]
Core spray System	Reactor vessel low water level (Level 1)	Level sensor	2 per trip system
Core spray System	Primary containment high pressure	Pressure sensor	2 per trip system
Core spray discharge valves	Reactor vessel low pressure	Pressure sensor	2 per trip system
Core spray sparger leak detection	Loop to loop pressure differential	Differential	1 (alarm only) pressure sensor

(1) For the minimum number of channels required for functional performance, see the Technical Specifications.

7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

7.4.1 DESCRIPTION

The following systems are provided for safe shutdown of the reactor:

a. Reactor core isolation cooling system

b. Standby liquid control system

c. Reactor shutdown cooling mode of the RHR system

d. Remote shutdown system

The following are supporting systems for safe shutdown of the reactor:

a. Emergency service water system

b. Residual heat removal service water system

c. Class 1E power systems

d. Shutdown ventilation systems:

1. RCIC system pump compartment unit coolers

2. RHR system pump compartment unit coolers

3. RSS (remote shutdown panels) ventilation system

7.4.1.1 Reactor Core Isolation Cooling System – Instrumentation and Controls

7.4.1.1.1 RCIC System Identification

7.4.1.1.1.1 RCIC Function

The RCIC system consists of a turbine, pump, piping, valves, accessories, and instrumentation designed to ensure that sufficient reactor water inventory is maintained in the reactor vessel, thus ensuring continuity of core cooling. Reactor vessel water is maintained or supplemented by the RCIC during the following conditions:

a. When the reactor vessel is isolated and maintained in the hot standby condition

b. When the reactor vessel is isolated and accompanied by a loss of normal coolant flow from the reactor feedwater system

c. When a complete plant shutdown under condition of loss of normal feedwater system flow is started before the reactor is depressurized to a level where the reactor shutdown cooling mode of the RHR system can be put into operation

7.4.1.1.1.2 RCIC Classification

Electrical components for the RCIC system are classified as Safety Class 2, seismic Category I, and Class 1E.

7.4.1.1.2 RCIC Power Sources

The RCIC system is provided with Class 1E power source. RCIC logic and outboard RCIC isolation valve logic are powered from 125 V dc bus A. Inboard RCIC isolation valve logic is powered from 125 V dc bus C. The system is capable of initiation and operation independent of ac power.

7.4.1.1.3 RCIC Equipment Design

7.4.1.1.3.1 RCIC General

When actuated, the RCIC system pumps water from either the CST or the suppression pool to the reactor vessel. The RCIC system includes a turbine-driven pump, a barometric condenser, a dc vacuum pump, a dc condensate pump, valves, controls, and sensors. The arrangement of equipment and controls is shown in drawings M-49 and M-50. The entire system is operable manually from the control room.

Pressure and level switches used in the RCIC system are located on instrument panels outside the drywell. The only operating component of the RCIC system that is located inside the drywell is the inboard steam line isolation valve.

A design flow functional test of the RCIC system may be performed during normal plant operation by drawing suction from the CST and discharging through a full flow test return line to the CST. The discharge valve to the feedwater line remains closed during the test, and reactor operation remains undisturbed. All components of the RCIC system are capable of individual functional testing during normal plant operation.

The control system provides automatic return from test to normal operating mode if system initiation is required, except for the following situations:

a. The RCIC flow controller AUTO/MANUAL feature in MANUAL mode maintains RCIC flow rate at set value; the operator can switch back to AUTO if required. This feature is required for operational flexibility during system test. This mode is annunciated by the manual out-of-service alarm.

b. Steam inboard/outboard isolation valves closed. Closure of either or both of these valves requires operator action to properly sequence their opening. An alarm sounds when either of these valves leaves the fully open position.

c. RCIC test switch in F012 or F013 position and test plug J1 inserted results in RCIC system being inoperable. Depending on whether test switch is in F012 or F013 position, one of the two series discharge valves are interlocked closed preventing reactor core isolation cooling. RCIC DIV 1 TEST STATUS alarm light in control room illuminates.

7.4.1.1.3.2 RCIC Initiating Circuits

Reactor vessel low water level is monitored by four indicating-type level sensors that sense the difference in pressure between a constant reference leg of water and the pressure that is due to the actual height of water in the vessel. The sensing lines for the RCIC sensors are physically separated and tap off the reactor water vessel at widely separated points.

The RCIC system is initiated only by low water level using a one-out-of-two-twice logic.

The RCIC system is initiated automatically after the receipt of a reactor vessel low water signal (level 2) and produces the design flow rate within 55 seconds. The system then functions to provide makeup water flow to the reactor vessel until level 8 is reached at which time the RCIC system automatically shuts down. The system will automatically restart if the level returns to the low level trip point. The controls are arranged to allow remote manual startup, operation, and shutdown.

The RCIC turbine is functionally controlled as shown in drawings E51-1030-F-004, E51-1030-F-005, E51-1030-F-006, E51-1030-F-007, E51-1030-F-008, and E51-1030-F-009. The turbine governor controls turbine speed and adjusts the turbine steam control valve so that demand pump discharge flow rate is obtained. The flow signal used for automatic control of the turbine is derived from a differential pressure measurement across a flow element in the RCIC system pump discharge line.

The turbine is automatically shut down by closing the turbine stop (trip throttle) valve if any of the following conditions are detected:

a. Mechanical turbine overspeed trip (one-out-of-one logic trip)

b. High turbine exhaust pressure trip (one-out-of-two logic trip)

c. RCIC turbine excessive moisture protective flow reduction at reactor vessel water level 8 (one-out-of-two-twice logic trip)

d. Low pump suction pressure trip (one-out-of-one logic trip)

e. RCIC isolation trip (one-out-of-two logic for turbine trip, for isolation one channel closes the inboard valve and one channel closes the outboard valve).

f. Remote manual trip

g. Local manual trip

Each of the isolation logics consists of the following:

a. Steam supply line high flow (one-out-of-two trip logic)

b. High turbine diaphragm exhaust pressure (two-out-of-two trip logic)

c. High area temperature (one-out-of-seven trip logic for Unit 1, one-out-of-six trip logic for Unit 2)

d. Low steam line pressure (two-out-of-two trip logic)

Precautions taken to preclude a spurious RCIC turbine shutdown or system isolation are as follows:

a. Use of coincident isolation trip logic circuits.

b. Use of time delay in logic of trip circuits (See NUREG-0737, Item II.K.3.15).

c. Use of safety-grade seismically qualified instrumentation and control components.

d. Use of trip settings far enough from normal operating values to reduce spurious trips, yet protect equipment from damage.

The series RCIC test return valve F022 and the HPCI test return to CST valve F011 are closed, unless opened by the operator for the RCIC flow test. If during flow test a low reactor water level condition occurs, RCIC initiates and F022 closes. Also, if either RCIC pump suction valves F029 or F031 is fully open, RCIC valve F022 and HPCI valve F011 will automatically close.

Turbine overspeed indicates a malfunction of the turbine control mechanism. High turbine exhaust pressure indicates a condition that threatens the physical integrity of the exhaust line. Low pump suction pressure warns that cavitation and lack of cooling can cause damage to the pump that could place it out of service. A turbine trip is initiated for these conditions so that if the causes of the abnormal conditions can be found and corrected, the system can be quickly restored to service. The trip settings are selected far enough from normal values so that a spurious turbine trip is unlikely, but not so far that damage occurs before the turbine is shut down. Turbine overspeed is detected by a standard turbine overspeed mechanical device.

Two pressure sensors are used to detect high turbine exhaust pressure. The logic for either sensor will initiate turbine shutdown. One pressure sensor is used to detect low RCIC system pump suction pressure.

Low steam line pressure in the supply line to the turbine indicates loss of motive force for the turbine, therefore the isolation valves are closed to shut down the turbine.

Pressure sensors monitor the pressure produced in the supply line to the turbine. Trip conditions signals are sent to the Leak Detection System (LDS) isolation logic to shut off the steam line.

High water level in the reactor vessel (level 8) indicates that the RCIC system has performed satisfactorily in providing makeup water to the reactor vessel. A further increase in level could damage the RCIC system turbine as a result of gross carryover of moisture. Four level sensors that sense differential pressure are arranged in a one-out-of-two-twice logic configuration to initiate closure of the F045 valve.

7.4.1.1.3.3 RCIC Logic and Sequencing

The scheme used for initiating the RCIC system is shown in drawings E51-1030-F-004, E51-1030-F-005, E51-1030-F-006, E51-1030-F-007, E51-1030-F-008, and E51-1030-F-009. The instrument settings for the RCIC system controls and instrumentation are listed in Chapter 16.

To prevent the pump from overheating at reduced flow, a pump discharge minimum flow line is provided to route the water from the pump back to the suppression pool.

The minimum flow line is controlled by an automatic dc MOV F019 whose control scheme is shown in drawings E51-1030-F-004, E51-1030-F-005, E51-1030-F-006, E51-1030-F-007, E51-1030-F-008, and E51-1030-F-009. At RCIC high flow, the valve is closed; conversely, at low flow with high pump discharge pressure, the valve is opened. The signals come from a sensor actuated by the pressure difference across a flow element in the RCIC pump discharge pipeline.

To prevent the RCIC steam supply pipeline from filling up with water and cooling the steam line excessively, a condensate drain pot, steam line drain, and appropriate valves are provided in a drain pipeline arrangement just upstream of the turbine supply valve. The control scheme is shown in drawings E51-1030-F-004, E51-1030-F-005, E51-1030-F-006, E51-1030-F-007, E51-1030-F-008, and E51-1030-F-009. The controls position valves F025 and F026 so that during normal plant operation steam line drainage is routed to the main condenser. The water level in the steam line drain condensate pot is controlled by a level switch and a direct-acting solenoid valve that energizes to allow condensate to flow out of the drain pot. After receiving an RCIC initiation signal, the drainage path is isolated.

The level in the drain pot is controlled primarily by a flow orifice (Unit 1) and steam trap (Unit 2); the level switch and trap bypass valve F054 are backups to the primary control.

Upon reduction in steam line pressure to the low pressure setpoint the isolation valves are closed to shutdown the system.

7.4.1.1.3.4 RCIC Bypasses and Interlocks

During test operation, the RCIC pump discharge is routed to the CST. A dc MOV F022 is installed in the pump discharge to the CST pipeline. The piping arrangement is shown in drawing M-49. The control scheme for the valves is shown in drawings E51-1030-F-004, E51-1030-F-005, E51-1030-F-006, E51-1030-F-007, E51-1030-F-008, and E51-1030-F-009. Upon receipt of an RCIC initiation signal, the valve closes and remains closed. A redundant valve (HPCI F011) on the same line is closed on HPCI initiation. The RCIC pump suction F010, RCIC pump discharge F022, and HPCI pump discharge F011 to CST valves are interlocked closed if the suppression pool suction valves F029 and F031 for RCIC are fully open.

7.4.1.1.3.5 RCIC Redundancy and Diversity

On a network basis, the RCIC is redundant to HPCI for the safe shutdown function. Therefore, RCIC as a system by itself is not required to be redundant.

Redundancy and diversity of initiating signals is a requirement stipulated only for the RPS and ESF. Therefore, diversity of initiating circuits is not a requirement for the RCIC system.

The RCIC is actuated by reactor low water level. Four level sensors in a one-out-of-two-twice circuit supply this signal.

7.4.1.1.3.6 RCIC Actuated Devices

All automatic valves in the RCIC are equipped with remote manual capability so that the entire system can be operated from the control room. MOVs are equipped with the appropriate limit and/or torque switches to turn off the motors when the fully open or fully closed positions are reached. Overload protection is provided to valve motors in accordance with Section 8.1.6.1.19. All MOVs and AOVs provide control room indication of valve position. The system is capable of initiation and operation independent of ac power.

To ensure that the RCIC can be brought to design flow rate within 55 seconds after receiving the initiation signal, the following maximum operating times for essential RCIC valves are provided by the valve operation mechanisms:

a. RCIC turbine steam supply valve (F045) 20 seconds

b. RCIC pump discharge valves (F012, F013) 23 seconds

c. RCIC pump minimum flow bypass valve (F019) 5 seconds

The operating time is the time required for the valve to travel from the fully closed to the fully open position, or vice-versa. The two RCIC steam supply line isolation valves F007 and F008 are normally open, and they are designed to isolate the RCIC steam line if there is a break in that line. A normally closed dc MOV F045 is located in the turbine steam supply pipeline just upstream of the turbine stop valve. After receiving an RCIC initiation signal (Level 2), this valve (F045) opens partially. The partial opening of the valve is to permit the turbine to attain an idle speed after which the ramp generator is turned on and the valve opens all the way. F045 remains open until either a predetermined high level (Level 8) is reached when the valve will automatically close or until manually closed by operator action from the control room.

The RCIC steam supply line isolation valves and steam line warm-up isolation valves automatically close on receipt of an RCIC automatic isolation signal. Detailed discussion is found in Section 7.6.1.3.3.3.

Two isolation valves are provided in the steam supply line to the turbine. The valves, one inside (F007) and one outside (F008) the primary containment, are normally open. They automatically close after receiving an RCIC isolation signal. These valves are operated by ac motors powered from different ac sources. The outboard isolation valve has a bypass line with an automatic remotely controlled valve (F076) in it. The bypass line is used to equalize and preheat the steam line.

The instrumentation for isolation consists of the following:

a. Outboard RCIC Turbine Isolation Valve (F008)

1. Differential temperature switches - RCIC equipment ventilation air inlet and outlet high differential temperature

2. Ambient temperature switches - RCIC equipment area high temperature

3. Ambient temperature switches - RCIC emergency area cooler high temperature

4. Differential pressure switches - RCIC steam line high flow or instrument line break

5. Two pressure switches - RCIC turbine exhaust diaphragm high pressure. Both sensors must activate to isolate.

6. Two pressure switches - RCIC steam supply pressure low. Indicates loss of the motive force for the turbine, therefore, the isolation valves are closed to shut down the turbine. Both sensors must activate to isolate.

7. Manual isolation if the system has been initiated

b. Inboard RCIC Turbine Isolation Valve (F007)

A similar set of instrumentation causes the inboard valve to isolate except for the manual isolation feature.

Three pump suction valves are provided in the RCIC system. One valve (F010) lines up pump suction from the CST; the other two (F029, F031) do so from the suppression pool. The CST is the preferred source. All valves are operated by dc motors. The control arrangement is shown in drawings E51-1030-F-004, E51-1030-F-005, E51-1030-F-006, E51-1030-F-007, E51-1030-F-008, and E51-1030-F-009. After receiving an RCIC initiation signal, the CST suction valve automatically opens. If the water level in the CST falls below a predetermined level, the RCIC pump suction is automatically transferred to the suppression pool. Redundant level sensors are used to detect the CST low water level condition. Either sensor can cause the suppression pool suction valve to open. When the suppression pool suction valves are opened, the CST suction valve automatically closes. Two dc motor-operated RCIC pump discharge valves in the pump discharge pipeline are provided. The control scheme for these valves is shown in drawings E51-1030-F-004, E51-1030-F-005, E51-1030-F-006, E51-1030-F-007, E51-1030-F-008, and E51-1030-F-009. They are arranged to open after receiving the RCIC initiation signal. The inboard valve closes automatically upon receipt of a turbine trip valve closure signal or steam supply valve closure signal.

7.4.1.1.3.7 RCIC Separation

As in the ECCS, the RCIC system is separated into two independent divisions designated 1 and 3. The RCIC system is a Division 1 system, but all inboard valves are Division 3. Division 1 logic is powered by the 125 V dc Division 1 bus A, and the Division 3 logic is powered by the 125 V dc Division 3 bus C. To maintain the required separation, the RCIC logic relays, cabling, instruments, and manual controls are mounted so that physical separation of Division 1 and Division 3 is maintained. The HPCI system is divisionalized in Divisions 2 and 4 and is therefore separated from RCIC.

The auxiliary systems that support the RCIC system are the barometric condenser system, which prevents turbine leakage, and the lube oil cooling water system. An initiation signal starts the condenser vacuum pump and opens the cooling water valve that initiates the barometric condenser and oil cooling action. The systems remain on until manually turned off, or tripped off by one of the parameters described in 7.4.1.1.3.2. The condensate pump starts when high level is sensed in the vacuum tank and automatically stops when tank level drops below the low level setpoint.

A complete description of the complete independence between divisions is given in Section 7.1.2.2.

7.4.1.1.3.8 RCIC Testability

The RCIC instrumentation and control system is capable of being tested during normal unit operation to verify the operability of each system component. Testing of the initiation sensors located outside the drywell is accomplished by valving out each sensor, one at a time, and applying a test pressure source.

This verifies the operability of the sensor. Trip units located in the auxiliary equipment room are calibrated individually by a calibration source with verification of setpoint by a digital readout located on the calibration module.

a. Calibration and test controls for the sensors are located in the reactor enclosure. Calibration and test controls for the trip units are located in the auxiliary equipment room. To gain access to the calibration points of each sensor, a cover plate must be removed. The control room operator is responsible for granting access to the calibration points. Only properly qualified plant personnel are granted access for testing or calibration adjustments.

   In addition to the above tests, operability of the sensors can be verified by cross-checking instrument readouts in the auxiliary equipment room at any time during operation.

b. Test jacks are provided to test the logic. Annunciation is provided in the control room whenever a test lug is inserted in a jack to indicate to the control room operator that the RCIC system is in the test status. Operation of the test plug switches initiates the RCIC system. Injection into the reactor is prevented by an interlock, actuated only when the test plug is inserted, which prevents the opening of one of the RCIC discharge valves. The test can be repeated with the other discharge valve interlock closed. The manual initiation switch can also be tested at this time. This sequence of tests ensures that all components are tested. A logic test of the RCIC does not interfere with the operation of any ECCS equipment if required by an initiation signal.

c. The functional performance of the RCIC system can be verified by pumping water from the CST, through the full flow test lines, and back to the CST. If initiation were to occur during this mode of operation, the valve line-up would automatically be changed so that water can be pumped to the reactor.

During the above testing, the operation of the RCIC system can be observed in the control room by panel lamps, indicators, recorders, annunciators, and computer printout.

7.4.1.1.4 RCIC Environmental Considerations

The control mechanisms for the inboard isolation valve are the only RCIC control components located inside the drywell that must remain functional in the post-LOCA environment. The RCIC control and instrumentation equipment located outside the drywell is selected in consideration of the environments in which it must operate. Selected safety-related RCIC instrumentation, such as

RCIC LDS instrumentation is qualified as described in Sections 3.10 and 3.11. However, the RCIC turbine instrumentation is not environmentally qualified because it is not required to operate in a potentially harsh environment per 10CFR50.49.

7.4.1.1.5 RCIC Operational Considerations

7.4.1.1.5.1 RCIC General Information

Normal core cooling is required if, during normal operation, the reactor becomes isolated from the main condenser by a closure of the MSIVs. Cooling is necessary because of the core fission product decay heat. Steam is vented through the pressure relief/safety valves to the suppression pool. The RCIC system maintains reactor water level by providing the makeup water. Initiation and control are automatic.

7.4.1.1.5.2 RCIC Reactor Operator Information

The following items are located in the control room for operator information:

a. Analog Indication

   1. RCIC steam supply pressure
   2. RCIC pump suction pressure
   3. RCIC pump discharge pressure
   4. RCIC pump discharge flow
   5. RCIC turbine speed
   6. RCIC turbine exhaust line pressure

b. Indicating Lamps

   1. Position of all MOVs
   2. Position of all solenoid-operated valves
   3. Turbine trip solenoid energized or de-energized
   4. All sealed-in circuits
   5. Pump status

c. Annunciators

   Annunciators are provided as shown in the RCIC FCD (drawings E51-1030-F-004, E51-1030-F-005, E51-1030-F-006, E51-1030-F-007, E51-1030-F-008, and E51-1030-F-009) and the RCIC system P&ID (M-49 and M-50).

7.4.1.1.5.3 RCIC Setpoints

Instrument settings for the RCIC system controls and instrumentation are listed in Chapter 16.

The reactor vessel low water level setting for RCIC system initiation is selected high enough above the active fuel to start the RCIC system before the low pressure ECCS is needed. The water level setting is far enough below normal levels that spurious RCIC system startups are avoided.

The low steam line pressure setpoint is established to terminate system function where there is insufficient motive force for the turbine.

7.4.1.1.6 RCIC - IEEE 279 - Design Basis

The following information is documented herein and as such satisfies the requirements of IEEE 279:

a. The generating station conditions that require protective action are identified in Chapter 15.

b. The generating station variables that must be monitored to provide protective actions are identified in Section 7.4.1.1.3.2 and in Chapter 16.

c. The minimum number and location of the sensors required to adequately monitor, for protective function purposes, those variables listed in Section 7.4.1.1.3.2 that have a spatial dependence do not exist for this system.

d. Prudent operational limits for each variable listed in Section 7.4.1.1.3.2 in each applicable reactor operation mode are identified in Chapter 16.

e. The margin, with appropriate interpretive information, between each operational limit and the level considered to mark the onset of unsafe conditions is included in the values developed in Chapter 16.

f. The levels that, when reached, will require protective action are identified in Chapter 16.

g. The range of transient and steady-state conditions of the energy supply are contained in Chapter 8.

h. The malfunctions, accidents, or other unusual events that could physically damage protection system components or could cause environmental changes leading to functional degradation of system performance, and for which provisions must be incorporated to retain necessary protective action, are identified in IEEE 279, paragraph 4.1 (Section 7.4.2.1.2.3.1.1).

i. Minimum performance requirements include the following:

    1. System response times

    2. System accuracies

3. Ranges (normal, abnormal, and accident conditions) of the magnitudes and rates of change of sensed variables to be accommodated until proper conclusion of the protective action is ensured have been considered and included in Chapter 15 and Chapter 16.

7.4.1.2 Standby Liquid Control System - Instrumentation and Controls

7.4.1.2.1 SLCS System Identification

7.4.1.2.1.1 SLCS Function

The instrumentation and controls for the SLCS are designed to initiate and continue injection of a liquid neutron absorber into the reactor when manually initiated or automatically initiated by the RRCS. This equipment also provides the necessary controls to maintain this liquid chemical solution well above saturation temperature in readiness for injection.

The instrumentation and controls are also designed to provide sufficient sodium pentaborate to the reactor vessel to maintain suppression pool pH at 7.0 or greater following a LOCA when manually initiated.

7.4.1.2.1.2 SLCS Classification

The SLCS is a backup method of shutting down the reactor to cold subcritical conditions by independent means other than the normal method using the control rods. Thus, the system is considered a "safe shutdown system." The standby liquid control process equipment and controls essential for injection of the neutron absorber solution into the reactor are designed to seismic Category I criteria. In addition, these controls are Class 1E, meeting the quality requirements of 10CFR50.

The SLCS process equipment and controls essential for post LOCA pH control in accordance with Regulatory Guide 1.183 (AST) are designed to Seismic Category I criteria and controls are Class 1E.

Nondirect process equipment, instrumentation, and controls of the system are not required to meet seismic Category I requirements; however, the local and control room mounted equipment is located in seismically qualified panels.

7.4.1.2.2 SLCS Power Sources

The SLCS pumps, valves, heaters, and associated controls are powered from Class 1E power supplies. The power supply to the explosive operated injection valves and injection pumps are from separate emergency buses. The power supply to both the control room bench board indicator lights and the level and pressure sensors is powered from an emergency instrument bus.

7.4.1.2.3 SLCS Equipment Design

7.4.1.2.3.1 SLCS General

The SLCS is a special "plant capability" event system. No single active component failure of any plant system or component would necessitate the operational function of the SLCS. It is included for two special cases:

a. Plant capability to shut down the reactor without control rods from normal operation (Section 15.9)

b. Plant capability to shut down the reactor without control rods from a transient incident (Sections 15.8 and 15.9)

c. Plant capability to maintain suppression pool water inventory at a pH of 7.0 or greater post LOCA in accordance with Regulatory Guide 1.183, Alternative Source Terms.

Although this system has been designed to a high degree of reliability with many safety system features, it is not required to meet the safety design basis requirements of the safety systems.

7.4.1.2.3.2 SLCS Initiating Circuits

The SLCS is manually initiated in the control room, when the operator determines that normal reactivity control systems have not shutdown the reactor as required, by turning the key-lock switch to the run position for either one or both of the two in-service pumps. Indicator lights located near each key-lock switch apprise the operator of the selected system initiation.

Two loops of the SLCS can also be automatically initiated by the RRCS after a time delay, provided that APRM power is not downscale and the key-lock switch is in the center normal position. This automatic initiation overrides the manual initiation signal; however, the manual shutoff signal overrides the automatic initiation signals. Section 7.6.1.8.3.4 describes the RRCS automatic initiation of the SLCS.

7.4.1.2.3.3 SLCS Logic and Sequencing

When a SLCS pump is started (manually or automatically), both squibs on its explosive- operated valve fire. Firing of either or both of the two squibs installed on each valve will open the valve. The SLCS is manually initiated in the control room by turning the key-locked switch for either one of both of the two in-service pumps to the run position. Only two SLCS pumps are started to prevent lifting the pressure relief valves(s) on high discharge header pressure with three SLCS pump operation.

SLCS operates automatically when both channels A and B of either RRCS division are tripped. Normally only SLCS pumps A and B are aligned to receive the start signal (key-lock switches in the normal position) with SLCS pump C automatic start signal blocked (key-lock switch in the stop position and the key removed). However, when either the A or B SLCS pump is out-of-service, then the C SLCS pump can be aligned to receive the automatic start signal (key-lock switch positioned to normal).

For automatic operation, both squibs on each injection valve fire, all three SLCS pumps receive a start signal when both channels A and B of either RRCS division are tripped.

The SLCS is provided with instrumentation and control to automatically shut off the SLCS pumps when the solution level in the storage tank is below the low level limit. This low level pump shutoff signal is provided by two-out-of-two logic. Three sets of storage tank level monitoring devices are provided to automatically shut off the SLCS pumps. Each set consists of two independent transmitters and trip units. There is a separate external line for each set of transmitters; this prevents a single instrument line problem from affecting all three SLCS pumps.

7.4.1.2.3.4 SLCS Bypasses and Interlocks

Initiation of SLCS pump A or C will close the inboard isolation valve of the RWCU system. Initiation of SLCS pump B will close the RWCU outboard isolation valve.

7.4.1.2.3.5 SLCS Redundancy and Diversity

Under special shutdown conditions, the SLCS is functionally redundant to the control rods in achieving and maintaining the reactor subcritical. Therefore, the SLCS as a system by itself is not required to be redundant. The power buses, pumps and explosive-operated injection valves are redundant so that a single component may be removed from service for maintenance during plant operation.

Diversity of initiating signals is a requirement only for RPS and ESF. Therefore, diversity of initiating circuits is not used in the SLCS design.

7.4.1.2.3.6 SLCS Actuated Devices

When the SLCS is initiated to inject a liquid neutron absorber into the reactor, the following devices are actuated:

a. Explosive valves are fired.

b. Injection pumps are started.

c. The pressure sensing equipment indicates that the SLCS is pumping liquid into the reactor.

d. The RWCU system inboard isolation valve closes on initiation of SLCS pumps A and C and the outboard isolation valve closes on initiation of SLCS pump B.

7.4.1.2.3.7 SLCS Separation

The SLCS is separated both physically and electrically from the CRD system. The SLCS instrument channels are separated in accordance with the requirements of IEEE 279 (1971).

7.4.1.2.3.8 SLCS Testability

The instrumentation and control system of the SLCS is tested when the system test is performed as outlined in Section 9.3.5.

7.4.1.2.4 SLCS Environmental Considerations

The environmental considerations for the instrument and control portions of the SLCS are discussed in Section 3.11. The instrument and control portions of the SLCS are seismically qualified not to fail during, and to remain functional following, an SSE. See Section 3.10 for seismic qualification aspects.

7.4.1.2.5 SLCS Operational Considerations

7.4.1.2.5.1 SLCS General Information

The control scheme for the SLCS is shown in drawings C41-1030-F-002, C41-1030-F-003 and C41-1030-F-004. The SLCS is automatically initiated by the RRCS or manually initiated by key-locked switches located in the control room. The SLCS pumps will automatically stop on SLCS storage tank low level or they may be stopped manually from the key-locked switches after an automatic initiation.

7.4.1.2.5.2 SLCS Reactor Operator Information

After the SLCS is initiated, the operator has several indicators and alarms to determine proper system operation. Indicator lights show which system was initiated, explosive valve continuity, isolation valve position, and inboard maintenance valve position. The control room annunciators indicate:

a. Isolation valve not fully open

b. Loss of continuity to the squib valves

c. SLCS storage tank Hi/Lo temperature

d. SLCS storage tank Hi/Lo level

e. SLCS A, B or C pump motor overload or loss of power.

Analog information is also available for the storage tank level and for pump pressures. At the local panel, additional operator information is available, such as storage tank level, system pressure, and storage tank temperature.

7.4.1.2.5.3 SLCS Setpoints

The SLCS has setpoints for the various instruments as follows:

a. The loss of continuity meter is set to activate the annunciator just below the trickle current that is observed when the primers of the explosive valves are new.

b. The SLCS storage tank temperature switch is set to activate an annunciator at high and low temperatures.

c. The SLCS storage tank level switch is set to activate an annunciator when the level is either high or low.

d. A thermostatically controlled heater maintains the temperature of the SLCS solution to prevent precipitation.

7.4.1.2.6 SLCS - IEEE 279 - Design Basis

SLCS is not a protection system, but it is designed to meet IEEE 279. The following information is documented herein and as such satisfies the requirements of IEEE 279:

a. The plant conditions that require protective action are identified in Chapter 15.

b. The generating station variables that must be monitored to provide protective actions are identified in Sections 7.4.1.2.3.2 and 7.6.1.8.3.4, and in Chapter 16.

c. The minimum number and location of the sensors required to adequately monitor, for protective function purposes, those variables listed in Section 7.4.1.2.3.2 that have a spatial dependence do not exist for this system.

d. Prudent operational limits for each variable listed in Section 7.4.1.2.3.2 in each applicable reactor operation mode are identified in Chapter 16.

e. The margin, with appropriate interpretive information, between each operational limit and the level considered to mark the onset of unsafe conditions is included in the values developed in Chapter 16.

f. The levels that, when reached, will require protective action are identified in Chapter 16.

g. The range of transient and steady-state conditions of both the energy supply and the environment during normal, abnormal, and accident circumstances throughout which the system must perform are contained in Chapter 8 for the energy supply, and Sections 3.10 and 3.11 for the environmental parameters.

h. The malfunctions, accidents, or other unusual events that could physically damage protection system components or could cause environmental changes leading to functional degradation of system performance, and for which provisions must be incorporated to retain necessary protective action, are identified in IEEE 279, paragraph 4.1 (Section 7.4.2.2.2.3.1.1).

i. Minimum performance requirements include the following:

    1. System response times

    2. System accuracies

    3. Ranges (normal, abnormal, and accident conditions) of the magnitudes and rates of change of sensed variables to be accommodated until proper conclusion of the protective action is ensured have been considered and included in Chapter 15 and Chapter 16.

7.4.1.3 Reactor Shutdown Cooling Mode of the RHR System -Instrumentation and Controls

7.4.1.3.1 RHR-SCM System Identification

7.4.1.3.1.1 Function

The RHR-SCM used during a normal reactor shutdown and cooldown performs a safe shutdown function.

The initial phase of a normal nuclear system cooldown is accomplished by routing steam from the reactor vessel to the main condenser, which serves as the heat sink.

The RHR-SCM consists of a set of pumps, valves, heat exchangers, and instrumentation designed to provide decay heat removal capability from the core. The system specifically accomplishes the following:

a. The RHR-SCM is capable of providing cooling for the reactor during shutdown operation after the vessel pressure is reduced to approximately 75 psig.

b. The system is capable of cooling the reactor water to a temperature at which reactor refueling and servicing can be accomplished.

The system can use a preferred method to accomplish its design objectives by directly extracting reactor vessel water from the reactor vessel via the recirculation loop and routing it to a heat exchanger and back to the vessel. An alternate method is to indirectly extract the water via relief valve discharge lines to the suppression pool and route the suppression pool water to the heat exchanger and back to the vessel.

7.4.1.3.1.2 RHR-SCM Classification

Electrical components for the RHR-SCM are classified as Safety Class 3, seismic Category I, and Class 1E.

7.4.1.3.2 RHR-SCM Power Sources

This system uses the safeguard 4 kV, 440 V ac, 120 V ac divisional instrument buses, and divisional 125 V dc sources.

7.4.1.3.3 RHR-SCM Equipment Design

7.4.1.3.3.1 RHR-SCM General

The reactor water is cooled by taking suction from one recirculation loop and pumping the water through the system heat exchangers back to the reactor vessel via both recirculation loops. If it is necessary to discharge a complete core load of reactor fuel to the spent fuel pool, a means is provided for making an intertie between the spent fuel pool and the RHR heat exchangers when required. This intertie increases the cooling capacity for cooling the spent fuel pool to handle the heat load for this situation. See drawing M-51 for the RHR system P&ID.

7.4.1.3.3.2 RHR-SCM Initiating Circuits

The operator manually initiates the RHR-SCM; automatic control is not necessary.

7.4.1.3.3.3 RHR-SCM Logic and Sequencing

The RHR-SCM is manually operated.

7.4.1.3.3.4 RHR-SCM Bypasses and Interlocks

To prevent the reactor shutdown cooling valves from opening except under proper conditions, the interlocks are provided as shown in Table 7.4-2.

The two RHR pumps (A and B) normally aligned for shutdown cooling are interlocked to trip if the reactor shutdown cooling valves and suction valves from the suppression pool are not properly positioned. Operation of the C and D RHR pumps in the shutdown cooling mode is controlled administratively.

7.4.1.3.3.5 RHR-SCM Redundancy and Diversity

The RHR-SCM contains two heat exchanger loops with each heat exchanger alignable to one of two RHR pumps. Either loop is enough to satisfy the cooling requirements for shutdown cooling. However, both loops share a common suction line with two suction valves in series. If one of the suction valves fails closed causing shutdown cooling to be lost, an alternate shutdown cooling flowpath may be established by manually switching to take suction water from the suppression pool and manually opening the ADS valves to allow reactor water to flow down to the suppression pool. The ADS valves may be actuated by either Division 1 or Division 3 power, thus providing redundancy if there is a divisional power failure.

If this failure occurs, an alternative flow path exists: water can be discharged from the reactor through the SRVs to the suppression pool, and then pumped to the reactor through an operable heat exchanger and associated LPCI injection valve.

During cold shutdown and refueling operation conditions, four subsystems of shutdown cooling exist, comprised of the A heat exchanger with the A RHR pump, A heat exchanger with the C RHR pump, B heat exchanger with the B RHR pump, and B heat exchanger with D RHR pump. If two required operable shutdown cooling subsystems are associated with the same heat exchanger, a failure of the shutdown cooling discharge valve or check valve associated with that heat exchanger will result in manual actions to effect valve repair, and if unsuccessful, may require cooling water flow to be returned through the LPCI line as described above.

Refer to Section 15.9 for a system level examination of the above operation.

Although instrumentation diversity is not required for the RHR-SCM, the design basis objective is achieved by two diverse shutdown cooling heat exchanger loops.

7.4.1.3.3.6 RHR-SCM Actuated Devices

All valves and pumps required for the RHR-SCM are equipped with remote manual switches in the control room, with the exception of alignment of the LPCI dedicated (C and D) RHR pumps for RHR-SCM operation which is performed locally. Further discussion of the general operation of the RHR system, including its other modes of operation, can be found in Section 7.3.1.1.

7.4.1.3.3.7 RHR-SCM Separation

Because various modes of operation of the RHR system perform safety-related functions (LPCI and containment cooling), any of the system's equipment performing safety-related functions satisfies the appropriate safety separation criteria (Section 7.3.1.1). The shutdown cooling mode of operation can use two diverse techniques. The separation between components used in these approaches satisfies separation criteria.

7.4.1.3.3.8 RHR-SCM Testability

The RHR pumps used for the RHR-SCM may be tested to full capacity during normal plant operation. All valves except those isolated by the reactor pressure interlock in the system may be tested during normal plant operation using the remote manual switches in the control room.

7.4.1.3.4 RHR-SCM Environmental Considerations

RHR control equipment is classified and seismically and environmentally qualified as discussed in Sections 3.2, 3.10, and 3.11.

7.4.1.3.5 RHR-SCM Operational Considerations

The RHR-SCM is used for normal shutdown.

7.4.1.3.5.1 RHR-SCM General Information

All controls for the RHR-SCM are located in the control room, with the exception of alignment of the LPCI dedicated (C and D) RHR pumps for RHR-SCM operation which is performed locally. Reactor operator information is provided as described in the RHR discussion of the LPCI mode in Section 7.3.1.1.

7.4.1.3.5.2 RHR-SCM Reactor Operator Information

See Section 7.3.1.1 for reactor operator information associated with the RHR in general. In addition, position indication on shutdown cooling maintenance valves 51-F060A and 51-F060B is provided.

7.4.1.3.5.3 RHR-SCM Setpoints

There are no safety-related setpoints involved in the operation of the RHR-SCM, except that reactor pressure and water level setpoints must be satisfied, and no isolation signal is present before the operator can begin this mode.

7.4.1.3.6 RHR-SCM - IEEE 279 - Design Basis

The following information is documented herein and as such satisfies the requirements of IEEE 279:

a. The generating station conditions which require protective action are identified in Chapter 15.

b. The generating station variables that must be monitored to provide protective actions are identified in Section 7.4.1.3.3.2 and in Chapter 16.

c. The minimum number and location of the sensors required to adequately monitor, for protective function purposes, those variables listed in Section 7.4.1.3.3.2 that have a spatial dependence do not exist for this system.

d. Prudent operational limits for each variable listed in Section 7.4.1.3.3.2 in each applicable reactor operation mode are identified in Chapter 16.

e. The margin, with appropriate interpretive information, between each operational limit and the level considered to mark the onset of unsafe conditions is included in the values developed in Chapter 16.

f. The levels that, when reached, will require protective action are identified in Chapter 16.

g. The range of transient and steady-state conditions of both the energy supply and the environment during normal, abnormal, and accident circumstances throughout which the system must perform are contained in Chapter 8 for the energy supply, and Sections 3.10 and 3.11 for the environmental parameters.

h. The malfunctions, accidents, or other unusual events that could physically damage protection system components or could cause environmental changes leading to functional degradation of system performance, and for which provisions must be incorporated to retain necessary protective action, are identified in IEEE 279, paragraph 4.1 (Section 7.4.2.3.2.3.1).

i. Minimum performance requirements include the following:
   1. System response times
   2. System accuracies
   3. Ranges (normal, abnormal, and accident conditions) of the magnitudes and rates of change of sensed variables to be accommodated until proper conclusion of the protective action is ensured have been considered and included in Chapter 15 and Chapter 16.

7.4.1.4 Remote Shutdown System

7.4.1.4.1 RSS Identification

7.4.1.4.1.1 RSS General

It is possible to carry out the reactor shutdown functions from outside the control room and bring the reactor to cold conditions in a safe and orderly fashion.

7.4.1.4.1.2 Postulated Conditions Assumed to Exist when the Control Room Becomes Inaccessible (RSS)

a. The plant is operating initially at, or less than, design power.

b. The plant is not experiencing any transient situations. Even though the loss of offsite ac power is considered unlikely, the essential controls and instrumentation on the remote shutdown panel or facilities are powered from a Class 1E power system bus. Manual controls of the diesel generator are available in the diesel generator enclosure.

c. The plant is not experiencing any accident situations. No DBA, including a LOCA, is assumed, so that complete control of ESF systems from outside the control room is not required.

d. All plant personnel have evacuated the control room.

e. The control room continues to be inaccessible for several hours.

f. The initial event that causes the control room to become inaccessible permits the reactor operator to manually scram the reactor before leaving the control room. If it is not possible to do so, the capability of opening the output breakers of the RPS logic from outside the control room can be used as a backup means to achieve initial reactor reactivity shutdown.

g. The main turbine pressure regulators may control reactor pressure via the bypass valves. However, to demonstrate that the plant can accommodate even loss of the turbine controls, it is assumed that this turbine-generator control panel function is also lost. Therefore, main steam line isolation is assumed to occur at a specified low turbine inlet pressure, and reactor pressure is relieved through the relief valves to the suppression pool.

h. The reactor feedwater system that is normally available is also assumed to be inoperable. Reactor water is made up by the RCIC system.

i. Power services are expected to be supplied for each essential system or equipment item in the remote shutdown system.

The above initial conditions and associated assumptions are very severe and conservatively bound any similarly postulated situation.

7.4.1.4.2 RSS Description

a. The system described provides remote control for reactor systems needed to carry out the shutdown function from outside the control room and bring the reactor to a cold condition in an orderly fashion.

b. The RSS provides a variation to the normal system used in the control room, permitting the shutdown of the reactor when feedwater is unavailable and the normal heat sinks (turbine and condenser) are lost.

c. Activation of relief valves and the RCIC system brings the reactor to a hot shutdown condition after scram and isolation are achieved by removing RPS power. During

this phase of shutdown, the suppression pool is cooled by operating the RHR system in the suppression pool cooling mode. Reactor pressure is controlled and core decay and sensible heat are rejected to the suppression pool by relieving steam pressure through the relief valves. Reactor water inventory is maintained by the RCIC system.

d. Manual operation of the relief valves cools the reactor and reduces its pressure at a controlled rate until reactor pressure becomes so low that the RCIC system discontinues operation.

e. The RHR system is then operated in the shutdown cooling mode using the RHR system heat exchanger to bring the reactor to the cold shutdown condition.

f. The RHRSW system is operated during operation of the RHR system in both the suppression pool cooling and shutdown cooling modes to provide cooling water to the RHR heat exchangers. A selector switch on the remote shutdown panel is used to operate either the spray pond or the cooling tower to cool the RHRSW. Additionally, spray or bypass can be selected when using the spray pond for cooling.

g. A redundant remote shutdown capability is provided as discussed in Sections 7.4.1.4.4, 7.4.1.4.5 and 7.4.2.4.2.2.1.

7.4.1.4.3 RSS Procedure

a. If evacuation becomes necessary, the operator scrams the reactor by depressing the scram switches at the control room panel.

b. Under normal conditions, the main turbine pressure regulator controls the reactor pressure while rejecting heat (steam) through the turbine bypass valves, and the feedwater control system controls water level.

c. The output breakers on feeders from RPS buses A and B to the RPS trip systems A and B, respectively, are opened as a backup means of scramming the reactor and closing the PCRVICS valves. The controls for this function are located on the RPS power distribution panel.

d. The remainder of the procedure assumes that the automatic pressure regulator is not available from time zero and the MSIVs are closed.

e. Transfer switches are operated to transfer control to the remote shutdown panel.

f. Relief valves not used in the remote shutdown system may open automatically and cycle to control reactor pressure. The reactor level starts to drop at a rate that depends on prior power level and elapsed time from scram.

g. The operator starts the RCIC system manually and maintains reactor level with RCIC. The level starts to rise as a result of RCIC system flow.

h. Reactor pressure is maintained by manually actuating the relief valves as necessary. While these relief valves are actuated, reactor water level, reactor pressure, and suppression pool temperature are observed.

i. The RHR system is used with one pump and heat exchanger and the associated RHRSW loop to cool the suppression pool.

j. If depressurization is required, reactor pressure is reduced by manually actuating the relief valves as necessary. While these relief valves are being activated, the reactor water level, reactor pressure, and suppression pool temperature are observed. The reactor cooldown rate is controlled so that it does not exceed 100°F per hour, as determined by observing the reactor pressure.

k. Reactor pressure is reduced to the shutdown cooling conditions. The RHR system is placed in the shutdown cooling mode. Cooldown is continued until the reactor is in the cold shutdown condition.

l. Reactor water level is held normal.

7.4.1.4.4 RSS Controls and Instrumentation - Equipment, Panels, and Displays

7.4.1.4.4.1 Control Room - RSS Interconnection Design Considerations

Some of the existing systems used for normal reactor shutdown operation are also used in the RSS to shut down the reactor from outside the control room. The RSS is designed to control the required shutdown systems from outside the control room irrespective of shorts, opens, or grounds in the control room control circuit that may have resulted from an event causing an evacuation. The functions needed for remote shutdown control are provided with manual transfer devices on the remote shutdown panel that override controls from the control room and transfer them to the RSS.

After transfer of control from the control room to the remote panel, all wiring and devices in the control room are isolated and cannot affect the operation of the transferred circuits. This is accomplished by running the control wiring from the equipment through the remote panel transfer switches to the control room.

All necessary power supplies are also transferred. Remote shutdown control is not possible without actuation of the transfer devices. Operation of the transfer devices causes an alarm in the control room. The remote shutdown panel is located in the remote shutdown room, which is in the control structure directly above the control room. Access to the panels is administratively controlled.

Adequate environmental control capability is provided at the location of these panels. The remote shutdown room and the control room are serviced by separate HVAC systems as described in Section 9.4.

In the remote shutdown room, transceivers for the plant public address system, the telephone system, and the distributed antenna system are provided.

Sections 7.4.1.4.2 and 7.4.1.4.3 describe steps for ensuring cold shutdown from departure of the control room through cold shutdown.

The following systems are required for safe remote shutdown:

a. RCIC system to maintain reactor water level

b. Relief valves and nuclear boiler system to reduce and monitor reactor vessel pressure, respectively

c. RHR system to control suppression pool water temperature and for reactor shutdown cooling mode

d. RHRSW system to supply cooling water to the RHR heat exchanger

e. ESW system to supply cooling water to RCIC and RHR room coolers, RHR motor oil and seal coolers, and the diesel generator

f. Containment and suppression pool system monitoring instrumentation

Table 7.4-3 is a listing of control and indicating devices on the remote shutdown panels.

7.4.1.4.5 RSS - IEEE 279 - Design Basis

The following information is documented herein and as such satisfies the requirements of IEEE 279:

a. The generating station conditions that require protective action are identified in Chapter 15.

b. The generating station variables that must be monitored to provide protective actions during RSS operation are identified in Table 7.4-3 and in Chapter 16.

c. The minimum number and location of the sensors required to adequately monitor, for protective function purposes, those variables listed in Table 7.4-3 that have a spatial dependence do not exist for this system.

d. Prudent operational limits for each variable listed in Table 7.4-3 in each applicable reactor operation mode are identified in Chapter 16.

e. The margin, with appropriate interpretive information, between each operational limit and the level considered to mark the onset of unsafe conditions is included in the values developed in Chapter 16.

f. The levels that, when reached, will require protective action are identified in Chapter 16.

g. The range of transient and steady-state conditions of both the energy supply and the environment during normal, abnormal, and accident conditions throughout

which the system must perform are contained in Chapter 8 for the energy supply, and Sections 3.10 and 3.11 for the environmental parameters.

h. The malfunctions, accidents, or other unusual events that could physically damage protection system components or could cause environmental changes leading to functional degradation of system performance, and for which provisions must be incorporated to retain necessary protective action, are identified in IEEE 279, paragraph 4.1 (Section 7.4.2.4.2.3.1).

i. Minimum performance requirements include the following:
   1. System response times
   2. System accuracies
   3. Ranges (normal, abnormal, and accident conditions) of the magnitudes and rates of change of sensed variables to be accommodated until proper conclusion of the protective action is ensured have been considered and included in Chapter 15 and Chapter 16.

j. As required by the Technical Specifications the remote shutdown monitoring instrumentation will be checked monthly and calibrated once per refueling cycle.

7.4.1.5 Emergency Service Water System - Instrumentation and Controls

For a description of the ESW system, see Section 7.3.1.1.11.

7.4.1.6 Residual Heat Removal Service Water System - Instrumentation and Controls

For a description of the RHRSW system, see Section 7.3.1.1.12.

7.4.1.7 Class 1E Power Systems

Descriptions of the standby power system can be found in the following:

a. Section 8.3.1 describes the onsite Class 1E ac power system.

b. Section 8.3.2 describes the onsite Class 1E dc power system.

7.4.1.8 Shutdown Ventilation Systems

7.4.1.8.1 RCIC System Pump Compartment Unit Coolers - Instrumentation and Controls

7.4.1.8.1.1 RCIC-UC System Identification

7.4.1.8.1.1.1 RCIC-UC Function

The RCIC-UC provides cooling to the RCIC pump-room during pump operation. For description and operation, see Section 9.4.2.

7.4.1.8.1.1.2 RCIC-UC Classification

Electrical components for the RCIC-UC are classified as seismic category I and Class 1E.

7.4.1.8.1.2 RCIC-UC Power Sources

Power for the instruments and controls associated with the RCIC-UC is supplied from the Class 1E 120 V ac system. See Chapter 8 for a description of the electrical system.

7.4.1.8.1.3 RCIC-UC Equipment Design

Equipment design is described in Section 9.4.2.

7.4.1.8.1.3.1 RCIC-UC Initiating Circuits

Each of the fans may be initiated in a protective function mode as follows:

a. A unit cooler may be manually started from the local control panel.

b. A fan may be started by initiating a high temperature switch.

7.4.1.8.1.3.2 RCIC-UC Logic and Sequencing

See drawing M-76FD for the control logic diagram.

Each pair of unit coolers is set up in a lead-lag mode. Automatic start is initiated under the following conditions:

a. When the area temperature exceeds the high temperature switch setting, the lead fan starts.

b. When the area temperature exceeds the high-high temperature switch, the standby fan starts.

The starting of a fan automatically opens a valve in the ESW system to supply cooling water to the unit.

The fan shuts down when the area temperatures drop below the low temperature switch setting.

7.4.1.8.1.3.3 RCIC-UC Bypasses and Interlocks

The hand switch of each fan, when in the off position, provides input to a local panel alarm that is relayed to the control room.

7.4.1.8.1.3.4 RCIC-UC Redundancy and Diversity

To maintain the redundancy of the mechanical equipment, controls and instrumentation are provided on a one-to-one basis with the mechanical equipment they serve. Diversity is not applicable.

7.4.1.8.1.3.5 RCIC-UC Actuated Devices

No additional devices or systems are actuated by the RCIC-UC.

7.4.1.8.1.3.6 RCIC-UC Separation

The controls, instrumentation, and power supplies are physically and electrically separated for each of the RCIC-UC. See Section 8.1.6.1 for a discussion of electrical separation.

7.4.1.8.1.3.7 RCIC-UC Testability

Operability of initiation circuits may be verified when the applicable pumps are operationally tested. The units may be manually tested by hand switches located on local control cabinets.

7.4.1.8.1.4 RCIC-UC Environmental Considerations

The controls for the subject equipment are located in the reactor enclosure. The environmental considerations for this area are provided in Section 3.11. Qualification information is also identified in Section 3.11.

7.4.1.8.1.5 RCIC-UC Operational Considerations

7.4.1.8.1.5.1 RCIC-UC General Information

The RCIC-UC are not required for normal cooling when the RCIC pumps are not operating.

7.4.1.8.1.5.2 RCIC-UC Reactor Operator Information

The operator is provided with a unit cooler system trouble alarm.

7.4.1.8.1.5.3 RCIC-UC Setpoints

For setpoints, see Chapter 16.

7.4.1.8.2 RHR System Pump Compartment Unit Coolers

7.4.1.8.2.1 RHR-UC System Identification

7.4.1.8.2.1.1 RHR-UC Function

The RHR-UC operation is the same during the RHR reactor shutdown cooling mode as for emergency RHR operation. See Section 7.3.1.1.15.5 for a description.

7.4.1.8.3 Remote Shutdown System Ventilation System

7.4.1.8.3.1 RSSV System Identification

7.4.1.8.3.1.1 RSSV System Function

The remote shutdown panels are located in the auxiliary equipment area of the control structure. See Section 7.3.1.1.15.5 for a description of the auxiliary equipment room ventilation system.

7.4.2 ANALYSIS

7.4.2.1 Reactor Core Isolation Cooling System - Instrumentation and Controls

7.4.2.1.1 RCIC General Functional Requirements Conformance

a. RCIC Safety Design Basis 7.1.2.1.17.1(a)

For events other than pipe breaks, the RCIC system has enough makeup capacity to prevent the reactor vessel water level from decreasing to the level where the core is uncovered.

b. RCIC Safety Design Basis 7.1.2.1.17.1(b)

The RCIC system is automatically initiated after receipt of a reactor vessel low water level signal as detailed in Section 7.4.1.1.3.2. The operator controls of the system are arranged to allow manual and remote manual operation.

c. RCIC Safety Design Basis 7.1.2.1.17.1(c)

The electrical control components of the RCIC system satisfy seismic Category I design requirements.

d. RCIC Safety Design Basis 7.1.2.1.17.1(d)

To provide a high degree of assurance that the RCIC system operates when necessary and in time to provide adequate inventory makeup, the power supply for the system is taken from highly reliable energy sources that are immediately available. Evaluation of instrumentation reliability for the RCIC system shows that a failure of a single initiating sensor does not prevent or falsely start the system.

e. RCIC Safety Design Basis 7.1.2.1.17.1(e)

The system is tested during plant operation using a series of overlapping tests, one of which is the design flow functional test. This test takes suction from the demineralized water in the CST and discharges through the full flow test return line back to the CST. During the test, the discharge valve to the reactor vessel remains closed and reactor operation is not disturbed. Control system design provides automatic return from the test mode to the operating mode if system initiation is required during testing, except for the conditions described in Section 7.4.1.1.3.1.

Chapter 15 examines the system level aspects of this system in-plant operation and consider its function under various plant transient events.

7.4.2.1.2 RCIC Specific Regulatory Requirements Conformance

Conformance of the transmitter/trip unit system, used for RCIC instrumentation, is discussed in Licensing Topical Report NEDO-21617-A, "Analog Transmitter/Trip Unit System for Engineered

Safeguard Sensor Inputs." Conformance of the other features with the regulatory requirements is discussed in the following sections.

7.4.2.1.2.1 RCIC Conformance To Regulatory Guides

7.4.2.1.2.1.1 RCIC - Regulatory Guide 1.6 (1971) - Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems (Safety Guide 6)

See Section 8.1.6.1.

Because it is not necessary for RCIC alone to meet the single failure criteria, redundant power sources are not required.

7.4.2.1.2.1.2 RCIC - Regulatory Guide 1.11 (1971) - Instrument Lines Penetrating Primary Reactor Containment (Safety Guide 11)

All RCIC instrument lines penetrating or connected to containment meet the guidelines of regulatory position C.1 of Regulatory Guide 1.11.

7.4.2.1.2.1.3 RCIC - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The RCIC is fully testable from initiating sensors to actuated devices during full power operation.

7.4.2.1.2.1.4 RCIC - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The safety-related portion of RCIC instrumentation and control is classified as seismic Category I and is qualified to remain functional during and following an SSE.

7.4.2.1.2.1.5 RCIC - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

Conformance to Regulatory Guide 1.30 is discussed in Section 8.1.6.1.

7.4.2.1.2.1.6 RCIC - Regulatory Guide 1.32 (1977) - Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants

Conformance to Regulatory Guide 1.32, as discussed in Section 8.1, applies to RCIC safety-related control instrumentation.

7.4.2.1.2.1.7 RCIC - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

Automatic indication is provided in the control room to inform the operator that the RCIC is inoperable. Annunciation is provided to indicate that the system or part of the system is inoperable. The RCIC has test bypasses generated by inserting test jacks. Any test bypass annunciates at the system level (i.e., RCIC out-of-service). Bypasses of certain infrequently used pieces of equipment, such as manual locked open valves, are not automatically annunciated in the control room; however, capability for manual activation of the system level bypass annunciator is provided in the

control room for those systems that have these infrequently used bypasses. An administratively controlled switch is used for this manual activation. Further examples of automatic indication of inoperability are shown in drawings E51-1030-F-004, E51-1030-F-005, E51-1030-F-006, E51-1030-F-007, E51-1030-F-008, and E51-1030-F-009.

The annunciator can be tested by depressing the appropriate annunciator test switch on the control room bench boards.

Individual indicators are arranged and grouped together on the control room panel to indicate which function of the system is out-of-service, bypassed, or otherwise inoperable. Indication of pressures, temperatures, and other system variables that are a result of system operation are not included with the bypass inoperability indicators.

As a result of design, preoperational testing, and startup testing, no erroneous bypass indication is anticipated.

The bypass inoperability indications supplement administrative controls and aid the operator in assessing the availability of component and system level protective actions. This indication does not perform a safety function.

Each indicator that can be periodically tested is provided with dual lamps.

7.4.2.1.2.1.8 RCIC - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

The RCIC meets the single failure criteria on a network basis in conjunction with HPCI. It is not necessary for the RCIC alone to meet the single failure criteria, because its function is duplicated by the HPCI.

7.4.2.1.2.1.9 RCIC - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

The RCIC may be automatically and manually initiated inside the control room as well as at the remote shutdown facility outside the control room.

7.4.2.1.2.1.10 RCIC - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

RCIC conformance to Regulatory Guide 1.75 is discussed in Section 7.1.2.5.19.

7.4.2.1.2.1.11 RCIC - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

RCIC conformance to Regulatory Guide 1.89 is discussed in Section 3.11.2.

7.4.2.1.2.1.12 RCIC - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Conformance is discussed in Section 7.5.2.5.1.1.2.

7.4.2.1.2.1.13 RCIC - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

RCIC conformance to Regulatory Guide 1.100 is discussed in Section 3.10.

7.4.2.1.2.1.14 RCIC - Regulatory Guide 1.105 (1976) - Instrument Setpoints

RCIC conformance to this guide is discussed in Section 7.1.2.5.25.

7.4.2.1.2.1.15 RCIC - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

RCIC conformance to this guide is discussed in Section 7.1.2.5.26.

7.4.2.1.2.2 RCIC Conformance to 10CFR50, Appendix A - General Design Criteria

7.4.2.1.2.2.1 RCIC - GDC 1 - Quality Standards and Records

See Section 7.1.2.6.

7.4.2.1.2.2.2 RCIC - GDC 2 - Design Bases for Protection Against Natural Phenomena

See Section 7.1.2.6 for RCIC conformance.

7.4.2.1.2.2.3 RCIC - GDC 3 - Fire Protection

See Section 7.1.2.6 for RCIC conformance.

7.4.2.1.2.2.4 RCIC - GDC 4 - Environmental and Dynamic Effects Design

See Section 7.1.2.6 for RCIC conformance.

7.4.2.1.2.2.5 RCIC - GDC 10 - Reactor Design

See Section 7.1.2.6 for RCIC conformance.

7.4.2.1.2.2.6 RCIC - GDC 13 - Instrumentation and Control

The reactor vessel water level, RCIC pump discharge pressure, and RCIC flow rate are monitored and displayed in the control room.

7.4.2.1.2.2.7 RCIC - GDC 20 - Protection System Functions

The RCIC system constantly monitors the water level in the reactor vessel and is automatically initiated when the level drops below the pre-established setpoint.

7.4.2.1.2.2.8 RCIC - GDC 21 - Protection System Reliability and Testability

The RCIC is fully testable from sensor to actuated device during normal operation.

7.4.2.1.2.2.9 RCIC - GDC 22 - Protection System Independence

The RCIC system is independent of the HPCI system to ensure that the safe shutdown function can be accomplished.

7.4.2.1.2.2.10 RCIC - GDC 29 - Protection Against Anticipated Operational Occurrences

The RCIC maintains the reactor vessel water level by providing makeup water if the reactor becomes isolated from the main condenser during normal operation.

7.4.2.1.2.3 RCIC Conformance to Industry Codes and Standards

Conformance of the transmitter/trip unit system, used for RCIC instrumentation, is discussed in Licensing Topical Report NEDO-21617-A, "Analog Transmitter/Trip Unit System for Engineered Safeguard Sensor Inputs." Conformance of the other features with industry standards is discussed in the following sections.

7.4.2.1.2.3.1 RCIC - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

7.4.2.1.2.3.1.1 RCIC - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The system is automatically initiated to perform the appropriate protective action with precision and reliability under the adverse conditions defined below:

a. Power supply voltage and frequency - Since the RCIC system is backed up by the independent HPCI system, the design provides tolerance to power supply failure in one motive power system or one control power system.

b. Temperature - The RCIC system is designed to operate properly in the high temperature environment expected during the events requiring system operation.

c. Humidity - The system is designed to function properly in the high humidity (steam) environment expected during the events requiring system operation.

d. Pressure - The system is designed to function properly in the full range of pressures expected during the events requiring system operation.

e. Vibration - Tolerance to environmentally induced vibration (earthquake, wind) is discussed in Section 3.10.

f. Accidents - The system tolerates any event requiring system operation.

g. Fire - Since the RCIC system is backed up by the independent HPCI system, the design provides tolerance to a fire in a single division raceway or enclosure.

h. Explosions - Explosions are not defined in the design basis.

i. Missiles - Since the RCIC system is backed up by the independent HPCI system, the design provides tolerance to any single missile destroying no more than one pipe, raceway, or electrical enclosure.

j. Lightning - Since the RCIC system is backed up by the independent HPCI system, the design provides tolerance to lightning damage to one auxiliary ac bus.

k. Flood - All instrumentation and controls are located above flood level or are protected from flood damage.

l. Earthquake - All control equipment is housed in a seismic Category I structure. Tolerance to earthquake damage is discussed in Section 3.10.

m. Wind and tornado - The structures containing RCIC components have been designed to withstand the meteorological events described in Section 3.3.2.

n. System response time and system accuracies - System response time and accuracy are covered in Chapter 16.

o. Ranges of monitored parameters - Instrument sensors and processing equipment are capable of displaying the full ranges of parameters expected during events requiring system operation.

7.4.2.1.2.3.1.2 RCIC - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criteria

The RCIC system alone is not required to meet the single failure criteria. The control logic circuits for RCIC initiation and control are housed in a single relay cabinet, and the power supply for the control logic and other RCIC equipment is from a single dc power source.

The RCIC system meets the single failure criteria on a network basis in conjunction with HPCI. It is not necessary for the RCIC alone to meet the single failure criteria in itself, because its function is duplicated or backed up by HPCI.

7.4.2.1.2.3.1.3 RCIC - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

The components of the RCIC instrumentation and control are of the same high quality as the ECCS systems.

7.4.2.1.2.3.1.4 RCIC - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

The RCIC safety-related controls and instrumentation have been qualified according to the requirements outlined in IEEE 323 (1971), as highlighted in Section 7.1.2.7.1. The conditions for which the equipment has been qualified are those identified in Sections 3.10 and 3.11. The conditions identified cover normal, abnormal, and accident environments both inside and outside the drywell.

7.4.2.1.2.3.1.5 RCIC - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The RCIC system instrument initiation channels satisfy the channel integrity objective.

7.4.2.1.2.3.1.6 RCIC - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

Channel independence for initiation sensors is not provided for the RCIC. Independence of HPCI and RCIC sensors is provided by electrical and mechanical separation. HPCI sensors are Division 2, and RCIC sensors are Division 1.

Disabling the sensors does not disable the control for both RCIC and HPCI initiation.

7.4.2.1.2.3.1.7 RCIC - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The RCIC system has no interaction with plant control systems. Annunciator circuits using contacts of sensors and logic relays cannot impair the operability of the RCIC system control because of electrical isolation.

7.4.2.1.2.3.1.8 RCIC - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

The RCIC system uses a direct measure of the need for coolant inventory makeup, e.g., reactor vessel low water level.

7.4.2.1.2.3.1.9 RCIC - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

All sensors are installed with calibration taps and instrument valves to permit testing during normal plant operation or during shutdown. An example of sensor calibration is shown in section 6 of NEDO-21617-A, "Analog Transmitter/Trip Unit System for Engineered Safeguard Sensor Trip Inputs."

7.4.2.1.2.3.1.10 RCIC - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The RCIC control system can be completely tested during normal plant operation to verify that each element of the system, whether active or passive, is capable of performing its intended function.

As part of this test, the turbine and RCIC pump are started in the test mode with the pump discharging into the CST. In this test mode, all major components except the isolation valves are tested. Valve operability tests complete the major system component testing.

7.4.2.1.2.3.1.11 RCIC - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

Calibrating a sensor that introduces a single instrument channel trip does not cause a protective function without the coincident trip of a second channel. There are no instrument channel bypasses. Removing a sensor from operation during calibration does not prevent the redundant instrument channel from functioning. An instrument channel is only briefly removed from service during calibration.

7.4.2.1.2.3.1.12 RCIC - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

There are no operating bypasses in the RCIC system.

7.4.2.1.2.3.1.13 RCIC - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Bypasses are automatically indicated by individual lights that designate which function of the system is out-of-service, bypassed, or otherwise inoperative. In addition, each of the indicated bypasses also activates a system out-of-service annunciator. A manual system out-of-service switch is provided for operator use for items that are only under administrative control.

7.4.2.1.2.3.1.14 RCIC - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

The access to means for bypassing is controlled by administrative procedures.

7.4.2.1.2.3.1.15 RCIC - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

This is not applicable because there are no multiple setpoints for the RCIC system.

7.4.2.1.2.3.1.16 RCIC - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It is Initiated

The final control elements for the RCIC system are essentially bistable, i.e., MOVs stay open or closed once they have reached their desired position, even though their starter may drop out. In the case of pump starters, the automatic initiation signal is electrically sealed in.

Thus, once protective action is initiated (i.e., flow established), it will go to completion until terminated by deliberate operator action or automatically stopped by high vessel water level or system malfunction trip signals.

7.4.2.1.2.3.1.17 RCIC - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

Each piece of RCIC actuation equipment required to operate (pumps and valves) is capable of manual initiation from the control room.

Failure of logic circuitry to initiate the RCIC system does not prevent manual initiation. However, failures of active components or control circuits that produce a RCIC turbine trip may disable the manual actuation of the RCIC system. Failures of this type are continuously monitored by alarms.

Because the RCIC system is independent of the HPCI system, the protective function can be accomplished even in the presence of a single failure within the manual, automatic, or common portions of the RCIC system. Manual initiation depends on the operation of a minimum of equipment.

7.4.2.1.2.3.1.18 RCIC - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

See Licensing Topical Report NEDO-21617-A for the compliance of the trip unit.

7.4.2.1.2.3.1.19 RCIC - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

Protective actions are directly indicated and identified by annunciator operation or a trip unit light with an identification tag that permits convenient visible verification of instrument channel status.

The combination of annunciation and trip unit observation is considered to fulfill the requirements of this criterion.

7.4.2.1.2.3.1.20 RCIC - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The RCIC control system is designed to provide the operator with accurate and timely information pertinent to its status. It does not introduce signals into other systems that could cause confusing anomalous indications. Information is provided continuously so that the operator can have a high degree of confidence that the RCIC function is available and/or operating properly.

7.4.2.1.2.3.1.21 RCIC - IEEE 279 (1971), Paragraph 4.21 - System Repair

The RCIC control system is designed to permit repair or replacement of components.

Recognition and location of a failed component is accomplished during periodic testing. The simplicity of the logic provides ease in detection and location of the problem, and components are mounted in such a way that they can be conveniently replaced in a short time.

7.4.2.1.2.3.1.22 RCIC - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Control room devices are identified by tags on the panels, that indicate the function of the device.

7.4.2.1.2.3.2 RCIC - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Conformance to IEEE 308 is as described in Section 8.3.1 for ac power supply and Section 8.3.2 for dc power supply to the safety-related instrumentation and controls.

7.4.2.1.2.3.3 RCIC - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

Specific conformance to the requirements of IEEE 323 is covered in Sections 7.1.2.7.4 and 3.11.

7.4.2.1.2.3.4 RCIC - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

See Section 8.1.6.1 for RCIC conformance.

7.4.2.1.2.3.5 RCIC - IEEE 338 (1971) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

The RCIC system is tested as described in Section 7.4.1.1.3.8.

7.4.2.1.2.3.6 RCIC - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Conformance to the requirements of IEEE 344 (1971) is detailed in Section 3.10.

7.4.2.1.2.3.7 RCIC - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

See Section 7.4.2.1.2.3.1.2 for RCIC conformance.

7.4.2.1.2.3.8 RCIC - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

See Section 7.1.2.7.11 for RCIC conformance.

7.4.2.2 Standby Liquid Control System - Instrumentation andControls

7.4.2.2.1 SLCS General Functional Requirements Conformance

The injection of the sodium pentaborate solution into the reactor is sufficient to shut down the reactor from full power to cold shutdown and maintain the reactor in a subcritical state.

Injection of sodium pentaborate solution into the reactor is also sufficient to maintain the suppression pool at a pH of 7.0 or higher following a LOCA.

Redundant, positive displacement pumps, explosive valves, and control circuits for the SLCS components are provided as described in Section 7.4.1.2. These constitute all of the active equipment required for injection of the sodium pentaborate solution. Continuity relays monitor the explosive valves, and indicator lights indicate system status on the reactor control console. Testability and redundant power sources are described in Sections 14.2, 7.4.1.2.2, and 7.4.1.2.3.8. The safety design basis is discussed in Section 7.1.2.1.18.1.

The SLCS can be automatically initiated by the RRCS. This initiation will override the manual start signal, but can be overridden by the manual stop signal. The SLCS will be automatically shut off by the low level in the SLCS storage tank.

Chapter 15 examines the system level aspects of the subject system under applicable plant events.

7.4.2.2.2 SLCS Specific Regulatory Requirements Conformance

7.4.2.2.2.1 SLCS Conformance to Regulatory Guides

7.4.2.2.2.1.1 SLCS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The SLCS is capable of testing from initiation to actuated devices, except squib valves, during normal operation. The system design uses squib valves for positive rapid operation, which cannot be tested during operation without injecting the sodium pentaborate. In the test mode, demineralized water rather than sodium pentaborate is circulated in the SLCS loops. The explosive valves may be tested when the plant is shut down. Otherwise, continuity in the explosive valve initiation circuits is continuously monitored and indicated in the control room during plant operation to ensure that the dual squibs in each valve are available.

7.4.2.2.2.1.2 SLCS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The control instrumentation required for injection of the SLCS is classified as seismic Category I and is qualified to remain functional during and following an SSE.

7.4.2.2.2.1.3 SLCS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

SLCS conformance to Regulatory Guide 1.30 is discussed in Section 8.1.6.1.

7.4.2.2.2.1.4 SLCS - Regulatory Guide 1.32 - Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants

SLCS conformance to IEEE 308 as discussed in Section 8.1 is applicable to SLCS control instrumentation.

7.4.2.2.2.1.5 SLCS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

The SLCS serves as a backup reactivity control system to the control rods. It is not necessary for the SLCS to meet the single failure criteria. The discharge pumps, pump motors, and explosive valves are redundant so that a single failure in these components does not prevent initiation of the SLCS.

7.4.2.2.2.1.6 SLCS - Regulatory Guide 1.63 (1978) - Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants

SLCS conformance to Regulatory Guide 1.63 is discussed in Section 8.1.

7.4.2.2.2.1.7 SLCS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

SLCS conformance to Regulatory Guide 1.75 is discussed in Section 7.1.2.5.19.

7.4.2.2.2.1.8 SLCS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

SLCS conformance to Regulatory Guide 1.89 is discussed in Section 3.11.

7.4.2.2.2.1.9 SLCS - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Conformance is discussed in Section 7.5.2.5.1.1.2.

7.4.2.2.2.1.10 SLCS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

SLCS conformance to Regulatory Guide 1.100 is discussed in Section 3.10.

7.4.2.2.2.1.11 SLCS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

SLCS conformance to this guide is discussed in Section 7.1.2.5.25.

7.4.2.2.2.1.12 SLCS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

SLCS conformance to this guide is discussed in Section 7.1.2.5.26.

7.4.2.2.2.2 SLCS Conformance to 10CFR50, Appendix A, General Design Criteria

7.4.2.2.2.2.1 SLCS - GDC 1 - Quality Standards and Records

See Section 7.1.2.6 for SLCS conformance.

7.4.2.2.2.2.2 SLCS - GDC 2 - Design Bases for Protection Against Natural Phenomena

See Section 7.1.2.6 for SLCS conformance.

7.4.2.2.2.2.3 SLCS - GDC 3 - Fire Protection

See Section 7.1.2.6 for SLCS conformance.

7.4.2.2.2.2.4 SLCS - GDC 4 - Environmental and Dynamic Effects Design Bases

See Section 7.1.2.6 for SLCS conformance.

7.4.2.2.2.2.5 SLCS - GDC 10 - Reactor Design

The SLCS is a backup method of manually shutting down the reactor to cold subcritical conditions by independent means other than the normal method, i.e., the control rod system.

7.4.2.2.2.2.6 SLCS - GDC 13 - Instrumentation and Control

The sodium pentaborate tank temperature and level and the explosive valves controlling circuit continuity are monitored and annunciated.

7.4.2.2.2.2.7 SLCS - GDC 26 - Reactivity Control System Redundancy and Capability

The SLCS provides the backup reactivity control system to the control rods.

7.4.2.2.2.3 SLCS Conformance to Industry Codes and Standards

7.4.2.2.2.3.1 SLCS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

7.4.2.2.2.3.1.1 SLCS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

RRCS will automatically initiate SLCS in the event of an ATWS condition. Also, the operator may manually initiate the SLCS. Display instrumentation in the control room provides the operator with information on neutron flux level, control rod position, and scram valve status so the operator can determine if SLCS initiation is required.

7.4.2.2.2.3.1.2 SLCS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criteria

The SLCS serves as backup to the control rod scram in controlling reactivity. It is not necessary for the SLCS to meet the single failure criteria. However, the pumps and the explosive valves are redundant so that a single active failure in these components does not prevent initiation of SLCS.

7.4.2.2.2.3.1.3 SLCS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

The components of the SLCS system instrumentation and controls are of the same high quality as the ECCS system.

7.4.2.2.2.3.1.4 SLCS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

No active components of the SLCS are required to operate in the drywell environment. A maintenance valve, test taps and drain line are the only components located inside the drywell. The maintenance valve is a normally locked open valve. The test taps and drain line are normally locked closed. Other SLCS equipment is located in the reactor enclosure or containment and is capable of operation during and following an SSE (Section 3.10).

7.4.2.2.2.3.1.5 SLCS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The SLCS is not required to operate during a DBA. It is designed to remain functional during and following an SSE.

7.4.2.2.2.3.1.6 SLCS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The SLCS serves as backup to the control rods in controlling reactivity. The channels are independent of each other, so that failure in one channel does not prevent operation of another channel.

7.4.2.2.2.3.1.7 SLCS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The SLCS has no interaction with plant control systems. It has no function during normal plant operation and is completely independent of control systems.

7.4.2.2.2.3.1.8 SLCS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

Display instrumentation in the control room provides the operator with information on neutron flux level, control rod position, and scram valve status. Using this information, the operator may manually initiate the SLCS.

7.4.2.2.2.3.1.9 SLCS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The explosive valve control circuit continuity is continuously monitored, and loss of continuity is annunciated in the control room. See also Section 7.4.2.2.2.1.1.

The testability of the sensors that provide information on neutron flux is discussed in Sections 7.2 and 7.7.

The testability of the rod position, because the RPIS is not safety-related, is limited to a sequential interrogation of the individual rod position information while stationary or during rod movement.

The scram valves can be tested during full power operation by individually scramming each valve from local test switches.

7.4.2.2.2.3.1.10 SLCS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The explosive valves may be tested during plant shutdown. The explosive valve control circuits are continuously monitored, and loss of continuity is annunciated in the control room. The remainder of the SLCS may be tested during normal plant operation to verify that each element is capable of performing its intended function. In the test mode, demineralized water rather than sodium pentaborate solution is circulated from and back to the test tank. See also Section 7.4.2.2.2.1.1. During testing of explosive valves demineralized water is injected to the vessel.

7.4.2.2.2.3.1.11 SLCS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

The pumps, pump motors, and associated controls are redundant so that one pump may be removed from service during normal plant operation.

7.4.2.2.2.3.1.12 SLCS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

There are no operating bypasses in the SLCS.

7.4.2.2.2.3.1.13 SLCS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

The removal of components from service is automatically or manually annunciated in the control room.

7.4.2.2.2.3.1.14 SLCS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Removal of components from service during normal plant operation is under administrative control.

7.4.2.2.2.3.1.15 SLCS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

There are no multiple setpoints in the SLCS.

7.4.2.2.2.3.1.16 SLCS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

The explosive valves remain open, once fired, and the pump motor operation, once initiated, does not stop unless terminated by operator action, or automatic low level shut off of the SLCS pumps is initiated.

7.4.2.2.2.3.1.17 SLCS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

The SLCS can be manually initiated.

7.4.2.2.2.3.1.18 SLCS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Setpoint adjustments, module calibration adjustments, and test setpoints are under administrative control.

7.4.2.2.2.3.1.19 SLCS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

The explosive valve status, is continuously indicated in the control room. Pump motor status is also indicated in the control room.

7.4.2.2.2.3.1.20 SLCS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

See Section 7.4.1.2.5.2 for a complete listing of operator information. The information readouts supplied minimize conditions that could cause meters, annunciators, and indicating lights to give anomalous information that might confuse the operator.

7.4.2.2.2.3.1.21 SLCS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The control circuits, pumps, and pump motors may be repaired or replaced during normal plant operation.

7.4.2.2.2.3.1.22 SLCS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

All control room controls and instrumentation are located in one control room panel and are clearly identified by nameplates.

The name of each system logic cabinet and the particular redundant portion is identified distinctively as being in the protective system. Cabling outside the cabinets is identified for safety classification. An identification scheme is used to distinguish between redundant cables and raceways. Details of this identification scheme are given in Section 8.1.6.1. Redundant racks are identified by the identification marker plates of instruments on the racks. Control room devices are identified by tags on the panels. These tags indicate the function of the devices.

7.4.2.2.2.3.2 SLCS - IEEE 308 (1971) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

The SLCS pumps, pump motors, and associated controls are physically separated and electrically isolated into independent load groups so that safety action provided by redundant counterparts is not compromised.

7.4.2.2.2.3.3 SLCS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

The requirements are satisfied through qualification testing as described in Sections 3.10 and 3.11, which contain further discussion on the degree of conformance.

7.4.2.2.2.3.4 SLCS - IEEE 338 (1971) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection System

See Section 7.4.2.2.2.3.1.10 for SLCS conformance.

7.4.2.2.2.3.5 SLCS - IEEE 344 (1971) Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

The control instrumentation of the SLCS required for injection is classified as seismic Category I and remains functional during and following an SSE. The qualification and documentation procedures used for seismic Category I equipment are discussed in Section 3.10.

7.4.2.3 Reactor Shutdown Cooling Mode of the RHR System - Instrumentation and Controls

7.4.2.3.1 RHR-SCM General Functional Requirements Conformance

The design of the RHR-SCM meets the general functional requirements as follows:

a. Control Room

1. Instrumentation and controls are provided that enable residual heat to be removed from the reactor vessel during normal shutdown.

2. Manual controls for reactor shutdown cooling are provided in the control room and on the remote shutdown panel.

3. The instrumentation used to monitor the performance of the system is also provided in the control room and the remote shutdown panel.

b. Valves

Manual control and position indication is provided. A single failure in the system does not cause a loss of capability to perform reactor shutdown cooling.

c. Instrumentation

Instrumentation is provided for shutdown cooling flow, heat exchanger shutdown cooling water, and RHRSW temperatures.

d. Annunciation

Annunciation of valve motor overload, heat exchanger cooling water outlet high temperature, heat exchanger cooling water inlet high temperature, shutdown suction header high pressure, and pump motor overload is provided in the control room.

e. Pumps

Manual controls and stop and start indicators are provided.

Section 15.9 examines the protective sequences relative to the above events and equipment. Chapter 15 considers the operation and the system level qualitative and NSOA aspects of this system.

Loss of plant instrument air or cooling water does not, by itself, prevent reactor shutdown cooling capability.

7.4.2.3.2 RHR-SCM Specific Regulatory Requirements Conformance

7.4.2.3.2.1 RHR-SCM Conformance to Regulatory Guides

Conformance of the ECCS portions of the RHR-SCM to regulatory guides is discussed in Section 7.3.2.

7.4.2.3.2.1.1 RHR-SCM - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Activation Functions (Safety Guide 22)

See Section 7.4.1.3.3.8 for RHR-SCM conformance.

7.4.2.3.2.1.2 RHR-SCM - Regulatory Guide 1.29 (1978) - Seismic Design Classification

See Section 3.10 for RHR-SCM conformance.

7.4.2.3.2.1.3 RHR-SCM - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

See Section 8.1.6.1 for RHR-SCM conformance.

7.4.2.3.2.1.4 RHR-SCM - Regulatory Guide 1.32 (1977) - Use of IEEE 308 (1971)

See Section 8.1 for RHR-SCM conformance.

7.4.2.3.2.1.5 RHR-SCM - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

See Section 7.4.1.3.5.2 for RHR-SCM conformance.

7.4.2.3.2.1.6 RHR-SCM - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

RHR-SCM controls and instrumentation are configured to satisfy the single failure criteria. Single failure susceptibility has been identified and resolved by designating alternate flow paths through the SRVs and suppression pool as backup for the single suction line, and through the LPCI injection valves as backup for the loss of outboard injection isolation valves and the shutdown cooling suction valves.

7.4.2.3.2.1.7 RHR-SCM - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

See Section 7.4.2.3.1 for RHR-SCM conformance.

7.4.2.3.2.1.8 RHR-SCM - Regulatory Guide 1.73 (1974) - Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants

See Section 7.1.2.5.18 for RHR-SCM conformance.

7.4.2.3.2.1.9 RHR-SCM - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

The RHR-SCM system used during a normal reactor shutdown and cooldown performs a safe shutdown function. See Section 7.3.1.1.4.3 for a discussion of the degree of conformance of the safety-related portions of the RHR. Also see Section 7.1.2.5.19.

7.4.2.3.2.1.10 RHR-SCM - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

See Section 3.11 for RHR-SCM conformance.

7.4.2.3.2.1.11 RHR-SCM - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Section 7.5.2.5.1.1.2 contains a discussion of the degree of conformance.

7.4.2.3.2.1.12 RHR-SCM - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

See Section 3.10 for RHR-SCM conformance.

7.4.2.3.2.2 RHR-SCM Conformance to 10CFR50, Appendix A, General Design Criteria

7.4.2.3.2.2.1 RHR-SCM - GDC 1 - Quality Standards and Records

See Section 7.1.2.6 for RHR-SCM conformance.

7.4.2.3.2.2.2 RHR-SCM - GDC 2 - Design Bases for Protection Against Natural Phenomena

See Section 7.1.2.6 for RHR-SCM conformance.

7.4.2.3.2.2.3 RHR-SCM - GDC 3 - Fire Protection

See Section 7.1.2.6 for RHR-SCM conformance.

7.4.2.3.2.2.4 RHR-SCM - GDC 4 - Environmental and Dynamic Effects Design Bases

See Section 7.1.2.6 for RHR-SCM conformance.

7.4.2.3.2.2.5 RHR-SCM - GDC 10 - Reactor Design

The RHR-SCM is designed with sufficient margin to maintain the fuel and RCPB within design limits using quality components and instrumentation to monitor its variables over their anticipated ranges for normal operation and anticipated operational occurrences of this RHR mode.

7.4.2.3.2.2.6 RHR-SCM - GDC 13 - Instrumentation and Control

The RHR-SCM is designed with sufficient margin to maintain the fuel and RCPB within design limits using quality components and instrumentation to monitor its variables over their anticipated ranges for normal operation and anticipated operational occurrences of this RHR mode.

7.4.2.3.2.2.7 RHR-SCM - GDC 15 - Reactor Coolant System Design

The RHR-SCM is designed with sufficient margin to maintain the fuel and RCPB within design limits using quality components and instrumentation to monitor its variables over their anticipated ranges for normal operation and anticipated operational occurrences of this RHR mode.

7.4.2.3.2.2.8 RHR-SCM - GDC 19 - Control Room

The RHR-SCM controls and instrumentation are provided in the main control room and the remote shutdown panel. The control functions do not compromise the separation design of the safety-related positions of the RHR system (Section 7.3.2.1.2.2).

7.4.2.3.2.2.9 RHR-SCM - GDC 20 - Protection System Functions

The RHR-SCM controls and instrumentation are provided in the main control room and the remote shutdown panel. The control functions do not compromise the separation design of the safety-related positions of the RHR system (Section 7.3.2.1.2.2).

7.4.2.3.2.2.10 RHR-SCM - GDC 21 - Protection System Reliability and Testability

The RHR-SCM controls and instrumentation are provided in the main control room and the remote shutdown panel. The control functions do not compromise the separation design of the safety-related positions of the RHR system (Section 7.3.2.1.2.2).

7.4.2.3.2.2.11 RHR-SCM - GDC 22 - Protection System Independence

The RHR-SCM controls and instrumentation are provided in the main control room and the remote shutdown panel. The control functions do not compromise the separation design of the safety-related positions of the RHR system (Section 7.3.2.1.2.2).

7.4.2.3.2.2.12 RHR-SCM - GDC 23 - Protection System Failure Modes

The RHR-SCM controls and instrumentation are provided in the main control room and the remote shutdown panel. The control functions do not compromise the separation design of the safety-related positions of the RHR system (Section 7.3.2.1.2.2).

7.4.2.3.2.2.13 RHR-SCM - GDC 24 - Separation of Protection and Control Systems

The RHR-SCM controls and instrumentation are provided in the main control room and the remote shutdown panel. The control functions do not compromise the separation design of the safety-related positions of the RHR system (Section 7.3.2.1.2.2).

7.4.2.3.2.2.14 RHR-SCM - GDC 34 - Residual Heat Removal

The RHR-SCM removes residual heat from the reactor when it is shut down and the main steam lines are isolated to maintain the fuel and RCPB within design limits. Redundant channels are provided to ensure performance even with a single failure. Onsite and offsite power are provided in case either source is not available when shutdown cooling is needed. Section 3.1 provides a discussion of RHR system compliance with GDC 34. Section 5.2.5 provides a discussion of the leak detection system and its application to the RHR system. Section 5.4 discusses a backup method for disposing of residual heat if the normal shutdown line becomes unavailable during shutdown.

7.4.2.3.2.3 RHR-SCM Conformance to Industry Codes and Standards

7.4.2.3.2.3.1 RHR-SCM - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

IEEE 279 does not apply to the RHR-SCM because it is not a safety system function; however, the degree of conformance of the safety portions of the RHR system is discussed in Sections 7.3.2.1.2.3.1, 7.3.2.4.2.3.1, and 7.3.2.6.2.2.3.1.

7.4.2.3.2.3.2 RHR-SCM - IEEE 308 (1971) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

RHR-SCM conformance to IEEE 308 is as discussed in Section 8.3.1 for the ac power supply to the RHR system of safety-related instrumentation and controls.

7.4.2.3.2.3.3 RHR-SCM - IEEE 317 (1972) - Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations

See Section 7.1.2.7.3.

7.4.2.3.2.3.4 RHR-SCM - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

See Section 7.1.2.7.4.

7.4.2.3.2.3.5 RHR-SCM - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

See Section 8.1.6.1.

7.4.2.3.2.3.6 RHR-SCM - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

See Sections 3.10 and 7.1.2.7.7.

7.4.2.3.2.3.7 RHR-SCM - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

See Section 7.4.2.3.2.1.8.

7.4.2.3.2.3.8 RHR-SCM - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment

See Section 7.1.2.7.11.

7.4.2.4 Remote Shutdown System - Instrumentation and Controls

7.4.2.4.1 RSS General Functional Requirements Conformance

For remote shutdown operation, no off-normal operation is assumed. Because the remote shutdown capability, by itself, does not perform any safety-related or protective function, it does not fall within the criteria set by IEEE 279. This system interfaces with safety-related systems, such as RHR and RCIC, and during normal operation becomes part of, and meets the design criteria for, these systems.

a. RSS Safety Design Basis 7.1.2.1.34.1(a)

   The reactor can be brought from full power operation to cold shutdown using controls located outside the control room. Section 7.4.1.4.1.2 details the systems that are used in this process. The design criteria for the RSS are addressed in the respective design requirements section.

b. RSS Safety Design Basis 7.1.2.1.34.1(b)

   Suitable procedures are provided for the operator to take the reactor to the cold shutdown condition.

Section 15.9 examines the protective sequences relative to the above requirements and equipment. Chapter 15 considers the operation and the system level qualitative NSOA aspects of this plant capability.

7.4.2.4.2 RSS Specific Regulatory Requirements Conformance

7.4.2.4.2.1 RSS Conformance to Regulatory Guides

7.4.2.4.2.1.1 RSS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The RSS is classified as seismic Category I and is qualified to remain functional during and following an SSE.

7.4.2.4.2.1.2 RSS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

Those RSS components that interface with safety-related systems maintain the integrity and channel separation of those systems. The separation criteria as defined in Section 8.1.6.1.14 is followed. Inside the remote shutdown panel, physical barriers between redundant divisions and between safety-related and nonsafety-related equipment are provided. Also see Section 7.1.2.5.19.

7.4.2.4.2.1.3 RSS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

See Section 3.11 for a discussion of the degree of conformance of RSS.

7.4.2.4.2.1.4 RSS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plant

See Section 3.10 for RSS compliance with Regulatory Guide 1.100.

7.4.2.4.2.2 RSS Conformance to 10CFR50, Appendix A, General Design Criteria

7.4.2.4.2.2.1 RSS - GDC 19 - Control Room

The RSS consists of equipment at appropriate locations outside the control room that is sufficient to provide and ensure prompt hot shutdown of the reactor and to maintain safe conditions during hot shutdown. The equipment also provides the capability for subsequent cold shutdown of the reactor.

The LGS remote shutdown system provides control of safety-related equipment at a panel in the remote shutdown room to bring the reactor to a cold shutdown condition if the control room should become uninhabitable. This capability is backed up by control of redundant equipment from local panels. The equipment qualification envelopes the service conditions expected to occur during shutdown conditions. The remote shutdown panel and transfer switches are seismically qualified. The instrumentation on this remote panel is single channel but is backed up by indications of the same parameters on other panels located in the auxiliary equipment room. The system is designed to achieve cold shutdown with the LOOP.

Operation of the transfer switches on the remote shutdown panel disables only the automatic actuation signal to a single division of the ESF equipment. This equipment can be manually placed in service from the remote panel.

Administrative procedures control access to the remote shutdown panel and its function. Additional remote shutdown procedures also control the operation of equipment from local panels including any information required to place this equipment in service.

7.4.2.4.2.3 RSS Conformance to Industry Codes and Standards

7.4.2.4.2.3.1 RSS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

These criteria are not applicable to the RSS by itself. During normal plant operation the RSS interfaces with and becomes part of the RCIC and RHR systems, which can be controlled remotely from the control room. During this time, the interfacing RSS instrumentation and controls maintain channel independence as required by IEEE 279 (1971), paragraph 4.6, and discussed in sections covering the compliance of each individual system with these criteria.

7.4.2.4.2.3.2 RSS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

Specific RSS conformance to requirements of IEEE 323 (1971) is covered in Sections 7.1.2.7.4 and 3.11.

7.4.2.4.2.3.3 RSS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

RSS conformance to the requirement of IEEE 344 (1971) is detailed in Section 3.10.

7.4.2.5 Emergency Service Water System – Instrumentation and Controls

For analysis of the ESW system, see Section 7.3.1.1.11.

7.4.2.6 Residual Heat Removal Service Water System - Instrumentation and Controls

For an analysis of the RHRSW system, see Section 7.3.1.1.12.

7.4.2.7 Class 1E Power Systems

For an analysis of the Class 1E power systems, see the following:

a. Section 8.3.1.2 for an analysis of the Class 1E ac power system

b. Section 8.3.2.2 for an analysis of the Class 1E dc power system

7.4.2.8 Shutdown Ventilation Systems

7.4.2.8.1 RCIC System Pump Compartment Unit Coolers - Instrumentation and Controls

7.4.2.8.1.1 RCIC-UC - General Functional Requirements Conformance

The RCIC-UC are designed with sufficient capacity and redundancy so that a single active failure does not prevent the system from performing its safety-related functions. They are automatically initiated by high temperature switches. For safety design basis refer to Section 7.1.2.1.14.1 and for additional details, refer to Section 9.4.

7.4.2.8.1.2 RCIC-UC to Specific Regulatory Requirements Conformance

7.4.2.8.1.2.1 RCIC-UC Conformance to Regulatory Guides

7.4.2.8.1.2.1.1 RCIC-UC - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The RCIC-UC can be manually initiated and can be tested during normal plant operation. The RCIC-UC actuation functions are periodically tested.

7.4.2.8.1.2.1.2 RCIC-UC - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The RCIC-UC comply with this regulatory guide as discussed in Section 3.2.

7.4.2.8.1.2.1.3 RCIC-UC - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

See Section 8.1.6.1.5 and Chapter 17 for RCIC-UC conformance.

7.4.2.8.1.2.1.4 RCIC-UC - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance with Regulatory Guide 1.53 is achieved by specifying, designing, and constructing the HCRIS to meet the single failure criterion, section 4.2 of IEEE 279 (1971) and IEEE 379 (1972). Redundant sensors and wiring are separated to ensure that a failure in a sensing element, the decision logic, or an actuator does not affect its redundant counterpart and prevent protective action. Separate channels are employed so that a fault affecting one channel does not prevent the redundant channel from operating properly.

7.4.2.8.1.2.1.5 RCIC-UC - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Compliance with Regulatory Guide 1.62 is achieved at the system level by the Control Room RCIC Manual Initiation circuitry which starts the unit coolers. In addition, controls are provided locally to manually initiate the unit coolers.

7.4.2.8.1.2.1.6 RCIC-UC - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

See Section 8.1.6.1 for RCIC-UC compliance with this regulatory guide.

7.4.2.8.1.2.1.7 RCIC-UC - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The qualification of Class 1E equipment for the RCIC-UC is discussed in Section 3.11.2.

7.4.2.8.1.2.1.8 RCIC-UC - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

RCIC-UC conformance with this regulatory guide is covered by Section 3.10.

7.4.2.8.1.2.1.9 RCIC-UC - Regulatory Guide 1.105 (1976) - Instrument Setpoints

To ensure initiation of the unit coolers to maintain the temperature of the RCIC pump compartment within the specified limits, instrument setpoints are selected to allow for the inaccuracy of the instrument, uncertainties in the calibration, and instrumentation drift likely to occur between calibrations.

7.4.2.8.1.2.1.10 RCIC-UC - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 8.1.6.1.21. for RCIC-UC conformance.

7.4.2.8.1.2.2 RCIC-UC Conformance to 10CFR50, Appendix A, General Design Criteria

7.4.2.8.1.2.2.1 RCIC-UC - GDC 1 - Quality Standards and Records

The RCIC-UC are included in an established quality assurance program described in Section 3.1 and Chapter 17.

7.4.2.8.1.2.2.2 RCIC-UC - GDC 2 - Design Bases for Protection Against Natural Phenomena

See Section 7.1.2.6.

7.4.2.8.1.2.2.3 RCIC-UC - GDC 3 - Fire Protection

See Section 7.1.2.6.

7.4.2.8.1.2.2.4 RCIC-UC - GDC 4 - Environmental and Dynamic Effects Design Bases

See Section 7.1.2.6.

7.4.2.8.1.2.2.5 RCIC-UC - GDC 13 - Instrumentation and Control

Instrumentation for the RCIC-UC is selected to monitor variables over anticipated ranges during normal and emergency operating conditions.

7.4.2.8.1.2.3 RCIC-UC Conformance to Industry Codes Standards

7.4.2.8.1.2.3.1 RCIC-UC - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

Conformance of the RCIC-UC with IEEE 279 (1971) is detailed below.

7.4.2.8.1.2.3.1.1 RCIC-UC - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The unit coolers are automatically initiated by high temperature switches.

7.4.2.8.1.2.3.1.2 RCIC-UC - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The ventilation system includes 100% capacity redundant unit coolers and independent sets of controls and power that meet the single failure criteria.

7.4.2.8.1.2.3.1.3 RCIC-UC - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the specific application. A quality control and assurance program is required to be implemented and documented by equipment vendors, which complies with the requirements set forth in 10CFR50, Appendix B.

7.4.2.8.1.2.3.1.4 RCIC-UC - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

See Section 3.11 for a discussion of equipment qualification.

7.4.2.8.1.2.3.1.5 RCIC-UC - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The unit coolers meet channel integrity by using the design features described in the other paragraphs of this section.

7.4.2.8.1.2.3.1.6 RCIC-UC - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control and power circuits for each unit cooler are physically and electrically separated.

7.4.2.8.1.2.3.1.7 RCIC-UC - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The unit coolers have no interaction with other plant control systems. Annunciator circuits using contacts at sensor and logic relays cannot impair the operability of the unit cooler control because of electrical isolation.

7.4.2.8.1.2.3.1.8 RCIC-UC - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

Initiation of the unit coolers is derived from high temperature signals from the corresponding pump-room.

7.4.2.8.1.2.3.1.9 RCIC-UC - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The unit coolers can be tested for operational availability as described in Section 7.4.1.8.1.3.7.

7.4.2.8.1.2.3.1.10 RCIC-UC - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The unit coolers can be tested during normal plant operation to verify that the system is capable of performing its intended function.

7.4.2.8.1.2.3.1.11 RCIC-UC - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

A channel bypass or removal of a component from an initiation circuit channel prevents the unit cooler from complying with the single failure criterion.

7.4.2.8.1.2.3.1.12 RCIC-UC - IEEE 279 (1971), Paragraph 4.12- Operating Bypasses

The unit cooler bypasses are discussed in Section 7.4.1.8.1.3.3.

7.4.2.8.1.2.3.1.13 RCIC-UC - IEEE 279 (1971), Paragraph 4.13- Indication of Bypasses

Each of the bypasses described in Section 7.4.1.8.1.3.3 is automatically indicated in the control room. In addition, each of these bypasses initiates a system out-of-service annunciator.

7.4.2.8.1.2.3.1.14 RCIC-UC - IEEE 279 (1971), Paragraph 4.14- Access to Means for Bypassing

Manual bypass of initiating circuits is procedurally controlled by administrative means.

7.4.2.8.1.2.3.1.15 RCIC-UC - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

The temperature switches are designed to allow trip setpoints to be adjusted to more stringent settings if required.

7.4.2.8.1.2.3.1.16 RCIC-UC - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

Once the unit coolers are initiated they continue to operate until the room temperature drops below the low temperature switch setpoint.

7.4.2.8.1.2.3.1.17 RCIC-UC - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

A single failure in the control system of a unit cooler cannot disable the automatic or manual operation of the other unit cooler.

7.4.2.8.1.2.3.1.18 RCIC-UC - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Access to temperature switch setpoints is restricted by administrative control.

7.4.2.8.1.2.3.1.19 RCIC-UC - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

System operation is indirectly indicated and identified by unit cooler trouble alarms.

7.4.2.8.1.2.3.1.20 RCIC-UC - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The information readout for each unit cooler is described in Section 7.4.1.8.1.5.2.

7.4.2.8.1.2.3.1.21 RCIC-UC - IEEE 279 (1971), Paragraph 4.21 - System Repair

The recognition and location of failed components is accomplished during periodic testing.

7.4.2.8.1.2.3.1.22 RCIC-UC - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Each logic cabinet and control panel is distinctively identified with a nameplate that identifies the safety system. Cables and cable trays are identified by a color code and tags that identify them as being of a separate channel.

7.4.2.8.1.2.3.2 RCIC-UC - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

See Section 8.1 for RCIC-UC conformance.

7.4.2.8.1.2.3.3 RCIC-UC - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

See Section 3.11.2. for RCIC-UC conformance.

7.4.2.8.1.2.3.4 RCIC-UC - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

The requirements of this standard have been met by the quality assurance program for construction of safety-related items.

7.4.2.8.1.2.3.5 RCIC-UC - IEEE 338 (1977) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

See Section 8.1.6.1.21 for RCIC-UC conformance.

7.4.2.8.1.2.3.6 RCIC-UC - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

See Section 3.10 for RCIC-UC conformance.

7.4.2.8.1.2.3.7 RCIC-UC - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The single failure criteria of IEEE 379 (1972) is met as described in Section 7.4.2.8.1.2.1.4.

7.4.2.8.1.2.3.8 RCIC-UC - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

See Section 8.1.6.1.14 for RCIC-UC conformance.

7.4.2.8.2 RHR System Pump Compartment Unit Coolers

See Section 7.3.2.15.5 for an analysis of RHR-UC.

7.4.2.8.3 Remote Shutdown System Ventilation System

See Section 7.3.2.15.6 for an analysis of the auxiliary equipment room ventilation system.

7.4.2.9 Additional Design Consideration Analyses

7.4.2.9.1 Loss of Plant Instrument Air

Loss of plant instrument air does not affect the capability of the plant to be safely shut down.

7.4.2.9.2 Loss of Cooling Water to Vital Equipment

Equipment vital to safe shutdown of the plant is cooled by the ESW system. A single failure in the ESW system does not prevent a safe shutdown of the reactor (Section 9.2.2).

7.4.2.9.3 Plant Load Rejection

Generator load rejection results in a turbine control valve fast closure that in turn initiates a reactor scram via the RPS. The RPS is described in Section 7.2.

7.4.2.9.4 Turbine Trip

Turbine trip closes a main stop valve, which in turn initiates a reactor scram via the RPS. The RPS is described in Section 7.2.

Table 7.4-1

REACTOR CORE ISOLATION COOLING INSTRUMENT SPECIFICATIONS

REACTOR FUNCTION	INSTRUMENT	RANGE
Reactor vessel high water level turbine trip (level 8)	Level sensor	-150/0/+60 inches[1]
Turbine exhaust high Pressure	Pressure sensor	0-30 psi
RCIC system pump high/low suction pressure	Pressure sensor	100 psig 30" Hg Vac
Reactor vessel low water level (level 2)	Level sensor	-150/0/+60 inches[1]
RCIC system steam supply low pressure	Pressure sensor	0-200 psig
Turbine overspeed	Centrifugal device	

(1) Instrument zero equal to 527.5 inches above vessel zero.

Table 7.4-2

REACTOR SHUTDOWN COOLING BYPASSES AND INTERLOCKS

VALVE FUNCTION MANUAL OPEN	REACTOR PRESSURE EXCEEDS SHUTDOWN	ISOLATION VALVE CLOSURE SIGNAL
Inboard suction isolation	Cannot open	Cannot open
Outboard suction isolation	Cannot open	Cannot open
Reactor injection	Cannot open	Cannot open
Radwaste discharge inboard	Can open	Cannot open
Radwaste discharge outboard	Can open	Cannot open
VALVE FUNCTION		
Auto (A) close or manual (M) close		
Inboard suction isolation	Closes A and M	Closes A and M
Outboard suction isolation	Closes A and M	Closes A and M
Reactor injection	Closes A and M	Closes A and M
Radwaste discharge inboard	Closes M	Closes A and M
Radwaste discharge outboard	Closes M	Closes A and M

Table 7.4-3

REMOTE SHUTDOWN PANEL INSTRUMENTATION

Unit 1	Unit 2	Hot Shutdown	Cold Shutdown	Description
RCIC System[1]				
HSS-49-191	HSS-49-291	X	X	Control - RCIC remote shutdown transfer Division II
HSS-49-192	HSS-49-292	X	X	Control - RCIC remote shutdown transfer Division I
HSS-49-193	HSS-49-293	X	X	Control - RCIC remote shutdown transfer
HSS-49-195	HSS-49-295	X	X	Control - RCIC remote shutdown transfer
HSS-49-196	HSS-49-296	X	X	Control - RCIC remote shutdown transfer
HV-49-1F076	HV-49-2F076	X		Control - RCIC steam line warmup valve
HV-49-1F060	HV-49-2F060	X	X	Control - RCIC turbine exhaust
HV-50-112	HV-50-212	X	X	Control - RCIC turbine trip throttle valve
HV-50-1F045	HV-50-2F045	X	X	Control - RCIC steam supply valve
HV-49-1F008	HV-49-2F008	X	X	Control - RCIC steam line outboard isolation valve
HV-49-1F007	HV-49-2F007	X	X	Control - RCIC steam line inboard isolation valve
HV-49-1F031	HV-49-2F031	X	X	Control - RCIC suppression pool water supply valve
HV-49-1F029	HV-49-2F029	X	X	Control - RCIC suppression pool water supply valve
HV-49-1F010	HV-49-2F010	X	X	Control - RCIC condensate storage to pump suction valve
HV-49-1F019	HV-49-2F019	X	X	Control - RCIC pump discharge minimum flow valve
HV-49-1F022	HV-49-2F022		X	Control - RCIC test loop isolation valve
HV-50-1F046	HV-50-2F046	X	X	Control - RCIC cooling water supply isolation

Table 7.4-3 (Cont'd)

Unit 1	Unit 2	Hot Shutdown	Cold Shutdown	Description
HV-49-1F012	HV-49-2F012	X	X	Control - RCIC pump outboard discharge valve
HV-49-1F013	HV-49-2F013	X	X	Control - RCIC pump inboard discharge valve
1OP220	2OP220	X	X	Control - RCIC barometric condenser condensate pump
1OP219	2OP219	X	X	Control - RCIC barometric condenser vacuum pump
HV-49-1F002	HV-49-2F002	X	X	Control - RCIC barometric condenser vacuum pump discharge valve
HV-49-1F080	HV-49-2F080	X	X	Control - RCIC turbine exhaust outboard vacuum relief isolation valve
HV-49-1F084	HV-49-2F084	X	X	Control - RCIC turbine exhaust inboard vacuum relief isolation valve
SI-50-1R003	SI-50-2R003	X	X	Indication - RCIC turbine speed
FIC-49-1R001	FIC-49-2R001	X	X	Controller - RCIC pump discharge flow
FI-49-1R001-1	FI-49-2R001-1	X	X	Indicator - RCIC pump discharge flow
LI-55-112-2	LI-55-212-2	X	X	Indicator - CST level
Nuclear Boiler System				
HSS-41-191	HSS-41-291	X	X	Control - Nuclear boiler remote shutdown transfer
PI-42-1R011	PI-42-2R011	X	X	Indication - Reactor vessel pressure
LI-42-1R010	LI-42-2R010	X	X	Indication - Reactor vessel level
PSV-41-1F013A	PSV-41-2F013A	X	X	Control - Main steam line relief valve
PSV-41-1F013C	PSV-41-2F013C	X	X	Control - Main steam line relief valve
PSV-41-1F013N	PSV-41-2F013N	X	X	Control - Main steam line relief valve

Table 7.4-3 (Cont'd)

Unit 1	Unit 2	Hot Shutdown	Cold Shutdown	Description
RHR System				
HSS-51-192	HSS-51-292	X	X	Control - RHR remote shutdown transfer
HSS-51-193	HSS-51-293	X	X	Control - RHR remote shutdown transfer
HSS-51-194	HSS-51-294	X	X	Control - RHR remote shutdown transfer
HSS-51-195	HSS-51-295	X	X	Control - RHR remote shutdown transfer
HSS-51-196	HSS-51-296	X	X	Control - RHR remote shutdown transfer
HSS-51-197	HSS-51-297	X	X	Control - RHR remote shutdown transfer
HSS-51-198	HSS-51-298	X	X	Control - RHR remote shutdown transfer
HV-51-1F009	HV-51-2F009		X	Control - RHR pump shutdown cooling suction valve
HV-51-1F008	HV-51-2F008		X	Control - RHR pump shutdown cooling suction valve
HV-51-1F006A	HV-51-2F006A	X	X	Control - RHR pump shutdown cooling suction valve
HV-51-1F006B	HV-51-2F006B	X	X	Control - RHR pump shutdown cooling suction valve
HV-51-1F004A	HV-51-2F004A	X	X	Control - RHR pump suction isolation valve
1AP202	2AP202	X	X	Control - RHR pump
HV-43-1F023A	HV-43-2F023A		X	Control - Recirculation pump suction valve
HSS-43-191	HSS-43-291		X	Control - Remote shutdown transfer
HV-51-1F007A	HV-51-2F007A	X	X	Control - RHR minimum flow bypass valve
HV-51-1F048A	HV-51-2F048A	X	X	Control - RHR HX bypass valve
HV-51-1F015A	HV-51-2F015A	X	X	Control - Shutdown cooling injection
HV-51-1F016A	HV-51-2F016A		X	Control - RHR drywell spray valve

Table 7.4-3 (Cont'd)

Unit 1	Unit 2	Hot Shutdown	Cold Shutdown	Description
RHR System (Cont'd)				
HV-51-1F017A	HV-51-2F017A	X	X	Control - RHR LPCI injection valve
HV-51-1F024A	HV-51-2F024A	X	X	Control - RHR full flow bypass valve
HV-51-1F027A	HV-51-2F027A	X	X	Control - RHR suppression pool spray valve
HV-51-1F047A	HV-51-2F047A	X	X	Control - RHR HX inlet valve
HV-51-1F003A	HV-51-2F003A	X	X	Control - RHR HX outlet valve
HV-51-1F049	HV-51-2F049		X	Control - RHR discharge to radwaste valve
HV-51-125A	HV-51-225A	X	X	Control - RHR full flow bypass valve
FI-51-1R005	FI-51-2R005	X	X	Indication - RHR system flow
ZI-51-148-2	ZI-51-248-2	X	X	HX bypass valve position
RHRSW System(2)				
HSS-12-015A-2		X	X	Control - Spray pond/cooling tower select
HSS-12-015C-2		X	X	Control - Spray pond/cooling tower select
HSS-12-016A-2		X	X	Control - Spray/bypass select
HSS-12-016C-2		X	X	Control - Spray/bypass select
HSS-12-094		X	X	Control - Remote shutdown transfer

Table 7.4-3 (Cont'd)

Unit 1	Unit 2	Hot Shutdown	Cold Shutdown	Description
RHRSW System (Cont'd)				
HSS-12-093		X	X	Control - Remote shutdown transfer
HV-51-1F014A	HV-51-2F014A	X	X	Control - RHRSW HX inlet valve
OAP506	OCP506	X	X	Control - RHRSW pump
HV-51-1F068A	HV-51-2F068A	X	X	Control - RHRSW HX outlet valve
PI-12-001A-2	PI-12-001A-3	X	X	Indicator - RHRSW pump discharge pressure
PI-51-105A-2	PI-51-205A-2	X	X	Indicator - RHRSW HX outlet pressure
The following valves of the ESW and RHRSW systems are actuated by signals from the transfer switches:				
HV-12-005 ESW and RHRSW pumps wetwell intertie gate				
HV-12-017A ESW and RHRSW cooling tower return cross-tie				
HV-11-015A ESW loop A discharge to RHRSW loop B				
ESW System				
OAP548		X	X	Control - ESW pump
PI-11-003A-2		X	X	Indication - ESW pressure
HV-11-011A		X	X	Control - ESW loop A return to RHRSW
HSS-11-091		X	X	Control - Remote shutdown transfer
HSS-11-092		X	X	Control - Remote shutdown transfer
HSS-11-093		X	X	Control - Remote shutdown transfer

Table 7.4-3 (Cont'd)

Unit 1	Unit 2	Hot Shutdown	Cold Shutdown	Description
Containment and Suppression Pool Monitoring System				
PI-42-170-2	PI-42-270-2	X	X	Indication - Drywell pressure
TI-57-122	TI-57-222	X	X	Indication - Drywell temperature
LI-55-115-2	LI-55-215-2	X	X	Indication - Suppression pool level
	LI-52-241	X	X	Indication - Suppression pool level
TI-41-102	TI-41-202	X	X	Indication - Suppression pool temperature
HS-55-126-2	-	X	X	Control-Suppression Pool Instrument Line Shutoff MOV
LI-55-141	-	X	X	Indication-Suppression Pool Level
Standby AC Power Supply[3]				
152-11509/CSR		X	X	101-D11 Safeguard switchgear feeder breaker
	152-11509/CSR	X	X	101-D21 Safeguard switchgear feeder breaker
152-11609/CSR		X	X	101-D12 Safeguard switchgear feeder breaker
	152-11609/CSR	X	X	101-D22 Safeguard switchgear feeder breaker

Table 7.4-3 (Cont'd)

Unit 1	Unit 2	Hot Shutdown	Cold Shutdown	Description
Standby AC Power Supply (Cont'd)				
152-11709/CSR		X	X	101-D13 Safeguard switchgear feeder breaker
	152-11709/CSR	X	X	101-D23 Safeguard switchgear feeder breaker
152-11502/CSR		X	X	201-D11 Safeguard switchgear feeder breaker
	152-11502/CSR	X	X	201-D21 Safeguard switchgear feeder breaker
152-11602/CSR		X	X	201-D12 Safeguard switchgear feeder breaker
	152-11602/CSR	X	X	201-D22 Safeguard switchgear feeder breaker
152-11702/CSR		X	X	201-D13 Safeguard switchgear feeder breaker
	152-11702/CSR	X	X	201-D23 Safeguard switchgear feeder breaker
152-11505/CSR		X	X	D114 Safeguard LC transformer breaker
	152-11505/CSR	X	X	D214 Safeguard LC transformer breaker
152-11605/CSR		X	X	D124 Safeguard LC transformer breaker
	152-11605/CSR	X	X	D224 Safeguard LC transformer breaker
152-11705/CSR		X	X	D134 Safeguard LC transformer breaker
	152-11705/CSR	X	X	D234 Safeguard LC transformer breaker
143-115/CS	143-115/CS	X	X	Control transfer
143-116/CS	143-116/CS	X	X	Control transfer
143-117/CS	143-117/CS	X	X	Control transfer

(1) Indicating lights are provided for these valves as well as the following: turbine tripped, turbine bearing oil pressure low, and turbine bearing oil temperature high.

(2) Indicating lights are provided for these valves as well as the RHRSW loop A return to spray pond high radiation.

(3) Indicating lights are provided for these breakers.

7.5 INFORMATION SYSTEMS IMPORTANT TO SAFETY

7.5.1 DESCRIPTION

7.5.1.1 General

This section describes the instrumentation that provides information that enables the operator to monitor transient reactor plant behavior to verify proper safety system performance following an accident and to perform required safety functions.

The SRDI is listed in Table 7.5-1. This table tabulates equipment illustrated in the various system P&IDs, IEDs, and FCDs referenced in Sections 7.2, 7.3, 7.4, and 7.6.

The instrumentation and ranges shown in Table 7.5-1 are selected based on their ability to provide the reactor operator with the information needed to perform normal plant maneuvers, and their capability to track process variables pertinent to safety during expected operational perturbations.

Table 7.5-3 identifies Regulatory Guide 1.97 variables applicable to LGS. Table 7.5-3 lists the instrumentation from Table 7.5-1 that provides indication of Regulatory Guide 1.97 variables.

Table 7.5-2 summarizes the LGS design and qualification criteria for the Regulatory Guide 1.97 display instrumentation and systems. Conformance with Regulatory Guide 1.97 is discussed in Section 7.5.2.5.1.1.2. Sections 7.5.1.4.2 and 7.5.1.4.3 describe the display instrumentation for indication of Regulatory Guide 1.97 variables. References are made to other sections for descriptions of the instrumentation systems.

The separation of redundant display instrumentation and electrical isolation of redundant sensors and channels is shown in elementary diagrams and in Table 7.1-6. The P&IDs, IEDs, FCDs, and elementary diagrams adequately illustrate the redundancy of monitored variables and component sensors and channels.

The arrangement of the control room and the auxiliary equipment room is shown in drawings M-602 and M-603, respectively.

7.5.1.2 Normal Operation

The information channel ranges and indicators are selected on the basis of giving the reactor operator the information needed to perform all normal plant startup, steady-state maneuvers, and to monitor all the process variables pertinent to safety during expected operational perturbations.

7.5.1.3 Transient Occurrences

The ranges of indicators and recorders provided are capable of covering the extremes of process variables and providing adequate information for all transient events.

7.5.1.4 Accident Conditions

Information readouts are designed to accommodate all credible accidents from the standpoint of operator action, information, and event monitoring requirements.

7.5.1.4.1 Initial Accident Event

The design basis of all ESFs is to mitigate the consequences of an accident without operator action or assistance for the first 10 minutes of the event. This requirement, therefore, makes it mandatory that all protective action necessary in the first 10 minutes be automatic. Therefore, although continuous monitoring of process variables is available, no operator action based on them is required.

7.5.1.4.2 Postaccident Monitoring

No operator action is required for at least 10 minutes following an accident, although the various monitoring devices are continuously tracking and indicating important parameter information and displaying it to the operator as well as recording appropriate data.

The DBA-LOCA serves as the envelope accident sequence event to provide and demonstrate the plant's postaccident monitoring capabilities. All other accidents have less severe requirements.

7.5.1.4.2.1 Reactor Monitoring

The following process instrumentation which monitor reactor conditions provides information to the operator after a design basis LOCA.

7.5.1.4.2.1.1 Reactor Water Level

a. Two wide range water level signals are transmitted from two independent differential pressure transmitters and recorded on two recorders. One channel records the wide range level and the other channel records the reactor pressure as stated in Section 7.5.1.4.2.1.2. The differential pressure transmitters have one side connected to a condensing chamber reference leg and the other side connected directly to a vessel nozzle for the variable leg. The range of the recorded level is from the top of the feedwater control range (just above the high level turbine trip point) to a point near the top of the active fuel. Each independent instrumentation channel is powered from separate Class 1E buses.

b. The fuel zone water level signals are transmitted from two differential pressure transmitters. The level signals are electronically compensated for variation in reactor water and steam density with respect to pressure. One signal goes to a fuel zone water level indicator and the other water level signal goes to a fuel zone water level recorder. The differential pressure transmitters have one side connected to a condensing chamber for the reference leg and the other side connected directly to the bottom tap of a calibrated jet pump for the variable leg. The fuel zone level transmitters are calibrated for saturated conditions for a reactor pressure of 0 psig. The level range is from over the top of the active fuel to near the bottom of the active fuel. The ranges of the wide range level and the fuel zone level overlap. Power is fed from two independent Class 1E power sources.

c. A continuous backfill system is connected to each condensing chamber reference leg. The backfill system provides a continuous flow of water from the Control Rod Drive (CRD) System to the reference leg. This flow of water will continuously purge the reference leg and preclude the build-up of noncondensable gas in the reference leg.

7.5.1.4.2.1.2 Reactor Pressure

Two reactor pressure signals are transmitted from two independent pressure transmitters and are recorded on two recorders. One channel records pressure and the other channel records the wide range level. The range of recorded pressure is from 0-1500 psig. Power is fed from two independent Class 1E power sources.

7.5.1.4.2.1.3 Primary Containment Pressure

Wide range primary containment signals are transmitted from two pressure transmitters. One signal is displayed in a recorder in the control room while the other signal is displayed on an indicator located in the control room. The range of both instruments is from -5 psig to 165 psig. Power is supplied from two independent Class 1E power sources.

One narrow range primary containment signal is transmitted from a pressure transmitter and is indicated in the control room. The range of the indicated pressure is from -5 to +5 psig. Power is supplied from a Class 1E power source.

7.5.1.4.2.1.4 Primary Containment Gas Analyzers

Two redundant analyzer packages, each containing a hydrogen sensor and an oxygen sensor, monitor primary containment hydrogen and oxygen. These analyzers are part of the CAC system (Section 6.2.5.2.2). The hydrogen sensor has a range of 0% to 10% (by volume) and the oxygen sensor has a range of 0% to 25% (by volume). Each analyzer is calibrated with a high (7%) and a low (2%) oxygen and hydrogen supply. The hydrogen and oxygen concentrations are indicated in the control room.

Power is supplied from two independent Class 1E power sources.

7.5.1.4.2.1.5 Primary Containment Radiation Monitors

Four ion chamber sensors measure the gross radioactivity present in the containment atmosphere and transmit their signals to radiation recorders located in the control room. (Section 7.6.1.1.6). The range of recorded radiation is from $1\text{-}10^8$ rads per hour. Power is supplied from two independent Class 1E power sources.

7.5.1.4.2.1.6 Suppression Chamber Pressure

One suppression chamber pressure signal is transmitted from a pressure transmitter and is recorded in the control room. This signal is displayed on a pressure recorder located in the control room. The range of recorded pressure is from -5 psig to 165 psig.

Power is supplied from a Class 1E power source.

7.5.1.4.2.1.7 Suppression Pool Temperature

Two independent divisionalized recorders are located in the control room to monitor temperatures from 16 independent temperature sensors located in the suppression pool. Eight temperature sensors are dedicated to each recorder. Power is supplied from two independent Class 1E power sources. Each recorder has a digital display with which the operator can select the sensor to be

displayed. Normally the display indicates the average temperature of the eight temperature sensor inputs. A control room alarm is generated when the average temperature increases to 95°F, 105°F, 110°F, and 120°F. In addition, an alarm will be provided when any temperature loop malfunctions.

The SPTMS is described in Appendix 3A.15.

7.5.1.4.2.1.8 Suppression Pool Water Level

Two suppression pool water level signals are transmitted from two independent level transmitters. Each signal is transmitted to an indicator, located in the control room.

Power is supplied from two independent Class 1E sources (Table 7.5-3).

7.5.1.4.2.2 Reactor Shutdown, Isolation, and Core Cooling Indication

7.5.1.4.2.2.1 Reactor Operator Information and Observations

The following information furnished to the control room operator permits him to assess reactor shutdown, isolation, and availability of emergency core cooling following the postulated accident.

a. Operator verification that reactor shutdown has occurred is made by observing the following indications:

    1. Control rod status lamps indicate each rod to be fully inserted; the power source is one of the instrument ac buses.

    2. Control rod scram pilot valve status lamps indicate open valves; the power source is an instrument ac bus.

    3. Neutron monitoring power range channels and recorders downscale; the power source is a dedicated UPS system.

    4. Annunciators for RPS variables and trip logic in the tripped state. The power source is dc from a plant battery. The function of the annunciators is to supply information to the operator. They are not protective systems as they do not provide trip signals.

    5. The plant process computer (Section 7.7) provides thermal-hydraulic information to the operator that is used to determine plant operating conditions.

b. The reactor operator verifies reactor isolation by observing one or more of the following indications:

    1. Isolation valve position lamps indicate valve closure; the power source is the same as for the associated motor, solenoid, operator and solenoid for AOVs.

2. Annunciators for the containment and reactor vessel isolation system variables, and trip logic in the tripped state. The power source is dc from the plant battery system.

c. Operation of the ECCS following the accident is verified by observing the following indicators:

1. Annunciators for HPCI, core spray, RHR, and ADS, sensor initiation logic trips. The power source is dc from a plant battery.

2. There are flow and pressure indications for each ECCS. The power sources are independent and are from the same Class 1E buses as the driven equipment.

3. Injection valve position lights indicating either open or closed valves. The power source is the same as for the valve motor.

4. Relief valve position lights indicate valve open or closed status through acoustical sensors located on piping directly downstream of the relief valves. Power is supplied from UPS.

5. Relief valve discharge pipe temperature monitors. The power source is instrument ac from one of the instrument ac buses.

6. Operation of the containment systems following the accident is verified by observing the following indications:

(a) Annunciators for containment high oxygen and high hydrogen. The power source is dc from the plant battery system.

(b) Indication and recording (by virtue of the non-safety related ERFDS/PMS computer) of containment oxygen and hydrogen concentrations (Table 7.5-1).

7. Operation of the auxiliary supporting systems following the accident is verified by observing the following indicators:

(a) Control room emergency ventilation: Recording and annunciation of radiation monitoring of the CREFAS intake and charcoal filter discharge duct (Table 7.5-1).

(b) Service water systems: RHRSW system flow and temperature (Table 7.5-3).

(c) SGTS, RERS, and REIS: Indication of flow for SGTS; indication of temperatures for SGTS and RERS charcoal filters; and reactor enclosure and refueling area differential pressure for REIS (Table 7.5-1).

7.5.1.4.2.2.2 System Operation Information Display Equipment

The following information furnished to the control room operator permits the operator to assess the operation of the safety-related systems:

a. HPCI: Three indicators, one displaying HPCI discharge flow rate, one displaying HPCI pump discharge pressure, and one displaying HPCI turbine steam pressure, are located in the control room.

b. CS: Two indicators each displaying CS flow rate for one of the two CS loops are located in the control room.

c. RHR: Four indicators, each displaying RHR flow rate for each loop, two indicators each displaying RHRSW flow rate for each RHR heat exchanger; two indicators each displaying RHR coolant outlet temperature for each RHR heat exchanger and two indicators, each displaying service water inlet temperature for each RHR heat exchanger, located in the control room.

d. RCIC: One indicator displaying RCIC flow rate, located in the control room.

e. ESW: Two indicators, each displaying ESW flow rate for each ESW loop and two indicators, each displaying ESW temperature for each ESW loop, located in the control room.

f. Drywell atmosphere temperature: One 2-pen recorder displaying drywell atmosphere temperature and suppression pool air space temperature, located in the control room.

g. Drywell sump level (floor drain and equipment drain tanks): A level indication for each tank, provided in the control room.

h. Equipment drain collection tank level: One indicator displaying high radioactive equipment drain collection tank level, located in the radwaste control room.

i. Floor drain collection tank level: One indicator displaying high radioactive floor drain collection tank level, located in the radwaste control room.

j. Chemical waste collection tank level: One indicator displaying high radioactive chemical waste tank level, located in the radwaste control room.

k. SLCS storage tank level: A CRT tank level readout for the SLCS storage tank, available in the control room through the ERFDS.

l. PCIG pressure: Two indicators, each displaying PCIG pressure, located in the control room.

m. CRD hydraulic charging water pressure: One indicator displaying CRD hydraulic charging pressure, located in the control room.

n. Reactor recirculation pump flow: One 2-channel recorder displaying reactor recirculation pump flow, located in the control room.

o. Deleted

p. Miscellaneous: In addition to the above displays, the following also provide information to enable the reactor operator in the control room to perform postaccident functions:

1. Control rod status lamps (Section 7.5.1.4.2.2.1.a.1)

2. Scram pilot valve status lamps (Section 7.5.1.4.2.2.1.a.2)

3. Neutron flux level meters (Section 7.5.1.4.2.2.1.a.3)

4. Main feedwater flow: Three indicators, each displaying feedwater flow for each feedwater line, located in the control room. Signals transmitted to these indicators are totalized and displayed as total main feedwater flow on a recorder located in the control room.

5. CST level: One recorder displaying CST level, located in the control room.

6. Condenser hotwell level: One recorder displaying condenser hotwell level, located in the control room.

7. Condenser pressure: condenser vacuum for each condenser shell is displayed on the HMI workstations located in the control room.

8. Main steam bypass valve position: Each main steam bypass valve open and close position is displayed on HMI workstations in the control room.

9. Circulating water pump discharge pressure: Four indicators, each displaying discharge pressure for each circulating water pump, located in the control room.

7.5.1.4.2.2.3 System Operation Information Display Equipment Qualification

The safety-related reactor shutdown information equipment up to the display is of the same high quality as the safety system's instrumentation.

The postaccident monitoring instrumentation is of a quality that is consistent with minimum maintenance requirements and low failure rates. The safety-related equipment and indication equipment that have seismic and environmental qualifications are discussed in Sections 7.5.2.5.1.3.2 and 7.5.2.5.1.3.3.

7.5.1.4.2.3 Plant Electrical System

Display instrumentation for the status of the 4.16 kV safeguard and battery buses is provided in the control room. Each 4.16 kV safeguard bus is monitored for voltage and frequency, and each battery bus is monitored for voltage and amperage. Eight indicators (two indicators per bus) are provided in the control room to monitor each of the 4.16 kV safeguard buses for voltage and

frequency. Eight indicators (two indicators per bus) are provided in the control room to monitor each of the battery buses for voltage and amperage.

7.5.1.4.2.4 Bypass Indication System

There are bypass indications through either administrative control or automatic systems level indications. These bypass capabilities are discussed independently for each safety system (Section 7.3).

7.5.1.4.3 Additional Instrumentation for Regulatory Guide 1.97 Variables

The following instrumentation provides postaccident indication in accordance with Regulatory Guide 1.97.

7.5.1.4.3.1 Radioactivity Concentration in Primary Coolant

Indication of radiation levels in primary coolant is provided by two methods are discussed in Section 7.5.2.5.1.1.2.4.4: (1) by means of the MSL-RMS and the AEO-RMS when the NSSS is not isolated; and (2) by means of the PASS when the NSSS is isolated.

a. MSL-RMS - Four redundant radiation detectors provide signals via rate meters to one 2-pen recorder in the control room. The 2-pen recorder allows the output of any two selected detector channels to be displayed. This system is described in Sections 7.6.1.1.1 and 11.5.2.1.1.

b. AEO-RMS - A radiation monitor designed to sense changes in the off- gas gross fission product concentration transmits signals to a recorder in the control room. This system is described in Section 11.5.2.2.8.

c. PASS - Grab samples of both the primary containment atmosphere and the reactor coolant are provided by the PASS. Analysis of these samples provides information for detection of a breach in the fuel cladding when the NSSS is isolated. This system is described in Section 11.5.5.

7.5.1.4.3.2 Radiation Exposure Rate in Areas Requiring Personnel Access Postaccident

As discussed in Section 7.5.2.5.1.1.2.4.11, area radiation monitors are provided in areas outside the reactor enclosure where access is needed after an accident. Signals from these monitors are available on a CRT display in the control room through the ERFDS or through a multipoint recorder. These monitors are listed in Table 7.5-3. Because these monitors are also used during normal operation, they are described in Section 12.3.4.1.

7.5.1.4.3.3 Airborne Radioactive Materials Released from Plant

In the event of an accident, the secondary containment is isolated and all exhaust from it is processed through the SGTS as described in Sections 6.2.3, 6.5.1.1, and 9.4.2. After a LOCA, any drywell purge from the CAC system is processed through the SGTS (Section 9.4.5.1). Because the SGTS exhausts into the north stack, the wide range accident monitor (Sections 7.6.1.1.8 and 11.5.2.2.1) of the north stack effluent radiation monitoring system is used to provide indication of airborne radioactive material releases postaccident.

Noble gas radioactivity concentration signals are transmitted from the wide range accident monitor to a 3-pen recorder that displays the entire range of the monitor, 10^{-7} μCi/cc to 10^{+5} μCi/cc in three overlapping scales. Indication of north stack flow rate is provided from a transmitter and displayed via a digital display/control module in the control room.

The system also provides grab sampling capability for particulates and halogens.

7.5.2 ANALYSIS

7.5.2.1 General

The SRDI provides adequate information to enable the operator to monitor transient reactor plant behavior and to verify proper safety system performance following an accident.

All protective actions required under accident conditions during the first 10 minutes are automatic and redundant so that immediate operator intervention is unnecessary.

The information provided, in addition to the performance of the emergency system, supplies sufficient time for the operator to make reasoned judgments and take action when required.

7.5.2.2 Normal Operation

Instrumentation ranges for normal, transient, or accident, conditions are selected to maintain the accuracy requirements for all conditions. The accuracy of SRDI is shown in Table 7.5-1.

7.5.2.3 Transient Occurrences

These occurrences are not limiting from the point of view of instrument ranges and functional capability (Section 7.5.2.2).

7.5.2.4 Accident Conditions

The DBA LOCA is the most extreme operational event. Information readouts are designed to accommodate this event from the standpoint of operator actions, information, and event tracking requirements.

7.5.2.4.1 Initial Accident Event

The design basis of all ESFs, to mitigate accident event conditions, takes into consideration that no operator action or assistance is required or recommended for the first 10 minutes of the event. This requirement therefore makes it mandatory that all protective action necessary in the first 10 minutes be automatic. Therefore, although continuous tracking of variables is available, no operator action based on them is intended within the first 10 minutes.

7.5.2.4.2 Postaccident Monitoring

The following process instrumentation provides information to the operator after a DBA LOCA for use in monitoring reactor conditions:

a. Reactor Water Level and Pressure:

Vessel water level and pressure sensor instrumentation described in Section 7.5.1.4.2.1 is redundant, electrically independent, and is qualified to be operable during and after a LOCA in conjunction with a SSE. Power is from two independent Class 1E instrument buses supplied from two of the divisional ac buses. This instrumentation complies with the independence and redundancy requirements of IEEE 279 (1971) and provides recorded outputs. The equipment performs its required functions during and after a seismic event, except that the recorders and indicators are not functional during the seismic event.

The reactor water level and pressure transmitters are mounted on two independent local racks. The transmitters and recorders are designed to operate during normal operation and postaccident environmental conditions. The design criteria that the instruments must meet are discussed in Section 7.1.2.1.7. There are two complete and independent channels of wide range reactor water level and reactor vessel pressure with each channel having its readout in the control room on a separate recorder.

Two recorders are furnished, each monitoring one channel of pressure and one channel of reactor water level.

An evaluation was conducted of the effects of high temperature on the reference legs of the water level measuring instruments resulting from the exposure to HELBs.

HELBs are breaks occurring in a fluid system whose normal plant conditions are either in operation or maintained pressurized under conditions where either or both of the following are met:

1. Maximum operating temperature exceeds 200°F.

2. Maximum operating pressure exceeds 275 psig.

These HELBs can be categorized into three sizes: a) large, b) intermediate, and c) small. Each break has its own temperature and pressure effects on the vessel drywell and suppression pool. However, the small HELB imposes the most severe temperature conditions on the drywell and is more likely to affect the vessel level instrumentation reference legs.

The LGS reactor vessel level instrumentation design consists of four divisions of cold reference leg, differential pressure, level indications. The design includes parallel reference and variable legs with an approximate 12 foot vertical drop in the drywell. This design minimizes the error in level indication caused by elevated drywell temperatures. Reference leg temperature and drywell temperature are monitored by the ERFDS. The LGS design also includes redundant, safety-grade, wide range and fuel zone reactor water level indication in the control room.

Under a small break accident condition, the maximum temperature in the drywell could approach 340°F. Given this elevated drywell temperature and the gradual depressurization of the reactor vessel, a potential boil-off condition could occur

when the reactor vessel pressure falls below 118 psia (corresponding to a 340°F saturation temperature). However, the EOPs have been written to prevent the boil-off conditions from occurring.

For purposes of illustration, the following sequence of events is assumed to occur. With the reactor and containment at the maximum normal conditions, a small HELB occurs that allows blowdown of reactor steam to the drywell. The resulting pressure increase in the drywell leads to a high drywell pressure signal that scrams the reactor, initiates high pressure ECCS, and activates the containment isolation system. Drywell temperature would increase rapidly and approach 340°F. However, reactor vessel pressure and level would tend to decrease at a slow rate due to the small size of the break. The ADS will not initiate until low RPV level and high drywell pressure signals have been received. In instruments with cold reference legs, the reference leg temperature could increase to the drywell ambient temperature, which will not exceed 340°F. Thus, under the least favorable possible conditions, a cold reference leg will not boil until the system pressure falls to 118 psia (T_{sat} at 340°F). Thus pressure maintained above about 100 psig is an assurance that boiling of the cold reference column has not occurred, even under the worst possible drywell temperature conditions. Given this information, the following scenarios show the accident conditions and operator actions.

The reactor operator is alerted to the incident by the drywell high pressure and temperature alarms and by the reactor scrams. At this point, the operator will start to follow the EOPs. The operator will be aware of the elevated drywell temperature and pressure and is required to monitor and control these parameters as well as suppression pool temperature and pressures. The operator will also be continuously monitoring RPV pressure and reference leg temperature and comparing these parameters against a curve to determine the potential for reference leg boiling.

The EOPs require the operator to control drywell pressure and temperature. The main concern, as it pertains to RPV level instrumentation, is drywell temperature. If the reactor pressure is maintained high enough, the saturation temperature will be higher than the drywell temperature and a boil-off condition will never occur. If, however, the drywell temperature cannot be controlled, the operator is required to shut down the drywell cooling system and initiate drywell sprays in accordance with the restrictions of the drywell spray initiation limit curve. The sprays will lower drywell temperature and prevent the boiling condition from occurring. Drywell sprays are also used to reduce drywell pressure in the event that the pressure cannot be controlled.

As previously mentioned, the operator is sensitive to the reference leg temperature versus reactor pressure curve. If at any time the existing conditions fall into the unsafe area above the curve, the operator will assess the ability to determine RPV water level. If RPV water level cannot be determined, a contingency EOP which addresses the inability to determine RPV level will be performed concurrently with the EOP being executed at that time. The operator would be aware of a boil-off condition by the occurrence of erratic level indications caused by the flashing fluid as it is forced out through the instrument line. The first action is to blowdown the vessel, then, flood the RPV to the elevation of the main steam lines using available

low pressure makeup systems until RPV level indication can be determined. The RPV will remain flooded to the elevation of the main steam lines until RPV level indication is available. Flooding the vessel also ensures that adequate core cooling is accomplished.

Therefore, the existing LGS design coupled with the required operator actions as prescribed by the EOPs are sufficient to prevent or mitigate any detrimental effects on the water level indication that may be caused by a small HELB.

b. Suppression Pool Water Level:

This instrumentation complies with the requirements of IEEE 279 (1971) and provides indicated outputs. Power is from two independent Class 1E independent buses. The equipment performs its required function during and after the seismic event, except that the indicators are not functional during the seismic event. The indicators are selected from equipment that meets the design specification in effect at the time of the plant design. This parameter is recorded in the ERFDS data base.

c. Containment Pressure:

This instrumentation is redundant, electrically independent, and is qualified to be operable during and after a LOCA. Power is from two independent Class 1E buses, and the instrumentation complies with the requirements of IEEE 279 (1971) and provides a recorded output. The equipment will perform its required function during and after a seismic event, except that the recorder and indicators are not functional during the seismic event.

d. Emergency Core Cooling Systems:

Performance of ECCS following an accident can be verified by observing redundant and independent indications as described in Section 7.5.1.4.2.2.1.c, and fully satisfies the need for operator verification of the system's operation.

Redundancy of instrumentation within the individual ECCS is not provided; however, redundancy is provided within the combination of ECCS. Each ECCS is provided with system flow-measuring indication and isolation valve status indication, thereby allowing the operator to assess the operating conditions. The indicators and recorders are selected from equipment that meets the design specifications in effect at the time of the plant design.

e. Control Room Habitability:

Performance of the control room habitability is verified by observing the redundant and independent indication listed in Table 7.5-1 which satisfies the need for operator verification of the system operation.

f. Service Water Availability:

The operation of the ESW and the RHRSW systems is verified by observing the indications described in Sections 7.3.1.1.11.12.2 and 7.3.1.1.12.12.2, respectively, and satisfies the need for operator verification of the operation of the system.

g. Containment Atmospheric Control:

The operation of the CAC system is verified by observing the indications described in Sections 7.5.1.4.2.2.1.c.6 and 7.3.1.1.6.1.2.12.2, and satisfies the need for operator verification of the system operation.

h. Primary Containment Post-LOCA Radiation

The rate of buildup/decay of radioactivity inside the primary containment is verified by observing the indications described in Section 7.5.1.4.2.1.5, and satisfies the need for operator verification that safety functions are being accomplished.

i. SGTS, RERS, and REIS:

Performance of the SGTS, RERS, and REIS is verified by observing indication as described in Section 7.5.1.4.2.2, and satisfies the need for operator verification of the operation of the systems.

7.5.2.4.3 Safe Shutdown Displays

The safe shutdown display instrumentation in Section 7.5.1 consists of the control rod status lamps, scram pilot valve status lamps, and neutron monitoring instrumentation. These displays are expected to remain operable following an accident to indicate the occurrence of safe and orderly shutdown.

The displays provide diversity in that they are in three separate systems. The neutron monitoring outputs are recorded. The indicators and recorders are selected from equipment that meets the design specification in effect at the time of the plant design.

Sufficient instrumentation is provided for the operator to verify proper cooling water flow for the various shutdown cooling systems and modes. Proper shutdown cooling mode operation is indicated by RHR pump running indication, position indication for MOVs, cooling water flow indication, and RHRSW flow indication. Annunciators are provided to indicate RHR pump trip, abnormal pump discharge pressure, and loss of RHR system integrity. Proper RCIC operation is indicated by RCIC pump discharge and suction pressure and valve position indication. Annunciators are provided to indicate abnormal turbine operating parameters, low RCIC pump flow, and high turbine steam flow.

The safe shutdown display instrumentation conforms to the power generation design basis in that:

a. Abnormal conditions requiring operator action are indicated or annunciated in the control room.

b. Sufficient instrumentation is provided for the operator to verify proper cooling water flow and cooling system piping integrity.

7.5.2.5 General Functional Requirements Conformance

Conformance of the transmitter/trip unit system, used for safe shutdown display, is discussed in the Licensing Topical Report NEDO-21617, Revision A, "Analog Transmitter/Trip Unit System for Engineered Safeguard Sensor Inputs". Conformance of the other features with the regulatory and industry standards is discussed in the following sections.

7.5.2.5.1 Specific Regulatory Requirements Conformance

7.5.2.5.1.1 Conformance to Regulatory Guides

7.5.2.5.1.1.1 Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The SRDI is designed to operate continuously, and there is no requirement for bypass provisions. Removal of instrumentation for servicing during plant operation is administratively controlled. Refer to the individual safety system analysis discussions of Regulatory Guide 1.47 contained in Sections 7.2, 7.3, 7.4 and 7.6.

7.5.2.5.1.1.2 Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

LGS conforms with the intent of the regulatory guide, which is to ensure that instrumentation systems be provided to assess equipment and plant conditions during and following an accident as required by GDC 13, GDC 19 and GDC 64. In general, the regulatory guide requirements are implemented except where deviations from the guide are justified technically and can be implemented without disrupting the general intent of the guide. In assessing Regulatory Guide 1.97, LGS has drawn on information in ANSI/ANS 4.5 and on data derived from other analyses and studies.

7.5.2.5.1.1.2.1 Design and Qualification Criteria

LGS conformance with the design and qualification criteria defined in the regulatory positions of Regulatory Guide 1.97 is summarized in Table 7.5-2 and discussed below (the paragraph numbers cited correspond to those in Regulatory Guide 1.97).

a. Paragraph 1.3: Instruments used for accident monitoring to meet the provisions of Regulatory Guide 1.97 have the proper sensitivity, range, transient response, and accuracy to ensure that the control room operator is able to perform the role of bringing the plant to, and maintaining it in, a safe shutdown condition and in assessing actual or possible releases of radioactive material following an accident.

   Accident monitoring instruments that are required to be environmentally qualified are qualified to the requirement of NUREG-0588 (Section 3.11.1). The seismic qualification of instruments, where required, is in accordance with Regulatory Guide 1.100 (Section 3.10).

   The LGS quality assurance program is used to comply with the quality assurance requirements (Section 8.1.6.1 and Chapter 17).

Periodic checking, testing, calibrating, and calibration verification of accident monitoring instrument channels (Regulatory Guide 1.118) are in accordance with the LGS Technical Specifications.

b. Paragraph 1.4: Instruments designated as Categories 1 and 2 for variable Types A, B, and C are identified in such a manner as to optimize the human factors engineering and presentation of information to the control room operator. This position is taken to clarify the intent of Regulatory Guide 1.97, which specified that these instruments be easily discerned for use during accident conditions.

c. Paragraph 1.6: It is LGS's position that Table 1 of Regulatory Guide 1.97 does not represent the minimum number of variables, correct ranges, or instrumentation categories for accident monitoring at a BWR facility. The LGS list of accident monitoring variables and classification of instrumentation as Category 1, 2 or 3 is in compliance with the intent and method used in Regulatory Guide 1.97. The LGS position on implementation of each variable is presented in Section 7.5.2.5.1.1.2.3.

d. Paragraph 2: Conformance with Paragraph 1.3 described above is applicable to the Type D and E variables of Regulatory Guide 1.97.

7.5.2.5.1.1.2.2 Analysis for Type A Variables

Regulatory Guide 1.97 (Rev 2) designates all Type A variables as plant specific, thereby defining none in particular. Type A variables for LGS have been selected in conformance with the definition in Regulatory Guide 1.97. Variables associated with contingency actions that will be identified in written procedures are excluded. The following is a list of Type A variables specific to LGS. Detailed description of each Type A variable is given in Section 7.5.1.4.2.1. The variables listed here are also included in Section 7.5.2.5.1.1.2.3.

a. Variable A1 - Oxygen and Hydrogen Concentration:

Operator action: If containment atmosphere approaches the combustible limits, initiate CGCS.

Safety function: Prevent combustible concentrations and thus preserve containment integrity.

b. Variable A2 - RPV Pressure:

Operator action: (1) Depressurize RPV and maintain safe cooldown rate by any of several systems, such as main turbine bypass valves, HPCI, RCIC, and RWCU; or (2) manually open one SRV to reduce pressure to below SRV setpoint if an SRV is cycling.

Safety function: (1) Core cooling; (2) maintain RCS integrity.

c. Variable A3 - RPV Water Level:

Operator action: Restore and maintain RPV water level.

Safety function: Core cooling

d. Variable A4 - Suppression Pool Water Temperature:

Operator action: (1) Operate available suppression pool cooling system when pool temperature exceeds normal operating limits; (2) scram reactor if temperature reaches limit for scram; (3) if suppression pool temperature cannot be maintained below the heat capacity temperature limit, maintain RPV pressure below the corresponding limit; and (4) close any SORV.

Safety function: (1) Maintain containment integrity and (2) maintain RCS integrity.

e. Variable A5 - Suppression Pool Water Level:

Operator action: Maintain suppression pool water level within normal operating limits: (1) transfer RCIC suction from the CST to the suppression pool in the event of high suppression pool level; and (2) if suppression pool water level cannot be maintained below the suppression pool load limit, maintain RPV pressure below corresponding limit.

Safety function: Maintain containment integrity.

f. Variable A6 - Drywell Pressure:

Operator action: Control primary containment pressure by any of several systems, such as containment pressure control systems, SGTS, suppression pool sprays, drywell sprays.

Safety function: (1) Maintain containment integrity and (2) maintain RCS integrity.

7.5.2.5.1.1.2.3 Plant Variables for Accident Monitoring

LGS's implementation of the variables listed in table 1 of Regulatory Guide 1.97 and the fulfillment of design criteria and assignment of qualification categories for the instrumentation proposed for their measurement are summarized in Table 7.5-5.

Measurement of the five variable types provides the following kinds of information to plant operators during and after an accident:

a. Type A - plant pressure, barrier and heat sink information, on the basis of which operators can take specified manual control actions

b. Type B - information about the accomplishment of plant safety functions

c. Type C - plant information about the breaching of barriers to fission product release

d. Type D - information about the operation of individual safety systems

e. Type E - information about the magnitude of the release of radioactive materials.

The categories are also related (in Regulatory Guide 1.97) to "key variables." Key variables are defined differently for the different variable types. For Type B and Type C variables, the key variables are those variables that most directly indicate the accomplishment of a safety function; instrumentation for these key variables is designated Category 1.

Key variables that are Type D variables are defined as those variables that most directly indicate the operation of an emergency safety system; instrumentation for these key variables is usually Category 2. Key variables that are Type E variables are defined as those variables that most directly indicate the release of radioactive material; instrumentation for these key variables is also usually Category 2.

The variables are listed in Table 7.5-5 in the same sequence as in table 1 of Regulatory Guide 1.97; however, for convenience in cross-referencing entries and supporting data, the variables are designated by letter and number. For example, the sixth B-type variable listed in Regulatory Guide 1.97 is denoted in Table 7.5-5 as variable B6.

The LGS position is shown for each variable. In general, there are three kinds of responses, the variable and instrumentation are: (1) implemented to meet the regulatory guide criteria; (2) implemented with qualifying exceptions or (3) not implemented.

As necessary, the positions are elaborated or substantiated in the supplementary analyses in Section 7.5.2.5.1.1.2.4. References to these analyses are made in the tabulation by citing the appropriate UFSAR section.

7.5.2.5.1.1.2.4 Regulatory Guide 1.97 Project Position

The issues used to substantiate deviation of the LGS system from the Regulatory Guide 1.97 criteria are presented below.

7.5.2.5.1.1.2.4.1 Variable B1 - Neutron Flux

Issue Definition

The measurement of neutron flux is specified as the key variable in monitoring the status of reactivity. Neutron flux is classified as a Type B variable, Category 1. The specified range is 10^{-6}% to 100% full power (SRM, APRM). The stated purpose is "Function detection; accomplishment of mitigation."

Discussion

The lower end of the specified range, 10^{-6}% full power, is intended to allow detection of an approach to criticality by some undefined and noncontrolled mechanism after shutdown.

In attempting to analyze the performance of the neutron flux monitoring systems, a scenario was postulated to obtain the required approach to criticality. Basically, it assumes an increase in reactivity from loss of boron in the reactor water after SLCS actuation.

The accident scenario incorporates the following factors:

a. The control rods fail (completely or partially) to insert, and the operator actuates the SLCS.

b. The SLCS shuts down the reactor.

c. A slow leak in the primary system results in an outgo of borated water and its replacement by water that contains no boron.

d. A range of leak rates up to 20 gpm was considered (Table 7.5-4).

Calculations were made to evaluate the rise in neutron population as a function of different leak rates. The calculations were made for a shutdown neutron level of $5x10^{-8}$% of full power. The choice of $5x10^{-8}$% was based on measurements at two BWR plants. The shutdown level was assumed to have a negative reactivity of 10 dollars, an assumption that is representative of a shutdown with all rods inserted. The results of the calculations are presented in Table 7.5-4. The numbers in the table refer to the time in hours required to increase the flux by 1 decade. For example, with a leak of 5 gpm, it takes 100 hr to increase the power from $5x10^{-8}$% to a $5x10^{-7}$%, and 10 hr to increase it from $5x10^{-7}$% to $5x10^{-6}$%.

The reactor is subcritical and the neutron level is given by:

$$\text{Neutron level} = S \cdot M, \qquad \text{(EQ. 7.5-1)}$$

where:

S = the source strength

M = the multiplication, which is given by:

$$M = 1/(1-k) \qquad \text{(EQ. 7.5-2)}$$

For k = 0.9, M is 10; for k = 0.99, M is 100 and so forth. For criticality, the denominator approaches 0, as (k) approaches 1.0. Thus, the above equation was used to calculate relative neutron flux levels for a subcritical reactor until the reactor was near critical; then the critical equation of power with excess reactivity was used. Reactor power is directly proportional to neutron level.

The increase in reactivity toward criticality can be turned around by actuating the SLCS. A second actuation of the SLCS would cause a decrease in reactivity because of the high concentration of boron in the injected SLCS fluid relative to that in the leaking fluid (nominally 400 ppm). The sensitivity of the detector must allow adequate time for the operator to act. For a scaling evaluation, 10 minutes was considered sufficient time for operator action for accident prevention and mitigation.

Table 7.5-4 shows that the detector sensitivity (i.e., lower range) requirement is a function of leak rate and therefore of reactivity addition rate. On the basis of a 20 gpm leak rate, Table 7.5-4 shows that a detector that is one scale (i.e., about 10^{-5}) within 3 decades of the shutdown power (10^{-8}) would allow 0.18 hr (10.8 minutes) for operator action before reactor power increased another decade. A total of 0.36 hr (21.6 minutes) would be available for operator action from the time the indicator comes on scale to the time reactor power reaches 0.5% of full power. An alarm would be provided to warn the operator when the neutron flux reaches some plant specific setpoint.

The 20 gpm leak rate, which was assumed to continue for 27.75 hr, was used to define the sensitivity of the detector. It should be noted that the assumed leak rate, extended over the 27.75 hr period, would result in a loss of inventory so large that it could not in reality go undetected by the operator. Moreover, reactivity addition caused by this gradual boron depletion is unlikely because boron concentration is sampled and measured periodically. Again, the improbable 20 gpm leak rate was used only to obtain a mechanistic and conservative approach for selection of instrument sensitivity.

An absolute criterion for the lower range must include consideration of the neutron source level. The use of the neutron level 100 days after shutdown is conservative. There is high probability that conditions would be stable and controllable 2 days after the emergency shutdown, for the core decay heat is at a low level and the boron monitoring system should be functioning by that time. The actual neutron level will vary with fuel design, fuel history, and shutdown control strength. Measurements of shutdown neutron flux (with all rods inserted) at two BWR reactors show readings of 30-80 counts/sec (1000 counts/sec corresponds to 10^{-8} of full power). Measurements on other BWR reactors and for different fuel histories would show some variation, but those variations would be small compared with a criterion that is concerned with units of decades.

Neutron flux is the key variable for measuring reactivity control. The degree to which this variable is important to safety is another consideration. The large number of detectors (i.e., SRMs and IRMs) that are driven into the core soon after shutdown makes it highly probable that one or more of the existing NMS detectors will be inserted. On the other hand, there is little probability that there would be, simultaneously, a need for this measurement (in terms of operator action to be taken) and an accident environment in which the NMS would be rendered inoperable. Further, the operator can always actuate the SLCS on loss of instrumentation.

Conclusion

The existing NMS is adequate to meet the requirement of neutron flux measurement with some upgrading to improve system reliability. The upgrade of the existing system consists of powering the safety-related portion of the system from an UPS as described in Section 7.6.1.4.5. A rigorous Category 1 requirement is not justified relative to the criterion of "importance to safety." A Category 2 classification of this measurement fully meets the intent of Regulatory Guide 1.97 for neutron flux indication.

7.5.2.5.1.1.2.4.2 Variable B4 - Coolant Level in Reactor

7.5.2.5.1.1.2.4.2.1 Reactor Level Monitoring

LGS used overlapping ranges to monitor coolant level in the reactor as discussed in Section 7.5.1.4.2.1.1.

The reference leg of the wide range water level transmitter is 5 feet lower than the Regulatory Guide 1.97 required tap, i.e., centerline of the main steam lines. It was necessary to use this range to eliminate long runs of exposed sensing line tubing that contribute to erratic indication. The variable leg of the fuel zone water level is below the bottom of the core support plate. These two level monitors cover the range specified by Regulatory 1.97 except as mentioned above.

7.5.2.5.1.1.2.4.2.2 Trend Recording

Issue Definition

The purpose of addressing this issue is to determine which variables set forth in Regulatory Guide 1.97 need trend recording.

Discussion

Regulatory Guide 1.97, paragraph 1.3.2(f), states the general requirements for trend recording as follows: "Where direct and immediate trend or transient information is essential for operator information or action, the recording should be continuously available from dedicated recorders." Using the BWROG EPGs as a basis, the only trended variables required for operator action are reactor water level and reactor vessel pressure.

Conclusions

For LGS, only reactor water level (variable B4) and reactor vessel pressure (variable B6) require trend recording.

7.5.2.5.1.1.2.4.3 Variables B8 and C6 - Drywell Sump Level (B8) and Drywell Drain Sumps Level (C6)

Issue Definition

Regulatory Guide 1.97 specifies Category 1 instrumentation to monitor drywell sump level (variable B8) and drywell drain sumps level (variable C6). These designations refer to the drywell equipment drain tank and floor drain tank levels. Category 1 instrumentation indicates that the variable being monitored is a key variable. In Regulatory Guide 1.97, a key variable is defined as "... that single variable (or minimum number of variables) that most directly indicates the accomplishment of a safety function ..." The following discussion supports the BWROG alternative position that drywell sump level and drywell drain sumps levels should be qualified to Category 3 instrumentation requirements.

Discussion

The LGS drywell has two drain sumps. One drain is the equipment drain sump, which collects identified leakage; the other is the floor drain sump, which collects unidentified leakage.

Although the level of the drain sumps can be a direct indication of breach of the RCS pressure boundary, the indication is not unambiguous because there can be water in those sumps during normal operation. Other instrumentation specified in Regulatory Guide 1.97 that would also indicate leakage in the drywell are identified below:

a. Drywell pressure - variable B7, Category 1

b. Drywell temperature - variable D7, Category 2

c. Primary containment area radiation - variable C5, Category 1.

The drywell sump levels signal neither automatically initiates safety-related systems nor alerts the operator to take safety-related actions. Both sumps have level detectors that provide only the following nonsafety indications:

a. Continuous volume indication

b. High level alarm

c. Low level alarm

d. Average sump leak rate

e. Sump leak rate increase alarm

Regulatory Guide 1.97 specifies instrumentation to function during and after an accident. The drywell sump systems are deliberately isolated at the primary containment penetration on receipt of an accident signal to establish containment integrity. This fact renders the drywell sump level signal irrelevant.

Therefore, by design drywell level instrumentation serves no useful accident monitoring function.

The EOPs use the RPV level and the drywell pressure as entry conditions for the RPV Control Procedure. A small line break will cause the drywell pressure to increase before a noticeable increase in the sump level. Therefore, the drywell sumps will provide a "lagging" versus "early" indication of a leak.

Conclusions

Based on the above, LGS believes that Category 3, "high quality off-the-shelf instrumentation" is appropriate for drywell sump level and drywell drain sumps level instrumentation.

7.5.2.5.1.1.2.4.4 Variable C1 - Radioactivity Concentration or Radiation Level in Circulating Primary Coolant

Issue Definition

Regulatory Guide 1.97 specifies that the status of the fuel cladding be monitored. The specified variable is C1 (radioactivity concentration or radiation level in circulating primary coolant). The range is given as "½ technical specification limit to 100 times technical specification limit (R/hr)". Instrumentation for measuring variable C1 is designated as Category 1. The purpose for monitoring this variable is given as "detection of breach", referring, in this case, to breach of fuel cladding.

Discussion

The critical actions that must be taken to prevent and mitigate a gross breach of fuel cladding in a BWR are (1) shut down the reactor and (2) maintain water level. Monitoring variable C1, as directed in Regulatory Guide 1.97, will have no influence on either of these actions. Any usefulness from this monitored variable falls into the category of "information that the barriers to release of radioactive material are being challenged" and "identification of degraded conditions

and their magnitude, so the operator can take actions that are available to mitigate the consequences." There are no additional operator actions to mitigate the consequences of fuel barriers being challenged, other than those based on Type A and B variables.

Although the subject of concern in the Regulatory Guide 1.97 requirement is assumed to be an isolated NSSS, LGS has given consideration to events that do not isolate the NSSS. The PASS provides a means of obtaining samples of reactor coolant and primary containment atmosphere. Analyses of these samples provide information on the status of fuel cladding integrity when the plant is isolated. Radiation monitors in the SJAE and main steam lines provide information on the status of fuel cladding when the plant is not isolated.

Conclusion

Instrumentation for measuring variable C1 is implemented as Category 3 because no planned operator actions are identified and no operator actions are anticipated based on this variable serving as the key variable.

7.5.2.5.1.1.2.4.5 Variable C14 - Radiation Exposure Rate

Issue Definition

Variable C14 is defined in table 1 of Regulatory Guide 1.97 as follows: "Radiation exposure rate (inside buildings or areas which are in direct contact with primary containment where penetrations and hatches are located)." The reason for monitoring variable C14 is given as "Indication of breach".

Discussion

The use of local radiation exposure rate monitors to detect breach or leakage through primary containment penetrations is impractical. In general, radiation exposure rate in the secondary containment will be largely a function of radioactivity in primary containment and in the fluids flowing in ECCS piping, which will cause direct radiation shine on the areas of concern where radioactive fluids are piped. Because of the amount of piping and the number of electrical penetrations and hatches and their widely scattered locations, local radiation exposure rate monitors could give ambiguous indications. Breach of containment is more appropriately assessed by using the noble gas effluent monitor provided to monitor variable E4 (Section 7.5.2.1.1.2.4.10).

Conclusion

LGS is not implementing this parameter. Other means of breach detection that are better suited to this function (as described above), are available. Radiation exposure rate monitors as described in Section 12.3.4.1 are provided in these buildings for indication of habitability only.

7.5.2.5.1.1.2.4.6 Variables D3 and D8 - Suppression Spray Flow (D3) and Drywell Spray Flow (D8)

Issue Definition

Regulatory Guide 1.97 specifies flow measurements of suppression chamber spray (variable D3) and drywell spray (variable D8) for monitoring the operation of the primary containment related systems. Instrumentation for measuring these variables is designated Category 2, with a range of 0% to 110% of design flow. These flows relate to spray flow for controlling pressure and temperature of the drywell and suppression chamber.

Discussion

The drywell sprays can be used to control the pressure and temperature of the drywell. The RHR system flow element is used for measuring drywell flow.

The pressure-suppression chamber sprays can be used to control the pressure and temperature in the suppression chamber. From the control room, the operator controls pressure and temperature by adjusting suppression chamber spray flow. The RHR system flow element is used for flow indication. The suppression chamber spray operates in parallel with the drywell spray and is regulated with a throttling valve. The flow is determined by RHR flow indication. The effectiveness of spray flow can be verified by pressure and temperature changes of the drywell and the suppression chamber as indicated in the control room.

Conclusions

The current plant equipment, in conjunction with operating practice, meets performance requirements of accuracy and reliability for measurement of spray flows into the drywell and suppression chamber.

7.5.2.5.1.1.2.4.7 Variables D13 through D17 - RCIC Flow (D13), HPCI Flow (D14), Core Spray System Flow (D15), LPCI System Flow (D16) and SLCS Flow (D17)

Issue Definition

Regulatory Guide 1.97 specifies flow measurements of the following systems: RCIC (variable D13), HPCI (variable D14), core spray (variable D15), LPCI (variable D16), and SLCS (variable D17). The purpose is for monitoring the operation of individual safety systems. Instrumentation for measuring these variables is designated as Category 2; the range is specified as 0% to 110% of design flow. These variables are related to flow into the RPV.

Discussion

The RCIC, HPCI, and CS systems each have one branch line (the test line) downstream of the flow-measuring element. The test line is provided with a MOV that is normally closed (two valves in series in the case of the HPCI). In addition, the valve in the test line closes automatically when the emergency system is actuated, thereby ensuring that indicated flow is not being diverted by the test line. Proper valve position can be verified by a direct indication of valve position.

Although the LPCI has several branch lines located downstream of each flow-measuring element, each of those lines is either normally closed or automatically aligned. On initiation of the LPCI, the valves in the system automatically line up for proper operation and prevent flow diversion by branch lines. Proper valve position can be verified by a direct indication of valve position.

For all of the above systems, there are valid primary indicators other than flow measurement to verify the performance of the emergency system; for example, vessel water level. With respect to SLCS, flow-measuring devices were not provided for this system. The pump discharge header pressure, which is indicated in the control room, will indicate SLCS pump operation. Besides the discharge header pressure observation, the operator can verify the proper functioning of the SLCS by monitoring the following:

a. Decrease in the level of the boric acid storage tank

b. Reactivity change in the reactor as measured by neutron flux and concentration of boron

c. Motor contactor indicating lights (or motor current); the use of these indications is believed to be a valid alternative to SLCS flow indication (some plants have indicators for open/close positions of check valves)

d. Squib valve continuity indicating lights

Conclusion

The flow measurement schemes for the RCIC, HPCI, CS, and LPCI are adequate in that they meet the requirements of Regulatory Guide 1.97. Monitoring the SLCS can be adequately done by measuring variables other than the flow.

7.5.2.5.1.1.2.4.8 Variable D18 - SLCS Storage Tank Level

Issue Definition

Regulatory Guide 1.97 lists SLCS storage tank level as a Type D variable with Category 2 design and qualification criteria.

Discussion

Regarding the instrumentation category requirement for variable D18, Regulatory Guide 1.97 indicates that it is a key variable in monitoring SLCS operation. Regulatory Guide 1.97 also states that, in general, key Type D variables be designed and qualified to Category 2 requirements.

In applying these requirements of the regulatory guide to this instrumentation, the following are noted:

a. The current design basis for the SLCS assumes a need for an alternative method of reactivity control without a concurrent LOCA or HELB. The environment in which the SLCS instrumentation must work is therefore a mild environment for qualification purposes.

b. The current design basis for the SLCS is recognized as considerably less than the importance to safety of the RPS and the engineered safeguards systems. Therefore, in accordance with the graded approach to quality assurance specified in Regulatory Guide 1.97, it is unnecessary to apply a full quality assurance program to this instrumentation.

Conclusion

SLCS storage tank level instrumentation will meet Category 3 design and qualification criteria as required by Regulatory Guide 1.97.

7.5.2.5.1.1.2.4.9 Variables D26 through D30 - Main Steam Bypass Valve Position (D26), Condenser Hotwell Level (D27), Condenser Pressure (D28), Circulating Water Pump Discharge Pressure (D29) and Reactor Recirculation Pump Flow (D30)

Issue Definition

Regulatory Guide 1.97 states that "The plant designer should select variables and information display channels required by his design to enable the control room personnel to ascertain the operating status of each individual safety system and other systems important to safety to that extent necessary to determine if each system is operating or can be placed in operation..." The purpose of this analysis was to determine whether certain other D-type variables should be added to table 1, Regulatory Guide 1.97.

Discussion

Regulatory Guide 1.97 addressed safety systems and systems important to safety to mitigate consequences of an accident. Another list of variables has been compiled for the BWR in NUREG/CR-2100. That report and a companion report, NUREG/CR-1440, address plant systems not important to safety, as well as systems that are important to safety. In particular, these reports consider the potential role of the turbine plant in mitigating certain accidents. These two reports were reviewed in determining whether the listed variables (D26 through D30) should be added to the Regulatory Guide 1.97 list.

The NUREG evaluations used a systematic approach to derive a variables list. The basic approach of the analysis was to focus on those accident conditions under which the operator is most likely to be confronted with "and/or" accident conditions that result in the most serious consequences if the operator should fail to accomplish his required tasks. This is a probabilistic event tree type of study, and the reports used the sequences of the Reactor Safety Study (WASH-1440), and similar studies. The events in each sequence that involved operator action were identified; also, events were added to the event tree to include additional operator actions that could mitigate the accident. The event tree defines a series of key plant states that could evolve as the accident progresses and as the operator attempts to respond. Thus the operator's informational needs are linked to these plant states.

NUREG/CR-2100 is a BWR evaluation undertaken to address appropriate operator actions, the information needed to take those actions, and the instrumentation necessary to provide the required information.

The sequences evaluated were:

a. Anticipated transient followed by loss of decay heat removal

b. Anticipated transients without scram

c. Anticipated transient together with failure of HPCI, RCIC, and low pressure ECCS

d. Large LOCA with failure of ECCS

e. Small LOCA with failure of ECCS

The Regulatory Guide 1.97 list is based on accidents that result in an isolated NSSS. The NUREG documents considered accidents that could be prevented or mitigated by using water inventory and the heat sink in the turbine plant.

Conclusion

Five of the 15 variables identified in the NUREG, but not in Regulatory Guide 1.97, are included as Type D, Category 3 additions to the Regulatory Guide 1.97 list. Four of these variables are in the turbine plant: the main steam bypass valve position, condenser hotwell level, condenser pressure, and circulating water pump discharge pressure. These variables provide a primary measure of the status of a heat sink or water inventory in the turbine plant. The turbine plant systems are not to be classed as "safety systems" or as systems important to safety. The reactor recirculation pump flow is also added to the Regulatory Guide 1.97 list.

7.5.2.5.1.1.2.4.10 Variable E2 - Reactor Building or Secondary Containment Radiation

Issue Definition

Regulatory Guide 1.97 specifies that reactor building or secondary containment area radiation (variable E2) should be monitored over the range of 10^{-1} R/h to 10^{4} R/h for Mark II containments. The classification for Mark II is Category 2.

Discussion

As discussed in the variable C14 analysis (Section 7.5.2.5.1.1.2.4.5), secondary containment area radiation is not an appropriate parameter to use to detect or assess primary containment leakage.

Conclusion

The specified reactor enclosure area radiation monitors are not required for the LGS secondary containment.

7.5.2.5.1.1.2.4.11 Variable E3 - Radiation Exposure Rate

Issue Definition

Regulatory Guide 1.97 specifies in table 1, variable E3, that radiation exposure rate (inside buildings or areas where access is required to service equipment important to safety) be monitored

over the range of 10^{-1} R/hr to 10^{4} R/hr for detection of significant releases, for release assessment, and for long-term surveillance.

Discussion

In general, access is not required to any area of the secondary containment to service equipment important to safety in a postaccident situation. If and when accessibility is re-established in the long-term, it will be done by a combination of portable radiation survey instruments and postaccident sampling of the secondary containment atmosphere. Lower range area radiation monitors (typically 3 decades lower than the Regulatory Guide 1.97 range) are provided for use only in those instances in which radiation levels are very mild.

There are areas outside secondary containment where access is needed postaccident for specific sampling, monitoring or analysis tasks. Dose rates greater than 10 R/hr are not expected in these areas. In the event that these areas experience dose rates greater than 10 R/hr, access could result in excessive operator exposure.

Conclusion

The LGS design does not require access to a harsh environment area to service safety-related equipment during an accident; portable radiation monitors will be provided to re-establish accessibility. Lower range area monitors are implemented as Category 3 for areas outside secondary containment where postaccident access is needed.

7.5.2.5.1.1.2.4.12 Variable E8 - Plant and Environs Radiation

Issue Definition

Regulatory Guide 1.97 specifies that plant and environs radiation (variable E8) should be monitored over the range of 10^{-3} R/hr to 10^{4} R/hr, photons and 10^{-3} Rad/hr to 10^{4} Rad/hr, beta radiations and low energy photons. The classification is Category 3.

Discussion

The plant inventory of portable radiation survey instrumentation described in Section 12.5.2.2.3 will be supplemented with additional equipment to enhance postaccident monitoring capabilities. This additional equipment will be comprised of low range, medium range, and high range portable ion chambers (1 mR/hr to 20,000 R/hr gamma and 20,000 Rad/hr beta), open window alpha scintillation probes, pancake GM probes, energy compensated beta/gamma GM probes (for low energy photons), and portable beta/gamma geiger counters. Audio speakers, alarming count rate meters, and extension arms will be provided for attachments to the survey instruments. Airborne radioactivity levels will be determined from laboratory analysis of particulate filters and iodine cartridge samples obtained with high and low volume samplers. Portable instruments and equipment reserved for emergency use will be located at an assembly area remote from the main plant.

Conclusion

A range of monitoring of 10^{4} R/hr would not enhance plant and environs radiation monitoring. LGS meets the intention and the purpose of the regulatory guide criteria.

7.5.2.5.1.1.2.4.13 Variable E13 - Primary Coolant and Sump

Issue Definition

Regulatory Guide 1.97 requires installation of the capability for obtaining grab samples (variable E13) of the containment sump, ECCS pump-room sumps, and other similar auxiliary building sumps for the purpose of release assessment, verification, and analysis.

Discussion

The need for sampling a particular sump must take into account its location and the sump design. For all accidents in which radioactive material would be in the primary containment sump, it will be isolated and will overflow to the suppression pool. A suppression pool sample can be obtained through the PASS as described in Section 11.5.5 and this can therefore be used as a valid alternative to a containment sump sample.

The analysis of ECCS pump-room sumps and other similar auxiliary building sump liquid samples can be used for release assessment, as suggested in Regulatory Guide 1.97 only if potentially radioactive water can be pumped out of a controlled area to an area such as radwaste. If the design does not allow sump pump-out on a high radiation signal, a sump sample does not contribute to release assessment. The use of the subject sump samples for verification and analysis is of little value; a sample of the suppression pool and reactor water, as required by other portions of Regulatory Guide 1.97, provides a better measurement for these purposes.

Conclusion

A suppression pool sample will be used as an alternative to a primary containment sump sample. The analysis of ECCS pump-room sumps and other similar auxiliary building sumps is a consideration only if the water is pumped out of the reactor enclosure (e.g., pumped to radwaste). LGS design does not allow sump pump-out on receipt of high radiation signal. The capability for sampling and analysis of ECCS pump-room and auxiliary building sumps is therefore not provided.

7.5.2.5.1.1.2.4.14 Variables C5 and E1 - Primary Containment Post-LOCA Radiation Monitoring System

Issue Definition

Regulatory Guide 1.97 requires that containment radiation after an event be measured to within a factor of two.

Discussion

The primary containment post-LOCA radiation monitoring system installed at Limerick Generating Station meets this requirement except under extreme conditions of high drywell temperature and low radiation levels.

The licensee was notified by the system vendor in February 1987 that under high drywell temperature conditions, Insulation Resistance (IR) leakage current may cause a system error.

Because the instrument signal at low radiation levels is very weak, high temperature IR leakage current significantly affects the accuracy of the indicated readings up to a maximum of 112.5 Rad/hr at the maximum design drywell temperature of 340°F. As a result, the indicated readings below 112.5 Rad/hr may not be within the factor of two accuracy recommendation of Regulatory Guide 1.97 Rev.2. The induced error decreases exponentially with drywell temperature and becomes insignificant below 230°F. This induced error is significant only under low radiation conditions coincident with high drywell temperatures, whereas the system will operate to perform its principal function under normal and varying temperature conditions during and following an accident.

Conclusion

Since this failure is apparent only under low radiation conditions coincident with high drywell temperature, whereas the principal function of the system is to monitor high radiation postaccident conditions, continued operation without replacing the cable is justified. As drywell temperature is reduced with time, the error will also be reduced.

7.5.2.5.1.2 Conformance to 10CFR50, Appendix B

The SRDIs, except the displays, are of the same type, and are subject to the same qualification testing, quality control, and documentation, in accordance with the recommendation of 10CFR50, Appendix B as the safety systems' instrumentation. The displays are of a high quality consistent with the rest of the SRDIs, and are proven through industrial usage. The displays' qualification testing, quality assurance program, and documentation are provided and maintained by the vendor. For further information, refer to Chapter 17.

7.5.2.5.1.3 Conformance to Industry Codes and Standards

7.5.2.5.1.3.1 IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

A discussion of the degree of conformance to IEEE 279 (1971) is not appropriate for application to SRDI. Most Regulatory Guide 1.97 Category 1 instrumentation meets the requirements of IEEE 279 (1971). Refer to the individual safety system discussion to find the degree of system conformance, for each parameter with a safety-related display instrumentation output.

7.5.2.5.1.3.2 IEEE 323 (1974) - IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations

Safety-related display instrumentation equipment, where required (Table 7.5-2), meets the requirement of IEEE 323 (1974). Refer to Section 3.11 for a discussion of the degree of conformance of the environment qualified for the SRDI equipment.

7.5.2.5.1.3.3 IEEE 344 (1975) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

SRDI equipment, where required (Table 7.5-2), meets the requirements of IEEE 344 (1975). Refer to Section 3.10 for a discussion of the degree of conformance for the seismic capacity of the qualified SRDI equipment.

Table 7.5-1

SAFETY-RELATED DISPLAY INSTRUMENTATION

PARAMETER MEASURED	INSTRUMENT NO.	NUMBER OF CHANNNELS[5]	RANGE	ACCURACY
Reactor vessel pressure	XR42-1R623A/B	2	0-1500 psig	0.5% FS[1]
Reactor vessel water level	XR42-1R623A/B LR42-1R615 LI42-1R610	2 1 1	-150" to +60"[3] -350" to -100"H_2O[4] -350" to -100"H_2O[4]	0.5% FS
HPCI flow	FI55-1R600-1	1	0-6000 gpm	±2% FS
HPCI discharge pressure	PI55-1R601	1	0-1500 psig	±2% FS
HPCI turbine steam pressure	PI55-1R602	1	0-1500 psig	±2% FS
CS flow	FI52-1R601A/B	2	0-8,800 gpm	±2% FS
RHR flow (LPCI and shutdown cooling)	FI51-1R603A/B/C/D	4	0-12,000 gpm	±2% FS
Containment radiation	RR26-191A/B	2	1-10^8rad/hr	±0.5% FS
Suppression pool temperature	TRS-041-101 TRS-041-103	1 1	30°F - 230°F 30°F - 230°F	±0.3% FS ±0.3% FS

Table 7.5-1 (Cont'd)

PARAMETER MEASURED	INSTRUMENT NO.	NUMBER OF CHANNNELS[5]	RANGE	ACCURACY
Containment pressure	PR57-101	1	-5 to +165 psig	±0.5% FS
	PI42-170-1	1	0-150 psig	±2% FS
	PI42-170-2	1	0-150 psig	±2% FS
	PI42-101	1	-5 to +165 psig	±2% FS
	PI57-121	1	-5 to +5 psig	±2% FS
Containment spray flow (RHR)	FI51-1R603A/B/C/D	4	0-12,000 gpm	±2% FS
Suppression chamber pressure	PR57-101	1	-5 to +165 psig	±0.5 FS
Suppression pool level	LR55-115	1	20-26 ft H_2O	±2% FS
	LI52-140A/B	2	0-50 ft H_2O	±2% FS
	LI55-115-1(Unit 1 only)	1	20-26 ft H_2O	±2% FS
	LI55-115-2	1	20-26 ft H_2O	±2% FS
	LI55-217(Unit 2 only)	1	20-26 ft	±2% FS
	LI55-141 (Unit 1 only)	1	20-30 ft H_2O	±1.5% FS
ESW pump discharge flow	FDI11-012A/B	2	-1000-0-1000 gpm	±2% FS
	FI11-013A/B	2	0-6,000 gpm	±2% FS
RHRSW HX inlet flow	FI51-1R602A/B	2	0-12,000 gpm	±2% FS
SGTS filter heater inlet temperature	TI76-001A/B	2	50°F-200°F	±2%
SGTS filter inlet temperature	TI76-003A/B	2	50°F-200°F	±2%
SGTS filter charcoal temperature	TI76-010A/B	2	200°F-680°F	±2%
Refueling floor/ outside $_{\Delta}P$	PDI76-099A/B	2	-.35 to +.05 in wg	±2%
Reactor enclosure/ outside $_{\Delta}P$	PDI76-198A/B	2	-.35 to + .05 in wg	±2%
Recirculation filter inlet temperature	TI76-182A/B	2	50°F-150°F	±2%

Table 7.5-1 (Cont'd)

PARAMETER MEASURED	INSTRUMENT NO.	NUMBER OF CHANNNELS[5]	RANGE	ACCURACY
Recirculation filter charcoal temperature	TI76-190A/B	2	200°F-680°F	±2%
SGTS flow	FI76-042	1	0-4000 cfm	±2%
Control room pressure differential	PDI78-054	1	+0.4 to -0.1 in wg	±2%
Emergency recirculation flow	FI78-015	1	0-3500 cfm	±2%
Emergency fresh air carbon filter temperature	TI78-008A/B	2	200°F-680°F	±2%
Control room return air duct temperature	TI78-024A/B	2	50°F-150°F	±2%
Control enclosure chilled water flow	FI90-034A/B	2	0-800 gpm	±2%
Chilled water supply temperature	TI90-025A/B	2	30°F-80°F	±2%
Chilled water return temperature	TI90-024A/B	2	30°F-80°F	±2%
Control room airborne activity	RIX26-007A/B/C/D (outside air intake)	4	10^{-6} to 10^{-1} Ci/cc	±25%
	RIX26-068C/D (emergency fresh air filter discharge)	2	10^{-6} to 10^{-1} Ci/cc	±25%

[1] FS = Full Scale
[2] Per steam line
[3] Instrument zero equal to 527.5 in above vessel zero
[4] Top active fuel indicated in red
[5] Electrical divisions
[6] The value listed in the column is the manufacturers stated accuracies for the device. These values are “FOR INFORMATION ONLY” the actual calibration requirements for the instrumentation systems are contained within the IISCP Program.

Table 7.5-2

DESIGN AND QUALIFICATION REQUIREMENTS FOR POSTACCIDENT MONITORING INSTRUMENTATION

REGULATORY GUIDE 1.97 CATEGORY/REQUIREMENT	1	2	3
Seismic Qualification (Regulatory Guide 1.100 (Rev 1)	Yes(1)	Yes(2)	No
Single Failure Criterion	Yes	No	No
Environmental Qualification (Regulatory Guide 1.89 (1974) & NUREG-0588 (Rev 1)	Yes(1)	Yes(1)	No
Power Supply	Class 1E	Class 1E or UPS	Instrument ac
Out-of-Service Interval	Continuous(7)	System Technical Specification	None(3)
Display Type	Continuous or On Demand	Continuous or On Demand	On Demand
Display Method	Indication(4)	Indication(5)(6)	Indication(5)(6)

(1) Where the signal is to be displayed by a non-Class 1E computer-based system, qualification includes the sensor and the computer input isolation device.

(2) Seismic qualification is needed, provided that the instrumentation is part of a safety-related system. Where the signal is to be displayed by a non-Class 1E computer-based system, seismic qualification includes the sensor and the computer input isolation device.

(3) Not necessary to include in the safety and environmental technical specifications unless specified by other requirements.

(4) Where direct and immediate trend or transient information is essential for operator information or action, recording is provided on dedicated recorders. Otherwise, it is available on demand.

(5) Dial, digital, CRT, or strip-chart recorder indication.

(6) Recording required for effluent radioactivity monitors, area radiation monitors, and meteorology monitors. Where direct and immediate trend or transient information is essential for operator information or action, the recording is provided on dedicated recorders. Otherwise, it is available on demand.

(7) Continuous service is achieved through redundant instrument channels.

Table 7.5-3

POSTACCIDENT MONITORING INSTRUMENTATION

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
Neutron flux	B1	2	Recorder (SRM)	2	0 - 125% rated power (SRM)	XR X-M1-1R602A,B (Non-Div)	Control room
			Recorder (IRM/APRM)	4	0 - 125% rated power (IRM)	XR X-M1-1R603A,B,C, D (Non-Div)	
					0 - 125% rated power (IRM/APRM)		
Control rod position	B2	3	Indicating lights	1 per control rod	Full-in or not full-in	ZS-047-205-AE-RL (Non-Div)	Control room
Reactor coolant level	A3 B4	1	Recorder	2	-150 to +60 inches (2)	XR42-1R623A (Div I)	Control room
						XR42-1R623A (Div II)	Control room
			Recorder	1	-350 to –100 inches H_2O(3)	LR42-1R615 (Div II)	Control room
			Indicator	1	-350 to –100 inches H_2O(3)	LI42-1R610 (Div II)	Control room
Reactor coolant pressure	A2 B6 C4, 9	1	Recorder	2	0 to 1500 psig	XR42-1R623A (Div I)	Control room
						XR42-1R623B (DIV II)	Control room
Reactor recirculation D30 pump flow	D30	3	Recorder	1	0 – 55,000 gpm/loop	FR43-1R614 (Non-Div) 2-Pens 1/Loop	Control room
RCS soluble boron concentration	B3	3	Grab sample			N/A	(6)

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
Primary containment and drywell pressure	A6 B7, 9	1	Recorder	1	-5 to +165 psig	PR57-101 (DIV I)	Control room
	C8, 10		Indicator	1	-5 to +165 psig	PI42-101 (DIV II)	Control room
	D4	2	Indicator	1	-5 psig to +5 psig	PI57-121 (DIV II)	Control room
Suppression pool water level	A5 C7 D5	1	Indicator	2	0 – 50 ft H_2O	LI52-140A (DIV I) LI52-140B (DIV II)	Control room Control room
Suppression pool water temperature	A4 D6	1	Indicator	2	30°F to 230°F	TI41-101 (DIV I) TI41-103 (DIV II)	Control room Control room
Drywell sump level	B8 C6	3	CRT	NA		ERFDS CRT (Non-Div)	Control room
1. Floor drain sump tank 2. Equipment drain tank					0-391.1 gal 0-402.7 gal		
Containment and drywell H_2 Concentration	A1 C11	3	Indicator	2	0% - 10% H_2	1A-S711 (DIV IV) 1A-S712 (DIV III)	Control room Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
Containment and drywell O_2 concentration	A1 C12	2	Indicator	2	0 – 25% O_2	1A-S711 (DIV IV) 1A-S712 (DIV III)	Control room Control room
Containment Isolation Valve position	B10	1					
HV13-106			Indicating lights	1 pair per valve	open/closed	HS13-106 (DIV III)	Control room
HV13-107			Indicating lights	1 pair per valve	open/closed	HS13-107 (DIV III)	Control room
HV13-108, 111			Indicating lights	1 pair per valve	open/closed	HS13-108 (DIV IV)	Control room
SV26-190A, C			Indicating lights	2 pair per valve	open/closed	HS26-190A (DIV III)	Control room
SV26-190B, D			Indicating lights	2 pair per valve	open/closed	HS26-190B (DIV II)	Control room
HV41-1F022A, B, C, D			Indicating lights	1 pair per valve	open/closed	HS41-122A, B, C, D (DIV I)	Control room
HV41-1F028A, B, C, D			Indicating lights	1 pair per valve	open/closed	HS41-128A, B, C, D (DIV I)	Control room
HV41-1F016			Indicating lights Indicating lights	1 pair per valve 1 pair per valve	open/closed open/closed	HS41-116 (DIV I) HS41-119 (DIV I)	Control room Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV41-109A, B			Indicating lights	I pair per valve	open/closed	HV41-109A, B (DIV I)	Control room
HV41-133A			Indicating lights	I pair per valve	open/closed	HV41-133A (DIV I)	Control room
HV41-133B			Indicating lights	I pair per valve	open/closed	HV41-133B (DIV II)	Control room
HV41-1F084			Indicating lights	I pair per valve	open/closed	HS41-186 (DIV I)	Control room
HV41-1F085			Indicating lights	I pair per valve	open/closed	HS41-187 (DIV II)	Control room
HV41-130A			Indicating lights	I pair per valve	open/closed	HS41-130A (DIV II)	Control room
HV41-130B			Indicating lights	I pair per valve	open/closed	HS41-130B (DIV I)	Control room
HV42-147A			Indicating lights	I pair per valve	open/closed	HS42-147A (DIV I)	Control room
HV42-147B			Indicating lights	I pair per valve	open/closed	HS42-147B (DIV II)	Control room
HV42-147C			Indicating lights	I pair per valve	open/closed	HS42-147C (DIV III)	Control room
HV42-147D			Indicating lights	I pair per valve	open/closed	HS42-147D (DIV IV)	Control room
HV43-1F019			Indicating lights	I pair per valve	open/closed	HS43-120 (DIV I)	Control room
HV43-1F020			Indicating lights	I pair per valve	open/closed	HS43-120 (DIV II)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV44-IF001			Indicating lights	I pair per valve	open/closed	HS44-101 (DIV I)	Control room
HV44-1F004			Indicating lights	I pair per valve	open/closed	HS-104 (DIV II)	Control room
HV48-1F006A			Indicating lights	I pair per valve	open/closed	HS48-103A (DIV I)	Control room
HV48-1F006B			Indicating lights	I pair per valve	open/closed	HS48-103B (DIV II)	Control room
HV49-1F013			Indicating lights	I pair per valve	open/closed	HS49-113-1 (DIV I)	Control room
HV49-1F007			Indicating lights	I pair per valve	open/closed	HS49-107-1 (DIV III)	Control room
HV49-1F008			Indicating lights	I pair per valve	open/closed	HS49-108-1 (DIV I)	Control room
HV49-1F076			Indicating lights	I pair per valve	open/closed	HS49-176-1 (DIV I)	Control room
HV49-1F031			Indicating lights	I pair per valve	open/closed	HS49-131-1 (DIV I)	Control room
HV49-1F060			Indicating lights	I pair per valve	open/closed	HS49-118-1 (DIV I)	Control room
HV49-1F019			Indicating lights	I pair per valve	open/closed	HS49-119-1 (DIV I)	Control room
HV49-1F002			Indicating lights	I pair per valve	open/closed	HS49-117-1 (DIV I)	Control room
HV49-1F084			Indicating lights	I pair per valve	open/closed	HS49-184-1 (DIV III)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV49-1F080			Indicating lights	I pair per valve	open/closed	HS49-180-1 (DIV I)	Control room
HV51-1F009			Indicating lights	I pair per valve	open/closed	HS51-109-1 (DIV I)	Control room
HV51-1F008			Indicating lights	I pair per valve	open/closed	HS51-108-1 (DIV II)	Control room
HV51-151A, B			Indicating lights	I pair per valve	open/closed	HS51-150A & B (DIV I)	Control room
HV51-1F015A			Indicating lights	I pair per valve	open/closed	HS51-115-1 (DIV II)	Control room
HV51-1F015B			Indicating lights	I pair per valve	open/closed	HS51-115B (DIV II)	Control room
HV51-1F021A			Indicating lights	I pair per valve	open/closed	HS51-121A (DIV I)	Control room
HV51-1F021B			Indicating lights	I pair per valve	open/closed	HS51-121B (DIV II)	Control room
HV51-1F016A			Indicating lights	I pair per valve	open/closed	HS51-116A-1 (DIV I)	Control room
HV51-1F016B			Indicating lights	I pair per valve	open/closed	HS51-116B (DIV II)	Control room
HV51-142A			Indicating lights	I pair per valve	open/closed	HS51-141A (DIV I)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV51-142B			Indicating lights	I pair per valve	open/closed	HS51-141B (DIV II)	Control room
HV51-142C			Indicating lights	I pair per valve	open/closed	HS51-141C (DIV III)	Control room
HV51-142D			Indicating lights	I pair per valve	open/closed	HS51-141D (DIV IV)	Control room
HV51-1F017A			Indicating lights	I pair per valve	open/closed	HS51-117A-1 (DIV I)	Control room
HV51-1F017B			Indicating lights	I pair per valve	open/closed	HS51-117B (DIV II)	Control room
HV51-1F017C			Indicating lights	I pair per valve	open/closed	HS51-117C (DIV III)	Control room
HV51-1F017D			Indicating lights	I pair per valve	open/closed	HS51-117D (DIV IV)	Control room
HV51-1F004A			Indicating lights	I pair per valve	open/closed	HS51-104A-1 (DIV I)	Control room
HV51-1F004B			Indicating lights	I pair per valve	open/closed	HS51-104B (DIV II)	Control room
HV51-1F004C			Indicating lights	I pair per valve	open/closed	HS51-104C (DIV III)	Control room
HV51-1F004D			Indicating lights	I pair per valve	open/closed	HS51-104D (DIV IV)	Control room
HV51-125A			Indicating lights	I pair per valve	open/closed	HS51-125A-1 (DIV I)	Control room
HV51-125B			Indicating lights	I pair per valve	open/closed	HS51-125B (DIV II)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV51-1F027A			Indicating lights	I pair per valve	open/closed	HS51-127A-1 (DIV I)	Control room
HV51-1F027B			Indicating lights	I pair per valve	open/closed	HS51-127B (DIV II)	Control room
HV51-105A			Indicating lights	I pair per valve	open/closed	HS51-105A (DIV III)	Control room
HV51-105B			Indicating lights	I pair per valve	open/closed	HS51-105B (DIV IV)	Control room
HV-C-51-2F103A (Unit 2 only)			Indicating lights	I pair per valve	open/closed	HS51-213A (DIV I)	Control room
HV-C-51-2F104B (Unit 2 only)			Indicating lights	I pair per valve	open/closed	HS51-234A (DIV II)	Control room
HV52-1F039A			Indicating lights	I pair per valve	open/closed	HS52-106A (DIV I)	Control room
HV52-1F039B			Indicating lights	I pair per valve	open/closed	HS52-106B (DIV II)	Control room
HV52-1F005			Indicating lights	I pair per valve	open/closed	HS52-105 (DIV I)	Control room
HV52-1F001A			Indicating lights	I pair per valve	open/closed	HS52-101A (DIV I)	Control room
HV52-1F001B			Indicating lights	I pair per valve	open/closed	HS52-101B (DIV II)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV52-1F001C			Indicating lights	I pair per valve	open/closed	HS52-101C (DIV III)	Control room
HV52-1F001D			Indicating lights	I pair per valve	open/closed	HS52-101D (DIV IV)	Control room
HV52-1F015A			Indicating lights	I pair per valve	open/closed	HS52-115A (DIV I)	Control room
HV52-1F015B			Indicating lights	I pair per valve	open/closed	HS52-115B (DIV II)	Control room
HV52-1F031A			Indicating lights	I pair per valve	open/closed	HS52-131A (DIV I)	Control room
HV52-1F031B			Indicating lights	I pair per valve	open/closed	HS52-131B (DIV II)	Control room
HV52-127			Indicating lights	I pair per valve	open/closed	HS52-127 (DIV I)	Control room
HV52-128			Indicating lights	I pair per valve	open/closed	HS52-128 (DIV II)	Control room
HV52-139, HV55-120,121			Indicating lights	I pair per valve	open/closed	HS55-120 (DIV II)	Control room
HV55-1F002			Indicating lights	I pair per valve	open/closed	HS55-102 (DIV IV)	Control room Panel 10C647
HV55-1F003			Indicating lights	I pair per valve	open/closed	HS55-103 (DIV II)	Control room Panel 10C647
HV55-1F100			Indicating lights	I pair per valve	open/closed	HS55-148 (DIV II)	Control room Panel 10C647
HV55-1F042			Indicating lights	I pair per valve	open/closed	HS55-142 (DIV II)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV55-1F072			Indicating lights	I pair per valve	open/closed	HS55-172 (DIV II)	Control room
HV55-1F071			Indicating lights	I pair per valve	open/closed	HS55-171 (DIV II)	Control room
HV55-1F095			Indicating lights	I pair per valve	open/closed	HS55-195 (DIV IV)	Control room
HV55-1F093			Indicating lights	I pair per valve	open/closed	HS55-193 (DIV II)	Control room
HV55-1F012			Indicating lights	I pair per valve	open/closed	HS55-112 (DIV II)	Control room
HV55-1F105			Indicating lights	I pair per valve	open/closed	HS55-105 (DIV II)	Control room
SV52-139, SV57-101			Indicating lights	I pair per valve	open/closed	HS57-101 (DIV I)	Control room
HV57-121			Indicating lights	I pair per valve	open/closed	HS57-121 (DIV I)	Control room
HS57-131			Indicating lights	I pair per valve	open/closed	HS57-131 (DIV I)	Control room
HV57-123			Indicating lights	I pair per valve	open/closed	HS57-123 (DIV I)	Control room
HV57-163			Indicating lights	I pair per valve	open/closed	HS57-163 (DIV IV)	Control room (7)
HV57-111			Indicating lights	I pair per valve	open/closed	HS57-111 (DIV II)	Control room
HV57-114			Indicating lights	I pair per valve	open/closed	HS57-114 (DIV II)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV57-161			Indicating lights	2 pair per valve	open/closed	HS57-161 (DIV III)	Control room
SV57-133			Indicating lights	I pair per valve	open/closed	HS55-133 (DIV I)	Control room
HV57-116			Indicating lights	I pair per valve	open/closed	HS57-116 (DIV IV)	Control room
SV57-141, 142, 143, 144, 145, 159			Indicating lights	I pair per valve	open/closed	HS57-153 (DIV IV)	Control room
SV57-132, 134, 150			Indicating lights	I pair per valve	open/closed	HS57-132 (DIV II)	Control room
SV57-184, 185, 186, 190, 195			Indicating lights	I pair per valve	open/closed	HS57-187 (DIV III)	Control room
SV57-183, 191			Indicating lights	I pair per valve	open/closed	HS57-183 (DIV I)	Control room
HV57-124			Indicating lights	I pair per valve	open/closed	HS57-124 (DIV I)	Control room
HV57-164			Indicating lights	2 pair per valve	open/closed	HS57-164 (DIV IV)	Control room (7)
HV57-162			Indicating lights	2 pair per valve	open/closed	HS57-162 (DIV III)	Control room (7)
HV57-105			Indicating lights	2 pair per valve	open/closed	HS57-105 (DIV II)	Control room
FV-D0-101A			Indicating lights	2 pair per valve	open/closed	HS-DO-101A (DIV III)	Control room
FV-DO-101B			Indicating lights	2 pair per valve	open/closed	HS-DO-101B (DIV IV)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV57-104			Indicating lights	I pair per valve	open/closed	HS57-104 (DIV II)	Control room
SV57-181			Indicating lights	I pair per valve	open/closed	HS57-181 (DIV II)	Control room
HV57-109			Indicating lights	I pair per valve	open/closed	HS57-109 (DIV II)	Control room
HV57-135			Indicating lights	I pair per valve	open/closed	HS57-135 (DIV II)	Control room
HV57-117			Indicating lights	I pair per valve	open/closed	HS57-117 (DIV I)	Control room
HV57-147			Indicating lights	I pair per valve	open/closed	HS57-147 (DIV II)	Control room
HV57-118			Indicating lights	I pair per valve	open/closed	HS57-118 (DIV I)	Control room
SV57-139			Indicating lights	I pair per valve	open/closed	HS57-139 (DIV I)	Control room
HV57-112			Indicating lights	I pair per valve	open/closed	HS57-112 (DIV I)	Control room
HV57-166			Indicating lights	2 pair per valve	open/closed	HS57-166 (DIV III)	Control room
HV57-169			Indicating lights	2 pair per valve	open/closed	HS57-169 (DIV IV)	Control room (7)

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV57-115			Indicating lights	1 pair per valve	open/closed	HS57-115 (DIV I)	Control room
HV59-129A			Indicating lights	1 pair per valve	open/closed	HS59-129A (DIV I)	Control room
HV59-129B			Indicating lights	I pair per valve	open/closed	HS59-129B (DIV II)	Control room
HV59-151A			Indicating lights	I pair per valve	open/closed	HS59-151A (DIV III)	Control room
HV59-151B			Indicating lights	I pair per valve	open/closed	HS59-151B (DIV IV)	Control room
HV59-131			Indicating lights	I pair per valve	open/closed	HS59-131 (DIV II)	Control room
HV59-101			Indicating lights	I pair per valve	open/closed	HS59-101 (DIV I)	Control room
HV59-102			Indicating lights	I pair per valve	open/closed	HS59-102 (DIV II)	Control room
XV59-141A, B, C, D, E			Indicating lights	I pair per valve	open/closed	Valve control monitor (10-C607)	Control room
HV59-135			Indicating lights	I pair per valve	open/closed	HS59-135 (DIV II)	Control room
HV61-102 (deleted on Unit 2) 112, 132			Indicating lights	I pair per valve	open/closed	HS61-112 (DIV I)	Control room
HV61-110			Indicating lights	2 pair per valve	open/closed	HS61-110 (DIV I)	Control room
HV61-130			Indicating lights	2 pair per valve	open/closed	HS61-130 (DIV IV)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV61-111			Indicating lights	2 pair per valve	open/closed	HS61-111 (DIV II)	Control room
HV61-131			Indicating lights	2 pair per valve	open/closed	HS61-131 (DIV II)	Control room
HV87-128, 129			Indicating lights	I pair per valve	open/closed	HS87-128 (DIV II)	Control room
HV87-122, 123			Indicating lights	I pair per valve	open/closed	HS87-122 (DIV II)	Control room
HV87-120A, 121A			Indicating lights	I pair per valve	open/closed	HSS87-121A (DIV I)	Control room
HV87-120B, 121B			Indicating lights	I pair per valve	open/closed	HSS87-121B (DIV I	Control room
Safety Relief Valves Position indication	D10	2					
PSV41-F013A			Indicating light	I per valve	open/closed	HS41-113A (Non-Div)	Control room
PSV41-F013B			Indicating light	I per valve	open/closed	HS41-113B (Non-Div)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
PSV41-F013C			Indicating light	I per valve	open/closed	HS41-113C (Non-Div)	Control room
PSV41-F013D			Indicating light	I per valve	open/closed	HS41-113D (Non-Div)	Control room
PSV41-F013E			Indicating light	I per valve	open/closed	HS41-113E (Non-Div)	Control room
PSV41-F013F			Indicating light	I per valve	open/closed	HS41-113F (Non-Div)	Control room
PSV41-F013G			Indicating light	I per valve	open/closed	HS41-113G (Non-Div)	Control room
PSV41-F013H			Indicating light	I per valve	open/closed	HS41-113H (Non-Div)	Control room
PSV41-F013J			Indicating light	I per valve	open/closed	HS41-113J (Non-Div)	Control room
PSV41-F013K			Indicating light	I per valve	open/closed	HS41-113K (Non-Div)	Control room
PSV41-F013L			Indicating light	I per valve	open/closed	HS41-113L (Non-Div)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
PSV41-F013M			Indicating light	I per valve	open/closed	HS41-113M (Non-Div)	Control room
PSV41-F013N			Indicating light	I per valve	open/closed	HS41-113N (Non-Div)	Control room
PSV41-F013S			Indicating light	I per valve	open/closed	HS41-113S (Non-Div)	Control room
Main steam bypass valve position	D26	3	HMI		0% - 100% open	XI-031-1(2)02 (Non-Div) XI-031-1(2)03 (Non-Div)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
Main feedwater flow	D1	3	Indicator	3 (1 per train)	0 – 7x10 ^{6} lbs/hr	FI06-1R604A (Non-Div)	Control room
						FI06-1R604B (Non-Div)	
						FI06-1R604C (Non-Div)	
			Recorder	1 (total flow)	0 – 18x10^{6} lbs/hr	FR41-1R607 (Non-Div)	Control room
CST Level	D2	3	Recorder	1	0-45 ft H_2O (Unit 1 only) 0-45 ft H_2O (Unit 2 only)	LR08-102 (Pen 1) (Non-Div) LR08-202 (Pen 1) (Non-Div)	Control room
Condenser Hotwell Level	D27	3	Recorder	1	36 – 56" H_2O	LR05-101 (Pens 1 & 2) (Non-Div)	Control room
Condenser Pressure	D28	3	Indicator	1 per shell	20-30" Hg Vac	PI05-101A (Non-Div)	Control room
						PI05-101B (Non-Div)	
						PI05-101C (Non-Div)	

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
Circulating Water Pump Discharge Pressure	D29	3	Indicator	1 per pump	0 – 100 psig	PI09-117A (Non-Div)	Control room
						PI09-117B (Non-Div)	
						PI09-117C (Non-Div)	
						PI09-117D (Non-Div)	
HPCI Flow	D14	2	Indicator	1	0 – 6000 gpm	FI55-1R600-1 (Div II)	Control room
ESW Flow	D22	2	Indicator	1 per train	0 – 6,000 gpm	FI11-013A (Div I)	Control room
						FI11-013B (Div II)	Control room
ESW Temperature	D22	2	Indicator	1 per train	0 – 200°F	TI11-007A (Div I)	Control room
						TI11-007B (Div II)	Control room
RHRSW System Flow	D22	2	Indicator	1 per train	0 – 12,000 gpm	FI51-1R602A (Div I)	Control room
						FI51-1R602B (Div II)	Control room
RHRSW System Temperature	D21	2	Indicator	1 per train	0 – 200°F	TI51-105A (Div I)	Control room
						TI51-105B (Div II)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
LPCI, RHR System Flow Drywell Spray Flow, Suppression Chamber Flow	D3, 8, 16, 19	2	Indicator	1 per train	0 – 12,000 gpm	FI51-1R603A (Div I)	Control room
						FI51-1R603B (Div II)	Control room
						FI51-1R603C (Div III)	Control room
						FI51-1R603D (Div IV)	Control room
RHR Heat Exchanger outlet temperature	D20	2	Indicator	1 per train	0°F-350°F	TI51-127A (Div I)	Control room
						TI51-127B (Div II)	Control room
RCIC Pump Discharge Flow	D13	2	Indicator	1	0 – 7 gpm	FI49-1R600-1 (Div 1)	Control room
Core Spray Flow	D15	2	Indicator	1 per train	0 – 8, 800 gpm	FI52-1R601A (Div I)	Control room
						FI52-1R601B (Div I)	Control room
Equipment Drain Collection Tank	D23	3	Indicator	1	0-10 ft H_2O	LI62-010 (Non-Div)	Radwaste Control room
Floor Drain Collection Tank	D23	3	Indicator	1	0-15 ft H_2O	LI63-010 (Non-Div)	Radwaste Control room
Chemical Waste Collection Tank	D23	3	Indicator	1	0-12 ft	LI64-001 (Non-Div)	Radwaste Control room
SLCS Storage Tank Level	D18	3	Indicator	1	0 – 5000 gal	LI48-1R601	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
Long Term N2 Supply to ADS System	D25	2	Indicator	2	0 – 150 psig	PI59-103A (Div III)	Control room
						PI59-103B (Div IV)	Control room
CRD Hydraulics Charging Water Pressure	D25	2(4)	Indicator	1	0 – 1600 psig	PIS46-1N600 (Non-Div)	Control room
Safety-related 4.16 kV Bus Voltage	D25	2	Indicator	1 per bus	0 – 5.25 kV	V/115-2 (Div I)	Control room
						V/116-2 (Div II)	Control room
						V/117-2 (Div III)	Control room
						V/118-2 (Div IV)	Control room
Safety-related 4.16 kV Frequency	D25	2	Indicator	1 per bus	55-60-65 Hz	F/AG501-2 (Div I)	Control room
						F/BG501-2 (Div II)	Control room
						F/CG501-2 (Div III)	Control room
						F/DG501-2 (Div IV)	Control room
125/250 V dc Class IE Power System Voltage	D25	2	Indicator	1 per bus	0-300 V	V/AD101 (Div I)	Control room
						V/BD101 (Div I)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
125/250 V dc Class IE Power System Current	D25	2	Indicator	1 per bus	1200-0-1200 A	A/AD101 (Div I)	Control room
						A/BD101 (Div II)	Control room
125 V dc Class IE Power System Voltage	D25	2	Indicator	1 per bus	0-150 V	V/CD101 (Div III)	Control room
						V/DD101 (Div IV)	Control room
125V dc Class IE Power System Current	D25	2	Indicator	1 per bus	500-0-500 A	A/CD101 (Div III)	Control room
						A/DD101 (Div IV)	Control room
Emergency Ventilation Damper Position	D24	2					
HV76-107			Indicating lights	1 pair per valve	Open/closed	HV76-107 (Div I)	Local Panel
HV76-108			Indicating lights	1 pair per valve	Open/closed	HV76-108 (Div I)	Local Panel
HV76-141 HV76-157			Indicating lights	1 per valve	Open/closed	HV76-141 HV76-157 (Div I)	Local Panel
HV76-142 HV76-158			Indicating lights	1 per valve	Open/closed	HV76-142 HV76-158 (Div II)	Local Panel

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV76-117 HV76-167			Indicating lights	1 per valve	Open/closed	HV76-117 HV76-167 (Div I)	Local Panel
HV76-118 HV76-168			Indicating lights	1 pair per valve	Open/closed	HV76-118 HV76-168 (Div II)	Local Panel
HD78-002A HD78-009A HV78-010A			Indicating lights	1 pair per valve	Open/closed	HS78-010A (Div III)	Control room(5)
HD78-002B HD78-009B HV78-010B			Indicating lights	1 pair per valve	Open/closed	HS78-010B (Div IV)	Control room(5)
HV78-20A			Indicating lights	1 pair per valve	Open/closed	HSS78-017A (Div I)	Control room
HV78-20B			Indicating lights	1 pair per valve	Open/closed	HSS78-017B (Div II)	Control room
HV78-020C HV78-021A			Indicating lights	1 pair per valve	Open/closed	HSS78-017C (Div III)	Control room
HV78-020D HV78-021B			Indicating lights	1 pair per valve	Open/closed	HSS78-017D (Div IV)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # [1]	CATEGORY [1]	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV76-019			Indicating lights	1 pair per valve	Open/closed	HV76-019 (Div I)	Local Panel[5]
HV76-020			Indicating lights	1 pair per valve	Open/closed	HV76-020 (Div II)	Local Panel[5]
HV76-151			Indicating lights	1 pair per valve	Open/closed	HV76-151 (Div I)	Local Panel
HV76-152			Indicating lights	1 pair per valve	Open/closed	HV76-152 (Div II)	Local Panel
HV76-159			Indicating lights	1 pair per valve	Open/closed	HV76-159 (Div I)	Local Panel
HV76-160			Indicating lights	1 pair per valve	Open/closed	HV76-160 (Div II)	Local Panel
HD76-183A HD76-193A			Indicating lights	1 pair per valve	Open/closed	HS76-193A (Div I)	Control room[5]
HD76-183B HD76-193B			Indicating lights	1 pair per valve	Open/closed	HS76-193B (Div II)	Control room[5]
HV76-012A HV76-011A			Indicating lights	1 pair per valve	Open/closed	HS76-013A (Div I)	Control room[5]
HV76-012B HV76-011B			Indicating lights	1 pair per valve	Open/closed	HD76-013B (Div II)	Control room[5]

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # [1]	CATEGORY [1]	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV76-030			Indicating lights	1 pair per valve	Open/closed	HS76-030 (Div I)	Control room
HV76-031			Indicating lights	1 pair per valve	Open/closed	HS76-031 (Div II)	Control room
HD76-340A PD-C76-341A			Indicating lights	1 pair per valve	Open/closed	HS76-040A (Div I)	Control room[5]
HD76-340B PD-C76-341B			Indicating lights	1 pair per valve	Open/closed	HV76-040B (Div II)	Control room[5]
HV76-196			Indicating lights	1 pair per valve	Open/closed	HV76-196 (Div I)	Local Panel[5]
HV76-197			Indicating lights	1 pair per valve	Open/closed	HV76-197 (Div II)	Local Panel[5]
HD78-026A HD78-027A			Indicating lights	1 pair per valve	Open/closed	HS78-026A (Div III)	Control room
HD78-026B HD78-027B			Indicating lights	1 pair per valve	Open/closed	HS78-026B (Div IV)	Control room
HV78-052A			Indicating lights	1 pair per valve	Open/closed	HV78-052A (Div III)	Control room
HV78-053A			Indicating lights	1 pair per valve	Open/closed	HV78-053A (Div III)	Control room
HV78-053B			Indicating lights	1 pair per valve	Open/closed	HD78-053B (Div IV)	Local panel
HV78-052B			Indicating lights	1 pair per valve	Open/closed	HV78-052B (Div IV)	Local panel
HV78-057A			Indicating lights	1 pair per valve	Open/closed	HV78-057A (Div III)	Local Panel

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
HV78-057B			Indicating lights	1 pair per valve	Open/closed	HV78-057B (Div IV)	Local panel
HV76-109			Indicating lights	1 pair per valve	Open/closed	HV76-109 (Div I)	Local panel
HV76-110			Indicating lights	1 pair per valve	Open/closed	HV76-110 (Div II)	Local panel
HD78-059A			Indicating lights	1 pair per valve	Open/closed	HD78-059A (Div III)	Control room
HD78-059B			Indicating lights	1 pair per valve	Open/closed	HD78-059B (Div IV)	Control room
HD78-060A			Indicating lights	1 pair per valve	Open/closed	HD78-060A (Div III)	Control room
HD78-060B			Indicating lights	1 pair per valve	Open/closed	HD78-060B (Div IV)	Control room
HV78-071A			Indicating lights	1 pair per valve	Open/closed	HV78-071A (Div III)	Local panel
HV78-071B			Indicating lights	1 pair per valve	Open/closed	HV78-071B (Div IV)	Local panel
Primary Containment Area Radiation – High Range	E1, C5	1	Recorder	2	1 to 10^8 R/hr	RR26-191A (Div III) RR26-191B (Div II)	Control room
Radiation Exposure Rate:	E3	3					
o Radwaste Enclosure Hallway, el 217'			Recorder (Multipoint)	1	10^{-2} to 10^4 mR/hr	RR-M1-0R601 (Non-Div)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
○ Turbine Area/Operating Floor/OSC, el 269'			Recorder (Multipoint)	1	10^{-2} to 10^{4} mR/hr	RR-M1-0R601 (Non-Div)	Control room
○ Main Control Room, el 269'			Recorder (Multipoint)	1	10^{-2} to 10^{4} mR/hr	RR-M1-0R601 (Non-Div)	Control room
○ North Stack Instrument Room, Reactor Enclosure el 411'			CRT	NA	10^{-2} to 10^{4} mR/hr	ERFDS CRT (Non-Div)	Control room
○ PASS Station Control Structure el 217'			CRT	NA	4.0 to 4 x 10^{3} mR/hr	ERFDS CRT (Non-Div)	Control room
Radiation Level in Circulating Primary Coolant:	C1	3					
○ Main Steam Line Radiation			Recorder	1	1 to 10^{6} mR/hr	RR41-1R603 (Non-Div)	Control room
○ SJAE Radiation			Recorder	1	1 to 10^{6} mR/hr	RR26-1R601 (Non-Div)	Control room
Noble Gases & Vent Flow Rate:	E4, C13, C15	2					
○ North Stack Radioactivity Concentration Wide Range Gas Monitor			Recorder	1	10^{-7} to $10^{+5}\mu$Ci/cc	RR26-076 (Div IV)	Control room
○ North Stack Flow			Indicator	1	500 - 3000 scfm Accident Range 0 – 664,000 scfm Normal Range	RIX26-076 (Div IV)	Control room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
Particulates and Halogens o North Stack Radioactivity Concentration with Onsite Analysis	E5	3	Filter/Sample Cartridge	1/module	Up to $10^{2}\mu$Ci/cc	OAF955 OBF955 OCF955	North Stack Rad Monitor
Airborne Radiohalogens and Particulates (Portable Sampling with Onsite Analysis)	E7	3	Portable Air Samples PING Particulate Monitor Spectroscopic System		10^{-12} to $10^{-3}\mu$Ci/cc	-	HP Field Office
Plant and Environs Radiation (Portable Instrumentation)	E8	3	Survey meters		1 mR/hr – 20,000 R/hr	-	-
Plant and Environs Radioactivity (Portable Instrumentation)	E9	3	Portable Air Samples PING Particulate Spectroscopic System		10^{-12} to $10^{-3}\mu$Ci/cc	-	HP Field Office
Wind Direction	E10	3	Recorder	2	0° - 540°	(SX-410 Channel 2/ PMS Point T1DRIHA), (SX-410 Channel 0/ PMS Point T1DRLHA) or (SX-410 Channel 20/ PMS Point T2DRUHA), (SX-410 Channel 15/ PMS Point T2DRIHA)	Control Room

Table 7.5-3 (Cont'd)

VARIABLES	TYPE/ ITEM # (1)	CATEGORY (1)	INDICATION				
			TYPE	QTY	INSTRUMENT RANGE	INSTRUMENT NO. (DIV)	LOCATION
Wind Speed	E11	3	Recorder	2	0 – 100 mph	(SX-410 Channel 3 PMS Point T1SPIHA), (SX-410 Channel 1/ PMS Point T1SPLHA) or (SX-41- Channel 21/ PMS Point T2SPUHA, SX-410 Channel 16/ PMS Point T2SPIHA)	Control room
Estimation of Atmospheric Stability	E12	3	Recorder	2	-10°F to 20°F	XR-MS-091 or XR-MS-092	Control room

(1) For definitions, refer to Section 7.5.2.5.1.1.2.3.

(2) Above instrument zero.

(3) 61 inches above top of active fuel with same instrument zero as the wide range level monitor.

(4) This variable is provided with non-Class 1E power.

(5) For emergency ventilation damper position, ERFDS monitoring is also provided aside from the position indicating lights.

(6) Grab samples of RCS soluble boron can be obtained from the postaccident monitoring system (Section 11.5.5).

(7) Valves HV-57-262, HV-57-263, HV-1(2)64, HV-57-269 are administratively controlled such that these valves are treated as seal closed barriers. These valves are electrically deactivated and, therefore, do not provide indication in the Control Room.

Table 7.5-4

RELATIVE NEUTRON FLUX VERSUS TIME[1]

Percent of power	Leakage rate, gpm (ramp rate, c/min)[2] 1(0.03)		5(0.15)		20(0.60)	
	Σ	Δ	Σ	Δ	Σ	Δ
$5x10^{-8}$	-555	500	-111	100	-27.75	25
$5x10^{-7}$	-55	50	-11	10	-2.75	2.5
$5x10^{-6}$	-5	5	-1	1	-0.25	0.25
$5x10^{-5}$	0		0		0	
$5x10^{-4}$	0.8	0.8	0.36	0.36	0.18	0.18
$5x10^{-3}$	1.33	0.53	0.51	0.15	0.25	0.07
$5x10^{-2}$	1.59	0.26	0.62	0.11	0.31	0.06
$5x10^{-1}$	1.80	0.21	0.72	0.10	0.36	0.05
$5x10^{0}$	1.89	0.09	0.80	0.08	0.40	0.04

(1) Shutdown flux = $5x10^{-8}$% of power.

(2) Σ = total number of hours; Δ = hours for neutron flux to increase by one decade.

Table 7.5-5

PLANT VARIABLES FOR ACCIDENT MONITORING

Type A Variables	Position
A1 Oxygen and Hydrogen Concentration	LGS meets regulatory guide criteria for all Type A variables.
A2 RPV Pressure	
A3 RPV Water Level	Criteria met for overlapping range of -350" - +60" (Section 7.5.2.5.1.1.2.4.2)
A4 Suppression Pool Water Temperature	
A5 Suppression Pool Water Level	
A6 Drywell Pressure	
Type B Variables	
B1 Neutron Flux	Classified as Category 2 (Section 7.5.2.5.1.1.2.4.1)
B2 Control Rod Position	Criteria met
B3 RCS soluble boron concentration (Grab sample)	Criteria met
B4 Coolant level in reactor	Criteria met for overlapping range of -350" - +60" (Section 7.5.2.5.1.1.2.4.2)
B5 BWR core thermocouples	Not implemented. Reactor level instrumentation adequate with EPGs
B6 RCS pressure	Criteria met (Section 7.5.2.5.1.1.2.4.2)
B7 Drywell pressure	Criteria met

Table 7.5-5 (Cont'd)

Type B Variables (Cont'd)	
B8 Drywell sump level	Criteria for Category 3 met (Section 7.5.2.5.1.1.2.4.3)
B9 Primary Containment Pressure	Criteria met
B10 Primary Containment Isolation Valve Position	Criteria met, redundant indication is not required on redundant isolation valves. Exclude check valves.
Type C Variables	
C1 Radioactivity concentration or radiation level in circulating primary coolant	Implemented as Category 3 (Section 7.5.2.5.1.1.2.4.4)
C2 Analysis of primary coolant (gamma spectrum)	Criteria met
C3 BWR core thermocouples	Will not implement (See B5)
C4 RCS pressure	Criteria met
C5 Primary containment area Radiation	Criteria met except at extreme drywell temperature (See E1 and Section 7.5.2.5.1.1.2.4.14)
C6 Drywell drain sumps level	Criteria met for Category 3 (Section 7.5.2.5.1.1.2.4.3)
C7 Suppression pool water level	Criteria met
C8 Drywell pressure	Criteria met
C9 RCS pressure	Criteria met
C10 Primary containment pressure	Criteria met
C11 Containment and drywell H_2 concentration	Criteria met
C12 Containment and drywell O_2 concentration	Criteria met
C13 Containment effluent radioactivity - noble gases (from identified release points including SGTS vent)	Criteria met (See E4)

Table 7.5-5 (Cont'd)

Type C Variables (Cont'd)	
C14 Radiation exposure rate (inside buildings or areas in direct contact with primary containment where penetrations are located)	Not implemented (See E2, E3 and Section 7.5.2.5.1.1.2.4.5)
C15 Effluent radioactivity - noble gases (from buildings as indicated above)	Criteria met (See E4)
Type D Variables	
D1 Main feedwater flow	Criteria met
D2 CST level	Criteria met
D3 Suppression spray flow	Current design is adequate (Section 7.5.2.5.1.1.2.4.6)
D4 Drywell pressure	Criteria met
D5 Suppression pool water level	Criteria met
D6 Suppression pool water temperature	Criteria met
D7 Drywell atmosphere temperature	Criteria met
D8 Drywell spray flow	Current design is adequate (Section 7.5.2.5.1.1.2.4.6)
D9	Deleted
D10 SRV position	Criteria met
D11 Isolation condenser system shell-side water level	N/A
D12 Isolation condenser system valve position	N/A
D13 RCIC flow	Criteria met (Section 7.5.2.5.1.1.2.4.7)

Table 7.5-5 (Cont'd)

Type D Variables (Cont'd)	
D14 HPCI flow	Criteria met (Section 7.5.2.5.1.1.2.4.7)
D15 Core spray system flow	Criteria met (Section 7.5.2.5.1.1.2.4.7)
D16 LPCI system flow	Criteria met (Section 7.5.2.5.1.1.2.4.7)
D17 SLCS flow	Alternate criteria met for Category 3 (Section 7.5.2.5.1.1.2.4.7)
D18 SLCS storage tank level	Criteria met for category 3 (Section 7.5.2.5.1.1.2.4.8)
D19 RHR system flow	Criteria met
D20 RHR heat exchanger outlet temperature	Criteria met
D21 Cooling water temperature to ESF components	Criteria met for main system flow
D22 Cooling water flow to ESF Components	Criteria met for main system flow
D23 High radioactivity liquid tank level	Criteria met
D24 Emergency ventilation damper position	Criteria met for damper actuated under accident conditions whose failure could result in radioactive release.
D25 Status of standby power and other energy sources	Criteria met, onsite sources only
D26 Main steam bypass valve position	Added to Regulatory Guide 1.97 list (Section 7.5.2.5.1.1.2.4.9)
D27 Condenser hotwell level	Added to Regulatory Guide 1.97 list (Section 7.5.2.5.1.1.2.4.9)
D28 Condenser pressure	Added to Regulatory Guide 1.97 list (Section 7.5.2.5.1.1.2.4.9)
D29 Circulating water pump discharge pressure	Added to Regulatory Guide 1.97 list (Section 7.5.2.5.1.1.2.4.9)

Table 7.5-5 (Cont'd)

Type D Variables (Cont'd)	
D30 Reactor recirculation pump Flow	Added to Regulatory Guide 1.97 list (Section 7.5.2.5.1.1.2.4.9)
Type E Variables	
E1 Primary containment area radiation - high range	Criteria met except at extreme drywell temperature (See C5 and Section 7.5.2.5.1.1.2.4.14)
E2 Reactor building or secondary containment area radiation	Not implemented (See C14, E3 and Section 7.5.2.5.1.1.2.4.10)
E3 Radiation exposure rate (inside buildings or areas where access is required to service equipment important to safety)	Implemented as Category 3 (See C14, E2 and Section 7.5.2.5.1.1.2.4.11)
E4 Noble gases and vent flow rate	Criteria met
E5 Particulates and halogens	Criteria met
E6 Radiation exposure meters	Deleted per NRC errata July 1981
E7 Airborne radiohalogens and particulates	Criteria met
E8 Plant and environs radiation	Criteria met (Section 7.5.2.5.1.1.2.4.12)
E9 Plant and environs radioactivity (MCA)	Criteria met
E10 Wind direction	Criteria met
E11 Wind speed	Criteria met
E12 Estimation of atmospheric stability	Criteria met
E13 Primary coolant and sump (grab sample)	Criteria met for primary coolant and suppression pool (Section 7.5.2.5.1.1.2.4.13)
E14 Containment air sample	Criteria met

7.6 ALL OTHER INSTRUMENTATION SYSTEMS REQUIRED FOR SAFETY

7.6.1 DESCRIPTION

This section examines and discusses the instrumentation and control aspects of the safety-related portions of the following plant systems:

a. Process radiation monitoring systems

   1. Main steam line radiation monitoring system
   2. Reactor enclosure ventilation exhaust radiation monitoring system
   3. Refueling area ventilation exhaust radiation monitoring system
   4. Control room ventilation radiation monitoring system
   5. Control room emergency fresh air radiation monitoring system
   6. Primary containment post-LOCA radiation monitoring system
   7. RHRSW radiation monitoring system
   8. North stack effluent radiation monitoring system

b. High pressure/low pressure systems interlocks

c. Leak detection systems

   1. Main steam line leak detection system
   2. RCIC system leak detection system
   3. RWCU system leak detection system
   4. HPCI system leak detection system

d. Neutron monitoring system

   1. Intermediate range monitor system
   2. Local power range monitor system
   3. Average power range monitor system

e. Safety/relief valve position indication system

f. Containment instrument gas system - ADS control

g. Safeguard piping fill system

h. Redundant reactivity control system

Systems not related to safety, and nonsafety-related portions of the above systems, are discussed in Section 7.7.

7.6.1.1 Process Radiation Monitoring Systems – Instrumentation and Controls

Radiation monitoring systems are provided on process liquid and gas lines that serve as discharge routes for radioactive materials. These include the following safety-related systems. (Nonsafety-related systems are described in Section 7.7.1.9.)

This system classification is provided in Table 3.2-1. The locations of radiation monitoring sensors identified in Section 7.6 are provided in Table 7.6-6. Additional discussion of the process radiation monitors is provided in Section 7.3.2.2.2.3.

7.6.1.1.1 Main Steam Line Radiation Monitoring System - Instrumentation and Controls

7.6.1.1.1.1 MSL-RMS Identification

High radiation in the vicinity of the main steam lines indicates a gross release of fission products from the fuel.

The high radiation alarm setting is selected high enough above background radiation levels to avoid spurious alarms, yet low enough to promptly detect a gross release of fission products from the fuel.

The objective of the MSL-RMS is to monitor for the gross release of fission products from the fuel and, upon indication of such release, to initiate appropriate alarms.

7.6.1.1.1.2 MSL-RMS Power Sources

The 120 V ac RPS buses A and B are the power sources for the MSL-RMS. Two channels are powered from one RPS bus, and the other two channels are powered from the other RPS bus.

7.6.1.1.1.3 MSL-RMS Initiating Circuits

Four gamma-sensitive instrument channels monitor the gross gamma radiation from the main steam lines. The detectors are physically located near the main steam lines just downstream of the outboard MSIVs. The detectors are geometrically arranged to detect significant increases in radiation level with any number of main steam lines in operation. Their location along the main steam lines allows the earliest practicable detection of a gross fuel failure.

Each monitoring channel consists of a gamma-sensitive ion chamber and a log radiation monitor, as shown in drawings M-26 and M-41. Capabilities of the monitoring channel are listed in Table 11.5-1. Each log radiation monitor has four trip circuits: one upscale high-high trip and one inoperative trip, either of which results in an alarm and a trip of the mechanical vacuum pump and its suction valve; one upscale high trip and one downscale trip, either of which results in an alarm only. The output from each log radiation monitor is displayed on a meter in the control enclosure.

7.6.1.1.1.4 MSL-RMS Logic and Sequencing

When a significant increase in the main steam line radiation level is detected (high-high condition), an alarm is given in the control room. At the same time, a trip signal is issued to stop the Mechanical Vacuum Pump and close its input line. This function is not safety related. The logic of pump trip is 1-out-of-2. Failure of one monitoring channel will not prevent a Mechanical Vacuum Pump trip; however, a failure in one monitoring channel in the high-high direction will cause an inadvertent MVP trip.

7.6.1.1.1.5 MSL-RMS Bypasses and Interlocks

No operational bypasses are provided with this system; however, the individual log radiation monitors may be bypassed for maintenance or calibration by the use of test switches on each monitor. The main steam line radiation monitors provide trip signals to operate the mechanical vacuum pump and close the vacuum pump line isolation valve.

7.6.1.1.1.6 MSL-RMS Redundancy and Diversity

The number of monitoring channels in this system provides the required redundancy and is verified in the circuit description.

The single failure criterion is met in the design by providing redundant sensors, logic channels, and trip systems that are seismically and environmentally qualified. The failure of a single component does not prevent the system from functioning in the event that protective action is required.

There is no diversity of monitoring variables.

7.6.1.1.1.7 MSL-RMS Testability

A built-in source of adjustable current is provided to simulate sensor input to each log radiation monitor for test purposes. The operability of each monitoring channel can be routinely verified by comparing the outputs of the channels during power operation.

7.6.1.1.1.8 MSL-RMS Environmental Considerations

This system is designed, and has been qualified, to meet the environmental conditions indicated in Section 3.11. In addition, this system is seismically qualified as described in Section 3.10.

7.6.1.1.1.9 MSL-RMS Operational Considerations

In the event of a high or low radiation condition detected within any of the channels, the system automatically activates the appropriate alarm annunciator in the control room. Radiation level indication is provided in the auxiliary equipment room. A continuous radiation record for any two selected channels is provided in a 2-pen recorder in the control room.

The panels in the control room, associated with the PCRVICS, are identified by tags that indicate the panel function and identification of the contained logic channels.

The only direct support required for the MSL-RMS is the electrical power system, which is provided from 120 V ac RPS buses A and B as described in Section 7.3.1.1.2.2 and Chapter 8.

7.6.1.1.2 Reactor Enclosure Ventilation Exhaust Radiation Monitoring System - Instrumentation and Controls

7.6.1.1.2.1 REVE-RMS Identification

The purpose of this system is to indicate when excessive amounts of radioactivity exist in the reactor enclosure ventilation exhaust and to provide signals for initiation of appropriate action so that the release of radioactive gases to the environs is limited to levels below guidelines of published regulations. The radiation monitoring system is shown in drawing M-26. Instrument characteristics are given in Table 7.6-1. The system consists of four independent channels monitoring the reactor zone.

Refer to Section 7.3.1.1.9 for a description of the isolation function for this system.

7.6.1.1.2.2 REVE-RMS Power Sources

The 120 V ac RPS buses A and B are the power sources for these systems. Two channels receive power from one RPS bus, and the other two channels receive power from the other RPS bus.

7.6.1.1.2.3 REVE-RMS Initiating Circuits

Each channel includes a GM-type of detector and an indicator and trip unit. Two channels share a 2-pen strip-chart recorder. All equipment except the detectors is located in the control room and the auxiliary equipment room. The detectors are located in the reactor enclosure HVAC discharge ducts.

7.6.1.1.2.4 REVE-RMS Logic and Sequencing

Each channel has an upscale trip as described in Section 11.5.2.

The four upscale trips are arranged into two trip systems, A and B. When both channels of either A or B are tripped, the resultant output of the trip system is an isolation signal that trips fans, closes valves to the vent exhaust system, and initiates the SGTS. The isolation signal also initiates isolation of the following primary containment lines: purge, vent, atmosphere sample containment, and instrument gas suction and discharge lines. There are two isolation valves in each of the above lines. Each trip system operates one or the other of these valves. The two valves in each line are redundant, and one is sufficient to provide isolation.

7.6.1.1.2.5 REVE-RMS Bypasses and Interlocks

No operational bypasses are provided, but the trip units for each sensor channel may be bypassed for maintenance or testing. Bypassing the trip unit causes a downscale alarm and actuates the upscale trip for the channel.

7.6.1.1.2.6 REVE-RMS Redundancy and Diversity

As discussed in Section 7.6.1.1.2.4, the reactor enclosure ventilation exhaust radiation monitoring system consists of four independent sensors and trip units, sensing a common variable. This

independence provides sufficient redundancy to ensure that a high radiation condition will be detected and protective action initiated.

No diversity of trip variables is provided.

7.6.1.1.2.7 REVE-RMS Testability

The monitors are readily accessible for inspection, calibration, and testing. Operability of the detectors can be verified through use of a portable gamma source.

7.6.1.1.2.8 REVE-RMS Environmental Considerations

The environmental considerations are given in Section 3.11.

In addition, this system is seismically qualified for conditions of an SSE as indicated in Section 3.10.

7.6.1.1.2.9 REVE-RMS Operational Considerations

7.6.1.1.2.9.1 REVE-RMS General Information

The reactor enclosure ventilation exhaust radiation monitoring system is required to prevent release of radioactive materials to the environs. The isolation function is performed automatically and provides annunciation in the control room to alert operating personnel of the condition.

7.6.1.1.2.9.2 REVE-RMS Reactor Operator Information

REVE-RMS and RAVE-RMS radiation alarms are combined in the control room. REVE-RMS and RAVE-RMS channels A/B and C/D share high-high/downscale alarms in the control room. There is an additional upscale alarm shared by all channels of the RAVE-RMS and REVE-RMS. Refer to Table 7.3-5 for system characteristics and display ranges.

7.6.1.1.2.9.3 REVE-RMS Setpoints

Refer to the Technical Specifications.

7.6.1.1.3 Refueling Area Ventilation Exhaust Radiation Monitoring System - Instrumentation and Controls

7.6.1.1.3.1 RAVE-RMS Identification

The purpose of this system is to indicate when excessive amounts of radioactivity exist in the refueling area ventilation exhaust, and to provide signals for initiation of appropriate action so that the release of radioactive gases to the environs is limited to levels below guidelines of published regulations. The radiation monitoring system is shown in drawing M-26 and its specifications are given in Table 7.3-5. The system consists of four independent channels.

Refer to Section 7.3.1.1.17 for a description of the isolation function.

7.6.1.1.3.2 RAVE-RMS Power Sources

The 120 V ac RPS buses A and B are the power sources for these systems. Two channels receive power from one RPS bus, and the other two channels receive power from the other RPS bus.

7.6.1.1.3.3 RAVE-RMS Initiating Circuits

Each channel includes a GM-type detector and an indicator and trip unit. Two channels share a 2-pen strip-chart recorder. All equipment except the detectors are located in the control room and auxiliary equipment room.

7.6.1.1.3.4 RAVE-RMS Logic and Sequencing

Each channel has an upscale trip as described in Section 11.5.2.

The four upscale trips are arranged into two trip systems, A and B. When both channels of either A or B are tripped, the resultant output of the trip system is an isolation signal that trips fans, closes valves to the vent exhaust system, and initiates SGTS. The isolation signal also initiates isolation of the following primary containment lines: purge, vent, atmosphere sample containment, instrument gas suction and discharge lines. There are two isolation valves in each of the above lines. Each trip system operates one of the valves. The two valves in each line are redundant, and one is sufficient to provide isolation.

7.6.1.1.3.5 RAVE-RMS Bypasses and Interlocks

No operational bypasses are provided, but the trip units for each sensor channel can be bypassed for maintenance or testing. Bypassing the trip unit causes a downscale alarm and actuates the upscale trip for the channel.

7.6.1.1.3.6 RAVE-RMS Redundancy and Diversity

As discussed in Section 7.6.1.1.3 the RAVE-RMS consists of four independent sensors and trip units, sensing a common variable. This independence provides sufficient redundancy to ensure that a high radiation condition is detected and protective action initiated.

No diversity of trip variables is provided.

7.6.1.1.3.7 RAVE-RMS Testability

The monitors are readily accessible for inspection, calibration, and testing. Operability of the detectors can be verified through use of a portable gamma source.

7.6.1.1.3.8 RAVE-RMS Environmental Considerations

The environmental considerations are given in Section 3.11.

In addition, this system is seismically qualified for conditions of an SSE as indicated in Section 3.10.

7.6.1.1.3.9 RAVE-RMS Operational Considerations

7.6.1.1.3.9.1 RAVE-RMS General Information

The RAVE-RMS is required to prevent release of radioactive materials to the environs. The isolation function is performed automatically and provides annunciation in the control room to alert operating personnel of the condition.

7.6.1.1.3.9.2 RAVE-RMS Reactor Operator Information

REVE-RMS and RAVE-RMS radiation alarms are combined in the control room. REVE-RMS and RAVE-RMS channels A/B and C/D share high-high/ downscale alarms in the control room. There is an additional upscale alarm shared by all channels of the RAVE-RMS and REVE-RMS. Refer to Table 7.3-5 for system characteristics and display ranges.

7.6.1.1.3.9.3 RAVE-RMS Setpoints

Refer to the Technical Specifications.

7.6.1.1.4 Control Room Ventilation Radiation Monitoring System - Instrumentation and Controls

7.6.1.1.4.1 CRV-RMS Identification

In the event of an accident in which a significant quantity of radioactive material escapes from the plant, there is a risk that a hazardous quantity of this material could be introduced into the control room and auxiliary equipment room via the intake louvers. In this eventuality, these rooms could become uninhabitable, and the capability of plant shutdown under accident conditions could be curtailed.

The CRV-RMS detects the presence of radioactivity in the intake louvers leading to the control room and auxiliary equipment room. Trip setting is selected at such a level as to close the air intake dampers before the radioactivity level in these rooms reaches a unacceptable level. The emergency fresh air system is also actuated by this trip.

7.6.1.1.4.2 CRV-RMS Power Supplies

Power to this monitoring system is supplied from four 120 V ac Class 1E buses, Divisions I, II, III, and IV.

7.6.1.1.4.3 CRV-RMS Initiating Circuits

The system initiating circuits are described in Sections 6.4, 7.3.1.1.10, and 9.4.1.

7.6.1.1.4.4 CRV-RMS Logic and Sequencing

Four independent sensors and isolation logic channels are provided to ensure protective action when required and to prevent inadvertent isolation resulting from instrumentation malfunctions. When a predetermined increase in radioactivity above normal background is detected, trip signals are transmitted to the control room dampers and emergency fresh air system. The output trip signal of each radiation detector initiates a logic division trip. The output trip signals are combined

in a one-out-of-two-twice logic. Logic A or C and B or D are required to initiate control room isolation. Failure of any one channel does not result in an inadvertent isolation action.

7.6.1.1.4.5 CRV-RMS Redundancy and Diversity

Redundancy of trip initiation signals for high radioactivity is provided by four independent detectors. Each radiation signal is associated with one of four logics with different power sources. Diversity of trip initiation signals is neither required nor provided.

7.6.1.1.4.6 CRV-RMS Testability

A built-in source for simulating a midrange radioactivity level is provided to simulate sensor input to each radiation detector for test purposes. The operability of each monitoring channel can be routinely verified by comparing the outputs of the channels during power operation.

7.6.1.1.4.7 CRV-RMS Environmental Considerations

This system is designed and qualified to meet the environmental conditions under all plant operating conditions. In addition, this system is seismically qualified as described in Section 3.10.

7.6.1.1.4.8 CRV-RMS Operational Conditions

Both control trip and annunciation capabilities are provided for by this system.

7.6.1.1.5 Control Room Emergency Fresh Air Radiation Monitoring System - Instrumentation and Controls

7.6.1.1.5.1 CREFA-RMS Identification

The CREFA-RMS is subordinated to the control room ventilation monitoring system. If the concentration of radioactive material entering the control room ducts reaches an unacceptable level, the control room radiation monitors trip, close the ventilation dampers, and start up the emergency fresh air system. In this eventuality, the control room radiation monitors are no longer functional, and the CREFA-RMS takes over the function of monitoring the control room ventilation air supply. Most of the noble gases present in the ventilation air pass through the HEPA charcoal filters, where the radioactive particulates and iodines are filtered out. Thus, the CREFA-RMS located downstream of the HEPA charcoal filters, continues to alarm as long as the unacceptable condition persists. If the control room operator judges that the concentration of noble gases entering the control room is unacceptable, the operator shuts off the ventilation system completely. The CREFA-RMS also provides information as to when the unacceptable condition has ended.

7.6.1.1.5.2 CREFA-RMS Power Supplies

Power to this monitoring system is supplied from two 120 V ac Class 1E buses, Divisions III and IV.

7.6.1.1.5.3 CREFA-RMS Initiating Circuits

The CREFA-RMS does not initiate any controls.

7.6.1.1.5.4 CREFA-RMS Logic and Sequencing

The CREFA-RMS is comprised of two independent and redundant channels. The trip circuits do not provide any control functions. Alarms annunciate in response to high, high-high, and downscale trips. Failure of either channel does not prevent the alarms or readouts from functioning.

7.6.1.1.5.5 CREFA-RMS Redundancy and Diversity

Redundancy of trip signals for high radioactivity is provided by two independent detectors. Each detector is supplied by a separate power source.

7.6.1.1.5.6 CREFA-RMS Testability

A built-in source for simulating a midrange radioactivity level is provided to simulate sensor input to each radiation detector for test purposes. The operability of each monitoring channel can be routinely verified by comparing the outputs of the channels during power operation.

7.6.1.1.5.7 CREFA-RMS Environmental Considerations

This system is designed and qualified to meet the environmental conditions under all plant operating conditions. In addition, this system is seismically qualified as described in Section 3.10.

7.6.1.1.5.8 Operational Considerations

The CREFA-RMS provides only alarm annunciation capability and readouts in the control room. No control functions are involved.

7.6.1.1.6 Primary Containment Post-LOCA Radiation Monitoring System - Instrumentation and Controls

7.6.1.1.6.1 PCPL-RMS Identification

The objective of the PCPL-RMS is to monitor the total intensity of gross radioactivity present inside the containment. In correlation with other points of consideration this information provides a basis for making postaccident decisions.

The PCPL-RMS is shown in drawing M-26and specifications are given in Table 7.6-1.

7.6.1.1.6.2 PCPL-RMS Power Sources

Power to this monitoring system is supplied from two 120 V ac Class 1E power buses.

7.6.1.1.6.3 PCPL-RMS Redundancy and Diversity

Four physically separated sensors, two in each of two electrical separation channels, provide the required redundancy.

7.6.1.1.6.4 PCPL-RMS Testability

A built-in source of adjustable current is provided to simulate sensor input to each radiation monitor for test purposes. The operability of each monitoring channel can be routinely verified by comparing the outputs of the channels during power operation.

7.6.1.1.6.5 PCPL-RMS Environmental Considerations

This system is designed and qualified to meet the environmental conditions under post accident considerations. In addition, this system is seismically qualified as described in Section 3.10.

Under high drywell temperature conditions, Insulation Resistance (IR) leakage current will cause a system error. Because the instrument signal at low radiation levels is very weak, high temperature IR leakage current significantly affects the accuracy of the indicated readings up to a maximum of 112.5 Rad/hr at the maximum design drywell temperature of 340°F. As a result, the indicated readings below 112.5 Rad/hr may not be within the factor of two accuracy recommendation of Regulatory Guide 1.97 Rev. 2. The induced error decreases exponentially with drywell temperature and becomes insignificant below 230°F. This induced error is significant only under low radiation conditions coincident with high drywell temperatures, whereas the system will operate to perform its principal function under normal and varying temperature conditions during and following an accident.

7.6.1.1.6.6 PCPL-RMS Operational Considerations

Continuous radiation levels are recorded on dedicated Class 1E recorders in the control room. Trip and annunciation capabilities are described in Section 11.5.2.3.1.

7.6.1.1.7 Residual Heat Removal Service Water Radiation Monitoring System - Instrumentation and Controls

7.6.1.1.7.1 RHRSW-RMS System Identification

The purpose of the RHRSW-RMS is to indicate to operations personnel when the radioactivity of a liquid stream being released to the environs exceeds pre-established limits.

7.6.1.1.7.2 RHRSW-RMS Power Sources

The 120 V ac uninterruptible buses are the power sources for this system.

7.6.1.1.7.3 RHRSW-RMS Equipment Design

Design of this system is described in Section 11.5. This system is classified as a safety system in order to ensure that it will be functional after an SSE or LOCA in accordance with GDC 64.

7.6.1.1.7.4 RHRSW-RMS Circuit Description

The RHRSW-RMS is shown in drawing M-26. Specifications are given in Table 7.6-1. Two channels monitor the common RHRSW discharges from Units 1 and 2 to the cooling pond.

Each channel has a scintillation detector and a radiation monitor. Each detector monitors a sample of the process liquid for gamma activity. The sample is drawn from the process system, flows through the shielded sample chamber where it is monitored, and then is returned to the process system.

Indication is provided in the control room.

The RHRSW system provides cooling water for the RHR heat exchangers, which may contain radioactive water from leakage in the heat exchangers. Leaks that could contaminate the service water are detected by the two monitors for the service water effluent. A high radiation signal trips the RHRSW pumps.

7.6.1.1.7.5 RHRSW-RMS Logic and Sequencing

The logic is provided in a single high signal. The trip signal shuts off the RHRSW pumps.

7.6.1.1.7.6 RHRSW-RMS Bypass and Interlocks

None are provided.

7.6.1.1.7.7 RHRSW-RMS Redundancy and Diversity

A single monitor is provided for each of the common RHRSW discharge lines. The loss of monitor operability is annunciated in the Main Control Room. Periodic grab sampling is used following a monitor failure.

7.6.1.1.7.8 RHRSW-RMS Actuated Devices

The RHRSW pumps are subject to shutoff.

7.6.1.1.7.9 RHRSW-RMS Separation

The channels associated with the common discharge lines are separated in accordance with IEEE 279, paragraph 4.6.

7.6.1.1.7.10 RHRSW-RMS Setpoints

Setpoints are such that the instrument will trip the control room annunciator and the RHRSW pump when the radioactive concentration of the RHRSW equals or exceeds ten-times the 10CFR20, Appendix B, Table 2 activity limits (post-1994).

7.6.1.1.8 North Stack Effluent Radiation Monitoring System - Instrumentation and Controls

7.6.1.1.8.1 NSE-RMS System Identification

Under an accident condition, the south stack is isolated, but the north stack continues to emit effluents received from the SGTS and other sources. Radioactivity levels in these effluents are monitored continually by means of the north stack monitoring system.

Two independent subsystems, the normal range subsystem and the wide range accident monitoring subsystem, are provided as described in Sections 7.6.2.1.8 and 11.5.2.2.1.

7.6.1.1.8.2 NSE-RMS Power Sources

Power to the wide range accident monitoring system is provided by one 120 V ac Class 1E bus.

7.6.1.1.8.3 NSE-RMS Redundancy and Diversity

Although no redundancy is required, two independent radiation monitors are provided as part of the normal range subsystem. The wide range subsystem provides an extended measuring range designed to function during an accident and to follow decreasing concentrations of noble gases following an accident.

7.6.1.1.8.4 NSE-RMS Testability

Built-in radioactive check sources for simulating midrange radiation levels are provided for each channel for test purposes. Remote controlled purge and check source capabilities are provided. The operability of each monitoring channel can be routinely verified by comparing the outputs of the two monitoring systems during power operation.

7.6.1.1.8.5 NSE-RMS Environmental Considerations

The wide range accident monitor has been designed and qualified to meet environmental conditions under all modes of plant operation, including accidents. The normal range monitor is designed to withstand the normal service environment.

7.6.1.1.8.6 NSE-RMS Operational Considerations

Annunciation, computation, and recording capabilities are provided for this system. The equipment is located in an area where the radiation environment is sufficiently low to afford personnel access over the range of plant operating conditions. However, the instrumentation is designed for remote operation and control as well as data retrieval.

7.6.1.2 High Pressure/Low Pressure Systems Interlocks - Instrumentation and Controls

7.6.1.2.1 HPLPSI Function Identification

The low pressure systems that interface with the RCPB, and the instrumentation that protects them from overpressurization, are discussed in this section.

7.6.1.2.2 HPLPSI Power Sources

The power for the interlocks is provided from the essential power supplies for the associated systems.

7.6.1.2.3 HPLPSI Equipment Design

At least two isolation valves are provided in series in each line.

As discussed in Section 5.4.7.1.1.5, all components which make up the steam condensing mode of the RHR system have either been abandoned in place or physically removed from the plant. Therefore, this mode is no longer required.

A list of high pressure/low pressure interlock equipment is provided in Table 7.6-7.

The interlocked valves of the HPLPSI meet BTP ICSB 3 in accordance with the following:

Two MOVs in Series (ICSB 3, paragraph 2)

E11-F008 and E11-F009 (RHR shutdown cooling suction outboard and inboard valves, respectively) are two manually activated MOVs in series. Both valves are inhibited from opening and close automatically if primary system pressure is above setpoint. Reactor pressure is also indicated in the control room. The logic components for both valves are independent. Each valve control circuit requires two reactor low pressure permissives before valves can open; this results in a four-out-of-four logic to open the suction line. Removal of one signal (one-out-of-four logic) isolates the line. The pressure permissive components rely on the transmitter trip unit combination which is testable from the control room.

Reactor pressure instrumentation used by the operator (via plant procedures) to initiate shutdown cooling is independent of the interlocks. Procedural controls ensure that the manually initiated shutdown cooling mode is not begun until the reactor pressure is below approximately 75 psig; A safety factor is maintained since the piping in the pump discharge has ratings that vary from 350-500 psig and the suction piping is rated at 190 psig.

Because of the foregoing additional safety design features, diversity of interlocks as suggested by ICSB 3, paragraph 2, has not been implemented for LGS. This is consistent with all other BWR testability (transmitter trip unit) enhanced plants such as Grand Gulf.

MOVs in Series with (Testable) Check Valves (ICSB 3, paragraph 3)

E11-F015A and E11-F015B (RHR shutdown cooling injection outboard valves) are manually activated MOVs in series with E11-F050A and E11-F050B (testable check AOVs),respectively. These MOVs (loop A and B) are inhibited from opening and close automatically if primary system pressure is above setpoint. Both valves use the same valve control circuit, which requires two reactor low pressure permissives before the valves can open. Removal of one pressure permissive signal will close the valves.

The remaining HPLPSI valves in this discussion are required for ECCS operation. The recommendation of ICSB 3 was followed in evaluating ECCS high pressure/low pressure interlocks on an individual case basis.

Paired MOVs and Air-Operated Check Valves

The valves listed below are paired MOVs and air-operated check valves, which isolate low pressure ECCS from higher pressure primary system.

E11-F017A, B, C, and D LPCI injection MOVs are interlocked to prevent opening when differential pressure across the valves exceeds the setpoint. This interlock applies to manual or automatic opening. The ΔP is indicated by a permissive alarm in the control room. The normally closed core spray inboard injection valves (E21-F005 and E21-F037) and the normally open outboard injection

valves (E21-F004A and E21-F004B) are interlocked by high reactor pressure (one-out-of-two-twice logic) to prevent their receiving an opening signal on automatic system initiation. The inboard injection valve is interlocked by limit switch with outboard injection valve position to permit testing, such that it may be opened manually only if the outboard valve is closed. The outboard valve is interlocked so that during an automatic CS system initiation, the outboard valve close circuit will be disabled.

7.6.1.2.3.1 HPLPSI Circuit Description

The RHR shutdown cooling suction valves from the recirculation line have independent interlocks to prevent the valves from opening when the reactor pressure is above the RHR system design pressure. These valves also receive a signal to close when reactor pressure is above the RHR system pressure.

The RHR shutdown cooling suction valve F008 is provided with an additional interlock which prevents a fire-induced open signal from causing it to open simultaneously with valve F009 when the reactor pressure is greater than the design capabilities of the RHR low-pressure piping.

The RHR system shutdown cooling discharge valves have two reactor pressure interlocks. Both of these low pressure permissives must be satisfied in order to open the valves. Each line has a remote testable check valve downstream of the discharge valve.

The RHR system LPCI injection valves open when differential pressure across the valves is low. There is a remote testable check valve downstream of the injection valve in each loop.

The CS system injection valves open when reactor pressure decreases below the system design pressure. There is a remote testable check valve downstream of each injection valve. There is an additional check valve downstream of the injection valve on loop B.

7.6.1.2.3.2 HPLPSI Logic and Sequencing

The RHR shutdown cooling valves are interlocked by reactor pressure in two-out-of-two logic. In all other cases, the sensor inputs operate the interlocks without logic combination.

7.6.1.2.3.3 HPLPSI Bypasses and Interlocks

There are no bypasses or interlocks in the high pressure/low pressure interlocks.

7.6.1.2.3.4 HPLPSI Redundancy

Each process line has two valves in series that are redundant in ensuring the interlock. The RHR shutdown cooling suction valves have independent interlocks to prevent the valves from opening when the reactor pressure is above the system design pressure.

The RHR shutdown cooling suction valve F008 is provided with an additional interlock which prevents a fire-induced open signal from causing it to open simultaneously with valve F009 when the reactor pressure is greater than the design capabilities of the RGR low-pressure piping.

7.6.1.2.3.5 HPLPSI Actuated Devices

The MOVs listed in Section 7.6.1.2.3 and Table 7.6-7 are the actuated devices.

7.6.1.2.3.6 HPLPSI Separation

Separation is maintained between redundant portions of the high pressure/low pressure interlocks by assigning the signals for the redundant electrically controlled valves to separate electrical divisions (Section 7.1.2.2.).

The redundant high pressure interlocked valves are powered by separate essential electrical power. The relay logic, which performs the function of preventing valve opening unless pressure is below setpoint, is the same essential power as that of the associated interlocked valve. The interlocked valves of the HPLPSI are provided in Table 7.6-8.

The sensors that actuate the interlock logic (on pressure below setpoint) are on separate instrument lines and power such that no single failure can prevent core cooling. The electrical separation of the HPLPSI is consistent with the systems of which they comprise a part and represent no deviation from the intent of Regulatory Guide 1.75 as discussed in Section 8.1.6.1.14.

7.6.1.2.3.7 HPLPSI Testability

The actuated devices (except those valves kept closed by reactor pressure interlocks) can be tested during reactor operation. The sensors are tested during reactor operation in the same manner that ESF sensors are tested. Refer to Section 7.3.1 for a discussion of testing ESF sensors.

7.6.1.2.4 HPLPSI Environmental Considerations

The instrumentation and controls for the high pressure/low pressure interlocks are qualified as Class 1E equipment. The sensors are mounted on local instrument panels and the control circuitry is housed in panels in the auxiliary equipment room and the control room. Refer to Sections 3.10 and 3.11 for details of the qualification testing.

7.6.1.2.5 HPLPSI Operational Considerations

7.6.1.2.5.1 HPLPSI General Information

The high pressure/low pressure interlocks are strictly automatic. There is no manual actuation capability. If the operator initiates a low pressure system, the interlocks prevent exposure of the low pressure piping to high pressure.

7.6.1.2.5.2 HPLPSI Reactor Operator Information

The status of each valve providing the high pressure/low pressure boundary is indicated in the control room. The state of the reactor pressure and RHR injection valve differential pressure sensors is indicated in the control room.

7.6.1.2.5.3 HPLPSI Setpoints

The setpoints for HPLPSI are contained in Chapter 16.

7.6.1.3 Leak Detection System - Instrumentation and Controls

The LDS consists of the following safety-related subsystems:

a. Main steam line leak detection system

b. RCIC leak detection system

c. RWCU leak detection system

d. HPCI leak detection system

7.6.1.3.1 LDS Identification

This section discusses the instrumentation and controls associated with the safety-related portion of the leak detection system. The nonsafety-related portion is described in Section 7.7.1.16. The LDS itself is discussed in Section 5.2.5.

The purpose of the leak detection system instrumentation and controls is to detect and provide the signals necessary to isolate leakage from the RCPB before predetermined limits are exceeded. Environmental conditions and qualification for the leak detection system are discussed in Sections 3.10 and 3.11. Seismic qualification of the main steam line break detection subsystem is discussed in Section 7.3.2.2.2.3.1.5.

7.6.1.3.2 LDS Power Sources

Separation requirements are applicable to leak detection signals that are associated with the PCRVICS. Four power sources are used to comply with separation criteria. The normal 120 V ac power feed to the equipment associated with Division 1, Division 2, Division 3 and Division 4 is from the safeguard DC/AC Inverters E21-K601A, B, C and D respectively. The alternate 120 V ac power source to the equipment is from safeguard instrument buses A, B, C and D respectively also.

7.6.1.3.3 LDS Equipment Design

7.6.1.3.3.1 LDS General

The systems or parts of systems that contain water or steam coming from the reactor vessel or supply water to the reactor vessel, and which are in direct communication with the reactor vessel, are provided with leakage detection systems.

Outside the primary containment, the piping within each system monitored for leakage is in compartments or rooms separate from other systems wherever feasible, so that leakage may be detected by sump pump monitoring outside of containment, ambient and differential area temperature indications, high process flow, high process differential flow, level alarms, or area radiation indication.

7.6.1.3.3.2 Main Steam Line Leak Detection System - Instrumentation and Controls

7.6.1.3.3.2.1 MSL-LDS Identification

The main steam lines are constantly monitored for leaks by the LDS. Steam line leaks cause changes in at least one of the following monitored operating variables: area ambient and differential temperature, flow rate, or low water level in the reactor vessel. If a leak is detected, the detection system responds by triggering an annunciator and initiating a steam line isolation trip logic signal. An isolation trip logic signal will not initiate on TE MSL Tunnel High Temperature, it will only trigger an annunciator.

The MSL-LDS consists of four types of monitoring circuits:

a. The first two of these circuits monitor the ambient and differential area temperature in the vicinity of the MSIVs and cause an alarm to be initiated when an observed temperature rises above a preset maximum. The ambient area temperature monitors will initiate an Outboard MSIV room main steam line isolation when the observed temperature rises above a preset maximum. The ambient temperature monitors are located along the entire steam line.

b. The third type of circuit monitors the volumetric rate and initiates an alarm and closure of isolation valves when the monitored flow rate exceeds a preset maximum.

c. The fourth type of circuit monitors reactor vessel water level and sends a trip signal to the isolation valve logic when the level decreases below a preselected setpoint.

The MSL-LDS has no manual bypass switch because the MSIV isolation logic is A or C and B or D. This permits testing of a single channel without affecting the isolation function or causing inadvertent isolation. Annunciation of "Reactor isolation system out-of-service inboard" and "Reactor isolation system out-of- service outboard" is manually provided by individual "NORM-INOP" switches. Each MSL-LDS temperature monitor point has bypass capabilities, but this function is not used.

7.6.1.3.3.2.2 Main Steam Line Temperature in Outboard MSIV Room and Turbine Enclosure Main Steam Tunnel Monitoring Subsystem - Instrumentation and Controls

7.6.1.3.3.2.2.1 Identification

High ambient temperature in the areas in which the main steam lines are located outside of the primary containment could indicate a leak in a main steam line. Each main steam line isolation logic channel is tripped by high ambient temperature in the outboard MSIV room. The automatic closure of various valves prevents the excessive loss of reactor coolant and the release of a significant amount of radioactive material from the RCPB.

High temperature in the vicinity of the main steam lines is detected by dual element thermocouples located above the main steam lines between the primary containment wall and the turbine. The detectors are located or shielded so that they are sensitive to air temperature and not the radiated heat from hot equipment.

The temperature sensors give an input to temperature indicating switches.

The temperature detection system is designed to detect steam leaks equivalent to 5 gpm. A total of 4 main steam line high ambient temperature channels are provided in the outboard MSIV room

and 32 are provided on the main steam line in the turbine enclosure. Each main steam line isolation logic channel is tripped by high ambient temperature in the outboard MSIV room.

Refer to Section 7.3 for a description of the isolation function.

7.6.1.3.3.2.2.2 Power Supplies

Power supplies are discussed in Section 7.3.1.1.2.

7.6.1.3.3.2.2.3 Initiating Circuits

Four ambient temperature sensing circuits monitor the outboard MSIV room, and thirty-two monitor the turbine enclosure. The temperature elements are connected to four separate instrumentation channels. The 36 ambient temperature elements are physically located near the main steam lines in the outboard MSIV room and the turbine enclosure. The locations of the temperature elements provide the earliest practicable detection of a main steam line leak.

7.6.1.3.3.2.2.4 Logic and Sequencing

When a predetermined increase in ambient temperature is detected, trip signals are transmitted to the PCRVICS. The PCRVICS initiates closure of all main steam line isolation and drain valves.

Four instrumentation channels are provided to ensure protective action when needed and to prevent inadvertent isolation resulting from instrumentation malfunctions.

The output trip signal of each logic channel initiates a trip logic division trip. The output trip signals of the trip logic divisions are combined in one-out-of-two-twice for the MSIVs or two-out-of-two logics for the main steam line drains. Logic channels A or C and B or D are required to initiate main steam line isolation. Logic channels A and B or C and D are required to initiate main steam line drain isolation. Thus, failure of any one division does not result in inadvertent action.

7.6.1.3.3.2.2.5 Redundancy and Diversity

Redundancy of alarm initiation signals for high ambient temperature is provided by 16 thermocouples installed at different locations within the main steam line tunnel. The temperature indicating switches associated with each thermocouple provides an input to one of four logic channels. Ambient temperature indicating switches A, B, C and D are normally powered by 120 V ac from the safeguard DC/AC Inverters E21-K601A, B, C and D respectively. The alternate power source to these switches is from the 120 V ac safeguard instrument buses A, B, C and D respectively also.

Diversity of trip initiation signals for a main steam line leak is provided by main steam line Outboard MSIV room ambient temperature, main steam line high flow, and steam line low pressure instrumentation. An increase in ambient temperature for Outboard MSIV room only, main steam line flow, or a decrease in pressure initiates main steam line and main steam line drain valve isolation.

7.6.1.3.3.2.2.6 Bypasses and Interlocks

There are no bypasses associated with this system or interlocks to other systems from a main steam line tunnel high temperature alarm. Each MSL-LDS temperature monitor point has bypass capabilities, but this function is not used.

7.6.1.3.3.2.2.7 Testability

Testability is the same as discussed in Section 7.3.1.1.2.11.

7.6.1.3.3.2.2.8 Environmental Considerations

This system is designed and qualified to meet the environmental conditions indicated in Section 3.11. This subsystem, except for the sensors located in the reactor enclosure, is installed in the turbine enclosure. Seismic qualification of the subsystem is discussed in Section 7.3.2.2.2.3.1.5.

7.6.1.3.3.2.3 Main Steam Line High Flow Monitoring Subsystem - Instrumentation and Controls

7.6.1.3.3.2.3.1 Identification

Main steam line high flow could indicate a breach in a main steam line. Automatic closure of isolation valves prevents excessive loss of reactor coolant and release of significant amounts of radioactive material from the RCPB.

The main steam line high flow trip setting is high enough to permit isolation of one main steam line for test at rated power without causing an automatic isolation of the other steam lines, yet low enough to permit early detection of a steam line break.

High flow in each main steam line is sensed by four indicating differential pressure sensors that sense the pressure difference across the flow element in each line.

Refer to Section 7.3.1 for a description of the isolation function.

7.6.1.3.3.2.3.2 Power Supplies

Refer to Figures 7.3-1 and 7.3-2.

7.6.1.3.3.2.3.3 Initiating Circuits

Sixteen differential pressure indicating switches, four for each main steam line, monitor the main steam line flow. Four differential pressure indicating sensors are installed on each main steam line and provide the earliest practicable detection of a main steam line break. One differential pressure circuit for each main steam line is associated with each of four logics.

7.6.1.3.3.2.3.4 Logic and Sequencing

When a significant increase in main steam line flow is detected, trip signals are transmitted to the PCRVICS. The PCRVICS initiates closure of all main steam line isolation and drain valves on any significant main steam line break.

Four instrumentation logics are provided to ensure protective action when required and to prevent inadvertent isolation resulting from instrumentation malfunctions. The output trip signal of each

instrumentation channel initiates a division logic trip. The output trip signals of the logic divisions are combined in one-out-of-two-twice and two-out-of-two logics is shown in Figures 7.3-1 and 7.3-2. Logic divisions A or C and B or D are required to initiate main steam line isolation. Logic divisions A and B or C and D are required to initiate main steam line drain isolation. Failure of any one logic does not result in inadvertent action.

7.6.1.3.3.2.3.5 Redundancy and Diversity

Redundancy of trip initiation signals for high flow is provided by two groups of redundant differential pressure sensors for each main steam line. Each differential pressure sensor for each main steam line is associated with one of four logic divisions. Two differential pressure trip channels for each main steam line are supplied from 120 V ac RPS bus A, and two are supplied from 120 V ac RPS bus B.

Diversity of the trip initiation signals for a main steam line break is provided by main steam line high flow, main steam line tunnel ambient temperature and main steam low pressure. An increase in main steam line flow, ambient temperature or a decrease in pressure initiates main steam line drain valve isolation.

7.6.1.3.3.2.3.6 Bypasses and Interlocks

There are no bypasses associated with this system or interlocks to other systems from main steam line high flow trip signals.

7.6.1.3.3.2.3.7 Testability

Testability is discussed in Section 7.3.1.1.2.11.

7.6.1.3.3.2.3.8 Environmental Considerations

This system is designed and qualified to meet the environmental conditions indicated in Section 3.11. In addition, this subsystem is seismically qualified as described in Section 3.10.

The main steam line leak detection containment isolation function is discussed in Section 7.3.1.

7.6.1.3.3.3 RCIC Leak Detection System - Instrumentation and Controls

7.6.1.3.3.3.1 RCIC-LDS Identification

The steam lines of the RCIC system are constantly monitored for leaks and breaks by the following types of monitoring circuits:

a. Equipment area and pipe chase area ambient and differential temperature monitoring (leaks)

b. RCIC steam flow rate monitoring (pipe break)

c. RCIC steam line pressure monitoring (pipe break)

d. RCIC turbine exhaust diaphragm pressure monitoring (pipe break)

Setpoints are predetermined which indicate a possible leak. If the setpoint is reached, an RCIC autoisolation signal is initiated and an annunciator activated in the control room.

7.6.1.3.3.3.2 RCIC-LDS Power Sources

Refer to Sections 7.4.1.1.2 and 7.6.1.3.2.

7.6.1.3.3.3.3 RCIC Equipment Area and Pipe Chase Area Ambient and Differential Temperature Monitoring Subsystem - Instrumentation and Controls

7.6.1.3.3.3.3.1 Circuit Description

RCIC area temperatures are monitored by instrumentation of the LDS. Monitored temperatures include the following:

a. RCIC pipe chase area temperatures

b. RCIC compartment ambient temperature

c. RCIC area ventilation air differential temperature

7.6.1.3.3.3.3.2 Initiating Circuits

For Unit 1, ten ambient temperature elements are installed in the RCIC pipe chase areas. Five sensors are associated with each autoisolation logic division. For Unit 2, eight ambient temperature elements are installed in the RCIC pipe chase areas. Four sensors are associated with each autoisolation logic division. Seven temperature elements are installed in the RCIC equipment compartment. Four of these elements form two differential temperature pairs which monitor high ventilation air differential temperature. One pair is associated with one logic division and the other pair is associated with the other logic division. The other three temperature elements monitor the RCIC pump compartment ambient temperature. One ambient temperature element is associated with one logic division and the other two ambient temperature elements are associated with the other logic division.

7.6.1.3.3.3.3.3 Logic and Sequencing

When any one monitored temperature reaches its setpoint, an RCIC autoisolation signal is initiated and an annunciator activated in the control room.

Closure of the outboard RCIC steam supply isolation valve and steam line warm-up isolation valve is controlled by one logic division and the inboard steam supply isolation valve by the other logic division.

Two instrumentation channels are provided to ensure protective action when required.

In order to close both the inboard and outboard isolation valves, both logic divisions must trip. Protection against inadvertent isolation due to instrumentation malfunction is not required or provided.

The manual bypass switch bypasses the temperature leak detection signal from the RCIC isolation logic. The RCIC isolation is arranged such that a trip of any one of the temperature indicating

switches results in RCIC isolation and RCIC turbine trip. The bypass switch allows testing without isolating the RCIC system. Administrative control is provided by a two-position key-lock bypass switch, with the key removable in the normal position. Separate switches are provided for each of the redundant divisions.

Each RCIC-LDS temperature monitor point has bypass capabilities, but this function is not used.

Divisional level of bypass is indicated automatically in the control room when the respective divisional switch is placed in bypass position. System level annunciation of "RCIC system out-of-service" is automatically annunciated in the control room when either of the bypass switches is placed in the bypass position.

The RCIC isolation function will still be available from the redundant logic. Manual capability to actuate system level annunciation of "RCIC system out-of-service" is provided by separate NORMAL-INOP switches for the redundant divisions. Annunciation will occur when either of the divisional switches is placed in the INOP position. The RCIC bypass switch and the RCIC system is in conformance to Regulatory Guide 1.47. The HPCI leak detection system has a bypass switch that serves the same capacity as the RCIC bypass switch. All of the comments made for the RCIC system are applicable to the HPCI system. The HPCI system conforms to all of the requirements of Regulatory Guide 1.47.

7.6.1.3.3.3.4 RCIC Steam Flow Rate Monitoring Subsystem - Instrumentation and Controls

7.6.1.3.3.3.4.1 Circuit Description

The RCIC steam line connecting the nuclear boiler and the RCIC turbine is monitored by differential pressure sensors which signal a high steam flow rate condition.

7.6.1.3.3.3.4.2 Initiating Circuits

Two differential pressure sensors are installed on separate taps of a venturi flow element inside the primary containment. Steam flow rate in excess of a predetermined setpoint indicates a possible steam line break and initiates a sensor trip signal.

Spurious system isolations are precluded by a time delay that prevents short-term flow peaks from initiating system isolation. At the end of the timing period, system isolation will occur only if the initiating signal remains above the trip setpoint. Time delay will reset each time signal drops below setpoint.

7.6.1.3.3.3.4.3 Logic and Sequencing

The autoisolation logic utilizes one-out-of-two logic. Closure of the outboard RCIC steam supply isolation valve and steam line warm-up isolation valve is controlled by one logic division and the inboard steam supply isolation valve by the other logic division.

7.6.1.3.3.3.5 RCIC Steam Line Pressure Monitoring Subsystem - Instrumentation and Controls

7.6.1.3.3.3.5.1 Circuit Description

The RCIC steam line connecting the nuclear boiler and the RCIC turbine is monitored by four pressure sensors which signal a low steam supply pressure condition.

7.6.1.3.3.3.5.2 Initiating Circuits

Four pressure sensors are installed on the steam pipe. Steam pressure below a predetermined setpoint indicates a possible line break and initiates a sensor trip signal.

7.6.1.3.3.3.5.3 Logic and Sequencing

The autoisolation logic utilizes two-out-of-two logic in each logic division. Closure of the outboard RCIC steam supply isolation valve and steam line warm-up isolation valve is controlled by one logic division and the inboard steam supply isolation valve by the other logic division.

7.6.1.3.3.3.6 RCIC Turbine Exhaust Diaphragm Pressure Monitoring Subsystem - Instrumentation and Controls

7.6.1.3.3.3.6.1 Circuit Description

The RCIC turbine exhaust diaphragm is monitored by pressure sensors which signal a high pressure condition.

7.6.1.3.3.3.6.2 Initiating Circuits

Four pressure sensors monitor the turbine exhaust diaphragm. If monitored pressure exceeds a predetermined setpoint, indicating a possible diaphragm rupture, a sensor trip signal occurs.

7.6.1.3.3.3.6.3 Logic and Sequencing

The autoisolation logic utilizes two-out-of-two logic in each logic division. Closure of the outboard RCIC steam supply isolation valve and steam line warm-up isolation valve is controlled by one logic division, and the inboard steam supply isolation valve by the other logic division.

7.6.1.3.3.3.7 RCIC-LDS Bypasses and Interlocks

Each RCIC-LDS temperature monitor point has bypass capabilities, but this function is not used.

The trip signals from the leak detection area temperature monitors can be bypassed by a manual bypass switch. This switch permits testing of the temperature monitors without initiating system isolation. Bypassing the temperature trip signals in one logic division will not prevent proper operation of the other division. No other bypasses or interlocks are provided.

7.6.1.3.3.3.8 RCIC-LDS Redundancy and Diversity

For Unit 1, redundancy of trip initiation for high ambient temperature is provided by 10 ambient temperature elements installed in RCIC pipe chase areas. Five temperature sensors are associated with each logic division.

For Unit 2, redundancy of trip initiation for high ambient temperature is provided by 8 ambient temperature elements installed in RCIC pipe chase areas. Four temperature sensors are associated with each logic division.

Redundancy of trip initiation signals for high ventilation air differential temperature and RCIC area high ambient temperature is provided by seven temperature elements. Four of these elements

form two differential temperature pairs which monitor high ventilation air differential temperature. One pair is associated with one logic division and the other pair is associated with the other logic division. The other three temperature elements monitor the RCIC pump compartment ambient temperature. One ambient temperature element is associated with one logic division and the other two ambient temperature elements are associated with the other logic division.

Redundancy of steam flow monitoring is provided by two differential pressure sensors, each associated with different logic divisions. Redundancy of RCIC steam supply low pressure monitoring is provided by two pairs of sensors in the RCIC steam supply line, each pair of sensors associated with different logic divisions. Turbine exhaust diaphragm pressure monitoring is provided by two pairs of sensors, each pair associated with different logic divisions.

Diversity of leak detection is provided by monitoring equipment area and pipe chase area ambient and differential temperature monitoring, steam flow rate monitoring, steam line pressure monitoring, and turbine exhaust diaphragm pressure monitoring.

7.6.1.3.3.3.9 RCIC-LDS System Testability

Testability is discussed in Sections 7.3.1.1.2.11.

7.6.1.3.3.3.10 RCIC-LDS Environmental Considerations

This system is designed and has been qualified to meet the environmental conditions indicated in Section 3.11. In addition, this system is seismically qualified as described in Section 3.10.

7.6.1.3.3.4 Reactor Water Cleanup Leak Detection System - Instrumentation and Controls

7.6.1.3.3.4.1 RWCU-LDS Identification

The purpose of this part of the leak detection system is to monitor the RWCU system components and isolate the system should a leak of sufficient magnitude occur.

The RWCU-LDS consists of the following two subsystems:

a. RWCU system high differential flow (Leakage monitoring by the flow comparison of RWCU system water inlet and outlet flow rate)

b. RWCU system area high temperature and differential temperature

The RWCU-LDS uses no manual bypass switch. Annunciation of RWCU isolation system out-of-service is by manual switches. The logic used results in isolation if the flow sensor or if any of the temperature sensors trip. Testing can cause isolation of the RWCU system. This does not present a problem because isolation of the RWCU system does not prevent any safety function.

7.6.1.3.3.4.2 RWCU System High Differential Flow Monitoring Subsystem

7.6.1.3.3.4.2.1 Circuit Description

The RWCU system inlet flow is compared to RWCU outlet flow. A flow element, flow transmitter, and square root converter for each of these three lines provide signals to a common flow summer

that trips two differential flow alarm units on a high differential flow condition. Each flow alarm unit starts a timer that, after a time delay to avoid spurious trips, activates an alarm and isolation. Flow and differential flow indications are provided in the control room.

7.6.1.3.3.4.2.2 Logic and Sequencing

Using one-out-of-two logic, the RWCU flow comparison monitoring circuit initiates an RWCU system isolation signal after a time delay from the time the flow rate difference exceeds a preset limit.

7.6.1.3.3.4.2.3 Bypasses and Interlocks

Each time a high differential flow condition exists, the alarm unit initiates a 45 second time delay to delay the alarm and isolation signal during the normal operation system surge, i.e., pump startup, valving changes, etc; if the high differential flow condition still exists upon timer expiration, then alarm and isolation are initiated. The RWCU system high differential flow monitoring subsystem has no bypass capabilities.

7.6.1.3.3.4.2.4 Redundancy and Diversity

RWCU system isolation redundancy is accomplished by independent actuation of the inboard and outboard isolation valves from their respective logic channels. Actuation signals to the inboard and outboard isolation valves are derived from two separate logic channels using individual trip units.

Diversity is accomplished through isolation by the following monitored variables: high differential flow, and ambient and differential temperature.

7.6.1.3.3.4.3 RWCU Area High Temperature and Differential Temperature Monitoring Subsystem

7.6.1.3.3.4.3.1 Identification

High temperature in the equipment room areas of the RWCU system could indicate a breach of the RCPB portion of the RWCU system. High ambient temperature and high differential temperature in the equipment area ventilation system initiates isolation of the RWCU system.

Refer to Section 7.3.1.1.2 for a description of isolation function of this system.

7.6.1.3.3.4.3.2 Power Supplies

Trip logic channels for the inboard and outboard valves are supplied from RPS 120 V ac bus A and B, respectively.

7.6.1.3.3.4.3.3 Initiating Circuits

Twelve ambient temperature and 12 differential temperature sensing circuits monitor the RWCU system area temperatures. Six ambient and 6 differential temperature circuits are associated with each of two instrumentation channels. Six ambient temperature elements are located in the pump-room and the heat exchanger room. Six pairs of temperature elements are located in the ventilation supply and exhaust areas of the above locations. The locations of the temperature elements provide the earliest practicable detection of any RWCU system high temperature leak.

7.6.1.3.3.4.3.4 Logic and Sequencing

When a significant increase in RWCU system area ambient or differential temperature is detected, trip signals are transmitted to the PCRVICS. The PCRVICS initiates closure of all RWCU system isolation valves.

Two independent instrumentation trip channels are provided to ensure protective action when required. The output trip signal of each instrumentation channel initiates a logic channel and closure of either the inboard or outboard RWCU system isolation valve. In order to close both the inboard and outboard isolation valves, both logic channels must trip. Protection against inadvertent isolation due to instrumentation malfunction is neither required nor provided.

7.6.1.3.3.4.3.5 Redundancy and Diversity

Redundancy of trip initiation signals for high ambient temperature is provided by two ambient temperature elements and associated temperature indicating switches installed in each RWCU system area, with each associated with a different logic channel.

Redundancy of trip initiation signals for high differential temperature is provided by two pairs of differential temperature elements and associated temperature indicating switches in each RWCU system area. Each pair of temperature elements and its temperature indicating switch are associated with one of two logic channels.

Diversity is discussed in Section 7.6.1.3.3.4.2.4.

7.6.1.3.3.4.3.6 Bypasses and Interlocks

RWCU system high ambient and differential temperature trips have no automatic bypasses.

There are no interlocks to other systems from the RWCU system ambient and differential temperature trip signals.

Each RWCU-LDS temperature monitor point has bypass capabilities, but this function is not used.

7.6.1.3.3.4.3.7 Testability

Testability is discussed in Section 7.3.1.1.2.11.

7.6.1.3.3.4.3.8 Environmental Considerations

This subsystem is designed and qualified to meet the environmental conditions indicated in Section 3.11. In addition, this subsystem is seismically qualified as described in Section 3.10.

7.6.1.3.3.5 HPCI System Leak Detection System - Instrumentation and Controls

7.6.1.3.3.5.1 HPCI-LDS Identification

The steam line of the HPCI system is constantly monitored for leaks and breaks by the following types of monitoring circuits:

a. Equipment area and pipe chase area ambient and differential temperature monitoring (leaks)

b. HPCI steam flow rate monitoring (pipe break)

c. HPCI steam line pressure monitoring (pipe break)

d. HPCI turbine exhaust diaphragm pressure monitoring (pipe break)

Setpoints are predetermined which indicate a possible leak. If a setpoint is attained, an HPCI autoisolation signal is initiated and an annunciator is activated in the control room.

7.6.1.3.3.5.2 HPCI-LDS Power Sources

Refer to Section 7.6.1.3.2.

7.6.1.3.3.5.3 HPCI Equipment Area and Pipe Chase Area Temperature Monitoring Subsystem - Instrumentation and Controls

7.6.1.3.3.5.3.1 Circuit Description

HPCI area monitored temperatures include the following:

a. HPCI pipe chase area ambient temperatures

b. HPCI compartment ambient temperature

c. HPCI area ventilation air differential temperature

7.6.1.3.3.5.3.2 Initiating Circuits

Eight ambient temperature elements are installed in the HPCI pipe chase areas. Four sensors are associated with each autoisolation logic division. Seven temperature elements are installed in the HPCI equipment compartment. Four of these elements form two differential temperature pairs which monitor high ventilation air differential temperature. One pair is associated with one logic division and the other pair is associated with the other logic division. The other three temperature elements monitor the HPCI pump compartment ambient temperature. One ambient temperature element is associated with one logic division and the other two ambient temperature elements are associated with the other logic division.

7.6.1.3.3.5.3.3 Logic and Sequencing

When any one monitored temperature reaches its setpoint, an HPCI autoisolation signal is initiated and an annunciator activated in the control room.

Closure of the outboard HPCI steam supply isolation valve and the steam line warm-up isolation valve is controlled by one logic division and the inboard steam supply isolation valve by the other logic division.

Two instrumentation channels are provided to assure protective action when required.

In order to close both the inboard and outboard isolation valves, both logic divisions must trip. Protection against inadvertent isolation due to instrumentation malfunction is not required or provided.

HPCI-LDS is also described in Section 7.6.1.3.3.3.3.3.

7.6.1.3.3.5.4 HPCI Steam Flow Rate Monitoring Subsystem - Instrumentation and Controls

7.6.1.3.3.5.4.1 Circuit Description

The HPCI steam line connecting the nuclear boiler and the HPCI turbine is monitored by differential pressure sensors which signal a high steam flow rate condition.

7.6.1.3.3.5.4.2 Initiating Circuits

Two differential pressure sensors are installed on separate taps of a venturi flow element inside the primary containment. Steam flow rate in excess of a predetermined setpoint indicates a possible steam line leak and initiates a sensor trip signal.

Spurious system isolations are precluded by a time delay that prevents short-term flow peaks from initiating system isolation. At the end of the timing period, system isolation will occur only if the initiating signal remains above the trip setpoint. Time delay will reset each time signal drops below setpoint.

7.6.1.3.3.5.4.3 Logic and Sequencing

The autoisolation logic utilizes one-out-of-two logic to isolate the HPCI steam line. Closure of the outboard HPCI steam supply isolation valve and steam line warm-up isolation valve are controlled by one logic division and the inboard steam supply isolation valve is controlled by a different logic division. Each logic division requires a two-out-of-two pressure signal to isolate the valves.

7.6.1.3.3.5.5 HPCI Steam Line Pressure Monitoring Subsystem - Instrumentation and Controls

7.6.1.3.3.5.5.1 Circuit Description

The HPCI steam line connecting the nuclear boiler and the HPCI turbine is monitored by four pressure sensors which signal a low steam supply pressure condition.

7.6.1.3.3.5.5.2 Initiating Circuits

Four pressure sensors are installed on the steam pipe. Steam pressure below a predetermined setpoint indicates a possible line break and initiates a sensor trip signal.

7.6.1.3.3.5.5.3 Logic and Sequencing

The autoisolation logic utilizes two-out-of-two logic in each logic division. Closure of the outboard HPCI steam supply isolation valve and steam line warm-up isolation valve is controlled by one logic division and the inboard steam supply isolation valve by the other logic division.

7.6.1.3.3.5.6 HPCI Turbine Exhaust Diaphragm Pressure Monitoring Subsystem - Instrumentation and Control

7.6.1.3.3.5.6.1 Circuit Description

The HPCI turbine exhaust diaphragm is monitored by pressure sensors which signal a high pressure condition.

7.6.1.3.3.5.6.2 Initiating Circuits

Four pressure sensors monitor the HPCI turbine exhaust diaphragm. If monitored pressure exceeds a predetermined setpoint, indicating a possible diaphragm rupture, a sensor trip signal occurs.

7.6.1.3.3.5.6.3 Logic and Sequencing

The autoisolation logic utilizes two-out-of-two logic in each logic division. Closure of the outboard HPCI steam supply isolation valve and steam line warm-up isolation valve are controlled by one logic division and the inboard steam supply isolation valve is controlled by the other logic division.

7.6.1.3.3.5.7 HPCI-LDS Bypasses and Interlocks

Each HPCI-LDS temperature monitor point has bypass capabilities, but this function is not used. The trip signals from the leak detection area temperature monitors can be bypassed by a manual bypass switch. This switch permits testing of the temperature monitors without initiating system isolation. Bypassing the temperature trip signals in one division will not prevent proper operation of the other division. No other bypasses or interlocks are provided.

7.6.1.3.3.5.8 HPCI-LDS Redundancy and Diversity

Redundancy of trip initiation for high ambient temperature is provided by 8 ambient temperature elements installed in the HPCI pipe chase areas. Four temperature sensors are associated with each logic division.

Redundancy of trip initiation signals for ventilation air high differential temperature and HPCI area high ambient temperature is provided by seven temperature elements. Four of these elements form two differential temperature pairs which monitor high ventilation air differential temperature. One pair is associated with one logic division and the other pair is associated with the other logic division. The other three temperature elements monitor the HPCI pump compartment ambient temperature. One ambient temperature element is associated with one logic division and the other two ambient temperature elements are associated with the other logic division.

Redundancy of steam flow monitoring is provided by two differential pressure sensors, each associated with different logic divisions. Redundancy of HPCI steam supply low pressure monitoring is provided by two pairs of sensors in the HPCI steam supply line, each pair of sensors associated with different logic divisions. Redundancy of turbine exhaust diaphragm pressure monitoring is provided by two pairs of sensors, each pair associated with different logic divisions.

Diversity of leak detection is provided by monitoring equipment area and pipe chase area ambient and differential temperature monitoring, steam flow rate monitoring, steam line pressure monitoring, and turbine exhaust diaphragm pressure monitoring.

7.6.1.3.3.5.9 HPCI-LDS Testability

Testability is discussed in Sections 7.3.1.1.2.11.

7.6.1.3.3.5.10 HPCI-LDS Environmental Considerations

This system is designed and has been qualified to meet the environmental conditions indicated in Section 3.11. In addition, this system is seismically qualified as described in Section 3.10.

7.6.1.4 Neutron Monitoring System - Instrumentation and Controls

The NMS consists of the following safety- related systems:

a. IRM system

b. LPRM system

c. APRM system

The nonsafety-related portion is described in Section 7.7.1.6.

The NMS FCD is shown in Figure 7.6-4, and the ranges of the systems are shown in Figure 7.6-8.

7.6.1.4.1 NMS Identification

The purpose of this system is to monitor power generation in the core and provide signals to the RPS, the RRCS, and the rod block portion of the RMCS. It also provides information for operation and control of the reactor.

The IRM and APRM systems provide a safety function and are designed to meet particular requirements established by the NRC. The LPRM system is designed to provide a sufficient number of LPRM inputs to the APRM system to meet the APRM requirements. All other portions of the NMS have no safety function. The system is classified as shown in Table 3.2-1. The safety-related systems are seismically and environmentally qualified as described in Sections 3.10 and 3.11 (Section 7.2.1).

7.6.1.4.2 NMS Power Sources

The power sources for each system are discussed in the individual circuit descriptions that follow.

7.6.1.4.3 Intermediate Range Monitor System

7.6.1.4.3.1 IRM Equipment Design

7.6.1.4.3.1.1 IRM Circuit Description

The IRM monitors neutron flux from the upper portion of the SRM range to the lower portion of the APRM range. The IRM system has eight IRM channels, each of which includes one detector that can be positioned in the core by remote control. The detectors are inserted into the core for a reactor startup and are withdrawn after the reactor mode selector switch is turned to RUN.

a. Power supply

Power is supplied separately from the two 120 V ac RPS sources. The channels are arranged so that loss of a power supply results in the loss of only one trip system of the RPS.

b. Physical arrangement

Each detector assembly consists of a miniature fission chamber attached to a low loss, quartz/fiber insulated transmission cable. When coupled to the signal conditioning equipment, the detector produces a reading of full-scale on the most sensitive range with a neutron flux of $4x10^8$ nv. The detector cable is connected underneath the reactor vessel to a triple-shielded cable that carries the pulses generated in the fission chamber to the preamplifier.

The detector and cable are located in the drywell. They are movable in the same manner as the SRM detectors and use the same type of mechanical arrangement (Figures 7.6-2 and 7.6-3).

c. Signal conditioning

A voltage amplifier unit located outside the drywell serves as a preamplifier. This unit converts the current pulses to voltage pulses, modifies the voltage signal, and provides impedance matching. The preamplifier output signal is coupled by a cable to the IRM signal conditioning electronics (Figure 7.6-5).

Each IRM channel receives its input signal from the preamplifier and operates on it with various combinations of preamplification gain and amplifier attenuation ratios. The amplification and attenuation ratios of the IRM and preamplifier are selected by a remote range switch that provides 10 ranges of increasing attenuation (the first six called low range and the last four called high range) acting on the signal from the fission chamber. As the neutron flux of the reactor core increases from $1x10^8$ nv to $1.5x10^{13}$ nv, the signal from the fission chamber is attenuated to keep the input signal to the inverter in the same range. The output signal, which is proportional to neutron flux at the detector, is amplified and supplied to a locally mounted meter. Outputs are also provided for a remote meter and recorder.

d. Trip functions

The IRM scram trip functions are discussed in Section 7.2. The IRM trips are shown in Table 7.6-2. The IRM rod block trip functions are discussed in Section 7.7.

7.6.1.4.3.1.1.1 IRM Bypasses and Interlocks

The arrangement of IRM channels allows one IRM channel in each group of four channels (A, C, E, and G, and B, D, F, and H) to be bypassed without compromising intermediate range neutron monitoring.

7.6.1.4.3.1.1.2 IRM Redundancy

The IRM system consists of eight IRM channels, four of which are connected to one RPS trip system and the other four are connected to the other RPS trip system. The redundancy and single failure requirements are met because any single failure with the IRM system cannot prevent needed safety action of the RPS (Section 7.2.1.1.4.1).

7.6.1.4.3.1.1.3 IRM Testability

Each IRM channel is tested and calibrated using written procedures. The IRM detector drive mechanisms and the IRM rod blocking functions are checked in the same manner as the SRM channels. Each IRM channel can be checked to ensure that the IRM high flux scram function is operable.

7.6.1.4.3.1.2 IRM Environmental Considerations

The wiring, cables, and connectors located in the drywell are designed for the same environmental conditions as the SRMs.

The IRM preamplifier, located in the reactor enclosure, and the monitor, located in the control room, are designed to operate under all expected environmental conditions in those areas. These IRM system components are designed to operate during and after design basis events, including earthquakes, and anticipated operational occurrences (Sections 3.10 and 3.11).

7.6.1.4.3.1.3 IRM Operational Considerations

The IRM range switches are upranged or downranged to follow increases and decreases in power within the range of the IRM to prevent either a scram or a rod block. The IRM detectors are inserted into the core whenever these channels are needed, and withdrawn from the core, when permitted, to prevent their burnup. The identification scheme for the IRM system is given in Section 7.2.

7.6.1.4.4 Local Power Range Monitor System

7.6.1.4.4.1 LPRM Equipment Design

7.6.1.4.4.1.1 LPRM Circuit Description

The LPRM consists of fission chamber detectors, signal conditioning equipment, and trip circuits. The LPRM provides outputs to the APRM, the RBM, and the process computer. The LPRM signal processing is performed by the same electronic equipment that performs the APRM functions.

a. Power supply

   Power for the LPRM, associated APRM channel, and channelized RBMs is provided by two independent 120 V ac buses, each of which is supplied by a UPS. Detector polarizing voltage for the LPRMs is supplied by eight pairs of redundant

LPRM detector DC power supplies, adjustable from 75 to 200 VDC. Each LPRM detector DC power supply pair powers approximately one-eighth of the LPRMs. Power for the LPRM detector DC power supplies comes redundantly from the two 120 Vac buses via intervening DC power supplies.

The LPRM detector DC power supplies are located in the electronic chassis that houses the LPRM signal processing equipment. Each electronic chassis houses one pair of LPRM detector DC power supplies and the electronics for processing approximately one-eight of the total LPRM detector signals (or approximately one-half of the 43 detectors per APRM/LPRM channel).

The intervening DC supplies are located in a separate power supply chassis. Each power supply chassis contains up to 4 Low Voltage DC Power Supplies (LVPSs). One of the 120 Vac busses provides input power to 2 of the LVPSs in the power supply chassis while the second 120 Vac bus provides input power to the other two LVPSs in the power supply chassis. Two of the LVPSs in the power supply chassis, one operating from each of the two 120 Vac busses, supply “auctioned” low voltage power to the electronic chassis. If either of the two 120 Vac power busses is lost, or if either of the two LVPSs fail, the remaining LVPS will continue to supply low voltage power to the electronic chassis.

The auctioned low voltage power input to the electronic chassis provides power to each of the pair of LPRM detector DC power supplies in the electronic chassis, and the LPRM (and APRM) signal processing hardware in the chassis. The LPRM detector polarizing voltage for all of the detectors processed by the electronic chassis (21 in one chassis and 22 in the other) is normally provided by one of the two LPRM detector DC power supplies in the electronic chassis. If that one DC power supply fails, the second LPRM detector DC power supply is automatically switched in to supply LPRM detector polarizing voltage.

The 75 - 200 Vdc LPRM detector DC power supplies can supply up to 3 milliamperes for each LPRM detector which ensures that the chambers can be operated in the saturated region at the maximum specified neutron fluxes. The voltage applied to the detectors varies no more than 2 Vdc over the maximum variation of electrical input and environmental parameters.

b. Physical arrangement

The LPRM includes 43 LPRM detector assemblies having detectors located at different axial heights in the core. Each detector assembly contains 4 fission chambers. These assemblies are distributed to monitor four horizontal planes throughout the core. Figure 7.6-6 shows the LPRM detector radial layout scheme that provides a detector assembly at every fourth intersection not containing control crosses of the water channels around the fuel bundles. Thus, the uncontrolled water gap has either an actual detector assembly or a symmetrically equivalent assembly in some other quadrant. The LPRM assembly consists of 4 neutron detectors permanently installed in a housing (Figure 7.6-6). The assemblies are installed and removed through the top of the vessel (when the head is removed). The upper end of the assembly is held to the top of the fuel guide by a spring-loaded plunger. A permanently installed sleeve (incore guide tube and incore housing) locates and constrains the assembly below the lower core plate and provides a sealing surface under the reactor vessel. Special sealing caps are

placed over the connection end of the assembly and over the penetration at the bottom of the vessel during installation or removal of an assembly. This prevents loss of reactor coolant water on removal of an assembly and also prevents the connection end of the assembly from being immersed in the water during installation or removal.

Each LPRM detector assembly contains 4 miniature ion chambers with an associated solid sheath cable. The chambers are vertically spaced in the LPRM detector assemblies in a way that gives adequate axial coverage of the core, complementing the radial coverage given by the horizontal arrangement of the LPRM detector assemblies. Each ion chamber produces a current that is coupled with the LPRM signal conditioning equipment to provide the desired scale indications.

Each miniature chamber consists of 2 concentric cylinders that act as electrodes. The inner cylinder (the collector) is mounted on insulators and is separated from the outer cylinder by a small gap. The gas between the electrodes is ionized by the charged particles produced as a result of neutron fissioning of the uranium-coated outer electrode. The chamber is operated at a polarizing potential of approximately 100 V dc. The negative ions produced in the gas are accelerated to the collector by the potential difference maintained between the electrodes. In a given neutron flux, all the ions produced in the ion chamber can be collected if the polarizing voltage is high enough. When this situation exists, the ion chamber is considered to be saturated. Output current is then independent of operating voltage.

Each assembly also contains a calibration tube for a TIP. The enclosing tube around the entire assembly contains holes that allow circulation of the reactor coolant water to cool the ion chambers. Numerous tests have been performed on the chamber assemblies, including tests of linearity, lifetime, gamma sensitivity, and cable effects. These tests and experience in operating reactors provide confidence in the ability of the LPRM system to monitor neutron flux to the design accuracy throughout the design lifetime.

c. Signal conditioning

The current signal from the LPRM detectors are transmitted to LPRM amplifiers located on LPRM Input Modules in the APRM/LPRM electronic chassis in the Auxiliary Equipment Room. Each LPRM Input Module provides amplification for up to 5 LPRM detector signals. The current signal from a chamber is transmitted directly to its amplifier through coaxial cable. The amplifier is a linear current amplifier whose voltage output is proportional to the current input and therefore proportional to the magnitude of the neutron flux. The amplifier output is “read” by the digital processing electronics. The digital electronics applies hardware gain corrections, performs filtering, and applies the LPRM gain factors. The digital electronics provide suitable output signals for the computer, recorders, annunciators, etc. The LPRM amplifiers also isolate the detector signals from the rest of the processing so that individual faults in one LPRM signal path will not affect other LPRM signals.

The LPRM signals can be read by the operator on the reactor console on either the APRM ODAs or the RBM ODAs. LPRM readings can be read on the APRM ODAs

by selecting summary LPRM displays. When a control rod is selected for movement, LPRM readings can be read on the RBM ODAs for the 16 LPRM detectors nearest to the selected rod (see Figure 7.7-14).

d. Trip functions

The trip functions for the LPRM provide trip signals to activate annunciators and displays on ODAs. Table 7.6-3 indicates the trips.

The trip levels can be adjusted to within ±0.1% of full-scale deflection and are accurate to ±1% of full- scale deflection in the normal operating environment.

7.6.1.4.4.1.1.1 LPRM Bypasses and Interlocks

Each LPRM channel may be individually bypassed. When the maximum number of bypassed LPRMs associated with any APRM channel has been exceeded, an APRM trouble alarm is generated by that APRM.

7.6.1.4.4.1.1.2 LPRM Redundancy

The LPRMs are divided into four groups for separation purposes. The LPRMs are separated so that in the event of a single failure under permissible APRM bypass conditions, a scram signal can be generated in the RPS when required.

7.6.1.4.4.1.1.3 LPRM Testability

LPRM channels are calibrated using data from previous full power runs and TIP data and can be tested with written procedures. The update uncertainty assigned to the LPRMs is twice the update uncertainty value specified in GE topical licensing report NEDC-32694P-A, "Power Distribution Uncertainties for Safety Limit MCPR Minimum Critical Ratio Evaluations, dated August 1999.

7.6.1.4.4.1.2 LPRM Environmental Considerations

Each individual chamber of the assembly is a moisture-proof, pressure-sealed unit. The chambers are designed to operate up to 600°F and 1250 psig. The wiring, cables, and connectors located within the drywell are designed for continuous-duty up to 150°F at 90% relative humidity and a single exposure to a peak temperature of 340°F at 100% relative humidity. The LPRMs are capable of functioning during and after design basis events such as earthquakes and anticipated operational occurrences (Sections 3.10 and 3.11).

7.6.1.4.4.1.3 LPRM Operational Considerations

The LPRM is a monitoring system with no special operating considerations.

7.6.1.4.5 Average Power Range Monitor System

(References 7.6-1 through 7.6-4 and Reference 7.6-6.)

7.6.1.4.5.1 APRM Equipment Design

7.6.1.4.5.1.1 APRM Circuit Description

The APRM System has four APRM channels. Each APRM uses input signals from 43 LPRM detectors. Each of the four APRM channels provides input to four 2-out-of-4 voter channels. Two of the voter channels are associated with each of the trip systems of the Reactor Protection System.

a. Power supply

Power for the LPRM, associated APRM channel, and channelized RBMs is provided by two independent 120 Vac buses, each of which is supplied by a UPS. Each APRM 2-out-of-4 voter channel receives power from one of the two 120 Vac busses with each bus supplying power to two of the voter channels. The APRM, LPRM and RBM functions will continue to operate as long as either of the two 120 Vac busses is still available. However, if one of the two 120 Vac busses is lost, the two Voter Channels supplied by that bus will go to the tripped state resulting in a RPS half scram.

b. Signal conditioning

The APRM channel uses digital electronic equipment which averages the output signals from a selected set of LPRMs, generates trip outputs via the 2-out-of-4 voter channels (see Section 7.6.1.4.5.1.1.c), and provides signals to readout equipment.

Each APRM channel can average the output signals from up to 43 LPRM channels. Assignment of LPRM channels to an APRM is shown in Table 1A and 1B on Figure 7.6-1 (Sheets 2 and 4) with the distribution through the core shown in Figure 7.2-9. The letters at the detector locations in Figure 7.6-1 refer to the axial positions of the detectors in the LPRM detector assembly. Position A is the bottom position, positions B and C are above position A, and position D is the top most LPRM detector position. The pattern provides LPRM signals from all four core axial LPRM detector positions throughout the core. Some LPRM detectors may be bypassed, but the averaging logic automatically corrects for these by removing them from the average.

The APRM flux value is developed by averaging the LPRM signals and then adjusting the average by a digitally entered factor to allow calibration of the APRM to be APRM power. The APRM power is processed through a first order filter with a six second time constant to calculate simulated thermal power. The APRM simulated thermal power upscale rod block and scram trip setpoints are varied as a function of reactor recirculation flow. The slope of the upscale rod block and scram trip response curves is set to track the required trip setpoint with recirculation flow changes. These calculations are all performed by the digital processor and result in a digital representation of APRM and simulated thermal power, and of the flow-biased rod block and scram setpoints.

Each APRM channel calculates a flow signal which is used to determine the APRM's flow-biased rod block and scram setpoints (see Figure 7.6-1). Each signal is determined by summing the flow signals from the two recirculation loops. These signals are sensed from two flow elements, one in each recirculation loop. The differential pressure from each flow element is routed to four differential pressure

transducers (eight total). The signals from two differential pressure transducers, one from each flow element, are routed to two inputs to each APRM digital electronics.

Each APRM also includes an OPRM Upscale Function. For this function, LPRMs are assigned to up to four OPRM cells with each cell including 4 LPRMs (see Figure 7.2-17). The OPRM function combines the signals from each LPRM in an OPRM cell and evaluates that combined cell signal using the OPRM algorithms to detect thermal-hydraulic instabilities.

All APRM channels are powered redundantly, via intervening low voltage DC power supplies, from both of the two APRM 120 Vac UPS power busses. The LPRM signal processing equipment is powered by the same sources as their associated APRM channels.

c. Trip function

The APRM trip functions are performed by digital comparisons with APRM electronics. For each RPS trip and rod block alarm, the APRM power of simulated thermal power, as applicable, is compared to the setpoint. If the power value exceeds the setpoint, the applicable trip is issued. Trip signals from each APRM channel are provided, via APRM interface hardware directly to the Reactor Manual Control System and via the APRM 2-out-of-4 voter channels to the Reactor Protection System (RPS). Table 7.6-4 lists the APRM trip functions and trip settings.

An OPRM upscale trip output is generated from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux indicated by the combined signals for the LPRM detectors in a cell with the period confirmations and relative cell amplitude exceeding specific setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM upscale trip is also issued from any APRM channel if either the growth rate or amplitude based algorithms detect growing oscillatory changes in the neutron flux from one or more cells in that channel. The OPRM upscale trip output is automatically enabled (not-bypassed) when the combined APRM STP is equal to or above the OPRM auto-enable power setpoint and recirculation flow is below the OPRM auto-enable flow setpoint. The OPRM upscale trip output is automatically bypassed when STP and/or recirculation flow are not within the OPRM trip enabled region. The OPRM upscale trip is active only when the reactor mode switch is in the RUN position.

At least two unbypassed APRM channels must be in the APRM upscale trip or inoperative trip state to cause an APRM/Inop RPS trip output from the APRM 2-out-of-4 voter channels (see Figure 7.6-7). Similarly, at least two unbypassed APRM channels must be in the OPRM upscale trip state to cause an OPRM RPS trip output from the APRM 2-out-of-4 voter channels. The APRM/Inop and OPRM trips are voted independently. In either of these conditions, all four voter channels will provide a RPS trip output, two to each RPS trip system. If only one unbypassed APRM channel is providing a trip output, each of the four APRM 2-out-of-4 voter channels will have a half-trip, but no trip signals will be sent to the RPS. Trip

outputs to the RPS are transmitted by removing voltage to a relay coil, so loss of power results in actuating the RPS trips. A simplified APRM/RPS interface circuit arrangement is shown in Figure 7.2-6.

Any one unbypassed APRM can initiate a rod block. Subsection 7.7, "Reactor Manual Control System," describes in more detail the APRM rod block functions.

In the startup mode of operation, the APRM "fixed" upscale trip setpoint is set down to a low level. This trip function is provided in addition to the existing IRM upscale trip in the startup mode.

The trips from one APRM can be bypassed by operator action in the control room, which bypasses both the APRM/Inop and OPRM trips from that APRM channel.

d. RRCS interface

APRM signal levels are sent to the RRCS to enable the initiation of the logic if additional reactivity control is necessary following an ATWS event. The use of this signal is discussed in Section 7.6.1.8.

7.6.1.4.5.1.1.1 APRM Bypasses and Interlocks

One of the four APRM channels can be bypassed at any time. None of the APRM 2-out-of-4 voter channels can be bypassed. An interlock circuit provides an APRM trouble alarm whenever the number of LPRM inputs to an APRM is less than the required minimum.

7.6.1.4.5.1.1.2 APRM Redundancy

Four independent channels of APRMs monitor neutron flux and each channel provides inputs to all four independent APRM 2-out-of-4 voter channels. A trip condition in any one APRM channel does not cause the APRM 2-out-of-4 voters to initiate a trip in any RPS trip system. The APRM 2-out-of-4 voter must recieve a trip signal from at least two unbypassed APRM channels in order to initiate a trip in any RPS trip system.

7.6.1.4.5.1.1.3 APRM Testability

APRM channels are calibrated using data from previous full power runs and are tested by written procedures. Each APRM channel can be tested individually for the operability of the APRM scram and rod blocking functions by introducing test signals.

7.6.1.4.5.2 APRM Environmental Considerations

All APRM equipment is installed in the control structure and operated in the environment as described in Section 3.11. The APRM system is capable of functioning during and after the design basis events, including earthquakes and anticipated operational occurrences (Sections 3.10 and 3.11).

7.6.1.4.5.3 APRM Operational Considerations

The APRM system is a monitoring system that has no special operational considerations.

7.6.1.5 Safety/Relief Valve Positions Indication System - Instrumentation and Controls

7.6.1.5.1 SRVPI System Identification

A positive and reliable OPEN/NOT OPEN indication of the SRVs alerts the operator to abnormal valve position which could cause release of reactor coolant.

The SRVPI system provides an indication and alarm of SRV position through the use of acoustic sensors. Accelerometers, two per valve, are mounted on piping downstream of the SRV. When an SRV is actuated, the accelerometer produces a signal proportional to the flow noise through the valve. This signal is then amplified and transmitted to a signal conditioning unit.

Each SRV is instrumented with two channels (active and passive) of in-containment equipment, consisting of accelerometers and connecting cables. The signals from both channels are routed to the SRVPI preamplifier where the active signal is amplified and routed to the SRVPI cabinet in the control room and used for alarm and indication, while the passive signal is available if needed.

7.6.1.5.2 SRVPI Power Supplies

The SRVPI system is powered from a 120 V ac UPS.

7.6.1.5.3 SRVPI Initiating Circuits

The SRVPI system senses steam flow through the valve and indicates OPEN/NOT OPEN status of the SRVs. It does not interface with, or provide actuation for any other system.

7.6.1.5.4 SRVPI Logic and Sequencing

Logic and sequencing do not apply to the SRVPI system.

7.6.1.5.5 SRVPI Bypasses and Interlocks

There are no bypasses or interlocks associated with this system.

7.6.1.5.6 SRVPI Redundancy and Diversity

Each SRV is provided with an active and a passive instrumentation channel. Each channel consists of an accelerometer and associated cables. The active and passive channel signals are routed to the preamplifier. The active channel signal is amplified, routed to the SRVPI cabinet in the control room and used for alarm and indication.

The passive channel signal is available for use at the preamplifier outside containment if a component of the active channel should fail. The SRV temperature monitoring system (Section 7.7.1.16.7) provides a backup for the SRVPI system. It senses valve opening through a diverse means. Another diverse means of valve position indication is provided by the redundant safety-grade suppression pool temperature monitoring system, powered from a Class 1E power source.

7.6.1.5.7 SRVPI Testability

Proper operation of each SRVPI channel can be checked during plant operations.

7.6.1.5.8 SRVPI Environmental Considerations

The SRVPI system is designed to operate under both environmental and seismic conditions as outlined in Sections 3.11 and 3.2.

7.6.1.5.9 SRVPI Operational Considerations

7.6.1.5.9.1 General Information

The SRVPI system uses acoustic sensors (accelerometers) to monitor steam flow through the SRV. When the signal generated from the sensor reaches a predetermined level, alarms in the control will actuate to alert the operator of an open SRV.

7.6.1.5.9.2 SRVPI Reactor Operator Information

The OPEN/NOT OPEN/WAS OPENED status of each SRV is provided for the operator in the control room, as well as a common annunciator indicating an open SRV.

7.6.1.5.9.3 SRVPI Setpoints

The setpoints for SRVPI are determined individually for each SRV using information obtained during system installation and initial plant testing. Cross-talk measurements are conducted to ensure that an alarming SRV will not cause another SRV to alarm.

7.6.1.6 Containment Instrument Gas System – Automatic Depressurization System Control - Instrumentation and Controls

7.6.1.6.1 CIGS-ADS Description

The CIGS-ADS consists of nitrogen bottles, pressure controls, and instrumentation and associated piping which tie into the two instrument gas supply headers to the ADS valves as shown in Section 9.3.1.3 and drawing M-59.

In the event that the nonsafety-related CIGS header is unable to supply gas to its ADS valves for use during long-term shutdown cooling or vessel venting, the gas supply for that header is automatically switched to its CIGS-ADS gas bottles. The CIGS-ADS gas bottles must be connected at all times during normal operation. Each CIGS-ADS header supplies instrument gas to its respective ADS valves. One set of ADS valves and its gas supply will meet the requirements for the backup long-term shutdown cooling path.

7.6.1.6.2 CIGS-ADS Initiating Circuits

The CIGS-ADS is initiated by a pressure switch which senses low pressure in the respective ADS gas supply header. The system can also be initiated manually.

7.6.1.6.3 CIGS-ADS Logic

In the event that low pressure is sensed in an ADS gas supply header, a pressure switch causes a solenoid-operated valve in the supply line from the CIGS to close and a solenoid-operated valve in

the CIGS-ADS supply to that header to open. Those actions may be controlled manually from the control room.

7.6.1.6.4 CIGS-ADS Bypasses

There are no bypasses in the CIGS-ADS.

7.6.1.6.5 CIGS-ADS Interlocks

The CIGS-ADS is interlocked with the nonsafety-related CIGS so that only one system at a time will provide instrument gas to the ADS valves.

7.6.1.6.6 CIGS-ADS Redundancy and Diversity

Diversity is not required for the CIGS-ADS. The CIGS-ADS is redundant in that each header is supplied by its own gas supply and separate divisional safeguard power.

7.6.1.6.7 CIGS-ADS Actuated Devices

The solenoid-operated shutoff valves in the CIGS supply line and the solenoid-operated shutoff valves in the CIGS-ADS supply line are actuated by this system.

7.6.1.7 Safeguard Piping Fill System - Instrumentation and Controls

7.6.1.7.1 SPFS Description

The SPFS pumps take suction from the suppression pool by way of the core spray suction line and discharge into the ECCS pump discharge lines to maintain these lines in a full condition. In this capacity, they are a backup to the condensate transfer system, which is the primary water source for keeping the ECCS discharge lines full. The SPFS pumps also discharge into the feedwater lines to provide a water seal in the event of any line break other than a feedwater line break inside containment. The SPFS is a supporting system to the ECCS.

7.6.1.7.2 SPFS Initiating Circuits

The SPFS is manually operated.

7.6.1.7.3 SPFS Logic

The SPFS pumps are started and stopped manually from the main control room. The shutoff valves to the feedwater lines are manually operated from the main control room. Refer to drawing M-52FD for logic diagram.

7.6.1.7.4 SPFS Bypasses and Interlocks

There are no bypasses or interlocks in the SPFS.

7.6.1.7.5 SPFS Redundancy and Diversity

There are two pumps powered from separate Class 1E buses in different divisions. Distribution of fill water from each pump is in accordance with redundancy of the ECCS (i.e., the A SPFS pump delivers fill water to RCIC, RHR loops A & C, etc.).

Each pump can provide seal water to either or both of the feedwater lines. There is a shutoff valve to each feedwater line from each pump. The shutoff valves from each pump are in the same division as their associated pump.

No diversity is provided for this system.

7.6.1.7.6 SPFS Actuated Devices

There are no actuated devices in this system.

7.6.1.8 Redundant Reactivity Control System – Instrumentation and Controls

7.6.1.8.1 RRCS System Identification

The RRCS is designed to mitigate the potential consequences of an ATWS event. The system consists of control panels, their associated ATWS detection and actuation logic, and the necessary interface logic to the recirculation system, the feedwater system, the SLCS, and the ARI components of the CRD system required to perform specific functions in response to an ATWS event.

7.6.1.8.2 RRCS Power Sources

RRCS Division 1, channels A and B are powered by the 125 V dc Bus A (Division 1), and RRCS Division 2, channels A & B are powered from 125 V dc Bus B (Division 2). The power supplies to the RRCS functions are available during all potential ATWS initiating events, including those events involving loss of normal power supplies.

7.6.1.8.3 RRCS Equipment Design

The RRCS consists of vessel pressure and level sensors, solid-state logic, control room cabinets and indications, and interfaces with several systems actuated to mitigate an ATWS event (Figure 7.6-10). The solid-state logic is divided into Divisions 1 and 2, each of which is subdivided into channels A and B. The logic is energized to trip, and both channels A and B of either division must be tripped to initiate the RRCS protective actions. The system can be manually initiated by depressing two push buttons (tripping both channels A and B) in the same division. This manual initiation function is designed so that no single operator action can result in an inadvertent initiation. The push button collar must be rotated to arm the switch before depressing will trip the logic. The manual initiation push buttons are located in the control room near the RPS manual scram push buttons. There are four RRCS manual initiation push buttons.

The RRCS logic monitors reactor dome pressure and water level. The logic will cause the immediate energization of the ARI valves when either the reactor high pressure trip setpoint or low water level 2 setpoint is reached, or the manual push buttons are armed and depressed (Table 7.6-5). Energization of the RRCS ARI valves depressurizes the scram air header independent of the logic and vent valves of the RPS system (Figure 7.6-11). The valves are sized to allow insertion of all control rods to begin within 15 seconds. Additional immediate RRCS response to the initiation signals include recirculation system pump motor breaker trip immediately if reactor

high pressure is received or 9 seconds after a low water level 2 signal is received. The high pressure initiation signal will initiate a feedwater runback after 25 seconds whether the feed pumps are in automatic or manual if the APRM not downscale trip signal is present. If power is not downscale after a 118 second time delay from the beginning of the ATWS event, the RWCU system will be isolated and the SLCS will be automatically initiated. Ten minutes after the SLCS initiation, the RRCS can be reset, provided that RRCS actuation parameters have reset and the RRCS manual reset push buttons are depressed.

The RRCS is continually checked by a solid-state microprocessor based self-test system. This self-test system checks the RRCS sensors, logic, and protective devices and itself.

7.6.1.8.3.1 RRCS Alternate Rod Insertion

The RRCS signal to insert the control rods is generated in either of two separate divisions (two-out-of-two logic in a given division) and results in the energization of eight valves. Two of these, F160A and B, vent the scram air supply line downstream of the F110A and B backup scram valves (Figure 7.6-11). These RRCS valves also act to block the supply of air to the scram header. Check valves F161A and B provide an air flow path around the F160 valves in the event one or more of the valves fails. Four additional RRCS valves (F162A, B, C, and D) vent the A and B scram header to the atmosphere. As the header depressurizes, the scram valves at each HCU will spring open, scramming the rods. Two RRCS valves (F163A and B) vent the scram air header to the SDV drain and vent valves, closing these valves and isolating the SDV. All eight RRCS ARI valves are normally de-energized. Positive position of the ARI solenoid valves is shown by voltage and plant air indications.

The ARI signal can be reset after a 30 second time delay, provided that the high reactor pressure, low water level 2, and manual initiation signals no longer exist.

7.6.1.8.3.2 RRCS Recirculation System Trips

The ATWS RPT contributes to the mitigation of the consequences of an ATWS event by tripping the recirculation pumps early in the event, reducing core flow and thereby reducing the core power generation.

Low water level 2 or high reactor pressure RRCS signals cause a trip of the recirculation pump drive motor breakers 3A, 3B, 4A, and 4B. There are two separate divisions of instrumentation with divisional power sources, each one with two pressure sensors and two level sensors. A reactor vessel high dome pressure signal from either division will immediately trip both recirculation pump motors. A reactor vessel low water level signal from either division will trip both recirculation pump motors after a 10 second delay. This reduction in core flow protects the vessel and fuel during the ATWS event by limiting core power during the time required for the scram air header to depressurize sufficiently to open the scram valves.

Both sensors in either division (i.e., two level sensors in one division or two pressure sensors in one division) are required to generate a trip signal. The ATWS RPT pump breakers are the same ones used in the EOC RPT. There are two breakers in series in each pump motor feed; the control logic of each breaker is assigned to a separate safety division.

Manual initiation of RRCS without reactor high pressure or reactor low level 2 does not trip the recirculation pump drive motor breaker; however, after manual initiation of RRCS, the breaker trip will occur if either reactor high pressure or low level 2 occur.

The ATWS RPT trip circuitry is separate from and independent of the EOC RPT trip circuitry. Separate trip coils are used in each breaker (one for ATWS RPT and one for EOC RPT). The trip coils are fed from RPS power supplies.

The trip circuits, including the sensors and the pump breakers, are Class 1E. The entire trip circuits may be tested during plant operation, except for opening of the pump breakers. ATWS RPT circuitry is separated from non-Class 1E circuitry in accordance with the LGS separation criteria.

Indicators and annunciators in the control room provide the status of the trip coils and the mechanical position of the pump circuit breakers. Actuation of the ATWS-RPT is recorded in the control room.

7.6.1.8.3.3 RRCS Feedwater Runback

The feedwater runback function mitigates the consequences of an ATWS event by stopping feedwater flow into the vessel, which reduces the core subcooling, thereby reducing the core power generation.

Reactor high pressure combined with a 25 second time delay and APRM power not downscale will initiate a feedwater runback. Feedwater flow will be reduced to 0% within 15 seconds. The logic to initiate feedwater runback is energized to trip and can be manually overridden 30 seconds after runback initiation. The runback reduces the input of cooler water flowing to the vessel. As average core coolant temperature increases, voids increase, reactivity decreases, and power is reduced.

The RRCS feedwater runback will occur whether the feed pumps are in automatic or in manual mode of control. The normal loss of signal interlock that prohibits changes in feedwater pump output during loss of signal conditions is disabled during ATWS.

7.6.1.8.3.4 Standby Liquid Control System Initiation

Low water level 2, reactor high pressure, or manual initiation of the RRCS immediately starts a timer. A signal will be sent to initiate the SLCS if, at the expiration of a 118 second time delay, the core power is not downscale as measured by the APRM system. Initiation of the SLCS requires start signals from both channels A and B of either division of RRCS. Receipt of these signals starts the two in-service pumps and causes the associated squibs to fire, opening the explosive valves. Both pumps will inject borated water into the vessel until the storage tank low level sensors, arranged in two-out-of-two logic, trip the pumps.

The SLCS pump control switches can be used to manually stop SLCS pump injection.

7.6.1.8.3.5 RRCS Impact on Other Systems

7.6.1.8.3.5.1 Reactor Water Cleanup System Isolation

When the SLCS is initiated to inject the neutron absorber into the reactor, the inboard isolation valve of the RWCU system is automatically closed from the SLCS Division 1 or 3 logic and the outboard valve is closed from the SLCS Division 2 logic. This RWCU isolation prevents removal and dilution of the neutron absorber.

7.6.1.8.3.5.2 Nuclear Boiler Instrumentation

Nuclear boiler system instrumentation is provided to monitor the reactor parameters required for ATWS mitigation and to provide signals that are indicative of a potential ATWS event. The instrumentation is provided to monitor reactor vessel high dome pressure and low vessel water level. The sensors, transducers, and trip units are Class 1E, independent from the RPS, and environmentally qualified to perform their protective function during ATWS events.

7.6.1.8.3.5.3 Neutron Monitoring System

The APRMs through the APRM interface hardware, provide a not downscale trip signal to the RRCS permissive logic. This signal is Class 1E and contains all available channels of input. APRM signals from NMS Divisions 1 and 2 are routed to RRCS Division 1 through isolators, and APRM signals from NMS Divisions 3 and 4 are sent to RRCS Division 2 through isolators. Loss of power to an APRM channel or an APRM INOP condition will result in an RRCS permissive signal. Bypassing an APRM channel will prevent the bypassed APRMs not downscale or INOP trip from supplying a permissive. Only one APRM at a time can be bypassed.

7.6.1.8.3.6 RRCS Reset

Each RRCS channel can be manually reset by depressing the RRCS reset push buttons (four, one for each tripped channel), provided that a specified time delay has elapsed since RWCU isolation and SLCS initiation. When the RRCS is reset, the following seal-in signals are broken:

a. RWCU isolation

b. Low water level 2

c. Manual initiation

d. High reactor pressure

e. Feedwater runback signal

f. SLCS initiation

The RRCS ARI function is reset by the RRCS ARI reset push buttons. This second set of four push buttons (one for each channel) will enable the reset of the ARI logic 30 seconds after initiation of ARI, provided that initiating signals have cleared. This 30 second time delay before the ARI reset permissive appears is designed to ensure that the RRCS ARI scram goes to completion.

7.6.1.8.3.7 RRCS Bypass

There is no RRCS bypass or operating bypass.

7.6.1.8.3.8 Separation

The RRCS is a two-divisional system. Separation is maintained between the redundant divisions of the system to ensure compliance with the separation and single failure criteria. This separation is done to satisfy the single failure criterion. The two divisions of RRCS logic are designed so that either can cause ARI, recirculation pump motor trip, feedwater runback, RWCU isolation, and SLCS injection when a sufficient power reduction has not occurred. The RRCS meets IEEE 279 (1971) and Regulatory Guide 1.75 (Rev 1).

7.6.2 ANALYSIS

7.6.2.1 Process Radiation Monitoring Systems – Instrumentation and Controls

7.6.2.1.1 Main Steam Line Radiation Monitoring System

The analysis for this system is discussed in Section 11.5.4.

7.6.2.1.2 Reactor Enclosure Ventilation Exhaust Radiation Monitoring System

The analysis for this system is discussed in Section 7.3.2.2.2.3.1.

7.6.2.1.3 Refueling Area Ventilation Exhaust Radiation Monitoring System

The analysis for this system is discussed in Section 7.3.2.2.2.3.1.

7.6.2.1.4 Control Room Ventilation Radiation Monitoring System

7.6.2.1.4.1 CRV-RMS General Functional Requirements Conformance

The control room ventilation system is provided with instrumentation and controls to ensure that it remains habitable in order to ensure the capability of plant shutdown under accident conditions. Instrumentation and controls for this purpose are safety-graded and selected to be operable under worst case environmental and seismic conditions at their respective locations.

The use of different divisional power for the redundant radiation monitoring system ensures that the system will be operational upon loss of a single divisional power source.

7.6.2.1.4.2 CRV-RMS Specific Regulatory Requirements Conformance

7.6.2.1.4.2.1 CRV-RMS Conformance to Regulatory Guides

7.6.2.1.4.2.1.1 CRV-RMS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The system is designed for periodic testing in accordance with IEEE 279.

7.6.2.1.4.2.1.2 CRV-RMS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The radiation monitoring system is qualified to seismic Category I criteria, in accordance with IEEE 344. Refer to Section 3.10.

7.6.2.1.4.2.1.3 CRV-RMS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The radiation monitoring system is qualified in accordance with IEEE 323 (1974).

7.6.2.1.4.2.1.4 CRV-RMS - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Section 7.5.2.5.1.1.2 contains a discussion of the degree of conformance.

7.6.2.1.4.2.1.5 CRV-RMS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electrical Equipment for Nuclear Power Plants

See Section 3.10 for a discussion of the degree of conformance.

7.6.2.1.4.2.1.6 CRV-RMS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

See Section 7.1.2.5.25 for a discussion of the degree of conformance.

7.6.2.1.4.2.1.7 CRV-RMS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26 for a discussion of the degree of conformance.

7.6.2.1.4.2.2 CRV-RMS Conformance to 10CFR50, Appendix A, General Design Criteria

7.6.2.1.4.2.2.1 CRV-RMS - GDC 1 - Quality Standards and Records

The radiation monitoring system is constructed in accordance with a documented quality assurance program.

7.6.2.1.4.2.2.2 CRV-RMS - GDC 2 - Design Bases for Protection Against Natural Phenomena

The system is designed to survive SSEs.

7.6.2.1.4.2.2.3 CRV-RMS - GDC 3 - Fire Protection

The system is designed to be fire resistant.

7.6.2.1.4.2.2.4 CRV-RMS - GDC 4 - Environmental and Dynamic Effects Design Bases

Redundancy of the system affords protection against missile damage.

7.6.2.1.4.2.2.5 CRV-RMS - GDC 5 - Sharing of Structures, Systems, and Components

Control room monitoring is common to both units of the plant, but a malfunction in either unit does not inhibit the function of this system.

7.6.2.1.4.2.2.6 CRV-RMS - GDC 13 - Instrumentation and Control

Instrumentation and controls are provided to monitor the control room atmosphere over the anticipated range of radiation levels for normal and accident conditions.

7.6.2.1.4.2.2.7 CRV-RMS - GDC 19 - Control Room

This system ensures the habitability of the control room under accident conditions.

7.6.2.1.4.2.2.8 CRV-RMS - GDC 20 - Protection System Functions

This system is designed to automatically initiate the control room protection controls in response to accident conditions.

7.6.2.1.4.2.2.9 CRV-RMS - GDC 21 - Protection System Reliability and Testability

This system is designed to incorporate adequate reliability and testability so that no single failure results in the loss of its protective function.

7.6.2.1.4.2.2.10 CRV-RMS - GDC 22 - Protection System Independence

The four channels are independent so that bypassing any one channel does not result in the loss of the system's protective function.

7.6.2.1.4.2.2.11 CRV-RMS - GDC 23 - Protection System Failure Modes

Redundancy ensures that failure of one channel does not prevent the system from carrying out its trip function. The system is designed to fail-safe on loss of power to the CRV-RMS.

7.6.2.1.4.2.2.12 CRV-RMS - GDC 24 - Separation of Protection and Control Systems

Protection and control systems are separated so that the loss of any one channel does not prevent a safety-related function.

7.6.2.1.4.2.2.13 CRV-RMS - GDC 29 - Protection Against Anticipated Operational Occurrences

The system is protected against anticipated operational occurrences.

7.6.2.1.4.2.2.14 CRV-RMS - GDC 64 - Monitoring Radioactivity Releases

This system provides an indirect method of monitoring the plant environs in that the radioactivity level of incoming air from the plant environment is continually measured during all operational occurrences including accidents.

7.6.2.1.4.2.3 CRV-RMS - Conformance to Industry Codes and Standards

7.6.2.1.4.2.3.1 CRV-RMS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

7.6.2.1.4.2.3.1.1 CRV-RMS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The radiation monitoring system consists of four independent channels. The failure of any one of these channels does not prevent this system from carrying out its safety-related functions of isolation and alarming.

7.6.2.1.4.2.3.1.2 CRV-RMS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

Components of the radiation monitoring system are carefully selected on the basis of suitability for the specific application. A quality control and assurance program is implemented and documented by the equipment vendor with the intent of complying with the requirements set forth in 10CFR50, Appendix B.

7.6.2.1.4.2.3.1.3 CRV-RMS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

See Section 7.6.2.1.4.2.2.

7.6.2.1.4.2.3.1.4 CRV-RMS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The radiation monitoring system is designed to maintain its functional capability under the environmental conditions and malfunctions that may occur in the design basis LOCA.

7.6.2.1.4.2.3.1.5 CRV-RMS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

Channel independence of sensors is provided by electrical and mechanical separation. Physical separation is maintained between each of the four channels.

7.6.2.1.4.2.3.1.6 CRV-RMS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The four channels are independent, so that a single failure does not prevent the system from carrying out its safety-related function.

7.6.2.1.4.2.3.1.7 CRV-RMS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The detectors used in the radiation monitoring system are equipped with check sources and can be checked one at a time during normal plant operation.

7.6.2.1.4.2.3.1.8 CRV-RMS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

Testing is achieved by check sources. There are no valves or moving parts in the radiation monitoring system requiring periodic testing. Instrument setpoints are tested by simulated signals to verify that the setpoints are within limits. Calibration sources are provided for periodic calibration.

7.6.2.1.4.2.3.1.9 CRV-RMS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

The system design of four redundant and independent channels permits the removal from operation of one channel for testing, calibration, or maintenance without preventing the remaining three channels from being operated to perform their protective function.

7.6.2.1.4.2.3.1.10 CRV-RMS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

A downscale alarm annunciates in the control room when a channel is bypassed.

7.6.2.1.4.2.3.1.11 CRV-RMS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

The control module in the control room requires a key for bypassing its function. This key is controlled by Operations.

7.6.2.1.4.2.3.1.12 CRV-RMS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

Setpoints of the monitoring system may be changed only by the control room operator by use of both his key and a code number to activate the microprocessor.

7.6.2.1.4.2.3.1.13 CRV-RMS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Access to setpoint adjustments, calibration points, and test setpoints is available to qualified plant personnel by means of the access key and code number.

7.6.2.1.4.2.3.1.14 CRV-RMS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

Initiation of shutoff of the control room ventilation system and startup of the emergency fresh air system is indicated in the control room.

7.6.2.1.4.2.3.1.15 CRV-RMS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

Meters located in the control room provide indications of radiation levels in the ventilation ducting. Indicator lights actuated when setpoints are exceeded provide information on alarm conditions. Trending is available on demand at the RMDS display consoles (Section 11.5.6) in the control room.

7.6.2.1.4.2.3.1.16 CRV-RMS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The system is designed to provide quick recognition of malfunction through check procedures. Accessibility is provided for the detectors and controls to facilitate repairs or adjustment. Malfunctioning components can easily be replaced.

7.6.2.1.4.2.3.1.17 CRV-RMS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Nameplates identify each module and instrument panel of the radiation monitoring system.

7.6.2.1.4.2.3.2 CRV-RMS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

Refer to Section 7.1.2.7.2.

7.6.2.1.4.2.3.3 CRV-RMS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

The Class 1E equipment qualification is demonstrated by the vendor by the type-tests on actual equipment in accordance with the purchase specification. Qualification documentation is maintained.

Refer to Section 3.10.

7.6.2.1.4.2.3.4 CRV-RMS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

Installation, inspection, and testing provisions are in accordance with Class 1E requirements.

7.6.2.1.4.2.3.5 CRV-RMS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Provisions are made for the periodic testing of this system in accordance with IEEE Class 1E requirements.

7.6.2.1.4.2.3.6 CRV-RMS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Capability of the instruments and controls to meet seismic requirements is demonstrated by the vendor. Documentation is maintained to verify that the equipment is seismically qualified.

Refer to Section 3.10.

7.6.2.1.4.2.3.7 CRV-RMS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

This system is designed in accordance with the single failure criterion for safety-related equipment.

7.6.2.1.4.2.3.8 CRV-RMS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Channel separation and electrical wiring separation are designed in accordance with IEEE 279 requirements.

7.6.2.1.4.3 CRV-RMS Preoperational Checkout

Preoperational tests are conducted prior to initial startup. The tests ensure functioning of all controls and active components. System reference characteristics such as setpoints are documented during preoperational testing and used as base points for measurements obtained during subsequent calibrations.

7.6.2.1.4.4 CRV-RMS Operational Tests

During plant operation, components of this system can be inspected at any time. Test frequency is consistent with the requirements of the plant Technical Specifications.

7.6.2.1.5 Control Room Emergency Fresh Air Radiation Monitoring System

7.6.2.1.5.1 CREFA-RMS General Functional Requirements Conformance

The CREFAS provides for the habitability of the control room when the main control room ventilation system is shut down. Radiation monitors in the normal control room ventilation system are not functional in this circumstance, so the CREFA-RMS provides for continued surveillance of the control room atmosphere.

7.6.2.1.5.2 CREFA-RMS Specific Regulatory Requirements Conformance

7.6.2.1.5.2.1 CREFA-RMS Conformance to Regulatory Guides

7.6.2.1.5.2.1.1 CREFA-RMS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The system is designed for periodic testing in accordance with IEEE 279.

7.6.2.1.5.2.1.2 CREFA-RMS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The CREFA-RMS is qualified to seismic Category I criteria, in accordance with IEEE 344. Refer to Section 3.10.

7.6.2.1.5.2.1.3 CREFA-RMS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The CREFA-RMS is qualified in accordance with IEEE 323 (1974).

7.6.2.1.5.2.1.4 CREFA-RMS - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Conformance is discussed in Section 7.5.2.5.1.1.2.

7.6.2.1.5.2.1.5 CREFA-RMS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

See Section 3.10 for a discussion of the degree of conformance.

7.6.2.1.5.2.1.6 CREFA-RMS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

See Section 7.1.2.5.25 for a discussion of the degree of conformance.

7.6.2.1.5.2.1.7 CREFA-RMS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26 for a discussion of the degree of conformance.

7.6.2.1.5.2.2 CREFA-RMS Conformance to 10CFR50, Appendix A, General Design Criteria

7.6.2.1.5.2.2.1 CREFA-RMS - GDC 1 - Quality Standards and Records

The radiation monitoring system is constructed in accordance with a documented quality assurance program.

7.6.2.1.5.2.2.2 CREFA-RMS - GDC 2 - Design Bases for Protection Against Natural Phenomena

The system is designed to survive SSEs.

7.6.2.1.5.2.2.3 CREFA-RMS - GDC 3 - Fire Protection

The system is designed to be fire resistant.

7.6.2.1.5.2.2.4 CREFA-RMS - GDC 4 - Environmental and Dynamic Effects Design Bases

Redundancy of the system affords protection against missile damage.

7.6.2.1.5.2.2.5 CREFA-RMS - GDC 5 - Sharing of Structures, Systems, and Components

Control room monitoring is common to both units of the plant, but a malfunction in either unit does not inhibit the function of this system.

7.6.2.1.5.2.2.6 CREFA-RMS - GDC 13 - Instrumentation and Control

Instrumentation and controls are provided to monitor the control room atmosphere over the anticipated range of radiation levels for normal and accident conditions.

7.6.2.1.5.2.2.7 CREFA-RMS - GDC 19 - Control Room

This system ensures habitability of the control room under accident conditions.

7.6.2.1.5.2.2.8 CREFA-RMS - GDC 21 - Protection System Reliability and Testability

This system is designed to incorporate adequate reliability and testability so that no single failure results in the loss of its monitoring function.

7.6.2.1.5.2.2.9 CREFA-RMS - GDC 22 - Protection System Independence

The two channels are independent so that bypass of either channel does not affect the other channel.

7.6.2.1.5.2.2.10 CREFA-RMS - GDC 23 - Protection System Failure Modes

Failure of either channel does not inhibit the function of the other.

7.6.2.1.5.2.2.11 CREFA-RMS - GDC 29 - Protection Against Anticipated Operational Occurrences

The system is protected against anticipated operational occurrences.

7.6.2.1.5.2.2.12 CREFA-RMS - GDC 64 - Monitoring Radioactivity Releases

This system provides an indirect method of monitoring the plant environs in that the radioactivity level of incoming air from the plant environment is measured while the emergency fresh air system is functioning during accident conditions.

7.6.2.1.5.2.3 CREFA-RMS Conformance to Industry Codes and Standards

7.6.2.1.5.2.3.1 CREFA-RMS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

7.6.2.1.5.2.3.1.1 CREFA-RMS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The CREFA-RMS consists of two independent channels. The failure of either of these channels does not prevent this system from carrying out its functions of readout and alarming.

7.6.2.1.5.2.3.1.2 CREFA-RMS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

Components of the radiation monitoring system are carefully selected on the basis of suitability for the specific application. A quality control and assurance program is implemented and documented by the equipment vendor with the intent of complying with the requirements set forth in 10CFR50, Appendix B.

7.6.2.1.5.2.3.1.3 CREFA-RMS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

The equipment is qualified to meet the standards of IEEE 323 (1974).

7.6.2.1.5.2.3.1.4 CREFA-RMS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The radiation monitoring system is designed to maintain its functional capability under the environmental conditions and malfunctions that may occur in the design basis LOCA.

7.6.2.1.5.2.3.1.5 CREFA-RMS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

Channel independence of sensors is provided by electrical and mechanical separation. Physical separation is maintained between the two channels.

7.6.2.1.5.2.3.1.6 CREFA-RMS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The detectors used in the CREFA-RMS are equipped with check sources, and can be checked one at a time during normal plant operation.

7.6.2.1.5.2.3.1.7 CREFA-RMS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

Testing is achieved by check sources. There are no valves or moving parts in the CREFA-RMS requiring periodic testing. Instrument setpoints are tested by simulated signals to verify that the setpoints are within limits. Calibration sources are provided for periodic calibration.

7.6.2.1.5.2.3.1.8 CREFA-RMS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

The system design of two redundant and independent channels permits the removal from operation of one channel for testing, calibration, or maintenance without preventing the remaining channel from operating normally.

7.6.2.1.5.2.3.1.9 CREFA-RMS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

Indication of bypass is provided by the extinguishing of the normal operation light when a channel is inoperative for test, calibration, or maintenance. The downscale alarm annunciates in the control room under this condition.

7.6.2.1.5.2.3.1.10 CREFA-RMS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

The control module in the control room requires a key for the bypassing of its function. This key is controlled by Operations.

7.6.2.1.5.2.3.1.11 CREFA-RMS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

Setpoints of the CREFA-RMS is controlled by the control room operator by use of both the key and a code number to activate the microprocessor.

7.6.2.1.5.2.3.1.12 CREFA-RMS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Access to setpoint adjustment, calibration points, and test setpoints is limited to qualified plant personnel by means of control of the access key and code number.

7.6.2.1.5.2.3.1.13 CREFA-RMS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

Meters located in the control room provide indications of radiation levels in the ducting. Indicator lights actuated by setpoints provide information on alarm conditions. Trending is available on demand at the RMDS display consoles (Section 11.5.6) in the control room.

7.6.2.1.5.2.3.1.14 CREFA-RMS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The CREFA-RMS is designed to provide quick recognition of malfunction through check procedures. Accessibility is provided for the detectors and controls to facilitate repairs or adjustments. Malfunctioning components can readily be replaced.

7.6.2.1.5.2.3.1.15 CREFA-RMS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Nameplates identify each module and instrument panel of the CREFA-RMS.

7.6.2.1.5.2.3.2 CREFA-RMS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

Class 1E equipment qualification is demonstrated by the vendor by type-tests on actual equipment in accordance with the purchase specification. Qualification documentation is maintained.

7.6.2.1.5.2.3.3 CREFA-RMS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

Installation, inspection, and testing provisions are in accordance with IEEE Class 1E requirements.

7.6.2.1.5.2.3.4 CREFA-RMS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Provisions are made for the periodic testing of this system in accordance with IEEE Class 1E requirements.

7.6.2.1.5.2.3.5 CREFA-RMS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Capability of the instruments and controls to meet seismic requirements is demonstrated by the vendor. Documentation is maintained to verify that the equipment is seismically qualified.
Refer to Section 3.10.

7.6.2.1.5.2.3.6 CREFA-RMS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

This system is designed in accordance with the single failure criterion for safety-related equipment.

7.6.2.1.5.2.3.7 CREFA-RMS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Channel separation and electrical wiring separation are designed in accordance with IEEE 279 requirements.

7.6.2.1.5.3 CREFA-RMS Preoperational Checkout

Preoperational tests are conducted prior to initial startup. The tests ensure functioning of all components and controls. System reference characteristics such as setpoints are documented during preoperational testing and used as base points for measurements obtained during subsequent calibrations.

7.6.2.1.5.4 CREFA-RMS Operational Tests

During plant operation, components of the CREFA-RMS can be operationally tested at any time. Test frequency intervals are established by plant staff.

7.6.2.1.6 Primary Containment Post-LOCA Radiation Monitoring System

7.6.2.1.6.1 PCPL-RMS General Functional Requirements Conformance

The primary containment is provided with gamma-sensitive radiation monitors to maintain continuing surveillance of the containment atmosphere under postaccident conditions.

The description in Section 11.5.2.3.1 demonstrates how the PCPL- RMS meets the safety design bases identified in Section 7.1.2.1.11.6.

7.6.2.1.6.2 PCPL-RMS Specific Regulatory Requirements Conformance

7.6.2.1.6.2.1 PCPL-RMS Conformance to Regulatory Guide

7.6.2.1.6.2.1.1 PCPL-RMS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The system is designed for periodic testing in accordance with IEEE 279.

7.6.2.1.6.2.1.2 PCPL-RMS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The radiation monitoring system is qualified to seismic Category I criteria, in accordance with IEEE 344. Refer to Section 3.10.

7.6.2.1.6.2.1.3 PCPL-RMS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The radiation monitoring system is qualified in accordance with IEEE 323 (1974).

7.6.2.1.6.2.1.4 PCPL-RMS - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Conformance is discussed in Section 7.5.2.5.1.1.2.

7.6.2.1.6.2.1.5 PCPL-RMS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance is discussed in Section 3.10.

7.6.2.1.6.2.1.6 PCPL-RMS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

See Section 7.1.2.5.25 for a discussion of the degree of conformance.

7.6.2.1.6.2.1.7 PCPL-RMS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26 for a discussion of the degree of conformance.

7.6.2.1.6.2.2 PCPL-RMS Conformance to 10CFR50, Appendix A, General Design Criteria

This system is designed to conform to the following criteria of 10CFR50, Appendix A:

7.6.2.1.6.2.2.1 PCPL-RMS - GDC 1 - Quality Standards and Records

A quality assurance program is established for the design and production of this system.

7.6.2.1.6.2.2.2 PCPL-RMS - GDC 2 - Design Bases for Protection Against Natural Phenomena

This system is designed and tested to meet seismic Category I requirements.

7.6.2.1.6.2.2.3 PCPL-RMS - GDC 3 - Fire Protection

Fire resistant components are used throughout.

7.6.2.1.6.2.2.4 PCPL-RMS - GDC 4 - Environmental and Dynamic Effects Design Bases

Redundancy of the system provides for missile damage.

7.6.2.1.6.2.2.5 PCPL-RMS - GDC 5 - Sharing of Structures, Systems, and Components

No components are shared between the unitized systems.

7.6.2.1.6.2.2.6 PCPL-RMS - GDC 13 - Instrumentation and Control

Operating ranges of the instrumentation are compatible with anticipated accident conditions.

7.6.2.1.6.2.2.7 PCPL-RMS - GDC 21 - Protection System Reliability and Testability

The system is designed for high functional reliability and inservice testability.

7.6.2.1.6.2.2.8 PCPL-RMS - GDC 22 - Protection System Independence

System redundancy and separation of channels provides for protection system independence.

7.6.2.1.6.2.2.9 PCPL-RMS - GDC 23 - Protection System Failure Modes

Loss of either channel in this system does not impair the function of the other.

7.6.2.1.6.2.2.10 PCPL-RMS - GDC 24 - Separation of Protection and Control Systems

The two channels are separated in accordance with IEEE 279 (1971).

7.6.2.1.6.2.2.11 PCPL-RMS - GDC 29 - Protection Against Anticipated Operational Occurrences

The system is designed to ensure functional reliability in the event of an anticipated operational occurrence.

7.6.2.1.6.2.2.12 PCPL-RMS - GDC 64 - Monitoring Radioactivity Releases

The requirement for the monitoring of the containment atmosphere is fulfilled.

7.6.2.1.6.2.3 PCPL-RMS Conformance to Industry Codes and Standards

7.6.2.1.6.2.3.1 PCPL-RMS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

7.6.2.1.6.2.3.1.2 PCPL-RMS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The design based on two electrical separation channels, each containing two monitoring channels, does not meet the single failure criterion. However, only two monitoring channels are required in accordance with Section 1.13.

7.6.2.1.6.2.3.1.3 PCPL-RMS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

A quality assurance program is adhered to in the production of this system.

7.6.2.1.6.2.3.1.4 PCPL-RMS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

The system is qualified in accordance with IEEE 323 (1974).

7.6.2.1.6.2.3.1.5 PCPL-RMS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The system is designed to meet the most extreme environmental conditions anticipated.

7.6.2.1.6.2.3.1.6 PCPL-RMS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The two redundant channels are independent and separate.

7.6.2.1.6.2.3.1.7 PCPL-RMS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The system serves no control function. However, the separation and independence of the two channels satisfies the remaining requirements of this section.

7.6.2.1.6.2.3.1.8 PCPL-RMS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

System inputs are derived from radioactivity measurements inside the containment.

7.6.2.1.6.2.3.1.9 PCPL-RMS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

Check signals are provided for the detectors. However, no check sources are provided.

7.6.2.1.6.2.3.1.10 PCPL-RMS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The check signal provides capability for testing during power operation. Calibration capabilities are discussed in Section 11.5.2.3.1.

7.6.2.1.6.2.3.1.11 PCPL-RMS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

Either channel can be bypassed for checking or servicing without impairing the functions of the other channel.

7.6.2.1.6.2.3.1.12 PCPL-RMS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

The bypassing of a channel results in downscale alarm in the control room.

7.6.2.1.6.2.3.1.13 PCPL-RMS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Administrative controls are provided as the means to remove a channel from service.

7.6.2.1.6.2.3.1.14 PCPL-RMS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

This requirement is not applicable.

7.6.2.1.6.2.3.1.15 PCPL-RMS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Access to setpoints is available in the control module. However, to change a setpoint necessitates the use of a supervisory key to prevent unauthorized adjustments.

7.6.2.1.6.2.3.1.16 PCPL-RMS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

Readouts are provided in the control room. Indication of the variable and monitor status are provided.

7.6.2.1.6.2.3.1.17 PCPL-RMS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The system is modular to facilitate quick repair or component replacement.

7.6.2.1.6.2.3.1.18 PCPL-RMS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Suitable system and component identification is provided.

7.6.2.1.6.2.3.2 PCPL-RMS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

The Class 1E equipment qualification is demonstrated by the type- tests on actual equipment. Qualification documentation is maintained.

7.6.2.1.6.2.3.3 PCPL-RMS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

Installation, inspection, and testing provisions are in accordance with Class 1E requirements.

7.6.2.1.6.2.3.4 PCPL-RMS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Provisions are made for the periodic testing of this system in accordance with IEEE Class 1E requirements.

7.6.2.1.6.2.3.5 PCPL-RMS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

Refer to Section 7.6.2.1.6.2.3.1.2.

7.6.2.1.6.2.3.6 PCPL-RMS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Channel separation and electrical wiring separation are designed in accordance with IEEE 384 requirements.

7.6.2.1.6.3 PCPL-RMS Preoperational Checkout

Preoperational tests are conducted prior to initial startup. The tests ensure functioning of all components and controls. System reference characteristics such as setpoints are documented during preoperational testing and used as base points for measurements obtained during subsequent calibrations.

7.6.2.1.6.4 PCPL-RMS Operational Tests

During plant operation, components of the PCPL-RMS can be operationally tested at any time. Test frequency is consistent with the requirements of plant Technical Specifications.

7.6.2.1.7 RHR Service Water Radiation Monitoring System

7.6.2.1.7.1 RHRSW-RMS General Functional Requirements Conformance

Service water piping from the RHR heat exchangers is provided with radiation monitors for detecting evidence of leakage through the interface between the service water and the RHR system. If significant radioactivity is detected in the service water, the radiation monitors provide signals to trip the RHRSW pumps. Alarm signals are annunciated in the control room.

7.6.2.1.7.2 RHRSW-RMS Specific Regulatory Requirements Conformance

7.6.2.1.7.2.1 RHRSW-RMS Conformance to Regulatory Guides

7.6.2.1.7.2.1.1 RHRSW-RMS - Regulatory Guide 1.21 (1974) - Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants

The RHRSW monitor is designed to keep an ongoing record should any radioactive material be released via the RHRSW system.

7.6.2.1.7.2.1.2 RHRSW-RMS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The system is designed to be periodically tested in accordance with IEEE 279.

7.6.2.1.7.2.1.3 RHRSW-RMS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

See Section 3.10 for a discussion of the degree of conformance.

7.6.2.1.7.2.1.4 RHRSW-RMS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

See Section 7.1.2.5.25 for a discussion of the degree of conformance.

7.6.2.1.7.2.1.5 RHRSW-RMS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26 for a discussion of the degree of conformance.

7.6.2.1.7.2.2 RHRSW-RMS Conformance to 10CFR50, Appendix A, General Design Criteria

7.6.2.1.7.2.2.1 RHRSW-RMS - GDC 1 - Quality Standards and Records

Quality standards and records are maintained for this system.

7.6.2.1.7.2.2.2 RHRSW-RMS - GDC 2 - Design Bases for Protection Against Natural Phenomena

The system is designed to seismic Category I criteria.

7.6.2.1.7.2.2.3 RHRSW-RMS - GDC 3 - Fire Protection

The system is designed to be fireproof.

7.6.2.1.7.2.2.4 RHRSW-RMS - GDC 4 - Environmental and Dynamic Effects Design Bases

Redundancy and component separation of this system provide protection against missile damage.

7.6.2.1.7.2.2.5 RHRSW-RMS - GDC 5 - Sharing of Structures, Systems, and Components

One monitoring channel is dedicated to each of the two common return lines of the RHRSW system. The two monitoring channels are shared by both units. However, this does not impair the function of the monitoring system because of the separation and independence of the two channels.

7.6.2.1.7.2.2.6 RHRSW-RMS - GDC 13 - Instrumentation and Control

The instrumentation is designed to cover the anticipated range of abnormal conditions.

7.6.2.1.7.2.2.7 RHRSW-RMS - GDC 20 - Protection System Functions

The system is designed to sense abnormal occurrences and to initiate operation of components important to safety.

7.6.2.1.7.2.2.8 RHRSW-RMS - GDC 21 - Protection System Reliability and Testability

The system is designed for high functional reliability and testability.

7.6.2.1.7.2.2.9 RHRSW-RMS - GDC 22 - Protection System Independence

The system provides independence of function.

7.6.2.1.7.2.2.10 RHRSW-RMS - GDC 23 - Protection System Failure Modes

Failure of one channel does not prevent the system from carrying out its protective function.

7.6.2.1.7.2.2.11 RHRSW-RMS - GDC 24 - Separation of Protection and Control Systems

Redundancy ensures that the failure of one channel does not prevent the system from carrying out its trip function.

7.6.2.1.7.2.2.12 RHRSW-RMS - GDC 29 - Protection Against Anticipated Operational Occurrences

The system is designed to ensure the high probability of carrying out its safety functions in the event of anticipated operational occurrences.

7.6.2.1.7.2.2.13 RHRSW-RMS - GDC 30 - Quality of Reactor Coolant Pressure Boundary

The system provides a means of detecting and identifying a source of reactor coolant leakage.

7.6.2.1.7.2.2.14 RHRSW-RMS - GDC 34 - Residual Heat Removal

The system provides leak detection of the RHR system.

7.6.2.1.7.2.2.15 RHRSW-RMS - GDC 38 - Containment Heat Removal

The system provides a means of leak detection and isolation of the RHR system.

7.6.2.1.7.2.2.16 RHRSW-RMS - GDC 40 - Testing of Containment Heat Removal System

The system provides one of the means for testing the integrity of the RHR system.

7.6.2.1.7.2.2.17 RHRSW-RMS - GDC 60 - Control of Releases of Radioactive Materials to the Environment

This system provides a means for controlling releases of radioactive materials to the environment.

7.6.2.1.7.2.2.18 RHRSW-RMS - GDC 64 - Monitoring Radioactivity Releases

This system monitors radioactivity releases from normal operations, operational occurrences, and from postulated accidents.

7.6.2.1.7.2.3 RHRSW-RMS Conformance to Industry Codes and Standards

7.6.2.1.7.2.3.1 RHRSW-RMS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

7.6.2.1.7.2.3.1.1 RHR-RMS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The RHRSW-RMS automatically alarms and trips the appropriate RHRSW pumps whenever the effluent radiation levels exceed a preset level.

7.6.2.1.7.2.3.1.2 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The monitoring system consists of one monitor dedicated to each of the common service water return lines. The failure of either channel is alarmed in the Main Control Room. Following the failure of a channel, grab sampling is performed on a periodic basis. Should a high radiation level be detected, the RHRSW pumps may be tripped and the appropriate RHR heat exchangers isolated by manual operator actions. Thus, the safety related function of detection and isolation are maintained.

7.6.2.1.7.2.3.1.3 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

Components of the radiation monitoring system are carefully selected on the basis of suitability for the specific application. A quality control and assurance program is implemented and documented by the equipment vendor with the intent of complying with the requirements set forth in 10CFR50, Appendix B.

7.6.2.1.7.2.3.1.4 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

The equipment is qualified in accordance with IEEE 323, except that no aging test conditions have been imposed.

7.6.2.1.7.2.3.1.5 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The radiation monitoring system is designed to maintain its functional capability under the environmental conditions and malfunctions that occur in the design basis LOCA.

7.6.2.1.7.2.3.1.6 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

Channel independence of detectors is provided by electrical and mechanical separation. Physical separation is maintained between each of the two channels (both units).

7.6.2.1.7.2.3.1.7 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The two channels (both units) are independent, so that a single failure does not prevent the system from carrying out its safety- related function.

7.6.2.1.7.2.3.1.8 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

Trip control signals are derived from measurement of activity levels in the RHRSW. Trip logic is not necessary.

7.6.2.1.7.2.3.1.9 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The detectors used in the radiation monitoring system are equipped with check sources and can be checked one at a time during normal plant operation.

7.6.2.1.7.2.3.1.10 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

Testing and calibration are achieved by means of check sources.

7.6.2.1.7.2.3.1.11 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

The system permits removal from operation of one channel for calibration, testing, or maintenance. With a channel bypass, the protective function is performed by periodic grab sampling of the service water.

7.6.2.1.7.2.3.1.12 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

A downscale alarm annunciates in the control room when a channel is bypassed.

7.6.2.1.7.2.3.1.13 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Means for channel bypass is limited to the control module in the auxiliary equipment room.

7.6.2.1.7.2.3.1.14 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

Setpoints of each monitoring channel may be changed in the control module located in the auxiliary equipment room.

7.6.2.1.7.2.3.1.15 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Access to setpoint adjustments is limited to control room personnel who have access to the rear of the control module in the auxiliary equipment room.

7.6.2.1.7.2.3.1.16 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.19 - Initiation of Protective Actions

Initiation of shutoff of the RHRSW pumps is indicated in the control room.

7.6.2.1.7.2.3.1.17 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

Rate meters located in the auxiliary equipment room and recorders located in the control room provide indications of activity levels in the RHRSW. Indicator lights actuated when setpoints are exceeded provide information on alarm conditions.

7.6.2.1.7.2.3.1.18 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The system is designed for quick recognition of malfunction through check procedures. Accessibility to the monitoring racks and controls is provided to facilitate repair or adjustment.

7.6.2.1.7.2.3.1.19 RHRSW-RMS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Nameplates identify each module and instrument panel of the radiation monitoring system.

7.6.2.1.7.2.3.2 RHRSW-RMS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

Aging test requirements in IEEE 323 (1971) were not complied with because this equipment was procured before the effective date of Regulatory Guide 1.89. Qualification documentation is maintained.

7.6.2.1.7.2.3.3 RHRSW-RMS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

Provisions are made for the installation, inspection, and testing of this system in accordance with Class 1E requirements.

7.6.2.1.7.2.3.4 RHRSW-RMS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

The system is periodically tested in accordance with a standard recalibration and functional test program.

7.6.2.1.7.2.3.5 RHRSW-RMS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Capability of the instruments and controls to meet seismic requirements is demonstrated by the vendor. Documentation is maintained to verify that the equipment is qualified. Refer to Section 3.10.

7.6.2.1.7.2.3.6 RHRSW-RMS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

Redundancy of the system ensures that a single failure does not prevent the system from carrying out its safety-related function.

7.6.2.1.7.2.3.7 RHRSW-RMS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

The channels of this system are separated in accordance with IEEE 279.

7.6.2.1.7.3 RHRSW-RMS Preoperational Checkout

Preoperational tests are conducted before initial startup. These tests ensure functioning of all controls and active components. System reference characteristics such as setpoints are documented during preoperational testing and are used as base points for measurements obtained during subsequent calibrations.

7.6.2.1.7.4 RHRSW-RMS Operational Tests

During plant operation, components of this system can be inspected at any time. Test frequency is consistent with the requirements of plant Technical Specifications.

7.6.2.1.8 North Stack Effluent Radiation Monitoring System

7.6.2.1.8.1 NSE-RMS General Functional Requirements Conformance

Two independent monitoring subsystems are provided:

a. Normal range plant subsystem

b. Wide range accident monitoring subsystem

Subsystem (a) is designed to monitor the north stack effluents under normal plant operating conditions. Subsystem (b) is designed to monitor the north stack effluents under normal plant operation, accident, and postaccident condition. Section 11.5.2.2.1 describes the system and shows how the design bases identified in Section 7.1.2.1.11.6.1 are met.

7.6.2.1.8.2 NSE-RMS Specific Regulatory Requirements

7.6.2.1.8.2.1 NSE-RMS Conformance to Regulatory Guides

7.6.2.1.8.2.1.1 NSE-RMS - Regulatory Guide 1.21 (1974) - Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid or Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants

Ongoing inventories of radiation particulates, iodines, and noble gases are provided for the preparation of Regulatory Guide 1.21, Appendix B reports.

7.6.2.1.8.2.1.2 NSE-RMS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The system will be periodically tested in accordance with IEEE 279 (1971).

7.6.2.1.8.2.1.3 NSE-RMS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

Subsystem (b), the wide range accident monitor is qualified to seismic Category I criteria to ensure the integrity of its Class 1E power source. The sampling nozzles and lines of the wide range accident monitor are designed to seismic Category II. Subsystem (a), the normal plant operation monitor, is designed to meet seismic Category II requirements.

7.6.2.1.8.2.1.4 NSE-RMS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

To ensure its functionability during and after an accident, Subsystem (b) is qualified to meet IEEE 323 (1974) requirements.

7.6.2.1.8.2.1.5 NSE-RMS - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Access Plant and Environs Conditions During and Following an Accident

Refer Section 7.5.2.5.1.1.2 for degree of compliance.

7.6.2.1.8.2.1.6 NSE-RMS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

See Section 3.10 for a discussion of the degree of conformance.

7.6.2.1.8.2.1.7 NSE-RMS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

See Section 7.1.2.5.25 for a discussion of the degree of conformance.

7.6.2.1.8.2.1.8 NSE-RMS Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26 for a discussion of the degree of conformance.

7.6.2.1.8.2.2 NSE-RMS Conformance to 10CFR50, Appendix A, General Design Criteria

7.6.2.1.8.2.2.1 NSE-RMS - GDC 1 - Quality Standards and Records

Quality assurance has been provided for the wide range accident monitor commensurate with its importance to safety in accordance with the guidelines of Regulatory Guide 1.97 (1980).

7.6.2.1.8.2.2.2 NSE-RMS - GDC 2 - Design Bases for Protection Against Natural Phenomena

The wide range accident monitor is designed to meet seismic Category I requirements as discussed in Section 7.6.2.1.8.2.1.3.

7.6.2.1.8.2.2.3 NSE-RMS - GDC 3 - Fire Protection

Fire resistant components are used throughout.

7.6.2.1.8.2.2.4 NSE-RMS - GDC 4 - Environmental and Dynamic Effects Design Bases

No provision is made for protection against missiles.

7.6.2.1.8.2.2.5 NSE-RMS - GDC 5 - Sharing of Structures, Systems, and Components

The wide range accident radiation monitoring subsystem is shared by both units of the plant. The system is designed to perform its safety function in the event of an accident in one unit and during the orderly shutdown and cooldown of the other unit.

7.6.2.1.8.2.2.6 NSE-RMS - GDC 13 - Instrumentation and Control

Operating ranges of the instrumentation cover normal plant operations, accident conditions, and postaccident conditions.

7.6.2.1.8.2.2.7 NSE-RMS - GDC 21 - Protection System Reliability and Testability

This system is designed for high functional reliability and inservice testability.

7.6.2.1.8.2.2.8 NSE-RMS - GDC 22 - Protection System Failure Modes

Two independent systems are provided. Within their operating ranges, redundancy and channel separation are provided, however only one system is provided for high range accident and postaccident conditions.

7.6.2.1.8.2.2.9 NSE-RMS - GDC 60 - Control of Releases of Radioactive Materials to the Environment

Surveillance is maintained of release of radioactive materials to the environment; however, remedial action is initiated by control room personnel.

7.6.2.1.8.2.2.10 NSE-RMS - GDC 64 - Monitoring Radioactive Releases

The requirement for monitoring radioactive releases from normal operations, anticipated operational occurrences, and from postulated accident is fulfilled.

7.6.2.1.8.2.3 NSE-RMS Conformance to 10CFR50, Appendix I

This system is equipped with instruments capable of state-of-the- art sensitivity to provide control room personnel with real-time information needed for restricting release of radioactive materials to limits as-low-as-practicable.

7.6.2.1.8.3 NSE-RMS Conformance to Industry Codes and Standards

7.6.2.1.8.3.1 NSE-RMS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

The wide range accident monitor is qualified to IEEE 323 (1974).

7.6.2.1.8.3.2 NSE-RMS - IEEE 344 (1971) - Guide for Seismic Qualifications of Class 1 Electric Equipment for Nuclear Power Generating Stations

The wide range accident monitor is qualified for seismic Category I as discussed in Section 7.6.2.1.8.2.1.3. Refer to Section 3.10.

7.6.2.1.8.3.3 NSE-RMS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

The wide range accident monitor is designed in accordance with IEEE 384 (1974).

7.6.2.1.8.4 NSE-RMS Preoperational Checkout

Preoperational tests are conducted prior to initial startup. The tests ensure functioning of all components and controls. System reference characteristics such as setpoints are documented during preoperational testing and used as base points for measurements obtained during subsequent calibrations.

7.6.2.1.8.5 NSE-RMS Operational Tests

During plant operation, components of the NSE-RMS can be operationally tested at any time. Test frequency is consistent with the requirements of plant Technical Specifications.

7.6.2.2 High Pressure/Low Pressure Systems Interlocks - Instrumentation and Controls

7.6.2.2.1 HPLPSI General Functional Requirements Conformance

For conformance discussion, refer to Sections 7.3.2.1, 7.3.2.4, and 7.4.2.3.

7.6.2.2.2 HPLPSI Specific Regulatory Requirements Conformance

7.6.2.2.2.1 HPLPSI Conformance to Regulatory Guides

7.6.2.2.2.1.1 HPLPSI - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

Refer to Section 7.1.

7.6.2.2.2.1.2 HPLPSI - Regulatory Guide 1.29 (1978) - Seismic Design Classification

For compliance to Regulatory Guide 1.29, see Section 7.1.2.5.6.

7.6.2.2.2.1.3 HPLPSI - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

For compliance to Regulatory Guide 1.30, see Section 8.1.6.1.5.

See Section 7.6.2.2.2.3.3 on conformance to IEEE 338 (1971).

7.6.2.2.2.1.4 HPLPSI - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

Refer to Section 7.1.2.5.11.

7.6.2.2.2.1.5 HPLPSI - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

See Section 7.6.2.2.2.3.4 on conformance to IEEE 379 (1972).

7.6.2.2.2.1.6 HPLPSI - Regulatory Guide 1.68 (1978) - Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors

Conformance is discussed in Section 14.2.

7.6.2.2.2.1.7 HPLPSI - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

See Section 7.1.2.5.19 on conformance to Regulatory Guide 1.75.

7.6.2.2.2.1.8 HPLPSI - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

See Section 3.10 for conformance to Regulatory Guide 1.100.

7.6.2.2.2.1.9 HPLPSI Regulatory Guide General Conformance Statement

Refer to Section 7.1.2.5 for a general conformance statement for Regulatory Guides 1.11, 1.45, 1.89, 1.105, and 1.118.

7.6.2.2.2.2 HPLPSI Conformance to 10CFR50, Appendix A, General Design Criteria

There are no general design criteria that apply to HPLPSI.

7.6.2.2.2.3 HPLPSI Conformance to Industry Codes and Standards

7.6.2.2.2.3.1 HPLPSI - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

The interlocks are designed in accordance with the single failure criterion, redundancy requirements, and testability criteria.

7.6.2.2.2.3.2 HPLPSI - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations

Conformance is discussed in Section 7.1.2.7.5.

7.6.2.2.2.3.3 HPLPSI - IEEE 338 (1971) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

The design of the interlocks is such that they can be tested during reactor operation except for the actuated devices (valves). The valves can be tested during startup and shutdown.

7.6.2.2.2.3.4 HPLPSI - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The low pressure process lines are protected as defined in Section 7.6.1.2.3. Where two redundant MOVs are used, the valves are interlocked with independent pressure transmitters and trip units so that not more than one redundant interlock is disabled by a single failure. The RHR shutdown cooling suction valve F008 is provided with an additional interlock which prevents a fire-induced open signal from causing it to open simultaneously with valve F009 when the reactor pressure is greater than the design capabilities of the RHR low-pressure piping. When only one MOV is used, a check valve is used in series with the MOV. The check valve will not open until reactor pressure has decreased to a value less than the low pressure process line design value.

7.6.2.2.2.3.5 HPLPSI IEEE General Conformance Statement

Refer to Section 7.1.2.7 for a general conformance statement for IEEE 308 (1974), 323 (1971), 344 (1971), and 384 (1974).

7.6.2.3 Leak Detection System - Instrumentation and Controls

7.6.2.3.1 LDS General Functional Requirements Conformance

The safety-related portions of the leak detection system are part of the PCRVICS, and conform to the design basis requirements for the PCRVICS as described in Section 7.3.1.1.2.1.

7.6.2.3.2 LDS Specific Regulatory Requirements Conformance

7.6.2.3.2.1 LDS Conformance to Regulatory Guides

7.6.2.3.2.1.1 LDS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The portion of the LDS that provides outputs to the system isolation logic is designed so that complete periodic testing of the isolation system actuation function is possible. This is accomplished by tripping the leak detection system one channel at a time from the leak detection panel in the control room. An indicator lamp is provided to show that the particular channel is tripped.

7.6.2.3.2.1.2 LDS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

All equipment that performs an isolation function is qualified to seismic Category I criteria (Section 3.10). The application of this equipment in the turbine enclosure is discussed in Section 7.3.2.2.2.3.1.5.

7.6.2.3.2.1.3 LDS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

For conformance discussion refer to Section 7.1.2.5.7.

7.6.2.3.2.1.4 LDS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The LDS annunciates all bypass conditions.

7.6.2.3.2.1.5 LDS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

The portions of the LDS that provide outputs to system isolation logic comply with this guide. Discussion is provided in Section 7.1.2.5.12 under Regulatory Guide 1.53.

7.6.2.3.2.1.6 LDS - Regulatory Guide 1.68 (1978) - Preoperational and Initial Startup Test Programs for Water-Cooled Reactor Power Reactors

The degree of conformance is discussed in Section 7.1.2.5.

7.6.2.3.2.1.7 LDS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Equipment

For a conformance discussion see Section 7.1.2.5.19.

7.6.2.3.2.1.8 LDS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The degree of conformance is discussed in Section 7.1.2.5.

7.6.2.3.2.1.9 LDS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

See Section 3.10 for discussion of the degree of conformance.

7.6.2.3.2.1.10 LDS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

See Section 7.1.2.5.25 for a discussion of the degree of conformance.

7.6.2.3.2.1.11 LDS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

See Section 7.1.2.5.26 for the discussion of the degree of conformance.

7.6.2.3.2.2 LDS Conformance to 10CFR50, Appendix A, General Design Criteria

7.6.2.3.2.2.1 LDS - GDC 1 - Quality Standards and Records

A quality assurance program for the LDS is established and implemented in order to provide adequate assurance that the system will satisfactorily perform its safety functions.

7.6.2.3.2.2.2 LDS - GDC 2 - Design Bases for Protection Against Natural Phenomena

For a conformance discussion, refer to Section 7.1.2.6.2.

7.6.2.3.2.2.3 LDS - GDC 3 - Fire Protection

For a conformance discussion, refer to Section 7.1.2.6.3.

7.6.2.3.2.2.4 LDS - GDC 4 - Environmental and Dynamic Effects Design Bases

For a conformance discussion, refer to Section 7.1.2.6.4.

7.6.2.3.2.2.5 LDS - GDC 10 - Reactor Design

The LDS is designed with an appropriate margin to monitor leakage from the RCPB.

7.6.2.3.2.2.6 LDS - GDC 13 - Instrumentation and Control

The leak detection sensors and associated electronics are designed to monitor the reactor coolant leakage over all expected ranges required for the safety of the plant.

Automatic initiation of the system isolation action, reliability, testability, independence, and separation are factored into leak detection design as required for isolation systems.

7.6.2.3.2.2.7 LDS - GDC 19 - Control Room

Controls and instrumentation are provided in the control room.

7.6.2.3.2.2.8 LDS - GDC 20 - Protection System Functions

Leak detection equipment senses accident conditions and initiates the PCRVICS when appropriate.

7.6.2.3.2.2.9 LDS - GDC 21 - Protection System Reliability and Testability

Protection-related equipment is arranged in two redundant divisions and maintained separately. Testing is covered in the conformance discussion for Regulatory Guide 1.22.

7.6.2.3.2.2.10 LDS - GDC 22 - Protection System Independence

Protection-related equipment is arranged in two redundant divisions so that no single failure can prevent isolation. Diversity of sensed variables is utilized.

7.6.2.3.2.2.11 LDS - GDC 23 - Protection System Failure Modes

Signals provided are such that isolation logic is fail-safe.

7.6.2.3.2.2.12 LDS - GDC 24 - Separation of Protection and Control Systems

The system has no control functions.

7.6.2.3.2.2.13 LDS - GDC 29 - Protection Against Anticipated Operational Occurrences

No anticipated operational occurrence can prevent an isolation.

7.6.2.3.2.2.14 LDS - GDC 30 - Quality of Reactor Coolant Pressure Boundary

The system provides means for the detection and general location of the source of reactor coolant leakage.

7.6.2.3.2.2.15 LDS - GDC 34 - Residual Heat Removal

Leak detection is provided for RHR lines penetrating the drywell.

7.6.2.3.2.2.16 LDS - GDC 35 - Emergency Core Cooling

ECCS leak detection is augmented by the sump monitoring system portion of the leak detection system. ECCS leaks can be identified by operator correlation of various flow, pressure, and reactor vessel level signals transmitted to the control room.

7.6.2.3.2.2.17 LDS - GDC 54 - Piping Systems Penetrating Containment

Leak detection is provided for main steam, RCIC, and RWCU lines penetrating the containment.

7.6.2.3.2.3 LDS Conformance to Industry Codes and Standards

7.6.2.3.2.3.1 LDS - IEEE 279 (1971) and 379 (1972) - Guide for the Application of the Single Failure Criterion

LDS isolation functions compliance with IEEE 279 (1971) and 379 (1972), is included in the IEEE 279 and 379 compliance discussions of the PCRVICS Section 7.3.2.2.3.1, for which this system provides logic trip signals.

7.6.2.3.2.3.2 LDS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

Leak detection compliance is shown in Section 7.1.2.7.4.

7.6.2.3.2.3.3 LDS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

For a conformance discussion, refer to Section 7.1.2.7.5.

7.6.2.3.2.3.4 LDS - IEEE 338 (1971) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Leak detection complies with IEEE 338 (1971). All active components of the LDS associated with the isolation signal can be tested during plant operation.

7.6.2.3.2.3.5 LDS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Leak detection system compliance is shown in Section 3.10.

7.6.2.3.2.3.6 LDS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generation Station Protection Systems

The degree of conformance is discussed in Section 7.1.2.7.8.

7.6.2.3.2.3.7 LDS - IEEE 384 (1977) - Criteria for Separation of Class 1E Equipment and Circuits

For an assessment, refer to Section 7.1.2.7.11.

7.6.2.4 Neutron Monitoring System - Instrumentation and Controls

7.6.2.4.1 Intermediate Range Monitor System

7.6.2.4.1.1 IRM General Functional Requirements Conformance

The analysis for the RPS trip inputs from the IRM system are discussed in Section 7.2.2.

7.6.2.4.1.2 IRM Power Generation Design Basis

The IRM is the primary source of information as the reactor approaches the power range. Its linear steps (approximately a half decade) and the rod blocking features on both high flux level and low flux level require that all the IRMs be on the correct range as core power is increased. The SRM overlaps the IRM. The sensitivity of the IRM is such that the IRM is on scale on the least sensitive (highest) range with approximately 15% reactor power.

The number and locations of the IRM detectors provide sufficient intermediate range neutron flux level information under the worst permitted bypass conditions. To ensure that each IRM is on the correct range, a rod block is initiated any time the IRM is both downscale and not on the most sensitive (lowest) scale. A rod block is initiated if the IRM detectors are not fully inserted in the core, unless the reactor mode switch is in the RUN position.

The IRM scram trips and the IRM rod block trips are automatically bypassed when the reactor mode switch is in the RUN position.

The IRM detectors and electronics have been tested under operating conditions and verified to have the operational characteristics described. They provide the level of precision and reliability required by the RPS safety design bases.

7.6.2.4.1.3 IRM Specific Regulatory Requirements Conformance

7.6.2.4.1.3.1 IRM Conformance with Regulatory Guides

7.6.2.4.1.3.1.1 IRM - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The portion of the IRM system that provides outputs to the RPS is designed to allow complete periodic testing of protection system actuation function as desired. The provision is accomplished by initiating an output trip of one IRM channel at any given time, which results in tripping one of the two RPS trip systems. Details are provided in the discussion of IEEE 279 (Section 7.2.2.1.2.3.1).

Indication of IRM bypass to operators is provided by indicator lamps.

7.6.2.4.1.3.1.2 IRM - Regulatory Guide 1.29 (1978) - Seismic Design Classification

All devices and circuitry from sensor to trip output are classified Category I (Section 7.1.2.5.6).

7.6.2.4.1.3.1.3 IRM - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

For compliance with Regulatory Guide 1.30, see Section 8.1.6.1.

7.6.2.4.1.3.1.4 IRM - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The IRM complies with this guide. Discussion is provided in Section 7.2.2.1.2.

7.6.2.4.1.3.1.5 IRM - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

The IRM complies with this guide. Discussion is provided in Section 7.2.2.1.2.1.8 under Regulatory Guide 1.53.

7.6.2.4.1.3.1.6 IRM - Regulatory Guide 1.68 (1978) - Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors

For conformance discussion refer to Section 7.1.2.5.16.

7.6.2.4.1.3.1.7 IRM - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

For conformance discussion refer to Section 7.1.2.5.19.

7.6.2.4.1.3.1.8 IRM - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The IRM complies with this guide. Discussion is provided in Section 7.2.2.1.2.

7.6.2.4.1.3.1.9 IRM - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

The IRM complies with this guide. Discussion is provided in Section 7.2.2.1.2.

7.6.2.4.1.3.1.10 IRM - Regulatory Guide 1.105 (1976) - Instrument Setpoints

The IRM complies with this guide. Discussion is provided in Section 7.2.2.1.2.

7.6.2.4.1.3.1.11 IRM - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

The IRM complies with this guide. Discussion is provided in Section 7.2.2.1.2.

7.6.2.4.1.3.2 IRM Conformance with 10CFR50, Appendix A, General Design Criteria

7.6.2.4.1.3.2.1 IRM - GDC 1 - Quality Standards and Records

The IRM, as an input to the RPS, complies with these criteria as discussed in Section 7.2.2.1.2.2.1.

7.6.2.4.1.3.2.2 IRM - GDC 2 - Design Bases for Protection Against Natural Phenomena

The IRM, as an input to the RPS, complies with these criteria as discussed in Section 7.2.2.1.2.2.2.

7.6.2.4.1.3.2.3 IRM - GDC 3 - Fire Protection

The IRM, as an input to the RPS, complies with these criteria as discussed in Section 7.2.2.1.2.2.3.

7.6.2.4.1.3.2.4 IRM - GDC 4 - Environmental and Dynamic Effects Design Bases

The IRM, as an input to the RPS, complies with these criteria as discussed in Section 7.2.2.1.2.2.4.

7.6.2.4.1.3.2.5 IRM - GDC 10 - Reactor Design

The IRM, as an input to the RPS, complies with these criteria as discussed in Section 7.2.2.1.2.2.5.

7.6.2.4.1.3.2.6 IRM - GDC 12 - Suppression of Reactor Power Oscillations

The IRM, as an input to the RPS, complies with these criteria as discussed in Section 7.2.2.1.2.2.6.

7.6.2.4.1.3.2.7 IRM - GDC 13 - Instrumentation and Control

The IRM detectors and associated electronics are designed to monitor the incore flux over all expected ranges required for the safety of the plant.

7.6.2.4.1.3.2.8 IRM - GDC 19 - Control Room

The IRM detectors and associated electronics are designed to monitor the incore flux over all expected ranges required for the safety of the plant.

7.6.2.4.1.3.2.9 IRM - GDC 20 - Protection System Functions

The IRM detectors and associated electronics are designed to monitor the incore flux over all expected ranges required for the safety of the plant.

7.6.2.4.1.3.2.10 IRM - GDC 21 - Protection System Reliability and Testability

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the IRM design as required for protection systems.

7.6.2.4.1.3.2.11 IRM - GDC 22 - Protection System Independence

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the IRM design as required for protection systems.

7.6.2.4.1.3.2.12 IRM - GDC 23 - Protection System Failure Modes

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the IRM design as required for protection systems.

7.6.2.4.1.3.2.13 IRM - GDC 24 - Separation of Protection and Control Systems

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the IRM design as required for protection systems.

7.6.2.4.1.3.2.14 IRM - GDC 25 - Protection System Requirements for Reactivity Control Malfunctions

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the IRM design as required for protection systems.

7.6.2.4.1.3.2.15 IRM - GDC 29 - Protection Against Anticipated Operational Occurrences

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the IRM design as required for protection systems.

7.6.2.4.1.3.3 IRM Conformance to Industry Codes and Standards

7.6.2.4.1.3.3.1 IRM - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

The IRM design is shown to comply with the design requirements of IEEE 279 in Section 7.2.2.1.2.3.1.

7.6.2.4.1.3.3.2 IRM - IEEE 317 (1972) - Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations

IRM conformance with IEEE 317 (1972) is endorsed by Regulatory Guide 1.63 (1978). For compliance to Regulatory Guide 1.63, see Section 8.1.6.1.

7.6.2.4.1.3.3.3 IRM - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

Written procedures and responsibilities are developed for the design and qualification of all Class 1E equipment. This includes preparation of specifications, qualification procedures, and documentation. Whenever possible, qualification testing or analysis is accomplished prior to release of the engineering design for production. Standards manuals are maintained and contain specifications, practices, and procedures for implementing qualification requirements; an auditable file of qualification documents is available for review.

7.6.2.4.1.3.3.4 IRM - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

IEEE 336 (1971) is endorsed by Regulatory Guide 1.30 (1972). For compliance to Regulatory Guide 1.30, see Section 8.1.6.1.

7.6.2.4.1.3.3.5 IRM - IEEE 338 (1971) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

IRM compliance with IEEE 338 is provided in Section 7.2.2.1.2.3.1 under IEEE 279, Paragraphs 4.9 and 4.10.

7.6.2.4.1.3.3.6 IRM - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

The IRMs are qualified for seismic events. Compliance is further shown in Section 3.10.

7.6.2.4.1.3.3.7 IRM - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

IRM signal separation, cabinet separation, use of isolation circuitry, and number of channels per trip system are methods used to meet the single failure criterion. Convenient tests and calibration circuits permit frequent checks for undetected failures.

7.6.2.4.1.3.3.8 IRM - IEEE 384 (1977) - Criteria for Separation of Class 1E Equipment and Circuits

For conformance discussion refer to Section 7.3.2

7.6.2.4.2 Local Power Range Monitor System

7.6.2.4.2.1 LPRM General Functional Requirement Conformance

The LPRM provides detailed information about neutron flux throughout the reactor core. The number of LPRM assemblies and their distribution is determined by extensive calculational and

experimental procedures. The division of the LPRM into various groups for ac power supply allows operation with one ac power supply failed or out-of-service without limiting reactor operation. Individual failed chambers can be bypassed. Neutron flux information for a failed chamber location can be interpolated from nearby chambers. A substitute reading for a failed chamber can be derived from an octant-symmetric chamber, or an actual flux indication can be obtained by inserting a TIP to the failed chamber position. Each output is electrically isolated so that an event (grounding the signal or applying a stray voltage) on the reception end does not destroy the validity of other LPRM signals. Tests and experience attest to the ability of the detector to respond proportionally to the local neutron flux changes.

The LPRM design conforms with the provisions of the safety design basis in that there are sufficient LPRM detectors to ensure that under worst case LPRM bypass conditions the APRM is capable of generating a trip signal to prevent fuel damage. The LPRM system utilizes 43 detector assemblies, each assembly monitoring all four axial planes in the core. Sufficient LPRM channels are assigned to each APRM channel to provide a valid signal for average core flux, even with the maximum number of channels bypassed. When more than the maximum allowable number of LPRM channels associated with an APRM channel are bypassed, an APRM trouble alarm occurs.

The LPRM design conforms to the provisions of the power generation design basis as follows:

a. The LPRM signals are proportional to the local neutron flux at various locations in the core. The LPRM subsystem utilizes 43 detector assemblies, each assembly consisting of four fission chambers located in different axial positions. The detector output characteristic is linear with neutron flux in the power range.

b. The LPRM system has trips for LPRM downscale and upscale. The trips are annunciated in the control room.

c. The LPRM provides signals to the process computer system which, utilizing additional inputs, computes local power densities for each fuel assembly, core power distribution, core thermal limits, and fuel exposure.

d. The LPRM provides signals to the RBM for the rod block trip function. When the averaged LPRM signal exceeds the rod block setpoint, control rod withdrawal is inhibited.

7.6.2.4.2.2 LPRM Specific Regulatory Requirements Conformance

7.6.2.4.2.2.1 LPRM Conformance to Regulatory Guides

7.6.2.4.2.2.1.1 LPRM - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

Refer to Section 7.1.2.5.5b for a general conformance statement for Regulatory Guide 1.22.

7.6.2.4.2.2.1.2 LPRM - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

For compliance to Regulatory Guide 1.30, see Section 8.1.6.1.

7.6.2.4.2.2.1.3 LPRM - Regulatory Guide 1.66 (1973) - Nondestructive Testing of Nuclear Products

This regulatory guide has been withdrawn by the NRC. The LPRM assembly dry tube was nondestructively examined in accordance with ASTM and ASME requirements; however, it was exempt from the requirements of Regulatory Guide 1.66 under note 3 of section C.

7.6.2.4.2.2.1.4 LPRM - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

Refer to Section 7.1.2.5.21 for a general conformance statement for Regulatory Guide 1.89.

7.6.2.4.2.2.2 LPRM Conformance to Industry Codes and Standards

7.6.2.4.2.2.2.1 LPRM - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

7.6.2.4.2.2.2.1.1 LPRM - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The LPRMs continuously supply flux level signals to the assigned APRM channel, which will automatically initiate the appropriate protective action whenever the core average flux reaches the trip setpoint.

7.6.2.4.2.2.2.1.2 LPRM - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

The LPRM is divided into four separate groups such that even in the event of a single failure under permissible APRM bypass conditions a scram signal can be generated in the RPS. Physical panel barriers and electrical isolation provides independence between groups. Redundant wiring and trip logic is physically separated to prevent a single failure from impairing a protective action.

7.6.2.4.2.2.2.1.3 LPRM - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

LPRM signals are processed by modules and components used on previous GE BWR plants which have exhibited high quality and reliability.

The detectors and related drive equipment as well as the trip logic circuitry are also of high quality and reliability.

7.6.2.4.2.2.2.1.4 LPRM - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

Qualification tests of LPRM equipment are conducted to confirm their adequacy for service. Environmental qualification is discussed in detail in Section 3.11.

7.6.2.4.2.2.2.1.5 LPRM - IEEE 279 (1971) Paragraph 4.5 - Channel Integrity

All components of LPRM are designed to operate under abnormal conditions of environment, power supply, and accidents.

7.6.2.4.2.2.2.1.6 LPRM - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The redundant channels of LPRM monitoring circuitry are physically separated from one another in conformance with this requirement.

7.6.2.4.2.2.2.1.7 LPRM - IEEE 279 (1971), Paragraph 4.7 - Control and Protective System Interaction

The LPRM output signals to the APRM are isolated from the output to the RBM. A failure in the RBM circuitry will not affect the output signal necessary for proper functioning of the APRM or RPS. Furthermore the APRM is designed such that a fault in any single LPRM output will not affect any other LPRMs supplying inputs to the same APRM channel.

7.6.2.4.2.2.2.1.8 LPRM - IEEE 279 (1971), Paragraph 4.8 - Deviation of System Inputs

The LPRM detector directly measures local neutron flux, which is a direct measure of local core power density.

7.6.2.4.2.2.2.1.9 LPRM - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

Proper detector operation can be verified during normal power operation by comparing detector response with TIP system response.

7.6.2.4.2.2.2.1.10 LPRM - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The gain adjustments for LPRMs are determined from process computer computations based on TIP flux measurements and reactor heat balance data.

7.6.2.4.2.2.2.1.11 LPRM - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

Each LPRM channel can be individually bypassed. When more than the permissible number of LPRM channels associated with an APRM channel is bypassed, an APRM trouble alarm is generated by that APRM.

7.6.2.4.2.2.2.1.12 LPRM - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

There are no operating bypass circuits provided for the LPRM or the APRM systems.

7.6.2.4.2.2.2.1.13 LPRM - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

ODAs in the control room indicate bypassed LPRM channels.

7.6.2.4.2.2.2.1.14 LPRM - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Manual bypassing of LPRM channels is accomplished by manual entry of settings in the NUMAC electronics, which are under the administrative control of the operator.

7.6.2.4.2.2.2.1.15 LPRM - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

The LPRM has no varying or multiple setpoints.

7.6.2.4.2.2.2.1.16 LPRM - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

See Section 7.2.2.1.2.3.1.16.

7.6.2.4.2.2.2.1.17 LPRM - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

See Section 7.2.2.1.2.3.1.17.

7.6.2.4.2.2.2.1.18 LPRM - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

Access to LPRM setpoint adjustments, calibration controls, and test setpoints is under the administrative control of plant supervisors.

7.6.2.4.2.2.2.1.19 LPRM - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

See Section 7.2.2.1.2.3.1.19.

7.6.2.4.2.2.2.1.20 LPRM - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The LPRM provides signals to the APRM for display of neutron flux level. Signals are also provided to the process computer, which, utilizing additional inputs, computes local power densities for each fuel assembly, core power distribution, core thermal units, and fuel exposure. LPRM upscale, downscale, and inoperative signals are annunciated in the control room.

7.6.2.4.2.2.2.1.21 LPRM - IEEE 279 (1971), Paragraph 4.21 - System Repair

Replacement of LPRM detectors must be accomplished during plant shutdown. Repair of the LPRM circuitry can be accomplished during plant operation by bypassing the affected channel. The design of the system facilitates rapid diagnosis and repair.

7.6.2.4.2.2.2.1.22 LPRM - IEEE 279 (1971), Paragraph 4.22 - Identification of Protective Systems

Each system cabinet is marked and the particular division is indicated on a marker plate. Cabling outside the cabinet is distinctively marked as are cable trays and racks.

7.6.2.4.2.2.2.2 LPRM - IEEE 317 (1972) - Electric Penetration Assemblies for Containment Structures for Nuclear Power Generating Stations

IEEE 317 (1972) is endorsed by Regulatory Guide 1.63 (1978). For compliance to Regulatory Guide 1.63, see Section 8.1.6.1.

7.6.2.4.2.2.2.3 LPRM - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

The LPRM equipment is qualified per the requirements of the standard.

7.6.2.4.2.2.2.4 LPRM - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

IEEE 336 (1971) is endorsed by Regulatory Guide 1.30 (1972). For conformance to Regulatory Guide 1.30, see Section 8.1.6.1.5.

7.6.2.4.2.2.2.5 LPRM - IEEE 338 (1971) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

LPRM equipment is designed so that individual channels can be taken out-of-service for test or calibration without affecting the remaining channels.

7.6.2.4.2.2.2.6 LPRM - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

The LPRM equipment is designed and qualified to function during and after an SSE. Refer to Section 3.10.

7.6.2.4.2.2.2.7 LPRM - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

The LPRM equipment is designed so that a single failure does not prevent needed safety functions.

7.6.2.4.2.2.2.8 LPRM - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

Refer to Section 7.1.2.7.11.

7.6.2.4.2.2.2.9 LPRM Conformance to 10CFR50, Appendix A, General Design Criteria

The degree of conformance is discussed in Section 7.6.2.4.3.2.2.

7.6.2.4.3 Average Power Range Monitor System

7.6.2.4.3.1 APRM General Functional Requirements Conformance

Each APRM derives its signal from LPRM information. The assignment, power separation, cabinet separation, and LPRM signal isolation are in accord with the safety design bases of the RPS. There are four APRM channels with the Reactor Protection System trip outputs from each routed to each of four APRM 2-out-of-4 voter channels. Two voter channels are associated with each Reactor Protection System trip system. This configuration allows one APRM channel to be bypassed plus one failure while still meeting the Reactor Protection System safety design basis.

Above a plant power level defined by Technical Specifications, the APRM power (and simulated thermal power) is adjusted periodically based on heat balance. This adjustment is made regularly at a rate sufficient to compensate for LPRM burnup and the related change in APRM values. However, coolant flow changes, control rod movements, and failed or bypassed LPRM inputs can also affect the relationship between APRM measured flux and reactor power. These predictable APRM variations are included in the analysis performed to determine minimum number of LPRM inputs required to be operable in order for the APRM channel to be operable. The analysis is performed, considering worst case combinations of failed LPRM inputs, at rate conditions by

assuming both continuous withdrawal of the maximum worth control rod and reduction of recirculation flow to 40% of rated flow. The minimum number of LPRM inputs for an APRM is determined such that the average of the remaining operable LPRM inputs still allows the APRM to track power excursions within the acceptance criteria assumed in plant safety analysis. If the number of operable LPRMs is less than required minimum, the APRM channel is declared inoperable.

There is also a minimum cells requirement applied to the OPRM upscale function. The minimum number of OPRM cells per APRM channel is established to ensure that thermal-hydraulic instabilities can be detected within the limits of the OPRM licensing methodology. If the number of cells is less than the required minimum, an OPRM/APRM trouble alarm is provided and the channel is declared inoperable.

The flow-referenced APRM scram setpoint is adequate to prevent fuel damage during an abnormal operational transient, as demonstrated in Chapter 15.

The APRM design conforms with the provision of the safety design bases in that under worst case LPRM bypass conditions the APRM is capable of generating a trip signal to prevent fuel damage. The APRM logic circuitry which interfaces with the RPS is discussed in Sections 7.2.1.1.4.2, 7.2.2.1.2.3.1.2, and 7.2.2.1.2.3.1.6.

The APRM design conforms to the provisions of the power generation design basis as follows:

a. Continuous indication of average reactor power is provided for the range of neutron flux from 0% to 125%.

b. An APRM upscale condition, or inoperative condition, or an APRM downscale condition, or a recirculation flow upscale condition, or less than the minimum number of LPRMs initiates a rod block. The rod block inhibits erroneous control rod motion to prevent circumstances that require a RPS protective action, and inhibits rod withdrawal when an APRM channel is disabled or unable to monitor core response.

c. Neutron flux level data are utilized by the process computer to compute power distribution and fuel exposure.

d. One primary APRM channel and one alternate APRM channel provide the reference reactor power signal for each RBM.

7.6.2.4.3.2 APRM Specific Regulatory Requirements Conformance

7.6.2.4.3.2.1 APRM Conformance to Regulatory Guides

7.6.2.4.3.2.1.1 APRM - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The portion of the APRM system that provides output to the RPS, the APRM 2-out-of-4 voters, is designed to allow complete periodic testing of protection system actuation functions. This provision is accomplished by initiating an output trip of one APRM 2-out-of-4 voter channel at any given time, which results in tripping one of the two RPS trip systems. Details are provided in Section 7.2.2.1.2.3.1 under IEEE 279 (1971).

Indication of APRM bypass to operators is provided by indicator lamps and ODA displays.

7.6.2.4.3.2.1.2 APRM - Regulatory Guide 1.29 (1978) - Seismic Design Classification

For conformance discussion refer to Section 3.1.2.

7.6.2.4.3.2.1.3 APRM - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

For compliance to Regulatory Guide 1.30, see Section 8.1.6.1.

7.6.2.4.3.2.1.4 APRM - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The APRM complies with these guides. Discussion is provided in Section 7.2.2.1.2.1.7 under Regulatory Guide 1.47.

7.6.2.4.3.2.1.5 APRM - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

For conformance discussion refer to Section 7.1.2.5.12.

7.6.2.4.3.2.1.6 APRM - Regulatory Guide 1.68 (1978) - Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors

For conformance discussion refer to Section 7.1.2.5.16.

7.6.2.4.3.2.1.7 APRM - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

For conformance discussion refer to Section 7.1.2.5.19.

7.6.2.4.3.2.1.8 APRM - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

Refer to Section 7.1.2.5.21.

7.6.2.4.3.2.1.9 APRM Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Section 7.5.2.5.1.1.2 contains a discussion of the degree of conformance.

7.6.2.4.3.2.1.10 APRM - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

See Section 3.10 for conformance.

7.6.2.4.3.2.1.11 APRM - Regulatory Guide 1.105 (1976) - Instrument Setpoints

For conformance discussion refer to Section 7.1.2.5.25.

7.6.2.4.3.2.1.12 APRM - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

For conformance discussion refer to Section 7.1.2.5.26.

7.6.2.4.3.2.2 APRM Conformance to 10CFR50, Appendix A, General Design Criteria

7.6.2.4.3.2.2.1 APRM - GDC 1 - Quality Standards and Records

For conformance discussion see Section 7.1.2.6.1.

7.6.2.4.3.2.2.2 APRM - GDC 2 - Design Bases for Protection Against Natural Phenomena

For conformance discussion see Section 7.1.2.6.2.

7.6.2.4.3.2.2.3 APRM - GDC 3 - Fire Protection

For conformance discussion see Section 7.1.2.6.3.

7.6.2.4.3.2.2.4 APRM - GDC 4 - Environmental and Dynamic Effects Design Bases

For conformance discussion see Section 7.1.2.6.4.

7.6.2.4.3.2.2.5 APRM - GDC 10 - Reactor Design

For conformance discussion refer to Section 7.1.2.6.6 and 7.2.2.1.2.2.5.

The APRM detection system and associated electronics are designed to monitor the incore flux over all expected ranges required for safety of the plant.

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the APRM design as required for protection systems.

7.6.2.4.3.2.2.6 APRM - GDC 12 - Suppression of Reactor Power Oscillations

Refer to Section 7.1.2.6.7 and 7.2.2.1.2.2.6.

7.6.2.4.3.2.2.7 APRM - GDC 13 - Instrumentation and Control

The APRM detection system and associated electronics are designed to monitor the incore flux over all expected ranges required for safety of the plant.

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the APRM design as required for protection systems.

7.6.2.4.3.2.2.8 APRM - GDC 19 - Control Room

The APRM detection system and associated electronics are designed to monitor the incore flux over all expected ranges required for safety of the plant.

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the APRM design as required for protection systems.

7.6.2.4.3.2.2.9 APRM - GDC 20 - Protection System Functions

The APRM detection system and associated electronics are designed to monitor the incore flux over all expected ranges required for safety of the plant.

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the APRM design as required for protection systems.

7.6.2.4.3.2.2.10 APRM - GDC 21 - Protection System Reliability and Testability

Refer to Section 7.1.2.6.12.

The APRM detection system and associated electronics are designed to monitor the incore flux over all expected ranges required for safety of the plant.

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the APRM design as required for protection systems.

7.6.2.4.3.2.2.11 APRM - GDC 22 - Protection System Independence

The APRM detection system and associated electronics are designed to monitor the incore flux over all expected ranges required for safety of the plant.

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the APRM design as required for protection systems.

7.6.2.4.3.2.2.12 APRM - GDC 23 - Protection System Failure Modes

The APRM detection system and associated electronics are designed to monitor the incore flux over all expected ranges required for safety of the plant.

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the APRM design as required for protection systems.

7.6.2.4.3.2.2.13 APRM - GDC 24 - Separation of Protection and Control Systems

The APRM detection system and associated electronics are designed to monitor the incore flux over all expected ranges required for safety of the plant.

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the APRM design as required for protection systems.

7.6.2.4.3.2.2.14 APRM - GDC 25 - Protection System Requirements for Reactivity Control Malfunctions

For conformance discussion refer to Section 7.1.2.6.16.

The APRM detection system and associated electronics are designed to monitor the incore flux over all expected ranges required for safety of the plant.

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the APRM design as required for protection systems.

7.6.2.4.3.2.2.15 APRM - GDC 29 - Protection Against Anticipated Operational Occurrences

Refer to Section 7.1.2.6.

The APRM detection system and associated electronics are designed to monitor the incore flux over all expected ranges required for safety of the plant.

Automatic initiation of protection system action, reliability, testability, independence, and separation are factored into the APRM design as required for protection systems.

7.6.2.4.3.2.3 APRM Conformance to Industry Codes and Standards

7.6.2.4.3.2.3.1 APRM - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

The APRM design is shown to comply with the design requirements of IEEE 279 in Section 7.2.2.1.2.3.1 and Subsection 4.4.1.1 of NEDC-32410P-A.

7.6.2.4.3.2.3.2 APRM - IEEE 317 (1972) - Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations

IEEE 317 (1972) is endorsed by Regulatory Guide 1.63 (1978). For compliance to Regulatory Guide 1.63, see Section 8.1.6.1.

7.6.2.4.3.2.3.3 APRM - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

APRM compliance is discussed in Section 7.1.2.7.4.

7.6.2.4.3.2.3.4 APRM - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

IEEE 336 (1971) is endorsed by Regulatory Guide 1.30. For compliance to Regulatory Guide 1.30, see Section 8.1.6.1.

7.6.2.4.3.2.3.5 APRM - IEEE 338 (1971) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

APRM compliance with IEEE 338 is shown in Section 7.2.2.1.2.3.1 under IEEE 279, Paragraphs 4.9 and 4.10.

7.6.2.4.3.2.3.6 APRM - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

APRM compliance is as shown in Section 7.1.2.7.7.

7.6.2.4.3.2.3.7 APRM - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

APRM signal separation, cabinet separation, use of isolation circuitry, and number of channels per trip system are methods used to meet the single failure criterion. Convenient test and calibration circuits permit regular checks for undetected failures.

7.6.2.4.3.2.3.8 APRM - IEEE 384 (1977) - Criteria for Separation of Class 1E Equipment and Circuits

For conformance discussion refer to Section 7.1.2.7.11.

7.6.2.5 Safety/Relief Valve Position Indication System - Instrumentation and Controls

7.6.2.5.1 SRVPI General Functional Requirements Conformance

The system provides alarm and indication of SRV position in the control room and provides a means to test the monitoring channels during system operation.

7.6.2.5.2 SRVPI Specific Regulatory Requirements Conformance

7.6.2.5.2.1 SRVPI Conformance to Regulatory Guides

7.6.2.5.2.1.1 SRVPI - Regulatory Guide 1.29 (1978) - Seismic Design Classification

Conformance is discussed in Section 7.6.2.5.2.1.5.

7.6.2.5.2.1.2 SRVPI - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

Conformance is discussed in Section 8.1.6.1.

7.6.2.5.2.1.3 SRVPI - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The SRVPI equipment is qualified for the environment expected during SRV discharge to the suppression pool and for 12 hours after a LOCA.

7.6.2.5.2.1.4 SRVPI - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Conformance is discussed in Section 7.5.2.5.1.1.2.

7.6.2.5.2.1.5 SRVPI - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

The SRVPI instrument is qualified to seismic Category I criteria in accordance with IEEE 344 (1975) and is mounted on seismic Category I equipment. The signal and power raceways for the system are routed through seismic Category I structures and are designated seismic Category IIA. Refer to Section 3.10.

7.6.2.5.2.2 SRVPI Conformance to 10CFR50, Appendix A, General Design Criteria

7.6.2.5.2.2.1 SRVPI - GDC 1 - Quality Standards and Records

The SRVPI is a nonsafety-related system designed and manufactured in accordance with approved documented procedures. A documented quality assurances program which complies with the pertinent quality assurance requirements of 10CFR50, Appendix B, is followed for installation of the instrumentation.

7.6.2.5.2.2.2 SRVPI - GDC 2 - Design Bases for Protection Against Natural Phenomena

Conformance is discussed in Section 7.6.2.5.2.1.5.

7.6.2.5.2.2.3 SRVPI - GDC 3 - Fire Protection

Fire resistant components are used throughout the SRVPI system.

7.6.2.5.2.2.4 SRVPI - GDC 4 - Environmental and Dynamic Effects Design Bases

Conformance is discussed in Section 7.1.2.6.4.

7.6.2.5.2.2.5 SRVPI - GDC 13 - Instrumentation and Control

The SRVPI system components are designed to provide indication during normal and accident conditions.

7.6.2.5.2.3 SRVPI Conformance to Industry Codes and Standards

7.6.2.5.2.3.1 SRVPI - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

Conformance is discussed in Section 7.6.2.5.2.1.3.

7.6.2.5.2.3.2 SRVPI - IEEE 338 (1977) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

Provisions are made for the periodic testing of this system in accordance with IEEE Class 1E requirements.

7.6.2.5.2.3.3 SRVPI - IEEE 344 (1975) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

Conformance is discussed in Section 7.6.2.5.2.1.5.

7.6.2.6 Containment Instrument Gas System - ADS Control - Instrumentation and Controls

7.6.2.6.1 CIGS-ADS General Functional Requirements Conformance

The following analysis demonstrates how the CIGS-ADS meets the safety design bases identified in Section 7.1.2.1.29.

The CIGS-ADS provides a backup supply of instrument gas to the ADS valves in the event that the non-safety-related CIGS equipment is not available. This function is safety-related. The ADS valves must be available for long-term operation. The ADS valves require a safety-related, seismic gas supply. The remainder of CIGS is non-safety-related, non-seismic.

7.6.2.6.2 CIGS-ADS Specific Regulatory Requirements Conformance

7.6.2.6.2.1 CIGS-ADS Conformance to Regulatory Guides

7.6.2.6.2.1.1 CIGS-ADS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

All controls for the CIGS-ADS are seismic Category 1.

7.6.2.6.2.1.2 CIGS-ADS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

See Section 8.1.6.1.

7.6.2.6.2.1.3 CIGS-ADS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

A low pressure alarm in the control room alerts the operator to low pressure in either set of nitrogen bottles.

7.6.2.6.2.1.4 CIGS-ADS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

Compliance is discussed in Section 7.1.2.5.12.

7.6.2.6.2.1.5 CIGS-ADS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

Compliance is discussed in Section 8.1.6.1.

7.6.2.6.2.1.6 CIGS-ADS - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Section 7.5.2.5.1.1.2 contains a discussion of the degree of conformance.

7.6.2.6.2.1.7 CIGS-ADS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

See Section 3.10.

7.6.2.6.2.2 CIGS-ADS Conformance to 10CFR50, Appendix A, General Design Criteria

7.6.2.6.2.2.1 CIGS-ADS - GDC 1 - Quality Standards and Records

This system is built in accordance with an established quality assurance program.

7.6.2.6.2.2.2 CIGS-ADS - GDC 2 - Design Bases for Protection Against Natural Phenomena

Compliance is discussed in Section 7.1.2.6.2.

7.6.2.6.2.2.3 CIGS-ADS - GDC 3 - Fire Protection

Compliance is discussed in Section 7.1.2.6.3.

7.6.2.6.2.2.4 CIGS-ADS - GDC 4 - Environmental and Dynamic Effects Design Bases

Compliance is discussed in Section 7.1.2.6.4.

7.6.2.6.2.2.5 CIGS-ADS - GDC 20 - Protection System Functions

The transfer from the instrument gas compressors (CIGS) to the CIGS-ADS as the gas source for the ADS valves is initiated automatically by a low pressure sensor in the respective header.

7.6.2.6.2.2.6 CIGS-ADS - GDC 21 - Protection System Reliability and Testability

The system is redundant on a system level; i.e., each gas source supplies sufficient ADS valves to accomplish the safety function. Testing during normal operation is possible without disrupting operation of the CIGS.

7.6.2.6.2.2.7 CIGS-ADS - GDC 22 - Protection System Independence

Diversity is not required for this system.

7.6.2.6.2.2.8 CIGS-ADS - GDC 23 - Protection System Failure Modes

On loss of instrument air or electric power, the system fails into an alignment that supplies nitrogen to the ADS valves.

7.6.2.6.2.2.9 CIGS-ADS - GDC 24 - Separation of Protection and Control Systems

The CIGS-ADS has no plant control functions.

7.6.2.6.2.2.10 CIGS-ADS - GDC 29 - Protection Against Anticipated Operational Occurrences

The CIGS-ADS is designed to withstand anticipated operational occurrences by seismic and environmental qualification as described in Sections 3.10 and 3.11.

7.6.2.6.2.3 CIGS-ADS Conformance to Industry Codes and Standards

7.6.2.6.2.3.1 CIGS-ADS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

7.6.2.6.2.3.1.1 CIGS-ADS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

On low supply pressure from the CIGS receivers, automatic transfer is effected to the CIGS-ADS gas bottles. The system is effective over the range of environmental conditions cited below:

a. Power supply voltages - Equipment is designed to operate within the range of voltages specified in Section 8.3.1.

b. Power supply frequency - Equipment is designed to operate within the range of power supply frequencies specified in Section 8.3.1.

c. Temperature - The system is operable at all temperatures that can result from a design basis LOCA.

d. Humidity - The system is operable at all humidities, including steam, that can result from a LOCA.

e. Pressure - The system is operable at all pressures resulting from a LOCA.

f. Radiation - The system is operable at all radiation levels expected for any design basis LOCA.

g. Vibration - The system will tolerate the conditions stated in Section 3.10.

h. Malfunction - The system will tolerate a single failure proof at the system level.

i. Accidents - The system will continue to operate during and following any DBA.

j. Fire - The system will tolerate raceway fires in a single division.

k. Explosions - Explosions are not defined in design bases.

l. Missiles - The system will tolerate any single missile destroying raceway, cabinet, or equipment in one division.

m. Lightning - Lightning damage to the electrical division powering the outboard isolation will render the system inoperative if the valve is closed on loss of power.

n. Floods - The plant is not subject to flooding, as discussed in Section 3.4.

o. Earthquake - The system will tolerate conditions stated in Section 3.10.

p. Wind and Tornado - All control equipment is located in a seismic Category 1 structure. See Section 3.3 for wind loadings.

q. System response times - The system response times are within the need to initiate alternate gas supply to the ADS valves.

r. System accuracies - Accuracies are within those needed for correct action.

s. Abnormal ranges of Sensed variables - Sensors are designed for the expected ranges and rates of change of variables.

7.6.2.6.2.3.1.2 CIGS-ADS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

A single active or passive electrical or control failure will not prevent the CIGS-ADS from performing its design safety function.

7.6.2.6.2.3.1.3 CIGS-ADS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the application. A quality assurance program is implemented.

7.6.2.6.2.3.1.4 CIGS-ADS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

The CIGS-ADS safety-related controls and instrumentation are qualified according to the requirements outlined in IEEE 323 (1971) as highlighted in Section 7.1.2.7.4. The qualifications criteria are identified in Sections 3.10 and 3.11. The parameters identified cover normal, abnormal, and accident environments.

7.6.2.6.2.3.1.5 CIGS-ADS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The CIGS-ADS meets the channel integrity objective by using the design features described in the other paragraphs of this section.

7.6.2.6.2.3.1.6 CIGS-ADS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The CIGS-ADS is a two train system. The control, instrumentation, and power circuits to each train of the system are physically and electrically separate from electrical channels in another division.

7.6.2.6.2.3.1.7 CIGS-ADS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The CIGS-ADS has no interaction with the plant control systems. Control room annunciator circuits taking input from this system are electrically isolated from the system and cannot impair its operability.

7.6.2.6.2.3.1.8 CIGS-ADS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

The CIGS-ADS is initiated by low pressure in the normal ADS gas supply header, from a pressure switch in each header.

7.6.2.6.2.3.1.9 CIGS-ADS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The pressure sensors for the CIGS-ADS can be checked by introducing a substitute input and observing system initiation.

7.6.2.6.2.3.1.10 CIGS-ADS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The pressure sensors used for system initiation can be tested and calibrated during power operation.

7.6.2.6.2.3.1.11 CIGS-ADS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

The two CIGS-ADS trains are separate electrically and physically. Removal of a component for maintenance prevents the operation of one train; however, operation of the other train is unaffected. The CIGS-ADS cannot be bypassed because all control is manual.

7.6.2.6.2.3.1.12 CIGS-ADS - IEEE 179 (1971), Paragraph 4.12 - Operating Bypasses

There are no operating bypasses.

7.6.2.6.2.3.1.13 CIGS-ADS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

A system out-of-service annunciator will be manually brought up by administrative procedures whenever system tests are performed.

7.6.2.6.2.3.1.14 CIGS-ADS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Access to components of the CIGS-ADS is controlled by administrative procedures.

7.6.2.6.2.3.1.15 CIGS-ADS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

This paragraph is not applicable.

7.6.2.6.2.3.1.16 CIGS-ADS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

The CIGS-ADS, once initiated, will perform its protective action to completion. The operator must reset the system to normal status.

7.6.2.6.2.3.1.17 CIGS-ADS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

The CIGS-ADS can be manually initiated.

7.6.2.6.2.3.1.18 CIGS-ADS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration and Test Points

Access is controlled by administrative procedures.

7.6.2.6.2.3.1.19 CIGS-ADS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

The positions of valves in the CIGS-ADS is indicated in the control room. Low gas supply header pressure is alarmed.

7.6.2.6.2.3.1.20 CIGS-ADS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

Valve position and low gas supply header pressure provides information to assure the operator of correct operation.

7.6.2.6.2.3.1.21 CIGS-ADS - IEEE 279 (1971), Paragraph 4.21 - System Repair

Malfunctioning components will be identified during periodic testing. The control logic is not complex, therefore location of a failed component is straightforward. The components are mounted to facilitate removal and replacement.

7.6.2.6.2.3.1.22 CIGS-ADS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Controls for the CIGS-ADS are located in control panels distinctively identified with nameplates that identifies them as having safety-related equipment. Cables and cable trays are color coded and tagged to identify them as being a separate channel.

7.6.2.6.2.3.2 CIGS-ADS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations See Section 3.11.

7.6.2.6.2.3.3 CIGS-ADS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

See Section 8.1.6.1 in the discussion of conformance to Regulatory Guide 1.30, which endorses/modifies this IEEE standard.

7.6.2.6.2.3.4 CIGS-ADS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection System

The operability of the CIGS-ADS can be verified and failures are detectable through testing during normal plant operation. The input sensor and setpoint are checked by the application of simulated signals.

7.6.2.6.2.3.5 CIGS-ADS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

See Section 3.10.

7.6.2.6.2.3.6 CIGS-ADS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

This system is not required to meet the single failure criterion.

7.6.2.6.2.3.7 CIGS-ADS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

This standard is not applicable to CIGS-ADS.

7.6.2.6.2.4 CIGS-ADS Additional Design Considerations Analysis

As identified in Regulatory Guide 1.70 (1978), paragraph 7.6.2, the following accidents are addressed:

a. Cold water slug injections - CIGS-ADS has no function in preventing or mitigating the consequences of this accident.

b. Refueling accidents - CIGS-ADS has no function in preventing or mitigating the consequences of these accidents.

c. Over-pressurization of low pressure systems - CIGS-ADS has no function in preventing or mitigating the consequences of this accident.

d. Fire - CIGS-ADS has no function in preventing or mitigating the consequences of fires.

7.6.2.7 Safeguard Piping Fill System - Instrumentation and Controls

7.6.2.7.1 SPFS General Functional Requirements Conformance

The following analysis shows how the SPFS meets the safety design bases identified in Section 7.1.2.1.41.1.

The SPFS provides water to the discharge lines of the ECCS pumps to maintain these lines in a full condition. The SPFS is normally on standby (not operating) and provides a safety-related backup to the condensate transfer system, which keeps the ECCS lines full during normal plant operation, through different piping connections. If the water level in the ECCS lines starts to drop, level instrumentation on the high point vents will annunciate an alarm in the control room, and the operator can start the SPFS pumps. The SPFS also provides water to the feedwater lines to maintain a water seal against discharge of containment atmosphere into the reactor enclosure in the event of any line break other than a feedwater line break inside containment. The SPFS is a supporting system to the ECCS. Once the fill system pumps are started, they operate continuously until they are turned off by the operator.

The SPFS is designed with redundancy as described in Section 7.6.1.7.5 so that no single active or passive electrical or control failure will prevent the SPFS from meeting its safety-related objective.

7.6.2.7.2 SPFS Specific Regulatory Requirements Conformance

7.6.2.7.2.1 SPFS Conformance to Regulatory Guides

7.6.2.7.2.1.1 SPFS - Regulatory Guide 1.22 (1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The SPFS pumps can be functionally tested during normal plant operation. The fill-water supply to feedwater line shutoff valves can be opened from the control room to verify operability.

7.6.2.7.2.1.2 SPFS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The SPFS is qualified to seismic Category I criteria, in accordance with IEEE 344. Refer to Section 3.10.

7.6.2.7.2.1.3 SPFS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

See Section 8.1.6.1.

7.6.2.7.2.1.4 SPFS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

A single failure within the SPFS will not prevent the SPFS from performing its safety function.

7.6.2.7.2.1.5 SPFS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The SPFS is qualified to meet Class 1E requirements.

7.6.2.7.2.1.6 SPFS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

Conformance with this regulatory guide is discussed in Section 3.10.

7.6.2.7.2.2 SPFS Conformance to 10CFR50, Appendix A, General Design Criteria

7.6.2.7.2.2.1 SPFS - GDC 1 - Quality Standards and Records

See Section 7.1.2.6.1.

7.6.2.7.2.2.2 SPFS - GDC 2 - Design Bases for Protection Against Natural Phenomena

See Section 3.1.

7.6.2.7.2.2.3 SPFS - GDC 3 - Fire Protection

See Section 3.1.

7.6.2.7.2.2.4 SPFS - GDC 4 - Environmental and Dynamic Effects Design Bases

See Section 3.1.

7.6.2.7.2.2.5 SPFS - GDC 5 - Sharing of Structures, Systems, and Components

No portions of the SPFS are shared between units.

7.6.2.7.2.2.6 SPFS - GDC 13 - Instrumentation and Control

Indicating lights are provided in the main control room to indicate operation of the SPFS pumps and to indicate the positions of the shutoff valves to the feedwater lines. Low pressure in the pump discharge lines is annunciated. The fill pumps are manually started and stopped from the control room. Low level in the ECCS pump discharge lines is annunciated in the control room by level instrumentation that is located on the vents at the high points of the lines. Feedwater line pressure is indicated in the control room so that the operator can determine if there has been a feedwater line break inside containment. If so, the operator can isolate the fill system from the broken line and still provide fill system water to the other (intact) feedwater line.

7.6.2.7.2.2.7 SPFS - GDC 20 - Protection System Functions

The SPFS is manually initiated.

7.6.2.7.2.2.8 SPFS - GDC 21 - Protection System Reliability and Testability

The components used in the SPFS are selected to ensure high functional reliability. The system can be tested and failures determined during normal plant operation.

7.6.2.7.2.2.9 SPFS - GDC 22 - Protection System Independence

The two SPFS trains are independent and physically separated with separate instruments to provide assurance that the protective function is not lost.

7.6.2.7.2.2.10 SPFS - GDC 23 - Protection System Failure Modes

The system is designed to tolerate a single active or passive electrical or control failure.

7.6.2.7.2.2.11 SPFS - GDC 29 - Protection Against Anticipated Operational Occurrences

The SPFS is designed to remain functional during anticipated operating occurrences.

7.6.2.7.2.3 SPFS Conformance to Industry Codes and Standards

7.6.2.7.2.3.1 SPFS - IEEE 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

7.6.2.7.2.3.1.1 SPFS - IEEE 279 (1971), Paragraph 4.1 - General Functional Requirement

The SPFS is manually initiated. It is effective over the full range of environmental conditions cited below:

a. Power supply voltages - Equipment is designed to operate within the range of voltages specified in Section 8.3.1.

b. Power supply frequency - Equipment is designed to within the range of power supply frequency specified in Section 8.3.1.

c. Temperature - The system is operable at all temperatures that can result from a design basis LOCA.

d. Humidity - The system is operable at all humidities, including steam, that can result from a LOCA.

e. Pressure - The system is operable at all pressures resulting from a LOCA.

f. Radiation - The system is operable at all radiation levels expected for any design basis LOCA.

g. Vibration - The system will tolerate the conditions stated in Section 3.10.

h. Malfunction - The system will tolerate any single component failure.

i. Accidents - The system will operate during and following any DBA.

j. Fire - The system will tolerate raceway fires in a single division.

k. Explosion - Explosions are not defined in design bases.

l. Missiles - The system will tolerate any single missile destroying raceway, cabinet, or equipment in one division.

m. Lightning - The system will tolerate lightning damage to one electrical division.

n. Flood - The plant is not subject to flooding as discussed in Section 3.4.

o. Earthquake - The system will tolerate conditions stated in Section 3.10.

p. Wind and Tornado - All control equipment is located in seismic Category 1 structure. See Section 3.3 for wind loadings.

q. System response times - The system is manually initiated.

r. System accuracies - Accuracies are within those needed for correct action.

s. Abnormal range of sensed variables - No variables are sensed.

7.6.2.7.2.3.1.2 SPFS - IEEE 279 (1971), Paragraph 4.2 - Single Failure Criterion

A single active or passive electrical or control failure will not prevent the SPFS from meeting its safety-related objective.

7.6.2.7.2.3.1.3 SPFS - IEEE 279 (1971), Paragraph 4.3 - Quality of Components and Modules

All safety-related components are selected on the basis of suitability for the application. A quality assurance program is implemented.

7.6.2.7.2.3.1.4 SPFS - IEEE 279 (1971), Paragraph 4.4 - Equipment Qualification

The SPFS safety-related controls and instrumentation have been qualified according to the requirements outlined in IEEE 323 (1971) as highlighted in Section 7.1.2.7.4, identified in Sections 3.10 and 3.11. The parameters identified cover normal, abnormal, and accident environments.

7.6.2.7.2.3.1.5 SPFS - IEEE 279 (1971), Paragraph 4.5 - Channel Integrity

The SPFS meets the channel integrity objective by using the design features described in the other paragraphs of this section.

7.6.2.7.2.3.1.6 SPFS - IEEE 279 (1971), Paragraph 4.6 - Channel Independence

The control, instrumentation, and power circuits to each SPFS pump and its associated feedwater shutoff valves are physically and electrically separated from the other pump and associated valves.

7.6.2.7.2.3.1.7 SPFS - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The SPFS has no interaction with the plant control systems. Control room annunciator circuits taking input from this system are electrically isolated from the system and cannot impair its operability.

7.6.2.7.2.3.1.8 SPFS - IEEE 279 (1971), Paragraph 4.8 - Derivation of System Inputs

There are no system inputs.

7.6.2.7.2.3.1.9 SPFS - IEEE 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

There are no sensed inputs to the SPFS.

7.6.2.7.2.3.1.10 SPFS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

The SPFS pumps and feedwater shutoff valves can be tested during normal plant operation.

7.6.2.7.2.3.1.11 SPFS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

The two SPFS trains are separate electrically and physically. Removal of a component for maintenance prevents the operation of one train; however, operation of the other train is unaffected. The SPFS cannot be bypassed because all control is manual.

7.6.2.7.2.3.1.12 SPFS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

All control for the SPFS is manual.

7.6.2.7.2.3.1.13 SPFS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

A common annunciator is provided in the control room to indicate low pump discharge pressure in either train of the SPFS, which may be a consequence of pump stoppage, whether by deliberate action or other reasons.

7.6.2.7.2.3.1.14 SPFS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

Access to components of the SPFS is procedurally controlled by administrative means.

7.6.2.7.2.3.1.15 SPFS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

This paragraph is not applicable to the SPFS.

7.6.2.7.2.3.1.16 SPFS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

The SPFS operates continuously once started by the operator and until stopped by the operator.

7.6.2.7.2.3.1.17 SPFS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

The SPFS is manually initiated.

7.6.2.7.2.3.1.18 SPFS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

This paragraph is not applicable to the SPFS.

7.6.2.7.2.3.1.19 SPFS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

The status of SPFS pumps and feedwater shutoff valves is shown by indicating lights on the control room panels.

7.6.2.7.2.3.1.20 SPFS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The SPFS pumps status and feedwater valve position provides information to assure the operator of correct operation.

7.6.2.7.2.3.1.21 SPFS - IEEE 279 (1971), Paragraph 4.21 - System Repair

Recognition of failed components is accomplished during testing of the system. During system operation, low discharge pressure is indicative of a failed pump. The control logic is not complex, therefore, location of a failed component is straightforward. The components are mounted to facilitate removal and replacement.

7.6.2.7.2.3.1.22 SPFS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

Controls for the SPFS are located in control panels distinctively identified with nameplates that identifies them as being a safety system. Cables and cable trays are color coded and tagged to identify them as being a separation channel.

7.6.2.7.2.3.2 SPFS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

See Section 3.11.

7.6.2.7.2.3.3 SPFS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

See Section 8.1.6.1 for a discussion of conformance with Regulatory Guide 1.30, which endorses/modifies this IEEE standard.

7.6.2.7.2.3.4 SPFS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

See Section 3.10.

7.6.2.7.2.3.5 SPFS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

A single failure within the SPFS will not prevent the SPFS from performing its safety function.

7.6.2.7.2.3.6 SPFS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

See Section 7.1.2.7.11.

7.6.2.7.2.3.7 SPFS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

The SPFS pumps and feedwater shutoff valves can be tested during normal plant operation. A failure of one valve during testing does not prevent the other valve from functioning.

7.6.2.7.2.4 SPFS Additional Design Considerations Analysis

As identified in Regulatory Guide 1.70 (1978), paragraph 7.6.2, the following accidents are addressed:

a. Cold water slug injection - SPFS has no function in preventing or mitigating the consequences of this accident.

b. Refueling accidents - SPFS has no function in preventing or mitigating the consequences of these accidents.

c. Overpressurization of low pressure systems - The SPFS has no function in preventing or mitigating the consequences of this accident.

d. Fires - SPFS has no function in preventing or mitigating the consequences of fires.

7.6.2.8 Redundant Reactivity Control System – Instrumentation and Controls

7.6.2.8.1 RRCS General Functional Requirements Conformance

The sensors, transmitters, trip units, and other assigned associated logic for the RRCS are Class 1E, separate and independent from the RPS, and environmentally qualified to expected ATWS conditions.

The RRCS is diverse from the RPS. No credible common mode failure can prevent both normal scram and ATWS prevention or mitigation functions. The RRCS is designed to independently monitor reactor pressure and water level and to shut down the nuclear chain reaction if these variables reach their respective trip setpoint. This shutdown is accomplished in the first few seconds after the trip by signals that cause rapid recirculation flow reduction and simultaneously open the ARI valves venting the air supply holding the scram valves shut.

Twenty-five seconds after the RRCS trip, additional core reactivity reduction is provided by a rapid termination (runback to 0%) of feedwater flow if the initiating signals include high pressure and core power is not downscale. Reactor high pressure is a symptom of loss of primary heat sink and is indicative of vessel isolation. The RRCS recirculation trips and feedwater runback serve to reduce core power below the steam flow capability of the SRVs.

7.6.2.8.2 RRCS Specific Regulatory Requirements Conformance

General exceptions to and positions taken on the regulatory guides, and the revision to the guide that is followed, are discussed in Sections 1.8 and 7.1.2.5. Specific applications of selected guides to the RRCS instrumentation and controls are discussed in this section.

7.6.2.8.2.1 RRCS Conformance to Regulatory Guides

7.6.2.8.2.1.1 RRCS - Regulatory Guide 1.6 (1971) - Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution System (Safety Guide 6)

The RRCS electrically powered safety loads are separated into load groups such that loss of any one group will not prevent the minimum safety functions from being performed. Division I RRCS logic is powered by 125 V dc from Bus A Division I. Division II logic is powered by 125 V dc from Bus B Division II.

7.6.2.8.2.1.2 RRCS - Regulatory Guide 1.22 (1972) – Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

The RRCS equipment is designed so that integrated system testing can be performed to verify overall system performance.

7.6.2.8.2.1.3 RRCS - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The sensors, transmitters, trip units and associated logic for the RRCS are classified as seismic Category I. The feedwater pump trip contacts are high quality but not necessarily safety-grade.

7.6.2.8.2.1.4 RRCS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

See Sections 1.8 and 7.1.2.5.

7.6.2.8.2.1.5 RRCS - Regulatory Guide 1.32 (1977) - Criteria for Safety-Related Electric Power and Protection Systems for Nuclear Power Plants

See Sections 1.8 and 7.1.2.5.

7.6.2.8.2.1.6 RRCS - Regulatory Guide 1.47 (1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

There is no RRCS bypass or operating bypass.

The following annunciators are provided to communicate system status to the operating personnel in the control room.

a. RRCS MANUAL INITIATION ARMED Division I/II

b. RRCS POTENTIAL ATWS Division I/II (receipt of high pressure or low water level 2)

c. 1A RECIRC PUMP MOTOR ATWS TRIP CIRCUIT POWER FAILURE
1B RECIRC PUMP MOTOR ATWS TRIP CIRCUIT POWER FAILURE

d. 1A RECIRC PUMP MOTOR TRIP
1B RECIRC PUMP MOTOR TRIP

e. RWCU ISOLATED

f. RRCS OUT OF SERVICE Division I (test fault, ATM calibration or gross failure)
RRCS OUT OF SERVICE Division II (test fault, ATM calibration or gross failure)

g. RRCS CONFIRMED ATWS Division I/II (timer has timed out and APRM power is not downscale, SLCS injection initiation signal is present)

h. RRCS CHANNEL ACTIVATED Division I/II

i. RRCS MANUAL INITIATION Division I/II

Additional operator interface with RRCS is provided by the following status lights. Each status light consists of a pair of bulbs for redundancy and an individual lamp test switch for each pair. These status lamps are repeated for Division II. All lamps are amber.

RRCS ARI INITIATION Division I
RRCS MANUAL INITIATION Division I
RRCS ARI READY FOR RESET Division I
RRCS READY FOR RESET Division I
RRCS TEST FAULT Division I
RRCS LOSS OF DC POWER Division I Channel A
RRCS LOSS OF DC POWER Division I Channel B
RRCS FEEDWATER RUNBACK INITIATED Division I
RRCS MANUAL INITIATION ARMED Division I
HIGH DOME PRESSURE Division I Channel A
HIGH DOME PRESSURE Division I Channel B

LOW WATER LEVEL 2 TRIP Division I Channel A
LOW WATER LEVEL 2 TRIP Division I Channel B
RRCS POTENTIAL ATWS Division I
RRCS RWCU ISOLATED Division I
RRCS CONFIRMED ATWS Division I
RRCS ATM CALIBRATION OR GROSS FAILURE Division I
RRCS TROUBLE Division I
RRCS RECIRCULATION PUMPS TRIPPED Division I

7.6.2.8.2.1.7 RRCS - Regulatory Guide 1.53 (1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

The RRCS meets the requirements of IEEE 279 (1971) and IEEE 379 (1972) (Section 7.6.2.8.2.3.1.2 and Section 7.6.2.8.2.3.6).

7.6.2.8.2.1.8 RRCS - Regulatory Guide 1.62 (1973) - Manual Initiation of Protective Actions

Means are provided for manual initiation of the RRCS protective actions. The RRCS ARI function and, after time delays, the SLCS are initiated upon depression of the RRCS manual initiation push button. The RRCS RPT and feedwater runback are not initiated by manual initiation of RRCS. These may be manually initiated at the respective system control panels using system breaker control switches.

7.6.2.8.2.1.9 RRCS - Regulatory Guide 1.68 (1978) - Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors

The RRCS meets Regulatory Guide 1.68 and will undergo preoperational and initial startup tests as described in Section 14.2.

7.6.2.8.2.1.10 RRCS - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

The RRCS meets Regulatory Guide 1.75. Methods for compliance with conditions involving the physical independence of electrical systems are discussed in Section 8.1.6.1.

7.6.2.8.2.1.11 RRCS - Regulatory Guide 1.89 (1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

The RRCS equipment is qualified to meet IEEE 323 (1974), IEEE 344 (1975) and Regulatory Guide 1.89.

7.6.2.8.2.1.12 RRCS - Regulatory Guide 1.100 (1977) - Seismic Qualification of Electric Equipment for Nuclear Power Generating Stations

The RRCS equipment is qualified to meet IEEE 344 (1975) and Regulatory Guide 1.100. Refer to Section 3.10.

7.6.2.8.2.1.13 RRCS - Regulatory Guide 1.105 (1976) - Instrument Setpoints

Instrument setpoints (accuracy, margin, and drift) for reactor power, water level, and pressure are described in the plant Technical Specifications.

7.6.2.8.2.1.14 RRCS - Regulatory Guide 1.118 (1978) - Periodic Testing of Electric Power and Protection Systems

The RRCS is continually checked by a solid-state microprocessor based self-test system that is part of the analog trip units. This system checks the RRCS sensors, logic, protective devices, and itself.

7.6.2.8.2.2 RRCS Conformance to 10CFR50, Appendix A, General Design Criteria

GDC that are generally applicable to all safety-related systems, are discussed in Section 3.1. Those with specific impact on the RRCS are described in this section.

7.6.2.8.2.2.1 RRCS - GDC 1 - Quality Standards and Records

See Section 7.1.2.2.

7.6.2.8.2.2.2 RRCS - GDC 2 - Design Bases for Protection Against Natural Phenomena

See Section 7.1.2.2.

7.6.2.8.2.2.3 RRCS - GDC 3 - Fire Protection

See Section 7.1.2.2.

7.6.2.8.2.2.4 RRCS - GDC 4 - Environmental and Dynamic Effects Design Bases

See Section 7.1.2.2.

7.6.2.8.2.2.5 RRCS - GDC 19 - Control Room

See Section 7.1.2.2.

7.6.2.8.2.2.6 RRCS - GDC 10 - Protection System Functions

The RRCS is completely automatic.

7.6.2.8.2.2.7 RRCS - GDC 21 - Protection System Reliability and Testability

The RRCS is designed for high functional reliability, and its logic can be tested for the safety functions to be performed. No single failure in this two divisional, four-channel protection system will result in the loss of the protective functions.

7.6.2.8.2.2.8 RRCS - GDC 22 - Protection System Independence

The RRCS is a two division Class 1E system separate and diverse from the RPS. It has functional diversity via ARI, RPT, and feedwater runback.

7.6.2.8.2.2.9 RRCS - GDC 24 - Separation of Protection and Control Systems

The RRCS protection system interfaces with control systems through isolation devices. Specifically, the RRCS signals to the recirculation system pump and the signal to the feedwater system to initiate runback both pass through isolators. This ensures that electrical failures in the control systems cannot propagate back into the RRCS system and therefore cannot prevent other channels in the RRCS divisions from performing their protective functions.

7.6.2.8.2.2.10 RRCS - GDC 29 - Protection Against Anticipated Operational Occurrences

The RRCS is highly reliable because it is redundant, Class 1E, functionally diverse and has continuous self-test capability.

7.6.2.8.2.3 RRCS Conformance to Industry Codes and Standards

7.6.2.8.2.3.1 RRCS - IEEE Standard 279 (1971) - Criteria for Protection Systems for Nuclear Power Generating Stations

7.6.2.8.2.3.1.1 RRCS - IEEE Standard 279 (1971), Paragraph 4.1 - General Functional Requirement

The RRCS will automatically initiate the appropriate protective actions whenever reactor high pressure or low water level 2 are received. These actions include tripping of the recirculation pump motor breakers, initiating a feedwater runback and RWCU system isolation.

7.6.2.8.2.3.1.2 RRCS - IEEE Standard 279 (1971), Paragraph 4.2 - Single Failure Criterion

The RRCS is two divisional with two channels (A and B) in each division. The RRCS protective action will be initiated when both channel A and channel B in either division are tripped. Different water level and pressure sensors feed each of the four channels of trip logic. Trip signals to trip the recirculation pump act on independent breakers. The feedwater runback and RWCU system isolation are capable of being initiated from either division. In this manner, any single failure within RRCS cannot prevent the protective actions at the system level from taking place.

7.6.2.8.2.3.1.3 RRCS - IEEE Standard 279 (1971), Paragraph 4.3 - Quality of Components and Modules

RRCS components and modules, and equipment in non-Class 1E systems supporting the RRCS (such as the recirculation system pump motor breaker ATWS trip coils), are Class 1E electrical, suitable for and consistent with the low failure rates required for nuclear power station safety-related equipment, except as noted below. High quality, although not necessarily safety-grade equipment shall be used to meet the feedwater control runback ATWS reliability requirements.

7.6.2.8.2.3.1.4 RRCS - IEEE Standard 279 (1971), Paragraph 4.4 - Equipment Qualification

Type test data or reasonable engineering extrapolation based on test data is available to verify that the RRCS can meet its performance requirements on a continuing basis.

7.6.2.8.2.3.1.5 RRCS - IEEE Standard 279 (1971), Paragraph 4.5 - Channel Integrity

RRCS channels and components meet the necessary functional requirements of the environmental conditions for components listed in the tables in Section 3.11.

7.6.2.8.2.3.1.6 RRCS - IEEE Standard 279 (1971), Paragraph 4.6 - Channel Independence

Each channel, A and B, of each division of logic is independent and physically separated from the other channel. Separate sensors provide signals of reactor pressure and water level for each channel of each division. Signals are routed through separate cabling to separate ATMs and RRCS logic. Actuation signals also travel to the trip-actuated devices via divisionally separated cabling. This design effectively decouples the effects of unsafe environmental factors, electrical transients, and physical accident consequences.

7.6.2.8.2.3.1.7 RRCS - IEEE Standard 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

The transmission of signals from RRCS protection system equipment for control system use is accomplished through isolation devices that are classified as part of the protection system and meet all the requirements of this standard. No credible failure at these isolators will prevent the associated protection system channel from meeting its design requirements.

7.6.2.8.2.3.1.8 RRCS - IEEE Standard 279 (1971), Paragraph 4.8 - Derivation of System Inputs

The RRCS system inputs, reactor pressure, and water level are derived from pressure and level transmitters that produce signals that are to the extent, feasible and practical, direct measures of these desired variables.

7.6.2.8.2.3.1.9 RRCS - IEEE Standard 279 (1971), Paragraph 4.9 - Capability for Sensor Checks

The RRCS self-test unit automatically checks the RRCS level and pressure sensors. The automatic check determines if the sensor output is downscale, within normal operating bounds, or too high. If the sensor output is found to be abnormal, an alarm is sounded. The sensor output can be observed and compared at the middle bay of the RRCS cabinet where the ATM diagnostic display is mounted.

7.6.2.8.2.3.1.10 RRCS - IEEE 279 (1971), Paragraph 4.10 - Capability for Testing and Calibration

Each RRCS sensor provides input to an analog trip module. The ATM electrically monitors the incoming sensor signal level and provides the appropriate output to the RRCS logic if that sensor signal level goes beyond its trip setpoints. Sensor signal level can be read at the ATM and compared to the known characteristics of the transmitter. Trip setpoint can be adjusted at the ATM, and the operability of this trip module is checked repeatedly by the RRCS self-test unit. RRCS sensors, logic, timers, and actuated devices are continuously checked by the RRCS self-test unit, thus meeting paragraph 4.10.

7.6.2.8.2.3.1.11 RRCS - IEEE 279 (1971), Paragraph 4.11 - Channel Bypass or Removal from Operation

The RRCS is designed such that portions may be removed from service for maintenance or testing without initiating the RRCS protective actions at the system level. Removal of portions of the RRCS for service will not result in protective actions because the system is normally de-energized.

7.6.2.8.2.3.1.12 RRCS - IEEE 279 (1971), Paragraph 4.12 - Operating Bypasses

There is no operating bypass affecting the RRCS.

7.6.2.8.2.3.1.13 RRCS - IEEE 279 (1971), Paragraph 4.13 - Indication of Bypasses

There is no manual bypass of the RRCS.

7.6.2.8.2.3.1.14 RRCS - IEEE 279 (1971), Paragraph 4.14 - Access to Means for Bypassing

The RRCS cannot be manually bypassed.

7.6.2.8.2.3.1.15 RRCS - IEEE 279 (1971), Paragraph 4.15 - Multiple Setpoints

There are no multiple setpoints applicable to the RRCS.

7.6.2.8.2.3.1.16 RRCS - IEEE 279 (1971), Paragraph 4.16 - Completion of Protective Action Once It Is Initiated

The RRCS protective actions are sealed in by the solid-state logic. The RRCS ARI function cannot be reset for 30 seconds after its initiation. This ensures that the scram will go to completion because the ARI valves are designed to vent the scram air header to cause all rods to begin scramming within 15 seconds. All other RRCS protective actions cannot be reset for at least 10 minutes. Operator control of the feedwater system can be regained 30 seconds after initiation of the RRCS feedwater runback. Because the runback is designed to bring feedwater flow to 0% within 15 seconds, this protective function will also go to completion.

7.6.2.8.2.3.1.17 RRCS - IEEE 279 (1971), Paragraph 4.17 - Manual Initiation

The RRCS can be manually initiated by depressing the manual initiation push buttons. The manual initiation signal is immediately sealed into the RRCS ARI logic.

7.6.2.8.2.3.1.18 RRCS - IEEE 279 (1971), Paragraph 4.18 - Access to Setpoint Adjustments, Calibration, and Test Points

The design of RRCS permits the administrative control of access to all setpoint adjustments, module calibration adjustments, and test setpoints via enclosing the ATMs and logic in key-locked cabinets.

7.6.2.8.2.3.1.19 RRCS - IEEE 279 (1971), Paragraph 4.19 - Identification of Protective Actions

RRCS protective actions are indicated and identified down to the channel level by status lights and annunciators.

7.6.2.8.2.3.1.20 RRCS - IEEE 279 (1971), Paragraph 4.20 - Information Readout

The RRCS provides the operator with pertinent information as to its condition via status lights and annunciators. This includes indication of the various stages of the RRCS logic actuation such as RPT, feedwater runback, and both potential and confirmed ATWS. An RRCS trouble annunciator is provided to signal a test fault, ATM in calibration or gross failure. Loss of power to RRCS is signaled by the RRCS trouble annunciator.

7.6.2.8.2.3.1.21 RRCS - IEEE 279 (1971), Paragraph 4.21 - System Repair

The RRCS system is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules. The use of the analog trip module facilitates the calibration, adjustment, or repair of the trip system. The modules are plug-in units that can be easily replaced. RRCS logic is separated by division and channel onto individual cards that can be easily replaced by spares.

7.6.2.8.2.3.1.22 RRCS - IEEE 279 (1971), Paragraph 4.22 - Identification of Protection Systems

The RRCS protection system equipment is identified distinctively as being in the protection system, and its equipment is marked to clearly indicate divisional separation. Panels are labeled with distinctive marker plates.

7.6.2.8.2.3.2 RRCS - IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

The RRCS meets IEEE 308. The logic is in two divisions. Each division has separate Class 1E power. RRCS components are energized to trip, therefore loss of power to one division will not affect protective actions of the RRCS.

7.6.2.8.2.3.3 RRCS - IEEE 323 (1971) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

The RRCS is in conformance with IEEE 323 as shown in Section 3.11.

7.6.2.8.2.3.4 RRCS - IEEE 338 (1975) - Criteria for the Periodic Testing of Nuclear Power Generating Station Protection Systems

RRCS compliance with IEEE 338 is demonstrated in Section 7.6.1.8.2, ATM self-test capability and in 7.6.2.8.2.3.1, paragraphs 4.9 and 4.10.

7.6.2.8.2.3.5 RRCS - IEEE 344 (1975) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

The RRCS is qualified for seismic events shown in Section 3.10.

7.6.2.8.2.3.6 RRCS - IEEE 379 (1972) - Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems

RRCS signal separation, cabinet separation, use of isolation circuitry, and number of channels per trip system are methods used to meet the single failure criterion. The RRCS self-test system eliminates nondetectable failures by continually checking RRCS sensors, logic, and trip devices.

7.6.2.8.2.3.7 RRCS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

The RRCS meets IEEE 384 as discussed in Section 7.1.2.7.11. The RRCS meets Regulatory Guide 1.75 as discussed in Section 7.6.1.8.2. Physical independence of electrical systems is discussed in Section 8.3.1.4.

7.6.2.9 Additional Design Considerations Analyses

7.6.2.9.1 General Plant Safety Analyses

The examination of the subject safety systems at the plant safety analyses level is presented in Chapter 15.

7.6.2.9.2 Cold Water Slug Injection

Refer to Section 15.5.1.

7.6.2.9.3 Refueling Accidents

Refer to Section 15.7.4.

7.6.2.9.4 Overpressurization of Low Pressure System

Refer to Section 7.6.1.2.

7.6.3 REFERENCES

7.6-1 NEDC-32410P-A, “Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC-PRNM) Retrofit Plus Option III Stability Trip Function,” October 1995.

7.6-2 NEDC-32410P-A, Supplement 1, “Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC-PRNM) Retrofit Plus Option III Stability Trip Function,” November 1997.

7.6-3 NEDO-31960-A and NEDO-31960-A, Supplement 1, “BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.

7.6-4 NEDO-32465-A, “Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications,” August 1996.

7.6-5 Deleted.

7.6-6 NEDE-33766P-A, Revision 1, "GEH Simplified Stability Solution (GS3)," March 2015.

Table 7.6-1

PROCESS RADIATION MONITORING SYSTEMS - INSTRUMENT CHARACTERISTICS

MONITORING SYSTEM	INSTRUMENT RANGE	INSTRUMENT SCALE (DECADE LOG)	TRIPS PER UPSCALE
MSL-RMS	1 to 10^6 mR/hr	6	2(1)
REVE-RMS	10^{-2} to 10^2 mR/hr	4	2(1)
RAVE-RMS	10^{-2} to 10^2 mR/hr	4	2(1)
CRV-RMS	10^{-6} to 10^{-1} μCi/cc	5	2(1)
CREFA-RMS	10^{-6} to 10^{-1} μCi/cc	5	2(2)
PCPL-RMS	10° to 10^8 R/hr	8	1(3)
RHRSW-RMS	10 to 10^6 cpm	5	1(1)
NSE-RMS	10^{-7} to 10^5 μCi/cc	12	2(3)

(1) A safety-related control trip is provided to shut off plant components.
(2) No control trip is provided. The trip provides annunciator alarm only.
(3) A nonsafety-related control trip is provided to shut off plant components.

Table 7.6-2

IRM SYSTEM TRIPS

TRIP FUNCTION	NORMAL SETPOINT	TRIP ACTION
IRM upscale	120/125 FS	Scram, annunciator, red light display
IRM inoperative	(1)	Scram, annunciator, red light display
IRM upscale	85/125 FS	Rod block, annunciator, amber light display
IRM downscale	3/125 FS	Rod block (exception on most sensitive scale), annunciator, white light display
IRM bypassed	-	White light display

(1) IRM is inoperative if module interlock chain is broken, operate/calibrate switch is not in operate position, detector polarizing voltage is below 80 V, or negative 20 V dc supply is lost.

Table 7.6-3

LPRM SYSTEM TRIPS

TRIP FUNCTION	TRIP RANGE	TRIP SETPOINT	TRIP ACTION
LPRM and downscale	0% to full Scale	3%	ODA inication annunciator
LPRM and Upscale	0% to full Scale	100%	ODA indication annunciator
LPRM and bypass	Manual selection	-	ODA indication APRM averaging compensation

Table 7.6-4

APRM SYSTEM TRIPS

TRIP FUNCTION	TRIP POINT RANGE	NOMINAL SETPOINT	ACTION
APRM Downscale Rod Block	0% to full-scale	To be provided in the Technical Specifications	Rod block, annunciator, APRM ODA, white light
APRM Simulated Thermal Power - Upscale (Setdown) Trip	10% to 30%	To be provided in the Technical Specifications	Scram, annunciator, APRM ODA, red light
APRM Simulated Thermal Power - Upscale (Setdown) Rod Block	7% to 27%	To be provided in the Technical Specifications	Rod block, annunciator, APRM ODA, amber light
APRM Simulated Thermal Power - Upscale Trip:			
- Two Recirculation Loop Operation	Varied with flow; intercept and slope adjustable	To be provided in the Technical Specifications	Scram, annunciator, APRM ODA, red light
- Single Recirculation Loop Operation	Varied with flow; intercept and slope adjustable	To be provided in the Technical Specifications	Scram, annunciator, APRM ODA, red light

Table 7.6-4 (Cont'd)

APRM SYSTEM TRIPS

TRIP FUNCTION	TRIP POINT RANGE	NOMINAL SETPOINT	ACTION
APRM Simulated Thermal Power - Upscale Rod Block:			
- Two Recirculation Loop Operation	Varied with flow; intercept and slope adjustable	To be provided in the Technical Specifications	Rod Block, annunciator, APRM ODA, amber light
- Single Recirculation Loop Operation	Varied with flow; intercept and slope adjustable	To be provided in the Technical Specifications	Rod Block, annunciator, APRM ODA, amber light
APRM Neutron Flux - Upscale Trip	10% to full-scale	To be provided in the Technical Specifications	Scram, annunciator, APRM ODA, red light
APRM Neutron Flux - Upscale Rod Block	10% to full-scale	To be provided in the Technical Specifications	Rod Block, annunciator, APRM ODA, amber light
APRM Inoperative Trip	Chassis mode switch, module interlocks open, or self-test	Not in operate mode or critical self-test fault	Scram, rod block, annunciator, APRM ODA, red light

Table 7.6-4 (Cont'd)

APRM SYSTEM TRIPS

TRIP FUNCTION	TRIP POINT RANGE	NOMINAL SETPOINT	ACTION
OPRM Upscale ***	Period based detection algorithm (PBDA) – Confirmation Count: 2-25 Amplitude: 1.00-1.30	To be provided in the Technical Specifications	Scram, annunciator, APRM ODA
	Amplitude based algorithm (ABA): 1.05-1.50	Not applicable ****	Scram, annunciator, APRM ODA
	Growth rate algorithm (GRA): 1.00-1.50	Not applicable ****	Scram, annunciator, APRM ODA
APRM Bypass	Manual switch	- -	White light

*** This trip can only occur when the reactor mode switch is in the RUN position, and the plant is operating within the OPRM trip enabled region of the power-flow map (reactor is operating at or above the lower power limit and below the upper flow limit).

**** The ABA and GRA are not credited in the safety analysis.

Table 7.6-5

RRCS TRIP LOGIC RESPONSE

RRCS After Signal	Immediate	9 Seconds After Initiation	25 Seconds After Initiation And APRM Not Downscale	30 Seconds After Initiation	118 Seconds After Initiation and APRM Not Downscale	10 Minutes and 118 Seconds After Initiation and APRM Not Downscale
Reactor High Pressure	ARI Recirc Pump Motor Trip Start 30, 25, and 118 second timers		Feedwater Runback	ARI reset permissive available	SLCS Initiation RWCU isolation 10 minute timer started	Reset possible if initiation signals have cleared
Reactor water Low Level 2	ARI Start 9, 30, and 118 second timers	Recirc Pump Motor Trip		ARI reset permissive available	SLCS Initiation RWCU isolation 10 minute timer started	Reset possible if initiation signals have cleared
Manual Intiation	ARI Start 30 And 118 second timers			ARI reset permissive available	SLCS Intiation RWCU isolation 10 minute timer started	Reset possible if initiation signals have cleared

Table 7.6-6

RADIATION MONITORING SYSTEM SENSOR LOCATION

Monitor	Location[1]
Main steam line	Main steam tunnel
Reactor enclosure ventilation exhaust	Reactor enclosure
Refueling floor ventilation exhaust	Reactor enclosure
Control room ventilation	Control enclosure
Control room emergency fresh air supply	Control enclosure
Primary containment post-LOCA	Primary containment
RHRSW	Diesel generator enclosure
North stack effluent	Reactor enclosure roof

(1) All of these locations are safety-related structures.

Table 7.6-7

HIGH PRESSURE/LOW PRESSURE INTERLOCK EQUIPMENT

		PARAMETER		
Process Line	Type	Valve	Sensed	Purpose
RHR shutdown cooling supply	MO MO	HV51-F009 HV51-F008	Reactor pressure (4)	Prevents valve opening until reactor pressure is low
RHR shutdown Cooling return	Check	HV51-F050A,B	N/A	N/A
	MO	HV51-F015A,B	Reactor pressure	Prevents valve opening until reactor pressure is low
	AO Check	HV51-151A,B 51-1200A, B	(1) N/A	(1) N/A
RHR LPCI line	AO	HV51-142A,B, C,D	(1)	(1)
	Check	HV51-F041A,B, C, D	N/A	N/A
	MO	HV51-F017A,B, C, D	Differential pressure across valve	Prevents valve opening until differential pressure is low
CS system	Check Check MO MO MO	HV52-F006A,B HV52-108 HV52-F005 HV52-F004A,B HV52-F037	N/A N/A Reactor pressure	N/A N/A Prevents valve opening until reactor pressure is low
	AO	HV52 F039A,B	(1)	(1)

Table 7.6-7 (Cont'd)

PARAMETER

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(1) No parameter sensed because the valves are opened solely by remote momentary push buttons, to equalize pressure across the check valve discs to permit testing of the opening of the check valves.

(2) Not used.

(3) Not used.

(4) The RHR shutdown cooling suction valve F008 is provided with an additional interlock which prevents a fire-induced open signal from causing it to open simultaneously with valve F009 when the reactor pressure is greater than the design capabilities of the RHR low-pressure piping.

Table 7.6-8

INTERLOCKED VALVES ON THE HPLPSI

SYSTEM	VALVE	POWER
RHR	E11-F008	ESS 2
	E11-F009	ESS 1
	E11-F050A, B	ESS 1
	E11-F015A, B	ESS 2
	E11-F017A	ESS 1
	E11-F017B	ESS 2
	E11-F017C	ESS 3
	E11-F017D	ESS 4
CS	E21-F004A	ESS 1
	E21-F004B	ESS 2
	E21-F005	ESS 1
	E21-F037	ESS 2

7.7 CONTROL SYSTEMS NOT REQUIRED FOR SAFETY

7.7.1 DESCRIPTION

This section discusses instrumentation and controls of systems whose functions are not essential to the safety of the plant. The systems include:

a. Reactor vessel instrumentation

b. Reactor manual control system

c. Recirculation flow control system

d. Feedwater control system

e. Pressure regulator and turbine-generator system

f. Neutron monitoring system - instrumentation and controls

1. Source range monitor system

2. Rod block monitor system

3. Traversing incore probe system

g. DELETED

h. Reactor water cleanup system

i. Process radiation monitoring systems

1. South stack effluent radiation monitoring system

2. Radwaste equipment rooms ventilation exhaust radiation monitoring system

3. Charcoal treatment system process exhaust radiation monitoring system

4. Recombiner rooms and hydrogen analyzer compartments exhaust radiation monitoring system

5. Steam exhauster discharge and vacuum pump exhaust radiation monitoring system

6. Radwaste enclosure and chem. lab ventilation exhaust radiation monitoring system

7. Air ejector offgas effluent radiation monitoring system

8. Primary containment leak detection radiation monitoring system

9. Hot maintenance shop ventilation exhaust radiation monitoring system

10. Liquid radwaste discharge radiation monitoring system

11. Service water radiation monitoring system

12. Reactor enclosure cooling water radiation monitoring system

j. Area radiation monitoring system

k. Gaseous radwaste system

l. Liquid radwaste system

m. Solid radwaste system

n. Fuel pool cooling and cleanup system

o. Refueling interlocks

p. Leak detection system

q. Emergency Response Facility Data System

r. Containment instrument gas system

s. Fire protection and suppression system

t. Nonsafety-related equipment area cooling ventilation systems

u. Rod worth minimizer

v. Plant monitoring system

w. Hydrogen water chemistry system

7.7.1.1 Reactor Vessel Instrumentation

Drawings M-41, M-43 and M-44 show the instrument numbers, arrangements of sensors, and sensing equipment used to monitor the reactor vessel conditions. Because the reactor vessel sensors used for safety-related systems are described and evaluated in other portions of this document, only the sensors not required for safety are described in this section.

7.7.1.1.1 RVI Identification

7.7.1.1.1.1 RVI General

The purpose of the reactor vessel instrumentation is to monitor the key reactor vessel operating variables during plant operation.

These instruments and systems are used to provide the operator with information during normal plant operation, startup, and shutdown. They are monitoring devices and provide no active power control or safety functions.

7.7.1.1.1.2 RVI Classification

The systems and instruments discussed in this section are designed to operate under normal and peak operating conditions of system and ambient pressures and temperatures, and are classified as not related to safety.

7.7.1.1.1.3 RVI Reference Design

Table 7.1-2 lists the reference design information. The RVI is an operational system and has no safety function. Therefore, there are no safety design differences between this system and those of the referenced design facilities. This system is functionally identical to the referenced system, except for RPV level instrumentation used during refueling.

7.7.1.1.2 RVI Power Sources

Nonsafeguard instrumentation is powered from a non-Class 1E 120 V ac 60 Hz instrument bus. Safeguard pressure, differential pressure, and level transmitter and trip unit channels are powered from divisional 24 V dc buses that are energized by Class 1E 120 V ac / 24 V dc power supplies. Some of these power supplies are energized from the appropriate Class 1E 120 V ac divisional instrument bus, and the others are energized from the Class 1E 125 V dc instrument bus for the division via a 125 V dc/120 V ac inverter. See Sections 7.2, 7.3, and 7.4 for more discussion of the Class 1E safeguard (divisional) power sources.

7.7.1.1.3 RVI Equipment Design

For safeguard and nonsafeguard sensing instruments located below the process tap, the sensing lines slope downward from the process tap to the instrument about ½ in/ft (the design minimum is ¼ in/ft, which is allowed for those lines that cannot be sloped a minimum ½ in/ft because of obstructions) so that air traps are not formed.

Where it is impractical to locate the instruments below the process tap, the sensing lines ascend vertically for at least 36 inches of process connection up to a high point vent located at an accessible elevation above the instrument, before sloping a minimum of ¼ in/ft to the instrument. The purpose of this is to prevent entrapment of a noncondensable gas in the sensing line.

7.7.1.1.3.1 RVI Circuit Description

7.7.1.1.3.1.1 RVI Jet Pump Flow

Chapter 5 gives a description of the reactor jet pump flow controls.

7.7.1.1.3.1.2 RVI Temperature

The reactor vessel temperature is indicated by several thermocouples placed at selected locations on the vessel shell and flange, as well as one on the vessel bottom head drain line as shown in

drawing M-41. These thermocouple temperatures are recorded at a local panel in the reactor enclosure and some selected thermocouples are input into the plant and ERFDS computers.

The reactor vessel temperature can also be determined on the basis of reactor coolant temperature. Temperatures needed for operation and compliance with the Technical Specification operating limits are obtained from one of several sources, depending on the operating condition. During normal operation, either reactor pressure (Section 7.7.1.1.3.1.5) or the inlet temperature of the coolant in the recirculation loops (drawing M-43) can be used to determine the vessel temperature. Below the operating span of the resistance temperature detectors in the recirculation loop, and above 212°F, the vessel pressure is used to determine the temperature. Below 212°F, the vessel coolant, and thus the vessel temperature, is shown by the RWCU system inlet temperature (drawing M-44). These three sources of input are available from the process computer and from indicators or recorders in the control room. During normal operation, vessel thermal transients are limited by operational constraints on parameters other than temperature.

7.7.1.1.3.1.3 RVI Water Level

Figure 7.7-1 shows the water level ranges and the vessel penetration for each range. The instruments that sense water level are differential pressure devices calibrated to be accurate at a specific vessel pressure and liquid temperature condition. Additional gauge pressure devices are used during refueling. Water level instrument line failure is addressed in Section 7.7.1.1.6. The following is a description of each water level range shown in Figure 7.7-1:

a. Shutdown water level range:

   This range is used to monitor the reactor water level during the shutdown condition when the reactor system is flooded for maintenance and head removal. The water level measurement design is of the condensate reference chamber-type when the vessel head is in place. The vessel temperature and pressure conditions used for the calibration are 0 psig and 120°F water in the vessel. The zero of the instrument is the bottom of the dryer skirt. The two vessel instrument penetrations used for this water level measurement are located at the top of the RPV head and just below the bottom of the dryer skirt. When the vessel head is removed for refueling, the condensate reference chamber and associated wet leg is not functional, and a gauge pressure transmitter is switched in, to measure shutdown range level. One indicator is provided in the control room to indicate reactor water level in the shutdown range.

b. Upset water level range:

   This range is used to monitor the reactor water when the level of the water goes off the narrow range scale on the high side. The upset range is also used during refueling to provide redundant level indication in the control room. The design and vessel taps are the same as outlined above. The vessel pressure and temperature condition for accurate indication are at the normal operating point, except for the gauge pressure transmitter used during refueling, which is calibrated to the same conditions as for the shutdown range instrumentation. The upset water level is continuously indicated by a recorder in the control room. The upset range recorder and narrow range indicators are located in close proximity to each other. The upset range upper limit is higher than the narrow range upper limit. Therefore, when the

indication goes off scale in the upscale direction on the narrow range indicator, water level indication can be read immediately from the upset range recorder.

c. Narrow water level range:

This range uses RPV taps at an elevation near the top of the dryer skirt and taps at an elevation near the bottom of the dryer skirt. The zero of the instrument is the bottom of the dryer skirt and the instruments are calibrated to be accurate at the normal operating point. The water level measurement design is of the condensate reference chamber-type and uses differential pressure devices as the primary elements. The feedwater control system uses this range for its water level control and indication inputs. For more information about the range, trip points, number of channels, and control room indication, see the discussion on the feedwater control system in Section 7.7.1.4.

d. Wide water level range:

This range uses RPV taps at an elevation near the top of the dryer skirt and taps at an elevation near the top of the active fuel. The zero of the instrument is the bottom of the dryer skirt and the instruments are calibrated to be accurate at the normal power operating point. The water level measurement design is of the condensate reference chamber-type, and uses differential pressure devices as the primary elements. Control room indication in the wide range is used for normal and accident conditions. See Section 7.5 for a description of the number of channels, type of indication, and ranges.

e. Fuel zone water level range:

This range uses RPV taps at an elevation near the top of the dryer skirt and taps at the jet pump diffuser skirt. The zero of the instrument is the bottom of the dryer skirt and the instruments are calibrated to be accurate at 0 psig and saturated condition. The fuel zone level transmitters output signals are electronically compensated for variation in reactor water and steam density with respect to pressure. The water level design is of the condensate reference chamber-type, and uses differential pressure devices as the primary elements. One recorder and one indicator are provided in the control room to indicate reactor water level in the fuel zone range. The top of the active fuel will be indicated in red.

The condensate reference chamber for the narrow range, wide range, and fuel zone water level range is common, as shown in drawing M-42. A continuous backfill system is connected to each condensing chamber reference leg. The backfill system provides a continuous flow of water from the Control Rod Drive (CRD) System to the reference leg. This flow of water will continuously purge the reference leg and preclude the build up of noncondensable gas in the reference leg.

7.7.1.1.3.1.4 RVI Reactor Core Hydraulics

A differential pressure transmitter indicates the core plate pressure drop by measuring the pressure difference between the core inlet plenum and the space just above the core support assembly (core plate and fuel supports). The instrument sensing line used to determine differential pressure is a pipe within a pipe arrangement attached to the reactor vessel tap initially designed to provide differential pressure taps and inject the liquid from the SLCS. Now SLCS is injected through the B Core Spray sparger and the differential pressure sensing line only taps the pressure above and below the core support assembly. The differential pressure of the core plate is recorded in the control room.

7.7.1.1.3.1.5 RVI Pressure

Pressure sensors/transducers, indicators, and transmitters detect reactor vessel internal pressure from the same instrument lines used to measure reactor vessel water level. The only nonsafety-related pressure measuring instruments provided are discussed in Section 7.7.1.4.

7.7.1.1.3.1.6 RVI Head Seal Leak Detection

Pressure between the inner and outer reactor vessel head seal ring is sensed by a local pressure indicator and a pressure switch that alarms in the control room. If the inner seal fails, the pressure at the pressure sensors increases to the vessel pressure. The plant continues to operate with the outer seal as a backup, and the inner seal can be repaired at the next outage when the head is removed. If both the inner and outer head seals fail, the leak is detected by an increase in drywell temperature and pressure.

7.7.1.1.3.1.7 RVI/SRV Leak Detection

Thermocouples are located in the discharge exhaust pipe of the SRV. The temperature signal goes to a multipoint recorder with an alarm and is activated by any temperature in excess of a set temperature, signaling that one of the SRV seals or pilot valves has started to leak (drawing M-41). The temperature signals can also be used as a means to determine SRV position, hence this instrumentation is a diverse backup to the SRVPI system (Section 7.6.1.5).

7.7.1.1.3.1.8 RVI Other Instruments

a. Steam temperature is measured and transmitted to the control room.

b. Feedwater temperature is measured and transmitted to the control room.

c. Feedwater conductivity is monitored and recorded locally. An instrument trouble alarm is provided in the control room (drawing M-23).

7.7.1.1.3.2 RVI Testability

There are no testability requirements for the RVI described in this section because the instruments are nonsafety-related and are not required for any postulated DBA or for safe shutdown. The instruments located outside the drywell can be tested during plant operation, while those that are inaccessible during plant operation can be tested during plant shutdown. Plant test procedures will establish methodology and frequency.

7.7.1.1.4 RVI Environmental Considerations

There are no special environmental considerations for the instruments described in this section.

7.7.1.1.5 RVI Operational Considerations

7.7.1.1.5.1 RVI General Information

The RVI discussed in this section is designed to augment the existing information from the safety-related systems so that the operator can start up, operate at power, shut down, and service

the reactor vessel in an efficient manner. None of this instrumentation is required to initiate any safety-related system.

7.7.1.1.5.2 RVI Operator Information

The following is the information that the operator has at his disposal from the instrumentation discussed in this section:

a. The temperature of the reactor coolant in the recirculation loops is recorded in the control room.

b. The RWCU inlet temperature is indicated in the control room.

c. Water level in the shutdown range is indicated in the control room.

d. Water level in the upset range is recorded in the control room.

e. Water level in the fuel zone range is indicated and recorded in the control room.

f. The core plate differential pressure and total core flow are recorded in the control room.

g. The reactor pressure is indicated and recorded in the control room.

h. The reactor head seal leak detection turns on an annunciator when the inner reactor head seal fails.

i. The discharge temperatures of all the SRVs are shown on a multipoint recorder in the control room. Any temperature point that exceeds the trip setting turns on an annunciator indicating that a SRV seal or pilot valve has started to leak.

j. Feedwater conductivity is recorded in the control room. The recorder turns on an annunciator in the control room on a high signal.

7.7.1.1.5.3 RVI Setpoints

The annunciator alarm setpoints for the reactor head seal leak detection, and SRV seal and pilot valve leak detection are set so that the sensitivity to the variable being measured provides adequate information.

Figure 7.7-1 includes a chart showing the relative indicated water levels at which various alarms are initiated.

Level trips to initiate various alarms and trip the main turbine and the feed pumps are discussed in Section 7.7.1.4.

7.7.1.1.6 Water Level Instrument Line Failure

An analysis has been performed to verify that there is sufficient redundancy in the water level instrumentation to prevent a sensing line failure (i.e., break, blockage or leak) concurrent with a

random single electrical failure from defeating an automatic RPS or ESF actuation. This analysis was conducted based on the methodology provided in Table 7.7-6.

The instrument reference lines common to feedwater control and to protective system sensors are identified in Table 7.7-7. An evaluation was performed to determine the consequences of failures in such reference lines concurrent with additional single failures in protective channels not dependent on the failed sensing line.

In the highly unlikely scenario, the most severe reference line was assumed to fail such that all attached level instruments erroneously indicated high levels. Then, additional worse case single failures were postulated in the circuits connected to the remaining reference line. The criteria for selection of the potential worst case combinations of reference line failure plus additional single failure was to determine those combinations, if any, which preclude automatic operation of a RPS and/or ESF system(s), and which may require manual action by the operator to bring the reactor to a safe condition. Worst case single division power supply loss was considered for ECCS and RCIC, but this is independent from other single failures which could affect RPS or MSIV closure, etc. (i.e., a power bus failure in RPS would fail "safe" causing a trip of that channel).

A review of the various failure combinations resulted in the identification of two cases which would represent the worst postulated failure paths. These are described as follows:

Case 1 was found to be failure of the Division 2 instrument reference line (i.e., connected to condensing chamber B21-D004B) combined with a failure "high" of the B21-N091D or H level transmitter. The worst case also assumes that the FCS level soft majority selector fails to perform its designed function of removing the failed transmitter signal from the level control signal. The feedwater controller responds to the high level error signal by reducing the feedwater flow. Following the loss of feedwater, water level will decrease to level 4, initiating a low water level alarm. Reactor scram will be initiated when water level decreases to the low water level 3 scram setpoint. The low water level 3 signal will result in the initiation of a second low water level alarm. As water level decreases to low water level 2, a third low water level alarm will initiate, the RCIC system will automatically start, and both recirculation pumps will trip. The HPCI system is unavailable due to the assumed failure. This scenario is identical to the sizing basis of the RCIC. The RCIC will provide sufficient water inventory makeup to prevent the water level from dropping below low water level 1, thus avoiding initiation of the ADS and the low pressure ECCS systems. The core remains covered at all times and no fuel failure would occur.

All other scenarios identified were less severe than the two cases just described. Those that involve failures which do not affect the level 3 scram are accompanied by either HPCI or HPCI + RCIC automatic initiation by low reactor water level 2 signals. Other scenarios which involve failures in the level 3 scram circuits are accompanied by scram due to ARI at level 2 and automatic initiation of both HPCI and RCIC.

The results of this assessment can be summarized as follows:

a. The LGS reactor system can withstand any reactor vessel level reference line break coupled with an additional worst single failure in a protective channel not dependent on the failed sensing line without compromising safety. This is assured by the following evaluations:

1. No part of the active fuel is uncovered at any time. This assures no fuel damage and no degradation of the CPR or reactivity release.

2. Both the vessel and the containment remain structurally sound throughout the postulated event. This provides secondary assurance that no reactivity can be released to the public.

3. The scenario postulated is a highly unlikely event (instrument line breakage with coincident random failure) and compounds it with worst case conditions through the event. Though no credit is taken in the scenarios identified, it is highly probable that the operator would recover feedwater immediately by switching the controller to the alternate instrument line because of the alarms that call his attention to level indication mismatch and the numerous low water level alarms. In addition, if the failed instrument reference line is either the Division 3 or 4 instrument line (i.e., connected to condensing chamber B21-D004C or D) no feedwater controller error would occur and there would be no reduction in feedwater flow.

LGS has the capability of providing automatic protection under all postulated scenarios. This is due to its four instrumentation divisions, which provide sufficient redundancy for automatic initiation of protection systems and eliminates the need for manual corrective action by the operator to prevent compromising plant safety.

b. There are no failure combinations that result in failure of both HPCI and RCIC. One of the two systems is always available.

c. Failure combinations which result in failure of the reactor to scram at low reactor water level 3 are always accompanied by reactor scram (due to ARI) and either HPCI or RCIC automatic initiation due to low reactor water level 2 signals.

It is concluded from this assessment of a break in a vessel level sensing line common to control and protective systems plus an additional worst single failure in a protective channel not dependent on the failed sensing line that the resulting accident is less severe and bounded by the DBAs already analyzed in Chapter 15.

7.7.1.2 Reactor Manual Control System - Instrumentation and Controls

7.7.1.2.1 RMCS Identification

7.7.1.2.1.1 RMCS General

The objective of the RMCS is to provide the operator with the means to make changes in nuclear reactivity so that reactor power level and power distribution can be controlled. The system allows the operator to manipulate control rods.

The RMCS instrumentation and controls consist of the electrical circuitry, switches, indicators, and alarm devices provided for operational manipulation of the control rods and surveillance of associated equipment.

This system includes the interlocks that inhibit rod movement (rod block) under certain conditions. The RMCS does not include any of the circuitry or devices used to automatically or manually scram the reactor (Section 7.2).

In addition, the mechanical devices of the CRDs and the CRD hydraulic system are not included in the RMCS. The latter mechanical components are described in Section 4.1.3.

7.7.1.2.1.2 RMCS Classification

This system is a power generation system and is classified as not related to safety.

7.7.1.2.1.3 RMCS Reference Design

Table 7.1-2 lists reference design information. The RMCS is an operational system and has no safety function. Therefore, there are no safety design differences between this system and those of the reference design facilities. This system is functionally identical to the referenced system.

7.7.1.2.2 RMCS Power Sources

a. Normal: The reactor manual control system receives its power from the 120 V ac instrumentation buses. Each of these buses receives its normal power supply from the appropriate 440 V ac standby power system.

b. Alternate: On loss of normal auxiliary power, the station diesel generators provide backup power to the 440 V standby ac power systems.

7.7.1.2.3 RMCS Equipment Design

7.7.1.2.3.1 RMCS General

The following discussions examine the control rod movement instrumentation and control aspects of the subject system, and the control rod position information system. The control descriptions include the following:

a. Control rod drive - control system

b. Control rod drive - hydraulic system

c. Rod block interlocks

The position descriptions include the following:

a. Rod position probes

b. Display electronics

Drawings M-46 and M-47 show the CRD hydraulic system. Drawings C11-1030-F-008, C11-1030-F-009, C11-1030-F-010, C11-1030-F-011, C11-1030-F-012, C11-1030-F-013, and C11-1030-F-014 show the FCD for the CRD hydraulic system.

Although they also show the arrangement of scram devices, these devices are not part of the RMCS. Control rods are moved by admitting water under pressure from the CRD water pump into the appropriate end of the CRD cylinder. The pressurized water forces

the piston, which is attached by a connecting rod to the control rod, to move. Three modes of control rod operation are used: insert, withdraw, and settle. Four solenoid-operated valves are associated with each control rod to accomplish the actions required for the operational modes. The valves control the path that the CRD water takes to the cylinder.

7.7.1.2.3.2 Rod Movement Controls

7.7.1.2.3.2.1 CRD Control System

7.7.1.2.3.2.1.1 Introduction

When the operator selects a control rod for motion and operates the rod insertion control switch, identical messages are formulated in the A and B portions of the rod drive control system as shown in Figure 7.7-3. A comparison test is made of these two messages, and if identical messages are confirmed, a serial message in the form of results is produced; then a serial message in the form of electrical pulses is transmitted to all HCUs. The message contains two portions: the identity or "address" of the selected HCU, and the operation data on the action to be executed. Only the selected HCU responds to this transmission and proceeds to execute the rod action commands. Hence, the drive water and exhaust valves for the selected rod open and allow the CRD water to follow a path that results in the desired control rod movement.

On receipt of the transmitted signal as shown in Figure 7.7-3, the responding HCU transmits three portions of an acknowledge message back to the auxiliary equipment room panel for comparison with the original message:

a. Its own hard-wire identity "address"

b. Its own operations currently being executed

c. Status indications of valve positions, accumulator conditions, and test switch positions.

In either rod motion direction, the A and B messages are formulated and compared each millisecond; if they agree, the message is transmitted to the HCU selected by the operator. Continued rod motion depends on receipt of a train of sequential messages because the HCU insert, withdraw, and settle valve control circuits are ac-coupled. The system must operate in a dynamic manner to effect rod motion. Postulated failures within the RMCS generally result in a static condition within the system, which prevents further rod motion.

Any disagreement between the A and B formulated messages or the C acknowledge message prevents further rod motion. However, electrical noise disruptions only momentarily affect the system in proportion to the duration of the offending source. Correct operation of the system resumes when the noise source ceases. In Figure 7.7-4, three action loops of the solid-state RMCS are depicted:

a. The high speed loop (a nominal 0.0002 second duration) services the control rod selected by the operator to transmit action commands and receive status indications.

b. The medium speed loop (a nominal 0.045 second duration) monitors the other control rods in the reactor, one at a time, to update their status display.

c. The low speed loop (on the order of 20 second to 100 second duration) exercises one HCU at a time to ensure correct execution of actions commanded. This provides for a continuous, periodic self-test of the entire RMCS.

The rod selection circuitry is arranged so that a rod selection is sustained until either another rod is selected, or separate action is taken to revert the selection circuitry to a no-rod-selected condition. Initiating movement of the selected rod prevents the selection of any other rod until the movement cycle of the selected rod has been completed. Reversion to the no-rod-selected condition is not possible (except for loss of control circuitry power) until any moving rod has completed its movement cycle.

The direction in which the selected rod moves is determined by the position of four switches located on the reactor control panel. These four switches, INSERT, WITHDRAW, CONTINUOUS INSERT and CONTINUOUS WITHDRAW, are push buttons that return to an off position by spring action.

7.7.1.2.3.2.1.2 CRD Insert Cycle

A description of the detailed operation of the RMCS during an insert cycle follows. The cycle is described in terms of the insert, withdraw, and settle commands emanating from the RMCS. The response of a selected rod to the various commands transmitted has been explained previously. Drawings C11-1030-F-008, C11-1030-F-009, C11-1030-F-010, C11-1030-F-011, C11-1030-F-012, C11-1030-F-013, and C11-1030-F-014 can be used to follow the sequence of an insert cycle.

With a control rod selected for movement, depressing the INSERT switch and then releasing it energizes the insert command for a specific time. Just as the insert command is removed, the settle command is automatically energized and remains energized for a specific time. The insert command time setting and the rate of drive water flow provided by the CRD hydraulic system determine the distance traveled by a rod. The time setting results in a one notch (6 inch) insertion of the selected rod for each momentary application of a rod-in signal from the rod movement switch. Continuous insertion of a selected control rod is possible by holding the INSERT switch down, as long as rod movement is within pattern restraints.

A second switch can be used to effect insertion of a selected control rod. This switch is the CONTINUOUS INSERT switch. By holding this switch in, the unit maintains the insert command in a continuous, energized state to cause continuous insertion of the selected control rod. When released, the timers are no longer bypassed and normal insert and settle cycles are initiated to stop the drive.

7.7.1.2.3.2.1.3 CRD Withdraw Cycle

A description of the detailed operation of the RMCS during a withdraw cycle follows. The cycle is described in terms of the insert, withdraw, and settle commands. The response of a selected rod to

the various commands transmitted has been explained previously. Drawings C11-1030-F-008, C11-1030-F-009, C11-1030-F-010, C11-1030-F-011, C11-1030-F-012, C11-1030-F-013, and C11-1030-F-014 can be used to follow the sequence of a withdrawal cycle.

With a control rod selected for movement, depressing the WITHDRAW switch energizes the insert valves for a short time. Energizing the insert valves at the beginning of the withdrawal cycle is necessary to allow the collet fingers to disengage the index tube. When the insert valves are de-energized, the withdraw and settle valves are energized for a controlled period of time. The withdraw valve is de-energized before movement is completed. The drive then settles until the collet fingers engage. The settle valve is then de-energized, completing the withdraw cycle . This withdrawal cycle is the same whether the withdrawal switch is held down continuously or momentarily depressed. The timers that control the withdrawal cycle are set so that the rod travels one notch (6-inches) per cycle. Provisions are included to prevent further control rod motion in the event of timer failure.

At high power levels when RWM is not operable, a selected control rod can be continuously withdrawn if the WITHDRAWAL switch is held in the depressed position at the same time that the CONTINUOUS WITHDRAWAL switch is held in the depressed position. With both switches held in these positions, the withdraw and settle commands are continuously energized. When released, the normal settle period completes the withdrawal cycle.

7.7.1.2.3.2.2 CRD Hydraulic System

One motor-operated pressure control valve, two air-operated flow control valves, and four solenoid-operated stabilizer valves are included in the CRD hydraulic system to maintain smooth and regulated system operation. These devices are shown in drawing M-46. The motor-operated pressure control valve is positioned by manipulating a switch in the control room. The switch for this valve is located close to the pressure indicator, which responds to the pressure changes caused by the movement of the valve. Only one flow control valve is in service at a time. The air-operated flow control valves are automatically positioned in response to signals from an upstream flow-measuring device. Only two stabilizer valves are in service at a time. The stabilizer valves are automatically controlled by the energization of the insert and withdraw commands. The control scheme is shown in drawings C71-1010-F-002, C71-1010-F-003, C71-1010-F-004, and C71-1010-F-005. Two drive water pumps are controlled by switches in the control room. Each pump automatically trips on indication of low suction pressure.

7.7.1.2.3.2.3 Rod Block Interlocks

7.7.1.2.3.2.3.1 RBI Trip System

A portion of the RMCS, upon receipt of input signals from other systems and subsystems, inhibits movement or selection of control rods.

7.7.1.2.3.2.3.2 RBI Grouping of Channels

The same grouping of neutron monitoring system equipment (SRM, IRM, APRM, and RBM) that is used in the RPS is also used in the rod block circuitry (Section 7.6.1.4).

Half of the total monitors (SRM, IRM, APRM, and RBM) provides inputs to one of the RMCS rod block logic circuits and the remaining half provides inputs to the other RMCS rod block logic circuit. Two APRM channels provide recirculation flow upscale rod blocks to one logic circuit; the other two

APRM channels provide recirculation flow upscale rod block signals to the other logic circuit. SDV high water level signals are provided as inputs into both of the rod block logic circuits. Both rod block logic circuits sense when the high water level scram trip for the SDV is bypassed.

The rod withdrawal block from the RWM trip prevents both notch insertion and continuous insertion. The rod insert block from the RWM functions prevents both notch insertion and continuous insertion.

The APRM rod block settings are varied as a function of recirculation flow and core thermal power, and the RBM rod block settings are varied as a function of core thermal power. Analyses show that the selected settings are sufficient to avoid both RPS action and local fuel damage as a result of a single control rod withdrawal error. Mechanical switches in the SRM and IRM detector drive systems provide the position signals used to indicate that a detector is not fully inserted. Additional detailed information on all the NMS trip channels is available in Section 7.6.1.4. The rod block from SDV high water level uses two nonindicating float switches installed on the scram discharge volume. Two additional float switches provide a control room annunciation of increasing level below the level at which a rod block occurs.

7.7.1.2.3.2.3.3 RBI Functions

The following discussion describes the various rod block functions and explains the intent of each function. The instruments used to sense the conditions for which a rod block is provided are discussed later. The rod block functions provided specifically for refueling situations are described in Section 7.7.1.15.

a. With the mode switch in the SHUTDOWN position, no control rod can be withdrawn. This enforces compliance with the intent of the shutdown mode.

b. The circuitry is arranged to initiate a rod block regardless of the position of the mode switch for the following conditions:

    1. Any APRM Simulated Thermal Power upscale rod block alarm - The purpose of this rod block function is to avoid conditions that would require RPS action if allowed to proceed. The APRM upscale rod block alarm setting is selected to initiate a rod block before the APRM high neutron flux or Simulated Thermal Power scram setting is reached.

    2. Any APRM inoperative alarm - This ensures that no control rod is withdrawn unless the average power range neutron monitoring channels are either in service or correctly bypassed.

    3. Any APRM LPRM low count alarm - This ensures that no control rod is withdrawn unless the average power range neutron monitoring channels have the required number of LPRM inputs to be considered operable.

    4. SDV high water level - This ensures that no control rod is withdrawn unless enough capacity is available in the SDV to accommodate a scram. The setting is selected to initiate a rod block earlier than the scram that is initiated on SDV high water level.

5. SDV high water level scram trip bypassed - This ensures that no control rod is withdrawn while the SDV high water level scram function is out-of-service.

6. The RWM can initiate a rod insert and a rod withdrawal block. The purpose of these functions is to reinforce procedural controls that limit the reactivity worth of control rods under low power conditions. The rod block trip settings are based on the allowable control rod worth limits established for the design basis rod-drop accident. Adherence to prescribed control rod patterns is the normal method by which this reactivity restriction is observed. Additional information on the RWM function is available in Section 7.7.1.21.

7. RPIS malfunction - This ensures that no control rod is withdrawn unless the RPIS is in service.

8. Either RBM upscale alarm - This function is provided to stop the erroneous withdrawal of a control rod so that local fuel damage does not result, although local fuel damage poses no significant threat in terms of radioactive material released from the nuclear system.

9. Either RBM inoperative alarm - This ensures that no control rod is withdrawn unless the RBM channels are in service or correctly bypassed.

c. With the reactor mode switch in the RUN position, any of the following conditions initiates a rod block:

1. Any APRM downscale alarm - This ensures that no control rod is withdrawn during power range operation unless the average power range neutron monitoring channels are operating correctly or are correctly bypassed. All unbypassed APRMs must be on scale during reactor operations in the RUN mode.

2. Either RBM downscale alarm - This ensures that no control rod is withdrawn during power range operation unless the RBM channels are operating correctly or are correctly bypassed. Unbypassed RBMs must be on scale during reactor operations in the RUN mode.

3. Any APRM recirculation flow upscale alarm - This ensures that the no control rod is withdrawn unless the APRM recirculation flow signals are operable and the flow rate in not unusually high.

d. With the mode switch in the STARTUP or REFUEL position, any of the following conditions initiates a rod block:

1. Any SRM detector not fully inserted into the core when the SRM count level is below the retract permit level and any IRM range switch is on either of the two lowest ranges - This ensures that no control rod is withdrawn unless all SRM detectors are correctly inserted, because they must be relied on to provide the operator with neutron flux level information.

2. An SRM upscale level alarm - This ensures that no control rod is withdrawn unless the SRM detectors are correctly retracted during a reactor startup. The block setting is selected at the upper end of the range over which the SRM is designed to detect and measure neutron flux.

3. Any SRM downscale alarm - This ensures that no control rod is withdrawn unless the SRM count rate is above the minimum prescribed for low neutron flux level monitoring.

4. Any SRM inoperative alarm - This ensures that no control rod is withdrawn during low neutron flux level operations unless neutron monitoring capability is available because all SRM channels are in service or correctly bypassed.

5. Any IRM detector not fully inserted into the core -This ensures that no control rod is withdrawn during low neutron flux level operations unless proper neutron monitoring capability is available because all IRM detectors are correctly located.

6. Any IRM upscale alarm - This ensures that no control rod is withdrawn unless the intermediate range neutron monitoring equipment is correctly upranged during a reactor startup. This rod block also provides a means to stop rod withdrawal in time to avoid conditions requiring RPS action (scram) in the event that a rod withdrawal error is made during low neutron flux level operations.

7. Any IRM downscale alarm except when the range switch is on the lowest range - This ensures that no control rod is withdrawn during low neutron flux level operations unless the neutron flux is being correctly monitored. This rod block prevents the continuation of a reactor startup if the operator upranges the IRM too far for the existing flux level. Thus, the rod block ensures that the IRM is on scale if control rods are to be withdrawn.

8. Any IRM inoperative alarm - This ensures that no control rod is withdrawn during low neutron flux level operations unless neutron monitoring capability is available because all IRM channels are in service or are correctly bypassed.

7.7.1.2.3.2.3.4 RBI Bypasses

To permit continued power operation during repair or calibration of equipment for selected functions that provide rod block interlocks, a limited number of manual bypasses are permitted as follows:

a. One SRM channel

b. Two IRM channels (one on either Bus A or Bus B)

c. One APRM channel

d. One RBM channel

The permissible IRM bypasses are arranged as two groups of equal numbers of channels. One manual bypass is allowed in each group. The groups are chosen so that adequate monitoring of the core is maintained with one channel bypassed in each group. The arrangement allows the bypassing of one IRM in each rod block logic circuit.

One of the four APRM channels can be bypassed at any time. The assignment of LPRMs to APRM channels is chosen so that adequate monitoring of the core is maintained with an APRM channel bypassed.

These bypasses are effected by positioning switches in the control room. A light in the control room indicates the bypassed condition.

An automatic bypass of the SRM detector position rod block is effected as the neutron flux increases beyond a preset low level on the SRM instrumentation. The bypass allows the detectors to be partially or completely withdrawn as a reactor startup is continued.

An automatic bypass of the RBM rod block occurs when the power level is below the preselected level or when a peripheral control rod is selected. Either condition indicates that local fuel damage is not threatened and that RBM action is not required.

The RWM system rod block functions are automatically bypassed when reactor power is above a preselected value in the power range. The RWM can be manually bypassed for maintenance at any time.

7.7.1.2.3.2.3.5 RBI Interface

Tables 7.7-4 and 7.7-5 detail the rod block interlocks used in the RMCS, as well as the rod blocking functions that originate in the neutron monitoring system.

7.7.1.2.3.2.3.6 RBI Redundancy

To achieve an operationally desirable performance objective where most failures of individual components would either be easily detectable or would not disable the rod movement inhibiting functions, the rod block logic circuitry is arranged as two redundant logic circuits. Each logic circuit receives input trip signals from a number of trip channels and each logic circuit can provide a separate rod block signal to inhibit rod withdrawal.

The output of each logic circuit is coupled to a comparator by electro-optical devices in the rod drive control cabinet. The formulated A and B signals are compared and rod blocks applied when either an A or B trip is present. Rod withdrawal is permitted only if the two signals agree at all times and no rod block signals are present. Because the transmitted signals are dynamic and vary with time, any RMCS failure that interrupts the dynamic signals transmitted to the HCUs prevents further control rod motion. Hence, failures consisting of short circuits, open circuits, loss of circuit continuity, or loss of power inhibit manual rod movement.

The rod block circuitry is effective in preventing rod withdrawal, if required, during both normal (notch) withdrawal and continuous withdrawal. If a rod block signal is received during a rod withdrawal, the control rod is automatically stopped at the next notch position, even during a continuous rod withdrawal.

The components used to initiate rod blocks in combination with refueling operations provide rod block trip signals to these same rod block circuits. These refueling rod blocks are described in Section 7.7.1.15.

7.7.1.2.3.2.3.7 RBI On-Line Testability

On-line testability of the systems and indication of bypassed or inoperable status of the system are provided.

7.7.1.2.3.2.3.8 RBI Environmental Considerations

The equipment is mounted in the control structure. Environmental conditions in the control structure are listed in Section 3.11.

7.7.1.2.3.2.3.9 RBI Operational Considerations

The rod block trips prevent an operator from withdrawing rods if the associated equipment is not capable of monitoring core response or, if unchecked, the withdrawals might require a RPS action (scram). There are no special operational considerations.

7.7.1.2.3.2.4 RBI Testability

In addition to the periodic self-test mode of system operation, the RMCS circuitry can be routinely checked for correct operation by manipulating control rods using the various methods of control. Detailed testing and calibration can be performed by using standard test and calibration procedures for the various components of the RMCS circuitry.

7.7.1.2.3.3 Rod Position Information System

This system includes the rod position probes and the electronic hardware that processes the probe signals and provides the data described above.

7.7.1.2.3.3.1 RPIS Position Probes

The position probe is a long cylindrical assembly that fits inside the CRD. It includes 53 magnetically operated reed switches located along the length of the probe and operated by a permanent magnet fixed to the moving part of the hydraulic drive mechanism. As the drive, and with it the control rod blade, moves along its length, the magnet causes reed switches to close as it passes over the switch locations. The particular closed switch then indicates where the CRD, and hence the rod itself, is positioned.

The switches are located as follows: one at each of 25 notch (even) positions; one at each of 24 midnotch (odd) positions; two at the fully inserted position (approximately the same location as the "00" notch); one at the fully withdrawn position (approximately the same location as the "48" notch); and one at the "overtravel," or decoupled, position.

All of the midnotch, or odd, switches are wired in parallel and treated as one switch (for purposes of external connections), and the two fully inserted switches are wired in parallel and treated as one switch. These and the remaining switches are wired in a 5x6 array (the switches short the

intersections) and are routed out in an 11 wire cable to the processing electronics (the probe also includes a thermocouple that is wired out separately from the 5x6 array) (Figure 7.7-5).

7.7.1.2.3.3.2 RPIS Electronics

The electronics consist of a set of "probe multiplexer cards" (one per four-rod group), a set of "file control cards" (one per 11-probe multiplexer cards), and one set of master control and processing cards serving the whole system. All probe multiplexer cards are the same except that each has a pair of plug-in "daughter cards" containing the identity code of one four-rod group (the probes for the corresponding four rods are connected to the probed multiplexer card).

7.7.1.2.3.3.3 RPIS Operation

The system operates on a continuous scanning basis with a complete cycle every 45 milliseconds. The operation is as follows: The control logic generates the identity code of one rod in the set, and transmits it using time multiplexing to all of the file control cards. These in turn transmit the identity with timing signals to all of the probe multiplexer cards. The one multiplexer card with the matching rod identity responds and transmits its identity (locally generated) plus the raw probe data for that rod back through the file control card to the master control and processing logic. The processing logic does several checks on the returning data. First, a check is made to verify that an answer was received. Next, the identity of the answering data is checked against that which was sent. Finally, the format of the data is checked for legitimacy. Only a single even position, or full-in plus position "00," or full-out plus position "48," or odd, or overtravel, or blank [no switch closed] are legitimate. Any other combination of switches is flagged as a fault.)

If the data passes all of these tests, it is decoded and transmitted in multiplexed form to the displays in the main control panel and is then loaded into a memory to be read by the computer as required.

As soon as one rod's data are processed, the next rod's identity is generated, processed, and repeated for all of the rods. When data for all rods have been gathered, the cycle repeats.

7.7.1.2.4 RMCS Environmental Considerations

The RMCS (control and position indication circuitry) is not required for any plant safety function nor is it required to operate in any associated design basis events or transient occurrences. The reactor manual control circuitry is required to operate only in the normal plant environments during normal power generation operations.

The CRD HCUs are located outside the drywell in the reactor enclosure. The logic, control units, and readout instrumentation are located in the control structure.

The CRDs' position detectors are located beneath the reactor vessel in the drywell. The normal design environments encountered in these areas are given in Section 3.11.

7.7.1.2.5 RMCS Operational Considerations

7.7.1.2.5.1 RMCS General Information

The RMCS is totally operable from the control room. Manual operation of individual control rods is possible with switches to effect control rod insertion, withdrawal, or settle. Rod position indicators provide the necessary information to ascertain the operating state and position of all control rods. Conditions that prohibit control rod insertion are alarmed with the rod block annunciator.

7.7.1.2.5.2 RMCS Reactor Operator Information

Table 7.7-1 gives information on the process instruments for the CRD hydraulic system. A large rod information display on the rod status display panel is patterned after a top view of the reactor core. The display allows the operator to acquire information rapidly by scanning.

Colored windows provide an overall indication of rod pattern and allow the operator to quickly identify an abnormal indication. The following information for each control rod is presented in the display:

a. Rod fully inserted (green)

b. Rod fully withdrawn (red)

c. Selected rod identification (coordinate position, white)

d. Accumulator trouble (amber)

e. Rod scram (blue)

f. Rod drift (red)

A separate, smaller display (the four-rod display) is located on the control console. This display shows the positions of the control rod selected for movement and the other rods in the rod group. For display purposes, the control rods are considered in groups of four adjacent rods (a four-rod group) centered around a common core volume monitored by four LPRM strings. Rod groups at the periphery of the core can have less than four rods. The four-rod display shows the positions, in digital form, of the rods in the group to which the selected rod belongs. A lighted background on the digital display indicates which of the four rods is selected for movement.

The four-rod display allows the operator to better focus his attention on the portion of the core experiencing rod motion. A full core rod position display would tend to be confusing and difficult to read. In addition, on demand by the operator, the Plant Monitoring System can provide a printout of all rod positions.

During startup or shutdown, rods of a given sequence which are either fully withdrawn or fully inserted are indicated on the full core display with the full-in or full-out lights. In addition to the whole core display, a drifting rod is indicated by an alarm and red light in the control room. The Plant Monitoring System also monitors the rod drift condition.

An indication is also provided for rod travel beyond the limits of normal rod movement. If the rod drive piston moves to the OVERTRAVEL position, an alarm is sounded in the control room. The overtravel alarm provides a means to verify that the drive-to-rod coupling is intact because, with the

coupling in its normal condition, the drive cannot be physically withdrawn to the overtravel position. Coupling integrity can be checked by attempting to withdraw the drive to the overtravel position.

For the displays above, the selected rod identification, accumulator trouble, and rod scram indicators are provided to the displays by the rod drive control system. The remaining information to the displays and the position information for the Plant Monitoring System are provided by the RPIS.

The following control room lights are provided to allow the operator to know the conditions of the CRD hydraulic system and the control circuitry:

a. Stabilizer valve selector switch position

b. Insert command energized

c. Withdraw command energized

d. Settle command energized

e. Withdrawal not permitted

f. Continuous withdrawal

g. Pressure control valve position

h. Flow control valve position

i. Drive water pump low suction pressure (alarm and pump trip)

j. Pump suction filter high differential (alarm only)

k. Charging water (to accumulator) low pressure (alarm only)

l. CRD temperature (alarm only)

m. SDV not drained (alarm only)

n. Scram valve pilot air header high/low pressure (alarm only)

o. System flow

p. SDV vent and drain valve position

q. Accumulator trouble alarm

r. Drive water filter differential pressure (alarm only)

7.7.1.2.5.3 RMCS Setpoints

The subject system has no safety setpoints.

7.7.1.3 Recirculation Flow Control System - Instrumentation and Controls

7.7.1.3.1 RFCS Identification

7.7.1.3.1.1 RFCS General

The objective of the RFCS is to control reactor power level, over a limited range, by controlling the flow rate of the reactor recirculating water (Figure 7.7-7).

The control valves varying the speed of the recirculation pumps by changing the voltage and frequency of the ac supply to each pump motor. The ac supply to each pump motor is provided by an Adjustable Speed Drive (ASD). The ASD consists of a transformer section coupled to a solid state power cell electronics section. Microprocessor controllers modulate the output of the power cells to convert the input 13.2 kV into the variable frequency MV output.

7.7.1.3.1.2 RFCS Classification

This system is a power generation system and not safety-related.

7.7.1.3.1.3 RFCS Reference Design

Table 7.1-2 lists reference design information. The RFCS is an operational system and has no safety function; therefore, there are no safety differences between this system and those of the above-referenced facilities. This system is functionally identical to the referenced system.

7.7.1.3.2 RFCS Power Sources

7.7.1.3.2.1 Normal/Alternate

a. Normal: ASD l20 Vac control power is derived from one of two dedicated UPS's (auctioneered) powered from their respective 480 Vac sources. Each UPS is capable of powering the control system for both ASD trains A and B, but normally only one UPS is dedicated to each drive.

b. Alternate: On loss of the normally aligned UPS or its 480 Vac source, the backup UPS automatically provides power to the ASD drive via the diode auctioneered circuit.

7.7.1.3.2.2 Deleted.

7.7.1.3.3 RFCS Equipment Design

7.7.1.3.3.1 RFCS General

Reactor recirculation flow is changed by adjusting the speed of the two reactor recirculating pumps. This is accomplished by adjusting the frequency and voltage of the electrical power supplied to the recirculation pump motor (Figure 7.7-7). Control of pump speed, and thus core flow, is such that at various control rod patterns, different power level changes can be accommodated. For a full power rod pattern, power change control down to approximately 65% of full power is possible using flow variation. Power control is possible over a range of approximately 35% of the maximum operating power level for that rod pattern.

An increase in recirculation flow temporarily reduces the void content of the moderator by increasing the flow of coolant through the core. The additional neutron moderation increases the reactivity of the core, which causes the reactor power level to increase. The increased steam generation rate increases the steam volume in the core with a consequent negative reactivity effect, and a new steady-state power level is established. When recirculation flow is reduced, the power level is reduced in the reverse manner.

7.7.1.3.3.2 RFCS Pump Drive Motor

7.7.1.3.3.2.1 RFCS Pump Drive Motor Control

Each recirculation pump motor has its own ASD for a power supply. The ASD uses digital controllers and solid state power electronics to vary the frequency and voltage supplied to the pump motor to give the desired pump speed.

7.7.1.3.3.2.2 RFCS Pump Drive Motor Trip

Two dual trip coil circuit breakers are placed in series in the power feed to each recirculation pump motor. The RPT feature uses one trip coil of each breaker to trip the recirculation pump motors when either a turbine stop valve closure or turbine control valve fast closure occurs. The RPT subsystem consists of sensors for EHC oil pressure, valve position, and turbine pressure, relays, switches and indications arranged in two separate divisions of logic, either one of which will generate a trip signal.

Turbine stop valve closure is detected by monitoring stop valve position. Turbine control valve fast closure is detected by monitoring control valve oil pressure. Closure of the A and B stop valves or fast closure of the A and B control valves will initiate the Division I RPT logic. Closure of the C and D stop valves or fast closure of the C and D control valves will initiate the Division II RPT logic. RPT is bypassed when reactor power is 29.5% as detected by turbine first stage pressure.

The recirculation pump motor breakers are also tripped by signals generated in the RRCS (Section 7.6.1.8) and by overcurrent relays monitoring the pump motor feeds (Section 8.1.6.1.12.a). The RRCS trip signal is connected to one trip coil; the RPT and overcurrent trip signals are connected to the other trip coil.

7.7.1.3.3.3 RFCS Variable-Frequency Drive

7.7.1.3.3.3.1 RFCS Adjustable Speed Drive

The two ASD trains and their associated controls are identical. The ASD can continuously supply power to the pump motor at any speed to approximately 99.2% of pump rated speed. The ASD is capable of starting the pump and accelerating it from a standstill to a desired operating speed when the pump motor thrust bearing is fully loaded by reactor pressure acting on the pump shaft. The main components of the ASD are MV input and output termination cabinets, input transformer cabinet, power electronic cell cabinets, control cabinet, relay cabinet and cooling cabinet.

a. Input and Output Termination Cabinets - where the 13.2kV supply and 4kV pump motor feed MV cables are terminated.

b. Transformer Cabinet - the transformer coverts the input 13.2 kV on the primary side down 750 Vac on the secondary side which is then connected directly to the power electronics cells. The ASD can operate under electrical supply variations of +/- 10% of rated voltage.

c. Power Electronics Cell Cabinets - there are three cabinets, each with four power cells connected in series per phase. They convert the input 750 Vac to the variable frequency / voltage proportional output which is fed directly to the pump motor. The power cells are composed mainly of a diode bridge, filtering capacitors, and an insulated gate bipolar transistor (IGBT). The lGBT is a semiconductor field effect transistor that fires a bipolar transistor to provide reliable high speed switching with high-power capabilities.

d. Control Cabinet - this cabinet houses the main controllers which control all the essential elements of the ASD and the PLCs which provide most of the interface between the main controllers and the plant. It also contains the pre-charge circuitry used to start the ASD.

The primary functions of the redundant main controllers include:

- regulate the firing of the power cells to produce the Pulse Width Modulated (PWM) output signal fed to the pump motor
- communicate to I/O and PLC for status information
- execute the plant specific System Operational Program (SOP)
- monitor drive and process parameters for alarm output

Only one of the two controllers is actively controlling all the power cells under all conditions. Typically, the “A” controller is active with the “B” controller in stand-by to take control should the “A” controller detect failure.

The primary functions of the redundant PLCs include:

- interface plant parameters and drive status between the plant and the main controller via I/O
- perform alarm checking of certain drive parameters
- the stand-by PLC monitors communications of the active PLC for failure detection
- actuates alarm and output status information

The pre-charge circuitry performs a controlled slow charge of the power cells capacitors to extend capacitor life.

e. Relay Cabinet – this cabinet houses protective relays for pump motor protection and over-frequency protection. These relays are arranged in a two-out-of-three logic and tied into the supply 13.2 kV breaker trip device. They provide backup equipment protection in the event of malfunction of failure of the ASD controllers.

f. Coolant Cabinet – this cabinet houses the coolant pumps, piping, valves and controls for supplying closed loop demineralized cooling water throughout the input transformer, power cells and cabinets. The coolant is routed to a heat exchanger dedicated to each ASD train which is cooled by service water. A third swing heat exchanger is kept in reserve to be

aligned to either ASD train as a backup, should the dedicated heat exchanger need to be taken OOS.

7.7.1.3.3.3.2 Deleted.

7.7.1.3.3.4 RFCS Speed Control Components

7.7.1.3.3.4.1 RFCS Speed Control Components for ASD

The ASD speed control system controls the firing of the power cells for both ASD trains. Each ASO train is individually controlled manually from either the MCR or locally at the ASD control cabinet. The speed control system Human Machine lnterface (HMI) is different for each location.

On MCR console *0-C602, it consists of two columns of three pushbuttons, one column dedicated for raising speed and the other for lowering speed. Speed can be raised or lowered at fixed step changes of 1, 5 or 10 rpm (raising) or 1, 5 or 30 rpm (lowering). All six pushbuttons are “one-shot” in that only one digital speed change command is read by the ASD for each press and release. Extending speed changes beyond the available increments requires repeat press/release of the appropriate pushbutton. The rate of change in speed of the pump is fixed at 2.5% / second for all commanded speed changes. The MCR controls interface with two redundant Remote I/O (RIO) cabinets per train. The RlOs convert each discrete analog speed change command to a digital signal for communication to the main speed controller. The speed change command must be received by both RlOs in order for the command to be acted upon by the ASD; otherwise a single speed change command to only one of the two RlOs will be ignored. This prevents uncontrolled speed changes from spurious invalid signals.

At the local control panel, it consists of a touch screen display HMI which graphically mimics the MCR console speed controls with the same functionality. The local HMI communicates directly to the main controller as a digital input. Transfer of control to the local HMI is via the keylock switch (controlled by SSV)) mounted on the control panel.

7.7.1.3.3.4.2 Deleted.

7.7.1.3.3.4.3 RFCS Manual Control Station

There is no manual control station. Instead, six discrete pushbuttons, each corresponding to a fixed speed change increment and direction, are used on the MCR console or on the local touch screen HMI.

7.7.1.3.3.4.4 RFCS Speed Controller

The ASD speed controller is a microprocessor based multi-card rack module device mounted inside the ASD control cabinet. It accepts the speed change command signals from the MCR console via the redundant RIOs and PLCs over redundant communication channels. It also receives speed change commands from the local touch screen HMI when it is enabled.

7.7.1.3.3.4.5 RFCS Signal Failure Alarm

The speed change command must be received simultaneously by both redundant RIOs for each ASD train to be acted upon by the controller. Invalid spurious signals are ignored. An algorithm

within the ASD controller selects which signal is valid and ignores the malfunctioning redundant channel. The algorithm also determines when the ignored channel signal is again valid. Loss of either one or both communication channels for all inputs between the ASO and each RIO results in a MCR alarm.

7.7.1.3.3.4.6 RFCS Startup Signal Generator

There is no discrete startup signal generator module within the ASD control system. Once the ASD is ready to run, startup control of the pump motor resides in the internal System Operating Program (SOP) code and eagle code of the speed controller.

7.7.1.3.3.4.7 RFCS Speed Limiter

The speed limiters for each ASD train are adjustable high speed limiter setpoints which reside in the speed controller System Operating Procedure (SOP) code.

The speed controller setpoint signal is automatically limited by the speed limiters to approximately 28% of rated speed if the recirculation pump main discharge valve is not fully open, if the feedwater flow is less than 20% of rated flow, or if the reactor level is less than level 3. The setpoint is limited to a speed corresponding to approximately 75% of rated core flow if the reactor level is low and any feedwater pump flow is low or if a condensate pump trips when feedwater flow is greater than 85% of Nuclear Boiler rated flow. If the discharge valve is closed and the pump is at high speed, the pump may overheat. If feedwater flow is less than 20% of rated flow, there is not enough subcooling of the downcomer water to provide the net positive suction head needed by the jet pumps and recirculating pumps to operate at flow rates greater than approximately 30%, this functionality is performed by the ASD internal controller.

7.7.1.3.3.4.8 RFCS Recirculation Loop Starting Sequence

Each recirculation loop is independently put into operation by operating the controls of each loop as follows:

a. The operator can not start the recirc pump unitl the “Ready to Precharge” light on MCR console *0-C602 is lit. This light indicates when all external plant and all internal ASD permissives required for pump start are met.

b. Anytime after the “Ready to Pre-charge” light is lit (no time limit) the operator can start the pump by taking the MV input breaker control switch to "Start." This initiates the Pre-charge/Start cycle.

c. During the Pre-charge/Start cycle the 480 Vac Pre-charge breaker closes which charges up the capacitors on the power cells.

d. Once the ASD power cell capacitors are fully charged and all permissives are still met, the ASD automatically closes the MV input breaker.

e. Once the MV is sensed at the ASD input, the ASD automatically ramps up the recirc pump motor from 0 to 20% speed at 5% / second, and then from 20% to 28% at 2.5% / second with no operator action.

f. Once at or above 28% speed, the operator can incrementally raise or lower speed while staying above 28%.

7.7.1.3.3.5 RFCS Testability

The ASD and associated speed controllers, are functioning during normal power operation. Any abnormal operation of these components can be detected during operation. The components that do not continually function during normal operation can be tested and inspected for calibration and operability during scheduled plant shutdowns. All the recirculation flow control system components can be tested and inspected during scheduled shutdowns.

7.7.1.3.4 RFCS Environmental Considerations

The RFCS is not required for safety purposes, nor is it required to operate after a DBA. The system is required to operate in the normal plant environment for power generation purposes only.

The only part of the recirculation flow control equipment in the drywell is the pump motor. It is subject to the design conditions environment specified in Section 3.11.

The logic control units and instrumentation are located in the control structure and are subject to that environment (Section 3.11).

7.7.1.3.5 RFCS Operational Considerations

7.7.1.3.5.1 RFCS General Information

The ASD system includes self-test, failure detection, indications and alarms to keep the operator informed of the status of the system and equipment, and to permit the operator to quickly determine the location of malfunctioning equipment. Temperature of the equipment is monitored and alarmed if safe levels are exceeded. A recorder for each loop displays the closed loop cooling temperature into the cabinets and out of the transformer and power cells. Each recorder also shows ASD output parameters of voltage, current power, frequency, and frequency demand. Indicators are provided to show recirculation loop flow and valve positions. MCR alarms alert the operator to approximately 256 drive and process alarm conditions which are individually displayed for quick diagnosis on the ASD touch screen display HMI on MCR panel 10-C602 and local control panel.

7.7.1.3.5.2 RFCS Reactor Operator Information

Indication and alarms are provided to keep the operator informed of the status of the systems and equipment, and to allow the operator to quickly determine the location of malfunctioning equipment.

The visual display consists of recirculation loop flow, valve position, speed demand, ASD cooling loop temperatures and ASD output parameters of volts, current, frequency and power. Alarms are provided to alert the operator to various ASD and process alarm conditions such as: malfunctioning equipment, loss of ASD communications, ASD cabinet and components high temperatures, cooling loop conductivity, temperature and level, high or low level runback initiation or bypass, speed hold, etc.

7.7.1.3.5.3 RFCS Setpoints

The subject system has no safety setpoints. However, signals from the RRCS can cause a trip of the recirculation pump motor breakers in the event of an ATWS (Section 7.6.1.8).

7.7.1.4 Feedwater Control System - Instrumentation and Controls

7.7.1.4.1 FCS Identification

7.7.1.4.1.1 FCS General

The FCS controls the flow of feedwater into the RPV to maintain the water in the vessel within predetermined levels during all plant operating modes. The predetermined range of water level is based on the requirements of the steam separators (this includes limiting carry-over, which affects turbine performance, and carry-under, which affects recirculation pump operation). The feedwater control system employs water level, steam flow, and feedwater flow as a three-element control.

Single-element control is also available based on water level only. Normally, the signal from the feedwater flow is equal to the steam flow signal; thus, if a change in the steam flow occurs, the feedwater flow follows. The steam flow signal anticipates the change in water level that results from a change in load. The level signal corrects any mismatch between the steam and feedwater flow that causes the level of the water in the reactor vessel to rise or fall accordingly.

7.7.1.4.1.2 FCS Classification

This system is a power generation system and is classified as not related to safety.

7.7.1.4.1.3 FCS Reference Design

Table 7.1-2 lists reference design information. The FCS is an operational system and has no safety function. Therefore, there are no safety differences between this system and those of the above-referenced facilities. The subject system is functionally identical to the referenced system.

7.7.1.4.2 FCS Power Sources

The FCS power is supplied by three independent sources so that no single power failure can incapacitate more than one of the three level sensing elements used for narrow range indication. Power for two of the three narrow range level sensing and indicating channels is supplied from the 120 V ac instrumentation buses and the other channel is powered from a plant 125 V dc battery and an inverter. The 120 V ac instrumentation bus feeds are each powered through a separate uninterruptible power supply. The FCS panel inserts are supplied with independent 120VAC power feeds. In all cases, each AC feed powers a separate power supply and is UPS backed. The configuration allows continuous operation upon loss of any power feed or power supply unit.

High Level 8 channels A and B level transmitters and corresponding equipment for High Level 8 trip logic are single fed by two independent 120VAC feeds. High Level 8 channel C and D transmitters and corresponding equipment for High Level 8 trip logic are powered by the same 125VDC power source. High Level 8 channel D is also powered by an AC source.

7.7.1.4.3 FCS Equipment Design

7.7.1.4.3.1 FCS General

During normal plant operation, the feedwater control system automatically regulates feedwater flow into the reactor vessel. The system can be manually operated.

The feedwater flow control instrumentation measures the water level in the reactor vessel, the feedwater flow rate into the reactor vessel, and the steam flow rate from the reactor vessel. During automatic operation, these three measurements are used to control feedwater flow.

The optimum reactor vessel water level is determined by the requirements of the steam separators. The separators limit water carry-over in the steam going to the turbines and limit steam carry-under in water returning to the core. The water level in the reactor vessel is maintained within ±2 inches of the setpoint value during normal steady-state operation and within the high and low level trip setpoints during normal plant maneuvering transients.

This control capability is achieved during plant load changes by balancing the mass flow rate of feedwater to the reactor vessel with the steam flow from the reactor vessel. The feedwater flow is regulated by controlling the speed of the turbine-driven feedwater pumps to deliver the required flow to the reactor vessel.

The RRCS can initiate a feedwater runback, reducing flow to 0% within 15 seconds. This runback is independent of the feedwater control operating mode and overrides the loss of signal interlock that prohibits change of feed pump output under loss of control signal conditions. Control of the feedwater system can be regained by the operator 30 seconds after the runback begins. This runback is discussed in Section 7.6.1.8.3.3. ATWS alarm lights are provided on the front of the feedwater control panel. The feedwater system trip contacts associated with the RRCS ATWS runback are required to be high quality but not necessarily safety-grade.

7.7.1.4.3.2 FCS Reactor Vessel Water Level Measurement

Reactor vessel narrow range water level is measured by four identical, independent sensing systems. For each channel, a differential pressure transmitter senses the difference between the pressure caused by a constant reference column of water and the pressure caused by the variable height of water in the reactor vessel. The differential pressure transmitters are installed on lines that serve other systems (Section 7.7.1.1). All four narrow range differential pressure transmitters are used as input to the digital FCS. The FCS system performs error checking and soft majority selection (SMS) on the four transmitters to ensure the final level control signal is accurate. This produces a highly reliable and fault tolerant system, reducing the likelihood of a transmitter failure causing a transient or SCRAM. Three narrow range differential pressure transmitters are used for MCR panel indication. All four narrow range differential pressure signals are displayed on the FCS operator workstation and are arranged to provide failure-tolerant trips of the main turbine and feed pump prime movers. A fifth level sensing system (upset range) provides level indication beyond the span of the narrow range devices.

The SMS water level and upset range water level are continually recorded in the control room.

7.7.1.4.3.3 FCS Steam Flow Measurement

Steam flow is sensed at each main steam line flow restrictor by a differential pressure transmitter. The signals from the four transmitters are sent to the FCS where it is manipulated to produce the true mass flow rate for each line. The FCS than transmits the flow rate of each line to indicators in the control room. The four steam line flow signals are also connected to a SMS within the FCS; the SMS selects the mid-value of its inputs. Total steam flow is calculated as this mid-value

multiplied by the number of valid steam flow signals. The total steam flow is recorded in the control room. All four differential pressure transmitter signals and the SMS flow signal are displayed on the FCS operator work station.

7.7.1.4.3.4 FCS Feedwater Flow Measurement

Feedwater flow is sensed at a flow element in each feedwater line by differential pressure transmitters. One transmitter is designated the primary feed flow measurement and the other is designated as the secondary feed flow measurement. In addition, a calculation of the feed flow is performed for each pump based on pump speeds, and on suction and discharge pressures, with miniflow measurement subtracted. The primary and secondary measurements are compared to each other and to the calculated measurement, to validate the values.

The signals from the transmitters are sent to the FCS where they are manipulated to produce a true mass flow rate for each line. The FCS then transmits the flow rate of each line to indicators in the control room. The total feedwater flow rate is sent to a recorder in the control room. The calculated feedwater flow rate is sent to the plant computer. All differential pressure transmitters, total feedwater flow, and calculated feedwater flow are displayed on the FCS operator workstation.

Feedwater flow is also sensed by a second flow measurement system based on ultrasonic flow measurement. The system includes spool pieces integrated into each feedwater line, where each spool piece contains ultrasonic transducers, a pressure trap for measuring fluid pressure, and a thermowell to measure fluid temperature. The ultrasonic transducers measure fluid velocity, while the pressure transmitters measure the feedwater pressure. Measurements from this system are combined to produce volumetric flow, mass flow, and temperature of the feedwater fluid so that the values can be utilized as inputs to core thermal power computations. Outputs from the system are received by the plant process computer.

7.7.1.4.3.5 FCS Feedwater/Level Control

The FCS has one manual mode and two modes of automatic operation. The manual mode operates the RFPs in parallel. The two automatic modes are single-element and three-element control. The FCS can automatically transfer from single-element to three-element control and vice versa. Single-element control utilizes only the reactor water level to determine the need for increasing or decreasing feedwater flow. Single-element control is normally used when reactor power is less than 20%. Three-element control receives input from three different parameters: reactor water level, total steam flow and total feedwater flow. When reactor power is above 20%, an automatic transfer to three-element control is performed. Automatic transfer can be blocked by the operator selecting forced single-element control before the setpoint is reached.

The FCS has a level controller in the control room. The level controller serves three functions: setting the level setpoint, transfer between single-element and three-element control and indication. Level setpoint is increased or decreased by pushbuttons. Transfer between single-element and three-element is performed by lighted pushbuttons. The level and feedwater flow controllers are balanced to allow bumpless transfer from single-element to three-element control.

During three-element control the reactor water level is compared to reactor water level setpoint and level controller. The level controller output signal is then summed together with the total steam flow to create a feedwater flow demand signal. The total feedwater flow is compared to the feedwater flow demand signal and is passed to the feedwater flow controller. The feedwater flow controller

output is then sent to the RFPs. Upon loss of condensate pump the feedwater flow is automatically limited to nominally 88% of rated feedwater flow.

To improve level control after a SCRAM, a predefined feedwater flow setpoint profile is used. The profile predicts the steam production after a scram and controls the feedwater flow in order to minimize flow and reactor level transients. The profile is also designed to meet the relative runback in the reactor recirculation flow, minimizing thermal stress on the reactor internals caused by non-preheated feedwater.

The scram profile can only be used if three-element control is possible. If the FCS is not in three-element control, then the FCS will automatically switch to three-element control. If the FCS cannot switch to three-element control, then single-element control continues to be active.

Once the scram profile reset logic has been satisfied, the post scram flow profile signals automatically reset and automatic bumpless transfer to single-element control occurs. The scram profile can only be active for a predefined period of time before it is forced to reset.

7.7.1.4.3.6 FCS Interlocks

The level control system also provides interlocks and control functions to other systems. When one of the reactor feed pumps is lost and coincident or subsequent low water level exists, or a condensate pump trips when feedwater flow is greater than 80% of Nuclear Boiler rated flow, recirculation flow is reduced to within the power capabilities of the remaining reactor feed pumps. This reduction helps avoid a low level scram by reducing the steaming rate. Reactor recirculation flow is also reduced on sustained low feedwater flow to ensure that adequate NPSH is provided for the recirculation system.

An interlock from total steam flow is used to initiate insertion of the RWM block. An alarm on low steam flow indicates that the above RWM insertion interlock setpoint is being approached. Alarms are also provided for high and low water level, and for reactor high pressure. Interlocks trip the plant turbine and feedwater pumps if there is reactor high water level. Interlocks trip the reactor recirculation pumps upon loss of the main generator coolant system if feedwater flow exceeds 44% of Nuclear Boiler rated flow.

7.7.1.4.3.7 FCS Turbine-Driven Feedwater Pump Control

Feedwater is delivered to the reactor vessel through turbine-driven feedwater pumps arranged in parallel. The turbines are driven by steam from the reactor vessel during normal operation, or from the auxiliary boilers during startup. The feedwater control signal from the level controller is fed to the turbine speed control systems, which adjust the speed of their associated turbine so that feedwater flow is proportional to the feedwater demand signal. Each turbine can be controlled by its manual/automatic transfer station. The M/A stations are located in the control room and their function is as follows: Manual fast or slow control of the RFP, transfer between Automatic and Manual mode Bias control, and Indication. In manual mode, pushbuttons are used to increase or decrease the M/A station output. Transfer between manual and automatic is performed by lighted pushbuttons. When two or more RFPs are in automatic mode, it is possible to bias the common control output between them. The bias adjustment is performed by the lower/raise pushbuttons on the M/A stations. The bias is maintained as long as all RFPs are in automatic mode. If two or more RFPs are transferred to manual mode, the M/A station output is balanced to actual control output value. The bias value is automatically adjusted to

zero for the RFP still in automatic mode. Each feedwater pump has a minimum flow valve. The minflow valve can be controlled in manual or automatic mode. Manual mode control is performed from M/A stations in the control room. In automatic mode, the minflow valve positions are controlled in an open loop to avoid the situation where the minflow control and the FCS "fight" each other. If the feedwater control signal to the turbine signal is lost, a digital output in the feedwater control circuit causes the turbine speed control system to lock the turbine speed "as is" and initiates an alarm in the control room. The level controller and the manual/automatic transfer stations associated with each turbine speed controller are the "bumpless transfer" type.

7.7.1.4.3.8 FCS Testability

All feedwater flow control system components can be tested and inspected before plant operation and during scheduled shutdowns. Reactor vessel water level indications from the three water level sensing systems can be compared during normal operation to detect instrument malfunctions. Steam mass flow rate and feedwater mass flow rate can be compared during constant load operation to detect inconsistencies in their signals. The FCS has a built in process model and disturbance tool. The process model is used during outages for testing and verification of parameter and control algorithm modifications. The process model simulates the final control elements. The disturbance tool allows operators to introduce disturbances at predefined locations in the control algorithm. The predefined locations are as follows: reactor water level setpoint, flow demand signal, total steam flow, total feedwater flow, and demand output of each final control element.

7.7.1.4.4 FCS Environmental Considerations

The feedwater control system is not required for safety purposes, nor is it required to operate after a DBA. This system is required to operate in the normal plant environment for power generation only. The reactor feed pumps in the turbine enclosure experience the normal design environments listed in Section 3.11.

7.7.1.4.5 FCS Operational Considerations

7.7.1.4.5.1 FCS General Information

The level controller is located in the control room where, at the operator's discretion, the system can be operated either manually or automatically.

Manual control of the individual turbine-driven feedwater pumps is available to the operator in the control room. This includes control of the low flow feedwater bypass valve that can be used for startup.

If there is a loss of feedwater and reactor vessel water level falls below the low level setpoint, the RPS causes plant shutdown, thus preventing any further lowering of the reactor vessel water level.

7.7.1.4.5.2 FCS Reactor Operator Information

Indicators and alarms, provided to keep the operator informed of the status of the system, are as noted in previous sections. The Operator Station provides an interface through which the Operator

can observe and interact with plant processes. The Operator can enter commands using the mouse or keyboard. Process alarms and events are time-tagged and presented in a list.

7.7.1.4.5.3 FCS Setpoints

The subject system has no safety setpoints.

7.7.1.5 Pressure Regulator and Turbine-Generator System - Instrumentation and Controls

7.7.1.5.1 PRTGS Identification

7.7.1.5.1.1 PRTGS General

One of the features of direct cycle BWRs is the direct passage of the nuclear boiler generated steam through the turbine and regenerative system. In this system the turbine is slaved to the reactor in that all steam generated by the reactor is normally accepted by the turbine. The operation of the reactor requires a pressure regulator to maintain a constant (within the range of the regulator controller proportional band setting) turbine inlet pressure.

The turbine pressure regulator normally controls the turbine control valves to maintain constant (within the range of the regulator controller proportional band setting) turbine inlet pressure. In addition, the pressure regulator also operates the steam bypass valves so that a portion of nuclear boiler rated flow can be bypassed when operating at steam flow loads above those that can be accepted by the turbine, as well as during the startup and shutdown phases.

The overall turbine-generator and pressure control system accomplishes the following:

a. Controls turbine speed and turbine acceleration

b. Operates the steam bypass system to keep reactor pressure within limits and avoid large power transients

c. Controls main turbine inlet pressure within the proportional band setting of the pressure regulator

7.7.1.5.1.2 PRTGS Classification

The PRTGS is classified as a primary power generation system. That is, it is not a safety system, but its operation is essential to the power production cycle.

7.7.1.5.1.3 PRTGS Reference Design

Table 7.1-2 lists reference design information. The subject instrumentation and control system is an operational system and has no safety function. Therefore, there are no safety design differences between this system and those of the reference design facilities. This system is functionally identical to the referenced systems.

7.7.1.5.2 PRTGS Power Sources

A. The DEHC electrical power is supplied by redundant 120Vac UPS Distribution Panels. Failure of either power supply source will not affected the operation of the PRTGS control functions.

7.7.1.5.3 PRTGS Equipment Design

7.7.1.5.3.1 PRTGS General

BWR pressure is controlled by regulating the main steam pressure through modulation of the turbine control or steam bypass valves. Command signals to these valves are generated by redundant control elements using the sensed turbine inlet pressure signals as the feedback, as shown in Figure 7.7-9. For normal operation, the turbine control valves regulate steam pressure; however, whenever the total steam flow demand from the pressure regulator exceeds the capacity of the turbine control valves, the pressure control system sends the excess steam flow directly to the main condenser through the steam bypass valves. The plant's ability to follow grid system load demands is determined by adjusting reactor power level, manually varying reactor recirculation flow, or manually moving control rods. In response to the resulting steam production changes, the pressure control system adjusts the turbine control valves to accept the steam output change, thereby regulating steam pressure.

7.7.1.5.3.2 PRTGS Steam Pressure Control

During normal plant operation, steam pressure is controlled by the main turbine control valves, positioned in response to the pressure regulation demand signal (Figure 7.7-9). The steam bypass valves are normally closed.

Two essentially redundant regulators are provided so that the one is the primary controller and the backup controller is in standby tracking the same steam flow demand signal to ensure, if required, an automatic bumpless transfer to the backup regulator. Each regulator accesses the pressure signal that is validated based upon the turbine inlet (throttle) pressure signals.

The turbine control valve (steam flow) demand signal is limited, after passage through the low value gate (Figure 7.7-9), to the signal required to fully open the main control valves. Thus, if the pressure control system requires that additional steam flow be released from the reactor when the control valves reach wide open, the control signal error to the bypass valves increases and causes bypass actuation.

7.7.1.5.3.3 PRTGS Steam Bypass System

The steam bypass system is designed to control steam pressure when reactor steam generation exceeds turbine requirements during startup (pressure, speed ramping, and synchronizing), sudden load reduction, and cooldown.

The bypass capacity of the system is 24.3% of the rated steam flow; sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram.

Normally, the bypass valves are closed and the pressure regulator controls the turbine control valves, directing all steam flow to the turbine. If the speed governor or the load limiter restricts steam flow to the turbine, the regulator controls system pressure by opening the bypass valves. If

the capacity of the bypass valves is exceeded while the turbine cannot accept an increase in steam flow, the system pressure rises and RPS action causes the reactor to shutdown.

The bypass valves are an automatically operated, regulating-type that are proportionally controlled by the turbine pressure regulator and control system.

The turbine control system provides a signal to the bypass valves that corresponds to both the "error" between the turbine control valve opening required by the controlling pressure regulator and the turbine control valve position demanded by the output of the low value gate circuit (Figure 7.7-9). An adjustable bias signal is provided to keep the bypass valves closed during momentary differences that occur during normal operational transients.

Bypass valves and controls are designed so that bypass steam flow is shut off upon loss of control system electrical power, hydraulic pressure, or low condenser vacuum.

7.7.1.5.3.4 PRTGS Turbine Speed-Load Control Systems

7.7.1.5.3.4.1 Normal Operation

During base load plant operation, the turbine load reference is held above the desired load, so that the pressure regulation demand governs the turbine control valves.

7.7.1.5.3.4.2 PRTGS Behavior of Turbine Outside of Normal Operation

a. Turbine startup

   Prior to turbine startup, sufficient reactor steam flow is generated to permit the steam bypass valves to maintain reactor pressure control while the turbine is brought up to speed and synchronized under its speed-load control.

b. Partial load rejection

   During partial load rejection transients, which appear to the reactor as a reduction in turbine load demand resulting from an increase in generator (or grid) frequency, the turbine pressure control scheme allows the reduced turbine speed-load demand to override the pressure regulation demand and thereby directly regulate the turbine control valves. The pressure controller modulates the bypass valves to maintain reactor pressure.

c. Turbine shutdown or turbine-generator trip

   During turbine shutdown or turbine-generator trip conditions, the main turbine stop valves and control valves are closed. Reactor steam flow is then passed through the steam bypass valves under steam pressure control and through the reactor SRVs, as needed.

d. Steam bypass operation

   Fast opening of the steam bypass valves during turbine trips or generator load rejections requires coordinated action with the turbine control system. When the turbine control valves are under pressure control, no bypass steam flow is demanded; conversely, when the turbine speed-load demand falls below the

pressure regulation demand, a net bypass flow demand is computed. During turbine or generator trip events resulting in fast closure of the turbine stop or control valves, the turbine control valve demand is immediately reduced to zero, causing the bypass steam flow demand to equal the initial pressure regulation demand.

e. Loss of turbine control system power

Turbine controls and valves are designed so that the turbine stop and control valves close upon loss of control system power or hydraulic pressure.

7.7.1.5.3.5 PRTGS Turbine-Generator to RPS Interface

The RPS initiates reactor scram when any monitored plant condition requires it. Two such conditions are: turbine stop valve closure and turbine control valve fast closure when reactor power is above 29.5% of rated power. The turbine stop valve closure signal is generated before the turbine stop valves have closed more than 5%. This signal originates from position switches that sense stop valve motion away from fully open. A limit switch is provided on each of the four turbine stop valves. The switches are closed when the stop valves are fully open, and open within 10 milliseconds after the setpoint is reached. The switches are electrically isolated from each other and from other turbine plant equipment.

The control valve fast closure signal is generated by four hydraulic oil pressure sensors that are distributed equally among the control valves and that sense hydraulic oil pressure decay as an indication of fast control valve closure. The switches are closed when the valves are open, and open within 30 milliseconds after the control valves start to close in a fast closure mode.

To avoid reactor scram due to stop valve closure or control valve fast closure when power is below 29.5% of rated power, two independent sensing lines are provided from pressure taps located in the turbine steam supply lines upstream of the high pressure turbine first stage and are connected to pressure switches to supply power level signals to the RPS. The pressure taps are located to provide a pressure signal proportional to turbine steam flow. The pressure taps are shared with other instrumentation sensors. All sensors have individual shutoff valves.

7.7.1.5.3.6 PRTGS Turbine-Generator to Main Steam Isolation System Interface

Four independent main condenser vacuum sensors provide an isolation signal to the NSSS MSIVs. Condenser vacuum transmitters and trip units are discussed in Section 7.3.1.1.2.

7.7.1.5.3.7 PRTGS Testability

Controls are provided to test the turbine valve RPS interface signal switches in the following ways:

a. Actuate each stop valve individually to the 10% closed point with no interaction with other valves

b. Actuate the following pairs of stop valves to the 10% closed point, one pair at a time: 1 and 2; 3 and 4; 1 and 3; 2 and 4

c. Actuate one control valve fast closure hydraulic oil pressure switch at a time by individually closing the control test mode

d. Individually test each main condenser low vacuum instrument channel

7.7.1.5.4 PRTGS Environmental Considerations

The turbine-generator control system is required to operate in the normal plant environment for power generation purposes only.

Instruments and controls on the turbine experience the turbine building normal design environment as listed in Section 3.11. The logic, remote control units, and instrument terminals located in the control structure experience the environment listed in Section 3.11.

7.7.1.5.5 PRTGS Operational Considerations

7.7.1.5.5.1 PRTGS General Information

Process variables controlled by the pressure regulator and speed/ load control system are displayed in the control room on the turbine-generator section of the control boards. Manual and automatic control modes for the various turbine-generator operational modes (such as startup, normal operation, and shutdown) are available to the operator from the control room. Automatic HMI display indication is provided to inform the operator as to the operating mode of the turbine-generator unit. The pressure control is active during all modes of operation and cannot be selected or deselected. The default mode allows the operator to select speed reference and rate, start up the turbine, close the bypass valves, and set the turbine in Turbine-Follow-Reactor mode.

Two pressure control channels, operating redundantly, receive inputs from validated pressure signals from the two pressure transducers in the main steam line upstream of the main steam stop valves and from the pressure reference function. Main steam pressure indications and pressure setpoint adjustments/indications are located on the HMI workstation of the turbine control panel. Minor and Major Trouble Pressure Control annunciation is provided in the control room.

7.7.1.5.5.2 PRTGS Reactor Operator Information

The NSSS pressure regulator has the following controls and information displayed in the control room:

a. Main steam pressure transducer output

b. Main steam pressure transducer output

c. Main steam pressure regulator setpoint A

d. Main steam pressure regulator setpoint B

e. Individual bypass valve position

f. Individual bypass valve demand control signal

g. Bypass valve test controls

h. Pressure regulator selection control

i. Individual control valve position

j. Individual control valve demand control signal

7.7.1.5.5.3 PRTGS Setpoints

There are no safety setpoints associated with this system.

7.7.1.6 Neutron Monitoring System - Instrumentation and Controls

The NMS consists of the following nonsafety-related systems:

a. Source range monitor system

b. Rod block monitor system

c. Traversing incore probe system

The safety-related portion is described in Section 7.6.1.4.

7.7.1.6.1 Source Range Monitor System

7.7.1.6.1.1 SRM Equipment Design

7.7.1.6.1.1.1 SRM Circuit Description

The SRM provides neutron flux information during reactor startup and low flux level operations. There are four SRM channels. Each includes one detector that can be physically positioned in the core from the control room (Figure 7.6-2).

The detectors are inserted into the core for reactor startup. They can be withdrawn if the indicated count rate is between preset limits or if the IRM is on the third range or above (Figure 7.6-3).

During initial startup, neutron flux is monitored by source range neutron monitoring channels, providing a scram signal when the preset flux level of any channel has been reached. This logic is removed from the scram circuitry after completion of initial startup.

a. Power Supply - The power for the monitors is supplied from the two 120 V ac RPS buses. Two monitors are powered from each bus.

b. Physical Arrangement - Each detector assembly consists of a miniature fission chamber and a low-noise, quartz fiber insulated transmission cable. The sensitivity of the detector is 1.2×10^{-3} cps/nv nominal, 5.0×10^{-4} cps/nv minimum, and 2.5×10^{-3} cps/nv maximum. The detector cable is connected underneath the reactor vessel to the multiple shielded coaxial cable. This shielded cable carries the pulses to a pulse current preamplifier located outside the drywell.

The detector and cable are located inside the reactor vessel in a dry tube sealed against reactor vessel pressure. A remote controlled detector drive system

moves the detector along the dry tube. The active length of fuel is positioned vertically up to 30 inches below the reactor fuel region (Figure 7.6-2). When a detector arrives at a travel end point, detector motion is automatically stopped. SRM drive control arrangement and logic are presented in Figure 7.6-3. The electronics for the SRM, their trips, and their bypasses are located in four cabinets. Source range signal conditioning equipment is designed so that it can also be used for open vessel experiments.

c. Signal Conditioning - A current pulse preamplifier provides amplification and impedance matching for the signal conditioning electronics (Figure 7.7-13).

The signal conditioning equipment converts the current pulses to analog dc currents that correspond to the logarithm of the count rate. The equipment also derives the period. The output is displayed on front panel meters and is provided to remote meters and recorders. The logarithm of the count rate meter displays the rate of occurrence of the input current pulses. The period meter displays the time in seconds for the count rate to change by a factor of 2.7. In addition, the equipment contains integral test and calibration circuits, trip circuits, power supplies, and selector circuits.

d. Trip Functions - The trip outputs of the SRM operate in the fail-safe mode. Loss of power to the SRM causes the associated outputs to become tripped.

The SRM provides signals indicating SRM upscale, downscale, inoperative, and incorrect detector position to the RMCS to block rod withdrawal under certain conditions. Any SRM channel can initiate a rod block. These rod blocking functions are discussed in Section 7.7.1.6.2. Appropriate lights and annunciators are also actuated to indicate the existence of these conditions. Refer to Table 7.7-4 for a description of the trip functions.

7.7.1.6.1.1.2 SRM Bypasses and Interlocks

One of the four SRM channels can be bypassed at any one time by a switch on the operator's control panel.

7.7.1.6.1.1.3 SRM Redundancy and Diversity

SRM channels are not redundant because SRM detectors are spatially dependent and do not serve as a backup to other detectors.

7.7.1.6.1.1.4 SRM Testability

Each SRM channel can be fully tested and calibrated using written procedures. Inspection and testing are performed as required on the SRM detector drive mechanism; the mechanism can be checked for full insertion and retraction capability. The various combinations of SRM trips can be introduced to ensure the operability of the rod blocking functions.

7.7.1.6.1.2 SRM Environmental Considerations

The wiring, cables, and connectors located within the drywell are designed for continuous-duty in the conditions described in Section 3.11. The above SRM system components are designed to operate during and after certain design basis events such as earthquakes and anticipated operational occurrences.

7.7.1.6.1.3 SRM Operational Considerations

The SRM system provides information to the operator. It is operated by inserting the SRM detectors into the core whenever these channels are needed, and withdrawing them, when permitted, to reduce their burnup.

7.7.1.6.2 Rod Block Monitor System

7.7.1.6.2.1 RBM Equipment Design

7.7.1.6.2.1.1 RBM Circuit Description

The RBM has two channels (Figure 7.6-4). Each channel uses input signals from a number of LPRM channels. A trip signal from either RBM channel initiates a rod block. One RBM channel can be bypassed without loss of system function. The minimum number of LPRM inputs required for each RBM channel to prevent an instrument inoperative alarm is four when using four LPRM assemblies, three when using three LPRM assemblies, and two when using two LPRM assemblies.

a. Power Supply - The RBM power is received from two independent 120 V ac buses, each of which is supplied by an UPS. Each RBM is supplied by two redundant DC power supplies. Each DC power supply is supplied by one of the two 120 Vac buses.

b. Signal Conditioning - The RBM signal is generated by averaging a set of LPRM signals. The LPRM signals used depend on the control rod selected. Upon selection of a rod for withdrawal or insertion, the conditioned signals from the LPRMs around that rod will be automatically selected by the two RBM channels (Figure 7.7-14 shows examples of the four possible LPRM/selected rod assignment combinations). For typical non-edge rod, each RBM channel averages LPRM inputs from two of the four B-level and D-level detectors, and all four of the C-level detectors (see Figure 7.7-14). A-level LPRM detectors are not included in the RBM averages, but are displayed to the operator. When a rod near, but not at, the edge of the core is selected, where there are fewer than four but at least two LPRM strings around the rod, the number of detectors used by the RBM channels is either six of four depending on how many LPRM strings are available. If a detector has been bypassed in the LPRM system, that detector is automatically deleted from the RBM processing and the averaging logic is adjusted to average only the remaining detectors.

   After selection of a control rod, each RBM channel calculates the average of the related LPRM detectors and calculates a gain factor that will adjust the average to 100. Thereafter, until another rod is selected, the gain factor is applied to the LPRM average to obtain the RBM signal value. The RBM signal value is compared to RBM trip setpoints.

When a peripheral rod is selected or the RBMs associated reference APRM power signal is below the automatic bypass level, the RBM function is automatically bypassed, the rod block outputs are set to “permissive”, and the RBM average is set to zero.

In the operating range, the RBM signal is accurate to approximately 1% of full-scale.

7.7.1.6.2.1.2 RBM Trip Function

The RBM is designed to prohibit erroneous withdrawal of a control rod during operation at core high power levels. This prevents local fuel damage under permitted bypass and/or LPRM detector chamber failure conditions and prevents local fuel damage during a single rod withdrawal error. Local fuel damage poses no significant threat relative to radioactive release from the plant.

The RBM supplies a trip signal to the RMCS to inhibit control rod withdrawal. The trip is initiated when RBM output exceeds the rod block setpoint. The RBM has three upscale trip levels and one downscale trip level. Figure 7.7-17 illustrates the trip setpoints. Below 30 percent rated power, fuel damage cannot occur for any single control rod withdrawal; hence, the RBM system is automatically bypassed. The low trip setpoint (LTSP) is enforced between 30 percent and 65 percent rated power, the intermediate trip setpoint (ITSP) is enforced between 65 percent and 85 percent rated power, and the high trip setpoint (HTSP) is enforced between 85 percent and 100 percent rated power. The percent rated power input used to automatically select the applicable RBM trip is provided by the APRM. The RBM system is automatically bypassed if the control rod has one or more adjacent fuel bundles comprising the outer boundary of the core. The operator can bypass one of the two RBM channels at any time. Either RBM channel can inhibit control rod withdrawal.

7.7.1.6.2.1.3 RBM Bypasses

The operator can bypass one of the two RBM channels at any time. Both RBM channels can be bypassed provided the following conditions are met:

for power $\geq$30% and <90%, MCPR $\geq$1.70
for power $\geq$90%, MCPR $\geq$1.40

7.7.1.6.2.1.4 RBM Redundancy

Although the RBM does not perform a safety-related function, in the interest of plant economics and availability, it is designed to meet certain salient design principles of a safety system. These include the following:

a. Redundant, separate, and isolated RBM channels.

b. Redundant, separate, isolated rod selection information.

c. Independent, isolated RBM level readouts and status displays from the RBM channels.

d. A mechanical barrier between channels A and B of the manual bypass switch.

e. Multiple manual RBM channel bypass is prohibited by switch design.

f. Fail-safe design; loss of power initiates a rod block.

g. A trip of either RBM channel initiates a rod block.

h. Redundant APRM simulated thermal power reference signals provided to each RBM for trip level information

i. Each RBM channel has a backup reference APRM

7.7.1.6.2.1.5 RBM Testability

The RBM channels are tested and calibrated with written procedures. The RBMs are functionally tested by introducing test signals into the RBM channels.

7.7.1.6.2.2 RBM Operational Considerations

Trip setpoint automatically changes to the next higher rod block setpoint line.

The RBM interfaces with the following safety-related systems:

a. LPRM: Separate, isolated LPRM flux level is provided to each RBM channel.

b. APRM: Independent, separate, isolated APRM simulator thermal power reference signals are supplied to each RBM channel for trip reference.

7.7.1.6.3 Traversing Incore Probe System

7.7.1.6.3.1 TIP System Identification

7.7.1.6.3.1.1 TIP General

Flux readings along the axial length of the core are obtained by fully inserting the traversing probe into one of the calibration guide tubes, then taking data as the probe is withdrawn. The analog data are available for display on a recorder or for use by the process computer. One traversing probe and its associated drive mechanism is provided for each of five groups of nine or ten incore guide tubes.

7.7.1.6.3.1.2 TIP Classification

This system is a power generation system and is not related to safety.

7.7.1.6.3.1.3 TIP Reference Design

Table 7.1-2 lists reference design information. The subject instrumentation and controls system is an operational system and has no safety function. Therefore, there are no safety design

differences between this system and those of the referenced design facilities. This system is functionally similar to the referenced system.

7.7.1.6.3.2 TIP Power Source

The power for the subject system is supplied from an instrument ac power source.

7.7.1.6.3.3 TIP Equipment Design

7.7.1.6.3.3.1 TIP General

There are five TIP machines as shown in Figure 7.6-1. The TIP machines have the following components:

a. One TIP

b. One drive mechanism

c. One indexing mechanism

d. Up to 10 incore guide tubes

The system allows calibration of LPRM signals by correlating TIP signals to LPRM signals as the TIP is positioned in various radial and axial locations in the core. The guide tubes inside the reactor are divided into groups. Each group has its own associated TIP machine.

7.7.1.6.3.3.2 TIP Equipment Arrangement

A TIP drive mechanism uses a gamma sensitive probe assembly attached to a flexible drive cable (Figure 7.7-10). The cable is driven from outside the drywell by a gearbox assembly. The flexible cable is contained by guide tubes that penetrate the reactor core. The guide tubes are a part of the LPRM detector assembly. The indexing mechanism allows the use of a single detector in any one of 10 different tube paths. The 10th tube is used for TIP cross calibration with the other TIP machines. The control system provides for both manual and semi-automatic operation. The electronics in the TIP panel in the control room amplifies and displays the TIP signal. Core position versus gamma flux may be plotted on an X-Y recorder in the control room, and is also provided to the Plant Monitoring System. A block diagram of the drive system is shown in Figure 7.6-3.

7.7.1.6.3.3.3 TIP Testability

The TIP equipment is tested and calibrated with written procedures.

7.7.1.6.3.4 TIP Environmental Considerations

The equipment and cabling located in the drywell are designed for continuous-duty up to 150°F and 100% relative humidity.

7.7.1.6.3.5 TIP Operational Considerations

The TIP can be operated during reactor operation to calibrate the LPRM channels. This system has no safety setpoints.

7.7.1.7 Deleted

7.7.1.8 Reactor Water Cleanup System - Instrumentation and Controls

7.7.1.8.1 RWCU System Identification

7.7.1.8.1.1 RWCU General

The purpose of the RWCU system is to provide for removal of soluble and insoluble waterborne impurities to reduce the secondary source of β and γ radiation.

7.7.1.8.1.2 RWCU Classification

This is a power generation system and is classified as not related to safety.

7.7.1.8.1.3 RWCU Reference Design

Table 7.1-2 lists reference design information. This control system is an operational system and has no safety function.

7.7.1.8.2 RWCU Power Sources

The RWCU system is powered from the plant instrumentation bus, with the exception of the Noble Metals Monitoring System Data Acquisition System, which is powered from a lighting panel power supply. No backup power source is necessary since the RWCU system is not a safety-related system. Adequate fuse protection is provided so that a short circuit within the system has only a local effect that can be easily corrected without interrupting reactor operation.

7.7.1.8.3 RWCU Equipment Design

7.7.1.8.3.1 RWCU General

The RWCU system is described in Section 5.4.8.

7.7.1.8.3.2 RWCU Circuit Description

The cleanup system is protected against overpressurization by relief valves. The ion exchange resin is protected from high temperature by temperature switches upstream of the filter/ demineralizer unit. One switch activates an alarm while a second switch closes the outboard isolation valve, which subsequently trips the cleanup pumps. The isolation valves also close automatically on a reactor low water level signal, when the SLCS is actuated, and on a "leak signal" from the leak detection system. See Section 7.3 for a detailed description of the isolation function.

A high differential pressure across the filter/demineralizer or its discharge strainer automatically isolates the units and sounds an alarm. The holding pump starts whenever there is a low flow through a filter/demineralizer.

A sampling station is provided to obtain reactor water samples from the inlet and outlet of both filter/demineralizers.

Flow, pressure, temperature, and conductivity are recorded or indicated on a panel in the control room. Instrumentation and controls for backwashing and precoating the filter/demineralizers are on a local panel outside the drywell. Alarms are sounded in the control room to alert the operator to abnormal conditions.

7.7.1.8.3.3 RWCU Testability

Because the RWCU system is usually in service during plant operation, satisfactory performance is demonstrated without the need for any special inspection or testing beyond that specified in the manufacturer's instructions.

7.7.1.8.4 RWCU Environmental Considerations

The RWCU system is not required for safety purposes nor is it required to operate after the DBA. The RWCU system is required to operate in the normal plant environment for power generation purposes only.

RWCU instrumentation and controls located in the RWCU equipment area are subject to the environment described in Section 3.11.

7.7.1.8.5 RWCU Operational Considerations

7.7.1.8.5.1 General Information

The RWCU system instrumentation and controls are not required for safe operation of the plant. They provide a means of monitoring parameters of the system and protecting the system.

7.7.1.8.5.2 RWCU Reactor Operator Information

See drawing M-44.

7.7.1.8.5.3 RWCU Setpoints

No safety-related setpoints are associated with the RWCU system.

7.7.1.9 Process Radiation Monitoring Systems – Instrumentation and Controls

7.7.1.9.1 South Stack Effluent Radiation Monitoring System

7.7.1.9.1.1 SSE-RMS Identification

The objective of the SSE-RMS is to monitor the quantity of radioactive gases, particulates, and iodines emitted from the south stack. Inasmuch as the south stack is a main point of potential escape of radioactive material to the environment, these data are used for the generation of Regulatory Guide 1.21 reports.

7.7.1.9.1.2 SSE-RMS Classification

This system is a power generation system and is classified as not related to safety. Inasmuch as the south stack will be isolated if there is an accident, the capability to monitor accident and postaccident conditions is not required.

7.7.1.9.1.3 SSE-RMS Reference Design

Table 7.1-2 lists reference design information. The SSE-RMS is an operational monitoring system and has no safety function.

7.7.1.9.1.4 SSE-RMS Power Sources

Power is provided by the 120 V ac instrument bus. Safety-related power is not required for this application.

7.7.1.9.1.5 SSE-RMS Equipment Design

7.7.1.9.1.5.1 SSE-RMS General

The south stack consists of two discrete ducts for the two units. Two isokinetic, representative samples of air are drawn from each duct in accordance with Regulatory Guide 1.21 and ANSI N13.1. Consequently, four independent radiation monitoring subsystems are provided. Each of these subsystems is provided with three channels for monitoring radioactive particulates, iodines, and noble gases in the stack effluents.

Each subsystem consists of three detectors, a microprocessor, and a local control and readout module. All subsystems are provided with high, high-high, and downscale alarm outputs.

7.7.1.9.1.5.2 SSE-RMS Circuit Description

Each monitoring subsystem has two upscale trips for high and high-high radiation and a downscale trip that indicates instrument trouble. These trips are actuated by the above conditions in any of the subsystem channels. These trips annunciate, but provide no control action. The trip circuits are set so that loss of power causes an alarm. The range of each channel is six decades and is selected to cover both normal and possible maximum radiation levels in the south stack effluents.

The monitors are located on the roof of the reactor enclosure, where the background radiation environment is minimal. These monitors are interfaced to the RMMS (Section 11.5.6) to allow indication, trending, and remote control at RMDS display consoles in the control room. Remote controls are provided for purging the noble gas chamber. Controls are also provided for remotely resetting the alarm setpoints and for checking detector operability.

7.7.1.9.1.5.3 SSE-RMS Testability

Check sources are provided for each detector to verify operability of each channel. Access to the controls and setpoints is restricted by the operator's key and coded input signals.

7.7.1.9.1.6 SSE-RMS Environmental Considerations

The monitoring racks, microprocessors, and isokinetic sampling systems are designed to meet the environmental conditions on the reactor enclosure roof. These systems are protected by a room

provided with ventilation, heating, and cooling. Radiation background in this location is minimal. See Section 3.11 for the environmental conditions of the equipment locations.

7.7.1.9.1.7 SSE-RMS Operational Considerations

7.7.1.9.1.7.1 SSE-RMS General Information

Annunciator outputs in the control room are shared for all subsystems. Redundancy and independence ensure continuous monitoring during periods of equipment checking, servicing, and shutdown. Fixed filters provide for continuous accumulation of radioactive samples that can be analyzed in the counting room. Digitized outputs of all three channels, as well as flow measurements, are provided as input data to the RMMS for the generation of Regulatory Guide 1.21 reports.

7.7.1.9.1.7.2 SSE-RMS Reactor Operator Information

Processed inputs to the control room provide the reactor operator with early warnings of anomalous changes in radioactive effluents. This information can be used as a guide for remedial action.

7.7.1.9.2 Radwaste Equipment Rooms Ventilation Exhaust Radiation Monitoring System

7.7.1.9.2.1 RERV-RMS Identification

The RERV-RMS is an off-line process radiation monitoring system that measures the concentration of radioactive material in the ventilation duct from the charcoal offgas treatment compartment. The purpose of this monitoring system is to detect leakage of radioactive noble gases from the charcoal beds. Such leakage could escape to the north stack.

7.7.1.9.2.2 RERV-RMS Classification

The RERV-RMS is a power generation system and is not related to safety.

7.7.1.9.2.3 RERV-RMS Reference Design

Table 7.1-2 lists reference design information. The RERV-RMS is designed to alarm in response to excessive concentrations of noble gases in the effluents released to the north stack, indicating leakage from the charcoal offgas treatment system.

7.7.1.9.2.4 RERV-RMS Power Sources

Power is supplied to the monitor by the 120 V ac uninterruptible bus B. The pumps and solenoid valves are supplied from the 120 V ac local power. The recorder and purge controls are supplied from the 120 V ac instrument bus.

7.7.1.9.2.5 RERV-RMS Equipment Design

7.7.1.9.2.5.1 RERV-RMS General

The RERV-RMS is a standard off-line process radiation monitoring system. It draws an air sample from a ventilation duct, passes this sample through a chamber containing a radiation detector, and then returns the sample to the duct.

7.7.1.9.2.5.2 RERV-RMS Circuit Description

The RERV-RMS is provided with a gamma-sensitive detector and converter that transmits its signal to a rate meter located in the auxiliary equipment room. This rate meter indicates the concentration of radioactivity in the air sample and transmits both a signal to a recorder in the control room and upscale/downscale alarm signals to annunciators in the control room. No control trip capabilities are provided. A flow indicator trips an annunciator if there is a malfunction of the sampling pump.

7.7.1.9.2.6 RERV-RMS Testability

Test signals are fed into the monitor via the control module in the auxiliary equipment room. A check source is provided for secondary calibration. Purge controls are also provided.

7.7.1.9.2.7 RERV-RMS Environmental Considerations

The monitoring rack is designed to meet the environmental conditions in the radwaste enclosure. The control module and recorder are in the environment of the auxiliary equipment room and control room. See Section 3.11 for the environmental conditions of the equipment locations.

7.7.1.9.2.8 RERV-RMS Operational Considerations

7.7.1.9.2.8.1 RERV-RMS General

Annunciator outputs of the RERV-RMS alarm signals are provided in the control room. Fixed filters for particulates and iodines provide for continuous accumulation of radioactive materials that can be analyzed in the counting room. However, very few, if any, particulates or iodines are expected in this application.

7.7.1.9.2.8.2 RERV-RMS Reactor Operator Information

Inputs to the control room provide the operator with an indication of leakage from the charcoal beds. If there is such an indication, remedial action can be taken.

7.7.1.9.3 Charcoal Treatment System Process Exhaust Radiation Monitoring System

7.7.1.9.3.1 CTSP-RMS Identification

The CTSP-RMS is identical with the system discussed in Section 7.7.1.9.2, except that the monitored sample is drawn from the charcoal offgas treatment system effluent pipe. The purpose of this monitoring system is to provide ongoing records and alarm capability for indicating unacceptable concentrations of noble gases in the effluents being released to the north stack.

7.7.1.9.3.2 CTSP-RMS Classification

The CTSP-RMS is a power generation system and is not related to safety.

7.7.1.9.3.3 CTSP-RMS Reference Design

Table 7.1-2 lists reference design information. The CTSP-RMS is designed to alarm in response to excessive concentrations of noble gases in effluents from the charcoal offgas treatment system.

7.7.1.9.3.4 CTSP-RMS Power Sources

Power is supplied to the monitors by the 120 V ac uninterruptible bus A. The pumps and solenoid valves are supplied from the 120 V ac local power. The recorder and purge controls are supplied from the 120 V ac instrument bus.

7.7.1.9.3.5 CTSP-RMS Equipment Design

7.7.1.9.3.5.1 CTSP-RMS General

The CTSP-RMS is a standard off-line process radiation monitoring system. It draws a gas sample from a process pipe, passes the sample through a chamber containing a radiation detector, and then returns the sample to the pipe.

7.7.1.9.3.5.2 CTSP-RMS Circuit Description

The CTSP-RMS is provided with a gamma-sensitive detector and converter that transmits its signal to a rate meter located in the auxiliary equipment room. This rate meter indicates the concentration of radioactive material in the gas sample and transmits both a signal to a recorder in the control room and upscale/downscale alarm signals to annunciators in the control room. No control trip capabilities are provided. A flow indicator trips an annunciator if the sampling pump malfunctions.

7.7.1.9.3.6 CTSP-RMS Testability

Test signals are fed into the monitor via the control module in the auxiliary equipment room. A check source is provided for secondary calibration. Purge controls are also provided.

7.7.1.9.3.7 Environmental Considerations

The monitoring rack is designed to meet the environmental conditions in the radwaste enclosure. The control module and recorder are in the environment of the auxiliary equipment room and control room. See Section 3.11 for the environmental conditions of the equipment locations.

7.7.1.9.3.8 CTSP-RMS Operational Considerations

7.7.1.9.3.8.1 CTSP-RMS General

Annunciator outputs of the CTSP-RMS alarm signals are provided in the control room. Fixed filters for particulates and iodines provide for continuous accumulation of radioactive materials that can be analyzed in the counting room. However, very few, if any, particulates or iodines are expected in this application.

7.7.1.9.3.8.2 CTSP-RMS Reactor Operator Information

Inputs to the control room provide the operator with an indication of the effectiveness of the charcoal offgas treatment system in arresting releases of radioactivity to the north stack. If there are unacceptable inputs, remedial action can be taken.

7.7.1.9.4 Recombiner Rooms and Hydrogen Analyzer Compartments Exhaust Radiation Monitoring System

7.7.1.9.4.1 RRHAC-RMS Identification

This off-line process radiation monitoring system detects the presence of radioactive material escaping to the north stack from the recombiner compartments, hydrogen analyzer compartments, and equipment drain sump vent. If there is a high radiation alarm, the manifolded sample line leading from the main ducts can be isolated, and each branch of this line can be checked separately to determine the exact source of leakage.

7.7.1.9.4.2 RRHAC-RMS Classification

This monitoring system is a power generation system and is not related to safety.

7.7.1.9.4.3 RRHAC-RMS Reference Design

Table 7.1-2 lists reference design information. This system is designed to alarm in response to significant concentrations of gross radioactivity in the duct effluents from the recombiner compartments, hydrogen analyzer compartments, or equipment drain sump vent. Capability is provided to locate the source of this radioactivity.

7.7.1.9.4.4 RRHAC-RMS Power Source

Power is supplied to the monitor by the 120 V ac uninterruptible bus B. The pumps and solenoid valves are supplied from the 120 V ac local power. The recorder and purge controls are supplied from the 120 V ac instrument bus.

7.7.1.9.4.5 RRHAC-RMS Equipment Design

7.7.1.9.4.5.1 RRHAC-RMS General

This standard off-line radiation monitoring system draws samples from two exhaust ventilation ducts, combines them, passes the samples through a chamber containing a radiation detector, and then returns the sample to the exhaust duct. The operator can select the branch sample line he chooses to check using a set of solenoid valves. In this way, seven discrete sources of radioactivity can be monitored with a single instrument system.

7.7.1.9.4.5.2 RRHAC-RMS Circuit Description

This monitoring system is provided with a gamma-sensitive detector and converter that transmits its signal to a rate meter located in the auxiliary equipment room. This rate meter indicates radioactivity in the air sample and transmits both a signal to a recorder in the control room and upscale/downscale alarm signals to an annunciator in the control room. No control trip capability is provided. A flow indicator trips an annunciator if there is a malfunction of the sampling pump. A

hand selector switch in the control room provides for determination of which of the following sources to monitor:

a. Main exhaust ducting

b. Recombiner compartment A

c. Recombiner compartment B

d. Hydrogen analyzer 1A, Hydrogen analyzer 2A

e. Hydrogen analyzer 1B, Hydrogen analyzer 2B

f. Hydrogen analyzer 1C, Hydrogen analyzer 2C

g. Equipment drain sump

The hand selector switch is normally set for the main exhaust duct.

7.7.1.9.4.6 RRHAC-RMS Testability

Test signals are fed into the monitor via the control module in the auxiliary equipment room. A check source is provided for secondary calibration. Purge controls are also provided.

7.7.1.9.4.7 RRHAC-RMS Environmental Considerations

The monitoring rack is designed to meet the environmental conditions in the control structure. The control module and recorder are in the environment of the auxiliary equipment room and control room. See Section 3.11 for the environmental conditions of the equipment locations.

7.7.1.9.4.8 RRHAC-RMS Operational Considerations

7.7.1.9.4.8.1 RRHAC-RMS General

Annunciator outputs of alarms from this monitoring system are provided in the control room. Fixed filters for particulates and iodines provide for continuous accumulation of radioactive materials that can be analyzed in the counting room. However, very few, if any, particulates or iodines are expected in this application.

7.7.1.9.4.8.2 RRHAC-RMS Reactor Operator Information

Inputs to the control room provide the operator with an indication of any evidence of leakage from the sources tabulated above. When such evidence is perceived, remedial action can be taken.

7.7.1.9.5 Steam Exhauster Discharge and Vacuum Pump Exhaust Radiation Monitoring System

7.7.1.9.5.1 SEDVP-RMS Identification

The SEDVP-RMS is an off-line radiation monitoring system that detects the presence of short half-life radioactive isotopes (mostly N-16) leaking from the steam seals of the turbine. The purpose of this system is to indicate the existence of such leakage. The monitor also provides the capability to sample the mechanical vacuum pump exhaust when this equipment is operated.

7.7.1.9.5.2 SEDVP-RMS Classification

The SEDVP-RMS is a power generation system and is not related to safety.

7.7.1.9.5.3 SEDVP-RMS Reference Design

Table 7.1-2 lists reference design information. The SEDVP-RMS is designed to alarm in response to significant evidence of radioactive isotopes escaping from the steam seals of the turbine or the mechanical vacuum pump exhaust.

7.7.1.9.5.4 SEDVP-RMS Power Source

Power is supplied to the monitors by the 120 V ac uninterruptible bus A. The pumps and solenoid valves are supplied from the 120 V ac local power. The recorder and purge controls and supplied from the 120 V ac instrument bus.

7.7.1.9.5.5 SEDVP-RMS Equipment Design

7.7.1.9.5.5.1 SEDVP-RMS General

The SEDVP-RMS is a standard off-line process radiation monitoring system. It draws a combined gas sample from the exhaust line leading from the steam packing exhaust condenser and mechanical vacuum pump exhaust, passes the sample through a chamber containing a radiation detector, and then returns the sample to the exhaust line. The source of detected radioactivity can be identified by manually isolating one of the sample lines.

7.7.1.9.5.5.2 SEDVP-RMS Circuit Description

The SEDVP-RMS is provided with a gamma-sensitive detector and converter that transmits its signal to a rate meter in the auxiliary equipment room. This rate meter indicates radioactivity in the gas sample and transmits a signal to a recorder in the control room. No control trip capabilities are provided.

7.7.1.9.5.5.3 SEDVP-RMS Testability

Test signals are fed into the monitor via the control module in the auxiliary equipment room. A check source is provided for secondary calibration. Purge controls are also provided.

7.7.1.9.5.5.4 SEDVP-RMS Environmental Considerations

The monitoring rack is designed to meet the environmental conditions in the turbine enclosure. The control module and recorder are in the environmental conditions of the auxiliary equipment room and control room. See Section 3.11 for the environmental conditions of the equipment locations.

7.7.1.9.5.5.5 SEDVP-RMS Operational Considerations

7.7.1.9.5.5.5.1 SEDVP-RMS General

Fixed filters for particulates and iodines continuously accumulate radioactive solids that can then be analyzed in the counting room. However, very few, if any, particulates or iodines are expected

in this application. A cooler and moisture separator are provided in the sample line to prevent damage to the detector as a result of excessive sample temperature.

7.7.1.9.5.5.5.2 SEDVP-RMS Reactor Operator Information

A recorder provides the operator with an indication of defectiveness of the turbine steam seals or excessive radiation in the vacuum pump exhaust.

7.7.1.9.6 Radwaste Enclosure and Chem. Lab. Expansion Ventilation Exhaust Radiation Monitoring System

7.7.1.9.6.1 REV-RMS Identification

The REV-RMS is an off-line instrument system that measures the concentration of gross radioactive effluents in the ventilation exhaust duct leading from the radwaste enclosure and chem. lab. expansion to the north stack. The purpose of the system is to provide ongoing records and alarm capability for gaseous radioactivity in effluents released to the north stack from the radwaste enclosure.

7.7.1.9.6.2 REV-RMS Classification

The REV-RMS is a power generation system and is not related to safety.

7.7.1.9.6.3 REV-RMS Reference Design

Table 7.1-2 lists reference design information. The REV-RMS is designed to alarm in response to excessive concentrations of gross radioactivity in the ventilation exhaust from the radwaste enclosure.

7.7.1.9.6.4 REV-RMS Power Sources

Power is supplied to the monitors by the 120 V ac uninterruptible bus A. The pumps and solenoid valves are supplied from the 120 V ac local power. The recorder and purge controls are supplied from the 120 V ac instrument bus.

7.7.1.9.6.5 REV-RMS Equipment Design

7.7.1.9.6.5.1 REV-RMS General

The REV-RMS is a standard off-line process radiation monitoring system. It draws an air sample from a ventilation duct, passes the sample through a chamber containing a radiation detector, and then returns the sample to the duct.

7.7.1.9.6.5.2 REV-RMS Circuit Description

The REV-RMS is provided with a gamma-sensitive detector and converter that transmits its signal to a rate meter in the auxiliary equipment room. This rate meter indicates radioactivity in the air sample and transmits both a signal to a recorder in the control room and upscale/downscale alarm signals to an annunciator in the control room. No control trip capabilities are provided. A flow indicator trips an annunciator if the sampling pump malfunctions.

7.7.1.9.6.6 REV-RMS Testability

Test signals are fed into the monitor via the control module in the auxiliary equipment room. A check source is provided for secondary calibration. Purge controls are also provided.

7.7.1.9.6.7 REV-RMS Environmental Considerations

The monitoring rack is designed to meet the environmental conditions in the control structure. The control module and recorder are in the environment of the auxiliary equipment room and control room. See Section 3.11 for the environmental conditions of the equipment locations.

7.7.1.9.6.8 REV-RMS Operational Considerations

7.7.1.9.6.8.1 REV-RMS General

Annunciator outputs of the REV-RMS alarm signals are provided in the control room. Fixed filters for particulates and iodines continuously accumulate radioactive solids that can be analyzed in the counting room. However, an insignificant quantity of particulates and iodines is expected.

7.7.1.9.6.8.2 REV-RMS Reactor Operator Information

Inputs to the control room provide the operator with evidence of the escape of airborne radioactive material from the radwaste enclosure. This can be used as a basis for diagnostic investigation.

7.7.1.9.7 Air Ejector Offgas Effluent Radiation Monitoring System

7.7.1.9.7.1 AEO-RMS Identification

The AEO-RMS measures the concentration of gross radioactivity in effluents from the steam jet air ejector downstream of the recombiner.

7.7.1.9.7.2 AEO-RMS Classification

This monitoring system is a power generation system and is not related to safety.

7.7.1.9.7.3 AEO-RMS Reference Design

Table 7.1-2 lists reference design information. This system serves the following functions:

a. It provides an ongoing record and indication of concentrations of radioactivity in air ejector offgas.

b. It provides the capability to detect fuel element contamination in the air ejector offgas.

c. It provides alarm annunciation capability.

d. It provides a grab sampling capability for detailed analysis in the counting room.

7.7.1.9.7.4 AEO-RMS Power Sources

Power is supplied to the two log monitors by the 120 V ac uninterruptible buses A and B. The linear monitor is supplied from a 20 V dc bus which is supplied from the 120 V ac uninterruptible Bus A. The pump and solenoid valves for grab sampling are supplied from 120 V ac local power. The recorder and purge controls are supplied from the 120 V ac instrument bus.

7.7.1.9.7.5 AEO-RMS Equipment Design

7.7.1.9.7.5.1 AEO-RMS General

This monitoring system is designed to provide indication and alarm if there are excessive discharges of radioactivity and to detect fuel element contamination in the air ejector effluents. It also provides grab sampling equipment for diagnostic purposes.

7.7.1.9.7.5.2 AEO-RMS Circuit Description

Two ionization chamber-type detectors with sensitivity ranges 1 mR/hr to 10^6 mR/hr are used to detect gross radioactive concentration in the air ejector effluents. In addition, a linear response channel is provided as an expanded scale device to aid in detecting fuel element contamination. The three channels provide outputs to recorders in the control room. A flow indicating switch provides annunciation if there is a high or low flow condition. By means of a local hand-selector switch, sampling pump controls, and solenoid valves controls, grab samples can be taken. The three rate meters are located in the auxiliary equipment room. Outputs from the log rate meters are fed to annunciators in the control room. Monitor purge controls are located in the control room.

7.7.1.9.7.6 AEO-RMS Testability

A built-in source of adjustable current is provided to simulate sensor input to each radiation monitor for test purposes.

7.7.1.9.7.7 AEO-RMS Environmental Considerations

The monitoring rack is designed to meet the environmental conditions in the control structure. The control module and recorders are in the environment of the auxiliary equipment and control rooms. See Section 3.11 for the environmental conditions of the equipment locations.

7.7.1.9.7.8 AEO-RMS Operational Considerations

7.7.1.9.7.8.1 AEO-RMS General

Annunciator outputs and control trip outputs are provided by this monitoring system. Controls are both local and located in the auxiliary equipment room or control room. Gross radioactivity readings can be further diagnosed using grab samples.

7.7.1.9.7.8.2 AEO-RMS Reactor Operator Information

Inputs to the control room apprise the operator of concentrations of radioactivity in the air ejector effluents, including indications of fuel element deterioration. Diagnostic capability is available.

7.7.1.9.8 Primary Containment Leak Detector Radiation Monitor

7.7.1.9.8.1 PCLD-RMS Identification

The objective of the PCLD-RMS is to indicate and record radiation levels of the primary containment atmosphere. The instrument provides alarm capability in response to a rapid increase in this radiation level. Alarm setpoints are discussed in Section 5.2.5.2.1.5.3.

7.7.1.9.8.2 PCLD-RMS Classification

The PCLD-RMS is a power generation system and is not related to safety.

7.7.1.9.8.3 PCLD-RMS Reference Design

Table 7.1-2 lists reference design information. The PCLD-RMS does not have a safety function.

7.7.1.9.8.4 PCLD-RMS Power Sources

Power is supplied to the monitor and recorder by a 120 V ac uninterruptible bus A. The pumps and solenoid valves are supplied from the 120 V ac local power. The purge control circuit is supplied from the 120 V ac instrument bus.

7.7.1.9.8.5 PCLD-RMS Equipment Design

7.7.1.9.8.5.1 PCLD-RMS General

A gas sample is drawn from the primary containment and is passed through the PCLD-RMS to measure the concentration of noble gases. Alarm capability is provided. Outputs are transmitted to a control module in the auxiliary equipment room, and to a recorder in the control room.

7.7.1.9.8.5.2 PCLD-RMS Circuit Description

The monitor channel has an upscale trip that indicates a rate of increase of radioactivity in the primary containment. A downscale trip is also provided to indicate instrument trouble. These trips annunciate, but provide no control action. The trip circuits are set so that loss of power causes an alarm. The five decade range is selected to cover both normal and maximum radiation levels (short of an accident resulting in shutdown) in the primary containment. If an accident occurs, the PCLD-RMS will be isolated, and its functions will cease.

The PCLD-RMS monitoring rack is adjacent to the primary containment. Outputs of this instrument are transmitted to the auxiliary equipment room and the control room. Remote controls purge the noble gas chamber, reset the alarm setpoints, and check the calibrations.

7.7.1.9.8.5.3 PCLD-RMS Testability

Test signals are fed into the monitor via the control module in the auxiliary equipment room. Check sources are provided for secondary calibration of each channel.

7.7.1.9.8.6 PCLD-RMS Environmental Considerations

The monitoring rack is designed to be suitable for the environmental conditions adjacent to the primary containment. Control modules and recorders are subjected to the environment of the

auxiliary equipment room and control room. See Section 3.11 for the environmental conditions of the equipment locations.

7.7.1.9.9 Hot Maintenance Shop Ventilation Exhaust Radiation Monitoring System

7.7.1.9.9.1 HMS-RMS Identification

The objective of the HMS-RMS is to indicate and record the quantity of radioactive material that escapes from the hot maintenance shop ventilation exhaust duct. Filters are provided in this duct, and sample air is drawn from a station downstream of the filters. Consequently, the quantity of radioactive material in the sample is normally negligible.

7.7.1.9.9.2 HMS-RMS Classification

This system is a power generation system and is not related to safety.

7.7.1.9.9.3 HMS-RMS Reference Design

Table 7.1-2 lists reference design information.

7.7.1.9.9.4 HMS-RMS Power Sources

The power source of the HMS-RMS is the 120 V ac lighting power.

7.7.1.9.9.5 HMS-RMS Equipment Design

7.7.1.9.9.5.1 HMS-RMS General

The system consists of two channels: one for monitoring particulate effluents, and the other for monitoring iodine effluents. Radioactive material in the gas sample is accumulated on filters where it is sensed by scintillator-type detectors. Output signals are transmitted to a microprocessor and then retransmitted to the RMMS (Section 11.5.6) for the purpose of insertion into Regulatory Guide 1.21 reports.

7.7.1.9.9.5.2 HMS-RMS Circuit Description

Each channel has two upscale trips that indicate high and high-high radiation and a downscale trip that indicates instrument trouble. These trips sound local alarms, but cause no control action. There are three trip indicating lights per channel on the control module. The range of each channel is six decades and is selected to cover both normal and possible maximum levels at the monitoring location. The system is self-contained, and all outputs are indicated on the local control module and RMMS.

7.7.1.9.9.5.3 HMS-RMS Testability

Check sources are provided to verify operability of each channel.

7.7.1.9.9.5.4 HMS-RMS Environmental Considerations

The system is designed to function within the environmental range of hot shop conditions.

7.7.1.9.10 Liquid Radwaste Discharge Radiation Monitoring System

7.7.1.9.10.1 LRD-RMS Identification

The LRD-RMS is an off-line process radiation monitoring system that measures the concentration of radioactive material in the liquid radwaste discharge to the cooling tower blowdown line. This liquid radwaste discharge includes discharges from the laundry drain, chemical wastes, floor drains, and oily waste treatment water sump. If unacceptable radioactive concentrations are detected in these discharges, valves in the discharge line automatically close, isolating the radwaste discharge system for the cooling tower blowdown line.

7.7.1.9.10.2 LRD-RMS Classification

The LRD-RMS is a power generation system and is not related to safety. However, control trip capability is provided to prevent the release of radioactive contamination to the environment.

7.7.1.9.10.3 LRD-RMS Reference Design

Table 7.1-2 lists reference design information. The LRD-RMS is designed to trip the isolation valves in the radwaste discharge line and to annunciate an alarm in the control room if there is an unacceptable concentration of radioactivity in the radwaste discharge. Data are also transmitted to a recorder in the radwaste control room.

7.7.1.9.10.4 LRD-RMS Power Sources

Power is supplied to the LRD-RMS from the 120 V ac uninterruptible bus A. Recorder power is supplied by the instrument bus in the radwaste control room. Power to the sample pump is supplied from the 120 V ac local bus.

7.7.1.9.10.5 LRD-RMS Equipment Design

7.7.1.9.10.5.1 LRD-RMS General

The LRD-RMS is a standard off-line process radiation monitoring system for liquids. It draws a sample from the radwaste discharge pipe, passes the sample through a chamber containing a radiation detector, and then returns the sample to the pipe.

7.7.1.9.10.5.2 LRD-RMS Circuit Description

The LRD-RMS has a gamma-sensitive detector and converter that transmits its signal to a rate meter located in the auxiliary equipment room. This rate meter indicates the concentration of radioactivity in the liquid sample and transmits a signal to a recorder in the radwaste control room and an upscale/downscale trip signal to the annunciator in the main control room. The upscale trip signal also actuates the trip relays to the radwaste discharge valves. A flow indicator switch trips an annunciator if the sample pump malfunctions.

7.7.1.9.10.6 LRD-RMS Testability

Test signals are fed into the monitor via the control module in the auxiliary equipment room. A check source is provided for secondary calibration.

7.7.1.9.10.7 LRD-RMS Environmental Considerations

Off-line monitoring was selected for this application in preference to in-line monitoring because of the problems involved in removing crud buildup and in decontamination. The monitoring rack is designed to meet the environmental conditions in the radwaste enclosure. The control module is in the environment of the auxiliary equipment room, and the recorder is in the environment of the radwaste control room. See Section 3.11 for the environmental conditions of the equipment locations.

7.7.1.9.10.8 LRD-RMS Operational Considerations

7.7.1.9.10.8.1 LRD-RMS General

Control trip signals close the radwaste discharge valves and alarm in the control room. Operation of the system is automatic, requiring minimum attention.

7.7.1.9.10.8.2 LRD-RMS Reactor Operator Information

Inputs to the radwaste control room and main control room provide the operators with an indication of excessive release of radioactive material via the radwaste liquids. Such releases are terminated automatically, after which remedial action can be taken.

7.7.1.9.11 Service Water Radiation Monitoring System

7.7.1.9.11.1 SW-RMS Identification

The SW-RMS is an off-line process radiation monitoring system that measures the concentration of radioactive material in the plant service water. The SW-RMS draws a sample from the main discharge pipe to the cooling tower. Plant service water is used to cool such normally nonradioactive areas as air compressors, turbine auxiliary systems, and pump bearings. It also cools the containment enclosure closed cooling water system through a heat exchanger. An increase in the radiation level of the service water stream may indicate a leak into the system from a contaminated stream.

7.7.1.9.11.2 SW-RMS Classification

The SW-RMS is a power generation system and is not related to safety.

7.7.1.9.11.3 SW-RMS Reference Design

Table 7.1-2 lists reference design information. The SW-RMS is designed to provide an alarm annunciation in the control room when a significant concentration of radioactive contamination is detected in the service water. Data are also transmitted to a control room recorder.

7.7.1.9.11.4 SW-RMS Power Sources

Power is supplied to the SW-RMS from the 120 V ac uninterruptible bus B. Power is supplied to the recorder from the 120 V ac instrument bus. The sample pump is powered by the 120 V ac local bus.

7.7.1.9.11.5 SW-RMS Equipment Design

7.7.1.9.11.5.1 SW-RMS General

The SW-RMS is a standard off-line process radiation monitoring system for liquids. It draws a sample from the service water discharge pipe, passes the sample through a shielded chamber containing a radiation detector, and then returns the sample to the pipe.

7.7.1.9.11.5.2 SW-RMS Circuit Description

The SW-RMS has a gamma-sensitive detector and converter that transmits a signal to a rate meter in the auxiliary equipment room. This rate meter indicates the concentration of radioactivity in the water sample and transmits upscale/downscale signals to the control room annunciator. It also transmits data to the control room recorder. A flow indicator switch trips an annunciator if the sample pump malfunctions.

7.7.1.9.11.6 SW-RMS Testability

Test signals are fed into the monitor via the control module in the auxiliary equipment room. A check source is provided for secondary calibration.

7.7.1.9.11.7 SW-RMS Environmental Considerations

The monitoring rack is designed to meet the environmental conditions of the turbine enclosure. The control module is in the environment of the auxiliary equipment room, and the recorder is in the environment of the control room. See Section 3.11 for the environmental conditions of the equipment locations.

7.7.1.9.11.8 SW-RMS Operational Considerations

7.7.1.9.11.8.1 SW-RMS General

Upscale/downscale trip signals actuate the annunciator in the control room. The monitoring system does not have a control trip function. Radiation data are continuously recorded in the control room.

7.7.1.9.11.8.2 SW-RMS Reactor Operator Information

The SW-RMS provides the operator with information on the concentration of radioactivity in the service water leaving the plant. If this concentration is unacceptable, remedial action can be taken.

7.7.1.9.12 Reactor Enclosure Cooling Water Radiation Monitoring System

7.7.1.9.12.1 RECW-RMS Identification

The RECW-RMS is an off-line process radiation monitoring system that measures the concentration of radioactive material in the RECW system. The RECW-RMS draws a sample from the pipe downstream of the cleanup nonregenerative heat exchangers, the reactor recirculation pump seal, and motor oil coolers. This cooling system constitutes a closed circuit and, consequently, no radioactive material in this circuit could be discharged to the environment. The reactor enclosure closed cooling water system cools potentially contaminated areas such as the nonregenerative heat exchanger, recirculation pumps, and various sample coolers. Radioactivity detected in this system indicates leakage in one or more of the heat exchangers.

7.7.1.9.12.2 RECW-RMS Classification

The RECW-RMS is a power generation system and is not related to safety.

7.7.1.9.12.3 RECW-RMS Reference Design

Table 7.1-2 lists reference design information. The RECW-RMS is designed to provide an alarm annunciation in the control room when a significant concentration of radioactive contamination is detected in the cooling water. Data are also transmitted to a recorder in the control room.

7.7.1.9.12.4 RECW-RMS Power Sources

Power is supplied to the RECW-RMS from the 120 V ac uninterruptible bus B. Power is supplied to the recorder from the 120 V ac instrument bus. The sample pump is powered by the 120 V ac local bus.

7.7.1.9.12.5 RECW-RMS Equipment Design

7.7.1.9.12.5.1 RECW-RMS General

The RECW-RMS is a standard off-line process radiation monitoring system for liquids. It draws a sample from the cooling system pipe, passes the sample through a shielded chamber containing a radiation detector, and then returns the sample to the pipe.

7.7.1.9.12.5.2 RECW-RMS Circuit Description

The RECW-RMS has a gamma-sensitive detector and converter that transmits a signal to a rate meter in the auxiliary equipment room. This rate meter indicates radioactivity in the water sample and transmits signals to the recorder and annunciator in the control room. A flow indicator switch trips an annunciator if the sample pump malfunctions.

7.7.1.9.12.6 RECW-RMS Testability

Test signals are fed into the monitor via the control module in the auxiliary equipment room. A check source is provided for secondary calibration.

7.7.1.9.12.7 RECW-RMS Environmental Considerations

The monitoring rack is designed to meet the environmental conditions of the reactor enclosure. The control module is in the environment of the auxiliary equipment room, and the recorder is in

the environment of the control room. See Section 3.11 for the environmental conditions of the equipment locations.

7.7.1.9.12.8 RECW-RMS Operational Considerations

7.7.1.9.12.8.1 RECW-RMS General

Upscale/downscale trip signals actuate the annunciator in the control room. The monitoring system provides no control trip function. Radiation data are continuously recorded in the control room.

7.7.1.9.12.8.2 RECW-RMS Reactor Operator Information

The RECW-RMS provides a backup for the service water radiation monitor. The RECW-RMS detects radiation only if radiation is present in the service water and if leaks occur between the service water system and the RECW system.

7.7.1.10 Area Radiation Monitoring System - Instrumentation and Controls

7.7.1.10.1 ARMS Identification

7.7.1.10.1.1 ARMS General

The ARMS indicates and records gamma radiation levels in areas where radioactive material is present, stored, handled, or inadvertently introduced.

7.7.1.10.1.2 ARMS Classification

This is a power generation system and is classified as not related to safety.

7.7.1.10.1.3 ARMS Reference Design

Table 7.1-2 lists reference design information. The ARMS instrumentation and control system is an operational monitoring system and has no safety function.

7.7.1.10.2 ARMS Power Sources

The power source for the ARMS is the 120 V ac instrument bus.

7.7.1.10.3 ARMS Equipment Design

7.7.1.10.3.1 ARMS General

The ARMS is described in Section 12.3.4. Each channel consists of a combined sensor and converter unit; a combined indicator and trip unit; a shared power supply; and a shared multipoint recorder. Each channel also has a local audio alarm auxiliary unit.

7.7.1.10.3.2 ARMS Circuit Description

Each monitor has an upscale trip that indicates high radiation, and a downscale unit that can indicate instrument trouble. These trips sound alarms but cause no control action. The trip circuits are set so that loss of power causes an alarm. There are two trip indicating lights in the front face of an indicator and trip unit. The range of the channel is six decades and is selected to cover both normal and possible maximum radiation levels at the monitoring location.

The monitors are located (Table 12.3-7) at various places in the containment, auxiliary/reactor enclosure, radwaste facility, turbine enclosure, control room, and other areas where radiation monitoring is desired, based on the following objectives:

a. To monitor the radioactivity level in areas where personnel may be required to work.

b. To provide a record of the radioactivity as a function of time at key locations throughout the plant.

Ranges and sensitivities are selected for each location based on the anticipated radioactivity level as provided by experimental measurements of levels in similar plants and shielding calculations. Local alarming and indication is provided at those remote sensor locations where a substantial increase in radiation levels might be immediately important to personnel in the area. This system does not have any bypass or interlock interfaces, however each channel can be bypassed.

7.7.1.10.3.3 ARMS Testability

An internal trip test circuit, adjustable over the full range of the trip circuit, is provided. The test signal is fed into the indicator and trip unit input so that a meter reading is provided in addition to a real trip. All trip circuits are of the latching-type and must be manually reset at the front panel.

A facility for calibrating these monitor units is provided. This is a test unit designed for use in the adjustment procedure for the area radiation monitor sensor and converter unit. It provides several gamma radiation levels between approximately 4 mR/hr to 300 MR/hr. The calibration unit source is an approved source.

A cavity in the calibration unit receives the sensor and converter unit. A window through which radiation from the source emanates is located on the back wall of the cylindrical lower half of the cavity. A chart on each unit indicates the radiation levels available from the unit for the various control settings.

7.7.1.10.4 ARMS Environmental Considerations

The sensor, converter, and local audio alarm auxiliary unit are designed to operate under the environmental conditions at the monitoring locations. The indicator/trip unit and the power supply are designed to operate under auxiliary equipment room environmental conditions and power source fluctuations to guarantee successful operation of the system. See Section 3.11 for the equipment location environmental conditions.

7.7.1.10.5 ARMS Operational Considerations

7.7.1.10.5.1 ARMS General Information

An annunciator window is provided for each operational area, such as the turbine building area or the auxiliary/reactor enclosure area, although there are a number of ARMS channels in the area, and any one of them can trip the annunciator.

7.7.1.10.5.2 ARMS Reactor Operator Information

An operator is able to identify the channel that causes the annunciation by checking the indicating lights of the indicator/trip units.

7.7.1.11 Gaseous Radwaste System - Instrumentation and Controls

7.7.1.11.1 GRS Identification

7.7.1.11.1.1 GRS General

The objective of the GRS is to process and control the release of gaseous radioactive wastes to the site environs so that the total radiation exposure to persons outside the controlled area is as-low-as-practicable and does not exceed applicable regulations.

7.7.1.11.1.2 GRS Classification

This system is required for power generation only and is classified as not related to safety.

7.7.1.11.1.3 GRS Reference Design

Table 7.1-2 lists reference design information. The subject instrumentation and control system is an operational system and has no safety function. Therefore, there are no safety design differences between this system and those of the reference design facilities. This system is functionally identical to the referenced system.

See drawings M-69 and M-70 for the system P&IDs.

7.7.1.11.1.4 GRS Power Source

The 120 V ac instrument bus provides power for the GRS instrumentation.

7.7.1.11.2 GRS Equipment Design

7.7.1.11.2.1 GRS General

This system is monitored by flow, temperature, pressure, conductivity, and hydrogen analyzers to ensure correct operation and control. Drawings M-69 and M-70 show the process parameters that are instrumented to alarm in the control room. They also indicate whether the parameters are recorded or just indicated. The reactor operator is in control of the system at all times.

The air ejector holdup pipe discharge radiation monitor continuously monitors radioactive effluents to the offgas charcoal treatment system. This monitor provides an alarm in response to high radiation in the offgas. A radiation monitor downstream of the charcoal offgas treatment system continuously monitors radioactive effluents from the charcoal beds. Thus, the radioactivity of the gas entering and leaving the charcoal offgas treatment system is continuously monitored, so that

the performance of this system is known to the operator at all times. Provisions are also made for the periodic extraction and analysis of grab samples of the influent and effluent gases for determining their compositions.

7.7.1.11.2.2 GRS Recombiner Instrumentation

Recombiner vessel temperatures are monitored by inlet and outlet thermocouples. Inlet process gas is monitored for temperature and annunciated in the main control room if its temperatures are high or low. Outlet gas temperature is measured and high temperature is annunciated in the main control room. In addition, gas outlet hydrogen concentration is recorded and alarmed (high) in the control room (drawing M-69). Recombiner inlet hydrogen can also be measured if required.

7.7.1.11.2.3 GRS Offgas Aftercondenser Condensate High and Low Level

The offgas aftercondenser condensate high and low levels are annunciated in the main control room. The level switches also control the aftercondenser drain valve. A control board mounted level controller provides remote/manual control of this valve.

7.7.1.11.2.4 GRS Offgas System Inlet Gas Measurements

The gas inlet to the offgas components is monitored for temperature, pressure, and moisture content on local panels and in the control room. These parameters are annunciated to alert the operator that corrective action is required.

7.7.1.11.2.5 GRS Hydrogen and Oxygen Analyzer Measurement System

Two oxygen analyzers are used to measure the oxygen content of the offgas process stream at the discharge of the aftercondenser. The system is designed to ensure that there is sufficient oxygen available to combine with the hydrogen and yet ensure that the oxygen level does not get too high so as to impose an increased fire hazard for the offgas charcoal beds. Oxygen concentration % output from the analyzer is displayed in the control room.

Three parallel independent hydrogen analyzers are used to measure the hydrogen content of the offgas process steam downstream of the offgas aftercondenser. One analyzer can be selected to measure hydrogen level upstream of the recombiner. The hydrogen concentration percentage output from the analyzers is recorded in the control room along with independent alarm annunciation for a high hydrogen concentration. Each hydrogen analyzer continuously withdraws a sample of the process offgas, analyzes the hydrogen content, and returns the sample gas to the main condenser. During normal plant operation, the main condenser vacuum provides the pumping force to withdraw the sample gas from the hydrogen analyzer system. Hydrogen percentage calibration checks are made by closing off the line to the offgas process line and admitting a hydrogen calibration gas or a hydrogen free gas; this test is periodically performed. The specified analyzer element is a thermal conductivity cell type of unit, and is designed to prevent hydrogen ignition. An auxiliary vacuum pump is provided to withdraw sample gases in the absence of sufficient main condenser vacuum.

7.7.1.11.2.6 Moisture Measurement

One independent moisture detector is placed upstream of the charcoal beds. The moisture content is indicated on a local panel and in the control room, and a high or above moisture content point alarms and annunciates on a local panel and in the control room to notify the operator of the possibility that corrective action may have to be taken.

7.7.1.11.2.7 GRS Charcoal Vessel Temperature Monitoring

The temperature of each charcoal vessel is monitored and indicated on a local panel and recorded in the control room. This parameter is also annunciated at both locations.

7.7.1.11.2.8 GRS Differential Pressure Measurements

Differential pressure is measured across the filter located downstream of the charcoal beds. High differential pressure is alarmed on a local panel and in the control room, and local differential pressure indication is provided.

7.7.1.11.2.9 GRS Testability

Because this is a process on-line monitoring, the cross-correlation of the data provides sufficient confirmation of the system's correct operation.

7.7.1.11.3 GRS Environmental Considerations

7.7.1.11.3.1 GRS General

The GRS is not required for safety purposes or required to operate after the DBA. The control system is required to operate in the normal plant environment for power generation purposes only. Radwaste controls and instrumentation located in the offgas equipment area are subject to the environmental and design conditions listed in Section 3.11.

7.7.1.11.3.2 GRS Local Instrument Panels

The local instrument panels are located in the operating area outside of the process stream's shield wall. The environmental conditions are the same as described above (Section 3.11).

7.7.1.11.3.3 GRS Special Considerations

The instrument sensing lines are rated for 2500 psig. This is sufficient to resist a hydrogen detonation in the process line, or in the tubing.

7.7.1.11.4 GRS Operational Considerations

7.7.1.11.4.1 GRS General Information

No operator action is required on the equipment described unless an alarmed condition occurs.

7.7.1.11.4.2 GRS Reactor Operator Information

Operator indicators and alarms are shown in drawing M-69.

7.7.1.11.5 GRS Setpoints

A hydrogen level of 2% alarms and annunciates in the control room .

7.7.1.12 Liquid Radwaste System - Instrumentation and Controls

7.7.1.12.1 LRS Identification

7.7.1.12.1.1 LRS Function

The objective of the LRS is to control the release of liquid and solid radioactive waste material to the environs.

7.7.1.12.1.2 LRS Classification

This system is required for power generation only and is classified as not related to safety.

7.7.1.12.1.3 LRS Reference Design

Table 7.1-2 lists reference design information.

7.7.1.12.2 LRS Power Sources

a. Normal: The 120 V ac instrument power is used for the liquid radwaste process control system.

b. Alternates: Because this is not an essential or safety system, no alternative power source is required.

7.7.1.12.3 LRS Equipment Design

The LRS is designed to process liquid waste water to remove particulates, impurities, and other materials and return the processed water for plant use.

Only those portions of the liquid radwaste system providing information that requires operator attention are described to show operator ability to take corrective action when needed.

7.7.1.12.3.1 LRS Equipment Operation

Waste water is collected in various sumps throughout the plant and is pumped into the radwaste collection tanks where it is processed. Excess processed liquids that are discharged from the plant are radiation-monitored, flow-controlled, and recorded.

The instrumentation and control system of the radwaste process is typical of a standard chemical and water treatment process. Tank levels are indicated and recorded in the radwaste control room and high tank levels are annunciated in the radwaste and main control room (drawings M-61, M-62, M-63 and M-64).

7.7.1.12.3.1.1 LRS Drywell Sumps Control

The drywell sumps discharge to the liquid radwaste system collection tanks (drawing M-61) by gravity. Flow integrators are provided in each sump discharge line to monitor flow out of the drywell sumps. The liquid discharge line from each drywell sump is provided with two drain valves for containment isolation and for sump level control during normal operation. When either isolation valve is closed, the liquid discharge from the drywell sump is stopped. Section 5.2.5.2.1.3.c gives a description of the operation of the sump discharge valves in conjunction with the drywell sump level monitoring system.

7.7.1.12.3.1.2 LRS Reactor and Turbine Enclosure Sumps

These sumps collect waste water from their respective areas and automatically pump out the sumps on level control. Alarm and annunciation in the radwaste and main control rooms occurs on a high-high and low sump level to allow the operator to take corrective action. Run-time meters with indicating lights are also provided to indicate the elapsed run-time of both sump pumps.

The discharge line from the floor drain sample tank to the cooling tower blowdown line isolates upon high radiation detection and alerts the operator. The discharge flow shutoff valves are operated by a key-lock switch that requires plant supervisory control of any releases.

7.7.1.12.3.1.3 LRS Tank Level and Process Control

All tanks containing waste liquids throughout the radwaste liquid processing system are provided with liquid level indicators, recorders, and alarm and annunciation in the radwaste and main control rooms to inform the operator that corrective action is to be taken for high or low liquid levels. The process is controlled by an operator from the radwaste control room panel. The control system is designed for manual startup and automatic stop when a process is completed (i.e., tank liquid contents have been emptied to the next process). Because this is a batch system, the operator has full control and responsibility for the system control process.

7.7.1.12.4 LRS Environmental Considerations

The radwaste control systems are not required for safety purposes or required to operate after the DBA. The radwaste control systems are required to operate in the normal plant environment for power generation purposes only. The environmental conditions are listed in Section 3.11.

7.7.1.12.5 LRS Operational Considerations

7.7.1.12.5.1 LRS General Information

The operator is in full control of the process system batches.

7.7.1.12.5.2 LRS Reactor Operator Information

Indicators and recorders are provided for all liquid tanks to inform the operator of the status of the system. Alarms and annunciation are provided to inform the operator that a tank must be emptied or processed, or that a particular piece of equipment malfunctioned, and corrective action must be taken.

7.7.1.12.5.3 LRS Setpoints

All tank levels are set to alarm and annunciate before reaching overflow level. This is sufficient time for the operator to take corrective action in the process control.

7.7.1.13 Solid Radwaste System - Instrumentation and Controls

7.7.1.13.1 SRS Identification

The SRS packages and solidifies radioactive wastes. The system contains the instruments and controls necessary to operate the principal process system. It is a power generation system and is classified as not related to safety. Table 7.1-2 lists reference design information.

7.7.1.13.2 SRS Power Sources

The power for the solids radwaste handling system is from an ac power source.

7.7.1.13.3 SRS Equipment Design

The process instrumentation and controls provided are as shown in drawings M-66 and M-67. The instrumentation and control equipment controls the operation of the system that is discussed in Section 11.4.

7.7.1.13.4 SRS Environmental Considerations

Controls and instrumentation for the solids radwaste handling system are designed to operate during those environmental conditions listed in Section 3.11.

7.7.1.13.5 SRS Operational Considerations

The SRS provides a means of monitoring parameters of the system and permits operator intervention if required.

7.7.1.14 Fuel Pool Cooling and Cleanup System – Instrumentation and Controls

7.7.1.14.1 FPCC Identification

7.7.1.14.1.1 FPCC General

The objective of the FPCC is to remove decay heat from the spent fuel storage pool water to ensure adequate cooling of irradiated stored assemblies. The fuel pool cooling system also purifies the spent fuel storage pool water. It maintains water clarity for fuel handling operations and fills and drains the fuel transfer canal. The process instrumentation and controls are shown in drawing M-53.

7.7.1.14.1.2 FPCC Classification

This system is required for power generation only and is classified as not related to safety.

7.7.1.14.1.3 FPCC Reference Design

Table 7.1-2 lists reference design information.

7.7.1.14.2 FPCC Power Sources

The 120 V ac instrument bus provides power for the FPCC system instrumentation.

7.7.1.14.3 FPCC Equipment Design

The following process instrumentation is provided:

a. Fuel pool water level alarms in the control room

b. Skimmer surge tank water level alarms in the main control room

c. Fuel pool cooling pump suction and discharge low pressure alarms in the main control room

d. Fuel pool cooling heat exchangers inlet temperature recorder and alarms in the main control room

e. Fuel pool cooling heat exchangers outlet temperature recorder and alarms

7.7.1.14.4 FPCC Environmental Considerations

Controls and instrumentation for the FPCC system are designed to operate during those environmental conditions listed in Section 3.11.

7.7.1.14.5 FPCC Operational Considerations

7.7.1.14.5.1 FPCC General Information

No operator action is required unless an alarm condition occurs.

7.7.1.14.5.2 Reactor Operator Information

See Section 7.7.1.14.3.

7.7.1.15 Refueling Interlocks - Instrumentation and Controls

7.7.1.15.1 RI Identification

The purpose of the RI is to restrict the movement of the control rods and the operation of refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations.

This equipment is not required to operate during a seismic event. The operability of the equipment can be verified after a seismic event without jeopardizing safety.

7.7.1.15.2 RI Power Sources

There is only one source of power for both channels of the logic circuits. However, this power source supplies the CRD system as well. A failure of this power supply prevents any rod motion.

7.7.1.15.3 RI Equipment Design

7.7.1.15.3.1 RI Circuit Description

The refueling interlock circuitry senses the condition of the refueling equipment and the control rods. Depending on the sensed condition, interlocks are actuated to prevent the movement of the refueling equipment or withdrawal of control rods (rod block). Redundant circuitry is provided to sense the following conditions:

a. All rods inserted (Section 7.7.1.15.3.2)

b. Refueling platform positioned near or over the core

c. Refueling platform main hoist, fuel-loaded

d. Deleted

e. Reactor mode switch in REFUEL position

7.7.1.15.3.2 RI Logic and Sequencing

The indicated conditions are combined in logic circuits to satisfy all restrictions on refueling equipment operations and control rod movement (drawings C11-1030-F-008, C11-1030-F-009, C11-1030-F-010, C11-1030-F-011, C11-1030-F-012, C11-1030-F-013, and C11-1030-F-014). A two channel circuit indicates that all rods are in. The rod-in condition for each rod is established by the closure of a magnetically operated reed switch in the rod position indicator probe. The rod-in switch must be closed for each rod before the all-rods-in signal is generated. This is not the same switch that provides rod numerical position information to the plant monitoring system (PMS) and four rod position display. Both channels must register the all-rods-in signal before the refueling interlock circuitry can indicate the all-rods-in condition.

During refueling operations, no more than one control rod is permitted to be withdrawn from core cells loaded with any fuel assemblies. This is enforced by a redundant logic circuit that uses the all-rods-in signal and a rod selection signal to prevent the selection of a second rod for movement with any other rod not fully inserted. Control rod withdrawal is prevented by comparison checking between the A and B portions of the RMCS and subsequent message transmission to the affected control rod. The simultaneous selection of two control rods is prevented by the interconnection arrangement of the select push buttons. With the mode switch in the refuel position, the circuitry prevents the withdrawal of more than one control rod and the movement of the refueling platform with the main hoist fuel-loaded over the core with any control rod withdrawn from core cells with any fuel assemblies.

The operation of refueling equipment is prevented by interrupting the motion commands to the equipment. The refueling platform is provided with two mechanical switches attached to the platform, which are tripped open by a long, stationary ramp mounted adjacent to the platform rail. The switches open before the platform or any of its hoists are physically located over the reactor vessel to indicate that the platform is approaching its position over the core.

Load cell readout is provided for all hoists. Indicators display given hoist loads directly to the hoist operator. Load sensing is by electronic load cells. Associated interlock functions are performed by electronic switches that compare the setpoint values with the signal generated by the electronic load cells.

The main hoist on the refueling platform is provided with switches that open when the hoist is fuel-loaded. The switches open at a load weight that is lighter than that of a single fuel assembly. This indicates when fuel is loaded on any hoist.

7.7.1.15.3.3 RI Bypasses and Interlocks

The rod block interlocks and refueling platform travel interlocks provide two independent levels of interlock action. The interlocks that restrict operation of the platform hoist and grapple provide a

third level of interlock action because they would be required only after a failure of a rod block and refueling platform travel interlock. The strict procedural control exercised during refueling operations is a fourth level of backup, even though this is actually the primary means of control.

7.7.1.15.3.4 RI Redundancy and Diversity

Although the refueling interlocks are not designed or required to meet the IEEE 279 (1971) criteria for nuclear power plant protection systems, a single component failure does not cause an interlock failure. Refueling interlocks are provided for use during planned refueling operations. Criticality is prevented during fuel assembly insertion, provided that the control rod in the associated control cell is fully inserted. The interlock systems accomplish this by:

a. Preventing operation of fuel-loaded refueling equipment over the core whenever any control rod is withdrawn

b. Preventing control rod withdrawal whenever fuel-loaded refueling equipment is over the core

c. Preventing withdrawal of more than one control rod when the mode switch is in the REFUEL position

The refueling interlocks have been designed utilizing redundancy of sensors and circuitry to provide a high level of reliability and assurance that the design bases are met. Each of the individual refueling interlocks discussed above need not meet the single failure criteria because the four essentially independent levels (including procedural control) of protection ensure that the design basis is met. For any of the "situations" listed in Table 7.7-3, a single interlock failure does not cause an accident, result in potential physical damage to fuel, or result in abnormal radiation exposure to personnel during fuel handling operations.

7.7.1.15.3.5 RI Actuated Devices

The refueling interlocks from the RMCS to the refueling equipment trip logic in the refueling equipment controls that interrupts motion commands to the equipment. This prevents fuel-loaded hoist operation over the core.

The interlocks from the refueling equipment to the RMCS actuate circuitry that provides a control rod block. The rod block prevents the operator from withdrawing any control rods.

7.7.1.15.3.6 RI Separation

The refueling interlocks are not designed to, or required to meet, the IEEE 279 (1971) criteria for nuclear power plant protection systems. However, a single interlock failure does not cause an accident. The interlocks are used in conjunction with administrative controls during planned refueling operations. Criticality is prevented during fuel insertion, provided that the control rod in the associated control cell is fully inserted.

7.7.1.15.3.7 RI Testability

Complete functional testing of all refueling interlocks prior to use positively indicates that the interlocks operate in the situations for which they are designed. The interlocks can be subjected to valid operational tests by loading the hoist with a dummy fuel assembly, positioning the refueling

platform, and withdrawing the control rods. Where redundancy is provided in the logic circuitry, tests can be performed on a periodic basis to ensure that each redundant logic element can independently perform its function.

7.7.1.15.4 RI Environmental Considerations

Refueling equipment is subjected to the conditions listed in Section 3.11 during normal operation.

Refueling components are designed to withstand design basis events such as earthquakes, accidents, and anticipated operational occurrences without consequential damage, but they are not required to be functional during or after the event without repair.

7.7.1.15.5 RI Operational Considerations

7.7.1.15.5.1 RI General Information

The refueling interlocks are provided for use during planned refueling operations.

7.7.1.15.5.2 RI Reactor Operator Information

In the refueling mode, the control room operator has indication whenever all control rods are fully inserted. This indication is control rod position data from the computer as well as control rod in and out status on the full core status display. Furthermore, whenever a control rod withdrawal block situation occurs, the operator receives annunciation and computer logs of the rod block. He can compare these outputs with the status of the variable providing the rod block condition. Both channels of the control rod withdrawal interlocks must agree that permissive conditions exist in order to move control rods; otherwise, a control rod withdrawal block is placed into effect. Failure of one channel may initiate a rod withdrawal block and does not prevent application of a valid control rod withdrawal block from the remaining operable channel.

In terms of refueling platform interlocks, the platform operator has digital-type readout indicators for the platform main hoist X-Y position relative to the reactor core.

The position of the grapple is shown on a digital indicator. Digital load cell indications of hoist loads are given for each hoist by locally mounted indicators. Individual joysticks or pendants are provided for local control of the platform and its hoists. The platform operator can immediately determine whether the platform and hoists are responding to his local instructions and can, in conjunction with the control room operator, verify proper operation of each of the three categories of interlocks listed previously.

7.7.1.15.5.3 RI Setpoints

There are no safety setpoints associated with this system because this system does not perform a safety function.

7.7.1.16 Leak Detection System - Instrumentation and Controls

The nonsafety-related portion of the leak detection system consists of the following systems:

a. Recirculation pump seal leak detection

b. RHR system leak detection

c. Drywell leak detection

d. Safety/relief valve leak detection

e. Reactor pressure vessel head leak detection

f. Core spray system leak detection

7.7.1.16.1 LDS System Identification

This section describes the instrumentation and controls associated with the nonsafety-related portion of the leak detection system. Section 7.6 describes the instrumentation and controls in the safety-related portion. This system is discussed in Section 5.2.5.

The purpose of the leak detection system instrumentation and controls is to detect and annunciate before predetermined limits are exceeded.

7.7.1.16.2 LDS Power Sources

Power for the nonsafety-related portion of the leak detection system is supplied from a reliable 120 V ac instrument bus.

7.7.1.16.3 LDS Equipment Design

7.7.1.16.3.1 LDS General

The systems or parts of systems that contain water or steam coming from the reactor vessel or supply water to the reactor vessel and that are in direct communication with the reactor vessel are provided with leakage detection systems.

The systems within the primary containment share a common area. Therefore, a common leakage detection system is used. Each of the methods used for leakage detection inside the primary containment is designed with the capability to detect leakage at less than the established leakage rate limits.

Major components within the primary containment are, by nature of their design, sources of leakage (e.g., pump seals, valve stem packing, and equipment warming drains), but have their leakage contained and piped to an equipment drain sump and are thereby identified.

Steam or water leaks from other equipment are collected in the floor drain sumps.

Each of the sumps is protected against overflowing to prevent leaks of an identified source from masking those from unidentified sources.

7.7.1.16.4 Recirculation Pump Seal Leak Detection System

7.7.1.16.4.1 RPS-LDS Identification

There are two recirculation pump seal leak detection systems, one for each of the pumps in the recirculation loops. The recirculation pump leak detection system consists of two types of monitoring circuits (Figure 7.6-2). The first of these monitors the pressure levels within the seal cavities, presenting the plant operator with a visual display of the sensed pressure in each of the two cavities. The second type of monitoring circuit used by the leak detection system monitors the rate of liquid flow from the seal cavities.

7.7.1.16.4.2 RPS-LDS Pump Seal Cavity Pressure Monitoring

7.7.1.16.4.2.1 Circuit Description

The pressure levels within seal cavity number 1 and seal cavity number 2 are measured with identical instruments arranged similarly. The pressure within the seal cavities is measured using a pressure transmitter. The pressure transmitter produces an output signal whose magnitude is proportional to the sensed pressure within its dynamic range. This output signal is then transmitted to a pressure indicator for plant operator readout.

7.7.1.16.4.2.2 Logic and Sequencing

No automatic action is initiated by the pump seal cavity pressure monitoring circuit.

7.7.1.16.4.2.3 Bypasses and Interlocks

No bypasses and interlocks are provided.

7.7.1.16.4.2.4 Redundancy and Diversity

No redundancy is provided in this monitoring circuit. The pump seal cavity pressure monitoring is a diverse method of leak detection to the seal cavity flow rate monitoring.

7.7.1.16.4.3 RPS-LDS Liquid Flow Rate Monitoring

7.7.1.16.4.3.1 Circuit Description

All condensate flowing past the recirculation pump seal packings and into the seal cavities is collected and sent by one of two drain systems to the primary containment equipment sump for disposal. The first drain system drains the major portion of the condensate collected within the Number 2 seal cavity. The condensate flow rate through the drain system is monitored by a flow switch. The point at which the flow switch contacts close can be adjusted so that the switch is actuated only above or below certain flow rates. Excessively high or low flow rates through this drain system activate an annunciator in the control room.

The second drain system drains the cavity beyond the Number 2 seal cavity collecting the condensate that has seeped (or leaked) past the outer seal. Flow instrumentation monitors the condensate flow through this drain system. A high rate through this system activates an annunciator in the control room.

7.7.1.16.4.3.2 Logic and Sequencing

No automatic action is initiated by the seal cavity flow and the second drain system's monitoring circuit.

7.7.1.16.4.3.3 Bypasses and Interlocks

There are no bypasses or interlocks provided.

7.7.1.16.4.3.4 Redundancy and Diversity

Redundancy is not provided. Backup indication of seal leakage is provided, however, by monitoring both seal cavities to verify seal failure.

Seal cavity monitoring diversity is provided by monitoring seal cavity pressure.

7.7.1.16.5 Residual Heat Removal Leak Detection System

7.7.1.16.5.1 RHR-LDS Identification

The leak detection system constantly monitors the steam lines of the RHR system for leaks. Leaks are detected by steam flow rate monitoring in the common RHR/HPCI steam line. If the monitored parameter indicates that a leak exists, the RHR-LDS activates an annunciator in the control room and initiates an HPCI isolation signal.

The RHR-LDS consists of three types of monitoring circuits. The first of these monitors equipment area ambient and differential temperature, actuating an annunciator when the temperature rises above a present maximum. The second type of circuit monitors the flow rate (differential pressure) through the common RHR/HPCI steam line, actuating an annunciator when the differential pressure (flow) rises above a present maximum. The third type of circuit monitors the shutdown cooling water flow rate and is also annunciated.

Detection of leakage from the ECCS during the long-term post-LOCA cooldown recovery involves detecting leaks from the RHR system. RHR room ambient and differential temperatures can be monitored from the control room. RHR flow and reactor water level can be also monitored from the control room to detect a large leak in the RHR system. All of these instruments are Class 1E instruments.

7.7.1.16.5.2 RHR-LDS Area Temperature Monitoring Leak Detection

7.7.1.16.5.2.1 Circuit Description

The LDS constantly monitors the RHR compartment of the RHR system. Leaks are detected by equipment area ambient and differential temperature, which actuates an annunciator when the temperature rises above a preset limit.

7.7.1.16.5.2.2 Logic and Sequencing

The RHR and ambient and differential temperature monitoring circuit activates an annunciator when the observed temperature exceeds a preset limit.

7.7.1.16.5.2.3 Bypasses and Interlocks

No bypasses or interlocks are associated with this system.

7.7.1.16.5.2.4 Redundancy and Diversity

One channel for ambient and one channel for differential temperature monitoring detect leaks in each RHR system equipment area.

Diversity is satisfied by providing ambient temperature, differential temperature, and RHR/HPCI steam line flow monitoring.

7.7.1.16.5.3 RHR-LDS Flow Rate Monitoring

7.7.1.16.5.3.1 Circuit Description

Flow rate is monitored on the RHR shutdown cooling return line.

7.7.1.16.5.3.2 Logic and Sequencing

Minimum flow bypass actuation is the only action initiated by RHR flow monitoring.

7.7.1.16.5.3.3 Bypasses and Interlocks

No bypasses or interlocks are associated with the process line pressure monitoring instrumentation for the RHR/HPCI common steam flow line.

7.7.1.16.5.3.4 Redundancy and Diversity

Isolation of the RHR system on a low pressure condition occurs by signaling a closure of both the common RHR/HPCI inboard and outboard isolation valves. Two redundant pressure sensing switch contacts are used in two-out-of-two coincidence in each logic division (i.e., A and B) to provide pressure monitoring in the common steam line feeding the HPCI and RHR systems. Because the RHR system is isolated by independent actuation of either logic channel, a single failure of a system component in either channel does not prevent the required isolation function.

Diversity is accomplished through isolation by the following monitored variables: steam line high flow, steam line pressure, and ambient and differential temperature.

7.7.1.16.6 Drywell Leak Detection System

7.7.1.16.6.1 D-LDS Identification

Drywell leak detection is accomplished by detecting the level change in two sumps. The level is monitored to detect a rate change that could indicate an abnormality within the primary containment. This instrumentation detects a small leak and provides early warning to the control room operator, permitting corrective measures to be implemented before the abnormality becomes severe (drawings M-61).

7.7.1.16.6.2 D-LDS Circuit Description

Each sump is continuously monitored by a transmitter. The signal, which is proportional to level, is linearized for the cylindrical shape of the sump tank and is converted to a flow rate. The flow rate into each sump tank is indicated and alarmed. Flow from each sump tank to radwaste is recorded and alarmed. The alarms are described in sections 5.2.5.2.1.3 and 9.3.3.5.

7.7.1.16.6.3 D-LDS Logic and Sequencing

Annunciation actuation is the only action initiated by the drywell leak detection monitoring circuit.

7.7.1.16.6.4 D-LDS Bypasses and Interlocks

There are no bypasses or interlocks associated with this subsystem.

7.7.1.16.7 Safety/Relief Valve Leak Detection System

7.7.1.16.7.1 SRV-LDS Identification

Normally, the SRVs are in the shut-tight condition and are all at about the same temperature. Steam passage through a valve increases the monitored temperature at the exhaust, causing an abnormal temperature reading on the Data Acquisition System (DAS). Relay contacts on the DAS, configured to actuate at a predetermined setpoint, close to complete an annunciator circuit. Leakage from a valve is usually characterized by a temperature increase on a single relief valve exhaust line.

7.7.1.16.7.2 SRV-LDS Discharge Line Temperature Monitoring

7.7.1.16.7.2.1 Circuit Description

A temperature element is placed in the discharge pipe of each SRV for remote indication of leakage. The output of each temperature element is connected to the BOP-DAS.

7.7.1.16.7.2.2 Logic and Sequencing

Annunciator actuation is the only action initiated by the SRV temperature monitoring circuit.

7.7.1.16.7.2.3 Bypasses and Interlocks

There are no bypasses or interlocks associated with this system.

7.7.1.16.7.2.4 Redundancy and Diversity

No redundancy or diversity is required for this system.

7.7.1.16.8 Reactor Pressure Vessel Head Leak Detection System

7.7.1.16.8.1 RPVH-LDS Identification

Pressure between the inner and outer head seal-ring is sensed by a pressure switch. If the inner seal leaks, the pressure sensor senses the increased pressure and actuates an alarm. The plant continues to operate with the outer seal as a backup. If both the inner and outer head seals leak, the leak is detected by an increase in drywell temperature and pressure.

7.7.1.16.8.2 RPVH-LDS Head Seal Integrity Pressure Monitoring

7.7.1.16.8.2.1 RPVH-LDS Circuit Description

A pressure sensor monitors the pressure between the inner and outer head seals.

7.7.1.16.8.2.2 RPVH-LDS Logic and Sequencing

No action is initiated by the reactor vessel head pressure monitoring circuit.

7.7.1.16.8.2.3 RPVH-LDS Bypasses and Interlocks

There are no bypasses or interlocks associated with this system.

7.7.1.16.8.2.4 Redundancy and Diversity

Redundant pressure-sensing instrumentation for detecting inner seal failure is not provided and the outer seal assembly provides backup if an inner seal leak occurs.

7.7.1.16.9 Core Spray System Leak Detection System

7.7.1.16.9.1 CS-LDS Identification

CS-LDS is designed to provide core spray cooling to the reactor core. CS-LDS has a safety-related function and is required to be operable following a LOCA.

7.7.1.16.9.2 CS-LDS Circuit Description

CS-LDS leaks are detected by the pressure differential across the reactor nozzle and core shroud actuating an annunciator when the pressure differential rises above a preset limit (drawings M-52).

7.7.1.17 Emergency Response Facility Data System Instrumentation and Controls

7.7.1.17.1 ERFDS Identification

The ERFDS is a part of the Plant Monitoring System described in Section 7.7.1.22. ERFDS performs the software functions described in this section utilizing the PMS hardware platform described in Section 7.7.1.22.3.

The ERFDS performs two major functions. First, it is the system that conforms with regulatory requirements for a SPDS. The ERFDS can generate real-time and historical visual displays, print records and plots which can be used to provide plant information that aid plant personnel during abnormal and emergency conditions in determining and controlling the value and trend of the key reactor and primary containment control parameters. In addition to the parameters required by Regulatory Guide 1.97 (Rev 2), as discussed in Section 7.5, the ERFDS will monitor the following safety-related parameters:

a. APRM

b. Scram signals

c. HPCI, initiation, speed, discharge pressure, EGM output, ramp output, flow controller output, steam line ΔP

d. RCIC parameters same as HPCI

e. RHR heat exchanger level and pressure

f. RCIC suction pressure control output

The SPDS portion of the LGS ERFDS meet the requirements of NUREG-0737 Supplement 1 as discussed below.

The other function is TRA, which provides a real-time and historical perspective for the operation of the power plant. The TRA functions provide high resolution recording capabilities for various plant parameters and the means for event monitoring, data archival, plotting, trending and analyzing in order to support the determination and analysis of plant transients.

7.7.1.17.2 Safety Parameter Display System

7.7.1.17.2.1 SPDS Human Factors

The SPDS portion of the LGS ERFDS meets the NRC requirements for an SPDS, in that, it provides aid to the operator in determining the safety status of the plant during abnormal or emergency conditions. The graphic displays available to the control room operator are based on the current revision of the EPGs and are formatted to give maximum assistance in following the LGS EOPs.

Human factors engineering has also been taken into account during development of the LGS SPDS to maximize the operator's ability to readily determine plant status and to minimize errors by the operator during its use.

The SPDS portion of the LGS ERFDS displays is a subset of the generic GE Emergency Response Information System displays. As such, its displays use patterns and colors for conveying current parameter values, trends, limit indications, and validation status that are based upon those used in the generic GE Emergency Response Information System displays.

The human factors reviews of the generic GE Emergency Response Information System displays consisted of a static review by human factor engineering professionals and a dynamic review which emphasized operator integration under dynamic conditions. This dynamic review consisted of a human factor engineering check using a checklist approach, the administration of 12 unique simulated transients, operator/system performance evaluations during the transients using the Perry Nuclear Power Plant EOPs, and data collection for the measurement of the usefulness of the Emergency Response Information System SPDS-related displays.

In general, the Emergency Response Information System was perceived by the operators as a significant aid in plant control during emergencies and was judged as presenting an exceptional source of synthesized/centralized information with regard to plant performance.

The SPDS will be operational during all modes of reactor operation defined in table 1.2 of the LGS Technical Specifications. However, operability of the SPDS does not constitute a Limiting

Condition for Operation because hardwired Class 1E instrumentation is available in the control room for the operator if the SPDS should become inoperable.

7.7.1.17.2.2 SPDS Parameter Validation

A means is incorporated in the design to assure that the data displayed are valid. The validation method used in the LGS SPDS is identical to the method common to all GE SPDSs. The following is a summary of the generic design.

All SPDS-related control parameters of the LGS ERFDS are validated parameters. The validation process generates a weighted average of control parameter signals consisting of either an average of all consistent signals or an average of all in-range signals if there are less than two consistent signals. The validation process generates a validation status that defines whether the average is validated (signals are consistent), nonvalidated (signals are in-range but not consistent), or bad data (signals cannot be measured). If the average cannot be determined, the validation process parameter is assigned "bad data" and the parameter value is replaced with asterisks. The signal average calculated is used to represent the instrument readings of the process variable unless additional compensation is performed on the signal average (e.g., reactor power), in which case the compensated value is used to represent the adjusted instrument reading. For those parameters that are not directly measured (e.g., RPV temperature and other bulk temperatures), calculations are performed to derive these variables from measured parameters.

7.7.1.17.2.3 SPDS Display Description

The LGS SPDS control room displays present the fundamental information needed by nuclear power plant personnel to respond to an emergency. Using standard computer keyboard and mouse at the graphic HMI display console, the user can manually select displays for viewing on the monitor.

The displays available at each graphic display console consist of:

		No. of Displays
a.	RPV Control display	1
b.	Containment Control display	1
c.	Critical plant variables	1
d.	Two-dimensional plots	11
e.	Trend plots	12
f.	Validation status displays	8
g.	H2 / O2 Control	1
h.	Containment Isolation Status	10
i.	Remote Manual Isolation Valve Menu	5

j.	System Status	16
k.	Plant Parameter Status	1

These displays provide real-time data with emphasis on showing the current plant status and recent trend history. RPV Control and Containment Control displays are keyed to the appropriate LGS EOPs. The critical plant variables display shows the LGS EOP entry conditions for Reactor Pressure Vessel (RPV) Control and Primary Containment Control. Trend plot displays contain real-time digital information, but their overall emphasis is to show the most recent trends. Two-dimensional plots present the limits defined in the LGS EOPs which are curves showing the relationship between two or more parameters. Validation status displays supply an evaluation of plant control parameter signals.

7.7.1.17.2.3.1 RPV Control Display

This display provides control room operators with the primary plant information required to execute the LGS EOPs developed from the RPV Control Guideline. This display is not intended to provide information to unlicensed personnel or personnel whose emergency response functions are not defined by the EOPs (e.g., engineers, supervisor, or management), although these personnel may use this display for detailed plant status information.

7.7.1.17.2.3.1.1 Event Targets

There are four event targets on the RPV Control Display. They give the status of the following events.

a. Group Isolation - Has a demand for isolation occurred and has the required isolation been successfully completed?

b. Safety/Relief Valve - Is any SRV open?

c. Main Steam Isolation Valve - Is an MSIV closure signal present and are the MSIVs open or shut?

d. Scram - Has a scram been initiated and have all control rods been fully inserted?

The event labels and color coding for border and text indicate event status of INACTIVE, SAFE, CAUTION, and ALARM.

7.7.1.17.2.3.1.2 Control Parameter Trend Plots

Each control parameter, as defined by the EPG, is presented in a trend plot minidisplay consisting of a time history data plot, bar graph, and digital readout. Control parameters for the RPV Control display are RPV water level, pressure, reactor power, and RPV temperature.

The horizontal scale of the time history data plot for all control parameters is the most recent ten minutes.

The bar graph and digital readout are used to highlight and pinpoint the current value of the control parameter. The color of the bar graph and border around the digital readout reflects the control parameter validation status.

A trend line tracks the value of each control parameter, and its color coding is the same as that for the bar graph. Whenever the trend line goes off the vertical scale, it appears either at the top of the plot if above scale or at the bottom of the plot if below scale. The user can manually enter upper and lower values of the desired scale range to establish the vertical plot scales.

7.7.1.17.2.3.1.3 Limit Tags

A control parameter may have up to five limit tags associated with it, each corresponding to a process limit identified by the LGS EOPs. Table 7.7-8 lists the limit tags that are associated with each of the trend plots on the RPV control display. The process limits are of two types: dynamic limits and control parameters and, therefore, may change with time. Static limits are limits that remain constant with time. In addition, each of the two types of process limits fall into two categories: upper limits and lower limits. Upper limits are limits that alert the system user when the limit is approached or exceeded from below. Lower limits are limits that alert the system users when the limit is approached or exceeded from above. The process limits further belong to two classes: alarm limits and permissive limits. An alarm limit informs the operator that an operating limit has been exceeded, whereas a permissive limit lets the operator know when an action is capable of being performed (e.g., 100% bypass value).

The process limit status is indicated by the color of the limit tag border. For permissive limit tags, the border colors indicate INACTIVE, ACTIVE, or BAD DATA/DATA NOT MEASURED. Permissive limit tags are ACTIVE, when the control parameter equals or exceeds the process limit and INACTIVE otherwise. For alarm limit tags, the border colors reflect SAFE, CAUTION, ALARM, or BAD DATA/DATA NOT MEASURED. Alarm limit tags are in the "alarm" state when the control parameter equals or exceeds the process limit, the "caution" state when the control parameter approaches the process limit, and the "safe" state if not in the "alarm" or "caution" state.

Limit lines are presented with trend lines to track the value of dynamic limits associated with the control parameters. Whenever data for a limit line is bad or not measured, the limit line is not plotted.

7.7.1.17.2.3.2 Containment Control Display

This top level display provides control room operators with the primary plant information required to execute the LGS EOP developed from the Containment Control Guideline.

7.7.1.17.2.3.2.1 Event Targets

There are four event targets on the Containment Control display. They give the status of the following events:

a. Group isolation (Section 7.7.1.17.2.3.1.1)

b. Safety/Relief Valve (Section 7.7.1.17.2.3.1.1)

c. Scram (Section 7.7.1.17.2.3.1.1)

d. HPCI - Should HPCI flow be reduced or should HPCI be secured?

The event labels border and text are color coded to indicate event status of INACTIVE, SAFE, CAUTION, and ALARM.

7.7.1.17.2.3.2.2 Control Parameter Trend Plots

Control parameters plotted for the Containment Control display are containment level, drywell pressure, drywell temperatures, wetwell pressure, suppression pool temperature, and suppression pool water level. Except for the drywell temperatures, all containment control parameters are validated parameters. The trend plot description is the same as given in Section 7.7.1.17.2.3.1.2.

7.7.1.17.2.3.2.3 Limit Tags

As on the RPV Control display, limit tags are associated with each of the trend plots on the Containment Control display. In addition, limit tags for primary containment hydrogen and oxygen concentrations are provided. The limit tag description is the same as given in Section 7.7.1.17.2.3.1.3. Table 7.7-9 lists the limit tags that are associated with each of the trend plots on the Containment Control display.

7.7.1.17.2.3.3 Critical Plant Variables Display

This top level display provides the control room operators, shift supervisor, TSC supervisor, and emergency director with the status of the critical plant variables, which are the variables controlled by the LGS EOPs.

The Critical Plant Variables display is an image of the plant and presents two types of EOP information: control parameters and their limits, and event indications. For each control parameter, the current digital readout is shown with the upper limit above and/or lower limit below. The label and color coding for each digital readout, limit tag, and event indication are identical to the corresponding digital readout, limit tag, or event indication in the RPV or Containment Control displays.

7.7.1.17.2.3.4 Trend Plot Displays

Trend plot displays are available for all control parameters. Each trend plot consists of a time history data plot, a bar graph giving the current reading, and a digital readout. Limit tags and limit lines are also supplied. The bar graph, digital readout, limit tags, trend lines, and limit lines are as specified for the control parameter trend plots and limit tags in the RPV or Containment Control displays.

The horizontal plot scale for all inputs is the most recent 30 minutes, except for Drywell/Suppression Pool Hydrogen Concentration and Drywell/Suppression Pool Oxygen Concentration which are the most recent 60 minutes. The plot displays include:

a. RPV Water Level

b. Suppression Pool Level

c. RPV Pressure

d. Reactor Power

e. RPV Temperature

f. Containment Water Level

g. Drywell Pressure

h. Wetwell Pressure

i. Suppression Pool Temperature

j. Drywell Temperature

k. Drywell/Suppression Pool Hydrogen Concentration

l. Drywell/Suppression Pool Oxygen Concentration

7.7.1.17.2.3.5 Two-Dimensional Plot Displays

These lower level displays provide operators in the control room and plant engineers in the control room and TSC with plots of the two-dimensional limits defined in the EOPs. These limits are also presented as limit tags on the RPV and Containment Control displays.

There are dynamic and static two-dimensional plot displays. Each two-dimensional display consists of an x-y plot with a forbidden region and a historical track, and digital readings of the current values of the dependent and independent parameters. Color coding for digital readings of control parameters is as specified for the RPV and Containment Control displays. Each two-dimensional display will show the forbidden regions with cross hatch line or SAFE/UNSAFE designated areas, the forbidden region appears on each plot as cross hatch, and the historical track is the curve that continuously tracks the values of the two parameters. The cursor at one end of the historical track represents the current plant status and is color coded the same as the limit status. The two-dimensional displays include:

a. Safety Relief Valve Tail Pipe Level Limit (dynamic)

b. Heat Capacity Temperature Limit (dynamic)

c. Primary Containment Pressure Limit A (dynamic)

d. Primary Containment Pressure Limit B (dynamic)

e. Pressure-Suppression Pressure (dynamic)

f. Minimum Pre-Depressurization Reactor Water Level A (static)

g. Minimum Pre-Depressurization Reactor Water Level A (static)

h. Reference Leg Saturation Limit (dynamic)

i. Drywell Spray Initiation Pressure Limit (dynamic)

j. Reactor Pressure Vessel Pressurization Limit (dynamic)

k. Decay Heat Removal Injection Rate (static)

7.7.1.17.2.3.6 Validation Status Displays

These lower level displays provide operators in the control room and plant engineers in the control room and TSC with an evaluation of the signals for all the control parameters plus core flow. The displays list each instrument that supplies a control parameter signal; indicate if the instrument raw data value is within its calibrated range; compensate individual signals if appropriate; present the compensated value; indicate if these values are consistent with each other; and average these values for a final value, with weighting factors if appropriate.

The upper right field of the display presents the final averaged value, plus indication if that value is compensated and/or validated. The color coding of the readouts are consistent with the control parameter trend plots in Section 7.7.1.17.2.3.1.2. The validation displays include:

a. RPV Level

b. RPV Pressure

c. Reactor Power

d. RPV Temperature

e. Drywell Pressure

f. Drywell Temperature

g. Pool Level

h. Pool Temperature

i. Reactor Core Flow

j. Containment Level

k. Wetwell Pressure

7.7.1.17.2.4 SPDS Isolation Devices

Except for the inputs from PRNM, isolation for Class 1 E SPDS signals connected to the LGS ERFDS is provided by analog and digital isolation amplifiers, provided by Scientech I&C. The isolators have been tested generically for electrical isolation, environmental qualification, and seismic qualification.

The analog isolation amplifier isolates the input, safety related, circuitry from the output, non-safety related, circuitry with three components. An isolation amplifier chip transmits each analog signal across a capacitive barrier in a pulse width modulated format. The power and

common for the circuitry on the input side of the isolator is separated from the output by isolated DC-DC converters. The circuit board of the isolator module has an isolation gap between input and output circuits. The adequacy of these insulation barriers has been tested by the application of credible live fault voltages to the output circuitry in a fault isolation test.

The digital isolation amplifier isolates the input, safety related, circuitry from the output, non-safety related, circuitry with three components. Each digital signal is optically coupled across the isolation barrier by an IC chip. The power and common for the circuitry on the input side of the isolator is separated from the output by isolated DC-DC converters. The circuit board of the isolator module has an isolation gap between input and output circuits. The adequacy of these insulation barriers has been tested by the application of credible live fault voltages to the output circuitry in a fault isolation test.

7.7.1.17.2.5 Verification and Validation Program

Historical Information: GE V&V information is historical information pertaining to the original SPDS creation for Limerick.

The Verification and Validation Program used in the development of the original GE LGS SPDS was identical to the program generically used for all GE-supplied SPDSs.

The methods employed in the Verification and Validation procedures ensure that the LGS SPDS will have the functions and characteristics required and that the functions perform correctly. The review and testing processes are designed to identify problems or weaknesses in the design requirements, the design, and the implementation of the design, and to correct those problems and weaknesses.

The specific V&V plan identifies quality audit points along the LGS SPDS development path. These quality audit points range from performing specification reviews to code walk-throughs to several levels of software and system testing. Heavy emphasis is placed on achieving independent V&V; that is, employing reviewers and testers who have not been directly involved in the design.

Major V&V milestones consist basically of preparation and review of design specifications, coding and review of coding, development of test plans and procedures, conductance of tests and review of test results. The V&V procedure is not only sequential but also iterative. Results that identify areas requiring correction are used to modify the design or further define requirements in order to resolve concerns.

The review of specifications is accomplished by the reviewers documenting comments on a controlled issued document during the development of these specifications. Each comment must be resolved by the responsible engineer to the satisfaction of the reviewers prior to the issue of any document. The testing phases produce test reports which show any discrepancies between expected and actual test results, these discrepancies must be resolved by the responsible engineer of the design group and the test repeated.

By performing the V&V procedures, a systematic and structured method is implemented to ensure that the correct functions are provided and that the functions provided are correct.

The RTime SPDS mirrors the original SPDS. RTime SPDS was verified using the SPDS Software Requirements Specifications and Software Design Documentation. RTime SPDS was validated during Factory Acceptance Testing, Site Acceptance Testing, and Modification Acceptance Testing.

7.7.1.17.3 Transient Recording and Analysis

The TRA function is used to record, monitor and display plant parameters during the startup testing and at rated power but does not provide control interaction. The system provides transient recordings of the parameters during startup and monitors them at full power.

7.7.1.18 Containment Instrument Gas System - Instrumentation and Controls

7.7.1.18.1 CIGS Identification

This system is designed to provide instrument gas to the pneumatic devices located inside the drywell and suppression chamber. The CIGS has no safety-related function and is not required to be operable following a LOCA. Two parts of this system are safety-related. One is the isolation valves provided on all instrument gas lines that penetrate the containment. These valves are part of the primary containment and reactor vessel isolation control system that is described in Section 7.3.1.1.2. The other part provides nitrogen gas to the ADS valves. This portion is described in Section 7.6.

7.7.1.18.2 CIGS Power Sources

The instrument panel power supply is provided by a 120 V ac Class 1E source to 120 V ac / 24 V dc power supply. The power to the instrument panel is shed after receiving a LOCA signal. The power may be manually reapplied as loading on the Class 1E buses permits.

7.7.1.18.3 CIGS Equipment Design

Equipment design is described in Section 9.3.1.

7.7.1.18.3.1 CIGS Initiating Circuits

A signal from a pressure switch located on the instrument gas receiver automatically starts and stops the instrument gas compressor.

7.7.1.18.3.1.1 CIGS Logic and Sequencing

Sequencing is not applicable for this system.

During normal unit operation, one of the two instrument gas compressors is selected as the lead compressor and is automatically started or stopped in response to the instrument gas system demand. The other instrument gas compressor serves as a standby. The standby compressor starts automatically if the lead compressor fails or if the lead compressor's continuous operation cannot meet the instrument gas system demand. The two trains are cross-connected by a common header. A backup to the PCIG system is provided by an intertie to the instrument air system.

7.7.1.18.3.1.2 CIGS Bypasses and Interlocks

This switch must be in the closed position for the bypass permissive to be satisfied. A separate switch is provided for the valves in each division. Placing the bypass switch in the bypass position initiates an alarm in the control room.

7.7.1.18.3.1.3 CIGS Redundancy and Diversity

Instrumentation and controls are provided on a one-to-one basis with the mechanical equipment.

7.7.1.18.3.2 CIGS Actuated Devices

The instrument gas compressors are actuated by hand switches in the instrument gas compressor control panel and by pressure switches located in the instrument gas receiver.

7.7.1.18.3.3 CIGS Separation

The outboard isolation valves, except for the valve in the A line header, are treated as Division II isolation valves. The inboard isolation valve and A line header outboard isolation valve 1 are treated as Division I isolation valves. This arrangement ensures that both instrument gas supply lines are not isolated on the trip of only one isolation logic. The power to the instrument panels is separated in accordance with their respective header isolation valves.

7.7.1.18.3.4 CIGS Testability

The isolation valves can be tested as described in Section 7.3.1. However, operation of the instrument gas system is disrupted during the test.

7.7.1.18.4 CIGS Environmental Considerations

The controls for this system are located in the reactor enclosure and the control room. For environmental considerations, see Section 3.11.

7.7.1.18.5 CIGS Operational Considerations

See Section 9.3.1.

7.7.1.19 Fire Protection and Suppression System - Instrumentation and Controls

7.7.1.19.1 FPSS Identification

7.7.1.19.1.1 FPSS General

The FPSS as related to the PGCC is described below. A detailed description and analysis of the PGCC can be found in GE topical report NEDO-10466-A, "Power Generation Control Complex."

The defense in depth concept of fire protection and suppression is implemented in the PGCC by operator use of hand-held fire extinguishers as a backup during fires involving the PGCC.

The total plant FPSS description is found in Section 9.5.1.

7.7.1.19.1.2 FPSS Classification

The PGCC fire protection and suppression system is classified as not related to safety.

7.7.1.19.1.3 FPSS Reference Design

The total plant fire protection design is discussed in Section 9.5.1.

7.7.1.19.2 FPSS Power Sources

The fire detection and alarm systems are provided with a 120 VAC emergency diesel/generator backed power supply, a 125 VDC BOP battery supply, and a 24 VDC battery backed power supply. Some heat detectors are powered by the 125 VDC BOP batteries. The other heat detectors are powered by 24 VDC from BOP converters, backed by 24 VDC batteries. The smoke detectors are powered by the 120 VAC emergency diesel/generator backed supply. The power source used for the automatic heat detection also provides power to the electrically operated valves of the automatic suppression system.

7.7.1.19.3 FPSS Equipment Design

7.7.1.19.3.1 FPSS General

The PGCC FPSS consists of products of combustion and rate-compensated/temperature detectors with a Halon 1301 fire suppressant system. In-plant fire water service and distribution systems are described in Section 9.5.1.

7.7.1.19.3.2 FPSS Equipment Arrangement

PGCC design provides a defense-in-depth approach to fire protection. Each floor section contains four smoke detectors and eight thermal detectors. Fire-stops of refractory material covered by silicone rubber are installed in the cable ducts. A Halon 1301 extinguishing agent is introduced into the floor section cable ducts via a header manifold and nozzle distribution system. This provides at least a 6% concentration of Halon within 10 seconds of activation, and with additional discharge to reach a 20% concentration within 45-55 seconds, there is sufficient Halon to maintain a 20% concentration for at least 20 minutes. In addition, the floor plate design allows for quick removal so that the control room operators may use hand-held fire extinguishers when required.

There are four smoke detectors in each termination cabinet. The various detectors are wired to contact points in the termination cabinets.

The gas bottles, gas control, suppression initiation and alarm annunciation equipment as well as the total plant alarm system are covered in Section 9.5.1.

7.7.1.19.3.3 FPSS Testability

Each hazard area was tested with Halon 1211 or carbon dioxide to check the pneumatic remote control, the tightness of the system and also verified that all pressure-operated controls functioned as specified and that all discharge nozzles were not obstructed.

A discharge concentration test of the Halon suppression system was performed and determined that the design concentration of Halon was obtained within the design discharge time in accordance with previously approved calculations. Each system is provided with a thermal detector for test purposes.

7.7.1.19.4 FPSS Environmental Considerations

The PGCC fire protection system will operate satisfactorily through a temperature range from -65°F to 104°F and through a humidity range from 50% to 100% relative humidity.

7.7.1.19.5 FPSS Operational Considerations

7.7.1.19.5.1 FPSS General

The PGCC detectors provide annunciation at the trouble panel located near the control room entrance. The trouble panel provides an alarm in the control room, and indicates a trouble condition in the PGCC area.

Activation of the Halon suppression system is automatic or manual by the panel operator. Shift supervision has key-lock access to the Halon Release Control Panel to deactivate the Halon suppression system during repair work. Safe operation procedures for use and testing of the total plant fire protection system are covered in Section 9.5.1.

7.7.1.19.5.2 FPSS Reactor Operator Information

Operator indications and alarms are shown in drawings M-22.

7.7.1.20 Nonsafety-Related Equipment Area Cooling Ventilation Systems - Instrumentation and Controls

7.7.1.20.1 Reactor Enclosure Ventilation System

See Section 9.4.2 for a description of this system.

7.7.1.20.2 Turbine Enclosure Ventilation System

See Section 9.4.4 for a description of this system.

7.7.1.20.3 Radwaste Enclosure and Chem. Lab. Expansion Ventilation System

See Section 9.4.3 for a description of this system.

7.7.1.20.4 Hot Maintenance Shop Ventilation System

See Section 9.4.8 for a description of this system.

7.7.1.20.5 Miscellaneous Enclosures Ventilation Systems

See Section 9.4.9 for descriptions of these systems.

7.7.1.21 Rod Worth Minimizer - Instrumentation and Controls

7.7.1.21.1 RWM Identification

7.7.1.21.1.1 RWM General

The NUMAC RWM is a dedicated microprocessor-based system with an RWM operator display, and a continuous operating self-test feature. It monitors and enforces adherence to established low power level rod insert and withdraw sequences. This function prevents the operator from establishing control rod patterns that are not consistent with the prescribed sequence by initiating appropriate rod insert block, rod withdraw block, and RWM inoperable. The RWM enforces control rod sequences designed to limit (and thereby minimize) individual control rod worths to acceptable levels as determined by the rod-drop accident design basis. The RWM function does not interfere with normal reactor operation and, in the event of failure, does not itself cause rod patterns to be established which would violate the rod-drop accident design basis. The RWM can operate independently of the PMS computer.

The RSCS has been deleted from the LGS plant. It's function is performed by the RWM system. The RWM acts to prevent withdrawal of an out-of-sequence control rod, to prevent continuous control rod withdrawal errors during reactor startup, and to minimize the core reactivity transient during a rod-drop accident. The consequences of a rod withdrawal error in the startup range are analyzed in Appendix 15B, demonstrating that the licensing basis criterion for fuel failure is still satisfied even when the RWM fails to block rod withdrawal. Thus, the RWM is not safety-related. The safety action required for the continuous control rod-drop incident (a reactor scram) is provided by the safety-related IRM system of the NMS. If the core flux scram trip setpoint is reached during a flux transient, the IRM will both block further rod withdrawal and initiate a scram. Furthermore, a second safety-related NMS scram trip, supplied the APRM, can terminate the core power transient. The RWM does not interface with safety-related systems. Refueling interlocks are not considered safety-related.

7.7.1.21.1.2 RWM Classification

The RWM is a power generation system and is classified as a system not related to safety.

7.7.1.21.1.3 RWM Reference Design

This system is an operational system and has no safety function. Table 7.1-2 lists the reference design information. There are no safety design differences between this system and the reference design since neither system performs a safety function. This system is functionally identical to the referenced system.

7.7.1.21.2 RWM Power Sources

The power for the RWM is supplied by a reliable source.

7.7.1.21.3 RWM Equipment Design

7.7.1.21.3.1 RWM Circuit Description

The RWM has the following system characteristics:

a. Capacity for four selectable operating sequences

b. Selection of operate/bypass/test inop modes

c. Substitute rod position entry capability from the RWM operator's display under key-lock (procedural) control

d. Capability to remove/restore rod from/to group, under key-lock (procedural) control

e. Rod coordinate indication of insert and withdraw error

f. Status indication of insert and withdraw blocks

g. Annunciation of RWM failure to RPIS

h. Identity and position of rods with an insert or withdraw error

i. Single group identification with subgroup capability

j. Text error messages at the RWM operator's display and RWM chassis

k. Rod by rod and group by group sequence control

l. Rapid power reduction

7.7.1.21.3.2 RWM Testability

The RWM processor design includes a self-test capability that identifies a failure to a functional module, annunciates the failure, and provides testing capability for verification of repair. The primary function of the self-test feature is to maximize instrument channel availability.

7.7.1.21.4 RWM Environmental Considerations

The instrument is designed for normal operation in the range of 5°C to 50°C and 10% to 90% relative humidity (noncondensing). It meets EMI requirements for the control room environment.

7.7.1.21.5 RWM Operational Considerations

7.7.1.21.5.1 RWM Operator Information

Display information includes multiple displays for different modes of operation and level of detail. Alternate displays are selected from the display panel through the use of SOFT SWITCHES whose functions are clearly marked on the panel. The use of alternate displays provides additional detail or an alternate set of displays for different modes of operation.

7.7.1.21.5.2 RWM System Interface

The RWM is designed to interface with other plant systems as follows:

a. RWM interfaces RPIS and RMCS data to the PMS via a fiber-optic multiplexed data link.

b. Rod identity and position data, and the identification of the selected rod, are obtained from the RPIS.

c. Interface to the RWM, for downloading, uploading, and printing sequences and for obtaining certain RWM status messages is accomplished via PMS terminal and printer.

d. Connections for ROD SELECTED AND DRIVING, RPIS INOP, LOW POWER SETPOINT, and LOW POWER ALARM POINT are input to the RWM. The RWM transmits these points to the PMS computer.

e. Required output from the RWM include INSERT PERMISSIVE, WITHDRAW PERMISSIVE, RWM OPERABLE, and RWM INOPERABLE signals. These signals interface to Channel 2 of the rod drive control system. The RWM is a dedicated processor with a continuously operating self-test feature. In the event of failure of the RWM, rod blocks and RWM INOP are applied. When the reactor power level is above the LOW POWER SETPOINT, the RWM rod blocks are automatically inhibited by the RWM.

f. Required inputs from the feedwater system are LOW POWER SETPOINT and LOW POWER ALARM POINT.

7.7.1.21.5.3 RWM Function

The RWM acts to prevent withdrawal of an out-of-sequence control rod, to prevent continuous control rod withdrawal errors during reactor startup, and to minimize the core reactivity transient during a rod-drop accident. The consequences of a rod withdrawal error in the startup range are analyzed in Appendix 15B, demonstrating that the licensing basis criterion for fuel failure is still satisfied even when the RWM fails to block rod withdrawal. Thus, the RWM is not safety-related. The safety action required for the continuous control rod-drop incident (a reactor scram) is provided by the safety-related IRM system of the NMS. If the core flux scram trip setpoint is reached during a flux transient, the IRM will both block further rod withdrawal and initiate a scram. Furthermore, a second safety-related NMS scram trip, supplied by the APRM, can terminate the core power transient. The RWM does not interface with safety-related systems. Refueling interlocks are not considered safety-related.

7.7.1.22 Plant Monitoring System - Instrumentation and Controls

7.7.1.22.1 PMS Identification

7.7.1.22.1.1 PMS General

The PMS performs six major functions. First, it performs the ERFDS functions as described in section 7.7.1.17. The ERFDS is the system that conforms with regulatory requirements for a SPDS. The PMS can generate real-time and historical visual displays, print records and plots which can be used to provide plant information that aid plant personnel during abnormal and emergency conditions in determining and controlling the value and trend of the key reactor and primary containment control parameters. The second function that the PMS performs is the necessary evaluation of the NSSS portion of nuclear power plant operation. The PMS gathers data, processes data, and provides current outputs for analysis and evaluation purposes. The NSSS programs perform the calculations and data logging required to provide current reactor core

performance information. Evaluations can be performed, including thermal power distribution, power ratios, energy summaries, enthalpies, data summaries, and calibration and diagnostics for the analysis of the nuclear steam supply. The third function performs BOP performance calculations such as turbine cycle, condenser, electrical, and heat exchanger performance. The fourth function is point log and alarm, which provides alarm display and logging, group point display, log generation and reporting, log and display editor, point data display/change, summary processing and reporting, trend pen recorder, and alarm sequence of events functions. The fifth function is transient recording and analysis, which provides a real-time and historical perspective for the operation of the power plant. The TRA functions provide high resolution recording capabilities for various plant parameters and the means for event monitoring, data archival, plotting, trending, analyzing, and automatic and on-demand logging in order to support the determination and analysis of plant transients. The sixth function is to collect and display meteorological data from the meteorological instrumentation described in Section 2.3 and transmit this meteorological data to the EPDS computer.

7.7.1.22.1.2 PMS Classification

The PMS is classified as a power generation system and is not required to perform any safety-related functions.

7.7.1.22.1.3 PMS Reference Design

The PMS is an operational system and has no safety function. Table 7.1-2 lists the reference design information. There are no safety design differences between this system and the reference design since neither system performs a safety function. This system is functionally identical to the referenced system.

7.7.1.22.2 PMS Power Sources

The power for the computer system is supplied by a reliable source. The DAS is supplied with divisional power as required.

7.7.1.22.3 PMS Equipment Design

7.7.1.22.3.1 PMS Circuit Description

The PMS hardware consists of three major elements:

a. The DAS, which consists of Chassis, I/O cards, node processor, and the chassis processor

b. Central processor units and their peripherals

c. Human Machine Interface (HMI) and peripheral devices

7.7.1.22.3.1.1 Data Acquisition System

The DAS used for PMS samples signals at high rates to allow high resolution of sequence of events or to perform transient analysis. The deletion of a point from processing shall not remove it from its normal scheduled scan by the I/O equipment and the scanned value shall be available for system maintenance and troubleshooting functions. This value shall be available as adjusted counts, raw signal and EU value when displayed.

Features of the DAS include the following:

a. RTP 3000 Series Chassis and I/O cards.

b. Processor cards send plant signals to the PMS (non-Class 1 E) through copper and fiber optic cables. For Class 1 E Panels, an isolation device has been installed between the field signals and the RTP chassis so as to meet the divisional separation and isolation.

7.7.1.22.3.1.2 Central Processing Unit

The CPU 64 bit, high speed and high throughput virtual memory computer. The processor's instruction set includes integral floating point, packed decimal arithmetic, and character string instructions. The virtual memory operating system provides for a multiuser, multi-language programming environment. There are two CPUs which are configured in a primary/backup arrangement. This allows CPU failover to be executed in the event of a CPU failure.

7.7.1.22.3.1.3 Human Machine Interface (HMI) and Peripheral Devices

In the man/machine interface, a color graphic display system is used. Internal memory capacity of this display system is capable of storing over 200 displays. The color graphics display terminals, along with smaller display terminals, allow access to the PMS functions. The system also includes other peripheral devices such as printer, display, hard copy devices, and high speed line printers.

7.7.1.22.3.2 PMS Testability

The PMS has certain self-checking provisions. It performs diagnostic checks to determine the operability of certain portions of the system hardware and performs internal programming checks to verify that input signals and selected program computations are either within specific limits or within reasonable bounds.

7.7.1.22.4 PMS Environmental Considerations

All the computer equipment, except for peripherals, is designed for continuous-duty up to 24°C and 60.0% relative humidity. The peripherals are designed to operate at up to 30°C and 90% (noncondensing) relative humidity.

7.7.1.22.5 PMS Operational Considerations

7.7.1.22.5.1 PMS NSSS Performance Calculation Programs

The NSSS subsystem is designed to enable plant operating personnel to calculate core performance data rapidly to allow the nuclear steam supply to be operated as close to its limits as

possible, to aid in safe operation of the plant, and to monitor fuel for uniform exposure and reloading purposes.

The functions of the nuclear steam supply performance evaluation subsystem include:

a. Periodic programs for logging a range of reactor performance data.

b. On-demand programs for reactor performance analysis.

c. Programs for a variety of other functions.

7.7.1.22.5.2 PMS Reactor Operators Information (Monitor, Alarm, and Logging Program)

a. Alarms

The PMS includes the capability to provide alarm notification and handle their acknowledgement by the user. Alarms are initiated automatically in response to a variable that has reached a specified condition. These alarms are provided for information, user acknowledgment, and historical perspective. The following features are included:

1. Choice of views; i.e., total plant or selected category

2. Use of color for conveying status

3. Alarm prioritization

4. Alarm chronology

5. Ability to segregate acknowledged and unacknowledged alarms

b. Logs

The logging function provides the capability to print out or display various logs on demand or control the automatic initiation of the logs which are either printed on a periodic basis or triggered by various plant conditions. The logging functions include special logs, periodic logs, post-trip/scram logs, turbine/generator logs, and SOE logs.

The system has been designed to avoid the loss of data if a log printer fails.

c. Sequence of Events

The SOE log is used as follows:

1. To aid in establishing the cause of a reactor scram and determine whether the reactor can be returned to normal operation

2. To provide records of RPS sensor trips

3. To verify proper operation of the ECCS

All SOE point changes will automatically be logged when a change of state occurs for any SOE input. The SOE function is capable of monitoring 500 digital points, and order of occurrences can be resolved to 100 ms.

7.7.1.22.5.3 PMS BOP Performance Calculation Programs

These programs perform calculations and log plant performance data not directly related to the nuclear system. The data stored by the BOP program can be printed out on logs. The BOP Periodic Log gives hourly and daily values for temperatures, power outputs, and flows associated with the main generator and turbines, and with the feedwater, recirculation, and RWCU systems. The BOP Monthly Log contains monthly averages and accumulations for plant gross and net power outputs, load distributions, turbine heat rates, and fuel burnup. Standard BOP performance calculations include the flow calculations, electrical calculations, turbine cycle performance calculations, condenser calculations, feedwater heater and moisture separator performance calculations, and unit performance calculations.

7.7.1.22.5.4 Collection and Display of Meteorological Data

The PMS automatically collects current meteorological data from the meteorological instrumentation described in Section 2.3 through a dedicated data link. Data collection and storage is per the requirements of Regulatory Guide 1.23, rev. 1. This data is available for display during normal operating conditions through PMS displays. These displays may also be available under post accident conditions.

The collected meteorological data is transmitted to the EPDS computer for display and use by the dose assessment model to calculate atmospheric dispersion values and dose from an accidental release of gaseous effluent.

The collected meteorological data is transmitted to the meteorological consultant for performance of activities described in Section 2.3.

7.7.2 ANALYSIS

The purpose of this subsection is to:

a. Demonstrate by direct or referenced analysis that the systems described are not required for any plant safety function

b. Demonstrate by direct or referenced analysis that the safety-related systems described elsewhere are capable of coping with all failure modes of the subject control systems

In response to Item (a), after considering and evaluating the design basis (Section 7.1.1), descriptions, and evaluations presented herein relative to the system, it can be concluded that these systems do not perform any safety function.

For consideration of Item (b), it is necessary to refer to the safety evaluations in Chapter 15. These sections demonstrate that the subject systems do not provide any design basis safety function and that any required safety functions are provided by other qualified systems.

7.7.2.1 Reactor Vessel Instrumentation

7.7.2.1.1 RVI General Functional Requirements Conformance

The RPV instrumentation is designed to provide redundant or augmented information from the safety-related systems. The operator uses this information to start up, operate at power, shut down, and service the reactor system in an efficient manner. None of this instrumentation is required to initiate or control any safety-related system.

7.7.2.1.2 RVI Specific Regulatory Requirements Conformance

Following are the specific regulatory requirements as well as those in 10CFR50, Appendix A, General Design Criteria requirements imposed on this sector vessel instrumentation.

7.7.2.1.2.1 RVI Conformance to Regulatory Guides

7.7.2.1.2.1.1 RVI - Regulatory Guide 1.11 (1971) - Instrument Lines Penetrating Primary Reactor Containment (Safety Guide 11)

Conformance to Regulatory Guide 1.11 is addressed in Section 6.2.4.

7.7.2.1.2.1.2 RVI - Regulatory Guide 1.75 (1978) - Physical Independence of Electric Systems

Conformance to Regulatory Guide 1.75 is discussed in Section 7.1.2.5.19.

7.7.2.1.2.2 Conformance to 10CFR50, Appendix A, General Design Criteria

7.7.2.1.2.2.1 RVI - GDC 13 - Instrumentation and Controls

The RPV information provides the operator with information on the reactor vessel operating variables during normal plant operation and anticipated operational occurrences so that the need to use the safety systems, although ready and able to respond, is minimized. Portions of this instrumentation are used in the feedwater system to maintain the reactor vessel operating variables within prescribed operating ranges.

7.7.2.1.2.2.2 RVI - GDC 24 - Separation of Protection and Control Systems

This instrumentation is not part of, or related to, any safety system. The circuitry of the safety systems is completely independent of this instrumentation so that failures of this instrumentation do not prevent the safety systems from initiating any action when required.

7.7.2.1.2.3 RVI Conformance to Industry Codes and Standards

7.7.2.1.2.3.1 RVI - IEEE 279 (1971), Paragraph 4.7 - Control and Protection System Interaction

This instrumentation is separate from and independent of the safety systems circuitry. There is no direct circuit-to-circuit or functional interactions between this instrumentation and the safety systems. No failures in this instrumentation can prevent the safety systems from meeting their minimum performance requirements.

7.7.2.2 Reactor Manual Control System - Instrumentation and Controls

7.7.2.2.1 RMCS General Functional Requirements Conformance

The circuitry described for the RMCS is completely independent of the circuitry controlling the scram valves. This separation of the scram and normal rod control functions prevents failures in the reactor manual control circuitry from affecting the scram circuitry. The scram circuitry is discussed in Section 7.2. Because each control rod is controlled as an individual unit, a failure that energizes any of the insert or withdraw solenoid valves affects only one control rod. The effectiveness of a reactor scram is not impaired if any one control rod malfunctions. It can be concluded that no single failure in the RMCS can prevent a reactor scram, and that repair, adjustment, or maintenance of RMCS components does not affect the scram circuitry.

Chapter 15 examines the various failure mode considerations for this system. The expected and abnormal transients and accident events analyzed envelop the NSOA associated with this system's components. These include the following:

a. Control rod withdrawal errors

b. Control rod-drop accident

The following are cited:

a. The RMCS is not required for plant safety functions. This system has no function associated with any DBA.

b. This system is not used for plant shutdown resulting from an accident or nonstandard operational conditions.

c. The function of the RMCS is to control core reactivity and thus power level. Interlocks from many different sources are incorporated to prevent the spurious operation of control rod drives or undesirable rod patterns throughout all ranges of operation.

d. This system contains no components, circuits, or instruments required for reactor trip. There are no operator manual controls that can prevent scram.

e. The requirements for the portions of the RMCS that interface with any safety system function include tolerance to single failures and component quality.

f. The rod withdrawal block trip function prevents an operator from carrying out actions that, if unchecked, could result in a RPS action (scram). A fixed margin separates the rod withdrawal block setpoints and the scram setpoints in IRM and APRM. There are no safety considerations.

g. No specific regulatory requirements apply to the rod block trip function. The circuits are designed to be normally energized (trip on loss of power) and are single active component failure tolerant. The equipment is designed to prevent the rod block trip circuitry from affecting the RPS trips in the IRM and APRM channels through the use of separate trip circuits and relays. IEEE standards do not apply because rod block trips are not required for any postulated design basis accident or for safe shutdown.

7.7.2.2.2 RMCS Specific Regulatory Requirements Conformance

The following statements represent the RMCS level of compliance with these applicable requirements.

7.7.2.2.2.1 RMCS Conformance to 10CFR50, Appendix A, General Design Criteria

7.7.2.2.2.1.1 RMCS - GDC 24 - Separation of Protection and Control Systems

No part of the RMCS is required for scram. The rod block functions provided by the NMS are the only instances where the RMCS uses any instruments or devices related to RPS functions. The rod block signals received from the NMS prevent improper rod motion before limits causing reactor scram are reached. Common APRM and IRM, detectors are used, but the signal is electrically isolated before its use in the RMCS (See Sections 7.6.1.4 and 7.6.2.4 for a description of this interface). This isolation is achieved through two separate relay trip units that prevent any feedback from the RMCS to the RPS. Single failure of a control component therefore does not degrade the RPS.

7.7.2.2.2.1.2 RMCS - GDC 26 - Reactivity Control System Redundancy and Capability

The RMCS is one of the two independent reactivity control systems as required by this GDC.

7.7.2.2.3 RMCS Power Generation Design Basis

The RMCS conforms to the provisions of the power generation design basis as discussed in the following.

a. The RMCS design limits the potential for inadvertent rod withdrawal, which could lead to RPS protective action by requiring deliberate operator action to effect rod withdrawal. The control buttons for rod withdrawal are spring-returned to the off position; two buttons must be held depressed for continuous rod withdrawal. Rod selection circuitry design prevents the withdrawal of more than one rod at a time.

b. Rod block interlocks in the RMCS design inhibit erroneous control rod motion to prevent circumstances that require an RPS protective action. Pertinent interlocks include the SDV high water level trip, APRM Simulated Thermal Power upscale trip, and IRM upscale trip (Section 7.7.1.2.3.2.3).

c. Rod block interlocks in the RMCS design inhibit erroneous control rod motion that could result in local fuel damage or undesirable core reactivity conditions. Pertinent interlocks include mode switch in SHUTDOWN, the RWM function, RBM (NMS) upscale and APRM recirculation flow upscale (Section 7.7.1.2.3.2.3).

d. Rod block interlocks inhibit rod movement whenever instrumentation is incapable of monitoring the core response or when protective system operating bypasses are in effect. Pertinent interlocks include APRM and RBM downscale or inoperative; APRM less than minimum number of LPRMs; IRM and SRM not fully inserted, downscale, or inoperative; rod position indicator malfunction; and SDV high level scram bypassed.

e. The RMCS design provides the operator with the information necessary to achieve prescribed control rod patterns and to provide information pertinent to the position and motion of the control rods. Each rod is instrumented to show its position if fully inserted or if fully withdrawn. The rod pattern controller provides information to the operator concerning rod inhibits, modes, and position.

7.7.2.3 Recirculation Flow Control System - Instrumentation and Controls

7.7.2.3.1 RFCS General Functional Requirements Conformance

The ASD has no mechanical inertia and will not supply any coast-down power to the pump motor after loss of ac power to the ASD or any other condition which trips the ASD. However, upon loss of the speed demand signal, the ASD will enforce a speed hold and continue to supply power to the pump motor to maintain the speed prior to the loss of control signal.

The analyses in Chapter 15 examine various failure modes and show that no malfunction in the RFCS can cause enough of a transient to damage the fuel barrier or exceed the nuclear system pressure limits as required by the safety design basis. Therefore, the system is classified as not required for safety.

7.7.2.3.2 RFCS Specific Regulatory Requirements Conformance

The RFCS is designed in compliance with the following GDC of Appendix A to 10CFR50; IEEE 279, Paragraph 4.7; and regulatory guides.

7.7.2.3.2.1 RFCS Conformance to 10CFR50, Appendix A, General Design Criteria

7.7.2.3.2.1.1 RFCS - GDC 12 - Suppression of Reactor Power Oscillations

See Section 7.1.2.6.7 for compliance discussion.

7.7.2.3.2.1.2 RFCS - GDC 13 - Instrumentation and Control

The RFCS is capable of monitoring and controlling its variables over their anticipated range for normal operation and for anticipated operational occurrences.

7.7.2.3.3 RFCS Power Generation Design Basis

The reactor RFCS conforms to the power generation design basis as follows:

The RFCS is designed to control the reactor power level, over a limited range, by controlling the flow rate of the reactor recirculating water. The control involves varying the speed of the recirculation pumps by supplying a demand signal to the ASD controller..

7.7.2.4 Feedwater Control System - Instrumentation and Controls

7.7.2.4.1 FCS General Functional Requirements Conformance

The FCS is a power generation system designed to maintain proper vessel water level. Interlocks are provided to lock the flow changing capabilities in the as-is condition if there is a control signal failure. If the vessel level rises too high, the feedwater pumps and plant main turbine are tripped. This is an equipment protective action that results in reactor shutdown by the RPS system as outlined in Section 7.2. Lowering the vessel level also causes the RPS to shut down the reactor.

The analyses in Chapter 15 examine the various failure mode considerations for this system relative to plant safety and operational effects. The analyses show that malfunctions of the FCS cannot cause enough of a transient to damage the fuel barrier or exceed the nuclear system pressure limits as required by the safety design basis. Therefore, the system is classified as not required for safety.

7.7.2.4.2 FCS Specific Regulatory Requirements Conformance

The FCS is not a safety-related system and is not required for safe shutdown of the plant, nor is it required during or after accident conditions.

No specific regulatory requirements are imposed on the system; however, the following general considerations are offered.

See Section 7.7.1.4 for a discussion of compliance details to the General Design Criteria.

7.7.2.4.3 FCS Power Generation Design Basis

The FCS, along with portions of RVI, regulates the feedwater flow over the entire power range of the reactor to maintain adequate water level in the reactor vessel, such that unnecessary initiation of safety-related systems because of low water level are prevented. The FCS instrumentation therefore augments safety-related information so that the operator can startup, operate, and shut down the reactor in an efficient manner.

7.7.2.5 Pressure Regulator and Turbine-Generator System - Instrumentation and Controls

7.7.2.5.1 PRTGS General Functional Requirements Conformance

Turbine speed and acceleration are controlled by a pressure regulator that controls steam throttle valve position to maintain constant reactor pressure. The turbine speed governor overrides the pressure regulator during an increase of system frequency or loss of generator load. Excess steam is automatically bypassed directly to the main condenser by the pressure-controlled bypass valves.

The analyses described in Chapter 15 examine the various failure mode considerations for this system relative to plant safety and operational effects. The analysis shows that malfunctions of the

PRTGS cannot cause enough of a transient to damage the fuel barrier or exceed the nuclear system pressure limits as required by the safety design basis. Therefore the system is classified as not required for safety.

7.7.2.5.2 PRTGS Specific Regulatory Requirements Conformance

No specific regulatory requirements are imposed on the PRTGS. However, the following general considerations should be noted.

See Section 7.7.1.5 for a discussion of compliance details to the General Design Criteria.

7.7.2.5.3 PRTGS General

The turbine-generator control system is not a safety-related system. The equipment protection systems provided as an integral part of the turbine-generator equipment override the turbine-generator control system. If there is a turbine-generator trip due to an equipment protection action, the control valve fast closure and the stop valve closure inputs to the RPS initiate reactor scram (Sections 7.2.1.1.4.2.d and 7.2.1.1.4.2.e).

Pressure regulator malfunctions that lead to low turbine inlet pressure are detected by pressure sensors provided in the PCRVICS which in turn initiate closure of the main steam line isolation valves (Section 7.3.1.1.2.4.5). Similarly, high turbine inlet pressure causes the RPS to detect high reactor pressure, which initiates reactor scram (Section 7.2.1.1.4.2.b).

Control malfunction (e.g., pressure regulation malfunction - upscale) that results in high flow through the turbine control valves and the bypass valves is detected by main steam flow sensors provided in the PCRVICS, which then initiate closure of the main steam line isolation valves (Section 7.3.1.1.2.4.5) and a subsequent reactor scram (Section 7.2.1.1.4.f).

Interfaces between the subject nonsafety-related system and safety-related systems (RPS and PCRVICS) are designed so that failure of the nonsafety-related components does not negate the necessary safety system functions.

7.7.2.5.4 PRTGS Power Generation Design Basis

See Section 7.1.2.1.10.3.

7.7.2.6 Neutron Monitoring System - Instrumentation and Controls

7.7.2.6.1 Source Range Monitor System

7.7.2.6.1.1 SRM General Functional Requirements Conformance

The arrangement of the neutron sources and startup chambers in the reactor is shown in Figure 7.6-1. This arrangement produces at least 3 counts/second in the SRM using the sensitivity noted in Section 7.7.1.6.1 and the design source strength at initial reactor startup. With the discriminator setting adjusted to produce the specified sensitivity, the signal-to-noise count ratio is above the 2:1 design basis for cold startup.

If the multiplication of one section of the core increases to put that section of the reactor on a 20 second period, the nearest SRM chamber shows an increase in count rate. In general, at least one detector indicates the change in multiplication.

Normal startup procedures ensure that withdrawal of control rods is distributed about the core to prevent excessive multiplication in any one section of the core.

Hence, each SRM chamber can respond in some degree during the initial rod withdrawal. During startup withdrawal, one of the four control rods adjacent to each SRM chamber and one control rod adjacent to each neutron source is withdrawn before the reactor is critical. This procedure reduces source and detector shadowing by the control blade and ensures increases in the detector signals as the core average neutron multiplication increases. Detector shadowing caused by the control blade reduces the SRM's ability to detect neutrons.

Examination of the sensitivity of the SRM detectors and their operating ranges of 10^6 counts/second indicates that the IRM is on scale before the SRM reaches full-scale (Figure 7.6-8).

7.7.2.6.1.2 SRM Specific Regulatory Requirements Conformance

There are no specific regulatory or IEEE requirements for the SRM system.

7.7.2.6.1.3 SRM Power Generation Design Basis

The SRM design conforms to the provisions of the power generation design basis as follows:

a. The SRM is designed so that over the operating range the ratio of signal-to-noise does not fall below a factor of two. Before initial power operation and with the control rods fully inserted, a count rate of at least 3 counts/ second will be detected from the installed source.

b. Under the worst possible startup rod withdrawal conditions, the SRM is capable of indicating a measurable increase in output signal from at least one detecting channel before the reactor period is less than 20 seconds.

c. During normal reactor startup the SRM is capable of indicating a substantial increase in output signals with the maximum permissible number of SRM channels out-of-service.

d. The indication on the upper scale of the SRM overlaps the indication on the lower scale of the IRM during reactor startup. The upper limit of the SRM range is $1x10^9$ nv nominal, and the lower limit of the IRM range is $1x10^8$ nv.

e. The SRM signal conditioning equipment processes the input to provide an output corresponding to the reactor period. This output is displayed in the control room and is also provided to remote recorders.

f. The SRM system has trips for SRM upscale, downscale, and instrument inoperable. With the reactor mode switch in STARTUP or REFUEL, any of these trips will initiate a rod block.

g. The SRM is designed to function in the maximum environmental conditions specified in Section 3.11.

h. Loss of single power bus will de-energize only half of the SRM channels and will not disable the monitoring and alarm functions of the remaining channels.

7.7.2.6.2 Rod Block Monitor System

7.7.2.6.2.1 RBM General Functional Requirements Conformance

Motion of a control rod causes the LPRMs adjacent to the control rod to respond strongly to the change in power in the region of the rod in motion. Figures 7.7-15 and 7.7-16 illustrate the calculated response of the two RBMs to the full withdrawal of a selected control rod from a region in which the design limits on power and flow exist. Curves are shown for the response when all LPRMs are operable and for cases when certain LPRMs are inoperable.

Because MCPR cannot reach 1.0 until the control rod is withdrawn through greater than half its stroke, the highest rod block setpoint halts rod motion well before local fuel damage can occur. This is true even with the adjacent and nearest LPRM detector assemblies failed.

7.7.2.6.2.2 RBM Specific Regulatory Requirements Conformance

IEEE standards and regulatory guides do not apply to the RBM system because it is not a protection system.

7.7.2.6.2.2.1 RBM Conformance to 10CFR50, Appendix A, General Design Criteria

7.7.2.6.2.2.1.1 RBM - GDC 24 - Separation of Protection and Control Systems

The RBM provides an interlocking function in the control rod withdrawal portion of the CRD RMCS. This design is separated from the protective functions in the plant to ensure their independence.

The RBM is designed to prevent inadvertent control rod withdrawal given an imposed single failure within the RBM. One of the two RBM channels is sufficient to provide an appropriate control rod withdrawal block.

7.7.2.6.2.3 RBM Power Generation Design Basis

The RBM design conforms to the provisions of the power generation design basis as follows:

a. The RBM inhibits erroneous control rod motion that could result in local fuel damage. An RBM upscale trip initiates the rod block. A rod block is also initiated by an RBM inoperative trip for any position of the reactor mode switch or RBM downscale with the mode switch in RUN, unless the RBM is correctly bypassed. One of the two RBM channels can be bypassed without loss of subsystem function because a trip signal from either RBM channel initiates a rod block.

b. RBM signal level is displayed to the operator and indicates the change in relative local power level.

7.7.2.6.3 Traversing Incore Probe System

7.7.2.6.3.1 TIP General Functional Requirements Conformance

An adequate number of TIP machines is supplied to ensure that each LPRM assembly can be probed by a TIP and that one LPRM (the central one) can be probed by every TIP to allow intercalibration. Typical TIPs are tested to prove linearity. The system has been field tested in an operating reactor to ensure reproducibility for repetitive measurements. The mechanical equipment has undergone life testing under simulated operating conditions to ensure that all specifications can be met. The system design allows semiautomatic operation for LPRM calibration and Plant Monitoring System use. The TIP machines can be operated manually for pointwise flux mapping.

7.7.2.6.3.2 TIP Specific Regulatory Requirements Conformance

There are no specific regulatory requirements for the TIP system.

7.7.2.7 Deleted

7.7.2.8 Reactor Water Cleanup System - Instrumentation and Controls

7.7.2.8.1 RWCU General Functional Requirements Conformance

The RWCU system is designed and supplied for plant equipment protection and operator information only. None of this instrumentation and control is required to initiate or control any safety-related system.

A high differential pressure across the filter/demineralizer or its discharge strainer automatically closes the unit's outlet valve after sounding an alarm. The holding pump starts whenever there is low flow through a filter/demineralizer. The precoat pump will not start or stop when the level in the precoat tank is low.

7.7.2.8.2 RWCU Specific Regulatory Requirements Conformance

7.7.2.8.2.1 RWCU Conformance to Regulatory Guides

7.7.2.8.2.1.1 RWCU - Regulatory Guide 1.56 (1978) - Maintenance of Water Purity in Boiling Water Reactors

The RWCU system provides the recorded conductivity measurements and alarms of influents and effluents of the demineralizers and records of the flow rate through each demineralizer as recommended in Regulatory Guide 1.56.

7.7.2.8.2.2 RWCU Conformance to 10CFR50, Appendix A, General Design Criteria

7.7.2.8.2.2.1 RWCU - GDC 63 - Monitoring Fuel and Waste Storage

To meet the requirements of GDC 63, monitors are placed in fuel and waste storage areas to give a continuous display of gamma levels and to alarm if a level exceeds the preselected level.

7.7.2.8.3 RWCU Power Generation Design Basis

The RWCU system design conforms to the power generation design basis as discussed in the following:

a. The RWCU system continuously processes reactor water to maintain water purity within specified limits. The system can be operated during normal plant operation, or during startup, shutdown, and refueling. The installed filter/demineralizer removes fission products, corrosion products, and other soluble and insoluble impurities.

b. Excess water can be removed from the reactor via the RWCU system to the main condenser, to the condensate storage tank, or to the equipment drain collection tank.

7.7.2.9 Process Radiation Monitoring Systems – Instrumentation and Controls

7.7.2.9.1 South Stack Effluent Radiation Monitoring System

7.7.2.9.1.1 SSE-RMS General Functional Requirements Conformance

The SSE-RMS is designed to draw two representative, isokinetic samples from each of the two unitized ducts in the south stack and to monitor these samples for radioactive particulates, iodines, and noble gases. These ducts provide exhaust venting for the reactor enclosure ventilation system. The monitoring systems are completely redundant and independent to ensure that monitoring capability is continuous during periods of maintenance. However, the system is not qualified for seismic Category I or IEEE Class 1E. If there is an accident, the south stack is isolated, and the SSE-RMS is not functional.

7.7.2.9.1.2 SSE-RMS Specific Regulatory Requirements Conformance

7.7.2.9.1.2.1 SSE-RMS Conformance to Regulatory Guides

7.7.2.9.1.2.1.1 SSE-RMS - Regulatory Guide 1.21 (1974) - Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants

The SSE-RMS is designed to comply with Regulatory Guide 1.21. Data generated by this instrument is transmitted to the RMMS (Section 11.5.6) to be incorporated into periodic Regulatory Guide 1.21 reports. Alarms are annunciated in the control room if radioactive concentrations exceed preset limits, but no control action is provided.

7.7.2.9.1.2.2 SSE-RMS Conformance to 10CFR50, Appendix A, General Design Criteria

7.7.2.9.1.2.2.1 SSE-RMS - GDC 13 - Instrumentation and Control

Instrumentation is provided to monitor radioactive effluents over their anticipated ranges for normal operation as well as anticipated operational occurrences.

7.7.2.9.1.2.2.2 SSE-RMS - GDC 64 - Monitoring Radioactivity Releases

Means are provided for monitoring effluent discharge paths for radioactivity that may be released from normal operations and anticipated operational occurrences.

7.7.2.9.1.2.3 SSE-RMS Conformance to 10CFR50, Appendix I

The SSE-RMS affords instrumentation with state-of-the-art sensitivity and quick response times to provide the operator with information that will ensure that radioactive effluents are as low as is reasonably practicable. In-place detectors for particulates, iodines, and noble gases provide real-time outputs in the control room to alert personnel to the escape of radioactive material in its early stages.

7.7.2.9.2 Radwaste Equipment Rooms Ventilation Exhaust Radiation Monitoring System - Instrumentation and Controls

7.7.2.9.2.1 RERV-RMS Power Generation Design Basis

This system is designed to provide a display and alarm capability in the control room for concentrations of radioactive material in the ventilation exhaust from the charcoal offgas treatment compartments. This monitoring system indicates leakage of radioactive material from the charcoal beds into the surrounding air.

7.7.2.9.2.2 RERV-RMS General Functional Requirements Conformance

This is an off-line process radiation monitoring system that measures the intensity of gamma radioactivity using a detector in a sampling chamber. High/downscale trip alarms are transmitted to annunciators in the control room.

7.7.2.9.2.3 RERV-RMS Specific Regulatory Requirements Conformance

Because the only purpose of this system is leak detection, it serves no safety-related function. The system is not required to meet any specific IEEE standards or regulatory guides. This system is used to detect a malfunction of the charcoal offgas treatment system, complying with GDC 60, because the charcoal treatment system controls releases of radioactive materials to the environment.

7.7.2.9.3 Charcoal Treatment System Process Exhaust Radiation Monitoring System - Instrumentation and Controls

7.7.2.9.3.1 CTSP-RMS Power Generation Design Basis

This system is designed to provide a display and alarm capability in the control room for concentrations of radioactive material in the effluents from the charcoal offgas treatment system. This monitoring system provides an indication of the effectiveness of the offgas treatment system in arresting radioactive discharges to the north stack.

7.7.2.9.3.2 CTSP-RMS General Functional Requirements Conformance

This is an off-line process radiation monitoring system that measures the intensity of gamma radioactivity by means of a detector in a sampling chamber. High/downscale trip alarms are transmitted to annunciators in the control room.

7.7.2.9.3.3 CTSP-RMS Specific Regulatory Requirements Conformance

There are no specific IEEE standards or regulatory guides that this system is required to meet. The system conforms to GDC 60, providing the operator with information on the effectiveness of the charcoal effluent treatment system in controlling releases of radioactive materials to the environment.

7.7.2.9.4 Recombiner Rooms and Hydrogen Analyzer Compartments Exhaust Radiation Monitoring System – Instrumentation and Controls

7.7.2.9.4.1 RRHAC-RMS - Power Generation Design Basis

This system is designed to provide a display and alarm capability in the control room if radioactive gaseous effluents leak from the recombiners, hydrogen analyzers, or equipment drain sumps. It can also localize the source of such leakage.

7.7.2.9.4.2 RRHAC-RMS General Functional Requirements Conformance

This is an off-line process radiation monitoring system that measures concentrations of radioactive gaseous effluents in the ventilation ducting from the recombiner compartments, hydrogen analyzer compartments, and equipment drain sump. High/downscale trip alarms are transmitted to an annunciator in the control room. A hand selector switch actuating a set of solenoid valves is provided for determining the source of the high radiation indication.

7.7.2.9.4.3 RRHAC-RMS Specific Regulatory Requirements Conformance

There are no specific IEEE standards or regulatory guides that this system is required to meet.

7.7.2.9.5 Steam Exhauster Discharge and Vacuum Pump Exhaust Radiation Monitoring System - Instrumentation and Controls

7.7.2.9.5.1 SEDVP-RMS Power Generation Design Basis

This monitoring system is designed to detect the presence of short half-life radioactive isotopes leaking from the steam seals of the turbines or excessive radioactivity in the mechanical vacuum pump exhaust.

7.7.2.9.5.2 SEDVP-RMS General Functional Requirements Conformance

This is an off-line process radiation monitoring system that measures the intensity of gamma radioactivity by a detector in a sampling chamber.

7.7.2.9.5.3 SEDVP-RMS Specific Regulatory Requirements Conformance

There are no specific IEEE standards or regulatory guides that this system is required to meet. It is a power generation system and serves no safety-related function.

7.7.2.9.6 Radwaste Enclosure Ventilation Radiation Monitoring System - Instrumentation and Controls

7.7.2.9.6.1 REV-RMS Power Generation Design Basis

This system is designed to provide a display and alarm capability in the control room if unacceptable radioactive concentrations leak into the radwaste enclosure ventilation exhaust.

7.7.2.9.6.2 REV-RMS General Functional Requirements Conformance

This is an off-line process radiation monitoring system that measures the concentration of gamma radioactivity in the ventilation exhaust from the radwaste enclosure by means of a detector in a shielded sampling chamber. Evidence of leakage in this system is to be used for diagnostic purposes.

7.7.2.9.6.3 REV-RMS Specific Regulatory Requirements Conformance

This is a power generation system and serves no safety-related function. There are no specific IEEE standards or regulatory guides that this system is required to meet.

7.7.2.9.7 Air Ejector Offgas Effluent Radiation Monitoring System - Instrumentation and Controls

7.7.2.9.7.1 AEO-RMS General Functional Requirements Conformance

The AEO-RMS monitors the offgas effluents downstream of the recombiner and provides indication and alarm under appropriate OUT OF ACCEPTABLE RANGE radiation levels.

The AEO-RMS monitors have characteristics sufficient to provide accurate indication of radioactivity in the air ejector offgas. Sufficient redundancy is provided to allow maintenance on one channel without losing the system indications.

7.7.2.9.7.2 AEO-RMS Specific Regulatory Requirements Conformance

No specific regulatory guides or IEEE standards apply to this system.

7.7.2.9.7.2.1 AEO-RMS Conformance to 10CFR50, Appendix A, General Design Criteria

7.7.2.9.7.2.1.1 AEO-RMS - GDC 13 - Instrumentation and Control

The system conforms to GDC 13 in that the instruments used cover the anticipated range of radiation under normal operating conditions with enough margin to include postulated accident conditions.

7.7.2.9.7.2.1.2 AEO-RMS - GDC 64 - Monitoring Radioactivity Releases

The system conforms to GDC 64 in that it monitors radioactive releases resulting from normal operations including anticipated operational occurrences.

7.7.2.9.8 Primary Containment Leak Detection Radiation Monitoring System - Instrumentation and Controls

7.7.2.9.8.1 PCLD-RMS General Functional Requirements Conformance

The PCLD-RMS supplements the leak detection instrumentation for the primary containment. This monitoring system continually samples the containment (drywell) atmosphere for radioactive noble gases. It is designed to respond to increases in the concentration of radioactivity in the containment atmosphere.

This system is not intended for use during or after a LOCA. In this eventuality, the PCLD-RMS will be automatically isolated from the containment. The PCLD-RMS is a power generation system, and is not safety-related.

7.7.2.9.8.2 PCLD-RMS Specific Regulatory Requirements Conformance

7.7.2.9.8.2.1 PCLD-RMS Conformance to Regulatory Guides

7.7.2.9.8.2.1.1 PCLD-RMS - Regulatory Guide 1.45 (1973) - Reactor Coolant Pressure Boundary Leakage Detection Systems

The PCLD-RMS is designed to provide one of the three independent means of detecting RCPB leakage. The systems provided meet the intent of Regulatory Guide 1.45 and meet or exceed the recommendations of ANSI/ISA S67.03.

7.7.2.9.8.2.2 PCLD-RMS 10CFR50, Appendix A, General Design Criteria

7.7.2.9.8.2.2.1 PCLD-RMS - GDC 2 - Design Bases for Protection Against Natural Phenomena

The PCLD-RMS is not designed to continue its leak detection capability after a SSE. The other RCPB leak detection systems are designed to withstand an SSE (sump level) or an OBE (drywell chiller drains).

7.7.2.9.8.2.2.2 PCLD-RMS - GDC 13 - Instrumentation and Control

The PCLD-RMS is designed to monitor for containment internal leakage over normal operation and anticipated occurrences, but not for accidents that result in containment isolation.

7.7.2.9.8.2.2.3 PCLD-RMS - GDC 64 - Monitoring Radioactivity Releases

The PCLD-RMS provides a means of monitoring the containment atmosphere for radioactivity released from the RCPB during normal operations and anticipated operational occurrences.

7.7.2.9.9 Hot Maintenance Shop Ventilation Exhaust Radiation Monitoring System - Instrumentation and Controls

7.7.2.9.9.1 HMS-RMS General Functional Requirements Conformance

The HMS-RMS monitors the effluents from the hot maintenance shop exhaust filters in the ventilation duct. All instrumentation is local. This system provides to the RMMS an ongoing record of the number of concentration of particulates and iodines discharged from the hot maintenance shop to the environment. Under normal operating conditions, this radioactive effluent is insignificant. If there is an anomalous occurrence, an alarm annunciator alerts hot maintenance personnel of a malfunction.

7.7.2.9.9.2 HMS-RMS Specific Regulatory Requirements Conformance

7.7.2.9.9.2.1 HMS-RMS Conformance to Regulatory Guides

7.7.2.9.9.2.1.1 HMS-RMS - Regulatory Guide 1.21 (1974) - Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants

The HMS-RMS is designed to comply with Regulatory Guide 1.21. Data generated by this instrument are transmitted to the RMMS (Section 11.5.6) to be incorporated into periodic Regulatory Guide 1.21 reports.

7.7.2.9.9.2.2 HMS-RMS Conformance to 10CFR50, Appendix A, General Design Criteria

7.7.2.9.9.2.2.1 HMS-RMS - GDC 13 - Instrumentation and Control

Instrumentation is provided to monitor radioactive effluents over their anticipated ranges for normal operation as well as for anticipated operational occurrences.

7.7.2.9.9.2.2.2 HMS-RMS - GDC 64 - Monitoring Radioactivity Releases

Means are provided for monitoring an effluent discharge path for radioactivity that may be released from normal operations and anticipated operational occurrences.

7.7.2.9.10 Liquid Radwaste Discharge Radiation Monitoring System - Instrumentation and Controls

7.7.2.9.10.1 LRD-RMS Power Generation Design Basis

This system is designed to trip the valves in the liquid radwaste discharge line when the concentration of radioactive effluents in the liquid radwaste discharge is unacceptable. The monitoring system also provides ongoing records of radioactive releases, together with displays in the radwaste control room and alarm annunciation in the main control room.

7.7.2.9.10.2 LRD-RMS General Functional Requirements Conformance

This is an off-line process radiation monitoring system that measures the gross concentration of radioactive isotopes in the liquid radwaste discharge. Combined with flow rate data, the radiation data are used to keep an inventory of the total liquid radioactive discharge from the plant. When concentrations of the discharges exceed permissible limits, these discharges are automatically stopped.

7.7.2.9.10.3 LRD-RMS Specific Regulatory Requirements Conformance

No specific IEEE standards apply to this system.

7.7.2.9.10.3.1 LRD-RMS Conformance to Regulatory Guides

7.7.2.9.10.3.1.1 LRD-RMS - Regulatory Guide 1.21 (1974) - Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants

The system conforms to Regulatory Guide 1.21 in maintaining records of discharges of radioactive effluents from the plant and in holding the discharges within permissible limits.

7.7.2.9.10.3.2 LRD-RMS Conformance to 10CFR50, Appendix A, General Design Criteria

7.7.2.9.10.3.2.1 LRD-RMS - GDC 60 - Control of Releases of Radioactive Materials to the Environment

The system controls releases of radioactive materials to the environment.

7.7.2.9.10.3.2.2 LRD-RMS - GDC 64 - Monitoring Radioactive Releases

The system provides a means of monitoring an effluent discharge path for radioactivity that may be released from normal operations and anticipated operational occurrences.

7.7.2.9.11 Service Water Radiation Monitoring System - Instrumentation and Controls

7.7.2.9.11.1 SW-RMS Power Generation Design Basis

This system is designed to provide a display and alarm capability in the control room if there is leakage of radioactive material into the plant service water. Concentrations of radioactive materials in the service water are detected in the discharge to the cooling tower. A display, an ongoing record, and an alarm annunciation capability are provided in the control room.

7.7.2.9.11.2 SW-RMS General Functional Requirements Conformance

This is an off-line process radiation monitoring system that measures the concentration of radioactive materials in the service water discharges. High/downscale trip alarms are transmitted to an annunciator in the control room. This information is used for diagnostic purposes.

7.7.2.9.11.3 SW-RMS Specific Regulatory Requirements Conformance

There are no specific IEEE standards or regulatory guides that this system is required to meet. It partially satisfies GDC 64, in that it monitors radioactive releases to the cooling tower resulting from normal operations and anticipated malfunctions.

7.7.2.9.12 Reactor Enclosure Cooling Water Radiation Monitoring System - Instrumentation and Controls

7.7.2.9.12.1 RECW-RMS Power Generation Design Basis

This system is designed to provide a display and alarm capability in the control room if there is leakage of radioactive material into the RECW. Such a condition could occur only if a leak occurs in the interface between the reactor enclosure cooling water system and the service water system, and if radioactive contamination is already present in the plant service water system. Consequently, the probability of a high radiation alarm is remote.

7.7.2.9.12.2 RECW-RMS General Functional Requirements Conformance

This is an off-line process radiation monitoring system that measures the concentration of radioactive materials in the cooling water. High/downscale alarm trips are transmitted to an annunciator in the control room. This information is used for diagnostic purposes.

7.7.2.9.12.3 RECW-RMS Specific Regulatory Requirements Conformance

There are no specific IEEE standards or regulatory guides that this system is required to meet.

7.7.2.10 Area Radiation Monitoring System - Instrumentation and Controls

7.7.2.10.1 ARMS General Functional Requirements Conformance

a. Sensor/converters monitor the gamma radiation levels at the selected locations and send a dc signal, proportional to the gamma level, to the control room where indicator/trip units display the signal.

b. Wherever it is necessary to have the local indication and alarm, an auxiliary unit and a horn are installed at the desired location. The auxiliary unit receives the signal from the indicator/trip unit both for display and alarm. The local alarm consists of an indicator and a red light. The light and horn are energized if the alarm level is exceeded.

7.7.2.10.2 ARMS Specific Regulatory Requirements Conformance

7.7.2.10.2.1 ARMS Conformance to Regulatory Guides

7.7.2.10.2.1.1 ARMS - Regulatory Guide 1.97 (1980) - Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

Section 7.5.2.5.1.1.2 contains a discussion of the degree of conformance.

7.7.2.10.2.2 ARMS Conformance to 10CFR50, Appendix A, General Design Criteria

7.7.2.10.2.2.1 ARMS - GDC 63 - Monitoring Fuel and Waste Storage

To meet the requirements of GDC 63, monitors are placed in fuel and waste storage areas to give a continuous display of gamma levels and to alarm if the levels exceed preselected heights.

7.7.2.11 Gaseous Radwaste System - Instrumentation and Controls

7.7.2.11.1 GRS General Functional Requirements Conformance

This is not a safety-related system.

The offgas flow recorder is provided to keep a record of all discharge volumes.

All instrumentation with connections to the offgas process lines is purchased and installed not to exceed a maximum leak rate of $1x10^{-6}$ atm-cc/sec to limit release of radioactive gases other than through the controlled process system release point after treatment.

Chapter 15 examines the various failure mode considerations for this system. These include:

a. Failure of the charcoal bed

b. Failure of the delay piping

7.7.2.11.2 GRS Specific Regulatory Requirements Conformance

7.7.2.11.2.1 GRS Conformance to Regulatory Guides

7.7.2.11.2.1.1 GRS - Regulatory Guide 1.21 (1974) - Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water- Cooled Nuclear Power Plants

The stack measurements (which include the offgas system effluents) provide the methods of measuring the effluents that are required to be reported.

7.7.2.12 Liquid Radwaste System - Instrumentation and Controls

7.7.2.12.1 LRS General Functional Requirements Conformance

The liquid radwaste flow for discharge to the blowdown line is flow controlled and monitored for activity level. The discharge flow shutoff valves are operated by key-lock switches that require plant supervisory control of any releases. The flow is recorded in the radwaste control room.

The packaged wastes are stored in a plant storage area set aside for this purpose. The radioactivity and quantity is the responsibility of plant supervisory personnel.

7.7.2.12.2 LRS Specific Regulatory Requirements Conformance

7.7.2.12.2.1 LRS Conformance to Regulatory Guides

7.7.2.12.2.1.1 LRS - Regulatory Guide 1.21 (1974) - Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water- Cooled Nuclear Power Plants

The radwaste flow measurements provide the method of measuring effluents that are required to be reported.

7.7.2.13 Solid Radwaste System - Instrumentation and Controls

7.7.2.13.1 SRS General Functional Requirements Conformance

The solid radwaste handling system is not a safety-related system. Therefore, the instrumentation supplied is for system equipment protection and for operator information only.

7.7.2.13.2 SRS Specific Regulatory Requirements Conformance

No specific regulatory requirements are imposed on the subject system instrumentation and controls.

7.7.2.14 Fuel Pool Cooling and Cleanup System – Instrumentation and Controls

7.7.2.14.1 FPCC General Functional Requirements Conformance

The FPCC system is not a safety-related system. Indicators and alarms are not needed to prevent an accident and are only used as an operator aid for plant equipment protection and for operator information.

The primary function of the FPCC system is to remove decay heat from the spent fuel storage pool water to ensure adequate cooling of irradiated stored assemblies. The FPCC system also purifies the spent fuel storage pool water. It maintains water clarity for fuel handling operations and fills and drains the fuel transfer canal.

The pool water temperature is controlled manually; automatic temperature control is not required. Once the desired cooler duty has been established, the cooling load changes gradually with time; only when spent fuel is added to or taken from the pool does the cooling load change rapidly. The two fuel pool cooling system pumps are controlled from the control room. All other functions of the FPCC system are accomplished by local manipulation of valves and control of the equipment.

The instrumentation in the FPCC system provides measurements that are used to indicate and alarm as indicated in Section 7.7.1.14.

The FPCC system is monitored for conductivity, temperature, pool level, flow rate, and leakage.

The conductivity measurement provides the operator with the information required to ensure that impurities in the water are maintained at acceptable levels.

Low flow (pump discharge pressure) and temperature monitoring provide the operator with the information required to ensure that the desired temperature is not exceeded and that filtering is maintained. Pool level and leakage monitoring provide the operator with information ensuring the maintenance of adequate shielding and cooling.

The FPCC system is an independent system during normal operation. Evaporative losses in the system can be replaced from the Demin Water System or by the condensate storage system. If the heat load becomes excessive, the shutdown cooling portion of the RHR system can be operated in parallel with the FPCC system to remove the excess heat, when in the shutdown mode.

7.7.2.14.2 FPCC Specific Regulatory Requirements Conformance

7.7.2.14.2.1 FPCC Conformance to 10CFR50, Appendix A, General Design Criteria

7.7.2.14.2.1.1 FPCC - GDC 61 - Fuel Storage and Handling and Radioactivity Control

The fuel pool cooling and cleanup system filters and cools the spent fuel pool water to remove residual heat and maintain pool water clarity for refueling operations. The controls and instrumentation designed for this system provide monitoring to ensure proper operation of the fuel pool cooling and cleanup system so that conductivity, temperature, levels, flow, and leakage are maintained at normal levels.

7.7.2.15 Refueling Interlocks - Instrumentation and Controls

7.7.2.15.1 RI General Functional Requirements Conformance

The refueling interlocks, in combination with core nuclear design and refueling procedures, limit the probability of an inadvertent criticality. The nuclear characteristics of the core ensure that the reactor is subcritical even when the highest worth control rod is fully withdrawn. Refueling procedures are written to avoid situations in which inadvertent criticality is possible. The combination of refueling interlocks for control rods and refueling platform interlocks provides redundant methods of preventing inadvertent criticality even after procedural violations. The interlocks on hoists provide yet another method of avoiding inadvertent criticality.

Table 7.7-3 illustrates the effectiveness of the refueling interlocks. This table considers various operational situations involving rod movement, hoist load conditions, refueling platform movement and position, and mode switch manipulation. The initial conditions in situations 4 and 5 appear to contradict the action of refueling interlocks, because the initial conditions indicate that more than one control rod is withdrawn, yet the mode switch is in REFUEL. Such initial conditions are possible if the rods are withdrawn when the mode switch is in STARTUP, and then the mode switch is turned to REFUEL. In all cases, correct operation of the refueling interlock prevents either the operation of loaded refueling equipment over the core when any control rod is withdrawn, or the withdrawal of any control rod when fuel-loaded refueling equipment is operating over the core. In addition, when the mode switch is in REFUEL, only one rod can be withdrawn; selection of a second rod initiates a rod block.

7.7.2.15.2 RI Specific Regulatory Requirements Conformance

No specific regulatory requirements apply to refueling interlocks. The refueling interlocks are designed to be normally energized (fail-safe) and single failure tolerant of equipment failures.

IEEE standards do not apply because the refueling interlocks are not required for any postulated DBA or for safe shutdown. The interlocks are required only for the refueling mode of plant operation. The requirements of 10CFR50, Appendix B, are met in the manner set forth in Chapter 17.

No specific GDC requirements apply to this system.

7.7.2.16 Leak Detection System - Instrumentation and Controls

7.7.2.16.1 LDS General Functional Requirements Conformance

Following are the analyses to demonstrate how various general function requirements listed under the leak detection system (Section 7.7.1.16) are satisfied.

7.7.2.16.2 LDS Specific Regulatory Requirements Conformance

7.7.2.16.2.1 LDS Conformance to Regulatory Guides

7.7.2.16.2.1.1 LDS - Regulatory Guide 1.45 (1973) - Reactor Coolant Pressure Boundary Leakage Detection Systems

Leakage into the primary reactor containment from identified sources such as valve stem packing, recirculation pump seal, head seal, etc., is separated so that flow rates are monitored separately from unidentified leakages and total flow rates can be established and monitored as described in Section 5.2.5.2.1.3.

Similarly, the flow rate for unidentified leakage is monitored to detect a pipe break in the primary containment.

Condensation from the drywell air coolers is monitored to provide a diverse means of detecting RCPB leakage. This monitoring provision is described in Section 5.2.5.2.1.4.

Noble gas radioactivity monitoring is also provided to supplement the flow measurement methods of RCPB leak detection, as described in Section 5.2.5.2.1.5.

The RCPB leak detection systems and equipment provided at LGS meet the intent of Regulatory Guide 1.45 and meet or exceed the recommendations of ANSI/ISA S67.03.

7.7.2.16.2.2 LDS Conformance to 10CFR50, Appendix A, General Design Criteria

7.7.2.16.2.2.1 LDS - GDC 13 - Instrumentation and Control

The leak detection sensors and associated electronics are designed to monitor reactor coolant leakage over all expected ranges required for the safety of the plant.

7.7.2.16.2.2.2 LDS - GDC 19 - Control Room

Controls and instrumentation are provided in the control room.

7.7.2.16.2.2.3 LDS - GDC 30 - Quality of Reactor Coolant Pressure Boundary

The system provides the means for detecting and locating the source of the reactor coolant leakage. This also applies to the sump drywell, recirculating pump, and SRV leak detection equipment.

7.7.2.16.2.2.4 LDS - GDC 34 - Residual Heat Removal

Leak detection is provided for the RHR shutdown cooling lines penetrating the drywell.

7.7.2.16.2.2.5 LDS - GDC 54 - Piping Systems Penetrating Containment

Leak detection is provided for the RHR shutdown cooling lines penetrating the containment. Sump fill rate monitoring provides leak detection for other pipes penetrating the containment and reactor enclosures.

7.7.2.16.2.3 LDS Conformance to Industry Codes and Standards

7.7.2.16.2.3.1 LDS - IEEE 344 (1971) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

The RHR and the drywell leak detection systems comply with this standard. See Section 3.10.

7.7.2.16.2.3.2 LDS - ANSI/ISA S67.03

The RCPB leak detection systems and equipment provided at LGS meet or exceed the recommendations of this standard.

7.7.2.17 Emergency Response Facilities Data System - Instrumentation and Controls

7.7.2.17.1 ERFDS General Functional Requirements Conformance

The ERFDS is designed to provide the operator with certain categories of information. The system augments information from other systems so that the operator can startup, operate at power, and shutdown in an efficient manner. This system is not required to initiate or control any safety-related system.

7.7.2.17.2 ERFDS Specific Regulatory Requirements Conformance

The ERFDS is not classified as a safety system and does not initiate any safety-related functions.

The ERFDS has provisions for appropriate isolation from interfacing equipment classified as Class 1E, and the maintenance of the ERFDS is possible without affecting the function of the interfacing Class 1E systems.

The following summarizes the requirements given in section 4.1 of NUREG-0737, Supplement 1 and generic design implementation characteristics which are fully applicable to LGS:

a. "Displays shall be available..."

Reliability has been designed into the ERFDS by providing

1. redundant and validated signals
2. on-line failure diagnostics
3. processor backup
4. use of quality components

"Provide concise displays of critical plant variables..."

This requirement is met by all top level displays discussed in Section 7.7.1.17.

b. "Continuous display of SPDS parameters shall be located conveniently to the control room operator..."

The installed ERFDS configuration ensures that this requirement will be met.

Graphic display consoles are located in the LGS control room. These consoles provide continuous display of SPDS parameters.

c. "The SPDS shall be suitably isolated from...safety systems."

This concern is addressed in Section 7.7.1.17 2.4.

d. "Prompt implementation of SPDS...information."

The schedule for implementation of the LGS SPDS is provided in Section 1.13, Item I.D.1. The selection of parameters included in the ERFDS was based on the guidance provided in NUREG-0696.

e. "The SPDS shall be designed to incorporate accepted human factors principles..."

This concern is addressed in Section 7.7.1.17.2 1.

f. "The minimum information to be provided shall be sufficient to provide information to plant operators about:"

"(i) Reactivity Control"

Reactor power is one of the EPG control parameters. Its control is addressed by the RPV Control display which includes the reactor power trend plot and the SCRAM event target. Expanded trend information is also given by the full page reactor power trend plot.

"(ii) Reactor core cooling and heat removal from the primary system"

Core cooling and heat removal are evidence by EPG control parameters of RPV water level and pressure. The RPV Control Display provides trend and value information for these parameters as well as for RPV temperature when the reactor is shutdown. It also provides event targets (e.g., SRV, MSIV). Expanded trend information is also given by the full page trend plot displays.

"(iii) Reactor coolant system integrity"

A breach of the reactor coolant boundary would be evident by the reactor and containment response (the latter for breaches in the primary containment). The initial alert would be evident on the Critical Plant Variables Display and/or the RPV Control and Containment Control Displays. Sufficient information to mitigate the consequences of a RCS breach in accordance with the LGS EOPs is given on the RPV Control and Containment Control Displays through indication of RPV water level, RPV pressure, SRV positions, drywell temperature, and drywell pressure.

"(iv) Radioactivity Control"

The LGS ERFDS monitors selected process and area radiation monitors in the plant. However, the computer-based system with primary responsibility for providing the process, area, and stack effluent radiation data required for radioactivity control is the RMMS. An RMMS color graphic CRT with keyboard is located in close proximity (within approximately 6 feet) of the ERFDS CRT in the control room. This provides control room personnel with concise displays of radioactivity control data in close proximity to the SPDS displays provided by the ERFDS. A description of the RMMS is given in Section 11.5.6.

"(v) Containment conditions"

Trends and values of containment control parameters and event indications that affect containment conditions (e.g., SRV OPEN, ISOLATION VALVE CLOSURE), are given on the Containment Control Display. Key top level information is given on the Critical Variables Display and expanded trend information on the full page trend plot displays.

7.7.2.18 Containment Instrument Gas System - Instrumentation and Controls

7.7.2.18.1 CIGS General Functional Requirements Conformance

Following are analyses that demonstrate how the CIGS satisfies applicable plant design requirements.

7.7.2.18.2 CIGS Specific Regulatory Requirements Conformance

7.7.2.18.2.1 CIGS Conformance to Regulatory Guides

7.7.2.18.2.1.1 CIGS - Regulatory Guide 1.30 (1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

See Section 8.1.6.1.

7.7.2.18.2.2 CIGS Conformance to 10CFR50, Appendix A, General Design Criteria

7.7.2.18.2.2.1 CIGS - GDC 13 - Instrumentation and Control

Instrumentation is provided to monitor the operation of the CIGS over its anticipated range of operating conditions. Manual operation of the system is possible from the local control panels.

7.7.2.18.2.2.2 CIGS - GDC 56 - Primary Containment Isolation

The suction line has two automatic isolation valves: one inside and one outside containment. The CIGS supply lines have an automatic isolation valve outside containment and a check valve inside containment.

7.7.2.18.2.3 CIGS Conformance to Industry Codes and Standards

7.7.2.18.2.3.1 CIGS - IEEE 336 (1971) - Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations

See Section 8.1.6.1.

7.7.2.18.2.3.1.2 CIGS - IEEE 384 (1974) - Criteria for Separation of Class 1E Equipment and Circuits

See Section 7.1.2.7.9.

7.7.2.19 Fire Protection and Suppression System - Instrumentation and Controls

7.7.2.19.1 FPSS General Functional Requirements Conformance

A local annunciator panel located in the auxiliary equipment room will receive a signal from the smoke detectors located in the raised floor. This panel will indicate which PGCC floor section has alarmed. The plant operator will decide, in case of fire, either to use a portable fire extinguisher through removable floor plates or to manually initiate the Halon system from a remote station. Automatic actuation is initiated by thermal detection.

7.7.2.19.2 FPSS Specific Regulatory Requirements Conformance

The PGCC design complies with the applicable requirements of the standards described in the GE topical report NEDO-10466-A, "Power Generation Control Complex."

7.7.2.20 Nonsafety-Related Equipment Area Cooling Ventilation Systems - Instrumentation and Controls

7.7.2.20.1 Power Generation Design Basis

Instruments and controls are provided to ensure adequate ventilation for equipment and personnel located in the areas serviced by the nonsafety-related equipment area cooling ventilation systems during normal plant operation.

7.7.2.20.2 General Functional Requirements Conformance

7.7.2.20.2.1 Reactor Enclosure Ventilation System

Instrumentation and controls are designed to provide the operator with information necessary to operate the reactor enclosure ventilation system in an efficient manner during normal plant operation. None of this instrumentation is required to initiate or control any safety-related systems because, after a DBA, operation is terminated upon initiation of the REIS.

7.7.2.20.2.2 Turbine Enclosure Ventilation System

Instrumentation and controls are designed to provide the operator with the information necessary to operate the turbine enclosure ventilation system efficiently during normal plant operation. The

turbine enclosure ventilation system is not safety-related and does not operate after a DBA. See Section 9.4.4.5 for instrumentation requirements.

7.7.2.20.2.3 Radwaste Enclosure and Chem. Lab. Expansion Ventilation System

Instrumentation and controls are designed to provide the operator with the information necessary to operate the radwaste enclosure and chem. lab. expansion ventilation system efficiently during normal plant operation. The radwaste enclosure ventilation system is not safety-related and does not operate after a DBA. See Section 9.4.3.5 for instrumentation requirements.

7.7.2.20.2.4 Hot Maintenance Shop Ventilation System

Instrumentation and controls are designed to provide the operator with the information necessary to operate the hot maintenance shop ventilation system efficiently during normal plant operation. The hot maintenance shop ventilation system is not safety-related and does not operate after a DBA. See Section 9.4.8.5 for instrumentation requirements.

7.7.2.20.2.5 Miscellaneous Enclosure Ventilation System

Instrumentation and controls are designed to provide the operator with the information necessary to operate the miscellaneous enclosure ventilation systems efficiently during normal plant operation. The miscellaneous enclosure ventilation systems are not safety-related and do not operate after a DBA. See Section 9.4.9.5 for instrumentation requirements.

7.7.2.20.3 Specific Regulatory Requirements Conformance

There are no specific IEEE standards or regulatory guides with which these systems must comply.

7.7.2.21 Rod Worth Minimizer - Instrumentation and Controls

7.7.2.21.1 RWM General Functional Requirements Conformance

7.7.2.21.1.1 RWM Power Generation Design Basis

The RWM monitors and enforces operator adherence to established startup, shutdown, and low power level control rod sequences. The startup or shutdown of the reactor can continue without the RWM when a second licensed operator or a technically qualified member of the unit technical staff is present to check rod movements.

7.7.2.21.2 RWM Specific Regulatory Requirements Conformance

The RWM is not classified as a safety-related system and is not required to initiate any safety-related functions.

7.7.2.21.2.1 RWM Conformance to Regulatory Guides

7.7.2.21.2.1.1 RWM - Regulatory Guide 1.29 (1978) - Seismic Design Classification

The RWM operator display panel meets the applicable portions of the regulatory guide.

7.7.2.21.2.2 RWM Conformance to Industry Codes and Standards

7.7.2.21.2.2.1 RWM - IEEE 388 (1974) - Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations

The RWM operator display panel and interconnecting cable meet the applicable portions of the regulatory guide.

7.7.2.22 Plant Monitoring System - Instrumentation and Controls

7.7.2.22.1 PMS General Functional Requirements Conformance

The plant monitoring system is designed to provide the operator with certain categories of information. The system augments information from other systems so that the operator can start up, operate at power, and shut down in an efficient manner. This system is not required to initiate or control any safety-related system. The analyses for the RWM function are contained in Section 7.7.1.21.

7.7.2.22.2 PMS Specific Regulatory Requirements Conformance

The PMS is not classified as a safety system and does not initiate any safety-related functions.

The PMS has provisions for appropriate isolation from interfacing equipment classified as Class 1E, and the maintenance of the PMS is possible without affecting the function of the interfacing 1E systems.

The PMS data acquisition system employs signal isolation and fiber optics cables designed to prevent electrical interference between the PMS and Class 1E safety systems. Thus the PMS conforms with all electrical isolation requirements.

7.7.2.22.2.1 PMS Conformance to Industry Codes and Standards

7.7.2.22.2.1.1 PMS - IEEE 323 (1974) - IEEE Trial Use Standard: General Guide for Qualifying Class 1 Electric Equipment for Nuclear Power Generating Stations

These DAS I/O modules are not Class 1E qualified but the Scientech I/C Isolators conform to this standard. Class 1E qualifications and conformance to the IEEE Standards applies only to those modules that provide isolation between Class 1E and Non-Class 1E circuits. (NUREG-0588 Category I)

7.7.2.22.2.1.2 PMS - IEEE 344 (1975) - Guide for Seismic Qualification of Class 1 Electric Equipment for Nuclear Power Generating Stations

These DAS I/O modules are not Class 1E but the Scientech I/C Isolators conform to this standard. Class 1E qualifications and conformance to the IEEE Standards applies only to those modules that provide isolation between Class 1E and Non-Class 1E circuits. See Section 3.10.

7.7.2.22.2.1.3 PMS - IEEE 383 (1974) - Guide for Type Test of Class 1 Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations

These DAS I/O modules are not Class 1E qualified but the Scientech l/C Isolators conform to this standard. Class 1E qualifications and conformance to the IEEE Standards applies only to those modules that provide isolation between Class 1E and Non-Class 1E circuits.

7.7.2.22.2.1.4 PMS - IEEE 384 (1981) - Criteria for Independence of Class 1E Equipment and Circuits

These DAS I/O modules are not Class 1E qualified but the Scientech l/C Isolators conform to this standard. No fault on the isolator output wiring can affect any isolator input signal. Class 1E qualifications and conformance to the IEEE Standards applies only to those modules that provide isolation between Class 1E and Non-Class 1E circuits.

Table 7.7-1

CRD HYDRAULIC SYSTEM PROCESS INDICATORS

MEASURED VARIABLE	INSTRUMENT TYPE
Total system flow	Flow indicator
Drive water pump suction pressure	Annunciator
Drive water filter differential pressure	Annunciator
Cooling water header differential pressure	Pressure indicator
Charging water header pressure	Annunciator and indicator
Drive water flow rate	Flow indicator
Cooling water header flow rate	Flow indicator
CRD temperature	Annunciator
SDV not drained	Annunciator
Scram valve pilot air header pressure	Annunciator
Drive water header differential pressure	Pressure indicator
Drive water pump suction filter differential pressure	Annunciator

Table 7.7-2

LOCATIONS FOR AREA RADIATION MONITORING SENSORS

CHANNEL NUMBER	EQUIPMENT NUMBER	MONITOR DESCRIPTION OF LOCATION	RANGE (mR/hr)	LOCAL ALARM
01	RE01-M1-1N001	RCIC pump compartment	.01-10^4	YES
01	RE01-M1-2N001	RCIC pump compartment	.01-10^4	YES
02	RE02-M1-1N001	HPCI pump-room el 177'	.01-10^4	YES
02	RE02-M1-2N001	HPCI pump-room el 177'	.01-10^4	YES
03	RE03-M1-1N001	Reactor enclosure sumps el 177'	.01-10^4	YES
03	RE03-M1-2N001	Reactor enclosure sumps el 177'	.01-10^4	YES
04	RE04-M1-1N001	CRD pumps area el 200'	.01-10^4	YES
04	RE04-M1-2N001	CRD pump area el 200'	.01-10^4	YES
05	RE05-M1-1N001	Turbine auxiliary bay hallway el 200'	.01-10^4	YES
05	RE05-M1-2N001	Turbine auxiliary bay hallway el 200'	.01-10^4	YES
06	RE06-M1-1N001	Isolation valve compartment el 201'	.01-10^4	YES
06	RE06-M1-2N001	Isolation valve compartment el 201'	.01-10^4	YES
07	RE07-M1-1N001	Condensate pump-room el 189'	.01-10^4	YES
07	RE07-M1-2N001	Condensate pump-room el 189'	.01-10^4	YES
08	RE08-M1-1N001	RHR division I room el 201'	.01-10^4	YES
08	RE08-M1-2N001	RHR division I room el 201'	.01-10^4	YES
09	RE09-M1-1N001	RHR division II room el 201'	.01-10^4	YES

Table 7.7-2 (Cont'd)

CHANNEL NUMBER	EQUIPMENT NUMBER	MONITOR DESCRIPTION OF LOCATION	RANGE (mR/hr)	LOCAL ALARM
09	RE09-M1-2N001	RHR division II room el 201'	.01-10^4	YES
10	RE10-M1-1N001	Steam vent area stairwell el 217'	.01-10^4	YES
10	RE10-M1-2N001	Steam vent area stairwell el 217'	.01-10^4	YES
11	RE11-M1-1N001	Reactor enclosure, railroad access airlock el 217'	.01-10^4	YES
11	RE11-M1-2N001	Reactor enclosure, railroad access airlock el 217'	.01-10^4	YES
12	RE12-M1-1N001	Hallway, condensate filter/ demineralizers el 217'	.01-10^4	YES
12	RE12-M1-2N001	Hallway, condensate filter/ demineralizers el 217'	.01-10^4	YES
13	RE13-M1-1N001	Turbine Enclosure, condenser area el 217'	1.0-10^6	YES
13	RE13-M1-2N001	Turbine enclosure, condenser area el 217'	1.0-10^6	YES
14	RE14-M1-1N001	Reactor drywell el 253'	1.0-10^6	YES
14	RE14-M1-2N001	Reactor drywell el 253'	1.0-10^6	YES
15	RE15-M1-1N001	Reactor enclosure, east el 253'	.01-10^4	YES
15	RE15-M1-2N001	Reactor enclosure, east el 253'	.01-10^4	YES

Table 7.7-2 (Cont'd)

CHANNEL NUMBER	EQUIPMENT NUMBER	MONITOR DESCRIPTION OF LOCATION	RANGE (mR/hr)	LOCAL ALARM
16	RE16-M1-1N001	Reactor Enclosure, west el 253'	.01-10^4	YES
16	RE16-M1-2N001	Reactor enclosure, west el 253'	.01-10^4	YES
17	RE17-M1-1N001	Neutron monitoring system area el 253'	.01-10^4	YES
17	RE17-M1-2N001	Neutron monitoring system area el 253'	.01-10^4	YES
18	RE18-M1-1N001	Neutron monitoring drive mechanism	.01-10^4	YES
18	RE18-M1-2N001	Neutron monitoring drive mechanism	.01-10^4	YES
19	RE19-M1-1N001	Turbine auxiliary bay hallway east el 239'	1.0-10^6	YES
19	RE19-M1-2N001	Turbine auxiliary bay hallway east el 279'	1.0-10^6	YES
20	RE20-M1-1N001	Turbine auxiliary bay hallway west el 239'	1.0-10^6	YES
20	RE20-M1-2N001	Turbine auxiliary bay hallway west el 239'	1.0-10^6	YES
21	RE21-M1-1N001	RWCU heat exchanger area el 283'	.01-10^4	YES
21	RE21-M1-2N001	RWCU heat exchanger area el 283'	.01-10^4	YES

Table 7.7-2 (Cont'd)

CHANNEL NUMBER	EQUIPMENT NUMBER	MONITOR DESCRIPTION OF LOCATION	RANGE (mR/hr)	LOCAL ALARM
22	RE22-M1-1N001	RWCU pump area el 283'	.01-10^4	YES
22	RE22-M1-2N001	RWCU pump area el 283'	.01-10^4	YES
23	RE23-M1-1N001	SLCS area el 283'	.01-10^4	YES
23	RE23-M1-2N001	SLCS area el 283'	.01-10^4	YES
24	RE24-M1-1N001	RWCU instrument rack el 283'	.01-10^4	YES
24	RE24-M1-2N001	RWCU instrument rack area el 283'	.01-10^4	YES
25	RE25-M1-1N001	Turbine auxiliary bay el 269'	.01-10^4	YES
25	RE25-M1-2N001	Turbine auxiliary bay el 269'	.01-10^4	YES
26	RE26-M1-1N001	Turbine enclosure washdown area el 269'	.01-10^4	YES
26	RE26-M1-2N001	Turbine enclosure washdown area el 269'	.01-10^4	YES
27	RE27-M1-1N001	RWCU filter area el 313'	.01-10^4	YES
27	RE27-M1-2N001	RWCU filter area el 313'	.01-10^4	YES

Table 7.7-2 (Cont'd)

CHANNEL NUMBER	EQUIPMENT NUMBER	MONITOR DESCRIPTION OF LOCATION	RANGE (mR/hr)	LOCAL ALARM
28	RE28-M1-1N001	Turbine enclosure equipment compartment exhaust filters area el 302'	.01-10^4	YES
28	RE28-M1-2N001	Turbine enclosure equipment compartment exhaust filters area el 302'	.01-10^4	YES
29	RE29-M1-1N001	Drywell head lay-down area el 352'	.01-10^4	YES
29	RE29-M1-2N001	Drywell head lay-down area el 352'	.01-10^4	YES
30	RE30-M1-1N001	Steam separator area el 352'	.01-10^4	YES
30	RE30-M1-2N001	Steam separator area el 352'	.01-10^4	YES
31	RE31-M1-1N001	Spent fuel pool el 352'	.01-10^4	YES
31	RE31-M1-2N001	Spent fuel pool el 352'	.01-10^4	YES
32	RE32-M1-1N001	New fuel storage vault el 352'	.01-10^4	YES
32	RE32-M1-2N001	New fuel storage vault el 352'	.01-10^4	YES
33	RE33-M1-1N001	Pool plug lay-down area el 352'	.01-10^4	YES
33	RE33-M1-2N001	Pool plug lay-down area el 352'	.01-10^4	YES
34	RE34-M1-1N001	$H_2/0_2$ analyzers area el 200'	.01-10^4	YES
34	RE34-M1-2N001	$H_2/0_2$ analyzers area el 200'	.01-10^4	YES

Table 7.7-2 (Cont'd)

CHANNEL NUMBER	EQUIPMENT NUMBER	MONITOR DESCRIPTION OF LOCATION	RANGE (mR/hr)	LOCAL ALARM
35	RE35-M1-1N001	Gaseous radwaste recombiner hallway, el. 180'	$.01\text{-}10^4$	YES
35	RE35-M1-2N001	Gaseous radwaste recombiner hallway, El. 180'	$.01\text{-}10^4$	YES
36	RE36-M1-0N001	Unit 1 deep bed demin area, el. 217’	$.01\text{-}10^4$	YES
41	RE41-M1-0N001	RWCU Sludge discharge mixing pump-room el. 162'	$.01\text{-}10^4$	YES
42	RE42-M1-0N001	Radwaste enclosure hallway el. 162'	$.01\text{-}10^4$	YES
43	RE43-M1-0N001	Concentrate storage discharge pump-room el. 191'	$.01\text{-}10^4$	YES
44	RE44-M1-0N001	Laundry drain processing room El. 191'	$.01\text{-}10^4$	YES
45	RE45-M1-0N001	Floor drain filter holding pump-room el. 191'	$.01\text{-}10^4$	YES
46	RE46-M1-0N001	Fuel pool holding pump-room el. 191'	$.01\text{-}10^4$	YES
47	RE47-M1-0N001	Precoat tank & pump-room el. 191'	$.01\text{-}10^4$	YES
48	RE48-M1-0N001	Remote shutdown control area el. 289'	$.01\text{-}10^4$	YES
49	RE49-M1-0N001	Radwaste cask loading area el. 217'	$.01\text{-}10^4$	YES

Table 7.7-2 (Cont'd)

CHANNEL NUMBER	EQUIPMENT NUMBER	MONITOR DESCRIPTION OF LOCATION	RANGE (mR/hr)	LOCAL ALARM
50	RE50-M1-0N001	Railroad car airlock el 217'	.01-10^4	YES
51	RE51-M1-0N001	Radwaste enclosure hallway el 217'	.01-10^4	YES
52	RE52-M1-0N001	Hot Maintenance Shop el 217'	.01-10^4	YES
53	RE53-M1-0N001	Entrance, turbine enclosure railroad el 217'	.01-10^4	YES
54	RE54-M1-0N001	Radwaste enclosure el 239'	.01-10^4	YES
55	RE55-M1-0N001	Radwaste exhaust fan area el 257'	.01-10^4	YES
56	RE56-M1-0N001	Control room el 269'	.01-10^4	YES
57	RE57-M1-0N001	Turbine area operating floor el 269'	.01-10^4	YES
58	RE58-M1-0N001	Standby-gas treatment filter room el 332'	.01-10^4	YES
59	RE59-M1-0N001	Source storage & calibration room, el 230'	.01-10^4	YES
-	RIAH-TA-001(1)	(Local) A turbine enclosure crane el 310'	.01-10^4	YES
-	RIAH-TA-002(1)	(Local) B turbine enclosure crane El 310'	.01-10^4	YES
-	RIAH-TA-003(1)	(Local) C turbine enclosure crane el 310'	.01-10^4	YES

(1) Local monitor only - requires local power supply (monitor and power supply supplied as part of BOP scope)

Table 7.7-2 (Cont'd)

CHANNEL NUMBER	EQUIPMENT NUMBER	MONITOR DESCRIPTION OF LOCATION	RANGE (mR/hr)	LOCAL ALARM
-	RIAH-TA-101(1)	(Local) Refueling platform, el 352'	.01-10^4	YES
-	RIAH-TA-201(1)	(Local) Refueling platform, el 352'	.01-10^4	YES
-	RIAH-TA-102(1)	(Local) Turb.deep bed VSL area, el 217	.01-10^2	YES
-	RIAH-TA-103(1)	(Local) Turb.deep bed VSL area, el 217	.01-10^2	YES
- -	RIAH-TA-203(1)	(Local) Turb.deep bed VSL area, el 217	.01-10^2	YES
-	RIAH-TA-025(1)	(Local) Source storage 1 calibration RM, el 191	.1-10^4	YES

Table 7.7-3

REFUELING INTERLOCK EFFECTIVENESS

SITUATION	REFUELING PLATFORM POSITION	HOISTS FG	CONTROL RODS	MODE SWITCH	ATTEMPT	RESULT
1	Not near core	UL	All rods in	Refuel	Move refueling platform over core	No restrictions
2	Not near core	UL	All rods in	Refuel	Withdraw rods	Cannot withdraw more than one rod
3	Not near core	UL	One rod withdrawn	Refuel	Move refueling platform over core	No restrictions
4	Not near core	L	One or more rods withdrawn	Refuel	Move refueling platform over core	Platform stopped before over core
5	Not near core	UL	More than one rod withdrawn	Startup	Move refueling platform over core	Platform stopped before over core
6	Over core	UL	All rods in	Refuel	Withdraw rods	Cannot withdraw more than one rod
7	Over core	Either Hoist L	All rods in	Refuel	Withdraw rods	Rod block
8	Not near core	UL	All rods in	Refuel	Withdraw rods	Rod block
9	Not near core	UL	All rods in	Refuel	Operate service platform hoist	No restrictions
10	Not near core	UL	One rod withdrawn	Refuel	Operate service platform hoist	Hoist operation Prevented
11	Not near core	UL	All rods in	Startup	Move refueling platform over core	Platform stopped before over core
12	Not near core	UL	All rods in	Startup	Operate service platform hoist	No restrictions
13	Not near core	UL	One rod withdrawn	Startup	Operate service platform hoist	Hoist operation prevented
14	Not near core	UL	All rods in	Startup	Withdraw rods	Rod block
15	Not near core	UL	All rods in	Startup	Withdraw rods	No restrictions
16	Over core	UL	All rods in	Startup	Withdraw rods	Rod block
17	Over core	UL	One or more rods withdrawn	Refuel	Lift a fuel assembly with FG	(Main) Hoist Operation prevented

FG - Fuel Grapple UL - Unloaded L - Fuel Loaded

Table 7.7-4

SRM SYSTEM TRIPS

TRIP FUNCTION	NORMAL SETPOINT	TRIP ACTION
SRM upscale	10^5 counts/second	Rod block, amber light display annunciator
SRM instrument inoperative	(1)	Rod block, amber light display annunciator
Detector retraction permissive (SRM downscale)	100 counts/second	Bypass detector full-in limit switch when above preset limit, annunciator, green light display, rod block when below preset limit with IRM range switches on first two ranges.
SRM period	50 sec	Annunciator, amber light display
SRM downscale	3 counts/second	Rod block, annunciator, white light display
SRM bypassed		White light display

(1) SRM is inoperative if module interlock chain is broken, OPERATE-CALIBRATE switch is not in operate position or detector polarizing voltage is below 90% of normal operating voltage (operationally determined).

Table 7.7-5

RBM SYSTEM TRIPS

TRIP FUNCTION	NOMINAL SETPOINT	TRIP ACTION
RBM upscale	To be provided in Technical Specifications	Rod block, annunciator, amber light display, RBM ODA
RBM inoperative	(1)	Rod block, annunciator, amber light display, RBM ODA
RBM downscale	To be provided in Technical Specifications	Rod block, annunciator, white light display, RBM ODA
RBM bypassed	Manual switch or peripheral rod selected or APRM reference below 30%	White light display, RBM ODA

(1) RBM is inoperative if module interlock chain is broken, chassis mode switch is not in the OPERATE position, less than 50% of available LPRM signals are above 3% threshold, or internal self-test logic indicates trouble.

NOTE: These values are for unit cycle 6 only. The Core Operating Limit Report specifies these values for each cycle.

Table 7.7-6

ANALYSIS METHODOLOGY

A. Michelson Concern (Reference line failure + single additional failure in a protective channel not dependent on the failed sensing line).

1. Determine the logic for combining channel trips to achieve protective actions.

2. Identify each case where a reactor vessel water level tap or sensing line failure concurrent with an additional random signal electrical failure induces a transient and precludes the automatic operation of a RPS and/or ESF system.

3. For each case identified, demonstrate how the redundancy or diversity of the plant design provides the reactor protection or safety system operation within acceptable limits. Typically, at this point all but one or two cases identified in Step 2 can be eliminated as concerns due to the redundancy of protection and/or ESF systems. For the one or two remaining cases (worst failure combination scenarios), transient analyses are performed to demonstrate that plant safety is not compromised.

4. Where manual action is required by the operators, identify the instrumentation and time available for the operator to take corrective action.

Note: For LGS, which has 4 instrumentation divisions, automatic protection is available under all scenarios so Step 4 is not required.

Table 7.7-7

LGS WATER LEVEL

CONDENSING CHAMBER		D004A	D004B	D004C	D004D
INSTRUMENTATION DIVISION:	ECCS	1	2	3	4
	RPS/NSSSS	IA	IB	IIA	IIB
	RRCS	1A 2A	1B 2B		
POWER SUPPLY	ECCS(E21-K602)	A	B	C	D
	RPS/NSSSS(B21-K613)	A	B	A	B
	RRCS	A	B	-	-

SYSTEM	LEVEL TRIP POINT	TRANSMITTER NUMBER[1]	TRIP UNIT NUMBER[1]	SYSTEM LOGIC
RPS	3	N080	N680	(A + B) . (C + D)
NSSSS	3	N080	N680	(A . B) + (C . D)
NSSSS	2	N081	N681	(A . B) + (C . D)
NSSSS (MSIV)	1	N081	N684	(A + B) . (C + D)
RHR (A) & CS (A)	1	N091	N691	(A . E)
RHR (B) & CS (B)	1	N091	N691	(B . F)
RHR (C) & CS (C)	1	N091	N691	(C . G)
RHR (D) & CS (D)	1	N091	N691	(D . H)
ADS (A)	1/3	N091[2]	N691[2]	(A_1.E_1.A_3)
ADS (C)	1/3	N091[2]	N691[2]	(C_1.G_1.C_3)
HPCI	2	N091 N091	N692B, F N692D, H	(B + D) . (F + H) .

Table 7.7-7 (Cont'd)

CONDENSING CHAMBER		D004A	D004B	D004C	D004D
INSTRUMENTATION DIVISION:	ECCS	1	2	3	4
	RPS/NSSSS	IA	IB	IIA	IIB
	RRCS	1A 2A	1B 2B		
POWER SUPPLY	ECCS(E21-K602)	A	B	C	D
	RPS/NSSSS(B21-K613)	A	B	A	B
	RRCS	A	B	-	-

SYSTEM	LEVEL TRIP POINT	TRANSMITTER NUMBER[1]	TRIP UNIT NUMBER[1]	SYSTEM LOGIC
RCIC	2	N091A, E N097A, E	N692A, E N697A, E	(A + A') . } (E + E')
				A & E = N692A, E A' & E' = N697A, E
HPCI Trip	8	N091	N693	(B +F) . (D + H)
RCIC Trip	8	N091A, E	N693A, E	(A + A') . } (E + E')
				A & E = N693A, E A & E' = N698A, E
RPT	2	N402	Analog trip module	(A . E) + (B . F)
ARI	2	N402	Analog trip module	(A . E) + (B . F)

[1] All instrument numbers are prefixed with B21- unless otherwise noted.
[2] Level 3 signal for ADS logic is from transmitter B21-N095 and trip unit B21-N695.

Table 7.7-8

TREND PLOT LIMIT TAGS FOR RPV CONTROL DISPLAY

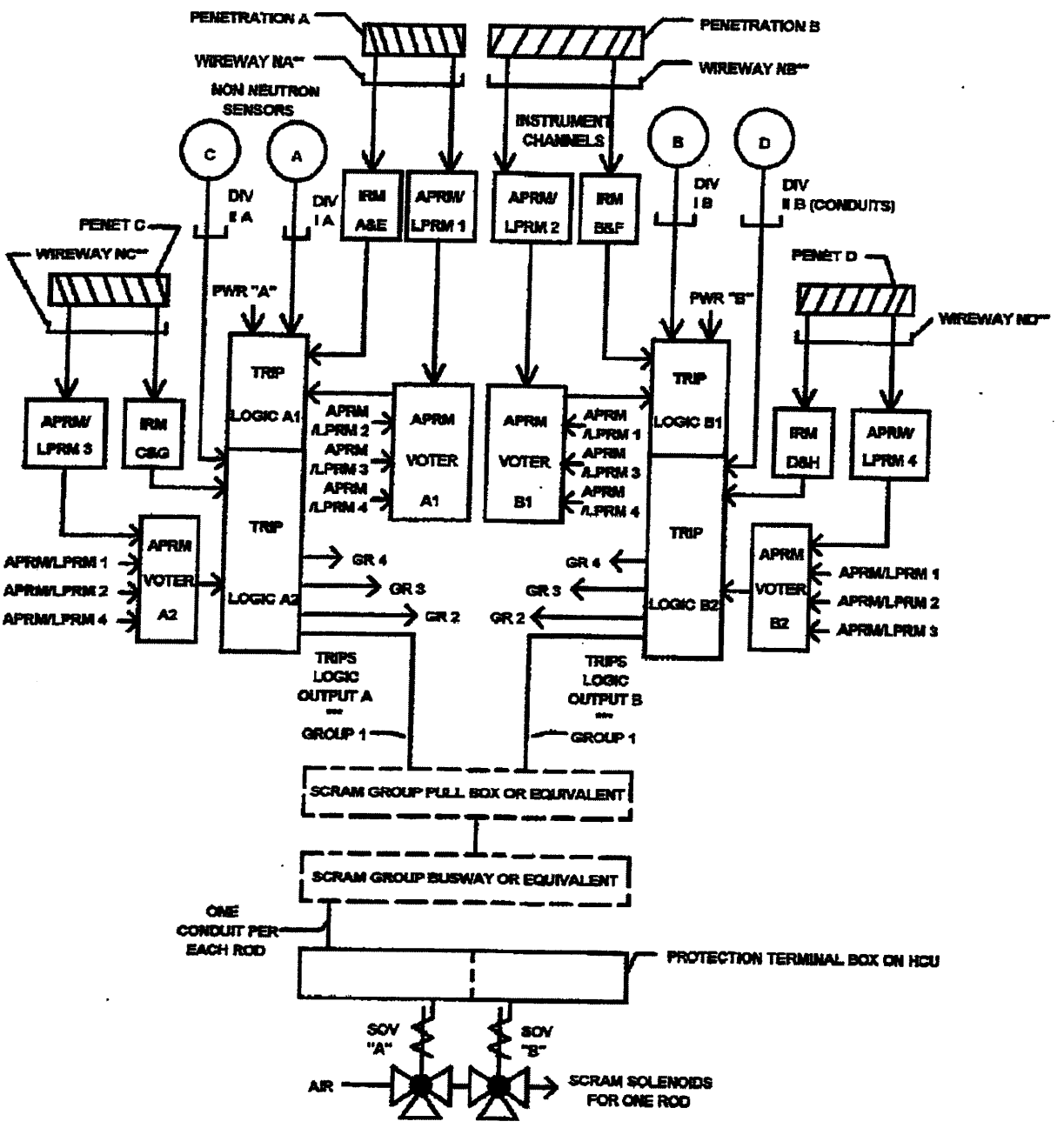
CONTROL PARAMETERS	STATIC LIMIT	DYNAMIC LIMITS
RPV water level	Trip Hi, Scram Lo, ADS Level TAF	None
RPV pressure	Scram Hi, 100% BPV(1)	SRV TPLL
Reactor power	APRM DNSCL	None
RPV temperature	None	None

(1) Indicates a permissive limit

Table 7.7-9

CONTAINMENT CONTROL DISPLAY TREND PLOT LIMITS

CONTROL PARAMETERS	STATIC LIMIT	DYNAMIC LIMIT
Containment Level		None
Drywell Pressure	Oper Hi	Spray
Wetwell Pressure	Oper Hi	Pressurization Limit-A, Pressurization Limit-B, Pressure-Suppression, Spray
Drywell Temperature	Design, Oper Hi	RPV Sat
Suppression Pool Temperature	Scram Temp, Oper Hi	
Suppression Pool Level	Oper Hi, Oper Lo, VAC BRKR	SRV Tail Pipe Level Limit



* RPS SENSORS A&B MAY BE CONNECTED TO A COMMON PROCESS TAP. C&D MAY ALSO SHARE ONE TAP. RPS SENSORS A&C OR B&D MUST NOT BE CONNECTED TO A COMMON PROCESS TAP.

** WIREWAYS NA, NB, etc. MAY BE ASSIGNED TO AND ROUTED WITH SEPARATED DIVISIONS AS APPROPRIATE TO PLANT LAYOUT.

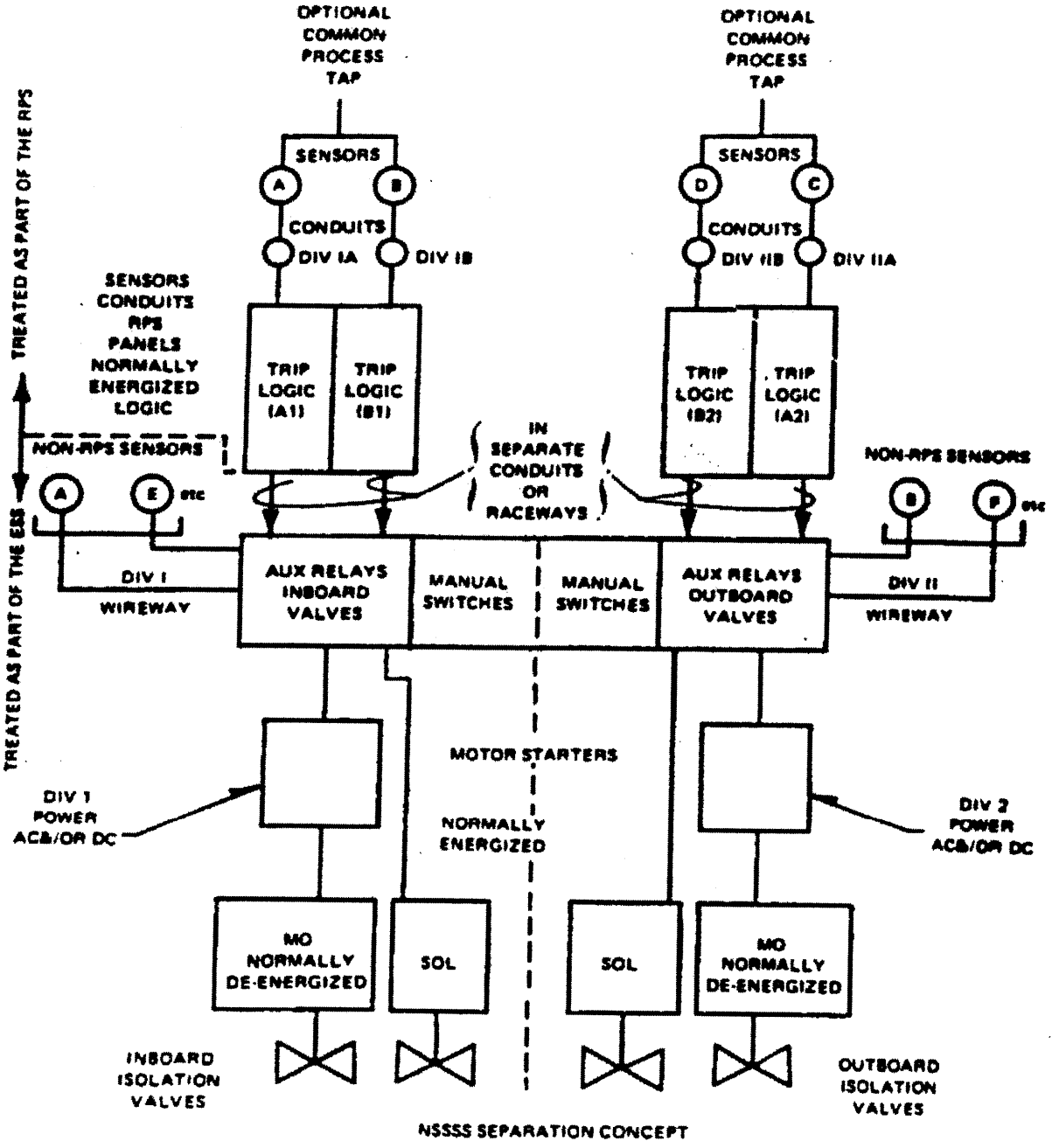
*** TRIP LOGICS A AND B OUTPUTS FOR EACH SCRAM GROUP MAY BE COMBINED IN A SINGLE CONDUIT AS DESIRED AFTER LEAVING THE RPS CABINETS

NOTE: Per NEI 98-03, this Figure in it's entirety, is classified as *HISTORICAL*.

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RPS SEPARATION CONCEPT

FIGURE 7.1-1 **Rev. 11 9/02**

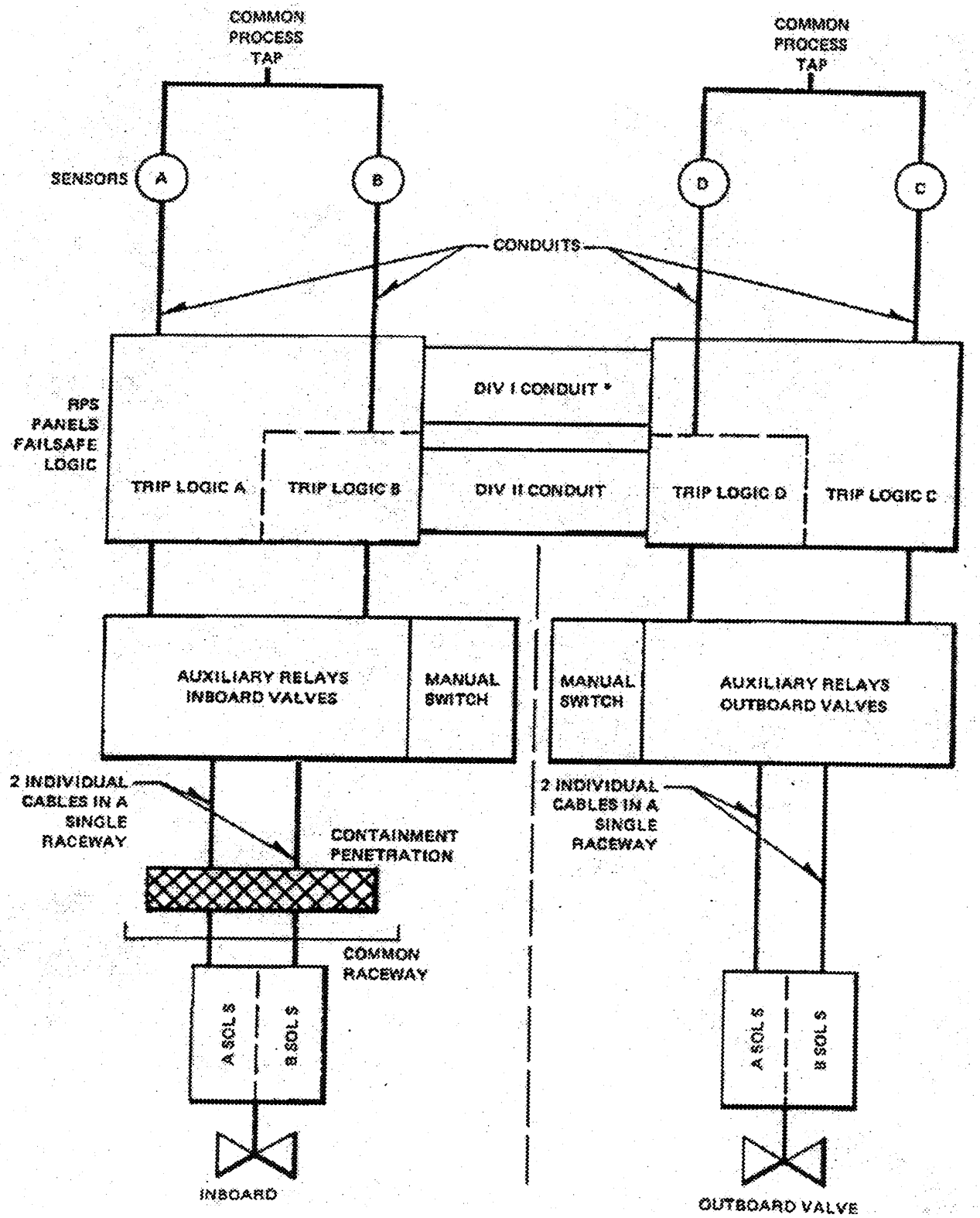


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PCRVICS SEPARATION CONCEPT

FIGURE 7.1-2 Rev. 11 9/02

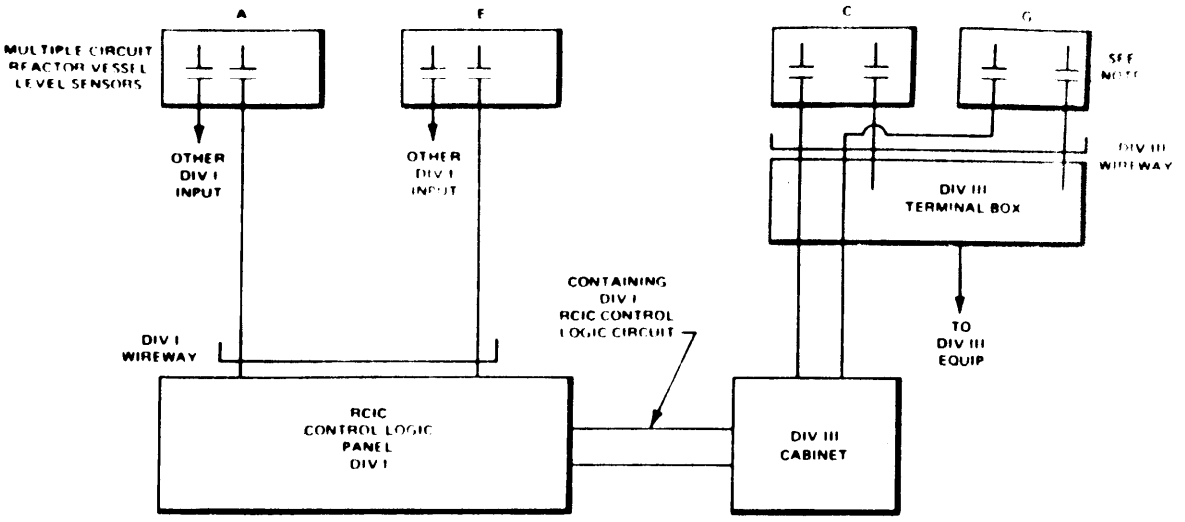


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MAIN STEAM LINE
ISOLATION SEPARATION CONCEPT

FIGURE 7.1-3 Rev. 11 9/02

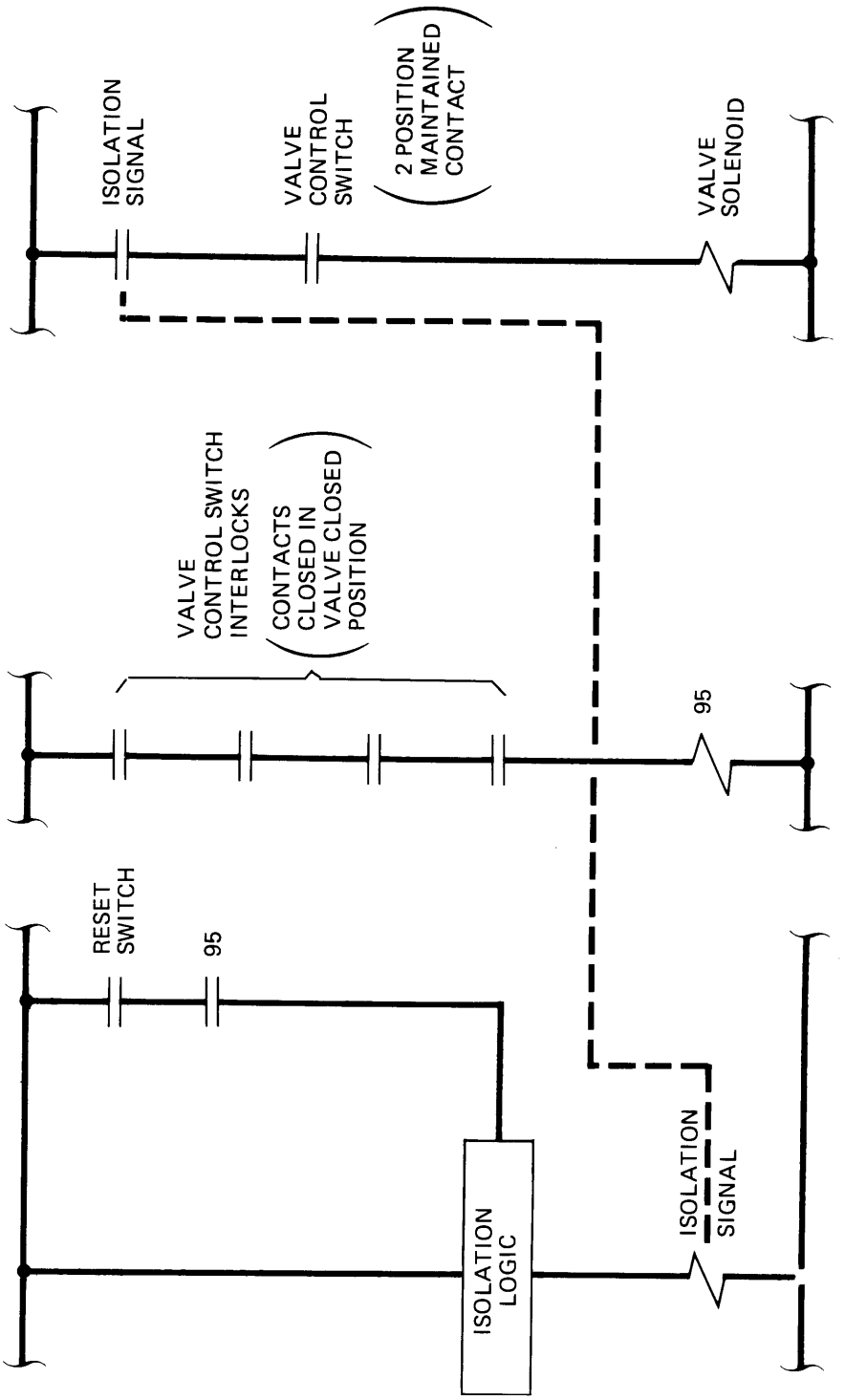


NOTE CIRCUITS FOR RCIC INITIATIONS UTILIZE CONTACTS ELECTRICALLY SEPARATE FROM THOSE USED FOR OTHER DIV III INPUTS

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RCIC SENSOR SEPARATION SCHEME

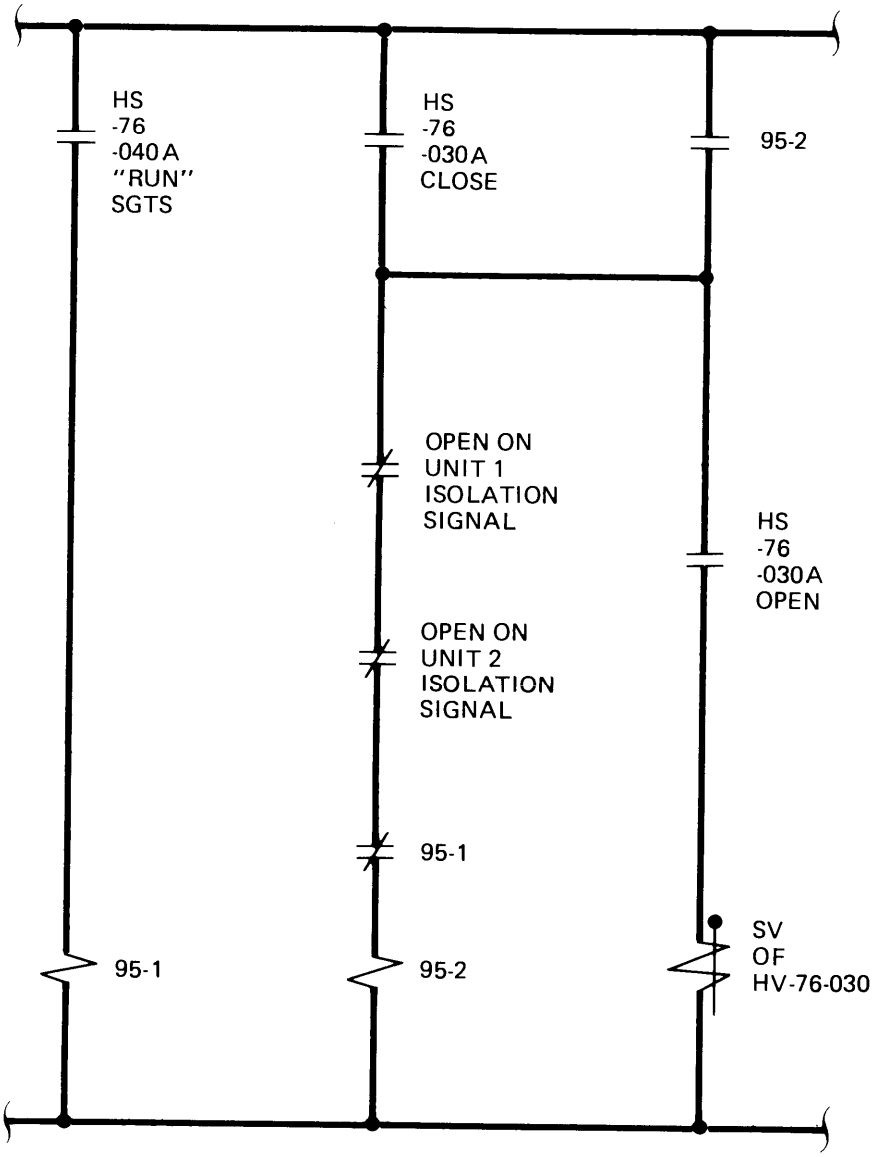
FIGURE 7.1-4



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TYPICAL ISOLATION SIGNAL RESET SCHEMATIC

FIGURE 7.1-5



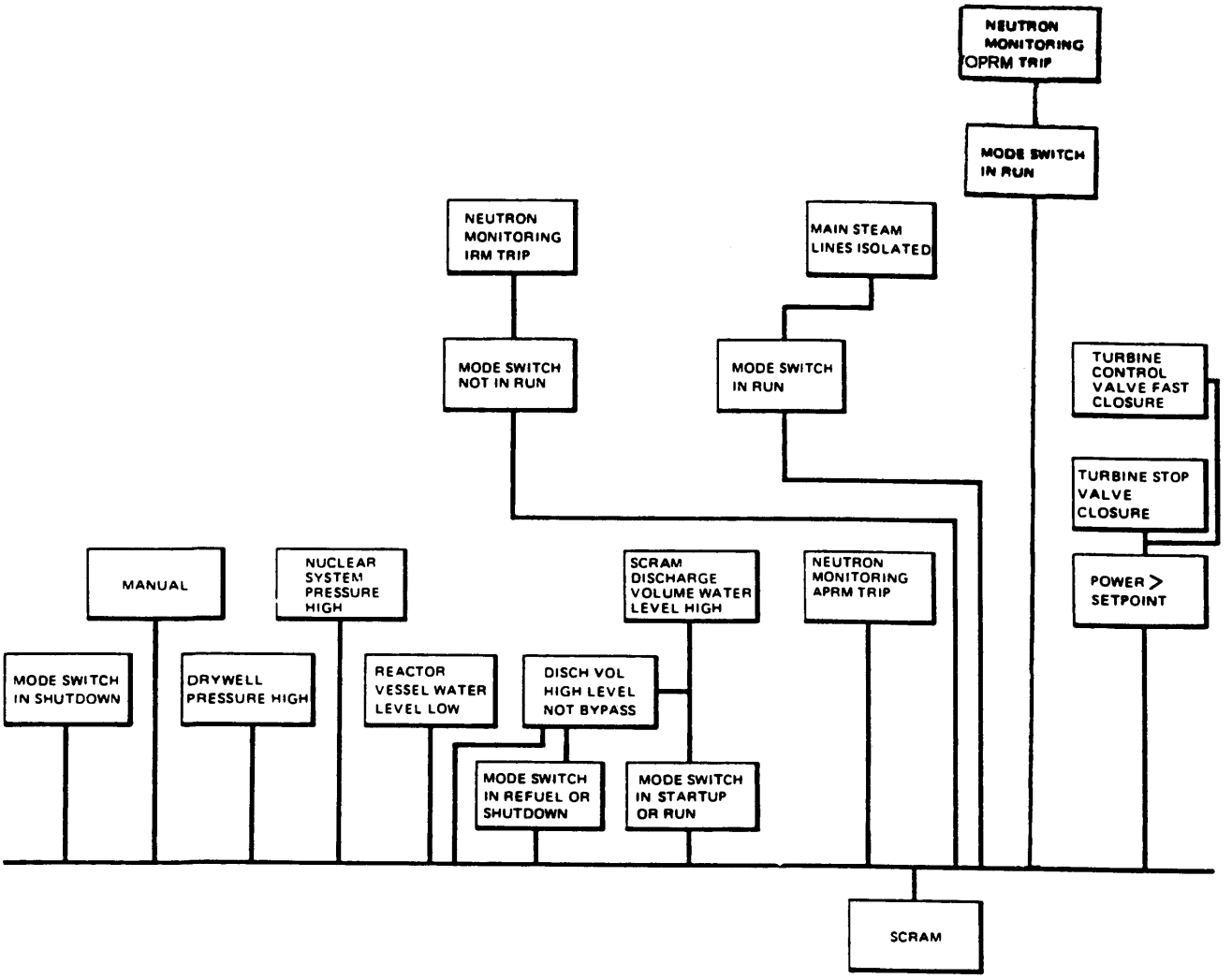
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TYPICAL DRYWELL PURGE FAN INLET ISOLATION VALVE SCHEMATIC

FIGURE 7.1-6

Figures 7.2-1

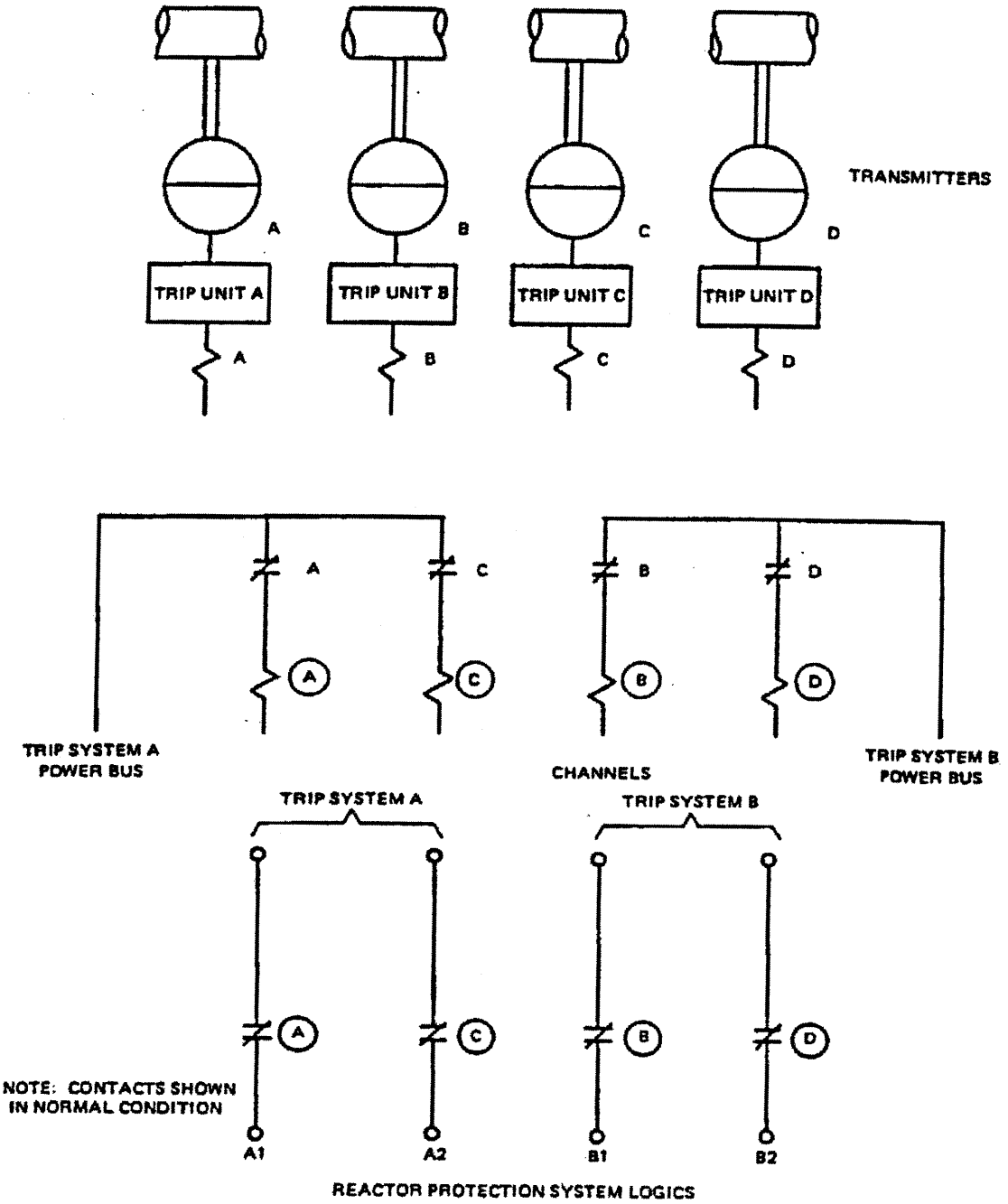
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REACTOR PROTECTION SYSTEM SCRAM FUNCTIONS

FIGURE 7.2-2 **REV. 13 09/06**



REACTOR PROTECTION SYSTEM LOGICS

CONFIGURATION FOR:

SCRAM DISCHARGE VOLUME HIGH WATER LEVEL
TURBINE CONTROL VALVE FAST CLOSURE
REACTOR VESSEL LOW WATER LEVEL

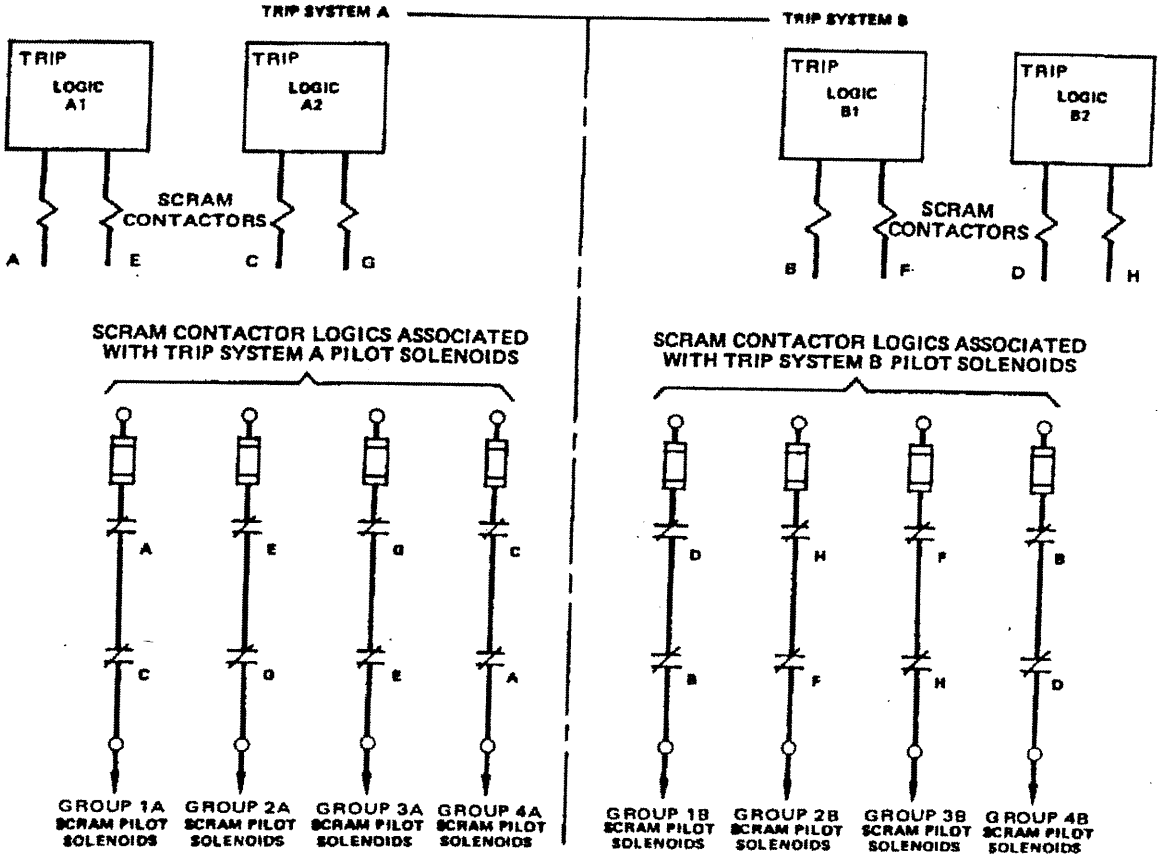
DRYWELL HIGH PRESSURE
REACTOR VESSEL HIGH PRESSURE

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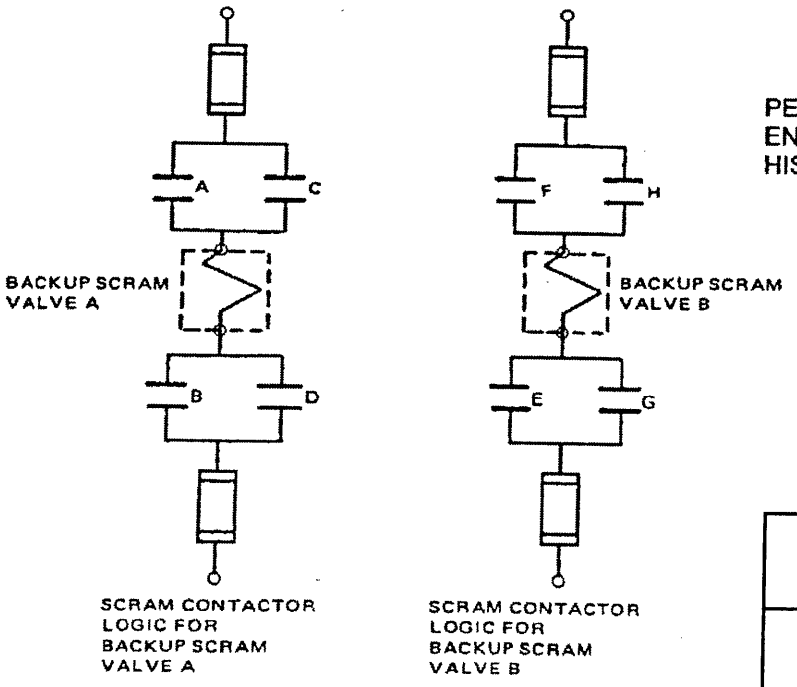
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ARRAGEMENT OF RPS CHANNELS AND LOGICS

FIGURE 7.2-3 Rev. 11 9/02



NOTE: CONTACTS SHOWN IN NORMAL CONDITION



SCRAM CONTACTOR LOGIC FOR BACKUP SCRAM VALVE A

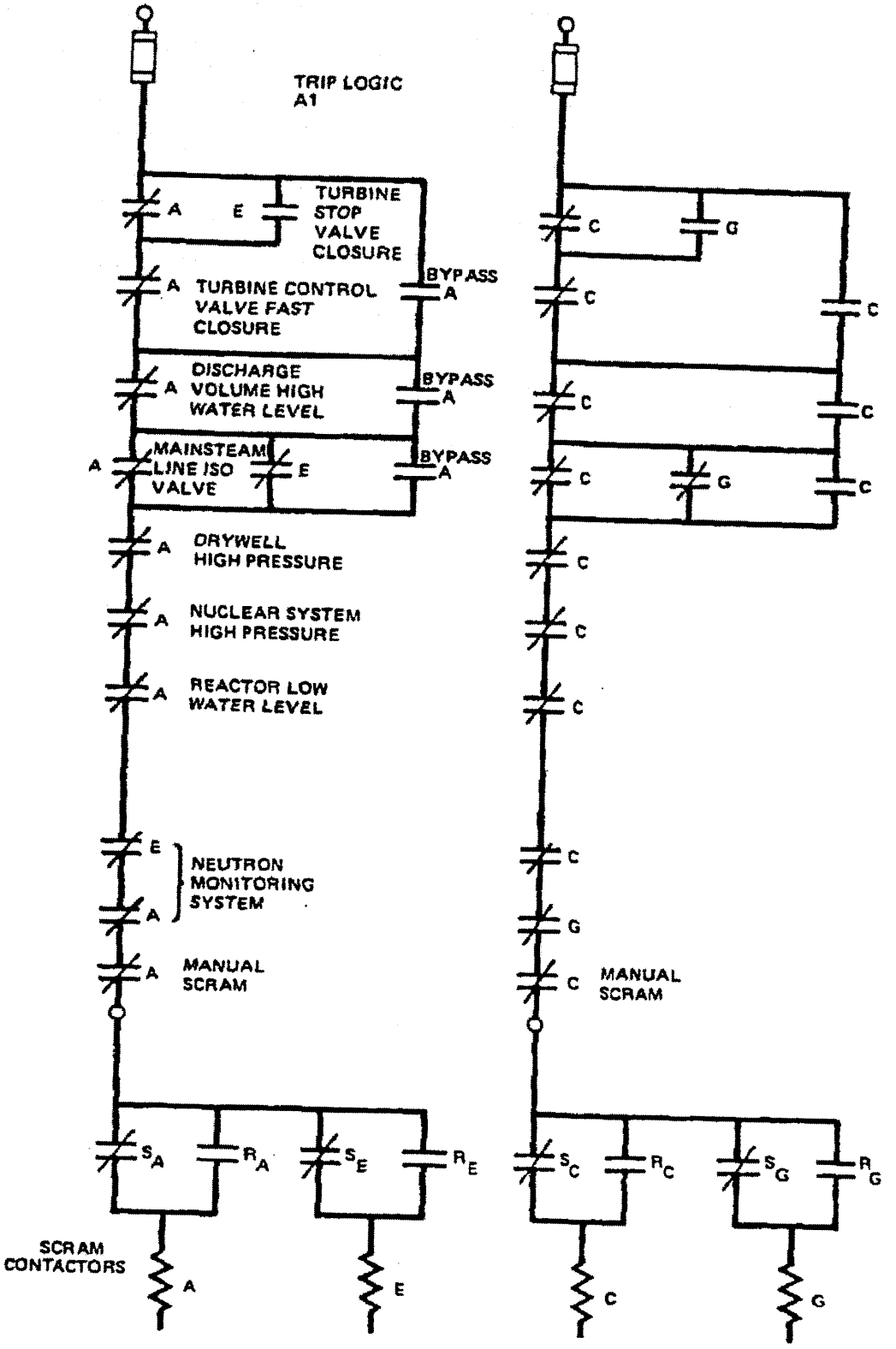
SCRAM CONTACTOR LOGIC FOR BACKUP SCRAM VALVE B

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SCRAM CONTACTORS AND SCRAM CONTACTOR ACTUATOR LOGICS (SCHEMATIC)

FIGURE 7.2-4 Rev. 11 9/02

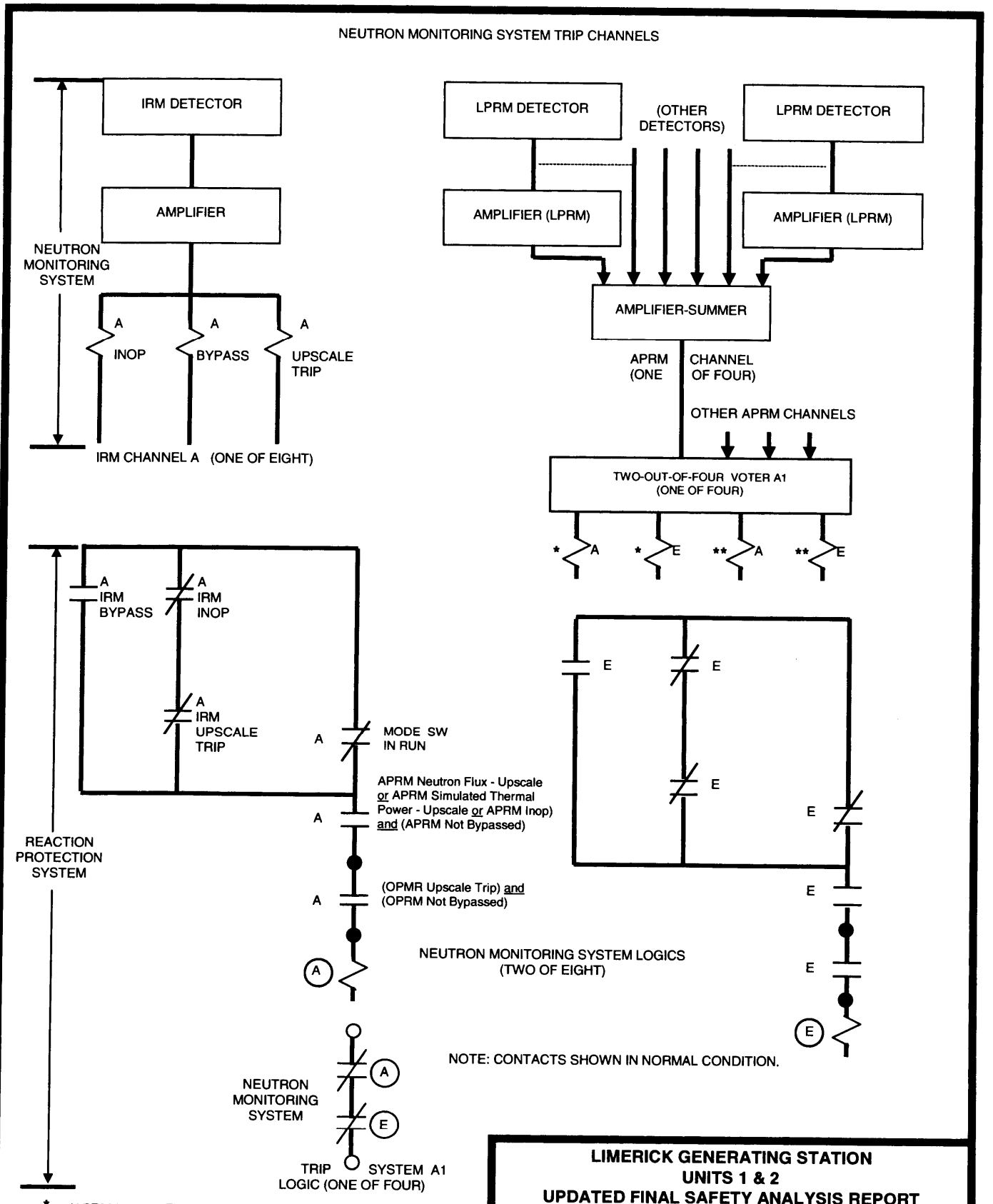


NOTE: CONTACTS SHOWN IN NORMAL CONDITION
R CONTACTS ARE RESET
S CONTACTS ARE SEALING

PER NEI 98-03, THIS FIGURE IN ITS ENTIRETY IS CLASSIFIED AS HISTORICAL

LOGICS FOR TRIP SYSTEM A (SCHEMATIC)

FIGURE 7.2-5 Rev. 11 9/02

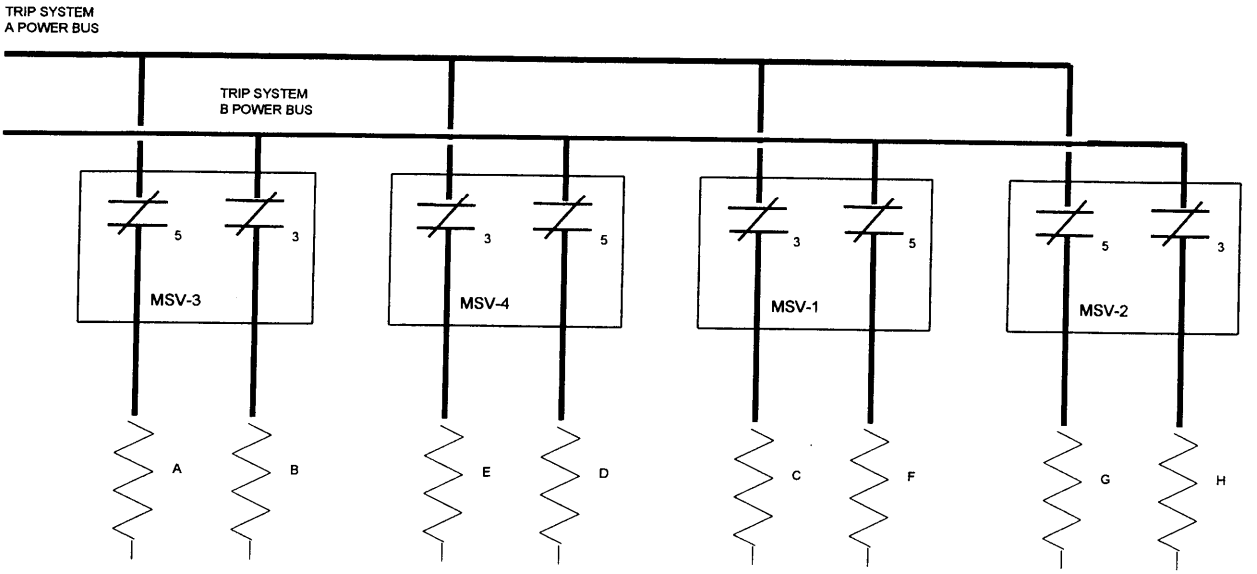


NOTE: PER NEI 98-03, THIS FIGURE, IN IT'S ENTIRETY, IS CLASSIFIED AS *HISTORICAL*.

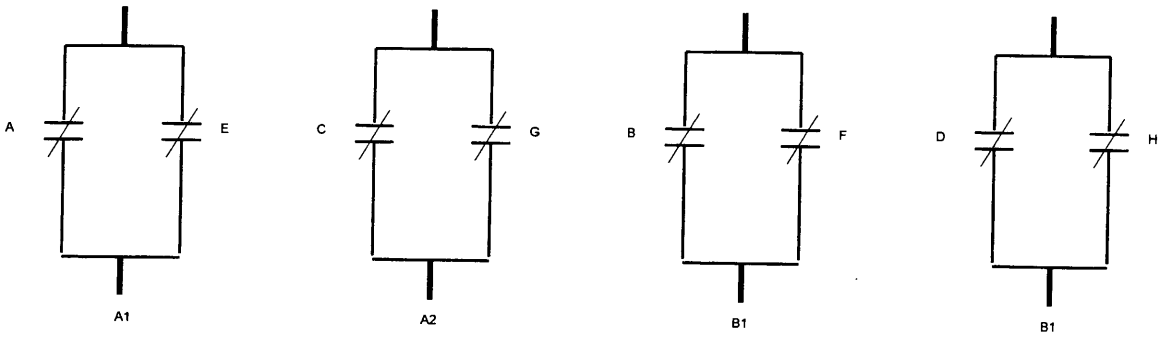
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RELATIONSHIP BETWEEN NEUTRON MONITORING SYSTEM AND REACTOR PROTECTION SYSTEM

FIGURE 7.2-6 **Rev. 13 09/06**



TURBINE STOP VALVE CLOSURE CHANNELS



REACTOR PROJECT SYSTEM LOGICS

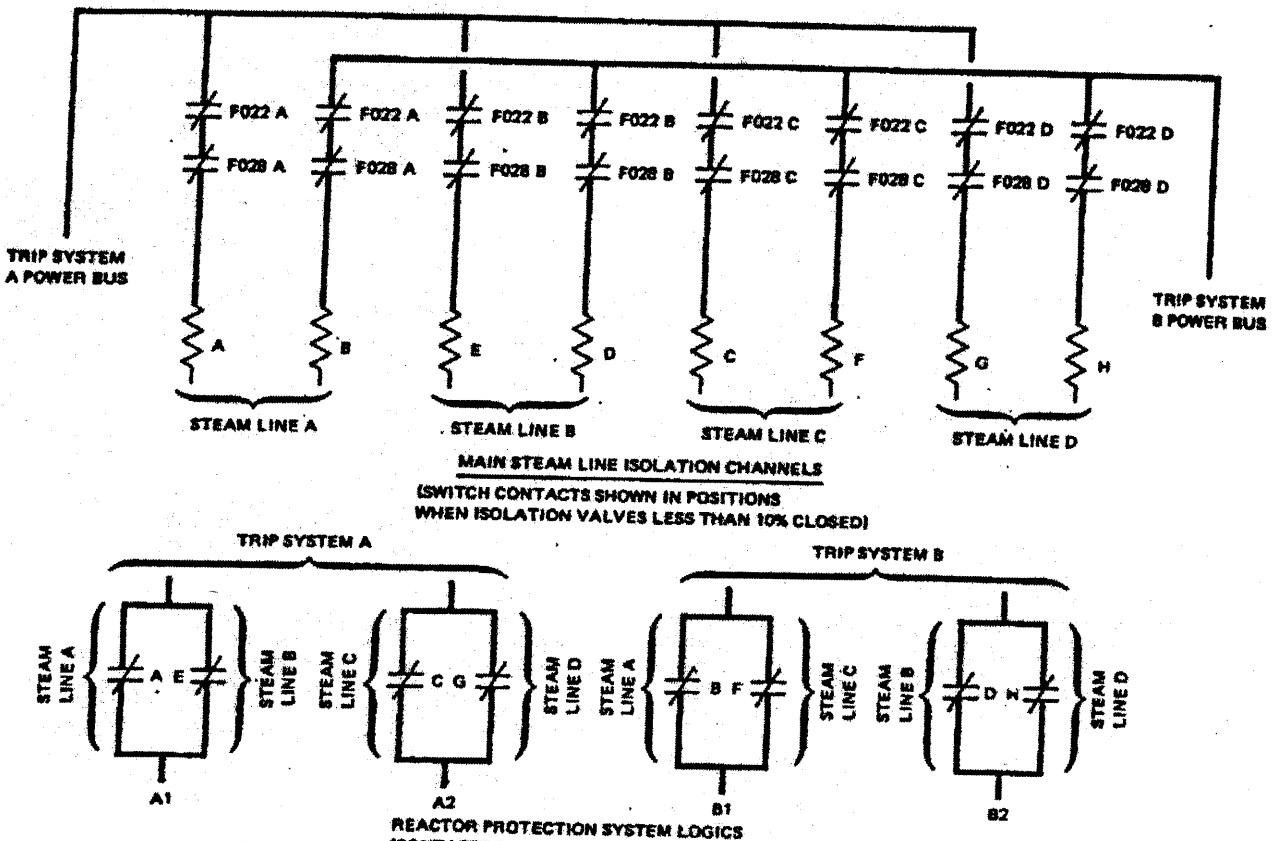
NOTE: CONTACTS SHOWN IN NORMAL CONDITION
NOTE: THREE OUT OF FOUR STOP VALVES MUST CLOSE TO CAUSE A SCRAM

NOTE: Per NEI 98-03, this Figure, in it's entirety, is classified as *HISTORICAL*.

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CONFIGURATION FOR TURBINE STOP VALVE CLOSURE INPUT TO RPS

FIGURE 7.2-7 **Rev. 11 9/02**



KEY:

F022A • STEAM LINE A, INBOARD VALVE
F028A • STEAM LINE A, OUTBOARD VALVE
F022B • STEAM LINE B, INBOARD VALVE
F028B • STEAM LINE B, OUTBOARD VALVE
F022C • STEAM LINE C, INBOARD VALVE
F028C • STEAM LINE C, OUTBOARD VALVE
F022D • STEAM LINE D, INBOARD VALVE
F028D • STEAM LINE D, OUTBOARD VALVE

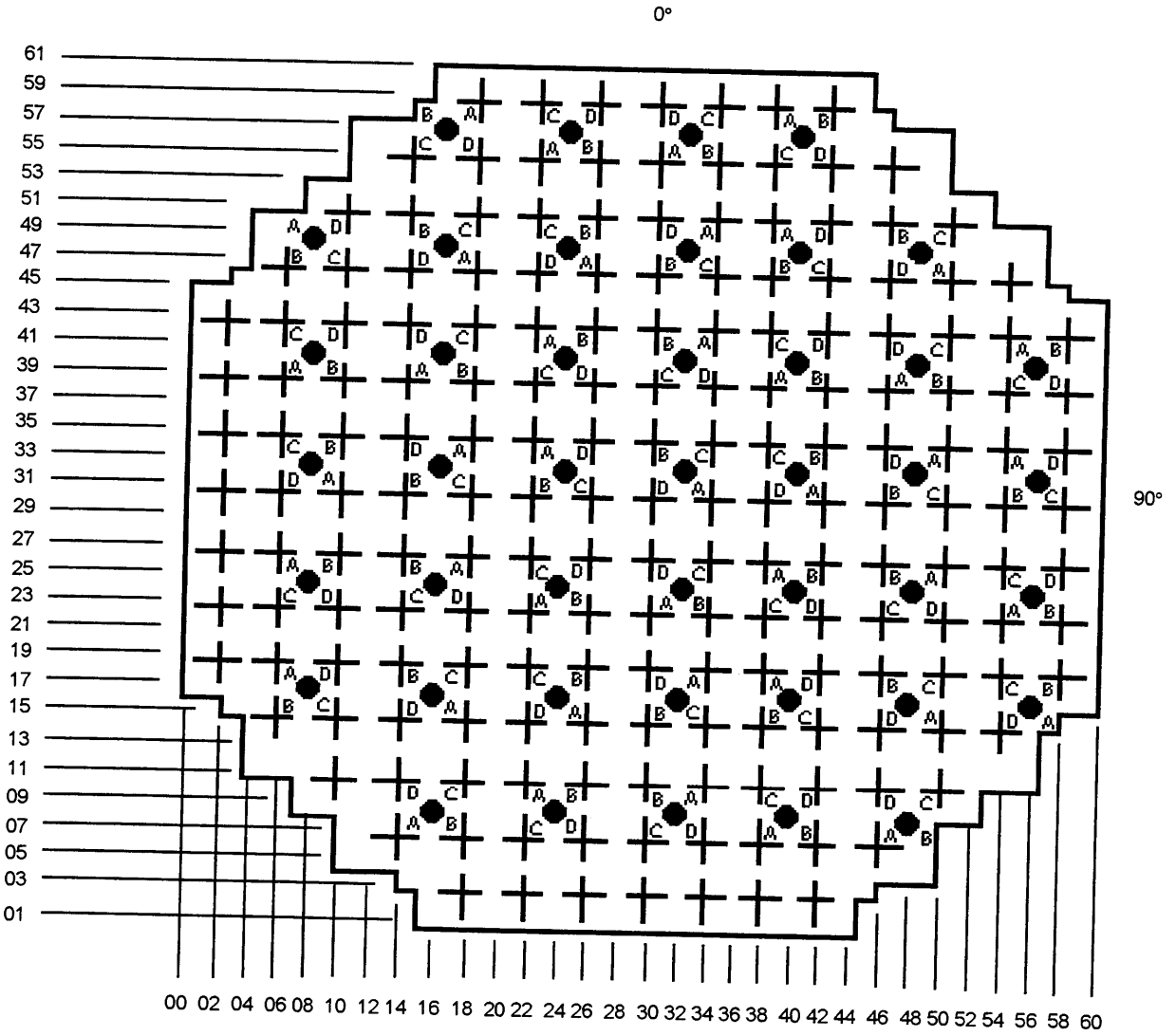
NOTE: ISOLATION OF THREE OR MORE STEAM LINES WILL CAUSE A SCRAM.

PER NEI 98-03, THIS FIGURE IN ITS ENTIRETY IS CLASSIFIED AS HISTORICAL

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CONFIGURATION FOR
STEAMLINE ISOLATION TRIP

FIGURE 7.2-8 Rev. 11 9/02



● LPRM STRING
UPPER LEFT LETTER – INPUT FOR APRM CHANNEL 1
LOWER LEFT LETTER – INPUT FOR APRM CHANNEL 2
LOWER RIGHT LETTER – INPUT FOR APRM CHANNEL 3
UPPER RIGHT LETTER – INPUT FOR APRM CHANNEL 4

APRM SYSTEM

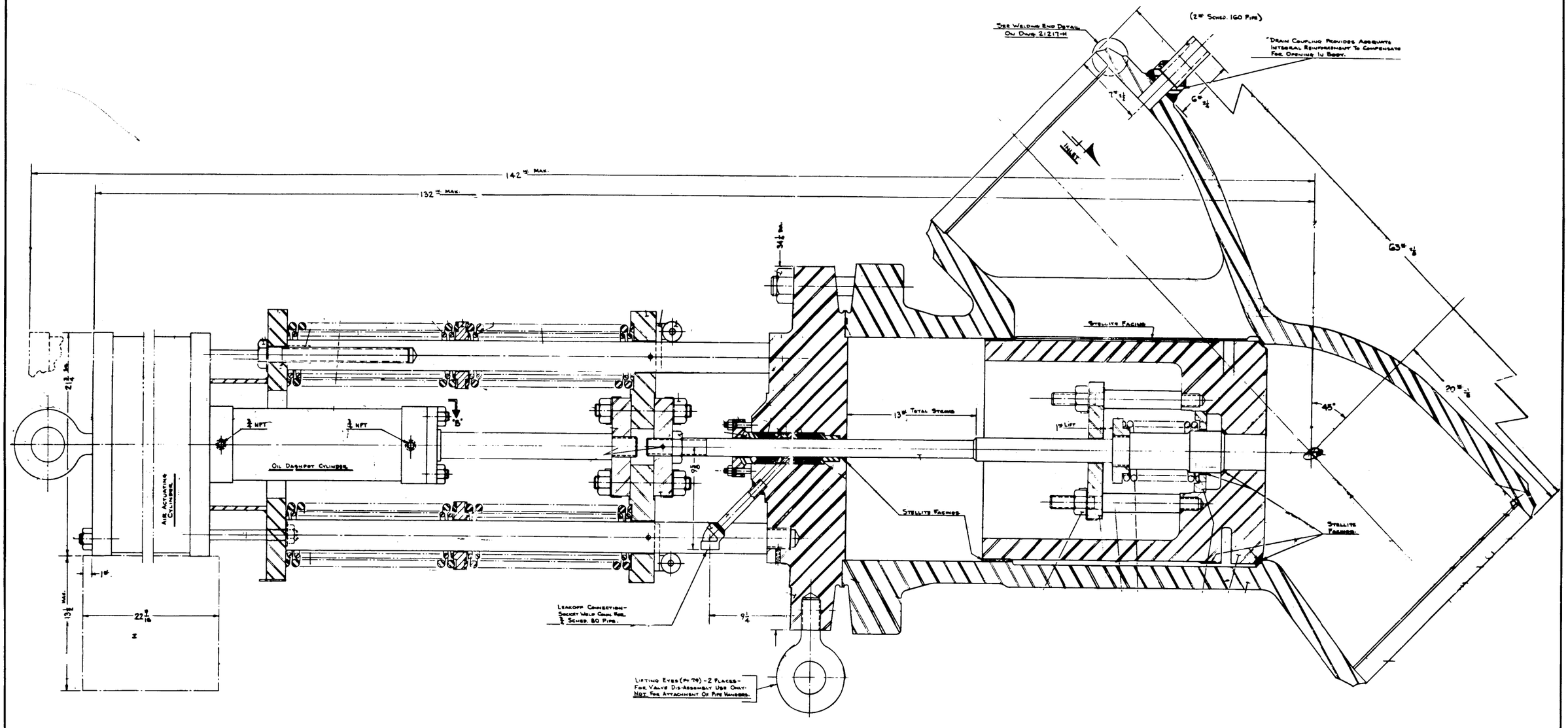
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LPRM CHANNEL ARRANGEMENT IN THE CORE AND APRM CHANNEL ASSIGNMENTS

FIGURE 7.2-9 **Rev. 10 10/00**

Figures 7.2-10 and 7.2-11

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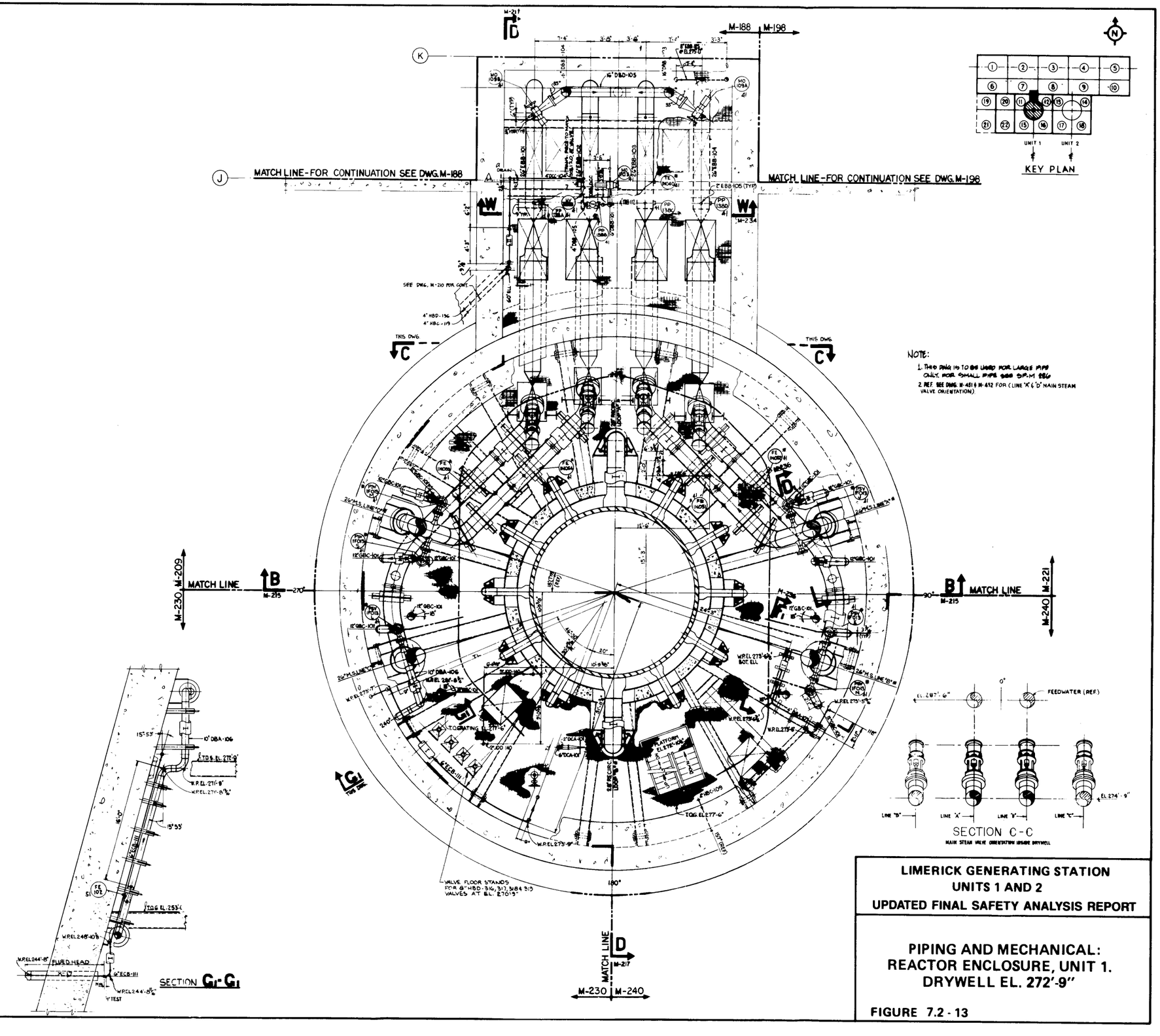


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OUTLINE DRAWING: 26" WELD END MAIN STEAM ISOLATION VALVE

FIGURE 7.2-12

REFERENCE DRAWINGS	
DWG. NO.	**UFSAR** FIG. NO.
M-188	-
M-198	-
M-211	1.2-61
M-215	1.2-71
M-217	1.2-72
M-221	1.2-54
M-236	1.2-70
M-240	1.2-56



NOTE:

1. THIS DWG IS TO BE USED FOR LARGE PIPE ONLY. FOR SMALL PIPE SEE DP-M 886
2. REF. SEE DWGS M-451 & M-452 FOR (LINE 'A' & 'D' MAIN STEAM VALVE ORIENTATION)

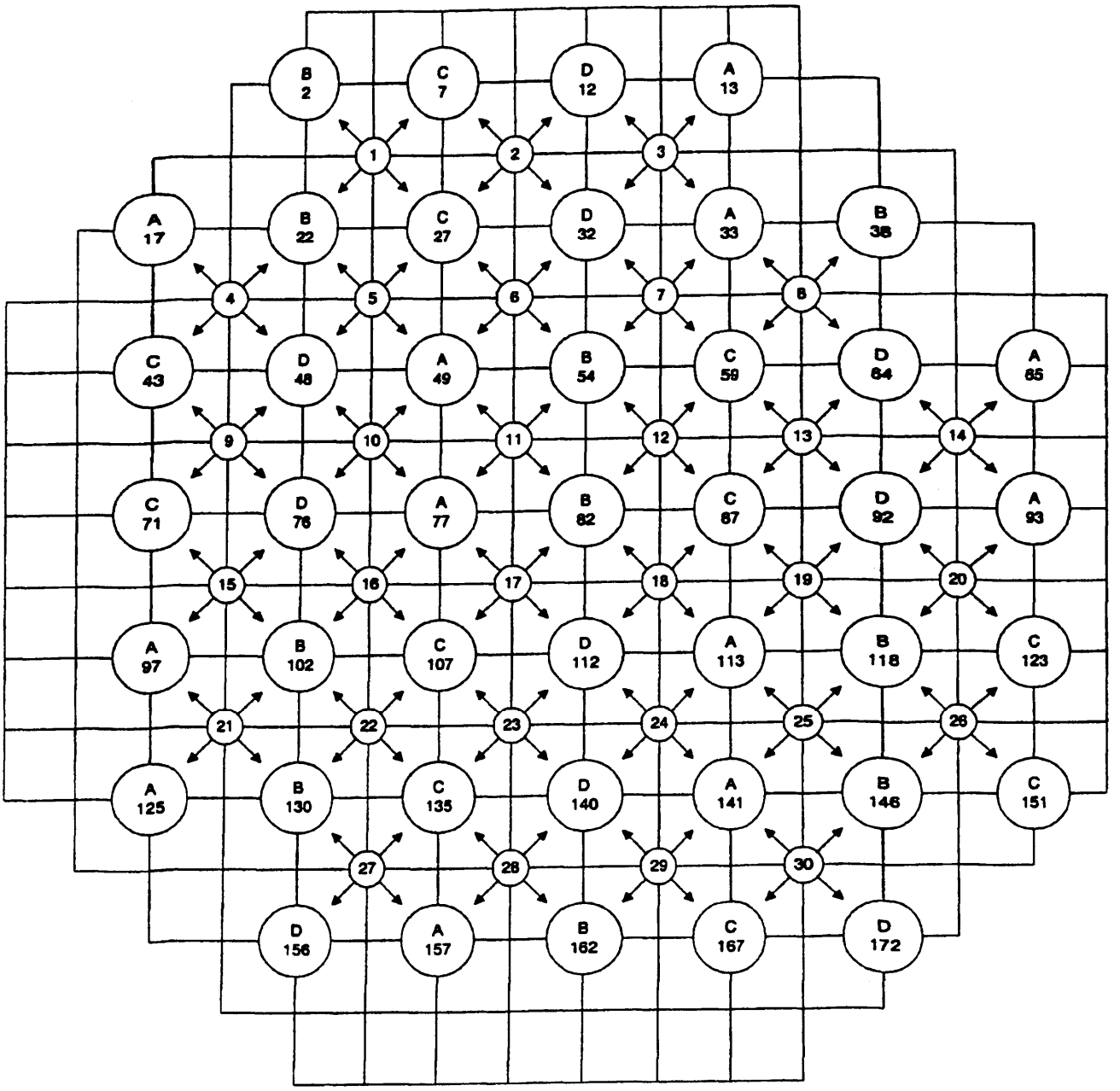
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PIPING AND MECHANICAL: REACTOR ENCLOSURE, UNIT 1. DRYWELL EL. 272'-9"

FIGURE 7.2 - 13

Figures 7.2-14 through 7.2-16

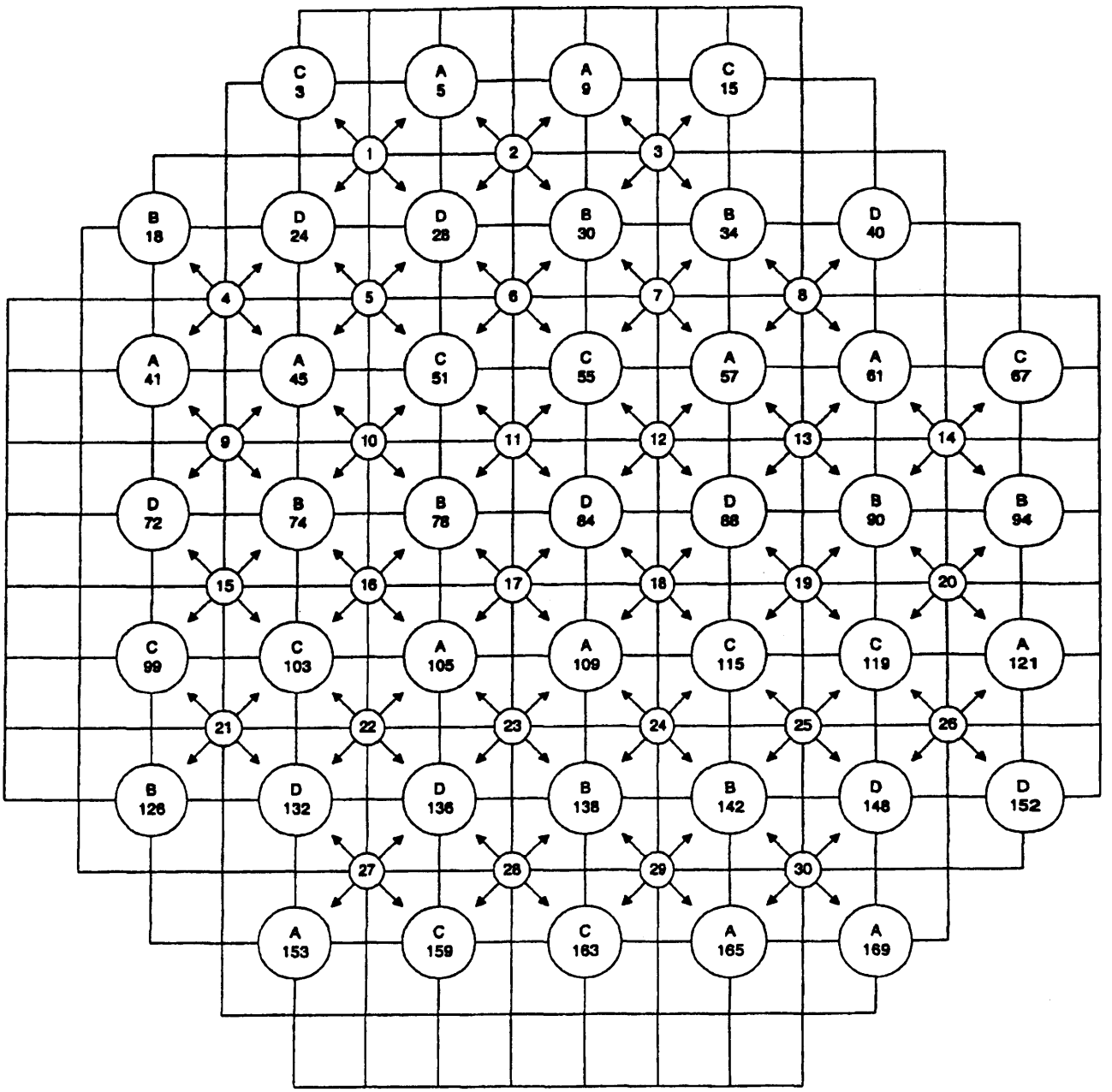
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OPRM Cell Assignments (Channel 1)

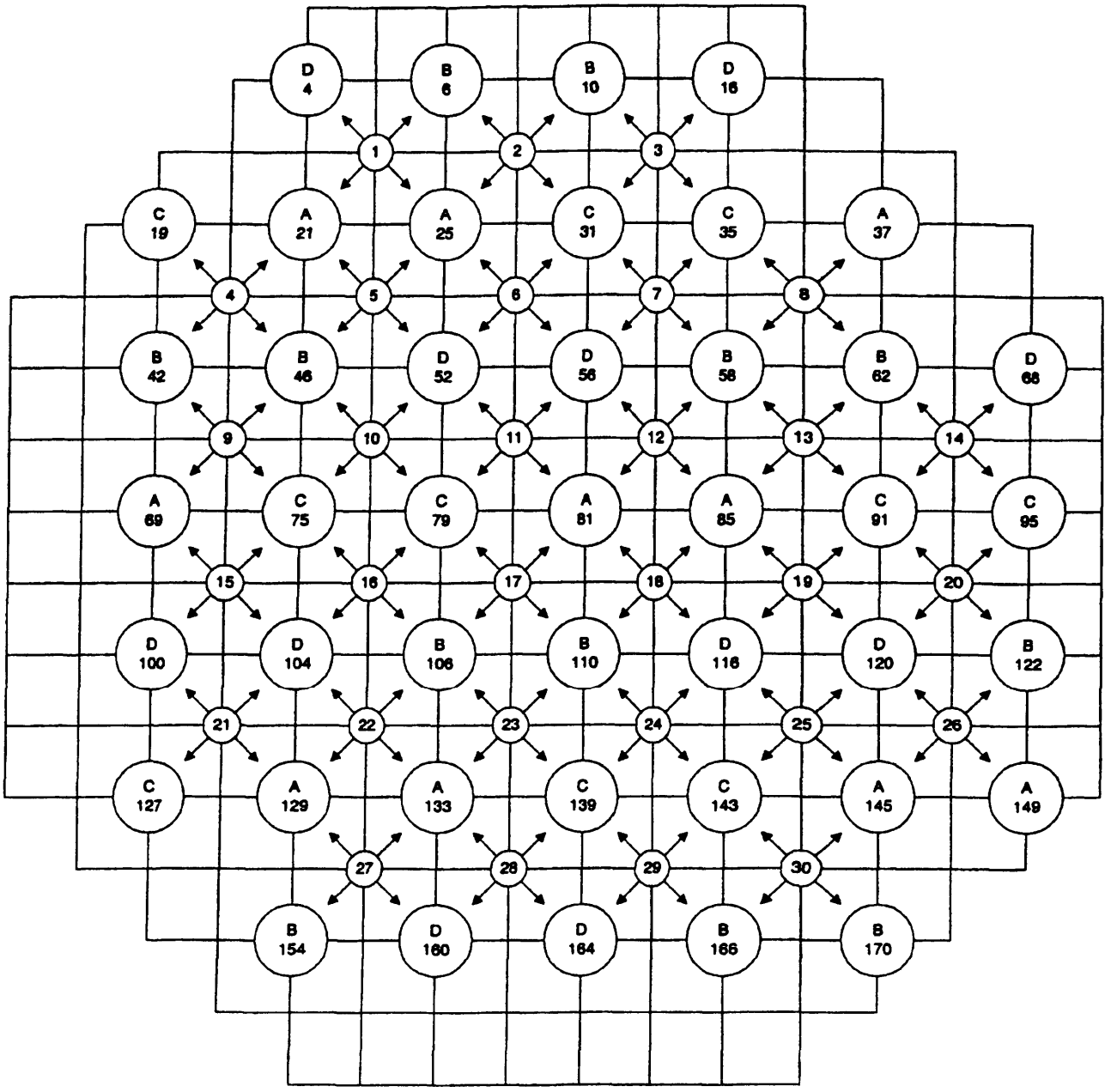
FIGURE 7.2-17 (Sheet 1 of 4) Rev. 13 09/06



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OPRM Cell Assignments (Channel 2)

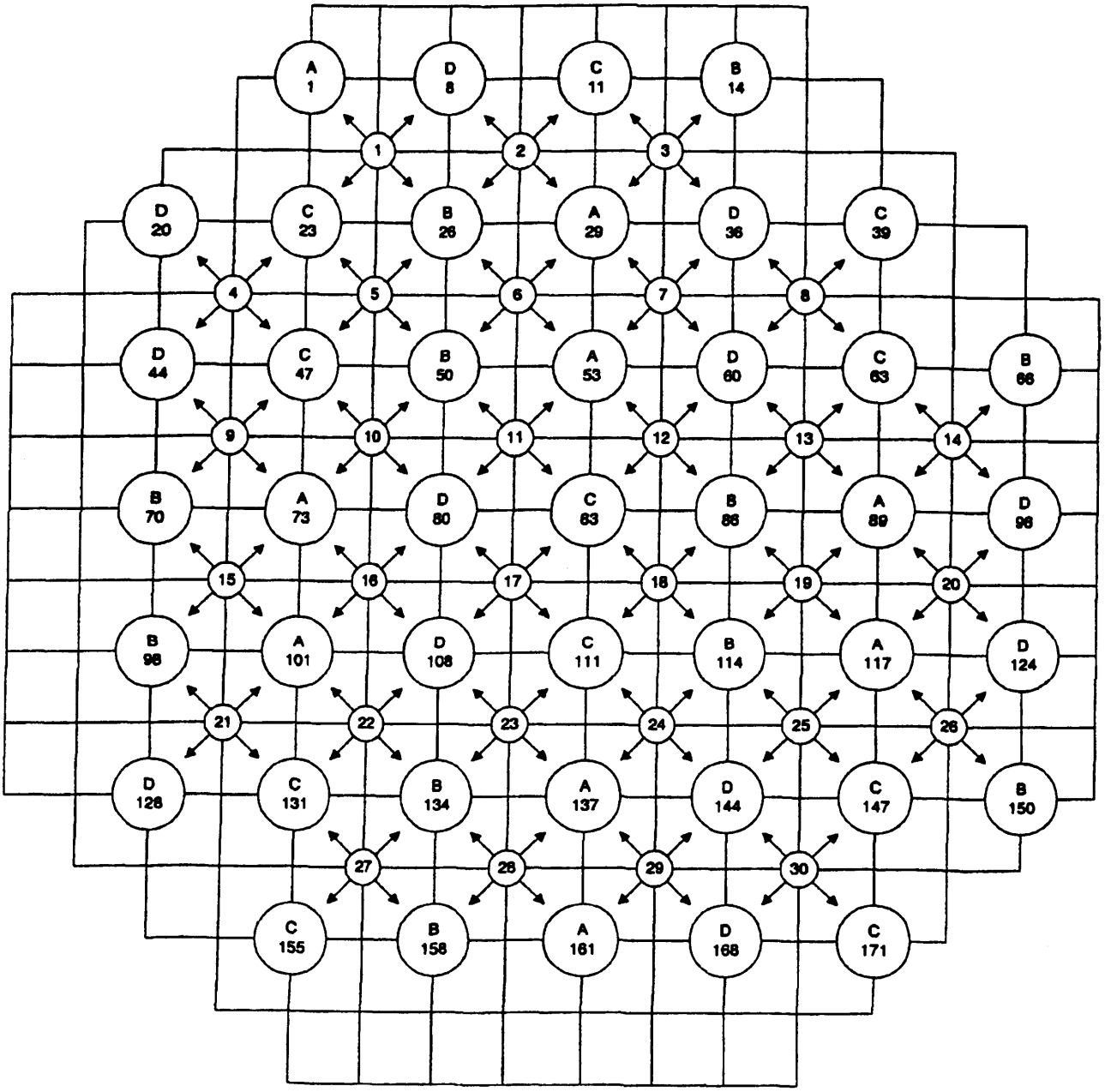
FIGURE 7.2-17 (Sheet 2 of 4) Rev. 13 09/06



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OPRM Cell Assignments (Channel 3)

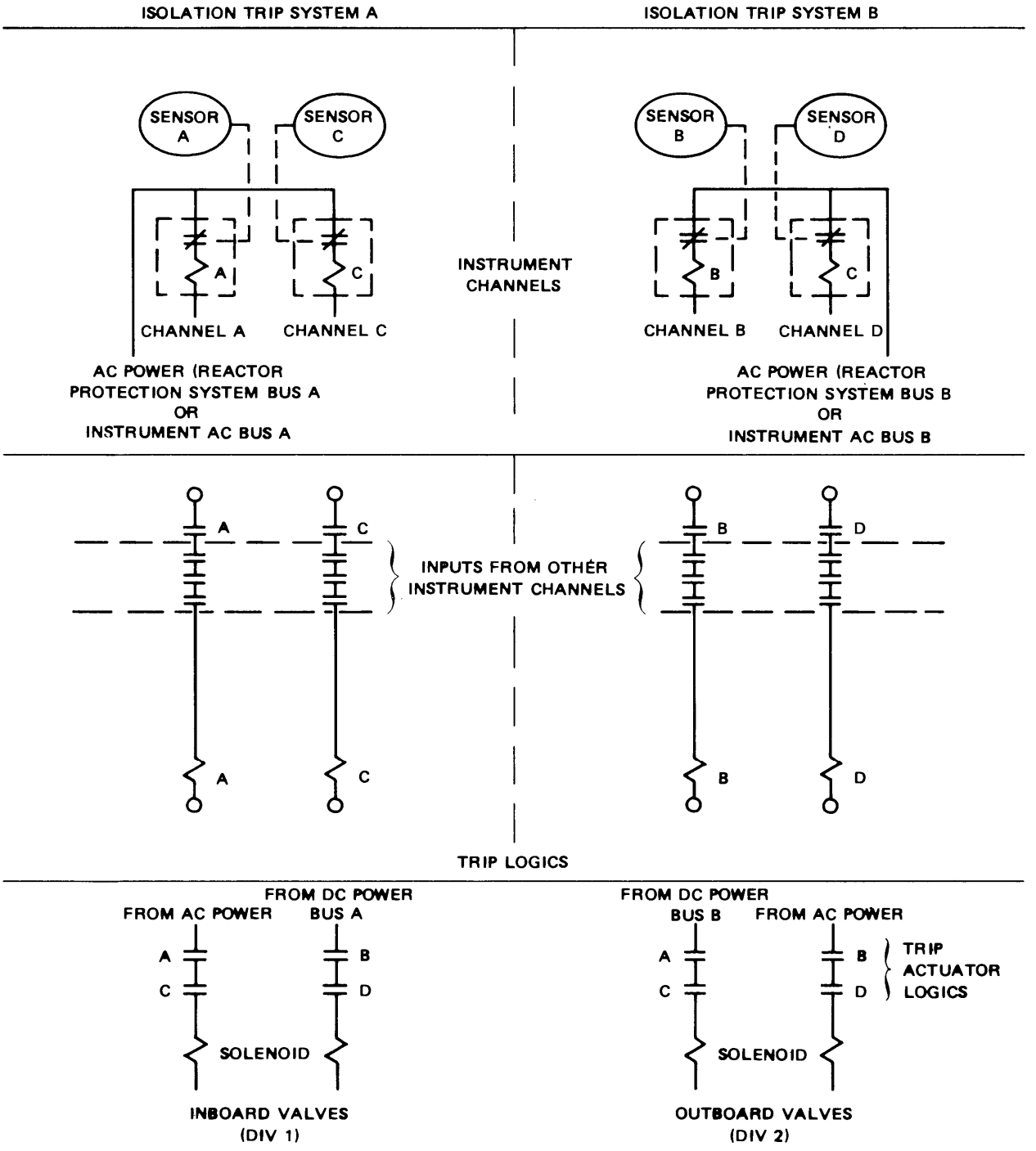
FIGURE 7.2-17 (Sheet 3 of 4) Rev. 13 09/06



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UPDATED FINAL SAFETY ANALYSIS REPORT

OPRM Cell Assignments (Channel 4)

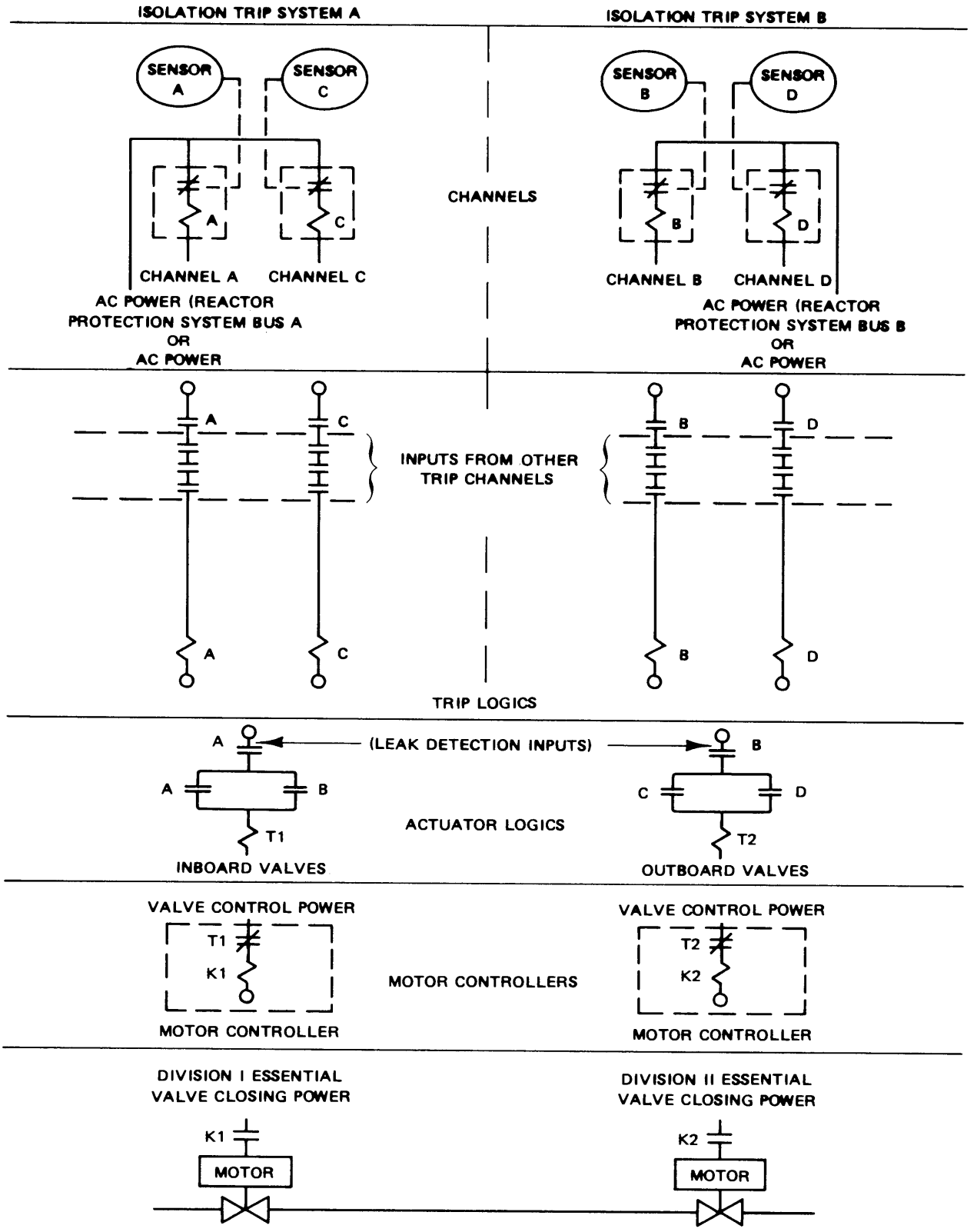
FIGURE 7.2-17 (Sheet 4 of 4) Rev. 13 09/06



LIMERICK GENERATING STATION
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ISOLATION CONTROL SYSTEM FOR MAIN STEAM LINE ISOLATION VALVES

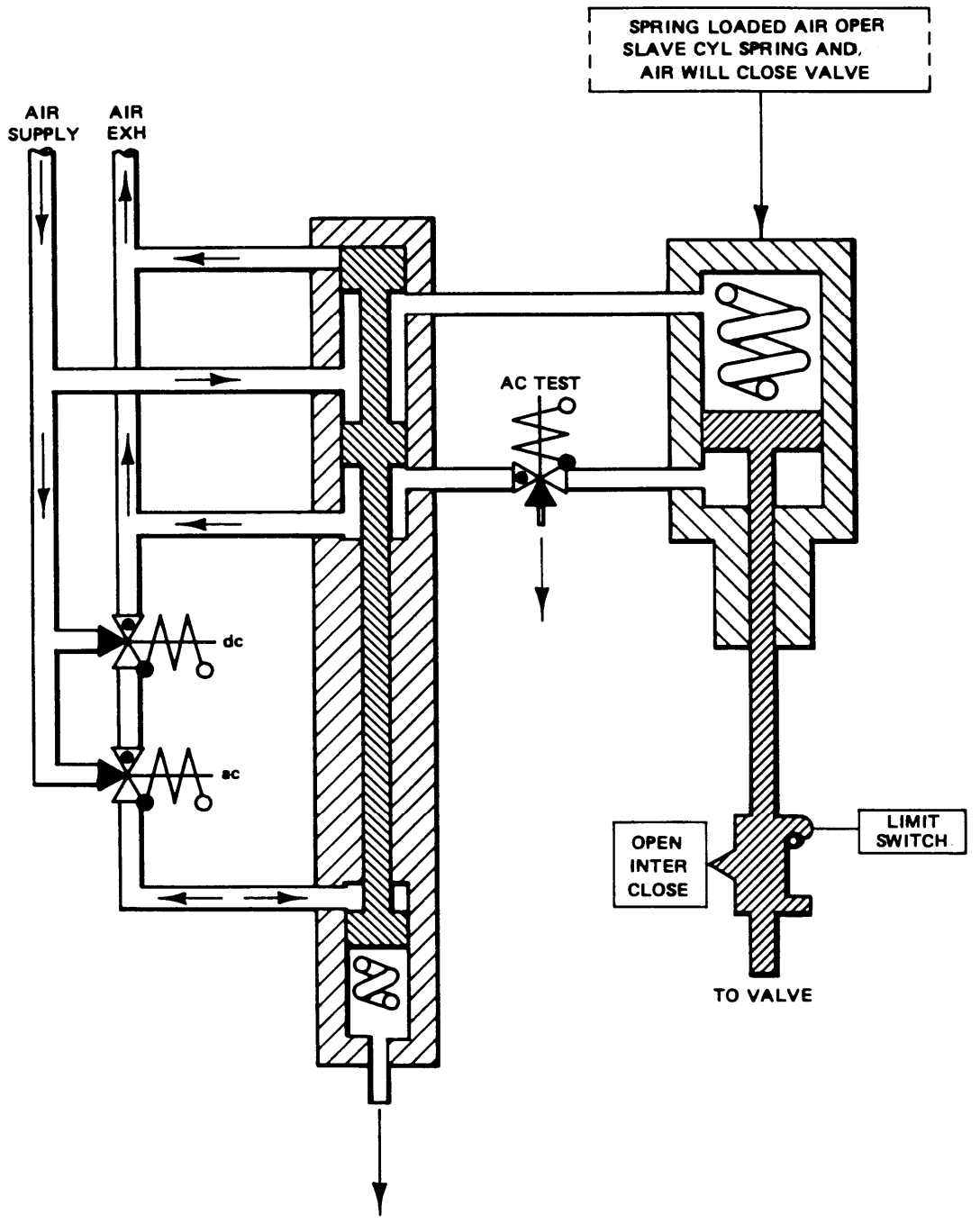
FIGURE 7.3-1



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ISOLATION CONTROL SYSTEM USING MOTOR-OPERATED VALVES

FIGURE 7.3-2

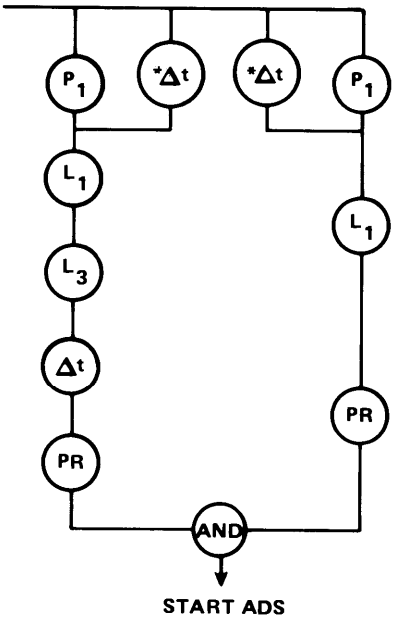


LIMERICK GENERATING STATION
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MAIN STEAM LINE ISOLATION VALVE CONTROL DIAGRAM

FIGURE 7.3-3

Rev. 5, 4/96



L1 —LOW REACTOR WATER LEVEL (LEVEL 1)

L3 —LOW REACTOR WATER LEVEL (LEVEL 3)

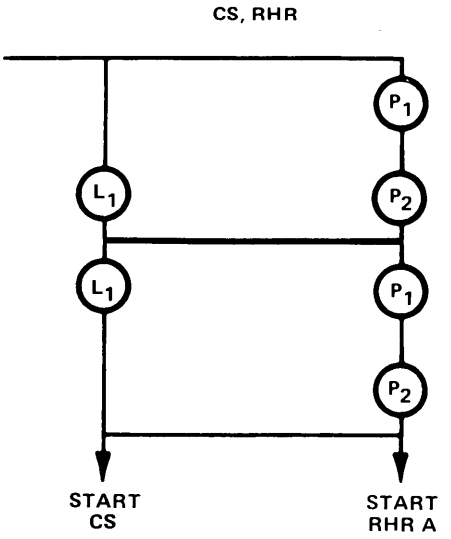
P1 —HIGH DRYWELL PRESSURE

P2 —REACTOR LOW PRESSURE PERMISSIVE

Δt — ADS TIME DELAY

PR —CS OR RHR PUMP RUNNING PERMISSIVE

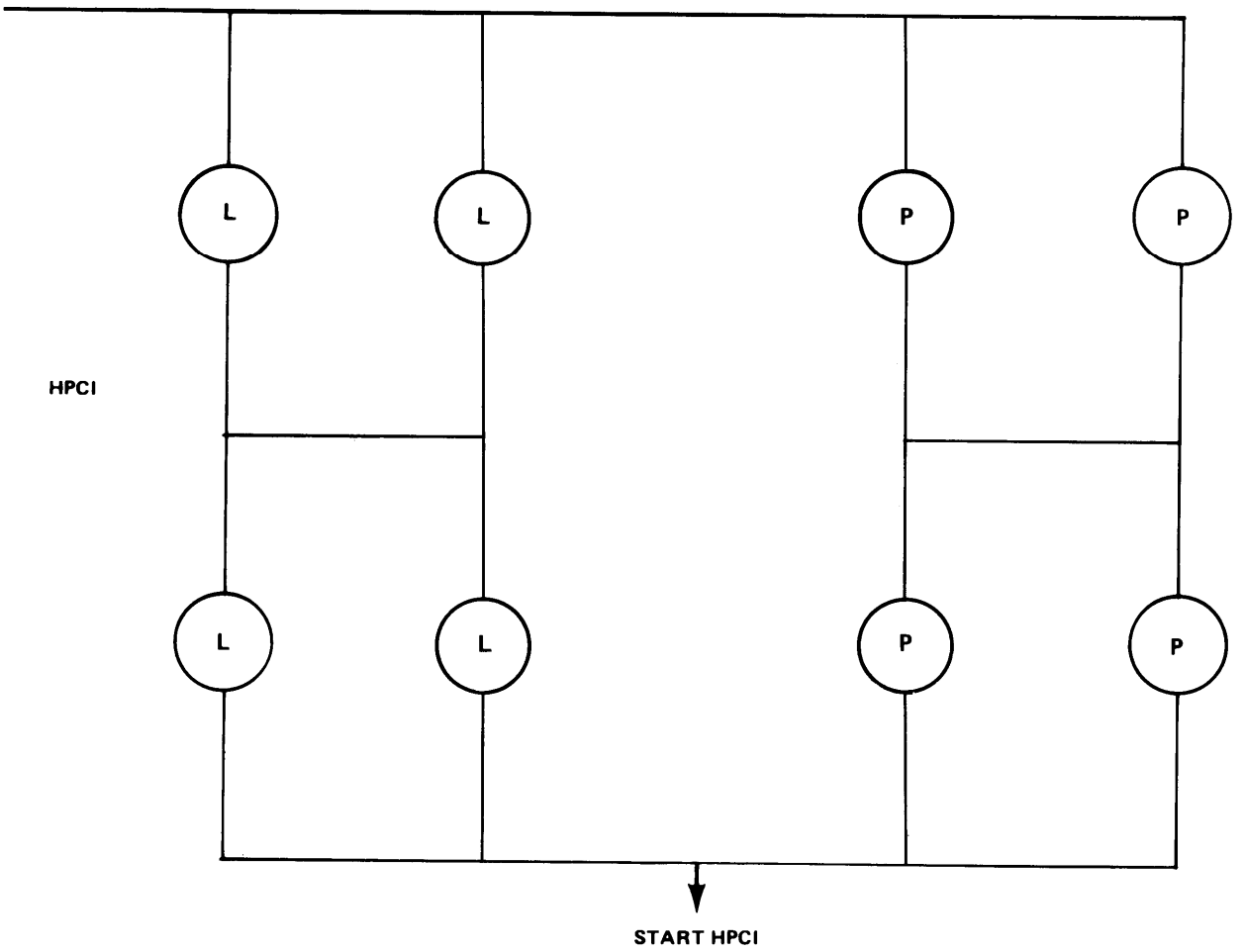
*Δt HIGH DRYWELL PRESSURE BYPASS TIME DELAY



LIMERICK GENERATING STATION
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SYSTEM LEVEL AUTOMATIC INITIATION LOGIC—ADS, CS, RHR

FIGURE 7.3-4



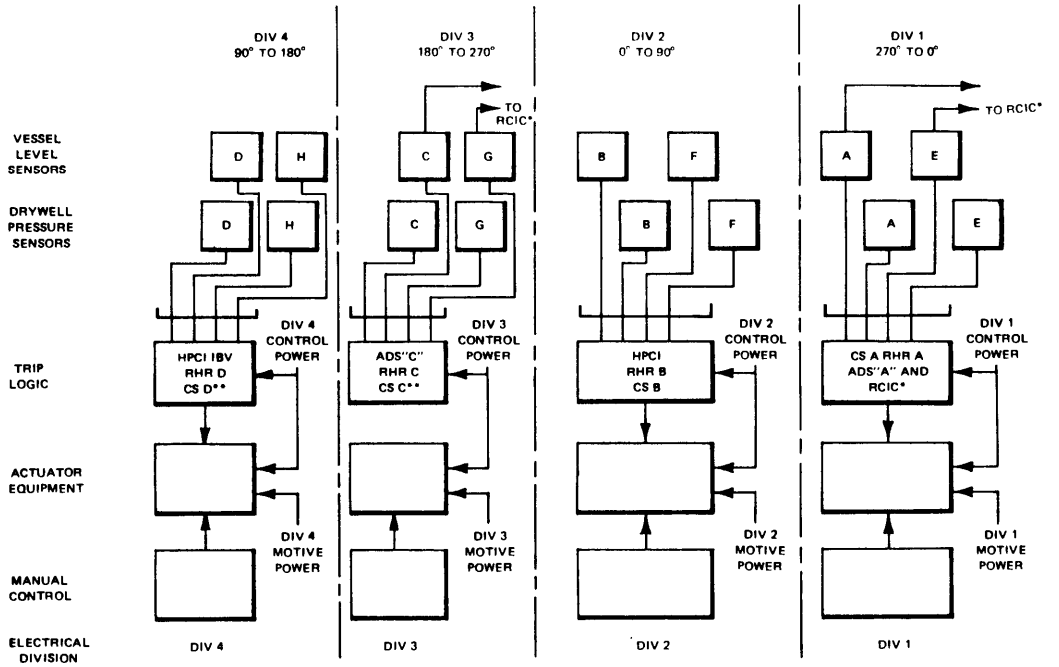
L —REACTOR VESSEL WATER LEVEL

P —HIGH DRYWELL PRESSURE

LIMERICK GENERATING STATION
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AUTOMATIC
INITIATION LOGIC—HPCI

FIGURE 7.3-5



* SEE FIGURE 7.1-4
** PUMP ONLY

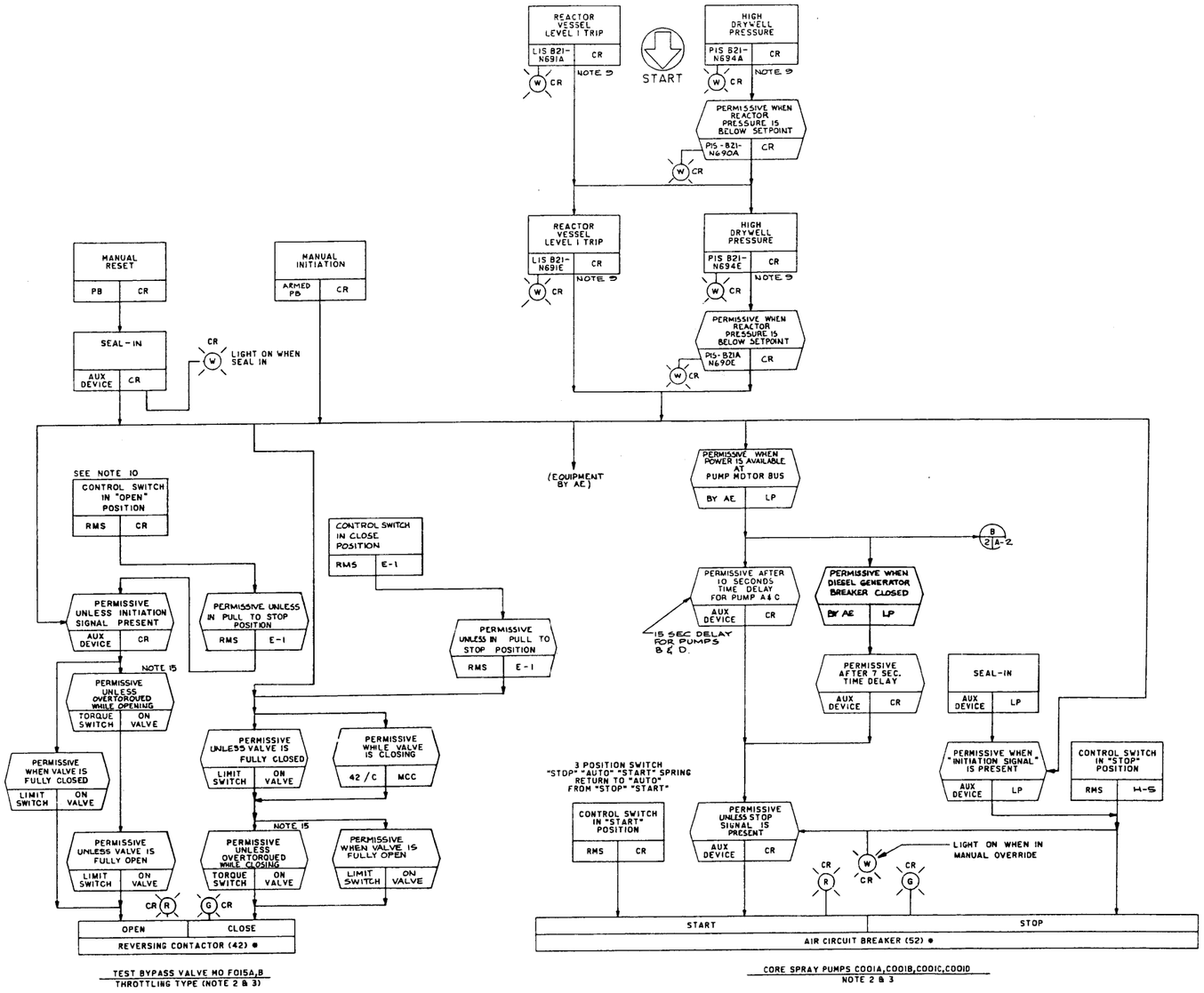
LIMERICK GENERATING STATION
UNITS 1 AND 2
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EMERGENCY CORE COOLING SYSTEM (ECCS) SEPARATION SCHEME

FIGURE 7.3-6

Figures 7.3-7 and 7.3-8

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TEST BYPASS VALVE MO F015A,B
THROTTLING TYPE (NOTE 2 & 3)

CORE SPRAY PUMPS C001A,C001B,C001C,C001D
NOTE 2 & 3

FCF: 238X129AD G1 & G2 (EZ1-1030)

NOTES:

1. THE CONTROL SYSTEM SHOWS SYSTEM 1, OPERATING SEQUENCE AFTER LOW WATER LEVEL OR HIGH DRYWELL PRESSURE SIGNAL IS AS FOLLOWS:

   CONDITION A — WITH PLANT ON NORMAL AUXILIARY POWER

   ACTIVE PUMPS: A & C — STARTS AFTER 10 SEC DELAY
   B & D — STARTS AFTER 15 SEC DELAY

   VALVES:

F004A	1 OPENS AFTER REAC LOW PRESS. PERM.
F004B	11 OPENS AFTER REAC LOW PRESS. PERM.
F005	1 OPENS AFTER REAC LOW PRESS. PERM.
F037	11 OPENS AFTER REAC LOW PRESS. PERM.
F015A	1 CLOSES IF OPEN - NO DELAY
F015B	11 CLOSES IF OPEN - NO DELAY
F031A	1 CLOSES AFTER FLOW ESTABLISHED
F031B	11 CLOSES AFTER FLOW ESTABLISHED

   CONDITION B — WITH PLANT ON STANDBY DIESEL POWER

   ACTIVE PUMP:

C001A & C	STARTS AFTER 7 SEC DELAY
C001B & D	STARTS AFTER 7 SEC DELAY

   VALVES: SAME SEQUENCE AS CONDITION A

2. DIV 2 CIRCUIT IDENTICAL TO CIRCUIT FOR DIV 1. DIV 3 & 4 PARTS IDENTIFIED AS FOLLOWS:

	DIV 1	DIV 2	DIV 3	DIV 4
PUMP	C001A	C001B	C001C	C001D
MIN FLOW BYPASS VALVES	F031A	F031B		
OUTBOARD ISOL. VALVE	F004A	F004B		
INBOARD ISOL. VALVES	F005	F037		
TESTABLE CHECK VALVES	F006A	F006B		
PUMP SUCTION VALVES	F001A	F001B	F001C	F001D
TEST BYPASS VALVES	F015A	F015B		
HIGH DRYWELL PRESS	B21-N694A,E	N694B,F	N694C,G	N694D,H
REACTOR VESSEL LEVEL	B21-N691A,E	N691B,F	N691C,G	N691D,H
REACTOR PRESSURE	B21-N690A,C, J,N	N690B,F,K,P	N690C,G	N690D,H

3. PUMP MOTOR CIRCUITS SHALL PROVIDE FOR OVERLOAD PROTECTION; OVERLOAD RELAYS TO BE APPLIED SO AS TO MAINTAIN POWER AS LONG AS POSSIBLE WITHOUT IMMEDIATE DAMAGE TO MOTOR OR HARM TO ENERGIZED POWER SYSTEM. VALVE MOTORS SHALL BE PROVIDED WITH OVERLOAD TRIP AND BREAKER SHORT CIRCUIT PROTECTIVE TRIPS.

4. MOTIVE POWER FOR DIV. 1,2,3 & 4 PUMPS SHALL ORIGINATE FROM A DIFFERENT EMERGENCY AC BUS. POWER FOR VALVES IN EACH DIV SHALL ORIGINATE FROM THE SAME BUS SUPPLYING PUMP POWER. CONTROL POWER FOR PUMPS & VALVES OF DIV 1,2,3, & 4 SHALL BE FROM A DIFFERENT SOURCE.

5. * = SWITCHGEAR DEVICE FUNCTION NUMBERS AIS1 SPEC. C37.2.

6. ALL EQUIPMENT AND INSTRUMENTS ARE PREFIXED BY SYSTEM NO. E21 UNLESS OTHERWISE NOTED

7. FOR LOCATION AND IDENTIFICATION OF INSTRUMENTS SEE INSTRUMENT DATA SHEET REF. 11.

8. SEE REFERENCE PSID'S FOR ADDITIONAL INFORMATION ON ALARMS. VALVE INDICATING LIGHTS AND PROCESS INSTRUMENTATION.

9. DIV 1-A,E,J,N; DIV 2-B,F,K,P; DIV 3-C,G, DIV 4-D,H.

10. UNLESS OTHERWISE NOTED ALL CONTROL SWITCHES SHALL BE TYPE, 3 POSITION SWITCH "CLOSE" - "AUTO" - "OPEN" SPRING RETURN TO "AUTO" FROM "CLOSE" OR "OPEN" POSITION, PULL TO STOP IN ALL POSITIONS.

12. THE CORE SPRAY SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH REF. 10.

13. LAMPS TO BE LOCATED BELOW REGULAR CORE SPRAY ANNUNCIATORS, LEGEND AS SHOWN.

14. SWITCH TO BE LOCATED BELOW LAMPS. SWITCH TO BE 2 POSITION "NORMAL" - "INOP".

15. REPRESENTATIVE OF PARALLEL TORQUE SWITCH COMBINATION, REFER TO REFERENCE 12

16. PUMP RUNNING SIGNAL FROM PUMPS A & B SUPPLIED BY AE, PUMP RUNNING SIGNAL FROM C & D SUPPLIED BY AUXILIARY DEVICE

REFERENCE DOCUMENTS:

	MPL ITEM NO.
1. NUCLEAR BOILER SYSTEM P&ID	B21-1010
2. NUCLEAR BOILER SYSTEM FCD	B21-1030
3. RESIDUAL HEAT REMOVAL SYSTEM FCD	E11-1030
4. CORE SPRAY SYSTEM P&ID	E21-1010
5. CORE SPRAY SYSTEM DES. SPEC	E21-4010
6. HPCI SYSTEM FCD	E41-1030
7. RCIC SYSTEM FCD	E51-1030
8. LOGIC SYMBOLS	A41-1030
9. RHR SYSTEM P&ID	E11-1010
10. ELECTRICAL EQUIP SEPARATION FOR SAFEGUARD SYS	A61-4050
11. INSTRUMENT DATA SHEET	E21-3050
12. CORE SPRAY SYSTEM ELEM. DIAG	E21-1040

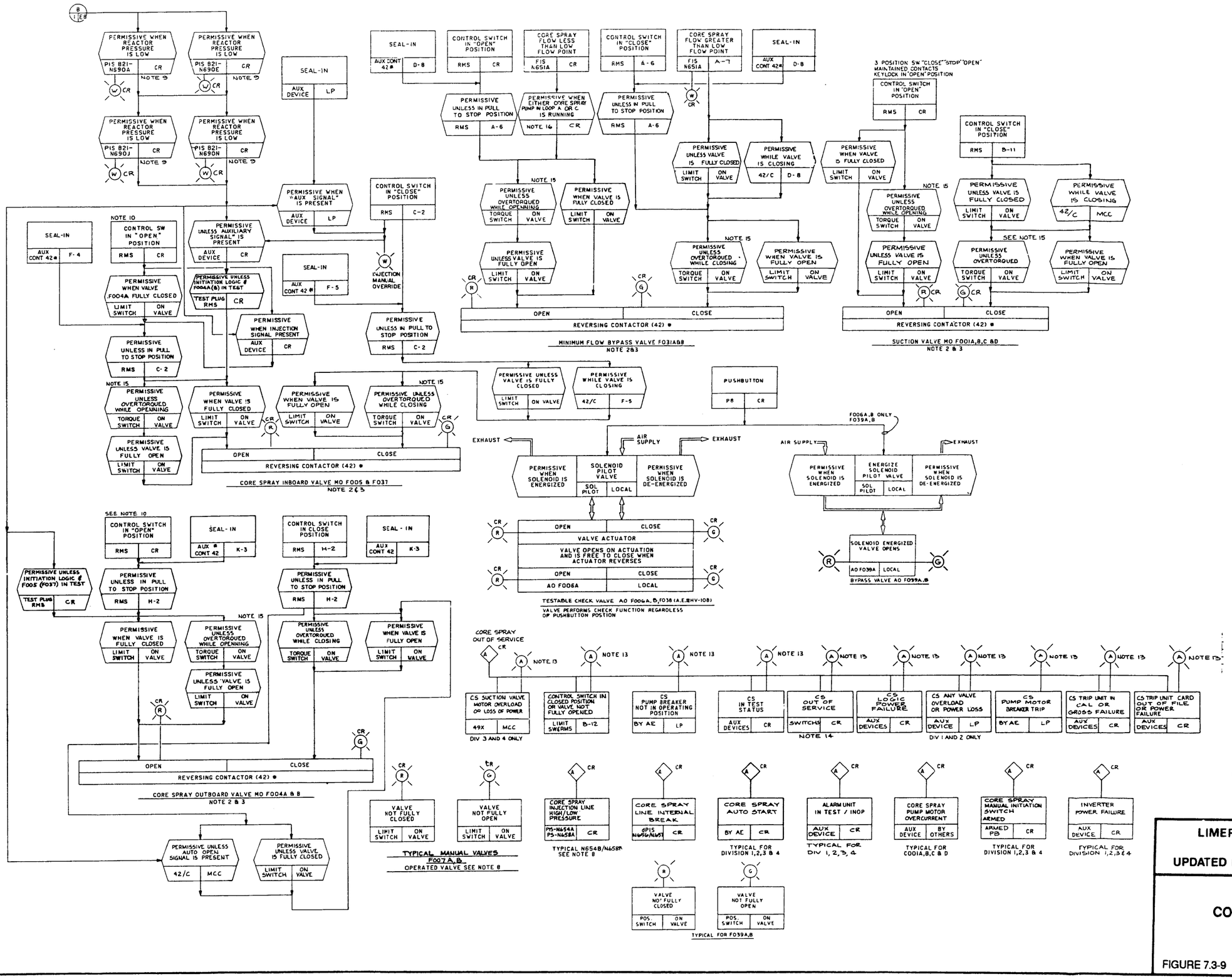
729E613AD, SHT. 1, REV. 10

Per NEI 98-03, this Figure in it's entirety is classified as *HISTORICAL*.

LIMERICK GENERATING STATION
UNITS 1 AND 2
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CORE SPRAY SYSTEM FCD
(SHEET 1 OF 2)

FIGURE 7.3-9 Rev. 11 9/02



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729E613AD, SHT. 2, REV. 10

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UPDATED FINAL SAFETY ANALYSIS REPORT

CORE SPRAY SYSTEM FCD
(SHEET 2 OF 2)

FIGURE 7.3-9

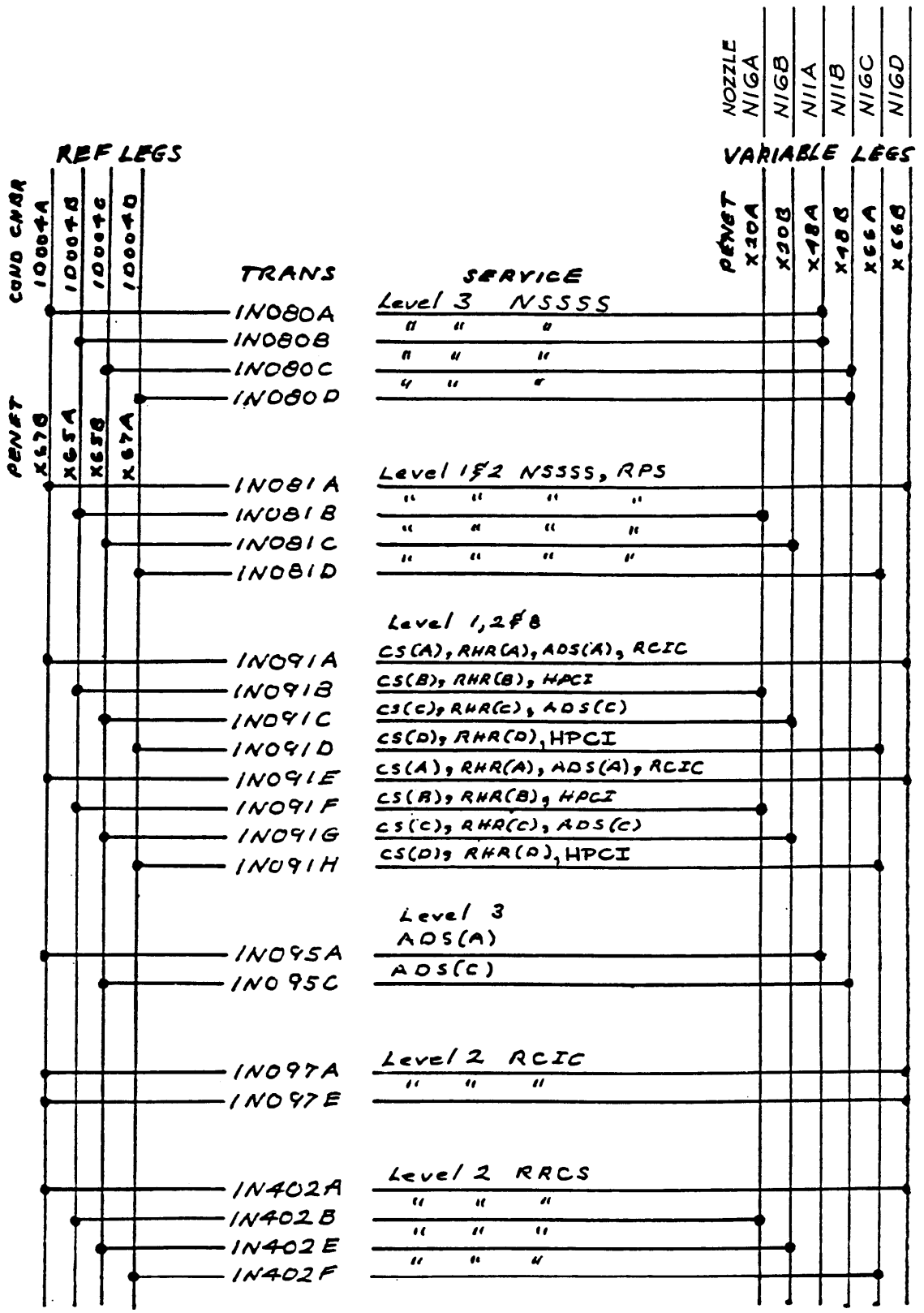
Rev. 11 9/02

Figure 7.3-10

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Figures 7.3-12 through 7.3-25

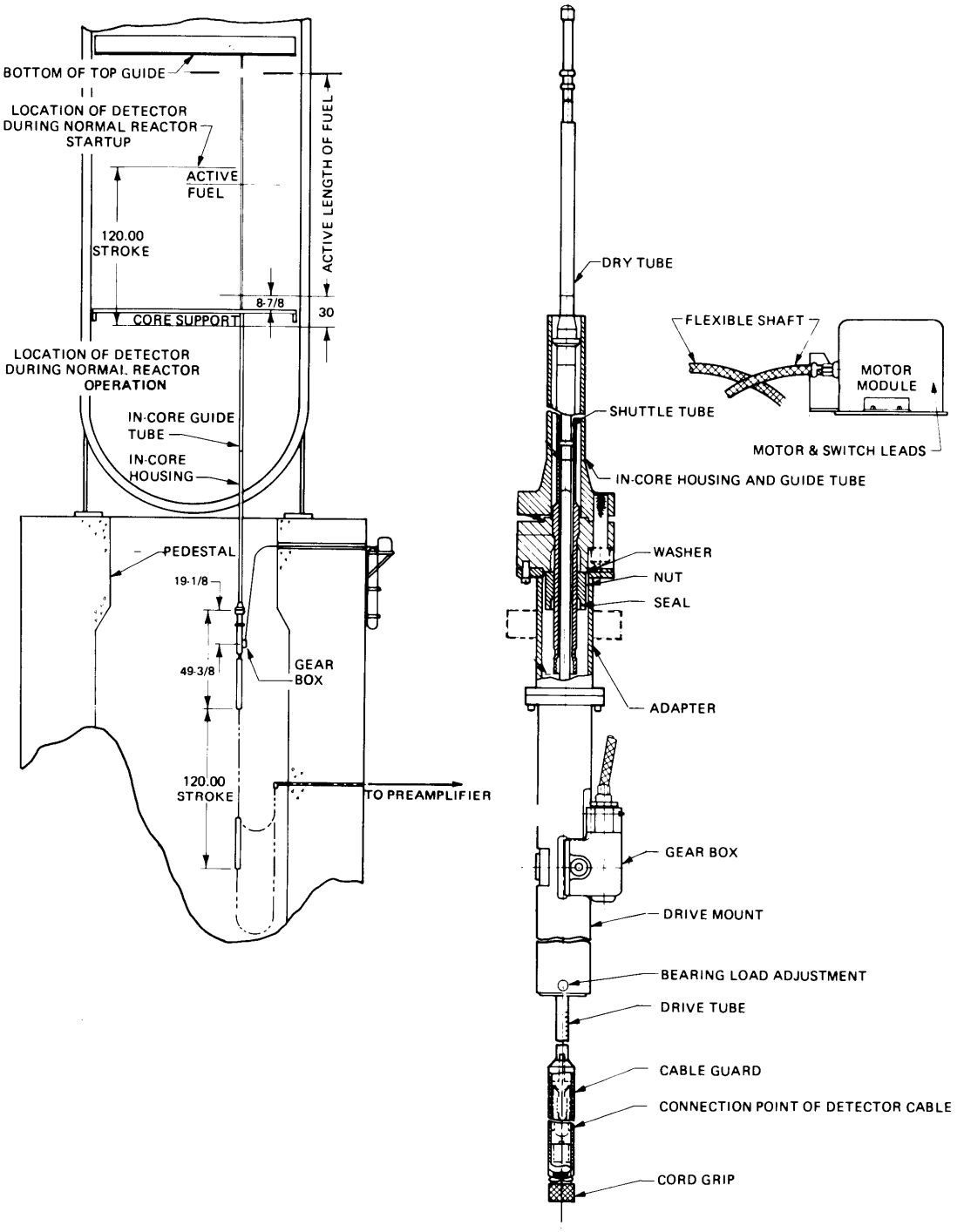
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LIMERICK GENERATING STATION
UNITS 1 AND 2
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LEVEL SENSOR CONNECTIONS

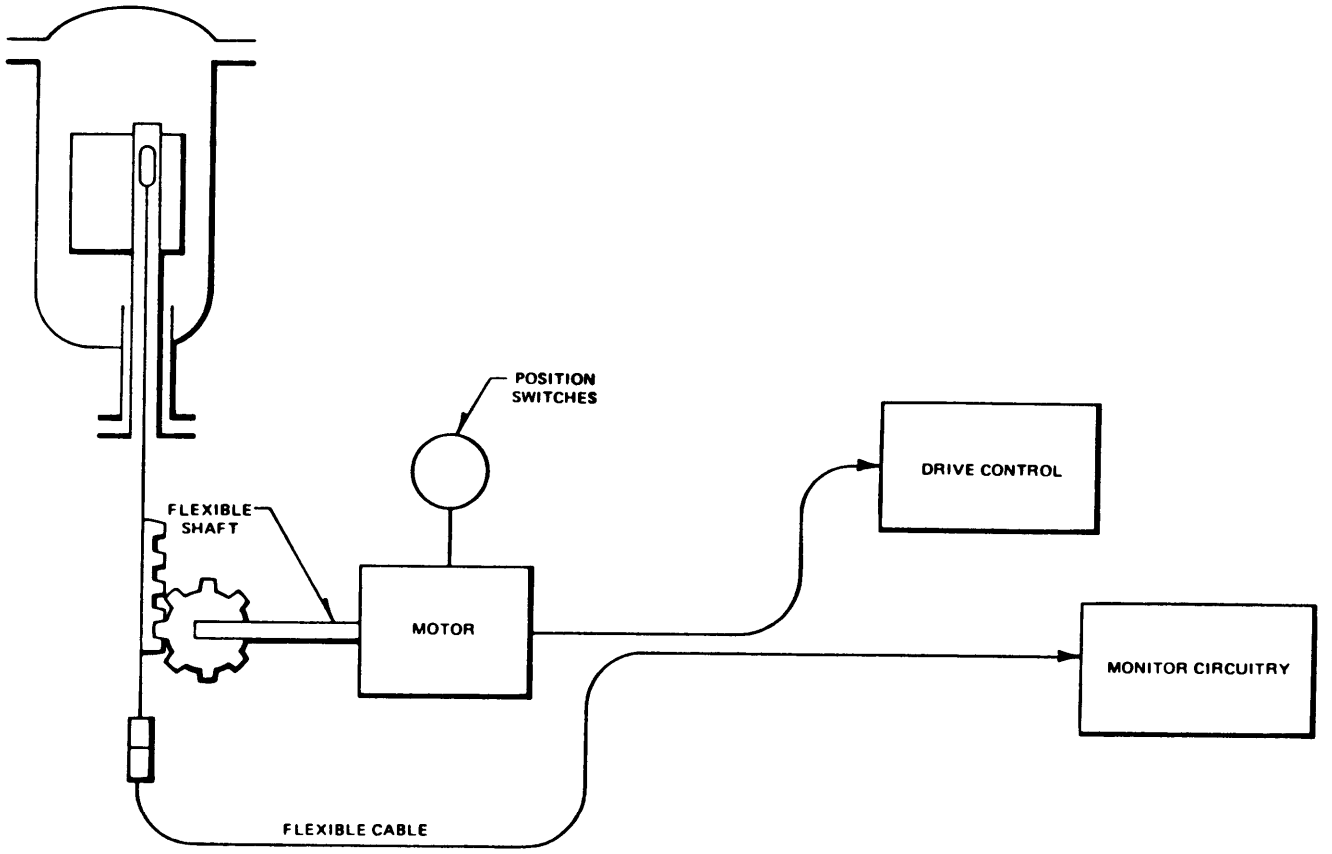
FIGURE 7.3-26 REV. 7 12/97



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SRM/IRM NEUTRON MONITORING UNIT

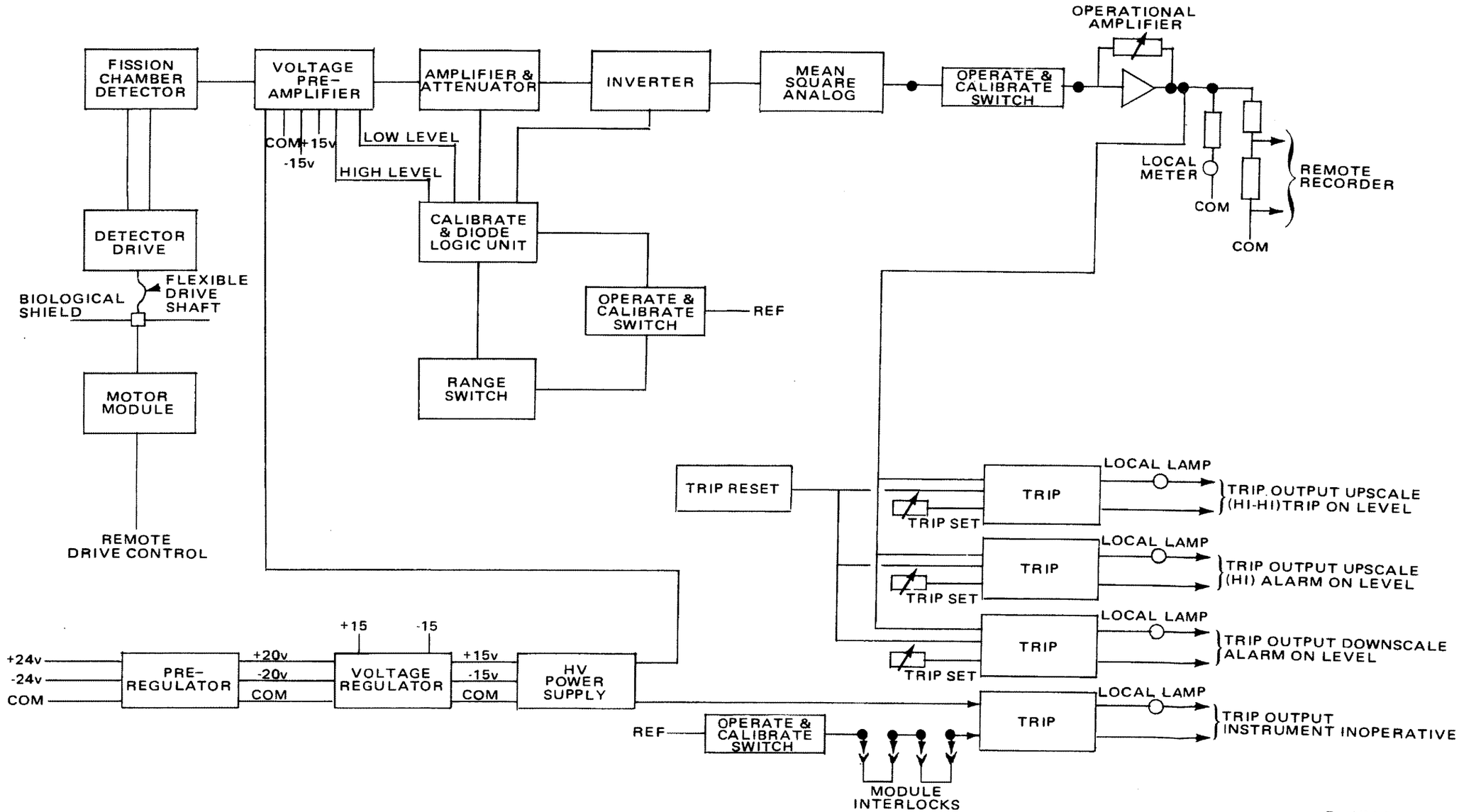
FIGURE 7.6-2



LIMERICK GENERATING STATION
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DETECTOR DRIVE
SYSTEM SCHEMATIC

FIGURE 7.6-3

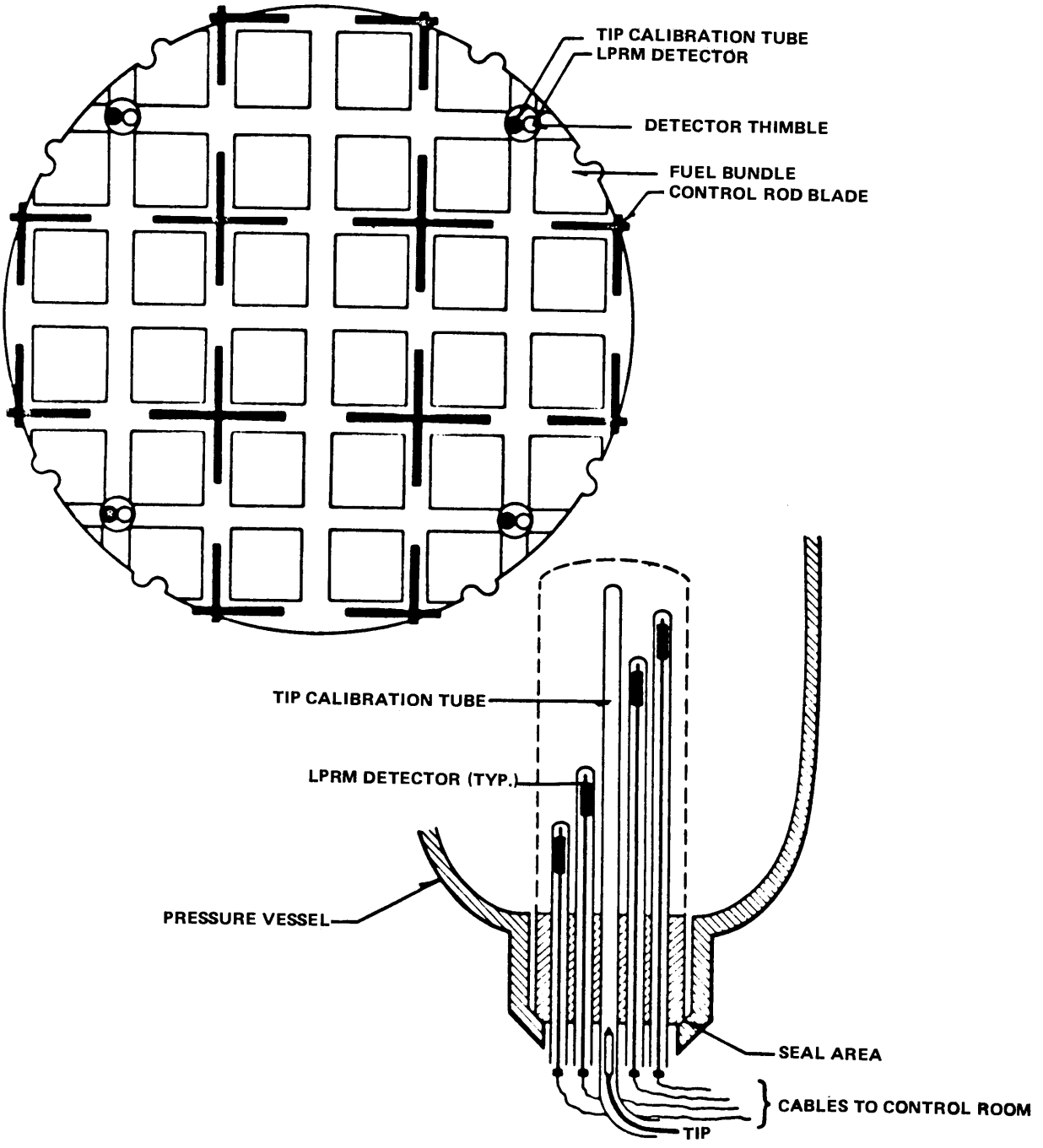


Per NEI 98-03, this Figure in it's entirety is classified as *HISTORICAL*.

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FUNCTIONAL BLOCK DIAGRAM OF IRM CHANNEL

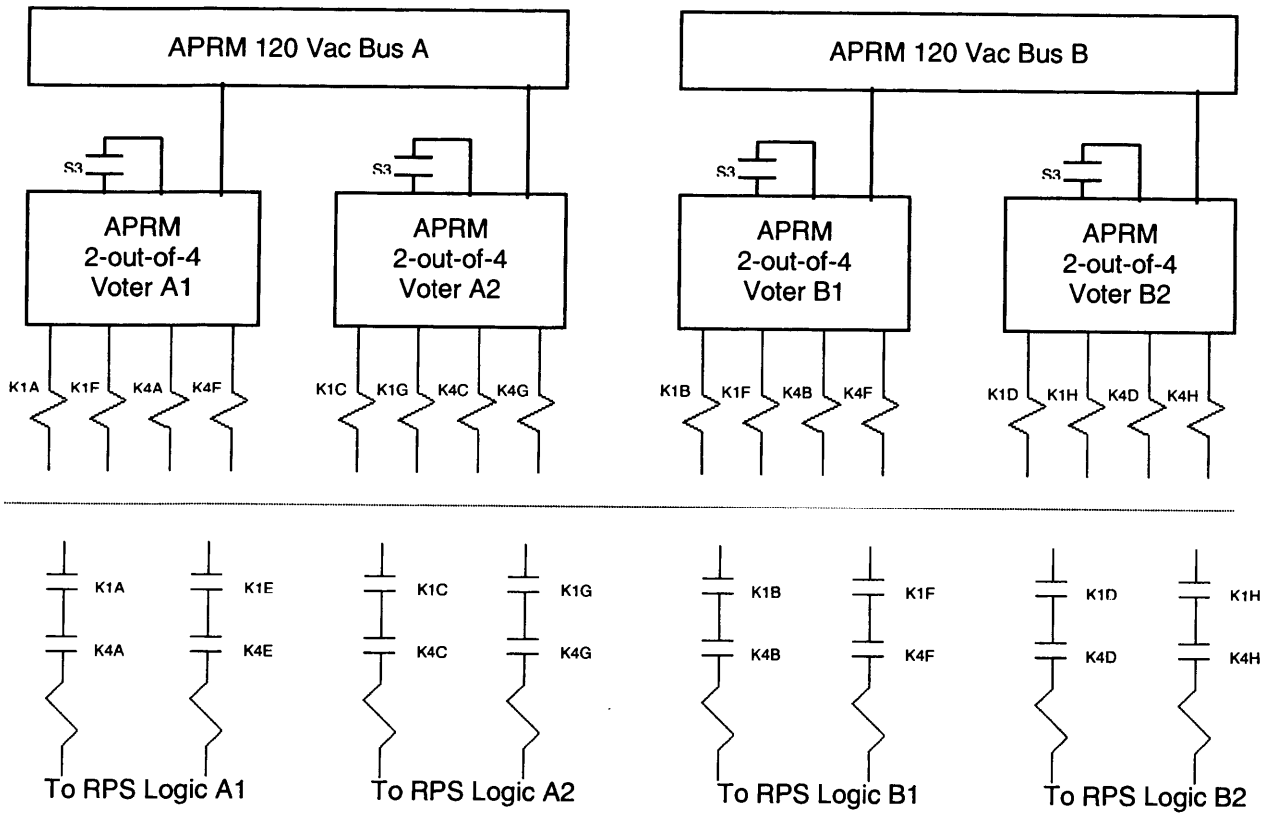
FIGURE 7.6-5 Rev. 11 9/02



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

POWER RANGE DETECTOR ASSEMBLY LOCATION

FIGURE 7.6-6



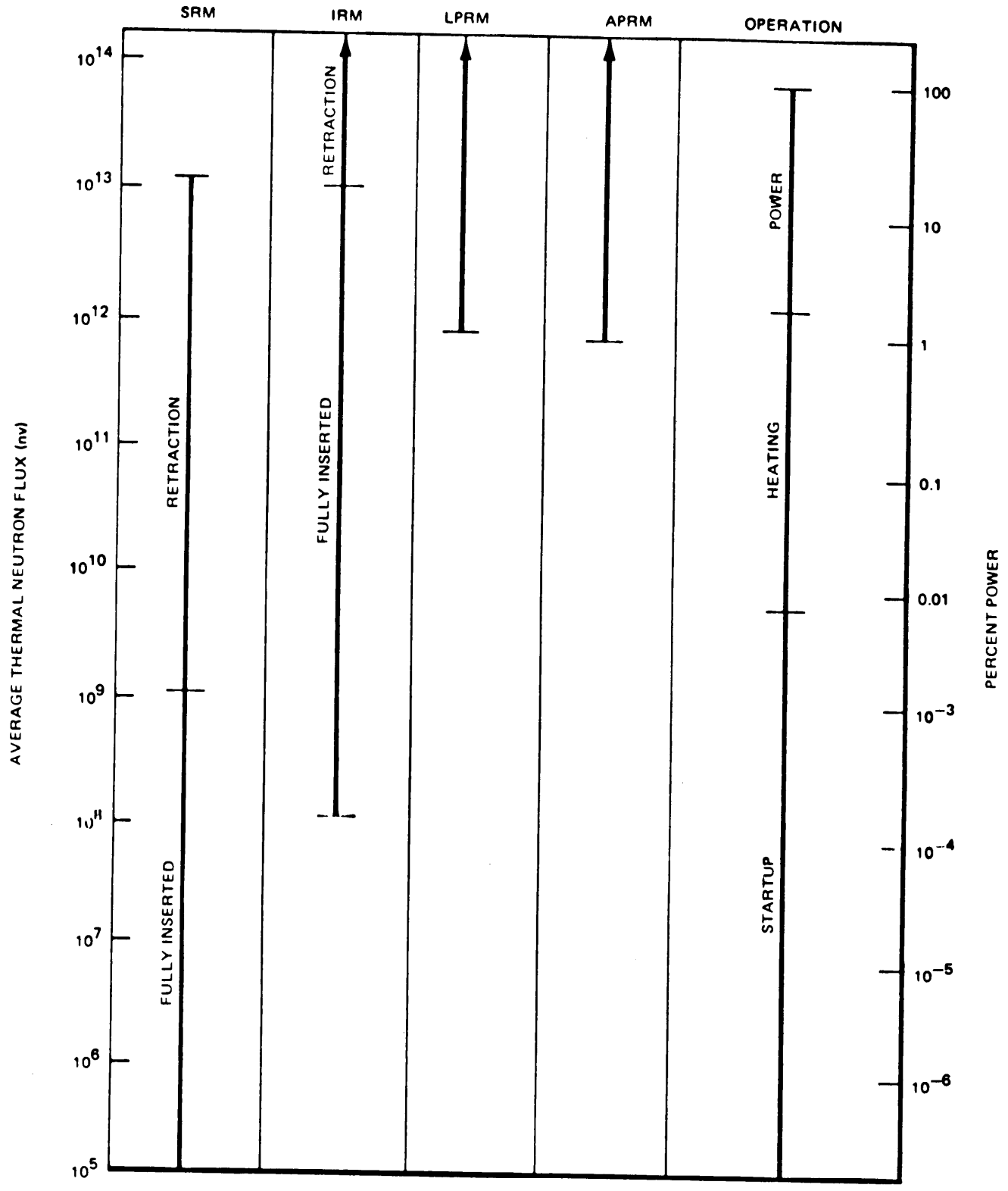
NOTE: Contacts are shown in normal operation position.

LEGEND: K1A, K1B, K1C, K1D, K1E, K1F, K1G, K1H = (APRM Neutron Flux – Upscale or APRM Simulated Thermal Power – Upscale or APRM Inop) and (APRM Not Bypasses)
K4A, K4B, K4C, K4D, K4E, K4F, K4G, K4H = (OPRM Upscale Trip) and (OPRM Not Bypassed)
S3 = APRM Bypass Switch

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APRM CIRCUIT ARRANGEMENT FOR REACTOR PROTECTION SYSTEM INPUT

FIGURE 7.6-7 **Rev. 13 09/06**

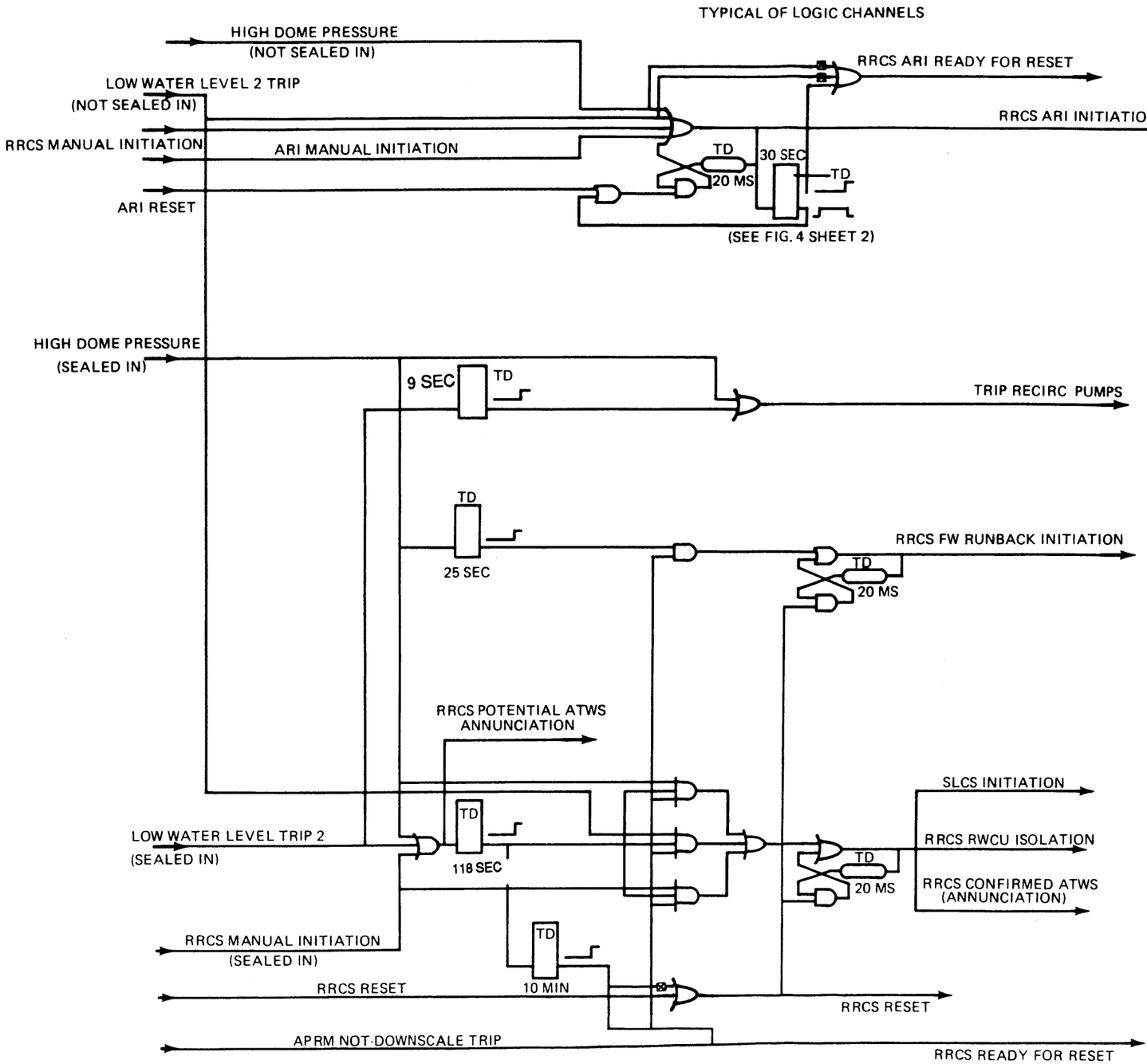


SOURCE

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RANGES OF NEUTRON MONITORING SYSTEM

FIGURE 7.6-8



Note: This figure is based on GE Drawing Number 944E194TR.

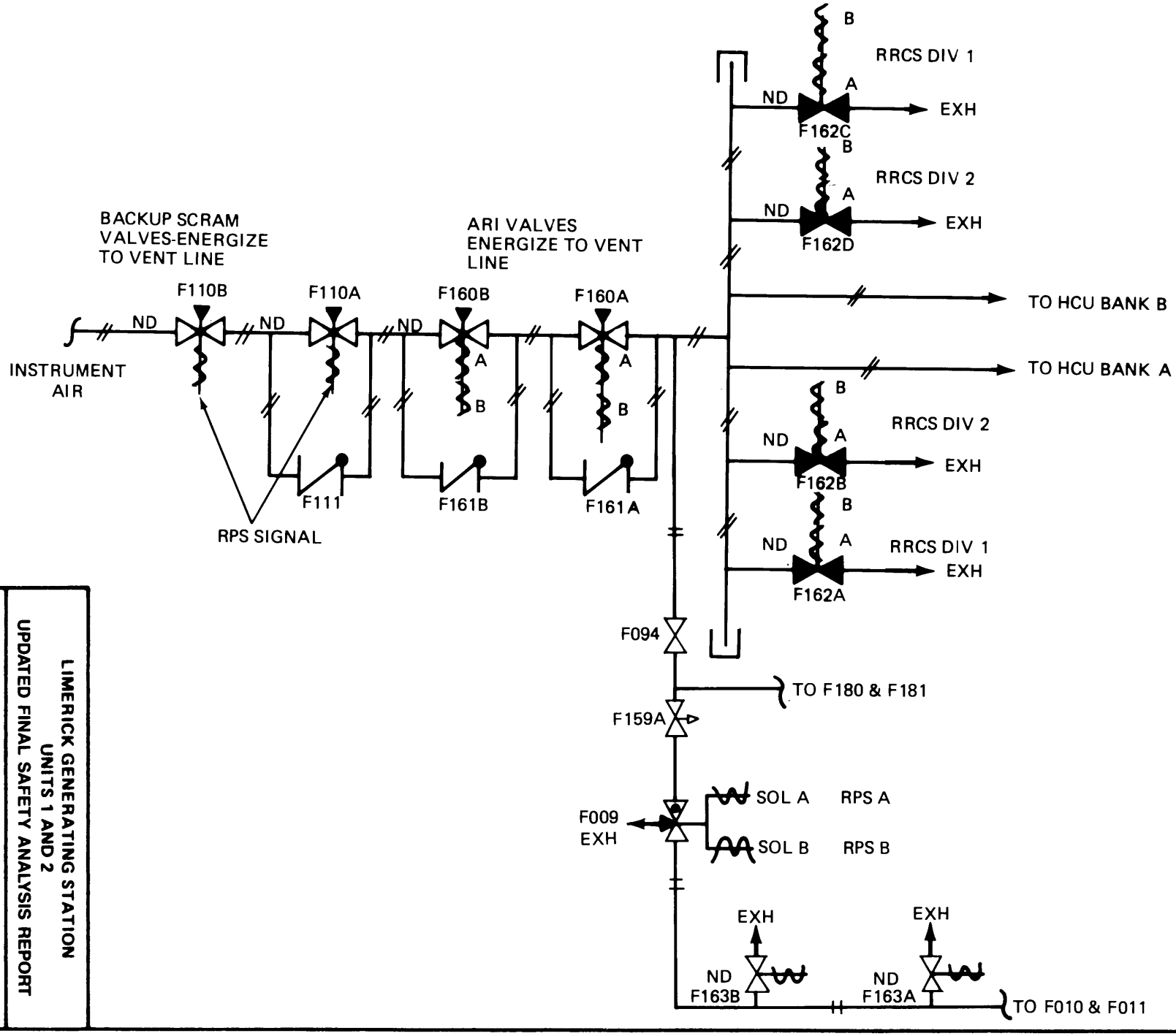
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RRCS INITIATION LOGIC

FIGURE 7.6-10

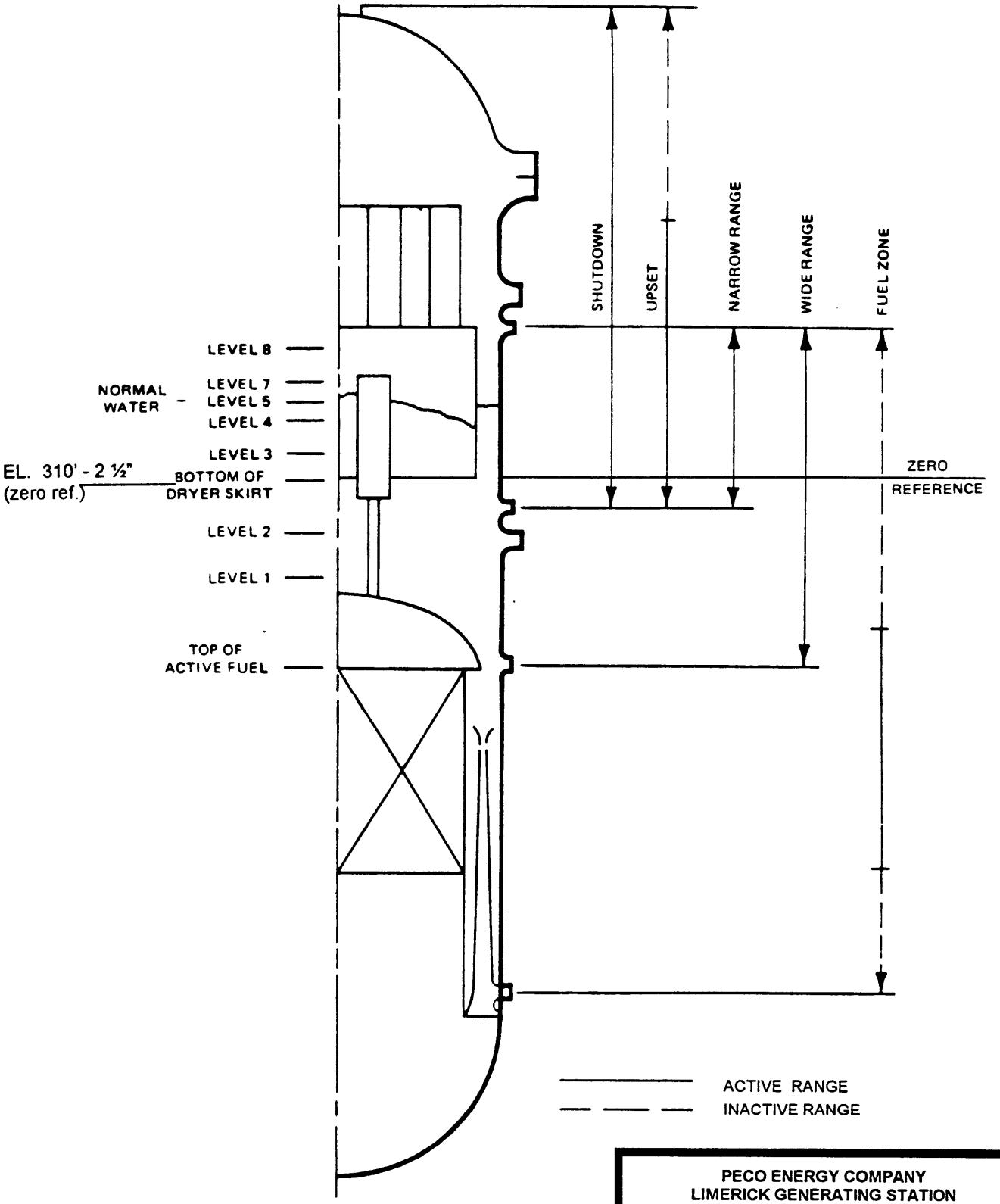
Rev. 11 9/02



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RRCS ARI VALVES

FIGURE 7.6-11



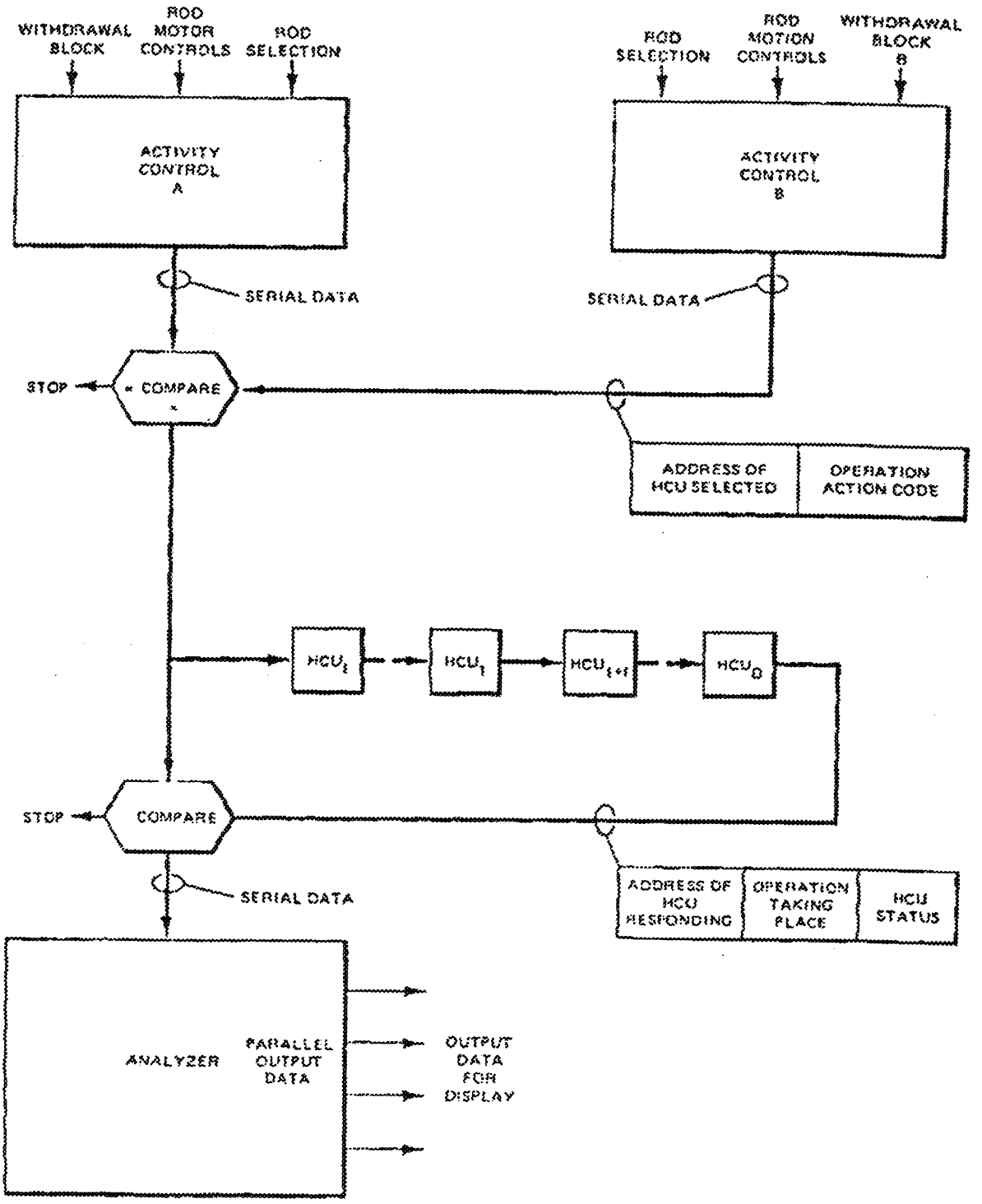
PECO ENERGY COMPANY
LIMERICK GENERATING STATION
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WATER LEVEL RANGE DEFINITION

FIGURE 7.7-1 Rev. 09 11/99

Figure 7.7-2

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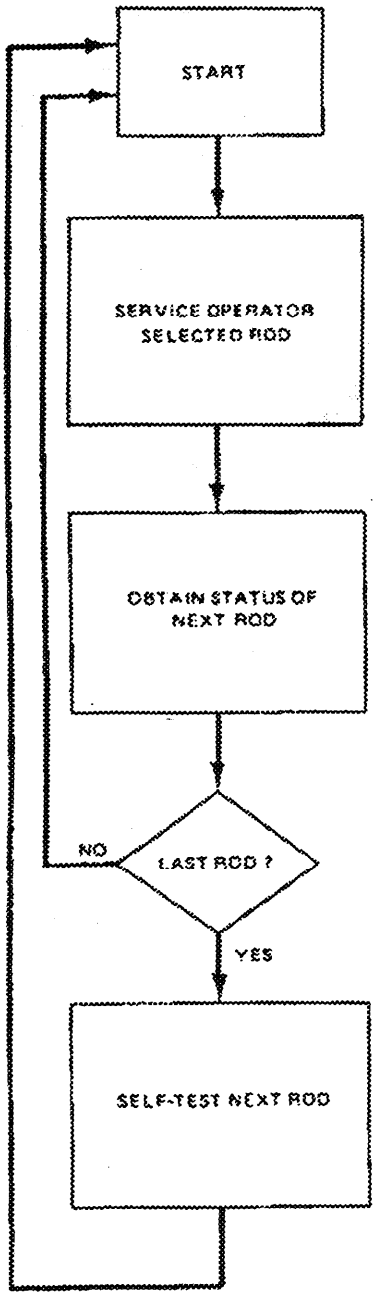


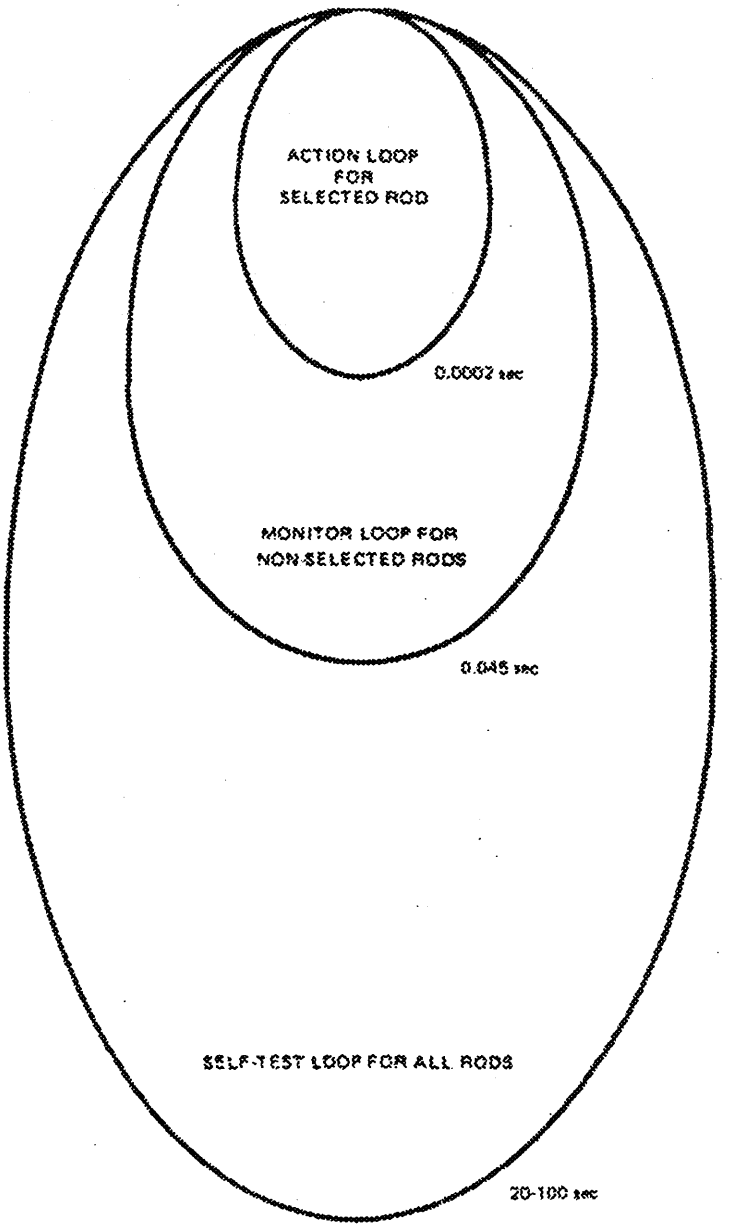
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REACTOR MANUAL CONTROL SYSTEM OPERATION

FIGURE 7.7-3 Rev. 11 9/02





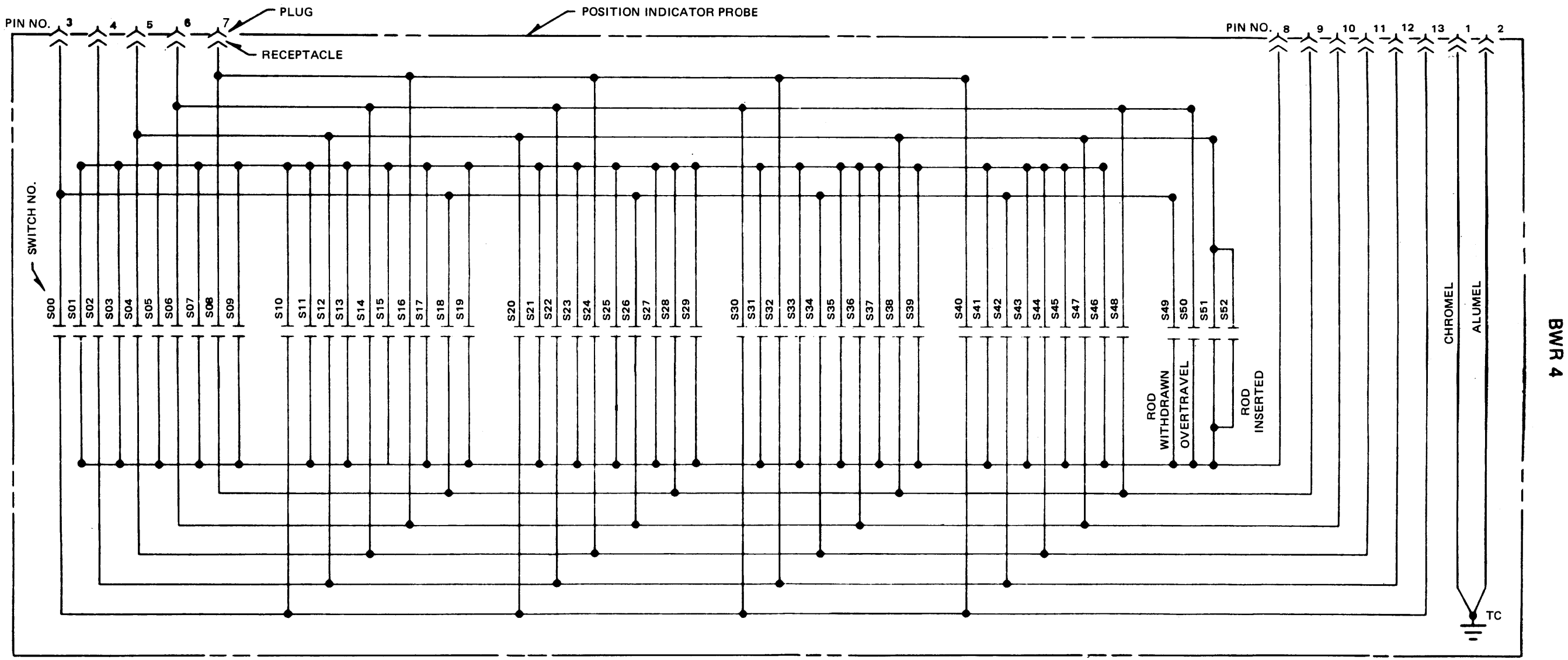
PER NEI 98-03, THIS FIGURE IN ITS ENTIRETY IS CLASSIFIED AS HISTORICAL

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REACTOR MANUAL CONTROL SELF-TEST PROVISIONS

FIGURE 7.7-4 Rev. 11 9/02

FCF 922D223



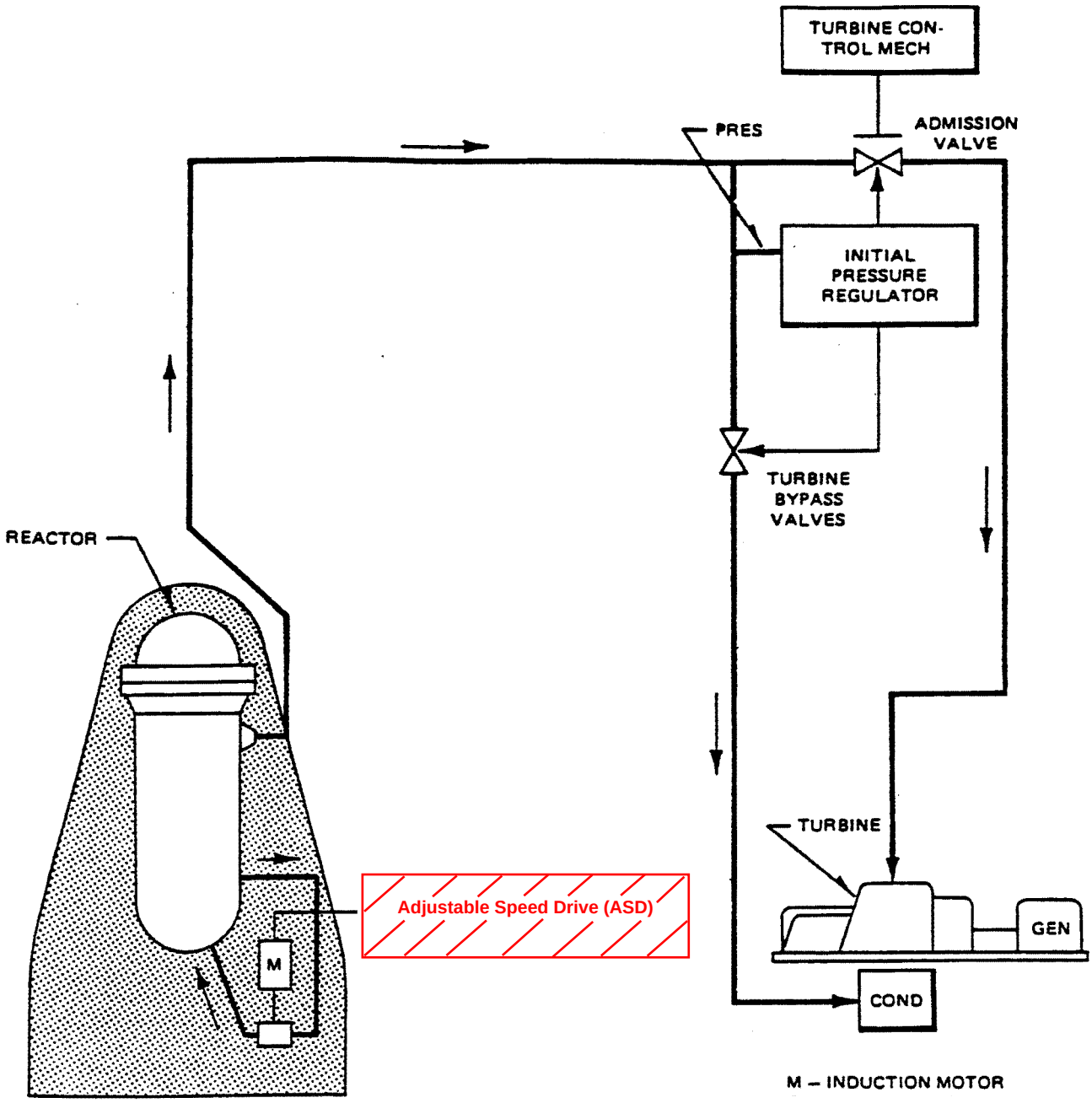
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ELEVEN–WIRE POSTITION PROBE

FIGURE 7.7-5

Figure 7.7-6

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LIMERICK GENERATING STATION
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RECIRCULATION FLOW CONTROL

FIGURE 7.7-7

Rev. 17 09/14

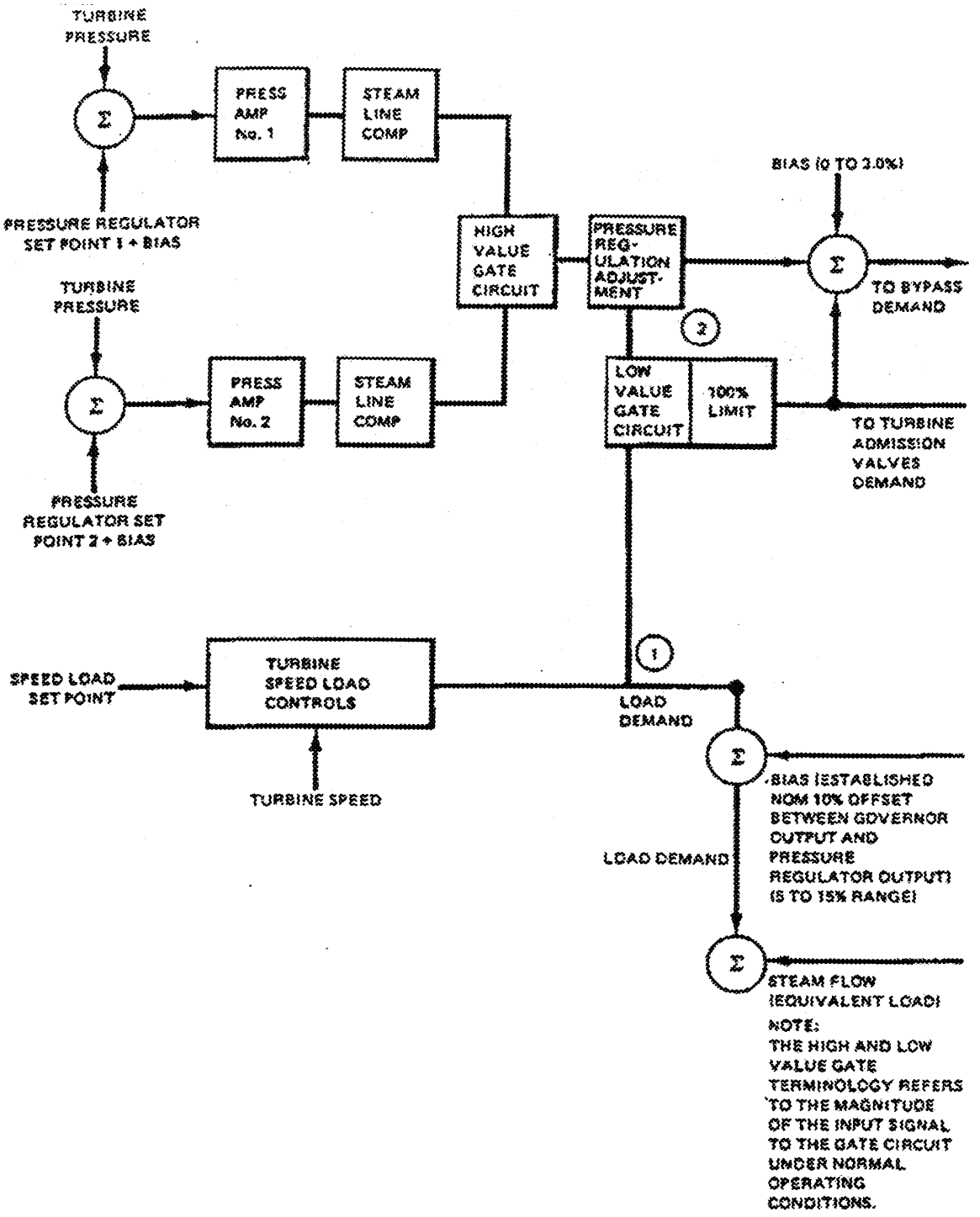
FIGURE 7.7-7A

Rev. 16 09/12

Figure 7.7-7A
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Figure 7.7-8

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UNITS 1 & 2
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SIMPLIFIED DIAGRAM TURBINE PRESSURE & SPEED LOAD CONTROL REQUIREMENTS

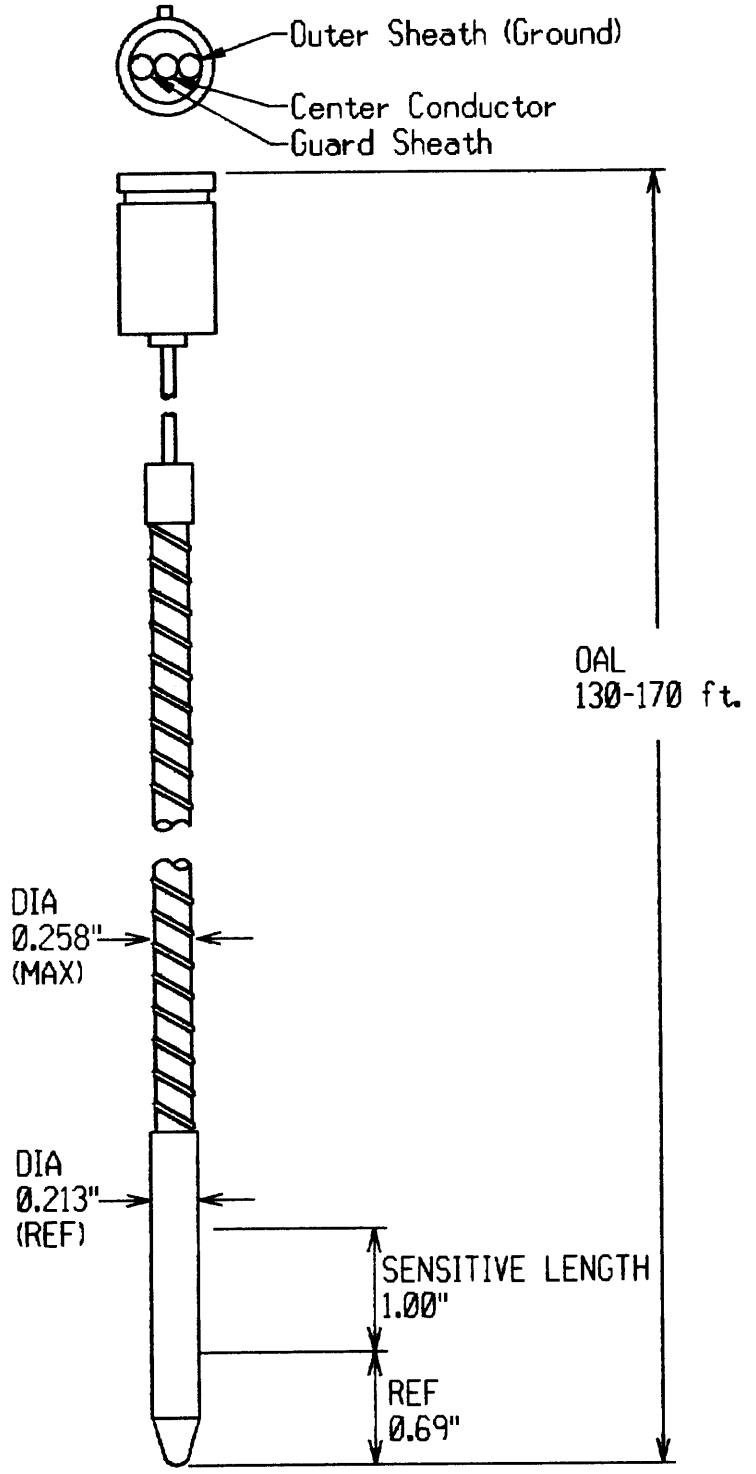
FIGURE 7.7-9 Rev. 11 9/02

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TRAVERSING INCORE
PROBE ASSEMBLY
(UNIT 1)
(SHEET 1 OF 2)

FIGURE 7.7-10 Rev. 1 July/91



LIMERICK GENERATING STATION
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TRAVERSING INCORE
PROBE ASSEMBLY
(SHEET 2 OF 2)

FIGURE 7.7-10 Rev. 1 July/91

Figure 7.7-11

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LIMERICK GENERATING STATION
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RPV CONTROL DISPLAY
(SHEET 1 OF 6)

FIGURE 7.7-12 Rev. 2 July/92

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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT CONTROL DISPLAY
(SHEET 2 OF 6)

FIGURE 7.7-12 Rev. 2 July/92

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LIMERICK GENERATING STATION
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CRITICAL PLANTS
VARIABLES DISPLAY
(SHEET 3 OF 6)

FIGURE 7.7-12 Rev. 2 July/92

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LIMERICK GENERATING STATION
UNITS 1 AND 2
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TREND PLOT DISPLAY
(SHEET 4 OF 6)

FIGURE 7.7-12 Rev. 2 July/92

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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TWO-DIMENSIONAL PLOT DISPLAY
(SHEET 5 OF 6)

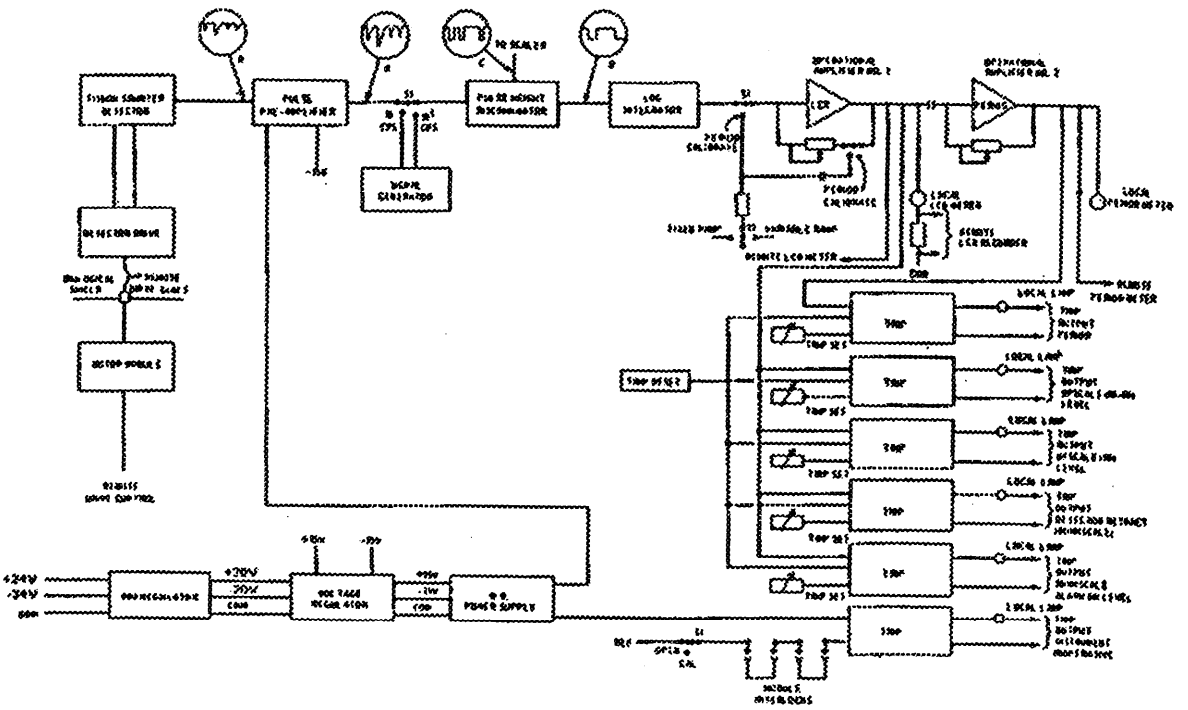
FIGURE 7.7-12 Rev. 2 July/92

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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

VALIDATION DISPLAY
(SHEET 6 OF 6)

FIGURE 7.7-12 Rev. 2 July/92

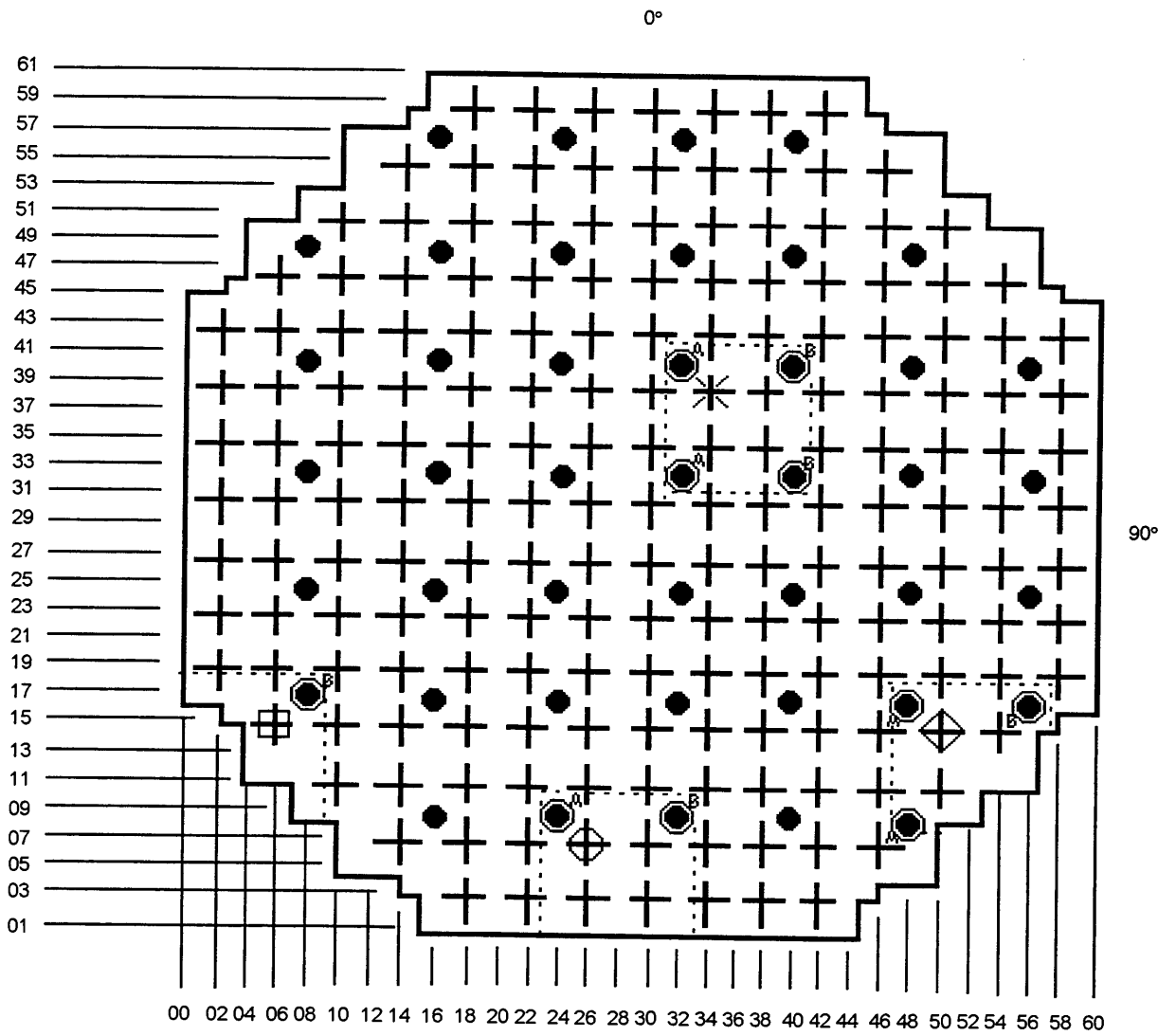


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FUNCTIONAL BLOCK DIAGRAM OF SRM CHANNEL

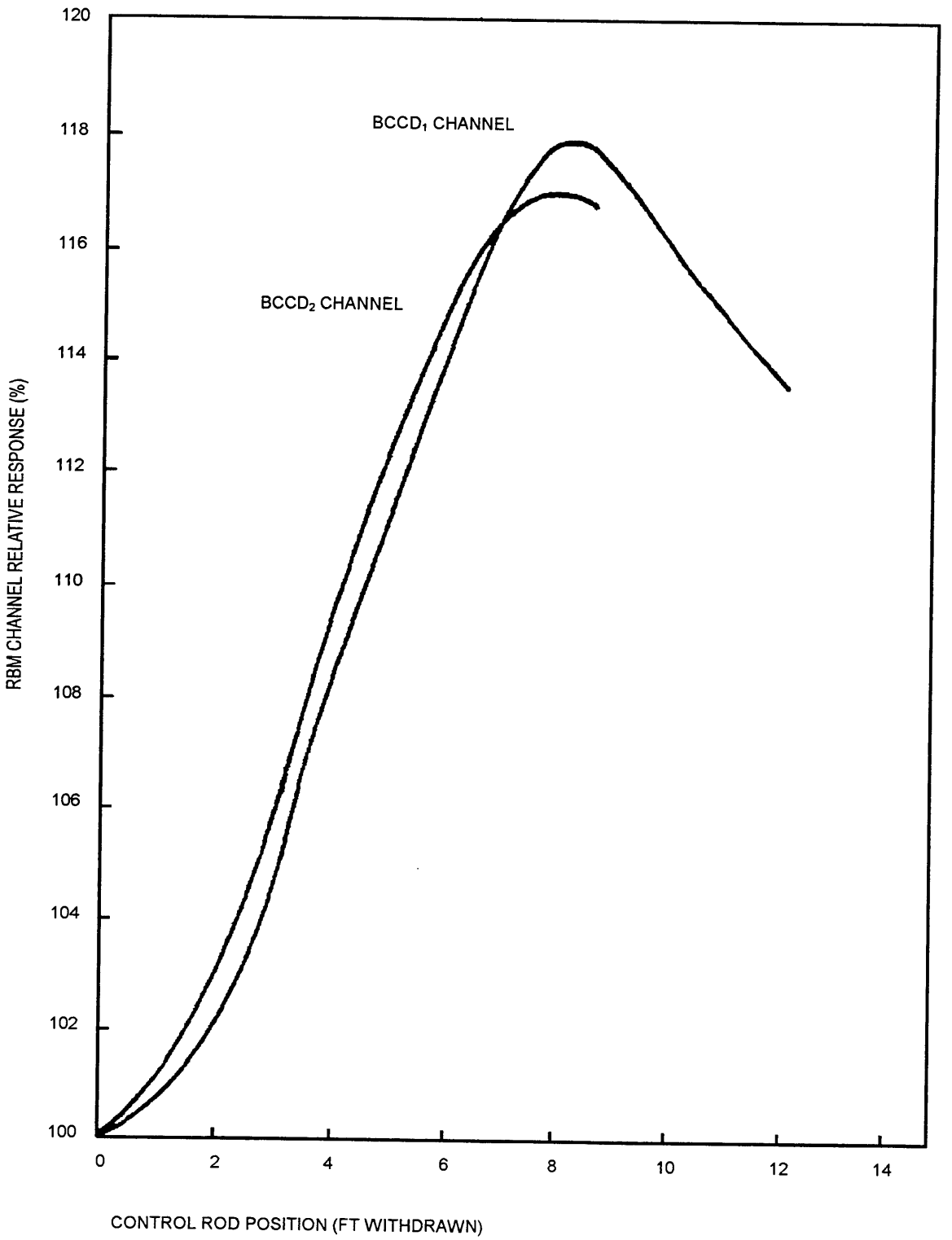
FIGURE 7.7-13 Rev. 11 9/02



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UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RBM ROD SELECTION COMBINATIONS

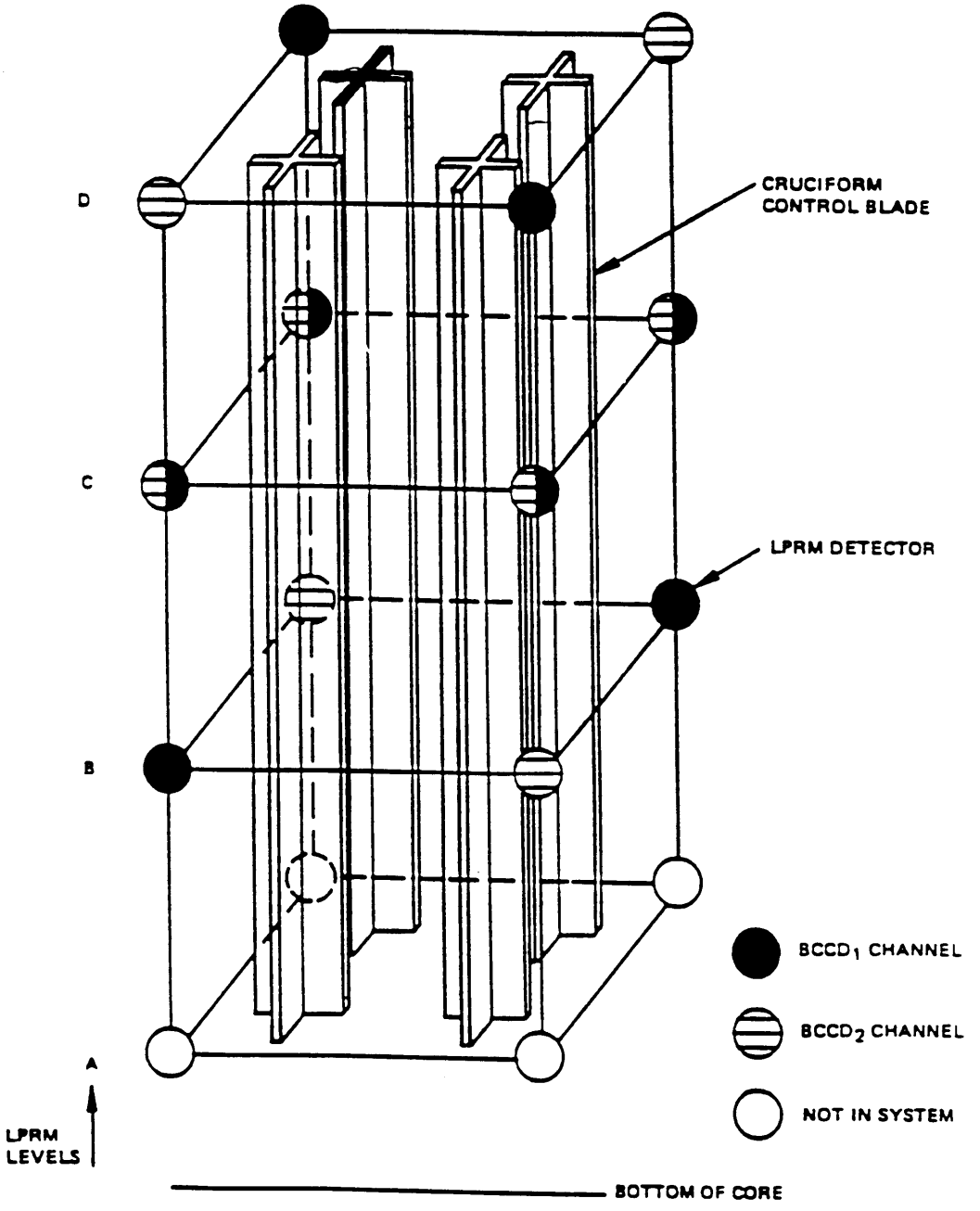
FIGURE 7.7-14 **Rev. 10 10/00**



LIMERICK GENERATING STATION
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TYPICAL RBM CHANNEL RESPONSE TO CONTROL ROD MOTION (NO FAILED LPRMS)

FIGURE 7.7-15 **Rev. 10 10/00**

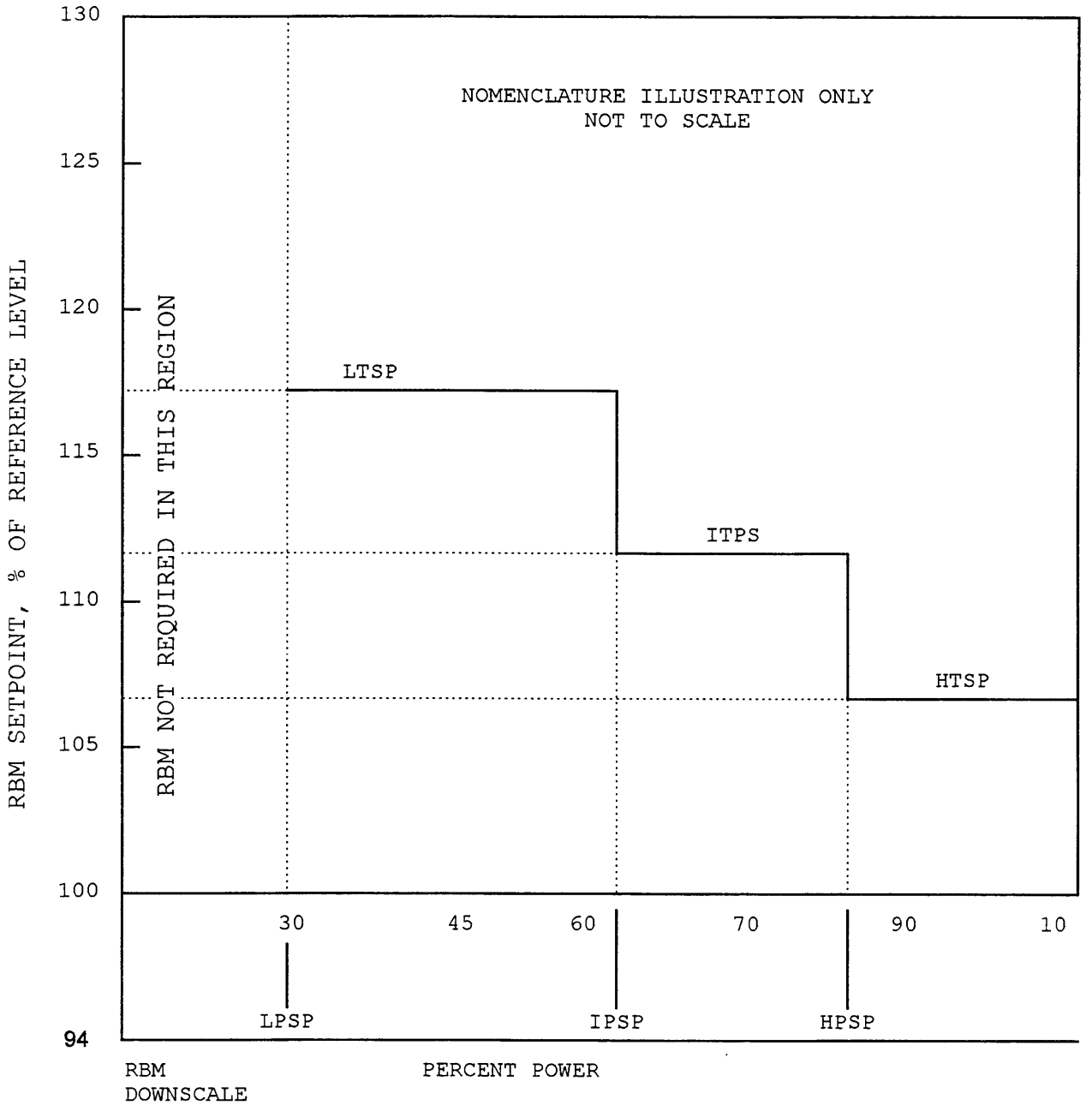


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NEW RBM $BCCD_1/BCCD_2$
LPRM ASSIGNMENT

FIGURE 7.7-16

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POWER DEPENDENT RBM TRIP NOMENCLATURE

FIGURE 7.7-17 **Rev. 10 10/00**

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CHAPTER 8 - ELECTRIC POWER

8.1 INTRODUCTION

8.1.1 GENERAL

The electric power systems of the LGS Units 1 and 2 are designed to generate and transmit electric power into the PJM power network.

The two independent offsite electric power source connections to LGS are designed to provide reliable power sources for plant auxiliary loads and the engineered safeguard loads of both units. An alternate independent, but currently not connected, 13 kV offsite source, available as a potential source, can be connected to supply the engineered safeguard loads of both units in the event of the loss of one of the connected offsite power sources.

The onsite ac electric power system consists of Class 1E and non-Class 1E power systems. The two offsite power systems provide the preferred ac electric power to all Class 1E loads. One source is the 220-13 kV startup transformer in the 220 kV substation. The second source is from a 13 kV tertiary winding of the 220-500 kV bus tie autotransformer in the 500 kV substation. In the event of total LOOP sources, eight onsite independent diesel generators (four diesel generators per unit) provide the standby power for all engineered safeguard loads.

The non-Class 1E ac loads are normally supplied through the unit auxiliary transformer from the main generator. However, during plant startup, shutdown, and postshutdown, power is supplied from the offsite power sources through the 220-13 kV startup transformer and the 220-500 kV bus tie autotransformer.

Onsite Class 1E and non-Class 1E dc systems supply all dc power requirements of the plant.

8.1.2 UTILITY POWER GRID AND OFFSITE POWER SYSTEMS

The Unit 1 and 2 generators are connected by a separate isophase bus to their respective main step-up transformer banks as shown in Drawing E-1. The Unit 1 main step-up transformer bank, with three single-phase power transformers, steps up the 22 kV generator voltage to 242 kV; the Unit 2 bank, with three single-phase power transformers, steps up the 22 kV generator voltage to 500 kV. The 220 kV and 500 kV substations each use a breaker and one-half scheme arranged in an interior main bus hop-over design. Each substation has three elements initially and is arranged for future expansion to four or more elements. Element refers to each bus-to-bus connection and includes the associated disconnect switches, potential transformers, protective relaying, and control systems. The substations are approximately 2150 feet apart and are interconnected by a 500-220 kV bus tie transformer and transmission line. The 500 kV substation feeds two substations on the PECO Energy system, Whitpain and PBAPS North, which are part of the Keystone 500 kV grid. Both the 500 kV and 220 kV substations and the associated transmissions are tied into the PJM Interconnection.

The 13 kV alternate offsite source to LGS is made available from the Limerick 66-13 kV substation. The substation receives bulk power from the Moser and Cromby Stations.

Plant startup power, which is the preferred power for the engineered safeguard systems, is provided from two independent offsite power sources. The power for the engineered safeguard systems can also be provided from the alternate offsite source. The three sources are as follows:

a. 220-13 kV transformer connected to the 220 kV substation

b. A 13 kV tertiary winding on the 500-220 kV bus tie autotransformer

c. 66-13 kV transformer connected to the 66 kV Cromby-Moser tie line

The Perkiomen pumping station receives power from two 33 kV transmission circuits to supply power to the makeup water pumps and their auxiliaries.

The offsite power systems and their interconnections are described in detail in Section 8.2.

8.1.3 ONSITE POWER SYSTEMS

The onsite power system for each unit is divided into two major categories:

a. Class 1E Power System

The Class 1E power system supplies all Class 1E loads and other loads that are needed for safe and orderly shutdown and maintaining the plant in a safe shutdown condition.

The Class 1E power system for each unit consists of four independent channels, A, B, C, and D, which provide power to four divisions of Class 1E loads. With the exception of the ESW system, the RHRSW system, the SGTS, CSCWS and the control room and control structure ventilation systems, which are common systems, any combination of three-out-of-four divisions of Class 1E loads in each unit meets the design basis requirements. Common loads for the ESW and the RHRSW systems are split between the Unit 1 and Unit 2 Class 1E power supplies. Common redundant loads for the SGTS, CSCWS and the control room and control structure ventilation systems are fed from Unit 1 Class 1E power supplies.

Any combination of three-out-of-four divisions (EDGs) is acceptable for a single failure. However, for ECCS requirements (as stated in paragraph 6.3.1.1.2), an EDG operable configuration of 2 out of 4 is also acceptable.

Load division separation is shown in Tables 7.1-4, 7.1-5 and 7.1-6. Electrical channel separation is shown in Table 8.1-1. Physical separation is discussed in Section 8.1.6.1.14.

The Class 1E power system is shown on drawings E-15, E-16, E-28, E-29, E-33, and E-34.

A detailed description of the onsite ac and dc power systems is found in Sections 8.3.1 and 8.3.2, respectively.

b. Non-Class 1E Power System

The non-Class 1E onsite power system supplies electric power to nonsafety-related plant auxiliary loads. The non-Class 1E auxiliary system distributes power at 13.2 kV, 2.3 kV, 440 V, and 208/120 V voltage levels. These distribution levels are grouped into two symmetrical bus systems emanating from the 13.2 kV level as shown in drawing E-1.

Power transmitted to the utility grid is discussed in Section 8.2.

A detailed description of the onsite ac and dc power systems is found in Sections 8.3.1 and 8.3.2, respectively.

8.1.4 SAFETY-RELATED LOADS

The Class 1E loads supplied by the standby ac power system are listed in Table 8.3-3. Class 1E loads supplied by the Class 1E dc system are listed in Tables 8.3-19 through 8.3-26.

8.1.5 DESIGN BASES

The following design bases are applied to the design of the onsite and offsite power systems:

8.1.5.1 Offsite Power System

a. Electric power from the offsite power sources to the onsite distribution system is provided by two physically separated transmission lines designed and located to minimize the likelihood of simultaneous failure.

b. The loss of a generating unit, or the loss of the most critical unit on the power grid, does not result in total LOOP.

c. If there is the loss of one of the offsite power sources, a third separate power source can be connected within a 72 hour period to meet Regulatory Guide 1.93. This source has more than adequate capacity to provide power to the safeguard loads of both units.

8.1.5.2 Onsite Power System

a. One unit auxiliary transformer per generating unit is provided to supply power to the plant electrical auxiliary distribution system.

b. The two offsite sources common to both units are provided to supply offsite power to the safeguard power system. The offsite sources also supply power to their respective plant auxiliary ac loads during plant startup, shutdown, and postshutdown.

c. An alternate offsite power source is provided that can be connected if there is a loss of one of the offsite sources. This alternate offsite source can be connected within 72 hours.

d. A spare safeguard transformer is provided that can be connected if there is a failure of either safeguard transformer.

e. The onsite Class 1E electric power system is divided into four independent divisions per unit. With the exception of the power supply requirements for the ESW system, the RHRSW system, the SGTS, CSCWS and the control room and control structure ventilation systems, which are common systems, any combination of three-out-of-four divisions of Class 1E power in each unit can shut down the unit safely and maintain it in a safe shutdown condition. Common loads for the ESW and RHRSW systems are split between the Unit 1 and Unit 2 Class 1E power systems. Common redundant loads for the SGTS, CSCWS and the control room and control structure ventilation systems are fed from Unit 1 Class 1E power supplies.

   Any combination of three-out-of-four divisions (EDGs) is acceptable for a single failure. However, for ECCS requirements (as stated in paragraph 6.3.1.1.2), an EDG operable configuration of 2 out of 4 is also acceptable.

f. Each unit has four independent dc Class 1E power systems corresponding to the four standby ac power system divisions and one independent dc non-Class 1E power system for the non-Class 1E dc loads.

g. Raceways are not shared by Class 1E and non-Class 1E cables, except where cables feed nonsafeguard equipment from Class 1E buses. Under these conditions, the non-Class 1E cables that are treated and identified as Class 1E are routed through one division of Class 1E raceways exclusively. Sharing of raceways in such cases is not considered to jeopardize the raceway separation, because the cables in such cases are isolated from the buses, by Class 1E isolation devices.

h. Special identification criteria as discussed in Section 8.1.6.1.14 are applied for Class 1E equipment, cabling, and raceways.

i. Separation criteria are established for preserving the independence of redundant Class 1E systems and providing isolation between Class 1E and non-Class 1E equipment.

j. The Class 1E electric systems are designed to satisfy the single failure criterion in accordance with IEEE 379.

k. Class 1E equipment and systems have been designed with the capability for periodic testing.

8.1.6 REGULATORY GUIDES AND IEEE STANDARDS

The design of the offsite power system complies with the requirements of GDC 5, GDC 17, and GDC 18 as discussed in Section 8.2.

Codes and standards applicable to the onsite power system are listed in Table 3.2-1. The design of the onsite power system complies with the requirements of GDC 2, GDC 4, GDC 5, GDC 17, GDC 18, and GDC 50 as discussed in Sections 8.3.1.2.1 and 8.3.2.2.1.

8.1.6.1 Conformance with Regulatory Guides

Conformance with applicable Regulatory Guides 1.6, 1.9, 1.22, 1.29, 1.30, 1.32, 1.40, 1.41, 1.47, 1.53, 1.62, 1.63, 1.73, 1.75, 1.81, 1.89, 1.93, 1.100, 1.106, 1.108, 1.118, 1.128, 1.129, and 1.131 is discussed below.

8.1.6.1.1 Regulatory Guide 1.6 (March 1971) - Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems (Safety Guide 6)

The design of the standby power system is in conformance with Regulatory Guide 1.6.

The standby power system consists of four independent divisions per unit. All safety-related loads are divided among the divisions so that loss of any one division does not prevent the minimum safety functions from being performed. Each division consists of both standby ac and dc power systems.

The ac loads of each division have connections to two independent offsite power supplies and to a single onsite diesel generator. The power feeder breakers to each division are interlocked so that only one of the power supplies can be connected at any one time, except during the diesel generator load test where the diesel generator is synchronized to one of the preferred offsite power sources. Only one diesel generator is tested at a time.

Each diesel generator is exclusively connected to the corresponding division. When operating from the standby sources, the diesel generator of one division cannot be paralleled, either manually or automatically, with the diesel generator of another division.

The dc power system of each unit consists of four division dc systems; two 125/250 V, 3-wire systems; and two 125 V, 2-wire systems. Each division is energized by its own batteries and chargers. The battery charger is supplied by its corresponding Class 1E ac power system. The dc power system of any one division is independent of any other dc power system.

8.1.6.1.2 Regulatory Guide 1.9 (March 1971) - Selection of Diesel Generator Set Capacity for Standby Power Supplies (Safety Guide 9)

The standby diesel generator capacities are in compliance with this edition of Regulatory Guide 1.9. Revisions 1 and 2 of the guide are not applicable to LGS as discussed in Section 1.8.

The continuous or the 2000 hour rating of the standby diesel generators is greater than the sum of conservatively estimated loads needed to be supplied following any design basis event. Load requirements are listed in Table 8.3-2.

The standby diesel generators are capable of starting and accelerating all engineered safeguard loads to the rated speed within the time and in the sequence shown in Table 8.3-1. They are capable of maintaining, during the steady-state and loading sequence, the frequency and voltage above a level that may degrade the performance of any of the loads below their minimum requirements. The standby diesel generators are capable of recovering from transients caused by step load increases or resulting from the disconnection of a partial or full load. Specifically, the standby diesel generators are designed to maintain frequency and voltage to not less than 95% and 75% of nominal, respectively, following a step load change. The frequency and voltage are restored to within 2% and 10% of nominal, respectively, within 60% of each load sequence time interval except for the time interval (3 seconds) between the RHR pump motor start and the load center breaker closure. However, during the preoperational tests, these loads started, accelerated, and operated successfully. In addition, during the recovery from transients caused by step load increases or

resulting from the disconnection of the largest single load, the speed of the diesel generator will not exceed 75% of the difference between the nominal speed and the overspeed trip setpoint or 115% of nominal, whichever is lower.

8.1.6.1.3 Regulatory Guide 1.22 (February 1972) - Periodic Testing of Protection System Actuation Functions (Safety Guide 22)

Refer to Section 7.1.2.5 for discussion of this guide.

8.1.6.1.4 Regulatory Guide 1.29 (February 1978) - Seismic Design Classification

The electrically related structures, systems, and components of this plant are in compliance with Regulatory Guide 1.29, except for paragraph C.1.m concerning the CRD manual control. Seismic design classification is discussed in Section 3.2.1.

8.1.6.1.5 Regulatory Guide 1.30 (August 1972) - Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Safety Guide 30)

The guidelines of ANSI N45.2.4 (1972) [IEEE 336 (1971)], as endorsed by this regulatory guide, have been met by the quality assurance program for the installation of safety-related items, although the standard is not specifically referenced in the constructor's quality assurance procedures. For QA during construction see the document "Limerick Generating Station Units 1 and 2; Summary Description of the Quality Assurance Program for Design and Construction," referenced in FSAR Section 17.1.

Conformance to the guide during plant operation is discussed in Section 17.2.

8.1.6.1.6 Regulatory Guide 1.32 (February 1977) - Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants

All safety-related electric systems are in compliance with Regulatory Guide 1.32, except as it refers to Regulatory Guide 1.75, which is discussed in Section 8.1.6.1.14. The portions of Regulatory Guide 1.32 applying to offsite power and dc power are discussed in Sections 8.2 and 8.3.2, respectively.

IEEE 308 (1974), "IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations" is generally accepted by Regulatory Guide 1.32.

Class 1E ac power systems are designed to ensure that any design basis event, as listed in table 1 of IEEE 308, does not cause either loss of electric power to more than one division, surveillance device, or protection system that could jeopardize the safety of the reactor unit; or transients in the power supplies, which could degrade the performance of any system.
Controls and indicators for the Class 1E 4 kV bus supply breakers are provided in the control room and on the switchgear. Controls and indicators for the standby ac power supplies are also provided in the control room and on the local diesel generator control panels. Control and indication for the standby power system is described in Section 8.3.1.

Class 1E equipment is distinctly identified in the field and in associated design, operating, and maintenance documents. Physical identification is described in Section 8.3.1.3.

Class 1E equipment is qualified by analysis, by successful use under required conditions, or by actual testing to demonstrate its ability to perform its function under any applicable design basis events.

The surveillance requirements of IEEE 308 are followed in design, installation, and operation of Class 1E equipment and consist of:

a. Preoperational equipment tests and inspections are performed in accordance with the requirements described in Chapter 14, with all components installed. These tests and inspections demonstrate:

   1. All components are correct and are properly mounted.

   2. All connections are correct, and circuits are continuous.

   3. All components are operational.

   4. All metering and protective devices are properly calibrated and adjusted.

b. Preoperational system tests are performed in accordance with the requirements described in Chapter 14, with all components installed. These tests demonstrate that the equipment operates within design limits and that the system is operational and meets its performance specifications. These tests also demonstrate:

   1. The Class 1E loads can operate on the preferred power supply.

   2. The loss of the preferred power supply is detected.

   3. The standby power supply is started and accepts design load in the sequence and time duration shown in Table 8.3-1.

   4. The standby power supply is independent of the preferred power supply.

c. Periodic equipment tests are performed at scheduled intervals in accordance with the requirements of Chapter 16 to detect the deterioration of the equipment toward an unacceptable condition, to demonstrate that standby power equipment and other components that are not running during normal operation of the station are operable, and to demonstrate the operational readiness of the system.

The standby ac power supplies are not shared by the two units. The standby capacity of each unit is sufficient to operate the engineered safeguard loads following a DBA on that unit.

The two preferred offsite power supplies are shared by both units. The capacity of each offsite power supply is sufficient to operate the loads required for safe shutdown of both units with a LOCA in one unit and a simultaneous safe shutdown of the other unit.

Battery testing is described in Technical Specifications.

8.1.6.1.7 Regulatory Guide 1.40 (March 1973) - Qualification Tests of Continuous-Duty Motors Installed Inside the Containment of Water-Cooled Nuclear Power Plants

Limerick complies with the intent of Regulatory Guide 1.40. Refer to Section 3.11.4 for a discussion of qualification testing.

8.1.6.1.8 Regulatory Guide 1.41 (March 1973) - Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignments

The preoperational testing program is described in Chapter 14, and is in conformance with Regulatory Guide 1.41 except as may be modified by the general statement on regulatory guides in Section 14.2.

The onsite Class 1E electric power system, designed in accordance with Regulatory Guide 1.6 and Regulatory Guide 1.32, is tested as part of the preoperational testing program and also after major modifications. The tests are performed in accordance with the requirements outlined in Chapter 14. These tests verify the independence between the redundant onsite power sources and their loads.

The onsite Class 1E electric power system is tested functionally, one division at a time, by allowing one division to be powered only by its associated diesel generator while the bus is isolated from the preferred offsite power source. The offsite power source is isolated by direct actuation of undervoltage relays monitoring the safeguard system.

A safety injection signal is simulated to start the diesel generators and initiate automatic sequencing. Functional performance of the loads is checked. Each test is of sufficient duration to achieve stable operating conditions, thus permitting the onset and detection of adverse conditions that could result from improper assignment of loads.

Testing of each division is performed to indicate that no interconnection of the divisions exists. The buses and loads of the division under test are monitored to verify absence of voltage on these buses and loads while the remaining redundant divisions are energized.

8.1.6.1.9 Regulatory Guide 1.47 (May 1973) - Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

The design of this plant is in compliance with Regulatory Guide 1.47, as follows:

a. An annunciator system is provided in the control room to automatically indicate, at the system level, the bypass or deliberately induced inoperability of the protection system, its auxiliary or supporting systems, and the systems actuated or controlled by the protection system.

b. Indication lights are used to indicate any bypass or inoperability status of components in the systems described in Item (a) above.

c. Manual capability to activate each system level annunciator is provided in the control room. Additional discussion is provided in Section 7.1.2.5.

8.1.6.1.10 Regulatory Guide 1.53 (June 1973) - Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems

The design of the electric power systems complies with the position statements of this regulatory guide.

Consistent with the single failure criterion, only one failure is assumed to occur in the system following a design basis event. No single component failure results in the simultaneous loss of ac power to the four divisions. A single failure cannot propagate to another load division.

Cables and raceways of different channels are physically separated in accordance with the provisions of Regulatory Guide 1.75, as discussed in Section 8.1.6.1.14.

8.1.6.1.11 Regulatory Guide 1.62 (October 1973) - Manual Initiation of Protective Actions

The LGS design is in conformance with Regulatory Guide 1.62, as follows:

a. Manual initiation of each protective action is provided at the system level.

b. Manual initiation of a protective action at the system level performs all actions performed by automatic initiation.

c. The switches for manual initiation of protective actions at the system level are located in the control room.

Further details for controls and instrumentation are provided in Section 7.1.2.6.

8.1.6.1.12 Regulatory Guide 1.63 (October 1973 and July 1978) - Electric Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants

The design of electric penetration assemblies is in compliance with Revision 0 (10/73) of Regulatory Guide 1.63, which endorses and amends IEEE 317 (1972), "IEEE Standard for Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations." Compliance with Revision 2 (7/78) of Regulatory Guide 1.63, which endorses IEEE 317 (1976), is also discussed in this section.

In accordance with Regulatory Guide 1.63, the electrical penetration assemblies are designed to withstand, without loss of mechanical integrity, the maximum fault condition versus time conditions that could occur as a result of a single random failure of circuit overload devices. The circuit breakers used for primary and backup protection are checked preoperationally and calibrated for time-overcurrent and instantaneous performance. These breakers, both Class 1E and non-Class 1E, will be checked periodically to ensure that their tripping characteristics have not changed. The fuses used for primary and backup protection are checked preoperationally for continuity and for proper model and size. The following system features are provided to ensure compliance with the regulatory guide:

a. Medium Voltage System

The only medium voltage loads in the primary containment are two variable-frequency reactor recirculating pump motors. Each recirculation pump motor is fed by an ASD which is capable of providing up to 4 kV. The ASDs are located in the turbine enclosure.

To protect the penetration assemblies, two redundant Class 1E circuit breakers are used in series to provide the required primary and backup protection. Separate divisions of 125 V dc control power are used for the operation of these breakers. Tripping signals for these primary and backup breakers are independent, physically separated, and powered from separate sources.

The mechanical integrity of the penetration assemblies is maintained under the most severe fault condition, including the most severe fault condition.

b. 440 V System

In addition to the primary circuit breaker or primary circuit breaker with thermal overload relay, a backup breaker located in the same MCC cubicle is connected in each circuit to provide backup protection of the penetration assemblies. For all such Class 1E circuits, the primary and backup breaker overload and short-circuit protection systems are qualified for the environmental conditions. For all non-Class 1E circuits that penetrate into the containment, two breakers are connected in series to provide primary and backup protection. These non-Class 1E breakers are identical in design and construction to that of Class 1E breakers, thereby assuring high reliability.

Typical time-current characteristics of these protective devices indicate that the penetration assemblies can withstand the available fault current for the time duration required to trip either or both the primary and backup circuit breakers.

c. 208 V and Lower Voltage Systems

The low voltage control circuits powered from control power transformers are self-limiting in that the circuit resistance and/or short-circuit capability limits the fault current to a level that does not damage the penetration assemblies. The maximum initial fault current available from the control circuit transformers at the penetration assembly is as follows:

Transformer Size	Maximum Initial Fault Current
120 VA	15.1 A
200 VA	40.6 A

The minimum conductor size for control circuits powered from control power transformers through the electrical penetrations is #12 AWG. The maximum fault current values indicated above are initial fault current values. The final short circuit values are less than these values due to increased resistance of conductor and control power transformer at elevated temperature caused by the short circuit. A #12 AWG conductor can withstand 41A for a duration of 1000 hours. The final value of the short circuit current after taking increased resistance of cable and transformer is 35A. The smallest wire size used in control circuits is #14 AWG. PECo Test Report 48503 shows that a #14 AWG wire can carry 75 A continuously without insulation breakdown. Based on the above, it is concluded that both the conductor through the penetration and the remainder of the control circuit can carry the maximum fault current developed by the control circuit transformers.

The remaining control and power circuits have a primary and backup fuse or breaker to ensure fault isolation. Typical time-current characteristics of these protective devices substantiate that the penetration assemblies can withstand the available fault current for the time duration required to trip either or both the primary and backup circuit breakers/fuses.

Field cables inside containment are connected to the containment penetration conductors in terminal boxes located next to the penetration. The method for connecting field cables to the penetration conductors is as follows:

1. Medium Voltage Power Penetration

   The terminal lug on the field cable is bolted to the penetration connector assembly. The terminal lug and the connector assembly are then covered by heat shrink tubing. These are non-Class 1E terminations.

2. Low Voltage Power, Control and Instrumentation, Thermocouple and Low Level Signal

   i. For penetration conductors that are 250 MCM, the terminal lugs on the penetration conductors and field cables are bolted and then covered by heat shrink tubing.

   ii. For all other cases, the penetration conductors and field cable are spliced by in-line barrel splice connectors covered by heat shrink tubing.

3. Control Rod Drive Penetration

   Field cables and penetration conductors are terminated by circular pin connectors. These are non-Class 1E terminations. The failure of the circular pin connectors will not degrade the containment pressure boundary integrity because the circular pin connectors do not form part of the pressure boundary.

4. Neutron Monitoring Penetration

   i. Field coaxial cables to penetration coaxial conductors are connected by coaxial connectors covered by heat shrink tubing.

   ii. Field coaxial cables to penetration #16 AWG conductors are spliced by in-line barrel splice connectors covered by heat shrink tubing.

All splices discussed in (2) and (4) are qualified to withstand a LOCA or steam line break accident. Supportive documentation that confirms the qualification of the splices is included in the LGS EQR.

d. Instrument Systems

The overload and short-circuit capability in the instrument systems are sufficiently low so that no damage can occur to the penetration assemblies.

Figures 8.1-2 through 8.1-5 provide time-current curves for penetrations in use at LGS. These curves include I^2t penetration and cable rating curves for instantaneous, long and short time overcurrent trips provided by primary and backup protective devices. In addition these curves include circuit configuration.

The LGS purchase order for electrical penetrations was issued on January 15, 1974, which precedes the issuance of Revisions 1 (5/77) and 2 (7/78) of the guide and the issuance of IEEE 317 (1976) as endorsed by these revisions of the guide. Therefore, LGS did not use the latest revisions of the guide.

However, the LGS electrical penetrations are in conformance with Regulatory Guide 1.63 (Rev 2 - 7/78), except as discussed and clarified by the following:

a. Rated Short-Circuit Current and Duration

The rated short-circuit current and duration for the electrical penetrations are based on maximum available fault currents, which were calculated using methods accepted by the industry, and on required breaker clearing time. The penetration manufacturer performed tests that were more severe than LGS service requirements. However, the latest revision of the guide requires that the short-circuit current must be based on the symmetrical current being initially fully offset by a dc component having a decrement based on specified x/r ratios. This was not specified for the LGS electrical penetrations and therefore not verified by the manufacturer.

b. Test Margins

The test parameters that were specified for qualification testing were conservative as compared to the maximum possible service conditions. In addition, the manufacturer exceeded these parameters in the conservative direction during qualification testing. Test margins according to IEEE 317 (1976) were not specified for the LGS penetrations.

c. Materials Flammability

All nonmetallic materials are required to be classified by testing as "nonburning" or "self-extinguishing" as defined by IEEE 317. An adhesive used on the interior of some types of shrink tubing used in the penetrations is flammable. It is noted that the use of this adhesive in a splice as used by Conax has been qualified by test to the flame test requirements of IEEE 383 (1974). The adhesive used in a splice is protected by the shrink tubing and, except for a small portion that oozes from the ends of the splice, is not exposed to air or open flames. The latent heat content of the exposed adhesive is much less than in an ordinary wooden match. The small amount that is present and its slow-burning characteristic mean that it could not be a significant source of flame or fire damage. This adhesive is a small amount of combustible material surrounded by a relatively large amount of noncombustible and self-extinguishing material. Therefore, it does not constitute a hazard.

d. Thermal Aging

To demonstrate that the assembly will survive an accident condition the prototype assembly was qualified by accelerated thermal aging equivalent to a 40 year plant life in the normal service environment, in accordance with IEEE 317 (1972). IEEE 317 (1976) and Regulatory Guide 1.63 require accelerated thermal aging tests in accordance with IEEE 98 and IEEE 101, at a minimum aging time of 5000 hours.

e. Type Tests

LGS penetration assembly prototype tests conform to IEEE 317 (1972). IEEE 317 (1976) as amended by the guide contains the following requirements, which were not considered for LGS penetration assembly prototype tests:

1. Specified sequence of required tests

2. Impulse withstand test on medium voltage power conductors

3. Partial discharge (corona) test

4. Cycling and aging test as related to shipping, storage, welding, and thermal cycling

5. Seismic tests in accordance with IEEE 344 (1975)

8.1.6.1.13 Regulatory Guide 1.73 (January 1974) - Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants

Selection of electric valve operators for use inside the containment is in compliance with Regulatory Guide 1.73.

The electric valve operators for service inside the containment are tested in accordance with IEEE 382 (1972), as modified by Regulatory Guide 1.73. The tests consist of aging, seismic, and accident or other special environmental requirements. Test parameters are discussed in Section 3.11.2.

8.1.6.1.14 Regulatory Guide 1.75 (September 1978) - Physical Independence of Electric Systems

The requirements of Regulatory Guide 1.75 are met, except as discussed and clarified below. The regulatory guide endorses the IEEE 384 (1974), "IEEE Trial Use Standard Criteria for Separation of Class 1E Equipment and Circuits," subject to the additions and clarifications delineated in section C of the guide.

a. General Separation Criteria

1. Required Separation

Electrical equipment and wiring for the engineered safeguard system and the RPS are segregated into separated channels/divisions as shown in Tables 7.1-4, 7.1-5, 7.1-6 and 8.1-1, so that no single credible event is capable of disabling sufficient equipment to prevent reactor shutdown, removal of decay heat from the core, or isolation of the primary containment if there is an accident. The engineered safeguard system and RPS are separated from

each other, and each is further separated into four channels/divisions. Separation requirements apply to control and instrument power and motive power for all systems concerned. The degree of separation required varies with the potential hazards in a particular area.

Arrangement and/or protective barriers ensure that no locally generated force or missile can destroy redundant portions of the engineered safeguard system and/or RPS.

The arrangement of wiring is designed to eliminate, insofar as is practicable, all potential for fire damage to cables and to separate the engineered safeguard or RPS channels/divisions so that fire in one division does not propagate to another division.

Equipment and circuits requiring separation are identified on documents and drawings in a distinctive manner.

2. Methods of Separation

The separation of circuits and equipment is achieved by separate safety class structures, distance, or barriers, or combination thereof.

The following isolation devices are used at LGS to provide isolation between Class 1E and non-Class 1E circuits:

(a) 4 kV circuit breakers

(b) 480 V circuit breakers

(c) 480 V motor starters

(d) Auxiliary relays

(e) Optic isolators

(f) Control switches

(g) Voltage transducers

(h) Electronic isolation amplifiers

(i) Electronic, magnetically coupled signal isolators

(j) Electronic, magnetically coupled signal converters

The circuit breakers and motor starters are qualified to perform an isolation function through prototype tests performed to NEMA and ANSI standards. In addition, the devices are qualified for seismic and environmental conditions in accordance with NUREG-0588 as discussed in Sections 3.10 and 3.11.

The auxiliary relays used as isolation devices are listed in section I.C. of Reference 8.1-1. The devices were tested for both overvoltage and overcurrent isolation. The test results are given in section 5.4 of the test report.

Optic isolators are seismically and environmentally qualified. The fiber optic cable inherently isolates the Class 1E input from the non-Class 1E system at the receiving end of the cable.

Isolation via qualified electronic magnetically coupled signal isolators and converters is achieved in various system applications such as RCIC. The magnetic coupling of component's input and output signals provides a high degree of passive isolation of damaging fault conditions.

Control switches are seismically qualified and located in a mild environment. The manufacturer's test data on breakdown voltages and current interrupting capacity of the contacts are used to determine the adequacy of the device for isolation purposes.

The voltage transducers are seismically qualified and located in a mild environment. They have been tested and accepted as isolation devices.

3. Compatibility with Mechanical Systems

The separation of Class 1E circuits and equipment ensures that the required independence is not compromised by the failure of mechanical systems served by the Class 1E systems. For example, Class 1E circuits are routed and/or protected so that the failure of related mechanical equipment of one redundant system cannot disable Class 1E circuits or equipment essential to the operation of the other redundant system(s).

4. Associated Circuits

Associated circuits are not uniquely identified as such. These circuits are treated and identified as Class 1E up to an isolation device and are isolated on a LOCA signal, with the following clarifications and exceptions:

(a) When relays and other devices are used as isolation devices between Class 1E and non- Class 1E circuits, the 6 inch separation

requirement at the device terminals is not maintained in accordance with IEEE 384 (1974), section 4.6.1. The basis for not providing 6 inches of separation at the device terminals is based on test results given in section 5.4 of the above mentioned test report, which shows that no separation is required between wires terminating on isolation relays.

(b) All feeders to non-Class 1E 4 kV motor loads and to all non-Class 1E 440 V MCCs that are fed from Class 1E buses are treated and identified as Class 1E even beyond the isolation device. However,

these loads are tripped in the event of a LOCA in the unit they are associated with and are routed in dedicated Class 1E raceways. They do not become associated with any other Class 1E division. The non-Class 1E motor loads that are fed from the Class 1E buses are in full compliance with IEEE 384 (1974), section 4.5.(2). The isolation device is the Class 1E 4 kV circuit breaker. The cable schemes associated with these breakers are Class 1E and are routed as such. Where these cables enter equipment, they are treated as non-Class 1E for separation purposes. These cables are isolated on an accident signal; therefore, they may be treated as non-Class 1E in accordance with IEEE 384 (1981).

(c) The public address and fire alarm panel that feeds non-Class 1E loads is fed from a Class 1E bus. This panel is not tripped on LOCA, because intentional disconnection of the fire alarm system is a violation of the National Fire Code and is considered unacceptable for plant safety. The distribution transformer and panel are qualified and seismically supported to Class 1E criteria. All circuits originating from this panel are run in conduits that contain only PA or fire alarm system wiring. All circuits originating from this panel are protected by thermal magnetic circuit breakers in the panel. In addition, the 440 V feed to the transformer is protected by a molded-case circuit breaker in the motor control center. Each of these circuit breakers is qualified and purchased as Class 1E; therefore, two Class 1E isolation devices exist between the non-Class 1E public address and fire alarm circuits and the Class 1E 440 V bus.

(d) Several non-Class 1E drywell cooler fan motors located inside the drywell are fed from a Class 1E bus, and the cabling is routed as Class 1E. The non-Class 1E RPS/UPS inverters are fed from a Class 1E dc bus, and the cabling is routed non-Class 1E. Two Class 1E circuit breakers are provided for redundant overcurrent protection on each of these circuits. These breakers provide isolation between the non-Class 1E load and the Class 1E bus and will be periodically tested. The non-Class 1E RCIC barometric condenser vacuum pump, RCIC vacuum tank condensate pump, HPCI vacuum tank condensate pump, and HPCI gland seal condenser vacuum are fed from a Class 1E bus, and the cabling is routed as Class 1E. Two class 1E fuses are provided on both the positive and negative feeds for redundant overcurrent protection. The non-Class 1E H2-O2 analyzers are fed from a Class 1E AC bus. Two Class 1E fuses are provided on each phase of the circuit for redundant overcurrent protection. The H2-O2 analyzers' cabling is routed as Class 1E up to the fuses, which are installed locally near the analyzers. The cabling downstream of the fuses is non-Class 1E. These loads are not automatically isolated on a LOCA signal.

(e) In several cases, redundant Class 1E overcurrent devices (e.g., fuses or breakers) are provided in series for isolation between Class 1E power sources and non-Class 1E instrumentation and controls.

5. Non-Class 1E Circuits

Non-Class 1E circuits are separated from Class 1E circuits by the separation requirements specified in Section 8.1.6.1.14.b. Non-Class 1E 440 V loads that are fed from Class 1E MCCs use a shunt trip device on the MCC breaker or a trip logic in the combination starter controls to isolate the circuit on a LOCA signal from the unit from which they are powered. These circuits are treated as non-Class 1E from the MCC to the load and control devices or they are routed as Class 1E only in the division with which they are associated.

6. Class 1E Circuits

Class 1E circuits are separated from Class 1E circuits of a different channel/division as described in items a.1, a.2, and a.3 above, except as discussed and clarified below.

The RCIC steam supply line inboard containment isolation valve is provided with a manually actuated power transfer switch which allows manual transfer from the valve's normal Division 3 source to an emergency Division 1 source. Physical independence is not maintained when the manual transfer switch is actuated to the emergency position because the valve's power and control cables, which are identified and routed as Division 3, are powered from Division 1 in this situation. The manual transfer switch enables this valve to be powered and controlled from a Division 1 emergency source in order to permit the valve to be opened in the event of a fire that requires the RCIC system for safe shutdown but which has caused the valve to spuriously close with subsequent loss of Division 3 ac power.

The manual transfer switch consists primarily of two molded-case circuit breakers with an interconnecting mechanical linkage that allows closure of only one breaker at a time. Qualification of the manual transfer switch ensures that the switch is capable of performing its safety function and/or remaining in a safe mode under all conditions postulated to occur during its installed life. Locking closed the door of the terminal box in which the manual transfer switch is located, locking open the Division 1 feeder breaker, and maintaining the keys to these locks under administrative control assures that control of the manual transfer switch and the Division 1 feeder breaker is limited to, aside from testing, operator discretion only in the event of a fire with concurrent loss of Division 3 ac power.

In addition, plant procedures require that:

(a) The valve be controlled from the remote shutdown panel with the remote shutdown panel transfer switch in the emergency position when using Division 1 power. This limits the interconnection of Division 3 circuits with Division 1 power to the MCC, the remote

shutdown panel and interconnecting wiring. Control complex wiring and circuits will not be involved.

(b) Division 3 power shall always be removed from the manual transfer switch (by opening one of the two circuit breakers in Division 3) before Division 1 power is connected and Division 1 power shall always be removed from the manual transfer switch (by opening one of the two circuit breakers in Division 1) before Division 3 is reconnected. This limits the number of power divisions connected to the manual transfer switch at any time to one.

Annunciation and indication of the manual transfer switch in the emergency position meets the requirements of Regulatory Guide 1.47. Testing of the manual transfer switch is limited to operating conditions 4 and 5 as defined by the Technical Specifications. Limiting the testing of the manual transfer switch to those operating conditions when the reactor is at low pressure provides adequate assurance that any potential consequence which might arise due to these Division 3 power and control cables becoming energized from a Division 1 source could not affect the operability of the minimum number of operable ac power sources specified by the Technical Specifications for these operating conditions.

b. Specific Separation Criteria

1. Cables and Raceways

The minimum separation distances for raceways are given in paragraphs 4 and 5 below. The following general criteria apply to all cable installations:

(a) Cable splices in raceways are prohibited. Cable splices are only made in manholes, boxes or suitable fittings. Splices in cables passing through the containment penetration assemblies are made in terminal boxes located next to the assemblies.

(b) Cables and raceways are flame retardant.

(c) The design basis is that the cable trays are not filled above the side rails. Tray fill for control cable trays and instrumentation cable trays is 50% maximum, i.e., the cross-sectional area of the cable in the tray will not exceed 50% of the available cross-sectional area of the tray, and 40% maximum for cable trays containing power cables. If tray fill exceeds the above stated maximum fill, tray fill is justified and documented.

(d) Some RPS cables are routed in ESF raceway. These cables are identified as RPS and routed in steel flexible conduit in accordance with GE design requirements. This installation is acceptable because flexible conduit provides the required system fail-safe protection and because none of the RPS cables are redundant to the ESF cables located in the same raceway.

2. Identification of Non-PGCC Cables and Raceways

Exposed Class 1E raceways are identified in a distinct and permanent manner at intervals not to exceed 15 feet. In addition, these raceways are also identified where they pass through walls and/or floors. Class 1E raceways are identified before the installation of their cables.

Cables installed in cable trays are identified at intervals not exceeding 5 feet, to facilitate initial verification that the installation conforms to the separation criteria. These cable identifications are applied before or during their installation.

Class 1E cables are identified by a permanent marker at each end in accordance with the design drawings or cable schedule.

Color coding is used to meet the above requirements and to distinguish between Class 1E systems and between Class 1E and non-Class 1E systems. The coding precludes the need to consult any reference material to distinguish between redundant Class 1E and between Class 1E and non-Class 1E systems.

Panel internal wiring is marked with its connection diagram identity at each point of termination.

3. Identification of PGCC Cables and Raceways

Cables run in the floor sections are color banded every ten feet. The longitudinal floor ducts of the power generation control complex are marked with color coded raceway markers on the top of the steel side beam. The cables contained in each duct are generally of one division only. A cable of one division may be run in the duct of another division only if it is run in flexible steel conduit. Because of the congestion of these ducts, only the top several cables are visible when the floor cover is removed.

The purpose of the requirement of IEEE 384 to color code cables every five feet is to aid in the installation of these cables to ensure that they are pulled into the correct raceway. Cable installation has been performed to approved quality control procedures and in accordance with the system cable routing document provided by GE.

Based on the above, we believe that no increase in plant safety would be achieved by marking the cables in the power generation control complex floor every five feet and that the present ten foot interval meets the intent of IEEE 384.

4. Cable Spreading Room/Control Complex

The control complex consists of control room, cable spreading room, and auxiliary equipment room. The auxiliary equipment room mainly consists of relay panels and terminal cabinets integrated with module-type floor sections, with lateral and longitudinal ducts that are used as raceways and barriers.

This module-type assembly, which is the PGCC, is covered separately in paragraph 6.

The control complex does not contain high energy equipment (such as switchgear and transformers) or potential sources of missiles or pipe whip and is not used for storing flammable materials.

Circuits in the cable spreading room and control room are limited to control functions, instrument functions, and those power supply circuits and facilities serving the control room. Power supply feeders to distribution panels are installed in enclosed raceways that qualify as barriers. The circuits passing through the cable spreading room are limited to 120/208 V ac and 250 V dc, except for lighting feeder circuits in the cable spreading area. The lighting feeder circuits are 277 V ac, but are routed in conduits used explicitly for lighting.

The minimum separation distance between the redundant Class 1E cable trays is 1 foot horizontally and 3 feet vertically. Where a 1 foot horizontal separation is not possible, lesser separation is justified by test and analysis or one of the following barrier arrangements is used: a flame retardant barrier is placed between the redundant cable trays and extends 1 foot above the trays or to the ceiling; or cables are installed in totally enclosed raceways up to a point where the minimum horizontal separation justified by test and analysis is met. Where cable trays of redundant channel/divisions must be stacked one above the other with less than 3 feet vertical spacing, lesser separation is justified by test and analysis or one of the following barrier arrangements is used: a flame retardant barrier is placed between the trays and extended to 6 inches beyond each side of the tray system or to the wall; or the cables are installed in totally enclosed raceways to a point where the minimum vertical separation justified by test and analysis is met. Where a crossover of one tray over another carrying a redundant channel/division is made, and minimum vertical separation distance (as determined by test and analysis) cannot be maintained, either fire barriers are installed between the trays extending a minimum of 1 foot beyond the crossing tray or cables are installed in enclosed raceway extending a minimum of one foot beyond the intersection. Separation requirements between Class 1E and non-Class 1E circuits are the same as for separation of redundant channel/divisions except where justified by test and analysis.

In general, a minimum separation of 1 inch is maintained between redundant enclosed raceways and between Class 1E and non-Class 1E enclosed raceways except in those cases where lesser separation is justified by test and analysis.

The separation provided between a totally enclosed raceway and a cable tray is the same as that provided between redundant cable trays except where lesser separation is justified by test and analysis.

The minimum separation required between redundant Class 1E dropout cables or between Class 1E and non-Class 1E dropout cables is one foot

horizontal and 3 feet vertical except in those cases where lesser separation has been justified by test and analysis. Dropout cables are defined as any cable length not routed within a raceway. In cases where the minimum separation criteria justified by test and analysis cannot be met, dropout cables are wrapped with a fiberglass sleeving to the point where the minimum separation criteria is achieved.

The test results and analysis contained in Wyle Laboratories Test Report 46960-3 are the basis for the lesser raceway and dropout cable separation referenced in paragraphs 4 and 5. The separation criteria derived from this analysis are contained in LGS drawing 8031-E-1406, section 2.0.

5. General Plant Areas

In plant areas where potential hazards such as missiles and pipe whip are excluded, the separation distance between redundant Class 1E cable trays is 3 feet between trays separated horizontally, if no physical barrier exists between trays. If a horizontal separation of less than 3 feet exists, alternate methods as stated in paragraph 4 above are required. Vertical stacking of trays is avoided wherever possible; however, where cable trays of redundant channel/divisions are stacked, a vertical separation distance of 5 feet is required, or alternate methods as stated in paragraph 4 above are required. Where a crossover of one tray over another carrying a redundant channel/division is made, and the minimum vertical separation distance as determined by test and analysis cannot be maintained, either fire barriers are installed between the trays extending a minimum of 3 feet beyond the crossing tray or cables are installed in enclosed raceway extending a minimum of 3 feet beyond the intersection.

Separation requirements between Class 1E and non-Class 1E circuits are the same as for separation of redundant channel/divisions except where justified by test and analysis.

The separation requirements between totally enclosed raceways and between a totally enclosed raceway and a cable tray are the same as stated in paragraph 4 above.

The minimum separation required between redundant Class 1E dropout cables or between Class 1E and non-Class 1E dropout cables is 3 feet horizontal and 5 feet vertical except in those cases where lesser separation has been justified by test and analysis. In cases where the minimum separation criteria justified by test and analysis cannot be met, dropout cables are wrapped with a fiberglass sleeving to the point where the minimum separation criteria are achieved.

NMS cables located in the subpile room under the RPV are exceptions to these separation criteria. These cables are separated and routed in flexible conduit in this room wherever possible, but they may touch wherever necessary due to spatial limitation. Cables of different NMS divisions in this

room are not bundled together where they are not in flexible conduit. Bundling of stainless steel jacketed LPRM cables is permitted.

6. Power Generation Control Complex

Detailed design basis, description, and safety evaluation aspects for the PGCC system are documented and presented in Reference 8.1-2. The separation criteria used for the internal panel wiring of the PGCC are given in Section 8.1.6.1.14.b.9.

Series-connected redundant protective devices are not required to clear faults internal to flexible conduit or to prevent overheating of adjacent cables. All flexible conduits in the power generation control complex are positively grounded to panel steel and were checked to ensure that the resistance to ground on the conduit is less than 4 ohms at all points. The probability of the failure of a single fuse to clear a fault was given in WASH-1400, appendix III, table III.2-1, as $3x10^{-5}$ to $3x10^{-6}$, which shows that this scenario is an extremely low probability event. In addition, the test results presented in section 5.3.2 of the above mentioned test report show that the damage of adjacent essential cables due to an uncleared internal conduit fault is not a credible event. For this reason, it is not necessary to install redundant overcurrent devices in circuits that run in flexible conduit.

7. Power Supply

(a) Standby Diesel Generators

Standby diesel generators are housed in separate compartments within a seismic Category I structure. The auxiliaries and local controls of each unit are housed in the same compartment as the unit they serve.

(b) DC System

Redundant Class 1E batteries and their associated chargers are located in separate compartments within a seismic Category I structure. Each battery room is exhausted by an individual ventilation duct to a common exhaust plenum. Two redundant Class 1E axial flow exhaust fans service the common exhaust duct-work.

Also, the battery chargers of redundant load groups are physically separated in accordance with the requirements of Regulatory Guide 1.75.

(c) AC Distribution System

All redundant Class 1E switchgear, MCCs, and distribution panels are physically separated in accordance with Regulatory Guide 1.75.

8. Penetrations

Redundant Class 1E containment electrical penetrations are dispersed around the circumference of the containment and are physically separated in accordance with the requirements of section 5.5 of IEEE 384 (1974). In general, non-Class 1E and RPS circuits are not routed in penetrations containing Class 1E circuits. Where Class 1E, RPS and non-Class 1E circuits are routed in the same penetration, separation is maintained by routing the cables in flex conduit or fiberglass sleeving up to the penetration feedthrough. Class 1E, RPS and non-Class 1E wiring are not routed through common feedthroughs. The feedthrough steel casing forms the separation barrier between Class 1E feedthrough of different divisions and between Class 1E and non-Class 1E feedthroughs and between ESF and RPS feedthroughs. Two divisions of Class 1E RTD wiring are also routed through the suppression pool penetration in this manner to maintain separation.

9. Control Room and Auxiliary Equipment Room Panels

The main control panels are located in a control room within a seismic Category I structure. The control room is protected from, and does not contain, high energy equipment such as switchgear, transformers, rotating equipment, or potential sources of missiles or pipe whip.

No single control panel includes wiring essential to the protective function of two systems that are redundant to each other, except as allowed by the following:

(a) Floor-to-panel fireproof barriers are provided between adjacent panels of different channels/ divisions.

(b) Penetration of separation barriers within a subdivided panel is permitted, provided that such penetrations are sealed or otherwise treated so that an electrical fire could not reasonably be expected to propagate from one section to the other and destroy the protective function.

(c) When locating manual control switches of redundant divisions on separate panels is considered prohibitively (or unduly) restrictive to manual operation of equipment, the switches are located on the same panel, provided that no credible single event in the panel can disable both sets of redundant manual or automatic controls.

The design basis for the internal panel separation criteria is presented in section 2.1 of the WASH-1400 test report. The basis of that test report is reflected in the description of the separation requirements for Class 1E components mounted in control panels (Item (5) below). The test program showed that the revised separation criteria are adequate for protection against the consequences of a sustained overcurrent condition on one of the circuits in the panel. The criteria are not designed to protect against an exposure fire in the panel because alternate safe shutdown methods are provided in

accordance with 10CFR50, Appendix R, in the event of a fire in the control room.

Wherever wiring of two divisions exists in a single panel section, separation is maintained as follows:

(1) A minimum of 6 inches spatial separation is maintained between Class 1E wiring of different divisions. IEEE 384 (1981), section 6.6.2, states that Class 1E cables and wires internal to control panels are to be separated by 6 inches, or a barrier shall be installed between redundant Class 1E wiring. The same separation is maintained between Class 1E and non-Class 1E wiring. Redundant Class 1E cables entering the control panel enclosure also meet these requirements.

External to the panel, the raceways meet the separation requirements of IEEE 384 for nonhazard areas. Where the cables pass through blockouts into the panels, they are separated by fire barriers.

(2) A minimum of 6 inches spatial separation is maintained between Class 1E and non-Class 1E wiring.

(3) Where the above spatial separation cannot be maintained, one or a combination of the following shall be provided:

- One of the divisions of wiring is enclosed in flexible steel conduit to the point where the above separation is achieved.

- Hygrade Thermoflex 1200 fiberglass sleeving is installed on control and instrumentation wiring to the point where the above separation is achieved.

- One inch spatial separation is maintained between Class 1E and non-Class 1E wiring where the non-Class 1E wiring is secured with stainless steel cable ties, and between redundant Class 1E wiring where both the divisions of wiring are secured with stainless steel cable ties.

(4) The following exceptions to the above separation criteria are allowed:

- Relays Used as Isolation Devices:

  Non-Class 1E wires terminating on contacts of isolation relays are not separated from other wires in

the same panel, regardless of safety status or division. They are not bundled with Class 1E wires.

Redundant Class 1E wires terminating on a common isolation relay are not separated from each other at the relay terminals. They are routed away from the relay to achieve the required separation within a minimum distance.

- Where Class 1E wiring is located above #10 AWG or smaller non-Class 1E wiring, one inch separation will be provided.

- Thermocouple wires of different divisions of the steam leak detection system do not require separation from any other thermocouple wires in panels C609, C611, C620, and C640. These thermocouple wires are separated from power and control cables using the separation criteria above. Bases for this exception are as follows:

  i) All thermocouple wires are #16 AWG, which will not ignite due to overcurrent.

  ii) All thermocouple cables for this system are routed in instrumentation trays that do not contain power or control cables; therefore, no potential overcurrent source exists for these wires.

- In certain cases, less than one inch separation is allowed between redundant enclosed raceways. The rationale for this exception is discussed in section 5.3.2 of Reference 8.1-1.

(5) Class 1E components of different divisions, but which are not redundant, installed on a common panel are separated by one inch or a flame retardant barrier. Non-Class 1E components are separated by one inch or a flame retardant barrier from Class 1E components. Class 1E components that serve redundant systems are separated by 6 inches or a flame retardant barrier, e.g., core spray A from core spray B. The fire-resistant materials that are used as barriers for internal panel separation are panel steel, solid or flexible steel conduit and fiberglass sleeving. Where a barrier is required between devices in a common panel, the metal casing of the device is considered to be an adequate barrier for containing internal device failures. The analyses that shows that a failure of one circuit will not affect an adjacent circuit are provided in Reference 8.1-1.

Exceptions to these component separation criteria are allowed in cases where it has been shown that a sustained overcurrent through the device will not cause the ignition of that device. Indicating lamps, isolation relays, panel meters, and terminal blocks are specific examples of this exception.

(d) Panel internal Class 1E wiring is not color coded. Wires are marked with their respective connection diagram identity at each point of termination. The connection diagram denotes the separation division for each cable.

10. Instrument Racks and Panels:

Redundant Class 1E instruments and instrument racks are separated so that any design basis event will not cause the failure of more than one division of instrumentation needed to mitigate the effects of that event.

Physical separation of redundant circuits and devices is provided within each instrument panel as discussed in paragraph 9 above.

11. Sensors and sensor-to-process connections:

Redundant Class 1E sensors and their connections to the process system have been sufficiently separated so that the functional capability of the protection system is maintained despite any single design basis event or result therefrom, including the secondary effects of design basis events, such as pipe whip, steam release, radiation, missiles, or flooding.

Where practicable, redundant Class 1E sensors and process connecting lines are brought out at widely divergent points, using large components, such as pressure vessels or pipes, as protective barriers. Where necessary, additional barriers are provided to protect against damage from a credible common cause.

12. MSIV and Turbine Stop Valve Terminal Boxes

In the MSIV and turbine stop valve terminal boxes, separation is not maintained within these boxes as any postulated failure in the box will not prevent the RPS from performing its intended safety function. Bases for this exception are provided below.

In each MSIV terminal box, two divisions of wiring are present, i.e., RPS ac (nonsafety-related) and one Class 1E dc division. Given a failure in the terminal box, three types of failures can be assumed:

i) Open circuit

ii) Hot short

iii) Short to ground

For the first scenario, the MSIVs would fail closed because the pilot solenoids would be de-energized. For the second scenario, while it could be postulated that the pilot solenoids would stay energized, the redundant MSIVs would not be affected because the outboard MSIV pilot solenoids are fed from different ac and dc buses than are the inboard MSIVs. For the third scenario, refer to item iii) below.

Any failure within these terminal boxes would not degrade the safety-related dc system because:

i) Given any failure, only one division of the four safety-related dc divisions would be involved.

ii) There is a 5 A fuse in both dc feed legs in the logic panel feeding the dc solenoids. There is also a 30 A fuse in each leg at the dc distribution panel. Because these two fuses are in series between the terminal box and the dc distribution bus, the probability of both fuses failing to clear a hot short is conservatively estimated to be $9x10^{-10}$ based on failure information given in WASH-1400, appendix III, table III.2-1. This is considered to be acceptable.

iii) A short of the dc feed to ground would not unacceptably degrade the dc system because each dc system is ungrounded. The ground would be detected by a Class 1E ground detector and the dc system would continue to operated as designed.

Other exceptions to the above criteria may be allowed. These exceptions will be analyzed to consider the magnitude and duration of a credible high impedance faulted condition and will be documented.

13. CAC Inboard Nitrogen Purge Isolation Valves

The control circuits for the two primary containment nitrogen purge inboard PCIVs, one valve for the drywell (HV-057-*21) and the other for the suppression chamber air space (HV-057-*31), are supplied from the same electrical division. A single failure is prevented by electrical interlocks between the valves, which utilize contacts in the position switches on the two valves. A normally open contact in the position switch of both valves is wired in series with the other valve control circuit. This arrangement prevents both valves from being open at the same time. The cables between the interlocks and the valves are run in separate conduits.

If one of the position switch contacts failed open, the interlocked valve would be prevented from being opened. If one of the contacts failed closed, the interlocked valve could be opened, however, the first valve would then go closed due to the interlock. Hot shorts between contacts on the position switches are not considered, since contacts on a switch have been evaluated to provide acceptable divisional separation. Shorts between cables are not credible since they are routed in separate conduits.

With the interlocks in place, electrical systems separation criteria (ref. UFSAR Section 7.1.2.2.3.2.2) and the single-failure criterion (IEEE 379, 1972 or 1979) are met.

8.1.6.1.15 Regulatory Guide 1.81 (January 1975) - Shared Emergency and Shutdown Electric System for Multi-Unit Nuclear Power Plants

The design of the standby electric power systems is in conformance with Regulatory Guide 1.81.

The dc power systems are not shared between the units.

Each unit is provided with separate and independent onsite ac and dc electric systems.

8.1.6.1.16 Regulatory Guide 1.89 (November 1974) - Qualification of Class 1E Equipment for Nuclear Power Plants

Regulatory Guide 1.89, Revision 0, does not apply to LGS. LGS electrical equipment requiring qualification was qualified in accordance with NUREG-0588, Category II as described in Sections 3.11 and the LGS EQR. Replacement components for electrical equipment requiring qualification that were installed after February 1985 are qualified to the requirements of 10CFR50.49 unless there are sound reasons to the contrary, as defined in Regulatory Guide 1.89 Rev. 1.

8.1.6.1.17 Regulatory Guide 1.93 (December 1974) - Availability of Electric Power Sources

LGS complies with this regulatory guide as discussed in the Technical Specifications.

8.1.6.1.18 Regulatory Guide 1.100 (August 1977) - Seismic Qualification of Electric Equipment for Nuclear Power Plants

This guide is not applicable to LGS per its implementation section.

Regulatory Guide 1.100 endorses and modifies IEEE 344 (1975), "Seismic Qualification of Class 1E Power and Protection Systems." LGS Class 1E equipment is in full compliance with IEEE 344 (1971) for components purchased before issuance of IEEE 344 (1975). All electrical equipment purchased later is qualified to IEEE 344 (1975). Seismic qualification of electrical equipment is discussed in Section 3.10.

8.1.6.1.19 Regulatory Guide 1.106 (March 1977) - Thermal Overload Protection for Electric Motors on Motor- Operated Valves

This guide is not applicable to LGS per its implementation section, nevertheless, the thermal overload design for motors on MOVs is in conformance with Regulatory Guide 1.106, except for Item b below.

Either thermal overload protection devices are not used, have permanent electrical jumpers installed, or are bypassed during an accident condition. The overload bypass philosophy on MOVs with overloads that do not have permanent jumpers is incorporated as follows:

a. MOVs with spring return-to-center control switches.

These MOVs can be initiated manually or automatically.

1. Manual initiation

During manual operation, the thermal overload is normally in the trip circuit; however, the thermal overload can be bypassed by holding the control switch

in the appropriate OPEN or CLOSE position. The associated OUT OF SERVICE annunciator will alarm, along with a white indicating light on the system's vertical board indicating a valve motor overload or loss of power condition. By checking the valve indicating lights, the operator can determine whether the alarm is due to loss of voltage or motor overload.

2. Automatic initiation

The thermal overload is bypassed in automatic operation of the Class 1E MOVs in which the same annunciation sequence occurs as described in Item 1 above.

b. MOVs with maintained contact control switches:

1. Valves not required to operate automatically during an accident.

The thermal overloads do not interrupt the MOV power circuit, but they alarm on an overload condition in the control room. The operator has the option to allow the valve to continue to operate or to interrupt power to the MOV by placing the control switch in the STOP position.

2. Valves required to operate automatically during an accident.

(a) Whenever the MOV operates, the thermal overloads do not interrupt the MOV power circuit, but they alarm on an overload condition in the control room.

8.1.6.1.20 Regulatory Guide 1.108 (August 1977) - Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants

The periodic testing of the diesel generator units will be in conformance with the requirements of Regulatory Guide 1.108 and IEEE 387 (1977) as follows:

a. The preoperational testing will be performed in accordance with the site test outlined in section 6.4 of IEEE 387 (1977).

b. A starting test as described in section 6.6.1 of IEEE 387 (1977) will be performed on each diesel generator as determined by Technical Specifications.

c. Periodic testing in accordance with section 6.6.2 of IEEE 387 (1977). Test frequency is determined by Technical Specifications.

In accordance with Station Blackout requirements, an emergency diesel generator reliability program which meets the requirements of USNRC Regulatory Guide 1.155 “Station Blackout” is in place.

8.1.6.1.21 Regulatory Guide 1.118 (June 1978) - Periodic Testing of Electric Power and Protection Systems

The LGS design provides the necessary capability for periodic testing of electric power systems in conformance with Section 5 of IEEE 338 (1977) as endorsed and amended by the guide.

Periodic testing capability of instrumentation and controls systems is discussed in Section 7.1.2.5.

Periodic testing of the Class 1E systems will be in accordance with Regulatory Guide 1.118 and IEEE 338 (1977).

8.1.6.1.22 Regulatory Guide 1.128 (October 1978) - Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants

This guide does not apply to LGS per its implementation section. Regulatory Guide 1.128 endorses and amends IEEE 484 (1975), "IEEE Recommended Practice for Installation Design and Installation of Large Lead Storage Batteries for Generating Stations and Substations." The installation design and installation of the Class 1E batteries for LGS are in conformance with IEEE 484 (1975).

8.1.6.1.23 Regulatory Guide 1.129 (February 1978) - Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Nuclear Power Plants

The maintenance and testing of the LGS batteries will be performed in accordance with IEEE 450 (1995).

An acceptance test of the battery capacity was performed at the factory prior to initial shipment. A service test, as described in IEEE 450-1980, Section 5.3, was performed on the Class 1E batteries on completion of the initial installation. Replacement batteries will receive an equivalent level of testing that envelopes both the acceptance and service tests. Thereafter, a service test, as described in IEEE 450 (1995), will be performed periodically in accordance with the Surveillance Frequency Control Program. Also, to determine the service life remaining in the battery, a performance test will be conducted at least once per 60 months. A modified performance test may be performed in lieu of the service test as described in IEEE 450 (1995).

IEEE 450-1995 is used for its recommendations regarding battery connection resistance as indicated in Annex D, Section D.2 of the standard, for specific gravity correction per Section 3.3.1.6 and 3.4.2 of the standard and for providing an alternative method to determine the state of charge of the battery per Section 4.5 of the standard.

8.1.6.1.24 Regulatory Guide 1.131 (August 1977) - Qualification Tests of Electric Cables, Field Splices, and Connections for Light-Water-Cooled Nuclear Power Plants

Regulatory Guide 1.131 endorses and modifies IEEE 383 (1974), "Type Test for Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations." LGS Class 1E cables, splices, and connections except for the battery cart intercell/intercart jumpers and cart to battery jumpers are in full compliance with IEEE 383 (1974). Compensatory measures are taken to mitigate the consequences of cable ignition in the area(s) in which the Non-IEEE 383 battery cart intercell/intercart cables and cart to battery cables are used. For further information on qualification testing refer to Section 3.11.

8.1.6.1.25 Regulatory Guide 1.155 (June 1988) - Station Blackout

LGS complies with Regulatory Guide 1.155 and was evaluated in accordance with the requirements using guidance from NUMARC 87-00, except where RG 1.155 takes precedence.

For LGS Units 1 and 2, the minimum required Station Blackout coping duration shall be four hours as determined by NUMARC 87-00 guidelines.

LGS has opted to use an alternate ac power (AAC) approach (excess diesel generator capacity) to cope with and recover from a station blackout. AAC power is available within one hour of the station blackout. For LGS Units 1 and 2, the AAC power source satisfies the requirements for station blackout.

For LGS Units 1 and 2, Emergency Diesel Generator target reliability levels are maintained at or above 0.95 per demand. An Emergency Diesel Generator reliability program is established to ensure that target reliability program is established to ensure that target levels are maintained.

Station Blackout is further described in Section 15.12.

8.1.6.2 Conformance with IEEE Standards

8.1.6.2.1 IEEE 387 (1972) - Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations

The design of the standby power supplies is in compliance with IEEE 387 (1972). The following paragraphs analyze compliance.

a. Adequate cooling and ventilation equipment is provided to maintain an acceptable service environment within the diesel generator compartments during and after any design basis event, even without support from the preferred power supply.

b. Each diesel generator is capable of starting, accelerating, and accepting load as described in Section 8.3.1. The diesel generator automatically initiates its cooling equipment within an acceptable time after starting.

c. Frequency and voltage limits and the basis of the continuous rating of the diesel generator are discussed in the compliance statement to Regulatory Guide 1.9 in Section 8.1.6.1.2.

d. Mechanical and electrical systems are designed so that a single failure affects the operation of only a single diesel generator.

e. Design conditions such as vibration, torsional vibration, and overspeed are considered in accordance with the requirements of IEEE 387 (1972).

f. Each diesel governor can operate in either the isochronous or droop mode and the voltage regulator can operate in either the parallel or nonparallel mode. During testing, the diesel generator is connected to and operated in parallel with the offsite power source. The electric governor is set in the droop mode whenever connected in parallel with a system in which another prime mover is controlling the frequency. Under automatic or emergency start conditions, the electric governing system and the voltage regulator are set automatically for isochronous and nonparallel mode, respectively.

g. Each diesel generator is provided with control systems permitting automatic and manual control. The automatic start signal is functional except when the diesel generator is in the maintenance mode. Provision is made for controlling the diesel

generator from the control room and from the diesel generator room. Section 8.3.1 provides further description of the control systems.

h. Voltage, current, frequency, and output power metering is provided in the control room to permit assessment of the operating condition of each diesel generator.

i. Surveillance instrumentation is provided in accordance with IEEE 387 as follows:

1. Starting system - starting air pressure low alarm

2. Lubrication system - lube oil pressure low, lube oil temperature high, lube oil level low, and lube oil keep-warm failure alarms

3. Fuel system - fuel oil level in day tank high and low, fuel oil pressure low, fuel oil strainer differential pressure high, fuel oil filter differential pressure high, fuel oil level in storage tank high, and low alarm

4. Primary cooling system - ESW low pressure

5. Secondary cooling system - jacket water temperature high, jacket water keep-warm failure, jacket water pressure low, and jacket water expansion tank level low alarms

6. Combustion air systems - no alarm is provided, because the diesel generator duct-work does not contain any automatic dampers or features to cause failure in the combustion air supply

7. Exhaust system - pyrometers located at local gauge panel

8. Generator - generator differential overcurrent, ground neutral overcurrent, generator phase overcurrent, and antimotoring trip and alarm

9. Excitation system - generator loss of excitation and overexcitation alarm and field ground alarm

10. Voltage regulation system - generator overvoltage alarm

11. Governor system - engine overspeed trip

12. Auxiliary electric system - 480 V ac auxiliary power off, 125 V dc control power off, dc fuel pump power off alarms

A detailed list of trip and alarm functions and testing of the diesel generator is discussed in Section 8.3.1.1.3.

8.1.6.3 Conformance with Branch Technical Positions

Conformance with applicable BTPs ICSB 4, ICSB 8, ICSB 11, ICSB 18, ICSB 21, PSB 1 and PSB 2 is discussed below.

8.1.6.3.1 BTP - ICSB 4 (November 1975) - Requirements on Motor- Operated Valves In The ECCS Accumulator Lines

This BTP is not applicable to LGS because LGS is a BWR and therefore does not have safety injection tanks in the ECCS.

8.1.6.3.2 BTP - ICSB 8 - Use of Diesel Generator Sets for Peaking

LGS is in compliance with BTP ICSB 8. The diesel generator sets will not be used for peaking service. To preclude a potential for common failure modes, onsite and offsite sources are not interconnected except for short periods during testing when only one diesel at a time is tested.

8.1.6.3.3 BTP - ICSB 11 - Stability of Offsite Power Systems

A discussion of the grid stability analysis is given in Section 8.2.2.

8.1.6.3.4 BTP - ICSB 18 - Application of the Single Failure Criterion to Manually Controlled Electrically Operated Valves

LGS is in compliance with ICSB 18, except for the requirement for redundant position indication in the main control room.

Valves HV-13-109 and HV-13-110 (ESW supply and return to reactor recirculation pump seal and motor oil cooler valves) have been locked in the closed position. The power feeds to the motor operators have been disconnected at the operator terminals and at the 480 V ac MCC compartments.

Remote position indication of these valves is not provided in the control room. Valve position is administratively controlled; the valves are locked in the required position and access to the keys is administratively controlled.

The position of these valves will be identified in a valve checkoff list. When verification of system operability is required, performance of the valve checkoff list in conjunction with the applicable lineup procedure is one method which may be used. When operability is verified in this manner, an independent verification of valve lineup will be accomplished by redundant performance of each valve checkoff list used. Use of a lineup procedure with its associated valve checkoff lists will not be the exclusive method available for verification of operability, but can be used in any circumstance. If valve positions are to be changed for surveillance or maintenance purposes, the procedure or other administrative control will have steps requiring return-to-normal valve lineup prior to completion. The shift supervisor will not consider the system operable until all valves identified within the boundaries of the surveillance/maintenance activities have been returned to the position specified in the valve checkoff list. If valve positions are changed for operational purposes, these changes will be made in accordance with procedures having similar administrative controls.

8.1.6.3.5 BTP - ICSB 21 - Guidance for Application of Regulatory Guide 1.47

LGS is in compliance with BTP ICSB 21. Compliance with this position is discussed in Sections 8.1.6.1.9 and 7.1.2.5.11.

8.1.6.3.6 BTP - PSB 1 - Adequacy of Station Electric Distribution System Voltages

LGS is in compliance with BTP PSB 1.

BTP PSB 1 is met at LGS using the same degraded grid voltage monitoring system that was accepted by the NRC for PBAPS Units 2 and 3 (Reference 8.1-3). The following discussion responds to the numbered positions of BTP PSB 1.

a. On both offsite sources to each Class 1E bus, an ITE-27N definite time-delay relay with a 60 second timer monitors the offsite source voltage. This relay is set to drop out at 0.94 per unit voltage. Actuation of this relay after a 60 second time-delay will trip the associated 4 kV bus feeder breaker. Loss of voltage on the 4 kV bus actuates a GPI relay which initiates a diesel generator start and a transfer to the alternate source respectively. The purpose of the 60 second time-delay is to allow sufficient time for the automatic load tap changers on the 101 and 201 safeguard transformers to adjust and counter the degraded voltage condition.

   An ITE-27 inverse-time relay with a timer is also installed on the source side of each offsite source to each Class 1E bus. This relay will be set at 0.875 per unit voltage with a total time-delay of 60 seconds or less. It performs the same function as the ITE-27N and provides inverse time-delay with degrading voltage for protection of Class 1E equipment between 0.875 and 0.70 per unit voltage.

   The time-delays associated with the ITE-27N and ITE-27 relays are automatically bypassed 9 seconds after the ITE-27N relay initiates when a LOCA signal is present. This limits the exposure of Class 1E equipment to degraded voltage condition to 9 seconds after the undervoltage relay operates while preventing spurious trips of the offsite source breaker during voltage transients caused by motor starts.

   An NGV relay with a 0.9 second timer is also installed on the source side of each offsite source to each Class 1E bus. The relay is set at 0.70 per unit voltage and will perform the same function as the above relays. This relay provides for the start of the diesel generator and the transfer of the bus on the total loss of the associated offsite source.

   A GPI relay monitors the voltage on each Class 1E 4 kV bus. The relay functions with no appreciable time-delay when the voltage on the bus falls below 0.40 per unit. Actuation of this relay initiates load shedding and after a time-delay provides a permissive signal to start the diesel generator and allow the affected bus to transfer to the alternate source. This relay also provides an automatic closure signal to the diesel generator breaker after further time-delay if the automatic transfer fails.

   An NGV relay for Unit 1 and an ITE-59D relay for Unit 2 with a setpoint of approximately 0.95 per unit also monitor the bus voltage on the 4 kV Class 1E buses. Actuation of either one of these relays initiates load sequencing after the voltage is restored to the bus. It is sealed in by the GPI relay to allow the load sequencing to continue during motor starting transients.

   The above voltage monitoring scheme does not provide coincident logic to preclude spurious trips to conform to BTP PSB 1. However, spurious action of one undervoltage relay will only start one diesel generator and then transfer the affected

bus to the alternate power source. The actuation of a second undervoltage relay is necessary to transfer the bus to the diesel generator. If the ITE-27N should fail to operate, it is backed up by the ITE-27. Therefore, this scheme conforms to the intent of the requirements of BTP PSB 1.

For periodic testing of this scheme, the individual relays can be bypassed with a permanently installed test block. When the test block bypass is in effect, the condition is annunciated in the control room, thereby meeting the requirements of the BTP and Regulatory Guide 1.47.

b. The GPI relay discussed above provides the load shedding on the Class 1E 4 kV buses. It is not bypassed during load sequencing because its setpoint for dropout is low enough to preclude spurious tripping under all load sequences.

c. The analyses required by this section of BTP PSB 1 were performed and were used in selecting the settings of the relays discussed above.

d. The tests required by this section of BTP PSB 1 will be performed during the startup test program.

Preoperational Test P-100.1 and the Voltage Regulation Verification Test, which is required by BTP-PSB-1 measure various bus voltages as loads are applied. These tests verify that proper voltage regulation on the 13.2 kV and 4 kV buses is maintained.

8.1.6.3.7 BTP - PSB 2 - Criteria For Alarms and Indications Associated With Diesel Generator Unit Bypassed And Inoperable Status

LGS is in compliance with BTP PSB 2. Compliance with this position is discussed in Sections 8.1.6.1.19 and 7.1.2.5.11.

8.1.7 REFERENCES

8.1-1 PECo Research and Test Division Test Report 48503, "Design Verification Test Report, Internal Panel Control Wiring Separation Criteria, LGS Units 1 and 2," (September 1, 1982).

8.1-2 GE Topical Report, "Power Generation Control Complex" NEDO-10466 and amendments.

8.1-3 Letter to E.G. Bauer, Jr. (PECO) from J.F. Stoly (NRC) on Dockets 50-277 and 50-278, (February 18, 1982).

Table 8.1-1

ELECTRICAL CHANNEL SEPARATION

CHANNEL A	CHANNEL B	CHANNEL C	CHANNEL D
Standby Diesel Generator & Auxiliaries A	Standby Diesel Generator & Auxiliaries B	Standby Diesel Generator & Auxiliaries C	Standby Diesel Generator & Auxiliaries D
Class 1E 4160 V Switchgear	Class 1E 4160 V Switchgear	Class 1E 4160 V Switchgear	Class 1E 4160 V Switchgear
Class 1E 480 V Load Center	Class 1E 480 V Load Center	Class 1E 480 V Load Center	Class 1E 480 V Load Center
Class 1E 480 V MCC	Class 1E 480 V MCC	Class 1E 480 V MCC	Class 1E 480 V MCC
Class 1E 125 V dc Distribution Panel	Class 1E 125 V dc Distribution Panel	Class 1E 125 V dc Distribution Panel	Class 1E 125 V dc Distribution Panel

8.2 OFFSITE POWER SYSTEM

8.2.1 DESCRIPTION

8.2.1.1 Offsite Power Sources

Offsite power is supplied from two independent, physically separated sources:

a. A 220-13 kV transformer No. 10 located at the LGS 220 kV substation

b. A 13 kV tertiary winding on the No. 4A and 4B 500-220 kV bus tie autotransformers through the No. 20 13-13 kV regulating transformer located in the LGS 500 kV substation

Physical and schematic representations of offsite and onsite transmission systems are shown in Figures 8.2-1, 8.2-2, and 8.2-6.

The LGS 220 kV substation supplies offsite power at 13.2 kV via the No. 10 220-13 kV transformer which has a nominal capacity of 61.6 MVA at 65°C and a 15 kV underground cable run of 1000 feet outside the station. A transition to cable bus is made inside the turbine enclosure, where the cable bus continues for 330 feet to the station auxiliary bus 10A103. The underground installation protects the power supply from variable weather conditions such as high velocity winds, icing, and lightning.

The line primary protective relaying consists of three differential relays, which under fault conditions trip and lock out station auxiliary bus 10A103 breakers and breaker 105 in the 220 kV substation. Phase overcurrent and ground overcurrent relays provide backup relay protection. Breaker 105 is also tripped by No. 10 transformer protective relays and 220 kV bus No. 7 protective relays.

In addition, both the No. 10 Station Auxiliary transformer and the 101 Safeguard transformer have Open Phase Detection (OPD) protective relaying. During an Open Phase Condition (OPC) event on the 10 Station Auxiliary transformer, the SEL relay monitoring this transformer will annunciate in the Control Room. After investigation and validation of the OPC, the 105 Substation Breaker (105 BRKR), the 25 Substation Breaker (25 BRKR), the 715 Substation Breaker (715 BRKR), the 725 Substation Breaker (725 BRKR), the 735 Substation Breaker (735 BRKR) and opens the No. 10 Circuit Switcher will be manually opened to isolate the 10 Station Auxiliary transformer.

During an OPC event on the 101 Safeguard transformer, the SEL relay monitoring this transformer will annunciate in the Control Room. After investigation and validation of the OPC, breakers 252-10301 and 252-10302 will be manually opened to isolate the 101 Safeguard transformer.

The 220 kV substation is supplied from three transmission sources:

a. 220-60 line which has a capacity[(1)] of 1200 MVA is routed on the east side of the Schuylkill River from the LGS 220 kV substation to a point opposite Cromby Station. From that point, the line leaves a railroad right-of-way, joins an existing PECO Energy right-of-way, and crosses the Schuylkill River to enter Cromby Station.

b. 220-61 line which has a capacity[1] of 1200 MVA is routed from the LGS 220 kV substation along the west side of the Schuylkill River on a railroad right-of-way to Lock Substation. The two 230 kV lines do not cross each other at any point.

c. The No. 4A and 4B bus tie autotransformers which interconnect the 220 kV and 500 kV substations and have a nominal capacity of 420 MVA each.

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[1] Capacity values provided are nominal; utilized values are higher.

The LGS 500 kV substation supplies offsite power at 13.2 kV to station auxiliary bus 20A103 from the tertiary winding of one of the No. 4A or 4B bus tie autotransformers through the No. 20 13-13 kV regulating transformer. The tertiary winding has a nominal capacity of 95.7 MVA and the No. 20 transformer has a nominal capacity of 58 MVA. This substation is physically located 2150 feet from the LGS 220 kV substation, effectively minimizing the likelihood of their simultaneous failure under operating conditions, postulated accidents, and natural disasters. The 13.2 kV power is transmitted 2100 feet to the station via an underground cable run and 400 feet of cable installed in a tray beneath the site access railroad bridge that spans Possum Hollow Run ravine. A transition to cable bus is made inside the turbine enclosure, where the cable bus continues for a distance of 330 feet to station auxiliary bus 20A103. The underground installation avoids exposure to adverse weather conditions.

As shown in Figures 8.2-1 and 8.2-2, the two offsite power sources do not share any common structures, systems, or components external to the generating station. Internal to the generating station, the offsite sources terminate in a common room on separate and independent buses that are approximately 90 feet apart. The No. 4 bus tie autotransformer that provides load flow stability between the 220 kV and 500 kV substations represents a common link between the two offsite sources; however, at least one 13 kV and two 220 kV circuit breakers provide isolation between the two startup feeds as shown in Figure 8.2-2.

Pilot wire relaying is used for line primary protection that, under fault conditions, trips and locks out station auxiliary bus 20A103 breakers and breaker 205 in the 500 kV substation. Backup relay protection is provided by phase overcurrent and ground overcurrent relays. Breaker 205 is also tripped by No. 4 transformer protective relays, 500-220 kV bus tie protective relays, and No. 20 regulating transformer protective relays.

In addition, both the No. 20 Regulating transformer and the 201 Safeguard transformer have OPD protective relaying. During an OPC event on the 20 Regulating transformer, the SEL relay monitoring this transformer will annunciate in the Control Room. After investigation and validation of the OPC, breaker 205 will be manually opened to isolate the 20 Regulating transformer. During an OPC event on the 201 Safeguard transformer, the SEL relay monitoring this transformer will annunciate in the Control Room. After investigation and validation of the OPC, breakers 252-10303 and 252-10304 will be manually opened to isolate the 201 Safeguard transformer.

The 500 kV substation is supplied from four transmission sources:

a. 5010 line which has a capacity[2] of 2780 MVA crosses the Schuylkill River from the west and runs above both of the 230 kV transmission lines. It is terminated in the LGS 500 kV substation. Where the existing 5010 line leaves the 500 kV substation towards the east, it becomes the 5030 line.

b. 5030 line which has a capacity(2) of 2780 MVA.

c. 5031 line which has a capacity(2) of 2780 MVA parallels the 5030 line from the 500 kV substation to Whitpain for the operation of LGS Unit 2.

d. The No. 4A and 4B bus tie autotransformers.

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(2) Capacity values provided are nominal; utilized values are within 2% of nominal.

From Figure 8.2-6, it can be seen that the requirements of GDC 17 are met in that in the unlikely event of the 5010 line falling and causing the failure of both 230 kV transmission lines, the 5030 line would still be available to provide an offsite source of power for the safe shutdown of the plant.

During unit operation, normal auxiliary power for the station is supplied from two 47 MVA unit auxiliary power transformers (one per unit) connected to the generator leads. Startup and Class 1E bus power is provided from the two independent offsite sources. Either offsite source can supply the 13.2 kV unit auxiliary buses and the 4 kV Class 1E buses for normal plant startup and shutdown and supply all normally connected loads including loads that may be automatically transferred to them when a LOCA in one unit coincides with a safe shutdown in the remaining unit. Each offsite source supplies an emergency auxiliary (safeguard) transformer with a nominal capacity of 14 MVA that steps down the 13.2 kV to 4.16 kV and connects through interlocked circuit breakers to every 4 kV Class 1E bus. Both offsite sources are available continuously to the Class 1E buses.

A spare 14 MVA 13.2/33-4.16 kV transformer is located onsite solely as a replacement for either the Unit 1 or Unit 2 13.2-4.16 kV safeguard transformer. The spare transformer has the same capacity as the safeguard transformers, which is more than adequate for safe shutdown of the plant. In the event of failure of either the Unit 1 or Unit 2 safeguard transformer, the faulty safeguard transformer will be removed and physically replaced by the spare.

The 6680, 66 kV transmission line serves as a potential, but currently not-connected alternate offsite source for use in the event of loss of one of the normal offsite sources. Line 6680 is tapped and provides power to the Limerick 66-13 kV substation. Aerial cable is installed between the 66-13 kV substation to a terminal pole located outside of the 220 kV substation where it converts to underground cable and is routed to the alternate offsite source breaker (No. 252-55401) installed north of the Unit 1 turbine building. In the event of loss of one of the normal offsite sources resulting in an outage time in excess of 72 hours, cables will be connected between breaker 252-55401 and the affected safeguard transformer. All work necessary to implement this alternate offsite source is expected to be accomplished within a 72 hour period to avoid a limiting condition of operation.

The capability to test the transfer of power from one offsite source to the other circuit can be accomplished from the control room (Drawing E-1). By tripping either the 101 or 201 transformer breaker, the loss of one offsite source will be simulated and the automatic transfer to the other offsite source will be initiated on the four Class 1E buses that are normally fed from that source. These buses can then be manually transferred back to their preferred source after the transformer breaker is closed.

The 66-13 kV substation has a capacity rating of 24 MVA which is sufficient to supply all connected and automatically transferred loads when a LOCA in one unit coincides with a safe shutdown in the

remaining unit. The 6680 line terminates at Cromby Station and Moser Substation. Moser substation receives bulk power from the Cromby Station via two 66 kV transmission lines, is solidly tied into the 33 kV distribution system and has three combustion turbine generators.

8.2.1.2 Switchyards

Both the 220 kV and 500 kV substations use a breaker and one-half scheme. This arrangement is shown in Figures 8.2-1 and 8.2-2. Both substations have three bus elements initially, with provisions for future expansion to four bus elements. Element refers to each bus-to-bus connection. The 500 kV substation contains a manually or automatically switched 200 Mvar shunt capacitor bank which is part of the PJM system of 500 kV capacitors. Both substations employ primary and backup relay protection plus breaker failure protection schemes. The substations are interconnected by a 500-220 kV bus tie transformer and a 220 kV transmission line. The tie line is approximately 100 feet from the Unit 1 generator line at the 220 kV substation and is approximately 200 feet from the Unit 2 generator line at the 500 kV substation. Both LGS substations ultimately interconnect with the PJM Interconnection through their respective transmission lines.

Each main generator is connected by an isolated phase bus to its respective step-up transformer bank. The Unit 1 maximum gross generator output of approximately 1240 MWe is fed to the 220 kV substation via three 22-242 kV, 525 MVA Unit 1 main transformers. The Unit 2 maximum gross generator output of approximately 1240 MWe feeds into the 500 kV substation via three 22-500 kV, 525 MVA Unit 2 main transformers. A system spare 22-220 kV 422 MVA transformer is installed next to the C phase Unit 1 transformer for immediate use should a fault occur on one of the three operating transformers. A system spare for the Unit 2 22-500 kV transformers is stored next to the Water Treatment Plant.

The relaying associated with the 220 kV and 500 kV substations and transmission lines is shown in Figure 8.2-4. Three separate protective relaying schemes are used on the 500 kV and 220 kV transmission lines. The first two schemes use primary and backup high speed relays with a power line carrier for directional comparison relaying logic. In the 500 kV substation, carrier relaying is on A phase and B phase of the transmission lines except for line 5031 which uses Fiber Synchronous Optical Network (SONET) for both primary and backup relaying. The 220 kV substation transmission line carrier relay protection is on A phase and C phase, except for line 220-61 which uses SONET for both primary and backup relaying. The redundant relays operate from separate current transformers and separate secondary windings of the same potential device. Each substation has its own dc battery and battery charger. The charger is fed from an essential ac bus which has two alternate feeds with an automatic throw-over. Low dc voltage is alarmed in the substation control house and the LGS control room. Because this dc system and the substation protective relays are non-Class 1E, redundancy is not required. Direct current control circuits are fused separately for the redundant relay protection channels. Each line relaying initiates operation of separate redundant trip coils at the 500 kV circuit breakers and one trip coil at the 220 kV circuit breakers. The third scheme is breaker failure protection for a stuck breaker. This is provided by tripping adjacent breakers and transmitting signals to trip the circuit breaker at the remote line terminal. Separate carrier paths or channels are provided for each line relaying scheme.

The use of three relaying schemes with independently fused direct current feeds and independent 500 kV circuit breaker trip coils, along with current shorting switches and potential switches, permits inservice shutdown and test of any one relay and control scheme while maintaining two protective relaying schemes in service. The use of the breaker and one-half arrangement allows for the outage of one breaker without taking a line, transformer, or generator out-of-service. Testing equipment is

installed for carrier line relaying to allow inservice functional testing of the directional comparison relaying logic. After initial calibration, the equipment is periodically inspected, and readings are recorded.

OPD protective relaying is installed on both the No. 10 Station Auxiliary transformer and 20 Regulating transformer in the Substations. These are independent schemes on the 500 kV and 220 kV sources which communicate with relays inside the station to protect the 10 and 20 Buses and their associated transformers.

Each 500 kV and 220 kV bus element has two protective bus differential relaying schemes, either of which may be shut down for testing while maintaining the other in service for bus protection. All control operations, except actual tripping of the breakers, can be done while maintaining the bus in service.

The 220 kV and 500 kV breakers in both the substations are controlled from the substation control houses. These breakers are also controlled via a SCADA system from the SAMAC Control Center with the following exceptions: Unit 1 breakers 535 and 635, Unit 2 breakers 235 and 335 and breakers 105 and 205. The above mentioned exceptions are controlled via independent hard-wired circuits from the LGS control room.

All circuit breakers have sufficient stored energy for at least one open-close-open operation after loss of power.

Figure 8.2-5 shows the cable trench arrangements in the 220 kV and 500 kV switchyards. All control power circuits to the switchyard equipment are routed in these trenches. Control circuits for the various pieces of equipment are separated into individual cables. Primary and backup relay and control circuits are separately fused and are separated into individual cables. All cables are direct-buried in the trenches.

Relay and circuit breaker functional trip tests on all of the offsite power sources are made periodically.

The substation control batteries are tested periodically as follows:

a. Weekly - Voltage and specific gravity of the pilot cell are recorded. Overall voltage of the battery is recorded.

b. Quarterly - Voltage is recorded for each cell, and specific gravity is recorded for at least 10% of cells. Overall battery voltage is recorded.

c. Yearly - Annual battery inspection in addition to the quarterly tests.

8.2.1.3 Control Room Monitoring of Offsite Power Systems

The status of the offsite power system is monitored in the control room. A dedicated supervisory system provides the following status indications along with other pertinent information:

a.[3] Transmission Line Current for:

220-60 Line	5030 Line
220-61 Line	5031 Line
5010 Line	

b.[3] 220 kV Substation Bus Voltage

c.[3] 500 kV Substation Bus Voltage

d.[3] 220 kV Substation Breaker Positions

e. 500 kV Substation Breaker Currents

f.[3] 500 kV Substation Breaker Positions

g.[3] #4 Tie Transformer current

h.[3] #105 Startup Breaker Position

i.[3] #205 Startup Breaker Position

j. Miscellaneous 220 kV and 500 kV Substation Alarms

8.2.1.4 Conclusion

The offsite power system has been designed for maximum reliability. All three sources of offsite power, including transmission lines and transformers, have sufficient capacity to supply all connected loads including loads that may be automatically transferred to them when a LOCA in one unit coincides with a safe shutdown in the remaining unit. The design and configuration of the offsite power system with provisions for periodic testing are in full conformance with GDC 5, GDC 17 and GDC 18, and Regulatory Guide 1.32 (1977) and Regulatory Guide 1.93 (1974).

8.2.2 ANALYSIS

8.2.2.1 Transient Stability

Detailed transient stability studies were made for both LGS units using load flow (POWERFLO) and transient stability (TRANSTAB) computer simulation programs. These computer programs are widely recognized in the electric utility industry and are being used by over 140 domestic and foreign utilities, government agencies, and universities.

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[3] Upon loss of the Unit 1 Plant Monitoring System, these items are available from the PECO Energy load dispatcher via dedicated phone line.

The stability evaluation consisted of analysis of prefault and postfault load flow simulations and of transient stability digital computer calculations. Examination of the 1985 peak and light load levels showed the light load level to be most critical for stability because of the higher impedance and lower system inertia seen by the LGS units. Thus, all results are based on 1985 light load conditions. For all load flow simulations and associated stability calculations, a detailed representation of the PECO Energy system and the other PJM Interconnection systems was modeled including a significant representation of the systems in the surrounding Interconnected Power Pools. Altogether 1208 buses, 2158 lines, and 180 individual generators were represented in the model. The LGS units and other PJM Interconnection generators were represented in the transient stability calculations by appropriate inertias and machine reactances, with generator excitation systems and turbine governors being modeled in great detail to accurately simulate generator transient performance. The generating units of companies outside the PJM Interconnection were represented by their transient reactances and inertias.

The results of the studies show that both LGS units are stable for the most severe type of fault (three-phase) at the most critical locations on the electric network system. Specifically, the LGS generating units are stable for the following conditions:

a. A three-phase fault on any single 500 kV or 230 kV LGS circuit that is cleared by primary protective equipment.

b. A three-phase fault on any single 500 kV or 230 kV LGS circuit, where the most critical LGS circuit breaker fails to open and the fault is cleared at LGS by backup protective equipment.

c. A three-phase fault on the transformer connecting the LGS 500 kV and 230 kV buses that is cleared by primary protective equipment.

d. A three-phase fault on the transformer connecting the LGS 500 kV and 230 kV buses, where the most critical circuit breaker fails to open and the fault is cleared at LGS by backup protective equipment.

e. Simultaneous three-phase faults on both LGS to Whitpain 500 kV circuits that are cleared by primary protective equipment.

Load flow simulations and stability calculations were examined to evaluate the transient and post-transient system conditions after the most serious network faults and after the sudden tripping of either LGS unit. The analysis of circuit loadings and bus voltages showed no adverse system conditions either during periods of steady-state operation or during system oscillations caused by a fault and its subsequent clearing.

Additional transient stability analyses were also completed to address the following three events:

a. Loss of the largest generating station, i.e., loss of PBAPS Units 2 & 3

b. Loss of the largest load

c. Loss of the most critical right-of-way, i.e., a three-phase fault on the four transmission lines on the 130-30 right-of-way:

1. 130-30 line, 138 kV
2. 220-62 line, 230 kV
3. 5030 line, 500 kV
4. 5031 line, 500 kV

The transmission system remained stable for all three cases with either one or both LGS units in service. The loss of both PBAPS units was the worst case affecting system frequency. A minimum system frequency of 59.95 Hz occurred 0.35 seconds after the trips, and it ran out to 0.48 seconds. During this transient, the LGS units will experience a minimum frequency 59.89 Hz. This is well within the design capabilities of all LGS electrical equipment.

The effect of the 200 Mvar manually or automatically switched shunt capacitor on the 500 kV substation bus and on Limerick generator stability was analyzed. The analysis showed no detrimental affect on the generator's stability even with the voltage regulators out of service. The study indicated voltage is slightly improved with the capacitor in service.

Additional transient stability studies are performed as major system changes occur. Recent examples include, Power Rerate Projects, Turbine Retrofit Projects, 500 kV capacitor additions, etc. The transmission system is tested against the MAAC Reliability Principles and Standards: Transmission Requirements. All single, double, double circuit/stuck breaker contingencies are run as part of these additional studies. These contingencies are tested at the peak, intermediate and light load levels, with and without the increase of Limerick 1 & 2 Unit outputs. All MAAC transmission lines, 230 kV and above are monitored for any voltage and thermal limit violations. Faults are initiated at the 500 kV and 230 kV buses in the Limerick area. The MAAC system was found to remain stable for all tested faults which are cleared by either the primary and/or backup protective equipment.

> Note: The information presented above regarding the Transient Stability is historical and is based on the original design basis conditions and does not represent current methodology required for licensing basis. The above transient stability studies were preformed in compliance with Mid-Atlantic Area Council (MAAC) standards. MAAC was replaced with Reliability First Corporation (RFC) as the regional reliability organization to monitor and enforce compliance with North American Electric Reliability Council (NERC) standards.

The Transient Stability study is performed by the Transient Planning Entity (PJM) periodically and per request basis for major system modifications. The Transmission Planning Entity normal stability testing enforces the NERC criteria including contingencies under NER standards:

- TPL-001 – Category A (Transmission Planning Standard for System Performance Under Normal Conditions),
- TPL-002 – Category B (Transmission Planning Standard for System Performance Following Loss of a Single Bulk Electric System Element), and
- TPL-003 – Category C (Transmission Planning Standard for System Performance Following Loss of Two or More Bulk Electric System Elements).

In addition to the NERC standard criteria, the Transmission Planning Entity reviews and enforces additional criteria testing as required by Nuclear Plant Interface Requirement (NPIR) for planning analyses of the electric system.

To satisfy the requirements of 10 CFR 50 Appendix A General Design Criterion – Electrical power systems (GDC 17), the results of the grid stability study must show that loss of the largest single supply to the grid does not result in the complete loss of preferred power. The analysis should consider the loss, through a single event, of the largest capacity being supplied to the grid, removal of the largest load from the grid, or loss of the most critical transmission line. This could be the total output of the station, the largest station on the grid, or possibly several large stations if these use common transmission tower, transformer, or a breaker in a remote switchyard or substation.

The above licensing basis requirements are considered Category B contingencies for which the Transmission Planning Entity ensures that they will not cause grid instability.

8.2.2.2 Outages of Transmission Lines in the Vicinity of LGS

To demonstrate the reliability of the transmission lines associated with LGS unscheduled outages of existing transmission lines in the area were investigated. The lines included in the study are the PBAPS to Whitpain 500 kV line, the three Whitpain to Plymouth Meeting 230 kV lines, and the Whitpain to North Wales 230 kV line. These lines were chosen because they presently link the substations associated with the LGS project.

8.2.2.3 Unscheduled Outages

Historically, outages in this area have been caused by lightning strikes, flashovers, galloping conductors, airplanes, and equipment failures.

Of the 14 outages listed in Table 8.2-1, 9 lasted less than one hour, 4 lasted less than one day, and one lasted 5 days.

Table 8.2-1

UNSCHEDULED OUTAGES

Lines	Length (mi)	1971	1972	1973	1974	1975	1976
PBAPS - Whitpain	72.4	0	0	1	0	1	5[1]
Plymouth Meeting - Whitpain	5.1	0	0	0	0	1	1
Plymouth Meeting - Whitpain	5.1	0	0	0	0	1	0
Plymouth Meeting - Whitpain	5.1	0	0	0	0	1	0
North Wales - Whitpain	3.5	0	0	1	0	0	2

(1) The PBAPS - Whitpain 500 kV line was interrupted four times on the same day in 1976 because of galloping conductors. Equipment has since been installed to prevent recurrence of the galloping conductors.

8.3 ONSITE POWER SYSTEMS

8.3.1 AC POWER SYSTEMS

8.3.1.1 Description

The onsite ac power systems are divided into Class 1E and non-Class 1E systems. Drawing E-1 shows a single-line diagram of both systems.

The onsite ac power systems consist of main generators, main step-up transformers, unit auxiliary transformers, safeguard transformers, and diesel generators, among other distribution system equipment. The onsite ac power distribution system has nominal bus voltage ratings of 13.8 kV, 4.16 kV, 2.4 kV, 480 V, and 208/120 V. Throughout this discussion and on all design drawings, the equipment utilization voltages are designated as 13.2 kV, 4 kV, 2.3 kV, 440 V, and 208/120 V.

8.3.1.1.1 Non-Class 1E Ac System

The non-Class 1E portion of the onsite power systems provides ac power for non-Class 1E loads. A limited number of non-Class 1E loads are important to the power generating equipment integrity and are fed from the Class 1E distribution system through the isolation devices.

The unit auxiliary transformer supplies all the non-Class 1E unit auxiliary loads. The unit auxiliary transformer primary is connected to the main generator isolated phase bus duct tap, while the secondary of the transformer is connected to the two 13.2 kV unit auxiliary buses through a nonsegregated phase bus.

During plant startup, shutdown, and postshutdown, power to the 13.2 kV buses is supplied from the offsite power sources, with one bus from each unit normally supplied through the 220-13kV startup transformer and one bus from each unit normally supplied through the 13 kV tertiary winding of either the No. 4A or 4B 500-220 kV bus tie autotransformer; the tertiary of the other autotransformer is available as a back-up source. In addition, during these conditions, manual or automatic fast transfer is provided to transfer the unit auxiliary buses to the startup power source to maintain continuity of power at the unit auxiliary distribution system. The interconnecting breakers are interlocked to prevent the connection of the startup power source and the unit auxiliary power source to the unit auxiliary buses at the same time.

In addition to the loading conditions mentioned in the above paragraph, the 13.2 kV startup buses also supply the power to the Class 1E loads through their respective 13.2 - 4.16 kV safeguard transformers, as discussed in Section 8.3.1.1.2.

The 13.2 kV unit auxiliary switchgear provides power to large auxiliary loads, 2.3 kV switchgears, and 440 V load centers. The 13.2 kV switchgear feeds double-ended 440 V load centers. A manual tie breaker is provided for each set of load centers to intertie the two load centers if there is a failure of one load center transformer. To prevent paralleling of the two power supplies to each set of load centers, bus tie breakers are electrically interlocked with corresponding bus breakers such that one bus breaker must be open before the tie breaker may be closed. If the tie breaker is closed, closing of both bus breakers will automatically open the tie breaker. Load centers generally supply power to 440 V loads larger than 100 hp and power for their respective motor control centers. The motor control centers supply 440 V loads smaller than 100 hp, while 440 V, 480/277 V, and 208/120 V panels provide miscellaneous loads such as unit heaters, space heaters, lighting systems, etc. The

13.2 kV switchgear also feeds a 2.3 kV switchgear which supplies power to general plant services loads.

Two uninterruptible 120 V ac distribution panels for the RPS and UPS are provided for each unit. Each 120 V UPS ac power system is fed from two sources through a static transfer switch. The preferred source is the 250 V dc MCC via an inverter. The 250 V dc MCC is normally fed from battery chargers/rectifiers which are backed up by class 1E batteries. The alternate source is a 480/120 V transformer, which is supplied through a transfer switch either from a non-Class 1E 440 V MCC or from a non-Class 1E 440 V MCC energized by a non-Class 1E UPS. Between the static transfer switch and the distribution panel, two circuit breakers in series are provided with redundant trip circuits that trip the breakers on overvoltage, undervoltage, and underfrequency conditions to provide protection of the RPS during any failure of the non-Class 1E power supply.

Two uninterruptible 120 V ac distribution panels for the APRM and RBM electronics, the SRVPI system, and the RPIS are provided for each unit. Each panel is fed from two sources through a static transfer switch. The preferred source is the non-Class 1E 125 V dc batteries through a static inverter. The alternate source is the 120 V ac RPS uninterruptible power supply.

480 V ac UPS power supply feeds (144D-C-F) are provided for the Unit 1 and 2 Plant Monitoring Systems (PMS).

For the Unit 1 PMS, one supply breaker feeds two computer power centers (10Y506 and 10Y507), located in the Technical Support Center and a 120V ac distribution panel (10Y161), located in the Auxiliary Equipment Room. The computer power centers contain a main breaker, transformer, and 120/208 V ac distribution panel which in turn feed the various computer hardware. Distribution Panel 10Y161 supplies the Data Acquisition System equipment that multiplexes Unit 1 plant signals to the PMS.

For the Unit 2 PMS, four supply breakers feed four computer power centers (00Y591, 00Y592, 00Y593, and 00Y594), located in the Technical Support Center. The computer power centers are designed as described above and feed the various computer hardware.

One additional supply breaker feeds computer power center 00Y595, located in the Unit 1 Inverter Room. The Unit 1 and 2 control room PMS console displays are fed from this panel.

The non-Class 1E ac equipment capacities are listed below:

a. Transformers

Main transformer (Unit 1)	3-1ϕ, 525 MVA, ODAF, 65°C 22-242 GRD Y/139.78 kV
Main transformer (Unit 2)	3-1ϕ, 525 MVA, ODAF 65°C 22-531 GRD Y/306 kV
Unit auxiliary transformers (both units)	1-3ϕ 31.47/41.95/52.45 MVA, OA/FA/FOA, 65°C 22-13.8 GND Y/7.96 kV 22Y-13.8 GRD Y/7.96-7.2 kV

Station auxiliary (startup) transformer (Unit 1)	1-3ϕ 36.96/49.28/61.6 MVA, OA/FOA/FOA, 65°C 230-14.18 Y/8.187 kV, LTC ±10% of 14.18 kV, automatic, on-line
Autotransformers, tertiary winding (startup) (Unit 2)	2-3ϕ OA/FOA/FOA H 252/336/420 MVA, 65°C X 252/336/420 MVA, 65°C Y 57.4/76.5/95.7 MVA, 65°C 515 GRD Y/297.3 -230 GRD Y/132.8-13.8 kV, LTC ±10% of 515 kV automatic, on-line
Safeguard transformers (both units)	1-3ϕ 11.2/14.0 MVA, OA/FA, 65°C 13.2-4.16 Y/2.4 kV, LTC ±10% of 4.16 kV, automatic, on-line
Transformers (Perkiomen Pumping Station) (Common to Units 1 and 2)	2-3ϕ 5.6/7.0 MVA, OA/FA, 65°C 34.4-4.16 Y/2.4 kV
Plant services transformers (both units)	1-3ϕ 5600/7000 kVA, OA/FA, 65°C, 13.2-2.4 Y/1.386 kV
Regulating Transformer (startup) (Unit 2)	1-3ϕ 35/46.667/58.333 MVA OA/FA/FA, 65°C 13.8 Y/7.97 - 13.8 Y/7.97-4.815 kV LTC -10.3 to +19.7% of 13.8 kV, automatic, on-line

b. Switchgear

13.2 kV Switchgear	1200/2500 A continuous rating, 750 MVA, 3ϕ 37,500 A rms symmetrical interrupting rating
2.3 kV Switchgear	1200/2000 A continuous rating 250 MVA 3ϕ class 37,500 A rms symmetrical interrupting rating

c.	440 V Unit load centers	
	Transformers	1000 kVA AA and 1000/1333 kVA AA/FA, 3ϕ, 60 Hz, 13200-480 GRD Y/277 V
	Horizontal Bus	1600 A continuous rating
	Vertical Bus	600 A continuous rating
	Breakers (metal clad)	22,000 A rms symmetrical, minimum interrupting rating
d.	440 V Unit load centers (Perkiomen Creek - common to Units 1 and 2)	
	Transformers	300 kVA AA, 3ϕ, 60 Hz, 4160-480 GRD Y/277 V
	Horizontal Bus	600 A continuous rating
	Vertical Bus	600 A continuous rating
	Breakers (metal clad)	22,000 A rms symmetrical minimum interrupting rating
e.	440 V MCCs	
	Horizontal bus	600 A continuous rating, 42,000 A rms symmetrical bracing
	Vertical bus	300 A minimum continuous rating, 42,000 A rms symmetrical bracing
	Breakers (molded-case)	22,000 A rms symmetrical, minimum interrupting rating
f.	120 V Instrument ac distribution panels	
	Buses	100/225A continuous rating 10,000 A rms symmetrical bracing
	Breakers (molded-case)	100 A frame size 5,000 A rms symmetrical interrupting rating

g.	120 V ac UPS and computer distribution panels	
	Buses	400 A continuous rating 5,000 A rms symmetrical bracing
	Fuses	200,000 A rms symmetrical interrupting rating

8.3.1.1.2 Class 1E Ac Power System

The Class 1E ac power system is the portion of the onsite power system that is shown after the 4 kV nonsegregated bus in Drawings E-15 and E-16 at the incoming 4 kV breaker.

The Class 1E ac system distributes power at 4 kV, 440 V, and 208/120 V. The loads that are fed by this Class 1E ac system are divided into four divisions in each unit and are shown in Drawings E-15 and E-16. Each load division has its own distribution system and power supplies.

The 4 kV bus of each Class 1E load division is provided with connections to two offsite power sources, designated as preferred and alternate power supplies. In addition, provisions exist for connection to a third offsite power source through a spare transformer if there is a failure of one of the two offsite sources or either of the safeguard transformers. Diesel generators are provided as a standby power supply if there is a total loss of the preferred and alternate power supplies. Standby power supply is discussed in Section 8.3.1.1.3.

The Class 1E ac power system and its components, and the diesels and their auxiliaries, are located in seismic Category I structures that provide protection from the effects of tornadoes, tornado missiles, turbine missiles, and external floods. The Class 1E AC Power System and its components are designated Class 1E safety related, and the diesels and their required auxiliaries are designated safety related for procurement and quality assurance purposes and have been qualified for seismic and hydrodynamic loads as well as environmental conditions that they may experience during normal operation and postulated accidents.

None of the electrical equipment that is required to mitigate the effects of a design basis event will become submerged as a result of a LOCA. The only electrical equipment that may experience temporary submergence is penetration assembly JX230A, which becomes submerged during the pool-swell experienced during an SRV discharge. To ensure that suppression pool temperature indication which is monitored by this penetration is maintained during the pool-swell, the entire penetration is encased by an enclosure to a point above the maximum pool level, thereby assuring that the electrical portion of the penetration will not be affected by the pool-swell.

The following material describes the various features of the Class 1E ac power system.

8.3.1.1.2.1 Power Supply Feeder

Each Class 1E 4 kV switchgear is provided with a preferred and an alternate offsite power supply feeder and one standby diesel generator feeder. Each bus is normally energized by the preferred power supply. If the preferred power source is not available at the 4 kV bus, automatic transfer is

made to the alternate power source, as described in Section 8.3.1.1.2.4. If both the preferred and the alternate power sources become unavailable, the loads on each bus are picked up automatically by the standby diesel generator assigned to that bus, as described in Section 8.3.1.1.3.

8.3.1.1.2.2 Bus Arrangement

The Class 1E ac power system for each unit is divided into divisions A, B, C, and D. Power supplies for each load division are discussed in Section 8.3.1.1.2.1. With the exception of the ESW system, the RHRSW system, the SGTS, CSCWS and the control room and control structure ventilation systems, which are common systems, all other Class 1E ac loads in each unit are divided among the four divisions so that any combination of three out of four divisions has the capability to supply the minimum required safety loads to safely shut down the unit. Common loads for the ESW and the RHRSW systems are split between the Unit 1 and Unit 2 Class 1E power supplies. Common redundant loads for the SGTS, CSCWS and the control room and control structure ventilation systems are fed from Unit 1 Class 1E power supplies.

Any combination of three-out-of-four divisions (EDGs) is acceptable for a single failure as shown on Table 8.3-2. However, for ECCS requirements (as stated in paragraph 6.3.1.1.2), an EDG operable configuration of 2 out of 4 is also acceptable.

The distribution system of each division consists of a 4 kV bus, a 440 V load center, several motor control centers, and several low voltage distribution panels. The 4 kV, load center, and motor control center bus arrangements are shown in Drawings E-15, E-16, E-18, and E-29.

8.3.1.1.2.3 Loads Supplied from Each Bus

Table 8.3-3 lists all the loads supplied from each Class 1E bus.

8.3.1.1.2.4 Manual and Automatic Interconnections Between Buses, Buses and Loads, and Buses and Supplies

No provisions exist for automatically connecting one Class 1E load division to another redundant Class 1E load division or for automatically transferring loads between load divisions. The incoming preferred power supply associated with a load division can supply the 4 kV Class 1E bus of the other load division by manual operation of the requisite 4 kV circuit breakers, when required.

For each load division, one 4 kV feeder circuit breaker is provided for the normal incoming preferred power source, and another 4 kV feeder circuit breaker is provided for the alternate power source. Safeguard bus 101 is the preferred power source for channels A and C for Unit 1 and channels B and D for Unit 2. Safeguard bus 201 is the preferred power source for channels B and D for Unit 1 and channels A and C for Unit 2. The normal preferred power source to each bus is electrically interlocked with the alternate power source such that the bus can be connected to only a single power source at any one time. In the event of loss of preferred power to the load division, the undervoltage relay on the bus initiates after a time-delay an emergency diesel generator start and after a further time delay an automatic transfer to the alternate power source. The time needed to complete this transfer varies depending on the magnitude of back electromagnetic force generated on the bus by large motor loads and by the voltage level of the degraded offsite source. In all cases, the transfer is complete in less than the 13 seconds it would take to re-energize the bus from the diesel generator on the loss of all offsite power. If automatic transfer fails, the undervoltage relay after a further time-delay enables a transfer of the bus to the diesel generator. In the event of losing both preferred and alternate power supplies, the diesel breaker closes when the generator reaches 95% of rated voltage and frequency at which time the division becomes powered from the diesel generator.

When the power system is operating from the diesel generator supply (LOOP), redundant load divisions cannot be manually connected together because the 4 kV circuit breakers controlling the incoming preferred and alternate power supplies to the Class 1E buses are interlocked to prevent the paralleling of the diesel generators.

During manually initiated bus transfers or testing, one diesel generator may be paralleled with the preferred or alternate source.

8.3.1.1.2.5 Interconnections Between Class 1E and Non-Class 1E Buses, Non-Class 1E Loads, and Class 1E Buses

The offsite power supply feeders through the startup buses, which supply power to both the Class 1E and non-Class 1E buses, are exempt from the associated circuit requirements in IEEE 384 (1974), section 4.5. There are no other bus ties between the Class 1E and non-Class 1E buses.

A further discussion of interconnections between Class 1E and non-Class 1E buses, non-Class 1E loads, and Class 1E buses is presented in Section 8.1.6.

8.3.1.1.2.6 Redundant Bus Separation

The Class 1E switchgear for the redundant Class 1E load divisions is located in separate seismic Category I rooms in the control and reactor enclosures to ensure electrical and physical separation. Electrical equipment separation is further discussed in Section 8.1.6.

8.3.1.1.2.7 Distribution Equipment Capacities

a.	4 kV Switchgear	1200 A continuous rating, 350 MVA, 3ϕ, 50,000 A rms symmetrical interrupting rating
b.	4 kV Switchgear (ATWS)	1200 A continuous rating, 250 MVA, 3ϕ, 37,500 A rms symmetrical interrupting rating
c.	440 V Unit load centers	
	Transformers	1000 kVA, AA, 3 phase, 60 Hz, 4160-480 GRD Y/277 V
	Horizontal Bus	1600 A continuous rating
	Vertical Bus	600 A continuous rating
	Breakers (metal clad)	22,000 A rms symmetrical, minimum interrupting rating

d.	440 V MCCs	
	Horizontal bus	600 A continuous rating 42,000 A rms symmetrical bracing
	Vertical bus	600 A continuous rating 42,000 A rms symmetrical bracing
	Breakers (molded-case)	22,000 A rms symmetrical, minimum interrupting rating and 14,000 A rms symmetrical with integral current limiter
e.	120 V Instrument ac distribution panels	
	Buses	225 A continuous rating 10,000 A rms symmetrical bracing
	Breakers (molded-case)	100 A frame size 5,000 A rms symmetrical interrupting rating

8.3.1.1.2.8 Automatic Load Shedding and Sequential Loading

Shedding of the loads off the Class 1E buses is achieved by using undervoltage relays that automatically trip the breakers on bus undervoltage or a LOCA signal in the unit with which the loads are associated. Load sequencing is accomplished by using time-delay relays on individual breaker control circuits.

The following describes load shedding and sequential loading after a LOCA:

a. With offsite power available, all Class 1E 4 kV breakers on the unit with the LOCA, except for the RHR pump motor feeder breakers and incoming source breakers, are tripped. The required Class 1E loads are then started in a preset time sequence as shown on Table 8.3-1(b). Common loads supplied from the unit without the LOCA, which are required to support the unit with the LOCA, are also started.

b. For a total LOOP, all Class 1E 4 kV breakers on the unit with the LOCA are tripped and the required Class 1E loads are then started in a preset time sequence as shown on Table 8.3-1(a). All Class 1E 4 kV breakers on the non-LOCA unit are also tripped with the exception of the load center feeder breakers. Common loads supplied by the non-LOCA unit, which are necessary to support the LOCA unit, are started automatically. All other 4 kV loads in the non-LOCA unit are started manually as required for emergency shutdown.

For further information, see Section 8.3.1.1.3.6.

8.3.1.1.2.9 Class 1E Equipment Identification

A clear identification is provided to distinguish between Class 1E and non-Class 1E equipment. Each division of the Class 1E cable and raceway is identified by a unique color and a numbering system. Section 8.3.1.3 discusses Class 1E and non-Class 1E equipment identification in detail.

8.3.1.1.2.10 Instrumentation and Control Systems for the Applicable Power Supply Identified

Power for the four divisions of Class 1E instrumentation and control circuits is supplied by the respective division of the Class 1E instrumentation and control distribution equipment. The power supplies for instrumentation and control circuits are described below.

a. Instrumentation - The instrumentation ac system supplies power for the Class 1E instruments.

   Four independent Class 1E 208/120 V ac power supplies are provided to supply the associated four channels of the instruments. The four bus arrangement provides a separate electric power supply to each of the four channels that are electrically and physically isolated from the other channels. Each power supply consists of a 480-208Y/120 V transformer and one or more distribution panels. The 440 V power supply is provided by the corresponding 440 V Class 1E MCC.

b. Control Circuits - Control power for the 4 kV Class 1E switchgear is supplied by the Class 1E 125 V dc system, while load centers and MCCs use 120 V ac for control power.

   Dc control power for the Class 1E switchgear is provided from Class 1E batteries of the same division. Four divisions of Class 1E batteries supply control power to the associated four divisions of the Class 1E switchgear. For a further description of the dc system, see Section 8.3.2.

   For each Class 1E load center, control power is supplied from a control bus connected to the load center power bus through a control transformer.

   MCC control power is supplied by individual control transformers connected to those breakers requiring control power. For selected control circuits, Class 1E 125 V dc control power is used to supplement the Class 1E 120 V ac supplied by individual control transformers.

8.3.1.1.2.11 Electric Circuit Protection Systems

Protective relay schemes and direct-acting trip devices on primary and backup circuit breakers are provided throughout the onsite power system to:

a. Isolate faulted equipment and/or circuits from unfaulted equipment and/or circuits

b. Prevent damage to equipment

c. Protect personnel

d. Minimize system disturbances

e. Maintain continuity of the power supply

The short-circuit protective system is analyzed to ensure that the various adjustable devices are applied within their ratings and set to be coordinated with each other to attain selectivity in their operation. The combination of devices and settings applied affords the selectivity necessary to isolate a faulted area quickly, with minimum disturbance to the rest of the system.

Each circuit breaker and protective relay is equipped with a visual indicator to identify its actuation.

To avoid spurious trips and to ensure correct selective operation of the protective devices and their associated breakers, minimum time intervals are maintained between the characteristic tripping curves of the various protective devices to account for pickup tolerances.

When coordinating inverse-time overcurrent relays, the time interval between relay characteristics is a minimum of 0.3-0.4 seconds. The interval consists of 0.08 seconds for circuit breaker operating time, 5 cycles, 0.10 seconds for relay overtravel, and 0.12-0.22 seconds for safety factor. The minimum time interval between relay characteristics and fuse characteristic curves is 0.2 seconds. The current pickup intervals between relay characteristics are selected to maintain tripping selectivity, which includes the separation margins required by relay pickup tolerances.

When coordinating low voltage power circuit breakers, molded-case circuit breakers and fuses, the characteristic curves generally do not overlap. In general, only a slight separation is made between the different characteristic curves because the curves represent minimum and maximum clearing times and include the tolerances of the protective device.

Per the LGS Fire Protection Plan, presented in Appendix 9A, Section 9A.6.1.1, all systems and components that are relied on for achieving safe shutdown receive power from the Class 1E ac distribution system or Class 1E dc power system. Offsite power may be credited as the source for the Class 1E ac distribution system for fire areas which do not require Alternative Shutdown and for which the offsite source(s) to the 4kV switchgear is not affected by fire damage. All circuits, both Class 1E and non-Class 1E, are individually protected by coordinated fault actuated protective devices. Proper coordination among these protection devices is discussed in Section 9A.6.1.1, and demonstrated by time-current coordination curves shown in Figures 9A-13 through 9A-20.

Time-current coordination curves for drywell penetrations are shown in UFSAR Figures 8.1-2 through 8.1-5.

Major types of protection measures employed include the following:

a. Bus differential relaying

   A bus differential relay scheme is provided for each Class 1E 4 kV bus. These relays provide high speed clearing of internal bus faults by tripping all circuit breakers connected to the faulted bus.

b. Overcurrent relaying

Each Class 1E 4 kV bus feeder circuit breaker is equipped with three very inverse-time overcurrent relays and one inverse-time ground fault relay to sense, and protect the bus from, overcurrent condition and to provide backup for feeder circuit protective relays.

Each 4 kV motor feeder circuit breaker has three overcurrent relays, each with one long-time, one high dropout instantaneous, and one standard instantaneous element for overload, locked rotor, and short-circuit protection. Each breaker is also equipped with an instantaneous ground sensor relay. Each 4 kV Class 1E motor is also provided with an overload alarm.

For 4 kV Class 1E motors, the circuit inverse-time protection is set for overload alarm at approximately 115% of motor full load current for motors with service factor (SF) = 1.0 and at approximately 130% full load current for SF = 1.15. The high dropout instantaneous element is set at 175% full load current and will trip for locked rotor and short-circuit currents, provided the inverse-time element has operated. The standard instantaneous element is set at greater than or equal to 160% of motor locked rotor current for short-circuit trip.

Each Class 1E 4 kV supply circuit breaker to a 480 V load center transformer is protected by three extremely inverse-time overcurrent relays with long-time and instantaneous elements. An instantaneous overcurrent ground sensor relay provides sensitive ground fault protection.

For Class 1E 480 V load center transformers, the transformer primary inverse-time protection is set between 200% to 300% of the transformer AA rating.

c. Undervoltage relaying

Each 4 kV Class 1E bus is equipped with undervoltage relays for initiating a diesel generator start, an automatic transfer from the preferred to the alternate offsite power source, shedding the loads off the 4 kV Class 1E buses as described in Section 8.3.1.1.2.8, and loading the diesel generator when both the preferred and alternate offsite power sources are not available.

Each Class 1E 4 kV bus feeder is equipped with three undervoltage relays for starting the diesel generator and automatic transfer to an alternate source upon sensing degraded grid voltage. Section 8.1.6.3.6 gives a description of the degraded grid voltage monitoring system. This design is in compliance with the intent of BTP PSB1.

d. Diesel generator differential relaying

Each diesel generator is equipped with differential relaying protection. This circuitry provides high speed disconnection to prevent severe damage in case of diesel generator internal faults.

e. 440 V Load center protection

Each load center circuit breaker is equipped with integral, solid-state, adjustable, direct-action trip devices providing instantaneous and/or inverse-time overcurrent

protection. Motor feeders are equipped with solid-state adjustable instantaneous and long-time overcurrent trip devices.

The overcurrent devices for breakers supplying 440 V MCCs are set to protect the feeder cables from short-circuit and thermal damage and to be selective with downstream protective devices.

Motor feeder long-time overcurrent devices are set at 145% to 150% motor full load current for motors with service factor (SF) = 1.15, and 130% to 135% full load current for motors with SF = 1.0. The instantaneous trip is set greater than or equal to 160% motor locked rotor current. The time-delay setting is adjusted for the motor characteristics such that acceleration is permitted, while protecting the motor for a locked rotor condition and thermal overload.

Each Class 1E load center feeder circuit breaker supplying non-Class 1E MCCs is equipped with an instantaneous undervoltage relay, which is set for pickup at 80% and dropout adjustable between 30% and 60% of nominal voltage.

f. 440 V MCC protection

Molded-case circuit breakers provide inverse-time overcurrent and/or instantaneous short-circuit protection for all connected loads. For motor circuits, the molded-case circuit breakers are equipped with an adjustable instantaneous magnetic trip function only. Motor thermal overload protection is provided by the heater element trip unit in each phase of the motor feeder circuit. The molded-case breakers for nonmotor feeder circuits provide thermal inverse-time overcurrent protection and instantaneous short-circuit protection. The thermal overload trip units for safety-related MOVs are bypassed in accordance with Section 8.1.6.1.19.

Thermal overload heater elements for Class 1E 460 V continuous-duty motors are selected taking into account the applicable ambient temperature compensation factor, voltage considerations and -10% manufacturing tolerance. The magnetic instantaneous trip on the molded-case breaker is set at approximately 200% locked rotor current to override the motor locked rotor current and to provide short-circuit protection. However, the final instantaneous trip setting may deviate from these guidelines based on test data obtained by field personnel.

The thermal magnetic breakers for nonmotor feeder circuits are set to have a thermal pickup at approximately 125% full load current and a magnetic instantaneous trip setting in excess of the load inrush current.

8.3.1.1.2.11.1 The information from this section has been relocated to the TRM.

8.3.1.1.2.12 Testing of the Ac System During Power Operation

All Class 1E power system equipment for which the Technical Specifications require periodic testing more frequently than every 24 months is provided with means to perform the required testing during power operation.

8.3.1.1.2.13 Power Systems and Equipment Shared Between Units

Each unit is provided with separate and independent onsite Class 1E ac power systems. The Class 1E power system for each unit consists of four independent Class 1E buses, powered by four independent diesel generators, which provide power to four divisions of Class 1E loads. The RHRSW and the ESW systems are considered common systems because each system supplies two independent cooling water loops which are common to both units. However, even though they are considered common systems, there is redundant equipment for these systems in each unit. The redundant equipment in each unit is powered by independent diesel generators in each unit and has the capacity to supply 100% of the required cooling water per unit. The SGTS, CSCWS and the control room and control structure ventilation systems are common systems, each with two 100% capacity redundant trains with common redundant components in each train powered from an independent diesel generator in Unit 1.

8.3.1.1.3 Standby Power Supply

The standby power supply for each division consists of one diesel generator set complete with accessories and fuel storage and transfer systems. Each diesel generator is connected to only one 4 kV Class 1E bus and is interlocked to prevent parallel operation during LOOP. The four Class 1E buses for each reactor unit are operated as separate buses (split bus system) and are not synchronized. Each diesel generator set is operated independently (from the other sets) and is disconnected from the utility power system, except during tests.

Each unit has four channels of standby power supply and four load divisions. With the exception of the standby power supply requirements for the ESW system, the RHRSW system, the SGTS, the CSCWS and the control room and control structure ventilation systems, which are common systems, the operation of three out of four channels of the standby power supply in each unit is adequate to satisfy minimum Class 1E load demand caused by a LOCA or LOOP sources. Common loads for the ESW and the RHRSW systems are split between Unit 1 and Unit 2 standby power supplies. Common redundant loads for the SGTS, the CSCWS and the control room and control structure ventilation systems are fed from Unit 1 standby power supplies. A detailed discussion of the load demand on each diesel, which includes load characteristics, load sequencing, bus assignments, etc., is covered in Section 8.3.1.1.3.6.

Any combination of three-out-of-four divisions (EDGs) is acceptable for a single failure. However, for ECCS requirements (as stated in paragraph 6.3.1.1.2), an EDG operable configuration of 2 out of 4 is also acceptable.

The diesel generators are capable of supplying power to the loads necessary to shut down and cool down the associated unit safely. The diesel engine is a 12-cylinder, model 38-TD8-1/8 colt. The generator is a single bearing bracket, model TGZDJ Beloit Power Systems/Fairbanks Morse. Each diesel generator is rated at 2850 kW for continuous operation and at 3135 kW for two hours of short-time operation in any 24 hour period and is qualified to a 100 start test. The diesel generators are selected so that their ratings satisfy the requirements of Regulatory Guide 1.9, as discussed in Section 8.1.6.1.2. In addition, the diesel generators are capable of operating for extended periods of time at either low load or unloaded in the case of a LOCA occurring with the availability of offsite power. For extended periods of low load operation (up to 30% load), the diesel generators are operated at 50% load or greater for at least one hour in every 12 hour period. The manufacturer's recommendations will be followed for loading up to 50% load. This prevents possible accumulation of combustion and lube oil products in the exhaust system. If a LOCA should occur and offsite power is available, the diesel generators in the unit experiencing

the LOCA would start automatically and run unloaded. After the offsite power grid, reactor parameters, and support systems have been stabilized and the LOCA signal reset, the unloaded diesel generators would be manually stopped and returned to standby. Even though the diesel generators would not be expected to run in this condition for an extended period of time, the capability to manually load the diesel generators to remove possible combustion and lube oil products from the exhaust system is provided.

The following sections discuss the functional aspects of the diesel generator.

8.3.1.1.3.1 Starting Initiating Circuits

The diesel generators are started by any of the following conditions:

a. LOOP at the 4 kV Class 1E buses

b. Low reactor water level (associated unit only)

c. High drywell pressure coincident with low reactor pressure (associated unit only)

d. Manual actuation of the start/automatic/stop control switch in the control room when the remote/local selector switch is in the REMOTE position

e. Manual actuation of the start/stop control switch on a local control station when the remote/local selector switch is in the LOCAL position

Two redundant control/starting circuits are provided for each diesel generator. The failure of one circuit does not prevent the respective diesel generator from starting or from operating continuously.

Although started automatically, the diesel generators are not automatically connected to their associated 4 kV Class 1E buses until the generator voltage and frequency are established, the breakers connecting the emergency buses to the offsite sources are tripped, and the bus voltage is zero. The diesel generator is stopped by the operator after he/she determines that continued operation of the diesel is not required. Diesel generator steady state operating frequency is maintained within a band as determined by the Technical Specifications.

8.3.1.1.3.2 Diesel Starting Mechanism and System

The diesel generator start system is described in Section 9.5.6. Each diesel engine is provided with immersion heaters in the engine jacket water and the lube oil system to maintain the engine coolant and lube oil temperature at an operable level for fast and reliable starting of the diesel engines. The standby jacket coolant heater and the standby jacket coolant circulating pump are interlocked for simultaneous operation when the jacket water temperature drops below the preset temperature and the engine is below the preset speed. The standby lube oil heater and the standby lube oil circulating pump are interlocked for simultaneous operation when the oil is below a preset temperature and the engine is below a preset speed. See Sections 9.5.5 and 9.5.7 for further description.

8.3.1.1.3.3 Tripping Devices

Each diesel and/or related generator circuit breaker, while supplying loads during a LOCA, are tripped only for the following conditions:

a. Engine overspeed

b. Diesel generator differential overcurrent

c. 4 kV bus differential overcurrent

When the diesel generator receives an emergency (LOCA) start signal, the LOCA relay is energized and the following trips are bypassed; specifically, the generator circuit breaker trip and/or engine shutdown functions for the following abnormal conditions will be overridden:

a. Generator phase overcurrent

b. Generator ground neutral overcurrent

c. Antimotoring

d. Jacket coolant high temperature

e. Jacket coolant low pressure

f. Lube oil high temperature

g. Lube oil low pressure

h. Deleted

i. 4 kV bus phase overcurrent

j. 4 kV bus ground overcurrent

The bypass circuitry contains the following:

a. A NORMAL/TEST switch is provided at the generator control panel to arm the bypassed engine shutdown functions during simulated LOCA testing.

b. The following abnormal conditions of the bypassed parameters are annunciated in the main control room:

    1. Generator phase overcurrent

    2. Generator ground neutral overcurrent

    3. Diesel generator protective trips not bypassed for LOCA test.

The following abnormal conditions of the bypassed parameters are annunciated at the local control panel and at a common DIESEL GENERATOR TROUBLE alarm in the main control room.

1. Jacket coolant temperature high

2. Jacket coolant pressure low

3. Lube oil temperature high

4. Lube oil pressure low

5. Diesel generator protective trip not bypassed for LOCA test.

c. Following a simulated LOCA test (after the LOCA signal is reset and the engine is stopped), the bypass trip circuit is manually reset by returning to NORMAL at the local panel. This rearms the trips for routine testing and permits them to be bypassed by an actual LOCA start signal.

The annunciator system for these trips provides indication of first out alarm. For example, when one or more abnormal conditions are annunciated at the local control panel, the DIESEL GENERATOR TROUBLE alarm in the main control room notifies the operator of a problem. The local control panel gives indication of which abnormal condition occurred first.

Directional overcurrent (reverse power) protection is provided but is permitted to trip the 4 kV bus breakers only during operation of the diesel generator in parallel with the preferred power supply during manually initiated testing.

To prevent spurious tripping of the engine due to malfunction of an engine protective device, three independent sensors are provided and connected in a two-out-of-three tripping logic for all trip conditions except engine overspeed and protective relays. The overspeed trip device is a simple, highly reliable mechanical device for which two-out-of-three tripping logic is unnecessary.

The starting circuit is equipped with a "fail to start" relay that interrupts the starting of the diesel generator if the diesel generator does not reach 200 rpm within a preset time following a start initiation. The "fail to start" relay causes the "start relay" and the "ready for auto start" relay to become deenergized, and provides a failure to start alarm both locally and in the main control room. Energizing the "fail to start" relay will prevent a subsequent auto or manual start. After correcting the trouble, the "fail to start" relay must be reset at the diesel generator by manually operating the engine shutdown reset located at the diesel generator local control panel.

8.3.1.1.3.4 Breaker Interlocks

Interlocks are provided in the closing and tripping of the 4 kV Class 1E circuit breakers to protect personnel and equipment from the following conditions:

a. Automatic energizing of electric devices or loads during maintenance

b. Automatic closing of the diesel generator breaker to any energized or faulted bus

c. Connecting two sources out of synchronism

8.3.1.1.3.5 Control Permissive

A single key-operated local/remote selector switch at the local control panel is provided for each diesel generator to block automatic start signals when the diesel is out-of-service for maintenance. An annunciator alarm in the control room indicates DIESEL NOT IN AUTO when the switch is not in the REMOTE position.

A control switch in the control room and a local control switch on the local control panel in the diesel generator room are provided to allow manual starting of the diesel when all protective systems are permissive. During periodic diesel generator tests, permissives and interlocks are designed to permit manual synchronizing and loading of the diesel generator with either offsite power source.

8.3.1.1.3.6 Loading of Diesel Generators

The diesel generators are designed to start and attain the required voltage and frequency within 10 seconds. The generator, static exciter, and voltage regulator are designed to permit the unit to accept the load and to accelerate the motors in the sequence and time requirements shown in Table 8.3-1(a). LGS does not use an emergency load sequencer associated with the offsite and onsite power sources. Sequencing of loads on the Class 1E buses is achieved by individual time-delay relays for each load. There are no short-circuits that could render both the onsite and offsite power sources unavailable.

Voltage drop calculations on starting large motors have been made to ensure proper acceleration of the pumps under the required conditions for core cooling after a DBA. Proper control and timing relays are provided so that each load is applied automatically at the proper time and in the starting sequence indicated in Table 8.3-1(a). When the automatic loading sequence of the Class 1E loads is completed, the operator may manually add additional loads as assigned in Table 8.3-3 but these loads should not exceed the available capacity of the diesel generator as limited by fuel consumption. The operator may also trip Class 1E loads if their continued operation is not necessary. Load shedding before diesel generator operation is discussed in Section 8.3.1.1.2.8.

Table 8.3-2 summarizes the maximum loading conditions of any one diesel generator for the situation in which all four diesel generators in each unit are in service and also for the situation in which any one of the eight diesel generators is out-of-service. Tables 8.3-3, 8.3-9 through 8.3-17 provide detailed backup data for the summary of Table 8.3-2. The Table 8.3-2 summary also incorporates both load center transformer losses and a load factor for frequency/voltage uncertainties. Table 8.3-3 shows the assignment of individual loads to the eight emergency buses and the eight diesel generators. Tables 8.3-9 through 8.3-17 indicate how heavily a diesel generator may be loaded during a Unit 1 DBA and a spurious LOCA in Unit 2 followed by an emergency shutdown of Unit 2 for time intervals of 0-10 minutes, 10-60 minutes, and beyond 60 minutes. These tables show that the calculated maximum loading of any one diesel generator for all time periods following a DBA is within the DEMA continuous rating of typical diesel generators that have been qualified and furnished for nuclear standby service. These tables also show that the loading is within the rating of each diesel generator as limited by fuel consumption.

8.3.1.1.3.7 Testing

Diesel generator testing consists of the following:

a. Preoperational test - Each diesel generator is tested at the site before reactor fuel loading, in accordance with the requirements of Chapter 14.

b. Periodic test - The diesel generator surveillance test program will provide for a minimum loading of 25% of rated load.

Equipment will undergo periodic surveillance testing in accordance with LGS Technical Specifications. This testing is implemented as part of the surveillance test program.

The manufacturer technical manuals and preventive maintenance recommendations will be reviewed and appropriate preventive maintenance actions will be incorporated into the preventive maintenance program. Equipment maintenance histories will be kept for the diesel generators, and completed preventive maintenance will be documented in the history. This will aid in the detection of repetitive failures that may be analyzed for corrective action directed at the cause of failure. The preventive maintenance program will be enforced and controlled as delineated in the administrative procedure for this program.

Within the maintenance program procedures, a "Return-to-Normal" section will be included to specify steps necessary to return the diesel generator system to operational status. After completion of "Return-to- Normal" section and required surveillance testing, the unit can be returned to the control room operator in automatic standby mode.

If the diesel generator is running in the test mode and an emergency demand start diesel signal is received, the diesel generator controls will automatically convert the governor from the droop to the isochronous mode and the automatic voltage regulator to the isolated mode. The generator breaker will also be automatically tripped if offsite power is available. Thus, the control of the diesel generator is returned to the automatic control system and loading may proceed as discussed in Sections 8.3.1.1.2.8 and 8.3.1.1.3.6.

Compliance with Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," is discussed in Section 8.1.6.1.20.

8.3.1.1.3.8 Fuel Oil Storage and Transfer System

The diesel generator fuel oil system is described in Section 9.5.4.

8.3.1.1.3.9 Diesel Generator Cooling and Heating Systems

The diesel generator cooling and heating systems are discussed in Section 9.5.5.

8.3.1.1.3.10 Instrumentation and Control Systems for Standby Power Supply

Control hardware is provided in the control room for each diesel generator for the following operations:

a. Starting and stopping

b. Manual synchronization

c. Frequency and voltage adjustment

Control hardware is provided at each of the local control panels for the following operations:

a. Starting and stopping

b. Frequency and voltage adjustment

c. Automatic or manual voltage regulator selection

d. Local or remote control selection (key-operated switch)

Electric metering instruments are provided in the control room for surveillance of the following diesel generator parameters:

a. Voltage

b. Current

c. Frequency

d. Power output (watts)

e. Reactive power output (var)

f. Field voltage

g. Field current

Electrical metering instruments are provided at the local control panel for surveillance of the following diesel generator parameters:

a. Voltage

b. Current

c. Frequency

d. Power output (watt)

e. Reactive power output (var)

f. Energy output (watt-hour)

g. Field voltage

h. Field current

The following abnormal diesel engine and generator conditions are annunciated at the local control panel:

a. Lube oil pressure low

b. Lube oil keep-warm failure

c. Lube oil temperature high

d. Lube oil filter differential pressure high

e. Lube oil strainer differential pressure high

f. Lube oil level low

g. Lube oil or jacket water circulating pump failure

h. Jacket water keep-warm failure

i. Jacket water temperature high

j. Jacket water expansion tank level low

k. Jacket water pressure low

l. Starting air pressure low

m. Fuel oil pressure low

n. Fuel oil strainer differential pressure high

o. Fuel oil filter differential pressure high

p. Fuel oil day tank level low

q. Fuel oil day tank level high

r. Overspeed trip

s. Crankcase pressure high

t. Drip pan/dirty fuel oil tank level high

u. Start failure

v. Not ready for autostart

w. Generator stator temperature high

x. Generator bearing temperature high

y. Generator field ground

z. Generator loss of excitation

aa. Generator overexcitation

bb. Field flash voltage loss

cc. Emergency stop

dd. Dc fuel pump running

ee. Fuel oil transfer strainer differential pressure high

ff. 480 V ac auxiliary power off

gg. 125 V dc control power off

hh. Dc fuel pump power off

ii. Generator overvoltage

jj. Switch not in auto

kk. Fuel oil day tank temperature high

ll. Diesel generator protective trips not bypassed for LOCA test

mm. Intercooler coolant pressure low

nn. Fire/local control diff/ground trip bypass for 1AG501 only
Fire/local control for 2AG501 only

oo. Diesel generator exhaust heat tracing trouble

The following abnormal diesel engine and generator conditions are annunciated at the main control panels:

a. Diesel generator trouble (for alarms (a) through (oo), above)

b. Diesel generator differential/ground lockout

c. Generator overcurrent

d. Generator neutral overcurrent

e. Diesel generator not in auto

f. Diesel generator failed to start

g. Diesel generator fuel oil storage tank high or low

h. Diesel generator not reset

i. Diesel generator protective trip not bypassed for LOCA test

8.3.1.1.3.11 Prototype Qualification Testing

To confirm the ability of the diesel generator to perform as required, in September 1968 the diesel generator manufacturer conducted a series of tests designed to:

a. Simulate the conditions experienced during nuclear plant protection service

b. Record performance under such simulated conditions

c. Allow the use of recorded performance data to design optimized generator and excitation system

d. Demonstrate starting and load acceptance reliability

The details of the motor starting test program are covered in Reference 8.3-1.

The diesel generator manufacturer has extensive operational experience with skidded control systems, including the many nuclear protection units already tested and delivered.

As discussed in Sections 1.8 and 8.1.6.2, LGS is committed to Regulatory Guide 1.9 (Rev. 0) and IEEE 387 (1972). The diesel generators, therefore, are not required to pass a 300 consecutive start qualification test. However, the 12-cylinder model 38-TD8-1/8 Colt diesel engine used at LGS was qualified to a 100 start test conducted in 1968. This model engine has been used in the following plants that have received Operating Licenses:

Robinson 2	Duane Arnold
Prairie Island 1 & 2	North Anna 1 & 2
Vermont Yankee	Millstone 1 & 2
Three Mile Island 1 & 2	Farley 1 & 2
Calvert Cliffs 1 & 2	Arkansas Nuclear One, 2
Crystal River 3	PBAPS 2 & 3
E.I. Hatch 1 & 2	Fermi 2

The LGS diesel generators are nearly identical to the diesel generators used to demonstrate start and load acceptance reliability tests. The differences are that LGS diesel generator units have tubular heat exchangers while the test unit was radiator-cooled, and the LGS units have combustion air that passes from the turbocharger to the blower while the order is reversed for the test unit. These differences are judged to be an improvement of reliability and load acceptance capability. Therefore, the tests are applicable to the LGS diesel generator units.

8.3.1.1.3.12 Conditions Prohibiting Diesel Generator Automatic Emergency Start and Associated Main Control Room Annunciators

Two groups of conditions render the diesel generator incapable of responding to an automatic start signal:

a. Abnormal conditions that may prevent start or cause trip or impede sustained operation

b. Control switch(es) in incorrect positions

The following is a tabulation of such conditions for both of these groups:

a. Abnormal Conditions

1. Engine overspeed
2. Generator differential overcurrent
3. 4 kV bus differential overcurrent
4. Generator antimotoring relay operation
5. Generator phase overcurrent
6. Generator neutral overcurrent
7. Lube oil low pressure
8. Lube oil high temperature
9. Jacket coolant low pressure
10. Jacket coolant high temperature
11. Failure to start relay operation
12. Crankcase high pressure
13. Diesel cell fire protection system activated(1)
14. Loss of 125 V dc control voltage to diesel control panel
15. Loss of 125 V dc to field flashing contacts
16. Loss of 125 V dc control voltage to 4 kV bus breakers and/or diesel generator breaker

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(1) Fire protection system actuation will not prevent an automatic start of the diesel generator, but sustained operation cannot be guaranteed.

17. 4 kV bus breakers and/or diesel generator breaker racked out
18. ESW valves closed

19. Starting air pressure low

20. Nonsafeguard 4 kV loads on 4 kV bus with loss of breaker trip voltage

b. Control Switch Incorrect Positions

21. Remote/local selector switch in LOCAL

22. Exciter shutdown reset switch in SHUTDOWN

23. Engine shutdown reset switch not RESET

24. Emergency stop switch in STOP

25. Generator 4 kV breaker control switch in PULL-TO-LOCK

26. Diesel control switch in PULL-TO-LOCK

27. Diesel start logic bypass switches (two of two per diesel) in BYPASS

The following annunciator legends are provided in the control room for diesel generator alarms for each diesel generator:

1. DG breaker trip

2. DG differential/ground lockout

3. Diesel failed to start

4. Diesel not in AUTO

5. Diesel running

6. DG breaker autoclose

7. DG not RESET

8. DG trouble

9. Standby ac power system out-of-service

10. Generator neutral overcurrent

11. DG protection trip not bypass for LOCA test

12. Generator overcurrent

13. Fire protection alarm panel 00C926 Trouble
(common for all diesel generators)

For each of the conditions listed above (conditions 1-26), the following annunciators are received in the control room:

Condition	Alarms
1	1, 8
2	1, 2
3	Bus Diff/Overcurrent Lockout
4	1
5	1, 12
6	1, 10
7	1, 8
8	1, 8
9	1, 8
10	1, 8
11	3, 8
12	8
13	13
14	8
15	8
16	9
17	9
18	9
19	8
20	9
21	4, 7, 8, 9
22	4, 7, 8, 9
23	7, 9
24	7, 8, 9
25	9
26	4
27	8

Each condition that brings up the system out-of-service alarm (#9) lights an indicating light on the system vertical board in the control room to allow the operator to distinguish what condition has caused the alarm.

The following control room annunciators that were listed above are also triggered by the indicated conditions that were not listed above:

Annunciator	Conditions
DG Trouble	• All conditions that alarm at the local diesel annunciator panel. These conditions are listed in Section 8.3.1.1.3.10.
Standby AC Power System Out-of-Service	• Bus undervoltage relays in test/loss of voltage

	• Safeguard load center breaker not connected/loss of control voltage • Out-of-service alarm manually initiated
Diesel Not In Auto	• Any of the following control switches are not in AUTO: - Jacket coolant heater - Coolant circulating pump - Lube oil heater - Lube oil circulating pump - Generator space heater - Dc auxiliary fuel oil pump

There are no conditions that render the diesel generator incapable of starting that are not alarmed in the control room.

8.3.1.1.3.13 The material in this Section has been rewritten and relocated to Section 13.2.1.7.

8.3.1.1.4 Electrical Equipment Layout

Class 1E switchgear, load centers, MCCs, and distribution panels of redundant channels are in separate rooms or are spatially separated by a predetermined safety distance or barrier. They are located in the reactor enclosure, the control enclosure, or the spray pond pumphouse.

Standby diesel generators, related Class 1E MCC's, and associated equipment are in separate rooms of the seismic Category I diesel generator enclosure. Each room is provided with a separate ventilation system.

The diesel generators do not generate harmful torsional vibrations when operating at any speed from 0% to 115% of rated speed. The engine gauge panel is located on the engine generator skid; however, it is mounted in a cradle on isolation springs. Colt (the manufacturer) has successfully used this method of mounting engine gauge boards for several years. Further, items critical to the continued operation of the unit are not mounted in the gauge panel. The annunciator and other sensitive items are located in freestanding electrical control panels. The control panel is physically separated from the diesel generator.

The following electrical equipment however, is located on the diesel generator skid:

a. Generator terminal box containing connections from the diesel generator to the local control panel.

b. Generator neutral box containing the connectors from the generator neutral grounding resistor.

c. Motor starter and heater control panel - All pump motors have automatically controlled magnetic starters, and the keep-warm heaters have automatically controlled contactors. The starter and contactors for the following motors and heaters are located in the starter panel at the generator end of the skid:

1. Jacket coolant heater

2. Jacket coolant circulating pump

3. Lube oil heater

4. Lube oil circulating pump

5. Generator space heater

6. Dc auxiliary fuel oil pump

d. Circuit breaker panel board - The following ac equipment on the skid is protected by circuit breakers that are located in the circuit breaker panel at the generator end of the skid:

1. Jacket coolant heater

2. Jacket coolant circulating pump

3. Lube oil heater

4. Lube oil circulating pump

5. Prelube pump

6. Generator space heater

e. Engine gauge panel - The following instruments are mounted in the engine gauge panel at the turbocharger end of the skid:

Instrument	Monitoring Function
6 Duplex Pressure Gauges	• Jacket water pump discharge pressure duplexed with air cooler coolant heat exchanger outlet pressure. • Fuel oil pressure upstream and downstream of the line filter in the discharge piping of the engine-driven fuel oil pump. • Fuel oil pressure upstream and downstream of the line filter in the discharge piping of the motor-driven fuel oil pump. • Engine inlet lube oil pressure duplexed with engine-driven oil pump discharge pressure.

	• Upper engine header pressure duplexed with the turbo-charger oil pressure. • Starting air pressure upstream of both air start valves.
2 Differential Pressure Indicators (mounted on separate adjacent gauge panel)	• Basket strainer differential pressure on the engine-drive fuel oil pump. • Basket strainer differential pressure on the motor-driven fuel oil pump.
1 Simple Pressure Gauge	• Scavenging air blower discharge pressure.
2 U-tube manometers	• Crankcase pressure. • Turbocharger inlet pressure.
3 Duplex temperature gauges	• Engine suction lube oil temperature duplexed with the engine-driven pump discharge lube oil temperature. • Jacket water temperature on both the engine-driven pump suction and the header discharge. • Scavenging air blower discharge temperature duplexed with the air cooler coolant inlet temperature.
1 15-point pyrometer	• Points 1 to 12 measure the individual cylinder exhaust temperatures, points 13 and 14 measure the turbocharger inlet temperatures, and Point 15 measures the combined exhaust temperature.
1 Tachometer	• Provides local indication of engine rpm.
1 Indicating Light	• Verifies that the local alarm circuits are armed.

Equipment associated with these instruments is housed within the engine gauge panel enclosure and is accessed through a fully gasketed dust-tight door.

The entire panel assembly is mounted in a cradle on isolation springs such that vibration-induced loads will not affect the performance of the instrumentation. Also, no items that are critical to the operation of the diesel under emergency conditions are housed within this enclosure.

f. Dc control relay and terminal box - The following relays are found in the relay and terminal box located at the generator end of the skid:

1. Emergency start relays

2. Normal start relays

3. Other control relays

4. Coolant temperature high switch

5. Coolant pressure low switch

6. Lube oil temperature high switch

7. Lube oil pressure low switch

8. Alarm relays

The relay and terminal box is mounted at the generator end of the skid. The box is not mounted on an isolation spring; however, the box is anchored to the skid at its base and supported at the top by two lengths of angle iron.

This is the manufacturer's standard design for mounting this box on the diesel generator skid. This box is supported and mounted to prevent any vibration-induced damage of the relays. The manufacturer has shown by over 20 years of use that this support design adequately protects the internal components in the relay and terminal box from harmful vibration levels.

The seismic qualification of the relays in the relay and terminal box has been addressed in the equipment qualification program, and the information is contained in the dynamic qualification package for the diesel generators. Vibrational aging was not performed on these relays as there is no valid method of performing accelerated aging for vibrational effects and because the vibrational levels which these relays may see have been shown through operating experience as not having any detrimental effects on the operation of these relays.

The licensee contacted several other nuclear stations which employ the same mounting design of the relay and terminal box as LGS. The stations contacted reported that there have been no vibration induced failures of the relays in question. In addition, the failure record at the stations contacted indicates that there have been no problems with the relays installed in the relay and terminal box.

The manufacturer, who is notified if there are any problems with the diesel generator equipment, stated that no vibration induced failures have been reported by any station.

For the reasons listed above, we believe that the relay and terminal box is adequately supported and that the components in this box are proven by experience to be protected against harmful vibration levels.

The above described methods of mounting have been the manufacturer's standard design for over 20 years. Neither the manufacturer nor the applicant, whose PBAPS units have been in service for about 10 years, have reported any vibration-induced failures in any of the components mounted on the diesel generator skid.

8.3.1.1.5 Design Criteria for Class 1E Equipment

The following design criteria are applied to the Class 1E equipment supplied from the onsite ac power system:

a. Motor size - Motor size (horsepower capability) is equal to or greater than the maximum horsepower required by the driven load under normal running, run-out, or discharge valve (or damper) closed condition.

b. Minimum motor accelerating voltage - The electrical system is designed so that the total voltage drop during the start of the last largest motor on the system is less than 25% and 20% of the nominal bus voltage at the 4 kV and 440 V buses, respectively. The Class 1E motors are specified with accelerating capability at 80% nominal voltage at their terminals for 460 V motors and 75% for 4 kV motors.

c. Motor starting torque - The motor starting torque is capable of starting and accelerating the connected load to normal speed within sufficient time to perform its safety function for all expected operating conditions, including the design minimum terminal voltage.

d. Minimum motor torque margin over pump torque through accelerating period - The minimum motor torque margin over pump torque through the accelerating period is determined by using actual pump torque curves and calculated motor torque curves at 75% or 80% terminal voltage. The minimum torque margin (accelerating torque) is such that the pump motor assembly reaches nominal speed in less than 5 seconds. This margin is usually not less than 10% of the pump torque.

e. Motor insulation - Insulation systems are selected on the basis of the ambient conditions to which the insulation is exposed. For Class 1E motors located within the containment, the insulation system is selected to withstand the postulated accident environment.

f. Temperature monitoring devices provided in large horsepower motors - Six RTDs or TCs, two per phase, are provided in the motor stator slots for Class 1E motors, as shown in Drawings E-15 and E-16. In normal operation, the RTDs or TCs at the hottest location (selected by test) monitors the motor temperature and provides an alarm on high temperature. Each bearing has a Type T copper-constant thermocouple bearing temperature device to alarm on high temperature.

g. Interrupting capabilities - The interrupting capabilities of the protective equipment are determined as follows:

    1. Switchgear

Switchgear interrupting capabilities are greater than the maximum short-circuit current available at the point of application. The magnitude of short-circuit currents in medium voltage systems is determined in accordance with ANSI C37.010 (1972). The offsite power system, a single operating diesel generator, and running motor contributions are considered in determining the fault level. Medium voltage power circuit breaker interrupting capability ratings are selected in accordance with ANSI C37.06 (1971).

2. Load centers, MCCs, and distribution panels

Load center, MCC, and distribution panel interrupting capabilities are greater than the maximum short-circuit current available at the point of application. The magnitude of short-circuit currents in low voltage systems is determined in accordance with ANSI C37.13 (1973) and NEMA AB1. Low voltage power circuit breaker interrupting capability ratings are selected in accordance with ANSI C37.16 (1973). Molded-case circuit breaker interrupting capabilities are determined in accordance with NEMA AB1.

h. Electric circuit protection - Electric circuit protection criteria are discussed in Section 8.3.1.1.2.11.

i. Grounding requirements - Equipment and system grounding are designed in accordance with the applicable industry codes and standards.

8.3.1.1.6 Logic and Schematic Diagrams

Sufficient logic and schematic diagrams are provided herein to permit an independent evaluation of compliance with safety criteria (Section 1.7).

8.3.1.1.7 Cable Derating and Cable Tray Fill

Cables are sized and cable trays are filled in accordance with the applicable codes and standards. The cables are properly derated for specific application in the location where they are installed.

a. Cable derating

The power and control cable insulation is designed for a conductor temperature of 90°C. The allowable current carrying capacity of the cable is based on not exceeding the insulation design temperature while the surrounding air is at an ambient temperature of 65°C for the primary containment and 40°C to 49°C for all other areas. The design operating conditions of all Class 1E cables are discussed in Section 3.11.

The power cable ampacities are established in accordance with ICEA (also known as IPCEA) publications P-53-426, P-54-440, and P-46-426. They are derated based on the type of installation, the conductor and ambient temperatures, the number of cables in a raceway, and the grouping of the raceways. The method of calculating these derating factors is determined from the ICEA publications and other applicable standards. For unique raceway configurations where the use of the applicable standard results in very conservative ampacity values, cables may be derated using

a heat transfer model which considers load diversity among the cables installed in the raceway.

For control circuits, which usually carry currents of less than 10 amperes, minimum #14 AWG conductors are generally used.

Instrumentation cable insulation is also designed for a conductor temperature of 90°C. The operating currents of these cables are low (usually mA or mV) and do not cause the design temperature to be exceeded at maximum design ambient temperature.

b. Cable tray fill

Section 8.1.6.1.14.b.1(c) gives cable tray fill criteria. The total weight of tray and cable does not exceed 36 pounds per linear foot for Unit 1 and does not exceed 45 pounds per linear foot for Unit 2.

Conduit fill is in compliance with tables I and II, chapter 9, National Electrical Code (1975).

c. Cable description

Power cables, control cables, and instrumentation cables are defined as follows:

1. Power cables

Power cables are those cables that provide electrical energy for motive power or heating to 13.2 kV ac, 4 kV ac, 2.3 kV ac, 440 V ac, 115 V ac, 240 V dc, and 120 V dc loads. For loads with voltage levels higher than 440 V ac, cables with 15 kV insulation are used. For loads with voltage levels at 440 V ac or lower, including dc loads, cables with 600 V insulation are used.

2. Control cables

Control cables are generally the cables for 120 V ac, 250 V dc, and 125 V dc, circuits between components responsible for the automatic or manual initiation of auxiliary electrical functions and the electrical indication of the state of auxiliary components. Control cables are rated 600 V insulation class.

3. Instrumentation cables

Instrumentation cables are those cables conducting low level instrumentation and control signals. These signals can be analog or digital. Typically, these cables carry signals from thermocouples, resistance temperature detectors, transducers, neutron monitors, etc.

8.3.1.1.8 Fire Barriers and Separation Between Redundant Trays

Electrical equipment and cabling is arranged to eliminate the propagation of an electrical fault from one separation group to another and to prevent the propagation of an exposure fire from affecting at least one safe shutdown group. Physical separation of cabling systems for compliance with Regulatory Guide 1.75 is discussed in Section 8.1.6.1.14.

Physical separation of cabling systems for compliance with 10CFR50, Appendix R, is discussed in Appendix 9A.

8.3.1.2 Analysis

8.3.1.2.1 General Design Criteria and Regulatory Guide Compliance

The following paragraphs analyze compliance with GDC 2, GDC 4, GDC 5, GDC 17, GDC 18, and GDC 50. All regulatory guides are discussed in Section 8.1.6.

8.3.1.2.1.1 GDC 2 - Design Bases for Protection Against Natural Phenomena

The requirements of the criteria are met, in that all components of the Class 1E onsite ac power system are housed in seismic Category I structures designed to protect them from natural phenomena. These components have been qualified to the appropriate seismic, hydrodynamic, and environmental conditions as described in Chapter 3.

8.3.1.2.1.2 GDC 4 - Environmental and Dynamic Effects Design Bases

The requirements of the criteria are met, in that all components of the Class 1E onsite ac power system are housed in seismic Category I structures designed to protect them from natural phenomena. These components have been qualified to the appropriate seismic, hydrodynamic, and environmental conditions as described in Chapter 3.

8.3.1.2.1.3 GDC 5 - Sharing of Structures, Systems, and Components

This criterion is met, in that there are no Class 1E components of the onsite ac power system that are shared between Units 1 and 2. There are common Class 1E loads that are shared by Unit 1 and Unit 2. These common loads are the RHRSW and ESW systems, for which the onsite ac power system from each unit supplies approximately half of the common equipment in each system; and common components of the SGTS, the CSCWS and the control room and control structure ventilation systems, which are supplied from the Unit 1 onsite ac power system.

8.3.1.2.1.4 GDC 17 - Electric Power Systems

An onsite electric power system is provided to permit the functioning of structures, systems, and components important to safety. With total loss of offsite power, the onsite power system provides sufficient capacity and capability to ensure that:

a. Specified acceptable fuel design limits and design conditions of the RCPB are not exceeded as a result of anticipated operational occurrences.

b. The core is cooled and containment integrity and other vital functions are maintained if there are postulated accidents.

Section 3.2 contains a list of structures, systems, and components important to safety. Tables 8.3-3 and 8.3-19 through 8.3-26 show that each of these loads important to safety is supplied from the onsite electric power supplies.

The onsite electric power system includes four load divisions per unit. With the exception of the ESW system, the RHRSW system, the SGTS, the CSCWS and the control room and control structure ventilation systems, which are common systems, the load divisions on each unit are redundant in that three load divisions are capable of ensuring (a) and (b) above. Common loads for the ESW and the RHRSW systems are split between the Unit 1 and Unit 2 onsite electric power systems. Common redundant loads for the SGTS, the CSCWS and the control room and control structure ventilation systems are included in the Unit 1 onsite electric power system. Sufficient independence is provided between redundant load divisions to ensure that postulated single failures affect only a single load division and are limited to the extent of total loss of that load division. The redundant load divisions remain intact to provide for the measures specified in (a) and (b) above.

During total LOOP, the Class 1E system is automatically isolated from the offsite power system and non-Class 1E onsite ac system.

In addition, each load division of the Class 1E power system is automatically isolated from the redundant load divisions. The combination of these factors in the design minimizes the probability of losing electric power from the onsite power supplies as a result of the loss of power from the transmission system or any disturbances of the non-Class 1E ac system.

The turbine-generator is automatically isolated from the switchyard following a turbine or reactor trip. Therefore, its loss does not affect the ability of either the transmission network or the onsite power supplies to provide power to the Class 1E system. Transmission system stability studies indicate that the trip of the most critical fully loaded generating unit does not impair the ability of the system to supply plant station service. Further discussion is provided in Section 8.2.2.

8.3.1.2.1.5 GDC 18 - Inspection and Testing of Electric Power Systems

The Class 1E system is designed to permit:

a. During equipment shutdown, periodic inspection and testing of wiring, insulation, connections, and relays to assess the continuity of the systems and the condition of components.

b. During normal plant operation, periodic testing of the operability and functional performance of onsite power supplies, circuit breakers, and associated control circuits, relays, and buses.

c. During plant shutdown, testing of the operability of the Class 1E system as a whole. Under conditions as close to design as practicable, the full operational sequence that brings the system into operation, including operation of signals of the ESF actuation system and the transfer of power between the offsite and the onsite power system, is tested.

A review of the electrical control circuitry associated with the safety systems reveals that an accident signal will override a test mode condition with the exception of the following:

a. Parts of the system that are bypassed or deliberately rendered inoperable to perform corrective maintenance or testing. For this case, only one redundant channel is bypassed at a time, and the system BYPASS/INOPERABLE status is alarmed in the control room. The redundant channels that remain in service are sufficient to ensure the initiation and completion of the required safety function.

b. The control system design of the HPCI and RCIC systems provides automatic alignment from test to operating mode if system operation is required except for the following:

1. The AUTO/MANUAL station is in manual on the flow controller. This feature is required for operator flexibility during system operation.

2. Steam inboard/outboard isolation valves; closure of either or both of these valves requires operator action to properly sequence their opening. An alarm sounds when either of these valves leaves the fully open position.

8.3.1.2.1.6 GDC 50 - Containment Design Basis

This criterion, as it relates to the design of circuits using containment electrical penetration assemblies, is met as discussed in Section 8.1.6.1.12.

8.3.1.2.2 Class 1E Equipment Exposed to Hostile Environment

The detailed information on all Class 1E equipment that must operate in a hostile environment during and/or subsequent to an accident is furnished in Section 3.11.

8.3.1.2.3 Loss of Instrumentation and Control Power System Bus

The Class 1E and non-Class 1E distribution panels which supply power to safety and non-safety related control systems and instrumentation which can be used to achieve cold shutdown have been reviewed. The identification of these systems and instruments was performed using the EOPs. The panels which supply the instruments and control systems identified are listed in Table 8.3-27.

There are ten Class 1E instrument ac panels per unit, two for each of the four Class 1E divisions plus two panels per unit for spray pond controls. These panels are fed ultimately from the safeguard 4 kV buses which also feed the 4 kV and 480 V loads associated with each Class 1E division of equipment. Because LGS is designed to be in compliance with the intent of Regulatory Guide 1.47, the loss of voltage to a 4 KV bus, 480 V safeguard load center and/or a safeguard 480 V MCC would result in several system level annunciator alarms being received in the control room. Undervoltage relays monitor control voltage availability to all Class 1E loads including pumps, fans and valves.

Upon sensing a loss of voltage to these components, an annunciator will indicate that the corresponding division of the appropriate safety system(s) is out of service. The following systems have OUT-OF-SERVICE (or TROUBLE) annunciators in the control room on loss of power:

RHR	Standby ac Power	Control Enclosure HVAC
Core Spray	PCRVICS	Reactor Enclosure
RCIC	ADS	Recirculation HVAC
HPCI	RPS	

ESW	REIS
	SGTS

When a system OUT OF SERVICE annunciator is initiated, a yellow status indicating light on the corresponding system vertical board will light to identify the cause of the out-of-service condition. Table 8.3-28 lists the status lights which alarm upon an undervoltage condition.

For the major power distribution buses, the alarms listed in Table 8.3-28, section II, annunciate in the control room to indicate an undervoltage condition.

In addition to the system level OUT-OF-SERVICE annunciators, the annunciators in section III of Table 8.3-28 alarm on loss of voltage to specific control and instrument loops that can be used in safe shutdown on the unit.

As shown in Table 8.3-29, at least one alarm is received in the control room when power is lost to the panels listed in Table 8.3-27. Not all of the alarms received for an undervoltage on these panels are shown. Additional secondary alarms may be received.

For those panels which are listed as having direct indication of loss of power, an undervoltage relay at the panel brings up an annunciator which specifically states that an undervoltage condition exists on the panel. For those panels which are shown as having indirect indications, the operator will be able to recognize that a particular panel has lost power from the description on his alarm response cards which list the possible causes of the alarm. Alarm response cards for the alarms listed in Table 8.3-29 for the panels shown as having indirect indication will note that panel loss of power is a possible cause of the alarm.

The control systems used to achieve a hot shutdown are designed to perform their intended function with a single active failure. As a result, the plant can be placed in a hot shutdown condition with the loss of any single power source. The plant can also be placed in a cold shutdown condition with any single power failure because two independent flow paths can be used. One utilizes the shutdown cooling mode of the RHR system. An alternate method of achieving a cold shutdown has been devised using the ADS valves, and the RHR system aligned with suction from the suppression pool and pump discharge through a RHR heat exchanger to the reactor via an LPCI line.

The instruments which provide information to the operator to help achieve a cold shutdown have been identified through a review of the EOPs, and are listed in Table 8.3-30. An analysis has been completed to determine if, for loss of power to the instrument, there is another instrument available that is fed from an independent bus which monitors the same parameter, or if an alternate method is available for determining the needed parameter. Along with the desired instruments, Table 8.3-30 lists the bus from which they are fed as well as the results of the loss of power evaluation.

8.3.1.3 Physical Identification of Safety-Related Equipment

Each circuit and raceway is given a unique alphanumeric identification, which distinguishes a circuit or raceway related to a particular voltage, function, or channel. In addition, channel identification for Class 1E cables and raceways is designated by a color scheme. One alpha character and the related color code are assigned to a load division on the basis of the following criteria:

a. Engineered safeguard channel A (blue) - Class 1E instrumentation, controls, and power cables, raceways, and equipment related to Division I loads

b. Engineered safeguard channel B (green) - Class 1E instrumentation, controls, and power cables, raceways, and equipment related to Division II loads

c. Engineered safeguard channel C (red) - Class 1E instrumentation, controls, and power cables, raceways, and equipment related to Division III loads

d. Engineered safeguard channel D (light brown) - Class 1E instrumentation, controls, and power cables, raceways, and equipment related to Division IV loads

e. Non-Class 1E - Non-Class 1E instrumentation, controls, and power cables, raceways, and related equipment

f. Separation group W - (blue/yellow) - RPS and NSSS instrumentation, control, and power cables, raceways, and equipment associated with Division A1 loads

g. Separation group X - (green/yellow) - RPS and NSSS instrumentation, control, and power cables, raceways, and equipment associated with Division B1 loads

h. Separation group Y - (red/yellow) - RPS and NSSS instrumentation, control, and power cables, raceways, and equipment associated with Division A2 loads

i. Separation group Z - (light brown/yellow) - RPS and NSSS instrumentation, control, and power cables, raceways, and equipment associated with Division B2 loads

The raceways are marked in a distinct, permanent manner at intervals that do not exceed 15 feet. The cables in these raceways are marked in a sufficiently durable manner and at intervals that do not exceed 5 feet throughout the entire cable length, except for portions of cable enclosed in conduit.

All Class 1E equipment will be labeled in a manner which identifies the equipment as class 1E, and distinguishes Unit 1 Class 1E equipment from Unit 2 class 1E equipment.

Design drawings provide identification of Class 1E equipment by showing the scheme or equipment number that contains the division identifier.

8.3.1.4 Independence of Redundant Systems

Section 8.1.6.1.14 contains the description of the criteria and their bases that establish the minimum requirements for the independence of redundant Class 1E electrical systems through physical arrangement and separation.

This section discusses the criteria and bases for the raceway and cable routing systems for preserving the independence of the redundant Class 1E power systems.

8.3.1.4.1 Raceway and Cable Routing

Cable trays and gutters are designated to route the following types of cable functions:

a. Both ac and dc power and control circuits below 600 V, including current and potential circuits for metering and relaying

b. Low level signal and instrumentation circuits

A raceway designated for one type of cable function contains cables of that function only. Wherever possible, trays are arranged so that power and control trays are at the top and instrumentation and low level signal trays on the bottom.

Exceptions to this separation requirement may be made in accordance with Specification E-1412.

4 kV Class 1E safety-related cables are routed in conduit only, as are all non-Class 1E cables above 600 V.

Cables corresponding to each channel separation group, as defined in Section 8.3.1.3, are run in separate conduits, cable trays, ducts, and penetrations.

8.3.1.4.2 Administrative Responsibilities and Controls for Ensuring Separation Criteria

The separation group identification described in Section 8.3.1.3 facilitates and ensures the maintenance of separation in the routing of cables and the connection of control boards and panels. At the time of the cable routing assignment, during design, the persons responsible for cable and raceway scheduling ensure that the separation group designation on the cable or raceway to be routed is compatible with a single-line diagram channel designation and other cables or raceways previously routed. Extensive use of computer facilities assists in ensuring separation correctness. Each cable and raceway is identified in the computer program, and the identification includes the applicable separation group designation. Auxiliary programs are made available specifically to ensure that cables of a particular separation group are routed through the appropriate raceways. The routing is also confirmed by quality control personnel during installation, to be consistent with the design document. Color identification of equipment and cabling (Section 8.3.1.3) assists field personnel in this effort.

8.3.2 DC POWER SYSTEMS

8.3.2.1 Description

Completely independent Class 1E and non-Class 1E dc power systems are provided for each unit. Except for the common systems described below, there are no common or shared dc power systems. The DC system for Unit 1 is shown in drawing E-33. The DC system for Unit 2 is shown in drawing E-34.

The RHRSW and the ESW system are considered common systems because each system supplies two independent cooling water loops which are common to both units. However, even though they are considered common systems, there is redundant equipment in each unit. For the redundant equipment in each unit, which has the capacity to supply 100% of the required cooling water per unit, the dc power is supplied by the Class 1E dc power systems in each unit. For the SGTS, CSCWS and the control room and control structure ventilation systems, which are common systems, each with two 100% redundant trains, the dc control systems, where applicable, and the isolation logic for the common redundant components in each train are supplied by the Class 1E dc power system in Unit 1.

There are four independent, four division Class 1E dc systems for each unit; two 125/250 V three-wire systems for Division I and II and two 125 V two-wire systems for Divisions III and IV. In

addition, each unit has a 250 V non-Class 1E dc system, and a 125/250 V non-Class 1E dc system, which are separate and independent from the Class 1E dc systems.

8.3.2.1.1 Class 1E Dc Power System

Each 125/250 V system is comprised of two 125 V batteries, each with its own charger, a fuse box for protection of each of the several 125 V power distribution circuits supplying 125/250 V MCCs (one for Division I and two for Division II), and three 125 V power distribution panels. There is a group of battery carts which can be connected to bypass defective battery cells in any one of the 125/250 V systems.

Each 125 V system is comprised of one 125 V battery with its own charger and a fuse box for protection of each of the several 125 V power distribution circuits supplying three 125 V power distribution panels. There is one battery cart which can be connected to bypass defective battery cells in any one of the 125 V systems.

The Class 1E dc power system and its components are located in seismic Category I structures that provide protection from the effects of tornadoes, tornado missiles, turbine missiles, and external floods. This system and its components are designated Class 1E for procurement and quality assurance purposes and have been qualified for seismic and hydrodynamic loads as well as environmental conditions that they may experience during normal operation and postulated accidents.

8.3.2.1.1.1 Class 1E Dc System Equipment Rating

a. 125 V dc Systems

Battery	60 lead-calcium cells, 250 amp-hr
Battery Cart	lead-calcium cells, 250 amp-hr
Charger	ac input - 480 V, 3ϕ, 60 Hz; dc output - 75 A continuous rating
Fuse box	
Bus	600 A continuous rating, 40,000 A short-circuit bracing
Fuse	10,000 A interrupting rating
Distribution panels	
Panel 1	
Main bus	200 A continuous rating, 40,000 A short-circuit bracing
Fuses	13,000 A interrupting rating
Panels 2 and 3	
Main bus	100 A continuous rating, 40,000 A short-circuit bracing

	Fuses	13,000 A interrupting capability
b.	125/250 V dc System	
	Battery	120 lead - calcium cells, 1500 amp-hr
	Battery Cart	lead - calcium cells, 1500 amp-hr
	Chargers	ac input - 480 V, 3ϕ, 60 Hz dc output - 300 A continuous
	Fuse box	
	Bus	2000 A continuous rating, 40,000 A short-circuit bracing
	Fuse	20,000 A interrupting rating
	Motor control centers	
	Main bus (horizontal)	600 A continuous rating 22,000 A short-circuit bracing
	Vertical bus	300 A continuous rating, 22,000 A short-circuit bracing
	Fuses	20,000 A minimum interrupting
	Distribution panels	
	Panel 1	
	Main bus	200 A continuous rating, 40,000 A short-circuit bracing
	Fuse	13,000 A interrupting rating
	Panels 2 and 3	
	Main bus	100 A continuous rating, 40,000 A short-circuit bracing
	Fuse	13,000 A interrupting capability

8.3.2.1.1.2 Class 1E Batteries

The 125/250 V battery consists of two sets of 60 shock-absorbent, clear plastic cells of the lead-calcium type. The 125/250 V battery is rated 1500 ampere-hours.

The 125/250 V battery carts consist of a set of shock absorbent, clear plastic cells of the lead-calcium type. The cells on the 125/250 V battery carts are rated 1500 ampere-hours.

The 125 V battery consists of a set of 60 shock-absorbent, clear plastic cells of the lead-calcium type. The 125 V battery is rated 250 ampere-hours.

The 125 V battery cart consist of a set of shock absorbent, clear plastic cells of the lead-calcium type. The cells on the 125 V battery cart is rated 250 ampere-hours.

Each Class 1E battery bank is sized to have sufficient capacity without its charger to independently supply the large break LOOP/LOCA load profile for 4 hours. During small break LOOP/LOCA and transients, the battery is designed to supplement the charger when ac is not available or when loads exceed the chargers capability. The capability of the dc and ac power systems to provide sufficient capacity to manage these events, which have undefined loading profiles, is bound by the large break LOOP/LOCA load profile tables and the capability of the battery chargers. Other design basis events (Fire - Safe Shutdown and SBO) require a battery to support specific ECCS equipment without the charger (e.g. for SBO, the analyses assume battery chargers are available one hour into the event). The various batteries are shown to be acceptable by analysis for the duration required by the event.

The battery chargers provide an equalizing voltage that is adjustable between 130 V dc and 145 V dc. The battery manufacturer recommended an equalizing voltage for the batteries between 139.8 V and 142.8 V for the 125 V dc system and between 279.6 V and 285.6 V for the 250 V dc system. The lead calcium batteries used at LGS are anticipated to require equalization on average only 15 days (4%) per year, during their operating life. Analysis has shown that the impact on connected components is an aging issue and that the change in expected life of these components due to battery equalization is considered negligible.

The rated (manufacturer's) battery capacity is 25% greater than required. In accordance with IEEE 450 (1995), "Battery Replacement Criteria," this margin allows replacement of the battery to be made when its capacity has decreased to 80% of its rated capacity (100% of design load).

All Class 1E 125V dc equipment which is required to operate under the design basis conditions is rated and qualified to operate at the voltage it will see during the battery duty cycle with the battery at the end of its life. The "end of its life" is defined as the battery capacity equal to 80% of its rated capacity. A system voltage analysis performed for circuits powered by Class 1E 125V dc distribution panels shows that the required Class 1E 125V dc components will have adequate voltage to operate under LOCA/LOOP, Station Blackout and fire safe shutdown conditions when the battery is required to supply the load. This analysis used an analytical voltage at the distribution panels derived from worst case conditions which was lower than that predicted by the Class 1E battery calculation.

Another Calculation for Class 1E 250V dc MCC's and associated circuits provided the maximum control and power cable lengths. This calculation used an analytical voltage level which is lower than that predicted by the Class 1E battery sizing calculation.

8.3.2.1.1.3 Class 1E Battery Chargers

The chargers are full wave, silicon-controlled rectifiers. The housings are free standing, NEMA Type I, and are ventilated. The chargers are suitable for float charging a lead-calcium battery. The chargers operate from a 440 V, 3-phase, 60 Hz supply. The chargers are supplied from separate 440 V MCCs. Each of these motor control centers is connected to an independent Class 1E ac bus. The chargers are in compliance with all applicable NEMA and ANSI standards.

The battery chargers are sized using the formula (1) in IEEE 946-1992 Section 6.2. The terms in this equation are as follows:

1) The continuous dc load is the expected load on the DC system at the end of the DBA duty cycle. Operator actions to manage the DC system load are acceptable. The loads in the DBA duty cycle are larger than the normal operating loads.

2) Ampere Hours (AH) is computed as the Ampere Hours removed by the DBA duty cycle. The design minimum charge state is the remaining battery charge after the DBA duty cycle. The Fully Charged state is approximately 98% charged, the state at which the charging current stabilizes.

The formula provides an estimate of recharge time. Two variables are not accounted for in the formula, electrolyte temperature and the recharge voltage. The cell voltage in the equalize range (>2.30 Vpc) provides assurance that the battery will charge correctly. Operator action is required to establish and to equalize voltage after a DBA duty cycle discharge. The temperature of the room will be maintained above the design minimum temperature during the charging process. The battery is estimated to be 98% charged when three consecutive battery charging current measurements are less than 2 amps for the LCR-21 and 1 amp for the KCR-7 batteries. The battery is sized to perform it's duty cycle at the 98% charged level. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the minimum float voltage established by the battery manufacturer (2.20 Vpc, average, or 132 V at the battery terminals). Cell voltage is not an accurate measure of charge since it is logarithmic to the charging current and plate polarization voltage varies with age. The negative plate polarization voltage increases in aged batteries, decreasing the available polarization voltage on the positive plate. Electrolyte specific gravity does not return to the "full charge" value for several weeks.

3) The approximate recharge time is 16 hours.

The battery chargers are the constant voltage-type, adjustable between 120 V and 145 V, with capability of operating as battery eliminators. The battery eliminator feature is incorporated as a precautionary measure to protect against the effects of inadvertent disconnection of the battery. The battery chargers are designed to function properly and remain stable on the disconnection of the battery. Variation of the charger output voltage has been determined by testing to be less than ±1% with or without the battery connected. The charger will maintain the dc output voltage within ±1%, with a maximum ripple of 2%, for any load from 0% to 100%. There are no planned modes of operation that would require battery disconnection except for periodic battery discharge tests which are performed only during plant shutdown.

Each battery charger output voltage is protected against overvoltage by a high voltage shutdown circuit. The overvoltage protection feature is incorporated to protect equipment from damage due to high voltage. When high voltage occurs, the unit disconnects the auxiliary voltage transformer, which results in charger shutdown. Before the unit is reactivated, it must be reset manually.

The following provisions have been made for the dc system for compliance with Regulatory Guide 1.47:

a. Loss of ac power to the battery charger is annunciated in the control room by the battery charger trouble annunciator.

b. Tripping of the charger dc output breaker is also annunciated as indicated above.

c. Battery voltage and current are monitored by voltmeters and ammeters located in the control room.

d. The voltage level at each dc bus is monitored by an undervoltage relay. Upon loss of dc voltage to the bus, the condition is annunciated in the control room.

The dc power system includes the following monitors and alarms:

a. Battery charger output current is indicated on an ammeter provided on the charger.

b. Battery current is indicated on dual range ammeters provided in the control room.

c. Battery voltage is indicated on voltmeters provided in the control room.

d. Battery charger output voltage is indicated on a voltmeter provided on the charger.

e. A battery high discharge rate will result in an undervoltage on the dc bus which may be caused by a ground fault between the bus and the battery. Both of these conditions are alarmed in the control room; therefore, the addition of the high discharge rate alarm is not required.

f. Dc bus undervoltage is alarmed in the control room by voltage monitoring relays located at each dc distribution bus. Dc bus overvoltage can only result from a failed battery charger. The battery charger trouble annunciator will alarm in the control room on charger low or high dc voltage.

g. A ground on each dc system is annunciated in the control room by a Class 1E ground detector dedicated to that division.

h. The battery fuse integrity is continuously monitored in the control room by ERFDS as the voltage from the battery terminals is input to this computer system and updated at least every 30 seconds. When battery voltage reaches 125 V dc, the power systems status light changes colors on the ERFDS display to direct the operator to the power system subdisplay where the battery voltage value is displayed. Battery voltage will decay to 125 V dc within approximately 8 minutes of loss of the battery charger or removal of the main battery fuses.

i. The tripping of the battery charger output breaker is alarmed in the control room by the battery charger trouble annunciator. Low dc output current initiates this alarm.

j. A battery charger trouble alarm is provided in the control room for each battery charger. This alarm is initiated for the following conditions:

High/low dc voltage

Low dc current

Low ac voltage

A calculation which tabulated the dc system loads based on the design and the load information was prepared and the resulting voltage profiles were determined. The results verified that the dc

distribution bus voltages will remain above the design minimum voltages during the postulated accident or post accident mode of operation.

The stability of the battery charger is not load dependent. The charger will maintain the dc output voltage within ±1%, with a maximum ripple of 2%, for any load from 0% to 100%.

8.3.2.1.1.4 Class 1E Battery Loads

Loads are diversified among different battery systems so that each system serves loads that are identical and redundant, or are different but redundant to plant safety, or are backup equipment to the ac driven equipment.

Where two-channel or four-channel redundancy and separation are required, such as control power for the four diesel generators and the four emergency switchgear assemblies, the loads are divided among the four divisions.

Power required for the larger loads, such as dc motor-driven pumps and valves, is supplied at 250 V from the two 125 V sources of each system, connected in series and distributed through 250 V dc motor control centers.

Power required for most dc control functions, such as that required for the control of the 4 kV circuit breakers and control relays, is supplied at 125 V from the several 125 V sources and distributed through 125 V dc power distribution panels.

The loading and testing of the Class 1E DC system calculations are performed which demonstrate the battery has sufficient capacity, and is tested in accordance with procedures described in IEEE 450 (1975).

8.3.2.1.1.5 Separation and Ventilation

Each Class 1E dc system (battery bank, charger and switchgear) is located in a compartment separate from the other Class 1E dc systems. The battery compartments are ventilated by a system that is designed to preclude the possibility of hydrogen accumulation. Section 9.4 contains a description of the battery compartment ventilation system.

The batteries are separated so that no single hazard could cause the loss of more than one division.

8.3.2.1.1.6 Inspection, Maintenance, and Testing

Testing of the dc power systems is performed before plant operation in accordance with the procedures described in IEEE 450 (1975). A dc voltage verification test is performed and completed during the startup test program prior to exceeding 5% power to verify that individual cell limits are not exceeded during the design discharge test, to demonstrate that the dc loads will function as necessary to assure plant safety at a battery terminal voltage equal to the acceptance criterion that has been established for minimum battery terminal voltage for the discharge load test, and to assure that each battery charger is capable of floating the battery on the bus or recharging the completely discharged battery within 8 hours while supplying the largest combined demands of the various steady-state loads under all plant operating conditions.

The voltage verification test will measure voltage at all Class 1E dc distribution buses and at the Class 1E dc equipment that must be operational when the battery is at minimum terminal voltage.

A confirmatory analysis comparing the test results to calculated dc voltage drop values will also be completed prior to exceeding 5% power.

[NOTE: The above information is for historical purposes only.]

The periodic testing of the battery chargers will verify their current-limiting characteristics.

Service and performance testing as defined in IEEE 450 (1995), Section 6.6, will be performed during refueling outages at intervals controlled by the Surveillance Frequency Control Program. As recommended by IEEE 450, the individual cell voltage readings will be taken between respective posts of like polarity of adjacent cells so that the voltage drop of the intercell connectors is measured. With this method, specific resistance measurements are not required because the resistance is measured by the voltage drop across the cell and connector.

Inservice tests, inspections, and resulting maintenance of the dc power systems, including batteries, chargers, and auxiliary, are specified in Chapter 16.

8.3.2.1.2 Non-Class 1E Dc System

The non-Class 1E dc systems, which are comprised of a 250 V and a 125/250 V dc system, are separate and independent from the Class 1E dc systems. The non-Class 1E and Class 1E dc systems do not share any loads.

8.3.2.1.3 Cable Derating and Cable Tray Fill

A discussion of cable derating and cable tray fill is included in Section 8.3.1.1.7.

8.3.2.1.4 Fire Barriers and Separation Between Redundant Trays

A discussion of fire barriers and separation between redundant trays is included in Section 8.3.1.1.8.

8.3.2.2 Analysis

8.3.2.2.1 Compliance with General Design Criteria, Regulatory Guides, and IEEE Standards

The following paragraphs analyze compliance of the Class 1E dc power systems with GDC 2, GDC 4, GDC 5, GDC 17, GDC 18, and GDC 50; Regulatory Guide 1.6, Regulatory Guide 1.32, Regulatory Guide 1.41, Regulatory Guide 1.81, and Regulatory Guide 1.93; and IEEE 308 and IEEE 450.

8.3.2.2.1.1 GDC 2 - Design Bases for Protection Against Natural Phenomena

The requirements of these criteria are met, in that all components of the Class 1E dc system are housed in seismic Category I structures designed to protect them from natural phenomena. These components have been qualified to the appropriate seismic, hydrodynamic, and environmental conditions as described in Chapter 3.

8.3.2.2.1.2 GDC 4 - Environmental and Dynamic Effects Design Bases

The requirements of these criteria are met, in that all components of the Class 1E dc system are housed in seismic Category I structures designed to protect them from natural phenomena. These components have been qualified to the appropriate seismic, hydrodynamic, and environmental conditions as described in Chapter 3.

8.3.2.2.1.3 GDC 5 - Sharing of Structures, Systems, and Components

With the exception of the common systems described below, this criterion is met for a two plant operation, in that there are no Class 1E components of the dc system that are shared between Units 1 and 2. The RHRSW and the ESW systems are considered common systems because each system supplies two independent cooling water loops which are common to both units. However, even though they are considered common systems, there is redundant equipment for these systems in each unit. For the redundant equipment in each unit, which has the capacity to supply 100% of the required cooling water per unit, the dc control power is supplied by the Class 1E dc systems in each unit. For the SGTS, the CSCWS and the control room and control structure ventilation systems, which are common systems, each with two 100% redundant trains, the dc control systems, where applicable, and the isolation logic for the common redundant components in each train are supplied from the Class 1E dc system in Unit 1.

8.3.2.2.1.4 GDC 17 - Electric Power Systems

Consideration of GDC 17 leads to the inclusion of the following factors in the design of the dc power systems:

a. Separate and independent 125 V and 125/250 V dc systems supply control power for each of the Class 1E ac load divisions.

b. The ac power for the battery chargers in each of these dc systems is supplied from the same ac load division for which the dc system supplies the control power.

c. Four independent Class 1E dc systems are provided to ensure the availability of the dc power system for maintaining the reactor integrity during postulated accidents.

d. Each of the four independent Class 1E dc systems, including batteries, chargers, dc switchgear and distribution equipment, are physically separate and independent.

e. Sufficient capacity, capability, independence, redundancy, and testability are provided in the Class 1E dc systems to ensure the performance of safety functions, assuming that there is a single failure.

8.3.2.2.1.5 GDC 18 - Inspection and Testing of Electric Power Systems

Each of the Class 1E dc systems is designed to permit:

a. Inspection and testing of wiring, insulation, and connections during equipment shutdown to assess the continuity of the system and the condition of its components.

b. Periodic testing of the operability and functional performance of the components of the systems during normal plant operation.

The Class 1E dc systems are periodically inspected and tested to assess the condition of the battery cells, charger, and other components in accordance with Chapter 16. Preoperational testing is discussed in Section 8.3.2.2.1.9 below for assessing compliance with Regulatory Guide 1.41.

8.3.2.2.1.6 GDC 50 - Containment Design Basis

This criterion, as it relates to the design of dc circuits using containment electrical penetration assemblies, is met as discussed in Section 8.1.6.1.12.

8.3.2.2.1.7 Regulatory Guide 1.6 (1971) - Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems (Safety Guide 6)

Separate Class 1E dc systems supply power for each of the four Class 1E load divisions. Loss of any one of the Class 1E dc systems does not prevent the minimum safety function from being performed. The Class 1E chargers are supplied from the same ac load division for which the dc system supplies the control power. Each of the four dc systems, including the battery bank, charger, and distribution system, is independent of each other system and of each non-Class 1E dc system. No provision exists for transferring loads between redundant dc systems. Thus, sufficient independence and redundancy exist to ensure performance of minimum safety functions, assuming that there is a single failure.

8.3.2.2.1.8 Regulatory Guide 1.32 (1977) - Criteria for Safety- Related Electric Power Systems for Nuclear Power Plants

The battery charger capacity for each of the Class 1E dc systems complies with this regulatory guide.

Each Class 1E battery charger has sufficient capacity to supply the largest combined demand of the various steady-state loads and the charging current required to restore the battery from the 1`design minimum charge state to the fully charged state, regardless of the plant status during the time in which these demands occur.

8.3.2.2.1.9 Regulatory Guide 1.41 (1973) - Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignments

To comply with this Regulatory Guide, the Class 1E dc systems are designed in accordance with Regulatory Guide 1.6 and Regulatory Guide 1.32 and are tested as follows:

a. Testing of the dc power system, including an acceptance test of battery capacity, is performed after installation and periodically during unit operation in accordance with the requirements described in Chapters 14 and 16.

b. The charger, battery connections, and charger supply are verified for proper assignment of ac load division.

c. Class 1E dc systems are functionally tested along with the associated ac load division by disconnecting and isolating the other ac load division, its ac power sources, and the associated dc system. Each test includes simulation of an ESF actuation signal, startup of the standby diesel generator and the load division under test, sequencing of loads, and the functional performance of the loads. During these tests, the ability of the dc

system to perform its intended functions, e.g., control of diesel generators and Class 1E ac switchgear, is verified.

d. Testing of each division of the Class 1E dc system is performed to ensure that no interconnections exist with redundant dc divisions. The buses and loads of the dc system under test are monitored to verify the absence of voltage while the remaining redundant divisions remain energized.

8.3.2.2.1.10 Regulatory Guide 1.81 (1975) - Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants

The requirements of the regulatory guide are met. Each generating unit is provided with separate and independent onsite dc electric power systems capable of supplying power to the control systems of the Class 1E loads and loads such as valves and actuators required for attaining a safe and orderly cold shutdown of the unit, assuming that there is a single failure. The RHRSW and the ESW systems are considered common systems because each system supplies two independent cooling water loops which are common to both units. However, even though they are considered common systems there is redundant equipment for these systems in each unit. For the redundant equipment in each unit, which has the capacity to supply 100% of the required cooling water per unit, the control systems are supplied by the onsite dc electric power systems in each unit. For the SGTS, the CSCWS and the control room and control structure ventilation systems, which are common systems, each with two 100% redundant trains, the dc control systems, where applicable, and the isolation logic for the common redundant components in each train are supplied from the onsite dc electric power system in Unit 1.

8.3.2.2.1.11 Regulatory Guide 1.93 (1974) - Availability of Electric Power Sources

Compliance is discussed in Section 8.1.6.

8.3.2.2.1.12 IEEE 308 (1974) - Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations

The Class 1E dc systems provide power to Class 1E loads and for control and switching of Class 1E systems. Physical separation and electrical isolation are provided to prevent the occurrence of common mode failures. The design of the Class 1E dc systems includes the following:

a. The Class 1E dc systems are separated into four channels to provide power to the four redundant load divisions.

b. The safety action by each division of loads is independent of the safety actions provided by their redundant counterparts.

c. Each Class 1E dc system includes power supplies that consist of one battery bank and one or two chargers as required.

d. Each Class 1E distribution circuit is capable of transmitting sufficient energy to start and operate all required loads in that circuit. Distribution circuits to redundant equipment are independent of each other. The distribution system is monitored to the extent that it is shown to be ready to perform its intended function. The dc auxiliary

devices required to operate equipment of a specific ac load division are supplied from the same load division.

e. The status of each protective dc fuse is monitored by an undervoltage relay which provides a system out-of-service alarm in the control room when dc control power is lost to a safety system or any of its components.

Each battery supply is continuously available during normal operations and following the loss of power from the ac system to start and operate all the required loads.

The dc systems are ungrounded; thus, a single ground fault does not cause immediate loss of the faulted system. Ground detection and alarm is provided for each dc system so that ground faults can be readily located and removed.

The Class 1E dc system equipment is protected and isolated by fuses for short circuits. The status of each dc system is monitored by checking for system undervoltage, system grounding, and battery charger trouble (ac power failure, charger failure, or charger output breaker trip).

The batteries are maintained in a fully charged condition and have sufficient stored energy to operate all necessary circuit breakers and provide an adequate amount of energy for all required Class 1E loads for 4 hours after loss of ac power.

Each battery charger has an input ac and output dc circuit breaker for isolation of the charger. Each battery charger is designed to prevent the ac supply from becoming a load on the battery due to a power feedback as the result of the loss of ac power to the chargers.

The battery charger ac supply breaker is periodically opened to verify the load-carrying ability of the battery.

Each Class 1E dc system is designed to meet seismic Category I requirements, as stated in Section 3.10. The batteries, battery chargers, and other components of the dc system are housed in the control enclosure, which is a seismic Category I structure.

Cracking of the Class 1E battery cases due to the battery stress points and their relationship with the battery rack support has been evaluated and will not occur to the LGS batteries based on test data. Cracking of the battery cases did not occur during qualification testing, which included seismic testing of an aged battery mounted in a battery rack. The arrangement used during qualification testing simulated the LGS battery/battery rack installation.

The battery carts are designed to support cells and confine their motion in the same manner as the battery racks. The carts amplify seismic floor motions to a lesser degree than the racks since they are only one battery tier high. Thus, when operating with cart mounted batteries, the same assurance against battery case cracking is provided as with the rack mounted batteries.

The connections between the cart mounted batteries and the rack mounted batteries are by means of flexible jumper cables fitted with clamps which are tightened onto the terminals. This arrangement assures that the connections between the cart mounted batteries and the rack mounted batteries remain intact during postulated dynamic events.

The periodic testing and surveillance requirements for the Class 1E batteries are detailed in Technical Specifications.

8.3.2.2.1.13 IEEE 450 (1995)-IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations

As discussed in Technical Specifications, the recommended practices of IEEE 450 (1995) for maintenance, testing, and replacement batteries are followed for the class 1E batteries with the exception of specific gravity monitoring frequency.

8.3.2.2.2 Physical Identification of Safety-Related Equipment

Physical identification of Class 1E equipment is discussed in Section 8.3.1.3.

8.3.2.2.3 Independence of Redundant Systems

The general considerations for the independence of Class 1E dc power systems are described in Section 8.3.1.4. The physical separation criterion is discussed in Section 8.1.6.1.14.

8.3.3 FIRE PROTECTION FOR CABLE SYSTEMS

The measures employed for the prevention of and protection against fires in electrical cable systems are covered in Sections 9.5.1, 8.3.1.1.7, and 8.3.1.1.8.

8.3.4 REFERENCES

8.3-1 IEEE Conference Paper No. 69CP 177-PWR, "Fast Starting Diesel Generators for Nuclear Plant Protection."

Table 8.3-1(a)

SEQUENCE OF EVENTS IN THE AUTOMATIC
APPLICATION OF EMERGENCY AC LOADS ON LOCA[1]
AND LOOP

EVENT	TIME (sec)
Signal to start diesel	0
Diesel ready to load; start one RHR pump motor	10
Apply power to 440 V auxiliaries and MOVs	13
Start one core spray pump motor	17
Start one ESW pump motor	55
Control room chiller	177
Reactor building recirculation fan	193

(1) This sequence applies to one diesel and its associated loads. The other diesels have a similar sequence and load.

Table 8.3-1(b)

SEQUENCE OF EVENTS IN THE AUTOMATIC
APPLICATION OF EMERGENCY AC LOADS ON LOCA
WITH OFFSITE POWER AVAILABLE[1]

EVENTS	TIME (sec)
Start RHR pumps C & D	0
Apply power to 440 V auxiliaries and MOVs	3.5
Start RHR pumps A & B	5
Start core spray pumps A & C	10
Start core spray pumps B & D	15
Start 4 ESW pumps	55
Control room chillers	167
Reactor buildings recirculation fans	183.5

(1) Diesel is started and remains on standby when offsite power is available.

TABLE 8.3-2 (Page 1 of 2)
SUMMARY OF LOADING
DIESEL GENERATOR AND EMERGENCY BUSES
SAFEGUARD AND SELECTED NON-SAFEGUARD LOADS

TABLE NO.	DESCRIPTION	MAXIMUM LOADING OF ANY ONE DIESEL GENERATOR (kW) 0 - 10 MIN	10 MIN - 1 HOUR	1 HOUR and LONGER
8.3 - 3	Assignment of safeguard and selected non-safeguard loads to diesel generators and emergency buses Both units in operation Unit 1 DBA; Unit 2 spurious LOCA	--	--	--
8.3 - 9	All D/G in service	2482	1999	1999
8.3 - 10	D11 D/G out-of -service	2487	2266	2266
8.3 - 11	D12 D/G out-of-service	2482	2341	2341
8.3 - 12	D13 D/G out-of-service	2482	1999	1999
8.3 - 13	D14 D/G out-of-service	2482	2307	2307
8.3 - 14	D21 D/G out-of-service	2482	2158	2158
8.3 - 15	D22 D/G out-of-service	2482	1982	1932
8.3 - 16	D23 D/G out-of-service	2482	2151	2151
8.3 - 17	D24 D/G out-of-service	2482	1925	1925

The above loadings are based on the minimum required engineered safeguard and selected non-safeguard loads for the following situation:

* Unit 1 DBA with a spurious LOCA in Unit 2 for the 0 -10 minute period following by an emergency shutdown of Unit 2.

TABLE 8.3-2 (Cont'd)

The case for a Unit 2 DBA is not tabulated. Due to the similarity in loading between Unit 1 and Unit 2, it has been determined that, for a Unit 2 DBA with a spurious LOCA and ESD in Unit 1, Unit 2 data on the following tables are conservative for Unit 1 and Unit 1 data are conservative for Unit 2.

All loads in the 0-10 minute period are automatically applied. Beyond 10 minutes, the major loads are manually connected or disconnected.

Nonsafeguard loads are tripped by the LOCA signal and may be manually added after the 0-10 minute period as permitted by the available capacity of the diesel generators (limited by fuel consumption) and as indicated in the table below.

The required minimum operation of ECCS pumps indicated is shown below:

	DESIGN BASIS ACCIDENT			EMERGENCY SHUTDOWN		
	0-10 min	10 min - 1 hr	Beyond 1 hr	0-10 min	10 min - 1 hr	Beyond 1 hr
RHR pumps	3	1	1	0	1	1
CS pumps	2	2	2	0	0	0
RHRSW pumps	0	1	1	0	1	1

Any combination of three-out-of-four divisions (EDGs) is acceptable for a single failure. However, the ECCS requirements (as stated in paragraph 6.3.1.1.2), an EDG operable configuration of two-out-of-four is also acceptable.

TABLE 8.3 – 3

ASSIGNMENT OF SAFEGUARD AND SELECTED NON-SAFEGUARD LOADS
TO DIESEL GENERATORS AND EMERGENCY BUSES

ITEM	LOAD DESCRIPTION	COMMENTS	EQUIP NO.	NUMBER OF OPERATING UNITS			CAPACITY EACH	RATED HP EACH	OPER KW EACH	STARTUP MODE & OPERATING							
										UNIT 1 or UNIT 2 DBA STANDBY				UNIT 1 or UNIT 2 EMERGENCY SHUTDOWN (2) STANDBY			
				UNIT 1	COMMON	UNIT 2				AUTO	AUTO	MAN	MAN	AUTO	AUTO	MAN	MAN
01	RHR PUMP	(9)	P202	4	0	4	1/3	1250	993	4	0	0	0	0	0	3	1
02	CORE SPRAY PUMP		P206	4	0	4	1/2	600	529	4	0	0	0	0	0	0	0
03	RHR SERVICE WATER PUMP	*	P506	0	4	0	F	700	519	0	0	0	2	0	0	0	2
04	ESW PUMP	*	P548	0	4	0	1/2	500	389	4	0	0	0	4	0	0	0
05	125V BATTERY CHARGER		D103	4 & 2	0	4 & 2	1/6	0	25 & 9	6	0	0	0	6	0	0	0
06	DRYWELL COOLER FAN		V212	16	0	16	1/8	30	20	8	8	0	0	8	8	0	0
07	DG ROOM VENT FAN		V512	8	0	8	1/2	20	15	4	4	0	0	4	4	0	0
08	RHR ROOM COOLING UNIT		V210	8	0	8	1/2	20	16	4	4	0	0	4	4	0	0
09	CORE SPRAY ROOM COOLING UNIT		V211	8	0	8	F	10	7 & 8	4	4	0	0	4	4	0	0
10	HPCI ROOM COOLING UNIT		V209	2	0	2	F	15	10	1	1	0	0	1	1	0	0
11	RCIC ROOM COOLING UNIT		V208	2	0	2	F	5	4	1	1	0	0	1	1	0	0
12	INSTRUMENT AC POWER SUPPLY		Y101	4	0	4	1/4	0	11 & 12	4	0	0	0	4	0	0	0
12	INSTRUMENT AC POWER SUPPLY		Y102	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	INSTRUMENT AC POWER SUPPLY		Y103	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	INSTRUMENT AC POWER SUPPLY		Y104	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	DG START AIR COMPRESSOR	o	K513	8	0	8	F	20	7	0	0	4	4	4	4	0	0
14	DG FUEL OIL TRANSFER PUMP		P514	4	0	4	F	1-1/2	1	0	0	0	4	0	0	0	4
15	SGTS HEATER	*	E188	0	2	0	F	0	44	2	0	0	0	2	0	0	0
16	SGTS ROOM UNIT COOLER	*	V140	0	2	0	F	1	1	1	1	0	0	1	1	0	0
17	SGTS ROOM ACCESS UNIT COOLER	*	V141	0	2	0	F	7-1/2	6	1	1	0	0	1	1	0	0
18	SGTS EXHAUST FAN	*	V163	0	2	0	F	40	32	1	0	0	0	1	0	0	0
19	RERS FAN		V213	2	0	2	F	200	151	1	1	0	0	1	1	0	0
20	HVAC DAMPER POWER		Y206	4	0	4	1/4	0	0	4	0	0	0	4	0	0	0
20	HVAC DAMPER POWER		Y207	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	HVAC DAMPER POWER		Y163	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	HVAC DAMPER POWER		Y164	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	CONTROL ROOM CHILLER	*	K112	0	2	0	F	0	329/330	1	1	0	0	1	1	0	0
22	CONTROL ROOM CHILLER WATER PP	*	P162	0	2	0	F	25	16	1	1	0	0	1	1	0	0
23	AUX PNL & COMP RM FAN COIL UNIT	*	V114	0	2	0	F	38.5	24	1	1	0	0	1	1	0	0
24	AUX PNL & COMP RM RETURN AIR UNIT	*	V120	0	2	0	F	20	16	1	1	0	0	1	1	0	0
25	CONTROL ROOM AIR COND UNIT	*	V116	0	2	0	F	40	32	1	1	0	0	1	1	0	0
26	CONTROL ROOM RETURN AIR FAN	*	V121	0	2	0	F	15	12	1	1	0	0	1	1	0	0
27	EMER SWGR & BTRY RM AIR COND UNIT	*	V118	0	2	0	F	15	9	1	1	0	0	1	1	0	0
28	AUX EQUIP & COMP RM AREA HTR	* ++	E193	0	2	0	F	0	52	0	0	0	0	1	1	0	0
29	CONTROL ROOM AREA HEATER	* ++	E192	0	2	0	F	0	40	0	0	0	0	1	1	0	0
30	CONT RM FRESH AIR INTAKE HTR	*	E191	0	2	0	F	0	32	0	0	0	0	0	0	0	0
31	SPRAY POND STATION HTG COIL FAN	*	V543	0	4	0	1/2	10	7	2	2	0	0	2	2	0	0
32	SLCS HEATERS	++	S213	1 & 1	0	1 & 1	F	0	8	1	0	0	1	1	0	0	1
33	CONTAINMENT H2 RECOMBINER		S403	2	0	2	F	0	48	0	0	1	1	0	0	1	1
34	CONT'L RM EMER FRESH AIR SPLY FAN	*	V127	0	2	0	F	10	6	1	1	0	0	1	1	0	0
35	CONTROL ROOM CHILLER OIL PUMP	*	P168	0	2	0	F	1-1/2	1	1	1	0	0	1	1	0	0
36	DG AUXILIARIES	o	G501	4	0	4	F	35KVA	14	4	0	0	0	4	0	0	0
37	DELETED																

TABLE 8.3 – 3 (Cont'd) (PAGE 2 OF 6)

ASSIGNMENT OF SAFEGUARD AND SELECTED NON- SAFEGUARD LOADS
TO DIESEL GENERATORS AND EMERGENCY BUSES

ITEM	LOAD DESCRIPTION	COMMENTS	EQUIP NO.	NUMBER OF OPERATING UNITS			CAPACITY EACH	RATED HP EACH	OPER KW EACH	STARTUP MODE & OPERATING							
										UNIT 1 or UNIT 2 DBA STANDBY				UNIT 1 or UNIT 2 EMERGENCY SHUTDOWN (2) STANDBY			
				UNIT 1	COMMON	UNIT 2				AUTO	AUTO	MAN	MAN	AUTO	AUTO	MAN	MAN
37	DELETED																
38	DELETED																
39	CRD PUMP	o	P158	2	0	2	F	250	133	0	0	0	0	0	0	1	1
40	DELETED																
41	RECW PUMP	++	P210	2	0	2	F	100	68	0	0	1	1	1	1	0	0
42	TECW	o	P103	2	0	2	F	15	11 & 12	0	0	1	1	1	1	1	0
43	INSTRUMENT AC POWER SUPPLY	o	Y105	4	0	4	1/4	0	0	0	0	0	4	4	0	0	0
43	INSTRUMENT AC POWER SUPPLY	o	Y106	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43	INSTRUMENT AC POWER SUPPLY	o	Y201	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43	INSTRUMENT AC POWER SUPPLY	o	Y202	0	0	0	0	0	0	0	0	0	0	0	0	0	0
44	EMERGENCY LIGHTING	o !	MISC	7	6	7	0	0	0	0	0	0	13	0	0	0	13
45	TURBINE GEN BEARING LIFT PUMP	o	P109	9	0	9	1/9	5	36 & 45 (TOTAL)	0	0	0	9	9	0	0	0
46	TURBINE GEN TURNING OIL PP	o	P111	1	0	1	F	40	32	0	0	0	1	1	0	0	0
47	TURBINE GEN TURNING GEAR	o	S103	1	0	1	F	60	48	0	0	0	1	1	0	0	0
48	RFPT GEAR	o	S106	3	0	3	F	1-1/2	1	0	0	0	3	3	0	0	0
49	INSTRUMENT GAS COMPRESSOR	o (12)	K203	2	0	2	F	5	1	0	0	1	1	1	1	0	0
50	INSTRUMENT AIR COMPRESSOR	o	K101	2	0	2	F	100	33	0	0	1	1	1	1	0	0
51	DELETED																
52	OSC XFMR PNLS OOL140 & OOL141	*	X186	0	1	0	0	30	24	0	0	0	1	0	0	0	1
53	TEST ENGINEER'S WORKSHOP	*	X187	0	1	0	0	30	12	0	0	0	1	0	0	0	1
54	NORTH STACK RM ANTENNA SYS XFMR	*	X595	0	1	0	0	15	9	0	0	0	1	0	0	0	1
55	DELETED																
56	CRD REPAIR RM COOLING FAN		V904	0	1	1	0	0	0	0	0	0	0	0	0	0	0
57	125V BATTERY CHARGER	o	D113	2	0	2	1/2	0	96	0	0	0	2	2	0	0	0
58	FIRE ALARM & P/A	* +	1X5	0	0	0	0	0	12	1	0	0	0	1	0	0	0
59	FUEL POOL COOLING WATER PUMP	o	P211	3	0	3	0	50	32	0	0	1	2	0	0	1	2
60	FUEL POOL SVC WTR BSTR PUMP (7)		P212	3	0	3	0	25	19	0	0	0	0	0	0	0	0
61	INSTR. AC PWR SUPPLY (SPRAY POND)	o	Y501	0	4	0	1/4	0	1	0	0	0	0	2	2	0	0
62	SPRAY POND PP STATION HTG COIL	++ *	E701	0	4	0	1/2	0	96	0	0	0	0	2	2	0	0
63	SGTS RM VENT EXHAUST FAN	o *(13)	V131	0	2	0	0	10	7	0	0	1	1	1	1	0	0
64	SECURITY AREAS AIR COND. (11)	o*	V565	0	2	0	0	17-1/2	14	0	0	1	1	0	0	0	1
65	PIPING FILL PUMP		P256	2	0	2	0	5	3	0	0	0	2	0	0	0	0
66	DRYWELL H2O2 ANALYZER		S205	1	0	1	0	1	1	0	0	0	1	0	0	0	1
67	SUPPRESSION POOL H2O2 ANALYZER		S206	1	0	1	0	1	1	0	0	0	1	0	0	0	1
68	CHILLER PUMP-OUT COMPRESSOR	o *	K114	0	2	0	0	2	2	0	0	0	0	0	0	0	0
69	SPRAY POND SUMP PUMP	o *	P578	0	4	0	0	5	2	0	0	4	0	0	4	0	0
70	AUX EG. RM & COMP RM ELEC HUMIDFR	o *	E743	0	2	0	0	0	43	0	0	0	0	1	0	0	0
71	CONT RM ELEC HUMIDIFIER	o *	E744	0	2	0	0	0	29	0	0	0	0	1	0	0	0
72	250V BATTERY CHARGER	o	D123	1	0	1	0	0	9	0	0	0	1	1	0	0	0
73	ALT. POWER SUPPLY TO 10X161 XFMR	o	10X161	1	0	0	0	37-1/2	30	0	0	0	0	0	0	0	0
74	STATIC INVERTER 00-D592 XFMR	o *	00-X592	0	1	0	0	37-1/2	30	0	0	0	0	0	0	0	0
75	TELEPHONE EQUIP POWER XFMR	o *	X503	0	1	0	0	7-1/2	6	0	0	0	1	1	0	0	0
76	RECOMBINER HYDROGEN ANALYZER	o	P947	3	0	3	0	1	1	0	0	0	0	0	0	0	0

TABLE 8.3 – 3 (Cont'd) (PAGE 3 OF 6)

ASSIGNMENT OF SAFEGUARD AND SELECTED NON-SAFEGUARD LOADS
TO DIESEL GENERATORS AND EMERGENCY BUSES

ITEM	LOAD DESCRIPTION	COMMENTS	EQUIP NO.	NUMBER OF OPERATING UNITS			CAPACITY EACH	RATED HP EACH	OPER KW EACH	STARTUP MODE & OPERATING							
										UNIT 1 or UNIT 2 DBA STANDBY				UNIT 1 or UNIT 2 EMERGENCY SHUTDOWN (2) STANDBY			
				UNIT 1	COMMON	UNIT 2				AUTO	AUTO	MAN	MAN	AUTO	AUTO	MAN	MAN
77	DIESEL GENERATOR BRIDGE CRANE	o	H501	4	0	4	0	23	18	0	0	0	0	0	0	0	0
78	440V POWER RECEPTACLES	o	W508	4	0	4	0	60	48	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	o *	H511	0	2	0	0	7/12	0.5	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	o *	H513	0	0	0	0	0	0	0	0	0	0	0	0	0	0
80	TURB BLDG EQUIP CMPT EXHAUST FAN	++	V106	2	0	2	0	250	198	0	0	0	0	0	0	0	0
81	DRYWELL CHILLER COMPRESSOR	++	K111	2	0	2	0	1302	1379	0	0	0	0	0	0	0	0
82	ROD DRIVE CONTROL CABINET XFMR	o	X516	1	0	1	0	10	8	0	0	0	0	1	0	0	0
83	SLCS PUMP		P208	3	0	3	0	40	32	0	0	0	0	0	0	0	0
84	RWCU SYSTEM RECIRC PUMP	(7)	P221	3	0	3	0	125	92	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	o	W201	4,1 & 3	0	4,1 & 3	0	60	48	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	o	W202	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	o	W205	0	0	0	0	0	0	0	0	0	0	0	0	0	0
86	440V POWER RECEPTACLE	o *	W601	0	1	0	0	60	48	0	0	0	0	0	0	0	0
87	440V POWER RECEPTACLE	o	W206	2	0	2	0	60	48	0	0	0	0	0	0	0	0
88	ANNUNCIATOR			4	0	4	0	0	1	0	0	0	4	0	0	0	4
89	TURB GEN TURN GEAR PIGGYBACK		S195	0	0	1	0	3	2	0	0	0	1	0	0	0	1
90	RHRSW CORROSION MONITORING	+++	Y215	1	0	0	F	105	77	0	0	0	0	0	0	0	0
91	ADMIN BLDG 480V DIST PNL	o+	00B500	0	1	0	0	45	36	0	0	0	0	0	0	0	0

LEGEND:

* - COMMON EQUIPMENT
o - NON SAFEGUARD LOADS THAT ARE TRIPPED BY LOCA SIGNAL AND MANUALLY RESTARTED AFTER 10 MINUTES OR MORE, IF NEEDED.
\+ - NON SAFEGUARD LOAD NOT TRIPPED BY A LOAD SIGNAL.
++ - NON SAFEGUARD LOADS TREATED AS SAFEGUARD LOAD BUT TRIPPED BY A LOCA SIGNAL AND CAN BE MANUALLY RESTARTED AFTER 10 MINUTES OR MORE, IF NEEDED.
+++ - NON SAFEGUARD LOAD TRIPPED BY A LOCA OR LOOP SIGNAL AND SHALL NOT BE RESTARTED UNTIL NORMAL PLANT OPERATION IS RESTORED. LOAD KEPT IN THE INACTIVE STATUS BY PLACING THE MCC BREAKER IN THE OPEN POSITION.
! - EMERGENCY LIGHTING NUMBERS ARE AS FOLLOWS: 1L87*, L10, 1L55*, 1L85*, X26, L16, L17, L130, 1X17*, 1X64, L6, 1L9, L86

(1) - MOV LOADS ARE NOT INCLUDED IN THIS TABLE AND THE DIESEL GENERATOR LOADING TABLES THAT FOLLOW BECAUSE OF THEIR SMALL MAGNITUDE AND SHORT DURATION
(2) - ASSIGNMENT OF THE LOADING ON THE DIESEL GENERATORS IS SUCH THAT THE SITUATION OF A DBA ON ONE UNIT AND SPURIOUS LOCA ON THE OTHER UNIT DOES NOT PRECLUDE SAFE SHUTDOWN OF THE UNITS. A SPURIOUS LOCA IS DEFINED AS A LOCA FOR 0-10 MINUTES AND EMERGENCY SHUTDOWN FOR BEYOND 10 MINUTES.
(7) - ALTHOUGH 3 PUMPS ARE INSTALLED, ONLY ONE IS POWERED FROM THE CLASS 1E SYSTEM.
(9) - MOD P00674 REPLACED THE 2A-P202 PUMP MOTOR. THE MOTOR IS MORE EFFICIENT AND THE LOAD ASSIGNMENT FOR THE D/G AND BUS 21 IS REDUCED BY 16 kW.
(10) - DELETED.
(11) - ALTHOUGH 2 AIR CONDITIONERS ARE INSTALLED, ONLY ONE IS POWERED FROM THE CLASS 1E SYSTEM.
(12) -ECR 04-00319 REPLACED THE MOTOR FOR 1A-K203. LOAD IS NOW 2 KW.
(13) - ECR 04-00569 REPLACED THE MOTOR FOR 0A-V131. LOAD IS NOW 7 KW.

TABLE 8.3 – 3 (Cont'd) (PAGE 4 OF 6)

ASSIGNMENT OF SAFEGUARD AND SELECTED NON-SAFEGUARD LOADS
TO DIESEL GENERATORS AND EMERGENCY BUSES

ITEM	LOAD DESCRIPTION	COMMENTS	EQUIP NO.	NUMBER OF OPERATING UNITS			ASSIGNMENT OF LOADS TO DIESEL GENERATORS AND EMERGENCY BUSES (IN kw)							
							UNIT 1 (UNIT 1 and UNIT 2 IN OPERATION)				UNIT 2 (UNIT 1 and UNIT 2 IN OPERATION)			
				UNIT 1	COMMON	UNIT 2	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
01	RHR PUMP	(9)	P202	4	0	4	993	993	993	993	977	993	993	993
02	CORE SPRAY PUMP		P206	4	0	4	529	529	529	529	529	529	529	529
03	RHR SERVICE WATER PUMP	*	P506	0	4	0	519	519	0	0	519	519	0	0
04	ESW PUMP	*	P548	0	4	0	380	389	0	0	0	0	389	389
05	125V BATTERY CHARGER		D103	4 & 2	0	4 & 2	51	50	9	9	51	51	9	9
06	DRYWELL COOLER FAN		V212	16	0	16	80	80	80	80	80	80	80	80
07	DG ROOM VENT FAN		V512	8	0	8	30	30	30	30	30	30	30	30
08	RHR ROOM COOLING UNIT		V210	8	0	8	32	32	32	32	32	32	32	32
09	CORE SPRAY ROOM COOLING UNIT		V211	8	0	8	14	16	14	16	14	14	14	14
10	HPCI ROOM COOLING UNIT		V209	2	0	2	0	20	0	0	0	20	0	0
11	RCIC ROOM COOLING UNIT		V208	2	0	2	8	0	0	0	8	0	0	0
12	INSTRUMENT AC POWER SUPPLY		Y101	4	0	4	11	11	12	11	12	12	12	12
12	INSTRUMENT AC POWER SUPPLY		Y102	0	0	0	0	0	0	0	0	0	0	0
12	INSTRUMENT AC POWER SUPPLY		Y103	0	0	0	0	0	0	0	0	0	0	0
12	INSTRUMENT AC POWER SUPPLY		Y104	0	0	0	0	0	0	0	0	0	0	0
13	DG START AIR COMPRESSOR	o	K513	8	0	8	14	14	14	14	14	14	14	14
14	DG FUEL OIL TRANSFER PUMP		P514	4	0	4	1	1	1	1	1	1	1	1
15	SGTS HEATER	*	E188	0	2	0	44	44	0	0	0	0	0	0
16	SGTS ROOM UNIT COOLER	*	V140	0	2	0	1	1	0	0	0	0	0	0
17	SGTS ROOM ACCESS UNIT COOLER	*	V141	0	2	0	6	6	0	0	0	0	0	0
18	SGTS EXHAUST FAN	*	V163	0	2	0	32	32	0	0	0	0	0	0
19	RERS FAN		V213	2	0	2	151	151	0	0	151	151	0	0
20	HVAC DAMPER POWER		Y206	4	0	4	4	4	16	20	2	2	0	0
20	HVAC DAMPER POWER		Y207	0	0	0	0	0	0	0	0	0	0	0
20	HVAC DAMPER POWER		Y163	0	0	0	0	0	0	0	0	0	0	0
20	HVAC DAMPER POWER		Y164	0	0	0	0	0	0	0	0	0	0	0
21	CONTROL ROOM CHILLER	*	K112	0	2	0	0	0	329/330	330	0	0	0	0
22	CONTROL ROOM CHILLER WATER PP	*	P162	0	2	0	0	0	16	16	0	0	0	0
23	AUX PNL & COMP RM FAN COIL UNIT	*	V114	0	2	0	0	0	24	24	0	0	0	0
24	AUX PNL & COMP RM RETURN AIR UNIT	*	V120	0	2	0	0	0	16	16	0	0	0	0
25	CONTROL ROOM AIR COND UNIT	*	V116	0	2	0	0	0	32	32	0	0	0	0
26	CONTROL ROOM RETURN AIR FAN	*	V121	0	2	0	0	0	12	12	0	0	0	0
27	EMER SWGR & BTRY RM AIR COND UNIT	*	V118	0	2	0	0	0	9	9	0	0	0	0
28	AUX EQUIP & COMP RM AREA HTR	* ++	E193	0	2	0	0	0	52	52	0	0	0	0
29	CONTROL ROOM AREA HEATER	* ++	E192	0	2	0	0	0	40	40	0	0	0	0
30	CONT RM FRESH AIR INTAKE HTR	*	E191	0	2	0	0	0	32	32	0	0	0	0
31	SPRAY POND STATION HTG COIL FAN	*	V543	0	4	0	7	7	0	0	0	0	7	7
32	SLCS HEATERS	++	S213	1 & 1	0	1 & 1	0	0	8	8	0	0	8	8
33	CONTAINMENT H2 RECOMBINER		S403	2	0	2	0	0	48	48	0	0	48	48
34	CONT'L RM EMER FRESH AIR SPLY FAN	*	V127	0	2	0	0	0	6	6	0	0	0	0
35	CONTROL ROOM CHILLER OIL PUMP	*	P168	0	2	0	0	0	1	1	0	0	0	0
36	DG AUXILIARIES	o	G501	4	0	4	14	14	14	14	14	14	14	14
37	DELETED													

TABLE 8.3 – 3 (Cont'd)

ASSIGNMENT OF SAFEGUARD AND SELECTED NON-SAFEGUARD LOADS
TO DIESEL GENERATORS AND EMERGENCY BUSES

ITEM	LOAD DESCRIPTION	COMMENTS	EQUIP NO.	NUMBER OF OPERATING UNITS			ASSIGNMENT OF LOADS TO DIESEL GENERATORS AND EMERGENCY BUSES (IN kw)							
							UNIT 1 (UNIT 1 and UNIT 2 IN OPERATION)				UNIT 2 (UNIT 1 and UNIT 2 IN OPERATION)			
				UNIT 1	COMMON	UNIT 2	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
37	DELETED													
38	DELETED													
39	CRD PUMP	o	P158	2	0	2	0	0	133	133	0	0	133	133
40	DELETED													
41	RECW PUMP	++	P210	2	0	2	0	0	68	68	0	0	68	68
42	TECW PUMP	o	P103	2	0	2	11	11	0	0	12	11	0	0
43	INSTRUMENT AC POWER SUPPLY	o	Y105	4	0	4	5	10	24	14	24	24	24	24
43	INSTRUMENT AC POWER SUPPLY	o	Y106	0	0	0	0	0	0	0	0	0	0	0
43	INSTRUMENT AC POWER SUPPLY	o	Y201	0	0	0	0	0	0	0	0	0	0	0
43	INSTRUMENT AC POWER SUPPLY	o	Y202	0	0	0	0	0	0	0	0	0	0	0
44	EMERGENCY LIGHTING	o !	MISC	7	6	7	11	70	109	99	0	59	80	68
45	TURBINE GEN BEARING LIFT PUMP	o	P109	9	0	9	45	0	0	0	36	0	0	0
46	TURBINE GEN TURNING OIL PP	o	P111	1	0	1	32	0	0	0	32	0	0	0
47	TURBINE GEN TURNING GEAR	o	S103	1	0	1	48	0	0	0	24	0	0	0
48	RFPT GEAR	o	S106	3	0	3	2	1	0	0	2	1	0	0
49	INSTRUMENT GAS COMPRESSOR	o (12)	K203	2	0	2	1	1	0	0	1	1	0	0
50	INSTRUMENT AIR COMPRESSOR	o	K101	2	0	2	0	0	33	33	0	0	33	33
51	DELETED													
52	OSC XFMR PNLS OOL140 & OOL141	*	X186	0	1	0	0	24	0	0	0	0	0	0
53	TEST ENGINEER'S WORKSHOP	*	X187	0	1	0	0	12	0	0	0	0	0	0
54	NORTH STACK RM ANTENNA SYS XFMR	*	X595	0	1	0	0	9	0	0	0	0	0	0
55	DELETED													
56	CRD REPAIR RM COOLING FAN		V904	0	1	1	0	0	0	0	0	0	0	0
57	125V BATTERY CHARGER	o	D113	2	0	2	0	0	0	96	0	0	0	96
58	FIRE ALARM & P/A	* +	1X5	0	0	0	0	0	0	12	0	0	0	0
59	FUEL POOL COOLING WATER PUMP	o	P211	3	0	3	32	32	0	32	32	32	0	32
60	FUEL POOL SVC WTR BSTR PUMP (7)		P212	3	0	3	19	0	0	0	19	0	0	0
61	INSTR. AC PWR SUPPLY (SPRAY POND)	o	Y501	0	4	0	1	1	0	0	0	0	8	8
62	SPRAY POND PP STATION HTG COIL	++ *	E701	0	4	0	96	96	0	0	0	0	96	96
63	SGTS RM VENT EXHAUST FAN	o *(13)	V131	0	2	0	7	7	0	0	0	0	0	0
64	SECURITY AREAS AIR COND. (11)	o *	V565	0	2	0	0	0	14	0	0	0	0	0
65	PIPING FILL PUMP		P256	2	0	2	3	3	0	0	3	3	0	0
66	DRYWELL H2O2 ANALYZER		S205	1	0	1	0	0	0	1	0	0	0	1
67	SUPPRESSION POOL H2O2 ANALYZER		S206	1	0	1	0	0	1	0	0	0	1	0
68	CHILLER PUMP-OUT COMPRESSOR	o *	K114	0	2	0	0	0	2	2	0	0	0	0
69	SPRAY POND SUMP PUMP	o *	P578	0	4	0	2	2	0	0	0	0	2	2
70	AUX EG. RM & COMP RM ELEC HUMIDFR	o *	E743	0	2	0	43	43	0	0	0	0	0	0
71	CONT RM ELEC HUMIDIFIER	o *	E744	0	2	0	29	29	0	0	0	0	0	0
72	250V BATTERY CHARGER	o	D123	1	0	1	0	9	0	0	0	9	0	0
73	ALT. POWER SUPPLY TO 10X161 XFMR	o	10X161	1	0	0	30	0	0	0	0	0	0	0
74	STATIC INVERTER 00-D592 XFMR	o *	00-X592	0	1	0	0	0	0	0	30	0	0	0
75	TELEPHONE EQUIP POWER XFMR	o *	X503	0	1	0	6	0	0	0	0	0	0	0
76	RECOMBINER HYDROGEN ANALYZER	o	P947	3	0	3	1	2	0	0	1	2	0	0

TABLE 8.3 – 3 (Cont'd) (PAGE 6 OF 6)

ASSIGNMENT OF SAFEGUARD AND SELECTED NON-SAFEGUARD LOADS
TO DIESEL GENERATORS AND EMERGENCY BUSES

ITEM	LOAD DESCRIPTION	COMMENTS	EQUIP NO.	NUMBER OF OPERATING UNITS			ASSIGNMENT OF LOADS TO DIESEL GENERATORS AND EMERGENCY BUSES (IN kw)							
							UNIT 1 (UNIT 1 and UNIT 2 IN OPERATION)				UNIT 2 (UNIT 1 and UNIT 2 IN OPERATION)			
				UNIT 1	COMMON	UNIT 2	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
77	DIESEL GENERATOR BRIDGE CRANE	o	H501	4	0	4	18	18	18	18	18	18	18	18
78	440V POWER RECEPTACLES	o	W508	4	0	4	48	48	48	48	48	48	48	48
79	SPRAY POND PUMP HOIST	o *	H511	0	2	0	0.5	0	0	0	0	0	0	0.5
79	SPRAY POND PUMP HOIST	o *	H513	0	0	0	0	0	0	0	0	0	0	0
80	TURB BLDG EQUIP CMPT EXHAUST FAN	++	V106	2	0	2	197	198	0	0	198	198	0	0
81	DRYWELL CHILLER COMPRESSOR	++	K111	2	0	2	0	0	1379	1379	0	0	1379	1379
82	ROD DRIVE CONTROL CABINET XFMR	o	X516	1	0	1	0	8	0	0	0	8	0	0
83	SLCS PUMP		P208	3	0	3	32	32	32	0	32	32	32	0
84	RWCU SYSTEM RECIRC PUMP	(7)	P221	3	0	3	0	0	92	0	0	0	92	0
85	440V POWER RECEPTACLES	o	W201	4,1 & 3	0	4,1 & 3	0	0	0	144	0	0	0	144
85	440V POWER RECEPTACLES	o	W202	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	o	W205	0	0	0	0	0	0	0	0	0	0	0
86	440V POWER RECEPTACLE/SP RECIRC	o *	W601	0	1	0	0	0	0	0	0	0	0	48
87	440V POWER RECEPTACLE	o	W206	2	0	2	0	48	0	0	0	48	0	0
88	ANNUNCIATOR			4	0	4	1	1	1	1	1	1	1	1
89	TURB GEN TURN GEAR PIGGYBACK		S195	0	0	1	0	0	0	0	2	0	0	0
90	RHRSW CORROSION MONITORING	+++	Y215	1	0	0	0	77	0	0	0	0	0	0
91	ADMIN BLDG 480V DISTR PNL	o+	00B500	0	1	0	0	0	36	0	0	0	0	0

LEGEND:

* - COMMON EQUIPMENT
o - NON SAFEGUARD LOADS THAT ARE TRIPPED BY LOCA SIGNAL AND MANUALLY RESTARTED AFTER 10 MINUTES OR MORE, IF NEEDED.
\+ - NON SAFEGUARD LOAD NOT TRIPPED BY A LOAD SIGNAL.
++ - NON SAFEGUARD LOADS TREATED AS SAFEGUARD LOAD BUT TRIPPED BY A LOCA SIGNAL AND CAN BE MANUALLY RESTARTED AFTER 10 MINUTES OR MORE, IF
+++ - NON SAFEGUARD LOAD TRIPPED BY A LOCA OR LOOP SIGNAL AND SHALL NOT BE RESTARTED UNTIL NORMAL PLANT OPERATION IS RESTORED. LOAD KEPT IN THE INACTIVE STATUS BY PLACING THE MCC BREAKER IN THE OPEN POSITION.
! - EMERGENCY LIGHTING NUMBERS ARE AS FOLLOWS: 1L87*, L10, 1L55*, 1L85*, X26, L16, L17, L130, 1X17*, 1X64, L6, 1L9*, L86

(1) - MOV LOADS ARE NOT INCLUDED IN THIS TABLE AND THE DIESEL GENERATOR LOADING TABLES THAT FOLLOW BECAUSE OF THEIR SMALL MAGNITUDE AND SHORT DURATION
(2) - ASSIGNMENT OF THE LOADING ON THE DIESEL GENERATORS IS SUCH THAT THE SITUATION OF A DBA ON ONE UNIT AND SPURIOUS LOCA ON THE OTHER UNIT DOES NOT PRECLUDE SAFE SHUTDOWN OF THE UNITS. A SPURIOUS LOCA IS DEFINED AS A LOCA FOR 0-10 MINUTES AND EMERGENCY SHUTDOWN FOR BEYOND 10 MINUTES.
(7) - ALTHOUGH 3 PUMPS ARE INSTALLED, ONLY ONE IS POWERED FROM THE CLASS 1E SYSTEM.
(9) - MOD P00674 REPLACED THE 2A-P202 PUMP MOTOR. THE MOTOR IS MORE EFFICIENT AND THE LOAD ASSIGNMENT FOR THE D/G AND BUS 21 IS REDUCED BY 16 kW.
(10) - DELETED.
(11) - ALTHOUGH 2 AIR CONDITIONERS ARE INSTALLED, ONLY ONE IS POWERED FROM THE CLASS 1E SYSTEM.
(12)—ECR 04-00319 REPLACED THE MOTOR FOR 1A-K203. LOAD IS NOW 2 KW.
(13)—ECR 04-00569 REPLACED THE MOTOR FOR 0A-V131. LOAD IS NOW 7 KW.

Tables 8.3-4 through 8.3-8

Tables 8.3-4 through 8.3-8
(Deleted)

Table 8.3-9

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DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

ALL DIESEL GENERATORS IN SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
1	RHR PUMP	P202	993	993	993	993	977	993	993	993	0	993	0	993	0	993	0	0	0	993	0	993	0	993	0	0
2	CORE SPRAY PUMP	P206	529	529	529	529	529	529	529	529	529	0	529	0	0	0	0	0	529	0	529	0	0	0	0	0
3	RHR SERVICE WATER PUMP	P506	0	0	0	0	0	0	0	0	0	519	0	0	0	519	0	0	0	519	0	0	0	519	0	0
4	ESW PUMP	P548	380	389	0	0	0	0	389	389	0	0	0	0	0	0	389	389	0	0	0	0	0	0	389	389
5	125V BATTERY CHARGER	D103	51	50	9	9	51	51	9	9	51	50	9	9	51	51	9	9	51	50	9	9	51	51	9	9
6	DRYWELL COOLER FAN	V212	80	80	0	0	80	80	0	0	80	80	0	0	80	80	0	0	80	80	0	0	80	80	0	0
7	DG ROOM VENT FAN	V512	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
8	RHR ROOM COOLING UNIT	V210	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
9	CORE SPRAY ROOM COOLING UNIT	V211	7	8	7	8	7	7	7	7	7	8	7	8	7	7	7	7	7	8	7	8	7	7	7	7
10	HPCI ROOM COOLING UNIT	V209	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0
11	RCIC ROOM COOLING UNIT	V208	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0
12	INSTRUMENT AC POWER SUPPLY	Y101	11	11	12	11	12	12	12	12	11	11	12	11	12	12	12	12	11	11	12	11	12	12	12	12
12	INSTRUMENT AC POWER SUPPLY	Y102																								
12	INSTRUMENT AC POWER SUPPLY	Y103																								
12	INSTRUMENT AC POWER SUPPLY	Y104																								
13	DG START AIR COMPRESSOR	K513	0	0	0	0	0	0	0	0	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
14	DG FUEL OIL TRANSFER PUMP	P514	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	SGTS HEATER	E188	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0
16	SGTS ROOM UNIT COOLER	V140	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
17	SGTS ROOM ACCESS UNIT COOLER	V141	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
18	SGTS EXHAUST FAN	V163	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0
19	RERS FAN	V213	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0
20	HVAC DAMPER POWER	Y163	4	4	16	20	2	2	22	2	4	4	16	20	2	2	22	2	4	4	16	20	2	2	22	2
20	HVAC DAMPER POWER	Y164																								
20	HVAC DAMPER POWER	Y206																								
20	HVAC DAMPER POWER	Y207																								
21	CONTROL ROOM CHILLER	K112	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0
22	CONTROL ROOM CHILLER WATER PUMP	P162	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
23	AUX PNL & COMP RM FAN COIL UNIT	V114	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0
24	AUX PNL & COMP RM RETURN AIR UNIT	V120	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
25	CONTROL ROOM AIR COND UNIT	V116	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0
26	CONTROL ROOM RETURN AIR FAN	V121	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0
27	EMER SWGR & BTRY RM AIR COND UNIT	V118	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0
28	AUX EQUIP & COMP RM AREA HTR (11)	E193	0	0	0	0	0	0	0	0	0	0	52	0	0	0	0	0	0	0	52	0	0	0	0	0
29	CONTROL ROOM AREA HEATER (11)	E192	0	0	0	0	0	0	0	0	0	0	40	0	0	0	0	0	0	0	40	0	0	0	0	0
30	CONTROL RM FRESH AIR INTAKE HTR (11)	E191	0	0	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	SPRAY POND STA. HTG COIL FAN (11)	V543	7	7	0	0	0	0	0	0	7	7	0	0	0	0	0	0	7	7	0	0	0	0	0	0
32	SLCS HEATERS	S213	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0
33	CONTAINMENT H2 RECOMBINER	S403	0	0	0	0	0	0	0	0	0	0	48	0	0	0	48	0	0	0	48	0	0	0	48	0

Table 8.3-9 (continued)

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DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION
ALL DIESEL GENERATORS IN SERVICE
UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
34	CONTROL ROOM FRESH AIR SUPPLY FAN	V127	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0
35	CONTROL ROOM CHILLER OIL PUMP	P168	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
36	DG AUXILIARIES	G501	0	0	0	0	0	0	0	0	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
37	DELETED																									
37	DELETED																									
38	DELETED																									
39	CRD PUMP	P158	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	DELETED																									
41	RECW PUMP	P210	0	0	0	0	0	0	0	0	0	0	68	0	0	0	68	0	0	0	68	0	0	0	68	0
42	TECW PUMP	P103	0	0	0	0	0	0	0	0	11	11	0	0	12	11	0	0	11	11	0	0	12	11	0	0
43	INSTRUMENT AC POWER SUPPLY	Y105	0	0	0	0	0	0	0	0	5	10	24	14	24	24	24	24	5	10	24	14	24	24	24	24
43	INSTRUMENT AC POWER SUPPLY	Y106																								
43	INSTRUMENT AC POWER SUPPLY	Y201																								
43	INSTRUMENT AC POWER SUPPLY	Y202																								
44	EMERGENCY LIGHTING	MISC	0	0	0	0	0	0	0	0	26	70	108	99	0	59	80	68	26	70	108	99	0	59	80	68
45	TURBINE GEN BEARING LIFT PUMP	P109	0	0	0	0	0	0	0	0	45	0	0	0	36	0	0	0	45	0	0	0	36	0	0	0
46	TURBINE GEN TURNING GEAR OIL PUMP	P111	0	0	0	0	0	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0
47	TURBINE GEN TURNING GEAR	S103	0	0	0	0	0	0	0	0	48	0	0	0	24	0	0	0	48	0	0	0	24	0	0	0
48	RFPT TURNING GEAR	S106	0	0	0	0	0	0	0	0	2	1	0	0	2	1	0	0	2	1	0	0	2	1	0	0
49	INSTRUMENT GAS COMPRESSOR	K203	0	0	0	0	0	0	0	0	2	0	0	0	1	0	0	0	2	0	0	0	1	0	0	0
50	INSTRUMENT AIR COMPRESSOR	K101	0	0	0	0	0	0	0	0	0	0	33	0	0	0	33	0	0	0	33	0	0	0	33	0
51																										
52	OSC XFMR PNLS 00L140 & 00L141	X186	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
53	TEST ENGINEER'S WORKSHOP	X187	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
54	NORTH STACK RM ANTENNA SYS XFMR	X595	0	0	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0
55																										
56	CRD REPAIR RM COOLING FAN	V904	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57	125V BATTERY CHARGER	D113	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	94	0	0	0	94	0	0	0	94
58	FIRE ALARM & P/A	1X5	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0
59	FUEL POOL COOLING WATER PUMP	P211	0	0	0	0	0	0	0	0	32	0	0	0	31	32	0	0	32	0	0	0	31	32	0	0
60	FUEL POOL SVC WATER BOOSTER PUMP	P212	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
61	INSTR. AC PWR SUPPLY (SPRAY POND)	Y501	1	1	0	0	0	0	8	8	1	1	0	0	0	0	8	8	1	1	0	0	0	0	8	8
62	SPRAY POND PP STA. HTG COIL (6,11)	E701	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	SGTS RM VENT EXHAUST FAN	V131	0	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0
64	SECURITY AREAS AIR COND.	V565	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	14	0	0	0	0	0
65	PIPING FILL PUMP	P256	0	0	0	0	0	0	0	0	3	3	0	0	3	3	0	0	3	3	0	0	3	3	0	0
66	DRYWELL H2O2 ANALYZER	S205	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
67	SUPPRESSION POOL H2O2 ANALYZER	S206	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
68	CHILLER PUMP-OUT COMPRESSOR	K114	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0	0	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-9 (continued)

CALC 6380E.07 PAGE : 3 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

ALL DIESEL GENERATORS IN SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
69	SPRAY POND SUMP PUMP	P578	0	0	0	0	0	0	0	0	2	2	0	0	0	0	2	2	2	2	0	0	0	0	2	2
70	AUX EG. RM & COMP RM ELE. HUMID (11)	E743	0	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0
71	CONTROL RM ELEC HUMIDIFIER (11)	E744	0	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0
72	250V BATTERY CHARGER	D123	0	0	0	0	0	9	0	0	0	9	0	0	0	9	0	0	0	9	0	0	0	9	0	0
73	ALT POWER SUPPLY TO 10X161 XFMR	10X161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
74	PNL 00-Y500 MAINT PWR SUPPLY VIA XFMR	00-X500	0	0	0	0	0	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	20	0	0	0
75	TELEPHONE EQUIP POWER XFMR	X503	0	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
76	RECOMBINER HYDROGEN ANALYZER	P947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
77	DIESEL GENERATOR BRIDGE CRANE	H501	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
78	440V POWER RECEPTACLE	W508	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H511	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H513																								
80	TURB BLDG EQUIP COMPT EXHAUST FAN	V106	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
81	DRYWELL CHILLER COMPRESSOR	K111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
82	ROD DRIVE CONROL CABINET XFMR	X516	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
83	SLCS PUMP	P208	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
84	RWCU SYSTEM RECIRC PUMP	P221	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W201	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W202																								
85	440V POWER RECEPTACLES	W205																								
86	440V POWER RECEPTACLES / SP RECIRC	W601	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
87	440V POWER RECEPTACLES	W206	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
88	MCC ANNUNCIATORS		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
89	TURB GEN TURNING GEAR PIGGYBCK MTR	S195	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0
90	RHRSW CORROSION MONITORING	Y215	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
91	ADMIN BLDG 480V DISTR PNL	00B500	0	0	0	0	0	0	0	0	0	0	66	0	0	0	0	0	0	0	66	0	0	0	0	0
	4kv BUS SUBTOTAL (kw)		2352	2130	2099	1630	1865	1741	2024	1996	1293	1867	1549	1329	568	1882	777	683	1293	1867	1549	1329	568	1882	777	683

LEGEND

(6) THE SPRAY POND PUMP STATION HEATING COILS ARE TRIPPED BY A LOCA SIGNAL.

(7) ASSIGNMENT OF THE LOADING ON THE DIESEL GENERATORS IS SUCH THAT THE SITUATION OF A DBA ON ONE UNIT AND SPURIOUS LOCA ON THE OTHER UNIT DOES NOT PRECLUDE SAFE SHUTDOWN OF THE UNITS. A SPURIOUS LOCA IS DEFINED AS A LOCA FOR 0-10 MINUTES AND EMERGENCY SHUTDOWN FOR BEYOND 10 MINUTES.

(11) HEATING LOADS AND COOLING LOADS ARE NOT COINCIDENT. THE COINCIDENT COOLING LOAD IS LARGER THAN THE COINCIDENT HEATING LOAD, THEREFORE, THE COOLING LOADS ARE SHOWN ENERGIZED.

Table 8.3-10

CALC 6380E.07 PAGE : 1 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION
D11 DIESEL GENERATOR OUT OF SERVICE
UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
1	RHR PUMP	P202	0	993	993	993	977	993	993	993	0	993	0	993	0	993	0	0	0	993	0	993	0	993	0	0
2	CORE SPRAY PUMP	P206	0	529	529	529	529	529	529	529	0	529	0	529	0	0	0	0	0	529	0	529	0	0	0	0
3	RHR SERVICE WATER PUMP	P506	0	0	0	0	0	0	0	0	0	0	0	0	519	519	0	0	0	0	0	0	519	519	0	0
4	ESW PUMP	P548	0	389	0	0	0	0	389	389	0	0	0	0	0	0	389	389	0	0	0	0	0	0	389	389
5	125V BATTERY CHARGER	D103	0	50	9	9	51	51	9	9	0	50	9	9	51	51	9	9	0	50	9	9	51	51	9	9
6	DRYWELL COOLER FAN	V212	0	80	80	0	80	80	0	0	0	0	80	80	80	80	0	0	0	0	80	80	80	80	0	0
7	DG ROOM VENT FAN	V512	0	30	30	30	30	30	30	30	0	30	30	30	30	30	30	30	0	30	30	30	30	30	30	30
8	RHR ROOM COOLING UNIT	V210	0	16	16	16	16	16	16	16	0	16	16	16	16	16	16	16	0	16	16	16	16	16	16	16
9	CORE SPRAY ROOM COOLING UNIT	V211	0	8	7	8	7	7	7	7	0	8	7	8	7	7	7	7	0	8	7	8	7	7	7	7
10	HPCI ROOM COOLING UNIT	V209	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0
11	RCIC ROOM COOLING UNIT	V208	0	0	0	0	8	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0	8	0	0	0
12	INSTRUMENT AC POWER SUPPLY	Y101	0	11	12	11	12	12	12	12	0	11	12	11	12	12	12	12	0	11	12	11	12	12	12	12
12	INSTRUMENT AC POWER SUPPLY	Y102																								
12	INSTRUMENT AC POWER SUPPLY	Y103																								
12	INSTRUMENT AC POWER SUPPLY	Y104																								
13	DG START AIR COMPRESSOR	K513	0	0	0	0	0	0	0	0	0	7	7	7	7	7	7	7	0	7	7	7	7	7	7	7
14	DG FUEL OIL TRANSFER PUMP	P514	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	SGTS HEATER	E188	0	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0
16	SGTS ROOM UNIT COOLER	V140	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0
17	SGTS ROOM ACCESS UNIT COOLER	V141	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0
18	SGTS EXHAUST FAN	V163	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0
19	RERS FAN	V213	0	151	0	0	151	0	0	0	0	151	0	0	151	0	0	0	0	151	0	0	151	0	0	0
20	HVAC DAMPER POWER	Y163	0	4	16	20	2	2	22	2	0	4	16	20	2	2	22	2	0	4	16	20	2	2	22	2
20	HVAC DAMPER POWER	Y164																								
20	HVAC DAMPER POWER	Y206																								
20	HVAC DAMPER POWER	Y207																								
21	CONTROL ROOM CHILLER	K112	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0
22	CONTROL ROOM CHILLER WATER PUMP	P162	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
23	AUX PNL & COMP RM FAN COIL UNIT	V114	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0
24	AUX PNL & COMP RM RETURN AIR UNIT	V120	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
25	CONTROL ROOM AIR COND UNIT	V116	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0
26	CONTROL ROOM RETURN AIR FAN	V121	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0
27	EMER SWGR & BTRY RM AIR COND UNIT	V118	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0
28	AUX EQUIP & COMP RM AREA HTR (11)	E193	0	0	0	0	0	0	0	0	0	0	52	0	0	0	0	0	0	0	52	0	0	0	0	0
29	CONTROL ROOM AREA HEATER (11)	E192	0	0	0	0	0	0	0	0	0	0	40	0	0	0	0	0	0	0	40	0	0	0	0	0
30	CONTROL RM FRESH AIR INTAKE HTR (11)	E191	0	0	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	SPRAY POND STA. HTG COIL FAN (11)	V543	0	7	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0	7	0	0	0	0	0	0
32	SLCS HEATERS	S213	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0
33	CONTAINMENT H2 RECOMBINER	S403	0	0	0	0	0	0	0	0	0	0	48	0	0	0	48	0	0	0	48	0	0	0	48	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-10 (continued)

CALC 6380E.07 PAGE : 2 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D11 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
34	CONTROL ROOM FRESH AIR SUPPLY FAN	V127	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0
35	CONTROL ROOM CHILLER OIL PUMP	P168	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
36	DG AUXILIARIES	G501	0	0	0	0	0	0	0	0	0	14	14	14	14	14	14	14	0	14	14	14	14	14	14	14
37	DELETED																									
37	DELETED																									
38	DELETED																									
39	CRD PUMP	P158	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	DELETED																									
41	RECW PUMP	P210	0	0	0	0	0	0	0	0	0	0	68	0	0	0	68	0	0	0	68	0	0	0	68	0
42	TECW PUMP	P103	0	0	0	0	0	0	0	0	0	11	0	0	12	11	0	0	0	11	0	0	12	11	0	0
43	INSTRUMENT AC POWER SUPPLY	Y105	0	0	0	0	0	0	0	0	0	10	24	14	24	24	24	24	0	10	24	14	24	24	24	24
43	INSTRUMENT AC POWER SUPPLY	Y106																								
43	INSTRUMENT AC POWER SUPPLY	Y201																								
43	INSTRUMENT AC POWER SUPPLY	Y202																								
44	EMERGENCY LIGHTING	MISC	0	0	0	0	0	0	0	0	0	70	108	99	0	59	80	68	0	70	108	99	0	59	80	68
45	TURBINE GEN BEARING LIFT PUMP	P109	0	0	0	0	0	0	0	0	0	0	0	0	36	0	0	0	0	0	0	0	36	0	0	0
46	TURBINE GEN TURNING GEAR OIL PUMP	P111	0	0	0	0	0	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0
47	TURBINE GEN TURNING GEAR	S103	0	0	0	0	0	0	0	0	0	0	0	0	24	0	0	0	0	0	0	0	24	0	0	0
48	RFPT TURNING GEAR	S106	0	0	0	0	0	0	0	0	0	1	0	0	2	1	0	0	0	1	0	0	2	1	0	0
49	INSTRUMENT GAS COMPRESSOR	K203	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0
50	INSTRUMENT AIR COMPRESSOR	K101	0	0	0	0	0	0	0	0	0	0	33	0	0	0	33	0	0	0	33	0	0	0	33	0
51																										
52	OSC XFMR PNLS 00L140 & 00L141	X186	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
53	TEST ENGINEER'S WORKSHOP	X187	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
54	NORTH STACK RM ANTENNA SYS XFMR	X595	0	0	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0
55																										
56	CRD REPAIR RM COOLING FAN	V904	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57	125V BATTERY CHARGER	D113	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	94	0	0	0	94	0	0	0	94
58	FIRE ALARM & P/A	1X5	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0
59	FUEL POOL COOLING WATER PUMP	P211	0	0	0	0	0	0	0	0	0	32	0	0	31	32	0	0	0	32	0	0	31	32	0	0
60	FUEL POOL SVC WATER BOOSTER PUMP	P212	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
61	INSTR. AC PWR SUPPLY (SPRAY POND)	Y501	0	1	0	0	0	0	8	8	0	1	0	0	0	0	8	8	0	1	0	0	0	0	8	8
62	SPRAY POND PP STA. HTG COIL (6,11)	E701	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	SGTS RM VENT EXHAUST FAN	V131	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
64	SECURITY AREAS AIR COND.	V565	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	14	0	0	0	0	0
65	PIPING FILL PUMP	P256	0	0	0	0	0	0	0	0	0	3	0	0	3	3	0	0	0	3	0	0	3	3	0	0
66	DRYWELL H2O2 ANALYZER	S205	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
67	SUPPRESSION POOL H2O2 ANALYZER	S206	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
68	CHILLER PUMP-OUT COMPRESSOR	K114	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0	0	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-10 (continued)

CALC 6380E.07 PAGE : 3 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D11 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
69	SPRAY POND SUMP PUMP	P578	0	0	0	0	0	0	0	0	0	2	0	0	0	0	2	2	0	2	0	0	0	0	2	2
70	AUX EG. RM & COMP RM ELE. HUMID (11)	E743	0	0	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0	43	0	0	0	0	0	0
71	CONTROL RM ELEC HUMIDIFIER (11)	E744	0	0	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0	29	0	0	0	0	0	0
72	250V BATTERY CHARGER	D123	0	0	0	0	0	9	0	0	0	9	0	0	0	9	0	0	0	9	0	0	0	9	0	0
73	ALT POWER SUPPLY TO 10X161 XFMR	10X161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
74	PNL 00-Y500 MAINT PWR SUPPLY VIA XFMR	00-X500	0	0	0	0	0	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	20	0	0	0
75	TELEPHONE EQUIP POWER XFMR	X503	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
76	RECOMBINER HYDROGEN ANALYZER	P947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
77	DIESEL GENERATOR BRIDGE CRANE	H501	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
78	440V POWER RECEPTACLE	W508	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H511	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H513																								
80	TURB BLDG EQUIP COMPT EXHAUST FAN	V106	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
81	DRYWELL CHILLER COMPRESSOR	K111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
82	ROD DRIVE CONROL CABINET XFMR	X516	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
83	SLCS PUMP	P208	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
84	RWCU SYSTEM RECIRC PUMP	P221	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W201	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W202																								
85	440V POWER RECEPTACLES	W205																								
86	440V POWER RECEPTACLES / SP RECIRC	W601	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
87	440V POWER RECEPTACLES	W206	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
88	MCC ANNUNCIATORS		0	1	1	1	1	1	1	1	0	1	1	1	1	1	1	1	0	1	1	1	1	1	1	1
89	TURB GEN TURNING GEAR PIGGYBCK MTR	S195	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0
90	RHRSW CORROSION MONITORING	Y215	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
91	ADMIN BLDG 480V DISTR PNL	00B500	0	0	0	0	0	0	0	0	0	0	66	0	0	0	0	0	0	0	66	0	0	0	0	0
	4kv BUS SUBTOTAL (kw)		0	2364	2179	1630	1865	1741	2024	1996	0	2135	1100	1938	1087	1882	777	683	0	2135	1100	1938	1087	1882	777	683

LEGEND

(6) THE SPRAY POND PUMP STATION HEATING COILS ARE TRIPPED BY A LOCA SIGNAL.

(7) ASSIGNMENT OF THE LOADING ON THE DIESEL GENERATORS IS SUCH THAT THE SITUATION OF A DBA ON ONE UNIT AND SPURIOUS LOCA ON THE OTHER UNIT DOES NOT PRECLUDE SAFE SHUTDOWN OF THE UNITS. A SPURIOUS LOCA IS DEFINED AS A LOCA FOR 0-10 MINUTES AND EMERGENCY SHUTDOWN FOR BEYOND 10 MINUTES.

(11) HEATING LOADS AND COOLING LOADS ARE NOT COINCIDENT. THE COINCIDENT COOLING LOAD IS LARGER THAN THE COINCIDENT HEATING LOAD, THEREFORE, THE COOLING LOADS ARE SHOWN ENERGIZED.

Table 8.3-11

CALC 6380E.07 PAGE : 1 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D12 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
1	RHR PUMP	P202	993	0	993	993	977	993	993	993	993	0	0	993	0	993	0	0	993	0	0	993	0	993	0	0
2	CORE SPRAY PUMP	P206	529	0	529	529	529	529	529	529	529	0	529	0	0	0	0	0	529	0	529	0	0	0	0	0
3	RHR SERVICE WATER PUMP	P506	0	0	0	0	0	0	0	0	0	0	0	0	519	519	0	0	0	0	0	0	519	519	0	0
4	ESW PUMP	P548	380	0	0	0	0	0	389	389	0	0	0	0	0	0	389	389	0	0	0	0	0	0	389	389
5	125V BATTERY CHARGER	D103	51	0	9	9	51	51	9	9	51	0	9	9	51	51	9	9	51	0	9	9	51	51	9	9
6	DRYWELL COOLER FAN	V212	80	0	0	80	80	80	0	0	0	0	80	80	80	80	0	0	0	0	80	80	80	80	0	0
7	DG ROOM VENT FAN	V512	30	0	30	30	30	30	30	30	30	0	30	30	30	30	30	30	30	0	30	30	30	30	30	30
8	RHR ROOM COOLING UNIT	V210	16	0	16	16	16	16	16	16	16	0	16	16	16	16	16	16	16	0	16	16	16	16	16	16
9	CORE SPRAY ROOM COOLING UNIT	V211	7	0	7	8	7	7	7	7	7	0	7	8	7	7	7	7	7	0	7	8	7	7	7	7
10	HPCI ROOM COOLING UNIT	V209	0	0	0	0	0	10	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	10	0	0
11	RCIC ROOM COOLING UNIT	V208	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0
12	INSTRUMENT AC POWER SUPPLY	Y101	11	0	12	11	12	12	12	12	11	0	12	11	12	12	12	12	11	0	12	11	12	12	12	12
12	INSTRUMENT AC POWER SUPPLY	Y102																								
12	INSTRUMENT AC POWER SUPPLY	Y103																								
12	INSTRUMENT AC POWER SUPPLY	Y104																								
13	DG START AIR COMPRESSOR	K513	0	0	0	0	0	0	0	0	7	0	7	7	7	7	7	7	7	0	7	7	7	7	7	7
14	DG FUEL OIL TRANSFER PUMP	P514	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	SGTS HEATER	E188	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0
16	SGTS ROOM UNIT COOLER	V140	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
17	SGTS ROOM ACCESS UNIT COOLER	V141	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
18	SGTS EXHAUST FAN	V163	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0
19	RERS FAN	V213	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0
20	HVAC DAMPER POWER	Y163	4	0	16	20	2	2	22	2	4	0	16	20	2	2	22	2	4	0	16	20	2	2	22	2
20	HVAC DAMPER POWER	Y164																								
20	HVAC DAMPER POWER	Y206																								
20	HVAC DAMPER POWER	Y207																								
21	CONTROL ROOM CHILLER	K112	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0
22	CONTROL ROOM CHILLER WATER PUMP	P162	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
23	AUX PNL & COMP RM FAN COIL UNIT	V114	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0
24	AUX PNL & COMP RM RETURN AIR UNIT	V120	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
25	CONTROL ROOM AIR COND UNIT	V116	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0
26	CONTROL ROOM RETURN AIR FAN	V121	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0
27	EMER SWGR & BTRY RM AIR COND UNIT	V118	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0
28	AUX EQUIP & COMP RM AREA HTR (11)	E193	0	0	0	0	0	0	0	0	0	0	52	0	0	0	0	0	0	0	52	0	0	0	0	0
29	CONTROL ROOM AREA HEATER (11)	E192	0	0	0	0	0	0	0	0	0	0	40	0	0	0	0	0	0	0	40	0	0	0	0	0
30	CONTROL RM FRESH AIR INTAKE HTR (11)	E191	0	0	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	SPRAY POND STA. HTG COIL FAN (11)	V543	7	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0
32	SLCS HEATERS	S213	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0
33	CONTAINMENT H2 RECOMBINER	S403	0	0	0	0	0	0	0	0	0	0	48	0	0	0	48	0	0	0	48	0	0	0	48	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-11 (continued)

CALC 6380E.07 PAGE : 2 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION
D12 DIESEL GENERATOR OUT OF SERVICE
UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
34	CONTROL ROOM FRESH AIR SUPPLY FAN	V127	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0
35	CONTROL ROOM CHILLER OIL PUMP	P168	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
36	DG AUXILIARIES	G501	0	0	0	0	0	0	0	0	14	0	14	14	14	14	14	14	14	0	14	14	14	14	14	14
37	DELETED																									
37	DELETED																									
38	DELETED																									
39	CRD PUMP	P158	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	DELETED																									
41	RECW PUMP	P210	0	0	0	0	0	0	0	0	0	0	68	0	0	0	68	0	0	0	68	0	0	0	68	0
42	TECW PUMP	P103	0	0	0	0	0	0	0	0	11	0	0	0	12	11	0	0	11	0	0	0	12	11	0	0
43	INSTRUMENT AC POWER SUPPLY	Y105	0	0	0	0	0	0	0	0	5	0	24	14	24	24	24	24	5	0	24	14	24	24	24	24
43	INSTRUMENT AC POWER SUPPLY	Y106																								
43	INSTRUMENT AC POWER SUPPLY	Y201																								
43	INSTRUMENT AC POWER SUPPLY	Y202																								
44	EMERGENCY LIGHTING	MISC	0	0	0	0	0	0	0	0	26	0	108	99	0	59	80	68	26	0	108	99	0	59	80	68
45	TURBINE GEN BEARING LIFT PUMP	P109	0	0	0	0	0	0	0	0	45	0	0	0	36	0	0	0	45	0	0	0	36	0	0	0
46	TURBINE GEN TURNING GEAR OIL PUMP	P111	0	0	0	0	0	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0
47	TURBINE GEN TURNING GEAR	S103	0	0	0	0	0	0	0	0	48	0	0	0	24	0	0	0	48	0	0	0	24	0	0	0
48	RFPT TURNING GEAR	S106	0	0	0	0	0	0	0	0	2	0	0	0	2	1	0	0	2	0	0	0	2	1	0	0
49	INSTRUMENT GAS COMPRESSOR	K203	0	0	0	0	0	0	0	0	2	0	0	0	1	0	0	0	2	0	0	0	1	0	0	0
50	INSTRUMENT AIR COMPRESSOR	K101	0	0	0	0	0	0	0	0	0	0	33	0	0	0	33	0	0	0	33	0	0	0	33	0
51																										
52	OSC XFMR PNLS 00L140 & 00L141	X186	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
53	TEST ENGINEER'S WORKSHOP	X187	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
54	NORTH STACK RM ANTENNA SYS XFMR	X595	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55																										
56	CRD REPAIR RM COOLING FAN	V904	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57	125V BATTERY CHARGER	D113	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	94	0	0	0	94	0	0	0	94
58	FIRE ALARM & P/A	1X5	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0
59	FUEL POOL COOLING WATER PUMP	P211	0	0	0	0	0	0	0	0	32	0	0	0	31	0	0	0	32	0	0	0	31	0	0	0
60	FUEL POOL SVC WATER BOOSTER PUMP	P212	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
61	INSTR. AC PWR SUPPLY (SPRAY POND)	Y501	1	0	0	0	0	0	8	8	1	0	0	0	0	0	8	8	1	0	0	0	0	0	8	8
62	SPRAY POND PP STA. HTG COIL (6,11)	E701	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	SGTS RM VENT EXHAUST FAN	V131	0	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0
64	SECURITY AREAS AIR COND.	V565	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	14	0	0	0	0	0
65	PIPING FILL PUMP	P256	0	0	0	0	0	0	0	0	3	0	0	0	3	3	0	0	3	0	0	0	3	3	0	0
66	DRYWELL H2O2 ANALYZER	S205	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
67	SUPPRESSION POOL H2O2 ANALYZER	S206	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
68	CHILLER PUMP-OUT COMPRESSOR	K114	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0	0	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-11 (continued)

CALC 6380E.07 PAGE : 3 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D12 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
69	SPRAY POND SUMP PUMP	P578	0	0	0	0	0	0	0	0	2	0	0	0	0	0	2	2	2	0	0	0	0	0	2	2
70	AUX EG. RM & COMP RM ELE. HUMID (11)	E743	0	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0
71	CONTROL RM ELEC HUMIDIFIER (11)	E744	0	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0
72	250V BATTERY CHARGER	D123	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0
73	ALT POWER SUPPLY TO 10X161 XFMR	10X161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
74	PNL 00-Y500 MAINT PWR SUPPLY VIA XFMR	00-X500	0	0	0	0	0	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	20	0	0	0
75	TELEPHONE EQUIP POWER XFMR	X503	0	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
76	RECOMBINER HYDROGEN ANALYZER	P947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
77	DIESEL GENERATOR BRIDGE CRANE	H501	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
78	440V POWER RECEPTACLE	W508	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H511	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H513																								
80	TURB BLDG EQUIP COMPT EXHAUST FAN	V106	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
81	DRYWELL CHILLER COMPRESSOR	K111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
82	ROD DRIVE CONROL CABINET XFMR	X516	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
83	SLCS PUMP	P208	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
84	RWCU SYSTEM RECIRC PUMP	P221	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W201	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W202																								
85	440V POWER RECEPTACLES	W205																								
86	440V POWER RECEPTACLES / SP RECIRC	W601	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
87	440V POWER RECEPTACLES	W206	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
88	MCC ANNUNCIATORS		1	0	1	1	1	1	1	1	1	0	1	1	1	1	1	1	1	0	1	1	1	1	1	1
89	TURB GEN TURNING GEAR PIGGYBCK MTR	S195	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0
90	RHRSW CORROSION MONITORING	Y215	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
91	ADMIN BLDG 480V DISTR PNL	00B500	0	0	0	0	0	0	0	0	0	0	66	0	0	0	0	0	0	0	66	0	0	0	0	0
	4kv BUS SUBTOTAL (kw)		2352	0	2099	1710	1865	1741	2024	1996	2206	0	1629	1409	1087	1850	777	683	2206	0	1629	1409	1087	1850	777	683

LEGEND

(6) THE SPRAY POND PUMP STATION HEATING COILS ARE TRIPPED BY A LOCA SIGNAL.

(7) ASSIGNMENT OF THE LOADING ON THE DIESEL GENERATORS IS SUCH THAT THE SITUATION OF A DBA ON ONE UNIT AND SPURIOUS LOCA ON THE OTHER UNIT DOES NOT PRECLUDE SAFE SHUTDOWN OF THE UNITS. A SPURIOUS LOCA IS DEFINED AS A LOCA FOR 0-10 MINUTES AND EMERGENCY SHUTDOWN FOR BEYOND 10 MINUTES.

(11) HEATING LOADS AND COOLING LOADS ARE NOT COINCIDENT. THE COINCIDENT COOLING LOAD IS LARGER THAN THE COINCIDENT HEATING LOAD, THEREFORE, THE COOLING LOADS ARE SHOWN ENERGIZED.

Table 8.3-12

CALC 6380E.07 PAGE : 1 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D13 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
1	RHR PUMP	P202	993	993	0	993	977	993	993	993	993	993	0	0	0	993	0	0	993	993	0	0	0	993	0	0
2	CORE SPRAY PUMP	P206	529	529	0	529	529	529	529	529	0	529	0	529	0	0	0	0	0	529	0	529	0	0	0	0
3	RHR SERVICE WATER PUMP	P506	0	0	0	0	0	0	0	0	0	0	0	0	519	519	0	0	0	0	0	0	519	519	0	0
4	ESW PUMP	P548	380	389	0	0	0	0	389	389	0	0	0	0	0	0	389	389	0	0	0	0	0	0	389	389
5	125V BATTERY CHARGER	D103	51	50	0	9	51	51	9	9	51	50	0	9	51	51	9	9	51	50	0	9	51	51	9	9
6	DRYWELL COOLER FAN	V212	80	80	0	0	80	80	0	0	80	0	0	80	80	80	0	0	80	0	0	80	80	80	0	0
7	DG ROOM VENT FAN	V512	30	30	0	30	30	30	30	30	30	30	0	30	30	30	30	30	30	30	0	30	30	30	30	30
8	RHR ROOM COOLING UNIT	V210	16	16	0	16	16	16	16	16	16	16	0	16	16	16	16	16	16	16	0	16	16	16	16	16
9	CORE SPRAY ROOM COOLING UNIT	V211	7	8	0	8	7	7	7	7	7	8	0	8	7	7	7	7	7	8	0	8	7	7	7	7
10	HPCI ROOM COOLING UNIT	V209	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0
11	RCIC ROOM COOLING UNIT	V208	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0
12	INSTRUMENT AC POWER SUPPLY	Y101	11	11	0	11	12	12	12	12	11	11	0	11	12	12	12	12	11	11	0	11	12	12	12	12
12	INSTRUMENT AC POWER SUPPLY	Y102																								
12	INSTRUMENT AC POWER SUPPLY	Y103																								
12	INSTRUMENT AC POWER SUPPLY	Y104																								
13	DG START AIR COMPRESSOR	K513	0	0	0	0	0	0	0	0	7	7	0	7	7	7	7	7	7	7	0	7	7	7	7	7
14	DG FUEL OIL TRANSFER PUMP	P514	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	SGTS HEATER	E188	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0
16	SGTS ROOM UNIT COOLER	V140	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
17	SGTS ROOM ACCESS UNIT COOLER	V141	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
18	SGTS EXHAUST FAN	V163	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0
19	RERS FAN	V213	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0
20	HVAC DAMPER POWER	Y163	4	4	0	20	2	2	22	2	4	4	0	20	2	2	22	2	4	4	0	20	2	2	22	2
20	HVAC DAMPER POWER	Y164																								
20	HVAC DAMPER POWER	Y206																								
20	HVAC DAMPER POWER	Y207																								
21	CONTROL ROOM CHILLER	K112	0	0	0	330	0	0	0	0	0	0	0	330	0	0	0	0	0	0	0	330	0	0	0	0
22	CONTROL ROOM CHILLER WATER PUMP	P162	0	0	0	20	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	20	0	0	0	0
23	AUX PNL & COMP RM FAN COIL UNIT	V114	0	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0
24	AUX PNL & COMP RM RETURN AIR UNIT	V120	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0
25	CONTROL ROOM AIR COND UNIT	V116	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0
26	CONTROL ROOM RETURN AIR FAN	V121	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0
27	EMER SWGR & BTRY RM AIR COND UNIT	V118	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0
28	AUX EQUIP & COMP RM AREA HTR (11)	E193	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	CONTROL ROOM AREA HEATER (11)	E192	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	CONTROL RM FRESH AIR INTAKE HTR (11)	E191	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0
31	SPRAY POND STA. HTG COIL FAN (11)	V543	7	7	0	0	0	0	0	0	7	7	0	0	0	0	0	0	7	7	0	0	0	0	0	0
32	SLCS HEATERS	S213	0	0	0	0	0	0	8	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0	8	0
33	CONTAINMENT H2 RECOMBINER	S403	0	0	0	0	0	0	0	0	0	0	0	0	0	0	48	0	0	0	0	0	0	0	48	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-12 (continued)

CALC 6380E.07 PAGE : 2 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D13 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
34	CONTROL ROOM FRESH AIR SUPPLY FAN	V127	0	0	0	8	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0	8	0	0	0	0
35	CONTROL ROOM CHILLER OIL PUMP	P168	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
36	DG AUXILIARIES	G501	0	0	0	0	0	0	0	0	14	14	0	14	14	14	14	14	14	14	0	14	14	14	14	14
37	DELETED																									
37	DELETED																									
38	DELETED																									
39	CRD PUMP	P158	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	DELETED																									
41	RECW PUMP	P210	0	0	0	0	0	0	0	0	0	0	0	68	0	0	68	0	0	0	0	68	0	0	68	0
42	TECW PUMP	P103	0	0	0	0	0	0	0	0	11	11	0	0	12	11	0	0	11	11	0	0	12	11	0	0
43	INSTRUMENT AC POWER SUPPLY	Y105	0	0	0	0	0	0	0	0	5	10	0	14	24	24	24	24	5	10	0	14	24	24	24	24
43	INSTRUMENT AC POWER SUPPLY	Y106																								
43	INSTRUMENT AC POWER SUPPLY	Y201																								
43	INSTRUMENT AC POWER SUPPLY	Y202																								
44	EMERGENCY LIGHTING	MISC	0	0	0	0	0	0	0	0	26	70	0	99	0	59	80	68	26	70	0	99	0	59	80	68
45	TURBINE GEN BEARING LIFT PUMP	P109	0	0	0	0	0	0	0	0	45	0	0	0	36	0	0	0	45	0	0	0	36	0	0	0
46	TURBINE GEN TURNING GEAR OIL PUMP	P111	0	0	0	0	0	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0
47	TURBINE GEN TURNING GEAR	S103	0	0	0	0	0	0	0	0	48	0	0	0	24	0	0	0	48	0	0	0	24	0	0	0
48	RFPT TURNING GEAR	S106	0	0	0	0	0	0	0	0	2	1	0	0	2	1	0	0	2	1	0	0	2	1	0	0
49	INSTRUMENT GAS COMPRESSOR	K203	0	0	0	0	0	0	0	0	2	0	0	0	1	0	0	0	2	0	0	0	1	0	0	0
50	INSTRUMENT AIR COMPRESSOR	K101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	33	0	0	0	0	0	0	0	33	0
51																										
52	OSC XFMR PNLS 00L140 & 00L141	X186	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
53	TEST ENGINEER'S WORKSHOP	X187	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
54	NORTH STACK RM ANTENNA SYS XFMR	X595	0	0	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0
55																										
56	CRD REPAIR RM COOLING FAN	V904	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57	125V BATTERY CHARGER	D113	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	94	0	0	0	94	0	0	0	94
58	FIRE ALARM & P/A	1X5	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0
59	FUEL POOL COOLING WATER PUMP	P211	0	0	0	0	0	0	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0	32	0	0
60	FUEL POOL SVC WATER BOOSTER PUMP	P212	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
61	INSTR. AC PWR SUPPLY (SPRAY POND)	Y501	1	1	0	0	0	0	8	8	1	1	0	0	0	0	8	8	1	1	0	0	0	0	8	8
62	SPRAY POND PP STA. HTG COIL (6,11)	E701	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	SGTS RM VENT EXHAUST FAN	V131	0	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0
64	SECURITY AREAS AIR COND.	V565	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
65	PIPING FILL PUMP	P256	0	0	0	0	0	0	0	0	3	3	0	0	3	3	0	0	3	3	0	0	3	3	0	0
66	DRYWELL H2O2 ANALYZER	S205	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
67	SUPPRESSION POOL H2O2 ANALYZER	S206	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
68	CHILLER PUMP-OUT COMPRESSOR	K114	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-12 (continued)

CALC 6380E.07 PAGE : 3 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION
D13 DIESEL GENERATOR OUT OF SERVICE
UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
69	SPRAY POND SUMP PUMP	P578	0	0	0	0	0	0	0	0	2	2	0	0	0	0	2	2	2	2	0	0	0	0	2	2
70	AUX EG. RM & COMP RM ELE. HUMID (11)	E743	0	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0
71	CONTROL RM ELEC HUMIDIFIER (11)	E744	0	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0
72	250V BATTERY CHARGER	D123	0	0	0	0	0	9	0	0	0	9	0	0	0	9	0	0	0	9	0	0	0	9	0	0
73	ALT POWER SUPPLY TO 10X161 XFMR	10X161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
74	PNL 00-Y500 MAINT PWR SUPPLY VIA XFMR	00-X500	0	0	0	0	0	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	20	0	0	0
75	TELEPHONE EQUIP POWER XFMR	X503	0	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
76	RECOMBINER HYDROGEN ANALYZER	P947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
77	DIESEL GENERATOR BRIDGE CRANE	H501	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
78	440V POWER RECEPTACLE	W508	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H511	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H513																								
80	TURB BLDG EQUIP COMPT EXHAUST FAN	V106	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
81	DRYWELL CHILLER COMPRESSOR	K111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
82	ROD DRIVE CONROL CABINET XFMR	X516	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
83	SLCS PUMP	P208	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
84	RWCU SYSTEM RECIRC PUMP	P221	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W201	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W202																								
85	440V POWER RECEPTACLES	W205																								
86	440V POWER RECEPTACLES / SP RECIRC	W601	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
87	440V POWER RECEPTACLES	W206	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
88	MCC ANNUNCIATORS		1	1	0	1	1	1	1	1	1	1	0	1	1	1	1	1	1	1	0	1	1	1	1	1
89	TURB GEN TURNING GEAR PIGGYBCK MTR	S195	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0
90	RHRSW CORROSION MONITORING	Y215	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
91	ADMIN BLDG 480V DISTR PNL	00B500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	4kv BUS SUBTOTAL (kw)		2352	2130	0	2114	1865	1741	2024	1996	1725	1829	0	1496	1056	1882	777	683	1725	1829	0	1496	1056	1882	777	683

LEGEND

(6) THE SPRAY POND PUMP STATION HEATING COILS ARE TRIPPED BY A LOCA SIGNAL.

(7) ASSIGNMENT OF THE LOADING ON THE DIESEL GENERATORS IS SUCH THAT THE SITUATION OF A DBA ON ONE UNIT AND SPURIOUS LOCA ON THE OTHER UNIT DOES NOT PRECLUDE SAFE SHUTDOWN OF THE UNITS. A SPURIOUS LOCA IS DEFINED AS A LOCA FOR 0-10 MINUTES AND EMERGENCY SHUTDOWN FOR BEYOND 10 MINUTES.

(11) HEATING LOADS AND COOLING LOADS ARE NOT COINCIDENT. THE COINCIDENT COOLING LOAD IS LARGER THAN THE COINCIDENT HEATING LOAD, THEREFORE, THE COOLING LOADS ARE SHOWN ENERGIZED.

Table 8.3-13

CALC 6380E.07 PAGE : 1 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D14 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
1	RHR PUMP	P202	993	993	993	0	977	993	993	993	993	993	0	0	0	993	0	0	993	993	0	0	0	993	0	0
2	CORE SPRAY PUMP	P206	529	529	529	0	529	529	529	529	529	0	529	0	0	0	0	0	529	0	529	0	0	0	0	0
3	RHR SERVICE WATER PUMP	P506	0	0	0	0	0	0	0	0	0	519	0	0	519	0	0	0	0	519	0	0	519	0	0	0
4	ESW PUMP	P548	380	389	0	0	0	0	389	389	0	0	0	0	0	0	389	389	0	0	0	0	0	0	389	389
5	125V BATTERY CHARGER	D103	51	50	9	0	51	51	9	9	51	50	9	0	51	51	9	9	51	50	9	0	51	51	9	9
6	DRYWELL COOLER FAN	V212	80	80	0	0	80	80	0	0	0	80	80	0	80	80	0	0	0	80	80	0	80	80	0	0
7	DG ROOM VENT FAN	V512	30	30	30	0	30	30	30	30	30	30	30	0	30	30	30	30	30	30	30	0	30	30	30	30
8	RHR ROOM COOLING UNIT	V210	16	16	16	0	16	16	16	16	16	16	16	0	16	16	16	16	16	16	16	0	16	16	16	16
9	CORE SPRAY ROOM COOLING UNIT	V211	7	8	7	0	7	7	7	7	7	8	7	0	7	7	7	7	7	8	7	0	7	7	7	7
10	HPCI ROOM COOLING UNIT	V209	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0
11	RCIC ROOM COOLING UNIT	V208	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0
12	INSTRUMENT AC POWER SUPPLY	Y101	11	11	12	0	12	12	12	12	11	11	12	0	12	12	12	12	11	11	12	0	12	12	12	12
12	INSTRUMENT AC POWER SUPPLY	Y102																								
12	INSTRUMENT AC POWER SUPPLY	Y103																								
12	INSTRUMENT AC POWER SUPPLY	Y104																								
13	DG START AIR COMPRESSOR	K513	0	0	0	0	0	0	0	0	7	7	7	0	7	7	7	7	7	7	7	0	7	7	7	7
14	DG FUEL OIL TRANSFER PUMP	P514	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	SGTS HEATER	E188	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0
16	SGTS ROOM UNIT COOLER	V140	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
17	SGTS ROOM ACCESS UNIT COOLER	V141	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
18	SGTS EXHAUST FAN	V163	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0
19	RERS FAN	V213	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0
20	HVAC DAMPER POWER	Y163	4	4	16	0	2	2	22	2	4	4	16	0	2	2	22	2	4	4	16	0	2	2	22	2
20	HVAC DAMPER POWER	Y164																								
20	HVAC DAMPER POWER	Y206																								
20	HVAC DAMPER POWER	Y207																								
21	CONTROL ROOM CHILLER	K112	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0
22	CONTROL ROOM CHILLER WATER PUMP	P162	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
23	AUX PNL & COMP RM FAN COIL UNIT	V114	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0
24	AUX PNL & COMP RM RETURN AIR UNIT	V120	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
25	CONTROL ROOM AIR COND UNIT	V116	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0
26	CONTROL ROOM RETURN AIR FAN	V121	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0
27	EMER SWGR & BTRY RM AIR COND UNIT	V118	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0
28	AUX EQUIP & COMP RM AREA HTR (11)	E193	0	0	0	0	0	0	0	0	0	0	52	0	0	0	0	0	0	0	52	0	0	0	0	0
29	CONTROL ROOM AREA HEATER (11)	E192	0	0	0	0	0	0	0	0	0	0	40	0	0	0	0	0	0	0	40	0	0	0	0	0
30	CONTROL RM FRESH AIR INTAKE HTR (11)	E191	0	0	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	SPRAY POND STA. HTG COIL FAN (11)	V543	7	7	0	0	0	0	0	0	7	7	0	0	0	0	0	0	7	7	0	0	0	0	0	0
32	SLCS HEATERS	S213	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0
33	CONTAINMENT H2 RECOMBINER	S403	0	0	0	0	0	0	0	0	0	0	48	0	0	0	48	0	0	0	48	0	0	0	48	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-13 (continued)

CALC 6380E.07 PAGE : 2 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION
D14 DIESEL GENERATOR OUT OF SERVICE
UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
34	CONTROL ROOM FRESH AIR SUPPLY FAN	V127	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0
35	CONTROL ROOM CHILLER OIL PUMP	P168	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
36	DG AUXILIARIES	G501	0	0	0	0	0	0	0	0	14	14	14	0	14	14	14	14	14	14	14	0	14	14	14	14
37	DELETED																									
37	DELETED																									
38	DELETED																									
39	CRD PUMP	P158	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	DELETED																									
41	RECW PUMP	P210	0	0	0	0	0	0	0	0	0	0	68	0	0	0	68	0	0	0	68	0	0	0	68	0
42	TECW PUMP	P103	0	0	0	0	0	0	0	0	11	11	0	0	12	11	0	0	11	11	0	0	12	11	0	0
43	INSTRUMENT AC POWER SUPPLY	Y105	0	0	0	0	0	0	0	0	5	10	24	0	24	24	24	24	5	10	24	0	24	24	24	24
43	INSTRUMENT AC POWER SUPPLY	Y106																								
43	INSTRUMENT AC POWER SUPPLY	Y201																								
43	INSTRUMENT AC POWER SUPPLY	Y202																								
44	EMERGENCY LIGHTING	MISC	0	0	0	0	0	0	0	0	26	70	108	0	0	59	80	68	26	70	108	0	0	59	80	68
45	TURBINE GEN BEARING LIFT PUMP	P109	0	0	0	0	0	0	0	0	45	0	0	0	36	0	0	0	45	0	0	0	36	0	0	0
46	TURBINE GEN TURNING GEAR OIL PUMP	P111	0	0	0	0	0	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0
47	TURBINE GEN TURNING GEAR	S103	0	0	0	0	0	0	0	0	48	0	0	0	24	0	0	0	48	0	0	0	24	0	0	0
48	RFPT TURNING GEAR	S106	0	0	0	0	0	0	0	0	2	1	0	0	2	1	0	0	2	1	0	0	2	1	0	0
49	INSTRUMENT GAS COMPRESSOR	K203	0	0	0	0	0	0	0	0	2	0	0	0	1	0	0	0	2	0	0	0	1	0	0	0
50	INSTRUMENT AIR COMPRESSOR	K101	0	0	0	0	0	0	0	0	0	0	33	0	0	0	33	0	0	0	33	0	0	0	33	0
51																										
52	OSC XFMR PNLS 00L140 & 00L141	X186	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
53	TEST ENGINEER'S WORKSHOP	X187	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
54	NORTH STACK RM ANTENNA SYS XFMR	X595	0	0	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0
55																										
56	CRD REPAIR RM COOLING FAN	V904	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57	125V BATTERY CHARGER	D113	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	0	94
58	FIRE ALARM & P/A	1X5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
59	FUEL POOL COOLING WATER PUMP	P211	0	0	0	0	0	0	0	0	0	32	0	0	31	32	0	0	0	32	0	0	31	32	0	0
60	FUEL POOL SVC WATER BOOSTER PUMP	P212	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
61	INSTR. AC PWR SUPPLY (SPRAY POND)	Y501	1	1	0	0	0	0	8	8	1	1	0	0	0	0	8	8	1	1	0	0	0	0	8	8
62	SPRAY POND PP STA. HTG COIL (6,11)	E701	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	SGTS RM VENT EXHAUST FAN	V131	0	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0
64	SECURITY AREAS AIR COND.	V565	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	14	0	0	0	0	0
65	PIPING FILL PUMP	P256	0	0	0	0	0	0	0	0	3	3	0	0	3	3	0	0	3	3	0	0	3	3	0	0
66	DRYWELL H2O2 ANALYZER	S205	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
67	SUPPRESSION POOL H2O2 ANALYZER	S206	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
68	CHILLER PUMP-OUT COMPRESSOR	K114	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0	0	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-13 (continued)

CALC 6380E.07 PAGE : 3 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D14 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
69	SPRAY POND SUMP PUMP	P578	0	0	0	0	0	0	0	0	2	2	0	0	0	0	2	2	2	2	0	0	0	0	2	2
70	AUX EG. RM & COMP RM ELE. HUMID (11)	E743	0	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0
71	CONTROL RM ELEC HUMIDIFIER (11)	E744	0	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0
72	250V BATTERY CHARGER	D123	0	0	0	0	0	9	0	0	0	9	0	0	0	9	0	0	0	9	0	0	0	9	0	0
73	ALT POWER SUPPLY TO 10X161 XFMR	10X161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
74	PNL 00-Y500 MAINT PWR SUPPLY VIA XFMR	00-X500	0	0	0	0	0	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	20	0	0	0
75	TELEPHONE EQUIP POWER XFMR	X503	0	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
76	RECOMBINER HYDROGEN ANALYZER	P947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
77	DIESEL GENERATOR BRIDGE CRANE	H501	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
78	440V POWER RECEPTACLE	W508	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H511	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H513																								
80	TURB BLDG EQUIP COMPT EXHAUST FAN	V106	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
81	DRYWELL CHILLER COMPRESSOR	K111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
82	ROD DRIVE CONROL CABINET XFMR	X516	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
83	SLCS PUMP	P208	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
84	RWCU SYSTEM RECIRC PUMP	P221	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W201	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W202																								
85	440V POWER RECEPTACLES	W205																								
86	440V POWER RECEPTACLES / SP RECIRC	W601	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
87	440V POWER RECEPTACLES	W206	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
88	MCC ANNUNCIATORS		1	1	1	0	1	1	1	1	1	1	1	0	1	1	1	1	1	1	1	0	1	1	1	1
89	TURB GEN TURNING GEAR PIGGYBCK MTR	S195	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0
90	RHRSW CORROSION MONITORING	Y215	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
91	ADMIN BLDG 480V DISTR PNL	00B500	0	0	0	0	0	0	0	0	0	0	66	0	0	0	0	0	0	0	66	0	0	0	0	0
	4kv BUS SUBTOTAL (kw)		2352	2130	2098	0	1865	1741	2024	1996	2174	1899	1629	0	1087	1363	777	683	2174	1899	1629	0	1087	1363	777	683

LEGEND

(6) THE SPRAY POND PUMP STATION HEATING COILS ARE TRIPPED BY A LOCA SIGNAL.

(7) ASSIGNMENT OF THE LOADING ON THE DIESEL GENERATORS IS SUCH THAT THE SITUATION OF A DBA ON ONE UNIT AND SPURIOUS LOCA ON THE OTHER UNIT DOES NOT PRECLUDE SAFE SHUTDOWN OF THE UNITS. A SPURIOUS LOCA IS DEFINED AS A LOCA FOR 0-10 MINUTES AND EMERGENCY SHUTDOWN FOR BEYOND 10 MINUTES.

(11) HEATING LOADS AND COOLING LOADS ARE NOT COINCIDENT. THE COINCIDENT COOLING LOAD IS LARGER THAN THE COINCIDENT HEATING LOAD, THEREFORE, THE COOLING LOADS ARE SHOWN ENERGIZED.

Table 8.3-14

CALC 6380E.07 PAGE : 1 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION
D21 DIESEL GENERATOR OUT OF SERVICE
UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
1	RHR PUMP	P202	993	993	993	993	0	993	993	993	0	993	0	993	0	993	0	0	0	993	0	993	0	993	0	0
2	CORE SPRAY PUMP	P206	529	529	529	529	0	529	529	529	529	0	529	0	0	0	0	0	529	0	529	0	0	0	0	0
3	RHR SERVICE WATER PUMP	P506	0	0	0	0	0	0	0	0	519	0	0	0	0	519	0	0	519	0	0	0	0	519	0	0
4	ESW PUMP	P548	380	389	0	0	0	0	389	389	0	0	0	0	0	0	389	389	0	0	0	0	0	0	389	389
5	125V BATTERY CHARGER	D103	51	50	9	9	0	51	9	9	51	50	9	9	0	51	9	9	51	50	9	9	0	51	9	9
6	DRYWELL COOLER FAN	V212	80	80	0	0	0	80	80	0	0	0	80	80	0	80	80	0	0	0	80	80	0	80	80	0
7	DG ROOM VENT FAN	V512	30	30	30	30	0	30	30	30	30	30	30	30	0	30	30	30	30	30	30	30	0	30	30	30
8	RHR ROOM COOLING UNIT	V210	16	16	16	16	0	16	16	16	16	16	16	16	0	16	16	16	16	16	16	16	0	16	16	16
9	CORE SPRAY ROOM COOLING UNIT	V211	7	8	7	8	0	7	7	7	7	8	7	8	0	7	7	7	7	8	7	8	0	7	7	7
10	HPCI ROOM COOLING UNIT	V209	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0
11	RCIC ROOM COOLING UNIT	V208	8	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0
12	INSTRUMENT AC POWER SUPPLY	Y101	11	11	12	11	0	12	12	12	11	11	12	11	0	12	12	12	11	11	12	11	0	12	12	12
12	INSTRUMENT AC POWER SUPPLY	Y102																								
12	INSTRUMENT AC POWER SUPPLY	Y103																								
12	INSTRUMENT AC POWER SUPPLY	Y104																								
13	DG START AIR COMPRESSOR	K513	0	0	0	0	0	0	0	0	7	7	7	7	0	7	7	7	7	7	7	7	0	7	7	7
14	DG FUEL OIL TRANSFER PUMP	P514	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	SGTS HEATER	E188	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0
16	SGTS ROOM UNIT COOLER	V140	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
17	SGTS ROOM ACCESS UNIT COOLER	V141	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
18	SGTS EXHAUST FAN	V163	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0
19	RERS FAN	V213	151	0	0	0	0	151	0	0	151	0	0	0	0	151	0	0	151	0	0	0	0	151	0	0
20	HVAC DAMPER POWER	Y163	4	4	16	20	0	2	22	2	4	4	16	20	0	2	22	2	4	4	16	20	0	2	22	2
20	HVAC DAMPER POWER	Y164																								
20	HVAC DAMPER POWER	Y206																								
20	HVAC DAMPER POWER	Y207																								
21	CONTROL ROOM CHILLER	K112	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0
22	CONTROL ROOM CHILLER WATER PUMP	P162	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
23	AUX PNL & COMP RM FAN COIL UNIT	V114	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0
24	AUX PNL & COMP RM RETURN AIR UNIT	V120	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
25	CONTROL ROOM AIR COND UNIT	V116	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0
26	CONTROL ROOM RETURN AIR FAN	V121	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0
27	EMER SWGR & BTRY RM AIR COND UNIT	V118	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0
28	AUX EQUIP & COMP RM AREA HTR (11)	E193	0	0	0	0	0	0	0	0	0	0	52	0	0	0	0	0	0	0	52	0	0	0	0	0
29	CONTROL ROOM AREA HEATER (11)	E192	0	0	0	0	0	0	0	0	0	0	40	0	0	0	0	0	0	0	40	0	0	0	0	0
30	CONTROL RM FRESH AIR INTAKE HTR (11)	E191	0	0	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	SPRAY POND STA. HTG COIL FAN (11)	V543	7	7	0	0	0	0	0	0	7	7	0	0	0	0	0	0	7	7	0	0	0	0	0	0
32	SLCS HEATERS	S213	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0
33	CONTAINMENT H2 RECOMBINER	S403	0	0	0	0	0	0	0	0	0	0	48	0	0	0	48	0	0	0	48	0	0	0	48	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-14 (continued)

CALC 6380E.07 PAGE : 2 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D21 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
34	CONTROL ROOM FRESH AIR SUPPLY FAN	V127	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0
35	CONTROL ROOM CHILLER OIL PUMP	P168	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
36	DG AUXILIARIES	G501	0	0	0	0	0	0	0	0	14	14	14	14	0	14	14	14	14	14	14	14	0	14	14	14
37	DELETED																									
37	DELETED																									
38	DELETED																									
39	CRD PUMP	P158	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	DELETED																									
41	RECW PUMP	P210	0	0	0	0	0	0	0	0	0	0	68	0	0	0	68	0	0	0	68	0	0	0	68	0
42	TECW PUMP	P103	0	0	0	0	0	0	0	0	11	11	0	0	0	11	0	0	11	11	0	0	0	11	0	0
43	INSTRUMENT AC POWER SUPPLY	Y105	0	0	0	0	0	0	0	0	5	10	24	14	0	24	24	24	5	10	24	14	0	24	24	24
43	INSTRUMENT AC POWER SUPPLY	Y106																								
43	INSTRUMENT AC POWER SUPPLY	Y201																								
43	INSTRUMENT AC POWER SUPPLY	Y202																								
44	EMERGENCY LIGHTING	MISC	0	0	0	0	0	0	0	0	26	70	108	99	0	59	80	68	26	70	108	99	0	59	80	68
45	TURBINE GEN BEARING LIFT PUMP	P109	0	0	0	0	0	0	0	0	45	0	0	0	0	0	0	0	45	0	0	0	0	0	0	0
46	TURBINE GEN TURNING GEAR OIL PUMP	P111	0	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0
47	TURBINE GEN TURNING GEAR	S103	0	0	0	0	0	0	0	0	48	0	0	0	0	0	0	0	48	0	0	0	0	0	0	0
48	RFPT TURNING GEAR	S106	0	0	0	0	0	0	0	0	2	1	0	0	0	1	0	0	2	1	0	0	0	1	0	0
49	INSTRUMENT GAS COMPRESSOR	K203	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0
50	INSTRUMENT AIR COMPRESSOR	K101	0	0	0	0	0	0	0	0	0	0	33	0	0	0	33	0	0	0	33	0	0	0	33	0
51																										
52	OSC XFMR PNLS 00L140 & 00L141	X186	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
53	TEST ENGINEER'S WORKSHOP	X187	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
54	NORTH STACK RM ANTENNA SYS XFMR	X595	0	0	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0
55																										
56	CRD REPAIR RM COOLING FAN	V904	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57	125V BATTERY CHARGER	D113	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	94	0	0	0	94	0	0	0	94
58	FIRE ALARM & P/A	1X5	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0
59	FUEL POOL COOLING WATER PUMP	P211	0	0	0	0	0	0	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0	32	0	0
60	FUEL POOL SVC WATER BOOSTER PUMP	P212	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
61	INSTR. AC PWR SUPPLY (SPRAY POND)	Y501	1	1	0	0	0	0	8	8	1	1	0	0	0	0	8	8	1	1	0	0	0	0	8	8
62	SPRAY POND PP STA. HTG COIL (6,11)	E701	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	SGTS RM VENT EXHAUST FAN	V131	0	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0
64	SECURITY AREAS AIR COND.	V565	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	14	0	0	0	0	0
65	PIPING FILL PUMP	P256	0	0	0	0	0	0	0	0	3	3	0	0	0	3	0	0	3	3	0	0	0	3	0	0
66	DRYWELL H2O2 ANALYZER	S205	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
67	SUPPRESSION POOL H2O2 ANALYZER	S206	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
68	CHILLER PUMP-OUT COMPRESSOR	K114	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0	0	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-14 (continued)

CALC 6380E.07 PAGE : 3 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D21 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
69	SPRAY POND SUMP PUMP	P578	0	0	0	0	0	0	0	0	2	2	0	0	0	0	2	2	2	2	0	0	0	0	2	2
70	AUX EG. RM & COMP RM ELE. HUMID (11)	E743	0	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0
71	CONTROL RM ELEC HUMIDIFIER (11)	E744	0	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0
72	250V BATTERY CHARGER	D123	0	0	0	0	0	9	0	0	0	9	0	0	0	9	0	0	0	9	0	0	0	9	0	0
73	ALT POWER SUPPLY TO 10X161 XFMR	10X161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
74	PNL 00-Y500 MAINT PWR SUPPLY VIA XFMR	00-X500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
75	TELEPHONE EQUIP POWER XFMR	X503	0	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
76	RECOMBINER HYDROGEN ANALYZER	P947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
77	DIESEL GENERATOR BRIDGE CRANE	H501	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
78	440V POWER RECEPTACLE	W508	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H511	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H513																								
80	TURB BLDG EQUIP COMPT EXHAUST FAN	V106	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
81	DRYWELL CHILLER COMPRESSOR	K111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
82	ROD DRIVE CONROL CABINET XFMR	X516	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
83	SLCS PUMP	P208	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
84	RWCU SYSTEM RECIRC PUMP	P221	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W201	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W202																								
85	440V POWER RECEPTACLES	W205																								
86	440V POWER RECEPTACLES / SP RECIRC	W601	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
87	440V POWER RECEPTACLES	W206	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
88	MCC ANNUNCIATORS		1	1	1	1	0	1	1	1	1	1	1	1	0	1	1	1	1	1	1	1	0	1	1	1
89	TURB GEN TURNING GEAR PIGGYBCK MTR	S195	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
90	RHRSW CORROSION MONITORING	Y215	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
91	ADMIN BLDG 480V DISTR PNL	00B500	0	0	0	0	0	0	0	0	0	0	66	0	0	0	0	0	0	0	66	0	0	0	0	0
	4kv BUS SUBTOTAL (kw)		2352	2130	2099	1629	0	1892	2104	1996	1700	1300	1629	1409	0	2033	857	683	1700	1300	1629	1409	0	2033	857	683

LEGEND

(6) THE SPRAY POND PUMP STATION HEATING COILS ARE TRIPPED BY A LOCA SIGNAL.

(7) ASSIGNMENT OF THE LOADING ON THE DIESEL GENERATORS IS SUCH THAT THE SITUATION OF A DBA ON ONE UNIT AND SPURIOUS LOCA ON THE OTHER UNIT DOES NOT PRECLUDE SAFE SHUTDOWN OF THE UNITS. A SPURIOUS LOCA IS DEFINED AS A LOCA FOR 0-10 MINUTES AND EMERGENCY SHUTDOWN FOR BEYOND 10 MINUTES.

(11) HEATING LOADS AND COOLING LOADS ARE NOT COINCIDENT. THE COINCIDENT COOLING LOAD IS LARGER THAN THE COINCIDENT HEATING LOAD, THEREFORE, THE COOLING LOADS ARE SHOWN ENERGIZED.

Table 8.3-15

CALC 6380E.07 PAGE : 1 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION
D22 DIESEL GENERATOR OUT OF SERVICE
UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
1	RHR PUMP	P202	993	993	993	993	977	0	993	993	0	993	0	993	977	0	0	0	0	993	0	993	977	0	0	0
2	CORE SPRAY PUMP	P206	529	529	529	529	529	0	529	529	529	0	529	0	0	0	0	0	529	0	529	0	0	0	0	0
3	RHR SERVICE WATER PUMP	P506	0	0	0	0	0	0	0	0	519	519	0	0	0	0	0	0	519	519	0	0	0	0	0	0
4	ESW PUMP	P548	380	389	0	0	0	0	389	389	0	0	0	0	0	0	389	389	0	0	0	0	0	0	389	389
5	125V BATTERY CHARGER	D103	51	50	9	9	51	0	9	9	51	50	9	9	51	0	9	9	51	50	9	9	51	0	9	9
6	DRYWELL COOLER FAN	V212	80	80	0	0	80	0	0	80	0	0	80	80	0	0	80	80	0	0	80	80	0	0	80	80
7	DG ROOM VENT FAN	V512	30	30	30	30	30	0	30	30	30	30	30	30	30	0	30	30	30	30	30	30	30	0	30	30
8	RHR ROOM COOLING UNIT	V210	16	16	16	16	16	0	16	16	16	16	16	16	16	0	16	16	16	16	16	16	16	0	16	16
9	CORE SPRAY ROOM COOLING UNIT	V211	7	8	7	8	7	0	7	7	7	8	7	8	7	0	7	7	7	8	7	8	7	0	7	7
10	HPCI ROOM COOLING UNIT	V209	0	10	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	10	0	0	0	0	0	0
11	RCIC ROOM COOLING UNIT	V208	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0
12	INSTRUMENT AC POWER SUPPLY	Y101	11	11	12	11	12	0	12	12	11	11	12	11	12	0	12	12	11	11	12	11	12	0	12	12
12	INSTRUMENT AC POWER SUPPLY	Y102																								
12	INSTRUMENT AC POWER SUPPLY	Y103																								
12	INSTRUMENT AC POWER SUPPLY	Y104																								
13	DG START AIR COMPRESSOR	K513	0	0	0	0	0	0	0	0	7	7	7	7	7	0	7	7	7	7	7	7	7	0	7	7
14	DG FUEL OIL TRANSFER PUMP	P514	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	SGTS HEATER	E188	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0
16	SGTS ROOM UNIT COOLER	V140	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
17	SGTS ROOM ACCESS UNIT COOLER	V141	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
18	SGTS EXHAUST FAN	V163	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0
19	RERS FAN	V213	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0
20	HVAC DAMPER POWER	Y163	4	4	16	20	2	0	22	2	4	4	16	20	2	0	22	2	4	4	16	20	2	0	22	2
20	HVAC DAMPER POWER	Y164																								
20	HVAC DAMPER POWER	Y206																								
20	HVAC DAMPER POWER	Y207																								
21	CONTROL ROOM CHILLER	K112	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0
22	CONTROL ROOM CHILLER WATER PUMP	P162	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
23	AUX PNL & COMP RM FAN COIL UNIT	V114	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0
24	AUX PNL & COMP RM RETURN AIR UNIT	V120	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
25	CONTROL ROOM AIR COND UNIT	V116	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0
26	CONTROL ROOM RETURN AIR FAN	V121	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0
27	EMER SWGR & BTRY RM AIR COND UNIT	V118	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0
28	AUX EQUIP & COMP RM AREA HTR (11)	E193	0	0	0	0	0	0	0	0	0	0	52	0	0	0	0	0	0	0	52	0	0	0	0	0
29	CONTROL ROOM AREA HEATER (11)	E192	0	0	0	0	0	0	0	0	0	0	40	0	0	0	0	0	0	0	40	0	0	0	0	0
30	CONTROL RM FRESH AIR INTAKE HTR (11)	E191	0	0	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	SPRAY POND STA. HTG COIL FAN (11)	V543	7	7	0	0	0	0	0	0	7	7	0	0	0	0	0	0	7	7	0	0	0	0	0	0
32	SLCS HEATERS	S213	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0
33	CONTAINMENT H2 RECOMBINER	S403	0	0	0	0	0	0	0	0	0	0	48	0	0	0	48	0	0	0	48	0	0	0	48	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-15 (continued)

CALC 6380E.07 PAGE : 2 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION
D22 DIESEL GENERATOR OUT OF SERVICE
UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
34	CONTROL ROOM FRESH AIR SUPPLY FAN	V127	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0
35	CONTROL ROOM CHILLER OIL PUMP	P168	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
36	DG AUXILIARIES	G501	0	0	0	0	0	0	0	0	14	14	14	14	14	0	14	14	14	14	14	14	14	0	14	14
37	DELETED																									
37	DELETED																									
38	DELETED																									
39	CRD PUMP	P158	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	DELETED																									
41	RECW PUMP	P210	0	0	0	0	0	0	0	0	0	0	68	0	0	0	68	0	0	0	68	0	0	0	68	0
42	TECW PUMP	P103	0	0	0	0	0	0	0	0	11	11	0	0	12	0	0	0	11	11	0	0	12	0	0	0
43	INSTRUMENT AC POWER SUPPLY	Y105	0	0	0	0	0	0	0	0	5	10	24	14	24	0	24	24	5	10	24	14	24	0	24	24
43	INSTRUMENT AC POWER SUPPLY	Y106																								
43	INSTRUMENT AC POWER SUPPLY	Y201																								
43	INSTRUMENT AC POWER SUPPLY	Y202																								
44	EMERGENCY LIGHTING	MISC	0	0	0	0	0	0	0	0	26	70	108	99	0	0	80	68	26	70	108	99	0	0	80	68
45	TURBINE GEN BEARING LIFT PUMP	P109	0	0	0	0	0	0	0	0	45	0	0	0	36	0	0	0	45	0	0	0	36	0	0	0
46	TURBINE GEN TURNING GEAR OIL PUMP	P111	0	0	0	0	0	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0
47	TURBINE GEN TURNING GEAR	S103	0	0	0	0	0	0	0	0	48	0	0	0	24	0	0	0	48	0	0	0	24	0	0	0
48	RFPT TURNING GEAR	S106	0	0	0	0	0	0	0	0	2	1	0	0	2	0	0	0	2	1	0	0	2	0	0	0
49	INSTRUMENT GAS COMPRESSOR	K203	0	0	0	0	0	0	0	0	2	0	0	0	1	0	0	0	2	0	0	0	1	0	0	0
50	INSTRUMENT AIR COMPRESSOR	K101	0	0	0	0	0	0	0	0	0	0	33	0	0	0	33	0	0	0	33	0	0	0	33	0
51																										
52	OSC XFMR PNLS 00L140 & 00L141	X186	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
53	TEST ENGINEER'S WORKSHOP	X187	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
54	NORTH STACK RM ANTENNA SYS XFMR	X595	0	0	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0
55																										
56	CRD REPAIR RM COOLING FAN	V904	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57	125V BATTERY CHARGER	D113	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	94	0	0	0	94	0	0	0	94
58	FIRE ALARM & P/A	1X5	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0
59	FUEL POOL COOLING WATER PUMP	P211	0	0	0	0	0	0	0	0	0	32	0	0	31	0	0	0	0	32	0	0	31	0	0	0
60	FUEL POOL SVC WATER BOOSTER PUMP	P212	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
61	INSTR. AC PWR SUPPLY (SPRAY POND)	Y501	1	1	0	0	0	0	8	8	1	1	0	0	0	0	8	8	1	1	0	0	0	0	8	8
62	SPRAY POND PP STA. HTG COIL (6,11)	E701	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	SGTS RM VENT EXHAUST FAN	V131	0	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0
64	SECURITY AREAS AIR COND.	V565	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	14	0	0	0	0	0
65	PIPING FILL PUMP	P256	0	0	0	0	0	0	0	0	3	3	0	0	3	0	0	0	3	3	0	0	3	0	0	0
66	DRYWELL H2O2 ANALYZER	S205	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
67	SUPPRESSION POOL H2O2 ANALYZER	S206	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
68	CHILLER PUMP-OUT COMPRESSOR	K114	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0	0	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-15 (continued)

CALC 6380E.07 PAGE : 3 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D22 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
69	SPRAY POND SUMP PUMP	P578	0	0	0	0	0	0	0	0	2	2	0	0	0	0	2	2	2	2	0	0	0	0	2	2
70	AUX EG. RM & COMP RM ELE. HUMID (11)	E743	0	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0
71	CONTROL RM ELEC HUMIDIFIER (11)	E744	0	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0
72	250V BATTERY CHARGER	D123	0	0	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0
73	ALT POWER SUPPLY TO 10X161 XFMR	10X161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
74	PNL 00-Y500 MAINT PWR SUPPLY VIA XFMR	00-X500	0	0	0	0	0	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	20	0	0	0
75	TELEPHONE EQUIP POWER XFMR	X503	0	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
76	RECOMBINER HYDROGEN ANALYZER	P947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
77	DIESEL GENERATOR BRIDGE CRANE	H501	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
78	440V POWER RECEPTACLE	W508	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H511	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H513																								
80	TURB BLDG EQUIP COMPT EXHAUST FAN	V106	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
81	DRYWELL CHILLER COMPRESSOR	K111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
82	ROD DRIVE CONROL CABINET XFMR	X516	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
83	SLCS PUMP	P208	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
84	RWCU SYSTEM RECIRC PUMP	P221	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W201	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W202																								
85	440V POWER RECEPTACLES	W205																								
86	440V POWER RECEPTACLES / SP RECIRC	W601	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
87	440V POWER RECEPTACLES	W206	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
88	MCC ANNUNCIATORS		1	1	1	1	1	0	1	1	1	1	1	1	1	0	1	1	1	1	1	1	1	0	1	1
89	TURB GEN TURNING GEAR PIGGYBCK MTR	S195	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0
90	RHRSW CORROSION MONITORING	Y215	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
91	ADMIN BLDG 480V DISTR PNL	00B500	0	0	0	0	0	0	0	0	0	0	66	0	0	0	0	0	0	0	66	0	0	0	0	0
	4kv BUS SUBTOTAL (kw)		2352	2130	2099	1629	1865	0	2024	2076	1700	1819	1629	1409	1465	0	857	763	1700	1819	1629	1409	1465	0	857	763

LEGEND

(6) THE SPRAY POND PUMP STATION HEATING COILS ARE TRIPPED BY A LOCA SIGNAL.

(7) ASSIGNMENT OF THE LOADING ON THE DIESEL GENERATORS IS SUCH THAT THE SITUATION OF A DBA ON ONE UNIT AND SPURIOUS LOCA ON THE OTHER UNIT DOES NOT PRECLUDE SAFE SHUTDOWN OF THE UNITS. A SPURIOUS LOCA IS DEFINED AS A LOCA FOR 0-10 MINUTES AND EMERGENCY SHUTDOWN FOR BEYOND 10 MINUTES.

(11) HEATING LOADS AND COOLING LOADS ARE NOT COINCIDENT. THE COINCIDENT COOLING LOAD IS LARGER THAN THE COINCIDENT HEATING LOAD, THEREFORE, THE COOLING LOADS ARE SHOWN ENERGIZED.

Table 8.3-16

CALC 6380E.07 PAGE : 1 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION
D23 DIESEL GENERATOR OUT OF SERVICE
UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
1	RHR PUMP	P202	993	993	993	993	977	993	0	993	993	993	0	0	0	993	0	0	993	993	0	0	0	993	0	0
2	CORE SPRAY PUMP	P206	529	529	529	529	529	529	0	529	0	529	0	529	0	0	0	0	0	529	0	529	0	0	0	0
3	RHR SERVICE WATER PUMP	P506	0	0	0	0	0	0	0	0	0	0	0	0	519	519	0	0	0	0	0	0	519	519	0	0
4	ESW PUMP	P548	380	389	0	0	0	0	0	389	380	0	0	0	0	0	0	389	380	0	0	0	0	0	0	389
5	125V BATTERY CHARGER	D103	51	50	9	9	51	51	0	9	51	50	9	9	51	51	0	9	51	50	9	9	51	51	0	9
6	DRYWELL COOLER FAN	V212	80	80	0	0	80	80	0	0	0	0	80	80	80	80	0	0	0	0	80	80	80	80	0	0
7	DG ROOM VENT FAN	V512	30	30	30	30	30	30	0	30	30	30	30	30	30	30	0	30	30	30	30	30	30	30	0	30
8	RHR ROOM COOLING UNIT	V210	16	16	16	16	16	16	0	16	16	16	16	16	16	16	0	16	16	16	16	16	16	16	0	16
9	CORE SPRAY ROOM COOLING UNIT	V211	7	8	7	8	7	7	0	7	7	8	7	8	7	7	0	7	7	8	7	8	7	7	0	7
10	HPCI ROOM COOLING UNIT	V209	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0
11	RCIC ROOM COOLING UNIT	V208	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0
12	INSTRUMENT AC POWER SUPPLY	Y101	11	11	12	11	12	12	0	12	11	11	12	11	12	12	0	12	11	11	12	11	12	12	0	12
12	INSTRUMENT AC POWER SUPPLY	Y102																								
12	INSTRUMENT AC POWER SUPPLY	Y103																								
12	INSTRUMENT AC POWER SUPPLY	Y104																								
13	DG START AIR COMPRESSOR	K513	0	0	0	0	0	0	0	0	7	7	7	7	7	7	0	7	7	7	7	7	7	7	0	7
14	DG FUEL OIL TRANSFER PUMP	P514	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	SGTS HEATER	E188	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0
16	SGTS ROOM UNIT COOLER	V140	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
17	SGTS ROOM ACCESS UNIT COOLER	V141	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
18	SGTS EXHAUST FAN	V163	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0
19	RERS FAN	V213	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0
20	HVAC DAMPER POWER	Y163	4	4	16	20	2	2	0	2	4	4	16	20	2	2	0	2	4	4	16	20	2	2	0	2
20	HVAC DAMPER POWER	Y164																								
20	HVAC DAMPER POWER	Y206																								
20	HVAC DAMPER POWER	Y207																								
21	CONTROL ROOM CHILLER	K112	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0
22	CONTROL ROOM CHILLER WATER PUMP	P162	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
23	AUX PNL & COMP RM FAN COIL UNIT	V114	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0
24	AUX PNL & COMP RM RETURN AIR UNIT	V120	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
25	CONTROL ROOM AIR COND UNIT	V116	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0
26	CONTROL ROOM RETURN AIR FAN	V121	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0
27	EMER SWGR & BTRY RM AIR COND UNIT	V118	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0
28	AUX EQUIP & COMP RM AREA HTR (11)	E193	0	0	0	0	0	0	0	0	0	0	52	0	0	0	0	0	0	0	52	0	0	0	0	0
29	CONTROL ROOM AREA HEATER (11)	E192	0	0	0	0	0	0	0	0	0	0	40	0	0	0	0	0	0	0	40	0	0	0	0	0
30	CONTROL RM FRESH AIR INTAKE HTR (11)	E191	0	0	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	SPRAY POND STA. HTG COIL FAN (11)	V543	7	7	0	0	0	0	0	0	7	7	0	0	0	0	0	0	7	7	0	0	0	0	0	0
32	SLCS HEATERS	S213	0	0	8	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0	8	0	0	0	0	0
33	CONTAINMENT H2 RECOMBINER	S403	0	0	0	0	0	0	0	0	0	0	48	0	0	0	0	0	0	0	48	0	0	0	0	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-16 (continued)

CALC 6380E.07 PAGE : 2 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D23 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
34	CONTROL ROOM FRESH AIR SUPPLY FAN	V127	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0
35	CONTROL ROOM CHILLER OIL PUMP	P168	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
36	DG AUXILIARIES	G501	0	0	0	0	0	0	0	0	14	14	14	14	14	14	0	14	14	14	14	14	14	14	0	14
37	DELETED																									
37	DELETED																									
38	DELETED																									
39	CRD PUMP	P158	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	DELETED																									
41	RECW PUMP	P210	0	0	0	0	0	0	0	0	0	0	68	0	0	0	0	68	0	0	68	0	0	0	0	68
42	TECW PUMP	P103	0	0	0	0	0	0	0	0	11	11	0	0	12	11	0	0	11	11	0	0	12	11	0	0
43	INSTRUMENT AC POWER SUPPLY	Y105	0	0	0	0	0	0	0	0	5	10	24	14	24	24	0	24	5	10	24	14	24	24	0	24
43	INSTRUMENT AC POWER SUPPLY	Y106																								
43	INSTRUMENT AC POWER SUPPLY	Y201																								
43	INSTRUMENT AC POWER SUPPLY	Y202																								
44	EMERGENCY LIGHTING	MISC	0	0	0	0	0	0	0	0	26	70	108	99	0	59	0	68	26	70	108	99	0	59	0	68
45	TURBINE GEN BEARING LIFT PUMP	P109	0	0	0	0	0	0	0	0	45	0	0	0	36	0	0	0	45	0	0	0	36	0	0	0
46	TURBINE GEN TURNING GEAR OIL PUMP	P111	0	0	0	0	0	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0
47	TURBINE GEN TURNING GEAR	S103	0	0	0	0	0	0	0	0	48	0	0	0	24	0	0	0	48	0	0	0	24	0	0	0
48	RFPT TURNING GEAR	S106	0	0	0	0	0	0	0	0	2	1	0	0	2	1	0	0	2	1	0	0	2	1	0	0
49	INSTRUMENT GAS COMPRESSOR	K203	0	0	0	0	0	0	0	0	2	0	0	0	1	0	0	0	2	0	0	0	1	0	0	0
50	INSTRUMENT AIR COMPRESSOR	K101	0	0	0	0	0	0	0	0	0	0	33	0	0	0	0	0	0	0	33	0	0	0	0	0
51																										
52	OSC XFMR PNLS 00L140 & 00L141	X186	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
53	TEST ENGINEER'S WORKSHOP	X187	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
54	NORTH STACK RM ANTENNA SYS XFMR	X595	0	0	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0
55																										
56	CRD REPAIR RM COOLING FAN	V904	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57	125V BATTERY CHARGER	D113	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	94	0	0	0	94	0	0	0	94
58	FIRE ALARM & P/A	1X5	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0
59	FUEL POOL COOLING WATER PUMP	P211	0	0	0	0	0	0	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0	32	0	0
60	FUEL POOL SVC WATER BOOSTER PUMP	P212	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
61	INSTR. AC PWR SUPPLY (SPRAY POND)	Y501	1	1	0	0	0	0	0	8	1	1	0	0	0	0	0	8	1	1	0	0	0	0	0	8
62	SPRAY POND PP STA. HTG COIL (6,11)	E701	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	SGTS RM VENT EXHAUST FAN	V131	0	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0
64	SECURITY AREAS AIR COND.	V565	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	14	0	0	0	0	0
65	PIPING FILL PUMP	P256	0	0	0	0	0	0	0	0	3	3	0	0	3	0	0	0	3	3	0	0	3	0	0	0
66	DRYWELL H2O2 ANALYZER	S205	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
67	SUPPRESSION POOL H2O2 ANALYZER	S206	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
68	CHILLER PUMP-OUT COMPRESSOR	K114	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0	0	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-16 (continued)

CALC 6380E.07 PAGE : 3 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D23 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
69	SPRAY POND SUMP PUMP	P578	0	0	0	0	0	0	0	0	2	2	0	0	0	0	0	2	2	2	0	0	0	0	0	2
70	AUX EG. RM & COMP RM ELE. HUMID (11)	E743	0	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0
71	CONTROL RM ELEC HUMIDIFIER (11)	E744	0	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0
72	250V BATTERY CHARGER	D123	0	0	0	0	0	9	0	0	0	9	0	0	0	9	0	0	0	9	0	0	0	9	0	0
73	ALT POWER SUPPLY TO 10X161 XFMR	10X161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
74	PNL 00-Y500 MAINT PWR SUPPLY VIA XFMR	00-X500	0	0	0	0	0	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	20	0	0	0
75	TELEPHONE EQUIP POWER XFMR	X503	0	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
76	RECOMBINER HYDROGEN ANALYZER	P947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
77	DIESEL GENERATOR BRIDGE CRANE	H501	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
78	440V POWER RECEPTACLE	W508	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H511	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H513																								
80	TURB BLDG EQUIP COMPT EXHAUST FAN	V106	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
81	DRYWELL CHILLER COMPRESSOR	K111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
82	ROD DRIVE CONROL CABINET XFMR	X516	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
83	SLCS PUMP	P208	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
84	RWCU SYSTEM RECIRC PUMP	P221	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W201	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W202																								
85	440V POWER RECEPTACLES	W205																								
86	440V POWER RECEPTACLES / SP RECIRC	W601	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
87	440V POWER RECEPTACLES	W206	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
88	MCC ANNUNCIATORS		1	1	1	1	1	1	0	1	1	1	1	1	1	1	0	1	1	1	1	1	1	1	0	1
89	TURB GEN TURNING GEAR PIGGYBCK MTR	S195	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0
90	RHRSW CORROSION MONITORING	Y215	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
91	ADMIN BLDG 480V DISTR PNL	00B500	0	0	0	0	0	0	0	0	0	0	66	0	0	0	0	0	0	0	66	0	0	0	0	0
	4kv BUS SUBTOTAL (kw)		2352	2130	2099	1630	1865	1741	0	1996	2026	1829	1100	945	1056	1879	0	751	2026	1829	1100	945	1056	1879	0	751

LEGEND

(6) THE SPRAY POND PUMP STATION HEATING COILS ARE TRIPPED BY A LOCA SIGNAL.

(7) ASSIGNMENT OF THE LOADING ON THE DIESEL GENERATORS IS SUCH THAT THE SITUATION OF A DBA ON ONE UNIT AND SPURIOUS LOCA ON THE OTHER UNIT DOES NOT PRECLUDE SAFE SHUTDOWN OF THE UNITS. A SPURIOUS LOCA IS DEFINED AS A LOCA FOR 0-10 MINUTES AND EMERGENCY SHUTDOWN FOR BEYOND 10 MINUTES.

(11) HEATING LOADS AND COOLING LOADS ARE NOT COINCIDENT. THE COINCIDENT COOLING LOAD IS LARGER THAN THE COINCIDENT HEATING LOAD, THEREFORE, THE COOLING LOADS ARE SHOWN ENERGIZED.

Table 8.3-17

CALC 6380E.07 PAGE : 1 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION
D24 DIESEL GENERATOR OUT OF SERVICE
UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
1	RHR PUMP	P202	993	993	993	993	977	993	993	0	0	993	0	993	977	0	0	0	0	993	0	993	977	0	0	0
2	CORE SPRAY PUMP	P206	529	529	529	529	529	529	529	0	529	0	529	0	0	0	0	0	529	0	529	0	0	0	0	0
3	RHR SERVICE WATER PUMP	P506	0	0	0	0	0	0	0	0	519	0	0	0	0	519	0	0	519	0	0	0	0	519	0	0
4	ESW PUMP	P548	380	389	0	0	0	0	389	0	0	389	0	0	0	0	389	0	0	389	0	0	0	0	389	0
5	125V BATTERY CHARGER	D103	51	50	9	9	51	51	9	0	51	50	9	9	51	51	9	0	51	50	9	9	51	51	9	0
6	DRYWELL COOLER FAN	V212	80	80	0	0	80	80	0	0	80	0	0	80	0	80	80	0	80	0	0	80	0	80	80	0
7	DG ROOM VENT FAN	V512	30	30	30	30	30	30	30	0	30	30	30	30	30	30	30	0	30	30	30	30	30	30	30	0
8	RHR ROOM COOLING UNIT	V210	16	16	16	16	16	16	16	0	16	16	16	16	16	16	16	0	16	16	16	16	16	16	16	0
9	CORE SPRAY ROOM COOLING UNIT	V211	7	8	7	8	7	7	7	0	7	8	7	8	7	7	7	0	7	8	7	8	7	7	7	0
10	HPCI ROOM COOLING UNIT	V209	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0	0	10	0	0
11	RCIC ROOM COOLING UNIT	V208	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0
12	INSTRUMENT AC POWER SUPPLY	Y101	11	11	12	11	12	12	12	0	11	11	12	11	12	12	12	0	11	11	12	11	12	12	12	0
12	INSTRUMENT AC POWER SUPPLY	Y102																								
12	INSTRUMENT AC POWER SUPPLY	Y103																								
12	INSTRUMENT AC POWER SUPPLY	Y104																								
13	DG START AIR COMPRESSOR	K513	0	0	0	0	0	0	0	0	7	7	7	7	7	7	7	0	7	7	7	7	7	7	7	0
14	DG FUEL OIL TRANSFER PUMP	P514	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	SGTS HEATER	E188	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0	44	0	0	0	0	0	0	0
16	SGTS ROOM UNIT COOLER	V140	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0
17	SGTS ROOM ACCESS UNIT COOLER	V141	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
18	SGTS EXHAUST FAN	V163	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0
19	RERS FAN	V213	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0	151	0	0	0
20	HVAC DAMPER POWER	Y163	4	4	16	20	2	2	22	0	4	4	16	20	2	2	22	0	4	4	16	20	2	2	22	0
20	HVAC DAMPER POWER	Y164																								
20	HVAC DAMPER POWER	Y206																								
20	HVAC DAMPER POWER	Y207																								
21	CONTROL ROOM CHILLER	K112	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0	0	0	329	0	0	0	0	0
22	CONTROL ROOM CHILLER WATER PUMP	P162	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
23	AUX PNL & COMP RM FAN COIL UNIT	V114	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0	0	0	24	0	0	0	0	0
24	AUX PNL & COMP RM RETURN AIR UNIT	V120	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0	0	0	16	0	0	0	0	0
25	CONTROL ROOM AIR COND UNIT	V116	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0	0	0	32	0	0	0	0	0
26	CONTROL ROOM RETURN AIR FAN	V121	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0
27	EMER SWGR & BTRY RM AIR COND UNIT	V118	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0
28	AUX EQUIP & COMP RM AREA HTR (11)	E193	0	0	0	0	0	0	0	0	0	0	52	0	0	0	0	0	0	0	52	0	0	0	0	0
29	CONTROL ROOM AREA HEATER (11)	E192	0	0	0	0	0	0	0	0	0	0	40	0	0	0	0	0	0	0	40	0	0	0	0	0
30	CONTROL RM FRESH AIR INTAKE HTR (11)	E191	0	0	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	SPRAY POND STA. HTG COIL FAN (11)	V543	7	7	0	0	0	0	0	0	7	7	0	0	0	0	0	0	7	7	0	0	0	0	0	0
32	SLCS HEATERS	S213	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0	0	0	8	0
33	CONTAINMENT H2 RECOMBINER	S403	0	0	0	0	0	0	0	0	0	0	48	0	0	0	48	0	0	0	48	0	0	0	48	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-17 (continued)

CALC 6380E.07 PAGE : 2 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D24 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
34	CONTROL ROOM FRESH AIR SUPPLY FAN	V127	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0
35	CONTROL ROOM CHILLER OIL PUMP	P168	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
36	DG AUXILIARIES	G501	0	0	0	0	0	0	0	0	14	14	14	14	14	14	14	0	14	14	14	14	14	14	14	0
37	DELETED																									
37	DELETED																									
38	DELETED																									
39	CRD PUMP	P158	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40	DELETED																									
41	RECW PUMP	P210	0	0	0	0	0	0	0	0	0	0	68	0	0	0	68	0	0	0	68	0	0	0	68	0
42	TECW PUMP	P103	0	0	0	0	0	0	0	0	11	11	0	0	12	11	0	0	11	11	0	0	12	11	0	0
43	INSTRUMENT AC POWER SUPPLY	Y105	0	0	0	0	0	0	0	0	5	10	24	14	24	24	24	0	5	10	24	14	24	24	24	0
43	INSTRUMENT AC POWER SUPPLY	Y106																								
43	INSTRUMENT AC POWER SUPPLY	Y201																								
43	INSTRUMENT AC POWER SUPPLY	Y202																								
44	EMERGENCY LIGHTING	MISC	0	0	0	0	0	0	0	0	26	70	108	99	0	59	80	0	26	70	108	99	0	59	80	0
45	TURBINE GEN BEARING LIFT PUMP	P109	0	0	0	0	0	0	0	0	45	0	0	0	36	0	0	0	45	0	0	0	36	0	0	0
46	TURBINE GEN TURNING GEAR OIL PUMP	P111	0	0	0	0	0	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0	32	0	0	0
47	TURBINE GEN TURNING GEAR	S103	0	0	0	0	0	0	0	0	48	0	0	0	24	0	0	0	48	0	0	0	24	0	0	0
48	RFPT TURNING GEAR	S106	0	0	0	0	0	0	0	0	2	1	0	0	2	1	0	0	2	1	0	0	2	1	0	0
49	INSTRUMENT GAS COMPRESSOR	K203	0	0	0	0	0	0	0	0	2	0	0	0	1	0	0	0	2	0	0	0	1	0	0	0
50	INSTRUMENT AIR COMPRESSOR	K101	0	0	0	0	0	0	0	0	0	0	33	0	0	0	33	0	0	0	33	0	0	0	33	0
51																										
52	OSC XFMR PNLS 00L140 & 00L141	X186	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
53	TEST ENGINEER'S WORKSHOP	X187	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
54	NORTH STACK RM ANTENNA SYS XFMR	X595	0	0	0	0	0	0	0	0	0	9	0	0	0	0	0	0	0	9	0	0	0	0	0	0
55																										
56	CRD REPAIR RM COOLING FAN	V904	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
57	125V BATTERY CHARGER	D113	0	0	0	0	0	0	0	0	0	0	0	94	0	0	0	0	0	0	0	94	0	0	0	0
58	FIRE ALARM & P/A	1X5	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	12	0	0	0	0
59	FUEL POOL COOLING WATER PUMP	P211	0	0	0	0	0	0	0	0	32	32	0	0	31	32	0	0	32	32	0	0	31	32	0	0
60	FUEL POOL SVC WATER BOOSTER PUMP	P212	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
61	INSTR. AC PWR SUPPLY (SPRAY POND)	Y501	1	1	0	0	0	0	8	0	1	1	0	0	0	0	8	0	1	1	0	0	0	0	8	0
62	SPRAY POND PP STA. HTG COIL (6,11)	E701	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	SGTS RM VENT EXHAUST FAN	V131	0	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0	7	0	0	0	0	0	0	0
64	SECURITY AREAS AIR COND.	V565	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	14	0	0	0	0	0
65	PIPING FILL PUMP	P256	0	0	0	0	0	0	0	0	3	3	0	0	3	3	0	0	3	3	0	0	3	3	0	0
66	DRYWELL H2O2 ANALYZER	S205	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
67	SUPPRESSION POOL H2O2 ANALYZER	S206	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0
68	CHILLER PUMP-OUT COMPRESSOR	K114	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0	0	0

CALC 6380E.07 As-Built Calculations Used LGS REV 15D

Table 8.3-17 (continued)

CALC 6380E.07 PAGE : 3 of 3

DIESEL GENERATOR AND EMERGENCY BUS LOADING WITH UNITS 1 & 2 IN OPERATION

D24 DIESEL GENERATOR OUT OF SERVICE

UNIT 1 DESIGN BASIS ACCIDENT; UNIT 2 SPURIOUS LOCA (7)

			0 - 10 MINUTES								10 - 60 MINUTES								1 HOUR AND LONGER							
			UNIT 1				UNIT 2				UNIT 1				UNIT 2				UNIT 1				UNIT 2			
ITEM	LOAD DESCRIPTION	EQUIP NO	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24	D/G BUS D11	D/G BUS D12	D/G BUS D13	D/G BUS D14	D/G BUS D21	D/G BUS D22	D/G BUS D23	D/G BUS D24
69	SPRAY POND SUMP PUMP	P578	0	0	0	0	0	0	0	0	2	2	0	0	0	0	2	0	2	2	0	0	0	0	2	0
70	AUX EG. RM & COMP RM ELE. HUMID (11)	E743	0	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0	43	0	0	0	0	0	0	0
71	CONTROL RM ELEC HUMIDIFIER (11)	E744	0	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0	29	0	0	0	0	0	0	0
72	250V BATTERY CHARGER	D123	0	0	0	0	0	9	0	0	0	9	0	0	0	9	0	0	0	9	0	0	0	9	0	0
73	ALT POWER SUPPLY TO 10X161 XFMR	10X161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
74	PNL 00-Y500 MAINT PWR SUPPLY VIA XFMR	00-X500	0	0	0	0	0	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	20	0	0	0
75	TELEPHONE EQUIP POWER XFMR	X503	0	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0
76	RECOMBINER HYDROGEN ANALYZER	P947	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
77	DIESEL GENERATOR BRIDGE CRANE	H501	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
78	440V POWER RECEPTACLE	W508	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H511	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	SPRAY POND PUMP HOIST	H513																								
80	TURB BLDG EQUIP COMPT EXHAUST FAN	V106	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
81	DRYWELL CHILLER COMPRESSOR	K111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
82	ROD DRIVE CONROL CABINET XFMR	X516	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
83	SLCS PUMP	P208	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
84	RWCU SYSTEM RECIRC PUMP	P221	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W201	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	440V POWER RECEPTACLES	W202																								
85	440V POWER RECEPTACLES	W205																								
86	440V POWER RECEPTACLES / SP RECIRC	W601	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
87	440V POWER RECEPTACLES	W206	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
88	MCC ANNUNCIATORS		1	1	1	1	1	1	1	0	1	1	1	1	1	1	1	0	1	1	1	1	1	1	1	0
89	TURB GEN TURNING GEAR PIGGYBCK MTR	S195	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	2	0	0	0
90	RHRSW CORROSION MONITORING	Y215	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
91	ADMIN BLDG 480V DISTR PNL	00B500	0	0	0	0	0	0	0	0	0	0	66	0	0	0	0	0	0	0	66	0	0	0	0	0
	4kv BUS SUBTOTAL (kw)		2352	2130	2099	1630	1865	1741	2024	0	1812	1689	1549	1409	1465	889	857	0	1812	1689	1549	1409	1465	889	857	0

LEGEND

(6) THE SPRAY POND PUMP STATION HEATING COILS ARE TRIPPED BY A LOCA SIGNAL.

(7) ASSIGNMENT OF THE LOADING ON THE DIESEL GENERATORS IS SUCH THAT THE SITUATION OF A DBA ON ONE UNIT AND SPURIOUS LOCA ON THE OTHER UNIT DOES NOT PRECLUDE SAFE SHUTDOWN OF THE UNITS. A SPURIOUS LOCA IS DEFINED AS A LOCA FOR 0-10 MINUTES AND EMERGENCY SHUTDOWN FOR BEYOND 10 MINUTES.

(11) HEATING LOADS AND COOLING LOADS ARE NOT COINCIDENT. THE COINCIDENT COOLING LOAD IS LARGER THAN THE COINCIDENT HEATING LOAD, THEREFORE, THE COOLING LOADS ARE SHOWN ENERGIZED.

Table 8.3-18

Table 8.3-18
(Deleted)

Table 8.3-18A

Table 8.3-18A
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Table 8.3-19

Table 8.3-19
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Table 8.3-20

Table 8.3-20
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Table 8.3-21

Table 8.3-21
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Table 8.3-22

Table 8.3-22
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Table 8.3-23

Table 8.3-23
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Table 8.3-24

Table 8.3-24
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Table 8.3-25

Table 8.3-25
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Table 8.3-26

Table 8.3-26
(Deleted)

Table 8.3-27

INSTRUMENT AND CONTROL SYSTEMS
POWER SUPPLY PANELS

Panel	Voltage	Division
Y101	120 V ac	I
Y102	"	II
Y103	"	III
Y104	"	IV
Y105	"	NS
Y106	"	NS
Y201	"	NS
Y202	"	NS
Y109	"	NS
Y110	"	NS
AY160	"	NS
BY160	"	NS
AD102	125 V dc	I
BD102	"	II
CD102	"	III
DD102	"	IV
AD108	"	NS
BD108	"	NS
AY185	120 V ac	NS
BY185	"	NS
00Y591	"	NS
00Y592	"	NS
Y163	"	III
Y164	"	IV

NS = Nonsafeguard

Table 8.3-28

UNDERVOLTAGE ALARMS

SECTION I

Number	Annunciator	Status Lights
1	Division I RHR Out-of-Service Panel AC801, #21	RHR Pump Breaker Control Power Undervoltage RHR Unit Coolers Out-of-Service RHRSW Pump Breaker Control Power Undervoltage Spray Pond MOV Overload/Loss of Power Spray Pond HVAC Out-of-Service RHR Relays Logic Power Failure RHR MOVs Overload/Loss of Power RHR Trip Units Out-of-File/ Loss of Power
2	Division II RHR Out-of-Service Panel CC801, #21	Same as #1
3	Division III RHR Out-of-Service Panel AC801, #36	Same as #1
4	Division IV RHR Out-of-Service Panel CC801, #36	Same as #1
5	Division I Core Spray Out-of-Service Panel AC801, #1	Core Spray Pump Breaker Control Power Undervoltage Core Spray Unit Coolers Out-of-Service Core Spray MOVs Overload/Loss of Power Core Spray Logic Power Failure Core Spray Trip Unit Out-of-File/Power Failure
6	Division II Core Spray Out-of-Service Panel CC801, #1	Same as #5
7	Division III Core Spray Out-of-Service Panel AC801, #11	Same as #5

Table 8.3-28 (Cont'd)

Number	Annunciator	Status Lights
8	Division IV Core Spray Out-of-Service Panel CC801, #11	Same as #5
9	RCIC Out-of-Service Panel C848, #1	RCIC Logic Power Failure RCIC Trip Unit Out of File/Power Failure RCIC Area Temperature Logic Power Failure RCIC Inverter Failure RCIC MOVs Overload/Loss of Power RCIC Unit Coolers Out-of- Service
10	HPCI Out-of-Service Panel C847, #1	HPCI Auxiliary Oil Pump Overload/Loss of Power HPCI Inverter Failure HPCI MOV Overload/Loss of Power HPCI Logic Power Failure HPCI Area Temperaure Logic Power Failure HPCI Trip Unit Out-of-File/ Power Failure HPCI Unit Coolers Out-of-Service
11	Division I ESW Out-of-Service Panel AC 867, #1	ESW MOVs Overload/Loss of Power Spray Pond MOVs Overload Loss of Power Spray Pond HVAC Out-of-Service EWS Pump Breaker Control Power Undervoltage
12	Division II ESW Out-of-Service Panel BC867, #16	Same as #11
13	Division III ESW Out-of-Service Panel AC867, #6	Same as #11
14	Division IV ESW Out-of-Service Panel BC867, #21	Same as #11
15	Division I Standby ac Power System Out-of-Service Panel AC861, #17	DG Cooling Water MOVs Overload/Loss of Power 201-DXX Bus Breaker Control Power Undervoltage

Table 8.3-28 (Cont'd)

Number	Annunciator	Status Lights
		101-DXX Bus Breaker Control Power Undervoltage Safeguard LC Xmfr. Breaker Control Power Undervoltage CRD Water Pump Breaker Control Power Undervoltage Turbine Enclosure Exhaust Fan Breaker Control Power Undervoltage Drywell Chiller Breaker Control Power Undervoltage DG Not Ready for Autostart
16	Division II Standby ac Power System Out-of-Service Panel BC861, #17	Same as #15
17	Division III Standby ac Power System Out-of-Service Panel CC861, #17	Same as #15
18	Division IV Standby ac Power System Out-of-Service Panel AC802, #17	Same as #15
19	Reactor Isolation System Outboard Out-of-Service Panel AC802, #25	NSSSS Trip Unit Out-of-File/ Power Failure NSSSS MOV Overload/Loss of Power
20	Reactor Isolation System Inboard Out-of-Service Panel AC802, #20	Same as #19
21	Division I ADS Out-of-Service Panel C826, #1	Relay Logic Power Failure Trip Unit Out-of-File/Power Failure
21A	Division III ADS Out-of-Service Panel C826, #11	Same as #21
22	RPS System A Out-of-Service Panel BC803, #5	Trip Unit Out-of-File/ Power Failure
22A	RPS System B Out-of-Service Panel BC803, #10	Same as #22

Table 8.3-28 (Cont'd)

SECTION II

Number	Bus	Voltage	Alarm	Panel/Window
23	10A101	13.2 kV	11 Unit Auxiliary Bus UV	1BC854/6
24	10A102	13.2 kV	12 Unit Auxiliary Bus UV	1BC854/9
25	20A101	13.2 kV	21 Unit Auxiliary Bus UV	2BC854/26
26	20A102	13.2 kV	22 Unit Auxiliary Bus UV	2BC854/29
27	10	13.2 kV	10 Startup Bus UV	00C860/4
28	20	13.2 kV	20 Startup Bus UV	00C860/24
29	101	4.16 kV	101 Safeguard Bus UV	1AC861/28
30	201	4.16 kV	201 Safeguard Bus UV	1AC861/29
31	D11	4.16 kV	D11 Safeguard Bus UV	1AC861/6
32	D12	4.16 kV	D12 Safeguard Bus UV	1BC861/6
33	D13	4.16 kV	D13 Safeguard Bus UV	1CC861/6
34	D14	4.16 kV	D14 Safeguard Bus UV	1DC861/6
35	D21	4.16 kV	D21 Safeguard Bus UV	2AC861/6
36	D22	4.16 kV	D22 Safeguard Bus UV	2BC861/6
37	D23	4.16 kV	D23 Safeguard Bus UV	2CC861/6
38	D24	4.16 kV	D24 Safeguard Bus UV	2DC861/6
39	AD102	125 V dc	PPA1/A3 125 V dc Distribution Panel UV	AC861/33
40	BD501	125 V dc	PPA2 125 V dc Distribution Panel UV	AC861/34
41	BD102	125 V dc	PPB1/B3 125 V dc Distribution Panel UV	BC861/34
42	BD501	125 V dc	PPB2 125 V dc Distribution Panel UV	BC861/35
43	CD102	125 V dc	PPC1/C3 125 V dc Distribution Panel UV	CC861/32
44	CD501	125 V dc	PPC2 125 V dc Distribution Panel UV	CC861/33

Table 8.3-28 (Cont'd)

Number	Bus	Voltage	Alarm	Panel/Window
45	DD102	125 V dc	PPD1/D3 125 V dc Distribution Panel UV	DC861/32
46	DD501	125 V dc	PPD2 125 V dc Distribution Panel UV	DC861/33
47	AD108	125 V dc	PP01 125 V dc Distribution Panel UV	1AC854/3 2BC854/18
48	BD108	125 V dc	PP02 125 V dc Distribution Panel UV	1AC854/4 2BC854/19
49	CD108	125 V dc	PP03 125 V dc Distribution Panel UV	1AC854/5 2BC854/20
50	DD108	125 V dc	PP04 125 V dc Distribution Panel UV	1AC854/8 2BC854/25

SECTION III

Number	Alarm	Panel/Window
51	A RFPT Control Volt Failure	BC868/5
52	B RFPT Control Volt Failure	BC868/10
53	C RFPT Control Volt Failure	BC868/15
54	A RPS/UPS Static Inverter Trouble	AC861/5
55	B RPS/UPS Static Inverter Trouble	BC861/5
56	RFPT Control Signal Failure	AC803/20
57	IRM Downscale	AC803/33
58	SRM Downscale	AC803/34
59	IRM Upscale/Inop	AC803/38
60	SRM Upscale/Inop	AC803/39
61	OPRM/APRM Trouble	BC803/5
62	Not Used	BC803/9
63	Not Used	BC803/13
64	RBM Downscale/Trouble	BC803/19
65	Not Used	BC803/14

Table 8.3-28 (Cont'd)

Number	Alarm	Panel/Window
66	RPIS Inop	BC803/25
67	SLCS Squib Valve Loss of Continuity	BC803/44
68	Division 1 Core Spray Trip Unit Inverter Power Failure	AC801/5
69	Division 2 Core Spray Trip Unit Inverter Power Failure	CC801/5
70	Division 3 Core Spray Trip Unit Inverter Power Failure	AC801/15
71	Division 4 Core Spray Trip Unit Inverter Power Failure	CC801/15
72	DELETED	
73	DELETED	
74	Main Steam Line (A/B) Radiation Monitor Downscale	C800/26
75	Main Steam Line (C/D) Radiation Monitor Downscale	C800/27
76	North Stack Radiation Monitor Downscale	00C824/23
77	South Stack Radiation Monitor Downscale	00C824/28
78	A RPS/UPS Distribution Panel Trouble	AC861/30
79	B RPS/UPS Distribution Panel Trouble	BC861/29
80	TSC/Computer Trouble	00C855/4
81	A Drywell Chiller Loss of Control Power	C881/11
82	B Drywell Chiller Loss of Control Power	C881/16
83	SPTMS Trouble Division I	AC803/23

Table 8.3-28 (Cont'd)

Number	Alarm	Panel/Window
84	SPTMS Trouble Division II	AC803/24
85	RDCS Inop	BC803/24
86	INTENTIONALLY LEFT BLANK	
87	CRD Trip Unit Out-of-Service	BC803/40
88	CRD Accumulator Trouble	BC803/26
89	A Recirculation MG Controller Signal Failure (Unit 2 only)	AC802/27
89A	A Recirculation ASD Major Failure (Unit 1 only)	AC902/07
90	B Recirculation MG Controller Signal Failure (Unit 2 only)	BC802/27
90A	B Recirculation ASD Major Failure (Unit 1 only)	AC902/07
91	1 RFPT Loss of Power	AC868/33
92	2 RFPT Loss of Power	AC868/38
93	3 RFPT Loss of Power	AC868/43
94	Turbine Enclosure HVAC Panel C126 Trouble	C881/36
95	Suppression Atmospheric Analyzer Trouble	C800/28
96	Drywell Atmospheric Analyzer Trouble	C800/4
97	PMS-1 Failover	CC861/10

Table 8.3-29

PANEL ALARMS WITH LOSS OF POWER
AS POSSIBLE INDIRECT CAUSE

Panel	Indication	Alarm No. / Name	
Y101	Indirect	1	Div. I RHR Out of Service (1)
		5	Div. I CS Out of Service (1)
		9	RCIC Out of Service (1)
		67	Standby Liquid Squib Valve Loss of Continuity
		83	Div. I SPOTMOS Trouble
		94	Turbine Enclosure HVAC Panel C126 Trouble
Y102	Indirect	2	Div. II RHR Out of Service (1)
		6	Div. II CS Out of Service (1)
		10	HPCI Out of Service (1)
		67	Standby Liquid Squib Valve Loss of Continuity
		84	Div. II SPOTMOS Trouble
		94	Turbine Enclosure HVAC Panel C126 Trouble
Y103	Indirect	3	Div. III RHR Out of Service (1)
		7	Div. III CS Out of Service (1)
		67	Standby Liquid Squib Valve Loss of Continuity
Y104	Indirect	4	Div. IV RHR Out of Service (1)
		8	Div. IV CS Out of Service (1)
Y105	Indirect	94	Turbine Enclosure HVAC Panel C126 Trouble
Y106	Indirect	87	CRD Trip Unit Out of Service
		88	CRD Accumulator Trouble
Y201	Indirect	56	RFPT Control Signal Failure
		66	RPIS INOP
		76	North Stack Radiation Monitor Downscale
		77	South Stack Radiation Monitor Downscale
		81	A DW Chiller Loss of Control Power
		93	C RFPT Loss of Power
Y202	Indirect	76	North Stack Radiation Monitor Downscale
		77	South Stack Radiation Monitor Downscale
		82	B DW Chiller Loss of Control Power
AY160	Direct	19	Reactor Isolation System Outboard Out of Service
		20	Reactor Isolation System Inboard Out of Service
		22	RPS System A Out of Service
		54	A RPS / UPS Static Invertor Trouble
		57	IRM Downscale
		58	SRM Downscale
		59	IRM Upscale / Inop
		60	SRM Upscale / Inop
		78	A RPS / UPS Distribution Panel Trouble

Table 8.3-29 (Cont'd)

Panel	Indication	Alarm No. / Name	
BY160	Direct	19	Reactor Isolation System Outboard Out of Service
		20	Reactor Isolation System Inboard Out of Service
		22A	RPS System B Out of Service
		55	B RPS / UPS Static Inverter Trouble
		57	IRM Downscale
		58	SRM Downscale
		59	IRM Upscale / Inop
		60	SRM Upscale / Inop
		79	B RPS / UPS Distribution Panel Trouble
Y109	Indirect	56	RFPT Control Signal Failure
		91	A RFPT Loss of Power
Y110	Indirect	56	RFPT Control Signal Failure
		92	B RFPT Loss of Power
AD102	Direct	1	Div. I RHR Out of Service
		5	Div. I CS Out of Service
		9	RCIC Out of Service
		11	Div. I ESW Out of Service
		15	Div. I Standby ac Power System Out of Service
		21	Div. I ADS Out of Service
		39	PPA1/A3 125V dc Distribution Panel UV
BD102	Direct	2	Div. II RHR Out of Service
		6	Div. II CS Out of Service
		10	HPCI Out of Service
		12	Div. II ESW Out of Service
		16	Div. II Standby ac Power System Out of Service
		41	PPB1/B3 125V dc Distribution Panel UV
CD102	Direct	3	Div. III RHR Out of Service
		7	Div. III CS Out of Service
		9	RCIC Out of Service
		13	Div. III ESW Out of Service
		17	Div. III Standby ac Power System Out of Service
		21A	Div. III ADS Out of Service
		43	PPC1/C3 125V dc Distribution Panel UV
		81	A DW Chiller Loss of Control Power

Table 8.3-29 (Cont'd)

Panel	Indication	Alarm No.	Alarm Name
DD102	Direct	4	Div. IV RHR Out of Service
		8	Div. IV CS Out of Service
		10	HPCI Out of Service
		14	Div. IV ESW Out of Service
		18	Div. IV Standby ac Power System Out of Service
		45	PPD1/D3 125V dc Distribution Panel UV
		82	B DW Chiller Loss of Control Power
AD108	Direct	47	PP01 125V dc Distribution Panel UV
		51	A RFPT Control Voltage Failure
BD108	Direct	48	PP02 125V dc Distribution Panel UV
		52	B RFPT Control Voltage Failure
AY185	Indirect	61	APRM Upscale Trip / Inop
		64	RBM Downscale
BY185	Indirect	61	APRM Upscale Trip / Inop
		64	RBM Downscale
00Y591	Indirect	80	TSC / Computer Trouble
00Y592	Indirect	80	TSC / Computer Trouble
Y163	Indirect	95	SP Atmospheric Analyzer Trouble
Y164	Indirect	96	DW Atmospheric Analyzer Trouble

Note: (1) Panel provides backup feed to system trip units; this alarm will sound only upon concurrent loss of the normal dc supply.

Table 8.3-30

INSTRUMENTS USED TO ACHIEVE COLD SHUTDOWN

Parameter	Instrument #	Bus	Evaluation
Reactor Level	LR42-1R608	Y109,Y110	A
	LI42-1R605	Y201	A
	LI42-1R606A	Y109	A
	LI42-1R606B	Y110	A
	LI42-1R606C	BD108	A
	LI42-1R604	AY160	A
	LI42-1R610	Y101,AD102	A
	LR42-1R615	Y102,BD102	A
	XR42-1R623A	Y101,AD102	A
	XR42-1R623B	Y102,BD102	A
Reactor Pressure	XR42-1R623A	Y101,AD102	A
	XR42-1R623B	Y102,BD102	A
	XR01-1R609	Y105,Y110	A
	PI42-1R605	Y109	A
Vessel Temperature	TR42-1R006	Y202	B
	TR42-1R007	Y202	B
NMS	APRM 1	AY185, BY185	O
	APRM 2	AY185, BY185	O
	APRM 3	AY185, BY185	O
	APRM 4	AY185, BY185	O
	RBM A	AY185, BY185	O
	RBM B	AY185, BY185	O
	SRM A, C	AY160	A
	SRM B, D	BY160	A
	IRM A, C, E, G	AY160	A
	IRM B, D, F, H	BY160	A
	SRM Recorder 602A	BY160	A
	SRM Recorder 602B	BY160	A
	IRM/APRM Recorder 603A	BY160	A
	IRM/APRM Recorder 603B	BY160	A
	IRM/APRM/RBM Recorder 603C	BY160	A
	IRM/APRM/RBM Recorder 603D	BY160	A
RPIS		BY185,Y106,Y201, MCC B130	C
Condenser Vacuum	PR05-101	Y106	D
	PI05-101A	Y106	D
	PI05-101B	Y106	D
	PI05-101C	Y106	D

Table 8.3-30 (Cont'd)

Parameter	Instrument #	Bus	Evaluation
CST level	LR08-102,202	Y106,Y105	F
	LI55-112,212	Y106	F
	LAHL08-112,212	AD108	F
Standby Liquid Control Tank Level	LI48-1R601	Y202	E
Pump Discharge Pressure	PI48-IN600A	Y101,AD102	E
	PI48-IN600B	Y102,BD102	E
	PI48-IN600C	Y103,CD102	E
Suppression Pool Temperature	TRS-041-101	Y101	A
	TRS-041-103	Y102	A
Suppression Pool Level	LI52-140A	Y101,AD102	A
	LI52-140B	Y102	A
	LR55-115	Y105,Y106	A
	LI55-115-1	Y105,Y106	A
Suppression Pool Pressure	PR57-101	Y101,AD102	A
	PR42-101	Y102,BD102	A
Drywell Pressure	PR57-101	Y101,AD102	A
	PI42-170-1	Y102,BD102	A
	PI42-101	Y101,AD102	A
	PI42-170	Y102,BD102	A
Drywell Temperature	TI77-101A-H	Y202	A,D
	TR57-110	Y105	A,D
	TR57-122	Y101	A,D
Turbine 1st Stage Pressure	PI01-112	Y106,Y105	B
CRD System Flow	FI46-R606	Y106	B
HPCI Instrumentation		BD102	G
HPCI Turbine-Pump Temperature	XR - 036-101	Y201	D
	XR - 036-102	Y106	D
HPCI Turbine Vibration	VR56-162	Y102	D
RCIC Instrumentation		AD102	H
Core Spray Instrumentation			
A Loop Flow	FI52-1R601A	Y101,AD102	K
B Loop Flow	FI52-1R601B	Y102,BD102	K
A Loop Disch Pressure	PI52-1R600A	Y101	L
B Loop Disch Pressure	PI52-1R600B	Y102,BD102	L

Table 8.3-30 (Cont'd)

Parameter	Instrument #	Bus	Evaluation
RHR Instrumentation			
A Loop Flow	FI51-1R603A	Y101,AD102	M
B Loop Flow	FI51-1R603B	Y102,BD102	M
C Loop Flow	FI51-1R603C	Y103	M
D Loop Flow	FI51-1R603D	Y104	M
RHR HX A Discharge Pressure	PI51-105A	Y101	M
RHR HX B Discharge Pressure	PI51-105B	Y102	M
Deleted			
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Deleted			
Deleted			
RHR Service Water			
A RHR HX Service Water Flow	FI51-1R602A	Y101,AD102	M
B RHR HX Service Water Flow	FI51-1R602B	Y102,BD102	M
RHR SW Loop A Discharge Pressure	PI12-001A	Y101	N
RHR SW Loop B Discharge Pressure	PI12-001B	Y102	N
RHR SW A HX Outlet Rad	RR12 - OR616A	Y103	N
RHR SW B HX Outlet Rad	RR12 - OR616B	Y104	N
RHR SW A Loop Return Rad	RR12 - OR615A	Y101	N
RHR SW B Loop Return Rad	RR12 - OR615B	Y102	N
Emergency Service Water			
ESW A Flow	FI11-013A	Y101	N
ESW B Flow	FI11-013B	Y102	N
ESW A Supply Pressure	PI11-003A	Y101	N
ESW B Supply Pressure	PI11-003B	Y102	N
ADS			
Relief Valve Position Indication	ZYI41-115EF	AY185	A
SRV Outlet Temperature	XR-036-101	Y201	B
	XR-036-102	Y106	B
Containment Instrument Gas			
A Instrument Gas Pressure	PI59-103A	Y103,CD102	B
B Instrument Gas Pressure	PI59-103B	Y104,DD102	B

Table 8.3-30 (Cont'd)

Parameter	Instrument #	Bus	Evaluation
Radiation Monitoring			
NSE-RMS	RMMS 00Y591,00Y592	Y201,Y202	D
SSE-RMS	RMMS 00Y591,00Y592	Y201,Y202	D
PCPL-RMS	RR26-191A, RMMS	Y103,00Y592	A
PCPL-RMS	RR26-191B, RMMS	Y102,00Y592	A
PCPL-RMS	RR26-191C, RMMS	Y103,00Y592	A
PCPL-RMS	RR26-191D, RMMS	Y102,00Y592	A
Containment Atmospheric Control			
Drywell 0_2	AI 57-150	Y164	B
Drywell H_2	AI 57-151	Y164	B
Pool 0_2	AI 57-187	Y163	B
Pool H_2	AI 57-188	Y163	B

EVALUATIONS

A. There is more than one instrument in the control room to monitor this parameter and these instruments are not fed from the same bus; therefore, the loss of one bus will not affect the operator's ability to determine the value of this parameter.

B. This parameter can be determined from other parameters or local instruments if needed. Loss of this parameter would not affect the capability of achieving a cold shutdown condition.

C. The RPIS receives data from the RMCS and is fed from non-Class 1E instrument buses. If power to these buses is lost, rod position indication will be lost in the control room. Loss of rod position indication does not prohibit a manual or automatic SCRAM; therefore, the capability to achieve a cold shutdown condition is not affected by loss of power to the RMCS or the RPIS.

D. Loss of this parameter does not affect the ability to achieve a cold shutdown condition.

E. The SLCS has been redesigned per ATWS requirements. The controls and instrumentation of this system have been designed to perform their function with a single failure; therefore, loss of power to a single division will not prevent the achievement of a cold shutdown condition.

Table 8.3-30 (Cont'd)

F. CST level indication will be lost when Y106 is lost; however, the tank HI/LOW level alarm will still be operable.

G. If power from panel BD102 is lost, the HPCI becomes inoperative. If this occurs, the ADS will be used to depressurize the reactor vessel so that the RCIC and RHR and core spray systems can be used to achieve a cold shutdown condition. Loss of HPCI due to loss of panel BD102 will not affect the ability to achieve a cold shutdown condition.

H. If power from panel AD102 is lost, the RCIC system becomes inoperative. If this occurs, the HPCI system can be used in its place; therefore, the loss of the RCIC system due to the loss of power from panel AD102 will not affect the ability to achieve a cold shutdown condition.

K. Core spray system instrumentation for Loop A is fed from Division 1 Class 1E power. Loop B instrumentation is fed from Division II. Loss of panel Y101 will cause loss of Loop A flow indication in the control room. Loss of Y102 will cause loss of Loop B flow indication. Loss of either of these panels does not affect the operability of the core spray system; therefore, the ability to achieve a cold shutdown condition is not affected.

L. Both of the supply panels must be lost in order to lose indication of this parameter.

M. The RHR system is composed of two redundant loops, each consisting of two pumps and one RHR heat exchanger. The pressure controllers, flow indicators, and pressure indicators for the A loop are fed from separate power panels than those for the B loop. The loss of one bus feeding RHR instrumentation would not affect the operating capability of the RHR system and therefore, would not affect the ability to achieve a cold shutdown.

N. This system has redundant loops. The instrumentation on each loop is fed from separate buses; therefore, the loss of one loop or panel will not affect the ability to achieve a cold shutdown condition with the remaining loop.

O. There is more than one instrument in the control room to monitor this parameter and these instruments are fed by two buses (redundant power); Therefore, the loss of one bus will not affect the operator’s ability to determine the value of this parameter.

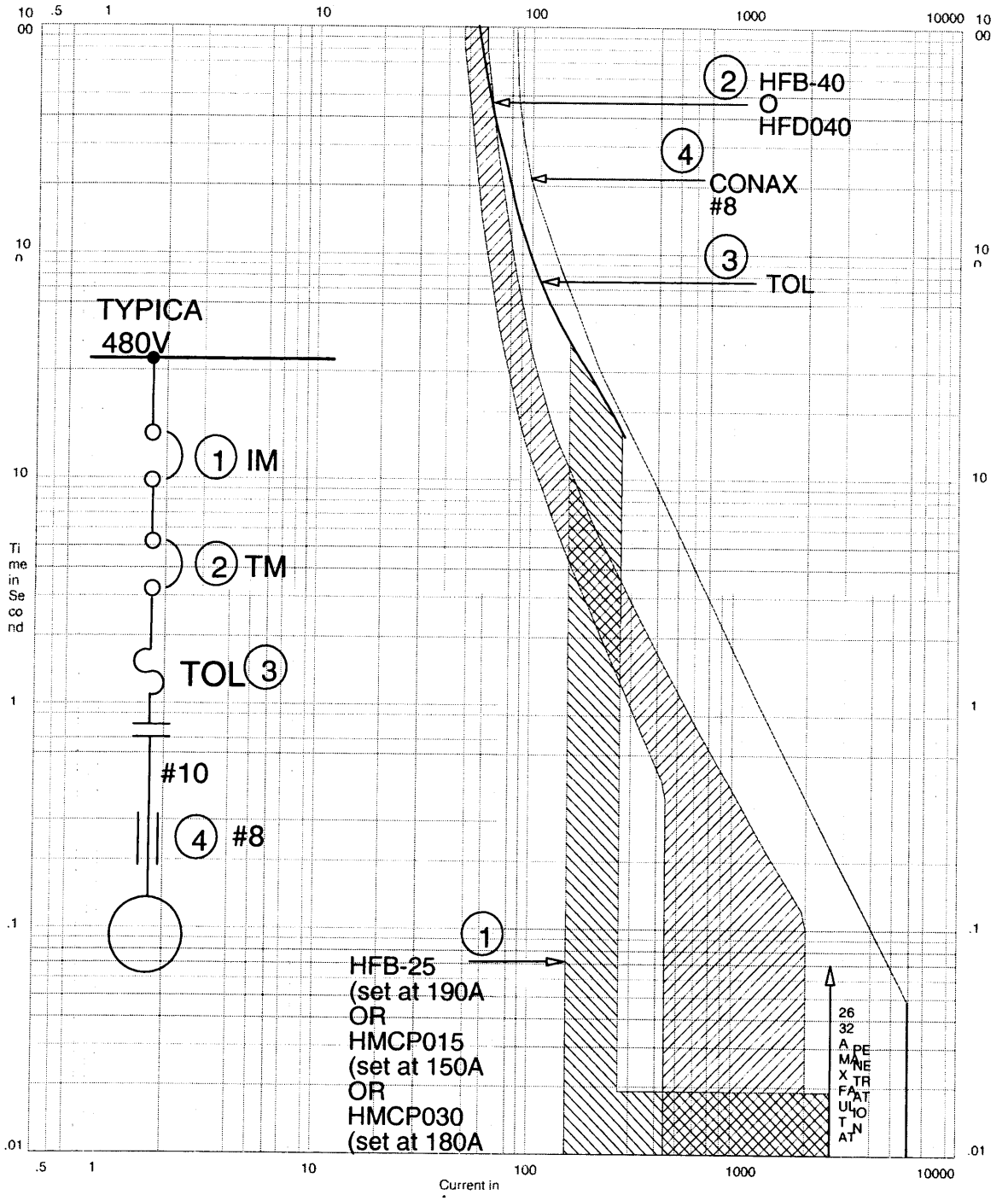
Table 8.3-31
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Table 8.3-32

(The information in this table has been relocated to the TRM)

Figure 8.1-1

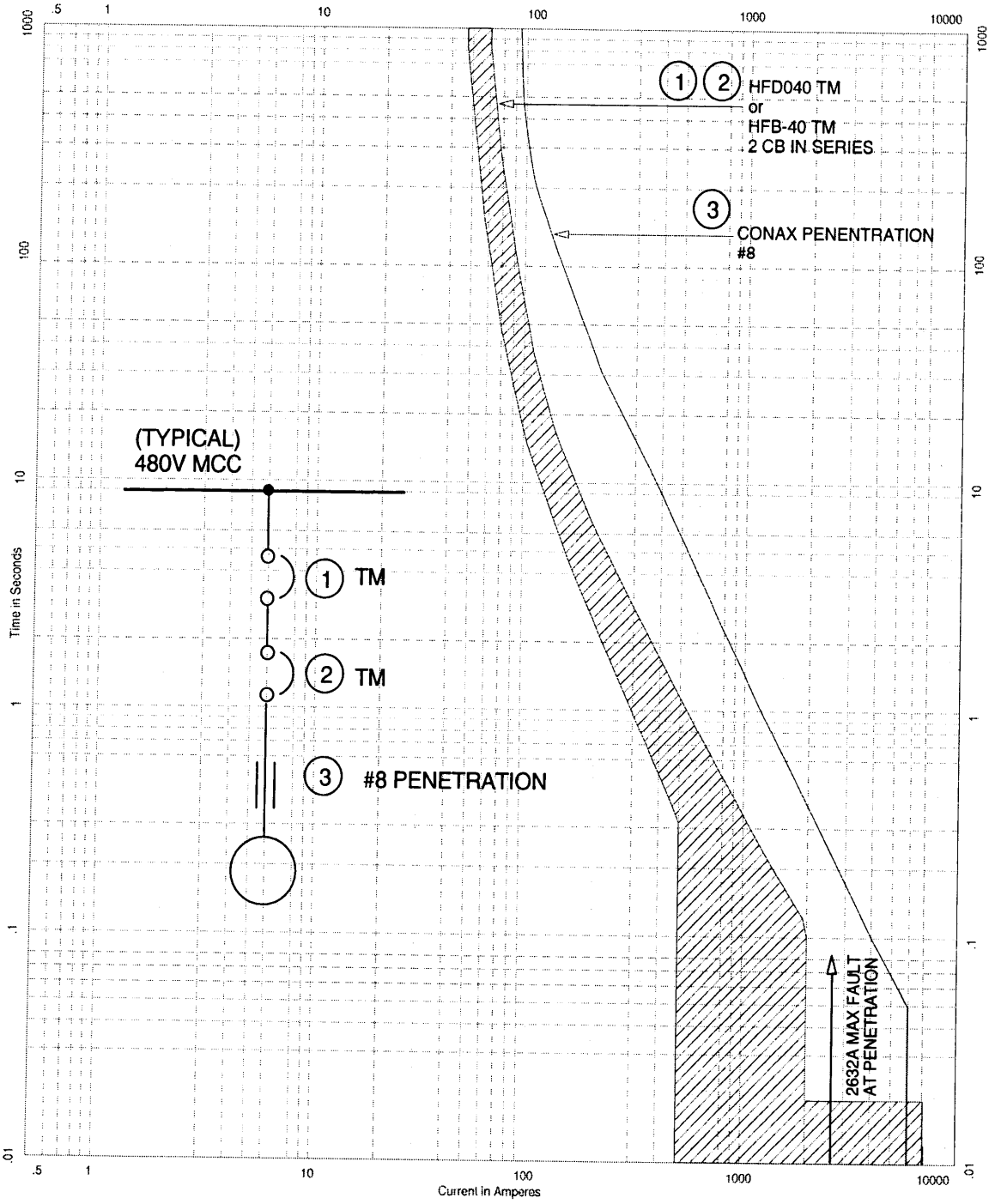
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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

440 VOLT SYSTEM
(Sheet 1 of 5)

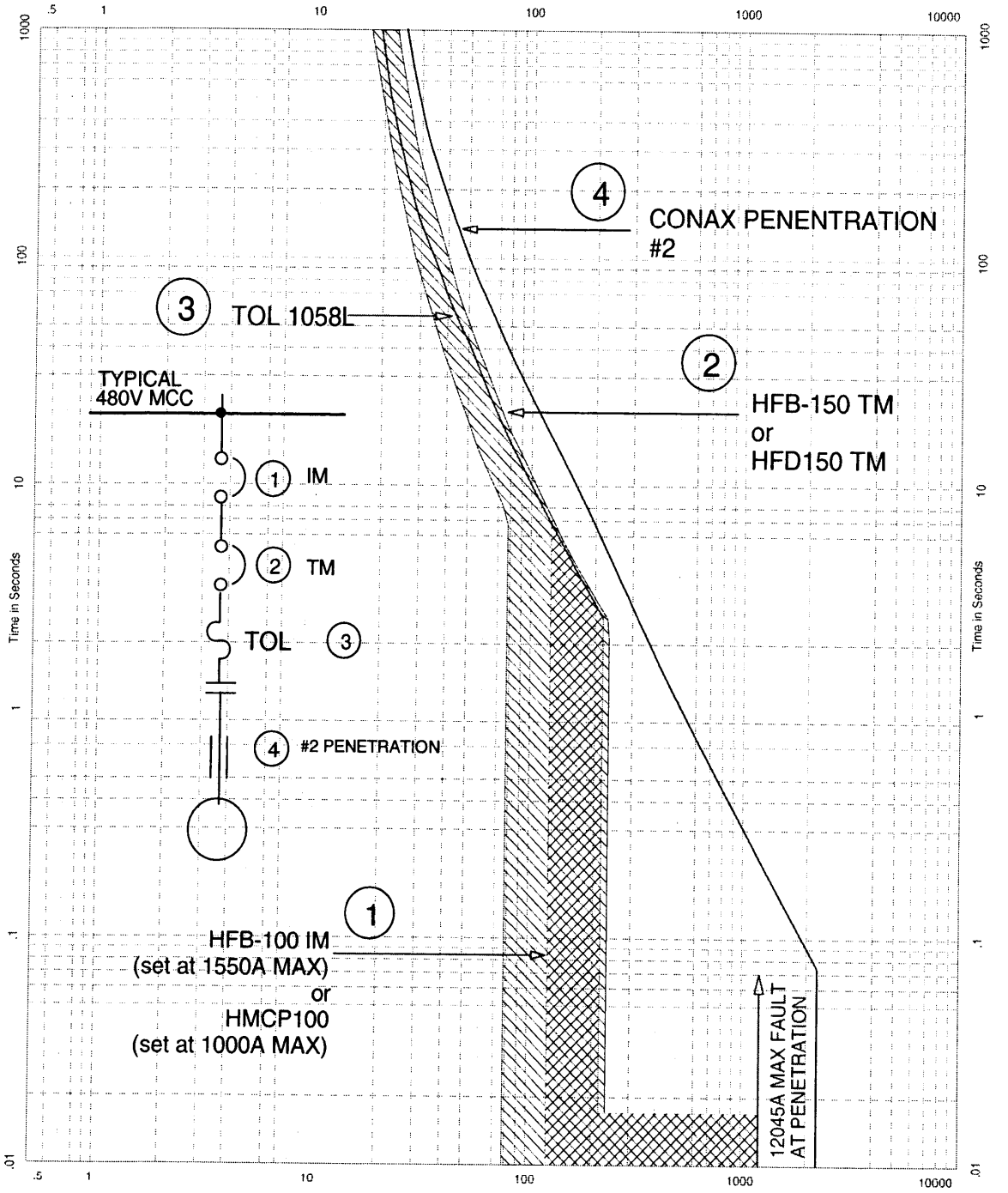
FIGURE 8.1-2 **Rev. 13 09/06**



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UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

440 VOLT SYSTEM
(Sheet 2 of 5)

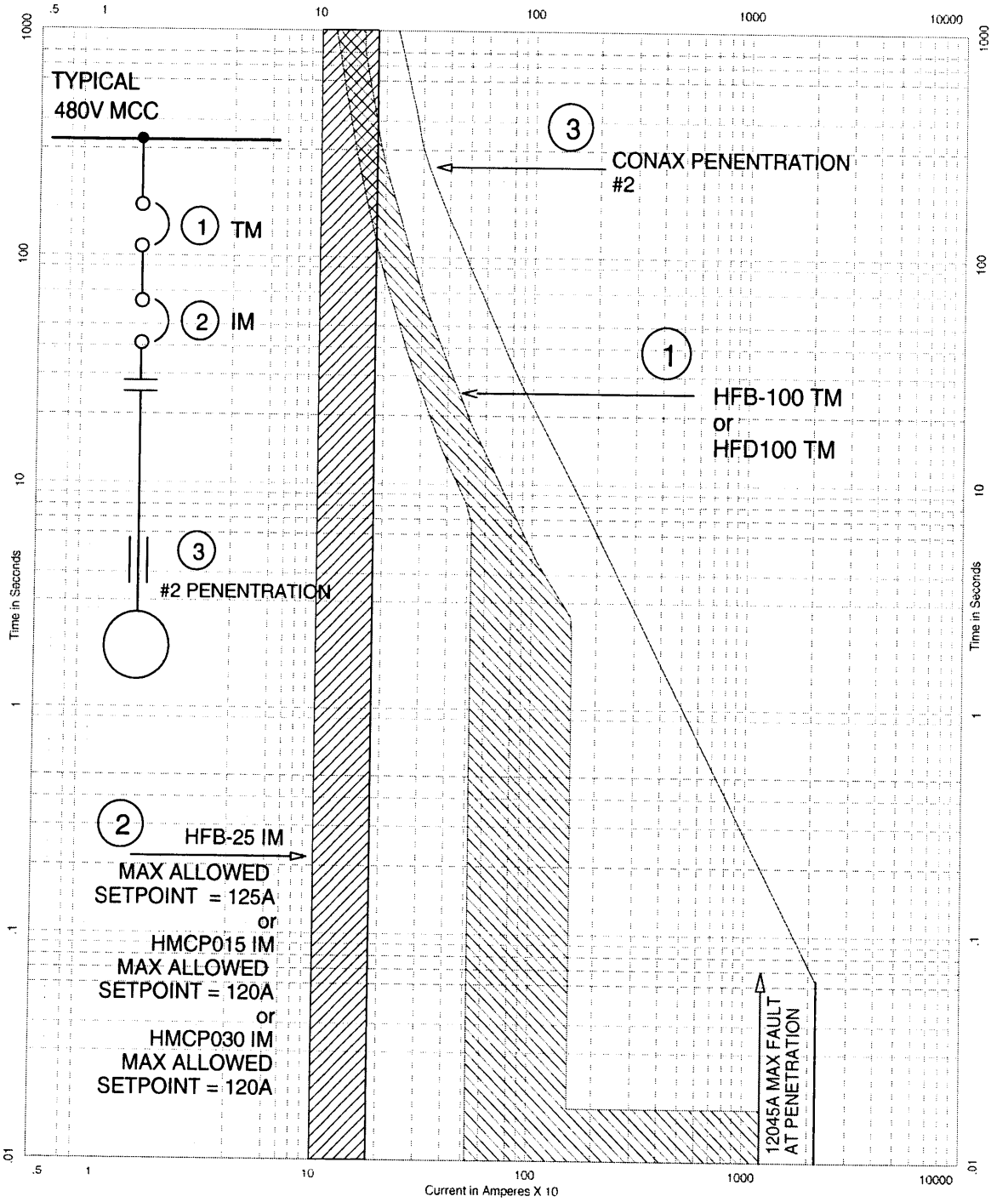
FIGURE 8.1-2 **Rev. 13 09/06**



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UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

440 VOLT SYSTEM
(Sheet 3 of 5)

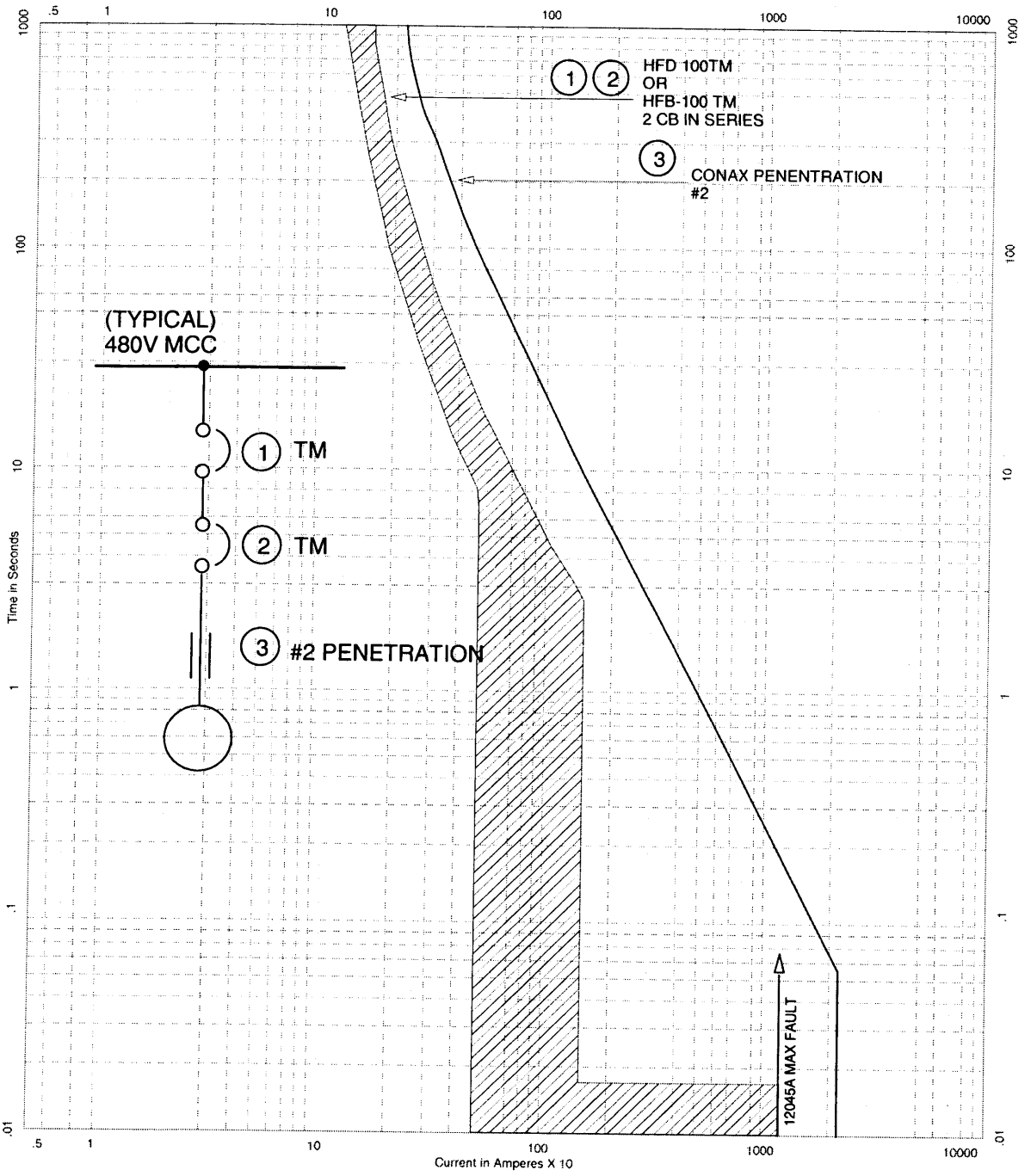
FIGURE 8.1-2 **Rev. 13 09/06**



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UNITS 1 AND 2
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440 VOLT SYSTEM
(Sheet 4 of 5)

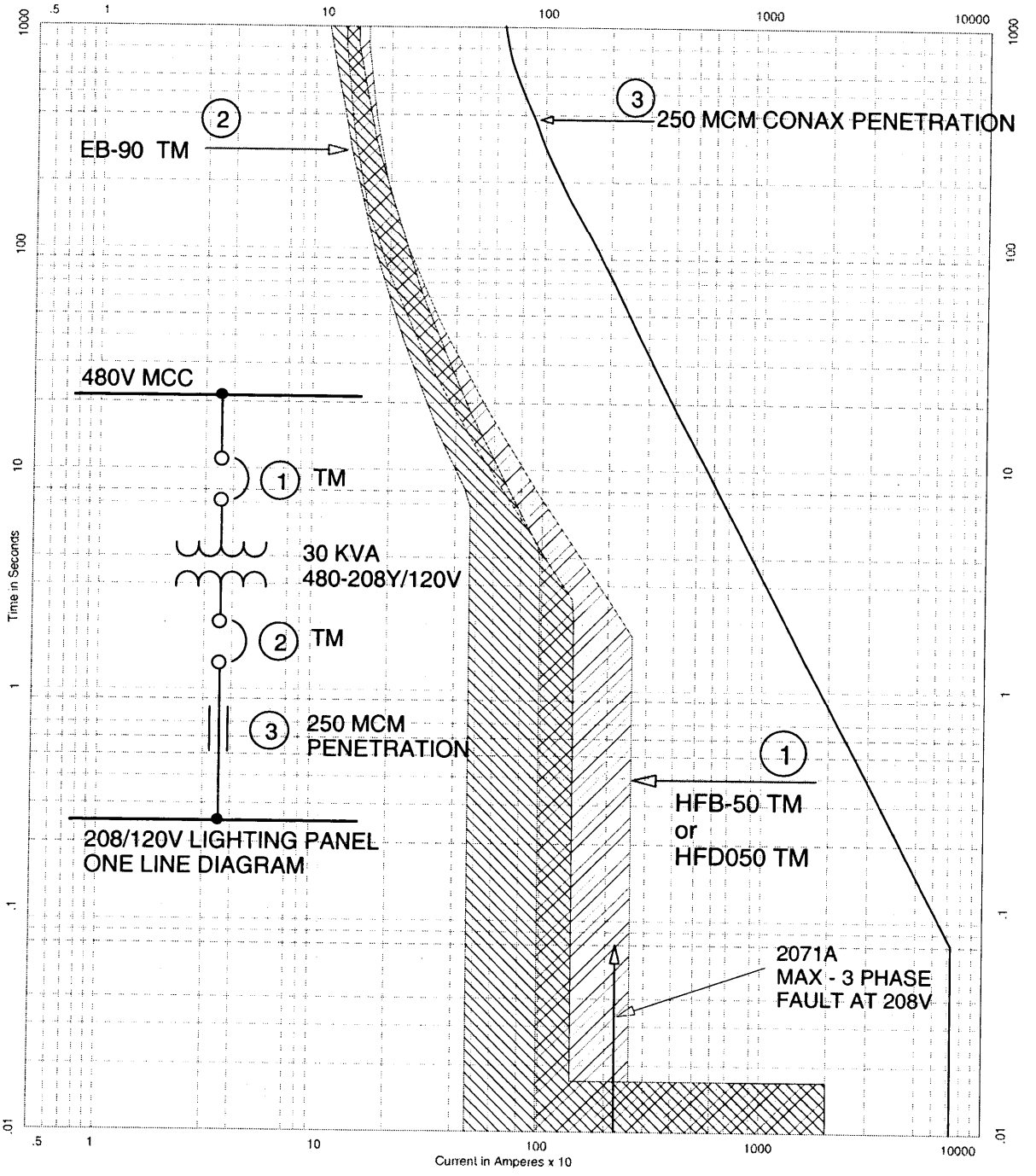
FIGURE 8.1-2 **Rev.13 09/06**



LIMERICK GENERATING STATION
UNITS 1 AND 2
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440 VOLT SYSTEM
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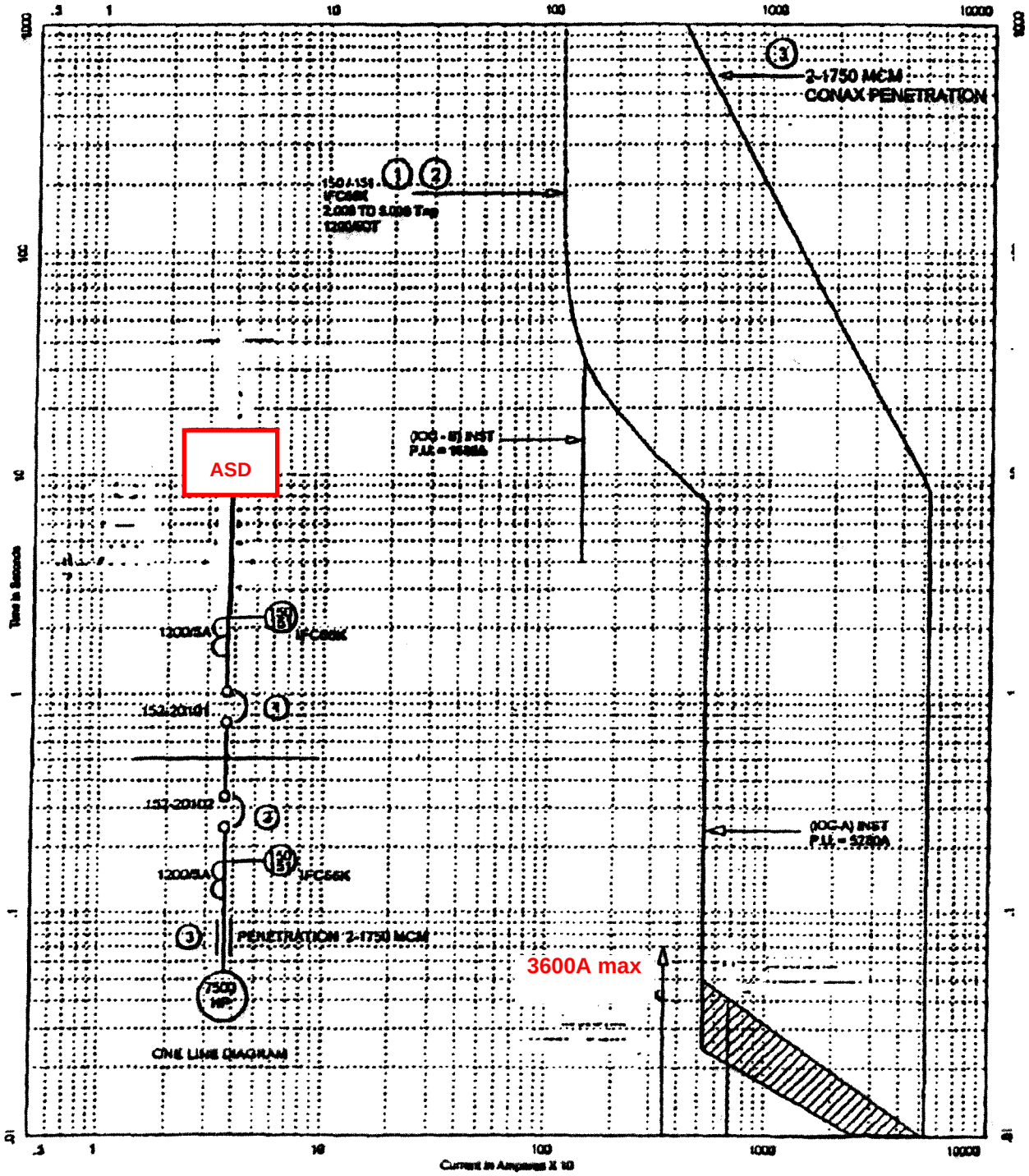
FIGURE 8.1-2 **Rev. 13 09/06**



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208V & LOWER VOLTAGE SYSTEM
(Sheet 2 of 3)

FIGURE 8.1-3 **Rev. 13 09/06**



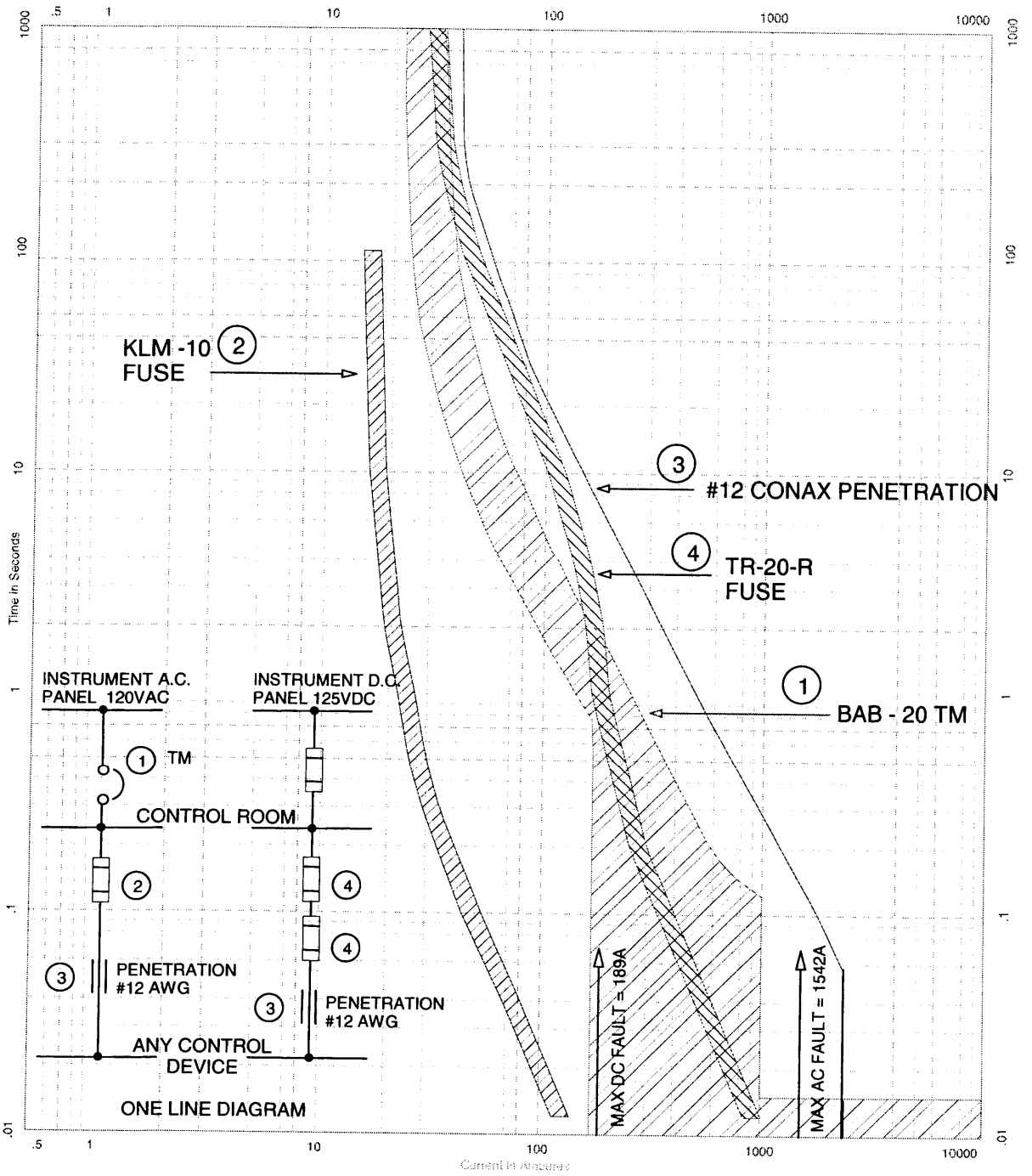
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MEDIUM VOLTAGE SYSTEM

(Sheet 1 of 1)

Figure 8.1-4 Rev. 17 09/14

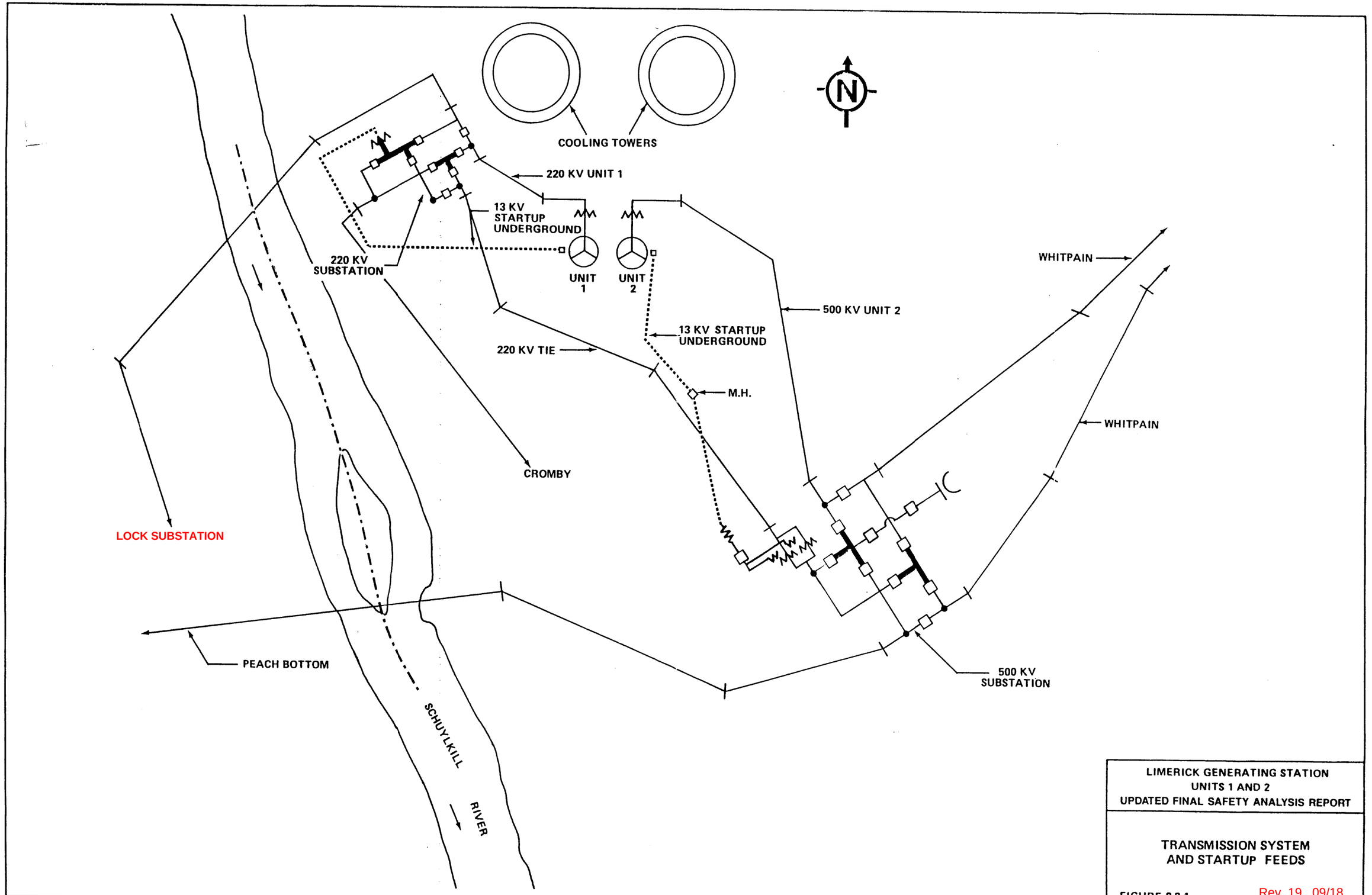
Figure 8.1-4 (Sheet 2 of 2)
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120 VOLT SYSTEM
(Sheet 1 of 1)

FIGURE 8.1-5 **Rev. 13 09/06**

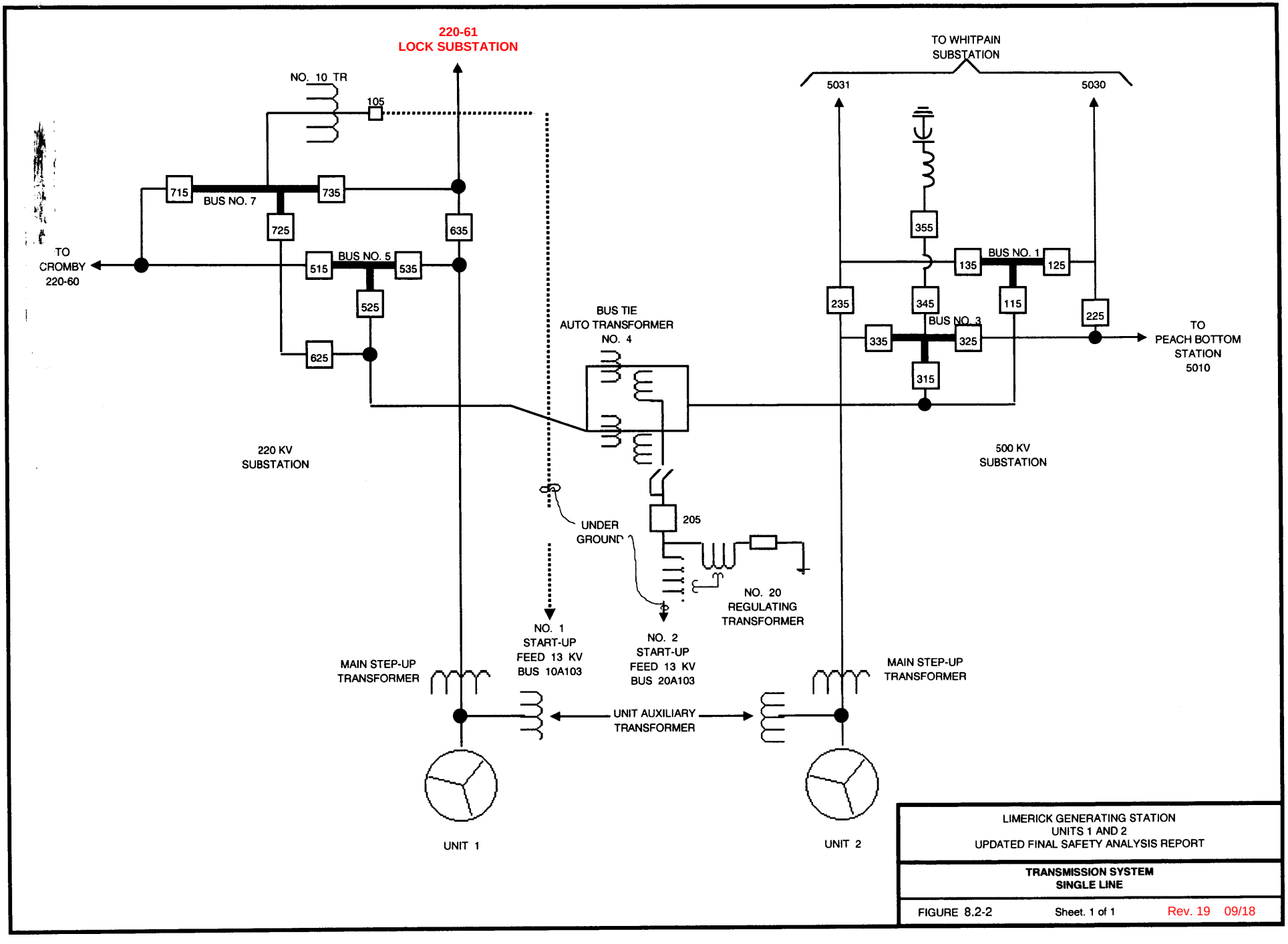


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TRANSMISSION SYSTEM
AND STARTUP FEEDS

FIGURE 8.2-1

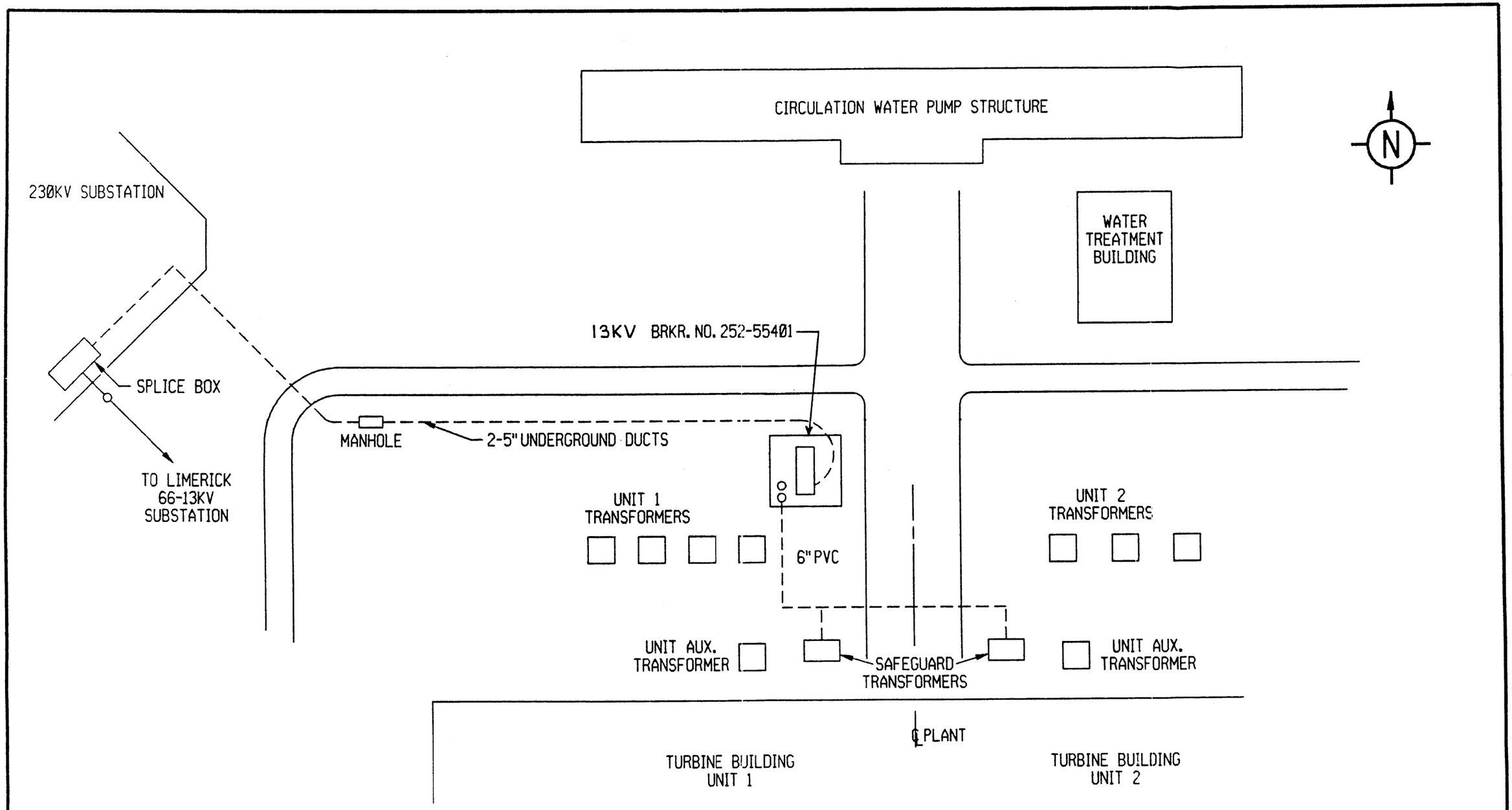
Rev. 19 09/18



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UNITS 1 AND 2
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TRANSMISSION SYSTEM
SINGLE LINE

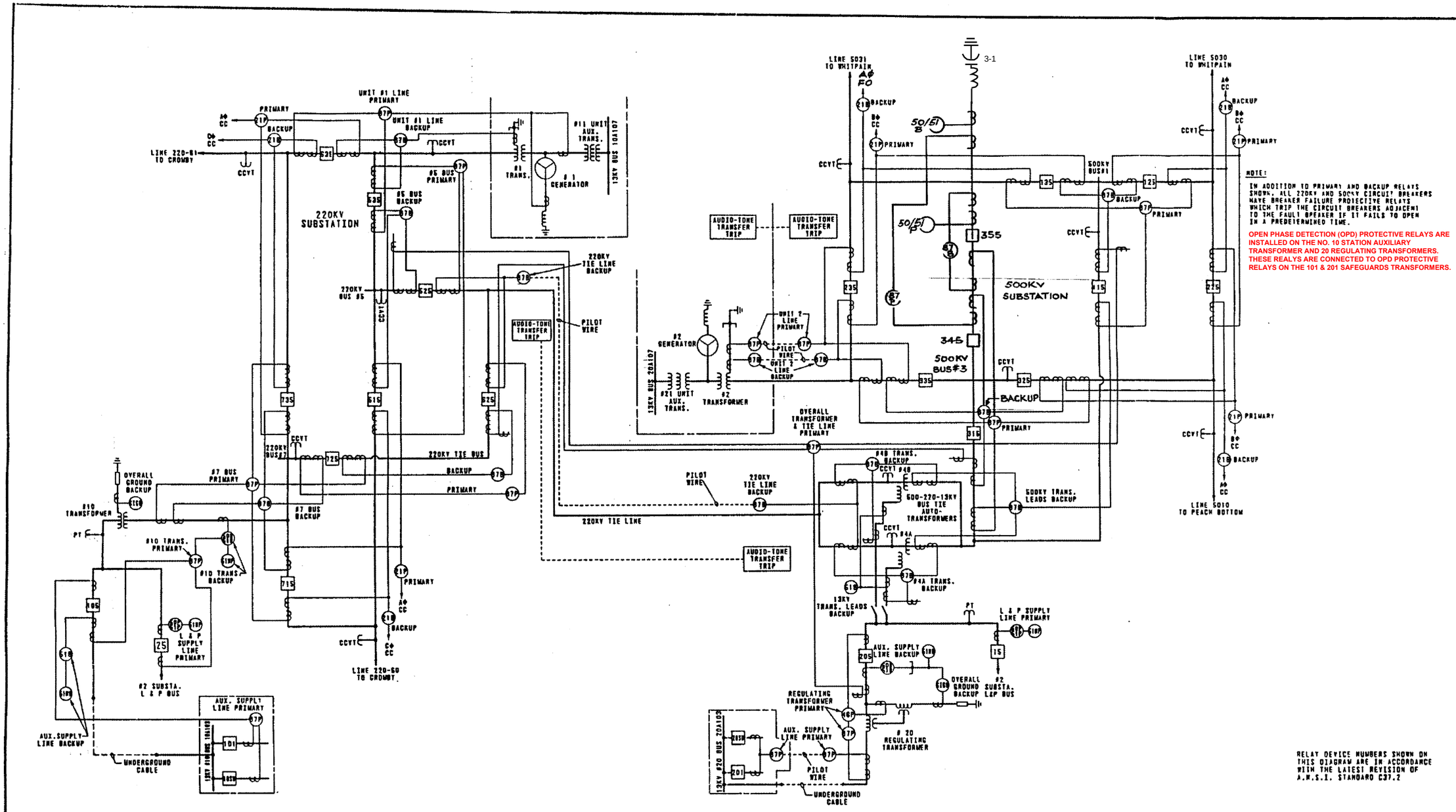
FIGURE 8.2-2 Sheet. 1 of 1 Rev. 19 09/18



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

THIRD OFF-SITE SOURCE
EMERGENCY BACK UP

FIGURE 8.2-3 REV. 3 NOV/93



NOTE:

IN ADDITION TO PRIMARY AND BACKUP RELAYS SHOWN, ALL 220KV AND 500KV CIRCUIT BREAKERS HAVE BREAKER FAILURE PROTECTIVE RELAYS WHICH TRIP THE CIRCUIT BREAKERS ADJACENT TO THE FAULT BREAKER IF IT FAILS TO OPEN IN A PREDETERMINED TIME.

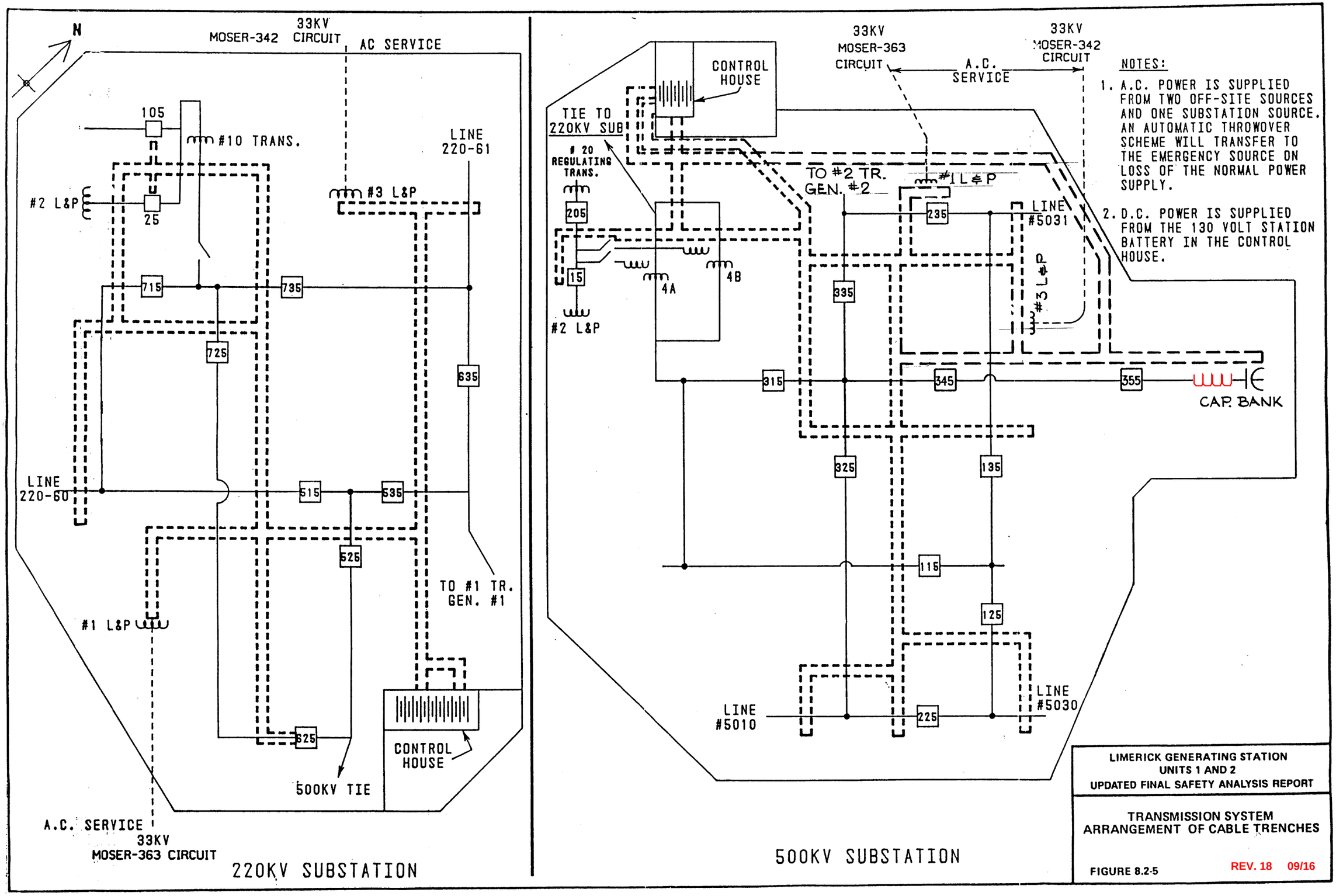
OPEN PHASE DETECTION (OPD) PROTECTIVE RELAYS ARE INSTALLED ON THE NO. 10 STATION AUXILIARY TRANSFORMER AND 20 REGULATING TRANSFORMERS. THESE REALYS ARE CONNECTED TO OPD PROTECTIVE RELAYS ON THE 101 & 201 SAFEGUARDS TRANSFORMERS.

RELAY DEVICE NUMBERS SHOWN ON THIS DIAGRAM ARE IN ACCORDANCE WITH THE LATEST REVISION OF A.N.S.I. STANDARD C37.2

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TRANSMISSION SYSTEM
RELAY SINGLE LINE DIAGRAM

FIGURE 8.2-4 REV. 19 09/18

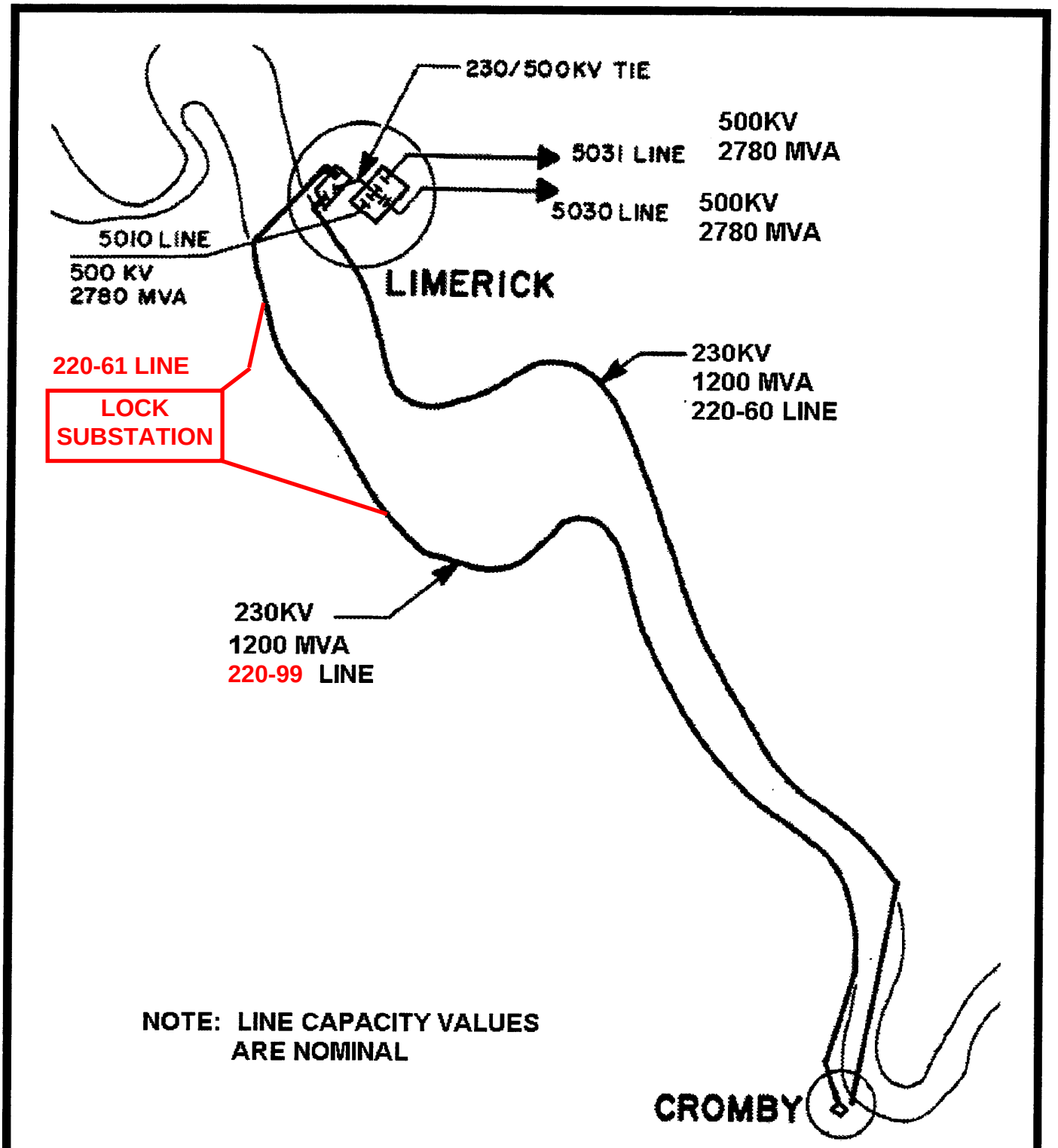


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TRANSMISSION SYSTEM
ARRANGEMENT OF CABLE TRENCHES

FIGURE 8.2-5

REV. 18 09/16



LIMERICK GENERATING STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TRANSMISSION SYSTEM
LINE ROUTINGS

FIGURE 8.2-6 Rev. 19 09/18

Figure 8.3-1 thru 8.3-3

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CHAPTER 9 - AUXILIARY SYSTEMS

9.1 FUEL STORAGE AND HANDLING

The fuel storage and handling facilities provide safe and effective means of storage, cooling, transportation, and handling of nuclear fuel from the time it reaches the plant in a non-irradiated condition until it leaves the plant after post-irradiation cooling. These systems have no function related to the safe shutdown of the plant.

Additional spent fuel storage is provided on site and within the plant protected area boundary by an Independent Spent Fuel Storage Installation (ISFSI) meeting the requirements of 10CFR72. Safety evaluations for the ISFSI are covered in separate "10CFR72.212" documents, and are therefore not detailed here. It is noted that existing UFSAR Section 9.1.4 and 9.1.5 references to a "cask" are actually referring to the shipping cask referred to above for the function to "leaves the plant after post-irradiation cooling." Minor differences for the ISFSI "transfer cask" (TC) and HI-TRAC VW cask handling, such as cask positioning for preparations for loading and post-loading decontamination, lids placement and sealing, are not covered herein.

9.1.1 NEW FUEL STORAGE

The new fuel is brought onsite prior to a scheduled refueling and is inspected and then stored in the spent fuel racks, which are located in the refueling area in the spent fuel pool (drawings M-122 and M-137).

9.1.1.1 Design Bases

New fuel is stored in the spent fuel pool. The design bases are discussed in Section 9.1.2.1.

9.1.1.2 Facility Description

The new fuel is stored in the spent fuel storage racks. The facility description is discussed in Section 9.1.2.2. Section 9.1.4 describes receipt inspection and handling of new fuel within the reactor enclosure.

9.1.1.3 Safety Evaluation

New fuel is stored in the spent fuel pool. Storage of new fuel bundles in the storage vault is prohibited by existing fuel handling procedures that require new fuel to be stored in the spent fuel pool. The safety evaluation is discussed in Section 9.1.2.3.

9.1.2 SPENT FUEL STORAGE

The spent fuel storage facility provides specially designed underwater storage space for the new and spent fuel assemblies. The facility is located in the refueling area and is shown in drawings M-122 and M-137. Prior to each refueling, new fuel is brought onsite, inspected, and stored in the spent fuel storage racks.

9.1.2.1 Design Bases

The following design bases for the spent fuel storage facilities are discussed in the indicated sections:

a.	Seismic and quality group classification	Section 3.2
b.	Protection from wind and tornado effects	Section 3.3
c.	Flood design	Section 3.4
d.	Missile protection	Section 3.5
e.	Protection against dynamic effects associated with postulated rupture of piping	Section 3.6
f.	Seismic design	Section 3.7
g.	Environmental design	Section 3.11
h.	Fire protection	Section 9.5.1

In addition to the design bases listed above, the following design bases and codes and standards are applicable to the spent fuel storage facilities:

a. The spent and new fuel storage facility is designed to store fuel assemblies so that a k_{eff} less than or equal to 0.95 is maintained, assuming that the fuel storage racks are fully loaded with fuel of the highest anticipated enrichment and flooded with nonborated water, in compliance with GDC 62. This is achieved through use of a neutron poisoning material (Boral) sandwiched in the racks between adjoining fuel assemblies to ensure subcriticality by at least 5% Δk under all conditions. The presence of Boral is verified by receipt and inservice testing.

b. The spent fuel storage facility and all piping connections are designed to prevent a loss of cooling water from the spent fuel pool that could uncover stored fuel.

c. The spent fuel storage facility is designed to remain functional following an SSE.

d. Failures of systems or structures not designed to seismic Category I standards and located in the vicinity of the spent fuel storage facility do not cause a decrease in the subcriticality provided.

e. The design of the spent fuel storage racks is such that a fuel assembly can be inserted into any designated rack storage location.

f. The spent fuel storage facility is designed to prevent accidental criticality of stored fuel under adverse environmental and postulated fuel handling accident conditions.

g. The spent fuel pool is designed to withstand thermal- stresses resulting from the pool water boiling.

h. The spent fuel pool is designed to accommodate the storage of approximately 539% of the total number of fuel assemblies in the reactor core. (Placement of the storage racks which contain control rod blades and/or defective fuel assemblies in the fuel pool could limit fuel storage capability to approximately 513%.) Storage capacity is dependent on rack installation.

i. Shielding for the stored spent fuel assemblies is designed to protect plant personnel from exposure to direct radiation greater than that permitted for continuous occupational exposure during normal operations.

j. Applicable codes and standards are provided in Table 9.1-21.

9.1.2.2 Facility Description

9.1.2.2.1 General Description

The spent fuel storage facility consists of the spent fuel pool, containing spent fuel storage racks, and serves as the storage area for irradiated fuel assemblies. The spent fuel pool and the adjacent reactor well, dryer/separator pool, and cask loading pit are located in the refueling area as shown in drawings M-122 and M-137. Figure 9.1-34 shows the initial layout of the Unit 1 fuel storage pool with a storage capacity of 3665 fuel assemblies (3714 fuel assemblies including the control rod blade/defective fuel storage rack). Figure 9.1-36 shows the initial layout of the Unit 2 fuel storage pool with a storage capacity of 3921 fuel assemblies (3970 fuel assemblies including the control rod blade/defective fuel storage rack). Figures 9.1-35 and 9.1-37 depict the potential maximum capacity layout for Unit 1 and Unit 2 (respectively) with a fuel storage capacity equal to the maximum licensed capacity of 4117 fuel assemblies. Cooling and cleanup of the spent fuel pool water is discussed in Section 9.1.3. Fuel handling systems are discussed in Section 9.1.4. The reactor enclosure crane is discussed in Section 9.1.5.

9.1.2.2.2 Component Description

9.1.2.2.2.1 Spent Fuel Pool

The spent fuel pool is a post-tensioned, reinforced concrete structure that forms an integral part of the reactor enclosure. The pool has a volume of approximately 46,000 ft^3 and is filled with demineralized water to a normal depth of 38'-3". This provides about 23 feet of water above the tops of the stored fuel assemblies.

The spent fuel pool is lined with stainless steel plate (Table 9.1-14) to minimize leakage and reduce corrosion product formation. A leakage collection system is provided to permit expedient detection of leaks through the stainless steel liner plate and to prevent the uncontrolled loss of pool water to areas below the pool. Drainage paths, designed to permit free gravity flow, are formed by welding channels behind the pool wall liner welded joints and by two trench monitoring systems embedded in the floor slab below the floor liner. The design of a typical drainage system is shown in Figure 9.1-40. Pool leakage is routed through a piping system, provided at the base of the pool wall, one of three dirty radwaste funnels as shown in drawing M-53. Leakage from each of seven segments of the leak collection system is routed through separate piping to enable identification of the area of the liner that is leaking.

Leakage is detected by observation of water flowing out of the piping into the dirty radwaste funnel (drawing M-53) or by low level indication in the skimmer surge tank or the spent fuel pool (drawing

M-53). Flow into the funnels is observed during periodic operator inspections. Skimmer surge tank low level alarms and trips are described in Section 9.1.3.5.

9.1.2.2.2.2 Spent Fuel Storage Racks

The Unit 1 and Unit 2 spent fuel pools are licensed for a maximum fuel storage capacity of 4117 fuel assemblies each. Analyses were performed prior to the installation of maximum density fuel storage racks for the Unit 2 spent fuel pool. All analyses performed for the Unit 2 spent fuel pool are bounding for the Unit 1 spent fuel pool design and installation.

The high density fuel storage racks are installed in the Unit 1 spent fuel storage pool in such a manner as to ensure that there is a Boral plate between each adjoining fuel storage position. Each storage module is level with each other module at the top. There are 7.25 inches of clearance from the bottom of the module to the pool floor. This ensures adequate clearance for cooling water to enter each fuel cell and, through natural convection, keep each fuel assembly adequately cooled.

The maximum density spent fuel storage racks are modular, freestanding, top entry racks designed to maintain the spent (and new) fuel in a space geometry whereby each fuel assembly has a neutron poisoning material between it and any adjoining fuel assemblies. This precludes the possibility of criticality under normal and abnormal conditions. The only point of contact of the maximum density spent fuel storage rack is with the bottom liner plate.

The maximum density spent fuel storage racks (Figure 9.1-41) consists of five basic structural components: the storage box subassembly, the baseplate, the neutron poison material, the picture frame sheathing, and the support legs. The storage box subassemblies (Figure 9.1-41) are fabricated from two precision formed stainless steel channels by seam welding. Each storage box subassembly has two lateral holes punched near the bottom edge to provide an auxiliary flow path. The stainless steel picture frame sheathing is attached to each side of a storage box subassembly by welds. The picture frame sheathing serves as the locator and retainer of the neutron poison material. A storage cell box subassembly, with picture frame sheathing and neutron poison material on all four sides is referred to as a composite box. The composite boxes are arranged in a checkerboard array and welded corner to corner to form an assemblage of storage cell locations (Figure 9.1-41). This assemblage is welded to the baseplate. The baseplate is 3/4 inches thick and provides a continuous horizontal surface for supporting the fuel assemblies. The baseplate has a concentric hole with a 45° taper in each storage cell location to provide a seating surface conforming to the fuel assembly. Adjustable support legs are welded to each corner of the baseplate. Each adjustment support leg is provided with a socket to enable remote leveling of the maximum density spent fuel storage rack after its placement in the fuel pool.

There are various sizes of maximum density spent fuel storage racks (Figures 9.1-35 through 9.1-37 and Table 9.1-23). The nominal center-to-center spacing between fuel assemblies in a maximum density spent fuel storage rack is 6.244 inches.

The neutron poison material used in the maximum density spent fuel storage racks is Boral. Boral is a thermal neutron poison material composed of boron carbide and 1100 alloy aluminum. The Boral is in plate form and is located and retained by the picture frame sheathing (Figure 9.1-41). The sheathed volumes which contain the Boral plates are vented.

The maximum density fuel storage racks are installed in the spent fuel storage pool in such a manner as to ensure that there is a Boral plate between each adjoining fuel storage position. Each maximum density spent fuel storage rack is level with each other rack at the top. There is a clearance of

approximately 7.00 inches between the bottom of the rack and the fuel pool floor liner. This ensures adequate clearance for cooling water to enter each fuel storage cell.

All materials used for construction are specified in accordance with the issue of the ASTM specifications. Traceability of major rack components to a heat lot are maintained. In addition, the suppliers' quality assurance/ quality control program was audited by the manufacturer and user to ensure that the Boral has the required minimum B_4C density and uniform B_4C distribution in each sheet. Boral traceability is maintained.

A dimensional, visual, and functional (including testing with a dummy fuel assembly) inspection of the racks is performed prior to shipment by the rack manufacturer.

The rack materials will have no significant degradation due to the total radiation doses expected in the spent fuel pool over the design life.

The racks are designed to withstand the loading under the following loading conditions: dead, live, jammed fuel assembly, dropped fuel assembly, thermal, OBE and design basis event seismic, SRV, and LOCA or chugging.

An ISI program will be in effect throughout the period in which spent fuel is stored in the spent fuel pool to ensure that the quality of the poisoned racks is maintained (Section 9.1.2.4).

9.1.2.2.2.3 Refueling Area Cavities

As shown in drawing M-122 and M-137, adjacent to the spent fuel pool, but on opposite sides of it, are the cask loading pit and the reactor well. Adjacent to the reactor well is the dryer/separator pool. The cask loading pit is common to the two reactor units. Like the spent fuel pool, these cavities are lined with stainless steel plate and are provided with liner leakage collection systems. The reactor well and the cask loading pit are connected to the spent fuel pool by fuel transfer canals approximately 4 feet wide. Each canal is provided with two gates to prevent loss of water from the spent fuel pool during periods when the adjacent cavity is not filled with water.

The cask loading pit is used for Low Level Radwaste (LLW) storage. In the cask loading pit free standing storage racks containing Storage Containers (SCs). The rack compartments hold LLW including control rod blades (CABs), fuel channels in sheaths, LPRM strings, velocity limiters, filters, stellite ball bearing and other small components. During LLW processing, processing equipment will be placed in the cask loading pit or on the Refuel Floor. The equipment can be removed when not in use. Equipment includes Activated Services Compactor (ASC) and Control Rod Blade Compactor (CABC), grapple, shear and punching tools, and supporting equipment. All LLW components are classified as non-safety related and Seismic II/I components. Because of the LLW stored in the cask loading pit, it must remain full at all times.

The cask loading pit is designed to permit the underwater loading of spent fuel assemblies into ISFSI transfer cask, HI-TRAC VW cask, and/or spent fuel shipping casks. Decontamination of the spent fuel shipping, HI-TRAC VW cask, and/or ISFSI transfer cask can be performed on the refueling floor adjacent to the cask loading pit. Cross connecting the Unit 1 and 2 spent fuel pools (SFPs) through the cask loading pit allows the transfer of spent fuel and equipment from one Unit's Spent Fuel Pit to the other unit's SFP. Prior to transferring fuel or equipment, adequate spent fuel pool cooling capacity must be verified.

The reactor well is a basically circular cavity located directly above the primary containment. Removal of the drywell head and reactor vessel head provides direct access from the reactor well to the inside of the reactor vessel. The reactor well is filled with water during transfer of fuel assemblies between the well and the spent fuel pool. Seals are provided at the bottom of the reactor well between the drywell and reactor well wall and a refueling bellows is provided between the reactor vessel and containment seal plate to prevent leakage of water out of the well.

The dryer/separator pool provides a place for storage of the steam dryer and steam separator when these two reactor components are removed from the reactor vessel. The dryer/separator pool is connected to the reactor well to permit underwater transfer of components between the two cavities. Seal plugs are provided to prevent loss of water during periods when the adjacent cavity is not filled with water.

9.1.2.2.2.4 Other Features

The ventilation system for the refueling floor area is designed to minimize potential offsite exposures if there is a significant release of radioactivity from the spent fuel storage facility. The ventilation system for the refueling floor area is discussed in Section 9.4.2.

The area radiation monitoring equipment for the spent fuel storage facility is described in Section 12.3.4.

9.1.2.3 Safety Evaluation

The subcriticality of the fuel assemblies stored in the spent fuel storage racks is the result of the geometrical arrangement of the fuel array and the presence of neutron-absorbing materials. The arrangement of the fuel assemblies in the spent fuel storage racks results in k_{eff} less than or equal to 0.95, assuming that the spent fuel storage racks are fully loaded with fuel of the highest anticipated enrichment. This is discussed in Section 9.1.2.3.1.

The design is in conformance with Regulatory Guide 1.13.

The bottoms of the fuel transfer canals between the spent fuel pool and the reactor well and between the spent fuel pool and cask loading pit are above the top of the stored spent fuel, thus ensuring that failure of the gates in these canals cannot result in the uncovering of the fuel.

To ensure that the spent fuel pool water level is not lowered by a malfunction of the fuel pool cooling and cleanup system, the system takes suction from the pool near the normal water level via the skimmer surge tanks. The system return lines enter the spent fuel pool from above the normal water level and are provided with siphon breaker holes near the normal water level to preclude the possibility of siphoning the pool.

The spent fuel storage facility is designed in accordance with seismic Category I requirements as specified in Section 3.2. The components (and supporting structures) of any system, equipment, or structure that is not seismic Category I and whose collapse could result in loss of a required function of the spent fuel storage facility are analytically checked to determine that they will not collapse when subjected to seismic loading resulting from the SSE.

All spent fuel pool gates and liners are seismic Category I.

Liner leakage detection system piping, the fuel pool cooling and cleanup system piping, and the wave suppression scupper piping are all seismic Category IIA. The only other piping attached to or in the spent fuel pool is from the RHR and ESW systems for backup cooling and makeup. This piping is seismic Category I.

Loss of any of the seismic Category IIA piping would not affect the ability to maintain spent fuel cooling or to maintain adequate submergence of the fuel.

Accidental dropping of movable heavy objects into the fuel pool is precluded by the use of administrative procedures, electrical interlocks to limit the load travel over the spent fuel pool, and the use of guardrails and curbs around all pools and the reactor wells to prevent fuel handling and servicing equipment from falling into the pools. The electrical interlocks and administrative procedures are described in Section 9.1.4. In addition, heavy load handling in the vicinity of the fuel pools is in compliance with NUREG-0612 guidelines such that the likelihood of a heavy load drop is precluded.

The design of the spent fuel pool provides enough reinforcement in the concrete to withstand the thermal-stresses resulting from pool boiling.

The maximum density spent fuel storage rack is capable of withstanding a force of 4000 pounds in any direction at the top of the rack without any permanent deformation of the fuel cell in the active fuel region.

The auxiliary hoist of the reactor enclosure crane has a maximum uplift force in excess of 4000 pounds. The auxiliary hoist does not handle new fuel above, or in the fuel pool, except to transfer new fuel to the fuel prep machines. Other fuel handling operations are performed by the hoists on the refueling platform which have an uplift (controlled) limit of 1200 pounds or less.

If there is a stuck fuel assembly, the lifting bail yields at an uplift force greater than 1500 pounds; therefore, possible damage to the racks is precluded even if the 1200 pound control limit is not considered.

9.1.2.3.1 Criticality Control

9.1.2.3.1.1 Basic Assumptions of Criticality Analysis

The spent fuel storage facility is designed to prevent accidental criticality of stored fuel under adverse environmental and postulated fuel handling accident conditions. The geometry of the spent fuel storage array is such that K_{eff} will be ≤0.95. Studies were performed which establish fuel storage compliance limits consistent with K_{eff} ≤0.95 for the Maximum Density racks (Reference 9.1-9). All General Electric supplied fuel shall comply with the fuel storage reactivity criteria in Reference 9.1-7 (GESTAR-II), which conservatively bounds the rack designs analyzed in Reference 9.1-9. Additional studies for fuel designs not covered under GESTAR-II are listed as references in Section 9.1.6. To ensure that the design criteria are met, the following normal and abnormal spent fuel storage conditions were analyzed:

a. Normal positioning in the spent fuel storage array

b. Pool water temperature increases to 212°F

c. Abnormal positioning in the spent fuel storage array

d. Dropped fuel bundle adjacent to storage area

e. Dropped fuel bundle on top of and through fuel storage racks.

Transport to Diffusion Correction	= 0.917 - 0.898 - 0.001
	= 0.018

This result should be applied to the adjusted PDQ k_{eff}

c. Summary of Results:

k_{eff} (PDQ) adjusted	0.915
Transport to Diffusion Correction, PDQ-KENO	0.018
Final k_{eff} (upper bound, 95% confidence)	0.933
Design Limit, k_{eff}	0.950

The final k_{eff} value (0.933) includes all the design specification tolerances, the postulation of a dropped fuel assembly, the model bias, and the 95% confidence interval from the KENO calculations. However, the negative reactivity effect (approximately -0.005 Δk) due to the presence of U-234 and the parasitic structure materials (i.e. spacer grids) in each assembly, and the positive reactivity effect (0.006 Δk) due to the possible absence of a Boral plate are not included.

9.1.2.3.1.2.1 Assumptions of Criticality Analysis - Maximum Density Spent Fuel Storage Racks

To ensure the analysis followed a conservative approach and conformed to the general guidelines of criticality safety analysis, the calculations were performed using the following criteria:

1) The racks are assumed to contain the most reactive fuel authorized to be stored.

2) Moderator is pure, unborated water at a temperature corresponding to the highest reactivity (4°C, 39.2°F)

3) Criticality safety analyses are based upon the k_{eff} of an infinite array of storage cells, ie, no credit is taken for neutron leakage (except as necessary in the assessment of abnormal/accident conditions)

4) Neutron absorption in minor structural member is neglected, ie, spacer grids are replaced by water.

9.1.2.3.1.2.2 Calculational Models - Maximum Density Spent Fuel Storage Racks

Initial criticality analyses of the maximum density spent fuel storage racks (1993) were performed using both the CASMO-3 code (a two-dimensional multi-group transport theory code) and the KENO-

5a code (a Monte Carlo code for eigenvalue neutronics calculations), using the 27-group SCALE cross-section library with Nordheim Integral Treatment and Working Library Production (NITAWL) subroutine for U-238 resonance shielding effects. Standardized Computer Analysis for Licensing Evaluation (SCALE) is a comprehensive modeling and simulation suite for nuclear safety analysis and design, developed and maintained by the Oak Ridge National Laboratory for the USNRC, USDOE, and NNSA. KENO and NITAWL are both modules of the SCALE analysis suite. CASMO-3 (Studsvik Scandpower, Inc.) was used to calculate the in-rack k values as well to evaluate small reactivity increments associated with manufacturing tolerances for earlier fuel analyses. Depletion calculations were not required of CASMO-3 as the peak reactivity of the limiting bundle (no gadolinia) was at zero exposure. Benchmark calculations indicated a bias of 0.0000 $\pm$0.0024 for CASMO-3 and 0.0101 $\pm$0.0018 (95% confidence) for NITAWL-KENO-5a.

With CASMO-3 no longer generally available, the criticality safety analysis for the GNF3 fuel (Reference 9.1-20) instead utilized the same criticality methodology used by Oyster Creek for its Boral rack analysis and approved by the NRC in Reference 9.1-18. Like Oyster Creek, the Limerick GNF3 criticality safety calculations were based on use of both the CASMO-4 code (a two-dimensional multi-group transport theory code) and the MCNP5 (a Monte Carlo code developed by Los Alamos National Lab). For the Oyster Creek standard cold core geometry (SCCG) methodology, many lattices are analyzed to provide a k(in-core) to k(in-rack) correlation. The CASMO-4 code was used to deplete lattices to their peak reactivities and to generate their core/rack conditions k values. The MCNP5 code was used for prudent validation purposes of the CASMO-4 results and the bias is shown in Reference 9.1-20.

In the geometric model used in the calculations above, each fuel rod and its cladding was described explicitly and reflecting boundary conditions (zero neutron current) were used in the axial direction and at the centerline of the Boral and stainless steel plates between storage cells. These boundary conditions have the effect of creating an infinite array of storage cells in the X and Y directions.

Since the cross section library in NITAWL is not valid below 20°C, a small correction factor (0.0026 δk, determined by CASMO-3) to 4°C was applied to the NITAWL-KENO-5a calculations (applicable to initial criticality analyses of the maximum density spent fuel storage racks using these methods).

9.1.2.3.1.2.3 Reference Case Calculations - Maximum Density Spent Fuel Storage Racks

a. Physical Parameters and Basic Storage Cell Geometry

The design basis storage rack cell consists of an egg-crate structure (Figure 9.1-41) with fixed neutron absorber material (Boral) of 0.0200 g/cm^2 boron-10 areal density (0.0185g/cm^2 boron-10 minimum) positioned between the fuel assembly storage cells. The storage cell design for analysis is based upon a nominal center-to-center lattice spacing of 6.244 inches. The 0.075 inch thick stainless steel box which defines the fuel assembly storage cell has a nominal inside dimension of 6.05 inches. This allows adequate clearance for inserting or removing the fuel assemblies, with or without the Zircaloy channel. Boral plates are not needed or used on the exterior walls of racks facing non-fueled regions, ie, the fuel pool walls. Manufacturing tolerances, used in evaluating uncertainties in reactivity, are listed in Table 9.1-26.

Along the outer periphery of racks facing another rack, the Boral is 4.70 inches wide rather than 5.0 inches wide. This small reduction in width is compensated by the water-gap between racks and by the thickness of the stainless steel.

Therefore, the reactivity consequences of the slightly reduced Boral width in these locations are negligible.

b. Results of the Design Basis Case Calculations

Using the input data from Table 9.1-24 and Figure 9.1-42, the k_{eff} values of the design basis case at 4°C were calculated. The maximum reactivity calculated by the CASMO-3 code is 0.9444. The maximum reactivity calculated by the NITAWL-KENO-5a code is 0.9412.

c. Fuel Effect

Because the racks must be able to store various fuel types additional fuel types were evaluated using the data from Table 9.1-24. The results are summarized in Table 9.1-27.

9.1.2.3.1.2.4 Sensitivity and Tolerance Reactivity Calculations - Maximum Density Spent Fuel Storage Racks

a. Temperature Effect

Using the design basis storage rack geometry, the temperature of the fuel pool water was varied. The results are given in Table 9.1-25.

b. Void Effect

The effect of boiling was studied by varying the voids from 0% to 20% at a temperature of 252°F with the reference geometry. The results are given in Table 9.1-25. As indicated, k_{eff} decreases continuously as the void fraction increases. Boiling at the submerged depth of the racks would occur at approximately 250°F.

c. Effect of Boron Loading Variation

The Boral Absorber plates used in the storage cells are nominally 0.075 inches thick. With a boron-10 areal density of 0.0200 g/cgm^2. The manufacturing tolerance limit is $\pm$0.0015 g/cm^2 in the boron-10 loading, which assures that the minimum boron-10 areal density will not be less than 0.0185 g/cm^2. Differential CASMO-3 calculations indicate that this tolerance limit results in an incremental reactivity uncertainty of $\pm$0.0051 δk (Table 9.1-26).

d. Effects of Boral Width Tolerance Variation

The reference storage cell design uses a Boral plate width of 5.00 $\pm$1/16 inches. For a reduction in width of the maximum tolerance, the calculated positive reactivity increment is +0.0018 δk (Table 9.1-26).

e. Effect of Storage Cell Lattice Pitch Variation

The design storage cell lattice spacing between fuel assemblies is 6.244 inches. For the manufacturing tolerance of $\pm$0.040 inches, the corresponding uncertainty in reactivity is $\pm$0.0027 δk as determined by the CASMO-3 code (Table 9.1-26).

f. Effect of Stainless Steel Thickness Tolerance

The nominal thickness of the stainless steel box and the stainless steel picture frame sheathing are 0.075 and 0.035 inches respectively. The maximum positive reactivity effect for a mean stainless steel thickness tolerance of ±0.008 inches is ±0.0004 δk as determined by the CASMO-3 code (Table 9.1-26).

g. Effect of Fuel Enrichment and Density Variation

The nominal design enrichment is 3.50 wt% U-235. CASMO-3 calculations of the sensitivity to an enrichment variation of ±0.05 wt% U-235 yielded an uncertainty in reactivity of 0.0033 δk.

The design basis calculation assumed a UO_2 stack density 95% theoretical density, corresponding to a density of 10.42 g/cm^3 . Calculations were also made to determine the sensitivity to a conservative tolerance in UO_2 fuel density of ±0.20 g/cm^3 in density or a maximum density of 10.62 g/cm^3. These calculations indicate that the storage rack k_∞ is increased by 0.0026 δk (Table 9.1-26). A lower fuel density would result in a correspondingly lower value of reactivity.

h. Effects of Zirconium Flow Channel

The design basis calculations assumed the presence of a flow channel. Elimination of the zirconium flow channel results in a decrease in reactivity of approximately 0.008 δk.

i. Effects of Water Gap Spacing Between Racks

For normal storage conditions with a water gap between racks, the array k_{eff} of a rack would be less than the reference design k_∞ and Boral plates along the wall of the racks facing the water gap would not be necessary. However, as an additional and precautionary measure, rack design provides for Boral plates on storage cells on one of the two rack walls along the water gap. With this conservative configuration, the design assures that, even under abnormal or accident conditions. the storage rack reactivity will remain less than the 0.95 k_{eff} regulatory limit.

9.1.2.3.1.2.5 Special Cases - Maximum Density Spent Fuel Storage Racks

a. Abnormal Location of a Fuel Assembly

It is theoretically possible to suspend a fuel assembly of the highest allowable reactivity outside and adjacent to the spent fuel storage rack. Neutron leakage, inherent along the rack edge, significantly reduces the reactivity consequences of an extraneous fuel assembly. Three dimensional KENO-5a calculations show that the k_{eff}, with an assembly outside of and adjacent to a rack, is less than the design basis k_∞ of an infinite radial array. Thus, the abnormal location of a fuel assembly will have a negligible reactivity effect.

b. Eccentric Fuel Assembly Positioning

The fuel assembly is normally located in the center of the storage rack cell with the bottom fittings and spacers that mechanically restrict lateral movement of the fuel assemblies. Nevertheless, calculations with the fuel assembly moved into the corner of the storage rack cell (four-assembly cluster at the closest approach), resulted in a substantial negative reactivity effect. Thus, the nominal case, with the fuel assembly positioned in the center of the storage cell, yields the maximum reactivity.

c. Dropped Fuel Assembly

For a drop of a fuel assembly on top of a rack, the fuel assembly will come to rest horizontally on top of the rack with a minimum separation distance from the fuel of more than 12 inches. A separation of 12 inches is sufficient to preclude neutron coupling (ie, an effectively infinite separation). Maximum expected deformation under seismic or accident conditions will not reduce the minimum spacing between fuel assemblies to less than 12 inches. Consequently, fuel assembly drop accidents will not result in a significant increase in reactivity (<0.0001 δk) due to the separation distance.

d. Fuel Rack Lateral Movement

Normally, the individual racks in the spent fuel pool are separated by a water gap. Lateral motion of a rack, postulated as a consequence of the design basis earthquake, could reduce or eliminate this water gap. Since the exterior walls of one of the racks along the water gap contains a Boral plate, closing the gap would not result in any increase above the design basis reactivity.

9.1.2.3.1.2.6 Summary and Conclusion - Maximum Density spent Fuel Storage Racks

For the design basis reactivity calculations with uniform enrichment of 3.50 wt%, the nominal storage cell infinite multiplication factor, k_∞, is 0.9366 (CASMO-3 code). With a δk of 0.0078 for all known uncertainties statistically combined, the maximum k_∞ in the fuel rack is 0.944 which is below the design basis limit of 0.95 for k_{eff}. Independent calculations with NITAWL-KENO-5a (1,250,000 histories in 2500 generations) gave a k_∞ (including all uncertainties) of 0.9335 $\pm$0.0077 (95% confidence, maximum k of 0.941) which is in good agreement with the CASMO-3 calculations (Table 9.1-28).

9.1.2.3.2 Structural Analyses

9.1.2.3.2.6 Bases For Analyses - Maximum Density Spent Fuel Storage Rack

The maximum density spent fuel storage racks are seismic Category I equipment as defined in Regulatory Guide 1.13. These racks are designed to withstand the effects of a design basis earthquake and remain functional, in accordance with Regulatory Guide 1.29 and 10CFR50.

The physical properties for the materials used in the manufacture of the maximum density spent fuel storage racks are given in Table 9.1-29. The load combinations and allowable stresses for the maximum density spent fuel storage racks are given in Table 9.1-30.

The structure of the racks is designed to remain functional (although some permanent deformation may occur) and to maintain the required spacing between stored fuel assemblies in the event of impact of a "heavy fuel assembly (consolidated fuel assembly)" (1360 pounds) dropped on the rack from a height of 36 inches. In this case, local plastic deformation is allowed at the point of impact. The structure of the racks is also analyzed for effects of the impact of the fuel bundle dropped through an empty storage cavity. Local failure of the baseplate is acceptable, a gross structural failure is not permissible. A comparative analysis with impact conditions, as stated above, is also conducted on a rack due to an uplift force of 4000 pounds on a stuck fuel bundle. No permanent deformation of the fuel cell in the active fuel region is allowed in this case. A force of 4000 pounds is well in excess of the maximum (controlled) uplift force from the refueling platform main hoist of 1200 pounds.

9.1.2.3.2.7 Seismic Analyses - Maximum Density Spent Fuel Storage Rack

A combination of time history and static seismic analysis was performed for the maximum density spent fuel storage racks by Holtec International. Rack dynamic simulations were performed using a 3-D single rack 22-degrees of freedom (DOF) model and a Whole Pool Multi-Rack (WPMR) model which considered all the racks in the pool.

a. 3-D 22-DOF Single Rack Model

The fuel rack motion is captured by modeling the rack as a twelve degree-of-freedom structure (Figures 9.1-43 through

9.1-45). Movement of the rack cross-section at any height is described by six degrees-of-freedom of the rack base and six degrees-of-freedom at the rack top. Rattling fuel assemblies within the rack are modeled by five lumped masses. Each lumped mass has two horizontal displacement degrees-of-freedom. Vertical motion of the fuel assembly mass is assumed to be equal to the rack vertical motion at the baseplate level. The centroid of each fuel assembly mass can be located off center, relative to the rack structure centroid at that level, to simulate a partially loaded rack.

Seismic motion of a rack is characterized by random rattling of the fuel assemblies in their individual storage locations. All fuel assemblies are assumed to move in-phase within a rack. This exaggerates computed dynamic loading on the rack structure and therefore yields conservative results.

Fluid coupling between the rack and fuel assemblies, and between the rack and the fuel pool wall, is simulated by appropriate inertial coupling in the system kinetic energy. Fluid coupling terms for rack-to-rack coupling are based on opposed-phase motion of adjacent modules.

Fluid damping and form drag is conservatively neglected. Sloshing is negligible at the top of the rack and is neglected in the analysis of the rack.

Potential impacts between rack and fuel assemblies are accounted for by appropriate "compression only" gap elements between the masses involved. The possible incidence of rack-to-wall or rack-to-rack impact is simulated by gap elements at the top and bottom of the rack in two horizontal directions. Bottom elements are located at the baseplate elevation.

Pedestals are modeled by gap elements in the vertical direction and as "rigid links" for transferring horizontal stress. Each pedestal support is linked to the fuel pool liner by two

friction springs. Local pedestal spring stiffness accounts for floor elasticity and for local rack elasticity just above the pedestal.

Rattling of fuel assemblies inside the storage locations causes the gap between fuel assemblies and the cell wall to change from a maximum of twice the nominal gap to a theoretical zero gap. Fluid coupling coefficients are based on the nominal gap.

b. Whole Pool Multi-Rack (WPMR) Model

The single rack 3-D (22-DOF) model outlined in the preceding subsection is used to evaluate structural integrity physical stability, and to initially assess kinematic compliance of the rack modules. Prescribing the motion of the racks adjacent to the module being analyzed is an assumption in the single rack simulation. For closely spaced racks, demonstration of kinematic compliance is further confirmed by modeling all modules in one comprehensive simulation using a Whole Pool Multi-Rack (WPMR) model. In the WPMR analysis, all racks are modeled, and their correct fluid interaction is included in the model.

The presence of fluid moving in the narrow gaps between the racks and between the racks and the fuel pool walls causes both near and far field fluid coupling effects. A single rack simulation can effectively include only hydrodynamic effects due to contiguous racks when a certain set of assumptions is used for the motion of the contiguous racks. In a WPMR analysis, far field fluid coupling effects of all the racks are accounted for by using the correct model of pool fluid mechanics. The external hydrodynamic mass due to the presence of walls or adjacent racks is computed in a manner consistent with fundamental fluid mechanics principles using conservative nominal fluid gaps in the fuel pool at the beginning of the seismic event.

The friction coefficient is ascribed to the support pedestal/pool bearing pad interface is consistent with experimental data. Friction coefficients, developed by a random number generator with Guaussian normal distribution characteristics, are imposed on each pedestal of each rack in the pool. The assigned values are then held constant during the entire simulation in order to obtain reproducible results. Thus, the WPMR analysis can simulate the effect of different coefficients of frictions at adjacent rack pedestals.

In the WPMR analysis, a reduced degree-of-freedom (RDOF) set is used to model each rack plus contained fuel. The rack structure is modeled by six degrees-of-freedom. A portion of contained fuel assemblies is assumed to rattle at the top of the rack, while the remainder of the contained fuel is assumed as a distributed mass attached to the rack. The rattling portion of the contained fuel is modeled by two horizontal degrees-of-freedom.

Thus, the WPMR model involves all the racks in the spent fuel pool with each individual rack modeled as an eight degree-of-freedom structure. The rattling portion of the fuel mass, within each rack, is chosen to ensure comparable results from displacement predictions from the single rack analysis using a 22-DOF model and the 8-DOF analysis under the same conditions. Unit 1 spent fuel pool configuration is bounded by the Unit 2 analyses.

9.1.2.3.2.8 Dropped Fuel Bundle Analysis - Maximum Density Spent Fuel Storage Rack

Analysis were performed to evaluate the effects of a dropped fuel assembly. Two scenarios were evaluated, the deep drop and shallow drop.

In the deep drop scenario a "heavy fuel assembly (consolidated fuel assembly)" is postulated to drop from a height of 36 inches above the top of a storage location and impacts the baseplate of the rack. While local failure of the baseplate is acceptable, a gross structural failure is not permissible. Also, the stored fuel array must remains subcritical. Results show that the spacing between cells is unaffected and the stored fuel array remains subcritical. Local baseplate deformation in the vicinity occurs, but the dropped fuel assembly does not impact the fuel pool liner. The impact results in a maximum baseplate movement toward the liner of less than 2.21 inches. The nominal baseplate height above the fuel pool liner is approximately 7.00 inches therefore, contact does not occur. If a fuel assembly drops through a cell located over a support leg, the impact load transmitted through the support leg to the fuel pool liner is less than the loads caused by a seismic event. Therefore, the concrete bearing pressures a calculated for the seismic event bound those due to a fuel drop accident.

In the shallow drop scenario a "heavy fuel assembly" is postulated to drop from a height of 36 inches above the top of the rack and impacts the top of the rack. Permanent deformation of the rack is acceptable, but it must be confined to the region above the top of the active fuel stored in the rack. The elevation of the top and bottom of active fuel must not be altered. Results show that the deformation caused by a dropped assembly will be less than or equal to 2.29 inches from the top of the rack. This region of deformation is less than the available cell length above the active fuel (over one foot). This load case bounds the scenario where the dropped fuel assembly rolls over after impact and impacts multiple locations.

9.1.2.3.2.9 Pool Interface Loads - Maximum Density Spent Fuel Storage Rack

The maximum density spent fuel storage load acting on the fuel pool were determined using the results of the 3-D 22-DOF model and the WPMR model described in Section 9.1.2.3.2.7. The results were determined to be acceptable and are summarized in Table 9.1-31.

9.1.2.3.2.10 Summary and Conclusions - Maximum Density Spent Fuel Storage Rack

The results of the structural analyses for the maximum density spent fuel storage racks are acceptable and summarized in Table 9.1-31.

9.1.2.3.3 Installation of New Maximum Density Racks

Racks are lifted individually from the refueling floor lay-down area and lowered into position in the pools using the 125 ton reactor enclosure crane and additional lifting devices provided by the rack vendor.

Each rack is aligned and leveled as it is placed in its proper pool. Each rack is a freestanding unit that rests on the pool floor using bearing pads attached to corner leveling screws. Leveling screws are adjusted by remotely controlled tools.

The requirements of 10CFR50, Appendix B, as included in the LGS Units 1 and 2 Quality Assurance Plan, Volume I, are implemented for receipt, storage, and installation of the spent fuel racks. Work is performed in accordance with procedures that are reviewed and approved prior to use. Inspections are performed and documented by personnel other than those who performed the work. Site activities are subject to audit by Nuclear Oversite.

9.1.2.4 Tests and Inspections

The spent fuel storage racks require no special periodic testing or inspection for nuclear safety purposes. However, test coupons may be installed in the Unit 1 and Unit 2 Spent Fuel Storage Racks. Test coupon analysis will only be performed on a discretionary basis based upon specific suspected degradation of neutron poisoning material. Spent fuel storage rack assignment in the spent fuel pool is surveyed at the time of installation.

9.1.2.4.1 Deleted

9.1.2.4.2 Deleted

9.1.2.4.3 Test Coupon Description and Installation

A typical test coupon is physically designed to simulate as nearly as possible, the actual in-service geometry, physical mounting, materials, and flow conditions of the neutron poison in the storage racks. The test coupons are mounted on a hanger assembly within the central eight feet of the fuel zone of the storage racks, where the gamma flux is expected to be reasonably uniform.

9.1.2.4.4 Test Coupon Inspection

Test coupon inspection is intended to identify changes in physical properties of the neutron poisoning material by performing various non-destructive and destructive testing.

9.1.3 FUEL POOL COOLING AND CLEANUP SYSTEM

The FPCC system is designed to remove the decay heat generated by the spent fuel assemblies stored in the fuel pool and to maintain the pool water at a clarity and purity suitable both for underwater operations and for the protection of personnel in the refueling area. The FPCC system has no function related to the safe shutdown of the plant.

9.1.3.1 Design Bases

a. The FPCC system piping is designed so that operator error or a loss of piping integrity cannot result in the draining of the spent fuel pool so that stored fuel would be uncovered.

b. The FPCC system is designed to provide a source of makeup water to ensure the maintenance of the fuel pool water level.

c. All piping and components of the FPCC system that form part of the flow path for makeup water from the ESW system, RHRSW system, and cooling water to and from the RHR system are designed to remain functional following an SSE.

d. The FPCC system is comprised of three pumps and three heat exchangers connected by a common header providing three approximately 50% capacity cooling trains. The Service Water System removes heat from the heat exchangers. Following an accident, two of the three pumps may be powered by emergency on-site power and any heat exchanger may be cooled by the Reactor Enclosure Cooling Water System. A precoat-type filter/demineralizer package is provided, through which a portion of the system flow can be diverted. As similar backup filter/demineralizer package common to both units is also provided.

e. The FPCC system was originally designed to maintain the bulk water temperature in the spent fuel pool at or below 140°F under normal operating conditions with two FPCC pumps and two FPCC heat exchangers in operation. This is based on the normal heat load discharge history shown in Table 9.1-2A.

The Unit 1 FPCC system is capable of removing 1.61 x 10^7 BTU/hr and Unit 2 FPCC system is capable of removing 1.805 x 10^7 BTU/hr with any one train unavailable. The FPCC systems have been evaluated for increased spent fuel storage capacity and faster fuel transfer rate (6.7 vs. 10 days) resulting in a heat load of 1.805 x 10^7 BTU/hr. The results show that on Unit 2 with any two FPCC pumps and any two FPCC heat exchangers in operation, the spent fuel pool bulk temperature will peak at 143°F. The spent fuel pool bulk temperature will exceed 140°F for approximately 2.5 days. This is based on the normal heat load discharge history shown in Table 9.1-2B (reference 9.1-15). This analysis is not applicable to Unit 1, since Unit 1 has a smaller capacity FPCC system and the ADHR would be used for heat loads exceeding 1.61 x 10^7 BTU/hr.

Each refueling offload scenario is cycle specific and is likely to vary from Table 9.1-2B. Therefore, administrative controls are maintained to assure that the spent fuel pool heat load does not exceed FPCC heat removal capacity during shutdown, refueling and power operating conditions such that the FPCC system is capable of maintaining the spent fuel pool cooling temperature at a maximum of 143°F, assuming a single active failure during normal operating conditions. If the anticipated heat load exceeds the FPCC capability, the Residual Heat removal (RHR) System is placed in service and FPCC is secured. When the spent fuel pool and reactor refueling cavity well are connected, the combined decay heat load of the in-core fuel and spent fuel pool inventory is typically removed by the RHR system, alone, operating as an alternate decay heat removal method (ADHR).

f. The FPCC system was originally designed to permit the RHR system to be used, through a cross-tie, to maintain the bulk water temperature in the spent fuel pool at or below 140°F, with a maximum anticipated decay heat load of 3.64x10^7 Btu/hr. This is based on one full core offloaded from the reactor ten days after shutdown to fill the spent fuel pool, plus the previous normal refueling loads from 18 month refuelings as shown in Table 9.1-2A.

A bounding analysis of the FPCC system has been performed, which considered a maximum reactor power of 3527 MW, spent fuel pool increased storage capacity and a faster fuel transfer rate. This analysis results in a maximum anticipated heat load of 4.832 x 10^7 Btu/hr. This is based on one full core offloaded from the reactor vessel approximately 40 hours after shutdown plus the previous normal refueling loads from 24 month refuelings as shown in Table 9.1-2B (references 9.1-16 and 9.1-17). A one-time per unit refueling cycle length extension to approximately 27 months (from a nominal 24 months) for Unit 1 Cycle 7 and Unit 2 Cycle 5 was evaluated. It was determined that the increase in decay heat generation due to each affected core's total operating period of 6.25 years (vs. 6 years) has no significant effect on maximum calculated fuel pool heat load.

The FPCC system cross-tie to RHR is normally used for the RHR ADHR method

to maintain both the spent fuel pool and reactor water temperatures below 140°F during refueling. See Section 5.4.7 for further discussion of ADHR method.

Additionally, the FPCC system(s) or the RHR fuel pool assist mode can be used to remove decay heat from both the spent fuel pool(s) and the reactor vessel by cooling the spent fuel pool(s). Evaluations have shown that with the reactor cavity flooded up and the fuel pool gates removed, natural circulation will transfer decay and sensible heat from the reactor vessel to the fuel pool(s). The required cooling capacity of the FPCC system(s) or the RHR fuel pool assist mode can be verified by calculation or demonstration to show that these systems are alternate methods of decay heat removal. Natural circulation will also induce reactor coolant circulation through the reactor core such that reactor core temperature can be accurately measured at an appropriate location.

g. The FPCC system is designed to maintain the optical clarity of the water in the spent fuel pool and other refueling area cavities (cask loading pit, reactor well, and dryer/separator pool) so that fuel handling and equipment handling operations are not hampered by limited visibility.

h. The FPCC system is designed to limit the fission product and activated corrosion product concentrations in the water of the spent fuel pool and other refueling area cavities to permit continuous occupancy of the refueling area by plant personnel.

The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the FPCC system are discussed in Section 3.2.

9.1.3.2 System Description

9.1.3.2.1 General Description

The FPCC system consists primarily of the pool water collection equipment, including wave suppression scupper and skimmer surge tanks, a cooling train with two heat exchangers, two pumps, a cleanup loop, and the discharge diffusers in the spent fuel pool. A backup heat exchanger and a backup pump are also included in the system.

9.1.3.2.2 Component Description

Design parameters for individual components of the FPCC system are listed in Table 9.1-1.

9.1.3.2.2.1 Skimmer Surge Tanks

Two skimmer surge tanks collect overflow water from the spent fuel pool and reactor well through skimmer drain openings, with adjustable weirs at the pool surface elevation. The skimmer surge tanks also collect overflow water from the cask loading pit and the dryer/separator pool via skimmer drain headers. A wave suppression scupper along one side of the spent fuel pool is drained via the skimmer drain headers. The skimmer surge tanks provide a suction head for the fuel pool cooling pumps and RHR pumps and serve as a buffer volume during transient flows in the normally closed-loop FPCC system.

9.1.3.2.2.2 Fuel Pool Heat Exchangers

Three fuel pool heat exchangers of the shell and straight tube-type are provided to transfer heat from the fuel pool water to the service water system (Section 9.2.1). Normally a maximum of two heat exchangers are in service and the third serves as a backup. The heat exchangers are arranged in parallel and are located in the reactor enclosure below the bottom of the skimmer surge tanks. Fuel pool water circulates through the shell side of the heat exchangers, and service water circulates through the tube side.

The service water side of the heat exchangers is maintained at a higher pressure than the fuel pool water side to minimize the possibility of radioactive contamination of the service water system from a tube leak.

Interconnecting piping is provided so that the heat exchangers can also be cooled by the RECW system in case the service water system is not available.

9.1.3.2.2.3 Fuel Pool Cooling Pumps

Three centrifugal pumps are provided to circulate water through the FPCC system. Normally a maximum of 2 pumps are in operation and the third serves as a backup. The pumps are arranged in parallel and take suction from the fuel pool heat exchangers through a common header. Two of the pumps are powered from Class 1E sources. The pumps can be operated from a panel located in the reactor enclosure and a panel located in the radwaste enclosure.

9.1.3.2.2.4 Fuel Pool Filter/Demineralizer Package

The cleanup loop of the FPCC system includes a filter/demineralizer package located separately in shielded cells in the radwaste enclosure. A spare filter/demineralizer package common to the two reactor units is also provided.

The fuel pool filter/demineralizer is a precoat-type, using powdered cation-anion resins as the coating media on the external surface of the filter elements. The filter elements are cylindrical stainless steel mesh, mounted vertically in a tube sheet and replaceable as a unit. The upper head of the filter/demineralizer vessel is removable for installing and replacing the filter elements. The ion exchange resin is a mixture of finely ground cation and anion resins, in proportions determined by service; this resin is referred to as precoat.

The precoat is applied to the surface of the filter elements by a flowing process called precoating. To maintain the filter medium on the filter elements during the interval between the precoating operation and the return-to-normal operation, or if there is an abnormal decrease in process flow, a centrifugal holding pump is provided with each filter/demineralizer to recirculate water through the unit.

The fuel pool filter/demineralizer system is designed to maintain water quality within the following limits:

a.	Conductivity:	$\leq$ 3 μmho/cm at 25°C
b.	Chlorides:	$\leq$ 0.5 ppm
c.	pH:	5.3 to 7.5 at 25°C

d. Total Suspended Solids: ≤ 1 ppm

A strainer is provided in the effluent stream of each filter/ demineralizer to limit the migration of filter medium particles that pass through the filter elements. The strainer is capable of withstanding a differential pressure greater than the shutoff head of the fuel pool cooling pumps.

9.1.3.2.2.5 Backwash and Precoat Equipment

The backwash and precoat subsystem is common to the two reactor units and serves all three filter/demineralizer packages. Included in the subsystem are a backwash air accumulator, precoat tank, and filter precoat pump. Compressed air from the backwash air accumulator is used in conjunction with condensate water to backwash the spent filter medium from the filter elements with a minimum volume of water. Backwash slurry is drained to the waste sludge tank of the solid radwaste system (Section 11.4).

New ion exchange resin is mixed in the precoat tank and transferred as a slurry by the filter-precoat pump to the filter/demineralizer, where it is deposited on the filter elements. An agitator is provided with the precoat tank for mixing. Piping and valves associated with the precoat subsystem allow the precoat water to be recirculated to the precoat tank or the suction side of the filter precoat pump. The precoat subsystem can also be used for cleaning and decontamination of the filter/demineralizers.

9.1.3.2.3 System Operation

The FPCC system removes decay heat from fuel stored in the spent fuel pool and includes equipment to maintain the purity of the water in the system. The FPCC system heat removal capacity is shown in Table 9.1-2B. Water from the spent fuel pool flows through weirs and a wave suppression scupper at the pool surface into two skimmer surge tanks adjacent to the pool. Water in the skimmer surge tanks flows by gravity through the fuel pool heat exchangers to the suctions of the fuel pool cooling pumps. From the pumps, water is returned to the spent fuel pool through two return lines. A portion of the discharge flow of the pumps can be diverted through the cleanup loop before being returned to the pool. Heat is removed from the fuel pool heat exchangers by the service water system (drawing M-10).

The filter/demineralizer in the cleanup loop maintains pool water purity and clarity by a combination of filtration and ion exchange. Disposable ion exchange resins in the filter/demineralizer remove ionic fission product and corrosion product impurities and also serve as a filter for particulate matter. The ion exchange resins are replaced when the pressure drop across the filter/demineralizer is excessive (≥25 psid at rated flow) or when the resins are exhausted as indicated by discharge conductivity being above the limit for the spent fuel pool given in Section 9.1.3.2.2. The backwash and precoat operations are controlled from the radwaste enclosure.

The FPCC system is sampled monthly at the filter/demineralizer influent and effluent lines. These grab samples are analyzed by gamma isotopic analysis. The ratio of the influent activity to the effluent activity (decontamination factor) will be determined from this analysis. The fuel pool filter/ demineralizer will be regenerated on low decontamination factor.

The grab samples will also be analyzed for pH, chloride, conductivity, and turbidity. Turbidity is an indication of insolubles. The pH, conductivity, and chloride limits are given in Section 9.1.3.2.2.

During normal plant operation, the FPCC system serves only the spent fuel pool. During refueling operations, however, when the reactor well, dryer/separator pool, and/or cask loading pit are filled with water, the FPCC system can be aligned to recirculate and process the water in all these cavities. Water from the refueling water storage tank (Section 9.2.7) is used to fill the refueling area cavities. The refueling water pumps fill the cask loading pit through its drain line and fill the reactor well and the dryer/separator pool through diffusers in the reactor well. After refueling activities are completed, the refueling water pumps transfer water from the refueling area cavities back to the refueling water storage tank via a condensate filter/demineralizer if additional cleanup is required. Gravity draining of the refueling water directly to the refueling water storage tank is also possible.

As the heat load on the spent fuel pool changes, the number of operating fuel pool cooling pumps and heat exchangers is adjusted to maintain the desired water temperature. The FPCC system has sufficient cooling capacity to maintain the spent fuel pool water at a temperature at or below 143°F, with a normal decay heat load of 1.61×10^7 Btu/hr on Unit 1 and 1.805×10^7 Btu/hr on Unit 2, with two pumps and two heat exchangers operating. The Unit 1 and 2 spent fuel pools can also be maintained cross connected as long as adequate spent fuel pool cooling capacity is verified.

If a heat load exceeding the capacity of the FPCC System is placed in the spent fuel pool, a cooling train of the RHR system (Section 5.4.7), consisting of an RHR pump and heat exchanger, can be substituted for the FPCC pumps and heat exchangers for cooling the pool water. A cross-connection between the drain line from the skimmer surge tanks and the RHR system allows one RHR pump to take suction from the skimmer surge tanks and pump fuel pool water through an RHR heat exchanger before returning it to the pool via return piping provided specifically for use with the RHR system Fuel Pool Cooling assist mode or via the normal Shutdown Cooling return path with RHR Alternate Decay Heat Removal method. The interconnecting piping between the RHR system and FPCC system is provided with either of two spool pieces, one with blind flanges for normal operation and one open spool piece for when the intertie is needed (drawing M-51). Administrative controls prevent the use of the RHR system intertie unless the associated reactor is shut down and is in the refueling mode. With the fuel pools cross-tied with one unit in refueling mode and RHR aligned to fuel pool cooling SST, there is no impact on the ability of refueling unit RHR system to perform its safety related functions. Also, there is no impact on the ability to safely shutdown the operating unit.

The conditions under which cooling of the spent fuel pool water by the RHR system alone would be required include the unloading of a full core load of irradiated fuel into the pool or isolation of fuel pool cooling system to support RHR ADHR operation or RHR Fuel Pool Cooling assist operation. The RHR system has sufficient heat removal capacity to maintain the spent fuel pool water at a temperature at or below 140°F, with a maximum anticipated decay heat load of 4.832×10^7 Btu/hr. The RHR system may also be used for cooling if the fuel pool cooling system should be unavailable. Connection of the RHR system requires:

a. Installation of RHR system spool pieces

b. Manual closure of normally open valve 053-✯007

c. Manual opening of normally closed valves 053-✯006, 053-✯024A and 053-✯024B

d. Adjustment of fuel pool overflow weirs, if required

e. Adjustment of Fuel Pool/SST water level to ensure adequate suction head for RHR pumps, if required

For Fuel Pool Cooling assist mode, the RHR supply and return lines and their associated valves are located in the fuel pool cooling pump and heat exchanger room at el 283' in the reactor enclosure.

The normal position of the above valves provides isolation of the safety-grade, seismic Category I RHR system from the FPCC system. The portion of the FPCC system downstream of valve 053-☆007 is designed to seismic Category I criteria (designated seismic Category IIA as discussed in Section 3.2.1) and would not be expected to fail due to a seismic event.

If normal fuel pool cooling should be lost as a result of a pipe break in the seismic Category IIA portion of the system, the quantity of water released would be limited to the inventory of the pool and reactor cavity above the overflow weirs, the skimmer surge tanks, and the pump suction piping. The flood height and environmental conditions resulting from this break would not prevent personnel access, which is required to take the manual actions described above. The maximum temperature (150°F) and pressure (31 psig) of the water in the line are not high enough to significantly affect the temperature, pressure, or humidity conditions in the room (the room is open at the top to the reactor enclosure access area at el 283'). The released fluid would not be highly radioactive. The water would drain out of the room at approximately the same rate as it flows from the break.

If there is a LOOP, the Class 1E buses are powered by the diesel generators, and the two FPCC pumps that receive Class 1E power can be restarted. Since normal service water is not available in this case, the FPCC heat exchangers can be cooled by the RECW system (which is in turn cooled by the ESW system) via interconnecting piping, after installation of normally removed spool pieces (drawings M-10, M-11 and M-13).

If there is a complete loss of capability to remove heat from the spent fuel pool using heat exchangers, heat can be removed by allowing the pool to boil and adding makeup water to maintain the pool water level. Makeup water requirements are shown in Table 9.1-2B. Makeup water is normally supplied to the skimmer surge tanks from the demineralized water makeup system (Section 9.2.5) by the actuation of a remote manually operated valve. If makeup water from this source is not available, makeup can be provided from the ultimate heat sink (spray pond) by either of two seismic Category I flow paths (drawings M-10, M-51 and M-53). The first of these backup makeup sources is a loop of the ESW system (Section 9.2.2) via a cross-connecting line to one of the RHR system return pipes in the spent fuel pool. The two ESW pumps in the ESW loop provide redundancy in motive power for this source of makeup supply. The manual valves that must be opened to initiate makeup from the ESW system are located in the control structure and are accessible after an accident. The second of these backup makeup sources is a loop of the RHRSW system (Section 9.2.3) via the piping of one RHR system loop and the cross-connecting piping leading to the RHR return piping in the spent fuel pool. The two RHRSW pumps in the RHRSW loop provide redundancy in motive power for this source of makeup supply. The manual valves that must be actuated and the spool piece that must be installed to establish this flow path are located in the reactor enclosure. These backup makeup water sources provide flow rates greater than the maximum makeup requirements shown in Table 9.1-2B. The spray pond design water volume includes its use as a source of makeup to the spent fuel pool for 30 days, without makeup to the pond during which time the cooling function of the FPCC system or RHR system can be established or an alternate makeup water supply can be established.

9.1.3.3 Safety Evaluation

The cooling water return lines to the spent fuel pool associated with both the FPCC system and RHR system penetrate the walls of the spent fuel pool within 4 feet of the normal pool water level. FPCC system cooling water return lines are provided with siphon breaker holes as close as possible to the normal water level to prevent the siphoning of pool water below the level of the holes. RHR system cooling water return lines terminate below the normal water level and above the minimum water level to prevent pool siphoning. The FPCC system takes suction from the spent fuel pool via the skimmer surge tanks through openings in the liner plate at the normal water level. There are no other piping penetrations in the pool liner plate. Therefore, there is no operator error or FPCC system malfunction that could result in the draining of the spent fuel pool so that stored fuel would be uncovered.

The spent fuel pool is provided with redundant seismic Category I makeup capability to ensure an adequate supply of makeup water to the spent fuel pool under conditions of maximum anticipated evaporation associated with fuel pool boiling. The radiological consequences of a boiling spent fuel pool are discussed in Section 9.1.3.6. Makeup water is supplied from the spray pond using either the ESW system or RHRSW system. Redundant pumps in each loop of the ESW and RHRSW systems provide assurance of the availability of motive power to pump the makeup water.

The portions of the FPCC system that form part of the flow path during makeup from the ESW or RHRSW systems or spent fuel pool cooling by the RHR system, up to and including the boundary isolation valves, are designed in accordance with seismic Category I requirements as discussed in Section 3.2. The components (and supporting structures) of any system, equipment, or structure that is not seismic Category I and whose collapse could result in the loss of a required function of the FPCC system are analytically checked to determine that they will not collapse when subjected to seismic loading resulting from the SSE.

The design of the FPCC system with respect to the following areas is discussed in the indicated sections:

a.	Protection from wind and tornado effects	Section 3.3
b.	Flood design	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11

A failure mode and effects analysis of the FPCC system is provided in Table 9.1-3.

The water level in the spent fuel storage pool is maintained at a height sufficient to provide shielding for required building occupancy. Radioactive particulates removed from the fuel pool are collected in filter/demineralizer units in shielded cells. For these reasons, the exposure of station personnel to radiation from the FPCC system is normally minimal. Further details of radiological considerations are discussed in Chapter 12.

9.1.3.4 Inspection and Testing Requirements

The FPCC system is preoperationally tested in accordance with the requirements of Chapter 14. The safety-related systems that provide makeup water are periodically tested in accordance with the requirements of Chapter 16.

9.1.3.5 Instrumentation Applications

Instrumentation is provided to annunciate the high and the low spent fuel pool water levels in the control room. Skimmer surge tank level instrumentation provides level indication at the refueling floor control panel, both high and low level annunciation at the refueling floor control panel and the fuel pool cooling pump control panel, and by a common trouble alarm in the main control room panel. A low level alarm indicates that makeup to the FPCC system is needed.

The temperature of fuel pool cooling water at the common inlet and at the outlet of each fuel pool heat exchanger is recorded and high temperature is annunciated in the control room; high outlet temperature in the combined heat exchanger discharge is annunciated in the control room through the plant computer.

The discharge pressure of each fuel pool cooling pump is indicated locally. Low pump discharge and suction pressure is annunciated by a local alarm in the fuel pool cooling pump panel and by a common trouble alarm in the main control room. The pumps are tripped individually on low suction pressure.

High leakage rates through the refueling bellows or reactor well seals are annunciated at the refueling floor control panel and by a common trouble alarm in the main control room.

The equipment associated with the cleanup loop is controlled and monitored from panels in the radwaste enclosure. The parameters monitored include differential pressure across the filter/demineralizer, flow rate through the filter/demineralizer, and pressure differential across the strainer downstream of the filter/demineralizer.

9.1.3.6 Analysis for Nonseismic Fuel Pool Cooling and Cleanup System

The FPCC system is not designed as a seismic Category I or engineered safeguards system except for interconnections with safety-related makeup water sources. The following analysis examines the consequences of a loss of spent fuel pool cooling and the use of the seismic Category I makeup water source.

It is assumed that loss of cooling to both spent fuel pools occurs. In addition, to maximize both the heat loads and the iodine inventories in the pools, sequential refuelings are postulated. The loss of cooling is assumed during the eleventh refueling, just after the refueling cavity water level is lowered and the RHR system is not available for cooling the cavity and spent fuel pool. The analysis involves an evaluation of the time to pool boiling, the makeup water requirements if the pool boils, and the thyroid dose consequences at the LPZ outer boundary due to iodine releases from the boiling pools. This analysis is still bounding for all spent fuel storage rack configurations up to and including maximum storage configuration of maximum density storage racks.

The assumptions used in this analysis were consistently chosen to be the worst case design basis assumptions, similar to those in regulatory guides for design basis accidents (e.g., Regulatory Guides 1.3, 1.25, etc). The combination of all of these design basis assumptions occurring at the

same time is extremely unlikely, making this accident, as analyzed, one of very low probability. Many of the assumptions are considered to be overly conservative; for example, operating experience with present BWR fuels (Reference 9.1-5) indicates that the assumption of 1% of the fuel with cladding failures is more conservative by at least a factor of 100 for 8x8 fuel bundles. Further, while some iodine release rate spiking factors of over 50 have been observed during startups and shutdowns, there are presently no data for the less severe temperature transients that would be associated with a boiling spent fuel pool. The assumption of 10% of the activity in the fuel gaps is at least 30 times the gap activity used for a realistic accident analysis in Chapter 15. A more realistic evaluation of this accident would result in releases of radioactivity, if any, many orders of magnitude below the calculated values. Further, the realistic releases would be well below the 10CFR50, Appendix I technical specifications, indicating that such an incident is of little or no consequence.

This conservatively assumes that it would take 20 hours to place the reactor in cold shutdown, realign valves, adjust the spent fuel pool weir, and install the interconnecting piping between the RHR system and the fuel pool cooling system (Section 5.4.7.1.1). The conservative results show that the pools would not boil until at least 13.5 hours after the loss of cooling at the average water heatup rate of 5.33°F/hr. If cooling is not restored before the pool boils, then makeup water from the seismic Category I ESW system can be added to the pool to keep the fuel covered at all times.

As shown in Table 9.1-4 the thyroid dose consequences of releasing the water that would evaporate from the boiling pool are well below the guideline values of 10CFR100.

The following assumptions were used to calculate the heat generation and boiling rates in the two spent fuel pools:

a. Each pool contains the maximum inventory of assemblies with the discharges shown in Table 9.1-2A. The last one-third cores are from the just-completed sequential refuelings. For Unit 1, the fuel has decayed for 47 days. For Unit 2, the decay time is 21 days, the length of time from shutdown until the water level in the refueling cavity has been lowered, and the RHR system would not be able to cool the refueling cavity and spent fuel pool. The minimum time to complete fuel unloading and loading for Unit 1 is 26 days. These decay times result in the maximum heat generation rates and maximum evaporation rates at times when the RHR system is not available.

b. The decay heat is calculated by using the decay heat equations presented in BTP APCSB 9-2. The decay heat generation rate for each pool is given in Table 9.1-5 for various times after the postulated loss of cooling.

c. All heat generated by the fuel is assumed to be absorbed by the water, to minimize the time to boiling. No heat is assumed to be lost to the surroundings by conduction through the concrete and steel or by evaporation. The temperature gradients from the fuel at the bottom of the pool to the cooler water at the top create convective water and heat currents that should thoroughly mix the water and promote an even distribution of heat, rather than localized points of surface boiling .

This does not preclude the performance of non-sequential outages less than 26 days in length.

The following assumptions were used to calculate the offsite doses for the loss of cooling to the spent fuel pools:

a. The saturation inventory of I-131 in the 3458 MWt core is 8.66×10^7 Ci.

b. During refueling, 276 fuel elements (one-third core) are transferred to the spent fuel pool. Iodine in fuel from past refuelings is negligible, due to the long times for decay.

c. It is assumed that 1% of the fuel rods in the core are defective and that this 1% is in the one-third core transferred to the spent fuel pool.

d. The iodine activity in the spent fuel pool water at the initiation of boiling is assumed to be negligible compared to the activity released from the fuel during pool boiling. Activity in the core coolant or from a shutdown spike would have been cleaned up to acceptably low levels by the RWCU and spent fuel pool cleanup systems before fuel transfer begins.

e. The spent fuel pool cooling systems are assumed to fail 47 days after shutdown for the first reactor and 21 days after shutdown for the second reactor. The 26 day difference is the minimum time to refuel the first unit. The 21 days is the time, after a complete fuel transfer, during which the water level in the refueling cavity is lowered, and the RHR system would not be able to cool the refueling and spent fuel pools in case of an accident.

f. The gap activity, or 10% of the rod activity, is available for leakage from the defective 1% of the rods. The leakage rate is assumed to be 2.9×10^{-8} per sec, which corresponds to a release rate of 2.6×10^{-3} Ci/sec for I-131 or 3.5×10^{-1} Ci/sec at 30 minutes for noble gases. This is the full power design fuel leak rate. It should be noted that the available activity in the gaps of the defective fuel rods may have already been significantly depleted by the shutdown spike.

g. A constant spike factor of various magnitudes up to 50 was applied to the I-131 leakage rate from the fuel to account for the potential spiking effects during the temperature transient. The leakage rate returns to the normal full power unspiked rate of 2.9×10^{-8} per sec when boiling begins, since the fuel should now be close to its new steady-state temperature. Although analyses were performed for release rate spike factors of up to 50, there are presently no data to support the spiking phenomena in the spent fuel pool boiling situation. Spikes have been observed for the large, rapid temperature and pressure changes associated with shutdowns and startups, but such significant spiking effects would not be expected during the long, slow temperature change of less than 65°F that would be associated with a loss of cooling. A comparison with the Eickelpasch and Hock paper, "Fission Product Releases After Reactor Shutdown," IAEA Sm 178/19 (1974), shows that the measured I-131 release rate at 9 days after shutdown is approximately 0.2 to 0.3 of the release rate at power. Since the temperature of the fuel during boiling is expected to be well below operating temperature, the use of the power leakage rate is considered to be extremely conservative.

h. The activity released from the fuel is assumed to be uniformly mixed in the 40,600 ft^3 (2.53×10^6 lb_m) of water in each spent fuel pool. The temperature gradients created in the pool by the fuel maintains the mixing process.

i. The normal spent fuel pool design maximum temperature is 140°F. For conservatism this is assumed to be the pool temperature at the time of loss of cooling.

j. The activity release rate from the pool depends on the evaporation (boiling) rate. No evaporation is assumed during the heatup period until the pool water reaches 212°F. All heat generated by the fuel is assumed to be absorbed by the water, and no losses through the concrete and steel are assumed. This results in the shortest time to boiling. The heat generation and evaporation rates after boiling starts are given as a function of time in Table 9.1-5.

k. The iodine partition factor at the pool surface is varied between 0.1 and 0.01 to determine the effects on the total release. Although the partition factor would vary as a function of time due to changing temperatures and iodine concentrations, a value greater than 0.1 should not be expected for this nonviolent evaporating process at the pool surface.

l. No credit is taken for iodine plateout on walls and equipment or for washout by condensing water vapor in the refueling area.

m. It is assumed that all activity in the steam released to the air in the refueling area is instantaneously released to the atmosphere without filtration or condensation in the ventilation system.

n. The atmosphere dispersion factors for dilution of the radioactive releases are the 5th percentile ground level X/Qs given below for the LPZ boundary distance. The time "0" is assumed to be the start of the accident when pool cooling is lost.

TIME	X/Q (sec/m^3)
0 - 8 hrs	4.0×10^{-5}
8 - 24 hrs	2.9×10^{-5}
1 - 4 days	1.4×10^{-5}
4 - 30 days	5.4×10^{-6}

o. The thyroid dose models and breathing rates given in Regulatory Guide 1.3 are used.

The following model was used to calculate the offsite thyroid doses from the release of radioiodine from the fuel:

a. The activity in the fuel available for leakage at the time of loss of cooling, S(0), is calculated using the reactor inventory equation from TID-14844, with the appropriate decay from shutdown until the loss of the cooling and the fractions of iodine available for release. During the pool heatup and boiling phases, the activity in the fuel gaps available for leakage, S(t), is adjusted for decay and losses by leakage to the pool.

$$S(t_n) = S(t_{n-1})\ e^{-(\lambda_d + \lambda_i)\Delta t} \quad (Ci) \qquad \text{(EQ. 9.1-1)}$$

where:

λ_d = decay lambda (1/sec)

λ_1 = leakage rate from the fuel (1/sec)

Δt = $t_n - t_{n-1}$ = time increment (sec)

b. The activity in the spent fuel pool as a function of time, A(t), is given by the solution to the following:

$$A(t_n) = A(t_{n-1})e^{-\lambda_d \Delta_t} - \lambda_{ev} A(t_{n-1})\Delta t + \lambda_1 S(t_n)\left[1 + (SF-1)(1-\varepsilon(t_n))\Delta t / V\right] \quad \text{(EQ. 9.1-2)}$$

where:

λ_{ev} = evaporation lambda from the pool (1/sec) x PF

PF = iodine partition factor at the pool surface

SF = spiking factor

ε = step-function = $\varepsilon = 0$ for $t_n \leq$ time to boil
$\varepsilon = 1$ for $t_n >$ time to boil

V = pool volume (ft^3)

A = activity in spent fuel pool (Ci/ft^3)

Since spent fuel pool makeup water will be available, the evaporation lambda is found by dividing the evaporation rate (ft^3/sec) by the constant pool water volume (ft^3).

c. The activity released to the atmosphere at any incremental time t_n is given by the following equation:

$$R(t_n) = R(t_{n-1}) + \lambda_{ev} V A(t_n)(1-f)\Delta t \quad \text{(EQ. 9.1-3)}$$

where:

R = activity released (Ci)

f = SGTS filter efficiency fraction (assumed to be zero)

The above equations are solved iteratively, using time steps of 450 seconds.

d. The thyroid dose at the LPZ is calculated using the equations and models from Regulatory Guide 1.3.

9.1.4 FUEL HANDLING SYSTEM

9.1.4.1 Design Bases

The fuel handling system is designed to provide a safe and effective means for transporting and handling fuel from the time it reaches the plant until it leaves the plant after postirradiation cooling. Safe handling of fuel includes design considerations for maintaining occupational radiation exposures as low as reasonably achievable during transportation and handling.

Design criteria for major fuel handling system equipment are provided in Tables 9.1-7 through 9.1-9, which list the safety class, quality group, and seismic category. Where applicable, the appropriate ASME, ANSI, industrial, and electrical codes are identified. Additional design criteria are shown below and expanded further in Section 9.1.4.2. The equipment discussed in this section was also reviewed to verify compliance with the guidelines of ANS 57.1 and ANS 57.2 (1976). There were no deviations identified except those discussed in Section 9.1.5.2 for the reactor enclosure crane and for the new fuel inspection/channeling stand and the upending platform.

The reactor enclosure crane main hoist or auxiliary hoist is used with a general purpose grapple to transfer new fuel from the new fuel inspection stand to the fuel prep machines in the fuel storage pool. From this point on, the fuel is handled by the telescoping grapple on the refueling platform.

The refueling platform is seismic Category I from a structural standpoint, in accordance with 10CFR50, Appendix A and 10CFR50, Appendix B. The allowable stress due to SSE loading is 120% of yield or 70% of ultimate, whichever is less. A dynamic analysis is performed on the structures using the response spectrum method, with load contributions resulting from each of three earthquakes being combined by the RMS procedure.

Working loads of the platform structures are in accordance with the AISC Manual of Steel Construction. All parts of the hoist systems are designed to have a safety factor of 5 based on the ultimate strength of the material. A redundant load path is incorporated in the main hoist so that no single component failure could result in a fuel bundle drop. Maximum deflection limitations are imposed on the main structures to maintain the relative stiffness of the platform. The welding of the platform is in accordance with AWS D14-1 or ASME Section IX. Gears and bearings meet AGMA Gear Classification Manual and ANSI B3.5 requirements. Materials used in the construction of load-bearing members meet ASTM specifications. For personnel safety, OSHA (29CFR1910.179) is applied. Electrical equipment and controls meet ANSI C-1, National Electric Code, and NEMA Publication No. ICI, MGI requirements.

The general purpose grapples and the main telescoping fuel grapples have redundant hooks. The main fuel grapple has an indicator that confirms positive grapple engagement.

The fuel grapple is used for lifting and transporting fuel bundles. It is designed as a telescoping grapple that can extend to the proper work level. At its normal up position, adequate shielding is still maintained over the fuel.

Redundant electrical limit switches are a part of the fuel grapple to preclude the possibility of raising radioactive material out of the water. The cables on the auxiliary hoists incorporate an adjustable, removable stop that jams the hoist cable against the hoist structure to prevent hoisting when the free-end of the cable is at a preset distance below water level.

The provision of a separate cask loading pool, capable of being isolated from the fuel storage pool, eliminates the potential for accidental dropping of the cask and rupturing of the fuel storage pool. See Chapter 15 for accident considerations.

9.1.4.2 System Description

Table 9.1-6 is a listing of typical tools and servicing equipment supplied with the nuclear system. The following paragraphs describe the use of some of the major tools and servicing equipment and address safety aspects of the design where applicable.

9.1.4.2.1 Spent Fuel Cask

The spent fuel cask is used to transfer spent reactor fuel assemblies from the spent fuel pool, via the cask pit to a fuel storage or fuel reprocessing facility. The cask can also be used for offsite shipment of irradiated reactor components such as control rod blades, incore monitors, etc.

The maximum loaded weight and hence the capacity of the cask is determined by the 125 ton lifting capacity of the reactor enclosure crane. The maximum loading height, ie, height of the open cask in the storage pit, is determined by the depth of the shipping cask pit from the gate bottom. This allows for a constant water depth over the fuel in transit from the reactor to the fuel pool and into the shipping cask.

It further allows underwater replacement of the lid and other operations that may pose unacceptable radiation hazards to personnel. Considerations facilitating decontamination of the cask are given in the design. The design of the cask meets all applicable regulations of the DOT and 10CFR71.

No specific type of cask has been chosen. Over the lifetime of the plant, several different sizes and models that the fuel handling facilities can accommodate may be used.

Additionally, an Independent Spent Fuel Storage Installation Transfer Cask has been chosen, as described in the Updated Final Safety Analysis Report for the Standardized NUMOS® Horizontal Modular Storage System for Irradiated Nuclear Fuel Rev 10, Transnuclear, Inc., NUH003.0103 and its NRC Certificate of Compliance No. 1004.

Also, a HI-TRAC VW cask is utilized as described in the Final Safety Analysis Report for the HI-STORM FW MPC Storage System, HI-2114830 and its NRC Certificate of Compliance No. 1032.

9.1.4.2.2 Cask Crane

The reactor enclosure crane is discussed in Section 9.1.5.

9.1.4.2.3 Fuel Servicing Equipment

The fuel servicing equipment described below is designed in accordance with the criteria listed in Table 9.1-7.

9.1.4.2.3.1 Fuel Prep Machine

The fuel preparation machine (Figure 9.1-5) is mounted on the wall of the fuel storage pool and can be used for stripping reusable channels from the spent fuel and for channeling the new fuel. The

machine is also used with the fuel inspection fixture to provide an underwater inspection capability and with the defective fuel storage container to contain a defective fuel assembly.

The fuel preparation machine consists of a work platform, a frame, and a movable carriage. The frame and movable carriage are located below the normal water level in the fuel storage pool, thus providing a water shield for the fuel assemblies being handled. The fuel preparation machine carriage has an uptravel stop to prevent raising irradiated fuel above the safe water shield level. The uptravel stop can be adjusted to allow new fuel to be transferred from the reactor enclosure overhead crane to the fuel prep machine carriage without submerging the crane hook in the fuel pool water. The movable carriage is operated by a foot pedal controlled air hoist.

9.1.4.2.3.2 New Fuel Inspection/Channeling Stand

The new fuel inspection/channeling stand serves as a support for a new fuel bundle undergoing receipt inspection and provides a working platform for technicians engaged in performing the inspection.

The new fuel inspection/channeling stand consists of a vertical column with a bearing seat, a lift unit to position the work platform at any desired level, and upper clamp to hold the fuel bundle in position. Bolted to the upper portion of the column is an articulating hoist mechanism consisting of two square tubes connected by a hinge pin. The articulating piece is normally lowered to avoid interference with the reactor enclosure crane. When channeling is being performed the articulating piece is raised by a double-acting air cylinder to its full height, and an electric hoist mounted on the piece that lowers the channel over the fuel bundle.

9.1.4.2.3.3 Channel Bolt Wrench

The channel bolt wrench (Figure 9.1-7) is a manually operated device approximately 12 feet (3.6 meters) in overall length. The wrench is used for removing and installing the channel fastener assembly while the fuel assembly is held underwater in the fuel preparation machine.

The channel bolt wrench has a socket that mates and captures the channel fastener cap screw.

9.1.4.2.3.4 Channel Handling Tool

The channel handling tool (Figure 9.1-8) is used in conjunction with the fuel preparation machine to remove, install, and transport fuel channels in the fuel storage pool.

The tool is composed of a handling bail, actuating knob, actuating shaft, angle guides, and jaws that engage the fuel channel. The jaws are actuated (extended or retracted) by manually rotating the actuating knob.

The channel handling tool is suspended by its bail from a spring balancer on the channel handling boom located on the fuel floor.

9.1.4.2.3.5 Fuel Pool Sipper

The fuel pool sipper (typical unit shown in Figure 9.1-9) provides a means of isolating a fuel assembly in demineralized water to concentrate fission products in relation to a controlled background.

The fuel pool sipper consists of a control panel assembly and a sipping container.

9.1.4.2.3.6 Fuel Inspection Fixture

The fuel inspection fixture (typical unit shown in Figure 9.1-10) is used in conjunction with the fuel preparation machine to permit remote inspection of a fuel bundle or assembly. The fixture consists of two parts: a lower bearing assembly and a guide assembly at the upper end of the carriage. The fuel inspection fixture permits the rotation of the fuel bundle or assembly in the carriage and provides, in conjunction with the vertical movement of the carriage, complete access for inspection.

9.1.4.2.3.7 Channel Gauging Fixture

The channel gauging fixture (Figure 9.1-11) is a go/no-go gauge which can be used to evaluate the condition of a new fuel channel before channeling.

The channel gauging fixture consists basically of a frame, gauging plate, and gauging block. The gauging plate is shimmed to correspond to the outside dimension of a usable fuel channel. The gauging block conforms to the inside dimension of the lower end of a usable fuel channel.

The channel gauging fixture is installed vertically between the two fuel preparation machines, and hangs from the fuel storage pool curb when in use. When not in use, the channel gauging fixture may be stored elsewhere in the fuel storage pool or on the fuel floor.

9.1.4.2.3.8 General Purpose Grapple

The general purpose grapple (Figure 9.1-12) is a handling tool used generally with the fuel. The grapple can be attached to the reactor enclosure main hoist, auxiliary hoist, jib crane, and the auxiliary hoists on the refueling platforms. The general purpose grapple is used to place new fuel in the inspection stand and to transfer the new fuel to the fuel pool. It can be used to handle fuel during channeling.

9.1.4.2.3.9 New Fuel Upending Platform

The upending platform is a structural steel frame that supports a 1 1/2 ton jib crane that has two hoists mounted on it. There is a 1-ton electric hoist and a 1/2 ton hand hoist. Only one hoist will be used at a time. The platform is a Seismic Category II structure.

The jib crane and electric hoist are used to raise the metal container into a vertical position and set it into the upending stand of the platform.

It is also possible to use the reactor enclosure crane to transfer the metal container into the unloading area.

The jib crane and the hand hoist are used to transfer the fuel bundles into one of the new fuel inspection/channeling stands which are located on either side of the platform.

9.1.4.2.3.10 Roller Conveyer

A gantry crane or the reactor enclosure crane will be used to transfer the metal container from a predesignated storage area to a roller conveyer. The roller conveyer is located adjacent to the upending platform and is used to position the metal container under the jib crane.

9.1.4.2.3.11 Gantry Crane

The 2-ton gantry crane can be used to transfer the metal container from the predesignated storage area to the roller conveyer. The gantry crane is designed to meet the requirements of the Limerick heavy loads program.

9.1.4.2.4 Servicing Aids

General area underwater lights are provided, with a suitable reflector for illumination. Suitable light support brackets are furnished to support the lights in the reactor vessel to allow the light to be positioned over the area being serviced, independently of the platform. Local area underwater lights are small-diameter lights for additional illumination. Drop lights are used for illumination where needed.

A radiation-hardened portable underwater closed-circuit television camera is provided. The camera may be lowered into the reactor vessel and/or fuel storage pool to assist in the inspection and/or maintenance of these areas. The camera may also be equipped with a right-angle lens to allow viewing at 90°.

A general purpose plastic viewing aid is provided to float on the water surface to provide better visibility. The sides of the viewing aid are brightly colored to allow the operator to observe it if it fills with water and sinks. A portable, submersible, underwater vacuum cleaner is provided to assist in removing crud and miscellaneous particulate matter from the pool floors or the reactor vessel. The pump and the filter unit are completely submersible for extended periods. The filter "package" is capable of being remotely changed, and the filters fit into a standard shipping container for offsite burial. Fuel pool tool accessories are also provided to meet servicing requirements. A fuel sampler is provided to detect defective fuel assemblies during open vessel periods while the fuel is in the core. The fuel sampler head isolates individual fuel assemblies by sealing the top of the fuel channel and pumping water from the bottom of the fuel assembly, through the fuel channel, to a sampling station, and returning it to the primary coolant system. After a "soaking" period, the water sample is radiochemically analyzed to determine possible fuel bundle leakage.

9.1.4.2.5 Reactor Vessel Servicing Equipment

The essentiality, the quality group, and the seismic category for this equipment are listed in Table 9.1-8. The following is a description of the equipment designs in reference to that table.

9.1.4.2.5.1 Reactor Vessel Service Tools

These tools are used when the reactor is shut down and the reactor vessel head is being removed or reinstalled.

9.1.4.2.5.2 Steam Line Plug

The GE steam line plugs are used during reactor refueling or servicing. They are inserted in the steam outlet nozzles from inside the reactor vessel to prevent a flow of water from the reactor well into the main steam lines during servicing of SRVs, MSIVs, or other components of the main steam lines, while the reactor water level is raised to the refueling level.

The steam line plug design provides two seals of different types. Each one is independently capable of holding full head pressure. The equipment is constructed of noncorrosive materials. Steam line plugs of various designs are utilized. Plug designs weighing more than a fuel bundle meet the

requirements of NUREG-0612. Current steam line plugs including handling tool weigh less than 1200 pounds and do not constitute heavy loads.

The Preferred Engineering steam line plugs have two 100% capacity redundant static seals that are actuated by a compressive spring mechanism. Only one static seal is required, but two are provided. The Preferred Engineering steam line plugs are designed to withstand a differential pressure of 50 psi without ejecting from the main steam line nozzle.

9.1.4.2.5.3 Shroud Head Bolt Wrench

This is a tool for the operation of the shroud head bolts. It is designed for a 40 year life, and is made of corrosion resistant materials for easy handling and corrosion resistance. Testing has been performed to confirm the design.

9.1.4.2.5.4 Head Holding Pedestal

Three pedestals are provided for mounting on the refueling floor for supporting the reactor vessel head. The flange surface rests on replaceable wear pads made of aluminum. When resting on the pedestals, the head flange is approximately 3 feet above the floor to allow access to the seal surface for inspection and O-ring replacement.

The pedestal structure is a carbon steel weldment, coated with an approved paint. It has a base with bolt holes for mounting it to the concrete floor. The structure is designed in accordance with AISC Manual of Steel Construction.

9.1.4.2.5.5 Head Nut and Washer Rack

The RPV head nut and washer rack maybe used for transporting and storing up to six nuts and washers. The rack is a box-shaped non-corrosive structure with dividers to provide individual compartments for each nut and washer. Each corner has a lug and shackle for attaching a four leg lifting sling.

The rack is designed with a safety factor of 5.

9.1.4.2.5.6 Head Stud Rack

The head stud rack may be used for transporting and storing six reactor pressure vessel studs. It is suspended from the reactor enclosure crane auxiliary hoist for lifting studs from the reactor well to the operating floor.

The rack is made of a non-corrosive material.

9.1.4.2.5.7 Dryer and Separator Sling

The dryer and separator sling is a lifting device used for transporting the steam dryer or the shroud head with the steam separators between the reactor vessel and the storage pools.

The sling consists of a cruciform structure, which is suspended from a hook box with four wire ropes and turnbuckles. The hook box, with two hook pins, engages the reactor enclosure crane main hook extension or sister hook, depending on wet or dry transfer method. Synthetic slings are an approved

equivalent alternate to the wire ropes. When synthetic slings are used they are designed to be attached directly to the reactor enclosure crane sister hook. On the end of each arm of the cross is a socket with a pneumatically operated pin for engaging the four lifting eyes on the steam dryer or shroud head. The hook extension may be used when the dryer or shroud head is transferred underwater.

The sling is designed so that one hook pin and one main beam of the cross is capable of carrying the total load and so that no single component failure can cause the load to drop or swing uncontrollably out of an essentially level attitude.

The safety factor of the lifting members is 5 or greater for the ultimate breaking strength of the material. The structure is designed in accordance with AISC Manual of Steel Construction. The completed assembly is proof-tested at 125% or greater of rated load, and all structural welds are magnetic particle inspected after the load test.

9.1.4.2.5.8 Reactor Pressure Vessel Head Strongback/Carousel

The Reactor Pressure Vessel (RPV) head strongback/carousel is used for lifting the vessel head. The strongback/carousel is an integrated piece of equipment consisting of a cruciform shaped strongback, a circular monorail, and a circular storage tray.

The strongback is a box beam structure which has a hook box with three pins in the center for engagement with the reactor building crane main hoist hook. Each arm has a liftrod for engagement to the four lift lugs on the RPV head. The monorail is mounted on extensions of the strongback arms and four additional arms equally spaced between the strongback arms. The monorail circle matches the stud circle of the reactor vessel and serves to suspend the stud tensioners and the nut storage tray. Each tensioner has an air-operated hoist with individual controls.

The strongback carousel is considered to be single-failure proof, since failure of a single load arm or load pin will not release the load. It is designed in compliance with NUREG-0612, and the AISC manual of steel construction. The RPV strongback carousel is also designed in compliance with ANSI N14.6 with the exception of material testing of the hook pins, clevis pins, and clevis rods. The lack of material testing does not affect the function or safety of the RPV strongback carousel as the assembly is load proof testing and undergoes pre-service NDE to ensure its continued integrity. The design load capacity for the equipment will be 135 tons.

9.1.4.2.5.9 Service Platform

The text is this section described features of the reactor service platform. The reactor service platform is obsolete equipment that has been permanently removed from the facility. The information in this section was removed.

9.1.4.2.5.10 Service Platform Support

The text is this section described features of the reactor service platform support. This equipment is obsolete equipment that has been permanently removed from the facility. The information in this section was removed.

9.1.4.2.5.11 Steam Line Plug Installation Tool

The steam line plug installation tool is suspended from the reactor enclosure crane, auxiliary platform, or refueling platform for transporting and installing the steam line plugs in the steam line

nozzles of the reactor vessel. This tool is made of aluminum; it is designed for a safety factor of 5 and is in accordance with the Aluminum Construction Manual by the Aluminum Association.

9.1.4.2.5.12 Fuel Floor Auxiliary Platform (FFAP)

The FFAP or auxiliary platform provides worker access and component hoisting capability in the Unit 1 and 2 reactor cavities, fuel pools, and cask pit areas to perform maintenance activities during, but not limited to, refueling outages. The auxiliary platform is constructed of steel framing using materials in accordance with ASTM Standards. Welding is in accordance with AWS D1.1 structural welding. The auxiliary platform is not designed to perform movements of reactor fuel, irradiated components, and heavy loads.

9.1.4.2.5.13 Reactor Cavity Work Platform (RCWP)

The Reactor Cavity Work Platform (also known as the GE “Scorpion” RCWP) is approved for use at Limerick. The descriptive statements below apply to GE RCWP.

The RCWP provides workers access to in-vessel components for inspections and repairs concurrent with irradiated component handling activities. The RCWP is assembled on the refuel floor and then placed into the reactor cavity after flood-up and is removed from the cavity while it is still flooded up. Procedural controls will assure that cavity water level is maintained within the required range as the RCWP is inserted into and removed from the water.

The RCWP displaces some cavity water since the bottom of the GE RCWP work trough is located at approximately elevation 348 feet 10 inches, with hollow supporting beams extending approximately 10 inches below the bottom. This reduces shielding provided between irradiated components and the surface of the water (directly above the irradiated component). Radiation controls will be in place to ensure personnel are not inadvertently overexposed in the event of unexpected increases in dose rated on the RCWP. At the normal uptravel limit of the Refueling Platform hoists, the water shielding provided for the RCWP workers, in combination with radiation protection program controls and protective measures, is adequate.

The GE RCWP may be equipped with two jig cranes each de-rated to a load rating of 500 lbs and each weighing approximately 500 lbs. The RCWP is not designed to handle fuel, irradiated components or heavy loads. The GE RCWP jib cranes are permitted to extend into the boundary zone during fuel handling based on a determination in a GE analysis that a collision between a loaded fuel grapple and the GE RCWP would not result in dropping the fuel bundle or mast fuel grapple assembly onto the core; and therefore the original FHA remains bounding.

Additional administrative controls will be in place during handling of irradiated components in the reactor cavity to assure that irradiated components are not inadvertently raised in close proximity to personnel on the RCWP. Additional administrative controls will be in place during fuel handling to minimize the likelihood of a collision of the fuel grapple assembly with the GE RCWP jib crane. Administrative controls similar to those implemented for fuel movement when the boundary zone limit system is not available will also be implemented for fuel movement when the RCWP jib crane is extended into the boundary zone.

The RCWP was constructed in accordance with AISC Manual of Steel Construction using materials in accordance with ASTM standards. Welding is in accordance with ANSI/AWS D1.6 , Structural Welding Code for Stainless Steel, and ANSI/AWS D1.1, Structural Welding Code for Carbon Steel.

The RCWP meets Seismic IIA criteria and will not fall into the reactor vessel during an SSE. The GE RCWP does not rely on buoyancy to maintain its seismic qualification.

9.1.4.2.6 In-Vessel Servicing Equipment

The instrument strongback attached to the reactor enclosure crane is used for servicing neutron monitoring incore detectors as they require replacement. The strongback initially supports the incore detectors into the reactor cavity. The incore detectors are then decoupled from the strongback and is guided into place while being supported by the instrument handling tool. The instrument handling tool is attached to a refueling platform auxiliary hoist and is used for removing and installing fixed incore detectors, as well as for handling neutron source holders and the source range monitor/intermediate range monitor dry tubes. The auxiliary platform may be used to install new local power range monitors and new source range monitor/intermediate range monitor dry tubes.

Each incore instrumentation guide tube is sealed by an O-ring on the flange. If the seal needs replacing, an incore guide tube sealing tool is provided. The tool is inserted into an empty guide tube and sits on the beveled guide tube entry in the vessel. When the drain on the water seal cap is opened, hydrostatic pressure seats the tool. The flange can then be removed for seal replacement.

The auxiliary hoists on the refueling platform are used with appropriate grapples to handle control rod blades, incore detector dry tubes, sources, and other reactor vessel internals. Interlocks on both the grapple hoists and auxiliary hoist are used to provide safety; the refueling interlocks are described and evaluated in Section 7.7.

9.1.4.2.7 Refueling Equipment

Fuel movement and reactor servicing operations are performed from a platform that spans the refueling, servicing, and storage cavities.

9.1.4.2.7.1 Refueling Platform

The refueling platform is a gantry crane that is used to transport fuel and reactor components to and from the fuel storage pool and the reactor vessel. The platform spans the fuel storage pool and reactor cavity on rails bedded in the refueling floor. A telescoping mast and grapple suspended from a trolley is used for transporting and orienting fuel assemblies for placement into the core, storage rack, or shipping cask. The platform is controlled from an operator station on the main trolley, with a position indicating system provided to position the grapple over core locations. The platform control system includes interlocks to verify the grapple load, prevent unsafe operation over the vessel during control rod movements, and limit vertical travel of the grapple. The grapple in its normal up position provides 8 feet minimum water shielding over the top of active fuel (6 feet 6 inches shielding over the top of the fuel assembly) during transit. The fuel grapple hoist has a redundant load path so that no single component failure results in a fuel assembly drop.

A refuel platform is provided for each reactor unit. Due to the common refueling area for both units, the refuel platforms can be operated over either unit's spent fuel pool to move fuel assemblies. Administrative controls have been established to assure that both platforms are not operated in close proximity when both platforms are transporting fuel.

Two 1000 pound capacity auxiliary hoists, administratively limited to 500 pounds for the handling of control rod blades within the reactor pressure vessel, one main trolley-mounted and one monorail mounted, are provided for servicing, such as LPRM replacement, fuel support piece replacement,

jet pump servicing, control rod blade replacement, main steam line plug installation and removal, and shroud head bolt latching and unlatching. The two auxiliary hoists mounted on the refueling platform are not intended for fuel handling. The main trolley auxiliary hoist and the monorail auxiliary hoist are each provided with a geared rotary limit switch that provides normal up and down limit stops. In addition, a stop block fastened to the hoist cable will operate a safety limit switch if the normal up limit should fail.

The auxiliary platform may be used to assist the refueling platform efforts, such as, installing new LPRMs, installing and removing main steam line plugs, and latching and unlatching shroud head bolts. The auxiliary platform is not designed to perform movements of reactor fuel, irradiated core components, and heavy loads.

If the motor is not stopped by either up limit, the stop block will jam against the hoist frame and trip the motor on (a) the load cell switch sensing of a jam condition, or (b) stalling of the hoist motor. In either event, there will be no resulting impact load on the cable because the block stops against the energy-absorbing portion of the hoist (i.e., spring-loaded plate or pivoted sheave arm).

Each cable is inspected by procedure prior to every refueling outage.

A Service Pole Caddy platform is attached on the rear side of the refueling platform at LGS. The platform provides an auxiliary work station for unlatching and latching the steam separator head bolts during refueling activities. The platform can also be utilized for other underwater servicing needs such as jet pump beam bolt untorquing and steam line plug installation. The platform is provided with high torque service poles and a motorized hoist to handle the poles.

9.1.4.2.8 Storage Equipment

Specially designed equipment storage racks are provided. Additional storage equipment is listed on Table 9.1-6. For fuel storage rack description and fuel arrangement, see Sections 9.1.1 and 9.1.2.

Defective fuel assemblies may be placed in defective fuel storage containers, which in turn are stored in a suitable storage rack. Defective fuel assemblies are assemblies that are unable to contain the fuel pellets and cannot be handled with normal fuel handling equipment. These may be used to isolate leaking or defective fuel while in the fuel pool and during shipping. Channels can be removed from the fuel bundle while in a defective fuel storage container.

The storage racks which hold control rod blades and/or defective fuel assemblies are special storage racks designed to hold various core components that cannot fit in the spent fuel storage racks. Control rod blades, incore detectors and dry tubes may also be stored on fuel pool walls (see Section 11.4.2.1.4). The storage rack is designed to hold control rod blades, control rod guide tubes, sipping containers and spent local power range monitor (LPRM) containers in any of its 49 storage cavities and defective fuel containers (with spent fuel) in any of 5 specially designed cavities. The special storage rack is nominally 83 inches square and 159.25 inches high. The empty, dry weight of the rack is approximately 12,190 pounds. The storage rack is placed in the fuel pool as indicated in Figures 9.1-34 and 9.1-36.

The storage rack's cavities are formed by a checker board placement of canisters. The canisters, stainless steel plate material bent in a rectangular shape, are welded to the bottom grid assembly such that the distance between cavity centers (i.e., canister centerline to intermediate cavity centerline) is approximately 11.665 inches. Storage cavities along the rack periphery will have their outer wall made from stainless steel plate welded to the outer walls of adjacent canisters. Along the

top of the rack is a 0.187 inch thick 3.50 inch wide stainless steel perimeter bar. The perimeter bar allows lateral loads to be shared by all canisters and helps to maintain the specified center-to-center cavity spacing.

The bottom grid assembly is made from stiffened stainless steel plate. For each cavity, a 3.625 inch diameter chamfered hole in the bottom load support plate of the grid assembly acts to center rack stored items and accommodates cavity cooling water flow.

The five cavities designed to hold defective fuel containers have a bottom load support that is 3.75 inches lower in the bottom grid assembly than the other 44 rack cavities.

The rack is supported by 4 foot assemblies (foot pad and foot adjusting screw), one centered under each of the four corner cells. The foot assembly will accommodate slight variations in the pool floor liner surface and is adjustable over a 1-inch band to facilitate rack leveling. The upper surface of the bottom grid assembly will be 9.75 (± 0.50) inches above the pool floor. This will allow at least 22 feet 8 inches of water above a fuel assembly placed in any one of the rack cavities. Ample space will exist under the rack for the flow of water to each of the cells.

The rack is seismic Category I and qualified structurally by detailed dynamic and static analyses. The rack is designed to withstand the effects of a Safe Shutdown Earthquake (SSE) and remain functional in accordance with NRC Regulatory Guide 1.29 and the Code of Federal Regulations Title 10, Part 50, Appendix A.

The dynamic evaluation for seismic loads used the non linear transient analysis computer program ANSYS. The transient boundary conditions (time histories) for the analysis were generated artificially utilizing the computer program SIMQKE with design response spectra characteristics provided by Limerick Specification 8031-G-19. The maximum calculated rack stress levels and displacements occurred during the Safe Shutdown Earthquake load analysis. The analysis determined that all computed stress levels were within appropriate limits for the rack structure and its individual constituents. Maximum potential displacements have been analyzed and determined to be acceptable.

The static evaluation determined rack suitability as a result of stress due to static load applications and fuel drop accident impact loads. All static load stresses are within appropriate limits for the rack structure and its individual constituents. The equivalent static load resulting from a dropped fuel assembly was obtained through an energy analysis. The impact damage resulting from the fuel drop accident is confined to a small area near the impact point. Stresses away from the impact point are low; therefore, the overall rack structure will not be adversely affected and no change in k_{eff} will be realized due to the rack structure realignment.

The fuel pool sipper may be used for out-of-core wet sipping at any time. It is used to detect a defective fuel bundle while circulating water through the fuel bundle in a closed system. The containers cannot be used for transporting a fuel bundle. The bail on the container head is designed not to fit into the fuel grapple.

9.1.4.2.9 Under-Reactor Vessel Servicing Equipment

The functions of the under-reactor vessel servicing equipment are as follows:

a. Remove and install CRDs

b. Remove and install the thermal sleeve

c. Install and remove the neutron detectors. Table 9.1-9 lists the equipment and tools required for servicing. Of the equipment listed, the equipment handling platform and the CRD handling equipment are powered electrically and/or pneumatically.

The CRD handling equipment is used to perform a CRD exchange (i.e. remove and install) from the CRD housing. The CRD handling equipment is designed in accordance with the following requirements:

- American Institute for Steel Construction (AISC) - Steel Construction Manual, 8th Edition;
- Aluminum Association - Specifications for Aluminum Structures, 5th Edition;
- American Welding Society, Specifications D1.1 and D1.2;
- Federal Specification on MIL-W-83420D, Wire Rope, Flexible for Aircraft Control;
- American National Standard ANSI B30.9-1971 (Wire Ropes);
- AGMA - American Gear Manufacturer's Association - Services Factors and Lead Classifications;
- NEMA - National Electric Manufacturer's Association (standards).

The equipment used to perform a CRD exchange is capable of inserting a force of approximately 1300 pounds. Also, all of the lifting components are equipped with adequate brakes or gears to prevent uncontrolled movement on a loss of air or component failure. The equipment is capable of re-inserting a CRD if it is still coupled to its control rod.

The equipment handling platform provides a working surface for equipment and personnel performing work in the under-vessel area. It is a polar platform capable of 360° rotation. This equipment is designed in accordance with the applicable requirements of OSHA (Volume 37, No. 202, Part 191 ON), AISC, and ANSI C-1 (National Electric Code).

The thermal sleeve installation tool locks, unlocks, and lowers the thermal sleeve from the control rod guide tube.

The incore flange seal test plug can be used to determine the pressure integrity of the incore flange O-ring seal. It is constructed of noncorrosive material.

The key bender is designed to install and remove the antirotation key that is used on the thermal sleeve.

9.1.4.2.10 Description of Fuel Transfer

9.1.4.2.10.1 Arrival of Fuel Onsite

New fuel is delivered by truck (or by rail) and moved into the refueling hatch at grade level. Secondary containment can be maintained while the new fuel is being hoisted to the refueling floor.

9.1.4.2.10.2 Refueling Procedure

The general refueling floor layout is shown in drawings M-122 and M-137. Component drawings of the principal fuel handling equipment are shown in Figures 9.1-5 through 9.1-12.

The fuel handling process takes place primarily on the refueling floor above the reactor. The principal locations and equipment are shown in drawings M-122 and M-137. The reactor cavity, fuel pool, and cask storage pit are connected to each other by canals. The fuel transfer canal is open during reactor refueling, and the cask pit canal is open during spent fuel and ISFSI transfer cask and HI-TRAC VW cask handling in the Reactor Enclosure. The canals can be closed by redundant gates, which make watertight barriers. However, gates between the cask pit and the spent fuel pool will normally remain open during the transfer cask and HI-TRAC VW cask handling in the Reactor Enclosure.

New fuel, in shipping crates, is brought up to the refueling floor through the hatches, and spent fuel, in a shipping cask, is lowered through the hatches to a truck or rail car near grade level. The new fuel is placed in predesignated storage areas where it remains until it is processed and put in the spent fuel pool.

The method for transferring the fuel bundles between the crate, the new fuel inspection/channeling stand and spent fuel storage pool is accomplished by using a gantry crane or the reactor enclosure crane (125 ton main or 15 ton auxiliary hoist). The fuel is transferred from a predesignated storage area to a roller conveyer. The roller conveyer is located adjacent to the upending platform. At this point, the top is upended and placed into a vertical upending stand. After the fuel is unloaded, it is inspected and transferred to the fuel preparation machine.

The main or auxiliary hoist is used with a general purpose grapple to transfer a new fuel assembly to a fuel preparation machine. The fuel preparation machine lowers the new fuel into the pool, and henceforth, the fuel is positioned in a storage rack by the telescoping grapple on the refueling platform. It should be noted that secondary containment must be established when moving new fuel over recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).

The storage racks in the fuel pool hold the fuel bundles or assemblies vertically, in an array that is subcritical under all possible conditions.

The new fuel inspection/channeling stand holds one bundle vertically. The inspector(s) rides up and down on a platform, and the bundle is manually rotated on its axis. Thus the inspectors can see all visible surfaces.

The refueling platform uses a grapple on a telescoping mast for lifting and transporting fuel bundles or assemblies. The telescoping mast can extend to the proper work level, and, in its normal up position, adequate water shielding is maintained over the fuel being handled.

The refueling platform moves over the fuel pool, lowers the grapple on the telescoping mast, and engages the bail on a new fuel assembly that is in the fuel storage rack. The assembly is lifted clear of the rack and moved through the transfer canal and over the appropriate empty fuel location in the core. The mast then lowers the assembly into the location, and the grapple releases the bail.

The operator can then move the platform until the grapple is over a spent fuel assembly that is to be discharged from the core. The assembly is grappled, lifted, and moved through the transfer canal to the fuel pool. Here it can be placed in a spent fuel storage rack, fuel prep machine or a fuel bundle sipping container.

If channeling is to be performed, an operator working at the fuel prep machine using the channel bolt wrench, removes the channel fastener from the top of the channel. The channel is then held, while a carriage lowers the fuel bundle out of the channel. The channel is then moved aside, and the refueling platform grapple carries the bundle and places it in a storage rack. The channel handling boom hoist moves the channel to storage, if appropriate.

In actual practice, channeling and dechanneling may be performed in many sequences, depending on whether a new channel is to be used or a used channel is to be installed on a new bundle and returned to the core. A channel storage rack is conveniently located near the fuel prep machines for temporary storage of channels that are to be reused.

To preclude the possibility of raising radioactive material out of the water, redundant electrical limit switches are incorporated in the main hoist and interlocked to prevent hoisting above the preset limit. In addition, the cables on the auxiliary hoists incorporate adjustable stops that jam the hoist cable against the hoist structure, which prevents hoisting if the limit switch interlock system fails.

When spent fuel is to be shipped, it is placed in a cask. The refueling platform grapples a fuel bundle from the storage rack in the fuel pool, lifts it, carries it through the cask pit canal into the cask storage pit, and lowers it into the cask. When the cask is loaded, the crane sets the cask cover on the cask and then lifts the cask out of the pool. The cask is then decontaminated, sealed and lowered through the open hatchway to the truck or rail car at near grade level.

The provision of a separate cask storage pit, capable of being isolated from the spent fuel pool, eliminates the potential for accidental dropping of the cask and rupturing of the fuel storage pool.

Additional detailed information is provided below.

a. New fuel preparation

1. Receipt and inspection of new fuel

The incoming new fuel is delivered to the station where it is unloaded in a designated receiving area. The new fuel is shipped inside of a dual container system. The system consists of an inner metal container and an outer metal container. Each set of containers holds two fuel bundles. The shipping weight of each unit is approximately three-thousand six hundred (3600) pounds. After the fuel is unloaded, the outer metal containers are first examined for damage received during shipment. The containers are transferred to the refueling hoist-way. The main or auxiliary hoist of the reactor enclosure crane will hoist the containers to the refueling floor where they are placed in a predesignated area.

A gantry crane or the reactor enclosure crane will transfer the inner metal containers to a roller conveyer. The roller conveyer is located adjacent to the upending platform. At this time, the top and front of the metal container are removed. Using a jib crane and an electric hoist, mounted on the upending

platform, the metal container is upended and placed into the unloading stand. Using the hand hoist, which is also attached to the jib crane, the fuel is removed from the metal container and placed into the new fuel inspection/channeling stand (one of the two).

2. Channeling

GNF3 may be shipped pre-channeled and would not require channeling onsite. If channeling onsite, channeling of the fuel bundle takes place in the new fuel inspection/channeling stand. The channel is first examined for damage or defects. The new channel is raised over the fuel bundle and slowly lowered onto the fuel bundle. Once the channel is around the fuel, a channel fastener is used to clamp the channel to the fuel bundle, creating a fuel assembly. The complete fuel assembly is transferred to the fuel prep machine using the main or auxiliary hoist of the reactor enclosure overhead crane with a general purpose grapple. Once in the fuel prep machine, it is then lowered into the fuel pool and transferred to the fuel pool racks using the refueling platform.

3. Equipment preparation

Before the plant shutdown for refueling, all necessary equipment must be placed in readiness. All necessary tools, grapples, slings, strongbacks, stud tensioners, etc are given a thorough check, and any defective (or well worn) parts are replaced. Air hoses on grapples are routinely leak tested. Crane cables are routinely inspected. All necessary maintenance and interlock checks are performed to ensure that there is no extended outage due to equipment failure.

The incore flux monitors, in their shipping container, are on the refueling floor. The channeled new fuel and the replacement control rod blades are ready in the fuel pool.

b. Reactor shutdown

The reactor is shut down according to a prescribed procedure. During cooldown the RPV is vented and filled to above flange level to equalize cooling. The reactor well shield plugs can be removed. The upper layer of shield plugs may be removed once reactor power is lowered to less than or equal to 100%. The lower layer of shield plugs may be removed after the reactor has achieved hot shutdown. Prior to the removal of shield plugs in other than cold shutdown, there are specific conditions required to be satisfied per the general plant procedures. This is accomplished with the reactor enclosure crane and the lifting strongback. There are 12 pieces to handle.

This operation also includes the removal of the canal plugs and the slot plugs. A total of 16 separate plugs must be removed and placed on the refueling floor. Removal of these plugs may be performed out of sequential order as conditions permit. The outer fuel pool gate may also be removed at this time. A sling is attached to the gate lifting lugs, and the reactor enclosure crane lifts the gate and places it on the fuel pool storage lugs.

1. Drywell head removal

   Immediately after removal of the lower layer of reactor well

   shield plugs, the work to unbolt the drywell head can begin. The drywell head is attached by removable studs. The studs are unscrewed from the captive nut on the drywell and supported on the lip of the head.

   The unbolted drywell head can be lifted by the overhead reactor enclosure crane attached by a hook box and transferred to its designated storage space on the refueling floor. The drywell seal surface protector can then be installed, if required.

2. Reactor well servicing

   When the drywell head has been removed, an array of piping is exposed that must be serviced. Various vent piping penetrations through the reactor well must be removed and the penetrations made watertight. Vessel head piping and head insulation must be removed and transported to storage on the refueling floor.

   The water level in the vessel is now brought to flange level in preparation for head removal.

c. Reactor vessel opening

1. Vessel head removal

   The stud tensioners, as part of the strongback/ carousel assembly, are transported by the reactor enclosure crane and positioned on the reactor vessel head. Each stud is tensioned and its nut is loosened sequentially. When the nuts are loose, they are backed off using a nut runner until only a few threads engage. The nut is then rotated free from the stud. The nuts and washers are placed in the racks provided for them and can be transported to the refueling floor for storage. Alternately, the nuts and washers may be placed in the carousel storage compartments and stored with the carousel. With the nuts and washers removed, the vessel stud protectors and vessel head guide caps are installed.

   The head strongback/carousel, transported by the reactor enclosure crane, is attached to the vessel head, and the head is transported to the head holding pedestals on the refueling floor. The head holding pedestals keep the vessel head elevated to facilitate inspection and O-ring replacement.

   The studs in line with the fuel transfer canal are removed from the vessel flange and can be placed in the rack provided. The loaded rack can be transported to the refueling floor for storage. Alternatively, the studs can be transported with the vessel head. The studs opposite the cattle chute are also removed to maintain balance when the studs are transported with the vessel head.

2. Dryer removal

The dryer/separator sling is lowered by the reactor enclosure crane and attached to the dryer lifting lugs. The dryer is lifted from the reactor vessel and transported to its storage location in the dryer/separator storage pool adjacent to the reactor well. Since the dryer is anticipated to be highly contaminated, the reactor well and storage pool is flooded and a wet transfer effected. An in-air transfer may be used if the dryer is kept wet to reduce the potential for airborne contamination.

3. Separator removal

From the auxiliary platform, or refueling platform work area, the four main steam lines are plugged from inside the vessel using the furnished plugs for this duty. The servicing of the main steam line isolation or safety relief valves can thus be accomplished without adding to the critical refueling path time. The separator is unbolted using shroud head bolt wrenches. This is accomplished by working from the auxiliary platform, or refueling platform.

The dryer/separator sling is lowered into the vessel and attached to the separator lifting lugs. If not already done, the water in the reactor well and in the dryer/separator storage pool is equalized with the fuel pool water level. This may be accomplished by raising the skimmer surge tank water levels, which communicates with both the spent fuel pool and reactor cavity. The separator is transferred underwater to its allotted storage place in the adjacent pool.

4. Fuel bundle sampling

During reactor operation, the core offgas radiation level is monitored. If a rise in offgas activity has been noted, fuel assemblies can be sampled during shutdown to locate any leaking fuel. Fuel sipping or sampling may be performed in the reactor vessel or the fuel storage pool in accordance with appropriate procedures. If a defective bundle is found, it can be stored in a special defective fuel storage container to prevent the spread of contamination in the fuel storage pool.

d. Refueling and reactor servicing

The remaining gate(s) isolating the fuel pool from the reactor well can be removed after the water level in the reactor well and dryer/separator storage pool is raised to the fuel pool water level, thereby interconnecting the fuel pool, the reactor well, and the dryer/separator storage pool. If required, the fuel pools can be cross-connected, at any time, through the cask storage pit to support refueling and reactor service. The actual refueling of the reactor can now begin.

1. Refueling

During a normal equilibrium outage, approximately one-third of the fuel is removed from the reactor vessel, two-thirds of the fuel is shuffled in the core (generally from peripheral to center locations), and one-third new fuel is installed. A full core off-load and reload may also be performed. The actual

fuel handling is done with the fuel grapple, which is an integral part of the refueling platform. The platform runs on rails over the fuel pool and the reactor cavity. In addition to the fuel grapple, the refueling platform is equipped with two auxiliary hoists that can be used with various grapples to service other reactor internals.

To move fuel, the fuel grapple is aligned over the fuel assembly, lowered, and grappled to the fuel assembly bail. The fuel assembly is manually raised out of the core, then may be automatically moved through the fuel transfer canal to the fuel pool, positioned over the storage rack, and lowered to its new storage location. Fuel is shuffled, and new fuel is manually grappled then moved (automatically or manually) from the storage pool to the reactor vessel in the same manner. The fuel movements outside of fuel entry zones may be accomplished in either the manual or automatic modes of operation for the refueling platform. Fuel movements inside the fuel entry zone may only be completed in the manual mode of operation.

A portable refueling shield is provided to reduce radiation dose rates in the drywell that are due to the transfer of spent fuel assemblies from the reactor vessel to the spent fuel pool. During refueling, the lead and steel shield is located in the reactor well, between the reactor vessel and the spent fuel pool, which permits continuous personnel occupancy of the drywell.

e. Vessel closure

The following steps, when performed, return the reactor to operating condition. In general, the procedures are the reverse of those described in the preceding sections. Many steps may be performed out of sequential order as conditions permit.

1. Install fuel pool gates and install cask pit gates as required. Restore operating unit skimmer surge tank as required.

2. Core verification: the core position of each fuel assembly must be verified to ensure that the desired core configuration has been attained.

3. CRD tests: the CRD timing, friction, and scram tests are performed.

4. Remove main steam line plugs.

5. Replace separator and latch.

6. Replace steam dryer.

7. Drain dryer/separator storage pool and reactor well and restore the outage unit skimmer surge tanks to normal operating levels as required.

8. Decontaminate reactor well.

9. Remove and store portable refueling shield.

10. Deleted.

11. Remove drywell seal surface covering, if used.

12. Open drywell vents.

13. Decontaminate dryer/separator storage pool.

14. Replace vessel studs.

15. Replace slot plugs.

16. Install reactor vessel head.

17. Install vessel head piping and insulation.

18. Replace dryer/separator canal plugs.

19. Hydro test vessel, if necessary.

20. Install drywell head.

21. Install reactor well shield plugs. Installation of the lower layer of the reactor cavity shield plugs must be completed prior to the reactor exceeding 1% reactor power. The upper layer of shield plugs and associated sealant material around the upper plugs must be installed prior to exceeding 25% reactor power.

22. Startup tests. The reactor is returned to full power operation. Power is increased gradually in a series of steps until the reactor is operating at rated power. At specific steps during the approach to power, the incore flux monitors are calibrated.

9.1.4.2.10.3 Departure of Fuel from Site

The spent fuel shipping cask arrives by rail car or truck in the refueling hatch at grade level. It is lifted from there by the 125 ton hook of a reactor enclosure crane to the refueling floor and placed in the shipping cask washdown area between the fuel pools of Units 1 and 2.

The cask outside is decontaminated of road dirt, the lid is removed by the reactor enclosure crane, and the cask is placed in the shipping cask pit. The loading of the cask with irradiated fuel commences. The refueling platform is used to transfer fuel bundles of sufficiently low decay heat level from the spent fuel storage racks underwater into the shipping cask.

Following underwater replacement of the cask lid, the cask is lifted for decontamination. The reactor enclosure crane then transfers the cask from the storage pit onto the shipping vehicle. At no time will the cask be lifted or carried over spent fuel.

9.1.4.3 Safety Evaluation

Safety aspects (evaluation) of the fuel servicing equipment are discussed in Section 9.1.4.2.3, and safety aspects of the refueling equipment are discussed throughout Section 9.1.4.2.7. A description

of fuel transfer, including appropriate safety features, is provided in Section 9.1.4.2.10. In addition, the following summary safety evaluation of the fuel handling system is provided below.

The fuel prep machine removes and installs channels with all parts remaining underwater. Mechanical stops prevent the carriage from lifting the irradiated fuel bundle or assembly to a height where water shielding is less than 7 feet. Irradiated channels, as well as small parts such as bolts and springs, are stored underwater. The spaces in the channel storage rack have center posts that prevent the loading of fuel bundles into this rack.

During the course of the controlled fuel inspection irradiated fuel components, no fuel assemblies or bundles, may be raised such that there is less than 7 feet of water shielding above individual fuel pins (or rods).

While an entire irradiated fuel bundle will not be raised above the minimum 7 feet shielding level, fuel inspection activities may require individual fuel rods to be raised to a height maintaining no less than 6 feet water coverage.

A pair of rails which guide an instrument holder may be installed between the fuel preparation machine handrail and the lower fuel inspection fixture to permit remote inspection of fuel bundles.

There are no nuclear safety problems associated with the handling of a single new fuel bundle or a pair of new fuel bundles. Equipment and procedures prevent an accumulation of more than two bundles in any location.

The refueling platform is designed to prevent it from toppling into the fuel pool or core during an SSE. Redundant interlocks are provided to prevent the following:

a. Travel of the refueling platforms over the reactor core while in the startup mode,

b. Lifting a fuel bundle over the reactor core with one or more control rods withdrawn from core cells containing fuel assemblies, and in the refuel mode, and

c. Withdrawing one or more control rods with the refueling platform carrying a fuel bundle over the reactor core while in the refuel mode, unless all four fuel assemblies have been removed from the core cell(s) with rod(s) withdrawn.

A boundary zone limit system is normally available to assist the refueling platform operator, who is responsible to prevent collision of the fuel grapple with the spent fuel pool or reactor cavity walls during movements of spent fuel. In its normal up position, the grapple is minimal 6 feet 6 inches below the water surface; therefore, a fuel assembly will not be raised to a point where it will not be adequately shielded by water during normal refueling conditions. The grapple is hoisted by redundant cables inside the mast and lowered by gravity. A digital readout is displayed to the operator, showing the exact coordinates of the grapple over the core.

The mast is suspended and gimballed from the trolley, near its top, so that the mast can be swung about the axis of platform travel, to remove the grapple from the water for servicing and storage.

The grapple has two independent hooks, operated by an air cylinder. Engagement is indicated to the operator.

In addition to the main hoist on the trolley, there is an auxiliary hoist on the trolley and another hoist on its own monorail. These three hoists are precluded from operating simultaneously, because control power is available to only one of them at a time. The two auxiliary hoists have load cells with interlocks that prevent the hoists from moving anything classified as a heavy load.

The two auxiliary hoists have electrical interlocks that prevent the lifting of their loads higher than 6 feet 6 inches underwater at the normal up position. Adjustable mechanical jam stops and redundant electrical interlocks on the cables back up these interlocks.

In summary, the fuel handling system complies with GDC 2, GDC 3, GDC 4, GDC 5, GDC 61, GDC 62, and GDC 63, and other applicable portions of 10CFR50.

A system level, qualitative-type FMEA relative to this system is discussed in Section 15.9.

The safety evaluation of the new and spent fuel storage is presented in Sections 9.1.1.3 and 9.1.2.3.

The safety considerations of the Control Rod Blade and Defective Fuel Storage Rack are presented in Section 9.1.4.2.

Regulatory Guide 1.13 (Rev 1) is applicable to the refueling platform within GE's scope of supply for this plant. The refueling platform is designed to prevent it from toppling into the fuel pool or core during an SSE.

9.1.4.4 Inspection and Testing Requirements

9.1.4.4.1 Inspection

Refueling and servicing equipment is subject to the strict controls of quality assurance, incorporating the requirements of 10CFR50, Appendix B. Components defined as essential to safety, such as the fuel storage racks and fuel prep machine, have an additional set of engineering specified "quality requirements" that identify safety-related features that require specific QA verification of compliance to drawing requirements.

Before shipment, every safety-related component inspection item is reviewed by QA supervisory personnel and combined into a summary product quality checklist. By issuance of the product quality checklist, verification is made that all quality requirements have been confirmed and are on record in the product's historical file.

9.1.4.4.2 Testing

Qualification testing is performed on refueling and servicing equipment before multiunit production. Test specifications are defined by the responsible design engineer and may include the sequence of operations, load capacity, and life cycles tests. These test activities are performed by an independent test engineering group, and in many cases a full design review of the product is conducted before and after the qualification testing cycle. Any design changes affecting function that are made after the completion of qualification testing are requalified by test, calculation, or design review.

Functional tests are performed in the shop before the shipment of production units and generally include electrical tests, leak tests, and sequence of operations tests.

When the unit is received at the site, it is inspected to ensure that no damage has occurred during transit or storage. Prior to use and at periodic intervals, each piece of equipment is again tested to ensure that the electrical and/or mechanical functions are operational.

Passive units, such as the fuel storage racks, are visually inspected before use.

9.1.4.5 Instrumentation Requirements

Most of the refueling and servicing equipment is manually operated and controlled by the operator's visual observations. This type of operation does not necessitate a dynamic instrumentation system.

However, there are several components that do have instrumentation and control systems.

9.1.4.5.1 Refueling Platform

The refueling platform has a nonsafety-related X-Y-Z position indicator system that informs the operator which core fuel cell the fuel grapple is accessing. The refueling platform controls in conjunction with the X-Y-Z position indicator system can automatically position the fuel grapple over any valid fuel cell location. An interlock status display is provided to the refueling platform operator. See Section 7.7 for a discussion of refueling interlocks.

Additionally, there is a series of mechanically and electronically activated switches and relays that provides monitor indications on the operator's console for grapple limits, hoist and cable load conditions, and confirmation that the grapple's hook is engaged.

A series of load cells is installed to provide automatic shutdown whenever threshold limits are exceeded on either the fuel grapple or the auxiliary hoist units.

9.1.4.5.2 Fuel Support Piece Grapple

Although the fuel support piece grapple is not essential to safety, it has an instrumentation system consisting of mechanical switches and indicator lights. This system can provide the operator with a positive indication that the grapple is properly aligned and oriented and that the grappling mechanism is either extended or retracted. The operator may elect to perform manual manipulations to determine grapple engagement.

9.1.4.5.3 Other Equipment

See Table 9.1-6 for additional refueling and servicing equipment not requiring instrumentation.

9.1.4.5.4 Radiation Monitoring

The radiation monitoring equipment for the refueling and servicing equipment is evaluated in Section 7.6.

9.1.5 REACTOR ENCLOSURE CRANE

The reactor enclosure crane is a bridge crane mounted on runway rails that are supported by the secondary containment superstructure. The crane serves both units and is designed to be used normally during maintenance and refueling operations.

9.1.5.1 Design Bases

a. The reactor enclosure crane is designed to move loads from one location to another in the refueling area and also between plant grade level and the refueling area level.

b. The reactor enclosure crane is designed to handle loads with a maximum weight of 125 tons while maintaining a minimum safety factor of 5.

c. The main hoisting system of the reactor enclosure crane is designed so that the failure of any single component does not result in a sudden displacement or dropping of the load.

d. The reactor enclosure crane is designed to prevent movement of the crane over the new fuel and spent fuel storage areas in the absence of specific action by the crane operator to allow such movement.

e. The reactor enclosure crane is designed to maintain its structural integrity in the event of an SSE.

9.1.5.2 Equipment Design

The reactor enclosure crane is a bridge crane mounted on runway rails that are supported by the secondary containment superstructure. The bridge consists of two welded box girders held together with structural end beams. These two end beams are supported by wheeled trucks that travel on top of the runway rails. Two trucks, each consisting of two wheels, are located at each end of the bridge.

The structural frame support for the reactor enclosure crane hoisting machinery is the trolley, which moves by tractive power on trucks over rails secured to the top of the two crane girders. Two hoists are provided, a main hoist with a design capacity of 125 tons and an auxiliary hoist with a design capacity of 15 tons (design rated load). The maximum critical load (MCL) for the main hoist is 125 tons and for the auxiliary hoist is 6.75 tons. The electric-powered hoists raise and lower loads by wire rope reeving through upper and lower sheaves, the lower sheaves being an integral part of the load block. Each hoist is equipped with a hook attached to its respective load block.

Design parameters for the reactor enclosure crane are listed in Table 9.1-10.

The fuel handling function of the reactor enclosure crane is to transport new fuel assemblies to the fuel preparation machines and to handle the spent fuel shipping casks. The crane was purchased prior to the issuance of ANS 57.1, and thus the requirements of this standard were not explicitly followed in the design and manufacture of the crane. The crane has been reviewed against the applicable requirements of ANS 57.1; these requirements and the results of the review are summarized in Table 9.1-22. ANS 57.1 guidelines not listed in Table 9.1-22 are either not applicable to the reactor enclosure crane during fuel handling or are recommendations rather than requirements.

All of the applicable guidelines of ANS 57.2 (1976) are met for the cask handling function of the reactor enclosure crane, except that the crane bridge is not prevented from passing over the spent fuel pool. The hoists, however, are prevented from lifting loads heavier than a fuel assembly over

stored spent fuel by interlocks and an administrative control system. Restrictions on heavy loads carried near the spent fuel pool are discussed in Reference 9.1-1.

The design of the reactor enclosure crane includes the following features:

a. Structural components

All the structural components and machinery of the reactor enclosure crane are designed for a full capacity of 125 tons on the main hoist or 15 tons on the auxiliary hoist (design rated load). The maximum critical load (MCL) for the main hoist is 125 tons and for the auxiliary hoist is 6.75 tons, with a minimum safety factor of 5 against ultimate failure for the load-carrying parts and the machinery. The structural components, except for the bridge girders, have a design safety factor of 2.5 against yield. For the hoisting mechanism, all load-carrying parts except structural members are designed with a minimum safety factor of 5 against ultimate failure. The calculated stresses of all load-carrying parts are in accordance with the requirements of Crane Manufacturer's Association of America Specification 70.

The structural members of the reactor enclosure crane are designed for a fatigue loading of 20,000-100,000 cycles, with each completed lift representing one cycle. The rotating machinery is designed for a fatigue life expectancy of 2,000,000 cycles, with each rotating component cycle represented by one revolution. Any load below 50% of the crane rated capacity does not reduce the life expectancy of the crane.

b. Mechanical components

The crane is of a single-trolley, indoor, electric overhead, bridge crane design. The trolley layout is shown in Figure 9.1-18.

The main hoist consists of two balanced, eight-part reeving systems to provide redundancy. The arrangement consists of two separate and redundant wire cables reeved side-by-side through the upper and lower sheaves, as shown in Figure 9.1-19. Each cable passes through a paired equalizer unit that adjusts for unequal cable length and is used as a load transfer safety system. This energy-absorbing device eliminates sudden load- displacement and shock to the crane system in the unlikely event of a cable break. The factor of safety (static) is halved when a cable breaks, but no swinging action occurs because each cable is reeved to both sides of the upper and lower sheaves.

The auxiliary hoist is provided with a two-part reeving system as shown in Figure 9.1-20.

The main functions of the main hoist equalizer system are to continually adjust the hook load so that any load under normal operation is shared equally by the redundant reeving systems and to transfer the shock of a cable break in an acceptably safe dynamic fashion to the remaining cable. The equalizer assembly is shown in Figure 9.1-21. The main hoist uses a redundant equalizer shaft that consists of a solid rod within a hollow tube; either shaft can support the full load if there is a failure of the other. If there is an exaggerated displacement of the equalizer assembly caused by a cable break, either of two proximity limit switches would be activated. The equalizer

system of the main hoist uses vane-type limit switches that stop the hoisting motion if the hoisting rope length needs adjustment. The hoisting motion also stops if one set of reeving fails, so that the broken cable can be removed before it becomes entangled with the other reeving system. This equipment protection mechanism stops the hoisting motion by cutting power to the hoist motor and setting the hoist brakes. Before making a series of lifts the equalizer bar can be visually inspected, and adjusted if necessary, so that an unnecessary power shutoff does not occur. If the equalizer bar needs to be adjusted during a lift, the load can be lowered and the adjustment made at the cable drum anchors. If the equalizer bar reaches the limits of its travel, which should occur only if one of the cables had already failed, the load can be safely lowered with the remaining cable so that a new cable can be installed.

The main hook is a two-pronged sister hook with safety latches and a cored bail hole. Redundancy is provided in the main hook by incorporating a coaxial "hook within a hook" design. The safety latches are required when handling loads using “flexible” rigging (such as slings) in order to prevent rigging from coming off the main hook when the rigging is slack. The shaft of the outer hook is bored out to accommodate the inner hook shaft as shown in Figure 9.1-22. Each hook is independently supported by its respective crosshead and antifriction bearings that are in turn supported by the load block, as shown in Figure 9.1-23. The bail hole and each set of prongs have a design rated capacity of 125 tons, with a conservative safety factor to ultimate strength greater than 5.

The main hoist mechanism is equipped with one load brake and three redundant holding brakes. The load brake is a dc-actuated, eddy current, control-type brake and is used to regulate load lowering and raising speed. The holding brakes are dc magnet brakes that employ rectifiers to permit the use of ac power supply. Two of the holding brakes are applied immediately when power is interrupted to the main and creep motors. The third holding break is applied after a short time-delay. All three holding breaks are released when power is supplied to either the main or creep motor with no time delays. The torque rating of each of the four hoist brakes is at least 150% of rated full load hoist motor torque.

c. Crane controls

An operator's cab is provided at the south end of the reactor enclosure crane. The crane can be controlled from the cab or from a radio controller.

Movements of the bridge, trolley, main hoist, and auxiliary hoist can be controlled from either the cab or the radio controller. Both the radio controller and cab controls include a main power control switch that will interrupt all power to the crane except for the utility lights and heaters. Motion control push buttons in the cab are of the momentary contact-type that return to the OFF position when released.

The radio controller uses levers for bridge, trolley, main hoist and auxiliary hoist motion. They are spring return to off position when released.

d. Hoist limit switches

The extent of travel for both the main hoist and the auxiliary hoist is limited for both the raising and lowering directions by a combination of limit switches. Redundant limit switches are provided for both hoists in the raising direction and for only the main hoist in the lowering direction. The primary protection for both hoists for both directions are geared limit switches coupled to the hoist drum shafts and interrupt power to the hoist motors via the control circuitry. The secondary protection for the auxiliary hoist in the raising direction is a weighted limit switch which also interrupts power to the auxiliary hoist motor via the control circuitry. The secondary protection for the main hoist in the raising direction for both the main and creep drive motors are weighted limit switches which interrupt power to each drive motor directly. The secondary protection for the main hoist in the lowering direction is a geared limit switch coupled to the gear case output shaft which interrupts all power to the crane except for the utility lights and heaters. When the power to any of the three hoist motors is interrupted, the breaks for that hoist will automatically set. The primary and upper redundant limit switches are wired so that the motor can be energized in the reverse direction after a limit switch has been tripped.

Both the main hoist and the auxiliary hoist are equipped with a centrifugal-type limit switch, located on the drum shaft, to provide automatic shutdown protection (hoist motor trip and setting of the holding brakes) against any control or motor malfunction that might result in a runaway condition of the load. The trip setting is at 120% or less of hoist motor synchronous speed.

A load-sensing system is provided for the main hoist, using a load cell mounted under the equalizer shaft. Digital readout of the load is provided in the operator's cab. Overload protection is provided by automatic shutdown (hoist motor trip and setting of the holding brakes), when the overload setpoint (100% to 115% of rated load) is exceeded.

The response time to stop the main hoist motion if there is actuation of a hoist overspeed, overload, or overtravel limit switch is such that the load block movement is less than 3 inches following actuation of one of the hoist limit switches.

e. Bridge and trolley drives and controls

The bridge and trolley have static stepless control on travel speed from minimum to maximum speed. Both the bridge and trolley have braking systems that must be energized to release and that automatically set if there is a power loss. The bridge is equipped with two electric brakes and two hydraulic brakes, each of which has a torque rating equal to 125% of maximum torque of one bridge drive motor. The trolley is equipped with two magnetic brakes, each of which has a torque rating equal to 50% of the maximum torque of the trolley drive motor.

The programmable limit system will provide protection to both the bridge and trolley near the ends of their respective rails to stop bridge or trolley movement before bumper contact occurs. In addition, the crane is equipped with zone travel programmable limit switches to prevent passage of the load over or near the spent fuel pool or the new fuel storage vault. These protected areas are shown in Figure 9.1-24. The tripping of the travel limit switches or motor overloads cuts off power to the bridge and trolley drive motors and sets the brakes. A key-locked bypass switch

is provided in the crane controls so that the operator may consciously override the zone travel limitations.

f. Thermal overload protection

Thermal overload protection is provided for motors on the crane to prevent continuation of motor-stalling torque. In addition, a thermal overload warning indication for the main hoist motor is provided in the operator's cab.

9.1.5.3 Loads

Refueling operations and spent fuel shipping cask handling are discussed in Section 9.1.4. The following is a listing of specific items, and their approximate weights, that are handled by the reactor enclosure crane during and after each reactor refueling.

Drywell head		104 tons
Reactor vessel head		88 tons
Steam separator assembly		82 tons
Steam dryer		39 tons
Reactor well shield plugs	No. 1 & 2	61 tons each
	No. 3 & 4	69 tons each
	No. 5 & 6	85 tons each
	No. 7 & 8	82 tons each
	No. 9 & 10	85 tons each
	No. 11 & 12	12 tons each
Reactor refueling shield		22 tons
Dryer/separator canal plugs	2 of No. 3	59 tons each
	No. 14	59 tons
Refueling slot plugs	No. 15	38 tons
	No. 16	38 tons
Spent fuel shipping cask		100 tons
Reactor Cavity Work Platform		38 tons
Independent Spent Fuel Storage Installation Transfer Cask *(115 tons assumed for conservatism)		107.6* tons
HI-TRAC VW cask *(125 tons assumed for conservatism)		123.7* tons

9.1.5.4 Safety Evaluation

Complete redundancy is provided for the main hoist load-bearing and load-holding equipment of the reactor enclosure crane, including sheaves, ropes, equalizer assembly, reducing gears, and holding brakes, so that no single component failure results in an uncontrolled lowering or dropping of a load within the rated capacity of the crane. The equalizer assembly is an energy-absorbing device that eliminates sudden load-displacement and shock to the crane system in the unlikely event of a rope break. This single failure proof design conforms to NUREG-0554 and NUREG-0612, as further discussed in Reference 9.1-1.

Load-bearing members and main hoist equipment of the reactor enclosure crane are designed in accordance with seismic Category I criteria so that the crane can structurally withstand the SSE and maintain the fully rated load in a static position during and following an SSE. Antiderail devices are installed to preclude derailment of the bridge or trolley under seismic loading.

The crane bridge and trolley are equipped with zone travel programmable limit switches to prevent passage of the load over or near the spent fuel pool and the new fuel storage vault. The travel limitations can be bypassed only by conscious operator action. Figure 9.1-24 illustrates the area on the refueling floor over which crane movement is prevented without such deliberate bypass. The spent fuel shipping cask is described in Section 9.1.4. A spent fuel shipping cask drop accident analysis is discussed in Section 15.7.5.

The cask storage pit is separated from the spent fuel pool to minimize the proximity of the spent fuel shipping cask to the fuel storage racks during cask handling operations. The layout of the refueling area is such that the cask is moved in a single straight line between the cask storage pit and the refueling hatch. Both the cask storage pit and the refueling hatch are located on the plant centerline, which allows cask handling to be performed without moving the bridge.

A FMEA for the reactor enclosure crane is presented in Table 9.1-11. Although it has been withdrawn, for purposes of information presentation, conformance with Regulatory Guide 1.104 is discussed in Table 9.1-12.

9.1.5.5 Inspection and Testing

Magnetic particle inspection of reactor enclosure crane components during fabrication is performed in accordance with ASTM E 109 and ASTM E 138 for dry and wet processes, respectively. Ultrasonic inspection is performed in accordance with ASTM A 388. NDT procedures for testing plate, shafts, and for groove welds and radiographic examination of groove welds are based on applicable ASTM and AWS D1.1 specifications.

9.1.5.5.1 Structural Members

The following welds are 100% examined by the magnetic particle method:

a. Girder top and bottom cover plate splice butt welds

b. Girder web plate splice butt welds

c. Girder top and bottom cover plate to web plate fillet welds

d. Girder notch shelf plate to web plate fillet welds

e. End truck top and bottom cover plate to web plate fillet welds

f. Trolley side, top and bottom cover plate to web plate fillet welds

g. Trolley side to girt plate fillet welds

h. Load block frame fillet welds as accessible

i. End tie top plate to web plate fillet welds

9.1.5.5.2 Load-Bearing Components

All gears, pinions, swivels, hoist shafts, and hook trunnions in both the main and auxiliary hoist assemblies are 100% nondestructively examined by the magnetic particle method, in addition to 100% ultrasonic examination of swivels.

9.1.5.5.3 Hooks

Following forging, both the main and auxiliary hooks are examined by both the ultrasonic and magnetic particle methods. Each hook is then given a load test by the crane manufacturer according to the following procedure: A dimensional check of the hook is performed and the dimensions recorded. The hook is then proof-tested at 200% of its rated capacity. After the test, the hook is given a magnetic particle examination, and its dimensions are rechecked and recorded. The hook is accepted if no cracks, permanent deformation, or other defects are produced by the testing.

9.1.5.5.4 Ropes

Samples are taken from each wire rope to be used in the crane and are subjected to destructive breaking strength tests to verify that the rope exceeds the manufacturer's published value for breaking strength. At least two such tests are performed on each rope.

9.1.5.5.5 Performance and Acceptance Tests

After erection of the crane in the reactor enclosure, extensive performance and acceptance testing is carried out, including:

a. Detailed checking of all mechanical and electrical components of the crane to verify proper assembly and operation

b. Running-in tests at no-load. This test includes all speeds and motions for which the crane is designed plus verification of the proper operation of all limit switches.

c. Load testing of the main hoist at 125% of its rated capacity and of the auxiliary hoist at 120% or greater of its rated capacity. These tests include the full range of movement for hoist raising and lowering and bridge and trolley travel.

d. Performance testing at 100% of the rated capacity. This test includes all speeds and motions for which the crane is designed, plus verification of the proper operation of all limit switches. However, performance testing at less than 100% of rated capacity

will be conducted on the geared upper limit switch, the programmable limit switches that limit movement over the spent fuel pool, and prevent movement to the extreme ends of the bridge and trolley rails. A performance test at 100% of the rated capacity will be conducted on the weighted upper limit switch. However, the load will be raised from a position just off the floor at maximum speed, and the upper limit switch will be manually tripped (Table 9.1-12, footnote 18).

9.1.6 REFERENCES

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9.1-3 "Simulated Rack Minimum Coefficient of Friction" by PaR.

9.1-4 Professor Ernest Rabinowicz, "Friction Coefficients of Water-Lubricated Stainless Steels for a Spent Fuel Rack Facility", Massachusetts Institute of Technology, performed for Boston Edison Company.

9.1-5 "Current Trends in Fuel Performance," presented at the ANS Topical Meeting on Water Reactor Fuel Performance, St. Charles, Illinois (May 9-11, 1977).

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9.1-9 “Evaluation of Limerick (Holtec) High Density Storage Rack K-infinity Criterion”, GENE-155-94-075, DRF J11-02394, October 14, 1994.

9.1-10 “SVEA-96 Lead Fuel Assemblies for Limerick 2”, Supplemental Lead Fuel Licensing Report, ABB Atom Report BR 91-042, January 1991.

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9.1-12 “GE14 Fuel Design Cycle-Independent Analyses for Limerick Generating Station, Units 1 and 2,” GE-NE-L12-00884-00-01P, March 2001.

9.1-13 “GE14 Spent Fuel Storage Rack Criticality Analysis for the Limerick Generating Station, Unit 2” Global Nuclear Fuel Document No. J11-03898-01-SFP, March 2001.

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9.1-15 "Limerick Report for Spent Fuel Storage Capacity Expansion," Holtec International Report No. HI-931012, Revision 2, approved October 1, 1993 (Technical Specifications Amendments 82 and 43 for Unit 1 and Unit 2, respectively).

9.1-16 "LGS Unit 1 and 2 Thermal Hydraulic Analysis for Reducing the In-Core Decay Time from 125 Hour to 40 Hours," approved January 9, 1995.

9.1-17 "Thermal Hydraulic Evaluation of Limerick Unit 1 Fuel Pool Cooling," Holtec International Report No. HI-2094497 approved February 3, 2010, Exelon Doc No. LEAM-MUR-0067.

9.1-18 "Oyster Creek Nuclear Generation Station - Issuance of Amendment RE: Increased Spent Fuel Pool Capacity (TAC No. MA5965)," NRC Safety Evaluation for Oyster Creek Amendment No. 215, September 15. 2000.

9.1-19 "Criticality Safety Evaluation for GNF2 Fuel in the SFP at Limerick,” Holtec International Report HI-2104779, Revision 1.

9.1-20 "Criticality Safety Analysis for GNF3 Fuel in the Limerick SFP," Holtec International Report HI-2210163, Revision 0.

Table 9.1-1

FUEL POOL COOLING AND CLEANUP SYSTEM DESIGN PARAMETERS

FUEL POOL COOLING PUMP

Type	Vertical, centrifugal
Quantity	2 plus 1 backup
Flow, each	600 gpm
Total discharge head	200 ft
Rated power, each	50 hp
Design pressure	127 psig
Design temperature	150°F

FUEL POOL F/D HOLDING PUMP

Type	Horizontal, centrifugal
Quantity	1 per filter/ demineralizer unit
Flow, each	27 gpm
Total discharge head	60 ft
Rated power, each	3 hp
Design pressure	175 psig
Design temperature	155°F

FUEL POOL SKIMMER SURGE TANK

Type	Vertical, cylindrical
Quantity	2
Capacity, each	4690 gal

FUEL POOL FILTER/DEMINERALIZER

Type	Vertical, cylindrical
Quantity	1 per reactor unit plus one spare
Flow, each	550 gpm
Design pressure	175 psig
Design temperature	235°F

FUEL POOL HEAT EXCHANGER *

Type	Shell and straight tube
Quantity	2 plus 1 backup *
Duty, each	4.0×10^6 Btu/hr

	Tube Side	Shell Side
Flow, each	1100 gpm	600 gpm
Design pressure	125 psig	75 psig
Design temperature	200°F	200°F

* For a normal refueling discharge heat load of 16.1 MBTU/hr, each Unit 1 heat exchanger is approxinmatley 50% capacity. For a normal refueling discharge heat load of 18.05 MBTU/hr, each Unit 2 heat exchanger is approximately 50% capacity. Administrative controls assure that FPCC is not relied on for fuel pool cooling, unless the heat load is equal to or less than 16.1 MBTU/hr on Unit 1 and 18.05 MBTU/hr on Unit 2.

Table 9.1-2

Table Information **Deleted**

Table 9.1-2A

FUEL POOL COOLING SYSTEM HEAT REMOVAL CAPACITY
AND MAKEUP REQUIREMENTS (ORIGINAL DESIGN)

PARAMETER	VALUE AT NORMAL HEAT LOAD		VALUE AT MAXIMUM HEAT LOAD	
Quantity of fuel	33% core:	4.5 yr exposure[3][1] 10 day decay	33% core:	4.5 yr exposure[2][1] 10 day decay
	33% core:	4.5 yr exposure[3] 1.5 yr decay + 1 mo	33% core	4.5 yr exposure[2] 10 day decay
	33% core:	4.5 yr exposure[3] 3.0 yr decay + 2 mo	33% core:	4.5 yr exposure[2] 10 day decay
	33% core:	4.5 yr exposure[3] 4.5 yr decay + 3 mo	33% core:	4.5 yr exposure[3] 1.5 yr decay + 1 mo
	33% core:	4.5 yr exposure[3] 6.0 yr decay + 4 mo	33% core:	4.5 yr exposure[3] 3.0 yr decay + 2 mo
	33% core:	4.5 yr exposure[3] 7.5 yr decay + 5 mo	33% core:	4.5 yr exposure[3] 4.5 yr decay + 3 mo
	33% core:	4.5 yr exposure[3] 9.0 yr decay + 6 mo	33% core:	4.5 yr exposure[3] 6.0 yr decay + 4 mo
	33% core:	4.5 yr exposure[3] 10.5 yr decay + 7 mo	33% core:	4.5 yr exposure[3] 7.5 yr decay + 5 mo
	33% core:	4.5 yr exposure[3] 12.0 yr decay + 8 mo	33% core:	4.5 yr exposure[3] 9.0 yr decay + 6 mo
	33% core:	4.5 yr exposure[3] 13.5 yr decay + 9 mo	33% core:	4.5 yr exposure[3] 10.5 yr decay + 7 mo
	13% core:	4.5 yr exposure[4][6] 15.0 yr decay + 9 mo	22% core:	4.5 yr exposure[5][6] 12.0 yr decay + 8 mo
Initial heat load	1.63×10^7 Btu/hr		3.64×10^7 Btu/hr	
Number of pumps and heat exchangers required	2		RHR system	
Water makeup requirements due to boiling losses	61.4 gpm maximum		-	

Table 9.1-2A (Cont'd)

(1) Exposure of fuel based on 39,420 MWD/MT for 4.5 yr exposure.
(2) This makes a full core discharge. The 4.5 yr exposure for the entire full core discharge is conservative.
(3) 33% core = 276 assemblies for conservatism.
(4) 13% core = 102 assemblies. This fills all fuel rack storage locations.
(5) 22% core = 166 assemblies. This fills all fuel rack storage locations.
(6) Assumes maximum spent fuel storage rack inventory, 23 racks (i.e. the Control Rod Blade and Defective Fuel Storage Rack is not in the pool).

Table 9.1-2B

FUEL POOL COOLING SYSTEM HEAT REMOVAL CAPACITY AND MAKEUP REQUIREMENTS - INCREASED STORAGE CAPACITY
(Reference 9.1-15)

	UNIT 1 [6]			
PARAMETER	VALUE AT NORMAL HEAT LOAD[1] [2] [5]		VALUE AT MAXIMUM HEAT LOAD[1] [2] [5]	
Quantity of fuel	36% core:	6 yr exposure 6.7 day decay [3]	100% core:	6 yr exposure 9.1 day decay [3]
	36% core:	6 yr exposure 2 yr decay	36% core	6 yr exposure 2 yr decay
	36% core:	6 yr exposure 4 yr decay	36% core:	6 yr exposure 4 yr decay
	36% core:	6 yr exposure 6 yr decay	36% core:	6 yr exposure 6 yr decay
	36% core:	6 yr exposure 8 yr decay	36% core:	6 yr exposure 8 yr decay
	36% core:	6 yr exposure 10 yr decay	36% core:	6 yr exposure 10 yr decay
	36% core:	6 yr exposure 12 yr decay	36% core:	6 yr exposure 12 yr decay
	36% core:	6 yr exposure 14 yr decay	36% core:	6 yr exposure 14 yr decay
	34% core:	6 yr exposure 16 yr decay	34% core:	6 yr exposure 16 yr decay
	37% core:	6 yr exposure 18 yr decay	37% core:	6 yr exposure 18 yr decay
	15% core:	6 yr exposure 20 yr decay	15% core:	6 yr exposure 20 yr decay
	103% core:	6 yr exposure 22 yr decay	103% core:	6 yr exposure 22 yr decay

Table 9.1-2B (Cont'd)

FUEL POOL COOLING SYSTEM HEAT REMOVAL CAPACITY
AND MAKEUP REQUIREMENTS - INCREASED STORAGE CAPACITY
(Reference 9.1-15)

UNIT 2

PARAMETER	VALUE AT NORMAL HEAT LOAD[1][2][5]		VALUE AT MAXIMUM HEAT LOAD[1][2][5]	
Quantity of fuel	36% core:	6 yr exposure 6.7 day decay [3]	100% core:	6 yr exposure 9.1 day decay [3]
	36% core:	6 yr exposure 2 yr decay	36% core	6 yr exposure 2 yr decay
	36% core:	6 yr exposure 4 yr decay	36% core:	6 yr exposure 4 yr decay
	36% core:	6 yr exposure 6 yr decay	36% core:	6 yr exposure 6 yr decay
	36% core:	6 yr exposure 8 yr decay	36% core:	6 yr exposure 8 yr decay
	36% core:	6 yr exposure 10 yr decay	36% core:	6 yr exposure 10 yr decay
	36% core:	6 yr exposure 12 yr decay	36% core:	6 yr exposure 12 yr decay
	36% core:	6 yr exposure 14 yr decay	36% core:	6 yr exposure 14 yr decay
	36% core:	6 yr exposure 16 yr decay	34% core:	6 yr exposure 16 yr decay
	37% core:	6 yr exposure 18 yr decay	36% core:	6 yr exposure 18 yr decay
	15% core:	6 yr exposure 20 yr decay	36% core:	6 yr exposure 20 yr decay
	36% core:	6 yr exposure 22 yr decay	36% core:	6 yr exposure 22 yr decay
	37% core:	6 yr exposure 24 yr decay	37% core:	6 yr exposure 24 yr decay
	29% core:	6 yr exposure 26 yr decay	29% core:	6 yr exposure 26 yr decay

Table 9.1-2B (Cont'd)

FUEL POOL COOLING SYSTEM HEAT REMOVAL CAPACITY
AND MAKEUP REQUIREMENTS - INCREASED STORAGE CAPACITY
(Reference 9.1-15)

PARAMETER	VALUE AT NORMAL HEAT LOAD (3) (6) (7)	VALUE AT MAXIMUM HEAT LOAD (3) (4)
Initial Heat Load	1.805×10^7 Btu/hr (3) (6) (7)	3.76×10^7 Btu/hr (3) (4)
Number of Pumps and Heat Exchangers Required	2	RHR system
Water Makeup Requirements due to boiling losses	39.7 gpm (7)	81 gpm (4)

(1) Percentage of core is based on 764 fuel assemblies.

(2) Fuel assemblies in the spent fuel pool prior to analysis.

(3) 125 hour in-core decay time prior to movement of fuel assemblies.

(4) For a reactor power of 3527 MW, an in-core decay time of 40 hours and a transfer rate of 10 fuel assemblies per hour (approximately 2.8 day decay), the initial heat load is 4.801×10^7 Btu/hr with a water makeup requirement of 102.02 gpm (Reference 9.1-17).

(5) A one time per unit refueling cycle length extension to approximately 27 months (from a nominal 24 months) for Unit 1 Cycle 7 and Unit 2 Cycle 5 was evaluated. The increase in decay heat generation due to each core's total operating period of 6.25 years (vs. 6 years) has been determined to have no significant effect on maximum calculated fuel pool heat load.

(6) Administrative controls assure that FPCC is not relied on for fuel pool cooling unless the heat load is equal to or less than 1.61×10^7 BTU/hr due to the smaller heat removal capacity of the backup Unit 1 FPCC heat exchanger.

(7) For a reactor power of 3527 MW, an in-core decay time of 40 hours and a transfer rate of 10 fuel assemblies per hour (approximately 2.8 day decay), the initial heat load is 2.477×10^7 Btu/hr with a water makeup requirement of 51.29 gpm (Reference 9.1-17).

Table 9.1-3

FUEL POOL COOLING SYSTEM
FAILURE MODES AND EFFECTS ANALYSIS

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Normal	Fuel pool cooling water pumps	Failure of one pump with two pumps operating or one pump when one pump is operating	Decreased or loss of system flow	Low pressure alarm on local control panel and common trouble alarm in main control room	The spare pump is started by the operator to restore design flow.
Normal	Service water pumps	Loss of service water pump	Decreased system flow	Low pressure alarm in main control room	The spare pump is started by the operator to restore design flow .
Normal	Fuel pool service water booster pumps	Loss of service water booster pump	Decreased system flow	Pump Trip alarm in main control room	The spare pump is started by the operator to restore design flow .
Normal	Makeup from demin water tank	Any failure or failures that result in loss of water supply	Loss of normal makeup of demineralized water	Visual inspection during filling operation	The pool can be filled by temporary means or from one of the seismic Category I makeup supplies.
Accident	RHR pump	Failure of pump with full core unloaded into spent fuel pool	Loss of RHR cooling supplementation	Low pressure alarm in main control room	The other RHR pump associated with the RHR heat exchanger that services the fuel pool is started to restore cooling flow to the spent fuel pool.
Accident	RHR heat exchanger	Loss of cooling water to heat exchanger with full core unloaded into spent fuel pool	Loss of RHR cooling supplementation	RHRSW pump discharge low pressure alarm in main control room	The other RHRSW pump in the RHRSW loop is started to to restore cooling water flow to the RHR heat exchangers.

Table 9.1-3 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Accident	RHR system valves	Failure of a single power-operated valve with full core unloaded into spent fuel pool	Loss of RHR cooling supplementation	Valve indication in main control room	If the RHR system cannot be realigned or the failed valve manually operated to restore cooling, boiling may occur. In this case sufficient water from seismic Category I makeup sources can be supplied to offset water losses due to boiling.
Accident	Power supply	Loss of offsite power	Loss of normal power to system	Alarm in main control room	Two of the fuel pool cooling pumps can be powered from the diesel generators. Additionally, the RECW system, in conjunction with the ESW system, can be used to provide cooling water to the fuel pool heat exchangers. These systems are powered from the diesel generators.
Accident	FPCC system	Loss of system function due to seismically induced damage	Loss of cooling to spent fuel pool	spent fuel pool low level alarm in the main control room	The spent fuel pool will start to boil. The seismic Category I makeup sources are used to supply sufficient water to offset losses due to boiling.
Accident	FPCC System	Loss of system function due to LOOP coincident with a design basis LOCA	Loss of cooling to spent fuel pool	Alarms in the main control room	If the FPCC pump controls or RECW intertie piping is not accessible post-LOCA, the seismic Category I ESW makeup source is used to supply sufficient water to offset losses due to boiling.

Table 9.1-3 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Accident	Seismic Category I makeup supply	Failure (including loss of power) of 1 ESW or RHRSW pump	Loss of seismic Category I makeup water	Low pressure and low level alarm alarm in main control room	The other ESW or RHRSW pump in the ESW or RHRSW loop is started to provide sufficient makeup water. These pumps are powered from separate electrical divisions.
Accident	RHRSW Seismic Category I makeup supply	Failure of a single power-operated valve	Loss of seismic Category I makeup water.	Low level alarm in main control room. Valve indication	The ESW system can be used to supply makeup water. (There are no power-operated valves in the ESW supply path whose single failure can cause a loss of makeup water.)

Table 9.1-4

RESULTS OF SPENT FUEL POOL (SFP) BOILING ANALYSIS

Unit 1: Time from loss of cooling to boiling - 17.5 hours(1)
Water heatup rate following loss of cooling - 4.11°F/hr(1)

Unit 2: Time from loss of cooling to boiling - 13.5 hours(1)
Water heatup rate following loss of cooling - 5.33°F/hr(1)

LPZ thyroid doses (rem) for the 30 day duration of the accident:

For a Spent Fuel Pool PF(2) of 0.1

	UNIT 1	UNIT 2	BOTH UNITS
Spike – 50	3.82×10^{-2}	3.75×10^{-1}	4.13×10^{-1}
Spike – 20	1.86×10^{-2}	1.88×10^{-1}	2.07×10^{-1}
Spike - 5	8.77×10^{-3}	9.47×10^{-2}	1.03×10^{-1}

For a Spent Fuel Pool PF(2) of 0.01

Spike – 50	4.02×10^{-3}	3.98×10^{-2}	4.38×10^{-2}
Spike – 20	1.96×10^{-3}	2.0×10^{-2}	2.2×10^{-2}
Spike - 5	9.27×10^{-4}	1.01×10^{-2}	1.1×10^{-2}

(1) Assuming loss of spent fuel pool cooling as described in Section 9.1.3.6

(2) PF = Iodine partition factor at the pool surface

Table 9.1-5

DECAY HEAT AND EVAPORATION RATES FOR LOSS OF SPENT FUEL POOL COOLING

	TIME AFTER LOSS OF COOLING (hrs)							
	13.5	17.5	24	96	360	480	600	720
UNIT 1								
Decay heat in pool (MBtu/hr)	10.4	10.4	10.4	10.2	9.6	9.37	9.18	9.0
Evaporation rate (ft^3/hr)	0.0	171.4	171.1	168.16	158.28	154.58	151.36	148.47
UNIT 2								
Decay heat in pool (MBtu/hr)	13.4	13.3	13.3	12.9	11.4	10.9	10.5	10.2
Evaporation rate (ft^3/hr)	220.75	219.85	218.96	212.82	187.49	180.35	173.29	168.07

Table 9.1-6

TOOLS AND SERVICING EQUIPMENT

FUEL SERVICING EQUIPMENT

Fuel preparation machines
Channel bolt wrenches
Channel handling tool
Fuel pool sipper
Channel gauging fixture
General purpose grapples
Fuel inspection fixture
Jib crane
Upending platform/jib crane
Roller conveyer
Gantry crane
New fuel inspection/channeling stand

SERVICING AIDS

Pool tool accessories
Actuating poles
General area underwater lights
Local area underwater lights
Drop lights
Underwater TV monitoring system
Underwater vacuum cleaner
Viewing aids
Light support brackets
Incore detector cutter
Incore manipulator

REACTOR VESSEL SERVICING EQUIPMENT

Reactor vessel servicing tools
Steam line plugs
Shroud head bolt wrenches
Head holding pedestals
Head stud rack
Dryer/separator sling
Head strongback
Steam line plug/installation tool
Vessel nut handling tool
Head nut and washer storage racks
Reactor enclosure crane main hook extension
Service Pole Caddy
Fuel Floor Auxiliary Platform
Reactor Cavity Work Platform Assembly

Table 9.1-6 (Cont'd)

IN-VESSEL SERVICING EQUIPMENT

Instrument strongback
Control rod grapple
Control rod guide tube grapple
Fuel support piece grapple
Grid guide
Jet pump servicing tools
Control rod latch tool
Instrument handling tool
Control rod guide tube seal
Incore guide tube seals
Blade guides
Fuel bundle sampler
Peripheral orifice grapple
Orifice holder
Combined grapple, CRB/FSP

REFUELING EQUIPMENT

Refueling equipment servicing tools
Refueling platform

STORAGE EQUIPMENT

Spent fuel storage racks
Channel storage racks
Control rod blade storage racks
Defective fuel storage container

UNDER-REACTOR VESSEL SERVICING EQUIPMENT

CRD servicing tools
CRD hydraulic system tools
NMS servicing tool
CRD handling equipment
Equipment handling platform
Thermal sleeve installation tool
Incore flange seal test plug
Key bender

Table 9.1-7

FUEL SERVICING EQUIPMENT

COMPONENT	ESSENTIAL CLASSIFICATION[1]	QUALITY GROUP[2]	SEISMIC CATEGORY[3]
Fuel prep machine	PE	E	I
New fuel inspection/channeling Stand	NE	E	-
Channel bolt wrench	NE	E	-
Upending stand/jib crane	NE	E	-
Channel handling tool	NE	E	-
Roller conveyer	NE	E	-
Fuel pool sipper	NE	E	-
Gantry crane	NE	E	-
Fuel inspection fixture	NE	E	-
Channel gauging fixture	NE	E	-
General purpose grapple	PE	E	-
Jib crane	PE	E	-

(1) NE - nonessential
PE - passive essential

(2) E - industrial code applies

(3) (-) - no seismic requirements

Table 9.1-8

REACTOR VESSEL SERVICING EQUIPMENT

ESSENTIAL COMPONENT	QUALITY CLASSIFICATION(1)	SEISMIC GROUP(2)	CATEGORY(3)
Reactor vessel servicing tools	NE	E	-
Steam line plug	PE	E	-
Shroud head bolt wrench	NE	E	-
Vessel nut handling tool	NE	E	-
Head holding pedestal	NE	E	-
Head nut and washer rack	NE	E	-
Head stud rack	NE	E	-
Dryer and separator sling	PE	E	-(4)
Reactor enclosure crane main hook extension	PE	E	-(4)
Head strongback/carousel	E	E	-(4)
Steam line plug installation tool	NE	E	-
Service Pole Caddy	NE	E	IIA
Fuel Floor Auxiliary Platform	NE	E	-
Reactor Cavity Work Platform	NE	E	IIA

(1) NE - nonessential
PE - passive essential

(2) E - industrial code applies

(3) (-) - no seismic requirements
(+) - seismic IIA requirements

(4) Dynamic analysis methods for seismic loading are not applicable, because this equipment is supported by the reactor service crane. Lifting devices are designed with a minimum safety factor of 5 and undergo proof testing.

Table 9.1-9

UNDER-REACTOR VESSEL SERVICING EQUIPMENT AND TOOLS

EQUIPMENT/TOOL	CLASSIFICATION	SEISMIC CATEGORY
CRD handling equipment	Nonessential	-
Equipment handling platform	Nonessential	-
Spring reel	Nonessential	-
Thermal sleeve installation tool	Nonessential	-
Incore flange seal test plug	Nonessential	-
Key bender	Nonessential	-
CRD servicing tools	Nonessential	-
CRD hydraulic system tools	Nonessential	-
NMS servicing tool	Nonessential	-

(-) - no seismic requirements

Table 9.1-10

REACTOR ENCLOSURE CRANE DESIGN PARAMETERS

BRIDGE	
Runway length	323'-0"
Bridge span	129'-2"
Bridge weight	410,000 lb
Number of wheels	8
Type of wheels	Parallel tread
Wheel size	27 in
Number of drive motors	2
Drive motor power	7.5 hp @ 720 rpm
Maximum travel speed	40 fpm
Minimum travel speed	4 fpm
Minimum incremental movement	¼ in
Number and type of brakes	(2) magnetic shoe (2) hydraulic shoe
Type of bumpers	Spring
Type of control	562 static stepless
TROLLEY	
Length of trolley travel	129'-2"
Trolley span	26'-6"
Trolley weight	124,000 lb
Number of wheels	4
Type of wheels	Parallel tread
Wheel size	24 in
Drive motor power	7.5 hp @ 720 rpm
Maximum speed	26.8 fpm
Minimum speed	3 fpm
Minimum incremental movement	1/8 in
Number and type of brakes	(1) magnetic shoe, (1) magnetic disc
Type of bumpers	Spring
Type of control	562 ac static stepless

Table 9.1-10 (Cont'd)

HOISTS	Main	Auxiliary
Rated lifting capacity	125 tons	15 tons
Drum size (pitch diameter)	64.25 in	30.25 in
Upper sheave size (pitch diameter)	30 in	None
Lower sheave sizes (pitch diameter)	33.75 in, 30 in	None
Equalizer sheave size (pitch diameter)	17.75 in	None
Rope-type	6x37 preformed, SEIP, IWRC	6x37 preformed, SS 304 IWRC
Rope diameter	1.25 in	1.125 in
Reeving-type	8 part	2 part
Number of reeving systems	2	1
Hoist motor power	50 hp	25 hp
Maximum hook speed	5 fpm	23 fpm
Minimum hook speed	0.5 fpm	2.3 fpm
Minimum incremental hook movement	1/32 in	1/8 in
Maximum travel of hook	164'-6"	165'-5"
Number and type of load brakes	(1) eddy Current	(1) eddy current
Number and type of holding brakes	(3) magnetic Shoe	(2) magnetic shoe
Type of control	563 static Stepless	563 static stepless

Table 9.1-11

REACTOR ENCLOSURE CRANE FAILURE MODES AND EFFECTS ANALYSIS

COMPONENT OR SUBSYSTEM	COMPONENT OR SUBSYSTEM FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	REMARKS
Power supply	LOOP	All crane movements stopped by setting crane holding brakes and tripping all drive motors	Crane operator	-
Main hoist hooks	Failure of one hook	None. The redundant hook supports the load.	Periodic inspection, if not identified during crane use)	-
Main hoist wire Ropes	Failure of one rope	Spurious, dynamic, load transfer to the redundant rope, followed by setting of crane holding brakes and cessation of all crane movements. The load is supported by the remaining rope at a minimum static factor of safety of 5.	Crane operator	Two vane switches, mounted on the equalizer frame, are provided to detect the wire rope failure and cut off power to the crane.
Main hoist drum	Failure of drum Shaft	Possible load stalling, or noise and irregular hoist operation. The crane operator stops hoist operation, resulting in setting of the holding brakes and the safe suspension of the load.	Crane operator	The load can be positioned over its storage or lay-down area and then lowered by manual operation of the hoist holding brakes.
Main hoist holding Brakes	Failure of one brake in the open position	None. Two additional holding brakes stop the main hoist movement and hold the load.	Periodic inspection	Three holding brakes are provided, all rated at 150% of the hoist full load motor torque at the point of application.

Table 9.1-11 (Cont'd)

COMPONENT OR SUBSYSTEM	COMPONENT OR SUBSYSTEM FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	REMARKS
Trolley holding Brakes	Failure of one brake in the open position	None. When the trolley drive motor is stopped, power to the holding brakes is also cut off, which sets the redundant brake.	Crane operator	Two holding brakes are provided, both rated at 50% of the trolley drive motor torque at the point of application.
Bridge holding Brake	Failure of one brake in the open position	None. When the bridge drive motors are stopped, power to the holding brakes is also cut off, which sets the remaining brake.	Crane operator	One holding brake and one foot-operated hydraulic brake are provided for each of the two bridge drive motors. The holding brake is rated at 100% of the bridge drive motor torque.
Main hoist drive gear cases	Failure of one gear case, resulting in gear disengagement:			Two gear cases (drive and idler case) are provided for the main hoist.
	a) Drive gear case	Spurious drum revolving in the load lowering direction. The overspeed switch activated by revolving drum sets the hoist holding brakes and stops the load.	Crane operator	
	b) Idler gear case	None. The drive gear case with the hoist motor and the holding brakes maintains control of the load.	Crane operator	

Table 9.1-11 (Cont'd)

COMPONENT OR SUBSYSTEM	COMPONENT OR SUBSYSTEM FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	REMARKS
Main hoist upward movement limit switch (geared-type)	Failure of switch:			-
	a) Open	Immediate power cutoff to the main hoist. As a result, the hoist is stopped through action of the hoist holding brakes.	Crane operator or periodic testing	
	b) Closed	None. If the hoist continues its upward travel it is stopped by action of the redundant upper limit switch.	Periodic testing	
Main hoist upward movement limit switch (contact-type)	Failure of switch:			Tripped by physical contact with moving load block as it moves upward.
	a) Open	Immediate power cutoff to the main hoist. As a result, the hoist is stopped through action of the hoist holding brakes.	Crane operator or periodic testing	
	b) Closed	None. Hoist upward movement is limited by the redundant upper limit switch, before it reaches this limit switch.	Periodic testing	

Table 9.1-11 (Cont'd)

COMPONENT OR SUBSYSTEM	COMPONENT OR SUBSYSTEM FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	REMARKS
Main hoist downward movement limit switches (geared-type)	Failure of one limit switch:			-
	a) Open	Immediate power cutoff to the main hoist. As a result, the hoist is stopped through action of the hoist holding brakes.	Crane operator or periodic testing	
	b) Closed	None.Hoist movement downward is terminated by the redundant lower limit switch.		
Bridge and trolley movement programmable limit switches	Failure of one switch associated with a given bridge or trolley position:			-
	a) Open	Immediate cutoff of power to respective drive motor(s) and holding brake(s) and stopping of all crane movements.	Crane operator	
	b) Closed	The load may enter the restricted area, unless prevented by crane operator action.	Periodic testing	

Table 9.1-12

COMPARISON WITH NRC REGULATORY GUIDE 1.104 (FEBRUARY 1976) - OVERHEAD CRANE HANDLING SYSTEMS FOR NUCLEAR POWER PLANTS

REGULATORY POSITION	CONFORMANCE	NON-CONFORMANCE	NOTES
C.1 Performance Specification Design Criteria			
a. Separate performance specification	X		(1)
b. Environmental operating conditions			
i. Electrical motors	X		
ii. Balance of crane			
1. Box girders vent and draining	X		(2)
2. NDTT		X	(3)
3. Cold proof test	X		(16)
4. Low alloy steel cold proof test			(4)
c. Seismic Category I	X		
d. NDE - lamellar tearing	X		
e. Fatigue analysis		X	(5)
f. Preheat – postheat welding	X		(6)
C.2 Safety Features			
a. Controls, devices, safe holding position	X		(7)
b. Auxiliary system, dual component, immobile position	X		

Table 9.1-12 (Cont'd)

REGULATORY POSITION	CONFORMANCE	NON-CONFORMANCE	NOTES
c. Means for repairing	X		(8)
d. Design for safety while repairing	X		
C.3 Equipment Selection			
a. Dual load attachment points	X		
b. Lifting devices - redundant design	X		(9)
c. Dual hoisting, 5 fpm limitation	X		
d. Head block and load block	X		
e. Dual reeving system - rope standard	X		
f. Fleet angles		X	(10)
g. 200% static design test		X	(11)
h. Sensing of overspeed, overloading, etc.	X		
i. Control system, motors, torque		X	(12)
j. Two-blocking precautions, etc.		X	(13)
k. Drum protection	X		
l. Excessive breakdown torque	X		
m. Hoisting brakes, holding brakes	X		(14)
n. Dynamic and static alignment	X		
o. Increment drives	X		

Table 9.1-12 (Cont'd)

REGULATORY POSITION	CONFORMANC	NON-CONFORMANCE	NOTES
p. Trolley and bridge motors	X		
q. Cab located controls	X		
r. Safety devices, limit devices	X		
s. Operating manuals – MWL	X		
t. Change from construction to operating	X		
u. Installation instructions	X		
C.4 Mechanical Check, Testing and Preventive Maintenance			
a. Mechanical check	X		
b. 125% static test (2-block)			
i. 125% static test		X	(19)
ii. 100% full performances test	X		(18)
iii. 2-block		X	(15)
c. Preventive maintenance	X		
d. Cold proof test	X		(16)
C.5 Quality Assurance	X		(17)

(1) Position C.1.a. The load lifts during construction were not greater than those for plant operation, therefore no separate specifications were prepared.

(2) Position C.1.b(1). Box girders are not of a closed design.

(3) Position C.1.b(3). The crane manufacturer did not perform impact testing on any structural members.

(4) Position C.1.b(4). Not applicable - no ASTM A514 is used.

Table 9.1-12 (Cont'd)

(5) Position C.1.e. The structural members of the crane are designed for a fatigue loading of 20,000-100,000 cycles, which far exceeds the conservatively estimated 4000 cycles in the life of the crane. Additional fatigue analysis is therefore deemed unnecessary.

(6) Position C.1.f. The preheat and postheat treatment of the welds is in accordance with AWS D1.1.

(7) Position C.2.a. Inadvertent operation must also be a function of administrative control, not just of design. The present design is considered to comply with the regulatory position.

(8) Position C.2.c. Provisions are made for manual operation of the main hoist holding brakes for lowering the load. No special provisions are made for manually moving the immobilized bridge or trolley; however, there are options available for moving the bridge or trolley if the electric power cannot be restored.

(9) Position C.3.b. The loads that have been determined to be critical loads are the spent fuel shipping cask and the portable refueling shield. A lifting yoke which is single failure proof in accordance with NUREG-0612 is provided for use in lifting the shipping cask with the reactor enclosure crane. Although the lifting rig provided for use with the portable refueling shield is not redundant in design, it is designed to support a weight equivalent to three times the weight of the portable refueling shield. This high degree of conservatism protects against the possibility of failure of the refueling shield's lifting rig.

(10) Position C.3.f. The fleet angle from drum to lead sheave is 3¼ degrees for LGS, which complies with the regulatory position. The regulatory position also recommends limiting the fleet angles between individual sheaves to 1½ degrees, whereas this parameter is 3½ degrees for LGS. This difference is justified by the following considerations:

a. The 3½ degree limitation has been proven to be a reliable parameter for rope leads off of drums, which are more critical than rope leads from sheaves, the latter being more deeply grooved.

b. With redundant reeving, sheave spacings are double the normal spacings. Thus, to maintain a 1½ degree fleet angle, the distance from the hook to the top of the crane would have to be needlessly and excessively increased to such a degree that it would be inconsistent with a good crane design.

The design ratio of running sheave pitch diameters to the rope diameter is 24:1 instead of the 30:1 or 26:1 recommended by Regulatory Guide 1.104. The 24:1 ratio is justified because, due to the large diameter of the wire rope used, 30:1 and 26:1 diameter ratios, sheave blanks are not readily available, and because the 24:1 ratio is recommended by the ASME Standard Committee on the Design of Overhead and Gantry Handling Systems for Critical Loads at Nuclear Power Plants in their comments on Regulatory Guide 1.104, dated March 18, 1976, and is consistent with the recommendations of CMAA Specification #70.

(11) Position C.3.g. ANSI B30.2 allows for a 125% load test of these components, and the crane is tested to this value.

Table 9.1-12 (Cont'd)

(12) Position C.3.i. The electric controls for the subject crane are set to limit the motor torque to 150% of rated motor torque.

(13) Position C.3.j. The crane is provided with dual upper limit switches to preclude the possibility of a "two- block" occurrence and an overload switch combined with overcurrent and rate of current rise cutouts to automatically terminate hoisting if there is a load hang-up.

(14) Position C.3.m. The crane design meets the requirements of this regulatory position, except that holding brake heat dissipation is accomplished by alternating the lowering and holding to provide time for cooling the brake mechanism. Also, administrative control is used to limit the lowering speed to less than 3.5 fpm if there is manual brake operation during emergency lowering.

(15) Position C.4.b.iii. No testing of these conditions is performed, since the reeving system is not designed for two-blocking or load hang-up as indicated in footnote 13 above.

(16) Position C.4.d. A cold proof test is performed with 125% of rated load below the minimum operating temperature for the crane during normal plant operation, which is 60°F. However, in no case is the test load increased above 125% of the rated load. Crane testing in excess of 125% of the rated load may adversely affect the safety of the crane, since any such tests may propagate undetectable material defects and thus increase the probability of crane component failures. Furthermore, such testing violates the ANSI B30.2 and 29CFR1910.179(k).

A NDE following the cold proof test is performed on 10% of each critical weld. Cold proof testing every 40 months, followed by NDE, will not be performed since the crane operating temperature will not be less than 60°F.

(17) According to the implementation section D.2 of the guide, the quality assurance discussion of paragraph C.5 is not applied to cranes ordered before September 1976. Although the LGS crane was ordered in August 1973, a quality assurance program was required of the vendor. However, this program could not and did not address the recommendations of paragraphs C.1 - C.4 as suggested in paragraph C.5.b of the guide.

(18) The geared upper limit switch will be tested using a 10% load to demonstrate the adequacy of the limit switch. The geared upper limit switch is dependent only on the drum position, and not on the crane load.

The programmable limit switches that limit movement over the spent fuel pool will be tested using a 0% load to demonstrate the adequacy of the limit switches. The programmable limit switches are dependent only on the position of the bridge and trolley, and not on the crane load.

Table 9.1-12 (Cont'd)

The travel programmable limit switches on the bridge and trolley that prevent movement to the extreme ends of the bridge and trolley rails will be tested using a 0% load to demonstrate the adequacy of the limit switch. The travel limits on the bridge and trolley are dependent only on the position of the bridge and trolley, and not on the crane load.

The weighted upper limit switch will be tested using 100% of the rated capacity by raising the load from a position just off the floor at a maximum speed and manually tripping the weighted upper limit switch before the hook attains enough height to trip the limit switch. Manual testing of the weighted upper limit switch will verify that the main hoist will stop raising and that all brakes will set with 100% of the rated capacity on the main hoist. Keeping the load at a minimum height off the floor will enable the weighted upper limit switch to be tested with the load in a safer position.

(19) The main hoist was tested at 125% of its rated load by raising the load off the floor and holding via the holding brakes then set back down. Not all positions of hoisting and bridge and trolley travel were tested with the 125% load. The auxiliary hoist was tested with at least 120% of its rated load by raising and lowering the load from minimum to maximum speed and holding the load via the holding brakes.

Table 9.1-13

UNIT 1 SPENT FUEL STORAGE RACK MODULES

Module I.D.	**Number of Cells**		**Module Envelope Size** (Note # 1)		**Shipping Weight** (Pounds) Note 2	**Number Of Cells Per Rack**
	N-S Direction	**E-W Direction**	**N-S** (Inches)	**E-W** (Inches)		
A1	18	14	112.73	87.76	23300	252
A2	18	14	112.73	87.76	23300	252
A3	17	14	106.49	87.76	22400	238
B1	18	17	112.73	106.49	27100	306
B2	18	17	112.73	106.49	27200	306
B3	17	17	106.49	106.49	26500	289
C1	18	18	112.73	112.73	28300	324
C2	17	18	106.49	112.73	27600	306
D	17	17	106.49	106.49	25700	289
E1	17	14	106.49	87.76	22100	238
E2	12	17	75.27	106.49	19200	204
F	12	18	75.27	112.73	17400	191
G	17	13	106.49	85.51	20700	221
H	18	13	112.73	112.73	25100	249

Notes

1 See Figure 9.1-34 for rack locations.
2 Weight is dry weight of rack only, without fuel.

Table 9.1-14

SPENT FUEL POOL MATERIALS

Description	Material Specification	Alloy	Finish
Fuel Pool Liner			
Plates	ASTM A240	Type 304	Stainless steel
Bars and shapes	ASTM A479	Type 304	Stainless steel
Control Rod Blade and Defective Fuel Storage Rack			
Perimeter bars	ASTM A240	Type 304L	Stainless Steel
Canisters	ASTM A240	Type 304L	Stainless Steel
Bottom grid assembly	ASTM A240	Type 304L	Stainless Steel
Foot assemblies	ASTM A564	Type 630	Stainless Steel
Spent Fuel Storage Racks			
Sheet Metal Stock	ASME SA240	Type 304L	Stainless Steel
Support Leg (internally threaded)	ASME SA240	Type 304L	Stainless Steel
Support Leg (externally threaded)	ASME SA564	Type 630	Stainless Steel

Table 9.1-15 through Table 9.1-20
have been deleted

Table 9.1-21

SPENT FUEL RACKS
APPLICABLE CODES AND STANDARDS

NUCLEAR REGULATORY COMMISSION	
Regulatory Guide 1.29	Seismic Design Classification (Rev 3), September 1979
Regulatory Guide 1.92	Combining Modal Responses and Spatial Components in Seismic Response Analysis (Rev 1), February 1976
Regulatory Guide 1.70	Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants (Rev 3), November 1978
SRP 3.8.4	Seismic Category I Structures, 1981
SRP 9.1.2	Spent Fuel Storage Review Responsibility, 1981
SRP 9.2.5	Ultimate Heat Sink, Pages 9.2.5-8 through 9.2.5-14, 1975
Regulatory Guide 1.38	Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (Rev 2), 1977
Regulatory Guide 1.13	Spent Fuel Storage Facility Design Basis (Rev 1), December 1975
Regulatory Guide 1.61	Damping Values for Seismic Design of Nuclear Power Plants (Rev 0), October 1973
INDUSTRY CODES AND STANDARDS	
ASME	Boiler and Pressure Vessel Code Sections III, V, IX, and Subsection NA Appendix I and XVII, 1977 Edition up to and including the winter 1978 Addendum
AISC	Steel Construction Manual AISC (7th Edition), June 1973, Including supplements
AA	Aluminum Construction Manual, Third Edition, April 1976, Specifications for Aluminum Structures
AA	Aluminum Standards and Data 5th Edition, January 1976
ASTM	ASTM Standards: A240, A276, A312, B209, B26, B211, B221 (Latest revision in effect at time of purchase order unless otherwise specified.)
ANSI N45.2	Quality Assurance Requirements of Nuclear Power Plants, 1971

Table 9.1-21 (Cont'd)

ANSI N45.2.2	Packaging and Shipping, Receiving, Storage and Handling of Items for Nuclear Power Plants, 1972, except Paragraphs 2.4 and 2.6
ANSI N16.9	Validation of Calculation Methods for Nuclear Criticality Safety, 1975
ASNT-TC-1A	American Society for Nondestructive Testing, 1975 Edition
AWS D1.1	American Welding Society, Structural Welding Code (Rev 2), 1979
10CFR50	Code of Federal Regulations, Title 10, Part 50 (Appendix A & B)
ACI 318 (1971)	Building Code Requirements for Reinforced Concrete
ANSI/ANS 57.2	Design Requirements for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Plants
ANSI/ANS 57.3	Design Requirements for New Fuel Storage Facilities at Light Water Reactor Plants

MILITARY SPECIFICATIONS

Mil-R-24243	Aluminum Rivet Specification
Mil-A-8625C	Anodizing

Table 9.1-22

COMPLIANCE WITH ANS 57.1 FOR REACTOR ENCLOSURE CRANE

ANS 57.1 Guidelines[1]	Extent of Compliance	Deviation and/or Justification
6.1 Safety Classification and Design Standards		
6.1.e (Minimum industry standard requirements)	Partial	The specification for the crane was issued for purchase in 1973, prior to the issuance of the design standards in 6.1.e. The crane was designed to earlier versions of applicable ASME and CMAA standards than those listed in ANS 57.1. Section 9.1.5 provides further information on design standards used for the crane.
6.2 System Design Requirements		
6.2.1 Safety Requirements		
6.2.1.1 (Interlock protection)	Partial	No underload indication or overload interlock is provided for the auxiliary hoist. The worst possible load drop from this hoist would be a ne fuel assembly drop into the spent fuel pool. The effects of this would be less severe than those resulting from a spent fuel handling accident (Section 15.7.4).
6.2.1.3 (Physical safety features)	Full	-
6.2.1.4 (Bridge travel annunciator)	Partial	A warning gong can be manually actuated from the operator's cab and from the radio controller.
6.2.1.5 (Fail-safe on full loss of power)	Full	-

Table 9.1-22 (Cont'd)

ANS 57.1 Guidelines[1]	Extent of Compliance	Deviation and/or Justification
6.2.1.6 (Manual disconnect)	Partial	Radio and cab controls include a main power switch that can cut all power to the crane.
6.2.2 Analysis Requirements		
6.2.2.1 (Design verification)	Full	-
6.2.2.2 (Seismic design)	Partial	The crane is designed as seismic Category I but is not required to function following an SSE. All features required to prevent dropping the load are designed not to fail (Section 3.2).
6.2.3 Design Features		
6.2.3.1 (Retaining devices)	Partial	Retaining devices are generally not provided because parts are never removed when the crane trolley is near the reactor vessel or spent fuel pool. Bead chains are not used.
6.2.3.2 (Fastener locking devices)	Partial	The suitable fastener devices listed are not used. The potential for parts falling into a fuel assembly is small because the crane trolley is restricted from traveling near the spent fuel pool and from carrying loads over the open reactor vessel (Section 9.1.5.2 and Reference 9.1-1).
6.2.3.3 (Surface finish)	Full	-
6.2.3.6 (Inertial loads)	Full	-
6.2.3.7 (Design for repair)	Full	-
6.2.3.9 (Manual movement)	Partial	Loads can be manually lowered after loss of power.

Table 9.1-22 (Cont'd)

ANS 57.1 Guidelines[1]	Extent of Compliance	Deviation and/or Justification
6.2.3.10 (Leakage collection)	Partial	All lubricated parts that can be positioned above the pool are provided with drip pans or other means to prevent lubricant from falling into the pool. Collection systems are not sized for 1.1 times the lubricant volume. However, the crane trolley is normally prohibited from traveling near the pool (Section 9.1.5.2).
6.2.3.12 (Load drop interlocks)	Partial	See ANS 57.1 Guideline 6.2.1.1
6.2.3.14 (Loudspeaker system)	Partial	A 6 channel public address system is provided in the drywell and refueling floor from the main control room. A telephone system is provided between the main control room and refueling floor. Both systems are powered by the plant emergency auxiliary system, which is backed up by emergency diesel generators. Circuits for the public address system and the telephone system are run in different conduits.
6.2.3.18 (Operator controls)	Full	-
6.2.3.20 (Corrosion)	Full	-
6.2.3.21 (Immersed components)	Full	-
6.2.3.22 (Materials properties)	Full	-
6.2.3.23 (Lamellar tearing)	Partial	Lamellar tearing is not specifically addressed in the crane design documents. Crane welding is in accordance with AWS D1.1-75 and AWS D14.1.
6.2.3.24 (Materials compatibility)	Full	-

Table 9.1-22 (Cont'd)

ANS 57.1 Guidelines[1]	Extent of Compliance	Deviation and/or Justification
6.2.3.25 (Lubricants and coatings)	Full	-
6.2.4 Specific Components Requirements		
6.2.4.1 Handling Equipment		
6.2.4.1.2 (Personnel clearances)	Full	-
6.2.4.1.5 (Area radiation monitors)	Full	-
6.2.4.1.9 (Automatically de-energize drive systems)	Full	-
6.2.4.1.10 (High humidity)	Full	-
6.3 Testing and Maintenance Provisions		
6.3.1 Testing		
6.3.1.1 Electrical Test Capabilities	Full	-
6.3.1.2 Mechanical Test Capabilities	Full	-
6.3.2 Maintenance (standard parts)	Full	-

Table 9.1-22 (Cont'd)

ANS 57.1 Guidelines[1]	Extent of Compliance	Deviation and/or Justification
6.3.2.1 Handling Equipment		
6.3.2.1.3 Auxiliary Fuel Handling Crane (easy access)	Full	-
6.3.2.1.9 General Requirements (safe disconnection of electrical hardware)	Partial	The features listed are generally not used. The crane trolley is normally prohibited from traveling near the spent fuel pool (Section 9.1.5.2).

[1] Guidelines not listed are either not applicable to the fuel handling function of the reactor enclosure crane or are recommendations, not requirements, of ANS 57.1.

TABLE 9.1-23

SIZES AND WEIGHTS OF MAXIMUM DESNITY SPENT FUEL STORGE RACKS

MODULE I.D.	NUMBER OF CELLS		MODULE ENVELOPE SIZE (See Note #1)		SHIPPING WEIGHT	NUMBER OF CELLS RACK
	N-S Direction	E-W Direction	N-S	E-W		
A1	18	14	112.77"	87.71"	22700#	252
A2	18	14	112.77"	87.71"	22700	252
A3	18	14	112.77"	87.71"	22700#	252
B1	18	17	112.77"	106.51"	27600#	306
B2	18	17	112.77"	106.51"	27600#	306
B3	18	17	112.77"	106.51"	27600#	306
C1	18	18	112.77"	112.77"	29200#	324
C2	18	18	112.77"	112.77"	29200#	324
D	17	17	106.51"	106.51"	26100#	289
E1	17	14	106.51"	87.71"	21500#	238
F	14	18	87.71	112.77"	22400#	248
G	17	18	106.51	112.77"	25800#	286
H	18	18	112.77"	112.77"	27000#	49
J ((Existing)	7	7	83"	83"	12200#	49
J (Alternate)	14	14	87.71"	87.71"	17700#	196

- See Figure 9.1-35 through 9.1-37 for locations

TABLE 9.1-24

REFERENCE CASE
MAXIMUM DENSITY SPENT FUEL STORAGE RACK
INPUT PARAMETERS[1]

	Standard 8x8	GE-9 8x8	GE-11 9x9	Siemens 9x9	GE-14 10x10
Clad outside diameter, in.	0.483	0.483	0.440	0.489	0.404
Clad inside diameter, in.	0.419	0.419	0.384	0.373	0.352
Clad material	Zr-2	Zr-2	Zr-2	Zr-2	Zr-2
UO_2 density, g/cc UO_2 (Tolerance $\pm$0.20)	10.42	10.42	10.42	10.42	10.503
Pellet diameter, in.	0.410	0.411	0.376	0.3665	0.345
Enrichment, wt% U-235 (Tolerance $\pm$0.05)	3.50	3.50	3.50	3.50	4.90
Number of water rods	2	1	2	1*	2
Inside diameter, in.	0.531	1.26	0.920	1.458	0.920
Outside diameter, in.	0.591	1.34	0.980	1.516	0.980
Fuel rod array	8x8	8x8	9x9	9x9	10x10
Number of fuel rods	62	60	74	72	92
Fuel rod pitch, in.	0.640	0.640	0.566	0.569	0.510
Fuel channel, material Inside dimension, in. Outside dimension, in.	 5.278 5.478	 5.278 5.438	 5.278 5.478	 5.278 5.438	 5.278 5.438

* Square central channel
[1] GNF2 and GNF3 are proprietary. See References 9.1-19 and 9.1-20.

TABLE 9.1-25

MAXIMUM DENSITY SPENT FUEL STORAGE RACK
EFFECT OF TEMPERATURE AND VOID ON REACTIVITY

CASE	INCREMENTAL REACTIVITY CHANGE, δK
4°C (39°F)	Reference
20°C (68°F)	-0.003
80°C (176°F)	-0.016
122°C (252°F)	-0.028
122°C, 20% Void	-0.039

TABLE 9.1-26

MAXIMUM DENSITY SPENT FUEL STORAGE RACKS
REACTIVITY UNCERTAINTIES DUE TO MANUFACTURING TOLERANCES

QUANTITY	NOMINAL VALUE	TOLERANCE	δK_∞
Boron loading	0.0200 g/cm^2	$\pm$0.0015 g/cm^2	$\pm$0.0051
Boral width	5.00 inches	$\pm$1/16 inches	$\pm$0.0018
Lattice spacing	6.244 inches	$\pm$0.040 inches	$\pm$0.0027
SS thickness	0.075 and 0.035 inches	$\pm$0.008 inches mean	$\pm$0.0004
Fuel enrichment	3.50% U-235	$\pm$0.05% U-235	$\pm$0.0033
Fuel density	10.42 g/cm^3	$\pm$0.20 g/cm^3	$\pm$0.0026
Statistical combination of uncertainties			$\pm$0.0074

TABLE 9.1-27

MAXIMUM DENSITY SPENT FUEL STORAGE RACKS
SUMMARY OF K_∞ FOR VARIOUS FUEL TYPES

FUEL	MAXIMUM K_∞
Standard (8x8)	0.944
GE-9 - 8x8	0.942
GE-11 - 9x9	0.941
Siemens - 9x9	0.934
GE-14 – 10X10	0.939
GNF2 – 10x10[1]	0.9375
GNF3 – 10x10[1]	0.9432

[1] See Reference 9.1-19 for GNF2 and Reference 9.1-20 for GNF3.

TABLE 9.1-28

MAXIMUM DENSITY SPENT FUEL STORAGE RACKS
SUMMARY OF CRITICALITY SAFETY ANALYSES

	CASMO	KENO
Temperature of analysis	4°C	4°C
Gadolinia content	None	None
Fuel enrichment, wt% U-235	3.50	3.50
Reference k_∞	0.9366	0.9234[1]
Calculational bias	0.0000	0.0101
Uncertainties		
Calculational	±0.0024	±0.0018
KENO statistics	NA	±0.0011
Tolerances[2]	±0.0074	±0.0074
Removal of flow channel	negative	negative
Eccentric position	negative	negative
Statistical combination[3] of uncertainties	±0.0078	±0.0077
TOTAL	0.9366 ± 0.0078	0.9335 ± 0.0077
Maximum reactivity	0.9444	0.9412

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1 Includes δk correction of +0.0026 to 4°C as determined by CASMO calculations.

2 See Table 9.1-26.

3 Square root of sum of square of all independent uncertainties.

TABLE 9.1-29

MAXIMUM DENSITY SPENT FUEL STORAGE RACK MATERIAL DATA

RACK MATERIAL DATA (200°F) (ASME - Section II,Part D)			
Material	Young's Modulus E (psi)	Yield Strength S_y (psi)	Ultimate Strength S_u (psi)
ASTM 240 304L S.S.	27.6×10^6	25000(1)	71000(1)
SUPPORT MATERIAL DATA (200°F)			
1. SA-240, Type 304L (upper part of support feet)	27.6×10^6	25000(1)	71000(1)
2. SA-564-630 (lower part of supportfeet age hardened at 1100°F)	27.9×10^6	106,300	140,000

(1) The material purchase order requires that the minimum limits for mechanicals be those of SA240-304.

TABLE 9.1-30

LOAD COMBINATIONS AND ALLOWABLE STRESSES -
MAXIMUM DENSITY SPENT FUEL STORAGE RACKS

There are two sets of criteria to be satisfied by the rack modules:

a. Kinematic Criteria

In order to be qualified as a physically stable structure it is necessary to demonstrate that an isolated rack in water would not overturn when an event of magnitude 1.1 times the governing faulted seismic loading conditions is applied

b. Stress Limit Criteria

Stress limits must not be exceeded under the postulated load combinations. The following loading combinations ar applicable and are the bounding load combinations.

Loading Combinations	Service Level
$D + L$ $D + L + T_o$ $D + L + T_o + E$ $D + L + T_o + SRV$	Level A
$D + L + T_2 + E$ $D + L + T_o + P_f$	Level B
$D + L + T_2 + E^9$ $D + L + T_o + F_d$ $D + L + T_2 + E^9 + SRV + LOCA$	Level D The functional capability of the fuel racks should be demonstrated.

TABLE 9.1-30 (Cont'd)

D = Dead weight-induced internal moments (including fuel assembly weight)

L = Live Load (not applicable for the fuel rack, since there are no moving objects in the rack load path)

F_d = Force caused by the accidental drop of the heaviest load from the maximum possible height specified in the PECO Specification

P_f = Upward force on the racks caused by postulated stuck fuel assembly

E = Operating Basis Earthquake (OBE)

E^9 = Safe Shutdown Earthquake (SSE)

T_o = Differential temperature induced loads (normal operating or shutdown condition based on the most critical transient or steady state condition)

T_2 = Differential temperature induced loads (the highest temperature associated with the postulated abnormal design conditions)

SRV = Safety Relief Valve Loading

LOCA = Loss-of-Cooling Accident Loads

T_2 and T_o produce local thermal stresses. the worst thermal stress field in a fuel rack is obtained when an isolated storage location has a fuel assembly generating heat at maximum postulated rate and surrounding storage locations contain no fuel. Heated water makes unobstructed contact with the inside of the storage walls,thereby producing maximum possible temperature difference between adjacent cells. Secondary stresses produced are limited to the body of the rack; that is support pedestals do not experience secondary (thermal) stresses.

TABLE 9.1-30 (Cont'd)

Stress limits for Various Conditions

Stress limits are derived form the ASME Code, Section III, Subsection NF Parameters and terminology are in accordance wit the ASME Code.

Normal and Upset Conditions (Level A or Level B)

a. Allowable stress in tension on a net section is:

$F_t = 0.6\ S_y$ (S_y = yield stress at temperature)

(F_t is equivalent to primary membrane stress)

b. Allowable stress in shear on a net section is:

$F_v = .4\ S_y$

c. Allowable stress in compression on a net section

$$F_a = \frac{\left[1 - \frac{(k\ell)^2}{2C^{2c}}\right] S_y}{\left\{\frac{5}{3} + \left[3\left(\frac{k\ell}{r}\right)/8C_c\right] - \left[\left(\frac{k\ell}{r}\right)^3/8C_c^3\right]\right\}}$$

where:

$$C_c = \left[\frac{(2n^2E)}{S_y}\right]^{1/2}$$

ℓ = unsupported length of component

k = length coefficient which gives influence of boundary conditions; e.g.

k = 1(simple support both ends)
= 2 (cantilever beam)
= 1/2 (clamped at both ends)

E = Young's Modulus

TABLE 9.1-30 (Cont'd)

r = radius of gyration of component

kl/r for the main rack body is based on the full height and cross section of the honeycomb region.

d. Maximum allowable bending stress at the outermost fiber of a net section, due to flexure about one plane of symmetry is :

$F_b = 0.60\ S_y$ (equivalent to primary bending)

e. Combined bending and compression on a net section satisfies:

$$\frac{f_a}{F_a} + \frac{C_{mx}f_{bx}}{D_xF_{bx}} + \frac{C_{my}f_{by}}{D_yF_{by}} < 1$$

where:

f_a = Direct compressive stress in the section

f_{fx} = Maximum bending stress along y-axis

f_{by} = Maximum bending stress along x-axis

C_{mx}= $C_{my} = 0.85$

$$D_x = 1 - \frac{f_a}{F_{ax}}$$

$$D_y = 1 - \frac{f_a}{F_{ey}}$$

$$F_{ax,ey} = \frac{12\ n^2\ E}{23\left(\frac{k\ell}{r}\right)^2_{x,y}}$$

and subscripts x,y reflect the particular bending plane.

TABLE 9.1-30 (Cont'd)

f. Combined flexure and compression (or tension) on a net section:

$$\frac{f_a}{0.6S_y} + \frac{f_{bx}}{F_{bx}} + \frac{f_{by}}{F_{by}} < 1.0$$

The above requirements are to be met for both direct tension or compression.

Level D Service Limits

Section F-1334 (ASME Section III, Appendix F), states that limits for the Level D conditions are the minimum of 1.2 (S_y/F_t) or ($0.7S_u/F_t$) times the corresponding limits for the Level A condition. S_u is ultimate tensile stress at the specified rack design temperature. For example, if the material is such that $1.2D_y$ is less than $0.7S_{u9}$ then the multiplier on the Level A limits, to obtain Level D limits, is 2.0. For the Limerick plant, however, a more conservative multiplier of 1.6 set in the UFSAR. All level D evaluations are based on this more conservative limit.

TABLE 9.1-31

SUMMARY OF WPMR ANALYSIS RESULTS FOR 700# REGULAR FUEL LOADINGS AND COMPARISON WITH BOUNDING RESULTS OF SINGLE RACK ANALYSES

CONDITIONS OF THE RUN		Maximum Displacements of Holtec Racks, in.				Maximum Pedestal Vertical Load, lbf
		Rack Top		Baseplate		
	SEISMIC	x	y	x	y	
WPMR2-R; 14 Holtec racks and 1 existing 7x7 rack; 700# channeled fuel fully loaded	SSE + SRV + LOCA	1.768 (R3)[1]	3.491 (R3)	1.605 (R3)	3.443 (R3)	210,000 (R1-F4)[1]
	SSE	3.079 (R3)	4.874 (R3)	2.869 (R3)	4.634 (R3)	205,900(R1-F4)
	OBE	1.316 (R3)	2.623 (R3)	1.264 (R3)	2.622 (R3)	150,600 (R10-F3)
WPMR1RFR: 15 Holtec racks; 700# channeled fuel fully loaded	SSE + SRV + LOCA	1.091 (R7)	.9466 (R3)	1.042 (R7)	.6953 (R3)	208,900 (R10-F4)
	SSE	1.121 (R7)	.8924 (R1)	1.072 (R7)	.6558 (R3)	196,400 (R13-F4)
	OBE	.4880 (R7)	.4488 (R7)	.4938 (R7)	.3510 (R3)	133,100 (R7-F2)
Bounding results from single rack analysis with 700# channeled fuel loadings for (SSE+SRV + LOCA), SSE and OBE Seismic loadings		1.0482	1.0149	.9445	.6037	266,191

TABLE 9.1-31 (Cont'd)

SUMMARY OF WPMR ANALYSIS RESULTS FOR 700# REGULAR FUEL LOADINGS AND COMPARISON WITH BOUNDING RESULTS OF SINGLE RACK ANALYSES								
CONDITIONS OF THE RUN		Maximum Fuel-Cell Impact Load Per Cell lbf.	Maximum Rack-to-Wall Impact Load, lbf		Maximum Rack-to-Wall Impact Load, lbf		Maximum Stress Factor of Rack Pedestals	Maximum Peak Dynamic Water Pressure on Wall, psi
	SEISMIC		Rack Top	Baseplate	Rack Top	Baseplate		
Bounding results from single rack analysis with 700# channeled fuel loadings for (SSE+SRV + LOCA), SSE and OBE seismic loadings		1040	0	0	113.9	1650.9	.650	N/A

TABLE 9.1-31 (Cont'd)

SUMMARY OF WPMR ANALYSIS RESULTS FOR 700# REGULAR FUEL LOADINGS AND COMPARISON WITH BOUNDING RESULTS OF SINGLE RACK ANALYSES

CONDITIONS OF THE RUN		Maximum Fuel-Cell Impact Load Per Cell lbf.	Maximum Rack-to-Wall Impact Load, lbf		Maximum Rack-to-Wall Impact Load, lbf		Maximum Stress Factor of Rack Pedestals	Maximum Peak Dynamic Water Pressure on Wall, psi
	SEISMIC		Rack Top	Baseplate	Rack Top	Baseplate		
WPMR2-R; 14 Holtec racks and 1 existing 7x7 rack; 700# channelled fuel fully loaded	SSE + SRV + LOCA	1412.0 (R3)	0	0	4185 No. 138[1] (8)	6570 No. 250 (44)	.384 $(R1\text{-}F4)_2$	22.8
	SSE	1165.1 (R3)	0	5599 No. 212 (6)	4318 No. 138 (8)	3903 No. 214 (8)	.351 (R1-F4)	23.5
	OBE	851.8 (R3)	0	0	1421 No. 173 (43)	1696 No. 222 (16)	.258 (R7-F2)	17.8
WPMR1RFR: 15 Holtec racks; 700# channeled fuel fully loaded	SSE + SRV + LOCA	690.8 (R3)	0	0	5271 No. 138 (8)	4656 No. 214 (8)	.371 (R10-F4)	24.6
	SSE	656.3 (R7)	0	0	3851 No. 138 (8)	4818 No. 247 (41)	.352 (R13-F4)	23.2
	OBE	542.9 (R3)	0	0	1560 No. 147 (17)	2059 No. 249 (43)	.265 (R7-F2)	17.1

1) In parenthesis are rack number and foot number with the maximum value, see Figure 9.1-47.
2) Impact spring number indicated in tables; in the parenthesis is the impact spring number indicated on layout Figure 9.1-47.

Table 9.1-32 has been deleted

9.2 WATER SYSTEMS

9.2.1 SERVICE WATER SYSTEM

The service water system supplies cooling water required for normal plant operation. The SWS has no safety-related function.

9.2.1.1 Design Bases

a. The SWS is designed to remove heat from heat exchangers in the turbine, reactor, and radwaste enclosures, and to transfer this heat to the cooling towers where it is dissipated.

b. The SWS is designed to operate during normal plant operation and plant shutdown with offsite power available.

c. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the SWS are discussed in Section 3.2.

9.2.1.2 System Description

The SWS, shown schematically on drawing M-10, is a single-loop cooling system utilizing three 50% capacity centrifugal pumps operating in parallel (one pump is on standby status). The pumps are located in the circulating water pump structure and circulate cooling water from the cooling tower, through the heat exchangers and back to the cooling tower. Each of the two generating units is provided with a separate SWS and cooling tower, although interconnections are provided so that either SWS can cool equipment common to both units. Design parameters for the major components of the SWS are listed in Table 9.2-1.

The SWS takes suction from the cooling tower basin. Water treatment to prevent long-term corrosion and organic fouling is discussed in Section 10.4.5.1.2.

During periods of low service water flow demand, the system is operated utilizing a single service water pump. System reliability is improved by operating a single service water pump closer to the rated capacity. To maintain back-up capability, an automatic pump start feature is available to be placed into service to automatically start the back-up pump in the event of a failure of the operating pump. This auto start feature is typically used during power operations when pump redundancy is desirable.

The service water flow to the heat exchangers is regulated by hand valves, temperature control valves, or solenoid-operated valves, as shown in drawing M-10.

The service water side (tube side) of the fuel pool heat exchangers is kept at a higher pressure than the shell side to prevent potential radioactive contamination of the service water, in case of a tube leak in a fuel pool heat exchanger. Pressure switches, located in the suction line to the fuel pool service water booster pumps, trip the pumps on low service water pressure.

During normal operation, the SWS supplies cooling water to various heat exchangers and coolers associated with the ESW system as shown in drawing M-11. In the event of a LOOP or LOCA, cooling for these components is automatically supplied by ESW. Switch-over to ESW cooling and isolation of the SWS from these components is discussed in Section 9.2.2.

The RECW and TECW heat exchangers are designed for nonessential service. However, they can be cross-connected to the ESW system (Section 9.2.2) so that in case of LOOP, the plant operator

can provide these heat exchangers with ESW. Isolation between the SWS and the ESW system for these heat exchangers is provided by two normally closed valves connected in series. These valves are key-locked and remote manually operated. Isolation of return lines is provided by check valves and one normally closed valve connected in series.

Interties are provided between the Unit 1 and Unit 2 SWS suction and return headers to provide for continued operation of a unit's SWS during plant shutdown in which the associated cooling tower may be out-of-service for maintenance. In this mode, an SWS pump of the shutdown unit takes suction from the opposite unit's SWS suction header and return flow is routed to the opposite unit's return header to its cooling tower. Heat loads on the SWS are reduced when the unit is shut down, and nonoperating or unnecessary heat exchangers are valved out and throttling may be performed to maintain proper pump and flow conditions.

During a refuel outage, the service water system supports decay heat removal during certain periods. In the event of loss of all service water pumps on the refuel unit, the operating unit can supply a limited quantity of service water through the common service water header to support decay heat removal. The service water is returned to the operating unit via the return header intertie described above.

9.2.1.3 Safety Evaluation

The SWS has no safety-related function. Failure of the system does not compromise any safety-related system or component, nor does it prevent a safe shutdown of the plant.

9.2.1.4 Tests and Inspections

System operability is demonstrated by use during normal plant operation. The service water system on each unit is equipped with three pumps in parallel, each of which is capable of providing somewhat greater than 50% of the system requirements at design conditions. This capability provides sufficient margin for component operational degradation and permits the removal of one pump from service for maintenance without affecting the normal operation of the plant.

Operational degradation of service water system components would be detected by observation of inadequate cooling or increased pressure drop. Most of the heat exchangers required for normal plant operation are supplied with redundant equipment that may be valved into service. The potential for plant disruption due to service water system component trouble is therefore minimized.

9.2.1.5 Instrumentation Applications

Local instrumentation is provided at the pumps and at the heat exchangers for maintenance, testing, and performance evaluation. The service water pumps discharge header is equipped with a pressure switch which sounds an alarm in the control room on low discharge pressure.

Radiation monitors in the service water return header to the cooling towers alarm in the control room on high or low radiation. The low alarm indicates monitor malfunction. See Section 11.5 for additional information on process radiation monitoring.

9.2.2 EMERGENCY SERVICE WATER SYSTEM

The ESW system is designed to supply cooling water to selected equipment during a LOOP condition or LOCA. The ESW system is safety-related.

9.2.2.1 Design Bases

a. The ESW system is designed to supply cooling water to essential equipment during a LOOP or LOCA.

b. The ESW system is designed to withstand the most severe natural phenomenon or site-related event (e.g., earthquake, tornado, hurricane, flood, or transportation accident) without impairing its function.

c. The ESW system is designed to prevent inadvertent leakage of radioactivity to the environment.

d. The ESW system is designed with sufficient capacity and redundancy so that a single active failure cannot impair the capability of the system to perform its safety-related functions.

e. The ESW system is designed to include the capability for full operational testing.

f. The ESW system is designed with connections to provide cooling water to certain nonessential equipment during a LOOP or LOCA as directed by Emergency Operating Procedures.

g. The ESW system is designed to include the capability of operating one loop from the remote shutdown panel.

h. The ESW system is designed to seismic Category I requirements. The quality group classification and corresponding codes and standards that apply to the ESW system are discussed in Section 3.2.

9.2.2.2 System Description

The ESW system is shown schematically in drawing M-11. Major equipment design parameters are listed in Table 9.2-2. It should be noted that the design parameters listed in Table 9.2.2 do not constitute performance requirements. ESW pump performance requirements are based on its ability to support the heat transfer rates listed in table 9.2-3. The system is common to Units 1 and 2, and consists of two independent loops (A and B), with two 50% system capacity (100% loop capacity) pumps per loop. Required heat removal rates for various heat exchangers and coolers served by ESW are listed in Table 9.2-3.

The ESW system is designed to supply cooling water to the following safety-related equipment:

a. RHR motor oil coolers

b. RHR pump compartment unit coolers

c. Core spray pump compartment unit coolers

d. Control room chillers

e. Standby diesel generator heat exchangers

f. RCIC pump compartment unit coolers

g. HPCI pump compartment unit coolers

h. Spent fuel pools (makeup water)

In addition to the above equipment, emergency procedures direct providing ESW to the following nonsafety-related equipment during a LOOP:

a. RECW heat exchangers

b. TECW heat exchangers

The reactor recirculation pump seal and motor coolers can be manually supplied with ESW as described in Section 9.2.8.2.

During normal plant operation all of the above equipment, with the exception of the diesel generators, is provided with cooling by the service water system.

Essential heat loads normally cooled by the service water system are automatically transferred to the ESW system under LOOP and LOCA accident conditions. This transfer is accomplished by the following automatic valve realignments:

a. The normally open check valve in each service water supply line closes as a result of the trip of the service water pumps, on a loss of offsite power, and the start of the ESW pumps.

b. The normally closed check valve in each ESW supply line opens as a result of the start of the ESW pumps.

c. The normally open isolation valves installed in series in each service water discharge line close on an ESW pump start signal.

d. The normally closed isolation valves installed in parallel in each ESW discharge line open on an ESW pump start signal.

The ESW pumps start automatically on diesel generator operation (e.g., diesel 1A or 2A cause ESW pump A to start) after speed, voltage, and bus breaker conditions are met, and after a load sequencing delay. ESW pump operation causes automatic valve and sluice gate realignments to:

a. Take pump suction from the spray pond.

b. Provide ESW to safety-related equipment.

c. Return the ESW to the spray pond via the RHRSW system and the spray networks.

The spray pond is described in Section 9.2.6. The operator may elect to realign the system to utilize the cooling towers, if they are available.

The components listed on Table 9.2-3 are provided with cooling water from either ESW loop A or B. Design heat removal rates are also shown in Table 9.2-3. Each diesel generator can be supplied with cooling water from ESW loop A or loop B. Normal system alignment, however, is such that loop

A supplies cooling water to the A and C diesel generators, and loop B supplies the B and D diesel generators.

Each loop is designed such that ESW flow to one unit can be isolated without adversely affecting flow to the other unit.

The valves on an ESW branch line serving a diesel generator are fed from power supplies of the same channel as the diesel generator. All other safety-related components in the ESW system are powered by channels A or C if they are in ESW loop A, or by channels B or D if they are in ESW loop B.

The ESW pumps can be manually started from the control room. The A ESW pump and associated A loop valves can be operated from the remote shutdown panel. The B and C ESW pumps can also be operated from the B and C pumps motor circuit breaker cubicles, respectively.

The ESW pumps are located in the spray pond pump structure. The A and B loop pumps are separated by physical barriers. The pump structure is described in Section 3.8.4. The spray pond pump structure is designed so that sufficient NPSH and adequate hydraulic conditions for proper pump operation are maintained down to a pond level below that associated with the design basis water loss. To verify adequate hydraulic conditions in the pump structure wet pits for proper long-term pump operation, it has been determined from model studies that acceptable hydraulic conditions exist down to elev. 243'-6". Drawing M-389 shows the elevations of the spray pond water levels, suction piping, and the ESW pump.

ESW loop A and B piping is physically separated or protected so that no single postulated event can impair the system's capability to perform its required safety functions. The ESW is combined with the RHRSW before it is returned to the spray pond or cooling tower. The return from each ESW loop is connected to both the A and B RHRSW loops.

Each ESW loop is also provided with two crossties to the RHRSW System and associated isolation valves. One crosstie is installed in a valve pit near the Spray Pond Pumphouse and the second crosstie is installed in the Reactor Building Pipe Tunnel. The crosstie lines and associated isolation valves allow the underground portion of the ESW or RHRSW supply piping of a given loop to be isolated for inspection or repairs without interrupting the supply of cooling water to the ESW or RHRSW System. Operating restrictions, however, apply to certain crosstied configurations and the use of these lines is administratively restricted.

The ESW supply and return yard piping is made of carbon steel, with approximately 200 mils corrosion allowance. All piping outside of the pump structure, main plant, and spray pond is coated for corrosion protection. All heat exchangers, except those in the RHR pump motor coolers have 90/10 Cu-Ni tubes. The 2A-P202 pump motor has type 316 stainless steel tubes in the oil coolers. The remaining RHR pump motor oil coolers have 90/10 Cu-Ni tubes. The heat transfer rates for essential components are verified by testing to ensure that the design basis heat transfer rate is being maintained. The fouling factor for each component is typically 0.002 hr-ft^2-°F/Btu. Water treatment provisions to prevent fouling are discussed in Section 9.2.6.

Radiation detectors are located on the combined ESW/RHRSW system return lines to detect inleakage of radioactive water. Only reactor recirculation pump seal coolers have a potential for radioactive inleakage to the ESW system. However, this line contains locked valves which further reduces the potential for inleakage into the ESW system. Control room alarms are provided on high

radiation. Radioactive leakage from the ESW system is controlled by closing the ESW return valves for the loop where the leak has been identified and realigning the system for operation from the alternate loop. These actions are initiated manually from the control room.

A significant difference between inlet and outlet flows in each ESW loop is indicated for net system water loss or inleakage and annunciated in the control room for net water loss only. Flooding detectors annunciate high water level in the RHR, RCIC, HPCI, and core spray pump compartments and the diesel generator compartments.

Credible pump leakage rates would be of no consequence because the design flow rate of each pump is approximately 6400 gpm. As stated in Section 9.2.2.2, a significant difference between the common pump discharge flow and return flow from each ESW loop is indicated and annunciated in the control room. This differential flow is indicative of ESW loop leakage, other than pump leakage, and provides the operator with indication of system degradation. The instrumentation is shown in drawing M-11.

If the lead cooler in any ECCS/RCIC pump compartment degrades to the point that room temperatures exceed desired levels, the redundant/standby cooler will automatically start. In the event that cooling capability degrades to the point that the compartments cannot be effectively cooled, high compartment temperature will be annunciated in the control room. Operator corrective actions could entail cooler repair, switching to the use of pumps located in another compartment, diverting more ESW flow to the compartment from other nonessential cooling loads, and/or opening compartment doors to facilitate cooling by natural circulation. After a DBA LOCA, use of ECCS equipment in another compartment is the most likely operator response due to high radiation conditions in the Reactor Enclosure. No credit has been taken for manual operator actions in the Reactor Enclosure in this scenario. One room unit cooler per ECCS/RCIC loop may be removed from service at the same time under administrative controls. Failure of both unit coolers in a HPCI, RCIC or Core Spray compartment is no worse than failure of the supported HPCI, RCIC or Core Spray equipment in the compartment because each compartment contains equipment associated with only one ECCS/RCIC loop. However, each RHR compartment contains LPCI equipment and two LPCI loops. Thus, a failure in one LPCI loop or a failure in one LPCI loop support system (such as the air cooling system or a power supply) could impact the other LPCI loop's equipment in the room. If both LPCI pumps' lead and standby unit coolers are in service prior to the DBA LOCA, no single active failure will result in less than the necessary number of coolers remaining functional to limit the RHR room temperature to less than 140 Degrees F. Analysis has demonstrated that any two unit coolers can adequately cool the RHR room to support both LPCI loops. If one or both LPCI pump standby unit coolers is/are out of service prior to the DBA LOCA (with the associated lead unit cooler in service), a single active failure could result in only one functional unit cooler in one RHR room, in which case that RHR room's temperature may exceed 140 Degrees F. Administrative controls are in place to assess and limit the risk of such maintenance configuration for the ECCS/RCIC room unit coolers. These coolers are a non-Tech Spec support system.

9.2.2.3 Safety Evaluation

All safety-related components (including supporting structures) of the ESW system are designed to seismic Category I requirements, as defined in Section 3.7. The piping is designed, fabricated, inspected, and tested in accordance with the requirements of ASME Section III, Class 3. The ESW system, with the exception of the buried piping and the piping in the spray pond, is housed within either the reactor enclosure or the spray pond pump structure, both of which are designed to the seismic Category I requirements discussed in Section 3.8.4. Evaluation of the ESW system with respect to the following areas is discussed in separate sections as indicated:

a.	Protection from wind and tornado effects	Section 3.3
b.	Flood design	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11
f.	Fire protection	Section 9.5.1
g.	Icing and freezing	Section 9.2.6

Each of the two independent ESW system loops is isolated from the other by barriers, separate trenches, or distance to ensure that simultaneous loss of both loops cannot occur. Power is supplied from four independent divisions. Failure of either a MOV, diesel generator, electrical division, or pump does not prevent the system from removing the full heat load. This arrangement ensures that the full heat removal capacity required is available after a postulated single active failure. See Table 9.2-4 for a failure mode and effects analysis of the ESW system.

Although not specifically included in the ESW system design basis, the cooling provided by a single ESW loop is sufficient to safely shut down both units at all times with the exception of the first 10 minutes of a postulated DBA LOCA. During this time, three RHR pumps may be required on the LOCA unit for flooding (LPCI mode). The RHR pumps are arranged so that only two can be cooled by each ESW loop. See section 6.3.2.5 for a discussion of single failure modes and effects on ECCS reliability.

Connections between the ESW system and the normal service water system, which supplies the equipment other than the diesel generators during normal plant operation, are provided with automatic AOVs and check valves. These isolate the service water system from the ESW system, so that a failure in the normal service water system does not impair ESW system operation. The check valves used at the interface of the essential (ESW) from nonessential (service water) piping is verified to be operable and to have less than 10 gpm leakage as part of the LGS ISI Program. Leakage of this magnitude will not compromise the safety function of the ESW system. Thus, even with this leakage at each interface, the ESW system could withstand a single active failure and still perform its safety function. In addition, seismic Category I manual gate valves are provided upstream of each interface check valve. These valves can be closed for more effective blocking during long-term operation of the ESW system (drawing M-11).

The crosstie piping between the ESW and RHRSW supply loops is provided with manual isolation valves which are locked in the safe position to prevent inadvertent mispositioning of these valves from disabling these systems.

Each ESW loop return is intertied to both ESW/RHRSW combined return headers to the spray pond, so that loss of a combined return header does not cause the loss of an ESW loop.

During certain maintenance configurations, one ESW loop may be lost due to the loss of a single ESW/RHRSW combined return header. However, sufficient redundancy and heat removal capacity remains in the other ESW loop such that ESW can perform its safety function.

Each ESW pump motor is powered from a separate Class 1E bus. Upon LOOP, the standby diesel generators automatically start to supply power to their respective buses, and thus power to the safety-related components of the ESW system. See Section 8.3 for a discussion of the onsite power system.

9.2.2.4 Tests and Inspections

The ESW system is preoperationally tested in accordance with the requirements of Chapter 14, and periodically tested in accordance with the requirements of Chapter 16. Inservice inspection is in accordance with the ASME Section XI for Section III, Class 3 components, or 10 CFR 50.69 Alternative Treatment, when applicable. Refer to Section 6.6.1 for further information.

9.2.2.5 Instrumentation Applications

The ESW system is designed for remote operation from the control room. In addition, one pump and the valves associated with its loop can be operated from the remote shutdown panel. A second pump in loop A can be operated using local controls at the C pump motor circuit breaker cubicle. The loop B pump can be operated using local controls at the B pump motor circuit breaker cubicle.

Local and remote indication is provided to monitor process parameters of the system. The following alarms are annunciated in the control room: pump discharge low pressure; flow differential high between influent and effluent showing net water loss. Temperature elements on pump motor provide input to plant computer.

Radiation alarms from the combined ESW/RHRSW return headers are annunciated in the control room.

9.2.3 RHR SERVICE WATER SYSTEM

The RHRSW system is a safety-related system, designed to supply cooling water to the RHR heat exchangers of both units.

9.2.3.1 Design Bases

a. The RHRSW system is designed to provide a reliable source of cooling water for all operating modes of the RHR system, including heat removal under postaccident conditions. It also provides water to flood the reactor core, or to spray the primary containment after an accident, if necessary.

b. The RHRSW system is designed to withstand the most severe natural phenomenon or site-related event (e.g., earthquake, icing conditions, tornado, hurricane, flood, or transportation accident) without impairing its function.

c. The RHRSW system is designed with sufficient capacity and redundancy so that a single failure of any active component, assuming the loss of offsite power, cannot impair the capability of the system to perform its safety-related functions.

d. The RHRSW system is designed to include the capability for testing through the full operational sequence that brings the system into operation for reactor shutdown and for LOCA.

e. The RHRSW system is designed to limit the possibility of any radioactive material release to the environment.

f. The RHRSW system is designed to include the capability of operating one loop from the remote shutdown panel.

g. The RHRSW system is designed to seismic Category I requirements. The quality group classification and corresponding codes and standards that apply to the design of the RHRSW system are discussed in Section 3.2.

9.2.3.2 System Description

The RHRSW system is shown schematically in drawing M-12. Major equipment design parameters are given in Table 9.2-5. It should be noted that the design parameters listed in Table 9.2-5 do not constitute performance requirements. RHRSW pump performance requirements are based on the pumps ability to support heat transfer regardless of discharge head. The system is common to the two reactor units, and consists of two loops. Each loop services one RHR heat exchanger in each unit, and provides sufficient cooling for safe shutdown, cooling, and accident mitigation of both units. The two RHRSW system return loops are cross-connected for flexibility. Two valves in series are provided on the cross-connect, so failure in one loop cannot affect the operation of the other. Each loop has two pumps located in the spray pond pump structure. One pump supplies 100% flow to one RHR heat exchanger. During two-unit operation, there are two heat exchangers (one per unit), and therefore, two of the four pumps are required for safe shutdown and accident mitigation. Description of the pump structure is found in Section 3.8.4. The RHR heat exchangers are described in detail in Section 5.4.7. The spray pond piping network is described in Section 9.2.6.

Spray pond pump structure wet pits are designed so that sufficient NPSH and adequate hydraulic conditions for proper pump operation are maintained down to a pond level below that associated with the design basis water loss. To verify adequate hydraulic conditions in the pump structure wet pits for proper long-term pump operation, it has been determined from model studies that acceptable hydraulic conditions exist down to elev. 243’-6”. Drawing M-389 shows the elevations of the spray pond water levels, suction piping and the RHRSW pump.

The RHRSW flows through the tube side of the RHR heat exchangers; the tubes of which are made of corrosion-resistant AL-6XN (Unit 1 and Unit 2B) and 304L stainless steel (Unit 2A). To reduce corrosion, the tube side of the heat exchangers can be laid up with demineralized water when the RHRSW system is not in operation.

It should be noted that a corrosion monitoring system was installed when 304SS tubes were in the Unit 1 RHR heat exchangers. The Unit 1 heat exchanger tubes have been changed to AL6XN material and there is no longer a need to actively monitor the corrosion of the original 304SS tube bundles. Accordingly the monitoring equipment has been placed in a de-energized and isolated inactive status. The design and minimum heat transfer rates are the same and are shown on drawing E11-1020-G-002 for normal and accident modes of RHR system operation. These heat transfer rates are based on the assumption that 5% of the RHR heat exchanger tubes are plugged and the remainder are fouled, RHR service water temperature is at a maximum, and RHR service water flow is at a minimum. Actual heat transfer rates will be greater than the minimum values based on actual tube and service water conditions plus the manufacturer's design conservatisms.

Credible pump leakage rates will be of no consequence. Excessive leakage in the RHRSW system would cause a high temperature alarm in the RHR system, a flooding alarm in the RHR room, or a

low flow indication for RHRSW in the RHR heat exchanger inlet. The redundant RHRSW loop can be used while the leakage problem is being corrected.

The RHRSW system supply and return yard piping is made of carbon steel with approximately 200 mils corrosion allowance. A portion of the RHRSW return piping within the pipe tunnel is stainless steel. All piping outside the pump structure, main plant, and spray pond is externally coated for corrosion protection. Exposed spray pond piping is painted. Water treatment provisions to prevent fouling are discussed in Section 9.2.6. The spray networks can be drained after use to minimize corrosion and provide protection from freezing.

The RHRSW system is available for normal shutdown or emergencies, and does not operate during normal power generation, except that the RHRSW system can be used in conjunction with the RHR system suppression pool cooling mode to maintain the suppression pool below specified temperature limits, and RHRSW can be operated in the spray mode for spray pond cooling and chemistry control purposes.

For two-unit operation, during a plant operating mode in which one unit is in an accident shutdown (LOCA) and the other unit is in a normal shutdown (including LOOP occurring during normal shutdown), with one RHRSW loop in service (two RHRSW pumps in operation, and one ESW pump in operation using one spray pond return header and two spray networks), the unit undergoing normal shutdown will be supplied with 5570 to 8000 gpm of RHRSW flow to the RHR heat exchanger. The RHRSW cooling water flow to the unit under normal shutdown is sufficient to remove the heat load on its RHR heat exchanger. The time to cool the RPV down to 200°F will increase but will remain within the shutdown requirements of the Technical Specifications. The unit in an accident shutdown will still be supplied with 8000 GPM of RHRSW flow to the RHR heat exchanger. The required RHRSW flows to each RHR heat exchanger can be attained by adjusting HV-51-2F068A/B or HV-51-1F068A/B. RHRSW flow to the RHR heat exchangers can be monitored through FI-51-1R602A/B and FI-51-2R602A/B.

The RHRSW pump motors obtain their power from separate Class 1E buses; the A and B pumps from Unit 1 buses A and B, respectively, and the C and D pumps from the Unit 2 buses A and B, respectively. If LOOP occurs, the diesel generators start automatically, providing emergency power to the buses. The pumps are started manually. It is not necessary to secure any of the ECCS pumps before starting the RHRSW pumps. The RHRSW valves obtain their power from the safeguard buses, with loop A valves receiving power from Division 1 and 3, and loop B valves from Division 2 and 4. The RHR heat exchanger inlet valves are powered by different electrical sources. Specifically, HV51-1F014A and RHRSW pump OAP506 are powered by Division I, Unit 1 while HV51-1F014B and RHRSW pump OBP506 are powered by Division II, Unit 1. In the event of a power supply failure, an RHR heat exchanger is removed from service by manually closing the heat exchanger service water outlet valve.

The RHRSW return and the return from both ESW loops share a common return header to the spray pond. Loss of one RHRSW/ESW return loop does not affect the capability of the second return loop to safely shut down either or both units during emergency conditions.

Under certain maintenance configurations, flow from the two return headers may be combined in one line for a limited period of time. Any active valves which could fail and disable this line will be blocked in the safe position. Passive failures which could cause the total failure of this line during this limited duration have been evaluated and are not considered credible.

Upon standby emergency diesel generator or ESW pump start, the RHR service water system automatically aligns itself to the spray pond mode, if it is not already in that mode. If the cooling tower mode is available, the system can be manually aligned to it. Bypass lines are provided to discharge water directly to the pond, rather than the spray networks, during periods when the pond is frozen.

Double remotely operated isolation valves are provided on the cross-tie lines between the RHRSW system and the RHR pump discharge, for flooding the containment or reactor core, if such action is necessary and no other source of water is available.

Radiation monitors are provided in the RHRSW system return headers to the spray pond. High activity in the return header causes an alarm and the pumps associated with that loop to stop. Overrides are provided to restart the pumps.

For detection of possible RHRSW system pipe breaks, flow indicators on each RHR heat exchanger inlet, and RHR room flooding detectors that annunciate on high water level, are provided.

9.2.3.3 Safety Evaluation

Safety-related components (including supporting structures) of the RHRSW system are designed to seismic Category I requirements, as defined in Section 3.7. The piping is designed, fabricated, inspected, and tested in accordance with the requirements of ASME Section III, Class 3 except as noted in Table 3.2-7. The RHRSW system, with the exception of the buried piping and the piping in the spray pond, is housed within either the reactor enclosure or spray pond pump structure, both of which are designed to seismic Category I requirements as discussed in Section 3.8.

Evaluation of the RHRSW system with respect to the following areas is discussed in separate sections as indicated:

a.	Protection from wind and tornado effects	Section 3.3
b.	Flood design	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11
f.	Fire protection	Section 9.5.1
g.	Icing and freezing	Section 9.2.6

There are two RHRSW loops, each loop serving one RHR heat exchanger in each unit, to supply cooling water for plant shutdown. Each loop is isolated from the other by barriers, separate trenches, or distance to ensure that simultaneous loss of both loops cannot occur. Failure of either a MOV, a diesel generator, or pump does not prevent the system from performing its safety function. This arrangement ensures that the full heat removal capacity required is available after the postulated active failure of a single component. See Table 9.2-6 for a failure mode and effects analysis of the RHRSW system.

Motors of the four RHRSW system pumps are connected to separate Class 1E buses.

9.2.3.4 Tests and Inspections

The RHRSW system is preoperationally tested in accordance with the requirements of Chapter 14, and periodically tested in accordance with the requirements of Chapter 16. Inservice inspection is in accordance with ASME Section XI for Section III, Class 3 components, or 10 CFR 50.69 Alternative Treatment, when applicable. Refer to Section 6.6.1 for further information.

9.2.3.5 Instrumentation Applications

The RHRSW system is designed for remote operation from the control room. Each pump has a discharge pressure switch which causes an alarm in the control room upon low discharge pressure. Each loop has a pressure transmitter in the common supply line for pressure indication in the control room.

The RHRSW supply line flow to each heat exchanger is indicated in the control room. Pressure and temperature in the return lines from each heat exchanger are indicated in the control room. High radiation alarms and radiation recorders are provided in the control room for each common return line. Temperature elements on the pump motors provide input to the plant computer.

Loop A pumps and valves can also be operated from the remote shutdown panel and pressure indication for the common supply line is provided. Loop B pump can be operated using local controls at the B pump motor circuit breaker cubicle.

9.2.3.6 Regulatory Commitments

The following table provides a description of the regulatory commitments identified in Exelon letter dated October 29, 2010 (Ref. 9.2-29), Attachment 4, as updated by supplemental letters dated December 3, 2010 (Ref. 9.2-30), and March 23, 2011 (Ref. 9.2-31), and is included in the Updated Final Safety Analysis Report as required by Amendment Nos. 203 to Facility Operating License No. NPF-39 and 165 to Facility Operating License No. NPF-85 for Limerick Generating Station (LGS), Units 1 and 2, respectively, dated July 29, 2011 (Ref. 9.2-32).

The amendments consist of changes to the LGS Technical Specifications (TS) of each unit extending the allowed outage time (AOT) from 72 hours to seven (7) days for the Suppression Pool Cooling mode of the Residual Heat Removal (RHR) system, the Residual Heat Removal Service Water (RHRSW) system, the Emergency Service Water (ESW) system, and the [Alternating Current] A.C. Sources – Operating (Emergency Diesel Generators [EDGs]).

The specific purpose of the amendments is to provide a 7-day TS AOT window to allow for repairs of the common RHRSW system piping. The AOT extension is only allowed once every other calendar year, for each unit, while one unit is operating and the opposite unit is shut down, with the reactor vessel head removed and rector cavity flooded.

The piping repairs are intended to repair certain known areas of degraded RHRSW return piping, and are expected to take several refueling outages on each unit to complete the full scope of repairs. However, the TS changes may be used for other future RHRSW piping maintenance activities, as necessary, as long as the appropriate TS restrictions and the regulatory commitments identified below are observed.

These regulatory commitments will be controlled as part of a special procedure developed specifically to govern plant operation while in the extended TS AOTs to perform RHRSW system piping repairs.

Technical Specification 3.7.1.1 Action a.3.a and a.3.b were changed to allow the use of the Risk Informed Completion Time (RICT) Program per Amendment Nos. 240 to Renewed Facility Operating License No. NPF-39 and 203 to Renewed Facility Operating License No. NPF-85 for Limerick Generating Station (LGS), Units 1 and 2, respectively, dated 2/28/2020. The amendments will allow the AOT to be increased to a maximum of 30 days based on the associated plant risk to the operating Unit.

Regulatory Commitments
1. The following action will be taken prior to entry into the proposed configuration: • Proper standby alignment of the operable RHRSW subsystem will be ensured by local verification of boundary valve and power supply position in accordance with a check-off list contained in the special procedure developed specifically to govern plant operations in the extended AOTs.
2. Also, the following actions will be taken prior to entry into the proposed configuration: • When the 'A' RHRSW subsystem is inoperable to allow for repairs of the RHRSW A subsystem piping with Limerick Generating Station Unit 2 shutdown, reactor vessel head removed and reactor cavity flooded, the following equipment will be verified as available and protected as defined in procedure OP-AA-108-117: o ESW loop A o Unit 1 RHR subsystems A and C o D11, D13, and D23 4kV buses and emergency diesel generators o Unit 1 Division 1 and Division 3 Safeguard DC • When the 'A' RHRSW subsystem is inoperable to allow for repairs of the RHRSW A subsystem piping with Limerick Generating Station Unit 1 shutdown, reactor vessel head removed and reactor cavity flooded, the following equipment will be verified as available and protected as defined in procedure OP-AA-108-117: o ESW loop A o Unit 2 RHR subsystems A and C o D11, D21, and D23 4kV buses and emergency diesel generators o Unit 2 Division 1 and Division 3 Safeguard DC • When the 'B' RHRSW subsystem is inoperable to allow for repairs of the RHRSW B subsystem piping with Limerick Generating Station Unit 2 shutdown, reactor vessel head removed and reactor cavity flooded, the following equipment will be verified as available and protected as defined in procedure OP-AA-108-117: o ESW loop B o Unit 1 RHR subsystems B and D o D12, D14, and D24 4kV buses and emergency diesel generators o Unit 1 Division 2 and Division 4 Safeguard DC

- When the 'B' RHRSW subsystem is inoperable to allow for repairs of the RHRSW B subsystem piping with Limerick Generating Station Unit 1 shutdown, reactor vessel head removed and reactor cavity flooded, the following equipment will be verified as available and protected as defined in procedure OP-AA-108-117:
-
    - o ESW loop B
    - o Unit 2 RHR subsystems B and D
    - o D12, D22, and D24 4kV buses and emergency diesel generators
    - o Unit 2 Division 2 and Division 4 Safeguard DC

3. Activities in the switchyard that adversely affect risk exposure are those that have the potential to cause a loss of offsite power, such as testing and maintenance activities. Therefore, testing and discretionary maintenance will be prohibited during the RHRSW subsystem piping repairs in the at-power unit switchyard and on equipment in the outage unit switchyard supporting operability of its offsite source. Accordingly, during the RHRSW subsystem piping repairs, the at-power unit switchyard will be protected in its entirety using either a lock and/or chain different than that used for normal access to the switchyard, or a physical barrier placed in front of the gate used for normal access to the switchyard. In addition, equipment in the outage unit switchyard supporting operability of its offsite source will be protected during the RHRSW subsystem piping repairs using protected equipment signs and physical barriers, such as barrier rope, physical devices, tape, etc., to prevent access to the equipment. This will be controlled through applicable corporate and station procedures for equipment protection, and through the special procedure developed specifically to govern plant operation while in the extended AOTs.

4. Operational Risk Activities (ORAs), as defined in procedure WC-AA-104, involve activities on risk significant systems that have the potential to derate the plant, i.e., cause a loss of planned generation. Typical ORAs involve: an activity that could cause equipment actuations that could cause loss of planned generation; instrument, fuse, or circuit board removal/installation; an activity that will cause a 1/2 scram or 1/2 trip; pressurization of common instrument sensing lines; placing of jumpers or lifting energized leads; an activity that could cause vibration or impact near operational risk sensitive equipment, etc. Such activities will be prohibited on the online unit during the RHRSW piping repairs. Exceptions to this must be approved by the senior plant management. This will be controlled as part of the special procedure developed specifically to govern plant operation while in the extended AOTs.

5. The extended weather forecast will be examined to ensure severe weather conditions that would threaten the loss of offsite power are not predicted prior to entry into the AOT. In the event of an unforeseen severe weather condition due to rapidly changing conditions, such as severe high winds, a briefing with crew operators will be performed to reinforce operator actions and responses in the event of a loss of offsite power (E-1 0/20). This will be controlled via the special procedure developed specifically to govern plant operation while in the extended AOTs.

6. Shift briefs will be performed to reinforce other potentially important operator actions associated with the performance of the extended AOT (i.e., operator actions to refill the condensate storage tank (CST), operator actions to vent containment, operator actions to

maximize control rod drive (CRD) injection to the vessel, and operator actions to support continued use of feedwater and condensate post-trip as necessary and if available). Additionally, during the 'A' RHRSW subsystem outage, a shift brief on alternate remote shutdown operations will be performed since some of the normally operated equipment from the remote shutdown panel will not be available. This will be controlled via the special procedure developed specifically to govern plant operation while in the extended AOTs.

7. Unattended transient combustibles and hot work will be prohibited in the areas listed below during the extended AOT. This will be controlled via the special procedure developed specifically to govern plant operation while in the extended AOTs.

   For an 'A' RHRSW subsystem outage window:
   - Fire Area 15, Unit 1 Division 2 (012) safeguard 4kV switchgear room
   - Fire Area 17, Unit 2 Division 2 (022) safeguard 4kV Switchgear room
   - Fire Area 24, Main Control Room (ECCS B panel 10-C601 (Bay A, B))
   - Fire Area 24, Main Control Room (ECCS B panel 20-C601 (Bay A, B))
   - Fire Area 25, Auxiliary Equipment Room

   For an 'B' RHRSW subsystem outage window:
   - Fire Area 13, Unit 1 Division 1 (011) safeguard 4kV Switchgear room
   - Fire Area 19, Unit 2 Division 1 (021) safeguard 4kV Switchgear room
   - Fire Area 24, Main Control Room (ECCS A panel 10-C601 (Bay C, D, E, F))
   - Fire Area 24, Main Control Room (ECCS A panel 20-C601 (Bay C, D, F))
   - Fire Area 25, Auxiliary Equipment Room
   - Fire Area 26, Remote Shutdown Panel

9.2.4 CLARIFIED WATER SYSTEM

The plant clarified water system provides filtered, clarified river water for use as lubricating water, and as the input stream for the makeup demineralizer system.

The plant clarified water system, shown in drawing M-17 is not safety-related, and does not convey radioactive material.

9.2.4.1 Design Bases

a. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the clarified water system is discussed in Section 3.2.

b. Raw water is clarified and filtered to an effluent turbidity not exceeding 1.0 NTU and is stored in the clarified water storage tank.

c. The clarified water system is not connected to any systems having the potential for containing radioactive material.

d. The clarified water system is designed to meet maximum anticipated plant water demands.

9.2.4.2 System Description

The clarified water system is shown in drawing M-17.

Influent for the clarified water system is supplied by the Perkiomen Creek or Schuylkill River. The river water turbidity is reduced in the raw water clarifier by chemical addition. The clarified water from the clarifier outlet flows by gravity to the clearwell. The flow through the clarifier is controlled by a level control valve on the clarifier inlet.

The clarifier is designed to operate on the upflow sludge blanket principle. Chemical addition is in proportion to the inlet flow to the clarifier. Backflushing and sludge blowdown from the clarifier can be manually controlled or automatically controlled in proportion to inlet flow. The sludge is directed to the normal waste for disposal.

The clarified water service pump takes suction from the clearwell, and discharges to the clarified water storage tank via three anthracite bed pressure filters. The clarified water standby pump serves as a backup to the clarified water service pump. The anthracite filters remove suspended solids from the clarifier effluent to maintain proper water clarity within the clarified water storage tank. Each filter has a design flow rate of 100 gpm. Backwashing of the anthracite filters is either manual or automatic, with normal operation being automatic. Under automatic operation, the filters are sequentially backwashed by the filter backwash pump, and are returned to service at the conclusion of the backwash cycle. The clarified water standby pump also serves as a backup to the filter backwash pump. The clarified water service pump, filter backwash pump, and clarified water standby pump are provided with minimum flow recirculation loops for pump protection during low flow demand.

Flow to the clarified water storage tank is controlled by a level control valve on the tank inlet. A controller, normally in manual mode, throttles the inlet valve to the clarified water storage tank level. The tank is located in the yard next to the water treatment enclosure, and is furnished with steam heating to prevent freezing.

The clarified water storage tank furnishes water for the following systems during normal operation:

a. Demineralized water makeup system

b. Lube water system

The makeup demineralizer feed-pumps provide water to the makeup demineralizer system as needed to maintain a pre-established level in the demineralized water storage tank. Operation of the pumps is manually initiated by local or remote hand switches.

A valve in the makeup demineralizer feed pump discharge header is automatically closed when neither feed pump is running, thereby preventing inadvertent drainage of the clarified water storage tank during pump shutdown. If the valve fails to open when either feed pump is started, or if the valve fails closed, the makeup demineralizer feed pumps are tripped by a position switch. The pumps are also tripped on low-low level signal from the clarified water storage tank.

With the exception of the clarified water storage tank, which is located outside, the equipment in the clarified water system is located in the water treatment enclosure.

9.2.4.3 Safety Evaluation

The clarified water system has no safety-related function. Failure of the system does not compromise any safety-related system or component, nor does it prevent a safe shutdown of the plant.

9.2.4.4 Testing and Inspection Requirements

System operability is demonstrated by use during normal plant operation.

9.2.4.5 Instrumentation Requirements

The clarified water system is furnished with control panels, located in the water treatment enclosure, which are designed for remote manual and automatic control of the processes. Clarified water flow, and turbidity are monitored to verify system performance, and to alarm when abnormal conditions exist.

The clarified water storage tank is equipped with level switches to actuate high and low level alarms; to trip the clarified water service pump, the filter backwash pump, and the makeup demineralizer pumps .

Automatic operation of any of the lube water pumps due to low pressure in pump discharge line is annunciated in the control room. Low-low pressure in the lube water pump discharge is alarmed locally.

Local pressure indicators are provided at the discharge of all pumps in the systems for pump head indication.

9.2.5 DEMINERALIZED WATER MAKEUP SYSTEM

The demineralized water makeup system provides a supply of treated water suitable as makeup for the plant and reactor systems, and for other demineralized water requirements. The demineralized water makeup system has no safety-related function.

9.2.5.1 Design Bases

a. The demineralized water makeup system is designed to provide 80 gpm supply of demineralized water, to meet maximum anticipated plant operating requirements.

b. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the demineralized water makeup system are discussed in Section 3.2.

c. The demineralized water makeup system is designed so that the treated water composition does not exceed the limits given below:

Conductivity, micromhos/cm	0.2
Total dissolved solids, ppm	0.1
Silica, ppm SiO_2	0.010

9.2.5.2 System Description

The demineralized water makeup system is shown in drawing M-18. Design parameters for the major components of the system are given in Table 9.2-8.

Clarified and filtered river water is supplied to a vendor supplied water purification system by the makeup demineralizer feed pumps (Section 9.2.4). Chlorine residual and organics are removed by the activated carbon filter which precedes the vendor supplied water treatment system. The carbon filter may be bypassed if not required as determined by the water treatment vendor. Inlet water pressure to the carbon filter is regulated to a pre-established value by a pressure-reducing valve.

The original demineralizer system is no longer in service. All demineralized water makeup needs are met by a vendor supplied water purification system.

Discharge from the vendor supplied water purification system is continuously monitored by conductivity measuring devices which initiate alarms on a local panel, and divert the flow to chemical waste when maximum allowable levels are reached. Monitoring of silica shall be accomplished through the chemistry sampling program.

Demineralized water is stored in the 50,000 gallon capacity demineralized water storage tank. The tank is outside, and is furnished with steam heating to prevent freezing. This water supply is used to fill the CSTs and refueling water storage tanks, prior to unit operation. Demineralized water is also used prior to unit operation for plant systems flushing and filling. During normal operation, demineralized water is used for, but not limited to the following services:

a. Condensate and refueling water storage tanks

b. Fuel pool skimmer surge tanks

c. RECW system

d. TECW system

e. Auxiliary boilers

f. SLCS

g. Chemistry laboratory

h. Radwaste system

i. Chilled water system

j. Plant demineralized water hose stations

k. Deleted

The demineralized water supply is provided by the demineralized water transfer jockey pump, or the demineralized water transfer pumps which are operated as needed to meet plant demineralized water demand.

9.2.5.3 Safety Evaluation

The demineralized water makeup system has no safety-related function. Failure of the system does not compromise any safety-related system or component, nor does it prevent a safe shutdown of the plant.

9.2.5.4 Testing and Inspection Requirements

System operability is demonstrated by use during normal plant operation.

9.2.5.5 Instrumentation Requirements

Local and remote indicators, alarms, and pressure relief valves are provided to monitor the system process and to protect system components. Pressure differential, level, flow, temperature, and alarms are provided for each applicable point in the demineralizer system. High and low level alarms are installed in the demineralized water storage tank.

9.2.6 ULTIMATE HEAT SINK

The UHS, a spray pond, serves the safety-related functions of providing cooling water, and acting as a heat sink for the ESW system and the RHRSW system during accident conditions.

9.2.6.1 Design Bases

a. The UHS is designed to provide sufficient cooling water to the ESW and RHRSW systems, permitting simultaneous safe shutdown and cooldown of both units, and maintaining them in a safe shutdown condition.

b. In the event of an accident in one unit, the UHS is designed to provide sufficient cooling water to the ESW and RHRSW systems to dissipate the heat for that accident safely, to permit the concurrent safe shutdown and cooldown of the other unit, and to maintain both units in a safe shutdown condition.

c. The UHS is sized so that makeup water is not required for at least 30 days, and design basis temperature and chemistry limits for safety-related equipment are not exceeded.

d. The UHS is designed to perform its safety function during periods of adverse meteorological conditions, resulting in maximum water consumption and minimum cooling capability.

e. The UHS is designed to withstand the most severe natural phenomenon or site-related event (e.g., SSE, tornado, hurricane, flood, freezing, or transportation accident), and reasonably probable combinations of less severe phenomena and/or events, without impairing its safety function.

   Note: For the case of tornadoes, the cooling towers and Schuylkill River makeup pumps supplement the Spray Pond as required, to mitigate the storm damage and provide required cooling.

f. The UHS is designed to withstand any credible single failure of manmade structural features without impairing its safety function.

g. The UHS is designed to automatically supply sufficient cooling water to the ESW and RHRSW systems, as required.

h. The UHS is designed to include the capability for full operational testing.

i. The UHS is designed so that the cooling towers may be used as the heat sink for normal shutdown operations, and for postaccident operations if they are available.

Codes and standards applicable to the UHS are listed in Table 3.2-1.

9.2.6.2 System Description

9.2.6.2.1 General Description

The UHS for both units is a highly reliable, seismic Category I spray pond, that ensures that an adequate source of cooling water is available at all times for reactor shutdown and cooldown, and for accident mitigation. The RHRSW and ESW systems (see Sections 9.2.2 and 9.2.3) receive cooling water via the spray pond pump structure located on the pond perimeter, and return the water to the spray pond via the spray networks, or winter bypass lines .

9.2.6.2.2 Spray Pond Description

The spray pond is of seismic Category I design, excavated below-grade, and sized for a water volume adequate for 30 days of cooling under design basis conditions. The general arrangement of the spray pond, spray networks, and spray pond pump structure is shown in Figure 9.2-6. Details of the spray pond excavation and finished grading are shown in Figures 3.8-55, 3.8-56, and 3.8-57. A summary of pond design data is shown in Table 9.2-9.

The pond is lined to minimize seepage. The pond bottom and soil cut slopes are covered with a soil-bentonite lining, while the rock-cut slopes are lined with shotcrete. See Sections 3.8.4.1 and 2.5 for further details of pond geology, geometry, and linings.

The pond is provided with a seismic Category I overflow weir to accommodate normal water level fluctuations, and an emergency spillway to limit the maximum water level in the pond during maximum precipitation conditions.

Four spray networks, which are arranged symmetrically in the pond, provide cooling for the ESW and RHRSW return water. The layout of the spray networks is shown in drawing M-384. The networks and their supply piping are suspended above water on reinforced concrete columns.

9.2.6.2.3 Spray Pond Pump Structure

The spray pond pump structure houses the RHRSW and ESW pumps, and associated piping and valves. See drawings M-388, M-390 and M-389 for the general arrangement of equipment within the structure, and drawings M-11 and M-12 for piping and instrumentation diagrams of the ESW and RHRSW systems.

The pump structure is located on the edge of the spray pond. Openings are provided in front of the structure to allow pond water to flow into the wet pits where the pump suctions are located. Closure

of the sluice gates on these openings, and realignment of system valves allows the ESW and RHRSW systems to shift from the spray pond mode to the cooling tower mode.

The wet pit area is divided into two sections, corresponding to the A and B loops of the RHRSW and ESW systems. The two areas are separated by a wall, with a sluice gate that can be closed to isolate the two trains. Each pump is installed in its own bay. A removable screen is placed at the entrance of each bay.

Provision of adequate net positive suction head for the pumps is discussed in Sections 9.2.2 and 9.2.3.

HVAC equipment maintains necessary ambient conditions for proper operation of the equipment (Section 9.4-7).

9.2.6.2.4 System Components

Piping and valves associated with the spray pond system are carbon steel. Safety-related portions are designed to seismic Category I requirements as defined in Section 3.7 and are installed, inspected, and tested in accordance with the requirements of ASME Section III, Class 3.

Four spray networks are provided: two redundant networks for each ESW/RHRSW combined return loop. The networks and network supply piping are completely above water, and are provided with a corrosion allowance of 250 mils. Network header piping is sized for proper flow rates to all nozzles in the network. Piping is sloped to allow complete drainage of the networks and network supply piping, to minimize corrosion and prevent freezing. The exterior surface of the piping is painted to provide additional corrosion protection.

The spray nozzles are precision cast stainless steel, of a design that provides good thermal performance, while minimizing drift loss. All nozzles are located at el 258', 7 feet above the normal pond water level, allowing for proper droplet formation and flight time. Procedural guidance assures proper flow rates so that the pressure drop across the nozzles necessary for proper spray performance (3.4 psi, minimum) is achieved for all anticipated modes of RHRSW and ESW operation. The nozzles have no internal parts susceptible to clogging. A cleanout connection is provided at the end of each of the twenty-eight spray pond supply header pipes, in order to periodically flush corrosion products from these pipes and thus ensure proper functioning of the spray nozzles.

A winter bypass line is provided for each ESW/RHRSW combined return line to allow bypassing the spray networks and returning the heated water directly to the pond volume.

Makeup water to the pond is supplied via a 6 inch branch line from the Schuylkill River makeup line to the cooling towers. The line enters the pond below normal pond water level; a single normally closed gate valve in the line prevent siphoning from the pond in the event of loss of pressure in the makeup line. Makeup to the spray pond is controlled manually. A level detector in the pond which alarms in the Main Control Room assures that proper level is maintained.

An 8 inch blowdown line and associated weir are provided on the western pond perimeter. The line is used for overflowing excess water during rain conditions and for water quality control.

Two drain sumps are provided in the bottom of the pump structure. The sump pumps discharge to the pond above the water surface to avoid siphoning of the pond to the pump structure.

9.2.6.3 System Operation

The spray pond is designed to automatically supply cooling water to the ESW and RHRSW systems when required, and to continue this function with a minimum of operator attention.

9.2.6.3.1 Normal Operation

The spray pond is normally in a standby mode, and, except for periodic testing or RHRSW operation for spray pond cooling and chemistry control, is used only for cooldown and shutdown operations, or during emergency or accident situations. Starting the ESW pumps causes sluice gates and system valves to automatically align for spray pond operation, if not already in that position. The operator may subsequently stop and start pumps, and remove or add spray networks from service as necessary to maintain proper flows and diesel loadings.

During standby, the pond level is manually maintained above the Tech. Spec. Minimum level of 250'-10" (9'-10" pond depth) by the makeup and blowdown lines. Design basis minimum operating level corresponds to el. 250'-10" (9'-10" pond depth). During long-term operation, without makeup and blowdown, the concentration of scale-forming constituents, which can impair heat exchanger performance, increases due to evaporation. Provisions are available for the manual addition of chemicals to inhibit scale formation from calcium carbonate. Sufficient spray pond inventory is provided such that other scale-producing agents, such as calcium sulfate, do not reach concentrations that might cause scaling during the 30 day postaccident period, when no makeup or blowdown is assumed.

9.2.6.3.2 Winter Operation

The spray pond is designed to perform its safety functions with an initial ice layer on the pond surface.

During icing conditions, return flow to the pond is initially directed to the winter bypasses, which inject the warm return water directly to the pond volume. The bypasses are directed toward the ends of the pond to allow the return water to circulate and mix with the pond volume, and avoid hydraulic short-circuiting. The increasingly warmer pond water causes any ice layer present on the pond surface to melt. Once a hole is formed in the ice layer, a return path for spray water is available, and the spray networks may be used as water temperature dictates.

9.2.6.3.3 Cooling Tower Operation

During normal shutdown and cooldown operations, the RHRSW system uses the spray pond or the cooling tower as the source of cooling water, and as the heat sink. The system may be aligned to use the cooling towers as the heat sink and water source by shutting the spray pond sluice gates, and diverting the return flow to the towers. Cooled water from the cooling tower basins flows back to the wet pits.

Should an emergency or accident condition arise while in the cooling tower mode, ESW pump start signals cause the system to automatically realign to the spray pond mode. Subsequently, and after assessment of the cooling tower's availability, the system may be placed in the cooling tower mode, if so desired.

9.2.6.4 Spray Pond Thermal Performance

9.2.6.4.1 Design Meteorology

Conservative design meteorological conditions were determined for two cases: maximum water consumption and minimum heat transfer. Since no long-term meteorological data from the LGS site exist, long-term data (40 years) from the NWS at Philadelphia International Airport for the period January 1, 1941 through December 31, 1980, were selected as the most representative available long-term record.

To demonstrate the applicability of Philadelphia data, a coefficient of thermal performance comparison was made between LGS and Philadelphia for the same 5 year period (January 1, 1972 through December 31, 1976) using 3 hourly averages of wind speed, dry-bulb temperature, and relative humidity from each site. Wind speed was taken from the LGS aerovane 30 feet above grade on Tower No. 1. The dry-bulb temperature from LGS Weather Station No. 1 (about 5 feet above grade) was used. Relative humidity was determined through an average of eight stations at and surrounding the LGS site. Location of towers and stations is discussed in Section 2.3.2.

A comparison of the frequency distributions of dry-bulb temperatures by 10% relative humidity groups shows that the Philadelphia data are similar to the LGS data for the 2½ year period from January 1, 1972 through June 30, 1974. At the higher humidities, where the minimum heat transfer case occurs, the distributions are essentially identical. At lower humidities, the Philadelphia dry-bulb temperatures are slightly higher. Representative comparisons are shown in Figures 9.2-8 and 9.2-9.

A comparison of the frequency distribution of daily average relative humidities, without regard to temperature, is listed in Table 9.2-10. This table also shows very similar frequency distribution over the 2½ year period, with Philadelphia exhibiting a slightly higher frequency of low humidities, and a slightly lower frequency of high humidities.

A comparison of the distribution of daily average wind speeds from Philadelphia Airport data with that from the LGS site, also listed in Table 9.2-10, show rather poor agreement. The airport exhibits considerably higher daily average wind speeds, especially during daytime hours since 1964. This is believed to be due to the location of the wind sensor near the runways, which results in the measurement of manmade wind from the aircraft. Since Philadelphia wind speeds are not considered representative of the LGS site, a natural wind speed of zero was assumed in the analysis of meteorological data for the spray pond design, in the minimum heat transfer case. This is a conservative assumption.

Since these comparisons of meteorological data from LGS with similar data from the Philadelphia Airport indicate that the Philadelphia Airport relative humidity and temperature are quite representative of the LGS site, and because the Philadelphia record is of sufficiently long duration to establish worst case conditions, the 40 years of Philadelphia data for humidity and temperature were used as the basis for the design of the spray pond.

The design meteorology was selected using the method of Reference 9.2-1, as discussed below. For maximum water consumption, the worst 30 day period was determined using a coefficient of water loss which combines losses due to evaporation and drift. The evaporation loss was calculated from the results of the work of Ranz and Marshall (Reference 9.2-2) on evaporation from water drops in air. The drift loss was calculated as a function of wind speeds, using a computer model (Section 9.2.6.4.1.1) whose predictions are based on field test results (Reference 9.2-3) of identical nozzles. A coefficient of water loss value (Section 9.2.6.4.1.1), which is proportional to water loss rate, was calculated for each day in the 40 year period of record. Running averages of the coefficient values were used to select the worst 30 day period for water loss. The worst 30 days for water loss began

May 30, 1958. The average conditions for that period are presented in Table 9.2-11. Since wind speeds at Philadelphia are generally higher than at the site, the use of Philadelphia data yields conservative results for maximum water consumption.

The minimum heat transfer meteorological conditions were determined using a similar technique. The Philadelphia meteorological data were modified for the minimum heat transfer case, however, by assigning a zero natural wind speed value to all data. This is conservative, in that it minimizes heat transfer. The average drop velocity was added to the natural wind speed to calculate evaporation. A coefficient of thermal performance (Section 9.2.6.4.1.1) was calculated for each day, using average daily data. Running averages were taken to determine the worst 30 days for heat transfer. The worst day was June 30, 1945, and the worst 30 day period began August 12, 1959. The resulting design meteorological conditions are given in Table 9.2-11.

Using the coefficient of performance technique described above, the worst meteorological conditions were also determined for the 5 year period from January 1, 1972 through December 31, 1976, with both Philadelphia and LGS site 3 hourly average data. Actual reported natural wind speeds were used in this comparison for the maximum water loss case; Philadelphia wind speeds were converted to a 30 foot elevation for comparison. Natural wind speed added to the drop velocity was used in selecting worst case conditions for the minimum heat transfer case.

Results, listed in Table 9.2-12, show that the worst conditions are very similar at both locations, with the Philadelphia conditions being more conservative in all cases, except the 30 day minimum heat transfer case. The use of zero natural wind speed in the actual thermal analysis of the spray pond makes the use of the Philadelphia data conservative in the minimum heat transfer case.

This comparison confirms that use of the Philadelphia meteorology data, as modified, is appropriate as a conservative basis for the design of the spray pond.

9.2.6.4.1.1 Meteorology Analysis Methods

Drift Loss Model

An independent model has been developed to predict drift losses. A review of the literature reveals no efforts directly applicable to calculation of drift losses from a spray pond. Due to basic system differences, cooling tower drift measurements cannot be applied directly to spray ponds; therefore, a model was developed from principles of analytical mechanics. The following parameters are included in the model:

a. Drop size spectrum

b. Wind speed and direction

c. Elevation necessary for loss of a drop from the pond

d. Distance of each nozzle from the perimeter of the pond in the direction of drift

e. Pressure drop across the nozzle

f. Angle at which water leaves the nozzle

g. Vertical air entrainment of droplets

Drift is caused by the horizontal drag force exerted on small drops as they move relative to the air. A water drop leaves the nozzle with a certain initial velocity, and from that time its motion is determined by drag and gravitational forces. By solving the equations of motion, the position of each drop is determined as a function of time. When all initial velocities are considered, the positions of drops of the same size that left the nozzle at the same time, trace out a locus in the horizontal plane. When drops of similar size are grouped together, a locus results for each drop size group. A schematic drawing of typical loci is shown in Figure 9.2-10, for one wind speed at one elevation. The loci are concentric circles for a wind velocity of zero, and are somewhat distorted and translated in the wind direction for nonzero wind speeds.

Once the loci have been determined, for a given wind speed, the fraction of flow lost by drift for each drop size group is the ratio of the length of the locus outside the pond perimeter to the total locus length. Since a locus represents the position of drops of a given group, no drops from that group are off the locus at the elevation; consequently, the length of the locus is used to calculate loss fraction rather than the enclosed area. The percentage of flow lost by drift is the sum over the drop size groups of the product of drift loss fraction and flow fraction.

$$P = \sum_{i=1}^{n} f_i B_i \qquad \text{(EQ. 9.2-1)}$$

where:

P	=	percentage of flow lost by drift
f_i	=	fraction of flow in drop size group (i) that is lost
B_i	=	fraction of total flow in drop size group (i)
n	=	number for drop size groups

In order to facilitate evaluation of the drag coefficient for each drop size group, the drops are assumed to be spherical. High speed photographs show that drops deviate very little from being spherical, especially for smaller diameters, which are most important in drift loss considerations.

Since the drag force on a sphere is proportional to the relative velocity raised to a power between 1 and 2 (depending on the Reynold's number), the resulting equations of motion are nonlinear. An approximation is made to allow a solution in closed-form, in which the drag force is assumed to vary linearly over a certain range of velocities. Two velocity ranges are used, and for all velocities the approximation equals or exceeds the actual drag force, thus preserving conservatism by maximizing drift losses. This approximation technique is depicted in Figure 9.2-11.

The linear drag force approximation, in combination with Newton's Second Law, is used to determine the acceleration of a drop. The acceleration is integrated to determine the position of the drop as a function of time. This is done for both the X and Z directions, shown in Figure 9.2-12, to determine

the coordinates, X_i (t,θ)' Z_i (t,θ)', of drop position for the ith drop size group, as a function of time and initial direction. The motion in the Y direction is used only for calculating the drop exposure time.

In order to find the locus of a given drop size group at the elevation necessary for loss from the pond, the time of flight or exposure time, must be calculated. The motion of a drop in the Y direction, shown in Figure 9.2-12, is used to calculate the exposure time. Since the water leaves the nozzle in a conical pattern, no drag is applied for the first few feet of travel in the vertical direction to allow maximizing the time in the air, which maximizes drift losses. Drag is applied immediately in the calculation of X and Z coordinates, in order to maximize drift losses. The vertical position, Y(t), is determined as a function of time; subsequently, the elevation necessary for loss from the pond is substituted for the position. The resulting implicit equation is solved for exposure time. There is a different exposure time for each drop size group, due to the dependence of drag force on drop diameter.

With the exposure time determined, the locus for each drop size group can be generated by considering all initial velocity directions. A computer program has been written to supply the coordinates of points on each locus. The locus in the X, Z plane for each drop size group is integrated numerically over its length to determine the fraction of the locus, hence the drop size group, that is beyond the perimeter of the pond. The losses for the different drop size groups are summed to determine the total drift loss percentage from the pond.

The computer model generates a drift loss versus perimeter distance curve (Figure 9.2-13), which is used to generate a drift loss vs wind speed curve that is unique for each pond. A typical example is shown in Figure 9.2-14. Drift loss vs wind speed is used as input to the coefficient of water loss, discussed later, and in the system model.

The percentage of flow lost due to drift is an input parameter for the system model. The system model uses it as a loss term in determining the water remaining in the spray pond at any time after the start of operation of the sprays. The drift loss for the LGS spray pond is determined as a function of wind speed. This information is entered as a table, wind speed versus drift loss, in the system program. The drift loss is determined from the table at each time step in the calculation of system parameters.

Coefficient of Thermal Performance

The coefficient of performance for heat loss was calculated from the following equation:

$$C = (1/M_d C_p) [-K\pi D_p (2 + 0.6 N_{re}^{1/2} N_{pr}^{1/3}) (T_d - T_a) - (\pi D_v D_p h_g)$$

$$(2 + 0.6 N_{re}^{1/2} N_{sc}^{1/3}) ((P_{ai}/R_v T_d^*) - (P_{ao}/R_v T_a^*))] \quad \text{(EQ. 9.2-2)}$$

where:

C = coefficient of performance, °F/sec

M_d = drop mass, lb

C_p = specific heat of water, Btu/lb-°F (assumed = 1)

K = thermal conductivity of moist air, Btu/sec-ft-°F

D_p = drop diameter, ft (0.008 ft)

N_{re} = Reynold's number, moist air (dimensionless)

N_{pr} = Prandtl number (dimensionless)

T_a = air dry-bulb temperature, °F

T_d = drop temperature, °F (pond temperature)

D_v = diffusion coefficient of water vapor in air, ft^2/sec

h_g = enthalpy or water vapor, Btu/lb

N_{sc} = Schmidt number (dimensionless)

P_{ai} = vapor pressure at T_a, lb/ft^2

P_{ao} = partial pressure of vapor in air, lb/ft^2

T_d^* = T_d + 460, °R

T_a^* = T_d + 460, °R

ρ_w = density of water, lb_m/ft^3 (62.4)

P_{ao} = (RH) $(C+C_2T_a+C_3T_a^2+C_4T_a^3+C_5T_a^4+C_6T_a^5)$ 70.5 lb/ft^2

P_{ai} = $(C_1+C_2T_d+C_3T_d^2+C_4T_d^3+C_5T_d^4+C_6T_d^5)$ 70.5 lb/ft^2

C_1 = 3.76515×10^{-2} inch Hg

C_2 = 2.5463×10^{-3} inch Hg/°F

C_3 = 2.96588×10^{-5} inch Hg/$°F^2$

C_4 = 8.40577×10^{-7} inch Hg/$°F^3$

C_5 = $7.-1246 \times 10^{-10}$ inch Hg/$°F^4$

C_6 = 4.33688×10^{-11} inch Hg/$°F^5$

RH = relative humidity

N_{sc} = ν/D_v

h_g = 1090 Btu/lb_m

D_v = $4.06 \times 10^{-8} (T_a^*)^{2.5}/(T_a + 901) ft^2/sec$

N_{pr} = $C_p\mu/k$

N_{re} = VD_p/ν

V = Wind velocity ft/sec

D_p = Drop diameter, 0.008 ft

v = Kinematic viscosity of air

υ = $1.45 \times 10^{-4} + (T_a - 32)(5.15 \times 10^{-7})$ ft^2/sec

K = $3.89 \times 10^{-6} + (3.89 \times 10^{-7} (T_a - 32))/68$ Btu/sec-ft-°F

M_d = $\rho_w V = \rho_w \pi d^3/6$ lb_m

ρ_w = 62.4 lb/ft^3

R_v = 85.5 (gas constant, vapor)

Coefficient of Water Loss

The water loss coefficient of performance is calculated from the following equation:

$$C_w = 1.25 \times 10^4 \ \pi D_v D_p (2 + 0.6 N_{re}^{1/2} N_{sc}^{1/3}) (P_{ai}/R_v T_d^*)$$

$$(P_{ao}/R_v T_a^*) + f_d \qquad \text{(EQ. 9.2-3)}$$

where:

f_d = drift loss fraction (from drift loss curve for corresponding wind speed typical curve shown in Figure 9.2-14)

C_w = water loss coefficient

The remainder of terms are as defined in Equation 9.2-2.

The equations used to represent the typical curve of Figure 9.2-14 are:

a. For wind speed less than or equal to 2.5 miles per hour

$$f_d = C \times 10^{-4} WS \qquad \text{(EQ. 9.2-4)}$$

where:

WS = wind speed, mph

C = a constant for the specific pond geometry

b. For wind speed greater than 2.5 miles per hour

$$f_d = Ae^{(B(WS))} \qquad \text{(EQ. 9.2-5)}$$

where:

A and B = constants for the specific pond geometry

9.2.6.4.2 Spray Pond Water Requirements

This section discusses the water requirements that were considered in determination of the spray pond design volume and used in the pond thermal performance analysis.

9.2.6.4.2.1 Evaporation Due to Plant Heat Load

Evaporation due to the plant heat load is determined from the total heat dissipated by the spray pond in 30 days, due to decay heat, sensible heat, and auxiliary system heat loads. The total decay heat dissipated in 30 days is 5.47×10^{10} Btu for both units, based on Reference 9.2-4 for finite reactor operation. This includes contributions from fission products and heavy elements.

The LOCA/SSD auxiliary system total heat generation for the first 30 days is 2.27×10^{10} Btu. The auxiliary system heat load includes loads due to operation of engineered safeguards equipment, including the standby diesel generators, which would be in service following the loss of offsite power. The LOCA/SSD auxiliary heat generation rate averages 31.2×10^6 Btu/hr for the first 30 hours, and 31.5×10^6 Btu/hr thereafter, total for both units. The two-unit SSD auxiliary heat generation rate averages 64.2×10^6 Btu/hr for the first 30 hours and 65.2×10^6 Btu/hr thereafter, total for both units. The total sensible heat load of the reactor pressure vessel, its internals, and the suppression pool is 1.93×10^8 Btu, referenced to a final temperature of 121.4°F. The resultant evaporation is 13.58×10^6 gallons in 30 days.

9.2.6.4.2.2 Natural Evaporation

Natural evaporation of the spray pond was based on the design meteorology of Section 9.2.6.4.1 and a constant pond surface area of 9.6 acres. The water loss due to natural evaporation is shown in Table 9.2-13. This is conservative because the average surface area over the 30 day accident scenario is less than 9.6 acres and the effect of the sprays suppressing evaporation is not taken into account.

The evaporation calculation was based on the methodology of Reference 9.2-5.

9.2.6.4.2.3 Drift Loss

Drift loss due to entrainment of spray droplets during periods of moderate and high winds has been estimated using data from spray pond tests (Reference 9.2-3) and a drift loss computer model

(Section 9.2.6.4.1.1). The 30 day period of highest water loss was determined by considering both evaporative and drift losses, as described in Section 9.2.6.4.2. For the 40 year period of meteorological record (January 1, 1941 to December 31, 1980), the worst 30 day period for water loss was found to be May 30 through June 28, 1958. The average wind speed for this 30 day period is 10.43 mph. Drift loss is minimized by placement of over 90% of the nozzles a minimum of 100 feet away from the perimeter of the pond. The remaining nozzles, located near the corners of the pond, are at least 60 feet away from the pond perimeter.

The operation of four RHRSW pumps and three ESW pumps after a two-unit SSD, results in the maximum loss of 1.44×10^5 gallons in 30 days, based on a spray flow rate of 9000 gpm per RHRSW pump and 5666 gpm per ESW pump.

This drift loss value is based on a pond surface area of 9.9 acres and nozzle height of 7.17 feet above the pond surface.

9.2.6.4.2.4 Seepage

The design seepage rate of 1.825×10^6 gallons in a 30 day period was used in the thermal analysis. A seepage test was conducted to verify that the allowable design seepage rate for the lined pond would not be exceeded. This test, which was conducted during the period December 13, 1982 to May 21, 1983, determined that the actual seepage loss was between 2.1×10^5 gallons and 3.8×10^5 gallons in 30 days, depending on how evaporation losses are measured. This rate is between 11% and 21% of the allowable design rate. Considering possible error contributions from all measurements, the upper limit of the seepage loss during the test is estimated to be approximately 40% of the allowable design rate, and the lower limit is effectively zero. Details of the spray pond seepage measurements and testing are discussed in Section 2.5.

9.2.6.4.2.5 Sedimentation

An allowance of 2.75×10^6 gallons of water is provided to ensure that frequent pond cleaning is unnecessary. This corresponds to a sediment layer of approximately 12 inches on the pond bottom. Accumulation of sediment on the spray pond pumphouse intake area concrete slab will be periodically checked as part of the inspection program required by Regulatory Guide 1.127. Based on the results of these inspections, a suitable program of reinspection and cleaning will be established. Any excessive accumulation of sediment will be removed by suction dredging equipment to prevent excessive particulate concentrations from occurring near the intake structure. Water removed from the pond with the sediment will be returned to the pond such that intake water quality is not adversely affected or limited to the capacity of the clean water makeup line.

9.2.6.4.2.6 Fuel Pool Cooling and Makeup

In the event of a LOOP, the spray pond is used as a source of cooling water for the spent fuel pool via the RECW system (Section 9.2.8). The heat dissipation for this service is included as an auxiliary system heat load in Section 9.2.6.4.2.1.

Provisions are also made to supply pond water directly to the fuel pools via the ESW or RHRSW system, in the event of unavailability of the fuel pool cooling system. Since cooling via the RECW system and direct makeup would not occur simultaneously, the makeup function does not represent an additional water loss.

9.2.6.4.2.7 Water Quality

The spray pond is treated with a mineral scale inhibiting chemical. The addition of chemical treatment allows the background chemical concentrations of the spray pond to increase due to normal water losses from drift and evaporation during non-accident operation. During an accident, the spray pond will normally increase in concentration, assuming no makeup. The mineral scale inhibiting chemical concentration will also increase in the same manner, preventing deposits on heat transfer surfaces. The spray pond will be analyzed periodically and adjustments made to scale inhibitor concentrations, as needed.

Provisions are also made to reduce the fouling effects associated with silting and biologics. Chemical treatment also includes the use of biocides and dispersants to maintain water quality.

9.2.6.4.2.8 Minimum Water Level for Operation

To verify adequate hydraulic conditions in the pump structure wet pits for proper long-term pump operation, it has been determined from model studies that acceptable hydraulic conditions exist down to el. 243'-6". This operational limit establishes the dead storage volume of the spray pond as 6.95 million gallons. This dead storage is utilized to fulfill the sedimentation volume requirements (Section 9.2.6.4.2.5) and used in the analysis of spray pond temperatures.

As discussed in the following section, the pond water level will not drop below el. 243'-6" at the end of the design basis 30 day period.

9.2.6.4.2.9 Total Volume Allocation

The design water allowances are shown in Table 9.2-13. Substantial margin (4.74×10^6 gallons) is shown to exist for the maximum water loss case

9.2.6.4.3 Evaluation of UHS Performance

The spray pond performance has been analyzed to assure that the design spray pond volume is adequate for 30 days of cooling without makeup or blowdown, and that the cooling water temperature does not exceed the design limit for the design basis heat input and meteorological conditions. The heat loads for the following conditions were examined:

a. One-unit LOCA, one-unit SSD

b. Two-unit SSD

The heat loads for the one-unit LOCA, one-unit SSD were modeled as a two-unit SSD with cooldown at the maximum rate of 100°F per hour and four RHR heat exchangers operable for the first 30 hours of the event. This model maximizes the heat rejection to the pond during the time when the peak pond temperature is reached. This results in the bounding pond temperature and maximum water loss. Therefore the two-unit SSD model with maximum heat rejection was used for the pond thermal and water loss analysis.

Other assumptions used in performing the transient analysis for performance evaluation include:

a. No makeup water is supplied to the spray pond during the 30 day period.

b. The decay heat generation rate is in accordance with NUREG 0800 Branch Technical Position ASB 9-2. (Reference 9.4-4)

c. Coincident with the postulated LOCA/SSD, the water level in the spray pond is at design minimum (corresponding to 29.07×10^6 gallons less the sedimentation allowance) .

d. Uniform mixing is assumed in the spray pond. Short circuiting was not observed in tests (Reference 9.2-3).

The spray efficiency values are determined using the spray cooling model described below. Comparisons of model predictions with test data show the model to be conservative (Section 9.2.6.4.3.4). The spray efficiency used in these transient analyses is presented in Figure 9.2-17 as a function of hot water temperature. The spray efficiency is determined for the minimum spray network flow rate of 8500 gpm. This flow corresponds to the minimun flow of two RHRSW pumps and one ESW pump divided between two spray networks. The minimum flow was combined with the heat loads defined above to create a model which envelopes all spray pond operating conditions.

Other pertinent data used in the analysis is presented in Table 9.2-14. The heat rejection rate to the spray pond is given in Figure 9.2-18 and Table 9.2-15 for decay heat, station auxiliary heat and sensible heat. The integrated decay heat, station auxiliary heat sensible heat and total heat are given in Figure 9.2-19 and Table 9.2-16. The initial spray pond temperature assumed, 88°F, corresponds to extreme monthly average atmospheric conditions that maximize initial temperature (Reference 9.2-8).

9.2.6.4.3.1 Analytical Techniques and Input Parameters

To perform the required transient analyses that demonstrate adequate performance of the ultimate heat sink, as measured against criteria specified by the U. S. Nuclear Regulatory Commission (NRC) in Regulatory Guide 1.27,[9] a spray pond model utilizing a new ultimate-heat-sink performance computer program has been developed. This computer program consists of various theoretical models that simulate the thermal performance of the spray pond subject to an imposed heat load and meteorological conditions, both of which vary with time. These meteorological conditions include the environmental dry-bulb temperature, relative humidity, and prevailing wind speed, if appropriate. In addition, the effects of solar radiation directly to the pond, infrared radiation from the atmosphere to the pond, and radiation from the pond to the environment are included along with heat transfer via convection and conduction between the spray pond and environment.

These models comprise the several modules (subprograms) that are described below. The computer program is written in the FORTRAN77 programming language, also known as FORTRAN X3.8 (1978*)*, using the Microsoft FORTRAN v5.1 compiler specifically for a microcomputer equipped with a 80386 central processing unit (CPU) and 80387 co-processor or 80486 CPU.

9.2.6.4.3.1.1 Spray-Pond Model

The spray-pond model (module) is used by the Limerick Spray Pond model to calculate the mass and temperature of the spray pond from conservation principles. Both the water inventory (pond mass) and temperature are expected to also change with time. The spray pond is assumed to be thermodynamically described by a single bulk temperature. Heat transfer and water loss from the pond surface can be considered a secondary effect with regard to the heat and mass transfer action of the spray network.[10] Thermal stratification is diminished because the pond volumes are relatively small compared to the amount of water being circulated.[11]

The rate of change of (internal) energy for the spray pond is determined from a simple energy balance

$$\frac{dE_p(t)}{dt} = H_{dp} + H_{sn} + H_{an} - H_{br} - H_{ev} - H_{cn} - H_{ps} \qquad \text{(EQ. 9.2-6)}$$

where:

H_{dp} - is the energy added via sprayed water, in the form of drops, falling on the spray pond surface;
H_{sn} - is the solar insolation (direct solar radiation to the pond);
H_{an} - is the radiation from the atmosphere to the pond;
H_{br} - is the infrared radiation from the pond to the atmosphere;
H_{ev} - is the energy loss due to evaporation from the pond surface;
H_{cn} - is the conductive energy loss from the pond to the atmosphere; and
H_{ps} - is the energy lost from the pond due to seepage through the basin liner.

Heat lost via conduction through the pond basin liner is neglected. In writing the above expression, it is explicitly assumed that the water in the spray pond can be represented by a single temperature that is independent of location.

In an analogous fashion, the rate of change of pond mass is just

$$\frac{dM_p(t)}{dt} = w_{dp} - W_{pe} - W_{sw} - W_{ps} \qquad \text{(EQ. 9.2-7)}$$

where:

w_{dp} - is the mass flow rate to the pond, in the form of drops falling to the pond surface, from the spray;
w_{pe} - is the evaporation rate from the pond surface;
w_{sw} - is return flow to the service water systems; and
w_{ps} - is the seepage losses through the pond basin liner.

Generally, apart from the direct solar radiation to the spray pond, the mass and energy flow rates are functions of time by way of the pond temperature which varies with time.

The total mass and energy of the spray pond can be obtained via numerical integration of a first-order Taylor's series expansion:

$$M(t + \Delta t) \approx M(t) + \frac{dM(t)}{dt}\Delta t$$

$$E(t + \Delta t) \approx E(t) + \frac{dE(t)}{dt}\Delta t \qquad \text{(EQ. 9.2-8)}$$

The temperature of the spray pond is determined from knowledge of the pond total internal energy E_p and mass M_p. Although the specific energy of water is a function of both temperature and pressure, it is only weakly dependent upon the pressure, and to an excellent approximation (about one part in ten thousand or 0.01%) values along the saturation line may be used. For temperatures below 373.15 K (100°C), the internal specific energy e_f is given by the product of the specific heat at constant volume for water, that is independent of temperature, and the temperature in Celsius. Hence, the spray pond specific energy is given by

$$\frac{E_p}{M_p} \equiv e(p_\infty, T_p) \approx e_f(T_p) \approx c_{vw}(T_p - T_o) \qquad \text{(EQ. 9.2-9)}$$

where c_{vw} = 4189.8 ± 5.1 J/kg-°C and T_o = 273.15 °K. Approximate determination of this spray pond temperature in this manner will produce an error in the temperature of about 0.01°C. In addition, note that the internal specific energy has been, in compliance with custom, referenced to 0°C, that is, at T_p = 273.15°K, the specific energy is zero.

9.2.6.4.3.1.1.1 Heat Load

As a matter of definition, the heat load rejected to the ultimate-heat sink Q_{Hx} is that energy added to the water from the spray-pond that is used as cooling for the sundry heat exchangers. The energy at the spray nozzles is the sum of the enthalpy of the cooling flow plus this heat load. Part of this energy is transferred to the atmosphere via evaporation or is lost by action of a prevailing wind carrying the sprayed water in the form of drops beyond the pond boundary. The energy added to the spray pond is equal to the heat load Q_{Hx}, plus the product of the spray mass flow rate and the pond specific enthalpy $w_{sw}h_f(T_p)$, minus the energy lost via evaporation from the sprays and driftloss, and is described below in Section 9.2.6.4.3.1.1.5. Figure 9.2-18 shows the spray-pond heat load as a function of time for a postulated design basis accident.

9.2.6.4.3.1.1.2 Solar Insolation

The average daily solar radiation absorbed by a body of water varies according to site latitude, time of year, and time of day. Various tabulations, graphs, and formulas are available which give the instantaneous solar radiation as a function of these parameters with an accuracy of about 5 percent. Because the average spray pond temperature is required for a period of one month, values for the instantaneous solar radiation will require time increments on the order of one hour. Such a formulation is cumbersome and requires long microcomputer running times and a formulation for average daily solar radiation is more appropriate. Thus, the average daily solar insolation (radiation that has been received) can be expressed in the form[12]

$$H_{an} = (1 - 0.0071C^2)H_oS_p \qquad \text{(EQ. 9.2-10)}$$

where H_o is the absorbed solar radiation for a clear sky in units of watts per meter squared, C represents the cloud in tenths of sky, and S_p is the pond surface area in units of square meters. Because of the rotation of the earth, H_o changes significantly throughout the daylight hours and, of course, is zero during the night. To facilitate computation, H_o is taken to be an average over a given time increment. However, if the increment is longer than about three or four hours, the accuracy of the absorbed solar radiation is unacceptable. Because the characteristic time required for significant changes in the ultimate-heat-sink system is on the order of one day, the absorbed solar radiation H_o is taken to be the average daily absorbed solar radiation in units of watts per square meter of pond

surface for a cloudless sky, and can be parameterized as a function of latitude and time (day) of year:[13]

$$H_o = A_{sn}(\lambda) + B_{sn}(\lambda)\sin\left(\frac{2\pi N}{366} + C_{sn}(\lambda)\right) \quad \text{(EQ. 9.2-11)}$$

where the parameters $A_{sn}(\lambda)$, $B_{sn}(\lambda)$, and $C_{sn}(\lambda)$ are functions of latitude λ between 26 °N and 46 °N. The standard error associated with equation [EQ 9.2-11] is less than 8.7 W/m^2.

9.2.6.4.3.1.1.3 Atmospheric Radiation

Infrared radiation from the atmosphere is a function of many variables, including the distribution of temperature, moisture, carbon dioxide, ozone and other atmospheric constituents. However, since not all these parameters are normally known, Anderson[14] proposed an empirical relationship of the form:[15]

$$H_{ra} = \sigma S_p\left[A_{ra}+B_{ra}P_v\left(T_a\right)\right]\left(1-\omega\right)T_a^4 \quad \text{(EQ. 9.2-12)}$$

where σ = 56.687 pW/m^2-°K^4 is the Stefan-Boltzmann constant, p_v the saturation pressure in units of Pa, ω is the pond surface reflectivity, and T_a the atmospheric temperature in units of °K. The parameters A_{ra} and B_{ra} are empirical parameters and functions of the cloud cover parameter C. As before, S_p is the surface area of the spray pond in units of meters squared.

9.2.6.4.3.1.1.4 Spray-Pond Radiation

The energy flux radiated from the spray pond in units of watts per square meter of pond surface area is given simply by

$$H_{br} = \epsilon\,\sigma\,S_p\,T_p^4 \quad H_{br} = \varepsilon\sigma\,S_p\,T_p^4 \quad \text{(EQ.9.2-13)}$$

where ϵ is the emissivity of the pond taken to be 0.97,[16] σ is the Stefan-Boltzmann constant, S_p is the spray pond surface area in units of meters squared, and T_p is the temperature of the pond surface in units of °C. Because the flow rate out from the pond to the sundry heat exchangers is in excess of 87% of the pond volume per day, it can be assumed that the pond is well mixed and the pond surface temperature is well-represented by the bulk average temperature T_p.

9.2.6.4.3.1.1.5 Spray-Pond Evaporation

Evaporation from the spray pond due to the plant heat load and heat input by the environment (natural evaporation) is calculated as part of the pond thermal performance module in the ultimate-heat-sink computer program. Evaporation from the surface of a body of water is a complicated phenomenon involving many factors and much discussed in the literature. The evaporative energy flux in units of watts per square meter of pond surface is proportional to the difference in steam (water vapor) concentration between the pond surface and the atmosphere. Hence, an empirical relation giving the energy loss rate in units of watts can be written in the form:

$$H_{pe}=Cf(U)[P_v(T_p)-\phi_a P_v(T_a)]S_p \quad \text{(EQ. 9.2-14)}$$

where C is a constant to convert from units of Btu/(day ft^2) to W/m^2, f(U) is the "wind function" and S_p is the surface area of the spray pond. The term $p_v(T_p)$ is the saturation pressure evaluated at the pond temperature and thus is a measure of the steam concentration at the spray pond surface, while the term $\phi_a\, p_v(T_a)$ is the partial pressure of steam (water vapor) in the atmosphere and so represents the concentration there. Hence, the difference between these terms is the concentration difference which drives the net evaporation.

The "wind function" f(U) describes the effect of a prevailing wind as it blows across the spray pond surface. One of the most accurate, but slightly non-conservative, empirical relations for the wind function is that given by Ryan and Harleman:[17]

$$f(U)=22.4(\Delta T_v)^{1/3}+14U \qquad \text{(EQ. 9.2-15)}$$

where ΔT_v is the "virtual" temperature difference between the spray pond surface water and the air above the pond and U is the prevailing wind speed in miles per hour. The virtual temperature has units of °F and is given by

$$\Delta\, T_v = \frac{5}{9}\left(\frac{p_{atm}\, T_p}{p_{atm} - 0.378\, p_v\,(T_p)} - \frac{p_{atm}\, T_a}{p_{atm} - 0.378\, p_v\,(T_a)}\right) \qquad \text{(EQ. 9.2-16)}$$

where T_p and T_a are respectively the spray pond and atmosphere temperatures in °K, $p_v(T_p)$ and $p_v(T_a)$ are respectively the vapor pressures at the pond surface and atmosphere in units of Pa, and p_{atm} is the total atmospheric pressure also in units of Pa.

Other wind speed functions commonly used can be selected by the user. The wind speed function proposed by Brady et al[18] which is derived from large-lake data is given by

$$f(U)=70 + 0.7U^2 \qquad \text{(EQ. 9.2-17)}$$

which has units Btu/(ft^2 day)/mm Hg. The prevailing wind speed U has units of miles per hour and is measured at ten feet above the surface of the pond. This model of the wind speed is generally more conservative than that proposed by Ryan and Harleman.

Comparison of predictions using each model with experimental data shows that the Brady formulation gives pond temperatures that are 5 - 11 °C higher than the Ryan and Harleman formulation.[19]

The wind speed function used by Thackston and Parker[20] is

$$f(U)=C_2\beta U \qquad \text{(EQ. 9.2-18)}$$

where C_2 is a conversion constant to convert from Btu/(hr ft^2)/in Hg to Btu/(day ft^2)/mm Hg and β is an empirical constant which depends on the size, shape and exposure of the water body, and on the location of the wind measurement. In the referenced work of Thackston and Parker, a value of 13.9 is used which was approximately the value obtained from their Lake Hefner studies.

9.2.6.4.3.1.1.6 Spray-Pond Conduction and Convection

The conduction and convection heat losses from the ultimate-heat-sink spray pond is driven by the temperature difference between the spray-pond and the atmosphere, and is dependent upon the prevailing wind. An empirical relation for this rate of energy loss is[21]

$$H_{cn} = \left(\frac{9}{5}\right) CB f(U)(T_p - T_a)S_p \qquad \text{(EQ. 9.2-19)}$$

where f(U) is the wind-speed function selected for the evaporation losses in Section 9.2.6.4.3.1.1.5, and C is a coefficient that converts from Btu/(day ft^2) to W/m^2. The parameter B = 0.26 mm Hg/°F is Bowen's Coefficient, and the temperatures have units °K.

9.2.6.4.3.1.2 Spray-Region Model

A spray field or region above the surface of the spray pond is created by operation of the spray network. Each nozzle creates a spray which forms a cone of water with an average angle α to the horizontal. In calm wind conditions, the sprayed water forms an "umbrella" which reaches some maximum height H above the pond surface and range R from the nozzle. All nozzles in concert generate a spray field or spray region above the surface of the spray pond in which the density of sprayed drops is great. As they pass through this region, the drops lose mass and energy via evaporation before entering the spray pond. As a result of this evaporative mass and energy loss, the temperature and relative humidity of the surrounding air is altered. Hence, consideration must be given to the modification of the environment in this region in order to adequately simulate the performance of the spray network.

Because the temperature and relative humidity vary appreciably throughout the spray field, this region is divided into segments. Two different methods for division are necessary depending upon whether or not there is a prevailing wind. As the sprayed water is hot, relative to the environment, it will heat the surrounding air and thereby reduce its density compared to the air outside the spray region. This difference in density will generate or induce a wind. Depending upon the temperature of the sprayed water and meteorological conditions, this buoyancy-induced wind can have a wind speed greater than that of a prevailing wind of low speed. However, as the prevailing wind speed increases, the effects of buoyancy become unimportant. Thus, to capture the physics of the spray region thermal performance when buoyancy is important, it is necessary to simulate the spray-region performance differently depending upon whether or not there exists a prevailing wind. Hence, both a low-wind-speed model and a high-wind-speed model are required. Which of these models dominate is determined by which model has the greater spray-region efficiency η which is described in more detail below in Section 9.2.6.4.3.1.2.4. Since this is not obvious, a priori, the Limerick Spray Pond model calculates the spray-region performance for each model separately and automatically selects those results (inputs to the spray pond) from that model with the greatest calculated efficiency.

9.2.6.4.3.1.2.1 Spray-Region Geometry

The spray nozzles are assumed to be arranged in a rectangular pattern with the long dimension parallel to the x-axis and the short dimension parallel to the y-axis. Hence, the spray region will also have a rectangular geometrical pattern. The height of the spray region H is just the height reached by the spray above the surface of the pond. The length of the spray region is just the length of the nozzle geometrical pattern (in the x-direction) plus twice the range of drops from a nozzle; similarly, the width of the spray region is the geometrical width (in the y-direction) plus twice this range. This geometry is subdivided differently depending upon whether a low-wind-speed model or a high-wind-speed model is being used. However, for both models, the height and overall extent of the spray region are the same.

A ballistic drop trajectory that neglects drag forces is used to determine the height H and range R for a given initial (nozzle) drop velocity u_o. The nozzle spray angle α, effective nozzle flow area A_{nz}, and number of nozzles N_{nz} are assumed known. From these, the initial drop velocity at the nozzle is given by

$$u_o = \frac{v_f \, w_{nz}}{A_{nz} \, N_{nz}} \qquad \text{(EQ. 9.2-20)}$$

where $\underline{v}_f$ is the liquid specific volume for water evaluated at the spray temperature at the nozzle. Once the initial drop velocity, which is a vector quantity, has been determined, vertical and horizontal components are easily obtained. Hence, the height is just

$$H \cong \frac{u_o^2}{2g} \sin^2 \alpha + y_o - y_p \qquad \text{(EQ. 9.2-21)}$$

where y_o is the height of the spray nozzle above the water surface and $y_p < 0$ is the elevation of the pond surface with respect to the initial surface elevation ($y_{p,init} = 0$). The horizontal range of a drop is the product of the horizontal velocity and the sum of the time required for the drop to reach the apex of its trajectory and the time required to free fall to the pond surface:

$$R \cong \frac{u_o^2}{2g} \left(1 + \sqrt{1 + \frac{2g(y_o - y_p)}{u_o^2 \sin^2 \alpha}} \right) \sin(2\alpha) \qquad \text{(EQ. 9.2-22)}$$

9.2.6.4.3.1.2.2 High-Wind-Speed Model

For the high wind speed submodel, the spray region is divided into N rectangular segments normally oriented such that the wind velocity is parallel to the long axis of the region as depicted in Figure 9.2-20. Such an orientation is considered conservative because were the wind assumed parallel to the short region axis there would be a larger volume with lower relative humidity and hence more evaporative loss from the sprayed water, hence a larger efficiency. However, the amount of water carried outside the spray pond boundary by the wind is minimum for the wind parallel to the long axis of the spray network and maximum for the wind parallel to the short axis. Therefore, spray pond analyses performed using the Limerick Spray Pond model are either for maximum pond temperature

or maximum water loss depending upon whether the long or short axis is input as the "length" of the spray network.

Since the total segment mass is explicitly assumed to be conserved,

$$\frac{dM_i}{dt} = w_{sp,i} + w_{s,i-1} + w_{a,i-1} - w_{s,i} - w_{a,i} - w_{dp,i} = 0 \qquad \text{(EQ. 9.2-23)}$$

where:

$w_{sp,i}$ - is the mass flow rate from all spray nozzles to the *ith* spray region segment and is just the product of total mass flow rate to all nozzles in the spray network and the ratio of the segment area (in the x-y plane) to the spray region area;

$w_{s,i-1}$ - is the water vapor (steam) mass flow rate from the *(i-1)th* segment to the *ith* segment;

$w_{a,i-1}$ - is the dry air mass flow rate from the *(i-1)th* segment to the *ith* segment;

$w_{s,i}$ - is the water vapor (steam) mass flow rate leaving the *ith* segment;

$w_{a,i}$ - is the dry air mass flow rate leaving the *ith* segment; and

$w_{dp,i}$ - is the dry water drop mass flow rate for all diameter groups leaving the *ith* segment for the spray pond.

As the segment mass is explicitly assumed to be conserved, so then are the individual air and steam-water (vapor-liquid) masses also conserved. Note that because of a change in phase, only the combination of steam plus water is conserved, steam and water are not conserved separately. In addition, it is also assumed that there is no flow out the top of the spray region, Hence, it follows that

(EQ. 9.2-24)

$$w_{sp,i} = w_{dp,i} + w_{ev,i}$$
$$w_{a,i} = w_{a,i-1}$$
$$w_{s,i} = w_{s,i-1} + w_{ev,i}$$

where $w_{ev,i}$ is the total evaporative rate from the drop of all diameter groups. As the mass flow rate entering the spray pond from the ith segment $w_{dp,i}$ is known, being determined in the drop dynamic module described below, the total rate of evaporation from all drops in the ith segment, $w_{ev,i}$, and the vapor (steam) mass flow rate to the (i+1)th segment, $w_{s,i}$, is also known.

9.2.6.4.3.1.2.3 Low-Wind-Speed Model

For the low-wind-speed submodel, the spray field is divided into a set of concentric rectangular segments as shown in Figure 9.2-21. The number of these segments is the same as the number in the high-wind speed model. Due to buoyancy, the warm humid air in each segment will rise and thereby draw cooler air from the outer segment. As a result, cool humid air (air-steam mixture) flows into each segment through its outer surface. Part of the flow exits the segment through the segment top surface and the remainder flows to the next inner segment. All the air entering the center

segment leaves through the top of that segment. Although there is no prevailing wind, there is an induced wind as a result of buoyancy. As before, each segment is assumed to be in thermodynamic equilibrium (single segment temperature). The hot water from the spray enters through the segment top as in the case of the high-wind speed model. Heat energy lost by spray is gained by the moist air. An energy balance similar to that in the high-wind speed model is constructed which, in this case however, includes the air leaving through the top of the segment. This flow out the top is calculated considering the buoyancy-driven motion

Consider the free-convection for a segment of the spray region in which the moist air temperature varies about some mean value. If all the moist air in this region were at this mean temperature and if the fluid were not moving, the pressure gradient in the segment would be given by the equation of motion with u = 0:

$$\nabla p = \langle \rho \rangle \vec{g} \qquad \text{(EQ. 9.2-25))}$$

in which the average density $\langle \rho \rangle$ is at the average temperature <T>. If the velocity gradients result entirely from temperature inequalities, the moist air motion is usually slow and equation [EQ. 9.2-25] may be assumed to be a reasonably good approximation of the pressure gradient. Making this assumption, the time-independent equation of motion in the vertical (z) direction can be expressed in the form:

$$\frac{1}{2}\frac{\partial v_i^2}{\partial z} = \left(1 - \frac{\langle \rho \rangle_i}{\rho}\right) g + \frac{dG_i}{dV} \qquad \text{(EQ. 9.2-26))}$$

where dG_i/dV is the rate per unit volume momentum is transferred to the moist air (air-steam mixture) in the segment via the falling drops. Integration over the segment volume and utilizing the Gauss-Ostrogradskii theorem,[22] the above expression becomes yields the vertical velocity at the top of the ith segment and is used to determine the induced wind velocity at the outer boundary of the spray region:

$$v_i = \sqrt{2\left(1 - \frac{\langle \rho \rangle}{\rho}\right) gH + 2\frac{G_i}{S_i}} \qquad \text{(EQ. 9.2-27))}$$

The parameter S_i represents the flow area at the top of the ith segment. The rate of momentum transfer to the moist air (air-steam mixture) via the falling drops in the segment G_i is given by Newton's Third Law and can be written as

$$G = -\frac{1}{2}\sum_{k=1}^{N_k} R_k \frac{\pi}{4} \int_t^{t_F} C_D D_k^2 \left| \frac{dy_k}{dt} - V_i \right| \left(\frac{dy_k}{dt} - V_i \right) dt \qquad \text{(EQ. 9.2-28))}$$

where V_i is the velocity in the vertical direction (along the y-axis) in the ith segment, R_k is the rate at which drops with an initial diameter D_k are created, and t_F is the "flight time" of that drop. The flight time is defined as the elapsed time required for a drop to travel from the nozzle to the surface of the spray pond drop and depends upon the initial drop diameter.

As before, the total mass in the ith segment is postulated to be conserved. Hence,

$$\frac{d M_i}{dt} = w_{sp,i} + w_{s,i-1} + w_{a,i-1} - w_{s,i} - \rho_{s,i} A_i v_i - w_{a,i} - \rho_{a,i} A_i v_i - w_{dp,i} \equiv 0 \qquad \text{(EQ. 9.2-29))}$$

where A_i is the area of the sides of the ith segment and $\rho_{a,i}$ is the air density of that segment. Because of phase change (evaporation), only the combination of steam plus water is conserved in addition to air, steam and water are not conserved separately. Therefore,

$$W_{sp,i}=W_{dp,i}+W_{ev,i}$$
$$W_{a,i}=W_{a,i-1} - \rho_{a,i}A_iV_i \qquad \text{(EQ. 9.2-30))}$$
$$W_{s,i}=W_{s,i-1}+W_{ev,i}-\rho_{s,i}A_iV_i$$

Starting at the last (inner most) segment where all air flows through the top of the segment, the above equation can be applied in a bootstrap fashion until the first segment is reached and the exerting dry air mass flow rate, and hence the induced inlet velocity, can be calculated. Once this induced velocity is known, the temperature in each segment is calculated exactly as for the high-wind speed model, except for the flow of humid air (air-steam mixture) through the segment top. Because the induced velocity is a function of the temperature difference, and thus the density difference, between the environment and a particular segment, this calculation proceeds iteratively until a convergence condition on the average drop temperature is satisfied.

9.2.6.4.3.1.2.4 Spray-Region Thermal Performance

The spray water in the form of drops passes through this region, losing mass and energy along the way by evaporation, and enters the spray pond. It is crucial that the spray pond temperature remain below a certain value in order for the service water
systems to remove the necessary amount of heat. This depends upon the evaporative mass and energy transfer from the spray drops to the air-steam mixture constituting the spray region atmosphere. This region or volume is characterized by the temperature and the relative humidity and is explicitly assumed to be at atmospheric pressure, defined as 1.01325 bar = 101.325 MPa. The spray water is considered to enter the spray field from the top at the initial temperature and exit through the bottom to the spray pond. The temperature of the drop (final drop temperature) as it enters the pond depends upon the amount of evaporative cooling that has occurred which, in turn, depends upon the temperature and relative humidity of the spray region.

The spray region for both the high- and low-wind speed submodels are divided into N small segments of equal volume as shown in Figure 9.2-22. Under the segment indexing convention used in the computer program, the 0th section is considered to be the environment, or the atmosphere, adjacent to the spray region. The parameters describing the environment are the (dry bulb) temperature, wet bulb temperature, relative humidity, and prevailing wind speed. Except for the wind speed, these parameters are transient and specified by the user as input data. (Either the wet bulb temperature

or the relative humidity, but not both, are specified and the unspecified parameter is calculated by the computer program.) The last segment is labeled as the (N+1)th segment. Each segment is considered to be in quasi-static thermodynamic equilibrium. Hence, the rate of energy change in the ith segment is zero and the energy gained by the air-steam (water) mixture is equal to that lost by the spray in that segment. Spray water enters the ith region from the nozzles with a flow rate w_{nz} and a liquid specific enthalpy h_f parameterized by the water temperature at the spray nozzle -- the spray temperature T_{sp}. The specific enthalpy at the nozzle is determined from the spray energy which is equal to the energy leaving the spray pond plus the heat load Q_{Hx}

$$h_f\,(T_{sp}) \;=\; h_f\,(T_p) \;+\; \frac{Q_{Hx}}{w_{sp}} \qquad \text{(EQ. 9.2-31))}$$

which is a defining equation for the spray temperature T_{sp}. Thus, the energy flow rate to the ith spray-region segment via sprayed water is

$$\dot{E}_{sp,i} \;\equiv\; w_{sp,i}\; h_f\,(T_{sp}) \qquad \text{(EQ. 9.2-32))}$$

Drops shortly after leaving the nozzle with a discrete spectrum of sizes described by the parameter f_k which is defined as the volume fraction of all drops which form with an initial diameter D_k. The drop group index k ranges from unity to a maximum value N_k which is the number of drop groups constituting the spectrum. Drops with initial diameter D_k are formed at a rate equal to

$$R_k \;=\; \frac{6\; f_k\; v_f}{\pi D_k^3}\; w_{sp,i} \qquad \text{(EQ. 9.2-33)}$$

where v_f is the specific volume of the liquid water evaluated at the spray initial temperature and N is the number of spray-region segments.

Each drop, regardless of size, has an initial velocity u_o oriented with angle α to the horizontal, and moves ballistically subject to gravitation and drag, losing mass and energy along its trajectory until entering the spray pond. A drop which originally had a diameter D_k enters the pond with a final mass $m_{d,k}$ which is smaller than the initial drop mass and a final drop temperature $T_{d,k}$. The drop group index parameter k is affixed to indicate the particular group to which the drop belongs. Equation [EQ 9.2-33] is also the rate at which drops that initially had a diameter D_k enter the spray pond, albeit with a smaller diameter. Drops which completely evaporate along their flight trajectory are considered to enter the spray pond with zero mass. The rate at which the spray in the form of drops enters the pond from the ith segment of the spray region is equal to the product of the rate of drop formation for drops with diameter D_k and the final mass $m_{d,k}$ of a drop which had that initial diameter, summed over the drop-size spectrum:

$$w_{dp,i} \;=\; \sum_{k=1}^{N_k} R_k\; m_{d,k} \qquad \text{(EQ. 9.2-34))}$$

For the kth drop-diameter group, the energy loss rate from the ith spray-region segment is just the product of the drop specific enthalpy $c_{pw}T_{d,k}$, the final mass of the drop $m_{d,k}$ and the rate at which

drops in this diameter group are created R_k. The total rate at which energy in the form of drops leaves the ith spray region is just the sum of the rates for each drop-diameter group:

$$\dot{E}_{dp,i} \equiv \sum_{k=1}^{N_k} R_k \, m_{d,k} \, C_{pw} \, T_{d,k} \qquad \text{(EQ. 9.2-35))}$$

Therefore, the rate at which the energy of the ith spray region changes is just the evaporative energy losses from the spray water, plus the energy of the steam (water vapor) and air entering the ith segment via the prevailing or induced wind, minus the rate of energy leaving the segment. By hypothesis, the segment is quasi-statically in equilibrium and thus:

$$\frac{dE_i}{dt} = \dot{E}_{sp,i} - \dot{E}_{dp,i} + w_{a,i-1} \, c_{pa} \, T_{i-1} + w_{s,i-1} \, h_S \, (T_{i-1}) - w_{s,i} \, h_S \, (T_i) - w_{a,i} \, c_{pa} \, T_i = 0 \qquad \text{(EQ. 9.2-36))}$$

where h_s is the specific enthalpy of steam and T_i is the temperature of the ith spray-region segment. Between 273.15 °K (0 °C) and 373.15 °K (100 °C), the vapor (steam) specific enthalpy h_s can be expressed as a linear function of the Celsius temperature plus an additive constant at the referent temperature of 0 °C. Such an expression is accurate to within -0.13% and can be readily derived from steam tables. Hence, over this temperature range:

$$h_g(T) \simeq C_{ps} \, (T - T_0) + h_{so}$$

where c_{ps} = 1748.0 J/kg-°C, h_{so} = 2501.3 kJ/kg, and T_o = 273.15 °K. It is similarly assumed that mass contained in the spray region does not change with time. Hence, in the ith segment, the rate of mass change is zero. In addition, the air and steam-water (vapor-liquid) masses are separately conserved. It is here that differences arise between the high-wind speed model and the low-wind speed model. These differences entail how the steam and air mass flow rates between the ith and (i+1)th sections are calculated, and will be discussed below in the appropriate sections.

Using these expressions the energy balance equation for the ith segment (equation EQ. 9.2-36), the equilibrium temperature is given by

$$T_i = \frac{\Delta \, \dot{E}_i + (w_{a,i-1} \, c_{pa} + w_{s,i-1} \, c_{ps}) \, T_{i-1} - w_{ev,i} \, (h_{so} - c_{ps} \, T_o)}{w_{a,i} \, c_{pa} + w_{s,i} \, c_{ps}}$$
$$= T_{i-1} + \frac{\Delta \, \dot{E}_i - w_{ev,i} \, (c_{ps} \, T_{i-1} + h_{s1})}{w_{a,i} \, c_{pa} + w_{s,i} \, c_{ps}} \qquad \text{(EQ. 9.2-38))}$$

where

$$\Delta \dot{E}_{r,i} \equiv \dot{E}_{sp,i} - \dot{E}_{dp,i} \qquad \text{(EQ. 9.2-39))}$$
$$h_{s1} \equiv h_{so} - c_{ps} T_o$$

and $w_{a,i-1}$ is the air (dry) mass flow rate entering the ith segment while $w_{a,i}$ is the flow rate leaving the segment.

The average spray-region thermal efficiency is a parameter useful for describing the performance of the spray region and is defined as

$$\eta = \frac{T_{sp} - \Theta_d}{T_{sp} - T_{wb}} \qquad \text{(EQ. 9.2-40))}$$

where T_{sp} is the temperature of the sprayed water at the nozzle, T_{wb} is the meteorological wet-bulb temperature, and Θ_d is the average drop temperature which is given by

$$\Theta_d \equiv \frac{\sum_{i=1}^{N} w_{d,i}\, c_{pw}\, T_{d,i}}{c_{pw} \sum_{i=1}^{N} w_{d,i}} \qquad \text{(EQ. 9.2-41))}$$

9.2.6.4.3.1.3 Drop Model

Between the time a drop leaves the nozzle and until it enters the spray pond, a drop moves along a ballistic trajectory exchanging both mass and energy with the spray region. The mass and energy exchange rates are determined by the drop thermodynamics while the trajectory is determined by the drop dynamics. For a given spray-region segment, each drop diameter group of the drop-size spectrum is considered separately and the results of the total spectrum combined to determine the mass flow rate to the spray pond surface $w_{dp,i}$, the energy flow rate to the pond surface $dE_{dp,i}/dt$, and the average temperature of the spectrum $T_{dp,i}$.

9.2.6.4.3.1.3.1 Ballistic Motion

A spherical drop of diameter D_k leaves the spray nozzle with an initial velocity u_o which makes angle θ to the horizontal. The equations of motion for this drop are

$$\frac{d}{dt} m_k \vec{u} = -\frac{1}{2} \rho_i C_d \frac{\pi}{4} D_k^2 |\vec{u} - \vec{V}| (\vec{u} - \vec{V}) - m_k \vec{g} - \frac{d m_k}{dt} \vec{u} \qquad \text{(EQ. 9.2-42))}$$

where **u** is the instantaneous drop velocity vector and **V** is wind velocity vector which is presumed to lie in the horizontal plane, and C_d is the drag coefficient which is a function of the Reynolds number.

The last term on the right side of equation [EQ. 9.2-42] is the rate of change of the momentum of the evaporating drop mass and is required for momentum conservation.[23] An approximation of C_d as a function of Reynolds number Re is given in the literature as[24]

$$C_d \simeq \begin{cases} \dfrac{24}{Re} & (Re < 2) \\ \dfrac{18.5}{Re^{0.6}} & (2 < Re < 500) \\ 0.44 & (Re > 500) \end{cases} \qquad \text{(EQ. 9.2-43)}$$

where the Reynolds number is given by

$$Re = \frac{\rho_i}{\mu_i} |\vec{u} - \vec{V}| D_k \qquad \text{(EQ. 9.2-44))}$$

in which ρ_i and μ_i are the average density and viscosity of the ith segment and D_k instantaneous drop diameter. Equation [EQ. 9.2-42] can be resolved along basis directions to yield

$$m_k \frac{d^2 Y_k}{dt^2} = -\frac{\pi}{8} \rho_i C_D D_k^2 |\vec{u} - \vec{V}| \frac{dy_k}{dt} - m_k g$$

$$m_k \frac{d^2 x_k}{dt^2} = -\frac{\pi}{8} \rho_i C_D D_k^2 |\vec{u} - \vec{V}| \left(\frac{dx_k}{dt} - V \right)$$

(EQ. 9.2-45)

Numerical solution of equation [EQ. 9.2-45] via Euler's method gives the trajectory of the drop expressed in terms of drop elevation y_k and range x_k which are functions of time. When the elevation of the drop y_k is equal to the elevation of the spray pond surface y_p, the integration ceases. This procedure is repeated for each of the N_k drop groups. The final drop mass of the kth group is $m_{d,k}$, i.e., the mass of the drop when its elevation is equal to that of the spray pond surface.

The rate at which drops in this group reach the pond surface is assumed to equal the rate at which they are created at the spray nozzle R_k. This is not strictly true as some drops will be carried by a prevailing wind beyond the spray pond boundary and thus become lost from the system. However, such an assumption is conservative as it deposits more energy to the spray pond than would occur in reality. Therefore, it is assumed that the rate for drops of the kth diameter group to enter the spray pond is equal to the rate at which they were created. Thus, the mass flow rate to the pond is given by equation [EQ. 9.2-34].

9.2.6.4.3.1.3.2 Mass and Energy Transfer

As the spray nozzles generate a spectrum of drop sizes and thus diameters, the mass and energy lost from the drops must be integrated over all drop diameters. A default drop size spectrum for the Sprayco 1751A nozzle is contained in the computer program; however, a different spectrum may be entered. A drop from the spray nozzle has an initial temperature equal to that of the water flowing to the nozzle. The internal energy of a drop of diameter D_k is given by

$$E_{d,k} = m_{d,k}\, c_{vw}\, (T_{d,k} - T_o) = \rho \frac{\pi}{6} D_k^3\, c_{vw}\, (T_{d,k} - T_o) \qquad \text{(EQ. 9.2-46))}$$

to a good approximation. The instantaneous rate at which the drop internal energy is changing is just the sum of the convective heat transfer from the drop to the ith spray-region segment plus the evaporative energy loss, the latter of which is the product of the evaporative mass loss and the vapor specific enthalpy evaluated at the drop temperature. Hence, the instantaneous rate of energy change is

$$\frac{dE_{d,k}}{dt} \equiv \dot{E}_{d,k} = - h_{x,k}\, \pi\, D_k^2\, (T_{d,k} - T_{a,i}) - \dot{m}_{e,k}\, h_g\, (T_{d,k}) \qquad \text{(EQ. 9.2-47))}$$

where the last term on the right side of equation [EQ. 9.2-47] is the rate of evaporation loss. The convective heat transfer coefficient $h_{x,k}$ for a spherical drop of diameter D_k is given in the literature[25] by

$$h_{x,k} = \frac{k_a}{D_k} \left(2 + 0.6\, Re^{1/2}\, Pr^{1/3}\right) \qquad \text{(EQ. 9.2-48))}$$

where k_a is the thermal conductivity of air which depends upon temperature. The instantaneous rate of evaporation from a spherical drop can be expressed in terms of the difference in vapor pressure at the drop surface and in the region far from the drop:[26]

$$\dot{m}_{e,k} \equiv - \frac{dm_{d,k}}{dt} = k_{m,k}\, \pi\, D_k^2 \frac{x_{so} - x_{s\infty}}{1 - x_{so}} = k_{m,k}\, \pi\, D_k^2 \left(\frac{p_{sat}\,(T_{d,k}) - p_{sat}\,(T_{a,i})}{p_\infty - p_{sat}\,(T_{a,i})} \right) \qquad \text{(EQ. 9.2-49))}$$

where $k_{m,k}$ is the mass-transfer coefficient and has units of kg/s-m^2, x_{so} is the vapor (steam) mass fraction at the drop surface, and $x_{s\circ}$ the mass fraction of the spray region segment. The mass fractions of the vapor (steam) are determined assuming both air and the water vapor (steam) can be described by the equation of state for an ideal gas and is thus equal to the ratio of the partial pressure to the total pressure.

During evaporation, both heat and mass transfer are occurring. A brute force solution requires simultaneous solution of the momentum, heat, and mass transfer field equations. However, in some cases, the heat and mass transfer boundary-layer profiles can be made to collapse on each other by proper definition of variables. This allows the solution of many mass-transfer problems at low mass-transfer rates by analogy with corresponding problems in heat transfer. Using one of the

Chilton-Colburn analogies,[27] the mass-transfer coefficient for a drop of diameter D_k is given in the literature[17]

$$k_{m,k} = \frac{\rho_{a,i}\ \lambda_{a,i}}{D_k}\left[2 + 0.60\left(\frac{D_k\ u_k\ \rho_{a,i}}{\mu_{a,i}}\right)^{1/2}\left(\frac{\mu_{a,i}}{\rho_{a,i}\ \lambda_{a,i}}\right)^{1/3}\right] = \frac{\rho_{a,i}\ \lambda_{a,i}}{D_k}\left(2 + 0.60\ Re_{a,i}^{1/2}\ Sc_{a,i}^{1/3}\right) \qquad \text{(EQ. 9.2-50))}$$

modified to change units and the dimensionless number groups forming the Reynolds and Schmidt numbers will be immediately recognized. Note that the convective and evaporative energy losses are functions of the drop diameter, velocity and temperature and will necessarily change along the drop's trajectory. The drop internal energy rate of change can be expressed in terms of the rate of change of drop mass and temperature as follows

(EQ.9.2-51)

$$\frac{dE_{d,k}}{dt} = \frac{dm_{d,k}}{dt}\ c_{vw}\ (T_{d,k} - T_O) + m_{d,k}\ c_{vw}\ \frac{dT_{d,k}}{dt} = -\ h_{x,k}\ \pi\ D_k^3\ (T_{d,k} - T_O) - \dot{m}_{d,k}\ h_g\ (T_{d,k})$$

from which the rate of change in drop temperature can be obtained to be

(EQ. 9.2-52)

$$\frac{dT_{d,k}}{dt} = -\frac{h_{x,k}\ \pi\ D_k^2\ (T_{d,k} - T_{a,i}) - \dot{m}_{e,k}\ [h_{fg}\ (T_{d,k}) + p_{sat}\ (T_{d,k})\ v_f\ (T_{d,k})]}{\rho\ \frac{\pi}{6}\ D_k^3\ c_{vw}}$$

$$= -\frac{6\ v_f}{D_k\ c_{vw}}\left[h_{x,k}\ (T_{d,k} - T_{a,i}) + k_{m,k}\left(\frac{p_{sat}\ (T_{d,k}) - p_{sat}\ (T_{a,i})}{p_\infty - p_{sat}\ (T_{d,k})}\right)(h_{fg} + p_{sat}\ v_v)\right]$$

As can be seen from equation [EQ. 9.2-52], the drop temperature rate of change consists of two terms representing convective and evaporative energy loss. Since evaporative mass and energy loss depend upon the drop diameter, each drop with diameter D_k will have a temperature T_k. This expression is numerically integrated from the time the drop is generated to the time when the drop enters the spray pond. During this integration, the properties of the air-steam (water) mixture in the spray region are considered constant. It is necessary to correct the convective heat transfer coefficient used in equation [EQ. 9.2-52] and the mass transfer coefficient used in equation [EQ. 9.2-49] because these factors depend, to some degree, upon the rates of heat and mass transfer. For low transfer rates, a multiplicative correction factor is adequate.

The rate of energy transfer to the spray pond by the drops from the ith segment is the product of the rate of drop formation, the final drop mass, and the liquid specific enthalpy, evaluated at the final drop temperature $T_{d,k}$, also summed over the drop-size spectrum:

$$\dot{E}_{dp,i} = \sum_{k=1}^{N_k} R_k\ m_{d,k}\ h_f\ (T_{d,k}) \qquad \text{(EQ. 9.2-53))}$$

Hence, the total evaporation rate and final drop temperature for the ith segment is just the difference between the rates at which mass enters the segment minus the rate at which mass leaves:

$$w_{ev,i} = w_{sp,i} - \sum_{k=1}^{N_k} R_k \, m_{d,k} \qquad \text{(EQ. 9.2-54))}$$

The final drop mass and temperature are obtained by numerically integrating the equations [EQ. 9.2-49] and [EQ. 9.2-52]. Final drop mass and temperature are defined as mass and temperature of the drop just prior to entering the spray pond. This integration need not be performed in synchrony with the mass and energy flow rates to the spray region and pond because the characteristic time for changes in drop mass and temperature is much shorter than the characteristic time for changes in spray region and pond parameters.

9.2.6.4.3.1.4 Drift Loss Model

The determination of water loss from the sprays due to the action of a prevailing wind, commonly referred to as "driftloss," has been incorporated as an integral part of the new Limerick Spray Pond model. Ideally, the driftloss mass flow rate would be calculated in conjunction with the drop dynamics of the ultimate-heat-sink computer program. However, as a practical matter, driftloss calculations are done in a separate module in order that an ultimate-heat-sink analysis requires a reasonable computer runtime. By computing the driftloss separately from the drop dynamics, certain approximations are necessary and are crafted such that the driftloss mass flow rate is conservative.

Mass loss from the spray region takes place when elevation of the drop y_k is equal to the elevation of the spray pond surface and the drop horizontal position, or range, R_k is beyond the pond boundary. To calculate the drift loss, the ballistic trajectory of drops from each drop diameter group is determined using equation and expressed in terms of drop elevation y_k and range x_k as functions of time. However, the drop mass is assumed constant and equal to the final drop mass calculated in the drop dynamics module. A constant-mass approximation is conservative since the drop inertia along its trajectory is less than would normally be the case; hence, the drag forces due to the prevailing wind will increase the drop range. Because driftloss constitutes a small fraction of the total spray-pond mass loss, such an approximation is not severe.

A water drop, assumed to be spherical with a constant diameter D_k, leaves the spray nozzle with an initial velocity u_o at an angle α to the horizontal. The equation of motion for this drop is

$$m_k \frac{d\vec{u}}{dt} = -\frac{1}{2} \rho_i C_d \frac{\pi}{4} D_k^2 \, |\vec{u} - \vec{V}| (\vec{u} - \vec{V}) - m_k \vec{g} \qquad \text{(EQ. 9.2-55))}$$

where **u** is the instantaneous drop velocity vector and **V** is wind velocity vector which is presumed to lie in the horizontal plane, and C_d is the drag coefficient which is a function of the Reynolds number. The last term on the right side of equation [EQ. 9.2-55] is the rate of change of the momentum of the evaporating drop mass and is required for momentum conservation.[28] An approximation of C_d as a function of Reynolds number Re is given above by [EQ. 9.2-43].

Equation 9.2-55 can be resolved along basis directions to yield

(EQ. 9.2-56))

$$m_k \frac{d^2 y_k}{dt^2} = -\frac{\pi}{8} \rho_i C_D D_k^2 |\vec{u} - \vec{V}| \frac{dy_k}{dt} - m_k g$$

$$m_k \frac{d^2 x_k}{dt^2} = -\frac{\pi}{8} \rho_i C_D D_k^2 |\vec{u} - \vec{V}| \left(\frac{dx_k}{dt} - V \right)$$

Numerical solution of equation [EQ. 9.2-56] gives the trajectory of the drop expressed in terms of drop elevation y_k and range x_k which are functions of time. When the elevation of the drop y_k is equal to the elevation of the spray pond surface y_p, the integration ceases. This procedure is repeated for each of the N_k drop groups. The final drop mass of the kth group is $m_{d,k}$, i.e., the mass of the drop when its elevation is equal to that of the spray pond surface as determined in the drop dynamics module.

If, during the driftloss ballistic trajectory calculation, the range of the drop, when it reaches the elevation of the spray-pond surface, is greater than the distance to the spray-pond boundary, the drop is presumed lost. In addition, all drops of this diameter that originate from a location closer to the edge of the spray network than the difference between the drop range and distance from the network to the pond boundary are also lost. If the mass of the lost drop $m^*_{d,k}$ is set is equal to the final drop mass $m_{d,k}$, the driftloss rate is given by

$$w_{dl,i} = \sum_k \xi_k R_k m^*_{d,k} \qquad \text{(EQ. 9.2-57))}$$

where R_k is rate at which drops of the kth drop-diameter group are produced and ξ_k is fraction of all drops sprayed in this group that are lost and given by

$$\xi_k = \frac{x_k|_{y_k=0} - B}{L_{sn}} \qquad \text{(EQ. 9.2-58))}$$

Clearly, the parameter ξ_k is bounded by unity and zero; that is, if it found to be less than zero, there is no drift loss is set equal to zero. The corresponding rate at which energy leaves the spray region is

$$\dot{E}_{dl} = \sum_k \xi_k R_k m^*_{d,k} c_{pw} T_{d,k} \qquad \text{(EQ. 9.2-59))}$$

These driftloss mass and energy flow rates are subtracted from the rate of change of spray-pond mass and energy during the spray-pond thermal performance determination.

9.2.6.4.3.2 Spray Cooling Thermal Performance Model

The computer model developed for the analysis includes the effects of the following parameters:

a. Drop mean diameter

b. Wind speed and direction

c. Air dry-bulb temperature

d. Air wet-bulb temperature or relative humidity

e. Height of nozzles above water level

f. Pressure drop through the nozzle or height attained by the spray

g. Dimensions of the spray volume

h. Water flow rate in spray volume

The spray pond is modeled as shown in Figure 9.2-20 for high wind speeds (above approximately 3 mph), and as shown in Figure 9.2-21 for low wind speeds, when cooling is assumed to be by natural convection only. The individual spray patterns are lumped together to form the spray volume, which is divided into a number of increments in the direction of the air movement. The temperature and vapor content of the air in each increment is assumed to be uniform within the increment, and is numerically the same as that exiting the preceding increment. The sprayed water temperature, air temperature, and air moisture content for each increment are calculated, and the results are combined to yield an average sprayed water temperature for the spray volume. A critical aspect of the calculation is the determination of the evaporation rate within the increment. The empirical work of Ranz and Marshall (Reference 9.2-2) on droplet heat and mass transfer is used as the basis for the evaporation rate and air temperature calculations. In their experiments, Ranz and Marshall suspended a drop from a capillary tube, supplied a known air flow over the drop surface, and measured the drop temperature, air temperature, drop diameter (held constant with water flow through the capillary tube from a microburet), and makeup flow rate from the microburet. In this way the heat transfer and evaporation rate were measured. Heat and mass transfer coefficients were derived by correlation with the data.

The increment mass and energy balance used in the calculation of spray cooling efficiency is shown schematically in Figure 9.2-22. Water enters the increment through the spray nozzles (flow rate (m_{ws}) at temperature (T_s)) and exits the increment after undergoing mass and energy transfer (flow rate (m_{wp}) at temperature (T_{di})). The amount of mass and energy transferred is calculated from heat and mass transfer coefficients derived empirically:

$$N_{nv} = \frac{h_c D}{K} = 2.0 + 0.60\, N_{pr}^{1/3} N_{re}^{1/2} \qquad \text{(EQ. 9.2-60)}$$

$$N_{SH} = \frac{h_d D}{D} = 2.0 + 0.60\, N_{sc}^{1/3} N_{re}^{1/2} \qquad \text{(EQ. 9.2-61)}$$

where:

N_{nv} = Nusselt number

N_{SH} = Sherwood number

h_c = heat transfer coefficient for conduction and convection

h_d = mass transfer coefficient

D = drop diameter

K = thermal conductivity of air/vapor mixture

D_v = diffusivity of vapor in air

N_{pr} = Prandtl number

N_{re} = Reynolds number

N_{sc} = Schmidt number

The energy transfer rate is the sum of the contributions from conduction, convection, and evaporation. The lifetime of a drop in the increment, calculated from the pond geometry and other parameters affecting the drop trajectory, is used with the energy transfer rate to determine the temperature of the cooled water leaving the increment. The moisture content of the air leaving the increment is determined from the mass transfer (evaporation) rate and the air flow rate (residence time of the air in the increment). The temperature of air exiting the increment is calculated from an energy balance on the increment. The exit air temperature and moisture content for increment (i) is used in increment (i + 1) to determine the heat and mass transfer rate in that increment. This process is repeated until all the increments have been treated.

At low wind speeds (less than approximately 3 mph), air enters the spray volume from all sides rather than one; therefore, a new increment definition is used for low wind speeds. The definition is shown schematically in Figure 9.2-21. The air velocity entering each increment is determined from the density difference between the air/vapor mixture in the increment and the ambient.

The spray cooling efficiency for zero wind speed is used as the lower limit for the spray cooling efficiency calculated for nonzero wind speeds (no natural convection). That is, if the spray cooling efficiency calculated by neglecting natural convection is less than that calculated with natural convection only, then the efficiency is taken to be that determined for natural convection (zero wind speed) only. This procedure shows good agreement with the test results, and avoids excessive conservatism.

The result of the calculation described above is a set of cooled water temperatures, one for each increment. Since the air temperature and moisture content for each increment is different, the cooled water temperatures are different. The incremental flow rate weighted average cooled water temperature, $\bar{T}$, is calculated.

$$\bar{T} = \sum_{i=1}^{n} F_i T_i / n \qquad \text{(EQ. 9.2-62)}$$

where:

F_i = spray water flow rate in increment (i)

T_i = cooled water temperature, increment (i)

n = number of increments in the spray volume

The thermal efficiency, E_{th}, is calculated from the ambient air wet-bulb temperature, T_{wb}, and the water temperature before spraying, T_s.

$$E_{th} = \frac{T_s - \bar{T}}{T_s - T_{wb}} \quad \text{(EQ. 9.2-63)}$$

The thermal performance prediction model gives more conservative results than other prediction methods available. The primary conservatism in the model is the lack of convective air motion into the spray volume (for all but very low wind speeds), which results in lower calculated efficiencies. The convective air motion is most

important at low wind speeds; consequently, the degree of conservatism increases as wind speed decreases. Since thermal performance at low wind speeds is most important, this is a desirable effect as long as the degree of conservatism is not unrealistic. Data taken at an existing spray pond have been used to demonstrate the degree of conservatism of the model, as discussed in Section 9.2.6.4.3.4.

9.2.6.4.3.3 Results of the UHS Performance Evaluation

The results of the performance evaluation of the spray pond system demonstrate that the spray pond meets the requirements for the maximum cooling water temperature and the 30-day water supply. The cooling water temperature for the design basis accident heat load is presented in Figure 9.2-23 and Table 9.2-17. The maximum calculated cooling water temperature, for the design (accident) heat load, is 93.48°F. This temperature is below the spray pond thermal performance design limit of 95°F. The minimum remaining water volume in the spray pond after 30 days is approximately 4.74 million gallons for the maximum water-loss analysis.

Furthermore, adequate means are provided in the design of the spray pond system to ensure continued cooling capability beyond 30 days. Water required to maintain the functional capability of the spray pond can be supplied by truck or other means.

9.2.6.4.3.4 Comparison of Spray Pond Thermal Performance Results

In order to verify the conservatism of the spray pond thermal performance model, the model has been applied to a the Rancho Seco spray pond system which has well-documented performance (Reference 9.2-3). At the request of the Atomic Energy Commission, SMUD arranged to have the Rancho Seco spray ponds tested to verify the ability of the ponds to meet the design criteria. SMUD asked the University of California, Berkeley, to perform an evaluation of the performance of the ponds. Of particular interest from a performance standpoint were the thermal efficiency of the nozzles and drift loss versus wind speed.

A comparison of the relevant parameters between the Rancho Seco and LGS ponds is given in Table 9.2-18.

The result of the comparison of the Rancho Seco performance test and model predictions is given in Table 9.2-19. It can be seen that the model predictions for the performance are more conservative than the measured efficiencies.

9.2.6.5 Safety Evaluation

9.2.6.5.1 Thermal Performance

As demonstrated in Section 9.2.6.4, the full spray pond is capable of providing cooling water within the design temperature limit for at least 30 days for the design basis event using conservative meteorology and assumptions.

9.2.6.5.2 Effects of Severe Natural Events or Site-Related Events

The UHS is capable of fulfilling its safety function concurrent with any of the following events: SSE; tornado; flood; drought; transportation accident; or fire.

The UHS is designed as seismic Category I to ensure that it remains functional following an SSE. Pond and pump structure designs are discussed in Section 3.8.4. The effects of the SSE with respect to wave generation and wave loadings on the network support columns are discussed in Section 2.4.8.

Functional integrity is maintained during a tornado because of the redundancy and separation of the networks, and the tornado protection of the spray pond pumphouse, and contingency procedures as discussed in Section 3.5.1.4.

The PMF level for the Schuylkill River is at el 181', whereas the bottom of the spray pond is at el 241', 60 feet above the PMF level. Therefore, the spray pond is affected only by flooding due to precipitation on the pond, and run-off from the adjacent drainage area. This is discussed in Section 2.4.8. The provision of an emergency spillway ensures that the pond cannot reach a level that could impair performance. Further, calculations show that the volume and velocity of water after PMF will not cause erosion.

Drought does not impair the cooling capability of the spray pond system. The spray pond is designed so that makeup water is not required for at least 30 days.

Potential damage to the spray pond from the design transportation accident (railroad explosion) is prevented by the physical separation between the spray pond and the tracks of the railway. The design transportation accident is discussed in Section 2.2.3.

Fire protection for the spray pond pumphouse is discussed in Section 9.5.1.

The spray pond system is physically removed from the balance of the station, except for interconnecting piping. The effect of failure of other station components cannot impair the capability of the spray pond to fulfill its safety objective.

9.2.6.5.3 Freezing Considerations

The only safety-related systems with piping that could be exposed to freezing conditions are the ESW and RHRSW systems. The majority of the piping for these systems is located inside heated buildings or buried below the frost line and therefore are not exposed to freezing conditions. The spray pond network piping is drained after each use and therefore is protected from freezing. Any piping that is not within buildings, buried, or drained is electrically heat traced to protect against freezing. The electrical supply for the heat tracing is not supplied from a Class 1E source because, in the event of auxiliary power loss, water would be flowing in the piping. This design is consistent with IEEE 622 (1979), "Recommended Practice for the Design and Installation of Electric Pipe Heating Systems for Nuclear Power Generating Stations."

The spray pond is permitted to freeze during cold weather; ice formation may occur at the pond surface. The spray pond system is designed to perform its safety function during periods of maximum freezing. The design basis freezing event is one producing a maximum of 15 inches of ice on the pond surface. Maximum ice thickness was determined by calculation of ice thickness for 33 winters from 1941 to 1974, using the daily average Philadelphia meteorology (Section 9.2.6.4.1). Heat and mass transfer analyses established mathematical models of freezing of the pond surface. These models are compared with measured reservoir ice thickness data to verify a conservative design. For each freezing period, a daily incremental thickness was calculated. The maximum thickness calculated for the 33 year period was 13.4 inches in February 1961. A design value of 15 inches has been selected to provide additional conservatism. Measurements taken on quiescent pools near the site during the winter of 1977, considered to be the most severe on record for this area, were all less than the design thickness.

Two spray network bypass lines are provided in the design to allow spray pond operation while ice exists at the pond surface, as discussed in Section 9.2.6.3.2.

An analysis demonstrates that hole formation occurs well before the system design maximum temperature of 95°F is reached at the pump suction. This analysis assumes hydraulic short circuiting between the discharge and suction piping and a simultaneous one-unit LOCA and shutdown of the other unit.

Frazil ice formation does not interfere with operation of the spray pond system. The phenomenon of frazil ice formation is associated with supercooled and generally swiftly flowing water. Since the spray pond is a nonflowing body of water, supercooling of the water cannot occur during either standby or operation of the spray pond system. A small amount of frazil ice formation at the surface of the spray pond is possible during periods of high winds. However, any mixing of the surface water deeper into the pond results in melting of the frazil ice. Once an ice layer forms on the pond, the effects of wind on water velocities and turbulence are eliminated, surface heat transfer will be greatly reduced, and frazil ice does not form.

The formation of anchor ice in the spray pond may occur under high wind conditions, but would be restricted to the uppermost part of the support columns. Ice accumulation on the support columns does not interfere with the operation of the spray pond system. As with frazil ice, formation of an ice layer inhibits anchor ice formation.

An accumulation of ice due to freezing rain sufficient to cause complete blockage of the spray nozzle was considered, but is not considered credible because of the large 1-9/64 inch opening and the shape of each nozzle, which has a raised vertical lip and sloped contour.

The design of concrete columns and footings supporting the pipe network in the spray pond considers the loads due to ice formation and ice expansion. These safety-related components have been adequately designed by combining these loads with other concurrent loads according to Table 3.8-10, including an SSE coincident with maximum ice thickness.

The interior of the spray pond pump structure is heated to a minimum of 65°F to prevent icing of the pumps and other components, or icing at the surface of the water in the wet pits. Ice from the spray pond is prevented from entering the wet pits by locating the tops of the sluice gates below normal pond water level.

9.2.6.5.4 Other Considerations

The ability of the UHS to perform its safety function assuming a single failure of an active component is demonstrated in discussions of the ESW and RHRSW systems, in Sections 9.2.2 and 9.2.3, respectively.

Transient analyses have been performed to determine the potential effects of water hammer on the spray networks. These analyses indicated that water hammer loads will not be significant and are adequately provided for in the design of the spray networks.

There are no credible failures of manmade structural features associated with the UHS. As discussed previously in this section, the spray pond is constructed completely in excavation. Structures associated with the pond (the pumphouse, spray network support piers, and the overflow weir) are designed to seismic Category I requirements. The system is designed so that the effects of flooding, missiles, and fire cannot affect the spray pond's safety function, as discussed in Sections 3.4, 3.5, and 9.5.1, respectively.

9.2.6.6 Conformance to Regulatory Guide 1.27

Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants," contains guidance on the design and performance analysis for ultimate heat sinks.

The LGS spray pond UHS was designed taking Revision 1 of this regulatory guide into consideration. The LGS UHS and performance analysis is in accordance with this revision of the guide, as demonstrated in this section, with the following exceptions and clarifications by regulatory guide position paragraph:

a. Paragraph C.1.a: The LGS performance analysis complies with the intent of this paragraph, in that a more conservative "coefficient of water loss" combining dry-bulb temperature, wet-bulb temperature, and wind speeds is used to determine the weather data periods resulting in the maximum amount of evaporation and drift loss.

b. Paragraph C.1.b: LGS complies partially with this paragraph,in that average temperatures for the 1 day and 30 day periods are used instead of diurnal variations in temperature. The coefficient of thermal performance was calculated for each day, using daily average data (Section 9.2.6.4.1).

Revision 2 of this regulatory guide is presently in effect. With respect to this revision, the following exceptions apply:

a. Paragraph C.1: Same as response to Paragraphs C.1.a and C.1.b of Revision 1 above.

b. Paragraph C.1.a: The critical time periods approach is not used as described in the LGS analysis. The worst 1 day followed by the worst 30 day meteorological conditions were used in accordance with Revision 1 of the regulatory guide. This approach, along with the other conservatisms in the analysis, is adequate to verify pond performance under design conditions.

c. Paragraph C.1.b: Same as Paragraph C.1 and C.1.a above.

d. Paragraph C.1.c: This paragraph is not applicable to the LGS design. The coefficient of thermal performance method used in the LGS design selects conservative design basis meteorology, as discussed in Section 9.2.6.4.1.

With respect to Paragraph C.2 of both revisions of the guide, LGS meets the criteria as discussed in Sections 3.4, 3.5, 9.2.6.5.4, and 9.5.1.

With respect to Paragraph C.3 of both revisions of the guide, LGS employs the option of one source of water for the UHS, for which, as discussed in Section 9.2.6.5.4 and the referenced sections therein, there is an extremely low probability of loss of capability.

9.2.6.7 Instrumentation and Alarms

As shown in drawing M-12, spray pond low level and high temperature are alarmed in the control room. Spray pond surface temperature (within the upper 2 feet of the surface) is provided in the control room. During operation of the RHRSW system, spray pond temperature can also be obtained via the inlet to the RHR heat exchanger in the control room.

Pond makeup and blowdown volumes are indicated by flow totalizers located in the makeup and blowdown lines.

9.2.6.8 Tests and Inspections

The UHS is preoperationally tested in accordance with the requirements of Chapter 14.

A seepage test was performed to verify that the values used in this analysis are conservative (Section 2.5.4.6.1).

Preoperational tests are performed to verify that design flows and pressures to the networks and within the networks are obtained.

Analyses have indicated that water hammer loads will not be significant, and therefore, no special testing for water hammer loads will be performed.

The verification of proper system flow and distribution, and the results of the SSES thermal performance tests (Docket No. 50-387) verify the LGS design, and therefore a thermal performance test for LGS is not considered necessary.

The spray pond system is tested periodically during normal plant operation in accordance with the requirements of Chapter 16.

9.2.7 CONDENSATE AND REFUELING WATER STORAGE FACILITIES

The condensate and refueling water storage facilities provide storage of condensate water for use in normal plant operations and refueling operations. The facilities have no safety-related function, except for the section of piping located in the reactor enclosure that supplies condensate to the HPCI pump.

9.2.7.1 Design Bases

The condensate and refueling water storage facilities are designed to perform the following functions:

a. Supply water to fill the reactor well, the dryer/separator storage pool, and the spent fuel cask storage pit of one unit during refueling operations, and provide storage for this water when refueling is completed.

b. Supply condensate for various processes in the radwaste system and makeup for the plant systems, including the condenser hotwells.

c. Supply condensate to the suctions of the HPCI, RCIC, and core spray pumps of both units.

d. Provide a minimum storage capacity of 135,000 gallons for the RCIC and HPCI pumps associated with each unit.

e. Provide the capability to filter the water in the refueling water storage tank by pumping it through the condensate demineralizers and returning it to the storage tank.

f. Provide storage for condensate rejected from the cycle.

g. Provide storage for condensate from the radwaste system.

h. Provide the capability to drain the reactor well through the condensate filter demineralizer and back to the storage tank.

i. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the condensate and refueling water storage facilities are discussed in Section 3.2.

j. Postulated radioactive releases due to liquid radwaste tank failures are discussed in Section 2.4.12.

9.2.7.2 System Description

The condensate and refueling water storage system is shown in drawing M-08. Design parameters for the major components of the system are given in Table 9.2-20.

9.2.7.2.1 Condensate Storage Tanks (Units 1 and 2)

The CSTs are the normal source of water for the HPCI and RCIC pumps for both operational use and testing. In addition, the tanks supply water to the core spray system for testing. For a discussion of the HPCI and core spray systems, refer to Section 6.3. For a discussion of the RCIC system, refer to Section 5.4.6.

The condensate transfer pumps and condensate transfer jockey pump take their suction from either of these tanks to provide water for various services in the radwaste enclosure, the reactor enclosure, and for the fuel pool filter/demineralizer backwash.

The lead condensate transfer pump, as selected by the hand selector switch, runs continuously and the standby condensate transfer pump will start automatically on low discharge header pressure. The condensate transfer jockey pump will operate only as a manual backup. The condensate transfer pumps and condensate transfer jockey pump are automatically tripped by a level switch upon receipt of a CST low level signal, and a discharge header low flow signal automatically trips the standby condensate transfer pump.

Makeup to the CSTs is supplied by the demineralized water transfer pumps. The tanks also act as surge tanks for the condensate system by receiving any rejected condensate from and making up any deficiency in the heat cycle.

9.2.7.2.2 Refueling Water Storage Tank

The refueling water storage tank stores the water that is used to fill the reactor well, the dryer/separator storage pool, and the fuel cask storage pit of both Units 1 and 2.

During refueling operations the water is pumped from the storage tank to the respective reactor well and dryer/separator pool via the manually operated refueling water pumps.

When refueling is complete, the water in the reactor well and dryer/separator pool is pumped by the refueling water pumps to the storage tank through one of the condensate filter/demineralizers. Makeup for the refueling water storage tank is supplied by the demineralized water transfer pumps, taking suction from the demineralized water storage tank.

The refueling water storage tank also provides water to fill the spent fuel cask storage pit. This water can be returned to the tank by the refueling water pumps through one of the condensate filter/demineralizers.

The Unit 1 and the Unit 2 CSTs and the refueling water storage tank are located outdoors, and are provided with freeze protection. The area occupied by the Unit 1 CST and refueling water storage tank is surrounded by a common dike capable of holding the combined contents of the tanks in the event of tank rupture or overflow. The Unit 2 CST is surrounded by a dike capable of holding the tank contents in the event of tank rupture or overflow. Tank overflows are routed directly to the liquid radwaste system. Drains from the dike areas can be selectively routed to either the normal waste or radwaste systems.

9.2.7.3 Safety Evaluation

The condensate and refueling water storage facilities have no safety-related function except for the section of piping located in the reactor enclosure that supplies condensate to the HPCI, RCIC, and

core spray pumps (Section 6.3). Failure of the nonsafety-related portions of the system does not compromise any safety-related system or component, nor does it prevent a safe shutdown of the plant.

9.2.7.4 Tests and Inspections

The condensate and refueling water storage facilities are preoperationally tested in accordance with Chapter 14.

9.2.7.5 Instrumentation Applications

9.2.7.5.1 Condensate Storage Tanks

These tanks are each provided with a level transmitter that operates a pen recorder located in the control room. In addition to the level transmitters, each tank has high and low level switches that alarm in the control room, and a low switch that trips the condensate transfer pumps and the condensate transfer jockey pump when the tank level reaches low level. The tank has a high level switch which actuates on CST high level to automatically close the condenser reject valves.

9.2.7.5.2 Refueling Water Storage Tank

This tank is provided with a level transmitter that operates pens on Unit 1 and Unit 2 pen recorders located in the control room. In addition, the tank has high and low level switches which alarm in the control room, and a low level switch that trips the refueling water pumps on tank low level.

9.2.8 REACTOR ENCLOSURE COOLING WATER SYSTEM

The RECW system is a closed-loop system that provides cooling water for miscellaneous reactor auxiliary plant equipment. The RECW system is not safety-related, except for the containment penetrations and isolation valves associated with the water supply to the reactor recirculation pump seal and motor oil coolers.

9.2.8.1 Design Bases

a. The RECW system is designed to remove the maximum anticipated heat loads developed by the components served by the system over the full range of the normal plant operating conditions and ambient temperature conditions.

b. The RECW system is designed to operate during normal operation and on LOOP without occurrence of a LOCA.

c. The system is designed to permit the use of corrosion inhibitors to prevent long-term corrosion and organic fouling of the water passages in the system.

d. The RECW system is designed to serve as a barrier between potentially radioactive systems and the plant service water system.

e. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the RECW system are discussed in Section 3.2.

f. A thermal relief valve was installed in Unit 1 and 2 primary containments on non-safety related RECW lines to enhance the design of the RECW systems to limit thermally induced pressurization concerns that were described in Generic Letter 96-06.

9.2.8.2 System Description

The RECW system consists of two 100% capacity cooling water pumps, two 100% heat exchangers, one head tank, one chemical addition tank, associated valves, piping, and controls as shown in drawing M-13. Major equipment design parameters are summarized in Table 9.2-21.

The RECW system provides demineralized cooling water to nonessential equipment located in the reactor and radwaste enclosures which have the potential to carry radioactive fluids, or which require a clean water supply to minimize long-term corrosion.

During normal operation, one RECW pump and one or two heat exchangers is in service. The second pump automatically starts on low pressure in the supply header. During normal plant operation, the RECW system furnishes cooling water to the following components:

a. Cleanup nonregenerative heat exchangers

b. Cleanup recirculation pump seal coolers/motor coolers

c. Reactor recirculation pump seal and motor oil coolers

d. Reactor enclosure equipment drain sump cooler

e. Sample station coolers

f. PCIG compressors and aftercoolers

The demineralized cooling water is circulated throughout the closed-loop by the RECW pumps. The pump motors are connected to Class 1E busses, and on a LOOP without occurrence of a LOCA, both pumps automatically restart. In this mode, the RECW system may be used to furnish cooling water to the reactor enclosure equipment drain sump cooler, and the reactor recirculation pump seal and motor oil coolers. However, the cooling capacity of RECW will be limited by the unavailability of the Service Water System. The rest of the system can be isolated by a valve which is remote manually operated from the control room. Cooling water to the RECW heat exchanger can be provided by the ESW System after a LOOP by manual realignment of the ESW and Service Water systems.

On a LOCA, both RECW pumps are tripped when their respective load centers are shed from the Class 1E bus, and both pumps are inhibited from automatically starting; however, they can be manually started as allowed by diesel generator loading. Coolant for the reactor recirculation pump seal and motor oil coolers can also be supplied by the ESW system if the RECW supply is not available. This switch-over can be accomplished by manual operation of the connecting valves. The connecting valves with motor operators have their power supplies disconnected, as shown in drawing M-13. The primary containment isolation valves associated with the RECW system are discussed in Section 6.2.4.

The RECW system has also the capability to supply cooling water to the fuel pool heat exchangers via a removable spool piece. The RECW system also has the capability during shutdown to supply drywell chilled water to the RWCU non-regenerative heat exchanger(s) and the 1A RWCU pump motor cooler in order to increase the cooling capacity of the RWCU alternate method of reactor decay heat removal. This line-up may only be established when containment isolation valves are not required to be operable or when the affected containment penetration is isolated as dictated by the Technical Specifications and Technical Requirements Manual.

Makeup water is supplied to the RECW head tank from the demineralized water system. The head tank provides necessary makeup water to the RECW system, as required. Chemicals are added to the system through the chemical addition tank for corrosion prevention.

The RECW pumps, heat exchangers, chemical addition tank, and head tank are all located in the reactor enclosure.

9.2.8.3 Safety Evaluation

The RECW system has no safety-related function, and is not required to be operable following a LOCA. Failure of the system does not compromise any safety-related system or component, nor does it prevent a safe shutdown of the plant.

RECW system piping and valves are discussed in Section 3.7, 6.2, and Table 3.2-1..

The reactor recirculation pump seals are cooled following a shutdown of the pump caused by LOOP for economic, and not safety reasons.

9.2.8.4 Tests and Inspections

The RECW system is preoperationally tested in accordance with the requirements of Chapter 14.

9.2.8.5 Instrumentation Applications

Local and remote indicators, alarms, and pressure relief valves are provided to monitor the system process and to protect system components. Low pressure and high temperature in the RECW system supply header are alarmed in the control room. Demineralized water supply to the RECW head tank is controlled by a level switch in the tank. High and low levels in the tank are also alarmed in the control room.

Continuous radiation monitors are installed in the pump suction header of the RECW system. This instrumentation records and alarms radioactivity leakage into the system in the control room.

9.2.9 TURBINE ENCLOSURE COOLING WATER SYSTEM

The TECW system is a closed-loop cooling system that provides cooling water for miscellaneous turbine plant components. The TECW system is not safety-related.

9.2.9.1 Design Bases

a. The TECW system is designed to remove the maximum anticipated heat loads developed by the components served by the system, over the full range of the normal plant operating conditions and ambient temperature conditions.

b. The TECW system is designed to operate during normal plant operation and on LOOP without occurrence of a LOCA.

c. The system is designed to permit use of corrosion inhibitors to prevent long-term corrosion and organic fouling of the water passages in the system.

d. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the TECW system are discussed in Section 3.2.

9.2.9.2 System Description

The TECW system consists of two 100% capacity cooling water pumps, two 100% capacity heat exchangers, one head tank, one chemical addition tank, and associated valves, piping, and controls as shown on drawing M-14. Major equipment design parameters are summarized in Table 9.2-22.

During normal plant operation, one TECW pump and one or two heat exchanger are in service. The second pump starts automatically on low pressure in the supply header. During normal plant operation, the TECW system furnishes demineralized cooling water to the following turbine plant components:

a. Condensate pump motor bearing oil coolers

b. Instrument air compressors and aftercoolers

c. Service air compressor and aftercooler

d. Sample station coolers

Demineralized cooling water is circulated throughout the closed-loop by the TECW pumps. The pump motors are connected to Class 1E busses, and on a LOOP both pumps automatically start. On a LOCA, both pumps trip when their respective load centers are shed from the Class 1E bus. Both pumps are inhibited from restarting; however, the operator can manually reconnect the pumps to the Class 1E bus if diesel loadings permit.

Makeup water is supplied to the TECW head tank from the demineralized water system. The head tank provides necessary makeup water to the TECW system, as required. When required, chemicals are added to the system through the chemical addition tank for corrosion prevention.

Valves on the cooling water supply to the instrument and service air compressor aftercoolers, and water jackets are interlocked with the compressor motors so that cooling water is provided while the compressors are running. Temperature control valves modulate the cooling water flow to maintain a set compressor temperature. The flow rate of cooling water to all other coolers is manually set by individual valves on the cooling water piping for each unit.

The TECW system pumps, heat exchangers, chemical addition tank, and head tank are all located in the turbine enclosure.

9.2.9.3 Safety Evaluation

The TECW system has no safety-related function, and is not required to be operable following a LOCA. Failure of the system does not compromise any safety-related system or components, nor does it prevent a safe shutdown of the plant.

9.2.9.4 Tests and Inspections

The TECW system is preoperationally tested in accordance with the requirements of Chapter 14.

9.2.9.5 Instrumentation Applications

Local and remote indicators, alarms, and pressure relief valves are provided to monitor the system process and protect system components. Low pressure and high temperature in the TECW supply header are alarmed in the control room. The demineralized water supply to the TECW head tank is controlled by a level switch in the tank. High and low levels in the tank are also alarmed in the control room.

9.2.10 CHILLED WATER SYSTEMS

9.2.10.1 Drywell Chilled Water System

The DCWS provides chilled water for cooling the air supply to the following areas:

a. Drywell

b. Reactor enclosure

c. Refueling area

d. Turbine enclosure

e. Radwaste enclosure

In addition, the system provides chilled water to the following equipment:

a. Recirculation pump motor air cooler

b. Drywell equipment drain sump cooling coil

c. Sample coolers

d. Mechanical vacuum pump seal cooler

e. RWCU non-regenerative heat exchangers

f. 1A RWCU pump motor cooler

9.2.10.1.1 Design Bases

a. The DCWS is not safety-related, except for the containment penetrations and the containment isolation valves. These are designed to meet seismic Category I requirements and are discussed in Section 6.2.4.

b. The chilled water piping inside the drywell is designed to ensure that it has no adverse effects on adjacent safety-related equipment in the event of a SSE.

c. During normal operation, the DCWS is designed to provide chilled water at 50°F to components serviced by the system.

d. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the DCWS are discussed in Section 3.2.

9.2.10.1.2 System Description

9.2.10.1.2.1 General Description

The DCWS is shown in drawing M-87. Design parameters for major components of the DCWS are listed in Table 9.2-23. Major components of the system include the following:

a. Two centrifugal water chillers

b. Two chilled water circulating pumps

c. One head tank (expansion tank)

d. One chemical feed tank

The water chiller unit includes a centrifugal compressor, condenser, evaporator, pump-out unit, oil pump, oil heater, all refrigerant piping, instrumentation, and controls. Each chiller unit and circulating pump is sized for 100% capacity.

Cooling water for the chiller condensers is provided by the service water system. Makeup water for the DCWS is provided by the demineralized water system through an automatic makeup water valve.

The chemical addition subsystem provides control against corrosion. Chemical addition to the system is manually initiated.

The head tank is vented to the atmosphere, and is located at the highest elevation in the system.

9.2.10.1.2.2 System Operation

During normal operation, one chilled water circulating pump and one chiller unit operate. However, to provide additional drywell cooling during normal operation, the system may be aligned with 2 chilled water circulating pumps, 2 containment piping systems, and one chiller unit operating. Reactor enclosure supply air cooling coils are not supplied with chilled water under normal conditions. The second chiller and pump can be started in the event of high temperature in the drywell, or reactor enclosure. The standby chiller is manually started if there is a failure of the operating chiller. The standby pump starts automatically or can be started manually if there is a failure of the operating pump.

The closed-loop refrigerant system in the water chiller unit extracts heat from water in the evaporator, and rejects heat to service water in the condenser. A temperature sensor, in the chilled water outlet, positions the inlet guide vanes of the compressor to maintain a constant outlet water temperature.

Inside containment, two independent piping systems connected to two sets of coolers are provided. Changeover from one to the other system is accomplished by switching the containment isolation

valves from the control room. A containment isolation signal closes the containment isolation valves. The valves can be reopened from the control room, if desired, to resume chilled water flow.

The RECW system may provide backup to the portion of DCWS that serves the drywell as allowed by the Primary Containment Isolation Valve Technical Specification LCO/Action requirements. The associated containment isolation valves for this service are administratively controlled as passive locked closed valves as described in UFSAR Section 6.2.4.3.1.3.2.11.

The RECW system also has the capability during shutdown to supply drywell chilled water to the RWCU non-regenerative heat exchanger(s) and the 1A RWCU pump motor cooler in order to increase the cooling capacity of the RWCU alternate method of reactor decay heat removal. This line-up may only be established when containment isolation valves are not required to be operable or when the affected containment penetration is isolated as dictated by the Technical Specifications and Technical Requirements Manual.

Chilled water flow through the cooling coils and unit coolers is controlled by temperature-actuated valves, as shown in drawing M-87.

Chilled water can be supplied to the refueling floor air supply cooling coil, to provide comfortable conditions for plant personnel.

9.2.10.1.3 Safety Evaluation

The DCWS has no safety-related function, except for the containment penetrations and containment isolation valves which are described in Section 6.2.4.

9.2.10.1.4 Tests and Inspections

The DCWS is preoperationally tested in accordance with the requirements of Chapter 14.

9.2.10.1.5 Instrumentation Applications

Chillers and pumps are operated from the control room. Failure of the lead chiller or pump causes an alarm in the control room. Pressures at pump suction, pump discharge, and chiller discharge are displayed locally. Chilled water temperatures and flows are indicated in the control room.

Level in the head tank is indicated locally and alarmed through a computer in the control room at low or high level.

9.2.10.2 Control Structure Chilled Water System

The CSCWS provides chilled water to maintain stipulated ambient air temperature (Section 3.11) in the following areas:

a. Control room

b. Auxiliary equipment room including the computer room

c. Emergency switchgear compartment

d. Battery room

e. SGTS compartment and access area

9.2.10.2.1 Design Bases

a. The CSCWS is designed to remain functional following an SSE.

b. The CSCWS is designed to supply adequate chilled water at 44°F to maintain the stipulated ambient air temperatures.

c. The CSCWS is designed so that a single failure of any active component, assuming LOOP, cannot result in the loss of chilled water supply.

d. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the CSCWS are discussed in Section 3.2.

e. The CSCWS supports operation of the Control Room HVAC System by providing chilled water during normal and design bases accident conditions.

9.2.10.2.2 System Description

9.2.10.2.2.1 General Description

The CSCWS is shown in drawing M-90. The system is common to Units 1 and 2, and consists of two independent, 100% capacity, chilled water systems. Piping interties, with double isolation valves, are provided between the two systems to provide flexibility. Design parameters for major components of the CSCWS are listed in Table 9.2-24. Major components of each system include the following:

a. One centrifugal water chiller

b. One chilled water circulating pump

c. One head tank (expansion tank)

d. One chemical feed tank

The chiller unit includes a centrifugal compressor, condenser, evaporator, pump-out unit, oil pump, oil heater, all refrigerant piping, and controls.

Cooling water for the chiller condensers is provided by the service water system during normal operation. On LOOP, the cooling water supply automatically switches over to the ESW system. Makeup water for the CSCWS is provided by the demineralized water system through an automatic makeup water valve.

The chemical addition subsystem provides control against corrosion. Chemical addition to the system is manually initiated.

The head tank is vented to the atmosphere, and is located at the highest elevation in the system.

9.2.10.2.2.2 System Operation

One of the two CSCWS is designed to be in operation during all modes of plant operation. For normal operation, hand switches for both chillers are placed in the normal after start or normal after stop position. When the lead chilled water pump is started from the control room, the corresponding chiller is normally started after all the safety requirements on the chiller unit are satisfied, and the chilled water flow is established .

The closed-loop refrigerant system in the chiller unit extracts heat from water in the evaporator, and rejects heat to service water in the condenser. A temperature sensor in the chilled water outlet positions the inlet guide vanes of the compressor to maintain a constant outlet water temperature.

The CSCWS is designed to perform its safety function assuming a single active failure. If there is a failure of any of the operating cooling coils or unit coolers except the main control room HVAC supply units, the standby unit starts and causes the standby chiller to start without interrupting the operation of the lead chiller. If the operating cooling coil for the main control room HVAC supply fails, the standby unit is manually started when required. If the lead chiller fails, the standby chiller is automatically activated by the standby fan cabinet when the lead fan cabinet fails to maintain the required temperature. The operating and standby chilled water loops can be interconnected by operating the gate valves in their interconnecting lines. The lead chiller continues to operate whenever the standby chiller is started automatically.

Chilled water flow through cooling coils and unit coolers is controlled by temperature-actuated valves as shown in drawing M-90.

9.2.10.2.3 Safety Evaluation

All safety-related components of the CSCWS are designed to seismic Category I requirements, as defined in Section 3.7. The safety-related components of the CSCWS are located in the seismic Category I designed control structure as discussed in Section 3.8. Power is supplied to these seismic Category I components from the Class 1E power sources as discussed in Section 8.3.

Piping, valve, or equipment failures (including supporting structures) that could result in the generation of a missile, in flooding, or in a pipe whip that could cause damage to safety-related equipment are discussed in Sections 3.5 and 3.6.

Two independent 100% capacity systems provide complete mechanical redundancy. Coupled with the redundancy of electrical design, a failure of any single active component cannot result in a complete loss of both CSCWS, thus assuring a safe shutdown condition. For a FMEA of the CSCWS, refer to Table 9.2-25.

9.2.10.2.4 Tests and Inspections

The CSCWS is preoperationally tested in accordance with the requirements of Chapter 14, and periodically tested in accordance with the requirements of Chapter 16.

9.2.10.2.5 Instrumentation Applications

Chillers and pumps are operated from the control room. Failure of the lead chiller or pump causes an alarm in the control room. Pressures at pump suction, pump discharge, and chiller discharge are

displayed locally. Chilled water temperatures and flows, and motor electrical currents, are indicated in the control room.

Level in the head tank is indicated locally and alarmed through a computer in the control room at low level.

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9.2-30 Letter from Pamela B. Cowan (Exelon Generation Company, LLC) to U.S. Nuclear Regulatory Commission, "License Amendment Request Response to Additional Questions, Proposed Technical Specification Allowed Outage Time Extensions to Support Residual Heat Removal Service Water Maintenance," dated December 3, 2010.

9.2-31 Letter from David P. Helker (Exelon Generation Company, LLC) to U.S. Nuclear Regulatory Commission, "Response to Request for Additional Information, License Amendment Request, Proposed Technical Specification Allowed Outage Time Extensions to Support Residual Heat Removal Service Water Maintenance," dated March 23, 2011.

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Table 9.2-1

SERVICE WATER SYSTEM DESIGN PARAMETERS

SERVICE WATER PUMPS	
Quantity	3 (50% capacity each)
Type	Horizontal, centrifugal
Capacity	18,000 gpm
Head	250 feet
Motor power rating	1500 hp
FUEL POOL SERVICE WATER BOOSTER PUMPS	
Quantity	3 (33-1/3% capacity each)
Type	Horizontal, centrifugal, single-stage
Capacity	1300 gpm
Head	60 feet
Motor power rating	25 hp

Table 9.2-2

EMERGENCY SERVICE WATER SYSTEM DESIGN PARAMETERS

PUMPS	
Quantity	4 (50% capacity each)
Fluid	Spray pond water
Type	Wet pit turbine
Design flow, each	6400(1) gpm
Total dynamic head	240(1) feet
Material	
Casing	Carbon steel
Shaft	Stainless steel
Impeller	Aluminum bronze
MOTORS	
Rated power	500 hp
Voltage/phase/cycle	4000/3/60
Speed	1200 rpm
Service factor	1.0

(1) Design parameters listed in Table 9.2.2 do not constitute performance requirements. ESW pump performance requirements are based on its ability to support the heat transfer rates listed in Table 9.2-3 regardless of discharge head. The pump design flow and total dynamic head values in this table were the basis for selecting the pumps; however, there is no licensing basis requirement for these particular design parameter values. Startup Testing and Surveillance Testing has demonstrated that the ESW System fulfills its required safety functions with the pumps delivering less flow and developing less total dynamic head. The pump design flow/head values in this table provide considerable margin from the system licensing design basis performance requirement to deliver the flow rates in Table 9.2-3.

Table 9.2-3

EMERGENCY SERVICE WATER SYSTEM DESIGN FLOWS
AND HEAT TRANSFER RATES

COMPONENT (Quantity per ESW Loop)	FLOW RATE in GPM [3] Loop 'A'	Loop 'B'	HEAT TRANSFER RATE in 10^6 Btu/hr
Standby Diesel Generator Heat Exchangers (4)	1800	1800	32.232 for four D/Gs
RHR Pump Motor Oil Cooler (4)	20.4	20.4	0.040 per pump
RHR Pump Room Unit Coolers (8 total, 4 each room, 1 room each Unit)	184 [5]	184 [5]	0.548 for A/C room 0.520 for B/D room
Core Spray Pump Room Unit Coolers (8 total, 2 each room, 2 rooms each Unit)	216 [6]	216 [6]	0.226 per room
HPCI Pump Room Unit Coolers (4 total, 2 each room, 1 room each Unit)	N/A	400 [4]	0.726 per room [4]
RCIC Pump Room Unit Coolers (4 total, 2 each room, 1 room each Unit)	160 [4]	N/A	0.303 per room [4]
Main Control Room Chiller (1)	450	450	2.873 per ESW Loop
RECW Heat Exchanger (1)	1166 [1]	1166 [1]	6.41 [1] for one HX
TECW Heat Exchanger (1)	243 [1]	243 [1]	0.3402 [1] for one HX
Reactor Recirculation Pump seal cooler and motor oil cooler (2 sets total, 1 set each Unit/Pump)	260 [1]	260 [1]	0.628 [1] for two pumps
Makeup to fuel pools	60	60	N/A
TOTAL	4399.4	4399.4	

NOTES:

[1] Non-essential service
[2] Footnote 2 deleted
[3] Flow rates required for each heat exchanger and room cooler to remove design heat loads will vary with heat exchanger/room cooler fouling. Acceptance criteria are administratively controlled by plant surveillance procedures.
[4] The minimum required flow for these coolers is zero. However, the coolers are still normally connected to the ESW system. Therefore all the essential components must receive their minimum flow rates with these coolers connected to ESW and receiving some flow. The flow and heat transfer rates shown are those used to calculate the maximum heat that could be removed from the HPCI and RCIC pump rooms to be used when analyzing the Ultimate heat sink. The Ultimate heat sink must be capable of dissipating the heat that will be removed from these rooms without adversely impacting its required function to support other essential components.
[5] RHR room – 23 gpm per cooler; the flow rates for both ESW loops are based on the higher A/C RHR room heat load and assumes two coolers per room in service (one blocked out of service and the other one fails - ESW valves does not open). From an ESW flow balancing standpoint, this scenario is the design basis case. From a Spray Pond performance standpoint, a different scenario is the design basis case. For the Spray Pond design basis case, the total heat load from the accident unit RHR rooms is 1.955 MBtu/hr.
[6] Core Spray room – 27 gpm per cooler

Table 9.2-4

EMERGENCY SERVICE WATER SYSTEM
FAILURE MODES AND EFFECTS ANALYSIS

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Accident	ESW pump	Loss of ESW 'A' pump (typical for 'B', 'C', & 'D' pumps)	ESW loop 'A' flow reduced	Pump discharge low pressure alarm control room	ESW pump 'C' running; adequate cooling flow maintained to ESW loop 'A' diesels and components(1)
Accident	Instrument air supply	Loss of air pressure to air pressure to air operated valves	System air operated valves become inoperable	Alarm in control room	AOVs fail to safe position; cooler inlet valves fail open; isolation valves fail shut; ESW supply valves fail open. System cooling to essential components not impaired.
Accident	Power Supply	LOOP	Normal power supply lost to system pumps and valves	Alarm in control room	Standby diesel generators start automatically, supplying power to all system components. ESW pumps to start automatically.
Accident	Power Supply	Failure of DII Class 1E bus (typical for D12, D23, & D24) for D13 & D14 Unit 1 operation/ Unit 2 construction)	Loss of ESW 'A' pump system valves powered from D11 (Section 8.3)	Alarm in control room	Same as for loss of ESW 'A' pump above.
Accident	Power Supply	Failure of D13 Class 1E bus (typical for D14, D21 & D22)	Loss of power to system valves powered from D13 (Section 8.3)	Alarm in control room	MOVs fail as-is. AOVs fail to safe condition as described for loss of instrument air above. System components not impaired.

Table 9.2-4 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Accident	Controls	Short-circuit in controls causes valve to fail in unsafe condition (pump failure discussed above)	Valve fails in unsafe position	Valve position indication. Coolers & chillers – trouble alarm. Diesel generators – high temperature alarm. ESW return line-differential flow alarm.	Case 1: Cooler inlet valve closure - redundant cooler automatically starts operation when standby fan unit(s) start. No effect on plant operation. When the standby Core Spray, HPCI or RCIC cooler is not in service, an eventual loss of the associated pump will occur. When a standby RHR cooler is not in service, eventual loss of both RHR pumps in the room may occur. No loss of safety function will occur since the ECCS pumps in separate rooms are redundant and HPCI/RCIC are needed for only 6 hours or less. Case 2: Diesel generator inlet/outlet valves closure – loss of diesel generator - see the effects above. Case 3: Loop return valve closure - valve to opposite combined RHRSW/ESW loop remains open, no loss of flow. Case 4: Intertie to nonessential system (service water and TECW) opens – redundant motor-operated or check valve remains shut, no loss of system integrity. Isolation valves on connections to RECW are remote manual (Section 6.2.4). Case 5: Chiller control valve or outlet valve closure-redundant chiller operates or redundant outlet valve remains open. No effect on plant operation.

(1) During the first ten minutes of a postulated LOCA, 3 RHR pumps, and therefore 3 diesels and their associated Class 1E busses may be required for the affected unit (Table 8.3-2). Both ESW pumps in a loop automatically start and would be operating during this time.

Table 9.2-5

RESIDUAL HEAT REMOVAL SERVICE WATER SYSTEM DESIGN PARAMETERS

PUMPS

Quantity	4(1)
Fluid	Spray pond water
Type	Wet pit turbine
Design flow, each	9000(2) gpm
Total dynamic head	240(2) feet
Material	
Casing	Carbon steel
Shaft	Stainless steel
Impeller	Aluminum bronze

MOTORS

Power rating	700 hp
Voltage/phase/cycle	4000/3/60
Speed	1200 rpm
Service factor	1.0

(1) One pump supplies 100% flow to one RHR heat exchanger. During two-unit operation, two heat exchangers (one per unit), and therefore two of the four pumps, are required for safe shutdown and accident mitigation. For two-unit and one ESW/RHRSW loop operation, the RHR heat exchanger of the unit under normal shutdown will receive 67% to 100% RHRSW flow and the unit with the LOCA will receive 100% RHRSW flow.

(2) Design parameters listed in Table 9.2-5 do not constitute performance requirements. RHRSW pump performance requirements are based on the pumps ability to support heat transfer regardless of discharge head. The pump design flow and total dynamic head values in this table were the basis for selecting the pumps; however, there is no licensing basis requirement for these particular design parameter values. Startup Testing and Surveillance Testing has demonstrated that the RHRSW System fulfills its required safety functions with the pumps delivering less flow and developing less total dynamic head. The pump design flow/head values in this table provide considerable margin from the system licensing design basis performance requirement to deliver at least 5570 gpm to an RHR heat exchanger on the unit undergoing emergency shutdown and at least 8000 gpm to an RHR heat exchanger on the unit experiencing an accident (see Section 9.2.3.2).

Table 9.2-6

RHR SERVICE WATER SYSTEM
FAILURE MODES AND EFFECTS ANALYSIS

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Normal/Accident	RHRSW pump	Failure of one RHRSW pump heat exchanger	Loss of cooling water to one RHR in control room	Pump discharge low pressure alarm RHRSW pumps supply sufficient	Unavailability of one RHR heat exchanger. Three remaining cooling to the other RHR heat exchangers of both units for safe shutdown, cooldown, and accident mitigation.
Accident	Power supply	LOOP supply	Loss of normal power to all system components	Alarm in control room	Plant is tripped. Standby diesel generators automatically start to supply power to all system components.
Accident	Power supply	Failure of D11 safeguard bus (typical for D12)	Loss of power to RHRSW 'A' pump and system valves powered from D11 (refer to Section 8.3)	Alarm in control room	Case I: System initially aligned to spray pond mode; loss of cooling to one RHR heat exchanger, remaining RHRSW pumps provide sufficient cooling water to other RHR heat exchangers. Valves remain in original position, failing as-is, thereby having no effect on system operation. Case II: System initially aligned to cooling tower mode; Loss of cooling to one RHR heat exchanger loss of 'A' spray network and loop 'A' winter bypass. Cooling towers isolated by redundant valves when system is automatically aligned to spray pond mode.

Table 9.2-6 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
					Remaining spray networks or winter bypass, and RHRSW pumps provide adequate cooling for shutdown, cooldown, and accident mitigation.
Accident	Power supply	Failure of D23 safeguard bus (typical for D13 during Unit 1 only operation)	Loss of power to system valves powered from D23 (Section 8.3)	Alarm in control room	Case I: System initially aligned to spray pond mode; valves remain in original position, failing as-is thereby having no effect on system operation. Case II: System initially aligned to cooling tower mode; loss of 'C' spray network and loop 'B' winter bypass. Unit 1 cooling tower isolated by redundant valves when system aligned to spray pond mode. Remaining networks and winter bypass provide sufficient cooling.
Accident	Power supply	Failure of D24 safeguard bus (typical for D14 during Unit 1 only operation)	Loss of power to system valves powered from D24 (Section 8.3)	Alarm in control room	Case I: System initially aligned to spray pond mode; valves remain in original position, failing as-is, thereby having no effect on system operation. Case II: System initially aligned to cooling tower mode; loss of 'D' spray network and loop 'B' winter bypass. Unit 2 cooling tower isolated by redundant valves when system aligned to spray pond mode. Remaining networks and winter bypass provide sufficient cooling.

Table 9.2-6 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Accident	Power supply	Loss of D11, D13, D21, and D23 safeguard buses (typical for loss of D12, D14, D22, and D24 safeguard buses)	Loss of RHRSW pumps 'A' and 'C' and system valves powered from D11, D13, D21 and D23 (Section 8.3)	Alarm in control room	Loss of cooling to one RHR heat exchanger in each unit. Valves fail as-is and thereby do not affect system operation. Two RHRSW pumps are sufficient for safe shutdown, cooldown, and accident mitigation.
Accident	Controls	Short-circuit in controls causes valve to fail in unsafe condition (pump failure discussed above)	Valve fails in unsafe condition	Valve position indication, flow temperature, and pressure indication for RHR heat exchanger valves	Case 1: RHR Heat exchanger inlet/outlet valve closure - loss of heat exchanger. Redundant heat exchanger provides sufficient cooling. Case 2: Spray network return valve closure - loss of one spray network. Remaining 3 networks provide sufficient cooling. Case 3: Winter bypass valve closure - loss of one RHRSW loop (until spray operation begins). Remaining RHRSW loop supplies sufficient cooling to both units. ESW system unaffected since it returns to both RHRSW return loops. Case 4: Spray pond sluice gate closure – remaining sluice gate and wet pit intertie provide flow path into wet pit. No effect on operation.

Table 9.2-6 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
					Case 5: Cooling tower supply and return or TECW return valve opens - redundant MOV or check valve prevents loss of flow. No effect on operation.
Normal/Accident	Radiation monitors	Radiation monitor fails low	Loss of radiation detection in RHRSW return loop. RHRSW pumps automatically tripped	High radiation alarm in control room	Monitoring of Loop return flows continues by taking grab samples on a periodic basis in accordance with the off-site dose Calculation manual. Pumps can be returned to service with manual override.
Normal/Accident	Radiation monitors	Radiation monitor fails high	Loss of radiation detection in RHRSW return loop RHRSW pumps automatically tripped.	High radiation alarm in control room	Monitoring of Loop return flows continues by taking grab samples on a periodic basis in accordance with the off-site dose Calculation manual. Pumps can be returned to service with manual override.

Table 9.2-7

CLARIFIED AND DOMESTIC WATER SYSTEMS DESIGN PARAMETERS

RAW WATER CLARIFIER	
Quantity	1
Type	Circular, upflow, solid contact, with internal variable-speed agitator
Capacity	310 gpm
Motor power rating	¾ hp
CLEARWELL	
Quantity	1
Type	Vertical, cylindrical
Capacity	5000 gallons
CLARIFIED WATER SERVICE PUMP CLARIFIED WATER STANDBY PUMP FILTER BACKWASH PUMP	
Quantity, each	1
Type	Horizontal, centrifugal, single-phase
Capacity, each	300 gpm
Head	90 feet
Motor power rating	15 hp
PRESSURE FILTERS	
Quantity	3 (33-1/3% capacity each)
Type	Vertical, pressure, anthracite bed
Capacity	100 gpm
Design pressure	100 psig

Table 9.2-7 (Cont'd)

CLARIFIED WATER STORAGE TANK	
Quantity	1
Type	Vertical, cylindrical
Capacity	200,000 gallons
MAKEUP DEMINERALIZER FEED PUMPS	
Quantity	2 (100% capacity each)
Type	Horizontal, centrifugal, single-stage
Capacity	90 gpm
Head	230 feet
Motor power rating	15 hp
LUBE WATER PUMPS	
Quantity	2 (100% capacity each)
Type	Horizontal, centrifugal, single-stage
Capacity	120 gpm
Head	300 feet
Motor power rating	25 hp

Table 9.2-8

DEMINERALIZED WATER MAKEUP SYSTEM DESIGN PARAMETERS

CARBON FILTER

Quantity	1
Type	Vertical, pressurized, activated carbon bed
Flow rate	120 gpm
Design pressure	125 psig

DEMINERALIZED WATER STORAGE TANK

Quantity	1
Type	Vertical, cylindrical
Capacity	50,000 gallons

DEMINERALIZED WATER TRANSFER PUMPS

Quantity	2 (100% capacity each)
Type	Horizontal, centrifugal, double suction, single stage
Capacity	150 gpm
Head	350 feet
Motor power rating	40 hp

DEMINERALIZED WATER TRANSFER JOCKEY PUMP

Quantity	1
Type	Horizontal, centrifugal, single stage
Capacity	60 gpm
Head	350 feet
Motor power rating	20 hp

Table 9.2-9

SPRAY POND DESIGN DATA

SPRAY NOZZLES	
Number	240 per spray network (4 networks)
Type	Hollow-cone spray pattern (Spray Engineering Co. ramp bottom model 1751A)
Capacity, each	51.0 - 64.6 gpm
SPRAY POND	
Dimensions at pond bottom	
Length	1000 feet
Width	400 feet
Depth	9'10" (at TECH SPEC minimum water level of 250'10" MSL)
Surface area	9.9 acres
Storage volume	29.06×10^6 gallons
Lining	Soil-Bentonite mixture
Network flow rate	12,250 - 15,500 gpm

Table 9.2-10

PERCENT FREQUENCY DISTRIBUTION OF
DAILY AVERAGE RELATIVE HUMIDITY AND WIND SPEED

	LGS 2½ YEARS	PHILADELPHIA 2½ YEARS	PHILADELPHIA 34 YEARS
Relative Humidity (%)			
90-100	12.3	7.9	6.3
80-89	17.7	17.3	15.7
70-79	29.4	22.9	24.7
60-69	20.1	23.7	26.2
50-59	14.7	17.5	18.5
<50	5.8	10.7	8.6
Wind Speed (mph)			
0-2	10.8	0.0	0.2
3-4	31.1	0.2	3.4
5-6	25.3	10.1	16.0
7-8	14.5	25.7	25.3
9-10	8.7	24.6	21.3
11-15	7.5	31.2	26.6
16-20	1.8	7.4	6.0
>20	0.4	0.9	1.1

Table 9.2-11

SPRAY POND SYSTEM DESIGN METEOROLOGY

	WORST 30 DAYS FOR WATER LOSS	WORST DAY FOR HEAT TRANSFER	WORST 30 DAYS FOR HEAT TRANSFER
Average dry-bulb temperature, °F	67.5	85.6	78.1
Average wet-bulb temperature, °F	59.2	78.6	73.4
Average natural wind speed, mph	10.43	0.0	0.0
Period	05/30/58 to 06/28/58	6/30/45	8/12/59 to 09/10/59

Table 9.2-12

COEFFICIENT OF THERMAL PERFORMANCE
COMPARISON OF LGS AND PHILADELPHIA WORST CASE
METEOROLOGICAL CONDITIONS (JANUARY 1, 1972 - DECEMBER 31, 1976)

	WORST 30 DAYS FOR WATER LOSS		WORST DAY FOR HEAT TRANSFER		WORST 30 DAYS FOR HEAT TRANSFER	
	LGS	PHILADELPHIA	LGS	PHILADELPHIA	LGS	PHILADELPHIA
Average dry-bulb temperature (°F)	72.0	75.1	80.7	84.2	75.3	78.1
Average wet-bulb temperature (°F)	64.8	65.8	74.6	78.3	70.4	70.9
Average natural wind speed at 30 ft elevation (mph)	5.6	9.7	2.3	5.7	4.1	7.1
Period	07/22/72 to 08/20/72	06/24 to 07/23/74	07/19/72	07/19/72	07/07 to 08/05/75	07/07 to 08/05/75
Coefficient	0.0135	0.0147	-12.22	-11.92	-14.28	-15.62

Table 9.2-13

SUMMARY OF SPRAY POND WATER ALLOWANCES

Allowances	VOLUME (millions of gallons) Final Design
Water Losses (max heat transfer case)	
Evaporation, plant heat load	13.58
Evaporation, natural	1.82
Drift loss	.14
Seepage	1.83
Total Water Loss	17.37
Nonwater Loss	
Sedimentation	2.75
Excess for minimum operating level (el. 243'-6")	4.20
Total Nonwater Loss	6.95
Total Required	24.33
Reserve for Water Loss	4.74
Total Water Pond Capacity	29.07

Table 9.2-14

DATA USED IN PERFORMANCE ANALYSES

A. INITIAL CONDITIONS (10 minutes after LOCA)

	LOCA UNIT	SHUTDOWN UNIT
Reactor Vessel		
Temperature, °F	250	550
Water mass, lb_m	550,000	700,000
RPV heat capacity, metal, Btu/°F	3.53×10^5	3.53×10^5
Water on Drywell Floor		
Temperature, °F	180	-
Water mass, lb_m	500,000	-
Suppression Pool		
Temperature, °F	150	104.6
Water mass, lb_m	7.01×10^6	7.36×10^6
Spray Pond		
Temperature, °F	88	

B. PHYSICAL PARAMETERS

Mass median drop size	3000 microns	
Included spray angle	76 degrees	
Pressure drop through nozzle	7 psi @ 51 gpm	
Height of spray above nozzle	7 ft @ 51 gpm	
	Min. heat transfer	Max. water loss
Flow/nozzle	35.4 gpm	64.6 gpm
Nozzle height above pond	6.0 ft	7.17 ft

Table 9.2-14 (Cont'd)

C. FLOW RATES (gpm)[3]

TIME	PARAMETER	LOCA UNIT	SHUTDOWN UNIT	COMMON
10-30 min	Containment spray	0	(1)	(1)
	Core spray	7,430	(1)	(1)
	Relief valves & RCIC	(1)	(2)	(1)
	RHR HX (shell side)	10,000	0	(1)
	RHR HX (tube side)	9,000	0	(1)
	ESW	(1)	(1)	13,000
30-180 min	Core spray	7,430	(1)	(1)
	RHR HX (shell side) LPCI mode	10,000	(1)	(1)
	RHR HX (tube side)	9,000	18,000	(1)
	ESW	(1)	(1)	13,000
3-30 hr	Core spray	7,430	(1)	(1)
	RHR HX (shell side)	10,000	(2)	(1)
	RHR HX (tube side)	9,000	18,000	(1)
	ESW	(1)	(1)	13,000
30-720 hr	Core spray	7,430	(1)	(1)
	RHR HX (shell side)	10,000	10,000	(1)
	RHR HX (tube side)	9,000	9,000	(1)
	ESW	(1)	(1)	13,000

(1) Not applicable

(2) Flow rate adjusted to limit cooldown rate to 100°F/hr

(3) These flow rates are used to compute heat loads to the spray pond. The spray pond performance analysis is based on bounding flow rates of 17,000 gpm (Min. Heat Transfer) and 53,000 gpm (max. Water Loss Case).

Table 9.2-15

HEAT REJECTION TO THE SPRAY POND (ONE-UNIT LOCA, ONE-UNIT SSD)

Time after Shutdown (min.)	Decay and ECCS Pump Heat Two Units (BTU/ hr)	Sensible Heat Two Units (BTU/ hr)	Auxiliary Loads Two Units (BTU/ hr)	ESW and RHRSW Pump Heat Two Units (BTU/hr)	Total Heat Load Two Units (BTU/ hr)
0	0.0000E+00	0.0000E+00	2.5200E+07	1.2400E+06	2.6440E+07
10	1.2942E+08	0.0000E+00	2.5200E+07	4.0400E+06	1.5866E+08
11	1.3223E+08	0.0000E+00	3.1590E+07	4.0400E+06	1.6786E+08
12	1.3499E+08	0.0000E+00	3.1590E+07	4.0400E+06	1.7062E+08
13	1.3768E+08	0.0000E+00	3.1590E+07	4.0400E+06	1.7331E+08
15	1.4291E+08	0.0000E+00	3.1590E+07	4.0400E+06	1.7854E+08
20	1.5474E+08	0.0000E+00	3.1590E+07	4.0400E+06	1.9037E+08
25	1.6504E+08	0.0000E+00	3.1590E+07	4.0400E+06	2.0067E+08
30	1.7449E+08	0.0000E+00	3.1590E+07	4.0400E+06	2.1012E+08
30.1	1.7467E+08	0.0000E+00	3.1590E+07	4.0400E+06	2.1030E+08
31	1.7627E+08	0.0000E+00	3.1590E+07	4.0400E+06	2.1190E+08
35	1.8315E+08	0.0000E+00	3.1590E+07	4.0400E+06	2.1878E+08
40	1.9118E+08	0.0000E+00	3.1590E+07	4.0400E+06	2.2681E+08
45	1.9861E+08	0.0000E+00	3.1590E+07	4.0400E+06	2.3424E+08
50	2.0550E+08	0.0000E+00	3.1590E+07	4.0400E+06	2.4113E+08
55	2.1191E+08	0.0000E+00	3.1590E+07	4.0400E+06	2.4754E+08
60	2.1790E+08	0.0000E+00	3.1590E+07	4.0400E+06	2.5352E+08
70	2.2885E+08	0.0000E+00	3.1590E+07	4.0400E+06	2.6448E+08
80	2.3849E+08	0.0000E+00	3.1590E+07	4.0400E+06	2.7412E+08
90	2.5122E+08	0.0000E+00	3.1590E+07	4.0400E+06	2.8685E+08
100	2.5877E+08	0.0000E+00	3.1590E+07	4.0400E+06	2.9440E+08
110	2.6551E+08	0.0000E+00	3.1590E+07	4.0400E+06	3.0114E+08
120	2.7156E+08	0.0000E+00	3.1590E+07	4.0400E+06	3.0719E+08
130	2.7700E+08	0.0000E+00	3.1590E+07	4.0400E+06	3.1263E+08
170	2.8992E+08	7.0600E+07	3.1550E+07	4.0400E+06	3.9811E+08
200	2.7891E+08	7.0600E+07	3.1550E+07	4.0400E+06	3.8510E+08
240	2.6663E+08	7.0600E+07	3.1550E+07	4.0400E+06	3.7282E+08
260	2.6115E+08	1.3064E+07	3.1550E+07	4.0400E+06	3.0981E+08
300	2.5119E+08	2.8281E+06	3.1550E+07	4.0400E+06	2.8960E+08
320	2.4661E+08	2.5063E+06	3.1550E+07	4.0400E+06	2.8471E+08
340	2.4228E+08	2.3500E+06	3.1550E+07	4.0400E+06	2.8022E+08
360	2.3817E+08	4.4279E+05	3.1550E+07	4.0400E+06	2.7420E+08
600	2.0201E+08	1.2552E+06	3.1550E+07	4.0400E+06	2.3886E+08
870	1.7936E+08	6.9974E+05	3.1550E+07	4.0400E+06	2.1564E+08
1080	1.6844E+08	4.8166E+05	3.1550E+07	4.0400E+06	2.0451E+08
1350	1.5878E+08	3.5075E+05	3.1550E+07	4.0400E+06	1.9472E+08
1440	1.5621E+08	3.0158E+05	3.1550E+07	4.0400E+06	1.9210E+08
1800	1.4779E+08	2.2610E+05	3.1550E+07	4.0400E+06	1.8361E+08
2280	1.3909E+08	1.8002E+05	3.1550E+07	4.0400E+06	1.7486E+08
3000	1.2859E+08	7.2244E+04	3.1550E+07	4.0400E+06	1.6425E+08
3720	1.1997E+08	7.2244E+04	3.1550E+07	4.0400E+06	1.5564E+08
4500	1.1222E+08	7.2244E+04	3.1550E+07	4.0400E+06	1.4788E+08
5220	1.0624E+08	7.2244E+04	3.1550E+07	4.0400E+06	1.4190E+08

Table 9.2-15 (cont.)

HEAT REJECTION TO THE SPRAY POND (ONE-UNIT LOCA, ONE-UNIT SSD)

Time after Shutdown (min.)	Decay and ECCS Pump Heat Two Units (BTU/ hr)	Sensible Heat Two Units (BTU/ hr)	Auxiliary Loads Two Units (BTU/ hr)	ESW and RHRSW Pump Heat Two Units (BTU/hr)	Total Heat Load Two Units (BTU/ hr)
5940	1.0116E+08	7.2244E+04	3.1550E+07	4.0400E+06	1.3682E+08
6660	9.6823E+07	7.2244E+04	3.1550E+07	4.0400E+06	1.3249E+08
7200	9.3980E+07	7.2244E+04	3.1550E+07	4.0400E+06	1.2964E+08
7920	9.0645E+07	7.2244E+04	3.1550E+07	4.0400E+06	1.2631E+08
8640	8.7745E+07	7.2244E+04	3.1550E+07	4.0400E+06	1.2341E+08
9360	8.5208E+07	7.2244E+04	3.1550E+07	4.0400E+06	1.2087E+08
10100	8.2908E+07	7.2244E+04	3.1550E+07	4.0400E+06	1.1857E+08
16600	7.0322E+07	7.2244E+04	3.1550E+07	4.0400E+06	1.0598E+08
19400	6.6966E+07	7.2244E+04	3.1550E+07	4.0400E+06	1.0263E+08
22300	6.4067E+07	7.2244E+04	3.1550E+07	4.0400E+06	9.9729E+07
23800	6.2728E+07	7.2244E+04	3.1550E+07	4.0400E+06	9.8390E+07
26600	6.0450E+07	7.2244E+04	3.1550E+07	4.0400E+06	9.6113E+07
29500	5.8334E+07	7.2244E+04	3.1550E+07	4.0400E+06	9.3996E+07
32400	5.8415E+07	7.2244E+04	3.1550E+07	4.0400E+06	9.2077E+07
41000	5.1624E+07	7.2244E+04	3.1550E+07	4.0400E+06	8.7287E+07
41800	5.1235E+07	7.2244E+04	3.1550E+07	4.0400E+06	8.6898E+07
42500	5.0902E+07	7.2244E+04	3.1550E+07	4.0400E+06	8.6564E+07
43200	5.0575E+07	7.2244E+04	3.1550E+07	4.0400E+06	8.6237E+07

Table 9.2-16

INTEGRATED HEAT REJECTION TO THE SPRAY POND

Time after Shutdown (min.)	Total Integrated Decay Heat Load (BTU)	Total Integrated Pond Heat Load (BTU)
0	0.0000E+00	
10	1.0785E+07	1.5425E+07
11	1.2965E+07	1.8148E+07
12	1.5192E+07	2.0966E+07
13	1.7464E+07	2.3832E+07
15	2.2141E+07	2.9696E+07
20	3.4543E+07	4.5068E+07
25	4.7866E+07	6.1361E+07
30	6.2013E+07	7.8477E+07
30.1	6.2304E+07	7.8827E+07
31	6.4936E+07	8.1994E+07
35	7.6917E+07	9.6349E+07
40	9.2514E+07	1.1492E+08
45	1.0875E+08	1.3413E+08
50	1.2559E+08	1.5393E+08
55	1.4298E+08	1.7429E+08
60	1.6089E+08	1.9517E+08
70	1.9812E+08	2.3834E+08
80	2.3707E+08	2.8322E+08
90	2.7787E+08	3.2997E+08
100	3.2037E+08	3.7841E+08
110	3.6406E+08	4.2803E+08
120	4.0882E+08	4.7873E+08
130	4.5453E+08	5.3038E+08
170	6.4351E+08	7.6863E+08
200	7.8571E+08	9.6193E+08
240	9.6756E+08	1.2146E+09
260	1.0555E+09	1.3283E+09
300	1.2263E+09	1.5281E+09
320	1.3093E+09	1.6239E+09
340	1.3908E+09	1.7180E+09
360	1.4708E+09	1.8104E+09
600	2.3512E+09	2.8365E+09
870	3.2093E+09	3.8592E+09
1080	3.8179E+09	4.5944E+09
1350	4.5541E+09	5.4927E+09
1440	4.7904E+09	5.7828E+09
1800	5.7024E+09	6.9100E+09
2280	6.8499E+09	8.3438E+09
3000	8.4560E+09	1.0378E+10
3720	9.9474E+09	1.2298E+10
4500	1.1457E+10	1.4271E+10
5220	1.2767E+10	1.6009E+10
5940	1.4012E+10	1.7682E+10

Table 9.2-16 (cont.)

INTEGRATED HEAT REJECTION TO THE SPRAY POND

Time after Shutdown (min.)	Total Integrated Decay Heat Load (BTU)	Total Integrated Pond Heat Load (BTU)
6660	1.5200E+10	1.9298E+10
7200	1.6058E+10	2.0477E+10
7920	1.7166E+10	2.2013E+10
8640	1.8236E+10	2.3511E+10
9360	1.9274E+10	2.4977E+10
10100	2.0311E+10	2.6453E+10
16600	2.8611E+10	3.8617E+10
19400	3.1814E+10	4.3484E+10
22300	3.4981E+10	4.8375E+10
23800	3.6566E+10	5.0851E+10
26600	3.9440E+10	5.5389E+10
29500	4.2310E+10	5.9984E+10
32400	4.5084E+10	6.4481E+10
41000	5.2826E+10	7.7335E+10
41800	5.3512E+10	7.8496E+10
42500	5.4108E+10	7.9508E+10
43200	5.4700E+10	8.0516E+10

Table 9.2-17

SPRAY POND TEMPERATURE TRANSIENT (ONE-UNIT LOCA, ONE-UNIT SSD)

TIME AFTER LOCA (min)	SPRAY POND TEMPERATURE (°F)	TIME AFTER LOCA (min)	SPRAY POND TEMPERATURE (°F)
0	88	7200	89.68
10	88	7920	89.52
10.1	88	8640	88.9
11	88	9360	88.82
12	88	10100	87.43
13	88.01	16600	87.38
15	88.02	19400	86.94
20	88.03	22300	86.7
25	88.04	23800	86.56
30	88.04	26600	86.16
30.1	88.04	29500	85.92
31	88.06	32400	85.71
35	88.07	41000	85.38
40	88.09	41800	84.61
45	88.11	42500	84.72
50	88.13	43200	84.08
55	88.15		
60	88.10		
70	88.23		
80	88.28		
90	88.34		
100	88.39		
110	88.45		
120	88.5		
130	88.74		
170	88.98		
200	89.29		
240	89.44		
260	89.66		
300	89.75		
320	89.85		
340	89.94		
360	90.92		
600	91.79		
870	92.32		
1080	92.85		
1350	92.92		
1440	93.09		
1800	93.14		
2280	93.48		
3000	92.92		
3720	93.03		
4500	91.96		
5220	91.53		
5940	90.59		
6660	90.35		

Table 9.2-18

SIZE COMPARISON OF RANCHO SECO AND LGS
SPRAY PONDS

	LGS	RANCHO SECO
Water flow rate (gpm) 49,000 (max)	16,500	
Nozzles	960 @ 51.0 gpm	304 @ 53.6 gpm
Water pressure at nozzle (psig)	7	7
Pond length at bottom (ft)	1000	330
Width at bottom (ft)	400	165
Depth (ft)	10	5
Volume (gal)	29.6×10^6	5.7×10^6
Area (acres)	9.9	1.3

Table 9.2-19

PERFORMANCE COMPARISON OF RANCHO SECO
TEST RESULTS AND MODEL RESULTS

Ambient Conditions				% Efficiency	
T_{wb} (°F)	T_{db} (°F)	Wind Speed (mph)	Spray Temperature	Rancho Seco	Model
60.98	81.50	13.0	79.88	41.7	35.72
61.52	80.96	12.5	80.06	47.5	34.89
55.04	51.08	5.3	77.36	32.5	31.84
48.56	51.98	1.0	77.36	28.8	31.00
64.94	56.48	6.0	77.54	30.9	31.6
71.06	57.56	6.5	78.62	35.5	22.10
72.32	95.00	7.0	80.06	38.9	31.91
69.62	93.02	6.6	81.14	34.3	28.85
66.56	85.64	8.4	80.78	45.8	30.02
60.98	72.32	3.8	80.24	34.5	32.96
60.26	69.26	3.8	79.7	28.5	34.61
54.20	57.92	1.0	101.4	35.2	39.16
53.06	57.02	1.6	100.0	36.2	38.23
51.98	55.94	1.3	97.88	34.4	37.24
48.92	53.06	1.0	101.66	34.5	36.70
48.02	51.08	0.4	97.34	34.6	35.62

Table 9.2-20

CONDENSATE AND REFUELING WATER STORAGE FACILITIES
DESIGN PARAMETERS

CONDENSATE STORAGE TANK	
Quantity	1
Type	Vertical, cylindrical, dome roof, with heating coil
Capacity	200,000 gallons
REFUELING WATER STORAGE TANK	
Quantity	1
Type	Vertical, cylindrical, dome roof, with heating coil
Capacity	550,000 gallons
CONDENSATE TRANSFER PUMPS	
Quantity	2 (100% capacity each)
Type	Horizontal, centrifugal, single-stage
Capacity, each	600 gpm
Head	250 feet
Motor power rating	60 hp
CONDENSATE TRANSFER JOCKEY PUMP	
Quantity	1
Type	Horizontal, centrifugal, two-stage
Capacity	70 gpm
Head	250 feet
Motor power rating	15 hp
REFUELING WATER PUMPS	
Quantity	2 (100% capacity each)
Type	Horizontal, centrifugal, single-stage
Capacity, each	1500 gpm
Head	180 feet
Motor power rating	100 hp

Table 9.2-21

REACTOR ENCLOSURE COOLING WATER SYSTEM DESIGN PARAMETERS

RECW PUMPS	
Quantity	2 (100% capacity each)
Type	Horizontal, centrifugal, single-stage
Capacity	1500 gpm
Head	170 feet
Motor power rating	100 hp
RECW HEAT EXCHANGERS	
Quantity	2 (100% capacity each)
Type	Horizontal, 2 pass, 1 shell
Duty	27×10^6 Btu/hr
Shell design	
Fluid	Demineralized water
Flow rate	700,000 lb/hr
Design pressure	175 psig
Design temperature	200°F
Tube design	
Fluid	Service water
Flow rate	1,500,000 lb/hr
Design pressure	150 psig
Design temperature	200°F
RECW HEAD TANK	
Quantity	1
Type	Vertical, cylindrical
Capacity	790 gallons
REACTOR ENCLOSURE CHEMICAL ADDITION TANK	
Quantity	1
Type	Vertical, cylindrical
Capacity	5 gallons

Table 9.2-22

TURBINE ENCLOSURE COOLING WATER SYSTEM DESIGN PARAMETERS

TECW PUMPS	
Quantity	2 (100% capacity each)
Type	Horizontal, centrifugal, single-stage
Capacity	225 gpm
Head	140 feet
Design temperature	100°F
Motor power rating	15 hp
TECW HEAT EXCHANGERS	
Quantity	2 (100% capacity each)
Type	Horizontal, 2 pass, 1 shell
Duty	2.5×10^6 Btu/hr
Shell design	
Fluid	Demineralized water
Flow rate	110,000 lb/hr
Design pressure	100 psig
Design temperature	200°F
Tube design	
Fluid	Service water
Flow rate	250,000 lb/hr
Design pressure	150 psig
Design temperature	200°F
TECW HEAD TANK	
Quantity	1
Type	Vertical, cylindrical
Capacity	210 gallons
TURBINE ENCLOSURE CHEMICAL ADDITION TANK	
Quantity	1
Type	Vertical, cylindrical
Capacity	5 gallons

Table 9.2-22 (Cont'd)

CONDENSATE PUMP MOTOR UPPER BEARING COOLERS	
Quantity	3 (100% capacity each)
Type	Coil
Duty	76,350 Btu/hr
Tube design	
Fluid	Demineralized water
Flow rate	6000 lb/hr
Design pressure	100 psig
Design temperature	100°F
CONDENSATE PUMP MOTOR LOWER BEARING COOLERS	
Quantity	3 (100% capacity each)
Type	Coil
Duty	12,725 Btu/hr
Tube design	
Fluid	Demineralized water
Flow rate	6000 lb/hr
Design pressure	100 psig
Design temperature	100°F

Table 9.2-23

DRYWELL CHILLED WATER SYSTEM DESIGN PARAMETERS

WATER CHILLERS	
Type	Centrifugal
Capacity	1500 tons
Power rating	1303 kW
Entering chilled water temperature	65°F
Leaving chilled water temperature	50°F
CHILLED WATER CIRCULATING PUMPS	
Type	Centrifugal, horizontal, split case
Flow rate	2400 gpm
Head	110 feet
Motor power rating	100 hp
HEAD TANK	
Type	Vertical, cylindrical
Volume	300 gallons
Pressure	Atmospheric
CHEMICAL FEED TANK	
Type	Vertical, cylindrical
Volume	5 gallons

Table 9.2-24

CONTROL STRUCTURE CHILLED WATER SYSTEM DESIGN PARAMETERS

WATER CHILLERS [1]	
Type	Centrifugal
Capacity	192 tons
Power rating	289 kW
Entering chilled water temperature	50.5°F
Leaving chilled water temperature	44.0°F
CHILLED WATER CIRCULATING PUMPS	
Type	Centrifugal, vertical, in-line
Flow rate	705 gpm
Head	80 feet
Motor power rating	25 hp
HEAD TANK	
Type	Vertical, cylindrical
Volume	34 gallons
Pressure	Atmospheric
CHEMICAL FEED TANK	
Type	Vertical, cylindrical
Volume	5 gallons

(1) Values specified resulted from changes made to the condenser flow rate documented by ECR 12-00110. Originally, supplied water chiller was rated for 250 tons, 329 kW power rating and an entering chilled water temperature of 52.5°F.

Table 9.2-25

CONTROL STRUCTURE CHILLED WATER SYSTEM
FAILURE MODES AND EFFECTS ANALYSIS

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
1. Normal	Normal power supply	Total LOOP	All system components are automatically supplied with power from diesel generators.	Alarm in the control room	No loss of safety function
2. Accident	Class 1E power supply	Loss of Class 1E power supply to one loop	None. The two redundant systems are powered from separate Class 1E busses. Cooling water to the chiller condensers is supplied from redundant ESW loops.	Alarm in the control room	No loss of safety function
3. Accident (LOCA or LOCA & LOOP)	Water chillers	Chiller failure	The standby chilled water system is automatically started from the control room. (Note 1)	Alarm in the control room	No loss of safety function
4. Accident (LOCA or LOCA & LOOP)	Chilled water circulating pump	Pump failure	The standby chilled water pump is automatically started from the control room.	Alarm in the control room	No loss of safety function
5. Normal or accident	System pressure boundary	Failure of pressure boundary in one loop	Loss of one chilled water loop. Standby chiller and pump are started manually from the control room. A completely redundant piping system is provided for the standby system.	Alarm in control room due to low level in head tank	No loss of safety function

Note 1 - The control structure chiller has several design feature protective trips to prevent chiller damage. If such a chiller trip occurs, the trip must be reset at the local panel before the chiller can be restarted from the control room. The local chiller control panel is located on elevation 200’ in the control structure which is readily accessible from the main control room during accident conditions.

9.3 PROCESS AUXILIARIES

9.3.1 COMPRESSED AIR AND GAS SYSTEMS

The compressed air and gas systems consist of the instrument air system, service air system, condensate filter/demineralizer backwash air system, Perkiomen Creek air system, Schuylkill River air system, and the primary containment instrument gas system. These systems supply plant equipment requiring compressed air and gas, as well as service air outlets located throughout the plant. The systems are shown on drawings M-09, M-15 and M-59 and are not safety-related except for:

a. Those seismic Category I portions of the primary containment instrument gas system provided for long-term ADS valve operation

b. The containment penetrations of the PCIG system (Section 9.3.1.3)

c. The containment penetration of the service air piping (Section 9.3.1.1)

d. The local seismic Category I gas reservoirs provided for valves with safety-related functions (Sections 5.4.5.2 and 5.2.2.4)

e. The local Unit 1 & 2 seismic Category I air reservoirs provided for the refueling floor inflatable seals (1, 2, 3, 4, 7 and 10) with safety-related functions. (See Section 9.3.1.1)

9.3.1.1 Station Air Systems

The station air systems include the instrument air system, service air system, and the condensate filter/demineralizer backwash air system and are shown in drawing M-15.

9.3.1.1.1 Design Bases

a. The instrument air system is designed to provide a continuous supply of filtered, dry, and oil-free air for pneumatic instruments and controls in the plant.

b. Each instrument air compressor unit is powered from a separate electrical bus.

c. Standby onsite power is available to the instrument air compressors, following a LOOP, to replenish compressed air storage as required.

d. The service air system is designed to provide compressed air to service air outlets located throughout the plant, to the refueling floor inflatable seals, and as a backup system for instrument air.

e. The condensate filter/demineralizer backwash air system is designed to provide oil-free air to the condensate filter/demineralizers during the backwashing operation.

f. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the compressed air systems are discussed in Section 3.2.

9.3.1.1.2 System Description

The instrument, service, and condensate filter/demineralizer backwash air systems are shown schematically on drawing M-15. Units 1 and 2 air systems are identical, except that the Unit 2 air distribution sequence may differ from Unit 1. Sequence of branches is not essential to the system's operation.

The instrument air system includes two identical trains, each consisting of an air intake filter/silencer, a compressor unit, an aftercooler with a built-in moisture separator, an air receiver, two parallel prefilters, a dryer, and two parallel after-filters. Each train has its own header that branches off into the instrument air subsystems. The headers can be interconnected through a common connecting line.

During normal unit operation, the two instrument air compressors maintain their respective headers at normal operating pressures. Each compressor will automatically load or unload in response to the instrument air system demand as sensed by pressure changes in its respective air receiver. The consequences of a failure of one instrument air train is mitigated by the redundant nature of the instrument air system design. Each instrument air user or their common headers are connected to both instrument air trains and hence would be supplied by the operative instrument air train. In addition, as mentioned in Section 9.3.1.1.1.d, the service air system provides a backup to the instrument air system. The instrument air system uses nonoil lubricated air compressors (cylinders).

The Unit 1 instrument air system supplies air to common areas, except the auxiliary boiler enclosure and the administration building, which are served from the Unit 2 instrument air system. The Unit 1 instrument air system also supplies air to both Units 1 and 2 cooling towers and the chlorination/acid enclosures. The Unit 2 instrument air system also serves as a backup to the entire Unit 1 system and vice-versa. The interconnecting valves are manually operated and normally closed.

The instrument air system provides the purge medium for the primary containment gas desiccant dryers, and also serves as a backup to the primary containment instrument gas system (Section 9.3.1.3). When low pressure is sensed in the instrument gas receiver tank, the station instrument air system can be manually placed into service as a backup. Filters capable of providing filtration of particulate greater than 3.0 microns will be provided at the interconnection of the PCIG system with the instrument air system. The instrument air system is provided with desiccant dryers that dry the gas to a -40°F dew point at line pressure psig and filters that remove 100% of all particles larger than 0.9 micron in diameter. The inservice filter will be switched to the parallel filters when high differential pressure exists across the inservice filter and the spent element will be replaced. The need for desiccant replacement is indicated when the local visual moisture indicating gel turns from blue to pink. In addition, excessive dryer outlet moisture is indicated locally and alarmed in the main control room as part of the dryer trouble alarm. The quality of air in the system will be periodically monitored to ensure that it is maintained within the requirements of the most current ANSI/ISA standard, per SOER 88-01 recommendations.

The dual drying towers of the instrument air dryer package alternately remove moisture from the air stream and expel the moisture to the atmosphere on an automatic cycle. Only one prefilter/afterfilter is normally in service. When the filters become dirty, as indicated on the control panel by differential pressure and alarmed in the control room as part of the dryer trouble alarm, the air flow is manually switched to the clean prefilter/afterfilter.

The instrument air system meets the requirements of ANSI MC11.1 (1976) with the exception that allowable particulate size has been determined based on equipment supplier recommendations

and engineering analysis. Most safety-related instrument air or gas users have been verified to be provided with an appropriately sized local, in-line filter connected to the user with copper or stainless steel tubing. Particulate limits for safety-related components not provided with individual filters have been investigated. After consultation with the equipment suppliers and review of applicable operating experience, it has been determined that a limit of no visible particulate (i.e., particles greater than 50 microns) will ensure long term reliable operation of the outboard MSIV and the CRD HCU. Documentation confirming this assessment has been obtained from the equipment suppliers.

Pneumatically operated valves and dampers which have a safety-related function are listed in Table 9.3-4. The valves are designed to fail in the safe position upon loss of air pressure, or are provided with local seismic Category I air reservoirs.

The instrument air system is switched automatically to the standby ac power supply during a LOOP. The compressors are tripped off the standby ac power source upon receiving a LOCA signal. One or more compressors may be restarted manually following a LOCA when diesel loadings allow.

The service air compressor serves as a backup to the instrument air compressors. A low instrument air system pressure signal automatically closes a valve in the service air system discharge header and diverts the capacity of the service air compressor to the instrument air system.

The service air system includes one 100% capacity air compressing train consisting of an air intake filter/silencer, a compressor unit, an aftercooler with a built-in moisture separator, and an air receiver for each unit plus a common backup train.

During normal plant operation the service air compressor is either running continuously or on automatic standby. On automatic standby the compressor automatically starts and stops on pressure signals. The Unit 2 service air system serves as a backup to the entire Unit 1 system and vice-versa. The interconnecting valve is manually operated and normally closed.

The Unit 1 service air system supplies air to common areas, i.e., the radwaste enclosure, water treatment enclosure, etc. Breathing air is normally supplied by the service air system. A single backup air compressor, aftercooler, moisture separator, and receiver tank (comparable to the service air compressors) can supply either Unit 1 or Unit 2 in the case of loss of service air.

The service air system also supplies air to all inflatable seals at the refueling floor of the reactor enclosures. Gas bottles of nitrogen are provided as a backup supply source for additional reliability. A gas bottle supply is automatically connected to each inflatable seal supply header when low pressure is detected in the normal service air supply line. In addition to the nitrogen bottle backup supply, a quick disconnect fitting is provided for connection to an additional gas bottle, if required. The Unit 1 & 2 inflatable seals (1, 2, 3, 4, 7 and 10) which form a secondary containment boundary are provided with a Seismic Category I backup supply source.

The condensate Filter/demineralizer Backwash Air Supply System includes two 35 cfm air compressors in each Unit that discharge to a pair of 125 cubic foot air receivers in Unit 1 and a single 250 cubic foot air receiver in Unit 2 which discharges to their respective air headers to supply backwash air to the Condensate Filter/Demineralizer vessels. These compressors can be operated manually or automatically by a signal from the Condensate Filter/Demineralizer System. One compressor functions as the controlling compressor and the other functions as the backup compressor and they alternate functions. The air receiver is sized to provide 5130 scfm of air flow at 125 psig to backwash the condensate filter/demineralizers and is controlled by the auto-start and auto-off capabilities of the two compressors.

All of the above air system equipment is located in the turbine enclosure.

9.3.1.1.3 Safety Evaluation

The instrument, service, and condensate filter/demineralizer backwash air systems have no safety-related function other than containment isolation and secondary containment boundary. Failure of the systems will not compromise any safety-related system or component or prevent a safe shutdown of the plant. Service air lines that penetrate containment have two manual normally closed valves for containment isolation. Refer to Section 6.2.4 for details of containment isolation design features. The service, air containment penetration and isolation valves are designed to seismic Category I and ASME Section III, Class 2 requirements as defined in Sections 3.7, and 6.2.

Piping and components to the Unit 1 & 2 seals 1, 2, 3, 4, 7 and 10 are designed to Seismic Category I, ANSI B31.1, Quality Group D for secondary containment boundary as defined in Table 3.2-1. These local safety-related air reservoirs are provided with a low pressure alarm, relief protection and a check valve for automatic isolation in the event of loss of service air.

The outboard MSIV is discussed in Section 5.4.5.2.

9.3.1.1.4 Tests and Inspections

The safety-related portions of the compressed air systems are preoperationally tested in accordance with Regulatory Guide 1.68.3, as stated in Section 14.2. Compliance to Regulatory Guide 1.68.3, position C.11. is demonstrated by the following program:

a. Verification that the specific type or model of safety-related solenoid valves and pneumatic valve actuators (Table 9.3-4) have been tested by the equipment suppliers for the maximum supply system pressure resulting from credible system failures.

b. For safety-related equipment that has not been tested by the equipment supplier, the equipment will be tested onsite at the maximum supply system pressure resulting from credible system failures to ensure that there will be no loss of operability.

c. Safety-related equipment that has been tested by the equipment supplier, but 1) are rated below the maximum credible supply system pressure and/or 2) fails the test in (b) above will be replaced by equipment with a higher service pressure rating or will be provided with appropriate overpressure protection devices.

System operability is demonstrated by use during normal plant operation. In addition, a measured value of less than 40 microns will be verified to exist at several points throughout the instrument air system downstream of the dryers.

Other periodic tests, verifications and maintenance were discussed in Section 9.3.1.1.2.

9.3.1.1.5 Instrumentation Application

Instrumentation is provided for each instrument air and service air compressor train to monitor and automatically control each compressor's operation.

The compressors are tripped on the following signals: low crankcase oil pressure, high crankcase oil temperature, high cooling water discharge temperature, high air pressure in the receiver, and high outlet air temperature. These signals and excessive water levels in the instrument air aftercooler inlet drip leg are annunciated in the control room by common trouble alarms. High air temperature in the aftercooler and moisture separators, and low pressure in the air header are also alarmed in the control room. Instrumentation is also provided for each instrument air dryer package train to monitor and automatically control each dryer's operation. High moisture content in the common instrument air dryer package discharge header is indicated locally and alarmed in the control room as part of the dryer trouble alarm. Also, indicated locally and alarmed in the control room as part of the dryer trouble alarm, are high pressure differential across the filters and dryer controller trouble.

Local pressure indication is provided on each inflatable seal pneumatic supply header. Low pneumatic supply pressure is alarmed locally for each inflatable seal and is also alarmed in the control room as a trouble alarm.

9.3.1.2 Perkiomen and Schuylkill Compressed Air Systems

9.3.1.2.1 Design Bases

a. The Perkiomen Creek intake structure compressed air system provides a continuous supply of filtered air for pneumatic instruments and controls, and for service air use inside the Perkiomen Creek intake structure.

b. The Schuylkill River intake structure compressed air system provides a continuous supply of filtered air to pneumatic instruments and controls, and for service air use inside the Schuylkill River intake structure.

c. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the Perkiomen and Schuylkill compressed air systems are discussed in Section 3.2.

9.3.1.2.2 System Description

The Perkiomen and Schuylkill compressed air systems are shown schematically in drawing M-09. Major equipment design parameters are given in Table 9.3-2. The Perkiomen and Schuylkill intake structures and their related compressed air systems are common to both Units 1 and 2.

The Schuylkill compressed air system includes two identical air compressors with identical receivers, a common filter, an instrument air dryer package, instrumentation, controls, interconnecting piping, and electrical wiring. The air compressors are connected in parallel and discharge to a common header. Instrument air is supplied to the traveling water screen control panel. Service air is supplied to the grease lube pumps and chain lubricator. The compressors are operated automatically to maintain a pre-established compressor tank pressure.

The Perkiomen compressed air system includes two sets of compressors. One set contains identical control valve air compressors connected in parallel to a common header which discharges to a common air receiver tank. The tank provides air to operate the Perkiomen pump control valves. The other set includes two identical pumphouse air compressors with an air receiver, air accumulator, instrumentation, controls, interconnecting pipe, and electrical wiring. The air compressor supplies air to a receiver which is used to backwash the Perkiomen stationary intake screens. In addition, the pumphouse air compressors supply air through a small air filter to an air accumulator tank to operate

the Perkiomen rotary strainer and the lube water booster pump control valves, and to service air connections.

9.3.1.2.3 Safety Evaluation

The Perkiomen Creek and Schuylkill River intake structure compressed air systems have no safety-related function. Failure of the systems will not compromise any safety-related system or component or prevent a safe shutdown of the plant.

9.3.1.2.4 Tests and Inspections

System operability is demonstrated by use during normal plant operation.

9.3.1.2.5 Instrumentation Application

Instrumentation is provided for each compressor to monitor and automatically control its operation. Low pressure in the air compressor discharge header and low pressure in the control valve air receiver are monitored and alarmed locally.

9.3.1.3 Primary Containment Instrument Gas System

9.3.1.3.1 Design Bases

a. The PCIG system is designed to provide instrument gas to the pneumatic devices located inside the drywell and suppression chamber.

b. The PCIG system is designed to provide a supply of instrument gas for long-term ADS valve operation.

c. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the PCIG system are discussed in Section 3.2.

9.3.1.3.2 System Description

The PCIG system is shown schematically on drawing M-59. Major equipment design parameters are given in Table 9.3-3. The instrument gas compressors take suction directly from the drywell atmosphere. The system, therefore, prevents a build-up of pressure in the primary containment due to pneumatic operator leakage.

The system provided for each unit consists of two full capacity trains of gas filters, compressors, aftercoolers, moisture separators, dryers, receivers, and associated piping, valves, controls, and instrumentation. Each train has its own distribution header within the primary containment.

The PCIG system meets the requirements of ANSI MC11.1 (1976) with the exception that allowable particulate size has been determined based on equipment supplier recommendations and engineering analysis. Most safety-related instrument air or gas users have been verified to be provided with an appropriately sized local, in-line filter connected to the user with copper or stainless steel tubing. Particulate limits for safety-related components not provided with individual filters (Unit 1 inboard MSIV and Unit 1 ADS SRV) have been investigated. After consultation with the equipment suppliers and review of applicable operating experiences, it has been determined that a limit of no visible particulate (i.e., particles greater than 50 microns) will ensure long-term reliable operation of

each component. Documentation confirming this assessment has been obtained from the equipment suppliers.

During normal operation, one of the two instrument gas compressors is selected as the lead compressor and is automatically started or stopped in response to the instrument gas system demand. The other instrument gas compressor serves as a standby. The standby compressor starts automatically if the lead compressor fails, or if the continuous operation of the lead compressor cannot meet the instrument gas system demand. The two trains can be cross-connected via common headers. A backup to the PCIG system is provided by an intertie to the instrument air system via a normally closed valve remote manually operated from the control room. The primary containment instrument gas system uses non-lubricated cylinder type air compressors.

The cooling water supply to the compressors and aftercoolers is regulated by temperature control valves on the cooling water outlets from the compressor cylinder jackets. Valves which are operated by gas pressure in the compressor manifold allow cooling water to flow during compressor operation and shut off cooling water when the compressor stops.

The refrigeration and desiccant dryers employed in this system lower the dew point to -40°F at 100 psig. The need for desiccant replacement is indicated when the local visual moisture indicating gel turns from blue to pink. The quality of air for safety-related PCIG users will be periodically verified to meet the dew point and oil content quality specified in ANSI MC11.1 (1976). A random sample of an inboard MSIV air supply header and an ADS SRV operator manifold will be tested once each refueling cycle. The filters provided at the outlet of the PCIG desiccant dryers are designed to remove particles 3 microns and larger. These filter elements will be inspected and replaced at least on an annual basis. The PCIG system will be periodically monitored to ensure that it is maintained within the particulate limits discussed in Section 9.3.1.3.4, per SOER 88-01 recommendations.

Pneumatically operated valves which have a safety-related function are listed in Table 9.3-4. The valves are designed to fail in the safe position upon loss of gas pressure or are provided with local seismic Category I gas reservoirs.

The PCIG system provides a safety-related gas supply for the ADS valves in the event that the non-safety related normal PCIG supply equipment is unavailable. Two seismic Category 1 gas supplies (nitrogen bottles) have been provided to assure the availability of the ADS valves for long-term ECCS cooling functions and for the alternate shutdown cooling flow path for the RHR system. One set of gas bottles serves three ADS valves; another set serves the other two ADS valves. These long-term gas supplies have been designed to remain operable following a LOOP. Either set of bottles will supply the ADS valves with sufficient nitrogen for seven days of operation and must be connected at all times during normal operation(ready for automatic alignment). Limiting Conditions for Operation and Surveillance Requirements for the long-term ADS gas supplies are specified in the Technical Requirements Manual.

The gas bottle supply will automatically begin supplying the seismic Category 1 ADS valve supply header with nitrogen when low pressure is sensed in the normal PCIG supply line. Thus, although not a design objective, this gas bottle supply will act as a backup for the short-term ECCS cooling operation of the ADS valves if leakage from the ADS valve accumulator boundary is excessive. The ADS valve accumulators are described in Section 5.2.2.4. ADS valve ECCS functions are described in Sections 5.2.2 and 6.3.

A seismic Category 1 external connection is also provided outside the reactor enclosure for post-seven day operation of two ADS valves for the alternate shutdown cooling flow path described in Section 5.4.7.5.

Redundant automatic valves are provided to isolate the seismic Category 1 portion of the PCIG system from the non-seismic Category 1 portions. Redundant manual valves are provided to isolate the seismic Category 1 portions of external connections from non-seismic Category 1 components when connection is not in use.

These two gas supplies are physically separated such that no single failure can prevent the required long-term operation of the ADS valves. Loss of power to the automatic valves that align the bottle supply to the ADS valve supply headers will cause the bottles to be aligned (fail safe positions).

Instruments and controls associated with the safety-related ADS valve gas supplies are discussed in Section 7.6. Other PCIG instruments and controls are discussed in Section 7.7.

9.3.1.3.3 Safety Evaluation

The PCIG system serves a safety-related function by provision of a gas supply for long-term operation of the ADS valves in the event the normal PCIG supply is not available. All components of the long-term ADS gas supply for the minimum required two ADS SRVs are seismic Category I except for the gas bottles. These gas bottles meet DOT standards, 49CFR178.37, Specification 3AA, and Interstate Commerce Commission Specifications, and are supported with seismic Category I supports.

Long-term ADS valve operation is used when the alternate shutdown cooling flow path is used, as discussed in Section 5.4.7.5, and when long-term reactor vessel venting using the ADS valves is desired. The long-term ADS gas supply for the minimum required two SRV's takes no credit for nonsafety-related equipment or instrumentation. This system is capable of performing its function during and following exposure to hostile environments as discussed in Section 3.11. Because leakage from the ADS valve accumulators and associated gas supply piping inside the drywell is anticipated to be very small as compared to the Post LOCA Hydrogen Recombiner flowrate, the gas supplied via the external connection can be either nitrogen or dry air.

Safety-related components, such as inboard MSIVs and ADS MSRVs, are provided with gas accumulators (Sections 5.4.5.2 and 5.2.2.4) for reliable short-term operation without PCIG system operation. The accumulators, however, are not part of the PCIG system.

Instrument gas lines that penetrate containment have isolation valves that automatically close on receipt of an isolation signal except for the seismic Category I gas supply. The seismic Category I gas supply containment penetration does not close on an isolation signal. The ADS gas supply will be isolated only when the gas supply pressure outside containment decreases to 2 psi above containment pressure. Refer to Section 6.2.4 for details of containment isolation design features. The system containment penetrations and isolation valves are designed to seismic Category I and ASME Section III, Class 2 requirements as defined in Sections 3.7 and 6.2. The system piping located inside the containment is designed to seismic Category I requirements as defined in Section 3.7, and to the Power Piping Code, ANSI B31.1 or ASME Section III, Class 3, and other standards as shown in Table 3.2-1, in the case of the long-term gas bottle supply subsystem.

Design features are also provided in the PCIG system that eliminate a potential source for radiological release during purging of the primary containment gas desiccant dryers as discussed in

Section 9.3.1.1.2, and to minimize primary containment bypass leakage via the PCIG system, as discussed in Section 6.2.3.

9.3.1.3.4 Tests and Inspections

The safety-related portion of the PCIG system is tested in accordance with Regulatory Guide 1.68.3, as stated in Section 14.2. Compliance to Regulatory Guide 1.68.3, position C.11. is demonstrated by the following program:

a. Verification that the specific type or model of safety-related solenoid valves and pneumatic valve actuators (Table 9.3-4) have been tested by the equipment suppliers for the maximum supply system pressure resulting from credible system failures.

b. For safety-related equipment that has not been tested by the equipment supplier, the equipment will be tested onsite at the maximum supply system pressure resulting from credible system failures to ensure that there will be no loss of operability.

c. Safety-related equipment that has been tested by the equipment supplier, but 1) are rated below the maximum credible supply system pressure and/or 2) fails the test in (b) above will be replaced by equipment with a higher service pressure rating or will be provided with appropriate overpressure protection devices.

System operability is demonstrated by use during normal plant operation. Containment isolation valves will be tested in accordance with the requirements of Technical Specifications. In addition, although visible particulate is greater than 50 microns, a measured value of less than 40 microns will be verified to exist in the PCIG system downstream of the dryers.

Other periodic tests, verifications, and maintenance were discussed in Section 9.3.1.3.2.

The alarms and isolation initiation instrumentation associated with the ADS long-term gas supply system will be calibrated at least once per operating cycle. Leak testing of the ADS long-term gas supply system is performed by use of a surveillance test as part of the primary containment leak rate testing program. Leakage from the bottles will be monitored daily by checking bottle pressures.

9.3.1.3.5 Instrumentation Applications

Instrumentation is provided for each compressor train to monitor and automatically control each compressor's operation. Switches monitoring the following parameters trip their respective compressor: low lube oil level, high discharge gas temperature, high receiver pressure, low suction pressure, and high suction temperature. The compressors are also tripped on compressor motor overload and loss of control power. Refrigerated dryer motor overload trips the dryer. Any compressor or refrigerated dryer trip actuates a common trouble alarm in the control room.

The condition of low instrument gas system receiver tank pressure is alarmed in the control room. The alarm is unspecific with respect to individual ADS accumulators.

The instrumentation associated with the ADS gas supply is as follows:

a. Pressure instrumentation is provided to automatically align the ADS long-term gas bottle supply to the ADS valve supply header.

b. Pressure instrumentation is installed in each of the two ADS gas supply piping branches outside containment to provide pressure indication in the control room. High or low pressure in the ADS long-term gas bottle supply header is alarmed in the control room.

c. Pressure instrumentation is provided to close the ADS gas supply containment isolation valves when system pressure decreases to 2 psi above primary containment pressure.

d. Position indication for the containment isolation valves and solenoid valves on the ADS gas supply is provided in the control room.

e. Local pressure indication is provided on each ADS long-term gas bottle supply header.

9.3.2 PROCESS SAMPLING SYSTEM

The process sampling system provides remote sampling facilities and the capability for sampling liquids of various process systems during normal plant power operation and shutdown conditions. The process sampling system is not safety-related.

Radiation monitoring of gaseous and liquid process streams is discussed separately in Section 11.5.

9.3.2.1 Design Bases

a. The portion of the process sampling system running from the RCPB to and including the first isolation valve outside the containment is constructed in accordance with ASME Section III, Class 1. Every other sample line, from the point where it connects to the process system including the first process shutoff valve (root valve), is the same classification as the system piping to which it connects. All sample lines downstream of the first isolation valve outside the containment or downstream of the root valves are in accordance with ANSI B31.1.

b. Lines connected to reactor water or main steam systems are of sufficient length to permit decay of short-lived nuclides so that sampling station personnel are not unnecessarily exposed to radiation. Additionally, shielding is installed at points on sampling piping to further curtail exposures (as described in Chapter 12) and ensure that they are kept below the limits of 10CFR20.

c. The process sampling systems are designed to ensure that representative samples of all appropriate process fluids are obtained.

d. The process sampling system is designed to permit effective line purging with a minimum loss of fluid volume.

e. The process sampling system is designed to provide the capability to conduct continuous analysis as well as to provide the facility for analysis of discrete samples (grab samples) in the laboratory.

f. The process sampling system is designed to prevent hazards to operating personnel from high pressure, temperature, or radiation levels of the process fluid during all modes of operation.

g. The process sampling systems for each unit are designed to be functionally similar, but operationally independent.

h. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the process sampling system are discussed in Section 3.2.

9.3.2.2 System Description

The process sampling system is illustrated schematically on drawing M-23. Locations of sample points are shown on the appropriate system P&IDs for the systems to be sampled. The process sampling system consists of sampling lines, valving, sample coolers, sample sinks, instrumentation, and analyzers.

Sampling stations are located in the water treatment area, yard area near the cooling towers and in the reactor, turbine, auxiliary boiler, and radwaste enclosures. The liquid radwaste collection sample station and the auxiliary boiler sample station are common for Units 1 and 2. The reactor and turbine enclosure sample stations are operationally independent systems with the following exception: the condensate transfer pumps discharge sample and the refueling water pumps discharge sample are located on the Unit 1 turbine station.

The reactor and turbine enclosure stations are equipped with analyzers that continuously monitor the critical parameters in the samples drawn from process lines. Portable instruments are used for periodic calibration of the analyzers. Grab samples may be taken periodically from each point at each station to determine chlorides or other constituents. When working with grab samples, the operator is protected by a fume hood that exhausts through the ventilation duct-work. The reactor, turbine and radwaste enclosure sampling stations are provided with demineralized water for washdown.

Sample flow rates to the monitors are adjusted to provide the following:

a. Ensure turbulence in the sample line to prevent plateout of radioactive materials

b. Minimize lag time to monitors

c. Slow the sample flow rate as required for the decay of radioactive nitrogen prior to entering the stations

d. Minimize the waste of high purity water and input to the radwaste system

Representative samples are drawn from process lines by sample nozzles extending into the pipe. Sample lines are as short as possible, consistent with the length required for radioactive decay, avoiding traps, dead legs, and dips upstream of the sample stations. The connecting tubing is sized for optimal flow rates to the stations.

At each station, samples are adjusted for pressure and temperature as required by the monitoring instruments and for the operators' safety. The individual sample coolers provide samples for

measurement at the reference temperature of 25°C. Deep bed condensate demineralizer system (DBCDS) turbine enclosure sample waste is returned to the hotwell make-up reject line. All other turbine enclosure sample waste is returned to the condensate drain tank except for the condensate pumps discharge sample sink which grains into the dirty radwaste drains. All other sample wastes are returned to the radwaste collection system except for the auxiliary boiler sample waste, cooling tower sample waste, and the high pressure condenser circulating water sample waste, which are returned to the normal waste system.

Tubing arrangement within the sample stations for selected sample lines susceptible to contamination allows purging into the sample sink or sink drain header by connecting the demineralized water hose to the grab sample outlet while shutting off the sample inlet valve. Tube fitting leakages are contained by a catch basin or sink.

9.3.2.3 Safety Evaluation

The process sampling system has no safety-related function. Failure of the system will not compromise any safety-related system or component, or prevent a safe shutdown of the plant. The process sampling lines, connected to the RCPB through the first isolation valve outside containment, are designed to seismic Category I requirements as defined in Section 3.7. Process sampling lines connected to other seismic Category I components are seismic Category I from the component through the first normally shut valve.

Sample lines that penetrate the containment are provided with isolation valves in accordance with GDC 55, as described in Section 6.2.4.

9.3.2.4 Testing and Inspection

The system will be preoperationally tested in accordance with the requirements of Chapter 14. System operability is demonstrated by use during normal plant operation.

9.3.2.5 Instrumentation Applications

Temperature and flow indicators are used to facilitate manual operation and to verify sample conditions before samples are drawn.

The DBCDS analytical variables are entered into the DBCDS PLC computers located in the radwaste control room. All other analytical variables are recorded at the sample stations or in the control room. The main variables pertaining to the quality of the reactor coolant are entered into the station computer. All monitored variables have alarm trips that signal when preset limits have been exceeded. DBCDS common trouble alarm is transmitted to the radwaste control room. DBCDS effluent high conductivity alarm and other common trouble alarms are transmitted to the control room.

9.3.3 PLANT DRAINAGE SYSTEMS

The plant drainage systems consist of the equipment and floor drainage radwaste systems, the normal waste system, the oily waste system, the acid waste system, the storm drainage system, and the sanitary waste system.

The equipment and floor drainage radwaste system, shown in drawing M-61, is the only drainage system which transfers potentially radioactive liquid wastes, and is described in detail in this section. The remaining drainage systems are also briefly described in this section. The plant drainage

systems have no safety-related function except for the containment penetrations and the drywell boundary extension of the drywell drainage system.

9.3.3.1 Design Bases

a. The equipment and floor drainage radwaste systems serve the following major structures and enclosures: primary containment, reactor enclosure, turbine enclosure, and radwaste enclosure. Plant general arrangement is shown in drawings C-2, M-110, M-111, M-112, M-113, M-114, M-115, M-116, M-117, M-118, M-119, M-120, M-121, M-122, M-123, M-124, M-125, M-126, M-127, M-128, M-129, M-130, M-131, M-132, M-133, M-134, M-135, M-136, M-137, M-138, M-140, M-141, M-142, M-143, M-144, M-145, M-146, M-388, M-389, and M-390. Nonradioactive drainage systems are provided for the collection and disposal of storm drainage, sanitary waste, oily waste, acid wastes, and normal waste.

b. The plant drainage system is designed to collect waste liquids from their points of origin and transfer them to a suitable processing or disposal area.

c. The plant drainage system is designed to handle the maximum anticipated influent without overflowing.

d. The plant drainage systems are designed and arranged to preclude inadvertent transfer of radioactive or potentially radioactive fluids to nonradioactive systems.

e. The drywell floor and equipment drain sumps, and the associated containment penetrations and instrumentation are designed to seismic Category I and quality group B requirements.

f. Vent lines from sumps containing potentially radioactive wastes are connected to filtered ventilation systems.

g. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the plant drainage systems are discussed in Section 3.2.

9.3.3.2 System Description

9.3.3.2.1 General Description

The plant drainage systems that provide for collection of various liquid wastes are listed below:

a. Equipment and floor drainage radwaste systems:

1. The liquid radwaste, collection subsystem collects potentially radioactive, liquid wastes from equipment and floor drainage of the primary containments, the reactor, turbine, and radwaste enclosures, and the control structure. All such drainage is conveyed by gravity to sumps within the respective enclosures and pumped from there to the collection tanks, except for the drywell sumps which are gravity drained to the respective collection tanks.

2. The chemical waste collection subsystem collects corrosive, potentially radioactive liquid wastes from the washdown areas, floor and equipment

drain filters, condensate and fuel pool filter/ demineralizers, laboratory drains, radwaste enclosure decontamination shower, and other miscellaneous sources in the turbine and radwaste enclosures. Nonradioactive, high conductivity wastes from the condensate demineralizer cell cooling coil drains and the RECW system drains from Units 1 and 2 are also collected by this system. Liquid wastes from the hot maintenance shop are collected in the shop sump and pumped to the chemical waste subsystem.

3. The laundry waste collection subsystem collects rain water from within the yard dikes for CST tanks (Units 1 & 2) and Refueling Water Storage Tank.

4. Treatment of the above wastes is discussed in Section 11.2.

b. Nonradioactive liquid wastes:

1. Oily waste drainage systems collect liquid wastes from the nonradioactive equipment areas in which oil is expected to be present. These areas include, turbine enclosures, the circulating water pump structure, diesel generator enclosures, transformer areas, lube and diesel oil storage tank areas, oil unloading areas, and the auxiliary boiler enclosure.

2. Acid waste drainage systems collect liquid wastes possibly containing nonradioactive chemicals and corrosive substances from the water treatment enclosure.

3. Storm drainage systems collect water resulting from precipitation on enclosure roofs and areaways, and paved and unpaved surface areas outside the enclosures.

4. The normal waste system collects liquid wastes from the nonradioactive equipment and floor drains, and is routed to the holding pond. Two parallel 750 gpm gravity differential Oil-Water Separator Systems (Solids Stormwater Interceptors and Oil-Water Separators), located immediately upstream of the holding pond, treat all flows entering the holding pond except for floor drainage from the holding pond treatment enclosure, Reactor/Refuel HVAC rooms U1 and U2, and diverted power block roof and yard storm drains which are routed directly to the holding pond. If necessary, further treatment at the holding pond includes oil separation. Holding pond effluent and cooling tower blowdown water flow is routed to the discharge diffuser in the Schuylkill River.

5. The sanitary drainage system collects liquid wastes and entrained solids discharged by all plumbing fixtures located in areas with no sources of potentially radioactive wastes and conveys them to a public sanitary sewage collection and treatment system. Drawing C-47 shows the yard drainage piping for the sanitary waste system.

The plant drainage systems consist of collection piping, equipment drains, floor drains, vents, traps, cleanouts, collection sumps, sump pumps, tanks, and instrumentation.

The arrangement is such that the open nonradioactive drain systems serve only nonrestricted areas where no radioactivity potential is present, exclusive of the lavatory wastes in the access control areas that are collected by the sanitary waste systems.

The plant areas with nonradioactive waste floor drains were reviewed for the potential for radioactive fluid to enter. The nonradioactive systems floor drains are either located in separate compartments and/or separated by curbs from the nearest radwaste drains, except as discussed below.

The following areas have normal waste or oily waste and radwaste drains located near one another, without curbs or other liquid barriers:

Area	Elevation	Drains	Description
1, 5	269	oily waste/ radwaste drains	Turbine Deck
8	304	normal waste/ radwaste drains	Control Room HVAC Area
6, 7 9, 10	302	normal waste/ radwaste drains	Turbine Enclosure HVAC Area
22	257	normal waste/ radwaste drains	Radwaste Enclosure HVAC (supply) Area
15, 16 17, 18	313	storm drains/ radwaste drains	Reactor Enclosure/ Refueling Area HVAC (supply) Area

Plugs are installed in all normal waste or oily waste floor drains in the first four of the above areas to prevent radioactive fluids from entering the nonradioactive drainage system. These plugs will be removed only for equipment maintenance or cleaning purposes. Plugs are installed in the radwaste drains located near storm drains in the last above area to maintain secondary containment integrity. The storm drains in this area are normally diverted to the holding pond where any inadvertent leakage of Drywell Chilled Water supplying the fan cooling coils can be held up for decay of trace amounts of Na-24 which may be present.

Rooms north of column lines N, at either end of the turbine enclosure (Areas 1, 5, el 217') have floor drains to oily waste. Three condensate lines (feedwater heater drains) are routed through the overhead of the compartments in separate, steel shielded pipe chases. In the unlikely event of a pipe failure, condensate could flow onto the floors of these rooms, and into air compressor rooms 328 and 357. For this reason, plugs have been installed in all oily waste floor drains of these four rooms. These plugs will be removed only for equipment maintenance or cleaning purposes.

In the event unidentified liquids collect at the location of a plugged floor drain, the collected liquids will be sampled to determine radioactive content prior to opening the floor drain or otherwise processing or disposing of liquids.

The drainage sources and expected inputs from areas of potential radioactivity are shown in Table 11.2-6.

9.3.3.2.2 Component Description

Components of the plant drainage systems are described in the following paragraphs. Major components and design parameters are listed in Table 9.3-5.

All plumbing and drainage systems are installed in accordance with ANSI A40.8, National Plumbing Code, and applicable local or state codes.

In areas of potential radioactivity, the collection system piping for the liquid system is carbon steel. Potentially radioactive laboratory and decontamination waste, regeneration waste, and detergent waste collection system piping is stainless steel. The fabrication and installation of the piping provides for a uniform slope which induces waste to flow in the piping at a velocity of not less than 2 ft/sec. Equipment drainage piping is terminated approximately 6 inches above the finished floor or drain receiver at each location where the discharge from equipment is to be collected. The final connections are made after the equipment is installed in its proper location.

All floor drains are installed with rims flush with the low point elevation of the finished floor. Floor drains in areas of potential radioactivity are welded directly to the collection piping and are threaded to permit the installation of threaded plugs, with the exception of the drains listed in Section 9.3.3.2.1, which are provided with friction-type plugs. The plugs may be used to seal off the floor drains for pressure testing of the drainage system. They may also be installed to prevent aspiration of radioactive particulates between compartments or installed in designated floor drains of the turbine building to prevent intrusion of EHC fluid or other undesirable fluids. They can also be installed in nonradioactive floor drains to prevent radioactive fluid from entering into the normal waste system.

Inlets to all drainage systems (except radwaste and storm drain systems) are provided with a vented P-trap water seal to minimize entry of vermin, foul odors, and toxic, corrosive, or inflammable vapors into the enclosure, unless an evaluation has been performed which determined such vented P-traps to be unnecessary. Vent lines to the outside atmosphere are provided downstream of the P-traps to prevent excessive back pressures that could cause blowout or siphoning of the water seal. Traps are not installed on radwaste system inlets in order to reduce the accumulation of radioactive debris.

Cleanouts are provided (when practicable) in all collection system piping where the change of direction is 90° or at maximum intervals of 50 feet in horizontal piping runs. Cleanouts for the potentially radioactive collection systems are welded directly to the piping.

Potentially radioactive collection sumps are provided with a fitted checker plate access cover for convenient maintenance access. All sumps except for the drywell are recessed in concrete and are located at the lowest elevation of the area served. The drywell sumps are located below the drywell slab. Each turbine, reactor, and radwaste enclosure and the hot maintenance shop sump is fitted with a vent pipe to exhaust potential sump gases to a ducted, filtered, enclosure exhaust system. The drywell sumps vent back into the drywell. Floor drain sumps in the reactor, turbine, and radwaste enclosures and the hot maintenance shop are provided with traveling belt-type oil removal equipment.

The drywell equipment drain sump and the reactor enclosure equipment drain sump are provided with cooling coils to keep the wastes at or below a temperature of 140°F.

The sanitary drainage system is normally aligned to the public sewer system. The alternate methods of sewage backup collection and holding will be used in the event the public sewer system is isolated and cannot be used. Drawing M-6389 shows the mechanical and structural components of the on-site sewage treatment and holding facility.

9.3.3.2.3 System Operation

The various floor and equipment drains drain directly to the appropriate collection point by gravity. Radwaste collected in the drywell floor drain sump (tank) and drywell equipment drain sump (tank) is gravity drained to the liquid radwaste system for processing. Sump discharge valves automatically open on a predetermined sump high level and close on a predetermined sump low level. All other radwaste collection sumps are provided with sump pumps that automatically start on a predetermined sump high level and stop on a predetermined low level. Sump discharge is pumped to the liquid radwaste system for processing. The drywell equipment drain sump and the reactor enclosure equipment drain sump are equipped with cooling coils.

Leakage inside the drywell drains to the drywell floor drain sump (except for piped valve and pump seal leak-offs and piping vents and drains which are routed to the drywell equipment drain sump).

Washdown of liquids to the plant radwaste floor drains will be administratively restricted to limit introduction of oils and other organic compounds to the radwaste system. Most oils that enter the area floor drain sumps are removed from the sump liquids before they can be transferred to the radwaste system. Sump pump setpoints are chosen to prevent pump-down of the top several inches of the sump contents, including any oils or other organic compounds collected on the surface of the sump liquid. Sumps are routinely inspected for presence of oils. Traveling belt-type oil removal equipment is provided and operated as necessary in the sumps to ensure that accumulated oils are not transferred to the radwaste system. Oils removed by the belts are gravity drained to a collection drum for disposal. Other organic compounds present in the sump liquid and not removed by the oil removal equipment are transferred with the dirty radwaste to the floor drain collection tank for processing (Section 11.2.2.1). Treated waste is collected in sample tanks, mixed by recirculation, and sampled. The treated waste is recycled to the condensate storage tanks for reuse only when samples indicate that it meets condensate storage water quality specifications. Treated waste that contains unacceptable levels of organic compounds is not transferred to the condensate storage tanks, but reprocessed in the liquid radwaste system or discharged from the plant.

The storm drainage system collects water resulting from precipitation on enclosure roofs and areaways, paved and unpaved surfaces, and irrigation runoffs outside the enclosures, and conveys it to Possum Hollow Run and the Schuylkill River. A Drain/Dewatering line has been added to aid in Condenser draining during outage periods. This line ties into the storm drainage system.

Five 150 gpm oil interceptors are installed in yard areas to intercept accidental oil spills near the points of oil storage and use. Effluent from the oil interceptors, as well as other normal waste drainage, is routed to the holding pond via two parallel 750 gpm Oil-Water Separator System (Solids Stormwater Interceptors and Oil-Water Separators).

Equipment drains that have the potential for oil contamination are gravity drained to the oily waste drainage system. This system drains through an oil intercepter to the oily waste sump. The separated water is drained to the normal waste sump and is pumped from the sump to the 5000 gallon normal waste holding tank. The reactor feed pump turbine lube oil reservoirs are enclosed within curbed areas, which are drained to the oily waste sump through oily waste plumbing. The main turbine lube oil reservoir and the lube oil storage tanks are enclosed within diked areas, which can be drained directly to the 7500 gallon oily waste holding tank. All the waste oil collected in the oily waste sump is transferred to the holding tank for transport offsite.

The acid waste system collects liquid waste possibly containing chemicals and corrosive substances discharged by laboratory fixtures, accidental spills and demin water sampling equipment. The acid waste system also serves the drains which are located in the water treatment enclosure, and conveys the liquid waste directly to the chemical waste sump. With the retirement of the demineralizer trains,

chemical and corrosive discharges to the acid waste system chemical waste sump have been virtually eliminated.

The liquid wastes in the chemical waste sump will be pumped to the water treatment enclosure sump. Clarifier blowdown, filter backwash, and other floor drainage in the water treatment enclosure are also routed to the water treatment enclosure sump. Discharge of the water treatment enclosure sump is directed to the setting basin. The settling basin effluent is routed to the holding pond.

The connection to the public sewer system is sized to carry the maximum anticipated sewage flow from the site. The alternate methods of sewage backup collection and holding will be used in the event that the public sewer system is not available or if sampling of the LGS sewage discharge indicates the presence of radiological contaminants. An isolation valve in the primary discharge line allows for blocking the outflow to public sewer system. Alternate methods of dealing with sewage treatment and disposal may be implemented as long as the method is analyzed to ensure compliance with State and Local requirements for sewage disposal.

9.3.3.3 Safety Evaluation

Except for the containment penetrations and the drywell boundary extension of the drywell drainage system, the plant drainage systems have no safety-related function. The containment penetrations are designed to seismic Category I and quality group B requirements, and are discussed in Section 6.2.4.

To provide assurance that the floor drain and equipment drain sump pumps do not automatically transfer water to the radwaste enclosure, these pumps are tripped on a containment high radiation signal.

If prolonged isolation of the sumps is necessary, the sump contents can be pumped to the suppression pool via a small pipe intertie. Operator actions necessary to change the valve lineup and restore pump operation are performed in accessible locations outside the reactor enclosure.

The liquid radwaste equipment and floor drain sumps are located within the primary containment (drywell), reactor enclosure, turbine enclosure, control structure, administration building (hot maintenance shop) and radwaste enclosure. As discussed in Section 9.3.3.2.2, the sumps are located at the lowest elevation in the respective structure to provide gravity drainage from all elevations.

The liquid radwaste from the drywell floor drain sump and drywell equipment drain sump is gravity fed down to the radwaste enclosure to the floor drain and equipment drain collection tanks, respectively. Backflooding from these drywell sumps could cause flooding on the drywell floor slab, which would be drained through the downcomers to the suppression pool. All safety-related equipment in the drywell is located above the floor slab and therefore is not subject to the effects of flooding.

The equipment and floor drain sumps are designed to remove floodwater from enclosures containing safety-related equipment such that the capability to achieve safe shutdown would not be compromised. Flooding due to a HELB or moderate energy line break is addressed in Section 3.6.1.

Credit is not taken for the operability of any nonseismic Category I plant drainage system piping, equipment and instrumentation in ensuring the safe shutdown of the plant, mitigating the consequences of an accident, or ensuring that offsite doses do not exceed 10CFR50.67 limits.

The loss of integrity of all nonseismic Category I piping, equipment and instrumentation due to a SSE is not credible and therefore the flooding which may accompany this type of failure is not explicitly included in the design basis for LGS. Studies have indicated that earthquakes do not cause significant piping failures (Reference 9.3-1).

There are no nonseismic Category I piping, equipment and instrumentation in the ECCS compartments which are fluid filled during normal operations. Even so, all nonseismic Category I piping, equipment and instrumentation in the ECCS compartments, including check valves and drain lines, have been assessed for SSE loads to verify that their integrity will be retained.

Although it is not expected that any materials in the ECCS compartments could cause the drains to become plugged, plugging of any single ECCS compartment drain would not impact safe shutdown. Flooding of any single ECCS compartment will not cause the failure of more than one redundant safety-related train.

In the event of drain line plugging in other areas of the plant, floodwaters would be drained to the lower elevations of the plant via stairwells, elevator shafts and equipment hatches.

As discussed above, significant flooding due to the failure of piping, equipment and instrumentation in the reactor enclosure is not expected. However, in the event that significant quantities of water are conveyed to the sumps at el 177', backflow into the ECCS compartments is prevented by the inclusion of a check valve where the dedicated drain line from each ECCS compartment (2 per RHR compartment) terminates in the sump. Each ECCS compartment is provided with separate drain lines from the compartment to the sump. Thus, failure of any check valve will not result in flooding of more than one ECCS compartment. An assessment has been performed to verify the ability of the check valves to remain functional following an SSE.

All nonseismic Category I piping, equipment and instrumentation in the reactor enclosure (including the check valves in the sump) have had 10CFR50, Appendix B quality assurance criteria applied to them commensurate with their importance to safety:

a. Each item has been assessed to verify that it will retain its integrity during and following an SSE.

b. The check valves have been designed to remain operable for an SSE.

c. Installation was performed by the same craftsmen and qualified welders as those installing Q-list systems.

d. Quality control inspections of the installation were conducted in accordance with criteria similar to the criteria for inspections of Q-list systems.

The check valves on the ends of the ECCS compartment drain lines and the portions of the ECCS compartment drain lines between the sump pit wall and the check valves will be placed on the Project Q-List to ensure that maintenance activities and any modifications will be performed in accordance with the applicable requirements of 10CFR50, Appendix B.

The seismic Category IIA drain lines which run through the ECCS compartments will be identified in an appendix to the Project Q-List to ensure that any maintenance of or modifications to these drain

lines will employ the level of quality assurance necessary to retain their seismic Category IIA classification.

The reactor enclosure sump is located adjacent to the ECCS pump compartments at el 177'. Each ECCS compartment is provided with a separate drain line to the reactor enclosure sump inlet header. In addition, each ECCS compartment is provided with watertight walls, floors, and doors to prevent flooding of multiple ECCS compartments. Flooding of multiple compartments by backflow from the sump through the drain system is prevented by check valves or plugs installed in the drain lines.

A piping failure in an ECCS compartment could flood both the ECCS compartment and the sump room and adjoining corridor. Level instrumentation is installed and alarms provided in the control room to alarm on high water level in the ECCS compartment. If the level instrumentation should fail, the loss of one ECCS compartment is an acceptable consequence of flooding due to equipment separation.

Backflooding from the reactor enclosure sump room up to el 201' is highly unlikely. Water entering the sump room and adjoining corridor through openings in the sump cover plate must fill the sump room before backing up onto an upper elevation. Because the sump room is large, sufficient time will be available to isolate the leak before filling the compartment.

Analysis of the reactor enclosure sumps and the drywell tank drainage systems has determined that the drywell floor drain tank and the drywell equipment drain tank will drain in less than 10 minutes regardless of whether one or two of the respective reactor enclosure drain sump pumps are running. Worst case drain times are adequate to ensure that reactor coolant pressure boundary leak detection capability is maintained consistent with Regulatory Guide 1.45 guidelines. As a result of the automatic drywell tank drain during reactor enclosure sump pump operation, unacceptable flooding is avoided.

Failure of the equipment and floor drain sumps in the turbine enclosure and in the control structure will not cause flooding damage to safety-related compartments because all safety-related equipment is located at higher elevations and the sump rooms are sufficiently large to allow enough time to isolate the leak before filling the compartments. The turbine enclosure and control structure share the same equipment and floor drain sumps on el 180' of the turbine enclosure. The lowest elevation of the turbine enclosure and control structure that contains safety-related equipment is el 200'.

Flooding due to failure of the equipment and floor drain sumps in the radwaste enclosure is of no consequence because the radwaste enclosure does not contain any safety-related equipment.

9.3.3.4 Tests and Inspections

All waste collection piping is tested prior to its embedment in concrete. Potentially radioactive drainage piping is pneumatically tested to 20 ±5 psig air for a minimum of 10 minutes, in accordance with ANSI B31.1 (1973). When in-place pressure testing is not practical, the tie-in welds will be examined via NDE per ANSI B31.1. Nonradioactive oily, acid, sanitary, and storm drainage piping is hydrostatically tested to the equivalent of a 10 foot head of water for a minimum of 15 minutes. The operability of the plant drainage systems is checked by normal use and by the instrumentation provided in the sumps and the control room.

9.3.3.5 Instrumentation Application

High and low level switches are provided in each sump to start and stop the sump pumps automatically. A separate level switch set at a higher level is provided to start the second pump.

The levels in the drywell floor and equipment drain sumps are alarmed in the control room. Levels on all other sumps are alarmed locally.

Flow from the drywell sumps is totalized each time a sump tank drains, and an alarm is actuated in the control room when a predetermined excessive volume is exceeded. All other radwaste sumps have automatic timers on the sump pumps to record the total cumulative run time for the pumps, and thus provide a means to determine the flow rate from each sump. The temperatures in the drywell and reactor enclosure equipment drain sumps are indicated and alarmed in the control room. Sight flow glasses are provided in nonembedded radwaste piping to aid in identifying the source of any excessive leakage.

9.3.4 CHEMICAL AND VOLUME CONTROL SYSTEM

Not applicable to boiling water reactors

9.3.5 STANDBY LIQUID CONTROL SYSTEM

9.3.5.I Design Bases

The SLCS has a safety-related function and the components required to meet that function are designed as a seismic Category I system. It meets the following design bases:

a. Backup capability for reactivity control is provided, independent of normal reactivity control provisions in the nuclear reactor, to be able to shut down the reactor if the normal control ever becomes inoperative.

b. The backup system has the capacity for controlling the reactivity difference between the steady-state rated operating condition of the reactor with voids and the cold shutdown condition, including shutdown margin, to assure complete shutdown from the most reactive condition at any time in core life.

c. The time required for actuation and effectiveness of the backup control is consistent with the nuclear reactivity rate of change predicted between rated operating and cold shutdown conditions. A fast scram of the reactor or operational control of fast reactivity transients is not specified to be accomplished by this system. However, its performance ensures compliance with the criteria imposed for the postulated events of anticipated transients without scram.

d. Means are provided by which the functional performance capability of the backup control system components can be verified periodically under conditions approaching actual use requirements. Demineralized water, rather than the actual neutron absorber solution, can be injected into the reactor to test the operation of all components of the system.

e. The neutron absorber will be dispersed within the reactor core in sufficient quantity to provide a reasonable margin for dilution, leakage, and imperfect mixing.

f. The system is reliable to a degree consistent with its role as a special safety system; the possibility of unintentional or accidental shutdown of the reactor by this system is minimized.

g. The system shall be capable of injecting sodium pentaborate into the reactor vessel to maintain the suppression pool water inventory at a pH of 7.0 or higher following a LOCA.

9.3.5.2 System Description

The SLCS (drawing M-48) is designed to be manually initiated from the control room to cause a sodium pentaborate solution to be pumped into the reactor if the operator determines that the reactor cannot be shut down or kept shut down with the control rods.

The SLCS is also designed to be manually initiated from the control room to pump sodium pentaborate into the reactor within 13 hours of the onset of a large break LOCA to maintain suppression pool pH at a level of 7.0 or higher. (Ref. 9.3-4)

The SLCS is also automatically initiated upon receipt of a signal from the RRCS logic. The sodium pentaborate solution is injected through the core spray line and sparger, which is used by the HPCI system. With two pumps operating, the SLCS can begin to deliver the control liquid to the Core Spray line within about 53 seconds after actuation. The actuation signal starts the two in-service pumps and actuates the associated explosive valves. However, the SLCS is not expected to be actuated because the CRD system, backed up by the ARI design, can shut down the reactor when required. Low vessel water level (level 2), high vessel pressure, or manual initiation of the RRCS starts a timer. If the core power is not downscale at the end of a predetermined time-delay, the SLCS injection as described above is initiated.

The boron solution tank, the test water tank, the three positive displacement pumps, the three explosive valves, the motor-operated stop-check shutoff valve, and associated local valves and controls are located in the reactor enclosure. The solution is pumped into the core spray line downstream of the air-operated testable check valve that leads to sparger B. It is sprayed radially over the top of the core (Sections 3.9.3, 3.9.5, 5.3, and 6.3.2).

The boron absorbs thermal neutrons and, when present in sufficient quantity in the reactor, will cause the reactor to become subcritical.

The specified neutron absorber solution is an aqueous solution of sodium pentaborate decahydrate ($Na_2B_{10}O_{16}•10H_20$). It is prepared by dissolving either sodium pentaborate decahydrate or stoichiometric quantities of borax and boric acid in the SLCS tank with demineralized water so that the solution fills the tank to at least the low level alarm point. The solution can be diluted with water to allow for evaporation losses or to lower the solution saturation temperature, provided that solution concentration requirements are met. An air sparger is provided in the tank for mixing. To prevent system plugging, the tank outlet is raised above the bottom of the tank.

Whenever the reactor is critical, the SLCS is able to deliver enough sodium pentaborate solution into the reactor to ensure reactor shutdown.

The minimum temperature of the solution in the tank and piping is consistent with that obtained from Figure 9.3-7 for the solution temperature. The saturation temperature is about 60°F with the solution at the recommended concentration of 13.4%. (Figure 9.3-7). Refer to Technical Specification 3/4.1.5

and Figure 3.1.5-1 for SLCS Boron-10 weight, sodium pentaborate concentration and temperature limits. The equipment containing the solution is installed in an area in which the air temperature is designed to be maintained within the range of 65°F to 106°F. An electrical resistance heater system consisting of a cycling heater, a mixing heater, and heat tracing provides backup heat sources to prevent precipitation of the sodium pentaborate from solution. The cycling heater is rated at 10 kW and operates automatically between 75°F and 85°F. The mixing heater is rated at 40 kW, is manually operated, and is used to facilitate chemical mixing. Heat tracing with automatic temperature control is provided between the storage tank and pump inlet to prevent sodium pentaborate precipitation in the pipe. Any portion of the electrical resistance heater system can be removed from service without affecting operation of the SLCS, as long as the temperature of the solution in the tank and heat traced piping remains above 70°F. High or low temperature, or high or low liquid level, causes an alarm in the control room.

The upper limit concentration of 13.8% has been established as a reasonable limit to prevent precipitation of the sodium pentaborte in the event of a loss of tank heating, which will allow the solution to cool.

Each positive displacement pump is sized to inject the solution into the reactor at 43 gpm. The pump and system design pressure between the explosive valves and the pump discharge is 1400 psig. The setpressure for the three relief valves is set at approximately 1400 psig. To prevent bypass flow from one pump, in case of relief valve failure in the line of another pump, a check valve is installed downstream from each relief valve line in the pump discharge pipe. An accumulator is installed downstream from each pump to damp out pump pulsations.

The three explosive actuated injection valves provide assurance of opening when needed, and ensure that the solution will not leak into the reactor even when the pumps are being tested.

Each explosive valve is closed by a plug in the inlet chamber. The plug is circumscribed with a deep groove so that the end readily shears off when pushed with the valve plunger. This opens the inlet hole through the plug. The sheared end is pushed out of the way in the chamber; it is shaped so it does not block the ports after release.

The shearing plunger is actuated by an explosive charge with dual ignition primers inserted in the side chamber of the valve. Ignition circuit continuity is monitored by a trickle current, and an alarm occurs in the control room if either circuit opens. Indicator lights show which primary circuit opened.

The SLCS is actuated by a three-position, key-locked switch on the control room console. This ensures that switching from the NORMAL position is a deliberate act. If the switch is in the RUN position and the storage tank level is above the zero level setpoint, the pump will start and the corresponding explosive actuated valve will open. In addition, a signal is sent to close RWCU isolation valve to prevent the loss or dilution of the control liquid.

A green light in the control room indicates that power is available to the pump motor contactor and that the contactor is de-energized (pump not running). A red light indicates that the contactor is energized (pump running).

Storage tank liquid level, pump discharge pressure, and loss of continuity on the explosive valves indicate that the system is functioning. Local switches are provided for testing the SLCS pumps. There is a keylocked Normal/Test switch, a pushbutton start switch and a pushbutton stop switch. These switches do not prevent the pumps from being started by the RRCS or manually from the control room when SLCS injection is needed. Pump discharge pressure, tank solution level, valve

injection status, and Lo-Lo level alarm are indicated in the control room. The SLCS pump can be shut off from the control room by positioning the switch in the stop position. Manual shutoff is possible even when an automatic RRCS signal is present. The pumps are shut off automatically at tank zero level using two-out-of-two logic for each pump.

Equipment drains and tank overflow are not piped to the radwaste system, but to separate containers (such as 55 gallon drums) that can be removed and disposed of independently of the radwaste system to prevent any trace of boron from inadvertently reaching the reactor.

Instrumentation consisting of solution temperature indication and control, solution level, and heater system status is provided locally at the storage tank. Table 9.3-6 contains the process data for the various modes of operation of the SLCS. Seismic category and quality class design criteria are included in Table 3.2-1. System testing requirements are discussed in Section 9.3.5.4. Environmental conditions for the SLCS are described in Section 3.11.

9.3.5.3 Safety Evaluation

The SLCS is a reactivity control system and is maintained in an operable status whenever the reactor is critical. The system is never expected to be needed for safety reasons because of the large number of independent control rods available to shut down the reactor.

The SLCS is also a chemical control system and is required to be operable whenever the potential for a LOCA exists. The addition of sodium pentaborate to the suppression pool maintains the pool pH at a minimum of 7.0 to minimize iodine releases from primary containment. SLCS pumps sodium pentaborate to the reactor vessel, where it is mixed with the reactor coolant which flows to the suppression pool through the LOCA pipe break. The SLCS addition must occur within 13 hours following a LOCA to ensure pH is maintained at 7.0 or above.

To ensure the availability of the SLCS, three sets of the components including necessary instruments and control logic devices are used in parallel redundancy to actuate the system active redundant mechanical components (such as pumps and explosive valves).

The system is designed to bring the reactor from rated power to a cold shutdown condition at any time in core life. The reactivity compensation provided will reduce reactor power from rated to zero level and allow cooling the nuclear system to room temperature, with the control rods remaining withdrawn in the rated power pattern. It includes the reactivity gains that result from complete decay of the rated power xenon inventory. It also includes the positive reactivity effects from eliminating steam voids, changing water density from hot to cold, reduced Doppler effect in uranium, reducing neutron leakage from boiling to cold, and decreasing control rod worth as the moderator cools.

The minimum average concentration of natural boron required in the reactor core to provide adequate shutdown margin, after operation of the SLCS, is 660 ppm (parts per million), or the equivalent concentration of enriched boron. With the use of enriched boron having a minimum boron-10 enrichment of 29 atom percent, the minimum weight of boron-10 available for injection into the reactor is 185 lbs. This quantity is based on the equivalent average concentration of natural boron (660 ppm) in the reactor coolant (including RHR system in the shutdown cooling mode and recirculation loops), at 68°F with vessel water level at level 8. This result includes an increase of 25% to allow for imperfect mixing and leakage.

Cooldown of the nuclear system requires a minimum of several hours to remove the thermal energy stored in the reactor, cooling water, and associated equipment. The controlled limit for the reactor vessel cooldown is 100°F per hour, and normal operating temperature is approximately 550°F. Use

of the main condenser and various shutdown cooling systems requires approximately 6 hours to bring the vessel to subcooled conditions. The maximum concentration of boron is required after xenon concentration reaches zero at the subcooled conditions.

The boron injection capability of the SLCS meets the requirements of the ATWS Rule (10CFR50.62) in conjunction with the new rod line developed for the ARTS/MELLLA program. As a result of this program it is determined that the boron-10 enrichment was required to be increased to a minimum of 29 atom percent to prevent exceeding a maximum suppression pool temperature of 190°F. Compliance with the ATWS Rule is demonstrated by periodic verification that the actual solution concentration, boron 10 enrichment, and pumping capacity satisfy the following equation:

$$\frac{C}{13\%\ wt.} \times \frac{E}{29\ atom\ \%} \times \frac{Q}{86\ gpm} \geq 1$$

where:

C = Sodium pentaborate solution concentration (% by weight)
Q = Two-pump flow rate (gpm)
E = Boron 10 enrichment (atom % Boron 10)

The SLCS equipment essential for injection of neutron absorber solution into the reactor and for suppression pool pH control is designed as seismic Category I (Chapter 3). Evaluation of the SLCS with respect to the following areas is discussed in separate sections as indicated:

a.	Protection from wind and tornado effects	Section 3.3
b.	Flood design	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11
f.	Fire protection	Section 9.5.1

The SLCS is required to be operable in the event of a plant offsite power failure therefore the pumps, valves, and controls are powered from the standby ac power supplies. Redundant components are powered and controlled from separate buses and circuits so that a single active failure of a power supply does not prevent system operation. The storage tank heaters are non-safeguard loads powered from safeguard buses and are tripped on a LOCA signal. The heaters can be manually re-energized after 10 minutes if required.

The SLCS pumps have sufficient pressure margin, up to the system relief valve set pressure of approximately 1400 psig, to assure solution injection into the reactor above the normal pressure in the bottom of the reactor. The nuclear system relief and safety valves begin to relieve pressure above approximately 1170 psig. Therefore, the SLCS positive displacement pumps cannot overpressurize the nuclear system.

Only one of the three SLCS pumps is needed to meet the design basis of Section 9.3.5.1. Two pumps are required to meet the requirements of the ATWS Rule (10CFR50.62). If a redundant component (e.g., one pump) is found to be inoperable, there is no threat to shutdown capability, and reactor operation can continue during repairs.

The SLCS is evaluated against the applicable GDC as follows:

a. GDC 2 and GDC 4: Refer to Sections 3.3, 3.4, 3.5, 3.6 and 3.11.

b. GDC 21: GDC 21 is applicable to protection systems only. The SLCS is a reactivity control system and should be evaluated against GDC 29 (see below).

c. GDC 26: The CRD system provides reactivity control under normal operation and anticipated operational occurrences The system is capable of holding the core subcritical under cold shutdown conditions. The recirculation flow control system is capable of accommodating reactivity changes during normal operation conditions (power changes and xenon burnout) . The SLCS provides an independent capability for achieving cold shutdown should the normal reactivity control by control rod drive system become inoperable. These systems, taken together, satisfy the requirements of GDC 26.

d. GDC 27: This criterion applies no specific requirements to the SLCS and therefore is not applicable. See Section 3.1 for discussion of combined capability.

f. GDC 29: The SLCS consists of three redundant pumps and injection valve loops. The SLCS also has test capability. A special test tank is supplied for providing test fluid for a periodic injection test. Pumping capability and suction valve operability may be tested at any time. A trickle current continuously monitors continuity of the firing mechanisms of the injection squib valves. A system level, qualitative-type FMEA evaluation, relative to this system's ability to meet active single failure criteria, is discussed in Section 15.9.

The SLCS is evaluated against the applicable regulatory guides as follows:

a. Regulatory Guide 1.26: Because the SLCS is a reactivity control system, all mechanical components are at least Quality Group B or equivalent. The SLCS storage tanks and all three of the Unit 1 and one of the Unit 2 accumulator vessels are constructed to alternate specifications as discussed in Sections 3.2.2.k and 3.2.2.1. Those portions which are part of the RCPB are Quality Group A. This is shown in Table 3.2-1.

b. Regulatory Guide 1.29: All components of the SLCS which are necessary for injection of the neutron absorber into the reactor and for suppression pool pH control following a LOCA are seismic Category I as shown in Table 3.2-1.

c. BTP APCSB 3-1 & BTP MEB 3-1: SLCS equipment is protected from a pipe break as discussed in Section 3.6.

d. Regulatory Guide 1.183: The adoption of Alternative Source Terms (AST) requires the use of SLCS to maintain the suppression pool inventory at a minimum pH of 7.0

following a LOCA. All components of SLCS necessary to perform this function are evaluated as required per Reg. Guide 1.183. (Ref. 9.3-3)

This system is used in special plant capability demonstration events cited in Section 15.9 (specifically Events 51 and 53), which are extremely low probability nondesign basis postulated incidents.

9.3.5.4 Testing and Inspection Requirements

Operational testing of the SLCS is performed in at least two parts to avoid the inadvertent injection of boron into the reactor.

With the storage tank outlet valve and the maintenance valve downstream of the explosive valve closed, and valves on the test tank discharge line and return line opened, demineralized water can be recirculated by locally starting a pump. This test can be accomplished during normal plant operation while the other loops are capable of injecting the control liquid in response to an initiation signal.

During a refueling or maintenance outage, all pumps and automatic valves can be tested. In the test mode, demineralized water is pumped from the test tank through the explosive valves into the vessel upon receiving a manual start signal. Separate tests verify a simulated ATWS signal from the RRCS logic would cause an injection. During testing, the storage tank outlet valve is closed while the test tank discharge valve is open.

After functional tests, the injection valve shear plugs and explosive charges must be replaced and all the valves returned to their normal positions, as indicated in drawing M-48.

After closing a local locked open valve to the reactor, leakage through the injection valves can be detected by opening valves at a test connection in the line between the containment isolation check valves. Position indicator lights in the control room indicate that the local valve is closed for tests or open and ready for operation. Leakage through the first check valve can be detected by opening the test connection shutoff valves in the line between the inner check valve and the outer containment motor-operated stop-check globe valve when the reactor is pressurized or during a refueling outage.

The test tank contains demineralized water for at least 5 minutes of pump operation. Demineralized water is available for refilling and flushing the system.

Should the boron solution ever be injected into the reactor, either intentionally or inadvertently, then after making certain that the normal reactivity controls will keep the reactor subcritical, the boron is removed from the RCS by flushing for gross dilution followed by operating the RWCU system.

The concentration of the sodium pentaborate in the solution tank is determined periodically by chemical analysis.

The boron-10 enrichment of the sodium pentaborate to be added to the tank will be verified to be $\geq$ 49 atom percent prior to adding the chemicals to the storage tank.

Electrical supplies and relief valves are also subjected to periodic testing.

The SLCS preoperational test is described in Chapter 14.

9.3.5.5 Instrumentation Requirements

The instrumentation and control system for the SLCS is designed to allow the injection of sodium pentaborate solution into the reactor and to maintain the solution well above its saturation temperature. A further discussion of the SLCS instrumentation is found in Section 7.4.

9.3.6 REFERENCES

9.3-1 "Seismic Performance of Piping in Past Earthquakes," ASCE Conference Report; R.L. Cloud Associates, Inc., (1980).

9.3-2 "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," NEDC-32193P, July 1993.

9.3-3 Regulatory Guide 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,” July 2000.

9.3-4 Design Analysis LM-0642, “Suppression Pool pH Calculation for Alternative Source Terms.”

Table 9.3-1

DELETED

Table 9.3-2

PERKIOMEN AND SCHUYLKILL COMPRESSED AIR SYSTEMS
DESIGN PARAMETERS

PERKIOMEN PUMPHOUSE AIR COMPRESSORS	
Quantity	2
Type	Piston
Capacity	72 scfm
Pressure rating	175 psig
Motor power rating	20 hp
PERKIOMEN PUMPHOUSE AIR RECEIVER	
Quantity	1
Type	Vertical, cylindrical
Capacity	66.84 ft^3
Pressure rating	150 psig
PERKIOMEN PUMPHOUSE AIR ACCUMULATOR	
Quantity	1
Type	Vertical, cylindrical
Capacity	1.33 ft^3
Pressure rating	275 psig
PERKIOMEN CONTROL VALVE AIR COMPRESSOR	
Quantity	2 (100% capacity each)
Type	Piston
Capacity	22.2 scfm
Pressure rating	175 psig
Motor power rating	5 hp

Table 9.3-2 (Cont'd)

PERKIOMEN CONTROL VALVE AIR RECEIVER

Quantity	1
Type	Vertical
Capacity	53.5 ft^3
Pressure rating	200 psig

SCHUYLKILL AIR COMPRESSORS

Quantity	2 (100% capacity each)
Type	Piston
Capacity	9.6 scfm
Motor power rating	3 hp

SCHUYLKILL AIR RECEIVER

Quantity	2
Type	Horizontal, cylindrical
Capacity	8.02 ft^3
Pressure rating	(not available in our records)

Table 9.3-3

PRIMARY CONTAINMENT INSTRUMENT GAS SYSTEM DESIGN PARAMETERS

INLET FILTER	
Quantity	2 (100% capacity each)
Type	Dry-type with renewable media
Rating	99% of 10 micron particles
COMPRESSORS	
Quantity	2 (100% capacity each)
Type	Reciprocating, wye, single acting, single-stage, water-cooled, nonlubricated
Capacity	10 acfm
Pressure rating	110 psig
Motor power rating	5 hp
AFTERCOOLERS	
Quantity	2 (100% capacity each)
Type	Shell and tube with tube bundle and baffled water circuits
Duty, each	2791 Btu/hr
Shell design	
Fluid	RECW
Flow rate	450 lb/hr
Design pressure	200 psig
Design temperature	300°F
Tube design	
Fluid	Air or nitrogen
Flow rate	10 cfm
Design pressure	150 psig
Design temperature	300°F

Table 9.3-3 (Cont'd)

MOISTURE SEPARATORS	
Quantity	2 (100% capacity each)
Type	Vertical, with built-in float-type drain trap
Capacity, each	50 cfm
Design pressure	150 psig
Design temperature	300°F
DRYERS	
Quantity	2 (100% capacity each)
Type	Refrigerant-type with moisture separator zone
Capacity, each	10 cfm
Humidity at inlet	Saturated
Outlet moisture content	34°F dew point at 105 psig
Quantity	2 (100% capacity each)
Type	Desiccant-type with electric heaters for regeneration
Capacity, each	10 cfm
Inlet conditions	
Pressure	90 to 115 psig
Temperature	55°F
Dew point	34°F at 105 psig
Outlet conditions	
Dew point	-40°F at 100 psig
OUTLET FILTER (DESICCANT DRYER)	
Quantity	2 (100% capacity each)
Type	Dry-type with renewable media
Rating	99.99% of 3 micron particles
GAS RECEIVERS	
Quantity	2 (100% capacity each)
Type	Vertical, ASME Code stamp
Capacity, each	80 ft^3
Pressure rating	125 psig

Table 9.3-3 (Cont'd)

OUTLET FILTER (Gas Receiver)

Quantity	2 (100% capacity each)
Type	Dry type with renewable media and built-in float-type drain trap
Rating	99.99% of 0.03 micron particles

Table 9.3-4

SAFETY-RELATED PNEUMATICALLY OPERATED VALVES AND DAMPERS[2]

SYSTEM AND VALVE OR DAMPER NO.	DESCRIPTION	DESIGN FUNCTION	NORMAL POSITION	FAIL POSITION	SAFE POSITION
A. EMERGENCY SERVICE WATER[3] (Drawing M-11)					
HV-11-041&071	Unit 1, Div 1 ESW return	ESW heat removal from Unit 1, Loop A coolers	Closed	Open	Open
HV-11-042&072	Unit 1 HPCI ESW return	ESW heat removal from Unit 1 HPCI pump-room coolers	Closed	Open	Open
HV-11-044&074 Unit 1, Div II ESW return ESW heat removal from Unit 1,	Closed	Open Loop B coolers	Open		
HV-11-121&123	Unit 1, Div I service water return	Isolation of Loop A coolers from service water system	Open	Closed	Closed
HV-11-125&126	Unit 1, Div II service water return	Isolation of Loop B coolers from service water system	Open	Closed	Closed
HV-11-043&073	Unit 1 HPCI service water Return	Isolation of HPCI pump-room coolers from service water system	Open	Closed	Closed
HV-11-124&128	ESW supply to Unit 1 RECW, heat exchangers	Isolation of RECW heat exchangers from ESW system	Closed	Closed	Closed
HV-11-127	ESW return from Unit 1, RECW heat exchangers	Isolation of RECW heat exchangers from ESW system	Closed	Closed	Closed
HV-11-101A-H & 201A-H	Inlet to core spray pump-room unit coolers	Heat removal from core spray pump-room unit coolers	Closed	Open	Open
HV-11-103A&B & 203A&B	Inlet to HPCI pump-room unit coolers	Heat removal from HPCI pump-room unit coolers	Closed	Open	Open
HV-11-106A&B & 206A&B	Inlet to RCIC pump-room unit coolers	Heat removal from RCIC pump-room unit coolers	Closed	Open	Open

Table 9.3-4 (Cont'd)

SYSTEM AND VALVE OR DAMPER NO.	DESCRIPTION	DESIGN FUNCTION	NORMAL POSITION	FAIL POSITION	SAFE POSITION
HV-11-104A-H & 204A-H	Inlet to RHR pump-room unit coolers	Heat removal from RHR pump-room unit coolers	Closed	Open	Open
HV-11-046&076	Unit 2, Div I ESW return	ESW heat removal from Unit 2, Loop A coolers	Closed	Open	Open
HV-11-049&079	Unit 2, RCIC ESW return	ESW heat removal from Unit 2, RCIC pump-room coolers	Closed	Open	Open
HV-11-047&077	Unit 2, Div II ESW return	Heat removal from Unit 2, Loop B coolers	Closed	Open	Open
HV-11-221&223	Unit 2, Div I service water return	Isolation of Loop A coolers from service water system	Open	Closed	Closed
HV-11-225&226	Unit 2, Div II service water return	Isolation of Loop B coolers from service water system	Open	Closed	Closed
HV-11-048&078	Unit 2, RCIC service water Return	Isolation of RCIC pump-room coolers from service water system	Open	Closed	Closed
HV-11-224&228	ESW supply to Unit 2, RECW heat exchangers	Isolation of RECW heat exchangers from RECW system	Closed	Closed	Closed
HV-11-227	ESW return from Unit 2, RECW heat exchangers	Isolation of RECW heat exchangers from RECW system	Closed	Closed	Closed

Table 9.3-4 (Cont'd)

SYSTEM AND VALVE OR DAMPER NO.	DESCRIPTION	DESIGN FUNCTION	NORMAL POSITION	FAIL POSITION	SAFE POSITION
B. NUCLEAR BOILER (Drawing M-41)					
HV-41-1F022A,B,C&D[1]	Main steam piping inside containment	Isolation	Open	Closed	Closed
HV-41-1F028A,B,C&D[1]	Main steam piping outside containment	Isolation	Open	Closed	Closed
HV-41-1F074A,B	Feedwater Inlet Check valve	Isolation	Open	Closed	Closed
HV-41-1F084	Main steam sample from main steam line "C"	Isolation	Closed	Closed	Closed
HV-41-1F085	Main steam sample from main steam line "C"	Isolation	Closed	Closed	Closed
PSV-41-1F013 E,H,K,M,S[1]	Main steam relief valves	Reactor depressurization (automatic depressurization)	Closed	-	-
PSV-41-1F013 A,B,C,D,F, G,J,L,N	Main steam relief valves	Reactor depressurization	Closed	-	-
C. REACTOR RECIRCULATION (Drawing M-43)					
HV-43-1F019&1F020	Recirculation pump discharge process sample line	Sample line isolation	Closed	Closed	Closed
D. CRD HYDRAULIC (Drawing M-41)					
XV-47-1F010	SDV vent valve	Isolation	Open	Closed	Closed
XV-47-1F011	SDV drain valve	Isolation	Open	Closed	Closed
XV-47-1-26	Scram inlet valve	Scram inlet	Closed	Open	Open
XV-47-1-27	Scram exhaust valve	Scram exhaust	Closed	Open	Open
XV-47-1F180	SDV drain valve	Isolation	Open	Closed	Closed
XV-47-1F181	SDV drain valve	Isolation	Open	Closed	Closed

Table 9.3-4 (Cont'd)

SYSTEM AND VALVE OR DAMPER NO.	DESCRIPTION	DESIGN FUNCTION	NORMAL POSITION	FAIL POSITION	SAFE POSITION
E. REACTOR CORE ISOLATION COOLING (Drawing M-49)					
HV-49-1F025	Steam drain line	Isolation	Open	Closed	Closed
HV-49-1F026	Steam drain line	Isolation	Open	Closed	Closed
LV-49-1F054	Steam drain line	Bypass	Closed	Closed	Closed
HV-50-1F004	Drain line on the RCIC	Drain isolation vacuum tank condensate pump	Closed	Closed	Closed
HV-50-1F005	Drain line on the RCIC	Drain isolation vacuum tank condensate pump	Open	Closed	Closed
F. RHR SYSTEM (Drawing M-51)					
HV-51-142A,B,C&D	LPCI pump discharge lines	Inboard testable check valve bypass to equalize pressure for testing check valves	Closed	Closed	Closed
HV-51-151A&B	Shutdown cooling return Lines	Inboard testable check valve bypass to equalize pressure for testing check valves	Closed	Closed	Closed
HV-51-1F079A&B & 1F080A&B	RHR heat exchanger discharge	Sample line isolation process sample line	Closed	Closed	Closed
HV-51-1F074	RHRSW intertie line drain	Drain line isolation	Open	Closed	Closed
HV-C-51-103A,B	RHR heat exchanger outlet bypass valve	Isolation	Closed	Closed	Closed
HV- 51-1F041A,B,C,D	LPCI injection testable check valve	Isolation	Closed	Closed	Closed
HV- 51-199A,B	RHR heat exchanger sample valve	Isolation	Open	Closed	Closed

Table 9.3-4 (Cont'd)

SYSTEM AND VALVE OR DAMPER NO.	DESCRIPTION	DESIGN FUNCTION	NORMAL POSITION	FAIL POSITION	SAFE POSITION
HV-51-156A&B & 157A&B	Demineralized water supply to RHR heat exchangers (tube side)	Isolation of demineralized water system from RHRSW	Closed	Closed	Closed
HV-51-158A&B	Demineralized water flush for RHR heat exchangers (tube side)	Shutoff demineralized water flush for RHR heat exchangers	Closed	Closed	Closed
G. CORE SPRAY SYSTEM					
HV-52-1F039A&B	Core spray pump discharge Line	Inboard testable check valve bypass to equalize pressure for testing check valves	Closed	Closed	Closed
HV-52-1F006A,B	A(B) loop testable check PCIV	Isolation	Closed	Closed	Closed
HV-51-108	B loop outboard discharge A/O check PCIV	Isolation	Closed	Closed	Closed
H. HIGH PRESSURE COOLANT INJECTION (Drawing E41-1020-G-002)					
HV-55-1F028	Steam drain line	Isolation	Open	Closed	Closed
HV-55-1F029	Steam drain line	Isolation	Open	Closed	Closed
HV-55-1F054	Steam drain line	Bypass	Closed	Closed	Closed
HV-56-1F025	Drain line on the HPCI	Drain isolation vacuum tank condensate pump	Open	Closed	Closed
HV-56-1F026	Drain line on the HPCI vacuum tank condensate pump	Drain isolation	Closed	Closed	Closed
I. CONTAINMENT ATMOSPHERIC CONTROL (Drawing M-57)					
HV-57-121	Nitrogen purge supply to drywell	Containment isolation	Closed	Closed	Closed
HV-57-123	Purge air inlet to drywell	Containment isolation	Closed	Closed	Closed
HV-57-124	Purge air inlet to suppression chamber	Containment isolation	Closed	Closed	Closed
HV-57-131	Nitrogen purge supply to suppression chamber	Containment isolation	Closed	Closed	Closed

Table 9.3-4 (Cont'd)

SYSTEM AND VALVE OR DAMPER NO.	DESCRIPTION	DESCRIPTION	NORMAL POSITION	FAIL POSITION	SAFE POSITION
HV-57-104	Purge exhaust from suppression chamber	Containment isolation	Closed	Closed	Closed
HV-57-117	Purge exhaust from drywell	Containment isolation	Closed	Closed	Closed
HV-57-118	Purge exhaust from suppression chamber	Containment isolation	Closed	Closed	Closed
HV-57-114	Purge exhaust from drywell	Containment isolation	Closed	Closed	Closed
J. PRIMARY CONTAINMENT INSTRUMENT GAS (Drawing M-59)					
HV-59-129A,B	Instrument gas supply to primary containment	Containment isolation	Open	Closed	Closed
HV-59-131	Instrument gas supply to TIP indexing mechanisms	Containment isolation	Open	Closed	Closed
HV-59-102	Instrument gas suction from primary containment	Containment isolation	Open	Closed	Closed
HV-59-135	Instrument gas supply to primary containment vacuum relief valves	Containment isolation	Open	Closed	Closed
K. LIQUID RADWASTE COLLECTION (Drawing M-61)					
HV-61-110	Drywell floor drain sump containment isolation valve	Drain and isolation	Open	Closed	Closed
HV-61-111	Drywell floor drain sump containment isolation valve	Drain and isolation	Closed	Closed	Closed
HV-61-130	Drywell equipment drain sump containment isolation valve	Drain and isolation	Open	Closed	Closed

Table 9.3-4 (Cont'd)

SYSTEM AND VALVE OR DAMPER NO.	DESCRIPTION	DESIGN FUNCTION	NORMAL POSITION	FAIL POSITION	SAFE POSITION
HV-61-131	Drywell equipment drain sump containment isolation valve	Drain and isolation	Closed	Closed	Closed
L. REACTOR ENCLOSURE HVAC[2] (Drawing M-76)					
HV-76-030&031	Drywell purge exhaust System	Isolation of drywell purge fans from SGTS	Closed	Closed	Closed
HV-76-107&108	Reactor enclosure air supply system	Isolation of system from outside air	Open	Closed	Closed
HV-76-117&118	Refueling area air supply System	Isolation of system from outside air	Open	Closed	Closed
HV-76-141&142	Reactor enclosure equipment compartment air exhaust system	Isolation of system from outside air	Open	Closed	Closed
HV-76-151&152	Reactor enclosure equipment compartment air exhaust to RERS inlet duct	Divert equipment compartment exhaust air to RERS inlet	Closed	Open	Open
HV-76-157&158	Reactor enclosure air exhaust system	Isolation of system from outside air	Open	Closed	Closed
HV-76-159&160	Reactor enclosure air exhaust to RERS inlet duct	Divert reactor enclosure exhaust air to RERS inlet	Closed	Open	Open
HV-76-167&168	Refueling area air exhaust System	Isolation of system from outside air	Open	Closed	Closed
HV-76-196&197	Reactor enclosure RERS discharge to SGTS inlet duct	Open air flow path from RERS to SGTS system on isolation signal	Closed	Open	Open
HV-76-019&020	Refueling Area to SGTS inlet duct	Open air flow path from refueling area to SGTS system on isolation system	Closed	Open	Open

Table 9.3-4 (Cont'd)

SYSTEM AND VALVE OR DAMPER NO.	DESCRIPTION	DESIGN FUNCTION	NORMAL POSITION	FAIL POSITION	SAFE POSITION
M. CONTROL STRUCTURE HVAC (Drawing M-78)					
HV-78-021A,B	Control room normal fresh air intake duct	Isolation of control room from nonfiltered outside air during radiation or toxic gas isolation	Open	Closed	Closed
HV-78-052A,B	Control room exhaust air Duct	Isolation of control room exhaust air duct from outside air during radiation or toxic gas isolation	Open	Closed	Closed
HV-78-057A,B & 071A,B	Control room toilet exhaust Duct	Isolation of control room toilet exhaust air duct from outside air during radiation or toxic gas isolation	Open	Closed	Closed
HD-78-053A,B	Control room return air Duct when open; in closed position air diverted to purge exhaust	Parallel dampers to allow return air to supply units Standby, Closed	Operating, Open Open	Open Open	Open Open
HD-78-090 A-F HD-78-091 A-F	Battery rooms exhaust/ return ducts	Series dampers to close upon loss of normal power to battery room exhaust fans	Open	Closed	Closed
HD-78-092A,B HD-78-093A,B	Emergency switchgear and battery room air conditioning unit inlet duct from battery rooms	Parallel dampers to open upon loss of normal power to battery room exhaust fans to allow recirculation and mixing of battery room return air	Closed	Open	Open
HD-78-030A,B	Control room exhaust purge selection	Parallel dampers to allow directional flow of purged air and smoke across control room in event of fire	Open	Open	Open

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(1) Includes local, seismic Category I accumulators

(2) Unless otherwise noted only valves and dampers in Unit 1 are listed. Valves and dampers in Unit 2 are identical, and the valve or damper number begins with a 2 or 5, rather than a 1 or 4, respectively. Valves or dampers whose number begins with a 0 are common to both units.

(3) System is common to both units, valves for both units are listed.

Table 9.3-5

PLANT DRAINAGE SYSTEMS COMPONENT DESCRIPTION [1]

	SUMPS			PUMPS					
DRAINAGE SYSTEM	QUANTITY	TYPE	WORKING CAPACITY (gal)	EACH QUANTITY	TYPE	TOTAL DISCHARGE HEAD (ft)	FLOW RATE EACH (gpm)	HP	DESIGN PRESS/TEMP (psig/^{O}F)
Drywell equipment drains	1	Horizontal, SS, tank with cooling coil	500	None	-	-	-	-	-
Drywell floor drains	1	Horizontal, SS, tank	500	None	-	-	-	-	-
Reactor enclosure equipment drains	1	Lined sump	1000	2	Vertical, centrifugal	70	50	5	150/140
Reactor enclosure floor drains	1	Lined sump	1000	2	Vertical, centrifugal	80	100	5	150/140
Radwaste enclosure equipment drains[2]	1	Lined sump	1000	2	Vertical, centrifugal	60	50	3	150/140
Radwaste enclosure floor drains[2]	1	Lined sump	1000	2	Vertical, centrifugal	60	50	3	150/140
Turbine enclosure condensate backwash area equipment drains	1	Lined sump	1000	2	Vertical, centrifugal	70	50	5	150/140
Turbine enclosure condensate backwash area floor drains	1	Lined sump	1000	2	Vertical, centrifugal	70	50	5	150/140
Turbine enclosure condensate pump area equipment drains	1	Lined sump	1000	2	Vertical, centrifugal	70	50	5	150/140
Turbine enclosure condensate pump area floor drains	1	Lined sump	1000	2	Vertical, centrifugal	70	50	5	50/140
Water treatment enclosure chemical waste drains[2]	1	Horizontal cylinder, brick lined	2100	2	Vertical, centrifugal	55	150	5	50/120
Water treatment enclosure normal waste drains[2]	1	Rectangular concrete	4500	2	Vertical, centrifugal	40	100	7.5	50/120
Turbine enclosure oily waste drains	1	Rectangular concrete	2500	2	Vertical, centrifugal	40	100	5	50/160
Turbine enclosure normal waste drains	3	Rectangular concrete	1700	6	Vertical, centrifugal	35	100	2	50/160
Circulating water pump structure normal waste drains	1	Rectangular concrete	2000	2	Vertical, centrifugal	35	100	2	30/140
Hot Maintenance Shop[2]	1	Lined Sump	1000	2	Vertical, centrifugal	80	50	5	150/140

[1] Component description is based on one unit.
[2] This equipment is common to Units 1 and 2.

Table 9.3-6

STANDBY LIQUID CONTROL SYSTEM OPERATING PRESSURE/TEMPERATURE CONDITIONS

	TEST MODES							
	STANDBY MODE [1]		CIRCULATION TEST[1]		INJECTION TEST[2]		OPERATING MODE	
PIPING	PRESS[3] (psig)	TEMP (^{O}F)	PRESS[3] (psig)	TEMP (^{O}F)	PRESS[3] (psig)	TEMP (^{O}F)	PRESS[3] (psig)	TEMP (^{O}F)
Pump suction	Storage tank static head	65/106[4]	Test tank static head[5]	65/106	Test tank static head[5]	65/106	Storage head static head	65/106
Pump discharge to explosive valve inlet	Storage tank static head	65/106	0/1220	65/106	40 plus reactor static head	65/106	(70 plus reactor static head) to 1220	65/106
Explosive valve outlet to but not including first motor-operated-stop-check (shutoff) globe valve	Reactor static head to 1205[6]	65/106	Reactor static head to 1205[6]	65/106	<40 plus reactor static head	65/106	(<70 plus reactor static head to <1220	65/106
Motor-operated stop-check globe valve to the reactor	Reactor static head to 1205[6]	65/560[7]	Reactor static head to 1205[6]	65/560[7]	Reactor static head[2]	<140[2]	Reactor static head to 1205[6]	65/560[7]

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(1) The pump flow rate is zero (pump not operating) during the standby mode and at rated flow during the test and operating modes.

(2) Reactor to be at 0 psig and <140°F before changing from the standby mode to the injection test mode.

(3) Pressures tabulated represent pressure at the points identified below. To obtain pressure at intermediate points in the system, the pressures tabulated must be adjusted for elevation difference and pressure drop between such intermediate points and the pressure points identified below:

Piping	Pressure Point
Pump suction	Pump suction flange inlet
Pump discharge to explosive valve inlet	Pump discharge flange outlet
Explosive valve outlet to but not including first isolation check valve	Explosive valve outlet
First isolation check valve to the reactor	Reactor sparger outlet

(4) During chemical mixing, the liquid in the storage tank will be at a maximum temperature of 160°F.

(5) Pump suction piping will be subject to demineralized water supply pressure during flushing and filling of the piping and during any testing where suction is taken directly from the demineralized water supply line rather than the test tank.

(6) Maximum reactor operating pressure is 1205 psig at reactor standby liquid control sparger outlet.

(7) 560°F represents maximum sustained operating temperature.

9.4 HEATING, VENTILATION, AND AIR CONDITIONING SYSTEMS

9.4.1 CONTROL ROOM AND CONTROL STRUCTURE VENTILATION SYSTEMS

The following systems are covered in this section:

a. Control room HVAC system (Section 9.4.1.1)

b. Auxiliary equipment room HVAC system (Section 9.4.1.2)

c. Emergency fresh air supply system (Section 9.4.1.3)

d. Control structure HVAC systems from turbine enclosure (Section 9.4.1.4)

e. SGTS equipment compartment HVAC systems (Section 9.4.1.5)

f. Emergency switchgear and battery compartments HVAC system and battery compartments system (Section 9.4.1.6)

9.4.1.1 Control Room HVAC System

The control room HVAC system is common to Units 1 and 2. It provides ventilation, cooling, and control of environmental conditions in the control room and the adjacent support offices, toilet, and utility rooms.

The control room HVAC system is safety-related. The toilet room exhaust fan, electric heating coils, roll filters and humidification systems are not safety-related.

9.4.1.1.1 Design Bases

a. The control room HVAC system maintains the space relative humidity for personnel comfort and equipment performance under normal operation.

b. The control room HVAC system maintains the space temperature for personnel comfort and ensures the operability of control room equipment and instruments under normal and accident conditions.

c. The control room HVAC system active components are designed with redundancy to meet the single active failure criteria.

d. The control room HVAC system equipment is served by redundant power supplies that are designed to meet IEEE 279 and IEEE 308.

e. The control room HVAC system monitors radioactive contamination in the outside air intake. It isolates the normal fresh air intake and reroutes contaminated fresh air through the emergency charcoal filters upon high radiation detection. A positive pressure is maintained in the control room to inhibit the infiltration of outside air.

f. The control room HVAC system monitors offsite toxic chemical contamination in the outside air intake. This system provides indication for manual isolation of the control

room upon offsite toxic chemical detection and recirculates control room air through charcoal filters.

g. Provision is made for purging areas served by the control room HVAC system of smoke from a fire by using a 100% fresh air supply and exhausting 100% of the air.

h. The control room HVAC system is designed to seismic Category I requirements, with the exception of the humidification equipment, roll-filters, electric duct heaters and toilet room exhaust fan. Seismic category, quality group classification, and corresponding codes and standards that apply to the control room HVAC system are discussed in Section 3.2. The electric duct heaters are seismic Category IIA. The roll-filter frame and supports are seismic Category I but not the filter media. The humidifier is supported by seismic Category I supports and is enclosed within a seismic Category I debris grille structure.

i. The equipment, ducts, and accessories for the control room HVAC system are missile-protected as discussed in Section 3.5.

j. The fresh air intake ducts are designed to withstand the pressure effects of a tornado.

k. The control room HVAC system is designed to operate during normal, shutdown, and accident conditions without loss of function.

l. Isolate exhaust duct of Unit 2 toilet room in the event of a high energy pipe break in the turbine enclosure.

m. The control room HVAC system is a subsystem of the control room emergency fresh air supply system (CREFAS) and provides the flowpath to and from the control room whenever the CREFAS is in operation.

9.4.1.1.2 System Description

The control room HVAC and auxiliary equipment room systems are similarly designed. The system description for both systems is given in Section 9.4.1.2.2.

9.4.1.2 Auxiliary Equipment Room HVAC System

The auxiliary equipment room HVAC system is common to Units 1 and 2, and it serves the auxiliary equipment room, remote shutdown room, computer room, control structure fan rooms, SGTS access area, and SGTS room.

The safety-related function of the auxiliary equipment room HVAC system is to provide cooling to the PGCC (located in the auxiliary equipment room), the remote shutdown room, and the control structure fan rooms. The humidification components, roll filters, and electric duct heaters are not safety-related.

9.4.1.2.1 Design Bases

a. The auxiliary equipment room HVAC system maintains the space temperature for personnel comfort (except the fan rooms, which are 104°F maximum and the SGTS access area EL. 377'-0 which is 107°F) and ensures the operability of the equipment under normal and accident conditions.

b. The auxiliary equipment room HVAC system maintains the space relative humidity as required for computer performance under normal operation.

c. The auxiliary equipment room HVAC system active components are designed with redundancy to meet the single active failure criteria.

d. The auxiliary equipment room HVAC system equipment is served by redundant Class 1E power supplies that are designed to meet IEEE 279 and IEEE 308.

e. Provision is made for purging areas served by the auxiliary equipment room HVAC system of smoke from a fire by selecting a 100% fresh air supply and 100% exhaust.

f. The auxiliary equipment room HVAC system is designed to seismic Category I requirements, with the exception of roll-filters, electric duct heaters, and the humidification equipment. The electric duct heaters are seismic Category IIA. The roll-filter frame and supports are seismic I but not the filter media. Seismic category, quality group classification, and corresponding codes and standards that apply to the auxiliary equipment room HVAC system are discussed in Section 3.2.

g. The equipment, ducts, and accessories for the auxiliary equipment room HVAC system are missile-protected as discussed in Section 3.5.

h. The auxiliary equipment HVAC system (except for humidification, roll-filter motors, and the electric duct heaters) is designed to operate during normal, shutdown, and accident conditions without loss of function.

9.4.1.2.2 System Description

The control room and auxiliary equipment room HVAC systems are similarly designed. Both systems are shown in drawing M-78. Design parameters for the control room and auxiliary equipment room HVAC systems are listed in Tables 9.4-1 and 9.4-2.

Each system is served by two 100% capacity redundant supply air handling units and two 100% capacity return air fans (one operating and one on standby). Each supply unit contains a roll-filter, chilled water cooling coils, a vaneaxial fan, and a humidifier. The air handling units are connected to a common seismic Category I supply and return duct system that distributes supply air throughout the space and returns room air to the units. The return air is cooled by chilled water cooling coils. The control room and the auxiliary equipment room air conditioning equipment are located within the seismic Category I control structure. Equipment in each redundant system is powered from an independent Class 1E power source, except for the electric humidifiers, roll-filter motors and the electric duct heaters.

The chilled water for the cooling coils in each system is supplied by a seismic Category I independent chilled water supply system. The chilled water systems are interlocked with their respective supply air fans in the same division. The chilled water system is described in Section 9.2.10.

When the fan starts, the chilled water pump in the same division automatically starts. Failure of any of the control room fans is annunciated in the control room. Following failure of any control room fan, the standby division air systems and chilled water pump start automatically. Some procedures direct manual operation of the control room HVAC system during plant operations to support testing, inspection, repair, replacement activities and normal system operation. When the control room HVAC system is operated in this manual mode, procedures direct the manual initiation of standby equipment and the use of an operator to compensate for the temporary removal of the automatic start of the fan(s) in "Off". During periods when the fan(s) may be left in "Off", the operator will be a dedicated operator in addition to the Technical Specifications minimum required staffing levels for the control room. Failure of any of the auxiliary equipment room fans is annunciated on the local panel with a common panel alarm annunciating in the control room. Following failure of any auxiliary equipment room fan, the standby division air systems and chilled water pump start automatically.

Fan selector switches in the control room panel allow manual selection of the control room fans. Fan selector switches on local panels OAC101 and OBC101 allow manual selection of the auxiliary equipment fans.

Each air system is provided with an air temperature controller that regulates the temperature of the room air. The controller modulates a three-way mixing valve to control chilled water flows through the cooling coils.

Each system supplies a minimum quantity of outside air and recirculates conditioned air to maintain space requirements; space humidity is controlled during normal operations.

The outside air is taken from an outside air intake system, which is described in the emergency fresh air supply system in Section 9.4.1.3.2. The control room and auxiliary equipment room HVAC systems are supplied with outside air through branch ducts from the outside air intake system. A preset quantity of outside air is provided for these systems. This branch outside air duct connects with the fan intake plenum which is equipped with an electric duct heater. Temperature elements sensing both the supply air and the return air provide input signals to an instrument loop that transmits a controlling signal to the electric heater to modulate the air temperature in the supply fan intake plenum. The duct heater unit is seismic Category IIA and is a non-Class 1E circuit.

A humidification system is provided for the control and auxiliary equipment room HVAC system. A humidistat mounted in the control room return air duct regulates a controller to maintain humidity in the control room. The humidification system is designed for normal operation only and is not a safety-related system.

The SGTS room is supplied by conditioned air from the control enclosure auxiliary equipment room supply system. This air is humidity controlled based on maintaining 50% ±5% relative humidity at 76°F in the auxiliary equipment room. During normal operation, the maximum SGTS room temperature is 104°F based on worst case outside temperature and humidity. Outside air is limited to 8% of total supply air during normal operation. The mixed air is dehumidified by the supply unit cooling coil. The SGTS room is further dehumidified, to below the auxiliary equipment room control point relative humidity, by the higher temperature in the SGTS room. This results in exhaust air humidity to the charcoal adsorbers well below 70%.

The areas served by the control room HVAC system are designed to be maintained at a positive pressure during the high radiation isolation mode and normal operation.

During normal operation, the pressurized air in the control room areas is relieved through a pressure differential control damper to the control room exhaust stack.

The operation of the control room HVAC system during the isolation phase is described in Section 6.4.

The toilet exhaust fan system is not safety-related. The hand control switches for the fan are located on the local control panel. The operation of this fan is strictly manual. Since the control room may be directly exposed to the outside environment through the control room toilet exhaust system, fail-closed, redundant isolation valves in series are installed at the intake of the toilet exhaust fan. These isolation valves are automatically closed by the high outside air radiation signals or are remote manually closed following a high offsite chlorine or toxic chemical signal.

Two steam flooding isolation dampers in series are provided in the exhaust duct of the Unit 2 turbine enclosure toilet room (drawing M-78) that could be exposed to a turbine enclosure high energy pipe break. The turbine enclosure toilet room has a common exhaust with the control room toilet room. Each damper is provided with a pressure differential switch that trips the release mechanism to close the damper on sensing high pressure developed inside the Unit 2 turbine enclosure. The leakage rate for isolation damper is 1 cfm/ft^2 maximum.

9.4.1.3 Emergency Fresh Air Supply System

The emergency fresh air supply system is common to Units 1 and 2. It is designed to provide filtration for control room fresh air and recirculated air during a high radiation accident and to provide filtration for control room recirculated air during a chlorine or offsite toxic chemical release accident to maintain control room habitability.

The emergency outside air supply system is safety-related and designed to seismic Category I requirements. Additional discussion of this system appears in Sections 6.4 and 6.5.1.

9.4.1.3.1 Design Bases

a. The emergency fresh air supply system is activated automatically by detection of radiation or remote manually by detection of chlorine or offsite toxic chemicals at the control room HVAC system outside air intake.

b. The emergency fresh air supply system is designed to recirculate and clean up control room air when offsite toxic chemicals or chlorine is present in the outside air.

c. The emergency fresh air supply system is designed to maintain filtered outside air supply to the control room areas during radiation accident conditions.

d. The emergency fresh air supply system is designed to maintain a positive pressure above atmospheric to inhibit air leakage into the control room areas during radiation isolation. The fresh air system is totally isolated, with the filters in a recirculation mode, only during a chlorine or offsite toxic chemical isolation.

e. The emergency fresh air supply system is designed to operate during and after an accident and isolation mode conditions without loss of function.

f. The emergency fresh air supply system active components are designed with redundancy to meet the single active failure criteria.

g. The emergency fresh air supply system equipment is served by redundant Class 1E power supplies, which are designed to meet IEEE 279 and IEEE 308.

h. The emergency fresh air supply system is designed to seismic Category I requirements.

i. The equipment, ducts, and accessories for the emergency fresh air supply system are housed in a missile-protected structure.

j. The emergency fresh air intake ducts are designed to withstand the pressure effects of a tornado.

k. The emergency fresh air supply system utilizes the control room HVAC system as a flowpath to and from the control room during operation.

9.4.1.3.2 System Description

The emergency fresh air supply system consists of two 100% seismic Category I filter trains complete with fans, as described in Sections 6.4 and 6.5.1. Each train is powered from an independent Class 1E power source.

The system is shown in drawing M-78. Design parameters are listed in Tables 9.4-1 and 9.4-2.

Each filter train is connected to a common seismic Category I duct system. The emergency fresh air supply system is located within the seismic Category I control structure.

As discussed in Section 6.4.3, not all of the return air from the control room passes through the CREFAS system when the outside air intake is closed. As indicated in Table 9.4-1, the CREFAS system is designed to process 3000 scfm, while the control room supply unit is designed for 26,200 scfm. Therefore, approximately 11% of the total control room air passes through the CREFAS system. During CREFAS system operation, valves HV-078-021A and HV-078-021B are closed, forcing any outside air entering the control room through the CREFAS system. By adjusting dampers PDC-078-013A,B and PDC-078-014A,B, a portion of the control room return air is allowed to mix

with the fresh air from processing through the CREFAS system. The mixing of outside air and return air is controlled by the room pressure and return air through the CREFAS system maintains the control room radiation doses below the allowable levels, as demonstrated by the analysis in Section 15.6.5.

When the emergency fresh air supply system is in operation, the volume of air flowing in the fan discharge duct is continuously indicated on a local panel. The filter train pressure differential is continuously indicated on a local control panel. The loss of airflow automatically trips and isolates the operating train and starts the standby train. Both loss of airflow and high pressure differential across the filter train are alarmed in the control room. Temperature detectors monitor the temperature of the charcoal adsorber. The temperature is alarmed and indicated in the control room. The fire protection water valves are manually actuated, if required. Actuation of the fire protection system will produce an alarm in the control room.

ESF atmosphere cleanup systems are accessible during normal operation and during anticipated transients. ESF atmosphere cleanup systems operate only after an accident or during drywell purge. This allows records to be kept of periodic tests performed during normal operation on all ESF atmosphere cleanup systems, which ensures that prefilters and HEPA filters are either changed on high pressure readings or checked on abnormal readings.

The outside air for the control room HVAC system and auxiliary equipment room HVAC system are taken from a common outside air intake. The outside air intake is missile-protected and connected to seismic Category I design duct systems.

During normal operation, the outside air is drawn through the ducts and distributed to each system as described above.

Each charcoal train is continuously purged with 1 cfm of dry instrument air; however, any amount of dry air continuously purged through the adsorbers and HEPA filters will entrain moisture and maintain moisture levels at a minimum because the duct-work is gas-tight and there is no internal humidity source. (The periodic operation of the ESF atmosphere cleanup train could introduce additional moisture into the system and increase moisture levels above those normally maintained.)

When high radiation is detected at the outside air intake, the control room outside air is automatically diverted through the emergency fresh air filter system. All isolation valves in the control room HVAC system close, except those on the emergency fresh air intake.

When offsite toxic chemical is detected at the outside air intake, the high toxic chemical signal is annunciated in the control room. All isolation valves in the control room HVAC system will be manually closed after a toxic chemical is detected. These include:

a. Exhaust isolation valves

b. Control room relief air duct isolation dampers

c. Outside air isolation valves, including the normal and emergency fresh air valves

The control room HVAC system is manually isolated for chlorine. After control room isolation is completed, the emergency fresh air system is started and operated to recirculate and clean up space air in the control room. The outside air intake valves remain closed during this mode of operation.

9.4.1.4 Control Structure HVAC Systems from Turbine Enclosure

The Unit 1 and 2 turbine enclosure HVAC systems provide heating, ventilating, and air conditioning during normal plant operation for given nonsafety-related areas on el 180', el 200', el 217', and el 254' in the control structure. These HVAC systems are not safety-related except the steam flooding isolation dampers, which are safety-related.

9.4.1.4.1 Design Bases

The turbine enclosure HVAC systems are designed to accomplish the following objectives during normal plant operation:

a. Maintain temperatures in the various spaces within specified limits (104°F maximum for access areas, pump-rooms, and cable spreading rooms; 112°F maximum for recombiner compartments, 122°F maximum for condensate backwash receiving tank compartment)

b. Meet the specified cooling and ventilation requirements to ensure the operability of the equipment and instruments without loss of function

c. Provide HEPA and charcoal filtration of potentially contaminated equipment compartment exhaust air prior to release to the atmosphere

d. Isolate supply and exhaust ducts and infiltration openings of compartments containing high energy pipes in the event of a pipe break.

9.4.1.4.2 System Description

The turbine enclosure HVAC systems serving the control structure are shown in drawings M-75, M-76, M-78 and M-79. Several areas of the control structure are served by the turbine enclosure Unit 1 and Unit 2 supply air, exhaust air, and filtered equipment compartment exhaust air systems. These areas are the condensate backwash receiving tank and pump compartments and the recombiner compartment on el 180', the control room chiller and analyzer compartments on el 200', the auxiliary switchgear room (makeup air) on el 217', and the cable spreading room on el 254'. These systems maintain the required design temperatures, supply ventilation air, and provide filtered exhaust for equipment compartments that may be contaminated. These systems do not operate on LOOP and are not safety-related.

Two steam flooding isolation dampers in series are provided on supply and exhaust ducts of selected compartments (drawing M-78) containing high energy piping. Each damper is provided with a pressure differential switch that trips the release mechanism to close the damper on sensing high pressure developed inside the room. The leakage rate for isolation damper is 1 cfm/ft^2 maximum.

9.4.1.5 SGTS Equipment Compartment HVAC Systems

The SGTS equipment compartment HVAC systems are common to Units 1 and 2.

The SGTS equipment compartment filtered exhaust system is designed to filter exhaust ventilation from the SGTS equipment compartment during normal plant operation. The SGTS room and SGTS access area unit coolers are designed to provide emergency cooling for the SGTS equipment compartment during SGTS operation under emergency conditions.

The SGTS equipment compartment filtered ventilation exhaust system is not a safety-related system. Conformance with Regulatory Guide 1.140 (March 1978) is discussed in Table 9.4-18. The SGTS room unit coolers and SGTS access area unit coolers are safety-related.

9.4.1.5.1 Design Bases

a. The SGTS equipment compartment HVAC systems are designed to maintain temperatures in the space within a range suitable for equipment performance.

b. The SGTS equipment compartment HVAC systems are designed to maintain adequate air flow for ventilation.

c. The SGTS room and SGTS access area unit coolers active components are designed with redundancy to meet the single active failure criterion.

d. The SGTS room and SGTS access area unit coolers are served by redundant Class 1E power supplies designed to meet IEEE 279 and IEEE 308.

e. The SGTS room and SGTS access area unit coolers are designed to seismic Category I requirements.

f. The SGTS room and SGTS access area unit coolers, ducts and accessories are housed in a missile-protected structure.

9.4.1.5.2 System Description

The SGTS equipment compartment HVAC systems are shown in drawing M-78. Design parameters are listed in Table 9.4-1.

Normal ventilation air for the SGTS equipment compartment is supplied from the auxiliary equipment HVAC system. The exhaust air is treated by a redundant, charcoal filtered, ventilation exhaust system prior to being discharged to the atmosphere. During standby diesel generator operation, redundant emergency SGTS unit coolers automatically cycle on room temperature to provide cooling. The normal ventilation exhaust system is supplied from a non-Class 1E circuit.

9.4.1.6 Emergency Switchgear and Battery Compartments HVAC System and Battery Compartments Exhaust System

The emergency switchgear and battery compartments HVAC system is common to Units 1 and 2. The emergency switchgear and battery compartments HVAC system is safety-related and is designed to provide ventilation and cooling for the Class 1E switchgear, batteries, inverters, and chilled water pump motors for both Units 1 and 2 under normal and abnormal station conditions. The battery rooms exhaust system is not safety-related and exhausts battery compartment air during normal station operation.

These systems are shown in drawing M-78. Equipment design parameters are listed in Table 9.4-1.

9.4.1.6.1 Design Bases

a. The emergency switchgear and battery compartments HVAC system is designed to maintain ambient temperatures suitable for equipment operation.

b. The active components of the emergency switchgear and battery compartments supply and return systems are designed with redundancy to meet the single active failure criterion.

c. The emergency switchgear and battery compartments supply and return systems equipment is served by redundant power supplies designed to meet IEEE 279 and IEEE 308.

d. The emergency switchgear and battery compartments supply and return system is designed to seismic Category I requirements.

e. The emergency switchgear and battery compartments HVAC system is housed in a missile-protected structure.

f. The battery compartments normal exhaust system is not safety-related and does not operate during LOOP. The battery compartments air is returned to the supply unit intake during emergency operation.

9.4.1.6.2 System Description

9.4.1.6.2.1 Battery Compartments Exhaust System

The system consists of redundant exhaust fans and isolation dampers. The system is designed to operate with one fan on standby and one operating. The branch ducts to each battery compartment are connected to a common duct system.

The battery compartments' makeup air is introduced by the turbine enclosure HVAC system. The exhaust fan system is designed to exhaust air from each battery compartment and discharge through the north vent stack to the atmosphere.

Two steam flooding isolation dampers in series are provided on exhaust ducts to the turbine enclosure (drawing M-78) that could be exposed to steam flooding breaks from energy piping. Each damper is provided with a pressure differential switch that trips the release mechanism to close the damper on sensing high pressure developed in the turbine enclosure. The leakage rate for isolation dampers is 1 cfm/ft^2 maximum.

During standby diesel generator operation (loss of offsite power), the battery compartment exhaust fans do not run, and the return from the battery rooms is diverted to the return duct-work for the emergency switchgear and battery compartment supply fans, diluted, and recirculated.

9.4.1.6.2.2 Emergency Switchgear and Battery Compartment Supply and Return Air System

The system consists of two 100% capacity seismic Category I air handling units (one operating and one standby). The systems are safety-related. Each air handling unit contains a roll-filter, a cooling coil, and a vaneaxial fan. The units are connected to a common seismic Category I supply and return duct system, which distributes supply air and returns compartment air from the two control structure chilled water pump motor locations on el 200', the control structure battery compartments on el 217' and el 239', the emergency switchgear compartments on el 239', and the inverter compartments on el 254'. The supply air is cooled by chilled water cooling coils. The emergency switchgear and battery compartment air conditioning equipment is located within the seismic Category I control structure. All equipment in each redundant system is powered from an independent Class 1E power source with the exception of the roll-filter motor.

The chilled water for the cooling coils in each system is supplied by a seismic Category I independent chilled water supply system. The chilled water systems, described in Section 9.2.10, are interlocked with their respective supply air fans in the same division.

When the supply fan starts, the chiller pump on the same division automatically starts. Failure of any of these fans is annunciated on the local panel, with a common panel alarm annunciating in the control room. When the standby fan starts, the standby division chilled water system starts automatically.

Fan selector switches on the local panel allow manual selection of systems.

Each air system is provided with an air temperature controller that regulates the temperature of the supply air. The controller modulates a three-way mixing valve to control the chilled water flow through the cooling coils.

9.4.1.7 Safety Evaluation

Safety-related control structure and control room HVAC systems are designed to maintain functional integrity during and after an SSE. Each system is provided with redundant equipment and controls to maintain uninterrupted room air circulation, and cooling, for personnel comfort and instrument functioning. Safety-related equipment is located within the control structure, a protected seismic Category I structure. During LOOP, standby power is automatically provided from the standby diesel generators for the continued operation of all safety-related equipment.

The single failure criterion for active safety-related equipment is met by using redundant equipment and controls and automatically switching from one redundant system to the other where actions are immediately required in response to accidents. The redundant control room air supply fan is manually started when required if a high operating supply fan discharge temperature occurs. Control room cooling can then be re-established in sufficient time, using manual actions, to maintain control room temperatures to support equipment and instrumentation functioning and operator comfort. Some procedures direct manual operation of the control room HVAC system during plant operations to support testing, inspection, repair, replacement activities and normal system operation. When the control room HVAC system is operated in this manual mode, procedures direct the manual initiation of standby equipment and the use of an operator to compensate for the temporary removal of the automatic start of the fan(s) in "Off". During periods when the fan(s) may be left in "Off", the operator will be dedicated operator in addition to the Technical Specifications minimum required staffing levels for the control room. Active equipment such as fans, controls, dampers, pumps, and chillers is redundant. Passive system components such as supply and return duct-work systems are common. Since redundant systems are provided for all temperature control functions of safety-related HVAC systems, temperature limits are not exceeded, and no degradation of equipment performance is anticipated.

This essential area has been provided with redundant HVAC equipment to maintain the required air flows and temperatures under normal and accident conditions. For failure mode and effects analysis, see Table 9.4-3 for both normal and accident conditions.

The control room HVAC system is designed to maintain environmental conditions within the space as specified for habitability and equipment operation under normal and abnormal operating conditions. The control room, which is the only critical manned area, will not exceed the comfort zone defined by ASHRAE during normal operating conditions. Equipment in the system is designed to seismic Category I requirements, except for the humidification equipment, roll filters, and electric duct heaters (seismic Category IIA). All duct-work and supports for the safety-related systems meet seismic Category I requirements. Habitability systems are further discussed in Section 6.4.

A radiation monitoring system is provided in the outside air intake to detect high radiation and initiate measures to ensure that personnel safety and equipment functions are not impaired and that the requirements of 10CFR20 are satisfied. In the event of a high radiation condition, the normal outside air supply to the control room HVAC system is diverted through the emergency fresh air filter train before being delivered to the control room. All isolation valves in the control room HVAC system close, except those on the emergency fresh air intake. These operations are annunciated in the control room.

The emergency fresh air filter train and the control room shielding are designed to limit the occupational dose level, as required by GDC 19.

The introduction of a controlled quantity of outside air maintains the control room and the other areas served by the control room HVAC system at a positive pressure with respect to surrounding areas. This positive pressure is maintained during all the plant operating conditions, except when the system is in the recirculation mode.

Offsite toxic chemical detectors are provided at the outside air intake to detect toxic chemical in the environment. In the event of a high chlorine or toxic chemical concentration, all isolation valves in the control room HVAC system close manually for all other toxic chemicals, including those on the emergency fresh air intakes. The control room HVAC system is switched to the recirculation mode to cycle room air through the emergency fresh air filter train (charcoal adsorber) system. The filter system is discussed in Section 6.5.1.

The control room HVAC system is initially in the radiation isolation mode. Under these circumstances, once the chlorine has been detected, manual action can be taken to realign the system to the chlorine isolation mode.

> Note: the possibility exists for a chlorine accident to occur while the control room HVAC system is operating in the radiation isolation mode for testing purposes or as required by the Action statement of an associated Technical Specifications Limiting Condition of Operation, and likewise, a high radiation accident could occur while the control room HVAC system is operating in the chlorine isolation mode for the same purposes. The mode of system operation with the control room HVAC system in these initial system configurations is described in Sections 2.2.3, 6.4.3 and 15.6.

A smoke purge system is provided with a capability to purge the control room or auxiliary equipment room areas. In the event of smoke as a result of fire in the control room areas or auxiliary equipment room areas, the operating personnel may elect to purge the space by manually switching the supply and exhaust systems to purge mode of operation, which repositions outside air and exhaust dampers so that 100% fresh air and 100% exhaust air provides once-through purge ventilation until the smoke is removed; then manually switch back to normal operation. The purge system is shown in drawing M-78.

The steam flooding isolation dampers have an active safety-related function in the control enclosure HVAC system. The function of the dampers is to contain the steam resulting from a pipe break within the equipment compartment in which the break occurs and preclude the spread of the steam through HVAC openings or duct-work into adjacent spaces which may contain safeguard equipment. The dampers are redundant series mounted fast closing counterweighted or spring-operated back pressure dampers. The dampers are normally open. Closure of the dampers is actuated by a pressure switch sensing the rise in pressure created by the discharge of fluid from a broken pipe. The switch activates a solenoid which disengages a pin and allows the damper blade to free fall or spring action into the closure position.

Each trouble alarm on the local control panel is alarmed in the control room as a panel group alarm. Indicating lights on the local panel identify the failed damper, which can be manually reset to the open position.

Refer to the following sections for further safety considerations included in the design:

a.	Protection from wind and tornado effects	Section 3.3

b.	Flood design	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11
f.	Fire protection	Section 9.5.1

9.4.1.8 Tests and Inspections

The control room and control structure HVAC systems and their components are thoroughly tested in a program consisting of the following:

a. Factory and component qualification tests (Table 9.4-4)

b. Onsite preoperational testing (Chapter 14)

c. Onsite subsequent periodic testing (Chapter 16)

Written test procedures establish minimum acceptable values for tests. Test results are recorded as a matter of performance record, thus allowing early detection of faulty performance.

All equipment is factory-inspected and tested in accordance with the applicable equipment specifications, codes, and quality assurance requirements. Refer to Table 9.4-4 for details of inspection and testing.

9.4.1.9 Instrumentation Requirements

The hand switches and the associated status indicating lights of safety-related equipment of the control room HVAC systems are located in the control room. Control switches for isolation valves are located in the control room, and indicating lights for isolation valves are located on local control panels.

Although the indicating lights for isolation valves are remote from the control room, the redundant isolation valves are in series and are designed to fail-safe in the closed position. In addition, the control logic is designed so that the redundant isolation signals of the isolation dampers override their corresponding control switch.

The control switches and status indicating lights for the remaining control structure HVAC equipment are located on the equipment, local panels, or local control stations.

Safety-related control room equipment failures, such as fans failing to establish airflow when required, are alarmed in the control room on one of two separate division annunciators. In addition, the following are alarmed or indicated in the control room:

a. High offsite toxic gas in the outside air

b. High radiation in the outside air

c. High temperature (preignition) in the charcoal adsorber of the emergency fresh air supply systems

d. High-high temperature (desorption) in the charcoal adsorber of the emergency fresh air supply systems

e. High-high-high temperature (ignition) in the charcoal adsorber of the emergency fresh air supply system

A failure of other control structure HVAC equipment is alarmed on local control panels and is retransmitted to the control room as a trouble alarm.

Instruments of the safety-related systems are seismically and environmentally qualified and redundant to meet the single failure criterion. Environmental qualification is discussed in Section 3.11.

9.4.2 REACTOR ENCLOSURE AND REFUELING AREA VENTILATION SYSTEMS

The following systems are covered in this section:

a. Nonsafety-related reactor enclosure and refueling area HVAC systems for normal operation and safety-related HVAC duct isolation (Section 9.4.2.1)

b. Safety-related reactor enclosure air cooling systems (Section 9.4.2.2)

The RERS and the SGTS are described in Section 6.5.1.

9.4.2.1 Reactor Enclosure and Refueling Area HVAC Systems for Normal Operation

The secondary containment is divided into three isolated ventilation zones. Zones I and II consist of the reactor enclosures which surround the primary containments of Units 1 and 2, respectively, below the floor at el 352'. Zone III consists of the common refueling area above the floor at el 352'. These zones are shown in Figures 6.2-27 through 6.2-35.

This section discusses Unit 1 reactor enclosure and refueling area HVAC systems. The Unit 2 reactor enclosure and refueling area HVAC systems are identical to those described for Unit 1. Each of the ventilation zones is provided with independent HVAC systems designed to operate during normal plant operation and during shutdown. The common refueling area has a separate Unit 1 and Unit 2 ventilation system. Zone III systems function during normal fuel handling and storage operation. The RERS, SGTS, and REIS are used after a postulated LOCA or on loss of differential pressure in Zone I or Zone II. The SGTS and RAIS may be used after a fuel handling accident or on a loss of differential pressure in Zone III. Table 6.2-28 identifies the associated secondary containment ventilation system automatic isolation valves that are required for normal separate zone alignment.

The ability to procedurally combine each of the reactor enclosure secondary containment zones to the common refueling area secondary containment zone exists. Refer to Section 6.2 for details of the interlock.

9.4.2.1.1 Design Bases

The portion of the reactor enclosure and refueling area ventilation systems that are associated with the RERS, SGTS and secondary containment isolation systems are safety-related. The remaining portion of the duct-work within the secondary containment boundary is not safety-related; however, it is seismically designed and analyzed to ensure that it will not damage the safety-related equipment and systems. Seismic classifications are shown in drawing M-76. Secondary containment isolation and isolation of the steam flooding dampers are the only active safety-related functions of the normal operation of the reactor enclosure and refueling area HVAC systems. These HVAC systems are designed to accomplish the following objectives during stable and transient operating conditions, from startup to full power to shutdown:

a. Provide filtered outside air at approximately 6.0 air changes per hour below the refueling floor and approximately 2.3 air changes per hour per unit in the refueling area above the refueling floor

b. Maintain air flow from areas of lesser to areas of greater potential contamination

c. Maintain space temperature so as not to exceed the maximum temperature of 104°F in the Refueling Area El. 352'-0", RERS Filter Compartments, Ventilation Fan Room El.313'-0", Access East El. 313'-0, North and South Corridors, Neutron Monitoring Area (Unit 1), Neutron Monitoring Area (Unit 2) and El. 177'-0" Access Areas; 110°F in the LPCI Isolation Valve Compartments, Core Spray Isolation Valve Compartment, Drywell Spray Isolation Valve Compartment and Backwash Receiving Tank Compartment; 112°F in the RWCU System Isolation Valve compartment; 113°F in the Piping Access El. 313'-0" and the RWCU System Non-Regenerative Heat Exchanger Compartments; 114°F in the RCIC Piping Area and 120°F in the HPCI Piping Area; 120°F in the Pipe Access (Nort) l. 201'-0" and North Pipe Access El.177'-0"; 122°F in the Main Steam Tunnel and Containment Isolation Valve Compartments El. 217'-0"; 123°F in the Pipe Tunnel El. 217'-0; 135°F in the Drywell Equipment Access (Southeast) El. 253'-0" and Drywell Equipment Access (Northwest) El. 253'-0"; 107°F in the South Cleanup Pump Room El. 313'-0" and in the Access (West) El. 201'-0"; and 106°F in the various remaining area of the reactor enclosure.

d. Maintain space temperature so that the minimum temperature is not below 65°F

e. Maintain the secondary containment at a negative pressure to prevent potential exfiltration of contaminated air.

f. Supply ventilation or purge air to the primary containment

g. Provide ventilation, cooling, and heating to the ECCS pump compartments during normal plant operation. (For safety-related cooling see Section 9.4.2.2).

h. Filter air exhausted from areas of greater potential contamination (equipment compartments - Zones I and II)

i. Monitor radiation in the unfiltered air from the refueling area (Zone III) exhaust system and isolate the refueling area on a high radiation signal

j. Monitor radiation in the reactor enclosure exhaust vent and isolate the reactor enclosure HVAC system on a high radiation signal

k. Provide for a transit time of exhaust air from the radiation monitors to the isolation valves of the refueling area unfiltered exhaust system so that the transit time is greater than the valve closing time plus the radiation monitor response time

l. Isolate appropriate ventilation zone or zones and start the RERS and/or SGTS upon receipt of the secondary containment isolation signal in the affected area

m. Isolate supply and exhaust ducts of compartments containing high energy pipes after a pipe break

n. Ensure that the secondary containment HVAC systems isolation valves and actuators are redundant, to meet the single active failure criterion

o. Ensure that the secondary containment HVAC systems isolation valve motor actuators are served by redundant power supplies that meet IEEE 279 and IEEE 308

p. Ensure that the HVAC isolation valves and actuators are designed to seismic Category I requirements

q. Ensure that the duct-work associated with the RERS, SGTS, and the secondary containment isolation systems are designed to seismic Category I requirements

Monitoring of radiation levels in the spent fuel pool area is discussed in Section 11.5.

9.4.2.1.2 System Description

The HVAC system P&ID for the reactor enclosure and refueling area is shown in drawing M-76. System design parameters are listed in Table 9.4-5. Chilled water is supplied to the air cooling coils in the HVAC systems by the DCWS, described in Section 9.2.10. The controls and instrumentation associated with each system are an integral part of the system.

All the equipment of the Unit 1 nonsafeguard air handling systems is located in two heating and ventilation equipment rooms (el 313' and el 332'). The two rooms are outside the secondary containment boundary.

Access to any zone from outside the zone or between the zones is through airlocks with airtight doors.

9.4.2.1.2.1 Reactor Enclosure Unit 1 (Zone I) Supply System (V-202) and Refueling Area (Zone III) Unit 1 Side Supply System (V-201)

Each system supplies its respective zone with conditioned 100% outdoor air. Each system includes, in the direction of air flow: outdoor air intake; roll filters; steam heating coils; chilled water cooling coils; three 50% capacity fans; two butterfly-type isolation valves in series; distribution duct-work with dampers; supply air outlets; and associated controls.

9.4.2.1.2.2 Reactor Enclosure Unit 1 (Zone I) Equipment Compartment Exhaust System (V-206)

This system exhausts air from equipment compartments with the higher potential for radioactive contamination. The system includes, in the direction of air flow: distribution duct-work with exhaust registers and dampers; two butterfly-type isolation valves in series; two 100% capacity filter trains; two 100% capacity fans; system discharge duct-work connecting to the reactor enclosure exhaust vent south stack; and associated controls. Each filter train contains prefilters, upstream HEPA filters, a charcoal absorber (2 inch deep vertical bed), and downstream HEPA filters.

Conformance of the equipment compartment exhaust air filter plenum to Regulatory Guide 1.140 is discussed in Table 9.4-18.

9.4.2.1.2.3 Reactor Enclosure Unit 1 (Zone I) Exhaust System (V-205) and Refueling Floor (Zone III) Unit 1 Side Exhaust System (V-204)

Each system exhausts air from the respective zone areas of lesser radioactive contamination potential. Each system includes, in the direction of air flows: distribution duct-work with exhaust registers and dampers; two butterfly-type isolation valves in series; three 50% capacity fans; discharge duct-work connecting to the reactor enclosure exhaust vent south stack; and associated controls.

9.4.2.1.2.4 Normal System Operation

During normal plant operation, the reactor enclosure and refueling area ventilation systems maintain the design temperature and pressure in the respective zones of Units 1 and 2. The supply air systems (V-202 and V-201) supply the respective zone with a constant air volume. Variable-pitch fan blades of exhaust systems V-205 and V-204 are modulated by appropriate pressure differential controllers to maintain a negative pressure in the secondary containment.

Each supply system is provided with two air temperature controllers (one for heating and one for cooling) to control the temperature of the air leaving the fans. The output of the steam heating coils is off-on, with face and bypass control. Chilled water flow through the cooling coils is modulated by three-way mixing valves controlled by the cooling controller. The cooling coils may be utilized during periods of high outside air temperature or periods of refueling outages.

The ventilation systems are designed to prevent high relative humidity during normal operation. The operation of the reactor enclosure equipment compartment exhaust system is similar to the operation of the turbine enclosure equipment compartment exhaust system (Section 9.4.4.2). The further heating of the access area air as it passes through the equipment compartments results in a relative humidity of less than 70% to the charcoal adsorbers.

Two of three 50% capacity fans of systems V-202, V-205, V-204, and V-201 operate during plant normal operation. When failure of a running fan or its discharge damper is detected the respective standby fan automatically starts. On failure of a fan or its discharge damper, the preferred air flow pattern is not affected.

Failure of the exhaust system results in an automatic shutdown of the supply ventilation systems in that zone. Failure of the reactor enclosure supply ventilation system resulting in high area negative pressure results in the automatic shutdown of the corresponding exhaust systems V-205 and V-206. Failure of the refueling area supply ventilation system resulting in high area negative pressure differential would automatically shut down the refueling area exhaust systems V-204.

Redundant radiation monitors are provided in the ducts of V-204 (refueling area exhaust system) upstream of the system isolation valves. A high radiation signal from any monitor automatically isolates the refueling area, as described in Section 9.4.2.1.3. The exhaust air transit time between the monitors and the V-204 system isolation valves is greater than the combined time of valve closure and the monitor response. The exhaust air transit time is 10 seconds and the combined monitor response and valve closing time is 4-6 seconds.

Redundant radiation monitors are also provided in the ducts of V-205 (reactor enclosure normal exhaust system) upstream of the system isolation valves. The isolation valves in this duct trip upon receipt of a high radiation signal as well as a LOCA signal (Section 9.4.2.1.3). The valve closure time is 3-5 seconds. The reactor enclosure normal exhaust air is not held up to assure closure of the valve prior to the exhaust air reaching the valves as the reactor enclosure normal exhaust system exhausts areas of the reactor enclosure which have a low release potential. If an accident (LOCA) were to occur which resulted in radioactivity escaping into those areas, isolation of this exhaust duct would be initiated upon receipt of a LOCA signal.

Isolation by this means would occur before any significant radioactivity is discharged due to the travel time from the affected compartments to the isolation valves. In any event, isolation will occur within about 5 seconds after receipt of a high radiation signal. Releases during this short time period will be a very small fraction of 10CFR50.67 limits.

The systems' intake louvers and exhaust vents are not safety-related and are outside the secondary containment; therefore, no provisions for missile protection are made for these portions.

All panel-mounted instruments and controls, including fan manual switches, are installed on local control panels. A group alarm from each panel is annunciated in the control room.

Two steam flooding isolation dampers in series are provided on supply and exhaust ducts of selected compartments (drawing M-76) containing high energy piping. Each damper is provided with a pressure differential switch that trips the release mechanism to close the damper, on sensing high pressure developed inside the room. The maximum design leakage rate for isolation dampers is 1 cfm/ft^2 at maximum delta P.

The primary containment is purged at a rate of 11,000 cfm. This amount of air is diverted to the primary containment from the reactor enclosure supply system. From there the air is filtered through the SGTS filter and exhausted to the environment via the north vent stack.

The reactor enclosure exhaust is provided with a radiation sampler in the south stack. A high radiation level in the exhaust air in the south stack is alarmed in the control room.

9.4.2.1.3 Safety Evaluation

The reactor enclosure ventilation system is housed within the seismic Category I reactor enclosure. The following safety design criteria are discussed in the following sections:

Wind and tornado protection	Section 3.3
Flood design	Section 3.4
Missile protection	Section 3.5

Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
Environmental design conditions	Section 3.11

The secondary containment isolation is an active safety-related function of the reactor enclosure and refueling area HVAC systems during normal operation. The passive safety-related function of the system is the use of related duct-work in the reactor enclosure recirculation mode, which is discussed in Section 6.5.1.

The isolation valves used for secondary containment isolation are redundant (two in series), fail closed, butterfly-type valves, operated by a spring-loaded air cylinder. If an active failure disables one of the two valves, the other one still performs the isolation function.

The appropriate ventilation zones of the secondary containment are automatically isolated upon receipt of one of the following signals:

Signal	Isolates Zone(s)
High radiation in the refueling area exhaust ducts	I(*), II(*), or III
High radiation in the reactor enclosure exhaust ducts	I, II, or III(*)
Low differential pressure in the referenced zone (after appropriate time delay)	I, II, or III
LOCA signal as described below	I, II, or III(*)
A manual isolation signal from the control room	I, II, or III

The LOCA signal, as applied to the HVAC isolation signal, consists of low reactor water level or high drywell pressure.

(*) The ability to procedurally combine each of the reactor enclosure secondary containment zones to the common refueling area secondary containment zone exists. When the zones are combined, the isolation signals for either of the zones will isolate all of the combined zones as required.
See Table 6.2-29.

Any of the above isolation signals results in the following automatic sequence for the affected zone or zones:

a. Close normally open isolation valves (two in series separating safety-related from nonsafety-related portions of each system) - Zones I, II, or III

b. Upon initiation of isolation valve closure, trip all running ventilation fans and prevent standby units from operating - Zones I, II, or III

c. Open normally closed isolation valves (two in parallel) on each duct connecting the RERS and SGTS fans and filters to the ventilation system duct-work used in the recirculation mode of operation - Zones I or II

d. Open normally closed isolation valves (two in parallel) located in the duct connecting the SGTS fans and filters to the refueling area, - Zone III

e. Start the RERS (Section 6.5.1) - Zones I or II

f. Start the SGTS (Section 6.5.1) - Zones I, II, or III

The steam flooding isolation dampers also have an active safety-related function in the reactor enclosure HVAC system. The function of the dampers is to contain the steam resulting from a pipe break outside containment within the equipment compartment in which the break occurs and preclude the spread of the steam through HVAC openings or duct-work into adjacent spaces which may contain safeguard equipment. The dampers are redundant series mounted fast closing counterweighted or spring-operated back pressure dampers. The dampers are normally open. Closure of the dampers is actuated by a pressure switch sensing the rise in pressure created by the discharge of fluid from a broken pipe. The switch activates a solenoid which disengages a pin and allows the damper blade to free fall or spring action into the closed position.

The failure of a steam flooding isolation damper in a closed position results in a loss of ventilation for the equipment compartment affected. Each trouble alarm on the local control panel is alarmed in the control room as a panel group alarm. Indicating lights on the local panel identify the failed damper, which can be manually reset to the open position.

The operational degradation of ventilation system components can be detected by direct equipment status indication (e.g., indicating lights for damper position or fan running status) or can be determined from abnormal temperature, differential pressure, alarms, and indication. Corrective action can then be taken.

Reactor enclosure and refueling area ventilation systems have been provided with redundant HVAC equipment to maintain the required air flows and temperatures under normal and accident conditions. See Table 9.4-7 for a failure modes and effects analysis of safety-related modes of operation. An FMEA during normal operation is not provided for the reactor enclosure for the following reasons:

a. Safety-related equipment in the ECCS compartments is cooled by individual redundant ECCS compartment coolers whenever the ECCS pumps start or the compartment temperature reaches 100°F as described in Section 9.4.2.2.2.

b. If the normal reactor enclosure ventilation system is lost, the SGTS and RERS will automatically start operating.

c. Safety-related equipment in the reactor enclosure is designed to perform safety functions under the environmental conditions resulting from a loss of the normal ventilation system.

9.4.2.1.4 Tests and Inspections

The reactor enclosure and refueling area HVAC systems and their components are thoroughly tested in a program consisting of the following:

a. Factory and component qualification tests (Table 9.4-4)

b. Onsite preoperational testing (Chapter 14)

c. Onsite subsequent periodic testing

Written test procedures establish minimum acceptable values for all tests. Test results are recorded as a matter of performance record, thus enabling early detection of faulty performance.

All equipment is factory-inspected and tested in accordance with the applicable equipment specifications, codes, and quality assurance requirements.

9.4.2.1.5 Instrumentation Requirements

See Section 9.4.2.2.5 for instrumentation requirements.

9.4.2.2 Safety-Related Reactor Enclosure Air Cooling System

The RHR, HPCI system, RCIC system, and core spray system pump compartment unit coolers and systems are covered in this section.

9.4.2.2.1 Design Bases

The reactor enclosure ECCS and RCIC pump compartment unit coolers are designed to accomplish the following objectives:

a. Maintain temperatures at a calculated maximum of 127°F in the HPCI pump compartment, 140°F in the RHR pump compartments, and 140°F in the Core Spray pump compartments after a DBA and 125.5°F in the RCIC pump compartment when RCIC is in operation. Allowable calculated maximum temperatures in the HPCI pump compartment (164°F) and RCIC pump compartment (155°F) have been established to permit HPCI and RCIC operability in the event of a loss of the pump compartment unit coolers.

b. Initiate automatic operation when the appropriate equipment in the ECCS/RCIC pump compartment starts

c. Initiate automatic operation upon a rise in temperature to 100°F in the ECCS/RCIC pump compartment served by the unit cooler

d. When the standby unit cooler is in service, initiate automatic operation of the standby unit cooler if the temperature in the ECCS/RCIC pump compartment increases to 110°F

e. Provide air flow over the ECCS/RCIC pump motors/turbines for cooling

f. Ensure that each RHR and Core Spray pump is provided with a separate ventilation system. Each ventilation system consists of two unit coolers. Each unit cooler is designed to accommodate 100% of the associated pump heat load. One cooler is required to support operability of each pump.

g. Ensure that the reactor enclosure ECCS/RCIC pump compartment unit coolers are served by redundant power supplies that meet IEEE 279 and IEEE 308

h. Ensure that the reactor enclosure ECCS/RCIC pump compartment unit coolers meet seismic Category I requirements

9.4.2.2.2 System Description

The safety-related air cooling systems are shown schematically on drawing M-76. System design parameters are shown in Table 9.4-6. All coolers are supplied by the normal service water system or ESW, if normal service water is not available. The controls and instrumentation associated with each system are an integral part of that system.

Each ECCS/RCIC pump compartment unit cooler recirculates and cools its respective compartment air and is capable of carrying the following cooling loads:

a. RHR and core spray pump compartment coolers - total cooling load associated with operation of ECCS pump(s) assuming a single active failure. See FMEA Table 9.4-7 for more details.

b. RCIC and HPCI pump compartment coolers - the total compartment cooling load

Each unit cooler consists of a cabinet with a cleanable cooling coil and a direct drive vaneaxial fan mounted outside of the cabinet. The unit coolers are mounted adjacent to the pumps they serve, and the lead cooler starts automatically when the respective pump starts or when the room temperature exceeds 100°F. When the standby cooler is inservice, the standby cooler will start automatically if either the lead unit cooler fails to start when its respective pumps starts or if the compartment temperature rises to 110°F. Each cooler is also provided with a hand switch in the local panel for manual operation. During normal plant operation, the reactor enclosure ventilation system is used to maintain the design conditions in the ECCS and RCIC pump compartments (Section 9.4.2.1).

9.4.2.2.3 Safety Evaluation

The safety related reactor enclosure air cooling system provides cooling to the ECCS/RCIC compartments as described in Section 9.4.2.2.2. The system is provided with HVAC equipment to maintain the required air flows and temperatures under normal and accident conditions. See Table 9.4-7 for a failure modes and effects analysis of safety-related modes of operation.

Safety-related equipment within the HPCI and RCIC compartments have equipment qualification requirements which enable HPCI and RCIC system operability during periods when there is a loss of unit cooler function.

All unit coolers, duct-work and supports, and other systems components meet seismic Category I requirements. Each unit cooler is designed to accommodate 100% of the associated pump heat load. For RHR/Core Spray, one cooler is required to support operability of each pump. For RHR, any two coolers in one RHR compartment are sufficient to support both pumps and all other EQ components located in the compartment. See Section 9.2.2.2 and Table 9.4-7 for more details.

9.4.2.2.4 Tests and Inspections

The system is preoperationally tested in accordance with the requirements of Chapter 14 and periodically tested in accordance with the requirements of Chapter 16.

9.4.2.2.5 Instrumentation Requirements

Hand switches, equipment status indicating lights, flow, temperature and pressure indicators and alarms for nonsafety- related reactor enclosure HVAC systems are located on local panels. General trouble alarms for each panel are located in the control room. These alarms are activated by any specific alarm on the local panel.

Hand switches for the isolation system are located in the control room. Status indicating lights for the isolation valves are located on the local panel.

Hand switches and status indicating lights for the unit coolers are located on local HVAC control panels.

The following alarms are annunciated in the control room:

a. Equipment status for safety-related equipment that may require operator action (refer to Section 7.3 for safety-related equipment alarm locations)

b. High radiation in refueling area or reactor enclosure exhaust ducts and the downscale signal from radiation monitors

c. Secondary alarms caused by closure of any of the steam flooding isolation dampers

d. Group alarm from each HVAC local control panel that has local alarms

e. Manually induced inoperability of safety-related systems is alarmed

f. Preignition temperatures for all charcoal filters

g. Low pressure differential in each zone

In addition, the following conditions are alarmed on the local HVAC control panels and transmitted to the control room as a group alarm:

a. Equipment status for nonsafety-related equipment and safety-related equipment that does not require immediate operator action (refer to Section 7.3 for safety-related alarm locations)

b. Elevated nonsafety-related charcoal filter temperature

All instruments and controls performing safety-related functions are qualified to seismic Category I requirements and are environmentally qualified as discussed in Section 3.11.

The redundancy and separation of instrumentation and controls conform to the redundancy and separation requirements of the equipment they control or monitor.

9.4.3 RADWASTE ENCLOSURE AND CHEM LAB EXPANSION VENTILATION SYSTEM

The radwaste enclosure and chem. lab. expansion ventilation system maintains area air temperatures and quality in the radwaste enclosure and chem. lab. expansion . The radwaste enclosure ventilation system is not safety-related.

9.4.3.1 Design Bases

The radwaste enclosure and chem lab expansion ventilation system is designed to operate during normal conditions and accomplish the following objectives:

a. Provide a supply of filtered and tempered outside air to areas in the structure.

b. Maintain airflow from areas of lesser to areas of greater potential contamination.

c. Maintain a suitable environment in the enclosure spaces for equipment, operation, and/or personnel comfort.

d. Maintain the enclosure at a slightly negative pressure to prevent potential exfiltration of contaminated air.

e. Filter, through HEPA filters, air exhausted from all areas, except the noncontaminated general areas indicated in drawing M-79.

f. Provide HEPA filtration for gases vented from radwaste tanks and pump sumps.

g. Discharge all exhaust air to the reactor enclosure north vent stack.

9.4.3.2 System Description

The radwaste enclosure and chem. lab. expansion ventilation system is shown schematically in drawing M-79. Equipment design parameters are listed in Tables 9.4-8 and 9.4-8A. The chilled water system supplying the cooling coils in the HVAC supply units is described in Section 9.2.10.

The radwaste enclosure supply air fans, plenums, and related control panel are located in the heating and ventilation equipment room on el 257'. The exhaust air fans, filter housings, and related control panels are located in the heating and ventilation equipment rooms on el 237' and el 257'.

The supply and exhaust fans are controlled to maintain a slightly negative building pressure; air is supplied to "clean" areas and exhausted from potentially contaminated compartments. Air exhausted from potentially contaminated compartments is filtered. All exhausted air is sampled by radiation monitors and is discharged to the north vent stack.

All major systems are provided with redundant fans (and exhaust filters) on automatic standby. The charcoal filter serving the tank and sump vents is equipped with a fire protection water spray system (Section 9.5.1).

9.4.3.2.1 Radwaste General Areas

The supply air unit for the corridors, heating and ventilation equipment areas, and other general compartments consists of two 100% capacity fans, with discharge dampers, connected to a common housing containing a roll-type filter, face and bypass dampers, steam heating coils, and a cooling coil. With air flow established in the exhaust systems for the general areas and equipment

compartments, one supply fan is started manually by a local hand switch; this switch also opens the discharge damper and the control air supply valve. Filtered and tempered outdoor air is distributed by duct-work to the aforementioned low contamination areas. Corridor air flows to the pump and equipment compartments (higher potential contamination). The fan blade pitch is automatically adjusted to maintain the corridors at a pressure lower than the turbine enclosure. Failure of the operating fan automatically activates the standby supply fan and its accessories. Failure of an associated exhaust system stops the supply fans.

Air in the radwaste supervisor room, radwaste control room, technician's room, monorail and access areas, crane control room, and heating and ventilation equipment areas is removed by two 100% capacity exhaust fans. One exhaust fan is started manually; this also opens the fan inlet and outlet dampers and the control air supply valve. The fan blade pitch is automatically adjusted to vary static pressure in the exhaust duct to ensure negative enclosure pressure. Failure of the operating exhaust system automatically activates the standby exhaust fan and its dampers.

9.4.3.2.2 Radwaste Equipment Compartments

The equipment and tank compartments are supplied with air from the corridors. Some compartments also have steam unit heaters, as indicated in drawing M-79.

Many of the equipment compartments have individual exhaust duct air flow regulators to modulate air flow in response to compartment temperature. The solid radwaste compartments have individual exhaust filter trains (prefilters and HEPA filters) that discharge into the equipment compartment exhaust duct.

The radwaste tanks and radwaste drainage sumps are mechanically vented through a HEPA filter by a single exhaust fan that also discharges into the equipment compartment exhaust duct.

Exhaust air collected from the equipment compartments, tank vents, and other potentially contaminated compartments indicated in drawing M-79 is removed by one of two 100% capacity exhaust units. One equipment compartment exhaust filter train is activated manually at the local control panel by opening the filter isolation dampers. The filter housing has prefilters and HEPA filters. The exhaust fan is also started manually at the local control panel which opens the fan inlet and outlet dampers. The fan blade pitch is automatically adjusted to maintain constant static pressure in the exhaust duct to ensure negative pressure in the tank and equipment compartments. Failure of the operating exhaust fan automatically activates the standby fan; however, switch-over to the standby filter train requires manual operator action. No humidity control of the air entering the radwaste enclosure tank filters is provided. The air entering these filters could be greater than 70% relative humidity, therefore no credit is taken for iodine adsorption in the offsite dose calculations.

Conformance with Regulatory Guide 1.140 is discussed in Table 9.4-18.

9.4.3.2.3 Radwaste Service and Control Area

The supply air unit V-302 for the service and control areas indicated on drawing M-79 consists of two 100% capacity fans, cooling coils, humidifiers, and discharge dampers connected to a housing containing a roll-type filter, inlet damper, and steam heating coil. Both fans discharge through a steam duct reheat coil. With air flow established in one chemistry lab exhaust unit, one supply fan is manually started; this also opens its discharge damper and the common inlet damper. Outdoor air is filtered, tempered, and humidified for the control and service areas (which have personnel occupancy). The supply air design temperature is maintained by a discharge duct thermostat, which

is reset by a thermostat in the radwaste enclosure control room. Failure of the operating fan automatically activates the standby fan and its accessories. Failure of the service and control area exhaust units stops the service and control area supply fans. Individual air conditioning units are provided in the laboratories and offices to augment the cooling of the rooms. Data Acquisition Room is maintained at 68° F±/-2°F and 50% relative humidity ±5% with individual air conditioning units and humidifier.

The radwaste control room, radwaste supervisor room, health physics room, and washroom are exhausted by the general areas exhaust fans. The source storage/standards preparation room, counting room, decontamination, and change area are exhausted by the chemistry laboratory air exhaust system, which contains two 100% capacity exhaust units. One service area exhaust fan (with associated filter train) is activated manually, which also opens the filter/fan isolation dampers. The filter housing contains prefilters and HEPA filters. Technician's Area is exhausted by the equipment compartment air exhaust system V-305.

9.4.3.2.4 Chemistry Laboratory Expansion

The Chemistry Laboratory Air Supply System and the Chemistry Laboratory Air Exhaust System are designed and constructed to serve the Radiologically Controlled Area only. The office Area and the Cold Lab are served by another system. The following are within the Radiologically Control Area:

- Hot Lab
- Frisk Area/Corridor
- Count Room
- Instrument Lab
- Mechanical Penthouse

The Count Room and Instrument Lab is designed for 68°F ± 2°F and 50% relative humidity ± 5% and the rest of the Chemistry Laboratory is designed for personnel comfort at 75°F ± 5°F and 50% relative humidity ± 10%. The thermostats are capable of being set and adjusted in 1°F increments.

A new HVAC supply system is provided for the Chemistry Laboratory. The Chemistry Laboratory Air Supply System includes low efficient filters (55%), high efficiency filters (95%), electrical heating coils, cooling coils, and fans. This supply system consists of two redundant 100% capacity fans, coils, and filters. Cooling is provided through two redundant 100% capacity air cooled, roof mounted condensing units. Roof top mounted mechanical equipment is provided with vibration isolators to minimize vibration problems. High efficiently filters are installed in the supply units to minimize lab dusting problems. The supply unit manufacturers's direct digital control package is provided for a constant volume system.

The count Room and Instrument Lab have stringent temperature and humidity requirements. Each of these rooms is provided with its individual environment control unit that will provide continuous complete control of temperature, humidity, and air cleanliness.

The existing Radwaste Service and Control Air Exhaust system (V-306) are renamed and used as the Chemistry Laboratory Air Exhaust System. The existing system contains two redundant 100% capacity filtration units, prefilters and HEPA filters. The rated capacity of the existing filtration units, fans and duct to the north vent stack is 2,850 cfm. The gas chromatograph, plasma spectrophotometer, and TOC's are exhausted through the Chemistry Laboratory Exhaust system.

The Chemistry Laboratory exhaust fans are interlocked with the supply fans to ensure exhaust fan operation prior to supply fan operation . The Chemistry Laboratory is maintained at a slight negative

pressure with respect to atmospheric pressure. The Hot Lab, Instrument Lab and Source Storage/Standards Preparation Room are maintained at a slight negative pressure with respect to the corridors. The Count Room is maintained at a slight positive pressure relative to the corridors.

An HVAC control panel contains instrumentation, handswitches, and annunciators for HVAC system trouble, and high filter differential pressure. A local panel trouble alarm is located in the Radwaste Control Room.

Electric unit heaters are located in the mechanical Penthouse to maintain penthouse temperature above 50°F.

The Office Area and Cold Lab are not in the Radiologically Controlled Area. A separate HVAC system is provided for these areas. The following areas are outside the Radiologically Controlled Area:

- Office Area
- Conference/Lunch Area
- Cold Lab
- Locker Area
- Rest Rooms
- Kitchenette Area

All areas of the Chemistry Laboratory Office Area are designed, installed, and tested in accordance with Section X of Division 3 of Specification NE-130.

Each Cold Lab fume hood is exhausted through its individual exhaust fan. Another exhaust fan is provided for the Rest rooms, Locker Area, and Kitchenette Area. Effluent from these three exhaust fans will not be filtered or radiologically monitored.

Exhaust duct pressure is varied by modulating the inlet damper to ensure negative pressure in the service areas. Failure of the operating exhaust unit automatically activates the standby fan and filter train.

9.4.3.2.5 Fume Hoods

The makeup air unit for the fume hoods in the chemistry laboratory and in the source storage/standard preparation room, radwaste enclosures consists of two 100% capacity fans, electric heating coils, high efficiency filters, (95%), low efficiency prefilters (65%) and discharge dampers. With air flow established in one fume hood exhaust unit, one supply fan is manually started, and its dampers are opened. Outdoor air is filtered, heated, and ducted to the fume hoods. Failure of the operating fan automatically activates the standby fan and its accessories. Failure of the fume hood exhaust system stops the fume hood supply fans.

The fume hoods are exhausted by two 100% capacity exhaust units. One exhaust fan (with associated filter train) is activated manually, which also opens the filter/fan isolation dampers. The filter housing contains prefilters and HEPA filters. Constant exhaust duct pressure is maintained by modulating the inlet damper to ensure negative pressures in the fume hoods. Failure of the operating exhaust unit automatically activates the standby fan and filter train.

The Fume Hood Air Exhaust System is interlocks with the Fume Hood Auxiliary Air Supply System to ensure exhaust fan operation prior to supply fan operation.

9.4.3.2.6 Charcoal Tank Vaults

The charcoal tank vaults for the offgas treatment system are air conditioned.

The primary and standby air conditioning systems each have 100% capacity. Each system consists of a refrigerant condensing unit, and three direct-expansion unit coolers ducted to the tank vaults. The primary system starts automatically on a temperature signal from any one of the three vaults. Failure of the primary system alarms the control room. The standby air conditioning system starts automatically on a high temperature signal from any of the three vaults. Both systems can be manually operated both locally and from the radwaste control room.

The air conditioning equipment for the offgas treatment charcoal tank vaults is located in the offgas treatment equipment room and access corridor on el 195'.

The charcoal tank rooms are also exhausted as described in Section 9.4.3.2.2.

9.4.3.3 Safety Evaluation

The radwaste enclosure ventilation system has no safety-related functions. Failure of the system does not compromise any safety-related system or component or prevent a safe shutdown of the plant.

9.4.3.4 Tests and Inspections

All HVAC equipment is inspected and tested during manufacture, installation, and startup. Air and water flows are measured and adjusted to design requirements with calibrated instruments.

9.4.3.5 Instrumentation Requirements

All hand control switches for the radwaste enclosure ventilation system are on local control panels in the radwaste enclosure. The local panels transmit any HVAC alarm signal to general trouble alarms located in the main control room. The following abnormal conditions are alarmed:

a. Air flow failure (all ducted fans)

b. Low pressure differential with respect to the turbine enclosure

c. Supply air heating coil failure

d. High general area exhaust temperature

e. High equipment compartment exhaust temperature

f. High pressure differential across an exhaust filter train

g. High pressure differential across supply filters

h. Supply filter media run-out

i. Charcoal tank room refrigeration equipment failure

All control for the Chemistry Laboratory Expansion ventilation system are on local control panels in the building penthouse. The local panels transmit a common "HVAC" Trouble alarm signal to the Radwaste Control Room. Local alarms for various trouble conditions are provided.

The system includes sensors, controllers, time delays, switches, and indicators to automatically switch or stop fans; open and close isolation dampers; advance roll-filter media; modulate control dampers; open or close steam heating coil valves; open, close, or modulate cooling coil valves; modulate steam humidifier control valves; adjust fan blade pitch; modulate duct regulators; start unit heaters; and indicate temperatures and filter pressure differentials.

9.4.4 TURBINE ENCLOSURE VENTILATION SYSTEM

The function of the turbine enclosure ventilation system is to maintain design air temperatures and quality in the turbine enclosure. The turbine enclosure ventilation system is not safety-related.

9.4.4.1 Design Bases

The turbine enclosure ventilation system is designed to operate during normal conditions and accomplish the following objectives:

a. Provide a supply of mixed, filtered, and tempered air to the turbine enclosures and to el 180', el 200', el 217', and el 254' in the control structure

b. Maintain airflow from areas of lesser to areas of greater potential contamination

c. Maintain the enclosure spaces within the following temperature ranges:

Electrical equipment areas	65°F to 106°F
Mechanical equipment areas	65°F to 117°F
Condenser/feedwater areas	65°F to 122°F
Control structure equipment compartments	65°F to 104°F
Control structure tank compartments	65°F to 122°F

d. Maintain the equipment compartment areas at slightly negative pressure to prevent potential exfiltration of contaminated air

e. Exhaust air from potentially contaminated spaces through particulate and charcoal filters

f. Discharge all exhaust air to the north vent stack

g. Provide cooling air to the Unit 2 MG sets

9.4.4.2 System Description

The schematic diagrams for the turbine enclosure and ventilated areas in the control structure are shown in drawings M-75 and M-78, respectively. Equipment design parameters are listed in Table 9.4-9. The chilled water system supplying the cooling coil banks and unit coolers is described in Section 9.2.10.

The turbine enclosure supply air unit, main exhaust fans, filters, and control panel are located in the HVAC equipment room at el 302'. The battery room exhaust fan is located outside the battery room. Individual unit coolers and unit heaters are located in the areas that they serve, as indicated in drawing M-75.

High relative humidity in normal ventilation exhaust systems is prevented. During outside conditions of high temperature and high humidity, the inlet air to the turbine enclosure passes through cooling coils resulting in dehumidification. Inside air is also recirculated through the coils. Equipment compartments use infiltration air from access areas which is exhausted through the turbine enclosure equipment compartment exhaust charcoal adsorbers. This yields a further temperature increase and dehumidification of this exhaust air which results in a relative humidity of less than 70% entering the charcoal adsorbers during worst case conditions.

Potentially contaminated compartments are only exhausted; makeup air is drawn from negative pressure "clean" areas (rather than direct supply) to prevent exfiltration from the compartments and from the structure. Potentially contaminated air is filtered and discharged, along with air from the noncontaminated areas, through the reactor enclosure north stack, which is monitored for radiation.

All major systems are provided with redundant fans on automatic standby. The equipment compartment exhaust fan motors, which are connected to 4 kV safeguard switchgear (because of their large size), are automatically deactivated upon a LOCA signal or LOOP.

The charcoal filters (in the filter housings serving the equipment compartments) are equipped with water spray fire protection systems. High charcoal temperatures are alarmed directly in the control room, as well as locally.

The systems described are for the Unit 1 turbine enclosure. Unit 2 systems are similar.

9.4.4.2.1 Supply System (V101)

The supply air unit for the turbine enclosure consists of three 50% capacity fans, with individual discharge dampers, connected to a common housing containing mixing dampers, a roll-type filter, face and bypass dampers, and a steam heating coil. The fans discharge into a common plenum and through two cooling coil banks, one for the reactor recirculation pump MG set area, and one for the other areas in the turbine enclosure and part of the control structure.

Two supply fans are started manually by local hand switches which also opens their respective discharge dampers. Outside and return air is mixed, filtered, heated or cooled, and distributed by duct-work to the operating floor, MG set area, equipment compartments, and part of the control structure.

Failure of an operating supply fan automatically activates the standby fan and its discharge damper. Loss of negative pressure in the sampled area will activate the local panel alarms and control room annunciators.

9.4.4.2.2 Unit Coolers

The following areas have individual chilled water unit coolers in addition to ventilation from the main supply unit:

a. Condensate transfer and refueling pump access

b. Feedwater heater compartments and access

c. RFPT compartment access

d. Mechanical vacuum pump compartment

The following areas have individual service water unit coolers in addition to ventilation from the main supply unit:

a. Main condenser compartment

b. Condensate pump compartment

There is at least one standby unit cooler in each of the above areas. The unit coolers can be started manually or automatically (by signals from inlet air thermostats).

9.4.4.2.3 Unit Heaters

Steam unit heaters are installed in the majority of the areas listed in tables A, C, E, F, and G of drawing M-75. The unit heaters are started automatically by local thermostats.

9.4.4.2.4 Return/Exhaust Air System (V105)

Air in the noncontaminated areas indicated in drawing M-75 is removed by three 50% capacity fans with individual discharge dampers. The fans discharge into a common duct, and the air is either exhausted to the reactor enclosure north stack or returned to the supply air unit and mixed with outside air.

Any two of the three turbine enclosure fans are started manually by local hand switches; this also opens their respective discharge dampers. A pressure differential controller automatically adjusts the blade pitch of the operating fans to maintain a negative pressure in the turbine enclosure. Failure of one operating exhaust fan automatically activates the standby fan and its dampers. An interlock with the Unit 2 reactor recirculation pump MG set controls prevents the starting of the Unit 2 MG sets when the exhaust fans are not operating.

9.4.4.2.5 Equipment Compartment Exhaust System (V106)

Air in the potentially contaminated equipment compartments indicated in drawing M-75 is filtered before being exhausted. Air vented from the condensate pump area sumps is filtered through individual prefilters and HEPA filters before being ducted to the main filter bank. Air from the condensate transfer and refueling pump access at el 200' is cooled by duct mounted chilled water coils and used to cool the holding pump compartments and condensate filter/demineralizer cells before being ducted to the exhaust filter bank.

The two 50% capacity filter banks each contain a prefilter, HEPA filter, charcoal adsorber, final HEPA filter, and inlet and outlet dampers. There is also a 50% capacity bypass duct for use when one of the filter banks requires servicing. The 50% capacity bypass duct is provided with a diffusion plate to simulate the pressure drop across the filter banks. There are two 100% capacity exhaust fans, each with inlet guide vanes and discharge damper. One exhaust fan and both filter trains are activated manually by local

hand switches. An air flow controller automatically adjusts the inlet guide vanes on the operating fan to maintain constant air flow from the equipment compartments. In the automatic mode, loss of flow from the operating fan deactivates that fan and activates the standby fan by use of a pneumatic electric relay (to provide divisional separation). The bypass duct diffusion plate may be removed under administrative control to achieve 100% bypass of filter banks when it is determined that filtration is not required to limit offsite doses.

The equipment compartment exhaust fans are fed from the respective 4 kV safeguard buses. However, they are automatically tripped on a LOCA signal or LOOP.

Conformance with Regulatory Guide 1.140 is discussed in Table 9.4-18.

9.4.4.2.6 Battery Compartment Exhaust Fan (V108)

The battery compartment is continuously exhausted by a single fan that is started manually by a hand switch on a local panel.

9.4.4.3 Safety Evaluation

The turbine enclosure ventilation system has no safety-related functions. Failure of the system does not compromise any safety-related system or component or prevent a safe shutdown of the plant.

9.4.4.4 Tests and Inspections

All HVAC equipment is inspected and tested during manufacture, installation, and startup. Air and water flows are measured and adjusted to design requirements, and the instruments are calibrated.

9.4.4.5 Instrumentation Requirements

All hand control switches for the turbine enclosure ventilation system are on local control panels in the turbine enclosure. The local panels transmit any ventilation alarm signal on to the control room panel. The following abnormal conditions are annunciated:

a. Air flow failure (all ducted fans)

b. Supply air heating coil failure

c. Supply air cooling coil failure

d. High motor or generator exhaust temperature

e. High general area exhaust temperature

f. High equipment compartment exhaust temperature

g. High charcoal adsorber temperature

h. High demineralizer cell exhaust temperature

i. High compartment temperature (compartments with unit coolers only)

j. High pressure differential across supply filter

k. High pressure differential across equipment compartment exhaust filter train

l. Supply filter media run-out

There are various sensors, controllers, switches, time delays, and indicators to automatically switch or stop fans, open and close isolation dampers, advance roll-filter media, modulate control dampers, open steam heating coil valves, open or modulate cooling coil valves, adjust fan blade or inlet guide vane pitch, start unit coolers and unit heaters, and indicate temperature, enclosure pressure, and filter resistance.

9.4.5 PRIMARY CONTAINMENT VENTILATION SYSTEM

Ventilation of the primary containment is provided by two systems: the containment atmospheric control system and the drywell air cooling system.

9.4.5.1 Containment Atmospheric Control System

The CAC system incorporates features for accomplishing a number of functions, including inerting of the primary containment with nitrogen, purging of the primary containment, limiting the differential pressure between drywell and wetwell, monitoring of hydrogen and oxygen concentrations in the primary containment, and controlling combustible gas concentrations in the primary containment after a LOCA. Those functions relating to post-LOCA combustible gas monitoring and control are discussed in Section 6.2.5, whereas all other functions are described in this section.

The CAC system serves the drywell and suppression chamber in various modes of operation during reactor operation, reactor shutdown, and postaccident conditions. Portions of the system are safety-related.

9.4.5.1.1 Design Bases

a. The CAC system is designed to provide a means by which nitrogen gas can be introduced into the primary containment at a high flow rate, thereby displacing air originally in the containment volume, for the purpose of reducing the oxygen concentration in the containment atmosphere.

b. The CAC system, operating in conjunction with the reactor enclosure ventilation system, is designed to provide a high volume purge flow to the drywell and suppression chamber to provide the proper atmosphere for early personnel access following shutdown of the reactor.

c. The CAC system is designed to control the containment pressure and oxygen concentration during all modes of reactor operation by supplying nitrogen gas to and/or releasing gases from the primary containment in a controlled manner.

d. The CAC system, operating in conjunction with the reactor enclosure ventilation system, the RERS, and the SGTS, is designed to remove radioactive contaminants from all primary containment gas prior to its release to the environment.

e. The combustible gas analyzer of the CAC system is designed to operate either in standby or continuous mode during normal operation to monitor the hydrogen and oxygen of the primary containment. However, the combustible gas analyzer is required to continuously monitor hydrogen and oxygen concentrations in the primary following a LOCA.

f. The CAC system is designed to provide a means of hydrogen and oxygen recombination with sufficient capacity to prevent the accumulation of a combustible concentration of gases within the primary containment following a LOCA.

g. The CAC system is designed to permit a controlled purge of the primary containment atmosphere at a low flow rate following a LOCA, as a backup means of combustible gas control.

h. The CAC system is designed to automatically isolate the lines that penetrate primary containment to ensure the integrity of the containment boundary during accident conditions.

i. The CAC system is designed to monitor the pressure and the temperature in both the drywell and suppression chamber.

j. The CAC system is designed to limit the differential pressure that can develop across the diaphragm slab.

k. The safety-related portions of the CAC system are designed to remain functional after an SSE.

l. The CAC system is designed so that a single failure of any active component, assuming LOOP, cannot result in the loss of a safety function.

9.4.5.1.2 System Description

The CAC system is shown schematically in drawing M-57. With the exception of the liquid nitrogen facility, which is located outdoors, the system is located entirely within the reactor enclosure.

9.4.5.1.2.1 Nitrogen Inerting

During power operation of the reactor, the oxygen content of the primary containment atmosphere is maintained at a concentration no greater than 4% by volume. This limit is established to preclude the attainment of a combustible gas mixture inside the containment if combustible gases are released into the containment atmosphere following a postulated accident.

This low oxygen atmosphere is achieved by displacing air in the primary containment with nitrogen gas. The nitrogen is supplied from a liquid nitrogen facility, which consists of two liquid nitrogen storage tanks and one steam heated water bath vaporizer. The liquid nitrogen facility is common to both reactor units. Gaseous nitrogen from the discharge of the vaporizer is supplied to the drywell and/or the suppression chamber as selected by the operator. The flow rate of nitrogen is controlled

to a value that is also selected by the operator. Gases released from the primary containment during nitrogen inerting are processed through the filters of the SGTS (Section 6.5.1.1) before release to the environment.

During the inerting operation, nitrogen is supplied to the containment and gases are released from the containment through the four high volume purge penetrations. Once the specified oxygen concentration in the primary containment has been achieved, nitrogen flow is terminated and the isolation valves in the high volume purge lines are closed.

9.4.5.1.2.2 High Volume Purge

High volume purging is performed during periods of reactor shutdown to maintain a well ventilated environment for personnel occupancy of the primary containment. High volume purging may also be performed during the operational modes of startup, power operation, and hot shutdown for the purpose of inerting and deinerting the primary containment.

High volume purging during the latter three operational modes will be restricted as follows:

a. Inerting will be completed within 72 hours after entering Operating Condition 2, STARTUP.

b. Deinerting will be initiated no more than 72 hours prior to entering Operating Condition 3, HOT SHUTDOWN, preliminary to a planned reactor shutdown.

c. The 18” and 24” primary containment purge valves are required to be closed except for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open.

The inert atmosphere (diluted with nitrogen to <4% 0_2) is purged from containment in anticipation of outages requiring containment access to allow inspections and limited repairs while the reactor is at some reduced power level. Inspections are also performed during power ascension prior to the inerting of containment. These inspections facilitate the early detection and location of coolant system leaks which could have an impact on unit reliability and safety if uncorrected.

High volume purge air is supplied to the CAC system by the reactor enclosure HVAC system, which is described in Section 9.4.2. The purge air is maintained within the normal temperature range for the reactor enclosure HVAC system. Gases exhausted from the primary containment during the high volume purge mode are processed by the SGTS (Section 6.5.1.1) prior to release to the environment. The number of high volume purge lines in use during the operational modes of startup, power operation, and hot shutdown will be limited to one supply line and one exhaust line. Purging and venting operations are normally performed through one 24 inch supply penetration and one 24 inch exhaust penetration. Only one SGTS train shall be used for purge gas filtration during the modes of startup, power operation, and hot shutdown. During such operations, the redundant SGTS train is isolated to ensure that both filter trains are not damaged if a LOCA were to occur during the purging or venting operations.

Because the purge and vent valves are opened during only a limited period of power operation (only open for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open), it is unlikely that a LOCA will occur while the valves are open. If a LOCA were to occur during this time, the containment isolation valves would close rapidly (6 seconds or less after receipt of isolation signal) and would terminate the release. Isolation will be complete long before any fuel damage or significant offsite exposure could occur. The containment isolation valves used have been specifically designed and qualified for this

service as described in Section 6.2.4.2. It is possible in such cases, however, for the downstream duct-work and/or SGTS filters to be damaged by the pressure surge preceding valve closure and/or the moisture content of the released gases.

Analyses have been performed to determined the potential for, and significance of, the above described sequence of events at LGS. Calculations indicate that the design pressure of the duct-work and the design differential pressure of the SGTS filters may be exceeded if the DBA LOCA occurred during purging. This could:

a. Result in the failure of the operating SGTS filter bank, and

b. Possibly cause equipment failures in the reactor enclosure due to duct impact, impingement, and/or the resulting environmental conditions.

Failure of the operating SGTS filter bank is of little significance due to the limited benefit derived from SGTS for accident sequences related to plant risk and the possibility that the backup filter bank would be available. The results of the Reactor Safety Study (WASH-1400, table 5-3) indicate that the failure of SGTS during a LOCA does not contribute to any significant releases in a BWR for the following reasons:

a. LOCA sequences contribute little to radioactive releases relative to transient sequences.

b. Consideration of SGTS failure is only relevant for small containment leaks (ie., compared with a containment overpressure rupture).

Because of the potential significance of equipment failures, calculations and detailed equipment location surveys have been performed for LGS to verify that:

a. The environmental qualifications for the LGS equipment are sufficient to ensure operability under the predicted environmental conditions, and

b. The potential does not exist for impact or impingement-related damage to essential equipment.

The above described conclusions also apply but with significant conservatism to the situation when either a medium or small LOCA is postulated to occur during purging. For a small LOCA, the duct-work is not expected to rupture, and the SGTS heaters can be expected to reduce the relative humidity of the incoming gases. For a medium LOCA if the duct-work should rupture, the amount of steam released into the reactor enclosure and the energy available for impact or impingement will be considerably less than that associated with a DBA LOCA.

The four high volume purge lines are each provided with two normally closed butterfly valves for containment isolation. The inboard isolation valve is pneumatic-cylinder-operated, and the outboard valve is motor-operated. These valves can be operated by hand switches in the control room and are automatically closed upon receipt of a containment isolation signal. Containment isolation is discussed further in Section 6.2.4.

The high volume purge lines are 18 inches, 20 inches and 24 inches in diameter. Seismic Category I debris screens, capable of withstanding LOCA differential pressures, will be provided on the purge line penetrations.

9.4.5.1.2.3 Low Volume Purge

Low volume purging is occasionally performed during reactor operation to maintain the pressure and oxygen concentration of the primary containment atmosphere within specified ranges. During reactor operation, the primary containment pressure is normally maintained in the range of 0.1 psig to 0.7 psig and the oxygen concentration is restricted to 4% (by volume) or less. Low volume purging involves occasionally introducing nitrogen into the primary containment and/or releasing gases from the primary containment and is used on an as-needed basis, rather than continuously. Gaseous nitrogen is supplied from the liquid nitrogen facility and is introduced into the containment through a 1 inch low volume purge line that connects to the discharge lines of both containment combustible gas analyzer packages, between the containment isolation valves on the latter lines. The flow rate of nitrogen into the containment is controlled by a MOV.

Gases are released from the primary containment through 2 inch low volume purge lines that connect to the high volume purge exhaust lines from the drywell and suppression chamber, inboard of the containment isolation valves on the latter lines. The exhaust flow rate is controlled by a MOV in each of the 2 inch lines. The exhausted gases are processed by the reactor enclosure equipment compartment exhaust filters (Section 9.4.2) prior to release to the environment.

Each low volume purge line is provided with two normally closed globe valves for containment isolation. The inboard isolation valve is motor-operated and the outboard valve is air-operated. These valves may be opened from the control room during normal plant operation and are automatically closed upon receipt of a containment isolation signal. Containment isolation is discussed further in Section 6.2.4.

The need for containment purging during normal operation is minimized by providing a PCIG system (Section 9.3.1.3). Purging for pressure control is required periodically during reactor system heatup and cooldown, if the PCIG system is out of service and the instrument air system is being used as a backup, or when other system leakage causes pressurization.

9.4.5.1.2.4 Combustible Gas Analyzers

Redundant hydrogen and oxygen analyzers are provided to monitor the primary containment atmosphere during normal operation and following a LOCA. The sampling system and analyzer packages are described in Section 6.2.5.

Each gas sample line is provided with two solenoid valves in series, for containment isolation. The isolation signals to these valves may be overridden by using key-locked bypass switches.

9.4.5.1.2.5 Containment Hydrogen Recombiner Packages

In the event of a LOCA, hydrogen and oxygen may be generated inside the primary containment. To control the buildup of oxygen and prevent a combustible concentration from occurring, redundant containment hydrogen recombiners are provided, as described in Section 6.2.5. The process gas supply and return lines for the recombiner packages connect to the high volume purge lines, inboard of the latter's containment isolation valves. The supply and return lines are each provided with two normally closed, MOVs for containment isolation. These valves may be operated from the control room during normal plant operation, and they automatically close upon receipt of a containment isolation signal. For operation of the recombiners after a LOCA, the isolation signals to these valves are overridden by using key-locked bypass switches. The portions of the recombiner system that would be exposed to the post-LOCA containment atmosphere have been designed to the same

pressures and temperatures as the containment. Containment isolation is discussed further in Section 6.2.4.

9.4.5.1.2.6 Post-LOCA Purge

As a backup to the redundant hydrogen recombiners, post-LOCA oxygen concentration can be controlled by purging the containment atmosphere. The post-LOCA purge is accomplished by the same method described above for the low volume purge. Under post-LOCA conditions, however, the gases exhausted from the containment are processed through the RERS and the SGTS (Section 6.5.1) prior to release to the environment. The isolation signals to the containment isolation valves on the low volume purge lines may be overridden by using key-locked bypass switches. Containment isolation is discussed further in Section 6.2.4.

9.4.5.1.2.7 Primary Containment Vacuum Relief Valve Assemblies

In order to limit the degree to which suppression chamber pressure can exceed drywell pressure, four primary containment vacuum relief valve assemblies are provided. The assemblies are located in the suppression chamber, each assembly being mounted on the side of a downcomer. Each assembly consists of two 24 inch (nominal diameter) vacuum relief valves mounted in series. When the suppression chamber pressure exceeds the drywell pressure by a specified amount, the vacuum relief valves open automatically, allowing gases from the suppression chamber to enter the downcomer and flow upward into the drywell, thereby equalizing pressure above and below the diaphragm slab.

A single vacuum relief valve (upstream-type) is shown schematically in Figure 9.4-6. The downstream valves are the same, except for a shorter body length. The valve consists of a swinging disk that closes an orifice in the body of the valve. The valve disk is keyed to a body-penetrating shaft that rotates as the disk opens or closes. By way of lever arms also keyed to this shaft, a compression spring holds the valve disk against the seat. When the differential pressure across the disk (in the opening direction) results in a force greater than the force exerted by the spring, the valve begins to open. The opening set pressure of the valve is 0.5 psid. However, because each assembly consists of two valves in series, actual tests performed on the valves indicate that measurable flow starts when the differential pressure across the valve assembly reaches about 1 psid, and both valves reach fully open position when the differential pressure is 2.9 psid.

The flow loss coefficient for the vacuum relief valves was calculated based on actual flow measurements conducted in the manufacturer's shop. The valve was mounted in a test rig, a differential pressure established across the valve, and the resulting flow rate was measured. Using this measurement, the loss coefficient for 24 inch pipe size was calculated to be 2.65 for a single valve and 5.3 for two valves mounted in series.

A valve operator is provided so that the valve can be opened to check the operation of the valve and the disk position indication system. Associated hand switches are located on a test panel in the reactor enclosure so that the valve may be tested remotely. When the switches are actuated, air pressure is applied to the actuating cylinder. This pressure overcomes the closing force applied by the spring and thus opens the valve.

9.4.5.1.3 Safety Evaluation

The safety-related functions of the CAC system include primary containment isolation, suppression chamber to drywell vacuum relief, suppression chamber pressure monitoring, and post-LOCA combustible gas monitoring and control.

All safety-related portions (including supporting structures) of the CAC system are designed to seismic Category I requirements as defined in Section 3.7. That piping which is safety-related is designed, fabricated, inspected, and tested in accordance with the requirements of the ASME Section III, Class 2, as discussed in Section 3.2. All safety-related portions of the CAC system are located within the reactor enclosure, which is designed to seismic Category I requirements as discussed in Section 3.8.4. Evaluation of the CAC system with respect to the following areas is discussed in the following sections:

a.	Protection from wind and tornado effects	Section 3.3
b.	Flood design	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11

Each line penetrating the primary containment (other than the hydrogen recombiner supply and return lines) is provided with redundant isolation valves powered from different divisions of Class 1E power. Therefore, in the event of failure of one division of Class 1E power, no more than one containment isolation valve in each pair is disabled, and the isolation function is assured. Each supply and return line for the hydrogen recombiners is provided with two containment isolation valves powered from the same division of Class 1E power. The purpose of powering all of a hydrogen recombiner's supply and return line isolation valves from the same division of Class 1E power is to maintain the operational capability of at least one hydrogen recombiner in the event of the loss of one of the Class 1E power divisions. In the event of a loss of one division of Class 1E power all of the isolation valves for the other recombiner will still be receiving power, and can be opened so that the recombiner can be put in service. The bypass of an isolation signal to any valve is annunciated in the control room.

The recombiner outlet lines are each provided with pressure relief valves to protect the outlet piping from overpressurization in the event of recombiner cooling water line isolation valve leakage from the RHR system during recombiner isolation.

The simplicity of design of the primary containment vacuum relief valve assemblies assures their ability to operate, when necessary, to limit the differential pressure across the diaphragm slab. The valves are of the swing-check configuration and require no motive power other than the differential pressure across the valve. The use of two valves in series within each assembly prevents a failure of any single valve in the stuck open position from compromising the pressure-suppression capability of the primary containment.

Post-LOCA combustible gas monitoring and control is discussed in detail in Section 6.2.5.

This essential area has been provided with redundant HVAC equipment to maintain the required air flows and temperatures under normal and accident conditions. A failure modes and effects analysis for the primary containment ventilation system is presented in Table 9.4-11 for both normal and accident conditions.

9.4.5.1.4 Tests and Inspections

The CAC system is preoperationally tested in accordance with the requirements of Chapter 14 and periodically tested in accordance with the requirements of the Technical Specifications (except for the hydrogen recombiners and combustible gas monitors). Inservice inspection of the safety-related portions of the system is in accordance with the ASME Section XI, for Section III, Class 2 components, or 10 CFR 50.69 Alternative Treatment, when applicable. Refer to Section 6.6.1 for further information.

The primary containment vacuum relief valve assemblies are preoperationally tested by the manufacturer to verify the opening set pressure. The set pressure is determined by applying a slowly increasing pressure to the inlet side of the valve and observing the point at which the inlet pressure suddenly stops increasing. This point indicates the start of leakage across the valve disk, which is the definition of the beginning of valve opening.

9.4.5.1.5 Instrumentation Applications

The CAC system is designed to be operated remotely from the control room. Power-operated valves are provided with hand switches and position indicating lights in the control room. All operations other than containment isolation are performed manually.

The liquid nitrogen facility is provided with controls and instrumentation necessary to maintain the pressure and temperature of the gaseous nitrogen supplied by the facility within appropriate ranges. The steam inlet piping to the water bath vaporizer is provided with a control valve which modulates to control the rate of steam admission to the steam coil inside the vaporizer. A temperature sensor immersed in the water bath provides a signal to this control valve so that the water bath temperature can be automatically controlled within a preset range. The pressure of the gaseous nitrogen leaving the liquid nitrogen facility is maintained at a nominal 50 psig by pressure control valves located in the nitrogen supply piping downstream of the vaporizer. A dual setpoint temperature switch installed in the nitrogen supply piping near the pressure control valves is wired into the control circuits of those valves. The presence of nitrogen in the piping at a temperature outside the range defined by the setpoints of the temperature switch will cause the switch to trip and the pressure control valves to close, thereby terminating the flow of nitrogen gas from the liquid nitrogen facility. Temperature elements in the nitrogen supply line are also connected to temperature switches with the same setpoints. These switches will trip when nitrogen at a temperature outside the range defined by the setpoints of the temperature switch is sensed, causing valves to close in the supply line and isolate the containment from the nitrogen supply.

During inerting of the primary containment through the high volume purge penetrations, the desired flow rate of nitrogen into the high volume purge piping is set by the operator on a flow controller in the control room. The measured flow rate in the nitrogen supply piping is displayed on the flow controller and is automatically compared to the value set on the flow controller; a signal corresponding to the difference between these two values is used to automatically modulate a flow control valve in the nitrogen supply piping so as to maintain the desired flow rate. When nitrogen is introduced into the primary containment in the low volume purge mode, the nitrogen flow rate in the low volume purge piping is recorded in the control room and the operator controls the flow rate by remotely actuating a MOV in that piping.

Gas pressure in the nitrogen supply lines is indicated in the control room. Temperature in the nitrogen supply lines is indicated locally and in the control room. An alarm is annunciated in the control room when the nitrogen temperature is too hot or too cold and when the nitrogen supply line is isolated, as discussed above.

Position indication for each vacuum relief valve is provided by a set of position switches that are actuated directly by the valve disk. The redundant position switches and their associated indicating lights on a test panel in the reactor enclosure provide visual indication when the valve is NOT FULLY CLOSED or NOT FULLY OPEN. When the valve is in an intermediate position, both the NOT FULLY CLOSED and NOT FULLY OPEN sets of lights are on. The position indicating switches are calibrated to indicate inboard valve disk displacement greater than or equal to 0.120 inch off the valve seat, and outboard valve disk displacement of greater than or equal to 0.050 inch off the valve seat. These setpoints ensure that the steam bypass leakage path will be maintained below $A/(k)^{½}$ = 0.046 ft^2 for the vacuum relief system, even with one of the outboard valves in the fully open position. A valve position other than fully closed is annunciated in the control room.

Atmosphere temperature in the drywell and suppression chamber is monitored by two temperature elements in each volume. The temperatures at all four points are recorded simultaneously in the control room. Drywell temperature is also indicated at the remote shutdown panel.

Pressures in the drywell and suppression chamber are monitored by pressure transmitters mounted outside the containment and are indicated in the control room. Drywell and suppression chamber pressures are also recorded in the control room.

9.4.5.2 Drywell Air Cooling System

The drywell air cooling system serves to remove heat from the drywell during normal plant operations and to maintain air circulation in the drywell under accident conditions. This latter function is safety-related.

9.4.5.2.1 Design Bases

a. The drywell air cooling system is designed to limit the temperature inside the drywell, during normal reactor operation, to an average of 135°F ①, with the maximum not to exceed 150°F in areas containing equipment which requires environmental qualification under 10CFR50.49 and not to exceed 160°F in other areas.

b. The drywell air cooling system is designed to limit the temperature inside the drywell, in the event of loss of offsite power and reactor scram, to 186°F in general drywell areas and 210°F in the area below the reactor vessel (inside the reactor pedestal).

c. The drywell air cooling system is designed to prevent concrete structures within the primary containment from exceeding their maximum design temperature during normal operation.

d. The drywell air cooling system is designed to maintain the drywell atmosphere in a thoroughly mixed condition following a LOCA to prevent stratification of hydrogen and oxygen that may be generated as a result of the accident.

e. Safety-related portions of the drywell air cooling system are designed to remain functional after an SSE.

f. The drywell air cooling system is designed so that a single failure of an active component, concurrent with a LOOP, cannot result in loss of a safety function.

① This was used for original HVAC system design basis conditions. Further evaluation has validated the HVAC for a drywell average air temperature of 150°F.

9.4.5.2.2 System Description

The drywell air cooling system is shown schematically in drawing M-77. The system includes eight drywell unit coolers, each of which contains two redundant cooling coils and two redundant fans. The design parameters of the unit coolers are listed in Table 9.4-10.

One fan in each drywell unit cooler is normally operating, with the second fan on standby. The standby fan starts automatically upon loss of the lead fan, sensed by a low air flow switch in the discharge duct from the unit cooler. During normal reactor operation, chilled water is supplied to the unit coolers by the DCWS (Section 9.2.10). Chilled water is normally supplied to only one of the two

redundant cooling coils in each unit cooler. In the event of a LOOP, the DCWS is not available, but cooling water flow to the unit coolers can be restored by remotely opening the valves in the cross-connection between the DCWS and the RECW system. The latter system is described in Section 9.2.8. RECW can be supplied simultaneously to both cooling coils in each unit cooler if the additional capacity is needed.

The drywell unit coolers are located in the lower section of the drywell between el 243' and el 265' and are arranged around the circumference of the drywell. Two of the unit coolers are provided with duct-work on both the suction and discharge sides, while the remaining six unit coolers have discharge duct-work only. Return air enters the latter unit coolers directly from the surrounding air space. The unit coolers (drawing M-77) serve specific areas of the drywell as follows:

a. Unit coolers 1AV-212 and 1BV-212 serve the MSRV area and the CRD area inside the reactor pedestal. Cooling air enters the CRD area through two penetrations in the reactor pedestal, 180° apart. Air exfiltrates from the CRD area through the four CRD piping penetrations in the pedestal.

b. Unit coolers 1CV-212 and 1DV-212 supply air to the area immediately below the refueling bellows and also to the drywell head area above the containment seal plate. Return air from the drywell head area is ducted to the suction side of the two unit coolers.

c. Unit coolers 1EV-212 and 1FV-212 serve the refueling bellows area, the area above the top of the reactor shield wall, and the annular area between the reactor vessel and the reactor shield wall. Cooling air is supplied to the reactor shield annulus through a ring header around the outside of the shield wall, which discharges into the annulus through 12 evenly spaced penetrations through the wall. From the discharge points near the bottom of the annulus, cooling air is forced upward between the shield wall and the reactor vessel insulation and is exhausted to the drywell general area at the top of the shield wall.

d. Unit coolers 1GV-212 and 1HV-212 supply air to the refueling bellows area, the area above the top of the reactor shield wall, and the drywell head area.

e. Unit coolers 1AV-212, 1BV-212, 1GV-212, and 1HV-212 are operated, as necessary, prior to and during the Type A test to maintain stable containment atmospheric conditions as discussed in section 6.2.6.1.b.

f. Air ducts that penetrate through the containment seal plate to the drywell head area will be removed and covered by water seal blind flanges during refueling operations.

g. Unit coolers 1AV-212 or 1BV-212, and 1GV-212 or 1HV-212 are in operation after a LOCA to maintain containment atmosphere in a thoroughly mixed condition.

The layout of the drywell air cooling system is shown in Figure 9.4-8.

9.4.5.2.3 Safety Evaluation

The safety-related portions of the drywell air cooling system (Unit coolers 1AV-212, 1BV-212, 1GV-212, and 1HV-212) are designed to seismic Category I requirements as defined in Section 3.7. The system is located within the primary containment, which is designed to seismic Category I

requirements as discussed in Section 3.8.1. Evaluation of the drywell air cooling system with respect to the following areas is discussed in the following sections:

a.	Protection from wind and tornado effects	Section 3.3
b.	Flood design	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11

The safety-related function of the drywell air cooling system is to maintain the drywell atmosphere in a thoroughly mixed condition after a LOCA to prevent stratification of hydrogen and oxygen that may be generated as a result of the accident. Cooling water supply to the unit coolers is not needed for this function. The cooling coils are seismically designed and are not postulated to fail in a manner that would block air flow to the unit cooler fans. The unit cooler cooling coil piping is protected from overpressurization due to thermal expansion of residual water in the pipe by a pressure relief valve. In the event of a postaccident cooling coil tube failure the flow of water will be temporary because the isolation valves, HV-122 and HV-128, will stop the flow of water to the drywell unit coolers. The flow rate of water resulting from a shear fracture of a 5/8 inch (outside diameter) coil tube can be removed from the unit cooler cabinet by the existing 2 inch drain line.

The drywell air cooling system uses duct relief valves to prevent transient differential pressures that would occur early in the blowdown phase of a LOCA from exceeding the drywell unit cooler housing and duct-work design pressure rating. The duct relief valves are shown on drawing M-77.

To ensure continued availability during a LOOP, all drywell unit cooler fans and controls are powered from Class 1E buses. Loss of one division of Class 1E power may cut off power to one fan in each of two safety-related unit coolers, however, one fan in each of at least two safety-related unit coolers remains operable.

A failure mode and effects analysis for the drywell air cooling and primary containment purge systems is presented in Table 9.4-11.

9.4.5.2.4 Tests and Inspections

The drywell air cooling system is preoperationally tested in accordance with the requirements of Chapter 14 and periodically tested in accordance with the requirements of Chapter 16.

9.4.5.2.5 Instrumentation Applications

The drywell air cooling system is designed to be operated remotely from the control room. All operations are performed manually, with the exception of automatic startup of a standby fan. Each unit cooler fan is provided with a separate hand switch in the control room.

Two flow elements are provided in the discharge duct from each unit cooler, one element being associated with each fan in the unit cooler. Upon detection of low flow from the unit cooler, failure of

the operating fan is annunciated in the control room through the plant computer, and the standby fan is automatically started.

Air temperature is monitored both upstream and downstream of the cooling coils in each unit cooler. Temperature indication for both locations is provided in the control room, and high downstream temperature is annunciated in the control room through the plant computer.

9.4.6 DIESEL GENERATOR ENCLOSURE VENTILATION SYSTEM

The diesel generator enclosure ventilation system maintains suitable ambient air temperatures for the diesel generators and their accessories during all modes of operation. The ventilation systems are safety-related. The heating system, including the plant heating system condensate pump-room ventilation system, is not safety-related.

9.4.6.1 Design Bases

To ensure a proper environment for diesel generator operation, each of the four (per unit) emergency diesel generator cells is individually ventilated and heated. The failure of any cell ventilation system affects only one diesel. The maximum cell design temperature is 115°F, with the diesels operating, and the minimum design temperature is 65°F. The ventilation system normally operates automatically by thermostat, but each fan can be manually started or stopped from its local panel. The design basis and equipment for Unit 2 diesel generator enclosure ventilation system is similar to Unit 1.

The design basis for the outdoor air temperature used in designing the HVAC systems for the diesel generator enclosure is in accordance with the 1977 ASHRAE Fundamentals, Volume 1, Chapter 23. The use of ASHRAE is consistent with the practices used by other plants in the nuclear industry. Table 1 of Chapter 23 of the 1977 ASHRAE Fundamentals shows that the highest 1% design dry-bulb temperature for the areas around LGS is 94°F. A design outside air temperature of 95°F was conservatively used for LGS. Due to internal heat loads in the diesel generator enclosures with the diesels operating and the design ventilation air flows, the diesel enclosure ambient temperature will be 20°F higher than the outdoor air temperature. This results in a maximum internal room temperature of 115°F. The diesel generators were qualified to operate at this design room temperature throughout their normal operating lives and any accident conditions.

The 1% design dry-bulb temperatures provided in ASHRAE represent values that have been equalled or exceeded for 1% of the total hours during the summer months of June through September. Therefore, this would imply that in a normal summer there would be less than 30 hours at or above the 94°F outside air temperature at the LGS site.

Hourly weather data from LGS Weather Station No. 1 was reviewed for the 10 year period from 1972 through 1981. For this 10 year period, it was found that there were only 5 hours for which the outdoor air temperature exceeded 95°F. These temperatures were: 96.2 (1 hour), 95.4 (1 hour), 95.3 (2 hours), and 95.2 (1 hour). The use of 106°F, the maximum temperature recorded in Philadelphia over the last century, does not represent a realistic design basis.

However, the few hours a year in which the room temperature might exceed 115°F due to an outside air temperature between 95°F and an assumed maximum of 106°F would not adversely affect the operation of the safety-related equipment in the diesel compartments. The higher room temperatures would not cause a prompt failure of any safety-related equipment in these compartments. Rather, room temperatures above 115°F would tend to shorten the long-term life of

the equipment. Because the room temperatures will be below 115°F more than 99% of the time, thermal aging would be insignificant.

Each Diesel generator ventilation system can be considered operable in the event that only one of the 50% capacity fans is available provided that the outside air temperature is 75°F or below.

9.4.6.2 System Description

The diesel generator enclosure ventilation system is shown in drawing M-81. Equipment design parameters are listed in Table 9.4-12. Each diesel generator cell is provided with a separate, full load ventilation system. The following description for one cell is applicable to all other cells.

Air is exhausted from the north end of the diesel generator cell by two 50% capacity, variable-pitch blade, vaneaxial fans, discharging vertically through a concrete exhaust house. Makeup outdoor air is drawn in at the south end of each cell through a concrete plenum and is directed by baffles to floor level. The mode of fan operation is set by a hand switch in the diesel generator cell. In automatic mode, a fan is started and its discharge damper is opened by a cell thermostat when its associated diesel generator is operating. A temperature controller varies the fan air flow rate by varying the pitch of the fan blades to maintain the cell temperature at 102°F. If the cell temperature exceeds 105°F with the diesel generator running, another thermostat starts the standby fan; its blade pitch is also controlled by a temperature controller to maintain the cell temperature at 102°F. When the diesel generator stops, and the cell temperature falls below 95°F, the fans stop and their respective dampers close. If the cell temperature exceeds the thermostat setpoint (110°F) whether the diesel generator is running or not, both exhaust fans are cycled on to prevent the cell from overheating.

Heating for each cell is provided by thermostatically controlled steam unit heaters that operate when the cell temperature falls below 65°F. The heating systems are not safety-related.

Dust intake in the diesel generator enclosure is minimized through the use of a labyrinthine intake path for outside air. The air enters the intake plenum through a horizontally mounted removable screen located under the roof overhang, at about 18 feet above grade elevation. Air is then drawn vertically another 6 feet into the plenum before it moves horizontally through an opening in the enclosure wall. Once inside the diesel generator enclosure, the air is directed downwards towards the floor by a ceiling-mounted baffle (drawing M-146). This air path affords ample opportunities for airborne particulates to settle out before they disperse throughout the enclosure.

Further dust protection is provided by covering the ground around the enclosure with grass, gravel, and asphalt. During the period of Unit 1 operation and Unit 2 construction, all yard work around the diesel generator enclosure will be completed. Concrete dust generation will be minimized by painting the floors with a masonry-type paint.

The electrical relays and switches associated with engine start are housed in enclosures with gasketed doors. The contacts for the relays and switches have internal contact surfaces, and many are also enclosed with dust tight covers.

In addition to the design features that minimize the impact of dust on the diesel generator operation, the preventive maintenance program for the control cabinets includes requirements for cleaning out dust accumulation.

Periodic testing of the diesel generators ensures their availability on demand.

Provisions made to protect combustion air from dust are discussed in Section 9.5.8.2.

The plant heating steam condensate pump-room ventilation is provided by a thermostatically controlled power roof ventilator that operates when the pump-room temperature is above 80°F.

9.4.6.3 Safety Evaluation

Each of the diesel generator cells is provided with a separate ventilation system that is located within the seismic Category I tornado and missile-protected enclosure. These ventilation systems are safety-related and designed to seismic Category I requirements, except for the control room annunciator and steam unit heaters. Each ventilation system is powered from the offsite sources under normal conditions and by its associated diesel generator on LOOP. Each ventilation system is designed to maintain the cell temperature below the continuous-duty ambient rating of the safeguard equipment located in the cell.

Evaluation of the diesel generator ventilation system with respect to the following areas is discussed in the following sections:

a.	Protection from wind and tornado effects	Section 3.3
b.	Flood protection	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11
f.	Fire protection	Section 9.5.1

Table 9.4-13 provides a failure modes and effects analysis. An FMEA during normal operation for the diesel generator enclosure is not provided because system operation is identical during both normal and accident conditions.

9.4.6.4 Tests and Inspections

The diesel generator ventilation system is preoperationally tested in accordance with the requirements of Chapter 14 and periodically tested in accordance with the requirements of Chapter 16.

9.4.6.5 Instrumentation Requirements

Each diesel generator ventilation fan can be started or stopped and changed from lead to lag fan operation in automatic mode from the local panels. When in the automatic mode, the fans start and stop, and their dampers open and close in response to the cell thermostats (with staged setpoints). Temperature sensing controllers automatically adjust the fan blade pitch to increase air flow rate with increased cell temperature. A low and a high temperature switch in each cell initiates an alarm in the control room if cell temperature is abnormal. Loss of power to an operating fan motor or failure

of a damper to fully open also initiate alarms in the control room. Each fan has its own separate set of controls.

9.4.7 SPRAY POND PUMP STRUCTURE VENTILATION SYSTEM

9.4.7.1 Design Bases

The spray pond pump structure ventilation system is safety-related. The function of the ventilation system is to maintain suitable ambient air temperatures for the ESW and RHRSW pumps and their associated accessories. To ensure a proper environment for pump operation, the redundant loop A and loop B pump areas are divided and individually ventilated and heated to maintain temperature between a maximum design value of 115°F and a minimum design value of 62°F. The ventilation system normally operates with the lead fan in the run mode. The standby fan will automatically start if required. Either fan may be placed in standby. Temperature is controlled automatically by modulating the inlet and return dampers or energizing structure heaters. The ventilation system is designed with sufficient redundancy so that the failure of any single active component does not prevent the system from performing its safety function.

The design basis for the outdoor air temperature used in designing the HVAC systems for the spray pond pumphouse is in accordance with the 1977 ASHRAE Fundamentals, Volume 1, Chapter 23. The use of ASHRAE is consistent with the practices used by other plants in the nuclear industry. Table 1 of Chapter 23 of the 1977 ASHRAE Fundamentals shows that the highest 1% design dry-bulb temperature for the areas around LGS is 94°F. A design outside air temperature of 95°F was conservatively used for LGS. Due to internal heat loads in the pump-room enclosures with the pumps operating and the design ventilation air flows, the enclosure ambient temperature will be 20°F higher than the outdoor air temperature. This results in a maximum internal room temperature of 115°F. The ESW and RHRSW pumps were qualified to operate at this design room temperature throughout their normal operating lives and any accident conditions.

The 1% design dry-bulb temperatures provided in ASHRAE represent values that have been equalled or exceeded for 1% of the total hours during the summer months of June through September. Therefore, this would imply that in a normal summer there would be less than 30 hours at or above the 94°F outside air temperature at the LGS site.

Hourly weather data from LGS Weather Station No. 1 was reviewed for the 10 year period from 1972 through 1981. For this 10 year period, it was found that there were only 5 hours for which the outdoor air temperature exceeded 95°F. These temperatures were: 96.2 (1 hour), 95.4 (1 hour), 95.3 (2 hours), and 95.2 (1 hour). The use of 106°F, the maximum temperature recorded in Philadelphia over the last century, does not represent a realistic design basis.

However, the few hours a year in which the room temperature might exceed 115°F due to an outside air temperature between 95°F and an assumed maximum of 106°F would not adversely affect the operation of the safety-related equipment in the spray pond pumphouse. The higher room temperatures would not cause a prompt failure of any safety-related equipment in these compartments. Rather, room temperatures above 115°F would tend to shorten the long-term life of the equipment. Because the room temperatures will be below 115°F more than 99% of the time, thermal aging would be insignificant.

9.4.7.2 System Description

The spray pond pump structure ventilation system is shown schematically in drawing M-81. The equipment design data are listed in Table 9.4-14. The two redundant spray pond pump compartments are provided with separate and identical dual ventilation systems. Each individual ventilation system is rated for 100% of the compartment heat load. The following description of ventilation equipment for one pump compartment also applies to the equipment for the other compartment. Each pump compartment has an outdoor air louver, a missile-protected concrete air plenum, and two separate steel mixing boxes, each containing an outdoor damper and a return air damper. Each mixing box feeds a separate fan cabinet containing an electric heating coil and vaneaxial fan. Outside and return air is mixed, tempered (as required) by electric heat, and supplied to the structure by the operating fan(s). Exhaust air from the structure is discharged through two wall louvers, which have manual dampers.

The outdoor air intake dampers are designed to fail closed to prevent freezing.

9.4.7.3 Safety Evaluation

Each pump compartment is ventilated and heated by two separate, completely independent, full capacity systems. The fans and thermostats are located in the seismic Category I spray pond pump structure, which is tornado-protected, missile-protected, and flood-protected. Each ventilation system is powered from the offsite power sources under normal conditions and by separate diesel generators on loss of offsite sources. The electric heaters are not required to operate after a LOCA due to the heat load from the ESW and RHRSW pump motors.

The ventilation system is safety-related and is designed to seismic Category I requirements. The ventilation system is designed to maintain the compartment temperature below the continuous-duty ambient rating of the safeguard electrical equipment located in the compartment and above freezing.

Evaluation of the spray pond pump structure ventilation system with respect to the following areas is discussed in the following sections:

a.	Protection from wind and tornado effects	Section 3.3
b.	Flood protection	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11
f.	Fire protection	Section 9.5.1

For a failure modes and effects analysis, see Table 9.4-15. An FMEA during normal operation for the spray pond pumphouse is not provided because system operation is identical during both normal and accident conditions.

9.4.7.4 Tests and Inspections

The spray pond pump structure ventilation system is preoperationally tested in accordance with the requirements of Chapter 14 and periodically tested in accordance with the requirements of Chapter 16.

9.4.7.5 Instrumentation Requirements

Each supply fan in the spray pond pump structure can be individually controlled by a hand switch in the control room. The fans are started by placing the hand switch in the run position.

In run mode, the lead fan is started and runs continuous. The outside air and return air dampers are energized when the compartment temperature is greater than 70°F and are modulated to maintain controller setpoint. The lag fan is started by its thermostat if the compartment temperature exceeds 105°F or decreases below 62°F.

The following control description applies to each operating fan. An electric controller sensing compartment temperature modulates the outside air damper and return air damper in the inlet plenum to the fan cabinet. When the temperature of the mixed air entering the fan drops below 64°F, a low temperature switch energizes the electric heater.

A low temperature safety switch, with its sensor in the inlet plenum, shuts down the fan and heater if the mixed air temperature falls below 35°F. A common temperature trouble is alarmed in the control room if the compartment temperature falls below 50°F or exceeds 115°F. A common fan/coil unit trouble is also alarmed in the control room. For a failure modes and effects analysis, see Table 9.4-15.

9.4.8 HOT MAINTENANCE SHOP VENTILATION SYSTEM

The hot maintenance shop ventilation system maintains air temperature, quality, and pressure in the hot maintenance shop. The hot maintenance shop ventilation system is not safety-related.

9.4.8.1 Design Bases

The hot maintenance shop ventilation system is designed to operate during normal conditions and to accomplish the following objectives:

a. Maintain the hot shop cells between 70°F and 76°F during working hours

b. Provide, to each cell, a supply of mixed return and outside air that has been filtered, washed, and tempered

c. Maintain cell average air velocity at 25 fpm to 50 fpm to move dust particles to exhaust grilles

d. Maintain the hot shop and equipment room at a negative pressure relative to other shops and the outdoors

e. Maintain airflow from areas of lesser to areas of greater potential contamination

f. Provide local fume and particle hoods at each cutting and cleaning machine to capture potentially contaminated particles at the source

g. Provide high velocity ducts and dust collectors with pocket filters to capture machined particles before they enter the HEPA filtration system

h. Provide HEPA filtration for exhaust air from the hot shop

j. Monitor and exhaust the air from the hot shop to the reactor enclosure east vent stack

9.4.8.2 System Description

The schematic diagram for the hot maintenance shop is shown on drawing M-82. Equipment design parameters are listed in Table 9.4-16. The air handlers, fans, compressor, condenser, unit heaters, control panel, and two dust collectors are located in the HVAC equipment compartment above the hot shop repair cells, at el 230'

The heat exchanger and pump supplying hot water for the hot shop air heating coils are located in the administration building penthouse, at el 282'.

The supply and exhaust fans are controlled to maintain a negative hot shop pressure. Filtered air is supplied to "clean" spaces and exhausted from potentially contaminated spaces. Dust particles from machining or cleaning operations are exhausted at the source. Exhausted air is filtered and sampled by radiation monitors before it is discharged to the east vent stack. All ducts are isolated by dampers from the outdoors during system shutdown.

9.4.8.2.1 Hot Shop Supply and Return System

The air handler for the repair cells and HVAC equipment compartment is shown in drawing M-82 as V-5001. The air handler for the lay-down area, cleanup cell, shower, and tool room is shown in drawing M-82 as V-5002. Each air handler consists of a 100% capacity fan connected to a housing containing a mixing plenum, prefilter, medium efficiency filter, air washer, direct-expansion cooling coil, and hot water coil.

With air flow established by the exhaust fans, either (or both) supply fan(s) may be started manually by local hand switches; this also opens the respective outside air damper and control air supply valve, and starts the water spray pump. Return and outdoor air is mixed, filtered, washed, tempered, and distributed by duct-work to the aforementioned areas. Air to the repair and cleanup cells is discharged through perforated ceilings to minimize induction of room particles. Air flows at an average velocity of 25 fpm to 50 fpm across the lay-down area and each cell to return grilles at the opposite end. Air also infiltrates from the machine shop to the hot shop lay-down area, and from the lay-down area to the repair and cleanup cells.

Seventy-eight percent of the supplied and infiltrated air is returned to the air handlers by grilles and duct-work for conditioning and recirculation as described above.

9.4.8.2.2 Fume and Particle Removal System

The dust collectors for the grinders and band saw are shown in drawing M-82 as V-5006 and V-5007. Each dust collection system consists of a hood, high velocity duct, pocket filter, fan, and exhaust duct.

Fume collectors for the erection plates, lathes, and electrostatic cleaners are also provided. Exhaust air from the dust collectors and from the fume hoods is conveyed by fan V-5004 to exhaust unit V-5003, as indicated in drawing M-82.

The dust collectors and fume exhaust fan are started manually by local hand switches. Particles from the grinders and saw are conveyed from the source and removed by pocket filters in each dust collector. Fumes discharged from the dust collectors, and dust and fumes removed by the fume hoods, are conveyed by sealed duct-work and exhaust fan V-5004 to the filter/ exhaust unit. Failure of fan V-5004 stops air handlers V-5011 and V-5002.

9.4.8.2.3 Exhaust System

The exhaust unit for the hot shop, shown in drawing M-82, consists of a 100% capacity fan (V-5003) with constant flow control connected to a housing containing a prefilter bank and a HEPA filter bank. An isolation damper is provided in the duct-work between the fan discharge and the vent stack.

The exhaust unit is started manually by a local hand switch, which also opens the supply damper and the control air supply valve.

Twenty-three percent of the air supplied to the hot shop is exhausted to the reactor enclosure east vent stack. The exhaust air is taken from the dust and fume collection system described in Section 9.4.8.2.2. The quantity of exhaust air is held constant by a fan blade controller on V-5003 to maintain a negative shop pressure (exhaust air quantity is designed to exceed outside air quantity, with clean or dirty filters). After filtration, the exhaust air is sampled and monitored for radioactivity and discharged into the reactor enclosure east vent stack. Failure of fan V-5003 stops air handler V-5001 and V-5002.

9.4.8.2.4 Refrigeration System

The refrigeration system serving the cooling coils in the two air handlers is shown in drawing M-82. The system consists of a refrigerant-22 compressor, an evaporative condenser with accessories, and the direct-expansion cooling coils in the air handlers. Outdoor air is used to remove the heat from the evaporative condenser.

9.4.8.3 Safety Evaluation

The hot maintenance shop ventilation system has no safety-related functions. Failure of the system does not compromise any safety-related system or component or prevent a safe shutdown of the plant.

9.4.8.4 Tests and Inspections

All HVAC equipment is inspected and tested during manufacture, installation, and startup. Air and water flows are measured and adjusted to design requirements using calibrated instruments. System operability is demonstrated by use during normal plant operation.

9.4.8.5 Instrumentation Requirements

All hand control switches for the hot maintenance shop ventilation system are on a local control panel in the shop HVAC equipment compartment. Hand switches for dust collectors are located outside the shop near the dust collectors.

The local panel transmits any HVAC alarm signal to the control room panel. The following abnormal conditions are alarmed:

a. Air flow failure (all ducted fans)

b. High pressure differential across a filter bank

There are various sensors, controllers, time delays, switches, and indicators to start and stop the fans, pumps, compressor, and condenser; to open and close dampers; to modulate hot water valves; to open and close refrigerant solenoid valves; to adjust fan blade; to cycle unit heaters; and to indicate temperatures and filter pressure differentials.

9.4.9 MISCELLANEOUS STRUCTURES VENTILATION SYSTEMS

Miscellaneous structures include the circulating water pump structure, water treatment enclosure, Schuylkill River pump structure, Perkiomen Creek pump structure, sewage treatment enclosure, auxiliary boiler enclosure, boiler fuel transfer enclosure, lube oil structure, chlorine and acid feed enclosure, and the administration building, and the technical support center. The ventilation systems for these structures are not safety-related.

9.4.9.1 Design Bases

The miscellaneous structures ventilation systems are designed to function during normal plant operations to maintain a suitable environment for equipment operation and/or personnel comfort.

a. Provide a supply of outside air to all enclosures

b. Provide a supply of filtered and conditioned air to the administration building offices and the water treatment enclosure laboratory

c. Exhaust gases and fumes from the chlorine and acid feed enclosure, shop welding areas, and battery rooms

d. Provide emergency cooling for the guard station, CAS, SAS, and telephone equipment room

9.4.9.2 System Description

Ventilation systems for miscellaneous structures other than the administration building are shown schematically in drawing M-81. The administration building ventilation system is shown in drawing M-80. Major equipment design parameters are listed in Table 9.4-17.

9.4.9.2.1 Circulating Water Pump Structure

The circulating water pump compartment is ventilated by 24 roof-mounted exhaust fans that are controlled by four staged room thermostats. Outside air is drawn through 10 wall louvers (with manual dampers) near ground level and is exhausted through the roof. The area is heated by 12 steam unit heaters; each heater is controlled by an individual area thermostat and 3 flash steam unit heaters, each controlled by an individual flash steam tank thermostat.

The compartment for the diesel-driven fire pump is ventilated by a roof-mounted exhaust fan controlled by a room thermostat. Outside air is drawn in through a wall louver (with manual damper) near ground level. The compartment is heated by a steam unit heater, which is controlled by a thermostat.

The chlorine equipment and equipment control compartments are ventilated by two roof-mounted exhaust fans controlled by individual compartment thermostats. Outside air is drawn in through wall louvers (with manual dampers) near ground level. The compartments are heated by individual steam unit heaters, each controlled by thermostat.

9.4.9.2.2 Water Treatment Enclosure

The water treatment area is ventilated by roof-mounted exhaust fans that are controlled by individual, staged, compartment thermostats. Outside air is drawn in through four wall louvers (with manual dampers) near ground level. The compartment is heated by six steam unit heaters, which are controlled by individual area thermostats.

The utility area is ventilated by a thermostatically controlled roof exhaust fan and heated by a thermostatically controlled steam unit heater.

The water treatment laboratory is cooled by a rooftop packaged air conditioner and heated by a steam coil in the supply duct-work. Compartment thermostats control the air conditioner and the steam coil control valve.

9.4.9.2.3 Sewage Treatment Enclosure

The sewage treatment equipment compartment is ventilated by two roof-mounted exhaust fans, each controlled by a thermostat. Outside air is drawn in through a wall louver (with manual damper) near ground level. The equipment compartment is heated by two electric unit heaters, which are controlled by individual area thermostats.

9.4.9.2.4 Schuylkill River Pump Structure

The Schuylkill River pump structure is ventilated by four roof-mounted exhaust fans, each controlled by a thermostat. Outside air is drawn in through wall louvers. The intake structure is heated by six electric unit heaters, which are controlled by individual area thermostats.

The Schuylkill River debris facility is ventilated by a wall exhaust fan, which is controlled by a hand switch. Outside air is drawn in through a wall louver (with manual damper). The debris facility is heated by two electric unit heaters, which are controlled by individual area thermostats.

9.4.9.2.5 Perkiomen Creek Pump Structure

The Perkiomen Creek pump structure is ventilated by three roof-mounted exhaust fans, each controlled by a compartment thermostat. Outside air is drawn in through wall louvers with motor-operated dampers. Heating is provided by five electric unit heaters, each controlled by an individual area thermostat.

The battery room has its own roof-mounted exhaust fan, which runs continuously. Battery room makeup air is drawn from the pump compartment.

9.4.9.2.6 Boiler Fuel Oil Transfer Enclosure

The fuel oil transfer enclosure is ventilated by two roof-mounted exhaust fans, each controlled by a thermostat. Outside air is drawn in through two wall louvers (with manual damper) near ground level. The equipment compartment is heated by two electric unit heaters that are controlled by individual area thermostats.

9.4.9.2.7 Auxiliary Boiler Enclosure

The auxiliary boiler enclosure is ventilated by six roof-mounted exhaust fans, each controlled by a compartment thermostat. Outside air is drawn in through wall louvers that have manual dampers. Combustion air for each boiler is ducted from separate outside air louvers to the boiler combustion air fans located on the boiler wind boxes.

9.4.9.2.8 Lube Oil Structure

The lube oil structure is ventilated by a roof-mounted exhaust fan that is thermostat controlled. Outside air is drawn in through a wall louver that has a manual damper. The compartment is heated by two steam unit heaters, each having its own area thermostat.

The calibration equipment storage compartment in the lube oil structure is ventilated by a roof-mounted exhaust fan and heated by a thermostatically controlled steam unit heater.

9.4.9.2.9 Chlorine and Acid Feed Enclosure

The chlorine and acid feed enclosure is ventilated by four roof exhaust fans ducted to floor level. The roof exhaust fans cycle on room thermostats. A wall exhaust fan is mounted near the acid tank to provide supplemental ventilation during chemical deliveries and system maintenance. The wall fan is controlled from a handswitch on the building exterior.

Outside air is drawn in through wall louvers. The enclosure is heated by five electric unit heaters controlled by individual area thermostats.

The chlorine and acid feed electrical equipment compartment is ventilated by a thermostatically controlled wall exhaust fan. Outside air is drawn in through a wall louver. Heating is provided by an electric unit heater which is controlled by a thermostat.

The circulating water chlorine and acid feed pipe trench is heated by 5 electric heaters, each controlled by an individual area thermostat.

9.4.9.2.10 Administration Building

The administration building office areas are air conditioned by a low velocity, variable volume system. Major components include a centrifugal water chiller, steam heat exchanger, hot and chilled water pumps, supply air handling unit, return air fan, and modulating room air terminals. Outside air and return air is mixed, filtered, heated or cooled, humidified, and supplied to the room terminal units. Room temperature is controlled by room thermostats modulating the ceiling terminal dampers and hot water coils.

During air handler breakdown, the telephone equipment room is ventilated by an exhaust fan.

The locker rooms and rest rooms are ventilated and heated by a supply air handling unit and exhaust air fan located in the penthouse.

The eastern extension is air conditioned by a separate built-up system located in an equipment compartment above the lobby.

The security areas are air conditioned by two redundant, packaged, air conditioning units located on the roof. The supply and return air paths are either ducted through security bars or otherwise limited to prevent unauthorized entry to the security areas. Fresh air intakes to each of the redundant systems are not located directly adjacent to any of the security areas. The primary packaged air conditioning unit is powered from a safeguard power supply which is tripped upon a LOCA signal. The stand-by packaged air conditioning unit is not powered from a safeguard power supply.

The warehouse, machine shop, and off-loading facility are all ventilated by roof-mounted exhaust fans, each controlled by its own room thermostat. Outside air is drawn in through automatically adjusted wall louvers. The machine shop is heated by an air handling unit with thermostatically controlled hot water coils; the other facilities are heated by thermostatically controlled hot water unit heaters.

9.4.9.2.11 Technical Support Center

The security areas are air conditioned by two redundant, packaged, air conditioning units located on the first floor. The supply and return air paths are either ducted through security bars or otherwise limited to prevent unauthorized entry to the security areas. Fresh air intakes to each of the redundant systems are not located directly adjacent to any of the security areas.

9.4.9.3 Safety Evaluation

The ventilation systems for the miscellaneous structures are not safety-related. Failure of the systems does not compromise any safety-related system or component or prevent a safe shutdown of the plant. There are multiple fans and unit heaters in the larger compartments. The air conditioning units for the security area in the administration building and the technical support center are redundant, located within the protected area, and powered from redundant power supply systems.

9.4.9.4 Tests and Inspections

Equipment is tested and balanced after installation to verify its operation and capacity. System operability is demonstrated by use during normal plant operation.

9.4.9.5 Instrumentation Requirements

The ventilation systems in the miscellaneous structures are controlled by local thermostats or local hand switches that can override the thermostat. The ventilation systems in the administration building are controlled by local thermostats and by hand and automatic controls mounted in control panels located in the administration building, eastern extension, and the machine shop. Alarm signals from the administration building, eastern extension, and shop control panels annunciate in the control room on equipment failure.

Table 9.4-1

CONTROL ROOM AND CONTROL STRUCTURE VENTILATION SYSTEM EQUIPMENT DESIGN PARAMETERS

SYSTEM	CONTROL ROOM SUPPLY	AUXILIARY EQUIPMENT ROOM SUPPLY	EMERGENCY SWITCHGEAR & BATTERY ROOMS SUPPLY	SGTS ROOM UNIT COOLERS
Identification no.	OAV-116, OBV-116	OAV-114, OBV-114	OAV-118, OBV-118	OAV-140, OBV-140
No. of units	2	2	2	2
Type	Air handling unit	Air handling unit	Air handling unit	Fan/coil unit
Flow rate, each (cfm)	26,200	33,600	15,535	1,000
Fan:				
Type	Vaneaxial	Vaneaxial	Vaneaxial	Vaneaxial
Drive	Direct (adj pitch)	Direct (adj pitch)	Direct (adj pitch)	Direct (adj pitch)
No. running	1	1	1	1
Static pressure	3.91	2.34	2.45	0.17
Total pressure (in wg)	4.61	3.09	2.9	0.29
Motor horsepower (each)	40	30	15	1
Cooling coils:				
Quantity, per unit	1	1	1	1
Rows	8	4	2	4
Cooling capacity (Btu/hr)	1,032,000	1,050,000	550,080	43,000
Electric duct heaters:				
Quantity, per unit	1	1	None	None
Heating capacity (kW)	50	65	-	-
Filters:				
Type	Roll	Roll	Roll	None
Pressure drop (in wg)	0.25 clean 0.5 dirty	0.25 clean 0.5 dirty	0.25 clean 0.5 dirty	-

Table 9.4-1 (Cont'd)

SYSTEM	BATTERY ROOMS EXHAUST	TOILET ROOM EXHAUST	SGTS COMPARTMENT ACCESS AREA UNIT COOLERS	CONTROL ROOM EMERGENCY FRESH AIR SUPPLY
Identification no.	OAV-124, OBV-124	OOV-126	OAV-141, OBV-141	OAV-127, OBV-127
No. of units	2	1	2	2
Type	Fan only	Fan only	Fan/coil unit	Fan and filter plenum
Flow rate, each (cfm)	8,000	775	2,500	3,000
Fan:				
Type	Vaneaxial	Centrifugal	Vaneaxial	Centrifugal
Drive	Direct (adj pitch)	Direct	Direct (adj pitch)	Direct
No. running	1	1	1	1
Static pressure (in wg)	-	1.5	0.69	11.0
Total pressure (in wg)	3.5	-	0.82	-
Motor horsepower (each)	7.5	1	7.5	10
Cooling coils:				
Quantity, per unit	None	None	1	None
Rows	-	-	3	-
Cooling capacity (Btu/hr)	-	-	110,000	-
Electric duct heaters:				
Quantity, per unit	None	None	None	1
Heating capacity (kW)	-	-	-	40
Filters:				
Type	None	None	None	Plenum w/prefilter, HEPA, charcoal, HEPA
Pressure drop (in wg)	-	-	-	Cartridge: 0.55 clean HEPA: 1.0 clean Charcoal: 1.1 ±0.15
Charcoal adsorber[1]				
Type	None	None	None	Rechargeable vertical bed
Depth (in)	-	-	-	2
Adsorber medium	-	-	-	Impregnated activated carbon
Assigned efficiency[2]	-	-	-	1.1 ±,0.15
Removing elemental iodine	-	-		95%
Removing organic iodine	-	-	-	95%
Residence time	-	-		0.25 sec

Table 9.4-1 (Cont'd)

SYSTEM	CONTROL ROOM RETURN AIR	AUXILIARY EQUIPMENT ROOM RETURN AIR	SGTS ROOM EXHAUST
Identification no.	OAV-121, OBV-121	OAV-120, OBV-120	OAV-131, OBV-131
No. of units	2	2	2
Type	Fan only	Fan only	Fan and filter plenum
Flow rate, each (cfm)	26,200	33,600	2,000
Fan:			
Type	Vaneaxial	Vaneaxial	Centrifugal
Drive	Direct (adj pitch)	Direct (adj pitch)	Direct
No. running	1	1	1
Static pressure (in wg)	1.3	1.95	12.6
Total pressure (in wg)	2.2	2.5	12.6
Motor horsepower (each)	15	20	10
Cooling coils:			
Quantity, per unit	None	None	None
Rows	-	-	-
Cooling capacity (Btu/hr)	-	-	-
Electric duct heaters:			
Quantity, per unit	None	None	None
Heating capacity (kW)	-	-	-
Filters:			
Type	None	None	Plenum w/prefilters, HEPA, charcoal, HEPA
Pressure drop (in wg)	-	-	Cartridge: 0.55 clean HEPA: 1.0 clean
Charcoal adsorber[1]			
Type	None	None	Vertical tray
Depth (in)	-	-	2
Filter medium	-	-	Impregnated activated carbon
Pressure drop (in wg)	-	-	1.1 ±0.15
Assigned efficiency[2]			
Removing elemental iodine	-	-	70%
Removing organic iodine	-	-	70%
Residence time	-	-	0.25 sec

[1] Physical property specifications of new activated carbon are given in Table 9.4-4.
[2] Efficiency designated by Regulatory Guide 1.52 for use in release analyses.

Table 9.4-2

CONTROL ROOM HVAC SYSTEM ISOLATION VALVE DESIGN PARAMETERS

ISOLATION VALVES	LOCATION	FUNCTION	OPERATOR TYPE	VALVE OPENING OR CLOSING TIME (SEC)	SPECIFIED LEAKAGE	FAIL POSITION
HV-78-021A HV-78-021B	Fresh air inlet duct to OAV-116 and OBV-116	Isolation of unfiltered fresh air to control room	Pneumatic	3-5	Zero leakage (bubble-tight)	Closed
HV-78-052A HV-78-052B	Normal control room exhaust air duct	Isolation of control room exhaust air duct from outside environment	Pneumatic	3-5	Zero leakage (bubble-tight)	Closed
HV-78-020A HV-78-020B HV-78-020C HV-78-020D	Fresh air inlet ducts to emergency fresh air filter for control room	Provide path for filtered fresh air for pressurization on high radiation. Isolate on chlorine release	Electrohydraulic	8-12 (adj)	Zero leakage (bubble-tight)	Closed
HV-78-010A HV-78-010B	Recirculation duct from control room return air duct to emergency fresh air filter inlet duct	Provide path for recirculation cleanup of control room air during radiation isolation, chlorine or offsite toxic chemical release isolation	Electrohydraulic	8-12 (adj)	Zero leakage (bubble-tight)	Closed
HV-78-057A HV-78-057B	Toilet exhaust duct – control Room	Isolate duct from outside environment	Pneumatic	3-5	Zero leakage (bubble-tight)	Closed
HV-78-071A HV-78-071B	Toilet exhaust branch duct from Unit 2 turbine enclosure	Isolate control room from Unit 2 turbine enclosure environment	Pneumatic	3-5	Zero leakage (bubble-tight)	Closed

Table 9.4-3

CONTROL ROOM AND CONTROL STRUCTURE VENTILATION SYSTEMS
FAILURE MODE AND EFFECT ANALYSIS

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency	Power supply	LOOP	None - all safety-related equipment and controls are redundant and are powered from separate standby diesel generators.	Alarm in the control room.	No loss of safety function
Emergency (LOCA, LOCA & LOOP, high radiation, offsite toxic gas, or chlorine release) and normal operation.	Control room and auxiliary equipment room HVAC system supply air handling units	Failure of fan motor	None - the standby fan automatically starts. Note 1	Alarm in the control room.	No loss of safety function
		Reduced air flow	None - the standby fan automatically starts. Note 1	Alarm in the control room.	No loss of safety function
		Loss of chilled water to cooling coil	None - For Auxiliary equipment room air handling unit, temperature switch high stops the running fan and the standby fan starts automatically. For control room supply air handling unit, temperature switch high causes C101 trouble alarm in control room. Then manual action can be taken to restore cooling to operating air handling unit or to place redundant fan/train in service. Note 1	High temperature switch on local panel C101, which causes C101 trouble alarm in the control room to activate. For the auxiliary equipment room HVAC system, the high temperature switch stops the running fan.	No loss of safety function
		Loss of heating	None - Air heating is not required during emergency operation.	Low temperature switch on local panel C101, which causes C101 trouble alarm in the control room to activate.	No loss of safety function

Table 9.4-3 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (LOCA, LOCA & LOOP, high radiation, chlorine or offsite gas release) and normal operation.	Control room and auxiliary equipment room HVAC system return air fans	Failure of fan motor	None - The standby Fan automatically starts. Note 1	Alarm in the control room.	No loss of safety function
		Reduced air flow	None - The standby fan automatically starts. Note 1	Alarm in the control room.	No loss of safety function
Emergency (LOCA, LOCA & LOOP, high radiation, chlorine, or offsite toxic gas release)	Control room emergency fresh air fans	Failure of fan motor	None - The standby fan automatically starts.	Alarm in the control room.	No loss of safety function
		Reduced air flow	None - The standby fan automatically starts.	Alarm in the control room.	No loss of safety function
Emergency (LOCA, LOCA & LOOP, high radiation, chlorine or offsite toxic gas release) and normal operation	Emergency switch gear and battery compartment air handling units	Failure of fan motor	None - The standby fan automatically starts.	Alarm in the control room.	No loss of safety function
		Reduced air flow	None - The standby fan automatically starts.	Alarm in the control room.	No loss of safety function
		Loss of chilled water to cooling coil	None – Temperature switch high stops the running fan. The standby fan fan starts automatically.	High temperature switch on local panel C101, which causes C101 trouble alarm in the control room to activate and stops the running fan.	No loss of safety function

Note 1: For control room HVAC system supply air and return fans, the standby fan can also be manually started.

Table 9.4-3 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency control room high radiation, chlorine or toxic gas release Isolation	Control room normal fresh air inlet duct isolation valves, normal exhaust duct isolation valves, toilet exhaust duct isolation valves	Loss of signal; valve stuck in open position	None - Valves are redundant in series. Second valve closes. Valves have fail closed action on loss of signal.	Radiation isolation signal trouble alarms in control rooms. Isolation valve position indicated on local panel C101.	No loss of safety function
	Control room emergency fresh air inlet valves	Loss of signal; valve stuck in closed position (radiation accident)	Parallel paths are provided to assure inlet to emergency fresh air filters on high radiation.	Radiation isolation signal trouble alarms in control room. Isolation valve position indicated on local panel C101.	No loss of safety function
		Valve stuck in open position (chlorine release accident)	Valves are in series on each parallel duct to assure isolation.	Isolation valve position indicated on panel seal C101.	No loss of safety function

Table 9.4-4

VENTILATION SYSTEMS TESTS AND INSPECTIONS

GENERAL

a. Safety-related components are designed, fabricated, installed, and tested under quality assurance requirements in accordance with 10CFR50, Appendix B.

b. For systems that must perform a safety-related function, periodic inservice testing of fans, valves, controls, and instrumentation in the systems is performed. MOVs and dampers are tested by opening and closing the valve or damper.

c. Equipment in seismic Category I systems is required by specification to meet LGS seismic requirements. Before each equipment item is shipped, the supplier of that item is required to submit an adequate analysis or applicable test data as evidence of compliance.

d. Systems designed to seismic Category I requirements are subjected to a program of vendor shop and field testing.

e. Standby units are tested at periodic intervals to verify the operation of essential features. Periodic tests of the activation circuitry and the system components are conducted during normal plant operation.

FANS

Centrifugal, propeller, and vaneaxial fans are tested in accordance with the AMCA Standard Test Code for Air Moving Devices, Bulletin 210. Vaneaxial fan blade setting adjustments are made to correct flow rates where necessary.

MOTORS

Motors are built, designed, rated, and tested in accordance with NEMA MG-1. Seismic Category I motors have certification for the NEMA tests required in Publication No. MG-1. Motors used within the containment comply with IEEE 334.

COOLING COILS

Cooling coils are furnished in accordance with ARI 410. Chilled water, service water, and emergency service water coils are hydrostatically and pneumatically tested. Seismic Category I coils are seismically qualified by analysis or testing on a shaker table.

Table 9.4-4 (Cont'd)

PARTICULATE FILTERS (SUPPLY AIR ROLL FILTERS)

Particulate filters are UL Class II.

PREFILTERS (USED IN SERIES WITH HEPA FILTERS)

The prefilters are certified to meet standards for UL Class 1 filters. Airflow resistance of the prefilters at rated flow is less than 0.55 inch wg (clean). Prefilters have an efficiency rating of 80% minimum by the NBS dust spot test.

HEPA FILTERS

a. Qualification Tests Before Installation

HEPA filters are constructed in accordance with MIL-F-51068C or ASME AG-1, "Filter Medium, Fire Resistant, High Efficiency" and MIL-F-51068C or ASME AG-1, "Filter, Particulate High Efficiency, Fire Resistant." The minimum tensile strength of the filter media is at least 2.5 lb/in of width, in accordance with requirements of MIL-F-51068C or ASME AG-1.

The filter medium is securely fastened to the sides and ends of the filter frame and sealed. Patching of holes or tears in the medium is not permitted.

The assembled filters are type-tested in accordance with UL 586, "High Efficiency Air Filter Units" requirements to minimize fire hazards. The filters are approved UL Class 1.

Each filter is tested for flow resistance at rated flow. The filter resistance is not to exceed the rated pressure drop of 1 inch wg under this condition.

The filters are rough-handled with the Q110 Vibrating Machine, DLA 26-18-67, and examined for damage, and the DOP penetration is determined in accordance with Section 4.3.4.1.

Filters are subjected to acceptance tests made by an NRC quality assurance station. The filter efficiency exceeds 99.97% when tested with monodispersed, thermally generated DOP aerosol having a mean particle size of 0.3 micron.

Table 9.4-4 (Cont'd)

Filters selected at random from the manufacturer's production line are subjected to moisture, overpressure resistance, and filter dust loading tests in order to initially qualify the filters. The moisture and overpressure resistance tests are performed in accordance with MIL-F-51068.

Each filter is individually tested by the appropriate NRC quality assurance station at 100% and 20% of the rated capacity.

b. Preoperational Tests for Acceptance (Performed in Filter Train Housing)

Visual and dimensional checks of the housing and mounting frames are made in the field to check for conformance with design specifications. Nonconforming items are rejected and replaced with acceptable equipment.

After installation, inplace testing of HEPA filter efficiency is conducted in accordance with section 10 of ANSI/ASME N510 (1980) (formerly ANSI N510 (1975)). The tests are conducted at the rated airflow, using the DOP aerosol test equipment, test procedures, and test reports specified in ANSI/ASME N510 (1980). The overall filtration efficiency is not less than 99.95%. When leaks exist that would result in inability to meet the specified system parameters, they are located and after repair or filter replacement, the system is tested again to ensure conformance with acceptance criteria.

CARBON ADSORBERS

Carbon adsorbers are tested as follows:

a. Qualification Tests Before Installation

1. Representative samples, taken from each original or replacement batch of activated carbon used for filling the adsorbers, are tested to meet the qualification and batch test results summarized in ANSI N509 (1980), table 5.1, except that laboratory analysis of carbon samples is performed in accordance with ASTM D3803-1989, for ESF systems, and Regulatory Guide 1.140 (Rev 1), table 1 for normal ventilation exhaust systems (as an alternative, the test requirements specified in ANSI N509 (1980), table 5-1 and ASTM D3803-1989 can be used for normal ventilation exhaust systems). The assigned removal efficiencies and minimum air residence times are as follows for relative humidities up to 70%:

Table 9.4-4 (Cont'd)

	Removal Efficiency	
Adsorber Depth	Safety-Related	Nonsafety-Related
2 inches (0.25 sec res time)	95.0 elemental 95.0 organic	70.0% elemental 70.0% organic
8 inches (1.0 sec res time)	99.0 elemental 99.0 organic	99.0% elemental 99.0% organic

Tests or calculations demonstrate that the residence times shown above are met.

2. Each charcoal adsorber cell is tested for leakage using the test method presented in ANSI N510 (1980) (formerly AEC Report DP1082). The tracer gas used in the test is either R-112 or R-11 (tetrachloro-difluorothane or trichlorofluoromethane). Tracer gas is mixed into the rated air flow in accordance with the above procedure. Leakage paths are identified and blocked by welding, as necessary, to meet the limiting requirements on leakage. Pressure drop across the cell is measured during the tracer gas test.

b. Inplace Testing of Adsorber

1. Refrigerant (R-11 or R-112) is introduced into the upstream side of the adsorber at a concentration of approximately 20 ppm at rated airflow. The downstream concentration is less than 0.05% of the upstream 20 ppm. No more than four tests are conducted on any given carbon filter cell. No radioactive isotopes are used in the efficiency tests performed on the carbon adsorbers.

2. The installed carbon adsorber filter bank is visually and dimensionally checked for conformance to the design specifications.

Table 9.4-4 (Cont'd)

FILTER HOUSINGS

In addition to the housing manufacturer's shop tests, a field performance test is conducted for each housing. The leakage rate is to be less than 0.05% of the rated air flow in cubic feet per minute for RERS filter and control room emergency fresh air filter housings and 0.1% for all other filter housings at 125% of the negative design pressure.

FILTER INSERVICE TESTS AND INSPECTIONS

a. The air filtering systems are subject to inplace testing at intervals specified in Regulatory Guide 1.52 (Rev 2) (ESF) or Regulatory Guide 1.140 (Rev 1) (non-ESF). Except HEPA filters and charcoal adsorbers are in-place tested as specified in Regulatory Guide 1.52 at least once per 48 months or tested as specified in Regulatory Guide 1.140 at intervals of approximately 24 months.

b. Periodic testing of the filter banks ensures that the filter bank performance is not degraded through normal use, or during standby, to a level below that assumed in the accident analyses. Test methods and sensitivities are the same as or equal to those for initial acceptance of the system components. Should the test results indicate that performance of a component has fallen to the level assumed in the accident analyses, the component is replaced.

c. Results of all tests are made available upon completion of performance and acceptance by PECo.

d. The following filter inservice tests and inspections are performed at regular intervals during plant life to determine that the filtration systems are functioning correctly:

    1. With the fan running, observe and record readings on the differential pressure gauges, which are mounted on the filter plenum.

    2. Prefilters are replaced when the pressure drop across them reaches 1.0 inch water column.

    3. HEPA filters are replaced when the pressure drop across them reaches 3.0 inches water column. Where there are two HEPA filter banks, the second one is changed at 4 inches wg.

Table 9.4-4 (Cont'd)

4. Field leak tests are conducted after each change of HEPA filters in a system.

5. Field leak tests of HEPA filter banks are made with cold generated dioctylphthalate, and a light scattering aerosol photometer is used for measuring percentage penetration. A penetration greater than the value specified in the test procedures requires corrective action, as stated previously.

6. Corrective action after a leak test may consist of increasing the contact pressure on a seal or replacement of a cell or cells. After corrective action is taken, an additional leak test is made.

7. Laboratory tests in compliance with ASTM D3803-1989 (with the exception that ANSI N509 (1980) test procedures can be used) and Regulatory Guide 1.140 (Rev 1), table 2 (with the exception that ANSI N509 (1980) and ANSI N510 (1980) test procedures and ASTM D3803-1989 can be used) of representative samples are performed (1) initially, (2) at least once per 24 months thereafter for systems maintained in standby status or after 720 hours of system operation, and (3) following painting, fire, or chemical release in any ventilation zone communicating with the system. The activated carbon adsorber section is replaced with new activated carbon meeting the physical property specifications of ANSI N509 (1980), table 5.1 and ASTM D3803-1989 or Regulatory Guide 1.140 (Rev 1), table 1, as appropriate. The adsorber is replaced if a representative sample fails to pass the applicable test in Regulatory Guide 1.52 (Rev 2) table 2 and ASTM D3803-1989 and Regulatory Guide 1.140 (Rev 1), table 2 or no representative samples are available for testing.

DUCT-WORK

a. For Unit 1, leakage tests on all duct-work are conducted during construction. This also applies to Unit 2 duct-work with the exception of duct-work in the primary containment (drywell).

b. All air distribution systems are tested and balanced to provide design air quantities at each outlet, within a tolerance of ±10%.

Table 9.4-4 (Cont'd)

c. Category I duct-work is supported by seismically designed duct hangers.

d. All Category I duct-work is seismically designed and based on the analysis and test results conducted by Bechtel Power Corporation in April, 1976.

CONTROLS

a. All controls and instrumentation are tested prior to plant operation.

b. Inservice tests and inspection procedures are incorporated in the plant operations manual and are performed at regular intervals during the life of the plant to show that the instruments are functioning properly. Recalibration, when necessary, is made at that time.

Table 9.4-5

REACTOR ENCLOSURE AND REFUELING AREA VENTILATION SYSTEMS DESIGN PARAMETERS

	ZONE I REACTOR ENCLOSURE			ZONE III REFUELING AREA	
ITEM	SUPPLY UNIT SYS NO. V-202	EXHAUST FAN SYS NO. V-205	EQUIP. COMP EXH SYSTEM SYS NO. V-206	UNIT I SIDE SUPPLY UNIT SYS NO. V-201	UNIT I SIDE EXHAUST FAN SYS NO. V-204
Type	Built-up unit	Fan on built-up exhaust plenum	Built-up unit	Built-up unit	Fans on built-up exhaust plenum
Number of units	1	1	2	1	1
Unit flow rate (cfm)	180,000	140,000	40,000	43,000[6]	43,000[6]
Fan:					
Type	Vaneaxial	Vaneaxial	Centrifugal	Vaneaxial	Vaneaxial
Drive	Direct	Direct	Direct	Direct	Direct
No. of fans per unit	3	3	1	3	3
No. of running fans	2	2	1	2	2
Motor horsepower, (each)	200	125	150	40	40
Cooling coils:					
No. of coils per unit	1	None	None	1	None
Capacity, each (Btu/hr)	5,200,000	-	-	1,570,000	-
Heating coils:					
No. of coils per unit	2	None	None	2	None
Capacity, each (Btu/hr)	10,700,000	-	-	3,200,000	-
Prefilters:					
Quantity	1 roll	None	35	1 roll	None
Size, each	35'x12'	24x24x12	16'x12'		
Pressure drop, (in wg)					
Clean	0.45 avg	-	0.55	0.45 avg	-
Dirty	0.45 avg	-	1.0	0.45 avg	-
Efficiency[1]	-	-	80% (min)	-	-
HEPA filter, upstream:					
Quantity	None	None	35/24x24x12	None	None
Size, each					
Pressure drop (in wg)	-	-	-	-	-
Clean	-	-	1.0	-	-
Dirty	-	-	3.0	-	-
Efficiency[2]			99.97%		

Table 9.4-5 (Cont'd)

	ZONE I **REACTOR ENCLOSURE**			ZONE III **REFUELING AREA**	
ITEM	SUPPLY UNIT SYS NO. V-202	EXHAUST FAN SYS NO. V-205	EQUIP. COMP EXH SYSTEM SYS NO. V-206	UNIT I SIDE SUPPLY UNIT SYS NO. V-201	UNIT I SIDE EXHAUST FAN SYS NO. V-204
Charcoal absorber[4]:	None	None	Rechargeable	None	None
Type			vertical bed	-	-
Depth (in)			2	-	-
Filter medium			Impregnated activated carbon activated carbon	-	-
Pressure drop (in wg)			1.1 ±0.15		
Assigned efficiency[5]				-	-
Removing elemental iodine			70%	-	-
Removing organic iodine			70%	-	-
Residence time	-	-	0.25 sec	-	-
HEPA Filter, downstream:	None	None	[3]	None	None

(1) Dust spot test on atmospheric dust
(2) By MIL Standard 282 DOP test method on 0.3 micron particles
(3) All design parameters same as HEPA, upstream
(4) Physical property specifications of new activated carbon are given in Table 9.4-4.
(5) Efficiency designated by Regulatory Guide 1.52 for use in release analyses.

Table 9.4-6

REACTOR ENCLOSURE SAFETY-RELATED AIR COOLING SYSTEM DESIGN PARAMETERS

ITEM	RCIC PUMP ROOM UNIT COOLERS V-208 A&B	HPCI PUMP ROOM UNIT COOLERS V-209 A&B	RHR PUMP ROOMS UNIT COOLERS		CORE SPRAY PUMP ROOMS UNIT COOLERS	
			RHR EAST V-210 **B&F, D&H**	RHR WEST V-210 **A&E, C&G**	EAST V-211 **B&F, D&H**	WEST V-211 **A&F, C&G**
Type	Fan cabinet	Fan cabinet	Fan cabinet	Fan cabinet	Fan cabinet	Fan cabinet
Number of units	2	2	4	4	4	4
Flow rate, each (cfm)	9,000	19,100	21,800	21,800	12,000	12,000
Fan:						
Type	Vaneaxial	Vaneaxial	Vaneaxial	Vaneaxial	Vaneaxial	Vaneaxial
Drive	Direct	Direct	Direct	Direct	Direct	Direct
No. of running fans	1	1	1	1	1	1
Total pressure (in wg)	2.5	2.9	4.17	4.17	3.4	3.4
Motor horsepower (each)	5	15	20	20	10	10
Cooling coil:						
No. of coils per unit	1	1	1	1	1	1
Cooling capacity, each (Btu/hr)	125,000	258,000	352,000	352,000	157,000	157,000

Table 9.4-7

REACTOR ENCLOSURE VENTILATION SYSTEM FAILURE MODES AND EFFECTS ANALYSIS[1]

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency	Power supply	Total LOOP	None. All safety-related equipment and controls are redundant and are powered from separate standby diesel generators.	Alarm in the control room	No loss of safety function.
Emergency (LOCA or LOCA + LOOP)	Cooling fans RHR room - east (V-210)	Loss of one fan	None, the standby fan is 100% capacity. When the standby fan is not in service, none, provided the other pump's standby fan is In service.	Local temperature element & switch Trouble alarm from local panel to control room	When either standby fan is in service, no loss of safety function. When either standby fan is not in service, eventual loss of both pumps may occur. The RHR pumps in separate room are redundant after ten minutes.
Emergency (LOCA or LOCA + LOOP)	Cooling fans RHR room - east (V-210)	Loss of both fans for one of the two pumps (safeguard LC bkr failure)	One LPCI Injection Valve does not open. One RHR pump runs on minimum flow until secured by operator or until it eventually fails.	Local temperature element & switch Trouble alarm from local panel to control room	No loss of safety function. The other pump's two coolers will adequately cool the room. Redundant ECCS satisfy the core cooling requirements. When the other pump's standby cooler is out of service, eventual loss of both pumps occurs.
Emergency (LOCA or LOCA + LOOP)	Cooling fans RHR room – west (V-210)	Loss of one fan	None, the standby fan is 100% capacity, When the standby fan is not in service, none, provided the other pump's standby fan is in service.	Local temperature element & switch Trouble alarm from local panel to control room	When either standby fan is in service, no loss of safety function. When either standby fan is not in service, eventual loss of both pumps may occur. The RHR pumps in separate room are redundant after ten minutes.
Emergency (LOCA or LOCA + LOOP)	Cooling fans RHR room - west (V-210)	Loss of both fans for one of the two pumps (safeguard LC bkr failure)	One LPCI Injection valve does not open. One RHR pump runs on minimum flow until secured by operator or until it eventually fails.	Local temperature element & switch Trouble alarm from local panel to control room	No loss of safety function. The other pump's two coolers will adequately cool the room. Redundant ECCS satisfy the core cooling requirements. When the other pump's standby cooler is out of service, eventual loss of both pumps occurs.
Emergency (LOCA or LOCA + LOOP)	Power Supply	LOOP + failure of one Diesel Generator	Loss of power for a LPCI pump, a pair or RHR room	Alarm in the control room	No loss of safety function because the other RHR pump's

		coolers, a Core Spray pump and its coolers		cooler(s) will adequately cool the room. Core Spray pumps in redundant loop are in separate compartments.	

Table 9.4-7 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (LOCA or LOCA + LOOP)	Cooling fans RCIC room (V-208)	Loss of one fan	None. The standby fan automatically starts.	Local temperature element & switch Trouble alarm from local panel to control room	No loss of safety function
Emergency (LOCA or LOCA + LOOP)	Cooling fans RCIC room (V-208)	Loss of both fans	None. RCIC operation without compartment unit coolers has been evaluated and determined acceptable	Local temperature element & switch Trouble alarm from local panel to control room	No loss of safety function
Emergency (LOCA or LOCA + LOOP)	Cooling fans HPCI room (V-209)	Loss of one fan	None. The standby fan automatically starts.	Local temperature element & switch Trouble alarm from local panel to control room	No loss of safety function
Emergency (LOCA or LOCA + LOOP)	Cooling fans HPCI room (V-209)	Loss of both fans	None. HPCI operation without compartment unit coolers has been evaluated and determined acceptable	Local temperature element & switch Trouble alarm from local panel to control room	No loss of safety function
Emergency (LOCA or LOCA + LOOP)	Cooling fans core spray pumps room (V-211)	Loss of one fan	When the standby fan is in service, none. The standby fan starts. When When the standby fan is not in service, eventual loss of the associated pump.	Alarm in the control room	When the standby fan is in service, no loss of safety function. When the standby fan is not in service, no loss of safety function. The core spray pumps in separate rooms are redundant.
Emergency (LOCA or LOCA + LOOP)	Cooling fans core spray pumps room (V-211)	Loss of both fans	Eventual loss of the associated pump.	Alarm in the control room	No loss of safety function. The core spray pumps in separate rooms are redundant.
Emergency (LOCA or LOCA + LOOP)	Emergency service water, cooling coils	Loss of ESW in one loop or loss of water due to pipe	Eventual loss of the associated pump.	Local temperature element & switch Trouble alarm from	No loss of safety function. The ECCS pumps are redundant.

break between
header and
individual unit coil

local panel to
control room

Table 9.4-7 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (Zone 3 isolation with or without LOOP)	Zone 3 isolating valves	Failure of one valve to close	None. The valves are redundant and are in series. The dampers are designed to fail-safe in the closed position.	Valve position indication on local panel C101 and ISOLATION INCOMPLETE alarm in control room	No loss of safety function.
Emergency (pipe break in rooms containing high energy piping)	Steam flooding isolation dampers	Failure of one damper to close	None. The dampers are redundant and are in series. Only one damper is needed to close and isolate.	Damper position indication on local panel	No loss of safety function.
Emergency (LOCA or LOCA + LOOP)	Zone 1 isolation valves	Failure of one valve to close	None. The valves are redundant and are in series. Only one valve is needed to close and isolate. In addition, the valves are designed to fail-safe in closed position.	Valve position indication on local panel C101 and ISOLATION INCOMPLETE alarm in control room	No loss of safety function.

(1) For recirculation system filter, fan, damper and valve FMEA see Section 6.5 and Table 6.5-6.

Table 9.4-8

RADWASTE ENCLOSURE VENTILATION SYSTEM EQUIPMENT DESIGN PARAMETERS[1]

ITEM	GENERAL AREA AIR SUPPLY OA/BV 301	SERVICE & CONTROL AREA AIR SUPPLY OA/BV 302	GENERAL AREA EXHAUST OA/BV 304
Type	Built-up unit	Built-up unit	In-line fans
Number of units	1	1	2
Flow rate, each (cfm)	63,150	9,300	16,490
Fan:			
Type	Vaneaxial	Vaneaxial	Vaneaxial
Drive	Direct	Direct	Direct
No. of fans per unit	2	2	1
No. of running fans	1	1	1
Static pressure (in wg)	5.7	2.6	5.7
Motor horsepower, (each)	75	15	25
Heating coils:			
No. of coils per unit	2	2	None
Capacity, each (Btu/hr)	3,700,000	443,000	
Cooling coils:			
No. of coils per unit	1	2	None
Capacity, each (Btu/hr)	2,020,000 (5)	867,200	
Prefilters:			
Type, Size (ft)	Glass, roll	Glass, roll	None
Capacity (cfm)	63,150	10,350	
NBS efficiency	-	-	
HEPA filters:	None	None	None
Charcoal adsorber:	None	None	None

Table 9.4-8 (Cont'd)

ITEM	CHEMISTRY LABORATORY AIR EXHAUST SYSTEM OA/BV 306	EQUIPMENT COMPARTMENT EXHAUST OA/BV 305	TANK AND SUMP EXHAUST OOV 318
Type	Built-up unit	Built-up unit	Built-up unit
Number of units	2	2	1
Flow rate, each (cfm)	2850	53,000	385
Fan:			
Type	Centrifugal	Vaneaxial	Centrifugal
Drive	Direct	Direct	Direct
No. of fans per unit	1	1	1
No. of running fans	1	1	1
Static pressure (in wg)	7.9	17.5	4.1
Motor horsepower, (each)	7-1/2	200	1/2
Heating coils:	None	None	None
Cooling coils:	None	None	None
Prefilters:			
Type, Size (ft)	2x2x1 cells	2x2x1 cells	2x2x1 cells
Capacity (cfm)	2850	53,000	
NBS efficiency	80%	80%	
HEPA filters:			
Type, Size (ft)	2x2x1 cells	2x2x1 cells	2x2x1 cells
Capacity (cfm)	2850	53,000	330
DOP efficiency	99.97%	99.97%	99.97%
Charcoal adsorber[2]	None	None	Charcoal tray,
Type, Size		2 inches	
		330	
Capacity (cfm)		70%	
Elemental iodine eff[3]		0%	
Methyl iodide efficiency[3]		0.25 sec	
Residence time			

(1) Offgas treatment charcoal tank vaults air conditioning equipment will be described later.
(2) Physical property specifications of new activated carbon are given in Table 9.4-4.
(3) Efficiency designated by Regulatory Guide 1.52 for use in release analyses.
(4) OA/BV321 - Abondoned in place by Mod.# 6126
(5) The 00-E366 Cooling Coil has 1 of its 3 individual cooling coil banks permanently blanked off.

TABLE 9.4.8A

CHEMISTRY LABORATORY VENTILATION SYSTEM EQUIPMENT DESIGN PARAMETERS

Item	Fume Hood Aux. Air Supply HV-1	Fume Hood Aux. Air Supply HV-2	Data Acquisition Cooling Unit 00V386	Data Acquisition Cooling Unit 00V387	Storage Room Cooling Unit 00V389
Type	Central Station	Central Station	Wall Mounted	Wall Mounted	Ceiling Mounted
Number of Units	One	One	One	One	One
Flow rate, each (cfm)	5510	5510	800	480	1050
Fan:					
Type	Centrifugal	Centrifugal	Centrifugal	Centrifugal	Centrifugal
Drive	Belt	Belt	Direct	Direct	Direct
No. of fans per unit	One	One	One	One	One
No. of running Fans	One	One	One	One	One
Static Pressure (in wg)	5 1/4	5 1/4	N/A	N/A	N/A
Motor Horsepower, (each)	15	15	0.9 FLA	0.5 FLA	2.1 FLA
Heating Coils:			None	None	None
No. of coils per unit	N/A	N/A	-	-	-
Capacity, each (Kw)	142	142	-	-	-
Cooling Coils:	None	None			
No. of coils per unit	-	-	N/A	N/A	N/A
Capacity each (BTU/hr)	-	-	24000	12600	36400
Prefilters					-
Type, Size (ft)	Glass, N/A	Glass, N/A	N/A	N/A	-
Capacity (cfm)	7425	7425	N/A	N/A	-
NBS efficiency	30%, 65%	30%, 65%	N/A	N/A	N/A
Final Filters:			-	-	-
Type, Size (FT)	Cartridge, N/A	Cartridge, N/A	-	-	-
Capacity (cfm)	5510	5510	-	-	-

TABLE 9.4.8A (Cont'd)

CHEMISTRY LABORATORY VENTILATION SYSTEM EQUIPMENT DESIGN PARAMETERS

Item	Fume Hood Aux. Air Supply HV-1	Fume Hood Aux. Air Supply HV-2	Storage Room (Existing Room #410) Cooling Unit 00V386	Data Acquisition (Existing Room #411) Cooling Unit 00V389
Type	Central Station	Central Station	Wall Mounted	Ceiling Mounted
Compressors:				
Number	None	None	None	None
Motor Horsepower	None	None	54 LRA	74 LRA
Number of Steps	None	None	One	One
Condensor Fans:				
Number	None	None	One	One
Motor Horsepower	None	None	54 LRA	1.6 LRA
HEPA Filters	None	None	None	None
Charcoal Absorber:(each)	None	None	None	None

Note: ACUs 00V-387 & 00V-388 are abandoned in the place (Mod 6148-0, Phase 3). Future use of these units is required if needed for supplementary cooling Rooms 418 & 412, respectively. The primary cooling for these rooms is provided from Air Supply System V-302.

TABLE 9.4.8A (Cont'd)

CHEMISTRY LABORATORY VENTILATION SYSTEM EQUIPMENT DESIGN PARAMETERS

Item	Fume Hood Aux. Exhaust EF-1	Fume Hood Aux. Exhaust EF-2	Fume Hood Aux. Exhaust EF-3	Fume Hood Aux. Exhaust EF-4	Conf/Lunch Exhaust EF-5	Toilet/Locker Exhaust EF-6
Type	Utility	Utility	Utility	Utility	Roof	Roof
Number of Units	One	One	One	One	One	One
Flow rate, each (cfm)	1120	1120	1200	750	200	400
Fan:						
Type	Centrifugal	Centrifugal	Centrifugal	Centrifugal	Centrifugal	Centrifugal
Drive	Belt	Belt	Belt	Belt	Belt	Belt
No. of fans per unit	One	One	One	One	One	One
No. of running Fans	One	One	One	One	One	One
Static Pressure (in wg)	11 1/2	11 1/2	0.6	0.5	3/8	3/8
Motor Horsepower, (each)	40	40	5	5	1/4	1/4
Heating Coils:						
No. of coils per unit	None	None	None	None	None	None
Capacity, each (BTU/hr)						
Cooling Coils:						
No. of coils per unit	None	None	None	None	None	None
Capacity each (BTU/hr)						
Prefilters						
Type, Size (ft)	Glass, N/A	Glass, N/A	None	None	None	None
Capacity (cfm)	11200	11200				
NBS efficiency	30%, 65%	30%, 65%				
HEPA Filters:	Yes	Yes	None	None	None	None
Charcoal Absorber:	None	None	None	None	None	None

TABLE 9.4.8A (Cont'd)

CHEMISTRY LABORATORY VENTILATION SYSTEM EQUIPMENT DESIGN PARAMETERS

Item	Penthouse Exhaust EF-7	Penthouse Exhaust EF-8				
Type	Roof	Roof				
Number of Units	One	One				
Flow rate, each (cfm)	3500	3500				
Fan:						
Type	Centrifugal	Centrifugal				
Drive	Belt	Belt				
No. of fans per unit	One	One				
No. of running Fans	One	One				
Static Pressure (in wg)	3/8	3/8				
Motor Horsepower, (each)	3/4	3/4				
Heating Coils:						
No. of coils per unit	None	None				
Capacity, each (BTU/hr)						
Cooling Coils:						
No. of coils per unit	None	None				
Capacity each (BTU/hr)						
Prefilters						
Type, Size (ft)	None	None				
Capacity (cfm)						
NBS efficiency						
HEPA Filters:	None	None				
Charcoal Absorber:	None	None				

TABLE 9.4.8A (Cont'd)

CHEMISTRY LABORATORY VENTILATION SYSTEM EQUIPMENT DESIGN PARAMETERS

Item	Chem Lab Area Air Air Supply AC-1	Chem Lab Area Air Supply AC-2	Environmental Control Unit AC-3	Environmental Control Unit AC-3	Conference/Lunch & Office Area AC-5
Type	Central Station	Central Station	N/A	N/A	Roof Top
Number of Units	One	One	One	One	One
Flow rate, each (cfm)	8500	8500	3600	2600	4200
Fan:					
Type	Centrifugal	Centrifugal	Centrifugal	Centrifugal	Centrifugal
Drive	Belt	Belt	Belt	Belt	Belt
No. of fans per unit	One	One	One	One	One
No. of running Fans	One	One	One	One	One
Static Pressure (in wg)	6 1/2	6 1/2	5	5	1.3
Motor Horsepower, (each)	20	20	1 1/2	1 1/2	3
Heating Coils:			None	None	None
No. of coils per unit	N/A	N/A	N/A	N/A	N/A
Capacity, each (Kw)	150	150	30	24	20
Cooling Coils:					
No. of coils per unit	4	4	N/A	N/A	N/A
Capacity each (BTU/hr)	590000	590000	58500	42000	150000
Prefilters					
Type, Size (ft)	Glass, N/A	Glass, N/A	N/A	N/A	Glass N/A
Capacity (cfm)	8500	8500	N/A	N/A	N/A
NBS efficiency	30%, 65%	30%, 65%	N/A	N/A	N/A
Final Filters:					
Type, Size (FT)	Cartridge, N/A	Cartridge, N/A	N/A	N/A	N/A
Capacity (cfm)	8500	8500	N/A	N/A	N/A
NBS Efficiency	95%	95%	N/A	N/A	N/A

TABLE 9.4.8A (Cont'd)

CHEMISTRY LABORATORY VENTILATION SYSTEM EQUIPMENT DESIGN PARAMETERS

Item	Chem Lab Area Air Air Supply AC-1	Chem Lab Area Air Supply AC-2	Environmental Conttol Unit AC-3	Environmental Control Unit AC-3	Conference/Lunch & Office Area AC-5
Compressors:					
Number	4	4	2	2	2
Motor Horsepower	2(10), 2(15)	2(10), 2(15)	2 1/2	2 1/4	2 (5 1/4)
Number of Steps	4	4	N/A	N/A	N/A
Condensor Fans:					
Number	6	6	N/A	N/A	N/A
Motor Horsepower	1	1	1	1	N/A
HEPA Filters	None	None	None	None	None
Charcoal Absorber:	None	None	None	None	None

Note: N/A - Not Applicable

Table 9.4-9

TURBINE ENCLOSURE VENTILATION SYSTEM EQUIPMENT DESIGN PARAMETERS

ITEM	TURBINE ENCLOSURE AIR SUPPLY V101	CLEAN AREA AIR EXHAUST V105	EQUIPMENT COMPARTMENT AIR EXHAUST V106	BATTERY COMPARTMENT EXHAUST V108
Type	Built-up unit	Built-up unit	Built-up unit	Fan
Number of units	1	1	1	1
Flow rate (cfm)	250,000	200,000	63,000	1170
Fan:				
Type	Vaneaxial	Vaneaxial	Centrifugal	Centrifugal
Drive	Direct	Direct	Direct	Direct
No. of fans per unit	3	3	2	1
No. of running fans	2	2	1	1
Static pressure (in wg)	5.75	5.55	17.75	2.5
Motor horsepower (each)	150	125	250	1
Heating coils:		None	None	None
No. of banks per unit	1	-	-	-
Capacity, each (Btu/hr)	15,700,000	-	-	-
Cooling coils:		None		None
No. of banks per unit	8	-	2 (in duct-work)	-
Capacity, each (Btu/hr)	1,500,000/420,000	-	464,000	-
Prefilters		None		None
Type, size (ft)	Glass, roll	-	2x2x1 cells	-
Capacity (cfm)	250,000	-	31,500/housing	-
NBS efficiency	-	-	80%	-
HEPA filters:	None	None		None
Type, size (ft)	-	-	2x2x1 cells	-
Capacity (cfm)	-	-	31,500/housing	-
DOP efficiency	-	-	99.97%	-
Type	Built-up unit	Built-up unit	Built-up unit	Fan
Charcoal adsorbers[1]:	None	None		None
Type, size	-	-	8-in deep rechargeable bed	-
Capacity (cfm)	-	-	31,500/housing	-
Elemental iodine eff[2]	-	-	99.0%	-
Methyl iodide efficiency[2]	-	-	99.0%	-
Residence time	-	-	1 sec	-

Table 9.4-9 (Cont'd)

ITEM	FEEDWATER HEATER COMPARTMENT COOLING V133 el 269'	FEEDWATER HEATER COMPARTMENT COOLING V124 el 239'	RFPT COMPARTMENT ACCESS COOLING V135	CT&RP COMPARTMENT ACCESS COOLING V136
Type	Unit cooler	Unit cooler	Unit cooler	Unit cooler
Number of units	2 per compartment	3 per compartment	4	2
Flow rate, each (cfm)	2800	5200	3400	1,850
Fan:				
Type	Vaneaxial	Propeller	Propeller	Propeller
Drive	Direct	Direct	Direct	Direct
No. of fans per unit	1	1	1	1
No. of running units	1 per compartment	2 per compartment	2	1
Total pressure (in wg)	1.55	0.65	0.59	0.48
Motor horsepower, (each)	2	3	1-1/2	3/4
Heating coils:	None	None	None	None
Cooling coils:				
No. of coil banks per Unit	1	1	1	1
Capacity, each (Btu/hr)	106,000	199,000	100,000	55,000
Filters	None	None	None	None

Table 9.4-9 (Cont'd)

ITEM	VACUUM PUMP COMPARTMENT COOLING V137	FEEDWATER HEATER ACCESS COOLING V138	CONDENSATE PUMP COMPARTMENT COOLING V112	MAIN CONDENSER COMPARTMENT COOLING V113
Type	Unit cooler	Unit cooler	Unit cooler	Unit cooler
Number of units	2	9	6	12
Flow rate, each (cfm)	1,170	7,650	34,500	32,000
Fan:				
Type	Propeller	Propeller	Vaneaxial	Vaneaxial
Drive	Direct	Direct	Direct	Direct
No. of fans per unit	1	1	1	1
No. of running units	1	6	4	8
Total pressure (in wg)	0.22	1.2	4.7	4.2
Motor horsepower, (each)	½	3	40 / 60	30
Heating coils:	None	None	None	None
Cooling coils:				
No. of coil banks per Unit	1	1	1	1
Capacity, each (Btu/hr)	42,000	293,000	500,000	658,000
Filters	None	None	None	None

(1) Physical property specifications of new activated carbon are given in Table 9.4-4.
(2) Efficiency designated by Regulatory Guide 1.52 for use in release analyses.

Table 9.4-10

DRYWELL UNIT COOLER DESIGN PARAMETERS

Type	Built-up
Number of unit coolers	8
Flow rate, each	7000 cfm
Fans:	
Type	Vaneaxial
Drive	Direct
No. of fans per unit cooler	2
External static pressure, each	3.5 in wg
Fan speed	3600 rpm
Motor power rating	30 hp
Cooling coils:	
No. of coils per unit cooler	2
Cooling capacity, each	575,000 Btu/hr
Heating coils	None
Filters	None(1)

(1) "Throw-away" type roughing filters 2 inches thick are used during plant construction only. No filters are used during plant operation.

Table 9.4-11

PRIMARY CONTAINMENT VENTILATION SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLAN OPERATION
Normal	Power supply	LOOP	Loss of fans in drywell unit coolers and loss of cooling water supply to unit coolers	Alarm in the control room and rise in drywell temperature indication in the control room	None. Fans in dry well unit coolers are powered from Class 1E buses and restart automatically when emergency power is available. Cooling water supply can be re-established by switching to the RECW system, which is powered from the diesel generators.
Emergency (LOOP)	Fans	Loss of one fan	Loss of air flow through one unit cooler	Alarm in the control room on computer	None. Standby fan starts automatically.
Emergency (LOCA or LOCA + LOOP)	Fans	Loss of one fan	Loss of air flow through one unit Cooler	Alarm in the control room on computer	None. Redundant unit coolers continue to operate.
Emergency (LOCA or LOCA + LOOP)	Containment isolation valve	Failure of one valve to close	Reduction in containment isolation barriers from two valves to one in the affected purge line	Indicating lights in the control room	None
Emergency (LOCA or LOCA + LOOP)	Power supply	Failure of one division of Class 1E power	Loss of power to one fan in two of the four safety-related unit coolers. Possible reduction in containment isolation barriers from two valves to one in the affected purge lines	Indicating lights in the control room	None. A minimum of one fan in each of two unit coolers continues to operate.

Table 9.4-12

DIESEL GENERATOR ENCLOSURE VENTILATION SYSTEM
EQUIPMENT DESIGN PARAMETERS

ITEM	EXHAUST FANS
Quantity, per cell	2
Flow rate, each (cfm)	35,000
Seismic category	I
Fan:	
Type	Vaneaxial
Drive	Direct
Static pressure (in wg)	1.6
Motor power rating, each (hp)	20
Cooling coil	None
Heating coil (BTU/hr)	None
Filters	None

Table 9.4-13

DIESEL GENERATOR ENCLOSURE VENTILATION SYSTEM
FAILURE MODES AND EFFECTS ANALYSIS

PLANT OPERATING MODE	SYSTEM COMPONENT	EFFECT OF FAILURE COMPONENT FAILURE MODE	ON SAFEGUARD EQUIPMENT	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency	Ventilation System	Total LOOP	None. Ventilation systems are powered from their associated diesel generators.	Alarm in control room	No loss of safety function
Emergency (LOCA or LOCA + LOOP)	Fan, damper, and instruments	Failure of fan, damper, or an instrument	Possible overheating of cell in summer and eventual loss of one diesel generator.	Alarm in control room on loss of power or high or low temperature	No loss of safety function. The remaining three diesel generators are sufficient for a safe shutdown
Emergency (LOCA or LOCA + LOOP)	Steam unit heaters	Loss of power or failure	None. Equipment is not affected by low temperature	Alarm in control room on low temperature	No loss of safety function
Emergency (LOCA or LOCA + LOOP)	Power roof ventilator	Loss of power or failure of fan	There is no safeguard equipment in the plant heating condensate pump-room.	None	No loss of safety function

Table 9.4-14

SPRAY POND PUMP STRUCTURE
VENTILATION SYSTEM EQUIPMENT DESIGN PARAMETERS

ITEM	FAN CABINET
Quantity	4
Flow rate, each (cfm)	30,000
Seismic Category	I
Fan:	
Type	Vaneaxial
Drive	Direct
External static pressure (in wg)	0.97
Motor power rating, each (hp)	10
Heating coil type	Electric
Capacity, each (Btu/hr)	410,000

Table 9.4-15

SPRAY POND PUMP STRUCTURE VENTILATION SYSTEM
FAILURE MODES AND EFFECTS ANALYSIS

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON SAFEGUARD EQUIPMENT	FAILURE MODE DETECTION	EFFECT OF FAILURE PLANT OPERATION
Emergency	Entire system	Total LOOP	None. All H&V systems are powered from onsite Class 1E power (diesel generators).	Alarm in control room	No loss of safety function
Emergency (LOCA or LOCA + LOOP)	Ventilation fans	Loss of one fan	None. Standby fan cabinet designed for 100% of cooling load. Automatic start on thermostat signal.	Alarm in control room	No loss of safety function
Emergency (LOCA or LOCA + LOOP)	Intake, exhaust, and return dampers	Loss of dampers in one system	None. Standby fan cabinet with separate dampers available. Automatic or manual start.	High or low temperature alarm in control room	No loss of safety function
Emergency (LOCA or LOCA + LOOP)	Instruments	Failure of instrument(s) in one system	None. Standby fan cabinet with separate dampers available. Automatic or manual start.	High or low temperature alarm in control room by standby instruments	No loss of safety function

Table 9.4-16

HOT MAINTENANCE SHOP VENTILATION SYSTEM
EQUIPMENT DESIGN PARAMETERS

ITEM	REPAIR AREA SUPPLY V-5001	CLEANUP AREA SUPPLY V-5002
Type	Air handler	Air handler
Flow rate (cfm)	20,000	10,000
Fan:		
Type	Vaneaxial	Vaneaxial
Drive	Direct	Direct
Total pressure (in wg)	4.3	4.4
Motor power rating (hp)	25	15
Cooling coils:		
Capacity (Btu/hr)	530,000	320,000
Heating coils:		
Capacity (Btu/hr)	500,000	239,000
Prefilters:		
Type	Glass pad	Glass pad
Efficiency by weight	70% AFI	70% AFI
Medium efficiency filters:		
Size, type	12 inch deep cell	12 inch deep cell
Efficiency by dust spot	90%-95% NBS	90%-95% NBS

Table 9.4-16 (Cont'd)

ITEM	EXHAUST UNIT V-5003	EXHAUST FAN V-5004
Type	Fan cabinet	In-line
Flow rate (cfm)	7000	7000
Fan:		
Type	Vaneaxial	Vaneaxial
Drive	Direct	Direct
Total pressure (in wg)	6.0	4.0
Motor power rating (hp)	20	10
Cooling coils:	None	None
Capacity (Btu/hr)		
Heating coils:	None	None
Capacity (Btu/hr)		
Prefilters:		
Size, type	12 inch deep cell	None
NBS efficiency	85%	
High efficiency filters:		
Type	HEPA cell	None
Efficiency	99.97% DOP	

Table 9.4-16 (Cont'd)

TEM	DUST COLLECTOR V-5006	DUST COLLECTOR V-5007
Type	Cabinet	Cabinet
Flow rate (cfm)	940	440
Fan:		
Type	Centrifugal	Centrifugal
Drive	Direct	Direct
Static pressure (in wg)	4.3	3.8
Motor power rating (hp)	1½	¾
Cooling coils:	None	None
Capacity (Btu/hr)		
Heating coils:	None	None
Capacity (Btu/hr)		
Prefilters:	None	None
Medium efficiency filters:		
Type	Pocket (bag)	Pocket
Efficiency by weight	99.9%	99.9%

Table 9.4-17

MISCELLANEOUS STRUCTURES VENTILATION SYSTEM EQUIPMENT DESIGN PARAMETERS (1)

Item	Circulating Water Pump Structure Exhaust	Circulating Water Pump Structure Heating	Diesel Fire Pump Compartment Exhaust	Diesel Fire Pump Compartment Heating	Chlorine Equipment Compartment Exhaust
Type	Roof ventilators	Unit heaters	Roof ventilator	Unit heater	Roof ventilators
Number of units	24	12/3 Flash steam	1	1	2
Flow rate, each (cfm)	22,980-32,068	999/508	32,068	886	2,345
Location	Roof	Compartment	Roof	Compartment	Roof
Fan:					
Type	Tubeaxial	Propeller	Tubeaxial	Propeller	Centrifugal
Drive	Direct	Direct	Direct	Direct	Direct
External Static Pressure (in wg)	2/8-3/8	0	3/8	0	3/4
Motor power, each (hp)	5 - 6	1/20 / 1/70	5	1/20	3/4
Cooling coil (Btu/hr)	None	None	None	None	None
Heating coil	None	Steam	None	Steam	None
Capacity, each (Btu/hr)		72,900 / 38,800		53,800	
Filters	None	None	None	None	None

Table 9.4-17 (Cont'd)

Item	Chlorine Equipment Compartment Heating	Water Treatment Eqpt Comp Exhaust	Water Treatment Eqpt Comp Heating	Water Treatment Utility Comp Exhaust	Water Treatment Utility Comp Heating
Type	Unit heaters	Roof ventilators	Unit heaters	Roof ventilator	Unit heater
Number of units	2	6	6	1	1
Flow rate, each (cfm)	508/550	3635 or 3527	1100	1150	508
Location	Compartment	Roof	Compartment	Roof	Compartment
Fan:					
Type	Propeller	Tubeaxial	Propeller	Centrifugal	Propeller
Drive	Direct	Direct	Direct	Direct	Direct
External Static Pressure (in wg)	0	1/4	0	3/4	0
Motor power, each (hp)	1/70, 1/20	3/8 or 1/2	1/20	3/8	1/70
Cooling coil (Btu/hr)	None	None	None	None	None
Heating coil	Steam	None	Steam	None	Steam
Capacity, each (Btu/hr)	38,800 / 58,000		83,800		38,800
Filters	None	None	None	None	None

Table 9.4-17 (Cont'd)

Item	Water Treatment Laboratory Air Cond	Sewage Treatment Equipment Comp Exhaust	Sewage Treatment Equipment Comp Heating	Schuylkill River Intake Structure Exhaust	Schuylkill River Intake Structure Heating
Type	Package air conditioner	Roof ventilators	Unit heaters	Roof ventilators	Unit heaters
Number of units	1	2	2	4	6
Flow rate, each (cfm)	1200	1022	670	13,700	850
Location	Roof	Roof	Compartment	Roof	Compartment
Fan:					
Type	Centrifugal	Centrifugal	Propeller	Tubeaxial	Propeller
Drive	Belt	Direct	Direct	Direct	Direct
External Static Pressure (in wg)	0.7	3/8	0	1/4	0
Motor power, each (hp)	1/2	1/8,1/6	1/10	3	1/12
Cooling coil (Btu/hr)	49,000 Btu/hr	None	None	None	None
Heating coil	Steam	None	Electric	None	Electric
Capacity, each (Btu/hr)	26,000		25,600		41,000
Filters	Glass pad	None	None	None	None

Table 9.4-17 (Cont'd)

Item	Schuylkill River Debris Facility Exhaust	Schuylkill River Debris Facility Heating	Perkiomen Pump Structure Exhaust	Perkiomen Pump Structure Heating	Perkiomen Pump Station Battery Room Exhaust
Type	Wall fan	Unit heater	Roof ventilator	Unit heater	Roof ventilator
Number of units	1	2	3	5	1
Flow rate, each (cfm)	1500	260	45,876	1530	380
Location	Wall	Equipment room	Roof	Compartment	Roof
Fan:					
Type	Propeller	Propeller	Tubeaxial	Propeller	Centrifugal
Drive	Direct	Direct	Direct	Direct	Direct
External Static Pressure (in wg)	1/4	0	1/4	0	1/4
Motor power, each (hp)	1/4	1/50	15	1/4	1/20
Cooling coil (Btu/hr)	None	None	None	None	None
Heating coil	None	Electric	None	Electric	None
Capacity, each (Btu/hr)		13,700		71,700	
Filters	None	None	None	None	None

Table 9.4-17 (Cont'd)

Item	Boiler Fuel Oil Transfer Enclosure Exhaust	Auxiliary Boiler Boiler Structure Exhaust	Boiler Fuel Oil Transfer Enclosure Heating	Chlorine & Acid Feed Electrical Equipment Compartment Exhaust	Chlorine & Acid Feed Electrical Equipment Compartment Heating	Chlorine & Acid Feed Pipe Trench Heating
Type	Roof ventilators	Roof ventilators	Unit heaters	Wall	Unit heater	Unit heater
Number of units	2	6	2	1	1	5
Flow rate, each (cfm)	2600	3635 or 3527	712	386 (un.1) 386 (un.2)	405	405
Location	Roof	Roof	Compartment	Wall	Compartment	Compartment
Fan:						
Type	Centrifugal	Tubeaxial	Propeller	Centrifugal	Propeller	Propeller
Drive	Direct	Direct	Direct	Direct	Direct	Direct
External Static Pressure (in wg)	1/8	1/4	0	1/4	0	0
Motor power, each (hp)	1/2	3/8 or 1/2	1/25	1/6 (un.1) 1/6 (un.2)	1/40	1/40
Cooling coil (Btu/hr)	None	None	None	None	None	None
Heating coil	None	None	Electric	None	Electric	Electric
Capacity, each (Btu/hr)			34,000		10,200	6800
Filters	None	None	None	None	None	None

Table 9.4-17 (Cont'd)

Item	Technical Support Center Security Areas Air Conditioning	Lube Oil Storage Exhaust	Lube Oil Storage Heating	Calibration Equipment Storage Comp Exhaust	Calibration Equipment Storage Comp Heating	Chlorine & Acid Feed Enclosure Ventilator	Chlorine & Acid Feed Enclosure Heating
Type	Air Handler	Roof ventilator	Unit heater	Roof ventilator	Unit heater	Roof/Wall ventilator	Unit heaters
Number of units	1 ; 1	1	2	1	1	4/1	4/1
Flow rate, each (cfm)		747	508	590	508	1190/2958	590/712
Location	First floor Mechanical Room	Roof	Compartment	Roof	Compartment	Roof / Wall	Compartment
Fan:							
Type	Centrifugal	Centrifugal	Propeller	Centrifugal	Propeller	Centrifugal	Propeller
Drive	Belt	Direct	Direct	Direct	Direct	Direct	Direct
External Static Pressure (in wg)	1	0.25	0	1/4	0	1/2;0	0
Motor power, each (hp)	5 ; 7½	1/6	1/70	1/12	1/70	1/4;1/3	1/40, 1/25
Cooling coil (Btu/hr)	360,000 ; 420,000	None	None	None	None	None	None
Heating coil	Electric	None	Steam	None	Steam	None	Electric
Capacity, each (Btu/hr)	102,000 ; 136,000		38,800		38,800		25,600 / 34,000
Filters	40% Pleated	None	None	None	None	None	None

Table 9.4-17 (Cont'd)

Item	Administration Building Air Conditioning Supply OOV 501	Administration Building Air Conditioning Return OOV 503	Administration Building H & V Supply OOV 505	Administration Building Exhaust OOV 509
Type	Air handler	In-line fan	Air handler	In-line fan
Number of units	1	1	1	1
Flow rate, each (cfm)	30,000	22,600	13,000	22,600
Location	Penthouse	Penthouse	Penthouse	Penthouse
Fan:				
Type	Vaneaxial	Vaneaxial	Vaneaxial	Vaneaxial
Drive	Direct	Direct	Direct	Direct
External Static Pressure (in wg)	3.8	1.3	2.5	1.2
Motor power, each (hp)	25	10	7-1/2	5
Cooling coil (Btu/hr)	1,440,000 Btu/hr	None	None	None
Heating coil	Hot water	None	Hot water	None
Capacity, each (Btu/hr)	1,200,000		890,000	
Filters	Glass roll	None	Glass pad	None

Table 9.4-17 (Cont'd)

Item	Administrative Building Telephone Equipment Room Exhaust OO/V	Security Areas Air Conditioning OA/B V565	Machine Shop Heating & Ventilating OOV 550	Administration Building Eastern Extension Air Conditioning OO V551
Type	In-line fan	Package air cond	Air handler	Air handler
Number of units	1	2	1	1
Flow rate, each (cfm)	1000	4000	8600	12,500
Location	Admin Bldg Bsmt	Guard station roof	Machine shop	Second floor
Fan:				
Type	Vaneaxial	Centrifugal	Vaneaxial	Guard station Vaneaxial
Drive	Direct	Belt	Direct	Direct
External Static Pressure (in wg)	0.75	1	2.3	3.6
Motor power, each (hp)	1/3	1/2	5	15
Cooling coil (Btu/hr)	None	111,000	None	810,000
Heating coil	None	None	Hot water	Hot water
Capacity, each (Btu/hr)			568,000	465,000
Filters	None	Glass pad	Glass pad	Glass pad

(1) Design data listed in Table 9.4-17 does not constitute performance requirements. There is no licensing basis requirement for these particular design parameter values. This information should be treated as historical information and does not require updating.

Table 9.4-18

CONFORMANCE WITH REGULATORY GUIDE 1.140[1]

REGULATORY GUIDE POSITION	TURBINE[2]	SGTS ROOM EXHAUST[2]	REACTOR[2]	RADWASTE[2]
Para C.1 - Environmental Design	Conform	Conform	Conform	Conform
Para. C.2 – System Design Criteria				
C.2.a	Conform	Conform	Conform	Conform
C.2.b	System is rated at 35,000 cfm. Space restrictions prohibit multiple train. HEPA filters are arranged 5 wide by 6 high. Platforms are provided in the plenum to service the filters	Conform	System is rated at 40,000 cfm. Space restrictions prohibit multiple train. HEPA filters are arranged 5 wide by 7 high. Platforms are provided in the plenum to service the filters	(A) Conform (B) System is rated at 53,000 cfm. Space restrictions prohibit multiple train. HEPA filters are arranged 8 wide by 6 high. Platforms are provided in the plenum to service the filters.
C.2.c	Conform	Conform	Conform	Conform
C.2.d	Conform	Conform	Conform	Conform
C.2.e	Conform	Conform	Conform	Conform
C.2.f	Allowable leak rate: (1) filter house, 0.1% of rated flow in cfm at 125% negative pressure; (2) duct work, 4.0% of scheduled air flow multiplied by ratio of the volume of duct being tested to the total volume of the duct run. The system is not in a high radiation zone	Same as Turbine	Same as Turbine	Same as Turbine except (A) filter plenum is located in a high radiation zone.

Table 9.4-18 (Cont'd)

REGULATORY GUIDE POSITION	TURBINE[2]	SGTS ROOM EXHAUST[2]	REACTOR[2]	RADWASTE[2]
Para C.3 – Component Design Criteria and Qualification Testing				
C.3.a	Conform	Conform	Conform	Conform
C.3.b	Conform	Conform	Conform	Conform
C.3.c	Conform	Conform	Conform	Conform
C.3.d	Due to space restrictions, system is rated at 35,000 cfm. HEPA filters are arranged 5 wide by 6 high.	Conform	Due to space restrictions, the system is rated 40,000 cfm. HEPA filters are arranged 5 wide by 7 high.	(A) Conform (B) Due to space restrictions, the system rated at 53,000 cfm. HEPA filters are arranged 8 wide by 6 high. Does not contain charcoal filter
C.3.e	Housing design generally meets guideline except that no view ports are provided	Same as Turbine	Same as Turbine	(A) Access doors are smaller than recommended due to lower cfm rating of system. (B) Same as Turbine
C.3.f	Conform except allowable duct leak rate of 4.0%	Same as Turbine	Same as Turbine	Same as Turbine
C.3.g	Conform[4]	Conform[4]	Conform[4]	(A) Does not contain charcoal filters. (B) Does not contain charcoal filter.
C.3.h through C.3.l	Conform	Conform	Conform	Conform

Table 9.4-18 (Cont'd)

REGULATORY GUIDE POSITION	TURBINE[2]	SGTS ROOM EXHAUST[2]	REACTOR[2]	RADWASTE[2]
Para C.4 – Maintenance				
C.4.a	Conform	Conform	Conform	Conform
C.4.b	Conform	Conform	Due to space restrictions, distance between filter banks is less than recommended	(A) The system is rated at 330 cfm and the physically small housing design provides easy access to filters for servicing (B) Same as Reactor
C.4.c	Conform	Conform	Conform	Conform
C.4.d	Conform	Conform	Conform	Conform
Part C.5 – In-Place Testing Criteria	Conform except tested at intervals of approximately 24 months[3]	Same as Turbine[3]	Same as Turbine[3]	(A) Same as Turbine[3] (B) Same as Turbine[3], Does not contain charcoal filter
Part C.6 – Laboratory Testing Criteria for Activated Carbon	Conform except tested at intervals of approximately 24 months[5]	Same as Turbine[5]	Same as Turbine[5]	(A) Same as Turbine[5] (B) Does not contain charcoal filter

(1) The LGS design was completed prior to the issuance of this guide, and therefore the guide was not specifically considered in the design

(2) Turbine - Turbine enclosure equipment compartment exhaust air filter plenum
SGTS - Standby gas treatment room exhaust air filter plenum
Reactor - Reactor enclosure equipment compartment exhaust air filter plenum
Radwaste - (A) Radwaste enclosure common tanks vent filter assembly
(B) Radwaste Enclosure Equipment Compartment Exhaust Filter Assembly.

(3) To ANSI/ASME N510 (1980) testing criteria.

(4) As an alternative, the criteria specified in the ANSI N509 (1980), table 5-1 can be used.

(5) As an alternative, the test procedures specified in the ANSI N509 (1980) and ANSI N510 (1980) can be used.

9.5 OTHER AUXILIARY SYSTEMS

9.5.1 FIRE PROTECTION PROGRAM

The term "fire protection system" refers to the integrated complex of components and equipment provided for detection and suppression of fires. In addition to this system, the "fire protection program" includes the concepts of design and layout implemented to prevent or mitigate fires, administrative controls and procedures, and the training of personnel to combat fires.

An evaluation of potential fire hazards has been performed and is summarized in the Fire Protection Evaluation Report (Appendix 9A). Included in the report are details of the locations of fire barriers that divide the plant into fire areas, the type and quantity of combustible material contained in each fire area, the fire detection and suppression systems provided in each fire area, and the effects of postulated fires on safety-related systems required for reactor shutdown. Also included is a comparison of the plant's fire protection provisions with the guidelines of BTP CMEB 9.5-1.

Fire protection operational conditions and remedial actions and test requirements are located in the Technical Requirements Manual and are incorporated herein by reference (reference 9.5-1). These requirements have been relocated from the Technical Specifications by Amendments 104 and 68 to the Unit 1 and Unit 2 Facility requirements was in accordance with NRC Generic Letter (GL) 86-10, "Implementation of Fire Protection Requirements", and GL-88-12, "Removal of Fire Protection Requirements for Technical Specifications".

These requirements are mandated by FOL Condition 2.C.(3).

9.5.1.1 Design Basis

The fire protection system is designed to perform the following functions:

a. To maintain safe shutdown ability by providing the capability to control the postulated fires encountered in all plant areas by the use of fixed and/or portable fire fighting equipment

b. To provide automatic fire detection and annunciation for selected areas of the plant for personnel safety and fire brigade notification

c. To supply rated flow of fire protection water, with one pump out-of-service, to points throughout the plant area where fire fighting may be required

d. To supply simultaneously the maximum flow for any automatic sprinkler or water spray system and 500 gpm for fire hoses for a minimum of 2 hours.

e. To preclude loss of function of plant safety-related structures, systems, or components due to seismic loading of the fire protection system

f. To prevent failure or inadvertent operation of the fire suppression system from jeopardizing the capability to achieve safe shutdown of the plant

g. To minimize the probability of the spread of fire by the use of fire barriers between hazards

The codes, standards, or guidelines considered and used in the design of the fire protection systems include the following:

a. "Basic Fire Protection for Nuclear Power Plants," American Nuclear Insurers - Mutual Atomic Energy Reinsurance Pool

b. "Building Regulations for Protection from Fire and Panic," Commonwealth of Pennsylvania, Department of Labor and Industry

c. Occupational Safety and Health Administration, Rules and Regulations for Fire Protection Systems (29CFR1910)

d. National Fire Protection Association (NFPA) Standards (listed in Table 9.5-1 and Appendix 9A)

e. Branch Technical Position CMEB 9.5-1, Revision 2 (part of NUREG-0800).

9.5.1.2 System Description

The fire protection system P&ID is shown in drawing M-22.

9.5.1.2.1 Facility Features for Fire Prevention

Consistent with other safety requirements, structures, systems, and components (including those required for safe shutdown) are designed and located to minimize the probability and effect of fires. Noncombustible and fire resistant materials are used to the maximum extent practicable throughout the plant to minimize fire potential by lessening the duration, severity, and intensity of combustion.

The structural features of all enclosures are constructed of noncombustible materials. Reinforced concrete, masonry block, and structural steel are the primary constituents of the various enclosures. Stairwells in the power block are enclosed in concrete or masonry block towers with walls rated as 2 hour fire barriers at a minimum. The doors of the stair towers have fire ratings of at least 1½ hours. The tower doors, being self-closing, minimize any smoke infiltration during a fire. The reactor enclosures, turbine enclosures, and radwaste enclosure are each provided with at least two separated stairwells; the control structure is provided with its own stairwell.

The use of plastic materials has been minimized to the greatest extent practicable. However, alternatives to plastic or elastomeric materials for electrical cable insulating systems, with an optimum balance of electrical, physical, and environmental characteristics, are not available. Cable insulation and jacketing materials are chosen for their fire retardant and self-extinguishing properties, such that fuel contribution to a cable fire is minimized and propagation of a fire along cables is self-limiting in the absence of an exposure fire. The types of electrical cable insulation and jacketing used in the plant are listed in Table 9.5-2.

Outside of the administration building and maintenance facilities, the use of plastic materials for interior architectural features is limited to vinyl asbestos floor tile or a resilient terrazzo-type tile in a small number of compartments. The flame spread and smoke generation rating of vinyl asbestos floor tile is 25 or less. The resilient terrazzo-type tile used to replace vinyl asbestos floor tiles, which can no longer be used as a replacement tile, has a flame spreading rate of 25 and a smoke generation rating of 780.

Thermal insulation materials are noncombustible, with the following exceptions:

a. Insulation for domestic cold water piping (in the administration building only) is a closed-cell foamed elastomer with an ASTM E-84 flame spread rating of 25 or less.

b. Insulation for the offgas refrigeration equipment (located only in the offgas enclosure) has an ASTM E-84 flame spread rating of 25 or less.

c. Insulation for duct-work and plenums of the ventilation systems has an ASTM E-84 flame spread rating of 25 or less and a smoke generation rating of 50 or less.

Foamed plastics are not used for construction or as insulation other than the thermal insulation noted above and that used in the construction of seismic separation gaps between the walls of adjacent seismically independent structures in the power block.

Suspended ceiling panels have UL ratings of 25 or less for fuel contribution, flame spread, and smoke contribution. Supports for suspended ceilings are noncombustible.

High voltage transformers are installed outdoors. The main, auxiliary, and safeguard transformers, which are located near the north side of the turbine enclosure, are provided with individual deluge systems and are separated from each other by 3 hour rated fire walls. The wall extensions between the Main Power Transformers are based on maintaining integrity for 3 hours. The turbine enclosure exterior walls are not fire rated. The main and plant services transformers are located more than 50 feet from any buildings, but the safeguard and auxiliary transformers are located within 14 feet of the turbine enclosure wall. The turbine enclosure contains some safety related and fire safe shutdown equipment, however, none of this equipment is credited for safe shutdown for a fire in the turbine building. The transformers are protected by an automatic water deluge system. Thus, operators will be alerted to a transformer fire and it will not impair the ability to safely shut down the plant.

9.5.1.2.2 Fire Protection Water Supply Systems

9.5.1.2.2.1 Water Source

The source of water for the fire protection system is two cooling tower basins that have a capacity of 7,200,000 gallons each, for a total capacity of 14,400,000 gallons. For a system pumping capacity of 5000 gpm, this allows continuous operation of both fire pumps for 48 hours. If one cooling tower basin or supply line is not available, the remaining water source provides both fire pumps with a 24 hour supply of water. Water for the fire pumps is taken from either Unit 1 or Unit 2 cooling tower water basins through connections to the circulating water lines. Check valves are installed at the pump discharges to prevent water from one source from being pumped into the other source.

9.5.1.2.2.2 Pumps

There are two (2) horizontal centrifugal-type fire pumps, each capable of 2500 gpm at a system head of 125 psig. The lead pump is electric motor-driven and the 100% capacity lag pump is diesel engine-driven. The pumps and their controllers are UL-listed.

The fire water system is capable of delivering 100 gpm per hose station at no less than 65 psig to any hose station, considering the operation of two hose stations simultaneously with the largest water demand flowing from any automatic suppression system in the vicinity of the hose station. In addition

to the 100 gpm per hose station, 300 gpm is assumed at the nearest outside fire hydrant to support manual fire fighting activities. This meets BTP section C.6.b.(11) requirement of 500 gpm for manual hose streams in addition to the largest suppression system design. When the fire pumps are not running, the standpipes are maintained full of water by a 2 inch connection to the service water system, which is capable of replenishing 50 gpm for leakage. When a portion of the fire water system is activated, a low pressure switch set at 100 psig provides a signal to start the motor-driven pump automatically. If the motor-driven pump fails to start, the diesel-driven pump receives a start signal at a lower pressure signal setpoint of 95 psig to start the diesel-driven pump automatically. Both pumps are stopped manually.

A third fire pump is provided as a backup to the two primary pumps. This pump is diesel engine driven and is placed in service as stated in the technical requirements manual bases 3/4 7.6 to satisfy the requirement of providing an alternate pump.

The electric power for the motor-driven fire pump is taken from a load center that is supplied from the non-Class 1E 13 kV switchgear. The primary power source for the switchgear is the unit auxiliary transformer, and the secondary power source is the offsite power supplies. If the primary power source fails, the switchgear is automatically transferred to one of the two offsite power supplies. Switching from one offsite power supply to the other can be performed manually from the control room.

The diesel oil supply tank for the diesel engine has a capacity of 550 gallons. This volume is sufficient to allow operation of the diesel engine for approximately 40 hours at full pump capacity.

The fire pumps are located at one end of the circulating water pump structure north of the power block. The motor-driven fire pump and its controls are in an area common with the circulating water pumps and are protected by hose reels and portable fire extinguishers. Each pump and it's driver and controls are located in a room separated from the remaining fire pumps by a fire wall with a minimum rating of three hours. The diesel oil day tank is located in a curbed area within the diesel-driven fire pump compartment. This compartment is provided with an automatic sprinkler system.

9.5.1.2.2.3 Yard Piping

Fire protection water is distributed to the various areas of the plant from a yard fire main loop which completely encircles the power block. The connections to the yard fire main loop from the two fire pumps located in the circulating water pump structure are spaced about 6 feet apart and are provided with valving so that either connection can be isolated while retaining 100% water supply capacity to the yard fire main.

The yard fire main loop consists of 12 inch cement-lined cast iron piping which is buried below the frost line. The west and east ends of the loop are cross-connected by piping that traverses the Unit 1 and Unit 2 turbine enclosures. Locked open postindicator valves provide sectionalized control and isolation of portions of the fire main loop. There are 12 yard hydrants spaced at intervals of 250-300 feet along the fire main loop. Each hydrant is provided with a key operated 6" gate valve with curb box or 6" post indicating gate valve for hydrant isolation. Five hose cart houses are located in the yard area in the vicinity of the hydrants, each enclosing a hose cart that can be manually moved to any hydrant where it is needed. The system of hydrants connected to the fire main loop is designed in accordance with NFPA 24.

9.5.1.2.2.4 Automatic Sprinkler System Water Supply

Water main headers are provided to supply water to the different areas protected by sprinkler systems. The deluge systems for the transformers located outside are connected to an 8 inch header.

Outside screw and yoke gate valves controlling each automatic sprinkler system are either electrically supervised, providing trouble annunciation to the control room, or are administratively locked open/throttled. The postindicator valves controlling the branches feeding the deluge and sprinkler systems and standpipe systems are locked open by locks having a frangible design.

9.5.1.2.3 Automatic Sprinkler Systems

9.5.1.2.3.1 Wet Pipe Sprinkler Systems

Wet pipe sprinkler systems are provided to protect the following areas and equipment:

a. Turbine enclosure - feedwater pump lube oil reservoir compartments

b. Turbine enclosure - lube oil storage tanks and electrohydraulic control power unit

c. Turbine enclosure - main turbine lube oil reservoir and lube oil centrifuge area

d. Turbine enclosure - main turbine condenser area

e. Turbine enclosure - main turbine moisture separator area

f. Reactor enclosure - electric cable penetration areas at el 253' and el 283'

g. Lube oil storage enclosure

h. Auxiliary boiler enclosure

i. Radwaste enclosure compactor area

j. Circulating water pump structure - diesel fire pump compartment

k. Deleted

l. Deleted

m. Deleted

n. Deleted

o. Control structure - cable spreading rooms and corridor (el 239’)

p. Turbine Enclosure - Facility/laydown area, Plant Operators Break Facility (Rm 468A,B,C) and Plant Operators Building (Rm 468)

q. Deleted

Wet pipe sprinkler system operation is initiated in the event of a rise in ambient temperature to the melting point of fusible links on sealed sprinkler heads, thus causing the spray heads to open. The flow of water through alarm check valves energizes a flow switch that transmits the alarm condition to the fire protection panels in the control room. The wet pipe sprinkler system for the cable spreading rooms and corridor does not have an alarm check valve, but is provided with a flow switch that transmits an alarm signal to the fire protection panels in the control room.

The wet pipe sprinkler system operation is terminated manually by shutting the outside screw and yoke gate valves. The OS&Y gate valve for the corridor (el. 239) wet pipe sprinkler system (WP-124) is locked in the throttled position to limit flow in the event of a postulated sprinkler system pipe break as identified by the PRA internal flooding analysis. Throttling the valve gives plant personnel adequate time to diagnose if fire or flood conditions have occurred and take the required action prior to a flood induced equipment failure to risk significant components.

9.5.1.2.3.2 Preaction Sprinkler Systems

Preaction sprinkler systems are provided to protect the following areas and equipment:

a. Reactor enclosure - HPCI pump compartment (el 177')

b. Reactor enclosure - RCIC pump compartment (el 177')

c. Reactor enclosure - RECW equipment area (el 201')

d. Reactor enclosure - Safeguard system access area (el 201')

e. Reactor enclosure - partial coverage at el 217', el 253', and el 283'

f. Standby diesel generator compartments

g. Turbine enclosure - railroad access area

h. Turbine enclosure - generator equipment area

i. Turbine enclosure - under the turbine's appearance lagging and turbine bearing housings 1 through 9 and under the generator's appearance lagging and bearing 10.

j. Deleted

k. Control structure - fan room at el 304' (sprinkler heads are located at the underside of the platform at el 313')and localized coverage in the 13.2 kV switchgear room (el 217').

l. Radwaste Building - Storage Room, Data Acquisition Room, Storage Room, Source Storage/Standard Preparation Room and Technician's Area.

m. The Chemistry Lab (commercial building) located adjacent to the Radwaste enclosure, which is separated from the Unit 1 reactor enclosure by 3-hour rated fire walls, will not adversely affect any safety-related systems. The Chemistry Lab is protected by wet pipe and preaction suppression systems at strategic locations along with hose stations and portable fire extinguishers also provided to support manual fire fighting efforts.

Each preaction sprinkler system is automatically actuated by area fire detectors that release a tripping device to open the deluge valve, thus supplying water under pressure to the closed sprinkler heads. A rise in ambient temperature to the melting point of the fusible links on the sealed sprinkler heads causes the spray heads to open.

The actuation of a heat detector actuates a local release control panel which in turn sends a signal to a fire alarm code transmitter. The fire alarm code transmitter sends a coded signal to the main control room fire alarm panel which sounds the horns throughout the plant.

The preaction system for the 13.2 kV switchgear room is similar to the other systems, except both fire detection and loss of air pressure must be received before the system will actuate. The area fire detection system alarms, as well as low air pressure alarm, is provided at a local panel with remote indication also provided in the control room. A separate deluge valve actuation alarm is provided both locally and in the control room.

9.5.1.2.3.3 Deluge Systems

Deluge systems are provided to protect the following areas and equipment:

a. Main transformers, auxiliary transformers, and safeguard transformers (all located outdoors)

b. Isophase bus ducts and bus duct supporting steel for main and auxiliary transformers (outside areas only)

c. Generator hydrogen seal oil unit

d. Main turbine lube oil reservoir and lube oil centrifuge.

Operation of a deluge sprinkler system is initiated by heat detection. The actuation of any heat detector alarms a local release control panel which then trips the deluge valve and sends a signal to a fire alarm code transmitter. The fire alarm code transmitter sends a coded signal to the main control room fire alarm panel which sounds the horns throughout the plant. Manual release of the deluge valve tripping device also initiates remote alarms.

9.5.1.2.3.4 Water Deluge Application for Charcoal Filters

Charcoal filters in the ventilation systems of the plant are provided with water deluge application systems for fire protection. The water is supplied to the filters by means of a fixed piping system.

An indicating gate valve is manually opened when a thermal sensor actuates a local alarm system and registers an alarm condition on the fire protection panels in the control room. The operation is terminated manually by shutting the gate valves.

9.5.1.2.3.5 Water Curtain Systems

Two types of water curtain suppression systems are provided in the plant: (a) systems that subdivide certain fire areas into two zones, and (b) systems that protect floor slab openings associated with equipment hatchways in the reactor enclosures.

Water curtain systems that serve to subdivide fire areas are provided at el 217', el 253', and el 313' in the reactor enclosures. Each water curtain system consists of an OS&Y gate valve, a deluge valve, a local pull station, piping, and open sprinkler heads. Each water curtain system is actuated

manually, using the local pull station to open the deluge valve. The pull station is located inside a stairwell near the location of the water curtain. Actuation of a water curtain system is sounded throughout the plant by a coded alarm. Operation of the system is terminated manually by shutting the OS&Y gate valve, which is located near the stairwell in which the pull station is located.

Each of the water curtain systems is designed to achieve a discharge density of 0.3 gpm/ft^2 at floor level. This is accomplished through the use of open sprinkler heads arranged in a linear array across the top of the water curtain location. In addition, sprinkler heads discharging horizontally inward from the sides of the water curtain are provided where necessary to achieve the design discharge density.

Water curtain systems that protect the equipment hatchways in the reactor enclosures are designed similarly to the water curtain systems described above. The equipment hatchways are located in the southeast corner of the Unit 1 reactor enclosure and the southwest corner of the Unit 2 reactor enclosure. Each hatchway consists of openings in the concrete floor slabs at el 253', el 283', and el 313', with the openings arranged above one another. The opening in each slab is protected by an individual water

curtain system having its distribution piping located at the underside of the slab and arranged around the perimeter of the opening. Each water curtain system is actuated manually, using a local pull station to open the deluge valve. The pull station is located inside the stairwell near the location of the water curtain. In addition to the pull station, each water curtain system is provided with an emergency trip valve located near the local control panel.

9.5.1.2.4 Wet Standpipes

Wet standpipes are designed for Class II service in accordance with NFPA 14. All areas in the power block are within reach of at least one effective hose stream. Each hose station has 100 feet of woven, jacket-lined fire hose. Hose stations are located outside entrances to normally unoccupied areas, and outside both entrances of the control room. Most areas of the plant have adjustable fog nozzles that can be adjusted down to a straight stream. In areas with electrical hazards, there are adjustable fog nozzles (intrinsically safe) that will not go down below a 30 degree fog pattern.

9.5.1.2.5 Foam Extinguishing System

A foam system is provided for the protection of the fuel oil transfer structure and one outdoor fuel oil storage tank, and is designed in accordance with NFPA 11. The foam is educed from a foam solution tank by water from the main fire water header. Contacts are provided to annunciate operation of the system in the control room.

The one storage tank is provided with a fixed foam maker at the tank. Foam making is initiated manually from a local station after a high temperature condition at the tank has been alarmed locally and annunciated on the fire protection panels in the control room. Fire protection inside the fuel oil transfer structure is provided by a foam play-pipe with hose rack. When the play-pipe is removed from its holder, an electric switch located in the holder actuates a control valve to allow foam solution to enter the hose. A squeeze-type play-pipe valve enables the operator to control the flow of foam.

9.5.1.2.6 Deleted

9.5.1.2.7 Halon Extinguishing Systems

Three independent Halon extinguishing systems are provided for the raised flooring at el 289' in the control structure. Two of the systems serve the auxiliary equipment room; one system is designed

to discharge simultaneously into all floor sections on the Unit 1 side of the room, and the other system is designed to discharge simultaneously into all floor sections on the Unit 2 side of the room. The third Halon system serves the remote shutdown room.

The flooring in the auxiliary equipment room and the remote shut-down room consists of 1 foot high floor sections resting on the concrete slab at el 289'. The floor sections are of all steel construction (except for aluminum honeycomb in the floor plates) and are used for the routing of cabling to and from the electrical equipment located in the two rooms. In the auxiliary equipment room, this equipment includes the PGCC equipment, the plant computers, the Samac panels, the river evacuation and PA panel, a tone cabinet, and fault detection equipment. The PGCC for each unit consists of floor sections that are 8 feet wide and 20 feet long, each of which has vertical panels mounted near the center of the floor section. A termination cabinet is located at one end of each PGCC floor section. Smoke detectors are located in the floor sections and termination cabinets. The equipment located in the remote shutdown room consists of the remote shutdown panels for Unit 1 and Unit 2. Smoke detectors are located within the floor sections in the remote shutdown room.

The Halon extinguishing systems are designed in accordance with NFPA 12A. Each Halon system is designed to achieve a concentration of 20% by volume with the raised flooring that it serves fully installed and secured. Each system includes two banks of Halon cylinders, each of which has sufficient capacity to maintain a 20% concentration for 20 minutes. In addition to having two banks of Halon cylinders, each system consists of distribution piping and nozzles, heat detectors, and a manual selector switch. The heat detectors serve to actuate the Halon system; a predischarge alarm is sounded first, followed by a time-delayed discharge of Halon. The manual selector switch is used to designate which of the two banks of Halon cylinders in each system will discharge automatically. Halon cylinders can be discharged manually at the hand switch location or at the cylinder locations. The unused bank of cylinders can be used to provide a supplemental discharge of Halon by manually actuating the release.

9.5.1.2.8 Portable Fire Extinguishers

Portable fire extinguishers, using extinguishing agents compatible with the combustible material in the area in which they are located, are provided throughout the plant.

9.5.1.2.9 Fire and Smoke Detection System

The fire and smoke detection system is in compliance with NFPA 72A (1979). The system also complies with the requirements of NFPA 72D (1975), with the following exceptions and clarifications:

a. No device is provided for permanently recording incoming signals with the date and time of receipt. (The logging of fire events by a device for permanently recording incoming signals is not needed, because plant operating procedures will require the operator on duty in the control room to update the plant log book with the date and time of alarms from the fire detection system as well as the date and time of initiation of any fire suppression system.)

b. Operation and supervision of the system is not the primary function of the operators. (The control room operators are responsible for monitoring and supervision of all plant systems, including the fire detection and fire suppression systems.)

c. The locations of early warning fire and smoke detectors were established under the direction of a registered fire protection engineer. (The locations of fire and smoke

detectors are in compliance with the guidance of NFPA 72E, with the clarification that ionization-type detectors in certain areas of the plant are located in accordance with subsections 4-3.1 and 4-3.1.1 of NFPA 72E. These subsections allow detector location to be determined based on engineering judgment considering ceiling shape, ceiling surfaces, ceiling height, configuration of contents, combustible characteristics, and ventilation. In areas where concrete floor slabs are supported by structural steel beams, the diffusion of ionized particles throughout the compartment volume during the incipient stage of the fire will negate the effect of beam depth and result in an appropriate level of detection capability.)

d. NFPA 72D (1979) references NFPA 72E (1978) for testing of smoke detectors. NFPA 72E (1978) requires functional testing of smoke detectors semiannually. Functional testing of smoke detectors at Limerick will be done annually which is in accordance with NFPA 72E (1990).

e. In fire area 2, the smoke detection system is upgraded to NFPA 72, 1996, Chapter 5 for detector location and spacing.

f. In fire area 98, the smoke detection system above the ASD System is upgraded to NFPA 72, 2010, Chapter 17 for detector location and spacing.

g. In fire area 111, the smoke detection system above the ASD System is upgraded to NFPA 72, 2010, Chapter 17 for detector location and spacing.

Fire and smoke monitoring, detection, and alarm are accomplished by installing smoke detectors and/or heat-responsive detectors in areas where fire potential exists. Fire and smoke detection systems for annunciation are separate from fire detection systems for actuation of fire extinguishing systems, except for the 13kV Switchgear Area (Fire Area 02). The smoke detection system in the 13kV Switchgear Area (Fire Area 02) provides early warning notification while also providing an input signal to the double interlock preaction system that provides localized protection.

The fire and smoke detection system is electrically supervised to detect circuit breaks, ground faults, and power failure. All fire or trouble alarms register on the audible/visual annunciator on the fire protection panels in the control room. Functional testing of the supervised circuits is done annually in accordance with NFPA Standard 72 (1990).

9.5.1.2.10 Deleted

9.5.1.2.11 Deleted

9.5.1.2.12 Area Fire Protection Provisions

Primary Containment

There are no standpipes with hose stations or automatic sprinklers installed inside the primary containment. One hose station is located near the entrance to the containment personnel hatch. During refueling and maintenance operations, administrative procedures control ignition sources in the primary containment. Fire protection, including portable fire extinguishers and fire watches, is also controlled by administrative procedures. Self-contained breathing apparatus are provided near the open containment entrances for fire fighting and damage control personnel.

Control Room

The control room's location within the control structure provides 3 hour fire barrier separation from other major plant areas. The control room consists of the control room proper and support facilities such as offices, toilet, and utility rooms. The walls and doors of the support facilities are constructed of noncombustible materials.

Manual fire fighting capability provided for the control room consists of portable Halon extinguishers within the control room, and portable carbon dioxide extinguishers outside of the control room. Additionally, fire hose (water) stations with UL-approved fixed fog nozzles are installed outside both entrances to the control room. No hose stations are located within the control room.

The control room is provided with ionization-type smoke detectors that actuate an audible and visible alarm on the fire protection panels in the control room.

Self-contained breathing apparatus with a minimum operating life of 4 hours are available for use by control room personnel.

The control room ventilation intake is provided with smoke detection capability to automatically detect and annunciate the presence of smoke. Upon receipt of the alarm, the control room ventilation system can be manually placed in the recirculation mode in order to isolate the control room from the outside.

To clear the control room of smoke when there is no smoke in the outside air intake, the ventilation system can be placed in the purge mode, in which the recirculation path is closed off and 100% of the air flow through the control room is outside air.

The control room purge mode can be initiated from both inside and outside the control room. The control room ventilation system is discussed further in Section 9.4.1.

All penetrations in the control room are sealed airtight and comply with a 3 hour fire rating designed to satisfy ASTM E-119 requirements.

Cable Spreading Room

The cable spreading room is separated from other areas of the plant by 3 hour rated fire barriers. Automatic fire protection is provided by a wet pipe sprinkler system. To provide for manual fire fighting, hose stations and portable fire extinguishers are provided outside the cable spreading room near one entrance. Accessibility for manual fire fighting operations is provided by aisles between cable trays, the length and breadth of the room. Two separate entrances to each cable spreading room are provided.

A smoke detection system is provided in each cable spreading room to alarm locally and remotely in the control room on detection of an incipient fire.

Two floor drains are provided in each cable spreading room to drain water from manual fire fighting operations and/or sprinkler actuation.

Auxiliary Equipment Room

The auxiliary equipment room is separated from other areas of the plant by 3 hour barriers. Facilities provided for manual fire fighting include portable CO_2 fire extinguishers located within the room and a manual hose station at the entrance to the room.

The PGCC and the computer facilities, both of which are located in the auxiliary equipment room, utilize raised flooring approximately 1 foot high. The raised flooring is divided into sections typically 8 feet wide and approximately 20 feet long; PGCC panels or computer equipment are mounted near the center of each floor section. The floor sections are of all-steel construction (except for aluminum honeycomb in the floor plates) and are each divided into four longitudinal raceways and numerous lateral raceways, each of which is totally enclosed and therefore physically isolated from adjacent raceways. To minimize the possibility of occurrence of a fire, the cabling routed in these raceways is provided with flame retardant insulation, and no other combustible material exists in the floor sections. The highest voltages present within the floor sections are 125 V dc and 120 V ac. To prevent the spread of a postulated fire between different divisions of raceways within a floor section or between adjacent floor sections, fire stops are provided at the ends of the longitudinal raceways, at the ends of those lateral raceways that do not have end caps, in the lateral raceways where cables run from a longitudinal to a lateral raceway, and at the raceway openings at the bottom of the vertical panels. These fire stops consist of refractory material covered by silicone rubber.

The floor sections of the auxiliary equipment room are provided with an automatic, total flooding, Halon 1301 system. The system is actuated by heat detectors located in the floor sections. Smoke detectors are also located in the termination cabinets. Additional smoke detectors are located near the ceiling throughout the general area of the auxiliary equipment room. Detection of a fire by the smoke and fire detectors is annunciated on the fire protection panels in the control room.

Remote Shutdown Room

The remote shutdown room is separated from other areas of the plant by 3 hour rated fire barriers. The north and west walls of the room are constructed of reinforced concrete, whereas the south and east walls are a gypsum drywall assembly constructed in accordance with UL Design U435 and D744.

The remote shutdown panels are mounted on raised flooring approximately 1 foot high which consists of all-steel construction. To minimize the possibility of occurrence of a fire, the cabling routed through the raised flooring is provided with flame retardant insulation, and no other combustible material exists in the raised flooring. The raised flooring of the remote shutdown room is separated from the raised flooring of the adjoining auxiliary equipment room by the 3 hour rated gypsum drywall assembly, which extends down to the concrete slab at el 289'.

The raised flooring of the remote shutdown room is provided with an automatic, total flooding, Halon 1301 suppression system. The system is actuated by heat detectors located in the raised flooring. Early warning of a fire in the remote shutdown room is provided by smoke detectors located within the raised flooring as well as at the ceiling of the room. The smoke detectors actuate an audible and visible alarm on the fire protection panels in the control room.

Provisions for manual fire fighting include a manual hose station and portable CO_2 fire extinguishers located near the entrance to the remote shutdown room.

Switchgear Compartments

The switchgear compartments in the control structure (4 kV switchgear at el 239' and 13.2 kV switchgear at el 217') are separated from other areas of the plant by 3 hour rated fire walls. The eight switchgear compartments at el 239' are separated by 3 hour rated fire walls. A localized preaction system is provided in the 13.2 kV switchgear room to protect redundant trains of cable trays which are provided with 1-hour rated fire barriers.

Manual fire fighting equipment provided for the switchgear compartments consists of portable CO_2 extinguishers at el 217' and el 239', plus portable CO_2 extinguishers adjacent to the compartment at el 217'. Additionally, fire hose stations are located near the entrances to the compartments at both elevations.

Station Battery Compartments

The four safety-related battery compartments in the control structure (at el 217' and el 239') are enclosed by 3 hour rated fire walls.

Uninterrupted ventilation capability is assured by two redundant 100% capacity seismic Category I fans, at a minimum rate of 12 air changes per hour, that preclude attainment of explosive hydrogen concentrations in the battery compartments.

The exhaust ducts from the Class 1E battery rooms are provided with safety-grade isolation dampers in both branches of duct-work leading to the battery room exhaust fans and to the emergency switchgear and battery room supply air fan cabinets. The dampers in the duct-work leading to the exhaust fans are provided with safety-related position switches which activate the dampers in the duct-work leading to the supply air fan cabinets. In the event of closure of any of the dampers leading to the exhaust fans, the dampers in the duct-work from the battery rooms of the affected reactor unit and leading to the air supply fan cabinets will automatically open, thereby establishing recirculation air flow through the affected battery rooms. This re-establishment prevents accumulation of hydrogen above safe limits.

Manual hose stations and portable extinguishers are provided in the battery compartment area. Heat and smoke detectors are installed in the battery compartments, with remote annunciation in the control room.

Turbine Enclosure

The turbine enclosure is separated from all other structures in the plant by 3 hour rated fire barriers with the exception of the radwaste enclosure which is a 2 hour rated fire barrier. Fire barriers internal to the enclosure are used to isolate areas with significant combustible loadings from each other. The types of fixed suppression systems provided for the various areas of the turbine enclosure include the following:

a. Feedwater pump lube oil reservoirs - wet pipe sprinkler

b. Main condenser and moisture separator area - wet pipe sprinkler

c. Lube oil storage tanks and electrohydraulic control power unit - wet pipe sprinkler

d. Main turbine lube oil reservoir and centrifuge - wet pipe sprinkler and deluge

e. Generator hydrogen seal oil unit - deluge

f. Generator equipment area - preaction sprinkler

g. Railroad access area - preaction sprinkler

h. Deleted

i. P.C. issue cage, Floor Operators Break Facility (Rm 468A,B,C) and Plant Operators Building (Rm 468) – wet pipe sprinkler

j. Deleted.

Diesel Generator Compartments

The four diesel generators for each reactor unit are separated from each other and other structures of the plant by fire barriers having 3 hour fire resistance ratings.

An automatic preaction sprinkler system protects each diesel generator cell and provides complete coverage of the cell. Flame and heat detectors are provided in each diesel generator cell. The flame and temperature detection systems annunciate in the control room.

Each diesel generator cell is provided with trapped and vented floor drains and an adequate drainage capacity to cope with the maximum sprinkler water flow in each room. The drainage system is arranged to prevent flow from one diesel generator cell from backflooding into another cell.

Each diesel generator cell is provided with a separate ventilation system which is controlled manually from a local control panel and is also started automatically by either high air temperature or a diesel engine start signal.

The diesel oil day tank for each diesel generator and the lube oil tank are installed within a 3 hour rated enclosure located inside the diesel generator cell. Each cell's preaction sprinkler system provides fire suppression for the 3 hour rated enclosure.

Diesel Oil Storage Area

There are eight 41,500 gallon capacity diesel oil storage tanks buried underground in the yard southwest of the diesel generator enclosures.

Safety-Related Pumps

The safety-related pumps located at the lowest elevation of the reactor enclosure are separated from each other by 3 hour rated fire walls. Access openings provided with watertight doors are nonrated.

Fire suppression provisions for the safety-related pump compartments in the reactor enclosure consist of preaction sprinklers for the HPCI and RCIC compartments, portable extinguishers at or near the compartment entrances, and hose stations close enough to the compartment entrances to provide complete coverage. In consideration of the low combustible loading in the spray pond pump structure, portable extinguishers only are deemed adequate to control and extinguish a single fire event at any pump in that structure.

Safety-related pump compartments are provided with smoke or temperature detectors that will annunciate in the control room.

Storage Area

A storage area is provided in a concrete vault with access from the top at the refueling floor level of the reactor enclosure. There is no combustible material inside the vault. A cover is provided for the vault and consists of steel plate welded to grating. The cover is normally kept on the vault except during periods of transfer in or out of the vault.

A portable extinguisher is available in the area immediately adjacent to the storage area, and a hose station is available within effective range. A floor drain in the refueling floor slab serves to collect any water in the vicinity of the storage vault cover. A floor drain is also provided at the bottom of the storage vault.

Spent Fuel Pool Area

A hose station and portable fire extinguisher are available at the spent fuel pool.

9.5.1.2.12 Area Fire Protection Provisions

Radwaste Enclosure

The radwaste enclosure is separated from other structures by 3 hour fire barrier, with the exception of the turbine enclosure which is a 2 hour fire barrier.

Automatic sprinkler protection is provided in the waste drum storage area at el 217' in the enclosure.

Automatic preaction sprinkler protection is provided in the renovated area: Storage Room, Data Acquisition Room, Storage Room, Source Storage/Standard Preparation Room and Technician's Area.

Hose stations and portable extinguishers are located on all levels of the radwaste enclosure and are within reach of the waste drum storage area.

Chemistry Laboratory Expansion

The Chemistry Laboratory Expansion is provided with automatic wet sprinkler system and automatic preaction sprinkle system protection.

Automatic wet sprinkler system protection is provided for the Hot Lab., Frisk/Corridor (RCA), Office Area, Air Lock, Corridor (Non RCA), Conference/Lunch, Cold Lab., Toilets, Locker and Vestibule.

Automatic preaction system protection is provided for the Count Room, Instrument Lab., and Penthouse.

Yard Transformers

High voltage, oil-filled transformers are installed outdoors and are protected by automatic deluge systems. Fixed temperature detectors annunciate in the control room.

Miscellaneous Areas

The cooling tower basins serve as a source of water for the fire protection system but not for any safety-related systems. The cooling towers are constructed entirely of noncombustable material except for the splash bars and drift eliminators, which are polyvinyl chloride, the splash bar

support grids, which are fire retardant polyester and fiberglass, and the wind vane panels, which are polypropylene. The fill material is contained in a ring-shaped area around the periphery of each tower. The ring is separated into six cells by fire walls located at 60° intervals. A fire occurring in any one cell would have no effect on safety-related structures or systems, since such a fire would not affect the structural integrity of the cooling tower and the towers are located away from safety-related structures. This arrangement has been accepted by ANI for design of cooling towers with PVC and polyester fill material and without fire protection sprinklers.

The warehouse, machine shop, construction shop, and auxiliary boiler room are each provided with an automatic wet pipe sprinkler system. These areas are also provided with manual hose stations and smoke detector coverage.

The administration building is provided with automatic wet pipe sprinkler systems in the main office area and the laboratory. All elevations of the administration building are provided with manual hose stations and smoke detector coverage.

9.5.1.2.13 Miscellaneous Areas

The No. 2 fuel oil outdoor above ground tank for the auxiliary boiler is provided with foam a suppression system and full capacity dike surrounding the tank.

Storage areas for dry ion exchange materials are remote from essential safety-related systems. Local hose stations and portable extinguishers are provided in the vicinity of storage areas for dry resins.

The water treatment enclosure is protected by portable fire extinguishers and local hose stations.

9.5.1.3 Safety Evaluation

The safety evaluation for the fire protection program is included in Appendix 9A.

9.5.1.4 Inspection and Testing Requirements

9.5.1.4.1 Preoperational Testing

Pumps

Each fire pump is subjected to factory hydrostatic testing to twice the maximum pressure developed at pump shutoff head. Each fire pump is tested with a calibrated motor at the factory to develop pump performance curves showing head, delivery, efficiency, and brake horsepower. After installation, the pumps are tested in accordance with the requirements of NFPA 20.

Piping

The underground piping is hydrostatically tested at a pressure of 200 psi for 2 hours. The leakage is required to be less than two quarts per hour per 100 joints. All hydrants are opened and closed under water pressure. All postindicator valves are fully closed and opened under water pressure to ensure proper operation.

All wet standpipe, wet pipe sprinkler, preaction sprinkler, and deluge system piping is hydrostatically tested at a pressure of 200 psi with no visible leakage. The dry pipe portions of preaction sprinkler systems are pressurized with air to 40 psi, and allowed to stand 24 hours; leaks that allow a loss of pressure over 1½ pounds during the 24 hours are repaired.

Halon 1301 System

After installation, the Halon system is inspected and tested to ensure that the system is in full operating condition and can achieve the design Halon concentration.

Smoke and Fire Detection System

The smoke and fire detection systems are tested for correct operation and function.

9.5.1.4.2 Operational Testing and Inspection

The fire pumps and associated equipment such as batteries, water supply, and fuel systems are periodically tested or inspected in accordance with the Technical Requirements Manual. The Technical Requirements Manual defines periodic test or inspection requirements to ensure operability of the fire suppression system.

9.5.1.5 Personnel Qualification and Training

The training program for plant personnel and the fire brigade in regard to fire fighting activities will be implemented in accordance with the Fire Protection Program, Section 13.2.1.5, 13.2.1.6. Qualifications of fire brigade members are described in Section 13.1.2.1.1.

9.5.2 COMMUNICATION SYSTEMS

The communication systems include internal (intraplant) and external (out-of-plant) systems and provide convenient, effective operational communications between various plant structures and locations and with points outside the station.

9.5.2.1 Design Bases

Various communication systems are provided in the plant to ensure reliable communication during plant startup, operation, shutdown, maintenance, and emergency conditions. The design bases of these systems are:

a. Voice communication between various plant structures and locations is provided with the following characteristics:

    1. Satisfactory voice communication in areas of extreme noise

    2. Three separate communication systems with simultaneous conversation possible on each system without interference

b. Voice communication to points outside the station is provided by a dial telephone system and by a backup radio system.

c. An evacuation and alarm system is provided to warn personnel of emergency conditions.

d. The communication systems are designed to be operable during a LOOP.

e. All communication components are nonsafety-related seismic Category II components. These components, when located in safety-related areas, are

supported on a selective basis to seismic Category IIA requirements as described in Section 3.2. The criteria for this selective basis and the design basis for seismic Category IIA supports are described in Section 3.2.

9.5.2.2 System Description

The plant communication systems consists of the intraplant public address system, the private automatic branch exchange telephone system, the intraplant maintenance telephone system, the evacuation alarm and river warning system, and the in-plant radio system. Descriptions of these systems are given in the following sections.

The public address and PABX telephone systems are illustrated in riser diagram form in drawings E-1366, E-1367, E-1368, E-1369, E-1370, and E-1371.

The PABX, PA, and in-plant radio systems are physically independent systems. They are ultimately powered by diverse Class 1E or battery backed-up/UPS sources. They serve as backup to one another in the event of system failures. These three independent voice communications systems have been designed and installed to provide assurance that any single event will not cause a complete loss of intraplant communication through the use of diverse technology, separate routing of cables, and separate diesel generator backed power supplies.

9.5.2.2.1 Intraplant Public Address System

The PA system is a 6 channel system permitting simultaneous usage of a page line and five party lines for intraplant use. Loudspeakers powered by individual amplifiers are located throughout the plant with muting facilities provided where required. The main control room is isolated (muted) from general plant paging announcements. However, each handset in the plant is equipped with an Emergency Control Room push button to activate (unmute) the control room speakers. The PA system is provided with a telephone line matching network for operation of the page channel by the PABX system described in Section 9.5.2.2.2.

The PA system has been equipped with an advanced page line control system for the enhancement of PAGE announcements throughout the site. This control system provides improved sound quality for emergency announcements made to and from the main control room. It is also capable of screening out page announcements that do not originate from designated page announcement control points such as the control room, TSC, OSC, security locations, etc. This screening feature has no effect on simultaneous usage of the 5 party lines along with the page announcement function, nor does it prevent the use of the page for contacting the control room or conducting local emergency (fire brigade) announcements within a given plant area. The primary purpose of the screening function is to reduce the number of locations where site wide page announcements can originate.

The overuse of page announcements reduce the effectiveness of emergency and other priority control room announcements. The control of the type and number of general page announcements will improve the level of effectiveness of the remaining page announcements.

The page line control system reduces troubleshooting time for individual PA component problems, thereby improving the maintenance and effective usefulness of the entire system. The page line control system has been designed not to interfere with the plant's ability to conduct emergency announcements or evacuation alarm announcement coverage. The control system has no effect on the evacuation capabilities described in Section 9.5.2.2.4.

PA handsets and speakers are located in vital areas throughout the plant and remote buildings. Multiple handsets are provided at many plant elevations. Automatic volume control is provided to overcome high background noise levels in areas with high ambient noise levels.

Page controlled emergency evacuation equipment that works in conjunction with the PA system is provided where evacuation coverage is required during plant evacuation. This emergency evacuation equipment does not interfere with the PA system (See Section 9.5.2.2.4 for further information).

The public address system is powered from a Class 1E 440 V motor control center through a 480/120 V transformer and distribution panel. The transformer and distribution panel are seismic Category I. The panel remains connected to the Class 1E bus during all accident conditions. The Class 1E 440 V motor control center is powered by the Division 4 Class 1E ac power system.

The cables for the PA system are routed in independent and separate conduits dedicated to the PA system, the majority of which are embedded. The main amplifier panel for this system is located in a seismic Category I structure in a mild environment and is mounted seismic Category IIA. The individual hand stations are securely mounted to the walls using 4 inch anchored bolts. The PA system is designed to remain functional during normal and emergency conditions. In addition, there is assurance that it will remain functional following a seismic event.

9.5.2.2.2 Private Automatic Branch Exchange Telephone System

The PABX/PBX equipment and cabling is supplied and installed by a telecommunications vendor. The telephones associated with the PBX are located throughout the plant. The primary source of power for the telephone system will come from non-Class 1E Administration Building MCC 00B539. The secondary source of power will come from Class 1E Control Area MCC 00B131. MCC 00B131 is powered from a Division 3 safeguard bus. The MCC feeder breaker is automatically shed on a LOCA signal, but it can be manually reset at the MCC. If both sources of power are unavailable, an uninterruptible power supply with a minimum of two hours of emergency battery power will supply the telephone system. Dedicated circuits between the Limerick Generating Station and Peach Bottom Atomic Power Station emergency PBXs allow continuation of limited two way commercial telephone service in the event that the Limerick main commercial telephone switch (PBX) becomes inoperable or unavailable. The PABX is not designed to remain operational after a design basis seismic event.

9.5.2.2.3 Intraplant Maintenance Telephone System

The intraplant maintenance telephone system is part of the PABX system consisting of telephone jacks. Portable PABX (dial-type) telephones may be connected to the maintenance telephone jacks.

This system provides an additional station-to-station, intraplant communication system for use during startup, maintenance, and normal operation, and consists of telephone jack stations located at various selected areas throughout the plant. The use of maintenance telephones allows uninterrupted private communication between the control room and the following areas: CRD equipment area, refueling platform area, turbine-generator operating deck, areas containing switchgear, load centers, and motor control centers, and other high maintenance activity areas. Although intended for maintenance, the capability exists to utilize this system in areas covered by the PABX system.

9.5.2.2.4 Evacuation Alarm and River Warning System

The evacuation alarm and river warning system is provided to warn personnel of emergency conditions. This system supplements the radiation monitoring systems described in Section 12.3.4.

The evacuation alarm system consists of a siren tone generator, PA system speakers, page controlled emergency evacuation equipment and a roof siren.

The evacuation alarm is manually initiated by a selector switch in the control room. This selector switch also selects the evacuation alarm coverage in the drywell of Unit 1, the drywell of Unit 2, or the whole plant including the initiation of the roof siren and the river broadcast speakers.

Page controlled emergency evacuation equipment that works in conjunction with the PA system is provided for audible/visual indication during plant emergency evacuation. These units are connected to the PA system and initiated only when the roof siren is activated. A visual indication is used due to high noise environments within the plant.

The river warning system consists of a tape recorder, a microphone, river broadcast speakers and an output feedback monitoring system.

The tape recorder transmits recorded messages, and the microphone transmits warning instructions through the river broadcast speakers. An initiation signal from a selector switch in the control room starts the tape recorder or renders the microphone available for transmission.

The monitoring system monitors the output of the river broadcast speakers and transmits it back to the monitoring speaker when the tape recorder is initiated or to the VU meter when the microphone is activated. Monitoring speaker and VU meter are located in the control room.

Power for this system is supplied from a seismic Category I distribution panel that is fed from a Class 1E bus.

9.5.2.2.5 In-Plant Radio System

Emergency communications within the plant can be maintained after the loss of the PA and PABX systems through the in-plant radio system. This system consists of distributed antennas throughout the plant with centralized rebroadcast transmitters/base stations. Lower power walkie-talkies with approximately 1.8 watt output are used with this system. The low power of the radios ensures that there will be no interference to low level control and instrument circuits. The system is designed to permit walkie-talkie to walkie-talkie and walkie-talkie to console communications from most locations within the plant and satellite buildings. Communication consoles are located at selected plant locations including the control room and remote shutdown room. Communication paths between consoles are hardwired, thus providing a means of communication between selected areas of the plant even with the failure of the radio base stations, PA system, and PABX system. The power for the base stations and consoles is from battery backed or UPS, non-Class 1E systems as further described in Section 9.5.2.3. In order to assure radio communications between the Main Control Room, Remote Shutdown Panel (RSP) Room, and Operational Support Center (OSC) in the event of a fire (in any one given area) and/or loss of power, the radio base station repeaters and their associated audio lines are designed to continue operating as further described. Communication lines are monitored for open or short circuits via the audio line monitoring system. This system consists of line monitors placed in the main audio trunk lines between fire zones/areas. The line monitors will continue to use the primary audio line path as long as the lines between monitors remain intact. In the event of a fault, the monitor will switch audio lines to enable alternate communication equipment.

9.5.2.2.6 Radio Communication

A backup offsite communications system consists of a radio system that provides communication between the control room and PECo Headquarters as well as other generating stations. Radio capability is also provided between the control room and local law enforcement authorities. Concurrently, the information is relayed to the Montgomery County Office of Emergency Preparedness. The radio transmitters are powered from a power source diverse from that which powers the PABX. The radio equipment is not designed to withstand the design basis seismic event.

The physical and electrical independence of the radios and the PABX provides assurance that a design basis seismic event would not cause the loss of offsite communications.

9.5.2.3 Safety Evaluation

The communications systems are not safety-related and are classified as non-Class 1E. When components of the communications systems are located within seismic Category I structures, these components are supported on a selective basis to seismic Category IIA requirements described in Section 3.2. The basis for providing Category IIA supports is to prevent the communications equipment from falling on safety-related equipment and impairing its ability to perform safe shutdown functions during a seismic event.

Following a design basis seismic event with coincident failure of all nonseismic equipment and components, LGS will attain a safe, cold plant shutdown from the main control room without the use of intraplant communication because all actions required under this scenario are taken in the control room. A Special Event procedure (SE-5, Earthquake) will instruct the plant operators to shut down the plant if a severe seismic event, including a DBE, takes place. This shutdown will be accomplished using the LGS Transient Response Implementation Plan Procedures (TRIPP). The TRIPP procedures will direct the plant operators on the actions to be taken to achieve a safe cold shutdown from the main control room when intraplant voice communications systems are not available. However, because the three intraplant communications systems use diverse technology and

Class 1E power sources, and because the critical active components of the PA system and the in-plant radio system are installed in seismic Category I structures, there is reasonable assurance that intraplant communications will be maintained following a design
basis seismic event.

The systems described above are conventional and have a history of successful operation at similar existing plants. System design considerations include diversity and operational reliability.

Physical and electrical separation is provided between primary and backup systems to minimize the possibility of a single occurrence affecting more than one system.

The communications systems have adequate flexibility to keep plant personnel informed of plant operational status at all times. If one handset station of the PA system is damaged or inaccessible or if extreme background noise prevents its use, multiple handset locations at each plant elevation provide easy access to an alternate handset of the PA system.

Failure of a single PABX telephone station does not affect the balance of the PABX telephone system. If failure of the central exchange or some other such failure makes the complete system inoperable, the public address system is used as backup in-plant communications.

The public address system is powered from a Class 1E 440 V motor control center through a 480 V - 120 V transformer and a 3-phase, 120 V distribution panel. The transformer and panel are seismic Category I and feed only the PA system and fire alarm system which are non-Class 1E. The cabling for these systems is routed in independent and separate conduits and no other systems' cables are routed in these conduits. For this reason and reasons of plant safety, this panel remains connected to the Class 1E bus during a LOCA. The Class 1E 440 V motor control center is powered by the Division 4 Class 1E 440 V load center. The Class 1E 440 V motor control center and load center are part of the Class 1E ac power system (Section 8.3.1.1.2). Failures of the fire alarm or PA systems will not affect the Class 1E bus because of the use of redundant overcurrent protection devices.

The primary source of power for the PABX/PBX telephone system will come from non-Class 1E Administration Building MCC 00B539. The secondary source of power will come from Class 1E Control Area MCC 00B131. MCC 00B131 is powered from Division 3 safeguard bus. The MCC feeder breaker is automatically shed on a LOCA signal, but it can be manually reset at the MCC. If both sources of power are unavailable, an uninterruptible power supply with a minimum of two hours of emergency battery power will supply the telephone system.

During the loss of both offsite power and the diesel generator associated with Division 4 bus, communication is maintained by the PABX telephone system and the in-plant radio system.

The in-plant radio system is powered by battery backed or UPS, non-Class 1E systems. Failure of any or all of its components will not affect any nuclear safety-related equipment. The audio line monitors are powered by a non-Class 1E power source (lighting panel). During the loss of power, the audio line monitoring equipment use their internal batteries (72-hr). The system is equipped with diagnostic lights on the audio line monitor equipment for surveillance testing.

9.5.2.4 Inspection and Testing Requirements

The communications systems will be tested by a preoperational test (1-P-99.3). Systems described above are conventional and have a history of successful operation at similar existing plants. These systems will be in routine use and maintenance, and this will ensure their availability.

Also, these systems will be used extensively during the preoperational and startup phases. Any deficiencies will become readily apparent and will be corrected. The power sources, for the PABX and Class 1E bus for the PA system, are tested separately via the preoperational and startup test program.

Maximum dB levels have not been established for the remote shutdown locations. During the startup program when operating ambient noise levels are present, communications between each remote operating location and the control room or remote shutdown room will be tested. At least two communications systems of the PABX, PA or in-plant radio system described in Section 9.5.2 will be proven to be adequate for communicating with these remote areas with normal plant ambient noise levels. All remote shutdown locations that may be used to safely shut down the plant in the event of a control room evacuation are identified in Table 9.5-13. Any locations that may be subsequently identified will be added to this table.

9.5.3 LIGHTING SYSTEM

The plant lighting system provides illumination levels required for safe performance of plant operation, security, shutdown, and maintenance duties. Emergency dc lighting is provided in essential areas for the safety of personnel during an ac power failure.

9.5.3.1 Design Bases

a. The lighting system is designed to provide illumination intensities required for the performance of activities in the various areas, and is equal to or greater than those recommended by the IES (Illumination Engineering Society). Lighting fixtures have been selected with consideration for environmental conditions and ease of maintenance.

b. The emergency lighting system provides lighting intensities required for use during emergencies or shutdown and meets the requirements stated in the "Building Regulations for Protection from Fire and Panic," Commonwealth of Pennsylvania, Department of Labor and Industry.

c. The lighting system for safety-related areas, including the control room, portions of the auxiliary equipment room, diesel generator enclosures, emergency switchgear area, and other areas requiring lighting during emergencies, is comprised of the normal lighting and emergency lighting systems as described in Sections 9.5.3.2.1 and 9.5.3.2.2.

d. The control room lighting system is provided with Light Emitting Diode (LED) lighting with special attention given to the reduction of glare and shadows at the control panels. The lighting fixtures are designed to provide diffused, indirect lighting,

e. Mercury gases are not used inside the primary containment or directly above the refueling area. Mercury switches are not used in the lighting system.

f. Outdoor area lighting provides illumination for plant security and safe movement of plant personnel. Lighting of the protected outdoor area is sufficient to permit effective visual inspection to facilitate nighttime television surveillance and patrol of the perimeter fence. The average footcandle level inside and along the security fence is 0.2 ftc or greater.

g. All lighting system components are nonsafety-related and, except as described in Section 9.5.3.2.2.a, are seismic

   Category II. These components, when located in safety-related areas, are supported on a selective basis to seismic Category IIA requirements as described in Section 3.2. The criteria for this selective basis and the design basis for seismic Category IIA supports are described in Section 3.2.

9.5.3.2 System Description

9.5.3.2.1 Normal Lighting

Power for normal lighting is supplied from the unit auxiliary or the startup buses which are described in Section 8.3.1. This system provides lighting for all indoor and outdoor areas. Outdoor security and roadway lighting is described in Section 9.5.3.2.3.

The high pressure sodium, mercury vapor, and some of the fluorescent and LED lighting fixtures rated at 480/277 V are fed from 480/277 V, 3-phase, 4-wire, grounded neutral system lighting panels, which are fed from the normal 440 V motor control centers. The incandescent, LED, and the fluorescent lighting fixtures rated at 208/120 V are fed from 208/120 V, 3-phase, 4-wire, grounded

neutral system lighting panels. These lighting panels are also fed from the normal 440 V motor control centers through dry-type transformers.

9.5.3.2.2 Emergency Lighting

The emergency lighting installation consists of an emergency dc and an emergency ac lighting system as described below:

a. Emergency Ac Lighting

Emergency ac (480/277 V) lighting is supplied from the Class 1E buses that automatically transfer to the diesel generator upon loss of the normal source. However, the emergency ac lighting panels are shed from the Class 1E buses if a LOCA occurs. The panels are manually reconnected to the Class 1E buses following a LOCA through administrative controls. Emergency ac lighting is provided in the safety-related areas and the areas requiring lighting during emergencies.

The control room emergency lighting circuit (1L9) is installed to seismic Category I requirements. The raceways from the Class 1E sources to the control room emergency ac lighting fixtures are routed in a seismic Category I structure. These raceways and the lighting fixtures are seismically supported.

b. Emergency Dc Lighting

Emergency dc lighting consists of a combination of ac/dc lighting fixtures normally supplied from the Class 1E buses, and self-contained battery powered units. Upon loss of the Class 1E ac source, an automatic transfer switch transfers the ac/dc lighting fixture immediately to the 125 V dc non-Class 1E station battery source. The 125 V dc non-Class 1E lighting system will provide power to the emergency ac/dc lighting system for one hour after a LOCA coincident with a LOOP. The battery chargers for this battery are fed from the Division IV diesel generator and can be manually reconnected to the diesel after the LOCA. On a LOOP without a LOCA, these chargers remain connected to the diesel generator, and dc lighting will remain available as long as the diesel is running. All emergency ac/dc lighting fixtures are incandescent-type or dual-input AC/DC LED.

Emergency lighting, energized from 8 hour battery-powered, self-contained units, is provided in areas where operator actions are required for operation of safe shutdown equipment needed to achieve shutdown during a fire. This emergency lighting is also provided for access and egress paths to these areas.

Emergency dc lighting fixtures and illuminated exit signs are located in the control room, stairways, and along exit routes from each floor throughout the plant.

Table 9.5-12 identifies the illumination intensities for the vital and hazardous areas where emergency lighting is provided for normal plant operation and the evacuation of personnel in the event of an accident. The table provides both the normal and emergency operating conditions for these areas. These illumination levels conform to the IES Lighting Handbook recommended levels. Column 4 of Table 9.5-12 shows the 125 V dc power-supplied lighting illumination intensity levels that are maintained in the control room and other areas of the plant between loss of offsite power and availability of onsite power.

Table 9.5-13 identifies the areas and lighting levels where remote actions are required to safely shutdown the plant in the event of a control room fire, auxiliary equipment room fire, or a failure of the remote shutdown system. The lighting levels provided at these locations are shown. In these areas, the loss of the diesel generator would leave the dc-supplied power system or the 8 hour battery-powered, self-contained units to provide lighting for the remote operations required in those areas as well as access to those areas.

The emergency ac/dc lighting system provides approximately 10% to 20% of the total lighting of the plant. The approximate percentage of emergency lighting fed from each division of Class 1E power is as follows:

a. Division 1 = 6%

b. Division 2 = 32%

c. Division 3 = 12%

d. Division 4 = 50%

The emergency lighting load is not divided equally among the four diesel generators due to plant utilization.

In the main control room, emergency ac lighting is supplied from Divisions 1 and 4 of Class 1E power. The emergency ac lighting supplied from each division of Class 1E power provides a uniform light level of approximately 20 footcandles in the main control room.

9.5.3.2.3 Outdoor Security and Roadway Lighting

Outdoor security and roadway lighting illuminates the "security" area and the security fence to 0.2 ftc or greater.

The outdoor lighting poles do not exceed 130 feet in height. Any 130 foot pole is designed to withstand a sustained wind velocity of 90 mph and gusts of up to 117 mph. Shorter poles are designed to withstand winds of higher velocity. All exterior lighting poles are designed in accordance with 1975 AASHTO specifications for structural supports for highway luminaries.

The security area lighting is supplied from the non-Class 1E buses. The other outdoor area lighting is generally supplied from the normal 440 V buses. In the far areas, remote from the normal 440 V source, this lighting is supplied from the nearby Class 1E buses. The lighting supplied from the Class 1E buses is shed on a LOCA signal. This lighting, however, can be manually reconnected to the Class 1E buses following a LOCA through administrative controls.

9.5.3.3 Safety Evaluation

The lighting systems are not safety-related and are classified as non-Class 1E. When components of the lighting systems are located within seismic Category I structures, these components are supported on a selective basis to seismic Category IIA requirements described in Section 3.2. The basis for providing Category IIA supports is to prevent the lighting equipment from falling on safety-related equipment and impairing its ability to perform safe shutdown functions during a seismic event.

During a design basis seismic event coincident with a LOOP and failure of all nonseismic equipment/components, the control room lighting will be maintained at approximately 20 footcandles by the emergency ac lighting system. The fixtures in the control room are seismically mounted and the power is from a Class 1E source. The raceway from the source to the control room will be routed in a seismic Category I structure and will be seismically supported.

Lighting is provided to permit the operators to shut down the plant safely and maintain it in a safe shutdown condition at all times. The lighting system provides lighting at all times in areas used during reactor shutdown or emergency.

During normal plant operation, all plant lighting systems are energized from the respective unit auxiliary buses and startup buses. In the event of ac power loss from both unit auxiliary and startup buses, the normal lighting system is inoperable. The emergency lighting system, however, remains operable, being energized from the safeguard buses. The emergency lighting system is provided with the capability for full functional tests to ensure the operability of the automatic switches and other components of the system. In the event of ac power loss from both unit auxiliary and startup buses, the standby diesel generators start and energize the respective Class 1E buses within 10 seconds. During the 10 second delay (diesel startup time) the dc emergency lighting system remains energized from the station 125 V dc battery supplies. This system design ensures continuity of illumination in all indoor and essential operating areas including all emergency access and exit routes. All emergency ac lighting is automatically isolated from the Class 1E buses on receipt of a LOCA signal.

9.5.3.4 Inspection and Testing Requirements

The lighting systems are preoperationally tested. System operability is demonstrated by use during normal plant operation.

A routine test exists to simulate loss of offsite ac power to the emergency ac/dc lighting automatic transfer switches. Visual inspection of the lighting system will indicate whether the transfer switches have operated properly. This routine test will be performed twice a year consistent with available manpower and plant conditions.

9.5.4 DIESEL GENERATOR FUEL OIL SYSTEM

The diesel generator fuel oil system provides onsite storage and delivery of fuel oil for at least seven days of continuous operation to all diesel generators while supplying post-accident power requirements. The diesel generator fuel oil system is a safety-related system.

9.5.4.1 Design Bases

The diesel generator fuel oil system design bases are as follows:

a. To provide onsite storage of fuel oil for the diesel generators for at least seven days of continuous operation and to allow for subsequent refilling

b. To ensure that the single failure of any active component does not affect the operation of more than one diesel

c. To remain operable during and after a SSE

d. To withstand wind, tornadoes, floods, and missiles

e. To be capable of being tested during plant operation

f. To provide sufficient fuel oil to the diesel engines for all loading conditions

The diesel generator fuel oil system is designed to seismic Category I requirements. The quality group classification and corresponding codes and standards that apply to the design of the system are discussed in Section 3.2 and shown in drawing M-20. The quality assurance program is discussed in Chapter 17.

All piping and equipment has been designed to withstand seismic accelerations and operating loads, regardless of design code. The manufacturer has developed a highly reliable engine piping system over the 44 years that the design of this basic engine has been in use.

9.5.4.2 System Description

The diesel generator fuel oil system P&IDs are shown in drawing M-20. Major component design parameters are listed in Table 9.5-3. Each diesel generator is provided with an independent fuel oil system. Each fuel oil system provides fuel oil to injectors and consists of a diesel oil storage tank, a diesel oil transfer pump, a day tank, an engine-driven fuel pump, a dirty fuel tank, a dc motor-driven auxiliary fuel pump, and associated piping, valves, strainers, and instrumentation. Details of the diesel oil storage tanks and their support structures are shown in Figure 3.8-64. The locations of the diesel oil storage tanks and the diesel generator enclosures are shown in Figure 3.8-58.

The description of the diesel generator fuel oil system components is as follows:

Diesel Oil Storage Tanks - One 41,500 gallon nominal capacity storage tank is provided for each diesel generator. The stored fuel oil is sufficient for seven days of continuous generator operation while supplying post-accident power requirements. The tanks are buried underground approximately 150 feet from the diesel generator enclosure as shown in Figure 3.8-58.

The diesel oil storage tanks are filled and replenished from trucks through the fill connection which branches to each of the reactor unit's four tanks. Each supply tank fill line has its own shutoff valve. A duplex-type basket strainer is provided in the fill line to prevent solid particles or debris from entering the storage tanks.

Connections for level instruments, manhole, day tank overflow return, vent, and pump support flange are provided on top of the tank. A concrete manhole for each tank, from grade to the tank connections, is furnished for access, maintenance, inspection, and repair, and can be used for emergency filling. Provisions have also been made for the collection of fuel oil that might leak from the diesel oil storage tanks into the surrounding concrete base. These provisions consist of two oil sumps, located at opposite ends of the row of eight tanks, plus associated collection piping. The sumps are of concrete manhole type and are buried completely underground. The underground collection piping consists of 6 inch diameter perforated corrugated metal pipe that is routed around the periphery of the group of eight tanks. Also, a waterproof membrane extends from ground level down to the concrete base and surrounds the eight tanks.

The locations of the sumps, the membrane, and the arrangement of the collection piping are shown in Figure 2.5-37 Sheet 8. In the unlikely event that a substantial amount of diesel oil was collected in

the sumps, the temperature would be low enough to maintain the oil below its flash point of approximately 125°F. Because no flammable vapors would be formed, the possibility of an explosion is eliminated.

To preclude the potential for a fire, there are no ignition or heat sources within the sumps. When the sumps are drained, a portable pump will be placed on the surface and a suction hose dropped into the sump. Administrative procedures will ensure that no ignition sources are present in the vicinity of this operation. In addition, the sumps are completely separated from the tanks such that a potential fire in one sump would not propagate to the tanks. Any fire in these sumps would be extinguished once the available oxygen in the sumps has been consumed.

The tanks are vented through a flame arrestor above grade. The tank vent point and the fill pipe opening are higher than the probable maximum flood level. Each of the tanks is provided with a pressure/vacuum relief valve to protect against overpressure and vacuum.

The tank vent lines with a flame arrestor, the vacuum/air release valve, and the fill line for all fuel oil storage tanks are seismic Category IIA and are therefore not expected to crimp when subjected to seismic loads. Alternate vent and fill paths (e.g., manhole of the tank) are available for use in the unlikely event of damage by a seismic event. Cross connections are also provided in the fuel oil supply and return lines to each diesel to allow any diesel to be supplied from any fuel oil storage tank (drawing M-20). Credible fill or vent line damage due to a seismic event would not affect the safe shutdown of the plant.

Corrosion Protection - The exterior and interior surfaces of the diesel oil tanks are coated with protective paints according to the coating manufacturer's instructions. The exterior surfaces are commercial blast-cleaned (SSPC-SP-6) and painted with two coats of Koppers Bitumastic No. 50. Each coat has a dry film thickness of 15 to 18 mils. The entire interior surface of the tank is blast-cleaned to white metal (SSPC-SP-5) with a profile of 1.0 to 3.0 mils. The sump area and bottom 1 foot vertical are coated with a minimum of three coats of an epoxy phenolic paint (Amercoat 90, manufactured by Ameron Protective Coatings) for a total dry film thickness of between 12.0 mils and 18.0 mils. This coating is proven for oil immersion service and has been certified by the manufacturer for compatibility with diesel fuel. In addition, the following measures have been taken to minimize the potential for internal corrosion and to mitigate its effects:

a. Corrosion Allowance: The tanks are provided with at least a 1/16 inch corrosion allowance in the shell and 1/8 inch in the sump.

b. Condensate Removal: The tanks are designed to permit easy removal of most condensation that may collect at the bottom of the tank. Each tank is equipped with a cylindrical sump affixed perpendicular to the bottom of the cylindrical tank such that the low point is directly beneath the manhole cover and dipstick nozzle. Figure 2.5-37 shows the details. Most of the condensate will flow down the tank walls and into the sump instead of being dispersed across the bottom of the tank.

   The accumulated condensate will be removed from the sump at the interval specified in the Technical Specifications by dropping one end of a flexible pipe through the dipstick nozzle and into the sump. A small pump will be attached to the other end of the pipe, which will draw the condensate from the sump and discharge it into a portable container for transportation to the plant oily waste processing facilities.

c. Fuel Oil Quality: The LGS tanks and the entire fuel oil transfer system are designed to maintain the highest level of fuel oil quality as practicable. The principal factors that have an effect on fuel oil quality are:

1. Variations in fuel oil temperature

2. Presence of water bottoms

3. Contact of fuel with copper or copper alloys

4. Contact of fuel with zinc.

The rate of fuel gum formation is greatly increased by warm temperatures. Cyclic changes in temperature also can cause the tank to breathe such that more volatile components of the fuel will evaporate. In addition, this breathing may contribute to condensation buildup in the tank. These effects are mitigated by locating the fuel oil storage tanks underground where overall temperatures are lower and atmospheric fluctuations are minimized.

The presence of water bottoms will promote tank rusting and corroding and will also supply a medium to support bacterial growth. Products of these processes will sometimes pick up existing gums, emulsify, and scatter throughout the fuel to the point where fuel quality may be degraded. As discussed in item b above, accumulated water bottoms will be removed at the interval specified in the Technical Specifications to help mitigate these effects.

When fuel oil comes in contact with copper and copper alloys, the rate of gum formation is increased. The copper acts as a catalyst in promoting and speeding the reaction. At LGS, none of the major components of the fuel oil transfer system that come into long-term contact with the fuel oil contain copper. However, some components in the injector system are made of copper alloys. Periodic exercising of the diesel generators will purge these components of any gum deposits before significant amounts are formed to impede fuel oil flow.

The role of zinc in the gumming process is not catalytic; however, the zinc may react adversely when exposed to fuel oil over a period of time. The zinc may form fuel soluble resinous materials that may degrade into insoluble gums as the fuel passes through the hot intake manifold and injectors. To preclude this occurrence at LGS, all sources of zinc have been removed from the fuel oil storage and transfer system.

d. Fuel Oil Specifications and Testing: The fuel oil purchased for the LGS diesel generators will be No. 2 diesel fuel and will meet the requirements of ASTM D975 (1981). To ensure proper fuel oil quality, samples will be tested in accordance with the plant technical specifications. Prior to the addition of new fuel to the storage tanks, the fuel will be tested for water and sediment content in accordance with ASTM D4176 (1982); and for kinematic viscosity, specific gravity, and flash point in accordance with ASTM D975 (1981). Within 31 days after obtaining this sample, it will also be tested for the remaining properties in Table 1 of ASTM D975 (1981). The exception to this is the analysis for sulfur which may be performed in accordance with ASTM D1552 (1979) or ASTM D2622 (1982). The fuel in the storage tanks will be sampled and tested for particulates in accordance with ASTM D2276 (1978) except that the filters specified in ASTM D2276-78 may have a nominal pore size of up to 3

microns. Fuel that does not pass the acceptance criteria of these standards will be brought into compliance or will be removed from the storage tanks and replaced with fresh fuel.

e. Particulate Contamination: To minimize the formation of rust on the tank interiors during the period between blast cleaning and initial loading of fuel oil, an elevated temperature will be maintained with the tanks. This elevated temperature is required to ensure proper curing of the epoxy coating and will also serve to maintain an elevated dew point, thereby precluding rust formation.

Alternatively for Unit 2, if the initial loading of fuel oil will occur more than one week after the final curing of the epoxy lining, the uncoated tank interior surfaces will be protected from corrosion by an application of preservative oil that will be inspected periodically and recoated if required. Prior to the initial loading of fuel oil, any accumulation of preservative oil along the top centerline and bottom vertical foot of the tank will be removed and wiped clean. The preservative oil remaining in the tank, although soluble in the fuel oil, will not cause the 40,000 gallon initial loading of fuel oil to exceed any ASTM D975 (1981) limit required of the diesel fuel oil.

If any particulates should accumulate in the fuel oil after the tanks are filled, from either rust or peeling of the epoxy coating, the transfer system is designed to prevent their entry into the diesel generator fuel oil injectors. The following points are applicable:

1. A basket strainer is provided on the fill connection to prevent solid particles or debris from entering the fuel oil storage tanks. In addition, the bottom of the tank is provided with a 36 inch diameter sump located 6 feet away from the tank fill nozzle. Sediment and water collected in this sump will not be stirred when the tank is replenished because agitation of the fuel oil would occur only underneath the fill nozzles.

2. The fuel oil transfer pumps take suction from a point 11 inches above the tank bottom. Because most particulates will settle to the bottom, significant ingress of particulates is not expected to occur.

3. The pumps are equipped with a suction strainer to prevent the entrance of any large particles or debris.

4. The pumps are of a sump pump design in which the casing and impeller are submerged and located directly in the pump suction. Liberal tolerances exist between the casing and impeller such that any particulates that may pass through the suction strainer will not damage the internals.

5. Any particulates passing through the pump would be trapped by one of the five duplex filters or strainers located between the fuel oil transfer pump discharge and the diesel engine. As shown on drawing M-20, basket strainers are located on the day tank supply piping and on the suctions of both the engine-driven fuel oil pump and the dc motor-driven fuel oil pump. Line filters are located on the discharge of both of these pumps to provide fine filtration of the fuel immediately prior to admission to the injectors.

6. Each of the above duplex filters and strainers is equipped with differential pressure indicators and alarms to notify the operators of impending clogging. The basket strainers will alarm when the pressure differential exceeds 3 psid. Due to the higher pressure drop required for fine fuel filtration in the line filters, the alarms on these filters will not sound until the pressure drop exceeds 13 psid. Both of these settings will provide ample time for the operator to manually switch to the other filter element before the operability of the diesel generators is compromised.

The above described system and procedures will provide sufficient protection against internal corrosion of the tanks due to condensation, while also ensuring that sediment turbulence and other long-term storage concerns will not result in degraded quality of the fuel oil.

Cathodic protection is also provided around the fuel oil storage tanks.

Diesel Oil Transfer Pumps - One diesel oil transfer pump is provided for each storage tank. The pump is connected to the pump support flange such that the pump casing and impeller are submerged. The diesel oil transfer pump discharge lines run directly to the diesel oil day tanks. Because the capacity of the transfer pump is greater than the fuel oil consumption of the diesel engine, the pump can supply fuel oil for the diesel and simultaneously increase the inventory of the day tank. The fuel oil transfer pumps are started and stopped automatically by day tank level switches. The pumps can also be operated manually at the local engine control panel by control switches. Diesel fuel oil transfer pumps are powered by the Class 1E ac power system from the same electrical division as the diesel generator it supplies. A suction strainer is provided at the pump inlet and a duplex strainer is provided in the pump discharge line.

Diesel Oil Day Tanks - One 850 gallon capacity diesel oil day tank is provided for each diesel generator. Each tank is located in a separate compartment within the diesel generator enclosure that is capable of containing a liquid volume in excess of the day tank capacity.

The tanks are provided with connections for filling, overflow, vents, drains, supply and return piping, and with access for tank inspection. Each tank has capacity for sufficient fuel oil for a minimum of 3½ hours of continuous diesel generator operation at full load. In the unlikely event of a failure in one of the supply systems, the associated day tank low level alarm will annunciate when the fuel oil remaining in the tank will provide approximately one more hour of full load operation so that the operator can take corrective action to prevent loss of the diesel.

The day tanks are vented to outside the diesel generator enclosure through a flame arrestor and are protected against overpressure and vacuum conditions. Their location provides a slight positive pressure at the fuel pumps. Overflow lines from the tank return excess fuel oil to the storage tank.

Diesel Generator Fuel Pumps - Each diesel generator is provided with two positive displacement fuel oil pumps, one diesel engine-driven and one dc motor-driven. Relief valves and line filters are furnished on the discharge of each pump. The pumps, valves, and associated piping are all located on the diesel engine skid in the diesel generator enclosure.

The diesel fuel pumps take suction from the day tank and pump fuel oil to the injectors on the diesel engine. On remote manual or automatic engine starts, the dc motor-driven pump starts simultaneously with the engine-driven pump when the diesel is started, and shuts off automatically about 10 seconds after the diesel attains a speed above 800 rpm. The dc motor-driven pump is armed to restart automatically 4 seconds after stopping at the end of the starting sequence, should

the fuel oil pressure at the engine-driven pump discharge drop below 10 psig. This provides a backup to the engine-driven pump during operation. When started by a low fuel oil pressure signal, the pump will stop only if the engine receives an emergency stop signal or if the operator places the local pump control switch in the OFF position.

On a local start, the dc motor-driven pump must be operated manually. The automatic restart feature will be armed when the pump start switch is returned to the AUTO position.

The source of power for the dc fuel oil pump motor is Class 1E 125 V dc power system from the respective electrical division of its diesel generator. The operating status of the dc motor-driven pump is indicated by alarms at the local control panel as "DC FUEL PUMP POWER OFF" or "DC FUEL PUMP RUNNING".

Both the dc motor-driven pump and the engine-driven pump supply more fuel to diesel engine than the engine can consume. The excess fuel is returned to the day tank.

Associated Piping - The diesel generator fuel oil system piping is all made of carbon steel except manufacture-supplied on-skid engine tubing, which may be steel, steel with copper braze, or other materials according to the specific application. The piping is shown on drawing M-20. The diesel oil supply and return lines of the four diesel generators associated with each unit are cross-connected so that any one of the diesel engines can be supplied from any one of the diesel oil storage tanks. The piping between the diesel oil storage tank and the diesel generator enclosure is buried. Corrosion protection for this underground piping is provided by protective wrapping and coating. Cathodic protection is also provided. All valves are located in a valve pit at the diesel oil storage tank or within the diesel generator enclosure. Basket strainers are provided in each transfer pump discharge line to prevent solid particles or debris from entering the day tanks.

Dirty Fuel Oil Tank - Each diesel has a small tank mounted on its skid to collect any leakage from the injector area or from a drip pan beneath the blower. Tank volume is approximately 5 gallons. It has a sight glass and a high level switch that initiates an alarm on the local control panel and a common alarm in the control room.

9.5.4.3 Safety Evaluation

The diesel generator fuel oil system is designed to seismic Category I requirements as defined in Section 3.7. The components of the system are located in the diesel oil storage tank valve pit or the diesel generator enclosure, which are designed to seismic Category I requirements as discussed in Section 3.8.

Protection against hurricanes, tornadoes, and missiles is provided by locating system components either underground or within the seismic Category I diesel generator enclosure.

Evaluation of the diesel generator fuel oil system with respect to the following areas is discussed in separate sections as indicated:

a.	Protection against wind and tornado effects	Section 3.3
b.	Flood design	Section 3.4
c.	Missile protection	Section 3.5

d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11
f.	Fire protection	Section 9.5.1

A single above ground fill connection to the fuel oil storage tanks is provided to supply each tank through an underground common header, as shown in drawing M-20. Each tank is equipped with a separate above ground vent line. Both the fill connection and the vent lines extend only a minimal distance above the ground. In the unlikely event of damage by tornado missiles, the following design features are present in the system to allow continued operation of the diesel generators:

a. Alternate paths for filling and venting each tank are available (e.g., manhole of the tank)

b. The vent line for each tank is backed up by a separate vacuum relief valve located within the tank valve pit. The valve pits are sealed; however, analyses have been performed which indicate that there is sufficient air mass within the 1880 ft^3 valve pit to relieve tank vacuum for a period of time in excess of 18 hours before the tank level drops below a point where the minimum required pump NPSH is not available. In the event of crimping of the above ground tank vent lines, steps will be taken to repair the vents or open the valve pit manhole covers within this time period.

c. Cross-connections are provided in the fuel oil supply and return lines to each diesel to allow any diesel to be supplied from any storage tank.

   As an example, if the storage tank A fill or vent lines were damaged so as to make the tank unavailable, and diesel generator B was not available, the following manual operator actions would be taken (drawing M-20): valves 1045B and 1101A would be closed and valves 1080A, 1080B, 1100A and 1100B would be opened. The B transfer pump would be started and would pump to the A day tank. When the A day tank is full, the full flow overflow line would return the diesel oil to the B storage tank. As noted in Section 9.5.4.2, the day tank has capacity for sufficient fuel for 3½ hours of continuous diesel generator operation at full load; sufficient fuel oil for approximately one hour of full load operation remains at the point where the low level alarm annunciates.

   Therefore, credible tornado missile damage to the fill line or a vent line would not affect the safe shutdown of the plant.

Exposure of the fuel oil system outside the diesel generator enclosure to ignition sources is minimized by underground burial of the piping and storage tanks. The diesel generator day tank is separated from ignition sources by locating the tank in a separate compartment in the diesel generator enclosure. All fuel oil system piping inside the diesel generator enclosure is located in a pipe trench below the diesel generator elevation except for a short run of piping between the day tank and the fuel oil pumps located on the diesel generator skid (drawings M-145 and M-146).

The total capacity of the underground diesel generator fuel oil storage tanks is sufficient for seven days of continuous operation of the diesel generators while supplying post-accident power requirements.

The diesel generator fuel oil system is designed so that failure of any one component results in the loss of fuel supply to no more than one diesel generator. Physical redundancy of active components in each diesel generator fuel oil system is not provided. An independent fuel oil supply train is provided for each diesel generator. Each transfer pump is powered from the Class 1E bus served by its respective diesel generator. Failure of one pump or diesel generator will not affect the operability of any component in another train. Only a maximum of three of the four diesel generators supplied for each unit are required during a LOOP and/or LOCA to meet the safeguard load requirements. Therefore, failure of any one component of the diesel generator fuel oil system does not preclude safe shutdown of the plant following a LOOP and/or LOCA. Table 9.5-4 gives a failure mode and effects analysis of the system.

Any combination of three-out-of-four divisions (EDGs) is acceptable for a single failure. However, for ECCS requirements (as stated in paragraph 6.3.1.1.2), an EDG operable configuration of 2 out of 4 is also acceptable.

The diesel oil transfer and return lines of the four fuel oil systems associated with each unit are cross-connected so that any one of the diesel engines can be supplied from any one of the diesel oil storage tanks, if required. These cross-connections are valved and require manual operation.

An adequate supply of diesel fuel oil is readily available from a large number of suppliers in the Philadelphia metropolitan area, with one day truck deliveries available. The plant is located one mile south of Route 422, a major highway which runs west into Reading and east into Philadelphia. Route 422 has easy accesses to the Pennsylvania Turnpike and the Schuylkill Expressway (Route 76). Under extremely unfavorable environmental conditions, these major highways should be available to provide access to the plant. Truck delivery via these routes would allow fuel oil to be supplied to the site. If necessary, the fuel oil will be obtained from a company located in Pottstown (3 miles from the plant).

Each diesel oil day tank is provided with a temperature switch that shuts off the diesel oil transfer pumps on high temperature. This prevents the pumping of fuel oil to the day tank in case of a fire in the day tank. Diesel fuel oil protection against low temperatures is achieved by enclosing the equipment in heated enclosures and by burying near or below the frost line.

9.5.4.4 Tests and Inspections

The diesel generator fuel oil storage and transfer system was preoperationally tested in accordance with the requirements of Chapter 14 and is periodically tested in accordance with the requirements of Technical Specifications. Periodic testing includes fuel oil sampling to ensure that the fuel quality requirements of the Technical Specifications are met. If, as a result of this testing, it is determined that unacceptable biogrowth is present in the tank, the diesel generator will be declared inoperable and the corrective action discussed in Section 9.5.4.2 paragraph d taken. The fuel oil storage tanks are provided with concrete manholes that permit access to the tank connections for periodic inspection of the tanks, pumps, and instrumentation. The day tanks, fuel pumps, and associated piping, strainers and valves are in the diesel generator enclosure and are accessible for inspection during testing and operation.

In addition to the Technical Specifications surveillance testing program, a comprehensive instrumentation maintenance program will be performed in conjunction with the diesel generation

inspection/ overhaul. This program will be based on the recommendations of the equipment vendor and operational experience.

9.5.4.5 Instrument Applications

Local and remote indicators, alarms, and pressure relief valves are provided to monitor the system process and protect system components.

The following functions are indicated locally:

a. Storage tank level

b. Transfer pump discharge pressure

c. Transfer pump discharge basket strainer upstream and downstream pressure

d. DELETED

e. Day tank level

f. Day tank temperature

g. Fuel pump suction basket strainer differential pressure (2)

h. Fuel pump discharge filter upstream and downstream pressure (2)

In addition, the storage tanks have dipsticks, and the dirty fuel oil tank has a sight glass.

The following functions are alarmed at the local engine control board and at a common trouble alarm in the control room:

a. Fuel oil pressure low

b. Fuel oil high differential pressure across fuel pump inlet duplex strainers

c. Fuel oil high differential pressure across fuel pump outlet duplex filters

d. Day tank low/high levels

e. Fuel oil high differential pressure across transfer pump discharge duplex strainers

f. Day tank high temperature

g. Dirty fuel oil tank/drip pan high level

The fuel oil storage tank low/high levels are alarmed in the control room only.

The following interlocks are provided on the diesel generator fuel oil system:

a. The day tank high temperature switch shuts down the transfer pump if a fire should occur in the day tank. This will cut off the fuel oil supply to the day tanks.

b. The diesel oil transfer pumps are started and stopped automatically by day tank level switches.

c. The diesel generator emergency stop switch signal overrides the dc auxiliary fuel oil pump run signal to ensure pump shutdown in the event of diesel generator engine shutdown.

Testing and maintenance of the system are discussed in Sections 17.2.2.4 and 17.2.2.6.

9.5.5 DIESEL GENERATOR COOLING WATER SYSTEM

The diesel generator cooling water system provides cooling water to the station diesel generators and is safety-related except for the electric circulating pump motor which is classified as non-safety related.

9.5.5.1 Design Bases

The design bases of the diesel generator cooling water system are as follows:

a. To cool the engine cylinder jackets, the combustion air, and the lubricating oil sufficiently to permit continuous operation of the diesel generator at full load.

b. To maintain the jacket coolant in a warmed condition while the diesel engine is in normal standby status to promote starting.

c. To ensure that the single failure of any active component will not affect the operation of more than one diesel generator.

d. To remain functional during and after an SSE.

e. To permit testing of active system components during plant operation.

f. To withstand wind, tornadoes, floods, and missiles.

The diesel generator cooling water system is designed to seismic Category I requirements or seismic category IIA as described in Section 3.2.2.d. The quality group classification and corresponding codes and standards that apply to the design of the system are discussed in Section 3.2.

All piping and equipment has been designed to withstand seismic accelerations and operating loads, regardless of design code. The manufacturer has developed a highly reliable engine piping system over the 44 years that the design of this basic engine has been in use.

9.5.5.2 System Description

The diesel generator cooling water system consists of two separate cooling loops: the jacket water cooling loop and the air cooler coolant loop. These loops are shown schematically in drawings M-20. Each loop is cooled by the ESW system discussed in Section 9.2.2. The general arrangement of the diesel generator system is shown in drawings M-145 and M-146. The lube oil cooler coolant loop is discussed in Section 9.5.7.

9.5.5.2.1 Jacket Water Cooling Loop

During operation, the jacket water cooling loop circulates treated cooling water that cools the diesel generator cylinder jackets under ambient conditions which are discussed in Section 9.4.6. The jacket water cooling loop consists of the following:

a. An expansion tank

b. An engine-driven jacket water pump

c. A motor-driven circulation pump and an electric heater to keep the engine warm during shutdown periods

d. An automatic thermostatic control valve

e. A shell and tube heat exchanger to dissipate the heat from the jacket water (shell side) to ESW (tube side)

f. Alarms, trips, indicators, valves, and piping

The jacket water cooling loop component design parameters are given in Table 9.5-5. The diesel generator ESW inlet temperature used for design (95°F) is based on the maximum post-LOCA ultimate heat sink temperature (Section 9.2.6). The use of this temperature in conjunction with appropriate fouling factors results in a conservative design because the seasonal variation in the ultimate heat sink ambient temperature ranges from 32°F to 88°F.

The jacket water cooling system is designed to completely fill without special venting provisions. System fill is performed in accordance with approved plant procedures. To ensure that all components and piping are maintained full of water, an expansion tank is connected to the pump suction piping. The expansion tank also serves the air cooler coolant loop. The expansion tank outlet nozzle is located approximately 8 feet above the top of the diesel engine.

The expansion tank is located at el 235'-1", and has a volume of 80 gallons. The diesel generator is located at el 217'. The difference in level between the expansion tank and the pump suction provides a positive static suction head for the pump. The pump has a rotary mechanical seal to prevent excessive leakage of water along the pump shaft. Normal maintenance of valves and system components in accordance with Section 17.2.2.6 will ensure that leakage rates will be kept below the amount requiring tank makeup within a 7 day period. Operational experience has shown that this is not a problem for the model of diesel generator used at LGS.

The need for addition of cooling water to the expansion tank is indicated by a local low level alarm and a common control room trouble alarm. A permanently installed, manually operated makeup water system is provided. In addition, coolant can be added through the tank water treatment connection if the normal makeup system is unavailable.

The engine-driven jacket water pump discharges the cooling water through the engine passages and the engine jacket header, and delivers it to a three-way thermostatically controlled valve. This valve directs the flow through or around the jacket water heat exchanger and back to the pump suction. Short-circuiting via the keep-warm system (described below) will be minimized by the line sizing of the keep-warm system (1½ inches) compared to the main loop (5 inches).

During engine shutdown periods, a centrifugal circulation pump, driven by a 1 hp ac motor, is designed to circulate the jacket coolant at a rate of 40 gpm through the 15 kW electric heater, the engine-driven pump, the jacket coolant piping, and the cylinder liner jackets. A branch line is provided to supply heated coolant to the air cooler coolant loop to keep it warm as an aid to quick starting.

The circulation pump runs continuously whenever the engine is shut down and maintains adequate water flow for keep-warm conditions when the engine is not operating. Under the control of the coolant heater thermostat, the heater cycles to maintain the keep-warm temperature of the coolant above 110°F. A relief valve, set at 40 psi, is provided in the coolant discharge line from the heater to protect the heater if the coolant flow is blocked and the heater fails to shut off automatically. A low coolant temperature alarm switch, set at 90°F decreasing, is provided in the coolant discharge line from the jacket header to give an alarm signal to the operator in the event of low coolant temperature (heater failure). When the engine is in operation, the recirculation is automatically stopped. The jacket coolant heater is electrically interlocked to the circulating pump motor starter so that the heater cannot operate unless this pump motor is in operation.

The cooling water in the closed cooling system is treated in accordance with current EPRI closed cooling water chemistry guidelines (E-0005-VC-00001).

The fouling factor on which the jacket water and air cooler coolant loop heat exchanger duties are based, as well as the ESW inlet design temperatures for these heat exchangers are provided in Tables 9.5-5 and 9.5-6. To preclude long-term corrosion and organic fouling in the diesel engine cooling system, demineralized water is used along with corrosion and biofouling control chemicals recommended by a qualified water treatment vendor and meeting all requirements of the engine manufacturer. Treatment compounds are evaluated for compatibility with all materials prior to being used in the coolant loops.

Antifreeze compounds will not be used in the jacket water and air cooler coolant loops due to the potential for degraded heat exchanger performance. In lieu of antifreeze, engine temperatures will be maintained by compartment heating, jacket water heating, and lube oil heating. Compartment temperatures are normally maintained above 65°F. If compartment temperatures should drop below 55°F, the condition will be alarmed in the control room and the operators will re-establish normal heating or provide temporary heating. If low temperatures continue to persist such that the keep-warm systems cannot maintain the water temperature at >90°F and/or lube oil temperature at >105°F, the common control room trouble alarm and additional local alarms will indicate the condition. The operators will then start the diesel generators to ensure that they were maintained in ready condition. Procedures for low load operation of the diesels will be followed (i.e., loading at a minimum of 50% power for 1 hour out of 12 hours at low load operation).

Sufficient capacity in each diesel generator cooling water system is provided so that the unit may be started from the standby condition and operated at full load. This operation can occur for at least 3 minutes without service water flow through the coolant heat exchanger before abnormally high temperature is reached.

9.5.5.2.2 Air Cooler Coolant Loop

The air cooler coolant loop is a closed-loop that provides cooling for the diesel generator combustion air and consists of the following:

a. An air cooler

b. An engine-driven air cooler water pump

c. An automatic thermostatic valve

d. An air cooler coolant heat exchanger

e. Alarms, indicators, valves, and piping.

The air cooler coolant loop design parameters are given in Table 9.5-6.

The engine-driven air cooler water pump discharges the treated cooling water through a three-way thermostatically controlled valve that directs the flow through or around the air cooler coolant heat exchanger. The water quality of the treated cooling water is the same as discussed in paragraph 9.5.5.2.1. The cooling water is then directed back to the engine where it goes through the air cooler and back to the pump suction. A constant water inventory is maintained in the system by an expansion tank that is connected to the pump suction piping. The expansion tank (Section 9.5.5.2.1) also serves the jacket water cooling loop. The air cooler and the air cooler coolant heat exchangers are shell and tube heat exchangers served by a closed-loop cooling water system and the ESW system, respectively.

9.5.5.3 Safety Evaluation

The diesel generator cooling water system is designed so that failure of any one component results in the loss of no more than one diesel generator. Since only three of the four diesel generators provided for each unit are required, failure of any one component of the diesel generator cooling water system does not preclude safe shutdown of the plant following a LOCA and/or a LOOP.

Any combination of three-out-of-four divisions (EDGs) is acceptable for a single failure. However, for ECCS requirements (as stated in paragraph 6.3.1.1.2), an EDG operable configuration of 2 out of 4 is also acceptable.

Protection against hurricanes, tornadoes, and missiles is provided by locating system components within the diesel generator enclosure. Each diesel generator cooling water system is completely enclosed with its respective diesel in a concrete, missile-protected cell that is isolated from the other units.

The diesel generator cooling water system is designed to seismic Category I requirements as defined in Section 3.7 or seismic Category IIA as described in Section 3.2.2.d. The system components are housed with their respective diesel generator unit in the diesel generator enclosure that is designed to seismic Category I requirements as discussed in Section 3.8.

Evaluation of the diesel generator cooling water system with respect to the following areas is discussed in separate sections as indicated:

a.	Protection against wind and tornado effects	Section 3.3
b.	Flood design	Section 3.4
c.	Missile protection	Section 3.5

d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11
f.	Fire protection	Section 9.5.1

9.5.5.4 Tests and Inspections

The diesel generator cooling water system was preoperationally tested in accordance with the requirements of Chapter 14 and is periodically tested in accordance with the requirements of the Technical Specifications. Operability of the cooling water system is checked during periodic testing of the diesel generator.

In addition to the Technical Specifications surveillance testing program, a comprehensive instrumentation maintenance program will be performed in conjunction with the diesel generation inspection/ overhaul. This program will be based on the recommendations of the equipment vendor and operational experience.

9.5.5.5 Instrument Applications

Local and remote indicators, switches, alarms, and pressure relief valves are provided to monitor the system's processes and protect systems components. When an alarm is received, the operator will investigate and initiate appropriate corrective action.

The following are provided to control system processes:

a. Jacket cooling water temperature switch - One temperature switch controls the standby heater. The switch is located downstream of the heater and is set to maintain a minimum jacket water temperature of 110°F.

b. Air cooler temperature controller - An air cooler temperature controller in the air cooler coolant loop (drawings M-20) will maintain the combustion air temperature below 145°F via an air operated three-way valve which modulates the air cooler coolant flow through the air cooler heat exchanger.

c. Jacket water heat exchanger thermostatically controlled three-way bypass valve - This valve is set to maintain the jacket water system temperature between 155°F and 170°F during normal operation.

d. Engine Run Switch (jacket coolant pressure switch) - One pressure switch is provided on the engine-driven jacket water pump discharge. This switch operates at the coolant pressure corresponding to an engine speed of 800 rpm to provide a backup to the tachometer relay for actuation of the alarm delay, low speed, and high speed relays (Section 9.5.6.2).

The following functions are alarmed at the local engine control board and at a common trouble alarm in the control room (Section 8.3.1.1.3.10):

a. Jacket cooling water expansion tank low level - Operator action is required to open the manually operated fill valve and restore the normal water level in the expansion tank.

b. Jacket cooling water high temperature - Three switches are provided. Any one switch will initiate an alarm, and any two will shut down the diesel via the shutdown relay, except during an emergency. The switches operate to alarm at 195°F increasing and to reset at 185°F decreasing.

c. Jacket water coolant low temperature (heater failure) - One coolant low temperature switch is provided. The switch operates to alarm at 90°F decreasing.

d. Jacket cooling water low pressure - Three switches are provided. Any one switch will initiate an alarm, and any two switches will shut down the diesel via the shutdown relay, except during an emergency. The switches operate to alarm at 16 psi decreasing and reset at 18 psi increasing.

e. Jacket water circulating pump failure - The standby jacket water circulating pump motor is provided with a thermal overload protective device. Actuation of this device will shut down the pump and initiate an alarm.

f. Air cooler coolant low pressure - One switch is provided downstream of the air cooler heat exchanger. The switch operates to alarm when the coolant pressure is at 10 psi decreasing and resets at 13 psi increasing.

The following signals trip the diesel engine and its related generator circuit breaker except during emergency (LOCA) operation as described above:

a. Jacket cooling water high temperature

b. Jacket cooling water low pressure

9.5.6 DIESEL GENERATOR STARTING SYSTEM

The diesel generator starting system supplies sufficient compressed air at sufficient pressure to initiate an engine start so that within 10 seconds after receipt of the start signal, the diesel generator is ready to accept load. The diesel generator starting system is safety-related except for the components and piping that have been downgraded as discussed in Section 3.2.2.d.

9.5.6.1 Design Bases

The design bases of the diesel generator starting system are as follows:

a. To initiate an engine start so that within 10 seconds after receipt of the start signal the diesel generator is ready to receive load

b. To remain functional during and after an SSE

c. To ensure that the single failure of any active component does not result in the loss of the starting function of any other diesel generator

d. To allow testing of active components of the system during plant operation

e. To withstand wind, tornadoes, floods, and missiles

The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the diesel generator starting system are discussed in Section 3.2.

All piping and equipment has been designed to withstand seismic accelerations and operating loads, regardless of design code. Portions of the Air Start System have been downgraded to Seismic Category IIA as shown on drawing M-20. These portions were designed and installed to Seismic Category I standards, however, they do not perform a safety related function. The manufacturer has developed a highly reliable engine piping system over the 44 years that the design of this basic engine has been in use.

9.5.6.2 System Description

Each diesel generator is equipped with two independent air starting systems. Each consists of a reciprocating air compressor, one air receiver, associated piping, valves, filters, strainers, instrumentation and controls. Each compressor is driven by a 20 hp motor connected to a 480 V Class 1E ac power supply. The starting system is shown in drawing M-20, and major component design parameters are listed in Table 9.5-7. The diesel generator general arrangement is shown in drawings M-145 and M-146.

In automatic operation, each of the motor-driven air compressors is controlled by a pressure switch to maintain the pressure in the air receivers above 225 psig. The compressors may be run manually. The air compressors are sized such that each compressor can fully charge its air receiver in no more than 30 minutes. Each air receiver was tested and provides at least five starts (in under ten seconds) of the diesel engine when fully charged. Each air receiver is provided with relief, drain, check, and shutoff valves to permit any receiver to be removed from service, repaired, and placed back in service, without affecting the air compressor or the other air receiver. Some diesel air receivers include a double valved normally closed connection which may be used to provide a backup air supply for certain MSRV's in the event PCIG is not available.

Each of the two air start trains consists of one solenoid-operated air start pilot valve, one manually operated air start pilot valve, one solenoid operated air vent valve, and one air start valve which admits the starting air to the engine-mounted air distributors and air start header.

Each air start distributor consists of a rotating cam that mechanically activates the correct pilot air valves to match the firing sequence. The pilot air valves admit control air to the pistons of the air start check valves, forcing them open to allow the starting air in the header to enter the cylinders in the proper sequence (drawing M-20).

Each of the two air start trains also supplies air to the Aft Main Bearing Lube Oil Booster, and to the Governor Actuator Booster. Either train may supply control air to the Combustion Air Temperature Control System.

The diesel engine start sequence is as follows:

A start signal energizes both the start relay and the cranking time control relay. The start relay energization will close and vent the air start solenoid valves on both trains. This causes the air start valves to admit air to the air distributors and thence to the proper cylinders, which

causes the engine to start rotating. Simultaneously, the air vent solenoid valves will be closed to prevent the loss of air between the air start valves and the distributors.

Normally at this point, the engine fires and the engine speed increases past 200 rpm, at which point the tachometer relay energizes the low speed relay to perform the following:

a. Disarm the start and cranking time control relays

b. De-energize the standby lube oil and jacket water keep- warm systems, the prelube pump, and the generator space heater - all via an auxiliary relay

c. Initiate generator field flashing

d. Enable the governor and voltage regulator setpoint controls to be manipulated for parallel operation (on a non-emergency start)

e. Energize the combustion air temperature control pilot solenoid valve

f. Enable automatic start of the diesel generator enclosure ventilation exhaust fan

g. Enable automatic start of the associated ESW pump (after a time-delay).

At 800 rpm, the tachometer relay energizes the alarm delay relay and the high speed relay that backs up the low speed relay for the functions listed in (a) and (e) above. The alarm delay relay picks up 10 seconds later to enable the diesel generator protective trip circuits and de-energize the dc auxiliary fuel oil pump. By this time, the engine will be up to operating speed, and all pressures will be up to operating values, so no alarm or shutdown will occur. The energization of the alarm delay relay and the high speed relay by the tachometer relay is backed up by parallel closure of the engine run switch (jacket coolant pressure switch), as discussed in Section 9.5.5.

An unsuccessful engine crank cycle is measured by the cranking time control relay which aborts the start attempt if 200 rpm is not reached within 7 seconds following the start signal. The system is designed for manual operation in the event of automatic starting air solenoid valve failure.

The following design features are provided to minimize concern over rust and moisture effects:

a. To prevent rust, none of the system pipes, air receivers, or filters are made of carbon steel.

b Filters are mounted upstream of the air start and vent solenoid valves. The filter elements are made of microfibrous material (not paper) from which coalesced liquid will drain into the bowl. The bowls are equipped with drainage provisions and will be drained periodically.

c. The design and construction of the Grove Flexflo air start valves used in this system is such that the presence of rust, other foreign particles, or liquids does not cause the valve to stick.

d. Drain connections are provided on the air receivers for removal of collected condensation.

e. Wye strainers are mounted upstream of the air start valves to remove any solid particles entrained by the air flow.

To prevent formation of rust particles in the starting system, none of the piping, filters or air receivers are constructed of carbon steel. The only components in the air start system fabricated of carbon steel are the bodies of the air start valves, the bodies of the air distributor and pilot air valve assemblies, and the valve poppet within the air start check valve. This is not of concern for the following reasons:

a. The moving components of the air distributors and the pilot air valves that are exposed to starting air are made of copper, bronze, or stainless steel. The bodies of the air start check valves are bronze. These components are all oil lubricated from the engine crankcase.

b. The air start valves consist of the valve body, the core, and a cylindrical diaphragm that completely isolates the starting air from the body. The core is provided with electroless nickel coating to prevent rusting.

Any entrained solid particles or liquid droplets are prevented from reaching critical system components by air strainers or filters. Drain connections are provided on the air receiver for draining off any collected condensate. The air start valves are not susceptible to valve sticking due to the presence of any foreign particles by virtue of their design and construction.

Administrative controls will be instituted to ensure that the air receivers will periodically be drained as recommended by the manufacturer.

Any oil droplets or vapors that may be present in the air leaving the compressors will condense and settle in the nominal 285 gallon air receivers and will be removed upon draining. The air receivers will return to the diesel compartment ambient temperature shortly after charging has been completed. If a small amount of oil should be removed from the receivers during the starting sequence, it would be of no consequence because:

a. Start and vent solenoid valves are protected from liquids by the filters described above.

b. Air start valves are not susceptible to liquid-caused problems as discussed above.

c. All engine-mounted components downstream of the air start valves are designed for and require oil lubrication.

The local control boards for the diesel generators contain control switches, auxiliary relays, and electrical equipment associated with the generator system. The local control panel is constructed of steel with continuously welded seams. All doors are gasketed and latched. The doors are louvered to allow ventilation of internally generated heat. The electrical relay and terminal box is totally enclosed and has gasketed doors. The raceway entrances to all electrical enclosures are sealed to prevent the entrance of dust or water, thus preventing the accumulation of dust on electrical control components. The contacts for the relays and switches have internal contact surfaces, and many are also enclosed with dust covers.

The motor control centers in each diesel generator cell are NEMA type 1, enclosed assemblies. All doors and bolted plates are gasketed. Additionally, the motor control centers are capped with a drip pan that prevents water, and dirt, from entering the enclosure.

9.5.6.3 Safety Evaluation

Safety-related components (including supporting structures) of the diesel generator starting system are designed to seismic Category I requirements as defined in Section 3.7. The system is located in the diesel generator enclosure that is designed to seismic Category I requirements as discussed in Section 3.8.

The diesel generator starting system is designed so that each diesel generator has an independent starting air system and the failure of one active component does not result in the loss of starting air to any other diesel generator. Only three of four diesel generators, for each unit, are required during a LOCA and/or LOOP to meet the safeguard load requirements. Therefore, failure of any one component of the diesel generator starting air system does not preclude safe shutdown of the plant following a LOCA and/or a LOOP. See Table 9.5-8 for a failure mode and effects analysis of the system.

Any combination of three-out-of-four divisions (EDGs) is acceptable for a single failure. However, for ECCS requirements (as stated in paragraph 6.3.1.1.2), an EDG operable configuration of 2 out of 4 is also acceptable.

Each diesel generator unit is protected against the effects of natural phenomena such as tornadoes, hurricanes, and floods. Evaluation of the diesel generator starting system with respect to the following areas is discussed in separate sections as indicated:

a.	Protection against wind and tornado effects	Section 3.3
b.	Flood design	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11
f.	Fire protection	Section 9.5.1

The starting air compressors are tripped during a LOCA; however, adequate compressed air for each diesel is stored in its associated air receivers. Each air start system holds sufficient air to start the diesel five times without compressor assistance.

As shown on drawing M-20, each compressor charges its receiver through a 1 inch line. A smaller (½ inch) line also connects from the air receiver pressure boundary. The following control devices are located at the compressor skid:

a. Pressure switches that control compressor start/stop operation; these are set to maintain receiver pressure above 225 psig.

b. Compressor unloading valves - Receiver pressure is supplied to the hydraulic unloader and unloader valve diaphragm actuator. During startup, the unloading valves hold the compressor suction valves open to prevent pressurization of the

cylinders until the compressor achieves rated speed because the available motor torque is not sufficient to accelerate the compressor underload.

c. Hand switches that are used to place the compressor in "Off", "Auto", or "Run".

Because a failure of either the pressure switch, sensing line, unloader, or actuator could result in a loss of air receiver pressure, these compressor components serve a passive safety-related function to maintain air receiver pressure boundary integrity. Therefore, these compressor components and their supporting structure have been designated as Q-passive and seismic Category I.

Air consumption and associated air receiver pressure drop are permitted only by the start and the cranking time control relays as described in the starting sequence (Section 9.5.6.2) and by the control air supply to the Combustion Air Temperature Control System. During the factory tests, an engine was started an average of ten (10) times from a single receiver at 250 psig. Successful starts are not possible when the air receiver pressure drops below 80 psig.

Two solenoid air start valve trains are installed on each diesel. Each train supplies air to half of the cylinders. If one valve train fails, the other valve train supplies sufficient starting air. In addition, manual air start valves are supplied on both air start valve trains. Failure of the compressors is indicated by an air receiver low pressure alarm and a common trouble alarm in the control room. This alarm is initiated by the receiver pressure falling below 200 psig, and is reset when the pressure increases above 215 psig. An operator will investigate the control room alarm and institute corrective action or declare the diesel inoperable. No harmful effects to the diesel engine will occur even if no operator action is taken.

9.5.6.4 Tests and Inspections

The diesel generator starting system was preoperationally tested in accordance with the requirements of Chapter 14 and is periodically tested in accordance with the requirements of Technical Specifications. Operability of the starting system is checked during periodic testing o the diesel generator.

9.5.6.5 Instrument Applications

Local indicators and controls, local and remote alarms, and pressure relief valves are provided to monitor the system process and protect the system components.

The following function is alarmed at the local engine control board and at a common trouble alarm in the control room:

a. Starting air pressure low

The following automatic function is provided:

a. The compressor associated with each receiver will start and stop to keep the receiver fully charged.

The following local indication is provided:

a. Receiver pressure

b. Starting air pressure

Pressure relief valves are provided on each of the air receivers and on the outlet of each air compressor.

9.5.7 DIESEL GENERATOR LUBRICATION SYSTEM

The diesel generator lubrication system provides essential lubrication to the components of the diesel generators. The system is safety-related except for the electrical circulating pump motor and the pre-lube pump motor which are classified as non-safety related.

9.5.7.1 Design Bases

The diesel generator lubrication system is designed to perform the following functions:

a. To supply, during diesel generator operation, a continuous flow of oil to all surfaces requiring lubrication at controlled pressure, temperature, and cleanliness

b. To warm and circulate the oil in normal standby status to promote diesel starting and prevent extreme lube oil viscosities

c. To ensure that the failure of any single active component does not affect the operation of more than one diesel

d. To remain functional during and after an SSE

e. To withstand wind, tornadoes, floods, and missiles

f. To permit testing of active system components during plant operation

The diesel generator lubrication system is designed to seismic Category I requirements or seismic category IIA as described in Section 3.2.2.d. The quality group classification and corresponding codes and standards that apply to the design of the system are discussed in Section 3.2.

All piping and equipment has been designed to withstand seismic accelerations and operating loads, regardless of design code. The manufacturer has developed a highly reliable engine piping system over the 44 years that the design of this basic engine has been in use.

9.5.7.2 System Description

The diesel generator lubrication system consists of an oil sump in the engine frame, a suction strainer, an engine-driven lube oil pump, a filter, an oil cooler, a dual element strainer, an ac motor-driven prelube pump, a recirculation pump, an electric immersion heater, and a lube oil makeup tank. Major system design parameters are shown in Table 9.5-9. The diesel generator general arrangement is shown in drawing M-145 and M-146. A schematic diagram of the lubrication system is shown in drawing M-20. The components are discussed below.

The oil sump is a gravity collection-type enclosed in the engine crankcase, complete with a dipstick and a low level switch to provide an alarm. The lube oil sump level is maintained during both operation and engine shutdown in accordance with station procedures by manual operation of the lube oil makeup tank outlet valve. The input to this level control is gravity fed from the lube oil makeup

tank, which is a vertical cylinder of sufficient capacity to supply lube oil for at least 7 days of continuous diesel generator operation.

During diesel generator operation, the lube oil is circulated through the engine by an engine driven lube oil pump. The engine-driven lube oil pump takes suction from the diesel generator sump and delivers the oil through the filter to a three-way thermostatically controlled valve that directs flow through or around the cooler. The oil then flows through a full flow strainer and back to the engine passages.

The filter is sized to ensure continuous full flow operation for a minimum of 7 days, using disposable cellulose cartridges. The filter elements are designed to remove particles down to 25 micron size and to absorb water. The filter is provided with a differential pressure indicator and a pressure switch that initiates an alarm on high differential pressure across the filter. The filters are manufactured with a built in relief valve that will bypass the filter on high differential pressure.

The lubricating oil cooler is a shell-and-tube heat exchanger with a removable tube bundle and floating head design. The tubes may be cleaned without removing any piping.

The strainer is a dual element-type sized to ensure continuous full flow operation. It is equipped with a differential pressure switch that initiates an alarm in the event of a high differential pressure across the strainer.

All pumps are of the positive displacement-type. The engine-driven pump has sufficient capacity to provide all lubricating oil requirements under full load operating conditions. The ac motor-driven prelube pump, fed from a Class 1E 480 V bus, will lubricate all wearing parts prior to a manual start. The circulating pump circulates lube oil from the sump through the electric immersion heater and back to the sump.

The immersion heater is provided to maintain the lube oil temperature at a preset value during standby periods.

There are two methods of manual operation of the diesel generator, local and remote. These are normally used for surveillance exercising. In local manual operation, the operator will start the prelube pump, which will operate for 140-180 seconds and then automatically shut down. The operator will then start the diesel generator. In remote manual operation, the operator will place the switch in START. This will start the prelube pump, which will operate for 3 minutes before an interlock permits the diesel generator to start. On emergency diesel generator start, the prelube pump does not operate because it is not required and would delay the diesel engine start.

There will be a monthly surveillance test on each diesel generator as determined by Technical Specifications. All of these planned engine starts will be preceded with an engine prelube of about 3 minutes. The engine is gradually accelerated to rated speed, synchronized to the grid and slowly loaded. The engines are occasionally run for special tests, routine plant operations and every 6 months run to demonstrate fast start capability.

The power source for the prelube pump motor is a Class 1E bus. The motor-driven circulating pump takes oil from the sump and directs it through the immersion heater and back to the sump to keep the engine in a warm standby mode for quick start operation. This pump recirculates 13 gpm of lube oil and is powered whenever the diesel generator is shut down. A thermostat downstream of the heater controls operation of the heater to maintain a minimum lube oil temperature of 125°F. The power source for both the pump and the heater is a Class 1E 480 V bus, fed from either of two offsite

sources. The switches controlling the lube oil heater and the lube oil circulating pump must both be placed in AUTO or the SWITCH NOT IN AUTO alarm on the local control panel and the D.G. TROUBLE alarm in the main control room will both be annunciated.

Lube oil vapors originating in the upper and lower crankcase compartments are drawn out of the engine by the crankcase evacuation system (drawing M-20). This built-in system maintains a subatmospheric pressure in the crankcase to minimize leakage of oil through the crankcase gaskets. It consists of an oil separator and air ejector connected to the crankcase breather housing. The ejector is operated by compressed air from the scavenging system air receiver (Section 9.5.8.2). The flow of air through the ejector draws crankcase vapors through the separator; the mixture is then carried to the ejector outlet and is discharged into the combustion exhaust outlet piping. The lube oil collected by the separator drains back to the crankcase.

9.5.7.3 Safety Evaluation

The diesel generator lubrication system and the crankcase evacuation system are designed to seismic Category I requirements as discussed in Section 3.7 or seismic category IIA as described in Section 3.2.2.d. The systems are located within the diesel generator enclosure that is designed to seismic Category I requirements as discussed in Section 3.8.

The diesel generator lubrication system is an integral part of the diesel generator. The system meets the single failure criterion in that, if a failure in this system prevents the satisfactory operation of the associated diesel generator, the other three diesel generators will provide adequate power to safely shut down the plant or to mitigate the consequences of the postulated accidents.

Any combination of three-out-of-four divisions (EDGs) is acceptable for a single failure. However, for ECCS requirements (as stated in paragraph 6.3.1.1.2), an EDG operable configuration of 2 out of 4 is also acceptable.

The crankcase evacuation system is an integral part of each diesel engine. It maintains a slight vacuum in the crankcase to minimize leakage of lubricating oil through the crankcase gaskets. It introduces a negligible amount of mass flow into the exhaust gas downstream of the turbocharger. While failure of this system would not directly cause a diesel trip, any abnormality in the engine crankcase that results in a positive pressure of greater than 0.6 inch H_2O, be it a failure of this system or any other, would be alarmed at the local control board and in the control room through the common trouble alarm.

To prevent possible damage or shutdown of a diesel engine during normal exercising from low lube oil, sump low level instrumentation is provided. Setpoints for alarms are sufficient to allow plant personnel adequate time for corrective action. During emergency operation, all lube oil trips are bypassed. Evaluation of the diesel generator lubrication system with respect to the following areas is discussed in separate sections as indicated:

a.	Protection against wind and tornado effects	Section 3.3
b.	Flood design	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with the postulated	

	rupture of piping	Section 3.6
e.	Environmental design	Section 3.11
f.	Fire protection	Section 9.5.1

9.5.7.4 Tests and Inspections

The diesel generator lubrication system was preoperationally tested in accordance with the requirements of Chapter 14 and is periodically tested in accordance with the requirements of Technical Specifications. Operability of the lubrication system is checked during periodic testing of the diesel generator.

The quality of the diesel generator lube oil will be maintained by complying with the surveillance standards set by the Fairbanks Morse Owners Group. The crankcase oil will be laboratory tested for dilution, sediment, and general detergent qualities on approximately six month intervals. Dilution can be suspected when low oil pressure exists, and a blue-gray exhaust smoke may indicate excessive lube oil consumption. Degradation of the oil quality would necessitate lube oil replacement. During periods of continuous operation, the lube oil levels in the lubricating oil sumps will be monitored and there will also be checks of the differential pressures across the oil filter. The strainer is equipped with a D.P. Switch that indicates an alarm in the event of a high D.P. The D.P. across the strainer can be checked indirectly by reading D.P. across lube oil header and pump discharge subtracted from the filter differential pressure. Differential pressure of approximately 15 psi is alarmed at the local annunciator panel and at the common trouble alarm in the control room. Both the filter and the strainer will be cleaned or replaced when the differential pressure exceeds 15 psi, or as the maintenance inspection surveillance dictates. In addition to this monitoring, there will also be local panel alarm indication for high lube oil temperature, low lube oil level, and low lube oil pressure.

9.5.7.5 Instrument Application

Local and remote indicators, alarms, and pressure relief valves are provided to monitor the system's processes and to protect system components.

The following functions are alarmed at the local engine control board and on a common trouble alarm in the control room.

a. Lubricating oil low pressure

b. Lubricating oil high temperature

c. Lubricating oil high differential pressure across the filter

d. Lubricating oil high differential pressure across the strainer

e. Lubricating oil low level

f. Circulating oil pump failure/malfunction

g. Lube oil heating system failure

The following signals trip the diesel engine and related generator circuit breaker during normal operation (i.e., testing, LOOP, or manual start):

a. Lube oil high temperature

b. Lube oil low pressure

During emergency operation (LOCA) these trips are bypassed. Local indication is provided for the following:

a. Makeup tank level

b. Lube oil temperature at the engine-driven pump discharge

c. Lube oil temperature at the strainer outlet

d. Filter differential pressure

e. Lube oil pressure at the engine-driven pump discharge

f. Lube oil pressure at the strainer outlet

g. Lube oil pressure at the upper lube oil header

h. Crankcase pressure

i. Lube oil pressure at the turbocharger

The following interlocks are provided on the diesel generator lubrication system:

a. On emergency start signal, the prelube pump is prevented from starting

b. On a start signal, when the diesel reaches approximately 200 rpm, the circulating pump is tripped

c. The heater is only operable when the circulating pump is operating

d. The pre-lube pump and the circulating pump are each locked out on an emergency stop.

9.5.8 DIESEL GENERATOR COMBUSTION AIR INTAKE AND EXHAUST SYSTEM

The diesel generator combustion air intake and exhaust system supplies combustion air to the diesel engines, and exhausts the combustion products to the atmosphere (drawing M-20). The diesel generator combustion air intake and exhaust system is a safety-related system. The diesel generator enclosure ventilation system is discussed in Section 9.4.6.

9.5.8.1 Design Bases

The diesel generator combustion air intake and exhaust system is designed to the following design bases:

a. To be capable of supplying adequate combustion air and disposing of resultant exhaust products to permit continuous operation of the diesel generators at full load.

b. To remain functional during and after an SSE.

c. To ensure that the single failure of any one component does not result in the loss of more than one diesel generator.

d. To be capable of being tested during plant operation.

e. To withstand wind, tornadoes, floods, and missiles.

The diesel generator combustion air intake and exhaust system is designed to seismic Category I requirements. The quality group classification and corresponding codes and standards that apply to the design of the system are discussed in Section 3.2.

All piping and equipment has been designed to withstand seismic accelerations and operating loads, regardless of design code. The manufacturer has developed a highly reliable engine piping system over the 44 years that the design of this basic engine has been in use.

9.5.8.2 System Description

The diesel generator combustion air intake and exhaust system is shown schematically in drawing M-20 and the design parameters are listed in Table 9.5-10. The diesel generator general arrangement is shown in drawings M-145 and M-146.

Each diesel generator has a separate exhaust and intake system consisting of an air intake filter, an exhaust silencer, and the necessary interconnecting piping and expansion joints for connection to the engine turbochargers and exhaust manifold.

The intake system draws outside air from the diesel generator enclosure air intake plenum through an air filter that is capable of removing 85 percent of 10 micron and larger particles. The piping is carbon steel.

Exhaust gas-driven turbochargers draw in a volume of air that is directed to the combustion cylinders. The air is compressed by the turbochargers and cooled by circulating cooling water through the air coolers. The air coolers are fin-tube type and are mounted directly in the engine air inlet headers downstream of the turbochargers. Operating in series with the turbochargers is a mechanical blower driven off the engine crankshaft. The function of the blower is to provide scavenging air to the scavenging air receiver at low load and speed until the turbochargers build up speed and capacity. Scavenging air is used to blow the hot exhaust gases out of the cylinders. A separate line out of the scavenging air receiver provides air to the crankcase evacuation system ejector (Section 9.5.7.2).

Following combustion, the hot exhaust gases leave the cylinders through the exhaust manifold and are used to drive the turbochargers. The gas leaves each turbocharger through an expansion joint, enters the exhaust piping, which includes a silencer, and is finally discharged to the atmosphere. The exhaust silencer is of the "residential" type, constructed of welded carbon steel. The expansion joints for the engine exhaust and air intake system are stainless steel, of the unguided bellows-type, with flanged connections. The horizontal portion of the exhaust piping inside of the Diesel enclosure is carbon steel. The portion of the exhaust piping outside of the enclosure is stainless steel as shown in drawing M-20.

9.5.8.3 Safety Evaluation

All safety related equipment and supports for this system are designed to seismic Category I requirements as discussed in Section 3.7.

The diesel generator combustion air intake and exhaust system is designed so that failure of any one component results in the loss of no more than one diesel generator. The loss of one diesel generator does not preclude adequate core cooling under accident conditions. Therefore, failure of any one component of the diesel generator combustion air intake and exhaust system does not preclude safe shutdown of the plant following a LOCA and/or a LOOP. See Table 9.5-11 for a failure mode and effects analysis of the system.

Protection against hurricanes, tornadoes, and missiles is provided by locating system components within the diesel generator enclosure. The vendor has certified that the equipment will be and/or remain operable for the range of design conditions given in Sections 3.3.2.1.a and 3.3.2.1.b.

As discussed in Section 9.5.1, water sprinklers are provided as the fire protection system for the diesel compartments. Gaseous extinguishing medium is not used in these compartments or in the surrounding areas outside the diesel generator enclosure, and therefore would not pose a hazard to the performance of the diesel generators.

Other gases that may intentionally or accidentally be released onsite are located remote to the diesel generator enclosures, and therefore would not pose a hazard to the performance of the diesel generators.

The probability of a fire outside the diesel generator enclosure concurrent with a LOOP that would cause products of combustion to foul the diesel air intake is extremely low. A spontaneous main turbine trip would not result from this external fire. A fire in the fuel oil storage tank outside the enclosure would immediately be alarmed in the control room and would be extinguished by a manually activated foam injection system provided with the tank. In the event of tank rupture, a continued foam application would cover the tank contents contained by an encircling dike. The fuel oil storage tank is located at a distance >120 ft from the diesel air intake. Lube oil storage consists of drum storage inside an enclosure and protected by a wet pipe sprinkler system. This lube oil storage enclosure is located east of the Unit 2 diesel generators, south of the auxiliary boiler enclosure, approximately 60 feet from the nearest Unit 2 diesel generator enclosure air intake. The area is protected by a fire hydrant system. Normal local winds would carry combustion products away from the diesel generator intakes as shown in the wind rose in EROL figures 2.3.2-1 through 2.3.2-3.

An analysis of a hypothetical fire in the diesel generator enclosure coincident with a single failure of the fire protection system and loss of offsite power has not been performed for the following reasons:

a. Quantities of combustibles sufficient to generate large amounts of smoke (e.g., lubricating oil) are contained in steel piping or components of high quality with respect to design, fabrication, and installation. The diesel and lube oil storage tanks in each diesel compartment are contained in separate, 3 hour rated enclosures.

b. A fire in a diesel compartment cannot precipitate a LOOP.

c. The diesel generator will be started and tested in accordance with the plant Technical Specifications. Therefore, it is unlikely that a large smoky fire, which is assumed to be initiated by the operation of the diesels, would occur coincident with a LOOP.

d. Failure of the automatic fire suppression system coincident with a large smoky fire and loss of all offsite power is not considered likely. Failure of the automatic deluge valve is the only single active failure that could preclude automatic fire suppression.

In the event such a remote combination of occurrences were to take place, the plant response would be as follows:

a. Fire detection alarms, located in the main control room, would alert plant personnel and identify the location of the fire

b. The fire detection alarm would alert the plant fire brigade, which would immediately respond to the alarm. Once the fire brigade arrived at the scene, the fire and its effects would be controlled by a combination of manual application of mist sprays to minimize the effects of smoke on the adjoining diesel engines and by manually opening the water deluge valve to the suppression system of the affected diesel. A yard fire hydrant is located directly adjacent to the south side of the diesel cells. Each water deluge valve has a manual override lever and is located in the pipe tunnel adjacent to the diesel cell (section A-A of drawing M-146). The pipe tunnel is physically separated from the diesel compartment environment by a 3 hour fire barrier.

   It is expected that the fire brigade arrival and manual deluge override would occur prior to the sequence of:

   1. Failure of the ventilation fans due to the effects of the fire

   2. Significant flow of smoke out through the inlet plenum of the affected diesel compartment

   3. Significant mixing of smoke in the intakes of the adjacent diesels.

Evaluation of the combustion air intake and exhaust system with respect to the following areas is discussed in separate sections as indicated:

a.	Protection from wind and tornado effects	Section 3.3
b.	Flood protection	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11
f.	Fire protection	Section 9.5.1

The air intake opening of the diesel generator enclosure and the outlet of the exhaust duct are designed to prevent recirculation of exhaust products and contamination of the diesel intake air. The

combustion air intake is located at the diesel generator enclosure air intake plenum. The screened air intake opening of the enclosure is located on the upper part of the south wall and is protected from rain, ice, and snow by a roof overhang (drawing M-146). The exhaust duct is terminated above the roof with a 6 foot piece of pipe. The exhaust pipe exit is over 17 feet higher than the enclosure air intake opening. The elbow at the base of the exhaust duct is heat traced to prevent accumulation of ice and snow.

As shown in drawing M-146, intake air for the diesel generators is drawn from the plenum side of the baffle plate; the temperature and humidity of this air will thus closely approximate that of the outdoor ambient environment. EROL section 2.3 contains information regarding the rate of ambient temperature and humidity experienced at the LGS site. The operability of the diesel generators will not be affected for ambient temperatures ranging from –5°F to 106°F or humidities ranging from 10% to 100%.

At temperatures above design value of 95°F, a reduction in continuous rating of approximately 2% would be required. This is not a concern due to the short duration of temperatures greater than 95°F and the existence of margin between equipment ratings and design basis plant loads.

Periodic loading of the diesel generators during extended periods of light load operation (Section 8.3.1.1.3) will eliminate any harmful buildup of carbon, lube oil, or fuel during periods of low temperature operation.

Because of the above described configuration and because the specific gravity of the exhaust gases leaving the exhaust duct is approximately one-third of the standard air specific gravity, exhaust gas contamination of air at the enclosure intake opening will be negligible irrespective of outdoor ambient temperature, wind speed, or direction. The exhaust duct extension, beyond the diesel generator enclosure roof, further improves exhaust gas dispersion. This extension is considered nonsafeguard in that it is not required to meet the system design requirements, and in that its failure will not interfere with the exhaust duct gas flow and consequently the performance of the diesel generator.

The flange portion of the exhaust piping above the roof is stainless steel and fastened with a weak bolted connection. If this portion of piping were to be struck by a tornado or turbine missile, the flanged portion would either remain intact or break free and fall away from the exhaust stack to the roof or to the ground. The bolted connection is far weaker than the section of steel pipe and would break free before the pipe could be deformed to block flow. This section of pipe falling to the roof has been previously analyzed as being acceptable because the roof is designed to withstand turbine and tornado missiles. Also the possibility of small pieces of metal falling into the stack as a result of a missile hit has been previously analyzed as being acceptable because the arrangement of the pipe and the presence of the silencer would prevent the pieces from reaching the turbocharger. For the low probability event of the pipe breaking off, the vertical discharge velocity and low specific gravity of the exhaust ensure that the recirculation would not be a problem.

The engine silencers are provided with drains for removal of condensation and precipitation that might collect at this point. The drains will be open continuously to allow for precipitation to drain into a Seismic Category I, Q-listed loop seal. Any dust that might accumulate in the exhaust piping will be blown out by the exhaust gases during periodic testing.

The remote potential exists for snow to accumulate in the 90° elbow at the base of the stack, since this elbow is located outside the diesel generator enclosure at the bottom of the air intake plenum. The presence of snow or ice in the elbow could increase the back pressure on the engine, and thereby increase the engine acceleration time and decrease performance. This potential is not felt to be significant since: (1) the exhaust piping from the engine to the underside of the roof of the

intake plenum is insulated and will therefore tend to retain heat from diesel exercises, and (2) the diesel bays are maintained at 65°F if plant heating steam is available and some heat will escape from the diesel bays to the intake plenum. Thus, extremely cold winter weather accompanied by a major snowstorm would be required to effect significant accumulation of snow in the exhaust stacks.

Nonsafety-grade electric heat tracing has been installed on the base of the exhaust stacks to provide heat in the event of a major snowstorm accompanied by extremely cold weather. In the event of failure of this system, the operators will start the affected diesel generator to provide heat.

The engine is not equipped with alarm or shutdown sensors for abnormal conditions in the intake and exhaust systems because the engines are designed to operate under all specified operating conditions.

9.5.8.4 Tests and Inspections

The system is preoperationally tested in accordance with the requirements of Chapter 14 and is periodically tested in accordance with the requirements of Technical Specifications. Operability of the combustion air intake and exhaust system is checked during the periodic testing of the diesel generator system.

The exhaust line is inspected as part of the ISI program.

9.5.8.5 Instrument Application

The following local indication is provided:

a. Exhaust manifold on the inlet to turbo charger temperature (2)

b. Blower discharge temperature

c. Cylinder exhaust temperature (each cylinder)

d. Combined exhaust temperature

e. Inlet air pressure

f. Blower discharge pressure

There are no alarms or interlocks on this system.

9.5.9 REFERENCES

9.5-1 Limerick Generating Station Units 1 and 2 Technical Requirements Manual, Fire Protection Section.

9.5-2 "American National Standard Fuel Oil Systems for Standby Diesel-Generators," American National Standards Institute (ANSI) N195 / American Nuclear Society (ANS) 59.51, approved 12 April 1976.

Table 9.5-1

NATIONAL FIRE PROTECTION ASSOCIATION STANDARDS
USED IN DESIGN OF FIRE PROTECTION SYSTEMS

NUMBER	TITLE
11	Foam Extinguishing Systems
12	Carbon Dioxide Extinguishing Systems
12A	Halon 1301 Systems
13	Installation of Sprinkler Systems
14	Standpipe and Hose Systems
15	Water Spray Fixed Systems
20	Centrifugal Fire Pumps
24	Outside Protection
30	Flammable and Combustible Liquids Code
70	National Electric Code
72	National Fire Alarm Code, Edition 1996, Chapter 5
72A	Local Protective Signaling Systems
72D	Proprietary Signaling Systems
72E	Automatic Fire Detectors, Edition 1990
75	Electronic Computer Data Processing Equipment
78	Lightning Protection Code
90A	Air Conditioning and Ventilation System
231	Indoor General Storage
231C	Rack Storage of Materials

Table 9.5-2

INSULATION AND JACKETING MATERIALS USED FOR ELECTRICAL CABLING

CABLE APPLICATION	INSULATION	JACKETING
Communication	Polyvinyl chloride	Polyvinyl chloride
Lighting	Thermoplastic (THHN, THWN, or THW)	None
Grounding	Thermoplastic (THW)	None
Instrumentation	Cross-linked polyethylene	Neoprene
Perkiomen pipeline supervisory control	Cross-linked polyethylene/armored	Polyvinyl chloride(4) or neoprene
	Flamtrol	Flamtrol
Coaxial and triaxial	Cross-linked Polyolefin	Cross-linked polyolefin
600 V control	Cross-linked polyethylene	Neoprene
	Rubber	Polyvinyl chloride(5)

Table 9.5-2 (Cont'd)

CABLE APPLICATION	INSULATION	JACKETING
Meteorological towers cable	Rockbestos "Heatzone I"	Rockbestos "Heatzone I"
	Vulkene	Polyvinyl chloride(6)
600 V power	Cross-linked polyethylene	Neoprene
	Ethylene propylene	Hypalon
	Cross-linked polyethylene	Polyvinyl chloride(7)
	Cross-linked Polyethylene	Chlorinated polyethylene
5 kV power	Ethylene propylene rubber	Hypalon
15 kV power	Ethylene propylene rubber	Semi-conducting chlorinated polyethylene
	Cross-linked polyethylene	Polyvinyl chloride
Computer cables	Cross-linked Polyethylene	Neoprene or Flamtrol
	Rayolin F	Flamtrol
Multiconductor(1)	Cross-linked polyethylene	Neoprene
Multiconductor (shielded)(1)	Cross-linked polyethylene or cross-linked modified polyolefin	Neoprene or cross-linked polyolefin

Table 9.5-2 (Cont'd)

CABLE APPLICATION	INSULATION	JACKETING
Twisted-shielded pairs(1)	Cross-linked polyalkene and	Cross-linked modified polyolefin polyvinylidene fluoride
Thermocouple(1)	Cross-linked polyethylene	Cross-linked polyethylene
Coaxial (RG type)(1)	Cross-linked polyethylene	Cross-linked polyethylene
Coaxial (twin conductor)(1)	Alkaneimide polymer cross-linked polyolefin	Cross-linked polyethylene
Coaxial (high temperature, radiation resistant)(1)	Cross-linked polyethylene	Cross-linked polyethylene
Twisted pairs or triples (high performance)(1)	Polyalkene and polyvinylidene fluoride	Cross-linked polyvinylidene fluoride and cross-linked polyolefin
Armored Coaxial Cable for Video signals from Drywell video cameras(3)	Cross-linked polyethylene	Polyvinyl Chloride
Armored Multiconductor cable for Drywell video camera control and audio signals(3)	Cross-linked polyethylene	Polyvinyl Chloride

Table 9.5-2 (Cont'd)

(1) These cables are associated with the PGCC.

(2) Insulation for lighting cables and grounding cables is specified as flame retardant in accordance with the National Electric Code. Insulation and jacketing for all other cables, with the exception of communications cables, are specified to meet the IEEE 383 flame test requirements.

(3) These cables were used with the Health Physics temporary video cameras and Remote Console, but are now abandoned.

The following cables are restricted to use in specific installations:

(4) Perkiomen pipeline direct burial supervisory control cable (outside plant)

(5) Meteorological towers cable (outside plant)

(6) Postaccident sampling system vendor-supplied cable which is in solenoid valve cabinets only.

(7) Main condenser areas and the condensate pump rooms

Table 9.5-3

DIESEL GENERATOR FUEL OIL SYSTEM
DESIGN PARAMETERS

DIESEL OIL STORAGE TANKS	
Quantity	4 (100% capacity each)
Type	Underground, horizontal, cylindrical
Capacity, each	41,500 gallons
Design pressure	Atmospheric
Design temperature	Ambient
Code design requirements	UL58, AWS, ASTM, SSPC National Fire codes Built to ASME Section III, Class 3 but not stamped Nondestructive examination in accordance with ASME Section III
DIESEL OIL TRANSFER PUMPS	
Quantity	4 (100% capacity each)
Type	Vertical, centrifugal sump
Capacity, each	20 gpm
Head	40 feet
Motor power rating	1½ hp
Code design requirements	Hydraulic Institute Standards
DIESEL OIL DAY TANK	
Quantity	4 (100% capacity each)
Type	Indoor, vertical, cylindrical, aboveground
Capacity, each	850 gallons
Design pressure	Atmospheric
Design temperature	Ambient
Code design requirements	ASME Section III, Class 3
ENGINE-DRIVEN FUEL PUMP	
Quantity	4 (100% capacity each)
Type	Positive displacement
Capacity, each	9 gpm
Head	25 psig
Code design requirements	DEMA

Table 9.5-3 (Cont'd)

DC MOTOR-DRIVEN PUMP

Quantity	4 (100% capacity each)
Type	Positive displacement, rotary
Capacity, each	10 gpm
Head	35 psig
Motor power rating	¾ hp
Code design requirements	DEMA

Table 9.5-4

DIESEL GENERATOR FUEL OIL SYSTEM
FAILURE MODES AND EFFECTS ANALYSIS

COMPONENT	MALFUNCTION	EFFECT ON SYSTEM
Storage tanks (one per diesel)	Loss of one tank	Supply to one diesel is lost; however, the capability is provided to supply that diesel from any of the other storage tanks.
Day tanks (one per diesel)	Loss of one tank	The fuel supply to one of the four diesels is lost. However, only three diesels for each unit are required for a safe shutdown following a LOCA and a LOOP. (See Note)
Transfer pumps (one per diesel)	Loss of one pump	Same as first item
Line between day tank and supply line isolation valve down-stream of cross connect (one per diesel)	Rupture of pipe	Same as second item
Line between storage tank and supply line isolation valve upstream of cross connect (one per diesel)	Rupture of pipe	Same as first item
Fuel oil pump (engine-driven, one per diesel)	Pump fails	Dc-driven pump automatically starts

Note: Any combination of three-out-of-four divisions (EDGs) is acceptable for a single failure. However, for ECCS requirements (as stated in paragraph 6.3.1.1.2), an EDG operable configuration of 2 out of 4 is also acceptable.

Table 9.5-5

DIESEL GENERATOR JACKET WATER COOLING LOOP DESIGN PARAMETERS

EXPANSION TANK	
Quantity	1 per diesel (4 total)
Capacity, each	80 gallons
Design code requirements	ASME Section III, Class 3
ENGINE-DRIVEN WATER PUMP	
Quantity	1 per diesel (4 total)
Typ	Centrifugal
Capacity, each	800 gpm
Head	46 psi
Design code requirements	Manufacturer's standard
MOTOR-DRIVEN CIRCULATION PUMP	
Quantity	1 per diesel (4 total)
Type	Centrifugal
Capacity, each	40 gpm
Head	6.5 psi
Motor power rating	1 hp
Design code requirements	Manufacturer's standard
JACKET WATER HEAT EXCHANGER	
Quantity	1 per diesel (4 total)
Type	Shell and tube
Duty, each(1)	2,965,000 Btu/hr
Shell design	
Fluid	Treated water
Flow rate	800 gpm
Design pressure	150 psi
Design temperature	300°F
Tube design	
Fluid (design inlet temperature)	ESW (109.5°F)
Flow rate (nominal)	700 gpm
Design pressure	150 psi
Design temperature	300°F
Design code requirements(2)	ASME Section III, Class 3 & Commonwealth of Pennsylvania

Table 9.5-5 (Cont'd)

STANDBY JACKET COOLANT HEATER

Quantity	1 per diesel (4 total)
Type	Immersion, electric
Rating	15 kW
Design code requirements	ASME IV

(1) Based on a fouling factor of 0.0025

(2) Replacement Sub-Assembly(ies) purchased after 11/2000 procured in accordance with US NRC Generic Letter 89-09 and ASME Section III, Class 3, equivalent requirements.

Table 9.5-6

DIESEL GENERATOR AIR COOLER COOLANT LOOP DESIGN PARAMETERS

AIR COOLER	
Quantity	2 per diesel
Type	Shell and tube
Tube design	
Fluid	Treated water
Flow rate	400 gpm
Design pressure	30 psi
Design temperature	300°F
Shell design	
Fluid	Air
Flow rate	15,000 cfm
Design pressure	30 psi
Design temperature	300°F
Design code requirements	Manufacturer's standard
ENGINE-DRIVEN AIR COOLER WATER PUMP	
Quantity	1 per diesel (4 total)
Type	Centrifugal
Capacity, each	400 gpm
Head	26 psi
Design code requirements	Manufacturer's standard
AIR COOLER COOLANT HEAT EXCHANGER	
Quantity	1 per diesel (4 total)
Type	Shell and tube
Duty, each(1)	2,346,000 Btu/hr
Shell design	
Fluid	Treated water
Flow rate	400 gpm
Design pressure	150 psi
Design temperature	300°F
Tube design	
Fluid (design inlet temperature)	ESW (95°F)
Flow rate (nominal)	700 gpm
Design pressure	150 psi
Design temperature	300°F
Design code requirements(2)	ASME Section III, Class 3, & Commonwealth of Pennsylvania

(1) Based on a fouling factor of 0.0025

(2) Replacement Sub-Assembly(ies) purchased after 11/2000 procured in accordance with US NRC Generic Letter 89-09 and ASME Section III, Class 3, equivalent requirements.

Table 9.5-7

DIESEL GENERATOR STARTING SYSTEM DESIGN PARAMETERS

STARTING AIR COMPRESSORS	
Quantity	2 per diesel, 8 total per Unit (100% capacity each)
Type	Reciprocating
Capacity, each	44 cfm
Motor power rating	20 hp
Voltage	460 V ac, three-phase, 60 Hz
Code design requirements	Manufacturer's standard
AIR RESERVOIR	
Quantity	2 per diesel, 8 total per Unit (100% capacity each)
Type	Vertical, cylindrical
Design Pressure	275 psig
Capacity, each	5 normal diesel starts
Code design requirements	ASME Section III, Class 3

Table 9.5-8

DIESEL GENERATOR STARTING SYSTEM
FAILURE MODES AND EFFECTS ANALYSIS

COMPONENT	MALFUNCTION	EFFECT ON SYSTEM
Air compressor (two per diesel)	Failure of a compressor to start	One of the dual air start systems is lost. The diesel is started by the other system.
Air reservoir (two per diesel)	Failure of the reservoir	Same as above
Line between air compressor and isolation valve	Rupture of pipe	Same as above
Line between the isolation valve and the air reservoir	Rupture of pipe	Same as above
Line between the air reservoir and the diesel	Rupture of pipe	Same as above

Table 9.5-9

DIESEL GENERATOR LUBRICATION SYSTEM DESIGN PARAMETERS

ENGINE-DRIVEN LUBE OIL PUMP	
Quantity	1 per diesel (4 total)
Type	Helical gear
Capacity, each	500 gpm
Head	80 psi
Design code requirements	Manufacturer's Standards
LUBE OIL COOLER	
Quantity	1 per diesel (4 total)
Type	Shell and tube
Duty, each(1)	2,747,000 Btu/hr
Shell design	
Fluid	lube oil
Flow rate	500 gpm
Design pressure	150 psig
Design temperature (maximum)	300°F
Tube design	
Fluid	Emergency service water
Flow rate	700 gpm
Design pressure	150 psig
Design temperature (maximum)	300°F
Design code requirements(2)	ASME Section III Class 3, & Commonwealth of Pennsylvania
AC MOTOR-DRIVEN PRELUBE OIL PUMP	
Quantity	1 per diesel (4 total)
Type	Rotary
Capacity, each	35 gpm
Head	50 psi
Motor power rating	5 hp
Design code requirements	Manufacturer's Standards
CIRCULATING PUMP	
Quantity	1 per diesel (4 total)
Type	Rotary
Capacity, each	13 gpm
Head	25 psi
Motor power rating	3 hp
Design code requirements	Manufacturer's Standards

Table 9.5-9 (Cont'd)

STANDBY LUBE OIL HEATER	
Quantity	1 per diesel (4 total)
Type	Immersion, electric
Rating	6 kW each
Design code requirements	ASME Section IV
LUBE OIL STRAINER	
Quantity	1 per diesel (4 total)
Type	Dual Element, full flow
Capacity	500 gpm each
Performance	150 mesh
Design code requirements	ASME Section VIII
LUBE OIL FILTER	
Quantity	1 per diesel (4 total)
Type	Single element, throwaway cellulose cartridges
Capacity, each	500 gpm
Design Requirement	25 microns
Performance	5 microns
Design code requirements	ASME Section VIII

(1) Based on normal conditions, lube oil thermostatically controlled.

(2) Replacement Sub-Assembly(ies) purchased after 11/2000 procured in accordance with US NRC Generic Letter 89-09 and ASME Section III, Class 3 equivalent requirements.

Table 9.5-10

DIESEL GENERATOR COMBUSTION AIR INTAKE AND
EXHAUST SYSTEM DESIGN PARAMETERS

AIR INLET FILTERS	
Quantity	1 per diesel (4 total)
Type	Floor-mounted
Capacity, each	16,000 cfm
Design pressure drop	10 in wg
Rated pressure drop, clean	2 in wg maximum
Design code requirements	Manufacturer's standard
EXHAUST SILENCER	
Quantity	1 per diesel (4 total)
Type	Residential
Attenuation compatibility	Low frequencies 23-26 dB, high frequencies 18-20 dB
Design code requirements	Manufacturer's standard

Table 9.5-11

DIESEL GENERATOR COMBUSTION AIR INTAKE AND EXHAUST SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

COMPONENT	MALFUNCTION	EFFECT ON SYSTEM
Inlet air Filter	Filter becomes clogged	Air supply to one diesel is lost; however, only three diesels for each unit are required for a safe shutdown following a LOCA and a LOOP. (See Note)
Inlet air piping	Rupture of pipe	Same as above
Exhaust gas piping	Rupture of pipe	Same as above
Exhaust Silencer	Failure of silencer causing flow obstruction	Same as above

Note: Any combination of three-out-of-four divisions (EDGs) is acceptable for a single failure. However, for ECCS requirements (as stated in paragraph 6.3.1.1.2), an EDG operable configuration of 2 out of 4 is also acceptable.

Table 9.5-12

LIGHTING SYSTEM
MINIMUM INTENSITIES OF ILLUMINATION

LOCATION [1]	Normal Maintained Footcandles	Emergency Lighting (Footcandles) AC Supplied	DC Supplied
Auxiliary Equipment (PGCC) Room el 289'	30	10	Silhouette
Main Control Rool el 269" – 0"	60	20	3
Fire Pump-Room (Circulating Water Pump Structure)	20	Silhouette	
Cable Spreading Room el 254' –0"	30	10	Silhouette
4 kV Switchgear Room el 239' – 0"	30	10	3
Remote Shutdown Room el 289'	30	10	3
13 kV Switchgear Area el 217' –0"	30	Silhouette	
Access from Control Room to Emerg Auxiliary Equip.	As indicated by applicable areas below	5	Silhouette
Access from Control Room to Reactor Area	As indicated by applicable areas below		
Reactor Enclosure			
El 177" – 0" El 201' – 0" El 217' – 0" El 253' – 0" El 283' – 0" El 313' – 0" & el 331' –0" El 352' – 0"	Refueling floor –30 Operating areas –20 Nonoperating Areas -10	Silhouette	
Diesel Generator Enclosure el 217' – 0"	30	10	3
Turbine Operating Floor	30	Silhouette	
Corridors & Stairways	20	Silhouette	Silhouette
Emergency Spray Pond Pump Structure Control Panels and Switchgear Area	20	Silhouette	
Radwaste			
Nonoperating Areas General	10 20	Silhouette Silhouette	

[1] Locations are inclusive of vital and hazardous areas

Table 9.5-13

REMOTE EMERGENCY SHUTDOWN LOCATIONS
MINIMUM INTENSITIES OF ILLUMINATION
(footcandles)

		EMERGENCY		
LOCATION[1]	NORMAL	AC	DC	SELF-CONTAINED 8 HR UNITS
Area 8, el 289' Panels C201	30	10	3	0.5
Area 8, el 239' 4 kV Switchgear rooms	30	10	3	0.5
DG Building, el 217'	30	10	3	0.5
Various Locations Hand-Operated Valves[2] and Other Manually Actuated Devices	10	Hand-held Lanterns		0.5

(1) Access paths to the above areas are provided with at least 0.5 footcandle of emergency dc lighting by the self-contained lighting units.

(2) Valves, breakers, switches, and other devices which must be manipulated in order to achieve safe shutdown in the event of a fire. (Appendix 9A)

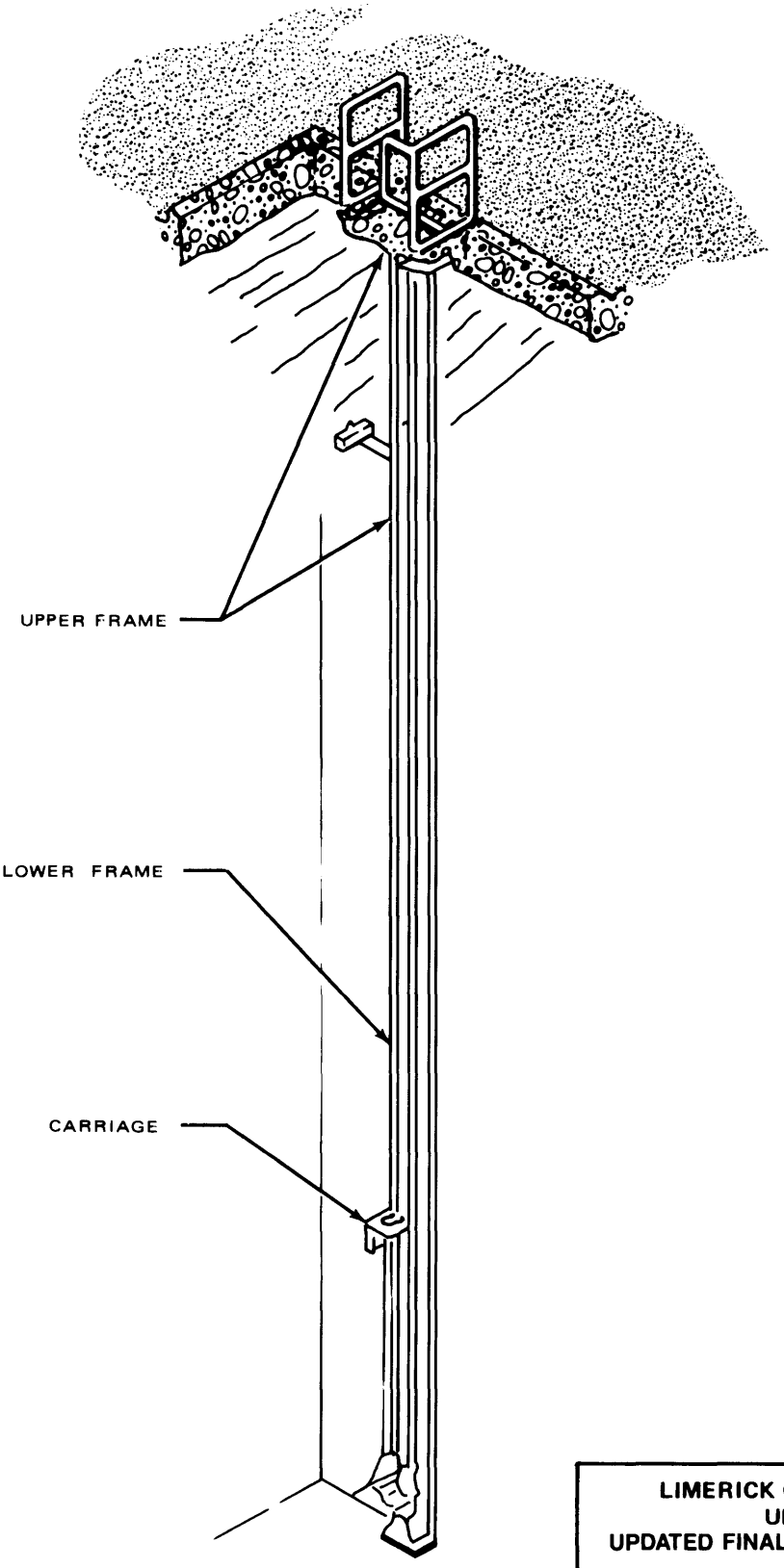
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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIGURE 9.1-1

Figure 9.1-2 thru 9.1-4

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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FUEL PREPARATION MACHINE
SHOWN INSTALLED IN
FACSIMILE FUEL POOL

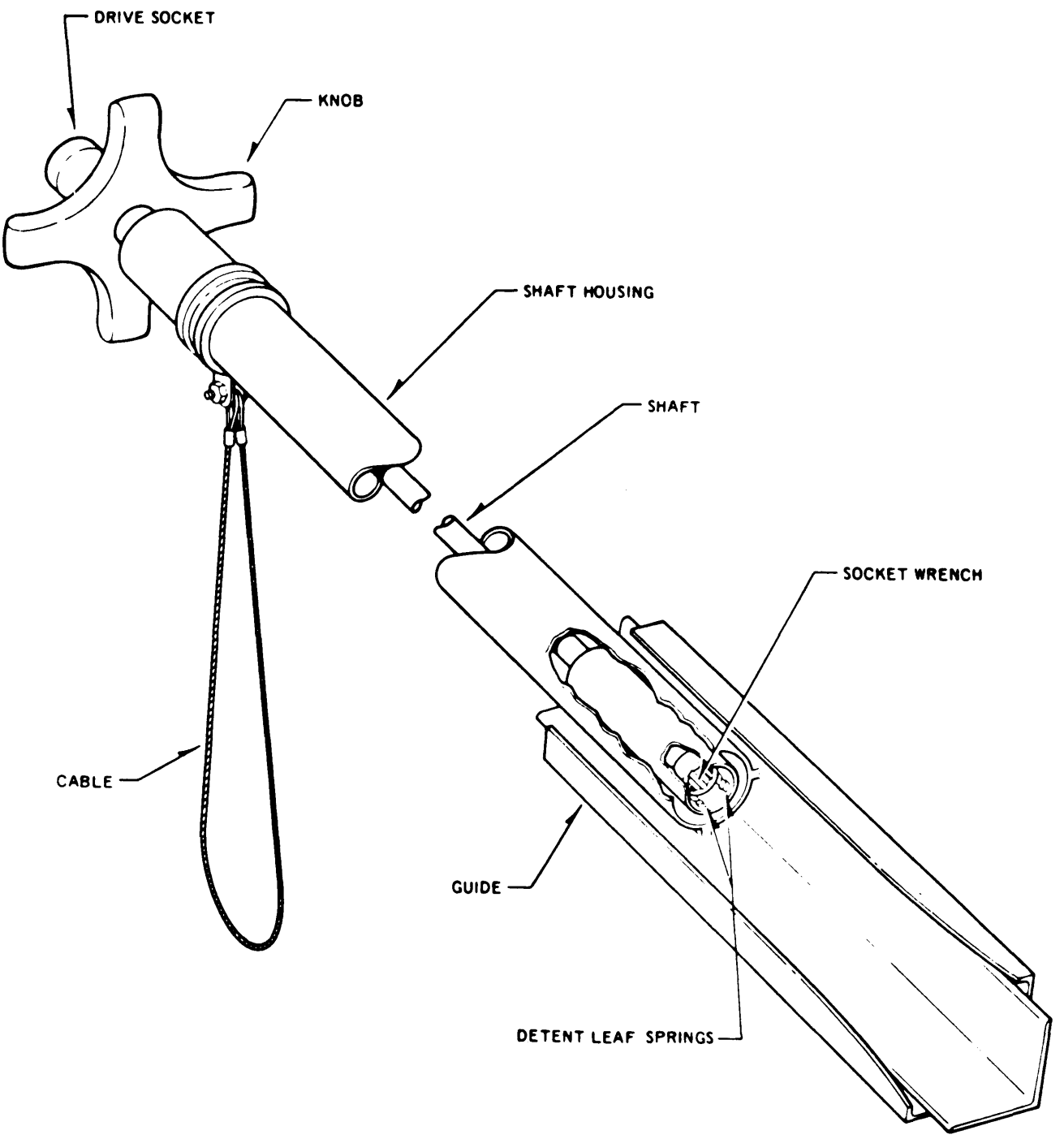
FIGURE 9.1-5

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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

NEW FUEL INSPECTION STAND

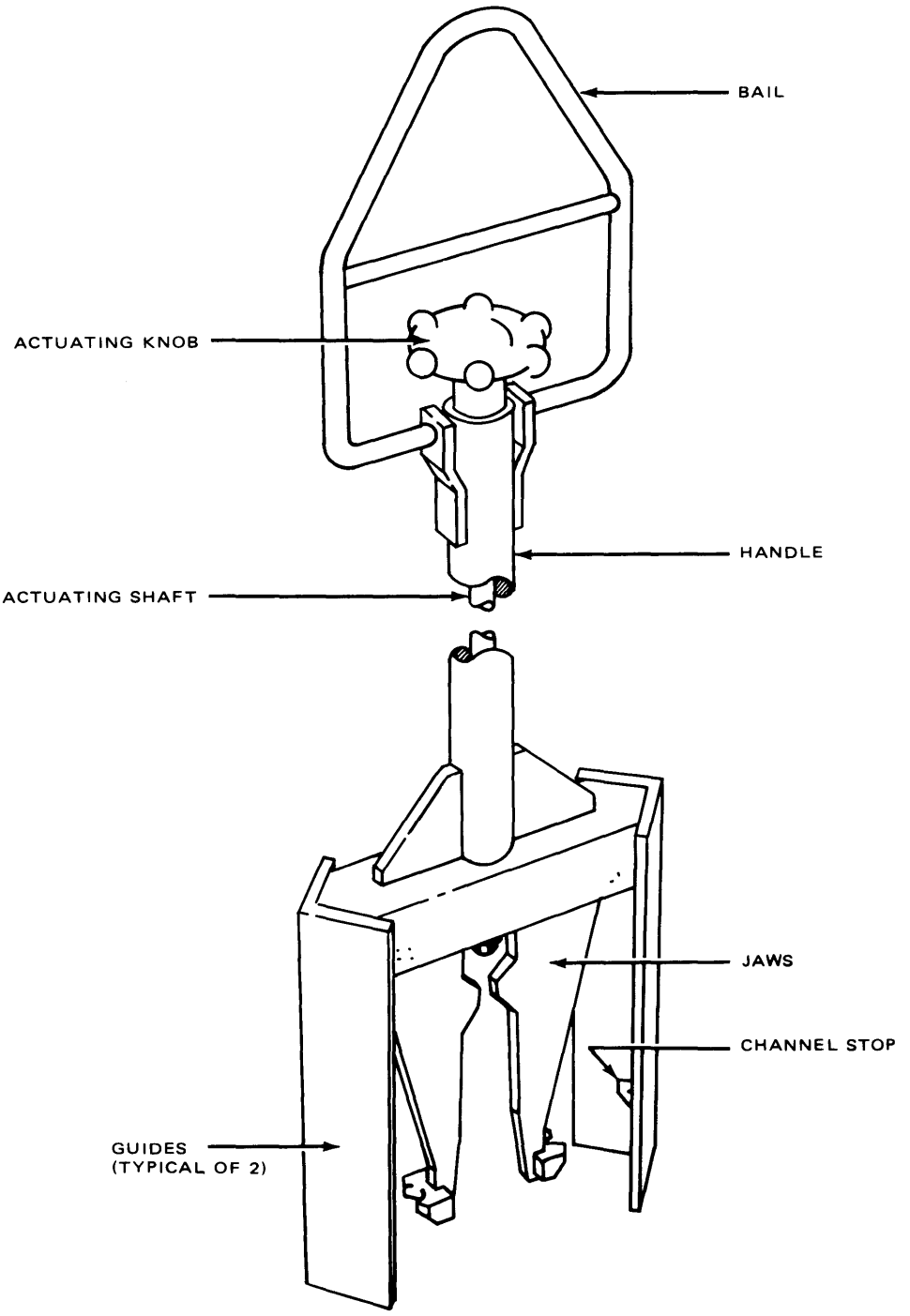
FIGURE 9.1-6 Rev. 2 July/92



LIMERICK GENERATING STATION
UNITS 1 AND 2
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CHANNEL BOLT WRENCH

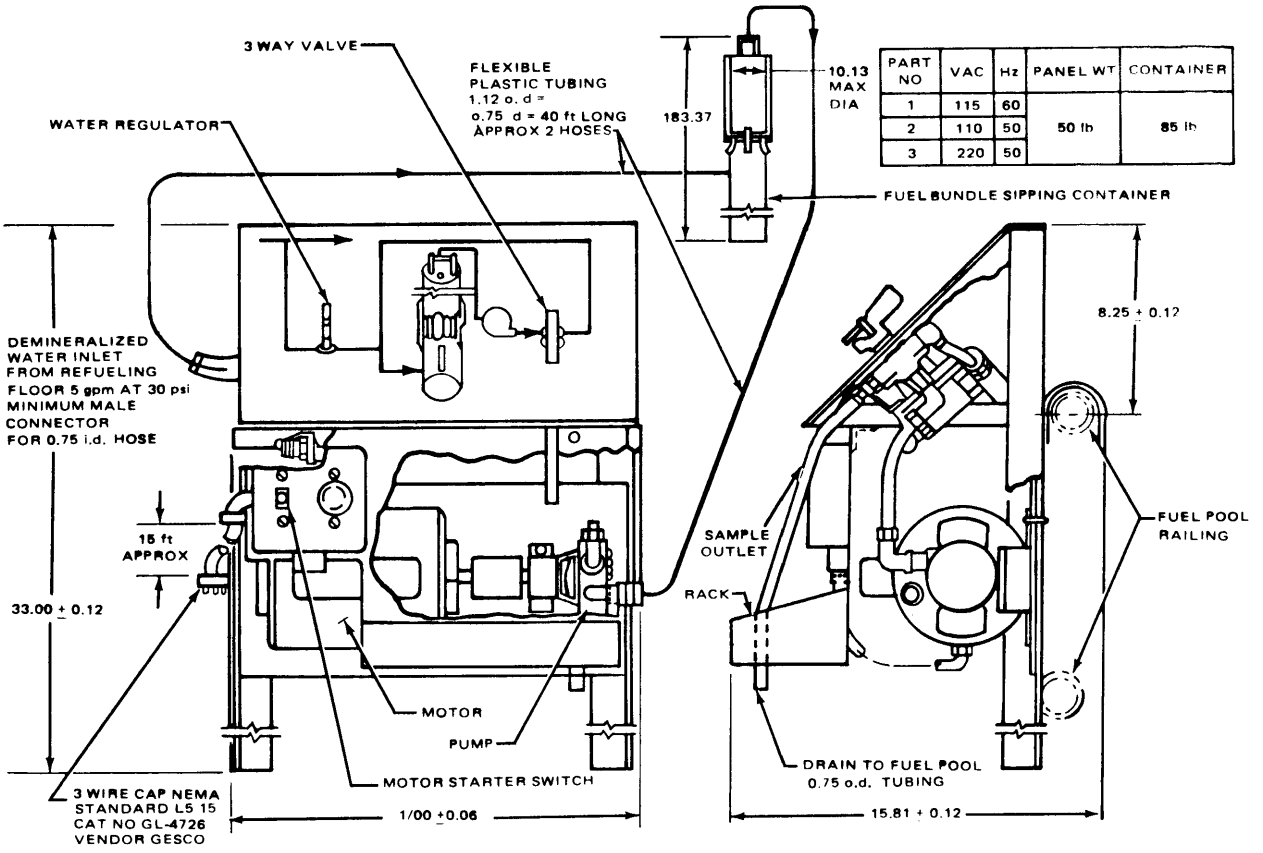
FIGURE 9.1-7



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CHANNEL HANDLING TOOL

FIGURE 9.1-8

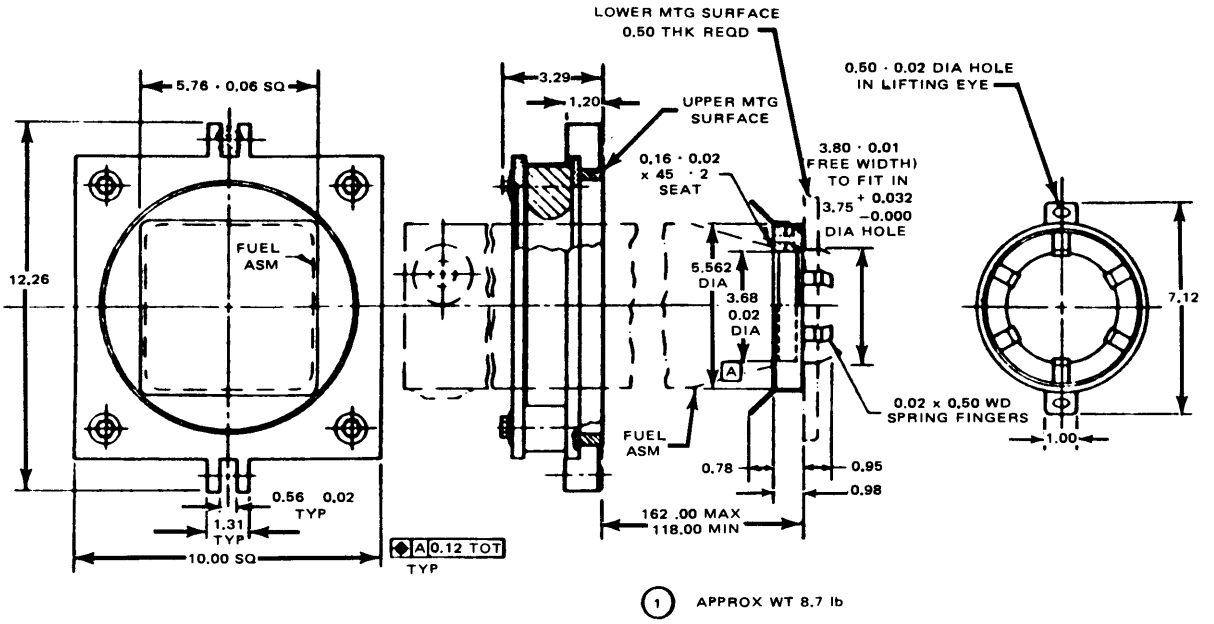


PART NO	VAC	Hz	PANEL WT	CONTAINER
1	115	60	50 lb	85 lb
2	110	50		
3	220	50		

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FUEL POOL SIPPER

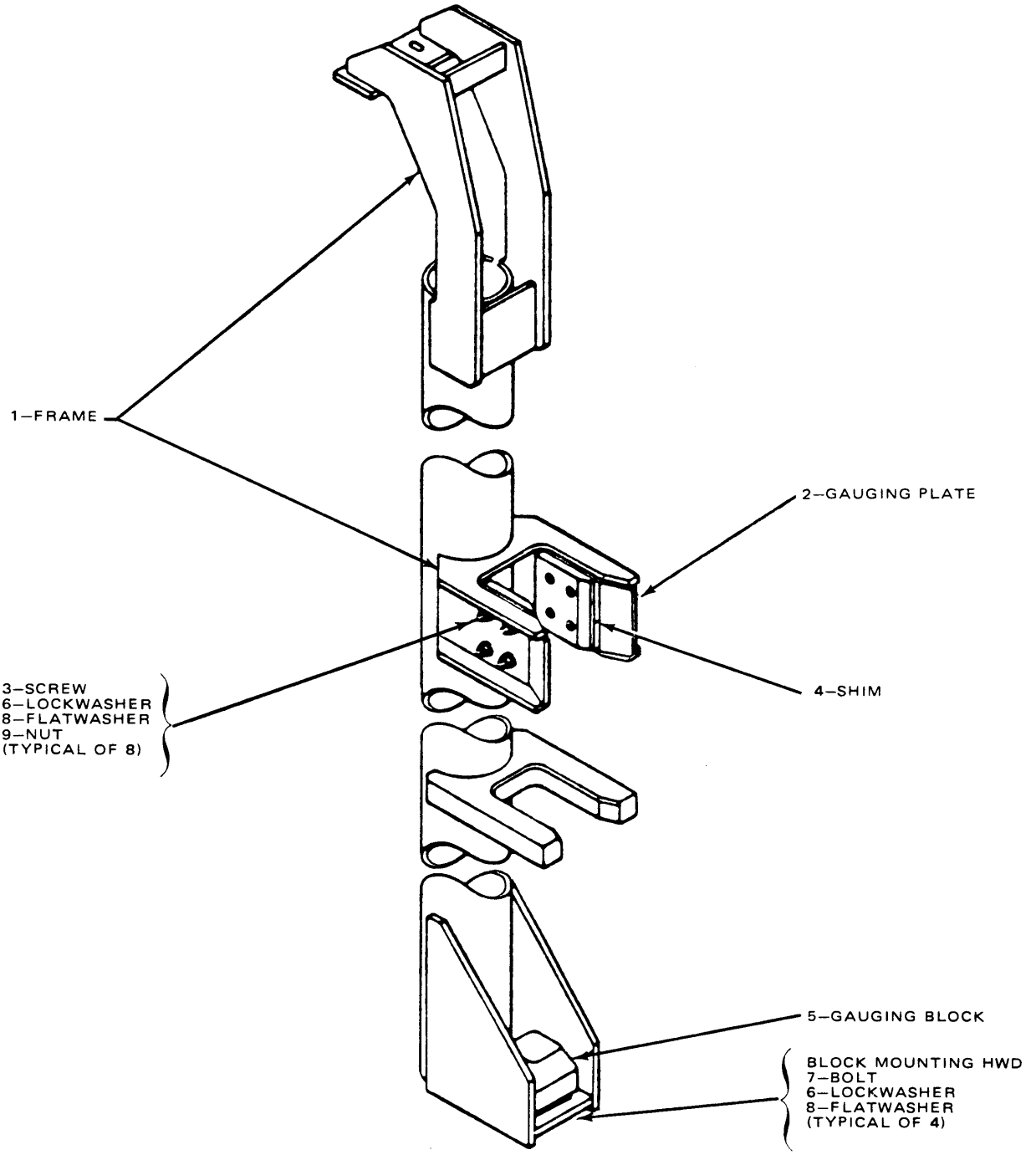
FIGURE 9.1-9



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FUEL INSPECTION FIXTURE

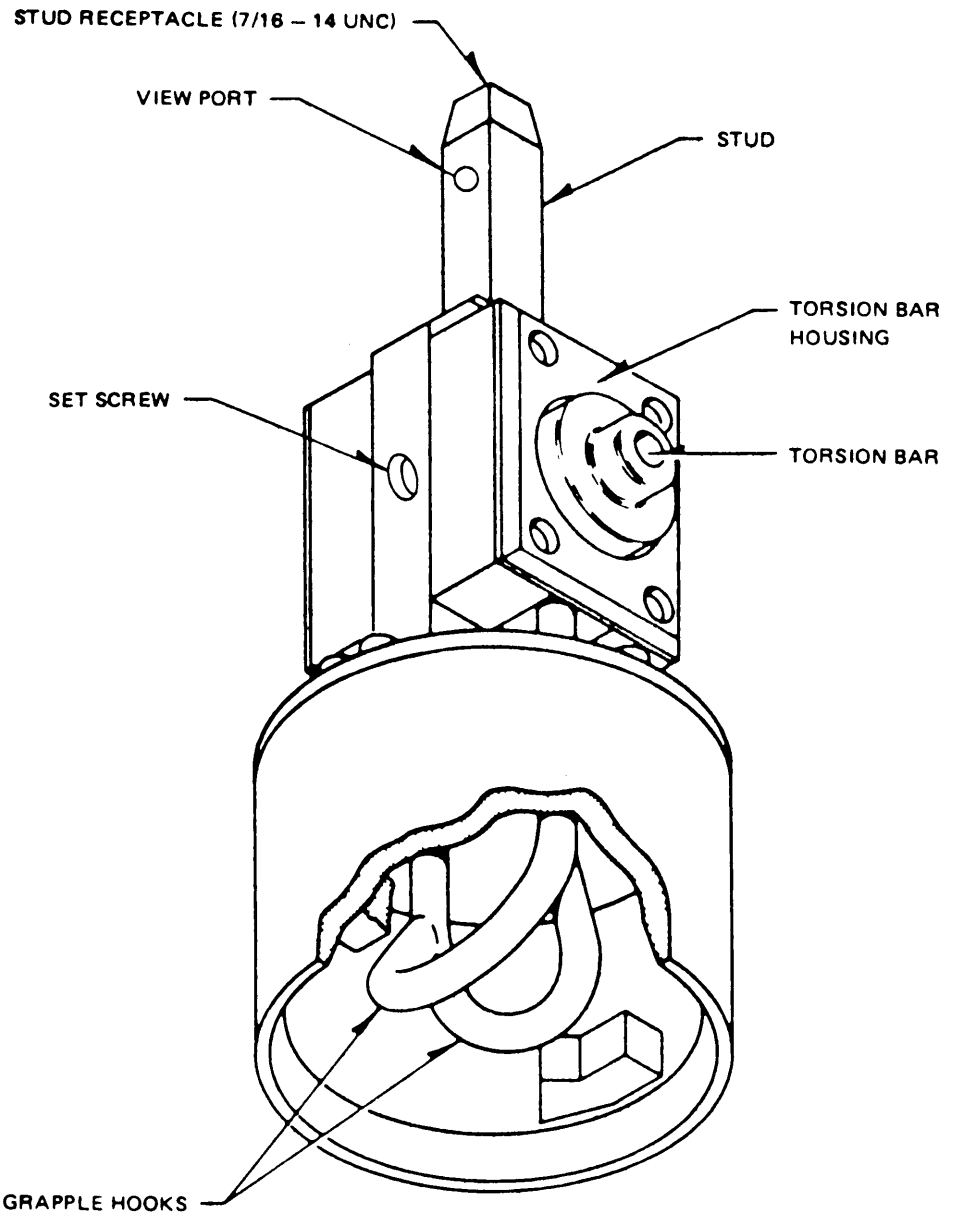
FIGURE 9.1-10



LIMERICK GENERATING STATION
UNITS 1 AND 2
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CHANNEL GAUGING FIXTURE

FIGURE 9.1-11



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GENERAL-PURPOSE GRAPPLE

FIGURE 9.1-12

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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REFUELING OUTAGE FLOW DIAGRAM

FIGURE 9.1-13 Rev. 2 July/92

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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SIMPLIFIED SECTION OF NEW FUEL HANDLING FACILITIES (SECTION X-X, FIGURE 9.1-17)

FIGURE 9.1-14 Rev. 1 July/91

Z:\MECH\ 0901014.S1

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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SIMPLIFIED SECTION OF REFUELING FACILITIES
(SECTION Y-Y, FIGURE 9.1-17)

FIGURE 9.1-15 Rev. 1 July/91

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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

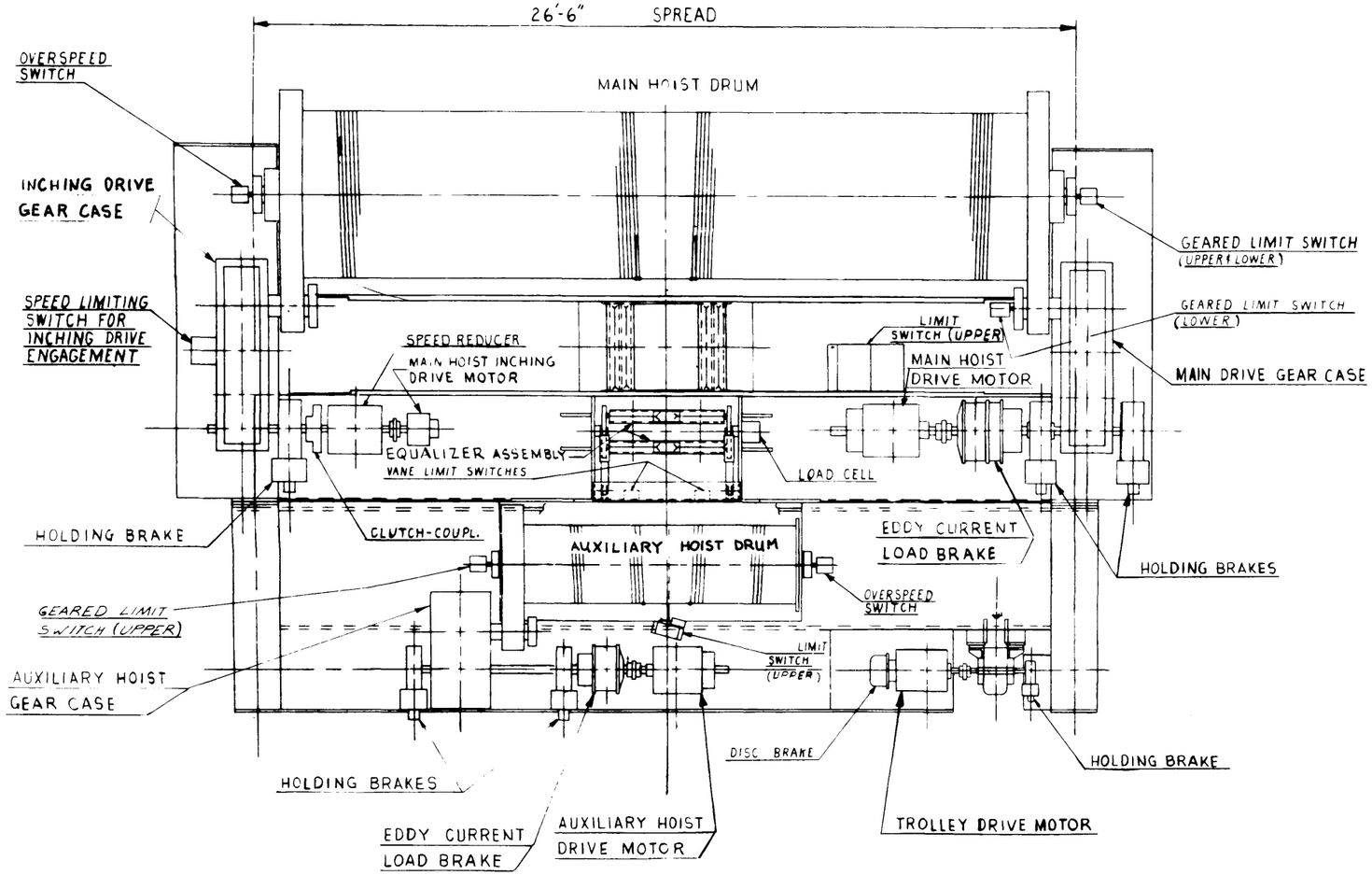
SIMPLIFIED SECTION OF
FUEL SHIPPING FACILITIES
(SECTION Z-Z, FIGURE 9.1-17)

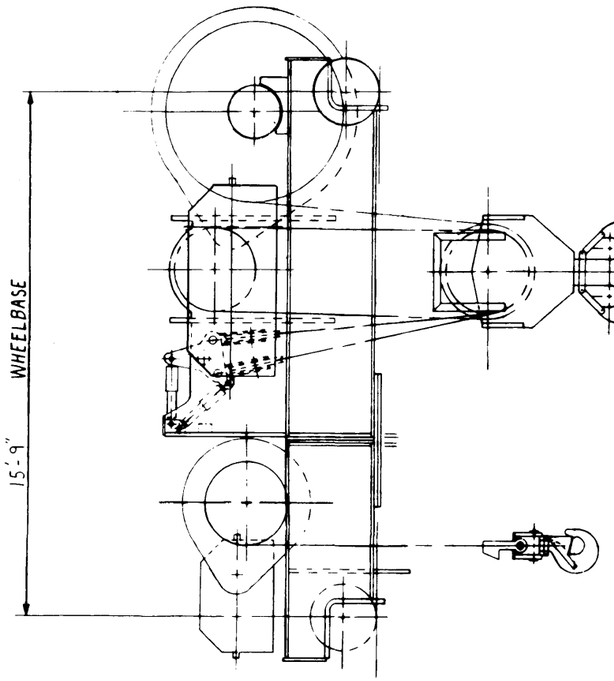
FIGURE 9.1-16 Rev. 1 July/91

Z:\MECH\ 0901016.S1

Figure 9.1-17

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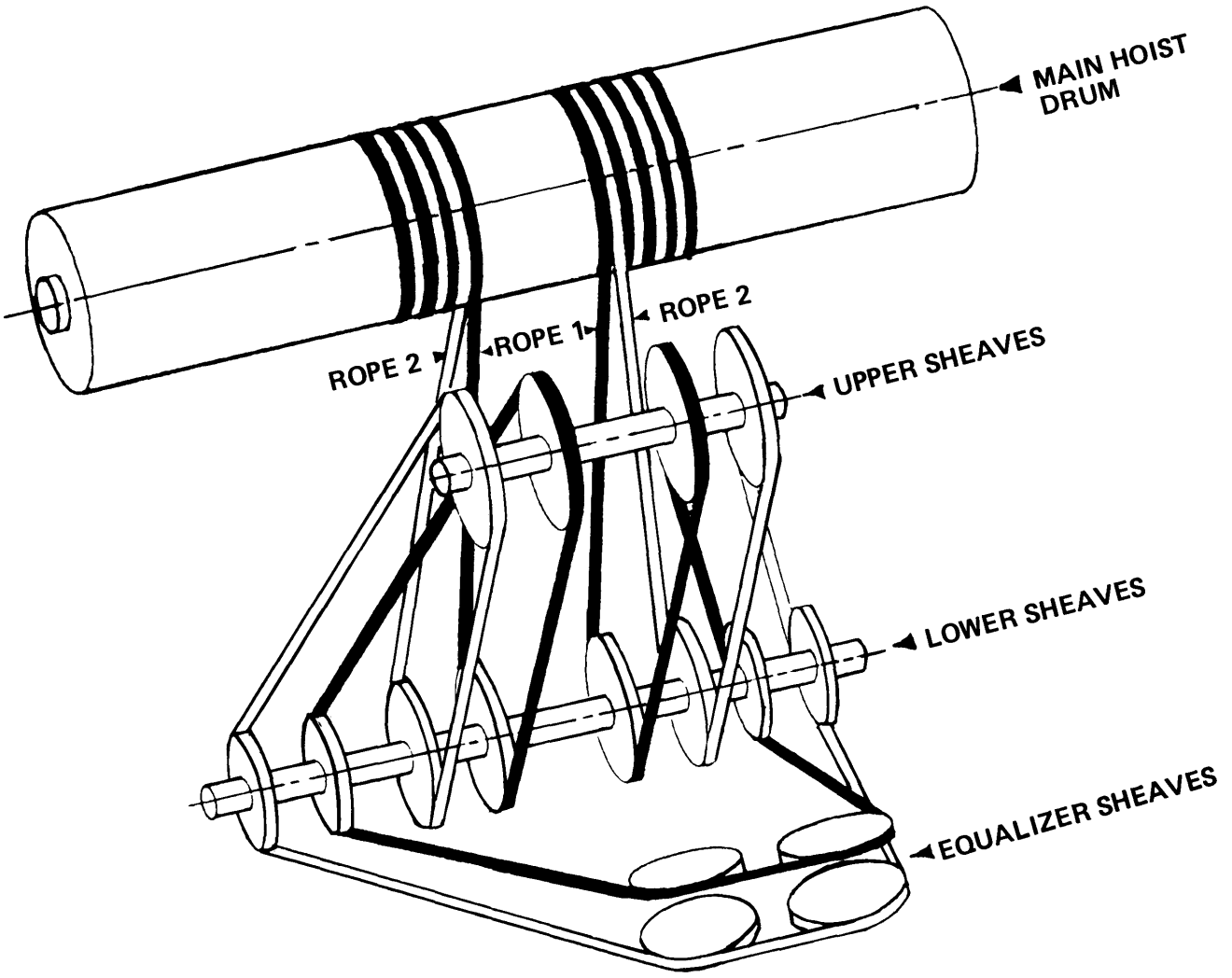




LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE CRANE TROLLEY LAYOUT

FIGURE 9.1-18



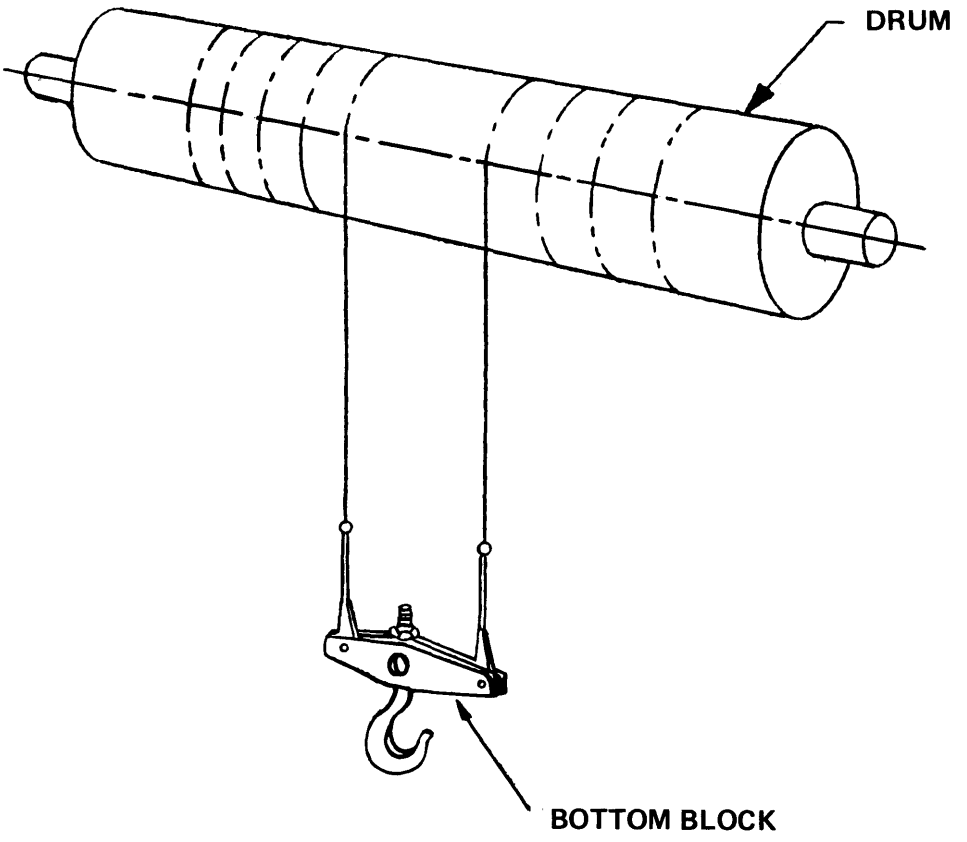
NOTE:

RELATIVE POSITION OF SHEAVES IS EXTENDED AND ANGLE OF VIEW IS DISTORED TO CLARIFY REEVING PATHS.

LIMERICK GENERATING STATION
UNITS 1 AND 2
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REACTOR ENCLOSURE
CRANE MAIN HOIST
REEVING SYSTEM

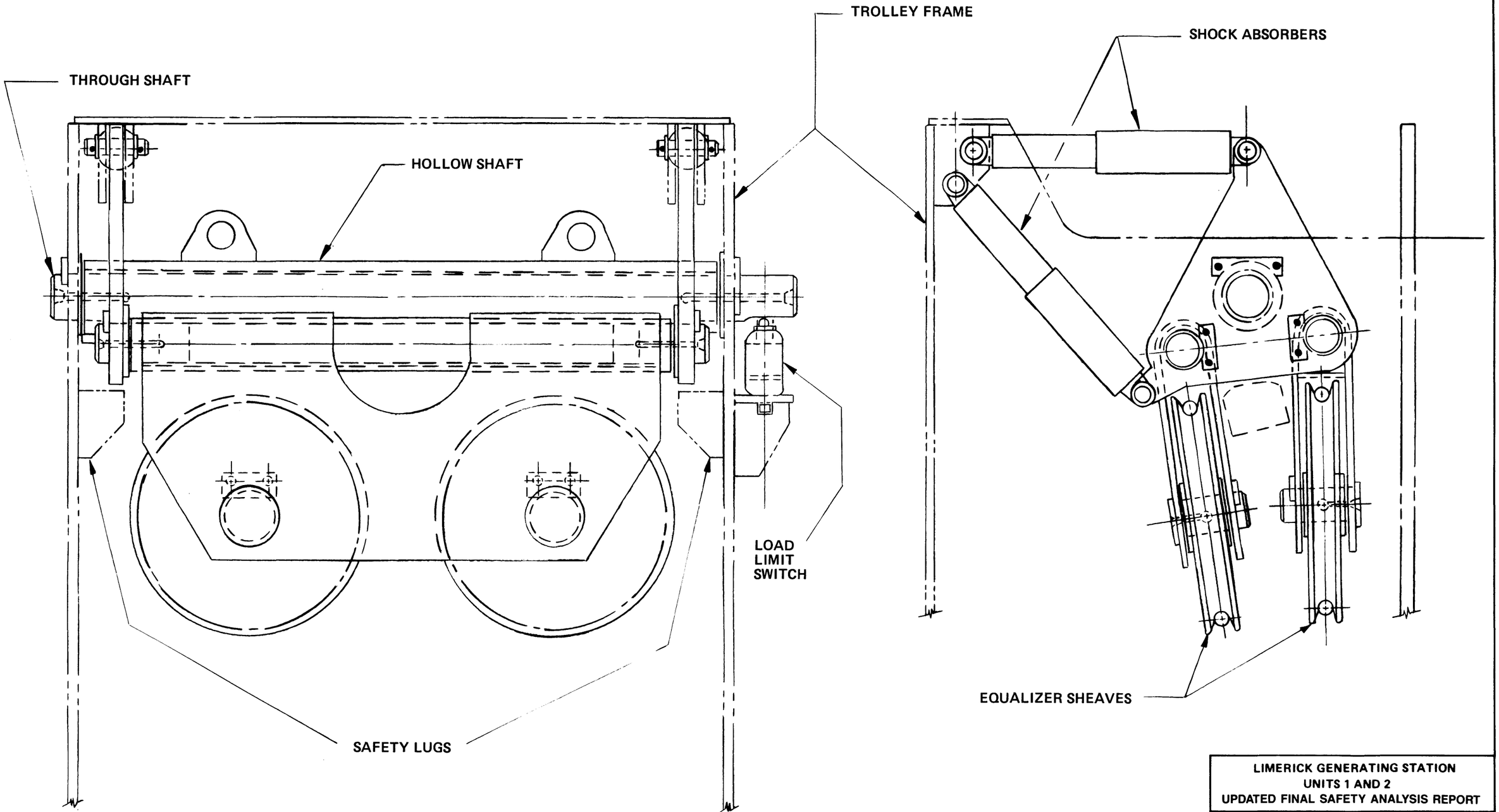
FIGURE 9.1-19



LIMERICK GENERATING STATION
UNITS 1 AND 2
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REACTOR ENCLOSURE
CRANE AUXILIARY
HOIST REEVING
SYSTEM

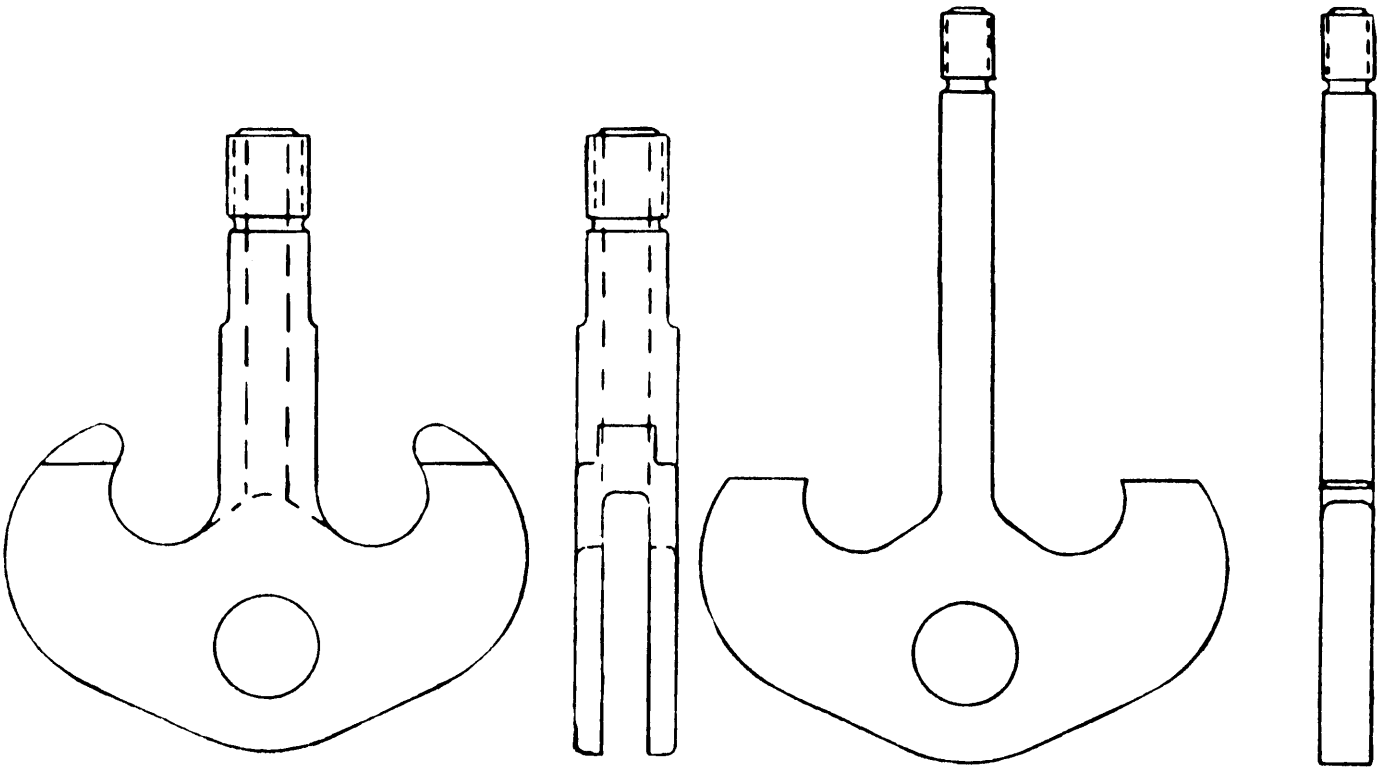
FIGURE 9.1-20



LIMERICK GENERATING STATION
UNITS 1 AND 2
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REACTOR ENCLOSURE CRANE
EQUALIZER ASSEMBLY

FIGURE 9.1-21



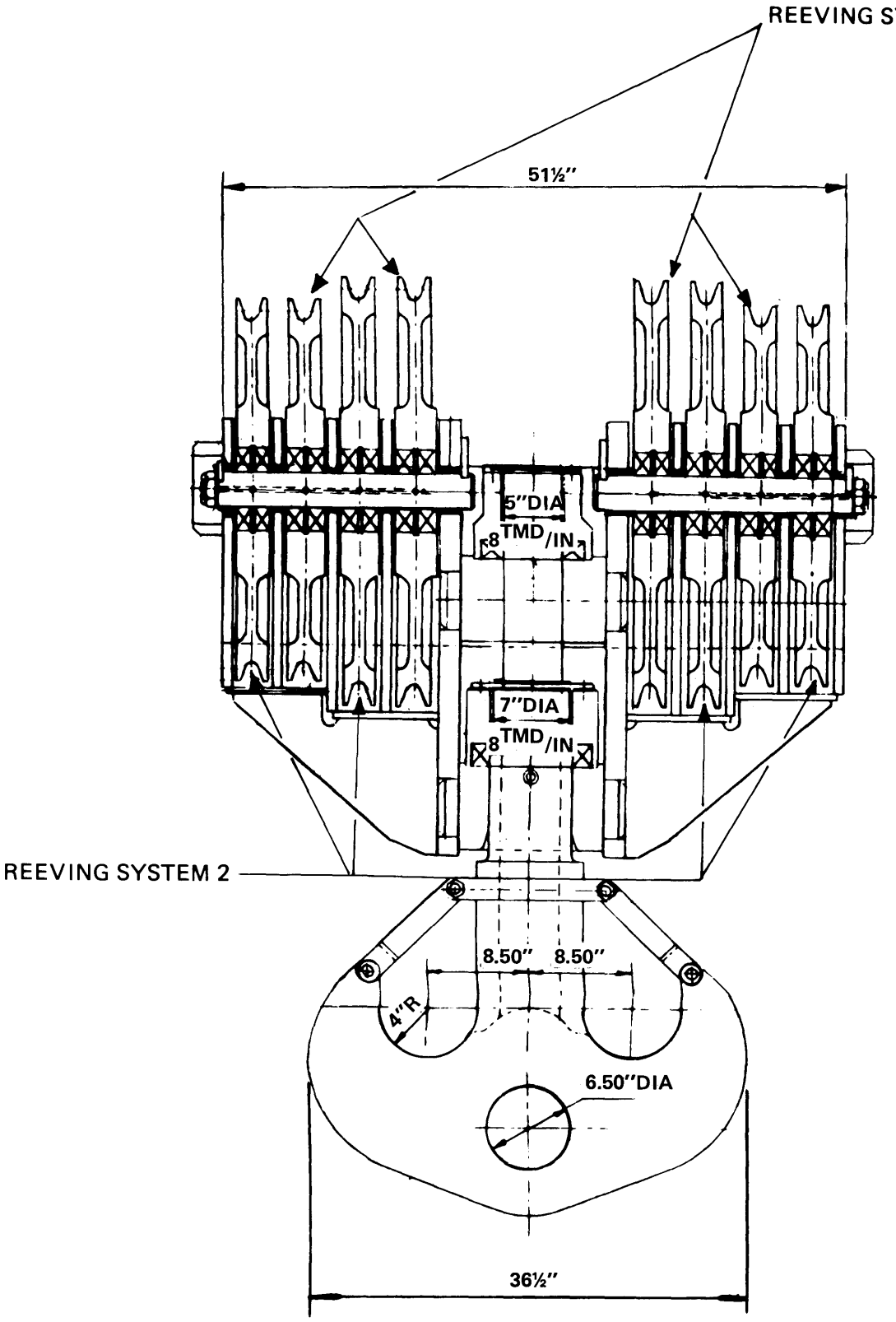
EXTERNAL HOOK

INTERNAL HOOK

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE
CRANE MAIN HOIST
REDUNDANT HOOK

FIGURE 9.1-22



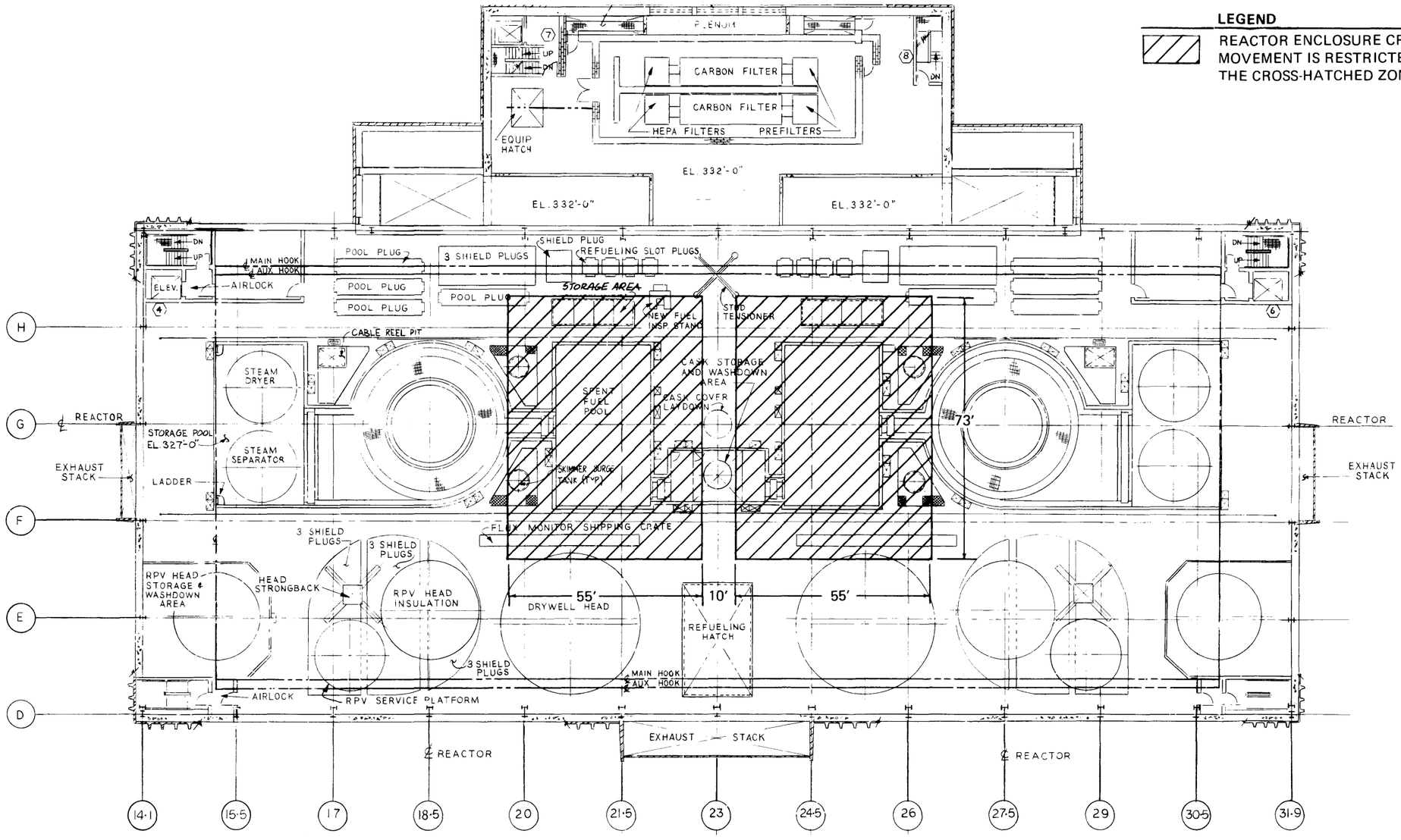
LIMERICK GENERATING STATION
UNITS 1 AND 2
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REACTOR ENCLOSURE
CRANE LOAD
BLOCK ASSEMBLY

FIGURE 9.1-23

LEGEND

REACTOR ENCLOSURE CRANE MOVEMENT IS RESTRICTED WITHIN THE CROSS-HATCHED ZONES.



NOTE: THE PURPOSE OF THIS DRAWING IS TO IDENTIFY THE RESTICTED AREA ABOVE WHICH THE HOOK OF THE REACTOR ENCLOSURE CRANE IS PROHIBITED FROM ENTERING WITHOUT DIRECT POSITIVE OPERATOR ACTION. BACKGROUND IS SHOWN FOR REFERENCE AND MAY NOT BE CORRECT. SEE FIGURES 1.2-14 AND 1.2-15 FOR CORRECT INFORMATION ON REFUELING FLOOR LAYOUT.

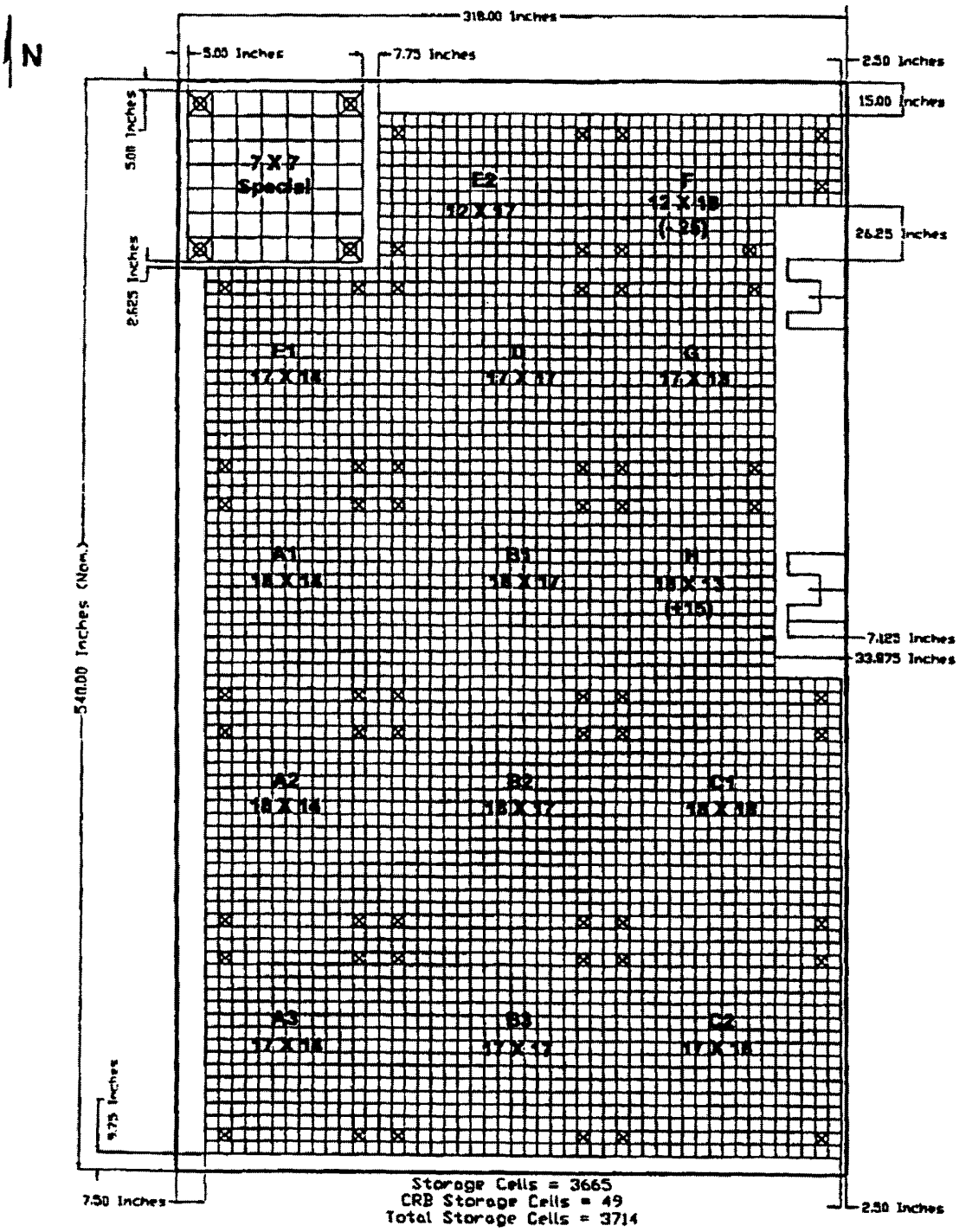
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR ENCLOSURE CRANE RESTRICTED AREA

FIGURE 9.1-24

Figure 9.1-25 thru 9.1-33

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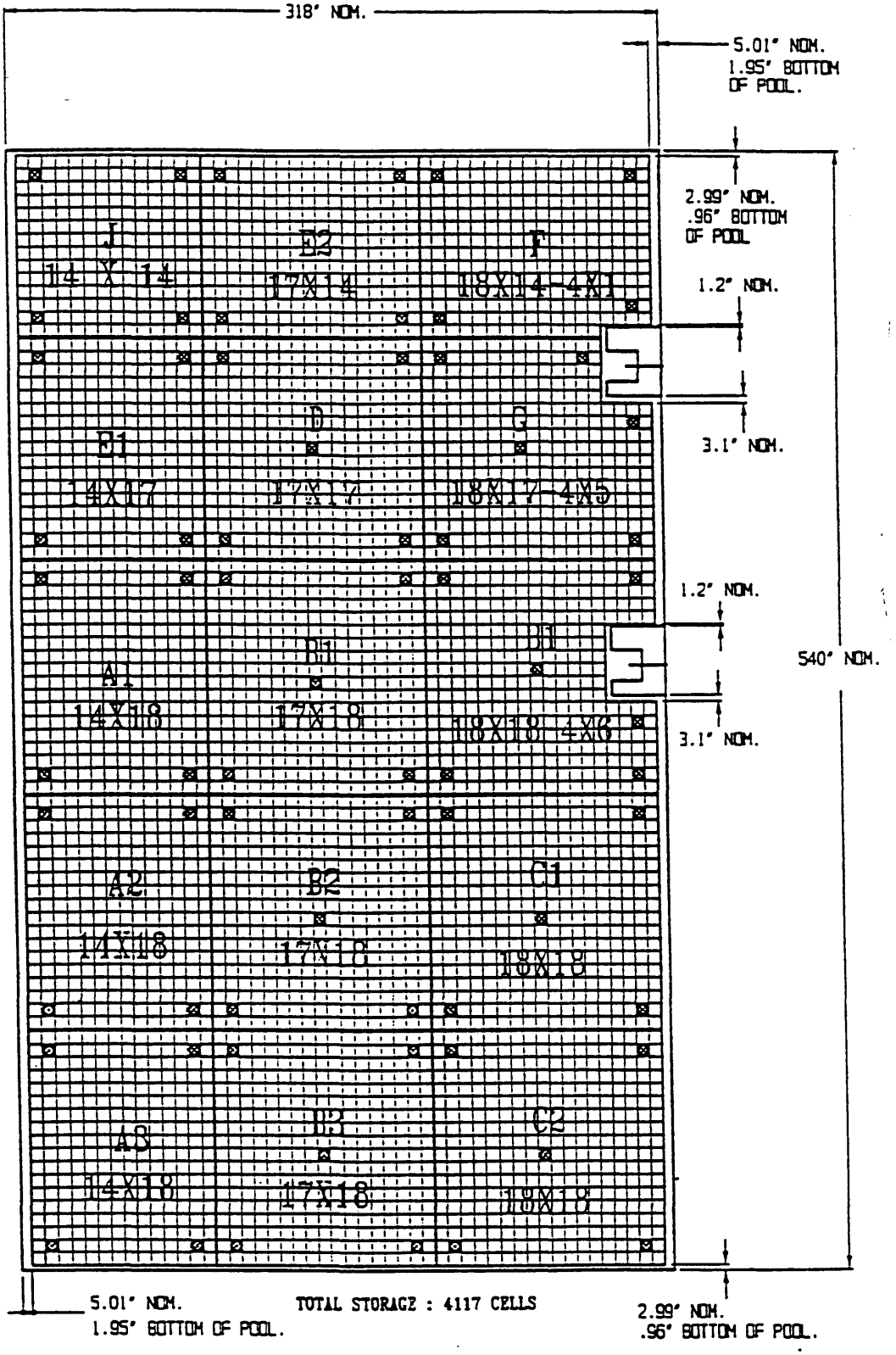
Notes:

1) Dimensions are For Information Only, refer to As-Built Drawings for actual dimensions.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

UNIT 1 FUEL POOL INITIAL LAYOUT

FIGURE 9.1-34 Rev. 12 9/04

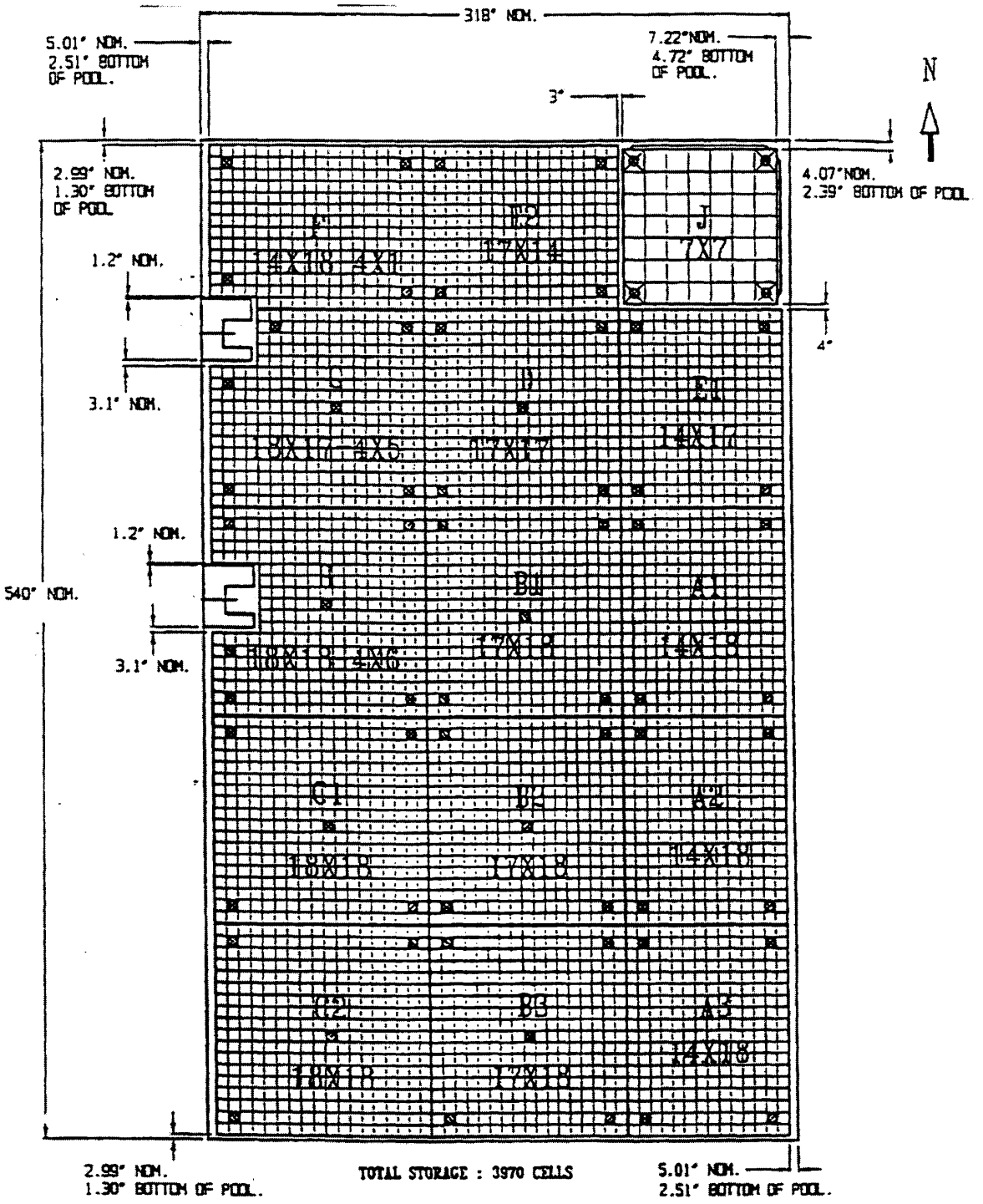


DIMENSIONS ARE FOR INFORMATION ONLY, REFER TO AS-BUILT DRAWINGS FOR ACTUAL DIMENSIONS

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

UNIT 1 FUEL POOL
LAYOUT FOR MAXIMUM CAPACITY

FIGURE 9.1-35 Rev. 5, 4/96



Storage Cells	= 3921
CRB Storage Cells	= 49
Total Storage Cells	= 3970

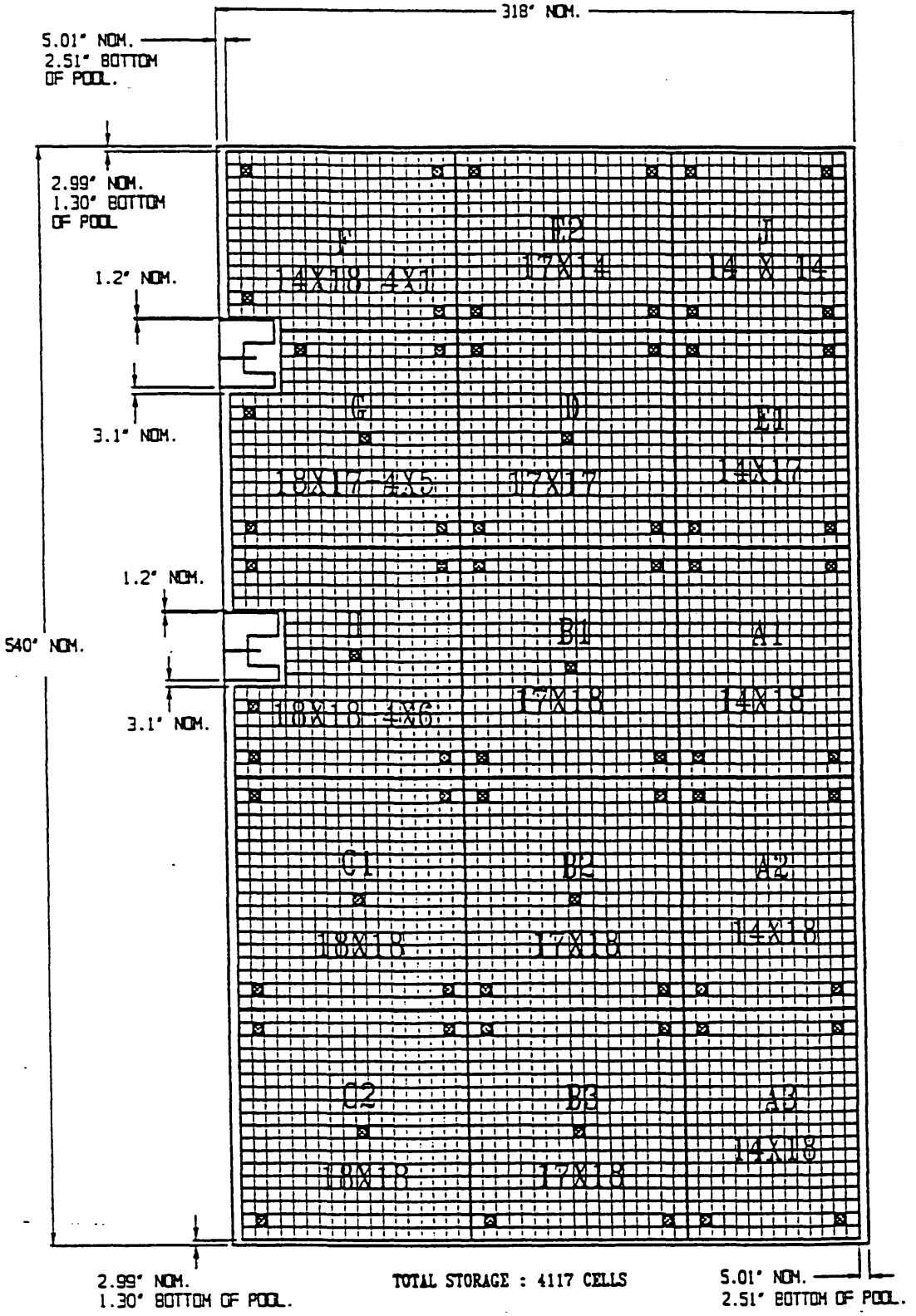
Notes:

1) Dimensions are For Information Only, refer to As-Built Drawings for actual dimensions.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

UNIT 2 FUEL POOL INITIAL LAYOUT

FIGURE 9.1-36 **Rev. 12 9/04**



DIMENSIONS ARE FOR INFORMATION ONLY, REFER TO AS-BUILT DRAWINGS FOR ACTUAL DIMENSIONS

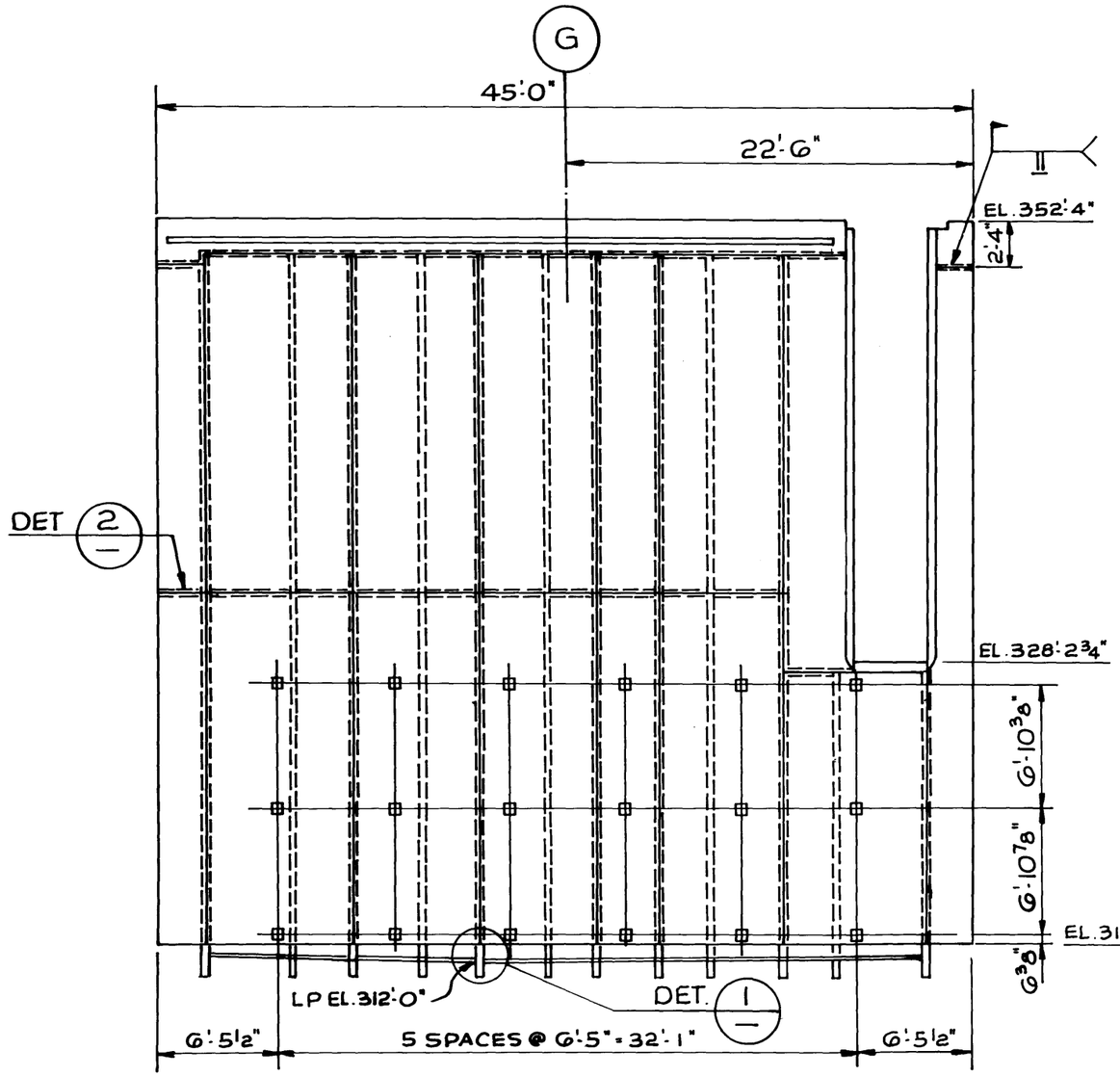
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

UNIT 2 FUEL POOL LAYOUT FOR MAXIMUM CAPACITY

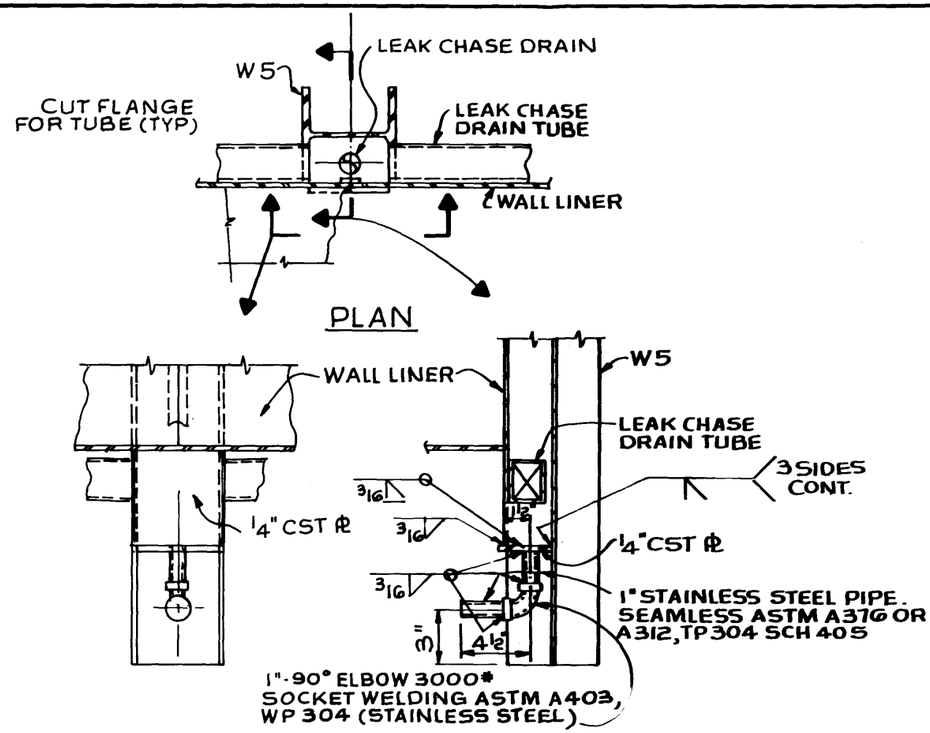
FIGURE 9.1-37 Rev. 5, 4/96

Figure 9.1-38 thru 9.1-39

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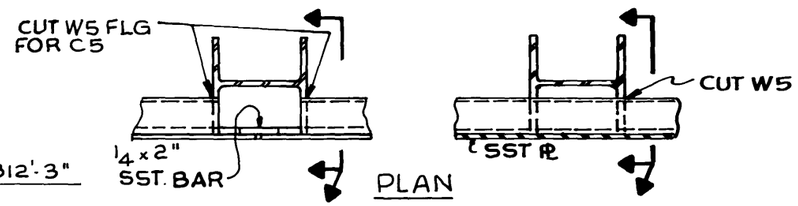


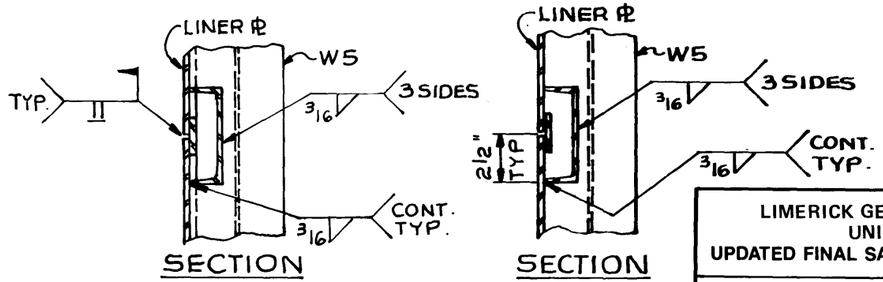
ENCLOSURE WALL ELEVATION
(LOOKING EAST)
N.T.S.



TYPICAL LEAK CHASE DRAIN DETAIL AT LOW POINTS

DETAIL 1
N.T.S.





TYPICAL HORIZ. LEAK CHASE DETAILS FOR WALL LINERS

DETAIL 2
N.T.S.

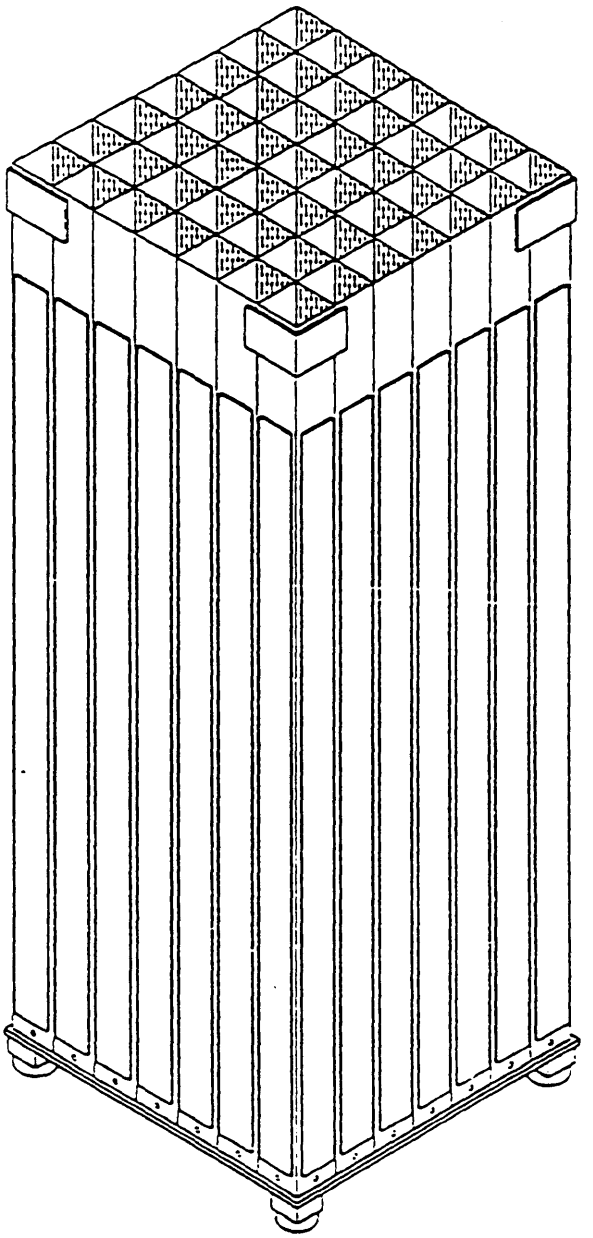
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-233, -234, and -244

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SPENT FUEL POOL
LINER LEAKAGE DETECTION SYSTEM
TYPICAL DRAINAGE PATH
FOR ENCLOSURE WALLS

FIGURE 9.1-40

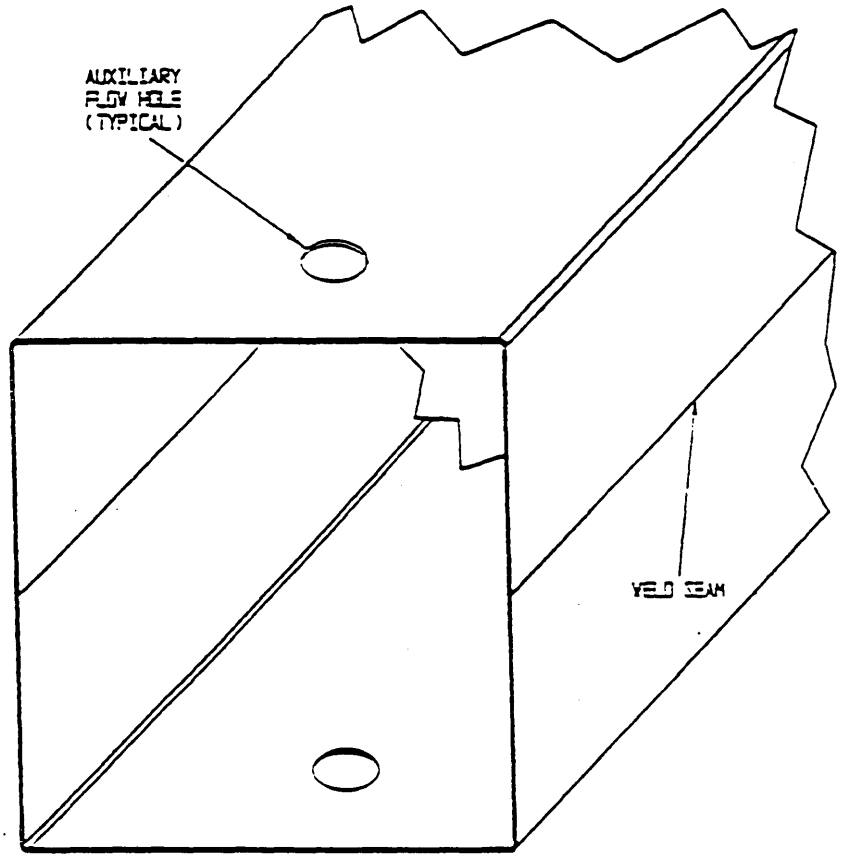


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAXIMUM DENSITY
SPENT FUEL STORAGE RACKS
(SHEET 1 OF 6)

FIGURE 9.1 –41

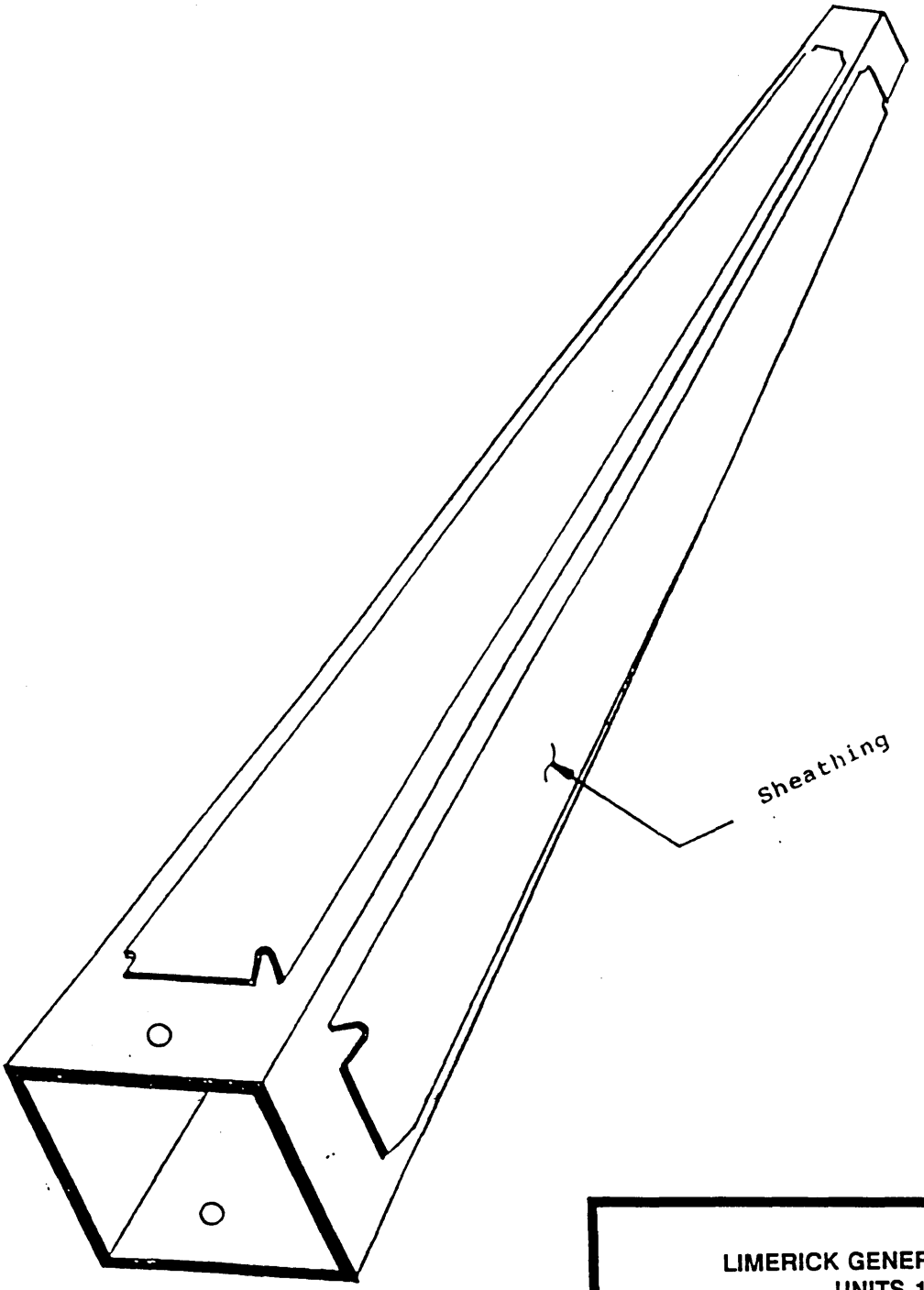
REV. 5 4/95



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAXIMUM DENSITY
SPENT FUEL STORAGE RACKS
(SHEET 2 OF 6)

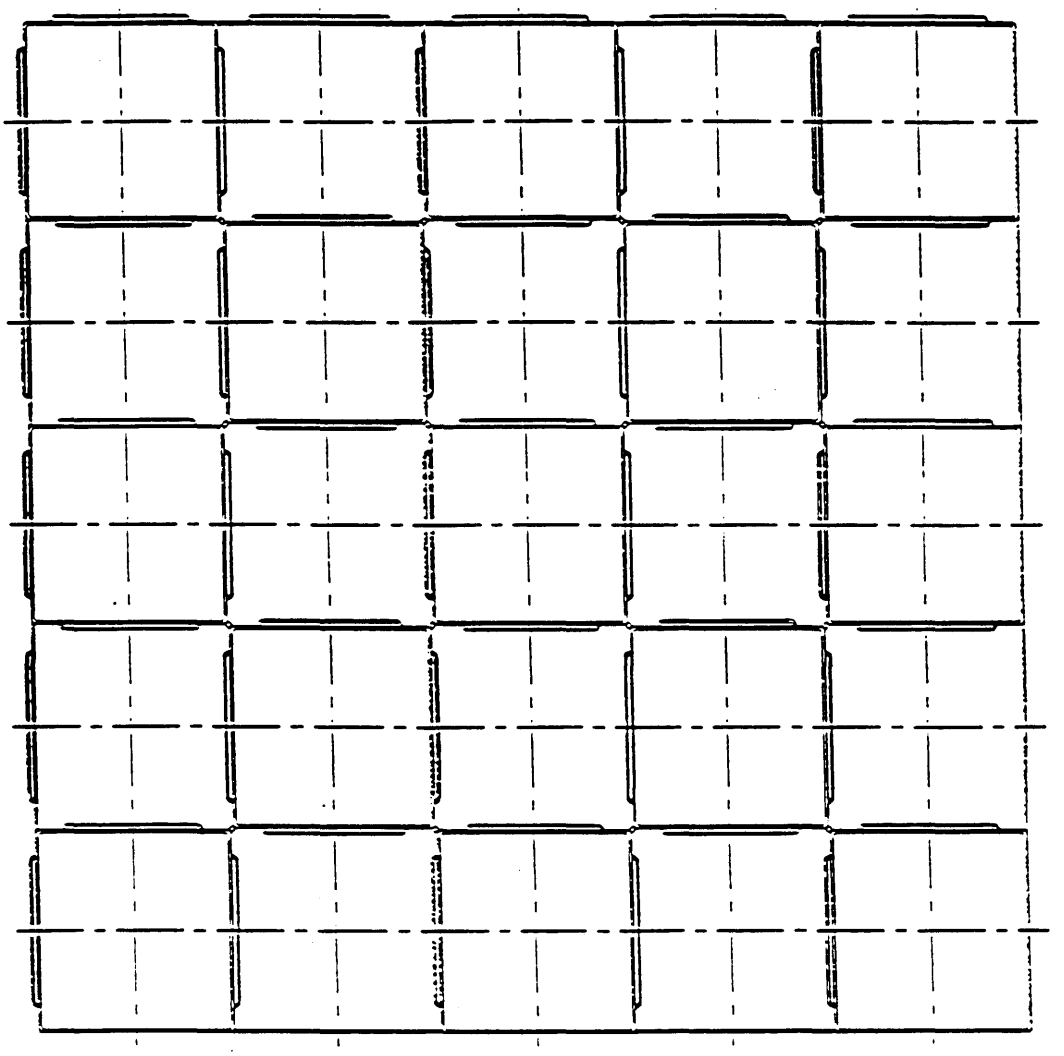
FIGURE 9.1-41 REV. 5 4/95



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAXIMUM DENSITY
SPENT FUEL STORAGE RACKS
(SHEET 3 OF 6)

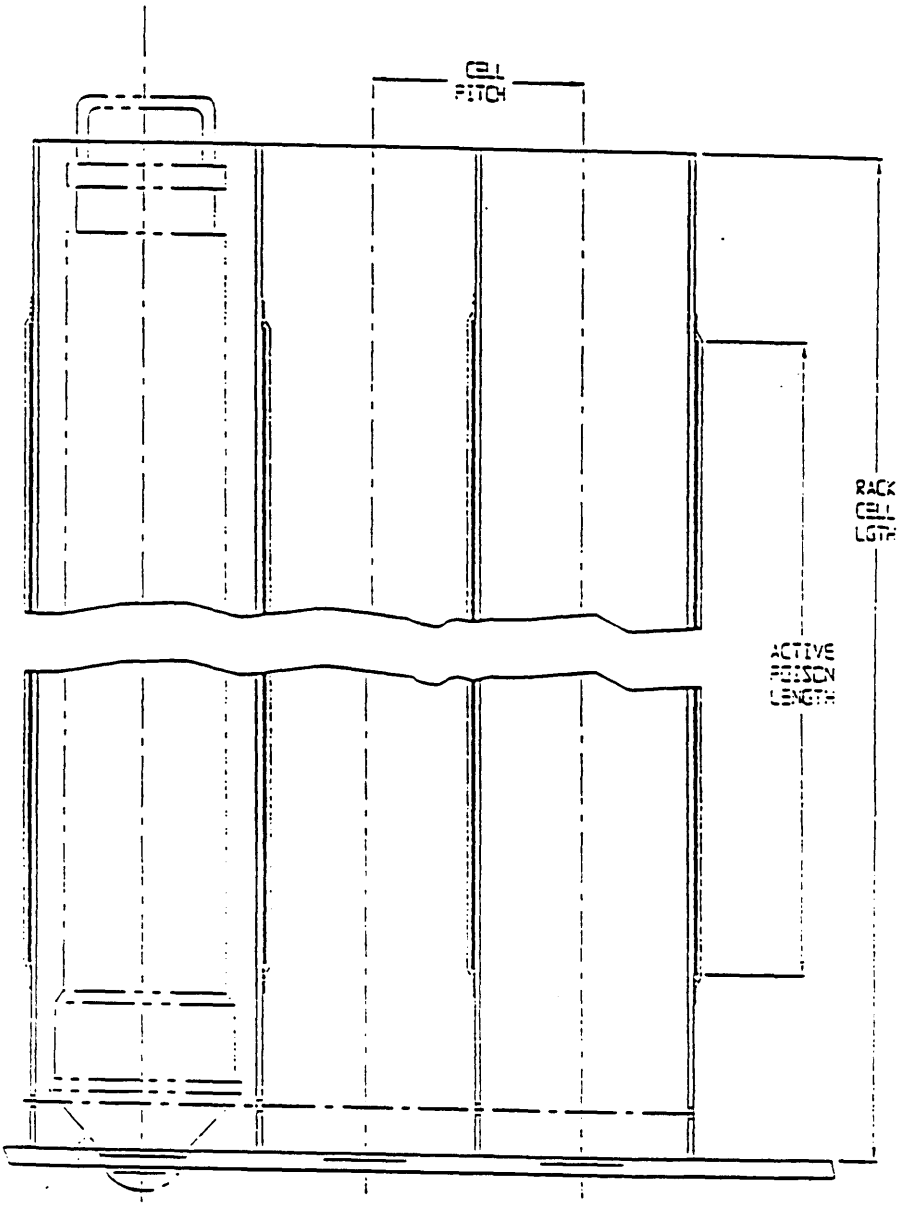
FIGURE 9.1 -41 REV. 5 4/95



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAXIMUM DENSITY
SPENT FUEL STORAGE RACKS
(SHEET 4 OF 6)

FIGURE 9.1 –41 REV. 5 4/95

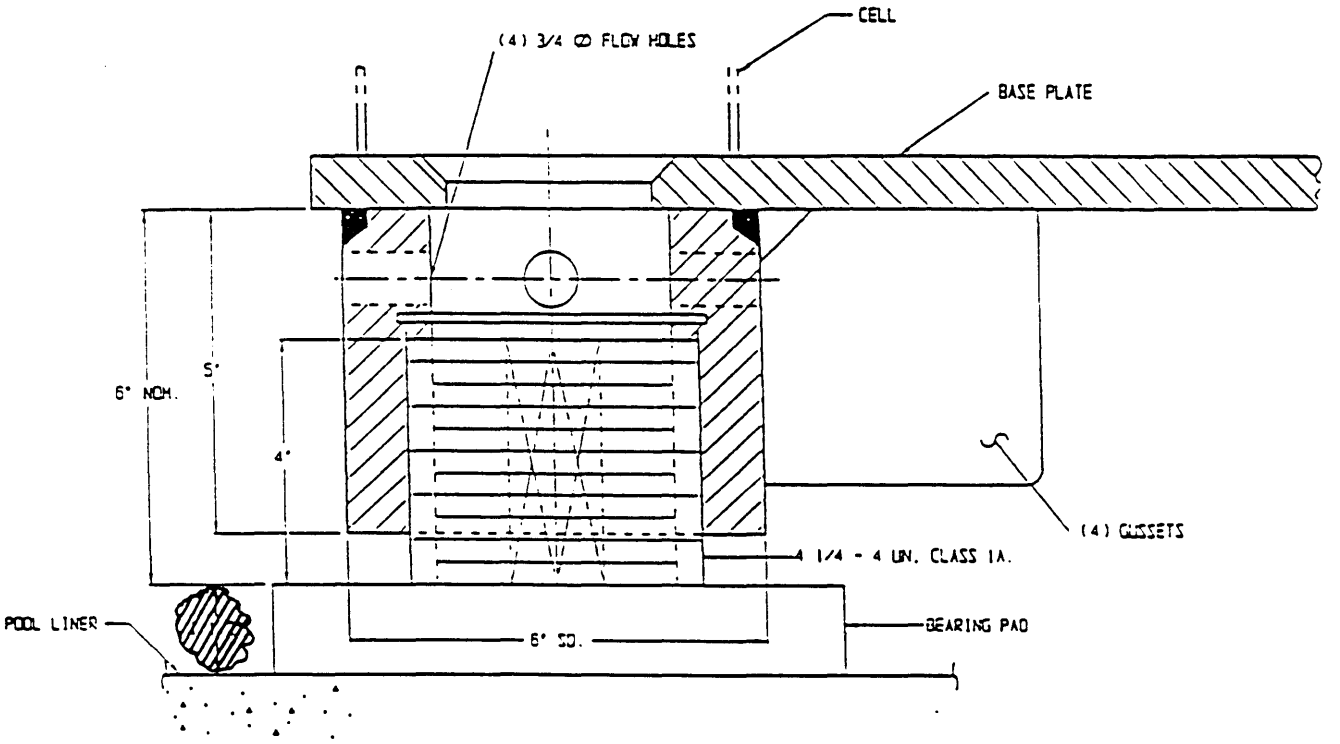


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAXIMUM DENSITY
SPENT FUEL STORAGE RACKS
(SHEET 5 OF 6)

FIGURE 9.1 -41

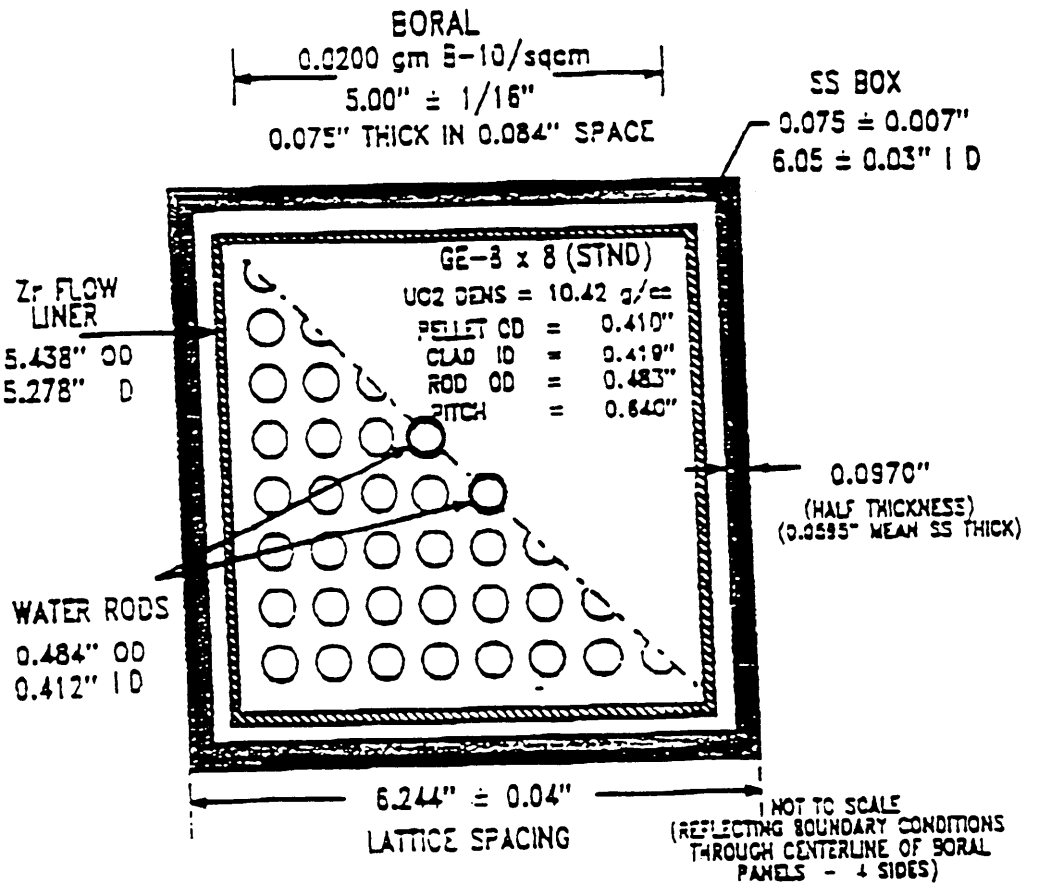
REV. 5 4/95



LIMERICK GENERATING STATION
UNITS 1 AND 2
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MAXIMUM DENSITY
SPENT FUEL STORAGE RACKS
(SHEET 6 OF 6)

FIGURE 9.1 -41 REV. 5 4/95



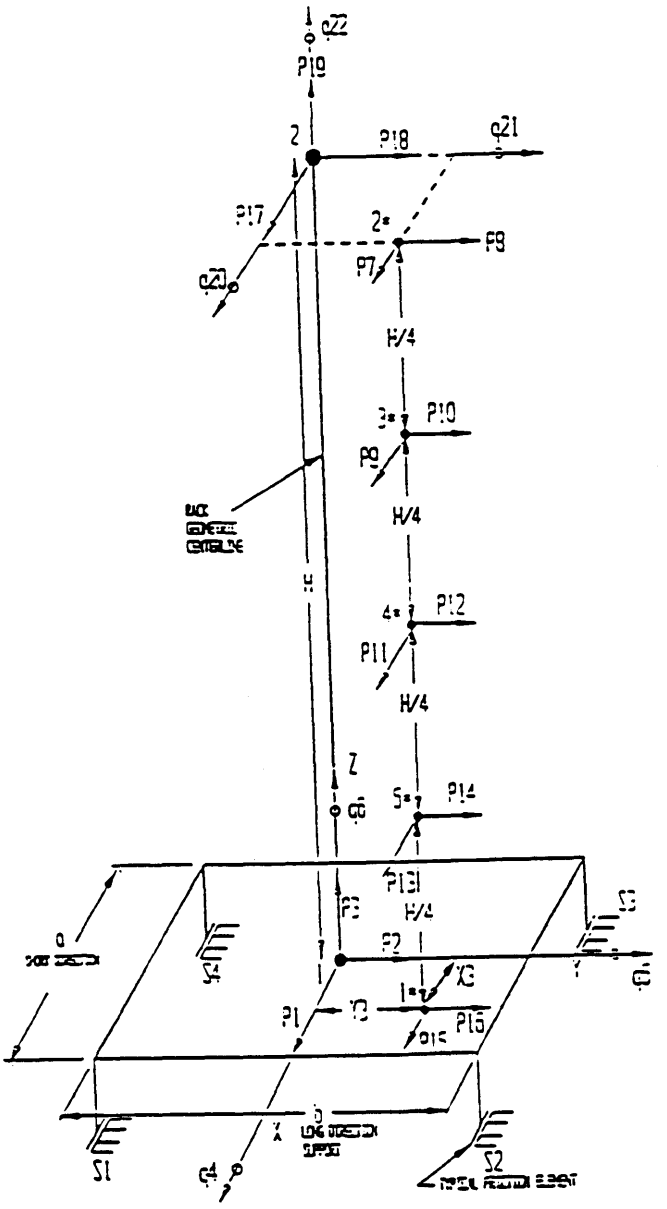
DIMENSIONS ARE FOR INFORMATION ONLY, REFER TO AS-BUILT DRAWINGS FOR ACTUAL DIMENSIONS

LIMERICK GENERATING STATION
UNITS 1 AND 2
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MAXIMUM DENSITY
SPENT FUEL CAVITY
GEOMETRY

FIGURE 9.1 –42

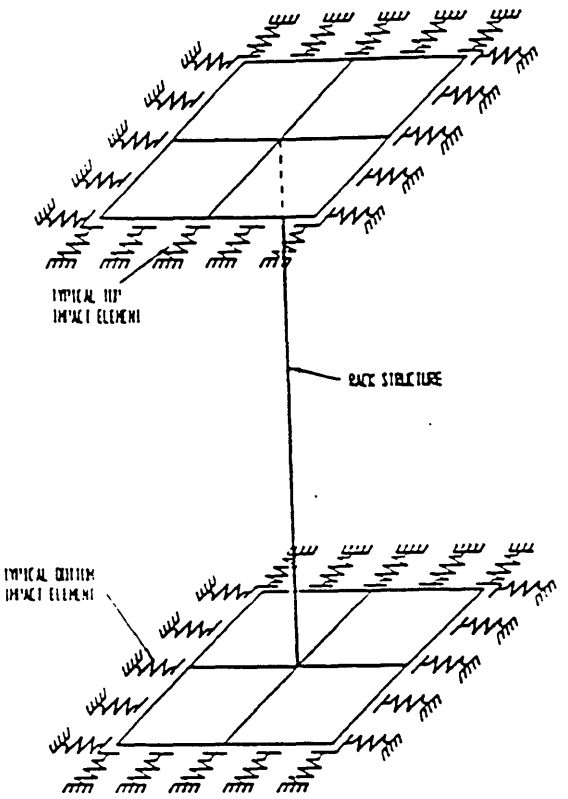
REV. 5 4/95



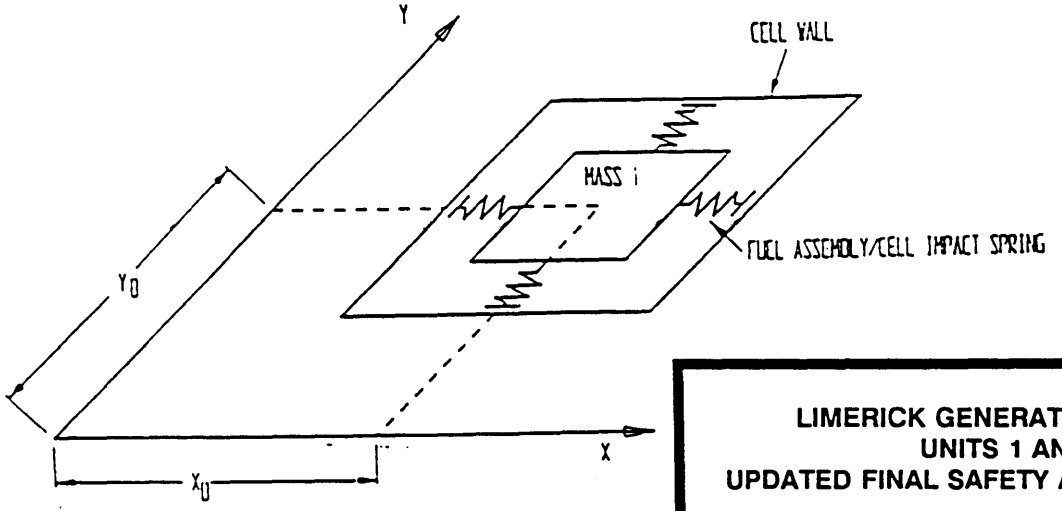
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAXIMUM DENSITY
SPENT FUEL STORAGE RACK
SCHEMATIC MODEL FOR DYNARACK

FIGURE 9.1-43 REV. 5 4/95



RACK TO RACK IMPACT SPRINGS

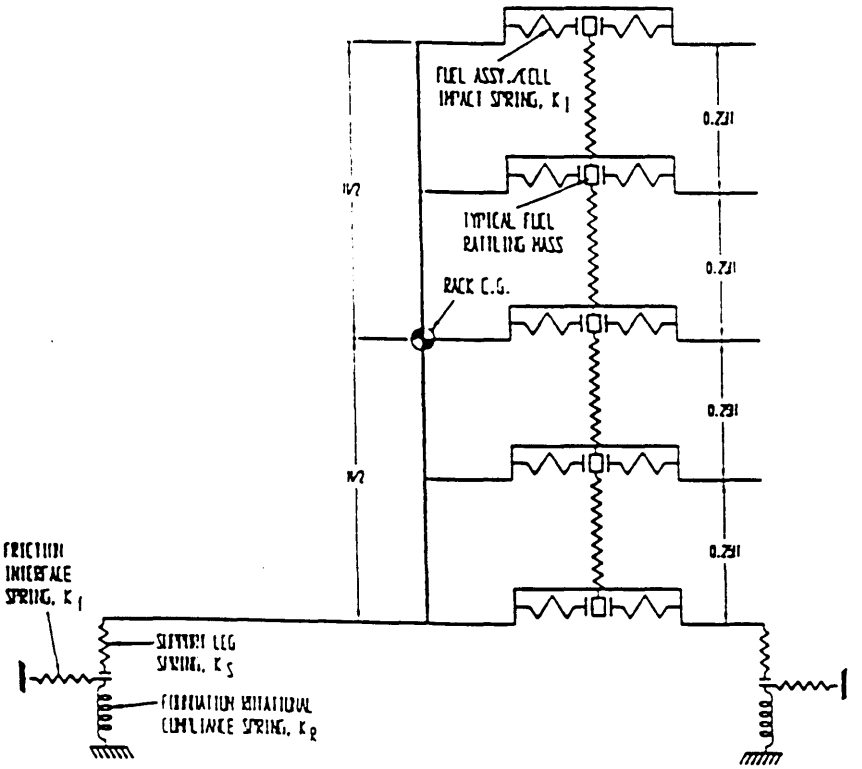


FUEL TO RACK IMPACT SPRINGS

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAXIMUM DENSITY
SPENT FUEL STORAGE RACK
DYNAMIC MODEL

FIGURE 9.1-44 REV. 5 4/95



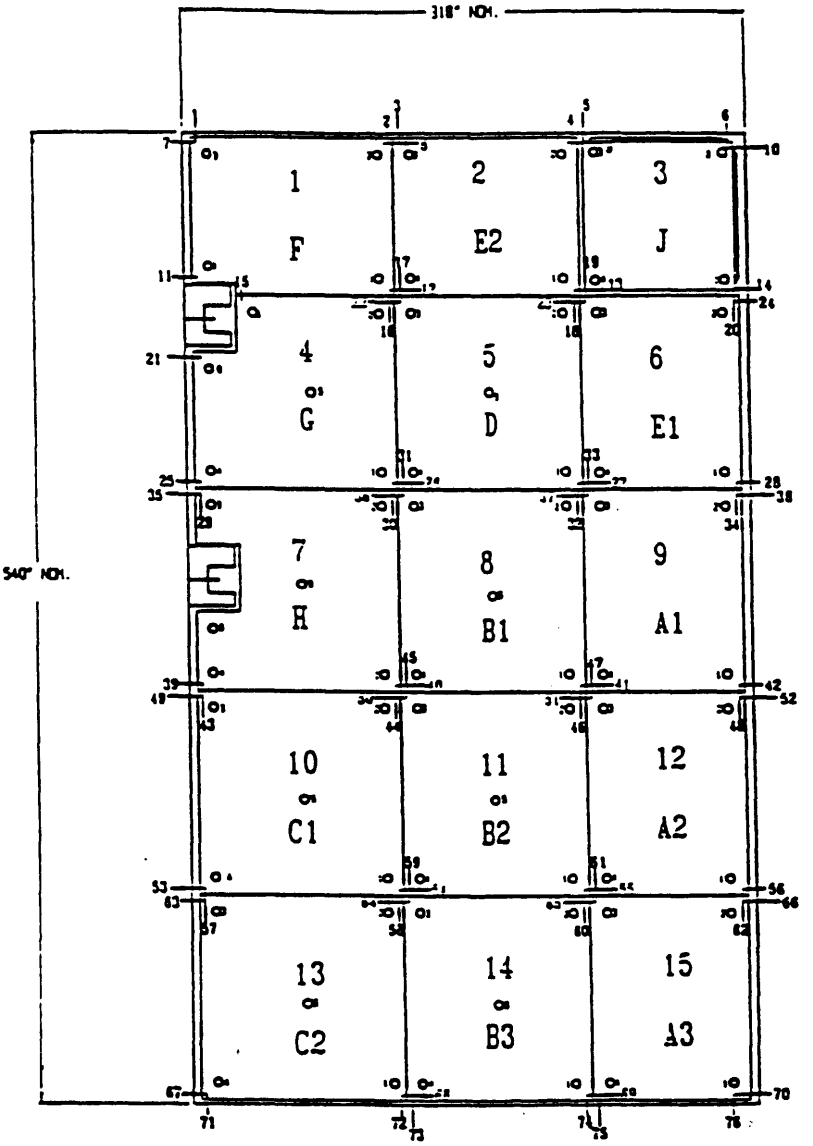
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAXIMUM DENSITY
SPENT FUEL STORAGE RACK
2-D VIEW OF MODEL

FIGURE 9.1-45 REV. 5 4/95

Figure 9.1-46

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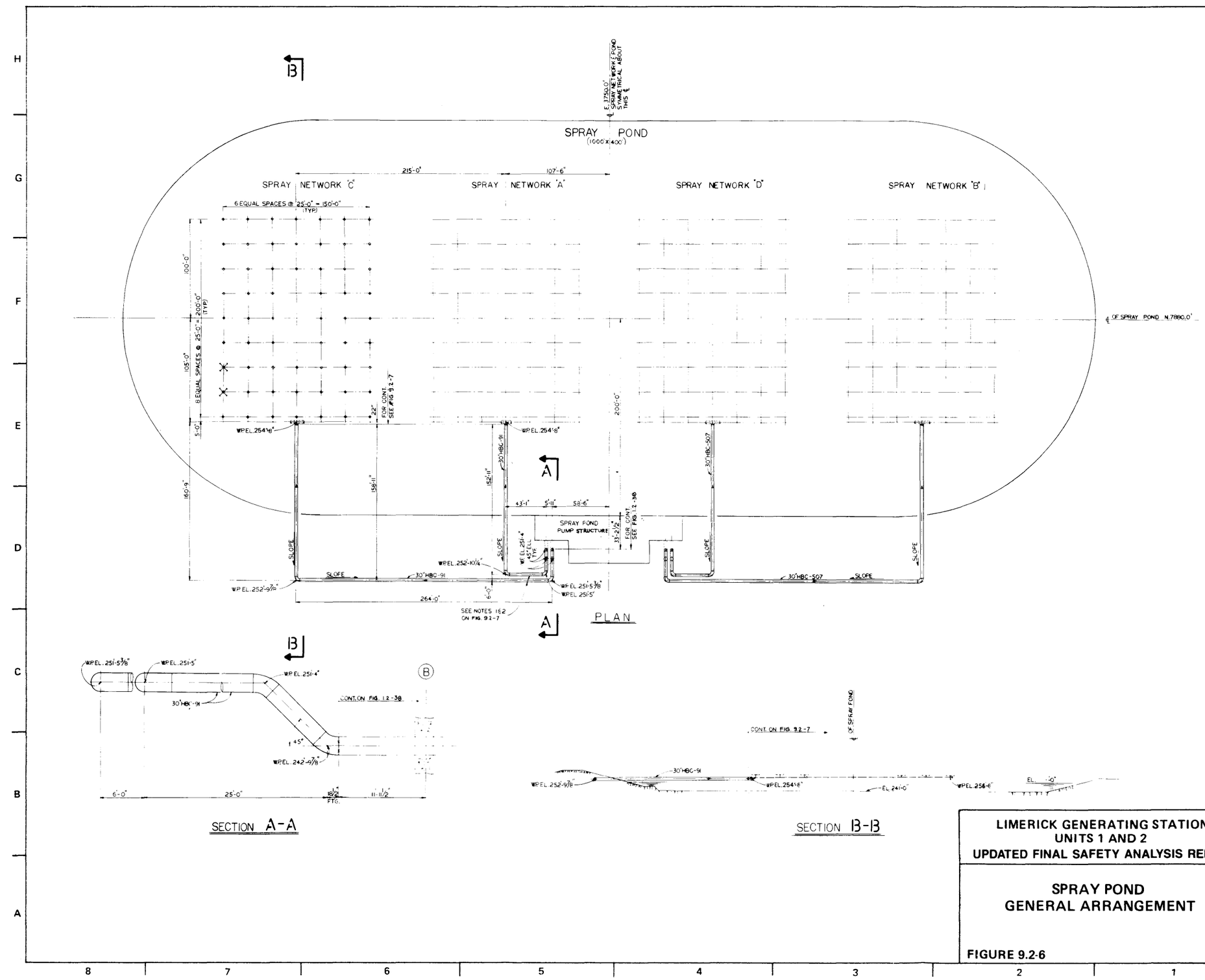
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

UNIT 2
WHOLE POOL MULTI-RACK
MODEL

FIGURE 9.1-47 REV. 13 09/06

Figure 9.2-1 thru 9.2-5

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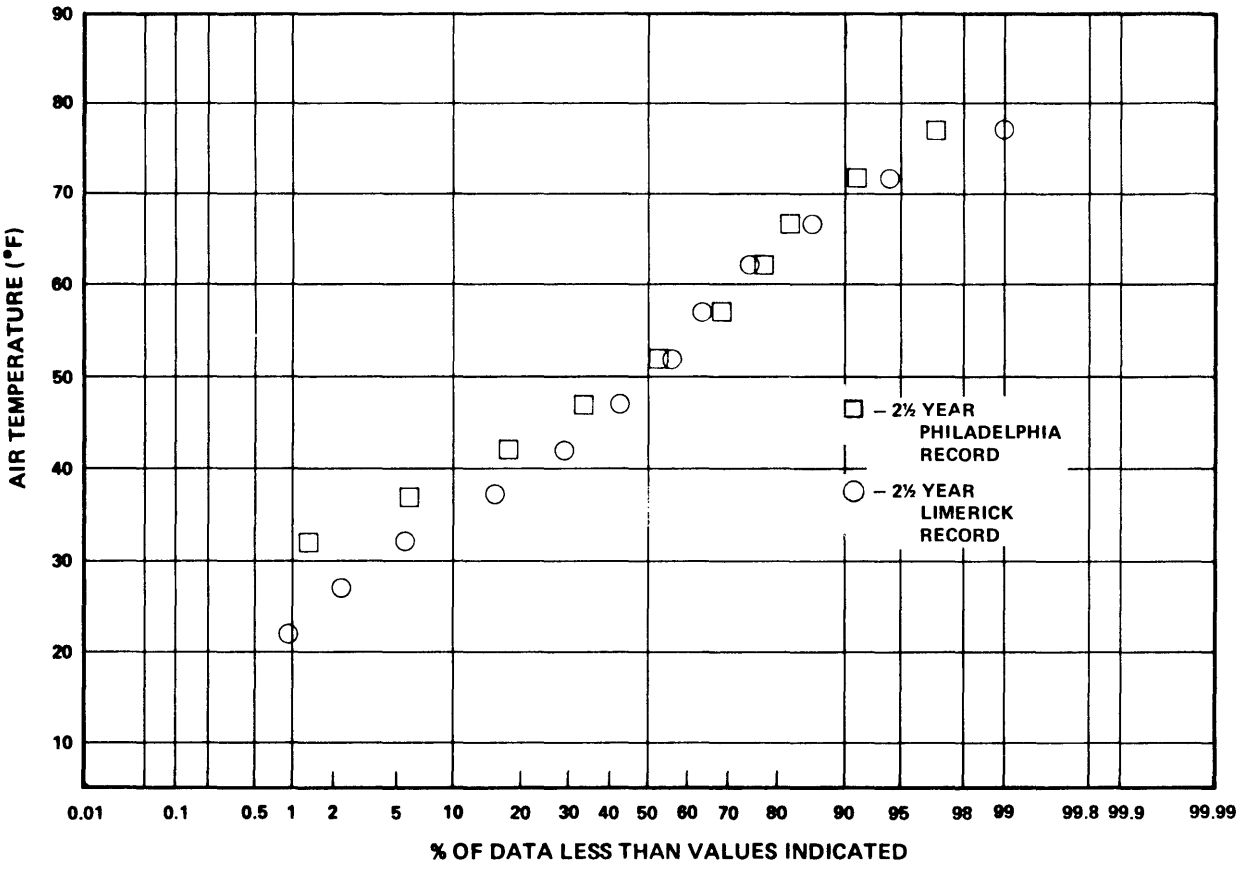
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SPRAY POND GENERAL ARRANGEMENT

FIGURE 9.2-6

Figure 9.2-7

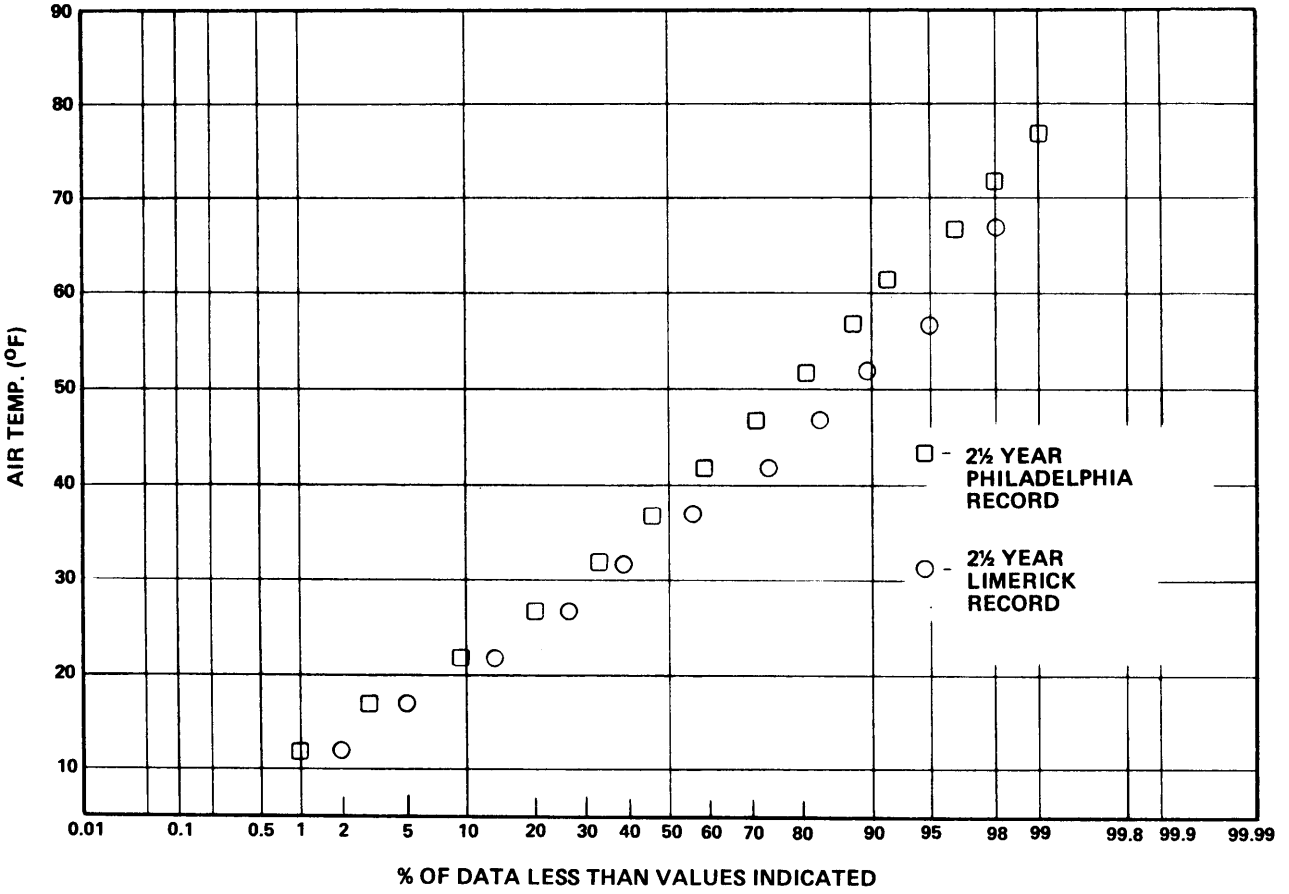
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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CUMULATIVE DISTRIBUTION OF 24-HOUR MEAN TEMPERATURE IN THE 90-100% RELATIVE HUMIDITY CLASS

FIGURE 9.2-8



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CUMULATIVE DISTRUBUTION OF 24 HOUR MEAN TEMPERATURES IN THE < 50% RELATIVE HUMIDITY CLASS

FIGURE 9.2-9

THIS FIGURE DELETED

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SCHEMATIC OF TYPICAL
LOCI USED IN SPRAY
POND DRIFT LOSS ANALYSIS

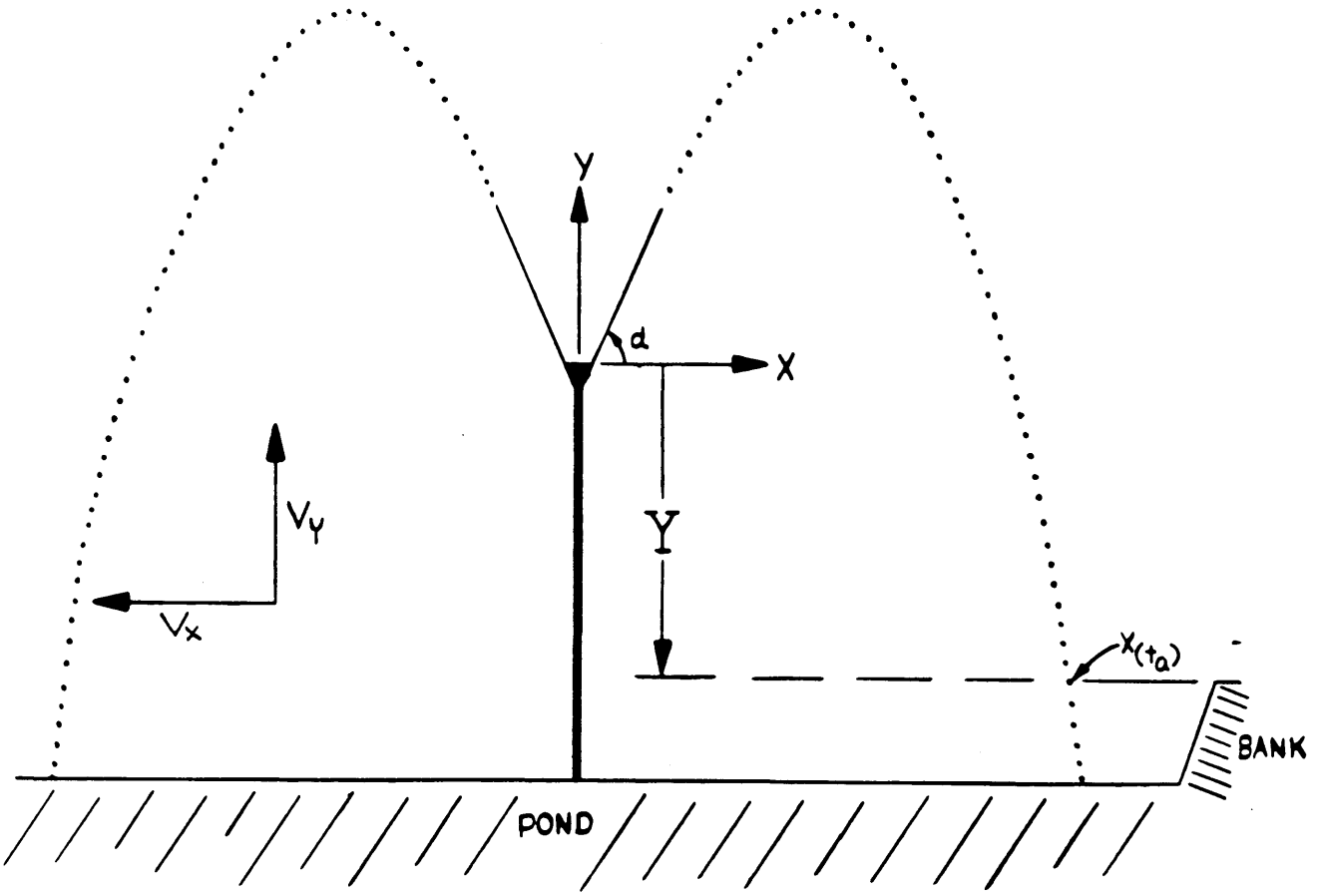
FIGURE 9.2-10 REV. 4 Nov./94

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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRAG FORCE APPROXIMATION
USED FOR SPRAY POND
DRIFT LOSS MODEL

FIGURE 9.2-11 REV. 4 Nov./94



$V_Y \equiv$ average vertical air velocity

$V_X \equiv$ wind velocity

$d \equiv$ angle of departure

$Y \equiv$ elevation of nozzle above elevation necessary for loss

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SPRAY POND DROPLET
TRAJECTORY PARAMETERS

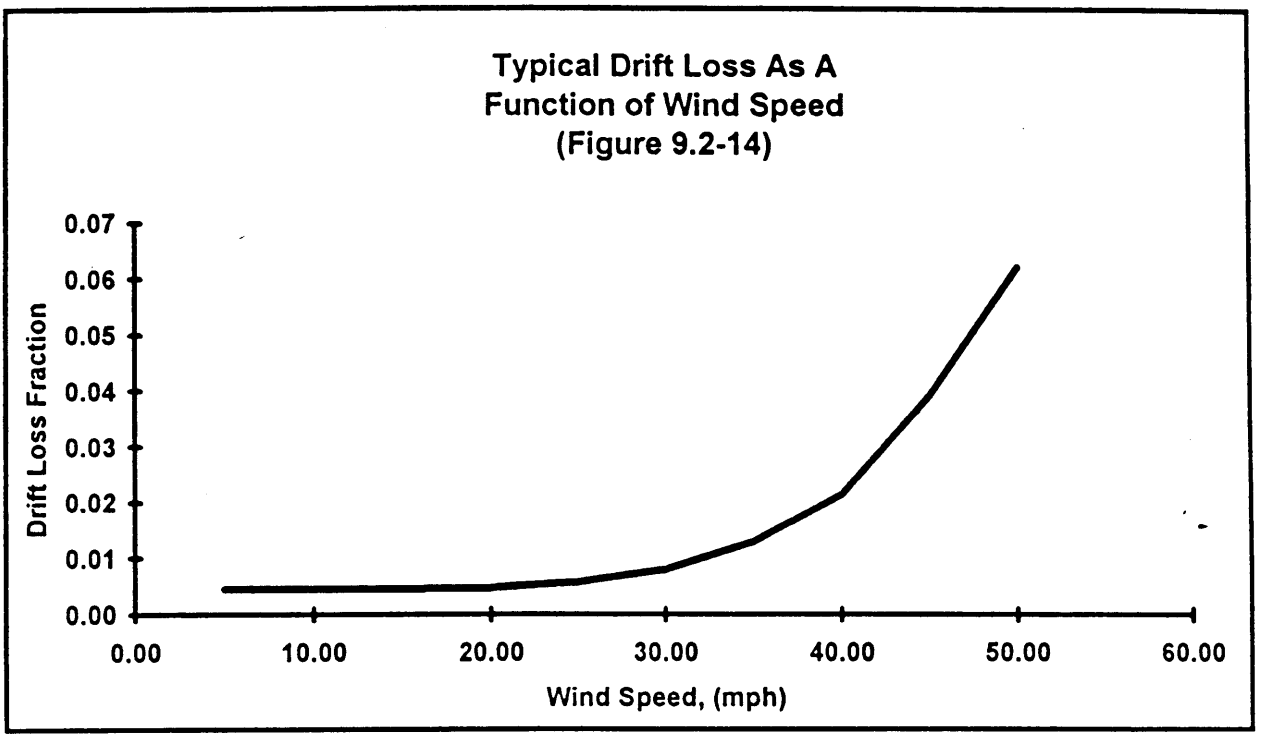
FIGURE 9.2-12 REV. 4 Nov./94

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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRIFT LOSS VS. NOZZLE DISTANCE
FROM SPRAY POND PERIMETER

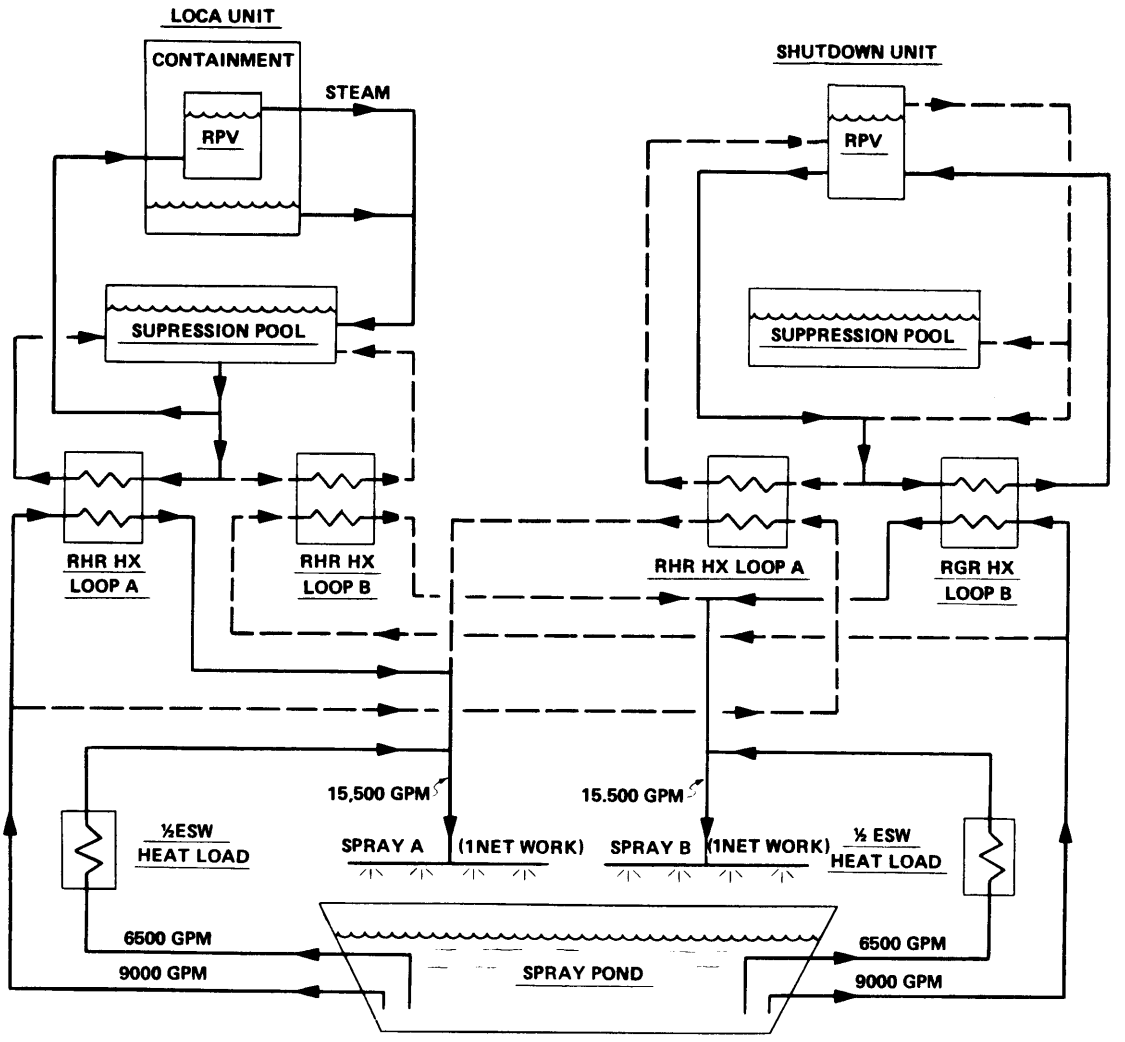
FIGURE 9.2-13 REV. 4 Nov./94



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL DRIFT LOSS AS A
FUNCTION OF WIND SPEED

FIGURE 9.2-14 REV. 4 Nov./94



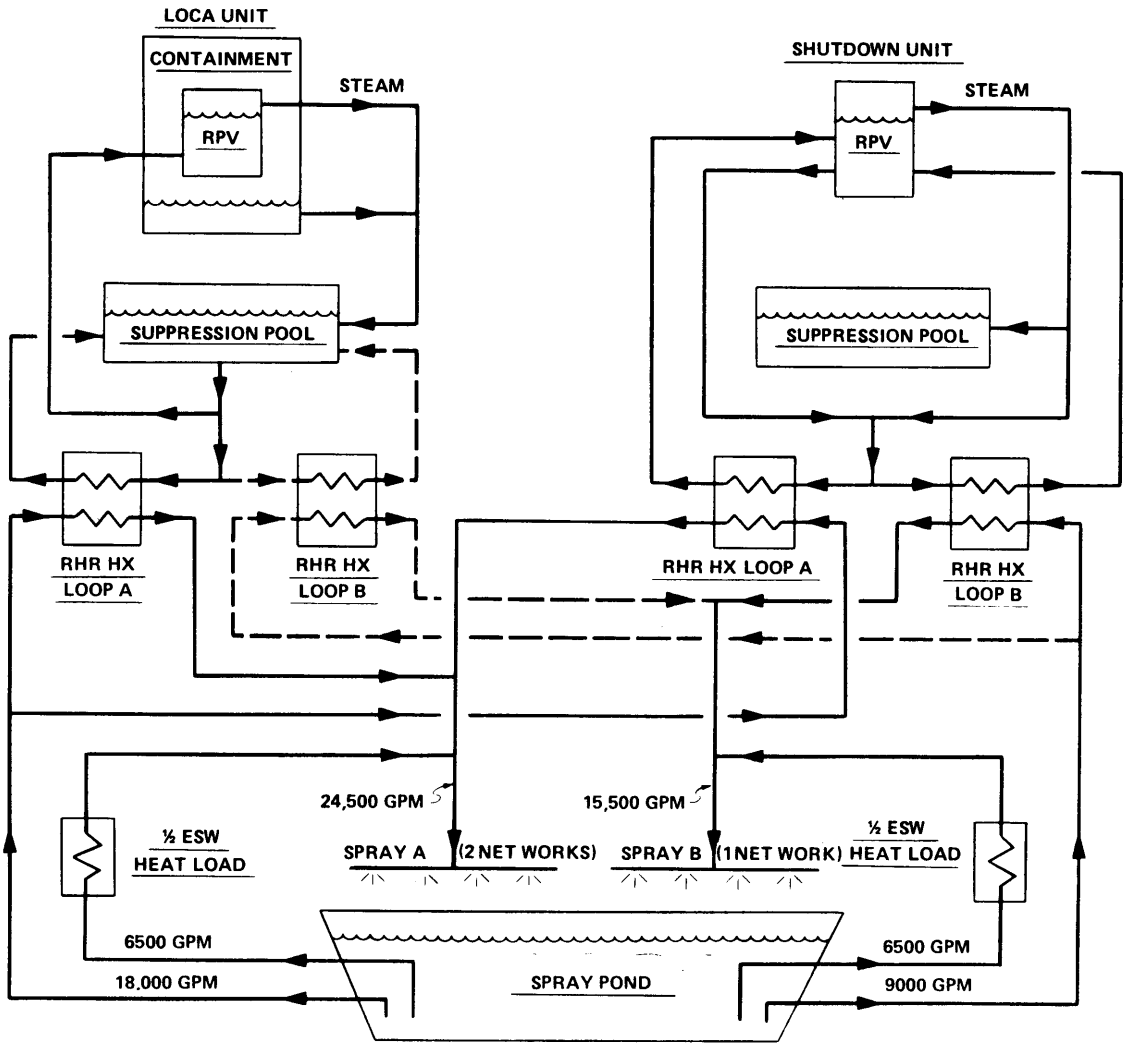
NOTE

DASHED LINES INDICATE POTENTIAL FLOW PATHS NOT USED IN THE SPRAY POND ANALYSIS.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SCHEMATIC OF HEAT REJECTION TO SPRAY POND (TIME < 30 HOURS)

FIGURE 9.2-15



NOTE

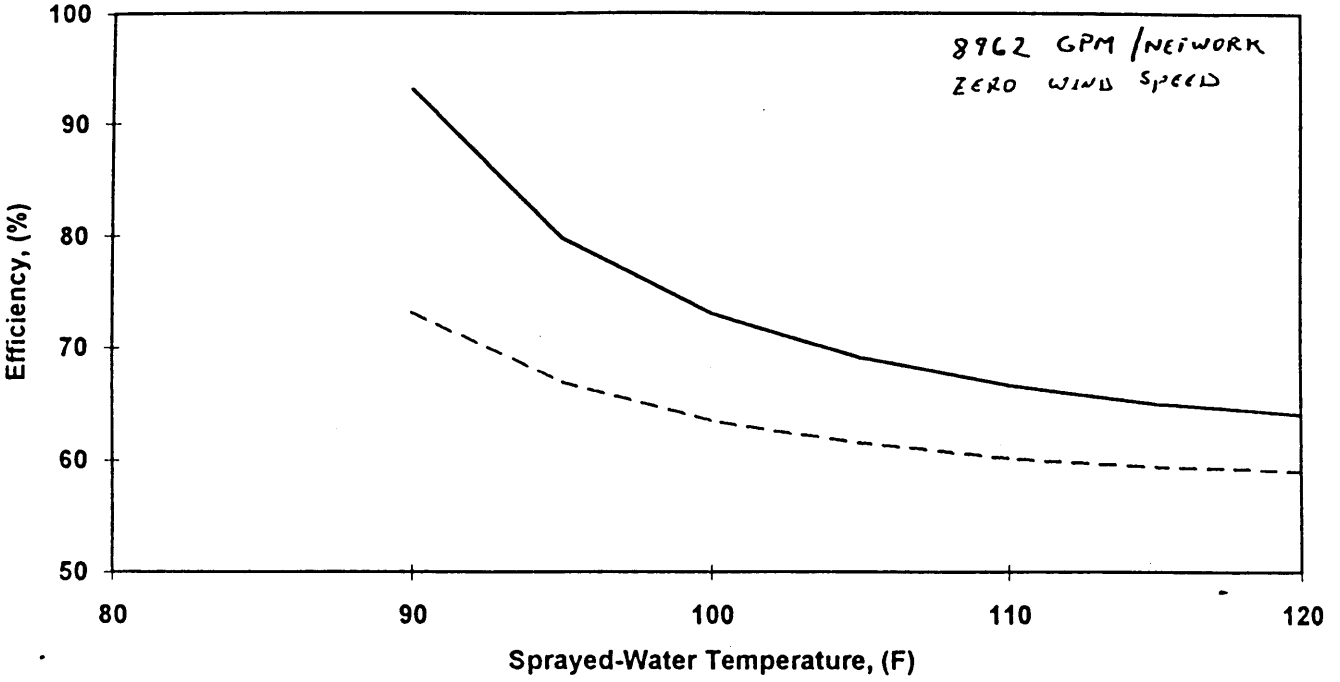
DASHED LINES INDICATE POTENTIAL FLOW PATHS NOT USED IN THE SPRAY POND ANALYSIS.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SCHEMATIC OF HEAT REJECTION TO SPRAY POND (TIME > 30 HOURS)

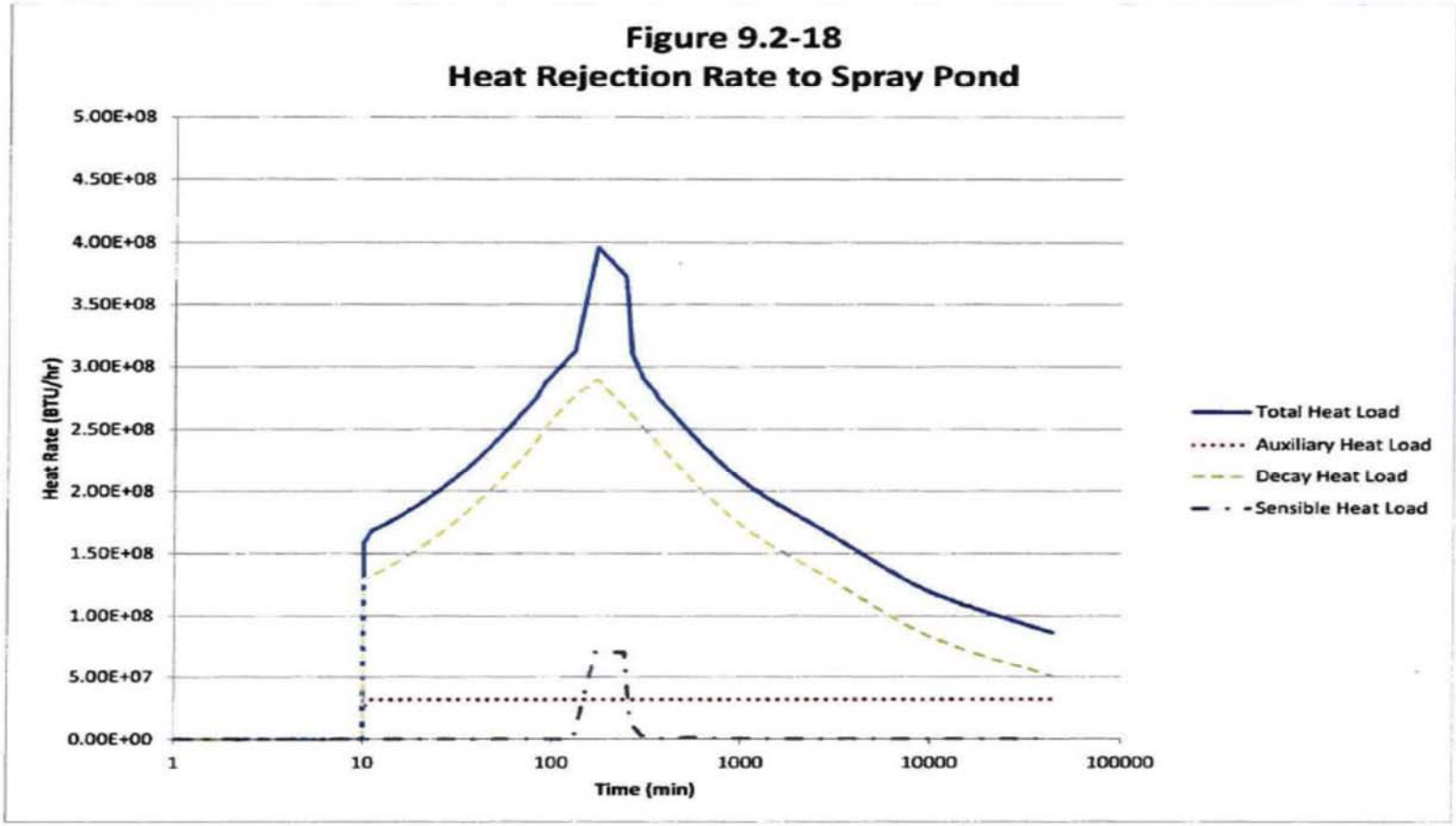
FIGURE 9.2-16

Spray Pond Thermal Efficiency
Figure 9.2-17



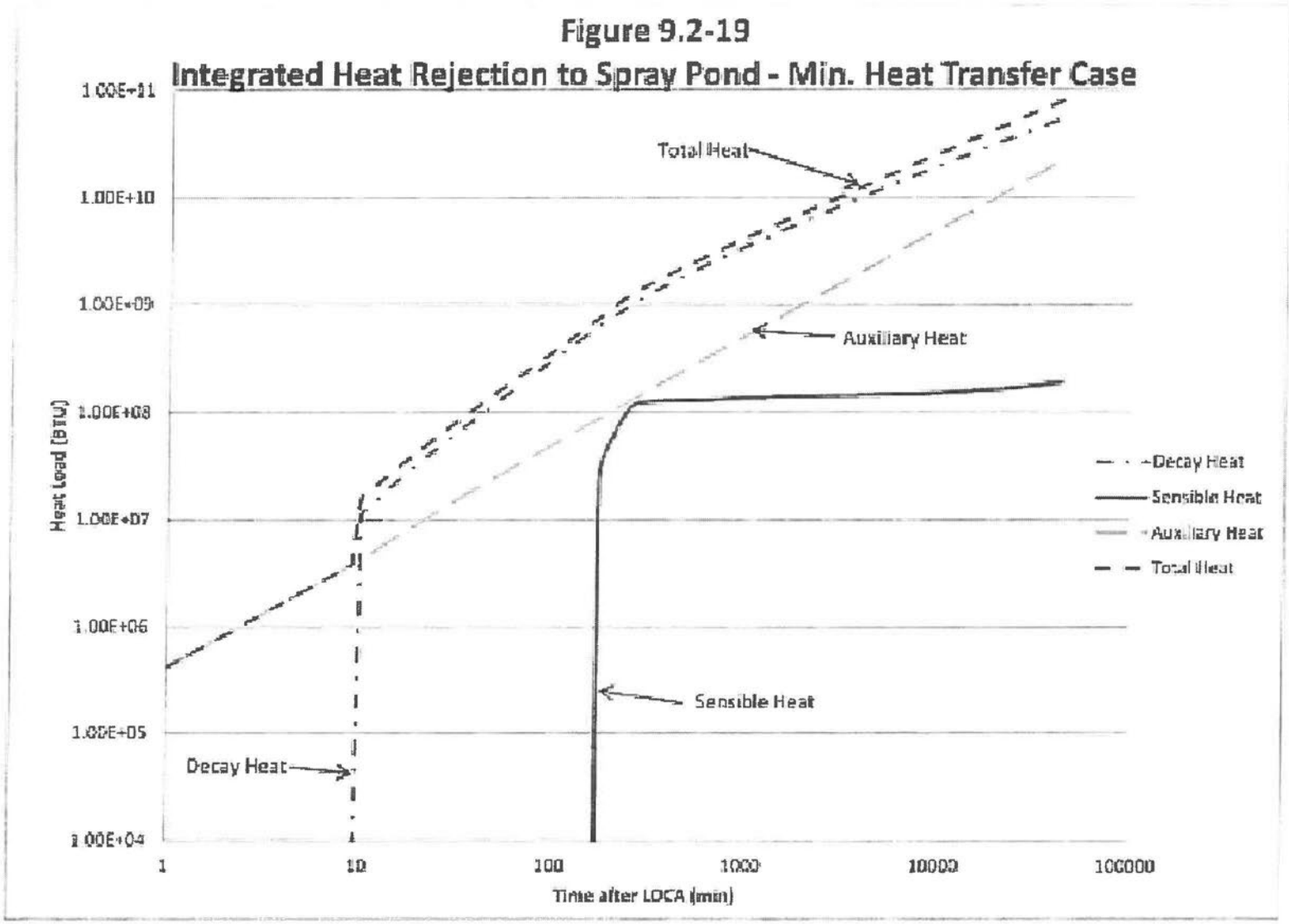
LIMERICK GENERATING STATION UNITS 1 AND 2 UPDATED FINAL SAFETY ANALYSIS REPORT
SPRAY POND THERMAL EFFICIENCY
FIGURE 9.2-17 REV. 4 Nov./94

Figure 9.2-18
Heat Rejection Rate to Spray Pond

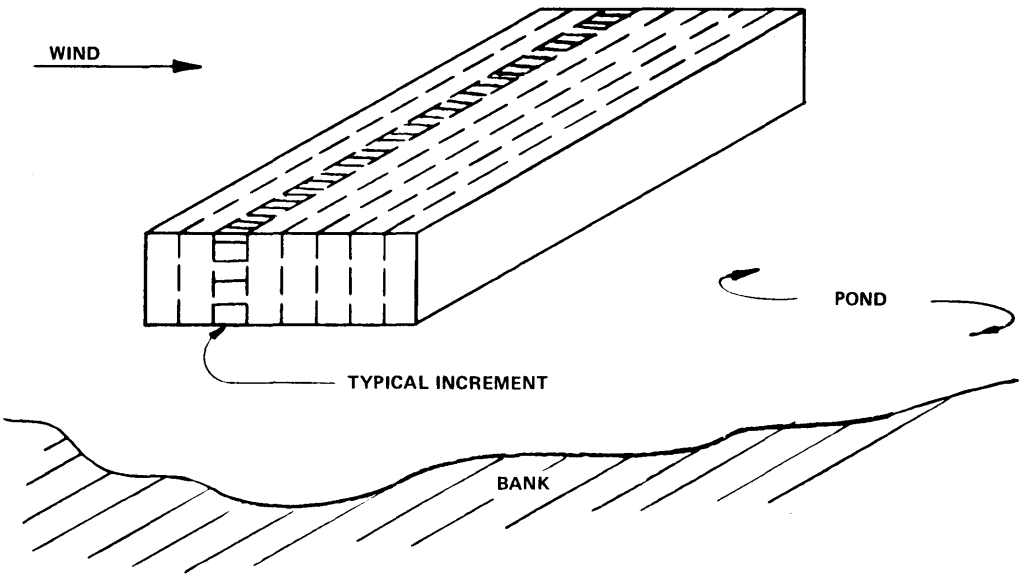


LIMERICK GENERATING STATION UNIT 1 AND 2 UPDATED FINAL SAFETY ANALYSIS REPORT	
HEAT REJECTION RATE TO SPRAY POND	
FIGURE 9.2-18	Rev. 22, 09/24

Figure 9.2-19
Integrated Heat Rejection to Spray Pond - Min. Heat Transfer Case



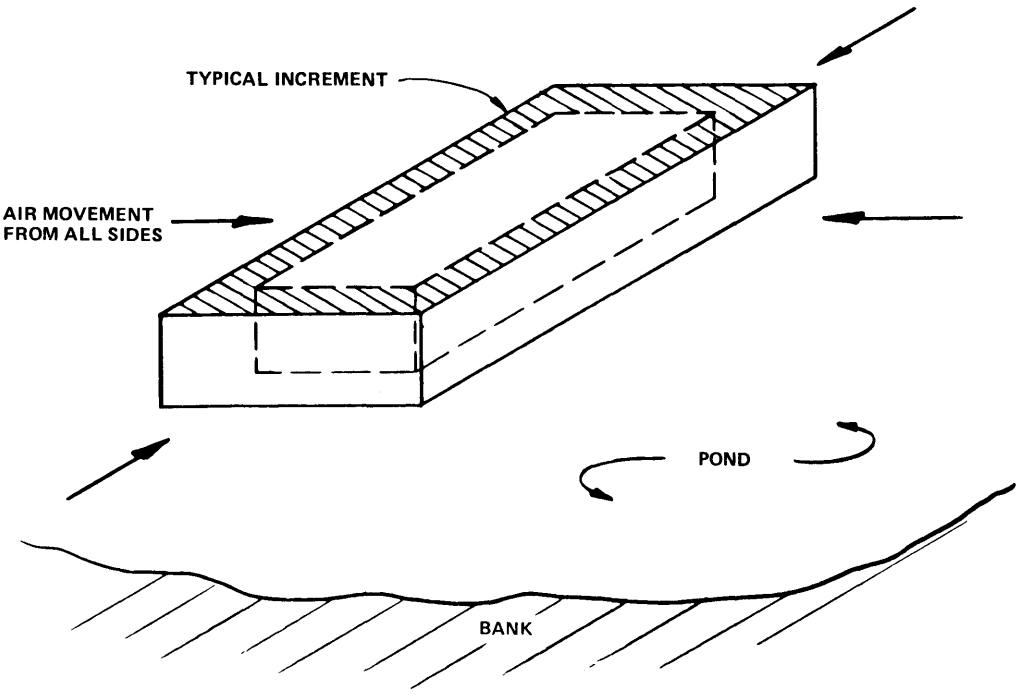
LIMERICK GENERATING STATION UNITS 1 AND 2 UPDATED FINAL SAFETY ANALYSIS REPORT	
INTEGRATED HEAT REJECTION TO THE SPRAY POND	
FIGURE 9.2-19	REV. 19 09/18



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SPRAY POND MODEL DIAGRAM:
NO NATURAL CONVECTION

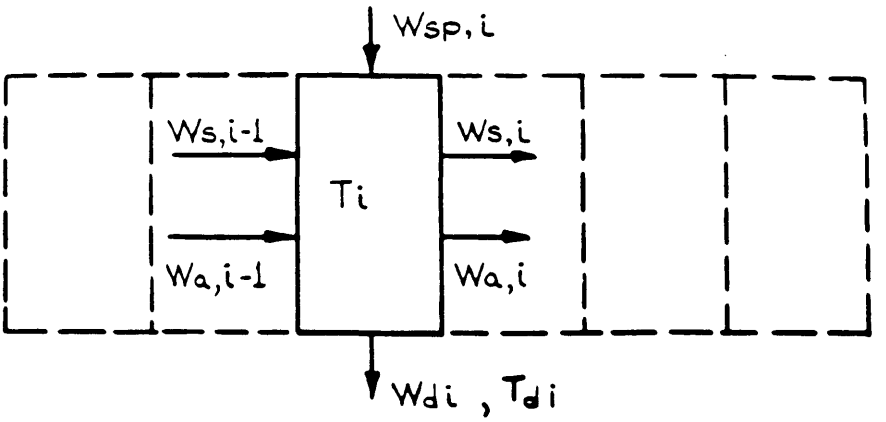
FIGURE 9.2-20



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SPRAY POND MODEL DIAGRAM:
NATURAL CONVECTION ONLY

FIGURE 9.2-21



Wsp,I = mass flow rate of spray into I th segment

Ws,I-1 = mass flow rate of vapor into I th segment

Wa,I-1 = mass flow rate of air vapor into I th segment

WdI = mass flow rate of water into pond from I th segment

TI = dry bulb air temperature in I th segment

TdI = temperature of water entering the pond from I th segment

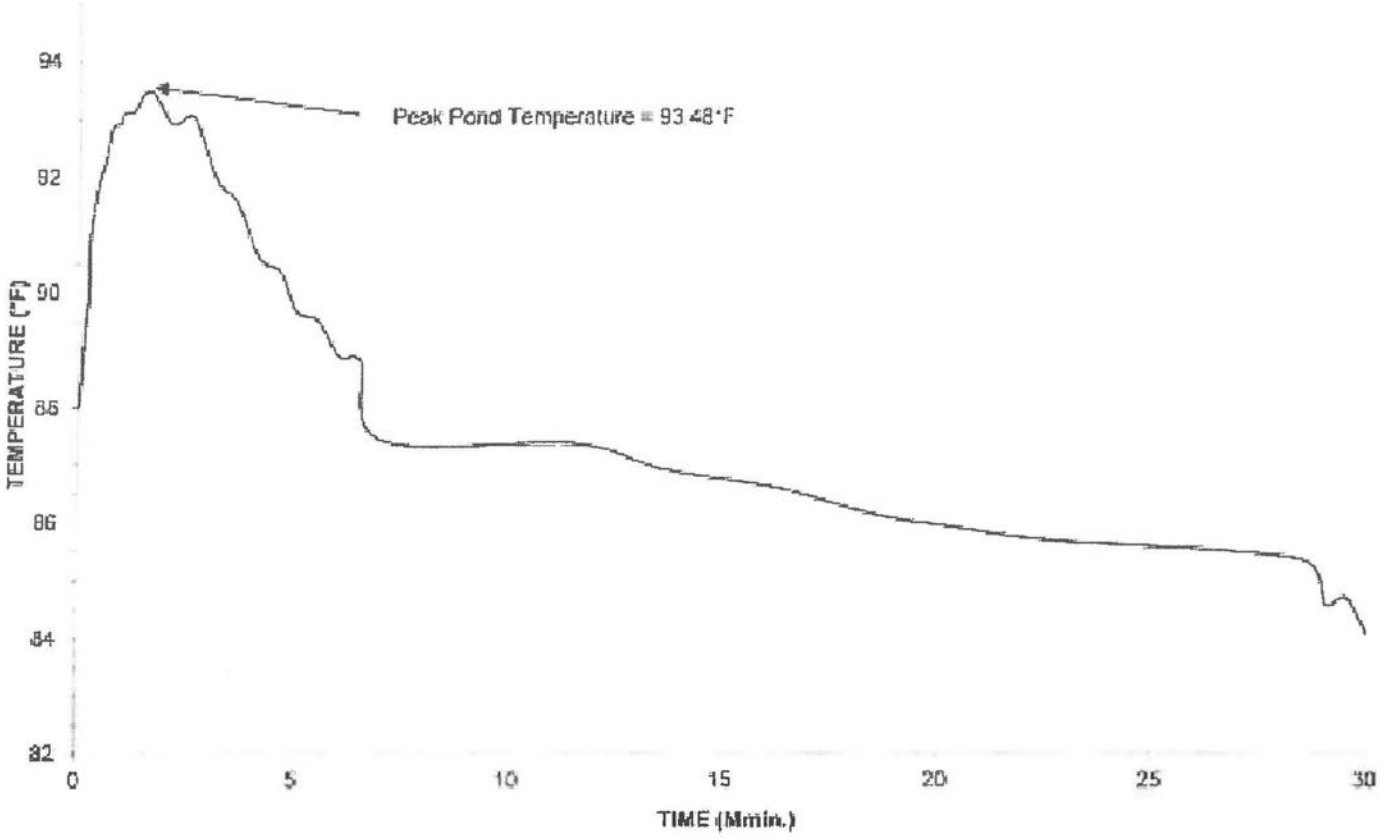
Ts = water temperature at nozzle

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SPRAY POND INCREMENTAL MASS AND ENERGY FLOW SCHEMATIC

FIGURE 9.2-22 REV. 4 Nov./94

FIGURE 9.2-23
SPRAY POND TEMPERATURE TRANSIENT



LIMERICK GENERATING STATION UNITS 1 AND 2 UPDATED FINAL SAFETY ANALYSIS REPORT	
SPRAY POND TEMPERATURE TRANSIENT	
FIGURE 9.2-23	REV. 19 09/18

Figures 9.2-24 thru 9.2-29

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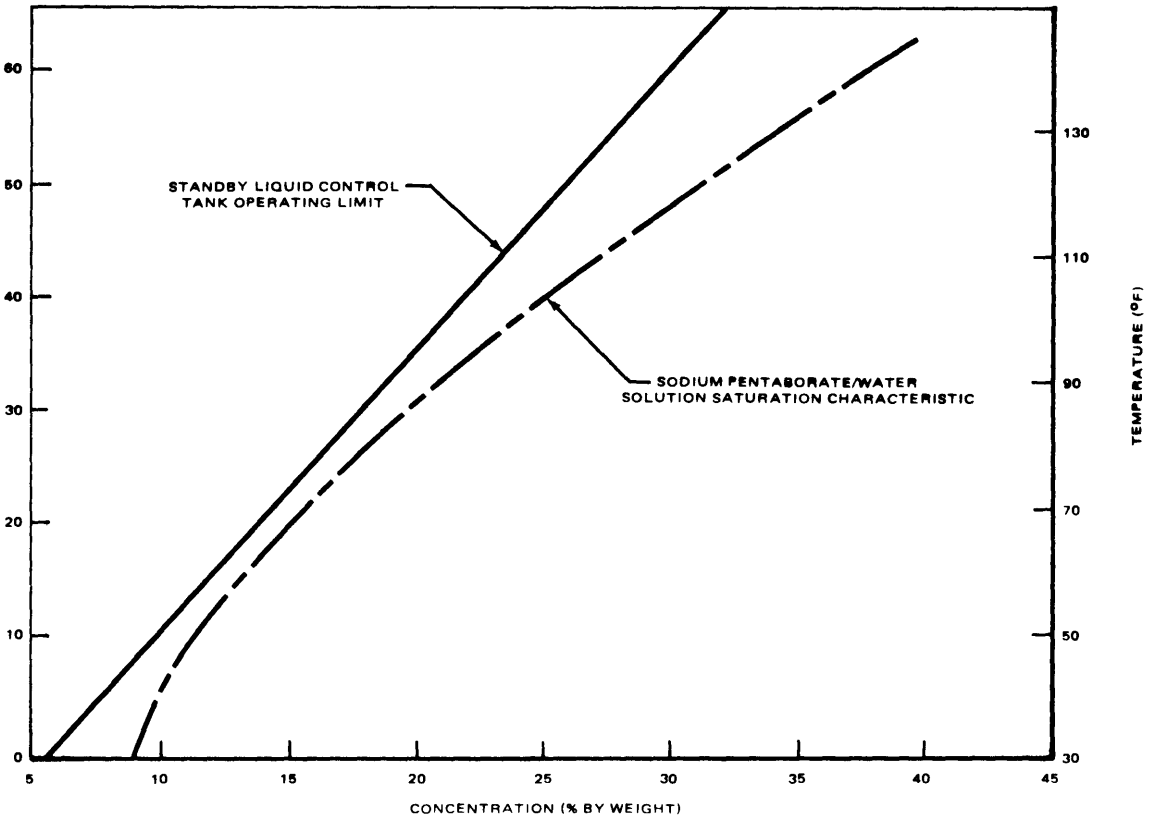
Figures 9.3-1 thru 9.3-5

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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

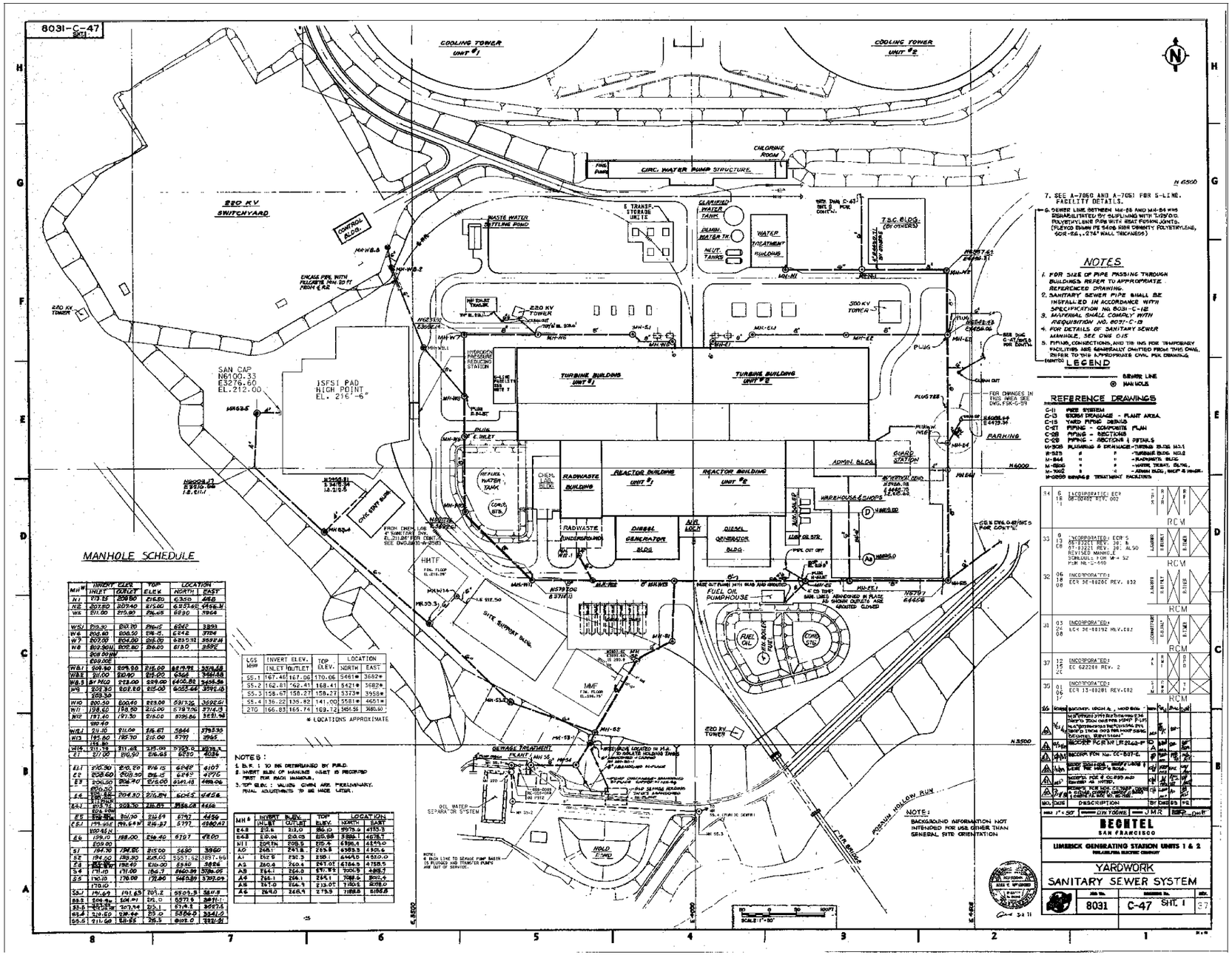
FIGURE 9.3-6



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SATURATION TEMPERATURE OF
SODIUM PENTABORATE SOLUTION

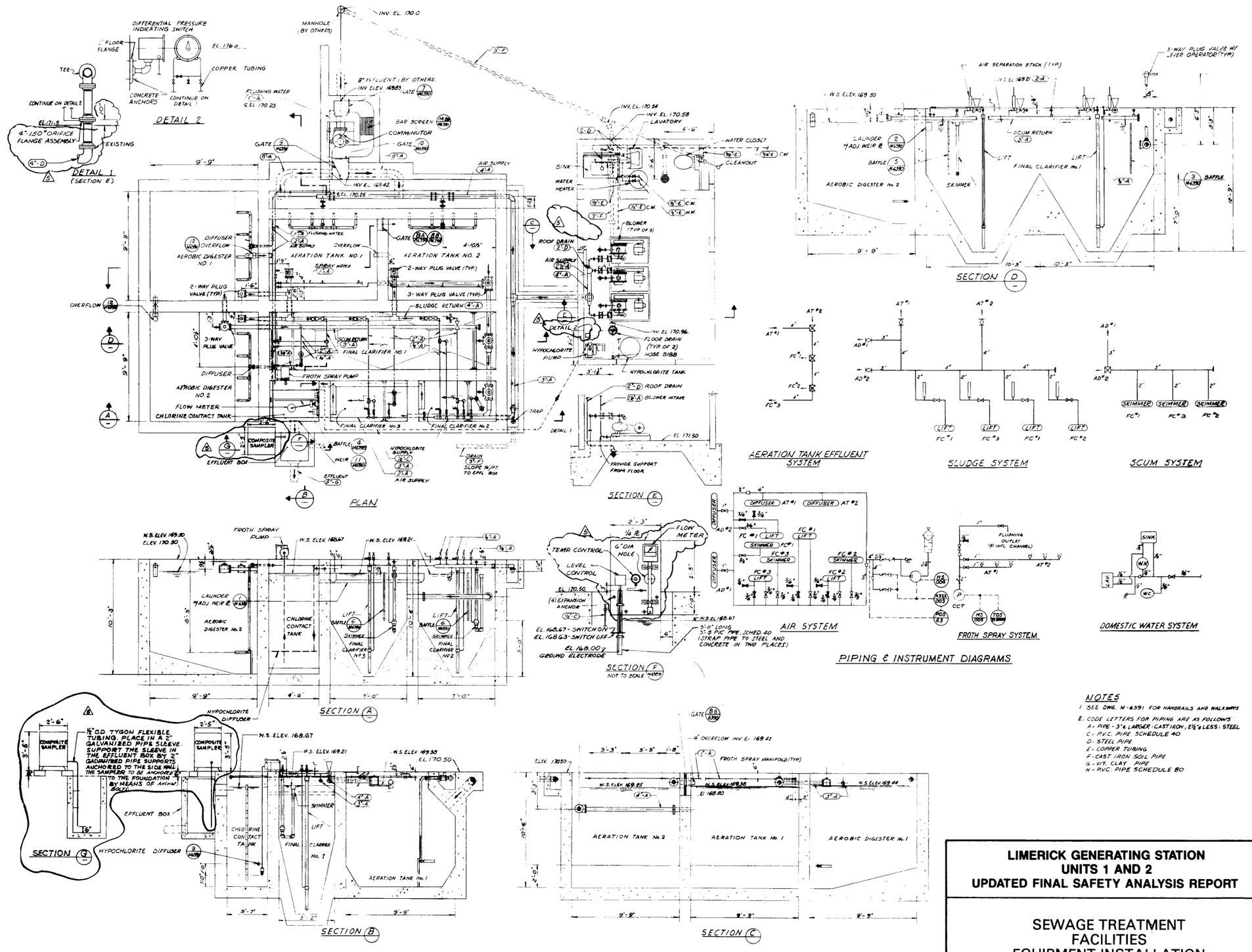
FIGURE 9.3-7



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

YARDWORK SANITARY SEWER SYSTEM

FIGURE 9.3-8 **REV. 21 09/22**



NOTES

1. SEE DWG. M-6391 FOR HANDRAILS AND WALKWAYS
2. CODE LETTERS FOR PIPING ARE AS FOLLOWS
   A - PIPE - 3" & LARGER: CAST IRON; 2½" & LESS: STEEL
   C - P.V.C. PIPE SCHEDULE 40
   D - STEEL PIPE
   E - COPPER TUBING
   F - CAST IRON SOIL PIPE
   G - VIT. CLAY PIPE
   H - P.V.C. PIPE SCHEDULE 80

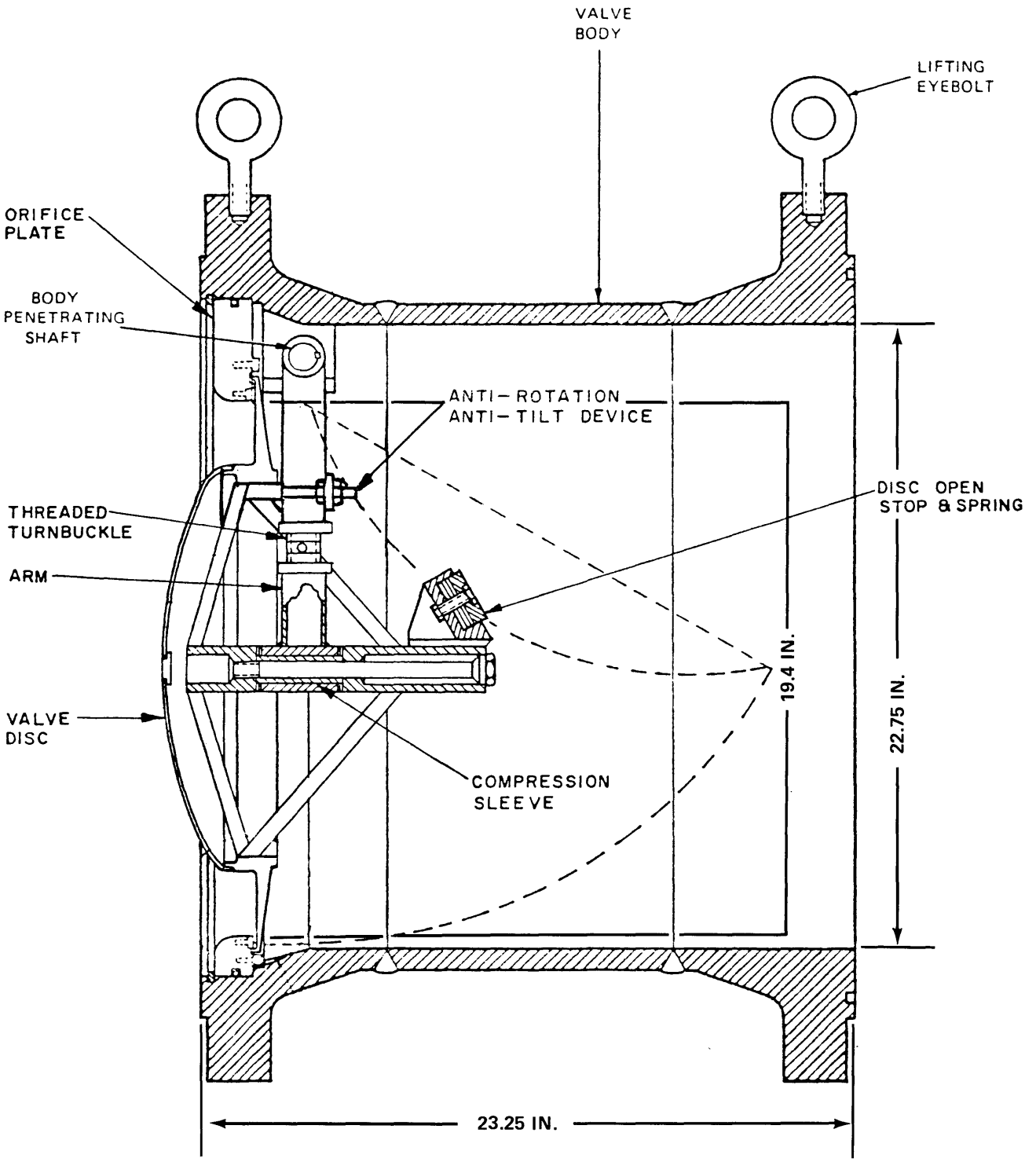
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SEWAGE TREATMENT
FACILITIES
EQUIPMENT INSTALLATION

FIGURE 9.3-9

Figures 9.4-1 thru 9.4-5

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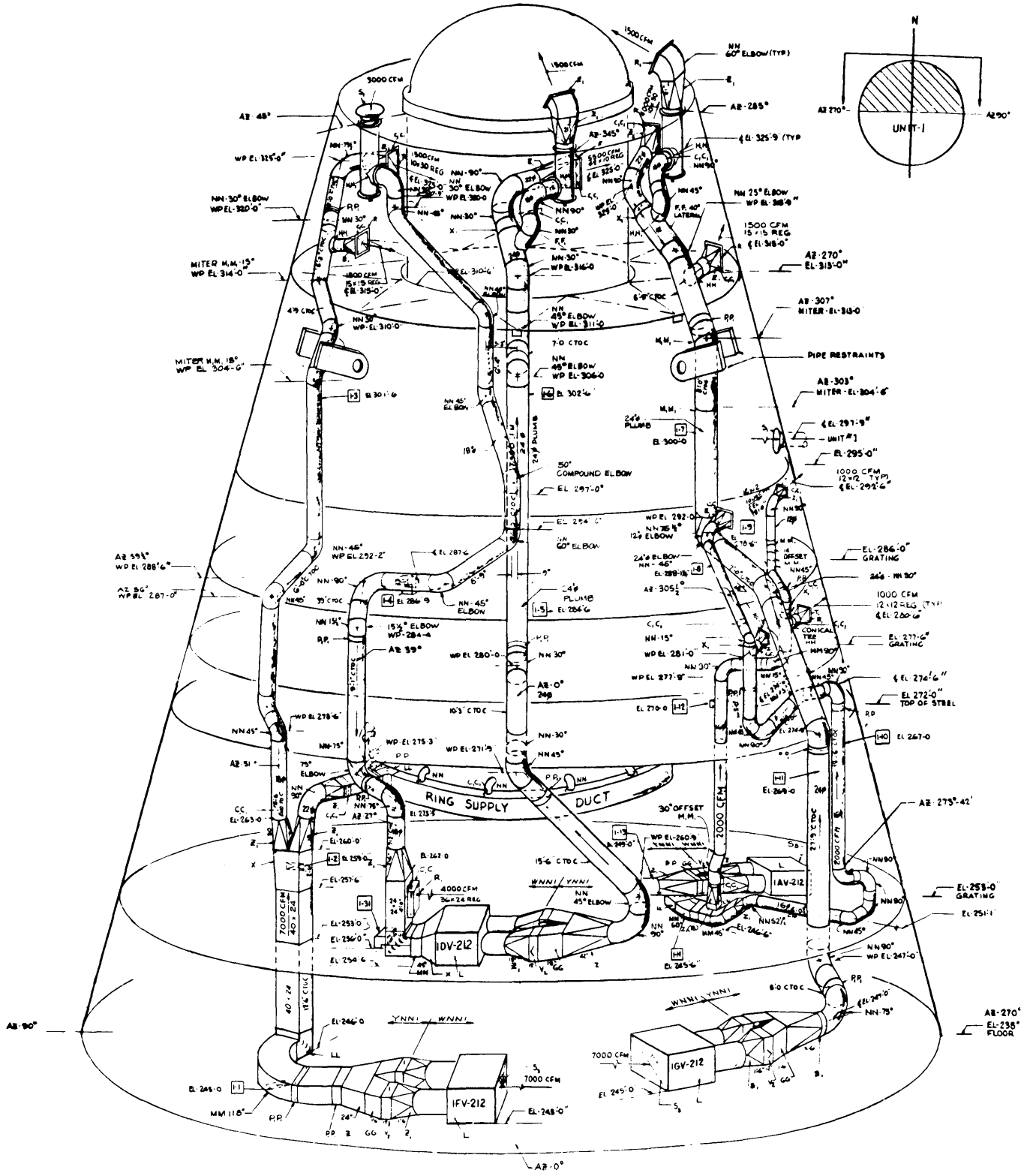
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRIMARY CONTAINMENT VACUUM RELIEF VALVE SCHEMATIC

FIGURE 9.4-6

Figure 9.4-7

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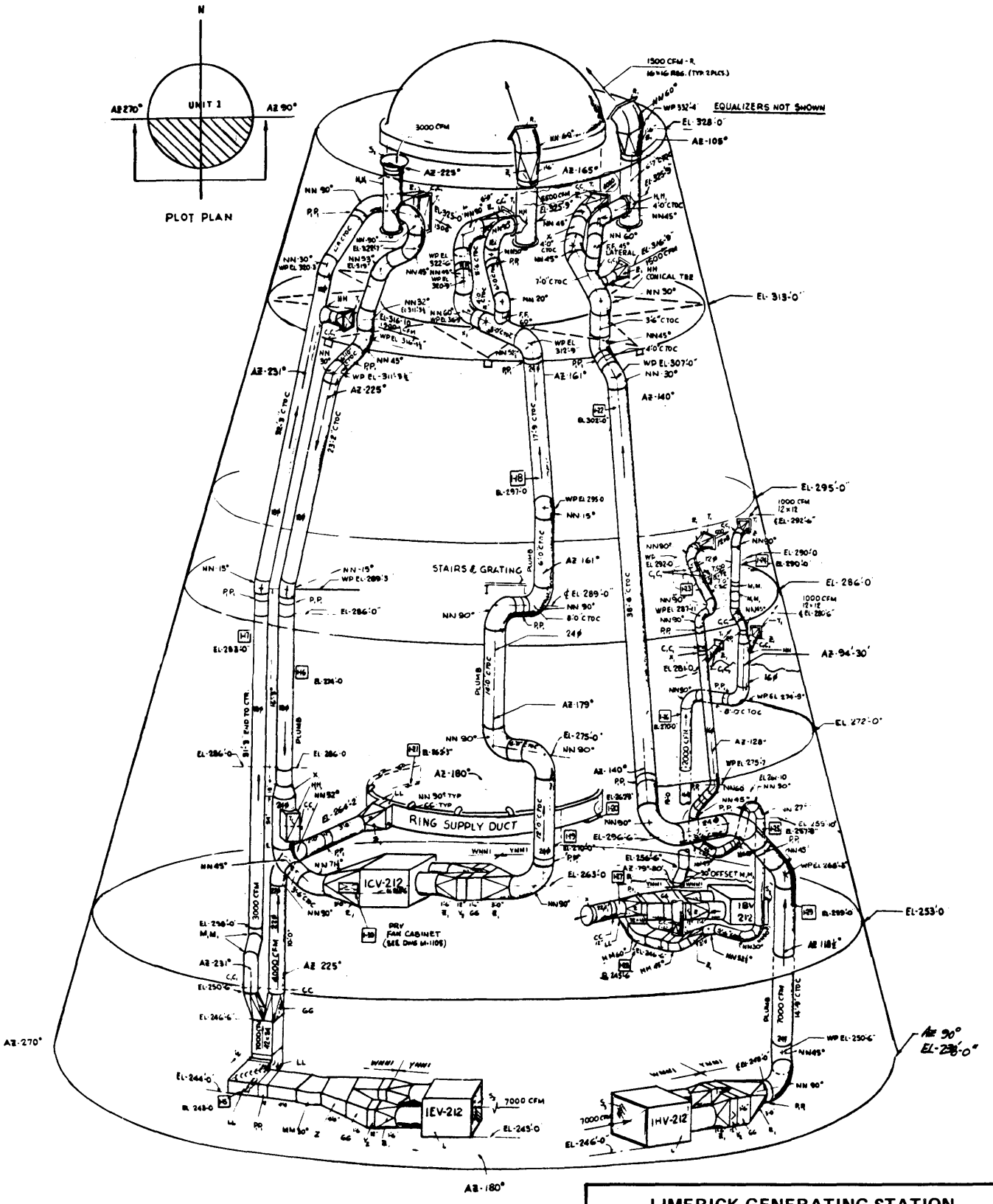


UNIT-1 - DRYWELL

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL AIR COOLING SYSTEM LAYOUT
(SHEET 1 OF 2)

FIGURE 9.4-8



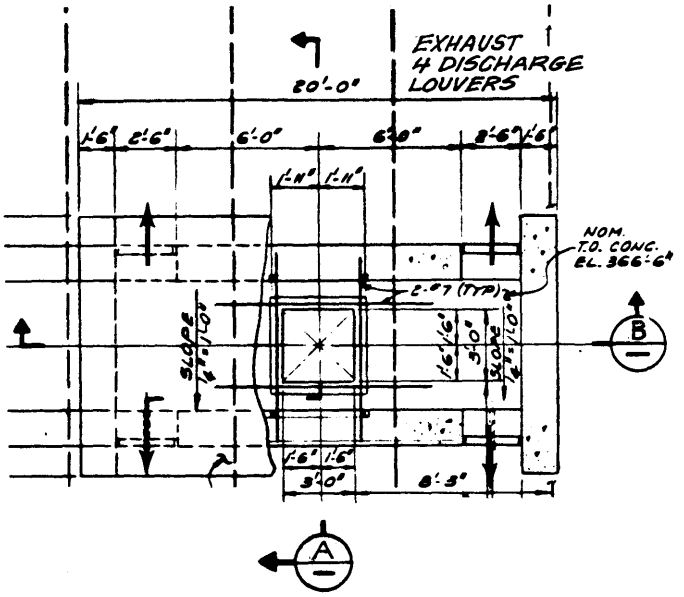
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

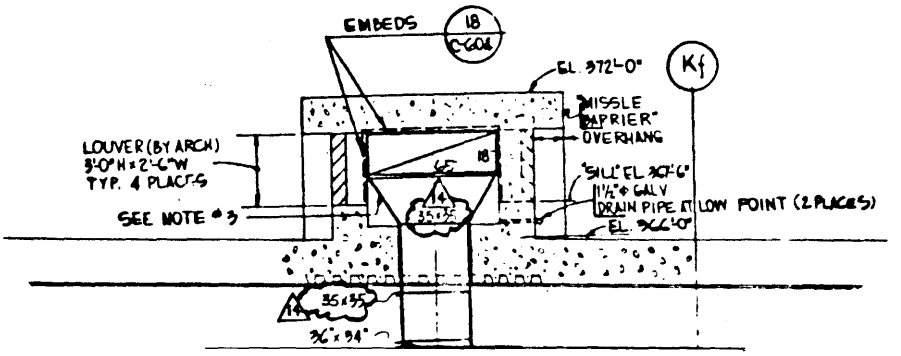
DRYWELL AIR COOLING SYSTEM LAYOUT (SHEET 2 OF 2)

FIGURE 9.4-8

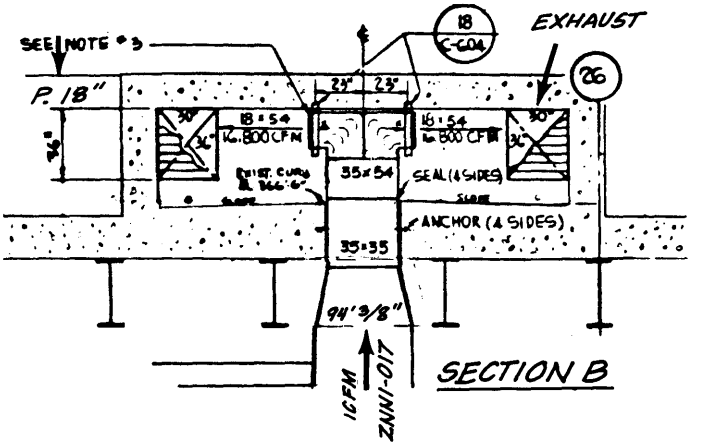
Figures 9.4-9 thru 9.4-11

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SECTION A



SECTION B

NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-455.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTROL STRUCTURE
EXHAUST AIR DISCHARGE

FIGURE 9.4-12

Figures 9.5-1 thru 9.5-12

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APPENDIX 9A - FIRE PROTECTION EVALUATION REPORT

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9A.2.8 Deleted

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APPENDIX 9A - FIRE PROTECTION EVALUATION REPORT

9A.1 INTRODUCTION

On September 30, 1976, the Director of the Division of Project Management, of the Office of Nuclear Reactor Regulation, requested a re-evaluation of the fire protection program for the LGS. Attached to that document was Appendix A to BTP ASB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976". The following report was prepared in response to that request and discusses the fire protection program as it relates to nuclear safety and addresses our conformance to BTP CMEB 9.5-1 (which superseded BTP ASB 9.5-1).

It is the licensee's philosophy that fire protection be provided for all company facilities to minimize the effects of a fire. Therefore, proper fire protection was an original design objective for LGS. Responsibility for the fire protection program is vested in licensee managerial personnel in the same manner as other operating and design responsibilities. To support these responsibilities, the licensee employs qualified fire protection personnel to ensure an adequate fire protection program is provided.

Bechtel Power Corporation provided the fire protection engineers and consultants to develop the design concept, prepare specifications, and select experienced fire protection contractors. Bechtel has designed the fire protection systems for several operating nuclear plants and has a specialized staff that monitors the latest in fire protection methods.

The term "fire protection system" refers to the integrated complex of components and equipment provided for detection and suppression of fires. In addition to this system, the "fire protection program" includes the concepts of design and layout implemented to prevent or mitigate fires, administrative controls and procedures, and personnel training. The fire protection program uses a defense-in-depth approach aimed at preventing fires, minimizing the effect of any fires that occur, providing appropriate fire detection and suppression equipment, and training personnel in fire prevention and fire fighting.

LGS has been evaluated with regard to fire protection to verify that the total fire protection program provides reasonable assurance that a fire will not prevent the performance of necessary safe shutdown functions and will not cause an undue risk to the health and safety of the public.

Section 9A.2 of this report provides a general description of the fire detection and suppression systems provided for LGS. Section 9A.3 presents point-by-point comparisons of the LGS fire protection program with the guidelines set forth in BTP CMEB 9.5-1 and 10CFR50, Appendix R. Section 9A.4 provides an evaluation of the combustible loadings in the plant and the ability of specific fire barriers to withstand postulated fires. Section 9A.5 provides an evaluation of the ability to safely shut the plant down in the event of a fire in any fire area. Section 9A.6 discusses special topics. Section 9A.7 provide a listing of references associated with this document.

9A.2 FIRE PROTECTION SYSTEM DESCRIPTION

This chapter provides a description of the fire suppression and fire detection systems. The specific guidelines contained in BTP CMEB 9.5-1 are addressed in Section 9A.3.

Figure 9A-1 shows the legend and symbols for P&IDs. The P&ID for the fire protection system is shown in Figure 9A-2.

9A.2.1 FIRE PROTECTION WATER SUPPLY SYSTEMS

9A.2.1.1 Water Source

The source of water for the fire protection system is two cooling tower basins which have a capacity of 7,200,000 gallons each, for a total capacity of 14,400,000 gallons. For a system pumping capacity of 5000 gpm, this allows continuous operation of both fire pumps for 48 hours. If one cooling tower basin or supply line is not available, the remaining water source provides both fire pumps with a 24 hour supply of water. Water for the fire pumps is taken from either Unit 1 or Unit 2 cooling tower water basins through connections to the circulating water lines. Check valves are installed at the pump discharges to prevent water from one source from being pumped into the other source.

9A.2.1.2 Pumps

There are two (2) horizontal centrifugal-type fire pumps, each capable of 2500 gpm at a system head of 125 psig. The 100% capacity lead pump is electric motor-driven and the 100% capacity lag pump is diesel engine-driven. The pumps and their controllers are UL-listed.

The fire water system is capable of delivering 100 gpm per hose station at no less than 65 psig to any hose station, considering the operation of two hose stations simultaneously with the largest water demand flowing from any automatic suppression system in the vicinity of the hose stations. In addition to the 100 gpm per hose station, 300 gpm is assumed at the nearest outside fire hydrant to support manual fire fighting activities. This meets BTP section C.6.b.(11) requirement of 500 gpm for manual hose streams in addition to the largest suppression system design. When the fire pumps are not running, the standpipes are maintained full of water by a 2 inch connection to the service water system which is capable of replenishing 50 gpm for leakage. When a portion of the fire water system is activated, a low pressure switch set at 100 psig provides a signal to start the motor-driven pump automatically. If the motor-driven pump fails to start, the diesel-driven pump receives a start signal at a lower pressure signal setpoint of 95 psig to start the diesel-driven pump automatically. Both pumps are stopped manually.

A third Fire pump is provided as a backup to the two primary pumps. This pump is diesel engine driven and is placed in service as stated in the technical requirements manual bases 3/4 7.6 to satisfy the requirement of providing an alternate pump.

The electric power for the motor-driven fire pump is taken from a load center that is supplied from the non-Class 1E, 13 kV switchgear. The primary power source for the switchgear is the unit auxiliary transformer, and the secondary power source is the offsite power supplies. If the primary power source fails, the switchgear is automatically transferred to one of the two offsite power supplies. Switching from one offsite power supply to the other can be performed manually from the control room.

The diesel oil supply tank for the diesel engine has a capacity of 550 gallons. This volume is sufficient to allow operation of the diesel engine for approximately 40 hours at full pump capacity.

The fire pumps are located at one end of the circulating water pump structure north of the power block. The motor-driven fire pump and its controls are in an area common with the circulating water pumps and are protected by hose stations and portable fire extinguishers. Each pump and it's driver and controls are located in a room separated from the remaining fire pumps by a fire wall with a minimum rating of 3 hours. The diesel oil day tank is located in a curbed area within the diesel-driven fire pump compartment. This compartment is provided with an automatic sprinkler system.

9A.2.1.3 Yard Piping

Fire protection water is distributed to the various areas of the plant from a yard fire main loop which completely encircles the power block. The connections to the yard fire main loop from the two fire pumps located in the circulating water pump structure are spaced about 6 feet apart and are provided with valving so that either connection can be isolated while retaining 100% water supply capacity to the yard fire main. The routing of the yard fire main loop and its branch piping is shown on Drawing C-11.

The yard fire main loop consists of 12 inch cement-lined cast iron piping which is buried below the frost line. The west and east ends of the loop are cross-connected by piping which traverses the Unit 1 and Unit 2 turbine enclosures. Locked open post-indicator valves provide sectionalized control and isolation of portions of the fire main loop. There are 12 yard hydrants spaced at intervals of 250-300 feet along the fire main loop. Each hydrant is provided with a key operated 6" gate valve with curb box or 6" post indicating gate valve for hydrant isolation. Five hose cart houses are located in the yard area in the vicinity of the hydrants, each enclosing a hose cart which can be manually moved to any hydrant where it is needed. The system of hydrants connected to the fire main loop is designed in accordance with NFPA 24. A Generic Letter 86-10 evaluation documents a deviation to NFPA 24 with respect to dry barrel hydrants that may contain measurable water in the barrel such that even with measurable water, provided it is below a depth that will not freeze, there will be no impact to hydrant functionality.

9A.2.2 WET PIPE SPRINKLER SYSTEMS

Wet pipe sprinkler systems are provided to protect the following areas and equipment:

a. Turbine enclosure - feedwater pump lube oil reservoir compartments

b. Turbine enclosure - lube oil storage tanks and electro- hydraulic control power unit

c. Turbine enclosure - main turbine lube oil reservoir and lube oil centrifuge area

d. Turbine enclosure - main turbine condenser area

e. Turbine enclosure - main turbine moisture separator area

f. Reactor enclosure - electric cable penetration areas at el 253' and el 283'

g. Radwaste enclosure compactor area

h. Lube oil storage enclosure

i. Auxiliary boiler enclosure

j. Deleted

k. Circulating water pump structure – diesel fire pump compartment

l. Deleted

m. Control structure - cable spreading rooms and corridor (el 239').

n. Turbine Enclosure - Facility/laydown area, Floor Operators Break Facility (Rm 468A,B,C) and Plant Operators Building (Rm 468)

o. Deleted

Each wet pipe sprinkler system consists of an outside screw and yoke gate valve, an alarm check valve assembly and/or flow switch, piping, and fusible element sprinkler heads.

Wet pipe sprinkler system operation is initiated when ambient temperature rises to the melting point of fusible links on sealed sprinkler heads, thus causing the spray heads to open. The flow of water through alarm check valves energizes a flow switch which transmits the alarm condition to the fire protection panels in the control room. The wet pipe sprinkler systems for the cable spreading rooms and corridor room 437 (el 239'(Fire Area 7)) do not have alarm check valves, but each of these systems are provided with a flow switch that transmits an alarm signal to the fire protection panels in the control room.

The wet pipe sprinkler system operation is terminated manually by shutting the OS&Y gate valve.

9A.2.3 PREACTION SPRINKLER SYSTEMS

Preaction sprinkler systems are provided to protect the following areas and equipment:

a. Reactor enclosure - HPCI pump compartment (el 177')

b. Reactor enclosure - RCIC pump compartment (el 177')

c. Reactor enclosure - RECW equipment area (el 201')

d. Reactor enclosure - safeguard system access area (el 201')

e. Reactor enclosure - partial coverage at el 217', el 253', and el 283'

f. Standby diesel generator compartments

g. Turbine enclosure - railroad access area

h. Turbine enclosure - generator equipment area

i. Turbine enclosure - under the turbine's appearance lagging and turbine bearing housings 1 through 9 and under the generator's appearance lagging and bearing 10.

j. Deleted.

k. Control structure - fan room at el 304' (sprinkler heads are located at the underside of the platform at el 313')

l. Control structure - localized coverage for the 13.2 kV switchgear room (el 217')

m. Radwaste Building- Storage Room, Data Acquisition Room Storage Room, Source Storage/Standard's Preparation Room, Technician's Area

n. The Chemistry Lab (commercial building) located adjacent to the Radwaste enclosure, which is separated from the Unit 1 reactor enclosure by 3-hour rated fire walls, will not adversely affect any safety-related systems. The Chemistry Lab is protected by wet pipe and preaction suppression systems at strategic locations along with hose stations and portable fire extinguishers also provided to support manual fire fighting efforts.

Each preaction sprinkler system is automatically actuated by area fire detectors that release a tripping device to open the deluge valve, thus supplying water under pressure to the closed sprinkler heads. A rise in ambient temperature to the melting point of the fusible links on the sealed sprinkler heads causes the spray heads to open, with subsequent water flow through those heads which have opened.

The actuation of a heat detector actuates a local release control panel which in turn sends a signal to a fire alarm code transmitter. The fire alarm code transmitter sends a coded signal to the main control room fire alarm panel which sounds the horns throughout the plant.

The preaction system for the 13.2 kV switchgear room is similar to the other systems, except both fire detection and loss of air pressure must be received before the system will actuate. The area fire detection system alarms, as well as low air pressure alarm, is provided at a local panel with remote indication also provided in the control room. A separate deluge valve actuation alarm is provided both locally and in the control room.

9A.2.4 DELUGE SYSTEMS

Deluge systems are provided to protect the following areas and equipment:

a. Main transformers, auxiliary transformers, and safeguard transformers (all located outdoors)

b. Isophase bus ducts and bus duct supporting steel for main and auxiliary transformers (outside areas only)

c. Generator hydrogen seal oil unit

d. Main turbine lube oil reservoir and lube oil centrifuge.

Operation of a deluge sprinkler system is initiated by heat detection. The actuation of any heat detector alarms a local release control panel which then trips the deluge valve and sends a signal to a fire alarm code transmitter. The fire alarm code transmitter sends a coded signal to

the main control room fire alarm panel which sounds the horns throughout the plant. Manual release of the deluge valve tripping device also initiates remote alarms.

9A.2.5 WATER DELUGE APPLICATION FOR CHARCOAL FILTERS

Charcoal filters in the ventilation systems of the plant are provided with water deluge application systems for fire protection. The water is supplied to the filters by means of a fixed piping system.

An indicating gate valve is manually opened when a thermal sensor actuates a local alarm system and registers an alarm condition on the fire protection panels in the control room. The operation is terminated manually by shutting the gate valve.

9A.2.6 WET STANDPIPES AND HOSE STATIONS

Wet standpipes are considered Class II in accordance with NFPA 14; however, the fire hose has been removed from the interior hose stations. The fire brigade brings the required hose to the fire scene in high-rise packs. Where there is a requirement for additional fire hose for a specific hose station (beyond 100') that additional fire hose is staged at the hose station. The term "hose station" and "manual hose station" are used throughout this document and in other licensing documents. These terms are considered to be synonymous with "hose connection." These terms indicate a connection with a globe valve and a 2-1/2" connection on a wet standpipe in which to attach hose for firefighting. Adjustable fog nozzles and electrically safe nozzles are brought to the scene by the fire brigade.

9A.2.7 FOAM EXTINGUISHING SYSTEM

A foam system is provided for the protection of the fuel oil transfer structure and one outdoor fuel oil storage tank, and is designed in accordance with NFPA 11. The foam is educted from a foam solution tank by water from the main fire water header. Contacts are provided to annunciate operation of the system in the control room.

The one storage tank is provided with a fixed foam maker at the tank. Foam making is initiated manually from a local station after a high temperature condition at the tank has been alarmed locally and annunciated on the fire protection panels in the control room. Fire protection inside the fuel oil transfer structure is provided by a foam play pipe with hose rack. When the play pipe is removed from its holder, an electric switch located in the holder actuates a control valve to allow foam solution to enter the hose. A squeeze-type play pipe valve enables the operator to control the flow of foam.

9A.2.8 DELETED

9A.2.9 HALON EXTINGUISHING SYSTEMS

Three independent Halon extinguishing systems are provided for the raised flooring at el 289' in the control structure. Two of the systems serve the auxiliary equipment room; one system is designed to discharge simultaneously into all floor sections on the Unit 1 side of the room, and the other system is designed to discharge simultaneously into all floor sections on the Unit 2 side of the room. The third Halon system serves the remote shutdown room.

The flooring in the auxiliary equipment room and the remote shutdown room consists of 1 foot high floor sections resting on the concrete slab at el 289'. The floor sections are of all-steel construction (except for aluminum honeycomb in the floor plates) and are used for the routing of cabling to and from the electrical equipment located in the two rooms. In the auxiliary equipment room, this equipment includes the PGCC equipment, the plant computers, the Samac panels, the river evacuation and PA panel, a tone cabinet, and fault detection equipment. The PGCC for each unit consists of floor sections that are 8 feet wide and 20 feet long, each of which has vertical panels mounted near the center of the floor section. A termination cabinet is located at one end of each PGCC floor section. Smoke detectors are located in the floor sections and termination cabinets. The equipment located in the remote shutdown room consists of the remote shutdown panels for Unit 1 and Unit 2. Smoke detectors are located within the floor sections in the remote shutdown room.

The Halon extinguishing systems are designed in accordance with NFPA 12A. Each Halon system is designed to achieve a concentration of 20% by volume with the raised flooring that it serves fully installed and secured. Each system includes two banks of Halon cylinders, each of which has sufficient capacity to maintain a 20% concentration for 20 minutes. In addition to having two banks of Halon cylinders, each system consists of distribution piping and nozzles, heat detectors, and a manual selector switch. The heat detectors serve to actuate the Halon system; a predischarge alarm is sounded first, followed by a time-delayed discharge of Halon. The manual selector switch is used to designate which of the two banks of Halon cylinders in each system will discharge automatically. Halon cylinders can be discharged manually at the hand switch location or at the cylinder locations. The unused bank of cylinders can be used to provide a supplemental discharge of Halon by manually actuating the release.

9A.2.10 WATER CURTAIN SYSTEMS

Two types of water curtain suppression systems are provided in the plant: (a) systems that subdivide certain fire areas into two zones, and (b) systems that protect floor slab openings associated with equipment hatchways in the reactor enclosures.

Water curtain systems that serve to subdivide fire areas are provided at el 217', el 253', and el 313' in the reactor enclosures. Each water curtain system consists of an OS&Y gate valve, a deluge valve, a local pull station, piping, and open sprinkler heads. Each water curtain system is actuated manually, using the local pull station to open the deluge valve. The pull station is located inside a stairwell near the location of the water curtain. Actuation of a water curtain system is sounded throughout the plant by a coded alarm. Operation of the system is terminated manually by shutting the OS&Y gate valve, which is located near the stairwell in which the pull station is located.

Each of the water curtain systems is designed to achieve a discharge density of 0.3 gpm/ft^2 at floor level. This is accomplished through the use of open sprinkler heads arranged in a linear array across the top of the water curtain location. In addition, sprinkler heads discharging horizontally inward from the sides of the water curtain are provided where necessary to achieve the design discharge density.

Water curtain systems that serve to protect the equipment hatchways in the reactor enclosures are designed similarly to the water curtain systems described above. The equipment hatchways are located in the southeast corner of the Unit 1 reactor enclosure and the southwest corner of the Unit 2 reactor enclosure. Each hatchway consists of openings in the concrete floor slabs at el 253', el 283', and el 313', with the openings arranged above one another. The opening in each slab is

protected by an individual water curtain system having its distribution piping located at the underside of the slab and arranged around the perimeter of the opening. Each water curtain system is actuated manually, using a local pull station to open the deluge valve. The pull station is installed inside the stairwell near the location of the water curtain. In addition to the pull station, each water curtain system can be actuated by use of an emergency trip valve located near the system's local control panel.

9A.2.11 PORTABLE FIRE EXTINGUISHERS

Portable fire extinguishers, using extinguishing agents compatible with the combustible material in the area in which they are located, are provided throughout the plant.

9A.2.12 FIRE AND SMOKE DETECTION SYSTEM

The fire and smoke detection system is in compliance with NFPA 72A (1979). The system also complies with the requirements of NFPA 72D (1975), with the following exceptions and clarifications:

a. No device is provided for permanently recording incoming signals with the date and time of receipt. (The logging of fire events by a device for permanently recording incoming signals is not needed, because plant operating procedures will require the operator on duty in the control room to update the plant log book with the date and time of alarms from the fire detection system and of initiation of any fire suppression system.)

b. Operation and supervision of the system is not the primary function of the operators. (The control room operators are responsible for monitoring and supervision of all plant systems, including the fire detection and fire suppression systems.)

c. The locations of early warning fire and smoke detectors were established under the direction of a registered fire protection engineer. (The locations of fire and smoke detectors are in compliance with the guidance of NFPA 72E, with the clarification that ionization-type detectors in certain areas of the plant are located in accordance with subsections 4-3.1 and 4-3.1.1 of NFPA 72E. These subsections allow detector location to be determined based on engineering judgement considering ceiling shape, ceiling surfaces, ceiling height, configuration of contents, combustible characteristics, and ventilation. In areas where concrete floor slabs are supported by structural steel beams, the diffusion of ionized particles throughout the compartment volume during the incipient stage of the fire will negate the effect of beam depth and result in an appropriate level of detection capability.

d. NFPA 72D (1979) references NFPA 72E (1978) for testing of smoke detectors. NFPA 72E (1978) requires functional testing of smoke detectors semiannually. Functional testing of smoke detectors at Limerick will be done in accordance with the Technical Requirements Manual.

e. In fire area 2, the smoke detection system is upgraded to NFPA 72, 1996, Chapter 5 for detector location and spacing.

f. In fire area 98, the smoke detection system above the ASD System is upgraded to NFPA 72, 2010, Chapter 17 for detector location and spacing.

g. In fire area 25, the locations of in-cabinet and under floor smoke detectors accepted was by the NRC in their review of GE NEDO-10466A Power Generation Control Complex Design Criteria and Safety Evaluation.

h. In fire area 111, the smoke detection system above the ASD System is upgraded to NFPA 72, 2010, Chapter 17 for detector location and spacing.

Fire and smoke monitoring, detection, and alarm are accomplished by installing smoke detectors and/or heat-responsive detectors in areas where fire potential exists. Fire and smoke detection systems for annunciation are separate from fire detection systems for actuation of fire extinguishing systems, except for the 13kV Switchgear Area (Fire Area 2). The smoke detection system in the 13 kV Switchgear Area (Fire Area 2) provides early warning notification while also providing an input signal to the double interlock preaction system that provides localized protection.

Although the fire and smoke detection system is primarily a Class B system, certain portions of it are designed as Class A. The local fire detection panels in safety-related areas of the plant (control structure, reactor enclosures, and diesel generator enclosures) and in the Unit 2 turbine enclosure are Class A. All other local fire detection panels are Class B. The detector systems and local panels for the Halon system in the raised flooring of the auxiliary equipment room are Class A. The heat detector wiring and local panel wiring for all sprinkler systems is Class B. Transmitter circuits from all local panels (both Class A and Class B) back to the fire protection alarm panel near the control room are Class B. Circuits in the fire protection alarm panel (00C926) are Class B.

Both the Class A and Class B portions of the fire and smoke detection system are electrically supervised to detect circuit breaks, ground faults, and power failure. Class A portions of the system have the capability to detect fire and smoke concurrent with a single break or single ground in the detection circuit; Class B portions of the system do not have this capability. Class A detection circuits utilize a four-wire system, whereas Class B detection circuits utilize a two-wire system with end-of-line resistor. Functional testing of the supervised circuits is done in accordance with the Technical Requirements Manual.

Annunciator circuits from the local fire suppression system panels to fire protection alarm panel 00C926 and from 00C926 to control room fire protection annunciator 0BC850 are not electrically supervised. Detection of smoke or fire is registered visually on a window of control room fire protection annunciator 0AC850 (identifying the location of the fire) and is sounded throughout the plant by a coded alarm. Trouble conditions (circuit breaks, ground faults, and power failures) in the fire and smoke detection system are registered by an audible alarm in the control room and by visual indication on the affected local fire detection panel as well as on a common window of control room fire protection annunciator 00C650. Actuation of any fire suppression system is sounded throughout the plant by a coded alarm. Trouble conditions in any fire suppression system are registered by an audible alarm in the control room and by visual indication on panel 00C926 and a common window of control room fire protection annunciator 0BC850.

9A.3 COMPARISON BETWEEN LGS FIRE PROTECTION PROGRAM AND NRC GUIDELINE DOCUMENTS

9A.3.1 NRC BRANCH TECHNICAL POSITION CMEB 9.5-1

The purpose of this section is to compare the fire protection provisions of LGS Units 1 and 2 with the guidelines in BTP CMEB 9.5-1.

To identify areas of potential impact and to facilitate comparison, a matrix addressing each guideline of the BTP and relating to the plant systems, equipment, and components, is included as Section 9A.3.1.1. The matrix has extracted all suggested guidelines from the BTP and given each an item number, 1 through 255. Each item has condensed a particular guideline and makes reference to the section in the BTP where that guideline can be found. The general degree of conformance to the guideline is indicated in the COMPARISON column, using codes defined as follows:

- C - indicates conformance to the guideline or conformance to its intent. Substantiating statements may be included as part of the matrix or in Section 9A.3.1.2.

- AC - indicates conformance to the guidelines by alternate means or methods. The manner of conformance is included in the matrix or discussed in Section 9A.3.1.2.

- NC - indicates that the plant is not in conformance and no design changes are planned. The basis for nonconformance to the guideline is included in the matrix or discussed in Section 9A.3.1.2.

- NA - indicates that the guideline is not applicable to LGS Units 1 and 2. Substantiating statements are included as part of the matrix in Section 9A.3.1.1.

In the REMARKS column, additional information is provided to explain or expand on the degree of conformance. Alternatively, reference may be made to Section 9A.3.1.2 (or other sections in this report) for a more detailed discussion. The item numbers in Section 9A.3.1.2 correspond to those in Section 9A.3.1.1.

9A.3.1.1 Detailed Comparison to Branch Technical Position CMEB 9.5-1

Specific items in the following table identify compliance to specific National Fire Protection Association (NFPA) codes (or standards) for the design, installation, and maintenance of fire protection systems. The fire protection systems at Limerick

Generating Station were originally designed and installed using the criteria found in the NFPA codes in order to comply with NRC guidance. NFPA codes provide guidance for the requirements for the performance of fire protection systems. This guidance provides reasonable assurance that the fire protection systems installed at Limerick Generating Station will provide timely warning and adequate suppression for the purpose of life safety and property protection.

The Fire Protection Program at Limerick Generating Station is based on a defense-in-depth philosophy with numerous barriers in place to ensure adequate protection of plant structures, systems and components as well as the health and safety of the public in the event of a postulated fire occurring. It is recognized that there are situations in the plant where verbatim compliance with all aspects of the NFPA codes have not been satisfied. When the fire protection systems were initially designed and installed, the NFPA codes were considered guidance documents, not verbatim compliance documents. Through the use of qualified designers, engineers, and installation personnel, alternative plant configurations may have been employed to satisfy the intent of the NFPA requirements.

Deviations that could potentially affect system performance are documented in the design record for the plant. Minor deviations, while considered during initial design and installation, are not necessarily documented in the design record for the plant.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
	Fire Protection Program			
1.	The fire protection program should be under the direction of an individual who has been delegated authority commensurate with the responsibilities of the position and who has available staff personnel knowledgeable in both fire protection and nuclear safety.	C.1.a(1)	C	
2.	The fire protection program should extend the concept of defense-in-depth to fire protection in fire areas important to safety, with the following objectives: • to prevent fires from starting; • to detect rapidly, control, and extinguish promptly those fires that do occur; • to provide protection for structures, systems, and components important to safety so that a fire that is not promptly extinguished by the fire suppression activities will not prevent the safe shutdown of the plant.	C.1.a(2)	C	
3.	Responsibility for the overall fire protection program should be assigned to a person who has management control over all organizations involved in fire protection activities. Formulation and assurance of program implementation may be delegated to a staff composed of personnel prepared by training and experience in fire protection and personnel prepared by training and experience in nuclear plant safety to provide a balanced approach in directing the fire protection program for the nuclear power plant.	C.1.a(3)	C	
4.	The staff should be responsible for: (a) Fire protection program requirements, including consideration of potential hazards associated with postulated fires, with knowledge of building layout and systems design. (b) Post-fire shutdown capability. (c) Design, maintenance, surveillance, and quality assurance of all fire protection features (e.g., detection systems, suppression systems, barriers, dampers, doors, penetration seals, and fire brigade equipment). (d) Fire prevention activities (administrative controls and training). (e) Fire brigade organization and training. (f) Prefire planning.	C.1.a(3)	C	
5.	The organizational responsibilities and lines of communication pertaining to fire protection should be defined through the use of organizational charts and functional description.	C.1.a(4)	C	

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
6.	Personnel qualification requirements for fire protection engineer reporting to the position responsible for formulation and implementation of the fire protection program.	C.1.a(5)	C	See Section 3.1.2
7.	The fire brigade members' qualifications should include a physical examination for performing strenuous activity, and the training described in Position C.3.d.	C.1.a(5)(b)	C	
8.	The personnel responsible for the maintenance and testing of the fire protection systems should be qualified by training and experience for such work.	C.1.a(5)(c)	C	
9.	The personnel responsible for the training of the fire brigade should be qualified by training and experience for such work.	C.1.a(5)(d)	C	
10.	The following NFPA publications should be used for guidance to develop the fire protection program; No. 4, No. 4A, No. 6, No. 7, No. 8, No. 27.	C.1.a(6)	C	
11.	On sites where there is an operating reactor and construction of modification of other units is underway, the superintendent of the operating plant should have a lead responsibility for site fire protection.	C.1.a(7)	C	
	Fire Hazards Analysis			
12.	The fire hazards analysis should demonstrate that the plant will maintain the ability to perform safe shutdown functions and minimize radioactive releases to the environment in the event of a fire.	C.1.b	C	See Sections 9A.4 and 9A.5.
13.	The fire hazards analysis should be performed by fire protection and reactor systems engineers to (1) consider potential in situ and transient fire hazards: (2) determine the consequences of a fire in any location in the plant; and (3) specify measures for fire prevention, detection, suppression, and containment.	C.1.b	C	
14.	Fires involving facilities shared between units should be considered.	C.1.b	C	Fires are postulated to occur in structures such as the control structure and the spray pond pump structure that are common to both reactor units.
15.	Fires due to man-made site-related events that have a reasonable probability of occurring and affecting more than one reactor unit should be considered.	C.1.b	C	See Section 9A.3.1.2.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
16.	Establishment of three levels of fire damage limits according to safety function (hot shutdown; cold shutdown; design basis accidents.)	C.1.b	C	
17.	The fire hazards analysis should separately identify hazards and provide appropriate protection in locations where safety-related losses can occur.	C.1.b	C	
	Fire Suppression System Design Basis			
18.	Total reliance should not be placed on a single fire suppression system. Backup fire suppression capability should be provided.	C.1.c(1)	C	All automatic fire suppression systems are backed up by two methods of manual extinguishment (hose stations and portable extinguishers).
19.	A single active failure or a crack in a moderate energy line in the fire suppression system should not impair both the primary and backup fire suppression capability.	C.1.c(2)	C	See Section 9A.3.1.2.
20.	The fire suppression system should be capable of delivering water to manual hose stations located within hose reach of areas containing equipment required for safe shutdown following an SSE.	C.1.c(3)	NC	See item 155.
21.	The fire protection systems should retain their original design capability for natural phenomena of less severity and greater frequency than the most severe natural phenomena.	C.1.c(4)	C	See Section 9A.3.1.2
22.	The fire protection systems should retain their original design capability for potential man-made site-related events that have a reasonable probability of occurring at a specific plant site.	C.1.c(4)	NC	See Section 9A.3.1.2
23.	The effects of lightning strikes should be included in the overall plant fire protection program.	C.1.c(4)	C	Lightning protection is provided per NFPA No. 78
24.	The consequences of inadvertent operation or of a crack in a moderate energy line in the fire suppression system should meet the guidelines specified for moderate energy systems outside containment in SRP section 3.6.1.	C.1.c(5)	C	See Section 9A.3.1.2.
	Alternative or Dedicated Shutdown			
25.	Alternative or dedicated shutdown capability should be provided where the protection of systems whose functions are required for a safe shutdown is not provided by established fire suppression methods or by Position C.5.b.	C.1.d	C	See item 20 of Section 9A.3.2.2.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
	Implementation of Fire Protection Programs			
26.	The fire protection program for buildings storing new reactor fuel and for adjacent fire areas that could affect the fuel storage area should be fully operational before fuel is received at the site.	C.1.e(1)	C	The fire protection program for the new fuel area will be completed and fully operational before fuel is received at the Site.
27.	The fire protection program for an entire reactor unit should be fully operational prior to initial fuel loading in that reactor unit.	C.1.e(2)	C	
28.	Special considerations for the fire protection program on reactor sites where there is an operating reactor and construction or modification of other units is under way.	C.1.e(3)	C	See Section 9A.3.1.2.
	Administrative Controls			
29.	Establishment of administrative controls to maintain the performance of the fire protection system and personnel.	C.2	C	
	Fire Brigade			
30.	The guidance in Regulatory Guide 1.101 should be followed as applicable.	C.3.a	C	
31.	Establishment of site brigade: minimum number of fire brigade members on each shift; qualification of fire brigade members; competence of brigade leader.	C.3.b	C	
32.	The minimum equipment provided for the brigade should consists of turnout coats, boots, gloves, hard hats, emergency communications equipment, portable ventilation equipment, and portable extinguishers.	C.3.c	C	
33.	Self-contained breathing apparatus using full-face positive-pressure masks approved by NIOSH (National Institute for Occupational Safety and Health—approval formerly given by the U.S. Bureau of Mines) should be provided for fire brigade, damage control, and control room personnel. At least 10 masks shall be available for fire brigade personnel. Control room personnel may be furnished breathing air by a manifold system piped from a storage reservoir if practical. Service or rated operating life shall be a minimum of one-half hour for the self contained units.	C.3.c	C	See Section 9A.3.1.2.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
	At least two extra air bottles should be located onsite for each self contained breathing unit. In addition, an onsite 6-hour supply of reserve air should be provided and arranged to permit quick and complete replenishment of exhausted supply air bottles as they are returned. If compressors are used as a source of breathing air, only units approved for breathing air shall be used; compressors shall be operable assuming a loss of offsite power. Special care must be taken to locate the compressor in areas free of dust and contaminants.			
34.	Recommendations for the fire brigade training program.	C.3.d	AC	See Section 9A.3.1.2.
	Quality Assurance Program			
35.	Establishment of quality assurance programs for the fire protection systems for safety-related areas; identification of specific criteria for QA programs.	C.4	AC	See Section 9A.3.1.2.
	Building Design			
36.	Fire barriers with a minimum rating of 3 hours should be provided to separate safety-related systems from any potential fires in nonsafety-related areas.	C.5.a(1)(a)	C	Structures housing safety-related systems are separated from nonsafety-related structures by 3 hour rated fire walls.
37.	Fire barriers with a minimum rating of 3 hours should be provided to separate redundant divisions of safety-related systems from each other.	C.5.a(1)(b)	AC	See Section 9A.3.1.2.
38.	Fire barriers with a minimum rating of 3 hours should be provided to separate individual units on a multiunit site.	C.5.a(1)(c)	C	Fire barriers rated for 3 hours are provided to separate Unit 1 structures from Unit 2 structures. Those structures that are common to both reactor units (such as the control structure and the central portion of the turbine enclosure) are separated form the adjacent structures of both reactor enclosures by 3 hour fire barriers.
39.	Fire barriers should be provided within a single safety division to separate components or cabling that present a fire hazard to other safety-related components.	C.5.a(2)	AC	See Section 9A.3.1.2.
40.	Openings through fire barriers for pipe, conduit, and cable trays which separate fire areas should be sealed or closed to provide a fire resistance rating equal to that required of the barrier.	C.5.a(3)	AC	See Section 9A.3.1.2.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
41.	Recommendations for internal sealing of conduits penetrating fire barriers.	C.5.a(3)	AC	See Section 9A.3.1.2
42.	Fire barrier penetrations that must maintain environmental isolation or pressure differentials should be qualified by test.	C.5.a(3)	C	Fire-rated penetration seals that are also required to perform other barrier functions (such as maintaining a pressure differential) are qualified by test for all the intended functions. The fire barrier function of a penetration seal is not required to be performed simultaneously with other barrier functions.
43.	Penetration designs should utilize only noncombustible materials.	C.5.a(3)	AC	See Section 9A.3.1.2.
44.	The penetration qualification tests should use the time-temperature exposure curve specified by ASTM E-119.	C.5.a(3)	C	The time-temperature exposure curve used in qualification tests for penetration seals is a specified by ASTM E-119-73.
45.	Acceptance criteria for penetration qualification tests.	C.5.a(3)	AC	See Section 9A.3.1.2.
46.	Penetration openings for ventilation systems should be protected by fire dampers having a rating equivalent to that required of the barrier.	C.5.a(4)	AC	See Section 9A.3.1.2.
47.	Flexible air duct couplings in ventilation and filter systems should be noncombustible.	C.5.a(4)	C	
48.	Door openings in fire barriers should be protected with equivalently rated doors, frames, and hardware that have been tested and approved by a nationally recognized laboratory.	C.5.a(5)	AC	See Section 9A.3.1.2.
49.	Fire doors should be self-closing or provided with closing mechanisms.	C.5.a(5)	AC	See Item 40 of Section 9A.3.2.2.
50.	Fire doors should be inspected semiannually to verify that automatic hold open, release, and closing mechanisms and latches are operable.	C.5.a(5)	AC	See Item 41 of Section 9A.3.2.1.
51.	Alternative means for ensuring that fire doors protect the door opening as required in case of fire.	C.5.a(5)	C	See Item 42 of Section 9A.3.2.2.
52.	The fire brigade leader should have ready access to keys for any locked fire doors.	C.5.a(5)	C	
53.	Areas protected by automatic total flooding gas suppression systems should have electrically supervised self-closing fire doors or should satisfy option (a) above.	C.5.a(5)	C	See Item 44 of Section 9A.3.2.1.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
54.	Personnel access routes and escape routes should be provided for each fire area.	C.5.a(6)	C	All fire areas are provided with personnel access routes and escape routes.
55.	Stairwells serving as escape routes, access routes for fire fighting, or access routes to areas containing equipment necessary for safe shutdown should be enclosed in masonry or concrete towers with a minimum fire rating of 2 hours and self-closing Class B fire doors.	C.5.a(6)	C	Stairwells of the type described in the guideline are each enclosed by a 2 hour rated envelope consisting or either reinforced concrete or concrete unit masonry walls with a minimum thickness of 8 inches. Each door opening that is a part of this envelope is provided with a UL Class B fire door. All penetrations through the walls of the envelope are sealed using penetration seal details that are qualified for use in 3 hour rated fire barriers.
56.	Fire exit routes should be clearly marked.	C.5.a(7)	C	
57.	Each cable spreading room should contain only one redundant safety division.	C.5.a(8)	NC	The cable spreading room for each reactor unit contains all four divisions of safety-related cabling. Raceways containing the different divisions of cabling are separated from each other in accordance with Regulatory Guide 1.75. Cabling associated with the remote shutdown panel is not routed through the cable spreading room.
58.	Cable spreading rooms should be separated from each other and from other areas of the plant by barriers having a minimum fire resistance of 3 hours.	C.5.a(8)	C	See Section 9A.3.1.2.
59.	Interior wall and structural components, thermal insulation materials, radiation shielding materials, and soundproofing should be noncombustible.	C.5.a(9)	AC	See Section 9A.3.1.2.
60.	Interior finishes should be noncombustible.	C.5.a(9)	AC	See Section 9A.3.1.2.
61	Metal deck roof construction should be non-combustible and listed as “acceptable for fire” in the UL Building Materials Directory, or listed as Class 1 in the Factory Mutual Approval Guide.	C.5.a(10)	C	See Section 9A.3.1.2.
62.	Suspended ceilings and their supports should be of noncombustible construction.	C.5.a(11)	C	See Section 9A.3.1.2.
63.	Concealed spaces should be devoid of combustibles except as noted in Position C.6.b.	C.5.a(11)	AC	See Section 9A.3.1.2.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
64.	Transformers installed inside fire areas containing safety-related systems should be of the dry-type or insulated and cooled with noncombustible liquid.	C.5.a(12)	C	All indoor transformers are either air cooled, dry-type, or cooled by noncombustible gases.
65.	Outdoor oil-filled transformers should have oil spill confinement features or drainage away from the buildings.	C.5.a(13)	C	See Section 9A.3.1.2.
66.	Outdoor oil-filled transformers should be located at least 50 feet distant from the building, or building walls within 50 feet of oil-filled transformers should be without openings and have a 3 hour fire resistance rating.	C.5.a(13)	AC	See Section 9A.3.1.2.
67.	Floor drains sized to remove expected fire fighting water flow without flooding safety-related equipment should be provided in areas where fixed water fire suppression systems are installed.	C.5.a(14)	AC	See Section 9A.3.1.2
68.	Floor drains should be provided in areas where hand hose lines may be used if such fire fighting water could cause unacceptable damage to safety-related equipment.	C.5.a(14)	AC	See Section 9A.3.1.2.
69.	Where gas suppression systems are installed, the drains should be provided with adequate seals, or the gas suppression system should be sized to compensate for the loss of the suppression agent through the drains.	C.5.a(14)	C	See Section 9A.3.1.2.
70.	Drains in areas containing combustible liquids should have provisions for preventing the backflow of combustible liquids to safety-related areas through the interconnected drain systems.	C.5.a(14)	C	See Section 9A.3.1.2.
71.	Water drainage from areas that may contain radioactivity should be collected, sampled, and analyzed before discharge to the environment.	C.5.a(14)	C	Potentially radioactive liquid wastes are collected and monitored prior to discharge.
	Safe Shutdown Capability			
72.	Fire damage should be limited so that one train of systems necessary to achieve and maintain hot shutdown conditions from either the control room or emergency control station is free of fire damage.	C.5.b(1)	C	
73.	Fire damage should be limited so that one train of systems necessary to achieve and maintain cold shutdown conditions from either the control room or emergency control station can be repaired within 72 hours.	C.5.b(1)	C	

NO.	CMEB 9.5-1 GUIDELINE	CMEB 9.5-1 ITEM NO.	COMPARISON	REMARKS
74.	Alternative means of ensuring that one train of systems necessary to achieve and maintain hot shutdown is free of fire damage.	C.5.b(2)	AC	See Item 18 of Section 9A.3.2.2.
75.	Provision of alternative or dedicated shutdown capability in certain fire areas.	C.5.b(3)	C	See Item 20 of Section 9A.3.2.2
76.	Alternative or Dedication Shutdown Capability	C.5.c	C	See Items 25 through 36 of Section 9A.3.2.
	Control of Combustibles			
77.	Safety-related systems should be separated from combustible materials where possible; where not possible, special protection should be provided to prevent a fire from defeating safety system function.	C.5.d(1)	C	To the maximum extent possible, significant concentrations of combustible materials are located outside structures containing safety-related components. In those cases for which this is not possible, such as the standby diesel generator fuel oil day tanks, special fire protection consisting of automatic fire suppression systems and/or construction capable of withstanding a fire is provided.
78.	Bulk gas storage (compressed or cryogenic) should not be permitted inside structures housing safety-related equipment. Flammable gases should be stored outdoors or in separate detached buildings.	C.5.d(2)	NC	See Section 9A.3.1.2.
79.	High pressure gas storage containers should be located with the long axis parallel to building walls.	C.5.d(2)	NC	See Section 9A.3.1.2.
80.	Use of compressed gases inside buildings should be controlled.	C.5.d(2)	C	See Section 9A.3.1.2.
81.	The use of plastic materials should be minimized. Halogenated plastics such as PVC and neoprene should be used only when substitute noncombustible materials are not available.	C.5.d(3)	C	See Section 9A.3.1.2.
82.	Storage of flammable liquids should comply with NFPA 30.	C.5.d(4)	C	Liquid fuels are stored either in aboveground tanks that have been provided with suitable fire barriers or in underground tanks.
83.	Hydrogen lines in safety-related areas should be either designed to seismic Class I requirements, or sleeved, or equipped with excess flow valves.	C.5.d(5)	C	Hydrogen lines in safety-related areas are designed to seismic Class I requirements.

NO.	CMEB 9.5-1 GUIDELINE	CMEB 9.5-1 ITEM NO.	COMPARISON	REMARKS
	Electrical Cable Construction, Cable Trays, and Cable Penetrations			
84.	Only metal should be used for cable trays.	C.5.e(1)	C	Cable trays are of all-metal construction.
85.	Only metallic tubing should be used for conduit. Thin-wall metallic tubing should not be used.	C.5.e(1)	NC	See Section 9A.3.1.2.
86.	Flexible metallic tubing should only be used in short lengths to connect components to equipment.	C.5.e(1)	C	Flexible metallic tubing used at raceway connections to components is limited to 5 feet in length.
87.	Other raceways should be made of noncombustible materials.	C.5.e(2)	C	Gutter-type raceways are of all-metal construction.
88.	Redundant safety-related cable systems outside the cable spreading room should be separated from each other and from potential fire exposure hazards in nonsafety-related areas by 3 hour fire barriers.	C.5.e(2)	AC	See Section 9A.3.1.2.
89.	These cable trays should be provided with continuous line-type heat detectors.	C.5.e(2)	NC	See Section 9A.3.1.2.
90.	Cables should be designed to allow wetting down with fire suppression water without electrical faulting.	C.5.e(2)	C	Cable insulating systems include proprietary jacketing materials designed for wetting.
91.	Redundant safety-related cable trays outside the cable spreading room should be accessible for manual fire fighting. Manual hose stations and portable hand extinguishers should be provided.	C.5.e(2)	C	
92.	Safety-related cable trays of a single division that are separated from redundant divisions by a 3 hour fire barrier and are accessible for manual fire fighting should be protected from the effects of a potential exposure fire by providing automatic water suppression.	C.5.e(2)	AC	See Section 9A.3.1.2.
93.	Safety-related cable trays that are not accessible for manual fire fighting should be protected by an automatic water systems.	C.5.e(2)	NA	Safety-related cable trays are not routed through areas that are inaccessible for Manual fire fighting.
94.	Safety-related cable trays that are not separated from redundant divisions by 3 hour fire barriers should be protected by automatic water suppression systems.	C.5.e(2)	AC	See Section 9A.3.1.2 and Item 92 above.
95.	The capability to achieve safe shutdown considering the effects of a fire involving fixed and transient combustibles should be evaluated with and without actuation of the automatic suppression system.	C.5.e(2)	C	See Section 9A.5.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
96.	Electric cable construction should pass the flame test in IEEE 383.	C.5.e(3)	AC	See Section 9A.3.1.2.
97.	Cable raceways should be used only for cables.	C.5.e(4)	C	
98.	Miscellaneous storage and piping for combustible liquids or gases should not create a potential exposure hazard to safety-related systems.	C.5.e(5)	C	See Section 9A.3.1.2.
	Ventilation			
99.	Smoke and corrosive gases should be discharged directly outside to an area that will not affect safety-related plant areas.	C.5.f(1)	AC	See Section 9A.3.1.2.
100.	To facilitate manual fire fighting, separate smoke and heat vents should be provided in certain areas.	C.5.f(1)	NC	See Section 9A.3.1.2.
101.	Release of smoke and gases containing radioactive materials to the environment should be monitored.	C.5.f(2)	C	See Section 9A.3.1.2.
102.	Any ventilation system designed to exhaust potentially radioactive smoke or gases should be evaluated to ensure that inadvertent operation or single failures will not violate the radiologically controlled areas of the plant.	C.5.f(2)	AC	See Section 9A.3.1.2.
103.	The power supply and controls for mechanical ventilation systems should be run outside the fire areas served by the system.	C.5.f(3)	AC	See Section 9A.3.1.2.
104.	Engineered safety feature filters should be protected in accordance with the guidelines of Regulatory Guide 1.52.	C.5.f(4)	C	See Section 9A.3.1.2.
105.	Air intakes for ventilation systems serving areas containing safety-related equipment should be located remote from the exhaust air outlets and smoke vents of other fire areas.	C.5.f(5)	C	Air intakes serving areas which contain safety-related equipment are remote from exhaust and smoke outlets of other fire areas.
106.	Stairwells should be designed to minimize smoke infiltration during a fire.	C.5.f(6)	C	Stair towers are provided with self-closing doors, which will minimize smoke infiltration during a fire.
107.	Where total flooding gas extinguishing systems are used, ventilation dampers, should be controlled in accordance with NFPA 12 and NFPA 12A.	C.5.f(7)	C	See Section 9A.3.1.2.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
	Lighting and Communication			
108.	Fixed self-contained lighting units with individual 8 hour battery power supplies should be provided in areas that must be manned for safe shutdown and for access and egress routes to and from all fire areas.	C.5.g(1)	AC	See Item 108 of Section 9A.3.1.2, and Item 23 of Section 9A.3.2.2.
109.	Sealed beam battery-powered portable hand lights should be provided for emergency use.	C.5.g(2)	C	Portable lights are provided.
110.	Fixed emergency communications independent of the normal plant communication system should be installed at preselected stations.	C.5.g(3)	AC	See Section 9A.3.1.2.
111.	A portable radio communications system should be provided for use by the fire brigade and other operations personnel required to achieve safe plant shutdown.	C.5.g(4)	AC	See Section 9A.3.1.2.
	Fire Detection			
112.	Detection systems should be provided for all areas that contain or present a fire exposure to safety-related equipment.	C.6.a(1)	AC	See Section 9A.3.1.2.
113.	Fire detection systems should comply with the requirements of Class A systems as defined in NFPA 72D and Class I circuits as defined in NFPA 70.	C.6.a(2)	AC	The fire and smoke detection system is partially Class A and partially Class B, as described in Section 9A.2.12. (Class A and Class B systems are defined in the 1975 edition of NFPA 72D.)
114.	Fire detectors should be selected and installed in accordance with NFPA 72E.	C.6.a(3)	C	See Section 9A.2.12.
115.	Testing of pulsed line-type heat detectors should demonstrate that the frequencies used will not affect the actuation of protective relays in other plant systems.	C.6.a(3)	NA	Pulsed line-type detectors are not used in the plant.
116.	Fire detection systems should give audible and visual alarm and annunciation in the control room.	C.6.a(4)	C	

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
117.	Where zoned detection systems are used in a given fire area, local means should be provided to identify which zone has actuated.	C.6.a(4)	C	A coding system has been established for all fire alarms in the plant so that the location of a fire can be determined from the sound of the alarm. A list of these codes and their corresponding detection areas will be posted at each fire alarm pull station.
118.	Local audible alarms should sound in the fire area.	C.6.a(4)	C	Fire alarms are annunciated throughout the plant, as well as in the local area in which a fire detector has been actuated.
119.	Fire alarms should be distinctive and unique so they will not be confused with any other plant system alarms.	C.6.a(5)	C	
120.	Primary and secondary power supplies which satisfies the provisions of section 2220 of NFPA 72D should be provided for the fire detection system and for electrically operated control valves for automatic suppression systems.	C.6.a(6)	AC	See Section 9A.3.1.2.
	Fire Protection Water Supply Systems			
121.	An underground yard fire main loop should be installed to furnish anticipated water requirements.	C.6.b(1)	C	An underground yard fire main loop has been provided and is in compliance with NFPA 24.
122.	Type of pipe and water treatment should be design consideration with tuberculation as one of the parameters.	C.6.b(1)	C	The yard fire main loop utilizes cement-lined cast iron pipe to reduce tuberculation. Water used fire protection service meets the requirements of NFPA 22 and does not require treatment.
123.	Means of inspecting and flushing the systems should be provided.	C.6.b(1)	C	Following its installation, the yard fire main loop was flushed and tested in accordance with NFPA 24 (1973), sections 98 and 99. Flushing of the loop is accomplished through the use of sectional control valves to direct the flow and yard hydrants to serve as discharge points.
124.	Approved visually indicating sectional control valves should be provided to isolate portions of the main for maintenance or repair.	C.6.b(2)	C	Postindicator valves provided for sectionalized control and isolation of portions of the yard fire main loop.
125	Valves should be installed to permit isolation of outside hydrants from the fire main for maintenance or repair without interrupting the water supply to automatic or manual fire suppression system.	C.6.b(3)	C	A key-operated gate valve with a curb box is provided in each lateral from the yard fire main loop to a fire hydrant.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
126.	The fire main system piping should be separate from service or sanitary water system piping.	C.6.b(4)	C	See Section 9A.3.1.2.
127.	A common yard fire main loop may serve multiunit nuclear power plant sites if cross-connected between units. Sectional control valves should permit maintaining independence of the loop around each unit.	C.6.b(5)	C	The yard fire main loop is common to both reactor units. The loop is cross-connected between units and provided with sectional control valves.
128.	A sufficient number of pumps should be provided to ensure that 100% capacity will be available assuming failure of the largest pump or a LOOP.	C.6.b(6)	C	Two fire pumps (one diesel-driven and one electric motor-driven) are provided, each capable of supplying 100% of the systems flow requirements.
129.	Individual fire pump connections to the yard fire main loop should be separated with sectionalizing valves between connections.	C.6.b(6)	C	
130.	Each pump and its driver and controls should be separated from the remaining fire pumps by a 3 hour fire wall.	C.6.b(60	C	
131.	The fuel for the diesel fire pump should be separated so that it does not provide a fire source exposing safety-related equipment.	C.6.b(6)	C	The diesel oil day tank is located in a curbed area within the diesel-driven fire pump compartment. This compartment is located in the circulating water pump structure, which is separated from all structures containing safety-related equipment.
132.	Alarms indicating pump running, driver availability, failure to start, and low fire main pressure should be provided in the control room.	C.6.b(6)	AC	Pump running, driver availability, and failure to start are annunciated in the control room. Fire main pressure is indicated in the control room but not annunciated.
133.	The fire pump installation should conform to NFPA 20.	C.6.b(6)	C	
134.	Outside manual hose installation should be sufficient to provide an effective hose stream to any onsite location where fixed or transient combustibles could jeopardize safety-related equipment. Hydrants should be installed approximately every 250 feet on the yard main system.	C.6.b(7)	AC	Hydrants are space between 250 rod and 300 feet apart along the fire main loop.
135.	Recommendations for hose houses and hose carts.	C.6.b(7)	AC	See Section 9A.3.1.2.
136.	Threads compatible with those used by local fire departments should be provided on all hydrants, hose couplings, and standpipe risers.	C.6.b(8)	C	

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
137.	Two separate, reliable freshwater supplies should be provided.	C.6.b(9)	C	The cooling tower basins of the Unit 1 and Unit 2 circulating water systems are used as the two sources of water for the fire pumps.
138.	Recommendations for tanks used to supply fire protection water.	C.6.b(9)	NA	Tanks are not utilized for fire protection Water supply.
139.	Recommendations for tanks used to supply fire protection water.	C.6.b(10)	NA	Tanks are not utilized for fire protection water supply.
140.	The fire water supply should be based on the largest expected flow rate for a period of 2 hours, but not less than 300,000 gallons.	C.6.b(11)	C	See Section 9A.3.1.2.
141.	The fire water supply should be capable of delivering the design demand over the longest route of the water supply system.	C.6.b(11)	C	In the event that a portion of the yard fire main loop is valved out of service, the fire pumps are capable of delivering the design demand over the longest route of the water supply system.
142.	Recommendations for freshwater lakes or ponds used to supply fire protection water.	C.6.b(12)	NA	Lakes or ponds are not utilized for fire protection water supply.
143.	Recommendations concerning use of other water systems for fire protection and the ultimate heat sink.	C.6.b(13)	NA	The fire protection system and the ultimate heat sink do not share a common water supply.
144.	Recommendations concerning use of other water systems as the source of fire protection water.	C.6.b(14)	AC	See Section 9A.3.1.2.
145.	Recommendations concerning connection of sprinkler systems and manual hose station standpipes to the yard fire main loop.	C.6.c(1)	C	See Item 19.
146.	Each sprinkler and standpipe system should be equipped with OS&Y gate valve or other approved shutoff valve and water flow alarm.	C.6.c(1)	AC	See Section 9A.3.1.2.
147.	Safety-related equipment should be protected from sprinkler discharge if such discharge could result in unacceptable damage to the equipment.	C.6.c(1)	AC	See Section 9A.3.1.2.
148.	Control and sectionalizing valves in the fire water systems should be electrically supervised (with indication in the control room) or administratively controlled.	C.6.c(2)	C	See Section 9A.3.1.2.
149.	All valves in the fire protection systems should be periodically checked to verify position.	C.6.c(2)	C	

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
150.	Fixed water extinguishing systems should conform to requirements of NFPA 13 and NFPA 15.	C.6.c(3)	AC	See Section 9A.3.1.2.
151.	Recommendations for interior manual hose installations.	C.6.c(4)	NC	See Section 9A.3.1.2.
152.	Individual standpipes should be at least 4 inches in diameter for multiple hose connections and 2.5 inches in diameter for single hose connections.	C.6.c(4)	AC	See Section 9A.3.1.2.
153.	Standpipe and hose station installations should follow the requirements of NFPA 14.	C.6.c(4)	AC	See Section 9A.3.1.2
154.	Hose stations should be located as dictated by the fire hazards analysis to facilitate access and use for fire fighting operations.	C.6.c(4)	C	
155.	Recommendations concerning seismic design of standpipes and hose connections.	C.6.c(4)	NC	See Section 9A.3.1.2.
156.	Recommendations concerning hose nozzle selection.	C.6.c(5)	C	
157.	Fire hose should be hydrostatically tested in accordance with NFPA 1962. Hose stored in outside hose houses should be tested annually. Interior standpipe houses should be tested every 3 years.	C.6.c(6)	C	
158.	Consideration of foam suppression systems for flammable liquid fires.	C.6.c(7)	C	See Section 9A.3.1.2.
	Halon Suppression Systems			
159.	Halon fire extinguishing systems should comply with NFPA 12A ad NFPA 12B. Only UL-Listed or FM-approved agents should be used.	C.6.d	C	Design and installation of the Halon 1301 system is in accordance with NFPA 12A.
160.	Provisions for locally disarming automatic Halon systems should be key-locked and under administrative control. Automatic Halon systems should not be disarmed unless controls as described in Position C.2.j are provided.	C.6.d	NC	Administrative controls do not exist permitting disarming of the Halon system.
161.	Preventive maintenance and testing of the systems, Including check-weighing of the Halon cylinders, should be done at least quarterly.	C.6.d	AC	Maintenance and testing dictated by Technical Requirements Manual and Preventative Maintenance Program.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
162.	Considerations for design of Halon suppression systems.	C.6.d	C	See Section 9A.3.1.2.
	Carbon Dioxide Suppression Systems			
163.	Carbon dioxide extinguishing systems should comply the requirements of NFPA 12.	C.6.e	NA	
164.	Carbon dioxide extinguishing systems should comply with with a predischarge alarm system and a discharge delay to permit personnel egress.	C.6.e	NA	
165.	Provisions for locally disarming automatic carbon dioxide systems should be key-locked and under administrative control. The systems should not be disarmed unless controls as described in Position C.2.c are provided.	C.6.e	NA	
166.	Considerations for design of carbon dioxide suppression systems.	C.6.e	NA	
167.	Fire extinguishers should be provided in areas that contain, or could present a fire exposure hazard to, safety-related equipment in accordance with NFPA 10.	C.6.f	C	See Section 9A.3.1.2
168.	Dry chemical extinguishers should be installed with due consideration given to possible adverse effects on safety-related equipment.	C.6.f	C	
	Primary and Secondary Containment			
169.	Fire protection for the primary and secondary containment areas should be provided for hazards identified by the fire hazards analysis.	C.7.a(1)	C	Fire hazards have been identified, as discussed in Section 9A.4, and fire suppression system have been provided

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
				accordingly. The types and locations of suppression systems are identified in Table 9A.1 and Figures 9A-4 through 9A-12.
170.	Because of the general inaccessibility of primary containment during normal plant operation, protection should be provided by automatic fixed systems.	C.7.a(1)	NC	See Section 9A.3.1.2.
171.	Operation of the fire protection systems should not compromise the integrity of the containment or other safety-related systems.	C.7.a(1)(a)	C	The fire protection systems does not penetrate the primary containment boundary. Also see Item 24.
172.	Recommendations for protection of safety-related cables and equipment inside noninerted containments.	C.7.a(1)(b)	NA	The primary containment is inerted with nitrogen during reactor operation.
173.	Recommendations concerning fire detection inside the primary containment.	C.7.a(1)(c)	NC	See Section 9A.3.1.2.
174.	For BWR drywells, standpipe and hose stations should be placed outside the drywell with adequate lengths of hose, no longer than 100 feet, to reach any location inside the drywell with an effective hose stream.	C.7.a(1)(d)	AC	Additional hose is staged at a hose station outside each drywell entrance to supplement the high-rise packs with sufficient additional hose to reach any location within the drywell with an effective stream.
175.	Recommendations for reactor coolant pump oil collection system in noninerted containments.	C.7.a(1)(e)	NA	The primary containment is inerted with nitrogen during normal reactor operation.
176.	For secondary containment areas, cable fire hazards that could affect safety should be protected as described in Position C.5.e(2).	C.7.a(1)(f)	--	See Items 88 through 95.
177.	Self-contained breathing apparatus should be provided near the containment entrances for fire fighting and damage control personnel. These units should be independent of any breathing apparatus provided for general plant activities.	C.7.a(2)	C	See Item 33.
	Control Room Complex			
178.	The control room complex should be separated from other areas of the plant by 3 hour rated fire barriers.	C.7.b	C	The control room is separated from other parts of the control structure by 3 hour rated floor slabs at el 269' and el 289'. Three hour rated walls at the north, south, east, and west sides of the control room separate it from the reactor enclosures and turbine enclosures.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
179.	Recommendations concerning peripheral rooms in the control room complex.	C.7.b	NC	See Section 9A.3.1.2.
180.	Recommendations concerning the use of Halon and carbon dioxide flooding systems in the peripheral rooms.	C.7.b	NA	The peripheral rooms adjacent to the control room are not provided with Halon or carbon dioxide flooding systems.
181.	Recommendations concerning manual fire fighting capability in the control room.	C.7.b	C	See Section 9A.3.1.2.
182.	Recommendations concerning fire detection in the control room.	C.7.b	AC	See Section 9A.3.1.2.
183.	Breathing apparatus for control room operators should be readily available.	C.7.b	C	See Item 33.
184.	Recommendations concerning control room ventilation.	C.7.b	C	See Section 9A.3.1.2.
185.	All cables that enter the control room should terminate in the control room.	C.7.b	C	
186.	Cables in under-floor and ceiling spaces should meet the separation criteria necessary for fire protection.	C.7.b	C	See Section 9A.3.1.2.
187.	Air handling functions should be ducted separately from cable runs in such spaces.	C.7.b	C	The space above the suspended ceiling in the control room is not used as an air plenum for ventilation of the control room. Ventilation air is deducted through the space above the suspended ceiling.
188.	Fully enclosed electrical raceways located in under-floor and ceiling spaces, if over 1 square foot in cross-sectional area, should have automatic fire suppression inside.	C.7.b	C	None of the fully enclosed raceways in the space above the suspended ceiling in the control room has a cross-sectional area exceeding 1 square foot. The raceways in the raised flooring of the auxiliary equipment room are provided with an automatic Halon suppression system, as described in Section 9A.2.9.
189.	Recommendations concerning automatic fire suppression in under-floor and ceiling spaces.	C.7.b	AC	See Section 9A.3.1.2.
190.	There should be no carpeting in the control room.	C.7.b	NC	See Section 9A.3.1.2.
	Cable Spreading Room			
191.	Recommendations concerning automatic fire suppression in the cable spreading room.	C.7.c	C	See Section 9A.3.1.2.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
192.	Open-head deluge and open directional spray systems should be zoned.	C.7.c	NA	Open-head water suppression systems are not used in the cable spreading room.
193.	Cable spreading rooms should have at least two remote and separate entrances for access by fire brigade personnel.	C.7.c(1)	C	
194.	Cable spreading rooms should have an aisle separation between tray stacks at least 3 feet wide and 8 feet high.	C.7.c(2)	NC	Cable trays in the cable spreading rooms are arranged to provide aisleways with a minimum headroom approximately 6.5 feet high and and a minimum width between tray stacks of approximately 3 feet. At certain locations, structural supports for the cable trays reduce the aisle width to a minimum of 17 inches. All points in the cable spreading rooms can be reached by an effective hose stream.
195.	Cable spreading rooms should have hose stations and portable extinguishers installed immediately outside the room.	C.7.c(3)	C	The locations of hose stations in the vicinity of the cable spreading rooms are shown in Figure 9A.7.
196.	Cable spreading rooms should have area smoke detection.	C.7.c(4)	C	The fire and smoke detection system is described in Section 9A.2.12. The number of detectors located in each fire area is listed in Table 9A.1.
197.	Cable spreading rooms should have continuous line-type heat detectors for cable trays inside the cable spreading room.	C.7.c(5)	NC	Continuous line-type heat detectors are not used in cable trays. Smoke detectors are provided in the cable spreading room (as specified in Table 9A-1) and will provide early warning for cable tray fires occurring in the cable spreading room. See Item 89 for further discussion.
198.	Drains to remove fire-fighting water should be provided.	C.7.c	C	
199.	When gas systems are installed, drains should have adequate seals or the gas extinguishing system should be sized to compensate for losses through the drains.	C.7.c	NA	
200.	A separate cable spreading room should be provided for each redundant division.	C.7.c	NC	See Item 57.
201.	Cable spreading rooms should not be shared between reactors.	C.7.c	C	Each reactor unit is provided with its own separate cable spreading room.
202.	Each cable spreading room should be separated from the others and from other areas of the plant by 3 hour fire barriers.	C.7.c	C	See Item 58 of Section 9A.3.1.2.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
203.	The ventilation system for the cable spreading room should be designed to isolate the area upon actuation of the gas extinguishing system.	C.7.c	NA	
204.	Separate manually actuated smoke venting that is operable from outside the room should be provided for the cable spreading room.	C.7.c	C	Portable smoke ejectors are used to clear smoke and toxic gases from the cable spreading rooms.
	Plant Computer Rooms			
205.	Recommendations concerning fire protection for computers performing safety-related functions.	C.7.d	NA	The plant computer is not safety-related.
206.	Nonsafety-related computers outside the control room should be separated from safety-related areas by 3 hour fire barriers and should be protected as needed to prevent damage to safety-related equipment.	C.7.d	AC	The plant computer is nonsafety-related and is located in the auxiliary equipment room. The auxiliary equipment room is separated from other areas of the plant by 3 hour fire barriers, but the computer is not separated (other than by distance) from safety-related panels in the auxiliary equipment room. Automatic fire suppression for the raised flooring in the auxiliary equipment room is discussed in Section 9A.2.9.
	Switchgear Rooms			
207.	Switchgear rooms containing safety-related equipment should be separated from the remainder of the plant by 3 hour fire barriers. Redundant switchgear safety divisions should be separated from each other by 3 hour fire barriers.	C.7.e	AC	The safety-related switchgear rooms at el 239' in the control structure are separated from each other and from the remaining areas of the plant by 3 hour rated fire walls. The concrete slab above these rooms is a 3 hour rated barrier, and the slab below the room is capable of a 3 hour fire rating with the exception of exposed structural steel members supporting the slabs.
208.	Automatic fire detectors should alarm and annunciate in the control room and alarm locally.	C.7.e	C	Each safety-related switchgear room is provided with smoke and heat detectors that annunciate in the control room and alarm locally.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
209.	Fire hose stations and portable fire extinguishers should be readily available outside the switchgear rooms.	C.7.e	C	
210.	Drains should be provided to prevent water accumulation from damaging safety-related equipment.	C.7.e	AC	See Section 9A.3.1.2.
211.	Remote manually actuated ventilation should be provided for venting smoke when manual fire suppression effort is needed.	C.7.e	NC	Ventilation features separate from the normal ventilation system are not provided for the switchgear rooms. Smoke removal can be accomplished using portable exhaust fans, if necessary.
	Remote Safety-Related Panels			
212.	Recommendations concerning separation and electrical isolation of remote safety-related panels.	C.7.f	AC	See Section 9A.3.1.2.
213.	The general area housing remote safety-related panels should be provided with automatic fire detectors that alarm locally and alarm and annunciate in the control room. Combustible materials should be controlled and limited to those required for operation. Portable extinguishers and manual hose stations should be readily available in the general area.	C.7.f	C	
	Safety-Related Battery Rooms			
214.	Safety-related battery rooms should be separated from each other and other areas of the plant by 3 hour rated fire barriers.	C.7.g	AC	The safety-related battery room are located in the control structure. These rooms are separated from each other and from the remaining areas of the plant by 3 hour rated fire walls. The floor slabs above and below the battery rooms are capable of 3 hour fire ratings with the exception of exposed structural steel members supporting the concrete slabs.
215.	DC switchgear and inverters should not be located in safety-related battery rooms.	C.7.g	AC	See section 3.1.2.
216.	Automatic fire detection should be provided to annunciate in the control room and alarm locally.	C.7.g	C	Each safety-related battery room is provided with smoke and heat detectors that annunciate in the control room and alarm locally.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
217.	Ventilation system in the battery rooms should be capable of maintaining the hydrogen concentration below 2%.	C.7.g	C	See Section 9A.3.1.2.
218.	Loss of ventilation should be alarmed in the control room.	C.7.g	C	See Section 9A.3.1.2.
219.	Portable extinguishers and manual hose stations should be readily available outside the battery rooms.	C.7.g	C	
	Turbine Building			
220.	The turbine building should be separated from adjacent structures containing safety-related equipment by 3 hour fire barriers.	C.7.h	C	The turbine enclosure is separated from the reactor enclosure and control structure by 3 hour rated fire walls.
221.	The fire barriers should be designed so as to maintain structural integrity in the event of collapse of the turbine structure.	C.7.h	C	See Section 9A.3.1.2.
222.	Openings and penetration in the fire barrier should be minimized and should not be located where the turbine oil system or generator hydrogen cooling system creates a fire exposure hazard to the barrier.	C.7.h	C	See Section 9A.3.1.2.
	Diesel Generator Areas			
223.	Diesel generators should be separated from each other and from other areas of the plant by 3 hour rated fire barriers.	C.7.i	C	The individual diesel generator cells, each of which encloses a single diesel generator, are separated from adjacent fire areas by 3 hour rated barriers consisting of 24 inch thick reinforced concrete walls and 18 inch thick reinforced concrete slabs. Each door opening in the 3 hour rated walls is provided with a UL Class A fire door. All penetration through the 3 hour rated walls and floor slabs are sealed using penetration seal details that are qualified for use in 3 hour rated fire barriers.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
224.	Automatic fire suppression should be installed to combat diesel generator or lubricating oil fires. Such systems should be designed for operation when the diesel is running without affecting the diesel.	C.7.i	AC	See Section 9A.3.1.2.
225.	Automatic fire detection should be provided to annunciate in the control room and alarm locally.	C.7.i	C	
226.	Portable extinguishers and manual hose stations should be readily available outside the area.	C.7.i	C	Portable extinguishers are available outside the diesel generator cells. Fire hydrants located in the yard can reach any area of the diesel generator cells.
227.	Drainage for fire fighting water and means for local manual venting of smoke should be provided.	C.7.i	AC	See Section 9A.3.1.2.
228.	Day tanks with total capacity up to 1100 gallons are permitted in the diesel generator area under specified conditions.	C.7.i	C	The day tank for each diesel generator has a capacity of 850 gallons.
229.	The day tank should be located in a separated enclosures with a 3 hour fire rating.	C.7.i	C	The day tank for each diesel generator is located in a vault that is separated from the remainder of the diesel generator cell by 3 hour rated fire walls.
230.	The day tank enclosures should be capable of containing the entire contents of the tank.	C.7.i	C	
231.	The day tank enclosure should be protected by an automatic fire suppression system.	C.7.i	C	The preaction sprinkler system provided in each diesel generator cell includes coverage of the day tank vault.
	Diesel Fuel Oil Storage Areas			
232.	Recommendations concerning diesel fuel oil tanks.	C.7.j	C	Each diesel generator is provided with a diesel fuel oil storage tank that has a capacity of 41,500 gallons. All eight tanks are located adjacent to each other and are buried underground.
233.	Above-ground tanks should be protected by an automatic fire suppression system.	C.7.j	NA	See Item 232.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
	Safety Related Pumps			
234.	Pump houses and rooms housing redundant safety-related pump trains should be separated from each other and from other areas of the plant by 3 hour rated fire barriers.	C.7.k	C	The safety-related pump compartments located at el 177' in the reactor enclosure are separated from each other and from other areas of the plant by 3 hour rated fire walls. The spray pond pump structure is located remote from other plant structures, and the two divisions of pumps within the structure are separated by a 3 hour rated fire wall.
235.	These rooms should be protected by automatic fire suppression unless a fire hazards analysis can demonstrate that a fire will not endanger equipment required for safe shutdown.	C.7.k	C	The HPCI compartment and the RCIC pump compartment are protected by automatic preaction sprinkler systems. Fires originating in other safety-related pump compartments would not endanger other safety-related equipment required for safe shutdown, as discussed in Section 9A.5.
236.	These rooms should be provided with automatic fire detection to annunciate in the control room and alarm locally.	C.7.k	C	
237.	Portable extinguishers and manual hose stations should be readily accessible.	C.7.k	NC	Portable extinguishers are provided for use in all areas housing safety-related pumps. Manual hose stations are provided for use in all areas housing safety-related pumps, except for the spray pond pump structure. In consideration of the low combustible loading in the spray pond pump structure, portable extinguishers are deemed adequate to control and extinguish a fire at any pump.
238.	Floor drains should be provided to prevent water accumulation from damaging safety-related equipment.	C.7.k	C	
239.	Provisions should be made for manual control of the ventilation systems to facilitate smoke removal.	C.7.k	C	The ventilation systems in areas housing safety-related pumps are provided with controls that are sufficient to permit manual control of the ventilation as necessary to facilitate smoke removal.
240.	Recommendations for fire protection of the new fuel area.	C.7.l	NA/AC	The normal storage area for new fuel is the spent fuel pool. Prior to plant operation and during the initial phases of plant operation, new fuel may be stored in a temporary outdoor storage area. Fire protection for this temporary new fuel storage area will be provided in accordance with guidelines established by ANI.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
	Spent Fuel Pool Area			
241.	Protection for the spent fuel pool area should be provided by hose stations and portable extinguishers.	C.7.m	C	Hose stations and portable extinguishers are located near the spent fuel pool.
242.	Automatic fire detection should be provided to annunciate in the control room and to alarm locally.	C.7.m	NC	See Section 9A.3.1.2, item 112.j.
	Radwaste and Decontamination Areas			
243.	Fire barriers, automatic fire suppression and detection, and ventilation controls should be provided.	C.7.n	C	See Section 9A.3.1.2.
	Safety-Related Water Tanks			
244.	Fire protection provisions for safety-related water tanks.	C.7.o	NA	The plant has no safety-related water tanks.
	Records Storage Areas			
245.	Records storage areas should be so located and protected that a fire in these areas does not expose safety-related systems or equipment.	C.7.p	C	
	Cooling Towers			
246.	Cooling towers should be of noncombustible construction or so located and protected that a fire will not adversely affect any safety-related systems or equipment.	C.7.q	C	The cooling towers are of noncombustible construction except for the fill material, which is polyvinyl chloride. No safety-related structures or systems are located near the cooling towers such that they could be affected by a fire in the cooling towers.
247.	Cooling towers should be of noncombustible construction when the basins are used for the ultimate heat sink or for the fire protection water supply.	C.7.q	AC	See Section 9A.3.1.2.
	Miscellaneous Areas			
248.	Location and protection of miscellaneous areas.	C.7.r	C	See Section 9A.3.1.2.

CMEB 9.5-1

NO.	CMEB 9.5-1 GUIDELINE	ITEM NO.	COMPARISON	REMARKS
	Storage of Acetylene/Oxygen Fuel Gases			
249.	Gas cylinder storage locations should not be in areas that contain or expose safety-related equipment or the fire protection systems that serve those safety-related areas.	C.8.a	C	Compressed gas storage cylinders for welding are located outdoors, away from safety-related components.
250.	A permit system should be required to use this equipment in safety-related areas of the plant.	C.8.a	C	
	Storage Areas for Ion Exchange Resins			
251.	Unused ion exchange resins should not be stored in areas that contain or expose safety-related equipment.	C.8.b	AC	Storage areas for dry ion exchange resins in safety-related equipment areas utilize approved metal storage containers.
	Hazardous Chemicals			
252.	Hazardous chemicals should not be stored in areas that contain or expose safety-related equipment.	C.8.c	AC	Procedural controls exist to ensure hazardous chemical storage in safety-related areas do not pose a fire risk.
	Materials Containing Radioactivity			
253.	Materials that collect and contain radioactivity should be stored in closed metal tanks or containers that are located in areas free from ignition sources or combustibles.	C.8.d	C	
254.	These materials should be protected from exposure to fires in adjacent areas.	C.8.d	C	
255.	Consideration should be given to requirements for removal of decay heat from entrained radioactive Materials.	C.8.d	C	Provisions for accommodating decay heat are considered when selecting containers.

9A.3.1.2 Explanatory Notes for Comparison to Branch Technical Position CMEB 9.5-1

Item 6

BTP Guideline

The position responsible for formulation and implementation of the fire protection program should have within his organization or as a consultant a fire protection engineer who is a graduate of an engineering curriculum of accepted standing and shall have completed not less than 6 years of engineering attainment indicative of growth in engineering competency and achievement, 3 years of which shall have been in responsible charge of fire protection engineering work. These requirements are the eligibility requirements as a Member in the Society of Fire Protection Engineers.

LGS Design

The Vice President, LGS, is responsible for the formulation and implementation of the fire protection program. In this capacity, he has access to the services of corporate support personnel, other Exelon sites, or vendors as necessary in the capacity of a fire protection engineer. The individual meets the requirements for membership in the Society of Fire Protection Engineers (i.e., a graduate of an engineering curriculum of accepted standing and shall have completed not less than 6 years of engineering attainment indicative of growth in engineering competency and achievement, 3 years of which shall have been in responsible charge of fire protection work).

In addition, fire protection consultants are available to assist in design and review tasks as required.

Item 15

BTP Guideline

Fires involving facilities shared between units and fires due to man-made site-related events that have a reasonable probability of occurring and affecting more than one reactor unit (such as an aircraft crash) should be considered.

LGS Design

The control structure, the spray pond pump structure, and the radwaste enclosure are common to the two reactor units. Fires are postulated to occur in these structures just as in other structures, and appropriate provisions are made for fire prevention, fire detection, and fire suppression.

For a discussion of fires due to man-made site-related events, refer to Item 22.

Item 19

BTP Guideline

A single active failure or a crack in a moderate energy line (pipe) in the fire suppression system should not impair both the primary and backup fire suppression capability. For example, neither the failure of a fire pump, its power supply or controls, nor a crack in a moderate energy line in the fire suppression system, should result in loss of function of both sprinkler and hose standpipe systems in an area protected by such primary and backup systems.

LGS Design

As described in Section 9A.2.1.2, fire water is supplied by two redundant pumps, each of which is capable of providing the design fire protection system flow rate at the design pressure. Power for the motor-driven fire pump is provided from either of two independent offsite power sources. The controls for the diesel engine-driven fire pump are dc-operated and are powered from batteries which supply only the engine-driven fire pump. Therefore, no single failure of the power supplies or controls can affect both fire pumps.

If a crack should occur in the yard fire main loop, sectional isolation valves can be used to isolate the damaged portion of the loop without affecting the majority of the loop. There is no single active failure that could affect the operability of both the sprinkler systems and manual hose stations for a given area. The standpipes supplying water to the sprinklers and manual hose stations have been designed to minimize the probability of a moderate energy crack occurring in these portions of piping. The standpipes were designed in accordance with NFPA requirements, for which the materials and standards of construction are the same as for ANSI B31.1, "Power Piping." The standpipes were seismically analyzed for safe shutdown earthquake loads in order to verify piping integrity under such loads. In the unlikely event that a crack does occur in a standpipe that supplies water to sprinklers and hose stations serving the same area, such that the ability to achieve design flow rates for the sprinklers and hose stations is affected, an effective hose stream could be provided to the area from a hose station attached to the closest unaffected standpipe.

Item 21

BTP Guideline

The fire protection systems should retain their original design capability for natural phenomena of less severity and greater frequency than the most severe natural phenomena (approximately once in 10 years) such as tornadoes, hurricanes, floods, ice storms, or small intensity earthquakes that are characteristic of the geographic region.

LGS Design

The fire pumps, the yard fire main loop, distribution piping within structures, manual hose stations, and fixed suppression systems are conservatively designed so as to retain their operability following the occurrence of natural phenomena with severities corresponding to a recurrence interval of once in 10 years.

Item 22

BTP Guideline

The fire protection systems should retain their original design capability for potential man-made site-related events such as oil barge collisions or aircraft crashes that have a reasonable probability of occurring at a specific plant site.

LGS Design

Transportation activities taking place near LGS, and the potential for accidents affecting the plant, are discussed in Section 2.2. As indicated in Section 2.2.2.4, there is no commercial traffic on the Schuylkill River in the vicinity of the site. As discussed in Section 2.2.3, the potential effects of an explosion occurring on nearby highways are exceeded in severity by the potential effects of a

railway explosion. Structures housing safety-related systems and components are designed to withstand impact from missiles generated by a railway explosion. Portions of fire protection systems that are located outside the safety-related structures could potentially be damaged by missiles generated by a railway explosion. However, such damage will not jeopardize safe shutdown capability since the systems and components, excluding offsite power, needed for safe shutdown are protected from damage due to missile impact and are isolated from the effects of fires occurring outside the safety-related structures.

Hazards to the plant resulting from aircraft operating in the vicinity of the site are discussed in Section 3.5.1.6. The control structure, reactor enclosure, and spray pond pump structure are designed to withstand the impact of the design aircraft (a Learjet) without loss of structural integrity. Portions of fire protection systems that are located outside these structures could potentially be damaged by aircraft impact. However, such damage will not jeopardize safe shutdown capability since the systems and components, excluding offsite power, needed for safe shutdown are protected from damage due to aircraft impact and are isolated from the effects of fires occurring outside the control structure, reactor enclosure, and spray pond pump structure.

Item 24

BTP Guideline

The consequences of inadvertent operation of or a crack in a moderate energy line in the fire suppression system should meet the guidelines specified for moderate energy systems outside containment in SRP section 3.6.1.

LGS Design

Moderate energy leakage cracks in fire suppression system piping are analyzed as discussed in Section 3.6. Section 3.6.1.2.2 summarizes the results of the moderate energy fluid system analysis and also provides references to other UFSAR sections that discuss the design bases and criteria that were used in the moderate energy fluid system analysis. The analysis demonstrates that the occurrence of a crack in moderate energy piping, including the fire suppression system piping, will not prevent the plant from being brought to a safe, cold shutdown.

Automatic suppression systems have been designed and located so that operation of the systems, either intentional or inadvertent, will not cause damage to redundant trains of safety-related equipment that is needed for safe shutdown of the plant. To the greatest extent practical, safety-related electrical components are located outside the coverage zones of automatic suppression systems. Where necessary, components that are needed in order to achieve safe shutdown and also are located within automatic suppression system coverage zones are designed to remain functional in the event of suppression system actuation. Four of the areas that are provided with automatic water-type suppression systems are the HPCI pump compartment, the RCIC pump compartment, the diesel generator cells, and the 13.2 kV switchgear room. Actuation of the suppression systems in the HPCI and RCIC pump compartments could cause damage significant enough to affect the operability of the systems in those compartments. In the diesel generator cells, baffles are provided to protect the generators and control devices from damage due to suppression system actuation. In the 13.2 kV switchgear room, the design features of the system mitigate the effects due to spurious actuation or MELB. This system is supervised with instrument air and incorporates a double interlock deluge valve that is maintained normally closed. Sprinkler flow is initiated only when two seperate inputs are received; one from a pneumatic actuator, due to the melting of the sprinkler fusible link(s) allowing the supervised air to be

released; and the other from the fire detection system that sends a signal to an electric solenoid valve. Loss of any of these four systems (HPCI, RCIC, or a single diesel generator and 13.2 kV switchgear room) due to suppression system actuation is acceptable, since redundant systems will remain available to bring the plant to a safe, cold shutdown.

There are no cases in which safe shutdown components have electrical interconnections with fire detection or fire suppression systems. Therefore, safe shutdown components cannot be inadvertently actuated or shut down due to either normal or abnormal signals in the control and power circuits of the fire detection and fire suppression systems.

The HPCI and RCIC pump compartments and the diesel generator cells are the only safety-related areas of the plant that are provided with automatic suppression systems and also are potentially subject to steam flooding as a result of high energy pipe breaks. Elevated compartment temperatures due to steam flooding could result in suppression system actuation if the temperatures are high enough to cause the deluge valve to open and the fusible links on the sealed sprinkler heads to open. However, loss of the HPCI system, RCIC system, or a single diesel generator due to suppression system actuation is acceptable, since redundant systems will remain available to bring the plant to a safe, cold shutdown.

Automatic (water) suppression systems located in safety-related areas of the plant are of the type that have fusible heads (either preaction or wet pipe). These systems cannot be actuated in the absence of a significant heat source in the vicinity of the sprinkler heads. Therefore, electrical anomalies in the circuits of the smoke and heat detection systems or the suppression system power supplies cannot cause inadvertent actuation of these suppression systems.

Item 28

BTP Guideline

On reactor sites where there is an operating reactor and construction or modification of other units is under way, the fire protection program should provide for continuing evaluation of fire hazards. Additional fire barriers, fire protection capability, and administrative controls should be provided as necessary to protect the operating unit from construction fire hazards.

LGS Design

Administrative procedures will be prepared to protect the operating Unit 1 from fire hazards associated with construction of Unit 2. Special precautions will be taken to prevent and control fire hazards. Use of open flames and welding or cutting equipment will be properly supervised.

Construction of both the underground yard fire main and the fire water distribution piping inside both units of the plant will be completed prior to Unit 1 operation so that manual hose station coverage will be available in Unit 2 as well as Unit 1. Portable fire extinguishers will also be available in the Unit 2 portions of the plant during its construction. The construction site will be kept clean and orderly and contractors' sheds will be kept outside the confines of new construction.

Item 33

BTP Guideline

Self-contained breathing apparatus using full face positive- pressure masks approved by the National Institute for Occupational Safety and Health (approval formerly given by the U.S. Bureau of Mines) should be provided for fire brigade, damage control, and control room personnel. At least 10 masks shall be available for fire brigade personnel. Control room personnel may be furnished breathing air by a manifold system piped from a storage reservoir if practical. Service or rated operating life shall be a minimum of one-half hour for the self-contained units.

At least two extra air bottles should be located onsite for each self-contained breathing unit. In addition, an onsite 6 hour supply of reserve air should be provided and arranged to permit quick and complete replenishment of exhausted supply air bottles as they are returned. If compressors are used as a source of breathing air, only units approved for breathing air shall be used; compressors shall be operable assuming a LOOP. Special care must be taken to locate the compressor in areas free of dust and contaminants.

LGS Design

Self-contained breathing apparatus will be available for use by control room personnel and fire brigade members. The breathing apparatus will have a minimum operating life of 4 hours for control room personnel and 1 hour for fire brigade members.

An onsite reserve air supply of six hours for at least five persons will be provided in stored air bottles. Compressors, if used, will be units approved for breathing air.

Item 34

BTP Guideline

Recommendations for the fire brigade training program.

LGS Design

Fire Protection program objectives for training fire brigade members is accomplished by using a combination of in plant areas and an off-site training facility that simulates plant physical conditions. Drills are conducted in conformance with plant fire drill procedures.

An off-site facility enables drills to include the use of live fire conditions. These elements plus the use of breathing apparatus and full protective clothing create actual conditions that would be encountered during a real plant fire emergency. Additional drills, including backshift unannounced drills are conducted in plant areas throughout the year. Unannounced drills are scheduled on a "per shift basis" in accordance with the corporate fire protection procedures.

Local fire departments are offered annual training associated with the responsibilities and duties of the plant fire brigade and offsite responders, operational precautions when fighting fires on nuclear power plant sites including awareness of the need for radiological protection of personnel and the special hazards associated with a nuclear power plant site.

Item 35

BTP Guideline

The quality assurance programs of applicants and contractors should ensure that the guidelines for design, procurement, installation, and testing and the administrative controls for the fire protection systems for safety-related areas are satisfied. The QA program should be under the management

control of the QA organization. This control consists of (1) formulating a fire protection QA program that incorporates suitable requirements and is acceptable to the management responsible for fire protection or verifying that the program incorporates suitable requirements and is acceptable to the management responsible for fire protection, and (2) verifying the effectiveness of the QA program for fire protection through review, surveillance, and audits. Performance of other QA program functions for meeting the fire protection program requirements may be performed by personnel outside of the QA organization. The QA program for fire protection should be part of the overall plant QA program.

LGS Design

The QA program described below will be under the management control of the licensee and their agent's organizations during the construction and operation phases.

a. Design and Procurement Document Control

The design review performed to compare the LGS design to the BTP guidelines provides assurance that necessary design features are included in appropriate design and procurement documents.

Deviations from the design and procurement documents will be controlled by mechanisms specified in the 10CFR50, Appendix B, QA program for this project.

b. Instructions, Procedures, and Drawings

These requirements will be met through the use of a documented, final installation inspection and through implementation of a written preoperational test.

c. Control of Purchased Material, Equipment, and Services

Based upon the status of procurement and the identification of significant design or manufacturing features, certain fire protection equipment may be subject to shop inspection during manufacture.

Receipt inspection at the site shall be performed.

d. Inspection

These requirements will be met through the use of a documented, final installation inspection and through implementation of a written preoperational test.

e. Test and Test Control

Documented preoperational test procedures including evaluation of results and follow-up action, if indicated, shall be employed to meet these requirements.

f. Inspection, Test, and Operating Status

Installation inspections, as described in Item 4 above, shall be documented in such a manner as to indicate the acceptability of the item/activity inspected. Deficiencies

shall be identified and corrected in accordance with mechanisms specified in the 10CFR50, Appendix B, QA program for this project.

Satisfactory completion of the preoperational test and release for operation shall be accomplished and documented in accordance with mechanisms specified in the 10CFR50, Appendix B, QA program for this project.

g. Nonconforming Items

Nonconforming items shall be identified, controlled, and corrected in accordance with the mechanisms specified in the 10CFR50, Appendix B, QA program for this project.

h. Corrective Action

Conditions adverse to fire protection (such as failures, malfunctions, deficiencies, deviations, defective components, and nonconformances) during the construction phase shall be reported and corrected in accordance with mechanisms specified in the 10CFR50, Appendix B, QA program for this project.

i. Records

Records shall be prepared and maintained to furnish evidence that the criteria described in Items 1 through 10 are being met for activities affecting the fire protection program.

j. Audits

The activities described above are subject to audit. In addition, implementation of receipt inspections, final installation inspections, and preoperational tests shall be subject to audit to conform with documented instructions, procedures, and drawings.

Item 37

BTP Guideline

Fire barriers with a minimum rating of 3 hours should be provided to separate redundant divisions of safety-related systems from each other.

LGS Design

Redundant divisions of safety-related systems will be separated from each other so as to achieve the three levels of fire damage limits established in Position C.1.b. The provision of fire barriers between redundant divisions of safety-related systems that do not have safe shutdown functions is not required. Fire barriers will be provided between redundant divisions of safe shutdown systems as necessary to ensure that one train of equipment necessary to achieve safe shutdown is maintained free of fire damage to the degree specified in Position C.1.b unless specified otherwise in Section 9A.5.

The reactor enclosures, turbine enclosures, diesel generator enclosures, radwaste enclosure, and administration building are separated from each other by 3 hour rated fire walls. Walls internal to these structures (and also the spray pond pump structure) which serve as boundaries between different fire areas are provided with fire ratings or construction details consistent with the fire hazard existing in each area. The locations of fire-rated walls are shown on Figures 9A-4 through 9A-12, and the walls surrounding each fire area are further described in the fire area discussions contained in Sections 9A.5.3 through 9A.5.9.

The structural steel beams supporting the floor slabs at el 254', el 269', el 289' and el 304' in the control structure were fireproofed to provide a 3 hour rating for the complete floor assembly during initial construction. Subsequently, Ref. 9A.7.5 approved an analytical method that demonstrated certain structural steel members did not require fire roofing. The structural steel beams supporting floor slabs in other areas have not been fireproofed. The fire ratings of floor slabs above and below each fire area are listed in the fire area discussions contained in Sections 9A.5.3 through 9A.5.9. Those slabs which are shown as "3 hr*" are capable of being rated as 3 hour fire barriers, except for the lack of fireproofing on the structural steel beams supporting the slab.

Reinforced concrete walls without penetrations are considered to qualify for a 3 hour fire rating, provided that the wall has a thickness of at least 6 inches. Concrete block walls designated as fire walls are constructed in accordance with UL Design No. U904, as a minimum. Fire walls incorporating metal studs with lath and plaster are constructed in accordance with UL Design No. U409. Fireproofing material is applied to structural steel beams in accordance with UL Design No. N706, N712, N742, or N760. Concrete block walls which are designated with a ″^″ have perpendicular steel beam penetrations that are evaluated as adequate for the hazards present in the fire areas under a deviation (see 9A.6.6).

Item 39

BTP Guideline

Appropriate fire barriers should be provided within a single safety division to separate components that present a fire hazard to other safety-related components or high concentrations of safety-related cables within that division.

LGS Design

The diesel generator day tanks constitute the most significant fire hazard posed by components within safety-related systems. As stated in Item 229, the day tank for each diesel generator is located in a vault that is separated from the remainder of the diesel generator cell by 3 hour rated fire walls. The HPCI, RCIC, RHR, and LPCI systems contain lesser fire hazards in the form of lubricating oil associated with the pumps and drivers in these systems. These pumps are located at el 177' in the reactor enclosure, which is compartmentalized to separate the pumps from each other and from other safety-related systems.

Fire barriers are not provided solely for the purpose of separating safety-related cables from other safety-related cables in the same division. Separation by distance or by fire barriers between redundant divisions is provided as necessary to ensure safe shutdown capability in the event of a fire. Separation to ensure independence between Class 1E and non-Class 1E circuits and between redundant divisions of Class 1E circuits is discussed in Section 8.1.6.1.14.

Item 40

BTP Guideline

Openings through fire barriers for pipe, conduit, and cable trays which separate fire areas should be sealed or closed to provide a fire resistance rating at least equal to that required of the barrier itself.

LGS Design

Pipe, conduit, and cable tray penetrations through fire-rated barriers will be sealed to provide a fire resistance rating that is consistent with that of the overall barrier. Such seals in fire barrier penetrations will be installed in accordance with the manufacturer's tested configurations where possible. Individual penetration seals that include configurations or features that constitute deviations from the manufacturer's tested configuration are reviewed and accepted by LGS's authorized insuring agency for use as fire-rated seals.

Item 41

BTP Guideline

Openings inside conduit larger than 4 inches in diameter should be sealed at the fire barrier penetration. Openings inside conduit 4 inches or less in diameter should be sealed at the fire barrier unless the conduit extends at least 5 feet on each side of the fire barrier and is sealed either at both ends or at the fire barrier with noncombustible material to prevent the passage of smoke and hot gases.

LGS Design

In areas of the plant that contain safety-related equipment, conduits that penetrate fire barriers will be sealed internally to prevent the passage of smoke and hot gases. For each penetrating conduit that extends 5 feet or more on both sides of the fire barrier, noncombustible seals will be provided on both sides of the fire barrier at the access point (junction box, termination at a cable tray, or equipment connection) that is closest to the fire barrier. For each penetrating conduit that extends less than 5 feet on either side of the fire barrier, a 3 hour fire rated seal will be provided either at the fire barrier or on one side of the barrier at the access point that is closest to the barrier. For the cases in which access to the interior of a conduit has been provided at the fire barrier via a junction box or condulet, the 3 hour seal is located at the barrier. Where no access has been provided at the barrier, the 3 hour seal is located at the access point that is closest to the barrier. For the cases in which the penetrating conduit is larger than 4 inches in diameter and the 3 hour seal is not located at the barrier, the conduit forms part of the fire barrier in combination with the seal. Conduits in this category are schedule 40 rigid steel and will maintain their integrity while exposed to a 3 hour fire.

Any installation which deviates from the above criteria for internal conduit seals is documented in a technical evaluation in the form of a fire hazards and safe shutdown analysis that is performed and reviewed by personnel responsible for fire protection and safe shutdown analyses for the plant. Each technical evaluation documents the as-built configuration and presents the rationale for concluding that the affected seal does not degrade the effectiveness of the fire barrier in preventing the spread of a postulated fire and in limiting the migration of smoke and hot gases. Each technical evaluation performed is retained as part of the permanent plant records.

For conduits that enter the bottom of floor-mounted components that are mounted on fire-rated floor slabs, 3 hour rated seals are normally installed inside each conduit at the point where it enters the component. In some cases, however, the congestion of cables in a conduit prevents the fire sealant material from being installed to the minimum thickness necessary to qualify as a 3 hour rated seal. In each such situation, a second seal is installed inside the conduit at the access point nearest to the component, with the thickness of the sealant material in the second seal being selected so that the combined thickness of the first and second seals is not less than the thickness required for a 3 hour rated seal.

For fire barriers that separate safety-related areas from nonsafety-related areas of the plant, conduit penetrations will be provided with internal seals in the same manner as discussed above for safety-related areas.

In areas of the plant not containing safety-related equipment, internal seals will be provided for conduits penetrating fire barriers that are adjacent to fire areas with high combustible loadings. The locations of the conduit seals with respect to the fire barrier being penetrated will be the same as discussed above for safety-related areas.

Item 43

BTP Guideline

Penetration designs should utilize only noncombustible materials.

LGS Design

All materials used in fire-rated penetration seals are either noncombustible or are listed by an independent testing laboratory for flame spread, smoke generation, and fuel contribution of 25 or less, as determined by testing in accordance with ASTM E-84. Alternatively, the fire retardation of caulking and adhesive materials that are used in small quantities as part of penetration seal assemblies may be demonstrated by successful completion of the fire test specified in section 3.B of the "ANI/MAERP Standard Method of Fire Tests of Cable and Pipe Penetration Fire Stops," issued in February of 1976. The following different types of seals will be used in fire-rated applications:

a. Cement-type grout.

b. Foamed silicone polymer. This is a self-vulcanizing material that results from the mixture of two liquid components.

c. Solid silicone polymer. The polymer is impregnated with a powdered high density filler.

d. Flexible boot with ceramic fiber. The boot material is silicone rubber with woven glass fiber reinforcing. Ceramic fiber is installed inside the boot, in the space between the penetrating object and the edge of the penetration. Stainless steel compression straps and silicone adhesives are used in attaching the boot.

e. Flexible boot with gel. The boot material is silicone rubber with woven glass fiber reinforcing. The boot is filled with a high density silicone dielectric gel. Stainless steel compression straps and silicone adhesives are used in attaching the boot.

Item 45

BTP Guideline

The acceptance criteria for the test should require that:

a. The fire barrier penetration has withstood the fire endurance test without passage of flame or ignition of cables on the unexposed side for a period of time equivalent to the fire resistance rating required of the barrier.

b. The temperature levels recorded for the unexposed side are analyzed and demonstrate that the maximum temperature does not exceed 325ºF.

c. The fire barrier penetration remains intact and does not allow projection of water beyond the unexposed surface during the hose stream test. The stream shall be delivered through a 1½ inch nozzle set at a discharge angle of 30% with a nozzle pressure of 75 psi and a minimum discharge of 75 gpm with the tip of the nozzle a maximum of 5 ft from the exposed face; or the stream shall be delivered through a 1½ inch nozzle set at a discharge angle of 15% with a nozzle pressure of 75 psi and a minimum discharge of 75 gpm with the tip of the nozzle a maximum of 10 ft from the exposed face; or the stream shall be delivered through a 2½ inch national standard play pipe equipped with $1^{1}/_{8}$ inch tip, nozzle pressure of 30 psi, located 20 ft from the exposed face.

LGS Design

In accordance with American Nuclear Insurer's NEL-PIA/MAERP, Standard Test method for penetration fire stops, a maximum allowable temperature of 325°F above ambient is applicable to temperature measurements taken at the seal surface on the unexposed side at locations not involving interfaces with objects that penetrate the seal. In accordance with IEEE 634 (1978), a maximum allowable temperature of 700°F is applicable to temperature measurements taken on the unexposed side at interfaces between the seal material and objects that penetrate the seal.

The acceptance criteria for penetration qualification tests are in agreement with those specified in paragraphs (a) and (c) above. The maximum unexposed side temperature criteria used by the ANI test standard was 325°F above ambient. Annular pipe anchors are used in the type of penetration involving a single pipe routed through a steel penetration sleeve that is embedded in a concrete wall. The pipe anchor consists of a steel plate spanning the annular space between the pipe and the penetration sleeve, and which is welded to both the pipe and the penetration sleeve over its entire circumference. Fire resistance for this type of penetration assembly is provided by installing mineral wool in the annular space to a minimum depth of 12 inches. This configuration has been tested for a 3 hour fire rating at the National Gypsum Company Research Center in cooperation with Factory Mutual Research. The assembly withstood the fire test and hose stream test with a maximum temperature of 425°F on the unexposed side of the annular anchor, measured at a location 1 inch from the surface of the pipe. This temperature is attributable to heat conduction

through the steel pipe. This seal configuration is acceptable because no cables are associated with the penetration.

Item 46

BTP Guideline

Penetration openings for ventilation systems should be protected by fire dampers having a rating equivalent to that required of the barrier.

LGS Design

Except for Fire Areas 3, 4, 5, and 6, ventilation ducts that penetrate fire barriers are provided with 3 hour rated fire dampers at penetrations of 3 hour rated barriers and with 1.5 hour rated dampers at penetrations of 1 hour fire barriers. Both classifications of fire dampers are UL-listed and manufactured to comply with NFPA 90 and the Commonwealth of Pennsylvania Fire Protection Code.

Fire Areas 3, 4, 5, and 6 ventilation duct penetrations, which communicate with Fire Area 2, have fire damper assemblies which have been evaluated per an Engineering Evaluation, dated 03/26/98 (Reference NCR-ECR LG 98-00470) and are commensurate with the postulated fire in these areas.

Item 48

BTP Guideline

Door openings in fire barriers should be protected with equivalently rated doors, frames, and hardware that have been tested and approved by a nationally recognized laboratory.

LGS Design

Door openings in fire barriers are protected with equivalently rated doors, frames, and hardware that have been rated as follows:

a. Hollow metal doors are listed by UL and classified as Class A (3 hour) for use in 3 hour rated fire barriers, Class B (1.5 hour) for use in 2 hour rated fire barriers, or Class C (¾ hour) for use in 1 hour rated fire barriers.

b. Roll-up doors less than 120 ft^2 in size are labeled with classification markings as described above for hollow metal doors. Roll-up doors larger than 120 ft^2 are not provided with UL classification labels but are certified by their manufacturer to be manufactured in compliance (except for size) with the requirements for doors of this class and type that are normally labeled as Class A.

c. Watertight doors are not provided with UL classification labels but are certified by the manufacturer to be equivalent to the requirements of the UL classification for special purpose type fire door and frame assemblies that are rated as Class A.

d. Missile-resistant doors are certified by the manufacturer to be designed so that the doors provide a degree of fire resistance equivalent to a 3 hour fire rating based on

exposure to temperatures as defined by the NFPA standard time-temperature curve. Because the missile-resistant doors are custom designed for each specific application, they are not provided with UL classification labels. Only three missile-resistant doors are specified for use in fire barriers, two of which are 3'-0" by 7'-0" single-leaf doors and one of which is a 7'-0" by 10'-0" double-leaf door. The manufacturer has verified by calculation that the deformation of these doors resulting from exposure to a standard 3 hour fire will remain within the values specified in the acceptance criteria of ASTM E-152-81.

e. Steamtight, airlock, and bullet-resistant doors are labeled as described above for hollow metal doors, except for doors with conditions that do not exactly match the physical units tested and approved by UL. Doors that are not labeled are certified by the door manufacturers to be fabricated in the same manner as the labeled units, except for variances due to special functions required for the doors. These variances include the following:

1. Door size - the size of double-leaf door tested by UL is 6'-0" by 7'-2" whereas the maximum size of the LGS doors is 9'-0" by 10'-0".

2. Door thickness - the maximum thickness tested by UL is 2¾" whereas the maximum thickness of the LGS doors is 4¼".

3. LGS' double-leaf steamtight and airlock doors contain a removable mullion that is not present in the UL-tested assemblies.

4. Minor hardware differences as follows:

   (a) Customized hinges

   (b) Locksets by Sonicbar Door Systems

   (c) Additional security hardware

   (d) Surface-mounted hardware

5. LGS' bullet-resistant doors have additional structural features for greater strength that were not included in the tested doors.

   The fire loadings on either side of the subject doors are low. The maximum equivalent severity in adjacent compartments is 35 minutes. In none of the cases are the in situ combustibles located immediately adjacent to the doors.

f. Door/frame assemblies not installed in tested configurations that have been evaluated to withstand for three hours the maximum fire expected in the Fire Area.

Doors that are specified for use in fire barriers but are not listed by UL are identified in the fire area discussions contained in Sections 9A.5.3 through 9A.5.9 by a double asterisk (**) following the indicated fire rating.

Item 58

BTP Guideline

Cable spreading rooms should be separated from each other and from other areas of the plant by barriers having a minimum fire resistance of 3 hours.

LGS Design

The cable spreading rooms are separated from each other and from adjacent fire areas by 3 hour rated fire barriers consisting of either reinforced concrete or concrete unit masonry walls with a minimum thickness of 12 inches, and reinforced concrete slabs with a minimum thickness of 12 inches. Exposed structural steel supporting the floor slabs above and below the cable spreading rooms are coated with fireproofing material in order to achieve a 3 hour fire rating. Each door opening in the 3 hour rated fire walls is provided with a UL Class A fire door. All penetrations through the 3 hour rated walls and slabs are sealed using penetration seal details that are qualified for use in 3 hour rated fire barriers. HVAC duct penetrations through the 3 hour rated walls are equipped with 3 hour rated fire dampers.

Item 59

BTP Guideline

Interior wall and structural components, thermal insulation materials, radiation shielding materials, and soundproofing should be noncombustible.

LGS Design

Most interior walls are constructed of either reinforced concrete, or concrete masonry units. Limited use is made of walls constructed of metal studs with either gypsum wallboard or gypsum plaster on expanded metal lath. Structural components consist of structural steel or reinforced concrete. Soundproofing materials, if required, will be noncombustible. Radiation shielding consists of concrete, concrete masonry unit, or steel plates, or other noncombustible materials.

Thermal insulation materials are noncombustible, with the following exceptions:

a. Insulation for domestic cold water piping (in the administration building only) is a closed-cell foamed elastomer with an ASTM E-84 flame spread rating of 25 or less.

b. Insulation for the offgas refrigeration equipment (located only in the offgas enclosure) has an ASTM E-84 flame spread rating of 25 or less.

c. Insulation for duct-work and plenums of the ventilation systems has an ASTM E-84 flame spread rating of 25 or less and a smoke generation rating of 50 or less.

Item 60

BTP Guideline

Interior finishes should be noncombustible.

LGS Design

Areas containing systems or equipment required for safe shutdown of the plant are unfinished, or are finished with materials that are either noncombustible or (except for floor coverings and vinyl cove base) are rated by an independent testing laboratory for flame spread and smoke generation of 25 or less.

Floor coverings in areas containing systems or equipment required for safe shutdown of the plant are Class I material as defined in NFPA 101. In order to qualify for this classification, the floor covering material must have a minimum critical radiant flux of 0.45 watts per square centimeter as determined by NFPA 253 ("Standard Method of Test for Critical Radiant Flux of Floor Covering Systems Using a Radiant Heat Energy Source").

Vinyl cove base is considered trim and incidental finish and may be Class III material as defined in NFPA 101. As such, it is rated for flame spread of 200 or less and smoke generation of 450 or less. Trim and incidental finish shall not exceed 10% of the aggregate wall and ceiling area of a room.

Item 61

BTP Guideline

Metal deck roof construction should be noncombustible and listed as "acceptable for fire" in the UL Building Materials Directory, or listed as Class 1 in the Factory Mutual System Approval Guide.

LGS Design

Metal deck roof construction is used only for the turbine enclosure, which is a nonsafety-related structure. The roof is constructed to meet the requirements of a Class 1 roofing system in accordance with the Factory Mutual System Approval Guide.

Item 62

BTP Guideline

Suspended ceilings and their supports should be of noncombustible construction.

LGS Design

Two different design details are used for the suspended ceiling in the control room. One detail includes mineral fiber panels resting on a metal grid system which is supported by steel wires. A second detail, used above the peripheral rooms adjacent to the control room, includes gypsum board panels supported from galvanized steel studs. The materials used in both of these details are either noncombustible or are listed by an independent testing laboratory for flame spread, smoke generation, and fuel contribution of 25 or less.

Item 63

BTP Guideline

Concealed spaces should be devoid of combustibles except as noted in Position C.6.b.

LGS Design

There are no combustible materials in the space above the suspended ceiling in the control room, other than electrical cables. These cables (associated primarily with control room annunciators and control room lighting) are routed in conduits, fully enclosed gutters, and cable trays. The cable trays are fully enclosed through the use of solid (steel) top and bottom covers. The only exposed cables in the space above the suspended ceiling are the control room annunciator cables that extend through the bottom covers on the cable trays. Since the annunciators are located immediately adjacent to the cable trays, the exposed length of cable is very short. The cable dropout openings in the tray bottoms will be sealed with ceramic fiber and a flame-retardant mastic coating to ensure that any fire originating within the cable trays is contained within the trays. Eleven smoke detectors are located above the suspended ceiling to provide early warning of fires occurring within the area.

Table 9A-3 lists the insulation and jacketing materials used for electrical cabling. As noted in the table, cable insulation and jacketing materials are specified to meet the IEEE 383 flame test requirements except for lighting, communications, and grounding cables. Lighting cables and communication cables are routed exclusively in conduit, and grounding cables are not routed through the space above the suspended ceiling in the control room.

Electrical cables are routed through the raised floor sections in the auxiliary equipment room. Access to the cables for manual fire fighting efforts is obtained by the removal of floor plates covering the floor sections. The floor plates are constructed of aluminum honeycomb bonded between sheet metal, and are easily removable using two quick-disconnect fasteners on each plate. Automatic fire detection systems and automatic Halon suppression systems are provided in the floor sections. Additional discussion of the auxiliary equipment room raised flooring and the Halon suppression system is provided in Sections 9A.2.9 and 9A.5.3.25.

Item 65

BTP Guideline

Outdoor oil-filled transformers should have oil spill confinement features or drainage away from the buildings.

LGS Design

The main transformers, the safeguard transformers, and the auxiliary transformers are each surrounded by a curb approximately 2 feet high. A floor drain is provided within each curbed area to drain liquids to the normal waste drainage system.

The fire walls that are located on three sides of each plant services transformer would prevent spilled oil from flowing toward the circulating water pump structure. The pavement in the vicinity of each transformer is sloped to provide drainage to nearby catch basins.

Item 66

BTP Guideline

Outdoor oil-filled transformers should be located at least 50 feet distant from the building, or by ensuring that such building walls within 50 feet of oil-filled transformers are without openings and have a fire resistance rating of at least 3 hours.

LGS Design

The main transformers are located more than 50 feet from any building. The plant services transformers are located adjacent to the circulating water pump structure, but are separated from it by free-standing 3 hour rated fire walls. The safeguard transformers and auxiliary transformers are located approximately 14 feet from the north side of the turbine enclosure. As described in Section 9A.2.4, the latter transformers are provided with automatically actuated deluge systems to suppress fires involving the transformers. This automatic suppression will prevent the turbine enclosure from being damaged as a result of a transformer fire. In addition, the turbine enclosure is nonsafety-related and does not contain any components that are needed in order to achieve safe shutdown of the plant.

Item 67

BTP Guideline

Floor drains sized to remove expected fire fighting water without flooding safety-related equipment should be provided in areas where fixed water fire suppression systems are installed.

LGS Design

Two water suppression systems are located in areas with no floor drains. A wet pipe system is located in the elevation 239' corridor (fire area 7) and localized preaction system in the 13.2 kV switchgear room, elevation 217' (fire area 2).

Although no floor drains are located in fire area 7, equipment in adjacent areas are provided with curbs, installed on 4" raised pads or the floor was sloped away from the equipment. Floor drains are also available in the adjacent battery rooms. No safety-related equipment (other than cabling) is located in fire area 7 which is also maintained as a combustible free zone, with the primary combustible loading from cables and cable tray encapsulating material. Although the UFSAR (Section 9A.5.3.7.c) states that ignition of electrical cabling in tray is "extremely unlikely in the absence of a fire source," a smoke detector system provides early warning of the slow developing incipient fire that would be typical for the types of combustibles in the area. The early activation of the smoke detection system provides an audible/visual annunciation in the control room whereby operator actions are expected to mitigate the consequences of the fire before it could develop sufficiently to cause the system to actuate. If the system were to actuate due to a fire event, a flow switch provides an additional alarm to the control room requiring immediate operator actions. As discussed in response to Item 68 below, credit was taken for the opening of doors due to fire brigade response, which would allow water from hand hoses to drain into adjacent nonsafety-related areas containing floor drains.

Although no floor drains are located in fire area 2, the design feature of the installed partial preaction system minimizes the impact to equipment. This system is supervised with instrument

air and incorporates a double interlock deluge valve that is maintained normally closed. Sprinkler flow is initiated only when two separate inputs are received; one from a pneumatic actuator, due to the melting of the sprinkler fusible link(s) allowing the supervised air to be released; and the other from the fire detection system that sends a signal to an electric solenoid valve. This system is installed to protect redundant cable trays encapsulated with a 1-hour fire rated material. Although the UFSAR (Section 9A.5.3.2.c) states that ignition of electrical cabling in tray is "extremely unlikely in the absence of a fire source," a smoke detector system provides early warning of a fire throughout the entire area. The early activation of the smoke detection system provides an audible/visual annunciation in the control room whereby operator actions are expected to mitigate the consequence of the fire before it could develop sufficiently to cause the system to actuate. However, should the system actuate due to a fire, the impact to safe shutdown is mitigated by the location of redundant components outside of this area. This is further supported by MELB evaluations performed in accordance with UFSAR Section 3.6 (Reference; Item 24 of Section 9A.3.1.1, "Detailed Comparison to Branch Technical Position CMEB 9.5-1", of Appendix 9A of the LGS UFSAR) that indicated that equipment was waterspray proof, or judged as not being required to ensure safe shutdown, containment integrity, or containment activity release to 10CFR50.67 limits. In addition, in accordance with Item 210 below, since floor drains were not provided in the safety-related switchgear rooms to prevent water accumulation, credit was taken for the opening of doors to drain water into areas not containing safety-related components.

Item 68

BTP Guideline

Floor drains should also be provided in other areas where hand hose lines may be used if such fire fighting water could cause unacceptable damage to safety-related equipment in the area.

LGS Design

All plant areas that are provided with drainage facilities have adequately sized drains to remove all the water discharged from a hand hose line. The only fire areas that are not provided with floor drains and which contain safety-related equipment that is needed for safe shutdown are the 4 kV switchgear compartments (fire areas 12 through 19), the static inverter compartments (fire areas 20 and 21), auxiliary equipment room (fire area 25), and remote shutdown room (fire area 26). The use of hand-held fire hoses in any of these fire areas will not result in flooding that causes unacceptable damage to safety-related equipment.

A fire hose can be used in the 4 kV switchgear compartments only by bringing the hose in through a doorway from adjacent fire areas. For fire areas 12, 14, 16, and 18, the fire hose would be brought in from the generator equipment area (fire zone 113B) along the north side of the control structure. Water discharged from a hose in one of these 4 kV switchgear compartments would flow through the open doorway to fire zone 113B and drain into the floor drains in that area. For fire areas 13, 15, 17, and 19, the fire hose would be brought in from the equipment hatch corridor (fire areas 97 for Unit 1 and 110 for Unit 2) via the control structure corridor (fire area 7). Water discharged from a hose in one of these 4 kV switchgear compartments would flow through the open doorway to fire area 7 and then through the doorway to the equipment hatch corridor. The equipment hatch corridor is provided with floor drains to dispose of the fire fighting water. Since the control structure corridor does not contain any safe shutdown components, the drainage of fire fighting water through the corridor will not have an adverse effect on safe shutdown capability.

A fire hose can be used in the Unit 1 static inverter compartment (fire area 20) only by bringing the hose in from the Unit 1 cable spreading room through an open doorway. Although the Unit 2 static inverter compartment (fire area 21) contains a manual hose station, the fire brigade would fight a fire in this compartment using a hose brought in from the generator equipment area (fire zone 113B) through an open doorway. For both the Unit 1 and Unit 2 static inverter compartments, the doorway that is used for access will remain open during fire fighting activities within the compartment. Water discharged from a hose in the Unit 1 static inverter compartment would flow through the open doorway to the Unit 1 cable spreading room, whereas water discharged from a hose in the Unit 2 static inverter compartment would flow to the generator equipment area. The cable spreading rooms and the generator equipment area are each provided with floor drains to dispose of the fire fighting water. Since the cable spreading room does not contain any safe shutdown components, the drainage of fire fighting water into the spreading room from the static inverter compartment will not have an adverse effect on safe shutdown capability.

A fire hose can be used in the remote shutdown room (fire area 26) only by bringing the hose in from the control structure stairwell through an open doorway. This stairwell hose reel is the only hose reel available to fight a fire in this area so the door will remain open during fire fighting activities within the room. Water discharged from the hose in the remote shutdown room would flow through the open doorway into the stairwell, which does not contain any safe shutdown components.

A fire hose can be used in the auxiliary equipment room (fire area 25) only by bringing the hose in from the control structure stairwell through an open doorway. This stairwell hose reel is the only hose reel available to fight a fire in this area from the primary attack route so the door will remain open during fire fighting activities within the room. Water discharged from the hose in the auxiliary equipment room would flow through the open doorway into the stairwell, which does not contain any safe shutdown components. The secondary attack route for this area is from fire area 111 through an open door on the east wall of the auxiliary equipment room. Water discharged from the hose in the auxiliary equipment room would flow through the open doorway into the fire area 111, which does not contain any safe shutdown components.

Nonsafety-related areas of the plant that adjoin safety-related areas are provided with floor drains. As a result, fire fighting water that is discharged into the nonsafety-related areas will be disposed of through the floor drains, so that water will not accumulate on the floor and create a potential for inadvertent flooding of the adjoining safety-related areas.

Item 69

BTP Guideline

Where gas suppression systems are installed, the drains should be provided with adequate seals, or the gas suppression system should be sized to compensate for the loss of the suppression agent through the drains.

LGS Design

Gas suppression systems are provided for the remote shutdown room (Halon 1301), and the raised flooring in the auxiliary equipment room (Halon 1301). Loss of Halon 1301 through floor drains is not possible, since the auxiliary equipment and remote shutdown rooms do not have floor drains.

Item 70

BTP Guideline

Drains in areas containing combustible liquids should have provisions for preventing the backflow of combustible liquids to safety-related areas through the interconnected drain systems.

LGS Design

For the safety-related pump compartments at el 177' of the reactor enclosure, floor drains leading to the reactor enclosure floor drain sump are each provided with backflow prevention devices. The only other safety-related areas of the plant that contain significant quantities of combustible liquids are the diesel generator cells. The drains from the diesel generator cells are not interconnected with drains from other safety-related areas of the plant. The drains from each diesel generator cell are provided with traps upstream of their connection to an oil separator receiver.

The turbine enclosure contains several oil storage tanks, but the floor drains from the turbine enclosure are not interconnected with drains from safety-related areas of the plant.

Item 78

BTP Guideline

Bulk gas storage (either compressed or cryogenic), should not be permitted inside structures housing safety-related equipment. Storage of flammable gas such as hydrogen should be located outdoors or in separate detached buildings so that a fire or explosion will not adversely affect any safety-related systems or equipment.

LGS Design

Compressed gases are stored either outdoors or in nonsafety-related structures whenever possible. Compressed gas cylinders used for welding are stored in the construction shop (during periods of usage only) and the machine shop. Hydrogen used in cooling of the main generators is provided from the HWC system tube trailer facility located outside the protected area.

Compressed gas cylinders are stored in safety-related areas of the plant for use with three different systems: PCIG, containment combustible gas monitoring, and offgas hydrogen monitoring. The PCIG system includes compressed gas cylinders located at el 217' in the reactor enclosure. These cylinders contain nitrogen only, and therefore do not constitute a hazard with respect to fire protection. The containment combustible gas monitoring system includes compressed gas cylinders located at el 253' and el 283' in the reactor enclosure. These cylinders contain oxygen and oxygen/nitrogen mixtures, which also do not constitute a hazard with respect to fire protection, since oxygen is not a fuel gas.

The span and reagent gas bottles for the containment combustible gas monitoring systems are located outside the south wall of the Reactor Enclosures. These bottles of high purity oxygen, high purity hydrogen, 7% oxygen and 7% hydrogen are considered transportable, not bulk. The bottles are oriented with the long axis parallel to the Reactor Enclosure walls, minimizing the impact of a bottle failure when combined with the robust design of the Reactor Enclosure.

The offgas hydrogen monitoring system includes two compressed gas cylinders located at el 200' in the control structure. One of these cylinders contains nitrogen and the other contains a nitrogen/hydrogen mixture with a hydrogen content of 7%. An inadvertent release of the nitrogen/hydrogen mixture into the control structure air volume would result in immediate dilution of the hydrogen concentration to less than 4%. Since a hydrogen concentration of less than 4% in air is not combustible, the nitrogen/hydrogen mixture does not constitute a hazard with respect to fire protection.

Item 79

BTP Guideline

High pressure gas storage containers should be located with the long axis parallel to building walls.

LGS Design

High pressure gas storage cylinders are stored vertically with their long axis parallel to turbine enclosure walls.

Item 80

BTP Guideline

Use of compressed gases (especially flammable and fuel gases) inside buildings should be controlled.

LGS Design

The usage of compressed gases for cutting and welding is limited to those activities authorized as to be outlined in the administrative procedures.

The usage of compressed fuel gases for laboratory and shop use is limited to a low pressure supply system for Bunsen burners in the radioactive chemistry laboratory in the radwaste enclosure and the instrument repair shop on the 269 foot level of the control structure. Compressed fuel gas cylinders and gas pressure- reducing stations are installed outside of the building at a location that does not expose nuclear safety-related structures, systems, and equipment to potential damage from fire at the storage location.

Item 81

BTP Guideline

The use of plastic materials should be minimized. In particular, halogenated plastics such as PVC and neoprene should be used only when substitute noncombustible materials are not available.

LGS Design

The use of plastic materials within the plant has been minimized to the greatest extent practicable. However, alternatives to plastic or elastomeric materials for electrical cable insulating systems, with an optimum balance of electrical, physical, and environmental characteristics, are not available. Cable insulation and jacketing materials are chosen for their fire-retardant and self-extinguishing

properties, such that fuel contribution to a cable fire is minimized and propagation of a fire along cables is self-limiting in the absence of an external fire hazard. The types of electrical cable insulation and jacketing used in the plant are listed in Table 9A-3.

Electrical components located throughout the plant, such as control panels, relay panels, motor control centers, and power distribution panels, contain relatively small amounts of plastic in the form of terminal blocks, relay cases, circuit breaker cases, and other small items. The use of plastic in these applications is necessary because of its electrically insulating properties.

Plastic materials are also used for electrical conduit, but only when embedded within poured concrete walls and floor slabs.

Item 85

BTP Guideline

Only metallic tubing should be used for conduit. Thin-wall metallic tubing should not be used.

LGS Design

Exposed conduit used for the routing of safety-related cables is rigid steel conduit. Conduit embedded in poured concrete walls and slabs may be either rigid steel or PVC. Conduits used for the routing of exposed nonsafety-related cables may be either rigid steel or EMT.

Item 88

BTP Guideline

Redundant safety-related cable systems outside the cable spreading room should be separated from each other and from potential fire exposure hazards in nonsafety-related areas by fire barriers with a minimum fire rating of 3 hours.

LGS Design

Fire exposure hazards in nonsafety-related areas are separated from safety-related areas by 3 hour rated fire barriers. Separation by distance or by fire barriers between redundant divisions of electrical cabling is provided as necessary to ensure safe shutdown capability in the event of a fire.

Item 89

BTP Guideline

These cable trays should be provided with continuous line-type heat detectors.

LGS Design

Fire detection capability for safety-related cables routed in cable trays is provided by smoke detectors (either ionization or photoelectric-type) in lieu of line-type heat detectors. The detection system is discussed in Section 9A.2.12, and the types and locations of detectors are listed in Table 9A-1. The determination of locations for early warning smoke detectors was performed under the direction of a registered fire protection engineer. Where the intent is to protect against postulated

fires involving specific fire hazards, the detectors are installed closer to the hazard in a position where the detectors will readily intercept the products of combustion.

Ionization and photoelectric detectors are the preferred means of detecting both incipient cable tray fires and exposure fires involving other hazards. Line-type heat detectors are not the preferred means of detecting cable tray fires because they will not initiate an alarm until the fire is beyond the incipient stage. This conclusion is supported by studies performed at Sandia Laboratories and reported in NUREG/CR-0488, "Nuclear Power Plant Fire Protection, Fire Detection." Table IV of the report states that ionization or photoelectric detectors are the detection method of choice for the hazards and room geometries commonly found in nuclear power plants. The report also states that thermally actuated detectors, such as line-type heat detectors, which have a delayed response time are not best suited for slow developing fires such as cable tray fires.

Item 92

BTP Guideline

Safety-related cable trays of a single division that are separated from redundant divisions by a fire barrier with a minimum rating of 3 hours and are normally accessible for manual fire fighting should be protected from the effects of a potential exposure fire by providing automatic water suppression in the area where such a fire could occur. Automatic area protection, where provided, should consider cable tray arrangements and possible transient combustibles to ensure adequate water coverage for areas that could present an exposure hazard to the cable system. Manual hose standpipe systems may be relied upon to provide the primary fire suppression (in lieu of automatic water suppression systems) for safety-related cable trays of a single division that are separated from redundant safety divisions by a fire barrier with a minimum rating of 3 hours and are normally accessible for manual fire fighting if all of the following conditions are met:

a. The number of equivalent standard 24 inch wide cable trays (both safety-related and nonsafety-related) in a given fire area is six or less;

b. The cabling does not provide instrumentation, control or power to systems required to achieve and maintain hot shutdown; and

c. Smoke detectors are provided in the area of these cable routings, and continuous line-type heat detectors are provided in the cable trays.

LGS Design

Although cable trays are not generally provided with automatic suppression system coverage, such coverage is provided in areas with high cable tray concentrations. A high cable tray concentration area is defined as that portion of a fire area which contains the equivalent of six or more 24 inch wide cable trays, arranged either vertically or horizontally, and which is bordered on all sides by a zone at least 20 feet wide that exhibits a natural break in cable tray congestion.

Fire areas that contain safety-related cable trays have been reviewed to identify high cable tray concentration areas as defined above. The areas identified and the type of automatic suppression system provided in each of the areas are as follows:

a. Fire areas 22 and 23, cable spreading rooms (at el 254' in the control structure). Each cable spreading room is protected by a wet pipe sprinkler system.

b. Northeast corner of fire area 44 (at el 217' in the Unit 1 reactor enclosure). The area of high cable tray concentration is protected by a preaction sprinkler system.

c. Northeast corner of fire area 45 (at el 253' in the Unit 1 reactor enclosure). The area of high cable tray concentration is protected by a preaction sprinkler system.

d. Northeast corner of fire area 47 (at el 283' in the Unit 1 reactor enclosure). The area of high cable tray concentration is protected by a preaction sprinkler system.

e. Northwest corner of fire area 67 (at el 217' in the Unit 2 reactor enclosure). The area of high cable tray concentration is protected by a preaction sprinkler system.

f. Northeast corner of fire area 67 (at el 217' in the Unit 2 reactor enclosure). The area of high cable tray concentration is protected by a preaction sprinkler system.

g. Southeast corner of fire area 67 (at el 217' in the Unit 2 reactor enclosure). The area of high cable tray concentration is protected by a preaction sprinkler system.

h. Northwest corner of fire area 68 (at el 253' in the Unit 2 reactor enclosure). The area of high cable tray concentration is protected by a preaction sprinkler system.

i. Northwest corner of fire area 70 (at el 283' in the Unit 2 reactor enclosure). The area of high cable tray concentration is protected by a preaction sprinkler system.

j. Central South side of fire area 2 (el 217') in the 13.2 kV switchgear room. The area of high cable tray concentration in the vicinity of the 1-hour fire rated encapsulations is protected by a localized preaction system.

Item 94

BTP Guideline

In other areas where it may not be possible because of other overriding design features necessary for reasons of nuclear safety to separate redundant safety-related cable systems by 3 hour rated fire barriers, cable trays should be protected by an automatic water system with open-head deluge or open directional spray nozzles arranged so that adequate water coverage is provided for each cable tray. Such cable trays should also be protected from the effects of a potential exposure fire by providing automatic water suppression in the area where such a fire could occur.

LGS Design

In areas that contain redundant divisions of safety-related cable trays that are not separated by 3 hour fire barriers, those specific trays that contain cables needed for safe shutdown are provided with separation by means of distance or by lesser-rated fire barriers (minimum 1 hour rating) and provided with automatic water suppression. Where separation alone is deemed sufficient to ensure safe shutdown capability in the event of fire, due to low combustible loading in the area, automatic water suppression to protect the cable trays is not provided.

Item 96

BTP Guideline

Electric cable construction should, as a minimum, pass the flame test in the current IEEE 383.

LGS Design

Electrical cable insulation and jacketing systems pass the IEEE 383 flame test except for some cables associated with the lighting, communication, and grounding systems, and (for Unit 2 only) some of the wires which are used to scan the location of embedded PVC conduits. Cables associated with the lighting and communication systems that do not meet the IEEE 383 flame test are routed exclusively in conduit or analyzed and found acceptable and are not routed together with cables associated with other plant systems. Grounding cables are routed independently from cables associated with other plant systems. For Unit 2, wires that are used to scan the location of embedded conduits are routed together with cables associated with other plant systems but are not permanently connected to any plant equipment or instrument. Only one scan wire no greater than #10 AWG exists in each of the embedded conduits for which location scanning capability is provided.

An insignificant length of data cable which is not IEEE 383 rated is added to the Unit 1 and Unit 2 drywell as a part of the MUR (Measurement Uncertainty Recapture) Project. These cables were evaluated and found to be acceptable. The cables were not routed together with cables associated with other plant systems.

An insignificant length of exposed control cable, which is not IEEE 383 rated, is added to each cell of the safety related manholes (101 through 110) as part of the Safety Related Manhole Drainage Project. Sump pumps are installed in each cell of the safety related manholes to keep the safety related cables from being submerged in water. The sump pumps are controlled by float switches that are manufactured with non-IEEE 383 control cable. These cables were evaluated in ECR 10-00461 to be acceptable for the area and application in which they are installed.

Item 98

BTP Guideline

Miscellaneous storage and piping for flammable or combustible liquids or gases should not create a potential exposure hazard to safety-related systems.

LGS Design

Piping for combustible liquids or gases is not routed through areas containing safety-related systems unless this is unavoidable due to the fact that the combustible liquids or gases are used by a safety-related component. The situations where this exception arises involve the fuel oil supply piping to the diesel generators and the reagent gas (hydrogen) tubing to the combustible gas analyzer packages.

The standby diesel generators are located in individual cells within the diesel generator enclosure. The fuel oil supply piping is routed so that the piping exposed in any given diesel generator cell serves only the one diesel generator in that cell. Therefore, a leak occurring at any location in the fuel oil supply piping can affect only one diesel generator.

The combustible gas analyzer packages are located in the reactor enclosure. The reagent gas tubing to these analyzer packages is designated seismic Category I and is designed and constructed in accordance with the ASME Section III, Class 2. As a result of the high quality standards applied to this tubing, it is extremely unlikely that any design basis event could cause a leak in the tubing.

Item 99

BTP Guideline

Smoke and corrosive gases should generally be discharged directly outside to an area that will not affect safety-related plant areas. The normal plant ventilation system may be used for this purpose if capable and available.

LGS Design

The products of combustion from a fire in any area of the plant will be removed by the normal plant ventilation systems and exhausted through the ventilation stacks above the reactor enclosure roof. A portion of the air exhausted from the control room, auxiliary equipment room, and control structure fan room is normally recirculated back to those rooms. Controls are available to permit switch-over to the purge mode, in which 100% of the exhaust air from these rooms is discharged to the atmosphere.

Item 100

BTP Guideline

To facilitate manual fire fighting, separate smoke and heat vents should be provided in specific areas such as cable spreading rooms, diesel fuel oil storage areas, switchgear rooms, and other areas where the potential exists for heavy smoke conditions.

LGS Design

As discussed in Item 99, the smoke resulting from a fire will be removed by the normal plant ventilation systems. Ventilation air from the cable spreading room is exhausted to the turbine enclosure. Fuel oil for the standby diesel generators is stored in underground tanks rather than inside any structure. Smoke removal from the switchgear rooms can be accomplished using portable exhaust fans, if necessary.

Item 101

BTP Guideline

Release of smoke and gases containing radioactive materials to the environment should be monitored in accordance with emergency plans as described in the guidelines of Regulatory Guide 1.101, "Emergency Planning for Nuclear Power Plants."

LGS Design

Radiation monitors are provided in the ventilation exhaust stacks to determine if the radioactive release to the environment is within the permissible limits of the plant Technical Specifications.

Exhaust from the control room is discharged directly to the atmosphere by alignment of dampers. Exhaust from potentially contaminated areas of the turbine enclosure and the control structure is discharged through deep-bed charcoal filters prior to release to the atmosphere, with a means provided to bypass the filters for direct discharge. Independent systems provide filtered exhaust from the radwaste enclosure and the reactor enclosure with discharge through ventilation exhaust stacks above the reactor enclosure roof.

Item 102

BTP Guideline

Any ventilation system designed to exhaust potentially radioactive smoke or gases should be evaluated to ensure that inadvertent operation or single failures will not violate the radiologically controlled areas of the plant design. This requirement includes containment functions for protecting the public and maintaining habitability for operations personnel.

LGS Design

No portion of the ventilation system is specifically dedicated to smoke removal except for the purge mode of the control room ventilation system (see Item 99.) The basic design of the overall plant ventilation system considers the effects of inadvertent operation and single failure. The fire dampers provided within the ventilation system affect only those portions isolated by the dampers with no adverse effects on the balance of the systems.

Item 103

BTP Guideline

The power supply and controls for mechanical ventilation systems should be run outside the fire area served by the system where practical.

LGS Design

With the exception of fire area 27, the power and control cabling associated with ventilation systems for safety-related areas is routed outside the area served by the system. Fire area 27 is the control structure fan room, located at el 304' in the control structure. Ventilation for the control structure fan room is provided by the auxiliary equipment room supply air fans (0AV114 and 0BV114) and return air fans (0AV120 and 0BV120). Both of these sets of fans, plus their associated control panels, are located in fire area 27. Because of this arrangement, it is impractical to route the power and control cables for the subject fans entirely outside of fire area 27. The control panels for the redundant fans are separated by a horizontal distance of more than 20 feet. In addition, fire area 27 is provided with smoke detectors and an automatic suppression system. Therefore, the possibility of losing all ventilation for fire area 27 due to a fire in the area is extremely remote.

The auxiliary equipment room fan systems are not relied on to aid in achieving safe shutdown in the event of a fire. If the auxiliary equipment room fan systems are disabled as the result of a fire, temporary ventilation can be provided by opening doors and using portable fans for air circulation and smoke ejection.

Item 104

BTP Guideline

Engineered safety feature filters should be protected in accordance with the guidelines of Regulatory Guide 1.52. Any filter that includes combustible materials and is a potential exposure fire hazard that may affect safety-related components should be protected as determined by the fire hazards analysis.

LGS Design

Manually actuated water deluge application systems are provided as integral components of the charcoal filters in the SGTS, the control room emergency ventilation system, the reactor enclosure equipment compartment exhaust system, and the reactor enclosure recirculation system. Heat detectors monitor charcoal filter temperature and alarm in the control room on high temperature.

The four filtration systems listed above also contain prefilters and HEPA filters that are constructed of fire retardant materials. Because of the low fire potential of these filter elements, and the fact that they are contained within all-metal plenums, they do not constitute a significant exposure fire hazard to other safety-related systems.

Item 107

BTP Guideline

Where total flooding gas extinguishing systems are used, area intake and exhaust ventilation dampers should be controlled in accordance with NFPA 12, "Carbon Dioxide Systems," and NFPA 12A, "Halon 1301 Systems," to maintain the necessary gas concentration.

LGS Design

The Halon suppression systems for the auxiliary equipment room discharge only within the raised flooring. Therefore, automatic termination of ventilation for the general area of the auxiliary equipment room is unnecessary.

Item 108

BTP Guideline

Fixed self-contained lighting consisting of fluorescent or sealed-beam units with individual 8 hour minimum battery power supplies should be provided in areas that must be manned for safe shutdown and for access and egress routes to and from all fire areas. Safe shutdown areas include those required to be manned if the control room must be evacuated.

LGS Design

Fixed self-contained lighting units with individual 8 hour battery power supplies are provided in all areas to which access may be needed for manual actuation of safe shutdown equipment, and in access and egress routes thereto. However, self-contained battery-powered lighting units are not necessarily provided in access and egress routes for fire areas that do not need to be manned for the purpose of actuating safe shutdown equipment. The locations where remote actions are required for achieving safe shutdown in the event of a postulated fire, and the lighting levels provided at these locations, are listed in Table 9.5-13. Self-contained battery-powered lighting units will maintain a lighting level of at least 0.5 footcandle in the listed areas and in access and egress paths thereto. The emergency lighting system is discussed further in Item 23 of Section 9A.3.2.2.

Item 110

BTP Guideline

Fixed emergency communications independent of the normal plant communication system should be installed at preselected stations.

LGS Design

The fixed communication systems to be used during emergencies are the same as those provided for normal plant communications. Both PA and PABX telephone systems are provided. The PA system has two-way communication facilities for speech input at handset stations. Each station is capable of originating and receiving communication through the use of a page channel and five noninterfering party-line channels. Handset stations are installed at preselected locations. Telephones are also installed at preselected locations throughout the plant, providing two-way intraplant communication. A portable radio communication system utilizing a distributed antenna system provides a backup to both the PA and PABX systems.

Item 111

BTP Guideline

A portable radio communications system should be provided for use by the fire brigade and other operations personnel required to achieve safe plant shutdown. This system should not interfere with the communications capabilities of the plant security force. Fixed repeaters installed to permit use of portable radio communication units should be protected from exposure fire damage. Preoperational and periodic testing should demonstrate that the frequencies used for portable radio communication will not affect the actuation of protective relays.

LGS Design

Emergency communications within the plant can be maintained after the loss of the PA and PABX systems through use of the in-plant radio system. This system consists of distributed antenna modules throughout the plant with centralized rebroadcast transmitters (base station repeaters). In the CMEB 9.5-1 Guideline Comparison, LGS identifies alternative compliance (AC), with item 111. The radios used by operations personnel every day are the same radios used by the fire brigade. Low power walkie-talkies operating with an output approximately 1.8 watt are used with this system. The low power of the radios ensures that there will be no interference with low level

control and instrument circuits. Preoperational testing and evaluation was performed. The alternate method of compliance with the item 111 is the routine use of low power radios in conjunction with identified radio exclusion zones. This AC method ensures radio communications will not affect the actuation of protective relays and therefore periodic testing is not required. The system is designed to permit walkie-talkie to walkie-talkie and walkie-talkie to console communications from any location within the plant and satellite buildings. Communication consoles are located at selected plant locations, including the control room and remote shutdown room. Communication paths between consoles are hardwired, thus providing a means of communication between selected areas of the plant even with the failure of the base station repeater, PA system, and PABX system.

The audio lines between the consoles and the base station repeater are monitored in order to limit the effects of fire-caused damage to the system. The audio line monitors will automatically disconnect the affected audio lines if a circuit fault is detected. This design feature ensures that the base station repeater and the communication consoles will not be damaged if a fire affects any of the audio lines. Alternate path communication is also available through the use of additional radio equipment for a direct radio link to the repeater. Although the antenna modules are not designed to withstand an exposure fire, the system is designed such that the failure of one module will not result in failure of the entire antenna system. The antenna modules will be located so as to minimize their proximity to combustible materials. In the event of failure of a local antenna module, plant personnel will also have access to the plant PA and PABX communication systems.

Item 112

BTP Guideline

Detection systems should be provided for all areas that contain or present a fire exposure to safety-related equipment.

LGS Design

Fire detection systems have been provided for all areas that contain safety-related equipment and/or cabling, with the exception of the following fire zones and fire areas:

a. Fire zone 28A; SGTS access area. This fire zone contains safe shutdown components and cabling. None of the safe shutdown cables or components are relied on for achieving shutdown in the event of a fire in fire area 28. The only combustible materials in this fire zone are the charcoal contained in the SGTS compartment ventilation exhaust filters and a fire hose station with dust cover. The charcoal is enclosed within a pair of steel filter plenums, both of which are provided with thermal sensors that initiate an annunciation in the control room if excessive temperatures occur.

b. Fire zone 28B; SGTS filter compartment. This fire zone does not contain any safe shutdown components or safe shutdown cabling. The only combustible materials in this fire zone are the charcoal contained in the SGTS filters and a fire hose station with dust cover. The charcoal is enclosed within a pair of steel filter plenums, both of which are provided with heat detectors that initiate an annunciation in the control room if excessive temperatures occur.

c. Fire zone 42B; isolation valve compartment (Unit 1). This fire zone contains safe shutdown cabling routed in conduits, but does not contain any safe shutdown components. None of the safe shutdown cables are relied on for achieving shutdown in the event of a fire in fire area 42.

d. Fire area 46; main steam tunnel (Unit 1). This fire area contains safe shutdown components and cabling. One component, HV-41-109A, has a passive safe shutdown function, is in the desired safe shutdown position, and is not subject to a spurious signal in the event of a fire in fire area 46.

e. Fire zone 47M; isolation valve compartment (Unit 1). This fire zone contains safe shutdown components and cabling. None of the safe shutdown cables or components are relied on for achieving shutdown in the event of a fire in fire area 47.

f. Fire zone 49; reactor ventilation supply fan room, el. 313 (Unit 1). This area contains safety related equipment, no safe shutdown equipment, and a low combustible loading. Safe shutdown capability is not impacted by a fire in this area.

g. Fire area 69; main steam tunnel (Unit 2). This fire area contains safe shutdown components and cabling. One component, HV-41-209A, has a passive safe shutdown function, is in the desired safe shutdown position, and is not subject to a spurious signal in the event of a fire in fire area 69.

h. Fire zone 70M; isolation valve compartment (Unit 2). This fire zone contains safe shutdown components and cabling. None of the safe shutdown cables or components are relied on for achieving shutdown in the event of a fire in fire area 70.

i. Fire area 75; service water pipe tunnel. This fire area contains safe shutdown components and cabling. None of the safe shutdown cables or components are relied on for achieving hot shutdown in the event of a fire in fire area 75. Two components, HV-11-011A and HV-11-015A, are utilized for achieving cold shutdown and are manually repositioned by operators after the fire is extinguished.

j. Fire zone 78A; refueling area. This fire zone does not contain any safe shutdown components or safe shutdown cabling.

   Fire detectors are not provided within the refueling area (el 352' in the reactor enclosure). The floor-to-ceiling height of this area is greater than 57 feet, which greatly limits the usefulness of photoelectric or ionization-type detectors mounted at ceiling level. The use of beam-type detectors as an alternative is not practical, because movement of the reactor enclosure crane and its loads would interfere with proper operation of the detectors. The lack of fire detectors in this area is acceptable for the following reasons:

   a. Equipment and cabling needs for safe shutdown in the event of a fire is not located in this area, as noted in Section 9A.5.4.27.

   b. There is no significant quantity of combustible materials located within this area.

k. Fire zones 122B, C, D, F; compartments in western portion of spray pond pump structure. Some of these fire zones contains safe shutdown components and cabling. None of the safe shutdown cables or components are relied on for achieving shutdown in the event of a fire in fire area 122.

l. Fire zones 123B, C, D, F; compartments in eastern portion of spray pond pump structure. Some of these fire zones contain safe shutdown components and cabling. None of the safe shutdown cables or components are relied on for achieving shutdown in the event of a fire in fire area 123.

The fire zones and fire areas discussed above do not contain combustible materials, with the exception of fire zone 28A, 28B and 78A. As discussed above in fire zone 28A and 28B, the charcoal in these fire zones is enclosed within steel filter plenums which are provided with temperature monitoring systems. As discussed above in fire zone 78A, the combustion of the insignificant quantity of combustible material located in this area and the excessive ceiling height make the installation of an automatic detection system impracticable.

The areas discussed above were evaluated in LEAF-0088 and it was determined that combustible free zones are not required to maintain compliance with BTP CMEB 9.5-1 Position C.6.a(1).

The reactor enclosures and the control structure are the only safety-related structures that are located immediately adjacent to nonsafety-related structures. The portions of the nonsafety-related structures that are adjacent to the reactor enclosures and control structure are provided with fire detection capability, with the exception of the following areas:

a. Fire zone 88A; condenser area and feedwater heater service area (Unit 1)

b. Fire zone 89B; condensate filter/demineralizer compartments (Unit 1)

c. Fire area 91; air ejector and steam packing exhauster compartment (Unit 1)

d. Fire area 92; vacuum pump-room (Unit 1)

e. Fire zone 94A; reactor feedwater pump access area (Unit 1)

f. Fire area 97; equipment hatch corridor (Unit 1)

g. Fire zone 101A; condenser area and feedwater heater service area (Unit 2)

h. Fire zone 102B; condensate filter/demineralizer compartments (Unit 2)

i. Fire area 104; air ejector and steam packing exhauster compartment (Unit 2)

j. Fire area 105; vacuum pump-room (Unit 2)

k. Fire zone 107A; reactor feedwater pump access area (Unit 2)

l. Fire area 110; equipment hatch corridor (Unit 2)

m. Fire zone 113A; railroad access area

n. Fire zone 113B; generator equipment area

o. Fire area 115; radwaste pipe tunnel

p. Fire area 116; miscellaneous radwaste equipment areas (el 162')

q. Fire area 118; miscellaneous radwaste equipment areas (el 191')

r. Fire area 120; radwaste control room, laboratories, laundry, decontamination and change areas, waste drum storage room, and cask loading area (el 217')

All of the areas listed above have relatively low combustible loadings. The safety related reactor enclosure and control structure are separated from non-safety related structures by 3-hour rated fire walls. There are some safety related equipment located within the non-safety-related structures adjacent to the reactor enclosure and control structure. None of the safety related equipment located within the non-safety related structures is credited for safe shutdown for a fire occurring within the fire area.

The smoke and fire detection system is described in Section 9A.2.12.

Item 120

BTP Guideline

Primary and secondary power supplies should be provided for the fire detection system and for electrically operated control valves for automatic suppression systems. Such primary and secondary power supplies should satisfy provisions of section 2220 of NFPA 72D. This can be accomplished by using normal offsite power as the primary supply with a 4 hour battery supply as secondary supply; and by providing capability for manual connections to the Class 1E emergency power bus within 4 hours of a LOOP. Such connection should follow the applicable guidelines in Regulatory Guide 1.6, Regulatory Guide 1.32, and Regulatory Guide 1.75.

LGS Design

Power for the early warning fire and smoke detection systems is provided from a Class 1E ac motor control center. In the event of a LOOP, the motor control center is powered from the standby diesel generators.

The detection and actuation systems for the Halon system and the deluge and preaction sprinkler systems are connected to a non-Class 1E dc power supply. The charger associated with the non-Class 1E batteries is powered from a Class 1E ac motor control center that is powered from the standby diesel generators in the event of a LOOP. In the event of loss of charging power to the batteries, the dc power system can supply its rated load for approximately 3 hours.

The above described power supplies are in compliance with applicable portions of Regulatory Guide 1.6, Regulatory Guide 1.32, and Regulatory Guide 1.75. They are also in compliance with section 2220 of NFPA 72D (1975), except for the rating period of the dc power supplies (3 hours rather than 4 hours).

Item 126

BTP Guideline

The fire main system piping should be separate from service or sanitary water system piping, except as described in Position C.5.c(4).

LGS Design

The fire protection water system does not include any piping that also functions as part of the service water or sanitary water systems. The 2 inch line that provides pressure maintenance for the fire protection water system is part of that system only and has no function in the operation of the service water system.

The pressure/maintenance feature of the LGS fire protection water system is designed in accordance with NFPA 20, in that the 2 inch connection from the service water system meets the requirements and function of a supply from a pressure/maintenance pump having the required rated capacity not less than the normal leakage rate and having a discharge pressure sufficient to maintain the desired fire protection system pressure. The water source for the service water system is the cooling tower basin, which is the same water source that the fire pumps utilize.

The maximum pressure that is expected to occur in the service water system at pump shutoff head is substantially less than the design pressure of the fire protection system piping. Therefore, off-normal operation of the service water system cannot result in an overpressure condition in the fire protection system piping.

Should one of the check valves in either of the 2 inch pressure maintenance lines fail to shut during startup of the fire pumps, sufficient pressure and capacity would still be available to provide an effective hose stream or automatic suppression system operation in an area containing safety-related equipment. Each pump has sufficient capacity and discharge pressure such that the small loss of water through the 2 inch connection is of no consequence.

Item 135

BTP Guideline

A hose house equipped with hose and combination nozzle and other auxiliary equipment recommended in NFPA 24, "Outside Protection," should be provided as needed, but at least every 1,000 feet. Alternatively, mobile means of providing hose and associated equipment, such as hose carts or trucks, may be used. When provided, such mobile equipment should be equivalent to the equipment supplied by three hose houses.

LGS Design

As indicated in NFPA 24 (1981), section 5-2.2, portable hose carts stored in permanent hose cart houses are acceptable alternatives to permanent hose houses. Hose cart houses are provided at 5 selected hydrants in the yard area at intervals of approximately 650 feet. Each hose cart will be equipped with the following fire fighting equipment:

a. 600 feet of 2½" rubber lined hose

b. 400 feet of 1½" rubber lined hose

c. Two 1½" adjustable spray nozzles

d. Two 1½" ball shutoff

e. One 2½" adjustable fog nozzle

f. One 2½" ball shutoff

g. One siamese connection (gated wye)

h. Two 2½" to 1½" spanner wrenches

i. One hydrant wrench

j. One 1½" Rockwood Fog Nozzle with 6 foot applicator

The above listing of equipment is in compliance with NFPA 24 (1981) except for the quantities of spray nozzles and spanner wrenches and for the deletion of fire axes and 30" play pipes.

A single spray nozzle is sufficient for use with the 2½" hose. The 2½" hose is intended to be used as a leader line for the gated wye. It is not expected that the plant fire brigade will need to use the 2½" hose for direct fire fighting. Hose coupling gaskets and an additional spanner wrench will be provided on the hose carts. Two spanner wrenches per hose cart house is sufficient to ensure their availability.

Due to security considerations, fire axes will not be provided on hose carts. Security personnel will have access to a halligan bar that will be provided to the fire brigade upon request. The 30" playpipes are not provided on the hose carts because of safety considerations related to excessive nozzle reaction loads. The 2½" fog nozzle provided for each hose cart is sufficient for use with the yard fire hydrants.

Item 140

BTP Guideline

The fire water supply should be calculated on the basis of the largest expected flow rate for a period of 2 hours, but not less than 300,000 gallons. This flow rate should be based (conservatively) on 500 gpm for manual hose streams plus the largest design demand of any sprinkler or deluge system as determined in accordance with NFPA 13 or NFPA 15.

LGS Design

Fire protection water is supplied from the basins of the two cooling towers in the Unit 1 and Unit 2 circulating water systems. The total capacity of each cooling tower basin is 7,200,000 gallons. Each fire water pump takes suction from both cooling tower basins through connections to the 96 inch circulating water lines.

The cooling tower basin storage capacity is well in excess of the 387,800 gallon capacity required for 2 hour operation of the turbine enclosure's main condenser compartment (fire zone 88A) sprinkler system at 2731 gpm concurrent with hose stream operation at 500 gpm. The sprinkler system in the main condenser compartment has the largest design demand of any sprinkler or deluge system in the plant.

Item 144

BTP Guideline

Other water systems that may be used as one of the two fire water supplies should be permanently connected to the fire main system and should be capable of automatic alignment to the fire main system. Pumps, controls, and power supplies in these systems should satisfy the requirements for the main fire pumps. The use of other water systems for fire protection should not be incompatible with their functions required for safe plant shutdown. Failure of the other system should not degrade the fire main system.

LGS Design

The suction piping of the fire pumps is permanently connected to the 96 inch circulating water lines that supply water from the cooling towers to the main condensers. Since there are no pumps or valves located in the circulating water lines between the cooling tower basins and the connection points of the fire pump suction lines, no realignments are necessary to make the circulating water system available to provide water to the fire pumps. Therefore, there are no active failures of the circulating water system that could degrade the fire main system, and no special requirements are needed for the circulating water pumps or their associated power supplies and controls.

Item 146

BTP Guideline

Each sprinkler and standpipe system should be equipped with OS&Y gate valve or other approved shutoff valve and water flow alarm.

LGS Design

Each sprinkler and deluge system is provided with an OS&Y gate valve adjacent to the system's automatic control or alarm valve. Each sprinkler system is provided with water flow alarms which send a signal to a fire alarm code transmitter. The fire alarm code transmitter sends a coded signal to the main control room fire alarm panel which sounds the horns throughout the plant.

Water flow in the standpipe systems due to manual hose station usage is indicated by pump running annunciation with the absence of automatic system actuation annunciation. Individual standpipe flow alarms are not provided.

Each connection of a fire water header to the yard fire main is provided with a postindicator valve to permit isolation of the header. In many cases, branch connections to the headers are provided with approved shutoff valves so that groups of sprinkler systems and/or manual hose stations can be isolated without interrupting the supply to other sprinkler systems and manual hose stations connected to the same header.

Item 147

BTP Guideline

Safety-related equipment that does not itself require sprinkler water fire protection but is subject to unacceptable damage if wet by sprinkler water discharge should be protected by water shields or baffles.

LGS Design

Safety-related equipment not requiring sprinkler protection is provided with water shields and/or protected from unacceptable water damage by zoned discharge or directional spray nozzles.

Item 148

BTP Guideline

Control and sectionalizing valves in the fire water systems should be electrically supervised or administratively controlled. The electrical supervision signal should indicate in the control room.

LGS Design

Control and sectionalizing valves in the fire protection water system are either electrically supervised or administratively controlled, as described below.

The valves that will be administratively controlled are the valves at the suction and discharge of the fire pumps, the OS&Y gate valves that control the water supply to standpipe systems and manual hose stations, plus the OS&Y gate valves that control the water supply to the sprinkler systems for electrical corridor room 437 and 13 kV switchgear room 336 (WP-124 and PR-107, respectively), plus the post indicator valves in the yard area that provide for sectional control of the fire main loop and control of the fire water headers branching into the various structures. These valves are padlocked in the open/throttled position so that they cannot be operated without breaking the padlocks. Padlocks are of a frangible design.

The valves that will be electrically supervised are the OS&Y gate valves that control the water supply to fixed (water) suppression systems. The supervisory switches on these valves have normally open contacts that close in the event of valve movement. The electrical supervision signal is indicated at fire protection alarm panel 00C926, located near the entrance to the control room, and is annunciated inside the control room.

Item 150

Sprinkler systems at LGS are designed and installed per the guidelines of NFPA 13 and 15 except as noted below.

1) Design Density - sprinkler systems at LGS are designed to deliver a design density in accordance with NFPA code requirements, however, the Operability of the TRM systems is based on the Minimum Effective Design Density (MEDD) as section 9A.6.5.

2) WP-75 is installed with obstructions to the sprinkler discharge pattern in several locations, the system was evaluated as acceptable in QA Audit AL87-158 PL.

3) The OS&Y gate valve for the corridor wet pipe sprinkler system (WP-124) is locked in the throttled position to limit flow in the event of a postulated risk significant sprinkler system pipe break. The fire code does not prohibit throttling the subject valve; however, this is a non-standard practice.

4) PR-1 is installed with obstructions to the sprinkler discharge pattern in the area of the isolated phase electrical ducting on elevations 217' and 239'; the system was evaluated as acceptable under GL 86-10 Fire Protection Engineering Evaluations.

Item 151

BTP Guideline

Interior manual hose installation should be able to reach any location that contains, or could present a fire exposure hazard to, safety-related equipment with at least one effective hose stream. To accomplish this, standpipes with hose connections equipped with a maximum of 100 feet of 1½ inch woven-jacket, lined fire hose and suitable nozzles should be provided in all buildings on all floors.

LGS Design

Wet standpipes are considered Class II in accordance with NFPA 14; however, the fire hose has been removed from the hose stations. The fire brigade brings the required hose to the fire scene in high-rise packs. The nominal length of fire hose in the high-rise packs is 100'. Where there is a requirement for additional fire hose for a specific hose station (beyond 100') that additional fire hose is staged at that specific hose station. The high-rise packs are provided with adjustable fog nozzles.

Fire suppression capability for the spray pond pump structure is provided by portable fire extinguishers rather than hose stations. As shown in Table 9A-1, the combustible loading in the various compartments of the spray pond pump structure is low enough that portable fire extinguishers are sufficient to extinguish any postulated fire. Those compartments that contain combustible materials are provided with fire detectors that annunciate in the control room. In addition, the spray pond pump structure is divided into two separate fire areas by a 3 hour rated fire wall along the centerline of the structure. A postulated fire in either fire area will leave at least one method available to safely shut the plant down.

Special considerations applicable to certain safety-related areas of the plant are as follows:

a. Fire areas 49 and 72 (reactor enclosure el 313') - The hose station in fire area 48 at the west end of fire area 49 is capable of providing coverage for fire area 49. The hose station in fire area 71 at the east end of fire area 72 is capable of providing coverage for fire area 72. An additional nominal 50 foot length of hose is stored in the vicinity of each of these hose stations to provide the necessary hose reach.

b. Fire area 75 (reactor enclosure el 198') - The southernmost hose stations in fire areas 42 and 65 are capable of providing coverage for fire area 75. An additional nominal 50 foot length of hose is stored in the vicinity of each of these hose stations to provide the necessary hose reach.

c. Fire areas 79 through 86 (diesel generator enclosure el 217') - Fire hose coverage for the diesel generator cells is provided by fire hydrants 8 and 9, with two hoses available from each hydrant.

Item 152

BTP Guideline

Individual standpipes should be at least 4 inches in diameter for multiple hose connections and 2.5 inches in diameter for single hose connections.

LGS Design

Wet standpipes are not less than 3 inches in diameter for one or two hose connections and 4 inches in diameter for three or more hose connections. The capability of the standpipes to provide the pressures and flow rates required by NFPA 14 has been verified by calculation. In all cases in which a 3" standpipe supplies more than one hose station, each of the affected hose stations is capable of delivering at least 100 gpm at 65 psig, considering the operation of two hose stations simultaneously with the largest water demand flowing from any automatic suppression system in the vicinity of the hose stations. In addition to the 100 gpm per hose station, 300 gpm is assumed at the nearest outside fire hydrant to support manual fire fighting activities. This meets BTP section C.6.b.(11) requirement of 500 gpm for manual hose streams in addition to the largest suppression system design.

Item 153

BTP Guidelines

Standpipes and hose station installations should follow the requirements of NFPA 14.

LGS Design

Standpipes and hose stations (hose connections) are provided in accordance with NFPA 14-1971. The hose stations are considered Class II but have 2-1/2" connections. Hose is not provided for occupant use. The fire brigade brings hose to the scene for firefighting. Extra hose may be provided at certain hose stations where extra hose is needed to reach plant areas.

Item 155

BTP Guideline

Provisions should be made to supply water at least to standpipes and hose connections for manual fire fighting in areas containing equipment required for safe plant shutdown in the event of an SSE. The piping system serving such hose stations should be analyzed for SSE loading and should be provided with supports to ensure system pressure integrity. The piping and valves for the portion of hose standpipe system affected by this functional requirement should, as a minimum, satisfy ANSI B31.1, "Power Piping." The water supply for this condition may be obtained by manual operator actuation of valves in a connection to the hose standpipe header from a normal seismic Category I water system such as the essential service water system. The cross connection should be (a) capable of providing flow to at least two hose stations (approximately 75 gpm per hose

station), and (b) designed to the same standards as the seismic Category I water system; it should not degrade the performance of the seismic Category I water system.

LGS Design

As discussed in Section 2.5, the region surrounding the LGS site has a low to moderate potential for seismic activity. The fire water system, including standpipes and manual hose stations, is designed as seismic Category II (except for portions of the system located in the control structure, reactor enclosure, and diesel generator enclosure, which are designed as seismic Category IIA) and is not designed to remain functional in the event of an SSE. All systems and components that are needed to ensure safe shutdown of the plant are designed as seismic Category I and are located in seismic Category I structures. These safe shutdown systems will therefore remain functional in the event of an SSE. In the event that one train of systems needed for safe shutdown is impaired due to fire following an SSE, the combination of separation and fire barriers that is provided between redundant trains of safe shutdown systems will ensure that at least one means of achieving safe shutdown remains available.

The standpipes that supply water to hose stations located in areas that contain equipment required for safe shutdown of the plant have been evaluated to verify the piping integrity under seismic loading associated with an SSE. The evaluation shows that piping integrity will be retained.

Item 158

BTP Guideline

Certain fires, such as those involving flammable liquids, respond well to foam suppression. Consideration should be given to use of mechanical low expansion foam systems, high expansion foam generators, or aqueous film-forming foam systems, including the aqueous film-forming foam deluge system. These systems should comply with the requirements of NFPA 11, NFPA 11A, NFPA 11B, and NFPA 16, as applicable.

LGS Design

Foam suppression systems have been provided for the protection of the fuel oil transfer structure and the one outdoor storage tank containing No. 2 fuel oil for the auxiliary boilers. These systems are designed in accordance with NFPA 11. NFPA 11A, NFPA 11B, and NFPA 16 are not applicable to the type of foam systems being used. The design of the foam suppression systems is discussed in Section 9A.2.7.

Item 162

BTP Guideline

Particular consideration should also be given to:

a. Minimum required Halon concentration, distribution, soak time, and ventilation control;

b. Toxicity of Halon;

c. Toxicity and corrosive characteristics of the thermal decomposition products of Halon; and

d. Location and selection of the activating detectors.

LGS Design

The following comments apply to the Halon 1301 system that is provided for the raised flooring in the auxiliary equipment room:

a. The design concentration for the Halon 1301 system is 20% with a 20 minute soak time. A system of distribution piping and nozzles is provided within the raised flooring so that the Halon is distributed evenly. Since the Halon is not discharged into the general air space of the auxiliary equipment room by virtue of the fact that the raised flooring sections are fully installed and secured when the system is operational, isolation of the ventilation system is not necessary to prevent the loss of Halon.

b. The Halon 1301 system is provided only under the raised floor of the auxiliary equipment room, rather than in the entire room. Emergency procedures will require personnel to use self-contained breathing apparatus when entering the auxiliary equipment room following the discharge of Halon.

c. The Halon 1301 system is designed to achieve a concentration of 6% within the first 10 seconds after discharge begins. This concentration is sufficient to extinguish the flames, which will largely end the production of toxic gases as a result of the thermal decomposition of Halon. Thus, rapid extinguishment of the flames will prevent the production of a significant quantity of toxic gases.

d. Heat detectors are used to provide the actuation signal for the Halon 1301 system. Eight heat detectors are located in each of the PGCC floor sections, and additional heat detectors are located in the raised flooring that surrounds the PGCC floor sections.

Item 166 - Deleted

Item 167

BTP Guideline

Fire extinguishers should be provided in areas that contain, or could present a fire exposure hazard to, safety-related equipment in accordance with guidelines of NFPA 10, “Portable Fire Extinguishers, Installation, Maintenance and Use.” Dry chemical extinguishers should be installed with due consideration given to possible adverse effects on safety-related equipment installed in the area.

LGS Design

Fire extinguishers are provided at the station following the guidelines of NFPA 10-1975 edition with two exceptions.

1. Class A (ordinary combustibles) extinguishers are not placed throughout the facility.

2. The maximum travel distance specified in Section 3 of NFPA 10-1975 are exceeded in several areas in the plant.

These two exceptions are acceptable due to the fact that the extinguishers are selected and located throughout the facility for use by the site fire brigade. Hose stations in the plant are available for use by the brigade as a replacement for Class A extinguishers. See the disposition of NCR LG 98-01687 for a detailed engineering analysis.

Item 170

BTP Guideline

Because of the general inaccessibility of primary containment during normal plant operation, protection should be provided by automatic fixed systems.

LGS Design

The primary containment is inerted with nitrogen during reactor operation, so that the oxygen concentration is maintained below 4% by volume. This inert atmosphere will prevent fires from occurring in the primary containment. For this reason, fixed suppression systems are not needed within the primary containment and are not provided.

Fire suppression coverage for the primary containment is provided by manual hose stations and portable fire extinguishers located outside the two entrances to the suppression chamber at el 217' and the two entrances to the drywell at el 253'.

Item 173

BTP Guideline

In primary containment, fire detection systems should be provided for each fire hazard. The type of detection used and the location of the detectors should be the most suitable for the particular type of fire hazard identified by the fire hazard analysis.

A general area fire detection capability should be provided in the primary containment as backup for the above described hazard detection. To accomplish this, suitable smoke or heat detectors compatible with the radiation environment should be installed.

LGS Design

Fire detectors are not provided inside the primary containment. During reactor operation, the primary containment is inerted with nitrogen, and the oxygen concentration is maintained below 4% by volume. This inert atmosphere will prevent fires from occurring in the primary containment. Administrative procedures provide for fire watches when necessary during maintenance operations when the drywell has been deinerted.

Item 179

BTP Guideline

Peripheral rooms in the control room complex should have automatic water suppression and should be separated from the control room by noncombustible construction with a fire resistance rating of 1 hour. Ventilation system openings between the control room and peripheral rooms should have automatic smoke dampers that close on operation of the fire detection or suppression system.

LGS Design

Elevation 269 feet in the control structure contains the control room proper as well as peripheral rooms at the west and east ends of the control room. The walls and ceilings separating the control room proper from the peripheral rooms are rated as 1 hour fire barriers except for one office wall, which contains a glazed opening as required to permit observation of control room activities. The glazed opening is constructed of ¼ inch thick wired glass mounted in a steel frame. The size of the glazed opening is 4'-2" by 4'-2".

The suspended ceiling above the peripheral rooms consists of two layers of gypsum board arranged and separated in accordance with UL Design No. L511. The gypsum board is supported from galvanized steel studs rather than the wooden joists shown in UL Design No. L511. The finish rating (as defined in the UL Fire Resistance Directory) of this installation is 71 minutes. For Unit 1, a 1 hour rated access door of a type that has been tested by Warnock Hersey International, Inc. has been installed in the suspended ceiling. The test methods and acceptance criteria are consistent with NFPA 251, "Standard Methods of Fire Tests of Building Construction and Materials."

Ventilation ducts serving the peripheral rooms are provided with 1 hour rated fire dampers that are actuated closed by fusible links. The entrance doors to the peripheral rooms in the control room complex may be kept open based on a Generic Letter 86-10 Evaluation. These doors do not perform any credited barrier function within the control room complex relative to mitigation of the effects of the postulated internal panel fire.

Although automatic suppression systems are not provided in the peripheral rooms, smoke detectors are located in each of these rooms to provide early warning of incipient fires. Manual fire fighting capability is provided for as discussed in Item 181.

Item 181

BTP Guideline

Manual fire fighting capability should be provided for both:

a. Fire originating within a cabinet, console, or connecting cables; and

b. Exposure fires involving combustibles in the general room area.

Portable Class A and Class C fire extinguishers should be located in the control room. A hose station should be installed immediately outside the control room.

Nozzles that are compatible with the hazards and equipment in the control room should be provided for the manual hose station. The nozzles chosen should satisfy actual fire fighting needs,

satisfy electrical safety, and minimize physical damage to electrical equipment from hose stream impingement.

LGS Design

Portable halon fire extinguishers are located in the control room. In addition, manual hose stations are located outside both entrances to the control room.

Item 182

BTP Guideline

Smoke detectors should be provided in the control room, cabinets, and consoles. Alarm and local indication should be provided in the control room.

LGS Design

Twenty-three detectors of the ionization-type are distributed throughout the control room, providing the capability to detect smoke that originates either inside or outside of the control room cabinets and consoles. Actuation of any of these detectors is annunciated by the control room fire protection annunciator. The indicator light on the detector itself will then identify the specific detector originating the alarm.

Smoke detectors are not located inside the individual cabinets and consoles in the control room. The control room panels are not gasketed and therefore are not airtight. Any smoke generated within the panels will quickly leak out and be detected by the smoke detectors in the control room. Tests performed on electrical wiring of the types used in the control room panels have shown that overheating of a single wire due to electrical faulting produces large quantities of acrid smoke well before ignition of the wire's insulation occurs. The quantity of smoke generated ensures that an incipient fire inside a control room panel will be promptly detected by the smoke detectors at the control room ceiling.

The electrical separation criteria that apply to wiring inside the control room panels are described in Section 8.1.6.1.14. The implementation of these criteria for the LGS control room panels ensures that any electrical fault in the wiring will be prevented from propagating to a redundant division of wiring. The adequacy of the electrical separation criteria to achieve this goal was demonstrated by a test program involving the types of wires and separation arrangements actually used at LGS. Therefore, the capability to achieve safe shutdown in the event of an electrical fire in any control room panel is ensured.

For the reasons discussed above, the smoke detectors at the control room suspended ceiling provide appropriate detection capability for fires originating inside the control room panels.

Item 184

BTP Guideline

The outside air intake(s) for the control room ventilation system should be provided with smoke detection capability to alarm in the control room to enable manual isolation of the control room ventilation system and thus prevent smoke from entering the control room.

LGS Design

The control room ventilation intake is provided with smoke detection capability to automatically detect and alarm the presence of smoke. Upon receipt of the alarm, the control room ventilation system can be manually placed in the recirculation mode in order to isolate the control room from the outside.

For purge operation of the control room ventilation system, the outside supply air and exhaust air dampers are fully opened and the return air damper to the control room is closed. The control room purge system can be operated from both inside and outside the control room.

Item 186

BTP Guideline

Cables in under-floor and ceiling spaces should meet the separation criteria necessary for fire protection.

LGS Design

The features of the raised flooring in the auxiliary equipment room that provided separation between redundant divisions of electrical cabling are described in Section 9A.5.3.25. In summary, each raceway within the raised flooring is totally enclosed and is used for only one division of cabling, unless additional barriers are provided.

Cables routed through the space above the suspended ceiling in the control room consist of low voltage control and instrumentation cables, plus lighting cables that serve the control room. The control and instrumentation cables are specified to meet the IEEE 383 flame test requirements, and have flame retardant jacketing that will not support flame propagation. Lighting cables are routed exclusively in conduits that are dedicated to lighting cable service only.

Item 189

BTP Guideline

Area automatic fire suppression should be provided for under-floor and ceiling spaces if used for cable runs unless all cable is run in 4 inch or smaller steel conduit or the cables are in fully enclosed raceways internally protected by automatic fire suppression.

LGS Design

The raised flooring in the auxiliary equipment room is provided with an automatic Halon suppression system as described in Section 9A.2.9.

The space above the suspended ceiling in the control room contains electrical raceways as described in Item 63 of Section 9A.3.1.2. An automatic suppression system is not needed for the space above the suspended ceiling, because of the following considerations:

a. All raceways are of the fully enclosed type as described in Item 63.

b. Cable insulation and jacketing materials are qualified to meet the IEEE 383 flame test requirements, except for lighting and communications cables, which are routed exclusively in conduit.

c. No power cables are routed through the space above the suspended ceiling. Only control and instrumentation cables are present. The probability of a fire generated by an overload and faulted cable is extremely low because this occurrence would require the simultaneous failure of two overcurrent protective devices. All cables routed in the trays have 600 V insulation and contain 125 V dc or 120 V ac circuits. The 277 V lighting circuits are all routed in conduit and are the highest voltage circuits routed above the suspended ceiling.

d. The suspended ceiling qualifies as a 1 hour rated fire barrier, with the exception of the annunciator cabinets that extend through the ceiling panels.

e. The existence of transient combustibles above the suspended ceiling is not a credible occurrence, because there are no catwalks or storage areas above the ceiling.

f. Eleven smoke detectors are located above the suspended ceiling to provide prompt warning of fires occurring within the area.

g. Because the control room is continuously manned, prompt response to any alarm indicating a fire above the suspended ceiling is assured. Manual fire fighting capability is provided by portable fire extinguishers located in the control room and two (2) portable carbon dioxide extinguishers and hose stations located near the control room entrance doors. The individual panels of the suspended ceiling are easily removable to permit access.

Item 190

BTP Guideline

There should be no carpeting in the control room.

LGS Design

Main control room carpeting has been tested in accordance with NFPA 253, "Standard Method of Test for Critical Radiant Flux of Floor Covering Systems Using a Radiant Heat Energy Source," or ASTM E-648, "Standard Test Method for Critical Radiant Flux of Floor Covering Systems Using Radiant Heat Energy Source," to comply with the requirements of a Class I interior floor finish as defined in NFPA 101, "Life Safety Code." The minimum critical radiant flux for a Class I interior floor finish is 0.45 W/cm^2. This minimum heat flux value provides reasonable assurance that the carpet will not present an unusual fire hazard in the control room.

Installing main control room carpeting that meets the requirements of a Class I interior floor finish is an acceptable deviation from section C.7.b of Branch Technical Position (BTP) CMEB 9.5-1 as documented in PBAPS NRC SER issued October 10, 1985.

Item 191

BTP Guideline

The primary fire suppression in the cable spreading room should be an automatic water system such as closed head sprinklers, open head deluge system, or open directional water spray system.

Deluge and open spray systems should have provisions for manual operation at a remote station; however, there should be provisions to preclude inadvertent operation. Location of sprinkler heads or spray nozzles should consider tray arrangements and possible transient combustibles to ensure adequate water coverage for areas that could present exposure hazards to the cable system. Cables should be designed to allow wetting down with water supplied by the fire suppression system without electrical faulting.

LGS Design

The primary fire suppression system in the cable spreading room is a wet pipe sprinkler system. The design of this system is discussed in Section 9A.2.2.

Electrical cabling is designed to allow wetting down without electrical faulting.

Item 210

BTP Guideline

Drains should be provided to prevent water accumulation from damaging safety-related equipment.

LGS Design

Floor drains are not provided in the safety-related switchgear rooms. In the event that hand hose lines are used for fire suppression in the switchgear rooms, the doors that would be open to provide access would provide a flow path for fire protection water to drain to areas not containing safety-related components.

The effects due to actuation of the 13.2 kV switchgear room preaction system are mitigated by the design features of this system. This system is supervised with instrument air and incorporates a double interlock deluge valve that is maintained normally closed. Sprinkler flow is initiated only when two separate inputs are received; one from a pneumatic actuator, due to the melting of the sprinkler fusible link(s) allowing the supervised air to be released; and the other from the fire detection system that sends a signal to an electric solenoid valve. (Refer to BTP Item 67 and 68 above for additional information.)

Item 212

BTP Guideline

Redundant safety-related panels remote from the control room complex should be separated from each other by barriers having a minimum fire rating of 3 hours. Panels providing remote shutdown capability should be separated from the control room complex by barriers having a minimum fire rating of 3 hours. Panels providing remote shutdown capability should be electrically isolated from the control room complex so that a fire in either area will not affect shutdown capability from the other area.

LGS Design

Most safety-related panels are located in either the control room or the auxiliary equipment room. These two rooms are separated from each other by a 3 hour rated floor slab. Some of the safety-related panels outside the control room and auxiliary equipment room are located within the same fire area as their redundant counterparts, with no intervening fire barriers. The panels that are located in this manner and are needed to achieve safe shutdown of the plant are separated by at least 20 feet horizontally, as required by section C.b.5 of BTP CMEB 9.5-1, Revision 2.

The remote shutdown panels are located at el 289' in the control structure, which is separated from the control room by a 3 hour rated floor slab. Transfer switches are provided on the remote shutdown panels to allow the operators to isolate the remote shutdown panels from control room and PGCC circuits. The remote shutdown panels are located in a room that is separated from the auxiliary equipment room (which contains the PGCC) by 3 hour rated fire walls.

Item 215

BTP Guideline

Dc switchgear and inverters should not be located in safety-related battery rooms.

LGS Design

Battery chargers and dc fuse boxes are located in the safety-related battery rooms along with the batteries that they serve. The potential sources of sparking within the battery chargers and fuse boxes are very limited. Each fuse box contains manually operated fuse disconnect switches at both the load side and the source side of the power bus. These fuse disconnect switches are provided for maintenance purposes and are not expected to be actuated during any postulated emergency condition. Each battery charger contains two circuit breakers that may open if an overcurrent condition develops at the battery charger. Such an occurrence is very unlikely because of the existence of current limiting devices (fuses, primarily) in each of the circuits within the dc power distribution system. Opening of these current limiting devices will prevent circuit faults from propagating back to the battery chargers.

Other dc power distribution system components (such as inverters and dc power distribution panels) are located outside the battery rooms, with the exception of the Division 2 battery room for Unit 1. This latter battery room contains two dc power distribution panels located in a corridor-like extension of the room that leads to a doorway into the turbine enclosure. The only potential source of sparking in the dc power distribution panels is the manual disconnect switches that are provided in each circuit.

Item 217

BTP Guideline

Ventilation systems in the battery rooms should be capable of maintaining the hydrogen concentration well below 2% (by volume).

LGS Design

Ventilation air for the safety-related battery rooms is supplied by the safety-related 0AV118 and 0BV118 fan cabinets, and is exhausted by the nonsafety-related 0AV124 and 0BV124 fan cabinets. Both sets of fans are 100% redundant and are controlled such that the standby fan will start running automatically if the lead fan fails. In the event of loss of flow through the battery room exhaust ducts, due either to fan stoppage or isolation damper closure, the battery room exhaust will automatically be recirculated to the suction of the 0AV118 and 0BV118 fan cabinets. The ventilation flow rate through the battery rooms provides 12 air changes per hour, which maintains hydrogen concentration far below 2% (by volume).

Item 218

BTP Guideline

Loss of ventilation should be alarmed in the control room.

LGS Design

The OAV118 and OBV118 fan cabinets, which supply ventilation air to the safety-related battery rooms, are provided with flow switches at the discharge of each fan. Low flow through an operating fan will be detected by the flow switches and annunciated at the control structure HVAC panels (OAC101 and OBC101). Alarms on these panels are relayed to the control room as a common trouble alarm.

Item 221

BTP Guideline

The fire barriers should be designed so as to maintain structural integrity even in the event of a complete collapse of the turbine structure.

LGS Design

The turbine enclosure is structurally separate from the reactor enclosure and control structure. The structural integrity of the fire barrier walls of the reactor enclosure and control structure will not be impaired by a collapse of the turbine enclosure.

Item 222

BTP Guideline

Openings and penetrations in the fire barrier should be minimized and should not be located where the turbine oil system or generator hydrogen cooling system creates a direct fire exposure hazard to the barrier.

LGS Design

Penetrations in the walls that separate the turbine enclosure from the reactor enclosure and the control structure are provided with 3 hour rated penetration seals, and doorways in these walls are provided with 3 hour rated fire doors.

The main turbine lube oil storage tanks and lube oil reservoir are located in compartments that are separated from the remainder of the turbine enclosure by 3 hour fire walls. Therefore, a fire occurring in any of these compartments would not affect the boundary wall separating the turbine enclosure from the reactor enclosure and control structure. The generator hydrogen seal oil unit is separated from the reactor enclosure boundary wall by a 3 hour rated fire wall, and is located more than 70 feet away from the nearest control structure wall.

Item 224

BTP Guideline

Automatic fire suppression should be installed to combat any diesel generator or lubricating oil fires; such systems should be designed for operation when the diesel is running without affecting the diesel.

LGS Design

Each diesel generator cell is provided with a preaction suppression system that is activated by heat detectors. Baffles are provided to protect the generators and control devices from damage due to suppression system water discharge.

Item 227

BTP Guideline

Drainage for fire fighting water and means for local manual venting of smoke should be provided.

LGS Design

Each diesel generator cell is provided with trapped and vented floor drains with adequate drainage capacity to cope with the maximum sprinkler water flow in each room.

Each diesel generator cell is provided with two exhaust fans, each capable of 40 air changes per hour for cooling and/or smoke removal. The ventilation system is controlled manually from a local control panel and is also started automatically by either high air temperature or a diesel engine start signal.

Item 242 - Deleted

Item 243

BTP Guideline

Fire barriers, automatic fire suppression and detection, and ventilation controls should be provided.

LGS Design

The radwaste enclosure, including the offgas enclosure, is separated from the reactor enclosure by a 3 hour rated fire wall and the turbine enclosure by a 2 hour rated fire wall. Automatic fire detection is provided in limited areas of the radwaste enclosure, as shown in Table 9A-1. In

consideration of the low combustible loading in the remaining areas of the radwaste enclosure, detection by personnel in the vicinity is deemed sufficient.

An automatic wet pipe sprinkler system is provided for the waste drum storage area at el 217' in the radwaste enclosure. Hose stations and portable fire extinguishers are provided for fire suppression coverage of the remainder of the radwaste enclosure.

Ventilation systems for the radwaste enclosure are manually controllable from control panels located in easily accessible areas of the radwaste enclosure.

Item 247

BTP Guideline

Cooling towers should be of noncombustible construction when the basins are used for the ultimate heat sink or for the fire protection water supply.

LGS Design

The cooling tower basins serve as a source of water for the fire protection system but not for any safety-related systems. The cooling towers are constructed entirely of noncombustible material except for the splash bars and drift eliminators, which are polyvinyl chloride, and the splash bar support grids, which are fire retardant polyester and fiberglass. The fill material is contained in a ring-shaped area around the periphery of each tower. The ring is separated into six cells by fire walls located at 60° intervals. A fire occurring in any one cell would have no effect on safety-related structures or systems, since such a fire would not affect the structural integrity of the cooling tower and the towers are located away from safety-related structures. The adequacy of this design was demonstrated by a large-scale burn test in July of 1978 that was conducted by the cooling tower vendor and witnessed by ANI. The tested design, which is the same as that used at LGS, has been accepted by ANI for design of cooling towers with PVC and polyester fill material and without fire protection sprinklers.

During normal operation of the plant, water from the circulating water system is continuously flowing over the fill material in the cooling tower, thereby eliminating the possibility of a fire in the fill material. Such a fire could occur only during relatively short periods when circulating water is bypassed around the fill material due to cold weather, or when the plant is shut down and the circulating water system is not operating. Even if a fire in one of the two cooling towers is assumed to result in unavailability of the water in the tower basin for fire protection use, the fire pumps will continue to be capable of operating when necessary. Each fire pump can take suction on either cooling tower basin, so that if one basin becomes unavailable due to fire, the other cooling tower basin will serve as a source of fire protection water.

Item 248

BTP Guideline

Miscellaneous areas such as shops, warehouses, auxiliary boiler rooms, fuel oil tanks, and flammable and combustible liquid storage tanks should be so located and protected that a fire or effects of a fire, including smoke, will not adversely affect any safety-related systems or equipment.

LGS Design

The machine shop, construction shop, warehouse, administration building, and auxiliary boiler enclosure are located adjacent to the Unit 2 reactor enclosure and turbine enclosure, but are separated from these structures by 3 hour rated fire walls so that fires occurring in any of the miscellaneous areas will not adversely affect any safety-related systems. The machine shop, construction shop, warehouse, administration building, and auxiliary boiler enclosure each are provided with wet pipe sprinkler systems at strategic locations. Hose stations and portable fire extinguishers are also provided to support manual fire fighting efforts. The one outdoor storage tank containing No. 2 fuel oil for the auxiliary boilers is separated from the nearest portion of the power block (the Unit 2 diesel generator enclosure) by more than 120 feet. The tank is provided with a foam extinguishing system, as described in Section 9A.2.7. The Chemistry Lab (commercial building) located adjacent to the Radwaste enclosure, which is separated from the Unit 1 reactor enclosure by 3-hour rated fire walls, will not adversely affect any safety-related systems. The Chemistry Lab is protected by wet pipe and preaction suppression systems at strategic locations along with hose stations and portable fire extinguishers also provided to support manual fire fighting efforts.

9A.3.2 10CFR50, APPENDIX R

In a letter dated 10/15/1981 (reference 9A.7.13) it was requested that a comparison to 10 CFR 50 Appendix R be included in the overall fire protection program submittal for Limerick Generating Station. In response to the NRC's request, this section was created. This section compares the fire protection provisions of LGS Units 1 and 2 with the guidelines of 10CFR50, Appendix R. Limerick Generating Station is not committed to the requirements of 10 CFR 50 Appendix R. Limerick Generating Station is committed to BTP CMEB 9.5-1, revision 2, July 1981 which subsumed many of the requirements of Appendix R.

To identify areas of potential impact and to facilitate comparison, a matrix addressing each guideline of Appendix R and relating to the plant systems, equipment, and components is included as Section 9A.3.2.1. The matrix has extracted all suggested guidelines from Appendix R and given each an item number, 1 through 45. Each item has condensed a particular guideline and makes reference to the section in Appendix R where that guideline can be found. The general degree of conformance to the guideline is indicated in the COMPARISON column, using codes defined as follows:

C - indicates conformance to the guideline or conformance to its intent. Substantiating statements may be included as part of the matrix or in Section 9A.3.2.2.

AC - indicates conformance to the guidelines by alternate means or methods. The manner of conformance is included in the matrix or discussed in Section 9A.3.2.2.

NC - indicates that the plant is not in conformance and no design changes are planned. The basis for nonconformance to the guideline is included in the matrix or discussed in Section 9A.3.2.2.

NA - indicates that the guideline is not applicable to LGS Units 1 and 2. Substantiating statements are included as part of the matrix in Section 9A.3.2.1.

In the REMARKS column, additional information is provided to explain or expand on the degree of conformance. Alternatively, reference may be made to Section 9A.3.2.2 for a more detailed discussion. The item numbers in Section 9A.3.2.2 correspond to those in Section 9A.3.2.1.

9A.3.2.1 Detailed Comparison to 10CFR50, Appendix R

NO.	APPENDIX R GUIDELINE	APPENDIX R ITEM NO.	COMPARISON	REMARKS
	Water Supplies for Fire Suppression Systems			
1.	Two separate water supplies shall be provided to furnish necessary water volume and pressure to the fire main loop.	A	C	
2.	Each supply shall consist of a storage tank, pump, piping, and appropriate isolation and control valves.	A	AC	In lieu of storage tanks, the cooling tower basins of the Unit 1 and Unit 2 circulating water systems are used as the two sources of water for the fire main loop.
3.	These supplies shall be separated so that a failure of one supply will not result in a failure of the other supply.	A	C	See Section 9A.3.2.2.
4.	Each supply of the fire water distribution system shall be capable of providing the maximum expected water demands for a period of 2 hours.	A	C	The storage capacity of each cooling tower is 7,200,000 gallons, which is well in excess of the 387,000 gallon volume required for two hour operation of the largest sprinkler system concurrent with hose stream operation at 500 gpm.
5.	Requirements for ensuring minimum water volume when storage tanks are used for combined service water/fire water uses.	A	NA	See Section 9A.3.2.2.
6.	Requirements for other water systems used as sources of fire protection water.	A	AC	See Section 9A.3.2.2
	Sectional Isolation Valves			
7.	Sectional isolation valves such as postindicator valves or key operated valves shall be installed in the fire main loop to permit isolation of portions of the main fire main loop for maintenance or repair without interrupting the entire water supply.	B	C	

NO.	APPENDIX R GUIDELINE	APPENDIX R ITEM NO.	COMPARISON	REMARKS
	Hydrant Isolation Valves			
8.	Valves shall be installed to permit isolation of outside hydrants from the fire main for maintenance or repair without interrupting the water supply to automatic or manual fire suppression systems.	C	C	
	Manual Fire Suppression			
9.	Standpipe and hose systems shall be installed so that at least one effective hose stream will be able to reach any location that contains or presents an exposure fire hazard to structures, systems, or components important to safety.	D	AC	See Section 9A.3.2.2
10.	Access to permit effective functioning of the fire brigade shall be provided to all areas that contain or present an exposure fire hazard to structures, systems, or components important to safety.	D	C	
11.	Standpipe and hose stations shall be inside PWR containments and BWR containments that are not inerted.	D	NA	The primary containment is inerted with nitrogen during reactor operation.
12.	For BWR drywells, standpipe and hose stations shall be placed outside the drywell with adequate lengths of hose to reach any location inside the drywell with an effective hose stream.	D	AC	Additional hose is staged at a hose station outside each drywell entrance to supplement the high-rise packs with sufficient additional hose to reach any location within the drywell with an effective hose stream.

NO.	APPENDIX R GUIDELINE	APPENDIX R ITEM NO.	COMPARISON	REMARKS
	Hydrostatic Hose Tests			
13.	Fire hose shall be hydrostatically tested at a pressure of 150 psi or 50 psi above maximum fire main operating pressure, whichever is greater. Hose stored in outside hose houses shall be tested annually. Interior standpipe hose shall be tested every three years.	E	C	
	Automatic Fire Detection			
14.	Automatic fire detection systems shall be installed in all areas of the plant that contain or present an exposure fire hazard to safe shutdown or safety-related systems or components. These fire detection systems shall be capable of operating with or without offsite power.	F	AC	See Item 112 of Section 9A.3.1.2
	Fire Protection of Safe Shutdown Capability			
15.	Fire damage shall be limited so that one train of systems necessary to achieve and maintain hot shutdown conditions from either the control room or emergency control station is free of fire damage.	G.1.a	C	
16.	Fire damage shall be limited so that systems necessary to achieve and maintain cold shutdown from either the control room or emergency control station can be repaired within 72 hours.	G.1.b	C	
17.	Consideration of associated nonsafety circuits as requiring protection to ensure freedom from fire damage.	G.2 (part of first paragraph)	C	See Section 9A.6.1
18.	Alternative means of ensuring that one train of systems necessary to achieve and maintain hot shutdown is free of fire damage (where cables or equipment of redundant trains are located in the same fire area).	G.2.a G.2.b G.2.c	AC	See Section 9A.3.2.2

NO.	APPENDIX R GUIDELINE	APPENDIX R ITEM NO.	COMPARISON	REMARKS
19.	Alternative means of providing fire protection inside noninerted containments.	G.2.d G.2.e G.2.f	NA	The primary containment is inerted with nitrogen during reactor operation.
20.	Provision of alternative or dedicated shutdown capability in certain fire areas.	G.3	NC	See Section 9A.3.2.2
	Fire Brigade			
21.	Requirements for the onsite fire brigade.	H	C	
	Fire Brigade Training			
22.	Requirements for training of fire brigade members.	I	AC	See Section 9A.3.2.2.
	Emergency Lighting			
23.	Emergency lighting units with at least an 8 hour battery power supply shall be provided in all areas needed for operation of safe shutdown equipment and in access and egress routes thereto.	J	C	See Section 9A.3.2.2.
	Administrative Controls			
24.	Establishment of administrative controls to minimize fire hazards.	K	C	
	Alternative and Dedicated Shutdown Capability			
25.	The shutdown capability provided for a specific fire area shall be able to achieve and maintain subcritical reactivity conditions in the reactor, maintain reactor coolant inventory, achieve and maintain hot shutdown conditions, achieve cold shutdown conditions within 72 hours, and maintain cold shutdown conditions thereafter.	L.1	C	

NO.	APPENDIX R GUIDELINE	APPENDIX R ITEM NO.	COMPARISON	REMARKS
26.	During the postfire shutdown, the reactor coolant system process variables shall be maintained within those predicted for a loss of normal ac power, and the fission product boundary integrity shall not be affected.	L.1	C	
27.	performance goals for the shutdown functions.	L.2	C	The systems and components relied on for hot shutdown and cold shutdown in the event of a fire have been selected so as to ensure that the listed goals are achieved.
28.	The alternative shutdown capability shall be independent of the specific fire areas.	L.3	C	
29.	The shutdown capability shall accommodate postfire conditions where offsite power is available and where offsite power is not available for 72 hours.	L.3	C	All systems and components relied on for hot shutdown and cold shutdown in the event of a fire are capable of being powered from the onsite power supplies, i.e., the station batteries and standby diesel generators.
30.	If the capability to achieve and maintain cold shutdown will not be available because of fire damage, the equipment and systems comprising the means to achieve and maintain the hot shutdown condition shall be capable of maintaining such conditions until cold shutdown can be achieved.	L.4	C	
31.	If the equipment and systems comprising the means to achieve and maintain hot shutdown conditions will not be capable of being powered by both onsite and offsite electric power systems because of fire damage, an independent onsite power system shall be provided.	L.4	NA	See Section 9A.3.2.2

NO.	APPENDIX R GUIDELINE	APPENDIX R ITEM NO.	COMPARISON	REMARKS
32.	Equipment and systems comprising the means to achieve and maintain cold shutdown conditions shall not be damaged by fire; or the fire damage to such equipment and systems shall be limited so that the systems can be made operable and cold shutdown can be achieved within 72 hours.	L.5	C	
33.	Materials for such repairs shall be readily available onsite and procedures shall be in effect to implement such repairs.	L.5	C	See Section 9A.3.2.2.
34.	If the equipment and systems comprising the means to achieve and maintain cold shutdown conditions (and which are used prior to 72 hours after the fire) will not be capable of being powered by both offsite and onsite power systems because of fire damage, and independent onsite power system shall be provided.	L.5	NA	See Section 9A.3.2.2.
35.	Shutdown systems installed to ensure positive shutdown capability need not be designed to meet seismic Category I criteria, single failure criteria, or other design basis accident criteria, except where required for other reasons.	L.6	C	
36.	Isolation of safe shutdown equipment and systems from associated nonsafety circuits.	L.7	C	See Section 9A.6.1
	Fire Barrier Cable Penetration Seal Qualification			
37.	Requirement Deleted	M	N/A	The non-combustibility requirement for fire barrier penetration seals was deleted from 10 CFR 50 Appendix R as documented in the Federal Register, volume 65, No. 119, Tuesday June 20, 2000 (Doc. 00-15544).
38.	Penetration seal designs shall be qualified by tests that are comparable to tests used to rate fire barriers.	M	C	See Section 9A.3.2.2

NO.	APPENDIX R GUIDELINE	APPENDIX R ITEM NO.	COMPARISON	REMARKS
	Fire Doors			
39.	Acceptance criteria for tests of penetration seal designs.	M.1 M.2 M.3	C	The listed criteria are included in documents discussed under item 38.
40.	Fire doors shall be self-closing or provided with closing mechanisms.	N	AC	See Section 9A.3.2.2
41.	Fire doors shall be inspected semiannually to verify that automatic hold open, release, and closing mechanisms and latches are operable.	N	AC	Fire doors that are not electrically supervised will be inspected semiannually. For doors that are electrically supervised, this supervision provides continual verification that the doors are in the closed position.
42.	Alternative means for ensuring that fire doors protect the door opening as required in case of fire.	N.1 N.2 N.3 N.4	C	See Section 9A.3.2.2
43.	The fire brigade Leader shall have ready access to keys for any locked fire doors.	N	C	
44.	Areas protected by automatic total flooding gas suppression systems shall have electrically supervised self-closing fire doors or shall satisfy option 1 above.	N	C	The only automatic total flooding gas suppression systems are the halon systems in the areas under the raised floor of the auxiliary equipment room and the remote shutdown room. There are no fire doors into these areas.
	Oil Collection System for Reactor Coolant Pump			
45.	The reactor coolant pump shall be equipped with an oil collection system if the containment is not inerted during normal operation.	0	NA	The primary containment is inerted with nitrogen during normal reactor operation.

9A.3.2.2 Explanatory Notes for Appendix R Comparison

Item 3

Appendix R Guideline

These supplies shall be separated so that a failure of one supply will not result in a failure of the other supply.

LGS Design

The Unit 1 and Unit 2 circulating water systems are completely separate, so that any failures occurring in one system will not affect the other system. The two fire pumps are located in separate compartments within the circulating water pump structure. The connections of the fire pump discharge lines to the fire main loop are located underground to minimize the potential for damage to the piping.

Item 5

Appendix R Guideline

When storage tanks are used for combined service water/fire water uses, the minimum volume for fire uses shall be ensured by means of dedicated tanks or by some physical means such as a vertical standpipe for other water service. Administrative controls, including locks for tank outlet valves, are unacceptable as the only means to ensure minimum water volume.

LGS Design

Storage tanks are not used as the sources of fire protection water. As noted in items 2 and 4 of Section 9A.3.2.1, fire protection water is obtained from the cooling tower basins of the Unit 1 and Unit 2 circulating water systems, each of which has a storage capacity of 7,200,000 gallons. Although the cooling tower basins also serve as the water sources for the service water systems, the storage capacity of the cooling tower basins is sufficient to ensure an adequate water supply for both systems (service water and fire protection water) without dedicating a certain volume of water to either system.

One of the two cooling tower basins will become unavailable as a source of fire protection water if the basin is drained to allow maintenance of it, or if the stop logs are inserted in the 96 inch circulating water lines from the cooling tower to allow work on some portion of the circulating water system. In this situation, the fire pump suction valves from the affected circulating water line will be closed in order to avoid jeopardizing the operability of the fire pumps. The unaffected circulating water lines and cooling tower will remain available to provide fire protection water to both the fire pumps.

Item 6

Appendix R Guideline

Other water systems used as one of the two fire water supplies shall be permanently connected to the fire main system and shall be capable of automatic alignment to the fire main system. Pumps, controls, and power supplies in these systems shall satisfy the requirements for the main fire

pumps. The use of other water systems for fire protection shall not be incompatible with their functions required for safe plant shutdown. Failure of the other system shall not degrade the fire main system.

LGS Design

The suction piping of the fire pumps is permanently connected to the 96 inch circulating water lines that supply water from the cooling towers to the main condensers. Since there are no pumps or valves located in the circulating water lines between the cooling tower basins and the connection points of the fire pump suction lines, no realignments are necessary to make the circulating water system available to provide water to the fire pumps. Therefore, there are no active failures of the circulating water system that could degrade the fire main system, and no special requirements are needed for the circulating water pumps or their associated power supplies and controls.

Item 9

Appendix R Guideline

Standpipe and hose systems shall be installed so that at least one effective hose stream will be able to reach any location that contains or presents an exposure fire hazard to structures, systems, or components important to safety.

LGS Design

Hose stations are located throughout the plant in areas that either contain systems and components important to safety or present an exposure fire hazard to such areas, with the exception of the spray pond pump structure. Fire suppression capability for the spray pond pump structure is provided by portable fire extinguishers.

As shown in Table 9A-1, the combustible loading in the various compartments of the spray pond pump structure is low enough that portable fire extinguishers are sufficient to extinguish any postulated fire. Those compartments that contain combustible materials are provided with fire detectors that annunciate in the control room. In addition, the spray pond pump structure is divided into two separate fire areas by a 3 hour rated fire wall along the centerline of the structure. A postulated fire in either fire area will leave at least one method available to safely shut the plant down.

Item 18

Appendix R Guideline

Except as provided for in paragraph G.3 of this section, where cables or equipment, including associated nonsafety circuits that could prevent operation or cause maloperation due to hot shorts, open circuits, or shorts to ground, of redundant trains of systems necessary to achieve and maintain hot shutdown conditions are located within the same fire area outside of primary containment, one of the following means of ensuring that one of the redundant trains is free of fire damage shall be provided:

a. Separation of cables and equipment and associated nonsafety circuits of redundant trains by a fire barrier having a 3 hour rating. Structural steel forming a part of or

supporting such fire barriers shall be protected to provide fire resistance equivalent to that required of the barrier;

b. Separation of cables and equipment and associated nonsafety circuits of redundant trains by a horizontal distance of more than 20 feet with no intervening combustible or fire hazards. In addition, fire detectors and an automatic fire suppression system shall be installed in the fire area; or

c. Enclosure of cable and equipment and associated nonsafety circuits of one redundant train in a fire barrier having a 1 hour rating. In addition, fire detectors and an automatic fire suppression system shall be installed in the fire area.

LGS Design

To the greatest extent practical, redundant trains of systems necessary to achieve and maintain hot shutdown are located in different fire areas, so that the redundant trains are separated by 3 hour fire barriers. In fire areas where this is not possible due to restrictions on equipment location and electrical cable routing, the capability to achieve hot shutdown is maintained by one of the following alternate means:

a. Enclosing the equipment and cabling of one redundant train in a 3 hour rated fire barrier.

b. Enclosing the equipment and cabling of one redundant train in a 1 hour rated fire barrier, and providing fire detection and automatic fire suppression in the fire area.

c. Dividing a fire area into two portions so that a fire is postulated to occur in only one portion at a time. Division of a fire area is accomplished by establishing a 20 foot wide zone that is free of combustible materials, and providing a water curtain suppression system within the combustible free zone. Components and equipment of redundant trains of systems that are necessary to achieve hot shutdown are located on opposite sides of the combustible free zone. Cables that are needed for operation of one redundant train and are routed through the portion of the fire area that contains equipment of the other redundant train are enclosed in a 3 hour rated fire barrier. Fire detection capability is provided on both sides of the combustible free zone.

d. Methods alternative to the foregoing are utilized in certain fire areas; these individual fire areas are discussed in Sections 9A.5.3, 9A.5.4, and 9A.5.5.

Item 20

Appendix R Guideline

Alternative or dedicated shutdown capability and its associated circuits, independent of cables, systems or components in the area, room or zone under consideration, shall be provided:

a. Where the protection of systems whose function is required for hot shutdown does not satisfy the requirement of paragraph G.2 of this section; or

b. Where redundant trains of systems required for hot shutdown located in the same fire area may be subject to damage from fire suppression activities or from the rupture or inadvertent operation of fire suppression systems.

In addition, fire detection and a fixed fire suppression system shall be installed in the area, room, or zone under consideration.

LGS Design

Systems whose function is required for hot shutdown are provided with protection against fire-caused damage in order to ensure that at least one of the redundant trains of these systems remains available in the event of a postulated fire and/or operation of a fire suppression system in any fire area or an alternative shutdown capability is provided to ensure that hot shutdown can be achieved. Alternative methods of shutdown are identified for fires which may occur in the control complex as discussed in Section 9A.5.3.

Components required for hot shutdown are designed so that rupture or inadvertent operation of fire suppression systems will not adversely affect the operability of these components. Where necessary, appropriate protection is provided to prevent impingement of water spray on components required for hot shutdown.

Alternative shutdown capability has been identified for fires that may occur in the control complex. However, a fixed fire suppression system may not be provided in the area, room, or zone under consideration. Compliance with Position C.5.c of BTP CMEB 9.5-1 is discussed in Section 9A.3.1.1, Item 76.

Item 22

Appendix R Guideline

Requirements for training of fire brigade members.

LGS Design

Fire Protection program objectives for training fire brigade members is accomplished by using a combination of in plant areas and an off-site training facility that simulates plant physical conditions. Drills are conducted in conformance with plant fire drill procedures.

An off-site facility enables drills to include the use of live fire conditions. These elements plus the use of breathing apparatus and full protective clothing create actual conditions that would be encountered during a real plant fire emergency. Additional drills, including backshift unannounced drills are conducted in plant areas throughout the year.

Item 23

Appendix R Guideline

Emergency lighting units with at least an 8 hour battery power supply shall be provided in all areas needed for operation of safe shutdown equipment and in access and egress routes thereto.

LGS Design

Fixed self-contained lighting units with individual 8 hour battery power supplies are provided in all areas to which access may be needed for manual actuation of safe shutdown of equipment, and in access and egress routes thereto. The locations where remote actions are required for achieving safe shutdown in the event of a postulated fire are listed in Table 9A-14. Self-contained battery powered lighting units will maintain a lighting level of at least nominal 0.5 footcandle in the listed areas and in access and egress paths thereto.

In addition to the self-contained individual battery powered lighting units, there is an emergency lighting system consisting of an ac subsystem and an ac/dc subsystem. The emergency ac lighting is powered from Class IE buses which automatically transfer to the standby diesel generators upon loss of the normal power source. Emergency ac lighting is provided throughout the plant to maintain minimum lighting levels necessary for access to and operation of equipment for a period greater than 24 hours. The general location of the emergency ac lighting and the associated lighting levels are shown on Table 9.5-12.

The emergency ac/dc lighting is normally powered from the Class IE buses. In the event of loss of the Class IE ac source, an automatic transfer switch immediately transfers this lighting to the 125 V dc non-Class IE station battery source. This power source will sustain the ac/dc lighting load on battery power for some period of time and could sustain the lights indefinitely if the diesel generator feeding the battery charger is available. All emergency ac/dc lighting fixtures are of the incandescent type. Emergency ac/dc lighting is provided throughout the plant to maintain minimum lighting levels necessary for access to and operation of equipment. The general location of the ac/dc lighting and the associated lighting levels are shown on Table 9.5-12.

The cables for both emergency lighting subsystems are routed exclusively in conduit, most of which is embedded in concrete. The locations of the power distribution buses and the cable routing for the two emergency lighting subsystems are separated to the extent practical such that a fire in any given area is not likely to cause the loss of both lighting subsystems in areas to which access is needed for the operation of safe shutdown equipment.

Item 31

Appendix R Guideline

If the equipment and systems comprising the means to achieve and maintain hot shutdown conditions will not be capable of being powered by both onsite and offsite electric power systems because of fire damage, an independent onsite power system shall be provided.

LGS Design

There is no postulated fire in any given fire area that could cause the simultaneous loss of both the offsite and onsite power supplies. Therefore, an additional redundant onsite power supply is not needed to ensure that safe shutdown can be achieved.

Item 33

Appendix R Guideline

Materials for such repairs shall be readily available onsite and procedures shall be in effect to implement such repairs.

LGS Design

A total of six different types of repair actions may be needed in order to compensate for the effects of fire-caused damage to equipment and systems involved in achieving and maintaining cold shutdown conditions. The six types of repair actions are described below.

a. It may be necessary to install a temporary cable in order to provide power to the ADS valves or the MSRVs and monitoring instruments at the Remote Shutdown Panel. The repair action is intended to ensure continued availability of electrical power to the ADS valves or MSRVs so that the valves can be opened by operators at the Control Room, PGCC, or Remote Shutdown Panel as necessary. In the case of power for the operation of the MSRVs from the Remote Shutdown Panel, power is also provided for the continued operation of Reactor Vessel and Suppression Pool instrumentation at the RSP. This repair action is only needed in the event of a loss of the ac power supplies to the battery chargers associated with the normal dc battery power supply. The temporary cable will be used to supply power from the Division 2 dc distribution panel to either the Division 1 or Division 3 circuit that provides power to the ADS valves or the MSRVs/RSP instruments.

b. The design of the ESW system includes intertie lines with both the Unit 1 service water system and the Unit 2 service water system. The intertie lines that allow water in the ESW piping to return to the service water system are each provided with two redundant air-operated isolation valves in series. When a given loop of the ESW system is placed in operation, the intertie lines associated with that particular loop need to be isolated in order to prevent long-term diversion of water from the ESW system to the service water system. It may be necessary to remove the air supply tubing for individual isolation valves to ensure that at least one valve in each intertie line closes and remains closed. This action is needed only if both isolation valves in a given intertie line remain open and cannot be reclosed during the first 24 hours of ESW system operation. The isolation valves affected are HV-011-043, HV-011-048, HV-011-121, HV-011-124, HV-011-125, HV-011-221, and HV-011-225.

c. A source of compressed gas may be required to support ADS valve or MSRV operation. The gas is required to allow opening of the valves as required for depressurization and shutdown. An air jumper will be used to connect the tank of a diesel generator air start system to the primary containment instrument gas system. Another air jumper will be connected to open valve HV-059-1(2)29B and leads to valve SV-059-1(2)52A or B may be cut to open it and allow the compressed gas system to function. This repair is only required if the primary containment instrument gas system does not operate.

d. If the Control Room or Auxiliary Equipment Room HVAC system becomes unavailable due to fire damage, it may be necessary to provide a temporary means

of ventilating the affected rooms. Ventilation for the control room will need to be re-established no earlier than nine hours after the loss of HVAC. Ventilation of the auxiliary equipment room and remote shutdown panel room will need to be re-established no earlier than seven hours after the loss of HVAC. Ventilation of the 4 kV switchgear rooms and static inverter rooms via natural convection will need to be re-established no earlier than four hours after the loss of HVAC. If necessary, a temporary ventilation capability will be established for the main control room, auxiliary equipment room and remote shutdown panel area by setting up portable fans and flexible duct-work and by opening doors to create an air flow pathway. The portable fans will be powered from either an onsite power source or a mobile diesel generator. A diesel generator that is dedicated to this service is stored onsite in a readily accessible location. Operability of the diesel generator will be ensured by a surveillance and maintenance program. This repair is only required if the normal HVAC fails as a result of the fire.

e. If the Spray Pond Pump Structure HVAC becomes unavailable due to fire damage, it may be necessary to provide a temporary means of ventilating the structure. Ventilation of the structure needs to be re-established no earlier than four and a half hours after the loss of HVAC. If necessary, a repair will be performed to establish a flow path for natural convection through the structure. In addition to opening doors in the spray pond pump structure, it will be necessary to partially disassemble a damper mechanism in order to permit the damper to be opened manually. This repair is only required if the normal HVAC fails as a result of the fire.

f. It may be necessary to utilize existing station procedures for "Loss of Shutdown Cooling" to establish a flow path for RHR shutdown cooling. Permissives to open the shutdown cooling suction line inboard and outboard isolation valves and the shutdown cooling return line outboard isolation valves are not included in the FSSD model and may not be available post-fire. Existing station procedures provide direction to Operations to establish the shutdown cooling flow path. Repair actions will operate the valves at the MCC via the use of jumpers.

For all six types of repairs described above, the tools and materials needed to perform the repairs are stored in readily accessible locations on site. Procedures governing the implementation of the repairs are in effect.

Item 34

Appendix R Guideline

If the equipment and systems comprising the means to achieve and maintain cold shutdown conditions (and which are used prior to 72 hours after the fire) will not be capable of being powered by both onsite and offsite power systems because of fire damage, an independent onsite power system shall be provided.

LGS Design

There is no postulated fire in any given fire area that could cause the simultaneous loss of both the offsite and onsite power supplies. Therefore, an additional redundant onsite power supply is not needed for permanent plant equipment to ensure that safe shutdown can be achieved. A mobile

diesel generator is stored onsite for use in providing power to temporary fans that may be needed to provide ventilation for the control room, auxiliary equipment room, and remote shutdown room.

Item 38

Appendix R Guideline

Penetration seal designs shall be qualified by tests that are comparable to tests used to rate fire barriers.

LGS Design

The designs of penetration seals in fire-rated barriers are tested to verify that the penetration seals are adequate to provide a specific degree of protection against the propagation of fire through the barriers. These tests are performed in accordance with the guidelines provided in the following documents:

a. Institute of Electrical and Electronics Engineers, IEEE 634 (1978), "IEEE Standard Cable Penetration Fire Stop Qualification Test".

b. NRC, Draft Regulatory Guide, "Qualification Test for Cable Penetration Fire Stops for Use in Nuclear Power Plants", (July 1979).

c. NEL-PIA/MAERP, "Standard Method of Fire Tests of Cable and Pipe Penetration Fire Stops", (February 1976).

d. American Nuclear Insurers, "ANI Position on Fire Stop Test Standards", (September 1979).

Item 40

Appendix R Guideline

Fire doors shall be self-closing or provided with closing mechanisms.

LGS Design

With the exception of watertight doors, all fire doors are provided with one of the following two features:

a. A self-closer to ensure that a normally closed door returns to the closed position after someone passes through it.

b. An automatic closing mechanism to ensure that a normally open door will close if there is a fire in the vicinity of the door.

Watertight doors that also serve as fire doors cannot be provided with self-closers or automatic closing mechanisms, due to the inherent restrictions of their design and function. These watertight doors are electrically supervised or inspected daily.

Item 42

Appendix R Guideline

One of the following measures shall be provided to ensure they will protect the opening as required in case of fire:

a. Fire doors shall be kept closed and electrically supervised at a continuously manned location;

b. Fire doors shall be locked and inspected weekly to verify that the doors are in the closed position;

c. Fire doors shall be provided with automatic hold open and release mechanisms and inspected daily to verify that doorways are free of obstructions; or

d. Fire doors shall be kept closed and inspected daily to verify that they are in the closed position.

LGS Design

Appropriate steps are taken to ensure that safe shutdown fire doors either are closed or will close when required in the event of a fire. One of the four measures listed above is followed for each safe shutdown fire door .

9A.4 EVALUATION OF POTENTIAL FIRE HAZARDS

9A.4.1 SCOPE OF EVALUATION

This chapter provides an evaluation of the potential for occurrence of fires within the plant and a summary of the capabilities of the existing fire protection program. This evaluation was performed for all structures that contain safety-related equipment or could affect safety-related structures by virtue of the fire hazards present.

A review of the plant was made to identify the combustible materials present, quantify the fire hazard in terms of combustible loading, and relate the potential hazard to the capabilities of the existing fire barriers and fire suppression systems. This information is presented in Table 9A-1 which lists the type of combustible materials present in each fire zone, the corresponding combustible loading, and the availability of detection and suppression equipment. Figures 9A-4 through 9A-12 show the locations of the fire zones, fire barriers, and fire suppression coverage.

9A.4.2 PROCEDURE

The evaluation of fire hazards was performed using a procedure that is summarized by the following steps:

a. For identification purposes, the various structures of the plant were divided into specific fire areas. A fire area is defined as that portion of a structure that is separated from other areas by boundaries (walls, floors, and ceilings) which are of a type of construction which is sufficient to prevent the spread of fire across the boundary, considering the combustible loading in the area. Many fire areas were further subdivided into fire zones to permit more precise identification of the locations of combustible materials, fire detection and suppression systems, and components associated with safety-related systems. The breakdown into fire zones was based on the locations of interior walls and slabs within each fire area. Fire areas are identified by a unique number, and fire zones within the same fire area are identified by a subletter. The fire area and fire zone designations are listed in Table 9A-1 "AREA-ZONE".

b. Each fire zone was surveyed to determine the type, quantity, and distribution of combustible materials present.

c. The combustible loading for each fire zone is determined based on the quantity of combustible materials present and the heat of combustion of each type of combustible material. The heat of combustion values used in this analysis are listed in Table 9A-2. The quantity of each type of combustible material (UNIT) is multiplied by the appropriate heat of combustion (BTU/UNIT) to determine the heat release (BTU) of each type of combustible material. The total heat release of all combustibles in the fire zone was then calculated by adding the heat release of each combustible material. To obtain the combustible loading (in BTU/ft^2) for each fire zone, the total heat release (in BTU) was divided by floor area of the fire zone.

d. The methodology for calculating fire severity (hours) is based on information presented in the 17th edition of the NFPA Handbook. The methodology uses the relationship between the calculated fire load in an area and an exposure to a fire severity which is equivalent to the standard time-temperature curve which is used

as the exposure fire in the fire resistance rating tests (ASTM E-119). The steps involved in calculating fire severity are as follows:

1. Calculate the fire load (BTU/ft^2) for an area as stated within the methodology.

2. Divide the calculated fire load by 80,000 BTU/ft ^{2}hr to obtain fire severity:

$$\text{Fire Severity} = \frac{\text{Fire Load BTU / ft}^2}{\text{80,000 BTU / ft}^2\,\text{hr}}$$

e. The clarification of the fire loading in a zone is based on the results of fire loading studies performed by the British (contained in the 17th edition of the Fire Protection Handbook). The results of the study show that the loading in an occupancy can be classified as low, moderate, or high, defined by the fire loading (BTU/ft^2) of the occupancy. The classifications are defined as follows:

Low - The fire load of a zone is classified as low if it does not exceed an average of 60,000 BTU/ft^2 of floor area. This loading corresponds to a fire severity of 45 minutes using the standard time temperature curve (ASTM E-119). Classification of fire load in a fire zone or area as low identifies the zone as having a fire severity below that which could be expected to be contained within a 1-hr fire rated enclosure.

Moderate - The fire load of a zone is classified as moderate if it exceeds an average of 60,000 BTU/ft^2 but does not exceed an average of 140,000 BTU/ft^2 of floor area. This loading corresponds to a fire severity of 1 hour, 45 minutes using the standard time temperature curve. Classification of fire load in fire zone or area as moderate identifies the zone as having a fire severity below that which could be expected to be contained within a 2-hr fire rated enclosure.

High - The fire load of a zone is classified as high if it exceeds an average of 140,000 BTU/ft^2 of floor area. This loading corresponds to a fire severity in excess of 1 hour, 45 minutes using the standard time temperature curve. Classification of fire zone or area as high identifies the zone as having a fire severity which could be expected to be contained within a 3-hour fire rated enclosure provided the defense in depth concept has been provided for high hazard concentrations of combustibles.

Control of Combustibles - The NRC granted a deviation on separation requirements based on fire protection defense-in-depth features and low combustible loading. In order to maintain the basis for the deviation from

separation requirements, the combustible loading in these areas shall be controlled.

Combustible loading is controlled in the RWCU Rooms resultant from a regulatory commitment to improve transient combustible controls as part of the Limerick response to Letter 88-20 (CM-3 - T04154).

Combustible loading is controlled in areas where there is no detection and contain or present an exposure to safety-related equipment or cables as documented in LEAF-0088.

Any increase in combustible loading shall be reviewed and approved by the licensee's fire protection engineer.

9A.5 ANALYSIS OF CAPABILITY TO ACHIEVE SAFE SHUTDOWN

9A.5.1 METHODOLOGY

This chapter provides an evaluation of the effects of postulated fires in each fire area on the ability of the operator to achieve a safe shutdown of the plant. Of the numerous possible combinations of equipment that could be used to effect a safe shutdown, four specific combinations were selected for detailed study for the purposes of this evaluation. These four shutdown methods are described in Section 9A.5.2.

In performing the safe shutdown analysis, the four shutdown methods were examined to determine the minimum equipment, control, and power requirements for operability of each method. The locations of the equipment itself and the cabling associated with the required equipment were identified with respect to the various fire areas.

Each fire area was then examined to determine which components associated with the shutdown methods, if any, would be rendered inoperable by the occurrence of a fire within the fire area. The results of the safe shutdown analysis are summarized in Sections 9A.5.3 through 9A.5.9 for each fire area.

The following assumptions were used in performing the safe shutdown analysis:

a. No credit is taken for manual fire fighting efforts or the operation of automatic fire suppression systems. The fire is assumed to disable all equipment and electrical cabling located in the fire area, unless the fire hazard analysis demonstrates otherwise. An electrical cable tray fire is assumed not to propagate from one tray to another, since separation is provided in accordance with Regulatory Guide 1.75.

b. Plant accidents and severe natural phenomena are not considered to occur concurrently with the postulated fire.

c. A single active component failure is not assumed to occur concurrently with the fire.

d. Credit is taken for reactor trip. Any fire affecting the RPS or the CRD circuitry will not prevent the reactor from being tripped. A reactor trip can be performed manually (in the control room), automatically (by the RPS logic), or by tripping the RPS power supplies (in the auxiliary equipment room).

e. No credit is taken for proper operation or proper positioning of equipment which is not separated or protected in accordance with the guidelines of 10CFR50, Appendix R, unless the safe shutdown analyses presented in Sections 9A.5.3 and 9A.5.4 demonstrate the adequacy of the existing design. For such equipment, loss of operability or spurious operation is assumed, whichever is more conservative. This assumption provides a worst case analysis regarding spurious signals associated with cabling failures in a fire area.

f. For Alternative or Dedicated Shutdown Capability as defined in Chemical Mechanical Engineering Branch Technical Position (CMEBTP) 9.5-1, "Fire Protection Program", and 10CFR50, Appendix R, III, L, offsite power is assumed to be unavailable during the first 72 hours after the onset of the fire. However, no

credit is taken for loss of offsite power in situations for which a loss of offsite power would be advantageous.

g. For Safe Shutdown, as defined in Chemical Mechanical Engineering Branch Technical Position 9.5-1, (CMEBTP) "Fire Protection Program", and 10CFR50, Appendix R, III, offsite power is assumed to be available: except if the fire would cause a loss of offsite power.

One single spurious operation of a non-high/low pressure interface FSSD component is postulated to occur for a fire event. Any number of hot shorts, open circuits, or shorts to ground may occur, but they will result in only one single spurious actuation. Three phase hot shorts of the proper voltage and phase sequence capable of spuriously operating a device are not postulated.

In the discussions of individual fire areas contained in Sections 9A.5.3 through 9A.5.9, paragraph (c) addresses the nature of the fire that is postulated to occur in each fire area. Paragraph (c) relates to potential fires involving in situ combustible materials, and does not preclude the postulation of fires involving transient combustibles. In all cases, the safe shutdown analysis and the resulting fire protection features for each fire area are based on the potential for an exposure fire to affect all components and cables within the fire area.

Those floor slabs identified by an asterisk following the indicated fire rating in the fire area discussions contained in Sections 9A.5.3 through 9A.5.9 are discussed in Item 37 of Section 9A.3.1. Those fire doors identified in Sections 9A.5.3 through 9A.5.9 by a double asterisk (**) following the indicated fire rating are discussed in Item 48 of Section 9A.3.1.

9A.5.2 DESCRIPTION OF REACTOR SHUTDOWN METHODS

The following sections provide descriptions of methods that can be used for reactor shutdown and cooldown. Each of these methods includes a system by which makeup water can be added to the reactor vessel, a system by which energy can be removed from the reactor vessel, and any support systems needed to accommodate energy removal to an ultimate heat sink or to return water to its supply source.

Although the safe shutdown analysis for the various fire areas places primary emphasis on achievement of reactor shutdown using the methods described below, many alternative shutdown methods would be available. Use of safety-related and nonsafety-related systems not addressed in the safe shutdown analysis, plus manual operation of certain equipment and controls, would provide numerous combinations of systems with adequate capability to safely shut the plant down.

9A.5.2.1 Reactor Shutdown With Balance of Plant Cooling Systems Available

After the turbine-generator has been tripped and all control rods inserted into the reactor core during the course of a normal shutdown and cooldown, reactor decay heat and sensible heat is removed by bypassing main steam to the condenser. Heat is removed from the condenser by the circulating water system and rejected to the atmosphere by the cooling tower. Makeup water is supplied to the reactor vessel by the condensate and feedwater system, taking suction on the condenser hotwell. When the reactor has been depressurized below a nominal 75 psig, the RHR system is initiated in the shutdown cooling mode of operation. In this mode, reactor water is circulated through the RHR heat exchangers, where it is cooled by the RHRSW system. Heat is rejected from the RHRSW system to the atmosphere by using either the cooling tower or the spray pond. The reactor vent valves are opened when reactor pressure reaches atmospheric.

9A.5.2.2 Reactor Shutdown Without Balance of Plant Cooling Systems Available

Four specific methods of achieving cold shutdown and maintaining the plant in that condition have been defined for use in analyzing the capability to safely shut the plant down in the event of a fire. Three of the specific shutdown methods (designated as methods A, B and C) are directed from the Main Control Room and may be supplemented by local operator actions, including actions at the Remote Shutdown Panel (RSP). The fourth shutdown method (designated as method R) is directed from the RSP and may be supplemented by local operator actions. Shutdown methods A, B, C and R each include systems and components necessary to accomplish the major functions of (a) providing makeup water to the reactor vessel, (b) depressurizing the reactor vessel, and (c) removing decay heat and sensible heat from the primary containment. The systems in each shutdown method that are directly relied on for accomplishing these functions are as follows:

Shutdown Method	Pressure Control	Inventory Control	Decay Heat Removal (Vessel)	Decay Heat Removal (Pool)
A	ADS or MSRV	RCIC	RHR in Shutdown Cooling Mode or Alternate Shutdown Cooling Mode	RHR in the Suppression Pool Cooling Mode
B	ADS or MSRV	HPCI	RHR in Shutdown Cooling Mode or Alternate Shutdown Cooling Mode	RHR in the Suppression Pool Cooling Mode
C	ADS or MSRV	RHR in the LPCI Mode	RHR in Shutdown Cooling Mode or Alternate Shutdown Cooling Mode	RHR in the Suppression Pool Cooling Mode
R	MSRV	RCIC	RHR (Loop A) in Shutdown Cooling Mode	RHR (Loop A) in the Suppression Pool Cooling Mode

The main safe shutdown components that may be relied upon to achieve safe shutdown using these methods are listed in Table
9A-4.

Method A

After closure of the Main Steam Isolation Valves (MSIVs), the RCIC system is used to supply makeup water to the reactor vessel from the suppression chamber. The operation of the RCIC system also removes energy from the reactor in the form of steam to drive the RCIC turbine. During the period in which steam is generated at a rate greater than the consumption of the RCIC system, steam is relieved to the suppression pool by automatic actuation of the Main Steam Relief Valves (MSRV's), which open when reactor pressure reaches the valve setpoint. Heat is removed from the suppression pool by operating a loop of the RHR system in the suppression pool cooling mode. In this mode, water from the suppression pool is circulated through the RHR heat exchanger and then returned to the suppression pool. In order to initiate

operation of the shutdown cooling mode of the RHR system, it is necessary to depressurize the reactor below a nominal pressure of 75 psig. This is accomplished by using the ADS valves or MSRV's to discharge steam to the suppression pool. When the reactor has been depressurized below 75 psig, operation of the RCIC system is terminated and the RHR system is switched from the suppression pool cooling mode to the shutdown cooling mode. An alternate shutdown cooling mode has been defined and may be used with Method A instead of the standard shutdown cooling mode. This involves using the RHR pump to circulate water from the suppression pool through the RHR heat exchanger and discharge it into the reactor vessel through the LPCI injection line or through the shutdown cooling return line to the reactor recirculation loop. Water from the reactor vessel is returned to the suppression pool by opening one or more of the ADS valves or MSRVs. The water level in the reactor vessel rises to the main steam line nozzles , allowing water to partially fill the main steam lines and then flow through the open relief valve and down the MSRV discharge line to the suppression pool.

In the suppression pool cooling mode and the shutdown cooling modes, heat is removed from the RHR heat exchanger by the RHRSW system, which in turn dissipates heat at the spray pond. The shutdown cooling or alternate shutdown cooling mode of RHR will maintain the reactor in a cold shutdown condition.

Depending on the location of a fire within the plant, certain operations that are used in this shutdown method may need to be performed manually from outside the control room. The specific operations are identified in Table 9A-14.

Method B

After closure of the Main Steam Isolation Valves (MSIVs), the HPCI system is used to supply makeup water to the reactor vessel from the suppression chamber. The operation of the HPCI system also removes energy from the reactor in the form of steam to drive the HPCI turbine. During the period in which steam is generated at a rate greater than the consumption of the HPCI system, steam is relieved to the suppression pool by automatic actuation of the Main Steam Relief Valves (MSRV's), which open when reactor pressure reaches the valve setpoint. Heat is removed from the suppression pool by operating a loop of the RHR system in the suppression pool cooling mode. In this mode, water from the suppression pool is circulated through the RHR heat exchanger and then returned to the suppression pool. In order to initiate operation of the shutdown cooling mode of the RHR system, it is necessary to depressurize the reactor below a nominal pressure of 75 psig. This is accomplished by using the ADS valves or MSRV's to discharge steam to the suppression pool. When the reactor has been depressurized below 75 psig, operation of the HPCI system is terminated and the RHR system is switched from the suppression pool cooling mode to the shutdown cooling mode. An alternate shutdown cooling mode has been defined and may be used with Method B instead of the standard shutdown cooling mode. This involves using the RHR pump to circulate water from the suppression pool through the RHR heat exchanger and discharge it into the reactor vessel through the LPCI injection line or through the shutdown cooling return line to the reactor recirculation loop. Water from the reactor vessel is returned to the suppression pool by opening one or more of the ADS valves or MSRVs. The water level in the reactor vessel rises to the main steam line nozzles , allowing water to partially fill the main steam lines and then flow through the open relief valve and down the MSRV discharge line to the suppression pool.

In the suppression pool cooling mode and the shutdown cooling modes, heat is removed from the RHR heat exchanger by the RHRSW system, which in turn dissipates heat at the spray

pond. The shutdown cooling or alternate shutdown cooling mode of RHR will maintain the reactor in a cold shutdown condition.

Depending on the location of a fire within the plant, certain operations that are used in this shutdown method may need to be performed manually from outside the control room. The specific operations are identified in Table 9A-14.

Method C

After closure of the MSIVs, the reactor is depressurized by manually controlling the valves of the ADS or three or more MSRVs. The opening of these valves allows reactor steam to be discharged to the suppression pool. Makeup water is supplied to the reactor vessel from the suppression pool by operating a loop of the RHR system in the LPCI mode after reactor pressure has decreased to a nominal 295 psig. When the reactor has been depressurized below 75 psig, the RHR system is switched from the suppression pool cooling mode to the shutdown cooling mode. An alternate shutdown cooling mode has been defined and may be used with method C instead of the standard shutdown cooling mode. This involves using the RHR pump to circulate water from the suppression pool through the RHR heat exchanger and discharge it into the reactor vessel through the LPCI injection line or through the shutdown cooling return line to the reactor recirculation loop. Water from the reactor vessel is returned to the suppression pool by opening one or more of the ADS valves or MSRVs. The water level in the reactor vessel rises to the main steam line nozzles , allowing water to partially fill the main steam lines and then flow through the open relief valve and down the MSRV discharge line to the suppression pool.

In the suppression pool cooling mode and the shutdown cooling modes, heat is removed from the RHR heat exchanger by the RHRSW system, which in turn dissipates heat at the spray pond. The shutdown cooling or alternate shutdown cooling mode of RHR will maintain the reactor in a cold shutdown condition.

Depending on the location of a fire within the plant, certain operations that are used in this shutdown method may need to be performed manually from outside the control room. The specific operations are identified in Table 9A-14.

Method R - Reactor Shutdown from Outside the Control Room

In the unlikely event that a fire disables or requires evacuation of the Control Room, an alternative shutdown capability is provided compliant with Position C.5.c of BTP CMEB 9.5-1. The capability is designated as shutdown method R and is used to effect a plant shutdown directed from the Remote Shutdown Panel (RSP).

The shutdown sequence is similar to Shutdown Method A except that the methodology is centered around equipment that may be controlled from the RSP. After closure of the Main Steam Isolation Valves (MSIVs), the RCIC system is used to supply makeup water to the reactor vessel from the suppression chamber. The operation of the RCIC system also removes energy from the reactor in the form of steam to drive the RCIC turbine. During the period in which steam is generated at a rate greater than the consumption of the RCIC system, steam is relieved to the suppression pool by automatic actuation of the Main Steam Relief Valves (MSRVs), which open when reactor pressure reaches the valve setpoint. Heat is removed from the suppression pool by operating the A loop of the RHR system in the suppression pool cooling mode. In this mode, water from the suppression pool is circulated through the RHR heat

exchanger and then returned to the suppression pool. In order to initiate operation of the shutdown cooling mode of the RHR system, it is necessary to depressurize the reactor below a nominal pressure of 75 psig. This is accomplished by using the MSRVs A, C, and N to discharge steam to the suppression pool. When the reactor has been depressurized below 75 psig, operation of the RCIC system is terminated and the A loop of the RHR system is switched from the suppression pool cooling mode to the shutdown cooling mode. In the suppression pool cooling mode and the shutdown cooling modes, heat is removed from the RHR heat exchanger by the RHRSW system, which in turn dissipates heat at the spray pond. The shutdown cooling mode of RHR will maintain the reactor in a cold shutdown condition.

Depending on the location of a fire within the plant, certain operations that are used in this shutdown method may need to be performed manually from outside the control room. The specific operations are identified in Table 9A-14.

9A.5.3 SAFE SHUTDOWN ANALYSIS - CONTROL STRUCTURE

9A.5.3.1 Fire Area 1: Recombiner Compartments, Condensate Backwash Compartments, and Control Structure Water Chiller Areas (el 180'-0" and 200'-0")

a. Structural and architectural design features of fire area (Figures 9A-4 and 9A-5):

	Construction	Rating
Walls:	W - Reinforced concrete	3 hr
	N - Reinforced concrete (part; contains 5 ft^2 of unrated metal blowout panels)	3 hr
	N - Reinforced concrete (part adjacent to stairwell no. 7)	2 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (part below el 200'-0")	3 hr
	S - Concrete masonry unit (part above el 200'-0", eastern half)	3 hr
	S - Concrete masonry unit (part above el 200'-0", western half, contains two HVAC penetrations without fire dampers)	None
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Steamtight door connecting to stairwell no. 7	1.5 hr
	Double steamtight door connecting to area 89 and 102	3 hr**
	Two double steamtight doors connecting area 102	3 hr**

b. Major safety-related components in fire area:

1. Control structure water chillers 0AK112 and 0BK112

2. Control structure chilled water circulation pumps 0AP162 and 0BP162

c. Postulated fire in area:

1. Ignition of electrical cabling in cable trays. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

2. Ignition of oil in a waste oil collection drum associated with the floor drain sump oil removal belt.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 1 contains safe shutdown cables and equipment.

Cables required to support shutdown methods B and C for Units 1 and 2 are either: encapsulated by qualified fire barrier, associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods B and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods B and C will be available to shutdown Units 1 and 2.

9A.5.3.2 Fire Area 2: 13 kV Switchgear Area (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Concrete masonry unit - (part adjacent to battery rooms)	3 hr
	E - Reinforced concrete - (remainder)	3 hr
	S - Reinforced concrete	3 hr
	W - Reinforced concrete (part)	3 hr
	W - Concrete masonry unit (part adjacent to battery rooms)	3 hr

	W - Reinforced concrete (part adjacent to stairwell no. 7)	2 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr*
Access:	Door connecting to stairwell no. 7	1.5 hr
	Doors connecting to areas 3, 4, 5, and 6	3 hr
	Double steamtight doors connecting to areas 94, 107, and 113	3 hr**

b. Major safety-related components in fire area:

1. Emergency switchgear and battery room fan cabinets OAV118 and OBV118 and associated ventilation dampers

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to the area.

A localized sprinkler system is provided in the area adjacent to the Column Line “J” wall, to provide protection for 1-hour encapsulated safe shutdown cables. When the temperature in the area reaches a nominal 200°F, combined with a smoke detection signal, the sprinklers will open to control the fire.

e. Effect of fire on safe shutdown:

Fire area 2 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Units 1 and 2 are either: encapsulated by a qualified fire barrier, associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, method C will be available to shutdown Units 1 and 2.

9A.5.3.3 Fire Area 3: Unit 1 Class 1E Battery Room (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	2 hr
	E - Concrete masonry unit	3 hr
	S - Concrete masonry unit	3 hr
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete (See Section 9A.3.1.2, Item 46)	3 hr*
Access:	Door connecting to area 2	3 hr

b. Major safety-related components in fire area:

1. Class 1E battery 1DD101 (Div. 4)

2. Battery charger 1DD103

3. Fuse box 1DD105

c. Postulated fire in area:

Ignition of battery cases and/or battery spacers as the result of an exposure fire.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detector, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 3 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.3.4 Fire Area 4: Unit 1 Class 1E Battery Room (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Concrete masonry unit	3 hr
	E - Concrete masonry unit	3 hr
	S - Concrete masonry unit	3 hr
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete (See Section 9A.3.1.2, Item 46)	3 hr*
Access:	Door connecting to area 2	3 hr

b. Major safety-related components in fire area:

1. Class 1E battery 1CD101 (Div. 3)

2. Battery charger 1CD103

3. Fuse box 1CD105

c. Postulated fire in area:

Ignition of battery cases and/or battery spacers as the result of an exposure fire.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detector, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 4 contains safe shutdown cables and equipment.

Cables associated with shutdown method A for Units 1 and 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method A for Units 1 and 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods B and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods B and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.3.5 Fire Area 5: Unit 2 Class 1E Battery Room (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Concrete masonry unit	3 hr
	W - Concrete masonry unit	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete (See Section 9A.3.1.2, Item 46)	3 hr*
Access:	Door connecting to area 2	3 hr

b. Major safety-related components in fire area:

1. Class 1E battery 2DD101 (Div. 4)
2. Battery charger 2DD103
3. Fuse box 2DD105

c. Postulated fire in area:

Ignition of battery cases and/or battery spacers as the result of an exposure fire.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detector, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 5 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1

and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.3.6 Fire Area 6: Unit 2 Class 1E Battery Room (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Concrete masonry unit	3 hr
	E - Reinforced concrete	3 hr
	S - Concrete masonry unit	3 hr
	W - Concrete masonry unit	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete (See Section 9A.3.1.2, Item 46)	3 hr*
Access:	Door connecting to area 2	3 hr

b. Major safety-related components in fire area:

1. Class 1E battery 2CD101 (Div. 3)
2. Battery charger 2CD103
3. Fuse box 2CD105

c. Postulated fire in area:

Ignition of battery cases and/or battery spacers as the result of an exposure fire.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 6 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1

and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.3.7 Fire Area 7: Corridor (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Concrete masonry unit	3 hr^
	E - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr
Access:	Doors connecting to areas 9, 11, 13, 15, 17, and 19	3 hr
	Steamtight doors connecting to areas 97 and 110	3 hr**

The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

b. Major safety-related components in fire area: None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. When the temperature in the area reaches a nominal 200°F, the sprinkler will open to control the fire. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to the area.

e. Effect of fire on safe shutdown:

Fire area 7 contains safe shutdown cables but does not contain safe shutdown equipment.

Cables required to support shutdown methods A and C for Units 1 and 2 are either: encapsulated by a qualified fire barrier, associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Units 1 and 2.

f. Deviations:

The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

9A.5.3.8 Fire Area 8: Unit 1 Class 1E Battery Room (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Concrete masonry unit	3 hr
	S - Concrete masonry unit	3 hr^
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr
Access:	Door connecting to area 9	3 hr
	Steamtight door connecting to area 113	3 hr

The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

b. Major safety-related components in fire area:

1. Class 1E batteries 1B1D101 and 1B2D101 (Div. 2)

2. Battery chargers 1B1D103 and 1B2D103

3. Fuse box 1BD105

4. Class 1E dc distribution panels 1BD162 (Div. 2) and 1DD162 (Div. 4)

c. Postulated fire in area:

Ignition of battery cases and/or battery spacers as the result of an exposure fire.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 8 contains safe shutdown cables and equipment.

Cables associated with shutdown methods A and C for Unit 1 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods A and C for Unit 1 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods A and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Units 1 and 2.

f. Deviations:

The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

9A.5.3.9 Fire Area 9: Unit 1 Class 1E Battery Room (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Concrete masonry unit	3 hr^
	E - Concrete masonry unit	3 hr
	S - Concrete masonry unit	3 hr^
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr

Access:	Doors connecting to areas 7 and 8	3 hr

The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

b. Major safety-related components in fire area:

1. Class 1E batteries 1A1D101 and 1A2D101 (Div. 1)

2. Battery chargers 1A1D103 and 1A2D103

3. Fuse box 1AD105

c. Postulated fire in area:

Ignition of battery cases and/or battery spacers as the result of an exposure fire.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 9 contains safe shutdown cables and equipment.

Cables required to support shutdown methods B and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods B and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods B and C will be available to shutdown Units 1 and 2.

f. Deviations:

The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

9A.5.3.10 Fire Area 10: Unit 2 Class 1E Battery Room (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Concrete masonry unit	3 hr^

	W - Concrete masonry unit	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr
Access:	Door connecting to area 11	3 hr
	Steamtight door connecting to area 113	3 hr

The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

b. Major safety-related components in fire area:

1. Class 1E batteries 2B1D101 and 2B2D101 (Div. 2)
2. Battery chargers 2B1D103 and 2B2D103
3. Fuse box 2BD105

c. Postulated fire in area:

Ignition of battery cases and/or battery spacers as the result of an exposure fire.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 10 contains safe shutdown cables and equipment.

Cables associated with shutdown methods A and C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods A and C for Unit 1 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area. The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and methods A and C will be available to shutdown Unit 2.

f. Deviations:

The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

9A.5.3.11 Fire Area 11: Unit 2 Class 1E Battery Room (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Concrete masonry unit	3 hr^
	E - Reinforced concrete	3 hr
	S - Concrete masonry unit	3 hr^
	W - Concrete masonry unit	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr
Access:	Doors connecting to areas 7 and 10	3 hr

The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

b. Major safety-related components in fire area:

1. Class 1E batteries 2A1D101 and 2A2D101 (Div. 1)
2. Battery chargers 2A1D103 and 2A2D103
3. Fuse box 2AD105

c. Postulated fire in area:

Ignition of battery cases and/or battery spacers as the result of an exposure fire.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 11 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Unit 1 and methods B and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 and methods B and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and methods B and C will be available to shutdown Unit 2.

f. Deviations:

The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

9A.5.3.12 Fire Area 12: Unit 1 4 kV Switchgear Compartment (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr§
	E - Concrete masonry unit	3 hr§
	S - Concrete masonry unit	3 hr§^
	W - Concrete masonry unit	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr
Access:	Door connecting to area 13	3 hr
	Steamtight door connecting to area 113	3 hr

Walls denoted above by the "§" symbol are capable of being rated as 3 hour fire barriers, except for unrated wall penetration assemblies associated with the 4 kV non-segregated phase bus ducts. These penetration assemblies are described in Section 9A.6.3. A maximum of two penetration assemblies are located in each of the walls indicated above. These walls separate fire area 12 from fire areas 13, 14, and 113. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

b. Major safety-related components in fire area:

1. Class 1E 4 kV switchgear 10A117 (Div. 3)

2. Class 1E dc distribution panels 1CD102 and 1CD162 (Div. 3)
3. Class 1E instrument ac distribution panel 10Y103 (Div. 3)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 12 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions may be taken to recover any functions that could be lost. Equipment associated with shutdown methods A, B and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any functions that could be lost.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods A, B and C will be available to shutdown Units 1 and 2.

f. Deviations:

The unrated wall penetration assemblies associated with the 4kV non-segregated phase bus ducts are a deviation from the requirements of CMEB 9.5-1, C.5.b. See section 9A.6.3. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

9A.5.3.13 Fire Area 13: Unit 1 4 kV Switchgear Compartment (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

		Construction	Rating
Walls:	N -	Concrete masonry unit	3 hr§^
	E -	Concrete masonry unit	3 hr§
	S -	Concrete masonry unit	3 hr^
	W -	Concrete masonry unit	3 hr
Floor:	Reinforced concrete		3 hr*
Ceiling:	Reinforced concrete		3 hr

Access: Doors connecting to areas 7 and 12 3 hr

Walls denoted above by the "§" symbol are capable of being rated as 3 hour fire barriers, except for unrated wall penetration assemblies associated with the 4 kV non-segregated phase bus ducts. These penetration assemblies are described in Section 9A.6.3. A maximum of two penetration assemblies are located in each of the walls indicated above. These walls separate fire area 13 from fire areas 12 and 15. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

f. Major safety-related components in fire area:

1. Class 1E 4 kV switchgear 10A115 (Div. 1)
2. Class 1E dc distribution panels 1AD102 and 1AD162 (Div. 1)
3. Class 1E instrument ac distribution panel 10Y101 (Div. 1)

f. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 13 contains safe shutdown cables and equipment.

Cables associated with shutdown methods B and C for Units 1 and 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods B and C for Units 1 & 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods B and C will be available to shutdown Units 1 and 2.

f. Deviations:

The unrated wall penetration assemblies associated with the 4kV non-segregated phase bus ducts are a deviation from the requirements of CMEB 9.5-1, C.5.b. See section 9A.6.3. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

9A.5.3.14 Fire Area 14: Unit 1 4 kV Switchgear Compartment (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Concrete masonry unit	3 hr§
	S - Concrete masonry unit	3 hr^
	W - Concrete masonry unit	3 hr§
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr
Access:	Door connecting to area 15	3 hr
	Steamtight door connecting to area 113	3 hr

Walls denoted above by the "§" symbol are capable of being rated as 3 hour fire barriers, except for unrated wall penetration assemblies associated with the 4 kV non-segregated phase bus ducts. These penetration assemblies are described in Section 9A.6.3. A maximum of two penetration assemblies are located in each of the walls indicated above. These walls separate fire area 14 from fire areas 12 and 16. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

b. Major safety-related components in fire area:

1. Class 1E 4 kV switchgear 10A118 (Div. 4)

2. Class 1E instrument ac distribution panel 10Y104 (Div. 4)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 14 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Units 1 and 2.

f. Deviations:

The unrated wall penetration assemblies associated with the 4kV non-segregated phase bus ducts are a deviation from the requirements of CMEB 9.5-1, C.5.b. See section 9A.6.3. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

9A.5.3.15 Fire Area 15: Unit 1 4 kV Switchgear Compartment (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Concrete masonry unit	3 hr^
	E - Concrete masonry unit	3 hr§
	S - Concrete masonry unit	3 hr^
	W - Concrete masonry unit	3 hr§
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr
Access:	Doors connecting to areas 7 and 14	3 hr

Walls denoted above by the "§" symbol are capable of being rated as 3 hour fire barriers, except for unrated wall penetration assemblies associated with the 4 kV non-segregated phase bus ducts. These penetration assemblies are described in Section 9A.6.3. A maximum of two penetration assemblies are located in each of the walls indicated above. These walls separate fire area 15 from fire areas 13 and 17. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

b. Major safety-related components in fire area:

1. Class 1E 4 kV switchgear 10A116 (Div. 2)

2. Class 1E instrument ac distribution panel 10Y102 (Div. 2)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 15 contains safe shutdown cables and equipment.

Cables associated with shutdown methods A and C for Unit 1 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods A and C for Unit 1 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods A and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Units 1 and 2.

f. Deviations:

The unrated wall penetration assemblies associated with the 4kV non-segregated phase bus ducts are a deviation from the requirements of CMEB 9.5-1, C.5.b. See section 9A.6.3. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

9A.5.3.16 Fire Area 16: Unit 2 4 kV Switchgear Compartment (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Concrete masonry unit	3 hr§
	S - Concrete masonry unit	3 hr^
	W - Concrete masonry unit	3 hr§
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr
Access:	Door connecting to area 17	3 hr
	Steamtight door connecting to area 113	3 hr

Walls denoted above by the "§" symbol are capable of being rated as 3 hour fire barriers, except for unrated wall penetration assemblies associated with the 4 kV non-segregated phase bus ducts. These penetration assemblies are described in Section 9A.6.3. A maximum of two penetration assemblies are located in each of the walls indicated above. These walls separate fire area 16 from fire areas 14 and 18. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

b. Major safety-related components in fire area:

1. Class 1E 4 kV switchgear 20A118 (Div. 4)

2. Class 1E instrument ac distribution panel 20Y104 (Div. 4)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 16 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a

fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

f. Deviations:

The unrated wall penetration assemblies associated with the 4kV non-segregated phase bus ducts are a deviation from the requirements of CMEB 9.5-1, C.5.b. See section 9A.6.3. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

9A.5.3.17 Fire Area 17: Unit 2 4 kV Switchgear Compartment (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Concrete masonry unit	3 hr^
	E - Concrete masonry unit	3 hr§
	S - Concrete masonry unit	3 hr^
	W - Concrete masonry unit	3 hr§
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr
Access:	Doors connecting to areas 7 and 16	3 hr

Walls denoted above by the "§" symbol are capable of being rated as 3 hour fire barriers, except for unrated wall penetration assemblies associated with the 4 kV non-segregated phase bus ducts. These penetration assemblies are described in Section 9A.6.3. A maximum of two penetration assemblies are located in each of the walls indicated above. These walls separate fire area 17 from fire areas 15 and 19. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

b. Major safety-related components in fire area:

1. Class 1E 4 kV switchgear 20A116 (Div. 2)

2. Class 1E instrument ac distribution panel 20Y102 (Div. 2)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 17 contains safe shutdown cables and equipment.

Cables associated with shutdown methods A and C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods A and C for Unit 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and methods A and C will be available to shutdown Unit 2.

f. Deviations:

The unrated wall penetration assemblies associated with the 4kV non-segregated phase bus ducts are a deviation from the requirements of CMEB 9.5-1, C.5.b. See section 9A.6.3. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

9A.5.3.18 Fire Area 18: Unit 2 4 kV Switchgear Compartment (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr§
	E - Concrete masonry unit	3 hr
	S - Concrete masonry unit	3 hr§^
	W - Concrete masonry unit	3 hr§

Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr
Access:	Door connecting to area 19	3 hr
	Steamtight door connecting to area 113	3 hr

Walls denoted above by the "§" symbol are capable of being rated as 3 hour fire barriers, except for unrated wall penetration assemblies associated with the 4 kV non-segregated phase bus ducts. These penetration assemblies are described in Section 9A.6.3. A maximum of two penetration assemblies are located in each of the walls indicated above. These walls separate fire area 18 from fire areas 16, 19, and 113. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

b. Major safety-related components in fire area:

1. Class 1E 4 kV switchgear 20A117 (Div. 3)

2. Class 1E dc distribution panel 2CD102 (Div. 3)

3. Class 1E instrument ac distribution panel 20Y103 (Div. 3)

1. Postulated fire in area:

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 18 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

f. Deviations:

The unrated wall penetration assemblies associated with the 4kV non-segregated phase bus ducts are a deviation from the requirements of CMEB 9.5-1, C.5.b. See section 9A.6.3. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

9A.5.3.19 Fire Area 19: Unit 2 4 kV Switchgear Compartment (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Concrete masonry unit	3 hr§^
	E - Concrete masonry unit	3 hr
	S - Concrete masonry unit	3 hr
	W - Concrete masonry unit	3 hr§
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr
Access:	Doors connecting to areas 7 and 18	3 hr

Walls denoted above by the "§" symbol are capable of being rated as 3 hour fire barriers, except for unrated wall penetration assemblies associated with the 4 kV non-segregated phase bus ducts. These penetration assemblies are described in Section 9A.6.3. A maximum of two penetration assemblies are located in each of the walls indicated above. These walls separate fire area 19 from fire areas 17 and 18. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

b. Major safety-related components in fire area:

1. Class 1E 4 kV switchgear 20A115 (Div. 1)

2. Class 1E dc distribution panel 2AD102 (Div. 1)

3. Class 1E instrument ac distribution panel 20Y101 (Div. 1)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 19 contains safe shutdown cables and equipment.

Cables associated with shutdown methods B and C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods B and C for Unit 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and methods B and C will be available to shutdown Unit 2.

f. Deviations:

The unrated wall penetration assemblies associated with the 4kV non-segregated phase bus ducts are a deviation from the requirements of CMEB 9.5-1, C.5.b. See section 9A.6.3. The concrete masonry unit wall designated with a "^" has penetrating steel beams that are a deviation from BTP CMEB 9.5-1, C.5.a(1)(b). See section 9A.6.6.

9A.5.3.20 Fire Area 20: Unit 1 Static Inverter Compartment (el 254'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Reinforced concrete	2 hr
	E - Concrete masonry unit	3 hr
	S - Reinforced concrete	3 hr
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete	3 hr
Ceiling:	Reinforced concrete	3 hr
Access:	Two doors connecting to area 22	3 hr
	Door providing access to panel 1BD102	3 hr

b. Major safety-related components in fire area:

1. 125 V dc power distribution panels 1BD102 (Div. 2) and 1DD102 (Div. 4)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, and excessive heat in the enclosure around 1BD102 will activate the heat detector, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 20 contains safe shutdown cables and equipment.

Cables required to support shutdown methods B and C for Units 1 and 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods B and C for Units 1 and 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Panel 1BD102 is enclosed by a 3-hour rated enclosure and is available for safe shutdown.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods B and C will be available to shutdown Units 1 and 2.

9A.5.3.21 Fire Area 21: Unit 2 Static Inverter Compartment (el 254'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
	W - Concrete masonry unit	3 hr
Floor:	Reinforced concrete	3 hr

Ceiling:	Reinforced concrete	3 hr
Access:	Two doors connecting to area 23	3 hr
	Steamtight door connecting to area 113	3 hr

b. Major safety-related components in fire area:

1. 125 V dc power distribution panels 2BD102 (Div. 2) and 2DD102 (Div. 4)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 21 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A and C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods A and C for Unit 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and methods A and C will be available to shutdown Unit 2.

9A.5.3.22 Fire Area 22: Unit 1 Cable Spreading Room (el 254'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Concrete masonry unit	3 hr
	S - Reinforced concrete	3 hr
	W - Reinforced concrete (part)	3 hr
	W - Concrete masonry unit (part)	3 hr
Floor:	Reinforced concrete	3 hr
Ceiling:	Reinforced concrete	3 hr
Access:	Two doors connecting to area 20	3 hr
	Doors connecting to area 23 and stairwell no. 7	3 hr

b. Major safety-related components in fire area:

1. Cabling for Division 1, 2, 3, and 4 safeguard equipment (in cable tray, gutter, and conduit)

2. Cabling for Division A1, A2, B1, and B2 of the RPS (in cable tray)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire. If the compartment temperature rises to 212°F, individual sprinkler heads in the wet pipe sprinkler system will open to control and/or extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 22, the Unit 1 cable spreading room, contains safe shutdown cables associated with shutdown methods A, B, and C for Units 1 and 2 but does not contain safe shutdown equipment.

Alternative shutdown capabilities are available via the use of transfer/isolation and control switches on the remote shutdown panel and other local control stations as well as manual operator actions.

Offsite power cannot be credited for alternative shutdown.

Therefore, method R will be available to shutdown Units 1 and 2.

9A.5.3.23 Fire Area 23: Unit 2 Cable Spreading Room (el 254'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Concrete masonry unit	3 hr
	S - Reinforced concrete	3 hr
	W - Concrete masonry unit	3 hr
Floor:	Reinforced concrete	3 hr
Ceiling:	Reinforced concrete	3 hr
Access:	Two doors connecting to area 21	3 hr
	Door connecting to area 23	3 hr

b. Major safety-related components in fire area:

1. Cabling for Division 1, 2, 3, and 4 safeguard equipment (in cable tray, gutter, and conduit)

2. Cabling for Division A1, A2, B1, and B2 of the RPS (in cable tray)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire. If the compartment temperature rises to 212°F, individual sprinkler heads in the wet pipe sprinkler system will open to control and/or extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 23, the Unit 2 cable spreading room, contains safe shutdown cables associated with shutdown methods A, B, and C for Units 1 and 2 but does not contain safe shutdown equipment.

Alternative shutdown capabilities are available via the use of transfer/isolation and control switches on the remote shutdown panel and other local control stations as well as manual operator actions.

Offsite power cannot be credited for alternative shutdown.

Therefore, method R will be available to shutdown Units 1 and 2.

9A.5.3.24 Fire Area 24: Control Room and Peripheral Rooms (el 269'-0")

a. Structural and architectural design features of fire area (Figure 9A-8):

	Construction	Rating
Walls:	N - Reinforced concrete (part adjacent to stairwell no. 7)	2 hr
	N - Reinforced concrete (part)	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
	W - Reinforced concrete (part)	3 hr
	W - Reinforced concrete (part adjacent to stairwell no. 7)	2 hr
Floor:	Reinforced concrete	3 hr
Ceiling:	Reinforced concrete	3 hr
Access:	Two steamtight doors connecting to area 114	3 hr**

b. Safety-related components in fire area:

Safety-related control panels as listed below are located in the control room.

Unit 1 Panels

10C600	Radiation monitoring Containment combustible gas analyzer (Div. 3 & 4)
10C601	RHR (Div. 1, 2, 3, 4) CS (Div. 1, 2, 3, 4) MSIVs (Div. 1, 2, 3, 4) Reactor pressure and level (Div. 1 & 2) CAC system (Div. 1, 2, 3, 4)
10C602	RWCU (Div. 1 & 2) Reactor recirculation system Reactor head vent valves Drywell floor and equipment drain sumps
10C603	Reactor control (Div. 1, 2, 3, 4)
10C614	NSSS temperature recorder and leak detection
10C626	ADS (Div. 1 & 3)

	Suppression pool temperature monitoring (Div. 1 & 2)
10C647	HPCI (Div. 2 & 4)
10C648	RCIC (Div. 1 & 3)
10C651	Feedwater, condensate, and turbine (Div. 1, 2, 3)
10C668	Feedwater (Div. 1)
10C669	Condensate (Div. 1)
10C681	Reactor enclosure HVAC (Div. 1 & 2)
1AC661	Safeguard ac power supply (Div. 1)
1BC661	Safeguard ac power supply (Div. 2)
1CC661	Safeguard ac power supply (Div. 3)
1DC661	Safeguard ac power supply (Div. 4)
1AC696	Containment hydrogen recombiner package "A" (Div. 1)
1BC696	Containment hydrogen recombiner package "B" (Div. 2)
Unit 2 Panels	
20C600	Radiation monitoring Containment combustible gas analyzer (Div. 3 & 4)
20C601	RHR (Div. 1, 2, 3, 4) CS (Div. 1, 2, 3, 4) MSIVs (Div. 1, 2, 3, 4) Reactor pressure and level (Div. 1 & 2) CAC system (Div. 1, 2, 3, 4)
20C602	RWCU (Div. 1 & 2) Reactor recirculation system Reactor head vent valves Drywell floor and equipment drain sumps
20C603	Reactor control (Div. 1, 2, 3, 4)
20C614	NSSS temperature recorder and leak detection
20C626	ADS (Div. 1 & 3) Suppression pool temperature monitoring (Div. 1 & 2)

20C647	HPCI (Div. 2 & 4)
20C648	RCIC (Div. 1 & 3)
20C651	Feedwater, condensate, and turbine (Div. 1, 2, 3)
20C668	Feedwater (Div. 1)
20C669	Condensate (Div. 1)
20C681	Reactor enclosure HVAC (Div. 1 & 2)
2AC661	Safeguard ac power supply (Div. 1)
2BC661	Safeguard ac power supply (Div. 2)
2CC661	Safeguard ac power supply (Div. 3)
2DC661	Safeguard ac power supply (Div. 4)
2AC696	Containment hydrogen recombiner package "A" (Div. 1)
2BC696	Containment hydrogen recombiner package "B" (Div. 2)

Common Panels

0AC667	ESW and RHRSW (Div. 1)
0BC667	ESW and RHRSW (Div. 2)
0CC667	ESW and RHRSW (Div. 3)
0DC667	ESW and RHRSW (Div. 4)
00C681	Control structure HVAC (Div. 3 & 4) Spray pond pump structure HVAC (Div. 1, 2, 3, 4)
00C691	Control room normal fresh air radiation monitoring (Div. 3 & 4) Control room emergency fresh air radiation monitoring (Div. 3 & 4) Containment area radiation monitoring (Div. 2 & 3)
00C692	Suppression pool temperature monitoring (Div. 1 & 2)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray, gutter, or control panels. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The raceways and control panels in the control room have been designed to incorporate divisional separation in order to maintain the independence of redundant divisions of safety-related cables and electrical devices. Considering the absence of combustibles which could contribute to an exposure fire in this area, the separation is adequate to prevent an electrical fire in one division of cabling from propagating and affecting a redundant division.

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. The operator will then bring the plant fire brigade to manually extinguish the fire. An electrical fire occurring in any of the control room panels will generate substantial quantities of smoke with an acrid odor, thereby ensuring immediate detection and location of such a panel fire.

e. Effect of fire on safe shutdown:

Fire area 24, the main control room, contains safe shutdown cables and equipment associated with shutdown methods A, B, and C for Units 1 and 2.

Alternative shutdown capabilities are available via the use of transfer/isolation and control switches on the remote shutdown panel and other local control stations as well as manual operator actions.

Offsite power cannot be credited for alternative shutdown.

Therefore, method R will be available to shutdown Units 1 and 2.

f. Deviations:

Carpeting installed in the Main Control Room that has been tested in accordance with NFPA or ASTM standards to assure minimum critical radiant heat flux values does not create a fire hazard in the area. See Section 9A.3.1.2, Item 190.

The peripheral rooms in the control room complex do not have automatic water suppression; however, incipient detection is provided and manual fire fighting capabilities are provided. Additionally, the entrance doors to the main control room peripheral rooms are kept open as it has been shown that they do not perform any credited barrier function. See Section 9A3,1.2, Item 179.

9A.5.3.25 Fire Area 25: Auxiliary Equipment Room (el 289'-0")

a. Structural and architectural design features of fire area (Figure 9A-8):

	Construction	Rating

Walls:	N - Reinforced concrete (part)	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
	W - Reinforced concrete (part)	3 hr
	W - Reinforced concrete (part adjacent to stairwell no. 7)	2 hr
	W - Gypsum board (part adjacent to fire area 26)	3 hr
Floor:	Reinforced concrete	3 hr
Ceiling:	Reinforced concrete	3 hr
Access:	Door connecting to stairwell no. 7	1.5 hr
	Steamtight door connecting to area 111	3 hr
	Door connecting to area 26	3 hr **

b. Major safety-related components in fire area:

Figure 9A-21 shows the locations of all panels, consoles, and vertical boards in the auxiliary equipment room. Those panels that are associated with the shutdown methods described in Section 9A.5.2.2 are identified in the figure.

The safety-related components located in the auxiliary equipment room consist mainly of the PGCC for Unit 1 and Unit 2. The PGCC for each unit consists of vertical boards mounted on raised floor sections, with a termination cabinet located at one end of each floor section. The safety-related portions of the PGCC are identified in the following listing. The listing applies specifically to Unit 1, but the Unit 2 PGCC is identical.

Floor Section & Terminating Cabinet	Vertical Board	
10U791 & 10C791	10C617	RHR and CS (Div. 1)
	10C640	RHR and CS (Div. 3)
	10C621	RCIC
	10C628	ADS (Div. 1)
	10C631	ADS (Div. 3)
10U792 & 10C792	10C618	RHR and CS (Div. 2)
	10C641	RHR and CS (Div. 4)
	10C620	HPCI
	10C613	Process instrumentation (Div. 2 & 4)
10U786	10C634	RRCS logic cabinet (Div. 1)
	10C635	RRCS logic cabinet (Div. 2)

10U787 & 10C787	10C608	Power range neutron monitoring
10U788 & 10C788	10C619	Jet pump instrumentation
	10C623	Outboard containment isolation valves
10U789 & 10C789	10C606	Startup range neutron monitoring "A"
	10C609	RPS channel A
10U790 & 10C790	10C633	Startup range neutron monitoring "B"
	10C611	RPS channel B
	10C646	Nuclear boiler system
10U793 & 10C793	10C622	Inboard containment isolation valves
	10C612	Feedwater and reactor recirculation instrumentation (Div. 1 & 3)

The PGCC and the computer facilities, both of which are located in the auxiliary equipment room, utilize raised flooring approximately 1 foot high. The raised flooring is divided into sections typically 8 feet wide and approximately 20 feet long; PGCC panels or computer equipment are mounted near the center of each floor section. The floor sections are of all-steel construction (except for the floor plates, which are aluminum) and are each divided into four longitudinal raceways and numerous lateral raceways, each of which is totally enclosed and therefore physically isolated from adjacent raceways. To minimize the possibility of occurrence of a fire, the cabling routed in these raceways is provided with flame retardant insulation, and no other combustible material exists in the floor sections. The highest voltages present within the floor sections are 125 V dc and 120 V ac. To prevent the spread of a postulated fire between different divisions of raceways within a floor section or between adjacent floor sections, fire stops are provided at the ends of the longitudinal raceways, at the ends of those lateral raceways which do not have end caps, in the lateral raceways where cables run from a longitudinal to a lateral raceway, and at the raceway openings at the bottom of the vertical panels. These fire stops consist of refractory material covered by silicone rubber.

The GE licensing topical report NEDO-10466-A, "Power Generation Control Complex Design Criteria and Safety Evaluation" (February 1979), describes the design concepts for the construction of the PGCC components, their arrangement within the PGCC, and the routing of interpanel cabling. The report includes test data that demonstrates the adequacy of the design with regard to fire protection. Additionally, a safety evaluation is provided which addresses NRC and industry safety guidelines and demonstrates design compliance.

A detailed comparison has been made between the design of the LGS PGCC and the design description of the generic PGCC contained in NEDO-10466-A. In all areas that could have an impact on fire protection capability (such as fire resistance, separation features, fire detection, and fire suppression), it was verified that the LGS design is either identical or equivalent to the design described in NEDO-10466-A.

The LGS design floor plates are constructed of aluminum honeycomb core bonded between aluminum sheet metal. The bottom skin is also covered by aluminum coated, steel sheet metal. This provides magnetic shielding and an optimum strength to weight

ratio. The top surface of each plate is covered in an aesthetic tile that meets the following requirements:

- Flame spread rating < 25 per ASTM E84.
- Critical radiant flux > 0.45 watts /sq.cm. per NFPA 253.

Each individual floor plate is lightweight and can be easily removed by one person using the installed, recessed, quick-disconnect fasteners. The LGS design has been determined to be equivalent to the design described in NEDO-10466-A.

The RPS and UPS power distribution panels (1AY160 and 1BY160 for Unit 1; 2AY160 and 2BY160 for Unit 2), which are not safety-related, are also located in the auxiliary equipment room.

In addition to the cabling routed through the raised flooring of the auxiliary equipment room, cables associated with safety-related systems are routed in conduits, gutter, and cable tray through the space above the raised flooring.

c. Postulated fire in area:

Ignition of electrical cabling in cable tray, termination cabinets, raised flooring, or vertical boards. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.) An electrical fire occurring within any of these enclosures or raceways is precluded from affecting two redundant shutdown methods simultaneously, through implementation of the electrical separation criteria presented in Section 8.1.6.1.14.

An exposure fire due to transient combustibles in the auxiliary equipment room would not prevent safe shutdown from being achieved for both units of the plant. A liquid combustible spilled onto the surface of the raised floor sections would flow through the cracks between adjacent floor plates, down into the longitudinal raceways of the floor sections. The heat detectors in the floor sections would detect the fire and initiate operation of the Halon suppression system, thereby extinguishing the fire promptly.

An exposure fire involving solid transient combustibles would be extremely limited in scope and confined to a small area due to the lack of available floor space in the auxiliary equipment room. The smoke detectors below the ceiling would detect the fire promptly and annunciate in the control room. The fire brigade would then be dispatched to extinguish the fire.

d. Consequences of fire with active fire suppression:

The raceways, raised flooring, termination cabinets, and vertical boards in the auxiliary equipment room have been designed to incorporate divisional separation in order to maintain the independence of redundant divisions of safety- related cables and electrical devices. The only fire potential in this area is ignition of cable insulation due to electrical faulting. Since the majority of the cables in the area involve low voltage instrument and control circuits, overload protection is provided, and cable insulation is flame retardant, this potential source of fire is minimal.

Particular attention has been given to minimizing the potential for fire and maximizing divisional separation in the PGCC and associated facilities. Considering the absence of combustibles which could contribute to an electrical fire in this area, the separation is adequate to prevent a fire in one division of cabling from propagating and affecting a redundant division.

Smoke detectors are located inside each of the termination cabinets and floor sections in the auxiliary equipment room to provide early warning of fires originating in these components. Additional fire detectors are located near the ceiling, to provide early warning of fires originating outside the termination cabinets and floor sections. Activation of any of the above smoke detectors will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire. A local panel is provided to identify the floor section in which smoke has been detected. In the event that a fire in the floor sections is not extinguished by fire brigade response, heat detectors in the floor sections will activate the Halon extinguishing system. The Halon system is described in Section 9A.2.9.

e. Effect of fire on safe shutdown:

Fire area 25 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Units 1 and 2 are either: encapsulated by a qualified fire barrier, associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Units 1 and 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, method C will be available to shutdown Units 1 and 2.

For a fire in the auxiliary equipment room, manual operator actions at the remote shutdown panel may be required. Ventilation air for the remote shutdown room is provided by duct-work that passes through the auxiliary equipment room. The air supply duct for the remote shutdown room does not contain any diffusers within the auxiliary equipment room. However, the air exhaust duct from the remote shutdown room includes two registers that exhaust air from the auxiliary equipment room. The auxiliary equipment room HVAC system, which serves the remote shutdown room as well as the auxiliary equipment room, normally operates in the recirculation mode. When a fire in the auxiliary equipment room is confirmed, the HVAC supply and exhaust smoke dampers for the remote shutdown room are closed minimizing the leakage of smoke into the remote shutdown room. In addition, special features of the walls between the remote shutdown room and the auxiliary equipment room will minimize the infiltration of smoke into the remote shutdown room. The potential smoke infiltration paths in those walls have been sealed, including installation of gaskets on both of the access doors into the remote shutdown room.

During initial plant licensing, the NRC had a concern that a fire in the auxiliary equipment room (AER) could affect plant safe shutdown actions and habitability in the remote shutdown panel room due to smoke infiltration through the HVAC ductwork. In Limerick SER, Supplement 2, Section 9.5.1.4.2 titled "Safe Shutdown Capability," PECO committed to modify the HVAC system so that the remote shutdown panel (RSP) room is maintained at a positive pressure, thereby preventing the infiltration of smoke.

In 1989, it was determined that the AER HVAC may be disabled during the postulated AER fire, and therefore could not maintain the RSP room at a positive pressure to prevent smoke infiltration.

To address this concern and commitment to minimize smoke infiltration into the RSP room, qualified manually operated smoke dampers were installed in the HVAC ductwork and all potential smoke infiltration paths in the RSP room walls have been sealed, including installation of gaskets on both of the access doors into the remote shutdown room. The fire brigade will manually isolate the dampers after verification of a fire in the AER. The dampers can also be manually isolated during plant remote shutdown if smoke is entering the RSP room through ventilation ducts due to a fire. The NRC reviewed the final configuration prior to Unit 2 fuel loading and found it acceptable. Reference Bechtel Letter to PECO #47554, NRC Inspection Report 50-352/89-12 and 50-353/89-19, LER 1-89-039, Letter from PECO to NRC dated June 30, 1989, Letter from PECO to NRC dated June 2, 1989, and NRC Inspection Report 50-352/90-04.

9A.5.3.26 Fire Area 26: Remote Shutdown Room (el 289'-0")

a. Structural and architectural design features of fire area (Figure 9A-8):

	Construction	Rating
Walls:	N - Reinforced concrete (part adjacent to stairwell no. 7)	3 hr
	E - Gypsum board	3 hr
	S - Gypsum board	3 hr
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete	3 hr
Ceiling:	Reinforced concrete	3 hr
Access:	Door connecting to stairwell no. 7	3 hr
	Door connecting to area 25	3 hr **

b. Major safety-related components in fire area:

1. Remote shutdown panel 10C201 (for Unit 1)

2. Remote shutdown panel 20C201 (for Unit 2)

c. Postulated fire in area:

Ignition of electrical cabling in raceways, raised flooring, or the remote shutdown panels. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.) An electrical fire occurring within these raceways or enclosures is precluded from affecting two redundant divisions of circuitry simultaneously, through implementation of the electrical separation criteria presented in Section 8.1.6.1.14.

An exposure fire due to transient combustibles in the remote shutdown room would not prevent safe shutdown from being achieved for both units of the plant. Damage to the remote shutdown panels due to an exposure fire would be either extremely limited or nonexistent because of the provisions described below.

Access to the remote shutdown panels is restricted by a woven wire partition that divides the remote shutdown room into two portions, as shown in Figure 9A-21. Access to the aisle-ways at the front and back sides of the remote shutdown panels can be gained only through locked doorways in the woven wire partition. The portion of the remote shutdown room that is outside the partition consists of only a short corridor that leads from stairwell no. 7 to fire area 25 (the auxiliary equipment room). This partition will prevent transient combustibles from being stored or transported in close proximity to the remote shutdown panels. The only portion of fire area 26 in which transient combustibles can be assumed to exist is the portion outside the partition. Any liquid combustible spilled onto the surface of the raised floor sections would flow through the cracks between adjacent floor plates, down into the raised flooring. The heat detectors in the raised flooring would detect the fire and initiate operation of the Halon suppression system, thereby extinguishing the fire promptly. Any solid combustible material would be located outside the woven wire partition and be of limited size due to the space constraints of the area.

d. Consequences of fire with active fire suppression:

Smoke detectors are located within the raised flooring of the remote shutdown room to provide early warning of fires originating in the raised flooring. Additional smoke detectors are located near the ceiling, to provide early warning of fires originating above the raised flooring. Activation of any of the above smoke detectors will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire. A local panel is provided to identify the floor section in which smoke has been detected. In the event that a fire in the raised flooring is not extinguished by fire brigade response, heat detectors in the raised flooring will activate the Halon extinguishing system. The Halon system is described in Section 9A.2.9.

e. Effect of fire on safe shutdown:

Fire area 26 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Units 1 and 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Units 1 and 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods C will be available to shutdown Units 1 and 2.

9A.5.3.27 Fire Area 27: Control Structure Fan Room (el 304'-0")

a. Structural and architectural design features of fire area (Figure 9A-9):

	Construction	Rating
Walls:	N - Reinforced concrete (parts adjacent to stairwell nos. 7 and 8)	2 hr
	N - Reinforced concrete (part)	3 hr
	E - Reinforced concrete (part adjacent to stairwell no. 8)	2 hr
	E - Reinforced concrete (part)	3 hr
	S - Reinforced concrete	3 hr
	W - Reinforced concrete (part)	3 hr
	W - Reinforced concrete (part adjacent to stairwell no. 7)	2 hr
Floor:	Reinforced concrete	3 hr
Ceiling:	Reinforced concrete	3 hr*
Access:	Doors connecting to stairwell nos. 7 and 8	1.5 hr
	Double steamtight door connecting to area 99	3 hr**
	Steamtight doors connecting to areas 99 and 112	3 hr
	Equipment hatch in ceiling (filled with 95 ft^2 of steel plate)	None

b. Major safety-related components in fire area:

1. HVAC 120 V ac distribution panel 10Y206 (Div. 1), which serves the following components:
   (a) Diesel generator enclosure HVAC control panel 1AC563
   (b) RHRSW radiation monitor 0AS578
   (c) Control structure HVAC local panel 0CC101
   (d) SGTS control panel 0AC124
   (e) RERS control panel 10C207
   (f) Reactor enclosure differential pressure panel 1AC253
   (g) Refueling area differential pressure panel 0AC254

2. HVAC 120 V ac distribution panel 10Y207 (Div. 2), which serves the following components:
   (a) RHRSW radiation monitor 0BS578

(b) Control structure HVAC local panel 0CC101
(c) SGTS control panel 0BC124
(d) RERS control panel 10C207
(e) Reactor enclosure differential pressure panel 1BC253
(f) Refueling area differential pressure panel 0BC254

3. HVAC 120 V ac distribution panel 10Y163 (Div. 3), which serves the following components:
   (a) Diesel generator enclosure HVAC control panel 1CC563
   (b) DELETED
   (c) Control structure HVAC local panel 0AC101
   (d) SGTS control panel 0CC124
   (e) Containment combustible gas analyzer package 10S206
   (f) ESW control valve XC-11-053A (for control structure chiller "A")
   (g) Control structure chilled water control valves XC-90-042A, XC-90-043A, and XC-90-044A
   (h) Containment combustible gas analyzer heat tracing panel 10C902

4. HVAC 120 V ac distribution panel 10Y164 (Div. 4), which serves the following components:
   (a) Diesel generator enclosure HVAC control panel 1DC563
   (b) DELETED
   (c) Control structure HVAC local panel 0BC101
   (d) SGTS control panel 0CC124
   (e) Containment combustible gas analyzer 10S205
   (f) ESW control valve XC-11-053B (for control structure chiller "B"
   (g) Control structure chilled water control valves XC-90-042B, XC-90-043B, and XC-90-044B
   (h) Containment combustible gas analyzer heat tracing panel 10C901

5. HVAC 120 V ac distribution panel 20Y207 (Div. 2), which serves the following components:
   (a) Diesel generator enclosure HVAC control panel 2BC563
   (b) Control structure HVAC local panel 0CC101
   (c) RERS control panel 20C207
   (d) Reactor enclosure differential pressure panel 2BC253

6. HVAC 120 V ac distribution panel 20Y164 (Div. 4), which serves the following components:
   (a) Diesel generator enclosure HVAC control panel 2DC563
   (b) Deleted
   (c) Containment combustible gas analyzer package 20S205
   (d) Containment combustible gas analyzer heat tracing panel 20C901

7. Motor control center 00B131 (Div. 3), which serves the following components:
   (a) HVAC 120 V ac distribution panel 10Y163
   (b) Control room emergency supply air fan (0AV127) and intake heater (0AE191)
   (c) Control room emergency air intake isolation valve HV-78-020C
   (d) Control room air supply fan cabinet (0AV116) and heater (0AE192)
   (e) Control room return air fan 0AV121

(f) Auxiliary equipment room supply air fan cabinet (0AV114) and heater (0AE193)
(g) Auxiliary equipment room return air fan 0AV120
(h) Emergency switchgear and battery room supply air fan cabinet 0AV118
(i) Control structure chilled water pump (0AP162), oil pump (0AP168), pump-out compressor (0AK114)

8. Motor control center 00B132 (Div. 4), which serves the following components:
(a) HVAC 120 V ac distribution panel 10Y164
(b) Control room emergency supply air fan (0BV127) and intake heater (0BE191)
(c) Control room emergency air intake isolation valve HV-78-020D
(d) Control room air supply fan cabinet (0BV116) and heater (0BE192)
(e) Control room return air fan 0BV121
(f) Auxiliary equipment room supply air fan cabinet (0BV114) and heater (0BE193)
(g) Auxiliary equipment room return air fan 0BV120
(h) Emergency switchgear and battery room supply air fan cabinet 0BV118
(i) Control structure chilled water pump (0BP162), oil pump (0BP168), and pump-out compressor (0BK114)

9. Control structure HVAC local panels 0AC101, 0BC101, 0CC101, and 0DC101

10. Auxiliary equipment room supply air fan cabinets OAV114 and OBV114

11. Control room supply air fan cabinets OAV116 and OBV116

12. Auxiliary equipment room return air fans OAV120 and OBV120

13. Control room return air fans OAV121 and OBV121 (14) Control room emergency fresh air supply fans and filter trains OAV127 and OBV127

c. Postulated fire in area:

Ignition of charcoal filters.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished. In the event of a fire in one of the control room emergency fresh air filters, a heat detector inside the filter plenum will cause an audible/visual annunciation to register on the fire protection panels. The fire brigade will utilize a manual valve in the fire protection water supply system to initiate operation of a water spray system inside the filter plenum.

The preaction sprinkler system in this area has been installed to provide protection against an exposure fire hazard. Other than the charcoal filters, which have their own water spray

systems, electrical cable insulation and jacketing constitutes the only in situ combustible material in the fire area. The insulation and jacketing is qualified in accordance with the IEEE 383 flame test requirements, and is present in such a small quantity that it constitutes a low combustible loading. The cable trays in this area are located at approximately the same elevation as the sprinkler heads. The sprinkler heads are provided with heat collecting shields to ensure prompt actuation in the event of a fire.

e. Effect of fire on safe shutdown:

Fire area 27 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A and C for Unit 1 and shutdown method C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A and C for Unit 1 and shutdown method C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Unit 1, and method C will be available to shutdown Unit 2.

f. Deviations

The existence of an equipment hatch with unrated steel panels in the ceiling of this fire area is acceptable because of the low combustible loadings in the areas above and below the equipment hatch, the low potential for transient combustibles in these areas, and the height of the equipment hatch above the floor (28 feet). These factors minimize the possibility of fire propagating through the equipment hatch. Penetrations of piping and electrical raceway through the ceiling are provided with 3 hour rated seals.

In the highly unlikely event that a fire in this area should propagate through the equipment hatch in the slab at elevation 332', safe shutdown capability would still be assured. Fire area 27 and fire area 28 both credit methods A and C for safe shutdown of Unit 1. Fire area 27 and fire area 28 both credit method C for safe shutdown of Unit 2.

The equipment hatch with unrated steel panels is a deviation from the requirements of CMEB 9.5-1, C.5.b. Although the steel panels are unrated, safe shutdown requirements are met in that safe shutdown can be achieved even with the unlikely failure of the unrated barriers.

The existence of an equipment hatch with unrated steel panels in the floor of this fire area is acceptable because of the low combustible loadings in the areas above and below the equipment hatch, the low potential for transient combustibles in these areas, and the height of the equipment hatch above the floor (28 feet) of the fire area below. These factors minimize the possibility of fire propagating through the equipment hatch. Penetrations of piping and electrical raceway through the floor are provided with 3 hour rated seals.

In the highly unlikely event that a fire in this area should propagate through the equipment hatch in the slab at elevation 332', safe shutdown capability would still be assured. Fire area 27 and fire area 28 both credit methods A and C for safe shutdown of Unit 1. Fire area 27 and fire area 28 both credit method C for safe shutdown of Unit 2.

The equipment hatch with unrated steel panels is a deviation from the requirements of CMEB 9.5-1, C.5.b. Although the steel panels are unrated, safe shutdown requirements are met in that safe shutdown can be achieved even with the unlikely failure of the unrated barriers.

9A.5.3.28 Fire Area 28: SGTS Filter Compartments and Access Area (el 332'-0")

a. Structural and architectural design features of fire area (Figure 9A-10):

	Construction	Rating
Walls:	N - Reinforced concrete (exterior wall, also contains louver openings)	None
	N - Reinforced concrete (parts adjacent to stairwell nos. 7 and 8)	2 hr
	E - Reinforced concrete (part adjacent to stairwell no. 8)	2 hr
	E - Reinforced concrete (part adjacent to fire area 69)	3 hr
	E - Reinforced concrete (part, exterior wall)	None
	S - Reinforced concrete	3 hr
	W - Reinforced concrete (part, exterior wall)	None
	W - Reinforced concrete (part adjacent to fire area 46)	3 hr
	W - Reinforced concrete (part adjacent to stairwell no. 7)	2 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete (roof slab)	None
Access:	Two doors connecting to stairwell no. 7	1.5 hr
	Door connecting to stairwell no. 8	1.5 hr
	Steamtight doors connecting to areas 46 and 69	3 hr
	Equipment hatch in floor (filled with 95 ft^2 of steel plate)	None

b. Major safety-related components in fire area:

1. SGTS filters
   Train A: 0AF169, 0AF170, 0AF183

Train B: 0BF169, 0BF170, 0BF183

2. SGTS exhaust fans 0AV109 and 0BV109

3. SGTS local control panels 0AC124, 0BC124, 0CC124, 0DC124

4. HVAC 120 V ac distribution panel 20Y206 (Div. 1), which serves the following components:
   (a) Diesel generator enclosure HVAC control panel 2AC563
   (b) Control structure HVAC local panel 0CC101
   (c) RERS control panel 20C207
   (d) Reactor enclosure differential pressure panel 2AC253

5. HVAC 120 V ac distribution panel 20Y163 (Div. 3), which serves the following components:
   (a) Diesel generator enclosure HVAC control panel 2CC563
   (b) DELETED
   (c) Containment combustible gas analyzer package 20S206
   (d) Containment combustible gas analyzer heat tracing panel 20C902

c. Postulated fire in area:

Ignition of charcoal filters.

d. Consequences of fire with active fire suppression:

In the event of a fire in one of the SGTS filters, a thermal sensor inside the filter plenum will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire. The fire brigade will utilize a manual valve in the fire protection water supply system to initiate operation of a water spray system inside the filter plenum.

e. Effect of fire on safe shutdown:

Fire area 28 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A , B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.4 SAFE SHUTDOWN ANALYSIS - UNIT 1 REACTOR ENCLOSURE

9A.5.4.1 Fire Area 29: Suppression Chamber (el 181'-11")

a. Structural and architectural design features of fire area (Figures 9A-4, 9A-5, and 9A-6):

	Construction	Rating
Walls:	All around - Reinforced concrete (primary containment wall)	None
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete (diaphragm slab)	None
Access:	Two access hatches connecting to area 44	None

b. Major safety-related components in fire area:

1. Primary containment vacuum relief valve assemblies PSV-57-137 A, B, C & D

c. Postulated fire in area:

Since there are no combustible materials located in this area, no fire is postulated to occur.

d. Consequences of fire with active fire suppression:

Not applicable (see item (c)).

e. Effect of fire on safe shutdown:

Fire area 29 contains safe shutdown cables and equipment.

During normal operation, primary containment is inerted. Since containment is inerted no fire is postulated.

9A.5.4.2 Fire Area 30: Drywell (el 237'-11")

a. Structural and architectural design features of fire area (Figures 9A-7, 9A-8, and 9A-9):

	Construction	Rating
Walls:	All around - Reinforced concrete (primary containment wall)	None
Floor:	Reinforced concrete (diaphragm slab)	None
Ceiling:	Steel dome (drywell head)	None

Access:	Equipment hatch connecting to area 45	None
	Equipment hatch with personnel lock connecting to area 45	None

b. Major safety-related components in fire area:

1. CRDM (total of 185)

2. MSIV (inboard, one per steam line)

3. MSRV (total of 14)

4. Drywell unit coolers (total of 8)

5. Inboard containment isolation valves for HPCI steam supply line, RCIC steam supply line, RWCU letdown line, and RHR shutdown cooling suction line

c. Postulated fire in area:

1. Leakage of lube oil from a recirculation pump motor onto the diaphragm slab, with subsequent ignition of the oil.

2. Ignition of electrical cabling in cable tray, gutter or direct supported metal clad cable.

3. Ingnition of non-scheduled electrical cabling.

d. Consequences of fire with active fire suppression:

The possibility of a fire in the drywell is limited to periods when the reactor is shut down. This is because the primary containment is inerted with nitrogen during reactor operation, so that the oxygen concentration is maintained below 4% by volume. This inert atmosphere will prevent fires from occurring in the primary containment during reactor operation.

In the event of a fire in the drywell while the reactor is shut down and the drywell deinerted, the operator will dispatch the plant fire brigade to el 253' in the reactor enclosure. The fire brigade will enter the drywell through the personnel airlock and will ensure extinguishment of the fire through the use of portable fire extinguishers or hoses from hose stations located outside the entrances to the drywell.

e. Effect of fire on safe shutdown:

Fire area 30 contains safe shutdown cables and equipment.

During normal operation, primary containment is inerted. Since containment is inerted, no fire is postulated.

9A.5.4.3 Fire Area 31: Residual Heat Removal Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	NW - Reinforced concrete (primary containment wall)	None
	N - Reinforced concrete	3 hr
	E - Reinforced concrete (part below el 201', exterior wall)	None
	E - Reinforced concrete (part above el 201')	3 hr
	S - Reinforced concrete (part below el 198', exterior wall)	None
	S - Reinforced concrete (part above el 198')	3 hr
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete (ceiling contains 115 ft^2 of unrated metal blowout panels leading to area 43)	None
Access:	Watertight doors connecting to areas 32 and 39	3 hr**
	Steamtight doors (el 201') connecting to areas 32 and 41	3 hr

b. Major safety-related components in fire area:

1. RHR pumps 1BP202 and 1DP202

2. RHR heat exchanger 1BE205

3. RHR compartment unit coolers 1BV210, 1DV210, 1FV210, and 1HV210

c. Postulated fire in area:

Leakage of lube oil from both RHR pump motors onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 31 contains safe shutdown cables and equipment.

Cables required to support shutdown method B for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method B for Unit 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods A and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Unit 1, and methods A, B, and C will be available to shutdown Unit 2.

f. Deviations:

The existence of unrated metal panels in the ceiling of this fire area is acceptable because the low combustible loadings in the areas above and below the panels and the height of the panels above the floor (40 feet) minimize the possibility of fire propagating through the panels. Penetrations of piping and electrical raceway through the ceiling are provided with 3 hour rated seals.

In the highly unlikely event that a fire in this area should propagate through the metal panels in the ceiling at elevation 217', safe shutdown capability would still be assured. Fire area 31 and the eastern portion of fire area 43 both credit method C for safe shutdown of Unit 1. The only exception is the need in the eastern portion of fire area 43 to use the Remote Shutdown Panel suppression pool temperature indicator TI-41-102. Although main control room indication is credited for a fire which is contained within fire area 31, the RSP indicator would also be available. The unlikely propagation of a fire through the metal panels does not impact safe shutdown of Unit 2.

The unrated metal panels are a deviation from the requirements of CMEB 9.5-1, C.5.b. Although the metal panels are unrated, safe shutdown requirements are met in that safe shutdown can be achieved even with the unlikely failure of the unrated barriers.

9A.5.4.4 Fire Area 32: Residual Heat Removal Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	W - Reinforced concrete	3 hr
	NW - Reinforced concrete	3 hr
	NE - Reinforced concrete (primary containment wall)	None
	E - Reinforced concrete	3 hr

	S - Reinforced concrete (part below el 198', exterior wall)	None
	S - Reinforced concrete (part above el 198')	3 hr
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete (ceiling contains 150 ft^2 of unrated metal blowout panels leading to area 43)	None
Access:	Watertight doors connecting to areas 31 and 33	3 hr**
	Steamtight doors (el 201') connecting to areas 31 and 42	3 hr

b. Major safety-related components in fire area:

1. RHR pumps 1AP202 and 1CP202

2. RHR heat exchanger 1AE205

3. RHR compartment unit coolers 1AV210, 1CV210, 1EV210, and 1GV210

4. ESW loop "A" valves (HV-11-041, HV-11-071, HV-11-121, and HV-11-123)

c. Postulated fire in area:

Leakage of lube oil from both RHR pump motors onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 32 contains safe shutdown cables and equipment.

Cables required to support shutdown method A for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method A for Unit 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods B and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods B and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods B and C will be available to shutdown Unit 1, and methods A, B, and C will be available to shutdown Unit 2.

f. Deviations:

The existence of unrated metal panels in the ceiling of this fire area is acceptable because the low combustible loadings in the areas above and below the panels and the height of the panels above the floor (40 feet) minimize the possibility of fire propagating through the panels. Penetrations of piping and electrical raceway through the ceiling are provided with 3 hour rated seals.

In the highly unlikely event that a fire in this area should propagate through the metal panels in the ceiling at elevation 217', safe shutdown capability would still be assured. Fire area 32 and the western portion of fire area 43 both credit method C for safe shutdown of Unit 1. The unlikely propagation of a fire through the metal panels does not impact safe shutdown of Unit 2.

The unrated metal panels are a deviation from the requirements of CMEB 9.5-1, C.5.b. Although the metal panels are unrated, safe shutdown requirements are met in that safe shutdown can be achieved even with the unlikely failure of the unrated barriers.

9A.5.4.5 Fire Area 33: Reactor Core Isolation Cooling Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	W - Reinforced concrete	3 hr
	N - Reinforced concrete	3 hr
	NW - Reinforced concrete	3 hr
	NE - Reinforced concrete (primary containment wall)	None
	SE - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (part adjacent to stairwell no. 3)	2 hr
	S - Reinforced concrete (part, exterior wall below el 198')	None
	S - Reinforced concrete (part, exterior wall above el 198')	3 hr

Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete (ceiling contains 25 ft^2 of unrated metal blowout panels leading to area 43)	None
Access:	Watertight doors connecting to areas 32 and 34	3 hr**
	Door connecting to stairwell no. 3	1.5 hr

b. Major safety-related components in fire area:

1. RCIC pump 10P203

2. RCIC turbine 10S212

3. RCIC compartment unit coolers 1AV208 and 1BV208

c. Postulated fire in area:

Leakage of lube oil from RCIC turbine onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 33 contains safe shutdown cables and equipment.

Cables required to support shutdown methods B and C for Unit 1 and shutdown methods A, B, and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods B and C for Unit 1 and shutdown methods A, B, and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods B and C will be available to shutdown Unit 1, and methods A, B, and C will be available to shutdown Unit 2.

f. Deviations:

The existence of unrated metal panels in the ceiling of this fire area is acceptable because the low combustible loadings in the areas above and below the panels and the height of the panels above the floor (40 feet) minimize the possibility of fire propagating through the panels. Penetrations of piping and electrical raceway through the ceiling are provided with 3 hour rated seals.

In the highly unlikely event that a fire in this area should propagate through the metal panels in the ceiling at elevation 217', safe shutdown capability would still be assured. Fire area 33 and the western portion of fire area 43 both credit method C for safe shutdown of Unit 1. The unlikely propagation of a fire through the metal panels does not impact safe shutdown of Unit 2.

The unrated metal panels are a deviation from the requirements of CMEB 9.5-1, C.5.b. Although the metal panels are unrated, safe shutdown requirements are met in that safe shutdown can be achieved even with the unlikely failure of the unrated barriers.

9A.5.4.6 Fire Area 34: High Pressure Coolant Injection Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	W - Reinforced concrete	3 hr
	N - Reinforced concrete	3 hr
	E - Reinforced concrete (primary containment wall)	None
	SE - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete (ceiling contains 160 ft^2 of unrated metal blowout panels leading to area 43)	None
Access:	Watertight doors connecting to areas 33 and 40	3 hr**

b. Major safety-related components in fire area:

1. HPCI pump 10P204
2. HPCI turbine 10S211
3. HPCI compartment unit coolers 1AV209 and 1BV209
4. Instrument rack 10C014 (HPCI)

c. Postulated fire in area:

Leakage of lube oil from HPCI turbine onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire will activate the smoke detectors in this area, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 34 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A and C for Unit 1 and shutdown methods A, B, and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A and C for Unit 1 and shutdown methods A, B, and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Unit 1, and methods A, B, and C will be available to shutdown Unit 2.

f. Deviations:

The existence of unrated metal panels in the ceiling of this fire area is acceptable because the low combustible loadings in the areas above and below the panels and the height of the panels above the floor (40 feet) minimize the possibility of fire propagating through the panels. Penetrations of piping and electrical raceway through the ceiling are provided with 3 hour rated seals.

In the highly unlikely event that a fire in this area should propagate through the metal panels in the ceiling at elevation 217', safe shutdown capability would still be assured. Fire area 34 and the western portion of fire area 43 both credit method C for safe shutdown of Unit 1. The unlikely propagation of a fire through the metal panels does not impact safe shutdown of Unit 2.

The unrated metal panels are a deviation from the requirements of CMEB 9.5-1, C.5.b. Although the metal panels are unrated, safe shutdown requirements are met in that safe shutdown can be achieved even with the unlikely failure of the unrated barriers.

9A.5.4.7 Fire Area 35: Core Spray Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

Construction	Rating

Walls:	W -	Reinforced concrete	3 hr
	N -	Reinforced concrete	3 hr
	E -	Reinforced concrete (primary containment wall)	None
	S -	Reinforced concrete	3 hr
Floor:	Reinforced concrete foundation mat		None
Ceiling:	Reinforced concrete		3 hr*
Access:	Watertight door connecting to area 40		3 hr**

b. Major safety-related components in fire area:

1. Core spray pump 1AP206

2. Core spray compartment unit coolers 1AV211 and 1EV211

3. Safeguard piping fill pump 1AP256

c. Postulated fire in area:

Leakage of lube oil from core spray pump motor onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire will activate the smoke detectors in this area, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 35 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.4.8 Fire Area 36: Core Spray Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	W - Reinforced concrete	3 hr
	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	SE - Reinforced concrete (primary containment wall)	None
	S - Reinforced concrete	3 hr
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Watertight door connecting to area 40	3 hr**

b. Major safety-related components in fire area:

1. Core spray pump 1CP206

2. Core spray compartment unit coolers 1CV211 and 1GV211

c. Postulated fire in area:

Leakage of lube oil from core spray pump motor onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 36 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.4.9 Fire Area 37: Core Spray Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	W - Reinforced concrete	3 hr

	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
	SW - Reinforced concrete (primary containment wall)	None
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Watertight door connecting to area 39	3 hr**

b. Major safety-related components in fire area:

1. Core spray pump 1DP206

2. Core spray compartment unit coolers 1DV211 and 1HV211

c. Postulated fire in area:

Leakage of lube oil from core spray pump motor onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 37 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.4.10 Fire Area 38: Core Spray Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	N -Reinforced concrete	3 hr
	E -Reinforced concrete	3 hr

	S -Reinforced concrete W -Reinforced concrete (primary containment wall)	3 hr None
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Watertight door connecting to area 39	3 hr**

b. Major safety-related components in fire area:

1. Core spray pump 1BP206
2. Core spray compartment unit coolers 1BV211 and 1FV211
3. Safeguard piping fill pump 1BP256

c. Postulated fire in area:

Leakage of lube oil from core spray pump motor onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire will activate the smoke detectors in this area, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 38 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.4.11 Fire Area 39: Sump Room and Passageway (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr

	E - Reinforced concrete (part adjacent to stairwell no. 1)	2 hr
	E - Reinforced concrete (part)	3 hr
	S - Reinforced concrete (part adjacent to unexcavated area),	None
	S - Reinforced concrete (part)	3 hr
	W - Reinforced concrete (part, primary containment wall)	None
	W - Reinforced concrete (part)	3 hr
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Watertight doors connecting to areas 31, 37 and 38	3 hr**
	Door connecting to stairwell no. 1	1.5 hr

b. Major safety-related components in fire area:

1. Containment isolation valves (HV-52-127 and HV-52-128) for suppression pool cleanup pump suction line

2. Instrument rack 10C076 (RHR pump "B" discharge pressure)

3. Instrument rack 10C078 (RHR pump "D" discharge pressure)

c. Postulated fire in area:

1. Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

2. Ignition of oil in a waste oil collection drum associated with the floor drain sump oil removal belt

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 39 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A and C for Unit 1 and shutdown methods A, B, and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A and C for Unit 1 and shutdown methods A, B, and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Unit 1, and methods A, B, and C will be available to shutdown Unit 2.

9A.5.4.12 Fire Area 40: Corridor (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	N - Reinforced concrete (part adjacent to stairwell no. 4)	2 hr
	N - Reinforced concrete (part)	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
	W - Reinforced concrete (part)	3 hr
	W - Reinforced concrete (part adjacent to stairwell no. 4)	2 hr
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Watertight doors connecting to areas 34, 35 and 36	3 hr**
	Door connecting to stairwell no. 4	1.5 hr
	Elevator door	0.75 hr

b. Major safety-related components in fire area:

1. HPCI pump discharge flow transmitters (FT-55-1N008 and FT-55-1N051)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 40 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A and C for Unit 1 and shutdown methods A, B, and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A and C for Unit 1 and shutdown methods A, B, and C for Unit 2

located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Unit 1, and methods A, B, and C will be available to shutdown Unit 2.

9A.5.4.13 Fire Area 41: Reactor Enclosure Cooling Water Equipment Area (el 201'-0")

a. Structural and architectural design features of fire area (Figure 9A-5):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete (part adjacent to stairwell no. 1)	2 hr
	E - Reinforced concrete (part)	3 hr
	E - Reinforced concrete (part adjacent to unexcavated area)	None
	S - Reinforced concrete	3 hr
	W - Reinforced concrete (part)	3 hr
	W - Reinforced concrete (primary containment wall)	None
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete (one portion of the ceiling slab, covering an area of 10 ft^2, has a reduced concrete thickness that varies between 4.5 inches and 9.0 inches.)	3 hr*
Access:	Door connecting to stairwell no. 1	1.5 hr
	Door connecting to area 31	3 hr

b. Major safety-related components in fire area:

1. Instrument rack 10C021 (Div. 2 RHR and Div. 2 RHRSW)

2. Suppression chamber pressure transmitter (PT-57-101)

3. ESW loop "B" valves (HV-11-044, HV-11-074, HV-11-124, HV-11-125, HV-11-126, HV-11-127 and HV-11-128)

4. HVAC unit cooler control panels 1BC208 and 1DC208

5. Motor control center 10B218, which serves the following components:
   (a) RHR loop "D" valves
   (b) RHR compartment unit coolers 1DV210 and 1HV210
   (c) Core spray loop "B" valves
   (d) Core spray compartment unit coolers 1DV211 and 1HV211
   (e) RHRSW outlet valve from RHR "B" heat exchanger (HV-51-1F068B)
   (f) Drywell unit cooler fans 1D2V212 and 1F2V212
   (g) Containment hydrogen recombiner 1BS403 and associated valves

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 41 contains safe shutdown cables and equipment.

Cables required to support shutdown method B for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method B for Unit 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods A and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Unit 1, and methods A, B, and C will be available to shutdown Unit 2.

9A.5.4.14 Fire Area 42: Safeguard System Access Area (el 201'-0")

a. Structural and architectural design features of fire area (Figure 9A-5):

	Construction	Rating
Walls:	N - Reinforced concrete (part adjacent to stairwell no. 4)	2 hr
	N - Reinforced concrete (part)	3 hr
	E - Reinforced concrete	3 hr
	SE - Reinforced concrete (primary containment wall)	None
	S - Reinforced concrete (part adjacent to stairwell no. 3)	2 hr

	S - Reinforced concrete (part)	3 hr
	W - Reinforced concrete (part)	3 hr
	W - Reinforced concrete (part adjacent to stairwell no. 4)	2 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete (One portion of the ceiling slab, covering an area the ceiling slab, covering an area of 10 ft^2, has a reduced concrete thickness that varies between 4.5 inches and 9.0 inches.)	3 hr*
Access:	Elevator door	0.75 hr
	Doors connecting to stairwell nos. 3 and 4	1.5 hr
	Door connecting to area 32	3 hr
	Watertight door connecting to area 75	3 hr**

b. Major safety-related components in fire area:

1. HPCI valves HV-55-1F007 (pump discharge) and HV-55-1F008 (pump discharge recirculation to CST)

2. RCIC valves HV-49-1F012 (pump discharge) and HV-49-1F022 (pump discharge recirculation to CST)

3. HPCI level transmitters (LT-55-IN061B&F) and turbine exhaust pressure transmitters (PT-56- 1N055D&H)

4. Instrument rack 10C017 (RCIC)

5. RCIC turbine exhaust pressure transmitters (PT-50-1N055C&G)

6. Instrument rack 10C018 (Div. 1 RHR and Div. 1 RHRSW)

7. Instrument rack 10C075 (RHR pump "A" discharge pressure)

8. Instrument rack 10C077 (RHR pump "C" discharge pressure)

9. HVAC unit cooler control panels 1AC208 and 1CC208

10. Motor control center 10B217, which serves the following components:
    (a) RHR loop "C" valves
    (b) RHR compartment unit coolers 1CV210 and 1GV210
    (c) Core spray pump suction valve (HV-52-1F001C)
    (d) Core spray compartment unit coolers 1CV211 and 1GV211
    (e) RHRSW outlet valve from RHR "A" heat exchanger (HV-51-1F068A)
    (f) Drywell unit cooler fans 1C2V212 and 1G2V212
    (g) Containment hydrogen recombiner 1AS403 and associated valves

c. Postulated fire in Area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 42 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 1 and shutdown methods A, B, and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown method C for Unit 1 and shutdown methods A, B, and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, method C will be available to shutdown Unit 1, and methods A, B, and C will be available to shutdown Unit 2.

9A.5.4.15 Fire Area 43: Safeguard System Isolation Valve Area (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (part)	3 hr
	S - Reinforced concrete (exterior wall, contains 150 ft^2 of unrated blowout panels)	None
	W - Concrete masonry unit	3 hr
	Interior boundary – Reinforced concrete (primary containment wall	None
Floor:	Reinforced concrete (contains 450 ft^2 of unrated metal blowout panels from areas 31, 32, 33, and 34)	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Two steamtight doors connecting to area 44	3 hr

b. Major safety-related components in fire area:

1. HPCI steam line containment isolation valves (HV-55-1F003 and HV-55-1F100)

2. RCIC steam line containment isolation valves (HV-49-1F008 and HV-49-1F076)

3. RHR system valves:
   (a) HV-51-1F008 (shutdown cooling suction containment isolation)
   (b) HV-51-1F015A&B (shutdown cooling return containment isolation)
   (c) HV-51-1F047A&B (heat exchanger inlet)
   (d) HV-C-51-1F048A&B (heat exchanger bypass)
   (e) HV-51-1F023 (head spray containment isolation)

4. CAC containment isolation valves (HV-57-109, HV-57-121, HV-57-123, HV-57-124, HV-57-131, HV-57-135, HV-57-147, HV-57-163, and HV-57-164)

5. PCIG containment isolation valves (HV-59-102, HV-59-129A, HV-59-129B, HV-59-131, HV-59-135, HV-59-151A, and HV-59-151B)

6. HPCI system leakage detection temperature elements

7. RCIC system leakage detection temperature elements

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

For the purposes of safe shutdown analyses, fire area 43 is divided into an eastern (43E) and a western (43W) portion through the establishment of a 20 foot wide zone that is free of combustible materials.

<u>43E</u>

The eastern portion of fire area 43 contains safe shutdown cables and equipment.

Cables required to support shutdown methods B and C for Unit 1 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods B and C for Unit 1 located in this fire area either have redundant components that are

not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods B and C will be available to shutdown Unit 1, and methods A, B, and C will be available to shutdown Unit 2, for a fire in the eastern half of fire area 43.

43W

The western portion of fire area 43 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 1 are either encapsulated by a qualified fire barrier, associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Unit 1 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods A, B, and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, method C will be available to shutdown Unit 1, and methods A, B, and C will be available to shutdown Unit 2, for a fire in the western half of fire area 43.

f. Deviations:

Fire area 43 is divided into a western portion and an eastern portion through the establishment of a 20 foot wide zone that is free of combustible materials. This combustible-free zone was created by using 1 hour rated fire barriers to enclose the cable trays that pass through the zone.

Several valves associated with the credited safe shutdown methods are located in fire area 43. Valves performing active, credited, redundant functions are located on opposite sides of fire area 43 and are separated by the combustible free zone. The only combustible materials in the intervening space are electrical cables in cable tray. The fire

barriers that enclose the portions of the cable trays that are within the combustible-free zone, eliminate the potential for a postulated fire to propagate through the combustible-free zone within the cable trays. The in situ combustible loading in fire area 43 is low. The potential for transient combustibles to exist in the space between credited, redundant valves is severely restricted by the arrangement of fire area 43 and the locations of commodities within it. The space between the credited, redundant equipment is relatively narrow and contains a high concentration of pipes and pipe supports. These obstructions effectively prevent the introduction of significant quantities of combustible materials into this space. The factors discussed above preclude the occurrence of a fire, involving either in situ combustibles or transient combustibles, that could simultaneously affect credited, redundant equipment.

The measures described above for physical separation and provision of fire barriers ensure that the plant can be safely shut down in the event of a fire in either the western portion or the eastern portion of fire area 43.

This is a deviation from the CMEB 9.5-1, C.5.b requirement for automatic suppression. This deviation is documented in reference 9A.7.5.

The existence of unrated metal panels in the floor of this fire area is acceptable because the low combustible loadings in the areas above and below the panels. Penetrations of piping and electrical raceway through the floor are provided with 3- hour rated seals. Unrated blowout panels exist in the south wall of the fire area that release to the outside of the reactor enclosure, which has no adjoining tire area impacts.

In the highly unlikely event that a fire in this area should propagate through the metal panels in the floor at elevation 217', safe shutdown capability would still be assured. Fire area 43, 31, 32, 33, and 34 all credit method C for safe shutdown of Unit 1. The unlikely propagation of a fire through the metal panels does not impact safe shutdown of Unit 2.

The unrated metal panels are a deviation from the requirements of CMEB 9.5-1, C.5.b. Although the metal panels are unrated, safe shutdown requirements are met in that safe shutdown can be achieved even with the unlikely failure of the unrated barriers.

9A.5.4.16 Fire Area 44: Safeguard System Access Area (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete (parts adjacent to stairwell nos. 1 and 4)	2 hr
	N - Reinforced concrete (part)	3 hr
	E - Reinforced concrete (part adjacent to stairwell no. 1)	2 hr
	E - Reinforced concrete (part)	3 hr
	S - Reinforced concrete (part adjacent to stairwell no. 3)	2 hr
	S - Reinforced concrete (part adjacent to fire area 124)	3 hr
	S - Reinforced concrete (part, exterior wall)	None
	W - Reinforced concrete (part adjacent to stairwell	2 hr

	nos. 3 and 4)	
	W - Reinforced concrete (part)	3 hr
	Interior boundary (part) - Reinforced concrete and concrete masonry unit walls	3 hr
	Interior boundary (part) - Reinforced concrete (primary containment wall)	None
Floor:	Reinforced concrete (Two portions of the floor slab, each of which covers an area of 10 ft^2, have a reduced concrete thickness that varies between 4.5 inches and 9.0 inches.)	3 hr*
Ceiling:	Reinforced concrete	3 hr*
Access:	Doors connecting to stairwell nos. 1, 3, and 4	1.5 hr
	Two steamtight doors connecting to area 43	3 hr
	Missile-resistant door connecting to area 76	3 hr**
	Equipment airlock door	None
	Elevator door	0.75 hr
	Suppression chamber access hatches	None
	Equipment hatchway in ceiling (200 ft^2 opening; protected by water curtain suppression system)	None

b. Major safety-related components in fire area:

1. Core spray full flow test recirculation valves (HV-52-1F015A&B)

2. CAC containment isolation valves (HV-57-104, HV-57-105, HV-57-112, HV-57-118, and HV-57-162)

3. RHR system valves:
   (a) HV-51-125A&B (containment isolation for recirculation to suppression chamber)
   (b) HV-51-1F027A&B (containment isolation for suppression chamber spray)
   (c) HV-51-1F010A&B (loops C and D recirculation to suppression chamber)
   (d) HV-51-1F024A&B (loops A and B recirculation to suppression chamber)

4. Instrument racks 10C001 (core spray loop A) and 10C019 (core spray loop B)

5. Instrument racks 10C015, 10C025, 10C041, and 10C042 (main steam and reactor recirculation flow)

6. Instrument racks 10C016 and 10C036 (HPCI)

7. Instrument racks 10C035 and 10C038 (RCIC)

8. Instrument racks 10C006, 10C009, 10C010, and 10C022 (reactor recirculation system pressure and jet pump flow)

9. RHR flow transmitters (FT-51-1N015A,B,C&D and FT-51-1N052A,B,C&D)

10. Motor control center 10B211, which serves the following components:
    (a) RHR loop "A" valves
    (b) RHR compartment unit coolers 1AV210 and 1EV210
    (c) Core spray loop "A" valves
    (d) Core spray compartment unit coolers 1AV211 and 1EV211
    (e) RHRSW inlet valve to RHR "A" heat exchanger (HV-51-1F014A)
    (f) RHR shutdown cooling suction inboard isolation valve (HV-51-1F009)
    (g) RCIC compartment unit coolers 1AV208 and 1BV208
    (h) RWCU inboard isolation valve (HV-44-1F001)
    (i) Main steam drain line inboard isolation valve (HV-41-1F016)
    (j) Drywell unit cooler fans 1A1V212, 1C1V212, 1E1V212, and 1G1V212

11. Motor control center 10B212, which serves the following components:
    (a) RHR loop "B" valves
    (b) RHR compartment unit coolers 1BV210 and 1FV210
    (c) Core spray loop "B" valves
    (d) Core spray compartment unit coolers 1BV211 and 1FV211
    (e) RHRSW inlet valve to RHR "B" heat exchanger (HV-51-1F014B)
    (f) RHR shutdown cooling return isolation valve (HV-51-1F015A)
    (g) Reactor recirculation pump suction valve (HV-43-1F023B)
    (h) HPCI compartment unit coolers 1AV209 and 1BV209
    (i) Drywell unit cooler fans 1B1V212, 1D1V212, 1F1V212, and 1H1V212

12. Motor control center 10B215, which serves the following components:
    (a) RHR loop "A" valves
    (b) RCIC system valves
    (c) Deleted
    (d) Suppression pool cleanup pump suction isolation valve (HV-52-127)
    (e) Drywell pressure tap isolation valve (HV-42-147A)
    (f) Drywell floor drain and equipment drain containment isolation valves (HV-61-112 and HV-61-132)

13. Motor control center 10B216, which serves the following components:
    (a) RHR loop "B" valves
    (b) HPCI system valves
    (c) Deleted
    (d) Suppression pool cleanup pump isolation valve (HV-52-128)
    (e) Drywell pressure tap isolation valve (HV-42-147B)
    (f) Suppression pool level tap isolation valves (HV-55-120 and HV-55-121)
    (g) RHR shutdown cooling suction outboard isolation valve (HV-51-1F008)
    (h) RWCU outboard isolation valve (HV-44-1F004)
    (i) Main steam drain line outboard isolation valve (HV-41-1F019)

14. Dc motor control center 10D201, which serves the following components:
    (a) RCIC system
    (b) Div. 1 RPS and UPS static inverter

15. Dc motor control center 10D202, which serves the HPCI system

16. Dc motor control center 10D203, which serves the following components:

(a) HPCI system
(b) Div. 2 RPS and UPS static inverter

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the fire occurs within the coverage area of one of the two preaction sprinkler systems in this fire area, the system will provide automatic suppression of the fire. When the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual fusible link sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

For the purposes of safe shutdown analyses, fire area 44 is divided into an eastern (44E) and a western (44W) portion through the establishment of two 20 foot wide zones.

<u>44E</u>

The eastern portion of fire area 44 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A and C for Units 1 and 2 are either encapsulated by a qualified fire barrier, associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods A and C for Units 1 and 2 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Units 1 and 2, for a fire in the eastern half of fire area 44.

<u>44W</u>

The western portion of fire area 44 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 1 are either associated with equipment that have redundant components that are not affected by a fire in this area, or

associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Unit 1 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods B and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods B and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, method C will be available to shutdown Unit 1, and methods B and C will be available to shutdown Unit 2, for a fire in the western half of fire area 44.

f. Deviation:

A 20 foot wide zone that is free of combustibles was created at two locations in fire area 44 by using a galvanized steel cable tray enclosure system to cover the cable trays that pass through the zone. This non-combustible configuration together with the enclosure end seals will prevent fire propagation across the combustible free zone. A fixed suppression system of the water curtain-type is located within each combustible-free zone to provide assurance that a postulated fire due to transient combustibles can be prevented from propagating through the combustible-free zones. The two combustible-free zones, one located in the southwest quadrant of the fire area and one located in the northeast quadrant of the fire area, divide fire area 44 into a western portion and an eastern portion.

Several components associated with the credited safe shutdown methods are located in fire area 44. Components performing active, credited, redundant functions are located on opposite sides of fire area 44 and are separated by the combustible free zone. The only combustible materials in the intervening space are electrical cables in cable tray up to the boundaries of the combustible free zone.

The locations of preaction sprinkler systems and water curtain suppression systems in fire area 44 are shown in Figure 9A-6.

The measures described above for physical separation, fire suppression, and provision of fire barriers ensure that the plant can be safely shut down in the event of a fire in either the western portion or the eastern portion of fire area 44.

This is a deviation from the CMEB 9.5-1, C.5.b requirement for automatic suppression. This deviation is documented in reference 9A.5.7.

9A.5.4.17 Fire Area 45: CRD Hydraulic Equipment Area and Neutron Monitoring System Area (el 253'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

Construction	Rating

Walls:	N - Reinforced concrete (parts adjacent to stairwell nos. 1 2 hr and 4)	
	N - Reinforced concrete (part)	3 hr
	E - Reinforced concrete (part adjacent to stairwell no. 1)	2 hr
	E - Reinforced concrete (part)	3 hr
	S - Reinforced concrete (part adjacent to stairwell no. 3)	2 hr
	S - Reinforced concrete (part, exterior wall)	None
	W - Reinforced concrete (parts adjacent to stairwell nos. 3 and 4)	2 hr
	W - Reinforced concrete (part)	3 hr
	Interior boundary (part adjacent to main steam tunnel) – Reinforced concrete	3 hr
	Interior boundary (part) – Reinforced concrete (primary containment wall)	None
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr*
Access:	Doors connecting to stairwell nos. 1, 3, and 4	1.5 hr
	Elevator door	0.75 hr
	Drywell access hatches	None
	Watertight door connecting to area 46	3 hr**
	Equipment hatchways in floor and protected by water curtain suppression systems)	None
	Double steamtight door airlock connecting to area 68	3 hr**

b. Major safety-related components in fire area:

1. DCWS valves HV-87-122, HV-87-123, HV-87-128, and HV-87-129 (supply and return line containment isolation)

2. CRD master control station

3. CRD hydraulic control units

4. Containment combustible gas analyzer sample package 10S206

5. Load center 10B203 (Div. 3)

6. Deleted

7. Instrument racks 10C004, 10C005, 10C026, and 10C027 (RPV instrumentation and LPCI injection valve ΔP transmitters)

8. SLCS injection line containment isolation valves (HV-48-1F006A&B)

9. Motor control center 10B223, which serves the following components:
   (a) LPCI injection containment isolation valve (HV-51-1F017C)

(b) RHR loop "C" minimum flow recirculation isolation valve (HV-51-105A)
(c) RCIC system valves
(d) SLCS pump 1AP208
(e) SLCS injection outboard isolation valve (HV-48-1F006)
(f) Drywell pressure tap isolation valve (HV-42-147C)
(g) Drywell unit cooler fans 1A2V212 and 1E2V212
(h) Reactor recirculation pump cooling water isolation valves (HV-13-106 and HV-13-107)

10. Motor control center 10B224, which serves the following components:
(a) LPCI injection containment isolation valve (HV-51-1F017D)
(b) RHR loop "D" minimum flow recirculation isolation valve (HV-51-105B)
(c) HPCI system valves
(d) SLCS pump 1BP208
(e) Drywell pressure tap isolation valve (HV-42-147D)
(f) Reactor recirculation pump cooling water source select valves (HV-13-108, HV-13-109, HV-13-110, and HV-13-111)
(g) Drywell unit cooler fans 1B2V212 and 1H2V212

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the fire occurs within the coverage area of the preaction sprinkler system in this fire area, the system will provide automatic suppression of the fire. When the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual fusible link sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

For the purposes of safe shutdown analyses, fire area 45 is divided into an eastern (45E) and a western (45W) portion through the establishment of a 20 foot wide zone that is free of combustible materials.

<u>45E</u>

The eastern portion of fire area 45 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 1 are either encapsulated by a qualified fire barrier, associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Unit 1 located in this fire area either have

redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods B and C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods B and C for Unit 2 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, method C will be available to shutdown Unit 1 and methods B and C will be available to shutdown Unit 2, for a fire in the eastern half of fire area 45.

45W

The western portion of fire area 45 contains safe shutdown cables and equipment.

Cables required to support shutdown methods B and C for Unit 1 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods B and C for Unit 1 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods B and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods B and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods B and C will be available to shutdown Units 1 and 2, for a fire in the western half of fire area 45.

f. Deviation

A 20 foot wide zone that is free of combustibles was created by ensuring, by analysis, that there are no intervening combustibles which could provide a path for fire propagation through the combustible-free zone. A fixed suppression system of the water curtain-type is located within the combustible-free zone to provide assurance that a postulated fire due to transient combustibles can be prevented from propagating through the combustible-free

zone. The combustible-free zone divides the fire area into a western portion and an eastern portion.

Several components associated with the credited safe shutdown methods are located in fire area 45. Components performing active, credited, redundant functions are located on opposite sides of fire area 45 and are separated by the combustible free zone. The only combustible materials in the intervening space are electrical cables in cable tray up to the boundaries of the combustible free zone. The locations of the preaction sprinkler system and the water curtain suppression system in fire area 45 are shown in Figure 9A-7.

The measures described above for physical separation, fire suppression, and provision of fire barriers ensure that the plant can be safely shut down in the event of a fire in either the western portion or the eastern portion of fire area 45.

This is a deviation from the CMEB 9.5-1, C.5.b requirement for automatic suppression. This deviation is documented in reference 9A.7.5.

If the fire occurs within the coverage area of the wet pipe sprinkler systems in this fire area, the systems will provide automatic suppression of the fire. When the compartment temperature rises to 212°F, individual fusible link sprinklers will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

9A.5.4.18 Fire Area 46: Main Steam Tunnel (el 253'-0")

a. Structural and architectural design features of fire area (Figures 9A-7, 9A-8, 9A-9, and 9A-10):

	Construction	Rating
Walls:	N - Reinforced concrete (contains 188 ft^2 of unrated metal blowout panels)	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (part , primary containment wall)	None
	S - Reinforced concrete (part)	3 hr
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete (part at el 295'-3")	3 hr*
	Reinforced concrete (part at el 365' roof slab)	None
Access:	Watertight door connecting to area 45	3 hr**
	Steamtight doors connecting to areas 28 and 47	3 hr

b. Major safety-related components in fire area:

1. Main steam line outboard containment isolation valves (HV-41-1F028 A,B,C&D)

2. Feedwater line outboard containment isolation valves (HV-41-1F032A&B and HV-41-1F074A&B)

3. Main steam drain line outboard containment isolation valve (HV-41-1F019)

4. RCIC injection valve (HV-49-1F013)

5. Steam line radiation sensors (RE-41-1N006A,B,C&D)

c. Postulated fire in area:

Since no combustible materials are located in this area, the origin of a postulated fire is indeterminate.

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the plant fire brigade will be dispatched to el 253' and/or el 283' in the reactor enclosure and will enter the main steam tunnel through doors at those elevations. The fire brigade will extinguish the fire using portable fire extinguishers or hose stations located outside the entrances to the main steam tunnel.

e. Effect of fire on safe shutdown:

Fire area 46 contains safe shutdown cables and equipment.

Cables required to support shutdown methods B and C for Unit 1 and shutdown methods A, B, and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods B and C for Unit 1 and shutdown methods A, B, and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods B and C will be available to shutdown Unit 1, and methods A, B, and C will be available to shutdown Unit 2.

9A.5.4.19 Fire Area 47: RWCU Compartments, FPCC Compartment, and General Equipment Area (el 283'-0" and el 295'-3")

a. Structural and architectural design features of fire area (Figure 9A-8):

	Construction	Rating
Walls:	N - Reinforced concrete (parts adjacent to stairwell nos. 1 and 4)	2 hr
	N - Reinforced concrete (part)	3 hr
	E - Reinforced concrete (part adjacent to stairwell no. 1)	2 hr
	E - Reinforced concrete (part)	3 hr
	S - Reinforced concrete (part adjacent to stairwell no. 3)	2 hr
	S - Reinforced concrete (part, exterior wall)	None
	W - Reinforced concrete (parts adjacent to stairwell nos. 3 and 4)	2 hr

	W - Reinforced concrete (part)	3 hr
	Interior boundary (east and west walls of area 46) – Reinforced concrete	3 hr
	Interior boundary (primary containment wall) – Reinforced concrete	None
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr*
Access:	Doors connecting to stairwell nos. 1, 3, and 4	1.5 hr
	Steamtight door connecting to area 46	3 hr
	Elevator door	0.75 hr
	Equipment hatchways in floor and ceiling (200 ft^2 openings; protected by water curtain suppression systems)	None

b. Major safety-related components in fire area:

1. Containment hydrogen recombiner packages 1AS403 and 1BS403

2. SLCS components:
   Storage tank 10T204
   Injection pumps 1AP208, 1BP208, and 1CP208
   Explosive valves XV-48-1F004A,B&C

3. Core spray loop "A" injection valves (HV-52-1F004A and HV-52-1F005)

4. Core spray loop "B" injection valves (HV-52-1F004B, HV-52-1F037, and HV-52-108)

5. RHR system valves:
   HV-51-1F017A,B,C&D (LPCI injection line containment isolation)
   HV-51-1F021A&B (drywell spray line containment isolation)
   HV-51-1F016A&B (drywell spray line shutoff)

6. HPCI system injection valve (HV-55-1F006)

7. RWCU supply line containment isolation valve (HV-44-1F004)

8. CAC purge line containment isolation valves (HV-57-111, HV-57-115, HV-57-114, and HV-57-161)

9. Containment combustible gas analyzer sample cabinet 10S205

10. Load center 10B204 (Div. 4)

11. Motor control center 10B213, which serves the following components:
    (a) RHR loop "A" valves
    (b) Core spray loop "A" valves
    (c) Feedwater startup recirculation valves (HV-41-109A&B)

(d) Shutoff valves for main steam to miscellaneous steam-driven components (HV-01-108, HV-01-109, HV-01-111, and HV-01-150)
(e) Drywell chilled water source select valves
(f) SGTS heater 0AE188
(g) SGTS exhaust fan 0AV109

12. Motor control center 10B214, which serves the following components:
(a) RHR loop "B" valves
(b) Core spray loop "B" valves
(c) Drywell cooling water containment isolation valves
(d) SGTS heater 0BE188
(e) SGTS exhaust fan 0BV109

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the fire occurs within the coverage area of the preaction sprinkler system in this fire area, the system will provide automatic suppression of the fire. When the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual fusible link sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

For the purposes of safe shutdown analyses, fire area 47 is divided into an eastern (47E) and a western (47W) portion through the establishment of a 20 foot wide zone that is free of combustible materials; no cable trays are located within this combustible-free zone.

47E

The eastern portion of fire area 47 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 1 are either encapsulated by a qualified fire barrier, associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Unit 1 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods B and C for Unit 2 are either encapsulated by a qualified fire barrier, associated with equipment that have redundant

components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost.

Equipment associated with shutdown methods B and C for Unit 2 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, method C will be available to shutdown Unit 1 and methods B and C will be available to shutdown Unit 2, for a fire in the eastern half of fire area 47.

47W

The western portion of fire area 47 contains safe shutdown cables and equipment.

Cables required to support shutdown methods B and C for Unit 1 are either encapsulated by a qualified barrier, associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods B and C for Unit 1 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods B and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods B and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods B and C will be available to shutdown Units 1 and 2, for a fire in the western half of fire area 47.

A postulated fire in the vicinity of the reactor vessel instrumentation reference leg could adversely affect reactor vessel water level indication due to reference leg density changes caused by an increase in water temperature. Since there are no fire initiators in close proximity to the reference leg tubing, administratively controlled combustible free zones, throughout reference leg locations will preclude any adverse effect on level indication, due to fire, prior to annunciation in the main control room.

f. Deviations:

A 20 foot wide zone that is free of combustible materials is maintained; no cable trays are located within this combustible-free zone. The combustible-free zone divides fire area 47 into a western portion and an eastern portion.

Several components associated with the credited safe shutdown methods are located in the eastern half of fire area 47. Components and cables performing active, credited, redundant functions are located on opposite sides of fire area 47 and are separated by the combustible free zone. The only combustible materials in the intervening space are electrical cables in cable tray up to the boundaries of the combustible free zone. The location of the precaution sprinkler system on fire area 47 is shown in Figure 9A-8.

The measures described above for physical separation, fire suppression, and provision of fire barriers ensure that the plant can be safely shut down in the event of a fire in either the western portion or the eastern portion of fire area 47.

This is a deviation from the CMEB 9.5-1, C.5.b requirement for automatic suppression. This deviation is documented in reference 9A.7.5.

9A.5.4.20 Fire Area 48: RWCU Holding Pump Compartments, RERS Fan Area, and Corridors (el 313'-0")

a. Structural and architectural design features of fire area (Figure 9A-9):

	Construction	Rating
Walls:	N - Reinforced concrete (part adjacent to stairwell no. 4)	2 hr
	N - Reinforced concrete (part)	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (part)	3 hr
	S - Reinforced concrete (part adjacent to stairwell no. 3)	2 hr
	W - Reinforced concrete (part, exterior wall)	None
	W - Reinforced concrete (part adjacent to stairwell no. 4)	2 hr
	Interior boundary - Reinforced concrete (primary containment wall)	None
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr*
Access:	Doors connecting to stairwell nos. 3 and 4	1.5 hr
	Airlock door connecting to area 49	3 hr
	Double airlock door connecting to area 49	3 hr**
	Elevator door	0.75 hr
	Equipment hatchway in floor (200 ft^2 opening; protected by water curtain suppression system)	None

b. Major safety-related components in fire area:

1. RERS fans (1AV213 and 1BV213)

2. Load center 10B201 (Div. 1)

3. Load center 10B202 (Div. 2)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

For the purposes of safe shutdown analyses, fire area 48 is divided into an eastern (48E) and a western (48W) portion through the establishment of a 20 foot wide zone that is free of combustible materials.

48E

The eastern portion of fire area 48 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods A and C for Unit 1 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods A and C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods A and C for Unit 2 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Units 1 and 2, for a fire in the eastern half of fire area 48.

48W

The western portion of fire area 48 contains safe shutdown cables and equipment.

Cables required to support shutdown methods B and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods B and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods B and C will be available to shutdown Units 1 and 2, for a fire in the western half of fire area 48.

f. Deviations:

Load centers 10B201 and 10B202 and their associated transformers are the only components credited for safe shutdown which are located in fire area 48. The horizontal separation between the two load centers is greater than 35 feet, and the only combustible materials in the intervening space are electrical cables in a cable tray. A 20 foot wide zone that is free of combustibles was created between the two load centers by using a galvanized steel cable tray enclosure system to cover the cable trays that pass through the zone. This non-combustible configuration together with the enclosure and seals will prevent fire propagation across the combustible zone. A fixed suppression system of the water curtain-type is located within the combustible-free zone to provide assurance that a postulated fire due to transient combustibles can be prevented from propagating through the combustible-free zone. To preclude the possibility of a spilled combustible liquid spreading across the area between the two load centers, a concrete curb is provided between the load centers, spanning the full width of the corridor in which the load centers are located. The curb is located within the coverage area of the water curtain system. To protect the load centers from radiant heat that could be generated by a postulated fire occurring in the area between the load centers, each load center is provided with a radiant heat shield. The heat shields are constructed of Marinite sheet and are located adjacent to the side of each load center that faces the concrete curb.

The measures described above for physical separation, fire suppression, and provision of fire barriers ensure that the plant can be safely shut down in the event of a fire in either the western portion or the eastern portion of fire area 48.

This is a deviation from the CMEB 9.5-1, C.5.b requirement for automatic suppression. This deviation is documented in reference 9A.7.5.

9A.5.4.21 Fire Area 49: Reactor Enclosure Lower Fan Room (el 313'-0")

a. Structural and architectural design features of fire area (Figure 9A-9):

	Construction	Rating

Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (part, exterior wall)	None
	S - Louvers open to outside atmosphere (part)	None
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete (part below fire area 50)	None
	Reinforced concrete (part below fire area 51)	3 hr*
Access:	Airlock door connecting to area 48	3 hr
	Double airlock door connecting to area 48	3 hr**
	Emergency exit in ceiling (6.25 ft^2 opening)	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Once the control room operators have been notified that a fire has occurred in this area, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 49 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.4.22 Fire Area 50: Reactor Enclosure Upper Fan Room and Equipment Compartment Exhaust Filter Rooms (el 331'-0")

a. Structural and architectural design features of fire area (Figure 9A-9):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (exterior wall)	None
	W - Reinforced concrete (part adjacent to stairwell no. 3)	2 hr
	W - Reinforced concrete (part)	3 hr
Floor:	Reinforced concrete	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Door connecting to stairwell no. 3	1.5 hr
	Two doors connecting to area 51	3 hr
	Emergency exit in floor (6.25 ft^2 opening)	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of charcoal filters.

d. Consequences of fire with active fire suppression:

In the event of a fire in one of the reactor enclosure equipment compartment exhaust filters, a thermal sensor inside the filter plenum will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the affected ventilation system will be shut down and the plant fire brigade will be dispatched to extinguish the fire. The fire brigade will utilize a manual valve in the fire protection water supply system to initiate operation of a water spray system inside the filter plenum.

e. Effect of fire on safe shutdown:

Fire area 50 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.4.23 Fire Area 51: RERS Filter Compartments (el 331'-0")

a. Structural and architectural design features of fire area (Figure 9A-9):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
	W - Reinforced concrete (exterior wall)	None
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr*
Access:	Two doors connecting to area 50	3 hr

b. Major safety-related components in fire area:

1. RERS filter assemblies (1AS297 and 1BS297)

c. Postulated fire in area:

Ignition of charcoal filters.

d. Consequences of fire with active fire suppression:

In the event of a fire in one of the RERS filters, a thermal sensor inside the filter plenum will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire. The fire brigade will utilize a manual valve in the fire protection water supply system to initiate operation of a water spray system inside the filter plenum.

e. Effect of fire on safe shutdown:

Fire area 51 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.4.24 Fire Area 75: Service Water Pipe Tunnel (el 198'-0")

a. Structural and architectural design features of fire area (Figure 9A-5):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	None
	S - Reinforced concrete (part adjacent to diesel generator	3 hr

	enclosures)	
	S - Reinforced concrete (exterior wall)	None
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete foundation	None
Ceiling:	Reinforced concrete (portion below fire areas 44, 67, and 79 through 86)	3 hr*
	Reinforced concrete (portion below fire areas 76, 124, and 125)	None
Access:	Watertight doors connecting to areas 42 and 65	3 hr**

b. Major safety-related components in fire area:

1. ESW discharge header isolation valves (HV-11-011A&B and HV-11-015A&B)

2. Flow transmitters FT-11-011A&B, FT-11-013A&B, and FT-12-015A&B for ESW supply and return headers

3. Pressure switches PSL-12-102A&B and PSL-12-202A&B for RHRSW supply to the RHR heat exchangers

c. Postulated fire in area:

Since no combustible materials are located in this area, the origin of a postulated fire is indeterminate.

d. Consequences of fire with active fire suppression:

Upon receipt of notification in the control room that a fire has occurred in this area, the plant fire brigade will be dispatched to extinguish the fire. Depending on the severity and location of the fire, certain components in the ESW and/or RHRSW systems may be affected.

e. Effect of fire on safe shutdown:

Fire area 75 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

f. Deviations:

The existence of an unrated ceiling for this fire area is acceptable because of the low combustible loadings in the pipe tunnel (fire area 75) below the ceiling and in the corridors and condensate pump rooms (fire areas 124 and 125) above the ceiling. In the highly unlikely event that a fire in this area should propagate through the unrated ceiling, safe shutdown capability would still be assured. Fire area 75 and fire areas 124 and 125 all credit methods A, B, and C for safe shutdown of both Units 1 and 2.

The unrated steel ceiling is a deviation from the requirements of CMEB 9.5-1, C.5.b. Although the ceiling is unrated, safe shutdown requirements are met in that safe shutdown can be achieved even with the unlikely failure of the unrated barrier.

9A.5.4.25 Fire Area 76: Refueling Hoist-way (el 217'-0")

a. Structural and architectural design features of fire area (Figures 9A-6, 9A-7, 9A-8, and 9A-9):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete foundation	None
Ceiling:	Concrete hatch plugs connecting to area 78	None
Access:	Missile-resistant doors connecting to areas 44 and 67	3 hr**
	Railroad car airlock doors	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Since no combustible materials are located in this area, the origin of a postulated fire is indeterminate.

d. Consequences of fire with active fire suppression:

Upon receipt of notification in the control room that a fire has occurred in this area, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 76 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.4.26 Fire Area 77: South Ventilation Exhaust Stack

a. Structural and architectural design features of fire area (Figures 9A-7, 9A-8, 9A-9, and 9A-10):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Precast concrete panels	None
	S - Precast concrete panels	None
	W - Precast concrete panels	None
Floor:	None (open to outside)	
Ceiling:	None (open to outside)	
Access:	Door connecting to area 78	3 hr

b. Major safety-related components located in fire area:

None

c. Postulated fire in area:

Since no combustible materials are located in this area, the origin of a postulated fire is indeterminate.

d. Consequences of fire with active fire suppression:

Upon receipt of notification in the control room that a fire has occurred in this area, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 77 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.4.27 Fire Area 78: Refueling Area (el 352'-0")

a. Structural and architectural design features of fire area (Figure 9A-10):

	Construction	Rating
Walls:	N - Reinforced concrete (part adjacent to stairwell nos. 4 and 6)	2 hr
	N - Reinforced concrete (part adjacent to fire areas 28, 46, and 69)	3 hr
	N - Reinforced concrete (part, exterior wall)	None
	E - Reinforced concrete (part adjacent to stairwell nos. 5 and 6)	2 hr
	E - Reinforced concrete (part)	None
	S - Reinforced concrete (part adjacent to stairwell nos. 3 and 5)	2 hr
	S - Reinforced concrete (part, exterior wall)	None
	W - Reinforced concrete (part adjacent to stairwell nos. 3 and 4)	2 hr
	W - Reinforced concrete (part, exterior wall)	None
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete roof slab	None
Access:	Doors to stairwell nos. 3, 4, 5, and 6	1.5 hr
	Two doors to area 77	3 hr

b. Major safety-related components in fire area:

1. Reactor enclosure crane

2. Refueling platforms for Units 1 and 2

3. Gate seals, stop seals, and reactor well seals

c. Postulated fire in area:

Ignition of stored materials as a result of an exposure fire. An exposure fire involving stored combustible materials in this fire area would be extremely limited in scope and confined to a small area due to the sparsely distributed combustibles within the refueling area. Ignition of the stored combustible materials is extremely unlikely in the absence of a fire source external to the materials.

d. Consequences of fire with active fire suppression:

Upon receipt of notification in the control room that a fire has occurred in this area, the plant fire brigade will be dispatched to extinguish the fire. No effect on safety related systems will result from a fire in the fire area.

e. Effect of fire on safe shutdown:

Fire area 78 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.4.28 Fire Area 126: North Stack Instrument Room and Vestibule (el 411'-9")

a. Structural and architectural design features of fire area (Figure 9A-10):

	Construction	Rating
Walls:	N - Precast concrete panels	2 hr
	E - Insulated metal siding	None
	S - Insulated metal siding	None
	W - Insulated metal siding	None
Floor:	Reinforced concrete	None
Ceiling:	Built-up roofing	UL Class A
Access:	Door connecting to north stack	1.5 hr
	Two doors to outside	None

b. Major safety-related components in fire area:

1. Wide range accident monitors 01S908 and 02S908

2. Wide range accident monitor microprocessor (RY-26-076)

c. Postulated fire in area:

Since no combustible materials are located in this area, the origin of a postulated fire is indeterminate.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 126 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.4.29 Fire Area 127: South Stack Instrument Room (el 411'-9")

a. Structural and architectural design features of fire area (Figure 9A-10):

	Construction	Rating
Walls:	N - Insulated metal siding	None
	E - Insulated metal siding	None
	S - Precast concrete panels	2 hr
	W - Insulated metal siding	None
Floor:	Reinforced concrete	None
Ceiling:	Built-up roofing	UL Class A
Access:	Door connecting to south stack	1.5 hr
	Two doors to outside	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Since no combustible materials are located in this area, the origin of a postulated fire is indeterminate.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 127 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.5 SAFE SHUTDOWN ANALYSIS - UNIT 2 REACTOR ENCLOSURE

9A.5.5.1 Fire Area 52: Suppression Chamber (el 181'-11")

a. Structural and architectural design features of fire area (Figures 9A-4, 9A-5, and 9A-6):

	Construction	Rating
Walls:	All around - Reinforced concrete (primary containment wall)	None
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete (diaphragm slab)	None
Access:	Two access hatches connecting to area 67	None

b. Major safety-related components in fire area:

1. Primary containment vacuum relief valve assemblies (PSV-57-237A,B,C&D)

c. Postulated fire in area:

Since there are no combustible materials located in this area, no fire is postulated to occur.

d. Consequences of fire with active fire suppression:

Not applicable (see item (c)).

e. Effect of fire on safe shutdown:

Fire area 52 contains safe shutdown cables and equipment.

During normal operation, primary containment is inerted. Since containment is inerted no fire is postulated.

9A.5.5.2 Fire Area 53: Drywell (el 237'-11")

a. Structural and architectural design features of fire area (Figures 9A-7, 9A-8, and 9A-9):

	Construction	Rating
Walls:	All around - Reinforced concrete (primary containment wall)	None
Floor:	Reinforced concrete (diaphragm slab)	None

Ceiling:	Steel dome (drywell head)	None
Access:	Equipment hatch connecting to area 68	None
	Equipment hatch with personnel lock connecting to area 68	None

b. Major safety-related components in fire area:

1. Control rod drive mechanisms (total of 185)

2. Main steam isolation valves (inboard, one per steam line)

3. Main steam relief valves (total of 14)

4. Drywell unit coolers (total of 8)

5. Inboard containment isolation valves for HPCI steam supply line, RCIC steam supply line, RWCU letdown line, and RHR shutdown cooling suction line

c. Postulated fire in area:

1. Leakage of lube oil from a recirculation pump motor onto the diaphragm slab, with subsequent ignition of the oil.

2. Ignition of electrical cabling in cable tray or direct supported metal clad cable.

d. Consequences of fire with active fire suppression:

The possibility of a fire in the drywell is limited to periods when the reactor is shut down. This is because the primary containment is inerted with nitrogen during reactor operation, so that the oxygen concentration is maintained below 4% by volume. This inert atmosphere will prevent fires from occurring in the primary containment during reactor operation.

In the event of a fire in the drywell while the reactor is shut down and the drywell deinerted, the operator will dispatch the plant fire brigade to el 253' in the reactor enclosure. The fire brigade will enter the drywell through the personnel airlock and will ensure extinguishment of the fire through the use of portable fire extinguishers or hose stations located outside the entrances to the drywell.

e. Effect of fire on safe shutdown:

Fire area 53 contains safe shutdown cables and equipment.

During normal operation, primary containment is inerted. Since containment is inerted no fire is postulated.

9A.5.5.3 Fire Area 54: Residual Heat Removal Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	NE - Reinforced concrete (primary containment wall)	None
	N - Reinforced concrete	3 hr
	W - Reinforced concrete (part below el 201', exterior wall)	None
	W - Reinforced concrete (part above el 201')	3 hr
	S - Reinforced concrete (part below el 198', exterior wall)	None
	S - Reinforced concrete (part above el 198')	3 hr
	E - Reinforced concrete	3 hr
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete (ceiling contains 115 ft^2 of unrated metal blowout panels leading to area 66)	None
Access:	Watertight doors connecting to areas 55 and 62	3 hr**
	Steamtight doors (at el 201') connecting to areas 55 and 64	3 hr

b. Major safety-related components in fire area:

1. RHR pumps 2AP202 and 2CP202

2. RHR heat exchanger 2AE205

3. RHR compartment unit coolers 2AV210, 2CV210, 2EV210, and 2GV210

c. Postulated fire in area:

Leakage of lube oil from both RHR pump motors onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 54 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B and C for Unit 1 and methods B and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B and C for Unit 1 and methods B and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B and C will be available to shutdown Unit 1 and methods B and C will be available to shutdown Unit 2.

f. Deviations:

The existence of unrated metal panels in the ceiling of this fire area is acceptable because the low combustible loadings in the areas above and below the panels and the height of the panels above the floor (40 feet) minimize the possibility of fire propagating through the panels. Penetrations of piping and electrical raceway through the ceiling are provided with 3 hour rated seals.

In the highly unlikely event that a fire in this area should propagate through the metal panels in the ceiling at elevation 217', safe shutdown capability would still be assured. Fire area 54 and the western portion of fire area 66 both credit method C for safe shutdown of Unit 2. The unlikely propagation of a fire through the metal panels does not impact safe shutdown of Unit 1.

The unrated metal panels are a deviation from the requirements of CMEB 9.5-1, C.5.b. Although the metal panels are unrated, safe shutdown requirements are met in that safe shutdown can be achieved even with the unlikely failure of the unrated barriers.

9A.5.5.4 Fire Area 55: Residual Heat Removal Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	E - Reinforced concrete	3 hr
	NE - Reinforced concrete	3 hr
	NW - Reinforced concrete (primary containment wall)	None
	W - Reinforced concrete	3 hr
	S - Reinforced concrete (part below el 198', exterior wall) None	
	S - Reinforced concrete (part above el 198')	3 hr
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete (ceiling contains 150 ft^2 of unrated metal blowout panels leading to area 66)	None

Access:	Watertight doors connecting to areas 54 and 56	3 hr**
	Steamtight doors (at el 201') connecting to areas 54 and 65	3 hr

b. Major safety-related components in fire area:

1. RHR pumps 2BP202 and 2DP202

2. RHR heat exchanger 2BE205

3. RHR compartment unit coolers 2BV210, 2DV210, 2FV210, and 2HV210

4. RCIC turbine exhaust line vacuum breaker valves HV-49-2F080 and HV-49-2F084

5. ESW loop "B" valves (HV-11-047, HV-11-077, HV-11-225, and HV-11-226)

c. Postulated fire in area:

Leakage of lube oil from both RHR pump motors onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 55 contains safe shutdown cables and equipment.

Cables required to support shutdown method B for Unit 1 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method B for Unit 1 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods A and C for Unit 1 and method C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A and C for Unit 1 and method C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and method C will be available to shutdown Unit 2.

f. Deviations:

The existence of unrated metal panels in the ceiling of this fire area is acceptable because the low combustible loadings in the areas above and below the panels and the height of the panels above the floor (40 feet) minimize the possibility of fire propagating through the panels. Penetrations of piping and electrical raceway through the ceiling are provided with 3 hour rated seals.

In the highly unlikely event that a fire in this area should propagate through the metal panels in the ceiling at elevation 217', safe shutdown capability would still be assured. Fire area 55 and the eastern portion of fire area 66 both credit method C for safe shutdown of Unit 2. The unlikely propagation of a fire through the metal panels does not impact safe shutdown of Unit 1.

The unrated metal panels are a deviation from the requirements of CMEB 9.5-1, C.5.b. Although the metal panels are unrated, safe shutdown requirements are met in that safe shutdown can be achieved even with the unlikely failure of the unrated barriers.

9A.5.5.5 Fire Area 56: Reactor Core Isolation Cooling Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	E - Reinforced concrete (exterior wall)	None
	N - Reinforced concrete	3 hr
	NE - Reinforced concrete	3 hr
	NW - Reinforced concrete (primary containment wall)	None
	SW - Reinforced concrete	3 hr
	W - Reinforced concrete	3 hr
	S - Reinforced concrete (part adjacent to stairwell no. 5)	2 hr
	S - Reinforced concrete (part, exterior wall below el 198')	None
	S - Reinforced concrete (part, exterior wall above el 198')	3 hr
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete (ceiling contains 25 ft^2 of unrated metal blowout panels leading to area 66)	None
Access:	Watertight doors connecting to areas 55 and 57	3 hr**
	Door connecting to stairwell no. 5	1.5 hr

b. Major safety-related components in fire area:

1. RCIC pump 20P203
2. RCIC turbine 20S212
3. RCIC compartment unit coolers 2AV208 and 2BV208

c. Postulated fire in area:

Leakage of lube oil from RCIC turbine onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 56 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Unit 1 and methods B and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 and methods B and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and methods B and C will be available to shutdown Unit 2.

f. Deviations:

The existence of unrated metal panels in the ceiling of this fire area is acceptable because the low combustible loadings in the areas above and below the panels and the height of the panels above the floor (40 feet) minimize the possibility of fire propagating through the panels. Penetrations of piping and electrical raceway through the ceiling are provided with 3 hour rated seals.

In the highly unlikely event that a fire in this area should propagate through the metal panels in the ceiling at elevation 217', safe shutdown capability would still be assured. Fire area 56 and the eastern portion of fire area 66 both credit method C for safe shutdown of Unit 2. The unlikely propagation of a fire through the metal panels does not impact safe shutdown of Unit 1.

The unrated metal panels are a deviation from the requirements of CMEB 9.5-1, C.5.b. Although the metal panels are unrated, safe shutdown requirements are met in that safe shutdown can be achieved even with the unlikely failure of the unrated barriers

9A.5.5.6 Fire Area 57: High Pressure Coolant Injection Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	E - Reinforced concrete (exterior wall)	None
	N - Reinforced concrete	3 hr
	W - Reinforced concrete (primary containment wall)	None
	SW - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete (ceiling contains 160 ft^2 of unrated metal blowout panels leading to area 66)	None
Access:	Watertight doors connecting to areas 56 and 63	3 hr**

b. Major safety-related components in fire area:

1. HPCI pump 20P204
2. HPCI turbine 20S211
3. HPCI compartment unit coolers 2AV209 and 2BV209
4. Instrument rack 20C014 (HPCI)

c. Postulated fire in area:

Leakage of lube oil from HPCI turbine onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire will activate the smoke detectors in this area, which will cause an audible-visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 57 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Unit 1 and methods A and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 and methods A and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and methods A and C will be available to shutdown Unit 2.

f. Deviations:

The existence of unrated metal panels in the ceiling of this fire area is acceptable because the low combustible loadings in the areas above and below the panels and the height of the panels above the floor (40 feet) minimize the possibility of fire propagating through the panels. Penetrations of piping and electrical raceway through the ceiling are provided with 3 hour rated seals.

In the highly unlikely event that a fire in this area should propagate through the metal panels in the ceiling at elevation 217', safe shutdown capability would still be assured. Fire area 57 and the eastern portion of fire area 66 both credit method C for safe shutdown of Unit 2. The unlikely propagation of a fire through the metal panels does not impact safe shutdown of Unit 1.

The unrated metal panels are a deviation from the requirements of CMEB 9.5-1, C.5.b. Although the metal panels are unrated, safe shutdown requirements are met in that safe shutdown can be achieved even with the unlikely failure of the unrated barriers.

9A.5.5.7 Fire Area 58: Core Spray Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	E - Reinforced concrete	3 hr
	N - Reinforced concrete	3 hr
	W - Reinforced concrete (primary containment wall)	None
	S - Reinforced concrete	3 hr
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Watertight door connecting to area 63	3 hr**

b. Major safety-related components in fire area:

1. Core spray pump 2BP206

2. Core spray compartment unit coolers 2BV211 and 2FV211

3. Safeguard piping fill pump 2BP256

c. Postulated fire in area:

Leakage of lube oil from core spray pump motor onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire will activate the smoke detectors in this area, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 58 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.5.8 Fire Area 59: Core Spray Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	E - Reinforced concrete	3 hr
	N - Reinforced concrete (part adjacent to fire areas 102 and 115)	3 hr
	N - Reinforced concrete (part adjacent to unexcavated area)	None
	W - Reinforced concrete	3 hr
	SW - Reinforced concrete (primary containment wall)	None
	S - Reinforced concrete	3 hr
Floor:	Reinforced concrete foundation mat	None

Ceiling:	Reinforced concrete	3 hr*
Access:	Watertight door connecting to area 63	3 hr**

b. Major safety-related components in fire area:

1. Core spray pump 2DP206

2. Core spray compartment unit coolers 2DV211 and 2HV211

c. Postulated fire in area:

Leakage of lube oil from core spray pump motor onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 59 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.5.9 Fire Area 60: Core Spray Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	E - Reinforced concrete	3 hr
	N - Reinforced concrete	3 hr
	W - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
	SE - Reinforced concrete (primary containment wall)	None

Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Watertight door connecting to area 62	3 hr**

b. Major safety-related components in fire area:

1. Core spray pump 2CP206

2. Core spray compartment unit coolers 2CV211 and 2GV211

c. Postulated fire in area:

Leakage of lube oil from core spray pump motor onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 60 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Unit 1 and methods B and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 and methods B and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and methods B and C will be available to shutdown Unit 2.

9A.5.5.10 Fire Area 61: Core Spray Compartment (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	W - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
	E - Reinforced concrete (primary containment wall)	None

Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Watertight door connecting to area 62	3 hr**

b. Major safety-related components in fire area:

1. Core spray pump 2AP206
2. Core spray compartment unit coolers 2AV211 and 2EV211
3. Safeguard piping fill pump 2AP256

c. Postulated fire in area:

Leakage of lube oil from core spray pump motor onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire will activate the smoke detectors in this area, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 61 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.5.11 Fire Area 62: Sump Room and Passageway (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	W - Reinforced concrete (part adjacent to stairwell no. 2)	2 hr
	W - Reinforced concrete (part)	3 hr

	S - Reinforced concrete (part adjacent to unexcavated area)	None
	S - Reinforced concrete (part)	3 hr
	E - Reinforced concrete (part, primary containment wall)	None
	E - Reinforced concrete (part)	3 hr
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Watertight doors connecting to areas 54, 60, and 61	3 hr**
	Door connecting to stairwell no. 2	1.5 hr

b. Major safety-related components in fire area:

1. Containment isolation valves (HV-52-227 and HV-52-228) for suppression pool cleanup pump suction line.

2. Instrument rack 20C075 (RHR pump "A" discharge pressure)

3. Instrument rack 20C077 (RHR pump "C" discharge pressure)

4. Instrument rack 20C018 (Div. 1 RHR and Div. 1 RHRSW)

c. Postulated fire in area:

1. Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

2. Ignition of oil in waste oil collection drum associated with the floor drain sump oil removal belt.

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 62 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.5.12 Fire Area 63: Corridor (el 177'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	N - Reinforced concrete (part adjacent to stairwell no. 6)	2 hr
	N - Reinforced concrete (part adjacent to unexcavated area)	None
	W - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
	E - Reinforced concrete (part adjacent to unexcavated area)	None
	E - Reinforced concrete (part adjacent to stairwell no. 6)	2 hr
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Watertight doors connecting to areas 57, 58, and 59	3 hr**
	Door connecting to stairwell no. 6	1.5 hr
	Elevator door	0.75 hr

b. Major safety-related components in fire area:

1. HPCI pump discharge flow transmitters (FT-55-2N008 and FT-55-2N051)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 63 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Unit 1 and methods A and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 and methods A and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1 and methods A and C will be available to shutdown Unit 2.

9A.5.5.13 Fire Area 64: Reactor Enclosure Cooling Water Equipment Area (el 201'-0")

a. Structural and architectural design features of fire area (Figure 9A-5):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	W - Reinforced concrete (part adjacent to stairwell no. 2)	2 hr
	W - Reinforced concrete (part adjacent to fire area 41)	3 hr
	W - Reinforced concrete (part adjacent to unexcavated area)	None
	S - Reinforced concrete	3 hr
	E - Reinforced concrete (part)	3 hr
	E - Reinforced concrete (primary containment wall)	None
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete (One portion of the ceiling slab, covering an area of 10 ft^2, has a reduced concrete thickness that varies between 4.5 inches and 9.0 inches.)	3 hr*
Access:	Door connecting to stairwell no. 2	1.5 hr
	Door connecting to area 54	3 hr

b. Major safety-related components in fire area:

1. Core spray loop "A" minimum flow recirculation valve (HV-52-2F031A)

2. Containment atmosphere sample return line isolation valves (SV-57-290 and SV-57-291)

3. ESW loop "A" valves (HV-11-046, HV-11-076, HV-11-221, HV-11-223, HV-11-224, HV-11-227 and HV-11-228)

4. HVAC unit cooler control panels 2AC208 and 2CC208

5. Motor control center 20B217, which serves the following components:
   (a) RHR loop "C" valves
   (b) RHR compartment unit coolers 2CV210 and 2GV210
   (c) Core spray loop "A" valves
   (d) Core spray compartment unit coolers 2CV211 and 2GV211
   (e) RHRSW outlet valve from RHR "A" heat exchanger (HV-51-2F068A)
   (f) Drywell unit cooler fans 2C2V212 and 2G2V212
   (g) Containment hydrogen recombiner 2AS403 and associated valves
   (h) HVAC 120 V ac transformer 20X283
   (i) PCIG supply header containment isolation valve (HV-59-251A)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 64 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Unit 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods B and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods B and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods B and C will be available to shutdown Unit 1, and method C will be available to shutdown Unit 2.

9A.5.5.14 Fire Area 65: Safeguard System Access Area (el 201'-0")

a. Structural and architectural design features of fire area (Figure 9A-5):

	Construction	Rating
Walls:	N - Reinforced concrete (part adjacent to stairwell no. 6)	2 hr
	N - Reinforced concrete (part)	3 hr
	W - Reinforced concrete	3 hr
	SW - Reinforced concrete (primary containment wall)	None
	S - Reinforced concrete (part adjacent to stairwell no. 5)	2 hr
	S - Reinforced concrete (part)	3 hr
	E - Reinforced concrete (part adjacent to unexcavated area)	None
	E - Reinforced concrete (part adjacent to stairwell no. 6)	2 hr
	E - Reinforced concrete (part adjacent to auxiliary boiler pipe tunnel)	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete (One portion of the ceiling slab, covering an area of 10 ft^2, has a reduced concrete thickness that varies between 4.5 inches and 9.0 inches.)	3 hr*
Access:	Elevator door	0.75 hr
	Doors connecting to stairwell nos. 5 and 6	1.5 hr
	Door connecting to area 55	3 hr
	Watertight door connecting to area 75	3 hr**

b. Major safety-related components in fire area:

1. HPCI valves HV-55-2F007 (pump discharge) and HV-55-2F008 (pump discharge recirculation to CST)

2. RCIC valves HV-49-2F012 (pump discharge) and HV-49-2F022 (pump discharge recirculation to CST)

3. HPCI level transmitters (LT-55-2N061B&F) and turbine exhaust pressure transmitters (PT-56-2N055D&H)

4. RCIC pump suction line level transmitters (LT-49-2N035A&E)

5. ESW loop "B" valves (HV-11-048, HV-11-049, HV-11-078, and HV-11-079)

6. Suppression chamber pressure transmitter (PT-57-201)

7. Instrument rack 20C017 (RCIC)

8. Instrument rack 20C021 (Div. 2 RHR and Div. 2 RHRSW)

9. Instrument rack 20C076 (RHR pump "B" discharge pressure)

10. Instrument rack 20C078 (RHR pump "D" discharge pressure)

11. HVAC unit cooler control panels 2BC208 and 2DC208

12. Motor control center 20B218, which serves the following components:
    (a) RHR loop "D" valves
    (b) RHR compartment unit coolers 2DV210 and 2HV210
    (c) Core spray pump suction valve (HV-52-2F001D)
    (d) Core spray compartment unit coolers 2DV211 and 2HV211
    (e) RHRSW outlet valve from RHR "B" heat exchanger (HV-51-2F068B)
    (f) Drywell unit cooler fans 2D2V212 and 2F2V212
    (g) Containment hydrogen recombiner 2BS403 and associated valves
    (h) HVAC 120 V ac transformer 20X284
    (i) PCIG supply header containment isolation valve (HV-59-251B)

c. Postulated fire in Area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 65 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Unit 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and method C will be available to shutdown Unit 2.

9A.5.5.15 Fire Area 66: Safeguard System Isolation Valve Area (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (part)	3 hr
	S - Reinforced concrete (exterior wall, contains 150 ft^2 of unrated blowout panels)	None
	W - Reinforced concrete	3 hr
	Interior boundary - Reinforced concrete (primary containment wall)	None
Floor:	Reinforced concrete (contains 450 ft^2 of unrated metal blowout panels from areas 54, 55, 56, and 57)	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Two steamtight doors connecting to area 67	3 hr

b. Major safety-related components in fire area:

1. HPCI steam line containment isolation valves (HV-55-2F003 and HV-55-2F100)

2. RCIC steam line containment isolation valves (HV-49-2F008 and HV-49-2F076)

3. RHR system valves:
   (a) HV-51-2F008 (shutdown cooling suction containment isolation)
   (b) HV-51-2F015A&B (shutdown cooling return containment isolation)
   (c) HV-51-2F047A&B (heat exchanger inlet)
   (d) HV-C-51-2F048A&B (heat exchanger bypass)

4. CAC system containment isolation valves (HV-57-209, HV-57-221, HV-57-223, HV-57-224, HV-57-231, HV-57-235, HV-57-247, HV-57-263, and HV-57-264)

5. PCIG system containment isolation valves (HV-59-202, HV-59-229A, HV-59-229B, HV-59-235, HV-59-251A, and HV-59-251B)

6. HPCI system leakage detection temperature elements

7. RCIC system leakage detection temperature elements

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

For the purposes of safe shutdown analyses, fire area 66 is divided into an eastern (66E) and a western (66W) portion through the establishment of a 20 foot wide zone that is free of combustible materials; no cable trays are located within this combustible-free zone.

66E

The eastern portion of fire area 66 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Unit 2 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and method C will be available to shutdown Unit 2, for a fire in the eastern half of fire area 66.

66W

The western portion of fire area 66 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 2 are either encapsulated by a qualified fire barrier, or associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown method C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Cables required to support shutdown methods A, B, and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and method C will be available to shutdown Unit 2, for a fire in the western half of fire area 66.

f. Deviations:

Fire area 66 is divided into a western portion and an eastern portion through the establishment of a 20 foot wide zone that is free of combustible materials. No cable trays are located within this combustible-free zone.

Several valves associated with the credited safe shutdown methods are located in fire area 66. Valves performing active, credited, redundant functions are located on opposite sides of fire area 66 and are separated by the combustible free zone. The only combustible materials in the intervening space are electrical cables in cable trays, and none of these cable trays are located within the combustible-free zone. The in situ combustible loading in fire area 66 is relatively light, with an equivalent severity of only 13 minutes. The potential for transient combustibles to exist in the space between credited, redundant valves is severely restricted by the arrangement of fire area 66 and the locations of commodities within it. The space between credited, redundant valves is relatively narrow and contains a high concentration of pipes and pipe supports. These obstructions effectively prevent the introduction of significant quantities of combustible materials into this space. The factors discussed above preclude the occurrence of a fire, involving either in situ combustibles or transient combustibles, that could simultaneously affect credited, redundant equipment.

The measures described above for physical separation and provision of fire barriers ensure that the plant can be safely shut down in the event of a fire in either the western portion or eastern portion of fire area 66.

This is a deviation from the CMEB 9.5-1, C.5.b requirement for automatic suppression. This deviation is documented in reference 9A.7.5.

9A.5.5.16 Fire Area 67: Safeguard System Access Area (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete (parts adjacent to stairwell nos. 2 and 6)	2 hr
	N - Reinforced concrete (part)	3 hr
	W - Reinforced concrete (part adjacent to stairwell no. 2)	2 hr
	W - Reinforced concrete (part)	3 hr
	S - Reinforced concrete (part adjacent to stairwell no. 5)	2 hr
	S - Reinforced concrete (part adjacent to fire area 125)	3 hr
	S - Reinforced concrete (part, exterior wall)	None
	E - Reinforced concrete (part adjacent to stairwell nos. 5 and 6)	2 hr
	E - Reinforced concrete (part)	3 hr
	Interior boundary (part) - Reinforced concrete walls	3 hr
	Interior boundary (part) - Reinforced concrete (primary containment wall)	None
Floor:	Reinforced concrete (Two portions of the floor slab, each of which covers an area of 10 ft^2, have a reduced concrete thickness that varies between 4.5 inches and 9.0 inches.)	3 hr*
Ceiling:	Reinforced concrete	3 hr*
Access:	Doors connecting to stairwell nos. 2, 5, and 6	1.5 hr
	Two steamtight doors connecting to area 66	3 hr
	Missile-resistant door connecting to area 76	3 hr**
	Equipment airlock door	None
	Elevator door	0.75 hr
	Suppression chamber access hatches	None
	Equipment hatchway in ceiling (200 ft^2 opening; protected by water curtain suppression system)	None

b. Major safety-related components in fire area:

1. Core spray full flow test recirculation valves (HV-52-2F015A&B)

2. CAC system containment isolation valves (HV-57-204, HV-57-205, HV-57-212, HV-57-218, and HV-57-262)

3. RHR system valves:
   (a) HV-51-225A&B (containment isolation for recirculation to suppression chamber)
   (b) HV-51-2F027A&B (containment isolation for suppression chamber spray)
   (c) HV-51-2F010A&B (loops C and D recirculation to suppression chamber)
   (d) HV-51-2F024A&B (loops A and B recirculation to suppression chamber)

4. Instrument racks 20C001 (core spray loop A) and 20C019 (core spray loop B)

5. Instrument racks 20C015, 20C025, 20C041, and 20C042 (main steam and reactor recirculation flow)

6. Instrument racks 20C016 and 20C036 (HPCI)

7. Instrument racks 20C035 and 20C038 (RCIC)

8. Instrument racks 20C006, 20C009, 20C010, and 20C022 (reactor recirculation system pressure and jet pump flow)

9. RHR flow transmitters (FT-51-2N015A,B,C&D and FT-51-2N052A,B,C&D)

10. Motor control center 20B211, which serves the following components:
    (a) RHR loop "A" valves
    (b) RHR compartment unit coolers 2AV210 and 2EV210
    (c) Core spray loop "A" valves
    (d) Core spray compartment unit coolers 2AV211 and 2EV211
    (e) RHRSW inlet valve to RHR "A" heat exchanger (HV-51-2F014A)
    (f) RHR shutdown cooling suction inboard isolation valve (HV-51-2F009)
    (g) RCIC compartment unit coolers 2AV208 and 2BV208
    (h) RWCU inboard isolation valve (HV-44-2F001)
    (i) Main steam drain line inboard isolation valve (HV-41-2F016)
    (j) Drywell unit cooler fans 2A1V212, 2C1V212, 2E1V212, and 2G1V212
    (k) Safeguard piping fill pump 2AP256
    (l) PCIG compressor suction line containment isolation valve (HV-59-201)
    (m) 120 V instrument ac distribution panel 20Y101
    (n) Battery chargers 2A1D103 and 2A2D103
    (o) Motor control center 20B215

11. Motor control center 20B212, which serves the following components:
    (a) RHR loop "B" valves
    (b) RHR compartment unit coolers 2BV210 and 2FV210
    (c) Core spray loop "B" valves
    (d) Core spray compartment unit coolers 2BV211 and 2FV211
    (e) RHRSW inlet valve to RHR "B" heat exchanger (HV-51-2F014B)
    (f) RHR shutdown cooling return isolation valve (HV-51-2F015A)

(g) Reactor recirculation pump suction valve (HV-43-2F023B)
(h) HPCI compartment unit coolers 2AV209 and 2BV209
(i) Drywell unit cooler fans 2B1V212, 2D1V212, 2F1V212, and 2H1V212
(j) Safeguard piping fill pump 2BP256
(k) CAC system purge line isolation valve (HV-57-205)
(l) 120 V instrument ac distribution panel 20Y102
(m) Battery chargers 2B1D103 and 2B2D103
(n) Motor control center 20B216

12. Motor control center 20B215, which serves the following components:
(a) RHR loop "A" valves
(b) RCIC system valves
(c) Deleted.
(d) Suppression pool cleanup pump suction isolation valve (HV-52-227)
(e) Drywell pressure tap isolation valve (HV-42-247A)
(f) Drywell floor drain and equipment drain containment isolation valves (HV-61-212 and HV-61-232)
(g) Main steam drain line flow control valve (HV-C41-2F020)

13. Motor control center 20B216, which serves the following components:
(a) RHR loop "B" valves
(b) HPCI system valves
(c) Deleted
(d) Suppression pool cleanup pump isolation valve (HV-52-228)
(e) Drywell pressure tap isolation valve (HV-42-247B)
(f) Suppression pool level tap isolation valves (HV-55-220 and HV-55-221)
(g) Reactor head spray outboard isolation valve (HV-51-2F023)
(h) RHR shutdown cooling suction outboard isolation valve (HV-51-2F008)
(i) RWCU outboard isolation valve (HV-44-2F004)
(j) Main steam drain line outboard isolation valve (HV-41-2F019)
(k) RHR to radwaste discharge line isolation valve (HV-51-2F049)

14. Dc motor control center 20D201, which serves the following components:
(a) RCIC system
(b) Div. 1 RPS and UPS static inverter

15. Dc motor control center 20D202, which serves the HPCI system

16. Dc motor control center 20D203, which serves the following components:
(a) HPCI system
(b) Div. 2 RPS and UPS static inverter

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the fire occurs within the coverage area of one of the three preaction sprinkler systems in this fire area, the system will provide automatic suppression of the fire. When the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual fusible link sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

For the purposes of safe shutdown analyses, fire area 67 is divided into an eastern (67E) and a western (67W) portion through the establishment of a 20 foot wide zone that is free of combustible materials.

67E

The eastern portion of fire area 67 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Unit 2 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods A and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Unit 1, and method C will be available to shutdown Unit 2, for a fire in the eastern half of fire area 67.

67W

The western portion of fire area 67 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 2 are either encapsulated by a qualified fire barrier, associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area.

Equipment associated with shutdown methods A, B, and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and method C will be available to shutdown Unit 2, for a fire in the western half of fire area 67.

f. Deviations:

Fire area 67 is divided into a western portion and an eastern portion through the establishment of a 20 foot wide zone that is free of combustible materials. All cable trays located within this combustible-free zone are enclosed by a galvanized steel cable tray enclosure system to cover the cable trays that pass through the zone. This non-combustible configuration together with the enclosure and seals will prevent fire propagation across the combustible zone. A fixed suppression system of the water curtain-type is located within the combustible-free zone to provide assurance that a postulated fire due to transient combustibles can be prevented from propagating through the combustible-free zone.

Several components associated with the credited safe shutdown methods are located in fire area 67. Components performing active, credited, redundant functions are located on opposite sides of fire area 67 and are separated by the combustible free zone. The only combustible materials in the intervening space are electrical cables in cable tray up to the boundaries of the combustible free zone.

The locations of preaction sprinkler systems and water curtain suppression systems in fire area 67 are shown in Figure 9A-6.

The measures described above for physical separation, fire suppression, and provision of fire barriers ensure that the plant can be safely shut down in the event of a fire in either the western portion or the eastern portion of fire area 67.

This is a deviation from the CMEB 9.5-1, C.5.b requirement for automatic suppression. This deviation is documented in reference 9A.7.5.

9A.5.5.17 Fire Area 68: CRD Hydraulic Equipment Area and Neutron Monitoring System Area (el 253'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Reinforced concrete (parts adjacent to stairwell nos. 2 and 6)	2 hr
	N - Reinforced concrete (part)	3 hr
	W - Reinforced concrete (part adjacent to stairwell no. 2)	2 hr
	W - Reinforced concrete (part)	3 hr

	S - Reinforced concrete (part adjacent to stairwell no. 5)	2 hr
	S - Reinforced concrete (part, exterior wall)	None
	E - Reinforced concrete (parts adjacent to stairwell nos. 5 and 6)	2 hr
	E - Reinforced concrete (part, exterior wall)	None
	Interior boundary (part adjacent to main steam tunnel) - Reinforced concrete	3 hr
	Interior boundary (part) - Reinforced concrete (primary containment wall)	None
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr*
Access:	Doors connecting to stairwell nos. 2, 5, and 6	1.5 hr
	Elevator door	0.75 hr
	Drywell access hatches	None
	Watertight door connecting to area 69	3 hr**
	Equipment hatchways in floor and ceiling (200 ft^2 openings; protected by water curtain suppression systems)	None
	Double steamtight door airlock connecting to area 45	3 hr**

b. Major safety-related components in fire area:

1. DCWS valves HV-87-222, HV-87-223, HV-87-228, and HV-87-229 (supply and return line containment isolation)

2. CRD system master control station

3. CRD system hydraulic control units

4. Containment combustible gas analyzer sample package 20S206

5. Load center 20B203 (Div. 3)

6. Deleted

7. Instrument racks 20C004, 20C005, 20C026, and 20C027 (RPV instrumentation and LPCI injection valve ΔP transmitters)

8. SLCS injection line containment isolation valves (HV-48-2F006A&B)

9. Reactor vessel pressure transmitters (PT-42-203A&B)

10. Reactor vessel water level transmitters (LT-42-215A&B)

11. Drywell pressure transmitters (PT-42-201 and PT-42-270)

12. PCIG supply line pressure monitoring instrumentation (PT-59-252A&B and PDS-59-206A&B)

13. Motor control center 20B223, which serves the following components:
    (a) LPCI injection containment isolation valve (HV-51-2F017C)
    (b) RHR loop "C" minimum flow recirculation isolation valve (HV-51-205A)
    (c) RCIC system valves (HV-49-2F007 and HV-49-2F084)
    (d) Standby liquid control pump 2CP208
    (e) Containment combustible gas analyzer sample package 20S206
    (f) Drywell pressure tap isolation valve (HV-42-247C)
    (g) Drywell unit cooler fans 2A2V212 and 2E2V212
    (h) Reactor recirculation pump cooling water isolation valves (HV-13-206 and HV-13-207)
    (i) Battery charger 2CD103
    (j) Instrument ac transformer 20X108
    (k) Feedwater line inboard maintenance isolation valve (HV-41-2F011B)

14. Motor control center 20B224, which serves the following components:
    (a) LPCI injection containment isolation valve (HV-51-2F017D)
    (b) RHR loop "D" minimum flow recirculation isolation valve (HV-51-205B)
    (c) HPCI system valves (HV-55-2F002 and HV-55-2F095)
    (d) Containment combustible gas analyzer sample package 20S205
    (e) Drywell pressure tap isolation valve (HV-42-247D)
    (f) Reactor recirculation pump cooling water source select valves (HV-13-208 and HV-13-211)
    (g) Drywell unit cooler fans 2B2V212 and 2H2V212
    (h) Battery charger 2DD103
    (i) Instrument ac transformer 20X109

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the fire occurs within the coverage area of one of the two preaction sprinkler systems in this fire area, the system will provide automatic suppression of the fire. When the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual fusible link sprinkler heads will

open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

If the fire occurs within the coverage area of the wet pipe sprinkler systems in this fire area, the systems will provide automatic suppression of the fire. When the compartment temperature rises to 200°F, individual fusible link sprinklers will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

For the purposes of safe shutdown analyses, fire area 68 is divided into an eastern (68E) and a western (68W) portion through the establishment of a 20 foot wide zone that is free of combustible materials; no cable trays are located within this combustible-free zone.

68E

The eastern portion of fire area 68 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A and C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods A and C for Unit 2 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and method C will be available to shutdown Unit 2, for a fire in the eastern half of fire area 68.

68W

The western portion of fire area 68 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 2 are either encapsulated by a qualified fire barrier, associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 1 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods A, B, and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and method C will be available to shutdown Unit 2, for a fire in the western half of fire area 68.

f. Deviations:

Fire area 68 is divided into a western portion and an eastern portion through the establishment of a 20 foot wide zone that is free of combustible materials. No cable trays are located within this combustible-free zone. A fixed suppression system of the water curtain-type is located within the combustible-free zone to provide assurance that a postulated fire due to transient combustibles can be prevented from propagating through the combustible-free zone.

Several components associated with the credited safe shutdown methods are located in fire area 68. Components performing active, credited, redundant functions are located on opposite sides of fire area 68 and are separated by the combustible free zone. The only combustible materials in the intervening space are electrical cables in cable tray up to the boundaries of the combustible free zone.

The locations of the preaction sprinkler systems and the water curtain suppression system in fire area 68 are shown in Figure 9A-7.

The measures described above for physical separation, fire suppression, and provision of fire barriers ensure that the plant can be safely shut down in the event of a fire in either the western portion or the eastern portion of fire area 68.

This is a deviation from the CMEB 9.5-1, C.5.b requirement for automatic suppression. This deviation is documented in reference 9A.7.5.

9A.5.5.18 Fire Area 69: Main Steam Tunnel (el 253'-0")

a. Structural and architectural design features of fire area (Figures 9A-7, 9A-8, 9A-9, and 9A-10):

	Construction	Rating
Walls:	N - Reinforced concrete (contains 233 ft^2 of unrated metal	3 hr

	blowout panels)	
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (part, primary containment wall)	None
	S - Reinforced concrete (part)	3 hr
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete (part at el 295'-3")	3 hr*
	Reinforced concrete (part at el 365' roof slab)	None
Access:	Watertight door connecting to area 68	3 hr**
	Steamtight doors connecting to areas 28 and 70	3 hr

b. Major safety-related components in fire area:

1. Main steam line outboard containment isolation valves (HV-41-2F028A,B,C&D)
2. Feedwater line outboard containment isolation valves (HV-41-2F032A&B and HV-41-2F074A&B)
3. Main steam drain line outboard containment isolation valve (HV-41-2F019)
4. Deleted
5. RCIC injection valve (HV-49-2F013)
6. Steam line radiation sensors (RE-41-2N006A,B,C&D)

c. Postulated fire in area:

Since no combustible materials are located in this area, the origin of a postulated fire is indeterminate.

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the plant fire brigade will be dispatched to el 253' and/or el 283' in the reactor enclosure and will enter the main steam tunnel through doors at those elevations. The fire brigade will extinguish the fire using portable fire extinguishers or hoses from hose stations located outside the entrances to the main steam tunnel.

e. Effect of fire on safe shutdown:

Fire area 69 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Unit 1 and methods B and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and

C for Unit 1 and methods B and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and methods B and C will be available to shutdown Unit 2.

9A.5.5.19 Fire Area 70: RWCU Compartments, FPCC Compartment, and General Equipment Area (el 283'-0" and el 295'-3")

a. Structural and architectural design features of fire area (Figure 9A-8):

	Construction	Rating
Walls:	N - Reinforced concrete (parts adjacent to stairwell nos. 2 and 6)	2 hr
	N - Reinforced concrete (part)	3 hr
	W - Reinforced concrete (part adjacent to stairwell no. 2)	2 hr
	W - Reinforced concrete (part)	3 hr
	S - Reinforced concrete (part adjacent to stairwell no. 5)	2 hr
	S - Reinforced concrete (part, exterior wall)	None
	E - Reinforced concrete (parts adjacent to stairwell nos. 5 and 6)	2 hr
	E - Reinforced concrete (part, exterior wall)	None
	Interior boundary (east and west walls of area 69) - Reinforced concrete	3 hr
	Interior boundary (primary containment wall) - Reinforced concrete	None
Floor:	Reinforced concrete	3 hr*
Ceiling:	einforced concrete	3 hr*
Access:	Doors connecting to stairwell nos. 2, 5, and 6	1.5 hr
	Steamtight door connecting to area 69	3 hr
	Elevator door	0.75 hr
	Equipment hatchways in floor and ceiling (200 ft^2 openings; protected by water curtain suppression systems)	None

b. Major safety-related components in fire area:

1. Containment hydrogen recombiner packages 2AS403 and 2BS403

2. SLCS components:
   (a) Storage tank 20T204
   (b) Injection pumps 2AP208, 2BP208, and 2CP208
   (c) Explosive valves XV-48-2F004A,B&C

3. Core spray loop "A" injection valves (HV-52-2F004A and HV-52-2F005)

4. Core spray loop "B" injection valves (HV-52-2F004B, HV-52-2F037, and HV-52-208)

5. RHR system valves:
   (a) HV-51-2F017A,B,C&D (LPCI injection line containment isolation)
   (b) HV-51-2F021A&B (drywell spray line containment isolation)
   (c) HV-51-2F016A&B (drywell spray line shutoff)

6. HPCI system injection valve (HV-55-2F006)

7. RWCU supply line containment isolation valve (HV-44-2F004)

8. CAC system purge line containment isolation valves (HV-57-211, HV-57-215, HV-57-214, and HV-57-261)

9. Containment combustible gas analyzer sample package 20S205

10. Load center 20B204 (Div. 4)

11. Motor control center 20B213, which serves the following components:
   (a) RHR loop "A" valves
   (b) Core spray loop "A" valves
   (c) Feedwater startup recirculation valve (HV-41-209A)
   (d) Shutoff valves for main steam to miscellaneous steam-driven components (HV-01-208, HV-01-209, HV-01-211, and HV-01-250)
   (e) Drywell chilled water source select valves (HV-87-220A&B, HV-87-221A&B, HV-87-224A&B, and HV-87-225A&B)
   (f) Feedwater line outboard containment isolation valve (HV-41-2F032B)
   (g) Feedwater line inboard maintenance isolation valve (HV-41-2F011A)
   (h) SLCS pump 2AP208
   (i) SLCS injection line containment isolation valve (HV-48-2F006A)
   (j) RERS train "A" valves (HV-76-209, HV-76-284A, and HV-76-291A)
   (k) CAC system containment isolation valves (HV-57-212 and HV-57-215)
   (l) HVAC 120 V ac distribution panel 20X281

12. Motor control center 20B214, which serves the following components:
   (a) RHR loop "B" valves
   (b) Core spray loop "B" valves

(c) Drywell cooling water containment isolation valves (HV-87-222, HV-87-223, HV-87-228, and HV-87-229)
(d) Feedwater startup recirculation valve (HV-41-209B)
(f) Feedwater line outboard containment isolation valve (HV-41-2F032A)
(g) SLCS pump 2BP208
(h) SLCS injection line containment isolation valve (HV-48-2F006B)
(i) RERS train "B" valves (HV-76-210, HV-76-284B, and HV-76-291B)
(j) CAC system containment isolation valve (HV-57-211)
(k) HVAC 120 V ac distribution panel 20X282

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the fire occurs within the coverage area of the preaction sprinkler system in this fire area, the system will provide automatic suppression of the fire. When the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual fusible link sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

For the purposes of safe shutdown analyses, fire area 70 is divided into an eastern (70E) and a western (70W) portion through the establishment of a 20 foot wide zone that is free of combustible materials; no cable trays are located within this combustible-free zone.

70E

The eastern portion of fire area 70 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Unit 2 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and method C will be available to shutdown Unit 2, for a fire in the eastern half of fire area 70.

70W

The western portion of fire area 70 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 2 are either encapsulated by a qualified fire barrier, associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and method C will be available to shutdown Unit 2, for a fire in the western half of fire area 70.

f. Deviations:

Fire area 70 is divided into a western portion and an eastern portion through the establishment of a 20 foot wide zone that is free of combustible materials. No cable trays are located within this combustible-free zone.

Several components associated with the credited safe shutdown methods are located in fire area 70. Components performing active, credited, redundant functions are located on opposite sides of fire area 70 and are separated by the combustible free zone. The only combustible materials in the intervening space are electrical cables in cable tray up to the boundaries of the combustible free zone.

The location of the preaction sprinkler system in fire area 70 is shown in Figure 9A-8.

The measures described above for physical separation, fire suppression, and provision of fire barriers ensure that the plant can be safely shut down in the event of a fire in either the western portion or the eastern portion of fire area 70.

This is a deviation from the CMEB 9.5-1, C.5.b requirement for automatic suppression. This deviation is documented in reference 9A.7.5.

9A.5.5.20 Fire Area 71: RWCU Holding Pump Compartments, RERS Fan Area, and Corridors (el 313'-0")

a. Structural and architectural design features of fire area (Figure 9A-9):

	Construction	Rating
Walls:	N - Reinforced concrete (part adjacent to stairwell no. 6)	2 hr
	N - Reinforced concrete (part)	3 hr
	W - Reinforced concrete	3 hr
	S - Reinforced concrete (part)	3 hr
	S - Reinforced concrete (part adjacent to stairwell no. 5)	2 hr
	E - Reinforced concrete (part, exterior wall)	None
	E - Reinforced concrete (part adjacent to stairwell no. 6)	2 hr
	Interior boundary - Reinforced concrete (primary containment wall)	None
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr*
Access:	Doors connecting to stairwell nos. 5 and 6	1.5 hr
	Airlock door connecting to area 72	3 hr
	Double airlock door connecting to area 72	3 hr**
	Elevator door	0.75 hr
	Equipment hatchway in floor ($200\ ft^2$ opening; protected by water curtain suppression system)	None

b. Major safety-related components in fire area:

1. RERS fans (2AV213 and 2BV213)

2. Load center 20B201 (Div. 1)

3. Load center 20B202 (Div. 2)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

For the purposes of safe shutdown analyses, fire area 71 is divided into an eastern (71E) and a western (71W) portion through the establishment of a 20 foot wide zone that is free of combustible materials; no cable trays are located within this combustible-free zone.

71E

The eastern portion of fire area 71 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A and C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown methods A and C for Unit 2 located in this fire area either have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and methods A and C will be available to shutdown Unit 2, for a fire in the eastern half of fire area 71.

71W

The western portion of fire area 71 contains safe shutdown cables and equipment.

Cables required to support shutdown method C for Unit 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area, or can be credited for safe shutdown by manual operator actions to recover any functions that could be lost.

Cables required to support shutdown methods A, B, and C for Unit 1 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and method C will be available to shutdown Unit 2, for a fire in the western half of fire area 71.

f. Deviation:

Load centers 20B201 and 20B202 and their associated transformers are the only components credited for safe shutdown which are located in fire area 71. The horizontal separation between the two load centers is approximately 35 feet, and there are no cable trays located in the intervening space. A 20 foot wide zone that is free of combustible materials is maintained between the two load centers. A fixed suppression system of the water curtain-type is located within the combustible-free zone to provide assurance that a postulated fire due to transient combustibles can be prevented from propagating through the combustible-free zone. To preclude the possibility of a spilled combustible liquid spreading across the area between the two load centers, a concrete curb is provided between the load centers, spanning the full width of the corridor in which the load centers are located. The curb is located within the coverage area of the water curtain system. To protect the load centers from radiant heat that could be generated by a postulated fire occurring in the area between the load centers, each load center is provided with a radiant heat shield. The heat shields are constructed of Marinite sheet and are located adjacent to the side of each load center that faces the concrete curb.

The measures described above for physical separation, fire suppression, and provision of fire barriers ensure that the plant can be safely shut down in the event of a fire in either the western portion or the eastern portion of fire area 48.

This is a deviation from the CMEB 9.5-1, C.5.b requirement for automatic suppression. This deviation is documented in reference 9A.7.5.

9A.5.5.21 Fire Area 72: Reactor Enclosure Lower Fan Room (el 313'-0")

a. Structural and architectural design features of fire area (Figure 9A-9):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (part, exterior wall)	None
	S - Louvers open to outside atmosphere (part)	None
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete (part below fire area 73)	None
	Reinforced concrete (part below fire area 74)	3 hr*
Access:	Airlock door connecting to area 71	3 hr
	Double airlock door connecting to area 71	3 hr**
	Emergency exit in ceiling (6.25 ft^2 opening)	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Once the control room operators have been notified that a fire has occurred in this area, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect on fire safe shutdown:

Fire area 72 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.5.22 Fire Area 73: Reactor Enclosure Upper Fan Room and Equipment Compartment Exhaust Filter Rooms (el 331'-0")

a. Structural and architectural design features of fire area (Figure 9A-9):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	W - Reinforced concrete	3 hr
	S - Reinforced concrete (exterior wall)	None
	E - Reinforced concrete (part adjacent to stairwell no. 5)	2 hr
	E - Reinforced concrete (part)	3 hr
Floor:	Reinforced concrete	None
Ceiling:	Reinforced concrete	3 hr*
Access:	Door connecting to stairwell no. 5	1.5 hr
	Two doors connecting to area 74	3 hr
	Emergency exit in floor (6.25 ft^2 opening)	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of charcoal filters.

d. Consequences of fire with active fire suppression:

In the event of a fire in one of the reactor enclosure equipment compartment exhaust filters, a thermal sensor inside the filter plenum will cause an audible/visual annunciation to

register on the fire protection panels in the control room. Once the alarm has been received in the control room, the affected ventilation system will be shut down and the plant fire brigade will be dispatched to extinguish the fire.

The fire brigade will utilize a manual valve in the fire protection water supply system to initiate operation of a water spray system inside the filter plenum.

e. Effect on fire safe shutdown:

Fire area 73 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.5.23 Fire Area 74: RERS Filter Compartments (el 331-0")

a. Structural and architectural design features of fire area (Figure 9A-9):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	W - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
	E - Reinforced concrete (exterior wall)	None
Floor:	Reinforced concrete	3 hr*
Ceiling:	Reinforced concrete	3 hr*
Access:	Two doors connecting to area 73	3 hr

b. Major safety-related components in fire area:

1. RERS filter assemblies (2AS297 and 2BS297)

c. Postulated fire in area:

Ignition of charcoal filters.

d. Consequences of fire with active fire suppression:

In the event of a fire in one of the reactor enclosure recirculation system filters, a thermal sensor inside the filter plenum will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire. The fire brigade will utilize a manual valve in the fire protection water supply system to initiate operation of a water spray system inside the filter plenum.

e. Effect on fire safe shutdown:

Fire area 74 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.6 SAFE SHUTDOWN ANALYSIS - DIESEL GENERATOR ENCLOSURES

9A.5.6.1 Fire Area 79: Diesel Generator Cell 1A (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (exterior wall)	None
	W - Reinforced concrete (exterior wall)	None
Floor:	Reinforced concrete (portion on foundation slab)	None
	Reinforced concrete (portion above fire area 75)	3 hr*
Ceiling:	Reinforced concrete roof slab	None
Access:	Door at north side of cell	3 hr
	Door at south side of cell	None

b. Major safety-related components in fire area:

1. Diesel generator 1A and auxiliaries
2. ESW supply and return shutoff valves (11-1131A, HV-11-132A, HV-11-133A, and HV-11-134A)
3. Diesel generator air exhaust fans 1AV512 and 1EV512
4. Diesel generator control board 1AC514
5. Dc distribution panel 1AD501 (serving diesel generator 1A and auxiliaries)
6. Motor control center 10B515, which serves the following components:
   (a) Auxiliaries of diesel generator 1A
   (b) ESW loop "A" discharge valve (HV-11-011A)

c. Postulated fire in area:

Leakage of fuel oil or lubricating oil from the diesel engine onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

A fire will activate the detectors in this area, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 79 contains safe shutdown cables and equipment.

Cables required to support shutdown methods B and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods B and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods B and C will be available to shutdown Units 1 and 2.

9A.5.6.2 Fire Area 80: Diesel Generator Cell 1C (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (exterior wall)	None
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete (portion on foundation slab)	None
	Reinforced concrete (portion above fire area 75)	3 hr*
Ceiling:	Reinforced concrete roof slab	None
Access:	Door at north side of cell	3 hr
	Door at south side of cell	None

b. Major safety-related components in fire area:

1. Diesel generator 1C and auxiliaries
2. ESW supply and return shutoff valves (11-1131C, HV-11-132C, HV-11-133C, and HV-11-134C)
3. Diesel generator air exhaust fans 1CV512 and 1GV512
4. Diesel generator control board 1CC514
5. Dc distribution panel 1CD501 (serving diesel generator 1C and auxiliaries)
6. Motor control center 10B517, which serves auxiliaries of diesel generator 1C

c. Postulated fire in area:

Leakage of fuel oil or lubricating oil from the diesel engine onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

A fire will activate the detectors in this area, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 80 contains safe shutdown cables and equipment.

Cables required to support shutdown method A for Units 1 and 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method A for Units 1 and 2 located in this fire area may have redundant components that are not affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods B and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods B and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.6.3 Fire Area 81: Diesel Generator Cell 1B (el. 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (exterior wall)	None
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete (portion on foundation slab)	None
	Reinforced concrete (portion above fire area 75)	3 hr*
Ceiling:	Reinforced concrete roof slab	None
Access:	Door at north side of cell	3 hr
	Door at south side of cell	None

b. Major safety-related components in fire area:

1. Diesel generator 1B and auxiliaries

2. ESW supply and return shutoff valves (HV-11-131B, HV-11-132B, 11-1133B, and HV-11-134B)

3. Diesel generator air exhaust fans 1BV512 and 1FV512

4. Diesel generator control board 1BC514

5. Dc distribution panel 1BD501 (serving diesel generator 1B and auxiliaries)

6. Motor control center 10B516, which serves auxiliaries of diesel generator 1B

c. Postulated fire in area:

Leakage of fuel oil or lubricating oil from the diesel engine onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

A fire will activate the detectors in this area, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 81 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Units 1 and 2.

9A.5.6.4 Fire Area 82: Diesel Generator Cell 1D (el. 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete (part adjacent to equipment airlock)	3 hr
	E - Reinforced concrete (part, exterior wall)	None
	S - Reinforced concrete (exterior wall)	None

	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete (portion on foundation slab)	None
	Reinforced concrete (portion above fire area 75)	3 hr*
Ceiling:	Reinforced concrete roof slab	None
Access:	Door at north side of cell	3 hr
	Door at south side of cell	None

b. Major safety-related components in fire area:

1. Diesel generator 1D and auxiliaries

2. ESW supply and return shutoff valves (HV-11-131D, HV-11-132D, 11-1133D, and HV-11-134D)

3. Diesel generator air exhaust fans 1DV512 and 1HV512

4. Diesel generator control board 1DC514

5. Dc distribution panel 1DD501 (serving diesel generator 1D and auxiliaries)

6. Motor control center 10B518, which serves the following components:
   (a) Auxiliaries of diesel generator 1D
   (b) ESW loop "B" discharge valve (HV-11-015B)

c. Postulated fire in area:

Leakage of fuel oil or lubricating oil from the diesel engine onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

A fire will activate the detectors in this area, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 82 contains safe shutdown cables and equipment.

Cables required to support shutdown method B for Units 1 and 2 are either associated with equipment that have redundant components that are not affected by a fire in this area, or associated with equipment for which manual operator actions can be taken to recover any functions that could be lost. Equipment associated with shutdown method B for Units 1 and 2 located in this fire area may have redundant components that are not

affected by a fire in this area, or manual operator actions may be taken to recover any essential functions that could be lost.

Cables required to support shutdown methods A and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.6.5 Fire Area 83: Diesel Generator Cell 2A (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (exterior wall)	None
	W - Reinforced concrete (part adjacent to equipment airlock)	3 hr
	W - Reinforced concrete (part, exterior wall)	None
Floor:	Reinforced concrete (portion on foundation slab)	None
	Reinforced concrete (portion above fire area 75)	3 hr*
Ceiling:	Reinforced concrete roof slab	None
Access:	Door at north side of cell	3 hr
	Door at south side of cell	None

b. Major safety-related components in fire area:

1. Diesel generator 2A and auxiliaries
2. ESW supply and return shutoff valves (11-2231A, HV-11-232A, HV-11-233A, and HV-11-234A)
3. Diesel generator air exhaust fans 2AV512 and 2EV512
4. Diesel generator control board 2AC514
5. Dc distribution panel 2AD501 (serving diesel generator 2A and auxiliaries)
6. Motor control center 20B515, which serves auxiliaries of diesel generator 2A

c. Postulated fire in area:

Leakage of fuel oil or lubricating oil from the diesel engine onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

A fire will activate the detectors in this area, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 83 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Unit 1 and methods B and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 and methods B and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and methods B and C will be available to shutdown Unit 2.9A.5.6.6 Fire Area 84: Diesel Generator Cell 2C (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (exterior wall)	None
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete (portion on foundation slab)	None
	Reinforced concrete (portion above fire area 75)	3 hr*
Ceiling:	Reinforced concrete roof slab	None
Access:	Door at north side of cell	3 hr
	Door at south side of cell	None

b. Major safety-related components in fire area:

1. Diesel generator 2C and auxiliaries

2. ESW supply and return shutoff valves (11-2231C, HV-11-232C, HV-11-233C, and HV-11-234C)

3. Diesel generator air exhaust fans 2CV512 and 2GV512

4. Diesel generator control board 2CC514

5. Dc distribution panel 2CD501 (serving diesel generator 2C and auxiliaries)

6. Motor control center 20B517, which serves the following components:
   (a) Auxiliaries of diesel generator 2C
   (b) ESW loop "A" discharge valve (HV-11-015A)

c. Postulated fire in area:

Leakage of fuel oil or lubricating oil from the diesel engine onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

A fire will activate the detectors in this area, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 84 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.6.7 Fire Area 85: Diesel Generator Cell 2B (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (exterior wall)	None
	W - Reinforced concrete	3 hr

Floor:	Reinforced concrete (portion on foundation slab)	None
	Reinforced concrete (portion above fire area 75)	3 hr*
Ceiling:	Reinforced concrete roof slab	None
Access:	Door at north side of cell	3 hr
	Door at south side of cell	None

b. Major safety-related components in fire area:

1. Diesel generator 2B and auxiliaries

2. ESW supply and return shutoff valves (HV-11-231B, HV-11-232B, 11-2233B, and HV-11-234B)

3. Diesel generator air exhaust fans 2BV512 and 2FV512

4. Diesel generator control board 2BC514

5. Dc distribution panel 2BD501 (serving diesel generator 2B and auxiliaries)

6. Motor control center 20B516, which serves the following components:
   (a) Auxiliaries of diesel generator 2B
   (b) ESW loop "B" discharge valve (HV-11-011B)

c. Postulated fire in area:

Leakage of fuel oil or lubricating oil from the diesel engine onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

A fire will activate the detectors in this area, which will cause an audible/visual to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 85 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Unit 1 and methods A and C for Unit 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Unit 1 and methods A and C for Unit 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Unit 1, and methods A and C will be available to shutdown Unit 2.

9A.5.6.8 Fire Area 86: Diesel Generator Cell 2D (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete (exterior wall)	None
	S - Reinforced concrete (exterior wall)	None
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete (portion on foundation slab)	None
	Reinforced concrete (portion above fire area 75)	3 hr*
Ceiling:	Reinforced concrete roof slab	None
Access:	Door at north side of cell	3 hr
	Door at south side of cell	None

b. Major safety-related components in fire area:

1. Diesel generator 2D and auxiliaries
2. ESW supply and return shutoff valves (HV-11-231D, HV-11-232D, 11-2233D, and HV-11-234D)
3. Diesel generator air exhaust fans 2DV512 and 2HV512
4. Diesel generator control board 2DC514
5. Dc distribution panel 2DD501 (serving diesel generator 2D and auxiliaries)
6. Motor control center 20B518, which serves auxiliaries of diesel generator 2D

c. Postulated fire in area:

Leakage of fuel oil or lubricating oil from the diesel engine onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

A fire will activate the detectors in this area, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 86 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.6.9 Fire Area 124: Diesel Generator Access Corridor for Unit 1 (el. 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete	3 hr
	W - Reinforced concrete (exterior wall)	None
Floor:	Reinforced concrete	None
Ceiling:	Reinforced concrete roof slab	None
Access:	Door to outside at west end of corridor	None
	Four doors at south side of corridor, leading to diesel generator cells	3 hr

b. Major safety-related components in fire area:

1. RHRSW radiation monitors 0AS578 and 0BS578

2. Deleted

3. Primary containment post-LOCA radiation monitoring electronics (RY-26-191A,B,C,D)

c. Postulated fire in area:

Since no combustible materials are located in this area, the origin of a postulated fire is indeterminate.

d. Consequences of fire with active fire suppression:

Upon receipt of notification in the control room that a fire has occurred in this area, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 124 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.6.10 Fire Area 125: Diesel Generator Access Corridor for Unit 2 (el. 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete (exterior wall)	None
	S - Reinforced concrete	3 hr
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete	None
Ceiling:	Reinforced concrete roof slab	None
Access:	Door to outside at east end of corridor	None
	Four doors at south side of corridor, leading to diesel generator cells	3 hr

b. Major safety-related components in fire area:

1. Deleted

2. Primary containment post-LOCA radiation monitoring electronics (RY-26-291A,B,C,D)

c. Postulated fire in area:

Since no combustible materials are located in this area, the origin of a postulated fire is indeterminate.

d. Consequences of fire with active fire suppression:

Upon receipt of notification in the control room that a fire has occurred in this area, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 125 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.7 SAFE SHUTDOWN ANALYSIS - SPRAY POND PUMP STRUCTURE

9A.5.7.1 Fire Area 122: Spray Pond Pump Structure, Western Half

a. Structural and architectural design features of fire area (Figures 9A-11 and 9A-12):

	Construction	Rating
Walls:	N - Reinforced concrete(exterior wall)	None
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (exterior wall)	None
	W - Reinforced concrete (exterior wall)	None
Floor:	Reinforced concrete foundation	None
Ceiling:	Reinforced concrete roof slab	None
Access:	Door connecting to area 123	3 hr
	Door connecting to outside	None
	Roll-up door connecting to outside	None

b. Major safety-related components in fire area:

1. ESW pumps OAP548 and OCP548
2. RHRSW pumps OAP506 and OCP506
3. Sluice gates HV-12-003A&C
4. RHRSW valves:
   (a) HV-12-031A&C (winter bypass line)
   (b) HV-12-032A&C (spray networks A and C)
   (c) HV-12-034A (spray network cross-connection)
   (d) HV-12-112 and HV-12-114 (inlet from the Unit 1 cooling tower)
5. Spray pond pump structure supply fans OAV543 and OCV543
6. Motor control centers OOB519 (Div. 1) and OOB521 (Div. 3), which serve the following components:
   (a) ESW loop "A" valves
   (b) RHRSW loop "A" valves
   (c) Spray pond pump structure supply fan OAV543 and associated heaters and dampers
   (d) Spray pond pump structure supply fan OCV543 and associated heaters and dampers
7. Class 1E instrument ac distribution panels 01Y501 (Div. 1) and 03Y501 (Div. 3)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 122 contains safe shutdown cables and equipment.

Cables required to support shutdown methods B and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods B and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods B and C will be available to shutdown Units 1 and 2.

9A.5.7.2 Fire Area 123: Spray Pond Pump Structure, Eastern Half

a. Structural and architectural design features of fire area (Figures 9A-11 and 9A-12):

	Construction	Rating
Walls:	N - Reinforced concrete(exterior wall)	None
	E - Reinforced concrete (exterior wall)	None
	S - Reinforced concrete (exterior wall)	None
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete foundation	None
Ceiling:	Reinforced concrete roof slab	None
Access:	Door connecting to area 122	3 hr
	Door connecting to outside	None
	Roll-up door connecting to outside	None

b. Major safety-related components in fire area:

1. ESW pumps OBP548 and ODP548

2. RHRSW pumps OBP506 and ODP506

3. Sluice gates HV-12-003B&D

4. RHRSW valves:
   (a) HV-12-031B&D (winter bypass line)

(b) HV-12-032B&D (spray networks B and D)
(c) HV-12- (spray network cross-connection)
(d) HV-12-212 and HV-12-214 (inlet from the Unit 2 cooling tower)

5. Spray pond pump structure supply fans OBV543 and ODV543

6. Motor control centers OOB520 (Div. 2) and OOB522 (Div. 4), which serve the following components:
(a) ESW loop "B" valves
(b) RHRSW loop "B" valves
(c) Spray pond pump structure supply fan OBV543 and associated heaters and dampers
(d) Spray pond pump structure supply fan ODV543 and associated heaters and dampers

7. Class 1E instrument ac distribution panels 02Y501 (Div. 2) and 04Y501 (Div. 4)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 123 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A and C will be available to shutdown Units 1 and 2.

9A.5.8 SAFE SHUTDOWN ANALYSIS - TURBINE ENCLOSURE

9A.5.8.1 Fire Area 87: Condensate Pump-Room (el 189'-0")

a. Structural and architectural design features of fire area (Figures 9A-5 and 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete(exterior wall)	None
	E - Reinforced concrete (below el 217 feet)	3 hr
	E - Concrete masonry unit (above el 217 feet)	2 hr
	S - Reinforced concrete (above el 217 feet)	3 hr
	W - Reinforced concrete	3 hr
	S- Reinforced concrete (below el 217 feet)	None
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:	Watertight door connecting to area 88	3 hr**
	Two doors connecting to area 113	1.5 hr
	Roll-up door connecting to area 113	2 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

1. Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

2. Ignition of oil in a waste oil collection drum associated with the floor drain sump oil removal belt.

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 87 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.2 Fire Area 88: Main Condenser Area and Feedwater Heater Rooms (el 200'-0" and el 239'-0")

a. Structural and architectural design features of fire area (Figures 9A-5, 9A-6, and 9A-7):

	Construction	Rating
Walls:	N - Reinforced concrete and concrete masonry unit (exterior wall, below el 217')	None
	N - Reinforced concrete and precast concrete panels (exterior wall, above el 217')	None
	E - Reinforced concrete (below el 217'; contains 25 ft^2 of unrated steel plate as separation from area 115)	3 hr
	E - Reinforced concrete and concrete masonry unit (above el 217')	3 hr
	S - Reinforced concrete and concrete masonry unit (below el 217')	3 hr
	S - Reinforced concrete (between el 217' and el 239')	3 hr
	S - Reinforced concrete (above el 239', contains 188 ft^2 of unrated metal blowout panels)	3 hr
	W - Reinforced concrete (portion north of column line N)	3 hr
	W - Concrete masonry unit and precast concrete panels (exterior wall south of column line N)	None
Floor:	Reinforced concrete foundation mat (el 200' and el 217')	None
	Reinforced concrete (el 239' supported by structural steel ;members without fireproofing)	None
Ceiling:	Reinforced concrete	None
Access:	Watertight doors connecting to areas 87 and 94	3 hr**
	Three doors connecting to area 89	3 hr
	Five doors connecting to area 97	3 hr
	Doors connecting to areas 95 and 113	3 hr

b. Major safety-related components in fire area:

1. Main turbine stop valve position switches (ZS-01-104A,B,C&D)

2. Turbine control valve fast closure pressure switches (PS-01-102A,B,C&D)

3. Main steam line area temperature detectors

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. If the fire is in the main condenser area and the compartment temperature rises to 212°F, individual sprinkler heads in the wet pipe sprinkler system will open to control and/or extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 88 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.3 Fire Area 89: Reactor Feedwater Pump Lube Oil Areas, Control Rod Drive Water Pump Area, and Condensate Filter/Demineralizer Compartments (el 200'-0")

a. Structural and architectural design features of fire area (Figures 9A-5 and 9A-6):

	Construction	Rating
Walls:	N -Reinforced concrete and concrete masonry unit (part adjacent to fire areas 88 and 115)	3 hr
	N -Reinforced concrete (part adjacent to unexcavated area)	None
	E -Reinforced concrete	3 hr
	S -Reinforced concrete	3 hr
	W -Reinforced concrete(exterior wall)	None
Floor:	Reinforced concrete foundation mat (contains 76 ft^2 grating opening connecting to area 115)	None
Ceiling:	Reinforced concrete (contains156 ft^2 grating opening connecting to area 94)	None
Access:	Three doors connecting to area 88	3 hr
	Double steamtight door connecting to area 1	3 hr**
	Door connecting to stairwell no. 30	1.5 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Leakage of lube oil from the reactor feedwater pump lube oil reservoirs onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The heat generated by a fire in this area will activate the heat detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 212°F, individual fusible link sprinkler heads in the wet pipe sprinkler systems will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 89 contains cables associated with providing offsite power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.4 Fire Area 90: Air Ejector and Steam Packing Exhauster Compartment (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

		Construction	Rating
Walls:	N -	Reinforced concrete	3 hr
	E -	Reinforced concrete concrete masonry unit	3 hr
	S -	Reinforced concrete	3 hr
	W -	Reinforced concrete and concrete masonry unit	3 hr
Floor:		Reinforced concrete foundation mat	None
Ceiling:		Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:		Door connecting to area 113	3 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 90 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.5 Fire Area 91: Air Ejector and Steam Packing Exhauster Compartment (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

		Construction	Rating
Walls:	N -	Reinforced concrete	3 hr
	E -	Reinforced concrete and concrete masonry unit	3 hr
	S -	Reinforced concrete and concrete masonry unit	3 hr
	W -	Reinforced concrete	3 hr
Floor:		Reinforced concrete (supported by structural steel members without fireproofing)	None
Ceiling:		Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:		Door connecting to area 113	3 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 91 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.6 Fire Area 92: Mechanical Vacuum Pump-Room (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Concrete masonry unit	3 hr
	E - Reinforced concrete	3 hr
	S - Concrete masonry unit	3 hr
	W - Reinforced concrete and concrete masonry unit	3 hr
Floor:	Reinforced concrete (supported by structural steel members without fireproofing)	None
Ceiling:	Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:	Door connecting to area 94	3 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 92 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.7 Fire Area 93: Air Compressor Area, EHC Power Unit Area, and Turbine Lube Oil Storage Tank Area (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

		Construction	Rating
Walls:	N -	Precast concrete panels (exterior wall)	None
	E -	Reinforced concrete	3 hr
	S -	Reinforced concrete	3 hr
	W -	Precast concrete panels (exterior wall)	None
Floor:		Reinforced concrete foundation mat	None
Ceiling:		Reinforced concrete (contains equipment hatch with 55 ft^2 of steel plate and a 96 ft^2 opening partially filled with grating)	None
Access:		Door connecting to area 94	3 hr
		Door connecting to stairwell no. 32	1.5 hr
		Roll-up door to outside	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Leakage of lube oil from the turbine lube oil storage tanks onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The heat generated by a fire in this area will activate the heat detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 212°F, individual fusible link sprinkler heads in the wet pipe sprinkler system will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 93 contains cables associated with providing offsite power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.8 Fire Area 94: Reactor Feedwater Pump-Turbine Compartments Reactor Feedwater Pump Access Area, Deep Bed Demineralizer Compartments (EL 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

		Construction	Rating
Walls:	N -	Reinforced concrete	3 hr.
	E -	Reinforced concrete and concrete masonry unit	3 hr.
	S -	Reinforced concrete (part)	3 hr.
	S -	Reinforced concrete (part adjacent to area 120)	2 hr.
	S -	Reinforced concrete and concrete masonry unit (part adjacent to area 89; contains 8 HVAC duct penetrations without fire dampers)	None
	S -	Precast concrete panels (part, exterior wall)	None
	W -	Precast concrete panels (exterior wall)	None
Floor:		Reinforced concrete (contains 156 ft^2 grating opening connecting to area 89)	None
Ceiling:		Reinforced concrete contains equipment hatch with 66 ft^2 of	None

	steel plate)	
Access:	Doors connecting to areas 92 and 93	3 hr.
	Doors connecting to area 120	1.5 hr.
	Steamtight door connecting to area 2	3 hr.**
	Watertight door connecting to area 88	3 hr.**
	Door connecting to stairwell no. 30	1.5 hr.
	Open stairwell leading up to area 95	None
	Roll-up doors to Entry Access (5-Line Outage Support Facility)	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 94 contains cables and equipment associated with providing offsite power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with providing offsite power to shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.9 Fire Area 95: MCC Room, TECW Equipment Area, and Turbine Lube Oil Reservoir and Centrifuge Area (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

		Construction	Rating
Walls:	N -	Precast concrete panels (exterior wall)	None
	E -	Reinforced concrete	3 hr
	S -	Reinforced concrete	3 hr
	W -	Precast concrete panels (exterior wall)	None
Floor:		Reinforced concrete (contains equipment hatch with 55 ft^2 of steel plate and a 96 ft^2 opening partially filled with grating)	None
Ceiling:		Reinforced concrete	None
Access:		Doors connecting to areas 88 and 96	3 hr
		Door connecting to stairwell no. 32	1.5 hr
		Open stairwell leading down to area 94	None

b. Major safety-related components in fire area:

1. Main turbine first-stage pressure transmitters (PT-01-1N052A,B,C&D)

2. Main steam line pressure transmitters (PT-01-1N076A,B,C&D)

c. Postulated fire in area:

Leakage of lube oil from the turbine lube oil reservoir onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The heat generated by a fire in this area will activate the heat detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 212°F, individual fusible link sprinkler heads in the wet pipe sprinkler system will open to control and/or extinguish the fire. In addition, a compartment temperature of 190°F will cause actuation of the deluge systems located over the turbine lube oil reservoir and the turbine lube oil centrifuge. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 95 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.10 Fire Area 96: Battery Room (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Concrete masonry unit	3 hr
	E - Reinforced concrete	3 hr
	S - Concrete masonry unit	3 hr
	W - Concrete masonry unit	3 hr
Floor:	Reinforced concrete (supported by structural steel members without fireproofing)	None
Ceiling:	Reinforced concrete	3 hr
Access:	Door connecting to area 95	3 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of battery cases and/or battery spacers as the result of an exposure fire.

d. Consequences of fire with active fire suppression:

The smoke and heat generated by a fire in this area will activate the smoke and heat detectors which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 96 contains cables and equipment associated with providing offsite power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with providing offsite power to shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.11 Fire Area 97: Equipment Hatch Corridor (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

		Construction	Rating
Walls:	N -	Reinforced concrete	3 hr
	E -	Reinforced concrete	3 hr
	S -	Reinforced concrete (part)	3 hr
	S -	Precast concrete panels (part, exterior wall)	None
	W -	Precast concrete panels (exterior wall)	None
Floor:		Reinforced concrete (contains equipment hatch with 66 ft^2 of steel plate)	None
Ceiling:		Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:		Five doors connecting to area 88	3 hr
		Steamtight door connecting to area 7	3 hr**
		Door connecting to stairwell no. 30	1.5 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 97 contains cables associated with providing offsite power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.12 Fire Area 98: Reactor Recirculation Pump MG Set Area and Feedwater Heater Rooms (el 269'-0")

a. Structural and architectural design features of fire area (Figure 9A-8):

		Construction	Rating
Walls:	N -	Concrete masonry unit	3 hr
	E -	Reinforced concrete	3 hr
	S -	Reinforced concrete (part)	3 hr
	S -	Precast concrete panels (part, exterior wall)	None
	W -	Precast concrete panels (exterior wall)	None
Floor:		Reinforced concrete (supported by structural steel members without fireproofing)	None
Ceiling:		Reinforced concrete (contains two equipment hatches covered with steel plate, one of 75 ft^2 and one of 110 ft^2)	None
Access:		Door connecting to stairwell	1.5 hr

no. 30	
Door connecting to area 45	3 hr
Two doors connecting to area 114	3 hr
Two roll-up doors connecting to area 114	3 hr**

b. Major safety-related components in fire area:

1. Junction boxes containing cables associated with the following components:
   (a) Main turbine stop valve position switches (ZS-01-104A,B,C&D)
   (b) Turbine control valve fast closure pressure switches (PS-01-102A,B,C&D)

c. Postulated fire in area:

Ignition of electrical cables in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. The preaction sprinkler system over the MG sets has been spared and is not in service. The ASD System has replaced the MG sets. Smoke detection has been added in the area over the ASD System.

e. Effect of fire on safe shutdown:

Fire area 98 contains safe shutdown cables and equipment.

Cables required to support shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 201 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.13 Fire Area 99: Turbine Enclosure HVAC Area and Equipment Compartment Exhaust Filter Area (el 302'-0")

a. Structural and architectural design features of fire area (Figure 9A-9):

	Construction	Rating
Walls: N -	Concrete masonry	3 hr

	unit	
	E - Reinforced concrete	3 hr
	S - Reinforced concrete (part)	3 hr
	S - Precast concrete panels (part, exterior wall)	None
	W - Precast concrete panels (exterior wall)	None
Floor:	Reinforced concrete (contains two equipment hatches covered with steel plate, one of 75 ft^2 and one of 110 ft^2)	None
Ceiling:	Metal deck, nonreinforced concrete, and built-up roofing	UL Class A
Access:	Door connecting to stairwell no. 30	1.5 hr
	Steamtight door connecting to area 27	3 hr
	Double steamtight door connecting to area 27	3 hr**

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of charcoal filters.

d. Consequences of fire with active fire suppression:

In the event of a fire in one of the turbine enclosure equipment compartment exhaust filters, a thermal sensor inside the filter plenum will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire. The fire brigade will utilize a manual valve in the fire protection water supply system to initiate operation of a water spray system inside the filter plenum. No effect on safety-related systems will result from a fire in this area.

e. Effect of fire on safe shutdown:

Fire area 99 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.14 Fire Area 100: Condensate Pump-Room (el 189'-0")

a. Structural and architectural design features of fire area (Figures 9A-5 and 9A-6):

		Construction	Rating
Walls:	N -	Reinforced concrete (exterior wall)	None
	E -	Reinforced concrete	3 hr
	S -	Reinforced concrete	3 hr
	W -	Reinforced concrete (below el 217')	3 hr
	W -	Reinforced concrete (above el 217')	2 hr
Floor:		Reinforced concrete foundation mat	None
Ceiling:		Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:		Watertight door connecting to area 101	3 hr**
		Two doors connecting to area 113	1.5 hr
		Roll-up door connecting to area 113	1.5 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

1. Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

2. Ignition of oil in waste oil collection drum associated with the floor drain sump oil removal belt.

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 100 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear, via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.15 Fire Area 101: Main Condenser Area and Feedwater Heater Rooms (el 200'-0" and el 239'-0")

a. Structural and architectural design features of fire area (Figures 9A-5, 9A-6, and 9A-7):

		Construction	Rating
Walls:	N -	Reinforced concrete and concrete masonry unit (exterior wall, below el 217')	None
	N -	Reinforced concrete and precast concrete panels (exterior wall, above el 217')	None
	E -	Reinforced concrete (portion north of column line N)	3 hr
	E -	Concrete masonry unit and precast concrete panels (exterior wall south of column line N)	None
	S -	Reinforced concrete and concrete masonry unit (below el 217')	3 hr
	S -	Reinforced concrete (between el 217'and el 239')	3 hr
	S -	Reinforced concrete (above el 239'; contains 188 ft^2 of unrated metal blowout panels)	3 hr
	W -	Reinforced concrete (below el 217'; contains 25 ft^2 of unrated steel plate as separation from area 115)	3 hr
	W -	Reinforced concrete and concrete masonry unit (above el 217')	3 hr
Floor:		Reinforced concrete foundation mat (el 200' and el 217')	None
		Reinforced concrete (el 239'; supported by structural steel	None

	members without fireproofing)	
Ceiling:	Reinforced concrete	None
Access:	Watertight doors connecting to areas 100 and 107	3 hr**
	Three doors connecting to area 102	3 hr
	Five doors connecting to area 110	3 hr
	Doors connecting to areas 108 and 113	3 hr

b. Major safety-related components in fire area:

1. Main turbine stop valve position switches (ZS-01-204A,B,C&D)

2. Turbine control valve fast closure pressure switches (PS-01-202A,B,C&D)

3. Main steam line area temperature detectors

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. If the fire is in the main condenser area and the compartment temperature rises to 212°F, individual sprinkler heads in the wet pipe sprinkler system will open to control and/or extinguish the fire.

e. Effect of fire on safe shutdown:

Replacement text for paragraph “e.”

Fire area 101 contains cables and equipment associated with providing offsite power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with providing offsite power to shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.16 Fire Area 102: Reactor Feedwater Pump Lube Oil Areas, Control Rod Drive Water Pump Area, and Condensate Filter/Demineralizer Compartments (el 200'-0")

a. Structural and architectural design features of fire area (Figures 9A-5 and 9A-6):

Walls:	N -	Reinforced concrete and concrete masonry unit (part adjacent to fire areas 101 and 115)	3 hr
	N -	Reinforced concrete (part adjacent to unexcavated area)	None
	E -	Reinforced concrete (exterior wall)	None
	S -	Reinforced concrete	3 hr
	W -	Reinforced concrete	3 hr
Floor:		Reinforced concrete foundation mat	None
Ceiling:		Reinforced concrete (contains 156 ft^2 grating opening connecting to area 107)	None
Access:		Three doors connecting to area 101	3 hr
		Two double steamtight doors connecting to area 1	3 hr**
		Door connecting to stairwell no. 31	1.5 hr
		Door connecting to area 115	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area;

Leakage of lube oil from the reactor feedwater pump lube oil reservoirs onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The heat generated by a fire in this area will activate the heat detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 212°F, individual fusible link sprinkler heads in the wet pipe sprinkler systems will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 102 contains cables and equipment associated with providing offsite power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with providing power to shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.17 Fire Area 103: Air Ejector and Steam Packing Exhauster Compartment (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

		Construction	Rating
Walls:	N -	Reinforced concrete	3 hr
	E -	Reinforced concrete and concrete masonry unit	3 hr
	S -	Reinforced concrete	3 hr
	W -	Reinforced concrete and concrete masonry unit	3 hr
Floor:		Reinforced concrete foundation mat	None
Ceiling:		Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:		Door connecting to area 113	3 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 103 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.18 Fire Area 104: Air Ejector and Steam Packing ExhausterCompartment (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Reinforced concrete	3 hr
	S - Reinforced concrete and concrete masonry unit	3 hr
	W - Reinforced concrete and concrete masonry unit	3 hr
Floor:	Reinforced concrete (supported by structural steel members without fireproofing)	None
Ceiling:	Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:	Door connecting to area 113	3 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 104 contains cables associated with providing offsite power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.19 Fire Area 105: Mechanical Vacuum Pump-Room (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Concrete masonry unit	3 hr
	E - Reinforced concrete and concrete masonry unit	3 hr
	S - Concrete masonry unit	3 hr
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete (supported by structural steel members without fireproofing)	None
Ceiling:	Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:	Door connecting to area 107	3 hr

b. Major safety-related components in fire area;

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 105 contains cables associated with providing offsite power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.20 Fire Area 106: Air Compressor Area, EHC Power Unit Area, and Turbine Lube Oil Storage Tank Area (el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Precast concrete panels (exterior wall)	None
	E - Precast concrete panels (exterior wall)	None
	S - Reinforced concrete	3 hr
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete (contains equipment hatch with 55 ft^2 of steel plate and a 96 ft^2 opening partially filled with grating)	None
Access:	Door connecting to area 107	3 hr
	Door connecting to stairwell no. 33	1.5 hr
	Roll-up door to outside	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Leakage of lube oil from the turbine lube oil storage tanks onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The heat generated by a fire in this area will activate the heat detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 212°F, individual fusible link sprinkler heads in the wet pipe sprinkler system will open to control and/or extinguish the fire. The plant fire brigade will be dispatched to ensure that the fire is extinguished. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 106 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.21 Fire Area 107: Reactor Feedwater Pump-Turbine Compartments and Reactor Feedwater Pump Access Area Deep Bed Demineralizer Compartments(el 217'-0")

a. Structural and architectural design features of fire area (Figure 9A-6):

	Construction	Rating
Walls:	N - Reinforced concrete	3 hr
	E - Precast concrete panels (exterior wall)	None
	S - Reinforced concrete (part)	3 hr
	S - Reinforced concrete and concrete masonry unit (part adjacent to area 102; contains 8 HVAC duct penetrations without fire dampers)	None
	W - Reinforced concrete and concrete masonry unit	3 hr
Floor:	Reinforced concrete (contains	None

	156 ft^2 grating opening connecting to area 102)	
Ceiling:	Reinforced concrete (contains equipment hatch with 66 ft^2 of steel plate)	None
Access:	Doors connecting to areas 105, 106, and an entryway to the Unit 2 reactor enclosure	3 hr
	Two doors connecting to the administration complex	3 hr
	Steamtight door connecting to area 2	3 hr**
	Watertight door connecting to area 101	3 hr**
	Door connecting to stairwell no. 31	1.5 hr
	Roll-up door to outside	None
	Open stairwell leading to area 108	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 107 contains cables and equipment associated with providing offsite power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with providing offsite power to shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.22 Fire Area 108: MCC Room, TECW Equipment Area, and Turbine Lube Oil Reservoir and Centrifuge Area (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Precast concrete panels (exterior wall)	None
	E - Precast concrete panels (exterior wall)	None
	S - Reinforced concrete	3 hr
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete (contains equipment hatch with 55 ft^2 of steel plate and a 96 ft^2 opening partially filled with grating)	None
Ceiling:	Reinforced concrete	None
Access:	Doors connecting to areas 101 and 109	3 hr
	Door connecting to stairwell no. 33	1.5 hr
	Open stairwell leading down to area 107	None

b. Major safety-related components in fire area:

1. Main turbine first-stage pressure transmitters (PT-01-2N052A,B,C&D)

2. Main steam line pressure transmitters (PT-01-2N076A,B,C&D)

c. Postulated fire in area:

Leakage of lube oil from the turbine lube oil reservoir onto the floor of the compartment, with subsequent ignition of the oil.

d. Consequences of fire with active fire suppression:

The heat generated by a fire in this area will activate the heat detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. If the compartment temperature rises to 212°F, individual fusible link sprinkler heads in the wet pipe sprinkler system will open to control and/or extinguish the fire. In addition, a compartment temperature of 212°F will cause actuation of the deluge systems located over the turbine lube oil reservoir and the turbine lube oil centrifuge. The plant fire brigade will be dispatched to ensure that the fire is extinguished.

e. Effect of fire on safe shutdown:

Fire area 108 contains cables and equipment associated with providing power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with providing offsite power to shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.23 Fire Area 109: Battery Room (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

	Construction	Rating
Walls:	N - Concrete masonry unit	3 hr
	E - Concrete masonry unit	3 hr
	S - Concrete masonry unit	3 hr
	W - Reinforced concrete	3 hr
Floor:	Reinforced concrete (supported by structural steel members without fireproofing)	None
Ceiling:	Reinforced concrete	3 hr
Access:	Door connecting to area 108	3 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of battery cases and/or battery spacers as the result of an exposure fire.

d. Consequences of fire with active fire suppression:

The smoke and heat generated by a fire in this area will activate the smoke and heat detectors which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 109 contains cables and equipment associated with providing offsite power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with providing offsite power to shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.24 Fire Area 110: Equipment Hatch Corridor (el 239'-0")

a. Structural and architectural design features of fire area (Figure 9A-7):

		Construction	Rating
Walls:	N -	Reinforced concrete	3 hr
	E -	Precast concrete panels (exterior wall)	None
	S -	Reinforced concrete (part)	3 hr
	S -	Precast concrete panels (part, exterior wall)	None
	W -	Reinforced concrete	3 hr
Floor:		Reinforced concrete (contains equipment hatch with 66 ft^2 of steel plate)	None
Ceiling:		Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:		Five doors connecting to area 101	3 hr
		Steamtight door connecting to area 7	3 hr**

Door connecting to stairwell no. 30	1.5 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 110 contains cables associated with providing offsite power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.25 Fire Area 111: Reactor Recirculation Pump MG Set Area and Feedwater Heater Rooms (el 269'-0")

a. Structural and architectural design features of fire area (Figure 9A-8):

		Construction	Rating
Walls:	N -	Concrete masonry unit	3 hr
	E -	Precast concrete panels (exterior wall)	None
	S -	Reinforced concrete (part)	3 hr
	S -	Precast concrete panels (part, exterior wall)	None
	W -	Reinforced concrete	3 hr

Floor:	Reinforced concrete (supported by structural steel members without fireproofing)	None
Ceiling:	Reinforced concrete (contains two equipment hatches covered with steel plate, one of 75 ft^2 and one of 110 ft^2)	None
Access:	Door connecting to stairwell no. 31	1.5 hr
	Door connecting to administration complex	3 hr
	Two doors connecting to area 114	3 hr
	Two roll-up doors connecting to area 114	3 hr**

b. Major safety-related components in fire area:

1. Junction boxes containing cables associated with the following components:
   (a) Main turbine stop valve position switches (ZS-01-204A,B,C&D)
   (b) Turbine control valve fast closure pressure switches (PS-01-202A,B,C&D)

c. Postulated fire in area:

Ignition of electrical cables in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling).

d. Consequences of fire with active fire suppression:

The smoke generated by a fire in this area will activate the smoke detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. The preaction sprinkler system over MG sets has been spared and is not in service. The ASD System has replaced the MG sets. Smoke detection has been added in the area over the ASD System.

e. Effect of fire on safe shutdown:

Fire area 111 contains cables and equipment associated with providing offsite power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with providing offsite power to shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 201 safeguard bus may be affected by a fire in this area. Offsite power to the 4kV switchgear via the 101 safeguard bus is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.26 Fire Area 112: Turbine Enclosure HVAC Area and Equipment Compartment Exhaust Filter Area (el 302'-0")

a. Structural and architectural design features of fire area (Figure 9A-9):

		Construction	Rating
Walls:	N -	Concrete masonry unit	3 hr
	E -	Precast concrete panels (exterior wall)	None
	S -	Reinforced concrete (part)	3 hr
	S -	Precast concrete panels (part, exterior wall)	None
	W -	Reinforced concrete	3 hr
Floor:		Reinforced concrete (contains two equipment hatches covered with steel plate, one of 75 ft^2 and one of 110 ft^2)	None
Ceiling:		Metal deck, nonreinforced concrete, and built-up roofing	UL Class A
Access:		Door connecting to stairwell no. 31	1.5 hr
		Steamtight door connecting to area 27	3 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of charcoal filters.

d. Consequences of fire with active fire suppression:

In the event of a fire in one of the turbine enclosure equipment compartment exhaust filters, a thermal sensor inside the filter plenum will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire. The fire brigade will utilize a manual valve in the fire protection water supply system to initiate operation of a water spray system inside the filter plenum. No effect on safety-related systems will result from a fire in this area.

e. Effect of fire on safe shutdown:

Fire area 112 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.8.27 Fire Area 113: Railroad Access Area and Generator Equipment Area (el 217'-0" and el 239'-0")

a. Structural and architectural design features of fire area (Figures 9A-6 and 9A-7):

		Construction	Rating
Walls:	N -	Reinforced concrete and concrete masonry unit (exterior wall)	None
	E -	Reinforced concrete and concrete masonry unit (part)	3 hr
	E -	Concrete masonry unit (part adjacent to area 100)	2 hr
	S -	Reinforced concrete and concrete masonry unit	3 hr§
	W -	Reinforced concrete and concrete masonry unit (part)	3 hr
	W -	Concrete masonry unit (part adjacent to area 87)	2 hr
Floor:		Reinforced concrete foundation mat	3 hr
Ceiling:		Reinforced concrete (contains a 1960 ft^2 hatchway partially filled \ with grating)	None
Access:		Two doors connecting to area 87 and two doors connecting to area 100	1.5 hr
		Roll-up door panel connecting to area 87	2 hr
		Roll-up door connecting to area 100	1.5 hr
		Door connecting to areas 88, 90, 91, 101, 103, and 104	3 hr
		Steamtight doors connecting to areas 8, 10, 12, 14, 16, and 18	3 hr
		Steamtight door connecting to stairwell no. 7	3 hr**

Double steamtight door connecting to area 2	3 hr**

Walls denoted above by the § symbol are capable of being rated as 3 hour fire barriers, except for unrated wall penetration assemblies associated with the 4kV nonsegregated phase bus ducts. These penetration assemblies are described in Section 9A.6.3. A maximum of two penetration assemblies are located in the wall indicated above. This wall separates fire area 113 from fire areas 12 and 18.

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Leakage of seal oil from the generator hydrogen seal oil units onto the floor of the compartment, with subsequent ignition of the oil or ignition of material stored in the Facility/laydown area, Floor Operators Break Facility (Rm 468A,B,C) and Plant Operators Building (Rm 468).

d. Consequences of fire with active fire suppression:

A rise in compartment temperature to 140°F will cause the deluge valve to open and prime the preaction sprinkler system with water. At 165°F, individual sprinkler heads will open to control and/or extinguish the fire. A rise in the temperature of the Facility/laydown area, Floor Operators Break Facility (Rm 468A, B, C) or Plant Operators Building (Rm 468) to 155°F will open individual sprinklers of the wet pipe sprinkler system in that area to control and/or extinguish the fire in the associated area. In addition, a compartment temperature of 212°F will cause actuation of the deluge systems located over the generator hydrogen seal oil units. The plant fire brigade will be dispatched to ensure that the fire is extinguished. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 113 contains cables and equipment associated with providing offsite power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area. Equipment associated with providing offsite power to shutdown methods A, B, and C for Units 1 and 2 located in this fire area have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

f. Deviations:

See Section 9A.6.3.

9A.5.8.28 Fire Area 114: Turbine Operating Floor (el 269'-0")

a. Structural and architectural design features of fire area (Figures 9A-8 and 9A-9):

		Construction	Rating
Walls:	N -	Precast concrete panels (exterior wall)	None
	E -	Precast concrete panels (exterior wall)	None
	S -	Reinforced concrete and concrete masonry unit	3 hr
	W -	Precast concrete panels (exterior wall)	None
Floor:		Reinforced concrete (contains a 1960 ft^2 hatchway partially filled with grating, plus 14 equipment hatches covered with steel plate)	None
Ceiling:		Metal deck, nonreinforced concrete, and built-up roofing	UL Class A
Access:		Doors connecting to stairwell nos. 32 and 33	1.5 hr
		Two doors connecting to area 98 and two doors connecting to area 111	3 hr
		Two roll-up doors connecting to area 98 and two roll-up doors connecting to area 111	3 hr**
		Two steamtight and bullet-resistant doors connecting to area 24	3 hr**
		Steamtight door connecting to stairwell no. 7	3 hr**

b. Major safety-related components located in fire area:

1. Main condenser pressure transmitters (PT-01-1N075A,B,C&D)

2. Junction boxes containing cables associated with the following components:
   (a) Main turbine first-stage pressure transmitters (PT-01-1N052A,B,C&D)
   (b) Main steam line pressure transmitters (PT-01-1N076A,B,C&D)

c. Postulated fire in area:

Ignition of electrical cabling in cable tray and ignition of materials present in the Control Room Annex. As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling, and an exposure fire involving the materials in the Control Room Annex would be extremely limited in scope and would be confined to a small area due to the configuration of the combustibles within the Control Room Annex. Ignition of the materials in the Control Room Annex is extremely unlikely in the absence of a fire source external to the materials.

d. Consequences of fire with active fire suppression:

The smoke and heat generated by a fire in this area will activate the early warning smoke and heat detectors, which will cause an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire. If the fire occurs under the turbine's appearance lagging or under the generator's appearance lagging, the preaction sprinkler system will provide automatic suppression of the fire. At 190°F, the deluge valve will open and prime the preaction sprinkler system with water. At 212°F, individual sprinkler heads will open to control and/or extinguish the fire. If the fire occurs at the Unit 1 and 2 turbine generator exciter bearings, the heat detectors within the exciter enclosure will annunciate the fire condition on the fire protection panel in the control room and initiate the coded alarm annunciation within the plant. A smoke detector suitable for high-velocity air flow in the exciter exhaust ductwork will annunciate the fire. No effect on safety-related systems will result from a turbine generator exciter bearing fire.

e. Effect of fire on safe shutdown:

Fire area 114 contains cables associated with providing power to safe shutdown components.

Cables for offsite power which supports shutdown methods A, B, and C for Units 1 and 2 are associated with equipment that have redundant components that are not affected by a fire in this area.

The availability of offsite power to the 4kV switchgear via the 101 and 201 safeguard buses may be affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.9 SAFE SHUTDOWN ANALYSIS - RADWASTE ENCLOSURE

9A.5.9.1 Fire Area 115: Radwaste Pipe Tunnel (el 183'-0", el 187'-0", el 191'-0", and el 200'-0")

a. Structural and architectural design features of fire area (Figures 9A-4 and 9A-5):

	Construction	Rating
Walls:	West wall near column line 18, approx. 19 feet north of column line N, between el 200' and el 205' - Steel plate (25 ft^2)	None
	East wall near column line 28, approx. 19 feet north of column line N, between el 200' and el 205' - Steel plate (25 ft^2)	None
	North wall at 7.5 feet north of column line J, between columns 23 and 26.6, and between el 200' and el 217' - Concrete masonry unit	3 hr
	East wall at column line 26.6 between el 200' and el 217' - reinforced concrete	3 hr
	South walls - Reinforced concrete	3 hr
	All other walls - Reinforced concrete and concrete masonry unit	None
Floor:	Below zone 115D between column lines 19.4 and 26.6 - Reinforced concrete (supported by structural steel members without fireproofing)	None
	Below all other portions of the fire area - Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete (contains 76 ft^2 grating opening connecting to area 89)	None
Access:	Door connecting to area 102	None
	Door connecting to area 118	3 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Since no combustible materials are located in this area, the origin of a postulated fire is indeterminate.

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 115 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.9.2 Fire Area 116: Miscellaneous Radwaste Equipment Areas (el 162'-0")

a. Structural and architectural design features of fire area (Figure 9A-4):

		Construction	Rating
Walls:	N -	Reinforced concrete	3 hr
	E -	Reinforced concrete (part north of column line D)	3 hr
	E -	Reinforced concrete (part south of column line D, exterior wall)	None
	S -	Reinforced concrete (exterior wall)	None
	W -	Reinforced concrete	None
Floor:		Reinforced concrete foundation mat	None
Ceiling:		Reinforced concrete (contains equipment hatch filled with 49 ft^2 of steel plate)	None
Access:		Doors connecting to stairwell nos. 1 and 2	1.5 hr

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

1. Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

2. Ignition of charcoal filters.

3. Ignition of oil in a waste oil collection drum associated with the floor drain sump oil removal belt.

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. In the event of a fire in the waste tank vent exhaust filter, a thermal sensor inside the filter plenum will cause an audible/visual annunciation to register on the fire protection panels in the control. The fire brigade will utilize a manual valve in the fire protection water supply system to initiate operation of a water spray system inside the filter plenum. No effect on safety-related systems will result from a fire in this area.

e. Effect of fire on safe shutdown:

Fire area 116 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.9.3 Fire Area 117: Offgas Pipe Tunnel (el 186'-0" and el 187'-6")

a. Structural and architectural design features of fire area (Figure 9A-4):

	Construction	Rating
Walls:	All walls - Reinforced concrete	None
Floor:	Reinforced concrete foundation mat	None
Ceiling:	Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:	Concrete hatch plugs	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Since no combustible materials are located in this area, the origin of a postulated fire is indeterminate.

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 117 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.9.4 Fire Area 118: Miscellaneous Radwaste Equipment Areas (el 191'-0")

a. Structural and architectural design features of fire area (Figure 9A-5):

		Construction	Rating
Walls:	N -	Reinforced concrete	3 hr
	E -	Reinforced concrete (part north of column line C)	3 hr
	E -	Reinforced concrete (part, exterior wall)	None
	S -	Reinforced concrete (exterior wall)	None
	W -	Reinforced concrete (part, exterior wall)	None
	W -	Reinforced concrete (part adjacent to area 119; contains piping and electrical penetrations without fire-rated seals and HVAC duct penetrations without fire dampers)	None
Floor:		Reinforced concrete (contains equipment hatch filled with 49 ft^2 of steel plate)	None
Ceiling:		Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:		Door connecting to area 115	3 hr
		Doors connecting to stairwell nos. 1 and 2	1.5 hr
		Door connecting to area 119	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 118 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.9.5 Fire Area 119: Offgas Equipment Areas (el 195'-0")

a. Structural and architectural design features of fire area (Figure 9A-5):

		Construction	Rating
Walls:	N -	Reinforced concrete	3 hr
	E -	Reinforced concrete (contains piping and electrical penetrations without fire-rated seals and HVAC duct penetrations without fire dampers)	None
	S -	Reinforced concrete (exterior wall)	None
	W -	Reinforced concrete (exterior wall)	None
Floor:		Reinforced concrete (supported in some areas by structural steel members without fireproofing)	None
Ceiling:		Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:		Door connecting to stairwell no. 1	1.5 hr
		Door connecting to area 118	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

Upon receiving notification that a fire has occurred in this area, the operator will dispatch the plant fire brigade to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 119 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.9.6 Fire Area 120: Radwaste Control Room, Laundry, Decontamination and Change Areas, Waste Drum Storage Room, and Cask Loading Area (el 217'-0")

Renovated Area of Radwaste Enclosure: Data Acquisition Room, Storage Room, Source Storage/Standard's Preparation Room, Technician's Area (el 217'-0)

a. Structural and architectural design features of fire area (Figure 9A-6):

		Construction	Rating
Walls:	N -	Reinforced concrete	2 hr
	E -	Reinforced concrete	3 hr
	S -	Reinforced concrete (part, exterior wall)	None
	S -	Reinforced concrete (part adjacent to stairwell no. 1)	2 hr
	W -	Reinforced concrete (exterior wall)	None
Floor:		Reinforced concrete (supported by structural steel members without fireproofing)	None
Ceiling:		Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:		Door connecting to area 94	1.5 hr

Door connecting to stairwell no. 4	3 hr
Doors connecting to stairwell nos. 2 and 3	1.5 hr
Two doors to outside	None
Roll-up door to outside	None
Open stairwell leading up to area 121	None
One door connecting to to Chem Lab Bldg	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

If a fire occurs in the fire zones which are provided with smoke or heat detectors, the smoke and heat generated by the fire will activate the detectors, causing an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire. If a fire occurs in the waste drum storage room and the temperature in that area rises to 212°F, individual fusible link sprinkler heads in the wet pipe sprinkler system will open to control and/or extinguish the fire. If the fire occurs in the health physics room, radwaste supervisor's office, warm chem. Lab, file storage area, conventional chem. room, or in the radiation chemical lab, the preaction sprinkler system will provide automatic suppression of the fire. At 190°F, the deluge valve will open and prime the preaction sprinkle system with water. At 212°F, individual sprinkler will open to control and/or extinguish the fire.

e. Effect of fire on safe shutdown:

Fire area 120 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.5.9.7 Fire Area 121: Centrifuge Rooms, Solid Radwaste Equipment Rooms, Ventilation Filter Compartments, and Supply and Exhaust Fan Areas (el 237'-0" and el 257'-0")

a. Structural and architectural design features of fire area (Figures 9A-7 and 9A-8):

Construction	Rating

Walls:	N -	Reinforced concrete	3 hr
	E -	Reinforced concrete	3 hr
	S -	Reinforced concrete (part, exterior wall)	None
	S -	Reinforced concrete (part adjacent to area 120 between el 237' and el 257'; contains piping and electrical penetrations without fire-rated seals)	None
	W -	Reinforced concrete (part adjacent to area 120 between el 237' and el 257'; contains piping penetrations without fire-rated seals)	None
	W -	Reinforced concrete (part, exterior wall)	None
Floor:		Reinforced concrete (supported by structural steel members without fireproofing)	None
Ceiling:		Reinforced concrete (supported by structural steel members without fireproofing)	None
Access:		Door connecting to stairwell no. 2	1.5 hr
		Two doors connecting to stairwell no. 3	1.5 hr
		Open stairwell leading down to area 120	None

b. Major safety-related components in fire area:

None

c. Postulated fire in area:

Ignition of electrical cabling in cable tray. (As discussed in Table 9A-3, the ignition of electrical cabling is extremely unlikely in the absence of a fire source external to the cabling.)

d. Consequences of fire with active fire suppression:

If a fire occurs in the fire zones which are provided with smoke detectors, the smoke generated by the fire will activate the detectors, causing an audible/visual annunciation to register on the fire protection panels in the control room. Once the alarm has been received in the control room, the plant fire brigade will be dispatched to extinguish the fire. No effect on safety-related systems will result from such a fire.

e. Effect of fire on safe shutdown:

Fire area 121 does not contain safe shutdown cables and equipment.

Offsite power to the 4kV switchgear via the 101 and 201 safeguard buses is not affected by a fire in this area.

Therefore, methods A, B, and C will be available to shutdown Units 1 and 2.

9A.6 SPECIAL TOPICS

9A.6.1 ANALYSIS OF ASSOCIATED CIRCUITS

Generic Letter 81-12, issued by the NRC on February 20, 1981, discussed the types of information that the NRC considers necessary for the completion of their reviews of safe shutdown capability in the event of a fire. One of the enclosures to Generic Letter 81-12 addressed the subject of associated circuits and the possibility that fire-induced damage to associated circuits could prevent operation or cause maloperation of the shutdown methods designated to be used in the event of a fire in the plant. Generic Letter 81-12 defines associated circuits to be those circuits (either safety-related or nonsafety-related) that have a separation from the equipment and cables of the redundant safe shutdown methods that is less than that required by section III.G.2 of Appendix R to 10CFR50 and also have any of the following:

a. A common power source with the safe shutdown equipment, and the power source is not electrically protected from the circuit by coordinated circuit breakers, fuses, or similar devices.

b. A connection to circuits of equipment whose spurious operation could adversely affect the shutdown capability.

c. A common enclosure or raceway with safe shutdown cables, and are not electrically protected by circuit breakers, fuses, or similar devices.

In accordance with guidance contained in Generic Letter 81-12, an analysis has been performed for LGS to verify that fire-induced damage to associated circuits will not jeopardize the plant's safe shutdown capability. This analysis utilizes a systems approach, wherein the features of circuit design, such as overcurrent protection, are evaluated together with cable routing and separation criteria in order to confirm the adequacy of the electrical system design to prevent fire-induced damage to nonsafe shutdown circuits from jeopardizing safe shutdown capability. The methodology and results of the analysis are summarized in the following sections.

9A.6.1.1 Associated Circuits Involving Common Power Sources

All systems and components that are relied on for achieving safe shutdown receive power from the Class 1E ac distribution system or Class 1E dc power system. Offsite power may be credited as the source for the Class 1E ac distribution system for fire areas which do not require Alternative Shutdown and for which the offsite source(s) to the 4kV switchgear is not affected by fire damage. The Emergency Seal Oil Pump (ESOP) that services the main generator and the Emergency Bearing Oil Pump (EBOP) that services the main turbine are powered exclusively by a dedicated non-Class 1E battery and do not involve a common power source with other plant equipment or systems. The main feed from the battery and the battery charger to both motors are protected by coordinated fault actuated protective devices. All other circuits, both Class 1E and non-Class 1E, are individually protected by coordinated fault actuated protective devices. Proper coordination among these protective devices is demonstrated by the time-current coordination curves shown in Figures 9A-13 through 9A-15 for the 4 kV and 440 V ac system, Figure 9A-16 for the 120 V ac system, and Figures 9A-17 through 9A-20 for the 125/250 V dc system. These curves are typical for each type of protective device and application that is represented. The time-current coordination curves show that for each voltage level, the individual circuit breakers or fuses will clear a fault prior to the operation of the source breaker or fuse protecting the source bus. Consequently, the fault-actuated protective devices will act to isolate any

faulted circuit without jeopardizing the availability of other circuits connected to the same power source.

Because of the use of fault-actuated protective devices in power circuits as described above, LGS does not have associated circuits involving common power sources, as defined by Generic Letter 81-12.

9A.6.1.2 Associated Circuits Involving Spurious Operation

Components whose spurious operation could adversely affect the shutdown capability are considered to be essential for safe shutdown of the plant. These components and the circuits that serve them are therefore treated as part of the safe shutdown systems and are included in the review of separation between the different shutdown methods. Item 18 of Section 9A.3.2.2 describes the physical separation, fire barriers, and suppression systems that are provided to ensure that at least one shutdown method remains available to shut the plant down in the event of a fire.

Because of the design and analysis approach described above, LGS does not have associated circuits involving spurious operation, as defined by Generic Letter 81-12.

9A.6.1.3 Associated Circuits Involving Common Enclosures and Raceways

Separation between the different divisions of Class 1E circuits and between Class 1E and non-Class 1E circuits is discussed in Sections 7.1.2.2.3.2 and 8.1.6.1.14.b. Cabling for Class 1E circuits is routed only in raceways designated for Class 1E use. Cabling for non-Class 1E circuits is routed only in raceways designated for non-Class 1E use, except for selected non-Class 1E loads fed from Class 1E buses, which are identified and treated as Class 1E and are routed in dedicated Class 1E raceways. Non-Class 1E cables identified and treated as Class 1E do not become associated with other Class 1E divisions.

The potential for propagation of an electrical fire in enclosures (either raceways or panels) is minimized by the selection of appropriate cable construction systems and by the provision of physical separation. Insulation and jacketing materials used in both Class 1E and non-Class 1E cables are flame retardant, as discussed in Table 9A-3.

As discussed in Section 9A.6.1.1, circuits are individually protected by coordinated fault-actuated protective devices. This protection ensures that faulted circuits in common enclosures will be isolated.

Because of the provisions described above for preventing fire propagation and isolating circuit faults in common enclosures, LGS does not have associated circuits involving common enclosures, as defined by Generic Letter 81-12.

9A.6.1.4 Summary

For the reasons discussed in the preceding sections, LGS does not have associated circuits in any of the three categories established by Generic Letter 81-12. Therefore, fire-induced damage to circuits that are not designated as necessary for safe shutdown will not affect the operability of any of the four safe shutdown methods described in Section 9A.5.2.2.

9A.6.2 ANALYSIS OF HIGH/LOW PRESSURE INTERFACES

Generic Letter 81-12, issued by the NRC on February 20, 1981, discussed the types of information that the NRC considers necessary for the completion of their reviews of safe shutdown capability in the event of a fire. One of the enclosures to Generic Letter 81-12 addressed the subject of interfaces between high pressure and low pressure systems. The NRC's concern involves the valves that serve to isolate low pressure systems from the high pressure reactor coolant system. If the isolation valves at a given interface point consist of two electrically controlled valves in series, and a single fire could damage the cabling associated with both valves, both valves could be caused to open. This consequence could result in a fire-induced LOCA through the high/low pressure system interface.

Information Notice 87-50, issued by the NRC on October 9, 1987, expressed a concern that spurious opening of high/low pressure interface isolation valves would overpressurize the low pressure systems connected to the reactor coolant system, thereby creating the potential for a LOCA that cannot be isolated. The information notice specifically addressed the case of a bypass line around a check valve in the discharge lines of the RHR system for certain plants. This information notice states that "Because of this bypass line around the check valve, credit for the check valve in preventing a LOCA at the high and low pressure interface can no longer be given."

A review of the LGS design has been performed to verify that a high/low pressure interface LOCA cannot be caused by a single fire. Each system that contains interfaces between the RCPB and low pressure portions of the system was reviewed to identify the valves that provide isolation at the interface point, and also to assess the susceptibility of the valves to simultaneous opening due to fire-caused damage. Table 9A-12 identifies each such high/low pressure interface and lists the valves at the interface point.

In May 2021, the NRC issed Revision 4 of Reg Guide 1.189. Section 5.3.2 documents that the NRC staff has reconsidered their position concerning 3-Phase hot shorts, and no longer believes they need to be postulated for High/Low Pressure Interfaces. This allowance is only applied on a case-by-case basis as documented in Table 9A-12.

9A.6.3 FIRE BARRIER PENETRATION ASSEMBLIES FOR 4 KV BUS DUCTS

At el 239' in the control structure, 4 kV nonsegregated phase bus ducts penetrate some of the walls that separate the 4 kV switchgear compartments (fire areas 12 through 19) from each other and from adjacent compartments. The bus ducts are either 15.4 by 36 inches or 19.4 by 36 inches in size, and are constructed of steel plate having a thickness of 0.119 inch. Inside these steel ducts, copper bus bars are supported by porcelain insulators. At each wall penetration, a smoke and hot gas barrier is provided internal to the duct. The bus duct penetrations have been evaluated as being adequate for the hazards present. See reference 9A.7.12.

9A.6.4 ANALYSIS OF EFFECTS OF MULTIPLE HIGH-IMPEDANCE FAULTS ON THE SAFE SHUTDOWN CAPABILITY OF THE PLANT

The NRC response to question No. 5.3.8 of "Appendix R Questions and Answers", an enclosure to Generic Letter 86-10 (issued by the NRC on April 24, 1986) states that in order to meet the separation criteria of sections III.G.2 and III.G.3 of Appendix R, multiple high impedance faults should be considered for all associated (nonsafe shutdown) circuits located in the fire area of concern.

In accordance with the guidelines contained in Generic Letter 86-10, a calculation has been performed for LGS to verify that postulated high impedance faults resulting from fire-induced damage to safe shutdown cables and associated (nonsafe shutdown) cables supplied from the same bus will not jeopardize the plant's safe shutdown capability. The calculation involved a review of protective device coordination with consideration given to multiple high impedance faults for power cables at the 13.2 kV, 4.16 kV, 480 V, and 120/208 V levels of the ac power distribution system and at the 125 V and 250 V levels of the dc power distribution system. The methodology used in the calculation is based on the intention of implementing restorative actions for manually clearing the effects of multiple high impedance faults if the effects were determined to be detrimental to safe shutdown capability. The methodology used and the results of this study are summarized in the following sections.

9A.6.4.1 Methodology and Assumptions

To determine if restorative actions were required for a particular circuit, a phase analysis approach was utilized as described below.

Phase 1 analysis is a gross screening of the power sources that support safe shutdown loads to evaluate the effects of a High Impedance Fault (HIF) load on the power source circuit breaker or fuse. All circuits from a safe shutdown bus are considered as experiencing simultaneous HIFs regardless of fire area influence. The combined load and HIF current is assumed just below the trip setpoint of the associated branch breaker and to continue indefinitely. The sum of all HIF and load currents on bus is determined and compared with the trip characteristics of the power supply protective device. The high impedance fault current contribution for each load was taken to be equal to the 1000 second current rating of the load's protective device. This value was chosen since it is the maximum current the protective device can pass for an indefinite time without a trip. The high impedance fault currents were summed and compared to the 60 second rating of the feeder breaker. If the sum was less than this rating, no restorative actions were considered to be necessary.

The basis for this approach is a flame test that was performed by the licensee for the PBAPS and which showed that 54 seconds was the maximum duration of an high impedance fault. As before, if the high impedance fault current applied to the feeder breaker did not exceed its 60 second rating, no restorative actions were deemed necessary.

Phase 2 of the analysis is applied to those panels that fail the Phase 1 analysis. This analysis is performed in more detail using the actual circuit routing on a per fire area basis, with only those cables routed through the fire area of concern experiencing a simultaneous HIF. Phase 3 of the analysis is applied to those panels that fail the Phase 2 analysis and review normally de-energized loads while considering the routing of both power and control cables when evaluating specific fire areas. Phase 4 of the analysis is applied to those panels that fail the Phase 3 analysis. This Phase determines if the failed panels are required for safe shutdown in the subject fire area and whether restorative procedures are technically feasible to maintain panel operability in the event of a fire.

9A.6.4.2 Results

The results and conclusions derived in this calculation were input into the LGS Fire Area Analysis Calculations which sufficiently demonstrate that the LGS post-fire safe shutdown capability for both units will not be jeopardized due to fire-induced multiple high impedance faults.

9A.6.5 MINIMUM EFFECTIVE DESIGN DENSITY (MEDD)

This Section will discuss the use of the "Minimum Effective Design Density" (MEDD) concept for determining the operability of water based suppression systems at the Limerick Generating Station Units 1 and 2 (LGS).

In general, the design basis of the Limerick Generating Station sprinkler systems is to provide a density of 0.30 gpm/ft^2 over the hydraulically most remote 3000 ft^2 (unless specified otherwise). Limerick Technical Specifications (now Technical Requirements Manual) define OPERABILITY as...

"A system, subsystem, train, component, or device shall be operable or have operability when it is capable of performing its specified function(s)."

In the referenced paragraph above, the words "capable of performing its specific function(s)" as applied to suppression systems, means their ability to control a fire. A literature review of fire test information on cable and oil fires was performed to determine the minimum effective design density. The focus of this review was to determine how low the design density could be and still extinguish a fire. The literature review was intended to determine the minimum effective design density that will control a fire.

EPRI Research, Sandia National Laboratories and Factory Mutual test reports were reviewed to determine the minimum effective density necessary to extinguish a cable tray fire or oil spill fire. These two fire scenarios were selected because they present the greatest challenge to the plant sprinkler systems and these were the fires postulated in the FPER for the plant areas protected by the majority of the Technical Requirements Manual sprinkler systems.

A variety of tests and studies performed by Factory Mutual Research Corporation and Sandia National Laboratories were reviewed to determine the minimum effective density for automatic water based suppression systems at LGS. The purpose of the tests and studies performed was to determine the required automatic sprinkler design density necessary to extinguish a developing fire in grouped cable tray installations and oil spill fires.

9A.6.5.1 Cable Tray Fires

Literature reviewed indicated that a "delivered" water application rate of 0.16 gpm/ft^2 would control the most severe fire investigated.

Water application rate is generally quantified in terms of discharge density. The discharge density is the average rate of water reaching a unit floor area in unit time and is expressed in units of gpm/ft^2 of floor area. In the tests reviewed, the water application rates are referenced as "delivered densities." Specifically, delivered density means the density (gpm/ft^2) which was delivered at the (top) surface of the burning test array. The delivered density should not be confused with the "design density" commonly used in sprinkler installation standards which is the density available from the sprinkler system in the absence of a fire. (Note: The LGS Specification for fire sprinkler system (M-49) is based on the "design density" concept) In a fire situation, the actual water reaching the burning fuel is usually less than the "design density" due to phenomena such as evaporation, or entrainment of droplets in the hot gas rising from a fire. A "delivered density" of 0.16 gpm/ft^2 is expected to be equivalent to a "design density" of 0.25 gpm/ft^2 because test indicates that the overall penetration of water is approximately 65% when ½" orifice standard

sprinklers are used. Therefore, a "design density" of 0.25 gpm/ft^2 is required to provide the "minimum effective density" for extinguishment of grouped cable tray fires.

9A.6.5.2 Oil Spill Fires

Factory Mutual Research Corporation has conducted a series of fire tests with the purpose of determining whether automatic sprinklers will protect against lubricating oil spill fires. In all the tests, the floor based fires were quickly controlled and the test building was satisfactorily protected by the sprinkler system. The conclusion of Factory Mutual Research Corporation testing indicated that "automatic sprinklers will stop the spread and extinguish the fire in an oil spill on the floor with a design density of 0.13 gpm/ft^2 with some margin of safety."

9A.6.5.3 Conclusion

The design density specified for the systems at LGS is not required to be met to provide control and extinguishment of the anticipated fires at the plant and, therefore, is not required to be met for system(s) to be considered operable. The design density for the sprinkler systems at LGS will continue to be 0.3 gpm/ft^2 (as specified specification M-49), however, for a system to be considered operable it needs to provide the minimum effective design densities of 0.25 gpm/ft^2 for grouped electrical cable hazards or 0.13 gpm/ft^2 for oil spill fire hazards.

9A.6.6 Fire Barrier Penetration Assemblies for 'I" Beams Through Block Walls

At elevation 239' in the control structure, "I" beams penetrate the concrete masonry unit (CMU) walls that separate the corridor, 4kV switchgear and battery compartments (fire areas 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18 and 19) from each other. The construction detail for sealing (three-hour rated) the beam penetration through the wall integrated performance requirements that included fire proof coating on the beams for structural steel exposure and stopping spread of fire and hot gasses through the barrier. Subsequently, Ref. 9A.7.5 approved an analytical method that demonstrated certain structural steel members did not require fire proofing. The beam penetrations have been evaluated as being adequate for the hazards present in these fire areas regardless of the fire proof coating on the beams. See reference 9A.7.14.

9A.7 REFERENCES

9A.7.1 Appendix A to BTP APCSP 9.5-1 “Guidelines for Fire Protection for Nuclear Power Plants docketed prior to July 1, 1976

9A.7.2 BTP CMEB 9.5-1 “Guidelines for Fire Protection for Nuclear Power Plants", Rev. 2, dated July ,1981

9A.7.3 Appendix R to 10 CFR 50 “Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979”

9A.7.4 NUREG-0991, LGS SER, August 30, 1983.

9A.7.5 NUREG-0991, Supplement 2, October 1984.

9A.7.6 NUREG-0991, Supplement 8, June 1989.

9A.7.7 NUREG-0991, Supplement 9, August 1989.

9A.7.8 Letter from Eugene J. Bradley (PECO) to Dr. Thomas E. Murley (USNRC) dated April 5, 1988 (Revision 10 to FPER).

9A.7.9 Engineering Analysis LEAF-0001 “Smoke Detector Engr Analysis For Fire Areas 1, 2 & 7”.

9A.7.10 Engineering Analysis LEAF-0002 “Suppression System Evaluation”.

9A.7.11 Engineering Analysis LEAF-0009 “Galvanized Steel Cable Tray Covers In CFZ-5”.

9A.7.12 Engineering Analysis LEAF-0010, “Switchgear Room Bus Duct Penetrations”.

9A.7.13 Letter from Darrell G. Eisenhut (NRC) to G. Bauer, Jr. (PECO) dated October 15, 1981, Subject: Appendix R of 10 CFR Part 50 - Fire Protection Rule (Limerick Generating Station, Units 1 and 2).

9A.7.14 Generic Letter 86-10 Evaluation EC 627453 Refined Fire Barrier Inspection Criteria for Area 8 239' Beam - Wall Penetrations.

Table 9A-1

FIRE PROTECTION EVALUATION

Legend for Table 9A-1

The information presented in each column of Table 9A-1 is explained as follows:

Area-Zone:	Identification code for fire areas and zones. Fire zones with identification codes beginning with the same number are located in the same fire area.
Structure:	Location of the fire area-zone, by structure. Locations are shown on Figures 9A-4 through 9A-12.
Elevation:	Elevation of the fire area-zone.
Room No.:	The room number as indicated on the Architectural drawings.
Fire Area-Zone Description:	Description of compartments included within the fire area or fire zone.
SR (Safety-Related):	Indicates whether or not the fire area or zone contains safety-related equipment or electrical cabling.
Floor Area (sqft):	Floor area of the fire area or fire zone.
Fire Hazard Material:	Type of combustible material located in the fire area-zone.
Combustible Loading:	Designator of "Low" (<60,000 BTU/ft^2), "Moderate" ($\geq$60,000 BTU/ft^2 or < 140,000 BTU/ft^2) or "High" ($\geq$140,000 BTU/ft^2).
Combustible Loading Change Limit (BTU/ ft^2)	Combustible loading changes which do not exceed these limits do not require additional documentation/justification by the plant Fire Protection Program Engineer.
Detection Type/No.:	Type of fire detectors and number detectors provided in the fire area or zone. Unless indicated otherwise, all smoke detectors are of the ionization type.
Suppression Type/Actuation:	Type of fire suppression system and method of actuation in the fire area

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
1 - A	CS	180'-0"	164 164A 164M	Corridor Corridor Mezzanine	Y	440 48 448 936		Low	N		HS	M
1 - B	CS	180'-0"	166 166A 166M	Corridor Corridor Mezzanine	Y	440 48 448 936	Cable Insulation	Low 160	N		HS	M
1 - C	CS	180'-0"	154	Recombiner room	N	670	Cable Insulation	Low 0	N		HS	M
1 - D	CS	180'-0"	155	Recombiner room	N	670	Cable Insulation	Low 0	N		HS	M
1 - E	CS	180'-0"	153	Future recombiner room	N	670		Low 0	N		HS	M
1 - F	CS	180'-0"	156	Future recombiner room	N	670		Low 0	N		HS	M
1 - G	CS	180'-0"	163	Backwash receiving tank room	Y	680	Cable Insulation	Low 600	N		HS	M
1 - H	CS	180'-0"	157	Backwash receiving tank room	N	680	Cable Insulation	Low 1040	N		HS	M
1 - J	CS	180'-0"	161 162 165	Backwash transfer pump room Backwash transfer pump room Sump pump room	N	108 108 126 342	Cable Insulation Lube Oil	Low 280	N		HS	M
1 - K	CS	180'-0"	158 159 160	Backwash transfer pump room Backwash transfer pump room Sump pump room	N	120 120 120 360	Cable Insulation Lube Oil	Low 960	N		HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
1 - L	CS	200'-0"	258/258A 362A 362B 362C 362D	Control structure chillers & Cooling water heat exchanger & pump room Analyzer compartment Analyzer compartment Analyzer compartment Analyzer compartment	Y	2200 35 35 35 35 2340	Cable Insulation Lube Oil R/A Insulation	Low 136	S	3	HS	M
1 - M	CS	200'-0"	263/263A 362E 362F 362G 362H	Control structure chillers & Cooling water heat exchanger & pump room Analyzer compartment Analyzer compartment Analyzer compartment Analyzer compartment	Y	2200 35 35 35 35 2340	Cable Insulation Lube Oil R/A Insulation	Low 112	S	3	HS	M
1 - N	CS	200'-0"	259	Recombiner access area	Y	1405	Thermo-Lag 330-1	Low 0	S	3	HS	M
2 -	CS	217'-0"	336	13 Kv switchgear area	Y	6570	Cable Insulation Thermo-Lag 330-1 Thermo-Lag 770-1	Low 640	S	49	PR (Localized)	A
3 -	CS	217'-0"	323	Battery room	Y	144	Battery Cases Battery Spacers Battery Covers Wood	Low 696	S H	1 1	HS E	M
4 -	CS	217'-0"	324	Battery room	Y	128	Battery Cases Battery Spacers Cable Insulation Battery Covers	Low 776	S H	1 1	HS E	M
5 -	CS	217'-0"	360	Battery room	Y	144	Battery Cases Battery Spacers Battery Covers	Low 696	S H	1 1	HS E	M
6 -	CS	217'-0"	361	Battery room	Y	144	Battery Cases Battery Spacers Battery Covers	Low 696	S H	1 1	HS E	M
7 -	CS	239'-0"	437	Corridor	Y	528	Cable Insulation Thermo-Lag 330-1	Moderate 1040	S	5	WP	A
8 -	CS	239'-0"	425	Battery room	Y	470	Battery Cases Battery Spacers Cable Insulation	Low 320	S H	2 1	HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
9 -	CS	239'-0"	436	Battery room	Y	470	Battery Cases Battery Spacers Cable Insulation	Low 80	S H	2 1	HS	M
10 - A	CS	239'-0"	426	Battery room	Y	468	Battery Cases Battery Spacers Cable Insulation	Low 216	S H	2 1	HS	M
10 - B	CS	239'-0"	454	Swtchgaer maintainence area	Y	360	Cable Insulation Wood	Low 0	S H	1 2	HS	M
11 -	CS	239'-0"	427	Battery room	Y	442	Battery Cases Battery Spacers Cable Insulation	Low 272	S H	2 1	HS	M
12 -	CS	239'-0"	434	4 kV switchgear room	Y	470	Cable Insulation Wood	Low 640	S H	2 2	HS	M
13 -	CS	239'-0"	435	4 Kv switchgear room	Y	470	Cable Insulation	Low 208	S H	2 2	HS	M
14 -	CS	239'-0"	432	4 Kv switchgear room	Y	400	Cable Insulation	Low 752	S H	2 2	HS	M
15 -	CS	239'-0"	433	4 Kv switchgear room	Y	400	Cable Insulation Thermo-Lag 330-1	Low 176	S H	2 2	HS	M
16 -	CS	239'-0"	430	4 Kv switchgear room	Y	400	Cable Insulation	Low 376	S H	2 2	HS	M
17 -	CS	239'-0"	431	4 Kv switchgear room	Y	400	Cable Insulation R/A Insulation Thermo-Lag 330-1	Low 248	S H	2	HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
18 -	CS	239'-0"	428	4 Kv switchgear room	Y	470	Cable Insulation R/A Insulation	Low 320	S H	2 2	HS	M
19 -	CS	239'-0"	429	4 Kv switchgear room	Y	470	Cable Insulation	Low 208	S H	2 2	HS	M
20 -	CS	254'-0"	452	Unit 1 static inverter room	Y	715	Cable Insulation Thermo-Lag 330-1 Thermo-Lag 770-1	Moderate 1400	S H	4 1	HS	M
21 -	CS	254'-0"	453	Unit 2 static inverter room	Y	986	Cable Insulation Thermo-Lag 330-1	Low 1000	S	6	HS	M
22 -	CS	254'-0"	449	Unit 1cable spreading room	Y	2610	Cable Insulation R/A Insulation Thermo-Lag 330-1	Moderate 768	S	14	HS E WP	M A
23 -	CS	254'-0"	450	Unit 2 cable spreading room	Y	2610	Cable Insulation	Moderate 768	S	14	HS E WP	M A
24 - A	CS	269'-0"	533	Control room	Y	5336	Cable Insulation Paper Plastic Carpet	Low 0	S S	23(1) 11(2)	CH HS	M
24 - B	CS	269'-0"	529 530	Control room kitchen Bathroom	Y	146 90 236	Paper Wood Plastic Alcohol	Low 0	S	1	CH HS	M
24 - C	CS	269'-0"	531	Library and conference room	Y	240	Paper Carpet Plastic	Moderate 0	S	1	CH HS	M
24 - D	CS	269'-0"	532	Shift manager's office	Y	225	Paper Carpet Plastic	Moderate 0	S	2	CH HS	M
24 - E	CS	269'-0"	534	Work control supervisor's office	Y	314	Cable Insulation Paper Carpet Plastic	Moderate 0	S	1(6)	CH HS	M

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading: Combustible Loading Change Limit	Detection: Type	Detection: No.	Suppression: Type	Suppression: Actuation
24 - F	CS	269'-0"	535	Conference room	Y	392	Cable Insulation Paper Wood Carpet Plastic	Moderate 0	S	1[6]	E HS	M
25 -	CS	289'-0"	542 541	Auxiliary equipment room Computer maintenance	Y	6676 126 6802	Cable Insulation Paper Plastic Wood Thermo-Lag 330-1 Thermo-Lag 770-1 Floor Tiles	Low 160	S S S S H H S S S H H	57[19] 56[20] 14[21] 32[22] 112[4], [20] 13[4], [21] 46[23] 6[24] 32[25] 88[4], [23] 8[4], [24]	H (Raised Floor)	A
26 -	CS	289'-0"	540	Remote shutdown room	Y	300	Cable Insulation Paper Plastic	Low 168	S S H	3[26] 2[27] 4[4],[27]	H (Raised Floor)	A
27 -	CS	304'-0"	619	Control structure fan room	Y	7610	Cable Insulation Charcoal Rubber R/A Insulation Thermo-Lag 330-1 Plastic	Control of Combustibles 152	S H H	10 4[3] 23[4]	PR FWS	A M
28 - A	CS	350'-0"	622/625 625A 704	SGTS Access Area & Access to FP Upper fan room mezzanine Elevator machine room	Y	3630 5632 98 9360	Charcoal Plastic R/A Insulation Rubber	Control of Combustibless [28] 0	H	4[3]	FWS HS	M
28 - B	CS	332'-0"	624 624A 624B	SGTS filter compartment SBGT filter A compartment SBGT filter B compartment	Y	1072 972 972 3016	Charcoal Plastic Rubber	Control of Combustibless [28] 0	H	4[3]	FWS HS	M
28 - C	CS	332'-0"	625	Control room fresh air intake plenum	Y	320		Low 0	S	3	HS	M
29 - A	RB-1	181'-11"	101	Suppression chamber	Y	5464		Low	N		HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
								0				
29 - B	RB-1	181'-11"	100	Suppression chamber inside pedestal	Y	314		Low 0	N			
29 - C	RB-1	217'-0"	100	Drywell drain sump area	Y	314		Low 0	N		HS	M
30 - A	RB-1	237'-11"	400 401 405	Drywell area Drywell equipment access Drywell personnel and equipment	Y	4627 65 290 4982	Cable Insulation Lube Oil R/A Insulation Alpha Maritex Lead Shielding Blanket Material Silicon Rubber	Low 352	N		HS	M
30 - B	RB-1	237'-11"	400	Drywell inside pedstal	Y	314	Cable Insulation	Low 1520	N		HS	M
31 -	RB-1	177'-0"	103 204	RHR Heat Exchanger & Pump Room B/D RHR Heat Exchanger & Pump	Y	2050 1880 3930	Cable Insulation Lube Oil Rubber Plastic	Low 240	S	6	HS	M
32 -	RB-1	177'-0"	102 203	RHR Heat Exchanger & Pump Room A/C RHR Heat Exchanger & Pump	Y	1700 1880 3580	Cable Insulation Lube Oil Plastic	Low 296	S	5	HS	M
33 -	RB-1	177'-0"	106 108 289	Airlock RCIC pump room RCIC pipeway	Y	36 830 300 1166	Cable Insulation Lube Oil	Low 800	S H	2 3(4)	PR	A

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TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
34 -	RB-1	177'-0"	109 288	HPCI pump room HPCI pipeway	Y	1380 550 1930	Cable Insulation Lube Oil R/A Insulation	Low 456	S H	3 4(4)	PR	A
35 -	RB-1	177'-0"	110	Core spray pump room	Y	575	Cable Insulation Lube Oil Plastic	Low 880	S	2	HS	M
36 -	RB-1	177'-0"	113	Core spray pump room	Y	600	Cable Insulation Lube Oil	Low 800	S	2	HS	M
37 -	RB-1	177'-0"	114 114A	Core spray pump room Pipeway	Y	600 108 708	Cable Insulation Lube Oil	Low 800	S	2	HS	M
38 -	RB-1	177'-0"	117	Core spray pump room	Y	575	Cable Insulation Lube Oil	Low 800	S	2	HS	M
39 -	RB-1	177'-0"	115 118	Sump room Passageway	Y	408 1176 1584	Cable Insulation	Low 56	S	4	HS	M
40 -	RB-1	177'-0"	111	Corridor	Y	525	Cable Insulation Rubber Plastic	Low 0	S	2	HS	M
41 -	RB-1	201'-0"	207 210	RECW equipment area Pipeway	Y	2920 108 3028	Cable Insulation	Low 248	S H	3 10(4)	PR	A
42 - A	RB-1	201'-0"	200 201	Safeguard systems access area Airlock	Y	3178 42 3220	Cable Insulation Rubber	Low 320	S H	3 12(4)	PR	A
42 - B	RB-1	201'-0"	209	Isolation valve compartment	Y	280		Control of Combustibles 0	N		HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
43 -	RB-1	217'-0"	306 307 309	Safeguard system Isolation valve area Safeguard system Isolation valve area Safeguard system Isolation valve area	Y	340 159 2446 2945	Cable Insulation R/A Insulation Thermo-Lag 330-1 Plastic	Control of Combustibles 0	S	8	HS	M
44 -	RB-1	217'-0"	301 302 303 304 308	Equipment airlock Pipeway Airlock Safeguard systems access area Airlock	Y	532 108 40 8269 42 8991	Cable Insulation Wood Thermo-Lag 330-1	Control of Combustibles 0	S H	27 22(4)	PR (Partial) WC	A M
45 - A	RB-1	253'-0"	402 406M 409 444	CRD hydraulic equipment area Mezzanine above room 406 CRD removal hatch Airlock	Y	12860 630 28 120 13638	Cable Insulation R/A Insulation Thermo-Lag 330-1 Lead Blanket Insulation (Nylon) Fiberglass	Control of Combustibles 0	S H	20 16(4)	PR (Partial) WC	A M
45 - B	RB-1	253'-0"	406	Neutron monitoring system area	Y	630	Cable Insulation Thermo-Lag 330-1	Control of Combustibles 0	S H	2 2(4)	PR (Partial)	A
45 - C	RB-1	253'-0"	403 404 408	CRD repair room CRD hydraulic equipment area Airlock	Y	785 154 35 974		Control of Combustibles 0	S	1	HS	M
46 -	RB-1	253'-0"	407 518 627	Main steam tunnel Main steam tunnel Steam vent platform	Y	870 1092 456 2418		Control of Combustibles Allowed 0	N		HS	M
47 - A	RB-1	283'-0"	500 506 506M 519 599 599M	General equipment area Corridor Corridor Service area Valve compartment Mezzanine above valve compartment	Y	392 8798 147 2610 170 216 12333	Cable Insulation Lube Oil Rubber R/A Insulation Thermo-Lag 330-1 Fiberglass	Control of Combustibles 0	S H	21 18(4)	PR (Partial)	A

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
47 - B	RB-1	295'-3"	523	Isolation valve compartment	Y	750	Cable Insulation R/A Insulation Thermo-Lag 330-1	Control of Combustibles 0	S	2	HS	M
47 - C	RB-1	283'-0"	511	Fuel pool cooling water pump and HX	Y	1660	Cable Insulation Shielding Blankets (Nylon Cover)	Control of Combustibles 0	S	2	HS	M
47 - D	RB-1	283'-0"	510 522	Isolation valve compartment Isolation valve compartment	Y	512 765 1277	Cable insulation Plastic	Control of Combustibles 0	S	1	HS	M
47 - E	RB-1	283'-0"	509	RWCU pump room	Y	160		Control of Combustibles 0	N		HS	M
47 - F	RB-1	283'-0"	508	RWCU pump room	Y	130		Control of Combustibles 0	N		HS	M
47 - G	RB-1	283'-0"	507	RWCU pump room	Y	145		Control of Combustibles 0	S	1	HS	M
47 - H	RB-1	283'-0"	505	Non-Regenerative Heat Exchanger	Y	420	Cable insulation Plastic	Control of Combustibles 0	S	1	HS	M
47 - J	RB-1	283'-0"	504	Non-Regenerative Heat Exchanger	Y	420	Cable insulation Plastic	Control of Combustibles 0	S	1	HS	M
47 - K	RB-1	283'-0"	503	Regenerative Heat Exchanger Room	Y	420	Cable insulation Plastic	Control of Combustibles 0	S	1	HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading: Combustible Loading Change Limit	Detection: Type	Detection: No.	Suppression: Type	Suppression: Actuation
47 - L	RB-1	283'-0"	502	RWCU backwash receiving tank area	Y	400		Control of Combustibles 0	N		HS	M
47 - M	RB-1	283'-0"	501 501A	Isolation valve compartment Isolation valve compartment	Y	469 128 597		Control of Combustibles 0	N		HS	M
48 - A	RB-1	313'-0"	600C 601 602 605 605A 605B 609A 609B	RWCU holding pump compartment Laydown Area Laydown Area RERS fan area and corridor Alcove Alcove RWCU filter demin compartment RWCU filter demin compartment	Y	245 990 2540 3100 270 270 48 48 7511	Cable Insulation R/A Insulation Thermo-Lag 330-1	Control of Combustibles 0	N	8	WC	M
48 - B	RB-1	313'-0"	600B	RWCU holding pump compartment	N	230	Cable insulation Plastic	Control of Combustibles 0	N		HS	M
48 - C	RB-1	313'-0"	600A	RWCU holding pump compartment	N	230	Cable insulation Plastic	Control of Combustibles 0	N		HS	M
49 -	RB-1	313'-0"	607 608 606	Reactor enclosure lower fan room Airlock Airlock	Y	4320 42 145 4507	Cable Insulation Thermo-Lag 330-1	Low 40	N		HS	M
50 - A	RB-1	331'-0"	615 613 614	Reactor enclosure upper fan room Corridor Airlock	Y	2416 182 42 2640	Fiberglass	Low 0	N		HS	M
50 - B	RB-1	331'-0"	616	Equip.compartment exhaust filter room	N	468	Charcoal	High 0	H	2(3)	FWS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
50 - C	RB-1	331'-0"	617	Equip.compartment exhaust filter room	N	468	Charcoal	High 0	H	2[3]	FWS	M
51 - A	RB-1	331'-0"	618	RERS filter compartment	Y	720	Charcoal	Low 0	H	2[3]	FWS	M
51 - B	RB-1	331'-0"	612	RERS filter compartment	Y	720	Charcoal	Low 0	H	2[3]	FWS	M
52 - A	RB-2	181'-11"	172	Suppression chamber	Y	5464		Low 0	N		HS	M
52 - B	RB-2	181'-11"	171	Suppression chamber inside pedestal	Y	314		Low 0	N		HS	M
52 - C	RB-2	217'-0"	171	Drywell drain sump area	Y	314		Low 0	N			
53 - A	RB-2	237'-11"	473 474 478	Drywell area Drywell equipment access Drywell personnel and equipment access	Y	4627 65 290 4982	Cable Insulation Lube Oil Alpha Maritex Lead Shielding Blanket Material Silicone Rubber	Low 320	N		HS	M
53 - B	RB-2	237'-11"	473	Drywell inside pedestal	Y	314	Cable Insulation	Low 1520	N		HS	M
54 -	RB-2	177'-0"	173 280	A/C RHR heat exchanger and pump A/C RHR heat exchanger and pump	Y	2050 1880 3930	Cable Insulation Lube Oil Rubber	Low 240	S	8	HS	M
55 -	RB-2	177'-0"	174 281	B/D RHR heat exchanger and pump B/D RHR heat exchanger and pump	Y	1700 1880 3580	Cable Insulation Lube Oil Rubber	Low 288	S	7	HS	M
56 -	RB-2	177'-0"	179 285 177	RCIC pump room RCIC pipeway Airlock	Y	830 120 42 992	Cable Insulation Lube Oil Wood	Low 800	S H	2 3[4]	PR	A

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
57 -	RB-2	177'-0"	180 283	HPCI pump room HPCI pipeway	Y	1380 550 1930	Cable Insulation Lube Oil Plastic	Low 456	S H	3 4(4)	PR	A
58 -	RB-2	177'-0"	181	Core sray pump room	Y	575	Cable Insulation Lube Oil	Low 880	S	2	HS	M
59 -	RB-2	177'-0"	184 184A	Core spray pump room Pipeway	Y	600 144 744	Cable Insulation Lube Oil	Low 800	S	2	HS	M
60 -	RB-2	177'-0"	185	Core spray pump room	Y	600	Cable Insulation Lube Oil	Low 800	S	2	HS	M
61 -	RB-2	177'-0"	188	Core sray pump room	Y	575	Cable Insulation Lube Oil	Low 880	S	2	HS	M
62 -	RB-2	177'-0"	186 189	Sump room Passageway	Y	304 1176 1480	Cable Insulation	Low 288	S	4	HS	M
63 -	RB-2	177'-0"	182	Corridor	Y	525	Cable Insulation Plastic Rubber	Low 0	S	2	HS	M
64 - A	RB-2	201'-0"	284	RECW equipment area	Y	4020	Cable Insulation	Low 248	S H	5 9	PR	A
64 - B	RB-2	201'-0"	286	Isolation valve compartment	Y	280	Thermo-Lag 330-1	Low 320	S	2	HS	M
65 -	RB-2	201'-0"	279 282 287	Safeguard system access area Airlock Pipeway	Y	3178 42 108 3328	Cable Insulation Plastic Rubber	Low 0	S H	4 14	PR	A

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading: Combustible Loading Change Limit	Detection: Type	Detection: No.	Suppression: Type	Suppression: Actuation
66 -	RB-2	217'-0"	374 375 376	Safeguard system Isolation valve area Safeguard system Isolation valve area Safeguard system Isolation valve area	Y	340 3512 2446 6298	Cable Insulation Thermo-Lag 330-1	Control of Combustibles 0	S	8	HS	M
67 -	RB-2	217'-0'	368 370 372 367 369	Pipeway Safeguard system access area Airlock Equipment airlock Airlock	Y	114 7836 35 532 40 8557	Cable Insulation Rubber Wood R/A Insulation Thermo-Lag 330-1	Control of Combustibles 0	S H	30 36	PR (Partial) WC	A M
68 - A	RB-2	253'-0"	475 476M 482 479M	CRD hydraulic equipment area Mezzanine above CRD maint. room CRD removal hatch Mezzanine above neut. mon. room	Y	11960 900 28 630 13518	Cable Insulation Rubber Thermo-Lag 330-1 Plastic Fiberglass	Control of Combustibles 0	S H	20 16	PR (Partial) WC	A M
68 - B	RB-2	253'-0"	479	Neutron monitoring system area	Y	630	Cable Insulation	Control of Combustibles 0	S	2	HS	M
68 - C	RB-2	253'-0"	476 477 481	CRD maintenance room CRD maintenance room Airlock	Y	785 225 35 1045	Fiberglass Polyester Resin Rubber	Control of Combustibles 0	S	2	HS	M
69 -	RB-2	253'-0"	480 587 626	Main steam tunnel Main steam tunnel Steam vent platform	Y	870 850 456 2176		Control of Combustibles 0	N		HS	M
70 - A	RB-2	283'-0"	574 580 580M 589 589M 594 596	General equipment area Corridor Mezzanine Valve compartment RHR valve compartment mezzanine Service area Fuel pool service water booster pump	Y	570 8555 147 170 216 2610 1935 14203	Cable Insulation Lube Oil Rubber R/A Insulation Thermo-Lag 330-1 Plastic Fiberglass	Control of Combustibles 0	S H	22 15	PR (Partial)	A

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
70 - B	RB-2	295'-3"	593	Isolation valve compartment	Y	750	Cable Insulation	Control of Combustibles 0	S	2	HS	M
70 - C	RB-2	283'-0"	585	Fuel pool cooling water pump and HX	Y	760	Cable Insulation Shielding Blankets (Nylon Cover)	Control of of Combustibles 0	S	2	HS	M
70 - D	RB-2	283'-0"	584 597	Isolation valve compartment Isolation valve compartment	Y	352 450 802	Cable Insulation	Control of Combustibles 0	S	1	HS	M
70 - E	RB-2	283'-0"	583	RWCU pump room	Y	160	Cable Insulation	Control of Combustibles 0	N		HS	M
70 - F	RB-2	283'-0"	582	RWCU pump room	Y	130	Cable Insulation	Control of Combustibles 0	N		HS	M
70 - G	RB-2	283'-0"	581	RWCU pump room	Y	145	Cable Insulation	Control of Combustibles 0	S	1	HS	M
70 - H	RB-2	283'-0"	579	Nonregenerative heat exchanger area	Y	420		Control of Combustibles 0	S	1	HS	M
70 - J	RB-2	283'-0"	578	Nonregenerative heat exchanger area	Y	420		Control of Combustibles 0	S	1	HS	M
70 - K	RB-2	283'-0"	577	Regenerative heat exchanger area	Y	420		Control of Combustibles 0	S	1	HS	M
70 - L	RB-2	283'-0"	576	RWCU backwash receiving tank area	Y	400		Control of Combustibles 0	N		HS	M
70 - M	RB-2	283'-0"	575 575A	Isolation valve compartment Isolation valve compartment	Y	675 50 725		Control of Combustibles 0	N		HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading: Combustible Loading Change Limit	Detection: Type	Detection: No.	Suppression: Type	Suppression: Actuation
71 - A	RB-2	313'-0"	637 638 641 633 636C 644 641A 641B 644A 644B	Laydown area Laydown area RERS fan area Gamma scan compartment Holding pump compartment corridor RWCU filter demin. access Alcove Alcove RWCU filter demin compartment RWCU filter demin compartment	Y	990 3540 3100 220 190 120 270 270 48 48 8796	Cable Insulation Plastic Rubber Thermo-Lag 330-1	Control of Combustibles 0	S S	17 1(6)	WC	M
71 - B	RB-2	313'-0"	636B	RWCU holding pump compartment	N	216		Control of Combustibles 0	N		HS	M
71 - C	RB-2	313'-0"	636A	RWCU holding pump compartment	N	216	Cable Insulation	Control of Combustibles 0	N		HS	M
72 -	RB-2	313'-0"	642 635 643	Airlock Airlock Reactor enclosure lower fan room	Y	42 145 4320 4507	Cable Insulation Plastic	Low 112	N		HS	M
73 - A	RB-2	331'-0"	647 650 652	Reactor enclosure upper fan room Airlock Corridor	Y	2416 42 190 2648	Plastic Cable Insulation	Low 0	N		HS	M
73 - B	RB-2	331'-0"	649	Equip. compartment exhaust filter room	Y	468	Charcoal	High 0	H	2(3)	FWS	M
73 - C	RB-2	331'-0"	648	Equip.compartment exhaust filter room	N	468	Charcoal	High 0	H	2(3)	FWS	M

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TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
74 - A	RB-2	331'-0"	651	RERS filter compartment	Y	720	Charcoal	Low 0	H	2[3]	FWS	M
74 - B	RB-2	331'-0"	653	RERS filter compartment	Y	720	Charcoal	Low 0	H	2[3]	FWS	M
75 -	RB-1/2	198'-0"	202	Service water pipe tunnel	Y	3840	Thermo-Lag 330-1	Control of Combustibles 0	N		HS	M
76 -	RB-1/2	217'-0"	310 300 366	Refueling hoistway Airlock Airlock	Y	1710 36 36 1782	Rubber	Low 0	N		HS	M
77 -	RB-1/2	360'-0"	711 711	South exhaust stack Air Lock	Y	620 145		Low 0	N			

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TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
78 - A	RB-1/2	352'-0"	603	New fuel storage vault	Y	182	Plastic	Control of Combustibles 0	N		HS	M
			604	Spent fuel pool		1032	Rubber					
			610	Skimmer surge tank pit		115	Polycarbonate					
			611	Skimmer surge tank pit		115	Lube Oil					
			634	Cask washdown and storage area		247	Cable Insulation					
			639	New fuel storage vault		126	Nylon					
			640	Spent fuel pool		1032						
			645	Skimmer surge tank pit		115						
			646	Skimmer surge tank pit		115						
			700	Refueling/laydown area		13637						
			702	Refueling/laydown area		780						
			702A	Steam dryer		3000						
			703	Airlock		36						
			707	Airlock		36						
			708	Refueling/laydown area		13637						
			710	Refueling/laydown area		780						
			710A	Steam dryer		3000						
						37985						
78 - B	RB-1/2	352'-0"	655	Airlock	Y	36	Cable Insulation	Low 144	N		HS	M
			701	Shower and dressing area		3500	Paper					
						3536						
78 - C	RB-1/2	352'-0"	654	Airlock	N	36		Low 0	N		HS	M
			705	Elevator machinery room		72						
			706	Elevator machinery room		72						
			709	Shower and dressing area		3500						
						3680						
79 -	DG1	217'-0"	311A	Diesel generator cell	Y	1690	Cable Insulation	Moderate 560	F	1	PR	A
			312A	Day tank room		72	Lube Oil					
							R/A Insulation		H	1		
						1762	Fuel Oil		H	5(4)		
							Rubber					
80 -	DG1	217'-0"	311C	Diesel generator cell	Y	1690	Cable Insulation	Moderate 560	F	1	PR	A
			312C	Day tank room		72	Lube Oil					
							R/A Insulation		H	1		
						1762	Fuel Oil		H	5(4)		
							Rubber					

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TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
81 -	DG1	217'-0"	311B 312B	Diesel generator cell Day tank room	Y	1690 72 1762	Cable Insulation Lube Oil R/A Insulation Fuel Oil Rubber	Moderate 560	F H H	1 1 5(4)	PR	A
82 -	DG1	217'-0"	311D 312D	Diesel generator cell Day tank room	Y	1690 72 1762	Cable Insulation Lube Oil R/A Insulation Fuel Oil Rubber	Moderate 560	F H H	1 1 5(4)	PR	A
83 -	DG2	217'-0"	315A 316A	Diesel generator cell Day tank room	Y	1690 72 1762	Cable Insulation Lube Oil R/A Insulation Fuel Oil Rubber	Moderate 560	F H H	1 1 5(4)	PR	A
84 -	DG2	217'-0"	315C 316C	Diesel generator cell Day tank room	Y	1690 72 1762	Cable Insulation Lube Oil Fuel Oil Rubber	Moderate 560	F H H	1 1 5(4)	PR	A
85 -	DG2	217'-0"	315B 316B	Diesel generator cell Day tank room	Y	1690 72 1762	Cable Insulation Lube Oil R/A Insulation Fuel Oil Rubber	Moderate 560	F H H	1 1 5(4)	PR	A
86 -	DG2	217'-0"	315D 316D	Diesel generator cell Day tank room	Y	1690 72 1762	Cable Insulation Lube Oil R/A Insulation Fuel Oil Rubber	Moderate 560	F H H	1 1 5(4)	PR	A
87 -	TB-1	189'-0"	256 342	Condensate pump room Condensate pump room	N	1620 1643 3263	Cable Insulation Lube Oil	Low 640	N		HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
88 - A	TB-1	200'-0"	253	Circ. water inlet pit area	Y	2332	Cable Insulation	Low	N		WP (Partial)	A
			254	Condenser Area		4600	Lube Oil	400				
			255	Drain cooler & circ. water outlet area		4260	Fiberglass					
			260A	feed pump turbine exhaust room		200	Rubber					
			261A	feed pump turbine exhaust room		200						
			262A	feed pump turbine exhaust room		200						
			332	Condenser Area		17248						
			332M	Main steam tunnel		3024						
			438	Feedwater heater service area		4885						
			438M	Main steam tunnel		6956						
						43905						
88 - B	TB-1	239'-0"	441	Feedwater heater room	N	2220	Cable Insulation	Low	N		HS	M
								480				
88 - C	TB-1	239'-0"	440	Feedwater heater room	N	2220		Low	N		HS	M
								0				
88 - D	TB-1	239'-0"	439	Feedwater heater room	N	2220		Low	N		HS	M
								0				
89 - A	TB-1	200'-0"	252	Control rod drive water pump area	N	6908	Cable Insulation	Low	H		WP (Partial)	A
			252A	Spent resin tank room		390	Lube Oil	216				
			252B	Resin measuring tank room		390	Plastic					
			260	Lube oil reservoir area		506	Rubber					
			261	Lube oil reservoir area		506	Wood					
			262	Lube oil reservoir area		253	R/A Insulation					
			265	Corridor		2290	Trash					
			212	Pipeway		726	Fiberglass					
			265M	Mezzanine		336						
				Permanent in-plant storage		12305						

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TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
89 - B	TB-1	200'-0"	264A	Condensate filter/demin compartment	N	190	Cable Insulation	Low	N		HS	M
			264B	Condensate filter/demin compartment		190		896				
			264C	Condensate filter/demin compartment		190						
			264D	Condensate filter/demin compartment		190						
			264E	Condensate filter/demin compartment		190						
			264F	Condensate filter/demin compartment		190						
			264G	Condensate filter/demin compartment		190						
			264H	Condensate filter/demin compartment		247						
			264I	Condensate filter/demin compartment		190						
			339A	Condensate filter/demin compartment		140						
			339B	Condensate filter/demin compartment		140						
			339C	Condensate filter/demin compartment		140						
			339D	Condensate filter/demin compartment		140						
			339E	Condensate filter/demin compartment		140						
			339F	Condensate filter/demin compartment		140						
			339G	Condensate filter/demin compartment		140						
			339H	Condensate filter/demin compartment		140						
			325A	Corridor		104						
			249	Pipeway		462						
						3453						
90 -	TB-1	217'-0"	333	Air ejec. and steam packing exhauster	N	1610	Cable Insulation	Low	N		HS	M
								184				
91 -	TB-1	217'-0"	334	Air ejec. and steam packing exhauster	N	1610	Cable Insulation	Low	N		HS	M
							Plastic	184				
92 -	TB-1	217'-0"	337	Vacuum pump room	N	702	Cable Insulation	Low	N		HS	M
							Lube Oil	960				
93 -	TB-1	217'-0"	328	Air compressor area	N	1342	Cable Insulation	High	N		WP (Partial)	A
			330	EHC power unit area		546	Lube Oil	1440				
			331	Lube oil storage tank area		1302	Plastic					
						3190	Rubber					
							Polyvinyl Chloride (PVC)					
							Fiberglass					
							Cloth					
							Polyethylene					

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TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
94 - A	TB-1	217'-0"	325	Reactor feed pump access area	Y	2968	Cable Insulation	Low	N		HS	M
			327	MCC area		802	Plastic	480				
			338	Passageway		450	Rubber					
			341	Control panel area		160	R/A Insulation					
			341A	Deep bed vessel area		336						
			341B	Deep bed vessel area		336						
			341C	Deep bed vessel area		336						
			341D	Deep bed vessel area		336						
			341E	Deep bed vessel area		336						
			341F	Deep bed vessel area		336						
			341G	Deep bed vessel area		336						
			341H	Deep bed vessel area		336						
			341I	Deep bed vessel area		336						
						7404						
94 - B	TB-1	217'-0"	340A	Reactor feed pump turbine compartment	N	570		Low	H	1	HS	M
								0				
94 - C	TB-1	217'-0"	340B	Reactor feed pump turbine compartment	N	570		Low	H	1	HS	M
								0				
94 - D	TB-1	217'-0"	340C	Reactor feed pump turbine compartment	N	570		Low	H	12	HS	M
								0				
94 - F	TB-1	217'-0"	341	Control panel area (western extension)	N	160		Low	N		HS	M
								0				
95 -	TB-1	239'-0"	442	MCC room	Y	280	Cable Insulation	High	H	7[4]	WP	A
			445	TECW equipment area		2357	Lube Oil	1280			DL	A
			446	Lube oil equipment area		840	Plastic					
						3477						
96 -	TB-1	239'-0"	443	Battery room	N	462	Battery Cases	Low	S	1	HS	M
							Battery Spacers	560	H	1		
							Cable Insulation					
97 -	TB-1	239'-0"	448	Equipment hatch corridor	N	2535	Cable Insulation	Low	N		HS	M
			448A	Passageway		390	Rubber	160				
						2925	Wood					

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TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
98 - A	TB-1	269'-0"	548 548M	Recirculation pump MG area Feedwater heater mezzanine	N	13020 2000 15020	Cable Insulation Plastic Rubber R/A Insulation	Low 400	S	19	HS	M
98 - B	TB-1	269'-0"	547	Feedwater heater room	N	880		Low 0	N		HS	M
98 - C	TB-1	269'-0"	546	Feedwater heater room	N	880		Low 0	N		HS	M
98 - D	TB-1	269'-0"	545	Feedwater heater room	N	880		Low 0	N		HS	M
99 - A	TB-1	302'-0"	620	Turbine enclosure HVAC area	N	13080	Cable Insulation Lube Oil Wood R/A Insulation Rubber Polycarbonate	Low 400	S	1	HS	M
99 - B	TB-1	302'-0"	621	TEECE filter area	N	1228	Charcoal	High 0	H	4(3)	FWS	M
100 -	TB-2	189'-0"	266 347	Condensate pump room Condensate pump room	N	1620 1643 3263	Cable Insulation Lube Oil	Low 960	N		HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
101 - A	TB-2	200'-0"	267	Drain cooler & circ. water outlet area	Y	4260	Cable Insulation	Low	N		WP (Partial)	A
			268	Condenser area		4600	Lube Oil	400				
			269	Circ. water inlet pit area		2332	Rubber					
			274A	feed pump turbine exhaust room		200	Fiber Reinforced					
			275A	feed pump turbine exhaust room		200	Plastic					
			276A	feed pump turbine exhaust room		200						
			355	Condenser area		17248						
			464	Feedwater heater service area		4885						
			464M	Main steam tunnel		6956						
			355M	Main steam tunnel		1080						
						41961						
101 - B	TB-2	239'-0'	458	Feedwater Heater Room	N	2220	Cable Insulation	Low	N		HS	M
								880				
101 - C	TB-2	239'-0'	457	Feedwater Heater Room	N	2220		Low	N		HS	M
								0				
101 - D	TB-2	239'-0'	456	Feedwater Heater Room	N	2220		Low	N		HS	M
								0				
102 - A	TB-2	200'-0"	270	Control rod drive water pump area	Y	6908	Cable Insulation	Low	H	7	WP (Partial)	A
			270A	Spent resin tank room		390	Lube Oil	560				
			270B	Resin measuring room		348	Wood					
			270C	Resin measuring room		42	FG Pipe Insulation					
			271	Stairway		506	Plastic					
			273A	Vertical pipeway		54	Fiberglass					
			274	Lube oil reseroir		506						
			275	Lube oil reseroir		506						
			276	Lube oil reseroir		253						
			277	Corridor		2560						
			277M	Mezzanine		336						
						12409						

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
102 - B	TB-2	200'-0"	352A	Condensate filter/demin compartment	N	140	Cable Insulation	Low 880	N		HS	M
			352B	Condensate filter/demin compartment		140						
			352C	Condensate filter/demin compartment		140						
			352D	Condensate filter/demin compartment		140						
			352E	Condensate filter/demin compartment		140						
			352F	Condensate filter/demin compartment		140						
			352G	Condensate filter/demin compartment		140						
			352H	Condensate filter/demin compartment		140						
			272A	Condensate filter/demin compartment		242						
			272B	Condensate filter/demin compartment		200						
			272C	Condensate filter/demin compartment		200						
			272D	Condensate filter/demin compartment		200						
			272E	Condensate filter/demin compartment		200						
			272F	Condensate filter/demin compartment		200						
			272G	Condensate filter/demin compartment		200						
			272H	Condensate filter/demin compartment		200						
			272I	Condensate filter/demin compartment		200						
			273	Vertical pipeway		496						
			346A	Corridor		104						
						3562						
103 -	TB-2	217'-0"	348	Air ejec. and steam packing exhauster	N	1610	Cable Insulation	Low 640	N		HS	M
104 -	TB-2	217'-0"	349	Air ejec. and steam packing exhauster	N	1610	Cable Insulation	Low 640	N		HS	M
105 -	TB-2	217'-0"	350	Vacuum pump room	N	702	Cable Insulation Lube Oil	Low 1000	N		HS	M
106 -	TB-2	217'-0"	356	Lube oil storage tank area	N	1302	Cable Insulation	High 1440	N		WP (Partial)	A
			357	Air compressor area		1342	Lube Oil					
			358	EHC power unit area		546	Fiberglass					
			359	Stairway		112	Polyethylene					
						3302	Plastic					
							Rubber					
							Cloth					

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
107 - A	TB-2	217'-0"	346	Reactor feed pump access area	N	2968	Cable Insulation	Low	N		HS	M
			351	Passageway		420	Rubber	480				
			354	Control panel area		5034	Plastic					
			354A	Deep bed vessel area		336						
			354B	Deep bed vessel area		336						
			354C	Deep bed vessel area		336						
			354D	Deep bed vessel area		336						
			354E	Deep bed vessel area		336						
			354F	Deep bed vessel area		336						
			354G	Deep bed vessel area		336						
			354H	Deep bed vessel area		336						
			354I	Deep bed vessel area		336						
			357A	MCC area		802						
			371	Vestibule		81						
						12329						
107 - B	TB-2	217'-0"	353A	Reactor feed pump turbine compartment	N	570		Low	H	1	HS	M
								0				
107 - C	TB-2	217'-0"	353B	Reactor feed pump turbine compartment	N	570		Low	H	1	HS	M
								0				
107 - D	TB-2	217'-0"	353C	Reactor feed pump turbine compartment	N	570		Low	H	1	HS	M
								0				
107 - E	TB-2	217'-0"	800	Secondary equipment access area	N	650		Low	H		HS	M
								0				
107 - F	TB-2	217'-0"	802	Health physics access control area	N	720		Low	S	1	HS	M
								0				
107 - G	TB-2	217'-0"	803	Vestibule	N	250		Low	S	1	HS	M
								0				

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	SR	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
108 -	TB-2	239'-0"	459 461 463	MCC area TECW equipment area Lube oil equipment room	Y	280 2357 840 3477	Cable Insulation Lube Oil Wood Plastic	High 1040	H	7(4)	AS (Partial) DL (Partial)	A A
109 -	TB-2	239'-0"	460	Battery room	N	462	Battery Cases Battery Spacers Cable Insulation	Low 880	S H	1 1	HS	M
110 -	TB-2	239'-0"	466 466A	Equipment hatch corridor Passageway	Y	2535 390 2925	Cable Insulation Rubber Wood Polycarbonate	Low 640	N		HS	M
111 - A	TB-2	269'-0"	562 563 564 564M 568 569	Janitor's room First aid locker Recirculation pump MG area MG set area mezzanine Maintenance Room Fire Brigade Locker	N	42 56 13020 2000 155 228 15501	Cable Insulation Plastic Rubber Wood Polycarbonate	Low 400	S S	20	HS	M
111 - B	TB-2	269'-0"	561	Feedwater heater room	N	880		Low 0	N		HS	M
111 - C	TB-2	269'-0"	560	Feedwater heater room	N	880		Low 0	N		HS	M
111 - D	TB-2	269'-0"	559	Feedwater heater room	N	880		Low 0	N		HS	M
112 - A	TB-2	302'-0"	628	Turbine enclosure HVAC area	N	13080	Cable Insulation Lube Oil Wood R/A Insulation Plastic Polycarbonate	Low 160	S		HS	M
112 - B	TB-2	302'-0"	629	TEECE filter area	Y	1228	Charcoal	High 0	H	2(3)	FWS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
113 - A	TB-1/2	217'-0"	335	Railroad access area	N	7632	Cable Insulation Lube Oil Plastic Rubber Wood Fiberglass Paper	Low 640	H H(5)	7(4) 7(4)	PR	A
113 - B	TB-1/2	239'-0"	447 465 467 468 468A 468B 468C	Generator equipment area Generator equipment area Ops hose storage facility Vibration analysis & predictive maint. Ops equipment storage facility Ops equipment storage facility Ops equipment storage facility	N	8976 8976 180 220 304 48 48 18752	Cable Insulation Lube Oil R/A Insulation Plastic Rubber Fiberglass	Low 320	H H(5) S	20(4) 20(4) 1(7)	PR DL (Partial) WP (11,12,13)	A A A
114 -	TB-1/2	269'-0"	543 544 549 550 551 558 565 565A 566 567 588 549A 552 553	Turbine operating floor Turbine laydown area Washdown area Turbine laydown area Clean steam seal evaporator room Turbine laydown area Washdown area Turbine laydown area Turbine laydown area Clean steam seal evaporator room Turbine laydown area Turbine laydown area Emergency fire responce facility I&C shop	N	7456 6984 552 4225 760 6984 770 3660 768 836 5440 4208 380 420 43443	Cable Insulation Cotton Cloth Plastic Rubber Wood Polycarbonate Paper Fiberglass Polyethylene	Low 104	H H S H S	8 41(4) 5(8) 2(14) 1(15)	PR (Partial) HS E	A M
115 - A	TUNNEL	187'-0"	119	Radwaste pipe tunnel	Y	943		Low 0	N		N	
115 - B	TUNNEL	187'-0"	121	Radwaste pipe tunnel	N	986		Low 0	N		N	

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection		Suppression	
									Type	No.	Type	Actuation
115 - C	TUNNEL	183'-0"	119 213A 120	Radwaste pipe tunnel Pipe Tunnel Access Unexcavatred Areas	Y	828 100 1686 2614		Low 0	N		N	
115 - D	TUNNEL	191'-0"	119	Radwaste pipe tunnel	Y	207		Low 0	N		N	
116 - A	RW	162'-0"	122	Pipe tunnel access	N	590		Low 0	N		N	
116 - B	RW	162'-0"	135	Corridor	N	1096	Cable Insulation	Low 880	N		HS	M
116 - C	RW	162'-0"	149	Corridor	N	496	Cable Insulation	Low 1040	N		HS	M
116 - D	RW	162'-0"	152 145	Corridor MCC room	N	154 160 314	Cable Insulation Wood	Low 960	N		HS	M
116 - E	RW	162'-0"	124	Waste sludge pump room	N	288		Low 0	N		HS	M
116 - F	RW	162'-0"	123	Waste sludge tank room	N	576		Low 0	N		HS	M
116 - G	RW	162'-0"	126	Condensate decant pump room	N	175		Low 0	N		HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
116 - H	RW	162'-0"	127	Condensate sludge discharge pump room	N	198	Cable Insulation	Low 800	N		HS	M
116 - J	RW	162'-0"	125	Condensate phase separator room	N	800		Low 0	N		HS	M
116 - K	RW	162'-0"	129	Condensate sludge discharge pump room	N	192		Low 0	N		HS	M
116 - L	RW	162'-0"	130	Condensate decant pump room	N	240		Low 0	N		HS	M
116 - M	RW	162'-0"	128	Condensate phase separator room	N	800		Low 0	N		HS	M
116 - N	RW	162'-0"	137	Chemical waste tank pump room	N	144		Low 0	N		HS	M
116 - P	RW	162'-0"	136	Chemical waste tank room	N	144		Low 0	N		HS	M
116 - Q	RW	162'-0"	131	Equipment drain collection tank room	N	864		Low 0	N		HS	M
116 - R	RW	162'-0"	132	Equipment drain collection tank room	N	320		Low 0	N		HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
116 - S	RW	162'-0"	134 133	Floor drain collection and sample tank rm. pump room	N	1045 605 1650	Cable Insulation	Low 560	N		HS	M
116 - T	RW	162'-0"	138 139	Floor drain spent resin pump room Equipment drain spent resin pump room	N	150 150 300	Cable Insulation	Low 1000	N		HS	M
116 - U	RW	162'-0"	140	Floor and equip. drain spent resin tank rm.	N	220		Low 0	N		HS	M
116 - V	RW	162'-0"	142	RWCU decant pump room	N	242	Cable Insulation	Low 1040	N		HS	M
116 - W	RW	162'-0"	141	RWCU phase separator roomn	N	320		Low 0	N		HS	M
116 - X	RW	162'-0"	144	RWCU sludge discharge mixing pump rm.	N	253	Cable Insulation	Low 960	N		HS	M
116 - Y	RW	162'-0"	143	RWCU phase separator roomn	N	320		Low 0	N		HS	M
116 - Z	RW	162'-0"	146	Equipment & floor drain sump & pump rm.	N	206	Lube Oil Cable Insulation	Low 960	H	2[3]	FWS	M
116 - AA	RW	162'-0"	147	Equipment drain sample pump room	N	400	Cable Insulation	Low 640	N		HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
116 - BB	RW	162'-0"	148	Equipment drain sample tank room	N	990	Cable Insulation	Low 0	N		HS	M
117	RW	187'-6"	150 150A thru 150F 151	Offgas pipe tunnel Valve gallery Valve gallery Sump room	N	819 1132 24 1975		Low 0	N		N	
118 - A	RW	191'-0"	227	Pipeway	N	384		Low 0	N		HS	M
118 - B	RW	191'-0"	213 235 229	Corridor Corridor Fuel pool filter/demin precoat tank & pump	N	660 976 968 2604	Cable Insulation	Low 880	N		HS	M
118 - C	RW	191'-0"	246	Corridor	N	496	Cable Insulation	Low 1040	N		HS	M
118 - D	RW	191'-0"	228	Laundry drain tank and pump room	N	792	Cable Insulation	Low 960	N		HS	M
118 - E	RW	191'-0"	231 231A 231B	Evaporator feed pump room Evaporator feed pump A tank room Evaporator feed pump B tank room	N	288 128 128 544	Cable Insulation	Low 1040	N		HS	M
118 - F	RW	191'-0"	232	Evaporator pump room	N	240	Cable Insulation	Low 800	N		HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection		Suppression	
									Type	No.	Type	Actuation
118 - G	RW	191'-0"	230	Evaporator tank room	N	576		Low 0	N		HS	M
118 - H	RW	191'-0"	234	Evaporator pump room	N	250		Low 0	N		HS	M
118 - J	RW	191'-0"	233	Evaporator tank room	N	250		Low 0	N		HS	M
118 - K	RW	191'-0"	235A	Control panel area	N	352	Cable Insulation R/A Insulation	Low 880	N		HS	M
118 - L	RW	191'-0"	242	Evaporator and condenser room	N	440	Cable Insulation	Low 1000	N		HS	M
118 - M	RW	191'-0"	243	Evaporator and condenser room	N	384		Low 0	N		HS	M
118 - N	RW	191'-0"	244	Chemical addition & source calibration rm.	N	432	Polyethylene	Low 0	N		HS	M
118 - P	RW	191'-0"	236A 236B 236C	Fuel pool holding pump compartment Fuel pool holding pump compartment Fuel pool holding pump compartment	N	170 187 120 527	Cable Insulation	Low 0	N		HS	M
118 - Q	RW	191'-0"	239A	Fuel pool filter/demin compartment	N	190	Cable Insulation	Low 1040	N		HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
118 - R	RW	191'-0"	239B	Fuel pool filter/demin compartment	N	165	Cable Insulation	Low 880	N		HS	M
118 - S	RW	191'-0"	239C	Fuel pool filter/demin compartment	N	165	Cable Insulation	Low 880	N		HS	M
118 - T	RW	191'-0"	237 238	Floor and equip. drain filter holding pump Floor and equip. drain filter holding pump	N	442 476 918	Cable Insulation	Low 0	N		HS	M
118 - U	RW	191'-0"	240A	Floor drain filter compartment	N	158	Cable Insulation	Low 960	N		HS	M
118 - V	RW	191'-0"	240B	Floor drain demin. compartment	N	168	Cable Insulation	Low 880	N		HS	M
118 - W	RW	191'-0"	241A	Equipment drain demin. compartment	N	180	Cable Insulation	Low 800	N		HS	M
118 - X	RW	191'-0"	241B	Equipment drain filter compartment	N	174	Cable Insulation	Low 880	N		HS	M
118 - Y	RW	191'-0"	247 248	Vestibule Floor and equip. drain surge tank pump	Y	147 48 195	Cable Insulation	Low 800	N		HS	M
118 - Z	RW	191'-0"	245	Floor and equip. drain surge tank room	N	3200		Low 0	N		HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
119 - A	RW	195'-0"	214 215 221A 221B 224A 224B 225	Corridor Corridor A offgas charcoal adsorber guard bed B offgas charcoal adsorber guard bed A offgas charcoal adsorber guard bed B offgas charcoal adsorber guard bed Refrigeration area	N	534 477 56 56 56 56 385 1620	Cable Insulation	Low 704	N		HS	M
119 - B	RW	195'-0"	217 217A	Offgas adsorber compartment Vestibule	N	665 57 722	Cable Insulation	Low 640	N		HS	M
119 - C	RW	195'-0"	220 220A	Offgas adsorber compartment Vestibule	N	665 57 722	Cable Insulation	Low 640	N		HS	M
119 - D	RW	195'-0"	223 223A	Offgas adsorber compartment Vestibule	N	665 57 722	Cable Insulation	Low 640	N		HS	M
119 - E	RW	195'-0"	216	Offgas adsorber vault	N	192		Low 0	N		HS	M
119 - F	RW	195'-0"	219	Offgas adsorber vault	N	192		Low 0	N		HS	M
119 - G	RW	195'-0"	222	Offgas adsorber vault	N	192		Low 0	N		HS	M
119 - H	RW	195'-0"	218	Offgas adsorber vault	N	182		Low 0	N		HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
119 - I	RW	195'-0"	214A	Reboiler area	N	1269	Cable Insulation	Low 0	N		HS	M
119 - J	RW	195'-0"	226A	Cooler condenser area	N	165		Low 0	N		HS	M
119 - K	RW	195'-0"	226B	Cooler condenser area	N	165		Low 0	N		HS	M
120 - A	RW	217'-0"	419	Corridor	N	720	Cable Insulation	Low 400	N		HS	M
120 - B	RW	217'-0"	413	Toilet	N	80		Low 0	N		HS	M
120 - C	RW	217'-0"	414 414A	Decontamination and change area Decontamination and change area	N	180 90 270	Cable Insulation Plastic	Low 880	S	1	HS	M
120 - D	RW	217'-0"	415	Radwaste control room	N	594	Cable Insulation Paper Wood Plastic Carpet	Low 1200	S S	4(1) 4(2)	HS	M
120 - E	RW	217'-0"	412	Health physics	N	240	Paper Plastic	Moderate 0	S	1	PR HS	A M
120 - F	RW	217'-0"	416	Radwaste supervisors office	N	90	Paper Plastic Wood	Low 0	N		PR HS	A M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
120 - G	RW	217'-0"	417	Warm chem lab	N	265	Paper Plastic Carpet	Moderate 0	H	1	PR HS	A M
120 - H	RW	217'-0"	410	Counting room	N	410	Paper Plastic Carpet	Low	S	2	PR HS	A M
120 - I	RW	217'-0"	412A	Files and storage area	N	80	Paper	Moderate 0	S	1	PR HS	A M
120 - J	RW	217'-0"	411	Conventional chem room	N	306	Cotton Cloth Paper Plastic Carpet	Low 0	H	2	PR HS	A M
120 - K	RW	217'-0"	418	Radiation chemical lab	N	480	Paper Plastic Carpet	Low 0	H	2	PR HS	A M
120 - L	RW	217'-0"	424	Corridor	N	3442	Cable Insulation Lube Oil Polycarbonate Cotton	Low 560	N		HS	M
120 - M	RW	217'-0"	420	Waste drum storage room	N	376	Cotton Cloth Plastic Rubber Wood	Low 0	N		WP	A

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
120 - N	RW	217'-0"	421	Cask loading area	N	638	Cable Insulation	Low	N		HS	M
			421A	External processing station		48	Wood	480				
			421B	HSA/LSA storage bay		506	Plastic					
			421C	HSA/LSA storage bay		374	Polyethylene					
			421M	HSA/LSA cask storage & cask loading		3445	Fiberglass					
			422A	HSA/LSA fill station		170	Rubber					
			422B	HSA/LSA fill station		202	Nylon					
			422C	HSA/LSA fill station		202	Lead Shielding					
			423	Decontamination and monitoring station		192	Covering					
						5777						

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
121 - A	RW	237'-0"	484	Air exhaust fan room	N	6320	Cable Insulation Lube Oil Plastic	Low 480	S		HS	M
121 - B	RW	237'-0"	485	Filter room	N	480		Low 0	N		HS	M
121 - C	RW	237'-0"	486	Filter room	N	480	Cable Insulation	Low 0	N		HS	M
121 - E	RW	237'-0"	471	Centrifuge room	N	337		Low 0	N		HS	M
121 - F	RW	237'-0"	470	Centrifuge room	N	188		Low 0	N		HS	M
121 - G	RW	237'-0"	469	Solidification equipment area	N	116		Low 0	N		HS	M
121 - H	RW	257'-0"	514 525	Future solidification room Exhaust fan area	N	1000 5937 6937	Cable Insulation	Low 480	S	10	HS	M
121 - J	RW	257'-0"	517	Future equipment area	N	290	Trash	Low 0	N		HS	M
121 - K	RW	257'-0"	516	Filter room	N	125		Low 0	N		HS	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
121 - L	RW	257'-0"	515	Filter room	N	125		Low 0	N		HS	M
121 - M	RW	257'-0"	526	Air supply fan room	N	5004	Cable Insulation R/A Insulation	Low 560	N		HS	M
122 - A	SPPH	268'-0'	1000	ESW and RHRSW pump area	Y	1539	Lube Oil Cable Insulation	Low 0	S	4	E	M
122 - B	SPPH	237'-0"	1011	Wet pit	Y	1318		Control of Combustibles 0	N		E	M
122 - C	SPPH	259'-6"	1011	ESW and RHRSW pipeway	Y	570		Low 0	N		E	M
122 - D	SPPH	268'-0"	1001	Access hatch area	Y	576	Wood	Control of Combustibles 0	N		E	M
122 - E	SPPH	251'-0"	1010	RHRSW valve compartment	Y	567	Cable Insulation	Low 0	S	2	E	M
122 - F	SPPH	237'-0"	1021	RHRSW pipeway	Y	567		Control of Combustibles 0	N		E	M
123 - A	SPPH	268'-0'	1005	ESW and RHRSW pump area	Y	1539	Lube Oil Cable Insulation	Low 0	S	4	E	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
123 - B	SPPH	237'-0"	1025	Wet pit	Y	1318		Control of Combustibles 0	N		E	M
123 - C	SPPH	259'-6"	1016	ESW and RHRSW pipeway	Y	570		Low 0	N		E	M
123 - D	SPPH	268'-0"	1006	Access hatch area	Y	576		Control of Combustibles 0	N		E	M
123 - E	SPPH	251'-0"	1015	RHRSW valve compartment	Y	567	Cable Insulation	Low 160	S	2	E	M
123 - F	SPPH	237'-0"	1026	RHRSW pipeway	Y	567		Control of Combustibles 0	N		E	M
124 - A	DG	217'-0"	313	U1 diesel generator access corridor	Y	890	Plastic	Low 0	S	4	FH	M
124 - B	DG	217'-0"	314	Condensate pump room	N	170		Low 0	N		FH	M
125 - A	DG	217'-0"	317	U2 diesel generator access corridor	Y	890	Plastic	Low 0	S	4	FH	M
125 - B	DG	217'-0"	318	Condensate pump room	N	170	Rubber	Low 0	N		FH	M

LGS FIRE PROTECTION PROGRAM
TABLE 9A-1 (Cont'd)

Area - Zone	Structure	Elevation	Room No.	Area-Zone Description	S R	Area (sqft)	Hazard Material	Combustible Loading Combustible Loading Change Limit	Detection Type	Detection No.	Suppression Type	Suppression Actuation
126 - A	RB 1/2	411'-9"	713	North stack instrument room	Y	1335	Cable Insulation Plastic	Low 0	S	2	E	M
126 - B	RB 1/2	411'-9"	712	Vestibule	N	289	Plastic	Low 0	N		E	M
127	RB 1/2	411'-9"	714	South stack instrument room	N	1152		Low 0	S	2	E	M

Combustible Loading
Low < 60,000 BTU/sqft
Moderate >/= 60,000 or < 140,000 BTU/sqft
High >/= 140,000 BTU/sqft

DETECTION TYPE:
S = SMOKE DETECTOR
H = HEAT DETECTOR
N = NO DETECTION

ACTUATION:
M = MANUAL
A = AUTOMATIC

SUPPRESSION TYPE :
CH = CARDOX HOSE REEL
CO_2 = CARBON DIOXIDE
DC = DRY CHEMICAL
DL = DELUGE SYSTEM
HS = HOSE STATION
HC = HOSE CART
N = NO SUPPRESSION
E = PORTABLE EXTINGUISHER
H = HALON
PR = PRE-ACTION SPRINKLER SYSTEM
WC = WATER CURTAIN SYSTEM
WP = WET PIPE SPRINKLER SYSTEM
WS = WATER SPRAY SYSTEM
FWS = FILTER WATER SPRAY SYSTEM
FH = FIRE HYDRANT

Table 9A-1 (Cont'd)

Notes:
(1) These smoke detectors are located below the suspended ceiling in the control room.
(2) These smoke detectors are located above the suspended ceiling in the control room.
(3) These heat detectors are located inside the charcoal filter plenum.
(4) These heat detectors are used to actuate the automatic suppression systems.
(5) Fire zone 113a and 113B are located in a portion of the turbine enclosure that is common to Unit 1 and Unit 2. The detectors identified by this note will be installed east of column line 23 for Unit 2 operation.
(6) These smoke detectors are of the photoelectric-type.
(7) These detectors are located inside offices 467, 568, and 569.
(8) These detectors are located inside offices 552, 553, 570, and 571.
(9) These smoke detectors are located inside the test engineer's workshop.
(10) Deleted
(11) This sprinkler system is installed above and inside facility/laydown area.
(12) This sprinkler system is installed in the Floor Operations Break Facility (Rm 468A, B, C).
(13) This sprinkler system is installed in the Plant Operations Building (Rm 468).
(14) These heat detectors are located inside the Unit 1/2 turbine generator exciter enclosures (2 per unit).
(15) These smoke detectors are located in the Unit 1/2 turbine generator exciter exhaust ductwork (1 per unit). (Detector suitable for high velocity airstream)
(16) Deleted.
(17) Room 258A floor area is contained in Room 258 floor area.
(18) Room 236A floor area is contained in Room 263 floor area.
(19) Common - Ceiling level.
(20) Unit 1 - PGCC Floor.
(21) Unit 1 - non-PGCC Floor.
(22) Unit - Termination Cabinets.
(23) Unit 2 - PGCC Floor.
(24) Unit 2 - non-PGCC Floor.
(25) Unit 2 - Termination Cabinets.
(26) Ceiling Level.
(27) Raised Floor.
(28) Charcoal enclosed in steel filter plenums has been accepted by NRC.

Table 9A-2

Heat of Combustion for Specific Materials (All values rounded to nearest 100 BTU/Unit)		
Material	Units	Heat of Combustion (BTU/Unit)
Acetylene Gas	lb	21,500
Alcohol (Ethyl)	gal.	83,800
Alcohol (Methyl)	gal.	65,500
Alpha Maritex Lead Shielding Blanket	Linear foot	2404
Battery Cases (Butadiene Acrylonitrile)	lb	17,200
Battery Spacers (Polystyrene Foam)	lb	17,100
Cable Insulation	lb	10,000
Carpet (Nylon)	lb	13,600
Charcoal	lb	14,900
Cloth (Cotton)	lb	8,800
Floor Tiles (Polyester Resin)	lb	10,000
Fuel Oil	gal.	135,500
Gasoline	gal.	120,600
Hydrogen	lb	61,000
Lube Oil	gal.	150,900
Lubricant (Grease)	lb	150,900
Methane Gas	cu. ft.	23,900
Oxygen	cu. ft.	0
Paper	lb	8,500
Plastic (Polyethylene)	lb	20,000
Propane	lb	21,700
Rubber (Butyl)	lb	19,700
Trash (40 lb bag)	ea.	290,500
Wood (White Pine)	lb	8,300
R/A Insulation	lb	8,000
Polycarbonate	lb	13,300
Thermo-Lag 330-1	lb	7,000
Thermo-Lag 770-1	lb	4,800
Polyvinyl Chloride (PVC)	lb	7,730
Fiberglass	lb	14,000
Silicon Rubber	lb	7,200

Table 9A-3

INSULATION AND JACKETING MATERIALS
USED FOR ELECTRICAL CABLING

CABLE APPLICATION	INSULATION	JACKETING
Communication	Polyvinyl chloride	Polyvinyl chloride
Lighting	Thermoplastic (THHN, THWN, or THW)	None
Grounding	Thermoplastic (THW)	None
Instrumentation	Cross-linked polyethylene	Neoprene
	Flamtrol (flame-retardant cross-linked polyolefin)	Flamtrol
Coaxial and triaxial	Cross-linked Polyolefin	Cross-linked polyolefin
600 V control	Cross-linked polyethylene	Neoprene
	Rubber	Neoprene
	Rockbestos "Heatzone I"	Rockbestos "Heatzone I"
600 V power	Cross-linked polyethylene	Neoprene
	Ethylene propylene rubber	Hypalon
	Cross-linked polyethylene(4)	Polyvinyl chloride
	Cross-linked Polyethylene	Chlorinated polyethylene
5 kV and 15 kV power(5)	Ethylene propylene rubber	Hypalon
	Ethylene propylene Rubber	Semi-conducting chlorinated polyethylene
	Cross-linked polyethylene	Polyvinyl chloride
Computer cables	Cross-linked polyethylene	Neoprene
	Rayolin F (cross-linked radiation-resistant polyolefin)	Flamtrol
Multiconductor(1)	Cross-linked polyethylene	Neoprene

Table 9A-3 (Cont'd)

CABLE APPLICATION	INSULATION	JACKETING
Multiconductor (shielded)(1)	Cross-linked polyethylene or cross-linked modified polyolefin	Neoprene or cross-linked polyolefin
Twisted shielded pairs(1)	Cross-linked polyalkene and polyvinylidene fluoride	Cross-linked modified polyolefin
Thermocouple(1)	Cross-linked polyethylene	Cross-linked polyethylene
Coaxial (RG-type)(1)	Cross-linked polyethylene	Cross-linked polyethylene polyvinyl chloride
Coaxial (twin conductor)(1)	Alkaneimide polymer cross-linked polyolefin polyethylene	Cross-linked polyethylene polyvinyl chloride
Coaxial (high temperature, radiation resistant)(1)	Cross-linked polyethylene	Cross-linked polyethylene
Twisted pairs or twisted triples (high performance)(1)	Polyalkene and polyvinylidene fluoride	Cross-linked polyvinylidene fluoride and cross-linked polyolefin
Armored Coaxial Cable for Video signals from Drywell video cameras(6)	Cross-linked polyethylene	Polyvinyl Chloride
Armored Multiconductor cable for Drywell video camera control and audio signals(6)	Cross-linked polyethylene	Polyvinyl Chloride

Table 9A-3 (Cont'd)

(1) These cables are associated with the PGCC and the deep bed demineralizer system.

(2) Insulation for lighting cables and grounding cables is specified as flame retardant in accordance with the National Electric Code. Insulation and jacketing for all other cables, with the exception of communications cables, are specified to meet the IEEE 383 flame test requirements. An insignificant length of data cable which is not IEEE 383 rated is added to the Unit 1 and Unit 2 drywell as a part of the MUR (Measurement Uncertainty Recapture) Project. The cables were evaluated and found to be acceptable. The cables were not routed together with cables associated with other plant systems.

(3) Ignition of electrical cabling, in the absence of a fire source external to the cabling, is extremely unlikely. The consequences of an overload condition are minimized by conservative cable ratings and by the use of overload devices in power circuits and fault current interrupting devices in essentially all circuits. In addition, cable insulation and jacketing materials are chosen for their fire retardant and self-extinguishing properties, such that fuel contribution to a cable fire is minimized and propagation of a fire along cables is self-limiting.

(4) This cable is used in the main condenser areas and condensate pump rooms.

(5) Use of cross-linked polyethylene insulation and polyvinyl chloride applies to 15kV cable only.

(6) These cables were used with the Health Physics temporary video cameras and Remote Console, but are now abandoned.

Table 9A-4

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
00A119	101 SAFEGUARD BUS	APS	0	428 429 430 431 432 433 434 435 447 YARD	018 019 016 017 014 015 012 013 113 YARD	
00A120	201 SAFEGUARD BUS	APS	0	428 429 430 431 432 433 434 435 465 YARD	018 019 016 017 014 015 012 013 113 YARD	
00B131	480V MCC	EPS	C	619	027	
00B132	480V MCC	EPS	D	619	027	
00B519	480V MCC	EPS	A	1000	122	
00B520	480V MCC	EPS	B	1005	123	
00B521	480V MCC	EPS	C	1000	122	
00B522	480V MCC	EPS	D	1005	123	
01X566	TRANSFORMER	EPS	A	1000	122	
01Y501	120V AC INST PANEL	EPS	A	1000	122	
02X566	TRANSFORMER	EPS	B	1005	123	
02Y501	120V AC INST PANEL	EPS	B	1005	123	
03X566	TRANSFORMER	EPS	C	1000	122	
03Y501	120V AC INST PANEL	EPS	C	1000	122	
04X566	TRANSFORMER	EPS	D	1005	123	
04Y501	120V AC INST PANEL	EPS	D	1005	123	
0AP506	RHRSW PUMP "A"	RHRSW	A	1000	122	1-RHRSW-A 2-RHRSW-A
0AP548	ESW PUMP "A"	ESW	A	1000	122	0-ESW-A 0-ESW-R
0AV543	SYSTEM "A" FAN CABINET	SPPV	A	1000	122	1-RHRSW-A 2-RHRSW-A 0-ESW-R 0-ESW-A
0AX103	101 SAFEGUARD XMFR	APS	0	YARD	YARD	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
0AX104	101 SAFEGUARD XMFR GROUNDING RESISTOR	APS	0	YARD	YARD	
0BP506	RHRSW PUMP "B"	RHRSW	B	1005	123	1-RHRSW-B 2-RHRSW-B
0BP548	ESW PUMP "B"	ESW	B	1005	123	0-ESW-B
0BV543	SYSTEM "B" FAN CABINET	SPPV	B	1005	123	2-RHRSW-B 1-RHRSW-B 0-ESW-B
0BX103	201 SAFEGUARD XMFR	APS	0	YARD	YARD	
0BX104	201 SAFEGUARD XMFR GROUNDING RESISTOR	APS	0	YARD	YARD	
0CP506	RHRSW PUMP "C"	RHRSW	A	1000	122	1-RHRSW-A 2-RHRSW-A
0CP548	ESW PUMP "C"	ESW	C	1000	122	0-ESW-A
0CV543	SYSTEM "C" FAN CABINET	SPPV	C	1000	122	1-RHRSW-A 2-RHRSW-A 0-ESW-A
0DP506	RHRSW PUMP "D"	RHRSW	B	1005	123	2-RHRSW-B 1-RHRSW-B
0DP548	ESW PUMP "D"	ESW	D	1005	123	0-ESW-B
0DV543	SYSTEM "D" FAN CABINET	SPPV	D	1005	123	0-ESW-B 1-RHRSW-B 2-RHRSW-B
101D112	101 NON-SAFEGUARD BATTERY	APS	0(D)	443	096	
101D113	BATTERY CHARGER	APS	0(D)	445	095	
102D112	102 NON-SAFEGUARD BATTERY	APS	0(D)	443	096	
102D113	BATTERY CHARGER	APS	0(D)	445	095	
105CROM*	105 CROMBY SUBSTATION BREAKER	APS	0	YARD	YARD	
10A103	10 STATION AUX BUS 13.2 KV	APS	0	336	002	
10A115	D11 SAFEGUARD SWGR	EPS	A	435	013	
10A116	D12 SAFEGUARD SWGR	EPS	B	433	015	
10A117	D13 SAFEGUARD SWGR	EPS	C	434	012	
10A118	D14 SAFEGUARD SWGR	EPS	D	432	014	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
10B129	480V MCC	EPS	A	548	098	
10B201	480V SAFEGUARD LOAD CTR	EPS	A	602W	048W	
10B202	480V SAFEGUARD LOAD CTR	EPS	B	602E	048E	
10B203	480V SAFEGUARD LOAD CTR	EPS	C	402W	045W	
10B204	480V SAFEGUARD LOAD CTR	EPS	D	506E	047E	
10B211	480V MCC	EPS	A	304W	044W	
10B212	480V MCC	EPS	B	304E	044E	
10B213	480V MCC	EPS	A	506W	047W	
10B214	480V MCC	EPS	B	506E	047E	
10B215	480V MCC	EPS	A	304W	044W	
10B216	480V MCC	EPS	B	304E	044E	
10B217	480V MCC	EPS	C	200	042	
10B218	480V MCC	EPS	D	207	041	
10B223	480V MCC	EPS	C	402W	045W	
10B224	480V MCC	EPS	D	402E	045E	
10B515	480V MCC	EPS	A	311A	079	
10B516	480V MCC	EPS	B	311B	081	
10B517	480V MCC	EPS	C	311C	080	
10B518	480V MCC	EPS	D	311D	082	
10D106	125/250V DC GROUND DETECTION CABINET	APS	0(D)	445	095	
10D114	125/250V DC FUSE BOX	APS	0(D)	445	095	
10D115	125/250V DC FUSE BOX	APS	0(D)	338	089	
10D116	UNIT CROSS TIE FUSE BOX	APS	0(D)	445	095	
10D201	250V DC MCC	EPS	A	304W	044W	
10D202	250V DC MCC	EPS	B	304E	044E	
10D203	250V DC MCC	EPS	B	304E	044E	
10P203	RCIC PUMP	RCIC	N/A	108	033	1-RCIC

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
10P204	HPCI PUMP	HPCI	N/A	109	034	1-HPCI
10P213	HPCI TURBINE AUXILIARY OIL PUMP	HPCI	B	109	034	1-HPCI
10TB-HPCIEGM*	HPCI TURBINE FLOW CONTROL	HPCI	B	200	042	
10TB-RCICEGM*	RCIC TURBINE FLOW CONTROL	RCIC	A	108	033	
10X106	TRANSFORMER	EPS	A	435	013	
10X107	TRANSFORMER	EPS	B	433	015	
10X108	TRANSFORMER	EPS	C	434	012	
10X109	TRANSFORMER	EPS	D	432	014	
10X110	TRANSFORMER	EPS	0(A)	438	088	
10X182	TRANSFORMER	EPS	C	619	027	
10X183	TRANSFORMER	EPS	D	619	027	
10X201	TRANSFORMER	EPS	A	602W	048W	
10X202	TRANSFORMER	EPS	B	602E	048E	
10X203	TRANSFORMER	EPS	C	402W	045W	
10X204	TRANSFORMER	EPS	D	506E	047E	
10X281	TRANSFORMER	EPS	A	619	027	
10Y101	120V AC INST PANEL	EPS	A	435	013	
10Y102	120V AC INST PANEL	EPS	B	433	015	
10Y103	120V AC INST PANEL	EPS	C	434	012	
10Y104	120V AC INST PANEL	EPS	D	432	014	
10Y105	120V AC INST PANEL	EPS	0(A)	438	088	
10Y163	120V AC DIST PANEL	EPS	C	619	027	
10Y164	120V AC DIST PANEL	EPS	D	619	027	
10Y206	120V AC DIST PANEL	EPS	A	619	027	
1A1D101	125V BATTERY	EPS	A	436	009	
1A1D103	BATTERY CHARGER	EPS	A	436	009	
1A1K513	1A1 DG STARTING AIR COMPRESSOR	SDG	A	311A	079	
1A1T558	A DG STARTING AIR RESERVOIR A1	SDG	N/A	311A	079	
1A2D101	125V BATTERY	EPS	A	436	009	
1A2D103	BATTERY CHARGER	EPS	A	436	009	
1A2T558	A DG STARTING AIR RESERVOIR A2	SDG	N/A	311A	079	
1AD102	125V DC DIST PANEL	EPS	A	435	013	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
1AD105	125/250V DC BUS FUSE BOX	EPS	A	436	009	
1AD162	125V DC DIST PANEL	EPS	A	435	013	
1AD501	125V DC POWER DIST PANEL	EPS	A	311A	079	
1AE205	1A RHR HEAT EXCHANGER	RHR	N/A	203	032	1-RHRASC-C 1-RHRSPC-C 1-RHRSPC-A 1-RHRSC-C 1-RHRLPCI-A 1-RHRASC-A 1-RHRSC-A
1AG501	DIESEL GENERATOR "A"	SDG	A	311A	079	
1AP202	RHR PUMP "A"	RHR	A	102	032	1-RHRASC-A 1-RHRSPC-A 1-RHRSC-A 1-RHRLPCI-A
1AP514	DIESEL OIL TRANSFER PUMP	SDG	A	YARD	YARD	
1AS252-1	A PCIG/ADS LONG TERM NITROGEN BOTTLE	PCIG	N/A	304W	044W	1-RHRASC-A 1-RHRASC-B
1AS252-2	A PCIG/ADS LONG TERM NITROGEN BOTTLE	PCIG	N/A	304W	044W	1-RHRASC-A 1-RHRASC-B
1AS252-3	A PCIG/ADS LONG TERM NITROGEN BOTTLE	PCIG	N/A	304W	044W	1-RHRASC-A 1-RHRASC-B
1AT003	MSRV ACCUMULATOR	MSRV	N/A	400	030	
1AV208	RCIC COMPARTMENT UNIT COOLER	REV	A	108	033	1-RCIC
1AV209	HPCI COMPARTMENT UNIT COOLER	REV	B	109	034	1-HPCI
1AV210	RHR COMPARTMENT UNIT COOLER	REV	A	102	032	1-RHRASC-A 1-RHRLPCI-A 1-RHRSC-A 1-RHRSPC-A
1AV512	CELL "A" AIR EXHAUST FAN	DGEV	A	311A	079	
1B1D101	125V BATTERY	EPS	B	425	008	
1B1D103	BATTERY CHARGER	EPS	B	425	008	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
1B1K513	1B1 DG STARTING AIR COMPRESSOR	SDG	B	311B	081	
1B1T558	B DG STARTING AIR RESERVOIR B1	SDG	N/A	311B	081	
1B2D101	125V BATTERY	EPS	B	425	008	
1B2D103	BATTERY CHARGER	EPS	B	425	008	
1B2T558	B DG STARTING AIR RESERVOIR B2	SDG	N/A	311B	081	
1BD102	125V DC DIST PANEL	EPS	B	452	020	
1BD105	125/250V DC BUS FUSE BOX	EPS	B	425	008	
1BD501	125V DC POWER DIST PANEL	EPS	B	311B	081	
1BE205	1B RHR HEAT EXCHANGER	RHR	N/A	204	031	1-RHRASC-D 1-RHRSPC-D 1-RHRSPC-B 1-RHRSC-D 1-RHRLPCI-B 1-RHRASC-B 1-RHRSC-B
1BG501	DIESEL GENERATOR "B"	SDG	B	311B	081	
1BP202	RHR PUMP "B"	RHR	B	103	031	1-RHRSC-B 1-RHRLPCI-B 1-RHRASC-B 1-RHRSPC-B
1BP514	DIESEL OIL TRANSFER PUMP	SDG	B	YARD	YARD	
1BS252-1	B PCIG/ADS LONG TERM NITROGEN BOTTLE	PCIG	N/A	304E	044E	1-RHRASC-A 1-RHRASC-B
1BS252-2	B PCIG/ADS LONG TERM NITROGEN BOTTLE	PCIG	N/A	304E	044E	1-RHRASC-A 1-RHRASC-B
1BS252-3	B PCIG/ADS LONG TERM NITROGEN BOTTLE	PCIG	N/A	304E	044E	1-RHRASC-A 1-RHRASC-B
1BV208	RCIC COMPARTMENT UNIT COOLER	REV	A	108	033	1-RCIC
1BV209	HPCI COMPARTMENT UNIT COOLER	REV	B	109	034	1-HPCI

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
1BV210	RHR COMPARTMENT UNIT COOLER	REV	B	103	031	1-RHRASC-B 1-RHRLPCI-B 1-RHRSC-B 1-RHRSPC-B
1BV512	CELL "B" AIR EXHAUST FAN	DGEV	B	311B	081	
1C1K513	1C1 DG STARTING AIR COMPRESSOR	SDG	C	311C	080	
1C1T558	C DG STARTING AIR RESERVOIR C1	SDG	N/A	311C	080	
1C2T558	C DG STARTING AIR RESERVOIR C2	SDG	N/A	311C	080	
1CD101	125V BATTERY	EPS	C	324	004	
1CD102	125V DC DIST PANEL	EPS	C	434	012	
1CD103	BATTERY CHARGER	EPS	C	324	004	
1CD105	125V DC BUS FUSE BOX	EPS	C	324	004	
1CD108	125V DC POWER DIST PANEL	APS	0(D)	338	089	
1CD501	125V DC POWER DIST PANEL	EPS	C	311C	080	
1CG501	DIESEL GENERATOR "C"	SDG	C	311C	080	
1CP202	RHR PUMP "C"	RHR	C	102	032	1-RHRSC-C 1-RHRSPC-C 1-RHRLPCI-C 1-RHRASC-C
1CP514	DIESEL OIL TRANSFER PUMP	SDG	C	YARD	YARD	
1CT003	MSRV ACCUMULATOR	MSRV	N/A	400	030	
1CV210	RHR COMPARTMENT UNIT COOLER "C"	REV	C	102	032	1-RHRASC-C 1-RHRLPCI-C 1-RHRSC-C 1-RHRSPC-C
1CV512	CELL "C" AIR EXHAUST FAN	DGEV	C	311C	080	
1D1T558	D DG STARTING AIR RESERVOIR D1	SDG	N/A	311D	082	
1D2T558	D DG STARTING AIR RESERVOIR D2	SDG	N/A	311D	082	
1DD101	125V BATTERY	EPS	D	323	003	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
1DD102	125V DC DIST PANEL	EPS	D	452	020	
1DD103	BATTERY CHARGER	EPS	D	323	003	
1DD105	125V DC BUS FUSE BOX	EPS	D	323	003	
1DD501	125V DC POWER DIST PANEL	EPS	D	311D	082	
1DG501	DIESEL GENERATOR "D"	SDG	D	311D	082	
1DP202	RHR PUMP "D"	RHR	D	103	031	1-RHRASC-D 1-RHRLPCI-D 1-RHRSC-D 1-RHRSPC-D
1DP514	DIESEL OIL TRANSFER PUMP	SDG	D	YARD	YARD	
1DV210	RHR COMPARTMENT UNIT COOLER "D"	REV	D	103	031	1-RHRSPC-D 1-RHRASC-D 1-RHRLPCI-D 1-RHRSC-D
1DV512	CELL "D" AIR EXHAUST FAN	DGEV	D	311D	082	
1ET003	MSRV ACCUMULATOR	ADS	N/A	400	030	
1EV210	RHR COMPARTMENT UNIT COOLER	REV	A	102	032	1-RHRASC-A 1-RHRLPCI-A 1-RHRSC-A 1-RHRSPC-A
1EV512	CELL "A" AIR EXHAUST FAN	DGEV	A	311A	079	
1FV210	RHR COMPARTMENT UNIT COOLER	REV	B	103	031	1-RHRASC-B 1-RHRSPC-B 1-RHRLPCI-B 1-RHRSC-B
1FV512	CELL "B" AIR EXHAUST FAN	DGEV	B	311B	081	
1GV210	RHR COMPARTMENT UNIT COOLER	REV	C	102	032	1-RHRSPC-C 1-RHRASC-C 1-RHRLPCI-C 1-RHRSC-C
1GV512	CELL "C" AIR EXHAUST FAN	DGEV	C	311C	080	
1HT003	MSRV ACCUMULATOR	ADS	N/A	400	030	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
1HV512	CELL "D" AIR EXHAUST FAN	DGEV	D	311D	082	
1KT003	MSRV ACCUMULATOR	ADS	N/A	400	030	
1MT003	MSRV ACCUMULATOR	ADS	N/A	400	030	
1NT003	MSRV ACCUMULATOR	MSRV	N/A	400	030	
1ST003	MSRV ACCUMULATOR	ADS	N/A	400	030	
201D112	201 NON-SAFEGUARD BATTERY	APS	0(D)	460	109	
201D113	BATTERY CHARGER	APS	0(D)	461	108	
202D112	202 NON-SAFEGUARD BATTERY	APS	0(D)	460	109	
202D113	BATTERY CHARGER	APS	0(D)	461	108	
205WHIT*	205 WHITPAIN SUBSTATION BREAKER	APS	0	YARD	YARD	
20A103	20 STATION AUX BUS 13.2 KV	APS	0	336	002	
20A115	D21 SAFEGUARD SWITCHGEAR	EPS	A	429	019	
20A116	D22 SAFEGUARD SWITCHGEAR	EPS	B	431	017	
20A117	D23 SAFEGUARD SWITCHGEAR	EPS	C	428	018	
20A118	D24 SAFEGUARD SWITCHGEAR	EPS	D	430	016	
20A121	CABLE BUS	APS	0	336 346 354 357A YARD	002 107 107 107 YARD	
20B129	480V MCC	EPS	A	564	111	
20B201	480V SAFEGUARD LOAD CTR	EPS	A	638W	071W	
20B202	480V SAFEGUARD LOAD CTR	EPS	B	638E	071E	
20B203	480V SAFEGUARD LOAD CTR	EPS	C	475W	068W	
20B204	480V SAFEGUARD LOAD CTR	EPS	D	580W	070W	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
20B211	480V MCC	EPS	A	370W	067W	
20B212	480V MCC	EPS	B	370E	067E	
20B213	480V MCC	EPS	A	580W	070W	
20B214	480V MCC	EPS	B	580E	070E	
20B215	480V MCC	EPS	A	370W	067W	
20B216	480V MCC	EPS	B	370E	067E	
20B217	480V MCC	EPS	C	284	064	
20B218	480V MCC	EPS	D	279	065	
20B223	480V MCC	EPS	C	475W	068W	
20B224	480V MCC	EPS	D	475E	068E	
20B515	480V MCC	EPS	A	315A	083	
20B516	480V MCC	EPS	B	315B	085	
20B517	480V MCC	EPS	C	315C	084	
20B518	480V MCC	EPS	D	315D	086	
20D106	125/250V DC GROUND DETECTION CABINET	APS	0(D)	463	108	
20D114	125/250V DC FUSE BOX	APS	0(D)	461	108	
20D115	125/250V DC FUSE BOX	APS	0(D)	351	102	
20D201	250V DC MCC	EPS	A	370W	067W	
20D202	250V DC MCC	EPS	B	370E	067E	
20D203	250V DC MCC	EPS	B	370E	067E	
20P203	RCIC PUMP	RCIC	N/A	179	056	2-RCIC
20P204	HPCI PUMP	HPCI	N/A	180	057	2-HPCI
20P213	HPCI TURBINE AUXILIARY OIL PUMP	HPCI	B	180	057	2-HPCI
20TB-HPCIEGM*	HPCI TURBINE FLOW CONTROL	HPCI	B	279	065	
20TB-RCICEGM*	RCIC TURBINE FLOW CONTROL	RCIC	A	179	056	
20X106	TRANSFORMER	EPS	A	429	019	
20X107	TRANSFORMER	EPS	B	431	017	
20X108	TRANSFORMER	EPS	C	428	018	
20X109	TRANSFORMER	EPS	D	430	016	
20X110	TRANSFORMER	EPS	0(A)	464	101	
20X201	TRANSFORMER	EPS	A	638W	071W	
20X202	TRANSFORMER	EPS	B	638E	071E	
20X203	TRANSFORMER	EPS	C	475W	068W	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
20X204	TRANSFORMER	EPS	D	580W	070W	
20X281	TRANSFORMER	EPS	A	625	028	
20X282	TRANSFORMER	EPS	B	619	027	
20X283	TRANSFORMER	EPS	C	625	028	
20X284	TRANSFORMER	EPS	D	619	027	
20Y101	120V AC INST PANEL	EPS	A	429	019	
20Y102	120V AC INST PANEL	EPS	B	431	017	
20Y103	120V AC INST PANEL	EPS	C	428	018	
20Y104	120V AC INST PANEL	EPS	D	430	016	
20Y105	120V AC INST PANEL	EPS	0(A)	464	101	
20Y163	120V AC DIST PANEL	EPS	C	625	028	
20Y164	120V AC DIST PANEL	EPS	D	619	027	
20Y206	120V AC DIST PANEL	EPS	A	625	028	
20Y207	120V AC DIST PANEL	EPS	B	619	027	
2A1D101	125V BATTERY	EPS	A	427	011	
2A1D103	BATTERY CHARGER	EPS	A	427	011	
2A1K513	2A1 DG STARTING AIR COMPRESSOR	SDG	A	315A	083	
2A1T558	A DG STARTING AIR RESERVOIR A1	SDG	N/A	315A	083	
2A2D101	125V BATTERY	EPS	A	427	011	
2A2D103	BATTERY CHARGER	EPS	A	427	011	
2A2T558	A DG STARTING AIR RESERVOIR A2	SDG	N/A	315A	083	
2AD102	125V DC DIST PANEL	EPS	A	429	019	
2AD105	125/250V DC BUS FUSE BOX	EPS	A	427	011	
2AD501	125V DC POWER DIST PANEL	EPS	A	315A	083	
2AE205	2A RHR HEAT EXCHANGER	RHR	N/A	280	054	2-RHRSC-A 2-RHRSPC-C 2-RHRSC-C 2-RHRLPCI-A 2-RHRASC-C 2-RHRASC-A 2-RHRSPC-A
2AG501	DIESEL GENERATOR "A"	SDG	A	315A	083	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
2AP202	RHR PUMP "A"	RHR	A	173	054	2-RHRSPC-A 2-RHRASC-A 2-RHRLPCI-A 2-RHRSC-A
2AP514	DIESEL OIL TRANSFER PUMP	SDG	A	YARD	YARD	
2AS252-1	A PCIG/ADS LONG TERM NITROGEN BOTTLE	PCIG	N/A	370E	067E	2-RHRASC-A 2-RHRASC-B
2AS252-2	A PCIG/ADS LONG TERM NITROGEN BOTTLE	PCIG	N/A	370E	067E	2-RHRASC-A 2-RHRASC-B
2AS252-3	A PCIG/ADS LONG TERM NITROGEN BOTTLE	PCIG	N/A	370E	067E	2-RHRASC-A 2-RHRASC-B
2AT003	MSRV ACCUMULATOR	MSRV	N/A	473	053	
2AV208	RCIC COMPARTMENT UNIT COOLER	REV	A	179	056	2-RCIC
2AV209	HPCI COMPARTMENT UNIT COOLER	REV	B	180	057	2-HPCI
2AV210	RHR COMPARTMENT UNIT COOLER	REV	A	173	054	2-RHRASC-A 2-RHRLPCI-A 2-RHRSC-A 2-RHRSPC-A
2AV512	CELL "A" AIR EXHAUST FAN	DGEV	A	315A	083	
2B1D101	125V BATTERY	EPS	B	426	010	
2B1D103	BATTERY CHARGER	EPS	B	426	010	
2B1K513	2B1 DG STARTING AIR COMPRESSOR	SDG	B	315B	085	
2B1T558	B DG STARTING AIR RESERVOIR B1	SDG	N/A	315B	085	
2B2D101	125V BATTERY	EPS	B	426	010	
2B2D103	BATTERY CHARGER	EPS	B	426	010	
2B2T558	B DG STARTING AIR RESERVOIR B2	SDG	N/A	315B	085	
2BD102	125V DC DIST	EPS PANEL	B	453	021	
2BD105	125/250V DC BUS FUSE BOX	EPS	B	426	010	
2BD501	125V DC POWER DIST PANEL	EPS	B	315B	085	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
2BE205	2B RHR HEAT EXCHANGER	RHR	N/A	281	055	2-RHRSC-B 2-RHRSPC-D 2-RHRSC-D 2-RHRLPCI-B 2-RHRASC-D 2-RHRASC-B 2-RHRSPC-B
2BG501	DIESEL GENERATOR "B"	SDG	B	315B	085	
2BP202	RHR PUMP "B"	RHR	B	174	055	2-RHRSPC-B 2-RHRASC-B 2-RHRLPCI-B 2-RHRSC-B
2BP514	DIESEL OIL TRANSFER PUMP	SDG	B	YARD	YARD	
2BS252-1	B PCIG/ADS LONG TERM NITROGEN BOTTLE	PCIG	N/A	370E	067E	2-RHRASC-A 2-RHRASC-B
2BS252-2	B PCIG/ADS LONG TERM NITROGEN BOTTLE	PCIG	N/A	370E	067E	2-RHRASC-A 2-RHRASC-B
2BS252-3	B PCIG/ADS LONG TERM NITROGEN BOTTLE	PCIG	N/A	370E	067E	2-RHRASC-A 2-RHRASC-B
2BV208	RCIC COMPARTMENT UNIT COOLER	REV	A	179	056	2-RCIC
2BV209	HPCI COMPARTMENT UNIT COOLER	REV	B	180	057	2-HPCI
2BV210	RHR COMPARTMENT UNIT COOLER	REV	B	174	055	2-RHRLPCI-B 2-RHRSC-B 2-RHRASC-B 2-RHRSPC-B
2BV512	CELL "B" AIR EXHAUST FAN	DGEV	B	315B	085	
2C1T558	C DG STARTING AIR RESERVOIR C1	SDG	N/A	315C	084	
2C2T558	C DG STARTING AIR RESERVOIR C2	SDG	N/A	315C	084	
2CD101	125V BATTERY	EPS	C	361	006	
2CD102	125V DC DIST PANEL	EPS	C	428	018	
2CD103	BATTERY CHARGER	EPS	C	361	006	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
2CD105	125V DC BUS FUSE BOX	EPS	C	361	006	
2CD108	125V DC POWER DIST PANEL	APS	0(D)	351	102	
2CD162	125V DC DIST PANEL	EPS	C	428	018	
2CD501	125V DC POWER DIST PANEL	EPS	C	315C	084	
2CG501	DIESEL GENERATOR "C"	SDG	C	315C	084	
2CP202	RHR PUMP "C"	RHR	C	173	054	2-RHRASC-C 2-RHRLPCI-C 2-RHRSC-C 2-RHRSPC-C
2CP514	DIESEL OIL TRANSFER PUMP	SDG	C	YARD	YARD	
2CT003	MSRV ACCUMULATOR	MSRV	N/A	473	053	
2CV210	RHR COMPARTMENT UNIT COOLER "C"	REV	C	173	054	2-RHRLPCI-C 2-RHRSC-C 2-RHRSPC-C 2-RHRASC-C
2CV512	CELL "C" AIR EXHAUST FAN	DGEV	C	315C	084	
2D1T558	D DG STARTING AIR RESERVOIR D1	SDG	N/A	315D	086	
2D2T558	D DG STARTING AIR RESERVOIR D2	SDG	N/A	315D	086	
2DD101	125V BATTERY	EPS	D	360	005	
2DD102	125V DC DIST PANEL	EPS	D	453	021	
2DD103	BATTERY CHARGER	EPS	D	360	005	
2DD105	125V DC BUS FUSE BOX	EPS	D	360	005	
2DD501	125V DC POWER DIST PANEL	EPS	D	315D	086	
2DG501	DIESEL GENERATOR "D"	SDG	D	315D	086	
2DP202	RHR PUMP "D"	RHR	D	174	055	2-RHRASC-D 2-RHRLPCI-D 2-RHRSC-D 2-RHRSPC-D
2DP514	DIESEL OIL TRANSFER PUMP	SDG	D	YARD	YARD	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
2DV210	RHR COMPARTMENT UNIT COOLER "D"	REV	D	174	055	2-RHRASC-D 2-RHRLPCI-D 2-RHRSC-D 2-RHRSPC-D
2DV512	CELL "D" AIR EXHAUST FAN	DGEV	D	315D	086	
2ET003	MSRV ACCUMULATOR	ADS	N/A	473	053	
2EV210	RHR COMPARTMENT UNIT COOLER	REV	A	173	054	2-RHRLPCI-A 2-RHRSC-A 2-RHRSPC-A 2-RHRASC-A
2EV512	CELL "A" AIR EXHAUST FAN	DGEV	A	315A	083	
2FV210	RHR COMPARTMENT UNIT COOLER	REV	B	174	055	2-RHRASC-B 2-RHRLPCI-B 2-RHRSC-B 2-RHRSPC-B
2FV512	CELL "B" AIR EXHAUST FAN	DGEV	B	315B	085	
2GV210	RHR COMPARTMENT UNIT COOLER	REV	C	173	054	2-RHRSPC-C 2-RHRASC-C 2-RHRLPCI-C 2-RHRSC-C
2GV512	CELL "C" AIR EXHAUST FAN	DGEV	C	315C	084	
2HT003	MSRV ACCUMULATOR	ADS	N/A	473	053	
2HV210	RHR COMPARTMENT UNIT COOLER	REV	D	174	055	2-RHRASC-D 2-RHRLPCI-D 2-RHRSC-D 2-RHRSPC-D
2HV512	CELL "D" AIR EXHAUST FAN	DGEV	D	315D	086	
2KT003	MSRV ACCUMULATOR	ADS	N/A	473	053	
2MT003	MSRV ACCUMULATOR	ADS	N/A	473	053	
2NT003	MSRV ACCUMULATOR	MSRV	N/A	473	053	
2ST003	MSRV ACCUMULATOR	ADS	N/A	473	053	
51-1F067A	RHR PUMP SHUTDOWN COOLING SUCTION VALVE	RHR	N/A	203	032	1-RHRSC-C

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
51-1F067B	RHR PUMP SHUTDOWN COOLING SUCTION VALVE	RHR	N/A	204	031	1-RHRSC-D
51-2F067A	RHR PUMP SHUTDOWN COOLING SUCTION VALVE	RHR	N/A	280	054	2-RHRSC-C
51-2F067B	RHR PUMP SHUTDOWN COOLING SUCTION VALVE	RHR	N/A	281	055	2-RHRSC-D
FC-55-1R600	FLOW CONTROLLER	HPCI	B	533	024	
FC-55-2R600	FLOW CONTROLLER	HPCI	B	533	024	
FI-11-013A	ESW LOOP A SUPPLY	ESW	A	533	024	0-ESW-A
FI-11-013B	ESW LOOP B SUPPLY	ESW	B	533	024	0-ESW-B
FI-49-1R001-1	PUMP DISCHARGE LINE FLOW INDICATOR	RCIC	A	540	026	1-RCIC
FI-49-1R600-1	PUMP DISCHARGE LINE FLOW INDICATOR	RCIC	A	533	024	1-RCIC
FI-49-2R001-1	PUMP DISCHARGE LINE FLOW INDICATOR	RCIC	A	540	026	2-RCIC
FI-49-2R600-1	PUMP DISCHARGE LINE FLOW INDICATOR	RCIC	A	533	024	2-RCIC
FI-51-1R005	HEAT EXCHANGER DISCHARGE LINE FLOW INDICATOR	RHR	A	540	026	1-RHRSC-A 1-RHRSPC-A
FI-51-1R602A	RHR HEAT EXCHANGER "A" SHELL SIDE INLET FLOW INDICATOR	RHRSW	A	533	024	1-RHRSW-A
FI-51-1R602B	RHR HEAT EXCHANGER "B" SHELL SIDE INLET FLOW INDICATOR	RHRSW	B	533	024	1-RHRSW-B
FI-51-1R603A	HEAT EXCHANGER DISCHARGE LINE FLOW INDICATOR	RHR	A	533	024	1-RHRSC-C 1-RHRSPC-C 1-RHRSPC-A 1-RHRLPCI-A 1-RHRASC-C 1-RHRASC-A 1-RHRSC-A

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
FI-51-1R603B	HEAT EXCHANGER DISCHARGE LINE FLOW INDICATOR	RHR	B	533	024	1-RHRSC-B 1-RHRSPC-D 1-RHRSC-D 1-RHRLPCI-B 1-RHRASC-D 1-RHRASC-B 1-RHRSPC-B
FI-51-1R603C	LOOP "C" DISCHARGE LINE FLOW INDICATOR	RHR	C	533	024	1-RHRLPCI-C
FI-51-1R603D	LOOP "D" DISCHARGE LINE FLOW INDICATOR	RHR	D	533	024	1-RHRLPCI-D
FI-51-2R005	HEAT EXCHANGER DISCHARGE LINE FLOW INDICATOR	RHR	A	540	026	2-RHRSC-A 2-RHRSPC-A
FI-51-2R602A	RHR HEAT EXCHANGER "A" SHELL SIDE INLET FLOW INDICATOR	RHRSW	A	533	024	2-RHRSW-A
FI-51-2R602B	RHR HEAT EXCHANGER "B" SHELL SIDE INLET FLOW INDICATOR	RHRSW	B	533	024	2-RHRSW-B
FI-51-2R603A	HEAT EXCHANGER DISCHARGE LINE FLOW INDICATOR	RHR	A	533	024	2-RHRSPC-C 2-RHRASC-C 2-RHRLPCI-A 2-RHRSC-A 2-RHRSC-C 2-RHRSPC-A 2-RHRASC-A
FI-51-2R603B	HEAT EXCHANGER DISCHARGE LINE FLOW INDICATOR	RHR	B	533	024	2-RHRSPC-D 2-RHRSPC-B 2-RHRSC-D 2-RHRSC-B 2-RHRLPCI-B 2-RHRASC-B 2-RHRASC-D
FI-51-2R603C	LOOP "C" DISCHARGE LINE FLOW INDICATOR	RHR	C	533	024	2-RHRLPCI-C
FI-51-2R603D	LOOP "D" DISCHARGE LINE FLOW INDICATOR	RHR	D	533	024	2-RHRLPCI-D
FI-55-1R600-1	PUMP DISCHARGE LINE FLOW INDICATOR	HPCI	B	533	024	1-HPCI
FI-55-2R600-1	PUMP DISCHARGE LINE FLOW INDICATOR	HPCI	B	533	024	2-HPCI

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
FIC-49-1R001	FLOW INDICATING CONTROLLER	RCIC	A	540	026	
FIC-49-1R600	FLOW INDICATING CONTROLLER	RCIC	A	533	024	
FIC-49-2R001	FLOW INDICATING CONTROLLER	RCIC	A	540	026	
FIC-49-2R600	FLOW INDICATING CONTROLLER	RCIC	A	533	024	
FIS-49-1N651	FLOW INDICATING SWITCH	RCIC	A	542	025	
FIS-49-2N651	FLOW INDICATING SWITCH	RCIC	A	542	025	
FIS-55-1N651	PUMP DISCHARGE LINE FLOW INDICATING SWITCH	HPCI	B	542	025	
FIS-55-2N651	PUMP DISCHARGE LINE FLOW INDICATING SWITCH	HPCI	B	542	025	
FISL-51-1N652A	FLOW INDICATING SWITCH	RHR	A	542	025	
FISL-51-1N652B	FLOW INDICATING SWITCH	RHR	B	542	025	
FISL-51-1N652C	FLOW INDICATING SWITCH	RHR	C	542	025	
FISL-51-1N652D	FLOW INDICATING SWITCH	RHR	D	542	025	
FISL-51-2N652A	FLOW INDICATING SWITCH	RHR	A	542	025	
FISL-51-2N652B	FLOW INDICATING SWITCH	RHR	B	542	025	
FISL-51-2N652C	FLOW INDICATING SWITCH	RHR	C	542	025	
FISL-51-2N652D	FLOW INDICATING SWITCH	RHR	D	542	025	
FS-49-1N659	FLOW SWITCH	RCIC	A	542	025	
FS-49-2N659	FLOW SWITCH	RCIC	A	542	025	
FS-55-1N659	FLOW SWITCH	HPCI	B	542	025	
FS-55-2N659	FLOW SWITCH	HPCI	B	542	025	
FT-49-2N051	FLOW TRANSMITTER	RCIC	A	279	065	
FT-51-1N001	FLOW TRANSMITTER	RHR	A	304W	044W	
FT-51-1N007A	FLOW TRANSMITTER	RHRSW	A	200	042	
FT-51-1N007B	FLOW TRANSMITTER	RHRSW	B	207	041	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
FT-51-1N015A	FLOW TRANSMITTER	RHR	A	304W	044W	
FT-51-1N015B	FLOW TRANSMITTER	RHR	B	304E	044E	
FT-51-1N015C	FLOW TRANSMITTER	RHR	C	304W	044W	
FT-51-1N015D	FLOW TRANSMITTER	RHR	D	304E	044E	
FT-51-1N052A	FLOW TRANSMITTER	RHR	A	304W	044W	
FT-51-1N052B	FLOW TRANSMITTER	RHR	B	304E	044E	
FT-51-1N052C	FLOW TRANSMITTER	RHR	C	304W	044W	
FT-51-1N052D	FLOW TRANSMITTER	RHR	D	304E	044E	
FT-51-2N001	FLOW TRANSMITTER	RHR	A	370W	067W	
FT-51-2N007A	FLOW TRANSMITTER	RHRSW	A	189	062	
FT-51-2N007B	FLOW TRANSMITTER	RHRSW	B	279	065	
FT-51-2N015A	FLOW TRANSMITTER	RHR	A	370W	067W	
FT-51-2N015B	FLOW TRANSMITTER	RHR	B	370E	067E	
FT-51-2N015C	FLOW TRANSMITTER	RHR	C	370W	067W	
FT-51-2N015D	FLOW TRANSMITTER	RHR	D	370E	067E	
FT-51-2N052A	FLOW TRANSMITTER	RHR	A	370W	067W	
FT-51-2N052B	FLOW TRANSMITTER	RHR	B	370E	067E	
FT-51-2N052C	FLOW TRANSMITTER	RHR	C	370W	067W	
FT-51-2N052D	FLOW TRANSMITTER	RHR	D	370E	067E	
FT-55-1N008	FLOW TRANSMITTER	HPCI	B	111	040	
FT-55-1N051	FLOW TRANSMITTER	HPCI	B	111	040	
FT-55-2N008	FLOW TRANSMITTER	HPCI	B	182	063	
FT-55-2N051	FLOW TRANSMITTER	HPCI	B	182	063	
FV-50-113	TURBINE CONTROL VALVE	RCIC	N/A	108	033	1-RCIC
FV-50-213	TURBINE CONTROL VALVE	RCIC	N/A	179	056	2-RCIC
FV-56-111	TURBINE CONTROL VALVE	HPCI	N/A	109	034	1-HPCI
FV-56-112	TURBINE STOP VALVE	HPCI	B	109	034	1-HPCI
FV-56-112	TURBINE STOP VALVE	HPCI	B	109	034	1-HPCITRIP
FV-56-211	TURBINE CONTROL VALVE	HPCI	N/A	180	057	2-HPCI
FV-56-212	TURBINE STOP VALVE	HPCI	B	180	057	2-HPCI
FV-56-212	TURBINE STOP VALVE	HPCI	B	180	057	2-HPCITRIP
FY-11-013A	ESW LOOP A SUPPLY	ESW	A	533	024	
FY-11-013B	ESW LOOP B SUPPLY	ESW	B	533	024	
FY-11-060B	ESW LOOP B SUPPLY	ESW	B	533	024	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
FY-49-1K001	SIGNAL ISOLATOR-FLOW	RCIC	A	540	026	
FY-49-1K013	SIGNAL ISOLATOR-FLOW	RCIC	A	540	026	
FY-49-1K014	SIGNAL ISOLATOR-FLOW	RCIC	A	540	026	
FY-49-1K015	SIGNAL ISOLATOR-FLOW	RCIC	A	540	026	
FY-49-1K601	SIGNAL ISOLATOR-FLOW	RCIC	A	533	024	
FY-49-2K001	SIGNAL ISOLATOR-FLOW	RCIC	A	540	026	
FY-49-2K013	SIGNAL ISOLATOR-FLOW	RCIC	A	540	026	
FY-49-2K014	SIGNAL ISOLATOR-FLOW	RCIC	A	540	026	
FY-49-2K015	SIGNAL ISOLATOR-FLOW	RCIC	A	540	026	
FY-49-2K601	SIGNAL ISOLATOR-FLOW	RCIC	A	533	024	
FY-51-114A	SQUARE ROOT CONVERTER	RHRSW	A	542	025	
FY-51-114B	SQUARE ROOT CONVERTER	RHRSW	B	542	025	
FY-51-1K600A	SQUARE ROOT CONVERTER	RHR	A	542	025	
FY-51-1K600B	SQUARE ROOT CONVERTER	RHR	B	542	025	
FY-51-1K600C	SQUARE ROOT CONVERTER	RHR	C	542	025	
FY-51-1K600D	SQUARE ROOT CONVERTER	RHR	D	542	025	
FY-51-1K011	SQUARE ROOT CONVERTER-RHR LOOP A FLOW	RHR	A	540	026	
FY-51-214A	SQUARE ROOT CONVERTER	RHRSW	A	542	025	
FY-51-214B	SQUARE ROOT CONVERTER	RHRSW	B	542	025	
FY-51-2K600A	SQUARE ROOT CONVERTER	RHR	A	542	025	
FY-51-2K600B	SQUARE ROOT CONVERTER	RHR	B	542	025	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
FY-51-2K600C	SQUARE ROOT CONVERTER	RHR	C	542	025	
FY-51-2K600D	SQUARE ROOT CONVERTER	RHR	D	542	025	
FY-55-1K601	SQUARE ROOT CONVERTER	HPCI	B	533	024	
FY-55-2K601	SQUARE ROOT CONVERTER	HPCI	B	533	024	
HD-81-041A	SYSTEM "A" OUTSIDE AIR INLET DAMPER	SPPV	A	1000	122	0-ESW-A 0-ESW-R 1-RHRSW-A 2-RHRSW-A
HD-81-041B	SYSTEM "B" OUTSIDE AIR INLET DAMPER	SPPV	B	1005	123	2-RHRSW-B 1-RHRSW-B 0-ESW-B
HD-81-041C	SYSTEM "C" OUTSIDE AIR INLET DAMPER	SPPV	C	1000	122	1-RHRSW-A 2-RHRSW-A 0-ESW-A
HD-81-041D	SYSTEM "D" OUTSIDE AIR INLET DAMPER	SPPV	D	1005	123	0-ESW-B 1-RHRSW-B 2-RHRSW-B
HD-81-042A	SYSTEM "A" RECIRCULATION AIR DAMPER	SPPV	A	1000	122	0-ESW-A 0-ESW-R 1-RHRSW-A 2-RHRSW-A
HD-81-042B	SYSTEM "B" RECIRCULATION AIR DAMPER	SPPV	B	1005	123	0-ESW-B 1-RHRSW-B 2-RHRSW-B
HD-81-042C	SYSTEM "C" RECIRCULATION AIR DAMPER	SPPV	C	1000	122	0-ESW-A 2-RHRSW-A 1-RHRSW-A
HD-81-042D	SYSTEM "D" RECIRCULATION AIR DAMPER	SPPV	D	1005	123	0-ESW-B 1-RHRSW-B 2-RHRSW-B
HV-11-011A	LOOP "A" DISCHARGE VALVE TO RHRSW RETURN HEADERS	ESW	A	202	075	0-ESW-A 0-ESW-R
HV-11-011B	LOOP "B" DISCHARGE VALVE TO RHRSW RETURN HEADERS	ESW	B	202	075	0-ESW-B
HV-11-015A	LOOP "A" DISCHARGE VALVE TO RHRSW RETURN HEADERS	ESW	C	202	075	0-ESW-A 0-ESW-R

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-11-015B	LOOP "B" DISCHARGE VALVE TO RHRSW RETURN HEADERS	ESW	D	202	075	0-ESW-B
HV-11-041	LOOP "A" EQUIPMENT HEADER RETURN VALVE	ESW	A	203	032	0-ESW-A 0-ESW-R
HV-11-042	HPCI COMPARTMENT UNIT COOLER RETURN VALVE	HPCI	B	109	034	1-HPCI
HV-11-043	SERVICE WATER INTERTIE VALVE FOR HPCI UNIT COOLER	ESW	B	109	034	0-ESW-B
HV-11-044	LOOP "B" EQUIPMENT HEADER RETURN VALVE	ESW	B	207	041	0-ESW-B
HV-11-046	LOOP "A" EQUIPMENT HEADER RETURN VALVE	ESW	A	281	055	0-ESW-R 0-ESW-A
HV-11-047	LOOP "B" EQUIPMENT HEADER RETURN VALVE	ESW	B	281	055	0-ESW-B
HV-11-048	SERVICE WATER INTERTIE VALVE FOR RCIC UNIT COOLER	ESW	A	279	065	0-ESW-A 0-ESW-R
HV-11-049	RCIC COMPARTMENT UNIT COOLER RETURN VALVE	RCIC	A	279	065	2-RCIC 0-ESW-R
HV-11-051A	SERVICE WATER INTERTIE VALVE FOR CONTROL STRUCTURE CHILLER	ESW		258	001	0-ESW-A 0-ESW-R
HV-11-051B	SERVICE WATER INTERTIE VALVE FOR CONTROL STRUCTURE CHILLER	ESW		263	001	0-ESW-B
HV-11-055A	SERVICE WATER INTERTIE FOR CONTROL STRUCTURE CHILLER	ESW		258	001	0-ESW-A

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-11-055B	SERVICE WATER INTERTIE VALVE FOR CONTROL STRUCTURE CHILLER	ESW		263	001	0-ESW-B
HV-11-071	LOOP "A" EQUIPMENT HEADER RETURN VALVE	ESW	C	203	032	0-ESW-A
HV-11-072	HPCI COMPARTMENT UNIT COOLER RETURN VALVE	HPCI	D	109	034	1-HPCI
HV-11-073	SERVICE WATER INTERTIE FOR HPCI UNIT COOLER	ESW	D	109	034	0-ESW-B
HV-11-074	LOOP "B" EQUIPMENT HEADER RETURN VALVE	ESW	D	207	041	0-ESW-B
HV-11-076	LOOP "A" EQUIPMENT HEADER RETURN VALVE	ESW	C	284	064	0-ESW-A
HV-11-077	LOOP "B" EQUIPMENT HEADER RETURN VALVE	ESW	D	281	055	0-ESW-B
HV-11-078	SERVICE WATER INTERTIE VALVE FOR RCIC UNIT COOLER	ESW	C	279	065	0-ESW-A
HV-11-079	RCIC COMPARTMENT UNIT COOLER RETURN VALVE	RCIC	C	279	065	2-RCIC
HV-11-103A	HPCI COMPARTMENT UNIT COOLER INLET VALVE	ESW	B	109	034	1-HPCI
HV-11-103B	HPCI COMPARTMENT UNIT COOLER INLET VALVE	ESW	B	109	034	1-HPCI
HV-11-104A	RHR COMPARTMENT UNIT COOLER "A" INLET VALVE	ESW	A	102	032	1-RHRLPCI-A 1-RHRSC-A 1-RHRASC-A 1-RHRSPC-A
HV-11-104B	RHR COMPARTMENT UNIT COOLER "B" INLET VALVE	ESW	B	103	031	1-RHRASC-B 1-RHRLPCI-B 1-RHRSC-B 1-RHRSPC-B
HV-11-104C	RHR COMPARTMENT UNIT COOLER "C" INLET VALVE	ESW	C	102	032	1-RHRASC-C 1-RHRSPC-C 1-RHRSC-C 1-RHRLPCI-C

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-11-104D	RHR COMPARTMENT UNIT COOLER "D" INLET VALVE	ESW	D	103	031	1-RHRASC-D 1-RHRLPCI-D 1-RHRSC-D 1-RHRSPC-D
HV-11-104E	RHR COMPARTMENT UNIT COOLER "E" INLET VALVE	ESW	A	102	032	1-RHRLPCI-A 1-RHRSC-A 1-RHRASC-A 1-RHRSPC-A
HV-11-104F	RHR COMPARTMENT UNIT COOLER "F" INLET VALVE	ESW	B	103	031	1-RHRASC-B 1-RHRLPCI-B 1-RHRSC-B 1-RHRSPC-B
HV-11-104G	RHR COMPARTMENT UNIT COOLER "G" INLET VALVE	ESW	C	102	032	1-RHRASC-C 1-RHRSPC-C 1-RHRLPCI-C 1-RHRSC-C
HV-11-104H	RHR COMPARTMENT UNIT COOLER "H" INLET VALVE	ESW	D	103	031	1-RHRASC-D 1-RHRLPCI-D 1-RHRSC-D 1-RHRSPC-D
HV-11-105	ESW TO TECW HX INTERTIE SHUTOFF VALVE	ESW	A	YARD	YARD	0-ESW-A 0-ESW-R
HV-11-106A	RCIC COMPARTMENT UNIT COOLER INLET VALVE	ESW	A	108	033	1-RCIC
HV-11-106B	RCIC COMPARTMENT UNIT COOLER INLET VALVE	ESW	A	108	033	1-RCIC
HV-11-107	ESW TO TECW HX INTERTIE SHUTOFF VALVE	ESW	C	YARD	YARD	0-ESW-A 0-ESW-R
HV-11-121	SERVICE WATER INTERTIE VALVE FOR LOOP "A" EQUIPMENT	ESW	A	203	032	0-ESW-R 0-ESW-A
HV-11-123	SERVICE WATER INTERTIE VALVE FOR LOOP "A" EQUIPMENT	ESW	C	203	032	0-ESW-A
HV-11-124	SHUT OFF VALVE FOR ESW TO RECW HEAT EXCHANGER INTERTIE LINE	ESW	B	207	041	0-ESW-B

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-11-125	SERVICE WATER INTERTIE VALVE FOR LOOP "B" EQUIPMENT	ESW	B	207	041	0-ESW-B
HV-11-126	SERVICE WATER INTERTIE VALVE FOR "B" LOOP EQUIPMENT	ESW	D	207	041	0-ESW-B
HV-11-128	SHUTOFF VALVE FOR ESW TO RHRSW HEAT EXCHANGER INTERTIE LINE	ESW	D	207	041	0-ESW-B
11-1131A	DIESEL GENERATOR "A" COOLING LOOP INLET VALVE	ESW	A	311A	079	
HV-11-131B	DIESEL GENERATOR "B" COOLING LOOP INLET VALVE	ESW	B	311B	081	0-ESW-A 0-ESW-R
11-1131C	DIESEL GENERATOR "C" COOLING LOOP INLET VALVE	ESW	C	311C	080	
HV-11-131D	DIESEL GENERATOR "D" COOLING LOOP INLET VALVE	ESW	D	311D	082	0-ESW-A 0-ESW-R
HV-11-132A	DIESEL GENERATOR "A" COOLING LOOP OUTLET VALVE	ESW	A	311A	079	
HV-11-132B	DIESEL GENERATOR "B" COOLING LOOP OUTLET VALVE	ESW	B	311B	081	
HV-11-132C	DIESEL GENERATOR "C" COOLING LOOP OUTLET VALVE	ESW	C	311C	080	
HV-11-132D	DIESEL GENERATOR "D" COOLING LOOP OUTLET VALVE	ESW	D	311D	082	
HV-11-133A	DIESEL GENERATOR "A" COOLING LOOP INLET VALVE	ESW	A	311A	079	0-ESW-B
11-1133B	DIESEL GENERATOR "B" COOLING LOOP INLET VALVE	ESW	B	311B	081	
HV-11-133C	DIESEL GENERATOR "C" COOLING LOOP INLET VALVE	ESW	C	311C	080	0-ESW-B
11-1133D	DIESEL GENERATOR "D" COOLING LOOP INLET VALVE	ESW	D	311D	082	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-11-134A	DIESEL GENERATOR "A" COOLING LOOP OUTLET VALVE	ESW	A	311A	079	
HV-11-134B	DIESEL GENERATOR "B" COOLING LOOP OUTLET VALVE	ESW	B	311B	081	
HV-11-134C	DIESEL GENERATOR "C" COOLING LOOP OUTLET VALVE	ESW	C	311C	080	
HV-11-134D	DIESEL GENERATOR "D" COOLING LOOP OUTLET VALVE	ESW	D	311D	082	
HV-11-203A	HPCI COMPARTMENT UNIT COOLER INLET VALVE	ESW	B	180	057	2-HPCI
HV-11-203B	HPCI COMPARTMENT UNIT COOLER INLET VALVE	ESW	B	180	057	2-HPCI
HV-11-204A	RHR COMPARTMENT UNIT COOLER "A" INLET VALVE	ESW	A	173	054	2-RHRASC-A 2-RHRLPCI-A 2-RHRSC-A 2-RHRSPC-A
HV-11-204B	RHR COMPARTMENT UNIT COOLER "B" INLET VALVE	ESW	B	174	055	2-RHRSC-B 2-RHRSPC-B 2-RHRASC-B 2-RHRLPCI-B
HV-11-204C	RHR COMPARTMENT UNIT COOLER "C" INLET VALVE	ESW	C	173	054	2-RHRASC-C 2-RHRLPCI-C 2-RHRSC-C 2-RHRSPC-C
HV-11-204D	RHR COMPARTMENT UNIT COOLER "D" INLET VALVE	ESW	D	174	055	2-RHRLPCI-D 2-RHRSC-D 2-RHRASC-D 2-RHRSPC-D
HV-11-204H	RHR COMPARTMENT UNIT COOLER "H" INLET VALVE	ESW	D	174	055	2-RHRASC-D 2-RHRLPCI-D 2-RHRSC-D 2-RHRSPC-D
HV-11-205	ESW TO TECW HX INTERTIE SHUTOFF VALVE	ESW	B	YARD	YARD	0-ESW-B
HV-11-206A	RCIC COMPARTMENT UNIT COOLER INLET VALVE	ESW	A	179	056	2-RCIC

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-11-206B	RCIC COMPARTMENT UNIT COOLER INLET VALVE	ESW	A	179	056	2-RCIC
HV-11-207	ESW TO TECW HX INTERTIE SHUTOFF VALVE	ESW	D	YARD	YARD	0-ESW-B
HV-11-221	SERVICE WATER INTERTIE VALVE FOR LOOP "A" EQUIPMENT	ESW	A	284	064	0-ESW-A 0-ESW-R
HV-11-223	SERVICE WATER INTERTIE VALVE FOR LOOP "A" EQUIPMENT	ESW	C	284	064	0-ESW-A
HV-11-224	SHUTOFF VALVE FOR ESW TO RECW HEAT EXCHANGER INTERTIE LINE	ESW	A	284	064	0-ESW-A 0-ESW-R
HV-11-225	SERVICE WATER INTERTIE VALVE FOR LOOP "B" EQUIPMENT	ESW	B	281	055	0-ESW-B
HV-11-226	SERVICE WATER INTERTIE VALVE FOR LOOP "B" EQUIPMENT	ESW	D	281	055	0-ESW-B
HV-11-228	SHUTOFF VALVE FOR ESW TO RECW HEAT EXCHANGER INTERTIE LINE	ESW	C	284	064	0-ESW-R 0-ESW-A
11-2231A	DIESEL GENERATOR "A" COOLING LOOP INLET VALVE	ESW	A	315A	083	
HV-11-231B	DIESEL GENERATOR "B" COOLING LOOP INLET VALVE	ESW	B	315B	085	0-ESW-R 0-ESW-A
11-2231C	DIESEL GENERATOR "C" COOLING LOOP INLET VALVE	ESW	C	315C	084	
HV-11-231D	DIESEL GENERATOR "D" COOLING LOOP INLET VALVE	ESW	D	315D	086	0-ESW-A 0-ESW-R
HV-11-232A	DIESEL GENERATOR "A" COOLING LOOP OUTLET VALVE	ESW	A	315A	083	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-11-232B	DIESEL GENERATOR "B" COOLING LOOP OUTLET VALVE	ESW	B	315B	085	
HV-11-232C	DIESEL GENERATOR "C" COOLING LOOP OUTLET VALVE	ESW	C	315C	084	
HV-11-232D	DIESEL GENERATOR "D" COOLING LOOP OUTLET VALVE	ESW	D	315D	086	
HV-11-233A	DIESEL GENERATOR "A" COOLING LOOP INLET VALVE	ESW	A	315A	083	0-ESW-B
11-2233B	DIESEL GENERATOR "B" COOLING LOOP INLET VALVE	ESW	B	315B	085	
HV-11-233C	DIESEL GENERATOR "C" COOLING LOOP INLET VALVE	ESW	C	315C	084	0-ESW-B
11-2233D	DIESEL GENERATOR "D" COOLING LOOP INLET VALVE	ESW	D	315D	086	
HV-11-234A	DIESEL GENERATOR "A" COOLING LOOP OUTLET VALVE	ESW	A	315A	083	
HV-11-234B	DIESEL GENERATOR "B" COOLING LOOP OUTLET VALVE	ESW	B	315B	085	
HV-11-234C	DIESEL GENERATOR "C" COOLING LOOP OUTLET VALVE	ESW	C	315C	084	
HV-11-234D	DIESEL GENERATOR "D" COOLING LOOP OUTLET VALVE	ESW	D	315D	086	
HV-12-003A	WET PIT SLUICE GATE	RHRSW	A	1000	122	0-ESW-A 0-ESW-R 1-RHRSW-A 2-RHRSW-A
HV-12-003B	WET PIT SLUICE GATE	RHRSW	B	1005	123	1-RHRSW-B 2-RHRSW-B 0-ESW-B

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-12-003C	WET PIT SLUICE GATE	RHRSW	C	1000	122	0-ESW-A 0-ESW-R 1-RHRSW-A 2-RHRSW-A
HV-12-003D	WET PIT SLUICE GATE	RHRSW	D	1005	123	0-ESW-B 1-RHRSW-B 2-RHRSW-B
HV-12-017A	LOOP "A" TO UNIT 2 COOLING TOWER CROSS-TIE VALVE	RHRSW	A	YARD	YARD	0-ESW-A 2-RHRSW-B 1-RHRSW-B 2-RHRSW-A 1-RHRSW-A 0-ESW-B 0-ESW-R
HV-12-017B	LOOP "B" TO UNIT 1 COOLING TOWER CROSS-TIE VALVE	RHRSW	B	YARD	YARD	0-ESW-A 2-RHRSW-B 1-RHRSW-B 2-RHRSW-A 0-ESW-B 1-RHRSW-A
HV-12-031A	SPRAY NETWORK BYPASS VALVE	RHRSW	A	1010	122	0-ESW-A 0-ESW-R 1-RHRSW-A 2-RHRSW-A
HV-12-031B	SPRAY NETWORK BYPASS VALVE	RHRSW	B	1015	123	0-ESW-B 1-RHRSW-B 2-RHRSW-B
HV-12-031C	SPRAY NETWORK BYPASS VALVE	RHRSW	C	1010	122	2-RHRSW-A 0-ESW-A 0-ESW-R 1-RHRSW-A
HV-12-031D	SPRAY NETWORK BYPASS VALVE	RHRSW	D	1015	123	2-RHRSW-B 1-RHRSW-B 0-ESW-B
HV-12-032A	SPRAY NETWORK INLET VALVE	RHRSW	A	1010	122	0-ESW-A 0-ESW-R 1-RHRSW-A 2-RHRSW-A
HV-12-032B	SPRAY NETWORK INLET VALVE	RHRSW	B	1015	123	0-ESW-B 1-RHRSW-B 2-RHRSW-B

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-12-032C	SPRAY NETWORK INLET VALVE	RHRSW	C	1010	122	0-ESW-A 0-ESW-R 1-RHRSW-A 2-RHRSW-A
HV-12-032D	SPRAY NETWORK INLET VALVE	RHRSW	D	1015	123	1-RHRSW-B 2-RHRSW-B 0-ESW-B
HV-12-034A	RHR SERVICE WATER SPRAY NOZZLE CROSS TIE VALVE	ESW	A	1010	122	2-RHRSW-B 0-ESW-B 0-ESW-R 1-RHRSW-A 2-RHRSW-A 1-RHRSW-B 0-ESW-A
HV-12-034B	RHR SERVICE WATER SPRAY NOZZLE CROSS TIE VALVE	ESW	B	1015	123	1-RHRSW-B 2-RHRSW-A 1-RHRSW-A 0-ESW-A 2-RHRSW-B 0-ESW-B
HV-12-111	RHRSW TO COOLING TOWER INTERTIE SHUTOFF VALVE	RHRSW	A	YARD	YARD	2-RHRSW-A 1-RHRSW-A 0-ESW-R 0-ESW-A
HV-12-113	RHRSW TO COOLING TOWER INTERTIE SHUTOFF VALVE	RHRSW	C	YARD	YARD	0-ESW-A 0-ESW-R 1-RHRSW-A 2-RHRSW-A
HV-12-211	RHRSW TO COOLING TOWER INTERTIE SHUTOFF VALVE	RHRSW	B	YARD	YARD	0-ESW-B 1-RHRSW-B 2-RHRSW-B
HV-12-213	RHRSW TO COOLING TOWER INTERTIE SHUTOFF VALVE	RHRSW	D	YARD	YARD	0-ESW-B 1-RHRSW-B 2-RHRSW-B
HV-41-109A	REACTOR FEEDWATER BYPASS VALVE	HI/LOW	A	518	046	1-HI/LOW 1-HPCI

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-41-109B	REACTOR FEEDWATER BYPASS VALVE	HI/LOW	B	518	046	1-HI/LOW 1-RCIC
HV-41-110	RX FW STARTUP FLUSHING SHUTOFF	HI/LOW	C	407	046	1-HI/LOW
HV-41-140	BYPASS LEAKAGE BARRIER VENT MAIN STEAM LINE BLEED DRAIN	HI/LOW	C	407	046	1-HI/LOW
HV-41-141	BYPASS LEAKAGE BARRIER VENT MAIN STEAM LINE BLEED DRAIN	HI/LOW	D	407	046	1-HI/LOW
HV-41-1F001	NUCLEAR BOILER SYS HEAD VENT VALVE	HI/LOW	0	400	030	1-HI/LOW
HV-41-1F002	NUCLEAR BOILER SYS HEAD VENT VALVE	HI/LOW	0	400	030	1-HI/LOW
HV-41-1F011A	FEEDWATER LINE "A" INBD MAINT ISO VALVE	HPCI	A	400	030	1-HPCI
HV-41-1F011B	FEEDWATER LINE "B" INBD MAINT ISO VALVE	RCIC	C	400	030	1-RCIC
HV-41-1F016	MAIN STEAM LINE DRAIN INBD PCIV	HI/LOW	A	400	030	1-HI/LOW
HV-41-1F019	MAIN STEAM LINE DRAIN OUTBD PCIV	HI/LOW	B	407	046	1-HI/LOW
HV-41-1F021	NUCLEAR BOILER SYSTEM MSL DRAIN TO COND.	HI/LOW	B	407	046	1-HI/LOW
HV-41-1F022A	A MAIN STEAM ISO VALVE INBD PCIV	HI/LOW	A,W	400	030	1-HI/LOW
HV-41-1F022B	B MAIN STEAM ISO VALVE INBD PCIV	HI/LOW	A,W	400	030	1-HI/LOW
HV-41-1F022C	C MAIN STEAM ISO VALVE INBD PCIV	HI/LOW	A,W	400	030	1-HI/LOW
HV-41-1F022D	D MAIN STEAM ISO VALVE INBD PCIV	HI/LOW	A,W	400	030	1-HI/LOW

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-41-1F028A	A MAIN STEAM ISO VALVE OUTBD PCIV	HI/LOW	B,X	407	046	1-HI/LOW
HV-41-1F028B	B MAIN STEAM ISO VALVE OUTBD PCIV	HI/LOW	B,X	407	046	1-HI/LOW
HV-41-1F028C	C MAIN STEAM ISO VALVE OUTBD PCIV	HI/LOW	B,X	407	046	1-HI/LOW
HV-41-1F028D	D MAIN STEAM ISO VALVE OUTBD PCIV	HI/LOW	B,X	407	046	1-HI/LOW
HV-41-1F084	MAIN STEAM LINE C INBD SAMPLE PCIV	HI/LOW	A	400	030	1-HI/LOW
HV-41-1F085	MAIN STEAM LINE C OUTBD SAMPLE PCIV	HI/LOW	B	510	047W	1-HI/LOW
HV-41-209A	REACTOR FEEDWATER BYPASS VALV	HI/LOW	A	587	069	2-HI/LOW 2-HPCI
HV-41-209B	REACTOR FEEDWATER BYPASS VALVE	HI/LOW	B	587	069	2-HI/LOW 2-RCIC
HV-41-210	RX FW STARTUP FLUSHING SHUTOFF	HI/LOW	C	480	069	2-HI/LOW
HV-41-240	BYPASS LEAKAGE BARRIER VENT MAIN STEAM LINE BLEED DRAIN	HI/LOW	C	480	069	2-HI/LOW
HV-41-241	BYPASS LEAKAGE BARRIER VENT MAIN STEAM LINE BLEED DRAIN	HI/LOW	D	480	069	2-HI/LOW
HV-41-2F001	NUCLEAR BOILER SYS HEAD VENT VALVE	HI/LOW	0	473	053	2-HI/LOW
HV-41-2F002	NUCLEAR BOILER SYS HEAD VENT VALVE	HI/LOW	0	473	053	2-HI/LOW
HV-41-2F011A	FEEDWATER LINE "A" INBD MAINT ISO VALVE	HPCI	A	473	053	2-HPCI
HV-41-2F011B	FEEDWATER LINE "B" INBD MAINT ISO VALVE	RCIC	C	473	053	2-RCIC
HV-41-2F016	MAIN STEAM LINE DRAIN INBD PCIV	HI/LOW	A	473	053	2-HI/LOW
HV-41-2F019	MAIN STEAM LINE DRAIN OUTBD PCIV	HI/LOW	B	480	069	2-HI/LOW

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-41-2F021	NUCLEAR BOILER SYSTEM MSL DRAIN TO COND.	HI/LOW	B	480	069	2-HI/LOW
HV-41-2F022A	A MAIN STEAM ISO VALVE INBD PCIV	HI/LOW	A,W	473	053	2-HI/LOW
HV-41-2F022B	B MAIN STEAM ISO VALVE INBD PCIV	HI/LOW	A,W	473	053	2-HI/LOW
HV-41-2F022C	C MAIN STEAM ISO VALVE INBD PCIV	HI/LOW	A,W	473	053	2-HI/LOW
HV-41-2F022D	D MAIN STEAM ISO VALVE INBD PCIV	HI/LOW	A,W	473	053	2-HI/LOW
HV-41-2F028A	A MAIN STEAM ISO VALVE OUTBD PCIV	HI/LOW	B,X	480	069	2-HI/LOW
HV-41-2F028B	B MAIN STEAM ISO VALVE OUTBD PCIV	HI/LOW	B,X	480	069	2-HI/LOW
HV-41-2F028C	C MAIN STEAM ISO VALVE OUTBD PCIV	HI/LOW	B,X	480	069	2-HI/LOW
HV-41-2F028D	D MAIN STEAM ISO VALVE OUTBD PCIV	HI/LOW	B,X	480	069	2-HI/LOW
HV-41-2F084	MAIN STEAM LINE C INBD SAMPLE PCIV	HI/LOW	A	473	053	2-HI/LOW
HV-41-2F085	MAIN STEAM LINE C OUTBD SAMPLE PCIV	HI/LOW	B	584	070E	2-HI/LOW
HV-43-1F019	RECIRC LOOP SAMPLE INBD PCIV	HI/LOW	A	400	030	1-HI/LOW
HV-43-1F020	RECIRC LOOP SAMPLE OUTBD PCIV	HI/LOW	B	501	047E	1-HI/LOW
HV-43-2F019	RECIRC LOOP SAMPLE INBD PCIV	HI/LOW	A	473	053	2-HI/LOW
HV-43-2F020	RECIRC LOOP SAMPLE OUTBD PCIV	HI/LOW	B	575	070W	2-HI/LOW
HV-44-1F031	RWCU RESTRICTED ORFICE BYPASS VALVE	HI/LOW	0	510	047W	1-HI/LOW
HV-44-1F034	RWCU DISCHARGE TO MAIN CONDENSER	HI/LOW	0	510	047W	1-HI/LOW
HV-44-1F035	RWCU DISCHARGE TO EQUIP DRAIN COLLECTION TANK	HI/LOW	0	510	047W	1-HI/LOW
HV-44-2F031	RWCU RESTRICTED ORFICE BYPASS VALVE	HI/LOW	0	584	070E	2-HI/LOW

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-44-2F034	RWCU DISCHARGE TO MAIN CONDENSER	HI/LOW	0	584	070E	2-HI/LOW
HV-44-2F035	RWCU DISCHARGE TO EQUIP DRAIN COLLECTION TANK	HI/LOW	0	584	070E	2-HI/LOW
HV-49-1F007	STEAM SUPPLY LINE INBD CTMT ISO VALVE	RCIC	C	400	030	1-RCIC 1-RCICTRIP
HV-49-1F008	STEAM SUPPLY LINE OUTBD CTMT ISO VALVE	RCIC	A	309E	043E	1-RCIC 1-RCICTRIP
HV-49-1F010	PUMP SUCTION VALVE FROM CONDENSATE STORAGE TANK	RCIC	A	108	033	1-RCIC
HV-49-1F012	RCIC PUMP DISCHARGE VALVE	RCIC	A	200	042	1-RCIC
HV-49-1F013	INJECTION VALVE TO FEEDWATER LINE	RCIC	A	518	046	1-RCIC
HV-49-1F019	MINIMUM FLOW BYPASS LINE CTMT ISO VALVE	RCIC	A	108	033	1-RCIC
HV-49-1F022	SHUTOFF VALVE IN DISCHARGE LINE TO CONDENSATE STORAGE TANK	RCIC	A	200	042	1-RCIC
HV-49-1F029	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER	RCIC	A	108	033	1-RCIC
HV-49-1F031	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER CTMT ISO VALVE	RCIC	A	108	033	1-RCIC
HV-49-1F060	TURBINE EXHAUST LINE CTMT ISO VALVE	RCIC	A	289	033	1-RCIC
HV-49-1F080	TURBINE EXHAUST LINE VACUUM BREAKER VALVE	RCIC	A	203	032	1-RCIC
HV-49-1F084	TURBINE EXHAUST LINE VACUUM BREAKER VALVE	RCIC	C	203	032	1-RCIC
HV-49-2F007	STEAM SUPPLY LINE INBD CTMT ISO VALVE	RCIC	C	473	053	2-RCIC 2-RCICTRIP
HV-49-2F008	STEAM SUPPLY LINE OUTBD CTMT ISO VALVE	RCIC	A	376E	066E	2-RCIC 2-RCICTRIP
HV-49-2F010	PUMP SUCTION VALVE FROM CONDENSATE STORAGE TANK	RCIC	A	179	056	2-RCIC

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-49-2F012	RCIC PUMP DISCHARGE VALVE	RCIC	A	279	065	2-RCIC
HV-49-2F013	INJECTION VALVE TO FEEDWATER LINE	RCIC	A	587	069	2-RCIC
HV-49-2F019	MINIMUM FLOW BYPASS LINE CTMT ISO VALVE	RCIC	A	281	055	2-RCIC
HV-49-2F022	SHUTOFF VALVE IN DISCHARGE LINE TO CONDENSATE STORAGE TANK	RCIC	A	279	065	2-RCIC
HV-49-2F029	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER	RCIC	A	179	056	2-RCIC
HV-49-2F031	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER CTMT ISO VALVE	RCIC	A	179	056	2-RCIC
HV-49-2F060	TURBINE EXHAUST LINE CTMT ISO VALVE	RCIC	A	285	056	2-RCIC
HV-49-2F080	TURBINE EXHAUST LINE VACUUM BREAKER VALVE	RCIC	A	281	055	2-RCIC
HV-49-2F084	TURBINE EXHAUST LINE VACUUM BREAKER VALVE	RCIC	C	281	055	2-RCIC
HV-50-112	TURBINE STOP VALVE	RCIC	A	108	033	1-RCIC 1-RCICTRIP
HV-50-1F045	STEAM SUPPLY LINE INLET VALVE TO TURBINE	RCIC	A	108	033	1-RCIC 1-RCICTRIP
HV-50-1F046	COOLING WATER LINE SHUTOFF VALVE	RCIC	A	108	033	1-RCIC
HV-50-212	TURBINE STOP VALVE	RCIC	A	179	056	2-RCIC 2-RCICTRIP
HV-50-2F045	STEAM SUPPLY LINE INLET VALVE TO TURBINE	RCIC	A	179	056	2-RCIC 2-RCICTRIP
HV-50-2F046	COOLING WATER LINE SHUTOFF VALVE	RCIC	A	179	056	2-RCIC
HV-51-105A	MINIMUM FLOW BYPASS LINE CTMT ISO VALVE	RHR	C	203	032	1-RHRASC-C 1-RHRLPCI-C 1-RHRSC-C 1-RHRSPC-C

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-51-105B	MINIMUM FLOW BYPASS LINE CTMT ISO VALVE	RHR	D	204	031	1-RHRLPCI-D 1-RHRSC-D 1-RHRASC-D 1-RHRSPC-D
HV-51-125A	SUPPRESSION POOL COOLING LINE CTMT ISO VALVE	RHR	A	304W	044W	1-RHRASC-A 1-RHRLPCI-A 1-RHRSPC-A 1-RHRSPC-C
HV-51-125B	SUPPRESSION POOL COOLING LINE CTMT ISO VALVE	RHR	B	304E	044E	1-RHRSC-B 1-RHRSPC-B 1-RHRASC-B 1-RHRLPCI-B 1-RHRSPC-D
HV-51-142A	1A LPCI INJECTION HEADER INBD PCIV	HI/LOW	A	400	030	1-HI/LOW
HV-51-142B	1B LPCI INJECTION HEADER INBD PCIV	HI/LOW	B	400	030	1-HI/LOW
HV-51-142C	1C LPCI INJECTION HEADER INBD PCIV	HI/LOW	C	400	030	1-HI/LOW
HV-51-142D	1D LPCI INJECTION HEADER INBD PCIV	HI/LOW	D	400	030	1-HI/LOW
HV-51-151A	1A RHR SHUTDOWN COOLING INJ HDR INLET PCIV	HI/LOW	A	400	030	1-HI/LOW
HV-51-151B	1B RHR SHUTDOWN COOLING INJ HDR INLET PCIV	HI/LOW	B	400	030	1-HI/LOW
HV-51-182A	RHR LOOP A/LOOP C INTERTIE ISO VALVE	RHR	A	309W	043W	1-RHRASC-A 1-RHRSPC-A 1-RHRSC-C 1-RHRSC-A 1-RHRLPCI-C 1-RHRASC-C 1-RHRSPC-C 1-RHRLPCI-A
HV-51-182B	RHR LOOP B/LOOP D INTERTIE ISO VALVE	RHR	B	309E	043E	1-RHRSC-B 1-RHRSPC-D 1-RHRSPC-B 1-RHRSC-D 1-RHRLPCI-D 1-RHRLPCI-B 1-RHRASC-B 1-RHRASC-D

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-51-1F003A	HEAT EXCHANGER SHELL SIDE DISCHARGE VALVE	RHR	A	203	032	1-RHRASC-A 1-RHRASC-C 1-RHRSC-A 1-RHRSC-C 1-RHRSPC-A 1-RHRSPC-C
HV-51-1F003B	HEAT EXCHANGER SHELL SIDE DISCHARGE VALVE	RHR	B	204	031	1-RHRASC-B 1-RHRSPC-D 1-RHRSPC-B 1-RHRASC-D 1-RHRSC-D 1-RHRSC-B
HV-51-1F004A	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER	RHR	A	102	032	1-RHRASC-A 1-RHRLPCI-A 1-RHRSC-A 1-RHRSPC-A
HV-51-1F004B	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER	RHR	B	103	031	1-RHRASC-B 1-RHRSPC-B 1-RHRLPCI-B 1-RHRSC-B
HV-51-1F004C	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER	RHR	C	102	032	1-RHRSPC-C 1-RHRASC-C 1-RHRLPCI-C 1-RHRSC-C
HV-51-1F004D	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER	RHR	D	103	031	1-RHRSPC-D 1-RHRSC-D 1-RHRASC-D 1-RHRLPCI-D
HV-51-1F006A	PUMP SUCTION VALVE FROM SHUTDOWN COOLING HEADER	RHR	A	102	032	1-RHRASC-A 1-RHRLPCI-A 1-RHRSC-A 1-RHRSC-B 1-RHRSC-C 1-RHRSC-D 1-RHRSPC-A
HV-51-1F006B	PUMP SUCTION VALVE FROM SHUTDOWN COOLING HEADER	RHR	B	103	031	1-RHRSC-B 1-RHRASC-B 1-RHRLPCI-B 1-RHRSC-C 1-RHRSC-D 1-RHRSPC-B 1-RHRSC-A
HV-51-1F007A	PUMP DISCHARGE MINIMUM FLOW BYPASS VALVE	RHR	A	102	032	1-RHRASC-A 1-RHRLPCI-A 1-RHRSC-A 1-RHRSPC-A

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-51-1F007B	PUMP DISCHARGE MINIMUM FLOW BYPASS VALVE	RHR	B	103	031	1-RHRASC-B 1-RHRSPC-B 1-RHRLPCI-B 1-RHRSC-B
HV-51-1F007C	PUMP DISCHARGE MINIMUM FLOW BYPASS VALVE	RHR	C	102	032	1-RHRASC-C 1-RHRLPCI-C 1-RHRSC-C 1-RHRSPC-C
HV-51-1F007D	PUMP DISCHARGE MINIMUM FLOW BYPASS VALVE	RHR	D	103	031	1-RHRSC-D 1-RHRSPC-D 1-RHRASC-D 1-RHRLPCI-D
HV-51-1F008	SHUTDOWN COOLING SUCTION LINE OUTBD CTMT ISO VALVE	RHR/ HILOW	B	309E 309W	043E 043W	1-HI/LOW 1-RHRSC-A 1-RHRSC-B 1-RHRSC-C 1-RHRSC-D
HV-51-1F009	SHUTDOWN COOLING SUCTION LINE INBD CTMT ISO VALVE	RHR/ HILOW	A	400	030	1-HI/LOW 1-RHRSC-A 1-RHRSC-B 1-RHRSC-C 1-RHRSC-D
HV-51-1F010A	PUMP DISCHARGE FULL FLOW BYPASS VALVE	RHR	C	304W	044W	1-RHRSPC-A 1-RHRSC-C 1-RHRLPCI-C 1-RHRASC-C 1-RHRSPC-C
HV-51-1F010B	PUMP DISCHARGE FULL FLOW BYPASS VALVE	RHR	D	304E	044E	1-RHRSPC-D 1-RHRASC-D 1-RHRLPCI-D 1-RHRSC-D 1-RHRSPC-B
HV-51-1F011A	HEAT EXCHANGER DISCH LINE TO SUPPRESSION CHAMBER SHUTOFF VALVE	RHR	N/A	203	032	1-RHRSPC-C 1-RHRSPC-A 1-RHRSC-C 1-RHRLPCI-A 1-RHRSC-A
HV-51-1F011B	HEAT EXCHANGER DISCH LINE TO SUPPRESSION CHAMBER SHUTOFF VALVE	RHR	N/A	204	031	1-RHRSC-D 1-RHRSPC-D 1-RHRLPCI-B 1-RHRASC-D 1-RHRASC-B 1-RHRSPC-B

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-51-1F014A	RHR HEAT EXCHANGER TUBE SIDE INLET VALVE	RHRSW	A	203	032	1-RHRSW-A
HV-51-1F014B	RHR HEAT EXCHANGER TUBE SIDE INLET VALVE	RHRSW	B	204	031	1-RHRSW-B
HV-51-1F015A	SHUTDOWN COOLING RETURN LINE OUTBD CTMT ISO VALVE	RHR	B	309W	043W	1-RHRASC-C 1-RHRSPC-C 1-RHRSPC-A 1-RHRSC-C 1-RHRLPCI-A 1-RHRASC-A 1-HI/LOW 1-RHRSC-A
HV-51-1F015B	SHUTDOWN COOLING RETURN LINE OUTBD CTMT ISO VALVE	RHR	B	309E 309W	043E 043W	1-RHRASC-B 1-RHRSC-D 1-RHRSPC-D 1-RHRSPC-B 1-HI/LOW 1-RHRASC-D 1-RHRLPCI-B 1-RHRSC-B
HV-51-1F016A	DRYWELL SPRAY LINE OUTBD CTMT ISO VALVE	RHR	A	501	047E	1-RHRASC-A 1-RHRASC-C 1-RHRLPCI-A 1-RHRSC-A 1-RHRSC-C 1-RHRSPC-A 1-RHRSPC-C
HV-51-1F016B	DRYWELL SPRAY LINE OUTBD CTMT ISO VALVE	RHR	B	523	047W	1-RHRSC-B 1-RHRSPC-D 1-RHRSC-D 1-RHRLPCI-B 1-RHRASC-D 1-RHRASC-B 1-RHRSPC-B
HV-51-1F017A	LPCI INJECTION LINE OUTBD CTMT ISO VALVE	RHR	A	510	047W	1-RHRLPCI-A 1-RHRSPC-C 1-RHRSPC-A 1-RHRSC-A 1-RHRASC-C 1-RHRASC-A 1-HI/LOW 1-RHRSC-C

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-51-1F017B	LPCI INJECTION LINE OUTBD CTMT ISO VALVE	RHR	B	599	047E	1-RHRLPCI-B 1-RHRSPC-B 1-RHRSPC-D 1-RHRSC-B 1-RHRASC-B 1-HI/LOW 1-RHRSC-D 1-RHRASC-D
HV-51-1F017C	LPCI INJECTION LINE OUTBD CTMT ISO VALVE	RHR	C	510	047W	1-RHRSPC-C 1-HI/LOW 1-RHRASC-C 1-RHRLPCI-C 1-RHRSC-C
HV-51-1F017D	LPCI INJECTION LINE OUTBD CTMT ISO VALVE	RHR	D	599	047E	1-RHRSPC-D 1-RHRSC-D 1-RHRLPCI-D 1-HI/LOW 1-RHRASC-D
HV-51-1F021A	DRYWELL SPRAY LINE INBD CTMT ISO VALVE	RHR	A	400	030	1-RHRASC-A 1-RHRASC-C 1-RHRLPCI-A 1-RHRSC-A 1-RHRSC-C 1-RHRSPC-A 1RHRSPC-C
HV-51-1F021B	DRYWELL SPRAY LINE INBD CTMT ISO VALVE	RHR	B	400	030	1-RHRASC-B 1-RHRASC-D 1-RHRLPCI-B 1-RHRSC-B 1-RHRSC-D 1-RHRSPC-B 1-RHRSPC-D
HV-51-1F024A	SUPPRESSION POOL COOLING LINE SHUTOFF VALVE	RHR	A	304W	044W	1-RHRSC-C 1-RHRASC-A 1-RHRSPC-A 1-RHRSPC-C 1-RHRSC-A 1-RHRASC-C 1-RHRLPCI-A
HV-51-1F024B	SUPPRESSION POOL COOLING LINE SHUTOFF VALVE	RHR	B	304E	044E	1-RHRASC-B 1-RHRASC-D 1-RHRLPCI-B 1-RHRSC-B 1-RHRSC-D 1-RHRSPC-B 1-RHRSPC-D

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-51-1F026A	HEAT EXCHANGER DISCHARGE LINE TO RCIC SHUTOFF VALVE	RHR	N/A	102	032	1-RHRSC-C 1-RHRSPC-A 1-RHRSC-A 1-RHRLPCI-A 1-RHRSPC-C
HV-51-1F026B	HEAT EXCHANGER DISCHARGE LINE TO RCIC SHUTOFF VALVE	RHR	N/A	103	031	1-RHRSPC-B 1-RHRSPC-D 1-RHRSC-D 1-RHRLPCI-B 1-RHRASC-D 1-RHRASC-B
HV-51-1F027A	SUPPRESSION POOL SPRAY LINE CTMT ISO VALVE	RHR	A	304W	044W	1-RHRASC-C 1-RHRLPCI-A 1-RHRSC-A 1-RHRSC-C 1-RHRASC-A
HV-51-1F027B	SUPPRESSION POOL SPRAY LINE CTMT ISO VALVE	RHR	B	304E	044E	1-RHRLPCI-B 1-RHRSC-B 1-RHRASC-D 1-RHRASC-B 1-RHRSC-D
HV-51-1F040	HEAT EXCHANGER DISCHARGE LINE TO RADWASTE SHUTOFF VALVE	RHR	A	203	032	1-RHRSPC-A 1-RHRSPC-C 1-RHRSC-C 1-RHRSC-A 1-RHRLPCI-A 1-RHRASC-C 1-RHRASC-A
HV-51-1F047A	HEAT EXCHANGER INLET VALVE FROM PUMP DISCHARGE	RHR	A	309W	043W	1-RHRSPC-C 1-RHRASC-C 1-RHRSC-A 1-RHRSC-C 1-RHRSPC-A 1-RHRASC-A
HV-51-1F047B	HEAT EXCHANGER INLET VALVE FROM PUMP DISCHARGE	RHR	B	309E	043E	1-RHRSPC-D 1-RHRSPC-B 1-RHRSC-D 1-RHRASC-B 1-RHRSC-B 1-RHRASC-D
HV-51-1F049	HEAT EXCHANGER DISCHARGE LINE TO RADWASTE SHUTOFF VALVE	RHR	B	203	032	1-RHRSC-C 1-RHRSPC-A 1-RHRSC-A 1-RHRLPCI-A 1-RHRASC-C 1-RHRASC-A 1-RHRSPC-C

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-51-1F068A	RHR HEAT EXCHANGER TUBE SIDE OUTLET VALVE	RHRSW	C	203	032	1-RHRSW-A
HV-51-1F068B	RHR HEAT EXCHANGER TUBE SIDE OUTLET VALVE	RHRSW	D	204	031	1-RHRSW-B
HV-51-1F073	RHRSW TO RHR INTERTIE LINE SHUTOFF VALVE	RHR	B	204	031	1-RHRSW-B
HV-51-1F068A	RHR HEAT EXCHANGER	RHRSW	C	203	032	1-RHRSW-A
HV-51-1F074	RHR SW CROSSTIE DRAIN VALVE	RHR	B	103	031	1-RHRSW-B
HV-51-1F075	RHRSW TO RHR INTERTIE SHUTOFF VALVE	RHR	B	204	031	1-RHRSW-B

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-51-205A	MINIMUM FLOW BYPASS LINE CTMT ISO VALVE	RHR	C	280	054	2-RHRSPC-C
HV-51-205A	MINIMUM FLOW BYPASS	RHR	C	280	054	2-RHRSC-C 2-RHRASC-C 2-RHRLPCI-C
HV-51-205B	MINIMUM FLOW BYPASS LINE CTMT ISO VALVE	RHR	D	281	055	2-RHRASC-D 2-RHRLPCI-D 2-RHRSC-D 2-RHRSPC-D
HV-51-225A	SUPPRESSION POOL COOLING LINE CTMT ISO VALVE	RHR	A	370W	067W	2-RHRASC-A 2-RHRLPCI-A 2-RHRSPC-A
HV-51-225A	SUPPRESSION POOL	RHR	A	370W	067W	2-RHRSPC-C
HV-51-225B	SUPPRESSION POOL COOLING LINE CTMT ISO VALVE	RHR	B	370E	067E	2-RHRASC-B 2-RHRSPC-D 2-RHRSPC-B 2-RHRLPCI-B 2-RHRSC-B
HV-51-242A	2A LPCI INJECTION HEADER INBD PCIV	HI/LOW	A	473	053	2-HI/LOW
HV-51-242B	2B LPCI INJECTION HEADER INBD PCIV	HI/LOW	B	473	053	2-HI/LOW
HV-51-242C	2C LPCI INJECTION HEADER INBD PCIV	HI/LOW	C	473	053	2-HI/LOW
HV-51-242D	2D LPCI INJECTION HEADER INBD PCIV	HI/LOW	D	473	053	2-HI/LOW
HV-51-251A	2A RHR SHUTDOWN COOLING INJ HDR INLET PCIV	HI/LOW	A	473	053	2-HI/LOW
HV-51-251B	2B RHR SHUTDOWN COOLING INJ HDR INLET PCIV	HI/LOW	B	473	053	2-HI/LOW
HV-51-282A	RHR LOOP A/LOOP C INTERTIE ISO VALVE	RHR	A	376W	066W	2-RHRASC-C 2-RHRSPC-A 2-RHRSC-C 2-RHRSC-A 2-RHRLPCI-A 2-RHRSPC-C 2-RHRASC-A 2-RHRLPCI-C

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-51-282B	RHR LOOP B/LOOP D INTERTIE ISO VALVE	RHR	B	376E	066E	2-RHRSC-B 2-RHRSPC-D 2-RHRSPC-B 2-RHRSC-D 2-RHRLPCI-D 2-RHRLPCI-B 2-RHRASC-B 2-RHRASC-D
HV-51-2F003A	HEAT EXCHANGER SHELL SIDE DISCHARGE VALVE	RHR	A	280	054	2-RHRASC-A 2-RHRASC-C 2-RHRSC-A 2-RHRSC-C 2-RHRSPC-A 2-RHRSPC-C
HV-51-2F003B	HEAT EXCHANGER SHELL SIDE DISCHARGE VALVE	RHR	B	281	055	2-RHRASC-B 2-RHRSPC-D 2-RHRSPC-B 2-RHRASC-D 2-RHRSC-B 2-RHRSC-D
HV-51-2F004A	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER	RHR	A	173	054	2-RHRASC-A 2-RHRLPCI-A 2-RHRSC-A 2-RHRSPC-A
HV-51-2F004B	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER	RHR	B	174	055	2-RHRASC-B 2-RHRLPCI-B 2-RHRSC-B 2-RHRSPC-B
HV-51-2F004C	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER	RHR	C	173	054	2-RHRSC-C 2-RHRSPC-C 2-RHRASC-C 2-RHRLPCI-C
HV-51-2F004D	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER	RHR	D	174	055	2-RHRLPCI-D 2-RHRSC-D 2-RHRSPC-D 2-RHRASC-D
HV-51-2F006A	PUMP SUCTION VALVE FROM SHUTDOWN COOLING HEADER	RHR	A	173	054	2-RHRLPCI-A 2-RHRSPC-A 2-RHRSC-D 2-RHRSC-C 2-RHRSC-A 2-RHRASC-A 2-RHRSC-B

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-51-2F006B	PUMP SUCTION VALVE FROM SHUTDOWN COOLING HEADER	RHR	B	174	055	2-RHRSC-A 2-RHRSC-D 2-RHRSPC-B 2-RHRASC-B 2-RHRSC-C 2-RHRLPCI-B 2-RHRSC-B
HV-51-2F007A	PUMP DISCHARGE MINIMUM FLOW BYPASS VALVE	RHR	A	173	054	2-RHRASC-A 2-RHRLPCI-A 2-RHRSC-A 2-RHRSPC-A
HV-51-2F007B	PUMP DISCHARGE MINIMUM FLOW BYPASS VALVE	RHR	B	174	055	2-RHRASC-B 2-RHRSPC-B 2-RHRLPCI-B 2-RHRSC-B
HV-51-2F007C	PUMP DISCHARGE MINIMUM FLOW BYPASS VALVE	RHR	C	173	054	2-RHRASC-C 2-RHRLPCI-C 2-RHRSC-C 2-RHRSPC-C
HV-51-2F007D	PUMP DISCHARGE MINIMUM FLOW BYPASS VALVE	RHR	D	174	055	2-RHRSC-D 2-RHRSPC-D 2-RHRASC-D 2-RHRLPCI-D
HV-51-2F008	SHUTDOWN COOLING SUCTION LINE OUTBD CTMT ISO VALVE	RHR/ HILOW	B	376E 376W	066E 066W	2-HI/LOW 2-RHRSC-A 2-RHRSC-B 2-RHRSC-C 2-RHRSC-D
HV-51-2F009	SHUTDOWN COOLING SUCTION LINE INBD CTMT ISO VALVE	RHR/ HILOW	A	473	053	2-HI/LOW 2-RHRSC-A 2-RHRSC-B 2-RHRSC-C 2-RHRSC-D
HV-51-2F010A	PUMP DISCHARGE FULL FLOW BYPASS VALVE	RHR	C	370W	067W	2-RHRSPC-C 2-RHRLPCI-C 2-RHRASC-C 2-RHRSPC-A 2-RHRSC-C
HV-51-2F010B	PUMP DISCHARGE FULL FLOW BYPASS VALVE	RHR	D	370E	067E	2-RHRSPC-D 2-RHRASC-D 2-RHRLPCI-D 2-RHRSC-D 2-RHRSPC-B
HV-51-2F011A	HEAT EXCHANGER DISCH LINE TO SUPPRESSION CHAMBER SHUTOFF VALVE	RHR	N/A	280	054	2-RHRSPC-C 2-RHRSPC-A 2-RHRSC-C 2-RHRLPCI-A 2-RHRSC-A

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-51-2F011B	HEAT EXCHANGER DISCH LINE TO SUPPRESSION CHAMBER SHUTOFF VALVE	RHR	N/A	281	055	2-RHRLPCI-B 2-RHRSPC-D 2-RHRSC-D 2-RHRASC-B 2-RHRASC-D 2-RHRSPC-B
HV-51-2F014A	RHR HEAT EXCHANGER TUBE SIDE INLET VALVE	RHRSW	A	280	054	2-RHRSW-A
HV-51-2F014B	RHR HEAT EXCHANGER TUBE SIDE INLET VALVE	RHRSW	B	281	055	2-RHRSW-B
HV-51-2F015A	SHUTDOWN COOLING RETURN LINE OUTBD CTMT ISO VALVE	RHR	B	376W	066W	2-RHRASC-C 2-RHRSPC-C 2-RHRSPC-A 2-RHRSC-C 2-RHRLPCI-A 2-RHRASC-A 2-HI/LOW 2-RHRSC-A
HV-51-2F015B	SHUTDOWN COOLING RETURN LINE OUTBD CTMT ISO VALVE	RHR	B	376E	066E	2-HI/LOW 2-RHRSPC-D 2-RHRSPC-B 2-RHRSC-D 2-RHRLPCI-B 2-RHRASC-B 2-RHRASC-D 2-RHRSC-B
HV-51-2F016A	DRYWELL SPRAY LINE OUTBD CTMT ISO VALVE	RHR	A	575	070W	2-RHRASC-A 2-RHRASC-C 2-RHRLPCI-A 2-RHRSC-A 2-RHRSC-C 2-RHRSPC-A 2-RHRSPC-C
HV-51-2F016B	DRYWELL SPRAY LINE OUTBD CTMT ISO VALVE	RHR	B	593	070E	2-RHRSC-B 2-RHRSPC-D 2-RHRSC-D 2-RHRLPCI-B 2-RHRASC-D 2-RHRASC-B 2-RHRSPC-B

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-51-2F017A	LPCI INJECTION LINE OUTBD CTMT ISO VALVE	RHR	A	589	070W	2-RHRLPCI-A 2-RHRSPC-C 2-RHRSPC-A 2-RHRSC-A 2-RHRASC-C 2-RHRASC-A 2-HI/LOW 2-RHRSC-C
HV-51-2F017B	LPCI INJECTION LINE OUTBD CTMT ISO VALVE	RHR	B	584	070E	2-RHRLPCI-B 2-RHRSPC-B 2-RHRSPC-D 2-RHRSC-B 2-RHRASC-B 2-HI/LOW 2-RHRSC-D 2-RHRASC-D
HV-51-2F017C	LPCI INJECTION LINE OUTBD CTMT ISO VALVE	RHR	C	589	070W	2-RHRSPC-C 2-HI/LOW 2-RHRASC-C 2-RHRLPCI-C 2-RHRSC-C
HV-51-2F017D	LPCI INJECTION LINE OUTBD CTMT ISO VALVE	RHR	D	584	070E	2-RHRSPC-D 2-RHRSC-D 2-RHRLPCI-D 2-HI/LOW 2-RHRASC-D
HV-51-2F021A	DRYWELL SPRAY LINE INBD CTMT ISO VALVE	RHR	A	473	053	2-RHRASC-A 2-RHRASC-C 2-RHRLPCI-A 2-RHRSC-A 2-RHRSC-C 2-RHRSPC-A 2-RHRSPC-C
HV-51-2F021B	DRYWELL SPRAY LINE INBD CTMT ISO VALVE	RHR	B	473	053	2-RHRASC-B 2-RHRASC-D 2-RHRLPCI-B 2-RHRSC-B 2-RHRSC-D 2-RHRSPC-B 2-RHRSPC-D
HV-51-2F024A	SUPPRESSION POOL COOLING LINE SHUTOFF VALVE	RHR	A	370W	067W	2-RHRSC-C 2-RHRASC-A 2-RHRSPC-A 2-RHRSPC-C 2-RHRSC-A 2-RHRASC-C 2-RHRLPCI-A

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-51-2F024B	SUPPRESSION POOL COOLING LINE SHUTOFF VALVE	RHR	B	370E	067E	2-RHRASC-B 2-RHRASC-D 2-RHRLPCI-B 2-RHRSC-B 2-RHRSC-D 2-RHRSPC-B 2-RHRSPC-D
HV-51-2F026A	HEAT EXCHANGER DISCHARGE LINE TO RCIC SHUTOFF VALVE	RHR	N/A	173	054	2-RHRSC-C 2-RHRSPC-A 2-RHRLPCI-A 2-RHRSPC-C 2-RHRSC-A
HV-51-2F026B	HEAT EXCHANGER DISCHARGE LINE TO RCIC SHUTOFF VALVE	RHR	N/A	174	055	2-RHRSPC-B 2-RHRSPC-D 2-RHRSC-D 2-RHRLPCI-B 2-RHRASC-D 2-RHRASC-B
HV-51-2F027A	SUPPRESSION POOL SPRAY LINE CTMT ISO VALVE	RHR	A	370W	067W	2-RHRSC-C 2-RHRASC-C 2-RHRLPCI-A 2-RHRSC-A 2-RHRASC-A
HV-51-2F027B	SUPPRESSION POOL SPRAY LINE CTMT ISO VALVE	RHR	B	370E	067E	2-RHRSC-B 2-RHRSC-D 2-RHRLPCI-B 2-RHRASC-B 2-RHRASC-D
HV-51-2F040	HEAT EXCHANGER DISCHARGE LINE TO RADWASTE SHUTOFF VALVE	RHR	A	280	054	2-RHRASC-A 2-RHRASC-C 2-RHRLPCI-A 2-RHRSC-A 2-RHRSC-C 2-RHRSPC-A 2-RHRSPC-C
HV-51-2F047A	HEAT EXCHANGER INLET VALVE FROM PUMP DISCHARGE	RHR	A	376W	066W	2-RHRSC-C 2-RHRSPC-A 2-RHRSPC-C 2-RHRSC-A 2-RHRASC-C 2-RHRASC-A
HV-51-2F047B	HEAT EXCHANGER INLET VALVE FROM PUMP DISCHARGE	RHR	B	376E	066E	2-RHRSPC-B 2-RHRSPC-D 2-RHRSC-D 2-RHRSC-B 2-RHRASC-D 2-RHRASC-B

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-51-2F049	HEAT EXCHANGER DISCHARGE LINE TO RADWASTE SHUTOFF VALVE	RHR	B	280	054	2-RHRASC-C 2-RHRLPCI-A 2-RHRSC-A 2-RHRSC-C 2-RHRSPC-A 2-RHRSPC-C 2-RHRASC-A
HV-51-2F068A	RHR HEAT EXCHANGER TUBE SIDE OUTLET VALVE	RHRSW	C	280	054	2-RHRSW-A
HV-51-2F068B	RHR HEAT EXCHANGER TUBE SIDE OUTLET VALVE	RHRSW	D	281	055	2-RHRSW-B
HV-51-2F073	RHRSW TO RHR INTERTIE LINE SHUTOFF VALVE	RHR	A	280	054	2-RHRSW-A
HV-51-2F074	RHR SW CROSS TIE DRAIN VALVE	RHR	A	173	054	2-RHRSW-A
HV-51-2F075	RHRSW TO RHR INTERTIE SHUTOFF VALVE	RHR	A	280	054	2-RHRSW-A
HV-52-139	CTMT ISO VALVE FOR LEVEL SENSING LINES	SPI	B	118	039	
HV-52-1F005	CORE SPRAY INBD ISO VALVE "A" LOOP	CS/ HILOW	A	523	047W	1-HI/LOW
HV-52-1F037	CORE SPRAY INBD ISO VALVE "B" LOOP	CS/ HPCI	B	523	047W	1-HPCI
HV-52-1F039A	1A LOOP CHECK EQUALIZING PCIV	HI/LOW	A	400	030	1-HI/LOW
HV-52-239	CTMT ISO VALVE FOR LEVEL SENSING LINES	SPI	B	189	062	
HV-52-2F005	CORE SPRAY INBD ISO VALVE "A" LOOP	CS/ HILOW	A	593	070E	2-HI/LOW
HV-52-2F037	CORE SPRAY INBD ISO VALVE "B" LOOP	CS/ HPCI	B	593	070E	2-HPCI
HV-52-2F039A	2A LOOP CHECK EQUALIZING PCIV	HI/LOW	A	473	053	2-HI/LOW
HV-55-120	CTMT ISO VALVE FOR LEVEL SENSING LINES	SPI	B	204	031	
HV-55-121	CTMT ISO VALVE FOR LEVEL SENSING LINES	SPI	B	204	031	
HV-55-124	CST TO SAFEGUARD SYSTEM ISOLATING VALVE (OUTLET)	HPCI RCIC	A	CST DIKED AREA	YARD	1-HPCI 1-RCIC
HV-55-125	CST TO SAFEGUARD SYSTEM ISOLATING VALVE (OUTLET)	HPCI RCIC	B	CST DIKED	YARD	1-HPCI 1-RCIC

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-55-126	CTMT ISO VALVE FOR LEVEL SENSING LINES	SPI	A	204	031	
HV-55-1F001	STEAM SUPPLY LINE INLET VALVE TO TURBINE	HPCI	B	109	034	1-HPCITRIP 1-HPCI
HV-55-1F002	STEAM SUPPLY LINE INBD CTMT ISO VALVE	HPCI	D	400	030	1-HPCITRIP 1-HPCI
HV-55-1F003	STEAM SUPPLY LINE OUTBD CTMT ISO VALVE	HPCI	B	309W	043W	1-HPCI 1-HPCITRIP
HV-55-1F004	PUMP SUCTION VALVE FROM CONDENSATE STORAGE TANK	HPCI	B	109	034	1-HPCI
HV-55-1F006	INJECTION VALVE TO CORE SPRAY LINE	HPCI	B	500	047E	1-HPCI
HV-55-1F007	PUMP DISCHARGE VALVE	HPCI	B	200	042	1-HPCI
HV-55-1F008	FULL FLOW TEST THROTTLE VALVE	HPCI	B	200	042	1-HPCI
HV-55-1F012	MINIMUM FLOW BYPASS LINE CTMT ISO VALVE	HPCI	B	288	034	1-HPCI
HV-55-1F041	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER	HPCI	B	109	034	1-HPCI
HV-55-1F042	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER CTMT ISO VALVE	HPCI	B	109	034	1-HPCI
HV-55-1F072	TURBINE EXHAUST LINE CTMT ISO VALVE	HPCI	B	288	034	1-HPCI
HV-55-1F093	TURBINE EXHAUST LINE VACUUM BREAKER VALVE	HPCI	B	200	042	1-HPCI
HV-55-1F095	TURBINE EXHAUST LINE VACUUM BREAKER VALVE	HPCI	D	288	034	1-HPCI
HV-55-1F105	HPCI PUMP DISCHARGE VALVE TO FEEDWATER	HPCI	B	518	046	1-HPCI
HV-55-220	CTMT ISO VALVE FOR LEVEL SENSING LINES	SPI	B	280	054	
HV-55-221	CTMT ISO VALVE FOR LEVEL SENSING LINES	SPI	B	280	054	
HV-55-224	CST TO SAFEGUARD SYSTEM ISOLATING VALVE (OUTLET)	HPCI RCIC	A	CST DIKED AREA	YARD	2-HPCI 2-RCIC
HV-55-225	CST TO SAFEGUARD SYSTEM ISOLATING VALVE (OUTLET)	HPCI RCIC	B	CST DIKED AREA	YARD	2-HPCI 2-RCIC

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-55-2F001	STEAM SUPPLY LINE INLET VALVE TO TURBINE	HPCI	B	180	057	2-HPCI 2-RCICTRIP
HV-55-2F002	STEAM SUPPLY LINE INBD CTMT ISO VALVE	HPCI	D	473	053	2-HPCI 2-HPCITRIP
HV-55-2F003	STEAM SUPPLY LINE OUTBD CTMT ISO VALVE	HPCI	B	376W	066W	2-HPCI 2-HPCITRIP
HV-55-2F004	PUMP SUCTION VALVE FROM CONDENSATE STORAGE TANK	HPCI	B	180	057	2-HPCI
HV-55-2F006	INJECTION VALVE TO CORE SPRAY LINE	HPCI	B	580E	070E	2-HPCI
HV-55-2F007	PUMP DISCHARGE VALVE	HPCI	B	279	065	2-HPCI
HV-55-2F008	FULL FLOW TEST THROTTLE VALVE	HPCI	B	279	065	2-HPCI
HV-55-2F012	MINIMUM FLOW BYPASS LINE CTMT ISO VALVE	HPCI	B	283	057	2-HPCI
HV-55-2F041	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER	HPCI	B	180	057	2-HPCI
HV-55-2F042	PUMP SUCTION VALVE FROM SUPPRESSION CHAMBER CTMT ISO VALVE	HPCI	B	180	057	2-HPCI
HV-55-2F072	TURBINE EXHAUST LINE CTMT ISO VALVE	HPCI	B	283	057	2-HPCI
HV-55-2F093	TURBINE EXHAUST LINE VACUUM BREAKER VALVE	HPCI	B	279	065	2-HPCI
HV-55-2F095	TURBINE EXHAUST LINE VACUUM BREAKER VALVE	HPCI	D	283	057	2-HPCI
HV-55-2F105	HPCI PUMP DISCHARGE VALVE TO FEEDWATER	HPCI	B	587	069	2-HPCI
HV-56-1F059	COOLING WATER LINE SHUTOFF VALVE	HPCI	B	109	034	1-HPCI
HV-56-2F059	COOLING WATER LINE SHUTOFF VALVE	HPCI	B	180	057	2-HPCI
HV-59-129B	INST GAS OUTBD PCIV	PCIG	B	306	043W	1-MSRV
HV-59-151A	CTMT ISO VALVE	PCIG	C	306	043W	1-RHRASC-C 1-RHRASC-D 1-RHRASC-B 1-RHRASC-A
HV-59-151B	CTMT ISO VALVE	PCIG	D	307	043E	1-RHRASC-B 1-RHRASC-C 1-RHRASC-D 1-RHRASC-A

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
HV-59-229B	INST GAS OUTBD PCIV	PCIG	B	375	066W	2-MSRV
HV-59-251A	CTMT ISO VALVE	PCIG	C	375	066W	2-RHRASC-D 2-RHRASC-C 2-RHRASC-A 2-RHRASC-B
HV-59-251B	CTMT ISO VALVE	PCIG	D	374	066E	2-RHRASC-A 2-RHRASC-B 2-RHRASC-C 2-RHRASC-D
HV-C41-1F020	MAIN STEAM LINE PRESSURE EQUALIZING VALVE	HI/LOW	A	407	046	1-HI/LOW
HV-C41-2F020	MAIN STEAM LINE PRESSURE EQUALIZING VALVE	HI/LOW	A	480	069	2-HI/LOW
HV-C44-1F033	RWCU DUMP FLOW CONTROL VALVE	HI/LOW	0	510	047W	1-HI/LOW
HV-C44-2F033	RWCU DUMP FLOW CONTROL VALVE	HI/LOW	0	584	070E	2-HI/LOW
HV-C51-1F048A	HEAT EXCHANGER BYPASS VALVE FROM PUMP DISCHARGE	RHR	A	309W	043W	1-RHRASC-A 1-RHRSPC-C 1-RHRSPC-A 1-RHRSC-C 1-RHRASC-C 1-RHRLPCI-A 1-RHRSC-A
HV-C51-1F048B	HEAT EXCHANGER BYPASS VALVE FROM PUMP DISCHARGE	RHR	B	309E	043E	1-RHRASC-B 1-RHRASC-D 1-RHRLPCI-B 1-RHRSC-B 1-RHRSC-D 1-RHRSPC-B 1-RHRSPC-D
HV-C51-2F048A	HEAT EXCHANGER BYPASS VALVE FROM PUMP DISCHARGE	RHR	A	376W	066W	2-RHRSC-C 2-RHRSPC-A 2-RHRSC-A 2-RHRSPC-C 2-RHRASC-C 2-RHRASC-A 2-RHRLPCI-A
HV-C51-2F048B	HEAT EXCHANGER BYPASS VALVE FROM PUMP DISCHARGE	RHR	B	376E	066E	2-RHRSC-D 2-RHRSPC-B 2-RHRSC-B 2-RHRLPCI-B 2-RHRASC-D 2-RHRASC-B 2-RHRSPC-D

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
KS-81-101A	CELL "A" TIMER	DGEV	A	311A	079	
KS-81-101B	CELL "B" TIMER	DGEV	B	311B	081	
KS-81-101C	CELL "C" TIMER	DGEV	C	311C	080	
KS-81-101D	CELL "D" TIMER	DGEV	D	311D	082	
KS-81-101E	CELL "A" TIMER	DGEV	A	311A	079	
KS-81-101F	CELL "B" TIMER	DGEV	B	311B	081	
KS-81-101G	CELL "C" TIMER	DGEV	C	311C	080	
KS-81-101H	CELL "D" TIMER	DGEV	D	311D	082	
KS-81-201A	CELL "A" TIMER	DGEV	A	315A	083	
KS-81-201B	CELL "B" TIMER	DGEV	B	315B	085	
KS-81-201C	CELL "C" TIMER	DGEV	C	315C	084	
KS-81-201D	CELL "D" TIMER	DGEV	D	315D	086	
KS-81-201E	CELL "A" TIMER	DGEV	A	315A	083	
KS-81-201F	CELL "B" TIMER	DGEV	B	315B	085	
KS-81-201G	CELL "C" TIMER	DGEV	C	315C	084	
KS-81-201H	CELL "D" TIMER	DGEV	D	315D	086	
LI-42-1R010	REACTOR VESSEL WATER LEVEL INDICATOR	RVI	A	540	026	1-RVI
LI-42-2R010	REACTOR VESSEL WATER LEVEL INDICATOR	RVI	A	540	026	2-RVI
LI-52-140A	SUPPRESSION POOL LEVEL INDICATOR	SPI	A	533	024	1-SPI
LI-52-140B	SUPPRESSION POOL LEVEL INDICATOR	SPI	B	533	024	1-SPI
LI-52-240A	SUPPRESSION POOL LEVEL INDICATOR	SPI	A	533	024	2-SPI
LI-52-240B	SUPPRESSION POOL LEVEL INDICATOR	SPI	B	533	024	2-SPI
LI-52-241	SUPPRESSION POOL LEVEL INDICATOR	SPI	A	540	026	2-SPI
LI-55-115-1	SUPPRESSION POOL LEVEL INDICATOR	SPI	0(A)	533	024	1-SPI
LI-55-115-2	SUPPRESSION POOL LEVEL INDICATOR	SPI	0(A)	540	026	1-SPI
LI-55-141	SUPPRESSION POOL LEVEL INDICATOR	SPI	A	540	026	1-SPI
LI-55-215-2	SUPPRESSION POOL LEVEL INDICATOR	SPI	0(A)	540	026	2-SPI
LI-55-217	SUPPRESSION POOL LEVEL INDICATOR	SPI	B	533	024	2-SPI

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
LIS-42-1N691A	LEVEL INDICATING SWITCH	CS	A	542	025	
LIS-42-1N691B	LEVEL INDICATING SWITCH	CS	B	542	025	
LIS-42-1N691C	LEVEL INDICATING SWITCH	CS	C	542	025	
LIS-42-1N691D	LEVEL INDICATING SWITCH	CS	D	542	025	
LIS-42-1N691E	LEVEL INDICATING SWITCH	CS	A	542	025	
LIS-42-1N691F	LEVEL INDICATING SWITCH	CS	B	542	025	
LIS-42-1N691G	LEVEL INDICATING SWITCH	CS	C	542	025	
LIS-42-1N691H	LEVEL INDICATING SWITCH	CS	D	542	025	
LIS-42-1N695A	LEVEL INDICATING SWITCH	ADS	A	542	025	
LIS-42-1N695C	LEVEL INDICATING SWITCH	ADS	C	542	025	
LIS-42-1N697A	LEVEL INDICATING SWITCH	RCIC	A	542	025	
LIS-42-1N697E	LEVEL INDICATING SWITCH	RCIC	A	542	025	
LIS-42-2N691A	LEVEL INDICATING SWITCH	CS	A	542	025	
LIS-42-2N691B	LEVEL INDICATING SWITCH	CS	B	542	025	
LIS-42-2N691C	LEVEL INDICATING SWITCH	CS	C	542	025	
LIS-42-2N691D	LEVEL INDICATING SWITCH	CS	D	542	025	
LIS-42-2N691E	LEVEL INDICATING SWITCH	CS	A	542	025	
LIS-42-2N691F	LEVEL INDICATING SWITCH	CS	B	542	025	
LIS-42-2N691G	LEVEL INDICATING SWITCH	CS	C	542	025	
LIS-42-2N691H	LEVEL INDICATING SWITCH	CS	D	542	025	
LIS-42-2N695A	LEVEL INDICATING SWITCH	ADS	A	542	025	
LIS-42-2N695C	LEVEL INDICATING SWITCH	ADS	C	542	025	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
LIS-42-2N697A	LEVEL INDICATING SWITCH	RCIC	A	542	025	
LIS-42-2N697E	LEVEL INDICATING SWITCH	RCIC	A	542	025	
LIS-49-1N635A	LEVEL INDICATING SWITCH	RCIC	A	542	025	
LIS-49-1N635E	LEVEL INDICATING SWITCH	RCIC	A	542	025	
LIS-49-2N635A	LEVEL INDICATING SWITCH	RCIC	A	542	025	
LIS-49-2N635E	LEVEL INDICATING SWITCH	RCIC	A	542	025	
LIS-55-1N661B	LEVEL INDICATING SWITCH	HPCI	B	542	025	
LIS-55-1N661F	LEVEL INDICATING SWITCH	HPCI	B	542	025	
LIS-55-1N662B	LEVEL INDICATING SWITCH	HPCI	B	542	025	
LIS-55-1N662F	LEVEL INDICATING SWITCH	HPCI	B	542	025	
LIS-55-2N661B	LEVEL INDICATING SWITCH	HPCI	B	542	025	
LIS-55-2N661F	LEVEL INDICATING SWITCH	HPCI	B	542	025	
LIS-55-2N662B	LEVEL INDICATING SWITCH	HPCI	B	542	025	
LIS-55-2N662F	LEVEL INDICATING SWITCH	HPCI	B	542	025	
LS-42-1N692A	LEVEL SWITCH	RCIC	A	542	025	
LS-42-1N692B	LEVEL SWITCH	HPCI	B	542	025	
LS-42-1N692D	LEVEL SWITCH	HPCI	D	542	025	
LS-42-1N692E	LEVEL SWITCH	RCIC	A	542	025	
LS-42-1N692F	LEVEL SWITCH	HPCI	B	542	025	
LS-42-1N692H	LEVEL SWITCH	HPCI	D	542	025	
LS-42-1N693A	LEVEL SWITCH	RCIC	A	542	025	
LS-42-1N693B	LEVEL SWITCH	HPCI	B	542	025	
LS-42-1N693D	LEVEL SWITCH	HPCI	D	542	025	
LS-42-1N693E	LEVEL SWITCH	RCIC	A	542	025	
LS-42-1N693F	LEVEL SWITCH	HPCI	B	542	025	
LS-42-1N693H	LEVEL SWITCH	HPCI	D	542	025	
LS-42-1N698A	LEVEL SWITCH	RCIC	A	542	025	
LS-42-1N698E	LEVEL SWITCH	RCIC	A	542	025	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
LS-42-2N692A	LEVEL SWITCH	RCIC	A	542	025	
LS-42-2N692B	LEVEL SWITCH	HPCI	B	542	025	
LS-42-2N692D	LEVEL SWITCH	HPCI	D	542	025	
LS-42-2N692E	LEVEL SWITCH	RCIC	A	542	025	
LS-42-2N692F	LEVEL SWITCH	HPCI	B	542	025	
LS-42-2N692H	LEVEL SWITCH	HPCI	D	542	025	
LS-42-2N693A	LEVEL SWITCH	RCIC	A	542	025	
LS-42-2N693B	LEVEL SWITCH	HPCI	B	542	025	
LS-42-2N693D	LEVEL SWITCH	HPCI	D	542	025	
LS-42-2N693E	LEVEL SWITCH	RCIC	A	542	025	
LS-42-2N693F	LEVEL SWITCH	HPCI	B	542	025	
LS-42-2N693H	LEVEL SWITCH	HPCI	D	542	025	
LS-42-2N698A	LEVEL SWITCH	RCIC	A	542	025	
LS-42-2N698E	LEVEL SWITCH	RCIC	A	542	025	
LSHL-20-121A	LEVEL SWITCH	SDG	A	312A	079	
LSHL-20-121B	LEVEL SWITCH	SDG	B	312B	081	
LSHL-20-121C	LEVEL SWITCH	SDG	C	312C	080	
LSHL-20-121D	LEVEL SWITCH	SDG	D	312D	082	
LSHL-20-122A	LEVEL SWITCH	SDG	A	312A	079	
LSHL-20-122B	LEVEL SWITCH	SDG	B	312B	081	
LSHL-20-122C	LEVEL SWITCH	SDG	C	312C	080	
LSHL-20-122D	LEVEL SWITCH	SDG	D	312D	082	
LSHL-20-221A	LEVEL SWITCH	SDG	A	316A	083	
LSHL-20-221B	LEVEL SWITCH	SDG	B	316B	085	
LSHL-20-221C	LEVEL SWITCH	SDG	C	316C	084	
LSHL-20-221D	LEVEL SWITCH	SDG	D	316D	086	
LSHL-20-222A	LEVEL SWITCH	SDG	A	316A	083	
LSHL-20-222B	LEVEL SWITCH	SDG	B	316B	085	
LSHL-20-222C	LEVEL SWITCH	SDG	C	316C	084	
LSHL-20-222D	LEVEL SWITCH	SDG	D	316D	086	
LSL-20-127A	LEVEL SWITCH	SDG	A	311A	079	
LSL-20-127B	LEVEL SWITCH	SDG	B	311B	081	
LSL-20-127C	LEVEL SWITCH	SDG	C	311C	080	
LSL-20-127D	LEVEL SWITCH	SDG	D	311D	082	
LSL-20-227A	LEVEL SWITCH	SDG	A	315A	083	
LSL-20-227B	LEVEL SWITCH	SDG	B	315B	085	
LSL-20-227C	LEVEL SWITCH	SDG	C	315C	084	
LSL-20-227D	LEVEL SWITCH	SDG	D	315D	086	
LT-42-115A	LEVEL TRANSMITTER	RVI	A	402W	045W	
LT-42-115B	LEVEL TRANSMITTER	RVI	B	402E	045E	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
LT-42-1N010	LEVEL TRANSMITTER	RVI	A	402W	045W	
LT-42-1N091A	LEVEL TRANSMITTER	CS	A	402W	045W	
LT-42-1N091B	LEVEL TRANSMITTER	HPCI	B	402E	045E	
LT-42-1N091C	LEVEL TRANSMITTER 402W	CS 045W	C	402E	045E	
LT-42-1N091D	LEVEL TRANSMITTER 402W	CS 045W	D	402E	045E	
LT-42-1N091E	LEVEL TRANSMITTER	CS	A	402W	045W	
LT-42-1N091F	LEVEL TRANSMITTER	HPCI	B	402E	045E	
LT-42-1N091G	LEVEL TRANSMITTER 402W	CS 045W	C	402E	045E	
LT-42-1N091H	LEVEL TRANSMITTER 402W	CS 045W	D	402E	045E	
LT-42-1N095A	LEVEL TRANSMITTER	ADS	A	402W	045W	
LT-42-1N095C	LEVEL TRANSMITTER 402W	ADS 045W	C	402E	045E	
LT-42-1N097A	LEVEL TRANSMITTER	RCIC	A	402W	045W	
LT-42-1N097E	LEVEL TRANSMITTER	RCIC	A	402W	045W	
LT-42-215A	LEVEL TRANSMITTER	RVI	A	475W	068W	
LT-42-215B	LEVEL TRANSMITTER	RVI	B	475E	068E	
LT-42-2N010	LEVEL TRANSMITTER	RVI	A	475W	068W	
LT-42-2N091A	LEVEL TRANSMITTER	CS	A	475W	068W	
LT-42-2N091B	LEVEL TRANSMITTER	CS	B	475E	068E	
LT-42-2N091C	LEVEL TRANSMITTER 475W	CS 068W	C	475E	068E	
LT-42-2N091D	LEVEL TRANSMITTER 475W	CS 068W	D	475E	068E	
LT-42-2N091E	LEVEL TRANSMITTER	CS	A	475W	068W	
LT-42-2N091F	LEVEL TRANSMITTER	CS	B	475E	068E	
LT-42-2N091G	LEVEL TRANSMITTER 475W	CS 068W	C	475E	068E	
LT-42-2N091H	LEVEL TRANSMITTER 475W	CS 068W	D	475E	068E	
LT-42-2N095A	LEVEL TRANSMITTER	ADS	A	475W	068W	
LT-42-2N095C	LEVEL TRANSMITTER 475W	ADS 068W	C	475E	068E	
LT-42-2N097A	LEVEL TRANSMITTER	RCIC	A	475W	068W	
LT-42-2N097E	LEVEL TRANSMITTER	RCIC	A	475W	068W	
LT-49-1N035A	LEVEL TRANSMITTER	RCIC	A	200	042	
LT-49-1N035E	LEVEL TRANSMITTER	RCIC	A	200	042	
LT-49-2N035A	LEVEL TRANSMITTER	RCIC	A	279	065	
LT-49-2N035E	LEVEL TRANSMITTER	RCIC	A	279	065	
LT-52-140A	LEVEL TRANSMITTER	SPI	A	118	039	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
LT-52-140B	LEVEL TRASNMITTER	SPI	B	118	039	
LT-52-240A	LEVEL TRANSMITTER	SPI	A	189	062	
LT-52-240B	LEVEL TRANSMITTER	SPI	B	189	062	
LT-52-241	LEVEL TRANSMITTER	SPI	A	189	062	
LT-55-115	LEVEL TRANSMITTER	SPI	0(A)	204	031	
LT-55-141	LEVEL TRANSMITTER	SPI	A	203	032	
LT-55-1N061B	LEVEL TRANSMITTER	HPCI	B	200	042	
LT-55-1N061F	LEVEL TRANSMITTER	HPCI	B	200	042	
LT-55-1N062B	LEVEL TRANSMITTER	HPCI	B	204	031	
LT-55-1N062F	LEVEL TRANSMITTER	HPCI	B	204	031	
LT-55-215	LEVEL TRANSMITTER	SPI	0(A)	280	054	
LT-55-217	LEVEL TRANSMITTER	SPI	B	174	055	
LT-55-2N061B	LEVEL TRANSMITTER	HPCI	B	279	065	
LT-55-2N061F	LEVEL TRANSMITTER	HPCI	B	279	065	
LT-55-2N062B	LEVEL TRANSMITTER	HPCI	B	280	054	
LT-55-2N062F	LEVEL TRANSMITTER	HPCI	B	280	054	
PCV-59-152A-1	PRESSURE CONTROL VALVE	PCIG	N/A	304W	044W	1-RHRASC-A 1-RHRASC-B 1-RHRASC-C 1-RHRASC-D
PCV-59-152A-2	PRESSURE CONTROL VALVE	PCIG	N/A	304W	044W	1-RHRASC-A 1-RHRASC-B 1-RHRASC-C 1-RHRASC-D
PCV-59-152A-3	PRESSURE CONTROL VALVE	PCIG	N/A	304W	044W	1-RHRASC-B 1-RHRASC-C 1-RHRASC-A 1-RHRASC-D
PCV-59-152B-1	PRESSURE CONTROL VALVE	PCIG	N/A	304E	044E	1-RHRASC-A 1-RHRASC-B 1-RHRASC-C 1-RHRASC-D
PCV-59-152B-2	PRESSURE CONTROL VALVE	PCIG	N/A	304E	044E	1-RHRASC-B 1-RHRASC-C 1-RHRASC-A 1-RHRASC-D
PCV-59-152B-3	PRESSURE CONTROL VALVE	PCIG	N/A	304E	044E	1-RHRASC-A 1-RHRASC-B 1-RHRASC-C 1-RHRASC-D
PCV-59-252A-1	PRESSURE CONTROL VALVE	PCIG	N/A	370E	067E	2-RHRASC-B 2-RHRASC-C 2-RHRASC-A 2-RHRASC-D

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PCV-59-252A-2	PRESSURE CONTROL VALVE	PCIG	N/A	370E	067E	2-RHRASC-A 2-RHRASC-B 2-RHRASC-C 2-RHRASC-D
PCV-59-252A-3	PRESSURE CONTROL VALVE	PCIG	N/A	370E	067E	2-RHRASC-B 2-RHRASC-C 2-RHRASC-A 2-RHRASC-D
PCV-59-252B-1	PRESSURE CONTROL VALVE	PCIG	N/A	370E	067E	2-RHRASC-A 2-RHRASC-B 2-RHRASC-C 2-RHRASC-D
PCV-59-252B-2	PRESSURE CONTROL VALVE	PCIG	N/A	370E	067E	2-RHRASC-A 2-RHRASC-D 2-RHRASC-B 2-RHRASC-C
PCV-59-252B-3	PRESSURE CONTROL VALVE	PCIG	N/A	370E	067E	2-RHRASC-A 2-RHRASC-B 2-RHRASC-C 2-RHRASC-D
PDIS-49-1N657A	PRESSURE DIFFERENTIAL INDICATING SWITCH	RCIC	A	542	025	
PDIS-49-1N657C	PRESSURE DIFFERENTIAL INDICATING SWITCH	RCIC	C	542	025	
PDIS-49-2N657A	PRESSURE DIFFERENTIAL INDICATING SWITCH	RCIC	A	542	025	
PDIS-49-2N657C	PRESSURE DIFFERENTIAL INDICATING SWITCH	RCIC	C	542	025	
PDIS-55-1N657B	STEAM SUPPLY LINE DIFFERENTIAL PRESURE INDICATING SWITCH	HPCI	B	542	025	
PDIS-55-1N657D	STEAM SUPPLY LINE DIFFERENTIAL PRESURE INDICATING SWITCH	HPCI	D	542	025	
PDIS-55-2N657B	STEAM SUPPLY LINE DIFFERENTIAL PRESURE INDICATING SWITCH	HPCI	B	533	024	
PDIS-55-2N657D	STEAM SUPPLY LINE DIFFERENTIAL PRESURE INDICATING SWITCH	HPCI	D	533	024	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PDISH-51-1N660A	PRESSURE DIFFERENTIAL INDICATING SWITCH	RHR	A	542	025	
PDISH-51-1N660B	PRESSURE DIFFERENTIAL INDICATING SWITCH	RHR	B	542	025	
PDISH-51-2N660A	PRESSURE DIFFERENTIAL INDICATING SWITCH	RHR	A	542	025	
PDISH-51-2N660B	PRESSURE DIFFERENTIAL INDICATING SWITCH	RHR	B	542	025	
PDISL-51-1N658A	PRESSURE DIFFERENTIAL INDICATING SWITCH	RHR	A	542	025	
PDISL-51-1N658B	PRESSURE DIFFERENTIAL INDICATING SWITCH	RHR	B	542	025	
PDISL-51-1N658C	PRESSURE DIFFERENTIAL INDICATING SWITCH	RHR	C	542	025	
PDISL-51-1N658D	PRESSURE DIFFERENTIAL INDICATING SWITCH	RHR	D	542	025	
PDISL-51-2N658A	PRESSURE DIFFERENTIAL INDICATING SWITCH	RHR	A	542	025	
PDISL-51-2N658B	PRESSURE DIFFERENTIAL INDICATING SWITCH	RHR	B	542	025	
PDISL-51-2N658C	PRESSURE DIFFERENTIAL INDICATING SWITCH	RHR	C	542	025	
PDISL-51-2N658D	PRESSURE DIFFERENTIAL INDICATING SWITCH	RHR	D	542	025	
PDS-49-1N660A	PRESSURE DIFFERENTIAL SWITCH	RCIC	A	542	025	
PDS-49-1N660C	PRESSURE DIFFERENTIAL SWITCH	RCIC	C	542	025	
PDS-49-2N660A	PRESSURE DIFFERENTIAL SWITCH	RCIC	A	542	025	
PDS-49-2N660C	PRESSURE DIFFERENTIAL SWITCH	RCIC	C	542	025	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PDS-55-1N660B	DIFFERENTIAL PRESSURE SWITCH	HPCI	B	542	025	
PDS-55-1N660D	DIFFERENTIAL PRESSURE SWITCH	HPCI	D	542	025	
PDS-55-2N660B	DIFFERENTIAL PRESSURE SWITCH	HPCI	B	542	025	
PDS-55-2N660D	PRESSURE DIFFERENTIAL SWITCH	HPCI	D	542	025	
PDS-59-106A	PRESSURE DIFFERENTIAL SWITCH	PCIG	C	402W	045W	
PDS-59-106B	PRESSURE DIFFERENTIAL SWITCH	PCIG	D	402E	045E	
PDS-59-206A	PRESSURE DIFFERENTIAL SWITCH	PCIG	C	475W	068W	
PDS-59-206B	PRESSURE DIFFERENTIAL SWITCH	PCIG	D	475E	068E	
PDSH-20-122A	PRESSURE DIFFERENTIAL SWITCH	SDG	A	311A	079	
PDSH-20-122B	PRESSURE DIFFERENTIAL SWITCH	SDG	B	311B	081	
PDSH-20-122C	PRESSURE DIFFERENTIAL SWITCH	SDG	C	311C	080	
PDSH-20-122D	PRESSURE DIFFERENTIAL SWITCH	SDG	D	311D	082	
PDSH-20-222A	PRESSURE DIFFERENTIAL SWITCH	SDG	A	315A	083	
PDSH-20-222B	PRESSURE DIFFERENTIAL SWITCH	SDG	B	315B	085	
PDSH-20-222C	PRESSURE DIFFERENTIAL SWITCH	SDG	C	315C	084	
PDSH-20-222D	PRESSURE DIFFERENTIAL SWITCH	SDG	D	315D	086	
PDSH-50-101	PRESSURE DIFFERENTIAL SWITCH	RCIC	A	108	033	
PDSH-50-201	PRESSURE DIFFERENTIAL SWITCH	RCIC	A	179	056	
PDSL-51-1N661A	PRESSURE DIFFERENTIAL SWITCH	RHR	A	542	025	
PDSL-51-1N661B	PRESSURE DIFFERENTIAL SWITCH	RHR	B	542	025	
PDSL-51-2N661A	PRESSURE DIFFERENTIAL SWITCH	RHR	A	542	025	
PDSL-51-2N661B	PRESSURE DIFFERENTIAL SWITCH	RHR	B	542	025	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PDT-49-1N057A	DIFFERENTIAL PRESSURE TRANSMITTER	RCIC	A	304E	044E	
PDT-49-1N057C	DIFFERENTIAL PRESSURE TRANSMITTER	RCIC	C	304E	044E	
PDT-49-2N057A	DIFFERENTIAL PRESSURE TRANSMITTER	RCIC	A	370E	067E	
PDT-49-2N057C	DIFFERENTIAL PRESSURE TRANSMITTER	RCIC	C	370E	067E	
PDT-51-1N058A	DIFFERENTIAL PRESSURE TRANSMITTER	RHR	A	402W	045W	
PDT-51-1N058B	DIFFERENTIAL PRESSURE TRANSMITTER	RHR	B	402E	045E	
PDT-51-1N058C	DIFFERENTIAL PRESSURE TRANSMITTER	RHR 402W	C 045W	402E	045E	
PDT-51-1N058D	DIFFERENTIAL PRESSURE TRANSMITTER	RHR 402W	D 045W	402E	045E	
PDT-51-1N060A	DIFFERENTIAL PRESSURE TRANSMITTER	RHR	A	506E	047E	
PDT-51-1N060B	DIFFERENTIAL PRESSURE TRANSMITTER	RHR	B	402E	045E	
PDT-51-2N058A	DIFFERENTIAL PRESSURE TRANSMITTER	RHR	A	475W	068W	
PDT-51-2N058B	DIFFERENTIAL PRESSURE TRANSMITTER	RHR	B	475E	068E	
PDT-51-2N058C	DIFFERENTIAL PRESSURE TRANSMITTER	RHR 475W	C 068W	475E	068E	
PDT-51-2N058D	DIFFERENTIAL PRESSURE TRANSMITTER	RHR 475W	D 068W	475E	068E	
PDT-51-2N060A	DIFFERENTIAL PRESSURE TRANSMITTER	RHR	A	580W	070W	
PDT-51-2N060B	DIFFERENTIAL PRESSURE TRANSMITTER	RHR	B	475E	068E	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PDT-55-1N057B	DIFFERENTIAL PRESSURE TRANSMITTER	HPCI	B	304W	044W	
PDT-55-1N057D	DIFFERENTIAL PRESSURE TRANSMITTER	HPCI	D	304W	044W	
PDT-55-2N057B	DIFFERENTIAL PRESSURE TRANSMITTER	HPCI	B	370W	067W	
PDT-55-2N057D	DIFFERENTIAL PRESSURE TRANSMITTER	HPCI	D	370W	067W	
PI-11-003A-1	ESW PUMP A DISCHARGE HEADER	ESW	A	533	024	0-ESW-A
PI-11-003A-2	ESW PUMP A DISCHARGE HEADER	ESW	A	540	026	0-ESW-R
PI-11-003B	ESW PUMP B DISCHARGE HEADER	ESW	B	533	024	0-ESW-B
PI-12-001A-1	RHRSW LOOP A HEADER PRESSURE	RHRSW	A	533	024	2-RHRSW-A 1-RHRSW-A
PI-12-001A-2	RHRSW LOOP A HEADER PRESSURE	RHRSW	A	540	026	1-RHRSW-A
PI-12-001A-3	RHRSW LOOP A HEADER PRESSURE	RHRSW	A	540	026	2-RHRSW-A
PI-12-001B	RHRSW LOOP B HEADER PRESSURE	RHRSW	B	533	024	1-RHRSW-B 2-RHRSW-B
PI-42-1R011	REACTOR VESSEL PRESSURE INDICATOR	RVI	A	540	026	1-RVI
PI-42-2R011	REACTOR VESSEL PRESSURE INDICATOR	RVI	A	540	026	2-RVI
PI-51-105A-1	RHR HEAT EXCHANGER 1AE205 SERVICE WATER DISCHARGE	RHRSW	A	533	024	1-RHRSW-A
PI-51-105A-2	RHR HEAT EXCHANGER 1AE205 SERVICE WATER DISCHARGE	RHRSW	A	540	026	1-RHRSW-A
PI-51-105B	RHR HEAT EXCHANGER 1BE205 SERVICE WATER DISCHARGE	RHRSW	B	533	024	1-RHRSW-B
PI-51-1R003A	RHR PUMP A DISCHARGE PRESSURE (LOCAL)	RHR	N/A	200	042	1-RHRSC-A 1-RHRSPC-A

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PI-51-205A-1	RHR HEAT EXCHANGER 2AE205 SERVICE WATER DISCHARGE	RHRSW	A	533	024	2-RHRSW-A
PI-51-205A-2	RHR HEAT EXCHANGER 2AE205 SERVICE WATER DISCHARGE	RHRSW	A	540	026	2-RHRSW-A
PI-51-205B	RHR HEAT EXCHANGER 2BE205 SERVICE WATER DISCHARGE	RHRSW	B	533	024	2-RHRSW-B
PI-55-1R601	PUMP DISCHARGE LINE PRESSURE INDICATOR	HPCI	B	533	024	1-HPCI
PI-55-2R601	PUMP DISCHARGE LINE PRESSURE INDICATOR	HPCI	B	533	024	2-HPCI
PIS-42-1N690A	PRESSURE INDICATING SWITCH	CS	A	542	025	
PIS-42-1N690B	PRESSURE INDICATING SWITCH	CS	B	542	025	
PIS-42-1N690C	PRESSURE INDICATING SWITCH	CS	C	542	025	
PIS-42-1N690D	PRESSURE INDICATING SWITCH	CS	D	542	025	
PIS-42-1N690E	PRESSURE INDICATING SWITCH	CS	A	542	025	
PIS-42-1N690F	PRESSURE INDICATING SWITCH	CS	B	542	025	
PIS-42-1N690G	PRESSURE INDICATING SWITCH	CS	C	542	025	
PIS-42-1N690H	PRESSURE INDICATING SWITCH	CS	D	542	025	
PIS-42-1N694A	PRESSURE INDICATING SWITCH	CS	A	542	025	
PIS-42-1N694B	PRESSURE INDICATING SWITCH	CS	B	542	025	
PIS-42-1N694C	PRESSURE INDICATING SWITCH	CS	C	542	025	
PIS-42-1N694D	PRESSURE INDICATING SWITCH	CS	D	542	025	
PIS-42-1N694E	PRESSURE INDICATING SWITCH	CS	A	542	025	
PIS-42-1N694F	PRESSURE INDICATING SWITCH	CS	B	542	025	
PIS-42-1N694G	PRESSURE INDICATING SWITCH	CS	C	542	025	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PIS-42-1N694H	PRESSURE INDICATING SWITCH	CS	D	542	025	
PIS-42-2N690A	PRESSURE INDICATING SWITCH	CS	A	542	025	
PIS-42-2N690B	PRESSURE INDICATING SWITCH	CS	B	542	025	
PIS-42-2N690C	PRESSURE INDICATING SWITCH	CS	C	542	025	
PIS-42-2N690D	PRESSURE INDICATING SWITCH	CS	D	542	025	
PIS-42-2N690E	PRESSURE INDICATING SWITCH	CS	A	542	025	
PIS-42-2N690F	PRESSURE INDICATING SWITCH	CS	B	542	025	
PIS-42-2N690G	PRESSURE INDICATING SWITCH	CS	C	542	025	
PIS-42-2N690H	PRESSURE INDICATING SWITCH	CS	D	542	025	
PIS-42-2N694A	PRESSURE INDICATING SWITCH	CS	A	542	025	
PIS-42-2N694B	PRESSURE INDICATING SWITCH	CS	B	542	025	
PIS-42-2N694C	PRESSURE INDICATING SWITCH	CS	C	542	025	
PIS-42-2N694D	PRESSURE INDICATING SWITCH	CS	D	542	025	
PIS-42-2N694E	PRESSURE INDICATING SWITCH	CS	A	542	025	
PIS-42-2N694F	PRESSURE INDICATING SWITCH	CS	B	542	025	
PIS-42-2N694G	PRESSURE INDICATING SWITCH	CS	C	542	025	
PIS-42-2N694H	PRESSURE INDICATING SWITCH	CS	D	542	025	
PIS-49-1N650	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-49-1N658A	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-49-1N658C	PRESSURE INDICATING SWITCH	RCIC	C	542	025	
PIS-49-1N658E	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-49-1N658G	PRESSURE INDICATING SWITCH	RCIC	C	542	025	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PIS-49-2N650	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-49-2N658A	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-49-2N658C	PRESSURE INDICATING SWITCH	RCIC	C	542	025	
PIS-49-2N658E	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-49-2N658G	PRESSURE INDICATING SWITCH	RCIC	C	542	025	
PIS-50-1N652	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-50-1N653	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-50-1N655A	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-50-1N655C	PRESSURE INDICATING SWITCH	RCIC	C	542	025	
PIS-50-1N655E	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-50-1N655G	PRESSURE INDICATING SWITCH	RCIC	C	542	025	
PIS-50-1N656A	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-50-1N656E	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-50-2N652	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-50-2N653	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-50-2N655A	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-50-2N655C	PRESSURE INDICATING SWITCH	RCIC	C	542	025	
PIS-50-2N655E	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-50-2N655G	PRESSURE INDICATING SWITCH	RCIC	C	542	025	
PIS-50-2N656A	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-50-2N656E	PRESSURE INDICATING SWITCH	RCIC	A	542	025	
PIS-51-1N655A	PRESSURE INDICATING SWITCH	ADS	A	542	025	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PIS-51-1N655C	PRESSURE INDICATING SWITCH	ADS	C	542	025	
PIS-51-1N655E	PRESSURE INDICATING SWITCH	ADS	A	542	025	
PIS-51-1N655G	PRESSURE INDICATING SWITCH	ADS	C	542	025	
PIS-51-1N656A	PRESSURE INDICATING SWITCH	ADS	A	542	025	
PIS-51-1N656C	PRESSURE INDICATING SWITCH	ADS	C	542	025	
PIS-51-1N656E	PRESSURE INDICATING SWITCH	ADS	A	542	025	
PIS-51-1N656G	PRESSURE INDICATING SWITCH	ADS	C	542	025	
PIS-51-2N655A	PRESSURE INDICATING SWITCH	ADS	A	542	025	
PIS-51-2N655C	PRESSURE INDICATING SWITCH	ADS	C	542	025	
PIS-51-2N655E	PRESSURE INDICATING SWITCH	ADS	A	542	025	
PIS-51-2N655G	PRESSURE INDICATING SWITCH	ADS	C	542	025	
PIS-51-2N656A	PRESSURE INDICATING SWITCH	ADS	A	542	025	
PIS-51-2N656C	PRESSURE INDICATING SWITCH	ADS	C	542	025	
PIS-51-2N656E	PRESSURE INDICATING SWITCH	ADS	A	542	025	
PIS-51-2N656G	PRESSURE INDICATING SWITCH	ADS	C	542	025	
PIS-52-1N655A	PRESSURE INDICATING SWITCH	ADS	A	542	025	
PIS-52-1N655C	PRESSURE INDICATING SWITCH	ADS	C	542	025	
PIS-52-1N655E	PRESSURE INDICATING SWITCH	ADS	A	542	025	
PIS-52-1N655G	PRESSURE INDICATING SWITCH	ADS	C	542	025	
PIS-52-2N655A	PRESSURE INDICATING SWITCH	ADS	A	542	025	
PIS-52-2N655C	PRESSURE INDICATING SWITCH	ADS	C	542	025	
PIS-52-2N655E	PRESSURE INDICATING SWITCH	ADS	A	542	025	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PIS-52-2N655G	PRESSURE INDICATING SWITCH	ADS	C	542	025	
PIS-55-1N650	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-55-1N658B	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-55-1N658D	PRESSURE DIFFERENTIAL INDICATING SWITCH	HPCI	D	542	025	
PIS-55-1N658F	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-55-1N658H	PRESSURE DIFFERENTIAL INDICATING SWITCH	HPCI	D	542	025	
PIS-55-2N650	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-55-2N658B	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-55-2N658D	PRESSURE INDICATING SWITCH	HPCI	D	542	025	
PIS-55-2N658F	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-55-2N658H	PRESSURE INDICATING SWITCH	HPCI	D	542	025	
PIS-56-1N652	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-56-1N653	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-56-1N655B	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-56-1N655D	PRESSURE INDICATING SWITCH	HPCI	D	542	025	
PIS-56-1N655F	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-56-1N655H	PRESSURE INDICATING SWITCH	HPCI	D	542	025	
PIS-56-1N656B	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-56-1N656F	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-56-2N652	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-56-2N653	PRESSURE INDICATING SWITCH	HPCI	B	542	025	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PIS-56-2N655B	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-56-2N655D	PRESSURE INDICATING SWITCH	HPCI	D	542	025	
PIS-56-2N655F	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-56-2N655H	PRESSURE INDICATING SWITCH	HPCI	D	542	025	
PIS-56-2N656B	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PIS-56-2N656F	PRESSURE INDICATING SWITCH	HPCI	B	542	025	
PISH-51-1N653A	PRESSURE INDICATING SWITCH	RHR	A	542	025	
PISH-51-1N653B	PRESSURE INDICATING SWITCH	RHR	B	542	025	
PISH-51-1N653C	PRESSURE INDICATING SWITCH	RHR	C	542	025	
PISH-51-1N653D	PRESSURE SWITCH INDICATING	RHR	D	542	025	
PISH-51-1N657	PRESSURE INDICATING SWITCH	RHR	B	542	025	
PISH-51-2N653A	PRESSURE INDICATING SWITCH	RHR	A	542	025	
PISH-51-2N653B	PRESSURE INDICATING SWITCH	RHR	B	542	025	
PISH-51-2N653C	PRESSURE INDICATING SWITCH	RHR	C	542	025	
PISH-51-2N657	PRESSURE INDICATING SWITCH	RHR	B	542	025	
PIT-51-105A	RHR HEAT EXCHANGER 1AE205 SERVICE WATER DISCHARGE	RHRSW	A	200	042	
PIT-51-105B	RHR HEAT EXCHANGER 1BE205 SERVICE WATER DISCHARGE	RHRSW	B	207	041	
PIT-51-205A	RHR HEAT EXCHANGER 2AE205 SERVICE WATER DISCHARGE	RHRSW	A	284	064	
PIT-51-205B	RHR HEAT EXCHANGER 2BE205 SERVICE WATER DISCHARGE	RHRSW	B	179	056	
PSH-12-004A	PRESSURE SWITCH - HIGH	RHRSW	A	1000	122	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PSH-12-004B	PRESSURE SWITCH - HIGH	RHRSW	B	1005	123	
PSH-12-004C	PRESSURE SWITCH - HIGH	RHRSW	A	1000	122	
PSH-12-004D	PRESSURE SWITCH - HIGH	RHRSW	B	1005	123	
PSL-11-002A	PRESSURE SWITCH - LOW	ESW	A	1000	122	
PSL-11-002B	PRESSURE SWITCH - LOW	ESW	B	1005	123	
PSL-11-002C	PRESSURE SWITCH - LOW	ESW	C	1000	122	
PSL-11-002D	PRESSURE SWITCH - LOW	ESW	D	1005	123	
PSL-12-001A	PRESSURE SWITCH - LOW	RHRSW	A	1000	122	
PSL-12-001B	PRESSURE SWITCH - LOW	RHRSW	B	1005	123	
PSL-12-001C	PRESSURE SWITCH - LOW	RHRSW	A	1000	122	
PSL-12-001D	PRESSURE SWITCH - LOW	RHRSW	B	1005	123	
PSL-12-102A	PRESSURE SWITCH - LOW	RHRSW	A	202	075	
PSL-12-102B	PRESSURE SWITCH - LOW	RHRSW	B	202	075	
PSL-12-202A	PRESSURE SWITCH - LOW	RHRSW	A	202	075	
PSL-12-202B	PRESSURE SWITCH - LOW	RHRSW	B	202	075	
PSL-42-101	PRESSURE SWITCH - LOW	RHR/ HILOW	B	402E	045E	
PSL-42-201	PRESSURE SWITCH - LOW	RHR/ HILOW	B	475E	068E	
PSL-50-101	PRESSURE SWITCH - LOW	RCIC	A	108	033	
PSL-50-201	PRESSURE SWITCH - LOW	RCIC	A	179	056	
PSL-51-1N654A	PRESSURE SWITCH - LOW	RHR	A	542	025	
PSL-51-1N654B	PRESSURE SWITCH - LOW	RHR	B	542	025	
PSL-51-1N654C	PRESSURE SWITCH - LOW	RHR	C	542	025	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PSL-51-1N654D	PRESSURE SWITCH - LOW	RHR	D	542	025	
PSL-51-2N653D	PRESSURE SWITCH - LOW	RHR	D	542	025	
PSL-51-2N654A	PRESSURE SWITCH - LOW	RHR	A	542	025	
PSL-51-2N654B	PRESSURE SWITCH - LOW	RHR	B	542	025	
PSL-51-2N654C	PRESSURE SWITCH - LOW	RHR	C	542	025	
PSL-51-2N654D	PRESSURE SWITCH - LOW	RHR	D	542	025	
PSV-41-1F013A	MAIN STEAM RELIEF VALVE "A"	MSRV	A	400	030	1-MSRV
PSV-41-1F013C	MAIN STEAM RELIEF VALVE "C"	MSRV	A	400	030	1-MSRV
PSV-41-1F013E	MAIN STEAM RELIEF VALVE "E" (ADS)	ADS	A,C	400	030	1-ADS
PSV-41-1F013H	MAIN STEAM RELIEF VALVE "H" (ADS)	ADS	A,C	400	030	1-ADS
PSV-41-1F013K	MAIN STEAM RELIEF VALVE "K" (ADS)	ADS	A,C	400	030	1-ADS
PSV-41-1F013M	MAIN STEAM RELIEF VALVE "M" (ADS)	ADS	A,C	400	030	1-ADS
PSV-41-1F013N	MAIN STEAM RELIEF VALVE "N"	MSRV	A	400	030	1-MSRV
PSV-41-1F013S	MAIN STEAM RELIEF VALVE "S" (ADS)	ADS	A,C	400	030	1-ADS
PSV-41-2F013A	MAIN STEAM RELIEF VALVE "A"	MSRV	A	473	053	2-MSRV
PSV-41-2F013C	MAIN STEAM RELIEF VALVE "C"	MSRV	A	473	053	2-MSRV
PSV-41-2F013E	MAIN STEAM RELIEF VALVE "E" (ADS)	ADS	A,C	473	053	2-ADS
PSV-41-2F013H	MAIN STEAM RELIEF VALVE "H" (ADS)	ADS	A,C	473	053	2-ADS
PSV-41-2F013K	MAIN STEAM RELIEF VALVE "K" (ADS)	ADS	A,C	473	053	2-ADS
PSV-41-2F013M	MAIN STEAM RELIEF VALVE "M" (ADS)	ADS	A,C	473	053	2-ADS
PSV-41-2F013N	MAIN STEAM RELIEF VALVE "N"	MSRV	A	473	053	2-MSRV
PSV-41-2F013S	MAIN STEAM RELIEF VALVE "S" (ADS)	ADS	A,C	473	053	2-ADS

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PT-11-003A	ESW PUMP A DISCHARGE HEADER	ESW	A	1011	122	
PT-11-003B	ESW PUMP B DISCHARGE HEADER	ESW	B	1016	123	
PT-12-001A	RHRSW LOOP A HEADER PRESSURE	RHRSW	A	1011	122	
PT-12-001B	RHRSW LOOP B HEADER PRESSURE	RHRSW	B	1016	123	
PT-42-103A	PRESSURE TRANSMITTER	RVI	A	402W	045W	
PT-42-103B	PRESSURE TRANSMITTER	RVI	B	402E	045E	
PT-42-1N006	PRESSURE TRANSMITTER	RVI	A	402W	045W	
PT-42-1N090A	PRESSURE TRANSMITTER	CS	A	402W	045W	
PT-42-1N090B	PRESSURE TRANSMITTER	CS	B	402E	045E	
PT-42-1N090C	PRESSURE TRANSMITTER	CS	C	402E 402W	045E 045W	
PT-42-1N090D	PRESSURE TRANSMITTER	CS	D	402E 402W	045E 045W	
PT-42-1N090E	PRESSURE TRANSMITTER	CS	A	402W	045W	
PT-42-1N090F	PRESSURE TRANSMITTER	CS	B	402E	045E	
PT-42-1N090G	PRESSURE TRANSMITTER	CS	C	402E 402W	045E 045W	
PT-42-1N090H	PRESSURE TRANSMITTER	CS	D	402E 402W	045E 045W	
PT-42-1N094A	PRESSURE TRANSMITTER	CS	A	402W	045W	
PT-42-1N094B	PRESSURE TRANSMITTER	CS	B	402E	045E	
PT-42-1N094C	PRESSURE TRANSMITTER	CS	C	402E 402W	045E 045W	
PT-42-1N094D	PRESSURE TRANSMITTER	CS	D	402E 402W	045E 045W	
PT-42-1N094E	PRESSURE TRANSMITTER	CS	A	402W	045W	
PT-42-1N094F	PRESSURE TRANSMITTER	CS	B	402E	045E	
PT-42-1N094G	PRESSURE TRANSMITTER	CS	C	402E 402W	045E 045W	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PT-42-1N094H	PRESSURE TRANSMITTER	CS	D	402E 402W	045E 045W	
PT-42-203A	PRESSURE TRANSMITTER	RVI	A	475W	068W	
PT-42-203B	PRESSURE TRANSMITTER	RVI	B	475E	068E	
PT-42-2N006	PRESSURE TRANSMITTER	RVI	A	475W	068W	
PT-42-2N090A	PRESSURE TRANSMITTER	CS	A	475W	068W	
PT-42-2N090B	PRESSURE TRANSMITTER	CS	B	475E	068E	
PT-42-2N090C	PRESSURE TRANSMITTER	CS	C	475E 475W	068E 068W	
PT-42-2N090D	PRESSURE TRANSMITTER	CS	D	475E 475W	068E 068W	
PT-42-2N090E	PRESSURE TRANSMITTER	CS	A	475W	068W	
PT-42-2N090F	PRESSURE TRANSMITTER	CS	B	475E	068E	
PT-42-2N090G	PRESSURE TRANSMITTER	CS	C	475E 475W	068E 068W	
PT-42-2N090H	PRESSURE TRANSMITTER	CS	D	475E 475W	068E 068W	
PT-42-2N094A	PRESSURE TRANSMITTER	CS	A	475W	068W	
PT-42-2N094B	PRESSURE TRANSMITTER	CS	B	475E	068E	
PT-42-2N094C	PRESSURE TRANSMITTER	CS	C	475E 475W	068E 068W	
PT-42-2N094D	PRESSURE TRANSMITTER	CS	D	475E 475W	068E 068W	
PT-42-2N094E	PRESSURE TRANSMITTER	CS	A	475W	068W	
PT-42-2N094F	PRESSURE TRANSMITTER	CS	B	475E	068E	
PT-42-2N094G	PRESSURE TRANSMITTER	CS	C	475E 475W	068E 068W	
PT-42-2N094H	PRESSURE TRANSMITTER	CS	D	475E 475W	068E 068W	
PT-49-1N050	PRESSURE TRANSMITTER	RCIC	A	200	042	
PT-49-1N058A	PRESSURE TRANSMITTER	RCIC	A	304E	044E	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PT-49-1N058C	PRESSURE TRANSMITTER	RCIC	C	304E	044E	
PT-49-1N058E	PRESSURE TRANSMITTER	RCIC	A	304E	044E	
PT-49-1N058G	PRESSURE TRANSMITTER	RCIC	C	304E	044E	
PT-49-2N050	PRESSURE TRANSMITTER	RCIC	A	279	065	
PT-49-2N058A	PRESSURE TRANSMITTER	RCIC	A	370E	067E	
PT-49-2N058C	PRESSURE TRANSMITTER	RCIC	C	370E	067E	
PT-49-2N058E	PRESSURE TRANSMITTER	RCIC	A	370E	067E	
PT-49-2N058G	PRESSURE TRANSMITTER	RCIC	C	370E	067E	
PT-50-1N052	PRESSURE TRANSMITTER	RCIC	A	108	033	
PT-50-1N053	PRESSURE TRANSMITTER	RCIC	A	108	033	
PT-50-1N055A	PRESSURE TRANSMITTER	RCIC	A	200	042	
PT-50-1N055C	PRESSURE TRANSMITTER	RCIC	C	108	033	
PT-50-1N055E	PRESSURE TRANSMITTER	RCIC	A	200	042	
PT-50-1N055G	PRESSURE TRANSMITTER	RCIC	C	108	033	
PT-50-1N056A	PRESSURE TRANSMITTER	RCIC	A	200	042	
PT-50-1N056E	PRESSURE TRANSMITTER	RCIC	A	200	042	
PT-50-2N052	PRESSURE TRANSMITTER	RCIC	A	179	056	
PT-50-2N053	PRESSURE TRANSMITTER	RCIC	A	179	056	
PT-50-2N055A	PRESSURE TRANSMITTER	RCIC	A	279	065	
PT-50-2N055C	PRESSURE TRANSMITTER	RCIC	C	179	056	
PT-50-2N055E	PRESSURE TRANSMITTER	RCIC	A	279	065	
PT-50-2N055G	PRESSURE TRANSMITTER	RCIC	C	179	056	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PT-50-2N056A	PRESSURE TRANSMITTER	RCIC	A	279	065	
PT-50-2N056E	PRESSURE TRANSMITTER	RCIC	A	279	065	
PT-51-1N053A	PRESSURE TRANSMITTER	RHR	A	200	042	
PT-51-1N053B	PRESSURE TRANSMITTER	RHR	B	118	039	
PT-51-1N053C	PRESSURE TRANSMITTER	RHR	C	200	042	
PT-51-1N053D	PRESSURE TRANSMITTER	RHR	D	118	039	
PT-51-1N055A	PRESSURE TRANSMITTER	ADS	A	200	042	
PT-51-1N055C	PRESSURE TRANSMITTER	ADS	C	118	039	
PT-51-1N055E	PRESSURE TRANSMITTER	ADS	A	200	042	
PT-51-1N055G	PRESSURE TRANSMITTER	ADS	C	118	039	
PT-51-1N056A	PRESSURE TRANSMITTER	ADS	A	200	042	
PT-51-1N056C	PRESSURE TRANSMITTER	ADS	C	118	039	
PT-51-1N056E	PRESSURE TRANSMITTER	ADS	A	200	042	
PT-51-1N056G	PRESSURE TRANSMITTER	ADS	C	118	039	
PT-51-1N057	PRESSURE TRANSMITTER	RHR	B	304E	044E	
PT-51-2N053A	PRESSURE TRANSMITTER	RHR	A	189	062	
PT-51-2N053B	PRESSURE TRANSMITTER	RHR	B	279	065	
PT-51-2N053C	PRESSURE TRANSMITTER	RHR	C	189	062	
PT-51-2N053D	PRESSURE TRANSMITTER	RHR	D	279	065	
PT-51-2N055A	PRESSURE TRANSMITTER	ADS	A	189	062	
PT-51-2N055C	PRESSURE TRANSMITTER	ADS	C	279	065	
PT-51-2N055E	PRESSURE TRANSMITTER	ADS	A	189	062	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PT-51-2N055G	PRESSURE TRANSMITTER	ADS	C	279	065	
PT-51-2N056A	PRESSURE TRANSMITTER	ADS	A	189	062	
PT-51-2N056C	PRESSURE TRANSMITTER	ADS	C	279	065	
PT-51-2N056E	PRESSURE TRANSMITTER	ADS	A	189	062	
PT-51-2N056G	PRESSURE TRANSMITTER	ADS	C	279	065	
PT-51-2N057	PRESSURE TRANSMITTER	RHR	B	370W	067W	
PT-52-1N055A	PRESSURE TRANSMITTER	ADS	A	110	035	
PT-52-1N055C	PRESSURE TRANSMITTER	ADS	C	117	038	
PT-52-1N055E	PRESSURE TRANSMITTER	ADS	A	113	036	
PT-52-1N055G	PRESSURE TRANSMITTER	ADS	C	114	037	
PT-52-2N055A	PRESSURE TRANSMITTER	ADS	A	188	061	
PT-52-2N055C	PRESSURE TRANSMITTER	ADS	C	181	058	
PT-52-2N055E	PRESSURE TRANSMITTER	ADS	A	185	060	
PT-52-2N055G	PRESSURE TRANSMITTER	ADS	C	184	059	
PT-55-1N050	PRESSURE TRANSMITTER	HPCI	B	109	034	
PT-55-1N058B	PRESSURE TRANSMITTER	HPCI	B	304W	044W	
PT-55-1N058D	PRESSURE TRANSMITTER	HPCI	D	304W	044W	
PT-55-1N058F	PRESSURE TRANSMITTER	HPCI	B	304W	044W	
PT-55-1N058H	PRESSURE TRANSMITTER	HPCI	D	304W	044W	
PT-55-2N050	PRESSURE TRANSMITTER	HPCI	B	180	057	
PT-55-2N058B	PRESSURE TRANSMITTER	HPCI	B	370W	067W	
PT-55-2N058D	PRESSURE TRANSMITTER	HPCI	D	370W	067W	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
PT-55-2N058F	PRESSURE TRANSMITTER	HPCI	B	370W	067W	
PT-55-2N058H	PRESSURE TRANSMITTER	HPCI	D	370W	067W	
PT-56-1N052	PRESSURE TRANSMITTER	HPCI	B	109	034	
PT-56-1N053	PRESSURE TRANSMITTER	HPCI	B	109	034	
PT-56-1N055B	PRESSURE TRANSMITTER	HPCI	B	109	034	
PT-56-1N055D	PRESSURE TRANSMITTER	HPCI	D	200	042	
PT-56-1N055F	PRESSURE TRANSMITTER	HPCI	B	109	034	
PT-56-1N055H	PRESSURE TRANSMITTER	HPCI	D	200	042	
PT-56-1N056B	PRESSURE TRANSMITTER	HPCI	B	109	034	
PT-56-1N056F	PRESSURE TRANSMITTER	HPCI	B	109	034	
PT-56-2N052	PRESSURE TRANSMITTER	HPCI	B	180	057	
PT-56-2N053	PRESSURE TRANSMITTER	HPCI	B	180	057	
PT-56-2N055B	PRESSURE TRANSMITTER	HPCI	B	180	057	
PT-56-2N055D	PRESSURE TRANSMITTER	HPCI	D	279	065	
PT-56-2N055F	PRESSURE TRANSMITTER	HPCI	B	180	057	
PT-56-2N055H	PRESSURE TRANSMITTER	HPCI	D	279	065	
PT-56-2N056B	PRESSURE TRANSMITTER	HPCI	B	180	057	
PT-56-2N056F	PRESSURE TRANSMITTER	HPCI	B	180	057	
SI-50-101	SPEED INDICATOR	RCIC	A	533	024	
SI-50-1R003	SPEED INDICATOR	RCIC	A	540	026	
SI-50-201	SPEED INDICATOR	RCIC	A	533	024	
SI-50-2R003	SPEED INDICATOR	RCIC	A	540	026	
SI-56-161	SPEED INDICATOR	HPCI	B	533	024	
SI-56-261	SPEED INDICATOR	HPCI	B	533	024	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
SV-52-139	CTMT ISO VALVE FOR LEVEL SENSING LINES	SPI	A	118	039	
SV-52-239	CTMT ISO VALVE FOR LEVEL SENSING LINES	SPI	A	189	062	
SV-57-101	CTMT ISO VALVE FOR LEVEL SENSING LINES	SPI	A	207	041	
SV-57-183	CTMT ISO VALVE FOR LEVEL SENSING LINES	SPI	A	309W	043W	
SV-57-201	CTMT ISO VALVE FOR LEVEL SENSING LINES	SPI	A	284	064	
SV-59-150A	COMPRESSED GAS SUPPLY SELECT VALVE	PCIG	C	304W	044W	1-RHRASC-A 1-RHRASC-B 1-RHRASC-C 1-RHRASC-D
SV-59-150B	COMPRESSED GAS SUPPLY SELECT VALVE	PCIG	D	304E	044E	1-RHRASC-B 1-RHRASC-A 1-RHRASC-D 1-RHRASC-C
SV-59-152A	COMPRESSED GAS SUPPLY SELECT VALVE	PCIG	C	304W	044W	1-RHRASC-A 1-RHRASC-B 1-RHRASC-C 1-RHRASC-D 1-MSRV
SV-59-152B	COMPRESSED GAS SUPPLY SELECT VALVE	PCIG	D	304E	044E	1-RHRASC-B 1-RHRASC-C 1-RHRASC-A 1-RHRASC-D
SV-59-250A	COMPRESSED GAS SUPPLY SELECT VALVE	PCIG	C	370E	067E	2-RHRASC-A 2-RHRASC-B 2-RHRASC-C 2-RHRASC-D
SV-59-250B	COMPRESSED GAS SUPPLY SELECT VALVE	PCIG	D	370E	067E	2-RHRASC-B 2-RHRASC-A 2-RHRASC-D 2-RHRASC-C
SV-59-252A	COMPRESSED GAS SUPPLY SELECT VALVE	PCIG	C	370E	067E	2-RHRASC-A 2-RHRASC-B 2-RHRASC-C 2-RHRASC-D 2-MSRV

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
SV-59-252B	COMPRESSED GAS SUPPLY SELECT VALVE	PCIG	D	370E	067E	2-RHRASC-B 2-RHRASC-C 2-RHRASC-A 2-RHRASC-D
TD-81-102A	CELL "A" AIR EXHAUST DAMPER	DGEV	A	311A	079	
TD-81-102B	CELL "B" AIR EXHAUST DAMPER	DGEV	B	311B	081	
TD-81-102C	CELL "C" AIR EXHAUST DAMPER	DGEV	C	311C	080	
TD-81-102D	CELL "D" AIR EXHAUST DAMPER	DGEV	D	311D	082	
TD-81-102E	CELL "A" AIR EXHAUST DAMPER	DGEV	A	311A	079	
TD-81-102F	CELL "B" AIR EXHAUST DAMPER	DGEV	B	311B	081	
TD-81-102G	CELL "C" AIR EXHAUST DAMPER	DGEV	C	311C	080	
TD-81-102H	CELL "D" AIR EXHAUST DAMPER	DGEV	D	311D	082	
TD-81-202A	CELL "A" AIR EXHAUST DAMPER	DGEV	A	315A	083	
TD-81-202B	CELL "B" AIR EXHAUST DAMPER	DGEV	B	315B	085	
TD-81-202C	CELL "C" AIR EXHAUST DAMPER	DGEV	C	315C	084	
TD-81-202D	CELL "D" AIR EXHAUST DAMPER	DGEV	D	315D	086	
TD-81-202E	CELL "A" AIR EXHAUST DAMPER	DGEV	A	315A	083	
TD-81-202F	CELL "B" AIR EXHAUST DAMPER	DGEV	B	315B	085	
TD-81-202G	CELL "C" AIR EXHAUST DAMPER	DGEV	C	315C	084	
TD-81-202H	CELL "D" AIR EXHAUST DAMPER	DGEV	D	315D	086	
TE-41-101A	TEMPERATURE ELEMENT	SPI	A	101	029	
TE-41-101B	TEMPERATURE ELEMENT	SPI	A	101	029	
TE-41-101C	TEMPERATURE ELEMENT	SPI	A	101	029	
TE-41-101D	TEMPERATURE ELEMENT	SPI	A	101	029	
TE-41-101E	TEMPERATURE ELEMENT	SPI	A	101	029	
TE-41-101F	TEMPERATURE ELEMENT	SPI	A	101	029	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
TE-41-101G	TEMPERATURE ELEMENT	SPI	A	101	029	
TE-41-101H	TEMPERATURE ELEMENT	SPI	A	101	029	
TE-41-103A	TEMPERATURE ELEMENT	SPI	B	101	029	
TE-41-103B	TEMPERATURE ELEMENT	SPI	B	101	029	
TE-41-103C	TEMPERATURE ELEMENT	SPI	B	101	029	
TE-41-103D	TEMPERATURE ELEMENT	SPI	B	101	029	
TE-41-103E	TEMPERATURE ELEMENT	SPI	B	101	029	
TE-41-103F	TEMPERATURE ELEMENT	SPI	B	101	029	
TE-41-103G	TEMPERATURE ELEMENT	SPI	B	101	029	
TE-41-103H	TEMPERATURE ELEMENT	SPI	B	101	029	
TE-41-201A	TEMPERATURE ELEMENT	SPI	A	172	052	
TE-41-201B	TEMPERATURE ELEMENT	SPI	A	172	052	
TE-41-201C	TEMPERATURE ELEMENT	SPI	A	172	052	
TE-41-201D	TEMPERATURE ELEMENT	SPI	A	172	052	
TE-41-201E	TEMPERATURE ELEMENT	SPI	A	172	052	
TE-41-201F	TEMPERATURE ELEMENT	SPI	A	172	052	
TE-41-201G	TEMPERATURE ELEMENT	SPI	A	172	052	
TE-41-201H	TEMPERATURE ELEMENT	SPI	A	172	052	
TE-41-203A	TEMPERATURE ELEMENT	SPI	B	172	052	
TE-41-203B	TEMPERATURE ELEMENT	SPI	B	172	052	
TE-41-203C	TEMPERATURE ELEMENT	SPI	B	172	052	
TE-41-203D	TEMPERATURE ELEMENT	SPI	B	172	052	
TE-41-203E	TEMPERATURE ELEMENT	SPI	B	172	052	
TE-41-203F	TEMPERATURE ELEMENT	SPI	B	172	052	
TE-41-203G	TEMPERATURE ELEMENT	SPI	B	172	052	
TE-41-203H	TEMPERATURE ELEMENT	SPI	B	172	052	
TE-76-121A	TEMPERATURE ELEMENT	REV	A	108	033	
TE-76-121B	TEMPERATURE ELEMENT	REV	A	108	033	
TE-76-122A	TEMPERATURE ELEMENT	REV	B	109	034	
TE-76-122B	TEMPERATURE ELEMENT	REV	B	109	034	
TE-76-123A	TEMPERATURE ELEMENT	REV	A	102	032	
TE-76-123B	TEMPERATURE ELEMENT	REV	B	103	031	
TE-76-123C	TEMPERATURE ELEMENT	REV	C	102	032	
TE-76-123D	TEMPERATURE ELEMENT	REV	D	103	031	
TE-76-123E	TEMPERATURE ELEMENT	REV	A	102	032	
TE-76-123F	TEMPERATURE ELEMENT	REV	B	103	031	
TE-76-123G	TEMPERATURE ELEMENT	REV	C	102	032	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
TE-76-123H	TEMPERATURE ELEMENT	REV	D	103	031	
TE-76-221A	TEMPERATURE ELEMENT	REV	A	179	056	
TE-76-221B	TEMPERATURE ELEMENT	REV	A	179	056	
TE-76-222A	TEMPERATURE ELEMENT	REV	B	180	057	
TE-76-222B	TEMPERATURE ELEMENT	REV	B	180	057	
TE-76-223A	TEMPERATURE ELEMENT	REV	A	173	054	
TE-76-223B	TEMPERATURE ELEMENT	REV	B	174	055	
TE-76-223C	TEMPERATURE ELEMENT	REV	C	173	054	
TE-76-223D	TEMPERATURE ELEMENT	REV	D	174	055	
TE-76-223E	TEMPERATURE ELEMENT	REV	A	173	054	
TE-76-223F	TEMPERATURE ELEMENT	REV	B	174	055	
TE-76-223G	TEMPERATURE ELEMENT	REV	C	173	054	
TE-76-223H	TEMPERATURE ELEMENT	REV	D	174	055	
TE-81-040A	TEMPERATURE ELEMENT	SPPV	A	1000	122	
TE-81-040B	TEMPERATURE ELEMENT	SPPV	B	1005	123	
TE-81-040C	TEMPERATURE ELEMENT	SPPV	C	1000	122	
TE-81-040D	TEMPERATURE ELEMENT	SPPV	D	1005	123	
TE-81-041A	TEMPERATURE ELEMENT	SPPV	A	1000	122	
TE-81-041B	TEMPERATURE ELEMENT	SPPV	B	1005	123	
TE-81-041C	TEMPERATURE ELEMENT	SPPV	C	1000	122	
TE-81-041D	TEMPERATURE ELEMENT	SPPV	D	1005	123	
TE-81-101A	TEMPERATURE ELEMENT	DGEV	A	311A	079	
TE-81-101B	TEMPERATURE ELEMENT	DGEV	B	311B	081	
TE-81-101C	TEMPERATURE ELEMENT	DGEV	C	311C	080	
TE-81-101D	TEMPERATURE ELEMENT	DGEV	D	311D	082	
TE-81-101E	TEMPERATURE ELEMENT	DGEV	A	311A	079	
TE-81-101F	TEMPERATURE ELEMENT	DGEV	B	311B	081	
TE-81-101G	TEMPERATURE ELEMENT	DGEV	C	311C	080	
TE-81-101H	TEMPERATURE ELEMENT	DGEV	D	311D	082	
TE-81-201A	TEMPERATURE ELEMENT	DGEV	A	315A	083	
TE-81-201B	TEMPERATURE ELEMENT	DGEV	B	315B	085	
TE-81-201C	TEMPERATURE ELEMENT	DGEV	C	315C	084	
TE-81-201D	TEMPERATURE ELEMENT	DGEV	D	315D	086	
TE-81-201E	TEMPERATURE ELEMENT	DGEV	A	315A	083	
TE-81-201F	TEMPERATURE ELEMENT	DGEV	B	315B	085	
TE-81-201G	TEMPERATURE ELEMENT	DGEV	C	315C	084	
TE-81-201H	TEMPERATURE ELEMENT	DGEV	D	315D	086	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
TI-41-101	SUPPRESSION POOL TEMPERATURE INDICATOR	SPI	A	533	024	1-SPI
TI-41-102	SUPPRESSION POOL TEMPERATURE INDICATOR	SPI	A	540	026	1-SPI
TI-41-103	SUPPRESSION POOL TEMPERATURE INDICATOR	SPI	B	533	024	1-SPI
TI-41-201	SUPPRESSION POOL TEMPERATURE INDICATOR	SPI	A	533	024	2-SPI
TI-41-202	SUPPRESSION POOL TEMPERATURE INDICATOR	SPI	A	540	026	2-SPI
TI-41-203	SUPPRESSION POOL TEMPERATURE INDICATOR	SPI	B	533	024	2-SPI
TI-50-140B	TEMPERATURE INDICATOR	RCIC	A	108	033	
TI-50-240B	TEMPERATURE INDICATOR	RCIC	A	179	056	
TISH-20-121A	TEMPERATURE INDICATING SWITCH	SDG	A	312A	079	
TISH-20-121B	TEMPERATURE INDICATING SWITCH	SDG	B	312B	081	
TISH-20-121C	TEMPERATURE INDICATING SWITCH	SDG	C	312C	080	
TISH-20-121D	TEMPERATURE INDICATING SWITCH	SDG	D	312D	082	
TISH-20-221A	TEMPERATURE INDICATING SWITCH	SDG	A	316A	083	
TISH-20-221B	TEMPERATURE INDICATING SWITCH	SDG	B	316B	085	
TISH-20-221C	TEMPERATURE INDICATING SWITCH	SDG	C	316C	084	
TISH-20-221D	TEMPERATURE INDICATING SWITCH	SDG	D	316D	086	
TISL-81-040A	TEMPERATURE INDICATING SWITCH	SPPV	A	1000	122	
TISL-81-040B	TEMPERATURE INDICATING SWITCH	SPPV	B	1005	123	
TISL-81-040C	TEMPERATURE INDICATING SWITCH	SPPV	C	1000	122	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
TISL-81-040D	TEMPERATURE INDICATING SWITCH	SPPV	D	1005	123	
TIT-76-121A	RCIC COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	A	200	042	
TIT-76-121B	RCIC COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	A	200	042	
TIT-76-122A	HPCI COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	B	207	041	
TIT-76-122B	HPCI COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	B	207	041	
TIT-76-123A	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	A	200	042	
TIT-76-123B	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	B	207	041	
TIT-76-123C	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	C	200	042	
TIT-76-123D	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	D	207	041	
TIT-76-123E	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	A	200	042	
TIT-76-123F	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	B	207	041	
TIT-76-123G	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	C	200	042	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
TIT-76-123H	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	D	207	041	
TIT-76-221A	RCIC COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	A	284	064	
TIT-76-221B	RCIC COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	A	284	064	
TIT-76-222A	HPCI COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	B	279	065	
TIT-76-222B	HPCI COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	B	279	065	
TIT-76-223A	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	A	284	064	
TIT-76-223B	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	B	279	065	
TIT-76-223C	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	C	284	064	
TIT-76-223D	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	D	279	065	
TIT-76-223E	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	A	284	064	
TIT-76-223F	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	B	279	065	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
TIT-76-223G	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	C	284	064	
TIT-76-223H	RHR COMPARTMENT TEMPERATURE INDICATING TRANSMITTER	REV	D	279	065	
TRS-41-101	DIV. I SUPPRESSION POOL TEMPERATURE MONITORING SYSTEM	SPI	A	533	024	
TRS-41-103	DIV. II SUPPRESSION POOL TEMPERATURE MONITORING SYSTEM	SPI	B	533	024	
TRS-41-201	DIV. I SUPPRESSION POOL TEMPERATURE MONITORING SYSTEM	SPI	A	533	024	
TRS-41-203	DIV. II SUPPRESSION POOL TEMPERATURE MONITORING SYSTEM	SPI	B	533	024	
TSH-HH76-121A	TEMPERATURE SWITCH	REV	A	200	042	
TSH-HH76-121B	TEMPERATURE SWITCH	REV	B	200	042	
TSH-HH76-122A	TEMPERATURE SWITCH	REV	A	207	041	
TSH-HH76-122B	TEMPERATURE SWITCH	REV	B	207	041	
TSH-HH76-123A	TEMPERATURE SWITCH	REV	A	200	042	
TSH-HH76-123B	TEMPERATURE SWITCH	REV	B	207	041	
TSH-HH76-123C	TEMPERATURE SWITCH	REV	C	200	042	
TSH-HH76-123D	TEMPERATURE SWITCH	REV	D	207	041	
TSH-HH76-123E	TEMPERATURE SWITCH	REV	A	200	042	
TSH-HH76-123F	TEMPERATURE SWITCH	REV	B	207	041	
TSH-HH76-123G	TEMPERATURE SWITCH	REV	C	200	042	
TSH-HH76-123H	TEMPERATURE SWITCH	REV	D	207	041	
TSH-HH76-221A	TEMPERATURE SWITCH	REV	A	284	064	
TSH-HH76-221B	TEMPERATURE SWITCH	REV	B	284	064	
TSH-HH76-222A	TEMPERATURE SWITCH	REV	A	279	065	
TSH-HH76-222B	TEMPERATURE SWITCH	REV	B	279	065	
TSH-HH76-223A	TEMPERATURE SWITCH	REV	A	284	064	
TSH-HH76-223B	TEMPERATURE SWITCH	REV	B	279	065	
TSH-HH76-223C	TEMPERATURE SWITCH	REV	C	284	064	
TSH-HH76-223D	TEMPERATURE SWITCH	REV	D	279	065	
TSH-HH76-223E	TEMPERATURE SWITCH	REV	A	284	064	
TSH-HH76-223F	TEMPERATURE SWITCH	REV	B	279	065	
TSH-HH76-223G	TEMPERATURE SWITCH	REV	C	284	064	
TSH-HH76-223H	TEMPERATURE SWITCH	REV	D	279	065	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
TSH-HH81-101A	TEMPERATURE SWITCH	DGEV	A	311A	079	
TSH-HH81-101B	TEMPERATURE SWITCH	DGEV	B	311B	081	
TSH-HH81-101C	TEMPERATURE SWITCH	DGEV	C	311C	080	
TSH-HH81-101D	TEMPERATURE SWITCH	DGEV	D	311D	082	
TSH-HH81-101E	TEMPERATURE SWITCH	DGEV	A	311A	079	
TSH-HH81-101F	TEMPERATURE SWITCH	DGEV	B	311B	081	
TSH-HH81-101G	TEMPERATURE SWITCH	DGEV	C	311C	080	
TSH-HH81-101H	TEMPERATURE SWITCH	DGEV	D	311D	082	
TSH-HH81-201A	TEMPERATURE SWITCH	DGEV	A	315A	083	
TSH-HH81-201B	TEMPERATURE SWITCH	DGEV	B	315B	085	
TSH-HH81-201C	TEMPERATURE SWITCH	DGEV	C	315C	084	
TSH-HH81-201D	TEMPERATURE SWITCH	DGEV	D	315D	086	
TSH-HH81-201E	TEMPERATURE SWITCH	DGEV	A	315A	083	
TSH-HH81-201F	TEMPERATURE SWITCH	DGEV	B	315B	085	
TSH-HH81-201G	TEMPERATURE SWITCH	DGEV	C	315C	084	
TSH-HH81-201H	TEMPERATURE SWITCH	DGEV	D	315D	086	
TSHL-76-121A	TEMPERATURE SWITCH	REV	A	200	042	
TSHL-76-121B	TEMPERATURE SWITCH	REV	B	200	042	
TSHL-76-122A	TEMPERATURE SWITCH	REV	A	207	041	
TSHL-76-122B	TEMPERATURE SWITCH	REV	B	207	041	
TSHL-76-123A	TEMPERATURE SWITCH	REV	A	200	042	
TSHL-76-123B	TEMPERATURE SWITCH	REV	B	207	041	
TSHL-76-123C	TEMPERATURE SWITCH	REV	C	200	042	
TSHL-76-123D	TEMPERATURE SWITCH	REV	D	207	041	
TSHL-76-123E	TEMPERATURE SWITCH	REV	A	200	042	
TSHL-76-123F	TEMPERATURE SWITCH	REV	B	207	041	
TSHL-76-123G	TEMPERATURE SWITCH	REV	C	200	042	
TSHL-76-123H	TEMPERATURE SWITCH	REV	D	207	041	
TSHL-76-221A	TEMPERATURE SWITCH	REV	A	284	064	
TSHL-76-221B	TEMPERATURE SWITCH	REV	B	284	064	
TSHL-76-222A	TEMPERATURE SWITCH	REV	A	279	065	
TSHL-76-222B	TEMPERATURE SWITCH	REV	B	279	065	
TSHL-76-223A	TEMPERATURE SWITCH	REV	A	284	064	
TSHL-76-223B	TEMPERATURE SWITCH	REV	B	279	065	
TSHL-76-223C	TEMPERATURE SWITCH	REV	C	284	064	
TSHL-76-223D	TEMPERATURE SWITCH	REV	D	279	065	
TSHL-76-223E	TEMPERATURE SWITCH	REV	A	284	064	
TSHL-76-223F	TEMPERATURE SWITCH	REV	B	279	065	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
TSHL-76-223G	TEMPERATURE SWITCH	REV	C	284	064	
TSHL-76-223H	TEMPERATURE SWITCH	REV	D	279	065	
TSHL-81-341A	TEMPERATURE SWITCH	SPPV	A	1000	122	
TSHL-81-341B	TEMPERATURE SWITCH	SPPV	B	1005	123	
TSHL-81-341C	TEMPERATURE SWITCH	SPPV	C	1000	122	
TSHL-81-341D	TEMPERATURE SWITCH	SPPV	D	1005	123	
TTICSL-81-041A	SYSTEM "A" FAN CABINET TEMPERATURE INDICATING CONTROLLER	SPPV	A	1000	122	
TTICSL-81-041B	SYSTEM "B" FAN CABINET TEMPERATURE INDICATING CONTROLLER	SPPV	B	1005	123	
TTICSL-81-041C	SYSTEM "C" FAN CABINET TEMPERATURE INDICATING CONTROLLER	SPPV	C	1000	122	
TTICSL-81-041D	SYSTEM "D" FAN CABINET TEMPERATURE INDICATING CONTROLLER	SPPV	D	1005	123	
TTICSHL-81-101A	CELL "A" EXHAUST FAN CONTROLLER	DGEV	A	311A	079	
TTICSHL-81-101B	CELL "B" EXHAUST FAN CONTROLLER	DGEV	B	311B	081	
TTICSHL-81-101C	CELL "C" EXHAUST FAN CONTROLLER	DGEV	C	311C	080	
TTICSHL-81-101D	CELL "D" EXHAUST FAN CONTROLLER	DGEV	D	311D	082	
TTICSHL-81-101E	CELL "A" EXHAUST FAN CONTROLLER	DGEV	A	311A	079	
TTICSHL-81-101F	CELL "B" EXHAUST FAN CONTROLLER	DGEV	B	311B	081	
TTICSHL-81-101G	CELL "C" EXHAUST FAN CONTROLLER	DGEV	C	311C	080	
TTICSHL-81-101H	CELL "D" EXHAUST FAN CONTROLLER	DGEV	D	311D	082	
TTICSHL-81-201A	CELL "A" EXHAUST FAN CONTROLLER	DGEV	A	315A	083	
TTICSHL-81-201B	CELL "B" EXHAUST FAN CONTROLLER	DGEV	B	315B	085	

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
TTICSHL-81-201C	CELL "C" EXHAUST FAN CONTROLLER	DGEV	C	315C	084	
TTICSHL-81-201D	CELL "D" EXHAUST FAN CONTROLLER	DGEV	D	315D	086	
TTICSHL-81-201E	CELL "A" EXHAUST FAN CONTROLLER	DGEV	A	315A	083	
TTICSHL-81-201F	CELL "B" EXHAUST FAN CONTROLLER	DGEV	B	315B	085	
TTICSHL-81-201G	CELL "C" EXHAUST FAN CONTROLLER	DGEV	C	315C	084	
TTICSHL-81-201H	CELL "D" EXHAUST FAN CONTROLLER	DGEV	D	315D	086	
TY-41-102	TEMPERATURE CONVERTER	SPI	A	540	026	
TY-41-202	TEMPERATURE CONVERTER	SPI	A	540	026	
TY-81-101A	TEMPERATURE SIGNAL SELECTOR	DGEV	A	311A	079	
TY-81-101B	TEMPERATURE SIGNAL SELECTOR	DGEV	B	311B	081	
TY-81-101C	TEMPERATURE SIGNAL SELECTOR	DGEV	C	311C	080	
TY-81-101D	TEMPERATURE SIGNAL SELECTOR	DGEV	D	311D	082	
TY-81-201A	TEMPERATURE SIGNAL SELECTOR	DGEV	A	315A	083	
TY-81-201B	TEMPERATURE SIGNAL SELECTOR	DGEV	B	315B	085	
TY-81-201C	TEMPERATURE SIGNAL SELECTOR	DGEV	C	315C	084	
TY-81-201D	TEMPERATURE SIGNAL SELECTOR	DGEV	D	315D	086	
XR-42-1R623A	REACTOR VESSEL PRESSURE AND WATER LEVEL RECORDER	RVI	A	533	024	1-RVI
XR-42-1R623B	REACTOR VESSEL PRESSURE AND WATER LEVEL RECORDER	RVI	B	533	024	1-RVI
XR-42-2R623A	REACTOR VESSEL PRESSURE AND WATER LEVEL RECORDER	RVI	A	533	024	2-RVI
XR-42-2R623B	REACTOR VESSEL PRESSURE AND WATER LEVEL RECORDER	RVI	B	533	024	2-RVI

Table 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Component	Description	Plant Sys.	Sfgd. Chan.	Room	Fire Area	FSSD Sys. Design.
ZC-81-102A	POSITION CONTROLLER	DGEV	A	311A	079	
ZC-81-102B	POSITION CONTROLLER	DGEV	B	311B	081	
ZC-81-102C	POSITION CONTROLLER	DGEV	C	311C	080	
ZC-81-102D	POSITION CONTROLLER	DGEV	D	311D	082	
ZC-81-102E	POSITION CONTROLLER	DGEV	A	311A	079	
ZC-81-102F	POSITION CONTROLLER	DGEV	B	311B	081	
ZC-81-102G	POSITION CONTROLLER	DGEV	C	311C	080	
ZC-81-102H	POSITION CONTROLLER	DGEV	D	311D	082	
ZC-81-202A	POSITION CONTROLLER	DGEV	A	315A	083	
ZC-81-202B	POSITION CONTROLLER	DGEV	B	315B	085	
ZC-81-202C	POSITION CONTROLLER	DGEV	C	315C	084	
ZC-81-202D	POSITION CONTROLLER	DGEV	D	315D	086	
ZC-81-202E	POSITION CONTROLLER	DGEV	A	315A	083	
ZC-81-202F	POSITION CONTROLLER	DGEV	B	315B	085	
ZC-81-202G	POSITION CONTROLLER	DGEV	C	315C	084	
ZC-81-202H	POSITION CONTROLLER	DGEV	D	315D	086	

LEGEND FOR TABLE 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

The information presented in each column of Table 9A-4 is explained as follows.

Component	Major Safe Shutdown Components NOTE: Components identified with an asterix (*) designate associations of equipment and cables that perform common functions. These designations are used for analysis purposes only, and do not represent plant identification.
Description	Brief description of the component
Plant Sys.	General FSSD system designation for the component, based on the function the component provides

KEY:

ADS	Automatic Depressurization System
APS	13kV Power Supply to the 4kV Safeguard Busses
CS	Core Spray
DGEV	Diesel Generator Enclosure Ventilation
EPS	Class 1E Power Distribution System
ESW	Emergency Service Water System
HI/LOW	Selected Reactor Coolant Pressure Boundaries and High Low Pressure Interfaces
HPCI	High Pressure Coolant Injection System
MSRV	Main Steam Relief Valves
PCIG	Primary Containment Instrument Gas System
RCIC	Reactor Core Isolation Cooling System
REV	Reactor Enclosure Ventilation
RHR	Residual Heat Removal System
RHRSW	Residual Heat Removal Service Water System
RVI	Reactor Vessel Instrumentation
SDG	Standby Diesel Generators and Auxiliaries
SPI	Suppression Pool Instrumentation
SPPV	Spray Pond Pump Structure Ventilation

LEGEND FOR TABLE 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

Sfgd. Chan.	Safeguard Channel designation for electrical components NOTE: Components identified with a letter in parenthesis are not designated as safeguard, but are energized from the Safeguard Channel indicated.
Room	Room location for the component Components located in rooms which are subdivided by Combustible Free Zones have an East or West suffix provided to more precisely identify their location.
Fire Area	Fire Area location for the component Components located in Fire Areas which are subdivided by Combustible Free Zones have an East or West suffix provided to more precisely identify their location.
FSSD Sys.	Fire Safe Shutdown System/Train Designation
Desig.	Populated for components which directly support a Safe Shutdown Function**.** KEY: A-BBBBB-C A Unit (0, 1, 2) BBBBB System Function Designation (see table below) C Loop/Train (provided for multi-train systems)

LEGEND FOR TABLE 9A-4 (Cont'd)

MAJOR COMPONENTS ANALYZED FOR FIRE SAFE SHUTDOWN

System Function Designations:

ESW	Emergency Service Water
ADS	Automatic Depressurization System
HI/LOW	Selected Reactor Coolant Pressure Boundaries and High Low Pressure Interfaces
HPCI	High Pressure Coolant Injection System
HPCITRIP	HPCI shutdown capability
MSRV	Main Steam Relief Valves
RCIC	Reactor Core Isolation Cooling System
RCICTRIP	RCIC shutdown capability
RHRASC	RHR Alternate Shutdown Cooling Mode
RHRLPCI	RHR Low Pressure Coolant Injection Mode
RHRSC	RHR Shutdown Cooling Mode
RHRSPC	RHR Suppression Pool Cooling Mode
RHRSW	RHR Service Water
RVI	Reactor Vessel Instrumentation - Direct-reading indication of Reactor parameters
SPI	Suppression Pool Instrumentation - Direct-reading indication of Suppression Pool parameters

Tables 9A-5 through 9A-11

Tables 9A-5 through 9A-11
(Deleted)

Table 9A-12

RCPB VALVES SUSCEPTIBLE TO
FIRE INDUCED SPURIOUS OPERATION

P&ID NUMBER	INTERFACE VALVES[1,2]	REMARKS
M-41	(U) HV-41-1F001 (D) HV-41-1F002 (U) HV-41-2F001 (D) HV-41-2F002	Located in piping from the RPV head vent line to the drywell equipment drain tank. If both valves open due to fire damage, the steam released into the drain tank would be vented into the drywell via the 4 inch vent line. No equipment needed for safe shutdown would be damaged.
M-41	(S) PSV-41-1F013A (S) PSV-41-2F013A	Located in a branch line connected to the main steam piping inside primary containment. Typical for suffix "B", "C", "D", "E", "F", "G", "H", "J", "K", "L", "M", "N", and "S" valves. If this valve opens, steam will be discharged from the reactor vessel to the suppression pool. Released reactor coolant will be retained inside the primary containment, and no equipment needed for safe shutdown will be damaged.
M-41	(U) HV-41-1F016 (D) HV-41-1F019 (U) HV-41-2F016 (D) HV-41-2F019	Located in the main steam drain line. If both of these valves open due to fire damage, various leakage paths downstream of the valves could allow reactor coolant to be discharged to the main condenser or the main steam tunnel. For all of the potential flow paths, this condition is acceptable because (a) the reactor vessel inventory can be maintained by the coolant makeup pumps that are available for each of the shutdown methods, (b) the mass inventory expected to be released is less than that expected for a main steam line break outside primary containment, and (c) the release of reactor coolant will not cause damage to any equipment needed for safe shutdown
M-41	(U) HV-41-1F022A (D) HV-41-1F028A (U) HV-41-2F022A (D) HV-41-2F028A	Located in the main steam lines between the reactor vessel and the turbine-generator. Typical for suffix "B", "C", and "D" valves. If both of these valves open simultaneously due to fire damage, the main steam piping outside primary containment would be pressurized. Although the main steam piping leading to the main turbine is designed as high pressure piping, there are a number of potential leakage paths associated with branch lines from the main steam lines. Because of the high reliability of the MSIVs and because of the fail-safe features of their design, these valves are assumed to retain their capability to close and remain closed during a postulated fire.

Table 9A-12 (Cont'd)

P&ID NUMBER	INTERFACE VALVES[1,2]	REMARKS
M-41	(U) HV-41-1F084 (D) HV-41-1F085	Located in the sample line from main steam line C to sample station 10S292 (20S292). If both valves open due to fire damage, a closed manual valve at the sample station would prevent steam blowdown.
M-41	(U) HV-41-109A (U) HV-41-109B (D) HV-41-110 (U) HV-41-209A (U) HV-41-209B (D) HV-41-210	Located in the feedwater recirculation line between the main feedwater headers and the main condenser. Opening either HV-041-1(2)09A or B and HV-041-1(2)10 will divert HPCI, RCIC, or RWCU to the main condenser. Valves HV-041-1(2)09A and HV-041-1(2)B are locked closed by locking open the breaker at the MCC per the plant operating procedures during plant startup. By de-energizing the breakers, fires which affect the control circuits to the valves are prevented from causing the valves to spuriously open. Spurious operation due to three phase faults to their power cable is not considered credible per Reg Guide 1.189 Revision 4.
M-43	(U) HV-43-1F019 (D) HV-43-1F020 (U) HV-43-2F019 (D) HV-43-2F020	Located in the sample line from recirculation loop B to sample station 10S292 (20S292). This spurious operation or loss of capability to close these valves due to fire damage, will allow the sample line to blowdown to clean radwaste system (CRWS). The leakage is acceptable because the inventory loss is within the RCIC pump make-up capability, the blowdown is limited by the 1/4 inch sample line and the release of reactor coolant will not cause damage to any equipment needed for safe shutdown.

Table 9A-12 (Cont'd)

P&ID NUMBER	INTERFACE VALVES[1,2]	REMARKS
M-44	(U) HV-44-1F031 (U) HV-C44-1F033 (D) HV-44-1F034 (D) HV-44-1F035 (U) HV-44-2F031 (U) HV-C44-2F033 (D) HV-44-2F034 (D) HV-44-2F035	Located in the blowdown line from the RWCU system. If only valve HV-C44-1(2)F033 opens spuriously together with either HV-44-1(2)F034 or HV-44-1(2)F035 valve water from the RWCU system would be discharged to either the main condenser or the equipment drain collection tank. No equipment needed for safe shutdown would be damaged by the discharge of reactor coolant and the reactor vessel inventory can be maintained by the coolant makeup pumps that are available for each of the shutdown methods. To ensure that HV-44-1(2)F031 does not open and the blowdown flow rate is limited to an acceptable value, the power circuit for valve HV- 44-1F031 (2F031) will be isolated (with the valve in the fully closed position) when reactor pressure exceeds 75 psig.
M-44	(S) SV-45-101A (S) SV-45-201A	Located in the RWCU filter/demineralizer sample line. Typical for the suffix "B" valve. The loss of capability to close these valves due to fire damage, will allow the sample line to blowdown to clean radwaste system (CRWS). The leakage is acceptable because the inventory loss is within the RICI pump make-up capability, the blowdaown is limited by the 1/4 inch sample line and the release of reactor coolant will not cause damage to any equipment needed for safe shutdown.
M-47	(U) XV-47-1F010 (D) XV-47-1F180 (U) XV-47-2F010 (D) XV-47-2F180	Located in the vent line from the scram discharge volume to an open floor drain. The SDV would be at high pressure only during the period following a scram and prior to reset of the scram signal. The discharge of water from the SDV into a floor drain during this period would not cause damage to any equipment needed for safe shutdown, and the flow rate would be low enough so that reactor vessel inventory could be maintained by the coolant makeup pumps that are available for each shutdown method.
M-47	(U) XV-47-1F011 (D) XV-47-1F181 (U) XV-47-2F011 (D) XV-47-2F181	Located in the drain line from the scram discharge volume to the equipment drain collection tank (via 8" HBC-133/233). The SDV would be at high pressure only during the period following a scram and prior to reset of the scram signal. The discharge of water from the SDV to the equipment drain collection tank during this period would not cause damage to any equipment needed for safe shutdown, and the flow rate would be low enough so that reactor vessel inventory could be maintained by the coolant makeup pumps that are available for each shutdown method.

Table 9A-12 (Cont'd)

P&ID NUMBER	INTERFACE VALVES[1,2]	REMARKS
M-49	(S) LV-49-1F054 (S) LV-49-2F054	Located in the drain line from the drain pot in the RCIC steam supply line. If this valve opens due to fire damage, main steam would be discharged to the main condenser. This condition is acceptable because (a) the reactor vessel inventory can be maintained by the coolant makeup pumps that are available for each of the shutdown methods, (b) the mass inventory expected to be released is less than that expected for a main steam line break outside primary containment, and (c) the release of reactor coolant will not cause damage to any equipment needed for safe shutdown.
M-50	(S) LV-50-110 (S) LV-50-210	Located in the drain line from the drain pot in the RCIC turbine exhaust line. If this valve opens due to fire damage, at a time when RCIC steam supply line shutoff valve HV-50-1F045 (2F045) is open, main steam could bleed into the RCIC barometric condenser. This condition is acceptable because (a) the reactor vessel inventory can be maintained by the coolant makeup pumps that are available for each of the shutdown methods, (b) the mass inventory expected to be released is less than that expected for a main steam line break outside primary containment, and (c) the release of reactor coolant will not cause damage to any equipment needed for safe shutdown.
M-51	(U) HV-51-1F009 (D) HV-51-1F008 (U) HV-51-2F009 (D) HV-51-2F008	Located in the RHR shutdown cooling suction line. If both valves open due to fire damage, the RHR pump suction lines could be damaged. In order to prevent both the upstream and downstream valves from opening simultaneously, an additional interlock by means of a pressure switch, is added to monitor the reactor vessel pressure for the downstream valve. Whenever the reactor vessel pressure exceeds the design capabilities of the RHR low pressure piping the contacts of the pressure switch will open, thereby isolating the opening relay of the downstream valves and preventing the valve to open.

Table 9A-12 (Cont'd)

P&ID NUMBER	INTERFACE VALVES[1,2]	REMARKS
M-51	(U) HV-51-151A (U) HV-51-1F050A (D) HV-51-1F015A (U) 51-1200A (U) HV-51-251A (U) HV-51-2F050A (D) HV-51-2F015A (U) 51-2200A	Located in the RHR loop A shutdown cooling return line. HV-51-1F050A (2F050A) is a check valve that will close to prevent reverse flow if HV-51-1F015A (2F015A) fails in the open position. The pneumatic operator on HV-51-1F050A (2F050A) is for testing purposes only and cannot unseat the valve disk or hold it open when a differential pressure exists across the valve. However, if bypass valve HV-51-151A (251A) and the outboard containment isolation valve both open due to fire damage, the flow through the bypass line will pressurize the shutdown cooling return piping outside the drywell. The flow through the bypass line will be limited by ¼" flow restricting orifice F0-51-151A (251A) to a value that is less than the capacity of downstream relief valve PSV-51-1F025A (2F025A). The discharged reactor coolant will not overpressurize or overheat the low pressure piping and will not cause damage to any equipment required for safe shutdown. In addition, the reactor vessel inventory can be maintained by the coolant makeup pumps that are available for each of the shutdown methods. (Typical for the loop B shutdown cooling return line.) Outboard isolation valve HV-051-1F015A (2F015A) has an additional piping path from the reactor coolant pressure boundary to penetration X-13A. This small-bore piping path connects the equalizing line of valve HV-51-1F050A (2F050A) to the bonnet vent line of the recirculation pump suction block valve HV-043-1F023A (2F023A). Spring-assisted, check valve 51-1200A (2200A) in this flow path will acts as an inboard isolation valve to penetration X-13A from the recirculation system. Check valve 51-1200A (2200A) performs the same PCIV's/PIV's functions in penetration X-13A as valves HV-051-1F050A (2F050A) and HV-051-151A (251A). (Typical for the loop B shutdown cooling return line.)
M-51	(U) HV-51-142A (U) HV-51-1F041A (D) HV-51-1F017A (U) HV-51-242A (U) HV-51-2F041A (D) HV-51-2F017A	Located in the loop A LPCI injection line. HV-51-1F041A (2F041A) is a check valve that will close to prevent reverse flow if HV-51-1F017A (2F017A) fails in the open position. The pneumatic operator on HV-51-1F041A (2F041A) is for testing purposes only and cannot unseat the valve disk or hold it open when a differential pressure exists across the valve. However, if bypass valve HV-51-142A (242A) and the outboard containment isolation valve both open due to fire damage, the flow through the bypass line will pressurize the LPCI injection piping outside the drywell. The flow through the bypass line will be limited by ¼" flow restricting orifice F0-51- 142A(242A) to a value that is less than the capacity of downstream relief valve PSV-51-1F025A (2F025A). The discharged reactor coolant will not overpressurize or overheat the low pressure piping and will not cause damage to any equipment required for safe shutdown. In addition, the reactor vessel inventory can be maintained by the coolant makeup pumps that are available for each of the shutdown methods. (Typical for LPCI injection lines B, C, and D.)

Table 9A-12 (Cont'd)

P&ID NUMBER	INTERFACE VALVES(1,2)	REMARKS
M-52	(U) HV-52-1F039A (U) HV-52-1F006A (D) HV-52-1F005 (U) HV-52-2F039A (U) HV-52-2F006A (D) HV-52-2F005	Located in the loop A core spray injection line. HV-52-1F006A (2F006A) is a check valve that will close to prevent reverse flow if HV-52-1F005 (2F005) fails in the open position. The pneumatic operator on HV-52-1F006A (2F006A) is for testing purposes only and cannot unseat the valve disk or hold it open when a differential pressure exists across the valve. However, if bypass valve HV-52-1F039A (2F039A) and the outboard containment isolation valve both open due to fire damage, the flow through the bypass line will pressurize the core spray injection piping outside the drywell. The flow through the bypass line will be limited by ¼" flow restricting orifice F0-52-106A (206A) to a value that is less than the capacity of downstream relief valve PSV-52-1F012A (2F012A). The discharged reactor coolant will not overpressurize or overheat the low pressure piping and will not cause damage to any equipment required for safe shutdown. In addition, the reactor vessel inventory can be maintained by the coolant makeup pumps that are available for each of the shutdown methods.
M-52	(U) HV-52-1F039B (U) HV-52-1F006B (D) HV-52-108 (U) HV-52-2F039B (U) HV-52-2F006B (D) HV-52-208	Located in the loop B core spray injection line. The pneumatic operator on check valve HV-52-1F006B (2F006B) is for testing purposes only and cannot unseat the valve disk or hold it open when a differential pressure exists across the valve. If bypass valve HV-52-1F039B (2F039B) opens due to fire damage, reverse flow cannot occur because outboard containment isolation valve HV-52-108 (208) is a check valve.
M-55	(S) HV-55-1F054 (S) HV-55-1F054	Located in the drain line of the HPCI steam supply line drain pot. If this valve opens due to fire damage, main steam could be discharged to the main condenser. This condition is acceptable because (a) the reactor vessel inventory can be maintained by the coolant makeup pumps that are available for each of the shutdown methods, (b) the mass inventory expected to be released is less than expected for a main steam line break outside primary containment, and (c) the release of reactor coolant will not cause damage to any equipment needed for safe shutdown.

(1) Upstream valves are identified by the (U) designation. Downstream valves are identified by the (D) designation. Single valves are identified by the (S) designation. For the purposes of this study, upstream valves are defined as those valves that are closest to the RCPB.

(2) For each entry in this table, two groups of interface valves are listed. The first group consists of valves in Unit 1 and the second group consists of the corresponding valves in Unit 2.

Table 9A-13
has been DELETED.

Table 9A-14

Operations That May Be Required To Be Performed Outside The Control Room

Equipment ID	Action Description
10-A116	Operate Local Control Switches
10-A118	Trip B Control Room Chiller For MHIF
10-C601-X1	Position Valves Using Emergency Control Switches - HV-51-125B, 1F004B, 1F015B, 1F027B, HV-C-51-1F048B
10-C601-X2	Position Valve Using Emergency Control Switch - HV-51-1F017B
10TB-49-1F007	Operate Power Transfer Switch - HV-49-1F007
1A-C514	Start Diesel 1AG501 Generator Using Local Controls
1B-C514	Start Diesel 1BG501 Generator Using Local Controls
20-A116	Operate Local Control Switches
20-C601-X1	Position Valves Using Emergency Control Switches - HV-51-2F015B, 2F027B, HV-C-51-2F048B
20-C601-X2	Position Valve Using Emergency Control Switch - HV-51-2F017B
20TB-49-2F007	Operate Power Transfer Switch - HV-49-2F007
2A-C514	Start Diesel 2AG501 Generator Using Local Controls
2B-C514	Start Diesel 2BG501 Generator Using Local Controls

Table 9A-14 (Cont'd)

Operations That May Be Required To Be Performed Outside The Control Room

Equipment ID	Action Description
ADS Control at 289'	Operate ADS Valves At The PGCC
HS-51-282B	Open Valve Using Local Controls - HV-51-282B
HS-56-162	Operate Switch At 10C201 To Runback HPCI Turbine
HS-56-262	Operate Switch At 20C201 To Runback HPCI Turbine
HV-11-011B	Close Manually To Prevent Long Term ESW Flow Diversion
HV-11-015A	Close Manually To Prevent Long Term ESW Flow Diversion
HV-11-015B	Open Manually

Table 9A-14 (Cont'd)

Operations That May Be Required To Be Performed Outside The Control Room

Equipment ID	Action Description
HV-12-031B	Close Manually
HV-12-031C	Open Manually
HV-12-032B	Open Manually
HV-12-032C	Open Manually
HV-12-032D	Open / Close Manually
HV-49-1F084	Open Manually
HV-49-2F084	Open Manually
HV-51-1F003B	Open Manually
HV-51-1F006B	Close Manually
HV-51-1F008	Open Manually
HV-51-1F010A	Close Manually
HV-51-1F014B	Open Manually
HV-51-1F015A	Close Manually
HV-51-1F017B	Close Manually
HV-51-1F024B	Open Manually
HV-51-1F047B	Open Manually
HV-51-1F049	Close Manually

Table 9A-14 (Cont'd)

Operations That May Be Required To Be Performed Outside The Control Room

Equipment ID	Action Description
HV-51-1F068A	Open Manually
HV-51-1F068B	Open Manually
HV-51-2F006B	Close Manually
HV-51-2F008	Open Manually
HV-51-2F010A	Close Manually
HV-51-2F015A	Close Manually
HV-51-2F024B	Open Manually
HV-51-2F049	Close Manually
HV-51-2F068A	Open Manually
HV-51-2F068B	Open Manually
HV-51-2F073	Close Manually
HV-55-126	Open Manually
HV-C-51-1F048A	Close Manually
HV-C-51-2F048B	Close Manually
Remote Shutdown Panel (289)	Operate Equipment, Monitor Instruments

SEE FIGURE 1.10-1

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT

PIPING AND INSTRUMENT
DIAGRAM LEGEND

FIGURE 9A-1

SEE FIGURE 9.5-1

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT

P&ID
FIRE PROTECTION

FIGURE 9A-2

Figure 9A-3

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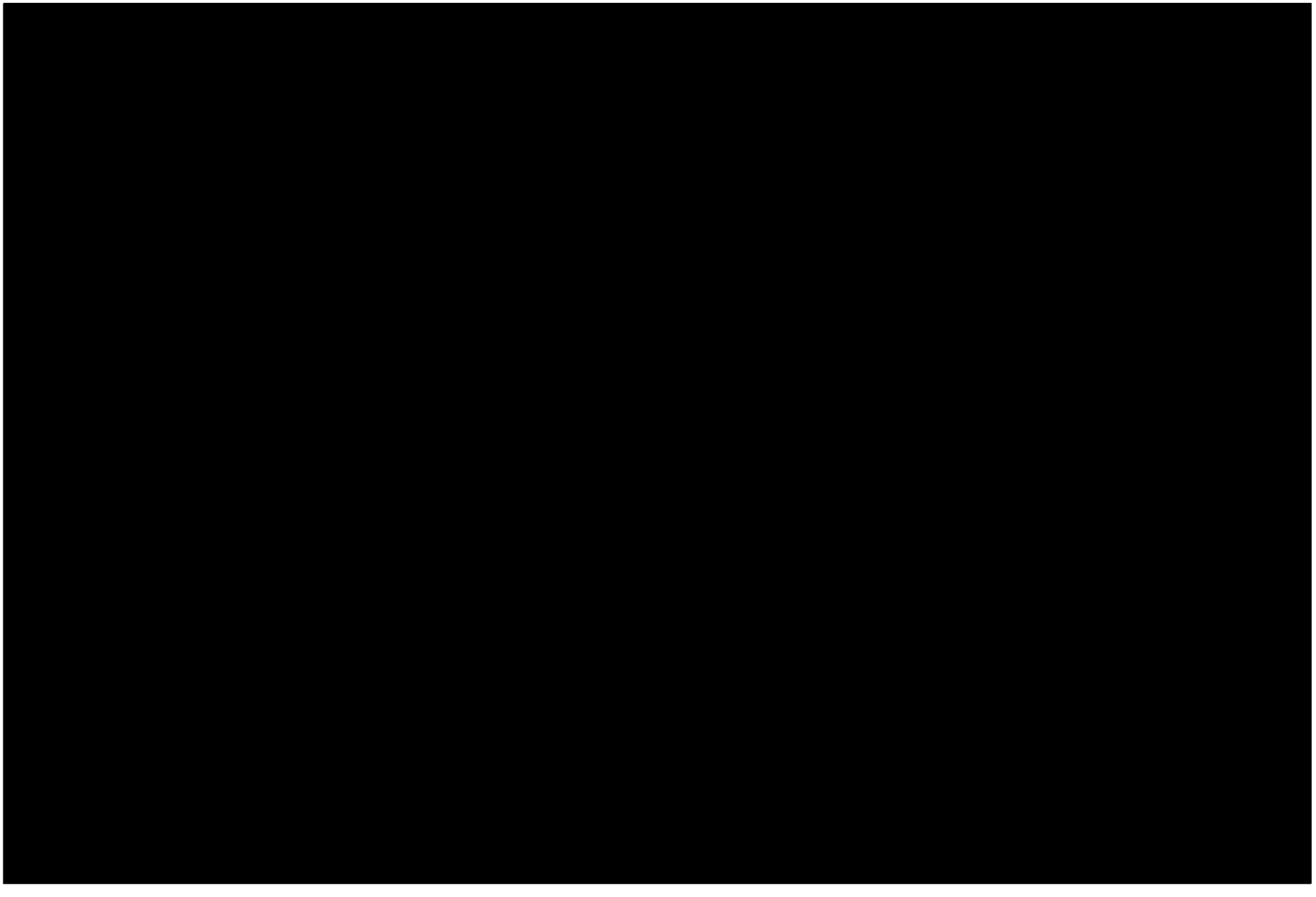
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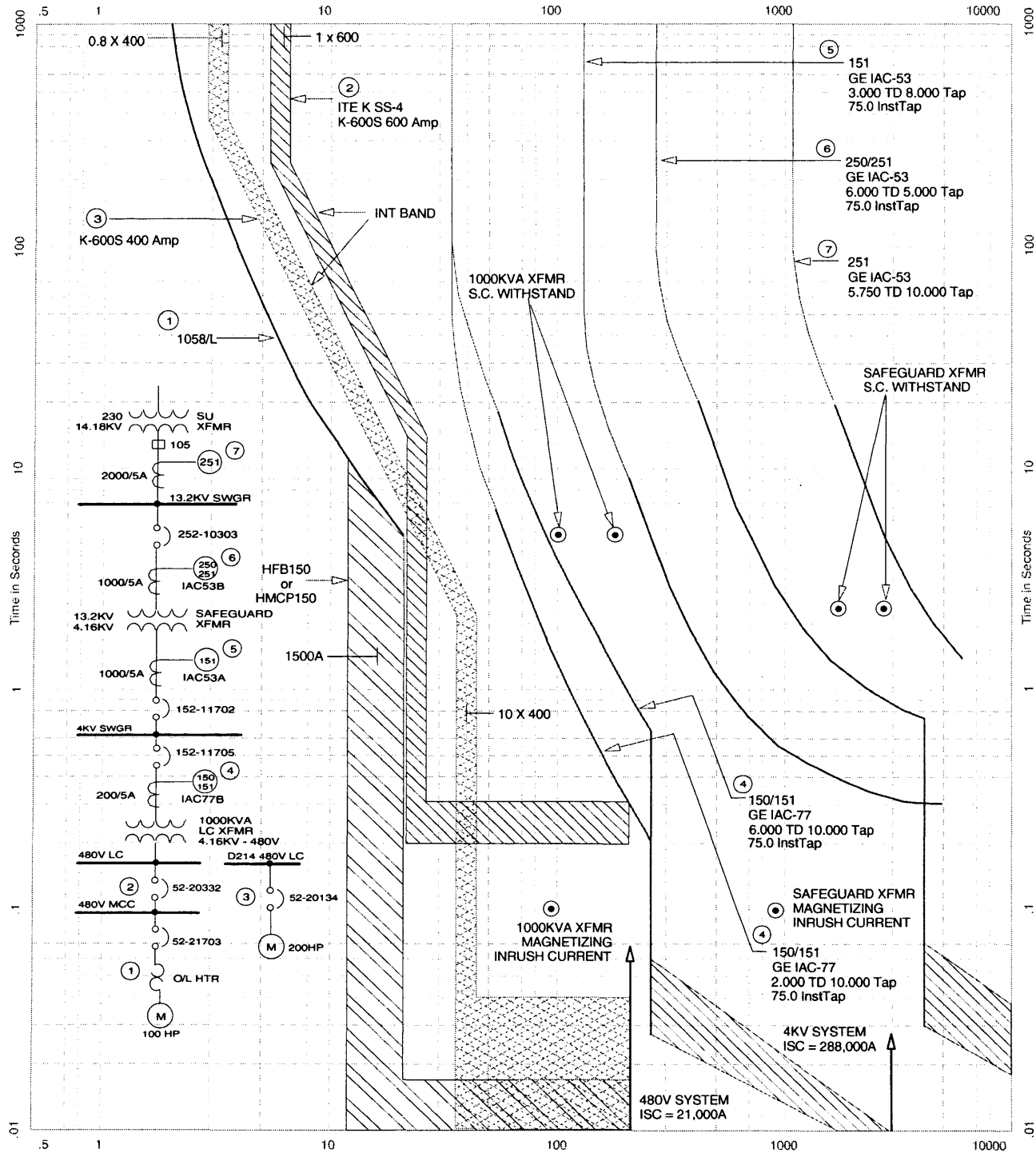




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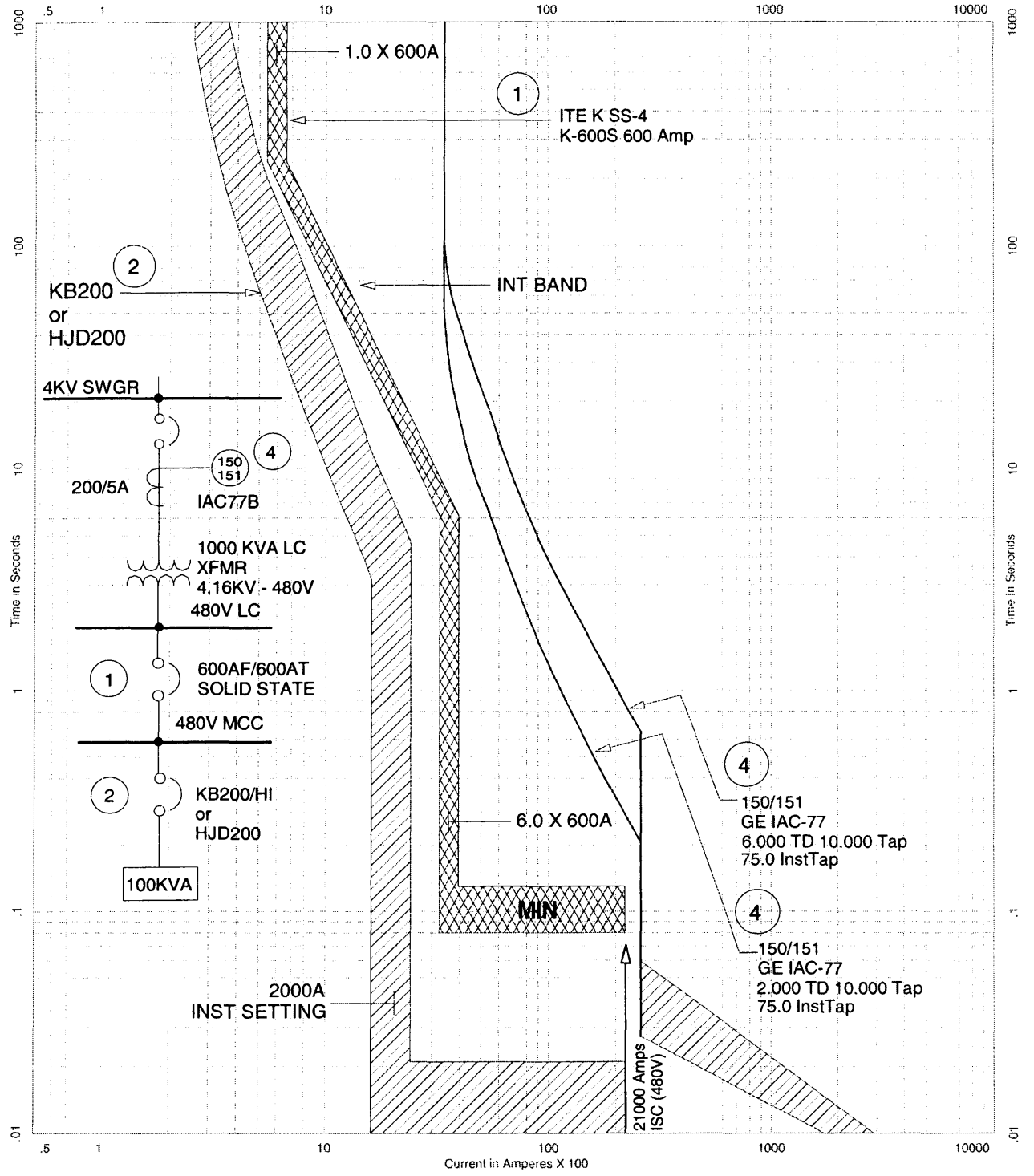


LIMERICK GENERATING STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT

SAFEGUARD AUX. SYSTEM PHASE O.C. PROTECTION AND COORDINATION

FIGURE 9A-13 Sht. 1 of 2 **Rev. 13 09/06**

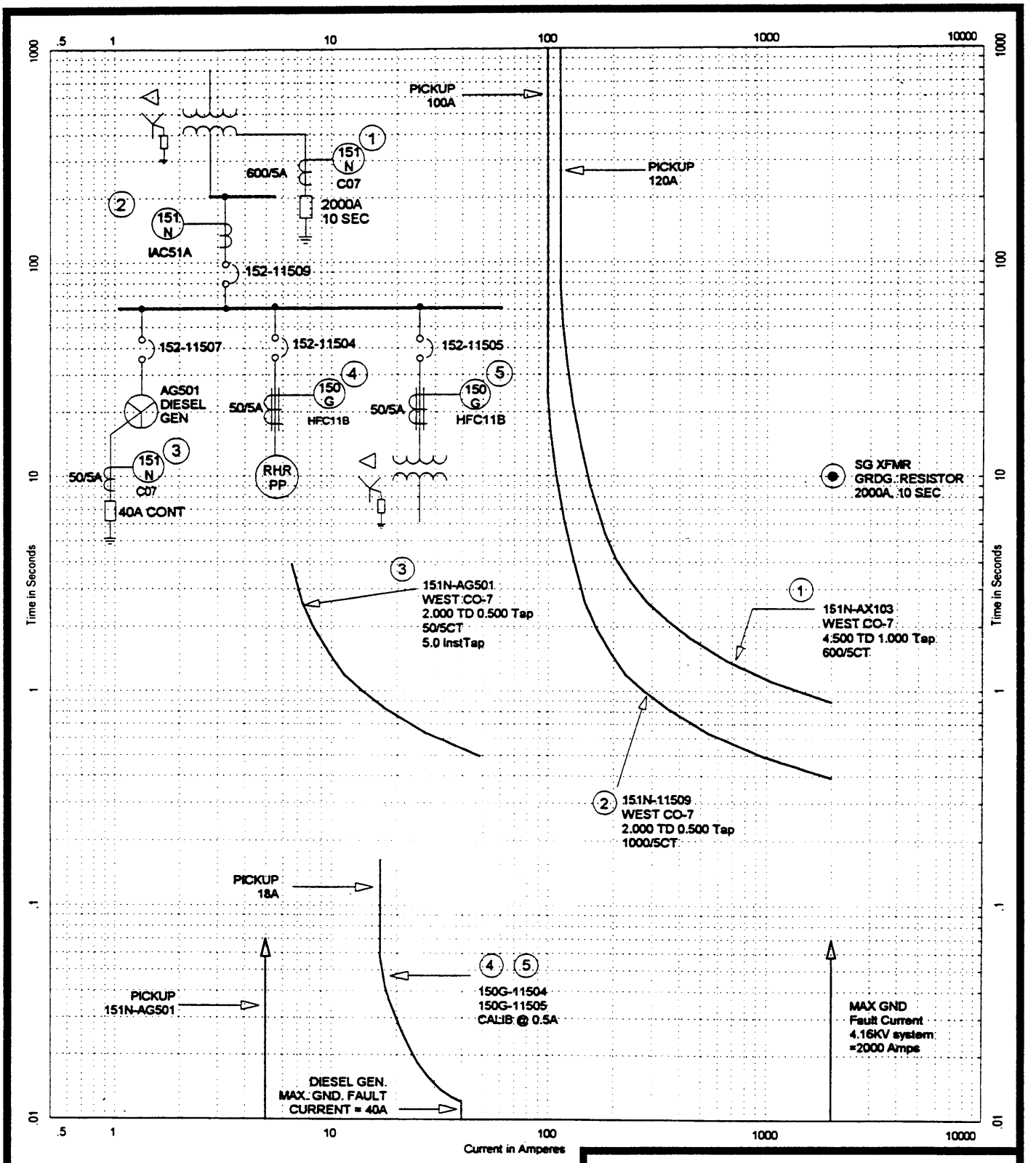


PECO ENERGY COMPANY
LIMERICK GENERATING STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT

SAFEGUARD AUX. SYSTEM PHASE O.C. PROTECTION AND COORDINATION

FIGURE 9A-13 Sht. 2 of 2 **Rev. 13 09/06**

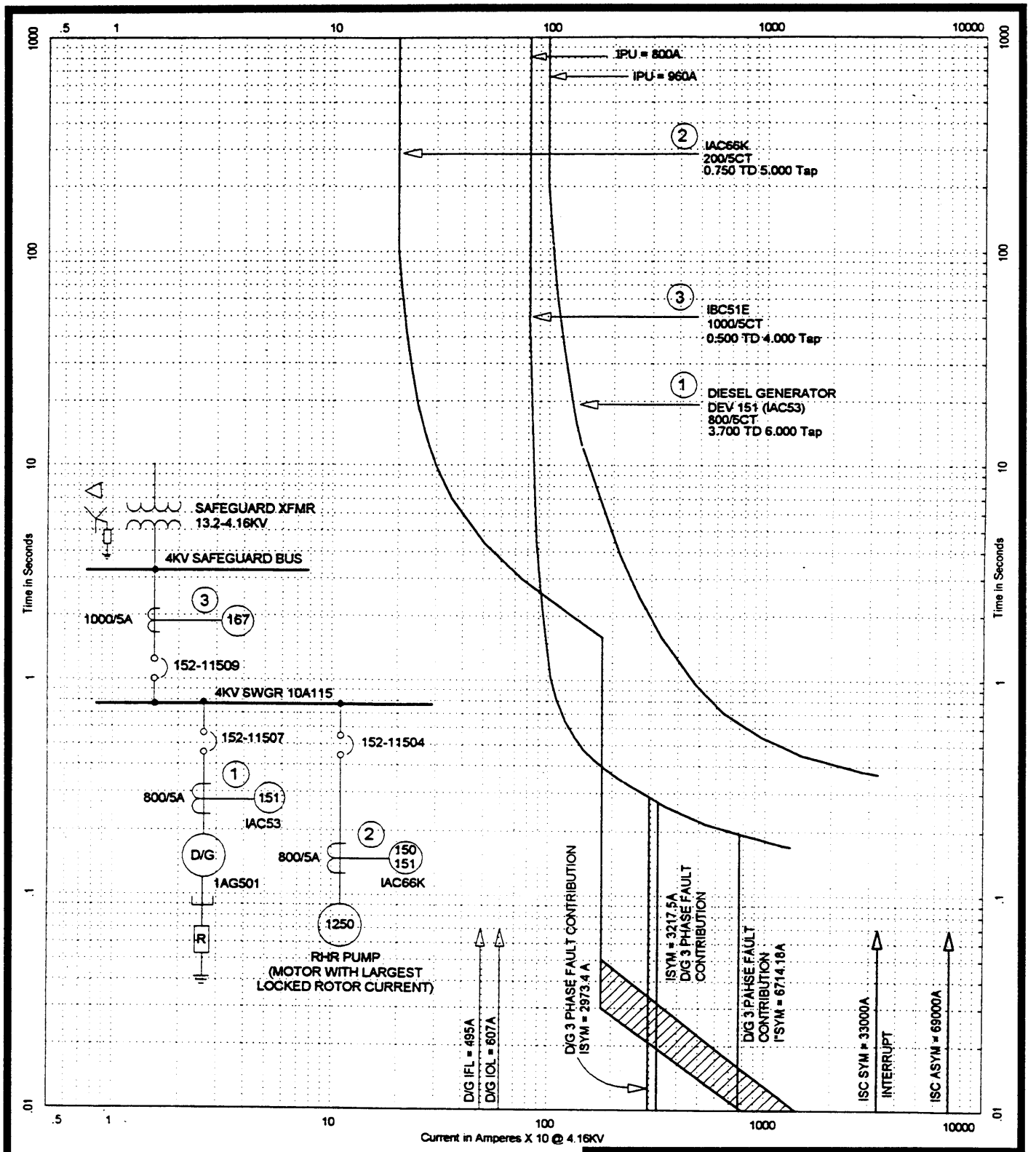


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UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT

SAFEGUARD AC SWITCHGEAR GROUND OVERCURRENT RELAY COORDINATION

FIGURE 9A-14 Sht. 1 of 1 Rev. 09 11/99

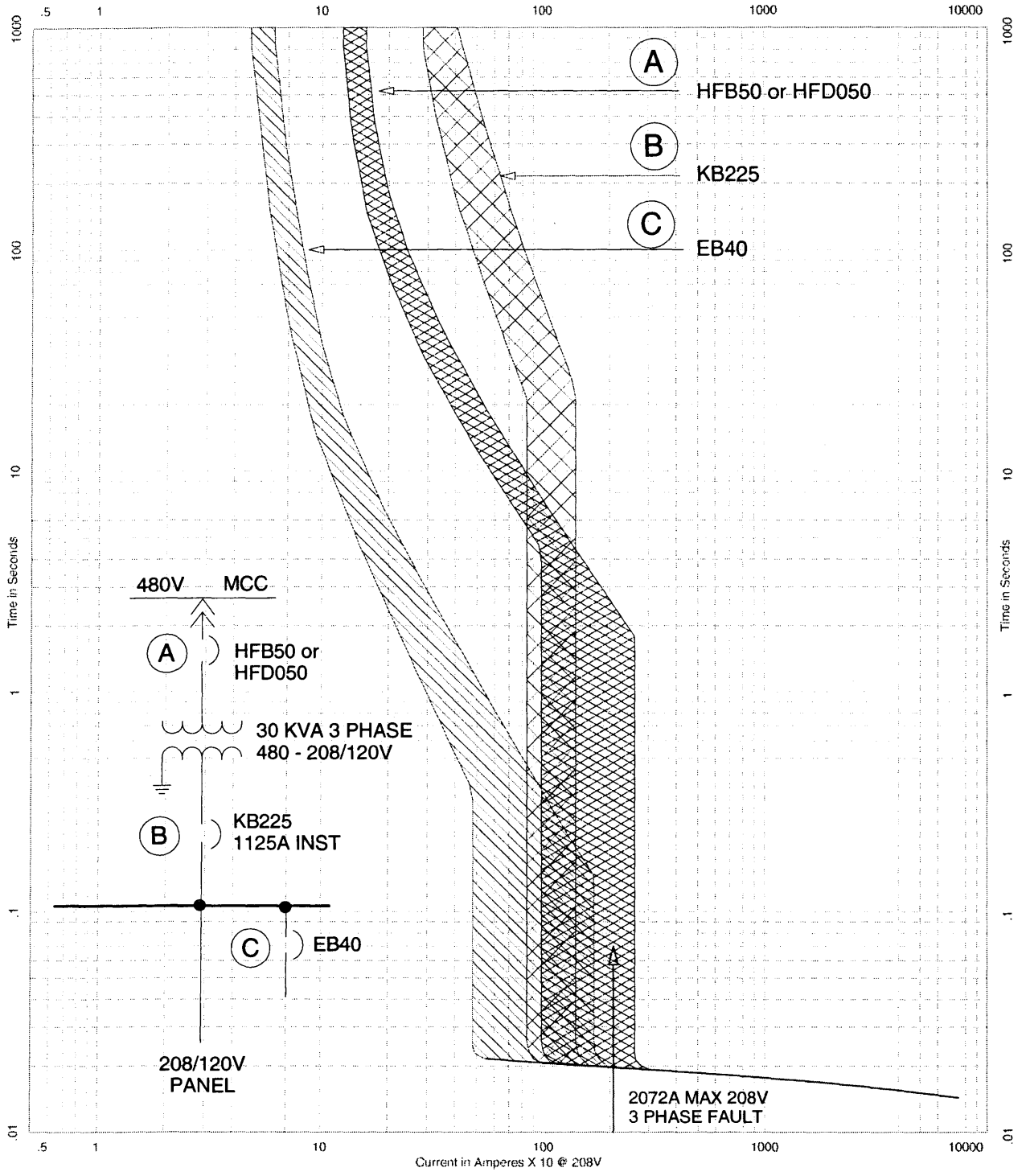


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FIRE PROTECTION EVALUATION REPORT

DIESEL GENERATOR PROTECTION RELAYS

FIGURE 9A-15 Sht. 1 of 1 Rev. 09 11/99

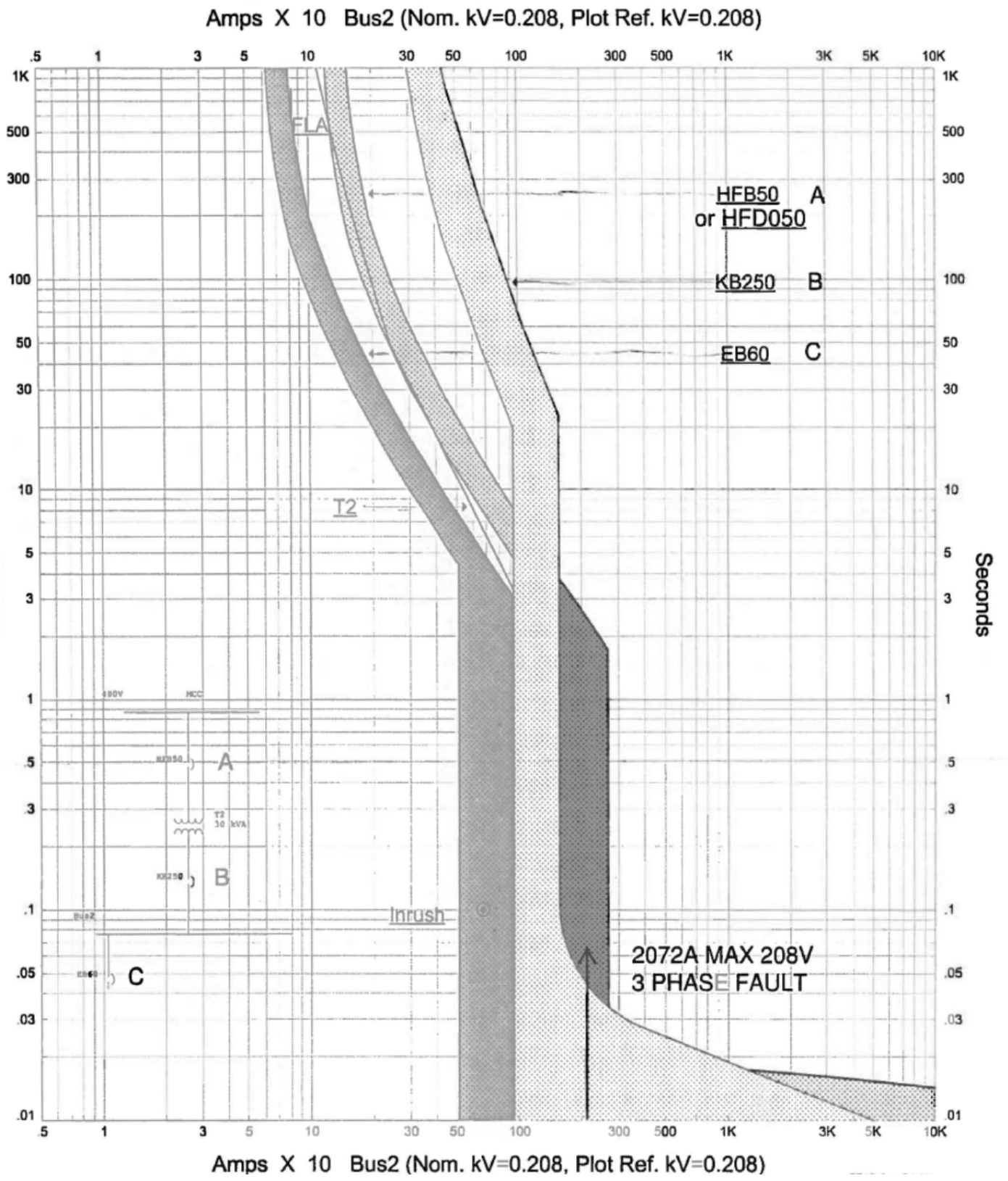


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT

208/120V SAFEGUARD AC CIRCUIT BREAKER COORDINATION

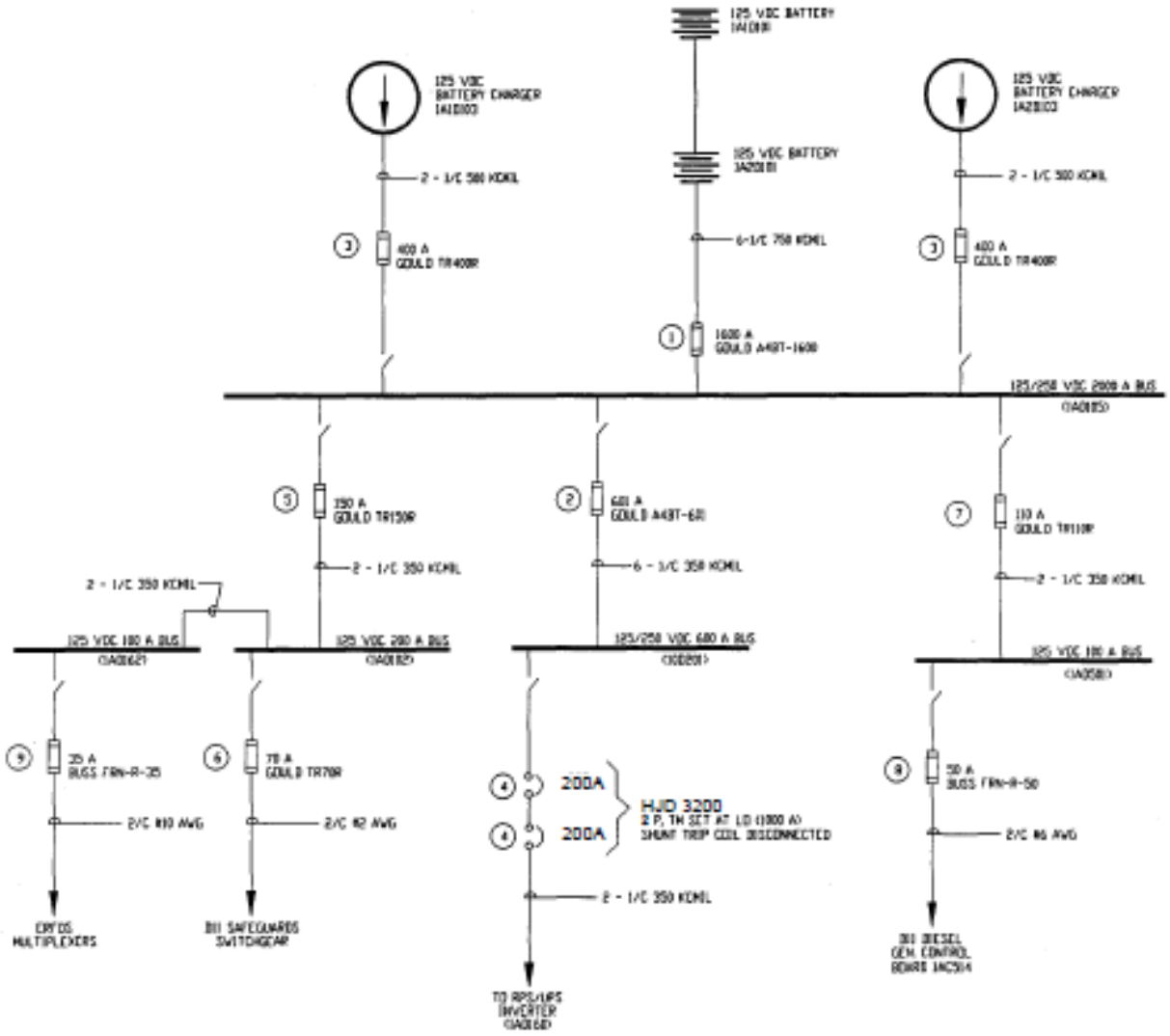
FIGURE 9A-16 Sht. 1 of 2 Rev. 19 09/18



LIMERICK GENERATION STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
208/120V SAFEGUARD AC CIRCUIT
BREAKER COORDINATION

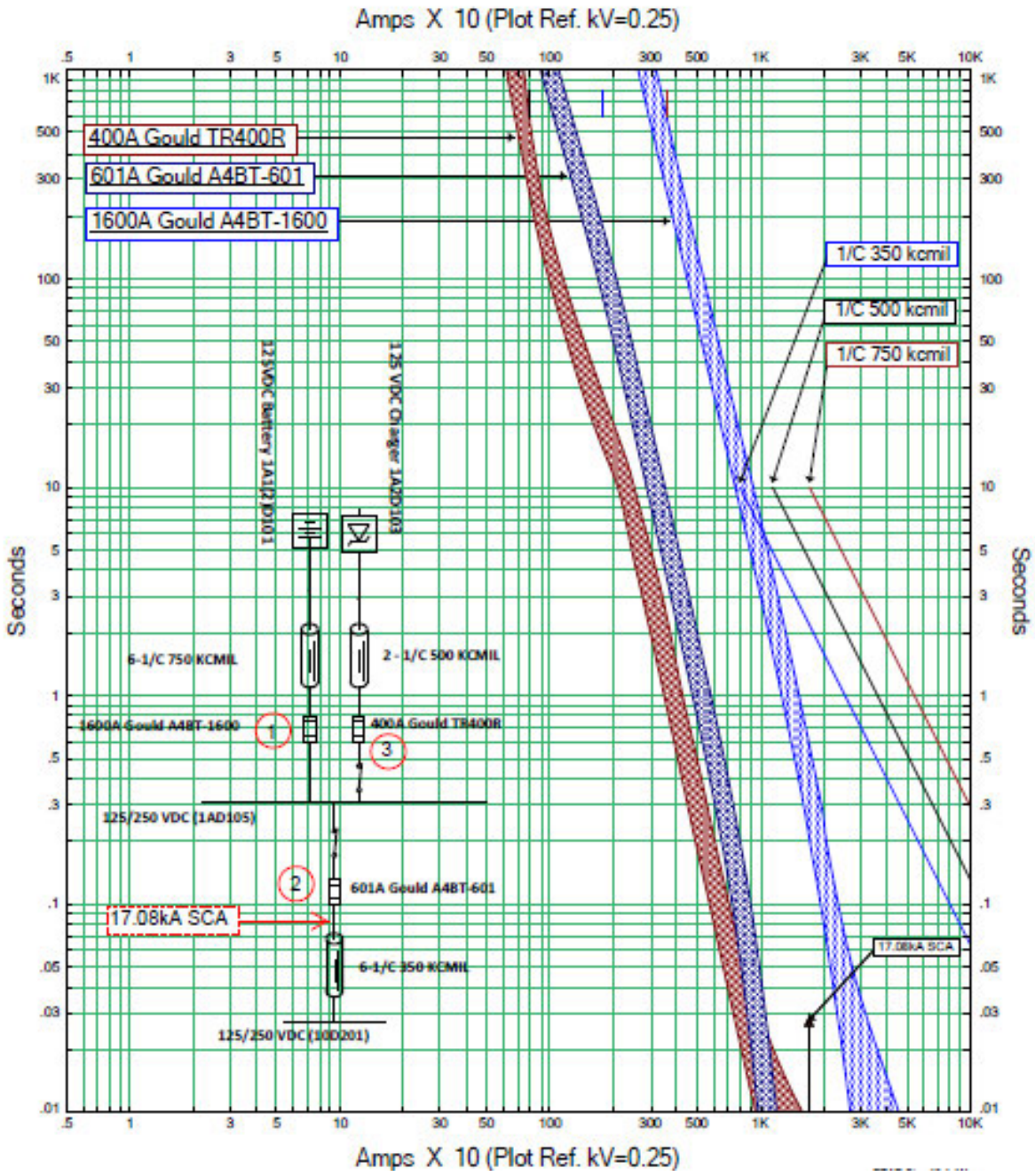
FIGURE 9A-16 Sht. 2 of 2 Rev. 19 09/18



LIMERICK GENERATING STATION
UNIT 1
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FIRE PROTECTION EVALUATION REPORT
DIVISION 1 125/250 Vdc SYSTEM
BATTERIES 1A1D101 & 1A2D101
PROTECTIVE DEVICE COORDINATION

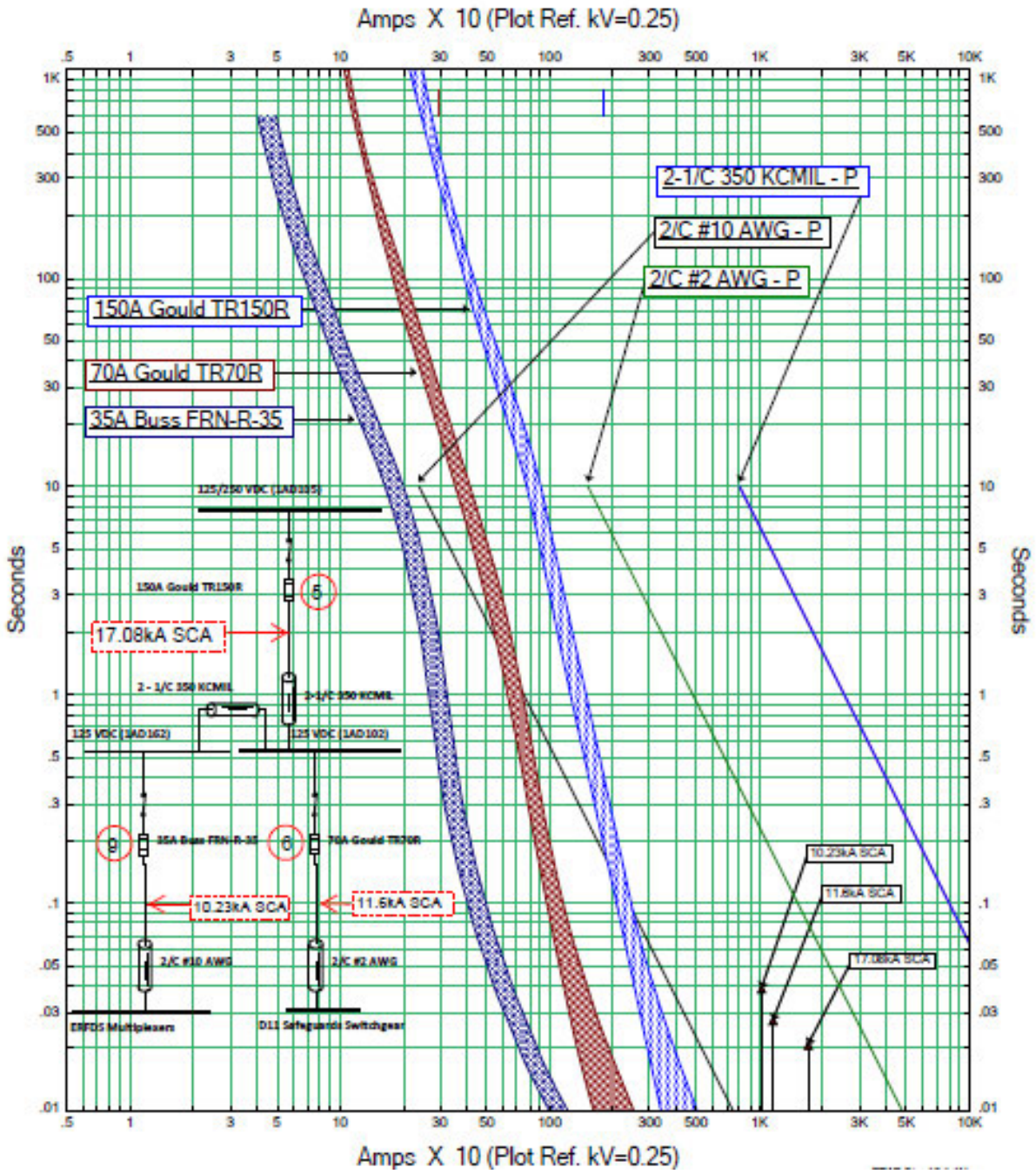
FIGURE 9A-17 **Sht. 1 of 10** **Rev. 21 09/22**



LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION 1 125/250 Vdc SYSTEM
BATTERIES 1A1D101 & 1A2D101
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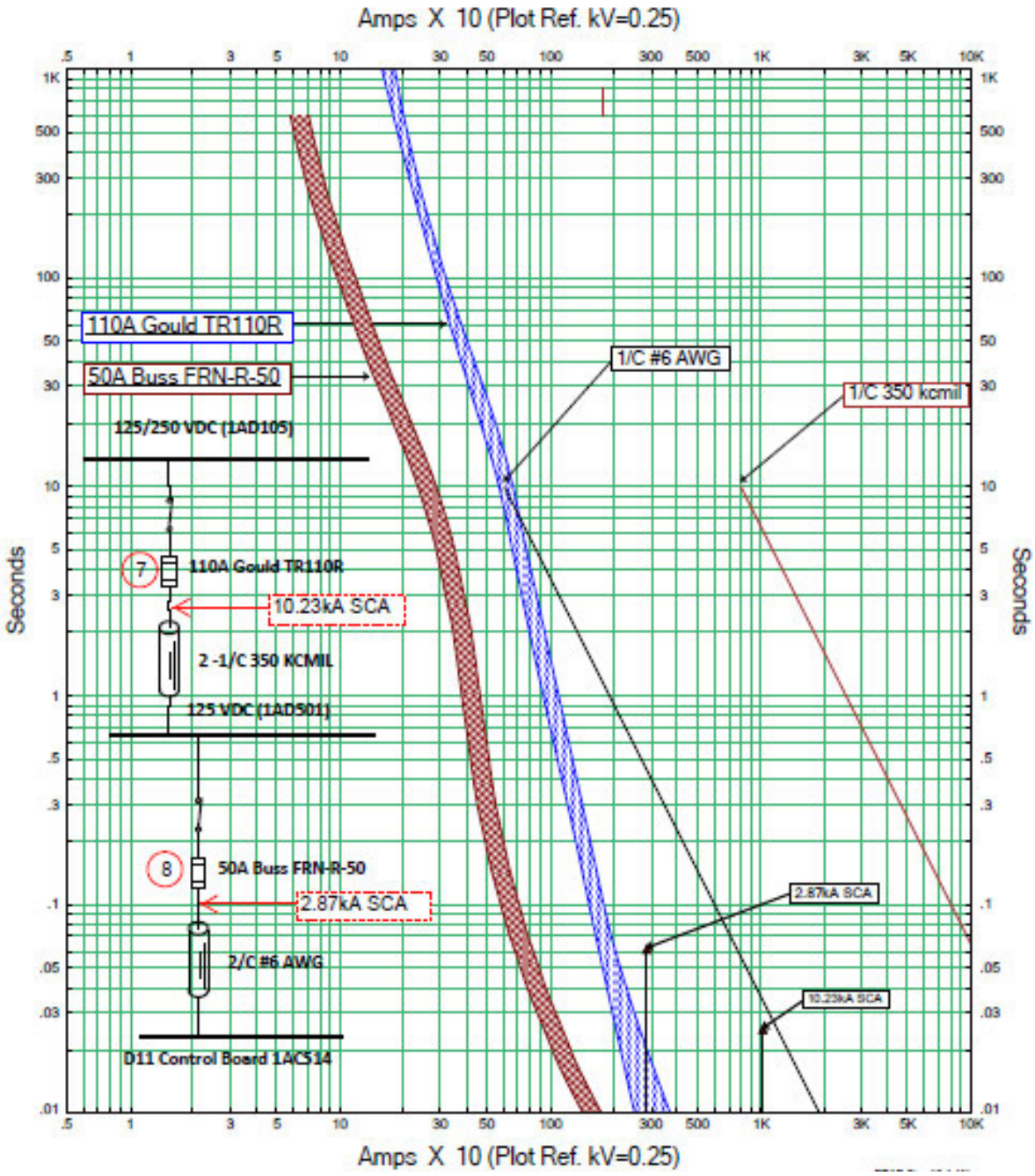
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LIMERICK GENERATING STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
125/250 Vdc SYSTEM
BATTERIES 1A1D101 & 1A2D101
PROTECTIVE DEVICE COORDINATION

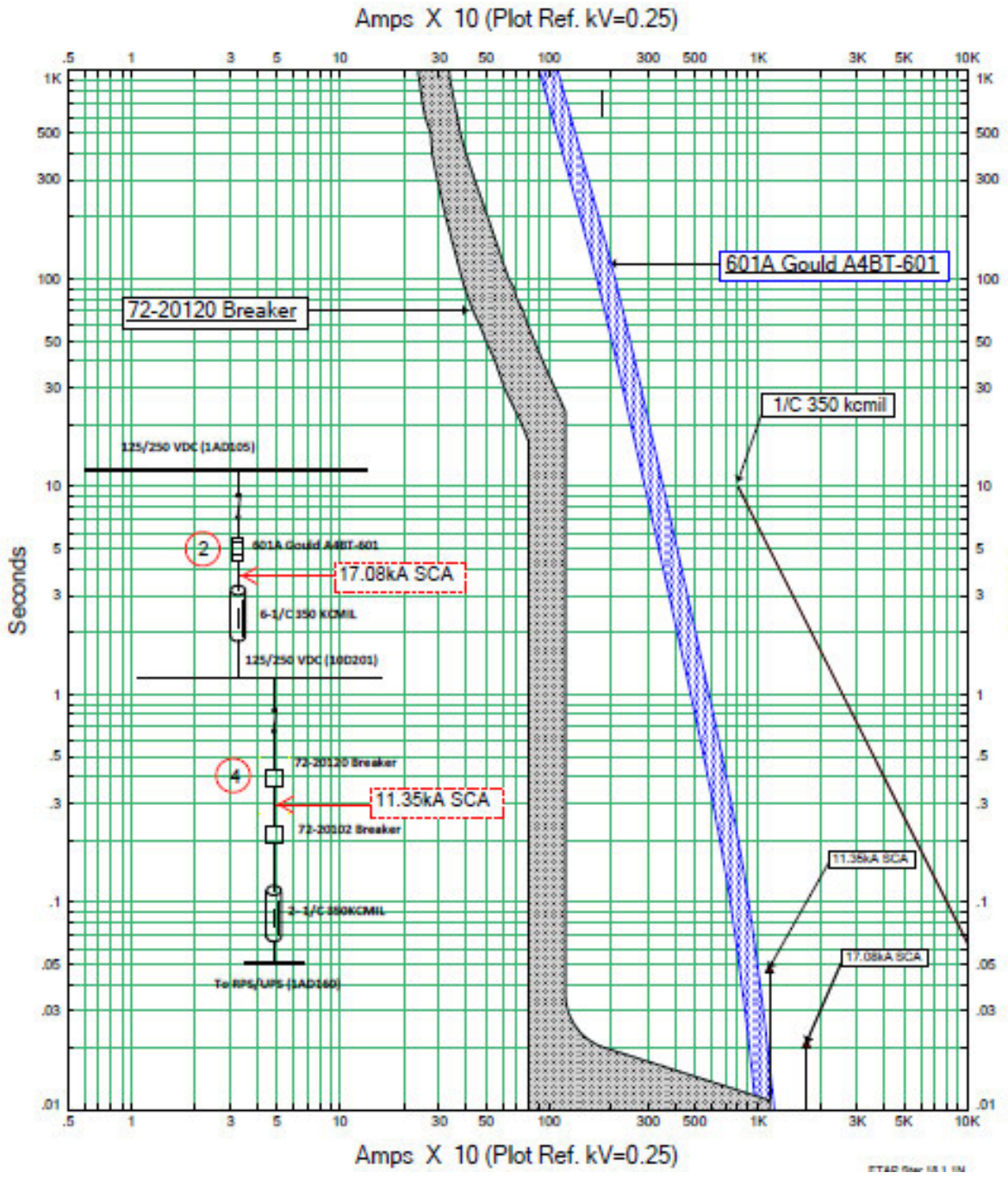
FIGURE 9A-17 **Sht. 3 of 10** **Rev. 21 09/22**



LIMERICK GENERATING STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION 1 125/250 Vdc SYSTEM
BATTERIES 1A1D101 & 1A2D101
PROTECTIVE DEVICE COORDINATION

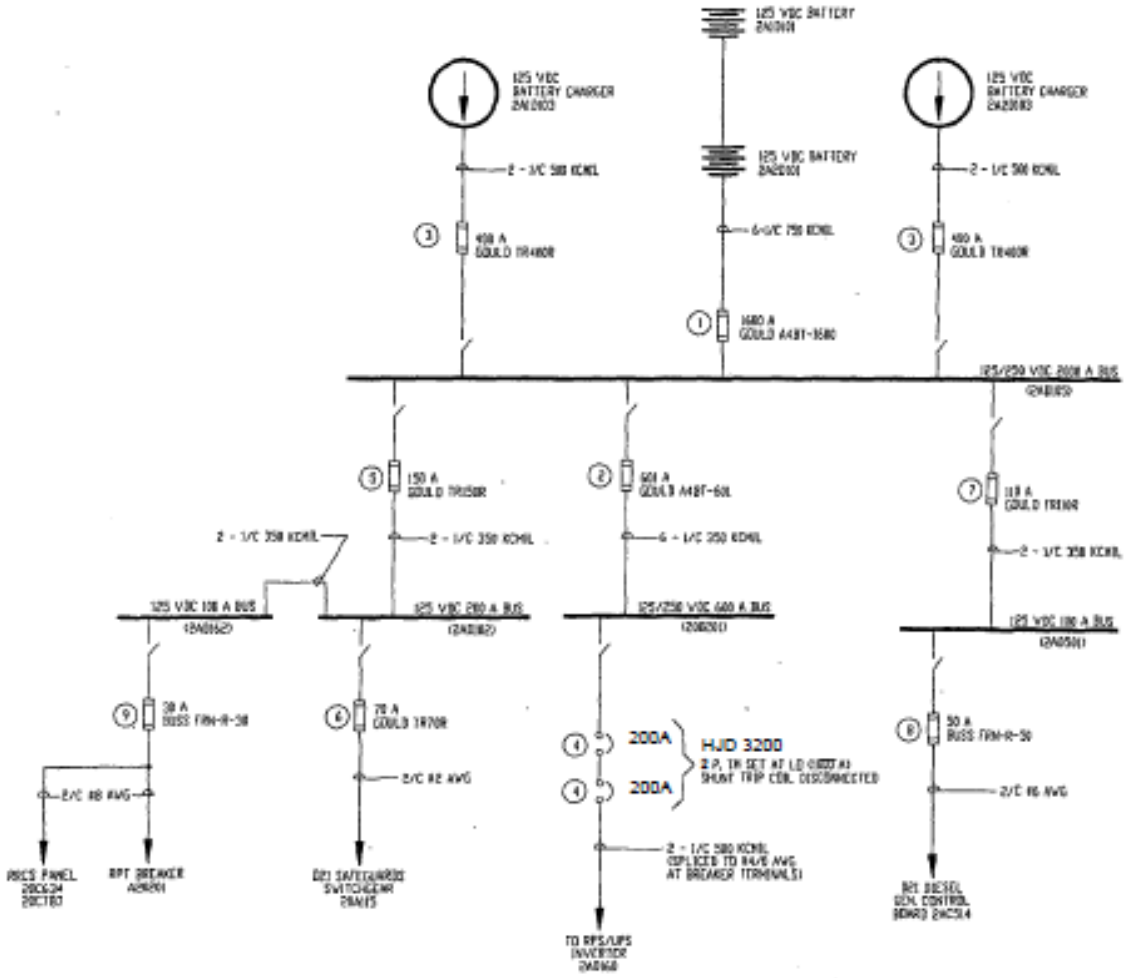
FIGURE 9A-17 **Sht. 4 of 10** **Rev. 21 09/22**



LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION 1 125/250 Vdc SYSTEM
BATTERIES 1A1D101 & 1A2D101
PROTECTIVE DEVICE COORDINATION

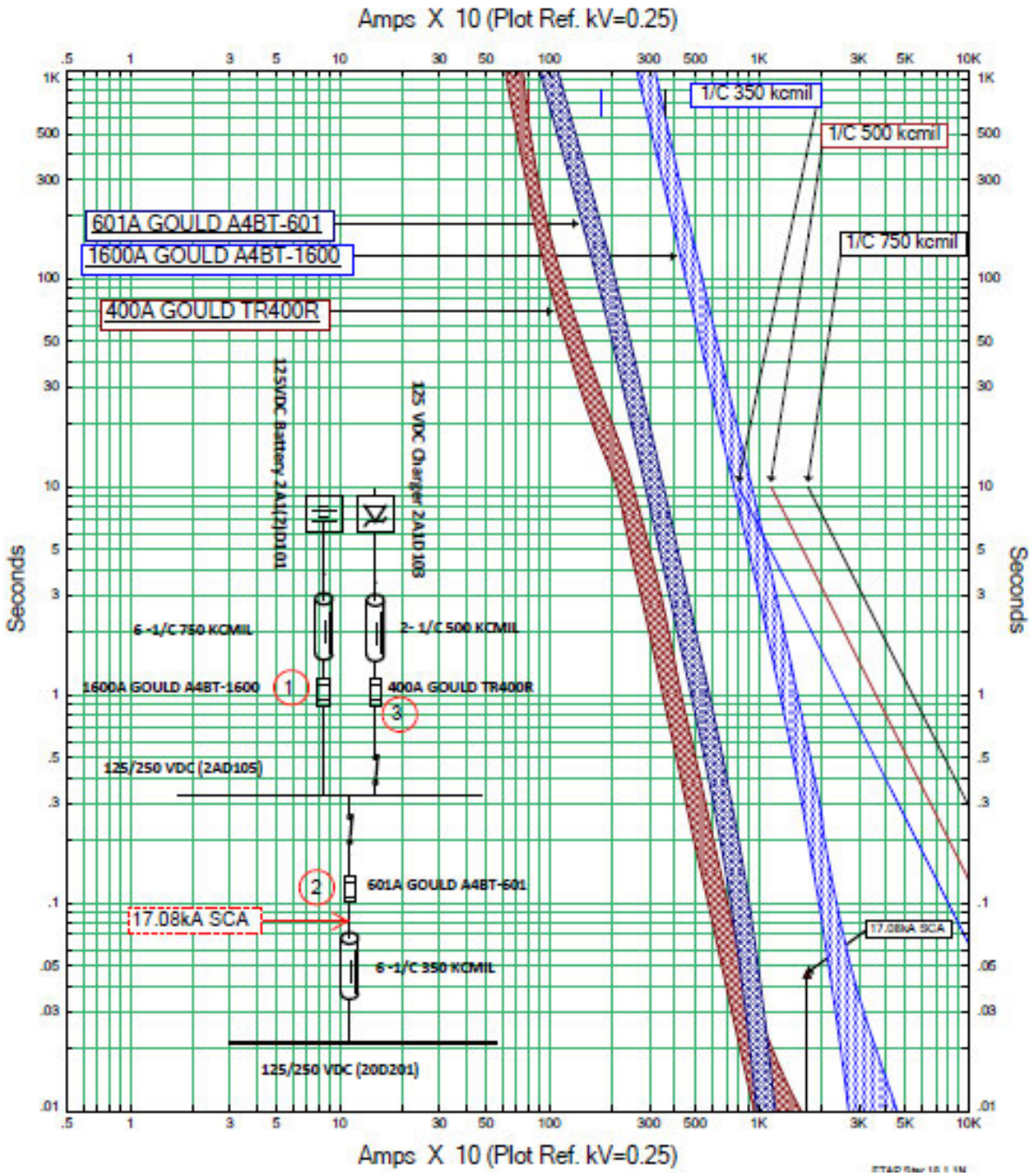
FIGURE 9A-17 **Sht. 5 of 10** **Rev. 21 09/22**



LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION 1 125/250 Vdc SYSTEM
BATTERIES 2A1D101 & 2A2D101
PROTECTIVE DEVICE COORDINATION

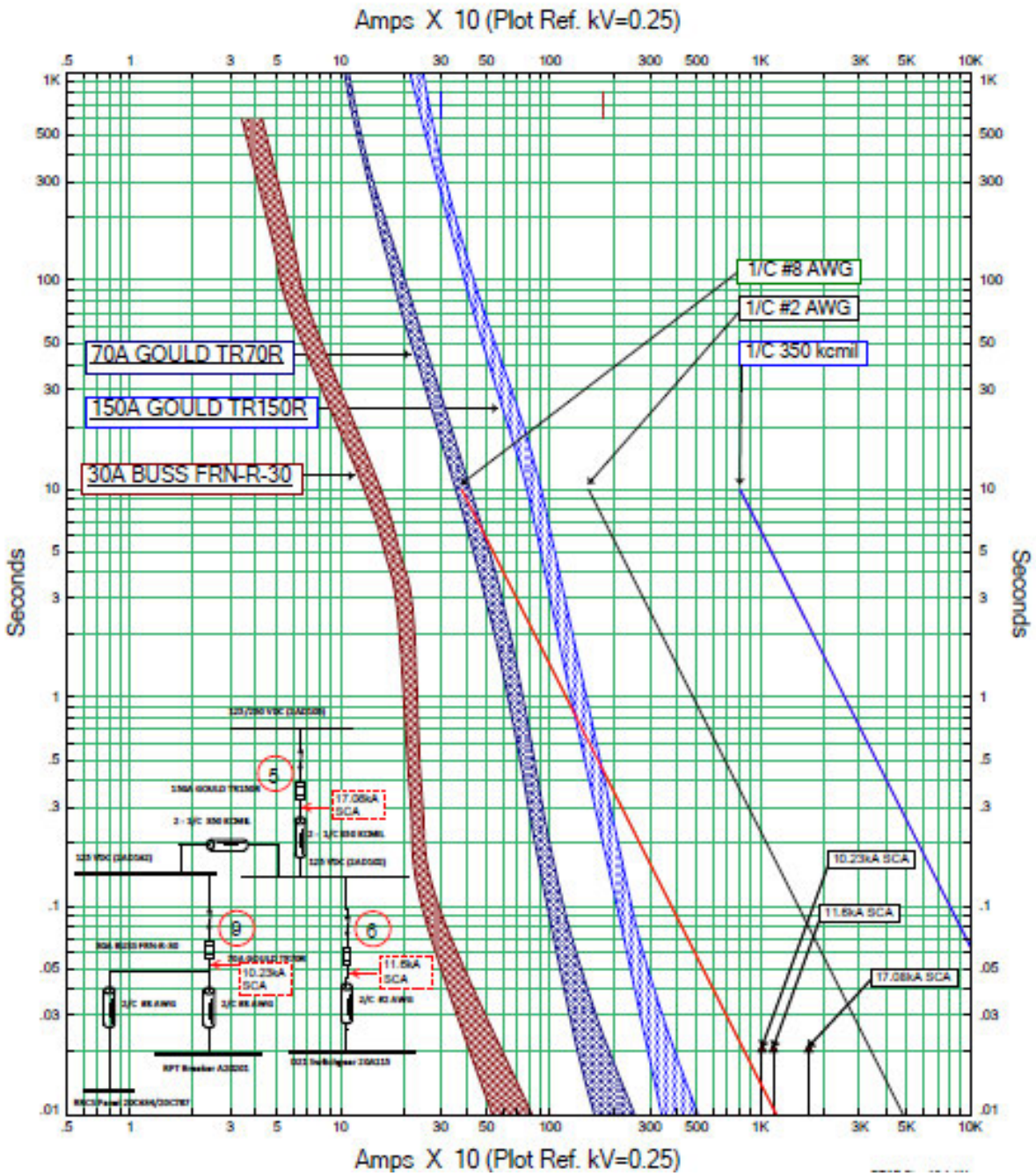
FIGURE 9A-17 **Sht. 6 of 10** **Rev. 21 09/22**



LIMERICK GENERATING STATION
UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION 1 125/250 Vdc SYSTEM
BATTERIES 2A1D101 & 2A2D101
PROTECTIVE DEVICE COORDINATION

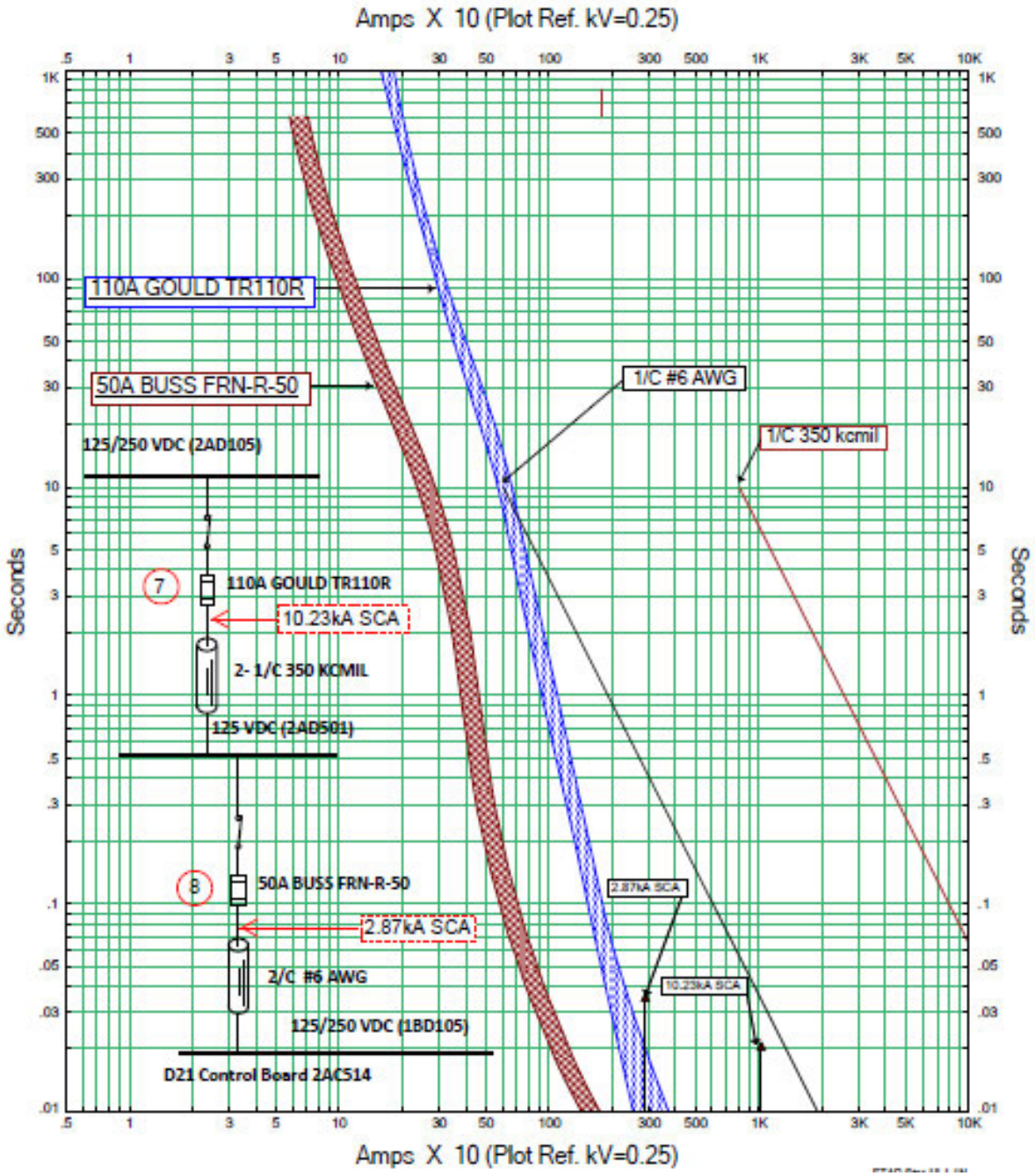
FIGURE 9A-17 **Sht. 7 of 10** **Rev. 21 09/22**



LIMERICK GENERATING STATION
UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION 1 125/250 Vdc SYSTEM
BATTERIES 2A1D101 & 2A2D101
PROTECTIVE DEVICE COORDINATION

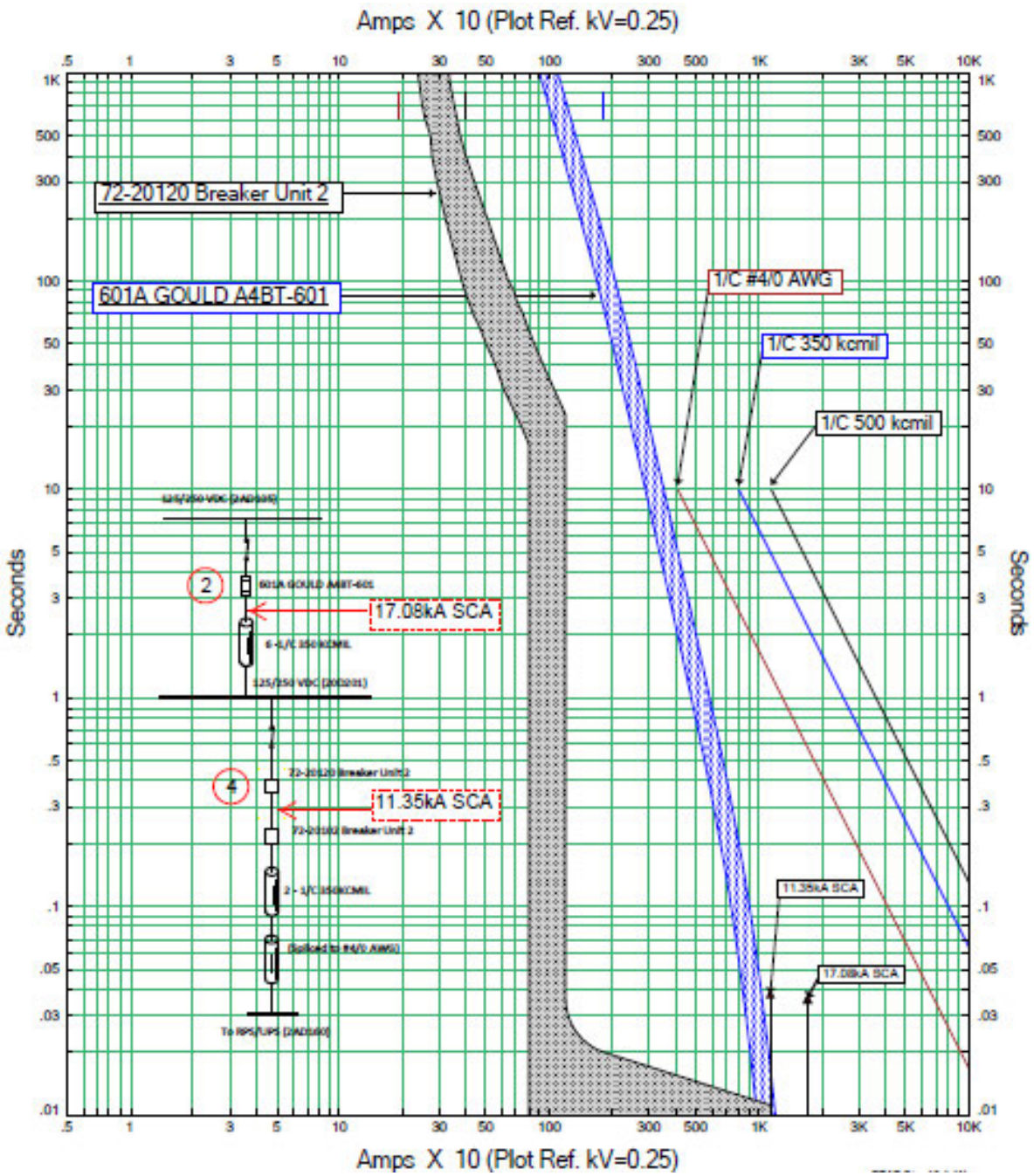
FIGURE 9A-17 **Sht. 8 of 10** **Rev. 21 09/22**



LIMERICK GENERATING STATION
UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION 1 125/250 Vdc SYSTEM
BATTERIES 2A1D101 & 2A2D101
PROTECTIVE DEVICE COORDINATION

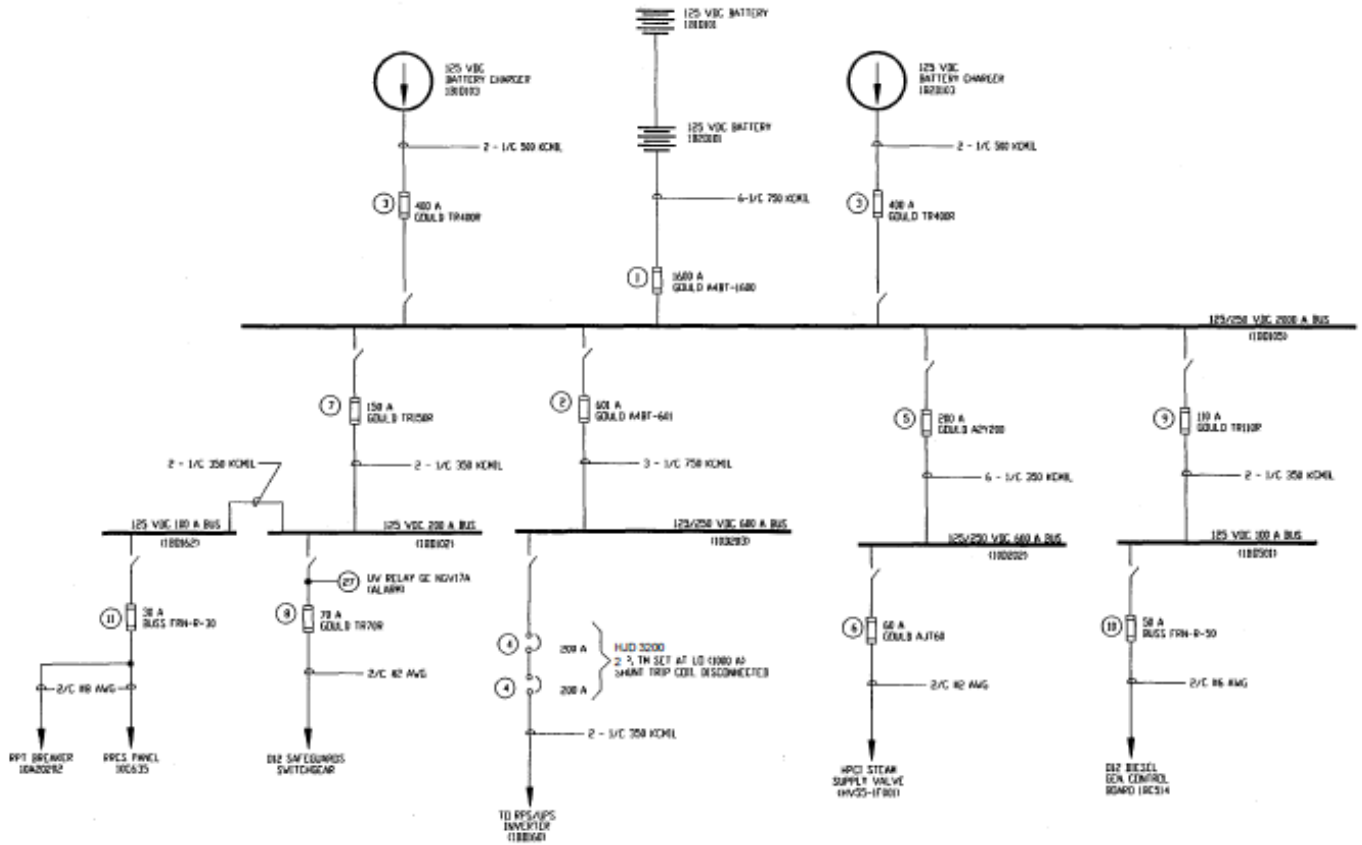
FIGURE 9A-17 **Sht. 9 of 10** **Rev. 21 09/22**



LIMERICK GENERATING STATION
UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION 1 125/250 Vdc SYSTEM
BATTERIES 2A1D101 & 2A2D101
PROTECTIVE DEVICE COORDINATION

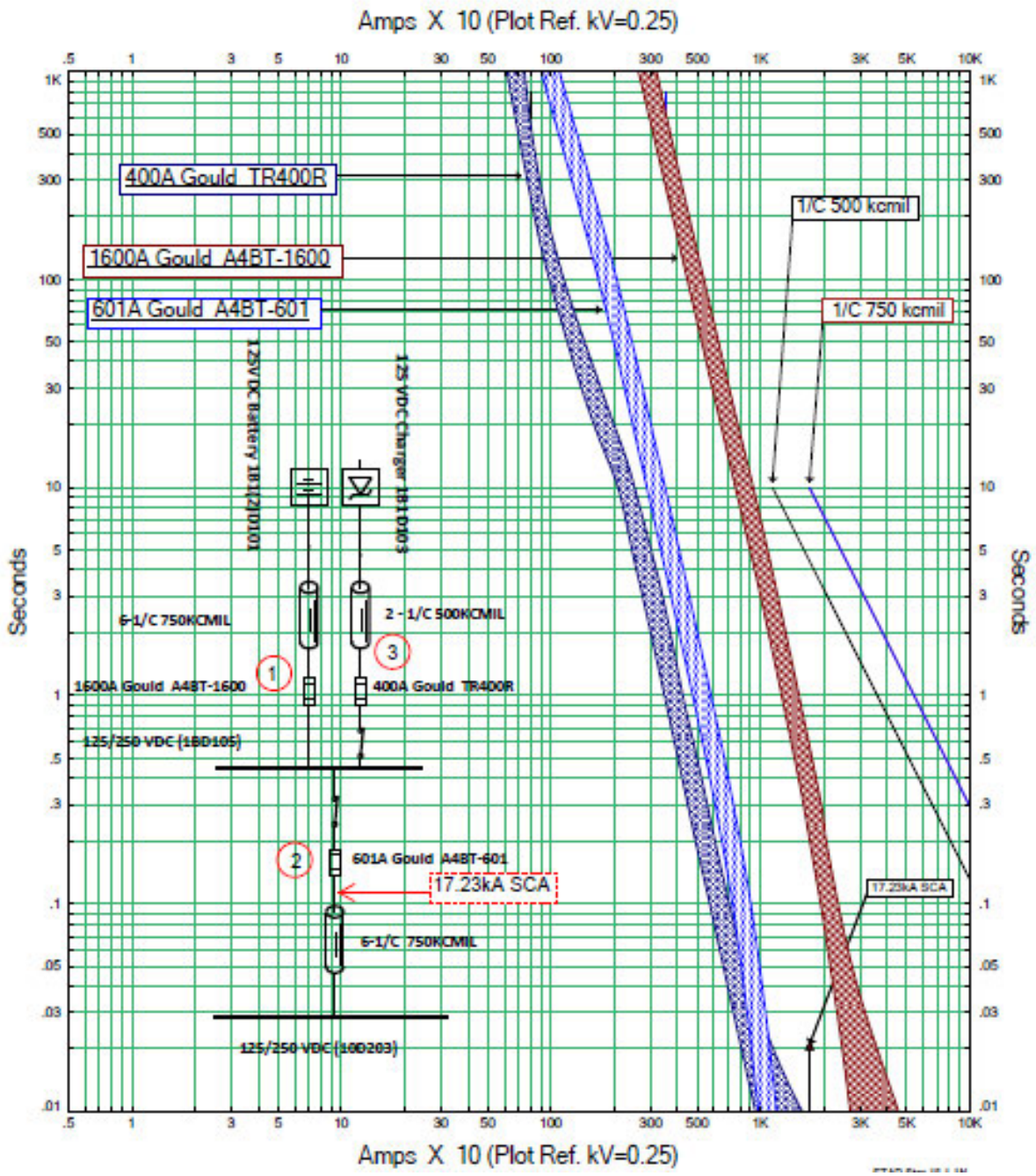
FIGURE 9A-17 **Sht. 10 of 10** **Rev. 21 09/22**



LIMERICK GENERATING STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION II 125/250 Vdc SYSTEM
BATTERIES 1B1D101 & 1B2D101
PROTECTIVE DEVICE COORDINATION

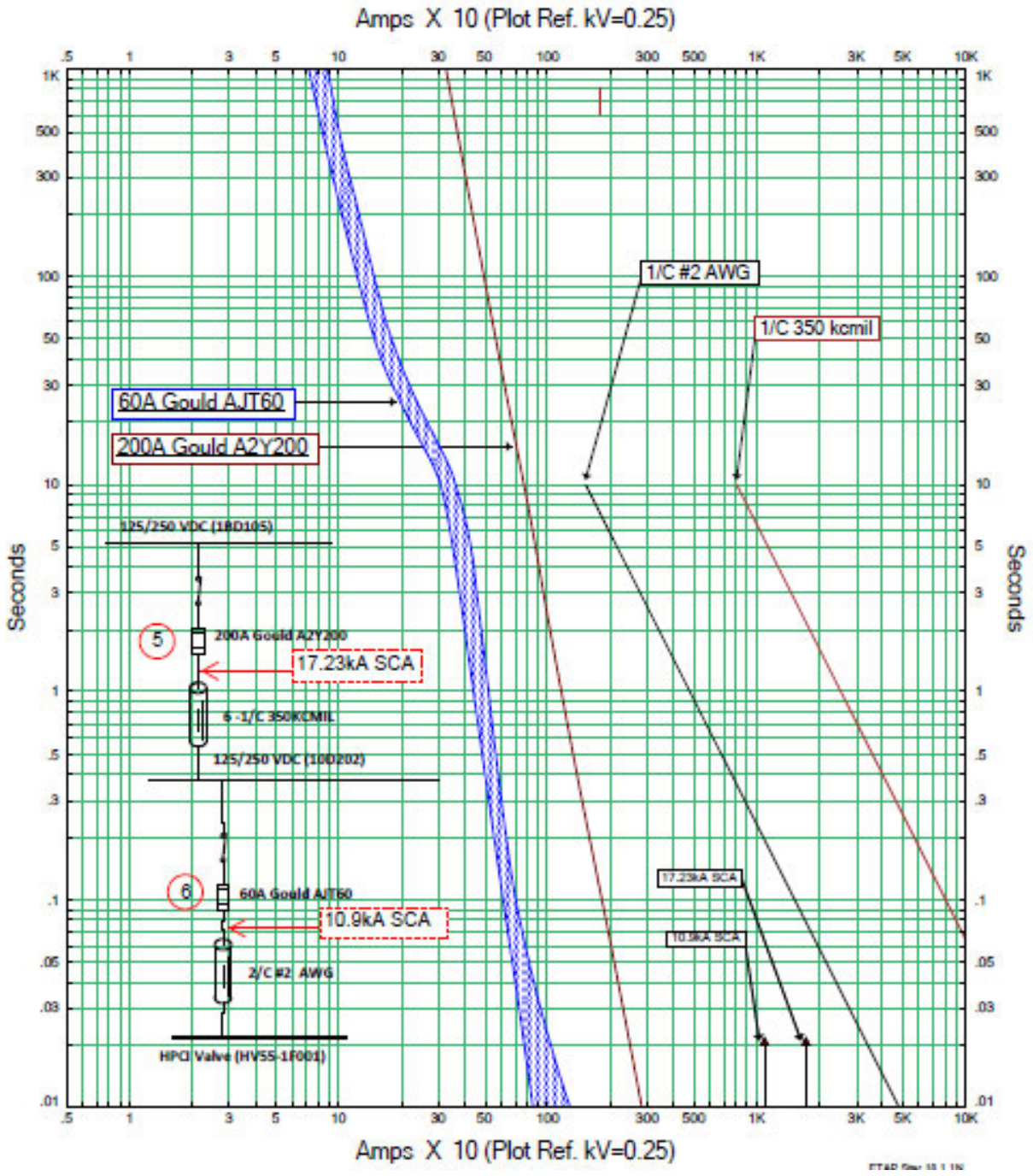
FIGURE 9A-18 **Sht. 1 of 12** **Rev. 21 09/22**



LIMERICK GENERATING STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION II 125/250 Vdc SYSTEM
BATTERIES 1B1D101 & 2B2D101
PROTECTIVE DEVICE COORDINATION

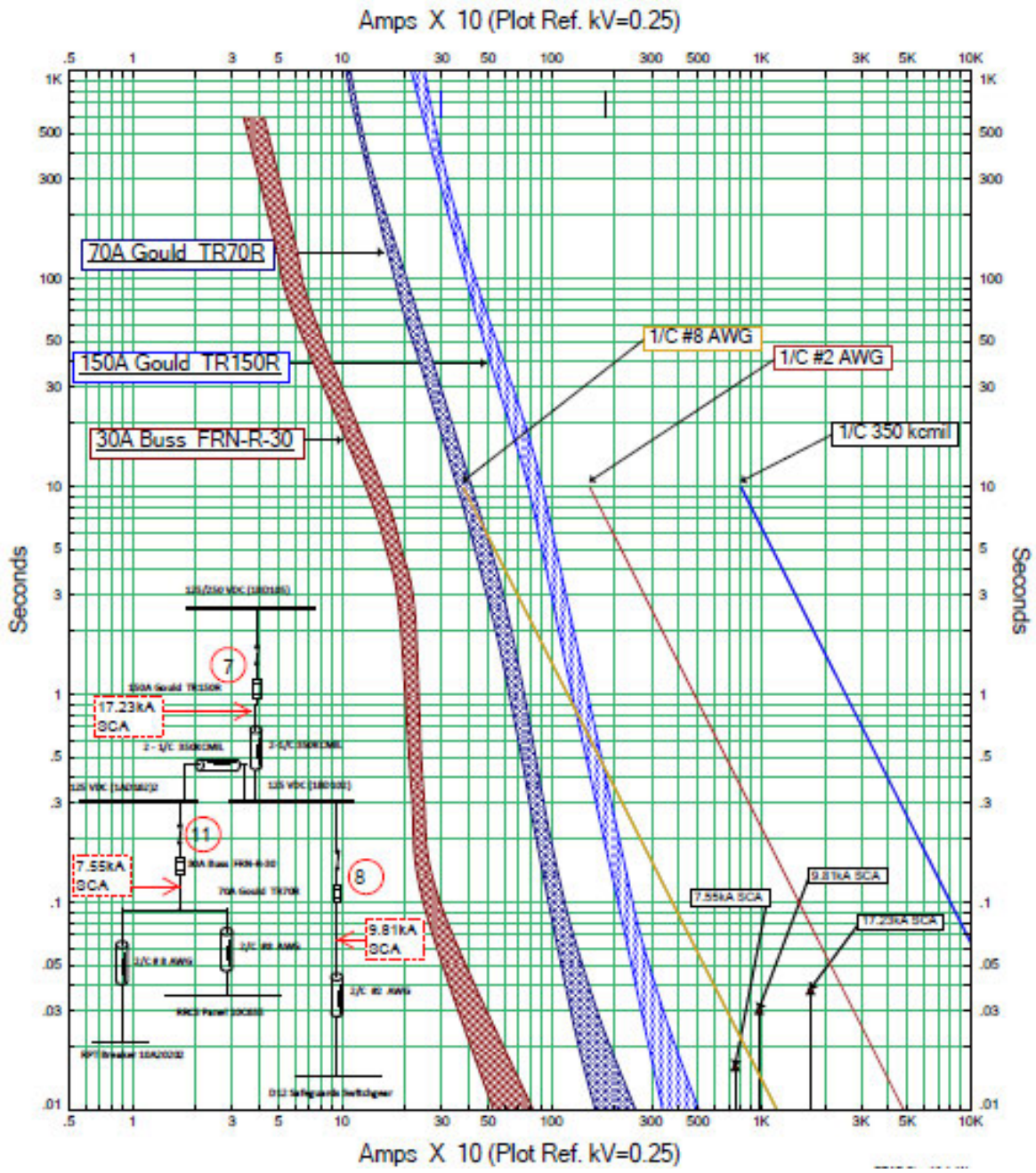
FIGURE 9A-18 **Sht. 2 of 12** **Rev. 21 09/22**



LIMERICK GENERATING STATION
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FIRE PROTECTION EVALUATION REPORT
DIVISION II125/250 Vdc SYSTEM
BATTERIES 1B1D101 & 2B2D101
PROTECTIVE DEVICE COORDINATION

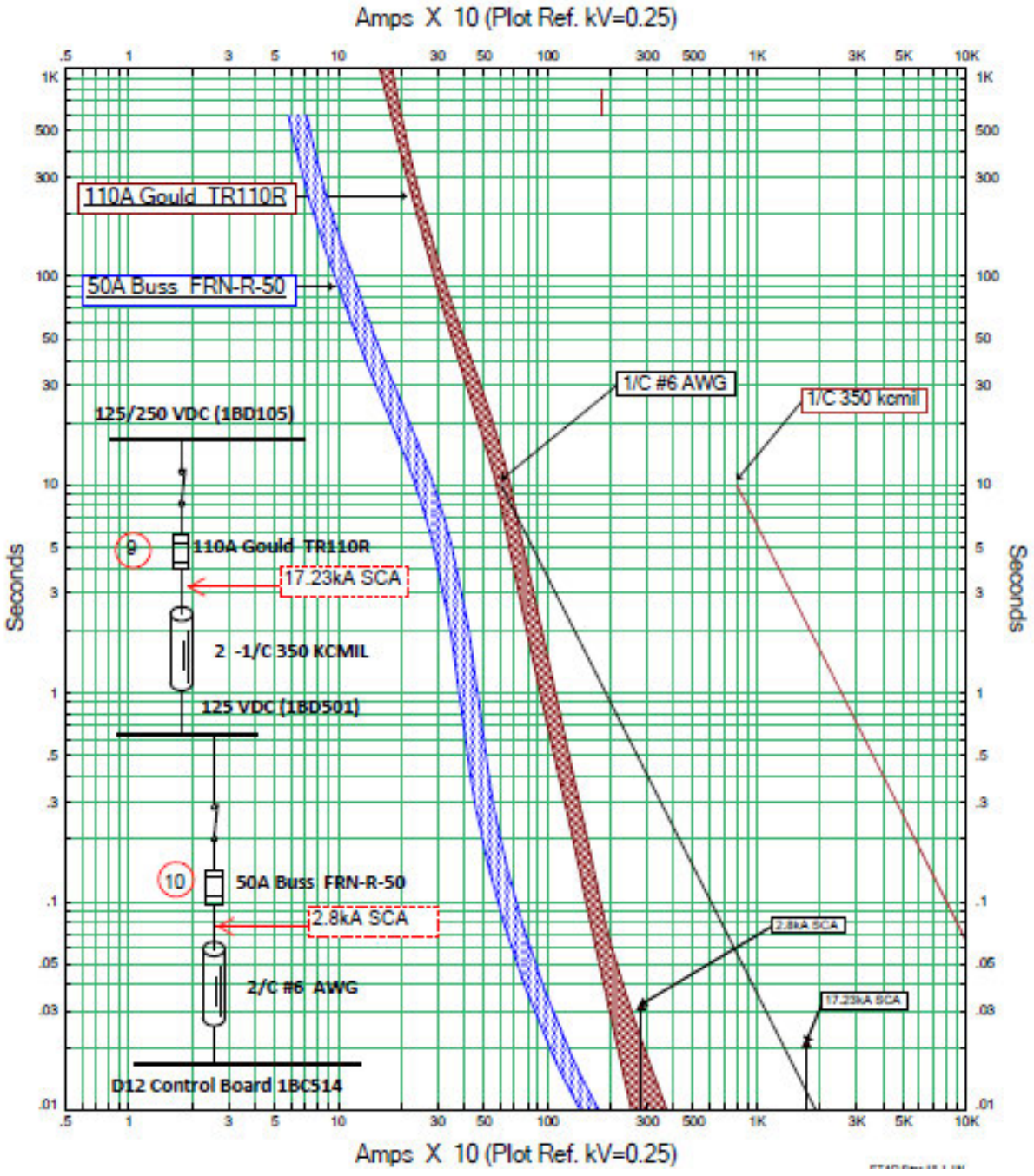
FIGURE 9A-18 **Sht. 3 of 12** **Rev. 21 09/22**



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FIRE PROTECTION EVALUATION REPORT
DIVISION II 125/250 Vdc SYSTEM
BATTERIES 1B1D101 & 2B2D101
PROTECTIVE DEVICE COORDINATION

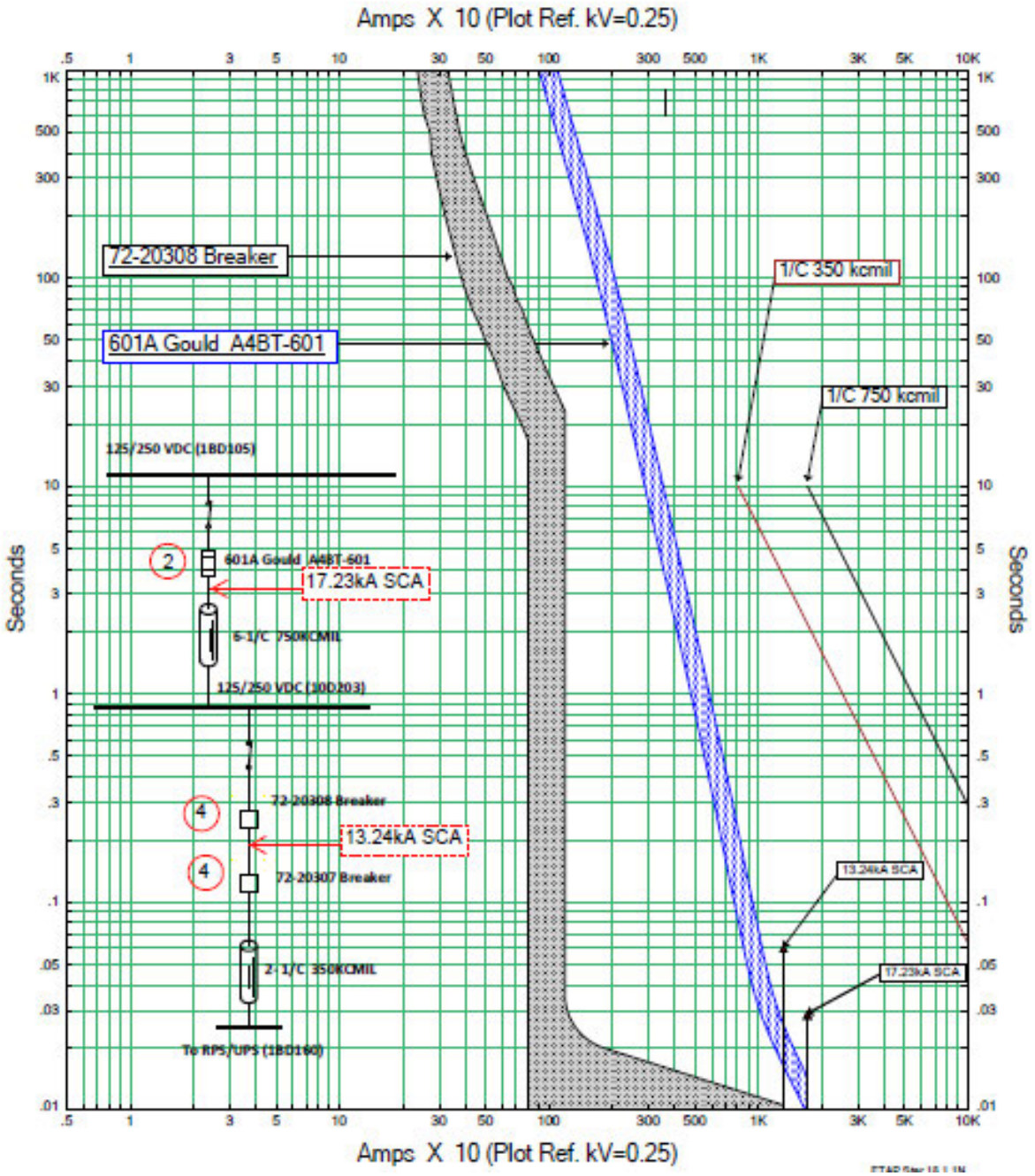
FIGURE 9A-18 **Sht. 4 of 12** **Rev. 21 09/22**



LIMERICK GENERATING STATION
UNIT 1
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FIRE PROTECTION EVALUATION REPORT
DIVISION II 125/250 Vdc SYSTEM
BATTERIES 1B1D101 & 1B2D101
PROTECTIVE DEVICE COORDINATION

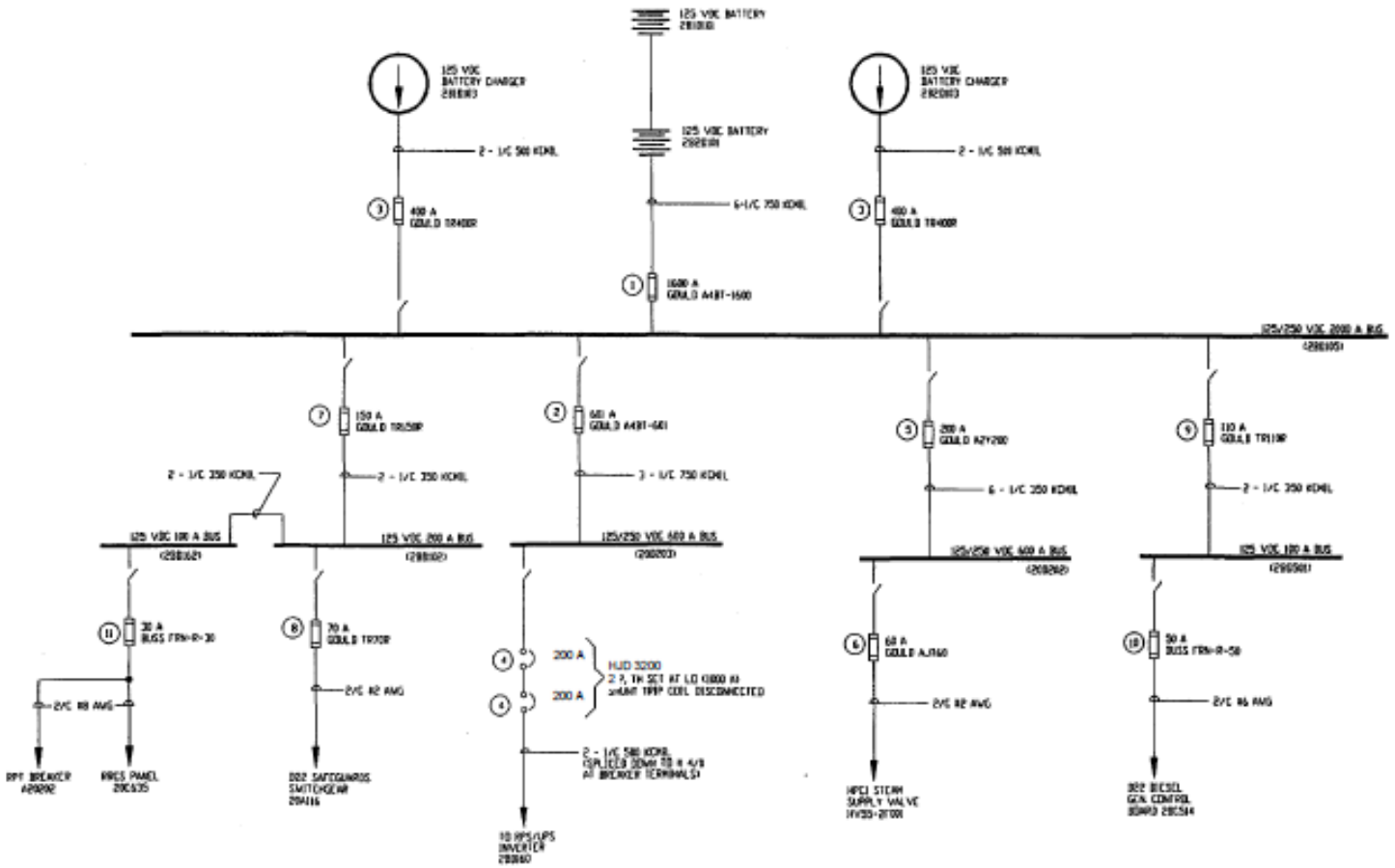
FIGURE 9A-18 **Sht. 5 of 12** **Rev. 21 09/22**



LIMERICK GENERATING STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION II 125/250 Vdc SYSTEM
BATTERIES 1B1D101 & 1B2D101
PROTECTIVE DEVICE COORDINATION

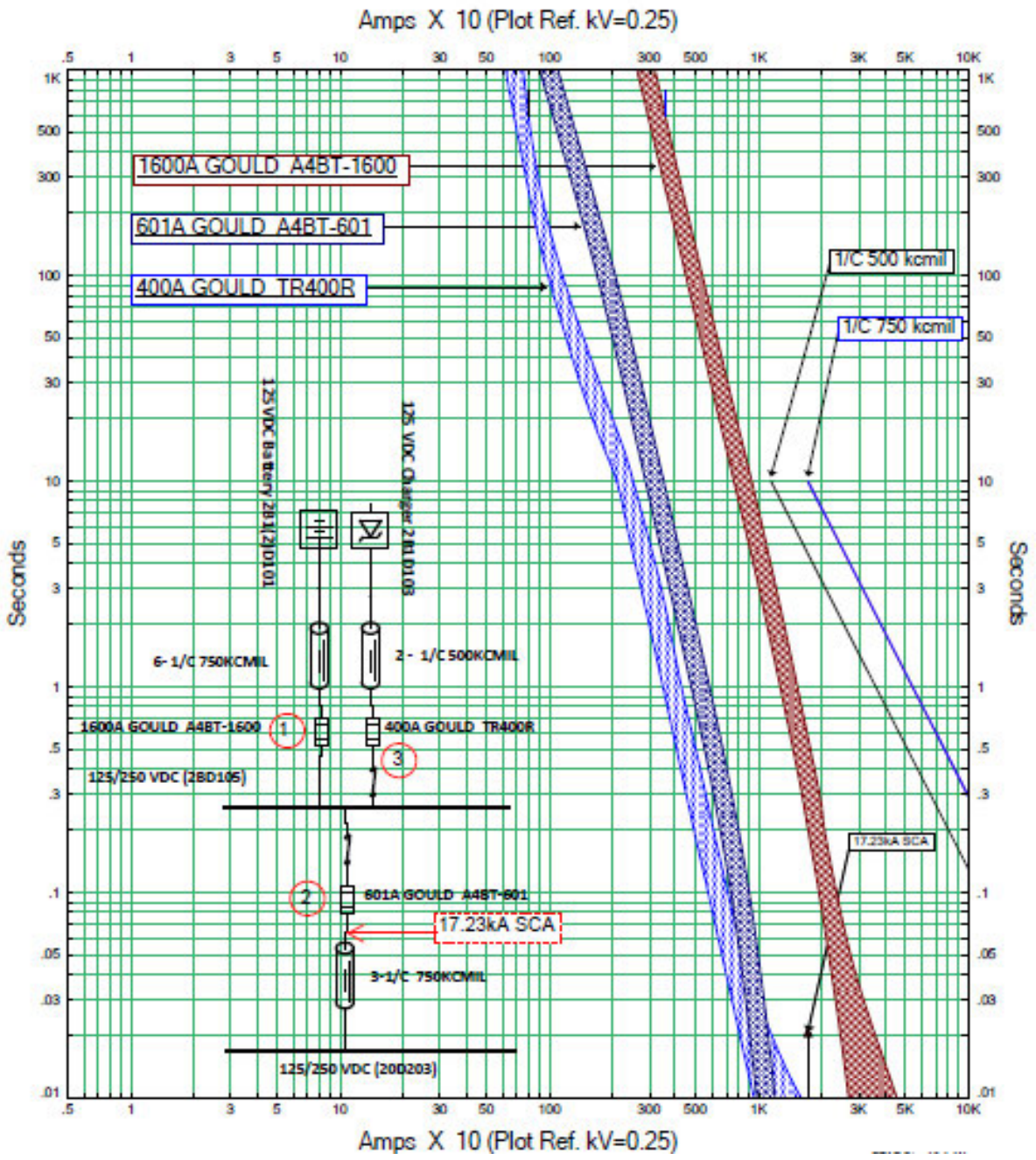
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LIMERICK GENERATING STATION
UNIT 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION II 125/250 Vdc SYSTEM
BATTERIES 2B1D101 & 2B2D101
PROTECTIVE DEVICE COORDINATION

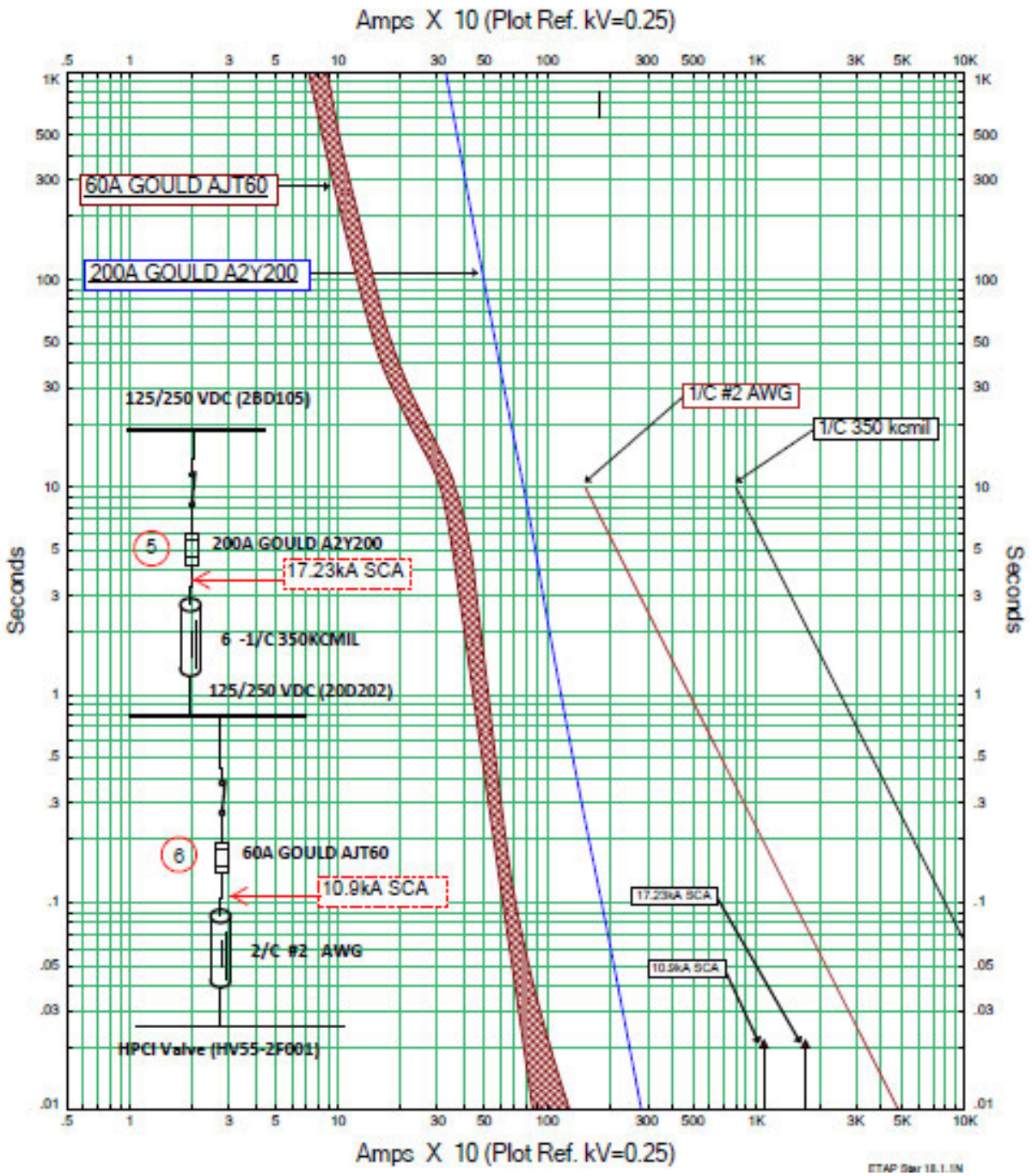
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UNIT 2
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FIRE PROTECTION EVALUATION REPORT
DIVISION II 125/250 Vdc SYSTEM
BATTERIES 2B1D101 & 2B2D101
PROTECTIVE DEVICE COORDINATION

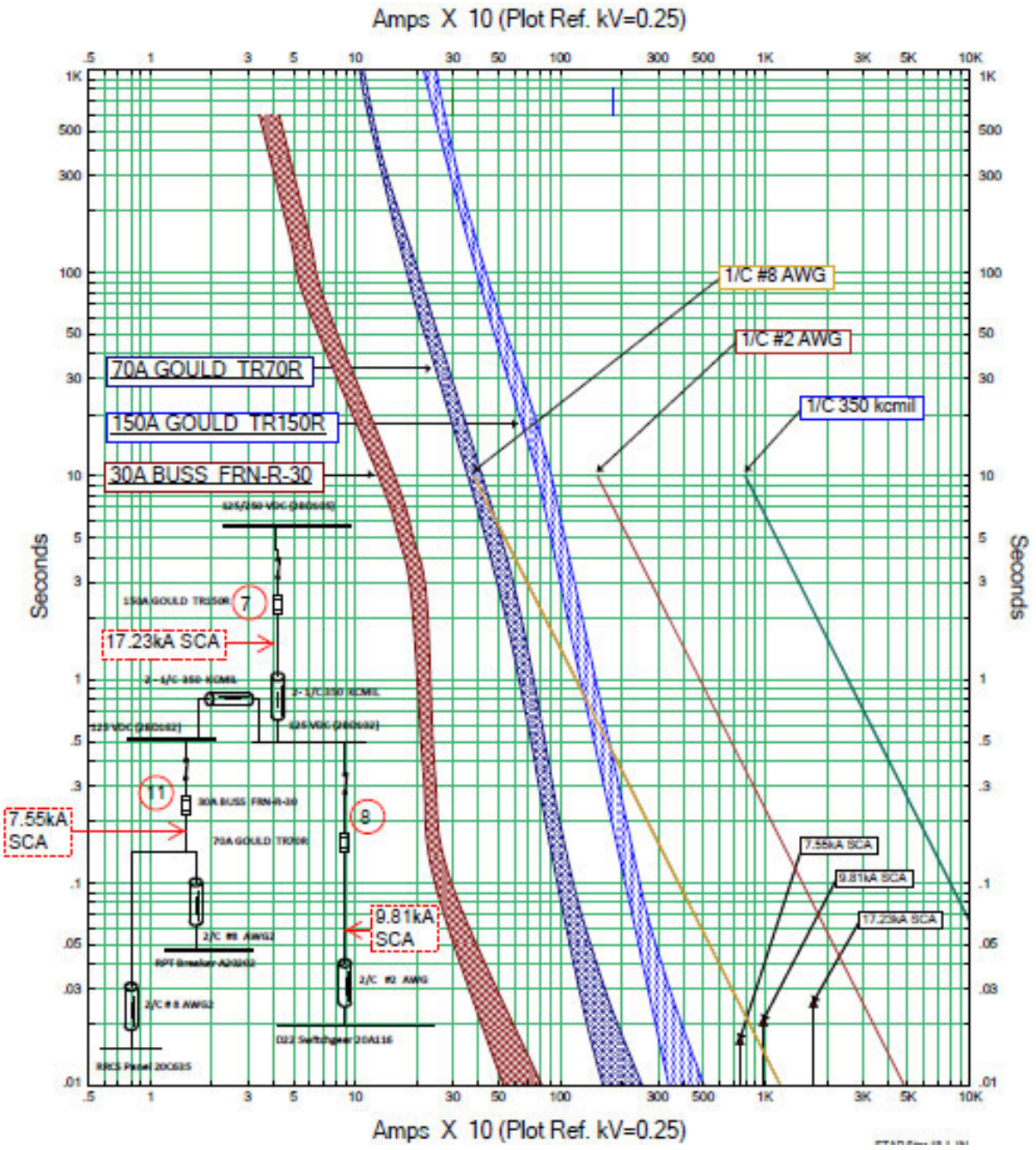
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FIRE PROTECTION EVALUATION REPORT
DIVISION II 125/250 Vdc SYSTEM
BATTERIES 2B1D101 & 2B2D101
PROTECTIVE DEVICE COORDINATION

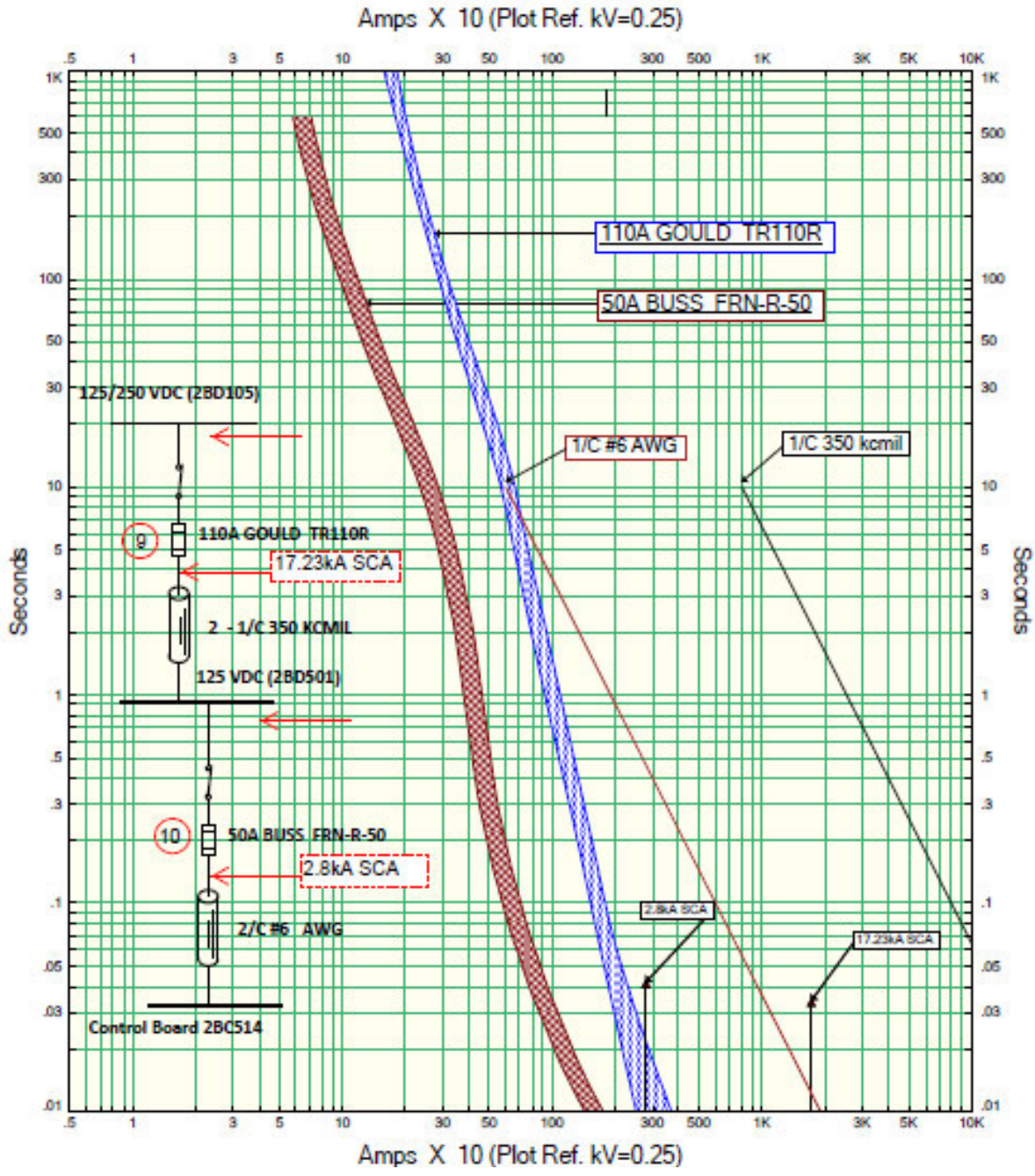
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LIMERICK GENERATING STATION
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FIRE PROTECTION EVALUATION REPORT
DIVISION II 125/250 Vdc SYSTEM
BATTERIES 2B1D101 & 2B2D101
PROTECTIVE DEVICE COORDINATION

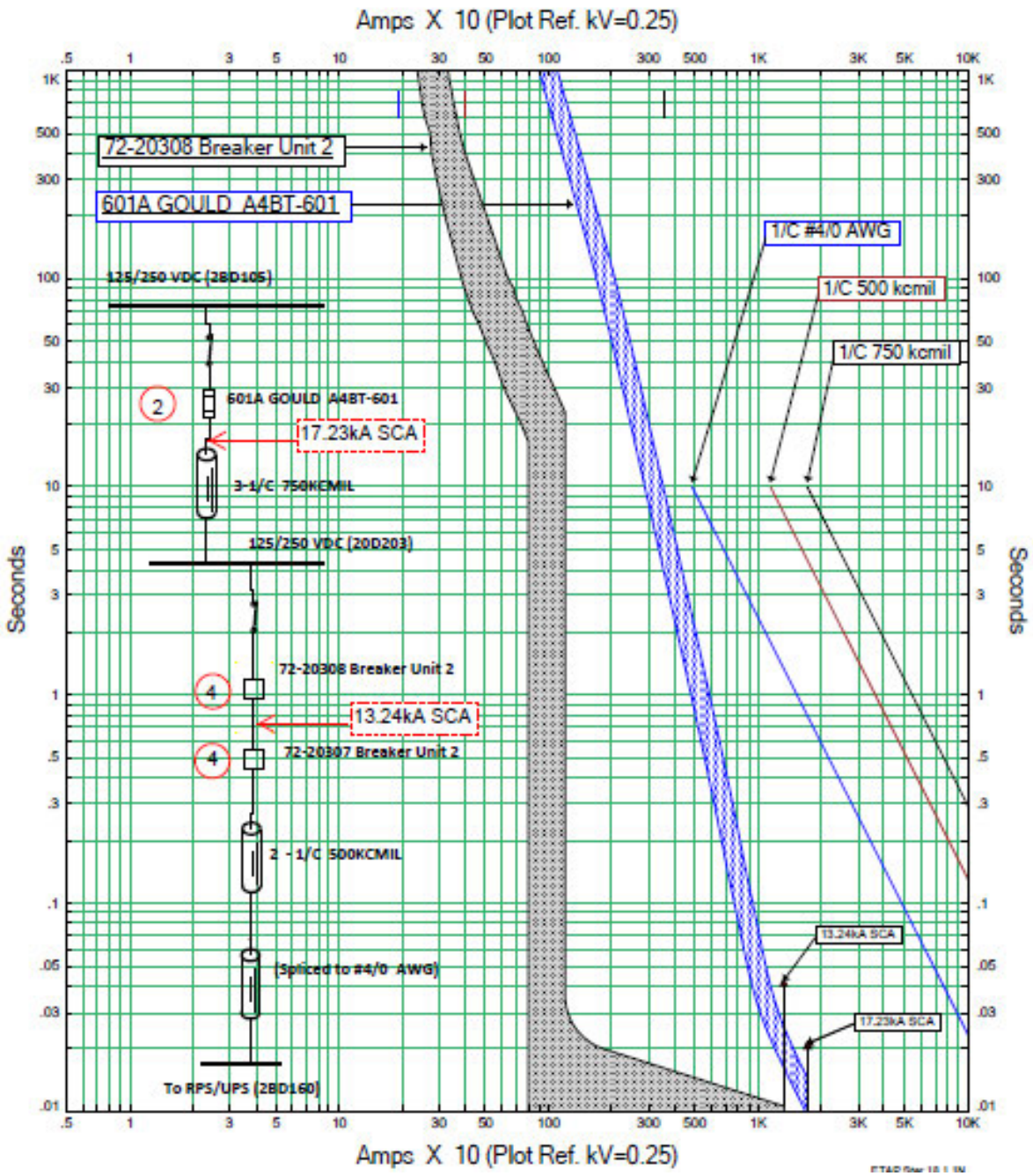
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UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION II 125/250 Vdc SYSTEM
BATTERIES 2B1D101 & 2B2D101
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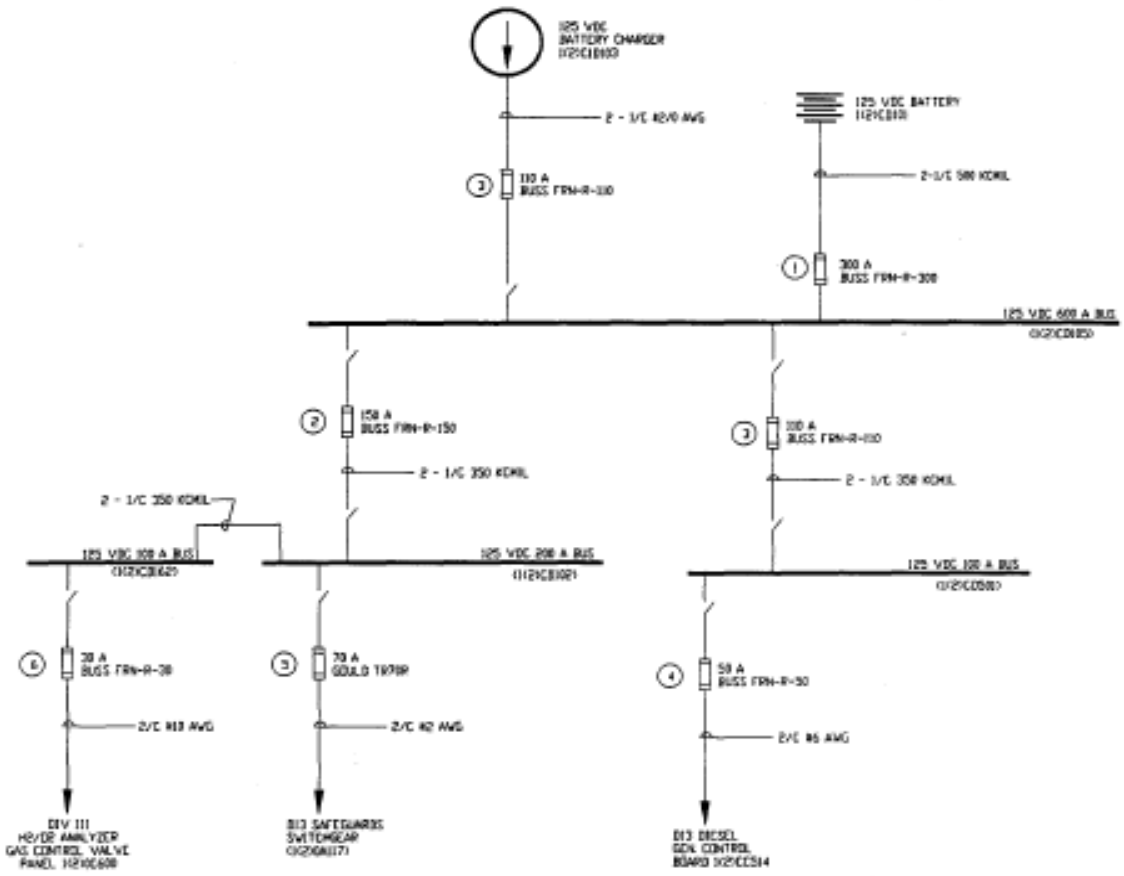
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DIVISION 125/250 Vdc SYSTEM
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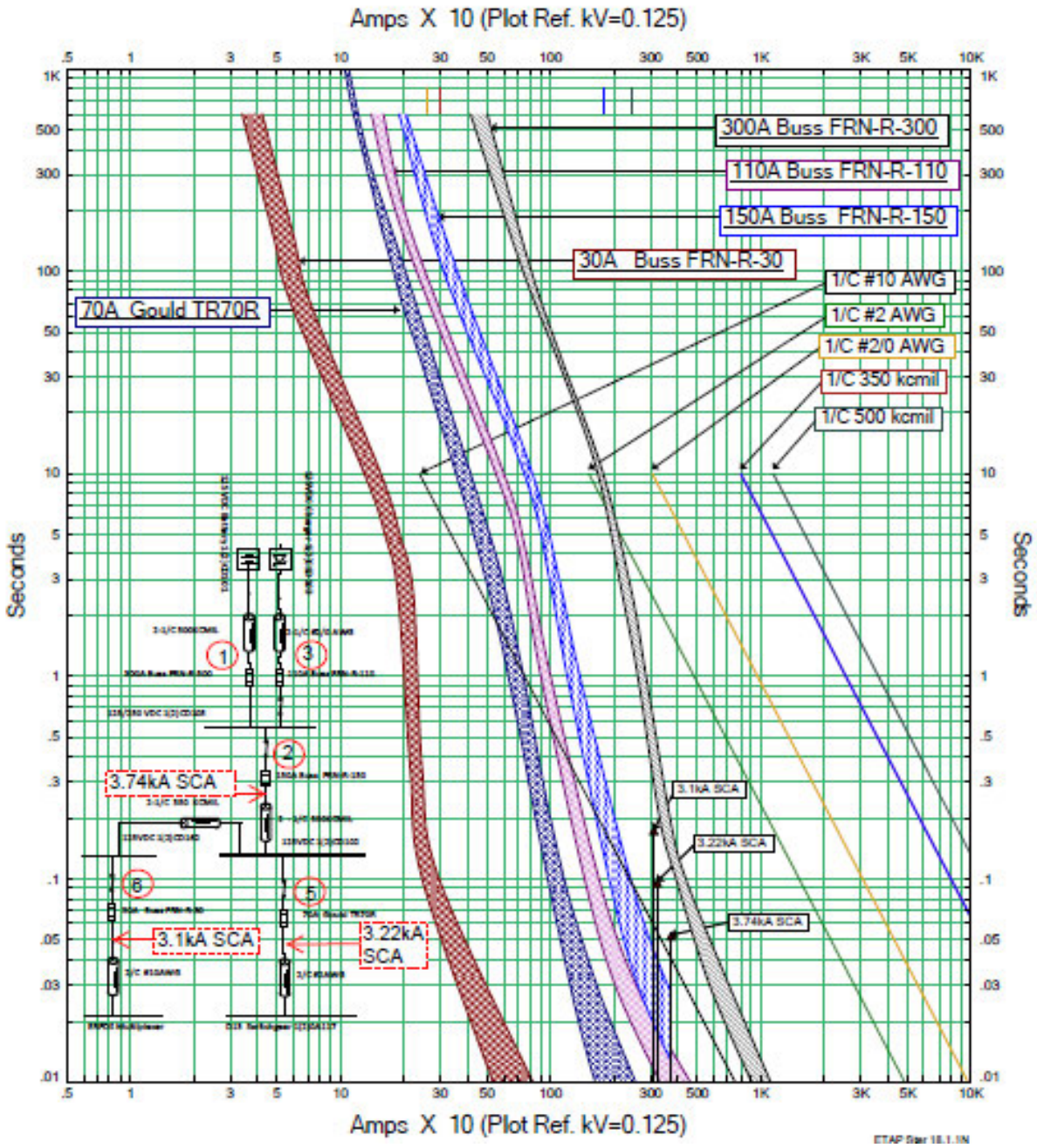
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FIRE PROTECTION EVALUATION REPORT
DIVISION III 125/250 Vdc SYSTEM
BATTERIES 1CD101 & 2CD101
PROTECTIVE DEVICE COORDINATION

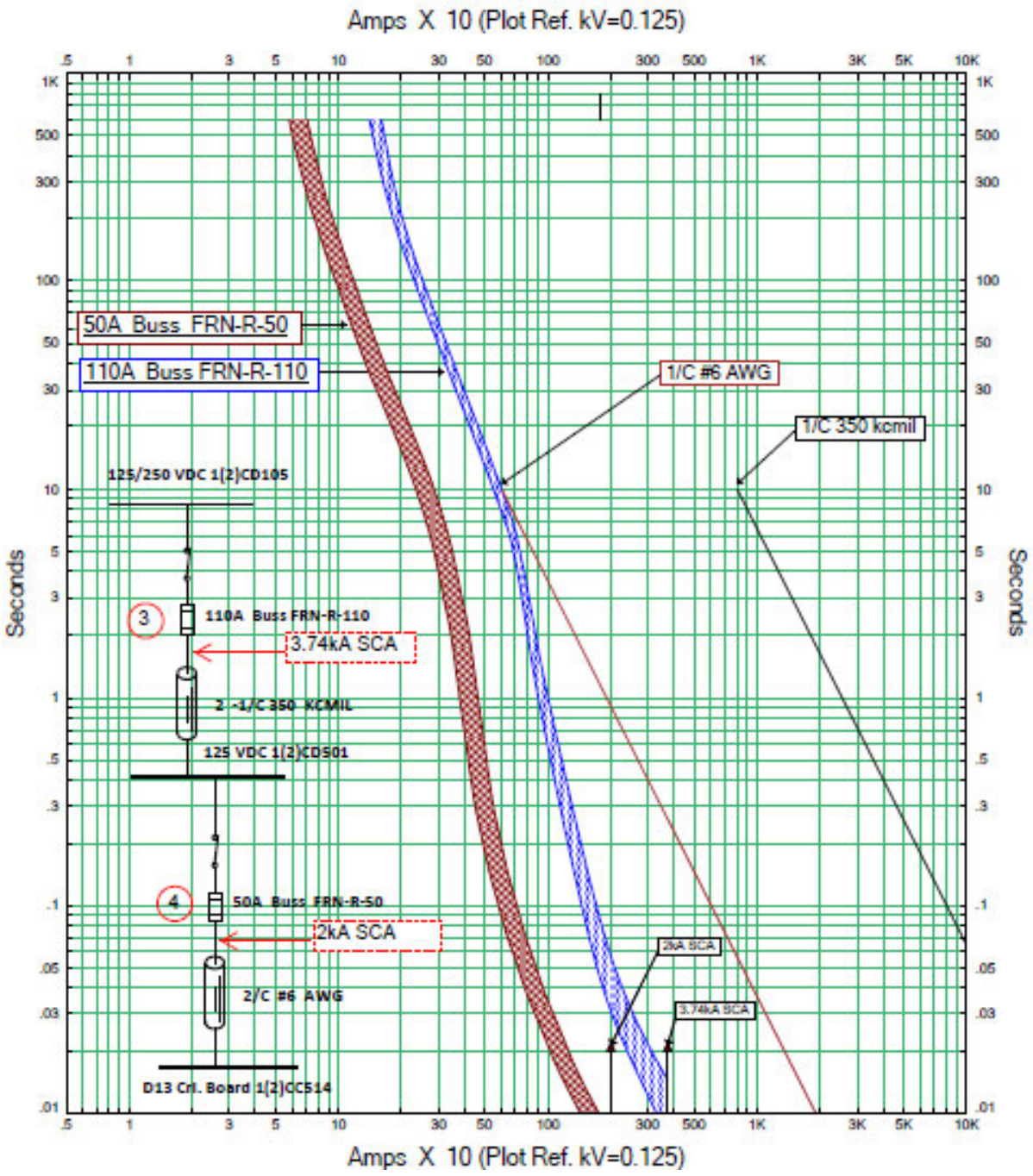
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LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION III 125/250 Vdc SYSTEM
BATTERIES 1CD101 & 2CD101
PROTECTIVE DEVICE COORDINATION

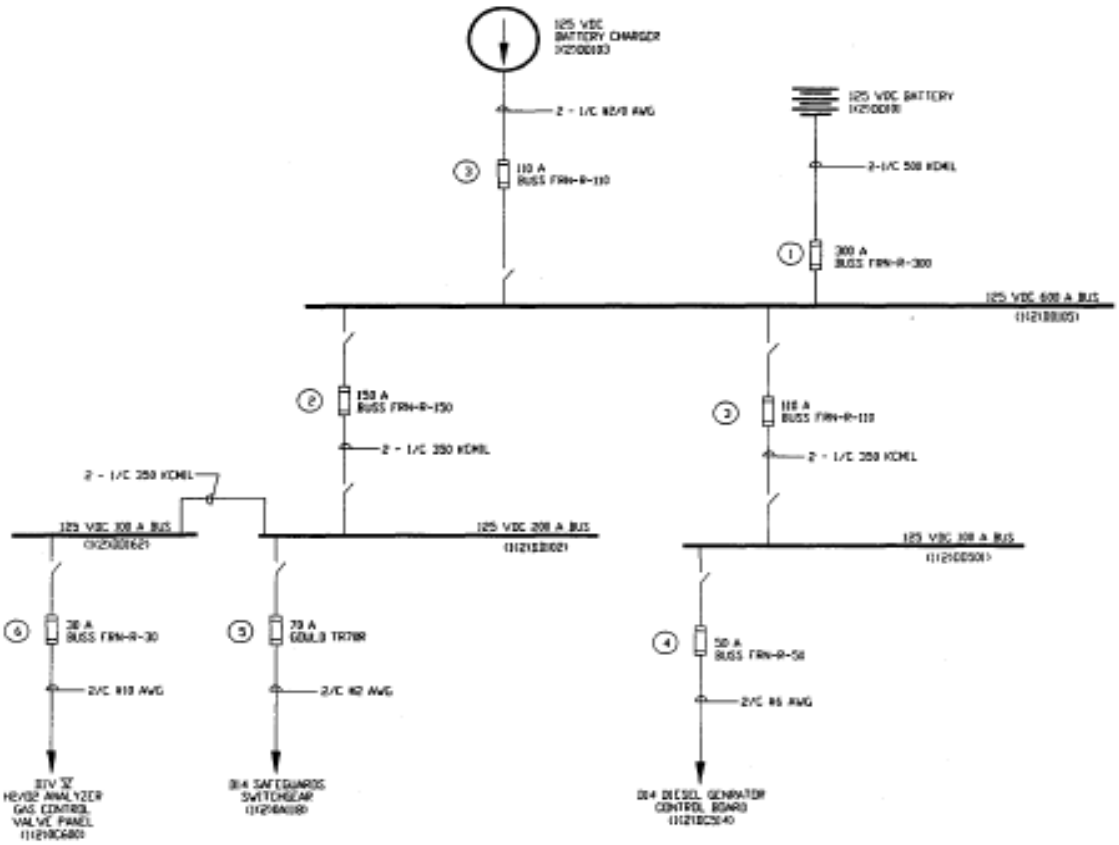
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LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION III 125/250 Vdc SYSTEM
BATTERIES 1CD101 & 2CD101
PROTECTIVE DEVICE COORDINATION

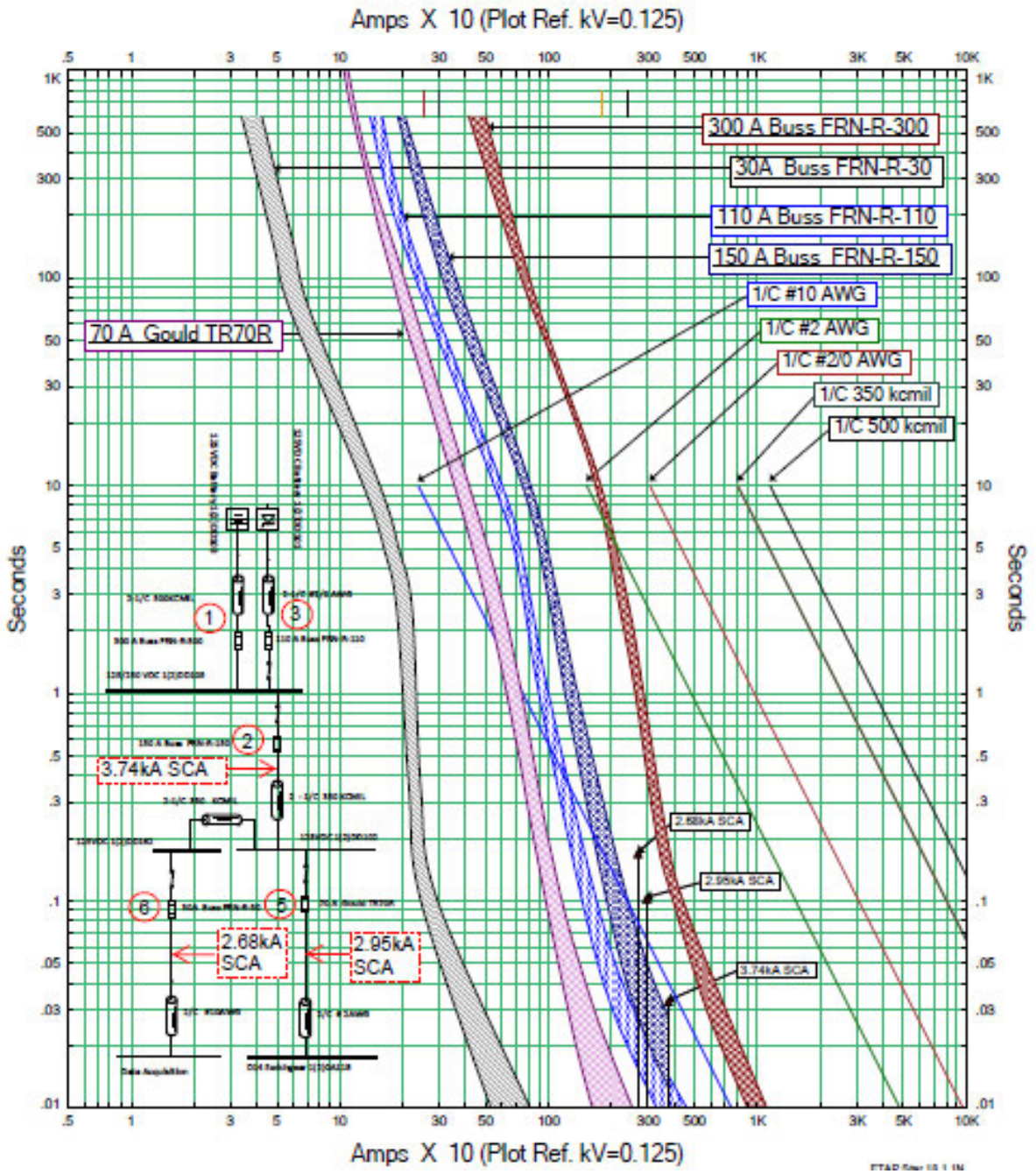
FIGURE 9A-19 **Sht. 3 of 3** **Rev. 21 09/22**



LIMERICK GENERATING STATION
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FIRE PROTECTION EVALUATION REPORT
DIVISION IV 125/250 Vdc SYSTEM
BATTERIES 1DD101 & 2DD101
PROTECTIVE DEVICE COORDINATION

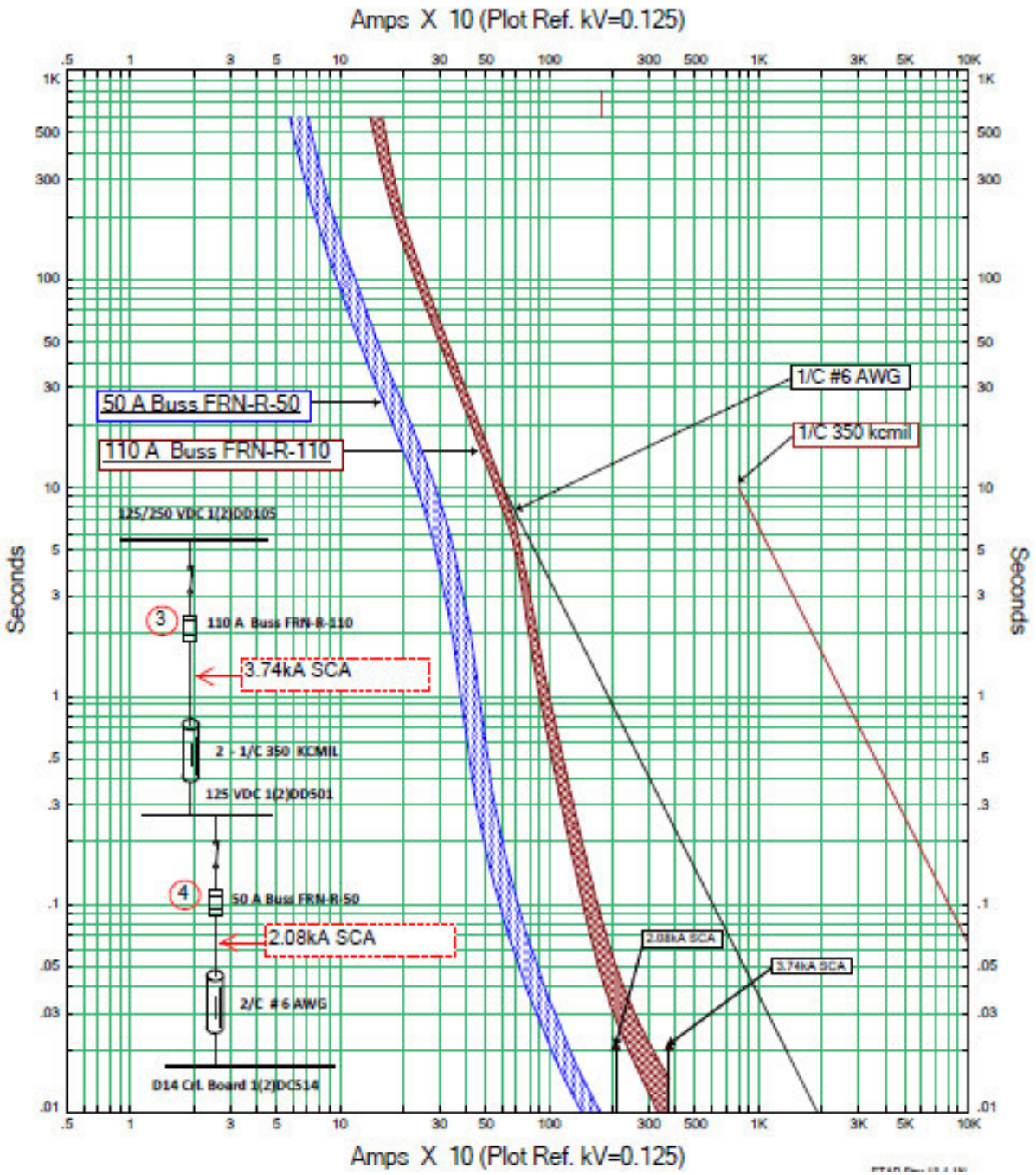
FIGURE 9A-20 **Sht. 1 of 3** **Rev. 21 09/22**



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UPDATED FINAL SAFETY ANALYSIS REPORT

FIRE PROTECTION EVALUATION REPORT
DIVISION IV 125/250 Vdc SYSTEM
BATTERIES 1DD101 & 2DD101
PROTECTIVE DEVICE COORDINATION

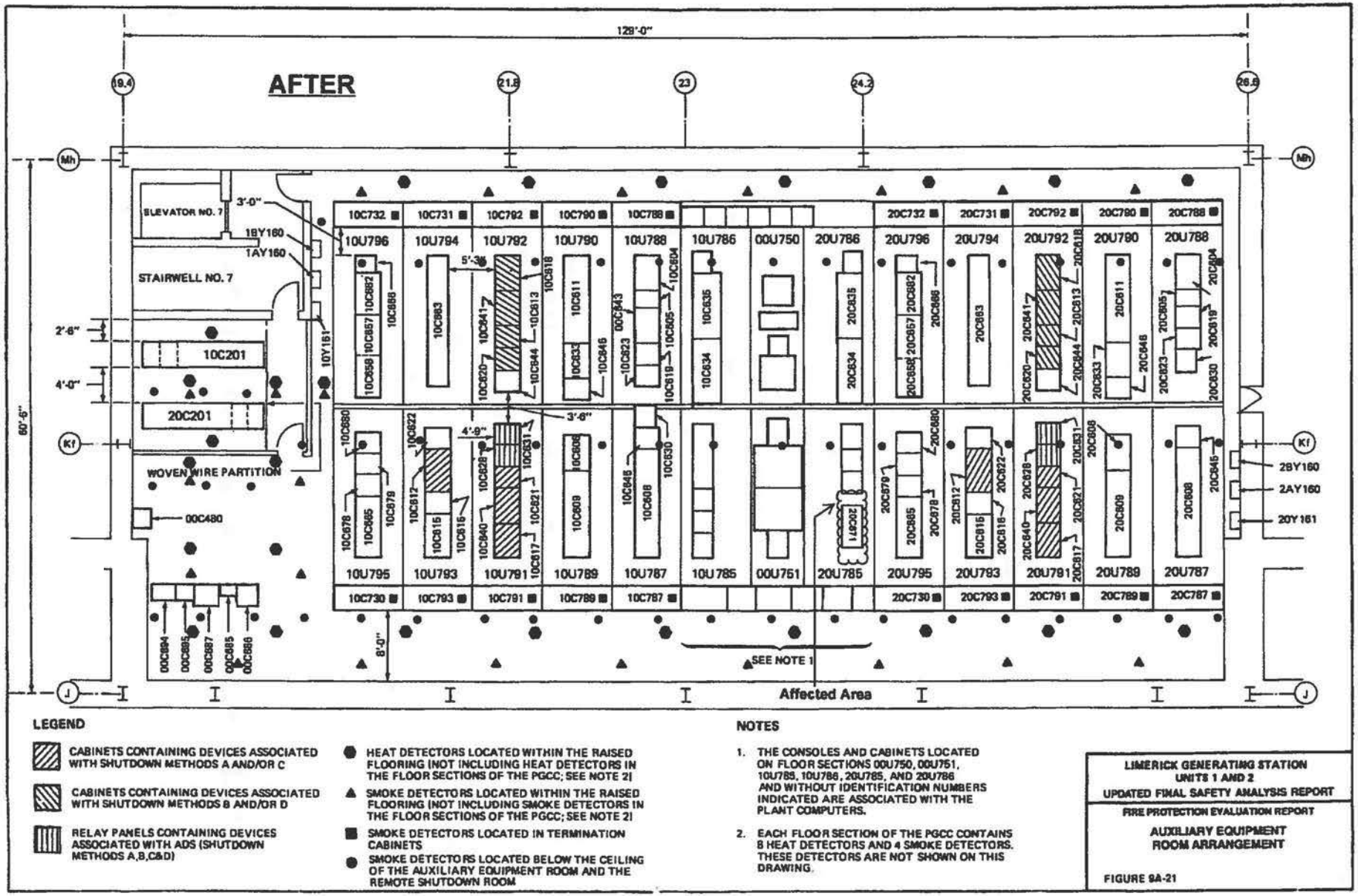
FIGURE 9A-20 **Sht. 2 of 3** **Rev. 21 09/22**



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FIRE PROTECTION EVALUATION REPORT
DIVISION IV 125/250 Vdc SYSTEM
BATTERIES 1DD101 & 2DD101
PROTECTIVE DEVICE COORDINATION

FIGURE 9A-20 **Sht. 3 of 3** **Rev. 21 09/22**



LEGEND

- CABINETS CONTAINING DEVICES ASSOCIATED WITH SHUTDOWN METHODS A AND/OR C
- CABINETS CONTAINING DEVICES ASSOCIATED WITH SHUTDOWN METHODS B AND/OR D
- RELAY PANELS CONTAINING DEVICES ASSOCIATED WITH ADS (SHUTDOWN METHODS A,B,C&D)
- HEAT DETECTORS LOCATED WITHIN THE RAISED FLOORING (NOT INCLUDING HEAT DETECTORS IN THE FLOOR SECTIONS OF THE PGCC; SEE NOTE 2)
- SMOKE DETECTORS LOCATED WITHIN THE RAISED FLOORING (NOT INCLUDING SMOKE DETECTORS IN THE FLOOR SECTIONS OF THE PGCC; SEE NOTE 2)
- SMOKE DETECTORS LOCATED IN TERMINATION CABINETS
- SMOKE DETECTORS LOCATED BELOW THE CEILING OF THE AUXILIARY EQUIPMENT ROOM AND THE REMOTE SHUTDOWN ROOM

NOTES

1. THE CONSOLES AND CABINETS LOCATED ON FLOOR SECTIONS 00U750, 00U751, 10U785, 10U786, 20U785, AND 20U786 AND WITHOUT IDENTIFICATION NUMBERS INDICATED ARE ASSOCIATED WITH THE PLANT COMPUTERS.
2. EACH FLOOR SECTION OF THE PGCC CONTAINS 8 HEAT DETECTORS AND 4 SMOKE DETECTORS. THESE DETECTORS ARE NOT SHOWN ON THIS DRAWING.

LIMERICK GENERATING STATION
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FIRE PROTECTION EVALUATION REPORT

AUXILIARY EQUIPMENT ROOM ARRANGEMENT

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CHAPTER 10 -STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The power conversion systems of each unit are designed to produce electrical energy through conversion of a portion of the thermal energy contained in the steam supplied from the reactor. Both systems condense the turbine exhaust steam into water and return it to the reactor as heated feedwater, with a major portion of its impurities removed.

The power conversion systems of the two units are identical, are not interconnected, and do not have common equipment. The major components of each unit's power conversion system are:

a. Turbine-generator with auxiliaries

b. Main condenser

c. Condensate pumps

d. Air ejector with water-cooled condenser

e. Clean steam seal system

f. Turbine bypass system

g. Condensate cleanup system

h. Reactor feed pumps

i. Feedwater heaters

j. Condensate storage systems

k. Interconnecting piping and valves

The circulating water system and, ultimately, the cooling towers remove the rejected heat to the main condenser. An overall flow diagram of the system is shown in “drawings M-01, M-02, M-03, M-04, M-05, M-06, M-07, M-09, M-16, and M-21.

Steam generated in the reactor is supplied to the high pressure turbine through the main stop and control valves and exhausted through cross-around lines to six moisture separators that remove moisture from the steam. The dried steam leaves the moisture separators and enters the low pressure turbines through combined intercept valves. After passing through the LP turbines, the steam exhausts to the main condensers, where it is condensed by the circulating water system (Section 10.4.5), deaerated, collected in the hotwell of the condenser, and returned to the cycle as condensate. The SJAEs continuously use a small part of the main steam supply to continuously remove noncondensable gases from the condenser. Steam is extracted from cross-around pipes downstream of the moisture separators to drive the reactor feed pump turbines during normal power operation.

Taking suction from the condenser hotwell, the condensate pumps deliver the condensate to the reactor feed pumps through the SJAE condenser, the steam packing exhauster condenser, the condensate cleanup demineralizers, the first heater drain coolers, and the five stages of low pressure feedwater heaters. The reactor feed pumps supply feedwater to the reactor through one stage of high pressure feedwater heaters.

Steam is extracted from stages of the HP and LP turbines and used to heat the condensate as it passes through the various feedwater heaters. The extraction steam is condensed in each heater, and the condensed steam is drained to the next lowest pressure heater. The total cascaded heater drains are collected in the drain cooler, from which they drain back to the condenser. The moisture removed from the steam by the moisture separators is drained to heater No. 4, where it mixes with the condensed extraction steam and is eventually drained back to the condenser.

If the water level in any heater or moisture separator becomes too high, the drains are automatically dumped directly to the condenser and the feedwater heater extraction isolation valves are automatically closed.

Normally, the turbine uses the steam being generated by the reactor; however, an automatic steam bypass system can discharge excess steam (as much as 24.3% of the design flow) directly to the condenser (Section 10.4.4).

Biological shielding is provided to protect operating personnel from exposure to high radiation levels. Section 12.3 provides additional discussion on radiation protection.

Except for portions of the feedwater lines from the RPV to the outermost isolation valves and the main steam lines from the RPV to the turbine stop valves, along with selected instruments listed in Chapter 7 used for the RPS, no other portions of the steam conversion and power conversion systems are safety-related.

References 10.2-9, 10.2-10, and 10.2-11 provides the heat balances for Unit 1 and Unit 2.

The design and performance characteristics for the steam and power conversion system are summarized in Table 10.1-1.

Table 10.1-1

DESIGN AND PERFORMANCE CHARACTERISTICS OF
POWER CONVERSION SYSTEM FOR GUARANTEED CONDITION

	Pre MUR-PU	Post MUR-PU
STEAM CONDITIONS AT THE TURBINE STOP VALVES		
Flow	14.97×10^6 lb/hr	15.287×10^6 lb/hr***
Pressure	1005 psia	1003 psia***
Temperature	545°F	
Enthalpy	1190.1 Btu/lb*	1190.0 Btu/lb***
Moisture content	0.41%*	0.43%***
FEEDWATER CONDITIONS		
Flow	14.95×10^6 lb/hr	15.255×10^6 lb/hr
Temperature	425.1°F	427.1°F
CONDENSER		
Air inleakage	337 lb/hr (75 scfm)	
Hotwell detention capacity	2 min	
MAIN STEAM BYPASS CAPACITY	25%	24.3%****

* These values are based on 0.1% moisture in the reactor steam dome and do not necessarily reflect current operating conditions.
** Data for Post MUR-PU notes differences only.
*** Conditions at upstream of turbine stop valves.
**** Turbine bypass capacity with respect to steam flow of 15.287 Mlb/hr.

10.2 TURBINE-GENERATOR

The turbine-generator receives steam from the nuclear steam supply system, converts a portion of the thermal energy contained in the steam to electric energy, and provides extraction steam for feedwater heating and for driving the reactor feed pump turbines. The turbine-generator is not safety-related.

10.2.1 DESIGN BASES

a. The turbine-generator is designed to meet the conditions listed in Table 10.2-1, which shows conditions at both 100% rerated power for LGS Units 1 and 2. The associated heat balance is Reference 10.2-9. New heat balances for last stage blade replacement are provided in References 10.2-10, and 10.2-11.

b. DELETED

c. The turbine-generator control system is designed to maintain constant reactor pressure during normal operation and to operate the steam bypass system up to 25% of full load to maintain constant reactor pressure during plant startup, transients, and shutdown. The turbine-generator control system is designed to accomplish the following control functions:

   1. Control speed and acceleration from 0% to 110%.

   2. Operate the steam bypass system to keep reactor pressure within acceptable limits.

   3. Control reactor pressure from 150 psig to 1050 psig.

d. The turbine-generator and ancillaries are designed and manufactured in accordance with GE and Siemens design practices.

10.2.2 DESCRIPTION

The general arrangement of the turbine-generator and associated systems with respect to plant structures and other systems is shown in drawings M-110, M-111, M-112, M-113, M-125, M-126, M-127, and M-128.

10.2.2.1 Turbine

The turbine unit consists of one double-flow high pressure and three double-flow low pressure turbines on the same shaft. The unit also includes six vertical moisture separator vessels of the nonreheat-type. The turbine is an 1800 rpm, tandem compound, nonreheat steam turbine.

The capability of the Unit 1 turbine when operating at 3515 MWt core thermal power with initial steam conditions of ~ 1002 psia, 1190.1 Btu/lbm, exhausting to the multi-pressure condenser and extracting steam for six feedwater heater stages and three reactor feed pump turbines is 1226.5 MW.

The capability of the Unit 2 turbine when operating at 3515 MWt core thermal power with initial steam conditions of 1004.5 psia, 1190 Btu/lbm, exhausting to the multi-pressure condenser and extracting steam for six feedwater heater stages and three reactor feed pump turbines is 1237.3 MW.

Steam from the reactor enters the turbine unit through four main steam lines. Each of the four steam lines to the HP turbine is connected to a main steam stop valve and a main steam control valve. The four stop valves and four control valves form a combined valve chest. A pressure equalizing line connects the stop valves together just below the valve seats. A nine-valve bypass chest is connected to the main steam lines between the MSIVs and the main stop valves to divert excess flow to the condenser. Steam from the high pressure turbine exhaust passes through the moisture separators, where the moisture content is reduced, through each of six combined intermediate valves to the low pressure turbines.

There is one stage of extraction from the HP turbine, one stage from the cross-around pipes upstream of the moisture separators, and four stages of extraction from each LP turbine. The extraction steam is used to heat the feedwater in six separate feedwater heater stages.

A portion of the cross-around steam is used to drive the RFPTs during normal operation. Main steam is used to drive the RFPTs during startup and shutdown modes.

10.2.2.2 Generator and Exciter

The generator is a 1,264,970 kVa, 1,800 rpm, direct-connected, four-pole, 60 Hz, 22,000 V synchronous generator with expected operating power factor of 0.985 and 0.58 short-circuit ratio, at a maximum hydrogen pressure of 75 psig. The generator is sized to accept the gross output of the turbine.

The generator excitation system consists of a 60-Hz, 1800 rpm air-cooled generator and liquid-cooled rectifiers controlled by a Digital Automatic Voltage Regulator with two redundant. The exciter is rated for a maximum output of 3460 kW at 540 V.

The generator stator is water-cooled and the rotor is hydrogen- cooled. The generator hydrogen system includes all necessary controls and regulators for hydrogen cooling. A seal oil system is provided to prevent hydrogen leakage through the generator shaft seals. A hydrogen makeup supply from the HWC system is provided to replace any hydrogen absorbed in and rejected from the seal oil. Carbon dioxide is used for purging the hydrogen supply line and/or the generator before and after generator use and ensures that an explosive mixture cannot be formed. The hydrogen and carbon dioxide systems are shown in drawing M-28. Protective measures to prevent fires and explosions during purging and normal operations consist of hydrogen pressure control stations, excess flow shutoff valves, alarms, and pressure safety devices. The buried piping which extends from the hydrogen pressure control stations to the turbine enclosure is of a pipe-within-a-pipe design providing environmental protection in the event of leakage or extended damage. Test connections are provided to analyze the air/CO_2 and H_2/CO_2 concentrations during purging. Hydrogen analyzing equipment is provided to continuously monitor hydrogen purity during normal operations. Removable spool pieces provide additional isolation, assuring that hydrogen does not leak into the generator during maintenance activities.

Hydrogen gas will be supplied from the HWC System to the Generator Hydrogen Cooling System. The manual isolation valves and a check valve are located between the HWC System and the Generator Hydrogen Cooling System. During system makeup the Generator Hydrogen Cooling System storage bottles will be isolated. The Generator Hydrogen Cooling System pressure reducing station(s) and excess flow valve will be utilized during system makeup from the HWC System. In the unlikely event of a hydrogen supply line rupture in the HWC System, the check

valve prevents depressurization of the Generator Cooling System, thereby minimizing the possibility of a generator trip.

10.2.2.3 Protective Valve Functions

The primary function of the main stop valves is to quickly shut off steam to the turbine under emergency conditions. The stop valve discs are totally unbalanced and cannot open against full pressure drop. An internal bypass valve is provided in one of the four stop valves to permit slow warming of the combined valve chest and to permit pressurization below the stop valve seat area to allow valve opening and to allow shell warming.

The turbine stop valves are designed by using a dynamic seismic analysis to withstand the OBE and SSE loads within the limits of the manufacturer's special criteria. A statement of adequacy has been provided by the manufacturer.

The function of the control valves is to throttle steam flow to the turbine during normal operation and promptly throttle steam flow when a overspeed is sensed. The valves, because of their size relative to their cracking pressure, are partially balanced. A small internal valve is opened first to decrease the pressure in a balance chamber. The valves are opened by individual hydraulic cylinders.

The function of the bypass valves is to pass steam directly from the reactor to the condenser without going through the turbine. The bypass valve chest is connected directly to the steam lines from the reactor and is composed of nine valves operated by individual hydraulic cylinders. When the valves are open, steam flows from the chest, through the valve seat, out the discharge casing, and through connecting piping to the pressure breakdown assemblies, where a series of orifices is used to further reduce the steam pressure before the steam enters the condenser (Section 10.4.4).

The function of the CIVs is to protect the turbine against overspeed from stored steam in the cross-around piping and moisture separators following turbine trip and to throttle and balance steam flow to the LP turbines. Each valve is composed of an intercept valve and an intermediate stop valve incorporated into a single casing. The two valves have separate operating mechanisms and controls. One valve is a positioning valve, while the other is an open/closed valve; however, both valves are capable of fast closure. The valves are located as close to the turbine as possible to limit the amount of uncontrolled steam available as an overspeed source.

During normal plant operation, the intercept valves are open. The intercept valves are capable of opening against maximum cross-around pressure and of controlling turbine speed during blowdown following a load rejection. The intermediate stop valves also remain open for normal operation, and they trip closed by actuation of the emergency governor or by operation of the master trip. They provide backup protection if the intercept valves or the normal control devices fail.

10.2.2.4 Extraction System Check Valves

The energy contained in the extraction and feedwater heater system can be of sufficient magnitude to cause overspeed of the turbine-generator following an electrical load rejection or turbine trip. Check valves are installed where necessary to prevent high energy steam from entering the turbine under these conditions. The extraction system check valves are shown in drawing M-02.

The check valves limit the amount of energy flashing back into the turbine so that the turbine speed increase is held below the maximum value. Power-assisted closure check valves are provided for heaters 3, 4, 6, and steam seal evaporator. Heater 2 is provided with spring assisted check valves. Heater 1 has no provision for preventing flashbacks into the turbine, since the distance to the turbine is short and internal energy is low. Heater 5 has no provision for preventing flashbacks into the cross-around piping, since the cross-around/ moisture separator system provides adequate capacity to protect the turbine.

The power-assisted check valves have an air piston that acts in opposition to a spring to keep the valve wide open during normal operation. On turbine trip, the extraction relay dump valve closes, venting the air from the piston actuators and thus allowing the springs to assist in closing the check valves.

10.2.2.5 System Operation

10.2.2.5.1 Control System

The turbine-generator control system is a Westinghouse Ovation® Digital EHC system. In Figure 10.2-13, the speed control unit produces the speed/acceleration error signal that is determined by comparing the desired speed from the reference speed software, with the actual speed of the turbine for steady-state conditions. Speed reference and acceleration rate control perform speed control ramps using entered targets and rates. If the turbine is off-line and in RESET condition, the operator can either enter the desired TARGET in rpm or select a preset TARGET of 1800 rpm. No validation is required when selecting speed target using the preset valve but a target entered via keyboard must satisfy the following validation rules before it is accepted by the system:

- Target must be greater than or equal to a minimum speed of 0 rpm
- Target must be less than a maximum speed of 1850 rpm
- Target must not be within a critical speed/resonance range

For step changes in speed, acceleration reference software takes over to either accelerate or decelerate the turbine at a selected rate to the new speed. There is no limit to the deceleration. In Figure 10.2-13, the speed/acceleration error signal is combined with the load requirements on the load control unit to provide the flow signal to the control valves.

Turbine control and protection are achieved via a combination of speed control, load control, flow control and overspeed protection.

In Figure 10.2-13, the speed control algorithm develops servo positioning demand signals for control valves and intercept valves to control the turbine speed and rate of acceleration. Based on the desired speed set point and selected acceleration rate, the speed control algorithm produces the speed error signal, which drives a reference bias to the output of load control algorithm. This in turn controls the positioning of the turbine control valves and hence the amount of steam energy admitted into the turbine rotating elements.

At the time of synchronization, the speed control algorithm has brought the turbine speed to a value that is close to 1800 rpm. At this point, changes to the load reference signal are used to control synchronization speed matching in preparation for breaker closure. Upon breaker closure, the load control algorithm is used to develop a steam flow signal representing the desired turbine load, up to and including maximum turbine load. The algorithm also includes the

ability to manually set an upper limit for turbine load. Under normal operation, the turbine operator controls the load reference setting via the HMI interface.

Because of the importance of overspeed protection, the speed control signal has three independent redundant channels. Three independent pulse signals are obtained from magnetic pickups located over a gear-toothed wheel on the turbine shaft. Loss of two-out-of-three (2/3) speed signals trips the turbine. (Section 10.2.2.6).

10.2.2.5.2 Emergency Trip System Functions

The emergency trip system trips the unit closing all valves on the following signals and therefore shuts down the turbine:

a. Turbine approximately 10% above rated speed (on overspeed, the tripping is performed by an electrical trip)

b. Turbine approximately 11% above rated speed while testing the overspeed trip device

c. Vacuum decreases to less than a preselected value

d. Excessive thrust bearing wear

e. Prolonged loss of generator stator coolant at loads in excess of a predetermined value

f. Remote manual trip on the control panel

g. Loss of hydraulic fluid supply pressure (loss of emergency trip system fluid pressure automatically closes the turbine valves and then energizes the master trip relay to prevent a false restart)

h. Low lubrication oil pressure

i. Loss of 2 out of 3 speed signals

j. Loss of both primary and secondary EHC power supplies

k. Operation of the manual electrical trip is at front standard

l. High level in moisture separators

m. High reactor water level

n. Power load unbalance

o. DELETED

p. DELETED

q. Reverse power

r. Generator breaker opening

To prevent spurious tripping due to single component failure, duplicated or triplicated trip sensing devices are provided for all trip inputs except for reverse power, back up overspeed and power\load unbalance and are wired to form a single fault tolerant tripping logic. Therefore, a signal from a single sensing element does not trip the turbine-generator. However, the turbine trips if a malfunction is monitored simultaneously by at least two sensing elements.

10.2.2.6 Overspeed Protection

The turbine overspeed protection system instrumentation and turbine speed control valves protect the turbine from excessive overspeed. Protection from turbine excessive overspeed is required since excessive overspeed of the turbine could generate potentially damaging missiles which could impact and damage safety-related components, equipment, or structures.

For speeds above 100% rated speed, the speed control system would fully close the turbine control valves by the time that 105% of rated speed is reached and the CIVs would be fully closed by the time that 107% of rated speed is reached.

To protect the turbine-generator against overspeed due to failure of the speed control system, two trip devices are provided, either of which when initiated closes the main stop valves, control valves, and combined intermediate valves, thus shutting down the turbine.

These two trip devices are as follows:

a. A primary electronic overspeed trip is provided by the Emergency Trip System (ETS) that uses Diverse Turbine Overspeed Protection System (DTOPS) and is initiated if the turbine speed reaches approximately 10% above rated speed.

b. A backup electronic overspeed trip is provided by the Turbine Control System (TCS) and is initiated at approximately 11 % above rated speed.

In Figure 10.2-11, the primary electronic overspeed trip uses a diverse and separate set of magnetic pickups which are comprised of 3 passive speed sensors for sensing speed from a toothed wheel mounted to the turbine shaft. When the turbine speed reaches the trip speed (10% above rated speed), the three independent overspeed protection trip modules located inside the DTOPS device provides three independent trip outputs that interface to the three Emergency Trip System (ETS) Testable Dump Manifold (TDM) solenoids. The ETS TDM utilizes a two-out-of-three (2/3) trip logic configuration to trip the turbine.

In Figure 10.2-11, the backup electronic overspeed trip uses a diverse and separate set of magnetic pickups which are comprised of 3 active speed sensors for sensing speed from a toothed wheel mounted to the turbine shaft. When the turbine speed reaches the trip speed (11 % above rated), the Turbine Control System (TCS) utilizes a two-out-of-three (2/3) trip logic and provides a trip output to its respective TDM unit, which utilizes a two-out-of-three (2/3) trip logic configuration to trip the turbine. This trip uses speed detector modules that are independent of the TCS software. In addition, the TCS software also generates a trip of the TDM unit.

Cross trip functions are provided for interlocking the DTOPS trip with the TCS trip.

Any one of these actions will trip the turbine, i.e., close the stop, control, and combined intercept valves.

When the overspeed trip system is under test, the TDMs can be tested with the plant on-line, without removing or disabling any actuation device.

An additional feature of the protective system that will minimize the likelihood of an overspeed condition is the power/load unbalance software. In Figure 10.2-12, generator load is sensed by means of three current transformers and is compared with the turbine power input which is sensed by the turbine intermediate pressure sensor. If the difference between the steam power input and the generator output rises to at least 40% in 35 msec, auxiliary relays will be actuated that will energize the control valves fast closing solenoids, and remove the load reference at the load control unit. The power load unbalance condition will trip the turbine through the generator protection circuit.

The diversity of devices shown on Table 10.2-2 ensures that stable operation following a turbine trip proceeds from the requirement that both the stop valves and the combined intermediate valves close in a turbine trip, thereby preventing steam from the main steam line from entering the turbine and preventing the expansion of steam already in the high pressure stage and in the moisture separator. An additional provision is made to automatically isolate the major steam extraction lines from the turbine by power-assisted check valves. Closure times of the check valves will be in accordance with the turbine manufacturer's recommendations.

There are four steam lines at the high pressure stage. Each line is provided with one stop valve in series with one control valve. Steam from the high pressure stage flows to the moisture separators and then to the three low pressure stages. Each of the six low pressure lines has a combined intermediate valve that consists of a stop valve in series with a control valve, in one housing. When a turbine trip is initiated, the above valve stroke time is within 0.2 seconds. Assuming a single failure within the above system of 20 valves in case of a turbine overspeed trip signal, the turbine will be successfully tripped.

Any postulated accident, including the effects of high or moderate energy pipe failures, that results in a loss of hydraulic pressure or loss of the electrical signal to the mechanical trip valve or the lockout valve will result in the closure of the main stop valves, control valves, and combined intermediate valves, thereby preventing a turbine overspeed condition. Damage to nearby safety-related equipment or systems or to the turbine overspeed equipment from a high energy or moderate energy piping failure (including failure of the connection from the low pressure turbine to the condenser, or a failure of the turbine bypass line) would not affect the capability to achieve safe shutdown, to scram the reactor, or to initiate a turbine trip.

Safety-related equipment located in the turbine enclosure includes:

a. PT-01-1N052A, B, C, D

b. PT-01-1N075A, B, C, D

c. PT-01-1N076A, B, C, D

d. PS-01-102A, B, C, D

e. ZS-01-104A, B, C, D

The functions of PS-01-102 and ZS-01-104 are described in Section 7.2.1. PT-01-1N052 monitors first-stage pressure on the turbine steam supply lines upstream of the high pressure turbine first stage. The signal is used to generate an automatic bypass of the reactor scrams, when the turbine load is below a preset value, resulting from turbine stop valve closure and turbine control valve fast closure.

PT-01-1N075 initiates MSIV closure on loss of main condenser vacuum, while PT-01-1N076 initiates MSIV closure in the event of low pressure in the main steam line.

For high energy or moderate energy pipe breaks, these instruments are not relied on to initiate a reactor trip or MSIV closure because other instruments are available to perform these functions. For example, a pipe break involving the main steam lines outside containment would cause automatic closure of the MSIVs due to any of the following signals: a) low pressure in the main steam lines b) high flow in the main steam lines, and c) high temperature in the vicinity of the main steam lines. MSIV closure would in turn generate a reactor trip signal.

Assuming an electrical load increase due to a system frequency dip with steady steam input to the turbine, the turbine speed decreases. In Figure 10.2-13, the active speed sensors pick up the change in speed. The speed control unit produces the speed/acceleration error signal that is determined by comparing the desired speed from the reference speed software, with the actual speed of the turbine for steady-state conditions. Speed reference and acceleration rate control perform speed control ramps using entered targets and rates.

In Figure 10.2-13, the speed control algorithm develops servo positioning demand signals for control valves and intercept valves to control the turbine speed and rate of acceleration. Based on the desired speed set point and selected acceleration rate, the speed control algorithm produces the speed error signal, which drives a reference bias to the output of load control algorithm. This in turn controls the positioning of the turbine control valves and hence the amount of steam energy admitted into the turbine rotating elements.

10.2.3 TURBINE DISC INTEGRITY

10.2.3.1 Material Selection

Turbine wheels and rotors for turbines operating with light water reactors are made from vacuum melted or vacuum-degassed Ni-Cr-Mo-V alloy steel by processes that minimize flaw occurrence and provide adequate fracture toughness. Tramp elements are controlled to the lowest practicable concentrations consistent with good scrap selection and melting practices and consistent with obtaining adequate initial and long-life fracture toughness for the environment in which the parts operate. The turbine wheel and rotor materials have the lowest fracture appearance transition temperatures and highest Charpy V-notch energies obtainable, on a consistent basis from water quenched Ni-Cr-Mo-V material at the sizes and strength levels used. Since the actual levels of FATT and Charpy V-notch energy vary, depending on the size of the part and the location within the part, etc, these variations are taken into account in accepting specific forgings for use in turbines for nuclear application.

Charpy tests essentially in accordance with Specification ASTM A-370 are included. Information regarding ranges of material and chemical properties for the limiting wheels (discs), including material chemical analysis of disc and rotor forgings and mechanical properties of disc material, is contained in Reference 10.2-2. This information, while provided for turbines in operation at the

time, is also applicable to the LGS turbines. The actual material characteristics are used to determine the probability of missile generation and inspection intervals (Section 10.2.3.6).

Built-up rotors (with disks shrink-fitted on a shaft) of low pressure turbines operating with light water reactors are exposed to a wet steam and risk of stress corrosion cracking in areas of high tensile stress. Stress corrosion cracks may grow to a size which could eventually result in disk disintegration and generation of missiles external through the turbine casing. The original General Electric low pressure rotors have been replaced because of early stress corrosion crack indications. The new Siemens low pressure turbine built-up rotors are made of NiCrMoV steel with 3.5% nickel and 1.5% chromium content with excellent through hardenability. The material has DIN designation 26NiCrMoV14 5 (similar to ASTM A 471 Class 14).

With this material it is possible to reach excellent fracture toughness and consistent yield strength levels throughout the entire forging. This is achieved by specifying a proper chemical composition with a low phosphor content to suppress temper embrittelment during the Quality Heat Treatment, and low sulfur content for high forging purity. In addition, a low silicon content, or Vacuum Carbon Deoxidization are specified respectively, to avoid macro segregation and to make sure that an adequate forging technique is selected.

Information regarding disk material selection, design considerations, manufacturing and heat treatment procedures, rotor life expectancy and stress corrosion conditions is contained in Reference 10.2-1.

10.2.3.2 Fracture Toughness

Suitable material toughness is obtained through the use of the materials described above to produce a balance of adequate material strength and toughness to ensure safety while simultaneously providing high reliability, availability, efficiency, etc, during operation. Bore stress calculations include components due to centrifugal loads, interference fit, and thermal gradients where applicable. The ratio of material fracture toughness, (K) (as derived from material tests on each wheel or rotor), to the maximum tangential stress for wheels and rotors at speeds from normal to 120% of rated speed is at least 2 square root inches (the highest anticipated speed resulting from a loss of load is 110%). Adequate material fracture toughness needed to maintain this ratio is ensured by destructive tests on material taken from the wheel or rotor. Fracture toughness estimation at room temperature was done using the formulas of Belgly and Logsden modified by Siemens for the uppershelf fracture toughness. Information regarding FATT and operating temperatures for the discs is contained in Reference 10.2-3. The actual material characteristics are used to determine the probability of missile generation and inspection intervals (Section 10.2.3.6).

The Siemens low pressure turbine rotors have a very low FATT such that warm-up time is not required to assure that toughness will be adequate to prevent brittle fracture during startup.

10.2.3.3 Compressive Stress

Besides environment and material strength, the operating stress levels substantially effect the crack initiation time and crack growth rate. Laboratory research and operational experience have proven that if the tensile stress level in the critical areas of the disk bore and keyways is limited to less than 50% of the yield stress level, the crack initiation time is substantially prolonged and crack growth rate is substantially reduced.

The stress in the critical areas of the shrink fit surface is a combination of shrink fit stress, thermal gradient stress, centrifugal force stress and the residual stress resulting from the manufacturing process. Siemens has developed a special High Quality Heat Treatment of turbine disks which is aimed at inducing a high level residual compressive stress (up to 60 Ksi) in the shrink fit and key way areas. As a result the combined stress on the surface is reduced to an acceptable level. In some critical areas, shot peening and rolling are introduced to further reduce the surface stress level, and consequently the risk of stress corrosion crack initiation.

10.2.3.4 Turbine Design

The turbine assembly is designed to withstand normal conditions and anticipated transients, including those resulting in turbine trip without loss of structural integrity. The design of the turbine assembly meets the following criteria:

a. The maximum tangential stress in wheels and rotors resulting from centrifugal forces, interference fit, and thermal gradients does not exceed 0.75 of the yield strength of the material at 125% of rated speed.

b. Turbine shaft bearings are designed to retain their structural integrity under normal operating loads and anticipated transients, including those leading to turbine trips.

c. The multitude of natural critical frequencies of the turbine shaft assemblies existing between zero speed and 20% overspeed is controlled in the design and operation so as to cause no distress to the unit during operation.

10.2.3.5 Preservice Inspection

The preservice inspection program is as follows:

a. Wheel and rotor forgings are rough machined with minimum stock allowance before heat treatment.

b. Each rotor and wheel forging is subjected to a 100% volumetric (ultrasonic) examination. Each finish- machined rotor and wheel is subjected to a surface magnetic particle and visual examination. Results of the above examination are evaluated by use of Siemens acceptance criteria. These criteria are more restrictive than those specified for Class 1 components in ASME Section III and V, and include the requirement that subsurface sonic indications are either removed or evaluated to ensure that they do not grow to a size that compromises the integrity of the unit during the service life of the unit.

c. All finish-machined surfaces are subjected to a magnetic particle examination. No magnetic particle flaw indications are permissible in bores, holes, keyways, and other highly stressed regions.

d. Each fully bucketed turbine rotor assembly is spin tested at or above the maximum speed anticipated following a load rejection from full load.

10.2.3.6 Inservice Inspection

The following Turbine System Maintenance Program describes the required inservice component testing and inspections which ensure that the missile generation probabilities described in UFSAR Section 3.5.1.3, Turbine Missiles, and Table 3.5-9, Turbine System Reliability Criteria, are maintained. Periodic inspection of the Turbine Stop Valves, Turbine Control Valves, Combined Intermediate Valves, and power-assisted steam extraction check valves are also included to provide additional assurance of reliable operation of the turbine overspeed protection systems.

The Turbine System Maintenance Program includes the following:

1. The low pressure turbine elements will be disassembled for inspection on a frequency that is determined by the missile probability analysis. The interval between each low pressure turbine's individual inspection will not exceed 110,000 operating hours. This inspection consists of visual, surface, and volumetric examinations. Inspections will be conducted in accordance with the supplier's instructions and will encompass the following techniques:

    a. Volumetric examination of the low pressure turbine disks,

    b. Visual and surface examination of the low pressure turbine stationary parts,

    c. Visual examination of accessible surfaces of low pressure turbine rotors and disks.

2. The overspeed protection system will be routinely tested in conformance with the assumptions of the missile probability analysis, as follows:

    a. The main turbine stop valves, main turbine control valves, and main turbine combined intermediate valves will be routinely exercised to ensure full freedom of motion. Exercising is accomplished by closing each valve and observing, by the valve position indicator, that it moves smoothly to a fully closed position. The frequency of testing (see Technical Requirements Manual, Section 3/4.3.8) will be no greater than once per 6 months as determined by the missile generation probability analysis in reference 10.2-5. This analysis supplements and is in accordance with the missile probability analysis methodology in Reference 10-2-3.

    b. The power-assisted extraction check valves will be routinely exercised to ensure full freedom of motion at a frequency of once per week. Testing will be performed to verify that each is capable of being actuated by its power cylinder.

    c. Verification of the proper operation of the following overspeed protection system devices/circuits will be performed at the f o 11 owing test frequencies per reference 10.2-4:

        i. ETS Primary Overspeed Trip Circuit (DTOPS). No greater than once per 6 months.

        ii. TCS Backup Overspeed Trip Circuit (SDM). No greater than once per 3 6 months.

iii. Testable Dump Manifold (TDM). No greater than once per 3 6 months.

3. The turbine's Electro-hydraulic Control System fluid will be sampled and analyzed at a frequency not greater than once per 3 months.

4. The following is not required by the Missile Generation Probability Analysis, but will be performed to provide additional assurance of reliable operation of the turbine overspeed protection systems.

   At least one power-assisted steam extraction check valve will be dismantled for visual and surface examination every second refueling outage. If indications of excessive wear or other conditions that could impair the proper functioning of the valve are found, additional valve inspection(s) will be conducted to determine if the condition is common to all extraction valves.

10.2.4 EVALUATION

The turbine-generator has no safety-related function. Failure of the system does not compromise any safety-related system or component or prevent a safe shutdown of the plant.

The turbine-generator control system design provides a stable control response to normal load fluctuations.

The main turbine bypass valves are capable of responding to the maximum closure rate of the turbine control valves so that reactor steam flow is not significantly affected until the magnitude of the load rejection exceeds the capacity of the bypass valves (24.3% of 15.287 Mlb/hr steam flow for Post MUR-PU conditions). Load rejections in excess of bypass valve capacity may cause the reactor to scram due to high pressure. Any condition causing the turbine stop valves to close directly initiates a scram before reactor pressure or neutron flux rise to the trip level.

Loss of electrical or hydraulic power causes all valves to close. If the control valves are tripped closed, the reactor scrams.

Abnormal operational transient analyses have been made for a component failure in the turbine-generator system and are discussed in Chapter 15. Operation with one turbine control valve (TCV) or one turbine stop valve (TSV) closed has been evaluated and reported in UFSAR Reference 5.4-3. This evaluation establishes steamline flow restrictions.

The primary source of activity in the steam and power conversion system is radiation from nitrogen-16 (N-16). N 16 has a half-life of approximately 7 seconds. The activated nitrogen is carried with the steam to the turbine. Fission product noble gases and other activation gases, such as oxygen-19 (0-19), nitrogen-17 (N-17), and nitrogen-13 (N-13), are also carried with the steam to the turbine. Some nongaseous fission and activation products are present in the turbine as a result of moisture carryover in the steam from the NSSS. A summary discussion of the anticipated operating concentrations of radioactive contaminants in the turbine-generator and associated systems is provided in Section 12.2.1.

The activity entering the LP turbine is reduced because of moisture separation and the transit time between the HP and LP turbines that permits the N-16 to decay.

The noncondensable gases in the condenser are removed by the SJAEs to the offgas system for processing and holdup before release to the environment; the offgas system is described in Section 11.3.

The activity remaining in the condensate is reduced significantly by the 2 minute (minimum) holdup time in the condenser hotwell.

Shielding requirements and expected radiation levels are discussed in Section 12.3.2 and drawings N-110, N-111, N-112, N-113, N-115, N-125, N-126, N-127, N-128, and N-130. The turbine-generator is in an administratively controlled access area.

10.2.5 TURBINE-GENERATOR SUPERVISORY INSTRUMENTS

Although the turbine is not readily accessible during operation, the turbine supervisory instrumentation is sufficient to detect any potential maloperation. The turbine supervisory instrumentation includes monitoring of the following variables:

a. Vibration and eccentricity

b. Thrust bearing wear

c. Exhaust hood temperature and spray pressure

d. Oil system pressures, levels, and temperatures

e. Bearing metal and oil drain temperatures

f. Shell temperatures

g. Deleted

h. Shell and rotor differential expansion

i. Electrical load, and control valve inlet pressure indication

j. Hydrogen temperature, pressure, and purity

k. Stator coolant temperature and conductivity

l. Stator winding temperature

m. Exciter air temperatures

n. Steam seal pressure

o. Steam packing exhauster vacuum

p. Steam chest pressure

q. Seal oil pressure

10.2.6 TESTS AND INSPECTIONS

Preoperational tests are performed in accordance with the requirements of Chapter 14. System operation is demonstrated by use during normal system operation. Inservice inspection and testing are discussed in Section 10.2.3.6.

10.2.7 REFERENCES

10.2-1 “Reliable Disk-Type Rotors for Nuclear Power Plants” for Presentation at the American Power Conference, April 27-29, 1987.

10.2-2 “LP Turbine Disks”, Siemens Technical Specifications TLV 9123-33/35 - SIEMENS PROPRIETARY.

10.2-3 “Missile Analysis Report, Limerick Units 1 and 2," Siemens Energy, Inc., CT-27554, November 29, 2016 *(including, as Appendix A: "Missile Probability Analysis Methodology for Limerick Generating Station, Units 1 and 2, with Siemens Retrofit Turbines” Siemens Power Corporation Engineering Report, ER-9605, Revision 2, June 18, 1997 - SIEMENS PROPRIETARY.

10.2-4 "Westinghouse Limerick Generating Station Unit 1 & 2 Turbine Control System Upgrade Reliability Analysis and Electronic Overspeed Protection Fault Tree Analysis, Revision 4, November 2020."

10.2-5 LEAM-0017, Revision 1, "Limerick Supplemental Turbine Missile Probability Analysis."

10.2-6 Deleted.

10.2-7 LEAM-MUR-0038, Reactor Heat Balance, Rev. 0, dated December, 2009.

10.2-8 LEAM-MUR-0005, Condensate Cleanup System, Rev. 0, dated September, 2009.

10.2-9 “Limerick Unit 1 and 2 Rated Condition with New Diagonal Ring,” Seimens Heat Flow Diagram Drawing Number WB-11614-2, July 10, 2010 (N-00E-246-00191).

10.2-10 LM-0300, "Limerick Unit Heat Balance at Rerate Power Levels of 3458 MWt and 3528 MWt (105% Rated and 102% of 105% Rerated Core Power), Revision 4.

10.2-11 LM-0722, LGS Unit 2 PEPSE Heat Balance Model, Revision 0.

Table 10.2-1

TURBINE-GENERATOR DESIGN CONDITIONS

TURBINE-GENERATOR OUTPUT		
At 100% rerated reactor power (maximum guaranteed)	1,245,475 kW	
STEAM CONDITIONS AT TURBINE STOP VALVES		
	Pre MUR-PU	Post MUR-PU
Flow		
100% flow	14.97 x 10^6 lb/hr lb/hr***	15.287 394 x 10^6
Pressure	1005 psia	1003 1002.9 psia***
Temperature	545.2°F	544.9°F
Moisture content	0.41%*	0.4342%***
Exhaust pressure, in. Hga		
	Guaranteed	
High pressure shell	2.75	2.15
Intermediate pressure shell	2.10	1.66
Low pressure shell	1.60	1.32
FINAL FEEDWATER TEMPERATURE		
100% flow (maximum guaranteed)	425.1°F	427432.12°F
STAGES OF FEEDWATER HEATING	6	
GENERATOR POWER FACTOR	0.985 (expected operating conditions)	
GENERATOR RATING	1,264,970 kVA	
VOLTAGE	22,000 V	
HYDROGEN PRESSURE	75 psia	

* This value is based on 0.1% moisture in the reactor steam dome and does not necessarily reflect current operating conditions.

** Data for Post MUR-PU notes differences only.

*** Conditions at upstream of turbine stop valves.

Table 10.2-2

TURBINE OVERSPEED PROTECTION

DEVICE	DESCRIPTION/ FUNCTION	TRIP SETTING	ACTUATING DEVICE INTERMEDIATE	ACTUATING DEVICE FINAL	ACTUATED VALVE	ACTUATED POSITION	POSTULATED EVENT INCLUDING CONSEQUENCES OF HIGH OR MODERATE ENERGY PIPE RUPTURE	RESPONSE
Speed Control Unit 2 Redundant Systems	Compares desired speed with reference speed	Above rated speed CV (Unit 1) Above rated speed CV-IV (Unit 2) Start to close at approximately 101% (Unit 1) Start to close (Unit 2)			All CV All IV	Close	signal[1]	Loss of electrical
	Load control unit provides flow signal to control valves	CV closed by 105% rated speed IV closed by 107% rated speed					Loss of hydraulic pressure	Close all SV, CV and CIV
Overspeed Trip	Close TMD remove electro-hydraulic control oil pressure, Close all concentric with shaft, eccentric on overspeed (Unit 2 only)	Unbalanced ring, 110% of rated speed	DTOPS Mechanical linkage - Unit 2 only	Testable Mechanical Dumptrip valve - Manifold Unit 2 only	All CV All CIV		All SV pressure	Close SV, CV and CIV	Loss of hydraulic
	Close mechanical trip valve (Unit 2 only) and Unit 1 only TDM (Unit 1 only) remove electro-hydraulic control oil press	DTOPS - Manifold - Unit 1 only	Testable Dump					
Backup Overspeed Trip	Toothed wheel magnetic pickup speed sensor electronic signal amplifier	111% of rated 112% of speed rated speed - Unit 2 only 111% of rated speed – Unit 1 only	TCS speed detector relay - modules	Master trip Dumptrip Unit 2 only (MTS) & master trip solenoids (MTSV-A&B) - Unit 2 only	Testable Mechanical All CV Manifold solenoid		All SV electrical All CIV	Close SV, CV, signal[2]	Loss of CIV	Close all
			TCS speed detector modules – Unit 1 only	Testable Dump Manifold - Unit 1 only				

Table 10.2-2 (Cont'd)

DEVICE	DESCRIPTION/ FUNCTION	TRIP SETTING	ACTUATING DEVICE		ACTUATED		POSTULATED EVENT INCLUDING CONSEQUENCES OF HIGH OR MODERATE ENERGY PIPE RUPTURE	RESPONSE
			INTERMEDIATE	FINAL	VALVE	POSITION		
	Close TMD remove mechanical electro-hydraulictrip valve and control oil pressuremaster trip solenoid valves (Unit 2 only); TDM (Unit 1 only); remove electro-hydraulic control oil press						Loss of hydraulic pressure	Close all SV, CV, and CIV
Power/ Load Unbalance	Gen current & steam pressure transducers, electronic comparators & control logics	40% Unbalanced within 35 msec			All CV	No change	Loss of electrical signal a) Loss of generator output signal b) Loss of turbine pressure signal	 Close all CV No action
	Energize CV fast closing solenoids & remove electro-hydraulic control oil press from the CVs.						Loss of hydraulic pressure	Close all SV, CV, and CIV

SV = Stop Valve
CV = Control Valve
CIV = Combined Intermediate Valve
IV = Intercept Valve

(1) Because there are two redundant systems, its function would not be impaired unless the electrical signal from both were lost. If the electrical signal from both are lost, the turbine would be tripped.

(2) For Unit 1, bBackup electrical overspeed would normally de-energize the solenoids of the associated Testable Dump Manifold. For Unit 2, backup electrical overspeed would normally de-energize both the master trip solenoids. Loss of signal to both will trip the turbine.

10.3 MAIN STEAM SUPPLY SYSTEM

The main steam supply system transports steam from the nuclear steam supply system to the power conversion system and to various kinds of auxiliary equipment.

10.3.1 DESIGN BASES

The design bases of the main steam supply system are as follows:

a. To deliver the required steam flow from the reactor to the turbine-generator, at rated temperature and pressure, over the full range of operation from turbine warmup to valves wide open

b. To provide motive steam to the SJAEs

c. To provide steam for the steam seal evaporator and driving steam for reactor feed pump turbines

d. To provide steam for the offgas recombiner preheater and condenser hotwell steam spargers

e. To bypass reactor steam to the condensers during startup and any time the quantity of steam produced by the reactor is more than the turbine-generator requires

The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the main steam supply system are discussed in Section 3.2. Environmental design is discussed in Section 3.11. Inservice inspection is discussed in Section 6.6.

10.3.2 DESCRIPTION

The main steam supply system is shown in drawings M-01 and M-41, and the design parameters are listed in Table 10.3-1. The system extends from the outermost containment isolation valve, up to but not including the turbine stop valves, and includes connected piping of 2½ inches nominal diameter or larger, up to and including the first valve that is either normally closed or is capable of automatic or remote manual closure during all modes of reactor operation.

The main steam piping consists of four 26 inch outside diameter lines from the outermost MSIVs to the main turbine stop valves. The use of four main steam lines permits testing of the turbine stop valves and MSIVs during plant operation, with only minimum load reduction.

The main steam line nuclear pressure relief system and MSIVs are described in Sections 5.2.2 and 5.4.5, respectively. The main stop valves and associated piping and components downstream of the valves are discussed in Section 10.2. The MSIVs, shutoff valves in connecting piping, turbine stop valves, and bypass valves are designed to close against maximum steam flow.

The main steam supply piping is designed and tested according to ASME Section III, Class 2 requirements and is fabricated of seam welded carbon steel.

Each main steam line is provided with a drain downstream of the outermost containment isolation valve. The drains are routed to the condenser through a common 3 inch header (drawing M-41). These drain lines form part of the boundary for the MSIV Leakage Alternate Drain Pathway

discussed in Section 6.7. Each main steam line is also provided with low point drains consisting of a drip leg which, under normal operation, collects moisture and drains it to the condenser through a normally open valve and a restricting orifice.

Pressure equalizing lines, 14 inch nominal size, branch from each main steam line and connect to the bypass valve chest through two 18 inch headers.

The main steam supply system also provides connections to supply steam to the SJAE, steam seal evaporator, gaseous radwaste recombiner preheater, reactor feed pump turbines, and condenser hotwell steam spargers.

10.3.3 EVALUATION

The main steam lines from the outer MSIV, up to but not including the turbine stop valve, and all branch lines 2½ inches in diameter and larger, up to and including their first valve, are seismic Category I and ASME Section III, Class 2. The main steam piping is supported to seismic Category I requirements up to and including the turbine stop valve. The pipe supports and restraints on this piping are designed in accordance with ANSI B31.7, Class II.

The main steam piping is seismic Category I up to the main stop valves. The main steam lines, up to and including the second isolation valves, are located in a seismic Category I structure. The remainder of the main steam piping, up to the stop valves, is located in the turbine enclosure, which is seismic Category II. However, as described in Sections 3.8.4.1.8 and 10.3.3, those portions of the turbine enclosure that support the main steam lines are designed so that the main steam lines, the turbine stop valves, and their supports maintain their integrity under the seismic loading resulting from the SSE.

In addition, all nonseismic Category I systems and components in the vicinity of the main steam lines are designed as seismic Category IIA as discussed in Section 3.2.1 for an SSE condition.

The dynamic input loads for the design of the main steam lines are derived from a time history model analysis of the supporting structures or an equivalent method, as described in Section 3.7. The main steam line supporting structures (those portions of the turbine enclosure) are such that the main steam lines and their supports can maintain their integrity within the ASME Section III, Class 2 requirements under seismic Category I loading conditions.

These seismic Category IIA items will be identified in UFSAR Table 3.2-1 to ensure that any maintenance of or modifications to these items will employ the level of quality assurance necessary to retain their seismic Category IIA classification.

Therefore no seismic Category I structures, systems, or components in the vicinity of the main steam lines will damage the main steam line during an SSE.

The main steam lines are designed with suitable accesses to permit inservice testing and inspections in accordance with ASME Section XI.

A system level qualitative-type failure modes and effects analysis is provided in Section 15.9.6 for active components associated with the main steam lines. Additional discussion of failures in these components is provided in Sections 6.7.3 and 15.2.4 and in Table 6.7-1.

10.3.4 INSPECTION AND TESTING REQUIREMENTS

The main steam lines are fabricated, examined, and tested in accordance with ASME Section III, Class 2.

The system is preoperationally tested in accordance with the requirements of Chapter 14 and periodically tested in accordance with the requirements of Chapter 16.

10.3.5 WATER CHEMISTRY (PWR)

This section is not applicable to LGS.

10.3.6 STEAM SUPPLY SYSTEM MATERIALS

10.3.6.1 Fracture Toughness

Design specifications for Class 2 piping do not require impact testing.

10.3.6.2 Material Selection and Fabrication

a. All materials used in the main steam lines are included in appendix I to ASME Section III.

b. Austenitic stainless steel is not used in the main steam supply system; therefore, Regulatory Guide 1.31, "Control of Stainless Steel Welding," Regulatory Guide 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel," and Regulatory Guide 1.44, "Control of the Use of Sensitized Stainless Steel," are not applicable.

c. The cleaning procedures for the main steam supply system are based on ANSI N45.2.1, Class B criteria. A discussion of compliance with Regulatory Guide 1.37 is included in Section 1.8.

d. Regulatory Guide 1.50, "Control of Preheat Temperature for Welding of Low Alloy Steel," is not applicable, since no low alloy steel is used in this system.

e. Regulatory Guide 1.71, "Welder Qualification for Areas of Limited Accessibility," is not applicable, since no low alloy or high alloy material is installed in the main steam supply system as described in this section.

f. Preheat temperatures for the welding of carbon steel components are in accordance with ASME Section III, Article D-1000.

g. Butt-welded pipe receives 100% radiography. Socket- welded pipe receives 100% magnetic particle or liquid penetrant examination. All nondestructive examination procedures conform to the ASME B&PV Code.

Table 10.3-1

MAIN STEAM SUPPLY SYSTEM DESIGN PARAMETERS

MAIN STEAM SUPPLY SYSTEM	
Number of lines	4
Size, O.D.	26 inches
Design pressure	1,115 psig
Design temperature	582°F

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

10.4.1 MAIN CONDENSERS

The main condenser system is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine bypass system. The main condenser system is not safety-related.

10.4.1.1 Design Bases

The design bases of the main condenser system are as follows:

a. To condense and deaerate the exhaust steam from the main turbine and reactor feed pump turbines

b. To accept and deaerate the drains from the feedwater heaters and other components in the heat cycle

c. To serve as a heat sink for the turbine bypass steam, extraction steam line drains, and heat cycle relief valve discharge

d. To retain for a minimum of 2 minutes the condensate formed during full load operation, to allow radioactive decay before returning the condensate to the cycle

10.4.1.2 Description

The main condenser is a triple pressure deaerating-type, comprising three separate shells, one low pressure, one intermediate pressure, and one high pressure. Differential pressure between shells ensures that gases are cascaded from higher to lower pressure shells. Main condenser design parameters are listed in Table 10.4-1. The condensers are supported on the turbine foundation mat, with each of the shells connected to the exhaust of one of the three LP turbines by a rubber expansion joint, which is secured between two steel frames, one welded to the turbine exhaust and the other to the condenser. General plant arrangement of the equipment is shown in drawings M-110, M-111 and M-112.

During normal operation, steam from each LP turbine is exhausted directly downward into its condenser shell through exhaust openings in the bottom of the turbine casings. The condenser also serves as a heat sink for several other flows, such as exhaust steam from the reactor feed pump turbines, cascading heater drains, air ejector condenser drain, condensate and reactor feed pump recirculation lines, feedwater heater shell operating vents, cross-around piping relief valves, and condensate pump suction vents. The steam exhausted to the condenser is condensed by water circulated through the condenser tubes by the circulating water system (Section 10.4.5).

The condensers are provided with reheating/deaerating hotwells that remove inleakage of air, plus hydrogen and oxygen present as a result of dissociation of water in the reactor and carry over to the condenser via main steam. Hydrogen is produced at a maximum design rate of approximately 138.4 scfm at full power operation. These noncondensable gases are cascaded from the HP shell, through the IP shell, to the LP shell, terminating at the cold water inlet end of the LP shell. They concentrate in the air cooling section of the condenser, from which they are removed by the mechanical vacuum pump at startup and by the SJAEs during normal operation (Section 10.4.2).

The condenser design air inleakage rate is 75 cfm. The circulating water quality is controlled through chemical treatment and blowdown. The oxygen content of the condensate does not exceed 0.0035 cm^3/l through all load ranges, as measured at the discharge of the condensate pumps, with an air inleakage of up to 75 cfm.

The condenser hotwells have sufficient storage capacity together with internal baffling to ensure a minimum retention of 2 minutes for condensate from the time it enters the hotwell until it is removed by the condensate pumps.

The inlet water boxes of the LP condenser shell and the outlet water boxes of the HP condenser shell are each provided with butterfly valves, permitting any of the condenser's four separate circulating water flow paths to be removed from service. This arrangement is schematically shown in Drawing M-09.

A loss of condenser vacuum actuates an alarm and ultimately trips the turbine and isolates the steam source. The condenser low vacuum alarm and low vacuum trip setpoints are bounded by those used in the loss of condenser vacuum transient evaluated in Section 15.2.5. However, should the turbine fail to isolate on loss of condenser vacuum, four rupture diaphragms on each condenser shell protect the condenser and turbine exhaust hoods against overpressure.

The condenser is designed to withstand the blowdown effects of steam from the turbine bypass system with no deleterious effects. High temperature drains are discharged into the condenser via spray pipe headers, which reduce the temperatures and pressures to an acceptable level for the condenser tubes before the steam enters the condenser, thus protecting the tubes from failures. The turbine bypass system is described in Section 10.4.4.

The condenser is fitted with 18 BWG Admiralty tubes and in the Unit 2 condenser some 90-10 copper-nickel tubes are also used, except in high velocity areas, where 20 BWG stainless steel tubes are used in the Unit 1 and Unit 2 condensers. Direct high velocity impingement of steam or water on the tubes and structural members inside the condenser is avoided by the use of baffles. The design parameters for the Admiralty tubes are shown in Table 10.4-1.

The condenser is designed and built to the standards of the Heat Exchange Institute and Foster Wheeler's standard practice.

10.4.1.3 Safety Evaluation

The main condenser system is not safety-related and is not required to be operable following a LOCA. Following a LOCA, the main condenser system is the ultimate heat sink for MSIV leakage alternate drain pathway described in Section 6.7. Failure of the system will not compromise any safety-related system or component or prevent the safe shutdown of the plant.

The anticipated inventory of radioactive contaminants during both operation and shutdown is discussed in Sections 11.1 and 11.3. The shielding and controlled access arrangement for the main condensers is described in Section 12.3.

Safety-related main steam radiation monitors are installed downstream of the outboard MSIVs in the main steam tunnel. These monitors provide a means of determining if high radiation is present

in the main steam entering the turbine/condenser. The main steam radiation monitoring system, including detection and control, is discussed in Sections 7.3.1.1, 7.6.1.1, and 11.5.2.1.

10.4.1.3.1 Radioactive Gases

Under normal operation, these gases are removed by the SJAEs and delivered to the gaseous radwaste system. To prevent unacceptable accidental releases of radioactivity to the environment, the ventilation system maintains a slight vacuum in the condenser area. Any radioactive gases that leak out of the condenser under abnormal conditions are removed by the ventilation system and processed through charcoal filters before being vented out of the turbine enclosure stack. Any noncondensable gases that accumulate in the condenser during operation are removed as described in Section 10.4.1.2. There is no significant buildup of hydrogen in the main condenser during shutdown, because it is isolated from potential sources of hydrogen. After processing, gases removed from the condenser are discharged to the atmosphere through the north vent stack. The north vent stack exhaust is monitored and controlled as discussed in Section 11.5.2.1. The condenser evacuation system, turbine enclosure ventilation system, and gaseous radwaste system are discussed in Sections 10.4.2, 9.4.4, and 11.3, respectively.

10.4.1.3.2 Condenser Leakage

If one or more condenser tubes develop leaks, or if a tube-to-tube sheet joint fails, the circulating water is forced into the condensate, thus raising its conductivity. To detect this condition, conductivity cells are installed in the condenser hotwell that alarm if the conductivity rises above acceptable limits. The measuring point location, together with flow path isolation capability, indicates which of the four flow paths contains the leaking tube so that the section may be dewatered. Condenser tube leaks beyond the ability of the condensate cleanup system to maintain conductivity within certain limits will cause a high conductivity alarm in the control room, followed by an orderly reactor shutdown. The reactor water chemistry limits are as follows:

a. Conductivity: $\leq$10 µmho/cm at 25°C

b. Chlorides: $\leq$0.5 ppm

c. pH: 5.3 to 8.6 at 25°C

This system is discussed in Section 10.4-6.

Potential contaminants from the circulating water include 1019 ppm total cations (as $CaCO_3$), 1019 ppm total anions (as $CaCO_3$), and 48 ppm SiO_2. If the condenser is operated with circulating water inleakage and the condensate cleanup system is fully bypassed, the critical contaminant for the reactor is chloride. With a circulating water chloride concentration of 164 ppm (as Cl) and assuming a nominal chloride concentration in the reactor vessel of 10 ppb, a 1 gpm condenser leak will allow operation for 100 minutes before the allowable concentration in the reactor of 200 ppb is exceeded. For a 2 gpm leak, the allowable operating time is 50 minutes, and so on. Maintenance of water quality when the condensate cleanup system is in operation is discussed in Section 10.4.6.

To prevent loss of vacuum, the condenser is of welded construction wherever practicable. The condenser is hydrostatically tested after installed to verify leak-tightness. Any potentially leakage

spots, such as the condensate pump gland seals, will be adjusted. Additional measures to prevent loss of vacuum include:

a. Maintaining adequate flow in the circulating water system.

b. Completely filling and maintaining level in the condenser water boxes to prevent air blanketing.

c. Maintaining the mechanical vacuum pump and a redundant SJAE to ensure adequate vacuum in the condenser.

Fouling of the condenser tubes is prevented by chlorination to prevent bacterial slime growth. Erosion of the condenser tubes and structural components is prevented by baffle plates (Section 10.4.1.2). High velocity areas of the condenser use 20 BWG stainless steel tubes (Section 10.4.1.2.).

10.4.1.3.3 Circulating Water System Rupture

The presence of any water accumulation in the condenser area due to a condenser or circulating water system leak or failure (i.e., expansion joint double guillotine rupture) is detected by sensors installed in each of the north and south basement areas, which actuate an alarm in the control room if there is flooding. These sensors are duplicated, with different alarm points so that the operator receives two warnings, separated by a time interval, to ensure that the warning is not false. On receipt of this alarm, the operator can shut down the circulating water pumps and close motorized condenser inlet and outlet valves.

In the event the expansion joint fails in the circulating water system, actions by the operator to isolate the leaking loop will limit the extent of flooding. If the isolation valves are inoperable or are not actuated by the operator, the maximum steady-state water level would be about el 223'.

In addition to the flooding sensors discussed above, the following measures are provided to protect other areas of the plant and minimize flood damage:

a. Annunciators in the control room indicate to the operator the location of the flooding, i.e., the north area or the south area.

b. The circulating water butterfly valves, motor operators, flooding sensors, and electrical power and control cables to them are operable underwater. However, no credit was taken for operation of the circulating water butterfly valves in calculating the maximum steady-state flood water level at el 223'.

c. The floor drainage system in the condenser area is designed so that water from the flooded area does not enter other areas of the plant. At the maximum steady- state water level of el 223', the water would overflow from the condenser area to the yard. The yard grade slopes away from the structure, so the water would flow across the yard, over the railroad, and into the Schuylkill River. There are no safety-related structures in the flow path.

d. The condenser chamber is watertight up to the maximum flood level of el 223', with watertight doors and seals in the pipe tunnel and HVAC ducts, and is designed to withstand the corresponding water pressure.

e. All electric conduits that exit a flood area below the maximum flood level of el 223' are sealed to prevent the flood from spreading to other areas. All cables in the cable trays below that elevation have waterproof insulation.

Neither a major rupture of the circulating water system nor a rupture of the condenser hotwell has any effect on any safety-related system.

10.4.1.4 Tests and Inspections

Each condenser shell receives a field hydrostatic test before initial operation, and the shell surfaces are inspected for visible leakage and/or excessive deflection. Each condenser water box also receives a shop hydrostatic test, a field hydrostatic test, and an inspection of all joints and external surfaces. After the completion of the tubing of the condenser, all tube joints are leak tested.

In addition prior to installation on the condenser all the tubes are subjected to either a pneumatic test or a hydrostatic test and are nondestructively tested by the eddy current method.

Inservice inspection of the main condenser will be performed as necessary. Those conditions that would lead to condenser inspection are high conductivity and/or loss of ability to maintain adequate vacuum.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

The main condenser evacuation system, shown in drawing M-07, establishes a vacuum in the condenser during startup and removes noncondensable gases during normal operation. The system is not safety-related.

10.4.2.1 Design Bases

The main condenser evacuation system is designed to perform the following functions:

a. Establish and maintain vacuum in the condenser during startup and normal operation

b. Remove the noncondensable gases from the main condenser during normal operation and discharge them to the gaseous radwaste recombination system

c. Condense any steam removed from the condenser with the noncondensable gases and return the condensate to the hotwell.

The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the main condenser evacuation system are discussed in Section 3.2.

10.4.2.2 System Description

The main condenser evacuation system consists of one 100% capacity vacuum pump with a water separator silencer and a seal water cooler, two redundant 100% capacity SJAE trains, associated valves, piping, and controls as shown in drawing M-07. System design parameters are listed in Table 10.4-2.

10.4.2.2.1 Mechanical Vacuum Pump

The mechanical vacuum pump is used during startup to establish vacuum in the condenser and to discharge the air drawn from the condenser to the atmosphere through the turbine enclosure equipment compartment exhaust air filter assemblies and turbine enclosure vent stack.

The mechanical vacuum pump and its suction valve are operated remotely from the control room. The suction valve is automatically closed on a main steam high-high radiation signal. The pump is shut down on high-high radiation or low seal water flow to the pump. A water separator removes the water droplets from the noncondensable gases before discharging the gases to the atmosphere through the turbine enclosure equipment compartment exhaust air filter assemblies and turbine enclosure vent stack.

The vacuum pump is designed to evacuate the main condenser from atmospheric pressure to 5 inches Hg absolute in approximately 4 hours.

10.4.2.2.2 Steam Jet Air Ejector

Once condenser vacuum has been established by the mechanical vacuum pump, one SJAE is placed in service to maintain vacuum, and the mechanical vacuum pump is shut down (see Section 11.3.2.1.4.7.1 for alternative SJAE operating modes). The air ejector is a full capacity two-stage unit, including four 25% capacity first-stage ejectors and one full capacity condenser and second-stage ejector. A redundant SJAE train is provided to maintain condenser vacuum if the first train is not available.

The four first-stage steam jet ejectors continuously remove noncondensable gases and some steam from the condenser and discharge them to the SJAE condenser where the carryover steam is condensed and returned to the main condenser. The gases are then removed from the SJAE condenser by the second-stage ejector and discharged to the gaseous radwaste recombination system, together with the second-stage ejector motive steam.

These gases normally include air inleakage, dissociated hydrogen and oxygen coolant activation products, and noble gases plus their daughter products. The largest contribution to the main condenser's offgas activity is the N-16 source.

For an inventory of radioactive contaminants in the effluent from the SJAE and the associated doses and a description of the gaseous radwaste recombination system (Section 11.3).

The steam and gas mixture present downstream of the second-stage SJAE eliminates the possibility of an explosion in the line, even though a mixture rich in hydrogen is present. The ejectors require motive steam at 110 psig to operate, which is obtained either from main steam or the auxiliary boilers when available, reduced in pressure through self-regulating pressure-reducing valves. The minimum required main steam pressure at the main steam stop valves for proper ejector operation is approximately 205 psig. Condensate taken from the condenser hotwell by the condensate pumps is used as the cooling medium for the SJAE condenser.

10.4.2.3 Safety Evaluation

The main condenser evacuation system has no safety-related function. Failure of the system does not jeopardize the function of any safety-related system or component or prevent a safe shutdown of the plant.

The radiological consequences of a failure of the SJAE line are evaluated in Chapter 15.

10.4.2.4 Tests and Inspections

The main condenser evacuation system is preoperationally tested in accordance with the requirements of Chapter 14.

10.4.2.5 Instrumentation Applications

Local and remote indicators, alarms, and pressure relief valves are provided to monitor the system process and protect system components.

The pressure in the motive steam line to both the primary ejector and secondary ejector and in the outlet line from the second-stage SJAE is sensed by a pressure switch that alarms on high pressure in the control room.

The mechanical vacuum pump is shut down automatically on receipt of a main steam high radiation signal.

A flow switch actuates a low flow alarm in the control room whenever low seal water flow exists concurrently with the operation of the mechanical vacuum pump.

A pressure transducer in the second-stage SJAE discharge actuates a pressure control valve to provide recycle flow to the condenser in the event of recombiner system transient conditions which approach maximum design conditions.

10.4.3 STEAM SEAL SYSTEM

10.4.3.1 Design Bases

a. The steam seal system is designed to provide a continuous supply of clean (low level radioactive) steam to the main turbine shaft seals, the stem packings of the stop valves, control valves, combined intermediate valves and bypass valves, the shaft seals of the reactor feed pump-turbines, and the stem packings of the reactor feed pump-turbine stop and control valves.

b. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the steam seal system are discussed in Section 3.2.

10.4.3.2 Description

The steam seal system (drawing M-07) consists of a steam seal evaporator, a steam seal pressure regulator, steam seal header, two full capacity steam packing exhausters with their respective condensers, associated piping, and valves. Major steam seal system design parameters are listed in Table 10.4-3.

The sealing function is provided by supplying clean (low radioactivity) steam to the turbine shaft seals and various valve stems. Of the sealing steam entering the turbine shaft seals, some leaks inward toward the turbine and some leaks outward into a vent annulus, which is maintained at a slight vacuum by the steam packing exhauster. A small amount of air is drawn into this vent annulus from the outside, and this air, together with the sealing steam, is drawn to the steam packing exhauster where the steam is condensed and returned to the condenser. The saturated air is discharged by the exhauster to the turbine enclosure vent stack. With this arrangement, radioactive steam is completely contained within the turbine loop. The cooling medium for condensing the steam is condensate from the condensate system.

The clean (low level radioactive) steam for the seals is generated in the steam seal evaporator by heating condensate with extraction or main steam. The evaporator is a horizontal shell and U-tube heat exchanger in which the extraction or main steam is passed through the U-tube bundle, which is partially immersed in condensate. The condensate for the evaporator is taken from the condensate system from a point downstream of the condensate demineralizer, and the heating steam is taken either from a main steam line or from the extraction steam line to heater No. 3.

The level of condensate in the evaporator is maintained within the required limits by a control valve. The sealing steam generated in the evaporator enters the steam seal supply header through the pressure control valve, which is set to maintain the pressure of the sealing steam at a preset value. Redundancy for this pressure control valve is provided by a motor-operated bypass valve that can be throttled to maintain the pressure of the sealing steam if the pressure control valve fails. An alternative source of sealing steam is available from the auxiliary boilers when available.

The steam packing exhausters discharge to the atmosphere through the north vent stack. The exhauster discharge is monitored for radioactivity.

10.4.3.3 Safety Evaluation

The steam seal system has no safety-related function. Failure of the system does not compromise any safety-related system or component or prevent a safe shutdown of the plant. If there is a failure in the steam seal system, the auxiliary boilers, when available, can provide an alternative source of clean sealing steam to the system. Therefore there is no radioactive leakage path to the environment.

10.4.3.4 Tests and Inspections

The system is preoperationally tested in accordance with the requirements of Chapter 14.

10.4.3.5 Instrumentation Applications

Local and remote indicators, alarms, and pressure relief valves are provided to monitor the system process and protect system components.

Pressures in the tube side of the steam seal evaporator and in the sealing steam header are sensed by pressure switches that alarm on low pressure in the control room. The condensate level in the steam seal evaporator drain tank and in the steam seal evaporator shell side are monitored by level switches that alarm on high or low water levels, respectively, in the control room. High pressure in the exhaust inlet header to the steam packing exhauster is also alarmed in the control room.

10.4.4 TURBINE BYPASS SYSTEM

The turbine bypass system, shown in drawing M-01, dissipates the energy of the main steam generated by the reactor that cannot be used by the turbine (24.3% of 15.287 Mlb/hr steam flow for Post MUR-PU conditions). The turbine bypass system is not safety-related.

10.4.4.1 Design Bases

a. The turbine bypass system is designed to control the pressure in the reactor during the following modes of operation:

   1. Reactor vessel heatup to rated pressure and subsequent cooldown

   2. Turbine run-up and run-down

   3. Power operation when the quantity of steam generated by the reactor exceeds that required by the turbine. In this mode, the system can bypass to the main condenser (24.3% of 15.287 Mlb/hr steam flow for Post MUR-PU conditions).

b. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the turbine bypass system are discussed in Section 3.2.

10.4.4.2 System Description

The turbine bypass system is shown in drawing M-01 and consists of:

a. Bypass valve chest assembly

b. Piping between the discharges of the bypass valves and the condensers

c. Pressure reducer assemblies

The bypass valve chest consists of nine separate bypass control valves mounted in individual compartments of a common valve chest. The valves are globe-type, with the stems arranged so that they reach the outside of the chest through the discharge chamber of the respective valve. This minimizes leakage when the valves are closed, since it is necessary only to seal the stem against condenser vacuum.

The discharge connections of the bypass valves are piped individually to the condensers. To reduce the pressure at which the bypassed steam enters the respective condenser, a pressure reducer assembly is installed in each bypass valve discharge line. The pressure reducer assembly consists of a series of pressure breakdown plates. Therefore, steam flow from any open bypass

valve is throttled through its pressure reducer assembly before discharging at reduced pressure via a spray pipe to the condenser.

To operate, the turbine bypass system receives a signal from the turbine control system (initial pressure regulator) to open the bypass valves whenever the actual steam pressure exceeds the preset steam pressure (lower than the main steam relief valve setpoint pressures) by a small margin. This occurs when the amount of steam generated by the reactor cannot be entirely absorbed by the turbine. The bypass valves are tripped closed when the vacuum in the main condenser falls below a preset value.

The bypass valves open sequentially and are used during normal startup and shutdown. If there is a full load rejection, such as would occur if the generator circuit breaker opened, all nine valves open to bypass (24.3% of 15.287 Mlb/hr steam flow for Post MUR-PU conditions), which is the maximum design flow of the bypass valves.

Failure of the bypass valves to open for any reason, such as a mechanical malfunction or insufficient vacuum in the condenser, causes the pressure in the reactor to increase, ultimately lifting the main steam relief valves, which discharge the excess steam to the suppression pool. The effect of such a situation on the reactor coolant system is described in Chapter 15.

10.4.4.3 Safety Evaluation

The turbine bypass system has no safety-related function. Failure of the turbine bypass system, including failure of the turbine bypass line, would have no effect on the capability to achieve safe shutdown of the plant.

10.4.4.4 Tests and Inspections

The system is preoperationally tested in accordance with the requirements of Chapter 14.

During the operations phase, bypass valves are inspected and tested consistent with industry practices. Test frequencies are determined in accordance with the Surveillance Frequency Control Program as described in the plant Technical Specifications.

10.4.4.5 Controls and Instrumentation

Pressure sensors are provided to close the bypass valves when the vacuum in the main condenser falls below a preset value.

The opening of the bypass valves at any time is alarmed by a limit switch on each bypass valve.

Meters and indicating lamps are provided to show valve position.

10.4.5 CIRCULATING WATER SYSTEM

10.4.5.1 Circulating Water

10.4.5.1.1 Design Bases

The circulating water system is designed to remove the design plant heat load using a hyperbolic natural draft cooling tower.

10.4.5.1.2 System Description

The circulating water system is a closed-loop system consisting of a cooling tower, the main condenser, four 25% capacity circulating water pumps, and associated piping, valves, controls, and instrumentation. The system is shown schematically in drawing M-09. The circulating water pumps and the cooling tower design parameters are given in Tables 10.4-4 and 10.4-5, respectively. Plant general arrangement is shown in drawings C-2, M-110 and M-126.

Circulating water from the cold water outlet of the cooling tower basin flows by gravity through the condensers to the suction of the circulating water pumps. The LP condenser is supplied by two 96 inch lines, each of which branches into two 78 inch lines before being connected to the condenser water boxes. The circulating water discharging from the LP condenser flows into the IP condenser and subsequently to the HP condenser in series. From the discharge of the HP condenser, each pair of 78 inch lines is combined into one of two 96 inch headers, with each header feeding two circulating water pumps. The pump discharge headers are run underground back to the cooling towers.

Motor-operated butterfly valves are provided in each of the 78 inch circulating water lines, one at the inlet to the LP condenser and another at the outlet from the HP condenser. These permit any of the four flow paths on the circulating water side (tube side) of the condensers to be isolated if there is tube leakage. Rubber expansion joints are provided at the inlet connections to the LP condenser, the outlet connections from the HP condenser, and in the interconnecting piping between the LP, IP, and HP condensers.

The circulating water pumps are the vertical, mixed flow, dry-pit type and are driven by electric motors. They are located in the circulating water pump structure, which also houses the service water and fire water pumps.

Motor-operated butterfly valves are provided in the suction and discharge of each pump so that they can be isolated if necessary. Expansion joints are also provided at the inlet and outlet connections of each pump.

The circulating water is chlorinated to prevent the formation of biological growth. Chlorine dioxide is used as the primary biocide with Sodium sodium hypochlorite is used as the biocidebackup. A brominated salt solution is also being injected to improve the effectiveness of the biocide. Sulfuric acid is added to the system on an intermittent basis to control pH and prevent scaling on condenser tubes. A cooling tower chemical treatment system is also being used to control mild steel and copper corrosion, heat exchanger scaling (service water and condenser), and deposition. Supplemental chemical treatment may also be used as needed for cooling tower foam control.

Makeup water is provided to the circulating water system to replace the water lost due to evaporation and drift in the cooling towers and blowdown from the system. The blowdown prevents the buildup of dissolved solids in the circulating water. The makeup water system is described in Section 10.4.5.2. See Section 2.4.11 for low water considerations.

Stationary screens, removable for cleaning, are located at the cooling tower outlet to prevent debris from entering the circulating water piping, condenser, and circulating water pumps, service water system, fire protection, RHRSW, and ESW systems.

The circulating water is transported through reinforced concrete flumes and carbon steel pipe lined with coal tar epoxy.

Each cooling tower is a hyperbolic, natural draft structure employing the cross-flow principle of heat transfer. The design circulating water flow rate through each tower is 476,600 gpm. The cooling tower basin has a storage capacity of 7.2×10^6 gallons of water. A blowdown system is provided to maintain the dissolved solids concentration ratio. Blowdown is taken from each cooling tower basin, combined, monitored, and discharged to the Schuylkill River.

10.4.5.1.3 Safety Evaluation

The circulating water system has no safety-related function and is not required to be operable following a LOCA. Failure of the system does not compromise any safety-related system or component, or prevent a safe shutdown of the plant. A postulated complete rupture of one of the expansion joints in the system does not affect any safety-related system. The floor drainage system in the condenser area is designed so that water from the flooded area does not enter other areas of the plant. The condenser area is designed so that water that would flow from a ruptured condenser inlet expansion joint overflows from the condenser area into the yard and does not affect any equipment outside the condenser compartment. The yard grade slopes away from the structure, so the water would flow across the yard, over the railroad, and into the Schuylkill River. For a more detailed discussion of a circulating water system rupture, see Section 10.4.1.3.3.

The potential for damage to other plant structures if the cooling tower collapses is slight, because the structure would tend to collapse inward. In addition, the structure is located a sufficient distance, over 500 feet, from any equipment or structure important to reactor safety to prevent damage due to cooling tower collapse.

10.4.5.1.4 Tests and Inspections

The condenser is tested as described in Section 10.4.1.3. The pumps, butterfly valves, and expansion joints are all tested by their respective manufacturers before shipment.

A hydrostatic test is performed on the circulating water pipe in accordance with AWWA standards.

The system is preoperationally tested in accordance with the requirements of Chapter 14.

10.4.5.1.5 Controls and Instrumentation

Pressure relief valves, local and remote indicators, and alarms are provided to monitor the system performance and protect system components. High and low water levels in the cooling tower basin are monitored and alarmed in the control room. The Perkiomen cooling tower makeup water flow control valves are closed automatically on a high water level in the cooling tower basin. The cooling tower stilling well temperature is monitored, and a heater is provided to prevent freezing within the well. The cooling tower is also provided with an icing control system to prevent freezing in the cooling tower fill. Flooding in the condenser compartments is monitored and alarmed in the control room.

Low and high pressures in the suction and discharge sides of the circulating water pumps, respectively, and low pressure in the lube water and cooling water supply headers to the circulating water pumps are monitored and alarmed in the control room.

Local indication of the pressure drop across each condenser shell is provided by pressure differential indicators. Thermocouples are also installed in these locations to monitor the circulating water temperature.

10.4.5.2 Makeup Water System

10.4.5.2.1 Design Bases

Makeup water is provided from the Perkiomen Creek and Schuylkill River. The makeup water system is common to Units 1 and 2. System design parameters are listed in Table 10.4-6.

10.4.5.2.2 System Description

The makeup water flow to the cooling tower is controlled by motor-operated flow control valves on the supplies from the Perkiomen pumping station and the Schuylkill pumping station. Unit 1 and Unit 2 flow is controlled manually via the respective valve position controllers. Makeup for the nonconsumptive use of water (blowdown) is provided from the Schuylkill River intake/pumping station. Makeup for the consumptive use of water (evaporation and drift) is provided from either the Schuylkill River pumping station or the Perkiomen Creek intake/pumping station, in accordance with criteria established by the Delaware River Basin Commission.

The Perkiomen makeup supply consists of three 50% capacity pumps, cylindrical wedge-wire screens and associated equipment, a 7.6 mile buried pipeline, and a 1,500,000 gallon makeup water storage tank at the plant site. The system is shown schematically in drawing M-09. The Perkiomen Creek pump design parameters are given in Table 10.4-6.

The Perkiomen Creek make-up pumps maintain tank level within normal range while supplying the needed make-up water flow rate. The pump motor drives are interlocked so that no more than two makeup pumps can run simultaneously. The pumps can be operated from either the control room or locally.

The Schuylkill River makeup water supply consists of three 29.8% capacity pumps and two 10.6% capacity pumps, with traveling water screens and associated equipment. The system is shown schematically in drawing M-09. Design parameters are listed in Table 10.4-6.

10.4.5.2.3 Safety Evaluation

The makeup water system has no safety-related function. Failure of the system does not compromise any safety-related system or component or prevent a safe shutdown of the plant.

10.4.5.2.4 Tests and Inspections

The pumps and associated equipment are tested by their respective manufacturers.

The makeup water system is preoperationally tested in accordance with the requirements of Chapter 14.

10.4.5.2.5 Controls and Instrumentation

Pressure relief valves, local and remote indicators, and alarms are provided to monitor the system performance and protect system components.

10.4.6 CONDENSATE CLEANUP SYSTEM

The condensate cleanup system is used for filtration and demineralization of the full hotwell condensate flow to maintain a high degree of purity in the nuclear steam and feedwater systems. The condensate cleanup system is not safety-related.

10.4.6.1 Design Bases

The condensate cleanup system is designed to maintain the condensate at the required purity by removing the following contaminants:

a. Products resulting from corrosion in the main steam and turbine extraction piping, feedwater heater shells, and drains

b. Suspended and dissolved solids that may be introduced by small leakages of circulating water through condenser tubes

c. Fission and activation products that are entrained in reactor steam and retained in the condensate leaving the hotwell

d. Solids carried into the condenser by makeup water and miscellaneous drains

The system is designed to clean the feedwater to maintain the following criteria during normal operation:

CONDENSATE QUALITY DURING NORMAL OPERATION

Specific conductivity @ 25°C	0.07 micromho/cm
pH @ 25°C	6.0 to 7.5
Total metallic impurities	9 ppb
Total iron (as Fe)	5 ppb
Total copper (as Cu)	0.1 ppb
Total nickel (as Ni)	2 ppb
Silica (as SiO_2)	5 ppb
Chloride (as Cl)	1 ppb

The bases for these limits are the prevention of crud buildup on fuel heat transfer surfaces, the need to minimize the transport of active corrosion products outside the core, and the protection of the RCPB.

The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the condensate cleanup system are discussed in Section 3.2.

Protection against dynamic effects associated with the postulated rupture of piping is discussed in Section 3.6. This system is designed and operated in accordance with Regulatory Guide 1.56.

10.4.6.2 System Description

The condensate cleanup (CCU) system is shown in drawing M-16. It consists of eight filter/demineralizers and eight deep bed demineralizers with their corresponding pumps, valves, piping, and controls. System design parameters are shown in Table 10.4-7. The condensate filter/demineralizer (CFD) subsystem and the deep bed condensate demineralizer (DBCD) are operated in series .

The system is used for filtration and demineralization of the full hotwell condensate flow to maintain a high degree of purity in the nuclear steam and feedwater systems. The condensate is pumped from the condenser hotwell by the condensate pumps, through the SJAE condenser and the steam packing exhauster condenser before entering the CCU system. Treated condensate leaving the CCU system passes through one drain cooler and five stages of low pressure feedwater heaters. From there, the reactor feed pumps feed the water through one stage of high pressure feedwater heaters into the reactor vessel.

The CCU demineralizers remove radioactive material created by corrosion product and fission product carryover from the main steam system. While radioactivity does not affect the capacity of the resins, the concentration of such radioactive materials in the demineralizer equipment requires shielding (Section 12.3).

The CFD system consists of eight filter/demineralizers, non-precoat type elements,which remove suspended solids from the condensate and feedwater streams. All eight vessels are in service at one time during normal conditions. However, full condensate flow can be maintained through seven vessels.

The condensate filter/demineralizers have been designed for vessel differential pressure cycle length as an indication of when to backwash the vessel. Accordingly, each vessel will be backwashed if:

a. The pressure drop from inlet to outlet reaches a preselected value between, due to buildup of suspended solids, or 10 to 20 psid.

b. The cycle length reaches a preselected value of runlength days, dependant upon the filter requirements.

Due to their high ionic capacity, the condensate deep bed demineralizers are the determining factor for pH control and ionic removal in the primary coolant.

The refueling water or condensate transfer pumps supply condensate quality water for backwashing the units. The exhausted resin is backwashed to the condensate backwash receiving tank for subsequent processing by the radwaste system (Section 11.4).

The condensate filter demineralizer system automatic flow balancing controls have the capability to be operated in either automatic or manual.

In the automatic mode of operation, a master flow controller, operating in conjunction with flow controllers located on each of the eight filter/demineralizer units, maintains an equal flow (±5%) through each of the seven operating filter/demineralizers. The master controller is overridden turning all operating vessel effluent valves wide open at a preselected value for high header differential pressure.

In the manual mode of operation, an operator will monitor individual filter demineralizer flows during normal operator rounds and manually adjust the flow with the individual flow controllers to achieve the desired flow balance among all of the operating condensate filter demineralizers.

In the automatic or manual mode of operation, if the differential pressure between the influent and effluent headers exceeds a predetermined value, a differential pressure switch sounds an annunciator on the control panel and in the control room. If there is an additional increase, the main bypass valve opens.

The flow rate through each filter/demineralizer is measured by a flow element and transmitter on the suction line of the vessel. Flow indication is provided both locally and in the main control room.

Condensate filter/demineralizers are manually placed in or out of service locally by the operator due to flow demand. The condensate filter/demineralizers are removed from service when the specific vessel reaches its backwash endpoint. Filter/demineralizer backwash operation is performed using system operating procedures. The backwash equipment is common to all eight vessels.

The Deep Bed Demineralizers consist of a battery of eight demineralizers vessels. All eight vessels are in service at one time during normal operating conditions. However, full condensate flow can be maintained through seven vessels.

Each vessel is filled (or refilled) with new resin using an eductor system. An air mix system is available, if required, to ensure a homogenous resin mix after the resin loading step is complete. Next, the vessel is filled, vented, and pressurized prior to aligning to condensate. Prior to aligning a new DBCD vessel to condensate (cut-in), the bed is rinsed to the hotwell at approximately 1500 gpm to allow residual contaminants from the resin manufacturing processes to be flushed from the bed.

The DBCD subsystem operates in series with the CFD subsystem.

This is accomplished as filtered condensate enters the vessels through an inlet flow distributor, passes vertically through a resin bed, and exits through a collector system. Resin used in the DBCD vessels is the bead type with a nominal bead size range between 20 and 40 mesh. The resin rests on a stainless steel collector system designed to withstand full condensate system differential pressure. The collector system is comprised of a header/lateral system which uses screen to support the bed. Immediately downstream of the vessels are basket strainers. The collector system and basket strainers provide redundant protection against bead resin intrusion to primary coolant.

A layup system is provided for extended outage periods which preserves the resin bed by maintaining a recirculating flow of condensate from the DBCD system outlet header to the inlet header.

This is a accomplished through the use of DBCD system block valves (HV-16-191 and 192) and two 3000 gpm centrifugal pumps configured for parallel operation. A layup flow of approximate 20% (or 750 gpm) normal in-service flow can be maintained through the use of these pumps.

Power for the DBCDs is provided from the site services substation. This substation is fed from the Moser 363 Line (formerly 2300 Line). The site services substation feeds the DBCD system MCC located in the Turbine Enclosure 217 elevation.

The control system for the DBCD system consists primarily of a programmable logic controller (PLC) for system monitoring and control. Input/output (I/O) cabinets provide the interface between system instruments and equipment and the PLC via I/O bus. Personal computers (PCs) are used to either interrogate the PLC for system status or to provide commands. The control of the DBCD system is maintained in software resident in the PLC and operator control station.

The DBCDs are controlled from either of two operator control stations located in a common console in the Radwaste Control Room. Each station consists of an 80386 microprocessor-based computer, operator and programming keyboards, and monitor display. Operator commands are entered onto the system through the operator keyboards and system status including system alarms are displayed on the monitors. Two operator control stations are provided to control and monitor different processes simultaneously.

A portable engineering work station comprised of an 80386 microprocessor-based computer is used to link with the common data highway network for system troubleshooting and performance monitoring.

In the Main Control Room (MCR), the DBCD has individual vessel flow indication (eight indicators - one per vessel), a system differential pressure indicator, and a system bypass valve control switch with interlocking high system differential pressure bypass. The bypass switch function is performed by the FCS and is independent of the Radwaste Control Room and the PLC/PC control system.

All DBCD vessel flow control valves have been aligned in a fixed open position (typically 80 - 100%) by de-energizing their associated motor operators on high differential pressure a 12" bypass valve is opened providing a bypass flow equivalent to one vessel. If differential pressure continues to increase a 30" bypass valve is opened allowing full DBCD system flow to be bypassed.

When the resin in a DBCD vessel has reached its designated endpoint, it is hydropneumatically transferred to the spent resin receiving tanks (SRT) in the Turbine Enclosure 200' elevation. This transfer sequence is automatically executed by the PLC after operator remote initiation. Because of the nature of the deep bed demineralizers, a vessel that has reached the endpoint still has a considerable amount of ion exchange capacity remaining. Therefore, these resins are stored in the SRTs for reuse in the radwaste floor and equipment drain processing system demineralizers (Section 11.2.2.4). Four SRTs are located in the Turbine Enclosure, each capable of holding one DBCD vessel's resin volume (320 ft^3). These tanks are located in a shielded locked high radiation area (Room 252A) which is sealed to contain tank leakage. Designated portions of SRT resin are educted to a resin measuring tanks (RMT) for hydropneumatic transfer to the radwaste demineralizers or from Unit 2 RMT to Unit 1 SRT "A" (1AT928). The operator can select resin transfer volumes to allow for use of 100% DBCD spend resin, or a new resin underlay and/or overlay in the radwaste demineralizers if necessary to enhance demineralizer performance. These operations are also automatically executed through the PLC after remote initiation by the radwaste control room operator. Valving, pumps, eductors, and instrumentation necessary to complete

these transfers are primarily located adjacent to the SRT room in a high radiation area (Zone IV) which is shielded from the SRTs. This configuration allows for maintenance and I&C activities while maintaining exposure ALARA. Service air used for hydropneumatic transfers is vented to the SRTs, where it is exfiltrated through the TEECE system. For transfers to the radwaste demineralizers, service air is vented to the radwaste enclosure ventilation system. One of four Unit 1 SRTs (1AT928) is provided with a recirculation loop and transfer pump which enables transfer to the external processing valve station for vendor processing. The SRTs are provided with overflow protection, level indication and high level alarms. All pressure-retaining equipment has been designed, procured, inspected, and tested consistent with Regulatory Guide 1.143.

The DBCD system has been designed for continuous operation to use the resin to either a total throughput endpoint or an endpoint determined by radwaste operations as necessary to meet radwaste floor and equipment drain demineralizer resin needs. The total throughput endpoint will be determined to ensure a reserved removal capacity consistent with Regulatory Guide 1.56. The performance of these vessels is best analyzed by measuring conductivity. The conductivity of the condensate is measured at the common influent header, the discharge of each demineralizer vessel, and the common effluent header. A high conductivity alarm for the common effluent header is found in the control room. Conductivity is monitored and local alarms for high reading are on the Deep Bed Condensate Demineralizer control panel (PC) in the radwaste control room.

10.4.6.3 Safety Evaluation

The condensate cleanup system has no safety-related function and is not required to be operable following a LOCA. Failure of the system does not compromise any safety-related system or component or prevent a safe shutdown of the plant.

10.4.6.4 Tests and Inspections

The DBCD and CFD vessels are tested in accordance with ASME Section VIII. Piping is inspected and tested in accordance with ANSI B31.1 with the exception of spent resin subsystem piping. This piping and associated pressure boundary equipment is inspected and tested in accordance with Regulatory Guide 1.143 .

The CFD system is preoperationally tested in accordance with the requirements of Chapter 14. The DBCD system was tested in accordance with Section 13.5.1.6. The condensate cleanup system is periodically tested in accordance with the requirements of Chapter 16.

10.4.6.5 Instrumentation Applications

Local and remote indicators, alarms, and pressure relief valves are provided to monitor the system process and to protect system components.

The conductivities are monitored for the following:

a. Influent of the condensate filter/demineralizer system

b. Influent A -D Effluent of the deep bed condensate demineralizer system

c. Effluent of each deep bed condensate demineralizer

In addition, conductivity alarms are provided to alert the operator for off-normal conditions. Flow rate and pressure differential indication, as well as alarms for high and low flow and high pressure differential are provided for each filter/demineralizer and deep bed demineralizer. A flow totalizer is provided for each deep bed demineralizer, rather than a recording flowmeter as suggested in Regulatory Guide 1.56.

The following instrumentation is specific for the Deep Bed Condensate Demineralizer system:

1) All indications and alarms are provided through PCs in the Deep Bed control panel located in the Radwaste Control Room.

2) System pressure differential indication and indication of each demineralizer flow is provided in the Main Control Room.

3) High system effluent conductivity is alarmed in the Main Control Room.

4) Conductivities for effluent from each demineralizer and for system influent and effluent are stored within the PCs located in the Deep Bed control panel.

5) Flows and total volume throughput of each demineralizer are stored within the PCs located in the Deep Bed control panel.

10.4.7 CONDENSATE AND FEEDWATER SYSTEMS

The condensate and feedwater systems remove condensed main steam from the condenser hotwells, heat it, and return it to the reactor to be converted into steam.

10.4.7.1 Design Bases

a. The condensate and feedwater systems are designed to return condensate from the condenser hotwell to the reactor at the required flows, pressure, temperature, and quality.

b. The systems are designed to automatically maintain the water levels in the reactor and the condenser hotwell during steady-state and transient conditions.

c. The condensate and feedwater systems from the condenser hotwell up to, but not including, the outermost primary containment isolation valve are not safety-related. The feedwater system from the outermost primary containment isolation valve to the reactor is safety-related. For the isolation criteria between this system and the RCPB, see Section 6.2.4.

d. Inservice inspection is performed in accordance with ASME Section XI for that portion of the feedwater system furnished in accordance with ASME Section III.

e. The condensate and feedwater systems are designed to permit continued operation of the plant at reduced power without reactor trip on loss of one of the three condensate pumps, one of the three reactor feed pumps, or one of the three strings of feedwater heaters.

f. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the condensate and feedwater systems are discussed in Section 3.2.

10.4.7.2 System Description

The condensate and feedwater systems are shown in drawings M-05 and M-06, respectively. The systems' design parameters are shown in Tables 10.4-8 and 10.4-9.

10.4.7.2.1 Condensate System

Three, 33-1/3% capacity, vertical, centrifugal condensate pumps take suction from a common header, which is connected to each condenser hotwell for flow equalization, and discharge into another common header. The condensate flow is then directed through the SJAE condenser and the steam packing exhauster condenser and into the condensate filter/demineralizer's common influent header. The condensate cleanup system is discussed in Section 10.4.6. Condensate then proceeds through the condensate demineralizer system and discharges into the common inlet header of the feedwater system.

The sealing water for the condensate pump seals is taken from the CST. The leak-off from the seals is piped to the liquid radwaste system.

A condensate recirculation system is furnished to maintain a minimum flow through each condensate pump, SJAE condenser, and steam packing exhauster condenser. A total minimum flow of 7500 gpm for all three condensate pumps is automatically maintained by a control valve in the common recirculation line. A bypass valve is provided around the control valve for maintenance accessibility during plant operation for Unit 1. Recirculated condensate is returned to the condenser.

A hotwell makeup and reject system maintains the condenser hotwell level during steady-state and transient conditions. Condensate is rejected to the CST to decrease the hotwell level or drained into the condenser from the storage tank to make up the hotwell level. A combination of small and large control valves, with a bypass valve, is used to control the makeup and reject flows. The small control valve controls the smaller normal flows, whereas the larger control valve is used during larger transient flows. The control valves are controlled by water level in the condenser hotwell. The condensate reject valves close on high level in the CST.

10.4.7.2.2 Feedwater System

Condensate from the deep bed condensate demineralizer effluent header divides and passes through three parallel strings of LP feedwater heaters. Feedwater downstream of the heaters is combined into a common header from which three, 1/3 capacity, turbine-driven reactor feed pumps take suction. The reactor feed pumps discharge the feedwater through HP feedwater heaters into a common mixing header for distribution through reactor containment isolation valves and into the reactor.

Injection water for the reactor feed pump seals is taken from the condensate pump discharge header and drained to the main condenser. An injection water booster pump is furnished to maintain a minimum differential pressure of 25 psid between the injection pressure and the reactor feed pump suction pressure.

Each reactor feed pump has a recirculation line connected to the main condenser. This recirculation line is tapped off the discharge line between the reactor feed pump and its discharge check valve and is used to maintain a minimum flow through the feed pump at startup and low load operation to avoid pump vibration and high running temperatures. A modulating reactor feed pump

recirculation system is used. Reactor feed pump flow to the vessel is used to establish the flow requirement through the recirculation line. The total reactor feed pump flow is the summation of recirculation flow and flow to the reactor as measured downstream of the HP feedwater heaters. The reactor feed pump recirculation valve is positioned, via an open loop control signal, to ensure that the minimum required flow through the pump is maintained.

The reactor feed pumps are driven by variable speed, six-stage turbines that receive steam from either the main steam header or the cross-around piping downstream of the moisture separators. During normal full power operation, the turbine drivers use low pressure cross-around steam. High pressure main steam is used during startup, low load, or transient conditions, when cross-around steam is either not available or is of insufficient pressure. The exhaust steam from each turbine driver is piped to the main condenser.

Before starting the reactor, the feedwater lines between the condensate cleanup system and the reactor are flushed to remove any crud present. The flow is pumped through these lines by the condensate pumps and recirculated to the condenser through the startup recirculation line. This ensures proper reactor water quality during startup.

The feedwater flow branches into two separate lines before entering the primary containment. Primary containment isolation in each branch is provided by a motor-operated stop-check valve, a pneumatic check valve outside the containment, and a check valve inside the containment. The motor-operated stop-check valves are supplied by a Class 1E power supply. Pneumatic check valves fail closed on loss of air pressure. However, the spring-loaded piston of the check valve will not close the valve on loss of power against normal flow from the normal direction. Section 6.2.4 contains a discussion of the containment isolation system.

Normally, the three condensate and three reactor feed pumps are in service, together with all three strings of feedwater heaters. The system is designed so that it can operate with any two condensate pumps, two reactor feed pumps, or two feedwater heater strings in service without a reactor scram. An abnormal operational transient analysis of the loss of a feedwater heater string is included in Chapter 15.

Both the condensate pumps and reactor feed pumps are designed to provide the maximum required design flows plus adequate margins to account for both transients and pump wear. Adequate margin is provided in the net positive suction head requirements to ensure noncavitating performance under operating and run-out conditions.

Each of the six feedwater heaters and drain coolers per heater string has BWG, 304 L stainless steel tubes installed.

During operation, steam and condensate are present in the feedwater heating portion of the system, which includes the extraction steam piping, feedwater heater shells, heater drain piping, and heater vent piping (drawings M-03 and M-04). If there is equipment leakage, the reactor feed pump turbines and feedwater heaters are compartmentalized to localize resultant higher radiation. Shielding and access requirements are provided as necessary (Section 12.3). The condensate and feedwater systems are designed to minimize leakage, with welded construction used where practicable. Relief valve discharges and operating vents are handled through closed systems.

To reduce radiation buildup on primary piping and components, soluble zinc oxide is injected into the suction side of the A/B reactor feed pumps from the Zinc Injection Passivation (GEZIPPZIP) skid which is installed at turbine building EL. 217'-0".

10.4.7.3 Safety Evaluation

The condensate and feedwater systems are not safety-related and are not required to be operable following a LOCA. Failure of the systems does not compromise any safety-related system or component or prevent a safe shutdown of the plant.

Feedwater system primary containment penetrations and isolation valves and piping inside containment are designed to seismic Category I and ASME Section III, Class 1 requirements as discussed in Sections 3.2, 3.7, and 6.2.

Protection against dynamic effects associated with the postulated rupture of piping is discussed in Section 3.6.

10.4.7.4 Tests and Inspections

That portion of the feedwater system designed to ASME Section III, Class 1 or 2 is inspected and tested in accordance with ASME Section XI.

The condensate and reactor feed pumps' performance is verified by shop testing. The casings of the condensate and reactor feed pumps are hydrostatically tested by their respective manufacturers before shipment. The shell and tube side of all feedwater heaters and drain coolers are hydrostatically tested to 1.5 times their design pressure in accordance with ASME Section VIII.

Before initial operation, the completed condensate and feedwater system receives a field hydrostatic test and inspection in accordance with the applicable code.

The system is preoperationally tested in accordance with the requirements of Chapter 14.

10.4.7.5 Instrumentation Applications

Local and remote indicators, alarms, and pressure relief valves are provided to monitor the system process and protect system components.

Controls are provided to maintain the condenser hotwell level so that on high level the excess condensate is transferred to the CST, while on low level makeup from the storage tank is admitted to the system. The condensate reject valves close on high level in the CST. Controls are also provided to maintain the correct levels in the feedwater heaters.

During startup the water level in the reactor is controlled by the condensate system startup valve and reactor feed pump discharge bypass valve. During normal operation the reactor feed pump-turbine speed regulates the level. The turbine speed signal is generated by the FCS. The FCS is discussed in Section 7.7 .

Monitoring equipment, including pressure indicators, flow and temperature indicators, and alarms for abnormal conditions, is provided in the control room to ensure the proper operation of system components.

10.4.8 STEAM GENERATOR BLOWDOWN SYSTEM (PWR)

This section is not applicable to LGS.

10.4.9 AUXILIARY FEEDWATER SYSTEM (PWR)

This section is not applicable to LGS.

10.4.10 AUXILIARY STEAM SYSTEM

The auxiliary steam system provides a source of LP noncontaminated steam for various startup and plant service functions. The system is not safety-related.

10.4.10.1 Design Bases

The system is designed to provide the operational flexibility necessary to accommodate the varying steam demands during all seasons and modes of operation.

The auxiliary steam system is designed to operate independently of the NSSS.

The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the auxiliary steam system are discussed in Section 3.2.

10.4.10.2 System Description

The auxiliary steam system is shown schematically on drawing M-21. Major component design parameters are listed in Table 10.4-10.

The plant auxiliary boilers are common to both Units 1 and 2. The auxiliary steam system consists of three water tube package boilers, a deaerator, three boiler feedwater pumps, three fuel oil pumps, a fuel oil storage tank for No. 2 oil, a chemical feed tank and pumps, and associated piping, valves, controls, and instrumentation. All major components of the auxiliary steam system are located in the auxiliary boiler structure, the fuel oil pump house, and the tank dike area.

The boiler control system is basically designed for unattended operation, except for cold startup operation of a boiler. Process steam and plant heating steam are distributed from the boiler steam outlet header. Condensate recovered from the plant heating system is returned to the deaerator, which provides condensate storage. Demineralized water is used for boiler makeup. An atmospheric blowdown tank is provided to control the water quality in the boilers. A pressure-reducing valve maintains plant heating steam system pressure. Final pressure reduction is accomplished, as required, by individual valves adjacent to the equipment served. Steam heating coils are provided in the auxiliary boiler mud drums to prevent freezing when the unit is not in operation. The auxiliary steam system can provide a backup for the clean steam seal system. The auxiliary steam system can provide a backup for main steam to the SJAE's for plant startup and shutdown. It also provides steam for condensate deaeration in the hotwell during plant startup. The condensate from this process is not returned to the deaerator but is drained to the main condenser.

The only connections between the auxiliary steam system and seismic Category I systems are those used for testing of the HPCI and RCIC turbines. The connections are made through pipe

spools containing spectacle flanges. After testing the blind portion of the spectacle flange is installed and the auxiliary steam system is isolated from any seismic Category I system. The connections between the auxiliary steam system and nonseismic Category I portions of the main steam system are protected by normally closed valves.

10.4.10.3 Safety Evaluation

The auxiliary steam system has no safety-related function. The system is designed so that a failure of the system or one of its components does not compromise any safety-related system or component or prevent a safe reactor shutdown.

10.4.10.4 Test and Inspections

The auxiliary steam system is proven operable by its use during startup and normal plant operation.

10.4.10.5 Instrumentation Application

Local and remote indicators, alarms, and pressure relief valves are provided to monitor the system process and protect system components. A common boiler trouble alarm is located in the control room.

10.4.11 HYDROGEN WATER CHEMISTRY SYSTEM

10.4.11.1 Design Bases

The purpose of the hydrogen water chemistry (HWC) system is to mitigate, in a timely manner, the chemical conditions in the recirculation water that allow intergranular stress corrosion cracking (IGSCC). The addition of hydrogen to the feedwater reduces the oxidizing chemistry conditions which promote IGSCC in reactor piping and components. Other regions of the reactor such as components in the vessel lower plenum, can also be protected from IGSCC by injecting hydrogen. The maximum injection rate for hydrogen gas is 1.6 ppm (71 scfm) to mitigate IGSCC in the recirculation piping and regions of the reactor vessel. The HWC system also supplies hydrogen to the Generator Hydrogen Cooling System.

Signals from the HWC control panel are sent to the Main Control Room for alarm, shutdown and process monitoring capabilities.

The HWC control system requires an interface with the Feedwater control system. Feedwater pump discharge flow and total feedwater flow are required by the HWC system.

The HWC control system also requires an interface with the Gaseous Radwaste/Recombination System. An SJAE train/recombiner trip signal is provided to trip the HWC system.

Flow control and air-operated isolation valves fail closed upon loss of instrument air or control power. Excess flow check valves in the hydrogen and oxygen supply lines mitigate the effects of a line break in the Turbine enclosure.

Manual shutdown switches are provided in the Main Control Room and on the local HWC control panel. These switches are provided as backup to the automatic trips of the system. Manual

switches allow HWC system shutdown from the MCR if the controllers would fail in a locked-up mode.

10.4.11.2 Safety Evaluation

The HWC system is not safety related; however, the installation and operation of the system increases the carryover of N-16 from the reactor to the steam system. Hydrogen injection by the HWC system causes the reactor water chemistry to become less oxidizing which results in a re-distribution of the N-16 normally produced by radiolysis in the reactor core. Under HWC conditions, more of the N-16 is carried over into the steam and less remains in the reactor water. Thus, areas where there is steam piping will experience a greater level of radiation due to the increased N-16. This increase results in a measurable increase in the gamma dose rate both inside and outside the radiation controlled area. Exposure at locations outside plant structures will also increase due to direct radiation and turbine shine from the N-16, which is a high energy gamma emitter. In order to minimize these effects, additional radiation shielding has been installed around the high pressure turbine and combined intermediate values. The increased exposure is within the estimates provided within Chapters 11 and 12.

Although the HWC system includes measures to prevent and detect leakage of hydrogen in the Turbine Enclosure, the potential for an undetected hydrogen leak has been considered. Pipe break leakage is limited by excess flow check valves. An analysis was performed for a hydrogen leak in the Turbine Enclosure (reference 2). Each area where the hydrogen line is located was considered with respect to ventilation. In the event of a loss of ventilation, the hydrogen monitors will provide an indication and alarm if a hydrogen leak were to develop. If a hydrogen monitor was to become inoperable, it will provide an alarm to alert Operations personnel to take corrective action.

The hydrogen and oxygen gas supply systems consist of high pressure tube vessels (trailers) located outside the plant's protected area. The tube vessels and trailers are DOT (Department of Transportation) approved and maintained in accordance with the applicable DOT regulations. Based on siting criteria in the EPRI Guidelines and National Fire Protection Association (NFPA) 50A, the hydrogen and oxygen tube trailers have been sited at sufficient distances from each other and structures, air intakes, or safety-related equipment to preclude an unacceptable impact on safety-related functions or analyses.

The transportation route for the hydrogen gas tube vessel delivery to the storage facility has been established following the guidelines of Regulatory Guide 1.91. A discussion on establishing the transportation route is provided in Section 2.2.

10.4.12 REFERENCES

1. "Guidelines for Permanent BWR Hydrogen Water Chemistry Installations - 1987 Revision," EPRI NP-5283-SR-A, September 1987.

2. "An Analysis of a Hydrogen Leak in the Turbine Building," LM-0542.

Table 10.4-1*

MAIN CONDENSER DESIGN PARAMETERS

MAIN CONDENSER	LOW PRESSURE SHELL	INTERMEDIATE PRESSURE SHELL	HIGH PRESSURE SHELL
Quantity	1	1	1
Type	Shell & tube	Shell & tube	Shell & tube
Features: three shell triple pressure, surface condenser			
Duty (Btu/hr)	2.571×10^9	2.544×10^9	2.610×10^9
Shell design			
Fluid	Steam	Steam	Steam
Turbine valve wide open flow rate (lb/hr)	2,784,090	2,784,090	2,784,090
Turbine maximum guaranteed load operating pressure	2.81 in Hga	3.56 in Hga	4.67 in Hga
Design pressure	29.5 in Hg vac	29.5 in Hg vac	29.5 in. Hg vac
Tube design			
Fluid	Water	Water	Water
Flow rate (gpm)	450,600	450,600	450,600
Operating pressure	15.15 psig	15.15 psig	15.15 psig
Design pressure	60 psig	60 psig	60 psig
Length (feet)	36	42	48
Inlet temperature (°F), design/ maximum	88.9/95	100.31/106.41	111.60/117.70
Hotwell storage volume at minimum level (gallons)	27,050	31,700	36,350
Overall Dimensions	36' tube sheet-to tube sheet x 29'-0" x 58'-8"H	41'-11¾" tube sheet-to -tube sheet x 29'-0" x 58'-8"H	47'-11¾" tube sheet-to -tube sheet x 29'-0" x 58'-8"H

* The values in this table represent equipment design parameters. The equipment has been evaluated for the operating conditions described per Reference 10.2-79.

Table 10.4-1 (Cont'd)

MAIN CONDENSER DESIGN PARAMETERS

MAIN CONDENSER	LOW PRESSURE SHELL	INTERMEDIATE PRESSURE SHELL	HIGH PRESSURE SHELL
No. of Tubes	24940	24940	24940
Exhaust steam temperature w/o bypass (°F)			
Maximum	114.0	123.0	135.00
Exhaust Steam Temperature w/bypass (°F)			
Maximum	105.0	110.0	116.0
Material	Admiralty[1] [2] B.111	Admiralty[1] [2] B.111	Admiralty[1] [2] B.111
OD (inches)	1.125	1.125	1.125
Gauge (BWG)	18	18	18
Total effective surface (ft^2)	262,638	306,666	350,696
Tube velocity (fps)	7.01	7.01	7.01

(1) 320 Type 304 stainless steel, 20 BWG tubes in the impingement area.

(2) Unit 2 condenser contains some 20 BWG ASTM B543-85 C706000 90-10 copper-nickel tubes.

Table 10.4-2

MAIN CONDENSER EVACUATION SYSTEM DESIGN PARAMETERS *

MECHANICAL VACUUM PUMP	
Quantity	1
Type	Rotary water ring
Capacity	2000 cfm
Design suction pressure	0 in Hga
Design temperature	150°F
Motor power rating	200 hp
SEAL WATER COOLER	
Quantity	1
Type	Horizontal, single-pass, straight tube
Duty	570,000 Btu/hr
Shell design	
Fluid	Distilled condensate
Flow rate	60 gpm
Design pressure	300 psig
Design temperature	300°F
Tube design	
Fluid	Drywell chilled water
Flow rate	150 gpm
Design pressure	150 psig
Design temperature	300°F
SEAL WATER PUMP	
Quantity	1
Type	Centrifugal, single-stage
Capacity	60 gpm
Head	73 ft
Motor power rating	2 hp
STEAM JET AIR EJECTORS	
Quantity	2 trains (100% capacity each) 4 first-stage elements per train (25% capacity each element) 1 second-stage element per train (100% capacity)
Design first-stage suction pressure	1.0 in Hga
Design second-stage suction pressure	7 psig

* The values in this table represent equipment design parameters. The equipment has been evaluated for the operating conditions described per Reference 10.2-79.

Table 10.4-2 (Cont'd)

MAIN CONDENSER EVACUATION SYSTEM DESIGN PARAMETERS *

Noncondensable gas flows measured at 70°F and 1 atmosphere	
Hydrogen	138.4 cfm
Oxygen	69.1 cfm
Dry air	75 cfm
Motive steam operating pressure	
Maximum/normal	200/110 psig

AIR EJECTOR CONDENSERS

Quantity	2 (100% capacity each)
Type	Intercondenser only, horizontal, two-pass, single shell
Duty	15.7×10^6 Btu/hr
Shell design	
Steam flow rate	12,500 lb/hr
Noncondensable flow rate	724 lb/hr
Design pressure	50 psig & vacuum
Design temperature	600°F
Tube design	
Fluid	Condensate
Flow rate	14,821,800 lb/hr
Design pressure	700 psig
Design temperature	200°F

Table 10.4-3 *

STEAM SEAL SYSTEM DESIGN PARAMETERS

STEAM SEAL EVAPORATOR	
Quantity	1
Type	Horizontal, two-pass, U-tube, with appended drain tank
Tube design	
Fluid	Steam
Flow rate	55,000 lb/hr
Design pressure	150 psig
Design temperature	450°F
Shell design	
Fluid	Water
Flow rate	127 gpm
Design pressure	150 psig
Design temperature	450°F
STEAM PACKING EXHAUSTER CONDENSERS	
Quantity	2 (100% capacity each)
Type	Horizontal, two-pass, single shell
Shell design	
Flow rate: air	2927 lb/hr
Steam	8435 lb/hr
Design pressure	15 psig
Design temperature	200°F
Tube design	
Fluid	Condensate
Flow rate	14,885,226 lb/hr
Design pressure	700 psig
Design temperature	200°F
STEAM PACKING EXHAUSTERS	
Quantity	2 (100% capacity each)
Fan type	Vertical, centrifugal
Capacity, each: air	4300 lb/hr
Steam	2614 lb/hr
Motor power rating	40 hp

* The values in this table represent equipment design parameters. The equipment has been evaluated for the operating conditions described per Reference 10.2-79.

Table 10.4-4

CIRCULATING WATER PUMPS DESIGN PARAMETERS

CIRCULATING WATER PUMPS	
Number of pumps per unit	4 (25% capacity each)
PUMP	
Type	Dry pit, mix flow
Rated flow and head, each	113,000 gpm at 110 feet
Rated speed	505 rpm
Power rating	3450 hp
MOTOR	
Type	Induction
Voltage/phase/frequency	13.2 kV/3 phase/60 Hz
Power rating	3500 hp

Table 10.4-5 *

COOLING TOWER DESIGN PARAMETERS

COOLING TOWERS	
Number of towers per unit	1
Type	Natural draft hyperbolic with cross-flow fill
SHELL	
Height	507.5 ft
Diameter	
Base	372 ft
Throat	201 ft
Top	220 ft
Material	Reinforced concrete
FILL	
Height	69 ft
Diameter	
Top	512 ft
Base	488 ft
Material	
Support	Reinforced concrete
Spacers	Glass reinforced polyester
Splash bars	Polyvinyl Chloride
RATED PERFORMANCE (PER TOWER)	
Flow rate	476,600 gpm
Wet-bulb temperature	75°F
Relative humidity	66%
Water temperature	
Entering	122.4°F
Leaving	88.9°F
Duty	7.9×10^9 Btu/hr
BASIN	
Height	9 ft
Diameter	488 ft
Capacity	7.2×10^6 gal.

* The values in this table represent equipment design parameters. The equipment has been evaluated for the operating conditions described per Reference 10.2-79.

Table 10.4-6

COOLING TOWER MAKEUP SYSTEMS DESIGN PARAMETERS

PERKIOMEN CREEK MAKEUP PUMPS	
Number of pumps	3 (50% capacity each)
PUMP	
Type	Wet-pit, vertical turbine
Rated flow and head, each	14,600 gpm at 440 ft
Rated speed	1180 rpm
Power rating	1915 hp
MOTOR	
Type	Induction
Voltage/phase/frequency	4.0 kV/3 phase/60 Hz
Power rating	2000 hp
SCHUYLKILL RIVER MAKEUP PUMPS (LARGE CAPACITY)	
Number of pumps	3 (29.8% capacity each)
PUMP	
Type	Wet-pit, vertical turbine
Rated flow and head, each	11,300 gpm at 224 ft
Rated speed	880 rpm
Power rating	775 hp
MOTOR	
Type	Induction
Voltage/phase/frequency	2.3 kV/3 phase/60 Hz
Power rating	800 hp
SCHUYLKILL RIVER MAKEUP PUMPS (SMALL CAPACITY)	
Number of pumps	2 (10.6% capacity each)
PUMP	
Type	Wet-pit, vertical turbine
Rated flow and head, each	4000 gpm at 224 ft
Rated speed	1180 rpm
Power rating	320 hp
MOTOR	
Type	Induction
Voltage/phase/frequency	2.3 kV/3 phase/60 Hz
Power rating	350 hp

Table 10.4-7 *

CONDENSATE CLEANUP SYSTEM DESIGN PARAMETERS

FILTER/DEMINERALIZER	
Quantity	8
Type	Non-precoat elements
Design flow rate, each	4315 gpm
Design temperature	150°F
Design pressure	700 psig
PRECOAT TANK	
Quantity	1
Type	Cylindrical
Capacity	595 gal (approx)
Diameter/height	54 in/60 in
Design pressure	Atmospheric
Design temperature	105°F
PRECOAT PUMP	
Quantity	1
Type	Centrifugal
Capacity	1410 gpm
Head	60 ft
Motor power rating	30 hp
HOLDING PUMP (Abandoned in place)	
Quantity	8
Type	Centrifugal
Capacity, each	60 gpm
Head	60 ft
Motor power rating	5 hp
DEEP BED DEMINERALIZERS	
Quantity	8
Type	Deep Bed, Resin Beads
Design flow rate, each	4315 gpm (45 gpm/ft$^{2)}$
Design temperature	150°F
Design pressure	700 psig

Table 10.4-7 (Cont'd)

CONDENSATE CLEANUP SYSTEM DESIGN PARAMETERS

SPENT RESIN TANKS	
Quantity	4
Type	Cylindrical
Capacity (Operating)	450 ft^3
Diameter/height	7'11"/9'-9"
Design Temperature	110°F
Design Pressure	Atmospheric
REFILL OVERFLOW TANK	
Quantity	1
Type	Cylindrical
Capacity	16 ft^3
Diameter/height	2'/5'(str)
Design Temperature	110°F
Design Pressure	Atmospheric
RESIN MEASURING TANK	
Quantity	1
Type	Cylindrical
Capacity (Operating)	105 ft^3
Diameter/height	4'6"/6'-6" str
Design Pressure	100 psig
Design Temperature	130°F
LAYUP PUMP	
Quantity	2
Type	Centrifugal
Capacity	3000 gpm
Head	58 ft
Motor Power Rating	60 hp
EDUCTOR PUMP	
Quantity	1
Type	Centrifugal
Capacity	150 gpm
Head	231 ft
Motor Power Rating	20 hp

Table 10.4-7 (Cont'd)

CONDENSATE CLEANUP SYSTEM DESIGN PARAMETERS

RESIN TRANSFER PUMP	
Quantity (Unit Only)	1
Type	Centrifugal
Capacity	200 gpm
Head	125 ft
Motor Power Rating	15 hp
DEWATERING PUMP	
Quantity	1
Type	Centrifugal
Capacity	240 gpm
Head	116 ft
Motor Power Rating	15 hp

* The values in this table represent equipment design parameters. The equipment has been evaluated for the operating conditions described per Reference 10.2-79.

Table 10.4-8 *

CONDENSATE SYSTEM DESIGN PARAMETERS

CONDENSATE PUMPS	
Quantity	3 (33½% capacity each)
Type	Seven-stage, vertical, canned centrifugal
Capacity, each	11,570 gpm
Head	1260 ft
motor power rating	4500 hp
CONDENSATE DRAIN TANK	
Quantity	1
Type	Horizontal, cylindrical
Volume	420 gal
Design pressure	Atmospheric
Design temperature	200°F

* The values in this table represent equipment design parameters. The equipment has been evaluated for the operating conditions described per References 10.2-5 and 10.2-69.

Table 10.4-9 *

FEEDWATER SYSTEM DESIGN PARAMETERS

DRAIN COOLERS 1AE107, 1BE107, and 1CE107

Quantity	3 (33-1/3% capacity each)
Type	Low pressure, horizontal, two-pass, U-tube, removable shell
Duty at VWO, each	84,091,000 Btu/hr
Shell side design	
Fluid	Drains
Flow rate each at VWO	1,966,506 lb/hr
Design pressure	50 psig and vacuum
Design temperature	300°F
Tube side design	
Flow rate each at VWO	4,941,324 lb/hr
Design pressure	700 psig
Design temperature	300°F

FEEDWATER HEATERS 11AE101, 11BE101, and 11CE101

Quantity	3 (33-1/3% capacity each)
Type	Low pressure horizontal two-pass, U-tube, mounted in condenser neck, removable tube bundle
Duty at VWO, each	137.320×10^6 Btu/hr
Shell side design	
Fluid/flow rate at VWO, each	Extraction steam and moisture/ 177,176 lb/hr Cascading drains in/1,789,330 lb/hr Cascading drains out/1,966,506 lb/hr
Design pressure	50 psig and vacuum
Design temperature	300°F
Tube side design	
Fluid	Feedwater
Flow rate at VWO, each	4,941,342 lb/hr
Design pressure	700 psig
Design temperature	300°F

* The values in this table represent equipment design parameters. The equipment has been evaluated for the operating conditions described per Reference 10.2-79.

Table 10.4-9 (Cont'd)

FEEDWATER SYSTEM DESIGN PARAMETERS

FEEDWATER HEATERS 12AE102, 12BE102, and 12CE102	
Quantity	3, 33-1/3% capacity each
Type	Low pressure, horizontal, two-pass, U-tube, mounted in condenser neck, removable tube bundle
Duty at VWO, each	186.392×10^6 Btu/hr
Shell side design	
Fluid/flow rate at VWO, each	Extraction steam and moisture/ 177,678 lb/hr Cascading drains in/1,611,563 lb/hr Cascading drains out/1,789,330 lb/hr
Design pressure	50 psig and vacuum
Design temperature	300°F
Tube side design	
Fluid	Feedwater
Flow rate at VWO, each	4,941,342 lb/hr
Design pressure	700 psig
Design temperature	300°F
FEEDWATER HEATERS 13AE103, 13BE103, and 13CE103	
Quantity	3, 33-1/3% capacity each
Type	Low pressure, horizontal, two-pass, U-tube, removable shell
Duty at VWO, each	316.584×10^6 Btu/hr
Shell side design	
Fluid/flow rate at VWO, each	Extraction steam and moisture/ 252,020 lb/hr Cascading drains in/1,359,633 lb/hr Cascading drains out/1,611,650 lb/hr
Design pressure	75 psig and vacuum
Design temperature	320°F
Tube side design	
Fluid	Feedwater
Flow rate at VWO, each	4,941,342 lb/hr
Design pressure	700 psig
Design temperature	320°F

Table 10.4-9 (Cont'd)

FEEDWATER SYSTEM DESIGN PARAMETERS

FEEDWATER HEATERS 14AE104, 14BE104, and 14CE104	
Quantity	3, 33-1/3% capacity each
Type	Low pressure, horizontal, two-pass, U-tube, removable shell
Duty at VWO, each	211.174x10^{o} Btu/hr
Shell side design	
Fluid/flow rate at VWO, each	Extraction steam/149,714 lb/hr Miscellaneous drains/558,770 lb/hr Cascading drains in/651,149 lb/hr Cascading drains out/1,359,633 lb/hr
Design pressure	125 psig and vacuum
Design temperature	375°F
Tube side design:	
Fluid	Feedwater
Flow rate at VWO, each	4,941,342 lb/hr
Design pressure	700 psig
Design temperature	355°F
FEEDWATER HEATERS 15AE105, 15BE105, and 15CE105	
Quantity	3, 33-1/3% capacity each
Type	Low pressure, horizontal, two-pass, U-tube, removable shell
Duty at VWO, each	235.227x10^{6} Btu/hr
Shell side design	
Fluid/flow rate at VWO, each	Cross-around steam/276,538 lb/hr Cascading drains in/374,611 lb/hr Cascading drains out/651,149 lb/hr
Design pressure	217 psig and vacuum
Design temperature	410°F
Tube side design:	
Fluid	Feedwater
Flow rate at VWO, each	4,941,342 lb/hr
Design pressure	700 psig
Design temperature	410°F

Table 10.4-9 (Cont'd)

FEEDWATER SYSTEM DESIGN PARAMETERS

REACTOR FEED PUMPS 1AP101, 1BP101, and 1CP101

Quantity	3, 33-1/3% capacity each
Type	Single-stage, double suction, centrifugal, variable-speed, horizontal
Capacity, each	12,900 gpm
Head	2314 ft
Driver	Dual admission steam turbine rated at 8000 hp

FEEDWATER HEATERS 16AE106, 16BE106, and 16CE106

Quantity	3, 33-1/3% capacity each
Type	High pressure, horizontal, two-pass, U-tube, removable shell
Duty at VWO, each	289.155×10^6 Btu/hr
Shell side design	
Fluid/flow rate at VWO, each	Extraction steam/374,611 lb/hr Drains out/374,611 lb/hr
Design pressure	425 psig and vacuum
Design temperature	490°F
Tube side design:	
Fluid	Feedwater
Flow rate at VWO, each	4,941,342 lb/hr
Design pressure	2100 psig
Design temperature	490°F

REACTOR FEED PUMP SEAL INJECTION BOOSTER PUMP 10P176

Quantity	1, 100% capacity
Type	Single-stage, centrifugal horizontal
Capacity	450 gpm
Head	235 ft
Driver	Electric motor at 50 hp

VWO - Valves wide open

Table 10.4-10

AUXILIARY STEAM SYSTEM DESIGN PARAMETERS

AUXILIARY BOILERS	
Quantity	3
Steam output, each	45,000 lb/hr
Design pressure	300 psig
Steam quality	99.5%
Fuel	No. 2 fuel oil
Atomizer	Steam or air
Fan type	Centrifugal, air foil design
Fan rating	12,900 cfm @ 11.5 in . water gauge
Fan motor power rating	40 hp
DEAERATOR	
Quantity	1
Type	Horizontal spray tray, uncontrolled inlet
Capacity	148,500 lb/hr
Storage	1650 gallons
Design pressure	50 psig
Water temperature	221°F
Oxygen guarantee	0.005 cm^3/l
AUXILIARY BOILER FEED PUMPS	
Quantity	3
Type	Vertical, canned suction, centrifugal, multistage
Capacity, each	150 gpm
Head	840 feet
Motor power rating	60 hp
BLOW-OFF TANK	
Quantity	1
Type	Atmospheric, vertical
Capacity	6000 lb/hr
Design pressure	75 psig

Figure 10.1-1
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Figure 10.1-2
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Figures 10.2-1 thru 10.2-3

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Figure 10.2-4
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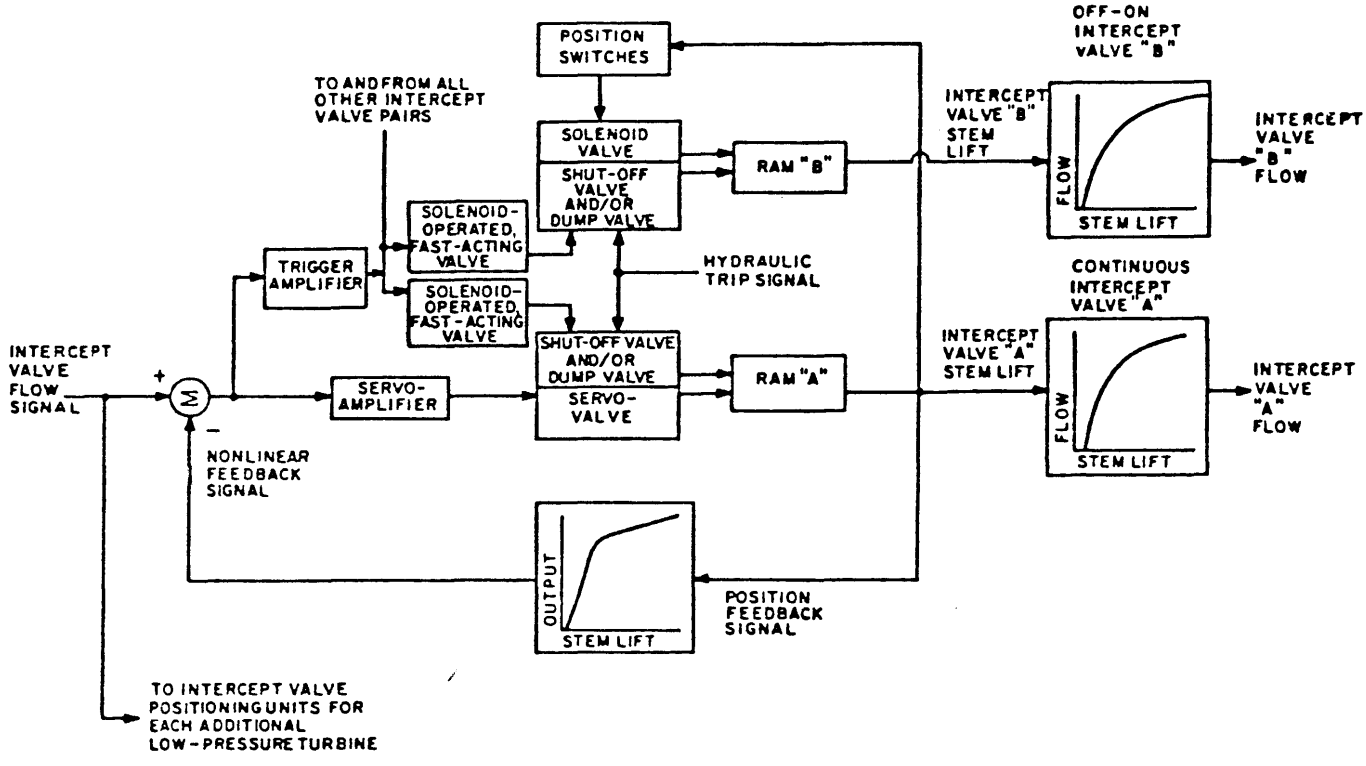
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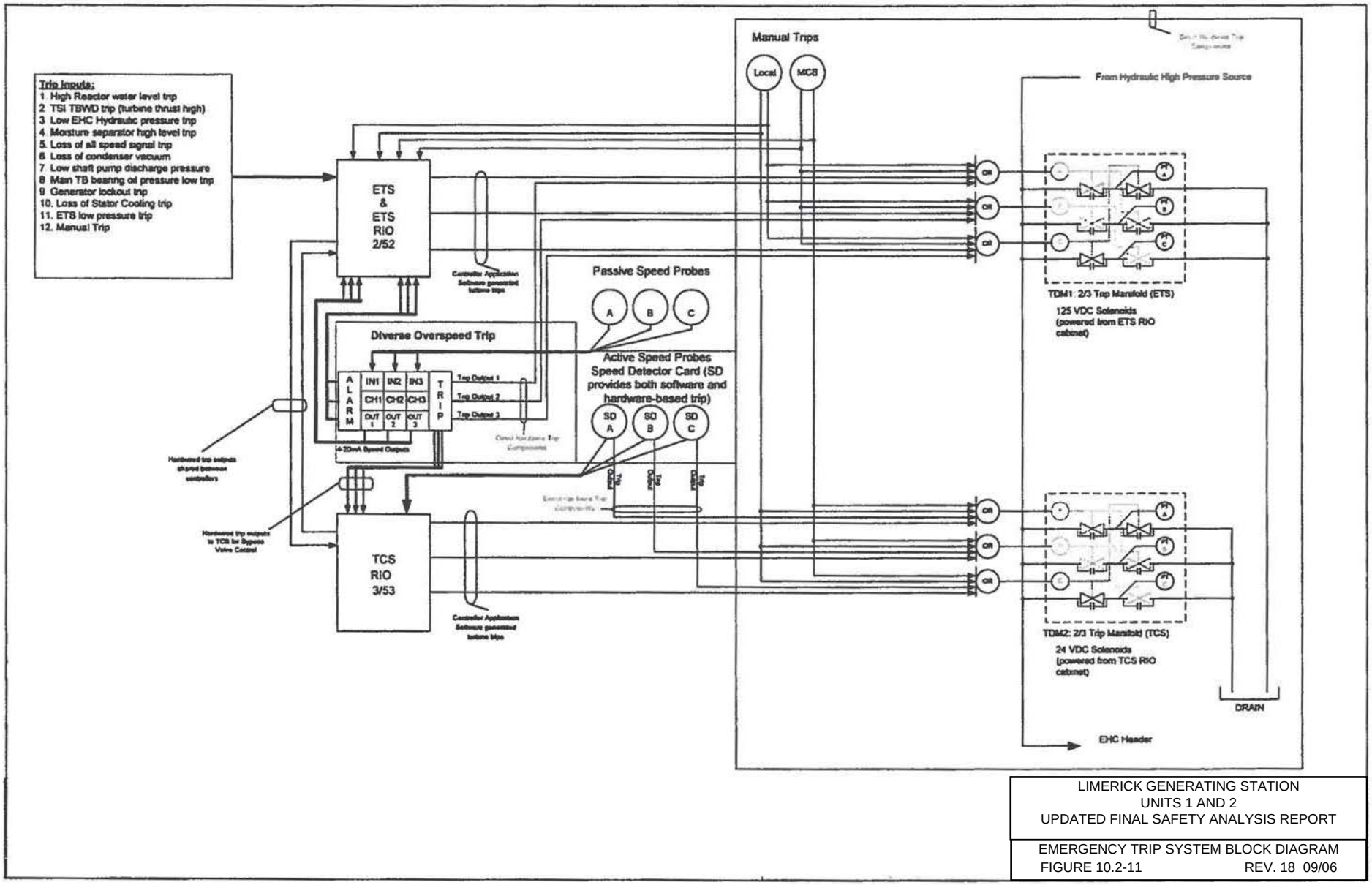
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UPDATED FINAL SAFETY ANALYSIS REPORT

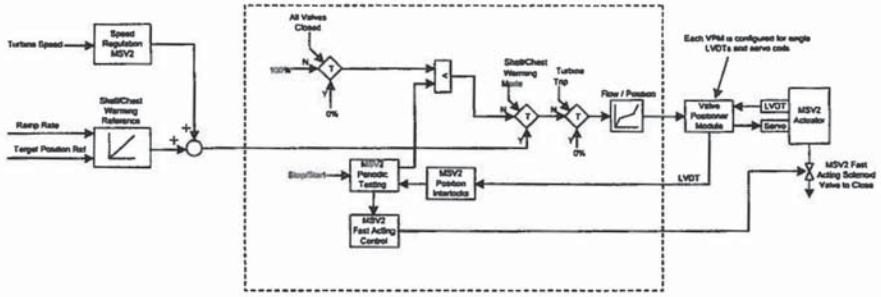
INTERCEPT VALVE POSITIONING

FIGURE 10.2-10

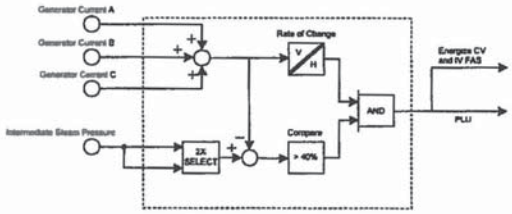


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EMERGENCY TRIP SYSTEM BLOCK DIAGRAM
FIGURE 10.2-11 REV. 18 09/06

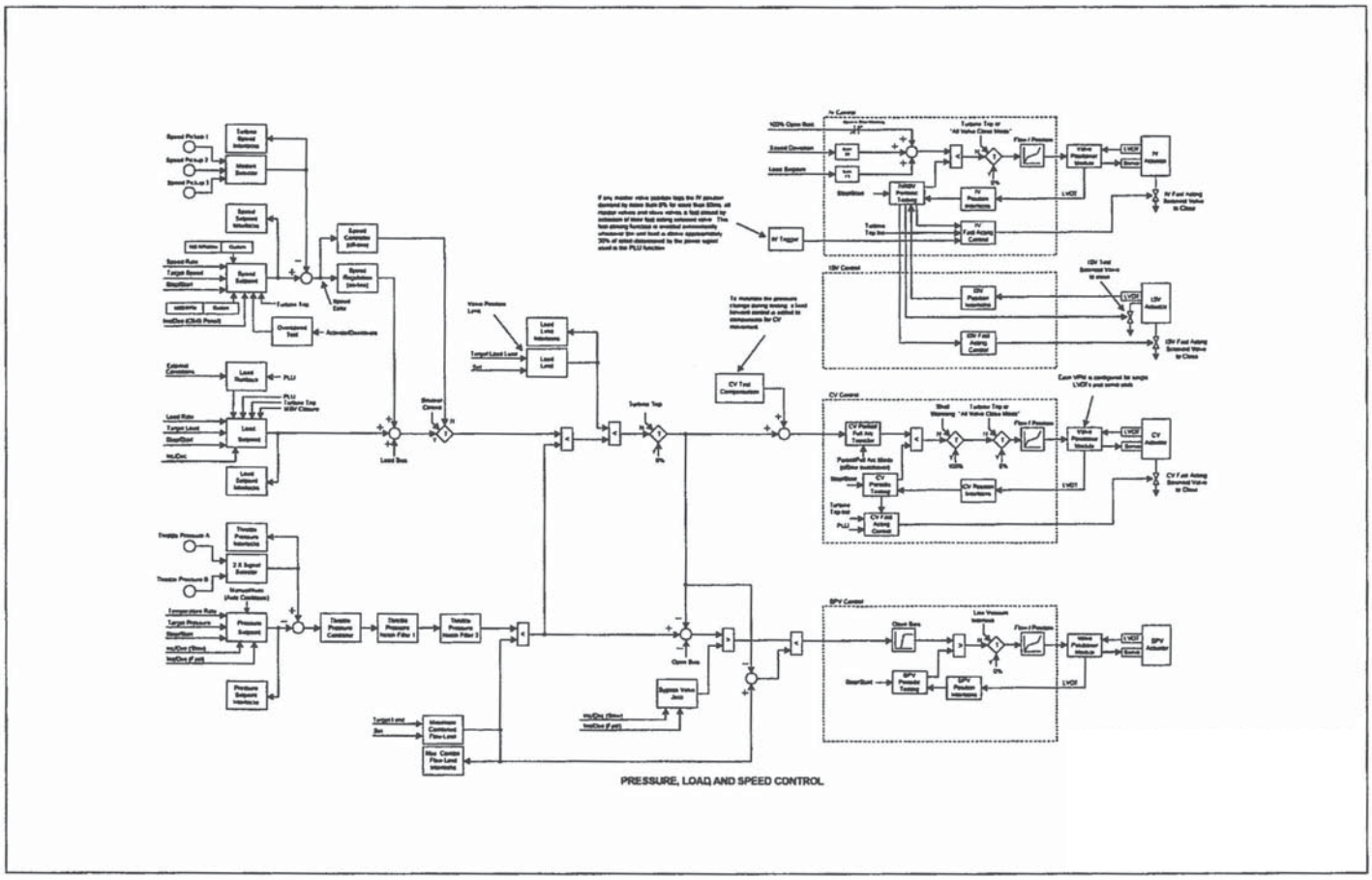


MSV2 CONTROL



POWER LOAD UNBALANCE

LIMERICK GENERATING STATION UNITS 1 AND 2 UPDATED FINAL SAFETY ANALYSIS REPORT
BLOCK DIAGRAM FOR POWER LOAD UNBALANCE SYSTEM AND MSV2 CONTROL FIGURE 10.2-12 REV. 18 09/16



PRESSURE, LOAD AND SPEED CONTROL

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

BLOCK DIAGRAM FOR
PRESSURE LOAD AND SPEED CONTROL SYSTEM
FIGURE 10.2-13 REV. 18 09/16

Figure 10.3-1

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11.5-1	Deleted
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CHAPTER 11 - RADIOACTIVE WASTE MANAGEMENT

11.1 SOURCE TERMS

The radioactivity source terms, reactor coolant concentrations, and offgas release rates used in the design and evaluation of LGS vary depending upon the specific application. This section gives nominal noble gas source terms based on an offgas release rate of 100,000 μCi/sec at 30 minutes decay. The corresponding halogen and particulate/corrosion product coolant concentrations are also given. From these source terms, the shielding design basis source terms given in Section 12.2.1 were derived. The shielding design basis fission product source terms correspond to an offgas release rate of 350,000 μCi/sec at 30 minute decay. The expected source terms, as used in Chapter 11 for 10CFR50, Appendix I evaluations and in Section 12.2.2 for in-plant airborne activity and exposure estimates, are based on the source terms in ANSI N237 (1976), as incorporated into NUREG-0016 and in accordance with Regulatory Guide 1.112. These expected source terms correspond to an offgas release rate of 60,000 μCi/sec at 30 minutes decay. The source terms used for accident analysis in Chapter 15 also vary with the application. The source terms are given for each accident in Chapter 15.

The information in this section defines the design basis radioactive material levels in the reactor water, steam, and offgas. The various radioisotopes listed are grouped as coolant activation products, noncoolant activation products, and fission products. The fission product levels are based on measurements of BWR reactor water and offgas at several stations through mid-1971. Emphasis was placed on observations made at KRB and Dresden 2. The design basis radioactive material levels do not necessarily include all the radioisotopes observed or theoretically predicted to be present. The radioisotopes included are considered significant to one or more of the following criteria:

a. Plant equipment design

b. Shielding design

c. Understanding system operation and performance

d. Measurement practicability

e. Evaluating radioactive material releases to the environment

For halogens, radioisotopes with half-lives of less than 3 minutes have been omitted. For other fission product radioisotopes in reactor water, radioisotopes with half-lives less than 10 minutes are not considered.

11.1.1 FISSION PRODUCTS

11.1.1.1 Noble Radiogas Fission Products

The noble radiogas fission product source terms observed in operating BWRs are generally complex mixtures whose sources vary from minuscule defects in cladding to "tramp" uranium on external cladding surfaces. The relative concentrations or amounts of noble radiogas isotopes can be described as follows:

Equilibrium: $R \sim k_1 Y$ (EQ. 11.1-1)

Recoil: $R \sim k_2 Y \lambda$ (EQ. 11.1-2)

The nomenclature in Section 11.1.1.4 defines the terms in these and succeeding equations. The constants (k_1) and (k_2) describe the fractions of the total fissions that are involved in each of the releases. The equilibrium and recoil mixtures are the two extremes of the mixture spectrum that are physically possible. When a sufficient time-delay occurs between the fission event and the release of the radiogases from the fuel to the coolant, the radiogases approach equilibrium levels in the fuel and the equilibrium mixture results. When there is no delay or impedance between the fission event and the release of the radiogases, the recoil mixture is observed.

Prior to Vallecitos Boiling Water Reactor and Dresden 1 experience, it was assumed that noble radiogas leakage from the fuel would be the equilibrium mixture of the noble radiogases present in the fuel.

The VBWR and the early Dresden 1 experience indicated that the actual mixture most often observed, approached a distribution which was intermediate in character to the two extremes (Reference 11.1-1). This intermediate decay mixture was termed the "diffusion" mixture. It must be emphasized that this "diffusion" mixture is merely one possible point on the mixture spectrum ranging from the

equilibrium to the recoil mixture and does not have the absolute mathematical and mechanistic basis for the calculational methods possible for equilibrium and recoil mixtures. However, the "diffusion" distribution pattern which has been described is as follows:

Diffusion: $R_g \sim k_3 Y \lambda^{0.5}$ (EQ. 11.1-3)

The constant (k_3) describes the fraction of total fissions that are involved in the release. The value of the exponent of the decay constant (λ) is midway between the values for equilibrium, 0, and recoil, 1. The "diffusion" pattern value of 0.5 was originally derived from diffusion theory.

Although the previously described "diffusion" mixture was used by GE as a basis for design since 1963, the design basis release magnitude used has varied from 0.5 Ci/sec to 0.1 Ci/sec as measured after 30 minute decay (t = 30 min). Since about 1967, the design basis release magnitude established and used (including the 1971 source terms) is an annual average of 0.1 Ci/sec (t = 30 min). This design basis is considered as an annual average, with some time above and some time below this value. This design value was selected on the basis of operating experience, rather than predictive assumptions. Several judgment factors, including the significance of environmental release, reactor water radioisotope concentrations, liquid waste handling and effluent disposal criteria, structure air contamination, shielding design, and turbine and other component contamination affecting maintenance, have been considered in establishing this level.

Noble radiogas source terms from fuel above 0.1 Ci/sec (t = 30 min) can be tolerated for reasonable periods of time. Continual assessment of these values is made on the basis of actual operating experience in BWRs (Reference 11.1-2).

While the noble radiogas source term magnitude had been established at 0.1 Ci/sec (t = 30 min), it was recognized that there may be a more statistically applicable distribution for the noble radiogas

mixture. Sufficient data were available from KRB operations from 1967 to mid-1971, along with Dresden 2 data from operation in 1970 and several months in 1971, to more accurately characterize the noble radiogas mixture pattern for an operating BWR.

The basic equation for each radioisotope used to analyze the collected data is:

$$R_g = K_g Y \lambda^m (1-e^{-\lambda t}) (e^{-\lambda t}) \qquad \text{(EQ. 11.1-4)}$$

With the exception of Kr-85 (with a half-life of 10.74 year), the noble radiogas fission products in the fuel are essentially at an equilibrium condition after an irradiation period of several months (rate of formation is equal to the rate of decay). So for practical purposes the term $(1-e^{-\lambda t})$ approaches 1 and can be neglected when the reactor has been operating at steady-state for long periods of time. The term $(e^{-\lambda t})$ is used to adjust the releases from the fuel (t = 0) to the decay time for which values are needed. Historically t = 30 min has been used. When discussing long, steady-state operation and leakage from the fuel (t = 0), the following simplified form of Equation 11.1-4 describes the leakage of each noble radiogas:

$$R_g = K_g Y \lambda^m \qquad \text{(EQ. 11.1-5)}$$

The constant (K_g) describes the magnitude of leakage. The relative rates of leakage for the different noble radiogas isotopes is accounted for by the variable (m) the exponent of the decay constant (λ).

Dividing both sides of Equation 11.1-5 by (Y), the fission yield, and taking the logarithm of both sides results in the following equation:

$$\log (R_g/Y) = m \log (\lambda) + \log (K_g) \qquad \text{(EQ. 11.1-6)}$$

Equation 11.1-6 represents a straight line when log R_g/Y is plotted versus log (λ); (m) is the slope of the line. This straight line is obtained by plotting (R_g/Y) versus (λ) on logarithmic graph paper. By fitting actual data from KRB and Dresden 2 (using least squares techniques) to the equation, the slope ($\overline{m}$) can be obtained. This can be estimated on the plotted graph. With radiogas leakage at KRB over the nearly 5 year period varying from 0.001 to 0.056 Ci/sec (t = 30 minutes), and with radiogas leakage at Dresden 2 varying from 0.001-0.169 Ci/sec (t = 30 min), the average value of (m) was determined. The value for (m) is 0.4, with a standard deviation of ±0.07. This is illustrated in Figure 11.1-1 as a frequency histogram. As can be seen from this figure, variations in (m) were observed in the range m = 0.1 to m = 0.6. After establishing the value of $\overline{m}$ = 0.4, the value of (K) can be calculated by selecting a value for (R), or as has been done historically, the design basis is set by the total design basis source term magnitude at t = 30 min. With ΣR_g at 30 min = 0.1 Ci/sec, (K) can be calculated as being 2.6×10^7 and Equation 11.1-4 becomes:

$$R_g = 2.6 \times 10^7 Y \lambda^{0.4} (1-e^{-\lambda T}) (e^{-\lambda t}) \qquad \text{(EQ. 11.1-7)}$$

This updated noble radiogas source term mixture has been termed the "1971 Mixture" to differentiate it from the "diffusion mixture." The noble gas source term for each radioisotope can be calculated from Equation 11.1-7. The resultant source terms are presented in Table 11.1-1 as leakage from fuel (t = 0) and after 30 minute decay. While Kr-85 can be calculated using Equation 11.1-7, the number of confirming experimental observations was limited by the difficulty of measuring very low release rates of this isotope. Therefore, the table provides an estimated range for Kr-85 based on a few actual measurements.

11.1.1.2 Radiohalogen Fission Products

Historically, the radiohalogen design basis source term was established by the same equation as that used for noble radiogases. In a fashion similar to that used with gases, a simplified equation can be shown to describe the release of each halogen radioisotope:

$$R_h = K_h Y \lambda^n \qquad \text{(EQ. 11.1-8)}$$

The constant (K) describes the magnitude of leakage from fuel. The relative rates of halogen radioisotope leakage is expressed in terms of (n), the exponent of the decay constant (λ). As was done with the noble radiogases, the average value was determined for (n). The value for $\overline{n}$ is 0.5 with a standard deviation of ±0.19. This is illustrated in Figure 11.1-2 as a frequency histogram. As can be seen from this figure, variations in (n) were observed in the range of n = 0.1 to n = 0.9.

It appeared that the use of the previous method of calculating radiohalogen leakage from fuel was overly conservative. Figure 11.1-3 relates KRB and Dresden 2 noble radiogas versus I-131 leakage. While Dresden 2 data, during the period August 1970 to January 1971, indicates that there is a relationship between noble radiogas and I-131 leakage under one fuel condition; there was no simple relationship for all fuel conditions experienced. The data also indicates that during this period, high radiogas leakages were not accompanied by high radioiodine leakage from the fuel. Except for one KRB datum point, all steady-state I-131 leakages observed at KRB or Dresden 2 were equal to or less than 505 μCi/sec. Even at Dresden 1 in March 1965, when severe defects were experienced in stainless steel clad fuel, I-131 leakages greater than 500 μCi/sec were not experienced. Figure 11.1-3 shows that these higher radioiodine leakages from the fuel were related to noble radiogas source terms of less than the design basis value of 0.1 Ci/sec (t = 30 min). This may be partially explained by inherent limitations due to internal plant operational problems that caused plant derating.

In general, it is not anticipated that operation at full power would continue for any significant time period with fuel cladding defects which would be indicated by I-131 leakage from the fuel in excess of 700 μCi/sec. When high radiohalogen leakages are observed, other fission products will be present in greater amounts.

Using these judgment factors and experience to date, the radiohalogen design basis source terms from fuel were established based on I-131 leakage of 700 μCi/sec. This value, as shown in Figure 11.1-3, accommodates the experience data and the noble radiogas design basis source term of 0.1 Ci/sec (t = 30 min). With the I-131 design basis source term established, (K_h) is calculated as being 2.4×10^7; and halogen radioisotope release can be expressed by the following equation:

$$R_h = 2.4 \times 10^7 \, Y \lambda^{0.5} \, (1 - e^{-\lambda T}) \, (e^{-\lambda t}) \qquad \text{(EQ. 11.1-9)}$$

Concentrations of radiohalogens in reactor water can be calculated using the following equation:

$$C_h = \frac{R_h}{(\lambda + \beta + \nu)M} \qquad \text{(EQ. 11.1-10)}$$

Although carryover of most soluble radioisotopes from reactor water to steam is observed to be <0.1% (<0.001 fraction), the observed "carryover" for radiohalogens has varied from 0.1% to about 2% on newer plants. The average of observed radiohalogen carryover measurements has been

1.2% by weight of reactor water in steam with a standard deviation of ±0.9. In the present source term definition, a radiohalogen carryover of 2% (0.02 fraction) is used.

The halogen release rate from the fuel can be calculated from Equation 11.1-9. Concentrations in reactor water can be calculated from Equation 11.1-10. The resultant concentrations are presented in Table 11.1-2.

11.1.1.3 Other Fission Products

The observations of other fission products (and transuranic nuclides, including Np-239) in operating BWRs are not adequately correlated by simple equations. For these radioisotopes, design basis concentrations in reactor water have been estimated conservatively from experience data and are presented in Table 11.1-3. Carryover of these radioisotopes from the reactor water to the steam is estimated to be <0.1% (<0.001 fraction). However, in addition to carryover, decay of noble radiogases in the steam leaving the reactor results in the production of noble gas daughter radioisotopes in the steam and condensate systems.

Some daughter radioisotopes (e.g., yttrium and lanthanum) are not listed as being in reactor water. Their independent leakage to the coolant is negligible; however, these radioisotopes may be observed in some samples in equilibrium, or approaching equilibrium, with the parent radioisotope.

Except for Np-239, trace concentrations of transuranic isotopes have been observed in only a few samples where extensive and complex analyses were carried out. The predominant alpha emitter present in reactor water is Cm-242 at an estimated concentration of 10^{-6} μCi/g or less, which is below the maximum permissible concentration (pre-1994 10CFR20) in drinking water applicable to continuous use by the general public. The concentration of alpha emitting plutonium radioisotopes is more than one order of magnitude lower than that of Cm-242.

Plutonium-241 (a beta emitter) may also be present in concentrations comparable to the Cm-242 level.

11.1.1.4 Nomenclature

The following list of nomenclature defines the terms used in equations for source term calculations:

R_g	=	leakage rate of a noble gas radioisotope (μCi/sec)
R_h	=	leakage rate of a halogen radioisotope (μCi/sec)
Y	=	fission yield of a radioisotope (atoms/fission)
λ	=	decay constant of a radioisotope (sec^{-1})
T	=	fuel irradiation time (sec)
t	=	decay time following leakage from fuel (sec)
m	=	noble radiogas decay constant exponent (dimensionless)
n	=	radiohalogen decay constant exponent (dimensionless)

K_g = a constant establishing the level of noble radiogas leakage from fuel

K_h = a constant establishing the level of radiohalogen leakage from fuel

C_h = concentration of a halogen radioisotope in reactor water (μCi/g)

M = mass of water in the operating reactor (g)

β = cleanup system removal constant (sec^{-1})

$$= \frac{\text{cleanup system flow rate (g/sec)}}{\text{M(g)}}$$

g = grams mass

ν = halogen steam carryover removal constant (sec^{-1})

$$= \frac{\left\lfloor \frac{C_s \ (\mu Ci/g)}{C_h \ (\mu Ci/g)} \right\rfloor \left[\text{steam flow (g/sec)}\right]}{\text{M(g)}}$$

C_s = concentration of halogen radioisotopes in steam (μCi/g)

11.1.2 ACTIVATION PRODUCTS

11.1.2.1 Coolant Activation Products

The coolant activation products are not adequately correlated by simple equations. Design basis concentrations in reactor water and steam have been estimated conservatively from experience data. The resultant concentrations are presented in Table 11.1-4.

11.1.2.2 Noncoolant Activation Products

The activation products formed by activation of impurities in the coolant or by corrosion of irradiated system materials are not adequately correlated by simple equations. The design basis source terms of noncoolant activation products have been estimated conservatively from experience data (Reference 11.1-3). The resultant concentrations are presented in Table 11.1-5. Carryover of these isotopes from the reactor water to the steam is estimated to be <0.1% (<0.001 fraction).

11.1.3 TRITIUM

In a BWR, tritium is produced by three principal methods:

a. Activation of naturally occurring deuterium in the primary coolant

b. Nuclear fission of UO_2 fuel

c. Neutron reactions with boron used in reactivity control rods

The tritium formed in control rods may be released if through-wall cracking of the control rod jacketing occurs. High exposure original equipment (OE) type control rods in particular have been observed to experience stress corrosion cracking of the jacketing material due to swelling of the contained boron carbide from neutron absorption. Propagation of through-wall cracking can result in boron leaching into the reactor coolant and release of accumulated tritium. Such tritium releases occur intermittently and have proven to be not quantifiable, with no clear trend having been established throughout the industry. The safety function of the control rod is not adversely affected since stress corrosion cracking and boron leaching are anticipated and accounted for, and a program exists to monitor and replace control rods as required. Following the routine, cyclic replacement of the high exposure and potentially cracked control rods with advanced designs less susceptible to stress corrosion cracking, tritium release into the reactor coolant from control rods is expected to be negligible .

A prime source of tritium available for release from a BWR is that produced from activation of deuterium in the primary coolant. Some fission product tritium may also transfer from fuel to primary coolant. This discussion is limited to the uncertainties associated with estimating the amounts of tritium generated in a BWR which are available for release.

All of the tritium produced by activation of deuterium in the primary coolant is available for release in liquid or gaseous effluents. The tritium formed in a BWR from deuterium activation can be calculated using the equation:

$$R_{act} = \frac{\Sigma \Phi V \lambda}{3.7 \times 10^4 P} \qquad \text{(EQ. 11.1-11)}$$

where:

R_{act} = tritium formation rate by deuterium activation ($\mu Ci/sec/MW_t$)

Σ = macroscopic thermal neutron cross-section (cm^{-1})

Φ = thermal neutron flux ($neutrons/cm^2\text{-}sec$)

V = coolant volume in the core (cm^3)

λ = tritium radioactive decay constant ($1.78 \times 10^{-9}\ sec^{-1}$)

P = reactor power level (MWt)

For recent BWR designs (R_{act}) is calculated to be $(1.3 \pm 0.4) \times 10^4$ $\mu Ci/sec/MWt$. The uncertainty indicated is derived from the estimated errors in selecting values for the coolant volume in the core, coolant density in the core, abundance of deuterium in light water (some additional deuterium is present because of the H(n,ν) D reaction), thermal neutron flux, and microscopic cross-section for deuterium.

The fraction of tritium produced by fission which may transfer from fuel to the coolant (which is then available for release in liquid and gaseous effluents) is more difficult to estimate. However, since zircaloy clad fuel rods are used in BWRs, essentially all fission product tritium remains in the fuel rods unless defects are present in the cladding material (Reference 11.1-4).

The study made at Dresden 1 in 1968 by the U.S. Public Health Service suggests that essentially all of the tritium released from the plant could be accounted for by the deuterium activation source (Reference 11.1-5). For purposes of estimating the leakage of tritium from defective fuel, it can be assumed that it leaks in a manner similar to the leakage of noble radiogases. Thus, use can be made of the empirical relationship described as the "diffusion mixture" used for predicting the source term of individual noble gas radioisotopes as a function of the total noble gas source term. The equation which describes this relationship is:

$$R_{dif} = KY\lambda^{0.5} \qquad \text{(EQ. 11.1-12)}$$

where:

R_{dif} = leakage rate of tritium from fuel (μCi/sec)

Y = fission yield fraction (atoms/fission)

λ = radioactive decay constant (sec^{-1})

K = a constant related to total tritium leakage rate

If the total noble radiogas source term is 0.1 Ci/sec after 30 minute decay, leakage from fuel can be calculated to be about 0.24 μCi/sec of tritium. To place this value in perspective in the U.S. Public Health Service study, the observed rate of Kr-85 (which has a half-life similar to that of tritium) was 0.06 to 0.4 times that calculated using the "diffusion mixture" relationship. This would suggest that the actual tritium leakage rate might range from 0.015-0.10 μCi/sec. Since the annual average noble radiogas leakage from a BWR is expected to be less than 0.1 Ci/sec (t = 30 min), the annual average tritium release rate from the fission source can be conservatively estimated at 0.12 ± 0.12 μCi/sec, or 0.0-0.24 μCi/sec.

Based on this approach, the estimated total tritium appearance rate in reactor coolant and the release rate in the effluent is about 20 Ci/yr.

Tritium formed in the reactor is generally present as tritiated oxide (HTO) and to a lesser degree as tritiated gas (HT). Tritium concentration (on a weight basis) in the steam formed in the reactor is the same as in the reactor water at any given time. This tritium concentration is also present in condensate and feedwater. Since radioactive effluents generally originate from the reactor and power cycle equipment, radioactive effluents also have this tritium concentration. The condensate storage tanks receive treated water from the liquid waste management system and reject water from the condensate system. Thus, all plant process water has a common tritium concentration.

Offgases released from the plant contain tritium, which is present as tritiated gas (HT) resulting from reactor water radiolysis as well as tritiated water vapor (HTO). In addition, water vapor from the turbine gland seal steam packing exhauster and a lesser amount present in ventilation air due to process steam leaks or evaporation from sumps, tanks, and spills on floors also contain tritium. The remainder of the tritium leaves the plant in liquid effluents or with solid wastes.

Recombination of radiolysis gases in the air ejector offgas system forms water, which is condensed and returned to the main condenser. This tends to reduce the amount of tritium leaving in gaseous effluents. Reducing the gaseous tritium release results in a slightly higher tritium concentration in

the plant process water. Reducing the amount of liquid effluent discharged also results in a higher process coolant equilibrium tritium concentration.

Essentially, all tritium in the primary coolant is eventually released to the environs, either as water vapor and gas to the atmosphere, as liquid effluent to the plant discharge, or as solid waste. Reduction due to radioactive decay is negligible due to the 12 year half-life of tritium.

The U.S. Public Health Service study at Dresden 1 estimated that approximately 90% of the tritium release was observed in liquid effluent, with the remaining 10% leaving as gaseous effluent (Reference 11.1-5). Efforts to reduce the volume of liquid effluent discharges may change this distribution so that a greater amount of tritium will leave as gaseous effluent. From a practical standpoint, the fraction of tritium leaving as liquid effluent may vary between 60% and 90%, with the remainder leaving in gaseous effluent.

11.1.4 FUEL FISSION PRODUCTION INVENTORY AND FUEL EXPERIENCE

11.1.4.1 Fuel Fission Product Inventory

Fuel fission product inventory information is used in establishing fission product source terms for accident analysis and is, therefore, discussed in Chapter 15.

11.1.4.2 Fuel Experience

A discussion of BWR fuel experience including fuel failure experience, burnup experience, and thermal conditions under which the experience was gained is presented in References 11.1-6, 11.1-7 and 11.1-8.

11.1.5 PROCESS LEAKAGE SOURCES

Process leakage results in potential release paths for noble gases and other volatile fission products via ventilation systems. Liquid from process leaks is collected and routed to the liquid waste management system. Radioactive releases from the liquid waste management system are discussed in Section 11.2. Radionuclide releases via ventilation paths are at extremely low levels and have been insignificant compared to process offgas from operating BWR plants. However, because the implementation of improved process offgas treatment systems make the ventilation release relatively significant, GE has conducted measurements to identify and qualify these low level release paths. GE maintains an awareness of other measurements by the EPRI and other organizations, and routine measurements by utilities with operating BWRs.

Leakage of fluids from the process system results in the release of radionuclides into plant structures. In general, the noble radiogases remain airborne and are released to the atmosphere with little delay via the structure's ventilation exhaust ducts. The radionuclides are partitioned between air and water, and airborne radioiodines may plateout on metal surfaces, concrete, and paint. A significant amount of radioiodine remains in air or is desorbed from surfaces. Radioiodines are found in ventilation air as methyl iodide and as inorganic iodine, which is here defined as particulate, elemental, and hypoiodous acid forms of iodine. Particulates are also in the ventilation exhaust air.

Experience with airborne radiological releases from the BWR enclosure HVAC and the main condenser mechanical vacuum pump have been compiled and evaluated in NEDO-21159 (Reference 11.1-9). This report is periodically updated to incorporate the most recent data on

airborne emission. The results of these evaluations are based on data obtained by utility personnel and special in-plant studies of operating BWR plants by independent organizations and GE. An evaluation of the radioactive releases from ventilation systems for compliance with 10CFR50, Appendix I is given in Section 11.3. An evaluation of exposures due to airborne radioactivity is given in Section 12.2.2.

11.1.6 REFERENCES

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11.1-2 J.M. Skarpelos and R.S. Gilbert, "Technical Derivation of BWR 1971 Design Basis Radioactive Source Tems", NEDO-10871, (March 1975).

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11.1-8 H.E. Williamson and D.C. Ditmore, "Current State of Knowledge of High Performance BWR Zircaloy Clad UO_2 Fuel", NEDO-10173, (May 1970).

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Table 11.1-1

NOBLE RADIOGAS SOURCE TERMS

ISOTOPE	HALF-LIFE	SOURCE TERMS @ t = 0 (μCi/sec)	SOURCE TERM @ t = 30 min (μCi/sec)
Kr-83m	1.86 hr	3.4×10^3	2.9×10^3
Kr-85m	4.4 hr	6.1×10^3	5.6×10^3
Kr-85	10.74 yr	10 to 20[1]	10 to 20[1]
Kr-87	76.0 min	2.0×10^4	1.5×10^4
Kr-88	2.79 hr	2.0×10^4	1.8×10^4
Kr-89	3.18 min	1.3×10^5	1.8×10^2
Kr-90	32.3 sec	2.8×10^5	-
Kr-91	8.6 sec	3.3×10^5	-
Kr-92	1.84 sec	3.3×10^5	-
Kr-93	1.29 sec	9.3×10^4	-
Kr-94	1.0 sec	2.3×10^4	-
Kr-95	0.5 sec	2.1×10^3	-
Kr-97	1.0 sec	1.4×10^1	-
Xe-131m	11.96 day	1.5×10^1	1.5×10^1
Xe-133m	2.26 day	2.9×10^2	2.8×10^2
Xe-133	5.27 day	8.2×10^3	8.2×10^3
Xe-135m	15.7 min	2.6×10^4	6.9×10^3
Xe-135	9.16 hr	2.2×10^4	2.2×10^4
Xe-137	3.82 min	1.5×10^5	6.7×10^2
Xe-138	14.2 min	8.9×10^4	2.1×10^4
Xe-139	40.0 sec	2.8×10^5	-
Xe-140	13.6 sec	3.0×10^5	-
Xe-141	1.72 sec	2.4×10^5	-
Xe-142	1.22 sec	7.3×10^4	-
Xe-143	0.96 sec	1.2×10^4	-
Xe-144	9.0 sec	5.6×10^2	-
	TOTALS	~2.5×10^6	~1.0×10^5

[1] Estimated from experimental observations.

Table 11.1-2

HALOGEN RADIOISOTOPES IN REACTOR WATER

ISOTOPE	HALF-LIFE	CONCENTRATION (μCi/g)
Br-83	2.40 hr	1.5×10^{-2}
Br-84	31.8 min	2.7×10^{-2}
Br-85	3.0 min	1.7×10^{-2}
I-131	8.065 day	1.3×10^{-2}
I-132	2.284 hr	1.2×10^{-2}
I-133	20.8 hr	8.9×10^{-2}
I-134	52.3 min	2.4×10^{-2}
I-135	6.7 hr	1.3×10^{-2}

Table 11.1-3

OTHER FISSION PRODUCT RADIOISOTOPES IN REACTOR WATER

ISOTOPE	HALF-LIFE	CONCENTRATION (μCi/g)
Sr-89	50.8 day	3.1×10^{-3}
Sr-90	28.9 yr	2.3×10^{-4}
Sr-91	9.67 hr	6.9×10^{-2}
Sr-92	2.69 hr	1.1×10^{-1}
Zr-95	65.5 day	4.0×10^{-5}
Zr-97	16.8 hr	3.2×10^{-5}
Nb-95	35.1 day	4.2×10^{-5}
Mo-99	66.6 hr	2.2×10^{-2}
Tc-99m	6.007 hr	2.8×10^{-1}
Tc-101	14.2 min	1.4×10^{-1}
Ru-103	39.8 day	1.9×10^{-5}
Ru-106	368.0 day	2.6×10^{-6}
Te-129m	34.1 day	4.0×10^{-5}
Te-132	78.0 hr	4.9×10^{-2}
Cs-134	2.06 yr	1.6×10^{-4}
Cs-136	13.0 day	1.1×10^{-4}
Cs-137	30.2 yr	2.4×10^{-4}
Cs-138	32.3 min	1.9×10^{-1}
Ba-139	83.2 min	1.6×10^{-1}
Ba-140	12.8 day	9.0×10^{-3}
Ba-141	18.3 min	1.7×10^{-1}
Ba-142	10.7 min	1.7×10^{-1}
Ce-141	32.53 day	3.9×10^{-5}
Ce-143	33.0 hr	3.5×10^{-5}
Ce-144	284.4 day	3.5×10^{-5}
Pr-143	13.58 day	3.8×10^{-5}
Nd-147	11.06 day	1.4×10^{-5}
Pu-239	2.35 day	2.4×10^{-1}

Table 11.1-4

COOLANT ACTIVATION PRODUCTS IN REACTOR WATER AND STEAM

ISOTOPE	HALF-LIFE	STEAM CONCENTRATION (μCi/g)	REACTOR WATER CONCENTRATION (μCi/g)
N-13	9.99 min	7×10^{-3}	4×10^{-2}
N-16	7.13 sec	$2.50 \times 10^{+2}$	$4.80 \times 10^{+1}$
N-17	4.14 sec	2×10^{-2}	6×10^{-3}
O-19	26.8 sec	8×10^{-1}	7×10^{-1}
F-18	109.8 min	4×10^{-3}	4×10^{-3}

Table 11.1-5

NONCOOLANT ACTIVATION PRODUCTS IN REACTOR WATER

ISOTOPE	HALF-LIFE	CONCENTRATION (μCi/g)
Na-24	15.0 hr	2.0×10^{-3}
P-32	14.31 day	2.0×10^{-5}
Cr-51	27.8 day	5.0×10^{-4}
Mn-54	313.0 day	4.0×10^{-5}
Mn-56	2.582 hr	5.0×10^{-2}
Co-58	71.4 day	5.0×10^{-3}
Co-60	5.258 yr	5.0×10^{-4}
Fe-59	45.0 day	8.0×10^{-5}
Ni-65	2.55 hr	3.0×10^{-4}
Zn-65	243.7 day	2.0×10^{-6}
Zn-69m	13.7 hr	3.0×10^{-5}
Ag-110m	253.0 day	6.0×10^{-5}
W-187	23.9 hr	3.0×10^{-3}

11.2 LIQUID WASTE MANAGEMENT SYSTEM

The liquid waste management system is designed to process and dispose of, or recycle all of the radioactive, or potentially radioactive liquid wastes generated in the operation of the plant. The liquid waste management system consists of equipment drain (low conductivity), floor drain (high conductivity), chemical waste, and laundry drain subsystems. These subsystems are shown on drawings M-62, M-63 and M-64. Equipment locations are shown on drawings provided in Section 1.2.

The plant drainage system, a major input source to the liquid waste management system, is described in Section 9.3.3. The equipment and floor drainage collection system is shown in drawing M-61. Sufficient treatment is available to process all waste water to condensate storage water quality or to preset quality limits acceptable for release to the environment. The liquid waste management system has no safety-related function.

11.2.1 DESIGN BASES

a. The system has the capability to process the maximum anticipated quantities of liquid wastes without impairing the operation or availability of the plant during both normal and expected occurrence conditions, to satisfy the requirements of 10CFR20 and 10CFR50.

b. Alternate process routes, subsystem cross-ties, and adequate volumes are designed into the system to provide for operational and anticipated surge waste volumes which could occur during refueling, abnormal leakage, decontamination activities, and equipment maintenance.

c. The system is designed so that no potentially radioactive liquids can be discharged to the environment unless they have been processed, monitored, and mixed with cooling tower blowdown. This results in an offsite release and radiation exposures to individuals and the general population (on an annual average basis) within the limits of 10CFR20 and 10CFR50.

d. The liquid waste management system design meets the requirements of GDC 60 and GDC 61.

e. The liquid waste management system is designed to keep the exposure to plant personnel as low as reasonably achievable (ALARA) during normal operation and plant maintenance, in accordance with Regulatory Guide 8.8.

f. The expected radionuclide activity concentrations in the liquid waste management process equipment are based on 60,000 μCi/sec noble gas release rate for one reactor unit after a 30 minute delay. The maximum expected radionuclide activity concentrations in the liquid waste management process equipment are based on 350,000 μCi/sec noble gas release rate for one reactor unit after a 30 minute delay.

g. All piping and equipment in the liquid waste management system are designed to seismic Category II requirements. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the liquid waste management system are discussed in Section 3.2.

h. Design features provided to reduce maintenance, equipment downtime, liquid leakage, or gaseous releases of radioactive materials to the enclosure atmosphere, to facilitate cleaning, or otherwise improve radwaste operations are discussed in Section 12.3.

i. All atmospheric liquid radwaste tanks are provided with an overflow connection adequately sized to accommodate expected tank inlet flow conditions. The overflow is connected below the tank vent and at least one inch above the high level, alarm trip point. Overflow liquid is routed to a redundant tank or to the nearest atmospheric drainage point, as shown in drawings M-62, M-63 and M-64.

j. Processed wastes are collected in sample tanks prior to their reuse in the condensate transfer system or are discharged in a controlled manner through the monitored discharge pipe into the cooling tower blowdown pipe for dilution, before entering the Schuylkill River.

k. The expected and maximum radionuclide activity inventories of liquid waste management system components containing significant amounts of radioactive liquids are shown in Tables 11.2-8 and 11.2-9, and are based upon the assumptions given in Table 11.2-1 and those listed below:

    1. Expected flow rates for streams (Figure 11.2-4) are given in Table 11.2-2.

    2. Reactor water radionuclide activity concentrations are as listed in Tables 11.1-1 through 11.1-5 for design conditions, and Table 11.2-3 for expected conditions.

    3. Decontamination factors within the liquid waste management system are as given in Table 11.2-4.

    4. While a process stream is collecting in a collection tank, the isotopes already in the tank are undergoing radioactive decay (see Table 11.2-5 for expected holdup times).

    5. One refueling shutdown per year per unit, not occurring simultaneously is assumed.

The expected daily inputs and activities for each of the subsystems is shown in Tables 11.2-6 and 11.2-7. An evaluation of the causes for the maximum expected inputs for each subsystem shows that operational modes exclude, and the unlikely occurrence of the same failure in both units minimizes, the potential for coincidental maximum input from both units into the same subsystem.

Control and monitoring of radioactive release in accordance with GDC 60 and GDC 64 is discussed in Sections 11.2.3 and 11.5.

11.2.2 SYSTEM DESCRIPTION

The liquid waste management system collects, monitors, processes, stores, and disposes of radioactive liquid wastes. The liquid waste management system piping, equipment, instrumentation, and flow paths are shown in drawings M-62, M-63 and M-64. Included

in the system are:

a. Piping and equipment carrying potentially radioactive wastes

b. Floor drain systems in controlled access areas which may contain potentially radioactive wastes

c. Tanks and sumps used to collect potentially radioactive wastes

The liquid wastes are collected in sumps located in all the enclosures housing radioactive equipment and are pumped to collection tanks located in the radwaste enclosure. Plant drainage systems, including measures taken to limit, control, and remove oil and other organic compounds, are discussed in Section 9.3.3.

The incoming wastes are classified, collected, and treated as floor drain, equipment drain, chemical, and laundry drain wastes.

Connections for tie-ins are provided, so that temporary equipment can draw suction from either the equipment drain surge tank (00T304) or floor drain surge tank (00T309) in order to process liquid radwaste when high demand is placed on the existing liquid radwaste processing equipment. After processing through the temporary equipment, the effluent stream will be recirculated back to either the equipment drain/floor drain surge tanks or routed to the equipment drain/floor drain sample tanks.

Equipment is selected, arranged, and shielded to minimize exposures to plant personnel during operation, inspection and maintenance. For example, sumps, pumps, valves, and instruments which may contain radioactivity are located in controlled access areas. Tanks and processing equipment that may contain significant quantities of radioactive material are shielded. Operation of the liquid waste management system is normally on a batch basis, as dictated by the waste generation rate from the plant. Protection against accidental discharge is provided by instrumentation for detection and alarm of abnormal conditions and by procedural controls.

The liquid waste management system is divided into several subsystems (Section 11.2.2.1), so that the liquid wastes from various sources can be kept segregated and processed separately. Cross-connections between the subsystems provide additional flexibility for processing of the wastes by alternate methods.

11.2.2.1 System Operation

The liquid waste management system consists of four process subsystems:

a. Equipment drain subsystem

b. Floor drain subsystem

c. Chemical waste subsystem

d. Laundry drain subsystem

11.2.2.1.1 Equipment Drain Subsystem

Low conductivity wastes from piping and equipment drains are collected in the equipment drain collection tank and/or the equipment drain surge tank. Other inputs received in the collection tank are listed in Table 11.2-7. Wastes collected in the equipment drain collection or surge tanks are processed on a batch basis through a precoat filter and mixed bed demineralizer and are then collected in one of two sample tanks.

From an equipment drain sample tank, wastes are normally returned to a CST for plant reuse. A recycle routing allows water which exceeds preset quality limits to be: recycled to the equipment drain collection tank for additional processing through the filter and demineralizer or recycled to the floor drain collection tank for additional processing. If the water inventory of the plant does not permit wastes to be returned to the CST, or if the wastes are unacceptable for plant reuse, then the wastes are routed to the floor drain subsystem and discharged from the plant after mixing with cooling tower blowdown.

11.2.2.1.2 Floor Drain Subsystem

Wastes originating mainly from the drywell, reactor, turbine, radwaste, and offgas enclosure floor drains are collected in the floor drain collection tank. In addition, high conductivity piping and equipment drains are also collected and treated with these wastes.

The wastes collected in the floor drain collection tank are processed through a precoat filter and, on an as needed basis, through the mixed bed demineralizer, bypassing floor drain sample tank No. 1, and discharged to floor drain sample tank No. 2 for final sampling and analysis. Provision is available to discharge directly to sample tank No. 1 for use when warranted. The basis for selecting the treatment path consists of water quality, equipment availability, and economic considerations. If the quality of the filtered waste in the sample tank No. 2 is unsuitable for plant reuse, then the flexibility exists to reprocess the batch through the floor drain system and floor drain demineralizer or to recycle it to the equipment drain collection tank.

Treated floor drain wastes are routinely discharged from the plant after mixing with cooling tower blowdown. If the treated wastes meet the specifications of water quality used in the plant (including reactor water chemistry parameters), and if the water inventory of the plant permits their recycle, then they may be returned to the CST for reuse.

11.2.2.1.3 Chemical Waste Subsystem

Chemical wastes collected in the chemical waste tank consist of laboratory wastes, decontamination solutions and other corrosive wastes. After being accumulated in the chemical waste tank, these wastes are chemically neutralized, if required, and transferred to the floor drain collection tank or floor drain surge tank for batch processing through the floor drain subsystem. The chemical waste subsystem is designed to permit addition of an evaporation system as an alternate means of waste processing. However, installation of this equipment was not completed for initial plant operation and the equipment has been abandoned.

11.2.2.1.4 Laundry Drain Subsystem

Laundry wastes consist of detergent-containing water from personnel decontamination facilities in the plant. These wastes are routed to two laundry drain tanks interconnected by an overflow line. In addition, rain water from within the yard dikes for Condensate Storage Tank (CST) tanks (Units 1 & 2) and Refueling Water Storage Tank may be routed to the two laundry drain tanks. From the tank, the wastes are processed through the laundry drain filter and collected in the sample tank for sampling and analysis.

Effluent from the sample tank is normally discharged through the monitored discharge pipe into the cooling tower blowdown pipe. High conductivity filtrate can be recycled to the laundry drain tanks or to the floor drain system.

The laundry drain system is no longer in service to process and discharge liquid waste. However, a valve remains open to a laundry drain tank for inputs from personnel decontamination facilities.

11.2.2.2 Process Equipment Description

Major components of the liquid waste management system are described below. A summary of the design parameters for major components is provided in Table 11.2-10.

11.2.2.2.1 Pumps

a. Sump Pumps

Liquid waste management system sump pumps are vertical, centrifugal-type pumps of standard design, cast iron construction. The top column closures on the pump support plates utilize vapor-tight gland-type seals. Each sump is provided with two pumps except the offgas enclosure floor drain sump which utilizes one pump.

Sump pumps start automatically when a predetermined high level in the sump is reached; the sump pump stops at a predetermined low water level.

b. Process Pumps

Liquid waste management system process pumps are vertical, in-line centrifugal pumps of ASME Section III, Class 3 design, stainless steel or carbon steel construction, and are provided with a mechanical-type seal.

11.2.2.2.2 Tanks

Tanks are sized to accommodate the anticipated volumes generated from the four liquid waste management subsystems. The tanks are constructed of carbon steel, stainless steel, or aluminum.

The tanks are provided with a mixing eductor and vented to the radwaste enclosure ventilation system. Refer to Section 9.4.3 for a discussion of the radwaste enclosure ventilation system.

11.2.2.2.3 Filters

a. Equipment and Floor Drain Filters

Equipment and floor drain filters are a precoat, removable, single element bundle-type design, using a powdered ion exchange resin or other filter media. Both filters are equipped with a common precoating tank and pump, and individual filter holding pumps.

Filter media lifetime is based on a pressure drop across the filter and not specific radioactive content. Both filters are backwashed to the waste sludge tank. The filter vessels are constructed of carbon steel and are designed to meet the

requirements of ASME Section III, Class 3. A corrosion-resistant lining is provided to minimize corrosion of the carbon steel vessels.

Each filter is located in a separate shielded room to minimize exposures to personnel during routine maintenance. Use of condensate water for backwashing and design of the filter internals ensure a minimum accumulation of radioactive material in the filters.

b. Laundry Drain Filter

The laundry drain filter is of a removable cartridge- type design. The filter vessel is constructed of stainless steel and designed to meet the requirements of ASME Section III, Class 3. Filter construction also permits "quick change" replacement of disposable cartridges to minimize personnel exposure to radiation.

11.2.2.2.4 Demineralizers

The equipment and floor drain demineralizers are deep-bed, mixed cation and anion-type, with flow rate capacities consistent with their associated filters.

A resin bed is replaced when effluent quality exceeds preset limits, as well as on high differential pressure.

The demineralizer vessels are constructed of carbon steel and are designed to meet the requirements of ASME Section III, Class 3. The vessels are equipped with a rubber lining. Fine mesh strainers are provided in the vessel discharge and in the piping downstream to prevent resin fines from being transferred to other portions of the system.

Both demineralizers were designed to be backwashed to their respective spent resin tanks. However, for normal plant operation, the demineralizers will be backwashed directly to the waste sludge tank via a bypass line (Section 11.4.2.1.1). New mixed dry resins are added to the demineralizer through a resin addition funnel and flow by gravity into the demineralizer to provide an even distribution. If desired, the capability exists for mixing the resin bed inside the vessel with air. Resins can also be supplied from the Deep Bed Condensate Demineralizer (DBCD) system. These resins are hydropneumatically transferred into the radwaste demineralizers (Section 10.4.6.2).

Each vessel is located in a separate shielded room to minimize exposures to personnel during routine maintenance of other equipment.

11.2.2.2.5 Radwaste Evaporators

Radwaste evaporators were not made operational for initial plant operation and have been abandoned (Section 11.2.2.1.3).

11.2.2.2.6 Piping

Liquid waste management system piping is routed to minimize crud traps. Radioactive piping is located in shielded areas to minimize personnel exposures. The floor drain, equipment drain, and laundry drain subsystem piping is constructed of carbon steel. The chemical waste subsystem piping is constructed of stainless steel. Liquid waste management system piping is designed to meet the requirements of ANSI B31.1.

11.2.3 RADIOACTIVE RELEASES

During processing of liquid wastes, radioactivity is removed so that the bulk of the liquid is restored to clean water, which is either recycled in the plant or discharged to the environment. The radioactivity removed from the liquids is concentrated in filters and ion exchange resins. These concentrated wastes are sent to the solid waste management system for treatment and eventual shipment to a licensed burial ground. If the liquid is to be discharged, the activity concentration is consistent with the discharge criteria of 10CFR20. Normally, most of the liquid passing through the liquid waste management system is recycled in the plant. However, the treatment in this system is such that these liquids can be discharged from the plant after monitoring, if required by plant water balance considerations or if the treated wastes do not meet the specifications of water quality used in the plant (including reactor water chemistry parameters). Activity concentration of tritiated water discharged from the system is consistent with the discharge criteria of 10CFR20. Normally, the liquid passing through the laundry drain subsystem is discharged directly, in accordance with 10CFR20 and 10CFR50 guidelines; however, it may be processed through the floor drain subsystem if necessary.

The expected annual activity releases for each waste stream are given in Table 11.2-11.

Design and administrative controls are incorporated into the liquid waste management system to prevent inadvertent releases to the environment. Controls include administrative procedures, operator training, redundant discharge valves, and discharge radiation monitors that trip alarms and initiate automatic discharge valve closure (Section 11.5). Prior to any discharging, activity concentrations are measured in samples taken from the various sample tanks. A single line is provided for plant discharges to minimize the potential for operator error. This line includes a loop seal with a siphon breaker to prevent inadvertent siphoning of the sample tanks.

The processed liquid waste that is not recycled in the plant is discharged into the cooling tower blowdown pipe on a batch basis. Flow rate measurement devices are provided in both the radwaste effluent line and the cooling tower blowdown line as shown on drawings M-63 and M-09, respectively. Processed liquid wastes are discharged at up to 280 gpm from the equipment and floor drain subsystems, and 10 gpm from the laundry drain subsystem. The discharges are mixed with the cooling tower blowdown flow to maintain the concentration of radionuclides at the release point below the limits of 10CFR20 (UFSAR Table 11.2-12). This mixing occurs within the site boundary and is used in determining specific activity concentrations for the releases. Expected average annual radionuclide concentrations are compared to 10CFR20 limits in Table 11.2-12.

The doses resulting from liquid effluents are a small fraction of the 10CFR20 dose limit of 500 mR/yr and well within 10CFR50, Appendix I design objectives as shown in Table 11.2-13.

Table 11.2-1

ASSUMPTIONS AND PARAMETERS USED FOR EVALUATION OF RADIOACTIVITY RELEASES

ITEM	VALUE OR REFERENCE
a. Nuclear Steam Supply System	
1. Maximum core thermal power	3527 MWt
2. Mass of reactor coolant in vessel at full power	5.5×10^5 lb
3. Total steam flow for 102% rated power	1.53×10^7 lb/hr
b. Reactor Water Cleanup System	
1. Average process flow rate for 2 vessels	1.33×10^5 lb/hr
2. Number of demineralizers	2
3. Powdex resin quantity per demineralizer (dry)	32 lb
4. Backwash frequency	3.3 days (6.6 day run for each demineralizer)
5. Backwash volume	1100 gal/backwash
c. Condensate Filter/Demineralizers	
1. Average total flow rate for 8 vessels 102% of rated power condition)	1.53×10^7 lb/hr
2. Number of filter/demineralizers	8
3. Backwash frequency	1.43 days (10 day run for each filter/demin)
4. Backwash volume	9000 gal/backwash
d. Liquid Waste Management System	
1. Sources, flow rates, and expected activities in process streams	Table 11.2-2

Table 11.2-1 (Cont'd)

ITEM	VALUE OR REFERENCE
2. Holdup times for collection, processing, and discharge	Table 11.2-5
3. Capacities of tanks and processing equipment	Table 11.2-10
4. Decontamination factors	Table 11.2-4
5. Liquid source terms for normal operation	Table 11.2-6
6. Quantity of tritium - released in liquid effluents (2 units)	11 Ci/yr
7. Average fraction of process streams discharged to environment after processing[1]	
(a) Floor drain subsystem	0.10
(b) Equipment drain subsystem	0.01
(c) Chemical drain subsystem	0.10
(d) Laundry drain subsystem	1.00
8. Liquid waste management system demineralizer resin replacement frequency	
(a) Floor drain	25.8 days
(b) Equipment drain	125.8 days
9. Liquid waste management system demineralizer backwash volume	
(a) Floor drain	1500 gal
(b) Equipment drain	1500 gal

(1) These values are taken from NUREG-0016 (April 1976), section 1.5.2.9.5.

Table 11.2-2

LIQUID WASTE MANAGEMENT SYSTEM FLOWS

STREAM NO.[1]	AVERAGE BATCH INTERVAL FOR NORMAL OPERATION OF BOTH UNITS (days)	VOLUME PER BATCH (gal)	NOMINAL FLOW RATE (gpm)	AVERAGE VOLUME PER DAY FOR NORMAL OPERATION OF BOTH UNITS (gal)	NORMAL ACTIVITY CONCENTRATION (μCi/cc)	MAXIMUM ACTIVITY CONCENTRATION (μCi/cc)
Floor Drain Subsystem						
1	-	-	-	10400	6.2×10^{-2}	1.1
2	1.6	16800	280	10400	1.1×10^{-2}	2.9×10^{-1}
3	1.6	16800	280	10400	1.1×10^{-3}	3.0×10^{-2}
4	1.6	16800	280	10400	2.1×10^{-5}	8.2×10^{-4}
5	1.6	16800	280	10400	1.4×10^{-5}	3.6×10^{-4}
Equipment Drain Subsystem						
6	-	-	-	38780	7.8×10^{-2}	1.4
7	0.53	20000	280	38780	2.6×10^{-2}	5.8×10^{-1}
8	0.53	20000	280	38780	2.6×10^{-3}	6.1×10^{-2}
9	0.53	20000	280	38780	3.2×10^{-5}	9.6×10^{-4}
10	0.53	20000	280	38780	2.1×10^{-5}	5.1×10^{-4}
Chemical Drain Subsystem[2]						
11	-	-	-	1200	8.7×10^{-3}	1.6×10^{-1}
12	5	6000	200	1200	7.3×10^{-4}	2.3×10^{-2}
13	5	6000	280	1200	7.1×10^{-4}	2.2×10^{-2}
14	5	6000	280	1200	7.2×10^{-5}	2.2×10^{-3}
15	5	6000	280	1200	1.4×10^{-6}	4.2×10^{-5}
16	5	6000	280	1200	1.2×10^{-6}	3.0×10^{-5}
Laundry Drain Subsystem						
17	-	-	-	900	1.0×10^{-4}	-
18	1	900	25	900	1.0×10^{-4}	-
19	1	900	25	900	1.0×10^{-4}	-
20	2	1800	10	900	1.0×10^{-4}	-

(1) Refer to Figure 11.2-4 for locations of stream nodal numbers.

(2) Batch frequencies, volumes, and activity concentrations are based on chemical waste processing via the floor drain subsystem (Section 11.2.2.1.3).

Table 11.2-3

EXPECTED RADIONUCLIDE ACTIVITY CONCENTRATIONS IN REACTOR COOLANT AND MAIN STEAM USED FOR EVALUATION OF RADIOACTIVITY RELEASES(1)

ISOTOPE	REACTOR WATER (μCi/g)	REACTOR STEAM (μCi/g)
Noble gases		
Kr-83m	-	1.12E-03
Kr-85m	-	1.94E-03
Kr-85	-	6.12E-06
Kr-87	-	6.73E-03
Kr-88	-	6.73E-03
Kr-89	-	4.18E-02
Kr-90	-	9.18E-02
Kr-91	-	1.12E-01
Kr-92	-	1.12E-01
Kr-93	-	2.96E-02
Kr-94	-	7.34E-03
Kr-95	-	6.73E-04
Kr-97	-	4.49E-06
Xe-131m	-	4.79E-06
Xe-133m	-	9.18E-05
Xe-133	-	2.65E-03
Xe-135m	-	8.57E-03
Xe-135	-	7.34E-03
Xe-137	-	4.79E-02
Xe-138	-	2.86E-02
Xe-139	-	9.18E-02
Xe-140	-	9.79E-02
Xe-141	-	7.96E-02
Xe-142	-	2.35E-02
Xe-143	-	3.88E-03
Xe-144	-	1.84E-04
Halogens		
Br-83	2.43E-03	4.86E-05
Br-84	3.70E-03	7.41E-05
Br-85	2.15E-03	4.30E-05
I-131	5.03E-03	1.01E-04

Table 11.2-3 (Cont'd)

ISOTOPE	REACTOR WATER (μCi/g)	REACTOR STEAM (μ/Ci/g)
I-132	2.42E-02	4.83E-04
I-133	1.91E-02	3.81E-04
I-134	5.29E-02	1.06E-03
I-135	1.76E-02	3.53E-04
Fission products		
Rb-89	3.63E-03	3.63E-06
Sr-89	1.01E-04	1.01E-07
Sr-90	6.08E-06	6.08E-09
Sr-91	3.77E-03	3.77E-06
Sr-92	9.61E-03	9.61E-06
Y-91	4.05E-05	4.05E-08
Y-92	5.27E-03	5.27E-06
Y-93	3.78E-03	3.78E-06
Zr-95	7.08E-06	7.08E-09
Zr-97	4.85E-06	4.85E-09
Nb-95	7.08E-06	7.08E-09
Nb-98	3.12E-03	3.12E-06
Mo-99	2.00E-03	2.00E-06
Tc-99m	1.84E-02	1.84E-05
Tc-101	6.62E-02	6.62E-05
Tc-104	5.93E-02	5.93E-05
Ru-103	2.02E-05	2.02E-08
Ru-105	1.79E-03	1.79E-06
Ru-106	3.04E-06	3.04E-09
Ag-110m	1.01E-06	1.01E-09
Te-129m	4.05E-05	4.05E-08
Te-131m	9.86E-05	9.86E-08
Te-132	1.00E-05	1.00E-08
Cs-134	3.04E-05	3.04E-08
Cs-136	2.02E-05	2.02E-08
Cs-137	7.09E-05	7.09E-08
Cs-138	7.42E-03	7.42E-06
Ba-139	8.10E-03	8.10E-06
Ba-140	4.04E-04	4.04E-07
Ba-141	7.42E-03	7.42E-06
Ba-142	4.39E-03	4.39E-06
La-142	4.09E-03	4.09E-06
Ce-141	3.03E-05	3.03E-08
Ce-143	2.97E-05	2.97E-08

Table 11.2-3 (Cont'd)

ISOTOPE	REACTOR WATER (μCi/g)	REACTOR STEAM (μCi/g)
Ce-144	3.04E-06	3.04E-09
Pr-143	4.04E-05	4.04E-08
Nd-147	3.03E-06	3.03E-09
W-187	2.94E-04	2.94E-07
Np-239	6.99E-03	6.99E-06
Coolant activation products		
N-13	5E-02	7E-03
N-16*	6E+01	5E+01
N-17	9E-03	2E-02
O-19	7E-01	2E-01
F-18	4E-03	4E-03
Noncoolant activation products		
Na-24	8.68E-03	8.68E-06
P-32	2.02E-04	2.02E-07
Cr-51	5.06E-03	5.06E-06
Mn-54	6.07E-05	6.07E-08
Mn-56	4.27E-02	4.27E-05
Fe-55	1.01E-03	1.01E-06
Fe-59	3.04E-05	3.04E-08
Co-58	2.02E-04	2.02E-07
Co-60	4.05E-04	4.05E-07
Ni-63	1.01E-06	1.01E-09
Ni-65	2.56E-04	2.56E-07
Cu-64	2.88E-02	2.88E-05
Zn-65	2.02E-04	2.02E-07
Zn-69	1.92E-03	1.92E-06
Tritium		
H-3	1E-02	1E-02

(1) The values in this table are calculated based on the GALE code in NUREG-0016 (April 1976).

* The N-16 values listed in the table are without Hydrogen Water Chemistry (HWC). Values with HWC are 4.80E+01 (water) and 2.50E+02 (steam).

Table 11.2-4

DECONTAMINATION FACTORS USED FOR EVALUATION OF RADIOACTIVITY RELEASES[1]

EQUIPMENT	IODINE	CESIUM AND RUBIDIUM	OTHERS
Equipment drain filter/ demineralizer[2]	10	2	10
Equipment drain demineralizer	100	10	100
Floor drain filter/ demineralizer[2]	10	2	10
Floor drain demineralizer	100	2	100
RWCU filter/demineralizer	10	2	10
Condensate filter/demineralizer	10	2	10
Laundry drain cartridge filter	1	1	1

(1) The values are taken from NUREG-0016 (April 1976), table 1-3.

(2) Powdered resin is used to precoat the filter/demineralizer; decontamination factor value of Powdex is used.

Table 11.2-5

EXPECTED HOLDUP TIMES FOR COLLECTION, PROCESSING, AND DISCHARGE USED FOR EVALUATION OF RADIOACTIVITY RELEASES

PROCESS SUBDIVISION	HOLDUP TIME (days)
Floor Drain Subsystem	
Collection	1.616
Processing	0.042
Sampling	0.042
Total	1.700
Equipment Drain Subsystem	
Collection	0.519
Processing	0.050
Sampling	0.042
Total	0.611
Chemical Drain Subsystem(1)	
Collection	5.000
Processing	0.063
Sampling	0.042
Total	5.105
Laundry Drain Subsystem	
Collection	1.000
Processing	0.025
Sampling	0.042
Total	1.067

(1) Holdup times shown for the chemical drain subsystem are based on processing via the floor drain subsystem (Section 11.2.2.1.3)

Table 11.2-6

AVERAGE DAILY INPUTS AND ACTIVITIES TO THE LIQUID WASTE MANAGEMENT SYSTEM FROM TWO UNITS

SOURCE			AVERAGE DAILY INPUT FROM TWO UNITS IN NORMAL OPERATION[1](gal)	PRIMARY COOLANT ACTIVITY FRACTION (PCA)
Floor drains				
Drywell			1400	1.0000
Reactor enclosure			4000	0.0100
Turbine enclosure	- condensate pump area		1000	0.0100
	- backwash area		3000	0.0100
Radwaste enclosure			1000	0.0100
		TOTAL	10400	0.1430
Equipment drains				
Drywell			6800	1.0000
Reactor enclosure			7440	0.0100
Turbine enclosure	- condensate pump area		2000	0.0100
	- backwash area		3920	0.0100
Radwaste enclosure			1060	0.0100
		TOTAL	21220	0.3270
Decant water				
RWCU phase separator			620	0.0020
Condensate phase separator			11983	0.0002
External processing effluent			5537	0.0020
		TOTAL	18139	0.0008
Chemical wastes				
Lab drains			1000	0.0200
Chemical lab drains			200	0.0200
		TOTAL	1200	0.0200
Laundry drains			900	-

[1] These values are taken directly from NUREG-0016 (April 1976).

Table 11.2-7

BATCHED INPUTS TO THE LIQUID WASTE MANAGEMENT SYSTEM FROM THE SOLID WASTE MANAGEMENT SYSTEM FOR NORMAL OPERATION OF TWO UNITS

	FIRST INTERMEDIATE COLLECTOR INPUT			SECOND INTERMEDIATE COLLECTOR INPUT			LIQUID RADWASTE INPUT TO EQUIPMENT DRAIN COLLECTION TANK FROM EACH SECOND INTERMEDIATE COLLECTOR	
SOURCE	COLLECTOR	BATCH SIZE (gal)	BATCH FREQUENCY PER COLLECTOR (days)	COLLECTOR	BATCH SIZE (gal)	BATCH FREQUENCY PER COLLECTOR (days)	BATCH SIZE (gal)	BATCH FREQUENCY (days)
RWCU filter/demineralizers (total of 4)	RWCU backwash receiving tanks (total of 2)	1100	3.3	RWCU phase separators (total of 2)	1100	3.4	1000	1.7
Condensate filter/demineralizers (total of 16)	Condensate backwash receiving tanks (total of 2)	9000	1.43	Condensate phase separators (total of 4)	9000	1.43	8300	0.72
Deep bed condensate demineralizers (Total of 8)	Spend resin tanks (Total of 4)	3675 TDD (w/320 cu. ft. of resin)	None			3675	TDD	
Spent resin tanks (Total of 4)	Resin measuring tank	375 TBD (w/85 cu. ft. of resin)	None	-	-	375	TBD	

Table 11.2-8

EXPECTED RADIONUCLIDE ACTIVITY INVENTORIES OF LIQUID WASTE MANAGEMENT SYSTEM COMPONENTS[1]

ISOTOPE	FLOOR DRAIN COLLECTION TANK	FLOOR DRAIN SAMPLE TANK NO. 1	FLOOR DRAIN SAMPLE TANK NO. 2	FLOOR DRAIN SURGE TANK	EQUIPMENT DRAIN COLLECTION TANK	EQUIPMENT DRAIN SAMPLE TANK	EQUIPMENT DRAIN SURGE TANK	CHEMICAL WASTE TANK	LAUNDRY DRAIN COLLECTION TANK	LAUNDRY DRAIN SAMPLE TANK
Br-83	1.98E-03	1.49E-04	1.49E-06	1.98E-03	8.99E-03	6.36E-06	9.24E-03	3.19E-05	none	none
Br-84	6.64E-04	1.80E-05	1.80E-05	6.64E-04	3.10E-03	6.46E-07	3.10E-03	1.07E-05	none	none
Br-85	3.64E-05	none	none	3.64E-05	1.70E-04	none	1.70E-04	5.88E-07	none	none
I-131	4.27E-02	4.25E-03	4.25E-05	1.29E-01	6.71E-02	6.68E-05	1.93E-01	1.86E-03	3.21E-06	6.17E-06
I-132	1.86E-02	1.37E-03	1.37E-05	1.87E-02	8.46E-02	5.85E-05	8.66E-02	3.01E-04	none	none
I-133	9.62E-02	9.29E-03	9.29E-05	1.30E-01	2.12E-01	2.03E-04	4.41E-01	2.08E-03	none	none
I-134	1.55E-02	6.98E-04	6.98E-06	1.55E-02	7.24E-02	2.77E-05	7.25E-02	2.51E-04	none	none
I-135	3.92E-02	3.53E-03	3.53E-05	3.99E-02	1.35E-01	1.19E-04	1.83E-01	6.44E-04	none	none
Rb-89	3.15E-04	1.06E-05	5.30E-04	3.15E-04	1.47E-03	2.89E-06	1.47E-03	5.09E-06	none	none
Cs-134	2.76E-04	1.38E-04	7.65E-06	9.84E-04	4.14E-04	2.07E-05	1.24E-03	1.38E-05	7.26E-05	1.45E-04
Cs-136	1.76E-04	8.80E-05	4.41E-05	5.68E-04	2.71E-04	1.36E-05	7.96E-04	8.10E-06	none	none
Cs-137	6.45E-04	3.22E-04	1.61E-04	2.31E-03	9.67E-04	4.83E-05	2.91E-03	3.21E-04	1.34E-04	2.68E-04
Cs-138	1.35E-03	1.86E-04	9.28E-05	1.35E-03	6.28E-03	6.67E-05	6.28E-03	2.17E-05	none	none
Na-24	3.66E-02	3.50E-03	3.50E-05	4.39E-02	9.00E-02	8.51E-05	1.69E-01	7.06E-04	none	none
P-32	1.76E-03	1.76E-04	1.76E-06	5.72E-03	2.72E-03	2.71E-06	7.98E-03	8.14E-05	none	none
Cr-51	4.51E-02	4.51E-03	4.51E-05	1.53E-01	6.85E-02	6.84E-05	2.03E-01	2.16E-03	none	none
Mn-54	5.51E-04	5.51E-05	5.51E-07	1.96E-03	8.27E-04	8.27E-07	2.48E-03	2.74E-05	5.59E-06	1.11E-05
Mn-56	3.72E-02	2.85E-03	2.85E-05	3.72E-02	1.68E-01	1.21E-04	1.73E-01	6.01E-04	none	none
Fe-55	9.21E-03	9.21E-04	9.21E-06	3.08E-02	1.29E-02	1.29E-05	3.86E-02	4.30E-04	none	none
Fe-59	2.73E-04	2.73E-04	2.73E-06	9.45E-04	4.13E-04	4.12E-07	1.23E-03	1.33E-05	none	none
Co-58	1.83E-03	1.83E-04	1.83E-06	6.38E-03	2.74E-03	2.74E-06	8.21E-03	8.95E-05	2.22E-05	4.44E-05
Co-60	3.68E-03	3.68E-06	3.68E-06	1.32E-02	5.52E-03	5.52E-06	1.66E-02	1.84E-04	5.04E-05	1.01E-04
Ni-63	9.21E-06	9.21E-07	9.81E-09	3.28E-05	1.38E-05	1.38E-08	4.15E-05	4.60E-07	none	none
Ni-65	2.22E-04	1.69E-05	1.69E-07	2.22E-04	1.00E-03	7.42E-07	10.4E-03	3.58E-06	none	none
Cu-64	1.09E-01	1.03E-02	1.03E-04	1.09E-01	2.86E-01	2.65E-04	2.86E-01	2.05E-03	none	none
Zn-65	1.83E-03	1.83E-04	1.83E-04	6.48E-03	2.75E-03	2.75E-06	8.26E-03	9.11E-05	none	none
Zn-69	6.16E-04	5.73E-05	5.73E-07	6.16E-04	2.88E-03	1.20E-06	2.88E-03	9.95E-06	none	none
Sr-89	9.17E-04	9.17E-05	9.17E-07	3.18E-03	1.29E-03	1.39E-06	4.13E-03	4.48E-05	none	none
Sr-90	5.53E-05	5.53E-06	5.53E-08	1.97E-04	8.29E-05	8.29E-08	2.49E-04	2.76E-06	none	none
Sr-91	1.16E-02	1.08E-03	1.08E-05	1.23E-02	3.41E-02	3.12E-05	5.38E-02	1.99E-04	none	none
Sr-92	7.87E-03	6.10E-04	6.10E-06	7.87E-03	3.53E-02	2.59E-05	3.67E-02	1.28E-04	none	none
Y-91	5.15E-04	5.21E-05	5.21E-07	2.00E-03	6.59E-04	6.77E-07	2.32E-03	2.78E-05	none	none
Y-92	1.42E-02	1.29E-03	1.29E-05	1.42E-02	5.50E-02	4.98E-05	6.61E-02	2.28E-04	none	none
Y-93	1.22E-02	1.14E-03	1.14E-05	1.32E-02	3.50E-02	3.22E-05	5.66E-02	2.13E-04	none	none
Zr-95	6.39E-05	6.38E-06	6.38E-08	2.23E-04	9.63E-05	9.62E-08	2.88E-04	3.13E-06	7.77E-06	1.54E-05
Zr-97	2.21E-05	2.12E-06	2.12E-08	2.77E-05	5.18E-05	4.94E-08	1.02E-04	4.47E-07	none	none

Table 11.2-8 (Cont'd)

ISOTOPE	FLOOR DRAIN COLLECTION TANK	FLOOR DRAIN SAMPLE TANK NO. 1	FLOOR DRAIN SAMPLE TANK NO. 2	FLOOR DRAIN SURGE TANK	EQUIPMENT DRAIN COLLECTION TANK	EQUIPMENT DRAIN SAMPLE TANK	EQUIPMENT DRAIN SURGE TANK	CHEMICAL WASTE TANK	LAUNDRY DRAIN COLLECTION TANK	LAUNDRY DRAIN SAMPLE TANK
Nb-95	6.44E-05	6.44E-06	6.44E-08	2.30E-04	9.65E-05	9.65E-08	2.90E-04	3.21E-06	1.11E-05	2.22E-05
Nb-98	8.98E-04	3.97E-05	3.97E-05	8.98E-04	4.19E-03	1.57E-06	4.19E-03	1.45E-05	none	none
Mo-99	1.50E-02	1.48E-03	3.44E-02	3.44E-02	2.56E-02	2.53E-05	6.78E-02	5.19E-04	none	none
Tc-99m	4.75E-02	4.39E-03	4.39E-05	6.66E-02	1.44E-04	1.31E-04	2.20E-01	1.04E-03	none	none
Tc-101	5.22E-03	2.68E-05	2.68E-07	5.22E-03	2.44E-02	6.92E-07	2.44E-02	8.44E-05	none	none
Tc-104	6.02E-03	5.97E-05	5.97E-05	6.02E-03	2.81E-02	1.75E-06	2.81E-02	9.71E-05	none	none
Ru-103	1.82E-04	1.81E-05	1.81E-07	6.23E-04	2.74E-04	2.74E-07	8.17E-04	8.78E-06	7.75E-07	1.54E-06
Ru-105	2.67E-03	2.28E-04	2.28E-06	2.68E-06	1.07E-02	8.89E-06	1.24E-02	4.32E-05	none	none
Ru-106	2.76E-05	2.76E-06	2.76E-08	9.81E-05	4.14E-05	4.14E-08	1.24E-04	1.38E-06	1.34E-05	2.67E-05
Ag-110m	9.18E-06	9.18E-07	9.18E-09	3.62E-05	1.24E-03	1.38E-05	4.14E-05	4.56E-07	2.46E-06	4.91E-06
Te-129m	3.62E-04	3.62E-05	3.62E-07	1.24E-03	5.50E-04	5.49E-07	1.63E-03	1.74E-05	none	none
Te-131m	5.93E-04	5.79E-05	5.79E-07	9.60E-04	1.17E-03	1.13E-06	2.70E-03	1.51E-05	none	none
Te-132	7.70E-05	7.63E-06	7.63E-08	1.87E-04	1.30E-04	1.28E-07	3.49E-04	2.79E-06	none	none
Ba-139	3.78E-03	2.30E-04	2.30E-06	3.78E-03	1.76E-02	9.67E-06	1.76E-02	6.11E-05	none	none
Ba-140	3.52E-03	3.51E-04	3.51E-06	1.12E-02	5.43E-03	5.42E-06	1.59E-02	1.61E-04	none	none
Ba-141	7.53E-04	7.47E-06	7.47E-08	7.53E-04	3.52E-03	2.19E-07	3.52E-03	1.21E-05	none	none
Ba-142	2.72E-04	6.21E-07	6.21E-09	2.72E-04	1.28E-03	1.36E-08	1.28E-03	4.39E-06	none	none
La-142	2.41E-03	1.56E-04	1.56E-06	2.41E-03	1.12E-02	6.62E-06	1.12E-02	3.89E-05	none	none
Ce-141	2.93E-04	2.93E-05	2.93E-07	1.01E-03	4.32E-04	4.36E-07	1.32E-03	1.42E-05	none	none
Ce-143	1.85E-04	1.81E-05	1.81E-07	3.13E-04	3.56E-04	3.47E-07	8.43E-04	4.92E-06	none	none
Ce-144	2.75E-05	2.75E-06	2.75E-08	9.80E-05	4.14E-05	4.14E-08	1.24E-04	1.37E-06	2.79E-05	5.58E-05
Pr-143	3.61E-04	3.61E-05	3.61E-07	1.19E-03	5.49E-04	5.48E-07	1.63E-03	1.69E-05	none	none
Nd-147	2.62E-05	2.61E-06	2.61E-08	8.25E-05	4.06E-05	4.05E-08	1.18E-04	1.18E-06	none	none
W-187	1.60E-03	1.56E-04	1.56E-04	2.34E-03	3.37E-03	3.24E-06	7.43E-03	3.71E-05	none	none
Np-239	5.05E-02	4.99E-03	4.99E-05	1.09E-01	8.83E-02	8.70E-05	2.30E-01	1.65E-03	none	none
OTHERS	2.75E-02	2.04E-04	2.04E-06	2.02E-02	2.75E-02	2.71E-05	5.06E-02	3.01E-04	4.65E-05	8.43E-05
TOTAL	6.83E-01	6.02E-02	1.06E-03	1.08E+00	1.80E+00	1.66E-03	2.84E-00	1.67E-02	3.98E-04	7.86E-04

(1) Activity inventories are given in Curies.
(2) Activity of daughter products resulting from radioactive decay of the influent isotopes during the accumulation period.

Table 11.2-9

MAXIMUM RADIONUCLIDE ACTIVITY INVENTORIES
OF LIQUID WASTE MANAGEMENT SYSTEM COMPONENTS(1)

ISOTOPE	FLOOR FLOOR DRAIN COLLECTION TANK	FLOOR DRAIN SAMPLE TANK NO. 1	DRAIN SAMPLE TANK NO. 2	FLOOR DRAIN SURGE TANK	EQUIPMENT DRAIN COLLECTION TANK	EQUIPMENT DRAIN SAMPLE TANK	EQUIPMENT DRAIN SURGE TANK	CHEMICAL WASTE TANK
Br-83	4.28×10^{-2}	3.21×10^{-3}	3.21×10^{-5}	4.28×10^{-2}	1.94×10^{-1}	1.38×10^{-4}	2.00×10^{-1}	6.91×10^{-4}
Br-84	1.69×10^{-2}	4.58×10^{-4}	4.58×10^{-6}	1.69×10^{-2}	7.91×10^{-2}	1.65×10^{-5}	7.91×10^{-2}	2.73×10^{-4}
Br-85	1.01×10^{-3}	-	-	1.01×10^{-3}	4.70×10^{-3}	-	4.70×10^{-3}	1.62×10^{-5}
I-131	3.86×10^{-1}	3.85×10^{-2}	3.85×10^{-4}	1.16	6.03×10^{-1}	6.04×10^{-4}	1.73	1.68×10^{-2}
I-132	1.55	1.49×10^{-1}	1.49×10^{-3}	3.49	3.12	2.85×10^{-3}	7.00	5.24×10^{-2}
I-133	1.57	1.52×10^{-1}	1.52×10^{-3}	2.12	3.45	3.33×10^{-3}	7.19	3.40×10^{-2}
I-134	2.46×10^{-1}	1.11×10^{-2}	1.11×10^{-4}	2.46×10^{-1}	1.15	4.40×10^{-4}	1.15	3.97×10^{-3}
I-135	1.01	9.10×10^{-2}	9.10×10^{-4}	1.03	3.47	3.07×10^{-3}	4.70	1.66×10^{-2}
Rb-89	-	-	-	-	-	-	-	-
Cs-134	5.09×10^{-3}	2.54×10^{-3}	1.27×10^{-3}	1.81×10^{-2}	7.59×10^{-3}	3.80×10^{-4}	2.27×10^{-2}	2.54×10^{-4}
Cs-136	3.36×10^{-3}	1.68×10^{-3}	8.40×10^{-4}	1.08×10^{-2}	5.15×10^{-3}	2.58×10^{-4}	1.51×10^{-2}	1.54×10^{-4}
Cs-137	7.64×10^{-3}	3.82×10^{-3}	1.91×10^{-3}	2.73×10^{-2}	1.14×10^{-2}	5.70×10^{-4}	3.41×10^{-2}	3.81×10^{-4}
Cs-138	1.21×10^{-1}	1.66×10^{-2}	8.30×10^{-3}	1.21×10^{-1}	5.64×10^{-1}	6.00×10^{-3}	5.64×10^{-1}	1.95×10^{-3}
Na-24	8.44×10^{-3}	8.06×10^{-4}	8.06×10^{-6}	1.01×10^{-2}	2.06×10^{-2}	1.96×10^{-5}	3.88×10^{-2}	1.63×10^{-4}
P-32	1.75×10^{-4}	1.75×10^{-5}	1.75×10^{-7}	5.66×10^{-4}	2.68×10^{-4}	2.68×10^{-7}	7.83×10^{-4}	8.06×10^{-6}
Cr-51	4.46×10^{-3}	4.45×10^{-4}	4.45×10^{-6}	1.51×10^{-2}	6.73×10^{-3}	6.73×10^{-6}	1.99×10^{-2}	2.13×10^{-4}
Mn-54	3.63×10^{-4}	3.63×10^{-5}	3.63×10^{-7}	1.29×10^{-3}	5.42×10^{-4}	5.42×10^{-7}	1.62×10^{-3}	1.81×10^{-5}
Mn-56	4.36×10^{-2}	3.33×10^{-3}	3.33×10^{-5}	4.36×10^{-2}	1.96×10^{-1}	1.42×10^{-4}	2.03×10^{-1}	7.03×10^{-4}
Fe-55	-	-	-	-	-	-	-	-
Fe-59	7.19×10^{-4}	7.18×10^{-5}	7.18×10^{-7}	2.49×10^{-3}	1.08×10^{-3}	1.08×10^{-6}	3.21×10^{-3}	3.50×10^{-5}
Co-58	4.51×10^{-2}	4.51×10^{-3}	4.51×10^{-5}	1.58×10^{-1}	6.76×10^{-2}	6.76×10^{-5}	2.02×10^{-1}	2.22×10^{-3}
Co-60	4.55×10^{-3}	4.55×10^{-4}	4.55×10^{-6}	1.62×10^{-2}	6.77×10^{-3}	6.77×10^{-6}	2.03×10^{-2}	2.27×10^{-4}
Ni-63	-	-	-	-	-	-	-	-
Ni-65	2.60×10^{-4}	1.99×10^{-5}	1.99×10^{-7}	2.60×10^{-4}	1.17×10^{-3}	8.48×10^{-7}	1.22×10^{-3}	4.20×10^{-6}
Cu-64	-	-	-	-	-	-	-	-
Zn-65	1.81×10^{-5}	1.81×10^{-6}	1.81×10^{-8}	6.44×10^{-5}	2.71×10^{-5}	2.71×10^{-8}	8.11×10^{-5}	9.02×10^{-7}
Zn-69	1.20×10^{-4}	1.14×10^{-5}	1.14×10^{-7}	1.40×10^{-4}	3.03×10^{-4}	2.86×10^{-7}	5.53×10^{-4}	2.25×10^{-6}
Sr-89	9.81×10^{-2}	9.80×10^{-3}	9.80×10^{-5}	3.41×10^{-1}	1.47×10^{-1}	1.47×10^{-4}	4.39×10^{-1}	4.79×10^{-3}
Sr-90	7.32×10^{-3}	7.32×10^{-4}	7.32×10^{-6}	2.61×10^{-3}	1.09×10^{-2}	1.09×10^{-5}	3.27×10^{-2}	3.65×10^{-4}
Sr-91	7.43×10^{-1}	6.91×10^{-2}	6.91×10^{-4}	7.92×10^{-1}	2.17	2.00×10^{-3}	3.44	1.28×10^{-2}
Sr-92	3.53×10^{-1}	2.73×10^{-2}	2.73×10^{-4}	3.53×10^{-1}	1.58	1.16×10^{-3}	1.65	5.70×10^{-3}
Y-91	-	-	-	-	-	-	-	-
Y-92	-	-	-	-	-	-	-	-
Y-93	-	-	-	-	-	-	-	-
Zr-95	1.26×10^{-3}	1.26×10^{-4}	1.26×10^{-6}	4.41×10^{-3}	1.89×10^{-3}	1.89×10^{-6}	5.64×10^{-3}	6.19×10^{-5}

Table 11.2-9

ISOTOPE	FLOOR FLOOR DRAIN COLLECTION TANK	FLOOR DRAIN SAMPLE TANK NO. 1	DRAIN SAMPLE TANK NO. 2	FLOOR DRAIN SURGE TANK	EQUIPMENT DRAIN COLLECTION TANK	EQUIPMENT DRAIN SAMPLE TANK	EQUIPMENT DRAIN SURGE TANK	CHEMICAL WASTE TANK
Zr-97	5.12×10^{-4}	4.91×10^{-5}	4.91×10^{-7}	6.42×10^{-4}	1.19×10^{-3}	1.14×10^{-6}	2.35×10^{-3}	1.03×10^{-5}
Nb-95	1.34×10^{-3}	1.34×10^{-4}	1.34×10^{-6}	4.75×10^{-3}	1.99×10^{-3}	1.99×10^{-6}	5.97×10^{-3}	6.65×10^{-5}
Nb-98	-	-	-	-	-	-	-	-
Mo-99	5.76×10^{-1}	5.70×10^{-2}	5.70×10^{-4}	1.33	9.79×10^{-1}	9.72×10^{-4}	2.60	2.00×10^{-2}
Tc-99m	2.38	2.18×10^{-1}	2.18×10^{-3}	3.12	7.50	6.67×10^{-3}	$1.10 \times 10^{+1}$	4.90×10^{-2}
Tc-101	3.87×10^{-2}	1.98×10^{-4}	1.98×10^{-6}	3.87×10^{-2}	1.81×10^{-1}	5.12×10^{-6}	1.81×10^{-1}	6.24×10^{-4}
Tc-104	-	-	-	-	-	-	-	-
Ru-103	5.96×10^{-4}	5.96×10^{-5}	5.96×10^{-7}	2.05×10^{-3}	8.97×10^{-4}	8.97×10^{-7}	2.67×10^{-3}	2.89×10^{-5}
Ru-105	-	-	-	-	-	-	-	-
Ru-106	8.26×10^{-5}	8.26×10^{-6}	8.26×10^{-8}	2.94×10^{-4}	1.23×10^{-4}	1.23×10^{-7}	3.69×10^{-4}	4.11×10^{-6}
Ag-110m	5.44×10^{-4}	5.44×10^{-5}	5.44×10^{-7}	1.93×10^{-3}	8.12×10^{-4}	8.12×10^{-7}	2.43×10^{-3}	2.71×10^{-5}
Te-129m	1.25×10^{-3}	1.25×10^{-4}	1.25×10^{-6}	4.29×10^{-3}	1.89×10^{-3}	1.89×10^{-6}	5.60×10^{-3}	6.04×10^{-5}
Te-131m	-	-	-	-	-	-	-	-
Te-132	1.32	1.31×10^{-1}	1.31×10^{-3}	3.21	2.21	2.20×10^{-3}	5.95	4.79×10^{-2}
Ba-139	2.62×10^{-1}	1.59×10^{-2}	1.59×10^{-4}	2.62×10^{-1}	1.22	6.68×10^{-4}	1.22	4.22×10^{-3}
Ba-140	2.74×10^{-1}	2.74×10^{-2}	2.74×10^{-4}	8.78×10^{-1}	4.21×10^{-1}	4.21×10^{-4}	1.23	1.25×10^{-2}
Ba-141	6.04×10^{-2}	5.99×10^{-4}	5.99×10^{-6}	6.04×10^{-2}	2.82×10^{-1}	1.76×10^{-5}	2.82×10^{-1}	9.75×10^{-4}
Ba-142	3.69×10^{-2}	8.42×10^{-5}	8.42×10^{-7}	3.69×10^{-2}	1.72×10^{-1}	1.85×10^{-6}	1.72×10^{-1}	5.96×10^{-4}
La-142	-	-	-	-	-	-	-	-
Ce-141	2.96×10^{-3}	3.01×10^{-4}	3.01×10^{-6}	1.09×10^{-2}	3.60×10^{-3}	3.87×10^{-6}	1.32×10^{-2}	1.53×10^{-4}
Ce-143	7.65×10^{-4}	7.49×10^{-5}	7.49×10^{-7}	1.30×10^{-3}	1.47×10^{-3}	1.44×10^{-6}	3.47×10^{-3}	2.04×10^{-5}
Ce-144	1.12×10^{-3}	1.12×10^{-4}	1.12×10^{-6}	3.97×10^{-3}	1.67×10^{-3}	1.67×10^{-6}	4.99×10^{-3}	5.55×10^{-5}
Pr-143	1.20×10^{-3}	1.19×10^{-4}	1.19×10^{-6}	3.98×10^{-3}	1.80×10^{-3}	1.80×10^{-6}	5.35×10^{-3}	5.66×10^{-5}
Nd-147	4.24×10^{-3}	4.23×10^{-4}	4.23×10^{-6}	1.33×10^{-2}	6.53×10^{-3}	6.53×10^{-6}	1.90×10^{-2}	1.91×10^{-4}
W-187	1.64×10^{-2}	1.59×10^{-3}	1.59×10^{-5}	2.38×10^{-2}	3.42×10^{-2}	3.32×10^{-5}	7.47×10^{-2}	3.79×10^{-4}
Np-239	6.07	6.00×10^{-1}	6.00×10^{-3}	$1.31 \times 10^{+1}$	$1.06 \times 10^{+1}$	1.05×10^{-2}	$2.74 \times 10^{+1}$	1.99×10^{-1}
OTHERS[2]	9.64×10^{-1}	9.52×10^{-2}	9.52×10^{-4}	1.54	2.91	2.87×10^{-3}	4.48	2.31×10^{-2}
TOTAL	$1.83 \times 10^{+1}$	1.73	2.95×10^{-2}	$3.37 \times 10^{+1}$	$4.34 \times 10^{+1}$	4.56×10^{-2}	$8.38 \times 10^{+1}$	5.14×10^{-1}

(1) Activity inventories are given in Curies.
(2) Activity of daughter products resulting from radioactive decay of the influent isotopes during the accumulation period.

Table 11.2-10

LIQUID WASTE MANAGEMENT SYSTEM COMPONENT PARAMETERS

A. TANKS

	QUANTITY	DESIGN PRESSURE/TEMP (psig/°F)	TYPE	MATERIAL	CAPACITY, EACH (gal)	DIAMETER HEIGHT
Equipment drain collection tank	1	Atmos/212	Vert cyl	CS	25,000	20'/11'
Equipment drain sample tanks	2	Atmos/212	Vert cyl	Aluminum	25,000	16'/17'
Equipment drain surge tank	1	Atmos/212	Vert cyl	CS	75,000	32'/13'
Floor drain collection tank	1	Atmos/212	Vert cyl	CS	21,000	15'/16'
Floor drain sample tank #1	1	Atmos/212	Vert cyl	CS	21,000	15'/16'
Floor drain sample tank #2	1	Atmos/212	Vert cyl	Aluminum	21,000	15'/16'
Floor drain surge tank	1	Atmos/212	Vert cyl	CS	75,000	32'/13'
Chemical waste tank	1	Atmos/212	Vert cyl	SS	7,500	10'/13'
Evaporator feed tank(1)	1	Atmos/212	Vert cyl	CS	7,500	11'/10.5'
Evaporator distillate sample tank(1)	1	Atmos/212	Vert cyl	Aluminum	7,500	11'/10'
Laundry drain tanks	2	Atmos/212	Vert cyl	CS	1,000	5.5'/6'
Laundry drain sample tank	1	Atmos/212	Vert cyl	CS	2,000	7'/7'
Backwash air accumulator	1	125/110	Vert cyl	CS	90 ft^3	4'/6.75'
Precoat tank	1	Atm/Ambient	Cyl	CS	800	6'/4'
Resin funnel	2	Atm/Ambient	Con cyl	CS	3 ft^3	1.5'/3.5'

Table 11.2-10 (Cont'd)

B. PUMPS

	QUANTITY	TYPE	RATED FLOW (gpm)	RATED HEAD, TDH (ft)	RATED POWER (hp)	DESIGN PRESSURE/TEMP. (psig/°F)
Equipment drain collection tank pump	1 centrifugal	Vert in-line	280	250	40	150/140
Equipment drain tanks pumps	2 centrifugal	Vert in-line	280	180	25	150/140
Equipment drain surge tank pump	1 centrifugal	Vert in-line	280	220	30	150/140
Floor drain collection tank pump	1 centrifugal	Vert in-line	280	250	40	150/140
Floor drain sample tank #1 pump	1 centrifugal	Vert in-line	280	110	15	150/140
Floor drain sample tank #2 pump	1 centrifugal	Vert in-line	280	180	25	150/140
Floor drain surge tank pump	1 centrifugal	Vert in-line	280	220	30	150/140
Chemical waste tank pump	1 centrifugal	Vert in-line	200	70	7.5	150/140
Evaporator feed tank pump(1)	2	Vert in-line centrifugal	20	25	1	150/140
Evaporator distillate sample tank pump(1)	1	Vert in-line centrifugal	50	130	7.5	150/140
Laundry drain tanks pumps	2 centrifugal	Vert in-line	25	105	5	150/140
Laundry drain sample tank pump	2 centrifugal	Vert in-line	10	65	2	150/140
Equipment drain filter holding pump	1	Horiz centrif	27	60	3	245/155
Floor drain filter holding pump	1	Horiz centrif	27	60	3	245/155
Precoat pump	1	Horiz centrif	688	75	20	150/155

Table 11.2-10 (Cont'd)

C. PROCESSING EQUIPMENT

	QUANTITY	TYPE DIAMETER HEIGHT	MATERIAL TYPE/NUMBER	RATED FLOW, EACH (gpm)	EQUIPMENT PARAMETER	DESIGN PRESSURE/TEMP. (psig/°F)
Equipment and floor drain filters	2	Precoat type 3'/7'	SS wire mesh element/90	280	Filter area: 275 ft^2	150/235
Equipment and floor drain demineralizers	2	Mixed bed 6'/6'	Effective resin volume of each	280	Resin bed depth: 3' min	150/235
Laundry drain filter	1	Shell: Vert cyl 8.6"/ 46"	Shell: SS	25	Filter area: 48 ft^2	75/250
		Cartridge: "Epocel-30" 6"/32"	Cartridge: Epoxy impregnated cellulose of 49 microns			

Table 11.2-11

EXPECTED YEARLY ACTIVITY RELEASED FROM LIQUID WASTE MANAGEMENT SYSTEMS[1]
(curies/year; totals are for 2 units)

ISOTOPE	FLOOR DRAIN SUBSYSTEM	EQUIPMENT DRAIN SUBSYSTEM	CHEMICAL DRAIN SUBSYSTEM	LWS SUBTOTAL	ADJUSTED TOTAL[2]	LAUNDRY DRAIN SUBSYSTEM	TOTAL
Br-83	2.52E-05	3.35E-05	1.13E-07	5.88E-05	6.70E-04	none	6.70E-04
Br-84	none	1.21E-06	none	1.21E-06	1.38E-05	none	1.38E-05
Br-85	none	none	none	none	none	none	none
I-131	9.59E-04	4.67E-04	1.35E-05	1.44E-03	1.64E-02	1.22E-03	1.76E-02
I-132	2.27E-04	3.02E-04	1.03E-06	5.30E-04	6.05E-02	none	6.05E-03
I-133	2.02E-03	1.38E-03	1.40E-05	3.41E-03	3.89E-02	none	3.89E-02
I-134	7.09E-05	8.74E-05	2.47E-07	1.59E-04	1.81E-03	none	1.81E-03
I-135	7.19E-04	7.55E-04	3.63E-06	1.48E-03	1.68E-02	none	1.68E-02
Rb-89	8.06E-06	1.34E-06	none	9.39E-06	1.07E-04	none	1.07E-04
Cs-134	1.56E-04	1.46E-04	2.51E-05	3.27E-04	3.73E-03	2.65E-02	3.02E-02
Cs-136	9.89E-04	9.50E-05	1.47E-05	1.10E-03	1.25E-02	none	1.25E-02
Cs-137	3.64E-03	3.40E-04	5.88E-05	4.04E-03	4.61E-02	4.90E-02	9.50E-02
Cs-138	5.68E-04	1.28E-04	1.57E-06	6.97E-04	7.95E-03	none	7.95E-03
Na-24	7.55E-04	5.70E-04	4.58E-06	1.33E-03	1.52E-02	none	1.52E-02
P-32	3.97E-05	1.91E-05	5.92E-07	5.93E-05	6.77E-04	none	6.77E-04
Cr-51	1.02E-03	4.81E-04	1.57E-05	1.51E-03	1.73E-02	none	1.73E-02
Mn-54	1.24E-05	5.80E-06	1.59E-07	1.84E-05	2.10E-04	2.04E-03	2.25E-03
Mn-56	4.91E-04	6.52E-04	2.23E-06	1.14E-03	1.31E-02	none	1.31E-02
Fe-55	2.08E-04	9.05E-04	3.14E-06	1.12E-03	1.27E-02	none	1.27E-02
Fe-59	6.15E-06	2.90E-06	9.69E-08	9.14E-06	1.04E-04	none	1.04E-04
Co-58	4.12E-05	1.93E-05	6.53E-08	6.06E-05	6.09E-04	8.16E-03	8.85E-03
Co-60	8.32E-05	3.89E-05	1.34E-06	1.23E-04	1.41E-03	1.84E-02	1.98E-02
Ni-63	2.08E-07	9.72E-08	none	3.05E-07	3.48E-06	none	3.48E-06
Ni-65	2.92E-06	3.88E-06	1.33E-08	6.81E-06	7.76E-05	none	7.76E-05
Cu-64	2.20E-03	1.85E-03	1.49E-05	4.06E-03	4.63E-02	none	4.63E-02
Zn-65	4.13E-05	1.93E-05	6.65E-07	6.13E-05	6.98E-04	none	6.98E-04
Zn-69	1.30E-05	4.04E-06	none	1.70E-05	1.94E-04	none	1.94E-04
Sr-89	2.07E-05	9.72E-06	3.26E-07	3.08E-05	3.15E-04	none	3.51E-04
Sr-90	1.24E-06	5.80E-07	2.01E-08	1.84E-06	2.10E-05	none	2.10E-05
Sr-91	2.27E-04	2.04E-04	1.21E-06	4.33E-04	4.93E-03	none	4.93E-03
Sr-92	1.07E-04	1.41E-04	4.89E-07	2.48E-04	2.83E-03	none	2.83E-03
Y-91	1.19E-05	4.87E-06	2.08E-07	1.70E-05	1.94E-04	none	1.94E-04
Y-92	2.61E-04	3.15E-04	1.30E-06	5.78E-04	6.59E-03	none	6.59E-03
Y-93	2.42E-04	2.12E-04	1.32E-06	4.55E-04	5.19E-03	none	5.19E-03
Zr-95	1.44E-06	6.78E-07	2.28E-08	2.16E-06	2.46E-05	2.86E-04	2.88E-03
Zr-97	4.60E-07	3.33E-07	none	7.93E-07	9.04E-06	none	9.04E-06
Nb-95	1.46E-06	6.78E-07	2.35E-08	2.16E-06	2.46E-05	4.08E-03	4.10E-03

Table 11.2-11 (Cont'd)

ISOTOPE	EQUIPMENT FLOOR DRAIN SUBSYSTEM	CHEMICAL DRAIN SUBSYSTEM	DRAIN SUBSYSTEM	LWS SUBTOTAL	LAUNDRY ADJUSTED TOTAL[2]	DRAIN SUBSYSTEM	TOTAL
Nb-98	5.70E-06	4.87E-06	1.38E-08	1.06E-05	1.21E-04	none	1.21E-04
Mo-99	3.32E-04	1.75E-04	3.68E-06	5.11E-04	5.82E-03	none	5.82E-03
Tc-99m	9.15E-04	8.20E-04	6.25E-06	1.74E-03	1.99E-02	none	1.99E-02
Tc-101	3.57E-07	2.43E-07	none	6.00E-07	6.84E-06	none	6.84E-06
Tc-104	1.34E-06	1.20E-06	none	2.54E-06	2.90E-05	none	2.90E-05
Ru-103	4.09E-06	1.92E-06	6.40E-08	6.07E-06	6.92E-05	2.86E-04	3.55E-04
Ru-105	4.43E-05	5.34E-05	2.13E-07	9.79E-05	1.12E-03	none	1.12E-03
Ru-106	6.23E-07	2.91E-07	none	9.14E-07	1.04E-05	4.90E-03	4.91E-03
Ag-110m	2.08E-07	9.72E-08	none	3.05E-07	3.48E-06	8.98E-04	9.01E-04
Te-129m	8.18E-06	3.86E-06	1.28E-07	1.22E-05	1.39E-04	none	1.39E-04
Te-131m	1.28E-05	7.81E-06	1.04E-07	2.07E-05	2.36E-04	none	2.36E-04
Te-132	1.71E-06	8.90E-07	2.00E-08	2.62E-06	2.99E-05	none	2.99E-05
Ba-139	3.13E-05	4.10E-05	1.28E-07	7.24E-05	8.26E-04	none	8.26E-04
Ba-140	7.92E-05	3.80E-05	1.16E-06	1.18E-04	1.35E-03	none	1.35E-03
Ba-141	1.67E-07	1.50E-07	none	3.17E-07	3.62E-06	none	3.62E-06
Ba-142	3.19E-09	2.12E-09	none	5.31E-09	6.06E-08	none	6.06E-08
La-142	2.24E-05	2.96E-05	9.47E-08	5.21E-05	5.94E-04	none	5.94E-04
Ce-141	6.62E-06	3.07E-06	1.04E-07	9.79E-06	1.12E-04	none	1.12E-04
Ce-143	4.00E-06	2.39E-06	3.40E-08	6.42E-06	7.32E-05	none	7.32E-05
Ce-144	6.23E-07	2.91E-07	none	9.14E-07	1.04E-05	none	1.04E-05
Pr-143	8.13E-06	3.85E-06	1.23E-07	1.21E-05	1.38E-04	none	1.38E-04
Nd-147	5.90E-07	2.84E-07	none	8.73E-07	9.96E-06	none	9.96E-06
W-187	3.42E-05	2.21E-05	2.52E-07	5.66E-05	6.45E-04	none	6.45E-04
Np-239	1.11E-03	6.03E-04	1.17E-05	1.73E-03	1.97E-02	none	1.97E-02
OTHERS[3]	2.28E-04	1.80E-04	2.16E-06	4.10E-04	4.68E-03	1.02E-02	1.49E-02
TOTAL	1.80E-02	1.12E-02	2.07E-04	2.94E-02	3.35E-01	1.28E-01	4.64E-01
H-3							1.12E+01

(1) Estimated releases are based on NUREG-0016, Revision 0, GALE Code evaluation.

(2) Increased the calculated LWS release by 0.15 Ci/yr per reactor using the same isotopic distribution as the calculated LWS releases to account for anticipated operational occurrences that result in unplanned releases.

(3) Activity of daughter products resulting from radioactive decay of the influent isotopes during the accumulation period.

Table 11.2-12

COMPARISON OF MAXIMUM CALCULATED RADIONUCLIDE CONCENTRATIONS IN THE ENVIRONMENT FROM ROUTINE LIQUID RELEASES TO 10CFR20 LIMITS(1)

ISOTOPE	AVERAGE ANNUAL CONCENTRATION IN WATER (μCi/ml)	10CFR20 TABLE II COLUMN 2 LIMIT(2) (μCi/ml)	% OF 10CFR20 LIMIT
Br-83	1.2×10^{-12}	3×10^{-6}	4.1×10^{-5}
Br-84	1.3×10^{-14}	-	-
Br-85	-	-	-
I-131	3.4×10^{-11}	3×10^{-7}	1.1×10^{-2}
I-132	1.1×10^{-11}	8×10^{-6}	1.4×10^{-4}
I-133	2.2×10^{-11}	1×10^{-6}	2.2×10^{-3}
I-134	3.4×10^{-12}	2×10^{-5}	1.7×10^{-5}
I-135	3.2×10^{-11}	4×10^{-6}	7.9×10^{-4}
R-89	2.0×10^{-13}	-	-
Cs-134	2.8×10^{-11}	9×10^{-6}	3.2×10^{-4}
Cs-136	2.3×10^{-11}	9×10^{-5}	2.6×10^{-5}
Cs-137	1.8×10^{-10}	2×10^{-5}	9.2×10^{-4}
Cs-138	1.5×10^{-11}	-	-
Na-24	2.9×10^{-11}	3×10^{-5}	9.5×10^{-5}
P-32	1.2×10^{-12}	2×10^{-5}	6.1×10^{-6}
Cr-51	3.3×10^{-11}	-	-
Mn-54	4.5×10^{-12}	1×10^{-4}	4.5×10^{-6}
Mn-56	2.4×10^{-11}	1×10^{-4}	2.4×10^{-5}
Fe-55	2.3×10^{-11}	8×10^{-4}	2.9×10^{-6}
Fe-59	1.9×10^{-13}	6×10^{-5}	3.2×10^{-7}
Co-58	1.7×10^{-11}	9×10^{-5}	1.9×10^{-5}
Co-60	4.0×10^{-11}	3×10^{-5}	1.3×10^{-4}
Ni-63	6.5×10^{-15}	3×10^{-5}	2.2×10^{-8}
Ni-65	1.4×10^{-13}	1×10^{-4}	1.4×10^{-7}
Cu-64	8.8×10^{-11}	2×10^{-4}	4.4×10^{-5}
Zn-65	1.3×10^{-12}	1×10^{-4}	1.3×10^{-6}
Zn-69	3.7×10^{-13}	2×10^{-3}	1.8×10^{-8}
Sr-89	6.5×10^{-13}	3×10^{-6}	2.2×10^{-5}
Sr-90	4.0×10^{-14}	3×10^{-7}	1.3×10^{-5}
Sr-91	9.3×10^{-12}	7×10^{-5}	1.3×10^{-5}
Sr-92	5.3×10^{-12}	6×10^{-5}	8.8×10^{-6}
Y-91	3.7×10^{-13}	3×10^{-5}	1.2×10^{-6}
Y-92	1.2×10^{-11}	6×10^{-5}	2.0×10^{-5}
Y-93	9.8×10^{-12}	3×10^{-5}	3.3×10^{-5}
Zr-95	5.8×10^{-12}	6×10^{-5}	9.7×10^{-6}
Zr-97	1.7×10^{-14}	2×10^{-5}	8.7×10^{-8}

Table 11.2-12 (Cont'd)

ISOTOPE	AVERAGE ANNUAL CONCENTRATION IN WATER (μCi/ml)	10CFR20 TABLE II COLUMN 2 LIMIT[2] (μCi/ml)	% OF 10CFR20 LIMIT
Nb-95	8.2×10^{-12}	1×10^{-4}	8.2×10^{-6}
Nb-98	2.2×10^{-13}	-	-
Mo-99	1.1×10^{-11}	4×10^{-5}	2.8×10^{-5}
Tc-99m	3.8×10^{-11}	3×10^{-3}	1.3×10^{-6}
Tc-101	1.2×10^{-14}	-	-
Tc-104	6.0×10^{-14}	-	-
Ru-103	7.0×10^{-13}	8×10^{-5}	8.8×10^{-7}
Ru-105	1.1×10^{-12}	1×10^{-4}	1.1×10^{-6}
Ru-106	9.8×10^{-12}	1×10^{-5}	9.8×10^{-5}
Ag-110m	1.8×10^{-12}	3×10^{-5}	6.1×10^{-6}
Te-129m	2.6×10^{-13}	2×10^{-5}	1.3×10^{-6}
Te-131m	4.5×10^{-13}	4×10^{-5}	1.1×10^{-6}
Te-132	5.6×10^{-14}	2×10^{-5}	2.8×10^{-7}
Ba-139	1.5×10^{-12}	-	-
Ba-140	2.6×10^{-12}	2×10^{-5}	1.3×10^{-5}
Ba-141	6.8×10^{-15}	-	-
Ba-142	1.1×10^{-16}	-	-
La-142	1.1×10^{-12}	-	-
Ce-142	2.0×10^{-13}	9×10^{-5}	2.3×10^{-7}
Ce-143	1.3×10^{-13}	4×10^{-5}	3.3×10^{-7}
Ce-144	2.0×10^{-14}	1×10^{-5}	2.0×10^{-7}
Pr-143	2.6×10^{-13}	5×10^{-5}	5.1×10^{-7}
Nd-147	1.8×10^{-14}	6×10^{-5}	3.1×10^{-8}
W-187	1.2×10^{-12}	6×10^{-5}	2.0×10^{-6}
Np-239	3.7×10^{-11}	1×10^{-4}	3.7×10^{-5}
H-3	2.2×10^{-8}	3×10^{-3}	7.5×10^{-4}

(1) Location: Liquid Discharge Outfall Area

(2) The concentration limits shown are reflective of the 10CFR20 Appendix B values prior to the 1994 revision of 10CFR20, and are consistent with those used in the original licensing of the plant. Current effluent release limits are based on the post-1994 10CFR20 regulation and are controlled by the Radioactive Effluent Controls Program defined by the Technical Specifications. New 10CFR20 limits went into effect on Jan. 5, 1994. As part of the power rerate evaluation, a comparison of the uprated liquid release concentration with the new 10CFR20 limits was made. All the uprated release concentrations were found to be less than 1% of their new limit.

Table 11.2-13

COMPARISON OF MAXIMUM INDIVIDUAL DOSES
RESULTING FROM LGS UNITS 1 AND 2 WITH
10CFR50, APPENDIX I DESIGN OBJECTIVES

	LGS LIQUID DOSE UNITS 1 & 2	10CFR50, APPENDIX I DESIGN OBJECTIVES/2 UNITS	% OF DESIGN OBJECTIVE
Total body	1.04 mRem/yr	6 mRem/yr	17.34%
Maximum organ	1.82 mRem/yr (bone)	20 mRem/yr	9.08%

11.3 GASEOUS WASTE MANAGEMENT SYSTEMS

The gaseous waste management systems include all systems that process potential sources of airborne releases of radioactive materials during normal operation and anticipated operational occurrences. Included are the offgas system and various ventilation systems. These reduce radioactive gaseous releases from the plant by filtration or delay, which allows decay of radioisotopes prior to release.

The function of the offgas system is to collect and delay release of noncondensable radioactive gases removed from the main condenser by the air ejectors during normal plant operation. Plant ventilation systems process airborne radioactive releases from other plant sources, such as equipment leakage, maintenance activities, the mechanical vacuum pump, and the steam seal system.

The offgas system is described in detail in this section. The ventilation systems are discussed briefly in this section and in greater detail in Section 9.4.

11.3.1 DESIGN BASES

a. The gaseous waste management systems are designed to control and monitor the release of radioactive materials in gaseous effluents in accordance with GDC 60 and GDC 64.

b. The offgas system design basis and maximum expected source terms correspond respectively to 100,000 μCi/sec and 60,000 μCi/sec of radioactive noble gases after 30 minute delay.

c. The gaseous waste systems are designed to limit offsite doses from routine station releases to significantly less than the limits specified in 10CFR20 and to operate within the dose objectives established in 10CFR50, Appendix I.

d. The gaseous waste management systems are designed with sufficient capacity and redundancy to accommodate all anticipated processing requirements of the plant during normal operation, including anticipated operational occurrences.

e. Continuous monitoring is provided for all potential pathways of airborne radioactive releases, with annunciation at levels lower than normal release limits.

f. Design provisions are incorporated which preclude the uncontrolled release of radioactivity to the environment as a result of any single operator error or any single active component failure.

g. The gaseous waste management system is designed to keep the exposure to plant personnel as low as reasonably achievable (ALARA) during normal operation and plant maintenance, in accordance with Regulatory Guide 8.8.

h. Design features are provided in the offgas system to control leakage and to facilitate operation and maintenance in accordance with the guidelines of Regulatory Guide 1.143.

i. The offgas system is designed in accordance with the guidelines of Regulatory Guide 1.143, with exception as discussed in Section 3.2.

j. Filtration units in the ventilation systems are designed, operated, and maintained in accordance with the guidelines of Regulatory Guide 1.140. with exceptions as discussed in Section 9.4.

k. The offgas system is designed to maintain the concentration of hydrogen in the gases exhausted from the main condenser below flammable limits.

l. Instrumentation is provided in the offgas system to detect abnormal concentrations of hydrogen and other system malfunctions.

m. The offgas system is designed to withstand the effects of a hydrogen explosion without breach of the pressure boundary.

11.3.2 SYSTEM DESCRIPTION

11.3.2.1 Offgas System

11.3.2.1.1 General

Noncondensable gases are continuously removed from the main condenser by the SJAE during plant operation. The offgas will consist of activation gases, fission product gases, radiolytic hydrogen and oxygen, and condenser air inleakage.

The offgas system is designed to reduce offgas radioactivity to permissible levels for release under all site atmospheric conditions.

The offgas system uses catalytic recombination for volume reduction and control of hydrogen concentration. Selective adsorption of fission product gases on charcoal is used to provide time for delay before release.

The location of the offgas system components is shown in general arrangement drawings in Section 1.2.

The seismic categories, quality group classifications, and corresponding codes and standards that apply to the design of the gaseous waste management system are discussed in Section 3.2.

11.3.2.1.2 Process Flow Description

Figure 11.3-1 is the process flow diagram for the offgas system and contains process design data for startup and normal operating conditions.

Drawings M-69 and M-70 are the piping and instrumentation diagrams for the offgas system.

During startup the mechanical vacuum pump is used to draw a vacuum in the main condenser as described in Section 10.4.2. Once condenser vacuum has been established by the mechanical vacuum pump and reactor steam is available, one of the two-stage SJAE trains are placed in service. As an alternative, during startup, shutdown and power operation, auxiliary steam can be used for SJAE operation when available.

The first-stage SJAEs continuously remove noncondensable gases and some steam from the condenser and discharge them to the SJAE condenser where the steam is condensed and returned to the main condenser. The gases are removed from the SJAE condenser by the second-stage ejector and discharged to the gaseous radwaste recombination system together with the second-stage ejector motive steam. This steam provides sufficient dilution to maintain hydrogen concentrations below combustible concentrations. A complete description of the SJAE is given in Section 10.4.2.

The offgas stream from the second-stage ejector is treated first in the recombiner portion of the offgas system. The purpose of the recombiner is to reduce the offgas volume and reduce the hydrogen concentration to less than 4% concentration by volume on a dry basis. The offgas first passes through the preheater in order to vaporize any water droplets and to achieve a sufficient temperature to start the catalytic reaction. Steam used for preheating is provided from the reactor feed pump-turbine steam supply line or from auxiliary steam when available. The recombination process takes place inside a recombiner vessel. The temperature of the gases leaving the recombiner rises as a function of the influent hydrogen concentration. This temperature rise is due to the heat of reaction of the recombination process. The reaction temperature rises approximately 120°F for each 1% of H_2 recombined. The catalyst is a metal mat-type. The elements are made of crimped high nickel alloy ribbons coated with platinum/palladium. Each recombiner has two independent electric heater assemblies.

Steam flow leaving the recombiner vessel is condensed in the aftercondenser and the offgas stream is cooled. The remaining noncondensable gas (principally air with traces of krypton and xenon) is delayed in a 26 inch diameter, 125 foot long holdup pipe. At a flow rate of 75 scfm, this pipe provides approximately 6.3 minutes of delay for the offgas prior to entering the charcoal adsorption train. Piping from the delay pipe to the charcoal treatment system is heat traced to reduce the possibility of moisture collecting in the line.

Further offgas cooling and condensing of water vapor takes place in the shell side of the cooler condenser heat exchanger. A chilled glycol solution is circulated on the tube side of this heat exchanger. The offgas is cooled to a dew point below 45°F before leaving the cooler condenser. Water that has condensed is drained from the cooler condenser into the condensate accumulator. The temperature of the gas stream increases to ambient (approximately 65°F) as it flows from the cooler condenser to the guard bed, thus preventing condensation.

The glycol solution circulated on the tube side of the cooler condenser heat exchanger is cooled in a closed-loop pumped refrigeration circuit. Dual brine pumps and redundant refrigeration units are provided in the glycol system.

Before entering the main charcoal vessels, the offgas stream passes through a guard bed. The function of the guard bed is to protect the main charcoal adsorbers from moisture if a malfunction of moisture removal features occurs as well as to adsorb impurities in the process gas that might adversely affect performance of the main charcoal vessels.

After passing through the guard bed, the gas enters the main charcoal adsorption beds. The charcoal adsorption beds, maintained at about 65°F by redundant room air conditioning units, selectively adsorb and delay the xenon and krypton from the bulk carrier gas. This delay permits the xenon and krypton to decay in place. The offgas stream then passes through a HEPA afterfilter where radioactive particulate matter and any charcoal fines are retained.

During offgas system operation, the offgas stream must pass through the charcoal adsorbers. Bypass piping around the entire adsorber train does not exist. The offgas stream is directed to the turbine enclosure vent stack where it is diluted with a minimum of 183,000 scfm of air before being released from the north stack.

Table 11.3-1 indicates the estimated annual release rate from the offgas system.

All moisture removed from the process stream is returned to the main condenser hot well or clean radwaste.

11.3.2.1.3 System Design Considerations

11.3.2.1.3.1 Charcoal Holdup Time

The krypton and xenon holdup times are closely approximated by the following equation:

$$T = 0.26 \frac{KM}{V} \qquad \text{(EQ. 11.3-1)}$$

where:

T = hold-up time, hours

K = dynamic adsorption coefficient, cm^3/g

M = mass of charcoal adsorber, thousands of pounds

V = gas flow rate, scfm

Dynamic adsorption coefficients for krypton and xenon used to determine gaseous effluent releases are discussed in NUREG-0016 (Reference 11.3-1). The charcoal adsorber beds are designed for a delay time of 35 days for xenon under both of the following conditions:

a. 75 scfm flow rate using manufacturer's guaranteed adsorption coefficients (733 cm^3/g for xenon and 31.8 cm^3/g krypton)

b.. BWR GALE code assumptions (NUREG-0016, Revision 0)

The offgas system is capable of handling changes in noncondensable flow rates up to 215 scfm (Unit 1) and 205 scfm (Unit 2) with both units running, or 225 scfm (Unit 1) and 215 scfm (Unit 2) with only one unit running, without operator attention. Even though the offgas system is capable of handling these limits, the air in-leakage should not exceed 150 scfm since it is the maximum design capability of the steam jet air ejectors.

With a condenser air inleakage rate of 30 scfm, the charcoal treatment system provides a design holdup time of 52 hours for krypton and 38.6 days for xenon based upon NUREG-0016 assumptions. Since it is expected that the condenser air inleakage will be below the design value and that the charcoal adsorption coefficients will be higher than the values in NUREG-0016 (References 11.3-3 and 11.3-4), the actual charcoal holdup time should be considerably longer than the design holdup time. Additionally, experience with newer fuel designs (8x8 assemblies)

indicates that substantially lower source terms than those used for system design may be expected.

11.3.2.1.3.2 Detonation Resistance

All portions of the LGS offgas system are designed to withstand the effects of a hydrogen detonation or are provided with protective features to preclude the existence of a detonable mixture of gases.

Design for extremely short duration (microsecond) loadings which accompany hydrogen detonations is outside the scope of normal industry design codes (i.e., ANSI B31.1, ASME B&PV Code, etc). The industry has developed a methodology for detonation-resistant design of offgas system piping, pressure vessels, and other components based on extensive theoretical and experimental work.

The magnitude of pressure pulses accompanying a hydrogen detonation have been shown to be a function of component geometry (i.e., length/diameter ratio), initial system pressure, and proximity to reflection points (i.e., pipe elbows, etc). The basic methodology used in the design of detonation-resistant BWR offgas systems is described in appendix C of ANSI/ANS 55.4 (1979). That methodology, with slight variations between the AEs and industry equipment suppliers, has been followed since the early 1970s and was used in the LGS design. The analytical methods used are best described as "static analyses using dynamic material properties". An appropriate wall thickness is determined using peak dynamic pressure and dynamic material properties. For convenience, this wall thickness is often expressed in terms of its code static pressure equivalent. Application of this methodology provides a conservative design without the need for detailed and laborious analysis of the gas dynamics of the system. The methodology has been demonstrated to be adequately conservative by theoretical analysis and operating experience:

a. A true dynamic analysis of system pressures will typically require a wall thickness one-half that indicated by this approach.

b. No BWR offgas system pressure boundary failures had been observed despite the occurrence of considerably more than 100 system detonations.

An ASME Code Committee (Committee on Air and Gas Treatment, Gas Processing Subcommittee) is currently working towards the codification of the above described industry methodology. The guidance provided in SRP 11.3 (i.e., approximately 20 times operating pressure) has been demonstrated to be nonconservative in many applications. (The contents of this paragraph are historical in nature and do not reflect present day activities.)

All offgas system detonation-resistant piping and components upstream of the charcoal treatment system have been analyzed using the method of analysis employed by Bechtel. All charcoal treatment system components have been analyzed using the method of analysis employed by the system supplier (Reference 11.3-5). Both analytical methods closely parallel that described in ANSI/ANS 55.4 and give approximately equal results.

The following is a discussion of factors relevant to the detonation resistance of the LGS offgas treatment system:

a. The SJAEs are designed to withstand a hydrogen detonation occurring at normal system operating pressure (3.5 psia). Because leakage into the standby SJAE train

could cause a detonation at higher initial pressures, provisions have been made to maintain the standby SJAE train at main condenser vacuum.

b. The SJAEs that are used do not employ a second-stage condenser. Thus, the driving steam from the SJAE second-stage provides dilution steam such that a detonable mixture of gases will not exist between the SJAE discharge and the offgas aftercondenser. Protective circuits are provided such the offgas system is automatically shut down when loss of dilution steam is detected (low system flow or high recombiner outlet temperature).

c. All system valves use spark-resistant trim.

d. All system piping, valves, vessels, instruments, and other components are designed to withstand the effects of a hydrogen detonation except portions of the piping between the SJAE discharge and the preheater. Detonable mixtures of gases in this piping are precluded as discussed in Item (b) above.

11.3.2.1.4 Component Description

The recombiner and associated equipment are located in the lowest level of the control structure. Each recombiner system consists of a preheater, recombiner vessel, and aftercondenser. The materials of construction, design temperatures, and pressures are listed in Table 11.3-3.

11.3.2.1.4.1 Preheater

The preheater is a U-tube parallel heat exchanger. Main steam is used to heat process gas before entering the recombiner. The process gas enters at approximately 280°F and is heated as required to vaporize water droplets and achieve sufficient temperature for catalytic reaction. Auxiliary steam may also be available for heating the process gas flow, should main steam be unavailable. Condensate from the tube side of the heat exchanger is collected in a drain pot underneath the preheater and is routed back to the condenser.

11.3.2.1.4.2 Recombiner

The hydrogen and oxygen in the gas stream are recombined in the recombiner vessel by a catalyst of platinum/palladium. Electric heaters with automatic temperature control are provided on the shell of each recombiner. The heaters are used for preheating the recombiner during startup and maintaining it in a dry condition during shutdowns.

11.3.2.1.4.3 Aftercondenser

The aftercondenser is a straight tube heat exchanger. Service water is circulated through the aftercondenser tubes to condense the steam in the offgas flow. Noncondensable gases are collected in the aftercondenser, cooled in the air cooler section and vented to the holdup pipe. Control valves are used to automatically maintain proper condensate level in the aftercondenser shell. Condensate from the air cooler section is collected in a drain tank. Condensate from both sources is returned to the main condenser hotwell, or diverted to clean radwaste if main condenser vacuum is not available or the conductivity instrumentation indicates that a tube leak exists.

11.3.2.1.4.4 Holdup Pipe

The holdup pipe is approximately 125 feet in length and 26 inches in diameter. The purpose of this holdup pipe is to provide delay time to allow N-16 decay before entering the charcoal adsorption portion of the offgas system. Baffles are provided in each holdup pipe to assure adequate mixing and delay.

11.3.2.1.4.5 Charcoal Adsorption System

11.3.2.1.4.5.1 Cooler Condenser

The cooler condenser is a straight tube heat exchanger with a glycol/water solution flowing through the tube side. The glycol system is provided with redundant circulation pumps and redundant refrigeration units that are cooled by service water.

Moisture formed in the cooling process is collected in an accumulator. This condensate is normally routed to clean radwaste but is automatically diverted to chemical waste if the measured conductivity indicates that a glycol leak could exist.

11.3.2.1.4.5.2 Guard Bed

The function of the guard bed is to protect the main charcoal adsorbers from moisture in the event of a malfunction of the moisture removal equipment and to remove contaminants that may be in the process stream which could be detrimental to the main adsorber beds. The guard bed is designed with a removable cover and an internal basket which contains the charcoal adsorbent. The basket allows easy charcoal replacement if necessary. The guard bed contains approximately 190 pounds of charcoal.

11.3.2.1.4.5.3 Main Charcoal Adsorber Bed

The Unit 1 adsorber train consists of two 11 foot diameter tanks and five 10 foot diameter tanks. The Unit 2 adsorber train consists of one 11 foot diameter tank and eight 10 foot diameter tanks. The different configurations for Units 1 and 2 are the result of space limitations within the enclosure, which was constructed before final system design.

Each adsorber train contains approximately 321,000 lbs of charcoal. The tanks are connected at the top and bottom by 4 inch piping. Portions of each unit's offgas system use a parallel flow path through the main adsorber beds. Appropriate valves are provided to facilitate flow balancing as required .

The charcoal adsorber tanks are maintained at a temperature of 65°F or below by redundant air conditioning systems. The last adsorber tank in the Unit 1 train is not located in an air conditioned vault and will operate at room ambient temperature. In the unlikely event that both air conditioning units are unable to function, the radioactive emissions from the offgas system might increase slightly. However, since substantial margin exists in the offgas system design, the releases would still be well below acceptable limits for expected air inleakage rates, radioactivity source terms, and adsorption coefficients.

11.3.2.1.4.5.4 Outlet HEPA Filter

A HEPA filter is provided to collect any entrained particulates or charcoal fines prior to release. These filters were individually tested during the startup test program using the DOP method. The filters are equipped with hinged covers to facilitate removal and replacement of the filter element.

11.3.2.1.4.5.5 Leakage of Radioactive Gases

The offgas system operates at approximately 7 psig during startup and at approximately 2 psig during normal operation. The differential pressure between the system and atmosphere is small, thus limiting the potential for leakage of radioactive gases.

Leakage of radioactive gases from offgas containing lines in the offgas system is further limited by the use of welded construction, by plug valves with plug and shank seals, globe valves with back-seats and packless design, and by using double stem packed valves with a bleed-off connection that is pressurized by instrument air to slightly higher than the system pressure, wherever practical.

All drains in the offgas system with the exception of the condensate accumulator drain are directed either to the main condenser or clean radwaste during normal operation. The condensate accumulator drains are directed to clean radwaste or chemical waste, as discussed in Section 11.3.2.1.4.3.1. In order to eliminate the possibility of gas leakage to the waste collector tanks should a level controller fail, loop seals or drain pots are provided.

All loop seals are the self-resealing type.

11.3.2.1.4.6 Instrumentation and Control

The offgas system is monitored at appropriate locations for flow, temperature, pressure, humidity, conductivity, radiation, and hydrogen concentration to verify specified operation and control as well as to ensure that the hydrogen concentration is maintained below the flammable limit. Sufficient instrumentation is provided to permit system operation and monitoring from the main control room. Drawings M-69 and M-70 indicate the process instrumentation.

A radiation monitor located upstream of the holdup pipe continuously monitors gaseous radioactivity input to the charcoal adsorption system. This is representative of gaseous radioactivity released from the reactor and therefore indicates the condition of the fuel cladding. Provision is made for grab sampling of the influent gases for the purpose of determining isotopic composition.

A radiation monitor is also provided at the outlet of the charcoal adsorbers to continuously monitor activity released from the system. The offgas system process radiation instrumentation is further discussed in Section 11.5.

Dilution steam flow (second-stage SJAE motive steam) is monitored upstream of the preheater and recorded in the control room. Low dilution steam flow automatically shuts the first-stage SJAE gas suction valves to prevent high concentrations of hydrogen in the offgas piping between the second-stage SJAEs and the preheater.

The HWC control system requires an interface with the Gaseous Radwaste/Recombination System. An SJAE train/recombiner trip digital output is provided to trip the HWC system.

The steam supply to the gas preheater is controlled by the offgas outlet temperature.

The temperature of the recombiner vessel and the inlet and outlet gases are monitored by thermocouples. A high temperature alarm is provided for the recombiner vessel, and high and low

temperature alarms are provided on the inlet and outlet lines to alarm a temperature outside of the design range.

Aftercondenser outlet temperature is recorded, and high temperature is alarmed in the main control room. This temperature indicates if adequate cooling flow exists in the aftercondenser.

Three thermal conductivity-type hydrogen analyzers and two oxygen analyzers are used to measure the hydrogen and oxygen content of the offgas process stream at the discharge of the aftercondenser. The system is designed to ensure that there is sufficient oxygen available to combine with the hydrogen and yet ensure that the oxygen level does not get too high so as to impose an increased fire hazard for the offgas charcoal beds. One of the hydrogen analyzers can be switched to measure the hydrogen content of the offgas stream at the inlet to the recombiner. The sample gas is returned to the main condenser. The hydrogen analyzers are designed to withstand the effects of a hydrogen detonation. The analyzer cell is not capable of causing a detonation, and the analyzer is designed with a flame arrestor on the sample side to inhibit such detonation. The hydrogen concentration is annunciated both locally and in the control room for high and high-high hydrogen concentration (2% and 4%, respectively). A common trouble alarm for cell failure, analyzer cell low flow and low bypass flow, is also provided. Because the offgas system is designed to withstand the effects of hydrogen detonation, no automatic control functions are required. Each hydrogen analyzer is independently calibrated. Condensate from the analyzers is routed to the aftercondenser air cooler drain.

The condensate level in the preheater and aftercondenser is maintained at appropriate levels by level control systems. These level control systems provide drainage either to the main condenser or clean radwaste. During normal operation condensate is directed to the main condenser. A conductivity element is provided in the drain to detect aftercondenser tube leakage if high conductivity is detected. Because the condensate from the air cooler portion of the aftercondenser already has a high conductivity reading due to dissolved air, this portion of aftercondenser drainage is routed to bypass the conductivity cell to avoid a false high reading. As a result, tube leakage in the aftercondenser air cooler will not be detected. Tube leakage in the air cooler section is not anticipated due to the mild service environment that this section of tubes experiences.

Cooler condenser performance is monitored by outlet temperature and moisture. High process outlet temperature is alarmed in the main control room. A moisture element is located downstream of the cooler condenser. The moisture element senses the process offgas dew point temperature. This temperature is indicated both at the local panel and in the main control room. High moisture in the process stream is alarmed both locally and in the main control room.

Moisture condensed from the process offgas in the cooler condenser is collected in the condensate accumulator. The condensate level is maintained at appropriate limits by a level control system. Condensate is normally drained to clean radwaste. A conductivity element is provided in the drain to detect glycol inleakage. If glycol inleakage is detected, drainage is routed to the chemical waste tank.

The guard bed is provided with both differential pressure and temperature indication. High differential pressure and high temperature are alarmed in the control room.

The charcoal beds in the adsorber vessels are monitored by thermocouples. High temperature is alarmed in the control room and at the local panel. Individual adsorber charcoal temperature is indicated at the local control panel and recorded in the control room. Each vessel is provided with two spare thermocouples which can be used if the first thermocouple fails.

Differential pressure is measured across the HEPA filter. High differential pressure is alarmed in the main control room. Flow from the discharge of the second-stage SJAE can be recycled to the main condenser if transient flow conditions approach system maximum. Recycle line operation is described in Section 10.4.2.5 .

Process offgas flow rate is monitored downstream of the HEPA filter. High flow rate is alarmed in the main control room and at the local panel. Flow rate is indicated locally and recorded in the main control room.

Thermocouples are provided in each charcoal adsorber tank room. The thermocouples automatically operate the room air conditioning units to maintain room temperature at or below 65°F. Room temperature is indicated and alarmed at the local panel. Room temperature is also alarmed and recorded in the main control room.

11.3.2.1.4.7 Offgas System Operating Procedure

11.3.2.1.4.7.1 Startup

Before starting the offgas system, the following conditions are necessary: main steam or auxiliary steam is available for the SJAEs and the preheater; cooling water (condensate) is supplied to the SJAE intercondenser; the recombiner is preheated to approximately 300°F by the electric heaters; service water is supplied to the aftercondenser, glycol refrigeration units, and compartment refrigeration units; the glycol coolant is chilled, one glycol pump is running and circulating chilled glycol through the cooler condenser; the adsorber rooms are at 65°F or below, and air circulation fans are operating .

The system can be started either with the main condenser at 20 in Hg vac with vacuum having been drawn by the mechanical vacuum pump or at atmospheric pressure with the initial vacuum drawn by the 2nd stage SJAE using auxiliary steam. With main condenser vacuum established, the system is prepared for startup by admitting main or auxiliary heating steam to the preheater, and selecting and setting various instrument control stations at the main control room system panels. The SJAE train discharge and main steam or auxiliary steam supply valves are opened. The 2nd stage SJAE is placed into service and a vacuum is drawn in the SJAE intercondenser. The discharge flow heats the process piping down through the preheater, recombiner, aftercondenser, and holdup pipe before being recirculated to the main condenser. The 1st stage SJAE air suction valves are opened to allow the 2nd stage SJAE to draw condenser vacuum down to approximately 25 to 26 in Hg vac. The mechanical vacuum pump can then be secured. Full condenser vacuum is achieved by performing the following: close the 1st stage air suction valves, open the 1st stage steam supply valves, re-open the 1st stage air suction valves. Once the 1st stage air suction valves are opened (with either the 1st stage SJAE in or out of service) the recirculation line downstream of the holdup pipe to the main condenser is closed and flow is directed to the charcoal treatment system. Recycle lines at the discharge of the 2nd stage SJAE will return some flow to the main condenser should system back pressure exceed approximately 7 psig at startup flows.

If the 2nd stage SJAE is used to draw the initial vacuum, the startup sequence is the same as above. The only difference is that auxiliary steam must be used.

11.3.2.1.4.7.2 Normal Operation and Shutdown

After startup, the flow rate of noncondensables exhausted by the SJAE should stabilize, primarily as a function of reactor power level and condenser inleakage. The instrumentation discussed in Section 11.3.2.1.4.4 can be used to monitor system performance. Operator action is not required for steady-state system operation, including changes in offgas noncondensable flow rates up to 215 scfm (Unit 1) and 205 scfm (Unit 2) with both units running, or 225 scfm (Unit 1) and 215 scfm (Unit 2) with only one unit running. Even though the offgas system is capable of handling these limits, the air in-leakage should not exceed 150 scfm since it is the maximum design capability of the steam jet air ejectors.

Normal operation is terminated following a normal reactor shutdown or a scram by shutting the gas suction valves to the SJAEs and then stopping steam flow to the SJAEs. Steam is secured to the first-stage SJAEs and then to the second-stage. Normal practice is to run the offgas system throughout reactor pressure vessel depressurization. Main steam can support SJAE operation down to 205 psig reactor pressure. Auxiliary steam may be used at any time during shutdown operations.

11.3.2.1.4.7.3 Equipment Malfunction

An equipment malfunction analysis, indicating the consequences and design precautions taken to accommodate failure of various components of the offgas system, is presented in Table 11.3-5.

11.3.2.1.4.8 Operator Error

The potential for operator error resulting in high offsite releases while operating the offgas system is small. Offgas flow from the SJAEs must be directed through the recombiner and ambient charcoal systems. There are no system bypasses other than the mechanical vacuum pump. The systems are instrumented such that the operators can detect and correct failures of various components in the systems (Table 11.3-5).

11.3.2.1.4.9 Serviceability and Reliability

Reliability of the offgas system is accomplished through redundancy and the use of passive components.

Two redundant SJAE systems, including intercondensers, are provided. Redundant level control valves, flow control valves, and instrumentation are furnished for the preheater. Redundant level control valves and instrumentation are supplied for the aftercondenser, holdup pipe, and condensate accumulator drains. Redundant glycol cooling pumps, glycol refrigeration units, charcoal adsorber vessels' compartment refrigeration units, and compartment fan coil units are provided. Redundant control valves may be operated or isolated from the control room; redundant equipment can be placed in or out-of-service from the control room. The recombiner systems of the two units may also be cross connected into one charcoal train through a spool piece interconnection. Each charcoal train can process up to 300 scfm of offgas noncondensable flow.

The guard beds and first charcoal adsorber vessels in each train can be bypassed if they become contaminated with moisture. The HEPA filter may also be bypassed if a high differential pressure condition exists.

Redundant equipment for the preheater, recombiner, and aftercondenser is not installed. Piping connections are installed that allow for a second recombiner system to be connected to the existing system of each unit in the future.

Serviceability is accomplished wherever possible, by using passive components and by locating in accessible areas equipment and instruments which are not passive or which require periodic maintenance.

Instruments for the recombiner system that require periodic maintenance are located outside the recombiner rooms. Instruments for the ambient charcoal system are either located outside rooms containing radioactive equipment or are shielded from radioactive equipment. Instrumentation requiring calibration are accessible during system operation.

The guard beds and HEPA filters are located in individual rooms and are provided with system bypasses. The vessels are designed with removable covers. This arrangement allows replacement of the charcoal basket or filter element when the offgas system is operating.

11.3.2.2 Other Radioactive Gas Release Paths

There are three general areas that contain sources of radioactive gas: the primary and secondary containment, the turbine enclosure, the radwaste enclosure and Chemical Laboratory Expansion . The description of the ventilation systems for these enclosures is presented in Section 9.4. The enclosure volumes, flow rates, sources, and other information required to calculate the airborne concentrations of radioactive materials are contained in Sections 12.2.2, 12.3.3, and 12.4.

11.3.2.2.1 Primary and Secondary Containment

As indicated in Section 9.4, the two reactor enclosures and the common refueling area have been designated as HVAC Zones I, II, and III. The primary containment and secondary containment HVAC systems that are important for the treatment of potentially radioactive air are the following: Zone I and Zone II equipment compartment exhaust systems, the SGTS, and the RERS.

The equipment compartment exhaust systems process ventilation exhaust from the areas in Zones I and II which are most likely to have sources of airborne radioactivity. These areas are listed on drawing M-76. The exhaust system contains HEPA and 2 inch charcoal filters. Discharge air from other areas in HVAC Zones I and II is released unfiltered through the reactor enclosure air exhaust system. Radiation monitors in the exhaust duct-work cause HVAC isolation on high-high radiation and initiate the RERS and SGTS. These systems provide increased filtration and delay of airborne radioactivity before release. Equipment compartment exhaust systems are more completely described in Section 9.4.

Air from HVAC Zone III (the common refueling area) is normally exhausted unfiltered through the refueling area air exhaust fans. Radiation monitors are provided in the exhaust duct-work to isolate normal HVAC and initiate the SGTS on high-high radiation. There may be small quantities of radioactivity released unfiltered from the refueling area and the spent fuel pool, especially during the early stages of refueling. However, the quantities of iodine and particulates released from this unfiltered source are expected to be much less than the releases from equipment leakage, equipment maintenance, and drywell purge, all of which are filtered. Considering the uncertainties in the calculation of the reactor enclosure releases and the conservative use of a minimum 90% efficiency for the charcoal filtration systems, it is expected that the actual releases from the reactor enclosure to the atmosphere should be lower than the estimates used in this evaluation.

During power operation, radioactivity released from minor system leakage inside the primary containment is contained, except for minor releases necessary to control containment pressure.

Pressure is controlled by use of the low volume purge. In this purge mode, gas is supplied by the containment atmosphere control system through 1 inch lines and is exhausted from the primary containment through 2 inch lines connecting to the high volume purge exhaust lines. Low volume purge air is processed through the equipment compartment exhaust system prior to release to the environment. The containment isolation valves on the high volume and low volume purge lines are closed on a containment isolation signal.

Before a shutdown requiring containment entry, the containment is purged of nitrogen and airborne radioactivity by the drywell purge system, which uses the SGTS filters to reduce releases. When required, high volume purging of the containment continues while maintenance activities are conducted inside primary containment. The MSRVs are vented to the suppression pool. The activity released from the actuation of these relief valves is contained in the primary containment until its atmosphere is purged through the SGTS when preparing for personnel access.

11.3.2.2.2 Radwaste Enclosure and Chemistry Laboratory Expansion

The supply system delivers filtered and tempered air that is distributed throughout the enclosure in quantities sufficient to maintain required temperatures. The equipment compartment exhaust system consists of two 100% capacity fans and two 100% capacity filter housings. The Chemistry Laboratory Expansion air exhaust system consists of two 100% capacity fans and two 100% capacity filter housings. The fume hood exhaust air system consists of two 100% capacity fans and two 100% capacity filter housings. Each filter housing has a bank of prefilters and a bank of HEPA filters. This exhaust system is balanced to assure that the flow of air within the enclosure is into areas with higher potential for airborne radioactivity contamination. The tank exhaust system provides a means of filtering and venting air from tanks and equipment housed in the radwaste enclosure. A single fan and filter train are employed for this purpose. There are HEPA filters in this system. Since the flow of air from tanks and equipment varies, space air is admitted as required to maintain system volume. Noncontaminated areas of the radwaste enclosure are exhausted by the unfiltered radwaste enclosure air exhaust system.

A radiation monitor is provided on the combined radwaste enclosure air and equipment compartment exhaust systems. All radwaste enclosure and Chemistry Laboratory Expansion exhaust systems discharge to the north stack.

Each of the above exhaust systems and the respective supply system are interlocked so that failure of the exhaust system shuts down the supply system. This condition is alarmed in the radwaste control room.

11.3.2.2.3 Turbine Enclosure

As indicated in Section 9.4.4, the turbine enclosure ventilation system contains a filtration system with HEPA filters and an 8 inch deep charcoal filter. Enclosure air from those areas of the turbine enclosure, where equipment leakage and airborne activity are most likely, is processed through the filtration system before it is released through the north stack to the atmosphere. Air from noncontaminated areas is released through the north stack without filtration.

In the past, discharge from the steam packing exhausters has presented a source of gaseous radioactive releases in some BWR plants. At LGS however, clean steam from the steam seal evaporator is provided for gland seal purposes and, therefore, essentially no activity is released from this system. Section 10.4.3 provides a detailed description of the gland seal steam system.

During the startup of each plant, air is removed from the main condenser by a mechanical vacuum pump. This vacuum pump discharges through the turbine enclosure equipment compartment exhaust air filter assemblies. The vacuum pump exhaust can bypass the turbine enclosure equipment compartment exhaust filters under administrative control when it is determined that filtration is not required to limit offsite doses. A radiation detector continuously monitors the effluent from the turbine enclosure exhaust system via the north stack, and an alarm is actuated upon the detection of a high radiation level.

11.3.3 RADIOACTIVE RELEASES AND ESTIMATED DOSES

The activity released from the various vents is monitored to ensure that the airborne concentrations at offsite locations will be below the limits of 10CFR20. In addition, the yearly releases are kept ALARA in order to meet the dose guidelines 10CFR50, Appendix I. The expected annual activity releases are given in Table 11.3-1.

An evaluation of the gaseous radioactive releases to show compliance with the above guidelines has been performed. The assumptions used in this evaluation are summarized in Table 11.3-2. The fractions of radioiodine and particulates assumed to be released from the reactor enclosure, the turbine enclosure, and the radwaste enclosure are included. These assumptions were based on NUREG-0016, Revision 0. A further discussion of each assumption follows:

a. Reactor Enclosure

As indicated in Sections 11.3.2.2.1 and 9.4.2, the reactor enclosure is ventilated during normal operation by two systems: the reactor enclosure exhaust system and the reactor enclosure equipment compartment exhaust system. Only the latter system includes HEPA and charcoal filter systems. The design philosophy is to identify those areas with the potential for airborne contamination and to exhaust them through the filtered exhaust. Clean areas are exhausted without filtration. This minimizes the mixing of air between contaminated and noncontaminated areas and thus maintains the airborne doses to workers in noncontaminated areas to ALARA conditions. Drawing M-76 identifies the areas served by each of the systems. Because the sources of equipment leakage within the reactor enclosure (e.g., RWCU pumps, RHR system, etc) are served by the filtered exhaust, it was assumed that all reactor enclosure releases are filtered.

To use the NUREG-0016, Revision 0, GALE code estimates of releases, it was conservatively assumed that the reactor enclosure (containment/auxiliary building) contributions were all released through 2 inch, 70% efficient charcoal filters and 99% efficient HEPA filters.

b. Turbine Enclosure

The areas of the turbine enclosure containing radioactive sources that could leak and result in airborne activity have been identified as shown in Sections 11.3.2.2.3 and 9.4.4.2.5 and on drawing M-75. The turbine enclosure ventilation systems have been set up such that the air flows from the clean areas to the areas of potential contamination and then is exhausted through the 8 inch charcoal and HEPA filters of the equipment compartment exhaust system. In addition, air from the clean areas is exhausted or recirculated by the turbine enclosure ventilation system to keep the airborne doses ALARA to workers in noncontaminated areas and to

minimize the cost and doses during maintenance for a larger filter system. Because all identified sources of activity are served by the filter system, it was assumed that all turbine enclosure releases identified by NUREG-0016, Revision 0, and the GALE code are released through the 8 inch, 99% efficient charcoal filters and the 99% efficient HEPA filters.

c. Radwaste Enclosure and Chemistry Laboratory Expansion

As indicated in Sections 11.3.2.2.2 and 9.4.3 and on drawing M-79, HEPA filters are installed on tank vents, HEPA filters are installed on the equipment compartment exhausts and the fume hood exhaust system, and the clean areas are exhausted unfiltered. By directing air flow to contaminated areas from the clean areas rather than using a recirculation-type system, airborne contamination is minimized, and most of the released activity is filtered before it is released. For the analysis indicated in Table 11.3-2, it was assumed that all particulate releases are filtered through either the 99% efficient tank vent HEPA filter or the 99% efficient HEPA filter on the equipment compartments identified as having the greatest potential for leakage. The above assumptions are reflected in the release analyses summarized in Tables 11.3-1 and 11.5-4, and the dose analyses summarized in Tables 11.3-7 and 11.3-4.

Expected average annual radionuclide concentrations are compared to 10CFR20 limits in Table 11.3-7.

The doses resulting from gaseous effluents are a small fraction of the 10CFR20 dose limit of 500 mRem/year and are well within 10CFR50, Appendix I design objectives, as shown in Table 11.3-4.

All gaseous releases are through the following three release points: the north stack, the south stack (one per unit), and the hot maintenance shop.

a. Offgas system

b. Mechanical vacuum pump and gland seal condenser exhaust systems

c. Containment purge system

d. SGTS

e. Turbine enclosure ventilation system

f. Radwaste enclosure ventilation system

g. Chemistry Laboratory Expansion air exhaust system

h. Chemistry Laboratory Expansion fume hood air exhaust system

The south stack serves the refueling floor and reactor enclosure ventilation exhaust. The locations of the stacks are shown on reactor enclosure general arrangement drawings in Section 1.2.

The hot maintenance shop exhaust serves the hot maintenance ventilation exhaust system.

The height, flow rate, heat content, and dimensions of the three release points are shown on Table 11.3-6.

11.3.4 REFERENCES

11.3-1 NUREG-0016, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Boiling Water Reactors (BWR-GALE Code)", NRC, (April 1976).

11.3-2 "Standards for Steam Surface Condensers", 6th Edition, Heat Exchange Institute, New York, NY, (1970).

11.3-3 D.P. Siegworth, "Measurement of Dynamic Adsorption Coefficients for Noble Gases on Activated Carbon", 12th AEC Air Cleaning Conference, (1971).

11.3-4 D. Underhill, "Design of Fission Gas Holdup Systems," 11th AEC Air Cleaning Conference, (1970).

11.3-5 "Analysis of Detonation Design Pressure for Hydrogen LGS Charcoal Offgas Treatment Systems", Helix Process Systems - PROPRIETARY.

Table 11.3-1

EXPECTED ANNUAL ACTIVITY RELEASED FROM GASEOUS WASTE MANAGEMENT SYSTEMS[1]
(Curies/year; 2 units)

NUCLIDE	REACTOR ENCLOSURE	TURBINE ENCLOSURE	RADWASTE ENCLOSURE	GLAND SEAL	AIR EJECTOR	MECHANICAL VACUUM PUMP	TOTAL
Ar-41	5.10e+01	<1.0	<1.0	<1.0	<1.0	<1.0	5.10E+01
Kr-83m	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0
Kr-85m	1.22E+01	1.39E+02	<1.0	<1.0	1.22E+01	<1.0	1.63E+02
Kr-85	<1.0	<1.0	<1.0	<1.0	5.71E+02	<1.0	5.71E+02
Kr-87	1.22E+01	2.65E+02	<1.0	<1.0	<1.0	<1.0	2.77E+02
Kr-88	1.22E+01	4.69E+02	<1.0	<1.0	<1.0	<1.0	4.81E+02
Kr-89	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0
Xe-131m	<1.0	<1.0	<1.0	<1.0	1.43E+01	<1.0	1.43E+01
Xe-133m	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0
Xe-133	2.65E+02	5.10E+02	2.04E+01	<1.0	1.14E+01	4.69E+03	5.60E+03
Xe-135m	1.88E+02	1.33E+03	<1.0	<1.0	<1.0	<1.0	1.51E+03
Xe-135	1.39E+02	1.29E+03	9.18E+01	<1.0	<1.0	7.14E+02	2.23E+03
Xe-137	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0
Xe-138	2.86E+01	2.86E+03	<1.0	<1.0	<1.0	<1.0	2.88E+03
TOTAL NOBLE GASES						1.38E+04	
I-131	2.04E-01	3.88E-03	1.02E-01	<1.0E-4	<1.0E-4	6.12E-02	3.71E-01
I-133	8.16E-01	1.55E-02E	3.67E-01	<1.0E-4	<1.0E-4	<1.0E-4	1.20E+00
TOTAL HALOGENS[4]						1.57E+00	

Table 11.3-1

NUCLIDE	REACTOR ENCLOSURE	TURBINE ENCLOSURE	RADWASTE ENCLOSURE	GLAND SEAL	AIR EJECTOR	MECHANICAL VACUUM PUMP	TOTAL
Tritium Gaseous Release							1.44E+02
Carbon-14	<1.0	<1.0	<1.0	<1.0	1.90E+01	<1.0	5.10E+01
Cr-51	1.22E-05	2.65E-04	1.84E-04	0.00E+00	0.00E+01	0.00E+00	4.61E-04
Mn-54	1.22E-04	1.22E-05	6.12E-04	0.00E+00	0.00E+00	0.00E+00	7.47E-04
Co-58	2.45E-05	1.22E-05	9.18E-05	0.00E+00	0.00E+00	0.00E+00	1.29E-04
Fe-59	1.63E-05	1.02E-05	3.06E-04	0.00E+00	0.00E+00	0.00E+00	3.33E-04
Co-60	4.08E-04	4.08E-05	1.84E-03	0.00E+00	0.00E+00	0.00E+00	2.28E-03
Zn-65	8.16E-05	4.08E-06	3.06E-05	0.00E+00	0.00E+00	0.00E+00	1.16E-04
Sr-89	3.67E-06	1.22E-04	9.18E-06	0.00E+00	0.00E+00	0.00E+00	1.35E-04
Sr-90	2.04E-07	4.08E-07	6.12E-06	0.00E+00	0.00E+00	0.00E+00	6.73E-06
Zr-95	1.63E-05	2.04E-06	1.02E-06	0.00E+00	0.00E+00	0.00E+00	1.94E-05
Sb-124	8.16E-06	6.12E-06	1.02E-06	0.00E+00	0.00E+00	0.00E+00	1.53E-05
Cs-134	1.63E-04	6.12E-06	9.18E-05	0.00E+00	0.00E+00	0.00E+00	2.67E-04
Cs-136	1.22E-05	1.02E-06	9.18E-06	0.00E+00	0.00E+00	0.00E+00	2.65E-05
Cs-137	2.24E-04	1.22E-05	1.84E-04	0.00E+00	0.00E+00	0.00E+00	4.41E-04
Ba-140	1.63E-05	2.24E-04	2.04E-06	0.00E+00	0.00E+00	0.00E+00	2.65E-04
Ce-141	4.08E-06	1.22E-05	5.30E-05	0.00E+00	0.00E+00	0.00E+00	6.94E-05
TOTAL AIRBORNE PARTICULATE RELEASE							5.32E-03

(1) Estimated releases based on NUREG-0016, Revision 0, GALE Code evaluation.
(2) * = Less than 1.0 Ci/yr
(3) ** = Less than 1.0×10^{-4} Ci/yr
(4) Includes both gaseous and particulate releases.

Table 11.3-2

ASSUMPTIONS AND PARAMETERS USED FOR EVALUATION OF GASEOUS RELEASES

Power	3527 MWt
Capacity factor	80%
Total steam flow	14.863×10^6 lb/hr
Mass of water in reactor	3.8×10^5 lb
RWCU filter/demineralizer flow	1.33×10^5 lb/hr
Fraction of feedwater through condensate filter/demineralizer	1.00
Gland seal system uses clean system with no radioactive releases	

Reactor Enclosure		
	Iodine Release Fraction	0.3 (2" Carbon Filter)
	Particulate Release Fraction	0.01 (HEPA Filter)
Turbine Enclosure		
	Iodine Release Fraction	0.01 (8" Deep-Bed Charcoal Filter)
	Particulate Release Fraction	0.01
Radwaste Enclosure		
	Iodine Release Fraction	1.0
	Particulate Release Fraction	0.01
Mechanical Vacuum Pump		
	Iodine Release Fraction	0.01
	Particulate Release Fraction	0.01

Charcoal Delay System designed with vendor coefficients for 35-day Xenon holdup at 75 scfm condenser inleakage. (This corresponds to 58.6 days Xe holdup using the NUREG-0016, Revision 0 methodology).

Table 11.3-3

OFFGAS SYSTEM MAJOR EQUIPMENT DESCRIPTION[3]

EQUIPMENT	EQUIPMENT NUMBERS	TYPE	QTY	MATERIAL	CAPACITY	SIZE	DESIGN PRESSURE/ TEMPERATURE (psig/°F)
Preheater	10E/20E-131	Shell and U-tube	2	Shell, Channel: CS Tubes, Sheet: SS	681,800 Btu/hr	697 ft² Effective area	Shell side: 350/450 Tube side: 350/450
Aftercondenser	10E/20E-127	Shell and straight tube	2	Shell, sheet: SS Tubes: Sanicro-28 (Unit 1), SS (Unit 2) Chanel: CS	16.3×10^6 Btu/hr	1003 ft²	Shell side: 350/1100 Tube side: 150/440
Recombiner	10S/20S-125	Vertical Cylinder	2	Shell: SS Internals: Catalyst support Assembly (SS) Catalyst: Metal mat coated with precious metals	1600 lbs Catalyst	Vessel: 76" OD, 102" high Catalyst: 51" Dia, 35" deep	350/1100 (Vessel)
Holdup pipe	KBG-106		2	CS		26" dia x 125"long	600/850
Outlet HEPA filter	10F/20F-371	Vertical Cylinder	2	Vessel: CS Internals: C size filter element	300 scfm at 0.4 psi	Vessel: 54" high, 14" dia Cartr: dia	445/150
Glycol cooler condenser	10E/20E-377	Shell and straight tube	2	Shell: SS Tubes: SS	86,760 Btu/hr	100.8 ft²	615/150
Guard bed vessel	10S/20S-370	Vertical Cylinder	2			136" dia x 36" high	175[2]/150
Charcoal adsorber vessels Unit 1	1AS/1BS-371 1CS-1GS-371	Vertical Cylinder	2 5	CS CS	82,125 lbs Charcoal each 31,500 lbs Charcoal lbs	132" dia x 354" high 120" dia x 174" high	375/150 250[1]/150

Table 11.3-3 (Cont'd)

EQUIPMENT	EQUIPMENT NUMBERS	TYPE	QTY	MATERIAL	CAPACITY	SIZE	DESIGN PRESSURE/ TEMPERATURE (psig/°F)
Charcoal adsorber vessels	2AS-371	Vertical Cylinder	1	CS	78,750 lbs Charcoal	132" dia x 354" high	375/150
Unit 2	2BS-2IS-371		8	CS	30,375 lbs Charcoal (each)	120" dia x 174" high	250(1)/150
Charcoal beds Units 1 and 2	----------	Sutcliffe Speakman 203C		Charcoal	Adsorber coefficient At design temperature Xe: 733, Kr: 31.8	Mesh size 8x16	----------
Glycol unit pumps	1AP/BP-700 2AP/BP-700	Centrifugal	4	CS	40 gpm ----------	----------	125 psig
Glycol fill Tank	10/20T-549	Vertical Cylinder	2	CS	----------	----------	125/150
Glycol Expansion tank	10/20T-550	Vertical Cylinder	2	CS	----------	----------	125/150
Glycol Air Separator	10/20S-515	Vertical Cylinder	2	CS	----------	----------	125/150
Refrigeration units (glycol)	1/2AE-376 1/2BE-376	Semi-Hermetic	4	Freon 22 Refrigerant	92,135 Btu/hr		
Refrigeration units (compartment cooling)	OAE-378 OBE-378	Semi-Hermetic	2	Freon 22 Refrigerant	125,000 Btu/hr	----------	----------

(1) Vessels have been hydrostatically tested at 375 psig.
(2) Calculation of code static-equivalent pressure based on actual full wall thickness and material properties yields 359 psig.
(3) Design Codes and Standards are provided in Table 3.2-1.

Table 11.3-4

COMPARISON OF MAXIMUM INDIVIDUAL DOSES
RESULTING FROM LGS UNIT 1 & 2 WITH 10CFR50,
APPENDIX I DESIGN OBJECTIVES

	LGS GASEOUS DOSE UNITS 1 & 2	10CFR50, APPENDIX I DESIGN OBJECTIVE (2 UNITS)	RM-50-2 SITE DESIGN OBJECTIVE[3]
Gamma air dose (mRad/yr)[1]	0.88	20	-
Beta air dose (mRad/yr)[1]	0.60	40	-
Total body of individual (mRem/yr)[1]	0.47	10	5
Skin of individual (mRem/yr)[1]	0.92	30	15
Any organ all pathways (mRem/yr)[2]	10.76 (Thyroid)	30	15

(1) Doses from noble gases only.
(2) Doses from radioiodines and air particulates with half-lives greater than eight days.
(3) Annex to 10CFR50, Appendix I, "Concluding Statement of Position of the Regulatory Staff, Public Rulemaking Hearing on Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As-Low-As-Practicable" for Radioactive Material in Light-Water-Cooled Nuclear Reactors", AEC Docket No. RM-50-2.

Table 11.3-5

OFFGAS SYSTEM EQUIPMENT MALFUNCTION ANALYSIS

EQUIPMENT ITEM	MALFUNCTION	CONSEQUENCES	DESIGN PRECAUTIONS
1. SJAE pressure control valves	Fail closed	Insufficient dilution of hydrogen in offgas.	Low flow signal will shut offgas suction valve. Low flow and low SJAE supply steam pressure will alarm in control room. Operator can start redundant SJAE train.
2. Piping from SJAE to and including holdup Pipe	Pressure boundary leakage	Increased local airborne radioactivity levels and increased releases from plant ventilation.	Area monitors in normally accessible areas will alarm. Ventilation releases will be filtered by turbine equipment compartment exhaust system and monitored. Low pressure system, radiographed welds, and system is designed to withstand hydrogen detonation.
3. Recombiner preheater	Steam leak from tube side into shell side.	1. Increased preheater outlet temperature	1. Temperature elements at preheater outlet would regulate steam flow to preheater
		2. Increased quantity of dilution steam	2. Additional steam flow would be condensed in the after condenser and returned to CRW or the main condenser.
	Liquid level instrument fails or level control valve fails	1. Level control valve opens. Preheater level drops. Steam recycles through drain line to main condenser.	1. Redundant level control instrumentation. Alarm on low condensate level in preheater. Operator closes level control valve or drain isolation valve from control room . Redundant level control valve provided.
		2. Level control valve closes.	2. Redundant level control valve provided. Will actuate automatically.

Table 11.3-5 (Cont'd)

EQUIPMENT ITEM	MALFUNCTION	CONSEQUENCES	DESIGN PRECAUTIONS
4. Recombiners	Catalyst deteriorates or is wetted	1. Recombiner outlet temperature drops.	1. Outlet temperature monitors record low temperature.
		2. High hydrogen concentrations at recombiner outlet.	2. Analyzers record hydrogen level and alarm at 2% and 4%. Operator isolates gas flow, or adjusts dilution.
5. Aftercondenser	Cooling water leak (tube to shell side)	The cooling water would leak to the shell side of the heat exchanger. Water flow would increase to the condenser.	Leakage would be detected by high conductivity in the drain line. High conductivity alarms in main control room . The aftercondenser drain can be swapped manually to clean radwaste. Excessive leakage would actuate aftercondenser high level alarm.
	Liquid level instrument fails or level control fails	1. Level control valve opens. Aftercondenser shell drain level drops or air cooler drain tank level drops. Steam or noncondensables recycle back to the main condenser, or clean radwaste.	1. Redundant level instrument alarms on low condensate level in aftercondenser. Operator closes level control valve or drain isolation valve from the control room. Loop seal provided on drain to clean radwaste to prevent offgas entering clean radwaste. Loop seal is self-resealing type.
		2. Level control valve closes.	2. Redundant level control valve provided. Redundant level control valve provided.
6. Piping from holdup pipe to HEPA filter exit	Pressure boundary leakage enclosure	Release of offgas mixture to radwaste or offgas enclosure will detect leakage.	Local radiation monitors in the radwaste Ventilation monitors in ducts from the offgas enclosure will detect leakage from offgas piping.

Table 11.3-5 (Cont'd)

EQUIPMENT ITEM	MALFUNCTION	CONSEQUENCES	DESIGN PRECAUTIONS
7. Holdup pipe	Liquid level instrument fails or level control valve fails	1. Level control valve opens. Holdup pipe drain pot liquid level drops. Offgas recycles through the drain line to the main condenser or to clean radwaste.	1. Redundant level instrumentation. Alarm on low condensate level in drain pot.Operator closes level control valve or drain isolation valve from control room. Loop seal provided on drain to clean radwaste to prevent offgas entering clean radwaste. Loop seal is of the self-resealing type.
		2. Level control valve closes	2. Redundant level control valve provided .
8. Glycol system	Mechanical failure (pumps or refrigeration units)	If glycol unit fails, the moisture content of the process stream will increase resulting in decreased adsorption.	The failure of the glycol system will activate alarms at local panel and alarms at main control room panel. Redundant glycol refrigeration units and glycol pumps are installed. Moisture instrumentation and temperature instrumentation is provided at the cooler condenser outlet. High outlet temperature and high moisture are alarmed at the local panel and in the main control room. In addition, system is oversized and glycol loop has sufficient thermal capacity which allows time to change over to redundant equipment.
9. Charcoal adsorbers	Moisture in gas stream	Charcoal adsorption performance will deteriorate gradually as charcoal gets wet. Holdup times decrease and plant gaseous releases will increase.	Increasing moisture in inlet stream will be detected by the moisture element. Various design precautions are included upstream to preclude moisture from entering adsorbers. Sacrificial guard beds are provided to protect main adsorber vessels.

Table 11.3-5 (Cont'd)

EQUIPMENT ITEM	MALFUNCTION	CONSEQUENCES	DESIGN PRECAUTIONS
10. Charcoal vault air conditioning units	Mechanical failure of refrigeration units or air coolers.	If ambient temperature increases, delay efficiency of charcoal beds decreases. Increased releases would occur depending on the fuel leakage rate.	Redundant air conditioning units are provided. Redundant fan and cooler for each cell provided. High ambient temperature alarms in main control room and local panel. Ambient temperature is recorded in the main control room. Refrigeration trouble alarm in main control room. Refrigeration system capacity is oversized for heat load.
11. Outlet HEPA filter	Plugging of filter media	Increasing differential pressure in HEPA will create higher system back pressure. SJAE bypass valve may open recycling offgas back to main condenser.	Differential pressure is alarmed in control room and indicated locally. DOP test connections are provided. HEPA filter can be bypassed for servicing.

Table 11.3-6

RELEASE POINT DATA

	TURBINE ENCLOSURE NORTH STACK (one only)	REACTOR ENCLOSURE SOUTH STACK (one per unit)	HOT MAINTENANCE SHOP
Height of release point above grade, ft	200	200	199
Annual average rate of air flow from release point, cfm	458,000	223,000	7,000
Annual average heat flow from release point, Btu/hr	26.2×10^6	5.4×10^6	---
Type and size of release point	Duct 20'x12'	Duct 10'x10'	Duct

Table 11.3-7

COMPARISON OF MAXIMUM CALCULATED RADIONUCLIDE CONCENTRATIONS IN THE ENVIRONMENT FROM ROUTINE ATMOSPHERIC RELEASES TO 10CFR20 LIMITS

LOCATION: ESE SITE BOUNDARY

ISOTOPE	AVERAGE ANNUAL CONCENTRATION IN AIR (μCi/ml)	10CFR20 TABLE II COLUMN 1 LIMIT[1] (μCi/ml)	% OF 10CFR20 LIMIT
Ar-41	1.00E-12	3E-08	3.3E-03
Kr-85M	3.23E-12	1E-07	3.2E-03
Kr-85	1.14E-11	3E-07	3.8E-03
Kr-87	5.57E-12	2E-08	2.8E-02
Kr-88	5.59E-12	2E-08	2.8E-02
Xe-131M	2.85E-13	4E-07	7.1E-05
Xe-133	1.10E-10	3E-07	3.7E-02
Xe-135M	2.69E-11	3E-08	9.0E-02
Xe-135	4.46E-11	1E-07	4.5E-02
Xe-138	5.05E-11	3E-08	1.7E-01
I-131	6.73E-15	1E-10	6.7E-03
I-133	2.24E-14	4E-10	5.6E-03
Cr-51	7.84E-18	8E-08	9.8E-09
Mn-54	1.26E-17	1E-10	6.7E-03
Fe-59	5.46E-18	2E-09	2.7E-07
Co-58	2.15E-18	2E-09	1.1E-07
Co-60	3.75E-17	3E-10	7.5E-07
Zn-65	1.95E-18	2E-09	9.7E-08
Sr-89	2.25E-18	3E-10	7.5E-07
Sr-90	1.12E-19	3E-11	3.7E-07
Zr-95	3.24E-19	1E-09	2.6E-07
Sb-124	2.56E-19	1E-10	2.6E-07
Cs-134	4.44E-18	4E-10	1.1E-06
Cs-136	4.44E-19	6E-09	7.4E-09
Cs-137	7.51E-18	5E-10	1.5E-06
Ba-140	4.44E-18	1E-09	4.4E-07
Ce-141	1.16E-18	5E-09	2.3E-08
H-3	2.39E-12	2E-07	1.5E-03
C-14	3.86E-13	1E-07	3.9E-04

[1] The concentration limits shown are reflective of the 10CFR20 Appendix B values prior to the 1994 revision of 10CFR20, and are consistent with those used in the original licensing of the plant. Current effluent release limits are based on the post-1994 10CFR20 regulation and are controlled by the Radioactive Effluent Controls Program defined by the Technical Specifications. New 10CFR20 limits went into effect on Jan. 1, 1994. As part of the power rerated evaluation, a comparison of the uprated atmospheric release concentrations with the new 10CFR20 limits was made. All the uprated released concentrations were found to be less than 1% of their new limit values.

11.4 SOLID WASTE MANAGEMENT SYSTEM

The applicant is committed to providing a solid waste management system that complies with the intent of BTP ETSB 11-3, "Design Guidance for Solid Radioactive Waste Management Systems Installed in Light-Water-Cooled Nuclear Power Reactor Plants.". A process control program that ensures suitability of packaged wastes for shipment and burial in consideration of applicable federal and state regulations and other requirements was submitted in conformance with the guidelines of SRP section 11.4 of NUREG-0800 (Reference 11.4-1). Process parameter tolerances were verified during preoperational testing of the solid radwaste system, and the final Process Control Program was submitted on March 7, 1985. Any revision to the program requires PORC approval.

The solid waste management system collects, monitors, processes, packages, and provides temporary storage facilities for radioactive spent bead and powdered resins and dry solid wastes for offsite shipment and permanent disposal. The solid waste management system does not have any safety-related functions. For the purpose of this section, the term "solid waste" is used for spent bead and powdered resins and dry solid waste produced from plant operation.

In addition, Class B and Class C Low-Level Radioactive Waste (LLRW) produced from plant operation may be shipped to Peach Bottom Atomic Power Station for storage.

Process and effluent radiological monitoring systems are discussed in Section 11.5.

11.4.1 Design Bases

a. The design objectives of the solid waste management system are:

   1. Provide collection, processing, packaging, and storage of solid wastes resulting from normal plant operations without limiting the operation or availability of the plant

   2. Provide a reliable means for handling solid wastes and allow system operation with ALARA radiation exposure to plant personnel

   3. Package solid wastes in suitable containers for offsite shipment and burial

   4. Prevent the release of significant quantities of radioactive materials to the environment so as to keep the overall exposure to the public well within 10CFR20 limits

b. Redundant and backup equipment, alternate routes, and interconnections are designed into the system to provide for operational occurrences such as refueling, abnormal leak rates, decontamination activities, equipment downtime, maintenance, and repair.

c. Equipment locations, compartments, drainage, ventilation, and components are designed to reduce maintenance, equipment downtime, leakage, and gaseous releases of radioactive materials to the structure atmosphere or to otherwise improve the system operations.

d. The solid waste management system is designed to package radioactive solid wastes for offsite shipment and burial in accordance with the requirements of applicable NRC and DOT regulations including 10CFR71 and 49CFR170 through 49CFR178. Final waste classification and waste form for offsite disposal will be consistent with the guidelines of 10CFR61. A shipping manifest consistent with 10CFR20.2006 will accompany the waste shipment. Waste stability for Class B and Class C wastes is provided by the use of high integrity containers which are designed in accordance with the "General Criteria for High Integrity Containers" established by the South Carolina Department of Health and Environmental Control on October 22, 1980. Concrete overpacks are used at the burial site to provide the compressive strength required for burial. This results in radiation exposures to individuals and the general population well within the limits of 10CFR20 and 10CFR50.

e. The solid waste management system is designed to seismic Category II requirements. The quality group classification and corresponding codes and standards that apply to the design of the solid waste management system are discussed in Section 3.2.

f. The expected and maximum radionuclide activity inventories of solid waste management system components containing significant amounts of radioactive liquids are shown in Tables 11.4-8 and 11.4-9.

    1. Expected flow rates for streams shown in Figure 11.4-3 are given in Table 11.4-4.

    2. Expected inputs and activities to the solid waste management system are shown in Tables 11.4-5 and 11.4-6.

g. A quality assurance program for the packaging and transportation of radioactive material shall be established which complies with the applicable requirements of 10CFR50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants", and 10CFR71, subpart H, "Packaging and Transportation of Radioactive Material, Quality Assurance".

11.4.2 SYSTEM DESCRIPTION

The solid waste management system P&IDs are shown in drawings M-66 and M-67. The process flow diagram is shown in Figure 11.4-3. Major equipment design parameters are listed in Tables 11.4-1, 11.4-2, and 11.4-3.

11.4.2.1 System Operation

The activities of the wastes entering the solid waste management system are dependent on the liquid activities in the various liquid systems such as the condensate, RWCU, fuel pool cleanup, equipment drain, and floor drain systems, whose activities are in turn a function of the reactor coolant activity. The activity of the reactor coolant is discussed in Section 11.1. Liquid waste management systems that supply input to the solid waste management system are discussed in Section 11.2.

The quantities of solid wastes generated are dependent on the plant operating factor, extent of equipment leakage, plant maintenance and housekeeping, and decontamination requirements.

Input to the solid waste management system is predominantly captured solids from filter/demineralizers and bead resins from deep-bed demineralizers. Powdered and bead resins are dewatered and then packaged in HICs or other approved containers for offsite disposal (Section 11.4.2.4).

11.4.2.1.1 Wet Solid Waste Processing

Wet solid wastes consist primarily of filtered solids from condensate filter/demineralizers and filtered solids, spent bead resins and powdered resins backwashed from RWCU, deep bed condensate demineralizers, floor drain, equipment drain, and fuel pool cleanup systems. Only spent resins from the RWCU system are expected to exceed LSA criteria. The rest of the solid wastes are expected to be low specific activity, as defined in 10CFR71.

The originally installed plant centrifuge system is no longer in service. Spent resins are transferred to the external processing station for dewatering through permanently installed plant systems/piping (Section 11.4.2.2.7).

The condensate filter/demineralizer are backwashed to the respective condensate backwash receiving tank and from there are pumped to one of two (per unit) phase separators. When the backwash material has settled in the phase separator, the clear water is decanted to the equipment drain tank for further processing. When a preset sludge level is reached in a phase separator, the other phase separator is used, while the sludge in the first phase separator is allowed to decay. After decay the sludge is pumped in slurry form to the external processing station for dewatering.

Backwash from the RWCU system is handled in a manner similar to the condensate filter/demineralizer system. There are two RWCU phase separators shared between two units. Each RWCU phase separator is sized for a normal 60 day collection (from both units) and 60 day decay time.

Spent bead resin from the DBCD can be transferred to the floor and equipment drain demineralizers for re-use (Section 10.4.6.2). DBCD system spent resin can also be processed externally (vendor process) by pumping resin from the DBCD system spent resin tanks (SRT) to the external processing station for collection in liners or high integrity containers.

Spent powdered resins from the equipment drain and floor drain filters and fuel pool cleanup filter/demineralizer are backwashed to the waste sludge tank, transferred to a condensate phase separator for processing and then pumped to the external processing station for dewatering. The waste sludge tank contents can also be processed directly to the external processing station for dewatering, based on plant conditions. Equipment and floor drain demineralizer spent resins were designed to be sluiced to their respective intermediate spent resin tanks before being pumped to the waste sludge tank. However, for normal plant operation, the spent resin tanks are not used. The exhausted bead resin from the liquid radwaste demineralizers will be sluiced directly to the waste sludge tank via a permanently installed bypass line.

The waste sludge tank holdup capacity does not approach the BTP ETSB 11-3 30 day criteria. However, the tank contents can be routed to the condensate phase separator for holdup and decanting in lieu of immediate dewatering by external processing. The use of redundant

dewatering process trains is expected to preclude the need for significant upstream waste slurry storage from a process equipment availability standpoint.

Slurries from the phase separators or the waste sludge tank are pumped to the external processing station. The slurry is approximately 5% by weight solid content and is dewatered to approximately 40% to 60% by weight solid content.

The vendor's external dewatering system shall be operated in accordance with the system's Topical Report and applicable procedures.

During initial system testing (preoperational), process parameters were established that provided reasonable assurance that the dewatered sludge contained essentially zero free liquid. Periodically during external waste processing, the free liquid parameters will be verified. Sludge samples may also be taken if an abnormal condition develops during waste processing. Records of process parameters will be maintained for individual waste batches. Dewatered waste shipments will comply with the applicable burial site criteria for maximum acceptable free liquid content, when shipped for burial.

11.4.2.1.2 Concentrated Liquid Waste Processing

Installation of the radwaste evaporators was not completed for plant operation and the system has been abandoned (Section 11.2.2.1.3). Because the solid waste management system does not include an installed solidification subsystem, any future concentrates produced would be solidified prior to offsite shipment by an acceptable mobile solidification system connected to the external processing station.

11.4.2.1.3 Dry Solid Waste Inputs

Dry wastes consist of air filters, miscellaneous paper, rags, etc, from contaminated areas; contaminated clothing, tools, and equipment parts that cannot be effectively decontaminated; and solid laboratory wastes. The activity of much of this waste is low enough to permit handling by contact. These wastes are collected in containers located in appropriate areas throughout the plant, as dictated by the volume of wastes generated during operation and maintenance. Compressible wastes are packaged manually into strong, tight containers. Noncompressible wastes are packaged manually in similar strong, tight containers or in other suitable containers. The filled containers are sealed and moved to a controlled access enclosed area for temporary storage. Because of its low activity, this waste can be stored until enough is accumulated to permit economical transportation to an offsite vendor for processing and/or to an offsite burial ground for final disposal.

11.4.2.1.4 Irradiated Reactor Internals

Irradiated reactor internals being replaced are removed from the RPV underwater and stored for radioactive decay in the spent fuel storage pool. Section 9.1.4 describes reactor vessel and in-vessel servicing equipment used for handling reactor components.

Some irradiated reactor internals are processed and then stored in Storage Containers (SCs) in free-standing storage racks in the cask loading pit prior to shipping. The rack compartments hold LLW including Control Rod Blades (CRBs), fuel channels in sheaths, LPRM strings, velocity limiters, filters, stellite ball bearing and other small components. During LLW processing, processing equipment will be placed in the cask loading pit or on the Refuel Floor.

An estimated average of seven of the control rod blades will be removed at each reactor outage (starting 10-15 years after operation) and stored on hangers on the fuel pool walls or in racks interspersed with the spent fuel racks. Offsite shipping is done in NRC licensed shipping casks.

An estimate of 30% of the power range monitor detectors will be replaced at each reactor outage. Actual power range monitor detector replacement is as required based on detector life. Spent incore detectors and dry tubes are cut or bent as required to facilitate subsequent storage. The incore detectors and dry tubes are stored with adequate water shielding on hangers on the fuel pool walls or within suitable storage containers. A cutting tool allows remote cutting of the incore detectors and dry tubes in the fuel pool or cask pit. The cut incore monitors and dry tubes and other small sized reactor internals are shipped offsite in suitable containers and/or shielded casks that can be loaded underwater.

A trolley-mounted disposal cask with an internal cable drum is supplied with the NSSS for source and intermediate range neutron monitor detector cables and the TIP wires.

11.4.2.2 Process Equipment Description

Major components of the solid waste management system include pumps, tanks, piping, centrifuges, discharge chute assemblies, capping machine, decontamination equipment, and handling equipment. The entire system is located in the radwaste enclosure with the exception of the condensate and reactor water cleanup backwash receiving tanks, which are located in the control enclosure and reactor enclosure, respectively. The designs of the radwaste, turbine, and reactor enclosures are discussed in Section 3.8.4. Equipment design parameters are listed in Tables 11.4-1, 11.4-2, and 11.4-3.

11.4.2.2.1 Pumps

Process pumps are vertical in-line centrifugal pumps of ASME Section III, Class 3 construction. All are made of carbon steel except the RWCU sludge discharge/mixing and the RWCU decant pumps, which are of stainless steel. All are provided with a mechanical-type seal.

11.4.2.2.2 Tanks

System collection and phase separator tanks are sized for normal plant waste volumes with sufficient excess capacity to accommodate equipment downtime and expected maximum volumes that may occur. Cross-connections between tanks are provided as appropriate for greater operational flexibility. Air spargers or recirculation lines are provided in the tanks to create a homogeneous slurry for pumping. All tanks are provided with overflow lines to route any inadvertent overflow to liquid radwaste collection sumps. All tanks are vented to their enclosures' respective ventilation system. See Section 9.4.3 for a discussion of the radwaste enclosure ventilation system.

All tanks are constructed to API 650. See Table 11.4-1 for tank materials.

11.4.2.2.3 Piping

The system piping material is carbon steel. The external processing station piping is stainless steel. Line sizing is based on maintaining adequate flow velocities to maintain slurries in suspension. The piping is laid out to avoid low points and other features that could create local "hot spots." The lines are normally flushed with condensate after a pumping or draining operation.

Process piping is constructed to ASME Section III, Class 3 or ANSI B31.1 (See Section 3.2 for further details).

11.4.2.2.4 Centrifuges

Two centrifuges were provided to dewater filter sludges and spent resins but are no longer in service. The water removed was returned to a condensate phase separator by gravity, and the dewatered sludges were directed to the HICs. The centrifuges are fabricated of stainless steel and are the continuous-feed, horizontal, solid bowl, sanitary-type.

11.4.2.2.5 Discharge Chute Assemblies

Discharge chutes from the centrifuges are equipped with telescoping fill chutes to interface with the HIC openings. A drip pot and sluice pan mechanism is positioned below the chute during chute flush and while HIC filling is not in progress. Major components with surfaces contacting radioactive materials are fabricated of stainless steel. This equipment is no longer in service.

11.4.2.2.6 Capping Machines

The capping machine automatically caps the HIC. Operation is controlled locally at the process cell viewed through the shielded glass window to verify proper closure. This equipment is no longer in service.

11.4.2.2.7 Solidification and Dewatering Equipment

The solid waste management system does not include a permanently installed solidification capability and the originally installed plant centrifuge system, designed for dewatering, is no longer in service. An external processing station has been provided to accommodate the use of a mobile solidification or dewatering system. Waste processing via a vendor's mobile solidification or dewatering system will be accomplished consistent with the vendor's process control procedures. Processed waste from the vendor's system will be packaged in suitable containers consistent with appropriate NRC and DOT regulations and receiving burial site requirements.

11.4.2.2.8 Decontamination Station Equipment

HICs were washed down with spray nozzles and air blast dried within an enclosed ventilated space within the decontamination cell to minimize the spread of contamination. A swipe sample mechanism and a contact radiation monitor are provided to verify decontamination and to determine the radiation level for shipping considerations. This equipment is no longer in service.

11.4.2.2.9

Information in this section has been deleted.

11.4.2.2.10 Handling Equipment

HIC handling is accomplished by an overhead crane and transfer carts.

The overhead crane moves HICs to and from storage cells and to trucks for offsite shipping. Operations can be viewed through a shielded glass window as well as on closed-circuit television monitors. Two area television cameras and one crane-mounted camera are provided.

HICs are moved in and out of process cells on railed, electric motor-driven transfer carts. If there is a motor failure, the carts can be manually placed in position by a push rod for HIC removal and for repair access. Cart operations are viewed and controlled from the shielded glass window of the process cell. Transfer carts are no longer in service.

11.4.2.3 Expected Volumes (Based on Original Plant Design Estimates)

It is estimated that approximately 12,720 cubic feet of dewatered waste will be generated per year. A breakdown of these wastes is given in Table 11.4-5.
Dry compressed waste is estimated at 28,500 cubic feet per year, representing about 3,886 fifty-five gallon drums per year. Noncompressible dry waste (filters, tools, etc) is estimated at 25,000 ft^3/yr. A breakdown of the dry waste from air filters is given in Table 11.4-6.

Table 11.4-10 presents the expected annual offsite shipment of solid wastes and their curie content.

11.4.2.4 Packaging

Low specific activity and other dewatered wastes, which meet the 10CFR61 classification as Class B and Class C waste, are packaged in large polyethylene HICs. The radioactivity contents of the shipping containers are listed in Table 11.4-7 for both expected and maximum conditions. Class A dewatered wastes may be packaged in HICs, strong, tight containers or other suitable containers. All wet wastes are consistent with the receiving burial site maximum free liquid criteria. Compressible dry waste is packaged in strong, tight containers. Noncompressible dry wastes are packaged in strong, tight containers or other suitable containers. All containers comply with applicable portions of 10CFR71, 49CFR170 through 49CFR178, and the receiving burial site container requirements, when shipped for direct burial.

11.4.2.4.1 HIC Service

The HIC is designed to contain concentrated radioactive waste materials generated during the removal of corrosion and activation products from plant process systems. The specific activity of these materials will range from trace quantities to no greater than 350 $\mu Ci/cm^3$. These values of specific activity include only radionuclides whose half-lives are greater than 5 years. In this specific HIC application, the predominant radionuclides are Co-60, Cs-137, Ni-63, Zn-65, Cr-51, and Mn-54.

The containerized waste form has three main constituents other than the corrosion activation products. These are:

a. Fibrous filter aid material derived from wood pulp fibers (cellulose) - this material is stable with respect to gas evolution in both acidic and basic solutions. In highly acidic solutions, cellulose will liquefy. High levels of ionizing radiation cause a break in the long molecular chains ($C_6H_{10}O_5$) with no significant loss of weight.

   This material is nonprotein and highly resistant to micro-organism ingestion.

b. Ion Exchange Bead Resin - This material consists of cation and anion exchange resins in bead form (O.4 mm to O.5 mm diameter spheres). The individual resin beads are formed from sulfonated polystyrene. The material exhibits chemical stability in pH ranges of O to 14.

c. Ion Exchange Resin Powder - This is identical to the above material; however, it is crushed to powder prior to use.

11.4.2.4.2 HIC Material

The container is to be molded polyethylene. The suitability of polyethylene for this particular application relies on its material characteristics: outstanding dielectric properties, excellent chemical resistance to solvents, acids, and alkalies, toughness, good barrier properties, high environmental stress cracking resistance, good cold impact strength, ultraviolet light stability, and radiation resistance.

11.4.2.4.3 HIC Integrity

Polyethylene is an extremely corrosion-resistant material with a high degree of chemical resistance both to the contents of the HIC and the earthen environment in which it will be buried. Testing will confirm the HIC's ability to withstand vibration, drop, compression, puncture, and pressure tests. Each container receives a variety of quality control checks to confirm individual HIC integrity.

The HIC is designed to maintain its physical integrity for 10 half-lives of the longest lived significant isotope. For routine resin wastes, this is Cs-137 which has a 30 year half-life. Therefore, the lifetime of this HIC is 300 years.

Concrete overpacks are used at the burial site to provide the compressive strength required for burial.

11.4.2.5 Storage Facilities

Storage is provided in storage bays for the HICs. Each HIC is located in its own shielded cubicle with a removable plug on top. There are 11 low specific activity and 12 high specific activity storage cubicles. At the expected waste generation rates presented in Table 11.4-5, the low specific activity storage bay provides a minimum storage capability of 30 days and the high specific activity storage bay provides a minimum storage capability of six months.

The storage compartments and process cell areas where the HICs are handled are equipped with floor drains for washdown of any spillage that may occur.

Compressible and other dry wastes are expected to be of low activity, and the strong, tight containers and other suitable containers will be stored in appropriately controlled unshielded areas throughout the plant before shipment. Storage area is available for at least one truckload of waste.

The general arrangements of the solid radwaste process cells, storage, and shipping areas are shown in Section 1.2.

Sources of radioactivity not stored inside the plant structures are discussed in Section 12.2.1.7.

11.4.3 REFERENCES

11.4-1 Letter from J.S. Kemper (PECo) to A. Schwencer (NRC), "Process Control Program," (November 30, 1983).

11.4-2 NRC letter dated May 31, 2011, Subject: Peach Bottom Atomic Power Station, Units 2 and 3 - Issuance of Amendments, Re: Storage of Low-Level Radioactive Waste Produced at Limerick Generating Station (TAC Nos. ME3092 and ME3093).

Table 11.4-1

SOLID WASTE MANAGEMENT SYSTEM TANK DESIGN PARAMETERS

TANK	QUANTITY	DESIGN PRESSURE (psig)	DESIGN TEMPERATURE (°F)	TYPE	MATERIAL	CAPACITY, EACH (gal)
RWCU backwash receiving Tank	2	Atmos	212	Vert cyl	Stainless steel	3,000
RWCU phase separator	2	Atmos	212	Vert cyl	Stainless steel	7,500
Waste sludge tank	1	Atmos	212	Horiz cyl	Carbon steel	16,000
Equipment drain spent resin tank(2)	1	Atmos	212	Vert cyl	Stainless steel	1,700
Floor drain spent resin tank(2)	1	Atmos	212	Vert cyl	Stainless steel	1,700
Condensate backwash receiving tank	2	Atmos	212	Horiz cyl	Carbon steel	20,000
Condensate phase separator	4	Atmos	212	Vert cyl	Carbon steel	15,000

(1) Deleted

(2) The floor and equipment drain spent resin tanks are not used for normal plant operation (Section 11.4.2.1.1).

Table 11.4-2

SOLID WASTE MANAGEMENT SYSTEM PUMP DESIGN PARAMETERS

PUMP	QUANTITY	TYPE	RATED FLOW (gpm)	RATED HEAD, TDH (ft)	RATED POWER (hp)	DESIGN PRESSURE TEMPERATURE (psig/°F)
RWCU decant pump	1	Vert in-line centrifugal	50	150	7.5	150/40-140
RWCU sludge discharge mixing pump	1	Vert in-line centrifugal	200	220	20	150/40-140
Waste sludge discharge mixing pump	1	Vert in-line centrifugal	200	219	25	150/40-140
Equipment drain spent resin pump[2]	1	Vert in-line centrifugal	200	100	10	150/40-140
Floor drain spent resin pump[2]	1	Vert in-line centrifugal	200	100	10	150/40-140
Condensate backwash transfer pumps	4	Vert in-line centrifugal	450	20	7.5	150/40-140
Condensate decant pump	2	Vert in-line centrifugal	450	100	25	150/40-140
Condensate sludge discharge mixing pump	2	Vert in-line centrifugal	400	224	40	150/40-140

(1) Deleted

(2) The floor and equipment drain spent resin pumps are not be used for normal plant operation (Section 11.4.2.1.1).

Table 11.4-3

SOLID WASTE MANAGEMENT SYSTEM PROCESS EQUIPMENT DESIGN PARAMETERS

CENTRIFUGES	
Quantity	2
Type	Solid bowl, horizontal, continuous solids discharge
Rating	Design feed rate 20 gpm Maximum feed rate 30 gpm Maximum solids capacity 750 lb/hr Centrifuge speed, bowl 3250 rpm conveyor 3224 rpm Developed G-forces 2050 Efficiency 98%
Drivers	
Type	Ac motor, 460 V, 60 Hz, 3-phase
Motor power rating	25 hp
Nominal speed	1800 rpm
SAMPLING EQUIPMENT	
Discharge Chute Resin Sampler	
Quantity	2
Type	Pneumatic piston
Sample Trolley	
Quantity	2
Driver	
Type	Ac motor, 460 V, 60 Hz, 3-phase
Motor power rating	½ hp
Sample Station	
Quantity	1
Type	Enclosed (with fume hood)

Table 11.4-3 (Cont'd)

DECONTAMINATION STATION

Washdown Mechanism	High pressure water
Pump	
Type	Single-stage centrifugal
Rating	
Flow	30 gpm
Head	1265'
Temperature	40°F-80°F
Driver	
Type	Ac motor, 460 V, 60 Hz, 3-phase
Motor power rating	40 hp
Speed	3600 rpm
Drying Mechanism	Air blast nozzle system inside
Flow	250 cfm
Temperature	70°F
Radiation Monitoring	
Type	GM tube
Range	1-1x10^6 mRem/hr
Swiping Mechanism	
Type	Remote manipulator
Container surface	
Coverage	50% minimum
Detector type	GM tube

FILL STATION

Discharge Chute	
Quantity	2
Material	Stainless steel
Telescopic Fill Chute	
Quantity	2
Material	Stainless steel
Positioning mechanism	Pneumatic cylinder

Table 11.4-3 (Cont'd)

Drip Pot/Sluice Pan	
Quantity	2
Material	Stainless steel
Positioning mechanism	Pneumatic cylinder
Radiation Monitor	
Quantity	2
Type	GM tube
Range	Surface: to 100 R/hr 3': to 10 R/hr
Swiping Mechanism	
Type	Pole
Capping Machine	
Quantity	2
Type of Cap	Screw-on
Cap Drive	
Type	Air motor
Positioning mechanism	Pneumatic cylinder
TRANSFER TABLES	
Large Transfer Tables	
Quantity	2
Capacity	8 tons
Travel	14'
Platform size	6.5'x6.5'
Velocity	15 fpm

Table 11.4-3 (Cont'd)

Vibrator Table Motors	
Quantity	4
Type	Ac motor, 460 V, 60 Hz, 3-phase
Motor power rating	6 hp
Speed	1200 rpm
HIC Platform Vacuum Pumps	
Quantity	2
Pump	
Type	Rotary
Driver	
Type	Ac motor, 460 V, 60 Hz, 3-phase
Motor power rating	1½ hp
OVERHEAD CRANE	
Quantity	1
Type	Bridge
Capacity	20 tons
Maximum speed	50 fpm

Table 11.4-4

SOLID WASTE MANAGEMENT SYSTEM FLOWS

STREAM NO.[1]	AVERAGE BATCH FREQUENCY FOR NORMAL OPERATION OF BOTH UNITS (no. batches/no. days)	MAXIMUM BATCH FREQUENCY FOR ONE UNIT[2] (1/day)	VOLUME PER BATCH (gal)	FLOW RATE (gpm)	NORMAL ACTIVITY CONCENTRATION (μCi/cc)	MAXIMUM ACTIVITY CONCENTRATION (μCi/cc)
21	2/6.8	2/1	1100	By gravity	36.5	1110
22	4/6.8	2/1	1100	By gravity	35.8	1100
23	1/60	-	5600	20	20.6	91.8
24	7/10	4/1	9000	By gravity	1.1	26.6
25	7/10	4/1	9000	450	1.0	26.4
26	1/14.3	-	13000	20	0.7	5.1
27	1/125.8	-	1500	By gravity	0.26	4.61
28A[3][5]	1/0.69	-	1925	By gravity	0.020	0.74
28B[3]	1/1.1	-	1925	By gravity	0.189	6.66
28C[3]	1/5	-	1925	By gravity	0.098	2.61
29	1/25.8	-	1500	By gravity	0.026	0.66
30[5][6]	1/2.5	-	12800	20	0.062	2.27
31A[4]	1/60	-	51 ft^3	By gravity	299	1340
31B[4]	1/14.3	-	235 ft^3	By gravity	5.07	37.4
31C[4][5][6	1/2.5	-	27 ft^3	By gravity	4.00	145

(1) See Figure 11.4-3 for the location of stream numbers.

(2) The maximum condition is assumed to happen 30 days per year per unit for the RWCU system and condensate filter/demineralizer system.

(3) 28A is the floor drain filter backwash.
28B is the equipment drain filter backwash.
28C is the fuel pool cleanup filter backwash.

(4) 31A is the RWCU sludge.
31B is the condensate sludge.
31C is the waste sludge.

(5) Batch frequencies, volumes, and activity concentrations are based on chemical waste processing via the floor drain subsystem (Section 11.2.2.1.3).

(6) Activity concentrations assume that exhausted bead resins from the liquid radwaste system are sluiced directly to the waste sludge tank (Section 11.4.2.1.1).

Table 11.4-5

WET WASTE INPUT TO THE SOLID WASTE MANAGEMENT SYSTEM[7]

SOURCE	WASTE TYPE	NORMAL BATCH SIZE (ft^3)	BATCH FREQUENCY (days)	NORMAL EXPECTED ACTIVITY (Ci/ft^3)	MAXIMUM ACTIVITY (Ci/ft^3)	EXPECTED ANNUAL VOLUME (ft^3)
RWCU phase separators	Dewatered spent powdered resin[1]	51	60	8.5	037.9	424[2]
Condensate phase separators	Dewatered spent powdered resin[1]/filtered solids	235	14	0.14	1.06	7670[2]
Waste sludge tank[5][6]	Dewatered spent resin beads and powdered resin[1][3]	27	2.5	0.11	4.12	4622[4]

(1) Density: 45 lb/ft^3 .
(2) Assume 10% of operating time generating maximum input (Table 11.4-4) and 85% plant capacity factor.
(3) From radwaste filter/demineralizer and deep-bed demineralizer.
(4) Add 20% to account for abnormal input.
(5) Batch frequency, activities, and annual volume are based on chemical waste processing via the floor drain subsystem (Section 11.2.2.1.3).
(6) Activity concentrations assume that exhausted bead resins from the liquid radwaste system are sluiced directly to the waste sludge tank (Section 11.4.2.1.1).
(7) Values are historical data based on original plant design estimates.

Table 11.4-6

DRY WASTE FROM FILTERS TO THE SOLID WASTE MANAGEMENT SYSTEM

SOURCE	EQUIPMENT NOS	WASTE TYPE	SIZE PER UNIT (in) OR WEIGHT PER UNIT	EXPECTED[3] NUMBER/WEIGHT OF FILTER PER YEAR	EXPECTED ANNUAL[3] VOLUME UNCOMPACTED (ft^3)
Charcoal Offgas Treatment System[1]					
HEPA (outlet)	10-F371 20-F371	Glass fiber – steel frame	11x8 dia	1	1
Control Structure - Standby Gas Treatment System					
HEPA	0A-F170 0B-F170	Glass fiber – steel frame	24x24x12	12	48
Charcoal	0A-F169 0B-F169	Bulk activated charcoal	1200 lb	2400 lb	80[2]
HEPA	0A-F183 0B-F183	Glass fiber – steel frame	24x24x12	6	24
Control Structure - Emergency Fresh Air Intake System					
Pre	0A-F159 0B-F159	Glass fiber particle board frame	24x24x12	3	12
HEPA	0A-F160 0B-F160	Glass fiber – steel frame	24x24x12	3	12
Charcoal	0A-F161 0B-F161	Bulk activated charcoal	770 lb	770 lb	26
HEPA	0A-F162 0B-F162	Glass fiber – steel frame	24x24x12	3	12

Table 11.4-6 (Cont'd)

SOURCE	EQUIPMENT NOS	WASTE TYPE	SIZE PER UNIT (in) OR WEIGHT PER UNIT	EXPECTED[3] NUMBER/WEIGHT OF FILTER PER YEAR	EXPECTED ANNUAL[3] VOLUME UNCOMPACTED (ft^3)
Reactor Enclosure - Recirculation System					
Pre	1A-F259 1B-F259 2A-F259 2B-F259	Glass fiber, particle board frame	24x24x12	80	320
HEPA	1A-F260 1B-F260 2A-F260 2B-F260	Glass fiber – steel frame	24x24x12	80	320
Charcoal	1A-F261 1B-F261 2A-F261 2B-F261	Bulk activated charcoal	12,900 lb	12,900 lb	430
HEPA	1A-F262 1B-F262 2A-F262 2B-F262	Glass fiber – steel frame	24x24x12	40	160
Turbine Enclosure –Equipment Compartment Exhaust Filters					
Pre	1A-F178 1B-F178 2A-F178 2B-F178	Glass fiber – steel frame	24x24x12	120	480
HEPA	1A-F194 1B-F194 2A-F194 2B-F194	Glass fiber – steel frame	24x24x12	120	480
Charcoal	1A-F179 1B-F179 2A-F179 2B-F179	Bulk activated charcoal	21,900 lb	43,800 lb	1460
HEPA	1A-F157 1B-F157 2A-F157 2B-F157	Glass fiber – steel frame	24x24x12	60	240
Turbine Enclosure - Condensate Backwash Receiving Tank Vent					
Pre	10-F166 20-F166	Glass fiber – steel frame	24x24x12 (U2) 24x24x11.5 (U1)	8	31
HEPA	10-F189 20-F189	Glass fiber - steel frame	24x24x12 (U2) 24x24x11.5 (U1)	8	31

Table 11.4-6 (Cont'd)

SOURCE	EQUIPMENT NOS	WASTE TYPE	SIZE PER UNIT (in) OR WEIGHT PER UNIT	EXPECTED[3] NUMBER/WEIGHT OF FILTER PER YEAR	EXPECTED ANNUAL[3] VOLUME UNCOMPACTED (ft^3)
Control Structure - Standby Gas Treatment Room					
Pre	0A-F196 0B-F196	Glass fiber – steel frame	24x24x12	4	16
HEPA	0A-F180 0B-F180	Glass fiber – steel frame	24x24x12	4	16
Charcoal HEPA	0A-F181 0B-F181 0A-F184 0B-F184	Tray type Glass fiber – steel frame	24x24x4 24x24x12	4 2	8 8
Turbine Enclosure - Condensate Backwash Area Floor Drain Sump Vent					
Pre	10-F172 20-F172	Glass fiber – steel frame	8x8x6	12	3
HEPA	10-F185 20-F185	Glass fiber – steel frame	8x8x6	12	3
Turbine Enclosure - Condensate Backwash Area Equipment Drain Sump Vent					
Pre	10-F173 20-F173	Glass fiber – steel frame	8x8x6	12	3
HEPA	10-F186 20-F186	Glass fiber – steel frame	8x8x6	12	3

Table 11.4-6 (Cont'd)

SOURCE	EQUIPMENT NOS	WASTE TYPE	SIZE PER UNIT (in) OR WEIGHT PER UNIT	EXPECTED[3] NUMBER/WEIGHT OF FILTER PER YEAR	EXPECTED ANNUAL[3] VOLUME UNCOMPACTED (ft^3)
Turbine Enclosure - Condensate Pump Area Floor Drain Sump Vent					
Pre	10-F174 20-F174	Glass fiber – steel frame	8x8x6	12	6
HEPA	10-F187 20-F187	Glass fiber – steel frame	8x8x6	12	6
Turbine Enclosure - Condensate Pump Area Equipment Drain Sump Vent					
Pre	10-F175 20-F175	Glass fiber – steel frame	8x8x6	12	6
HEPA	10-F188 20-F188	Glass fiber – steel frame	8x8x6	12	6
Reactor Enclosure – Equipment Compartment Exhaust					
Pre	1A-F254 1B-F254 2A-F254 2B-F254	Glass fiber – steel frame	24x24x12	140	560
HEPA	1A-F255 1B-F255 2A-F255 2B-F255	Glass fiber – steel frame	24x24x12	140	560
Charcoal	1A-F257 1B-F257 2A-F257 2B-F257	Bulk activated charcoal	21,900 lb	43,800 lb	1460
HEPA	1A-F258 1B-F258 2A-F258 2B-F258	Glass fiber – steel frame	24x24x12	70	280
Reactor Enclosure - RWCU Backwash Receiving Tank Vent					
Pre	10-F256 20-F256	Glass fiber – steel frame	24x24x12	12	48
HEPA	10-F263 20-F263	Glass fiber – steel frame	24x24x12	12	48

Table 11.4-6 (Cont'd)

SOURCE	EQUIPMENT NOS	WASTE TYPE	SIZE PER UNIT (in) OR WEIGHT PER UNIT	EXPECTED[3] NUMBER/WEIGHT OF FILTER PER YEAR	EXPECTED ANNUAL[3] VOLUME UNCOMPACTED (ft^3)
Radwaste Enclosure - Equipment Compartment Exhaust					
Pre	0A-F354 0B-F354	Glass fiber – steel frame	24x24x12	96	386
HEPA	0A-F355 0B-F355	Glass fiber – steel frame	24x24x12	96	386
Radwaste Enclosure - Service and Control Area Exhaust					
Pre	0A-F356 0B-F356	Glass fiber – steel frame	24x24x12	12	48
HEPA	0A-F357 0B-F357	Glass fiber – steel frame	24x24x12	12	48
Radwaste Enclosure - Centrifuge Room Exhaust					
Pre	0A-F360 0B-F360	Glass fiber – steel frame	24x24x12	12	48
HEPA	0A-F383 0B-F383	Glass fiber – steel frame	24x24x12	12	48
Radwaste Enclosure - Laundry Room Exhaust					
Pre	00-F361	Glass fiber – steel frame	24x24x12	2	8
HEPA	00-F375	Glass fiber – steel frame	24x24x12	2	8

Table 11.4-6 (Cont'd)

SOURCE	EQUIPMENT NOS	WASTE TYPE	SIZE PER UNIT (in) OR WEIGHT PER UNIT	EXPECTED[3] NUMBER/WEIGHT OF FILTER PER YEAR	EXPECTED ANNUAL[3] VOLUME UNCOMPACTED (ft^3)
Radwaste Enclosure - Handling and Storage Area Exhaust					
Pre	00-F366	Glass fiber – steel frame	24x24x12	4	16
HEPA	00-F374	Glass fiber – steel frame	24x24x12	4	16
Radwaste Enclosure - Common Tank Vent					
HEPA	00-F384	Glass fiber – steel frame	24x24x12	6	12
Radwaste Enclosure - Centrifuge Vent					
Pre	0A-F367 0B-F367	Glass fiber – steel frame	12x12x6	12	6
HEPA	0A-F380 0B-F380	Glass fiber – steel frame	12x12x6	12	6
Radwaste Enclosure - Floor and Equipment Drain Sump Vent					
HEPA	00-F368 00-F369	Glass fiber – steel frame	2/8x8x6	12	3
				Total	8345

(1) The charcoal guard beds are not expected to be replaced during the life of the plant.
(2) Charcoal density: 30 lb/ft^3.
(3) Expected volumes are based on original plant design estimates.

Table 11.4-7

EXPECTED AND MAXIMUM SHIPPING CASK INVENTORIES(Ci)[1] [5]

	EXPECTED[2]		MAXIMUM	
Isotope	Low Specific Activities[4]	High Specific Activities	Low Specific Activities[4]	High Specific Activities
Br-83	none	none	-	-
Br-84	none	none	-	-
Br-85	none	none	-	-
I-131	1.33E+00	4.56E-04	1.19×10^{1}	4.11×10^{-3}
I-132	3.81E-05	none	6.52×10^{-1} -	
I-133	5.13E-06	none	8.35×10^{-5}	-
I-134	none	none	-	-
I-135	none	none	-	-
Rb-89	none	none	-	-
Cs-134	4.09E-02	4.98E+00	7.54×10^{-1}	9.18×10^{1}
Cs-136	1.95E-03	3.94E-04	3.70×10^{-2}	7.52×10^{-3}
Cs-137	9.84E-02	1.35E+01	1.18	1.61×10^{2}
Cs-138	none	none	-	-
Na-24	1.62E-08	none	3.72×10^{-9}	-
P-32	2.90E-02	8.75E-03	2.87×10^{-3}	8.67×10^{-4}
Cr-51	2.05E+00	1.18E+01	2.02×10^{-1}	1.17
Mn-54	7.92E-02	7.87E+00	5.24×10^{-2}	5.19
Mn-56	none	none	-	-
Fe-55	1.32E+00	1.72E+02	-	-
Fe-59	1.98E-02	3.71E-01	5.17×10^{-2}	9.76×10^{-1}
Co-58	1.76E-01	6.80E+00	4.37	1.69×10^{2}
Co-60	$5.^{84E-01}$	7.34E+01	7.24×10^{-1}	9.07×10^{1}
Ni-63	1.49E-03	1.96E-01	-	-
Ni-65	none	none	-	-
Cu-64	none	none	-	-
Zn-65	2.55E-01	2.35E+01	2.52×10^{-3}	2.32×10^{-1}
Zn-69	none	none	-	-
Zn-69m	none	none	-	-
Sr-89	7.26E-02	1.72E-02	7.75	1.84×10^{2}
Sr-90	8.49E-03	1.16E+00	1.18	1.53×10^{2}
Sr-91	none	none	-	-
Sr-92	none	none	-	-
Y-91	5.20E-02	1.55E+00	1.24	3.85×10^{1}
Y-92	none	none	-	-
Y-93	none	none	-	-
Zr-95	5.85E-03	1.99E-01	1.16×10^{-3}	3.92
Zr-97	none	none	-	-

Table 11.4-7 (Cont'd)

	EXPECTED[2]		MAXIMUM	
Isotope	Low Specific Activities[4]	High Specific Activities	Low Specific Activities[4]	High Specific Activities
Nb-95	8.46E-03	3.88E-01	$1.70x10^{-1}$	7.71
Nb-98	none	none	-	-
Mo-99	3.89E-03	none	$1.48x10^{-1}$	-
Tc-99m	3.71E-03	none	$1.42x10^{-1}$ -	
Tc-101	none	none	-	-
Tc-104	none	none	-	-
Ru-103	1.18E-02	1.72E-01	$3.89x10^{-2}$	$5.66x10^{-1}$
Ru-105	none	none	-	-
Ru-106	4.05E-03	4.19E-01	$1.21x10^{-2}$	1.25
Ag-110m	1.29E-03	1.19E-01	$7.62x10^{-2}$	7.08
Te-129m	2.04E-02	2.02E-01	$7.02x10^{-2}$	$6.98x10^{-1}$
Te-131m	1.36E-06	none	-	-
Te-132	3.71E-05	none	$6.34x10^{-1}$	-
Ba-139	none	none	-	-
Ba-140	4.65E-02	6.83E-03	3.62	$5.31x10^{-1}$
Ba-141	none	none	-	-
Ba-142	none	none	-	-
La-142	none	none	-	-
Ce-141	1.61E-02	1.49E-01	$1.73x10^{-1}$	1.65
Ce-143	9.24E-08	none	$3.83x10^{-6}$	-
Ce-144	3.94E-03	3.79E-01	$1.58x10^{-1}$	$1.53x10^{1}$
Pr-143	5.61E-03	1.25E-03	$1.91x10^{-2}$	$4.22x10^{-3}$
Nd-147	2.53E-01	1.17E-05	$4.07x10^{-2}$	$1.89x10^{-3}$
W-187	3.99E-07	none	$4.06x10^{-6}$	-
Np-239	6.61E-03	none	$7.90x10^{-1}$	-
Other[3]	1.94E-01	1.51E+01	6.70	$3.23x10^{2}$
TOTAL	6.44E+00	3.36E+02	$4.29x10^{1}$	$1.26x10^{3}$

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(1) Container inventories are based on the specific activity levels of the source waste as processed by the external processing station and assume a filled container storage period prior to shipment of 15 days for low specific activity waste and 90 days for high specific activity waste.

(2) Low specific activity inventories are based on a prorated mixture of condensate sludge and waste sludge. High specific activity inventories are based on RWCU sludge. Container inventories assume 90% fill.

Table 11.4-7 (Cont'd)

(3) "Other" isotopes consist of daughter products resulting from radioactive decay of the influent isotopes during accumulation and storage periods.

(4) The prorated portion of low specific activity due to waste sludge is based on direct sluicing of exhausted bead resins from the liquid radwaste system to the waste sludge tank.

(5) Values are historical data based on original plant design estimates

Table 11.4-8

EXPECTED RADIONUCLIDE INVENTORIES OF SOLID WASTE MANAGEMENT SYSTEM COMPONENTS[1]

NUCLIDE	RWCU BACKWASH RECEIVING TANK	RWCU PHASE SEPARATOR	CONDENSATE BACKWASH RECEIVING TANK	CONDENSATE PHASE SEPARATOR	FLOOR DRAIN[4] SPENT RESIN TANK	EQUIPMENT DRAIN[4] SPENT RESIN TANK	WASTE[2][4] SLUDGE TANK
1Br-83	2.46E-01	8.97E-01	1.50E-01	9.56E-01	1.58E-04	2.50E-04	3.40E-03
Br-84	6.98E-02	1.81E-02	3.59E-02	1.62E-01	1.18E-05	1.90E-05	5.08E-04
Br-85	4.72E-04	1.86E-05	3.00E-03	2.06E-06	6.10E-08	9.81E-08	1.88E-05
I-131	1.91E+01	1.70E+02	1.59E+01	1.75E+02	1.59E-02	1.50E-01	3.55E-01
I-132	2.32E+00	8.43E+00	1.42E+00	8.98E+00	1.42E-03	2.32E-03	3.11E-02
I-133	1.69E+01	6.73E+01	1.08E+01	7.49E+01	2.82E-02	4.97E-02	5.09E-01
I-134	1.77E+00	5.44ED+00	9.93E-01	5.32E+00	4.51E-04	7.25E-04	1.46E-02
I-135	5.12E+00	1.98E+01	3.22E+00	2.17E+01	7.19E-03	1.04E-02	1.22E-01
Rb-89	2.62E-02	4.27E-02	5.36E-04	1.52E-03	7.54E-07	1.98E-05	1.09E-04
Cs-134	1.51E-01	5.21E+00	7.11E-03	1.41E-01	1.11E-03	4.29E-02	1.37E-03
Cs-136	8.54E-02	1.11E+00	3.72E-03	5.01E-02	3.99E-04	4.68E-03	8.36E-04
Cs-137	3.54E-01	1.24E+01	1.66E-02	3.33E-01	2.61E-03	1.06E-01	3.18E-03
Cs-138	1.42E-01	3.68E-01	3.65E-03	1.66E-02	6.74E-06	1.77E-04	5.75E-04
Na-24	5.69E+00	2.24E+01	1.81E-01	1.24E+00	9.83E-03	1.55E-02	1.70E-01
P-32	8.60E-01	1.15E+01	3.75E-02	5.13E-01	6.67E-04	1.07E-	51E-02
Cr-51	2.33E+01	4.63E+02	1.05E+00	1.69E+01	1.71E-02	5.05E-01	3.93E-01
Mn-54	3.01E-01	1.00E+01	1.41E-02	2.76E-01	2.11E-04	1.73E-02	4.89E-03
Mn-56	4.65E+00	1.69E+01	1.42E-01	9.10E-01	3.17E-03	4.99E-03	6.68E-02
Fe-55	5.06+00E	1.74E+02	2.39E-01	4.72E+00	none	none	none
Fe-59	1.44E-01	3.52E+00	6.62E-03	1.15E-01	1.04E-04	4.54E-03	2.40E-03
Co-58	9.77E-01	2.69E+01	4.52E-02	8.29E-01	6.98E-04	3.83E-02	1.60E-02
Co-60	2.02E+00	7.07E+01	9.50E-02	1.89E+00	1.42E-03	1.31E-01	3.27E-02
Ni-63	5.06E-03	1.79E-01	2.38E-04	4.76E-03	3.54E-06	3.34E-04	8.18E-05
Ni-65	2.77E-02	1.01E-01	8.48E-04	5.42E-03	1.89E-05	2.96W-05	3.97E-04
Cu-64	1.64E+01	6.44E+01	5.28E-01	3.69E+00	none	none	none
Zn-65	1.00E+00	3.27E+01	4.68E-02	9.13E+00	7.04E-04	5.59E-02	1.62E-02
Zn-69	7.13E-02	2.23E-01	2.01E-03	1.10E-02	3.09E-08	3.15E-05	5.88E-04
Sr-89	4.88E-01	1.24E+01	2.24E-02	3.99E-01	3.51E-04	1.63E-02	8.06E-03
Sr-90	3.04E-02	1.07E+00	1.43E-03	2.86E-02	2.12E-05	1.99E-03	4.92E-04
Sr-91	1.59E+00	6.22E+00	5.03E-02	3.44E-01	2.60E-03	3.79E-03	4.39E-02
Sr-92	9.86E-01	3.62E+00	3.02E-02	1.94E-01	7.05E-04	1.10E-03	1.46E-02
Y-91	3.08E-01	8.37E+00	1.44E-02	2.63E-01	2.09E-04	1.12E-02	4.91E-03
Y-92	1.83E+00	7.08E+00	5.74E-02	3.90E-01	2.23E-03	3.34E-03	3.97E-02
Y-93	1.70E+00	6.66E+00	5.39E-02	3.68E-01	2.83E-03	4.11E-03	4.77E-02
Zr-95	3.42E-02	9.25E-01	1.57E-03	2.87E-02	2.44E-05	1.29E-03	5.63E-04
Zr-97	3.61E-03	1.43E-02	1.14E-04	7.93E-04	6.18E-06	1.02E-05	1.09E-04
Nb-95	3.53E-02	1.14E+00	1.65E-03	3.24E-02	2.47E-05	1.77E-03	5.71E-04
Nb-98	1.02E-01	3.12E-01	2.86E-03	1.52E-02	2.56E-05	4.11E-05	8.37E-04

Table 11.4-8 (Cont'd)

NUCLIDE	RWCU BACKWASH RECEIVING TANK	RWCU PHASE SEPARATOR	CONDENSATE BACKWASH RECEIVING TANK	CONDENSATE PHASE SEPARATOR	FLOOR DRAIN[4] SPENT RESIN TANK	EQUIPMENT DRAIN[4] SPENT RESIN TANK	WASTE[2][4] SLUDGE TANK
Mo-99	4.80E+00	2.35E+01	1.71E-01	1.31E+00	5.27E-03	1.97E-02	1.10E-01
Tc-99m	8.94E+00	3.91E+01	3.00E-03	2.16E+00	1.08E-02	2.71E-02	2.05E-01
Tc-101	4.16E-01	6.18E-01	8.11E-03	2.10E-02	4.08E-05	6.57E-05	3.19E-03
Tc-104	5.34E-01	9.90E-01	1.16E-02	3.76E-02	6.05E-05	9.72E-05	3.89E-03
Ru-103	9.52E-02	2.20E+00	4.35E-03	7.47E-02	6.91E-05	2.67E-03	1.59E-03
Ru-105	3.41E-01	1.30E+00	1.06E-02	7.06E-02	3.68E-04	5.50E-04	6.71E-03
Ru-106	1.51E-02	5.07E-01	7.08E-04	1.39E-02	1.06E-05	8.90E-04	2.45E-04
Ag-110m	5.01E-03	1.64E-01	2.35E-04	4.58E-03	3.52E-06	2.82E-04	8.14E-05
Te-129m	1.89E-01	4.12E+00	8.61E-03	1.44E-01	1.38E-04	4.78E-03	3.16E-03
Te-131m	1.26E-01	5.17E-01	4.13E-03	2.88E-02	1.89E-04	4.05E-04	3.61E-03
Te-132	2.63E-02	1.37E-01	9.69E-04	7.64E-03	2.74E-05	1.16E-04	5.82E-04
Ba-139	4.55E-01	1.54E+00	1.34E-02	7.93E-02	1.75E-04	2.82E-02	4.58E-03
Ba-140	1.68E+00	2.10E+01	7.32E-02	9.65E-01	3.00E-03	1.93E-05	3.00E-02
Ba-141	6.69E-02	1.23E-01	1.45E-03	4.71E-03	8.33E-07	1.21E-06	4.86E-04
Ba-142	1.89E-02	2.14E-02	3.22E-04	6.40E-04	1.84E-07	2.69E-04	1.59E-04
La-142	2.93E-01	1.02E+00	8.74E-03	5.28E-02	1.39E-05	2.02E-03	3.14E-03
Ce-141	1.53E-01	3.29E+00	7.00E-03	1.16E-01	3.56E-04	3.64E-04	2.52E-03
Ce-143	4.17E-02	1.71E-01	1.36E-03	9.56E-03	2.24E-05	1.36E-04	1.15E-04
Ce-144	1.50E-02	4.99E-01	7.06E-04	1.38E-02	4.22E-05	8.61E-04	2.45E-04
Pr-143	1.80E-01	2.38E+00	7.89E-03	1.07E-01	3.34E-04	2.19E-03	3.13E-03
Nd-147	1.22E-02	1.39E-01	5.28E-04	6.62E-03	2.05E-05	1.24E-04	2.21E-04
W-187	3.06E-01	1.22E+00	9.81E-03	6.81E-02	1.42E-04	9.27E-04	9.04E-03
Np-239	1.50E+01	6.92E+01	5.24E-01	3.86E+00	1.05E-02	5.74E-02	3.61E-01
OTHERS[3]	3.26E+00	3.36E+01	1.16E-01	1.53E+00	1.59E-02	1.01E-01	3.04E-01
Total	1.51E+02	1.44+03	3.65E+01	3.33E+02	1.48E-01	1.45E+00	2.98E+00

(1) Activity inventories are given in curies.

(2) Activity inventory is based on chemical waste processing via the floor drain subsystem (Section 11.2.2.1.3).

(3) Activity of daughter products resulting from radioactive decay of the influent isotopes during the accumulation period.

(4) The floor and equipment drain spent resin tanks are not used for normal plant operation. Exhausted bead resin from the liquid radwaste sytems will be sluiced directly to the waste sludge tank (Section 11.4.2.1.1). The listed waste sludge tank curie inventory represents activity levels of the floor drain, equipment drain, and fuel pool filter/demineralizer backwashes. To determine the waste sludge tank inventory including an exhausted resin bed, the listed isotopic inventory from the appropriate spent resin tank should be added directly to the listed waste sludge tank inventory.

Table 11.4-9

MAXIMUM RADIONUCLIDE INVENTORIES OF SOLID WASTE MANAGEMENT SYSTEM COMPONENTS[1]

NUCLIDE	RWCU BACKWASH RECEIVING TANK	RWCU PHASE SEPARATOR	CONDENSATE BACKWASH RECEIVING TANK	CONDENSATE PHASE SEPARATOR	FLOOR DRAIN[4] SPENT RESIN TANK	EQUIPMENT DRAIN[4] SPENT RESIN TANK	WASTE[2][4] SLUDGE TANK
Br-83	5.34	$1.94 \times 10^{+1}$	3.25	$2.07 \times 10^{+1}$	3.82×10^{-4}	5.40×10^{-3}	7.35×10^{-2}
Br-84	1.78	4.61	9.16×10^{-1}	4.15	3.32×10^{-5}	4.82×10^{-4}	1.30×10^{-2}
Br-85	1.31×10^{-2}	5.15×10^{-4}	8.41×10^{-4}	5.70×10^{-5}	1.85×10^{-7}	2.71×10^{-6}	5.17×10^{-4}
I-131	$1.72 \times 10^{+2}$	$1.55 \times 10^{+3}$	$1.43 \times 10^{+2}$	$1.59 \times 10^{+3}$	2.49×10^{-1}	1.35	3.19
I-132	$4.89 \times 10^{+2}$	$2.51 \times 10^{+3}$	$3.59 \times 10^{+2}$	$2.79 \times 10^{+3}$	3.94×10^{-1}	2.07	$1.23 \times 10^{+1}$
I-133	$2.78 \times 10^{+2}$	$1.10 \times 10^{+3}$	$1.79 \times 10^{+2}$	$1.25 \times 10^{+3}$	1.18×10^{-1}	8.12×10^{-1}	8.31
I-134	$2.82 \times 10^{+1}$	$8.64 \times 10^{+1}$	$1.58 \times 10^{+1}$	$8.45 \times 10^{+1}$	7.89×10^{-4}	1.15×10^{-2}	2.32×10^{-1}
I-135	$1.32 \times 10^{+2}$	$5.11 \times 10^{+2}$	$8.30 \times 10^{+1}$	$5.61 \times 10^{+2}$	2.50×10^{-2}	2.69×10^{-1}	3.16
Cs-134	2.79	$9.62 \times 10^{+1}$	1.31×10^{-1}	2.60	2.04×10^{-2}	7.91×10^{-1}	2.49×10^{-2}
Cs-136	1.63	$2.13 \times 10^{+1}$	7.10×10^{-2}	9.58×10^{-1}	7.61×10^{-3}	8.92×10^{-2}	1.58×10^{-2}
Cs-137	4.20	$1.48 \times 10^{+2}$	1.97×10^{-1}	3.95	3.10×10^{-2}	1.25	3.74×10^{-2}
Cs-138	$1.27 \times 10^{+1}$	$3.31 \times 10^{+1}$	3.28×10^{-1}	1.49	6.04×10^{-4}	1.59×10^{-2}	5.16×10^{-2}
Na-24	1.32	5.17	4.16×10^{-2}	2.87×10^{-1}	4.68×10^{-4}	3.58×10^{-3}	3.92×10^{-2}
P-32	$8.52 \times 10^{+1}$	1.15	3.73×10^{-3}	5.09×10^{-2}	1.60×10^{-4}	1.06×10^{-3}	1.49×10^{-3}
Cr-51	2.30	$4.58 \times 10^{+1}$	1.04×10^{-1}	1.68	5.28×10^{-3}	4.99×10^{-2}	3.85×10^{-2}
Mn-54	1.99×10^{-2}	6.60	9.30×10^{-3}	1.82×10^{-1}	5.66×10^{-4}	1.14×10^{-2}	3.20×10^{-3}
Mn-56	5.45	$1.99 \times 10^{+1}$	1.66×10^{-1}	1.07	4.15×10^{-4}	5.84×10^{-3}	7.81×10^{-2}
Fe-59	3.80×10^{-1}	9.27	1.75×10^{-2}	3.05×10^{-1}	9.55×10^{-4}	1.17×10^{-2}	6.26×10^{-3}
Co-58	$2.42 \times 10^{+}$	$6.69 \times 10^{+2}$	1.12	$2.05 \times 10^{+1}$	6.41×10^{-2}	9.48×10^{-1}	3.95×10^{-1}
Co-60	2.50	$8.73 \times 10^{+1}$	$1.17 \times 10^{-}$	2.34	7.27×10^{-3}	4.01×10^{-1}	4.01×10^{-2}
Ni-63	-	-	-	-	-	-	-
Ni-65	3.25×10^{-2}	1.19×10^{-1}	9.94×10^{-3}	6.36×10^{-3}	2.47×10^{-6}	3.47×10^{-5}	4.65×10^{-4}
Cu-64	-	-	-	-	-	-	-
Zn-65	9.91×10^{-3}	3.25×10^{-1}	4.64×10^{-4}	9.04×10^{-3}	2.81×10^{-5}	5.54×10^{-4}	1.60×10^{-4}
Zn-69m	1.83×10^{-2}	7.14×10^{-2}	5.76×10^{-4}	3.96×10^{-3}	6.14×10^{-6}	4.84×10^{-5}	5.36×10^{-4}
Sr-89	$5.22 \times 10^{+1}$	$1.33 \times 10^{+3}$	2.40	$4.28 \times 10^{+1}$	1.35×10^{-1}	1.75	8.56×10^{-1}
Sr-90	4.03	$1.42 \times 10^{+2}$	1.89×10^{-1}	3.79	1.17×10^{-2}	2.64×10^{-1}	6.45×10^{-2}
Sr-91	$1.04 \times 10^{+2}$	$4.00 \times 10^{+2}$	3.23	$2.21 \times 10^{+1}$	2.66×10^{-2}	2.44×10^{-1}	2.81
Sr-92	$4.42 \times 10^{+1}$	$1.62 \times 10^{+2}$	1.35	8.71	3.54×10^{-3}	4.94×10^{-2}	4.99×10^{-1}
Y-91	-	-	-	-	6.83×10^{-3}	1.88×10^{-1}	6.38×10^{-2}
Y-92	-	-	-	-	1.01×10^{-2}	4.94×10^{-2}	4.99×10^{-1}
Y-93	-	-	-	-	-	-	-
Zr-95	6.76×10^{-1}	$1.83 \times 10^{+1}$	3.12×10^{-2}	5.69×10^{-1}	1.77×10^{-3}	2.54×10^{-2}	1.10×10^{-2}
Zr-97	8.36×10^{-2}	3.30×10^{-1}	2.69×10^{-3}	1.80×10^{-2}	3.22×10^{-5}	2.35×10^{-4}	2.51×10^{-3}
Nb-95	7.32×10^{-1}	$2.34 \times 10^{+1}$	3.43×10^{-2}	6.68×10^{-1}	2.08×10^{-3}	3.60×10^{-2}	1.18×10^{-2}
Nb-98	-	-	-	-	-	-	-
Mo-99	$1.86 \times 10^{+2}$	$9.04 \times 10^{+2}$	6.66	$5.04 \times 10^{+1}$	1.43×10^{-1}	7.58×10^{-1}	4.23
Tc-99m	$4.15 \times 10^{+2}$	$1.78 \times 10^{+3}$	$1.38 \times 10^{+1}$	$9.85 \times 10^{+2}$	1.78×10^{-1}	1.18	9.50

Table 11.4-9 (Cont'd)

NUCLIDE	RWCU BACKWASH RECEIVING TANK	RWCU PHASE SEPARATOR	CONDENSATE BACKWASH RECEIVING TANK	CONDENSATE PHASE SEPARATOR	FLOOR DRAIN[4] SPENT RESIN TANK	EQUIPMENT DRAIN[4] SPENT RESIN TANK	WASTE[2][4] SLUDGE TANK
Tc-101	3.08	4.58	6.01×10^{-2}	1.56×10^{-1}	3.33×10^{-5}	4.86×10^{-4}	2.36×10^{-2}
Tc-104	-	-	-	-	-	-	-
Ru-103	3.14×10^{-1}	7.26	1.43×10^{-2}	2.46×10^{-1}	7.70×10^{-4}	8.79×10^{-3}	5.18×10^{-3}
Ru-105	-	-	-	-	-	-	-
Ru-106	4.52×10^{-2}	1.52	2.12×10^{-3}	4.17×10^{-2}	1.30×10^{-4}	2.67×10^{-3}	7.27×10^{-4}
Ag-110m	2.97×10^{-1}	9.78	1.39×10^{-2}	2.72×10^{-1}	$8.44 \times 10^{+4}$	1.67×10^{-2}	4.79×10^{-2}
Te-129m	6.54×10^{-1}	$1.43 \times 10^{+1}$	2.98×10^{-2}	5.00×10^{-1}	1.57×10^{-3}	1.65×10^{-2}	1.09×10^{-1}
Te-131m	-	-	-	-	-	-	-
Te-132	$4.53 \times 10^{+2}$	$2.36 \times 10^{+3}$	$1.67 \times 10^{+1}$	$1.32 \times 10^{+1}$	3.81×10^{-1}	1.99	9.95
Ba-139	$3.15 \times 10^{+1}$	$1.07 \times 10^{+2}$	$9.25 \times 10^{+1}$	5.48	1.34×10^{-3}	1.95×10^{-2}	3.17×10^{-2}
Ba-140	$1.32 \times 10^{+2}$	$1.65 \times 10^{+3}$	5.72	$7.54 \times 10^{+1}$	2.37×10^{-1}	1.50	2.32
Ba-141	5.37	9.95	1.17×10^{-1}	3.79×10^{-1}	6.69×10^{-5}	9.76×10^{-4}	3.89×10^{-2}
Ba-142	2.57	2.92	4.37×10^{-2}	8.69×10^{-2}	2.49×10^{-5}	3.65×10^{-4}	2.15×10^{-2}
La-142	-	-	-	-	2.49×10^{-5}	3.65×10^{-4}	2.15×10^{-2}
Ce-141	1.67	$3.64 \times 10^{+1}$	7.64×10^{-2}	1.28	3.68×10^{-3}	3.13×10^{-2}	2.25×10^{-2}
Ce-143	1.74×10^{-1}	7.11×10^{-1}	5.70×10^{-3}	3.96×10^{-2}	9.38×10^{-5}	5.62×10^{-4}	4.78×10^{-3}
Ce-144	6.10×10^{-1}	$2.02 \times 10^{+1}$	2.86×10^{-2}	5.59×10^{-1}	1.74×10^{-3}	3.49×10^{-2}	9.82×10^{-3}
Pr-143	6.01×10^{-1}	8.00	2.64×10^{-2}	3.59×10^{-1}	1.13×10^{-3}	7.36×10^{-3}	1.03×10^{-3}
Nd-147	2.00	$2.25 \times 10^{+1}$	8.56×10^{-2}	1.07	3.37×10^{-3}	2.01×10^{-2}	3.56×10^{-2}
W-187	3.14	$1.27 \times 10^{+1}$	1.01×10^{-1}	7.10×10^{-1}	1.45×10^{-3}	9.47×10^{-3}	9.20×10^{-2}
Np-239	$1.81 \times 10^{+3}$	$8.32 \times 10^{+3}$	$6.34 \times 10^{+1}$	$4.64 \times 10^{+2}$	1.27	6.90	4.32×10^{-2}
OTHERS[3]	$2.21 \times 10^{+2}$	$2.47 \times 10^{+3}$	8.89	$1.09 \times 10^{+2}$	4.02×10^{-1}	3.24	6.35
Total	$4.64 \times 10^{+3}$	$2.68 \times 10^{+4}$	$9.06 \times 10^{+2}$	$7.31 \times 10^{+3}$	3.75	$2.62 \times 10^{+1}$	$1.09 \times 10^{+2}$

(1) Activity inventories are given in curies.

(2) Activity inventory is based on chemical waste processing via the floor drain subsystem (Section 11.2.2.1.3).

(3) Activity of daughter products resulting from radioactive decay of the influent isotopes during the accumulation period.

(4) The floor and equipment drain spent resin tanks are not used for normal plant operation. Exhausted bead resin from the liquid radwaste systems will be sluiced directly to the waste sludge tank (Section 11.4.2.1.1). The listed waste sludge tank curie inventory represents activity levels of the floor drain, equipment drain, and fuel pool filter/demineralizer backwashes. To determine the waste sludge tank inventory including an exhausted resin bed, the listed isotopic inventory from the appropriate spent resin tank should be added directly to the listed waste sludge tank inventory.

Table 11.4-10

EXPECTED ANNUAL SOLID WASTE MANAGEMENT SYSTEM CONTAINERS TO BE SHIPPED AND ACTIVITY CONTENTS

CONTAINER TYPE	CAPACITY	CONTENTS	EXPECTED ACTIVITY Ci/CONTAINER	ANNUAL QUANTITY OF CONTAINERS FOR SHIPMENT
High integrity	63 ft^3	Dewatered HSA sludge	(1) (3) 337	8
High integrity	120 ft^3	Dewatered LSA sludge	(1) (3) 6.4	118
Steel drum		55 gal dry waste	Compacted $2x10^{-2}$	(2) 3886
Wood box	100 ft^3	Uncompacted dry waste	(2) $6x10^{-3}$	250

(1) Assumes fill to 90% of container capacity.
(2) Estimates based on operational data from PBAPS.
(3) Values are historical data based on original plant design estimates.

11.5 PROCESS AND EFFLUENT RADIOLOGICAL MONITORING AND SAMPLING SYSTEMS

The process and effluent radiological monitoring and sampling systems, including the primary containment radiation monitoring system, are contained in the PRMS. The PRMS is provided to furnish information to operations personnel regarding radioactivity levels in principal plant process and effluent streams to assist in maintaining radiation levels as low as reasonably achievable. The system is also provided to verify compliance with applicable governmental regulations for the containment, control, and release of radioactivity in liquid and gaseous effluents generated as a result of normal or abnormal operation of the plant. The design objectives and criteria are primarily determined by the system designation of either:

a. Safety-related systems

b. Monitoring systems for plant operation, and operator information.

c. Postaccident monitoring and sampling systems

The PRMS is composed of the following process and effluent radiation monitors:

a. Safety-related systems

   1. Main steam line radiation monitors

   2. Reactor enclosure ventilation exhaust radiation monitors

   3. Refueling area ventilation exhaust radiation monitors

   4. Control room ventilation radiation monitors

   5. Control room emergency fresh air radiation monitors

   6. RHR service water radiation monitors

b. For plant operation and operator information

   1. North stack effluent radiation monitors

   2. South stack effluent radiation monitors

   3. Radwaste equipment rooms ventilation exhaust radiation monitor

   4. Charcoal treatment system process exhaust radiation monitors

   5. Recombiner room and hydrogen analyzer compartments exhaust radiation monitors

   6. Steam exhauster discharge and vacuum pump exhaust radiation monitors

   7. Radwaste enclosure and Chemistry Laboratory Expansion ventilation exhaust radiation monitor

8. Air ejector offgas effluent radiation monitors

9. Primary containment leak detector radiation monitors

10. Hot maintenance shop ventilation exhaust radiation monitor

11. Liquid radwaste discharge radiation monitor

12. Service water radiation monitors

13. Reactor enclosure cooling water radiation monitors.

c. Postaccident systems

1. Primary containment post-LOCA radiation monitors

2. North stack wide range accident monitoring system

3. Postaccident sampling system

11.5.1 DESIGN BASES AND SPECIFIC REQUIREMENTS

In general, the radiation monitoring systems are designed to measure and record radioactivity levels, to alarm on high radioactivity levels, and to prevent the release of radioactive liquids, gases, and particulates. The PRMS aids in protecting the general public and plant personnel from exposure to radiation or radioactive materials in excess of those limits allowed by the applicable regulations.

The main objectives of the PRMS for normal operation are as follows:

a. To provide surveillance of radioactivity levels in process and effluent streams from minimum detectable levels to levels commensurate with Technical Specification limits by indicating and recording these levels, by alarming at abnormal activity levels, and by initiating or causing the initiation of corrective action when applicable.

b. To provide data for estimating total released activity.

For some anticipated operational occurrences the PRMS activates necessary isolation or diversion valves, thereby terminating releases if radioactivity levels exceed pre-established setpoints.

The main objective of radiation monitoring systems required for safety is to initiate appropriate protective action to limit the potential release of radioactive materials from the reactor vessel and reactor enclosure refueling area, if predetermined radiation levels are exceeded.

All radiological effluent monitors that actuate an ESF system have been dynamically qualified to the requirements of IEEE 344 (1971). See Section 3.10. In addition, all safety-related radiological effluent monitors that are located in a harsh environment have been environmentally qualified to the requirements of NUREG-0588, Category II.

Radiological effluent monitors that actuate an ESF system were procured in accordance with the requirements of 10CFR50, Appendix B, as interpreted at the time of their procurement. The design

of these monitors and their system is consistent with the quality assurance criteria of Regulatory Guide 1.143, and the factors influencing instrumentation selection identified in ANSI 13.10 (1974) were considered.

Information regarding the process and effluent monitoring system's compliance with Regulatory Guide 1.97 (Rev 2) is provided in Section 7.5. LGS will meet the guidance of Regulatory Guide 4.15 (Rev 1) for roof vent and liquid effluent monitors.

11.5.1.1 General Design Criteria

Specific design criteria for monitoring systems are discussed under the system description when applicable. General criteria taken into consideration in the design of the PRMS are as follows:

a. The PRMS is designed to monitor pathways for release of radioactive materials to the environment in conformance with GDC 60, GDC 63, and GDC 64 and 10CFR50, Appendix I, and Regulatory Guide 1.21.

b. The PRMS provides early warning of increasing radioactivity levels indicative of equipment failure, filter failure, system malfunction, or deteriorating system performance by using a high alarm setpoint.

c. The PRMS initiates prompt corrective action, either automatically or through operator response, on high radioactivity level by using a high-high alarm setpoint.

d. Monitors and detectors are selected with sensitivities and ranges in accordance with radiation levels anticipated at specific detector locations.

e. In general, monitors register full-scale if exposed to radiation levels exceeding full-scale indication. Monitors that do not have this characteristic are designed such that the maximum levels from the DBA do not exceed their upper range with the exception of the north stack effluent normal range monitors when radiation levels exceed the range of the north stack effluent normal range monitors the wide range accident monitor provides indication.

f. Radioactivity levels are continuously indicated and recorded in the control room with the exception of liquid radwaste effluent activity (recorded in the radwaste control room), the PASS system radiation monitors (indicated locally), Steam Packing Exhauster/Mechanical Vacuum Pump discharge, and the hot maintenance shop ventilation exhaust activity (indicated via the RMDS computer locally). The control room air supply, emergency fresh air, hot maintenance shop ventilation exhaust activity, and north and south stack effluent activity are indicated and trended on demand in the control room or indicated locally.

g. Audible control room alarms are initiated on high radioactivity levels and on signal, circuit, or power failures.

h. Monitor components requiring calibration, maintenance and inspection are accessible, and spare equipment is commercially available.

i. Insofar as practical, self-monitoring of components is provided to the extent that power failure or component malfunction causes annunciation and channel trip.

j. Off-line (sampling-type) radiation monitoring systems are designed to be unaffected by background radiation levels of up to 2.5 mRem/hour. Off-line monitors are located in areas where the maximum background does not increase the minimum detectable concentration above the required monitor lower range. Accident dose rates have been considered in locating monitors that are required for safety or postaccident. In-line radiation monitoring systems will generally indicate changes in background radiation levels. Environmental qualification of safety-related components is discussed in Section 3.11.

k. Safety-related components of the PRMS required for safe shutdown are protected against the effects of extreme winds, floods, tornadoes, or missiles by locating them in a structure designed to withstand such conditions (Chapter 3).

l. Safety-related monitors are designed to seismic requirements consistent with the seismic design of the system being monitored.

m. Independence of redundant monitors that are safety-related is maintained by providing adequate separation of detectors, signal cabling, power supplies, and actuation circuits for isolation and diversion valves to meet IEEE 279 criteria.

11.5.1.2 Basis for Detector Location Selection

Normal and potential paths for release of radioactive material are selected for monitoring as follows:

a. Process lines that may discharge radioactive fluids to the environs, in order to indicate the radioactivity level and to alarm in the control room when established limits for the release of radioactive materials are reached or exceeded.

b. Process lines that do not discharge directly to the environs, in order to indicate possible process system malfunctions by detecting increases in radioactivity levels.

Monitored processes and detector locations are listed in Table 11.5-1 and shown in drawing M-26.

11.5.1.3 Expected Radiation Levels

The expected radioactivity concentrations in the process and effluent streams are such that radiation levels at the site boundary are a small fraction of 10CFR20 limits and will be ALARA.

11.5.1.4 Quantity to be Measured

The principal radionuclides to be monitored are indicated in Table 11.5-1. All channels measure gross radioactivity.

11.5.1.5 Detector Type, Sensitivity, and Range

The detectors are Geiger-Muller tubes, ionization chambers, or scintillation crystals that detect either beta or gamma radiation, depending on the application. In general, ion chambers are used in high intensity or high temperature applications, GM tubes are used for gross measurements, beta scintillators are used for relatively precise measurements of noble gases, and gamma scintillators are used for relatively precise measurement of iodines and particulates. The sensitivity

and range are selected so that the alarm setpoint is at least an order of magnitude higher than the detector threshold and so that the instrument reads on scale during normal operation. Detector type, sensitivity, and nominal ranges of each process and effluent monitor are indicated in Table 11.5-1.

11.5.1.6 Setpoints

Setpoints for effluent monitors are established to meet Offsite Dose Calculation Manual Limits as required by the Technical Specifications which encompass 10CFR20 limits and ALARA guidelines. Setpoints for process monitors are established to provide a warning of increased system activity and to initiate corrective action where appropriate. In all cases, the setpoints are established to maintain offsite radiological effects within applicable regulation limits.

Changing of the setpoints is under the administrative control of the plant manager or his authorized delegate.

Two independently adjustable radiation setpoints are provided for most monitors. The high setpoint normally activates only an alarm, while the high-high setpoint activates an alarm and initiates corrective action where appropriate. Setpoints are at least twice the background level if practicable to reduce the number of spurious trips. Radiation monitoring system setpoints and associated functions are provided in Table 11.5-2.

11.5.1.7 Annunciators and Alarms

All process and effluent radiation monitors indicate and audibly alarm in the control enclosure as shown in Table 11.5-2.

An operator can acknowledge the alarm and silence the audible alarm, but he cannot clear the annunciator window until the alarm condition has been cleared at the PRMS panels located in the control enclosure. Radiation alarms can be cleared only if the indication is less than the setpoint.

At the PRMS panels in the control enclosure, the channel that alarmed and the type of alarm are determined by the lights associated with three types of alarms. These alarm lights are as follows:

a. A high alarm light illuminates or a display indication is provided when the radioactivity exceeds preset limits that have been selected to provide an early warning.

b. A high-high alarm light illuminates or a display indication is provided when the radioactivity exceeds preset limits that have been selected to initiate appropriate corrective action. The high-high alarm actuates the trip auxiliaries in those applications where a control trip is automatic.

c. A low (failure) alarm light illuminates or a display indication is provided when the meter reaches a downscale trip point which indicates that there is a detector signal, circuit, or power failure. In certain cases, as shown in Table 11.5-2, this downscale alarm also actuates the trip auxiliaries.

11.5.1.8 Calibration, Maintenance, Inspection, Decontamination, and Replacement

All instruments are calibrated upon installation. Calibration sources are provided for periodic recalibration of the detectors.

Purge capability is provided to all off-line instrument racks. In event of severe contamination, the modules in question or the entire rack may be transferred to the hot maintenance shop for decontamination.

A schedule for periodic replacement of instrument components, such as photomultiplier tubes and detectors, is based on manufacturer's recommendations. Instrument rack installation facilitates access for inspection, testing, maintenance, and repairs.

Components of the radiological monitoring systems are designed for convenient replacement. The assemblies are designed for a minimum life of 40 years when maintained in accordance with the manufacturers' recommendations including periodic parts replacement.

11.5.2 SYSTEM DESCRIPTION

Specific information on the PRMS is tabulated in Tables 11.5-1 and 11.5-2 and arrangements are shown in drawing M-26.

11.5.2.1 Systems Required for Safety

11.5.2.1.1 Main Steam Line Radiation Monitoring System

This system monitors the gamma radiation level exterior to the main steam lines. The normal radiation level is produced primarily by coolant activation gases plus smaller quantities of fission gases being transported with the steam.

The system consists of four redundant instrument channels. Each channel consists of a local detector (gamma-sensitive ion chamber) and a control room radiation monitor with an auxiliary trip unit. Power for two channels (A and C) is supplied from RPS bus A and the other two channels (B and D) from RPS bus B. Channels A and C are physically and electrically independent of channels B and D. One 2-pen recorder allows the output of any two selected channels to be recorded.

The detectors are physically located near the main steam lines just downstream of the outboard main steam line isolation valves in the space between the primary containment and secondary containment walls. The detectors are geometrically arranged so that this system is capable of detecting significant increases in radiation level with any number of main steam lines in operation. Table 11.5-1 lists the sensitivity and range of the detectors.

Each radiation monitor has four alarm circuits: two upscale (high-high and high), one downscale (low), and one inoperative. Each alarm is visually displayed on the PRMS panels located in the control room. A high-high or inoperative signal results in a high-high/inoperative alarm, mechanical vacuum pump shutdown and mechanical vacuum pump suction valve closure. A high alarm actuates a main steam line high radiation annunciator common to all channels. A downscale alarm actuates a main steam line downscale annunciator common to all channels. Each radiation monitor visually displays the measured radiation level.

The MSL-RMS is safety-related and is discussed in detail in Section 7.6.

11.5.2.1.2 Reactor Enclosure Ventilation Exhaust Radiation Monitoring System

This system monitors the radiation level of the air in the reactor enclosure ventilation system exhaust duct prior to its discharge from the structure.

The system consists of four redundant instrument channels. Each channel consists of a local detection assembly (a sensor and converter unit containing a GM tube and electronics) and a radiation monitor. Power for two channels (A and C) is supplied from RPS bus A and the other two channels (B and D) from RPS bus B. Channels A and C are physically and electrically independent of channels B and D. Two 2-pen recorders allow the output of the channels to be recorded continuously. The detection assemblies are located outside the exhaust duct upstream of the ventilation isolation valves.

Each radiation monitor has three alarm circuits: high-high, high, and low. Two high-high trips in channels A and B initiate closure of the reactor enclosure ventilation isolation valves and the startup of the RERS and SGTS train A. The same conditions for channels C and D initiate closure of the corresponding tandem isolation valves and startup of the RERS and SGTS train B. Alternate inboard and outboard valves are actuated independently by the two sets of trip channels. The same logic configuration of the four channels also initiates closure of the primary containment purge and vent valves.

An upscale trip is visually displayed on the affected radiation monitor and actuates a reactor enclosure ventilation high-high radiation annunciator common to all channels. A downscale trip is also visually displayed on the radiation monitor and actuates an annunciator common to all channels. An additional alarm for high radiation is provided by the recorder and actuates a common reactor enclosure ventilation high radiation annunciator. Each radiation monitor visually displays the measured radiation level.

The location and monitoring characteristics of the reactor enclosure ventilation radiation monitoring channels are adequate to provide detection capability for abnormal amounts of radioactivity in the reactor enclosure ventilation exhaust and to initiate isolation. The redundancy and arrangement of channels are sufficient to ensure that no single failure can prevent isolation when required. The upscale trips meet the design requirements of IEEE 279 (1971) as described in Section 7.3.2.2.

11.5.2.1.3 Refueling Area Ventilation Exhaust Radiation Monitoring System

This system monitors the radiation level in the ventilation exhaust duct from the refueling area, including the area over the fuel pool. The monitoring system is identical to the REVE-RMS with the same channel trip logic and protective action initiation, with the exception of the initiation of the RERS.

During refueling operation (including criticality tests), the monitoring system acts as an emergency safety feature against the consequences of a refueling or control rod-drop accident. The response of the REVE-RMS to the refueling accident is discussed in Chapter 15.

11.5.2.1.4 Control Room Ventilation Radiation Monitoring System

This system monitors the radiation level in the supply air to the control room. No measurable activity is expected to be present; however, in the event of a DBA, fission gases could escape from the plant structures and be drawn into the supply air intake. In the Control Room Radiation Isolation Mode HEPA/charcoal filter will remove radioactive particulates and iodines.

There are four independent monitors, separated in accordance with IEEE 279 (1971), that monitor air inside the control enclosure intake duct. These in-line monitors respond to the gross radioactivity in the vicinity of the detectors. Each monitor provides three alarm conditions: low, high, and high-high. The low, high, and high-high alarms trip the control room annunciator. The high-high alarm trips the control room fresh air isolation valves and starts the CREFAS, which provides for the filtration of the incoming air through HEPA/charcoal filters. The trip of any monitor A, B, C, or D shuts off the control room fresh air supply, and the trip of either monitors A and C, or B and D, starts the CREFAS. (See Section 6.4 for a more detailed discussion of control room isolation on detection of high radiation.)

11.5.2.1.5 Control Room Emergency Fresh Air Radiation Monitoring System

Upon initiation of the CREFAS system, this monitor indicates radioactivity concentration levels downstream of control room ventilation HEPA/charcoal filters. Radioactive noble gas concentration is measured. These in-line monitors detect gross radiation only. Two monitors, separated in accordance with IEEE 279 (1971), monitor sample air from the control room emergency fresh air duct.

Each monitor provides three alarm conditions: low, high, and high-high. These alarms trip annunciators in the control room.

11.5.2.1.6 RHR Service Water Radiation Monitoring System

This system is comprised of two monitors for sampling the combined RHRSW loop return flows to the spray pond or cooling tower. One monitor serves Loop “A”, the other serves Loop “B”.

Each monitor provides three alarm conditions: high-high/INOP/DNSCL, high radiation, and high/low sample pump flow. These signals trip annunciators in the control room, and the high-high/INOP/DNSCL trips the RHRSW pumps. Should a monitor failure occur, grab samples are used to measure radioactivity in the fluid.

These monitors are qualified as IEEE Class 1E.

The monitors for sampling the combined RHRSW loop return to the spray pond or cooling tower are safety-related.

11.5.2.2 Systems Required for Plant Operation

11.5.2.2.1 North Stack Effluent Radiation Monitoring System

The NSE-RMS is comprised of two subsystems:

a. North stack effluent monitors for normal plant operation

b. Wide range accident monitoring subsystem

The objectives of the normal plant operation subsystem are to indicate whether the limits of actual release of radioactive material to the environs are reached or exceeded, and to measure the quantity of release of radioactive material during normal plant operation, in compliance with 10CFR50 and Regulatory Guide 1.21.

The NSE-RMS, including the isokinetic sampling system and the wide range accident monitoring subsystem, is designed to carry out the following functions:

a. To provide continuous isokinetic and representative samples of the stack flow in compliance with the requirements of GDC 64, Regulatory Guide 1.21, and ANSI 13.1 (1971).

b. To continuously record releases of radioactive particulates, iodines and noble gases to the environs so that the total quantity of radioactive material released can be evaluated.

c. To alarm, in event that specified rates of release of radioactive material are exceeded.

d. To provide continuous real-time indications of radioactive releases during the accident and postaccident modes of operation.

e. Provide an isolation signal to the containment purge valves in the event of high radiation in the north stack effluent.

The north stack exhausts from the following systems:

a. Unit 1 turbine enclosure exhaust

b. Unit 1 turbine enclosure equipment compartment exhaust (including mechanical vacuum pump exhaust)

c. Unit 2 turbine enclosure exhaust

d. Unit 2 turbine enclosure equipment compartment exhaust (including mechanical vacuum pump exhaust)

e. Radwaste enclosure equipment compartment exhaust

f. Chemistry Laboratory fume hood exhaust

g. Chemistry Laboratory air exhaust

h. Control structure battery compartment exhaust

i. Unit 1 steam packing condenser and effluents from the recombination system

j. Unit 2 steam packing condenser and effluents from the recombination system

k. SGTS enclosure exhaust

l. Unit 1 battery compartment exhaust

m. Unit 2 battery compartment exhaust

n. Control structure toilet room exhaust

o. SGTS filter exhaust

p. Drywell purge system exhaust

q. Offgas treatment system exhaust

r. Radwaste enclosure air exhaust

Sampling stubs are provided on the exhaust ducts of most of the systems listed above for the purpose, of extracting grab samples as needed (see drawing M-26 for specific locations).

11.5.2.2.1.1 Isokinetic Sampling and Radiation Monitoring Systems

Units 1 and 2 share the north stack and consequently the same RMS. Under normal plant operation, the stack flow rate varies from about 350,000 cfm for Unit 1 only in operation to about 668,450 cfm for both units in operation. The expected composition and concentrations of the effluent under normal plant operation are given in Table 11.5-4. Following an accident flow may be reduced.

Under this condition, the flow rate will be below the range capability of the isokinetic sampling system of the north stack normal range monitors, but the wide range accident subsystem will continue to provide representative data. The north stack is provided with three equally spaced honeycomb grids that serve the purpose of stabilizing, equalizing, and collimating the stack flow in order that the exhaust flow rate can be measured accurately and representative air sampling can be achieved. A flow rate sensing array is provided, consisting of 128 uniformly spaced total pressure sensors and 32 uniformly spaced static pressure sensors for providing an instantaneous traverse across the stack. A differential pressure sensor connected to this sensing array provides the stack flow rate signal. To allow maintenance without losing monitoring capability, a redundant stack flow rate signal is provided by nine thermal-type velocity sensors connected to an averaging network. A local switch allows selection of one of the two stack flow signals to be input to the microprocessor-based north stack effluent and wide range accident monitors for isokinetic control of the sample flow rates. The stack flow rate and sampling flow rates are indicated on demand in the control room via the wide range accident monitoring subsystem readout module or the RMDS display consoles (Section 11.5.6).

Two independent sampling arrays, each consisting of a set of 64 uniformly spaced isokinetic nozzles are provided for extracting representative samples at the stack cross-section. One array provides a sample for the normal plant operation radiation monitoring subsystem and the other for the wide range accident monitoring subsystem. Sample bypasses with associated pumps and flow controls are provided to allow the sampling array flow to follow the stack flow rate isokinetically without exceeding the maximum sample flow range of the monitors. The system has the capability to maintain isokinetic conditions with variations in stack flow rate of ±25%. The sample is split into parallel paths. Each half is passed through a particulate filter provided with a radiation detector indicating the corresponding integrated measurement of the particulate effluent, an iodine filter provided with an in-place detector, and a noble gas monitoring chamber. Thus, each of the two redundant monitoring racks provide the following outputs:

a. Sampling flow rates

b. Particulate radioactivity, integrated

c. Iodine radioactivity, integrated

d. Noble gas radioactive concentration

From these data and the stack flow measurement, the total radioactive effluent may readily be evaluated. Readouts from the detectors are fed into microprocessors, which in turn provide outputs to the RMDS display consoles in the control room. The microprocessors are provided with memory retention capability to preclude the loss of data in event of a power failure.

There are one downscale and two upscale common alarms which annunciate abnormal conditions on either monitor in the control room. The upscale alarms indicate high and high-high radiation in any of the three detector channels, and the downscale alarm indicates instrument malfunction.

For the normal plant operation mode, the characteristics of the isokinetic sampling system and radiation monitoring subsystem provide plant operations personnel with complete and accurate data of radioactive materials released to the environs from the north stack. The system thus enables personnel to control activity release rates. Sufficient redundancy is provided to allow maintenance and checking of one channel without losing monitoring capability.

11.5.2.2.1.2 Wide Range Accident Monitor

The wide range accident monitoring subsystem is independent of the normal plant operation monitoring subsystem and operates continuously. Effluent samples are drawn via two sample flow paths. During normal plant operation, one sample, drawn from the second 64 nozzle array described above, is passed through a particulate filter, iodine filter, and low range noble gas detector assembly. This provides redundancy to the normal plant operation monitoring subsystem. If the low range detector approaches its upscale limit, the system automatically starts pumping effluent sample from a separate comb-type probe located downstream of the isokinetic nozzle arrays. This sample is passed through shielded particulate and iodine filters and a midrange and high range noble gas detector assembly. When the midrange detector reaches a preselected point, the low range detector is automatically purged and flow through it is stopped. Purging ensures that the low range detector can resume monitoring when activity again decreases. A similar automatic purge/shutdown cycle is performed on the midrange and high range detectors when activity decreases.

The low range detector assembly consists of a shielded chamber and a beta-sensitive plastic scintillation detector. The midrange and high range detectors use cadmium telluride solid-state sensors housed in a shielded chamber. Detector outputs are fed into the microprocessor that applies conversion factors, determines if alarm setpoints have been exceeded and retains data for each detector channel in history files. In addition, the microprocessor automatically calculates effluent release rate per unit time based on detector measurement and stack flow rate. Background subtraction is provided based on manually entered background values. Outputs of the microprocessor are transmitted to a readout module, the RMDS display consoles, and recorders in the control room. One 3-pen recorder provides indication of radioactivity concentration in the low range, midrange, and high range channels, while effluent release rate is recorded in a digital recorder. The RMDS display consoles can also provide trend printouts on demand of the microprocessor history files. The microprocessors have memory retention in event of loss of power. One downscale and two upscale alarms annunciate abnormal monitor conditions to the control room. The wide range accident monitoring subsystem also provides a nonsafety-related

isolation signal to the containment purge valves on high-high radiation and loss of control power to the system.

The monitor is initially calibrated by the manufacturer using gaseous and solid sources including Sr-90. Transfer sources are then used to transfer this calibration data base to the plant by realigning each detector to the conditions established during primary calibration. Calibration is performed periodically in the plant at designated intervals according to the plant Technical Specifications.

Dissemination of information from this monitor via the RMMS data links to the control room, TSC, and EOF, as well as consideration of radionuclide distribution as a function of time after shutdown in dose assessment is discussed in Section 11.5.6.

The particulate and iodine filters of the wide range accident monitoring subsystem are used as grab sample modules to provide the capability of collecting representative samples of iodines and particulates for onsite analysis during and following an accident. The sample lines are heat traced to preclude entrained moisture in the effluent stream that could degrade the filters. Three removable filter modules are provided in both sample flow paths to allow continuous collection. This also allows the control room operator to select a clean set of filters in order to prevent appreciable concentrations of noble gases produced by iodine decay in a loaded filter, which could be falsely interpreted by the noble gas detectors as high activity in the effluent stream. Controls are provided in the control room to select filters, to grab samples locally and remotely, and to initiate automatically timed grab sampling. Filters on the high activity sample flow path are housed in shielded enclosures designed for ease of removal and replacement of filter media. Filter removal is provided by means of quick disconnect couplings. After removal, the filter is placed in a shielded cask for transport to the onsite analysis facility. The filter enclosure and transport cask have been designed and the access routes have been selected in accordance with the requirements of NUREG-0737 to keep personnel exposure in sample handling and transport below the GDC 19 limits of 5 rem whole body exposure and 75 rem to the extremities during the duration of the accident. The sample filter, constructed of silver zeolite, has a collection efficiency of 99% for iodine and for 0.3 micron particles.

11.5.2.2.2 South Stack Effluent Radiation Monitoring System

The objectives and functions of the SSE-RMS are the same as those of the north stack normal plant operation monitoring subsystem. A system for postaccident monitoring is not provided because any HVAC exhaust to this stack containing accident effluents is automatically isolated.

The south stack encloses two independent exhaust ducts servicing the reactor enclosures for Unit 1 and Unit 2, respectively. The stack exhausts ventilation air from the following systems:

a. Unit 1 Duct

    1. Unit 1 reactor enclosure exhaust

    2. Unit 1 reactor enclosure equipment compartment exhaust

    3. Refueling floor Unit 1 side exhaust

b. Unit 2 Duct

1. Unit 2 reactor enclosure exhaust
2. Unit 2 reactor enclosure equipment compartment exhaust
3. Refueling floor Unit 2 side exhaust

Each of these two ducts is monitored by means of two redundant monitors. Consequently, four independent sets of data are obtained of stack flow rates and corresponding sampling rates.

Flow rates in each of the two ducts vary from about 43,000 cfm to about 223,000 cfm. The expected composition and concentrations of the effluent under normal plant operation are given in Table 11.5-4. The stack flow is collimated to provide a uniform velocity distribution over the entire cross-section to assure representative sampling. Flow rate in each duct is measured by a manifold containing 64 uniformly spaced total pressure sensors and 16 static pressure sensors to provide an instantaneous ongoing velocity traverse. A differential pressure sensor connected to the manifold provides the flow rate signal to both monitors associated with each duct for isokinetic control of the sample flow rate. Sampling is done by an array of 32 uniformly spaced isokinetic nozzles.

Radiation detection in each monitor is done by means of a particulate filter, iodine filter and noble gas chamber in series. Each of these items is shielded and provided with a dedicated detector. The gas chamber has a beta scintillation detector consisting of a beta-sensitive crystal optically connected to a photomultiplier tube.

The other two detectors are similar in construction except that the iodine detector is gamma-sensitive. The output from the preamplifier is fed to a microprocessor, which in turn provides output to the RMDS display consoles in the control room. Digitized outputs are also available locally. Stack flow rates, sampling flow rates, and concentration of particulates, iodines, and noble gases are indicated on demand.

There are one downscale and two upscale common alarms that are annunciated in the control room for abnormal conditions in any of the four monitors. The downscale alarm indicates instrument malfunction and the upscale alarms indicate high and high-high radiation in any of the three detector channels.

11.5.2.2.3 Radwaste Equipment Rooms Ventilation Exhaust Radiation Monitoring System

The common duct that collects exhaust air from the charcoal offgas treatment equipment compartments ventilation ducts is continually monitored for airborne radioactivity. High-high, high, and low radiation are annunciated in the control room. Although particulate/iodine concentration is not anticipated, the monitors are provided with particulate/iodine filters as backups. In the event of a high radiation alarm, the ventilation exhaust from each compartment can be monitored separately.

11.5.2.2.4 Charcoal Treatment System Process Exhaust Radiation Monitoring System

Two charcoal offgas trains (Unit 1 and Unit 2) exhaust the processed gases via HEPA filters to the north stack. Each of the exhaust pipes is monitored to detect malfunction in the corresponding offgas train. Low, high, and high-high radiation are annunciated in the control room.

11.5.2.2.5 Recombiner Room and Hydrogen Analyzers Exhaust Radiation Monitoring System

RRHAC-RMS monitor detects airborne radioactivity in the ventilation ducts of the recombiner compartments, drain sump rooms, and hydrogen analyzer compartments in the control structure. Exhaust air in the common duct from the recombiner compartments and drain sump rooms and the common duct from the hydrogen analyzer compartments is continuously monitored prior to return to the turbine enclosure equipment compartment ventilation filters for eventual release through the north stack. Low, high, and high-high radiation are annunciated in the control room. The source of the radiation can be identified by means of a hand selector switch/solenoid valve arrangement which allows switching the sample line to the individual return duct of potentially contaminated compartments.

11.5.2.2.6 Steam Exhauster Discharge and Vacuum Pump Exhaust Radiation Monitoring System

The SEDVP-RMS monitor provides an indication of radioactivity in the discharge of the steam packing exhauster to the north vent stack. The sampling arrangement allows the capability to also monitor the mechanical vacuum pump exhaust at the water separator discharge when this equipment is operated during startup.

11.5.2.2.7 Radwaste Enclosure and Chemistry Laboratory Expansion Ventilation Exhaust Radiation Monitoring System

Monitoring of the main exhaust duct of the radwaste enclosure and Chemistry Laboratory Expansion provides for general surveillance of gaseous effluents from equipment compartments and access areas of these structures prior to discharge to the north stack. The REV-RMS instrumentation also provides backup for the RERV-RMS monitor. Low, high, and high-high radiation alarms annunciate in the control room.

11.5.2.2.8 Air Ejector Offgas Effluent Radiation Monitoring System

The AEOE-RMS monitors radioactivity in the main condenser offgas after it has passed through the SJAE condenser, recombiner and aftercondenser. This is representative of gaseous radioactivity released from the reactor and therefore indicates the condition of the fuel cladding.

A continuous sample is extracted from the offgas pipe via a stainless steel sample line and passed through a sample chamber and a sample panel before being returned to the suction side of the SJAE. The sample chamber is a steel pipe that is internally polished to minimize plateout. It can be purged with room air to check detector response to background radiation. The sample panel measures and indicates sample line flow. Heat tracing is provided in the sample line between the sample chamber and panel to prevent moisture condensation in the sample panel.

The sample chamber is monitored by three channels. Each channel has a gamma-sensitive ionization chamber mounted outside the sample chamber. Two channels have logarithmic radiation monitors with low, high, and high-high alarm outputs that annunciate in the control room.

The third monitoring channel has linear radiation sensing capability designed to detect radioactive fragments resulting from fuel cladding deterioration. Small changes in the offgas gross fission product concentration can be detected by the continuous use of the linear radiation monitor. The linear radiation monitor is not a process monitor such as the channels described above, but is utilized as an expanded scale device for aiding in measurement of small changes in the offgas radiation level. The detector is a gamma-sensitive ionization chamber that monitors the same sample as the logarithmic monitors. The system uses a linear readout with a range switch instead of a logarithmic readout. The output from the monitor is recorded on a 1-pen recorder.

Grab samples can be obtained for determining isotopic composition by using the semiautomatic vial sampler panel. To draw a sample, a serum bottle is inserted into a sample chamber, the sample lines are evacuated, and a sample valve is opened to allow offgas to enter the bottle. The bottle is then removed and the sample is analyzed in the counting room with a multichannel gamma pulse height analyzer to determine the concentration of the various noble gas radionuclides. A correlation between the observed activity and the monitor reading permits calibration of the monitor.

11.5.2.2.9 Primary Containment Leak Detector Radiation Monitoring System

The design objective of the PCLD-RMS is to detect leakage in the primary containment. The leak detection monitor is designed to monitor and alarm for gaseous radioactivity (Section 5.2.5.2.1.4).

The monitoring system is provided with four main control room annunciated alarms (high-high, high, downscale, and abnormal sample flow). Rate meter output is recorded on a recorder in the main control room.

11.5.2.2.10 Hot Maintenance Shop Ventilation Exhaust Radiation Monitoring System

Equipment serviced in the hot maintenance shop is expected to be contaminated with residual particulate radioactivity. A small quantity of radioactive iodine might also be present. No radioactive gases are anticipated.

Continuous isokinetic sampling of the maintenance shop exhaust duct, downstream of the HEPA filters, is conducted in accordance with ANSI N13.1. The flow controller in the monitor skid maintains isokinetic sample flow proportional to the constant exhaust duct flow. This sample is passed through fixed particulate and iodine filters. Separate detectors measure the gross radioactivity accumulated on these filters. The microprocessor-based monitor calculates radioactivity concentration based on the value of sample flow in memory and measured accumulated radioactivity over a time period. A recording of this radioactivity concentration is made locally, and an annunciator alarms in the event of discharges in excess of limits specified in the radioactive Effluent Controls Program defined in the Technical Specifications. All instrumentation is mounted locally.

11.5.2.2.11 Liquid Radwaste Discharge Radiation Monitoring System

Waste liquid may be discharged on a batch basis from sample tanks in the liquid waste management system as discussed in Section 11.2.3. Prior to discharge, the liquid in the tank is recirculated, sampled, and analyzed for radioactivity, and the release and dilution rates are determined. The expected composition and concentrations of the effluent from each sample tank under normal plant operation are given in Table 11.5-5. The liquid radwaste effluent discharges into the cooling tower blowdown line. The LRD-RMS monitor measures activity in the discharge line to prevent concentration in the cooling tower blowdown line from exceeding ten-times the 10CFR20, Appendix B, Table 2 activity limits (post-1994).

Monitoring is performed in an off-line sample rack in preference to in-line monitoring. This arrangement affords improved sensitivity and precludes the necessity of shutting down the radwaste discharge line in order to purge accumulated radioactive sludge from the monitoring system.

The monitoring channel consists of a gamma scintillation detector/ preamplifier, a rate meter in the auxiliary equipment area, and a 1-pen recorder in the radwaste control room. A low alarm trip will initiate discharge valve closure because the trip circuit has been designed to "fail-safe" in the event of a loss of power. The high trip alarms in the radwaste control room and the high-high trip initiates discharge valve closure. Since the radwaste release is based upon batch analysis, the basis for the alarm setpoint on the monitor is that an alarm be given on a gross release in the range 10^{-6} μCi/cc to 10^{-2} μCi/cc as a gross check against significant operator error. The alarm setpoint may vary from batch to batch depending upon the activity concentration of the batch and the available cooling tower discharge flow that is used to dilute the fluid effluent prior to leaving the site boundary.

11.5.2.2.12 Service Water Radiation Monitoring System

Plant service water return flow discharges to the cooling tower. The return flow is monitored by the SW-RMS monitor. No activity attributable to reactor operation is expected to be present in this line. For radioactivity to be present, leakage would have to occur simultaneously in equipment cooled by the RECW system and in the RECW heat exchanger. Thus, this monitor provides a backup for the RECW-RMS monitor.

Off-line monitoring is selected to facilitate decontamination without shutdown of the service water system. The channel consists of a detector, preamplifier, a rate meter in the auxiliary equipment room, and a 1-pen recorder in the control room. The rate meter provides a high and high-high alarm in the control room. Annunciation due to low sample flow rate also is provided. The alarm setpoint is based upon detecting leakage into the service water with the setpoint set sufficiently above background to preclude spurious alarms.

11.5.2.2.13 Reactor Enclosure Cooling Water Radiation Monitoring System

The RECW system cools components that may contain radioactive liquids, but does not normally carry any radioactive materials unless the cooled components leak. A radiation monitor is provided to measure radioactivity in the system.

An off-line monitor is employed, to facilitate decontamination without shutdown of the reactor enclosure cooling water system. The channel consists of a gamma scintillation detector, preamplifier, rate meter, and 1-pen recorder. The channel is provided with a high and high-high alarm that annunciate in the control room. The high alarm setpoint is set sufficiently above background to preclude spurious alarms. A low flow annunciator also is provided.

11.5.2.2.14 Process Sampling System

A process sampling system is provided to allow grab sampling for evaluation of water quality and radioactivity levels in liquid process waste streams. The sample analysis results will provide operators with information for taking necessary corrective actions. This system is designed to provide representative samples from process streams at central sample stations for use in minimizing leakage, spillage, and potential radiation exposure to operational personnel. Where applicable, means are provided for sample water cooling and for maintaining a fixed or measured sample flow rate. This system is described in Section 9.3.2.

No provisions have been made for sampling and analysis of laboratory and sample waste systems because all laboratory and sample station drains are routed to either the liquid radwaste, normal

waste, or condensate systems, depending on their origin and quality. Processing takes place in their respective systems.

There are no liquid radwaste tanks outside buildings. The condensate and refueling water storage tanks that are located outside of buildings are sampled downstream of their respective transfer pumps via connections to the process sampling system.

Although the process sampling system is designed to provide liquid samples from many plant process streams, radionuclide sampling will be periodically performed on the following process systems:

a. FPCC

b. RECW

c. Liquid radwaste - equipment drain processing

d. Liquid radwaste - floor drain processing

e. Liquid radwaste - chemical and laundry processing

11.5.2.3 Postaccident Systems

11.5.2.3.1 Primary Containment Post-LOCA Radiation Monitoring System

The PCPL-RMS is comprised of four ion chamber sensors for the primary containment in the event of a LOCA. After such a postulated accident, the monitoring system measures the gross radioactivity present in the containment atmosphere. This information is transmitted to control room personnel to provide them with a basis for making safety-related decisions. The PCPL-RMS provides a trip signal to the containment sump pumps on an upscale alarm indication. A downscale annunciator is provided to indicate instrument malfunction.

The sensors are located in separate areas of containment to provide independent measurements and to view large fractions of the containment volume (drawings N-119 and N-134). Consideration to accessibility for maintenance and calibration was given in the selection of the sensor locations. The sensors are located in relatively open areas to prevent shielding that could impair their detection function.

The monitoring system provides energy response from 60 KeV to 3 MeV, with uniform response within ±20% from 80 KeV to 3 MeV. Onsite calibration of the monitors will be performed with a calibrated 100 millicurie Cs-137 gamma source that will provide an effective dose rate of approximately 10 R/hr. A built-in current source is provided in the monitors to allow calibration checks through electronic signal substitution for the decades above 10 R/hr.

Under high drywell temperature conditions, Insulation Resistance (IR) leakage current will cause a system error. Because the instrument signal at low radiation levels is very weak, high temperature IR leakage current significantly affects the accuracy of the indicated readings up to a maximum of 112.5 Rad/hr at the maximum design drywell temperature of 340°F. As a result, the indicated readings below 112.5 Rad/hr may not be within the factor of two accuracy recommendation of Regulatory Guide 1.97 Rev. 2. The induced error decreases exponentially with drywell temperature and becomes insignificant below 230°F. This induced error is significant only under low radiation conditions coincident with high drywell temperatures, whereas the system will operate to perform

its principal function under normal and varying temperature conditions during and following an accident.

11.5.2.3.2 North Stack Wide Range Accident Monitoring System

The north stack wide range accident monitoring system is discussed in Section 11.5.2.2.1.

11.5.2.3.3 Postaccident Sampling System

The PASS is discussed in Section 11.5.5.

11.5.3 EFFLUENT MONITORING AND SAMPLING

The requirements of GDC 64 are implemented with respect to effluent discharge paths by means of the following monitoring stations:

a. Gaseous Effluents:

1. Reactor enclosure ventilation exhaust (Section 11.5.2.1.2)

2. Refueling area ventilation exhaust (Section 11.5.2.1.3)

3. Standby gas treatment system (Section 11.5.2.2.1)

4. North stack ventilation exhaust (Section 11.5.2.2.1)

5. South stack ventilation exhaust (Section 11.5.2.2.2)

6. Charcoal offgas system compartments ventilation exhaust (Section 11.5.2.2.3)

7. Charcoal offgas system effluent (Section 11.5.2.2.4)

8. Recombiner, hydrogen/oxygen analyzers, and equipment drain sump (Section 11.5.2.2.5)

9. Steam seal effluent (Section 11.5.2.2.6)

10. Radwaste enclosure and Chemistry Laboratory Expansion ventilation exhaust (Section 11.5.2.2.7)

11. Hot shop ventilation exhaust (Section 11.5.2.2.10).

Sampling stubs are provided on all major exhaust ducts for the purpose of extracting grab samples as required.

b. Liquid Effluents:

1. Residual heat removal service water (Section 11.5.2.1.6)

2. Liquid radwaste discharge (Section 11.5.2.2.11)

3. Plant service water (Section 11.5.2.2.12).

11.5.4 PROCESS MONITORING AND SAMPLING

The requirements of GDC 60 are implemented with respect to the automatic termination of gaseous and liquid effluent discharges by means of the following monitoring systems:

a. Main steam line (Section 11.5.2.1.1)

b. Reactor enclosure ventilation exhaust (Section 11.5.2.1.2)

c. Refueling area ventilation exhaust (Section 11.5.2.1.3)

d. Residual heat removal service water (Section 11.5.2.1.6)

e. Liquid radwaste discharge (Section 11.5.2.2.11).

The requirements of GDC 63 are implemented with respect to the monitoring of radiation levels in radioactive fuel and waste storage systems by means of the following monitoring systems:

a. Area radiation monitor channels 31 and 32 (Section 12.3.4.1)

b. Refueling area ventilation exhaust (Section 11.5.2.1.3)

c. Radwaste enclosure and Chemistry Laboratory Expansion ventilation exhaust (Section 11.5.2.2.7)

d. Liquid radwaste discharge (Section 11.5.2.2.11).

The following liquid process systems are provided with grab sample stations for laboratory measurement of radioactive concentrations for satisfying the requirements of GDC 63 and GDC 64:

a. Liquid radwaste systems (Sections 11.5.2.2.14.c, 11.5.2.2.14.d, and 11.5.2.2.14.e)

b. Reactor enclosure cooling water (Section 11.5.2.2.14.b)

c. Spent fuel pool treatment system (Section 11.5.2.2.14.a)

d. Residual heat removal service water (Section 11.5.2.1.6)

11.5.5 POSTACCIDENT SAMPLING SYSTEMS

The PASS is designed to obtain representative liquid and gas grab samples from the primary coolant system and from within the primary and secondary containments for radiological and chemical analysis under accident conditions. The grab samples are subsequently transported to the Chemistry Laboratory Expansion and counting facility for chemical and radioisotopic analyses, or shipped offsite for analysis.

The PASS was designed to satisfy certain requirements of NUREG-0737 (Item II.B.3).

Limerick license amendment numbers 166/129 approved the elimination of the requirement to have and maintain the Post Accident Sampling System. The following items were committed to as part of the license amendment numbers 166/129.

1. Limerick has developed contingency plans for obtaining and analyzing highly radioactive samples of reactor coolant, suppression pool, and containment atmosphere. The contingency plans are contained in the Limerick chemistry procedures. Establishment of contingency plans is considered a regulatory commitment.

2. The capability for classifying fuel damage events at the Alert level threshold has been established at a level of core damage associated with radioactivity levels of 300 micro-curies/gm dose equivalent iodine in the primary coolant system. This capability is described in Limerick's emergency plans and emergency plan implementing procedures. The capability for classifying fuel damage is considered a regulatory commitment.

3. Limerick has established the capability to monitor radioactive iodines that have been released offsite to the environs. This capability is described in the emergency plans and emergency plan implementing procedures. The capability to monitor radioactive iodines is considered a regulatory commitment.

The following information contained in the UFSAR regarding the regulatory requirements for post accident sampling is retained for historical purposes.

The system design minimizes operating complexities and "in-line" instrumentation, is modular for maintenance and contamination control purposes, and is compact in size to reduce the amount of shielding required. The system can be used to provide samples under all plant conditions, ranging from normal shutdown and power operation to postaccident conditions.

The PASS P&ID is shown in drawing M-30. The equipment includes isolation and control valves, piping racks, shielded sample stations (gas and liquid), liquid chillers, and control panels. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the PASS are discussed in Section 3.2. A separate PASS is provided for each unit with common demineralized water and nitrogen support systems.

11.5.5.1 System Description

11.5.5.1.1 Sample Points

a. Wetwell and Drywell Atmospheres

Sample lines are installed to obtain atmosphere samples from two separate areas in both the drywell and wetwell. Drywell samples are taken at el 291' and el 242'. Wetwell samples are taken at el 222' on opposite sides of the containment. The sample lines tap into the CAC system sample lines outside the primary containment and outboard of the second containment isolation valve. Containment gas samples will be representative of conditions throughout the primary containment because the containment is not compartmentalized and the atmosphere is fully mixed.

b. Secondary Containment Atmosphere

A sample line is provided to allow sampling of secondary containment atmosphere noble gases to aid in determining postaccident accessibility of the reactor enclosure. Samples are taken in the vicinity of access doors 191 (Unit 1) and 287 (Unit 2) on el 217'.

The reactor enclosure is not a vital area requiring post accident access as defined in Section 1.13. For design basis events the reactor enclosure is largely inaccessible due to airborne noble gas activity. With use of self-contained breathing apparatus (SCBA), noble gases are the limiting factor throughout the accident. Once accessibility is determined using PASS, reactor enclosure airborne iodine activity can be determined using portable equipment available to HP personnel, in order to assess the need for SCBA in long term accident recovery operations.

c. Reactor Coolant and Suppression Pool

When the reactor is pressurized, reactor coolant samples are obtained from a tap off the jet pump pressure instrument system. The sample point is on a noncalibrated jet pump instrument line outside the primary containment and downstream of the excess flow check valve. This sample point location is preferred over the normal reactor sample points on the RWCU system inlet line and recirculation line because the RWCU is expected to remain isolated under accident conditions, and it is possible that the recirculation line containing the sample line may be isolated. The jet pump pressure tap is in a location protected from damage and debris. This sample point provides representative samples of reactor coolant under various reactor conditions:

1. Normal operation/small pipe break: Reactor water level can be maintained at or near normal water level. With a nearly normal water level, or at least water in the upper plenum, natural circulation will occur with a large loop from the downcomer to the shroud region via the jet pumps. With thermal conditions pumping water up through the core and back down past the tap from which the PASS sample is taken, a representative relationship will exist which will allow the results of the sample to be related to the condition of the core.

2. Large Pipe Break: A large pipe break, such as a recirculation pump suction line break, may occur wherein the water level may be controlled only by the height of the jet pumps and the ability to add water to the vessel. The sample taps are located sufficiently low to permit sampling at a reactor water level even below the lower core support plate. As reactor pressure decays, LPCI is initiated into the core region. This water volume supplies more coolant than is boiled off by the decay heat. This excess water will flow down past the core, up through the jet pumps, and out through the postulated break, assuring a representative sample at the sample point.

To ensure a representative liquid sample from the jet pumps at low (<1%) power conditions for small break or nonbreak events, the reactor water level will be raised to the level of the moisture separator when this action is not inconsistent with station EOPs. This will fully flood the separators and will provide a thermally induced recirculation flow path for mixing. Alternatively, operating at least one reactor recirculation pump 1(2)A-P201 or 1(2)B-P201 at minimum speed or higher will provide sufficient mixing.

Samples will be taken from the reactor via the jet pump pressure instrument lines as long as possible. This allows a more direct and therefore faster response to core conditions. Upon decay or loss of reactor pressure, the jet pump sample point is lost, and the RHR loops sample points must be employed for sampling. Reactor coolant and/or suppression pool samples may be taken from the RHR sample lines, depending on the mode of RHR operation. These sample lines tap off downstream of the second system isolation valve in the RHR system sample lines at the discharge of each RHR heat exchanger.

1. LPCI: Suppression pool water is injected into the core, flows up through the jet pumps, and back to the suppression pool via the postulated break. The system will be operated for an estimated 30 minutes minimum prior to sampling of the suppression pool water to ensure that a representative sample is obtained at the sample taps.

2. Shutdown Cooling: The RHR system, aligned in the shutdown cooling mode, provides cooling and circulation of reactor coolant through the core, resulting in a representative sample at the RHR sample taps.

3. Suppression Pool Cooling: The RHR system, aligned in the suppression pool cooling mode, provides cooling and circulation of the suppression pool water. The system will be operated for an estimated 30 minutes minimum prior to sampling of the suppression pool water to ensure that a representative sample is obtained at the RHR sample taps.

11.5.5.1.2 Isolation Valves and Sample Lines

Containment isolation for the drywell and wetwell gas sample lines is provided by the existing CAC system sample line isolation valves. Jet pump instrument line containment isolation is provided by the existing restricting orifice and excess flow check valve upstream of the sample tap. Containment isolation for the RHR sample lines is provided by the existing RHR sample line automatic isolation valves. All automatic isolation valves can be overridden from the control room. PASS remote-operated sample line valves are controlled from local panels located adjacent to the sample stations.

All safety-related solenoid isolation and control valves that are part of the PASS are environmentally qualified for the conditions in which they must operate. Table 3.2-1 contains a description of the safety-related portions of the PASS, and Section 3.11 contains a description of the equipment qualification program.

Nonsafety-related valves that are part of the PASS are not included in the LGS equipment qualification program. However, those valves that are not accessible for repair after an accident do not contain materials that, if degraded, would prevent the PASS from performing its sampling function.

Sample line routings are as direct and short as practical. Recirculation flow rates in the liquid sample lines are maintained in the turbulent flow regime. The gas sample lines are equipped with heat trace which was originally intended to prevent plate-out of iodine vapor. The PASS is not used for iodine sampling. Therefore, the heat trace is not required for proper gas sampler operation.

11.5.5.1.3 Piping Rack

The piping rack, which is installed within the reactor enclosure, includes sample coolers and control valves that determine the liquid sample flow path to the sample station. The rack provides a flow path to recirculate liquid samples, bypassing the sample stations, until a representative sample condition is obtained. The cooling water is supplied by the RECW system.

11.5.5.1.4 Sample Station and Control Panels

The sample station consists of a floor stand, frame, and sample enclosures, and is mounted flush against the outside of the secondary containment wall. Included within the sample station are equipment trays that contain modularized liquid and gas samplers. The liquid sample portion of the sample station is shielded with 6 inches of lead brick, whereas the gas sampler has 2 inches of lead shielding. The various sample and return lines enter the sample station enclosure through the back by way of a penetration through the reactor enclosure wall. Control instrumentation is installed in two control panels mounted side-by-side. One of these panels contains the conductivity and radiation level readouts. The other control panel contains the flow, pressure, and temperature indicators, and various valve controls and switches. A graphic display is provided directly below the main control panel which shows the status of the pumps and valves. A radiation monitor provides an indication of dose rates in the immediate vicinity of the control panel and is used to limit operator exposure.

11.5.5.1.4.1 Gas Sampler

The gas sample system is designed to operate at pressures ranging from subatmospheric to the design pressures of the primary containment one hour after a LOCA. The sample flow is chilled to remove moisture, and a 15 cc nominal grab sample can be taken for determination of gaseous activity and gas composition by gas chromatography. The gas is collected in an evacuated vial using hypodermic needles. When purging the drywell and wetwell gas sample lines to obtain a representative sample, the flow is returned to the wetwell. During purging of the secondary containment line and when flushing the sample panel lines with nitrogen, flow is returned to secondary containment. The sample station design allows for sample gas or nitrogen flushing of the entire sample panel line downstream of the four-position selector valve. This capability will minimize cross-contamination between the various samples.

11.5.5.1.4.2 Liquid Sampler

The liquid sample system is designed to operate at pressures from 0-1150 psi. The design flow rate of 0.2 to 1 gpm is sufficient to maintain turbulent flow in the sample line and serves to minimize cross-contamination between samples. The flow is returned to the suppression pool. The liquid sampling system is designed to allow demineralized water flushing of the system lines from a point in the piping station through the sampling needles. A radiation monitor in the sample enclosure monitors the sample return to provide assessment of sample activity level and the effectiveness of the demineralized water flush after sampling.

a. Diluted Liquid Sample

All liquid samples are taken into nominal 15 milliliter septum bottles mounted on sampling needles. In the sampling lineup, the sample flows through a conductivity cell (0.1-1000 μmho/cm) and through a ball valve bored to nominal 0.10 milliliter volume. After flow through the sample panel is established, the ball valve is rotated

90°, and a syringe is used to flush the sample and a measured volume of diluent (generally 10 milliliters) through the valve and into the sample bottle. This provides an initial dilution of up to 100:1 nominal. The sample bottle is contained in a shielded cask and remotely positioned on the sample needles through an opening in the bottom of the sample enclosure.

b. Nondiluted Liquid

The sample station can provide depressurized samples of the primary coolant. Ten milliliter aliquots nominal of degassed liquid may be taken for offsite (or onsite depending on activity level) analyses, which requires a relatively large undiluted sample. This sample is obtained remotely using the large volume cask and cask positioner through a needle on the underside of the sample station enclosure .

The PASS system was originally designed to obtain dissolved gas samples from the primary coolant as a means of assessing core damage per NUREG-0737. However, core damage assessment is accomplished by use of the CAC system as described in UFSAR Section 6.2.5. Therefore, this PASS feature is not used.

11.5.5.1.4.3 Sample Station Ventilation

The sample station enclosure is vented to a Zone V room in the secondary containment. Ventilation is facilitated by differential pressure between the control structure and reactor enclosure. The ventilation rate required for heat removal and proper sweep velocity during operation is about 40 scfm. A pressure gauge is attached to the sample station enclosure to monitor the pressure differential between the enclosure and the general sampling area in the control structure. The pressure differential will assure the operator that airborne activity in the sample enclosure will be swept into secondary containment.

11.5.5.1.4.4 Sample Station Sump

The sample station is provided with a bottom sump to collect liquid leakage. This sump can be isolated, pressurized, and discharged into the sample station liquid return line to the suppression pool.

11.5.5.1.4.5 Sample Handling Tools and Transport Containers

Appropriate sample handling tools and transporting casks are used. Gas vials are installed and removed by use of a vial positioner through the front of the gas sampler. The vial is manually lowered into a shielded cask directly from the positioning tool. This allows the operator to maintain a distance of about three feet from the unshielded vial. The cask provides about 1-1/8 inches of lead shielding. A 1/8 inch diameter hole is drilled in the cask so that an aliquot can be withdrawn from the vial with a gas syringe without exposing the analyst to the unshielded vial.

The small volume (diluted) liquid sample cask is a cylinder with a lead wall thickness of about 2 inches. The cask weighs approximately 50 pounds and has a handle which allows it to be carried by one person.

The nominal 10 milliliter undiluted sample is taken in a 700 pound lead shielded cask which is transported and positioned by a four-wheel dolly. The sample is shielded by about 5½ inches of lead. A licensed shipping cask for transport of the undiluted samples to the offsite analysis facility

(Section 11.5.5.2.2) has been procured in conjunction with a group of other utilities. This cask will be placed in a centrally located, continuously attended warehouse facility.

11.5.5.1.4.6 Sample Station Power Supply

The PASS isolation and control valves, sample station control panels, and auxiliary equipment are connected to an instrument ac distribution panel which is powered from an engineered safeguard system bus. Following a LOOP, the engineered safeguard system bus is powered from the onsite diesel generators. The RECW system, which is needed for the sample coolers, is also powered from the emergency diesel generators following a LOOP.

All electrically operated components associated with the PASS are capable of being supplied with power and operated within 30 minutes of an accident in which there is core degradation, assuming a LOOP.

11.5.5.2 Description of Sample Preparation/Chemistry and Nuclear Counting Facilities

After the samples are obtained from the sample station, they will be transported to the Chemistry Laboratory Expansion where they will be diluted as necessary and appropriate aliquots taken for chemical and radioisotopic analysis. The radioisotopic analysis will be done in an area where background radiation can be kept to a minimum. The primary facility for performance of these analyses is the chemistry laboratories and counting room in the Chemistry Laboratory Expansion. In addition to these onsite facilities, which are intended to handle the gas samples and the diluted liquid samples, prior arrangements will be made with an offsite laboratory for supplemental and confirmatory analysis of samples as required.

11.5.5.2.1 Onsite Facilities

The chemistry lab is equipped to handle the gas samples and the nominal 0.1 ml diluted liquid samples. The maximum activities of these samples will be 0.50 Ci and 0.32 Ci, respectively, using one hour decay and the fractional releases of core inventory as discussed in Section 11.5.5.5.

The laboratory will maintain a dedicated inventory of items such as lead bricks for shielding, gas syringes, gloves, reagents for analysis, etc., which will be needed in case of an accident. The laboratory will be equipped with a gas chromatograph, pH meter, conductivity meter, turbidimeter and other instrumentation needed to perform the required analyses. This equipment, however, may not be dedicated exclusively to postaccident analysis. Supplied air or self-contained breathing masks will be available in the event of high activity levels in the ventilation supply or accidental spills in the laboratory.

The primary counting facility located adjacent to the chemistry laboratories in the Chemistry Laboratory Expansion is equipped to handle the gamma spectra analyses required for postaccident samples. The detectors in the counting room are equipped with lead shields connected to computer based analyzer systems which have automatic peak search and isotope identification capabilities. The capability to purge the volume within the shield with compressed gas is available for at least one detector assembly. This will help prevent atmospheric noble gas activity released during an accident from swamping the detector.

It is expected that the first set of postaccident samples will be analyzed in the chemistry lab/counting room facilities located in the Chemistry Laboratory Expansion approximately two hours after the start of an accident. At this time, the chemistry lab will be a Zone III area and therefore accessible for performing the required chemical analyses. The lab becomes a Zone II

area within 20 hours following an accident. The counting room is a Zone II area within two hours, and a Zone I area within 6 hours following an accident. Shielding for the PASS is further discussed in Section 1.13.2 (Item II.B.2).

The most direct route from the sampler location to the chemistry lab is through the control structure and Unit 1 turbine enclosure to the radwaste enclosure on el 217' and then through the doorway (ramp) of the west wall of the radwaste building to the Chemistry Laboratory Expansion. However, during the first 20 hours following an accident, high radiation in portions of this access path require that an alternate route from sampler to labs be taken. Operators must exit through the north of the turbine enclosure, travel around the west end of the radwaste building, and enter the lab/counting room area in the Chemistry Laboratory Expansion through the doorway of the west wall radwaste building.

11.5.5.2.2 Arrangements for Offsite Analyses

A part of the LGS approach to postaccident sampling is the establishment of prior arrangements with an offsite laboratory for confirmatory and supplemental analyses.

11.5.5.3 Sample Collection and Transport Procedures

It is anticipated that the first set of samples will be taken within one hour following a LOCA, with samples taken approximately every 4 hours for the remainder of the first 24 hours. Following day one, it is expected that three samples per day may be taken for the remainder of the first week, with samples once per day following the first week for the duration of the accident.

The following is a conservative time sequence for sampling, transport, and analysis to demonstrate that samples can be obtained and analyzed within the specified 3 hour period:

a. Recirculate sample, install sample vial - 15 min

b. Operate sample station - 15 min

c. Transport sample to lab - 20 min

d. Analyze sample - 60 min

Atmosphere sample lines from the CAC system and liquid samples from the RHR system are automatically isolated following a containment isolation signal. The sample station operator(s) must confirm with the control room personnel that the necessary isolation valves are opened. A telephone extension to the control room is provided near the PASS control panel.

Controls for all other PASS sample line valves are located on or adjacent to the PASS control panel. All controls for valves that are a part of the sampler or piping rack are located on the PASS control panel.

Following a series of presampling checks and procedures, including adjustment of the enclosure damper to ensure adequate ventilation, checks of demineralized water and nitrogen supplies, flushing of system with demineralized water, draining the trap and sump, etc., the system is ready for obtaining the samples.

11.5.5.4 Chemical/Radiochemical Procedures

The PASS provides a means of obtaining primary coolant, suppression pool, and primary and secondary containment air samples for radiochemical and chemical analysis following a major reactor accident. Because of the extremely high radioactivity levels associated with extensive fuel damage, the PASS was developed to provide the capability of obtaining the necessary samples and performing analyses, as required, for immediate plant needs, or as defined by regulatory requirements. Procedures have been established for shipping samples to appropriate facilities to perform detailed analyses on multicurie level samples.

11.5.5.4.1 Sample Preparation

All sample bottles, etc., will be identified prior to sampling to eliminate unnecessary exposure resulting from handling high level samples. A centralized logging system will be developed to track sample aliquot identification, dilution factors, sample disposition, etc.

Liquid samples will be taken at the sample station in septum-type bottles and transported to the analysis facility in lead containers.

Sample aliquots are taken from the septum bottles for analysis or further dilution. Aliquoting and transfer will be performed using shielded containers, or behind a lead brick pile. Calibrated hypodermic syringes will be used for aliquoting the higher activity samples. Tongs or other holding/clasping devices will be available for holding the sample bottle during the transfer and dilutions to reduce hand and body exposure. Unless prohibited by the intended analysis, dilutions will be done using very dilute (about 0.01 N) nitric acid as the diluent to minimize sample plateout problems.

Primary coolant samples obtained from the sampling station are diluted by a factor of 100 (0.1 ml coolant diluted to 10 ml). Under severe accident conditions, a calibrated syringe would be used to obtain an aliquot for this sample for further dilutions. At the maximum expected primary coolant activity level (3 Ci/cc), a dilution factor of 1×10^5 would be required for gamma spectroscopy.

Direct counting of the initial nominal 100:1 dilution sample would allow analysis at coolant activity levels down to 1 μCi/cc. In addition, the degassed, undiluted nominal 10 ml sample available from the sample station could be used for analysis of samples in the 10^{-2} μCi/cc to 10^{-3} μCi/cc range. Thus, useful samples may be obtained from the postaccident sampling station for coolant activity levels ranging from DBA source terms to well below the maximum level that can be tolerated at the normal reactor sample station.

Gas samples are taken at the sample station in a nominal 15 milliliter septum bottle. A lead carrier is furnished with a small hole at the septum end so that a gas sample can be withdrawn from the carrier using a hypodermic syringe without having to handle the bottle.

Samples taken from the gas sample bottle will either be injected into a gas chromatograph for analysis or diluted for gamma spectroscopy. The dilutions will be performed in a manner analogous to the liquid samples. Fractional milliliter samples can be transferred to new 15 ml gas bottles without concern for sample leakage due to pressurization. For larger volume aliquots, a gas syringe will be used to draw a partial vacuum in the bottle prior to sample transfer.

11.5.5.4.2 Chemical Analysis

Approved chemistry procedures are chosen on the basis of simplicity, stability, minimum of radiation exposure and least likelihood to cause major contamination problems. They have been

tested for radiation sensitivity and are suitable for use at the PASS design basis source term of 3.13 Ci/gm, and where applicable, with the design basis 0.1 ml to 10 ml nominal dilution at the sample station.

a. Gross activity, gamma spectra analyses will be accurate within at least a factor of two over a coolant activity range of 10 μCi/cc to 10 Ci/cc (Additional information is provided in Section 11.5.5.4.1).

b. Boron concentrations will be determined by an approved Chemistry procedure. Concentrations between 50 ppm and 1100 ppm are of interest for BWR reactivity control in the event sufficient control rods are not inserted to shutdown the reactor. The approved method with the 100:1 diluted sample will have an accuracy of ±10% over the described range.

   Tests have been performed to verify that none of the expected post accident chemical constituents (I, Cs^{+}, Ba^{+2}, La^{+3}, Ce^{+4}, Cl^{-}, B, Li^{+}, NO^{-3}, NH^{+4}, K^{+}) will interfere with this analysis method.

c. The chloride analysis performed onsite will be accomplished using an approved Chemistry procedure. The use of the method with the nominal 100:1 diluted sample will result in a accuracy of at least ±10% for coolant concentration over the range of 500 ppb to 20 ppm.

   Tests have been performed to verify that none of the expected post accident chemical constituents listed above will interfere with the results of this analysis for the procedures and equipment which will be employed.

   Offsite provisions for chloride analysis will be accurate ±10% over the range 0.5 ppm to 20 ppm and ±0.05 ppm below concentrations of 0.5 ppm.

d. A combination electrode will be used to measure the pH of coolant samples. Testing performed by GE has verified that expected levels of irradiation result in a shift of less than 0.3 pH units.

e. The postaccident sample station is equipped with a 0.1 cm^{-1} conductivity cell. The conductivity meter has a linear scale with a six-position range selector switch to give conductivity ranges of 0-3 μmho/cm, 0-10 μmho/cm, 0-30 μmho/cm, 0-100 μmho/cm, 0-300 μmho/cm, and 0-1000 μmho/cm when using the 0.1 cm^{-1} cell. This conductivity measurement system will be used to determine the primary coolant or suppression pool conductivity. During normal operation the LGS Technical Specifications require maintaining the primary coolant below 1.0 μmho/cm (at 25°C), and conductivity measurements are the primary method of coolant chemical control.

   Conductivity measurements are, of course, nonspecific, but they serve the important function of indicating changes in chemical concentrations and conditions. Perhaps even more important, in the case of the BWR primary coolant, the conductivity measurements can establish upper limits of possible chemical concentrations and can eliminate the need for additional analyses.

The conductivity measurement can also be used to bound the possible range of pH values.

11.5.5.4.3 Radiochemical Analysis/Gamma Ray Spectroscopy

After the samples have been brought to the chemistry laboratory and appropriately diluted, they can be carried without shielding to the counting room which is adjacent to the chemistry laboratory. The appropriate dilution factors will be somewhat dependent on the detector and shelf arrangements available. A prior determination of the maximum desirable dose rates for the various shelf configuration will be made to minimize this problem. The present Gamma Spectrometer in the onsite counting room will handle the analysis of these samples within 3 hours from the time a decision is made to sample.

The gas samples will be counted in the PASS gas sample vials, and the liquid samples will be counted in the standard sample bottles used during normal operation because calibration curves for these geometries will be available and regularly updated. In general, the counting of the postaccident sample will follow the normal counting room procedures. The peak search and identification library will contain the principal gamma rays of the following isotopes in addition to the standard activated corrosion products:

a. Noble gases: Kr-85, Kr-85m, Kr-87, Kr-88, Xe-131m, Xe-133, Xe-133m, Xe-135

b. Iodines: I-131, I-132, I-133, I-135

c. Cesiums: Cs-134, Cs-137

d. Others: Ba/La-140, Ce-141, Ce-144, Ru-106, Te-129, Te-129m, Te-131, Te-131m, Np-239

If the levels of noble gases in the ambient atmosphere surrounding the detector are high enough to cause significant interference or to overload the detector, a compressed air or nitrogen purge of the detector shield volume will be maintained.

The onsite radiological and chemical laboratory facilities are equipped with gamma spectral analysis equipment to quantify the radionuclides present in gas and liquid samples. Shielding is provided for the radiation detectors to minimize the effect of background radiation. Initial dilutions are performed in the process of taking liquid samples at the sample stations. Any additional dilutions required will be performed in the laboratory fume hood behind a lead brick pile.

11.5.5.4.4 Gas Analysis

A gas chromatograph will be used to measure hydrogen and oxygen concentrations in containment atmosphere. The accuracy of the containment gas analysis will be at least ±5% between 0.1% and 30% (volume) of the constituent.

11.5.5.4.5 Determination of Extent of Core Damage

A generic procedure to assess the extent of core damage based on radionuclide concentrations and other parameters has been prepared by the BWROG and transmitted to the NRC by letter from T.J. Dente (BWROG) to D. Eisenhut (NRC) dated June 17, 1983. A licensee procedure based on this methodology has been prepared and transmitted to the NRC.

11.5.5.4.6 Storage and Disposal of Sample

Short-term sample storage areas will be provided in the chemistry laboratory and counting room facilities. The area to be used for long-term storage of the samples is the source storage room, number 244, in the radwaste enclosure. Low level wastes generated by the chemistry procedures will be flushed to radwaste. Ultimate procedures for disposal of the samples will be determined later; however, after a sufficiently long decay period, the activity levels will be significantly reduced. This will ease exposure problems during disposal.

11.5.5.4.7 System Testing and Operator Training

Equipment used for post-accident sampling and analyses will be calibrated and tested per an approved preventive maintenance program. The testing program is designed so that sampling operations are conducted approximately every twenty-four months.

11.5.5.5 Dose Rate Analysis

The post-LOCA core inventory of fission products was calculated assuming a three year irradiation, 100% availability, and reactor operation at 102% of rated power. Fractional releases of fission products from the fuel to the reactor water, suppression pool, and containment atmosphere were based on Regulatory Guide 1.3 and Regulatory Guide 1.7 assumptions. The resulting source terms were used in the design of PASS shielding and in determining doses to operators.

The sampling and analysis provisions at LGS have been designed such that it will be possible to obtain and analyze a sample following an accident without exceeding the criteria of GDC 19. Time sequences and calculated dose rates to verify compliance for a sample taken one hour post-LOCA are given in Table 11.5-3.

11.5.6 RADIATION AND METEOROLOGICAL MONITORING SYSTEM

11.5.6.1 General Description

The RMMS is a system consisting of data acquisition computers with report generating capabilities designed to perform the following functions:

a. Collect radioactivity level information from selected microprocessor-based process radiation monitors throughout the plant

b. Remotely operate radiation monitors

c. Display radiation levels

d. Generate radioactive effluent reports for compliance with Regulatory Guide 1.21

e. Calculate offsite dose consequences from normal plant operation releases

f. Calculate offsite dose consequences from accident conditions in accordance with NUREG-0654.

g. Meteorological data is transmitted from the met towers to Unit I PMS for display, averaging and transmission to EPDS.

11.5.6.2 RMMS Hardware Description

Deleted

11.5.6.2.1 Radiation Monitoring and Display System

The RMDS is a dual-computer system that monitors, stores, and displays information obtained from selected process radiation monitors described in Section 11.5.2.

The RMDS also transmits radioactivity concentration and stack flow rate information obtained from the process radiation monitors to the EPDSto be used in calculating offsite doses.

The RMDS dual-computer configuration is designed with one computer being the primary computer. The computer collects data from the process radiation monitors and displays the data on RMDS workstations. The second computer is redundant and will take over the functions of the primary computer, if the primary computer fails. The dual hardware configuration gives increased assurance of the availability of radiation monitoring data to plant personnel through the RMDS workstations and to the EPDS through a data link.

In the RMDS dual-computer configuration, each computer is capable of storing dynamically created data. RMDS workstations located in the control room and TSC are interfaced to the RMDS computers to allow the access of information from the computers and process radiation monitors and to display process radiation monitors status.

The RMDS has data links that communicate with process radiation monitors located throughout the plant. The RMDS also has a data link that communicates with the EPDS. The EOF has access to RMDS data through the EPDS. The two RMDS computers communicate with each other and with the workstations over a local area network.

The RMDS provides process radiation monitors status and RMDS status through annunciation of alarm conditions at the RMDS display consoles to supplement the process radiation monitors alarms at the plant annunciator panel. The operator is alerted of abnormal conditions through visual alarms located at each RMDS display console. Trend displays of the process radiation monitors data are available as demand prints are available for display or hard copy at the RMDS display consoles.

11.5.6.3 RMMS Software Description

11.5.6.3.1 RMDS Software Description

The RMDS software is designed to help the plant operator display and retrieve information from the RMDS and the process radiation monitors memory, and to initiate process radiation monitors control functions. The RMDS software also handles the communications interface between the process radiation monitors and the RMDS and between the RMDS and the EPDS.

The RMDS software consists of the following programs:

a. Operator interface programs to allow operator communications via the RMDS workstations

b. Alarm log and display programs

c. System fail-over software

d. Communications software and control programs.

e. Collect, quality check (evaluate), and report radiological effluent release data from onsite monitors

11.5.6.3.2 Effluent Release Software Description

The Effluent Dose Calculation Computer Program is designed to help the plant operators and health physicists meet NRC regulatory requirements for measuring, evaluating, and reporting releases of radioactive materials in gaseous and liquid effluents and for classifying and reporting the categories and the curie content of radioactive solid wastes. The software functions are grouped into the following two categories:

a. Generate a data base and store data in a retrievable form

b. Compute short-time or accumulated offsite radiation doses from various effluent discharge pathways caused by the release of gaseous and/or liquid radioactive materials.

In performing the above functions, the procedures used adhere to specific guidelines. Calculations of liquid dispersion use either site specific factors or equations that conform to the standards of Regulatory Guide 1.113; and calculations of radiation doses conform to Regulatory Guide 1.109 (Rev 1). Effluent release summaries and the environmental pathway dose summary are prepared in accordance with Regulatory Guide 1.21 (Rev 1). The above regulatory guides and 10CFR50, Appendix I were used to develop the Effluent Dose Calculation software.

The functions that the Effluent Dose Calculation software performs are related to routine operations. The operator is provided with the capability to inspect the contents of the data base and to perform dose calculations. The operator can perform both gaseous and liquid effluent calculations. The method used to perform gaseous calculations is based on hourly averages of meteorological and effluent data. Liquid calculations are based on batch release data.

To satisfy NRC reporting requirements for routine operation, the Effluent Dose Calculation Software has the capability to generate two reports:

a. An effluent release summary, describing releases of gaseous and liquid effluents and shipments of solid waste

b. An environmental pathway dose summary, showing total body and body organ doses by age group for environmental pathways for gaseous and liquid effluents.

The dose assessment model performs calculations of atmospheric dispersion and dose for accidental release of gaseous effluent. To perform calculations of atmospheric dispersion (X/Q values), the dose assessment model prompts the operator to enter meteorological data.

Meteorological data is used to compute the dispersion conditions for a given release point. Dose calculations can be done using radiological release data obtained automatically from the EPDS or entered manually by the operator.

The dose assessment model is described in detail in the Emergency Plan.

The results of the accidental dose calculations, in addition to being available at the control room, TSC, and EOF, are available to local, State, and Federal emergency officials.

Table 11.5-1

PROCESS AND EFFLUENT RADIATION MONITORING SYSTEMS

MONITORED PROCESS	TOTAL NO. OF CHANNELS (BOTH UNITS)	DETECTOR TYPE	DETECTOR LOCATION	CHANNEL RANGE	SENSITIVITY	PRINCIPAL RADIONUCLIDES MEASURED
Main steam line	8	Gamma-ion chamber	Immediately downstream of main steam isolation valve	1 to 10^6 mrem/hr	1 mrem/hr	Coolant activation gases
Reactor enclosure exhaust	8	Gamma-GM	Reactor enclosure exhaust duct	0.01 to 10^2 mrem/hr	0.01 mrem/hr	Kr-85
Refueling area exhaust	8	Gamma-GM chamber	Refueling area exhaust duct	0.01 to 10^2 mrem/hr	0.01 mrem/hr	Kr-85
Control room supply	4	Beta-scint	Main intake ventilation duct	10^{-4} to 10^1 μCi/cc	$1x10^{-6}$ μCi/cc (Xe-133)	Kr-85
Control room emergency fresh air	2	Beta-scint	Emergency fresh air supply duct	10^{-4} to 10^1 μCi/cc	$1x10^{-3}$ μCi/cc (Xe-133)	Kr-85
RHR service water	2	Gamma-scint	Common RHRSW/ESW Discharge Lines	10 to 10^6 counts/sec	$1.29x10^{-7}$ μCi/cc (Cs-137)	Cs-137 Co-60
North stack				(1)		
Normal range subsystem	6	a. Beta-scint(Part.) b. Gamma-scint(Iodine) c. Beta-scint(Noble Gas)	Cross-section of north stack at el 402'	a. 10^{-12} to 10^{-6} μCi/cc b. 10^{-11} to 10^{-5} μCi/cc c. 10^{-7} to 10^{-1} μCi/cc	$1x10^{-7}$ μCi/cc (Xe-133)	Kr-85, I-131 Sr-90, Y-90
Wide range subsystem	3(3)	Beta-scint	Cross-section of north stack at el 402'	10^{-7} to 10^{-1}, 10^{-4} to 10^2 and 10^{-1} to 10^5 μCi/cc(3)	$1 x 10^{-7}$ μCi/cc (Xe-133)	

Table 11.5-1 (Cont'd)

MONITORED PROCESS	TOTAL NO. OF CHANNELS (BOTH UNITS)	DETECTOR TYPE	DETECTOR LOCATION	CHANNEL RANGE	SENSITIVITY	PRINCIPAL RADIONUCLIDES MEASURED
South stack	12(2)	Beta-scint, gamma-scint, particle/iodine filter	Cross-section of south stack at el 402'	(2)	$1x10^{-7}$ μCi/cc (Xe-133)	Kr-85, I-131 Sr-90, Y-90
Charcoal offgas compartment exhaust	1	Beta-GM, particle filter	Charcoal offgas compartment exhaust ducts	10 to 10^6 counts/min	$1.46x10^{-6}$ μCi/cc (Xe-133)	Kr-85
Charcoal offgas effluent	2	Beta-GM, particle filter	Charcoal offgas exhaust pipe	10 to 10^6 counts/min	$1.46x10^{-6}$ μCi/cc (Xe-133)	Kr-85
Recombiner compartment exhaust	2	Beta-GM, particle filter	Recombiner compt and H_2/O_2 units exhaust ducts	10 to 10^6 counts/min	$1.46x10^{-6}$ μCi/cc (Xe-133)	Kr-85
Containment post-LOCA	8	Gamma-ion chamber	Inside primary containment	1 to 10^6 counts/min	10^2 to 10^8 rads/hr	
Steam seal	2	Gamma-GM, particle filter	Downstream of junction of mechanical vacuum pump exhaust and steam seal exhaust	10 to 10^6 counts/min	$1.46x10^{-6}$ μCi/cc (Xe-133)	Kr-85
Radwaste enclosure exhaust	1	Gamma-GM, particle filter	Main exhaust duct of radwaste enclosure	10 to 10^6 counts/min	$1.46x10^{-6}$ μCi/cc (Xe-133)	Kr-85
Air ejector effluent	6	Gamma-ion chamber	SJAE discharge pipes to recombiner	10 to 10^6 mr/hr	1 mrem/hr	Noble gas fission products
Primary containment leak detection	2 (1 per unit)	Beta-scint particle filter (active)	Primary containment at el 292'	10 to 10^7 counts/min	$1x10^{-6}$ μCi/cc (Xe-133) $1x10^{-9}$ μCi/cc (Sr-90)	Fission gas daughter and corrosion activation products

Table 11.5-1 (Cont'd)

MONITORED PROCESS	TOTAL NO. OF CHANNELS (BOTH UNITS)	DETECTOR TYPE	DETECTOR LOCATION	CHANNEL RANGE	SENSITIVITY	PRINCIPAL RADIONUCLIDES MEASURED PRINCIPAL
Hot maintenance exhaust shop	1	Beta-scint filter a. particle b. Iodine	Ventilation exhaust duct from hot maintenance shop	a. 10^{-12} to 10^{-6} μCi/cc b. 10^{-11} to 10^{-5} μCi/cc	$1x10^{-11}$ μCi/cc Y-90, Co-60	I-131, Sr-90
Radwaste discharge	1	Gamma-scint	Radwaste drain line to cooling tower blowdown line	10 to 10^6 counts/sec	$1.29x10^{-7}$ μCi/cc (Cs-137)	Cs-137 Co-60
Service water	2	Gamma-scint	Main pipe to cooling tower	10 to 10^6 counts/sec	$1.29x10^{-7}$ μCi/cc (Cs-137)	Cs-137 Co-60
Reactor enclosure cooling water	2	Gamma-scint	Reactor enclosure cooling water upstream of pumps	10 to 10^6 counts/sec	$1.29x10^{-7}$ μCi/cc (Cs-137)	Cs-137 Co-60
Dose rate at PASS control panel	2	Gamma-ion chamber	PASS control panel	1 to 10^4 mrem/hr	1 mrem/hr	(4)
PASS liquid sample		2 chamber	Gamma-ion sample return	PASS liquid mrem/hr	0.01 to 10^2	0.01 mrem/hr(4)
PASS gaseous sample	2	Gamma-ion chamber	PASS gas sample particulate/iodine filter	1 to 10^4 mrem/hr	1 mrem/hr	(4)

(1) Three detectors in each of two redundant systems: a) Particulate, b) Iodine, and c) Noble gas.
(2) Four noble gas detectors (10^{-7} to $5x10^{-1}$ μCi/cc), four particulate detectors (10^{-12} to 10^{-6} μCi/cc), and four iodine detectors (10^{-11} to 10^{-5} μCi/cc).
(3) Three noble gas detectors with overlapping ranges.
(4) Not applicable.

Table 11.5-2

RADIATION MONITORING SYSTEM SETPOINTS AND FUNCTIONS

	LOW		HIGH		HIGH-HIGH	
MONITORED PROCESS	SETPOINT[1]	FUNCTION	SETPOINT[1]	FUNCTION	SETPOINT[1]	FUNCTION
Main steam line[2]	Below Background[6]	Annunciate	1.5 x Full Power	Annunciate	3 x Full Power	Annunciate Trip mechanical vacuum pump & suction valve
Reactor enclosure ventilation exhaust	Below Background[6]	Annunciate	Above Background[6]	Annunciate	Technical Specifications	Annunciate Trip HVAC valves Start RERS Start SGTS Trip containment purge & vent valves
Refueling floor ventilation exhaust	Below Background[6]	Annunciate	Above Background[6]	Annunciate	Technical Specifications	Annunciate Trip HVAC valves Start SGTS Trip containment purge & vent valves
Control room air supply[3]	[7]	Annunciate	Above Background[6]	Annunciate	Technical Specifications	Annunciate Trip fresh air isolation valves Start emergency fresh air system
Control room emergency fresh air[3]	[7]	Annunciate	[11]	Annunciate	[11]	Annunciate
RHR service water[4][2]	Below Background[6]	(Same as high-high)	Above Background[6]	Annunciate	Technical Specifications	Annunciate Trip RHRSW pumps
North stack[3] normal range	[7]	Annunciate	a.Calculated per ODCM (Noble Gas) b.$3.8 \times 10^{-}$ μCi/cc (Iodine)	Annunciate	a.Calculated (Noble Gas) b.7.66×10^{-7} μCi/cc (Iodine)	Annunciate per ODCM

Table 11.5-2 (Cont'd)

	LOW		HIGH		HIGH-HIGH	
MONITORED PROCESS	SETPOINT[1]	FUNCTION	SETPOINT[1]	FUNCTION	SETPOINT[1]	FUNCTION
North stack[3] wide range	[7]	Annunciate	Calculated er ODCM		Calculated per ODCM (Noble Gas)	Annunciate Trip containment purge & vent valves
South stack[3]	[7]	Annunciate	a. Calculated per ODCM (Noble Gas) b. 1.1×10^{-8} μCi/cc Iodine)	Annunciate b. 2.27×10^{-6}	a. Calculated per ODCM (Noble Gas) μCi/cc (Iodine)	Annunciate
Radwaste equipment rooms ventilation exhaust[3]	[9]	Annunciate	[9]	Annunciate	[9]	Annunciate
Charcoal treatment system process exhaust[3]	[9]	Annunciate	[9]	Annunciate	[9]	Annunciate
Recombiner compartment & H_2 analyzers exhaust[3]	[9]	Annunciate	[9]	Annunciate	[9]	Annunciate
Primary containment post-LOCA	[7][8]	Annunciate	50 R/hr	---	1×10^2 R/hr	Trip reactor enclosure sump pumps
Steam exhauster discharge & vacuum pump exhaust	[9]	Annunciate	1.5xBackground	Annunciate	[9]	Annunciate
Radwaste enclosure exhaust[3]	[9]	Annunciate	[9]	Annunciate	[9]	Annunciate
Air ejector/after condenser effluent[2][3]	Below Background[6]	(Same as high-high)	1.5xNormal Full Power Background [12]	Annunciate	Technical Specifications	Annunciate

Table 11.5-2 (Cont'd)

	LOW		HIGH		HIGH-HIGH	
MONITORED PROCESS	SETPOINT[1]	FUNCTION	SETPOINT[1]	FUNCTION	SETPOINT[1]	FUNCTION
Primary containment leak detection[3]	Below Background	Annunciate	[10] [10]	Annunciate	[10]	Annunciate
Hot maintenance shop exhaust[5]	[7]	Annunciate	[11]	Annunciate	[11]	Annunciate Locally
Radwaste discharge[4]	[9]	(Same as high-high)	7.6×10^{-6} μCi/cc	Annunciate	Calculated per ODCM	Annunciate Trip radwaste discharge valve
Service water[4]	[9]	Annunciate	Above Background	Annunciate	Calculated per ODCM	Annunciate
Reactor enclosure cooling water[4]	[9]	Annunciate	Above[6] Background	Annunciate	Technical Specifications	Annunciate
Dose rate at PASS control panel	N/A		N/A		N/A	
PASS liquid sample	N/A		N/A		N/A	
PASS gaseous sample	N/A		N/A		N/A	

(1) NA designation in this column means that an associated alarm is not provided.
(2) Monitoring system inoperative alarms are also provided for this process. The alarm performs the same function as the high-high alarm.
(3) In addition to the alarms shown, these processes also are provided with high/low flow alarms that annunciate in the control room.
(4) In addition, low sample pump flow alarms annunciate in the control room.
(5) This system is used for particulate/iodine monitoring only.
(6) Setpoints are determined after normal background values are established during startup testing. The high setpoint is set at twice the background value if practicable.
(7) Setpoints are factory set based on parameters of the detector.
(8) A bias source is provided in this monitor to maintain minimum indication when the ambient radiation is below channel range.
(9) Low setpoint is set below expected radioactivity concentration for normal operation. High setpoint is set at twice this value if practicable.
(10) Setpoints are set significantly above background to prevent nuisance alarms (Section 5.2.5.2.1.5).
(11) This monitor is used for information only. Setpoints may be set for operator information above normal radioactivity concentration values established during startup testing.
(12) Setpoint not to exceed 2100 mR/Hr.

Table 11.5-3

POSTACCIDENT SAMPLING
DOSE ASSESSMENT[1][2]

Liquid Sample	Time (min)	Background Dose Rate (mR/hr)	Sample Dose Rate (mR/hr)	Integrated Dose Rate (Rem)
Recirculate Sample	5	722	27	0.06
Operate Sampler	5	722	112	0.07
Transport Sample Cask	10	3766	8	0.63
Handle Sample	10 sec	9	182	0.01
Analyze Sample	20	9	91	0.03
Total				0.80
Gas Sample				
Recirculate Sample	5	722	75	0.07
Operate Sampler	5	722	289	0.08
Handle Bottle	1	722	332	0.02
Transport Sample Cask	10	3766	43	0.63
Analyze Sample	20	9	37	0.01
Total				0.82
Total (All samples)				1.62

(1) Doses listed are 1 hour post-LOCA, except for those associated with MSIV Leakage Alternate Drain Pathway. Worst case doses resulting from this pathway peak are at 4 days and are:

	Liquid Sample	Gas Sample	Iodine/Particulate Sample	Total
WHOLE BODY(REM)	0.036	0.037	0.036	0.11
BETA SKIN(REM	0.0007	0.0008	0.0007	0.0032
THYROID (REM)	0.20	0.20	0.20	0.60

(2) Some additional dose to extremities will result from the limited handling of samples in the laboratory. Because of the use of sample dilutions, small volume samples, shielded casks, lead brick piles, and laboratory extension devices (i.e., tongs), doses to the extremities are estimated to be 100 mR to 200 mR for each sample.

Table 11.5-4

GASEOUS EFFLUENTS COMPOSITION AND CONCENTRATIONS

		Concentrations[1] (μCi/cc)	
		South Stack	North Stack
Noble Gases	Ar-41	7.18×10^{-9}	[4]
	Kr-83m	[3]	[4]
	Kr-85m	1.72×10^{-9}	1.50×10^{-8}
	Kr-85	[3]	5.67×10^{-8}
	Kr-87	1.72×10^{-9}	2.63×10^{-8}
	Kr-88	1.72×10^{-9}	4.65×10^{-8}
	Kr-89	[3]	[4]
	Xe-131m	[3]	1.42×10^{-9}
	Xe-133m	[3]	[4]
	Xe-133	3.73×10^{-8}	5.29×10^{-9}
	Xe-135m	2.64×10^{-8}	1.32×10^{-7}
	Xe-135	1.95×10^{-8}	2.07×10^{-7}
	Xe-137	[3]	[4]
	Xe-138	4.02×10^{-9}	2.83×10^{-7}
Halogens[2]	I-131	2.87×10^{-11}	1.62×10^{-11}
	I-133	1.15×10^{-10}	4.05×10^{-11}
Airborne Particulate	C- 14	[3]	1.92×10^{-9}
	Cr-51	1.72×10^{-15}	4.45×10^{-14}
	Mn-54	1.72×10^{-14}	6.20×10^{-14}
	Co-58	3.45×10^{-15}	1.03×10^{-14}
	Fe-59	2.30×10^{-15}	3.14×10^{-14}
	Co-60	5.74×10^{-14}	1.86×10^{-13}
	Zn-65	1.15×10^{-14}	3.44×10^{-15}
	Sr-89	5.17×10^{-16}	1.30×10^{-14}
	Sr-90	2.87×10^{-17}	6.48×10^{-16}
	Zr-95	2.30×10^{-15}	3.04×10^{-16}
	Sb-124	1.15×10^{-15}	7.09×10^{-16}
	Cs-134	2.30×10^{-14}	1.03×10^{-14}
	Cs-136	1.72×10^{-15}	1.42×10^{-15}
	Cs-137	3.16×10^{-14}	2.14×10^{-14}
	Ba-140	2.30×10^{-15}	2.47×10^{-15}
	Ce-141	5.74×10^{-16}	6.48×10^{-15}

[1] Expected concentrations at maximum stack flow rates may increase in proportion to power.
[2] Includes both gaseous and particulate releases.
[3] Less than 1.44×10^{-10} μCi/cc.
[4] Less than 5.06×10^{-10} μCi/cc.

Table 11.5-5

LIQUID EFFLUENTS COMPOSITION AND CONCENTRATION

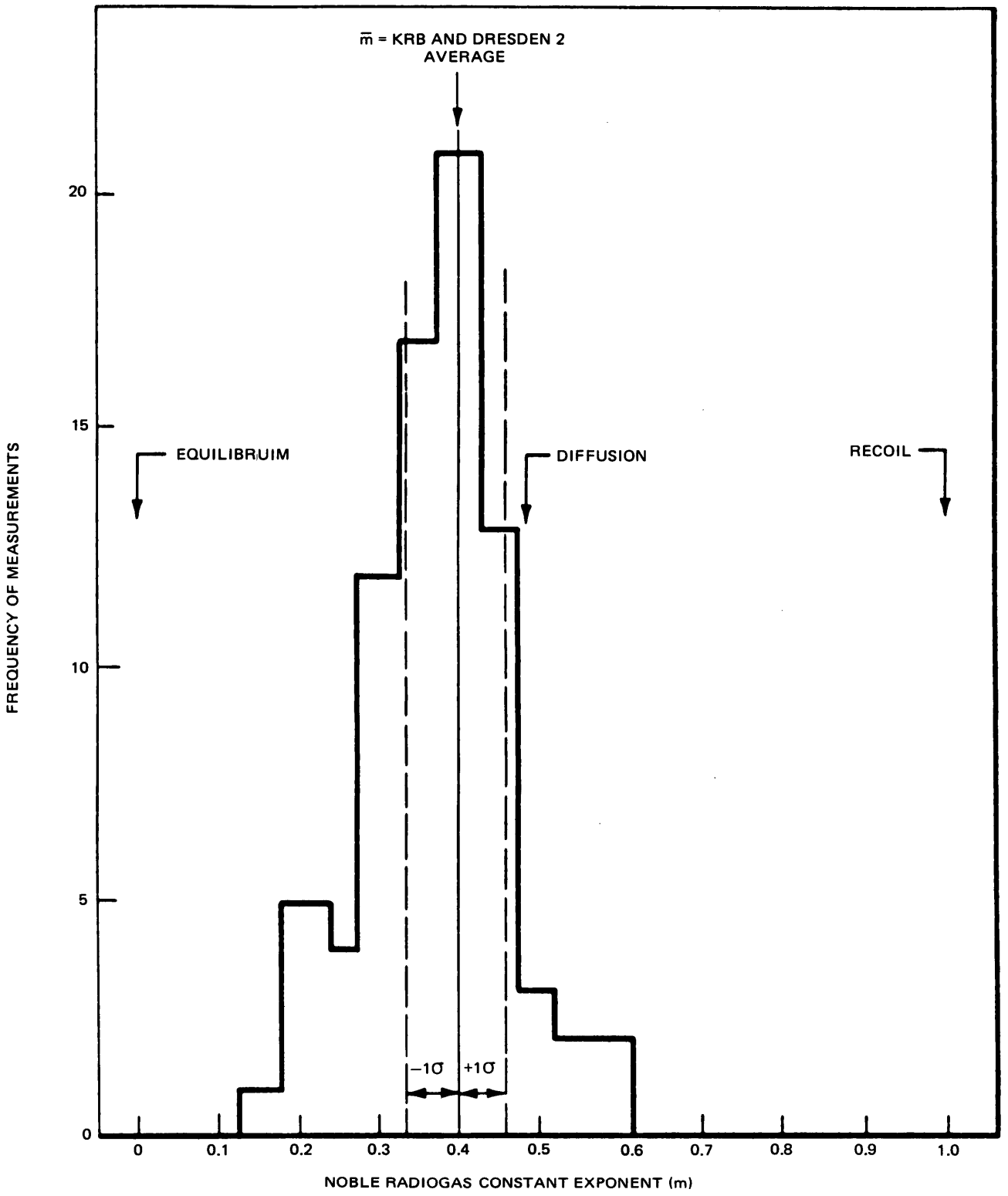
Isotope	Concentration[1] (μCi/cc) Floor Drain Sample Tank[2]	Equipment Drain Sample Tank[2]	Laundry Drain Sample Tank
Br-83	1.72×10^{-8}	6.12×10^{-8}	-
Br-84	-	2.22×10^{-9}	-
Br-85	-	-	-
I-131	6.54×10^{-7}	8.55×10^{-7}	9.65×10^{-7}
I-132	1.55×10^{-7}	5.52×10^{-7}	-
I-133	1.38×10^{-6}	2.52×10^{-6}	-
I-134	4.84×10^{-8}	1.60×10^{-7}	-
I-135	4.91×10^{-7}	1.38×10^{-6}	-
Rb-89	5.50×10^{-9}	2.45×10^{-9}	-
Cs-134	1.07×10^{-7}	2.67×10^{-7}	2.09×10^{-5}
Cs-136	6.75×10^{-7}	1.74×10^{-7}	-
Cs-137	2.49×10^{-6}	6.22×10^{-7}	3.86×10^{-5}
Cs-138	3.88×10^{-7}	2.33×10^{-7}	-
Na-24	5.15×10^{-7}	1.04×10^{-6}	-
P-32	2.71×10^{-8}	3.49×10^{-8}	-
Cr-51	6.94×10^{-7}	8.81×10^{-7}	-
Mn-54	8.49×10^{-9}	1.06×10^{-8}	1.61×10^{-6}
Mn-56	3.35×10^{-7}	1.19×10^{-6}	-
Fe-55	1.42×10^{-7}	1.66×10^{-6}	-
Fe-59	4.20×10^{-9}	5.30×10^{-9}	-
Co-58	2.81×10^{-8}	3.53×10^{-8}	6.43×10^{-6}
Co-60	5.68×10^{-8}	7.11×10^{-8}	1.45×10^{-5}
Ni-63	1.42×10^{-10}	1.78×10^{-1}	-
Ni-65	1.99×10^{-9}	7.09×10^{-9}	-
Cu-64	1.50×10^{-6}	3.38×10^{-6}	-
Zn-65	2.82×10^{-8}	3.53×10^{-8}	-
Zn-69	8.84×10^{-9}	7.39×10^{-9}	-
Sr-89	1.41×10^{-8}	1.78×10^{-8}	-
Sr-90	8.49×10^{-10}	1.06×10^{-9}	-
Sr-91	1.55×10^{-7}	3.73×10^{-7}	-
Sr-92	7.31×10^{-8}	2.58×10^{-7}	-
Y-91	8.14×10^{-9}	8.90×10^{-9}	-
Y-92	1.78×10^{-7}	5.77×10^{-7}	-
Y-93	1.65×10^{-7}	3.88×10^{-7}	-
Zr-95	9.81×10^{-10}	1.24×10^{-9}	2.25×10^{-6}
Zr-97	3.14×10^{-10}	6.08×10^{-1}	-

Table 11.5-5 (Cont'd)

Concentration[1]
(μCi/cc)

Isotope	Floor Drain Sample Tank[2]	Equipment Drain Sample Tank[2]	Laundry Drain Sample Tank
Nb-95	9.95×10^{-10}	1.24×10^{-9}	3.22×10^{-6}
Nb-98	3.89×10^{-9}	8.90×10^{-9}	-
Mo-99	2.26×10^{-7}	3.21×10^{-7}	-
Tc-99m	6.24×10^{-7}	1.50×10^{-6}	-
Tc-101	2.44×10^{-10}	4.44×10^{-1}	-
Tc-104	9.12×10^{-10}	2.20×10^{-9}	-
Ru-103	2.79×10^{-9}	3.51×10^{-9}	2.25×10^{-7}
Ru-105	3.02×10^{-8}	9.78×10^{-8}	-
Ru-106	4.25×10^{-10}	5.32×10^{-1}	3.86×10^{-6}
Ag110M	1.42×10^{-10}	1.78×10^{-1}	7.08×10^{-7}
Te129M	5.58×10^{-9}	7.06×10^{-9}	-
Te131M	8.70×10^{-9}	1.43×10^{-8}	-
Te132	1.17×10^{-9}	1.63×10^{-9}	-
Ba-139	2.14×10^{-8}	7.50×10^{-8}	-
Ba-140	5.40×10^{-8}	6.96×10^{-8}	-
Ba-141	1.14×10^{-10}	2.74×10^{-1}	-
Ba-142	2.18×10^{-12}	3.88×10^{-1}	-
La-142	1.53×10^{-8}	5.41×10^{-8}	-
Ce-141	4.52×10^{-9}	5.62×10^{-9}	-
Ce-143	2.73×10^{-9}	4.37×10^{-9}	-
Ce-144	4.25×1^{-10}	5.32×10^{-1}	-
Pr-143	5.55×10^{-9}	7.04×10^{-9}	-
Nd-147	4.02×10^{-10}	5.19×10^{-10}	-
W-187	2.33×10^{-8}	4.05×10^{-8}	-
Np-239	7.59×10^{-7}	1.10×10^{-6}	-

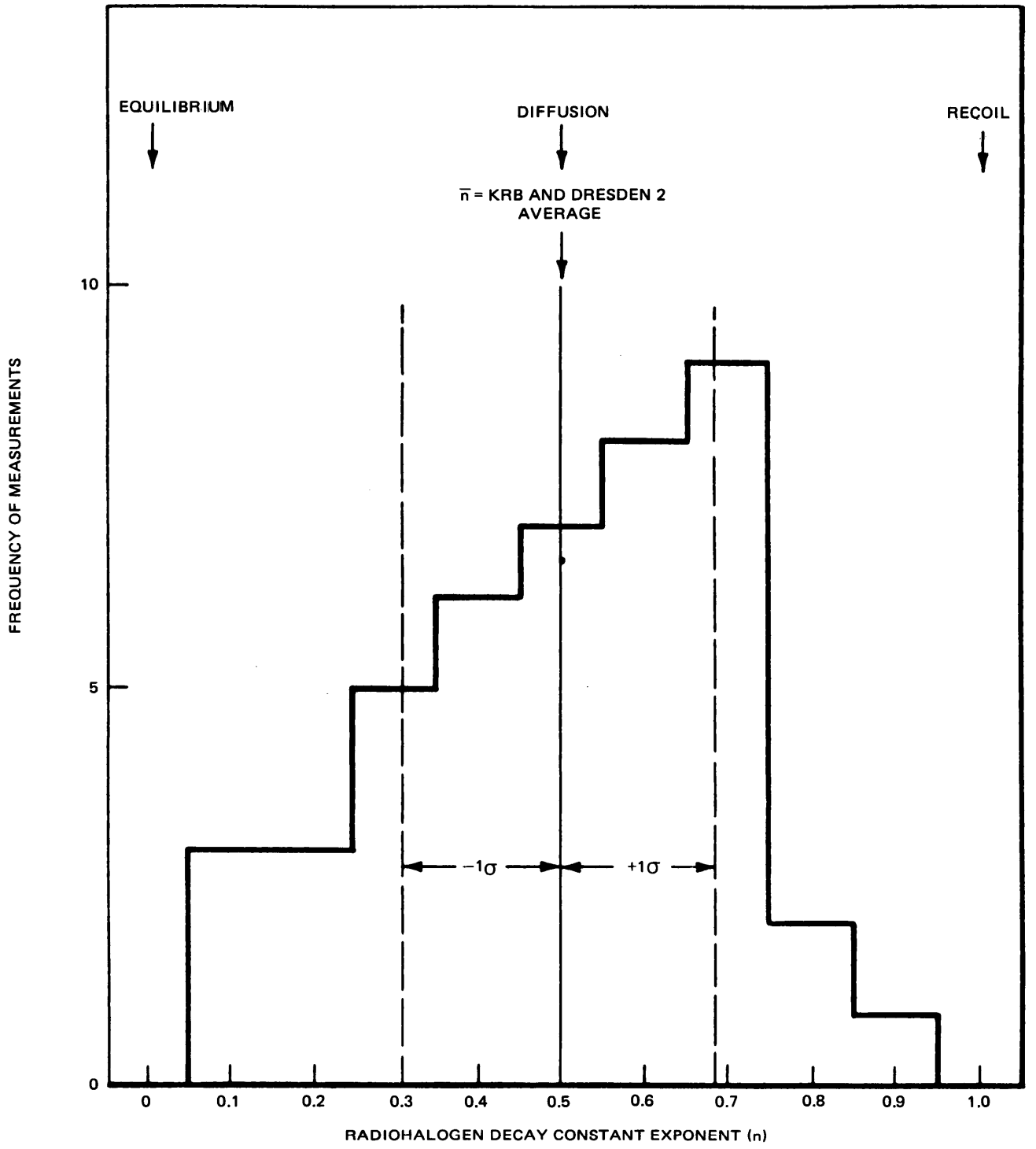
(1) Concentrations are prior to dilution in the cooling tower blowdown, and may increase in proportion to power. Sample tank pump capacities are presented in Table 11.2-10.
(2) Equipment drain sample tank discharges are routed to the cooling tower blowdown line via the floor drain system.
(3) Deleted



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NOBLE RADIOGAS DECAY CONSTANT EXPONENT FREQUENCY HISTOGRAM

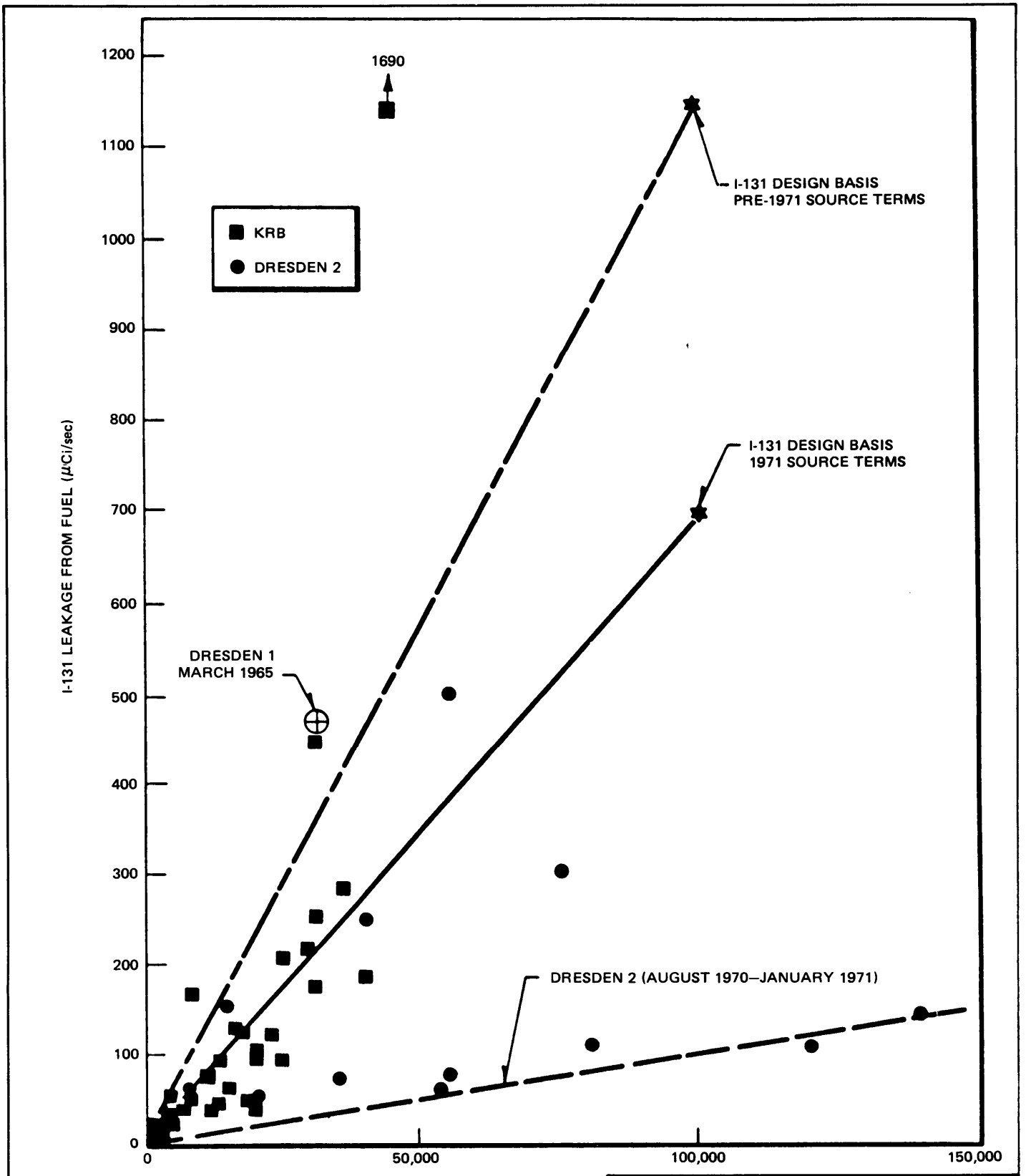
FIGURE 11.1-1



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RADIOHALOGEN DECAY CONSTANT EXPONENT FREQUENCY HISTOGRAM

FIGURE 11.1-2



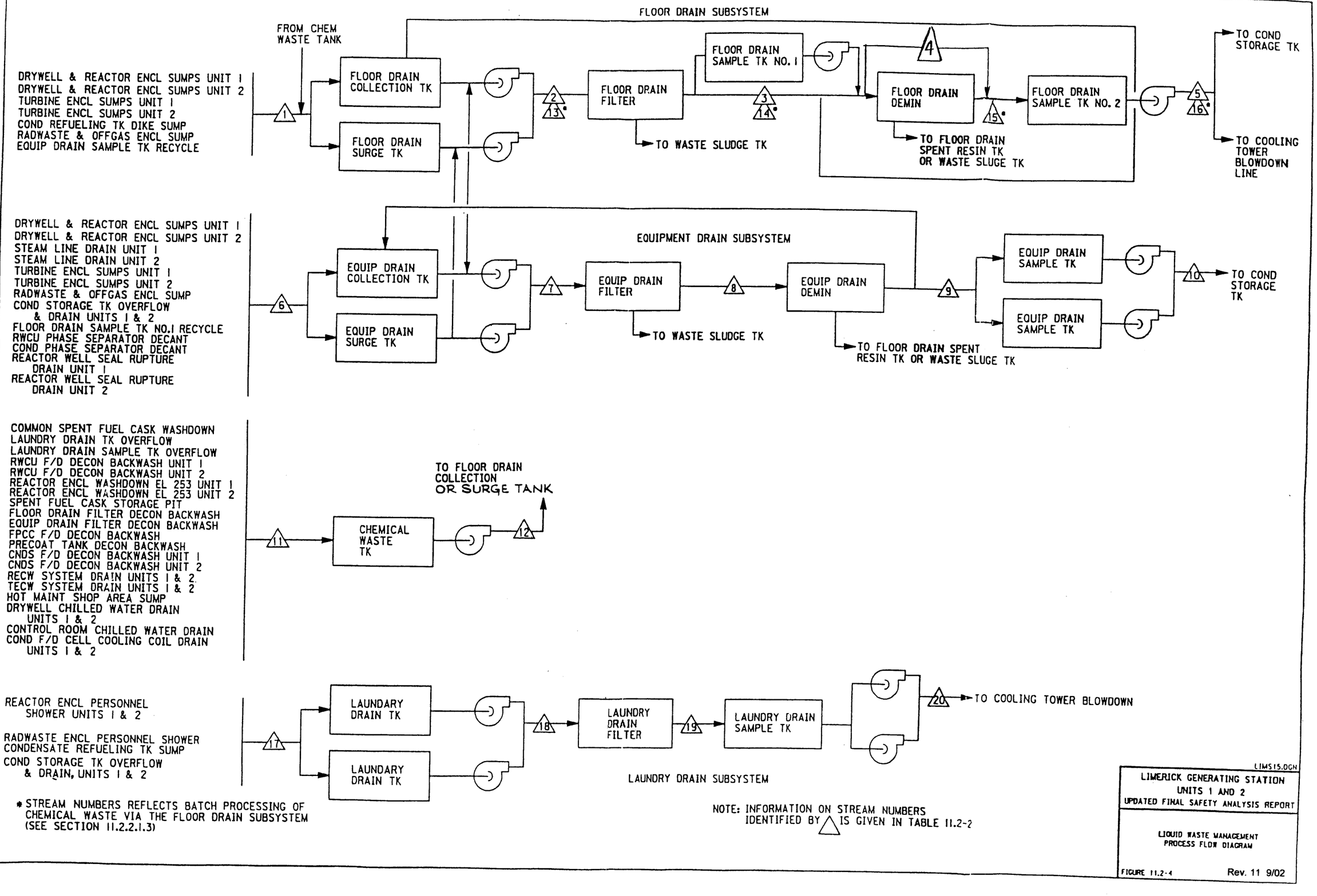
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NOBLE RADIOGAS LEAKAGE VERSUS I-131 LEAKAGE

FIGURE 11.1-3

Figures 11.2-1 thru 11.2-3

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FLOOR DRAIN SUBSYSTEM
FROM CHEM WASTE TANK
DRYWELL & REACTOR ENCL SUMPS UNIT 1
DRYWELL & REACTOR ENCL SUMPS UNIT 2
TURBINE ENCL SUMPS UNIT 1
TURBINE ENCL SUMPS UNIT 2
COND REFUELING TK DIKE SUMP
RADWASTE & OFFGAS ENCL SUMP
EQUIP DRAIN SAMPLE TK RECYCLE
1
FLOOR DRAIN COLLECTION TK
FLOOR DRAIN SURGE TK
2
13*
FLOOR DRAIN FILTER
TO WASTE SLUDGE TK
FLOOR DRAIN SAMPLE TK NO. 1
3
14*
4
FLOOR DRAIN DEMIN
15*
TO FLOOR DRAIN SPENT RESIN TK OR WASTE SLUGE TK
FLOOR DRAIN SAMPLE TK NO. 2
5
16*
TO COND STORAGE TK
TO COOLING TOWER BLOWDOWN LINE
DRYWELL & REACTOR ENCL SUMPS UNIT 1
DRYWELL & REACTOR ENCL SUMPS UNIT 2
STEAM LINE DRAIN UNIT 1
STEAM LINE DRAIN UNIT 2
TURBINE ENCL SUMPS UNIT 1
TURBINE ENCL SUMPS UNIT 2
RADWASTE & OFFGAS ENCL SUMP
COND STORAGE TK OVERFLOW & DRAIN UNITS 1 & 2
FLOOR DRAIN SAMPLE TK NO.1 RECYCLE
RWCU PHASE SEPARATOR DECANT
COND PHASE SEPARATOR DECANT
REACTOR WELL SEAL RUPTURE DRAIN UNIT 1
REACTOR WELL SEAL RUPTURE DRAIN UNIT 2
6
EQUIP DRAIN COLLECTION TK
EQUIP DRAIN SURGE TK
EQUIPMENT DRAIN SUBSYSTEM
7
EQUIP DRAIN FILTER
TO WASTE SLUDGE TK
8
EQUIP DRAIN DEMIN
9
TO FLOOR DRAIN SPENT RESIN TK OR WASTE SLUGE TK
EQUIP DRAIN SAMPLE TK
EQUIP DRAIN SAMPLE TK
10
TO COND STORAGE TK
COMMON SPENT FUEL CASK WASHDOWN
LAUNDRY DRAIN TK OVERFLOW
LAUNDRY DRAIN SAMPLE TK OVERFLOW
RWCU F/D DECON BACKWASH UNIT 1
RWCU F/D DECON BACKWASH UNIT 2
REACTOR ENCL WASHDOWN EL 253 UNIT 1
REACTOR ENCL WASHDOWN EL 253 UNIT 2
SPENT FUEL CASK STORAGE PIT
FLOOR DRAIN FILTER DECON BACKWASH
EQUIP DRAIN FILTER DECON BACKWASH
FPCC F/D DECON BACKWASH
PRECOAT TANK DECON BACKWASH
CNDS F/D DECON BACKWASH UNIT 1
CNDS F/D DECON BACKWASH UNIT 2
RECW SYSTEM DRAIN UNITS 1 & 2
TECW SYSTEM DRAIN UNITS 1 & 2
HOT MAINT SHOP AREA SUMP
DRYWELL CHILLED WATER DRAIN UNITS 1 & 2
CONTROL ROOM CHILLED WATER DRAIN
COND F/D CELL COOLING COIL DRAIN UNITS 1 & 2
11
CHEMICAL WASTE TK
TO FLOOR DRAIN COLLECTION OR SURGE TANK
12
REACTOR ENCL PERSONNEL SHOWER UNITS 1 & 2
RADWASTE ENCL PERSONNEL SHOWER
CONDENSATE REFUELING TK SUMP
COND STORAGE TK OVERFLOW & DRAIN, UNITS 1 & 2
17
LAUNDARY DRAIN TK
LAUNDARY DRAIN TK
18
LAUNDRY DRAIN FILTER
19
LAUNDRY DRAIN SAMPLE TK
20
TO COOLING TOWER BLOWDOWN
LAUNDRY DRAIN SUBSYSTEM
* STREAM NUMBERS REFLECTS BATCH PROCESSING OF CHEMICAL WASTE VIA THE FLOOR DRAIN SUBSYSTEM (SEE SECTION 11.2.2.1.3)
NOTE: INFORMATION ON STREAM NUMBERS IDENTIFIED BY △ IS GIVEN IN TABLE 11.2-2
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LIQUID WASTE MANAGEMENT PROCESS FLOW DIAGRAM
FIGURE 11.2-4
Rev. 11 9/02

MODE I - STARTUP WITH SECOND STAGE SJAE IN HOGGING OPERATION

LOCATION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
TEMPERATURE °F	70.0	335.0	298.0	298.0	278.0	390.0	390.0	390.0	390.0	100.0	96.0	65.0	399.0	399.0	110.0	100.0	93.0	65.0
PRESSURE PSIA	3.3	125.0	21.8	21.8	20.7	20.0	20.0	19.6	19.4	17.6	17.4	17.4	248.0	248.0	61.7	17.6	64.7	17.4
MASS FLOW RATE LBM/HR																		
STEAM OR VAPOR	430.0	10,300.0	10,730.0	8,795.0	1,935.0	1,935.0	1,935.0	1,935.0	1,935.0	38.0	34.0	12.0	827.0	827.0	-	-	-	-
WATER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	600,000.0	1,897.0	600,000.0	26.0
AIR	5,500.0	-	5,500.0	4,467.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	-	-	-	-	-	-
HYDROGEN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OXYGEN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL	5,930.0	10,300.0	16,230.0	13,262.0	2,968.0	2,968.0	2,968.0	2,968.0	2,968.0	1,071.0	1,067.0	1,045.0	827.0	827.0	600,000.0	1,897.0	600,000.0	26.0

MODE II - NORMAL OPERATION , 75 SCFM CONDENSER AIR INLEAKAGE

LOCATION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
TEMPERATURE °F	115.0	335.0	309.0		300.0	390.0	390.0	839.0	839.0	110.0	89.0	65.0	399.0	399.0	120.0	110.0	93.0	65.0
PRESSURE PSIA	3.3	125.0	19.0		17.8	17.1	17.1	16.7	16.6	16.4	16.1	16.1	248.0	248.0	61.7	16.4	64.7	16.1
MASS FLOW RATE LBM/HR																		
STEAM OR VAPOR	654.0	10,300.0	10,954.0	-	10,954.0	10,954.0	10,954.0	11,343.0	11,343.0	17.8	9.3	4.0	827.0	827.0	-	-	-	-
WATER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	600,000.0	11,325.0	600,000.0	13.8
AIR	339.0	-	339.0	-	339.0	339.0	339.0	339.0	339.0	339.0	339.0	339.0	-	-	-	-	-	-
HYDROGEN	43.4	-	43.4	-	43.4	43.4	43.4	-	-	-	-	-	-	-	-	-	-	-
OXYGEN	345.5	-	345.5	-	345.5	345.5	345.5	-	-	-	-	-	-	-	-	-	-	-
TOTAL	1,381.9	10,300.0	11,681.9	0.0	11,681.9	11,681.9	11,681.9	11,682.0	11,682.0	356.8	348.3	343.0	827.0	827.0	600,000.0	11,325.0	600,000.0	13.8

MODE III - MAXIMUM DESIGN OPERATION, 150 SCFM CONDENSER AIR INLEAKAGE

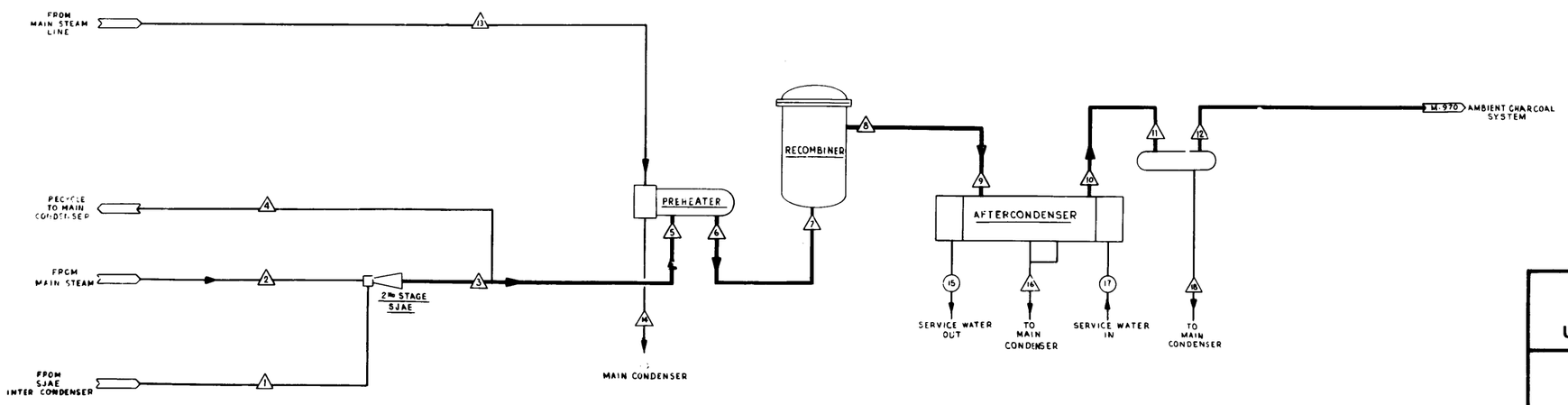
LOCATION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
TEMPERATURE °F	115.0	335.0	304.0		294.0	389.0	389.0	813.0	813.0	110.0	97.0	65.0	399.0	399.0	120.0	110.0	93.0	65.0
PRESSURE PSIA	3.3	125.0	21.7		20.3	19.6	19.5	19.1	19.0	18.2	17.2	17.2	248.0	248.0	61.7	18.2	64.7	17.2
MASS FLOW RATE LBM/HR																		
STEAM OR VAPOR	828.0	10,300.0	11,128.0	-	11,128.0	11,128.0	11,128.0	11,517.0	11,517.0	32.0	22.0	8.0	827.0	827.0	-	-	-	-
WATER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	600,000.0	11,485.0	600,000.0	24.0
AIR	678.0	-	678.0	-	678.0	678.0	678.0	678.0	678.0	678.0	678.0	678.0	-	-	-	-	-	-
HYDROGEN	43.4	-	43.4	-	43.4	43.4	43.4	-	-	-	-	-	-	-	-	-	-	-
OXYGEN	345.5	-	345.5	-	345.5	345.5	345.5	-	-	-	-	-	-	-	-	-	-	-
TOTAL	1,894.9	10,300.0	12,194.9	0.0	12,194.9	12,194.9	12,194.9	12,195.0	12,195.0	710.0	700.0	686.0	827.0	827.0	600,000.0	11,485.0	600,000.0	24.0

MODE IV - STARTUP WITH MECHANICAL VACUUM PUMP OPERATING PARALLEL WITH SJAE

LOCATION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
TEMPERATURE °F	70.0	335.0	298.0	298.0	278.0	390.0	390.0	390.0	390.0	100.0	96.0	65.0	399.0	399.0	110.0	100.0	93.0	65.0
PRESSURE PSIA	3.3	125.0	21.8	21.8	20.7	20.0	20.0	19.6	19.4	17.6	17.4	17.4	248.0	248.0	61.7	17.6	64.7	17.4
MASS FLOW RATE LBM/HR																		
STEAM OR VAPOR	211.0	10,300.0	10,511.0	6,570.0	3,941.0	3,941.0	3,941.0	3,941.0	3,941.0	38.0	34.0	12.0	827.0	827.0	-	-	-	-
WATER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	600,000.0	3,903.0	600,000.0	26.0
AIR	2,700.0	-	2,700.0	1,667.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	-	-	-	-	-	-
HYDROGEN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OXYGEN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL	2,911.0	10,300.0	13,211.0	8,237.0	4,974.0	4,974.0	4,974.0	4,974.0	4,974.0	1,071.0	1,067.0	1,045.0	827.0	827.0	600,000.0	3,903.0	600,000.0	26.0

MODE V - TWO UNITS OPERATING , CROSS CONNECTED, 75 SCFM CONDENSER AIR INLEAKAGE IN EACH UNIT

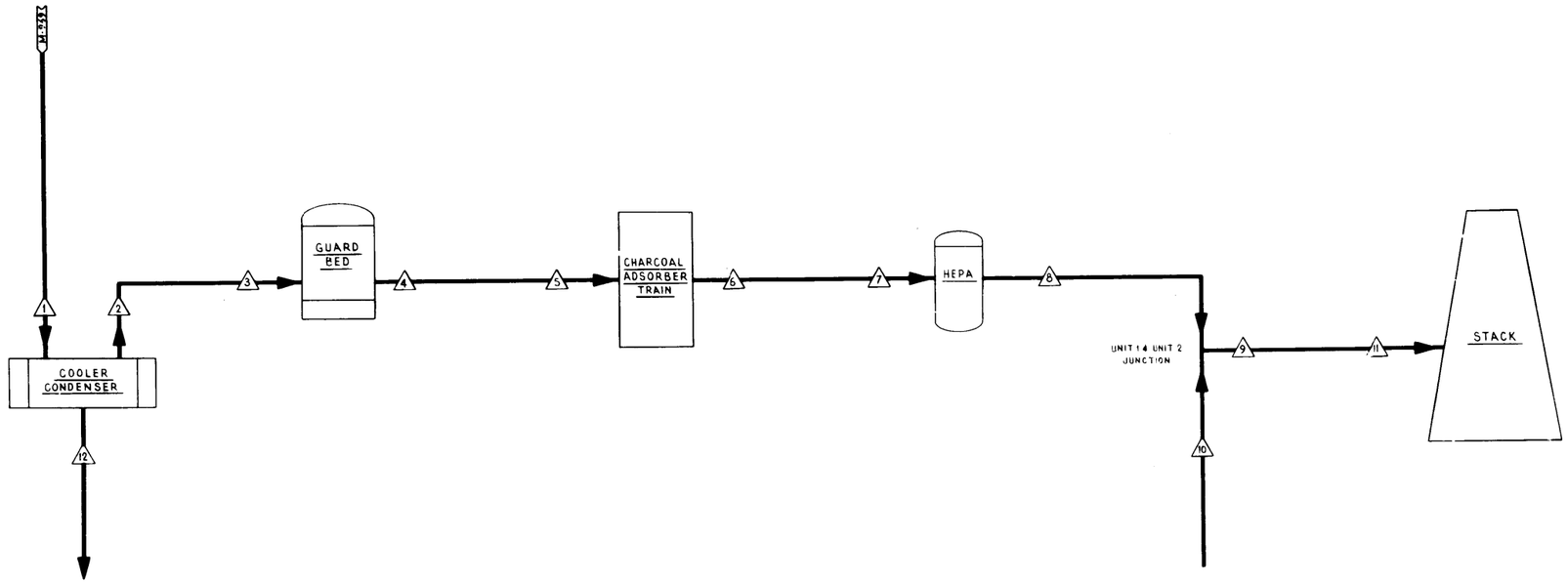
LOCATION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
TEMPERATURE °F	115.0	335.0	309.0		300.0	390.0	390.0	839.0	839.0	110.0	77.0	65.0	399.0	399.0	120.0	110.0	93.0	65.0
PRESSURE PSIA	3.3	125.0	20.0		18.8	18.1	18.1	17.7	17.6	17.4	17.1	17.1	248.0	248.0	61.7	17.4	64.7	17.1
MASS FLOW RATE LBM/HR																		
STEAM OR VAPOR	654.0	10,300.0	10,954.0	-	10,954.0	10,954.0	10,954.0	11,343.0	11,343.0	17.8	6.2	4.0	827.0	827.0	-	-	-	-
WATER	-	-	-	-	-	-	-	-	-	-	-	-	-	-	600,000.0	11,325.0	600,000.0	13.8
AIR	339.0	-	339.0	-	339.0	339.0	339.0	339.0	339.0	339.0	339.0	339.0	-	-	-	-	-	-
HYDROGEN	43.4	-	43.4	-	43.4	43.4	43.4	-	-	-	-	-	-	-	-	-	-	-
OXYGEN	345.5	-	345.5	-	345.5	345.5	345.5	-	-	-	-	-	-	-	-	-	-	-
TOTAL	1,381.9	10,300.0	11,681.9	0.0	11,681.9	11,681.9	11,681.9	11,682.0	11,682.0	356.8	345.2	343.0	827.0	827.0	600,000.0	11,325.0	600,000.0	13.8



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

GASEOUS WASTE SYSTEM
PROCESS DIAGRAM
(SHEET 1 OF 2)

FIGURE 11.3-1



MODE I - STARTUP WITH SECOND STAGE SJAE IN HOGGING OPERATION

LOCATION	1	2	3	4	5	6	7	8	9	10	11	12
TEMPERATURE °F	110.0	45.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	45.0
PRESSURE PSIA	17.2	16.8	16.8	16.3	16.2	15.6	15.4	15.1	15.0	15.0	14.8	16.8
MASS FLOW RATE LBM/HR												
VAPOR	12.0	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	-	7.2	-
WATER	-	-	-	-	-	-	-	-	-	-	-	4.8
AIR	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	-	1,033.0	-
TOTAL	1,045.0	1,040.2	1,040.2	1,040.2	1,040.2	1,040.2	1,040.2	1,040.2	1,040.2	0.0	1,040.2	4.8

MODE II - NORMAL OPERATION , 75 SCFM CONDENSER AIR INLEAKAGE

LOCATION	1	2	3	4	5	6	7	8	9	10	11	12
TEMPERATURE °F	110.0	40.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	40.0
PRESSURE PSIA	16.0	15.7	15.7	15.4	15.4	15.2	15.2	14.9	14.9	14.9	14.8	15.7
MASS FLOW RATE LBM/HR												
VAPOR	4.0	1.8	1.8	1.8	1.8	1.8	1.8	1.8	3.6	1.8	3.6	-
WATER	-	-	-	-	-	-	-	-	-	-	-	2.2
AIR	339.0	339.0	339.0	339.0	339.0	339.0	339.0	339.0	678.0	339.0	678.0	-
TOTAL	343.0	340.8	340.8	340.8	340.8	340.8	340.8	340.8	681.6	340.8	681.6	2.2

MODE III - MAXIMUM DESIGN OPERATION, 150 SCFM CONDENSER AIR INLEAKAGE

LOCATION	1	2	3	4	5	6	7	8	9	10	11	12
TEMPERATURE °F	110.0	40.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	40.0
PRESSURE PSIA	17.0	16.7	16.5	15.9	15.8	15.5	15.4	15.1	15.0	15.0	14.8	16.7
MASS FLOW RATE LBM/HR												
VAPOR	8.0	3.4	3.4	3.4	3.4	3.4	3.4	3.4	6.7	3.4	6.7	-
WATER	-	-	-	-	-	-	-	-	-	-	-	4.6
AIR	678.0	678.0	678.0	678.0	678.0	678.0	678.0	678.0	1,356.0	678.0	1,356.0	-
TOTAL	686.0	681.4	681.4	681.4	681.4	681.4	681.4	681.4	1,362.7	681.4	1,362.7	4.6

MODE IV - STARTUP WITH MECHANICAL VACUUM PUMP OPERATING PARALLEL WITH SJAE

LOCATION	1	2	3	4	5	6	7	8	9	10	11	12
TEMPERATURE °F	110.0	45.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	45.0
PRESSURE PSIA	17.2	16.8	16.8	16.3	16.2	15.6	15.4	15.1	15.0	15.0	14.8	16.8
MASS FLOW RATE LBM/HR												
VAPOR	12.0	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	-	7.2	-
WATER	-	-	-	-	-	-	-	-	-	-	-	4.8
AIR	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	1,033.0	-	1,033.0	-
TOTAL	1,045.0	1,040.2	1,040.2	1,040.2	1,040.2	1,040.2	1,040.2	1,040.2	1,040.2	0.0	1,040.2	4.8

MODE V - TWO UNITS OPERATING , CROSS CONNECTED, 75 SCFM CONDENSER AIR INLEAKAGE IN EACH UNIT

LOCATION	1	2	3	4	5	6	7	8	9	10	11	12
TEMPERATURE °F	110.0	38.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	38.0
PRESSURE PSIA	17.0	16.7	16.5	15.9	15.8	15.5	15.4	15.1	15.0	15.0	14.8	16.7
MASS FLOW RATE LBM/HR												
VAPOR	8.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	-	2.1	-
WATER	-	-	-	-	-	-	-	-	-	-	-	5.9
AIR	678.0	678.0	678.0	678.0	678.0	678.0	678.0	678.0	678.0	-	678.0	-
TOTAL	686.0	680.1	680.1	680.1	680.1	680.1	680.1	680.1	680.1	0.0	680.1	5.9

LIMERICK GENERATING STATION
UNITS 1 AND 2
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GASEOUS WASTE SYSTEM
PROCESS DIAGRAM
(SHEET 2 OF 2)

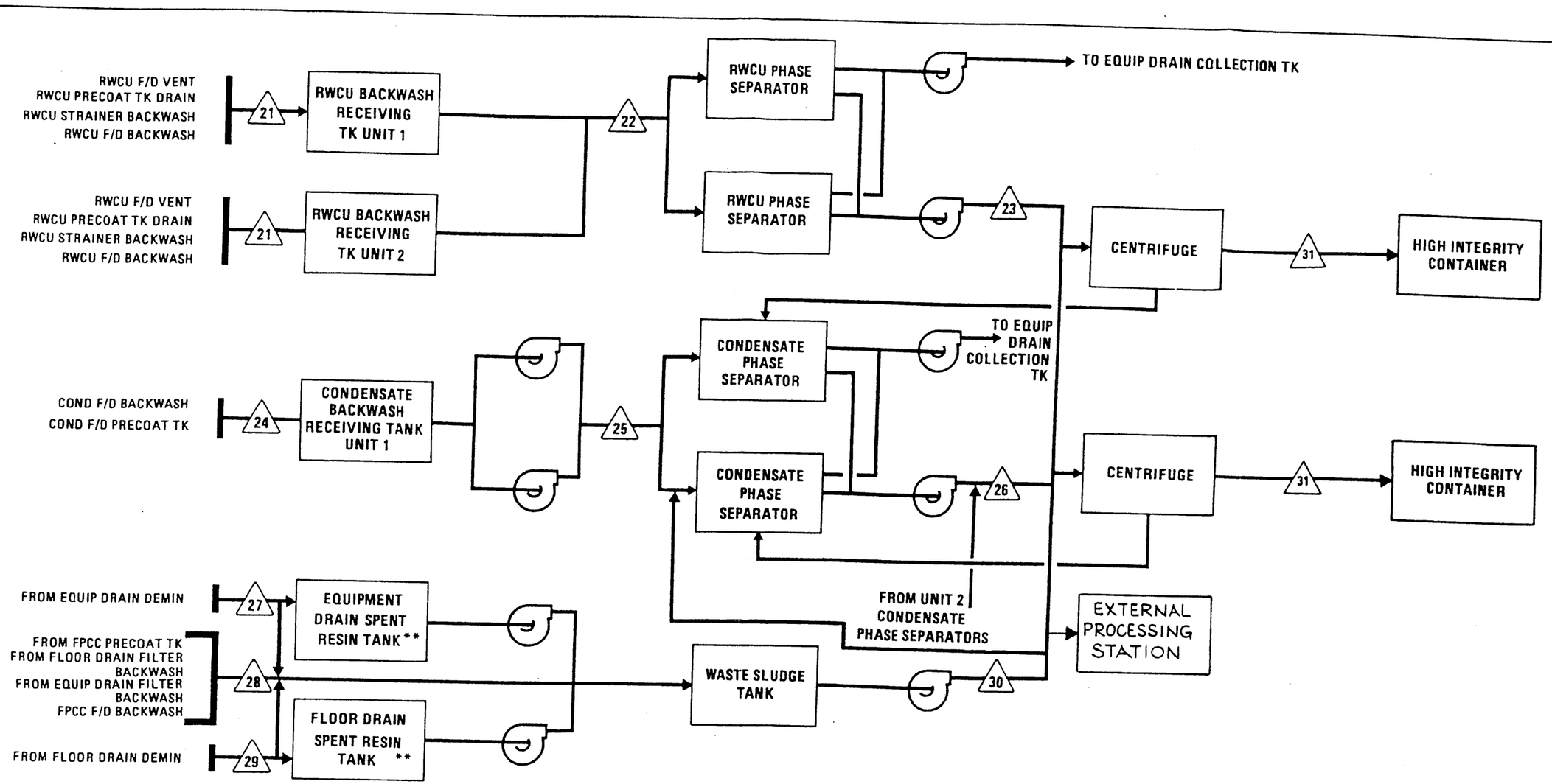
FIGURE 11.3-1

Figures 11.3-2 thru 11.3-3

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Figures 11.4-1 thru 11.4-2

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** THE SPENT RESIN TANKS ARE NOT USED FOR NORMAL PLANT OPERATION (SECTION 11.4.2.1.1).

NOTE:

INFORMATION ON STREAM NUMBERS IDENTIFIED BY △ IS GIVEN IN TABLE 11.4-4.

LIMERICK GENERATING STATION
UNITS 1 AND 2
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SOLID WASTE MANAGEMENT
SYSTEM PROCESS FLOW DIAGRAM

FIGURE 11.4-3

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CHAPTER 12- RADIATION PROTECTION

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12.1 ENSURING THAT OCCUPATIONAL RADIATION EXPOSURES ARE AS LOW AS REASONABLY ACHIEVABLE

12.1.1 POLICY CONSIDERATIONS

12.1.1.1 Management Policy

It is the licensee's policy to maintain occupational radiation exposure ALARA at LGS. This includes maintaining the annual dose to individuals working at the station ALARA, and keeping the annual integrated dose to station personnel ALARA. The management of this company is firmly committed to performing all reasonable actions to ensure that radiation exposures are maintained ALARA.

Sections 12.1.2 and 12.3 discuss the ALARA considerations that have been incorporated into the design of the LGS.

LGS will be operated and maintained in such a manner as to ensure that occupational radiation exposures are ALARA and that protection against radiation is in accordance with 10CFR20. The health physics provisions which accomplish this goal are described in Section 12.5.

12.1.1.2 Management Responsibilities

Chapter 13 describes the Limerick Generating Station operating organization and the licensee's corporate organization.

The President and Chief Nuclear Officer has the ultimate responsibility for operation of the Limerick Generating Station. This responsibility includes those activities necessary to ensure that radiation exposures are maintained ALARA. Responsibility is delegated to the Senior Vice President - Nuclear Operations and to the Vice President - Station Support (for all activities performed by the Station Support Department), and to the Vice President - Limerick Generating Station for all activities performed at the station. The Station Support Department provides technical support as needed to the Limerick Generating Station health physics organization in an effort to maintain the highest standards of exposure minimization. The Vice President - Limerick Generating Station delegates responsibility for the ALARA program through the Plant Manager to the Radiation Protection Manager who has responsibility for all actions required to maintain station exposures ALARA. The responsibilities of the Station Support Division staff, the Plant Manager, and Radiation Protection Manager in regard to ALARA are further described in Section 13.1.2.1.2. These responsibilities correspond to the applicable functions described in Regulatory Guide 8.8, Rev. 3 and Regulatory Guide 8.10, Rev.1.

12.1.1.3 Policy Implementation

The licensee provides the environment and support for the ALARA policy to function. The company's commitment to this policy is manifested in the plant design, established procedures, the provisions for review of procedures and plant design, provisions for subsequent procedure revisions and plant modifications, and the establishment of extensive varietal training programs.

General Employee Training, which encompasses radiological health aspects, is described in Sections 13.2.1.2. Such training enhances personnel awareness of licensee management's policy

of maintaining exposures ALARA, of actual and potential problems, and of the need to develop proper attitudes. The training stresses the individual's responsibility to cooperate in maintaining exposures ALARA and the importance of adhering to approved procedures. The content of the training is adjusted in recognition of the duties, responsibilities, and anticipated radiation exposure of those receiving instruction and includes information on the biological effects of such exposure. The staff of the Radiation Protection Manager has well defined functions, responsibilities, and authorities to ensure proper supervision and implementation of health physics procedures. The Radiation Protection Manager has the authority to prevent unsafe practices and to direct steps to prevent any unnecessary radiation exposures. The plant staff health physics group assures that communication with supervisors of the various station service groups (e.g., maintenance, construction, instrument technicians, contractors) and operating supervisors occurs for the purpose of evaluating a course of action regarding ALARA for specific station activities. Such evaluation includes the review of appropriate procedures; the extent of existing or potential hazards, occupationally and to the general public; and the merits of applying special techniques to the performance of a job. Such communication with work forces is an effective means to respond to worker questions and concerns and to obtain information on actual working conditions, such as mobility, access, habitability, and necessary tooling, which can lead to future improvements.

The plant staff health physics group is knowledgeable of the origins of radiation exposure in the plant and its magnitudes. They recognize which jobs or locations cause the highest exposures. This information is obtained via area surveys, Radiation Work Permits (or equivalent), and personnel dosimetry. Analysis of these and other data for repeat or similar activities is performed to determine whether exposures are being decreased or at least prevented from increasing. There is prompt investigation of exposures of record which exceed expected values. Judicious application of dose extensions is exercised by review of prior data and analysis of the need for the exposure. The health physics procedures provide for appropriate documentation of reviews, surveys, analyses, and investigations such that corrective action or modification may be accomplished and subsequent data may be compared to the original data to verify effectiveness of the change. The need for modification to satisfy ALARA shall be based on consideration of the economics of equipment modification in relation to benefits to health and safety and other societal and socioeconomic considerations, including the utilization of atomic energy in the public interest.

To verify that the health physics operations at the station are functioning within the ALARA concept, a formal review shall be performed under the cognizance of the Station ALARA Council every three years (based upon the date of commercial operation of Unit 1). The review shall include review of applicable station procedures and practices, exposure records, the content of training programs which affect ALARA considerations, and consultation with the plant staff health physics group. The objective of the review is to evaluate the adequacy of the ALARA effort and, as appropriate, to determine means to lower exposures. The results of the review shall be documented, including identification of the procedures and records reviewed, the review team's evaluation, and any recommendations for improvements.

12.1.2 DESIGN CONSIDERATIONS

This section describes those considerations which are applied to the plant design for the purpose of incorporating features which provide for maintaining occupational radiation exposures ALARA.

Refer to Sections 12.3.1, 12.3.2, and 12.3.3 for details of design for maintaining personnel radiation exposures ALARA.

Experiences and data from operating plants are evaluated to decide if and how equipment or facility designs can be improved to reduce overall plant personnel exposures. During plant design,

operating reports and data such as that given in WASH-1311, NUREG-75/032, NUREG-0109 and Compilation and Analysis of Data on Occupational Radiation Exposure Experienced at Operating Nuclear Power Plants (References 12.1-1 through 12.1-4, respectively), are reviewed to determine which operations, procedures or types of equipment were most significant in producing personnel exposures. Methods to mitigate such exposures have been implemented wherever possible and practicable.

12.1.2.1 General Design Considerations

The objectives of the plant design for ALARA purposes are: to minimize the need for, and duration of, personnel access into high radiation areas, and to establish radiation levels as low as practicable in routinely occupied areas.

Both equipment and facility designs are considered in achieving these objectives during plant operations including normal operations, maintenance and repair, refueling operations, fuel storage, inservice inspection, waste handling and disposal, and other anticipated operational occurrences.

In addition to equipment and facility designs, system designs are considered to ensure that exposures are maintained ALARA. For example, both the primary coolant system and the condensate system are provided with cleanup capability to reduce the inventory of circulating corrosion products. This is one of the methods employed to minimize both the activation of these corrosion products and their subsequent deposition on the interior surfaces of piping and equipment.

The project design organization is responsible for ensuring that the design and construction of the facility are such that occupational exposures are ALARA. To the extent practicable, this includes:

a. Design concepts and station features that reflect consideration of the activities of station personnel that might be anticipated and that might lead to personnel exposure to substantial sources of radiation; and assurance that station design features have been provided to reduce the anticipated exposures of station personnel to these sources of radiation.

b. Specifications for equipment that reflect the objectives of ALARA, including among others, considerations of reliability, durability, serviceability, and limitations of internal accumulations of radioactive material.

12.1.2.2 Equipment Design Considerations

Considerations for equipment design include:

a. Reliability, long service life, maintenance and calibration requirements, durability.

b. Convenience for servicing, including disassembly and reassembly, modular design concept for rapid component replacement, removal for servicing in lower radiation area.

c. Remote operation, inspection, monitoring, servicing, and repair including the use of special tools or equipment.

d. Redundant equipment to reduce the urgency for immediate repairs, thus providing time for planning repairs with ALARA in mind.

e. Isolation, draining, flushing, or decontamination of systems to reduce crud deposition and thus reduce radiation levels.

f. Isolation of components from contaminated process fluids.

g. Use of high quality components, such as valves, which minimize or preclude the leakage of radioactive material.

h. Use of closed drain systems for contaminated process fluids to preclude the creation of airborne contamination that is due to spillage.

12.1.2.3 Facility Design Considerations

Considerations for facility design include:

a. Location of equipment according to the need for access to maintain, inspect, monitor, or operate so as to minimize radiation exposure.

b. Use of valve stem extensions, articulated if necessary, to operate valves from behind shield walls.

c. Transport of contaminated components for service in lower radiation areas or for reuse in other parts of the plant.

d. Separation of sources of radiation such as pipe runs, storage tanks, and filters from normally occupied areas.

e. Use of permanent shielding between sources of radiation and access and service areas.

f. Maintaining ventilation flow paths from clean areas to contaminated areas.

g. Use of surface coatings to facilitate decontamination.

h. Use of labyrinth entrances to shielded cavities.

12.1.2.4 ALARA Design Review

For the operating plant, procedures provide for review of subsequent plant design and modifications by the radiation protection group, when applicable, and documentation of an ALARA design review. Procedures are described in Section 12.1.3. The following material describes the ALARA design review for the initial plant design and construction and is historical in nature.

Bechtel, as agent for the licensee, has developed an "In-Plant Radiation Exposure ALARA Review Specification". This specification was applied during all construction phases to perform multidisciplinary reviews of the plant to assure a design that:

a. Maintains the annual operating and maintenance radiation doses to individuals ALARA

b. Keeps the annual integrated radiation doses to all personnel ALARA.

This specification defined the purpose of the review; established the project ALARA review team; and described the discipline ALARA review process, the extent and format of ALARA review meetings, and the method of noting and resolving ALARA design changes. This specification is consistent with design guidelines given in Regulatory Guide 8.8.

The Bechtel Project Mechanical/Nuclear Group was responsible for the overall coordination of the ALARA design review and the interaction between the various Bechtel project disciplines, Bechtel Construction, the Bechtel Staff Radiation Protection Group, and the licensee.

The groups involved in the ALARA review program and their relationships are shown on Figure 12.1-1.

An experienced engineer from the Mechanical/Nuclear Group served as the project ALARA coordinator and was responsible for overall coordination of the ALARA reviews. Duties included maintaining the ALARA Review Specification and the ALARA documentation file, expediting the ALARA reviews, and resolving any ALARA inconsistencies. The project ALARA coordinator obtained input and expertise from the licensee, the Radiation Protection Group, and other Bechtel groups, as required.

An engineer was assigned from each engineering discipline to serve as the discipline ALARA representative. The discipline ALARA representatives coordinated and conducted the ALARA reviews within the discipline, interfaced between the discipline and the project ALARA coordinator, and expedited any design changes that resulted from the ALARA review.

Engineers from the field were assigned as construction ALARA representatives. They were responsible for reviewing field designs and field modifications to existing designs for consistency with the ALARA Review Specification. The construction ALARA coordinator coordinated the ALARA reviews in the field and interfaced between construction and engineering.

Experienced radiation protection specialists from the staff of the chief nuclear engineer provided health physics and radiation protection design input to the project. A radiation protection specialist was assigned to support the project design and ALARA review and was responsible for interfacing between the group and the project ALARA coordinator. The radiation protection specialist represented the staff radiation protection group during the ALARA reviews.

The licensee’s ALARA coordinator was a licensee engineer who represented the licensee during the ALARA reviews. One of the responsibilities was to advise the project ALARA coordinator of potential ALARA problems based on the licensee's experience from operating plants, by receiving input from the licensee’s Health Physics and Operations groups. The licensee’s ALARA coordinator also reviewed and provided input to the ALARA Review Specification, reviewed exceptions to the ALARA design criteria, and provided licensee input for resolving ALARA inconsistencies that were identified during the ALARA review.

To facilitate documentation and coordination of the ALARA review effort, a scheduled system and activity design review approach was followed. Maximum review effort was expended on those systems and activities as identified in Table 12.1-1 that in the past had resulted in the highest occupational radiation exposures in operating plants. Each system and activity was divided into plant areas. The ALARA design review was conducted by reviewing each of these areas.

The design review was conducted in the home office by the discipline ALARA representatives, project ALARA coordinator, and the radiation protection specialist. The major tools used in the design review were the ALARA design review considerations checklist, which identified design features that were judged to be generally cost effective with respect to maintaining occupational radiation exposures ALARA, and the ALARA design review considerations sign-off sheet. The sign-off sheet documented the review of the design by the responsible discipline(s). The discipline ALARA representatives and the radiation protection specialist verified that the design considerations assigned to their groups were met.

The ALARA review of field designs and modifications was conducted by the construction ALARA representatives. The discipline responsible for the new design or modification was responsible for documenting that it had been reviewed for ALARA. The project ALARA coordinator coordinated any reviews that affected other disciplines or groups.

Compliance with the ALARA design review considerations was documented by the reviewer on the design review considerations sign-off sheets, which are kept on file. Any exceptions to the considerations were reviewed on a case-by-case basis.

12.1.2.5 ALARA Design Considerations for Decommissioning

The design features necessary to maintain radiation exposures ALARA during decommissioning operations are, in general, the features that have been implemented to keep exposures ALARA during the operational life of the plant. These are discussed in Sections 12.1.2.1, 12.1.2.2, 12.1.2.3, and 12.3. Some of these features that are especially applicable to decommissioning are discussed below.

a. Flushing and draining connections will provide for removal of radioactive fluids, allow rinsing to reduce residual activity, and provide an entry point for introduction of decontamination solutions.

b. Ventilation systems to minimize the spread of airborne radioactivity will be particularly useful in preventing exposures to internal radioactivity during decommissioning when large quantities of airborne radioactive particulates can be generated by cutting, sawing, and demolition.

c. The space envelopes reserved around equipment to facilitate maintenance will also allow for more rapid dismantling because cutting machines and other decommissioning equipment can be quickly installed with correspondingly lower exposure time.

d. The use of flanged connections on pumps in radioactive waste systems, and the removal provisions built into some major plant components, will reduce exposures to personnel during removal of these items.

e. Separation of radioactive from nonradioactive systems, and location of active components of nonradioactive systems in low radiation areas, will permit dismantling of normally clean systems with minimal exposure to personnel.

f. The availability of a complete, shielded radwaste facility will allow efficient low dose processing of residual fluids and decontamination solutions, as well as the packaging and shipping of solid radioactive materials. Other existing facilities, such

as access control stations and decontamination areas, will also perform their intended functions in helping to keep exposures ALARA.

g. The use of liners and protective coatings will lower exposures by minimizing decontamination times and by reducing the quantities of materials that must be handled as radioactive waste.

12.1.3 OPERATIONAL CONSIDERATIONS

This section describes the development and implementation of operating procedures, including procedures for radiation protection and the ALARA program.

Plant procedures are further described in Section 13.5. Health physics operations are described in Section 12.5.

12.1.3.1 Procedure Development

Various procedures are written for the different activities associated with plant operations. These include procedures for operating, maintenance, surveillance testing, fuel handling, emergencies, radiation protection, and administration. The development of each variety of procedure is described in the administrative procedures.

The different procedures are prepared by personnel having experience and expertise in that particular area. The experience gained from operation of the PBAPS units and other plants is incorporated into procedure development. Each procedure is reviewed and approved per Administrative procedure process. Health physics personnel review procedures for activities which can affect radiation exposure.

Procedures are subject to revision whenever improved techniques or increased safety are indicated.

12.1.3.2 Exposure Reduction Procedures

The ALARA concept is first and foremost practiced on the job by communication between health physics technicians or health physics supervisors and the workers. The health physics representatives are aware of the radiation conditions and advise the workers accordingly.

Specific radiation procedures describe the techniques to determine the radiological conditions in an area. Once determined, procedures describe the actions necessary to incorporate exposure reduction techniques as required.

12.1.3.3 General ALARA Techniques

The predominant exposure dose is received during outages. Although ALARA considerations are not limited to outage work, the activities conducted during outages are the most significant for dose reduction.

During the outage planning stages, an ALARA representative is designated by Health Physics supervision to review the jobs planned and evaluate the need for an ALARA effort. Examples of some techniques that apply to an ALARA evaluation are:

a. Reducing dose rate from a system by draining, flushing, filling, decontaminating.

b. Installing permanent or temporary shielding if the net result is reduction in man-rem.

c. Training workers to improve proficiency, thus reducing stay time in the radiation area.

d. Maintaining the work force in radiation areas to the minimum required to perform the job efficiently and safely.

e. Establishing control points in low radiation areas.

f. Avoiding excess conservatism in prescribing protective clothing and respirators to avoid undue stress and decreased efficiency of the workers.

g. Using special tools for remote handling of components.

h. Planning and preparing techniques and tools needed to accomplish the job before the job is started.

i. Using historical data for comparable jobs as guidelines and to establish an expected dose limit for the job.

j. Using remote monitoring/alarming dosimeters in high radiation areas to maintain close checks on personnel exposures.

k. Providing adequate communications to facilitate performance of the job and to alert workers to adverse changes in radiation conditions.

l. Source identification and use of routine or special survey data.

m. Construction of contamination containment devices such as glove boxes and tents.

n. Removing components to low radiation areas for servicing or repair.

o. Planning for adequate space and auxiliary services, such as lighting, welding leads, service air lines, and TV cameras, as necessary to accomplish the work quickly.

p. Establishing auxiliary ventilation/filtration systems.

q. Wet transfer or storage of contaminated components to prevent airborne contamination.

r. Contingency planning to account for known personnel hazards or accidents which may occur.

s. Isolating systems to be worked on or possible load reductions or plant shutdowns to reduce doses.

The ALARA representative communicates with other disciplines (maintenance, operating, instrument and control, etc.) as appropriate to discuss the implementation of ALARA techniques. The cooperation of more than one discipline is usually required for most jobs.

The dosimetry program consists of DLRs or equivalent badges processed by a National Voluntary Laboratory Accreditation Program (NVLAP) accredited contractor for official data of record. Additionally, direct reading dosimeters are used as the unofficial dosimetric device. The computerized dosimetry record system and the ability to process the unofficial dosimetric device onsite provide a powerful tool for maintaining surveillance and managing each worker's dose accumulation. The direct reading dosimeters provide immediate readings and are available to obtain estimated exposures whenever there is concern. Workers' assignments to radiation areas can then be limited if administrative guidelines or regulatory limits are approached.

This same system produces tabulated lists of workers' exposures-to-date for each supervisor. These lists are provided routinely so the supervisors can know the dose accumulation of their workers, observe trends, and assign work duties more efficiently. Changes to the dosimetry program, such as contractor service versus onsite processing, frequency of badge changes, and types of dosimetric devices are made periodically to enhance the value of the program. Annual exposure reviews will be performed by the Engineer - Health Physics and Chemistry in order to identify groups with the highest exposure.

12.1.3.4 Operating Experience

Experience gained during operation of PBAPS Units 2 and 3 serves as a basis for procedures, techniques, and administrative controls for LGS. Exposure data from specific jobs previously performed at PBAPS have caused design changes during construction of LGS. The LGS Hot Maintenance Decontamination Shop design incorporates lessons learned from PBAPS.

12.1.4 REFERENCES

12.1-1 T.D. Murphy, WASH-1311, UC-78, "A Compilation of Occupational Radiation Exposure from Light-Water-Cooled Nuclear Power Plants 1969-1973", NRC, Radiological Assessment Branch, (May 1974).

12.1-2 T.D. Murphy, et.al., NUREG-75/032, "Occupational Radiation Exposure at Light-Water-Cooled Power Reactors 1969-1974", NRC, Radiological Assessment Branch, (June 1975).

12.1-3 T.D. Murphy, et. al., NUREG-0109, "Occupational Radiation Exposure at Light-Water-Cooled Power Reactors 1968-1975", NRC, Radiological Assessment Branch, (August 1976).

12.1-4 C.A. Pelletier, et. al., National Environmental Studies Project, "Compilation and Analysis of Data on Occupational Radiation Exposure Experienced at Operating Nuclear Power Plants", Atomic Industrial Forum, (September 1974).

Table 12.1-1

SYSTEMS AND ACTIVITIES INCLUDED IN ALARA REVIEW

1. Waste Management Systems
   a. Liquid Waste Management System
   b. Solid Waste Management System
   c. Gaseous Waste Management System
2. Reactor Water Cleanup System
3. Fuel Pool Cooling and Cleanup System
4. Condensate Demineralizer System
5. Reactor Coolant System
6. Residual Heat Removal System
7. Main Steam System
8. Air Removal System
9. Feedwater System
10. High Pressure Coolant Injection System
11. Reactor Core Isolation Cooling System
12. Maintenance Activities
    a. Drywell Area Activities
    b. Refueling Area Activities
    c. Main Condenser Area Activities
    d. Inservice Inspection Activities
    e. TIP Maintenance Activities
    f. CRD Removal and Maintenance Activities
    g. Local Leak Rate Testing Activities

Table 12.1-1 (Cont'd)

h. Hot Maintenance Shop Activities

i. Snubber Inspection Activities

13. Miscellaneous

a. Radiation Zone I and II Areas

12.2 RADIATION SOURCES

In this section the sources of radiation that form the basis for shield design and the sources of airborne radioactivity required for the design of personnel protective measures and for dose assessment are discussed and identified.

12.2.1 CONTAINED SOURCES

The shielding design source terms are based on a noble gas fission product offgas release rate of 0.35 Ci/sec (after 30 minutes of decay) and the corresponding fission, activation, and corrosion product concentrations in the primary coolant. The guidance provided in ANSI N237 was not used to determine the shielding design source terms for LGS. The specific alternate methods used for calculating source term magnitudes are described in Section 11.1. The shielding design source terms in the primary coolant are listed in Tables 12.2-1 through 12.2-5. Throughout most of the primary coolant system, activation products, principally nitrogen-16, are the primary radiation sources for shielding design.

Basic reactor data and core region descriptions used for this section are listed in Tables 12.2-6 through 12.2-8.

The shielding design source terms are presented by enclosure location and system. Locations of the equipment discussed in this section are shown on the shielding and radiation zoning drawings, drawings N-110, N-111, N-112, N-113, N-115, N-116, N-117, N-118, N-119, N-120, N-121, N-122, N-124, N-125, N-126, N-127, N-128, N-130 N-131, N-132, N-133, N-134, N-135, N-136, N-137, N-140, N-141, N-142, and N-143. Detailed data on source descriptions for each shielded area are presented in Tables 12.2-11 through 12.2-13.

Shielding source terms presented in this section and associated tables are based on conservative assumptions about system and equipment operations and characteristics to provide reasonably conservative radioactivity concentrations for shielding design. For all systems transporting radioactive materials, conservative allowance is made for transit decay while at the same time providing for daughter product formation. Assumptions from NUREG-0016 (Reference 12.2-1) were also used where applicable. Therefore, the shielding source terms are not intended to approximate the actual system design radioactivity concentrations.

12.2.1.1 Primary Containment

12.2.1.1.1 Reactor Core

The radiation within the drywell during full power operation includes neutron and gamma radiation resulting from the fission process in the core. Tables 12.2-9 and 12.2-10 list the multigroup neutron and gamma ray fluxes at the outside surfaces of the RPV and the primary shield at the core midplane. The gamma fluxes include those resulting from capture or inelastic scattering of neutrons within the RPV, the core shroud, and the primary shield, as well as gamma radiation resulting from prompt fission and fission product decay. The largest radiation sources after reactor shutdown are the decaying fission products in the fuel. Table 12.2-14 lists the fuel assembly source terms. Secondary sources include the structural material activation of the RPV, its internals, and the piping and equipment located in the primary containment; and the activated corrosion products accumulated or deposited in the internals of the RPV, the primary coolant piping, and other process system piping in the primary containment.

12.2.1.1.2 Reactor Coolant System

Sources of radiation in the RCS used for shielding design are fission products estimated to be released from fuel and activation and corrosion products that are circulated in the reactor coolant. These sources are listed in Tables 12.2-1 through 12.2-5. The N-16 concentration in the reactor coolant, with HWC, is bounded at 4.8×10^{-5} Ci/gm of coolant at the reactor recirculation outlet nozzle.

12.2.1.1.3 Main Steam System

Radiation sources in the main steam system piping include activation gases, principally N-16, and the corrosion and fission products carried over to the main steam system.

The N-16 concentration without HWC in the steam is assumed to be 5.0×10^{-5} Ci/gm of steam leaving the reactor vessel at the nozzle. Fission product radioactivity corresponds to an offgas release rate of 0.35 Ci/sec at 30 minutes decay from the reactor nozzle. Partition factors for carryover of radioactivity into the main steam system are 100% for gases, 2% by weight for halogens, and 0.1% by weight for particulates. These partition factors are applied to the reactor water shielding source terms as given in Tables 12.2-1 through 12.2-5.

Hydrogen injection by the HWC system causes the reactor water chemistry to become less oxidizing which results in a re-distribution of the N-16 normally produced by radiolysis in the reactor core. Under HWC conditions more of the N-16 is carried over into the steam and less remains in the reactor water. Under HWC conditions the N-16 concentration in the steam is 2.50×10^{-4} Ci/gm.

12.2.1.1.4 Drywell Sumps

The concentrations of radioisotopes used for shielding design for the drywell equipment and floor drain sumps are listed in Table 12.2-15.

12.2.1.2 Reactor Enclosure and Refueling Area

12.2.1.2.1 Reactor Water Cleanup System

Radiation sources in the RWCU system consist of those radioisotopes carried in the reactor water. The activity inventory is based on component transit times. The radioisotopes for the RWCU recirculation pumps, regenerative and nonregenerative heat exchangers, filter/demineralizers, holding pumps, and the backwash receiving tank are the accumulated fission, activation, and corrosion products, based on the inlet reactor coolant concentrations given in Tables 12.2-1 through 12.2-5, allowing for decay due to transit time. Tables 12.2-16 through 12.2-23 provide the shielding design source terms for these components.

12.2.1.2.2 Residual Heat Removal System

The pumps, heat exchangers, and associated piping of the RHR system are carriers of radioactive materials. For plant shutdown, the RHR pumps and heat exchangers are the radiation sources, resulting from the radioisotopes carried in the reactor coolant after four hours of decay following shutdown. The source terms listed in Table 12.2-24 are used for the shielding calculations for this system.

12.2.1.2.3 Reactor Core Isolation Cooling System

Components of the RCIC system that contain radiation sources are the RCIC turbine and steam inlet and exhaust piping. The steam radioactivity, as discussed in Section 12.2.1.1.3, without decay correction for transit from the RPV steam nozzles, is used for the shielding calculations for this system and is listed in Table 12.2-25.

12.2.1.2.4 High Pressure Coolant Injection System

The radiation sources for the HPCI system are the HPCI turbine and the steam inlet and exhaust piping. The steam radioactivity, as discussed in Section 12.2.1.1.3, decayed for the appropriate transit time, is used for the shielding calculations for this system and is listed in Table 12.2-26.

12.2.1.2.5 Core Spray System

The core spray system components, during testing, use condensate from the CST which contains very low radioactivity concentrations (Table 12.2-87); therefore, no shielding is required.

12.2.1.2.6 Spent Fuel Storage and Transfer

The predominant radiation sources in the spent fuel storage and transfer areas are the spent fuel assemblies. For shielding design purposes only, the spent fuel pool is assumed to contain 2862 fuel assemblies. These spent fuel assemblies are conservatively assumed to have 48 hours of decay. Shielding design source terms are shown in Table 12.2-14.

12.2.1.2.7 Fuel Pool Cooling and Cleanup System

Sources of radiation in the FPCC system result from the transfer of radioisotopes from the reactor coolant and crud deposits on spent fuel assemblies into the spent fuel pool during refueling operations. The shielding design source terms for the FPCC system are presented in Table 12.2-27. These source terms then undergo subsequent decay and accumulation on the FPCC filter/ demineralizers. Table 12.2-28 shows the FPCC filter/demineralizers shielding design source terms. The shielding design source terms for the FPCC heat exchanger are shown in Table 12.2-29.

12.2.1.2.8 Reactor Enclosure HVAC System

Components of the reactor enclosure HVAC system that contain sources of radioactivity are the equipment compartment exhaust air filters. Table 12.2-30 shows the reactor enclosure equipment exhaust air filters shielding design source terms.

12.2.1.2.9 Control Rod Drives

Shielding design source terms for the CRD mechanisms after removal from the RPV are shown in Table 12.2-31.

12.2.1.3 Turbine Enclosure

12.2.1.3.1 Primary Steam and Power Conversion Systems

Radiation sources for piping and equipment that contain primary steam are based on the radioisotopes carried over into the main steam from the reactor coolant and include fission product gases and halogens, particulate fission and corrosion products, and gaseous activation products

as discussed in Section 12.2.1.1.3. Steam density variations and steam transit times through equipment and pipes are factored into the shielding source term evaluation to account for volumetric dilution effects, radiological decay, and daughter product generation. Tables 12.2-32 through 12.2-36 show the shielding design source terms for the following components that use main steam; moisture separators, cross-around piping, feedwater heaters, steam seal evaporator, and the reactor feed pump-turbine.

12.2.1.3.2 Condensate and Feedwater Systems

The radiation sources in the condensate and feedwater systems are based on decayed main steam radioactivity (Section 12.2.1.1.3). Eighty percent of the N-16 and 100% of the noble gases are assumed to be removed from the condensate and feedwater systems by the main condenser air removal system. The gaseous radiation sources in the hotwell are shown in Table 12.2-37; they are negligible in the remainder of the condensate and feedwater systems. The hotwell is designed for a two minute holdup of condensate, and therefore N-16 radioactivity at the condenser outlet is negligible. Particulate fission products, activated corrosion products, and the particulate daughter products from the decay of fission product gases in transit through the turbine and condenser are the inlet radiation sources to the condensate system. These shielding design source terms, as shown in Table 12.2-38, are present in the condensate pumps and piping and accumulate on the condensate filter/ demineralizers. Table 12.2-39 provides the shielding design source terms for the condensate filter/demineralizer and the condensate backwash receiving tank. The shielding design source terms for the feedwater system are listed in Table 12.2-40.

12.2.1.3.3 Gaseous Radwaste Recombination System

Shielding design sources in the gaseous radwaste recombination system originate from noble gases and other noncondensable gases removed from the main condenser, and the radioactivity entering with the extraction driving steam to the SJAEs. The radioactivity entering is based on the primary steam radioactivity as described in Section 12.2.1.1.3, decayed for the expected transit time to the SJAEs. Eighty percent of the N-16 and 100% of the noble gases are assumed to be removed from the condenser by the SJAEs. The specific activities or quantities of radioactivity, including particulate daughters, in the SJAE condenser, mechanical vacuum pump, offgas pipe, preheater, recombiner, recombiner catalyst, aftercondenser, and H_2 analyzers, to be used for shielding design calculations, are shown in Tables 12.2-41 through 12.2-48.

12.2.1.3.4 Turbine Enclosure HVAC System

Components of the turbine enclosure HVAC system that contain sources of radioactivity are the equipment compartment exhaust air filters and the SGTS air filters. Tables 12.2-49 and 12.2-50 show the turbine enclosure equipment exhaust air filters and the SGTS air filters shielding design source terms.

12.2.1.4 Radwaste Enclosure

12.2.1.4.1 Liquid Waste Management System

Liquid radwaste is collected and processed as discussed in Section 11.2. The liquid waste management system shielding design sources are radioisotopes, including fission and corrosion products, present in the reactor coolant. The components of this system contain varying amounts of radioactivity, depending on the system and equipment design.

The concentrations of radioisotopes used for shielding design for pipes, tanks, filters, demineralizers, abandoned and unused evaporators (Section 11.2.2.1.3), and equipment and floor drain sumps may be derived from or are listed in Tables 12.2-51 through 12.2-69. Shielding for each component of the liquid waste management system is based on reactor coolant concentrations given in Tables 12.2-1 through 12.2-5.

12.2.1.4.2 Solid Radwaste System

The solid radwaste system collects, monitors, processes, packages, and provides temporary storage facilities for radioactive spent bead and powdered resins and dry solid wastes for offsite shipment and permanent disposal. The system is described in Section 11.4.

The high integrity containers used for packaging resin wastes are washed free of external surface contaminants and stored in concrete shielded compartments before shipment. The aforementioned operations are accomplished using remote container loading, transfer, and an overhead crane. Shielding design source terms for the solid radwaste system components are based on reactor coolant concentrations given in Tables 12.2-1 through 12.2-5 and are presented in Tables 12.2-70 through 12.2-77, and 12.2-101 through 12.2-103.

12.2.1.4.3 Radwaste Enclosure HVAC System

Components of the radwaste and offgas enclosures HVAC system that contain sources of radioactivity are the equipment compartment exhaust air filters. Table 12.2-78 shows the radwaste and offgas enclosure equipment exhaust air filters shielding design source terms.

12.2.1.5 Offgas Enclosure

12.2.1.5.1 Gaseous Radwaste Charcoal Treatment System

The gaseous radwaste charcoal treatment system as described in Section 11.3 is located in the offgas enclosure and receives effluent from the gaseous radwaste recombination system for further decay before release.

The shielding design terms for the charcoal treatment system components are based on the expected transit times for noble gases and the formation and accumulation of noble gas daughter products. These gases pass through the charcoal treatment system and out the turbine enclosure stack. The shielding design source terms for the piping, filters, and charcoal treatment system equipment are presented in Tables 12.2-79 through 12.2-82.

12.2.1.5.2 Offgas Enclosure HVAC System

See Section 12.2.1.4.3 for the offgas enclosure HVAC shielding design source terms.

12.2.1.6 Shielding Design Sources Resulting from Design Basis Accidents

The shielding design for the control room is based on radiation sources resulting from DBAs. Control room shielding design considers radiation sources from the primary containment, the reactor enclosure, the turbine enclosure and control structure, and the SGTS filters. The shielding design source terms for these areas are given in Tables 12.2-83 through 12.2-86.

With regards to the Independent Spent Fuel Storage Installation, a postulated accidental sealing failure can potentially produce a gaseous effluent. This effluent is limited by the requirements of

10CFR72.106, which does not require consideration of simultaneous contributions to dose from the plant.

12.2.1.7 Stored Radioactivity

The only sources of radioactivity not stored inside the plant structures are the refueling water storage tank, the CST, 10CFR20.2002 storage area, the radwaste storage pad and designated material laydown areas in the protected area.

During normal operation of the Independent Spent Fuel Storage Installation only direct radiation is emitted from loaded dry storage containers. The radiation dose is limited by the requirements of 10CFR72.104, which considers the direct dose from the storage containers in combination with the normal plant sources and effluents.

The CST contains low concentrations of radioisotopes. A dike is provided around the CST so that unrestricted access is limited to areas with a dose rate less than 2 mRem/hr. The CST source terms are shown in Table 12.2-87.

The refueling water storage tank also has low concentrations of radioisotopes when water is returned from the refueling pool. The refueling water storage tank is surrounded by a dike which limits unrestricted access to areas with a dose rate less than 0.2 mRem/hr. The refueling water storage tank source terms are shown in Table 12.2-88.

Provisions have been made to recycle the water from both the condensate and refueling water storage tanks through the condensate filter/demineralizers.

The 10CFR20.2002 storage area is an area north of the radwaste storage pad and northwest of the spray pond. The area is approximately 1.5 acres in size and approved for storage of slightly contaminated soils, sediment and sludges as approved by the 10CFR20.2002 application. Annual and maximum limits for the amount of material and radioactivity concentration are established by the 10CFR20.2002 application for the material stored there. The offsite dose at the nearest residence will not exceed 0.101 mrem/year from the radioactive waste material stored at the 10CFR20.2002 storage area.

The radwaste storage pad is located outside the protected area, but within the site restricted area, southwest of the spray pond and northwest of the Unit 1 cooling tower. The waste material on the pad consists of low level waste being stored on a temporary (interim) basis, awaiting offsite shipment, and contaminated reusable material. Storage pad boundary dose rates are set such that exposure of personnel in unrestricted areas is in accordance with 10CFR20.1301 requirements. The normal offsite dose to any member of the public will not exceed 1.0 mR/year from the radioactive waste material on the storage pad and 1.0 mR/year from storage of contaminated reusable material.

Designated area within the protected area are used for temporary storage of very low level contaminated material. This material consists of reusable materials to support plant operations and maintenance activities, and materials awaiting processing or offsite shipment for subsequent recycling, recovery, or free release to the extent achievable. The normal offsite dose from this category of material is included in the 1.0 mr/yr limit from storage of contaminated reusable material on the radwaste storage pad.

No other radiation sources aside from the Independent Spent Fuel Storage Installation (ISFSI) are normally stored outside the plant structures. Spent fuel is stored in the spent fuel pool until it is placed in the spent fuel shipping cask for offsite transport or into the ISFSI Transfer Cask or HI-TRAC VW cask for placement at the ISFSI for interim storage. Space is provided in the radwaste enclosure for storage of spent filter cartridges and solidified spent resins. Radiation sources stored inside the plant structures are shielded to provide a dose rate of less than 2 mRem/hr for all areas outside plant structures.

12.2.1.8 Special Sources

Special materials used in the radiochemistry laboratory and sealed sources used for calibration require special handling equipment and are shielded accordingly. Unsealed sources and radioactive samples are handled in conventional hoods that exhaust to the ventilation system. Design features provided are discussed in Section 12.3.1.

The TIP system gamma detector and its drive cable become radiation sources following activation by neutrons in the reactor. The level of the radiation source depends upon the material compositions of the components, the irradiation history and decay time. The material composition of the gamma TIP is shown in Table 12.2-89. The radiation levels from the detector and cable are shown in Table 12.2-104 for a range of decay times after the TIP is retracted from the reactor vessel.

The reactor startup sources are shipped to the site in special shielded casks. The sources are transferred from the cask to the source holders. The source holders are then loaded underwater into the reactor. The sources are removed from the reactor and placed in the spent fuel pool or sent offsite.

12.2.2 Airborne Radioactive Material Sources

12.2.2.1 Sources of Airborne Radioactivity

The sources of airborne radioactivity found in the various areas of the plant are mostly from process leakage of the systems carrying radioactive gases, steam, and liquids. Depending on the type of the system and its physical condition, such as system pressures and temperatures, leakage is in the form of a gas, steam, liquid, or a mixture of these.

12.2.2.2 Production of Airborne Radioactive Materials

Radioactive materials become airborne through a number of mechanisms. The most common production mechanisms are spraying, splashing, flashing, evaporation, and diffusion.

12.2.2.3 Locations of Sources of Airborne Radioactivity

Practically all the sources of airborne radioactivity are found in the reactor, turbine, and radwaste and offgas enclosures. Within these structures the radioactivity is released in equipment cubicles, valve and piping galleries, sampling stations, radwaste handling and shipping areas, cleaning and decontamination areas, and repair shops.

12.2.2.4 Control of Airborne Radioactivity

Ventilation is an effective means of controlling airborne radioactive materials. Ventilation flow paths are such that air from low potential airborne areas flows into higher potential airborne areas. This flow pattern ensures that radioactivity released in the above mentioned source locations, which usually have low personnel access requirements, has little chance to escape into areas with a high personnel occupancy such as corridors, working aisles, and operating floors. Levels of airborne radioactivity are periodically checked by surveys of the plant by the radiation protection staff.

12.2.2.5 Methodology for Estimating the Concentration of Airborne Radioactive Material Within the Plant

To estimate the airborne radioactive material concentrations at locations within the plant, the following methodology was used:

a. Estimate the total airborne releases (in curies per year) for each of the plant enclosures.

b. Estimate a distribution for these releases among the various equipment areas of each enclosure based on operating data and engineering judgement.

c. Determine the annual exhaust flow from each equipment area.

d. Calculate the resultant airborne radionuclide concentration (Ci/cc) in each equipment area based on the release distribution (Ci/yr) and exhaust flow rate (cc/yr).

The following sections discuss each step in the above procedure in more detail.

12.2.2.6 Estimation of Total Airborne Releases Within the Plant

The estimated quantities of airborne radioactive material produced in the plant enclosures are given in Table 12.2-93. These releases were based upon BWR-GALE (Reference 12.2-1), a computerized mathematical model for calculating the release of radiological materials in gaseous and liquid effluents. Assumptions applicable to the development of Table 12.2-93 from BWR-GALE are as follows:

a. The reactor enclosure releases are taken to be the sum of the auxiliary enclosure and containment enclosure releases calculated by BWR-GALE.

b. Turbine enclosure releases from BWR-GALE are assumed to include any airborne radioactive material produced in the control structure.

c. The radwaste enclosure releases from BWR-GALE are "per reactor" and consequently are doubled for LGS. Offgas enclosure releases are assumed to be included in the radwaste enclosure releases.

d. Tritium releases from BWR-GALE are divided equally between the reactor and turbine enclosures.

e. Since the BWR-GALE code for gaseous releases is based on actual operating plant data, releases for both normal operations and anticipated operational occurrences are assumed to have been included.

12.2.2.7 Distribution of Airborne Releases Within the Plant

In the approach taken to determine the anticipated distribution of gaseous effluents, it is assumed that all airborne radioactive material originates only within the equipment areas of the plant. It is further assumed that a major percentage of the release is generated within a few specific areas of each enclosure, with the remainder coming from other equipment areas. Eighty percent of each enclosure's release is distributed as described below among the major contributing areas, and 20% is assigned to the "other equipment areas" category. Releases are assumed to be generated continuously throughout the year except for the drywell, where a 30 day release period is used.

The basis for the selection and relative contributions of the major areas is EPRI report NP-495 (Reference 12.2-2). This report provides data on the important sources of iodine-131 at operating BWRs and uses measured data to determine the relative release rate from each source. The relative release rates for all airborne radionuclides are, except for reactor enclosures tritium, assumed to be directly proportional to the iodine-131 release rates. Since the spent fuel pool and the reactor vessel (when it is open during refueling) are the major sources of airborne tritium in the reactor enclosure, tritium releases for that enclosure are assigned entirely to the refueling area.

Table 12.2-94 lists the major airborne contributors in each enclosure and the percentage of the total enclosure release assigned to each. Tables 12.2-95 through 12.2-97 provide the specific equipment areas of the plant associated with the major contributors and the applicable exhaust air flow rates. Note that only those equipment areas that have a significant potential for airborne radioactive material releases were included in the
"other equipment areas" category.

12.2.2.8 Estimated Airborne Radioactive Material Concentrations Within the Plant

The airborne radionuclide concentrations for each equipment area were calculated using the following methodology. For a specific area, the appropriate enclosure release (Table 12.2-93) was multiplied by the applicable release percentage for the area (Table 12.2-94) and divided by the area's annual exhaust flow (Table 12.2-95, 12.2-96, or 12.2-97). The resultant concentrations are presented in Tables 12.2-98 through 12.2-100, which also include the fractions of the maximum permissible concentrations in air as defined in 10CFR20 Appendix B, Table I (pre-1994).

12.2.2.9 Changes to Source Data Since PSAR

Airborne radioactive material sources were not specified in the LGS PSAR. Section 12.2.2 has been added in compliance with the "Standard Format and Content of Safety Analysis Report for Nuclear Power Plants," Regulatory Guide 1.70.

12.2.3 REFERENCES

12.2-1 NUREG-0016 (Revision 0), "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents From Boiling Water Reactors," Office of Standards Development, NRC, Washington, D.C. (April 1976).

12.2-2 EPRI NP-495, "Sources of Radioiodine at Boiling Water Reactors," Project 274-1, Final Report, (February 1978).

Table 12.2-1

NOBLE GAS SHIELDING DESIGN SOURCE TERMS[1]

ISOTOPE	HALF-LIFE	STEAM SPECIFIC ACTIVITY (μCi/g)	REACTOR WATER SPECIFIC ACTIVITY (μCi/g)
Kr-83m	1.86 hr	6.68×10^{-3}	-
Kr-85m	4.4 hr	1.20×10^{-2}	-
Kr-85	10.74 yr	3.93×10^{-5}	-
Kr-87	76.0 min	3.93×10^{-2}	-
Kr-88	2.79 hr	3.93×10^{-2}	-
Kr-89	3.18 min	2.55×10^{-1}	-
Kr-90	32.3 sec	5.50×10^{-1}	-
Kr-91	8.6 sec	6.48×10^{-1}	-
Kr-92	1.84 sec	6.48×10^{-1}	-
Kr-93	1.29 sec	1.94×10^{-1}	-
Kr-94	1.0 sec	4.52×10^{-2}	-
Kr-95	0.5 sec	4.12×10^{-3}	-
Xe-131m	11.96 day	2.95×10^{-5}	-
Xe-133m	2.26 day	5.70×10^{-4}	-
Xe-133	5.27 day	1.61×10^{-2}	-
Xe-135m	15.7 min	5.11×10^{-2}	-
Xe-135	9.16 hr	4.32×10^{-2}	-
Xe-137	3.82 min	2.95×10^{-1}	-
Xe-138	14.2 min	1.75×10^{-1}	-
Xe-139	40.0 sec	5.50×10^{-1}	-
Xe-140	13.6 sec	5.89×10^{-1}	-
Xe-141	1.72 sec	4.71×10^{-1}	-
Xe-142	1.22 sec	1.43×10^{-1}	-
Xe-143	0.96 sec	2.36×10^{-2}	-
Xe-144	9.0 sec	1.10×10^{-3}	-

(1) All fission product specific activities are based on an offgas release rate of 0.35 Ci/sec at 30 minutes decay.

Table 12.2-2

HALOGEN SHIELDING DESIGN SOURCE TERMS[1]

ISOTOPE	HALF-LIFE	STEAM SPECIFIC ACTIVITY[2] (μCi/g)	REACTOR WATER SPECIFIC ACTIVITY (μCi/g)
Br-83	2.40 hr	1.05×10^{-3}	5.25×10^{-2}
Br-84	31.8 min	1.89×10^{-3}	9.45×10^{-2}
Br-85	3.0 min	1.19×10^{-3}	5.95×10^{-2}
I-131	8.06 day	9.10×10^{-4}	4.55×10^{-2}
I-132	2.28 hr	8.40×10^{-3}	4.20×10^{-1}
I-133	20.8 hr	6.23×10^{-3}	3.12×10^{-1}
I-134	52.3 min	1.68×10^{-2}	8.40×10^{-1}
I-135	6.7 hr	9.10×10^{-3}	4.55×10^{-1}

(1) All fission product specific activities are based on an offgas release rate of 0.35 Ci/sec at 30 minutes decay.

(2) A 2.0% by weight carryover from reactor water to steam is assumed.

Table 12.2-3

OTHER FISSION PRODUCT SHIELDING DESIGN SOURCE TERMS[1]

ISOTOPE	HALF-LIFE	STEAM SPECIFIC ACTIVITY[2] (μCi/g)	REACTOR WATER SPECIFIC ACTIVITY (μCi/g)
Sr-89	50.8 day	1.09×10^{-5}	1.09×10^{-2}
Sr-90	28.9 yr	8.05×10^{-7}	8.05×10^{-4}
Sr-91	9.67 hr	2.42×10^{-4}	2.42×10^{-1}
Sr-92	2.69 hr	3.85×10^{-4}	3.85×10^{-1}
Zr-95	65.5 day	1.40×10^{-7}	1.40×10^{-4}
Zr-97	16.8 hr	1.12×10^{-7}	1.12×10^{-4}
Nb-95	35.1 day	1.47×10^{-7}	1.47×10^{-4}
Mo-99	66.6 hr	7.70×10^{-5}	7.70×10^{-2}
Tc-99m	6.00 hr	9.80×10^{-4}	9.80×10^{-1}
Tc-101	14.2 min	4.90×10^{-4}	4.90×10^{-1}
Ru-103	39.8 day	6.65×10^{-8}	6.65×10^{-5}
Ru-106	368 day	9.10×10^{-9}	9.10×10^{-6}
Te-129m	34.1 day	1.40×10^{-7}	1.40×10^{-4}
Te-132	78.0 hr	1.72×10^{-4}	1.72×10^{-1}
Cs-134	2.06 yr	5.60×10^{-7}	5.60×10^{-4}
Cs-136	13.0 day	3.85×10^{-7}	3.85×10^{-4}
CS-137	30.2 yr	8.40×10^{-7}	8.40×10^{-4}
Cs-138	32.3 min	6.65×10^{-4}	6.65×10^{-1}
Ba-139	83.2 min	5.60×10^{-4}	5.60×10^{-1}
Ba-140	12.8 day	3.15×10^{-5}	3.15×10^{-2}
Ba-141	18.3 min	5.95×10^{-4}	5.95×10^{-1}
Ba-142	10.7 min	5.95×10^{-4}	5.95×10^{-1}
Ce-141	32.53 day	1.37×10^{-7}	1.37×10^{-4}
Ce-143	33.0 hr	1.23×10^{-7}	1.23×10^{-4}
Ce-144	284.4 day	1.23×10^{-7}	1.23×10^{-4}
Pr-143	13.58 day	1.33×10^{-7}	1.33×10^{-4}
Nd-147	11.06 day	4.90×10^{-8}	4.90×10^{-5}
Np-239	2.35 day	8.40×10^{-4}	8.40×10^{-1}

(1) All fission product specific activities are based on an offgas release rate of 0.35 Ci/sec at 30 minutes decay.

(2) A 0.1% by weight carryover from reactor water to steam is assumed.

Table 12.2-4

COOLANT ACTIVATION PRODUCT SHIELDING DESIGN SOURCE TERMS

ISOTOPE	HALF-LIFE	STEAM SPECIFIC ACTIVITY (μCi/g)	REACTOR WATER SPECIFIC ACTIVITY (μCi/g)
N-13	9.99 min	7.00×10^{-3}	4.00×10^{-2}
N-16*	7.13 sec	$2.50 \times 10^{+2}$	$4.80 \times 10^{+1}$
N-17	4.14 sec	2.00×10^{-2}	6.00×10^{-3}
O-19	26.8 sec	8.00×10^{-1}	7.00×10^{-1}
F-18	109.8 min	4.00×10^{-3}	4.00×10^{-3}

* With Hydrogen Water Chemistry.

(1) Refer to LGS UFSAR Section 10.4.11 for the details of Hydrogen Water Chemistry System.

Table 12.2-5

NONCOOLANT ACTIVATION PRODUCT SHIELDING DESIGN SOURCE TERMS

ISOTOPE	HALF-LIFE	STEAM SPECIFIC ACTIVITY[1] (μCi/g)	REACTOR WATER SPECIFIC ACTIVITY (μCi/g)
Na-24	15.0 hr	2.00×10^{-6}	2.00×10^{-3}
P-32	14.31 day	2.00×10^{-8}	2.00×10^{-5}
Cr-51	27.8 day	5.00×10^{-7}	5.00×10^{-4}
Mn-54	313.0 day	4.00×10^{-8}	4.00×10^{-5}
Mn-56	2.58 hr	5.00×10^{-5}	5.00×10^{-2}
Co-58	71.4 day	5.00×10^{-6}	5.00×10^{-3}
Co-60	5.25 yr	5.00×10^{-7}	5.00×10^{-4}
Fe-59	45.0 day	8.00×10^{-8}	8.00×10^{-5}
Ni-65	2.55 hr	3.00×10^{-7}	3.00×10^{-4}
Zn-65	243.7 day	2.00×10^{-9}	2.00×10^{-6}
Zn-69m	13.7 hr	3.00×10^{-8}	3.00×10^{-5}
Ag-110m	253.0 day	6.00×10^{-8}	6.00×10^{-5}
W-187	23.9 hr	3.00×10^{-6}	3.00×10^{-3}

[1] A 0.1% by weight carryover from reactor water to steam is assumed.

Table 12.2-6

BASIC REACTOR DATA[1]

PARAMETER		VALUE USED IN MODEL
Reactor rated thermal power		3527 megawatts
Overall average core power density		53.8 watts/cc
Core power peaking factors:		
At core center		
$\frac{P_{max}}{P_{ave_Z}}$	(axial)	1.5
$\frac{P_{max}}{P_{ave_R}}$	(radial)	1.4
At core boundary		
$\frac{P_{max}}{P_{ave_Z}}$	(axial)	0.5
$\frac{P_{max}}{P_{ave_R}}$	(radial)	0.7

Core volume fractions:

Material	Density gm/cc	Volume Fraction
UO_2	10.4	0.254
Zr	6.4	0.140
H_2O	1.0	0.274
Void	0	0.332

Average water density between core and vessel and below the core	0.74 g/cc
Average water-steam density above core:	
In the plenum region	0.23 g/cc
Above the plenum (homogenized)	0.6 g/cc
Average steam density	0.036 g/cc

(1) This table represents the physical data required to form the reactor vessel model, which includes volume fractions, reactor power, and power distribution.

Table 12.2-7

CORE REGION DESCRIPTION TO DETERMINE
RADIAL FLUX DISTRIBUTION AT REACTOR CORE MIDPLANE

REGION DESCRIPTION	REGION THICKNESS (cm)	CUMULATIVE THICKNESS (cm)	MATERIAL
Active fuel zone	237.60	237.60	Core
Water	20.37	257.97	Water
Core shroud	5.08	263.05	Stainless steel
Water	58.26	321.31	Water
Pressure vessel liner	0.476	321.786	Stainless steel
Pressure vessel	16.354	338.14	Carbon steel
Air	51.76	389.89	Air
Steel liner (primary shield)	1.27	391.16	Carbon steel
Concrete (primary shield)(1)	48.26	439.42	Magnetite/ ilmenite
Steel liner (primary shield)	3.81	443.23	Carbon steel
Air gap	418.78	862.01	Air
Primary containment	195.58	1057.59	Ordinary concrete

(1) Ilmenite/magnetite aggregate mixture

Table 12.2-8

MATERIAL COMPOSITION TO DETERMINE RADIAL FLUX DISTRIBUTIONS AT REACTOR CORE MIDPLANE

ELEMENT	MATERIAL (10^{24} atoms/cc)						
	CORE	WATER	STAINLESS STEEL-304	CARBON STEEL	CONCRETE[(1)]	AIR	ORDINARY CONCRETE
H	1.83×10^{-2}	4.89×10^{-2}			3.66×10^{-3}		7.84×10^{-3}
O	2.26×10^{-2}	2.44×10^{-2}			4.51×10^{-2}	1.12×10^{-5}	4.41×10^{-3}
Mo	5.93×10^{-4}						
U-235	1.24×10^{-4}						
U-238	5.46×10^{-3}						
Mg					9.69×10^{-4}		1.43×10^{-4}
A					1.32×10^{-3}		2.39×10^{-3}
Si			1.69×10^{-3}	4.19×10^{-4}	5.49×10^{-3}		1.57×10^{-2}
Ca					4.00×10^{-3}		2.91×10^{-3}
Ti							2.17×10^{-3}
Mn			1.73×10^{-3}	8.59×10^{-4}	4.86×10^{-4}		
Fe			5.76×10^{-2}	8.40×10^{-2}	1.16×10^{-2}		3.09×10^{-4}
C			3.18×10^{-4}	1.00×10^{-3}			
Cr			1.73×10^{-2}				
Ni			8.06×10^{-3}				
N						4.17×10^{-5}	
Na							1.05×10^{-3}
K							6.91×10^{-4}
S							5.30×10^{-5}

(1) Magnetite/ilmenite mixture

Table 12.2-9

CALCULATED GAMMA RAY AND NEUTRON FLUXES AT OUTSIDE SURFACE OF RPV

Outside Vessel At Core Midplane[1]

GAMMA ENERGY (upper Mev)	GAMMA FLUX (γ/cm^2-sec)	NEUTRON ENERGY (upper ev)	NEUTRON FLUX (η/cm^2-sec)
10.0	3.81e+07	1.50e+07	3.22e+05
8.0	1.16e+08	1.22e+07	1.10e+05
6.5	1.14e+08	1.00e+07	2.44+06
5.0	1.40e+08	8.18e+06	4.47+06
4.0	2.55e+08	6.36e+06	6.16e+05
3.0	1.90w+08	4.96e+06	4.43e+06
2.5	2.90e+08	4.06e+06	7.34e+06
2.0	2.50e+08	3.01e+06	8.45e+06
1.66	3.09e+08	2.46e+06	2.72e+06
1.33	4.03e+08	2.35e+06	1.67e+07
1.0	3.18e+08	1.83e+06	5.67e+07
0.8	3.87e+08	1.11e+06	1.62e+08
0.6	1.01e+09	5.50e+05	4.32e+08
0.4	6.26e+08	1.10e+05	3.06e+08
0.3	1.29e+09	3.35e+03	7.50e+07
0.2	1.73e+09	5.83e+02	6.42e+07
0.1	9.61e+07	1.01e+02	4.40e+07
0.05	1.77e+05	2.90e+01	2.88e+07
		1.07e+01	3.19e+07
		3.06e+00	2.01e+07
		1.12e+00	1.56e+07
		4.14e-01	1.61e+07

(1) At 100% power. For geometry, See Table 12.2-7.

Table 12.2-10

CALCULATED GAMMA RAY AND NEUTRON FLUXES AT OUTSIDE SURFACE OF PRIMARY SHIELD

Outside Surface of Primary Shield at Core Midplane (1)

GAMMA ENERGY (upper Mev)	GAMMA FLUX (ν/cm^2 sec)	NEUTRON ENERGY (upper ev)	NEUTRON FLUX (η/cm^2 sec)
10.0	1.23e+05	1.50e+07	8.32e+02
8.0	4.99e+05	1.22e+07	2.66e+03
6.5	4.88e+05	1.00e+07	5.59e+03
5.0	4.81e+05	8.18e+06	9.76e+03
4.0	7.02e+05	6.36e+06	1.28e+04
3.0	4.50e+05	4.96e+06	8.53e+03
2.5	5.61e+05	4.06e+06	1.06e+04
2.0	4.61e+05	3.01e+06	1.61e+04
1.66	5.36e+05	2.46e+06	7.88e+03
1.33	6.72e+05	2.35e+06	2.53e+04
1.0	5.06e+05	1.11e+06	5.63e+04
0.8	6.28e+05	5.50e+05	8.55e+04
0.6	1.28e+06	5.50e+05	1.18e+05
0.4	6.26e+05	1.10e+05	7.89e+04
0.3	7.22e+05	3.35e+02	2.53e+04
0.2	4.85e+05	5.83e+02	2.43e+04
0.1	1.33e+04	1.01e+02	2.17e+04
0.05	2.87e+01	2.90e+01	1.25e+04
		1.07e+01	1.83e+04
		3.06e+00	1.34e+04
		1.12e+00	1.10e+04
		4.14e-01	1.27e+04

(1) At 100% power. For geometry, See Table 12.2-7.

Table 12.2-11

TURBINE ENCLOSURE AND CONTROL STRUCTURE SHIELDING DESIGN RADIATION SOURCE DESCRIPTION

ROOM NO.	ELEVATION (Ft - In)	DOMINANT RADIATION SOURCE	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE[1] DENSITY (g/cc)	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
119	183 - 0 187 – 0 191 - 0	Offgas holdup piping	26" ϕ EBC-106	26" ϕ pipe x 70' long	0.00173	0.578	12.2-43
121		Offgas holdup piping	26" ϕ EBC-106	26" ϕ pipe x 70' long	0.00173	0.578	12.2-43
154	180 - 0	Offgas aftercondenser	10E127	33" ϕ vessel x 9'-8" long	0.774	0.625	12.2-47
		Offgas Recombiner	10S125	60" ϕ vessel x 8'-6" high	0.154	1.1875	12.2-45
		Offgas preheater	10E131	25" ϕ vessel x 9'-6" long	0.575	0.500	12.2-44
161	180 – 0	Condensate backwash receiving tank discharge pump	1BP159	6" ϕ pipe x 10' long	1.0	0.280	12.2-39
162	180 – 0	Condensate backwash receiving tank discharge pump	1AP159	6" ϕ pipe x 10' long	1.0	0.280	12.2-39
163	180 - 0	Condensate backwash receiving tank	10T130	7.4' ϕ tank x 28' long	1.0	0.3125	12.2-39
165	180 – 0	Condensate backwash receiving tank area equipment and floor drain sumps	1BP129, 1AP129, 1BP128, 1AP128	2" ϕ pipe x 10' long	1.0	0.218	12.2-69
249	200 – 0 208 – 0	Offgas piping	4" ϕ HBC-262	4" ϕ pipe x 100' long	0.00173	0.237	12.2-43

Table 12.2-11 (Cont'd)

ROOM NO.	ELEVATION (Ft - In)	DOMINANT RADIATION SOURCE	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE[1] DENSITY (g/cc)	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
253	200 – 0	RFPT exhaust ducting (plus sources in room #254)	-	61" ϕ duct x 6' long	0.000132	0.75	12.2-36
254	200 – 0	Main condenser hotwells	1AE108, 1BE108, 1CE108	40' ϕ well x 4' long	1.0	0.75	12.2-37
255	200 - 0	Drain coolers (plus sources in room #254)	1AE107, 1BE107, 1CE107	58" ϕ vessel x 25.25' long	1.427	0.50	12.2-34
256	189 – 0	Condensate pumps	1AP102, 1BP102, 1CP102	36" ϕ pipe x 44' long	1.0	0.375	12.2-38
259	200 - 0	Recombiner catalyst element	10S125	4'-8" ϕ element x 2' - 10" high	0.529	0.0	12.2-46
264A-I	200 – 0	Condensate filter/ demineralizer backwash piping	10" ϕ HBD-168	10" ϕ pipe x 100' long	1.0	0.365	12.2-39
332	217 – 0	Moisture separators	1A1T104, 1B1T104, 1C1T104, 1A2T104, 1B2T104, 1C2T104	12.5' ϕ vessel x 24' high	0.376	0.394	12.2-33
333	217 - 0	Steam jet air ejector	1BE109	37.5" ϕ vessel x 20' long	0.718	0.375	12.2-41
334	217 - 0	Steam jet air ejector	1AE109	37.5" ϕ vessel x 20' long	0.718	0.375	12.2-41
337	217 – 0	Mechanical vacuum pump	10P105	10' ϕ pipe x 20' long	0.000216	0.365	12.2-42

Table 12.2-11 (Cont'd)

ROOM NO.	ELEVATION (Ft - In)	DOMINANT RADIATION SOURCE	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE[1] DENSITY (g/cc)	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
339A-H	217 – 0	Condensate filter/ demineralizer	1AF106 through 1HF106	72" ϕ vessel x 70' high	1.0	1.50	12.2-39
340A-C	217 – 0	Reactor feed pump turbines	1AS105, 1BS105, 1CS105	10" ϕ pipe x 14' long	0.005803	0.365	12.2-36
342	217 - 0	Condensate pumps	1AP102, 1BP102, 1CP102	30" ϕ pipe x 20' long	1.0	0.63	12.2-38
362A-D	200 - 0	H_2 analyzers	3/8" BWG tubing	3/8" ϕ tube x 20' long	0.00173	0.375	12.2-48
438	239 – 0	Main steam piping	26" ϕ EBB-101	26" ϕ pipe x 200' long	0.036	0.928	12.2-1 through 12.2-5
439	239 – 0	Feedwater heaters	13CE103	74" ϕ vessel x 47.2' long	0.728	0.563	12.2-34
			14CE104	69" ϕ vessel x 39.6' long	0.785	0.625	
			15CE105	68" ϕ vessel x 35.5' long	0.689	0.563	
440	239 – 0	Feedwater heaters	13BE103	74" ϕ vessel x 47.2' long	0.728	0.563	12.2-34
			14BE104	69" ϕ vessel x 39.6' long	0.785	0.625	
			15BE105	68" ϕ vessel x 35.5' long	0.689	0.563	

Table 12.2-11 (Cont'd)

ROOM NO.	ELEVATION (Ft - In)	DOMINANT RADIATION SOURCE	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE[1] DENSITY (g/cc)	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
441	239 - 0	Feedwater heaters	13AE103	74" `ϕ vessel x 47.2' long	0.728	0.563	12.2-34
			14AE104	69" ϕ vessel x 39.6' long	0.785	0.625	
			15AE105	68" ϕ vessel x 35.5' long	0.689	0.563	
544	269 - 0	Turbine deck piping	28" ϕ HP turbine inlet	28" ϕ vessel x 15' long	0.036	1.4	12.2-32
			42" ϕ HP turbine exhaust	42" ϕ vessel x 15' long	0.00709	0.625	12.2-32
			42" ϕ cross-around piping	42" ϕ vessel x 15' long	0.00610	0.625	12.2-32
545	69 - 0	Feedwater heater	16CE106	69" ϕ vessel x 34' long	1.144	1.125	12.2-34
546	269 - 0	Feedwater heater	16BE106	69" ϕ vessel x 34' long	1.144	1.125	12.2-34
547	269 – 0	Feedwater heater	16AE106	69" ϕ vessel x 34' long	1.114	1.125	12.2-34
551	269 – 0	Steam seal	10E128	80" ϕ vessel x 32' long	0.540	0.620	12.2-35
621	304 – 0	Turbine enclosure equipment compartment exhaust air filters	1AF157, 1AF194, 1BF157, 1BF194, 1AF178, 1AF179, 1BF178, 1BF179	15.306' ϕ filter x 11.5" thick	0.00129	0.0	12.2-49

Table 12.2-11 (Cont'd)

ROOM NO.	ELEVATION (Ft - In)	DOMINANT RADIATION SOURCE	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE(1) DENSITY (g/cc)	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
624	332 - 0	SGTS air filters	0AF170, 0BF170, 0AF183, 0BF183, 0AF169, 0BF169	10.852' ϕ filter x 11.5" thick	0.00129	0.0	12.2-50
252A	200-0	Spent resin tanks	1AT928, 1DT928	8'-0 ϕ vessel 7'-2" resin height	1.0	.1875	12.2-101
252B	200-0	Spent resin piping	Various	3" ϕ x vessel lengths	1.0	.12	12.2-101
252C	200-0	Resin Measuring tank	1OT930	4'-6" ϕ vessel 8'-0" resin height	1.0	.250	12.2-101
341 A to H	217-0	Deep bed vessels	1AT927, 1HT927	11'-0 ϕ bed 4"0" height	1.0	1.375	12.2-101
270A	200-0	Spent resin tanks	2AT928, 2DT928	8'-0 ϕ vessel 7'-2" resin height	1.0	.1875	12.2-101
270B	200-0	Spent resin piping	Various	3" ϕ x vessel lengths	1.0	.12	12.2-101
270C	200-0	Resin Measuring tank	2OT930	4'-6" ϕ vessel 8'-0" resin height	1.0	.250	12.2-101
354 A to H	217-0	Deep bed vessels	2AT927, 2HT927	11'-0 ϕ bed 4'-0" height	1.0	1.375	12.2-101

(1) "Effective source Density" is density of radiation source or combination of sources used in shielding design analyses.

Table 12.2-12

REACTOR ENCLOSURE SHIELDING DESIGN RADIATION SOURCE DESCRIPTION

ROOM NO.	ELEVATION (Ft - In)	DOMINANT RADIATION SOURCE	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE DENSITY[1] (g/cc)	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
102	177 – 0	RHR heat exchanger, pumps, and piping	1AE205	53.75" ϕ vessel x 25.1' high	1.406	0.8125	12.2-24
103	177 – 0	RHR heat exchanger, pumps, and piping	1BE205	53.75" ϕ vessel x 25.1' high	1.406	0.8125	12.2-24
108	177 – 0	RCIC pump turbine	10S212	6" ϕ pipe x 20' long	0.0396	0.432	12.2-25
109	177 – 0	HPCI pump turbine	10S211	12" ϕ pipe x 30' long	0.0414	0.687	12.2-26
110	177 – 0	Core spray pump	1AP206	16" ϕ pipe x 20' long	1.0	0.375	12.2-87
113	177 – 0	Core spray pump	1CP206	16" ϕ pipe x 20' long	1.0	0.375	12.2-87
114	177 – 0	Core spray pump	1DP206	16" ϕ pipe x 20' long	1.0	0.375	12.2-87
114A	177 – 0	Pipe-way - RWCU backwash receiving tank to phase separator	2" □ HBC-113	2" ϕ pipe x 20' long	1.0	0.218	12.2-22
115	177 - 0	Reactor enclosure equipment and floor drain sumps	1BP225, 1AP225, 1AP226, 1BP226	6" ϕ pipe x 20' long	1.0	0.280	12.2-69
117	177 – 0	Core spray pump	1BP206	16" ϕ pipe x 20' long	1.0	0.375	12.2-87
203	201 – 0	RHR heat exchanger	1AE205	53.75" ϕ vessel x 25.1' high	1.406	0.375	12.2-24
204	201 – 0	RHR heat exchanger	1BE205	53.75" ϕ vessel x 25.1' high	1.406	0.8125	12.2-24

Table 12.2-12 (Cont'd)

REACTOR ENCLOSURE SHIELDING DESIGN RADIATION SOURCE DESCRIPTION

ROOM NO.	ELEVATION (Ft - In)	DOMINANT RADIATION SOURCE	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE DENSITY[1] (g/cc)	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
209	201 – 0	Drywell equipment and floor drain piping	4" ϕ HBD-162, 4" ϕ HBC-115	4" ϕ pipe x 15' long	1.0	0.237	12.2-15
296	201 – 0	Piping - RWCU backwash receiving tank to phase separator	2" ϕ HBC-113	2" ϕ pipe x 15' long	1.0	0.218	12.2-22
297	201 – 0	HPCI turbine inlet piping	12" ϕ EBB-108	12" ϕ pipe x 30' long	0.0414	0.687	12.2-26
298	201 – 0	RCIC turbine inlet piping	6" ϕ EBB-109	6" ϕ pipe x 15' long	0.0396	0.432	12.2-25
306	241 – 3	Streaming through drywell penetrations	Reactor recirc piping	28" ϕ pipe x 3' long	0.73	1.076	12.2-2 through 12.2-5
307	241 – 3	Streaming through drywell penetrations	Reactor recirc piping	28" ϕ pipe x 3' long	0.73	1.076	12.2-2 through 12.2-5
309	217 – 0	HPCI turbine inlet piping	12" ϕ EBB-108	12" ϕ pipe x 20' long	0.0414	0.687	12.2-26
310	217 – 0	Spent fuel shipping cask	Spent fuel, 0.5 years decay	7' ϕ cask x 20' high	1.00	Sufficient for 10 mR/hr at 3 ft	-
401	253 – 0	Streaming through drywell penetrations	Reactor recirc piping	28" ϕ pipe x 40' long	0.73	1.07	12.2-2 through 12.2-5
403	253 – 0	Contaminated CRD mechanisms	CRD filter	4" ϕ tube x 18" long	5.305	0.0	12.2-31
404	253 – 0	Decontaminated CRD mechanisms	CRD element	4" ϕ tube x 14'-1" long	5.305	0.0	12.2-31
405	253 – 0	Streaming through drywell penetrations	Reactor recirc piping	28" ϕ pipe x 40' long	0.73	1.076	12.2-2 through 12.2-5

Table 12.2-12 (Cont'd)

REACTOR ENCLOSURE SHIELDING DESIGN RADIATION SOURCE DESCRIPTION

ROOM NO.	ELEVATION (Ft - In)	DOMINANT RADIATION SOURCE	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE DENSITY[1] (g/cc)	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
406	253 - 0	TIP and cable	Activated TIP	0.213" ϕ cable cable	7.86 x 12' long	0.0475	12.2-90 through 12.2-92
407	263 – 0	Main steam piping	26" ϕ EBB-101	26" ϕ pipe x 26' long	0.036	0.928	12.2-1 through 12.2-5
409	253 – 0	Streaming through drywell penetrations	Reactor recirc piping	28" ϕ pipe x 15' long	0.73	1.076	12.2-2 through 12.2-5
501	283 – 0	Streaming through drywell penetrations	Reactor recirc piping	28" ϕ pipe x 2' long	0.73	1.076	12.2-2 through 12.2-5
502	283 – 0	RWCU backwash receiving tank	10T217	8' ϕ tank x 2.925' high	1.0	0.1875	12.2-22
503	283 – 0	RWCU regenerative heat exchangers	10E207	16.25" ϕ vessel x 19.92' long	2.104, 2.143, 2.188 (3HX's)	0.875	12.2-17, 12.2-18, 12.2-19
504	283 – 0	RWCU nonregenerative heat exchangers	1BE208	17.25" ϕ vessel x 23' long	1.777, 1.785 (2HX's)	0.375	12.2-20, 12.2-21
505	283 – 0	RWCU nonregenerative heat exchangers	1AE208	17.25" ϕ vessel x 23' long	1.777, 1.785 (2HX's)	0.375	12.2-20, 12.2-21
507	283 – 0	RWCU recirculation pump	1AP221	4" ϕ pipe x 7.5' long	0.73	0.337	12.2-16
508	283 – 0	RWCU recirculation pump	1BP221	3" ϕ pipe x 7.5' long	0.73	0.300	12.2-16
509	283 – 0	RWCU recirculation pump	1CP221	3" ϕ pipe x 7.5' long	0.73	0.300	12.2-16

Table 12.2-12 (Cont'd)

REACTOR ENCLOSURE SHIELDING DESIGN RADIATION SOURCE DESCRIPTION

ROOM NO.	ELEVATION (Ft - In)	DOMINANT RADIATION SOURCE	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE DENSITY[1] (g/cc)	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
510	283 – 0	Piping - RWCU backwash receiving tank to phase separator	2" ϕ HBC-113	2" ϕ pipe x 20' long	1.0	0.218	12.2-22
511	283 – 0	Fuel pool cooling water heat exchangers	1AE202, 1BE202, 1CE202	25.25" ϕ vessel x 23' long	1.55	0.375	12.2-29
518	279 – 0	Main steam piping	26" ϕ EBB-101	26" ϕ pipe x 35' long	0.036	0.928	12.2-1 through 12.2-5
522	296 - 0, 300 – 3	Piping - RWCU backwash receiving tank to phase separator	2" ϕ HBC-113	2" ϕ pipe x 20' long	1.0	0.218	12.2-22
523	295 – 3	Streaming through drywell penetrations	6" ϕ EBB-101	26" ϕ pipe x 2' long	0.036	0.928	12.2-1 through 12.2-5
599	283 - 0, 287 - 0, 295 - 0	Streaming through drywell penetrations	26" ϕ EBB-101	26" ϕ pipe x 2' long	0.036	0.928	12.2-1 through 12.2-5
600A,B	313 – 0	RWCU filter/demineralizer holding pumps and back wash piping	1AP223, 1BP223, 4" ϕ ECC-102	4" ϕ pipe x 20' long	1.0	0.237	12.2-22 12.2-23
604	312 – 0	Spent fuel	Spent fuel, 2 days decay	5.476 in^2 assy. x 150 inches long, 1224 assemblies	2.236	0.0	12.2-14
609A,B	313 – 0	RWCU filter/demineralizer	1AF203, 1BF203	33" ϕ tank x 5' high	0.957	1.50	12.2-22

Table 12.2-12 (Cont'd)

REACTOR ENCLOSURE SHIELDING DESIGN RADIATION SOURCE DESCRIPTION

ROOM NO.	ELEVATION (Ft - In)	DOMINANT RADIATION SOURCE	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE DENSITY[1] (g/cc)	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
616	331 – 0	Reactor enclosure equipment compartment exhaust air filters	1AF254, 1AF258, 1AF257, 1AF255	15.918' ϕ filter x 11.5" thick	0.001293	0.0	12.2-30
617	331 – 0	Reactor enclosure equipment compartment exhaust air filters	1BF254, 1BF258, 1BF257, 1BF255	15.918' ϕ filter 1BF258,	0.001293 x 11.5" thick	0.0	12.2-30
634	308 – 6	Spent fuel assembly	Spent fuel, 0.5 years decay	5.476 in^2 assy. x 150" long	4.534	0.0	12.2-14

(1) "Effective source Density" is density of radiation source or combination of sources used in shielding design analysis.

Table 12.2-13

RADWASTE AND OFFGAS ENCLOSURE SHIELDING DESIGN RADIATION SOURCE DESCRIPTION

ROOM NO.	ELEVATION (FT - IN)	DOMINANT RADIATION SOURCE(S)	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE DENSITY (g/cc)[1]	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
123	162 – 0	Waste sludge tank	00T31	10.44' ϕ tank x 21' long	1.0	0.5	12.2-76
		RWCU filter/demineralizer backwash piping	2" HBC-113	2" ϕ pipe x 30' long	1.0	0.216	12.2-22
124	162 – 0	Waste sludge mixing pump	00P322	3" ϕ pipe x 22' long	1.0	0.216	12.2-76
125	162 – 0	Condensate phase separators (Unit 1)	1AT316, 1BT316	15' ϕ tank x 1.21' high	1.22	0.437 (+2 feet water to roof)	12.2-70
126	162 – 0	Condensate phase separator decant pump (Unit 1)	10P332	6" ϕ pipe x 15' long	1.0	0.280	12.2-72
		Equipment drain filter backwash piping	6" HBC-36	6" ϕ pipe x 12' long	1.0	0.280	12.2-54
127	162 – 0	Condensate phase separator decant pump (Unit 1)	10P331	4" ϕ pipe x 15' long	1.0	0.237	12.2-71
128	162 – 0	Condensate phase separator (Unit 2)	2AT316, 2BT316	15' ϕ tank x 1.21' high	1.22	0.4375 (+2 feet water to roof)	12.2-70
129	162 – 0	Condensate phase separator sludge pump (Unit 2)	20P331	4" ϕ pipe x 15' long	1.0	0.237	12.2-71

Table 12.2-13 (Cont'd)

ROOM NO.	ELEVATION (FT - IN)	DOMINANT RADIATION SOURCE(S)	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE DENSITY (g/cc)[1]	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
130	162 – 0	Condensate phase separator decant pump (Unit 2)	20P332	6" ϕ pipe x 15' long	1.0	0.280	12.2-72
131	162 – 0	Equipment drain collection tank	00T302	20' ϕ tank x 8.5' high	1.0	0.4375	12.2-51
		Fuel pool filter/ demineralizer backwash piping	6" HBC-7	6" ϕ pipe x 30' long	1.0	0.280	12.2-28
132	162 – 0	Equipment drain collection tank pump	00P301	4" ϕ pipe x 20' long	1.0	0.237	12.2-51
		Fuel pool filter/ Demineralizer backwash piping	6" HBC-7	6" ϕ pipe x 11' long	1.0	0.280	12.2-28
133	162 – 0	Floor drain collection tank pump and sample tank pumps	00P309, 00P313, 00P314	4" ϕ pipe x 20' long	1.0	0.237	12.2-57, 12.2-59, 12.2-60
		Equipment drain filter backwash piping	6" HBC-36	6" ϕ pipe x 56' long	1.0	0.280	12.2-54
134	162 – 0	Floor drain collection nk and sample tanks	00T306, 00T307, 0T308	15' ϕ tank x 2.7' high	1.0	0.4375	2.2-57, 2-59, 12.2-60
		Floor drain filter backwash piping	6" HBC-37	6" ϕ pipe x 10' long	1.0	0.280	12.2-61
136	162 – 0	Chemical waste tank	00T314	10' ϕ tank x 10.21' high	1.0	0.1875	12.2-64
		RWCU filter/demineralizer backwash piping	2" HBC-10	2" ϕ pipe x 25' long	1.0	0.216	12.2-22

Table 12.2-13 (Cont'd)

ROOM NO.	ELEVATION (FT - IN)	DOMINANT RADIATION SOURCE(S)	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE DENSITY (g/cc)[1]	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
137	162 – 0	Chemical waste tank pump	00P321	3" ϕ pipe x 20' long	1.0	0.120	12.2-64
		RWCU filter/demineralizer backwash piping	2" HBC-10	2" ϕ pipe x 5' long	1.0	0.216	12.2-22
138	162 – 0	Floor drain spent resin pump	00P323	3" ϕ pipe x 10' long	1.0	0.216	12.2-63
		Equipment drain filter backwash piping	6" HBC-36	6" ϕ pipe x 20' long	1.0	0.280	12.2-54
139	162 – 0	Equipment drain spent resin pump	00P317	3" ϕ pipe x 10' long	1.0	0.216	12.2-56
		Equipment drain filter backwash piping	6" HBC-36	6" ϕ pipe x 13' long	1.0	0.280	12.2-54
140	162 – 0	Equipment and floor drain spent resin tanks	00T323, 00T324	6' ϕ tank x 3.274' high	1.0	0.1875	12.2-55, 12.2-62
141	162 – 0	RWCU phase separator	0BT318	11.5' ϕ tank x 4.3' high	1.22	0.1875 (+2 feet water to roof)	12.2-73
142	162 – 0	RWCU phase separator decant pump	00P336	1.5" ϕ pipe x 6' long	1.0	0.200	12.2-75
		RWCU filter/demineralizer backwash piping	2" HBC-10	2" ϕ pipe x 13' long	1.0	0.216	12.2-22
143	162 – 0	RWCU phase separator	0AT318	11.5' ϕ tank x 4.3' high	1.22	0.1875 (+2 feet water to roof)	12.2-73

Table 12.2-13 (Cont'd)

ROOM NO.	ELEVATION (FT - IN)	DOMINANT RADIATION SOURCE(S)	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE DENSITY (g/cc)[1]	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
144	162 – 0	RWCU phase separator sludge pump	00P334	3" ϕ pipe x 15' long	1.0	0.216	12.2-74
146	162 – 0	Equipment and floor drain sumps and pumps	0AP337, 0BP337, 0AP338, 0BP338	2" ϕ pipe x 10' long	1.0	0.218	12.2-69
147	162 – 0	Equipment drain sample tanks pumps	0AP305, 0BP305	4" ϕ pipe x 20' long	1.0	0.120	12.2-53
148	162 – 0	Equipment drain sample tanks	0AT303, 0BT303	16' ϕ tank x 13.3' high	1.0	0.1875	12.2-53
216	181 – 2	Charcoal filter	1AS371	10.76' ϕ vessel x 28' high	0.545	1.44	12.2-81
217	195 – 0	Charcoal filter	1CS371, 1DS371, 1ES371, 1FS371	9.75' ϕ vessel x 14.5' high	0.545	0.865	12.2-81
218	195 – 0	Charcoal filter	1GS371	See Room 217	0.545	0.865	12.2-81
219	195 – 0	Charcoal filter	1BS371	See Room 216	0.545	1.44	12.2-81
220	195 – 0	Charcoal filter	2BS371, 2DS371, 2FS371, 2HS371	See Room 217	0.545	0.865	12.2-81
221A	195 – 0	Guard bed	10S370	2.92' ϕ vessel x 2.92' high	0.545	0.5	12.2-80
221B	195 – 0	Guard bed	20S370	See Room 221A	0.545	0.5	12.2-80
222	195 – 0	Charcoal filter	2AS371	See Room 216	0.545	1.44	12.2-81
223	191 – 0	Charcoal filter	2CS371, 2ES371, 2GS371, 2IS371	See Room 217	0.545	0.865	12.2-81
224A	191 – 0	Outlet HEPA filter	10F371	1.08' ϕ cylinder x 4.5' high	0.0013	0.432	12.2-82

Table 12.2-13 (Cont'd)

ROOM NO.	ELEVATION (FT - IN)	DOMINANT RADIATION SOURCE(S)	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE DENSITY (g/cc)[1]	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
224B	195 – 0	Outlet HEPA filter	20F371	See Room 224A	0.0013	0.432	12.2-79
226A	195 – 0	Cooler condenser (drain pot)	10E377	8" ϕ pipe x 0.672' high	1.0	0.322	12.2-79
226B	195 – 0	Cooler condenser (drain pot)	20E377	See Room 226A	1.0	0.322	12.2-79
227	191 – 0	RWCU backwash piping	2" HBC-213	2" ϕ pipe x 10' long	1.0	0.218	12.2-22
228	191 – 0	Laundry drain tanks, pumps, and filter	0AT311, 0BT311, 00F313, 00T312, 0AP318, 0BP318, 0AP319, 0BP319	7' ϕ tank x 6.25' high	1.0	0.4375	12.2-67, 12.2-68
230	191 – 0	Evaporator feed tank and evaporator distillate sample tank (abandoned)	00T320, 00T321	11' ϕ tank x 8.44' high	1.0	0.1875	12.2-64, 12.2-66
231[2]	191 – 0	Evaporator feed tank pumps (abandoned)	OAP326, OBP326	1.5" ϕ pipe x 20' long	1.0	0.145	12.2-64
232[2]	191 – 0	Evaporator distillate pump (abandoned	00P327	2" ϕ pipe x 20' high	1.0	0.1875	12.2-66
233[2]	191 – 0	Radwaste evaporator concentrate storage tank (abandoned)	00T322	10' ϕ tank x 6.81' high	1.0	0.1875	12.2-77
		RWCU phase separator discharge piping	1.5" HBC-14	1.5" ϕ pipe x 27' long	1.0	0.200	12.2-74
234[2]	191 – 0	Concentrate storage tank discharge and mixing pump (abandoned)	00P328	1" ϕ pipe x 15' long	1.0	0.133	12.2-77
235A	191-0	RWCU phase separator discharge piping	1.5" HBC-14	1.5" ϕ pipe 19' long	1.0	0.200	12.2-74

Table 12.2-13 (Cont'd)

ROOM NO.	ELEVATION (FT - IN)	DOMINANT RADIATION SOURCE(S)	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE DENSITY (g/cc)[1]	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
236	191 – 0	Fuel pool filter/ demineralizer holder pumps and backwash piping	00P340, 10P340, 20P340, 6" 0 HBC-103	6" ϕ pipe x 10' long	1.0	0.280	12.2-28
237	191 – 0	Floor drain filter holding pump and backwash piping	00P312, 6" 0 HBC-28 15' long	6" ϕ pipe x	1.0	0.280	12.2-61
238	191 – 0	Equipment drain filter holding pump and backwash piping	00P304, 6" 0 HBC-25	6" ϕ pipe x 15' long	1.0	0.280	12.2-54
239A	191 – 0	Fuel pool filter/ demineralizer	10F311	3' ϕ tank x 5' high	1.0	0.4375	12.2-28
239B	191 – 0	Fuel pool filter/ demineralizer	00F311	3' ϕ tank x 5' high	1.0	0.4375	12.2-28
239C	191 – 0	Fuel pool filter/ demineralizer	20F311	3' ϕ tank x 5' high	1.0	0.4375	12.2-28
240A	191 – 0	Floor drain filter	00F307	3' ϕ tank x 5' high	1.0	0.4375	12.2-61
240B	191 – 0	Floor drain demineralizer	00F306	6' ϕ tank x 3.274' high	1.0	1.5 (3/4" for roof)	12.2-62
241A	191 – 0	Equipment drain demineralizer	00F301	6' ϕ tank x 3.275' high	1.0	1.5 (3/4" for roof)	12.2-55
241B	191 – 0	Equipment drain filter	00F302	3' ϕ tank x 5' high	1.0	0.4375	12.2-54

Table 12.2-13 (Cont'd)

ROOM NO.	ELEVATION (FT - IN)	DOMINANT RADIATION SOURCE(S)	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE DENSITY (g/cc)[1]	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
242[2]	191 – 0	Radwaste evaporator and condenser (abandoned)	SKID A	7.5' ϕ tank x 3.33' high	1.0	0.1875	12.2-65
		RWCU phase separator discharge piping	1.5"	HBC-14 1.5" ϕ pipe x 19' long	1.0	0.200	12.2-74
243[2]	191 – 0	Radwaste evaporator and condenser (abandoned)	SKID B	7.5' ϕ tank x 3.33' high	1.0	0.1875	12.2-65
		RWCU phase separator discharge piping	1.5" HBC-14	1.5" ϕ pipe x 19' long	1.0	0.200	12.2-74
245	191 – 0	Equipment drain surge tank and floor drain surge tank	00T304, 00T309	32' ϕ tank x 9.97' high	1.0	0.4375	12.2-52, 12.2-58
247	191 – 0	Floor drain surge tank pump	00P310	4" ϕ pipe 20' long	1.0	0.237	12.2-58
248	191 – 0	Equipment drain surge tank pump	00P302	4" ϕ pipe x 20' long	1.0	0.237	12.2-52
421	217 – 0	HIC with high specific activity resin	HSA-HIC	4'-6" ϕ container x 5' high	0.72	0.0	12.2-101
421A	217 – 0	HSA sludge transfer piping	1.5"	1.5" ϕ pipe x HBC-14	1.0	0.200 20 ft long	12.2-74
421B	217 – 0	HIC with low specific activity resin	LSA-HIC	6'-0" ϕ container x 6' ϕ in. high	0.72	0.0	12.2-102
421C	217 – 0	HIC with high specific activity resin	HSA-HIC	4'-6" ϕ container x 5' high	0.72	0.0	12.2-101
421M	228 - 6 & 237 – 0	HIC with high specific activity resin	HSA-HIC	4'-6" ϕ container x 5' high	0.72	0.0	12.2-101

Table 12.2-13 (Cont'd)

ROOM NO.	ELEVATION (FT - IN)	DOMINANT RADIATION SOURCE(S)	SOURCE IDENTIFICATION	SOURCE GEOMETRY	EFFECTIVE SOURCE DENSITY (g/cc)[1]	EQUIPMENT SELF-SHIELDING (STEEL THICKNESS IN INCHES)	UFSAR SOURCE TABLE
422A	217 – 0	High specific activity sludge transfer piping	1.5" HBC-14	1.5" ϕ pipe x 17' long	1.0	0.200	12.2-74
422B	217 – 0	HIC with high specific activity resin	HSA-HIC	4'-6" ϕ container x 5' high	0.72	0.0	12.2-101
422C	217 – 0	HIC with high specific activity resin	HSA-HIC	4'-6" ϕ container x 5' high	0.72	0.0	12.2-101
423	217 – 0	HIC with high specific activity resin	HSA-HIC	4'-6" ϕ container x 5' high	0.72	0.0	12.2-101
469	237 – 0	High specific activity sludge transfer piping	1.5" HBC-14	1.5" ϕ pipe x 20' long	1.0	0.200	12.2-74
470	237 – 0	Centrifuge	OAS313	1'-0" ϕ tank x 4' long	0.86	1.0	12.2-103
471	237 – 0	Centrifuge	OBS813	1'-0" ϕ tank x 4' long	0.86	1.0	12.2-103
485	237 – 0	Radwaste enclosure equipment compartment exhaust air filters	0BF355, 0BF354	18.766' ϕ filter x 0.9583' thick	0.001293	0.0	12.2-78
486	237 – 0	Radwaste enclosure equipment compartment exhaust air filters	0AF355, 0AF354	18.766' ϕ filter x 0.9583' thick	0.001293	0.0	12.2-78
515	257 – 0	Centrifuge air filters	OAF380, OAF383	18.8' ϕ cylinder x 0.9583' long	0.00129	0.0	12.2-78
516	257 – 0	Centrifuge air filters	OBF380, OBF383	18.8' ϕ cylinder x 0.9583' long	0.00129	0.0	12.2-78

(1) "Effective Source Density" is density of radiation source or combination of sources used in shielding design analyses.
(2) These rooms contain components associated with the abandoned radwaste evaporator system. Installation of these components was not completed for plant operation (Section 11.2.2.1.3).

Table 12.2-14

SPENT FUEL ASSEMBLY SHIELDING DESIGN SOURCE TERMS[1][2][3]

SPENT FUEL STORAGE POOL[4]

Isotope[6]	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)
Kr-85m	2.38E-04	Ru-105	8.62E-04	Pr-143	2.42E+00
Kr-85	1.81E-02	Ru-106	9.99E-04	Pr-144	2.19E+00
Kr-87	3.00E-12	Rh-103m	2.61E+00	Pr-145	6.79E-03
Kr-88	7.82E-06	Rh-105m	2.07E-04	Nd-147	9.96E-01
Xe-133m	1.76E-02	Rh-105	6.81E-01	Nd-149	6.03E-09
Xe-133	3.02E+00	Rh-106	9.99E-01	Pm-147	4.08E-01
Xe-135m	6.88E-03	Rh-109	3.41E-15	Pm-149	5.14E-01
Xe-135	1.83E-01	Pd-107	7.07E-12	Pm-151	1.03E-01
I-131	1.45E+00	Pd-109	5.11E-02	Sm-153	2.74E-01
I-132	2.19E+00	Sb-127	1.23E-01	Eu-156	2.75E-01
I-133	6.88E+00	Sb-129	2.46E-04	Sm-151	8.66E-06
I-134	4.29E-16	Te-127	1.09E-01	Sm-147	1.48E-14
I-135	2.20E-02	Te-129m	1.03E-03	Nd-144	3.46E-18
Rb-88	8.76E-06	Te-129	8.74E-04	Cs-135	9.12E-10
Sr-89	1.46E+00	Te-131m	8.99E-02	Xe-131m	1.05E-13
Sr-90	4.36E-07	Te-131	1.65E-02	I-129	1.48E-11
Sr-91	6.04E-02	Te-132	2.12E+00	Te-127m	4.10E-04
Sr-92	9.65E-06	Te-133m	9.73E-018	Ag-109m	5.11E-02
Y-90	1.86E-07	Te-133	1.32E-18	Pd-109m	3.69E-15
Y-91	1.91E+00	Te-134	8.94E-21	Tc-99	1.01E-07
Y-92	6.87E-04	Ba-139	1.24E-10	Nb-98	5.69E-19
Y-93	9.80E-02	Ba-140	2.70E+00	Nb-97m	3.79E-01
Zr-95	2.76E+00	La-140	2.96E+00	Nb-95m	1.72E-02
Zr-97	4.08E-01	La-141	5.78E-04	Zr-93	1.87E-09
Nb-95	2.81E+00	La-142	1.26E-09	Nb-93m	3.62E-13
Nb-97	4.39E-01	Ce-141	2.78E+00	Y-91m	3.91E-02
Mo-99	4.56E+00	Ce-143	9.44E-01	Y-89m	1.46E-04
Tc-99m	4.35E+00	Ce-144	2.19E+00	Rb-87	2.29E-15
Ru-103	2.66E+00				

Table 12.2-14 (Cont'd)

SPENT FUEL SHIPPING CASK[5]

Isotope[6]	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)
Kr-85	1.76E-02	Rh-106	7.10E-01	Pm-147	3.68E-01
Xe-133	1.54E-10	Pd-107	7.07E-12	Eu-156	8.11E-05
I-131	2.60E-07	Sb-127	1.15E-15	Sm-151	1.24E-05
I-132	3.53E-17	Te-127	4.44E-04	Sm-147	1.29E-12
Sr-89	1.36E-01	Te-129m	2.62E-05	Nd-144	2.56E-16
Sr-90	4.31E-07	Te-129	1.68E-05	Cs-135	9.81E-10
Y-90	4.31E-07	Te-132	3.43E-17	Xe-131m	4.90E-07
Y-91	2.27E-01	Cs-137	7.96E-07	I-129	2.03E-11
Zr-95	4.09E-01	Ba-140	1.53E-04	Te-127m	4.46E-04
Nb-95	7.91E-01	La-140	1.76E-04	Tc-99	2.79E-07
Mo-99	1.25E-19	Ce-141	5.90E-02	Nb-95m	8.66E-03
Tc-99m	1.20E-19	Ce-144	1.40E+00	Zr-93	1.94E-09
Ru-103	1.11E-01	Pr-143	2.53E-04	Nb-93m	4.63E-11
Ru-106	7.10E-01	Pr-144	1.40E+00	Y-89m	1.36E-05
Rh-103m	1.09E-01	Nd-147	1.21E-05	Rb-87	2.29E-15

(1) Based on EOL assembly (1000 days irradiation).
(2) Assumes reactor to have been operating at 3323 MW_t. Expect shielding to be sufficient for approximate 6% power increase to 3515 MWt.
(3) Assumes 764 assemblies per core.
(4) Assumes 2 days decay, when earliest fuel transfer from core to storage pool is expected.
(5) Assumes 0.5 years decay, when earliest offsite transport is expected.
(6) Isotopes with specific activities less than 1.0×10^{-20} are not listed.
Note: This table applies to the assumed spent fuel shipping cask, and not to the Independent Spent Fuel Storage Installation (ISFSI) Transfer Cask or HI-TRAC VW cask which will have significantly lower activities due to increased decay period of the ISFSI fuel.

Table 12.2-15

DRYWELL EQUIPMENT AND FLOOR DRAIN SUMPS SHIELDING DESIGN SOURCE TERMS[1]

ISOTOPE[2]	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)
Br-83	5.25×10^{-8}	Tc-99m	9.80×10^{-7}	Ce-144	1.23×10^{-10}
Br-84	9.45×10^{-8}	Tc-101	4.90×10^{-7}	Pr-143	1.33×10^{-10}
Br-85	5.95×10^{-8}	Ru-103	6.65×10^{-11}	Nd-147	4.90×10^{-11}
I-131	4.55×10^{-8}	Ru-106	9.10×10^{-12}	Np-239	8.40×10^{-7}
I-132	4.20×10^{-7}	Te-129m	1.40×10^{-10}	Na-24	2.00×10^{-9}
I-133	3.12×10^{-7}	Te-132	1.72×10^{-7}	P-32	2.00×10^{-11}
I-134	8.40×10^{-7}	Cs-134	5.60×10^{-10}	Cr-51	5.00×10^{10}
I-135	4.55×10^{-7}	Cs-136	3.85×10^{-10}	Mn-54	4.00×10^{-11}
Sr-89	1.09×10^{-8}	Cs-137	8.40×10^{-10}	Mn-56	5.00×10^{-8}
Sr-90	8.05×10^{-10}	Cs-138	6.65×10^{-7}	Co-58	5.00×10^{-9}
Sr-91	2.42×10^{-7}	Ba-139	5.60×10^{-7}	Co-60	5.00×10^{-10}
Sr-92	3.85×10^{-7}	Ba-140	3.15×10^{-8}	Fe-59	8.00×10^{-11}
Zr-95	1.40×10^{-10}	Ba-141	5.95×10^{-7}	Ni-65	3.00×10^{-10}
Zr-97	1.12×10^{-10}	Ba-142	5.95×10^{-7}	Zn-65	2.00×10^{-12}
Nb-95	1.47×10^{-10}	Ce-141	1.37×10^{-10}	Zn-69m	3.00×10^{-11}
Mo-99	7.70×10^{-8}	Ce-143	1.23×10^{-10}	Ag-110m	6.00×10^{-11}
				W-187	3.00×10^{-9}

(1) Assumes 100% of specific activity in reactor water, less activation gases (Tables 12.2-2, 12.2-3, and 12.2-5).
(2) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-16

RWCU SYSTEM RECIRCULATION PUMPS SHIELDING DESIGN SOURCE TERMS [1][2]

ISOTOPE[3]	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)
Br-83	3.82×10^{-8}	Ba-141	4.27×10^{-7}	Y-89m	5.27×10^{-13}
Br-84	6.84×10^{-8}	Ba-142	4.23×10^{-7}	Xe-135	1.25×10^{-10}
BR-85	3.94×10^{-8}	Ce-141	9.96×10^{-11}	Xe-135m	1.86×10^{-9}
I-131	3.32×10^{-8}	Ce-143	8.94×10^{-11}	Xe-133m	4.92×10^{-13}
I-132	3.07×10^{-7}	Ce-144	8.94×10^{-11}	Xe-133	8.58×10^{-12}
I-133	2.27×10^{-7}	Pr-143	9.71×10^{-11}	Xe-131m	3.44×10^{-15}
I-134	6.10×10^{-7}	Nd-147	3.58×10^{-11}	Kr-85m	4.60×10^{-11}
I-135	3.32×10^{-7}	Np-239	6.13×10^{-7}	Kr-85	2.79×10^{-19}
Sr-89	7.92×10^{-9}	Ag-110	2.93×10^{-13}	Kr-83m	1.01×10^{-10}
Sr-90	5.88×10^{-10}	Zn-69	1.12×10^{-13}	N-13	2.84×10^{-8}
Sr-91	1.76×10^{-7}	Pu-239	1.40×10^{-17}	N-16	2.48×10^{-6}
Sr-92	2.81×10^{-7}	Pm-147	7.62×10^{-18}	N-17	6.37×10^{-11}
Zr-95	1.02×10^{-10}	Pr-144	1.51×10^{-12}	O-19	2.79×10^{-7}
Zr-97	8.17×10^{-11}	La-142	1.36×10^{-9}	N-18	2.91×10^{-9}
Nb-95	1.07×10^{-10}	La-141	5.44×10^{-10}	Na-24	1.46×10^{-9}
Mo-99	5.62×10^{-8}	La-140	2.80×10^{-12}	P-32	1.46×10^{-11}
Tc-99	7.15×10^{-7}	Te-129	2.79×10^{-13}	Cr-51	3.65×10^{-10}
Tc-101	3.50×10^{-7}	Rh-106	2.95×10^{-12}	Mn-54	2.92×10^{-11}
Ru-103	4.85×10^{-11}	Rh-103m	2.42×10^{-13}	Mn-56	3.64×10^{-8}
Ru-106	6.64×10^{-12}	Tc-99	1.90×10^{-18}	Cu-58	3.65×10^{-9}
Te-129m	1.02×10^{-10}	Nb-97m	1.93×10^{-11}	Cu-60	3.65×10^{-10}
Te-132	1.25×10^{-7}	Nb-97	6.45×10^{-14}	Fe-59	5.84×10^{-11}
Cs-134	4.09×10^{-10}	Nb-95m	1.11×10^{-16}	Ni-65	2.19×10^{-10}
Cs-136	2.81×10^{-10}	Y-92	3.88×10^{-10}	Zn-65	1.46×10^{-12}
Cs-137	6.13×10^{-10}	Y-91	2.51×10^{-13}	Zn-69m	2.19×10^{-11}
CS-138	4.81×10^{-7}	Y-91m	6.05×10^{-10}	Ag-110m	4.38×10^{-11}
Ba-139	4.07×10^{-7}	Y-90	4.79×10^{-14}	W-187	2.19×10^{-9}
Ba-140	2.30×10^{-8}				

[1] Based on shielding design source terms given in Tables 12.2-2 through 12.2-5.
[2] Pumps are assumed to be 25.4 seconds downline from the reactor recirculation loop.
[3] Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-17

RWCU SYSTEM REGENERATIVE HEAT EXCHANGER - FIRST-STAGE SHIELDING DESIGN SOURCE TERMS[1][2][3][4]

ISOTOPE[5]	ACTIVITY (Ci) Tube Side	ACTIVITY (Ci) Shell Side	ISOTOPE	ACTIVITY (Ci) Tube Side	ACTIVITY (Ci) Shell Side
Br-83	5.96×10^{-3}	1.22×10^{-3}	La-141	1.36×10^{-4}	2.27×10^{-4}
Br-84	1.06×10^{-2}	1.99×10^{-3}	La-140	7.04×10^{-7}	1.30×10^{-6}
Br-85	5.78×10^{-3}	3.55×10^{-4}	Te-129	7.01×10^{-8}	1.27×10^{-7}
I-131	5.18×10^{-3}	1.09×10^{-3}	I-129	3.06×10^{-1}	$^{9}5.94 \times 10^{-19}$
I-132	4.77×10^{-2}	9.89×10^{-3}	Rh-106	6.34×10^{-7}	2.18×10^{-7}
I-133	3.55×10^{-2}	7.44×10^{-3}	Rh-103m	6.09×10^{-8}	1.09×10^{-7}
I-134	9.48×10^{-2}	1.86×10^{-2}	Ic-99	4.79×10^{-1}	8.84×10^{-13}
I-135	5.18×10^{-2}	1.08×10^{-2}	Nb-97m	4.47×10^{-6}	2.45×10^{-6}
Sr-89	1.24×10^{-3}	2.60×10^{-4}	Nb-97	2.17×10^{-8}	1.18×10^{-7}
Sr-90	9.17×10^{-5}	1.93×10^{-5}	Nb-95m	2.81×10^{-1}	5.18×10^{-11}
Sr-91	2.75×10^{-2}	5.75×10^{-3}	Y-92	9.98×10^{-5}	1.78×10^{-4}
Sr-92	4.37×10^{-2}	8.99×10^{-3}	Y-91	6.35×10^{-8}	1.23×10^{-7}
Zr-95	1.59×10^{-5}	3.36×10^{-6}	Y-91m	1.52×10^{-4}	2.71×10^{-4}
Zr-97	1.27×10^{-5}	2.67×10^{-6}	Y-90	1.21×10^{-8}	2.23×10^{-8}
Nb-95	1.67×10^{-5}	3.52×10^{-6}	Y-89m	1.02×10^{-7}	2.60×10^{-8}
Mo-99	8.77×10^{-3}	1.84×10^{-3}	Xe-135	3.15×10^{-5}	5.67×10^{-2}
Tc-99m	1.11×10^{-1}	2.32×10^{-2}	Cs-135	4.73×10^{-1}	2.73×10^{-14}
Tc-101	5.39×10^{-2}	8.72×10^{-3}	Xe-135m	4.64×10^{-4}	7.96×10^{-1}
Ru-103	7.57×10^{-6}	1.59×10^{-6}	Xe-133m	1.24×10^{-7}	6.68×10^{-4}
Ru-106	1.04×10^{-6}	2.18×10^{-7}	Xe-133	2.16×10^{-6}	1.16×10^{-2}
Te-129m	1.59×10^{-5}	3.36×10^{-6}	Xe-131m	8.66×10^{-1}	1.98×10^{-5}
Te-132	1.95×10^{-2}	4.11×10^{-3}	Kr-85m	1.12×10^{-5}	1.01×10^{-4}
Cs-134	6.38×10^{-5}	6.71×10^{-5}	Kr-85	1.11×10^{-1}	6.13×10^{-12}
Cs-136	4.38×10^{-5}	4.61×10^{-5}	Kr-83m	2.53×10^{-5}	1.60×10^{-2}
Cs-137	9.57×10^{-5}	1.01×10^{-4}	N-13	4.34×10^{-3}	6.30×10^{-3}
Cs-138	7.46×10^{-2}	7.00×10^{-2}	N-16	8.69×10^{-2}	6.22×10^{-15}
Ba-139	6.34×10^{-2}	1.28×10^{-2}	N-17	7.82×10^{-7}	negligible
Ba-140	3.59×10^{-3}	7.55×10^{-4}	O-19	3.01×10^{-2}	3.10×10^{-5}
Ba-141	6.60×10^{-2}	1.13×10^{-2}	F-18	4.54×10^{-4}	9.23×10^{-4}
Ba-142	6.49×10^{-2}	9.76×10^{-3}	Na-24	2.28×10^{-4}	4.77×10^{-5}
Ce-141	1.55×10^{-5}	3.28×10^{-6}	P-32	2.28×10^{-6}	4.79×10^{-7}
Ce-143	1.39×10^{-5}	2.93×10^{-6}	Cr-51	5.69×10^{-5}	1.19×10^{-5}
Ce-144	1.40×10^{-5}	2.94×10^{-6}	Mn-54	4.56×10^{-6}	9.58×10^{-7}
Pr-143	1.51×10^{-5}	3.19×10^{-6}	Mn-56	5.68×10^{-3}	1.16×10^{-3}

Table 12.2-17 (Cont'd)

ISOTOPE[5]	ACTIVITY (Ci) Tube Side	Shell Side	ISOTOPE	ACTIVITY (Ci) Tube Side	Shell Side
Nd-147	5.58×10^{-6}	1.17×10^{-6}	Co-58	$5.69 \times 10^{-4} 19 \times 10^{-4}$	
Np-239	9.57×10^{-2}	2.01×10^{-2}	Co-60	5.69×10^{-5}	1.19×10^{-5}
Ag-110	6.11×10^{-8}	1.87×10^{-8}	Fe-59	9.11×10^{-6}	1.91×10^{-6}
Zn-69	2.83×10^{-8}	5.06×10^{-8}	Ni-65	3.41×10^{-5}	6.99×10^{-6}
Pu-239	3.53×10^{-1}	6.55×10^{-1}	Zn-65	2.28×10^{-7}	4.79×10^{-8}
Pm-147	1.92×10^{-1}	3.56×10^{-1}	Zn-69m	3.41×10^{-6}	7.15×10^{-7}
Pr-144	3.77×10^{-7}	6.30×10^{-7}	Ag-110m	6.83×10^{-6}	1.43×10^{-6}
La-142	3.39×10^{-4}	5.22×10^{-4}	W-187	3.42×10^{-4}	7.17×10^{-5}

(1) Based on shielding design source terms given in Tables 12.2-2 through 12.2-5.
(2) Tube side is reactor water with 37.5 seconds decay accumulated for 6.98 seconds at 341.7 gpm at 0.757 g/cc; shell side is filtered and demineralized reactor water with 353.81 seconds decay accumulated for 14.7 seconds at 310 gpm at 0.834 g/cc.
(3) Shell side assumes a decontamination factor of 10 across the filter/demineralizer (except for Cs and Rb, which have a DF of 2, and gases, which have a DF of 1).
(4) Shell side includes noble gases generated by particulate parents accumulating on filter/demineralizer resins.
(5) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-18

RWCU SYSTEM REGENERATIVE HEAT EXCHANGER - SECOND-STAGE SHIELDING DESIGN SOURCE TERMS[1][2][3][4]

ISOTOPE[5]	ACTIVITY (Ci) Tube Side	ACTIVITY (Ci) Shell Side	ISOTOPE	ACTIVITY (Ci) Tube Side	ACTIVITY (Ci) Shell Side
Br-83	6.41×10^{-3}	1.28×10^{-3}	La-141	1.72×10^{-4}	2.29×10^{-4}
Br-84	1.14×10^{-2}	2.09×10^{-3}	La-140	8.91×10^{-7}	1.31×10^{-6}
Br-85	6.06×10^{-3}	3.94×10^{-4}	Te-129	8.87×10^{-8}	1.27×10^{-7}
I-131	5.58×10^{-3}	1.14×10^{-3}	I-129	3.88×10^{-1}	5.95×10^{-19}
I-132	5.13×10^{-2}	1.04×10^{-2}	Rh-106	7.49×10^{-7}	2.28×10^{-7}
I-133	3.82×10^{-2}	7.79×10^{-3}	Rh-103m	7.70×10^{-8}	1.10×10^{-7}
I-134	1.02×10^{-1}	1.95×10^{-2}	Tc-99	6.06×10^{-1}	8.87×10^{-13}
I-135	5.57×10^{-2}	1.13×10^{-2}	Nb-97m	5.45×10^{-6}	2.56×10^{-6}
Sr-89	1.33×10^{-3}	2.72×10^{-4}	Nb-97	3.04×10^{-8}	1.17×10^{-7}
Sr-90	9.87×10^{-5}	2.02×10^{-5}	Nb-95m	3.56×10^{-1}	5.20×10^{-11}
Sr-91	2.96×10^{-2}	6.02×10^{-3}	Y-92	1.24×10^{-4}	1.78×10^{-4}
Sr-92	4.70×10^{-2}	9.43×10^{-3}	Y-91	8.04×10^{-8}	1.23×10^{-7}
Zr-95	1.72×10^{-5}	3.51×10^{-6}	Y-91m	1.92×10^{-4}	2.72×10^{-4}
Zr-97	1.37×10^{-5}	2.80×10^{-6}	Y-90	1.53×10^{-8}	2.24×10^{-8}
Nb-95	1.80×10^{-5}	3.69×10^{-6}	Y-89m	1.16×10^{-7}	2.72×10^{-8}
Mo-99	9.44×10^{-3}	1.93×10^{-3}	Xe-135	3.99×10^{-5}	5.91×10^{-2}
Tc-99m	1.20×10^{-1}	2.43×10^{-2}	Cs-135	7.05×10^{-1}	2.20×10^{-14}
Tc-101	5.77×10^{-2}	9.24×10^{-3}	Xe-135m	5.86×10^{-4}	8.43×10^{-1}
Ru-103	8.15×10^{-6}	1.67×10^{-6}	Xe-133m	1.57×10^{-7}	7.00×10^{-4}
Ru-106	1.12×10^{-6}	2.28×10^{-7}	Xe-133	2.73×10^{-6}	1.22×10^{-2}
Te-129m	1.72×10^{-5}	3.51×10^{-6}	Xe-131m	1.10×10^{-9}	2.07×10^{-5}
Te-132	2.10×10^{-2}	4.30×10^{-3}	Kr-85m	1.40×10^{-5}	1.06×10^{-4}
Cs-134	6.86×10^{-5}	7.03×10^{-5}	Kr-85	1.64×10^{-1}	5.67×10^{-12}
Cs-136	4.72×10^{-5}	4.83×10^{-5}	Kr-83m	3.20×10^{-5}	1.68×10^{-2}
Cs-137	1.03×10^{-4}	1.05×10^{-4}	N-13	4.64×10^{-3}	6.72×10^{-3}
Cs-138	8.01×10^{-2}	7.37×10^{-2}	N-16	4.64×10^{-2}	2.83×10^{-14}
Ba-139	6.82×10^{-2}	1.34×10^{-2}	N-17	2.54×10^{-7}	-
Ba-140	3.86×10^{-3}	7.90×10^{-4}	O-19	2.72×10^{-2}	4.65×10^{-5}
Ba-141	7.07×10^{-2}	1.20×10^{-2}	F-18	4.88×10^{-4}	9.68×10^{-4}
Ba-142	6.93×10^{-2}	1.04×10^{-2}	Na-24	2.45×10^{-4}	5.00×10^{-5}
Ce-141	1.67×10^{-5}	3.44×10^{-6}	P-32	2.45×10^{-6}	5.02×10^{-7}
Ce-143	1.50×10^{-5}	3.07×10^{-6}	Cr-51	6.13×10^{-5}	1.25×10^{-5}
Ce-144	1.50×10^{-5}	3.07×10^{-6}	Mn-54	4.90×10^{-6}	1.00×10^{-6}
Pr-143	1.63×10^{-5}	3.34×10^{-6}	Mn-56	6.11×10^{-3}	1.22×10^{-3}

Table 12.2-18 (Cont'd)

ISOTOPE[5]	ACTIVITY (Ci) Tube Side	Shell Side	ISOTOPE	ACTIVITY (Ci) Tube Side	Shell Side
Nd-147	6.00×10^{-6}	1.23×10^{-6}	Co-58	6.13×10^{-4}	1.25×10^{-4}
Np-239	1.03×10^{-1}	2.11×10^{-2}	Co-60	6.13×10^{-5}	1.25×10^{-5}
Ag-110	7.13×10^{-8}	1.96×10^{-8}	Fe-59	9.80×10^{-6}	2.01×10^{-6}
Zn-69	3.57×10^{-8}	5.09×10^{-8}	Ni-65	3.66×10^{-5}	7.34×10^{-6}
Pu-239	4.47×10^{-1}	6.57×10^{-1}	Zn-65	2.45×10^{-7}	5.02×10^{-8}
Pm-147	2.43×10^{-1}	3.57×10^{-1}	Zn-69m	3.67×10^{-6}	7.49×10^{-7}
Pr-144	4.77×10^{-7}	6.35×10^{-7}	Ag-110m	7.35×10^{-6}	1.51×10^{-6}
La-142	4.27×10^{-4}	5.29×10^{-4}	W-187	3.68×10^{-4}	7.51×10^{-5}

(1) Based on shielding design source terms given in Tables 12.2-2 through 12.2-5.
(2) The tube side is reactor water with 44.48 seconds decay accumulated for 7.52 seconds at 317.0 gpm at 0.815 g/cc; the shell side is filtered and demineralized reactor water with 338.41 seconds decay accumulated for 15.4 seconds at 294 gpm at 0.879 g/cc.
(3) The shell side assumes a DF of 10 across the filter/demineralizer (except for Cs and Rb, which have a DF of 2, and gases, which have a DF of 1).
(4) The shell side includes noble gases generated by particulate parents accumulating on filter/demineralizer resins.
(5) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-19

RWCU SYSTEM REGENERATIVE HEAT EXCHANGER - THIRD-STAGE SHIELDING DESIGN SOURCE TERMS[1][2][3][4]

ISOTOPE[5]	ACTIVITY (Ci) Tube Side	Shell Side	ISOTOPE	ACTIVITY (Ci) Tube Side	Shell Side
Br-83	6.95×10^{-3}	1.37×10^{-3}	La-141	2.17×10^{-4}	2.33×10^{-4}
Br-84	1.23×10^{-2}	2.24×10^{-3}	La-140	1.12×10^{-6}	1.33×10^{-6}
Br-85	6.38×10^{-3}	4.46×10^{-4}	Te-129	1.12×10^{-7}	1.29×10^{-7}
I-131	6.05×10^{-3}	1.22×10^{-3}	T-129	4.90×10^{-1}	6.03×10^{-19}
I-132	5.57×10^{-2}	1.10×10^{-2}	Rh-106	8.79×10^{-7}	2.43×10^{-7}
I-133	4.14×10^{-2}	8.30×10^{-3}	Rh-103m	9.71×10^{-8}	1.12×10^{-7}
I-134	1.10×10^{-1}	2.09×10^{-2}	Tc-99	7.65×10^{-1}	9.01×10^{-13}
I-135	6.04×10^{-2}	1.20×10^{-2}	Nb-97m	6.60×10^{-6}	2.71×10^{-6}
Sr-89	1.44×10^{-3}	2.90×10^{-4}	Nb-97	4.22×10^{-8}	1.18×10^{-7}
Sr-90	1.07×10^{-4}	2.15×10^{-5}	Nb-95m	4.49×10^{-1}	5.28×10^{-11}
Sr-91	3.21×10^{-2}	6.41×10^{-3}	Y-92	1.56×10^{-4}	1.81×10^{-4}
Sr-92	5.10×10^{-2}	1.00×10^{-2}	Y-91	1.02×10^{-7}	1.25×10^{-7}
Zr-95	1.85×10^{-5}	3.74×10^{-6}	Y-91m	2.42×10^{-4}	2.77×10^{-4}
Zr-97	1.49×10^{-5}	2.98×10^{-6}	Y-90	1.93×10^{-8}	2.28×10^{-8}
Nb-95	1.96×10^{-5}	3.93×10^{-6}	Y-89m	1.31×10^{-7}	2.90×10^{-8}
Mo-99	1.02×10^{-2}	2.06×10^{-3}	Xt-135	5.04×10^{-5}	6.26×10^{-2}
Tc-99m	1.30×10^{-1}	2.59×10^{-2}	Cs-135	1.03×10^{-1}	1.61×10^{-14}
Tc-101	6.22×10^{-2}	9.97×10^{-3}	Xt-135m	7.38×10^{-4}	9.08×10^{-1}
Ru-103	8.85×10^{-6}	1.78×10^{-6}	Xe-133m	1.98×10^{-7}	7.45×10^{-4}
Ru-106	1.21×10^{-6}	2.43×10^{-7}	Xe-133	3.45×10^{-6}	1.29×10^{-2}
Te-129m	1.86×10^{-5}	3.74×10^{-6}	Xe-131m	1.38×10^{-9}	2.20×10^{-5}
Te-132	2.28×10^{-2}	4.58×10^{-3}	Kr-85m	1.74×10^{-5}	1.12×10^{-4}
Cs-134	7.45×10^{-5}	7.48×10^{-5}	Kr-85	2.38×10^{-1}	5.19×10^{-12}
Cs-136	5.12×10^{-5}	5.14×10^{-5}	Kr-83m	4.03×10^{-5}	1.79×10^{-2}
Cs-137	1.12×10^{-4}	1.12×10^{-4}	N-13	4.99×10^{-3}	7.29×10^{-3}
Cs-138	8.67×10^{-2}	7.89×10^{-2}	N-16	2.36×10^{-2}	1.43×10^{-13}
Ba-139	7.39×10^{-2}	1.43×10^{-2}	N-17	7.55×10^{-8}	-
Ba-140	4.19×10^{-3}	8.41×10^{-4}	O-19	2.45×10^{-2}	7.24×10^{-5}
Ba-141	7.64×10^{-2}	1.29×10^{-2}	F-18	5.29×10^{-4}	1.03×10^{-3}
Ba-142	7.46×10^{-2}	1.12×10^{-2}	Na-24	2.66×10^{-4}	5.32×10^{-5}
Ce-141	1.81×10^{-5}	3.66×10^{-6}	P-32	2.66×10^{-6}	5.34×10^{-7}
Ce-143	1.63×10^{-5}	3.27×10^{-6}	Cr-51	6.65×10^{-5}	1.34×10^{-5}
Ce-144	1.63×10^{-5}	3.27×10^{-6}	Mn-54	5.32×10^{-6}	1.07×10^{-6}
Pr-143	1.77×10^{-5}	3.55×10^{-6}	Mn-56	6.62×10^{-3}	1.30×10^{-3}

Table 12.2-19 (Cont'd)

ISOTOPE[5]	ACTIVITY (Ci) Tube Side	Shell Side	ISOTOPE	ACTIVITY (Ci) Tube Side	Shell Side
Nd-147	6.52×10^{-6}	1.31×10^{-6}	Co-58	6.65×10^{-4}	1.34×10^{-4}
Np-239	1.11×10^{-1}	2.24×10^{-2}	Co-60	6.65×10^{-5}	1.34×10^{-5}
Ag-110	8.26×10^{-8}	2.08×10^{-8}	Fe-59	1.06×10^{-5}	2.14×10^{-6}
Zn-69	4.51×10^{-8}	5.18×10^{-8}	Ni-65	3.97×10^{-5}	7.82×10^{-6}
Pu-239	5.65×10^{-1}	6.67×10^{-1}	Zn-65	2.66×10^{-7}	5.34×10^{-8}
Pm-147	3.07×10^{-1}	3.63×10^{-1}	Zn-69m	3.99×10^{-6}	7.98×10^{-7}
Pr-144	6.00×10^{-7}	6.49×10^{-7}	Ag-110m	7.98×10^{-6}	1.60×10^{-6}
La-142	5.36×10^{-4}	5.42×10^{-4}	W-187	3.99×10^{-4}	7.99×10^{-5}

(1) Based upon shielding design source terms given in Tables 12.2-2 through 12.2-5.
(2) The tube side is reactor water with 52.0 seconds decay accumulated for 8.15 seconds at 292.4 gpm at 0.885 g/cc; shell side is filtered and demineralized reactor water with 322.01 seconds decay accumulated for 16.4 seconds at 278 gpm at 0.929 g/cc.
(3) The shell side assumes a DF of 10 across the filter/demineralizer (except for Cs and Rb, which have a DF of 2, and gases, which have a DF of 1).
(4) The shell side includes noble gases generated by particulate parents accumulating on filter/demineralizer resins.
(5) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-20

RWCU SYSTEM NONREGENERATIVE HEAT EXCHANGER - FIRST-STAGE SHIELDING DESIGN SOURCE TERMS[1][2]

ISOTOPE[3]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	1.30×10^{-2}	Ba-142	1.34×10^{-1}	Xe-135	1.58×10^{-4}
Br-84	2.28×10^{-2}	Ce-141	3.40×10^{-5}	Cs-135	5.40×10^{-17}
Br-85	1.04×10^{-2}	Ce-143	3.05×10^{-5}	Xe-135m	2.27×10^{-3}
I-131	1.33×10^{-2}	Ce-144	3.05×10^{-5}	Xe-133m	6.17×10^{-7}
I-132	1.04×10^{-1}	Pr-143	3.31×10^{-5}	Xe-135	1.08×10^{-5}
I-133	7.76×10^{-2}	Nd-147	1.22×10^{-5}	Xe-131m	4.32×10^{-9}
I-134	2.05×10^{-1}	Np-239	2.09×10^{-1}	Kr-85m	5.08×10^{-5}
I-135	1.13×10^{-1}	Re-187	3.57×10^{-20}	Kr-85	1.18×10^{-12}
Sr-89	2.70×10^{-3}	Ag-110	1.81×10^{-7}	Kr-83m	1.25×10^{-4}
Sr-90	2.01×10^{-4}	Zn-69	1.40×10^{-7}	N-13	8.95×10^{-3}
Sr-91	6.01×10^{-2}	Po-239	1.76×10^{-11}	N-16	1.26×10^{-3}
Sr-92	9.53×10^{-2}	Pm-147	9.58×10^{-12}	N-17	3.38×10^{-10}
Zr-95	3.49×10^{-5}	Pr-144	1.85×10^{-6}	O-19	1.90×10^{-2}
Zr-97	2.79×10^{-5}	La-142	1.64×10^{-3}	F-18	9.87×10^{-4}
Nb-95	3.66×10^{-5}	La-141	6.67×10^{-4}	Na-24	4.98×10^{-4}
Mo-99	1.92×10^{-2}	La-140	3.51×10^{-6}	P-32	4.98×10^{-6}
Tc-99m	2.44×10^{-1}	Te-129	3.48×10^{-7}	Cr-50	1.25×10^{-4}
Tc-101	1.13×10^{-1}	I-129	1.54×10^{-18}	Mn-54	9.97×10^{-6}
Ru-103	1.66×10^{-5}	Rh-106	2.00×10^{-6}	Mn-56	1.24×10^{-2}
Ru-106	2.27×10^{-6}	Rh-103m	3.02×10^{-7}	Co-58	1.25×10^{-3}
Te-129m	3.49×10^{-5}	Tc-99	2.39×10^{-12}	Co-60	1.25×10^{-4}
Te-132	4.27×10^{-2}	Nb-97m	1.71×10^{-5}	Fe-59	1.99×10^{-5}
Cs-134	1.40×10^{-4}	Nb-97	1.79×10^{-7}	Ni-65	7.42×10^{-5}
Cs-136	9.60×10^{-5}	Nb-95m	1.39×10^{-10}	Zn-65	4.98×10^{-7}
Cs-137	2.09×10^{-4}	Y-92	4.86×10^{-4}	Zn-69m	7.47×10^{-6}
Cs-138	1.60×10^{-1}	Y-91	3.19×10^{-7}	Ag-110m	1.46×10^{-5}
Ba-139	1.38×10^{-1}	Y-91m	7.53×10^{-4}	W-187	7.47×10^{-4}
Ba-140	7.85×10^{-3}	Y-90	6.01×10^{-8}		
Ba-141	1.40×10^{-1}	Y-89m	2.65×10^{-7}		

(1) Based on shielding design source terms given in Tables 12.2-2 through 12.2-5.
(2) Reactor water with 85.75 seconds decay accumulated for 15.29 seconds at 277.5 gpm at 0.931 g/cc.
(3) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-21

RWCU SYSTEM NONREGENERATIVE HEAT EXCHANGER - SECOND-STAGE SHIELDING DESIGN SOURCE TERMS[1][2]

ISOTOPE[3]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	1.32×10^{-2}	Ba-141	1.41×10^{-1}	Y-90	7.13×10^{-8}
Br-84	2.30×10^{-2}	Ba-142	1.35×10^{-1}	Y-89m	2.73×10^{-7}
Br-85	9.93×10^{-3}	Ce-141	3.46×10^{-5}	Xe-135	1.88×10^{-4}
I-131	1.15×10^{-2}	Ce-143	3.11×10^{-5}	Cs-135	7.46×10^{-17}
I-132	1.06×10^{-1}	Ce-144	3.11×10^{-5}	Xe-135m	2.68×10^{-3}
I-133	7.90×10^{-2}	Pr-143	3.37×10^{-5}	Xe-133m	7.32×10^{-7}
I-134	2.08×10^{-1}	Nd-147	1.24×10^{-5}	Xe-133	1.28×10^{-5}
I-135	1.15×10^{-1}	Np-239	2.13×10^{-1}	Xe-131m	5.12×10^{-9}
Sr-89	2.75×10^{-3}	Re-187	4.23×10^{-20}	Kr-86m	5.86×10^{-5}
Sr-90	2.04×10^{-4}	Ag-110	1.89×10^{-7}	Kr-85	1.60×10^{-12}
Sr-91	6.11×10^{-2}	Zn-69	1.66×10^{-7}	Kr-83m	1.49×10^{-4}
Sr-92	9.69×10^{-2}	Pu-239	2.09×10^{-11}	N-13	8.95×10^{-3}
Zr-95	3.55×10^{-5}	Pm-147	1.14×10^{-11}	N-16	2.88×10^{-4}
Zr-97	2.84×10^{-5}	Pr-144	2.18×10^{-6}	N-17	2.66×10^{-11}
Nb-95	3.73×10^{-5}	La-142	1.92×10^{-3}	0-19	1.34×10^{-2}
Mo-99	1.95×10^{-2}	La-141	7.87×10^{-4}	F-18	1.00×10^{-3}
Tc-99m	2.48×10^{-1}	La-140	4.16×10^{-6}	Na-24	5.07×10^{-4}
Tc-101	1.14×10^{-1}	Te-129	4.12×10^{-7}	P-32	5.07×10^{-6}
Ru-103	1.69×10^{-5}	T-129	1.83×10^{-18}	Cr-51	1.27×10^{-4}
Ru-106	2.30×10^{-6}	Rh-106	2.12×10^{-6}	Mn-54	1.01×10^{-5}
Te-129m	3.55×10^{-5}	Rh-103m	3.58×10^{-7}	Mn-56	1.26×10^{-2}
Te-132	4.35×10^{-2}	Tc-99	2.83×10^{-12}	Cu-58	1.27×10^{-3}
Cs-134	1.42×10^{-4}	Nb-97m	1.89×10^{-5}	Cu-60	1.27×10^{-4}
Cs-136	9.77×10^{-5}	Nb-97	2.32×10^{-7}	Fe-59	2.03×10^{-5}
Cs-137	2.13×10^{-4}	Nb-95m	1.65×10^{-10}	Ni-65	7.55×10^{-5}
Cs-138	1.62×10^{-1}	Y-92	5.76×10^{-4}	Zn-65	5.07×10^{-7}
Ba-139	1.40×10^{-1}	Y-91	3.79×10^{-7}	Zn-69m	7.60×10^{-6}
Ba-140	7.99×10^{-3}	Y-91m	8.91×10^{-4}	Ag-110m	1.52×10^{-5}
				W-187	7.60×10^{-4}

(1) Based on shielding design source terms given in Tables 12.2-2 through 12.2-5.
(2) Reactor water with 101.04 seconds decay accumulated for 15.57 seconds at 272.5 gpm at 0.948 g/cc.
(3) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-22

RWCU SYSTEM FILTER/DEMINERALIZER AND BACKWASH RECEIVING TANK
SHIELDING DESIGN SOURCE TERMS[1][2][3][4]

ISOTOPE[5]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	5.92	Cs-138	$1.43 \times 10^{+1}$	Rh-103m	2.92×10^{-1}
Br-84	2.01	Ba-139	$3.21 \times 10^{+1}$	Tc-99	2.08×10^{-5}
Br-85	6.96×10^{-2}	Ba-140	$1.26 \times 10^{+2}$	Nb-97m	7.48×10^{-2}
I-131	$1.65 \times 10^{+2}$	Ba-141	6.85	Nb-97	8.05×10^{-2}
I-132	$4.68 \times 10^{+2}$	Ba-142	3.93	Nb-95m	5.63×10^{-3}
I-133	$2.66 \times 10^{+2}$	Ce-141	1.59	Y-92	$4.42 \times 10^{+1}$
I-134	$2.98 \times 10^{+1}$	Ce-143	1.65×10^{-1}	Y-91	6.95
I-135	$1.28 \times 10^{+2}$	Ce-144	5.82×10^{-1}	Y-91m	$5.83 \times 10^{+1}$
Sr-89	$4.97 \times 10^{+1}$	Pr-143	5.75×10^{-1}	Y-90	2.12
Sr-90	3.85	Nd-147	1.91×10^{-1}	Y-89m	4.97×10^{-3}
Sr-91	$9.86 \times 10^{+1}$	Np-239	$1.73 \times 10^{+3}$	Cs-135	4.76×10^{-7}
Sr-92	$4.37 \times 10^{+1}$	Rd-187	7.21×10^{-13}	Na-24	1.26
Zr-95	6.47×10^{-1}	Ag-110	3.70×10^{-3}	P-32	8.16×10^{-1}
Zr-97	8.03×10^{-2}	Zn-69	1.75×10^{-2}	Cr-51	2.20
Nb-95	7.00×10^{-1}	Pu-239	6.03×10^{-4}	Mn-54	1.90×10^{-1}
Mo-99	$1.77 \times 10^{+2}$	Pm-147	5.03×10^{-4}	Mn-56	5.36
To-99m	$4.01 \times 10^{+2}$	Sm-147	2.14×10^{-17}	Co-58	$2.32 \times 10^{+1}$
Tc-101	4.26	Pr-144	5.80×10^{-1}	Co-60	2.39
Ru-103	3.00×10^{-1}	Nd-144	1.56×10^{-18}	Fe-59	3.64×10^{-1}
Ru-106	4.33×10^{-2}	La-142	4.61	Ni-65	3.22×10^{-2}
Te-129m	6.26×10^{-1}	Te-129	3.97×10^{-1}	Zn-65	9.49×10^{-3}
Te-132	$4.32 \times 10^{+2}$	I-129	2.40×10^{-10}	Zn-69m	1.75×10^{-2}
Cs-134	2.67	Rh-106	4.33×10^{-2}	Ag-110m	2.85×10^{-1}
Cs-136	1.56			W-187	3.01
Cs-137	4.02				

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Filter/demineralizer is assumed to be 154.11 seconds downline from the reactor recirculation loop.
(3) Filter/demineralizer resins are assumed to accumulate all nongaseous isotopes in reactor water for 6.8 days at 135 gpm at 0.957 g/cc.
(4) Backwash volume for the receiving tank is assumed to be 1100 gallons.
(5) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-23

RWCU SYSTEM FILTER/DEMINERALIZER HOLDING PUMPS SHIELDING DESIGN SOURCE TERMS[1][2][3][4]

ISOTOPE[5]	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)
Br-83	4.91×10^{-9}	Ba-140	3.01×10^{-9}	Y-90	7.29×10^{-14}
Br-84	8.12×10^{-9}	Ba-141	4.71×10^{-8}	Y-89m	1.04×10^{-13}
Br-85	1.83×10^{-9}	Ba-142	4.18×10^{-8}	Xe-135	2.22×10^{-7}
I-131	4.35×10^{-9}	Ce-141	1.31×10^{-11}	Xe-135m	3.34×10^{-6}
I-132	3.96×10^{-8}	Ce-143	1.17×10^{-11}	Xe-133m	2.67×10^{-9}
I-133	2.97×10^{-8}	Ce-144	1.17×10^{-11}	Xe-133	4.64×10^{-8}
I-134	7.53×10^{-8}	Pr-143	1.27×10^{-11}	Xe-131m	7.90×10^{-11}
I-135	4.32×10^{-8}	Nd-147	4.69×10^{-12}	Kr-85m	4.01×10^{-10}
Sr-89	1.04×10^{-9}	Np-239	8.03×10^{-8}	Kr-85	1.20×10^{-17}
Sr-90	7.70×10^{-11}	Ag-110	7.46×10^{-14}	Kr-83m	6.43×10^{-8}
Sr-91	2.30×10^{-8}	Zn-69	1.66×10^{-13}	N-13	2.72×10^{-8}
Sr-92	3.61×10^{-8}	Pu-239	2.14×10^{-17}	N-16	1.40×10^{-17}
Zr-95	1.34×10^{-11}	Pm-147	1.16×10^{-17}	O-19	5.96×10^{-10}
Zr-97	1.07×10^{-11}	Pr-144	2.10×10^{-12}	F-18	3.71×10^{-9}
Nb-95	1.41×10^{-11}	La-142	1.77×10^{-9}	Na-24	1.91×10^{-10}
Mo-99	7.36×10^{-9}	La-141	7.56×10^{-10}	P-32	1.91×10^{-12}
Tc-99m	9.30×10^{-8}	La-140	4.25×10^{-12}	Cr-51	4.78×10^{-11}
Tc-101	3.68×10^{-8}	Te-129	4.15×10^{-13}	Mn-54	3.83×10^{-12}
Ru-103	6.36×10^{-12}	Rh-106	8.70×10^{-13}	Mn-56	4.68×10^{-9}
Ru-106	8.71×10^{-13}	Rh-103m	3.59×10^{-13}	Co-58	4.78×10^{-10}
Te-129	1.34×10^{-11}	Tc-99	2.88×10^{-18}	Co-60	4.78×10^{-11}
Te-132	1.64×10^{-8}	Nb-97m	9.61×10^{-12}	Fe-59	7.66×10^{-12}
Cs-134	2.68×10^{-10}	Nb-97	3.66×10^{-13}	Ni-65	2.81×10^{-11}
Cs-136	1.84×10^{-10}	Nb-95m	1.69×10^{-16}	Zn-65	1.91×10^{-13}
Cs-137	4.02×10^{-10}	Y-92	5.82×10^{-10}	Z-69m	2.86×10^{-12}
Cs-138	2.86×10^{-7}	Y-91	3.98×10^{-13}	Ag-110m	5.74×10^{-12}
Ba-139	5.14×10^{-8}	Y-91m	8.90×10^{-10}	W-187	2.86×10^{-10}

(1) Based on shielding design source terms given in Tables 12.2-2 through 12.2-5.
(2) Pumps are assumed to be 295.01 seconds downline from the reactor recirculation loop.
(3) A DF of 10 is assumed across the filter/demineralizer (except for Cs and Rb, which have a DF of 2, and gases, which have a DF of 1).
(4) Includes noble gases generated by particulate parents accumulating on filter/demineralizer resins.
(5) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-24

RHR SYSTEM SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	SPECIFIC ACTIVITY (Ci/g)	ISOTOPE	SPECIFIC ACTIVITY (Ci/g)	ISOTOPE	SPECIFIC ACTIVITY (Ci/g)
Br-83	1.66×10^{-8}	Ba-141	5.78×10^{-11}	Y-90	3.63×10^{-11}
Br-84	5.06×10^{-10}	Ba-142	1.61×10^{-13}	Y-89m	1.08×10^{-12}
I-131	4.49×10^{-8}	Ce-141	2.43×10^{-10}	Xe-135	9.45×10^{-8}
I-132	2.42×10^{-7}	Ce-143	1.13×10^{-10}	Cs-135	5.48×10^{-18}
I-133	2.72×10^{-7}	Ce-144	1.22×10^{-10}	Xe-135m	9.38×10^{-8}
I-134	3.43×10^{-8}	Pr-143	1.33×10^{-10}	Xe-133m	3.48×10^{-10}
I-135	3.00×10^{-7}	Nd-147	4.85×10^{-11}	Xe-133	6.16×10^{-9}
Sr-89	1.08×10^{-8}	Np-237	8.00×10^{-7}	Xe-131m	2.64×10^{-12}
Sr-90	8.05×10^{-10}	Ag-110	7.80×10^{-13}	Kr-85m	3.64×10^{-10}
Sr-91	1.81×10^{-7}	Zn-69	2.46×10^{-11}	Kr-85	3.35×10^{-15}
Sr-92	1.38×10^{-7}	Pu-239	1.06×10^{-14}	Kr-83m	2.10×10^{-8}
Zr-95	1.40×10^{-10}	Pm-147	5.89×10^{-15}	N-13	2.24×10^{-15}
Zr-97	9.51×10^{-11}	Pr-144	1.22×10^{-10}	F-18	8.78×10^{-10}
Nb-95	1.47×10^{-10}	La-142	1.33×10^{-8}	Na-24	1.66×10^{-9}
Mo-99	7.39×10^{-8}	La-141	2.44×10^{-8}	P-32	1.98×10^{-11}
Tc-99m	6.44×10^{-7}	La-140	2.09×10^{-9}	Cr-51	4.98×10^{-10}
Tc-101	3.39×10^{-12}	Te-129	8.15×10^{-11}	Mn-54	4.00×10^{-11}
Ru-103	6.63×10^{-11}	Rh-106	9.10×10^{-12}	Mn-56	1.70×10^{-8}
Ru-106	9.10×10^{-12}	Rh-103m	6.14×10^{-11}	Co-58	4.99×10^{-9}
Te-129m	1.40×10^{-10}	Tc-99	1.21×10^{-15}	Co-60	5.00×10^{-10}
Te-132	1.65×10^{-7}	Nb-97m	8.86×10^{-11}	Fe-59	7.98×10^{-11}
Cs-134	5.60×10^{-10}	Nb-97	9.04×10^{-11}	Ni-65	1.02×10^{-10}
Cs-136	3.82×10^{-10}	Nb-95m	8.49×10^{-14}	Zn-65	2.00×10^{-12}
Cs-137	8.40×10^{-10}	Y-92	1.23×10^{-7}	Zn-69m	2.45×10^{-11}
Cs-138	3.80×10^{-9}	Y-91	3.46×10^{-10}	Ag-110m	6.00×10^{-11}
Ba-139	7.53×10^{-8}	Y-91m	1.11×10^{-7}	W-187	2.67×10^{-9}
Ba-140	3.12×10^{-8}				

[1] Based on shielding design source terms given in Tables 12.2-2 through 12.2-5.
[2] RHR system is assumed to begin operation 4 hours after shutdown.
[3] Assumes no cleanup of reactor coolant after shutdown.
[4] Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-25

RCIC SYSTEM SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)
Br-83	4.16×10^{-11}	Ba-140	1.25×10^{-12}	Xe-137	1.17×10^{-8}
Br-84	7.48×10^{-11}	Ba-141	2.36×10^{-11}	Xe-138	6.93×10^{-9}
Br-85	4.71×10^{-11}	Ba-142	2.36×10^{-11}	Xe-139	2.18×10^{-8}
I-131	3.60×10^{-11}	Ce-141	5.40×10^{-15}	Xe-140	2.33×10^{-8}
I-132	3.33×10^{-10}	Ce-143	4.85×10^{-15}	Xe-141	1.87×10^{-8}
I-133	2.47×10^{-10}	Ce-144	4.85×10^{-15}	Xe-142	5.66×10^{-9}
I-134	6.65×10^{-10}	Pr-143	5.27×10^{-15}	Xe-143	9.35×10^{-10}
I-135	3.60×10^{-10}	Nd-147	1.94×10^{-15}	Xe-144	4.36×10^{-11}
Sr-89	4.30×10^{-13}	Np-239	3.33×10^{-11}	N-13	2.77×10^{-10}
Sr-90	3.19×10^{-14}	Kr-83m	2.65×10^{-10}	N-16	1.98×10^{-6}
Sr-91	9.56×10^{-12}	Kr-85m	4.75×10^{-10}	N-17	7.92×10^{-10}
Sr-92	1.52×10^{-11}	Kr-85	1.56×10^{-12}	O-19	3.17×10^{-8}
Zr-95	5.54×10^{-15}	Kr-87	1.56×10^{-9}	F-18	1.58×10^{-10}
Zr-97	4.44×10^{-15}	Kr-88	1.56×10^{-9}	Na-24	7.92×10^{-14}
Nb-95	5.82×10^{-15}	Kr-89	1.01×10^{-8}	P-32	7.92×10^{-16}
Mo-99	3.05×10^{-12}	Kr-90	2.18×10^{-8}	Cr-51	1.98×10^{-14}
Tc-99m	3.88×10^{-11}	Kr-91	2.57×10^{-8}	Mn-54	1.58×10^{-15}
Tc-101	1.94×10^{-11}	Kr-92	2.57×10^{-8}	Mn-56	1.98×10^{-12}
Ru-103	2.63×10^{-15}	Kr-93	7.68×10^{-9}	Cu-58	1.98×10^{-13}
Ru-106	3.60×10^{-16}	Kr-94	1.79×10^{-9}	Cu-60	1.98×10^{-14}
Te-129m	5.54×10^{-15}	Kr-95	1.63×10^{-10}	Fe-59	3.17×10^{-15}
Te-132	6.79×10^{-12}	Xe-131m	1.17×10^{-12}	Ni-65	1.19×10^{-14}
Cs-134	2.22×10^{-14}	Xe-133m	2.26×10^{-11}	Zn-65	7.92×10^{-17}
Cs-136	1.52×10^{-14}	Xe-133	6.38×10^{-10}	Zn-69m	1.19×10^{-15}
Cs-137	3.33×10^{-14}	Xe-135m	2.02×10^{-9}	Ag-110m	2.38×10^{-15}
Cs-138	2.63×10^{-11}	Xe-135	1.71×10^{-9}	W-187	1.19×10^{-13}
Ba-139	2.22×10^{-11}				

(1) Based on shielding design source terms given in Tables 12.2-1 through 12.2-5.
(2) Inlet steam to RCIC turbine, with conditions of 1120 psig and 575°F.
(3) No decay is assumed in transit from the RPV steam nozzles.
(4) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-26

HPCI SYSTEM SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)
Br-83	4.35×10^{-11}	Ce-141	5.65×10^{-15}	Xe-144	4.55×10^{-11}
Br-84	7.82×10^{-11}	Ce-143	5.07×10^{-15}	N-13	2.90×10^{-10}
Br-85	4.93×10^{-11}	Ce-144	5.07×10^{-15}	N-16	2.07×10^{-6}
I-131	3.77×10^{-11}	Pr-143	5.51×10^{-15}	N-17	8.28×10^{-10}
I-132	3.48×10^{-10}	Nd-147	2.03×10^{-15}	0-19	3.31×10^{-8}
I-133	2.58×10^{-10}	Np-239	3.48×10^{-11}	F-18	1.66×10^{-10}
I-134	6.96×10^{-10}	Kr-83m	2.77×10^{-10}	Na-24	8.28×10^{-14}
I-135	3.77×10^{-10}	Kr-85m	4.97×10^{-10}	P-32	8.28×10^{-16}
Sr-89	4.49×10^{-13}	Kr-85	1.63×10^{-12}	Cr-51	2.07×10^{-14}
SR-90	3.33×10^{-14}	Kr-87	1.63×10^{-9}	Mn-54	1.66×10^{-15}
Sr-91	1.00×10^{-11}	Kr-88	1.63×10^{-9}	Mn-56	2.07×10^{-12}
Sr-92	1.59×10^{-11}	Kr-89	1.06×10^{-8}	Co-58	2.07×10^{-13}
Zr-95	5.80×10^{-15}	Kr-90	2.28×10^{-8}	Co-60	2.07×10^{-14}
Zr-97	4.64×10^{-15}	Kr-91	2.68×10^{-8}	Fe-59	3.31×10^{-15}
Nb-95	6.09×10^{-15}	Kr-92	2.68×10^{-8}	Ni-65	1.24×10^{-14}
Mo-99	3.19×10^{-12}	Kr-93	8.03×10^{-9}	Zn-65	8.28×10^{-17}
Tc-99m	4.06×10^{-11}	Kr-94	1.87×10^{-9}	Zn-69m	1.24×10^{-15}
Tc-101	2.03×10^{-11}	Kr-95	1.71×10^{-10}	Ag-110m	2.48×10^{-15}
Ru-103	2.75×10^{-15}	Xe-131m	1.22×10^{-12}	W-187	1.24×10^{-13}
Ru-106	3.77×10^{-16}	Xe-133m	2.36×10^{-11}		
Te-129m	5.80×10^{-15}	Xe-133	6.67×10^{-10}		
Te-132	7.10×10^{-12}	Xe-135m	2.12×10^{-9}		
Cs-134	2.32×10^{-14}	Xe-135	1.79×10^{-9}		
Cs-136	1.59×10^{-14}	Xe-137	1.22×10^{-8}		
Cs-137	3.48×10^{-14}	Xe-138	7.25×10^{-9}		
Cs-138	2.75×10^{-11}	Xe-139	2.28×10^{-8}		
Ba-139	2.32×10^{-11}	Xe-140	2.44×10^{-8}		
Ba-140	1.30×10^{-12}	Xe-141	1.95×10^{-8}		
Ba-141	2.46×10^{-11}	Xe-142	5.92×10^{-9}		
Ba-142	2.46×10^{-11}	Xe-143	9.77×10^{-10}		

(1) Based on shielding design source terms given in Tables 12.2-1 through 12.2-5.
(2) Inlet steam to HPCI turbine, with conditions of 1120 psig and 560°F.
(3) Decay is assumed in transit from the RPV steam nozzles.
(4) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-27

FPCC SYSTEM SHIELDING DESIGN SOURCE TERMS [1][2]

ISOTOPE[3]	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)
Br-83	1.05×10^{-10}	Tc-99m	1.96×10^{-9}	Ce-144	2.45×10^{-13}
Br-84	1.89×10^{-10}	Tc-101	9.80×10^{-10}	Pr-143	2.66×10^{-13}
Br-85	1.19×10^{-10}	Ru-103	1.33×10^{-13}	Nd-147	9.80×10^{-14}
I-131	9.10×10^{-11}	Ru-106	1.82×10^{-14}	Np-239	1.68×10^{-9}
I-132	8.40×10^{-10}	Te-129m	2.80×10^{-13}	Na-24	4.00×10^{-12}
I-133	6.23×10^{-10}	Te-132	3.43×10^{-10}	P-32	4.00×10^{-14}
I-134	1.68×10^{-9}	Cs-134	1.12×10^{-12}	Cr-51	1.00×10^{-12}
I-135	9.10×10^{-10}	Cs-136	7.70×10^{-13}	Mn-54	8.00×10^{-14}
Sr-89	2.17×10^{-11}	Cs-137	1.68×10^{-12}	Mn-56	1.00×10^{-10}
Sr-90	1.61×10^{-12}	Cs-138	1.33×10^{-9}	Cu-58	1.00×10^{-11}
Sr-91	4.83×10^{-10}	Ba-139	1.12×10^{-9}	Cu-60	1.00×10^{-12}
Sr-92	7.70×10^{-10}	Ba-140	6.30×10^{-11}	Fe-59	1.60×10^{-13}
Zr-95	2.80×10^{-13}	Ba-141	1.19×10^{-9}	Ni-65	6.00×10^{-13}
Zr-97	2.24×10^{-13}	Ba-142	1.19×10^{-9}	Zn-65	4.00×10^{-15}
Nb-95	2.94×10^{-13}	Ce-141	2.73×10^{-13}	Zn-69m	6.00×10^{-14}
Mo-99	1.54×10^{-10}	Ce-143	2.45×10^{-13}	Ag-110m	1.20×10^{-13}
			W-187	6.00×10^{-12}	

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.

(2) Reactor water (less gases) diluted to 0.2%, with no decay (this corresponds to a gross specific activity of 1.6×10^{-2} μCi/cc).

(3) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-28

FPCC SYSTEM FILTER/DEMINERALIZER SHIELDING DESIGN SOURCE TERMS[1][2][4]

ISOTOPE[3]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	2.32×10^{-2}	Cs-138	6.54×10^{-2}	I-129	2.21×10^{-12}
Br-84	9.19×10^{-3}	Ba-139	1.41×10^{-1}	Rh-106	2.75×10^{-4}
Br-85	5.45×10^{-4}	Ba-140	7.42×10^{-1}	Rh-103m	1.81×10^{-3}
I-131	9.31×10^{-1}	Ba-141	3.27×10^{-2}	Tc-99	1.44×10^{-7}
I-132	2.32	Ba-142	2.00×10^{-2}	Nb-97m	3.24×10^{-4}
I-133	1.60	Ce-141	9.90×10^{-3}	Nb-97	3.49×10^{-4}
I-134	1.33×10^{-1}	Ce-143	7.37×10^{-4}	Nb-95m	4.46×10^{-5}
I-135	5.57×10^{-1}	Ce-144	3.69×10^{-3}	Y-92	1.91×10^{-1}
Sr-89	3.10×10^{-1}	Pr-143	3.42×10^{-3}	Y-91	4.48×10^{-2}
Sr-90	2.45×10^{-2}	Nd-147	1.11×10^{-3}	Y-91m	2.52×10^{-1}
Sr-91	4.28×10^{-1}	Np-239	8.22	Y-90	1.62×10^{-2}
Sr-92	1.91×10^{-1}	Re-187	4.97×10^{-15}	Y-89m	3.10×10^{-5}
Zr-95	4.05×10^{-3}	Ag-110	2.34×10^{-5}	Cs-135	3.19×10^{-9}
Zr-97	3.49×10^{-4}	Zn-69	7.59×10^{-5}	Na-24	5.49×10^{-3}
Nb-95	4.44×10^{-3}	Pu-239	4.58×10^{-6}	P-32	4.83×10^{-4}
Mo-99	8.64×10^{-1}	Pm-147	4.43×10^{-6}	Cr-51	1.35×10^{-2}
Tc-99m	1.83	Sm-147	2.80×10^{-19}	Mn-54	1.20×10^{-3}
Tc-101	2.09×10^{-2}	Pr-144	3.68×10^{-3}	Mn-56	2.36×10^{-2}
Ru-103	1.86×10^{-3}	Nd-144	1.46×10^{-20}	Cu-58	1.45×10^{-1}
Ru-106	2.75×10^{-4}	La-142	2.00×10^{-2}	Cu-60	1.52×10^{-2}
Te-129	3.86×10^{-3}	La-141	3.27×10^{-2}	Fe-59	2.26×10^{-3}
Te-132	2.15	La-140	5.91×10^{-1}	Ni-65	1.41×10^{-4}
Cs-134	6.01×10^{-5}	Te-129	2.45×10^{-3}	Zn-69m	7.59×10^{-5}
Cs-136	9.22×10^{-3}			Ag-110	1.80×10^{-3}
Cs-137	2.56×10^{-2}			W-187	1.31×10^{-2}
				Ag-110m	1.80×10^{-3}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Fuel pool water (Table 12.2-27) accumulated for 10 days at 280 gpm.
(3) Isotopes with activities less than 1.0×10^{-20} are not listed.
(4) For shielding design of associated piping, backwash volume to waste sludge tank is 1925 gallons.

Table 12.2-29

FUEL POOL HEAT EXCHANGER SHIELDING DESIGN SOURCE TERMS[1]

ISOTOPE[2]	ACTIVITY (Ci)
Na-24	2.25×10^{-2}
P-32	2.25×10^{-4}
Cr-51	5.63×10^{-3}
Mn-54	4.50×10^{-4}
Mn-56	5.63×10^{-1}
Co-58	5.63×10^{-2}
Co-60	5.63×10^{-3}
Fe-59	9.00×10^{-4}
Ni-65	3.38×10^{-3}
Zn-65	2.25×10^{-5}
Zn-69m	3.38×10^{-4}
Ag-110m	6.75×10^{-4}
W-187	3.38×10^{-2}

(1) Corrosion (noncoolant activation) products in reactor water (given in Table 12.2-5) with no decay were normalized to yield a contact dose rate of 200 mR/hr for one fuel pool heat exchanger.

(2) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-30

REACTOR ENCLOSURE EQUIPMENT COMPARTMENT
EXHAUST AIR FILTERS SHIELDING DESIGN SOURCE TERMS[1][2]

ISOTOPE[3]	ACTIVITY (Ci)
I-131	1.90×10^{-2}
I-133	7.95×10^{-3}
Co-60	9.37×10^{-3}
Co-58	1.64×10^{-4}
Cr-51	3.29×10^{-5}
Mn-54	2.03×10^{-3}
Fe-59	7.18×10^{-5}
Zn-65	1.25×10^{-3}
Zr-95	3.55×10^{-4}
Sr-89	6.50×10^{-5}
Sr-90	1.73×10^{-5}
Sb-124	1.64×10^{-4}
Cs-134	1.19×10^{-2}
Cs-136	5.68×10^{-5}
Cs-137	1.90×10^{-2}
Ba-140	7.08×10^{-5}
Ce-141	4.49×10^{-5}
La-140	7.08×10^{-5}
Y-90	1.71×10^{-5}
Y-89m	6.50×10^{-9}
Nb-95	3.46×10^{-4}
Nb-95m	7.08×10^{-6}

(1) Based on NUREG-0016, Revision 0, table 1-1 (Reference 12.2-1) release rates, with fission products adjusted to 0.35 Ci/cc offgas release rate at 30 minutes decay.

(2) Assumes a one year accumulation of all these isotopes at 40,000 cfm.

(3) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-31

CONTROL ROD DRIVE MECHANISM SHIELDING DESIGN SOURCE TERMS[1]

CONTAMINATED CRD MECHANISM FILTER[2]		CONTAMINATED CRD MECHANISM BODY[3]		DECONTAMINATED CRD MECHANISM BODY[4]	
Isotope[5]	Activity (Ci)	Isotope[5]	Activity (Ci)	Isotope[5]	Activity (Ci)
Na-24	2.32×10^{-2}	Na-24	4.35×10^{-2}	Na-24	2.18×10^{-3}
P-32	2.32×10^{-4}	P-32	4.35×10^{-4}	Pa-32	2.18×10^{-5}
Cr-51	5.79×10^{-3}	Cr-51	1.09×10^{-2}	Cr-51	5.44×10^{-4}
Mn-54	4.63×10^{-4}	Mn-54	8.70×10^{-4}	Mn-54	4.35×10^{-5}
Mn-56	5.79×10^{-1}	Mn-56	1.09	Mn-56	5.44×10^{-2}
Co-58	5.79×10^{-2}	Co-58	1.09×10^{-1}	Co-58	5.44×10^{-3}
Co-60	5.79×10^{-3}	Co-60	1.09×10^{-2}	Co-60	5.44×10^{-4}
Fe-59	9.26×10^{-4}	Fe-59	1.74×10^{-3}	Fe-59	8.70×10^{-5}
Ni-65	3.47×10^{-3}	Ni-65	6.53×10^{-3}	Ni-65	3.26×10^{-4}
Zn-65	2.32×10^{-5}	Zn-65	4.35×10^{-5}	Zn-65	2.18×10^{-6}
Zn-69m	3.47×10^{-4}	Zn-69m	6.53×10^{-4}	Zn-69m	3.26×10^{-5}
Ag-110m	6.95×10^{-4}	Ag-110m	1.31×10^{-3}	Ag-110m	6.53×10^{-5}
W-187	3.47×10^{-2}	W-187	6.53×10^{-2}	W-187	3.26×10^{-3}

(1) Based on shielding design source terms given in Tables 12.2-1 through 12.2-5.
(2) Specific activity of corrosion products in the reactor coolant concentrated in the filter to yield a contact dose rate of 50 R/hr.
(3) Specific activity of corrosion products in the reactor coolant concentrated in the body to yield a contact dose rate of 10 R/hr.
(4) Specific activity of corrosion products in the reactor coolant concentrated in the body to yield a contact dose rate of 0.5 R/hr.
(5) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-32

TURBINE OPERATING DECK SHIELDING DESIGN SOURCE TERMS[1][2]

SOURCE	DECAY TIME IN TRANSIT (seconds)	AVERAGE DENSITY (g/cc)	AVERAGE N-16 SPECIFIC ACTIVITY (μCi/cc)
Main steam piping to high pressure turbine	3.27	3.78×10^{-2}	1.38
High pressure turbine exhaust piping	3.63	7.44×10^{-3}	2.61×10^{-1}
Cross-around piping to combined intercept valves	6.43	6.41×10^{-3}	1.71×10^{-1}

(1) Based on shielding design source terms given in Tables 12.2-1 through 12.2-5.
(2) Assumes a total rated flow of main steam from the RPV of 14,140,500 lb/hr.

Table 12.2-33

MOISTURE SEPARATOR SHIELDING DESIGN SOURCE TERMS[1]

VAPOR REGION IN MOISTURE SEPARATOR BODY [2]

Isotope[4]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Br-83	6.42E-04	La-143	1.35E-06	N-17	5.60E-03
Br-84	1.15E-03	Cs-142	2.10E-02	O-19	4.38E-01
Br-85	7.16E-04	La-142	2.41E-07	F-18	2.44E-03
I-131	5.57E-04	Cs-141	1.59E-02	Na-24	1.23E-06
I-132	5.14E-03	La-141	8.84E-08	P-32	1.23E-08
I-133	3.81E-03	Cs-140	1.57E-02	Cr-51	3.06E-07
I-134	1.03E-02	La-140	4.35E-10	Mn-54	2.44E-08
I-135	5.57E-03	Cs-139	1.86E-03	Mn-56	3.06E-05
Sr-89	6.64E-06	Cs-135	9.14E-16	Co-58	3.06E-06
Sr-90	4.93E-07	Rb-95	3.91E-04	Co-60	3.06E-07
Sr-91	1.49E-04	Sr-95	2.90E-05	Fe-59	4.90E-08
Sr-92	2.60E-04	Y-95	6.96E-08	Ni-65	1.84E-07
Zr-95	8.57E-08	Nb-95m	1.76E-14	Zn-65	1.23E-09
Zr-97	6.85E-08	Rb-94	5.83E-03	Zn-69m	1.84E-06
Nb-95	8.99E-08	Sr-94	2.17E-14	Ag-110m	3.67E-08
Mo-99	4.71E-05	Y-94	2.62E-07	W-187	1.84E-06
Tc-99	5.99E-04	Rb-93	2.38E-02	Kr-83m	4.08E-03
Tc-101	2.99E-04	Sr-93	1.15E-04	Kr-85m	7.34E-03
Ru-103	4.07E-08	Y-93	4.13E-09	Kr-85	2.40E-05
Ru-106	5.57E-09	Rb-92	1.04E-01	Kr-87	2.40E-02
Te-129m	8.57E-08	Y-92	6.31E-08	Kr-88	2.40E-02
Te-132	1.05E-04	Rb-91	1.49E-02	Kr-89	1.53E-01
Cs-134	3.43E-07	Y-91	3.94E-11	Kr-90	3.05E-01
Cs-136	2.36E-07	Y-91m	9.47E-08	Kr-91	2.85E-01
Cs-137	5.15E-07	Rb-90	5.94E-03	Kr-92	1.35E-01
Cs-138	5.88E-04	Y-90	7.48E-12	Kr-93	2.37E-02
Ba-139	3.43E-04	Rb-89	5.47E-04	Kr-94	2.80E-03
Ba-140	1.93E-05	Y-89m	1.22E-10	Kr-95	1.05E-04
Ba-141	3.95E-04	Rb-88	7.35E-05	Xe-131m	1.80E-05
Ba-142	4.65E-04	Rb-87	5.20E-20	Xe-133m	3.49E-04
Ce-141	8.35E-08	Ag-110	5.98E-11	Xe-133	9.85E-03
Ce-143	7.49E-08	Zn-69	1.76E-11	Xe-135m	3.12E-02
Ce-144	7.49E-08	Pu-239	2.18e-15	Xe-135	2.64E-02
Pr-143	8.13E-08	Pm-147	1.19e-15	Xe-137	1.78E-01

Table 12.2-33 (Cont'd)

VAPOR REGION IN MOISTURE SEPARATOR BODY[2]

Activity Isotope[4]	(Ci	Activity Isotope	(Ci)	Activity Isotope	(Ci)
Nd-147	3.00E-08	Te-129	4.35E-11	Xe-138	1.07E-01
Np-239	5.14E-04	Rh-106	5.74E-10	Xe-139	3.12E-01
Cs-144	4.92E-04	Rh-103m	3.78E-11	Xe-140	2.94E-01
Ba-144	9.75E-05	Tc-99	2.96E-16	Xe-141	4.34E-02
La-144	3.36E-06	Nb-97m	3.38E-09	Xe-142	1.03E-02
Pr-144	2.37E-10	Nb-97	4.95E-12	Xe-143	6.02E-04
Cs-143	2.28E-03	N-13	4.26E-03	Xe-144	4.68E-04
Ba-143	6.79E-04	N-16	1.94E+01		0.00E+00

Table 12.2-33 (Cont'd)

LIQUID REGION IN MOISTURE SEPARATOR DRAIN TANK[3]

Isotope[4]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Br-83	4.37E-03	Cs-137	3.50E-06	Nb-97m	5.15E-08
Br-84	7.83E-03	Cs-138	2.76E-03	Nb-97	1.12E-10
Br-85	4.75E-03	Ba-139	2.32E-03	Nb-95m	2.76E-13
I-131	3.79E-03	Ba-140	1.31E-04	Y-92	9.65E-07
I-132	3.50E-02	Ba-141	2.45E-03	Y-91	6.22E-10
I-133	2.60E-02	Ba-142	2.44E-03	Y-91m	1.50E-06
I-134	6.97E-02	Ce-141	5.68E-07	Y-90	1.18E-10
I-135	3.79E-02	Ce-143	5.09E-07	Y-89m	1.66E-09
Sr-89	4.52E-05	Ce-144	5.09E-07	Cs-135	2.88E-19
Sr-90	3.34E-06	Pr-143	5.54E-07	N-16	2.03E+00
Sr-91	1.00E-03	Nd-147	2.04E-07	Na-24	8.32E-06
Sr-92	1.60E-03	Np-239	3.50E-03	P-32	8.32E-08
Zr-95	5.82E-07	Ag-110	8.57E-10	Cr-51	2.09E-06
Zr-97	4.66E-07	Zn-69	2.79E-10	Mn-54	1.66E-07
Nb-95	6.11E-07	Pu-239	3.49E-14	Mn-56	2.07E-04
Mo-99	3.20E-04	Pm-147	1.90E-14	Co-58	2.09E-05
Tc-99	4.07E-03	Pr-144	3.76E-09	Co-60	2.09E-06
Tc-101	2.02E-03	La-142	3.39E-06	Fe-59	3.33E-07
Ru-103	2.77E-07	La-141	1.36E-06	Ni-65	1.25E-07
Ru-106	3.79E-08	La-140	6.94E-09	Zn-65	8.32E-09
Te-129m	5.82E-07	Te-129	6.92E-10	Zn-69m	1.25E-07
Te-132	7.14E-04	Rh-106	6.39E-09	Ag-110m	2.50E-07
Cs-134	2.33e-06	Rh-103m	6.02E-10	W-187	1.25E-05
Cs-136	1.61e-06	Tc-99	4.72E-15		

(1) Based on shielding design source terms given in Tables 12.2-1 through 12.2-5.
(2) Main steam with 3.63 seconds decay accumulated for 2.185 seconds at rated flow per moisture separator.
(3) All particulates and 20% of N-16 that enter the moisture separator accumulated for 14.85 seconds at rated flow per moisture separator drain tank.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-34

FEEDWATER HEATERS AND DRAIN COOLER SHIELDING DESIGN SOURCE TERMS[1][2]

Equipment	N-16 ACTIVITY IN SHELL SIDE OF FEEDWATER HEATERS		
	Vapor Region (Ci)	Liquid Region [3] (Ci)	Total (Ci)
Feedwater Heater No. 106	5.54	3.71	9.25
Feedwater Heater No. 105	3.84	2.88	6.72
Feedwater Heater No. 104	1.41	5.31	6.72
Feedwater Heater No. 103	1.61	3.04	4.65
Feedwater Heater No. 102	5.89×10^{-1}	2.23	2.82
Feedwater Heater No. 101	3.45×10^{-1}	2.22	2.57
Feedwater Heater Drain cooler	--	5.41×10^{-1}	5.41×10^{-1}

(1) Based on shielding source terms given in Table 12.2-4.
(2) All data are based on "Valve Wide Open" flow conditions.
(3) Assumes 20% of N-16 in steam that condenses enters the liquid region.

Table 12.2-35

STEAM SEAL EVAPORATOR SHIELDING DESIGN SOURCE TERMS[1][2]

Isotope[3]	ACTIVITY (Ci)	Isotope	ACTIVITY (Ci)	Isotope	ACTIVITY (Ci)
Br-83	2.69×10^{-5}	Ba-143	3.23×10^{-5}	N-16	4.80×10^{-1}
Br-84	4.82×10^{-5}	La-143	2.07×10^{-7}	N-17	9.77×10^{-5}
Br-85	2.93×10^{-5}	Cs-142	2.83×10^{-4}	O-19	1.60×10^{-2}
I-131	2.33×10^{-5}	La-142	2.51×10^{-8}	F-18	1.02×10^{-4}
I-132	2.15×10^{-4}	Cs-141	6.64×10^{-4}	Na-24	5.12×10^{-8}
I-133	1.60×10^{-4}	La-141	8.71×10^{-9}	P-32	5.12×10^{-10}
I-134	4.29×10^{-4}	Cs-140	1.23×10^{-3}	Cr-51	1.28×10^{-8}
I-135	2.33×10^{-4}	La-140	4.00×10^{-11}	Mn-54	1.02×10^{-9}
Sr-89	2.78×10^{-7}	Cs-139	1.61×10^{-4}	Mn-56	1.28×10^{-6}
Sr-90	2.06×10^{-8}	Cs-135	8.38×10^{-17}	Co-58	1.28×10^{-7}
Sr-91	6.32×10^{-6}	Rb-95	4.63×10^{-6}	Co-60	1.28×10^{-8}
Sr-92	1.25×10^{-5}	Sr-95	1.78×10^{-6}	Fe-59	2.05×10^{-9}
Zr-95	3.59×10^{-9}	Y-95	1.25×10^{-8}	Ni-65	7.68×10^{-9}
Zr-97	2.87×10^{-9}	Nb-95m	1.62×10^{-15}	Zn-65	5.12×10^{-11}
Nb-95	3.77×10^{-9}	Rb-94	9.33×10^{-5}	Zn-69m	7.69×10^{-10}
Mo-99	1.97×10^{-6}	Sr-94	1.57×10^{-5}	Ag-110m	1.54×10^{-9}
Tc-99m	2.51×10^{-5}	Y-94	5.38×10^{-8}	W-187	7.69×10^{-8}
Tc-101	1.24×10^{-5}	Rb-93	6.96×10^{-4}	Kr-83m	1.71×10^{-4}
Ru-103	1.70×10^{-9}	Sr-93	1.13×10^{-5}	Kr-85m	3.07×10^{-4}
Ru-106	2.33×10^{-10}	Y-93	1.09×10^{-9}	Kr-85	1.01×10^{-6}
Te-129m	3.59×10^{-9}	Rb-92	3.59×10^{-3}	Kr-87	1.01×10^{-3}
Te-132	4.39×10^{-6}	Y-92	6.28×10^{-9}	Kr-88	1.01×10^{-3}
Cs-134	1.43×10^{-8}	Rb-91	1.09×10^{-3}	Kr-89	6.29×10^{-3}
Cs-136	9.86×10^{-9}	Y-91	3.61×10^{-12}	Kr-90	1.14×10^{-2}
Cs-137	2.16×10^{-8}	Y-91m	8.72×10^{-9}	Kr-91	8.09×10^{-3}
Cs-138	3.35×10^{-5}	Rb-90	5.06×10^{-4}	Kr-92	1.72×10^{-3}
Ba-139	1.45×10^{-5}	Y-90	6.84×10^{-13}	Kr-93	1.81×10^{-4}
Ba-140	8.12×10^{-7}	Rb-89	4.95×10^{-5}	Kr-94	1.17×10^{-5}
Ba-141	1.90×10^{-5}	Y-89m	9.91×10^{-12}	Kr-95	2.10×10^{-7}
Ba-142	2.23×10^{-5}	Rb-88	6.73×10^{-6}	Xe-131m	7.56×10^{-7}
Ce-141	3.50×10^{-9}	Ag-110	5.06×10^{-12}	Xe-133m	1.46×10^{-5}
Ce-143	3.14×10^{-9}	Zn-69	1.61×10^{-12}	Xe-133	4.13×10^{-4}
Ce-144	3.14×10^{-9}	Pu-239	2.00×10^{-16}	Xe-135m	1.30×10^{-3}
Pr-143	3.41×10^{-9}	Pm-147	1.09×10^{-16}	Xe-135	1.11×10^{-3}

Table 12.2-35 (Cont'd)

Isotope[3]	ACTIVITY (Ci)	Isotope	ACTIVITY (Ci)	Isotope	ACTIVITY (Ci)
Nd-147	1.26×10^{-9}	Te-129	3.99×10^{-12}	Xe-137	7.33×10^{-3}
Np-239	2.15×10^{-5}	Rh-106	4.93×10^{-11}	Xe-138	4.45×10^{-3}
Cs-144	1.46×10^{-5}	Rh-103m	3.46×10^{-12}	Xe-139	1.19×10^{-2}
Ba-144	7.64×10^{-6}	Tc-99	2.72×10^{-17}	Xe-140	9.69×10^{-3}
La-144	7.04×10^{-7}	Nb-97m	3.00×10^{-10}	Xe-141	2.57×10^{-4}
Pr-144	2.16×10^{-11}	Nb-97	5.97×10^{-13}	Xe-142	4.88×10^{-5}
Cs-143	2.08×10^{-5}	N-13	1.77×10^{-4}	Xe-143	1.20×10^{-6}
				Xe-144	1.29×10^{-5}

(1) Based upon shielding design source terms given in Tables 12.2-1 through 12.2-5.
(2) Main steam with 6.59 seconds decay accumulated for 7.49 seconds at 3929 gpm at 0.0138 g/cc.
(3) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-36

REACTOR FEED PUMP TURBINE SHIELDING DESIGN SOURCE TERMS[1][2]

RFPT INLET STEAM[3]

Isotope[5]	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)
N-13	4.03×10^{-11}	Nd-147	2.84×10^{-16}	Xe-144	4.02×10^{-12}
N-16	1.62×10^{-7}	Np-239	4.87×10^{-12}	Cs-144	4.42×10^{-12}
N-17	4.27×10^{-11}	Na-24	1.16×10^{-14}	Ba-144	1.19×10^{-12}
O-19	4.02×10^{-9}	P-32	1.16×10^{-16}	La-144	5.32×10^{-14}
F-18	2.32×10^{-11}	Cr-51	2.90×10^{-15}	Pr-144	2.85×10^{-18}
Br-83	6.09×10^{-12}	Mn-54	2.32×10^{-16}	Cs-143	1.50×10^{-11}
Br-84	1.09×10^{-11}	Mn-56	2.90×10^{-13}	Ba-143	7.33×10^{-12}
Br-85	6.75×10^{-12}	Co-58	2.90×10^{-14}	La-143	2.00×10^{-14}
I-131	5.28×10^{-12}	Co-60	2.90×10^{-15}	Cs-142	1.58×10^{-10}
I-132	4.87×10^{-11}	Fe-59	4.64×10^{-16}	La-142	3.01×10^{-15}
I-133	3.62×10^{-11}	Ni-65	1.74×10^{-15}	Cs-141	1.57×10^{-10}
I-134	9.74×10^{-11}	Zn-65	1.16×10^{-17}	La-141	1.08×10^{-15}
I-135	5.28×10^{-11}	Zn-69m	1.74×10^{-16}	Cs-140	1.84×10^{-10}
Sr-89	6.30×10^{-14}	Ag-110m	3.48×10^{-16}	La-140	5.25×10^{-18}
Sr-90	4.67×10^{-15}	W-187	1.74×10^{-14}	Cs-139	2.21×10^{-11}
Sr-91	1.41×10^{-12}	Kr-83m	3.87×10^{-11}	Rb-95	2.77×10^{-12}
Sr-92	2.55×10^{-12}	Kr-85m	6.96×10^{-11}	Sr-95	3.31×10^{-13}
Zr-95	8.12×10^{-16}	Kr-85	2.28×10^{-13}	Y-95	1.06×10^{-15}
Zr-97	6.50×10^{-16}	Kr-87	2.28×10^{-10}	Rb-94	4.58×10^{-11}
Nb-95	8.53×10^{-16}	Kr-88	2.28×10^{-10}	Sr-94	2.60×10^{-12}
Mo-99	4.47×10^{-13}	Kr-89	1.45×10^{-9}	Y-94	4.13×10^{-15}
To-99m	5.69×10^{-12}	Kr-90	2.81×10^{-9}	Rb-93	2.19×10^{-10}
To-101	2.83×10^{-12}	Kr-91	2.46×10^{-9}	Sr-93	1.48×10^{-12}
Ru-103	3.86×10^{-16}	Kr-92	9.40×10^{-10}	Y-93	6.87×10^{-17}
Ru-106	5.28×10^{-17}	Kr-93	1.41×10^{-10}	Rb-92	1.01×10^{-9}
Te-129m	8.12×10^{-16}	Kr-94	1.35×10^{-11}	Y-92	7.72×10^{-16}
Te-132	9.95×10^{-13}	Kr-95	3.74×10^{-13}	Rb-91	1.72×10^{-10}
Cs-134	3.25×10^{-15}	Xe-131m	1.71×10^{-13}	Y-91	4.72×10^{-19}
Cs-136	2.23×10^{-15}	Xe-133m	3.31×10^{-12}	Y-91m	1.14×10^{-15}
Cs-137	4.88×10^{-15}	Xe-133	9.34×10^{-11}	Rb-90	7.06×10^{-11}
Cs-138	6.03×10^{-12}	Xe-135m	2.95×10^{-10}	Y-90	8.99×10^{-20}
Ba-139	3.26×10^{-12}	Xe-135	2.51×10^{-10}	Rb-89	6.57×10^{-12}
Ba-140	1.83×10^{-13}	Xe-137	1.68×10^{-9}	Y-89m	1.43×10^{-18}
Ba-141	3.88×10^{-12}	Xe-138	1.01×10^{-9}	Rb-88	8.86×10^{-13}
Ba-142	4.65×10^{-12}	Xe-139	2.90×10^{-9}	Ag-110	7.09×10^{-19}

Table 12.2-36 (Cont'd)

RFPT INLET STEAM[3]

Isotope[5]	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)
Ce-141	7.92×10^{-16}	Xe-140	2.64×10^{-9}	Zn-69	2.12×10^{-19}
Ce-143	7.11×10^{-16}	Xe-141	2.37×10^{-10}	Te-129	5.24×10^{-19}
Ce-144	7.11×10^{-16}	Xe-142	5.19×10^{-11}	Rh-106	6.83×10^{-18}
Pr-143	7.72×10^{-16}	Xe-143	2.14×10^{-12}	Rh-103m	4.56×10^{-19}
				Nb-97m	4.05×10^{-17}
				Nb-97	6.35×10^{-20}

Table 12.2-36 (Cont'd)

RFPT EXHAUST STEAM[4]

Isotope[5]	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)
N-13	9.14×10^{-13}	Pr-143	1.75×10^{-17}	Xe-142	1.18×10^{-12}
N-16	3.67×10^{-09}	Nd-147	6.44×10^{-18}	Xe-143	4.85×10^{-14}
N-17	9.68×10^{-13}	Np-239	1.10×10^{-13}	Xe-144	9.12×10^{-14}
O-19	9.12×10^{-11}	Na-24	2.63×10^{-16}	Cs-144	1.00×10^{-13}
F-18	5.26×10^{-13}	P-32	2.63×10^{-18}	Ba-144	2.70×10^{-14}
Br-83	1.38×10^{-13}	Cr-51	6.58×10^{-17}	La-144	1.21×10^{-15}
Br-84	2.48×10^{-13}	Mn-54	5.26×10^{-18}	Pr-144	6.45×10^{-20}
Br-85	1.53×10^{-13}	Mn-56	6.57×10^{-15}	Cs-143	3.40×10^{-13}
I-131	1.20×10^{-13}	Co-58	6.58×10^{-16}	Ba-143	1.66×10^{-13}
I-132	1.10×10^{-12}	Co-60	6.58×10^{-17}	La-143	4.53×10^{-16}
I-133	8.19×10^{-13}	Fe-59	1.05×10^{-17}	Cs-142	3.58×10^{-12}
I-134	2.21×10^{-12}	Ni-65	3.94×10^{-17}	La-142	6.82×10^{-17}
I-135	1.20×10^{-12}	Zn-65	2.63×10^{-19}	Cs-141	3.56×10^{-12}
Sr-89	1.43×10^{-15}	Zn-69m	3.95×10^{-18}	La-141	2.45×10^{-17}
Sr-90	1.06×10^{-16}	Ag-110m	7.89×10^{-18}	Cs-140	4.16×10^{-12}
Sr-91	3.20×10^{-14}	W-187	3.95×10^{-16}	La-140	1.19×10^{-19}
Sr-92	5.78×10^{-14}	Kr-83m	8.78×10^{-13}	Cs-139	5.01×10^{-13}
Zr-95	1.84×10^{-17}	Kr-85m	1.58×10^{-12}	Rb-95	6.28×10^{-14}
Zr-97	1.47×10^{-17}	Kr-85	5.17×10^{-15}	Sr-95	7.51×10^{-15}
Nb-95	1.93×10^{-17}	Kr-87	5.16×10^{-12}	Y-95	2.41×10^{-17}
Mo-99	1.01×10^{-14}	Kr-88	5.17×10^{-12}	Rb-94	1.04×10^{-12}
To-99m	1.29×10^{-13}	Kr-89	3.28×10^{-11}	Sr-94	5.89×10^{-14}
To-101	6.41×10^{-14}	Kr-90	6.38×10^{-11}	Y-94	9.36×10^{-17}
Ru-103	8.75×10^{-18}	Kr-91	5.58×10^{-11}	Rb-93	4.97×10^{-12}
Ru-106	1.20×10^{-18}	Kr-92	2.13×10^{-11}	Sr-93	3.36×10^{-14}
Te-129m	1.84×10^{-17}	Kr-93	3.19×10^{-12}	Y-93	1.56×10^{-18}
Te-132	2.26×10^{-14}	Kr-94	3.05×10^{-13}	Rb-92	2.29×10^{-11}
Cs-134	7.37×10^{-17}	Kr-95	8.47×10^{-15}	Y-92	1.75×10^{-17}
Cs-136	5.06×10^{-17}	Xe-131m	3.88×10^{-15}	Rb-91	3.89×10^{-12}
Cs-137	1.11×10^{-26}	Xe-133m	7.50×10^{-14}	Y-91	1.07×10^{-20}
Cs-138	1.37×10^{-13}	Xe-133	2.12×10^{-12}	Y-91m	2.59×10^{-17}

Table 12.2-36 (Cont'd)

RFPT EXHAUST STEAM[4]

Isotope[5]	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)
Ba-139	7.38×10^{-14}	Xe-135m	6.69×10^{-12}	Rb-90	1.60×10^{-12}
Ba-140	4.15×10^{-15}	Xe-135	5.68×10^{-12}	Rb-89	1.49×10^{-13}
Ba-141	8.78×10^{-14}	XE-137	3.81×10^{-11}	Y-89m	3.25×10^{-20}
Ba-142	1.05×10^{-13}	Xe-138	2.29×10^{-11}	Rb-88	2.01×10^{-14}
Ce-141	1.80×10^{-17}	Xe-139	6.57×10^{-11}	Ag-110	1.61×10^{-20}
Ce-143	1.61×10^{-17}	Xe-140	5.97×10^{-11}	Te-129	1.19×10^{-20}
Ce-144	1.61×10^{-17}	Xe-141	5.37×10^{-12}	Rh-106	1.55×10^{-19}
				Rh-103m	1.03×10^{-20}
				Nb-97m	9.17×10^{-19}

(1) Based on shielding design source terms given in Tables 12.2-1 through 12.2-5.
(2) Based on cross-around steam 6.0 seconds from RPV nozzles.
(3) Cross-around steam conditions of 104.8 psia and 1196.3 Btu/lb.
(4) Cross-around steam with RFPT exhaust conditions of 5.17" Hg (abs) and 994.0 Btu/lb.
(5) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-37

MAIN CONDENSER HOTWELL SHIELDING DESIGN SOURCE TERMS[1]

CARRYOVER COMPONENT[2]

Isotope[6]	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)
Br-83	1.05×10^{-9}	Tc-99m	9.80×10^{-10}	Ce-144	1.23×10^{-13}
Br-84	1.89×10^{-9}	Tc-101	4.90×10^{-10}	Pr-143	1.33×10^{-13}
Br-85	1.19×10^{-9}	Ru-103	6.65×10^{-14}	Nd-147	4.90×10^{-14}
I-131	9.10×10^{-10}	Ru-106	9.10×10^{-15}	Np-239	8.40×10^{-10}
I-132	8.40×10^{-9}	Te-129m	1.40×10^{-13}	Na-24	2.00×10^{-12}
I-133	6.23×10^{-9}	Te-132	1.72×10^{-10}	P-32	2.00×10^{-14}
I-134	1.68×10^{-8}	Cs-134	5.60×10^{-13}	Cr-51	5.00×10^{-13}
I-135	9.10×10^{-9}	Cs-136	3.85×10^{-13}	Mn-54	4.00×10^{-14}
Sr-89	1.09×10^{-11}	Cs-137	8.40×10^{-13}	Mn-56	5.00×10^{-11}
Sr-90	8.05×10^{-13}	Cs-138	6.65×10^{-10}	Co-58	5.00×10^{-12}
Sr-91	2.42×10^{-10}	Ba-139	5.60×10^{-10}	Co-60	5.00×10^{-13}
Sr-92	3.85×10^{-10}	Ba-140	3.15×10^{-11}	Fe-59	8.00×10^{-14}
Zr-95	1.40×10^{-13}	Ba-141	5.95×10^{-10}	Ni-65	3.00×10^{-13}
Zr-97	1.12×10^{-13}	Ba-142	5.95×10^{-10}	Zn-65	2.00×10^{-15}
Nb-95	1.47×10^{-13}	Ce-141	1.37×10^{-13}	Zn-69m	3.00×10^{-14}
Mo-99	7.70×10^{-11}	Ce-143	1.23×10^{-13}	Ag-110m	6.00×10^{-14}
				W-187	3.00×10^{-12}

NITROGEN COMPONENT[3][4]

Isotope[6]	Specific Activity (Ci/cc)
N-16	8.59×10^{-7}

Table 12.2-37 (Cont'd)

FALLOUT COMPONENT[5]

Isotope[6]	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)
Cs-144	7.16×10^{-10}	Cs-140	3.59×10^{-8}	Rb-93	3.58×10^{-8}
Ba-144	2.35×10^{-10}	Ba-140	8.39×10^{-14}	Sr-93	3.06×10^{-10}
La-144	1.27×10^{-11}	La-140	9.67×10^{-19}	Y-93	1.71×10^{-14}
Ce-144	7.76×10^{-19}	Cs-139	4.41×10^{-9}	Rb-92	1.71×10^{-7}
Cs-143	1.90×10^{-9}	Ba-139	2.19×10^{-12}	Sr-92	6.70×10^{-11}
Ba-143	1.32×10^{-9}	Cs-138	4.38×10^{-10}	Y-92	1.04×10^{-14}
La-143	4.51×10^{-12}	Cs-137	1.50×10^{-15}	Rb-91	3.32×10^{-8}
Ce-143	4.51×10^{-12}	Rb-95	3.73×10^{-10}	Sr-91	2.54×10^{-12}
Cs-142	2.20×10^{-8}	Sr-95	6.24×10^{-11}	Y-91	3.47×10^{-19}
Ba-142	2.35×10^{-10}	Y-95	2.46×10^{-13}	Y-91m	8.39×10^{-16}
La-142	1.02×10^{-13}	Zr-95	6.89×10^{-20}	Rb-90	1.40×10^{-8}
Cs-141	2.73×10^{-8}	Rb-94	6.60×10^{-9}	Sr-90	4.00×10^{-17}
Ba-141	9.26×10^{-11}	Sr-94	5.06×10^{-10}	Rb-89	1.32×10^{-9}
La-141	1.31×10^{-14}	Y-94	9.83×10^{-13}	Sr-89	7.06×10^{-16}
				Rb-88	1.78×10^{-10}

(1) Based on shielding design source terms given in Tables 12.2-1 through 12.2-5.
(2) Reactor water activities with a water/steam carryover factor of 0.02 by weight for halogens and 0.001 for others (coolant activation gases and noble gas fission products are excluded).
(3) Assumes a 5.815 second transit time from the RPV steam nozzles to the main condensers.
(4) Assumes 20% of the N-16 in the steam that condenses enters and accumulates in the hotwell for 2 minutes at the rated flow of 2,659,391 lb/hr.
(5) Noble gas daughters created during the 7 second transit time from the RPV steam nozzles to the condensers noncondensables exhaust.
(6) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-38

CONDENSATE SYSTEM SHIELDING DESIGN SOURCE TERMS[1][2]

CARRYOVER_COMPONENT[3]

Isotope[5]	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)
Br-83	1.04×10^{-9}	Cs-136	3.85×10^{-13}	Rh-103m	1.55×10^{-15}
Br-84	1.81×10^{-9}	Cs-137	8.40×10^{-13}	Nb-97m	7.80×10^{-14}
Br-85	7.50×10^{-10}	Cs-138	6.37×10^{-10}	Nb-97	1.06×10^{-15}
I-131	9.10×10^{-10}	Ba-139	5.51×10^{-10}	Nb-95m	7.19×10^{-19}
I-132	8.32×10^{-9}	Ba-140	3.15×10^{-11}	Y-92	2.50×10^{-12}
I-133	6.22×10^{-9}	Ba-141	5.51×10^{-10}	Y-91	1.65×10^{-15}
I-134	1.64×10^{-8}	Ba-142	5.25×10^{-10}	Y-91m	3.87×10^{-12}
I-135	9.07×10^{-9}	Ce-141	1.37×10^{-13}	Y-90	3.10×10^{-16}
Sr-89	1.08×10^{-11}	Ce-143	1.22×10^{-13}	Y-89m	1.08×10^{-15}
Sr-90	8.05×10^{-13}	Ce-144	1.23×10^{-13}	Na-24	2.00×10^{-12}
Sr-91	2.41×10^{-10}	Pr-143	1.33×10^{-13}	P-32	2.00×10^{-14}
Sr-92	3.82×10^{-10}	Nd-147	4.90×10^{-14}	Cr-51	5.00×10^{-13}
Zr-95	1.40×10^{-13}	Np-239	8.37×10^{-10}	Mn-54	4.00×10^{-14}
Zr-97	1.12×10^{-13}	Ag-110	7.54×10^{-16}	Mn-56	4.96×10^{-11}
Nb-95	1.47×10^{-13}	Zn-69	7.20×10^{-16}	Co-58	5.00×10^{-12}
Mo-99	7.70×10^{-11}	Pm-147	4.93×10^{-20}	Co-60	5.00×10^{-13}
Tc-99m	9.77×10^{-10}	Pr-144	9.45×10^{-15}	Fe-59	8.00×10^{-14}
Tc-101	4.44×10^{-10}	La-142	8.31×10^{-12}	Ni-65	2.97×10^{-13}
Ru-103	6.65×10^{-14}	La-141	3.41×10^{-12}	Zn-65	2.00×10^{-15}
Ru-106	9.10×10^{-15}	La-140	1.81×10^{-14}	Zn-69m	2.99×10^{-14}
Te-129m	1.40×10^{-13}	Te-129	1.79×10^{-15}	Ag-110m	6.00×10^{-14}
Te-132	1.71×10^{-10}	Rh-106	8.53×10^{-15}	W-187	3.00×10^{-12}
Cs-134	5.60×10^{-13}				

Table 12.2-38 (Cont'd)

FALLOUT COMPONENT[4]

Isotope[5]	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)
Ba-144	2.84×10^{-13}	Ba-140	1.62×10^{-12}	Rb-92	2.62×10^{-14}
La-144	1.79×10^{-11}	La-140	5.80×10^{-16}	Sr-92	1.58×10^{-10}
Ce-144	1.38×10^{-16}	Cs-139	3.81×10^{-9}	Y-92	1.01×10^{-12}
Pr-144	6.17×10^{-18}	Ba-139	7.02×10^{-11}	Rb-91	1.06×10^{-8}
Ba-143	1.66×10^{-12}	Cs-138	4.20×10^{-10}	Sr-91	4.95×10^{-11}
La-143	2.56×10^{-11}	Cs-137	1.50×10^{-15}	Y-91	2.08×10^{-16}
Ce-143	4.52×10^{-12}	Sr-95	1.47×10^{-11}	Y-91m	4.91×10^{-13}
Pr-143	3.20×10^{-16}	Y-95	4.77×10^{-12}	Rb-90	8.70×10^{-9}
Ba-142	2.75×10^{-10}	Zr-95	4.72×10^{-17}	Sr-90	1.10×10^{-15}
La-142	4.43×10^{-12}	Sr-94	2.69×10^{-10}	Y-90	2.36×10^{-19}
Cs-141	8.54×10^{-10}	Y-94	3.12×10^{-11}	Rb-89	1.21×10^{-9}
Ba-141	6.41×10^{-10}	Rb-93	1.27×10^{-14}	Sr-89	2.38×10^{-14}
La-141	3.07×10^{-12}	Sr-93	6.03×10^{-10}	Y-89m	1.94×10^{-18}
Ce-141	3.90×10^{-17}	Y-93	1.43×10^{-12}	Rb-88	1.65×10^{-10}
Cs-140	1.02×10^{-8}				

(1) Based on shielding design source terms given in Tables 12.2-1 through 12.2-5.
(2) Assumes 2 minutes decay in transit through the condenser hotwell.
(3) Reactor water activities with a water/steam carryover factor of 0.02 by weight for halogens and 0.001 for others (coolant activation gases and noble gas fission products are excluded).
(4) Noble gas daughters created during the 7 second transit time from the RPV steam nozzles to the condensers noncondensables exhaust.
(5) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-39

CONDENSATE SYSTEM FILTER/DEMINERALIZER AND BACKWASH RECEIVING TANK SHIELDING DESIGN SOURCE TERMS[1][2][3]

CARRYOVER COMPONENT[4]

Isotope[6]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Br-83	3.54	Cs-138	4.81×10^{-1}	Rh-103m	1.40×10^{-2}
Br-84	1.35	Ba-139	1.07	Tc-99	1.12×10^{-6}
Br-85	5.00×10^{-2}	Ba-140	5.72	Nb-97m	2.50×10^{-3}
I-131	$1.43 \times 10^{+2}$	Ba-141	2.31×10^{-1}	Nb-97	2.69×10^{-3}
I-132	$4.31 \times 10^{+1}$	Ba-142	1.34×10^{-1}	Nb-95m	3.44×10^{-4}
I-133	$1.79 \times 10^{+2}$	Ce-141	7.63×10^{-2}	Y-92	1.47
I-134	$2.00 \times 10^{+1}$	Ce-143	5.67×10^{-3}	Y-91	3.46×10^{-1}
I-135	$8.56 \times 10^{+1}$	Ce-144	2.85×10^{-2}	Y-91m	1.95
Sr-89	2.39	Pr-143	2.64×10^{-2}	Y-90	1.25×10^{-1}
Sr-90	1.89×10^{-1}	Nd-147	8.56×10^{-3}	Y-89m	2.39×10^{-4}
Sr-91	3.29	Np-239	$6.33 \times 10^{+1}$	Cs-135	4.92×10^{-7}
Sr-92	1.46	Re-187	3.83×10^{-14}	Na-24	4.22×10^{-2}
Zr-95	3.12×10^{-2}	Ag-110	1.81×10^{-4}	P-32	3.73×10^{-3}
Zr-97	2.69×10^{-3}	Zn-69	5.85×10^{-4}	Cr-51	1.04×10^{-1}
Nb-95	3.43×10^{-2}	Pu-239	3.54×10^{-5}	Mn-54	9.30×10^{-3}
Mo-99	6.66	Pm-147	3.42×10^{-5}	Mn-56	1.80×10^{-1}
Tc-99m	$1.41 \times 10^{+1}$	Sm-147	2.16×10^{-18}	Co-58	1.12
Tc-101	1.45×10^{-1}	Pr-144	2.84×10^{-2}	Co-60	1.17×10^{-1}
Ru-103	1.43×10^{-2}	Nd-144	1.13×10^{-19}	Fe-59	1.75×10^{-2}
Ru-106	2.12×10^{-3}	La-142	1.54×10^{-1}	Ni-65	1.08×10^{-3}
Te-129m	2.98×10^{-2}	La-141	2.52×10^{-1}	Zn-65	4.64×10^{-4}
Te-132	$1.66 \times 10^{+1}$	La-140	4.55	Zn-69m	5.84×10^{-4}
Cs-134	1.31×10^{-1}	Te-129	1.89×10^{-2}	Ag-110m	1.39×10^{-2}
Cs-136	7.10×10^{-2}	I-129	1.71×10^{-11}	W-187	1.01×10^{-1}
Cs-137	1.97×10^{-1}	Rh-106	2.12×10^{-3}		

Table 12.2-39 (Cont'd)

FALLOUT COMPONENT[5]

Isotope[6]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Ba-144	5.54×10^{-7}	La-140	3.22×10^{-1}	Zr-93	1.65×10^{-9}
La-144	2.24×10^{-4}	Cs-139	8.38×10^{-1}	Nb-93m	1.03×10^{-12}
Ce-144	3.90×10^{-5}	Ba-139	9.90×10^{-1}	Rb-92	7.68×10^{-9}
Pr-144	3.90×10^{-5}	Cs-138	3.17×10^{-1}	Sr-92	6.07×10^{-1}
Ba-143	3.29×10^{-6}	Cs-137	3.53×10^{-4}	Y-92	6.13×10^{-1}
La-143	8.33×10^{-3}	Cs-135	5.22×10^{-10}	Rb-91	2.56×10^{-1}
Ce-143	2.18×10^{-1}	Sr-95	2.22×10^{-4}	Sr-91	9.72×10^{-1}
Pr-143	7.30×10^{-2}	Y-95	1.48×10^{-3}	Y-91	1.02×10^{-1}
Cs-142	4.30×10^{-20}	Zr-95	1.61×10^{-4}	Y-91m	5.74×10^{-1}
Ba-142	7.02×10^{-2}	Nb-95	1.50×10^{-5}	Rb-90	5.62×10^{-1}
La-142	8.09×10^{-2}	Nb-95m	1.77×10^{-6}	Sr-90	6.67×10^{-4}
Cs-141	5.22×10^{-3}	Rb-94	7.33×10^{-17}	Y-90	4.41×10^{-4}
Ba-141	2.77×10^{-2}	Sr-94	7.53×10^{-3}	Rb-89	4.33×10^{-1}
La-141	2.97×10^{-1}	Y-94	2.33×10^{-2}	Sr-89	5.91×10^{-2}
Ce-141	5.57×10^{-2}	Rb-93	4.37×10^{-9}	Y-89m	5.91×10^{-6}
Cs-140	2.25×10^{-1}	Sr-93	1.16×10^{-1}	Rb-88	6.84×10^{-2}
Ba-140	4.04×10^{-1}	Y-93	1.39×10^{-1}	Rb-87	2.96×10^{-14}

(1) Based on shielding design source terms given in Tables 12.2-1 through 12.2-5.
(2) Assumes 2.25 minutes decay in transit through condenser hotwell and piping to filter/demineralizer.
(3) Backwash volume for the receiving tank is assumed to be 9000 gallons.
(4) Carryover component of condensate accumulated for 10 days at 4314 gpm at 1.0 g/cc.
(5) Fallout component of condensate accumulated for 10 days at 4314 gpm at 1.0 g/cc.
(6) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-40

FEEDWATER SYSTEM SHIELDING DESIGN SOURCE TERMS[1]

CARRYOVER COMPONENT[2]

Isotope[4]	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)
Br-83	1.04×10^{-10}	Cs-134	2.80×10^{-13}	Ni-65	2.97×10^{-14}
Br-84	1.81×10^{-10}	Cs-136	1.92×10^{-13}	Zn-65	2.00×10^{-16}
Br-85	7.50×10^{-11}	Cs-137	4.20×10^{-13}	Zn-69m	2.99×10^{-15}
I-131	9.10×10^{-11}	Cs-138	3.18×10^{-10}	Ag-110m	6.00×10^{-15}
I-132	8.32×10^{-10}	Ba-139	5.51×10^{-11}	W-187	3.00×10^{-13}
I-133	6.22×10^{-10}	Ba-140	3.15×10^{-12}	Ag-110	7.54×10^{-17}
I-134	1.64×10^{-9}	Ba-141	5.51×10^{-11}	Zn-69	7.20×10^{-17}
I-135	9.07×10^{-10}	Ba-142	5.25×10^{-11}	Pm-147	4.93×10^{-20}
Sr-89	1.08×10^{-12}	Ce-141	1.37×10^{-14}	Pr-144	9.45×10^{-16}
Sr-90	8.05×10^{-14}	Ce-143	1.22×10^{-14}	La-142	8.31×10^{-13}
Sr-91	2.41×10^{-11}	Ce-144	1.23×10^{-14}	La-141	3.41×10^{-13}
Sr-92	3.82×10^{-11}	Pr-143	1.33×10^{-14}	La-140	1.81×10^{-15}
Zr-95	1.40×10^{-14}	Nd-147	4.90×10^{-14}	Te-129	1.79×10^{-16}
Zr-97	1.12×10^{-14}	Np-239	8.40×10^{-11}	Rh-106	8.53×10^{-16}
Nb-95	1.47×10^{-14}	Na-24	2.00×10^{-13}	Rh-103m	1.55×10^{-16}
Mo-99	7.70×10^{-12}	P-32	2.00×10^{-15}	Nb-97m	7.80×10^{-15}
Tc-99m	9.77×10^{-11}	Cr-51	5.00×10^{-14}	Nb-97	1.06×10^{-16}
Tc-101	4.44×10^{-11}	Mn-54	4.00×10^{-15}	Nb-95m	7.19×10^{-20}
Ru-103	6.65×10^{-15}	Mn-56	4.96×10^{-12}	Y-92	2.50×10^{-13}
Ru-106	9.10×10^{-16}	Co-58	5.00×10^{-13}	Y-91	1.65×10^{-16}
Te-129m	1.40×10^{-14}	Co-60	5.00×10^{-14}	Y-91m	3.87×10^{-13}
Te-132	1.71×10^{-11}	Fe-59	8.00×10^{-15}	Y-90	3.10×10^{-17}
				Y-89m	1.08×10^{-16}

Table 12.2-40 (Cont'd)

FALLOUT COMPONENT[2]

Isotope[4]	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)	Isotope	Specific Activity (Ci/cc)
Ba-144	2.84×10^{-14}	Cs-140	5.09×10^{-9}	Y-93	1.43×10^{-13}
La-144	1.79×10^{-12}	Ba-140	1.62×10^{-13}	Rb-92	1.31×10^{-14}
Ce-144	1.38×10^{-17}	La-140	5.80×10^{-17}	Sr-92	1.59×10^{-11}
Pr-144	6.17×10^{-19}	Cs-139	1.91×10^{-9}	Y-92	1.01×10^{-13}
Ba-143	1.66×10^{-13}	Ba-139	7.02×10^{-12}	Rb-91	5.23×10^{-9}
La-143	2.56×10^{-12}	Cs-138	2.10×10^{-10}	Sr-91	4.95×10^{-12}
Ce-143	4.52×10^{-13}	Cs-137	7.50×10^{-16}	Y-91	2.08×10^{-17}
Pr-143	3.20×10^{-17}	Sr-95	1.47×10^{-12}	Y-91m	4.91×10^{-14}
Ba-142	2.75×10^{-11}	Y-95	4.77×10^{-13}	Rb-90	4.35×10^{-9}
La-142	4.43×10^{-13}	Zr-95	4.72×10^{-18}	Sr-90	1.10×10^{-16}
Cs-141	4.27×10^{-10}	Sr-94	2.69×10^{-11}	Y-90	2.36×10^{-20}
Ba-141	6.41×10^{-11}	Y-94	3.12×10^{-12}	Rb-89	6.03×10^{-10}
La-141	3.07×10^{-13}	Rb-93	6.36×10^{-15}	Sr-89	2.38×10^{-15}
Ce-141	3.90×10^{-18}	Sr-93	6.03×10^{-11}	Y-89m	1.94×10^{-19}
				Rb-88	8.23×10^{-11}

NOBLE GAS GENERATION COMPONENT[3]

Xe-135	4.67×10^{-9}	Xe-133	9.78×10^{-10}	Kr-85m	1.35×10^{-11}
Xe-135m	7.02×10^{-8}	Xe-131m	2.14×10^{-12}	Kr-85	3.17×10^{-17}
Xe-133m	5.59×10^{-11}			Kr-83m	1.36×10^{-9}

(1) Based on shielding design source terms given in Tables 12.2-1 through 12.2-5.
(2) Based on condensate activity, Table 12.2-38, with appropriate DFs applied: 2 for Cs and Rb, and 10 for others.
(3) Noble gases generated by particulate parents accumulating on filter/demineralizer resins.
(4) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-41

SJAE CONDENSER SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
CS-144	1.23×10^{-3}	Y-95	4.99×10^{-7}	O-19	1.19
Ba-144	4.42×10^{-4}	Zr-95	1.52×10^{-13}	F-18	7.12×10^{-3}
La-144	2.61×10^{-5}	Nb-95m	1.70×10^{-18}	Kr-83m	1.19×10^{-2}
Ce-144	1.73×10^{-12}	Rb-94	1.07×10^{-2}	Kr-85m	2.14×10^{-2}
Pr-144	2.04×10^{-15}	Sr-94	9.44×10^{-4}	Kr-85	7.00×10^{-5}
Cs-143	2.91×10^{-3}	Y-94	2.01×10^{-6}	Kr-87	6.99×10^{-2}
Ba-143	2.37×10^{-3}	Rb-93	6.16×10^{-2}	Kr-88	7.00×10^{-2}
La-143	9.01×10^{-6}	Sr-93	5.89×10^{-4}	Kr-89	4.42×10^{-1}
Ce-143	1.37×10^{-10}	Y-93	3.58×10^{-8}	Kr-90	8.37×10^{-1}
Pr-143	1.19×10^{-14}	Rb-92	2.98×10^{-1}	Kr-91	6.79×10^{-1}
Cs-142	3.50×10^{-2}	Sr-92	1.30×10^{-4}	Kr-92	2.05×10^{-1}
Ba-142	4.37×10^{-4}	Y-92	2.20×10^{-8}	Kr-93	2.58×10^{-2}
La-142	2.08×10^{-7}	Rb-91	6.22×10^{-2}	Kr-94	1.99×10^{-3}
Cs-141	4.85×10^{-2}	Sr-91	5.13×10^{-6}	Kr-95	4.14×10^{-5}
Ba-141	1.80×10^{-4}	Y-91	9.08×10^{-13}	Xe-131m	5.26×10^{-5}
La-141	2.77×10^{-8}	Y-91m	1.83×10^{-9}	Xe-133m	1.02×10^{-3}
Ce-141	7.75×10^{-14}	Rb-90	2.66×10^{-2}	Xe-133	2.87×10^{-2}
Cs-140	6.77×10^{-2}	Sr-90	8.17×10^{-11}	Xe-135m	9.05×10^{-2}
Ba-140	1.70×10^{-7}	Y-90	6.82×10^{-16}	Xe-135	7.70×10^{-2}
La-140	7.58×10^{-12}	Rb-89	2.51×10^{-3}	Xe-137	5.14×10^{-1}
Cs-139	8.38×10^{-3}	Sr-89	1.45×10^{-9}	Xe-138	3.10×10^{-1}
Ba-139	4.48×10^{-6}	Y-89m	1.46×10^{-14}	Xe-139	8.68×10^{-1}
Cs-138	8.35×10^{-4}	Rb-88	3.40×10^{-4}	Xe-140	7.58×10^{-1}
Cs-137	2.86×10^{-9}	Rb-87	2.40×10^{-19}	Xe-141	3.97×10^{-2}
Cs-135	4.23×10^{-15}	N-13	1.24×10^{-2}	Xe-142	8.04×10^{-3}
Rb-95	5.86×10^{-4}	N-16	$3.44 \times 10^{+1}$	Xe-143	2.37×10^{-4}
Sr-95	1.15×10^{-4}	N-17	1.02×10^{-2}	Xe-144	1.10×10^{-3}

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Main steam (activation and fission gases only) with 7.0 seconds decay accumulated for 1.0 second at rated flow.
(3) Assumes a 20% washout of N-16 in the main condensers.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-42

MECHANICAL VACUUM PUMP SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)
Br-83	3.22×10^{-9}	Cs-140	1.84×10^{-7}	Sr-90	1.47×10^{-14}
Br-84	5.74×10^{-9}	Ba-140	1.57×10^{-11}	Y-90	2.08×10^{-18}
Br-85	2.47×10^{-9}	La-140	3.94×10^{-15}	Rb-89	5.20×10^{-8}
I-131	2.87×10^{-9}	Cs-139	9.96×10^{-8}	Sr-89	4.67×10^{-13}
I-132	2.63×10^{-8}	Ba-139	9.96×10^{-10}	Y-89m	3.17×10^{-17}
I-133	1.96×10^{-8}	Cs-138	2.04×10^{-8}	Rb-88	8.44×10^{-9}
I-134	5.18×10^{-8}	Cs-137	6.36×10^{-14}	Kr-83m	2.09×10^{-8}
I-135	2.86×10^{-8}	Sr-95	6.05×10^{-11}	Kr-85m	3.77×10^{-8}
Cs-135	1.09×10^{-19}	Y-95	1.44×10^{-11}	Kr-85	1.24×10^{-10}
Cs-144	8.96×10^{-13}	Zr-95	1.17×10^{-16}	Kr-87	1.22×10^{-7}
Ba-144	1.80×10^{-11}	Rb-94	6.49×10^{-19}	Kr-88	1.23×10^{-7}
La-144	2.16×10^{-10}	Sr-94	1.02×10^{-9}	Kr-89	5.42×10^{-7}
Ce-144	9.03×10^{-16}	Y-94	9.27×10^{-11}	Kr-90	1.76×10^{-7}
Pr-144	2.95×10^{-17}	Rb-93	4.72×10^{-13}	Kr-91	9.19×10^{-10}
Ba-143	1.50×10^{-11}	Sr-93	2.15×10^{-9}	Kr-92	2.38×10^{-17}
La-143	8.23×10^{-11}	Y-93	4.21×10^{-12}	Xe-131m	9.31×10^{-11}
Ce-143	4.36×10^{-14}	Rb-92	1.72×10^{-12}	Xe-133m	1.80×10^{-9}
Pr-143	1.18×10^{-18}	Sr-92	6.25×10^{-10}	Xe-133	5.08×10^{-8}
Ba-142	9.20×10^{-10}	Y-92	3.31×10^{-12}	Xe-135m	1.49×10^{-7}
La-142	1.25×10^{-11}	Rb-91	1.13×10^{-7}	Xe-135	1.36×10^{-7}
Cs-141	4.87×10^{-9}	Sr-91	3.42×10^{-10}	Se-137	6.74×10^{-7}
Ba-141	2.12×10^{-9}	Y-91	1.08×10^{-15}	Xe-138	5.14×10^{-7}
La-141	8.31×10^{-12}	Y-91m	2.56×10^{-12}	Xe-139	3.00×10^{-7}
Ce-141	8.82×10^{-17}	Rb-90	2.22×10^{-7}	Xe-140	1.66×10^{-8}
				Xe-144	7.86×10^{-13}

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-2.
(2) Assumes all fission gases and halogens in main steam at 100% reactor power.
(3) Assumes a transit time of 109 seconds from the RPV steam nozzles to the mechanical vacuum pump, at 3% reactor power.
(4) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-43

OFFGAS PIPING SHIELDING DESIGN SOURCE TERMS [1][2][3][4]

ISOTOPE[5]	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)
N-13	3.99×10^{-7}	Kr-89	1.45×10^{-5}	Xe-135m	2.91×10^{-6}
N-16	2.28×10^{-3}	Kr-90	3.13×10^{-5}	Xe-135	2.46×10^{-6}
N-17	1.14×10^{-6}	Kr-91	3.69×10^{-5}	Xe-137	1.68×10^{-5}
O-19	4.56×10^{-5}	Kr-92	3.69×10^{-5}	Xe-138	9.97×10^{-6}
F-18	2.28×10^{-7}	Kr-93	1.11×10^{-5}	Xe-139	3.13×10^{-5}
Kr-83m	3.81×10^{-7}	Kr-94	2.58×10^{-6}	Xe-140	3.36×10^{-5}
Kr-85m	6.84×10^{-7}	Kr-95	2.35×10^{-7}	Xe-141	2.68×10^{-5}
Kr-85	2.24×10^{-9}	Xe-131m	1.68×10^{-9}	Xe-142	8.15×10^{-6}
Kr-87	2.24×10^{-6}	Xe-133m	3.25×10^{-8}	Xe-143	1.34×10^{-6}
Kr-88	2.24×10^{-6}	Xe-133	9.18×10^{-7}	Xe-144	6.27×10^{-8}

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Main steam (activation and fission gases only) with no decay (at RPV nozzles).
(3) Assumes a 20% washout of N-16 in the main condensers.
(4) Credit for decay is taken for shielding various segments of the offgas piping.
(5) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-44

OFFGAS PREHEATER SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Cs-144	2.50×10^{-4}	Zr-95	6.70×10^{-7}	N-17	1.86×10^{-3}
Ba-144	4.35×10^{-5}	NB-95	6.67×10^{-7}	0-19	3.49×10^{-1}
La-144	2.54×10^{-5}	NB-95m	1.34×10^{-8}	F-18	2.17×10^{-3}
Ce-144	1.84×10^{-5}	Rb-94	2.09×10^{-4}	Kr-83m	3.63×10^{-3}
Pr-144	1.84×10^{-5}	Sr-94	3.77×10^{-5}	Kr-85M	6.52×10^{-3}
Cs-143	2.72×10^{-5}	Y-94	3.54×10^{-5}	Kr-85	2.14×10^{-5}
Ba-143	6.10×10^{-6}	Rb-93	1.97×10^{-3}	Kr-87	2.13×10^{-2}
La-143	3.85×10^{-6}	Sr-93	5.02×10^{-4}	Kr-88	2.13×10^{-2}
Ce-143	3.85×10^{-6}	Y-93	4.99×10^{-4}	Kr-89	1.34×10^{-1}
Pr-143	3.85×10^{-6}	Zr-93	3.41×10^{-10}	Kr-90	2.46×10^{-1}
Cs-142	9.81×10^{-4}	Nb-93m	1.19×10^{-11}	Kr-91	1.83×10^{-1}
Ba-142	1.47×10^{-4}	Rb-92	1.73×10^{-2}	Kr-92	4.16×10^{-2}
La-142	1.46×10^{-4}	Sr-92	4.23×10^{-3}	Kr-93	4.27×10^{-3}
Cs-141	1.32×10^{-3}	Y-92	4.23×10^{-3}	Kr-94	2.52×10^{-4}
Ba-141	7.42×10^{-4}	Rb-91	1.96×10^{-2}	Kr-95	3.68×10^{-6}
La-141	7.42×10^{-4}	Sr-91	1.56×10^{-2}	Xe-131m	1.60×10^{-5}
Ce-141	7.42×10^{-4}	Y-91	1.55×10^{-2}	Xe-133m	3.10×10^{-4}
Cs-140	2.27×10^{-2}	Y-91m	9.18×10^{-3}	Xe-133	8.75×10^{-3}
Ba-140	1.77×10^{-2}	Rb-90	2.20×10^{-2}	Xe-135m	2.76×10^{-2}
La-140	1.77×10^{-2}	Sr-90	7.21×10^{-4}	Xe-135	2.35×10^{-2}
Cs-139	2.13×10^{-2}	Y-90	7.16×10^{-4}	Xe-137	1.56×10^{-1}
Ba-139	2.07×10^{-2}	Rb-89	1.08×10^{-2}	Xe-138	9.45×10^{-2}
Cs-138	7.53×10^{-3}	Sr-89	1.06×10^{-2}	Xe-139	2.58×10^{-1}
Cs-137	4.15×10^{-4}	Y-89m	1.06×10^{-6}	Xe-140	2.14×10^{-1}
Cs-135	6.33×10^{-10}	Rb-88	1.71×10^{-3}	Xe-141	5.89×10^{-3}
Rb-95	4.25×10^{-6}	Rb-87	3.59×10^{-1}	Xe-142	1.08×10^{-3}
Sr-95	7.58×10^{-7}	N-13	3.01×10^{-3}	Xe-143	2.11×10^{-5}
Y-95	6.72×10^{-7}	N-16	8.86	Xe-144	2.93×10^{-4}

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.

(2) Main steam (activation and fission gases only) with 9.1 seconds decay accumulated for 0.305 seconds at rated flow (includes an 18 month buildup of 1% of the particulate daughters of gases).

(3) Assumes a 20% washout of N-16 in the main condensers.

(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Note: Since the short term activity reaches equilibrium within a few days after startup, extending the refueling cycle to 24 months does not contribute a significant amount to the total dose from the system.

Table 12.2-45

OFFGAS RECOMBINER SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Cs-144	1.89×10^{-3}	Y-95	7.36×10^{-5}	N-16	$1.81 \times 10^{+1}$
Ba-144	3.15×10^{-3}	Zr-95	7.34×10^{-5}	N-17	3.65×10^{-3}
La-144	3.22×10^{-3}	Nb-95	7.31×10^{-5}	O-19	7.44×10^{-1}
Ce-144	2.36×10^{-3}	Nb-95m	1.47×10^{-6}	F-18	4.70×10^{-3}
Pr-144	2.36×10^{-3}	Rb-94	2.97×10^{-3}	Kr-83m	7.85×10^{-3}
Nd-144	6.10×10^{-19}	Sr-94	4.02×10^{-3}	Kr-85m	1.41×10^{-2}
Cs-143	2.62×10^{-4}	Y-94	4.03×10^{-3}	Kr-85	4.62×10^{-5}
Ba-143	4.13×10^{-4}	Rb-93	5.06×10^{-2}	Kr-87	4.62×10^{-2}
La-143	4.22×10^{-4}	Sr-93	5.88×10^{-2}	Kr-88	4.62×10^{-2}
Ce-143	4.22×10^{-4}	Y-93	5.88×10^{-2}	Kr-89	2.89×10^{-1}
Pr-143	4.22×10^{-4}	Zr-93	4.02×10^{-8}	Kr-90	5.26×10^{-1}
Cs-142	1.15×10^{-2}	Nb-93m	1.40×10^{-9}	Kr-91	3.80×10^{-1}
Ba-142	1.67×10^{-2}	Rb-92	4.45×10^{-1}	Kr-92	7.86×10^{-2}
La-142	1.67×10^{-2}	Sr-92	5.15×10^{-1}	Kr-93	7.56×10^{-3}
Cs-141	8.29×10^{-2}	Y-92	5.15×10^{-1}	Kr-94	4.09×10^{-4}
Ba-141	8.61×10^{-2}	Rb-91	1.98	Kr-95	5.34×10^{-6}
La-141	8.61×10^{-2}	Sr-91	2.00	Xe-131m	3.47×10^{-5}
Ce-141	8.61×10^{-2}	Y-91	2.00	Xe-133m	6.70×10^{-4}
Cs-140	2.27	Y-91m	1.18	Xe-133	1.89×10^{-2}
Ba-140	2.30	Rb-90	2.58	Xe-135m	5.97×10^{-2}
La-140	2.38	Sr-90	9.43×10^{-2}	Xe-135	5.08×10^{-2}
Cs-139	2.70	Y-90	9.37×10^{-2}	Xe-137	3.37×10^{-1}
Ba-139	2.71	Rb-89	1.40	Xe-138	2.04×10^{-1}
Cs-138	9.83×10^{-1}	Sr-89	1.40	Xe-139	5.52×10^{-1}
Cs-137	5.46×10^{-2}	Y-89m	1.40×10^{-4}	Xe-140	4.52×10^{-1}
Cs-135	8.34×10^{-8}	Rb-88	2.22×10^{-1}	Xe-141	1.01×10^{-2}
Rb-95	5.00×10^{-5}	Rb-87	4.74×10^{-12}	Xe-142	1.79×10^{-3}
Sr-95	7.33×10^{-5}	N-13	6.51×10^{-3}	Xe-143	3.06×10^{-5}
				Xe-144	6.07×10^{-4}

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.

(2) Main steam (activation and fission gases only) with 9.51 seconds decay accumulated for 0.66 seconds at rated flow (includes an 18 month buildup for all the particulate daughters of gases).

(3) Assumes a 20% washout of N-16 in the main condensers.

(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Note: Since the short term activity reaches equilibrium within a few days after startup, extending the refueling cycle to 24 months does not contribute a significant amount to the total dose from the system.

Table 12.2-46

OFFGAS RECOMBINER CATALYST ELEMENT SHIELDING
DESIGN SOURCE TERMS[1]

ISOTOPE[2]	ACTIVITY (Ci)
Ce-144	2.35×10^{-3}
Pr-144	2.35×10^{-3}
Nd-144	6.12×10^{-19}
Ce-143	2.57×10^{-4}
Pr-143	4.17×10^{-4}
La-142	3.92×10^{-7}
La-141	1.27×10^{-3}
Ce-141	8.47×10^{-2}
Ba-140	2.17
La-140	2.27
Ba-139	1.81×10^{-5}
Cs-138	3.41×10^{-14}
Cs-137	5.46×10^{-2}
Cs-135	8.34×10^{-8}
Zr-95	7.26×10^{-5}
Nb-95	7.31×10^{-5}
Nb-95m	1.47×10^{-6}
Y-93	1.19×10^{-2}
Zr-93	4.02×10^{-8}
Nb-93m	1.41×10^{-9}
Sr-92	1.11×10^{-3}
Y-92	1.63×10^{-2}
Sr-91	3.59×10^{-1}
Y-91	1.98
Y-91m	2.32×10^{-1}
Sr-90	9.43×10^{-2}
Y-90	9.38×10^{-2}
Sr-89	1.38
Y-89m	1.38×10^{-4}
Rb-87	4.74×10^{-12}

(1) Particulate activity in recombiner (Table 12.2-45) with 24 hours decay.
(2) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-47

OFFGAS AFTERCONDENSER SHIELDING DESIGN SOURCE TERMS [1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Cs-144	1.11×10^{-2}	Y-95	7.88×10^{-8}	N-17	3.00×10^{-2}
Ba-144	8.63×10^{-3}	Zr-95	1.25×10^{-13}	O-19	$2.92 \times 10^{+1}$
La-144	2.38×10^{-3}	Nb-95	2.71×10^{-19}	F-18	2.93×10^{-1}
Ce-144	8.91×10^{-10}	Nb-95m	5.16×10^{-20}	Kr-83m	4.89×10^{-1}
Pr-144	5.69×10^{-12}	Rb-94	1.05×10^{-3}	Kr-85m	8.81×10^{-1}
Cs-143	5.23×10^{-5}	Sr-94	2.76×10^{-4}	Kr-85	2.89×10^{-3}
Ba-143	4.65×10^{-5}	Y-94	2.94×10^{-6}	Kr-87	2.88
La-143	9.44×10^{-7}	Rb-93	2.91×10^{-2}	Kr-88	2.88
Ce-143	7.98×10^{-11}	Sr-93	1.23×10^{-3}	Kr-89	$1.68 \times 10^{+1}$
Pr-143	4.87×10^{-16}	Y-93	3.79×10^{-7}	Kr-90	$2.17 \times 10^{+1}$
Cs-142	5.00×10^{-3}	Zr-93	6.32×10^{-20}	Kr-91	7.38
Ba-142	1.87×10^{-4}	Rb-92	4.72×10^{-1}	Kr-92	4.47×10^{-1}
La-142	4.27×10^{-7}	Sr-92	1.00×10^{-3}	Kr-93	2.67×10^{-2}
Cs-141	2.20×10^{-2}	Y-92	8.76×10^{-7}	Kr-94	9.22×10^{-4}
Ba-141	3.25×10^{-4}	Rb-91	1.85	Kr-95	7.59×10^{-6}
La-141	2.31×10^{-7}	Sr-91	6.35×10^{-4}	Xe-131m	2.17×10^{-3}
Ce-141	5.92×10^{-13}	Y-91	4.22×10^{-10}	Xe-133m	4.19×10^{-2}
Cs-140	3.11	Y-91m	1.02×10^{-6}	Xe-133	1.18
Ba-140	3.19×10^{-5}	Rb-90	1.95	Xe-135m	3.67
La-140	1.75×10^{-9}	Sr-90	2.32×10^{-8}	Xe-135	3.18
Cs-139	6.94×10^{-1}	Y-90	8.33×10^{-13}	Xe-137	$1.98 \times 10^{+1}$
Ba-139	1.41×10^{-3}	Rb-89	2.67×10^{-1}	Xe-138	$1.26 \times 10^{+1}$
Cs-138	9.45×10^{-2}	Sr-89	5.70×10^{-7}	Xe-139	$2.50 \times 10^{+1}$
Cs-137	3.09×10^{-7}	Y-89m	1.87×10^{-11}	Xe-140	$1.28 \times 10^{+1}$
Cs-135	4.86×10^{-13}	Rb-88	3.88×10^{-2}	Xe-141	2.91×10^{-2}
Rb-95	9.15×10^{-6}	Rb-87	2.75×10^{-17}	Xe-142	4.41×10^{-3}
Sr-95	3.76×10^{-6}	N-13	3.97×10^{-1}	Xe-142	4.35×10^{-5}
		N-16	$2.61 \times 10^{+2}$	Xe-144	1.09×10^{-2}

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Main steam (activation and fission gases only) with 10.45 seconds decay accumulated for 41.25 seconds at rated flow.
(3) Assumes a 20% washout of N-16 in the main condensers.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-48

H_2 ANALYZERS SHIELDING DESIGN SOURCE TERMS[1][2][3][4][5][7]

ISOTOPE[6]	SPECIFIC ACTIVITY (Ci/cc)
N-13	3.04×10^{-7}
N-16	1.01×10^{-4}
N-17	6.84×10^{-11}
O-19	1.82×10^{-5}
F-18	2.27×10^{-7}
Kr-83m	3.80×10^{-7}
Kr-85m	6.84×10^{-7}
Kr-85	2.25×10^{-9}
Kr-87	2.23×10^{-6}
Kr-88	2.24×10^{-6}
Kr-89	1.25×10^{-5}
Kr-90	1.38×10^{-5}
Kr-91	3.41×10^{-6}
Kr-92	5.96×10^{-8}
Kr-93	1.29×10^{-9}
Kr-94	1.19×10^{-11}
Kr-95	1.65×10^{-14}
Xe-131m	1.69×10^{-9}
Xe-133m	3.26×10^{-8}
Xe-133	9.20×10^{-7}
Xe-135m	2.83×10^{-6}
Xe-135	2.47×10^{-6}
Xe-137	1.48×10^{-5}
Xe-138	9.72×10^{-6}
Xe-139	1.65×10^{-5}
Xe-140	7.04×10^{-6}
Xe-141	8.19×10^{-10}
Xe-142	7.63×10^{-11}
Xe-143	9.47×10^{-14}
Xe-144	4.84×10^{-9}
Cs-144	4.84×10^{-9}
Ba-144	4.84×10^{-9}
La-144	4.84×10^{-9}
Ce-144	4.84×10^{-9}
Pr-144	4.84×10^{-9}
Cs-143	9.47×10^{-14}
Ba-143	9.47×10^{-14}
La-143	9.47×10^{-14}
Ce-143	9.47×10^{-14}
Pr-143	9.47×10^{-14}

Table 12.2-48 (Cont'd)

ISOTOPE[6]	SPECIFIC ACTIVITY (Ci/cc)
Cs-142	7.63×10^{-11}
Ba-142	7.63×10^{-11}
La-142	7.63×10^{-11}
Cs-141	8.17×10^{-10}
Ba-141	8.17×10^{-10}
La-141	8.17×10^{-10}
Ce-141	8.17×10^{-10}
Cs-140	7.04×10^{-6}
Ba-140	7.04×10^{-6}
La-140	7.04×10^{-6}
Cs-139	1.65×10^{-5}
Ba-139	1.65×10^{-5}
Cs-138	9.72×10^{-6}
Cs-137	8.96×10^{-6}
Cs-135	2.28×10^{-11}
Rb-95	1.65×10^{-14}
Sr-95	1.65×10^{-14}
Y-95	1.65×10^{-14}
Zr-95	1.65×10^{-14}
Nb-95	1.65×10^{-14}
Nb-95m	3.31×10^{-16}
Rb-94	1.19×10^{-11}
Sr-94	1.19×10^{-11}
Y-94	1.19×10^{-11}
Rb-93	1.29×10^{-9}
Sr-93	1.29×10^{-9}
Y-93	1.29×10^{-9}
Zr-93	2.39×10^{-14}
Nb-93m	1.30×10^{-14}
Rb-92	5.96×10^{-8}
Sr-92	5.96×10^{-8}
Y-92	5.96×10^{-8}
Rb-91	3.41×10^{-6}
Sr-91	3.41×10^{-6}
Y-91	3.41×10^{-6}
Y-91m	2.01×10^{-6}
Rb-90	1.38×10^{-5}
Sr-90	8.75×10^{-6}
Y-90	8.75×10^{-6}
Rb-89	1.25×10^{-5}
Sr-89	1.25×10^{-5}

Table 12.2-48 (Cont'd)

ISOTOPE[6]	SPECIFIC ACTIVITY (Ci/cc)
Y-89m	1.25×10^{-9}
Rb-88	2.24×10^{-6}
Rb-87	1.29×10^{-15}

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Assumes a 20% washout of N-16 in the main condensers.
(3) Based on activity at outlet of offgas recombiner aftercondenser.
(4) Assumes an 18.6 second holdup pipe between aftercondenser outlet and analyzer cells.
(5) Assumes a flow rate of 0.3 scfm of offgas through the analyzer tubing (includes a 40 year buildup of particulate daughters of gases).
(6) Isotopes with specific activities less than 1.0×10^{-20} are not listed.
(7) Based on sum of radiation sources in analyzer cells.

Table 12.2-49

TURBINE ENCLOSURE EQUIPMENT COMPARTMENT
EXHAUST AIR FILTERS SHIELDING DESIGN SOURCE TERMS[1][2]

ISOTOPE[3]	ACTIVITY (Ci)
I-131	2.12×10^{-2}
I-133	8.89×10^{-3}
Co-60	1.87×10^{-3}
Co-58	1.64×10^{-4}
Cr-51	1.43×10^{-3}
Mn-54	4.07×10^{-4}
Fe-59	8.97×10^{-5}
Zn-65	1.25×10^{-4}
Zr-95	8.87×10^{-5}
Sr-89	4.34×10^{-3}
Sr-90	6.91×10^{-5}
Sb-124	2.47×10^{-4}
Cs-134	8.91×10^{-4}
Cs-136	9.47×10^{-6}
Cs-137	2.08×10^{-3}
Ba-140	1.95×10^{-3}
Ce-141	2.70×10^{-4}
La-140	1.95×10^{-3}
Y-90	6.85×10^{-5}
Y-89m	4.34×10^{-7}
Nb-95	8.66×10^{-5}
Nb-95m	1.77×10^{-6}

(1) Based on NUREG-0016, Revision 0, table 1-1 (Reference 12.2-1) release rates, with fission products adjusted to 0.35 Ci/sec offgas release rate at 30 minutes decay.

(2) Assumes a one year accumulation of all these isotopes at 63,000 cfm.

(3) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-50

SGTS AIR FILTERS SHIELDING DESIGN SOURCE TERMS[1][2]

ISOTOPE[3]	ACTIVITY (Ci)
I-131	4.66×10^{-3}
I-133	1.61×10^{-2}
Co-60	7.97×10^{-5}
Co-58	4.77×10^{-6}
Cr-51	2.38×10^{-6}
Mn-54	2.39×10^{-5}
Fe-59	3.18×10^{-6}
Zn-65	1.59×10^{-5}
Zr-95	1.11×10^{-5}
Sr-89	2.51×10^{-6}
Sr-90	1.40×10^{-7}
Sb-124	5.57×10^{-6}
Cs-134	1.12×10^{-4}
Cs-136	8.28×10^{-6}
Cs-137	1.54×10^{-4}
Ba-140	1.10×10^{-5}
Ce-141	2.78×10^{-6}
La-140	9.02×10^{-7}
Y-90	7.79×10^{-9}
Y-89m	2.51×10^{-10}
Nb-95	4.50×10^{-8}
Nb-95m	8.37×10^{-9}

(1) Assumes untreated airborne release rate from drywell during purging to be 7 times that from reactor enclosure during normal operation, from NUREG-0016, Revision 0, tables 1-1 and 2-11 (Reference 12.2-1).

(2) Based on drywell purge for 10 hours at 11,000 cfm.

(3) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-51

EQUIPMENT DRAIN COLLECTION TANK SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	1.94×10^{-1}	Cs-137	1.14×10^{-2}	Tc-99	2.11×10^{-8}
Br-84	7.91×10^{-2}	Cs-138	5.64×10^{-1}	Nb-97m	1.11×10^{-3}
Br-85	4.70×10^{-3}	Ba-139	1.22	Nb-97	1.05×10^{-3}
I-131	6.03×10^{-1}	Ba-140	4.21×10^{-1}	Nb-95m	1.75×10^{-6}
I-132	3.12	Ba-141	2.82×10^{-1}	Y-92	1.25
I-133	3.45	Ba-142	1.72×10^{-1}	Y-91	6.85×10^{-3}
I-134	1.15	Ce-141	3.60×10^{-3}	Y-91m	1.20
I-135	3.47	Ce-143	1.47×10^{-3}	Y-90	7.44×10^{-4}
Sr-89	1.47×10^{-1}	Ce-144	1.67×10^{-3}	Y-89m	1.47×10^{-5}
Sr-90	1.09×10^{-2}	Pr-143	1.80×10^{-3}	Zn-69	2.77×10^{-4}
Sr-91	2.17	Nd-147	6.53×10^{-3}	Cs-135	1.82×10^{-10}
Sr-92	1.58	Np-239	$1.06 \times 10^{+1}$	Na-24	2.06×10^{-2}
Zr-95	1.89×10^{-3}	Pu-239	2.17×10^{-7}	P-32	2.68×10^{-4}
Zr-97	1.19×10^{-3}	Re-187	4.12×10^{-16}	Cr-51	6.73×10^{-3}
Nb-95	1.99×10^{-3}	Pm-147	1.23×10^{-6}	Mn-54	5.42×10^{-4}
Mo-99	9.79×10^{-1}	Pr-144	1.61×10^{-3}	Mn-56	1.96×10^{-1}
Tc-99m	7.50	La-142	1.72×10^{-1}	Fe-59	1.08×10^{-3}
Tc-101	1.81×10^{-1}	La-141	2.49×10^{-1}	Co-58	6.76×10^{-2}
Ru-103	8.97×10^{-4}	La-140	4.20×10^{-2}	Co-60	6.77×10^{-3}
Ru-106	1.23×10^{-4}	Te-129	1.05×10^{-3}	Ni-65	1.17×10^{-3}
Te-129m	1.89×10^{-3}	I-129	4.64×10^{-14}	Zn-65	2.71×10^{-5}
Te-132	2.21	Ag-110	1.06×10^{-5}	Zn-69m	3.03×10^{-4}
Cs-134	7.59×10^{-3}	Rh-106	1.23×10^{-4}	Ag-110m	8.12×10^{-4}
Cs-136	5.15×10^{-3}	Rh-103m	7.81×10^{-4}	W-187	3.42×10^{-2}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Equipment drains (17.9% of reactor water less gases) accumulated for 0.5157 days at 26.93 gpm.
(3) This activity is in 20,000 gallons.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-52

EQUIPMENT DRAIN SURGE TANK SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	2.00×10^{-1}	Cs-137	3.41×10^{-2}	Rh-103m	2.52×10^{-3}
Br-84	7.91×10^{-2}	Cs-138	5.64×10^{-1}	Tc-99	1.13×10^{-7}
Br-85	4.70×10^{-3}	Ba-139	1.22	Nb-97m	2.18×10^{-3}
I-131	1.73	Ba-140	1.23	Nb-97	2.29×10^{-3}
I-132	7.00	Ba-141	2.82×10^{-1}	Nb-95m	1.47×10^{-5}
I-133	7.19	Ba-142	1.72×10^{-1}	Y-92	1.64
I-134	1.15	Ce-141	1.32×10^{-2}	Y-91	4.23×10^{-2}
I-135	4.70	Ce-143	3.47×10^{-3}	Y-91m	2.01
Sr-89	4.39×10^{-1}	Ce-144	4.99×10^{-3}	Y-90	6.11×10^{-3}
Sr-90	3.27×10^{-2}	Pr-143	5.35×10^{-3}	Y-89m	4.38×10^{-5}
Sr-91	3.44	Nd-147	1.90×10^{-2}	Zn-69	5.45×10^{-4}
Sr-92	1.65	Np-239	$2.74 \times 10^{+1}$	Cs-135	2.10×10^{-9}
Zr-95	5.64×10^{-3}	Pu-239	1.78×10^{-6}	Na-24	3.88×10^{-2}
Zr-97	2.35×10^{-3}	Re-187	3.00×10^{-15}	P-32	7.83×10^{-4}
Nb-95	5.97×10^{-3}	Pm-147	1.08×10^{-5}	Cr-51	1.99×10^{-2}
Mo-99	2.60	Sm-147	1.02×10^{-19}	Mn-54	1.62×10^{-3}
Tc-99m	$1.10 \times 10^{+1}$	Pr-144	4.93×10^{-3}	Mn-56	2.03×10^{-1}
Tc-101	1.81×10^{-1}	La-142	1.72×10^{-1}	Fe-59	3.21×10^{-3}
Ru-103	2.67×10^{-3}	La-141	2.82×10^{-1}	Co-58	2.02×10^{-1}
Ru-106	3.69×10^{-4}	La-140	3.25×10^{-1}	Co-60	2.03×10^{-2}
Te-129m	5.60×10^{-3}	Te-129	3.43×10^{-3}	Ni-65	1.22×10^{-3}
Te-132	5.95	I-129	4.60×10^{-13}	Zn-65	8.11×10^{-5}
Cs-134	2.27×10^{-2}	Ag-110	3.16×10^{-5}	Zn-69m	5.53×10^{-4}
Cs-136	1.51×10^{-2}	Rh-106	3.69×10^{-4}	Ag-110m	2.43×10^{-3}
				W-187	7.47×10^{-2}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Equipment drains (17.9% of reactor water less gases) accumulated for 1.547 days at 26.93 gpm.
(3) This activity is in 60,000 gallons.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-53

EQUIPMENT DRAIN SAMPLE TANK SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	1.94×10^{-4}	Cs-137	5.69×10^{-4}	Tc-99	2.11×10^{-11}
Br-84	7.91×10^{-5}	Cs-138	2.82×10^{-2}	Nb-97m	1.11×10^{-6}
Br-85	4.70×10^{-6}	Ba-139	1.22×10^{-3}	Nb-97	1.05×10^{-6}
I-131	6.03×10^{-4}	Ba-140	4.21×10^{-4}	Nb-95m	1.75×10^{-9}
I-132	3.12×10^{-3}	Ba-141	2.82×10^{-4}	Y-92	1.25×10^{-3}
I-133	3.45×10^{-3}	Ba-142	1.72×10^{-4}	Y-91	6.85×10^{-6}
I-134	1.15×10^{-3}	Ce-141	3.60×10^{-6}	Y-91m	1.20×10^{-3}
I-135	3.47×10^{-3}	Ce-143	1.47×10^{-6}	Y-90	7.44×10^{-7}
Sr-89	1.47×10^{-4}	Ce-144	1.67×10^{-6}	Y-89m	1.47×10^{-8}
Sr-90	1.09×10^{-5}	Pr-143	1.80×10^{-6}	Zn-69	2.77×10^{-7}
Sr-91	2.17×10^{-3}	Nd-147	6.53×10^{-6}	Cs-135	9.10×10^{-12}
Sr-92	1.58×10^{-3}	Np-239	1.06×10^{-2}	Na-24	2.06×10^{-5}
Zr-95	1.89×10^{-6}	Pu-239	2.17×10^{-10}	P-32	2.68×10^{-7}
Zr-97	1.19×10^{-6}	Re-187	4.12×10^{-19}	Cr-51	6.73×10^{-6}
Nb-95	1.99×10^{-6}	Pm-147	1.23×10^{-9}	Mn-54	5.42×10^{-7}
Mo-99	9.79×10^{-4}	Pr-144	1.61×10^{-6}	Mn-56	1.96×10^{-4}
Tc-99m	7.50×10^{-3}	La-142	1.72×10^{-4}	Fe-59	1.08×10^{-6}
Tc-101	1.81×10^{-4}	La-141	2.49×10^{-4}	Co-58	6.76×10^{-5}
Ru-103	8.97×10^{-7}	La-140	4.20×10^{-5}	Co-60	6.77×10^{-6}
Ru-106	1.23×10^{-7}	Te-129	1.05×10^{-6}	Ni-65	1.17×10^{-6}
Te-129m	1.89×10^{-6}	I-129	4.64×10^{-17}	Zn-65	2.71×10^{-8}
Te-132	2.21×10^{-3}	Ag-110	1.06×10^{-8}	Zn-69m	3.03×10^{-7}
Cs-134	3.79×10^{-4}	Rh-106	1.23×10^{-7}	Ag-110m	8.12×10^{-7}
Cs-136	2.57×10^{-4}	Rh-103m	7.81×10^{-7}	W-187	3.42×10^{-5}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Activity in equipment drain collection tank with DFs applied for filter and demineralizer (DF for Cs and Rb = (0.5)(0.1) = 0.05 and DF for others = (0.1)(0.01) = 0.001).
(3) This activity is in 20,000 gallons.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-54

EQUIPMENT DRAIN FILTER SHIELDING DESIGN SOURCE TERMS[1][2][4]

ISOTOPE[3]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	2.00×10^{-1}	Cs-137	2.41×10^{-2}	Rh-103m	1.75×10^{-3}
Br-84	7.91×10^{-2}	Cs-138	5.64×10^{-1}	Tc-99	6.85×10^{-8}
Br-85	4.70×10^{-3}	Ba-139	1.22	Nb-97m	1.83×10^{-3}
I-131	1.24	Ba-140	8.76×10^{-1}	Nb-97	1.89×10^{-3}
I-132	5.38	Ba-141	2.82×10^{-1}	Nb-95m	7.53×10^{-6}
I-133	5.90	Ba-142	1.72×10^{-1}	Y-92	1.61
I-134	1.15	Ce-141	8.88×10^{-3}	Y-91	2.48×10^{-2}
I-135	4.48	Ce-143	2.70×10^{-3}	Y-91m	1.81
Sr-89	3.09×10^{-1}	Ce-144	3.50×10^{-3}	Y-90	3.16×10^{-3}
Sr-90	2.31×10^{-2}	Pr-143	3.79×10^{-3}	Y-89m	3.08×10^{-5}
Sr-91	3.12	Nd-147	1.36×10^{-3}	Cs-135	1.05×10^{-9}
Sr-92	1.65	Np-239	$2.06 \times 10^{+1}$	Na-24	3.32×10^{-2}
Zr-95	3.99×10^{-3}	Re-187	1.63×10^{-15}	P-32	5.58×10^{-4}
Zr-97	1.97×10^{-3}	Ag-110	2.23×10^{-5}	Cr-51	1.41×10^{-2}
Nb-95	4.21×10^{-3}	Zn-69	4.65×10^{-4}	Mn-54	1.14×10^{-3}
Mo-99	1.93	Pu-239	9.19×10^{-7}	Mn-56	2.03×10^{-1}
Tc-99m	$1.01 \times 10^{+1}$	Pm-147	5.42×10^{-7}	Co-58	1.42×10^{-1}
Tc-101	1.81×10^{-1}	Pr-144	3.45×10^{-3}	Co-60	1.43×10^{-2}
Ru-103	1.89×10^{-3}	La-142	1.72×10^{-1}	Fe-59	2.27×10^{-3}
Ru-106	2.60×10^{-4}	La-141	2.79×10^{-1}	Ni-65	1.21×10^{-3}
Te-129m	3.97×10^{-3}	La-140	1.72×10^{-1}	Zn-65	5.72×10^{-5}
Te-132	4.38	Te-129	2.38×10^{-3}	Zn-69m	4.78×10^{-4}
Cs-134	1.60×10^{-2}	I-129	2.24×10^{-13}	Ag-110m	1.72×10^{-3}
Cs-136	1.07×10^{-2}	Rh-106	2.60×10^{-4}	W-187	6.02×10^{-2}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Equipment drains (17.9% of reactor water less gases) accumulated for 1.09 days at 26.93 gpm.
(3) Isotopes with activities less than 1.0×10^{-20} are not listed.
(4) For shielding design of associated piping, backwash volume to waste sludge tank is 1925 gallons.

Table 12.2-55

EQUIPMENT DRAIN DEMINERALIZER AND SPENT RESIN TANK SHIELDING DESIGN SOURCE TERMS [1][2][3][5]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	2.00×10^{-2}	Cs-138	2.82×10^{-1}	Ag-110	1.18×10^{-4}
Br-84	7.91×10^{-3}	Ba-139	1.22×10^{-1}	Rh-106	1.41×10^{-3}
Br-85	4.70×10^{-4}	Ba-140	1.48	Rh-103m	6.50×10^{-3}
I-131	1.38	Ba-141	2.82×10^{-2}	Tc-99	9.45×10^{-7}
I-132	2.26	Ba-142	1.72×10^{-2}	Nb-97m	2.80×10^{-4}
I-133	1.00	Ce-141	3.32×10^{-2}	Nb-97	3.01×10^{-4}
I-134	1.15×10^{-1}	Ce-143	6.41×10^{-4}	Nb-95m	3.15×10^{-4}
I-135	4.80×10^{-1}	Ce-144	1.88×10^{-2}	Y-92	1.65×10^{-1}
Sr-89	1.22	Pr-143	7.18×10^{-3}	Y-91	1.92×10^{-1}
Sr-90	1.32×10^{-1}	Nd-147	2.01×10^{-2}	Y-91m	2.18×10^{-1}
Sr-91	3.70×10^{-1}	Np-239	7.47	Y-90	1.25×10^{-1}
Sr-92	1.65×10^{-1}	Pu-239	3.44×10^{-5}	Y-89m	1.22×10^{-4}
Zr-95	1.68×10^{-2}	U-235	2.74×10^{-15}	Zn-69	6.54×10^{-5}
Zr-97	3.01×10^{-4}	Th-231	2.60×10^{-15}	Cs-135	9.37×10^{-8}
Nb-95	2.17×10^{-2}	Pa-231	1.07×10^{-19}	Na-24	4.73×10^{-3}
Mo-99	8.11×10^{-1}	Re-187	3.06×10^{-14}	P-32	1.03×10^{-3}
Tc-99m	1.64	Pm-147	6.86×10^{-4}	Cr-51	4.16×10^{-2}
Tc-101	1.81×10^{-2}	Sm-147	3.22×10^{-16}	Mn-54	6.13×10^{-3}
Ru-103	6.64×10^{-3}	Pr-144	1.88×10^{-2}	Mn-56	2.03×10^{-2}
Ru-106	1.41×10^{-3}	Nd-144	4.76×10^{-19}	Fe-59	8.49×10^{-3}
Te-129m	1.30×10^{-2}	La-142	1.72×10^{-2}	Cu-58	6.16×10^{-1}
Te-132	2.11	La-141	2.82×10^{-2}	Cu-60	8.13×10^{-2}
Cs-134	4.47×10^{-1}	La-140	1.47	Ni-65	1.22×10^{-4}
Cs-136	9.58×10^{-2}	Te-129	8.33×10^{-3}	Zn-65	3.01×10^{-4}
Cs-137	6.89×10^{-1}	I-129	5.49×10^{-11}	Zn-69m	6.54×10^{-5}
				Ag-110m	9.07×10^{-3}
				W-187	1.13×10^{-2}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Filtered equipment drains (DF of 2 for Cs and Rb and DF of 10 for others) accumulated for 62.6 days at 26.93 gpm.
(3) This activity is in 85 ft^3 of spent resin.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.
(5) The equipment drain spent resin tank will not be used for initial plant operation (Section 11.4.2.1.1).

Table 12.2-56

EQUIPMENT DRAIN SPENT RESIN TANK PUMP SHIELDING DESIGN SOURCE TERMS[1][2][3][5]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
I-131	7.90×10^{-3}	Ce-141	9.27×10^{-3}	Te-129	2.47×10^{-3}
I-132	5.75×10^{-6}	Ce-143	4.72×10^{-17}	I-129	1.05×10^{-10}
Sr-89	5.55×10^{-1}	Ce-144	1.62×10^{-2}	Ag-110	1.00×10^{-4}
Sr-90	1.32×10^{-1}	Pr-143	3.40×10^{-4}	Rh-106	1.26×10^{-3}
Zr-95	8.92×10^{-3}	Nd-147	4.69×10^{-4}	Rh-103m	2.27×10^{-3}
Nb-95	1.48×10^{-2}	Np-239	1.50×10^{-7}	Tc-99	9.80×10^{-7}
Mo-99	2.58×10^{-7}	Pu-239	3.64×10^{-5}	Nb-95m	1.89×10^{-4}
Tc-99m	2.47×10^{-7}	U-235	8.56×10^{-15}	Y-91	9.58×10^{-2}
Ru-103	2.32×10^{-3}	Th-231	8.41×10^{-15}	Y-90	1.32×10^{-1}
Ru-106	1.26×10^{-3}	Pa-231	1.27×10^{-19}	Y-89m	5.55×10^{-5}
Te-129m	3.85×10^{-3}	Re-187	3.13×10^{-14}	Cs-135	9.51×10^{-8}
Te-132	5.58×10^{-6}	Pm-147	8.77×10^{-4}	P-32	5.61×10^{-5}
Cs-134	4.23×10^{-1}	Sm-147	1.23×10^{-15}	Cr-51	9.33×10^{-3}
Cs-136	4.60×10^{-3}	Pr-144	1.62×10^{-2}	Mn-54	5.34×10^{-3}
Cs-137	6.87×10^{-1}	Nd-144	1.30×10^{-18}	Fe-59	3.41×10^{-3}
Ba-140	5.74×10^{-2}	La-140	6.60×10^{-2}	Co-58	3.44×10^{-1}
				Co-60	7.96×10^{-2}
				Zn-65	2.54×10^{-4}
				Ag-110m	7.71×10^{-3}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Equipment drain spent resin with 60 days decay.
(3) This activity is in a 1500 gallon slurry.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.
(5) The equipment drain spent resin tank and pump will not be used for initial plant operation (Section 11.4.2.1.1).

Table 12.2-57

FLOOR DRAIN COLLECTION TANK SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	4.28×10^{-2}	Cs-138	1.21×10^{-1}	Tc-99	2.57×10^{-8}
Br-84	1.69×10^{-2}	Ba-139	2.62×10^{-1}	Nb-97m	4.76×10^{-4}
Br-85	1.01×10^{-3}	Ba-140	2.74×10^{-1}	Nb-97	5.01×10^{-4}
I-131	3.86×10^{-1}	Ba-141	6.04×10^{-2}	Nb-95m	3.43×10^{-6}
I-132	1.55	Ba-142	3.69×10^{-2}	Y-92	3.52×10^{-1}
I-133	1.57	Ce-141	2.96×10^{-3}	Y-91	9.66×10^{-3}
I-134	2.46×10^{-1}	Ce-143	7.65×10^{-4}	Y-91m	4.35×10^{-1}
I-135	1.01	Ce-144	1.12×10^{-3}	Y-90	1.42×10^{-3}
Sr-89	9.81×10^{-2}	Pr-143	1.20×10^{-3}	Y-89m	9.81×10^{-6}
Sr-90	7.32×10^{-3}	Nd-147	4.24×10^{-3}	Zn-69	1.19×10^{-4}
Sr-91	7.43×10^{-1}	Np-239	6.07	Cs-135	4.88×10^{-10}
Sr-92	3.53×10^{-1}	Pu-239	4.12×10^{-7}	Na-24	8.44×10^{-3}
Zr-95	1.26×10^{-3}	Re-187	6.92×10^{-16}	P-32	1.75×10^{-4}
Zr-97	5.12×10^{-4}	Pm-147	2.52×10^{-6}	Cr-51	4.46×10^{-3}
Nb-95	1.34×10^{-3}	Sm-147	2.48×10^{-20}	Mn-54	3.63×10^{-4}
Mo-99	5.76×10^{-1}	Pr-144	1.10×10^{-3}	Mn-56	4.36×10^{-2}
Tc-99m	2.38	La-142	3.69×10^{-2}	Fe-59	7.19×10^{-4}
Tc-101	3.87×10^{-2}	La-141	6.03×10^{-2}	Co-58	4.51×10^{-2}
Ru-103	5.96×10^{-4}	La-140	7.52×10^{-2}	Co-60	4.55×10^{-3}
Ru-106	8.26×10^{-5}	Te-129	7.68×10^{-4}	Ni-65	2.60×10^{-4}
Te-129m	1.25×10^{-3}	I-129	1.08×10^{-13}	Zn-65	1.81×10^{-5}
Te-132	1.32	Ag-110	7.08×10^{-6}	Zn-69m	1.20×10^{-4}
Cs-134	5.09×10^{-3}	Rh-106	8.26×10^{-5}	Ag-110m	5.44×10^{-4}
Cs-136	3.36×10^{-3}	Rh-103m	5.64×10^{-4}	W-187	1.64×10^{-2}
Cs-137	7.64×10^{-3}				

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Floor drains (14.3% of reactor water less gases) accumulated for 1.616 days at 7.22 gpm.
(3) This activity is in 16,800 gallons.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-58

FLOOR DRAIN SURGE TANK SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	4.28×10^{-2}	Cs-137	2.73×10^{-2}	Rh-103m	1.99×10^{-3}
Br-84	1.69×10^{-2}	Cs-138	1.21×10^{-1}	Tc-99	1.36×10^{-7}
Br-85	1.01×10^{-3}	Ba-139	2.62×10^{-1}	Nb-97m	5.97×10^{-4}
I-131	1.16	Ba-140	8.78×10^{-1}	Nb-97	6.42×10^{-4}
I-132	3.49	Ba-141	6.04×10^{-2}	Nb-95m	3.42×10^{-5}
I-133	2.12	Ba-142	3.69×10^{-2}	Y-92	3.53×10^{-1}
I-134	2.46×10^{-1}	Ce-141	1.09×10^{-2}	Y-91	4.67×10^{-2}
I-135	1.03	Ce-143	1.30×10^{-3}	Y-91m	4.67×10^{-1}
Sr-89	3.41×10^{-1}	Ce-144	3.97×10^{-3}	Y-90	1.31×10^{-2}
Sr-90	2.61×10^{-2}	Pr-143	3.98×10^{-3}	Y-89m	3.41×10^{-5}
Sr-91	7.92×10^{-1}	Nd-147	1.33×10^{-2}	Zn-69	1.40×10^{-4}
Sr-92	3.53×10^{-1}	Np-239	$1.31 \times 10^{+1}$	Cs-135	3.13×10^{-9}
Zr-95	4.41×10^{-3}	Pu-239	3.74×10^{-6}	Na-24	1.01×10^{-2}
Zr-97	6.42×10^{-4}	Re-187	4.67×10^{-15}	P-32	5.66×10^{-4}
Nb-95	4.75×10^{-3}	Pm-147	2.95×10^{-5}	Cr-51	1.51×10^{-2}
Mo-99	1.33	Sm-147	1.06×10^{-18}	Mn-54	1.29×10^{-3}
Tc-99m	3.12	Pr-144	3.95×10^{-3}	Mn-56	4.36×10^{-2}
Tc-101	3.87×10^{-2}	La-142	3.69×10^{-2}	Fe-59	2.49×10^{-3}
Ru-103	2.05×10^{-3}	La-141	6.04×10^{-2}	Co-58	1.58×10^{-1}
Ru-106	2.94×10^{-4}	La-140	5.63×10^{-1}	Co-60	1.62×10^{-2}
Te-129m	4.29×10^{-3}	Te-129	2.71×10^{-3}	Ni-65	2.60×10^{-4}
Te-132	3.21	I-129	1.39×10^{-12}	Zn-65	6.44×10^{-5}
Cs-134	1.81×10^{-2}	Ag-110	2.51×10^{-5}	Zn-69m	1.40×10^{-4}
Cs-136	1.08×10^{-2}	Rh-106	2.94×10^{-4}	Ag-110m	1.93×10^{-3}
				W-187	2.38×10^{-2}

(1) Based upon shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Floor drains (14.3% of reactor water less gases) accumulated for 5.769 days at 7.22 gpm.
(3) This activity is in 60,000 gallons.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-59

FLOOR DRAIN SAMPLE TANK NO. 1 SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	4.28×10^{-3}	Cs-137	3.82×10^{-3}	Tc-99	2.57×10^{-9}
Br-84	1.69×10^{-3}	Cs-138	6.04×10^{-2}	Nb-97m	4.76×10^{-5}
Br-85	1.01×10^{-4}	Ba-139	2.62×10^{-2}	Nb-97	5.01×10^{-5}
I-131	3.86×10^{-2}	Ba-140	2.74×10^{-2}	Nb-95m	3.43×10^{-7}
I-132	1.55×10^{-1}	Ba-141	6.04×10^{-3}	Y-92	3.52×10^{-2}
I-133	1.57×10^{-1}	Ba-142	3.69×10^{-3}	Y-91	9.66×10^{-4}
I-134	2.46×10^{-2}	Ce-141	2.96×10^{-4}	Y-91m	4.35×10^{-2}
I-135	1.01×10^{-1}	Ce-143	7.65×10^{-5}	Y-90	1.42×10^{-4}
Sr-89	9.81×10^{-3}	Ce-144	1.12×10^{-4}	Y-89m	9.81×10^{-7}
Sr-90	7.32×10^{-4}	Pr-143	1.20×10^{-4}	Zn-69	1.19×10^{-5}
Sr-91	7.43×10^{-2}	Nd-147	4.24×10^{-4}	Cs-135	2.44×10^{-10}
Sr-92	3.53×10^{-2}	Np-239	6.07×10^{-1}	Na-24	8.44×10^{-4}
Zr-95	1.26×10^{-4}	Pu-239	4.12×10^{-8}	P-32	1.75×10^{-5}
Zr-97	5.12×10^{-5}	Re-187	6.92×10^{-17}	Cr-51	4.46×10^{-4}
Nb-95	1.34×10^{-4}	Pm-147	2.52×10^{-7}	Mn-54	3.63×10^{-5}
Mo-99	5.76×10^{-2}	Pr-144	1.10×10^{-4}	Mn-56	4.36×10^{-3}
Tc-99m	2.38×10^{-1}	La-142	3.69×10^{-3}	Fe-59	7.19×10^{-5}
Tc-101	3.87×10^{-3}	La-141	6.03×10^{-3}	Co-58	4.51×10^{-3}
Ru-103	5.96×10^{-5}	La-140	7.52×10^{-3}	Co-60	4.55×10^{-4}
Ru-106	8.26×10^{-6}	Te-129	7.68×10^{-5}	Ni-65	2.60×10^{-5}
Te-129m	1.25×10^{-4}	I-129	1.08×10^{-14}	Zn-65	1.81×10^{-6}
Te-132	1.32×10^{-1}	Ag-110	7.08×10^{-7}	Zn-69m	1.20×10^{-5}
Cs-134	2.54×10^{-3}	Rh-106	8.26×10^{-6}	Ag-110m	5.44×10^{-5}
Cs-136	1.68×10^{-3}	Rh-103m	5.64×10^{-5}	W-187	1.64×10^{-3}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Floor drain collection tank activity with DFs applied for the filter (DF = 2 for Cs and Rb, DF = 10.0 for other isotopes).
(3) This activity is in 16,800 gallons.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-60

FLOOR DRAIN SAMPLE TANK NO. 2 SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	4.28×10^{-5}	Cs-137	3.82×10^{-4}	Tc-99	2.57×10^{-11}
Br-84	1.69×10^{-5}	Cs-138	6.04×10^{-3}	Nb-97m	4.76×10^{-7}
Br-85	1.01×10^{-6}	Ba-139	2.62×10^{-4}	Nb-97	5.01×10^{-7}
I-131	3.86×10^{-4}	Ba-140	2.74×10^{-4}	Nb-95m	3.43×10^{-9}
I-132	1.55×10^{-3}	Ba-141	6.04×10^{-5}	Y-92	3.52×10^{-4}
I-133	1.57×10^{-3}	Ba-142	3.69×10^{-5}	Y-91	9.66×10^{-6}
I-134	2.46×10^{-4}	Ce-141	2.96×10^{-6}	Y-91m	4.35×10^{-4}
I-135	1.01×10^{-3}	Ce-143	7.65×10^{-7}	Y-90	1.42×10^{-6}
Sr-89	9.81×10^{-5}	Ce-144	1.12×10^{-6}	Y-89m	9.81×10^{-9}
Sr-90	7.32×10^{-6}	Pr-143	1.20×10^{-6}	Zn-69	1.19×10^{-7}
Sr-91	7.43×10^{-4}	Nd-147	4.24×10^{-6}	Cs-135	2.44×10^{-11}
Sr-92	3.53×10^{-4}	Np-239	6.07×10^{-3}	Na-24	8.44×10^{-6}
Zr-95	1.26×10^{-6}	Pu-239	4.12×10^{-10}	P-32	1.75×10^{-7}
Zr-97	5.12×10^{-7}	Re-187	6.92×10^{-19}	Cr-51	4.46×10^{-6}
Nb-95	1.34×10^{-7}	Pm-147	2.52×10^{-9}	Mn-54	3.63×10^{-7}
Mo-99	5.76×10^{-4}	Pr-144	1.10×10^{-6}	Mn-56	4.36×10^{-5}
Tc-99m	2.38×10^{-3}	La-142	3.69×10^{-5}	Fe-59	7.19×10^{-7}
Tc-101	3.87×10^{-5}	La-141	6.03×10^{-5}	Co-58	4.51×10^{-5}
Ru-103	5.96×10^{-7}	La-140	7.52×10^{-5}	Co-60	4.55×10^{-6}
Ru-106	8.26×10^{-8}	Te-129	7.68×10^{-7}	Ni-65	2.60×10^{-7}
Te-129m	1.25×10^{-6}	I-129	1.08×10^{-16}	Zn-65	1.81×10^{-8}
Te-132	1.32×10^{-3}	Ag-110	7.08×10^{-9}	Zn-69m	1.20×10^{-7}
Cs-134	2.54×10^{-4}	Rh-106	8.26×10^{-8}	Ag-110m	5.44×10^{-7}
Cs-136	1.68×10^{-4}	Rh-103m	5.64×10^{-7}	W-187	1.64×10^{-5}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Floor drain sample tank No. 1 activity with DFs applied for the demineralizer (DF=10 for Cs and Rb, DF=100 for others).
(3) This activity is in 16,800 gallons.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-61

FLOOR DRAIN FILTER SHIELDING DESIGN SOURCE TERMS[1][2][4]

ISOTOPE[3]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	4.27×10^{-2}	Cs-137	4.35×10^{-3}	Rh-103m	3.14×10^{-4}
Br-84	1.69×10^{-2}	Cs-138	1.21×10^{-1}	Tc-99	1.14×10^{-8}
Br-85	1.01×10^{-3}	Ba-139	2.62×10^{-1}	Nb-97m,	3.55×10^{-4}
I-131	2.26×10^{-1}	Ba-140	1.59×10^{-1}	Nb-97	3.62×10^{-4}
I-132	1.02	Ba-141	6.04×10^{-2}	Nb-95m	1.16×10^{-6}
I-133	1.13	Ba-142	3.69×10^{-2}	Y-92	3.37×10^{-1}
I-134	2.46×10^{-1}	Cs-141	1.56×10^{-3}	Y-91	4.04×10^{-3}
I-135	9.24×10^{-1}	Ce-143	5.07×10^{-4}	Y-91m	3.61×10^{-1}
Sr-89	5.58×10^{-2}	Ce-144	6.33×10^{-4}	Y-90	4.89×10^{-4}
Sr-90	4.17×10^{-3}	Pr-143	6.85×10^{-4}	Y-89m	5.58×10^{-6}
Sr-91	6.28×10^{-1}	Nd-147	2.47×10^{-4}	Cs-135	1.55×10^{-10}
Sr-92	3.52×10^{-1}	Np-239	3.81	Na-24	6.48×10^{-3}
Zr-95	7.21×10^{-4}	Re-187	2.58×10^{-16}	P-32	1.01×10^{-4}
Zr-97	3.82×10^{-4}	Ag-110	4.03×10^{-6}	Cr-51	2.56×10^{-3}
Nb-95	7.61×10^{-4}	Zn-69	9.04×10^{-5}	Mn-54	2.07×10^{-4}
Mo-99	3.56×10^{-1}	Pu-239	1.43×10^{-7}	Mn-56	4.35×10^{-2}
Tc-99m	2.05	Pm-147	8.29×10^{-8}	Co-58	2.58×10^{-2}
Tc-101	3.87×10^{-2}	Pr-144	6.22×10^{-4}	Co-60	2.59×10^{-3}
Ru-103	3.42×10^{-4}	La-142	3.69×10^{-2}	Fe-59	4.11×10^{-4}
Ru-106	4.71×10^{-5}	La-141	5.91×10^{-2}	Ni-65	2.60×10^{-4}
Te-129m	7.18×10^{-4}	La-140	2.70×10^{-2}	Zn-65	1.03×10^{-5}
Te-132	8.06×10^{-1}	Te-129	4.25×10^{-4}	Zn-69m	9.39×10^{-5}
Cs-134	2.90×10^{-3}	I-129	3.37×10^{-14}	Ag-110m	3.10×10^{-4}
Cs-136	1.95×10^{-3}	Rh-106	4.70×10^{-5}	W-187	1.15×10^{-2}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Floor drains (14.3% of reactor water less gases) accumulated for 0.92 days at 7.22 gpm.
(3) Isotopes with activities less than 1.0×10^{-20} are not listed.
(4) For shielding design of associated piping, backwash volume to waste sludge tank is 1925 gallons.

Table 12.2-62

FLOOR DRAIN DEMINERALIZER AND SPENT RESIN TANK SHIELDING DESIGN SOURCE TERMS [1][2][3][5]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPES	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	4.28×10^{-3}	Cs-138	6.04×10^{-2}	Rh-103m	7.10×10^{-4}
Br-84	1.69×10^{-3}	Ba-139	2.62×10^{-2}	Tc-99	7.21×10^{-8}
Br-85	1.01×10^{-4}	Ba-140	2.37×10^{-1}	Nb-97m	5.99×10^{-5}
I-131	2.59×10^{-1}	Ba-141	6.04×10^{-3}	Nb-97	6.44×10^{-5}
I-132	4.81×10^{-1}	Ba-142	3.69×10^{-3}	Nb-95m	2.61×10^{-5}
I-133	2.14×10^{-1}	Ce-141	3.81×10^{-3}	Y-92	3.53×10^{-2}
I-134	2.46×10^{-2}	Ce-143	1.37×10^{-4}	Y-91	1.89×10^{-2}
I-135	1.03×10^{-1}	Ce-144	1.59×10^{-3}	Y-91m	4.67×10^{-2}
Sr-89	1.25×10^{-1}	Pr-143	1.12×10^{-3}	Y-90	9.10×10^{-3}
Sr-90	1.07×10^{-2}	Nd-147	3.40×10^{-3}	Y-89m	1.25×10^{-5}
Sr-91	7.92×10^{-2}	Np-239	1.60	Zn-69	1.40×10^{-5}
Sr-92	3.53×10^{-2}	Pu-239	2.53×10^{-6}	Cs-135	1.48×10^{-9}
Zr-95	1.65×10^{-3}	U-235	7.06×10^{-17}	Na-24	1.01×10^{-3}
Zr-97	6.44×10^{-5}	Th-231	6.10×10^{-17}	P-32	1.58×10^{-4}
Nb-95	1.91×10^{-3}	Re-187	2.38×10^{-15}	Cr-51	5.04×10^{-3}
Mo-99	1.73×10^{-1}	Pm-147	3.60×10^{-5}	Mn-54	5.19×10^{-4}
Tc-99m	3.51×10^{-1}	Sm-147	5.72×10^{-18}	Mn-56	4.36×10^{-3}
Tc-101	3.87×10^{-3}	Pr-144	1.59×10^{-3}	Fe-59	8.96×10^{-4}
Ru-103	7.26×10^{-4}	La-142	3.69×10^{-3}	Co-58	5.96×10^{-2}
Ru-106	1.19×10^{-4}	La-141	6.04×10^{-3}	Co-60	6.64×10^{-3}
Te-129m	1.48×10^{-3}	La-140	2.23×10^{-1}	Ni-65	2.60×10^{-5}
Te-132	4.49×10^{-1}	Te-129	9.46×10^{-4}	Zn-65	2.58×10^{-5}
Cs-134	3.69×10^{-2}	I-129	2.11×10^{-12}	Zn-69m	1.40×10^{-5}
Cs-136	1.50×10^{-2}	Ag-110	1.01×10^{-5}	Ag-110m	7.75×10^{-4}
Cs-137	5.60×10^{-2}	Rh-106	1.19×10^{-4}	W-187	2.43×10^{-3}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Filtered floor drains (DF of 2 for Cs and Rb and DF of 10 for others) accumulated for 23.7 days at 7.22 gpm.
(3) This activity is in 85 ft^3 of spent resin.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.
(5) The floor drain spent resin tank will not be used for initial plant operation (Section 11.4.2.1.1).

Table 12.2-63

FLOOR DRAIN SPENT RESIN TANK PUMP SHIELDING DESIGN SOURCE TERMS[1][2][3][5]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
I-131	4.03×10^{-2}	Ce-143	2.57×10^{-9}	Nb-97m	3.98×10^{-14}
I-132	4.54×10^{-3}	Ce-144	1.51×10^{-3}	Nb-97	4.60×10^{-14}
I-133	4.42×10^{-9}	Pr-143	3.78×10^{-4}	Nb-95m	2.77×10^{-5}
Sr-89	9.40×10^{-2}	Nd-147	8.79×10^{-4}	Y-91	1.51×10^{-2}
Sr-90	1.07×10^{-2}	Np-239	2.71×10^{-3}	Y-91m	3.75×10^{-18}
Sr-91	5.81×10^{-18}	Pu-239	2.95×10^{-6}	Y-90	1.07×10^{-2}
Zr-95	1.31×10^{-3}	U-235	2.37×10^{-16}	Y-89m	9.40×10^{-6}
Zr-97	4.27×10^{-14}	Th-231	2.25×10^{-16}	Zn-69	7.44×10^{-17}
Nb-95	1.75×10^{-3}	Re-187	2.54×10^{-15}	Cs-135	1.54×10^{-9}
Mo-99	7.94×10^{-4}	Pm-147	6.43×10^{-5}	Na-24	3.77×10^{-14}
Tc-99m	7.59×10^{-4}	Sm-147	2.66×10^{-17}	P-32	5.56×10^{-5}
Ru-103	4.97×10^{-4}	Pr-144	1.51×10^{-3}	Cr-51	2.94×10^{-3}
Ru-106	1.14×10^{-4}	Nd-144	4.16×10^{-20}	Mn-54	4.94×10^{-4}
Te-129m	9.55×10^{-4}	La-140	8.46×10^{-2}	Fe-59	6.45×10^{-4}
Te-132	4.41×10^{-3}	Te-129	6.12×10^{-4}	Co-58	4.83×10^{-2}
Cs-134	3.62×10^{-2}	I-129	5.01×10^{-12}	Co-60	6.59×10^{-3}
Cs-136	5.02×10^{-3}	Ag-110	9.50×10^{-6}	Zn-65	2.43×10^{-5}
Cs-137	5.59×10^{-2}	Rh-106	1.14×10^{-4}	Zn-69m	6.93×10^{-17}
Ba-140	7.35×10^{-2}	Rh-103m	4.87×10^{-4}	Ag-110m	7.31×10^{-4}
Ce-141	2.42×10^{-3}	Tc-99	7.94×10^{-8}	W-187	7.19×10^{-10}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Floor drain spent resin with 21.6 days decay.
(3) This activity is in a 1500 gallon slurry.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.
(5) The floor drain spent resin tank and pump will not be used for initial plant operation (Section 11.4.2.1.1).

Table 12.2-64

CHEMICAL WASTE TANK AND EVAPORATOR FEED TANK SHIELDING DESIGN SOURCE TERMS[1][2][3][5]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	6.91×10^{-4}	Cs-138	1.95×10^{-3}	Tc-99	1.83×10^{-9}
Br-84	2.73×10^{-4}	Ba-139	4.22×10^{-3}	Nb-97m	9.59×10^{-6}
Br-85	1.62×10^{-5}	Ba-140	1.25×10^{-2}	Nb-97	1.03×10^{-5}
I-131	1.68×10^{-2}	Ba-141	9.75×10^{-4}	Nb-95m	4.33×10^{-7}
I-132	5.24×10^{-2}	Ba-142	5.96×10^{-4}	Y-92	5.70×10^{-3}
I-133	3.40×10^{-2}	Ce-141	1.53×10^{-4}	Y-91	6.44×10^{-4}
I-134	3.97×10^{-3}	Ce-143	2.04×10^{-5}	Y-91m	7.54×10^{-3}
I-135	1.66×10^{-2}	Ce-144	5.55×10^{-5}	Y-90	1.68×10^{-4}
Sr-89	4.79×10^{-3}	Pr-143	5.66×10^{-5}	Y-89m	4.79×10^{-7}
Sr-90	3.65×10^{-4}	Nd-147	1.91×10^{-4}	Zn-69	2.25×10^{-6}
Sr-91	1.28×10^{-2}	Np-239	1.99×10^{-1}	Cs-135	4.25×10^{-11}
Sr-92	5.70×10^{-3}	Pu-239	4.80×10^{-8}	Na-24	1.63×10^{-4}
Zr-95	6.19×10^{-5}	Re-187	6.23×10^{-17}	P-32	8.06×10^{-6}
Zr-97	1.03×10^{-5}	Pm-147	3.64×10^{-7}	Cr-51	2.13×10^{-4}
Nb-95	6.65×10^{-5}	Sm-147	1.12×10^{-20}	Mn-54	1.81×10^{-5}
Mo-99	2.00×10^{-2}	Pr-144	5.53×10^{-5}	Mn-56	7.03×10^{-4}
Tc-99m	4.90×10^{-2}	La-142	5.96×10^{-4}	Fe-59	3.50×10^{-5}
Tc-101	6.24×10^{-4}	La-141	9.75×10^{-4}	Co-58	2.22×10^{-3}
Ru-103	2.89×10^{-5}	La-140	7.46×10^{-3}	Co-60	2.27×10^{-4}
Ru-106	4.11×10^{-6}	Te-129	3.82×10^{-5}	Ni-65	4.20×10^{-6}
Te-129m	6.04×10^{-5}	I-129	1.69×10^{-14}	Zn-65	9.02×10^{-7}
Te-132	4.79×10^{-2}	Ag-110	3.52×10^{-7}	Zn-69m	2.25×10^{-6}
Cs-134	2.54×10^{-4}	Rh-106	4.11×10^{-6}	Ag-110m	2.71×10^{-5}
Cs-136	1.54×10^{-4}	Rh-103m	2.80×10^{-5}	W-187	3.79×10^{-4}
Cs-137	3.81×10^{-4}				

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Chemical wastes (2% of reactor water less gases) accumulated for 5.0 days at 0.833 gpm.
(3) This activity is in 6000 gallons.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.
(5) Installation of the abandoned evaporator feed tank was not completed for plant operation (Section 11.2.2.1.3).

Table 12.2-65

RADWASTE EVAPORATOR SHIELDING DESIGN SOURCE TERMS[1][2][3][5]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY ((Ci)
Br-83	7.04×10^{-13}	Ce-143	4.87×10^{-6}	Nb-97	5.95×10^{-7}
I-131	3.71×10^{-2}	Ce-144	9.06×10^{-4}	Nb-95m	1.45×10^{-5}
I-132	3.94×10^{-2}	Pr-143	2.22×10^{-4}	Y-92	1.76×10^{-8}
I-133	2.96×10^{-3}	Nd-147	5.87×10^{-5}	Y-91	8.18×10^{-3}
I-135	9.46×10^{-6}	Np-239	1.06×10^{-1}	Y-91m	4.73×10^{-5}
Sr-89	5.04×10^{-2}	Re-187	1.58×10^{-15}	Y-90	6.56×10^{-3}
Sr-90	6.67×10^{-3}	Ag-110	5.70×10^{-6}	Y-89m	5.04×10^{-6}
Sr-91	7.32×10^{-5}	Zn-69	6.53×10^{-8}	Cs-135	9.62×10^{-10}
Sr-92	5.75×10^{-11}	Pu-239	1.81×10^{-6}	Na-24	5.82×10^{-6}
Zr-95	7.22×10^{-4}	U-235	2.24×10^{-16}	P-32	3.20×10^{-5}
Zr-97	5.52×10^{-7}	Th-231	2.16×10^{-16}	Cr-51	1.52×10^{-3}
Nb-95	9.95×10^{-4}	Pm-147	3.92×10^{-6}	Mn-54	2.98×10^{-4}
Mo-99	1.33×10^{-2}	Sm-147	2.93×10^{-18}	Mn-56	2.72×10^{-12}
Tc-99m	1.27×10^{-2}	Pr-144	9.06×10^{-4}	Co-58	2.67×10^{-2}
Ru-103	2.61×10^{-4}	Nd-144	3.64×10^{-20}	Co-60	4.09×10^{-3}
Ru-106	6.91×10^{-5}	La-142	5.95×10^{-18}	Fe-59	3.43×10^{-4}
Te-129m	4.97×10^{-4}	La-141	2.66×10^{-9}	Ni-65	1.49×10^{-14}
Te-132	3.83×10^{-2}	La-140	4.90×10^{-2}	Zn-65	1.45×10^{-5}
Cs-134	4.45×10^{-3}	Te-129	3.19×10^{-4}	Zn-69m	6.08×10^{-8}
Cs-136	5.88×10^{-4}	I-129	3.66×10^{-12}	Ag-110m	4.38×10^{-4}
Cs-137	6.96×10^{-3}	Rh-106	6.91×10^{-5}	W-187	4.85×10^{-5}
Ba-139	8.76×10^{-19}	Rh-103m	2.56×10^{-4}		
Ba-140	4.46×10^{-2}	Tc-99	4.90×10^{-8}		
Ce-141	1.26×10^{-3}	Nb-97m	5.14×10^{-7}		

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Chemical wastes (2% of reactor water less gases) accumulated for 91.575 days at 0.833 gpm, with 3 days decay.
(3) This activity is in 1100 gallons of concentrate.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.
(5) Installation of the abandoned radwaste evaporator system was not completed for plant operation (Section 11.2.2.1.3).

Table 12.2-66

EVAPORATOR DISTILLATE TANK SHIELDING DESIGN SOURCE TERMS[1][2][3][5]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (ci)
Br-83	7.04×10^{-16}	Ba-140	1.07×10^{-6}	Y-92	1.76×10^{-12}
I-131	1.30×10^{-5}	Ce-141	1.48×10^{-8}	Y-91	7.10×10^{-8}
I-132	2.60×10^{-5}	Ce-143	4.49×10^{10}	Y-91m	4.74×10^{-9}
I-133	2.91×10^{-6}	Ce-144	5.51×10^{-9}	Y-90	2.79×10^{-8}
I-135	9.46×10^{-9}	Pr-143	5.00×10^{-9}	Y-89m	4.60×10^{-11}
Sr-89	4.60×10^{-7}	Nd-147	1.58×10^{-9}	Zn-69	6.51×10^{-12}
Sr-90	3.65×10^{-8}	Np-239	8.21×10^{-6}	Cs-135	5.24×10^{-15}
Sr-91	7.34×10^{-9}	Pu-239	7.89×10^{-12}	Na-24	5.79×10^{-10}
Sr-92	5.75×10^{-15}	Pm-147	7.41×10^{-11}	P-32	6.97×10^{-10}
Zr-95	6.00×10^{-9}	Pr-144	5.51×10^{-0}	Cr-51	1.98×10^{-9}
Zr-97	5.48×10^{-11}	La-141	2.66×10^{-13}	Mn-54	1.79×10^{-9}
Nb-95	6.61×10^{-9}	La-140	1.02×10^{-6}	Mn-56	2.72×10^{-16}
Mo-99	9.46×10^{-7}	Te-129	3.64×10^{-9}	Fe-59	3.34×10^{-9}
Tc-99m	9.06×10^{-7}	I-129	3.65×10^{-17}	Co-58	2.15×10^{-7}
Ru-103	2.74×10^{-9}	Ag-110	3.49×10^{-11}	Co-60	2.27×10^{-8}
Ru-106	4.09×10^{-10}	Rn-106	4.09×10^{-10}	Ni-65	1.49×10^{-18}
Te-129m	5.69×10^{-9}	Rn-103m	2.69×10^{-9}	Zn-65	8.94×10^{-11}
Te-132	2.52×10^{-6}	Tc-99	2.34×10^{-13}	Zn-69m	6.07×10^{-12}
Cs-134	2.53×10^{-8}	Nb-97m	5.10×10^{-11}	Ag-110m	2.68×10^{-9}
Cs-136	1.33×10^{-8}	Nb-97	5.90×10^{-11}	W-187	4.70×10^{-9}
Cs-137	3.81×10^{-8}	Nb-95m	7.67×10^{-11}		

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Activity in evaporator feed tank with 3.0 days decay and DFs applied for the evaporator (DF of 1000 for I and Br and DF of 10,000 for others).
(3) This activity is in 6000 gallons.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.
(5) Installation of the abandoned evaporator distillate tank was not completed for plant operation (Section 11.2.2.1.3).

Table 12.2-67

LAUNDRY DRAIN COLLECTION TANK SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)
Mn-54	5.48×10^{-6}
Co-58	2.18×10^{-5}
Co-60	4.94×10^{-5}
Zr-95	7.62×10^{-6}
Nb-95	1.09×10^{-5}
Ru-103	7.60×10^{-7}
Ru-106	1.31×10^{-5}
Ag-110m	2.41×10^{-6}
I-131	3.15×10^{-6}
Cs-134	7.12×10^{-5}
Cs-137	1.31×10^{-4}
Ce-144	2.74×10^{-5}
Pr-144	2.69×10^{-5}
Ag-110	3.13×10^{-8}
Rh-106	1.31×10^{-5}
Rh-103m	7.02×10^{-7}
Nb-95m	1.33×10^{-8}

(1) Based on untreated detergent waste activities presented in NUREG-0016, Revision 0, Tables 2-31 and 2-32 (Reference 12.2-1).
(2) Laundry drains accumulated for 1.0 days at 0.625 gpm.
(3) This activity is in 900 gallons.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-68

LAUNDRY DRAIN SAMPLE TANK SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)
Mn-54	1.09×10^{-5}
Co-58	4.35×10^{-5}
Co-60	9.88×10^{-5}
Zr-95	1.52×10^{-5}
Nb-95	2.18×10^{-5}
Ru-103	1.51×10^{-6}
Ru-106	2.62×10^{-5}
Ag-110m	4.81×10^{-6}
I –131	6.05×10^{-6}
Cs-134	1.42×10^{-4}
Cs-137	2.63×10^{-4}
Ce-144	5.47×10^{-5}
Pr-144	5.42×10^{-5}
Ag-110	6.25×10^{-8}
Rh-106	2.62×10^{-5}
Rh-103m	1.43×10^{-6}
Nb-95m	4.99×10^{-8}

(1) Based on untreated detergent waste activities presented in NUREG-0016, Revision 0, tables 2-31 and 2-32 (Reference 12.2-1).
(2) Laundry drains accumulated for 2.0 days at 0.625 gpm.
(3) This activity is in 1800 gallons.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-69

REACTOR, TURBINE, AND RADWASTE ENCLOSURES EQUIPMENT AND FLOOR DRAIN SUMPS
SHIELDING DESIGN SOURCE TERMS[1]

ISOTOPE[2]	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)
Br-83	5.25×10^{-10}	Tc-99m	9.80×10^{-9}	Ce-144	1.23×10^{-12}
Br-84	9.45×10^{-10}	Tc-101	4.90×10^{-9}	Pr-143	1.33×10^{-12}
Br-85	5.95×10^{-10}	Ru-103	6.65×10^{-13}	Nd-147	4.90×10^{-13}
I-131	4.55×10^{-10}	Ru-106	9.10×10^{-14}	Np-239	8.40×10^{-9}
I-132	4.20×10^{-9}	Te-129m	1.40×10^{-12}	Na-24	2.00×10^{-11}
I-133	3.12×10^{-9}	Te-132	1.72×10^{-9}	P-32	2.00×10^{-13}
I-134	8.40×10^{-9}	Cs-134	5.60×10^{-12}	Cr-51	5.00×10^{-12}
I-135	4.55×10^{-9}	Cs-136	3.85×10^{-12}	Mn-54	4.00×10^{-13}
Sr-89	1.09×10^{-10}	Cs-137	8.40×10^{-12}	Mn-56	5.00×10^{-10}
Sr-90	8.05×10^{-12}	Cs-138	6.65×10^{-9}	Co-58	5.00×10^{-11}
Sr-91	2.42×10^{-9}	Ba-139	5.60×10^{-9}	Co-60	5.00×10^{-12}
Sr-92	3.85×10^{-9}	Ba-140	3.15×10^{-10}	Fe-59	8.00×10^{-13}
Zr-95	1.40×10^{-12}	Ba-141	5.95×10^{-9}	Ni-65	3.00×10^{-12}
Zr-97	1.12×10^{-12}	Ba-142	5.95×10^{-9}	Zn-65	2.00×10^{-14}
Nb-95	1.47×10^{-12}	Ce-141	1.37×10^{-12}	Zn-69m	3.00×10^{-13}
Mo-99	7.70×10^{-10}	Ce-143	1.23×10^{-12}	Ag-110m	6.00×10^{-13}
				W-187	3.00×10^{-11}

(1) Assumes 1% of specific activity in reactor water, less activation gases (Tables 12.2-2, 12.2-3, and 12.2-5).
(2) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-70

CONDENSATE PHASE SEPARATORS SHIELDING DESIGN SOURCE TERMS[1][2][3][4]

CARRYOVER COMPONENT

Isotope[5]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Br-83	$2.48 \times 10^{+1}$	Cs-138	3.36	Te-129	3.19×10^{-1}
Br-84	9.44	Ba-139	7.51	I-129	8.73×10^{-10}
Br-85	3.50×10^{-1}	Ba-140	$7.54 \times 10^{+1}$	Rh-106	4.17×10^{-2}
I-131	$1.59 \times 10^{+3}$	Ba-141	1.62	Rh-103m	2.41×10^{-1}
I-132	$3.17 \times 10^{+2}$	Ba-142	9.37×10^{-1}	Tc-99	2.59×10^{-5}
I-133	$1.25 \times 10^{+3}$	Ce-141	1.28	Nb-97m	1.75×10^{-2}
I-134	$1.40 \times 10^{+2}$	Ce-143	4.00×10^{-2}	Nb-97	1.88×10^{-2}
I-135	$5.99 \times 10^{+2}$	Ce-144	5.57×10^{-1}	Nb-95m	9.43×10^{-3}
Sr-89	$4.26 \times 10^{+1}$	Pr-143	3.59×10^{-1}	Y-92	$1.03 \times 10^{+1}$
Sr-90	3.79	Nd-147	1.07×10^{-1}	Y-91	6.49
Sr-91	$2.30 \times 10^{+1}$	Np-239	$4.68 \times 10^{+2}$	Y-91m	$1.36 \times 10^{+1}$
Sr-92	$1.02 \times 10^{+1}$	Re-187	8.51×10^{-13}	Y-90	3.31
Zr-95	5.69×10^{-1}	Ag-110	3.53×10^{-3}	Y-89m	4.26×10^{-3}
Zr-97	1.88×10^{-2}	Zn-69	4.10×10^{-3}	Cs-135	1.05×10^{-5}
Nb-95	6.68×10^{-1}	Pu-239	9.19×10^{-4}	Na-24	2.96×10^{-1}
Mo-99	$5.08 \times 10^{+1}$	U-235	3.15×10^{-14}	P-32	5.09×10^{-2}
Tc-99m	$1.03 \times 10^{+2}$	Th-231	2.80×10^{-14}	Cr-51	1.68
Tc-101	1.01	Pa-231	1.42×10^{-18}	Mn-54	1.82×10^{-1}
Ru-103	2.46×10^{-1}	Pm-147	1.42×10^{-3}	Mn-56	1.26
Ru-106	4.17×10^{-2}	Sm-147	2.76×10^{-16}	Co-58	$2.05 \times 10^{+1}$
Te-129m	5.00×10^{-1}	Pr-144	5.57×10^{-1}	Co-60	2.34
Te-132	$1.32 \times 10^{+2}$	Nd-144	6.37×10^{-18}	Fe-59	3.05×10^{-1}
Cs-134	2.60	La-142	1.08	Ni-65	7.54×10^{-3}
Cs-136	9.58×10^{-1}	La-141	1.77	Zn-65	9.04×10^{-3}
Cs-137	3.95	La-140	$7.23 \times 10^{+1}$	Zn-69m	4.09×10^{-3}
				Ag-110m	2.72×10^{-1}
				W-187	7.09×10^{-1}

Table 12.2-70 (Cont'd)

FALLOUT COMPONENT

Isotope[5]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Ba-144	3.88×10^{-6}	La-140	5.11	Y-93	9.72×10^{-1}
La-144	1.57×10^{-3}	Cs-139	5.86	Zr-93	3.44×10^{-8}
Ce-144	7.64×10^{-4}	Ba-139	6.93	Nb-93m	6.38×10^{-11}
Pr-144	7.64×10^{-4}	Cs-138	2.22	Rb-92	5.38×10^{-8}
Ba-143	2.31×10^{-5}	Cs-137	7.06×10^{-3}	Sr-92	4.25
La-143	5.83×10^{-2}	Cs-135	1.05×10^{-8}	Y-92	4.29
Ce-143	1.54	Rb-95	1.43×10^{-19}	Rb-91	1.79
Pr-143	1.14	Sr-95	1.56×10^{-3}	Sr-91	6.81
Cs-142	3.01×10^{-19}	Y-95	1.04×10^{-2}	Y-91	1.91
Ba-142	4.91×10^{-1}	Zr-95	2.93×10^{-3}	Y-91m	4.02
La-142	5.66×10^{-1}	Nb-95	7.21×10^{-4}	Rb-90	3.93
Cs-141	3.65×10^{-2}	Nb-95m	4.87×10^{-5}	Sr-90	1.33×10^{-2}
Ba-141	1.94	Rb-94	5.13×10^{-16}	Y-90	1.17×10^{-2}
La-141	2.08	Sr-94	5.27×10^{-2}	Rb-89	3.03
Ce-141	9.42×10^{-1}	Y-94	1.63×10^{-1}	Sr-89	1.05
Cs-140	1.58	Rb-93	3.06×10^{-8}	Y-89m	1.05×10^{-4}
Ba-140	5.33	Sr-93	8.09×10^{-1}	Rb-88	4.79×10^{-1}
				Rb-87	5.93×10^{-13}

(1) Based on shielding design source terms given in Tables 12.2-1 through 12.2-5.
(2) Condensate with 2.25 minutes decay accumulated for 28.6 days at 30,200 gpm.
(3) Assumes a 2.25 minute transit time through the hotwell to the filter/demineralizers.
(4) This activity is in 1600 gallons of sludge (spent resin).
(5) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-71

CONDENSATE PHASE SEPARATOR SLUDGE MIXING AND DISCHARGE PUMP SHIELDING DESIGN SOURCE TERMS[1][2][3]

CARRYOVER COMPONENT

Isotope[4]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
I-131	$1.43 \times 10^{+2}$	Ce-144	5.20×10^{-1}	Tc-99	2.80×10^{-5}
I-132	3.38×10^{-1}	Pr-143	8.72×10^{-2}	Nb-97m	2.22×10^{-14}
I-133	1.36×10^{-7}	Nd-147	1.86×10^{-2}	Nb-97	2.57×10^{-14}
Sr-89	$2.95 \times 10^{+1}$	Np-239	1.20×10^{-1}	Nb-95m	8.96×10^{-3}
Sr-90	3.78	Re-187	8.96×10^{-13}	Y-91	4.79
Sr-91	2.81×10^{-20}	Ag-110	3.27×10^{-3}	Y-91m	1.81×10^{-20}
Zr-95	4.23×10^{-1}	Zn-69	9.73×10^{-18}	Y-90	3.78
Zr-97	2.39×10^{-14}	Pu-239	1.04×10^{-3}	Y-89m	2.95×10^{-3}
Nb-95	5.91×10^{-1}	U-235	1.08×10^{-13}	Cs-135	1.09×10^{-5}
Mo-99	4.72×10^{-2}	Th-231	1.04×10^{-13}	Na-24	8.95×10^{-15}
Tc-99m	4.51×10^{-2}	Pa-231	1.53×10^{-18}	P-32	1.31×10^{-2}
Ru-103	1.51×10^{-1}	Pm-147	2.40×10^{-3}	Cr-51	8.37×10^{-1}
Ru-106	3.96×10^{-2}	Sm-147	1.32×10^{-15}	Mn-54	1.71×10^{-1}
Te-129m	2.83×10^{-1}	Pr-144	5.20×10^{-1}	Co-58	$1.57 \times 10^{+1}$
Te-132	3.28×10^{-1}	Nd-144	1.83×10^{-17}	Co-60	2.32
Cs-134	2.53	La-140	$1.91 \times 10^{+1}$	Fe-59	2.00×10^{-1}
Cs-136	2.32×10^{-1}	Te-129	1.81×10^{-1}	Zn-65	8.36×10^{-3}
Cs-137	3.94	I-129	2.07×10^{-9}	Zn-69m	9.06×10^{-18}
Ba-140	$1.65 \times 10^{+1}$	Rh-106	3.96×10^{-2}	Ag-110m	2.52×10^{-1}
Ce-141	7.11×10^{-1}	Rh-103m	1.48×10^{-1}	W-187	2.45×10^{-9}
Ce-143	2.97×10^{-8}				

Table 12.2-71 (Cont'd)

FALLOUT COMPONENT

Isotope[4]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Ce-144	7.14×10^{-4}	Cs-137	7.04×10^{-3}	Nb-93m	1.94×10^{-10}
Pr-144	7.14×10^{-4}	Cs-135	1.05×10^{-8}	Y-91	1.41
Nd-144	2.51×10^{-20}	Zr-95	2.18×10^{-3}	Sr-90	1.33×10^{-2}
Ce-143	1.14×10^{-6}	Nb-95	1.48×10^{-3}	Y-90	1.33×10^{-2}
Pr-143	3.15×10^{-1}	Nb-95m	4.62×10^{-5}	Sr-89	7.29×10^{-1}
Ce-141	5.25×10^{-1}	Y-93	2.28×10^{-20}	Y-89m	7.29×10^{-5}
Ba-140	1.18	Zr-93	3.52×10^{-8}	Rb-87	5.93×10^{-13}
La-140	1.35				

(1) Based on shielding design source terms given in Tables 12.2-1 through 12.2-5.
(2) Condensate phase separator sludge decayed for 28 days.
(3) This activity is in a 13,000 gallon slurry.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-72

CONDENSATE PHASE SEPARATOR DECANT PUMP SHIELDING DESIGN SOURCE TERMS[1][2]

ISOTOPE[3]	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)
Br-83	7.88×10^{-12}	Cs-136	7.68×10^{-14}	Rh-103m	6.71×10^{-15}
Br-84	5.11×10^{-12}	Cs-137	1.68×10^{-13}	Tc-99	7.01×10^{-20}
Br-85	1.14×10^{-17}	Cs-138	3.66×10^{-11}	Nb-97m	2.00×10^{-14}
I-131	9.07×10^{-12}	Ba-139	6.78×10^{-11}	Nb-97	9.45×10^{-15}
I-132	7.08×10^{-11}	Ba-140	6.29×10^{-12}	Nb-95m	4.29×10^{-18}
I-133	6.02×10^{-11}	Ba-141	1.18×10^{-11}	Y-92	1.21×10^{-11}
I-134	7.55×10^{-11}	Ba-142	2.72×10^{-12}	Y-91	1.37×10^{-14}
I-135	8.20×10^{-11}	Ce-141	3.19×10^{-14}	Y-91m	1.54×10^{-11}
Sr-89	2.17×10^{-12}	Ce-143	2.40×10^{-14}	Y-90	1.85×10^{-15}
Sr-90	1.61×10^{-13}	Ce-144	2.45×10^{-14}	Y-89m	2.17×10^{-16}
Sr-91	4.50×10^{-11}	Pr-143	2.66×10^{-14}	Na-24	3.82×10^{-13}
Sr-92	5.96×10^{-11}	Nd-147	9.77×10^{-15}	P-32	3.99×10^{-15}
Zr-95	2.80×10^{-14}	Np-239	1.66×10^{-10}	Cr-51	9.99×10^{-14}
Zr-97	2.15×10^{-14}	Ag-110	1.56×10^{-16}	Mn-54	8.00×10^{-15}
Nb-95	2.94×10^{-14}	Zn-69	3.02×10^{-15}	Mn-56	7.64×10^{-12}
Mo-99	1.52×10^{-11}	Pu-239	5.42×10^{-19}	Co-58	1.00×10^{-12}
Tc-99m	1.76×10^{-10}	Pm-147	2.96×10^{-19}	Co-60	1.00×10^{-13}
Tc-101	5.03×10^{-12}	Pr-144	2.23×10^{-14}	Fe-59	1.60×10^{-14}
Ru-103	1.33×10^{-14}	La-142	9.88×10^{-12}	Ni-65	4.58×10^{-14}
Ru-106	1.82×10^{-15}	La-141	7.37×10^{-12}	Zn-65	4.00×10^{-16}
Te-129m	2.80×10^{-14}	La-140	1.08×10^{-13}	Zn-69m	5.71×10^{-15}
Te-132	3.40×10^{-11}	Te-129	8.13×10^{-15}	Ag-110m	1.20×10^{-14}
Cs-134	1.12×10^{-13}	Rh-106	1.82×10^{-15}	W-187	5.83×10^{-13}

(1) Based on shielding design source terms given in Tables 12.2-1 through 12.2-5.
(2) Activity is 0.02% of reactor water with one hour decay.
(3) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-73

RWCU SYSTEM PHASE SEPARATOR SHIELDING DESIGN SOURCE TERMS[1][2][3][4]

ISOTOPE[5]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	$2.11 \times 10^{+1}$	Ba-139	$1.28 \times 10^{+2}$	Rh-106	1.45
Br-84	7.95	Ba-140	$1.58 \times 10^{+3}$	Rh-103m	6.81
Br-85	2.52×10^{-1}	Ba-141	$2.69 \times 10^{+1}$	Tc-99	9.70×10^{-4}
I-131	$1.48 \times 10^{+3}$	Ba-142	$1.53 \times 10^{+1}$	Nb-97m	3.00×10^{-1}
I-132	$2.42 \times 10^{+3}$	Ce-141	$3.48 \times 10^{+1}$	Nb-97	3.22×10^{-1}
I-133	$1.07 \times 10^{+3}$	Ce-143	6.84×10^{-1}	Nb-95m	3.26×10^{-1}
I-134	$1.18 \times 10^{+2}$	Ce-144	$1.93 \times 10^{+1}$	Y-92	$1.77 \times 10^{+2}$
I-135	$5.12 \times 10^{+2}$	Pr-143	7.65	Y-91	$1.99 \times 10^{+2}$
Sr-89	$1.27 \times 10^{+3}$	Nd-147	2.15	Y-91m	$2.33 \times 10^{+2}$
Sr-90	$1.36 \times 10^{+2}$	Np-239	$8.01 \times 10^{+3}$	Y-90	$1.28 \times 10^{+2}$
Sr-91	$3.94 \times 10^{+2}$	Re-187	3.14×10^{-11}	Y-89m	1.27×10^{-1}
Sr-92	$1.74 \times 10^{+2}$	Ag-110	1.22×10^{-1}	Cs-135	1.92×10^{-5}
Zr-95	$1.75 \times 10^{+1}$	Zn-69	7.01×10^{-2}	Na-24	5.06
Zr-97	3.22×10^{-1}	Pu-239	3.53×10^{-2}	P-32	1.10
Nb-95	$2.24 \times 10^{+1}$	U-235	2.68×10^{-12}	Cr-51	$4.38 \times 10^{+1}$
Mo-99	$8.69 \times 10^{+2}$	Th-231	2.54×10^{-12}	Mn-54	6.32
Tc-99m	$1.76 \times 10^{+3}$	Pa-231	1.05×10^{-16}	Mn-56	$2.15 \times 10^{+1}$
Tc-101	$1.67 \times 10^{+1}$	Pm-147	6.97×10^{-2}	Co-58	$6.40 \times 10^{+2}$
Ru-103	6.95	Sm-147	3.11×10^{-14}	Co-60	$8.36 \times 10^{+1}$
Ru-106	1.45	Pr-144	$1.93 \times 10^{+1}$	Fe-59	8.87
Te-129m	$1.37 \times 10^{+1}$	Nd-144	4.68×10^{-16}	Ni-65	1.29×10^{-1}
Te-132	$2.26 \times 10^{+3}$	La-142	$1.84 \times 10^{+1}$	Zn-65	3.11×10^{-1}
Cs-134	$9.21 \times 10^{+1}$	La-141	$3.02 \times 10^{+1}$	Zn-69m	6.99×10^{-2}
Cs-136	$2.04 \times 10^{+1}$	La-140	$1.57 \times 10^{+3}$	Ag-110m	9.36
Cs-137	$1.42 \times 10^{+2}$	Te-129	8.75	W-187	$1.21 \times 10^{+1}$
Cs-138	$5.67 \times 10^{+1}$	I-129	5.48×10^{-8}		

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Reactor coolant (less gases) accumulated for 60 days at 708 gpm at 0.73 g/cc.
(3) Assumes a 3 minute transit time from reactor vessel to phase separator.
(4) This activity is in 700 gallons of sludge (spent resin).
(5) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-74

RWCU SYSTEM PHASE SEPARATOR SLUDGE DISCHARGE AND MIXING PUMP SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
I-131	8.46	Ce-141	9.72	Te-129	2.59
I-132	6.15×10^{-3}	Ce-143	5.04×10^{-14}	I-129	1.08×10^{-7}
I-133	4.79×10^{-19}	Ce-144	$1.66 \times 10^{+1}$	Rh-106	1.30
Sr-89	$5.76 \times 10^{+2}$	Pr-143	3.63×10^{-1}	Rh-103m	2.38
Sr-90	$1.35 \times 10^{+2}$	Nd-147	5.01×10^{-2}	Tc-99	1.01×10^{-3}
Zr-95	9.28	Np-239	1.61×10^{-4}	Nb-95m	1.97×10^{-1}
Nb-95	$1.53 \times 10^{+1}$	Re-187	3.22×10^{-11}	Y-91	$9.96 \times 10^{+1}$
Mo-99	2.77×10^{-4}	Ag-110	1.03×10^{-1}	Y-90	$1.35 \times 10^{+2}$
Tc-99m	2.65×10^{-4}	Pu-239	3.74×10^{-2}	Y-89m	5.76×10^{-2}
Ru-103	2.43	U-235	8.67×10^{-12}	Cs-135	1.95×10^{-5}
Ru-106	1.30	Th-231	8.51×10^{-12}	P-32	5.97×10^{-2}
Te-129m	4.04	Pa-231	1.24×10^{-16}	Cr-51	9.82
Te-132	5.97×10^{-3}	Pm-147	9.02×10^{-2}	Mn-54	5.51
Cs-134	$8.71 \times 10^{+1}$	Sm-147	1.25×10^{-13}	Co-58	$3.57 \times 10^{+2}$
Cs-136	9.81×10^{-1}	Pr-144	$1.66 \times 10^{+1}$	Co-60	$8.18 \times 10^{+1}$
Cs-137	$1.41 \times 10^{+2}$	Nd-144	1.32×10^{-15}	Fe-59	3.56
Ba-140	$6.12 \times 10^{+1}$	La-140	$7.04 \times 10^{+1}$	Zn-65	2.62×10^{-1}
				Ag-110m	7.95
				W-187	8.93×10^{-18}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) RWCU system phase separator sludge decayed for 60 days.
(3) This activity is in a 5600 gallon slurry.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-75

RWCU SYSTEM PHASE SEPARATOR DECANT PUMP SHIELDING DESIGN SOURCE TERMS[1][2]

ISOTOPE[3]	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)	ISOTOPE	SPECIFIC ACTIVITY (Ci/cc)
Br-83	1.06×10^{-13}	Ba-139	6.63×10^{-15}	Nb-97	9.07×10^{-14}
I-131	8.35×10^{-11}	Ba-140	5.97×10^{-11}	Nb-95m	9.40×10^{-16}
I-132	2.86×10^{-10}	Ce-141	7.11×10^{-13}	Y-92	1.74×10^{-11}
I-133	2.75×10^{-10}	Ce-143	1.48×10^{-13}	Y-91	2.66×10^{-12}
I-134	7.77×10^{-18}	Ce-144	2.44×10^{-13}	Y-91m	5.59×10^{-11}
I-135	7.55×10^{-11}	Pr-143	2.62×10^{-13}	Y-90	3.90×10^{-13}
Sr-89	2.14×10^{-11}	Nd-147	9.20×10^{-14}	Y-89m	2.14×10^{-15}
Sr-90	1.61×10^{-12}	Np-239	1.25×10^{-9}	Cs-135	1.44×10^{-19}
Sr-91	8.65×10^{-11}	F-18	8.96×10^{-16}	Na-24	1.32×10^{-12}
Sr-92	1.66×10^{-12}	Ag-110	1.56×10^{-15}	P-32	3.81×10^{-14}
Zr-95	2.77×10^{-13}	Zn-69	1.93×10^{-14}	Cr-51	9.75×10^{-13}
Zr-97	8.42×10^{-14}	Pu-239	1.13×10^{-16}	Mn-54	7.98×10^{-14}
Nb-95	2.94×10^{-13}	Pm-147	6.88×10^{-17}	Mn-56	1.57×10^{-13}
Mo-99	1.20×10^{-10}	Pr-144	2.44×10^{-13}	Co-58	9.90×10^{-12}
Tc-99m	2.31×10^{-10}	La-142	3.32×10^{-15}	Co-60	1.00×10^{-12}
Ru-103	1.31×10^{-13}	La-141	1.36×10^{-12}	Fe-59	1.58×10^{-13}
Ru-106	1.82×10^{-14}	La-140	2.07×10^{-11}	Ni-65	9.14×10^{-16}
Te-129m	2.74×10^{-13}	Te-129	1.76×10^{-13}	Zn-65	3.99×10^{-15}
Te-132	2.77×10^{-10}	Rh-106	1.82×10^{-14}	Zn-69m	1.80×10^{-14}
Cs-134	1.12×10^{-12}	Rh-103m	1.28×10^{-13}	Ag-110m	1.20×10^{-13}
Cs-136	7.32×10^{-13}	Tc-99	6.85×10^{-18}	W-187	2.99×10^{-12}
Cs-137	1.68×10^{-12}	Nb-97m	7.84×10^{-14}		

(1) Based on shielding design source terms given in Tables 12.2-2 through 12.2-5.
(2) Reactor water decayed for 24 hours, with a phase separation partition factor of 0.2%.
(3) Isotopes with specific activities less than 1.0×10^{-20} are not listed.

Table 12.2-76

WASTE SLUDGE TANK AND DISCHARGE AND MIXING PUMP SHIELDING DESIGN SOURCE TERMS[1][2]

FIRST COMPONENT[3]

Isotope[5]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Br-83	2.00×10^{-1}	Cs-137	9.62×10^{-2}	I-129	3.72×10^{-12}
Br-84	7.91×10^{-2}	Cs-138	5.64×10^{-1}	Rh-106	1.04×10^{-3}
Br-85	4.70×10^{-3}	Ba-139	1.22	Rh-103m	7.10×10^{-3}
I-131	4.35	Ba-140	3.21	Tc-00	4.44×10^{-7}
I-132	$1.40 \times 10^{+1}$	Ba-141	2.82×10^{-1}	Nb-97m	2.76×10^{-3}
I-133	9.71	Ba-142	1.72×10^{-1}	Nb-97	2.96×10^{-3}
I-134	1.15	Ce-141	3.86×10^{-2}	Nb-95m	9.89×10^{-5}
I-135	4.80	Ce-143	5.68×10^{-3}	Y-92	1.65
Sr-89	1.21	Ce-144	1.40×10^{-2}	Y-91	1.59×10^{-1}
Sr-90	9.22×10^{-2}	Pr-143	1.44×10^{-2}	Y-91m	2.18
Sr-91	3.69	Nd-147	4.91×10^{-3}	Y-90	3.87×10^{-2}
Sr-92	1.65	Np-239	$5.41 \times 10^{+1}$	Y-89m	1.21×10^{-4}
Zr-95	1.57×10^{-2}	Re-187	1.50×10^{-14}	Cs-135	1.03×10^{-8}
Zr-97	2.97×10^{-3}	Ag-110	8.88×10^{-5}	Na-24	4.69×10^{-2}
Nb-95	1.68×10^{-2}	Zn-69	6.50×10^{-4}	P-32	2.06×10^{-3}
Mo-99	5.38	Pu-239	1.11×10^{-5}	Cr-51	5.43×10^{-2}
Tc-99m	$1.38 \times 10^{+1}$	Pm-147	8.10×10^{-6}	Mn-54	4.56×10^{-3}
Tc-101	1.81×10^{-1}	Sm-147	2.18×10^{-19}	Mn-56	2.03×10^{-1}
Ru-103	7.33×10^{-3}	Pr-144	1.39×10^{-2}	Co-58	5.61×10^{-1}
Ru-106	1.04×10^{-3}	Nd-144	2.39×10^{-20}	Co-60	5.72×10^{-2}
Te-129m	1.53×10^{-2}	La-142	1.72×10^{-1}	Fe-59	8.87×10^{-3}
Te-132	$1.28 \times 10^{+1}$	La-141	2.82×10^{-1}	Ni-65	1.22×10^{-3}
Cs-134	6.40×10^{-2}	La-140	1.78	Zn-65	2.28×10^{-4}
Cs-136	3.96×10^{-2}	Te-129	9.67×10^{-3}	Zn-69m	6.51×10^{-4}
				Ag-110m	6.83×10^{-3}
				W-187	1.08×10^{-1}

Table 12.2-76 (Cont'd)

SECOND COMPONENT[4]

Isotope[5]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Br-83	1.27×10^{-3}	Cs-137	1.30×10^{-2}	Rh-106	1.41×10^{-4}
Br-84	1.90×10^{-9}	Cs-138	1.65×10^{-8}	Rh-103m	9.80×10^{-4}
I-131	6.02×10^{-1}	Ba-139	5.65×10^{-4}	Tc-99	6.13×10^{-8}
I-132	1.86	Ba-140	4.42×10^{-1}	Nb-97m	3.40×10^{-4}
I-133	1.26	Ba-141	3.17×10^{-14}	Nb-97	3.93×10^{-4}
I-134	1.38×10^{-5}	Ce-141	5.43×10^{-3}	Nb-95m	1.23×10^{-5}
I-135	2.89×10^{-1}	Ce-143	7.95×10^{-4}	Y-92	8.65×10^{-2}
Sr-89	1.64×10^{-1}	Ce-144	1.89×10^{-3}	Y-91	2.29×10^{-2}
Sr-90	1.25×10^{-2}	Pr-143	1.98×10^{-3}	Y-91m	2.10×10^{-1}
Sr-91	3.26×10^{-1}	Nd-147	6.77×10^{-4}	Y-90	4.92×10^{-3}
Sr-92	1.54×10^{-2}	Np-239	7.67	Y-89m	1.64×10^{-5}
Zr-95	2.13×10^{-3}	Re-187	2.04×10^{-15}	Cs-135	1.47×10^{-9}
Zr-97	3.65×10^{-4}	Ag-110	1.21×10^{-5}	Na-24	5.47×10^{-3}
Nb-95	2.28×10^{-3}	Zn-69	7.84×10^{-5}	P-32	2.84×10^{-4}
Mo-99	7.61×10^{-1}	Pu-239	1.42×10^{-6}	Cr-51	7.41×10^{-3}
Tc-99m	1.18	Pm-147	9.72×10^{-7}	Mn-54	6.19×10^{-4}
Tc-101	6.31×10^{-18}	Sm-147	1.99×10^{-20}	Mn-56	1.62×10^{-3}
Ru-103	9.99×10^{-4}	Pr-144	1.89×10^{-3}	Co-58	7.62×10^{-2}
Ru-106	1.41×10^{-4}	La-142	1.71×10^{-4}	Co-60	7.76×10^{-3}
Te-129m	2.09×10^{-3}	La-141	7.31×10^{-3}	Fe-59	1.21×10^{-3}
Te-132	1.80	La-140	2.37×10^{-1}	Ni-65	9.52×10^{-6}
Cs-134	8.68×10^{-3}	Te-129	1.34×10^{-3}	Zn-65	3.09×10^{-5}
Cs-136	5.44×10^{-3}	I-129	4.38×10^{-13}	Zn-69m	7.30×10^{-5}
				Ag-110m	9.27×10^{-4}
				W-187	1.45×10^{-2}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) This activity is in 13,475 gallons of sludge slurry.
(3) Equipment drains accumulated for 4.36 days at 26.93 gpm, with no decay.
(4) Floor drains accumulated for 2.76 days at 7.22 gpm, with 0.51 days decay.
(5) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-77

RADWASTE EVAPORATOR CONCENTRATE STORAGE TANK SHIELDING DESIGN SOURCE TERMS[1][2][3][5]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Br-83	7.04×10^{-13}	Ce-141	1.47×10^{-3}	Tc-99	1.80×10^{-7}
I-131	3.71×10^{-2}	Ce-143	4.89×10^{-6}	Nb-97m	5.14×10^{-7}
I-132	3.95×10^{-2}	Ce-144	2.53×10^{-3}	Nb-97	5.95×10^{-7}
I-133	2.96×10^{-3}	Pr-143	2.24×10^{-4}	Nb-95m	2.31×10^{-5}
I-135	9.46×10^{-6}	Nd-147	5.88×10^{-4}	Y-92	1.76×10^{-8}
Sr-89	7.14×10^{-2}	Np-239	1.06×10^{-1}	Y-91	1.22×10^{-2}
Sr-90	2.41×10^{-2}	Pu-239	6.67×10^{-6}	Y-91m	4.74×10^{-5}
Sr-91	7.34×10^{-5}	U-235	2.97×10^{-15}	Y-90	2.40×10^{-2}
Sr-92	5.75×10^{-11}	Th-231	2.95×10^{-15}	Y-89m	7.14×10^{-6}
Zr-95	1.13×10^{-3}	Pa-231	1.21×10^{-19}	Zn-69	6.53×10^{-8}
Zr-97	5.52×10^{-7}	Re-187	5.75×10^{-15}	Cs-135	3.50×10^{-9}
Nb-95	1.76×10^{-3}	Pm-147	1.47×10^{-4}	Na-24	5.82×10^{-6}
Mo-99	1.33×10^{-2}	Sm-147	4.43×10^{-16}	P-32	3.24×10^{-5}
Tc-99m	1.27×10^{-2}	Pr-144	2.53×10^{-3}	Cr-51	1.69×10^{-3}
Ru-103	3.26×10^{-4}	Nd-144	3.86×10^{-19}	Mn-54	8.41×10^{-4}
Ru-106	2.03×10^{-4}	La-142	5.95×10^{-18}	Mn-56	2.72×10^{-12}
Te-129m	5.88×10^{-4}	La-141	2.66×10^{-9}	Fe-59	4.54×10^{-4}
Te-132	3.84×10^{-2}	La-140	4.94×10^{-2}	Co-58	4.36×10^{-2}
Cs-134	1.45×10^{-2}	Te-129	3.77×10^{-4}	Co-60	1.42×10^{-2}
Cs-136	5.94×10^{-4}	I-129	2.00×10^{-11}	Ni-65	1.49×10^{-14}
Cs-137	2.51×10^{-2}	Ag-110	1.54×10^{-5}	Zn-65	3.88×10^{-5}
Ba-139	8.76×10^{-19}	Rh-106	2.03×10^{-4}	Zn-69m	6.08×10^{-8}
Ba-140	4.49×10^{-2}	Rh-103m	3.19×10^{-4}	Ag-110m	1.18×10^{-3}
				W-187	4.85×10^{-5}

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Chemical wastes (2% of reactor water less gases) with 3.0 days decay accumulated for 33 days at 0.833 gpm.
(3) This activity is in 4000 gallons.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.
(5) Installation of the abandoned evaporator concentrate tank was not completed for plant operation (Section 11.2.2.1.3).

Table 12.2-78

SOLID RADWASTE CENTRIFUGE AIR FILTERS AND
RADWASTE ENCLOSURE EQUIPMENT COMPARTMENT
EXHAUST AIR FILTERS SHIELDING DESIGN SOURCE TERMS[1][2]

ISOTOPE[3]	ACTIVITY (Ci)
I-131	1.11×10^{-2}
I-133	4.21×10^{-3}
Co-60	1.69×10^{-1}
Co-58	2.46×10^{-3}
Cr-51	1.98×10^{-3}
Mn-54	4.07×10^{-2}
Fe-59	5.38×10^{-3}
Zn-65	1.87×10^{-3}
Zr-95	8.87×10^{-5}
Sr-89	6.50×10^{-4}
Sr-90	2.07×10^{-3}
Sb-124	8.23×10^{-5}
Cs-134	2.67×10^{-2}
Cs-136	1.71×10^{-4}
Cs-137	6.23×10^{-2}
Ba-140	3.54×10^{-5}
Ce-141	2.34×10^{-3}
La-140	3.54×10^{-5}
Y-90	2.05×10^{-3}
Y-89m	6.50×10^{-8}
Nb-95	8.66×10^{-5}
Nb-95m	1.77×10^{-6}

(1) Based on NUREG-0016, Revision 0, table 1-1 release rates, with fission products adjusted to 0.35 Ci/sec offgas release rate at 30 minutes decay. All isotopes are multiplied by 2 to account for two reactors.

(2) Assumes a one year accumulation of all these isotopes at 53,000 cfm.

(3) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-79

CHARCOAL TREATMENT SYSTEM COOLER CONDENSER SHIELDING DESIGN SOURCE TERMS[1]

	COOLER CONDENSER DRAIN POT COMPONENT[3]			COOLER CONDENSER HEAT EXCHANGER BODY COMPONENT[4]	
Isotope[2]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
La-144	1.26×10^{-11}	Zr-95	9.60×10^{-7}	N-13	3.30×10^{-2}
Ce-144	6.46×10^{-7}	Nb-95	2.35×10^{-10}	O-19	9.59×10^{-9}
Pr-144	4.30×10^{-7}	Nb-95m	4.48×10^{-11}	F-18	6.97×10^{-2}
La-143	1.10×10^{-2}	Sr-94	2.45×10^{-6}	Kr-83m	1.16×10^{-1}
Ce-143	2.38×10^{-4}	Y-94	3.33×10^{-2}	Kr-85m	2.26×10^{-1}
Pr-143	1.52×10^{-7}	Sr-93	1.17×10^{-1}	Kr-85	7.87×10^{-4}
Ba-142	8.61×10^{-2}	Y-93	1.48×10^{-2}	Kr-87	6.45×10^{-1}
La-142	4.48×10^{-2}	Zr-93	2.64×10^{-13}	Kr-88	7.19×10^{-1}
Cs-141	9.86×10^{-17}	Nb-93m	2.86×10^{-19}	Kr-89	8.02×10^{-2}
Ba-141	4.00×10^{-1}	Sr-92	2.81×10^{-1}	Kr-90	5.72×10^{-8}
La-141	5.79×10^{-2}	Y-92	2.70×10^{-2}	Xe-131m	5.90×10^{-4}
Ce-141	1.50×10^{-5}	Rb-91	6.69×10^{-5}	Xe-133m	1.13×10^{-2}
Cs-140	3.62×10^{-5}	Sr-91	2.82×10^{-1}	Xe-133	3.22×10^{-1}
Ba-140	1.36×10^{-2}	Y-91	3.27×10^{-5}	Xe-135m	3.99×10^{-1}
La-140	1.06×10^{-4}	Y-91m	5.27×10^{-2}	Xe-135	8.59×10^{-1}
Cs-139	8.95×10	Rb-90	3.16×10^{-1}	Xe-137	1.86×10^{-1}
Ba-139	5.63×10	Sr-90	3.32×10^{-5}	Xe-138	1.50×10
Cs-138	$5.84 \times 10^{+1}$	Y-90	1.54×10^{-7}	Xe-139	2.71×10^{-6}
Cs-137	1.14×10^{-4}	Rb-89	$2.84 \times 10^{+1}$	Xe-140	4.78×10^{-15}
Cs-135	6.65×10^{-10}	Sr-89	1.11×10^{-2}		
Sr-95	7.61×10^{-11}	Y-89m	1.10×10^{-6}		
Y-95	1.77×10^{-3}	Rb-88	$2.61 \times 10^{+1}$		
	Rb-87	3.43×10^{-14}			

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Isotopes with activities less than 1.0×10^{-20} are not listed.
(3) This particulate activity is assumed to be uniformly distributed throughout the 0.78 ft^3 volume of condensate in the drain pot.
(4) This gaseous activity is assumed to be uniformly distributed throughout the 1.54×10^5 cc volume of the entire (homogenized) cooler condenser heat exchanger body.

Table 12.2-80

CHARCOAL GUARD BED SHIELDING DESIGN SOURCE TERMS[1][3]

(Unit 1)

Isotope[2]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Xe-131m	9.87	Cs-140	2.32	Y-93	1.29×10^{-2}
Xe-133m	$3.14 \times 10^{+1}$	Ba-140	2.30	Zr-93	2.38×10^{-7}
Xe-133	$1.26 \times 10^{+3}$	La-140	2.30	Nb-93m	1.30×10^{-7}
Xe-135m	$2.65 \times 10^{+2}$	Cs-139	$1.34 \times 10^{+1}$	Rb-92	9.74×10^{-2}
Xe-135	$8.22 \times 10^{+2}$	Ba-139	$1.34 \times 10^{+1}$	Sr-92	9.64×10^{-2}
Xe-137	$1.08 \times 10^{+2}$	Cs-138	$3.71 \times 10^{+2}$	Y-92	9.64×10^{-2}
Xe-138	$3.73 \times 10^{+2}$	Cs-137	$6.45 \times 10^{+1}$	Rb-91	9.93×10^{-1}
Xe-139	$1.34 \times 10^{+1}$	Cs-135	7.53×10^{-3}	Sr-91	9.85×10^{-1}
Xe-140	2.32	Kr-83m	$2.48 \times 10^{+1}$	Y-91	9.85×10^{-1}
Xe-141	2.29×10^{-2}	Kr-85m	3.85	Y-91m	5.81×10^{-1}
Xe-142	5.42×10^{-3}	Kr-85	7.49×10^{-2}	Rb-90	8.08
Xe-143	3.99×10^{-4}	Kr-87	$1.12 \times 10^{+1}$	Sr-90	5.09
Xe-144	1.43×10^{-3}	Kr-88	$1.15 \times 10^{+1}$	Y-90	5.09
Cs-144	1.43×10^{-3}	Kr-89	$3.19 \times 10^{+1}$	Rb-89	$3.16 \times 10^{+1}$
Ba-144	1.43×10^{-3}	Kr-90	8.13	Sr-89	$3.16 \times 10^{+1}$
La-144	1.43×10^{-3}	Kr-91	9.95×10^{-1}	Y-89m	3.16×10^{-3}
Ce-144	1.41×10^{-3}	Kr-92	9.74×10^{-2}	Rb-88	$1.14 \times 10^{+1}$
Pr-144	1.41×10^{-3}	Kr-93	1.30×10^{-2}	Rb-87	6.44×10^{-9}
Nd-144	1.59×10^{-17}	Kr-94	1.49×10^{-3}	N-13	8.75×10^{-2}
Cs-143	3.99×10^{-4}	Kr-95	6.97×10^{-5}	N-16	$2.38 \times 10^{+1}$
Ba-143	3.99×10^{-4}	Rb-95	6.97×10^{-5}	N-17	4.41×10^{-3}
La-143	3.99×10^{-4}	Sr-95	6.96×10^{-5}	O-19	1.83
Ce-143	3.95×10^{-4}	Y-95	6.91×10^{-5}	F-18	6.15×10^{-2}
Pr-143	3.95×10^{-4}	Zr-95	6.90×10^{-5}	Br-83	$2.28 \times 10^{+1}$
Cs-142	5.42×10^{-3}	Nb-95	6.90×10^{-5}	Br-84	8.52
Ba-142	5.42×10^{-3}	Nb-95m	1.38×10^{-6}	Br-85	2.97×10^{-1}
La-142	5.38×10^{-3}	Rb-94	1.49×10^{-3}	I-131	$1.61 \times 10^{+3}$
Cs-141	2.29×10^{-2}	Sr-94	1.49×10^{-3}	I-132	$1.71 \times 10^{+2}$
Ba-141	$2.29 \times 10^{-}$	Y-94	1.48×10^{-3}	I-133	$1.15 \times 10^{+3}$
La-141	2.27×10^{-2}	Rb-93	1.30×10^{-2}	I-134	$1.27 \times 10^{+2}$
Ce-141	2.27×10^{-2}	Sr-93	1.29×10^{-2}	I-135	$5.54 \times 10^{+2}$

Table 12.2-80 (Cont'd)

CHARCOAL GUARD BED SHIELDING DESIGN SOURCE TERMS[1][3]

(Unit 2)

Isotope[2]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Xe-131m	9.87	Cs-140	2.25	Y-93	1.24×10^{-2}
Xe-133m	$3.14 \times 10^{+1}$	Ba-140	2.22	Zr-93	2.30×10^{-7}
Xe-133	$1.26 \times 10^{+3}$	La-140	2.22	Nb-93m	1.25×10^{-7}
Xe-135m	$2.64 \times 10^{+2}$	Cs-139	$1.31 \times 10^{+1}$	Rb-92	9.41×10^{-2}
Xe-135	$8.22 \times 10^{+2}$	Ba-139	$1.30 \times 10^{+1}$	Sr-92	9.32×10^{-2}
Xe-137	$1.06 \times 10^{+2}$	Cs-138	$3.70 \times 10^{+2}$	Y-92	9.31×10^{-2}
Xe-138	$3.71 \times 10^{+2}$	Cs-137	$6.36 \times 10^{+1}$	Rb-91	9.60×10^{-1}
Xe-139	$1.31 \times 10^{+1}$	Cs-135	7.53×10^{-3}	Sr-91	9.53×10^{-1}
Xe-140	2.25	Kr-83m	$2.45 \times 10^{+1}$	Y-91	9.53×10^{-1}
Xe-141	2.21×10^{-2}	Kr-85m	3.34	Y-91m	5.62×10^{-1}
Xe-142	5.24×10^{-3}	Kr-85	7.22×10^{-2}	Rb-90	7.69
Xe-143	3.85×10^{-4}	Kr-87	9.66	Sr-90	4.84
Xe-144	1.38×10^{-3}	Kr-88	9.90	Y-90	4.84
Cs-144	1.38×10^{-3}	Kr-89	$2.80 \times 10^{+1}$	Rb-89	$2.77 \times 10^{+1}$
Ba-144	1.38×10^{-3}	Kr-90	7.74	Sr-89	$2.77 \times 10^{+1}$
La-144	1.38×10^{-3}	Kr-91	9.63×10^{-1}	Y-89m	2.77×10^{-3}
Ce-144	1.37×10^{-3}	Kr-92	9.41×10^{-2}	Rb-88	9.80
Pr-144	1.37×10^{-3}	Kr-93	1.26×10^{-2}	Rb-87	5.53×10^{-9}
Nd-144	1.54×10^{-17}	Kr-94	1.44×10^{-3}	N-13	8.69×10^{-2}
Cs-143	3.85×10^{-4}	Kr-95	6.73×10^{-5}	N-16	$2.30 \times 10^{+1}$
Ba-143	3.85×10^{-4}	Rb-95	6.73×10^{-5}	N-17	4.27×10^{-3}
La-143	3.85×10^{-4}	Sr-95	6.72×10^{-5}	O-19	1.78
Ce-143	3.81×10^{-4}	Y-95	6.67×10^{-5}	F-18	6.15×10^{-2}
Pr-143	3.81×10^{-4}	Zr-95	6.66×10^{-5}	Br-83	$2.28 \times 10^{+1}$
Cs-142	5.24×10^{-3}	Nb-95	6.66×10^{-5}	Br-84	8.50
Ba-142	5.24×10^{-3}	Nb-95m	1.33×10^{-6}	Br-85	2.92×10^{-1}
La-142	5.20×10^{-3}	Rb-94	1.44×10^{-3}	I-131	$1.61 \times 10^{+3}$
Cs-141	2.21×10^{-2}	Sr-94	1.44×10^{-3}	I-132	$1.71 \times 10^{+2}$
Ba-141	2.21×10^{-2}	Y-94	1.43×10^{-3}	I-133	$1.15 \times 10^{+3}$
La-141	2.19×10^{-2}	Rb-93	1.26×10^{-2}	I-134	$1.27 \times 10^{+2}$
Ce-141	2.19×10^{-2}	Sr-93	1.25×10^{-2}	I-135	$5.54 \times 10^{+2}$

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Isotopes with activities less than 1.0×10^{-20} are not listed.
(3) Based on 150 scfm main condenser air inleakage.

Table 12.2-81

CHARCOAL MAIN BED SHIELDING DESIGN SOURCE TERMS

This table lists the shielding design source terms for the various components that comprise the charcoal main bed. The table is divided into the following parts:

a. First Half of Adsorber Number 1 (Unit 1)

b. Second Half of Adsorber Number 1 (Unit 1)

c. Adsorber Number 2 (Unit 1)

d. Adsorber Number 3 (Unit 1)

e. Adsorber Number 4 (Unit 1)

f. Adsorber Number 1 (Unit 2)

g. Adsorber Number 2 (Unit 2)

h. Adsorber Number 3 (Unit 2)

i. Adsorber Number 4 (Unit 2)

j. Adsorber Number 5 (Unit 2)

Table 12.2-81(a)

FIRST HALF OF ADSORBER NUMBER 1 (UNIT 1)[1][3][4]

ISOTOPE[2]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Xe-131m	$1.72 \times 10^{+1}$	Cs-135	3.21×10^{-2}	Rb-91	2.29×10^{-3}
Xe-133m	$2.06 \times 10^{+2}$	Kr-83m	$8.68 \times 10^{+1}$	Sr-91	9.87×10^{-3}
Xe-133	$8.12 \times 10^{+3}$	Kr-85m	$2.28 \times 10^{+2}$	Y-91	9.86×10^{-3}
Xe-135m	$1.25 \times 10^{+1}$	Kr-85	1.03	Y-91m	5.83×10^{-3}
Xe-135	$3.51 \times 10^{+3}$	Kr-87	$3.89 \times 10^{+2}$	Rb-90	2.96×10^{-1}
Xe-137	3.13×10^{-3}	Kr-88	$6.32 \times 10^{+2}$	Sr-90	2.05×10^{-1}
Xe-138	$4.03 \times 10^{+1}$	Kr-89	$3.79 \times 10^{+1}$	Y-90	2.05×10^{-1}
Ce-144	1.41×10^{-5}	Kr-90	2.46×10^{-1}	Rb-89	$3.82 \times 10^{+1}$
Pr-144	1.41×10^{-5}	Kr-91	6.89×10^{-6}	Sr-89	$3.79 \times 10^{+1}$
Nd-144	1.59×10^{-19}	Kr-92	1.36×10^{-18}	Y-89m	3.79×10^{-3}
La-143	2.21×10^{-7}	Sr-95	6.64×10^{-8}	Rb-88	$6.31 \times 10^{+2}$
Ce-143	3.93×10^{-6}	Y-95	6.28×10^{-7}	Rb-87	2.22×10^{-7}
Pr-143	3.95×10^{-6}	Zr-95	6.90×10^{-7}	N-13	5.37
Ba-142	1.34×10^{-6}	Nb-95	6.90×10^{-7}	N-16	$1.76 \times 10^{+1}$
La-142	3.95×10^{-5}	Nb-95m	1.38×10^{-8}	N-17	1.32×10^{-3}
Ba-141	2.44×10^{-5}	Sr-94	3.74×10^{-6}	O-19	7.84
La-141	2.06×10^{-4}	Y-94	1.43×10^{-5}	F-18	5.73
Ce-141	2.27×10^{-4}	Rb-93	1.89×10^{-13}	Br-83	2.28×10^{-1}
Cs-140	2.50×10^{-18}	Sr-93	1.04×10^{-4}	Br-84	8.52×10^{-2}
Ba-140	2.30×10^{-2}	Y-93	1.29×10^{-4}	Br-85	2.89×10^{-3}
La-140	2.30×10^{-2}	Zr-93	2.38×10^{-9}	I-131	$1.61 \times 10^{+1}$
Cs-139	2.00×10^{-3}	Nb-93m	1.30×10^{-9}	I-132	1.71
Ba-139	9.37×10^{-2}	Rb-92	6.47×10^{-13}	I-133	$1.15 \times 10^{+1}$
Cs-138	$4.20 \times 10^{+1}$	Sr-92	9.60×10^{-4}	I-134	1.27
Cs-137	6.47×10^{-1}	Y-92	9.66×10^{-4}	I-135	5.54

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Isotopes with activities less than 1.0×10^{-20} are not listed.
(3) Based on 150 scfm main condenser air inleakage.
(4) This activity is assumed to be uniformly distributed throughout the first half of adsorber number 1, which is composed to two parallel units, 1AS371 and 1BS371.

Table 12.2-81(b)

SECOND HALF OF ADSORBER NUMBER 1 (UNIT 1)[1][3][4]

ISOTOPE[2]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Xe-131m	$1.33 \times 10^{+1}$	Kr-85	1.03	Sr-90	2.05×10^{-3}
Xe-133m	$5.59 \times 10^{+1}$	Kr-87	$4.17 \times 10^{+1}$	Y-90	2.05×10^{-3}
Xe-133	$4.68 \times 10^{+3}$	Kr-88	$2.30 \times 10^{+2}$	Rb-89	7.91×10^{-6}
Xe-135m	1.64	Y-95	1.10×10^{-15}	Sr-89	3.78×10^{-1}
Xe-135	1.54	Zr-95	6.89×10^{-9}	Y-89m	3.78×10^{-5}
Ce-144	1.40×10^{-7}	NB-95	6.90×10^{-9}	Rb-88	$2.30 \times 10^{+2}$
Pr-144	1.40×10^{-7}	Nb-95m	1.38×10^{-10}	Rb-87	2.61×10^{-8}
Ce-143	4.61×10^{-9}	Y-94	3.43×10^{-11}	O-19	1.10×10^{-8}
Pr-143	3.49×10^{-8}	Sr-93	1.39×10^{-15}	F-18	5.23
La-141	2.38×10^{-14}	Y-93	9.94×10^{-7}	Br-83	2.13×10^{-3}
Ce-141	2.08×10^{-6}	Zr-93	2.38×10^{-11}	Br-84	6.23×10^{-4}
Ba-140	1.82×10^{-4}	Nb-93m	1.30×10^{-11}	Br-85	1.05×10^{-6}
La-140	2.04×10^{-4}	Sr-92	3.38×10^{-6}	I-131	1.61×10^{-1}
Cs-137	6.47×10^{-3}	Y-92	7.40×10^{-6}	I-132	1.59×10^{-2}
Cs-135	3.64×10^{-4}	Sr-91	7.37×10^{-5}	I-133	1.15×10^{-1}
Kr-83m	$1.90 \times 10^{+1}$	Y-91	9.86×10^{-5}	I-134	1.05×10^{-2}
Kr-85m	$1.20 \times 10^{+2}$	Y-91m	4.74×10^{-5}	I-135	5.41×10^{-2}
				N-13	1.98

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Isotopes with activities less than 1.0×10^{-20} are not listed.
(3) Based on 150 scfm main condenser air inleakage.
(4) This activity is assumed to be uniformly distributed throughout the second half of adsorber number 1, which is composed of two parallel units, 1AS371 and 1BS371.

Table 12.2-81(c)

ADSORBER NUMBER 2 (UNIT 1)[1][3][4]

ISOTOPE[2]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Xe-131m	8.93	Kr-85	1.11	Y-90	2.05×10^{-5}
Xe-133m	$1.39 \times 10^{+1}$	Kr-87	4.56	Rb-89	1.30×10^{-12}
Xe-133	$2.36 \times 10^{+3}$	Kr-88	$8.73 \times 10^{+1}$	Sr-89	3.77×10^{-3}
Xe-135m	8.60×10^{-1}	Zr-95	6.88×10^{-11}	Y-89m	3.77×10^{-7}
Xe-135	1.54×10^{-1}	Nb-95	6.90×10^{-11}	Rb-88	$8.74 \times 10^{+1}$
Ce-144	1.38×10^{-9}	Nb-95	1.38×10^{-12}	Rb-87	2.87×10^{-9}
Pr-144	1.38×10^{-9}	Y-94	8.05×10^{-17}	N-13	7.33×10^{-1}
Ce-143	5.39×10^{-12}	Y-93	7.55×10^{-9}	O-19	1.28×10^{-17}
Pr-143	2.84×10^{-10}	Zr-93	2.38×10^{-13}	F-18	4.80
Ce-141	1.90×10^{-8}	Nb-93m	1.30×10^{-13}	Br-83	1.99×10^{-5}
Ba-140	1.45×10^{-6}	Sr-92	1.19×10^{-8}	Br-84	4.56×10^{-6}
La-140	1.65×10^{-6}	Y-92	4.40×10^{-8}	Br-85	3.86×10^{-10}
Cs-137	6.46×10^{-5}	Sr-91	5.50×10^{-7}	I-131	1.61×10^{-3}
Cs-135	4.77×10^{-6}	Y-91	9.85×10^{-7}	I-132	1.47×10^{-4}
Kr-83m	4.29	Y-91m	3.55×10^{-7}	I-133	1.14×10^{-3}
Kr-85m	$6.64 \times 10^{+1}$	Sr-90	2.05×10^{-5}	I-134	8.70×10^{-5}
				I-135	5.28×10^{-4}

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Isotopes with activities less than 1.0×10^{-20} are not listed.
(3) Based on 150 scfm main condenser air inleakage.
(4) This activity is assumed to be uniformly distributed throughout adsorber number 2, which composed of two parallel units, 1CS371 and 1DS371.

Table 12.2-81(d)

ADSORBER NUMBER 3 (UNIT 1)[1][3][4]

ISOTOPE[2]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Xe-131m	7.23	Kr-85m	$3.03 \times 10^{+1}$	Y-90	2.05×10^{-7}
Xe-133m	4.61	Kr-85	9.73×10^{-1}	Rb-89	9.51×10^{-20}
Xe-133	$1.47 \times 10^{+3}$	Kr-87	4.00×10^{-1}	Sr-89	3.76×10^{-5}
Xe-135m	4.63×10^{-1}	Kr-88	$2.73 \times 10^{+1}$	Y-89m	3.76×10^{-9}
Xe-135	2.48×10^{-6}	Zr-95	6.86×10^{-13}	Rb-88	$2.74 \times 10^{+1}$
Ce-144	1.37×10^{-11}	Nb-95	6.90×10^{-13}	Rb-87	2.58×10^{-10}
Pr-144	1.37×10^{-11}	Nb-95m	1.38×10^{-14}	N-13	2.73×10^{-1}
Ce-143	8.79×10^{-15}	Y-93	5.62×10^{-11}	F-18	4.50
Pr-143	2.37×10^{-12}	Zr-93	2.38×10^{-15}	Br-83	1.85×10^{-7}
Ce-141	1.76×10^{-10}	Nb-93m	1.30×10^{-15}	Br-84	3.33×10^{-8}
Ba-140	1.19×10^{-8}	Sr-92	3.88×10^{-11}	Br-85	1.38×10^{-13}
La-140	1.37×10^{-8}	Y-92	2.24×10^{-10}	I-131	1.61×10^{-5}
Cs-137	6.46×10^{-7}	Sr-91	4.02×10^{-9}	I-132	1.37×10^{-6}
Cs-135	1.57×10^{-6}	Y-91	9.84×10^{-9}	I-133	1.13×10^{-5}
Kr-83m	8.15×10^{-1}	Y-91m	2.59×10^{-9}	I-134	7.18×10^{-7}
		Sr-90	2.05×10^{-7}	I-135	5.15×10^{-6}

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Isotopes with activities less than 1.0×10^{-20} are not listed.
(3) Based on 150 scfm main condenser air inleakage.
(4) This activity is assumed to be uniformly distributed throughout adsorber number 3, which is composed to two parallel units, 1ES371 and 1FS271.

Table 12.2-81(e)

ADSORBER NUMBER 4 (UNIT 1)[1][3][4]

ISOTOPE[2]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY Ci)
Xe-131m	3.08	Kr-85m	9.53	Sr-90	2.05×10^{-9}
Xe-133m	9.71×10^{-1}	Kr-85	4.86×10^{-1}	Y-90	2.05×10^{-9}
Xe-133	$5.14 \times 10^{+2}$	Kr-87	3.63×10^{-2}	Sr-89	3.76×10^{-7}
Xe-135m	1.36×10^{-1}	Kr-88	6.52	Y-89m	3.76×10^{-11}
Xe-135	8.23×10^{-2}	Zr-95	6.85×10^{-15}	Rb-88	6.53
Ce-144	1.36×10^{-13}	Nb-95	6.90×10^{-15}	Rb-87	2.33×10^{-11}
Pr-144	1.36×10^{-13}	NB-95m	1.38×10^{-16}	N-13	5.99×10^{-2}
Ce-143	1.43×10^{-17}	Y-93	4.34×10^{-13}	F-18	2.04
Pr-143	1.97×10^{-14}	Zr-93	2.38×10^{-17}	Br-83	1.73×10^{-9}
Ce-141	1.63×10^{-12}	Nb-93m	1.30×10^{-17}	Br-84	2.41×10^{-10}
Ba-140	9.81×10^{-11}	Sr-92	1.45×10^{-13}	Br-85	4.53×10^{-17}
La-140	1.12×10^{-10}	Y-92	1.17×10^{-12}	I-131	1.60×10^{-7}
Cs-137	6.46×10^{-9}	Sr-91	3.05×10^{-11}	I-132	1.27×10^{-8}
Cs-135	7.69×10^{-7}	Y-91	9.83×10^{-11}	I-133	1.12×10^{-7}
Kr-83m	1.39×10^{-1}	Y-91m	1.97×10^{-11}	I-134	5.89×10^{-9}
				I-135	5.02×10^{-8}

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Isotopes with activities less than 1.0×10^{-20} are not listed.
(3) Based on 150 scfm main condenser air inleakage.
(4) This activity is assumed to be uniformly distributed throughout adsorber number 4, which is composed of one unit, 1GS371.

Table 12.2-81(f)

ADSORBER NUMBER 1 (UNIT 2)[1][3][4]

ISOTOPE[2]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Xe-131m	$1.71 \times 10^{+1}$	Cs-135	3.20×10^{-2}	Rb-91	2.82×10^{-3}
Xe-133m	$2.06 \times 10^{+2}$	Kr-83m	$8.96 \times 10^{+1}$	Sr-91	9.58×10^{-3}
Xe-133	$8.12 \times 10^{+3}$	Kr-85m	$2.40 \times 10^{+2}$	Y-91	9.57×10^{-3}
Xe-135m	$1.25 \times 10^{+1}$	Kr-85	1.10	Y-91m	5.66×10^{-3}
Xe-135	$3.50 \times 10^{+3}$	Kr-87	$3.97 \times 10^{+2}$	Rb-90	4.47×10^{-1}
Xe-137	3.09×10^{-3}	Kr-88	$6.59 \times 10^{+2}$	Sr-90	2.96×10^{-1}
Xe-138	$4.01 \times 10^{+1}$	Kr-89	$4.08 \times 10^{+1}$	Y-90	2.96×10^{-1}
Ce-144	1.37×10^{-5}	Kr-90	3.95×10^{-1}	Rb-89	$4.10 \times 10^{+1}$
Pr-144	1.37×10^{-5}	Kr-91	3.64×10^{-5}	Sr-89	$4.06 \times 10^{+1}$
Nd-144	1.54×10^{-19}	Kr-92	3.36×10^{-16}	Y-89m	4.06×10^{-3}
La-143	2.13×10^{-7}	Sr-95	9.07×10^{-8}	Rb-88	$6.59 \times 10^{+2}$
Ce-143	3.80×10^{-6}	Y-95	6.20×10^{-7}	Rb-87	2.27×10^{-7}
Pr-143	3.82×10^{-6}	Zr-95	6.66×10^{-7}	N-13	5.31
Ba-142	1.29×10^{-6}	Nb-95	6.66×10^{-7}	N-16	$1.70 \times 10^{+1}$
La-142	3.81×10^{-5}	Nb-95m	1.33×10^{-8}	N-17	1.27×10^{-3}
Ba-141	2.35×10^{-5}	Rb-94	3.17×10^{-20}	O-19	7.61
La-141	1.99×10^{-4}	Sr-94	4.44×10^{-6}	F-18	5.70
Ce-141	2.19×10^{-4}	Y-94	1.39×10^{-5}	Br-83	2.28×10^{-1}
Cs-140	2.42×10^{-18}	Rb-93	3.57×10^{-12}	Br-84	8.49×10^{-2}
Ba-140	2.22×10^{-2}	Sr-93	1.04×10^{-4}	Br-85	2.85×10^{-3}
La-140	2.23×10^{-2}	Y-93	1.25×10^{-4}	I-131	$1.61 \times 10^{+1}$
Cs-139	1.94×10^{-3}	Zr-93	2.30×10^{-9}	I-132	1.71
Ba-139	9.12×10^{-2}	Nr-93m	1.25×10^{-9}	I-133	$1.15 \times 10^{+1}$
Cs-138	$4.18 \times 10^{+1}$	Rb-92	1.44×10^{-11}	I-134	1.27
Cs-137	6.38×10^{-1}	Sr-92	9.29×10^{-4}	I-135	5.54
				Y-92	9.34×10^{-4}

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Isotopes with activities less than 1.0×10^{-20} are not listed.
(3) Based on 150 scfm main condenser air inleakage.
(4) This activity is assumed to be uniformly distributed throughout adsorber number 1, which is composed of one unit, 2AS371.

Table 12.2-81(g)

ADSORBER NUMBER 2 (UNIT 2)[1][3][4]

ISOTOPE[2]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Xe-131m	$1.06 \times 10^{+1}$	Kr-87	$3.38 \times 10^{+1}$	Y-90	2.96×10^{-3}
Xe-133	$4.88 \times 10^{+1}$	Kr-88	$1.95 \times 10^{+2}$	Rb-89	3.71×10^{-6}
Xe-133	$3.84 \times 10^{+3}$	Y-95	3.39×10^{-16}	Sr-89	4.05×10^{-1}
Xe-135m	1.68	Zr-95	6.65×10^{-9}	Y-89m	4.05×10^{-5}
Xe-135	1.70	Nb-95	6.66×10^{-9}	Rb-88	$1.95 \times 10^{+2}$
Ce-144	1.35×10^{-7}	Nb-95	1.33×10^{-10}	Rb-87	2.16×10^{-8}
Pr-144	1.35×10^{-7}	Y-94	1.79×10^{-11}	N-13	2.01
Ce-143	4.44×10^{-9}	Sr-93	2.99×10^{-16}	0-19	1.09×10^{-8}
Pr-143	3.37×10^{-8}	Y-93	9.41×10^{-7}	F-18	5.40
La-141	2.28×10^{-14}	Zr-93	2.30×10^{-11}	Br-83	2.13×10^{-3}
Ce-141	2.01×10^{-6}	Nb-93m	1.25×10^{-11}	Br-84	6.23×10^{-4}
Ba-140	1.76×10^{-4}	Sr-92	3.02×10^{-6}	Br-85	1.06×10^{-6}
La-140	1.97×10^{-4}	Y-92	6.92×10^{-6}	I-131	1.61×10^{-1}
Cs-137	6.38×10^{-3}	Sr-91	7.00×10^{-5}	I-132	1.59×10^{-2}
Cs-135	3.36×10^{-4}	Y-91	9.57×10^{-5}	I-133	1.15×10^{-1}
Kr-83m	$1.59 \times 10^{+1}$	Y-91m	4.51×10^{-5}	I-134	1.05×10^{-2}
Kr-85m	$1.02 \times 10^{+2}$	Sr-90	2.96×10^{-3}	I-135	5.41×10^{-2}
Kr-85	8.91×10^{-1}				

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Isotopes with activities less than 1.0×10^{-20} are not listed.
(3) Based on 150 scfm main condenser air inleakage.
(4) This activity is assumed to be uniformly distributed throughout adsorber number 2, which is composed of two parallel units, 2BS371 and 2CS371.

Table 12.2-81(h)

ADSORBER NUMBER 3 (UNIT 2)[1][3][4]

ISOTOPE[2]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Xe-131m	8.73	Kr-85	8.91×10^{-1}		
Xe-133m	$1.77 \times 10^{+1}$	Kr-87	4.93	Rb-89	2.76×10^{-12}
Xe-133	$2.50 \times 10^{+3}$	Kr-88	$8.17 \times 10^{+1}$	Sr-89	4.05×10^{-3}
Xe-135m	8.45×10^{-1}	Zr-95	6.64×10^{-11}	Y-89m	4.05×10^{-7}
Xe-135	1.60×10^{-1}	Nb-95	6.66×10^{-11}	Rb-88	$8.18 \times 10^{+1}$
Ce-144	1.34×10^{-9}	Nb-95m	1.33×10^{-12}	Rb-87	3.04×10^{-9}
Pr-144	1.34×10^{-9}	Y-94	1.32×10^{-16}	N-13	7.08×10^{-1}
Ce-143	8.42×10^{-12}	Y-93	7.42×10^{-9}	O-19	7.16×10^{-18}
Pr-143	2.88×10^{-10}	Zr-93	2.30×10^{-13}	F-18	4.79
Ce-141	1.87×10^{-8}	Nb-93m	1.25×10^{-13}	Br-83	1.98×10^{-5}
Ba-140	1.47×10^{-6}	Sr-92	1.23×10^{-8}	Br-84	4.51×10^{-6}
La-140	1.68×10^{-6}	Y-92	4.41×10^{-8}	Br-85	3.47×10^{-10}
Cs-137	6.38×10^{-5}	Sr-91	5.44×10^{-7}	I-131	1.61×10^{-3}
Cs-135	4.82×10^{-6}	Y-91	9.57×10^{-7}	I-132	1.47×10^{-4}
Kr-83m	4.26	Y-91m	3.51×10^{-7}	I-133	1.14×10^{-3}
Kr-85m	$5.90 \times 10^{+1}$	Sr-90	2.96×10^{-5}	I-134	8.64×10^{-5}
		Y-90	2.96×10^{-5}	I-135	5.27×10^{-4}

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Isotopes with activities less than 1.0×10^{-20} are not listed.
(3) Based on 150 scfm main condenser air inleakage.
(4) This activity is assumed to be uniformly distributed throughout adsorber number 3, which is composed of two parallel units, 2DS371 and 2ES371.

Table 12.2-81(i)

ADSORBER NUMBER 4 (UNIT 2)[1][3][4]

ISOTOPE[2]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Xe-131m	7.20	Kr-85	8.51×10^{-1}	Rb-89	2.06×10^{-18}
Xe-133m	6.45	Kr-87	7.08×10^{-1}	Sr-89	4.04×10^{-5}
Xe-133	$1.62 \times 10^{+3}$	Kr-88	$3.32 \times 10^{+1}$	Y-89m	4.04×10^{-9}
Xe-135m	4.55×10^{-1}	Zr-95	6.63×10^{-13}	Rb-88	$3.32 \times 10^{+1}$
Xe-135	1.69×10^{-1}	Nb-95	6.66×10^{-13}	Rb-87	4.35×10^{-10}
Ce-144	1.33×10^{-11}	Nb-95m	1.33×10^{-14}	N-13	2.64×10^{-1}
Pr-144	1.33×10^{-11}	Y-93	5.86×10^{-11}	F-18	4.49
Ce-143	1.59×10^{-14}	Zr-93	2.30×10^{-15}	Br-83	1.85×10^{-7}
Pr-143	2.44×10^{-12}	Nb-93m	1.25×10^{-15}	Br-84	3.29×10^{-8}
Ce-141	1.74×10^{-10}	Sr-92	4.99×10^{-11}	Br-85	1.24×10^{-13}
Ba-140	1.23×10^{-8}	Y-92	2.59×10^{-10}	I-131	1.61×10^{-5}
La-140	1.42×10^{-8}	Sr-91	4.22×10^{-9}	I-132	1.37×10^{-6}
Cs-137	6.37×10^{-7}	Y-91	9.55×10^{-9}	I-133	1.13×10^{-5}
Cs-135	1.59×10^{-6}	Y-91m	2.72×10^{-9}	I-134	7.13×10^{-7}
Kr-83m	1.15	Sr-90	2.96×10^{-7}	I-135	5.14×10^{-6}
Kr-85m	$3.27 \times 10^{+1}$	Y-90	2.96×10^{-7}		

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Isotopes with activities less than 1.0×10^{-20} are not listed.
(3) Based on 150 scfm main condenser air inleakage.
(4) This activity is assumed to be uniformly distributed throughout adsorber number 4, which is composed of two parallel units, 2FS371 and 2GS371.

Table 12.2-81(j)

ADSORBER NUMBER 5 (UNIT 2)[1][3][4]

ISOTOPE[2]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)
Xe-131m	6.01	Kr-85m	$1.99 \times 10^{+1}$	Sr-90	2.96×10^{-9}
Xe-133m	2.36	Kr-85	8.92×10^{-1}	Y-90	2.96×10^{-9}
Xe-133	$1.06 \times 10^{+3}$	Kr-87	1.14×10^{-1}	Sr-89	4.03×10^{-7}
Xe-135m	2.31×10^{-1}	Kr-88	$1.49 \times 10^{+1}$	Y-89m	4.03×10^{-11}
Xe-135	1.67×10^{-1}	Zr-95	6.62×10^{-15}	Rb-88	$1.49 \times 10^{+1}$
Ce-144	1.32×10^{-13}	Nb-95	6.66×10^{-15}	Rb-87	6.98×10^{-11}
Pr-144	1.32×10^{-13}	Nb-95m	1.33×10^{-16}	N-13	9.29×10^{-2}
Ce-143	3.02×10^{-17}	Y-93	4.67×10^{-13}	F-18	3.98
Pr-143	2.06×10^{-14}	Zr-93	2.30×10^{-17}	Br-83	1.72×10^{-9}
Ce-141	1.63×10^{-12}	Nb-93m	1.25×10^{-17}	Br-84	2.38×10^{-10}
Ba-140	1.03×10^{-10}	Sr-92	2.11×10^{-13}	Br-85	4.08×10^{-17}
La-140	1.19×10^{-10}	Y-92	1.49×10^{-12}	I-131	1.60×10^{-7}
Cs-137	6.37×10^{-9}	Sr-91	3.32×10^{-11}	I-132	1.27×10^{-8}
Cs-135	1.54×10^{-6}	Y-91	9.55×10^{-11}	I-133	1.12×10^{-7}
Kr-83m	3.53×10^{-1}	Y-91m	2.14×10^{-11}	I-134	5.85×10^{-9}
				I-135	5.01×10^{-8}

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Isotopes with activities less than 1.0×10^{-20} are not listed.
(3) Based on 150 scfm main condenser air inleakage.
(4) This activity is assumed to be uniformly distributed throughout adsorber number 5, which is composed of two parallel units, 2HS371 and 2IS371.

Table 12.2-82

OUTLET HEPA FILTER SHIELDING DESIGN SOURCE TERMS[1][3]

UNIT 1

Activity Isotope[2]	(Ci)	Activity Isotope	(Ci)
Xe-131m	2.03×10^{-4}	Zr-93	2.41×10^{-19}
Xe-133m	5.27×10^{-5}	Nb-93m	1.31×10^{-19}
Xe-133	3.17×10^{-2}	Sr-92	8.94×10^{-16}
Xe-135m	2.88×10^{-3}	Y-92	8.49×10^{-15}
Xe-135	2.06×10^{-3}	Sr-91	2.68×10^{-13}
Ce-144	1.37×10^{-15}	Y-91	9.92×10^{-13}
Pr-144	1.37×10^{-15}	Y-91m	1.73×10^{-13}
CE-143	5.79×10^{-20}	SR-90	2.07×10^{-11}
Pr-143	1.81×10^{-16}	Y-90	2.07×10^{-11}
Ce-141	1.58×10^{-14}	Sr-89	3.79×10^{-9}
Ba-140	8.98×10^{-13}	Y-89m	3.79×10^{-13}
La-140	1.03×10^{-12}	Rb-88	2.04×10^{-2}
Cs-137	6.53×10^{-11}	Rb-87	2.54×10^{-13}
Cs-135	2.68×10^{-8}	N-13	1.14×10^{-3}
Kr-83m	4.29×10^{-4}	F-18	4.99×10^{-2}
Kr-85m	1.28×10^{-2}	Br-83	1.68×10^{-11}
Kr-85	7.60×10^{-4}	Br-84	2.07×10^{-12}
Kr-87	3.20×10^{-5}	Br-85	8.62×10^{-20}
Kr-88	7.96×10^{-3}	I-131	1.62×10^{-9}
Zr-95	6.91×10^{-17}	I-132	1.23×10^{-10}
Nb-95	6.97×10^{-17}	I-133	1.12×10^{-9}
Nb-95m	1.39×10^{-18}	I-134	5.40×10^{-11}
Y-93	3.85×10^{-15}	I-135	5.00×10^{-10}

Table 12.2-82 (Cont'd)

OUTLET HEPA FILTER SHIELDING DESIGN SOURCE TERMS[1][3]

UNIT 2

Isotope[2]	Activity (Ci)	Isotope	Activity (Ci)
Xe-131m	2.03×10^{-4}	Zr-93	2.33×10^{-19}
Xe-133m	5.28×10^{-5}	Nb-93m	1.27×10^{-19}
Xe-133	3.17×10^{-2}	Sr-92	8.64×10^{-16}
Xe-135m	2.05×10^{-3}	Y-92	8.20×10^{-15}
Xe-135	2.09×10^{-3}	Sr-91	2.60×10^{-13}
Ce-144	1.32×10^{-15}	Y-91	9.63×10^{-13}
Pr-144	1.32×10^{-15}	Y-91m	1.68×10^{-13}
Pr-143	1.75×10^{-16}	Sr-90	2.99×10^{-11}
Ce-141	1.53×10^{-14}	Y-90	2.99×10^{-11}
Ba-140	8.70×10^{-13}	Sr-89	4.06×10^{-9}
La-140	1.00×10^{-12}	Y-89m	4.06×10^{-13}
Cs-137	6.44×10^{-11}	Rb-88	2.06×10^{-13}
Cs-135	3.49×10^{-8}	Rb-87	7.23×10^{-13}
Kr-83m	4.25×10^{-4}	N-13	6.71×10^{-4}
Kr-85m	1.27×10^{-2}	F-18	4.75×10^{-2}
Kr-85	7.60×10^{-4}	Br-83	1.62×10^{-11}
Kr-87	3.20×10^{-5}	Br-84	1.75×10^{-12}
Kr-88	7.95×10^{-3}	Br-85	1.46×10^{-20}
Zr-95	6.68×10^{-17}	I-131	1.62×10^{-9}
Nb-95	6.73×10^{-17}	I-132	1.19×10^{-10}
Nb-95m	1.34×10^{-18}	I-133	1.12×10^{-9}
Y-93m	3.71×10^{-19}	I-134	4.87×10^{-11}
		I-135	4.94×10^{-10}

(1) Based on shielding design source terms given in Tables 12.2-1 and 12.2-4.
(2) Isotopes with activities less than 1.0×10^{-20} are not listed.
(3) Based on 150 scfm main condenser air inleakage.

Table 12.2-83

CONTROL ROOM SHIELDING DESIGN SOURCE TERMS - PRIMARY CONTAINMENT

	ACTIVITY (CURIES) AT TIME POST-LOCA[1][2][3][4]										
ISOTOPE	0.0 HR	.50 HR	1.00 HR	2.00 HR	4.00 HR	8.00 HR	16.00 HR	24.00 HR	96.00 HR	240.00 HR	720.00HR
I-131	2.22E+07	2.21E+07	2.21E+07	2.20E+07	2.18E+07	2.15E+07	2.09E+07	2.03E+07	1.54E+07	8.92E+06	1.44E+06
I-132	3.30E+07	2.84E+07	2.43E+07	1.79E+07	9.67E+06	2.83+06	2.42E+05	2.07E+04	5.14E-06	3.15E-25	0.00E+00
I-133	5.11E+07	5.03E+07	4.94E+07	4.77E+07	4.46E+07	3.89E+07	2.95E+07	2.24E+07	1.90E+06	1.36E+04	9.56E-04
I-134	5.95E+07	3.99E+07	2.67E+07	1.20E+07	2.43E+06	9.87E+04	1.64E+02	2.71E-01	2.58E-26	0.00E+00	0.00E+00
I-135	4.65E+07	4.42E+07	4.19E+07	3.77E+07	3.07E+07	2.02E+04	8.78E+06	3.81E+06	2.10E+03	6.40E-04	1.21E-25
I-136	2.37E+07	6.88E+00	2.00E-06	1.69E-19	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Br-83	3.89E+06	3.37E+06	2.92E+06	2.18E+06	1.22E+06	3.88E+05	3.87E+04	3.86E+03	3.75E-06	3.55E-24	0.00E+00
Br-84	7.02E+06	3.64E+06	1.90E+06	5.11E+05	3.71E+04	1.97E+02	5.52E-03	1.55E-07	0.00E+00	0.00E+00	0.00E+00
Br-85	9.84E+06	9.44E+03	9.04E+00	8.30E-06	7.01E-18	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Kr-83m	1.59E+07	1.33E+07	1.09E+07	7.52E+06	3.57E+06	8.02E+05	4.05E+04	2.04E+03	4.38E-09	2.00E-32	0.00E+00
Kr-85m	3.97E+07	3.67E+07	3.39E+07	2.90E+07	2.11E+07	1.13E+07	3.20E+06	9.12E+03	1.11E+01	1.63E-09	0.00E+00
Kr-85	1.35E+06	1.35E+06	1.35E+06	1.35E+06	1.35E+06	1.35E+06	1.35E+06	1.34E+06	1.32E+06	1.28E+06	1.15E+06
Kr-87	7.63E+07	5.80E+07	4.42E+07	2.55E+07	8.55E+06	9.58E+05	1.20E+04	1.51E+02	1.17E-15	0.00E+00	0.00E+00
Kr-88	1.06E+08	9.38E+07	8.29E+07	6.48E+07	3.95E+07	1.47E+07	2.03E+06	2.82E+05	5.24E-03	1.82E-18	0.00E+00
Kr-89	1.40E+08	2.00E+05	2.87E+02	5.85E+07	2.45E-15	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Xe-133m	5.19E+06	5.15E+06	5.12E+06	5.05E+06	4.93E+06	4.67E+06	4.21E+06	3.79E+06	1.49E+06	2.28E+05	4.44E+02
Xe-133	2.04E+08	2.03E+08	2.02E+08	2.01E+08	1.99E+08	1.95E+08	1.86E+08	1.77E+08	1.18E+08	5.19E+07	3.39E+06
Xe-135m	5.49E+07	1.45E+07	3.80E+06	2.63E+05	1.26E+03	2.90E-02	1.53E-11	8.09E-21	0.00E+00	0.00E+00	0.00E+00
Xe-135	1.92E+08	1.85E+08	1.79E+08	1.65E+08	1.42E+08	1.05E+08	5.70E+07	3.10E+07	1.31E+05	2.29E+00	3.28E-16
Xe-137	1.84E+08	8.69E+05	4.13E+03	9.30E-02	4.72E-11	1.22E-29	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Xe-138	1.81E+08	5.48E+07	1.66E+07	1.54E+06	1.32E+04	9.67E-01	5.20E-09	2.79E-17	0.00E+00	0.00E+00	0.00E+00

(1) Assumes the reactor to have been operating for 1000 days at 3458 Mw(t) at time of LOCA.

(2) Assumes 100% of noble gases and 25% of halogens in core are released to primary containment atmosphere.

(3) Assumes 0.5% per day leak rate from primary to secondary containment.

(4) This activity is assumed to be uniformly distributed throughout the free air volume of primary containment, including the drywell and wetwell. This volume is 404,000 ft^3.

Table 12.2-84

CONTROL ROOM SHIELDING DESIGN SOURCE TERMS - REACTOR ENCLOSURE

ACTIVITY (CURIES) AT TIME POST-LOCA[1][2][3][4][5][6]

ISOTOPE	0.0 HR	50 HR	1.00 HR	2.00 HR	4.00 HR	8.00 HR	16.00 HR	24.00 HR	96.00 HR	240.00 HR	720.00 HR
I-131	0.00E+00	1.88E+03	3.09E+03	4.39E+03	5.14E+03	5.23E+03	5.08E+03	4.93E+03	3.74E+03	2.17E+03	3.50E+02
I-132	0.00E+00	2.40E+03	3.40E+03	3.56E+03	2.27E+03	6.86E+02	5.89E+01	5.04E+00	1.24E-09	7.66E-29	0.00E+00
I-133	0.00E+00	4.25E+03	6.91E+03	9.51E+03	1.05E+04	9.44E+03	7.17E+03	5.46E+03	4.61E+02	3.29E+00	2.33E-07
I-134	0.00E+00	3.38E+03	3.74E+03	2.40E+03	5.70E+02	2.40E+01	3.98E-02	6.60E-05	6.27E-30	0.00E+00	0.00E+00
I-135	0.00E+00	3.74E+03	5.87E+03	7.53E+03	7.21E+03	4.91E+01	2.13E+0	9.27E+02	5.11E-01	1.56E-07	2.94E-29
I-136	0.00E+00	5.82E-04	2.80E-10	3.38E-23	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Br-83	0.00E+00	2.86E+02	4.08E+02	4.36E+02	2.89E+02	9.41E+01	9.39E+00	9.37E-01	9.11E-10	8.62E-28	0.00E+00
Br-84	0.00E+00	3.09E+02	2.65E+03	1.02E+02	8.74E+00	4.78E-02	1.35E-06	3.76E-11	0.00E+00	0.00E+00	0.00E+00
Br-85	0.00E+00	7.99E-01	1.26E-03	1.65E-09	1.65E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Kr-83m	0.00E+00	1.36E+03	2.23E+03	3.01E+03	2.73E+03	1.13E+03	9.86E+01	6.48E+00	2.15E-11	1.00E-34	0.00E+00
Kr-85m	0.00E+00	3.78E+03	6.92E+03	1.16E+04	1.62E+04	1.60E+04	7.81E+03	2.89E+03	5.46E-02	8.19E-12	0.00E+00
Kr-85	0.00E+00	1.39E+02	2.74E+02	5.39E+02	1.03E+03	1.91E+03	3.27E+03	4.24E+03	6.51E+03	6.43E+03	5.79E+03
Kr-87	0.00E+00	5.98E+03	9.01E+03	1.02E+04	6.56E+03	1.36E+03	2.93E+01	4.78E-01	5.76E-18	0.00E+00	0.00E+00
Kr-88	0.00E+00	9.67E+03	1.69E+04	2.59E+04	3.03E+04	2.08E+04	4.96E+03	8.91E+02	2.58E-05	9.13E-21	0.00E+00
Kr-89	0.00E+00	2.06E+01	5.84E-02	2.35E-07	1.88E-18	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Xe-133m	0.00E+00	5.31E+02	1.04E+03	2.02E+03	3.78E+03	6.63E+03	1.03E+04	1.20E+04	7.33E+03	1.15E+03	2.23E+00
Xe-133	0.00E+00	2.09E+04	4.13E+04	8.05E+04	1.53E+05	2.75E+05	4.53E+05	5.62E+05	5.81E+05	2.61E+05	1.70E+04
Xe-135m	0.00E+00	1.49E+03	7.76E+02	1.05E+02	9.69E-01	4.11E-05	3.73E-14	2.58E-23	0.00E+00	0.00E+00	0.00E+00
Xe-135	0.00E+00	1.91E+04	3.63E+04	6.60E+04	1.09E+05	1.49E+05	1.39E+05	9.82E+04	6.43E+02	1.15E-02	1.65E-18
Xe-137	0.00E+00	8.96E+01	3.41E-01	3.72E-05	3.63E-14	1.73E-32	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Xe-138	0.00E+00	5.64E+03	3.40E+03	6.16E+02	1.01E+01	1.38E-03	1.26E-00	8.84E-20	0.00E+00	0.00E+00	0.00E+00

=_____

(1) Assumes the reactor to have been operating for 1000 days at 3458 Mw(t) at time of LOCA.

(2) Assumes 100% of noble gases and 25% of halogens in core are released to primary containment atmosphere.

(3) Assumes 0.5% per day leak rate from primary to secondary containment.

(4) Assumes a secondary containment recirculation system flow rate of 60,000 cfm with a charcoal filter efficiency of 0.95 for halogens.

(5) Assumes a SGTS flow rate of 2778 cfm with a charcoal filter efficiency of 0.99 for halogens.

(6) This activity is assumed to be uniformly distributed throughout the free air volume of the secondary containment. This volume is 4,000,000 ft^3, and includes the common refueling floor for both units.

Table 12.2-85

CONTROL ROOM SHIELDING DESIGN SOURCE TERMS - TURBINE ENCLOSURE AND CONTROL STRUCTURE[1][2][3][4][5][6][7]

TOTAL INTEGRATED ACTIVITY (CURIES) RELEASED TO EXTERNAL ENVIRONMENT FROM SGTS (NO DECAY)

ISOTOPE	0 to 8 HRS	8 to 24 HRS	24 to 96 HRS	96 to 720 HRS
I-131	7.56E-01	1.69E+00	6.47E+00	1.87E+01
I-132	3.54E-01	4.62E-02	4.08E-04	0.00E+00
I-133	1.52E+00	2.42E+00	3.03E+00	2.81E-01
I-134	1.94E-01	6.12E-04	0.00E+00	0.00E+00
I-135	1.03E+00	7.97E-01	1.88E-01	0.00E+00
I-136	1.10E-04	0.00E+00	0.00E+00	0.00E+00
Br-83	4.44E-02	6.75E-03	6.12E-05	0.00E+00
Br-84	1.07E-02	0.00E+00	0.00E+00	0.00E+00
Br-85	2.08E-04	0.00E+00	0.00E+00	0.00E+00
Kr-83m	7.30E+02	1.58E+02	7.14E-01	0.00E+00
Kr-85m	4.54E+03	5.63E+03	8.62E+02	0.00E+00
Kr-85	3036E+02	2.14E+03	1.76E+04	1.61E+05
Kr-87	1.94E+03	1.21E+02	0.00E+00	0.00E+00
Kr-88	8.12E+03	4.63E+03	1.63E+02	0.00E+00
Kr-89	7.06E+00	0.00E+00	0.00E+00	0.00E+00
Xe-133m	1.21E+03	6.64E+03	3.18E+04	2.39E+04
Xe-133	4.93E+04	2.95E+05	1.92E+06	4.20E+06
Xe-135m	6.59E+01	0.00E+00	0.00E+00	0.00E+00
Xe-135	3.25E+04	8.95E+04	6.47E+04	3.06E+02
Xe-137	1.39E+01	0.00E+00	0.00E+00	0.00E+00
Xe-138	1.71E+02	0.00E+00	0.00E+00	0.00E+00

(1) Assumes reactor to have been operating for 1000 days at 3458 Mw(t) at time of LOCA.
(2) Assumes 100% of noble gases and 25% of halogens in core are released to primary containment atmosphere.
(3) Assumes 0.5% per day leak rate from primary to secondary containment.
(4) Assumes a secondary containment recirculation system flow rate of 60,000 cfm with a charcoal filter efficiency of 0.95 for halogens.
(5) Assumes an SGTS flow rate of 2778 cfm with a charcoal filter efficiency of 0.99 for halogens.
(6) Assumes turbine enclosure and control structure intake environs cloud immediately, allowing only for atmospheric dispersion.
(7) Building wake atmospheric dispersion factors (X/Q) used are given by post-LOCA time period:
0 to 8 HRS 3.46×10^{-4} sec/m^3
8 to 24 HRS 2.04×10^{-4} sec/m^3
24 to 96 HRS 1.30×10^{-4} sec/m^3
96 to 720 HRS 5.71×10^{-5} sec/m^3

Table 12.2-86

CONTROL ROOM SHIELDING DESIGN SOURCE TERMS - STANDBY GAS TREATMENT SYSTEM CARBON FILTER

ACTIVITY (CURIES) AT TIME POST-LOCA[1][2][3][4][5][6]

ISOTOPE	0.0 HR	.50 HR	1.00 HR	2.00 HR	4.00 HR	8.00 HR	16.00 HR	24.00 HR	96.00 HR	240.00 HR	720.00 HR
I-131	0.00E+00	1.05E+00	3.68E+00	1.16E+01	3.18E+01	7.46E+01	1.57E+02	2.35E+02	7.48E+02	1.11E+03	5.66E+02
I-132	0.00E+00	1.34E+00	4.04E+00	9.45E+00	1.41E+01	9.80E+00	1.83E+00	2.41E-01	2.49E-10	3.91E-29	0.00E+00
I-133	0.00E+00	2.38E+00	8.21E+00	2.52E+00	6.48E+01	1.35E+02	2.22E+02	2.60E+02	9.20E+01	1.68E+00	3.75E-07
I-134	0.00E+00	1.89E+00	4.45E+00	6.34E+00	3.53E+00	3.42E-01	1.23E-03	3.15E-06	1.25E-30	0.00E+00	0.00E+00
I-135	0.00E+00	2.09E+00	6.98E+00	2.00E+00	4.46E+01	7.01E+01	6.61E+01	4.43E+01	1.02E-01	7.49E-08	4.75E-29
I-136	0.00E+00	3.25E-07	3.33E-13	8.96E-26	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Br-83	0.00E+00	1.59E-01	4.86E-01	1.15E+00	1.79E+00	1.35E+00	2.91E-01	4.47E-02	1.82E-10	4.40E-28	0.00E+00
Br-84	0.00E+00	1.72E-01	3.15E-01	2.70E-01	5.41E-02	6.81E-04	4.15E-08	1.80E-12	0.00E+00	0.00E+00	0.00E+00
Br-85	0.00E+00	4.46E-04	1.50E-06	4.39E-12	1.02E-23	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

(1) Assumes the reactor to have been operating for 1000 days at 3458 Mw(t) at time of LOCA.
(2) Assumes 100% of noble gases and 25% of halogens in core are released to primary containment atmosphere.
(3) Assumes 0.5% per day leak rate from primary to secondary containment.
(4) Assumes a secondary containment recirculation system flow rate of 60,000 cfm with a charcoal filter efficiency of 0.95 for halogens.
(5) Assumes a SGTS flow rate of 2778 cfm with a charcoal filter efficiency of 0.99 for halogens.
(6) This activity is assumed to be uniformly distributed throughout the SGTS carbon filter.

Table 12.2-87

CONDENSATE STORAGE TANK SHIELDING DESIGN SOURCE TERMS[1][2][3]

CARRYOVER COMPONENT

Isotope[4]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Br-83	7.43×10^{-3}	Cs-138	5.44×10^{-3}	Re-187	7.09×10^{-18}
Br-84	3.06×10^{-3}	Ba-139	2.35×10^{-3}	Ag-110	5.88×10^{-8}
Br-85	1.16×10^{-4}	Ba-140	2.22×10^{-3}	Zn-69	8.17×10^{-7}
I-131	6.15×10^{-2}	Ba-141	5.30×10^{-4}	Pu-239	4.88×10^{-9}
I-132	6.51×10^{-2}	Ba-142	3.08×10^{-4}	U-235	1.81×10^{-20}
I-133	2.20×10^{-1}	Ce-141	2.43×10^{-5}	Pm-147	3.43×10^{-9}
I-134	4.46×10^{-2}	Ce-143	5.45×10^{-6}	Pr-144	9.14×10^{-6}
I-135	1.54×10^{-1}	Ce-144	9.24×10^{-6}	La-142	3.32×10^{-4}
Sr-89	8.07×10^{-4}	Pr-143	9.76×10^{-6}	La-141	4.95×10^{-4}
Sr-90	6.09×10^{-5}	Nd-147	3.41×10^{-6}	La-140	8.10×10^{-4}
Sr-91	5.38×10^{-3}	Np-239	4.51×10^{-2}	Te-129	6.29×10^{-6}
Sr-92	3.03×10^{-3}	Na-24	5.94×10^{-5}	I-129	1.55×10^{-15}
Zr-95	1.04×10^{-5}	P-32	1.42×10^{-6}	Rh-106	6.87×10^{-7}
Zr-97	3.59×10^{-6}	Cr-51	3.66×10^{-5}	Rh-103m	4.63×10^{-6}
Nb-95	1.11×10^{-5}	Mn-54	3.02×10^{-6}	Tc-99	2.36×10^{-10}
Mo-99	4.33×10^{-3}	Mn-56	3.76×10^{-4}	Nb-97m	3.34×10^{-6}
Tc-99m	1.83×10^{-2}	Co-58	3.73×10^{-4}	Nb-97	3.42×10^{-6}
Tc-101	3.32×10^{-4}	Co-60	3.78×10^{-5}	Nb-95m	4.27×10^{-8}
Ru-103	4.91×10^{-6}	Fe-59	5.93×10^{-6}	Y-92	2.66×10^{-3}
Ru-106	6.87×10^{-7}	Ni-65	2.25×10^{-6}	Y-91	8.52×10^{-5}
Te-129m	1.03×10^{-5}	Zn-65	1.51×10^{-7}	Y-91m	3.07×10^{-3}
Te-132	1.00×10^{-2}	Zn-69m	8.48×10^{-7}	Y-90	1.70×10^{-5}
Cs-134	2.12×10^{-4}	Ag-110m	4.52×10^{-6}	Y-89m	8.07×10^{-8}
Cs-136	1.36	3.18×10^{-4}			

Table 12.2-87 (Cont'd)

FALLOUT COMPONENT

Isotope[4]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci
Ba-144	2.50×10^{-9}	Cs-139	9.64×10^{-3}	Nb-93m	2.34×10^{-16}
La-144	9.43×10^{-7}	Ba-139	1.07×10^{-2}	Rb-92	8.90×10^{-11}
Ce-144	2.24×10^{-8}	Cs-138	3.59×10^{-3}	Sr-92	4.19×10^{-3}
Pr-144	2.21×10^{-8}	Cs-137	5.68×10^{-7}	Y-92	3.67×10^{-3}
Ba-143	1.45×10^{-8}	Cs-135	8.40×10^{-13}	Rb-91	2.96×10^{-3}
La-143	3.16×10^{-5}	Sr-95	1.03×10^{-6}	Sr-91	7.71×10^{-3}
Ce-143	1.43×10^{-5}	Y-95	6.53×10^{-6}	Y-91	1.22×10^{-4}
Pr-143	9.49×10^{-7}	Zr-95	1.02×10^{-7}	Y-91m	4.40×10^{-3}
Ba-142	3.21×10^{-4}	Nb-95	2.70×10^{-9}	Rb-90	6.50×10^{-3}
La-142	3.46×10^{-4}	Nb-95m	4.18×10^{-10}	Sr-90	1.06×10^{-6}
Cs-141	6.05×10^{-5}	Rb-94	8.50×10^{-19}	Y-90	2.95×10^{-7}
Ba-141	2.84×10^{-3}	Sr-94	4.02×10^{-5}	Rb-89	4.96×10^{-3}
La-141	2.60×10^{-3}	Y-94	1.20×10^{-4}	Sr-89	9.86×10^{-5}
Ce-141	7.48×10^{-5}	Rb-93	5.07×10^{-11}	Y-89m	9.86×10^{-9}
Cs-140	2.61×10^{-3}	Sr-93	8.74×10^{-4}	Rb-88	7.83×10^{-4}
Ba-140	7.60×10^{-4}	Y-93	7.24×10^{-4}	Rb-87	4.77×10^{-17}
La-140	2.77×10^{-4}	Zr-93	1.27×10^{-12}		

(1) Based on shielding design source terms listed in Tables 12.2-1 through 12.2-5.
(2) Based on condensate activity with appropriate DFs applied: 2 for Cs and Rb; 10 for others.
(3) Equilibrium activity of cleaned-up condensate flowing through a 200,000 gallon tank at 100 gpm.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-88

REFUELING WATER STORAGE TANK SHIELDING DESIGN SOURCE TERMS[1][2][3]

ISOTOPE[4]	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (Ci)	ISOTOPE	ACTIVITY (ci)
Br-83	1.03×10^{-2}	Cs-137	1.75×10^{-3}	Tc-99	3.84×10^{-10}
Br-84	4.92×10^{-3}	Cs-138	1.75×10^{-1}	Nb-97m	3.82×10^{-5}
Br-85	2.92×10^{-4}	Ba-139	7.25×10^{-2}	Nb-97	3.05×10^{-5}
I-131	1.87×10^{-2}	Ba-140	1.30×10^{-2}	Nb-95m	2.70×10^{-8}
I-132	1.17×10^{-1}	Ba-141	1.75×10^{-2}	Y-92	4.06×10^{-2}
I-133	1.17×10^{-1}	Ba-142	1.07×10^{-2}	Y-91	1.07×10^{-4}
I-134	7.10×10^{-2}	Ce-141	8.97×10^{-5}	Y-91m	3.98×10^{-2}
I-135	1.40×10^{-1}	Ce-143	4.79×10^{-5}	Y-90	1.16×10^{-5}
Sr-89	4.51×10^{-3}	Ce-144	5.10×10^{-5}	Y-89m	4.50×10^{-7}
Sr-90	3.35×10^{-4}	Pr-143	5.53×10^{-5}	Cs-135	1.72×10^{-12}
Sr-91	8.14×10^{-2}	Nd-147	2.02×10^{-5}	Na-24	7.25×10^{-4}
Sr-92	8.11×10^{-2}	Np-239	3.37×10^{-1}	P-32	8.27×10^{-6}
Zr-95	5.82×10^{-5}	Re-187	6.62×10^{-18}	Cr-51	2.07×10^{-4}
Zr-97	4.13×10^{-5}	Ag-110	3.24×10^{-7}	Mn-54	1.66×10^{-5}
Nb-95	6.12×10^{-5}	Zn-69	8.58×10^{-6}	Mn-56	1.02×10^{-2}
Mo-99	3.11×10^{-2}	Pu-239	3.38×10^{-9}	Co-58	2.08×10^{-3}
Tc-99m	3.01×10^{-1}	Pm-147	1.87×10^{-9}	Co-60	2.08×10^{-4}
Tc-101	1.12×10^{-2}	Pr-144	4.75×10^{-5}	Fe-59	3.32×10^{-5}
Ru-103	2.76×10^{-5}	La-142	9.94×10^{-3}	Ni-65	6.11×10^{-5}
Ru-106	3.79×10^{-6}	La-141	1.12×10^{-2}	Zn-65	8.32×10^{-7}
Te-129m	5.81×10^{-5}	La-140	6.64×10^{-4}	Zn-69m	1.08×10^{-5}
Te-132	6.95×10^{-2}	Te-129	2.74×10^{-5}	Ag-110m	2.50×10^{-5}
Cs-134	1.17×10^{-3}	I-129	6.16×10^{-16}	W-187	1.14×10^{-3}
Cs-136	7.96×10^{-4}	Rh-103m	2.10×10^{-5}		

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) Filtered and demineralized fuel pool water (DF of 2 for Cs and Rb, DF of 10 for others) accumulated for 6.11 hours at 1500 gpm.
(3) This activity is in 550,000 gallons.
(4) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-89

TRAVERSING INCORE PROBE MATERIALS

DETECTOR REGION

Material	Weight (g)
304L stainless steel (Co ≤ 0.014%)	4.92
Commercially pure titanium	0.662
Alumina	0.885
Nickel/iron alloy	0.248
Copper	0.021

CABLE REGION

Material	Weight (g/inch)
AISI 304L stainless steel (Co ≤ 0.014%)	0.43
AISI 1070 carbon steel	2.16
Magnesium oxide (insulation)	0.0798

Table 12.2-90

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Table 12.2-91

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Table 12.2-92

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Table 12.2-93

ESTIMATED IN-PLANT AIRBORNE RADIOACTIVE RELEASES[1]
(Ci/year)

ISOTOPE	TURBINE(2) ENCLOSURE (PER UNIT)	REACTOR ENCLOSURE (PER UNIT)	RADWASTE(3) ENCLOSURE (PER PLANT)
H-3	4.1E+01	4.1E+0E	-
Kr-83m	-	-	-
Kr-85m	6.9E+01	6.1E+00	-
Kr-85	-	-	-
Kr-87	1.3E+02	6.1E+00	-
Kr-88	2.3E+02	6.1E+00	-
Kr-89	-	-	-
Xe-131m	-	-	-
Xe-133m	-	-	-
Xe-133	2.6E+02	1.3E+02	2.0E+01
Xe-135m	6.6E+02	9.4E+01	-
Xe-135	6.4E+02	6.9E+01	9.2E+01
Xe-137	-	-	-
Xe-138	1.4E+03	1.4E+01	-
I-131	1.9E-01	3.5E-01	1.0E-01
I-133	7.8E-01	1.4E+00	3.7E-01
Co-60	2.0E-03	2.0E-02	1.8E-01
Co-58	6.1E-04	1.2E-03	9.2E-03
Cr-51	1.3E-02	6.1E-04	1.8E-02
Mn-54	6.1E-04	6.1E-03	6.1E-02
Fe-59	5.1E-04	8.2E-04	3.1E-02
Zn-65	2.0E-04	4.1E-03	3.1E-01
Zr-95	1.0E-04	8.2E-04	1.0E-04
Sr-89	6.1E-03	1.8E-04	9.2E-04
Sr-90	2.0E-05	1.0E-05	6.1E-04
Sb-124	3.1E-04	4.1E-04	1.0E-04
Cs-134	3.1E-04	8.2E-03	9.2E-03
Cs-136	5.1E-02	6.1E-04	9.2E-04
Cs-137	6.1E-0E	1.1E-02	1.8E-02
Ba-140	1.1E-02	8.2E-04	2.0E-04
Ce-141	6.1E-04	2.0E-04	5.3E-03

(1) BWR-GALE Computer Code (Reference 12.2-1).
(2) Includes control structure releases.
(3) Includes offgas enclosure releases.

Table 12.2-94

ESTIMATED IN-PLANT DISTRIBUTION OF AIRBORNE RADIOACTIVITY RELEASES[1]

RELEASES	AIRBORNE RELEASE FRACTION (%)
Turbine Enclosure[2]	
Condenser areas	60.30
SJAE areas	7.00
Mechanical vacuum pump areas	3.50
Turbine hall areas	9.20
Other equipment areas[3]	20.00
	100.00
Reactor Enclosure	
RWCU pump areas	23.65
RWCU filter/demineralizer areas	9.80
Refueling areas[4]	9.15
ECCS areas (RHR, HPCI, etc.)	7.40
Drywell areas	30.00
Other equipment areas[3]	20.00
	100.00
Radwaste Enclosure[5]	
Solids handling areas	8.40
Liquid waste handling areas	71.60
Other equipment areas[3]	20.00
	100.00

(1) Based on report for EPRI Research Project 274-1 (Reference 12.2-2).
(2) Includes control structure equipment areas.
(3) Assumes 80% of enclosure release by major areas listed and 20% by all other equipment areas within the enclosure.
(4) All of reactor enclosure tritium is assumed to be released in the refueling area.
(5) Includes offgas enclosure equipment areas.

Table 12.2-95

REACTOR ENCLOSURE AIRBORNE SOURCE DESCRIPTIONS

AREAROOM NOS. AND[1] TOTAL EXHAUST DESIGNATION	TOTAL ANNUAL[2] AREAS INCLUDED	FLOW (cfm)	EXHAUST (cc/yr)
RWCU pump	503,504,505,507,508, 509,510,522	$1.16x10^{+4}$	$1.7x10^{+14}$
RWCU filter/demineralizer	502,600,609	$2.63x10^{+3}$	$3.9x10^{+13}$
Refueling	700	$5.20x10^{+4}$	$7.7x10^{+14}$
ECCS	102,103,108,109,203, 204,297,298,309	$9.34x10^{+3}$	$1.4x10^{+14}$
Drywell	400,400A,400B,400C, 400D,400E	$1.10x10^{+4}$	$1.3x10^{+13}$
Others	115,209,296,399,402A, 403,406,407A,501,511, 518A,523,599,616,617, 618	$3.26x10^{+4}$	$4.9x10^{+14}$

(1) See drawings N-116, N-117, N-118, N-119, N-120, N-121, N-122, N-131, N-132, N-133, N-134, N-135, N-136, and N-137.
(2) Based on continuous release, 365 days per year except for drywell where release is assumed to occur entirely within 30 days.

Table 12.2-96

TURBINE ENCLOSURE AIRBORNE SOURCE DESCRIPTIONS

AREA DESIGNATION	ROOM NOS. AND[1] AREAS INCLUDED	TOTAL EXHAUST FLOW (cfm)	TOTAL ANNUAL[2] EXHAUST (cc/yr)
Condenser	253,254,255,256, 332,342,499	$9.10x10^{+3}$	$1.4x10^{+14}$
Steam jet air ejector	154,333,334	$1.35x10^{+4}$	$2.0x10^{+14}$
Mech vacuum pump	337	$2.50x10^{+2}$	$3.7x10^{+12}$
Turbine hall	544	$2.40x10^{+4}$	$3.6x10^{+14}$
Others	119,119A,119B,161, 162,163,165,249, 249A,259,264,299, 339,340,407,438, 439,440,441,498, 518,545,546,547, 551,621,624	$4.85x10^{+4}$	$7.2x10^{+14}$

(1) See drawings N-110, N-111, N-112, N-113, N-115, N-125, N-126, N-127, N-128, and N-130.
(2) Based on continuous release, 365 days per year.

Table 12.2-97

RADWASTE AND OFFGAS ENCLOSURE AIRBORNE SOURCE DESCRIPTIONS

AREA DESIGNATION	ROOM NOS. AND[1] AREAS INCLUDED	TOTAL EXHAUST FLOW (cfm)	TOTAL ANNUAL[2] EXHAUST (cc/yr)
Solid radwaste handling	123,124,125,126,127,128,129, 130,138,139,140,141,142,143, 144,233,234,422,423,470,471, 515,516	$1.26x10^{+4}$	$1.9x10^{+14}$
Liquid radwaste handling	131,132,133,134,136,137,147, 148,230,231,232,237,238,240, 241,242,243,245,247,248,472	$1.90x10^{+4}$	$2.8x10^{+14}$
Others	122,146,227,228,236,239,485, 486, offgas equipment areas	$1.29x10^{+4}$	$1.9x10^{+14}$

(1) See drawings N-140, 141 and N-142.
(2) Based on continuous release, 365 days per year.

Table 12.2-98

ESTIMATED AIRBORNE CONCENTRATIONS IN THE REACTOR ENCLOSURE[1]

NUCLIDE	MPC[2] µCi/cc	RWCU PUMP AREAS Concen. µCi/cc	RWCU PUMP AREAS Fraction of MPC	RWCU FILTER/ DEMINERALIZER AREAS Concen. µCi/cc	RWCU FILTER/ DEMINERALIZER AREAS Fraction of MPC	REFUELING AREAS Concen. µCi/cc	REFUELING AREAS Fraction of MPC	ECCS EQUIPMENT AREAS Concen. µCi/cc	ECCS EQUIPMENT AREAS Fraction of MPC	DRYWELL AREAS Concen. µCi/cc	DRYWELL AREAS Fraction of MPC	OTHER EQUIPMENT AREAS Concen. µCi/cc	OTHER EQUIPMENT AREAS Fraction of MPC
H-3	5.0E-06	-	-	-	-	5.2E-08	1.0E-02	-	-	-	-	-	-
Kr-83m	6.0E-06	-	-	-	-	-	-	-	-	-	-	-	-
Kr-85m	1.0E-06	8.5E-09	1.4E-04	1.5E-08	2.5E-04	7.2-10	1.2E-05	3.3E-09	5.4E-05	1.4E-07	2.4E-02	2.4E-09	4.1E-04
Kr-85	1.0E-06	-	--	-	-	-	-	-	-	-	-		
Kr-87	1.0E-06	8.5E-09	8.5E-03	1.5E-08	1.5E-02	7.2E-10	7.2E-04	3.3E-09	3.3E-03	1.4E-07	1.4E-01	2.4E-09	2.4E-03
Kr-88	1.0E-06	8.5E-09	8.5E-03	1.5E-08	1.5E-02	7.2E-10	7.2E-04	3.3E-09	3.32E-03	1.4E-07	1.4E-01	2.4E-09	2.4E-03
Kr-89	1.0E-06	-	-	-	-	-	-	-	-	-	-	-	-
Xe-131m	2.0E-05	-	-	-	-	-	-	-	-	-	-	-	-
Xe-133m	1.0E-05	-	-	-	-	-	-	-	-	-	-	-	-
Xe-133	1.0E-05	1.8E-07	1.8E-02	3.4E-07	3.4E-02	1.5E-08	1.5E-03	7.0E-08	7.0E-03	3.1E-06	3.1E-01	5.4E-08	5.4E-03
Xe-135m	1.0E-06	1.3E-07	1.3E-01	2.3E-07	2.3E-01	1.1E-08	1.1E-02	5.0E-08	5.0E-02	2.1E-06	2.1E-01	3.9E-08	3.9E-02
Xe-135	4.0E-06	9.7E-08	2.4E-02	1.7E-07	4.3E-02	8.3E-09	2.1E-03	3.7E-08	9.2E-03	1.6E-06	4.1E-01	2.9E-08	7.1E-03
Xe-137	1.0E-06	-	-	-	-	-	-	-	-	-	-	-	-
Xe-138	1.0E-06	1.9E-08	1.9E-02	3.6E-08	3.6E-02	1.7E-03	1.7E-03	7.5E-09	7.5E-03	3.3E-07	3.3E-01	5.8E-09	5.8E-03
I-131	9.0E-09	4.8E-10	5.3E-02	8.7E-10	9.6E-02	4.1E-11	4.5E-03	1.8E-10	2.0E-02	8.0E-09	8.8E-01	1.4E-010	1.6E-02
I-133	3.0E-08	1.9E-09	6.5E-02	3.6E-09	1.2E-01	1.7E-10	5.8E-03	7.5E-10	2.5E-02	3.3E-08	1.1E+00	5.8E-010	1.9E-02
Co-60	9.0E-09	2.9E-11	3.2E-03	5.1E-11	5.7E-03	2.4E-12	2.7E-04	1.1E-11	1.2E-03	4.7E-10	5.2E-02	8.4E-012	9.3E-04
Co-58	5.0E-08	1.7E-12	3.5E-05	3.1E-12	6.1E-05	1.4E-13	2.9E-06	6.4E-13	1.3E-05	2.9E-11	5.7E-04	5.0E-013	1.0E-06
Cr-51	2.0E-06	8.5E-13	4.2E-07	1.5E-12	7.7E-07	7.2E-14	3.6E-08	3.3E-13	1.6E-07	1.4E-11	7.1E-06	2.4E-013	1.2E-07
Mn-54	4.0E-08	8.5E-12	2.1E-04	1.5E-11	3.8E-04	7.2E-13	1.8E-05	3.3E-12	8.2E-05	1.4E-10	3.6E-03	2.4E-012	6.1E-05
Fe-59	5.0E-08	1.1E-12	2.2E-05	2.0E-12	4.1E-05	9.7E-14	1.9E-06	4.3E-13	8.6E-06	1.8E-11	3.7E-04	3.4E-013	6.7E-06
Zn-65	6.0E-08	5.7E-12	9.5E-05	1.0E-11	1.7E-04	4.9E-13	8.2E-06	2.1E-12	3.6E-05	9.4E-11	1.6E-03	1.6E-012	2.7E-05
Zr-95	3.0E-08	1.1E-12	3.7E-05	2.0E-12	6.8E-05	9.7E-14	3.2E-06	4.3E-13	1.4E-05	1.8E-11	6.1E-04	3.4E-013	1.1E-05
Sr-89	3.0E-08	2.6E-13	8.5E-06	4.6E-13	1.5E-05	2.1E-14	7.1E-07	9.7E-14	3.2E-06	4.3E-12	1.4E-04	7.4E-014	2.5E-06
Sr-90	1.0E-09	1.4E-14	1.4E-05	2.6E-14	2.5E-05	1.2E-15	1.2E-06	5.4E-15	5.4E-06	2.3E-13	2.3E-04	4.2E-015	4.2E-06
Sb-124	2.0E-08	5.7E-13	2.9E-05	1.0E-12	5.1E-05	4.9E-14	2.4E-06	2.1E-13	1.1E-05	9.4E-12	4.7E-04	1.6E-013	8.2E-06
Cs-134	1.0E-08	1.1E-11	1.1E-03	2.0E-11	2.0E-03	9.7E-13	9.7E-05	4.3E-12	4.3E-04	1.8E-10	1.8E-02	3.4E-012	3.4E-04
Cs-136	2.0E-07	8.5E-13	4.2E-06	1.5E-12	7.7E-06	7.2E-14	3.6E-07	3.3E-13	1.6E-06	1.4E-11	7.1E-05	2.4E-013	1.2E-06
Cs-137	1.0E-08	1.5E-11	1.5E-05	2.9E-11	2.9E-03	1.3E-12	1.3E-04	5.9E-12	5.9E-04	2.5E-10	2.5E-02	4.6E-012	4.6E-04
Ba-140	4.0E-08	1.1E-12	2.8E-05	2.0E-12	5.1E-05	9.7E-14	2.4E-06	4.3E-13	1.1E-05	1.8E-11	4.6E-04	3.4E-013	8.4E-06
Ce-141	2.0E-07	2.9E-13	1.4E-06	5.1E-13	2.6E-06	2.4E-14	1.2E-07	1.1E-13	5.6E-07	4.7E-12	2.3E-05	8.4E-014	4.2E-07

(1) Based on gaseous releases given in BWR-GAL Computer Code (Reference 12.2-1).
(2) MPC is the maximum permissible concentration as defined in 10CFR20, Appendix B (pre-1994).

Table 12.2-99

ESTIMATED AIRBORNE CONCENTRATIONS IN THE TURBINE ENCLOSURE(1)(2)

NUCLIDE	MPC(3) μCi/cc	Concen. μCi/cc	Fraction of MPC	Concen. μCi/cc	Fraction of MPC	Concen. μCi/cc	Fraction of MPC	Concen. μCi/cc	Fraction of MPC	Concen. μCi/cc	Fraction of MPC
H-3	5.0E-06	1.7E-07	3.5E-02	1.4E-08	2.9E-03	3.9E-07	7.8E-02	1.0E-08	2.0E-03	1.1E-08	2.2E-03
Kr-83m	1.0E-06	-	-	-	-	-	-	-	-	-	-
Kr-85m	6.0E-06	3.0E-07	4.9E-02	2.4E-08	4.1E-03	6.5E-07	1.1E-01	1.7E-08	2.9E-03	1.9E-08	3.2E-03
Kr-85	1.0E-05	-	-	-	-	-	-	-	-	-	-
Kr-87	1.0E-06	5.7E-07	5.7E-01	4.6E-08	4.6E-02	1.2E-06	1.2E+00	3.4E-08	3.4E-02	3.7E-08	3.7E-02
Kr-88	1.0E-06	1.0E-07	1.0E+00	8.2E-08	8.2E-02	2.2E-06	2.2E+00	6.0E-08	6.0E-02	6.5E-08	6.5E-02
Kr-89	2.0E-06	-	-	-	-	-	-	-	-	-	
Xe-131m	2.0E-05	-	-	-	-	-	-	-	-	-	-
Xe-133m	1.0E-05	-	-	-	-	-	-	-	-	-	-
Xe-133	1.0E-05	1.1E-06	1.1E-01	8.9E-08	8.9E-03	2.4E-06	2.4E-01	6.5E-08	6.5E-03	7.0E-08	7.0E-03
Xe-135m	1.0E-06	2.9E-06	2.9E-01	2.3E-07	2.3E-01	6.2E-06	6.2E+00	1.7E-07	1.7E-01	1.8E-07	1.8E-01
Xe-135	4.0E-06	2.8E-06	2.8E+00	8.2E-08	5.6E-02	6.1E-06	1.5E+00	1.6E-07	4.1E-02	1.7E-07	4.3E-02
Xe-137	1.0E-06	-	-	-	-	-	-	-	-	-	-
Xe-138	1.0E-06	6.1E-06	6.1E+00	5.0E-07	5.0E-01	1.3E-05	1.3E+01	3.7E-07	3.7E-01	4.0E-07	4.0E-01
I-131	9.0E-09	8.4E-10	9.3E-02	6.7E-11	7.5E-03	1.8E-09	2.0E-01	5.0E-11	5.6E-03	5.4E-11	6.0E-03
I-133	3.0E-08	3.4E-09	1.1E-01	2.8E-10	9.2E-03	7.3E-09	2.4E-01	1.9E-10	6.5E-03	2.1E-10	7.1E-03
Co-60	9.0E-09	8.8E-12	9.7E-04	7.1E-13	7.9E-05	1.9E-11	2.2E-03	5.2E-13	5.8E-05	5.7E-13	6.3E-05
Co-58	5.0E-08	2.7E-12	5.3E-05	2.1E-13	4.3E-06	5.8E-12	1.2E-04	1.5E-13	3.1E-06	1.7E-13	3.5E-06
Cr-51	2.0E-06	5.7E-11	2.9E-05	4.6E-12	2.3E-06	1.2E-10	6.1E-05	3.4E-12	1.7E-06	3.7E-12	1.8E-06
Mn-54	4.0E-08	2.7E-12	6.6E-05	2.1E-13	5.4E-06	5.8E-12	1.5E-04	1.5E-13	3.8E-06	1.7E-13	4.3E-06
Fe-59	5.0E-08	2.2E-12	4.5E-05	1.7E-13	3.5E-06	4.8E-12	9.6E-05	1.3E-13	2.7E-06	1.4E-13	2.9E-06
Zn-65	6.0E-08	8.8E-13	1.5E-05	7.1E-14	1.2E-06	1.9E-12	3.2E-05	5.2E-14	8.7E-07	5.7E-14	9.5E-07
Zr-95	3.0E-08	4.4E-13	1.5E-05	3.6E-14	1.2E-06	9.7E-13	3.2E-05	2.7E-14	8.8E-07	2.9E-14	9.5E-07
Sr-89	3.0E-08	2.7E-11	8.8E-04	2.1E-12	7.1E-05	5.8E-11	1.9E-03	1.5E-12	5.1E-05	1.7E-12	5.8E-05
Sr-90	1.0E-09	8.8E-14	8.8E-05	7.1E-15	7.1E-06	1.9E-13	1.9E-04	5.2E-15	5.2E-06	5.7E-15	5.7E-06
Sb-124	2.0E-08	1.3E-12	6.6E-05	1.0E-13	5.1E-06	2.9E-12	1.4E-04	7.9E-14	3.9E-06	8.5E-14	4.2E-06
Cs-134	1.0E-08	1.3E-12	1.3E-04	1.0E-13	1.0E-05	2.9E-12	2.9E-04	7.9E-14	7.9E-06	8.5E-14	8.5E-06
Cs-136	2.0E-07	2.2E-13	1.1E-06	1.7E-14	8.7E-08	4.8E-13	2.4E-06	1.3E-14	6.6E-08	1.4E-14	7.1E-08
Cs-137	1.0E-08	2.7E-12	2.7E-04	2.1E-13	2.1E-05	5.8E-12	5.8E-04	1.5E-13	1.5E-05	1.7E-13	1.7E-05
Ba-140	4.0E-08	4.8E-11	1.2E-03	3.9E-12	9.7E-05	1.0E-10	2.6E-03	2.9E-12	7.1E-05	3.2E-12	7.9E-05
Ce-141	2.0E-07	7.9E-12	3.9E-05	2.1E-13	1.1E-06	5.8E-12	2.9E-05	1.5E-13	7.7E-07	1.7E-13	8.7E-07

(1) Includes control structure areas.
(2) Based on gaseous releases given in BWR-GALE Computer Code (Reference 12.2-1).
(3) MPC is the maximum permissible concentration as defined in 10CFR20, Appendix B (pre-1994).

Table 12.2-100

ESTIMATED AIRBORNE CONCENTRATIONS IN THE RADWASTE AND OFFGAS ENCLOSURES[1]

NUCLIDE	MPC[2] μCi/cc	SOLID RADWASTE HANDLING AREAS Concen. μCi/cc	SOLID RADWASTE HANDLING AREAS Fraction of MPC	LIQUID RADWASTE HANDLING AREAS Concen. μCi/cc	LIQUID RADWASTE HANDLING AREAS Fraction of MPC	OTHER EQUIPMENT AREAS Concen. μCi/cc	OTHER EQUIPMENT AREAS Fraction of MPC
H-3	5.0E-06	-	-	-	-	-	-
Kr-83m	1.0E-06	-	-	-	-	-	-
Kr-85m	6.0E-06	-	-	-	-	-	-
Kr-85	1.0E-05	-	-	-	-	-	-
Kr-87	1.0E-06	-	-	-	-	-	-
Kr-88	1.0E-06	-	-	-	-	-	-
Kr-89	1.0E-06	-	-	-	-	-	-
Xe-131m	2.0E-05	-	-	-	-	-	-
Xe-133m	1.0E-05	-	-	-	-	-	-
Xe-133	1.0E-05	9.0E-09	9.0E-04	5.2E-08	5.2E-03	2.1E-08	2.1E-03
Xe-135m	1.0E-06	-	-	-	-	-	-
Xe-135	4.0E-06	4.1E-08	1.0E-03	2.3E-07	5.9E-02	9.7E-08	2.4E-02
Xe-137	1.0E-06	-	-	-	-	-	-
Xe-138	1.0E-06	-	-	-	-	-	-
I-131	9.0E-09	4.5E-11	5.0E-03	2.7E-10	2.9E-02	1.1E-10	1.2E-02
I-133	3.0E-08	1.6E-10	5.4E-03	9.4E-10	3.1E-02	3.9E-10	1.3E-02
Co-60	9.0E-09	8.2E-11	9.1E-03	4.7E-10	5.2E-02	1.9E-10	2.2E-02
Co-58	5.0E-08	4.1E-12	8.2E-05	2.3E-11	4.7E-04	9.7E-12	1.9E-04
Cr-51	2.0E-06	8.2E-12	4.1E-06	4.7E-11	2.3E-05	1.9E-11	9.7E-06
Mn-54	4.0E-08	2.8E-11	6.9E-04	1.5E-10	3.8E-03	6.4E-11	1.6E-03
Fe-59	5.0E-08	1.3E-11	2.7E-04	7.9E-11	1.6E-03	3.3E-11	6.5E-04
Zn-65	6.0E-08	1.3E-12	2.2E-05	7.9E-12	1.3E-04	3.3E-12	5.4E-05
Zr-95	3.0E-08	4.5E-14	1.5E-06	2.7E-13	8.8E-06	1.1E-13	3.7E-06
Sr-89	3.0E-08	4.1E-13	1.4E-05	2.3E-12	7.8E-05	9.7E-13	3.2E-05
Sr-90	1.0E-09	2.8E-13	2.8E-04	1.5E-12	1.5E-03	6.4E-13	6.4E-04
Sb-124	2.0E-08	4.5E-14	2.2E-06	2.7E-13	1.3E-05	1.1E-13	5.6E-06
Cs-134	1.0E-08	4.1E-12	4.1E-04	2.3E-11	2.3E-03	9.7E-12	9.5E-04
Cs-136	2.0E-07	4.1E-13	2.0E-06	2.3E-12	1.2E-05	9.7E-13	4.8E-06
Cs-137	1.0E-08	8.2E-12	8.2E-04	4.7E-11	4.7E-03	1.9E-11	1.9E-03
Ba-140	4.0E-08	9.0E-14	2.2E-06	5.2E-13	1.3E-05	2.1E-13	5.4E-06
Ce-141	2.0E-07	2.3E-12	1.2E-05	1.3E-11	6.6E-05	5.6E-12	2.8E-05

(1) Based on gaseous releases given in BWR-GALE Computer Code (Reference 12.2-1).
(2) MPC is the maximum permissible concentration, as defined in 10CFR20, Appendix B (pre-1994).

Table 12.2-101

CONDENSATE SYSTEM DEEP BED/DEMINERALIZER, SPENT RESIN AND RESIN MEASURING TANKS SHIELDING DESIGN SOURCE TERMS[1][2][3]

CARRYOVER COMPONENT[4]

Isotope[6]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Br-83	3.38×10^{-1}	Cs-138	3.99×10^{-1}	Rh-103m	8.44×10^{-2}
Br-84	1.35×10^{-1}	Ba-139	5.76×10^{-1}	Tc-99	7.05×10^{-6}
Br-85	7.67×10^{-3}	Ba-140	1.74	Nb-97m	2.48×10^{-3}
I-131	$2.37 \times 10^{+1}$	Ba-141	1.55×10^{-1}	Nb-97	2.55×10^{-3}
I-132	$4.39 \times 10^{+0}$	Ba-142	2.67×10^{-2}	Na-24	4.05×10^{-3}
I-133	$1.75 \times 10^{+1}$	Ce-141	1.69×10^{-1}	P-32	9.24×10^{-4}
I-134	$1.98 \times 10^{+0}$	Ce-143	1.97×10^{-3}	Cr-51	4.48×10^{-2}
I-135	$8.10 \times 10^{+0}$	Ce-144	8.26×10^{-2}	Mn-54	2.82×10^{-2}
Sr-89	1.99	Pr-143	7.82×10^{-3}	Mn-56	1.73×10^{-2}
Sr-90	9.71×10^{-1}	Nd-147	1.74×10^{-2}	Co-58	1.13
Sr-91	6.76×10^{-1}	Np-239	$6.37 \times 10^{+0}$	Co-60	5.50×10^{-1}
Sr-92	3.11×10^{-1}	Pr-144m	1.24×10^{-3}	Ag-110m	3.78×10^{-2}
Zr-95	2.89×10^{-2}	Ag-110	5.67×10^{-4}	W-187	9.74×10^{-3}
Zr-97	2.55×10^{-4}	Zn-69	5.56×10^{-5}	Fe-59	1.15×10^{-2}
Nb-95	4.55×10^{-2}	Pu-239	2.69×10^{-4}		
Mo-99	6.85×10^{-1}	Pm-147	5.05×10^{-3}		
Tc-99m	$1.39 \times 10^{+0}$	Ba-137m	$4.73 \times 10^{+0}$		
Tc-101	1.57×10^{-2}	Pr-144	8.26×10^{-2}		
Ru-103	8.46×10^{-3}	Ba-136m	1.21×10^{-2}		
Ru-106	6.90×10^{-3}	Ni-65	1.09×10^{-4}		
Te-129m	1.51×10^{-2}	Zn-65	1.23×10^{-3}		
Te-132	$1.80 \times 10^{+0}$	Zn-69m	5.56×10^{-5}		
Cs-134	$2.67 \times 10^{+0}$	Te-129	9.56×10^{-3}		
Cs-136	8.09×10^{-2}	I-129	5.68×10^{-10}		
Cs-137	$5.00 \times 10^{+0}$	Rh-106	6.90×10^{-3}		

Table 12.2-101 (Cont'd)

FALLOUT COMPONENT [5]

Isotope[6]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Ba-144	2.34×10^{-4}	La-140	$1.74 \times 10^{+0}$	Zr-93	2.95×10^{-8}
La-144	2.53×10^{-4}	Cs-139	4.72×10^{-1}	Nb-93m	1.03×10^{-9}
Cs-144	1.34×10^{-4}	Rb-92	1.45×10^{-1}	Rb-91	3.64×10^{-1}
Pr-144	8.26×10^{-2}	Cs-143	6.33×10^{-4}	Y-90	9.64×10^{-4}
Ba-143	1.29×10^{-3}	Y-92	3.11×10^{-1}	Rb-88	3.55×10^{-2}
La-143	1.43×10^{-3}	Cs-135	2.82×10^{-6}		
Sr-95	8.11×10^{-5}	Rb-95	2.63×10^{-5}		
Y-95	8.68×10^{-5}	Y-91	6.75×10^{-1}		
Cs-142	6.92×10^{-3}	Y-91m	3.85×10^{-1}		
Rb-90	4.01×10^{-1}	Rb-88	3.55×10^{-2}		
La-142	2.67×10^{-2}	Nb-95m	2.60×10^{-4}		
Cs-141	1.27×10^{-1}	Rb-94	3.37×10^{-3}		
Sr-94	4.44×10^{-3}	Rb-89	2.24×10^{-1}		
La-141	1.55×10^{-1}	Y-94	4.48×10^{-3}		
Rb-93	3.92×10^{-2}	Y-93m	1.72×10^{-2}		
Cs-140	4.40×10^{-1}	Sr-93	4.41×10^{-2}		
Y-93	4.41×10^{-2}	U-235m	2.69×10^{-4}		

NOBEL GAS GENERATION COMPONENT [7]

Isotope[6]	Activity (Ci)	Isotope	Activity (Ci)	Isotope	Activity (Ci)
Xe-135	$8.10 \times 10^{+0}$	Xe-133m	2.60×10^{-1}	Kr-83m	3.38×10^{-1}
Xe-135m	$1.75 \times 10^{+1}$	Kr-85m	7.65×10^{-3}		
Xe-133m	5.09×10^{-1}	Kp-85	1.48×10^{-4}		

(1) Based on shielding design source terms given in Tables 12.2-38.
(2) Based on condensate activity with appropriate DF's applied: 2 for Cs, Rb, and 10 for others.
(3) Resin source volume for the deep bed demineralizer and spent resin tanks is 364.4 cu.ft; resin measuring tank 85 cu.ft.
(4) Carryover component of condensate accumulated for 180 days at 4114 gpm at 1.0 g/cc.
(5) Fallout component of condensate accumulated for 180 days at 4114 gpm at 1.0 g/cc.
(6) Isotopes with activities less than 1.0×10^{-12} are not listed.
(7) Noble gases generated by particulate parents accumulating on deep-bed demineralizer resins.

Table 12.2-102

DEWATERED LSA SPENT RESIN CAKE SHIELDING DESIGN SOURCE TERMS[1][2]

Isotope[3]	Activity (Ci)	Isotope[3]	Activity (Ci)
Ag-110	3.27×10^{-3}	Pr-143	5.22×10^{-1}
Ag-110m	2.52×10^{-1}	Pr-144	3.16×10^{-1}
Ba-140	$2.07 \times 10^{+1}$	Pu-239	1.04×10^{-3}
Ce-141	1.31	Rb-87	3.18×10^{-11}
Ce-143	1.17×10^{-6}	Re-187	8.96×10^{-13}
Ce-144	5.22×10^{-1}	Rh-103m	1.48×10^{-1}
Co-58	$1.57 \times 10^{+1}$	Rh-106	3.96×10^{-2}
Co-60	2.32	Ru-103	1.51×10^{-1}
Cr-51	8.37×10^{-1}	Ru-106	3.96×10^{-2}
Cs-134	2.53	Sm-147	1.32×10^{-14}
Cs-135	1.15×10^{-5}	Sr-89	$5.09 \times 10^{+1}$
Cs-136	2.32×10^{-1}	Sr-90	3.87
Cs-137	4.17	Sr-91	4.43×10^{-20}
Fe-59	2.00×10^{-1}	Tc-99	2.80×10^{-5}
I-129	2.07×10^{-9}	Tc-99m	4.51×10^{-2}
I-131	$1.43 \times 10^{+2}$	Te-129	1.81×10^{-1}
I-132	3.38×10^{-1}	Te-129m	2.83×10^{-1}
I-133	1.36×10^{-7}	Te-132	3.28×10^{-1}
La-140	$2.38 \times 10^{+1}$	Th-231	1.04×10^{-13}
Mn-54	1.71×10^{-1}	U-235	1.08×10^{-13}
Mo-99	4.72×10^{-2}	W-187	2.45×10^{-9}
Na-24	8.95×10^{-15}	Y-89m	5.09×10^{-3}
Nb-93m	2.27×10^{-10}	Y-90	3.87
Nb-95	5.93×10^{-1}	Y-91	7.88
Nb-95m	9.01×10^{-3}	Y-91m	2.32×10^{-20}
Nb-97	2.57×10^{-14}	Y-93	2.60×10^{-20}
Nb-97m	2.22×10^{-14}	Zn-65	8.36×10^{-3}
Nd-144	1.84×10^{-17}	Zn-69	9.73×10^{-18}
Nd-147	1.86×10^{-1}	Zn-69m	9.06×10^{-18}
Np-239	1.20×10^{-1}	Zr-93	4.13×10^{-8}
P-32	1.31×10^{-2}	Zr-95	4.25×10^{-1}
Pa-231	1.53×10^{-18}	Zr-97	2.39×10^{-14}
Pm-147	2.40×10^{-2}		

(1) Based on shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) This activity is in 235 ft^3.
(3) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-103

SOLID RADWASTE CENTRIFUGE SHIELDING DESIGN SOURCE TERMS[1][2]

Isotope[3]	Activity (Ci)	Isotope[3]	Activity (Ci)
Ag-110	1.03×10^{-1}	Pm-147	9.02×10^{-2}
Ag-110m	7.95	Pr-143	$1.66 \times 10^{+1}$
Ba-140	$6.12 \times 10^{+1}$	Pr-144	$1.66 \times 10^{+1}$
Ce-141	9.73	Pu-239	3.74×10^{-2}
Ce-143	5.04×10^{-14}	Re-187	3.22×10^{-11}
Ce-144	$1.66 \times 10^{+1}$	Rh-103m	2.38
Co-58	$3.57 \times 10^{+2}$	Rh-106	1.30
Co-60	$8.18 \times 10^{+1}$	Ru-103	2.43
Cr-51	9.82	Ru-106	1.30
Cs-134	$8.71 \times 10^{+1}$	Sm-147	1.25×10^{-13}
Cs-135	1.95×10^{-5}	Sr-89	$5.76 \times 10^{+2}$
Cs-136	9.81×10^{-1}	Sr-90	$1.35 \times 10^{+2}$
Cs-137	$1.41 \times 10^{+2}$	Tc-99	1.01×10^{-3}
Fe-59	3.56	Tc-99m	2.65×10^{-4}
I-129	1.08×10^{-7}	Te-129	2.59
I-131	8.46	Te-129m	4.04
I-132	6.15×10^{-3}	Te-132	5.97×10^{-3}
I-133	4.79×10^{-19}	Th-231	8.51×10^{-12}
La-140	$7.04 \times 10^{+1}$	U-235	8.67×10^{-12}
Mn-54	5.51	W-187	8.93×10^{-18}
Mo-99	2.77×10^{-4}	Y-89m	5.76×10^{-2}
Nb-95	$1.53 \times 10^{+1}$	Y-90	$1.35 \times 10^{+2}$
Nb-95m	1.97×10^{-1}	Y-91	$9.96 \times 10^{+1}$
Nd-144	1.32×10^{-15}	Zn-65	2.63×10^{-1}
Nd-147	5.01×10^{-2}	Zr-95	9.28
Np-239	1.61×10^{-4}		
P-32	5.97×10^{-2}		
Pa-231	1.24×10^{-16}		

(1) Based on the shielding design source terms given in Tables 12.2-2, 12.2-3, and 12.2-5.
(2) This activity is in 400 ft^3.
(3) Isotopes with activities less than 1.0×10^{-20} are not listed.

Table 12.2-104

RADIATION LEVELS FROM THE TIP DETECTORS AND CABLES[1]

DECAY TIME (DAYS)	DOSE RATE, R/hr DETECTOR[2]	CABLE[3]
0.0014	6.0	58
0.0035	5.0	57
0.021	4.0	50
0.042	3.4	44
0.083	2.6	34
0.17	1.5	19
0.50	0.18	2.4
1.00	0.014	0.10
2.00	0.0041	0.019

(1) Based on 3 years of simulated use consisting of 1 hour of detector exposure in core semimonthly.
(2) At 1 meter.
(3) At 1 meter from the midpoint of the 12 foot length of irradiated cable adjacent to the detector.

12.3 RADIATION PROTECTION DESIGN FEATURES

12.3.1 FACILITY DESIGN FEATURES

Specific design features for maintaining personnel exposures ALARA are discussed in this section. These are used in addition to, and in conjunction with, the more generalized design features described in Section 12.1.2.

12.3.1.1 Common Equipment and Component Designs for ALARA

This section describes the design features used for several general classes of equipment and components. Since these classes of equipment are common to many of the plant systems, the features employed in each system to minimize exposures are similar and can be discussed generically by equipment type.

Filters: Filters that accumulate radioactivity are supplied with the means either to backflush/recharge the filter remotely or to perform cartridge replacement with semiremote tools (i.e., long-handled tools). For cartridge filters, adequate space is provided to allow removing, loading, and transporting the cartridge to the solid radwaste storage area.

Demineralizers: Demineralizers in radioactive systems are designed so that spent resin can be remotely transferred to spent resin tanks and fresh resin can be remotely loaded into the demineralizers. The demineralizers and piping can be flushed with condensate or demineralized water to remove any accumulations of resin. The equipment and floor drain demineralizers are typical examples; these are shown on drawings M-62 and M-63, respectively.

Evaporators: System abandoned (Section 11.2.2.1.3).

Pumps: Wherever practicable, pumps in radioactive areas are provided with mechanical seals to reduce seal servicing time. Pumps and associated piping are arranged to provide adequate space and access for maintenance. Small pumps are installed in a manner that allows easy removal if necessary. All pumps in radioactive waste systems are provided with flanged connections for ease of removal. Pump casings have connections for draining the pump prior to maintenance. The use of base plates with drains connected to the floor drain system minimizes the spread of contamination resulting from leakage of continuously operating pumps.

Tanks: Whenever practicable, tanks are provided with sloped bottoms and bottom outlet connections. Overflow lines are lower than vent lines and are directed to the waste collection system to prevent an overflow from spreading contamination within plant structures. For tanks containing radioactive material, the tank and associated discharge piping can be flushed to reduce radiation levels if required for entry into the tank cells. Access is provided for removal, maintenance, or inspection of tank motor agitators and also for cleaning operations involving tank internals. The solid radwaste collection system (drawing M-66 and Figure 12.3-2) provides examples of these features.

Heat Exchangers: Heat exchangers are provided with corrosion-resistant tubes of stainless steel or other suitable materials with tube-to-tube sheet joints usually welded to minimize leakage. Impact baffles are provided and tube side and shell side velocities are limited to minimize erosive effects. Space is reserved for tube bundle removal, and provisions for flushing are supplied.

Instruments: Instrument devices are located in low radiation zones and away from radiation sources whenever practicable to reduce personnel exposure during maintenance. Primary instrument devices, which for functional reasons are located in high radiation zones, are designed for easy removal to a lower radiation zone for maintenance and calibration. Some instruments located in high radiation zones, such as thermocouples, are provided in duplicate to preclude the need for immediate entry in case of instrument failure and allow maintenance to be performed at a later time when radiation levels may be lower. Transmitters and readout devices are located in low radiation zones. Instrument and sensing lines are provided with flushing capability and are routed to minimize radioactive gas buildup. Backflushing capability exists for reactor vessel sensing lines. Tanks containing two-phase fluids are fitted with probe-type instruments.

Whenever practicable, diaphragm seals are provided on instrument sensing lines on process piping that contains highly radioactive solids to reduce radiation exposures during servicing of the instrument. Instrument and sensing line connections are typically located in or above the piping midplane to avoid corrosion product buildup.

Valves: To minimize personnel exposures from valve operations and maintenance, motor-operated, air-operated, or other remotely actuated valves are used to the maximum extent practicable where the reduction in operational exposure is greater than the expected increase in maintenance exposure associated with the remote operator.

Whenever practicable, valves are located in valve galleries and are shielded separately from the major components that accumulate radioactivity. Long runs of exposed radioactive piping are minimized in valve galleries. In areas where manual valves are used on frequently operated radioactive process lines, either reach rods or radiation shielding is provided to minimize personnel exposure.

For equipment located in high radiation zones, remote actuators are provided for frequently operated valves associated with system operation. Examples of remote actuators can be seen on drawing M-66. All other valve operations are either infrequent or performed when the equipment is not operating. To the maximum extent practicable, these valves are provided with straight reach rods to allow operators to feel whether or not the valves are tightly closed. Valves with reach rods are installed with their stems located in a horizontal position wherever possible, so that the reach rods are also horizontal but above head level to prevent restriction of access during maintenance.

Provisions are made in many radiation areas to drain adjacent radioactive components when maintenance is required on valves.

Wherever practicable, valves for clean, nonradioactive systems are separated from radioactive sources and are located in readily accessible areas. Vent, drain, and instrument root isolation valves on radioactive systems are located close to the process piping or equipment with which they are associated. This minimizes the lengths of piping carrying process fluids when these valves are closed.

Manually operated valves required for normal operation and shutdown are not located in filter and demineralizer valve compartments.

For large valves (2½ inches and larger) originally supplied and installed in lines carrying radioactive fluids, a double set of packing with a lantern ring is usually provided. Such valves, except those having a packing gland which constitutes a direct communication path between primary containment atmosphere and the reactor building, are being systematically provided with an

improved packing arrangement that eliminates use of the second packing set. Power-actuated valves so changed are also being fitted with automatic gland adjustment capability. A stuffing box is also provided with a leak-off connection that may be piped to a drain header. Flow from the leak-off is stopped by a plug or a manual stop valve. Full ported valves are used in systems containing radioactive solids.

Valve designs with minimum internal crevices are used where crud trapping could become a problem, such as in piping carrying spent resin. Globe valves two inches and smaller in radioactive systems are Y-pattern-type to facilitate rodding if plugged.

Piping: The piping in pipe chases is designed for the lifetime of the unit. The number of valves or instruments in the pipe chases has been reduced to the maximum extent practicable. Piping layout is discussed in Section 12.3.1.2.

Floor Drains: Floor drains and sloped floors are provided for each room or cubicle that has serviceable components containing radioactive liquids. Whenever practicable, drain lines are embedded in concrete floors which provide shielding. If a radioactive drain line must pass through a radiation zone lower than that at which it will terminate, proper shielding is provided. Local gas traps or porous seals are not used on radwaste floor drains. Gas traps are provided at the common sump or tank. Wherever practicable, provisions exist for removing plugging in drain piping. Floor drains are designed to handle potential backflooding.

Lighting: Multiple electric lights are provided for each cell or room containing highly radioactive components so that the burnout of a single lamp does not require entry and immediate replacement of the defective lamp; sufficient illumination still remains available. Lighting in a radioactive area is actuated from outside the area and long-life bulbs are used. Section 9.5.3 describes the lighting system.

HVAC: The HVAC system is designed to minimize radioactive buildup and provides for easy access and fast replacement of the filter elements. Filter banks and components are separated from adjacent banks and components. Section 12.3.3 provides additional description of the HVAC radiation protection design features.

Sample Stations: Sample stations for routine sampling of process fluids are located in accessible areas. Shielding is provided at the local sample stations as required to maintain radiation zoning in proximate areas and minimize personnel exposure during sampling. The counting room and laboratory facilities are described in Section 12.5.

Clean Services: Wherever practicable, clean services such as compressed air piping, clean water piping, ventilation ducts, and cable trays are not routed through radioactive pipe-ways. In addition, active components of these clean services are located outside high radiation areas wherever possible to minimize any radiation exposure associated with maintenance of clean systems.

12.3.1.2 Common Facility and Layout Designs for ALARA

This section describes the design features used for standard-type plant processes and layout situations for radioactive systems and for potentially radioactive systems. These features are used in conjunction with the general equipment designs described in Section 12.3.1.1 and include the details discussed in the following paragraphs:

Valve Galleries: Valve galleries are provided with shielded entrances for personnel protection. In many cases, the valve galleries are divided by shielding or distance into subcompartments that service only two or three components so that personnel are only exposed to the valves and piping associated with a few components at any given location. Process isolation valves are located close to wall penetrations. Floor drains are provided to control radioactive leakage, and curbs are supplied as necessary. To facilitate decontamination in valve galleries, concrete surfaces are covered with a smooth surfaced coating that allows easy decontamination.

Piping: Each piping run is analyzed to determine the potential radioactivity level and maximum expected surface dose rate. Radioactive pipes are routed separately from nonradioactive pipes to minimize personnel exposure. Pipes carrying radioactive materials are routed through controlled access areas zoned for a corresponding level of activity. Where radioactive piping must be routed through corridors or other low radiation areas, shielded pipe-ways are provided. Valves and instruments are not normally placed in radioactive pipe-ways. Wherever practicable, each equipment compartment is used as a pipe-way only for those pipes associated with equipment in the compartment. Doing so minimizes exposure due to the operation of one system while maintenance is being performed on another system that is shut down.

Piping is designed to minimize low points and dead legs. Drains are provided on piping where low points and dead legs cannot be eliminated. Where possible, thermal expansion loops are raised rather than dropped. In radioactive systems, the use of nonremovable backing rings in the piping joints is minimized to eliminate a potential crud trap for radioactive materials. Wherever possible, branch lines having little or no flow during normal operation are connected above the horizontal midplane of the main pipe. Line size changes are typically made by eccentric reducers. Orifices are placed in vertical lines wherever possible.

Piping carrying resin slurries is run with large radius bends wherever possible instead of elbows, and horizontal runs are minimized. To prevent possible crud buildup, flow control valves and orifices are not normally used unless they are required for system operation. Large diameter piping is typically used with a minimum number of pipe fittings to reduce crud accumulation.

Field Run Piping: All routing of radioactive process piping, large and small, is reviewed by the engineering office to ensure that the radiation zone routing is proper and that the above principles are being employed.

Penetrations: Penetrations are normally located with an offset between the source and the accessible areas to minimize radiation streaming. If offsets are not practicable, penetrations are located as far as possible above the floor elevation to reduce the exposure to personnel. If neither of these two methods is used, then alternative means are employed, such as using baffle shield walls or radiation shielding in the area around the penetration.

Contamination Control: Access control and traffic patterns are considered in the basic plant layout to minimize the spread of contamination. Equipment vents and drains from radioactive systems are normally piped directly to the collection system instead of allowing any contaminated fluid to flow across to the floor drain. All-welded piping systems are used for radioactive systems to the maximum extent practicable to reduce system leakage and crud buildup at joints. The valves in some radioactive systems are provided with leak-off connections piped directly to the collection system.

Decontamination of potentially contaminated areas within the plant is facilitated by the application of suitable smooth surfaced coatings to the concrete floors and walls.

Floor drains and sloping floors are provided in all potentially radioactive areas of the plant. In addition, radioactive and potentially radioactive drains are separated from nonradioactive drains.

Systems that become highly radioactive, such as the radwaste slurry transport system, are provided with flush and drain connections. Certain systems have provisions for chemical cleaning prior to maintenance.

Equipment Layout: In systems where process equipment is a major radiation source (such as fuel pool cleanup, radwaste, condensate demineralizer, etc.), pumps, valves, and instruments are separated from the process component. This allows servicing and maintenance of items in reduced radiation zones. Control panels are located in the lowest dose radiation zones. Redundant equipment can be separated from each other, and shielding is provided between the equipment to allow maintenance concurrent with system operation.

Except for HVAC components, major components (such as tanks, demineralizers, and filters) in radioactive systems are located in individual shielded compartments. For highly radioactive components (such as filters and demineralizers), completely enclosed shielded compartments with hatch openings are provided. Provision is made for some major plant components for removal to lower dose radiation zones for maintenance. Large HVAC filter plenums with multiple filter cartridges are individually shielded.

Labyrinth entrance-way shields or shielding doors are provided for each compartment or plenum from which radiation could stream to access areas and exceed the radiation dose limits for those areas. Adequate space for removal of components is provided.

Wherever practicable, lubrication of equipment in radiation areas is achieved with the use of tube-type extensions to reduce exposure during maintenance.

Figures 12.3-1 to 12.3-7 provide typical layout arrangements for demineralizers, liquid and particulate filters, waste sludge tanks, offgas recombiners, sample stations, charcoal beds, and their associated valve compartments or galleries.

Exposure from routine in-plant inspection is controlled by locating inspection points in shielded low background radiation areas wherever possible. Radioactive and nonradioactive systems are normally separated to limit radiation exposure from routine inspection of nonradioactive systems. For radioactive systems, emphasis is placed on adequate space and ease of motion in a shielded inspection area. Where longer times for routine inspection are required and permanent shielding is not feasible, sufficient space for portable shielding is normally provided. In high radiation areas where routine surveillance is required, remote viewing devices are provided as needed. Typically, equipment and valves in high radiation areas are made easily accessible by providing permanent access platforms, easily removable insulation, etc. Equipment man-ways are readily accessible. Equipment lay-down area requirements are considered in the layout, and adequate space is provided where necessary.

Facilities for Handling Sealed and Unsealed Radioactive Material: As discussed in Section 12.2.1.8, special materials used in the radiochemistry laboratory require the design of special handling equipment. For unsealed materials, the following are provided:

a. Exhaust hoods that exhaust to the ventilation system are located in areas such as sample stations and the radiochemistry laboratory.

b. Decontamination facilities, the radiochemical laboratory, controlled zone shop, and instrument repair shops are situated at various locations in the plant and are described in Section 12.5.

c. An area for the repair and maintenance of removed CRDs is provided in the reactor enclosure in close proximity to the CRD removal hatch.

12.3.1.3 Radiation Zoning and Access Control

Access to areas inside the plant structures and plant yards is regulated and controlled. Each high radiation area (as defined in 10CFR20) is provided with a personnel alert barrier. Each high radiation area with a dose rate greater than 1 Rem/hour and very high radiation areas (as defined in 10CFR20) require additional controls per Health Physics Supervision. Section 12.5 describes the control of ingress and egress of plant operating personnel to controlled access areas and the procedures employed to ensure that personnel exposure is within the limits prescribed by 10CFR20.

All plant areas are categorized into radiation zones according to expected radiation levels. Each radiation zone defines either the highest component dose rate in the area or the radiation level to which the aggregate of all contributing sources must be attenuated by shielding, whichever is higher. Each room, corridor, and pipe-way of every plant structure is evaluated for potential radiation sources during normal operation, including anticipated operational occurrences and shutdown. The radiation zone categories used, and their descriptions, are given in Table 12.3-1, and the specific zoning for each plant area is shown in drawings N-110, N-111, N-112, N-113, N-115, N-116, N-117, N-118, N-119, N-120, N-121, N-122, N-124, N-125, N-126, N-127, N-128, N-130 N-131, N-132, N-133, N-134, N-135, N-136, N-137, N-139, N-140, N-141, N-142, and N-143. All frequently used areas such as corridors are shielded for Zone I or Zone II access.

The locations of airborne radioactivity and area radiation monitors are described in Section 12.3.4. Unit 1 and common area radiation monitors are shown on drawings N-110, N-111, N-112, N-113, N-115, N-116, N-117, N-118, N-119, N-120, N-121, N-122, N-124, N-125, N-126, N-127, N-128, N-130 N-131, N-132, N-133, N-134, N-135, N-136, N-137, N-139, N-140, N-141, N-142, and N-143, and Table 12.3-7. Unit 2 area radiation monitors are shown on Table 12.3-7.

12.3.1.4 Control of Activated Corrosion Products

To minimize the radiation exposure associated with the deposition of activated corrosion products in reactor coolant and auxiliary systems, the following steps have been taken:

a. The reactor coolant system consists mainly of austenitic stainless steel, carbon steel, and low alloy steel components. The nickel content of these materials is low, and it is controlled in accordance with applicable ASME material specifications. A small amount of nickel base material (Inconel 600) is employed in the reactor vessel internal components. Inconel 600 is required where components are attached to the reactor vessel shell, and the coefficient of expansion must match the thermal expansion characteristics of the low alloy vessel steel. Inconel 600 is selected because it provides the proper thermal expansion characteristics and adequate corrosion resistance, and it can be readily fabricated and welded.

b. Materials employed in the reactor coolant system are purchased to ASME material specification requirements. No special controls on levels of cobalt impurities are specified.

c. Hard-facing and wear materials having a high percentage of cobalt are restricted to applications where no satisfactory alternative materials are available.

d. A high temperature filtration system is not employed in the RWCU. The reasons for this decision include:

   1. Lack of quantitative data on the removal efficiency for insoluble cobalt by the high temperature filter.

   2. Uncertainty in the deposition model, including the relative effectiveness of cobalt removal on deposition rate.

   3. Doubtful cost-effectiveness in an area where other methods under study (such as decontamination) may prove better at reducing dose rates while also being more cost-effective.

e. Items a, b, and c above also apply to valve materials in contact with reactor coolant. Valve packing materials are selected primarily for their properties in the particular environment.

f. Sections 12.1.2.2, 12.3.1.1, and 12.3.1.2 describe the various flushing, draining, testing, and chemical addition connections that have been incorporated into the design of piping and equipment that handle radioactive materials. If decontamination is to be performed, these connections are used for that purpose.

g. The plant is designed with a powdered resin, pressure precoat cleanup system for the primary coolant in the reactor, and a full flow condensate cleanup system for the feedwater. These systems are described in Sections 5.4.8 and 10.4.6, respectively.

h. A chemistry control program to reduce crud buildup has been developed based upon studies performed by GE. This program will be implemented at LGS.

12.3.2 SHIELDING

In this section the bases for radiation shielding and shielding configurations are discussed.

12.3.2.1 Design Objectives

The basic objective of the plant radiation shielding is to reduce personnel exposures, in conjunction with a program of controlled personnel access to and occupancy of radiation areas, to levels that are within the dose regulations of 10CFR50 and are ALARA within the dose regulations of 10CFR20. Shielding and equipment layout and design are considered in ensuring that exposures are kept ALARA during all anticipated personnel activities in all areas of the plant containing radioactive materials.

The plant conditions considered in radiation shielding design are normal operation including anticipated operational occurrences at full power, and plant shutdown. The shielding design objectives are as follows:

a. To ensure that radiation exposure to plant operating personnel, contractors, administrators, visitors, and proximate exclusion area boundary occupants are ALARA and within the limits of 10CFR20.

b. To ensure sufficient personnel access and occupancy time to allow normal anticipated maintenance, inspection, and safety-related operations required for each plant equipment and instrumentation area.

c. To reduce potential equipment neutron activation and mitigate radiation damage to materials.

The control room is sufficiently shielded so that the direct dose plus the inhalation dose (calculated in Chapter 15) in the event of DBAs does not exceed the limits of GDC 19.

12.3.2.2 General Shielding Design

Shielding is provided to attenuate direct radiation through walls and penetrations, and to attenuate scattered radiation to less than the upper limit of the radiation zone for each area shown in drawings N-110, N-111, N-112, N-113, N-115, N-116, N-117, N-118, N-119, N-120, N-121, N-122, N-124, N-125, N-126, N-127, N-128, N-130 N-131, N-132, N-133, N-134, N-135, N-136, N-137, N-140, N-141, N-142, and N-143, which show the minimum shielding requirements for all plant areas. Shielding design criteria and shielding design source terms for specific plant equipment are presented in Section 12.2.

The material used for most of the plant shielding is ordinary concrete with a minimum bulk density of 140 lb/ft^3. Whenever poured-in-place concrete has been replaced by concrete blocks or other material, design ensures protection on an equivalent shielding basis as determined by the shielding characteristics of the concrete block and associated grout fill material selected. As discussed in Section 1.8, Regulatory Guide 1.69 is not employed for LGS. Further discussion of concrete standards is contained in Section 3.8. Water is used as the primary shield material for areas above the spent fuel transfer and storage areas.

The guidance provided in Regulatory Guide 8.8 was followed for LGS. ALARA design features are discussed in Sections 12.1.2 and 12.3.1. Specific features pertaining to shielding are described below.

12.3.2.3 Shielding Calculational Methods

The shielding thicknesses provided to ensure compliance with plant radiation zoning and to minimize plant personnel exposure are based on maximum equipment activities under the plant operating conditions, as described in Section 12.2. The thickness of each shield wall surrounding radioactive equipment is determined by approximating the actual geometry and physical condition of the source or sources. The isotopic concentrations are converted to gamma ray sources using data from standard References 12.3-1 through 12.3-5.

The geometric model assumed for shielding evaluation of pipes, tanks, heat exchangers, filters, demineralizers, and evaporators (abandoned) is a finite cylindrical volume source. In cases where

radioactivity is deposited on surfaces, such as inside pipe, the source is treated as a cylindrical annulus. Typical computer codes that are used for original design shielding analysis are listed in Table 12.3-2, which includes References 12.3-6 through 12.3-15. Shielding attenuation data used in those codes include gamma mass attenuation coefficients (Reference 12.3-16), gamma buildup factors (Reference 12.3-17), neutron/gamma multigroup cross-sections (Reference 12.3-18), and albedos (Reference 12.3-19). Additional sources of information pertaining to shielding techniques include References 12.3-20 through 12.3-27. This list of publications and computer programs are as applied in the original plant design and are not meant to be all-inclusive.

Shielding design for plant changes use programs and references which are industry standards at the time of the change. Examples of standards include those developed by the American Nuclear Society's ANS-6 Radiation Protection and Shielding Division, and the International Commission on Radiological Protection.

Computer programs used include those distributed by the Oak Ridge National Radiation Safety Information Computational Center, or commercially developed programs implementing established methods and parameters in industry standards.

The shielding thicknesses are selected to reduce the aggregate computed radiation level from all contributing sources below the upper limit of the radiation zone specified for each plant area. Shielding requirements are evaluated at the point of maximum radiation dose through any wall. Therefore, the actual anticipated radiation levels in the greater region of each plant area are below this maximum dose and therefore below the radiation zone upper limit.

Where shielded entry-ways to compartments containing high radiation sources are necessary, labyrinths or mazes are designed so that the scattered dose rate plus the direct dose rate through the shield wall from all contributing sources is below the upper limit of the radiation zone specified for each plant area.

12.3.2.4 Turbine Enclosure Shielding Design

Radiation shielding is provided as necessary for the following systems in the turbine enclosure and control structure, excluding the control room, to ensure that zone access requirements (drawings N-110, N-111, N-112, N-113, N-115, N-125, N-126, N-127, N-128, and N-130) are met for the surrounding areas:

a. Main steam system

b. Condensate system

c. Feedwater system

d. Air removal system

e. Sealing steam system

f. Condensate cleanup system

g. Gaseous radwaste recombiner system

h. Turbine enclosure HVAC system

i. Control room HVAC system.

12.3.2.5 Control Room Shielding Design

Drawings N-113, N-115, N-116, N-117, N-118, N-119, N-120, N-121, N-122, N-124, N-128, N-130 N-131, N-132, N-133, N-134, N-135, N-136, N-137, N-139, N-140, N-141, N-142, N-143 and Figure 12.3-26 represent layout and isometric drawings of the control room, showing its relationship to the reactor enclosure.

The design basis LOCA dictates the shielding requirements for the control room. Shielding is provided to permit access and occupancy of the control room under LOCA conditions with radiation doses limited to 5 rem whole body from all contributing modes of exposure for the duration of the accident, in accordance with GDC 19.

The design basis LOCA is described in Section 15.6.5. The direct radiation from airborne fission products inside the reactor enclosure contributes less than 50 mRem to personnel inside the control room for the 30 day period following a LOCA, based on the radioactivity sources described in Section 12.2.

The assumptions used to determine control room habitability are listed in Regulatory Guide 1.3 and are discussed in Section 15.0.

For isotopes that escape from the drywell to the reactor enclosure, credit is taken for shielding by the internal structures in the reactor enclosure. Shielding credit is taken for the reactor enclosure and control structure walls. For all isotopes that remain within the drywell, shielding credit is taken for the drywell wall.

12.3.2.6 Reactor Enclosure and Refueling Area Shielding Design

During reactor operation, the steel-lined, reinforced concrete drywell wall and the reactor enclosure walls protect personnel occupying adjacent plant structures and yard areas from radiation originating in the reactor vessel and in associated equipment within the reactor enclosure. The reactor vessel shield wall, drywell wall, and various equipment compartment walls, together with the reactor enclosure walls, reduce the radiation levels in the yard area outside the reactor enclosure to less than Zone I maximum dose rates, for those areas that are normally accessible.

Where personnel and equipment removal hatch openings or penetrations pass through the drywell wall, additional shielding, such as labyrinths or doors, is provided to attenuate the radiation to below the required level defined by the radiation zone outside the drywell wall.

Inside Drywell Structure: Areas within the drywell are Zone V and are normally inaccessible during plant operation. The reactor vessel shield provides shielding for access in the drywell during shutdown and reduces the activation of and radiation damage to drywell equipment and materials.

Outside Drywell Structure: The drywell wall reduces radiation levels in accessible areas of the reactor enclosure from sources within the drywell to below the maximum level for Zone II. Shielding requirements for the personnel access and equipment removal and CRD removal hatch openings are shown on drawings N-119 and N-134 in the areas numbered 401, 405, and 409, respectively. Shielding for these areas includes high density concrete, because neutron shielding must be considered for these large openings in the drywell wall. Drywell piping and electrical penetrations are shielded by providing either lock shields within the penetration assembly or a shielded penetration room. Shielded piping penetration room locations and bulk shielding requirements are

shown on drawings N-118, N-119, N-120, N-133, N-134, and N-135. These rooms, numbered 306, 307, 309, 501, 510, 522, 523, and 599 are designated radiation Zone V during reactor power operation and are provided with personnel access controls.

Radiation shielding is provided as necessary for the following systems in the reactor enclosure and refueling area to ensure that the radiation zone and access requirements (drawings N-116, N-122, N-131, N-137, and N-139) are met for surrounding areas:

a. RWCU system

b. FPCC system

c. Neutron monitoring system

d. HPCI system

e. RCIC system

f. RHR system

g. Core spray system

h. Reactor enclosure and refueling area HVAC systems.

Main steam lines are located within shielded structures from the drywell wall to the reactor enclosure wall.

Spent fuel is a primary source of radiation during refueling. Because of the extremely high activity of the fission products contained in the spent fuel assemblies and the proximity of Zone II areas, extensive shielding is provided for areas surrounding the fuel transfer canal and pool to ensure that radiation levels remain below zone levels specified for adjacent areas.

After reactor shutdown, RHR system pumps and heat exchangers are in operation to remove heat from the reactor water. The radiation levels in the vicinity of this equipment will temporarily reach Zone V levels due to corrosion and fission products in the reactor water. Shielding is provided to attenuate radiation from RHR equipment during shutdown cooling operations to levels consistent with the radiation zoning requirements of adjacent areas. Adequate shielding is also provided to maintain radiation zoning requirements during the hot standby operation of the RHR system.

The concrete shield walls surrounding the spent fuel cask loading, storage, and transfer areas, as well as the shield walls surrounding the fuel transfer and storage areas, are sufficient to limit radiation levels outside the shield walls in all accessible areas to below Zone II maximum dose rates.

Water in the spent fuel pool provides shielding above the spent fuel transfer and storage areas. Radiation levels at the fuel handling equipment are calculated to be below Zone II maximum dose rates during normal operations.

Water is also used as shielding material above the steam dryer and separator storage area. Concrete walls and water in the pool are designed to provide Zone II dose rates in adjacent accessible areas during storage of the dryer and separator.

A portable refueling shield is provided to reduce radiation dose rates in the drywell that are due to the transfer of spent fuel assemblies from the reactor vessel to the spent fuel pool. During refueling, the lead and steel shield is located in the reactor well, between the reactor vessel and the spent fuel pool, which permits continuous personnel occupancy of the drywell.

In addition, a temporary local personnel alarming rate meter is expected to be used in the drywell, with local alarms. Access controls to the upper reaches of the drywell aid in ensuring satisfactory protection for personnel.

12.3.2.7 Radwaste Enclosure Shielding Design

Radiation shielding is provided as necessary for the following systems in the radwaste enclosure to ensure that the radiation zone and access requirements (drawings N-140 through N-143) are met for surrounding areas:

a. Liquid radwaste equipment drain subsystem

b. Liquid radwaste floor drain subsystem

c. Liquid radwaste chemical waste subsystem

d. Liquid radwaste laundry drain subsystem

e. Solid radwaste system

12.3.2.8 Offgas Enclosure Shielding Design

Radiation shielding is provided as necessary for the gaseous radwaste system in the offgas enclosure to ensure that zone access requirements (drawings N-140 through N-142) are met for surrounding areas.

12.3.2.9 Diesel Generator Enclosure Shielding Design

There are no radiation sources in the diesel generator enclosure; therefore, no radiation shielding is required for the enclosure.

12.3.2.10 Miscellaneous Plant Areas and Plant Yard Areas

Radiation shielding is provided for all radiation sources located in plant enclosures so that radiation levels at accessible areas outside are maintained below Zone I levels. Plant yard areas that are frequently occupied by plant personnel are accessible during normal operation and shutdown. These areas are surrounded by a security fence and closed off from areas accessible to the general public.

12.3.3 VENTILATION

The plant ventilation system provides a suitable environment for personnel and equipment during normal operation and anticipated operational occurrences. Detailed HVAC system descriptions are provided in Section 9.4. Control room habitability is discussed in Section 6.4.

12.3.3.1 Design Objectives

The systems are designed to operate so that the in-plant airborne activity levels for normal operation (including anticipated operational occurrences) in the general personnel access areas are within the limits of 10CFR20. The systems operate to reduce the spread of airborne radioactivity during normal and anticipated abnormal operating conditions.

During postaccident conditions, the ventilation system for the plant control room provides a suitable environment for personnel and equipment and ensures continuous occupancy in this area. The plant ventilation systems are designed to comply with the airborne radioactivity release limits for offsite areas during normal operation.

12.3.3.2 Design Criteria

Design criteria for the plant HVAC systems include the following:

a. During normal operation and anticipated operational occurrences, the average and maximum airborne radioactivity levels to which plant personnel are exposed in restricted areas (as defined in pre-1994 10CFR20) of the plant are ALARA and within the limits specified in 10CFR20. The average and maximum airborne radioactivity levels in unrestricted areas (as defined in pre-1994 10CFR20) of the plant during normal operation and anticipated operational occurrences will be ALARA and within the limits of 10CFR20.

b. During normal operation and anticipated operational occurrences, the dose from concentrations of airborne radioactive material in unrestricted areas beyond the exclusion area boundary will be ALARA and within the limits specified in 10CFR20 and 10CFR50.

c. The dose limits of 10CFR50.67 will be satisfied following those hypothetical accidents, described in Chapter 15, that involve a release of radioactivity from the plant.

d. The dose to control room personnel shall not exceed the limits specified in GDC 19 and 10CFR50.67 following those hypothetical accidents, described in Chapter 15, that involve a release of radioactivity from the plant.

12.3.3.3 Design Guidelines

To accomplish the design objectives, the following guidelines are followed whenever practicable.

12.3.3.3.1 Guidelines to Minimize Airborne Radioactivity

The following design guidelines describe equipment and layout features that minimize the formation of airborne radioactivity:

a. Equipment vents and drains are piped directly to a collection device connected to the collection system instead of allowing any radioactive fluid to flow across the floor to the floor drain.

b. All-welded piping systems are used on radioactive systems to the maximum extent practicable to reduce system leakage.

c. Decontaminatable coatings are applied to the concrete floors and walls of potentially radioactive areas to facilitate decontamination.

d. Radioactive equipment has design features that minimize the potential for airborne radioactive contamination during maintenance operations. These features include flush connections on pump casings for draining and flushing the pump before maintenance and flush connections on piping systems that could handle radioactive fluids.

e. Exhaust hoods are used in the laboratories, work areas, and sample stations to facilitate processing of radioactive samples by forcing contaminants away from the personnel breathing areas and into the ventilation and filtering systems.

f. Equipment decontamination facilities are ventilated to ensure control of released radioactivity and prevent the spread of radioactive contamination.

g. The valves in some systems are provided with leak-off connections piped directly to the collection system.

h. To minimize the amount of airborne radioactivity that results from valve packing leakage, most larger valves (2½ inches and larger) are supplied and installed with a double set of packing and lantern ring in lines carrying radioactive fluids. The stuffing box is provided with a leak-off connection which is usually plugged, but may be piped through a manual stop valve to a drain header. An improved packing arrangement is being systematically provided for such valves and eliminates use of the second packing set. The exceptions for those valves that have a packing gland, which constitutes a direct communication path between primary containment atmosphere and the reactor building. These valves are being fitted with an improved packing arrangement that uses two packing sets and a lantern ring to maintain packing gland testability. Power-actuated valves, as part of the improved packing arrangement, are fitted with automatic gland adjustment capability.

12.3.3.3.2 Guidelines to Control Airborne Radioactivity

a. The airflow is directed from areas with lesser potential for radioactive contamination to areas with greater potential for radioactive contamination.

b. In building compartments with a potential for radioactive contamination, a greater volumetric flow is exhausted from the area than is supplied to the area to minimize the amount of uncontrolled exfiltration from the area, or makeup air for the exhaust from the area is infiltrated from surrounding less contaminated areas with no direct supply to the area provided.

c. Floor and equipment drain collection tank vents are piped to a collection header and processed by the ventilation system.

d. Air is supplied to each principal enclosure via separate supply intakes and duct systems.

e. Air being discharged from potentially contaminated areas of the reactor and turbine enclosures is passed through prefilters, HEPA filters, and charcoal filters before release (drawings M-75 and M-76). Air being discharged from the radwaste enclosure is passed through prefilters and HEPA filters as shown in Figure 9.4-3. In addition, to aid in minimizing the quantity of radioactive material discharged, means are provided to isolate the reactor enclosure and the control room upon indication of high airborne activity levels.

f. Suitable primary containment isolation valves are installed in accordance with GDC 54 and GDC 56, including valve controls, to ensure that the containment integrity is maintained.

g. Only exhaust duct-work serves potentially contaminated equipment rooms. The duct-work is at negative pressure so that any leakage is directed into the duct.

12.3.3.3.3 Guidelines to Minimize Personnel Exposure from HVAC Equipment

a. Ventilation ducts are designed to minimize the leakage of radioactive contamination into or out of ducts (as applicable) and the buildup of radioactive contamination within the ducts. Internal obstructions are avoided wherever practicable. Within the reactor enclosure and control structure, welded construction of duct sections is used, and flanged and gasketed joints are used to join duct-work segments. Seismic class II duct-work in the turbine and radwaste enclosures is constructed to Sheet Metal and Air Conditioning Contractors National Association standards modified to allow no more than 4% leakage. All duct-work is 100% leak tested after installation.

b. Access and service of ventilation systems in potentially radioactive areas are improved by component location to minimize operator exposure during maintenance, inspection, and testing, as follows:

    1. The outside air supply units and building exhaust system components are enclosed in ventilation equipment rooms. These equipment rooms are located in radiation Zone II areas and are accessible to the operators. Work space is provided around each unit for anticipated maintenance, testing, and inspection. Filter adsorber units comply with the access and service requirements of Regulatory Guide 1.52 and Regulatory Guide 1.140, to the extent discussed in Sections 6.5.1 and 9.4, respectively.

    2. Local cooling equipment servicing the normal building requirements is located in low radiation areas whenever practicable.

c. All filter systems in which radioactive materials could accumulate to produce significant radiation fields external to the duct-work are appropriately located and shielded to reduce exposure to personnel.

d. The HVAC system is designed to allow fast replacement of components. To simplify element handling, access to active elements is direct from working platforms. Space is provided on the platforms for accommodating safe personnel

movement during replacement of components, including the use of necessary material handling facilities, and during any inplace testing operations.

e. The prefilters and HEPA filters are designed with replaceable 2 foot by 2 foot units that are clamped in place against compression seals. The filter housings are designed, tested, and proven to be airtight with bulkhead-type doors that are closed against compression seals. There are two types of charcoal filters: tray-type and rechargeable-type. The tray-type charcoal filter units are designed with replaceable trays clamped in place against compression seals. There are three trays for each 2 foot by 2 foot unit. The rechargeable charcoal filter units are designed with perforated metal beds filled with bulk charcoal. The bulk charcoal in the beds can be drained and refilled.

f. While most of the activity in the filter train is eliminated by simply removing the contaminated filters, further decontamination of the internal structure is facilitated by the proximity of electrical outlets for operation of decontamination equipment, and water supply for washdown of the interior, if necessary. Drains are provided on the filter housing for removal of contaminated water.

g. Filters in all systems are changed based on the airflow and the pressure drop across the filter bank. Charcoal adsorbers are changed based on the residual adsorption capacity of the bed as measured by the testing of carbon samples taken from the removable canisters located in the carbon bed. The testing of the carbon adsorbers and all other components is described in Sections 6.5 and 9.4.

12.3.3.4 Design Description

Portions of the ventilation systems serving the following enclosures are assumed to be potentially radioactive and are discussed in detail in Section 9.4.

a. Turbine enclosure

b. Control structure

c. Secondary containment

d. Radwaste enclosure

e. Chemistry Laboratory Expansion

f. Offgas enclosure

Although the control room is considered a nonradioactive area, radiation protection is provided to ensure habitability (Section 6.4).

Ventilation system design parameters are given in Tables 12.3-3 through 12.3-6.

A typical layout of a potentially radioactive filter unit is given on Figure 12.3-7.

12.3.4 AREA RADIATION AND AIRBORNE RADIOACTIVITY MONITORING INSTRUMENTATION

12.3.4.1 Area Radiation Monitors

Fixed area radiation monitors are mounted throughout the plant at selected locations. Each location contains a gamma-sensitive detector, local indicator, and local alarm (visual and audio). Indicators, alarms, and recorders are located in the control room, except for the nine local area monitors (Section 12.3.4.1.3). Alarm setpoints are adjusted from the auxiliary equipment room/control room except for local area monitors.

The location and range for each monitor are given in Table 12.3-7. Ranges specified are consistent with the potential dose rates for a given area. Selection of location is based on the equipment in the area and the need for personnel access. In some locations, the detector is mounted immediately inside a cavity while associated local indicators and alarms are mounted just outside the access door. Personnel are thereby alerted to unusual radiation levels within the cavity before initiating access. Experience at PBAPS Units 2 and 3 was used in determining locations.

Area monitors located at fuel storage areas comply with the requirements of 10CFR70.24. These and area monitors in the radwaste enclosure comply with requirements of GDC 63. The area radiation monitors, with associated alarms, indicators and recorders in the main control room provide the capability to alert supervisors and personnel in that area of abnormally high and unexpected radiation levels. Subsequent notification to appropriate plant personnel could avoid inadvertent unnecessary exposure. Unexpected increases in radiation levels may be due to changes in operations, deposition of crud, or transport of radioactive material (e.g., sources) within the plant. Recorded area radiation monitor readings serve to define trends that may result from build-up, spills, or contamination of a process fluid.

Control and calibration of radiation monitoring (fixed and portable) are provided by procedures that are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

12.3.4.1.1 Design Bases

The purpose of the area radiation monitoring system is to provide personnel protection in accordance with the guidelines of 10CFR20, 10CFR50, 10CFR70, and Regulatory Guide 8.8. The area radiation monitoring system has no function related to the safe shutdown of the plant or to the quantitative monitoring of the release of radioactive material to the environment. Consistent with this purpose, the area radiation monitoring system is designed to provide the following functions:

a. Warn of excessive gamma radiation levels in areas where nuclear fuel is stored or handled, in accordance with 10CFR70.24(a)(2).

b. Provide operating personnel with a record and indication in the control room of gamma radiation levels at selected locations within the various plant structures, in accordance with Regulatory Guide 8.8.

c. Supplement other systems in detecting abnormal migrations of radioactive material in or from process streams.

d. Provide local alarms at strategic locations throughout the plant, in accordance with Regulatory Guide 8.8, where a substantial change in radiation levels or loss of sensing capability might be of immediate danger to personnel in the area.

e. Contribute supervisory information to the control room so that correct decisions can be made with respect to deployment of personnel in the event of a radiation accident.

f. Assist in the detection of unauthorized or inadvertent movement of radioactive material in the plant including the radwaste enclosure.

g. Furnish information for conducting radiation surveys.

h. Area Radiation Monitors may be removed from service for maintenance, testing, or known evolutions which would cause an ARM to alarm. Additionally an ARM may be removed from service to clear control room annunciators so other ARM alarms will not be masked. ARM's may be removed from service if the appropriate compensatory actions, if required, are taken (i.e. HP surveys, access control) when the ARM is removed from service.

The above functions are performed under the following design conditions:

h. Environmental parameters shown in Table 12.3-8 are applicable to the design of the area radiation monitoring equipment except for the monitors located inside primary containment, where the detectors are designed for a normal operating temperature range of 64°F to 151°F (up to 340°F for accident conditions) and a pressure range of atmospheric to 2 psig.

i. Noise from any source in the operating environment should not disturb the meter indication by more than ±2% of equivalent full-scale.

j. The detector/indicator and trip unit should be responsive to gamma radiation over an energy range of 0.08 MeV to 7 MeV. The energy dependence should not exceed ±20% of the indicated scale reading for a dose rate of approximately 50 mRem/hr resulting from 0.1 MeV to 3 MeV gammas.

k. At the control room, the reading should be reproducible within ±10% of the local indicated point, and drift should not exceed ±0.2% of equivalent linear full-scale for a 24 hour period or ±2% for a 30 day period.

l. The range of the monitors is shown in Table 12.3-7. The ranges selected ensure readout of both the highest and lowest anticipated radiation levels, in accordance with Regulatory Guide 8.8.

m. Operate without effective change in performance when the ac supply voltage changes over a range of ±10% from nominal value or has a frequency variation of ±5% from nominal value.

n. Operate so that interruption or failure of the ac power supply will result in actuation of the trip circuit to produce an alarm, in accordance with Regulatory Guide 8.8.

12.3.4.1.2 Design Details

The area radiation monitoring system is shown in the typical functional block diagram of Figure 12.3-27. Each channel consists of a combined sensor/converter unit, a local auxiliary unit (readout with visual and audible alarm), a combined indicator/trip unit, a shared power supply, and a shared

multipoint recorder. The locations of the radiation sensors are indicated in Table 12.3-7. Further design details of the area radiation monitoring system are as follows:

a. Each indicator and trip unit is provided with one upscale trip continuously adjustable over the entire scale and one downscale trip adjustable over the lower decade. Provision is made to permit the upscale trip to be set and checked for accuracy with respect to the indicator.

b. Detectors are wall-mounted and suitable for operation in the anticipated plant environment with no additional protection.

c. Panel locations of the remote equipment are shown in Table 12.3-9.

d. The following features are provided for components located in the auxiliary equipment room:

   1. Radiation level indicator (meter)

   2. High radiation alarm light (amber)

   3. Downscale alarm light (white)

   4. Alarm reset (push button)

   5. Meter zero adjust (on the amplifier)

   6. Alarm level adjust

   7. Trip check push button

   8. Power supply switch and "power-on" light (clear lens)

   9. Indicators to show power supply voltages

   10. Annunciator outputs

   11. Recorder outputs

e. The radiation monitors are calibrated at regular time intervals in accordance with station procedures. Calibration methods are covered in detail in the equipment procedures manual.

f. The following annunciators are located in the control room to alert the operator:

   1. Reactor enclosure area, high radiation (Units 1 and 2)

   2. Refueling floor area, high radiation (Units 1 and 2)

   3. Turbine enclosure area, high radiation (Units 1 and 2)

   4. Turbine enclosure common area, high radiation

   5. Radwaste enclosure common area, high radiation

6. Reactor enclosure common area, high radiation
7. Admin. bldg. area, high radiation
8. Unitized area, Rad monitors downscale
9. Common area, Rad monitors downscale

12.3.4.1.3 Local Area Monitors

In addition to the area radiation monitors described above, ten local area monitors are provided, located on each of the two refueling bridges, the three turbine enclosure crane cabs, the east and west unit 1 and 2 turbine enclosure deep bed vessel areas, and the health physics and chemistry source storage and calibration room. The essential differences between these monitors and those area monitors described above are as follows:

a. No outputs to the control room are provided.

b. Alarms are local only.

c. No recorders are provided.

d. Local power (battery) packs are provided in the event of external power cutoff, except for the local area radiation monitors in the health physics and chemistry source storage and calibration room, and east and west Unit 1 and 2 turbine enclosure deep bed vessel areas.

The power for the turbine enclosure cranes is turned off except when the cranes are being used or tested. The battery backup for the crane monitors is not available when the crane power is off.

A portable alarming rate meter will be used in the drywell to warn plant personnel if a core component is dropped during fuel transfer operations. The meter will have local alarms to ensure adequate personnel warning. Administrative controls will be used to prevent access to the upper drywell and unnecessary high exposures to personnel.

12.3.4.1.4 Postaccident Area Radiation Monitors

In the event of an accident, access will be required to certain locations outside secondary containment to perform sampling, analysis, and monitoring tasks. The identified areas include the counting room and chemistry laboratory, the main control room, the turbine enclosure near the control room exit, the north stack instrument room, the postaccident sampling station. The operational support center utilizes a portable arm. The area monitors associated with these locations have been designated as postaccident area radiation monitors. In addition to having dose rates available through the shared multipoint recorder in the control room, instantaneous and stored data are available on demand for display and trending in the control room, TSC via the RMMS computer system. Data from PMS is transmitted to the EOF via the emergency plan display system (EPDS). The ranges of these area monitors are specified in Table 12.3-7 and incorporate the highest anticipated postaccident dose rates for these locations. The design details and operating conditions are as described in Sections 12.3.4.1 and 12.3.4.2. Compliance with Regulatory Guide 1.97 (Rev 2) is discussed in Section 7.5.

12.3.4.2 Airborne Monitoring

Airborne radioactivity monitoring is accomplished by use of the following:

a. Monitoring ventilation ducts in key locations throughout the plant.

b. Continuous air monitors which are portable, cart-mounted, and monitor particulate activity.

c. High and low volume portable samplers capable of attaching filters and charcoal cartridges for particulate and iodine monitoring.

The ventilation system monitors are located at positions which provide representative air concentrations and a rapid indication of abnormal conditions. Those systems which require HEPA filtration have monitors upstream of the filters. Both the in-line GM tube and beta scintillator, and off-line particulate, iodine, and noble gas monitoring configurations can be utilized. Readout and annunciation are provided in the main control room. The off-line monitors provide the capability to obtain particulate and iodine samples for isotopic analysis. Emergency dc power is provided in the event of a LOOP. The detectors are calibrated routinely and after any maintenance work is performed on the detector.

CAMs are located in freely accessible areas where airborne radioactivity is most likely to exist. These CAMs are mobile and can be moved from area to area as deemed necessary by plant conditions or maintenance operations. CAMs incorporate either fixed or movable filters for the collection of particulate activity, which is monitored directly by a detector. Readout is recorded in counts per minute. The filters can be removed for further analysis using counting room instrumentation. Audible and visual alarms indicate when setpoint levels have been exceeded. The detectors are calibrated routinely and after any maintenance work is performed on the detector.

The CAM's primary function is to indicate trends and sudden changes in airborne activity. Typical locations are solid waste handling areas, spent fuel pool areas, and the reactor operating floor and turbine building. The monitoring system is capable of detecting particulate, iodine and noble gas radioactivity. A flexible hose can be attached to the monitor intake and inserted into a cavity or work area to detect the presence of localized airborne activity. Conformance to Regulatory Guide 8.2 is discussed in Section 12.5.1.

Ventilation monitors and CAMs are used as trending devices and will indicate areas and times needing special samples taken.

Alarm setpoints are set at low levels to ensure close respiratory controls. CAMs, however, cannot account for inversion conditions or properly identify isotopic content of the air. When a setpoint is reached, the monitor alarms. The reason for the alarm is evaluated and when necessary, grab air samples are taken and analyzed in the counting lab. The DAC hours are isotopically calculated by the computer program or are done manually. Appropriate actions can then be taken based on accurate data.

Potentially airborne accessible areas are air sampled at regular intervals. The survey/sampling frequency is designed for that area by the routine survey program.

Low and high volume samples with filter paper or charcoal cartridges are used. These are described in more detail in Section 12.5.3.1.3.

Airborne monitoring provides the information necessary to determine stay times in given areas and applicable respiratory equipment. The information is also of value in identifying process system leakage. Such monitoring is conducted in accordance with the guidelines of Regulatory Guide 1.21.

Control and calibration of radioactivity monitoring (fixed and portable) are provided by procedures that are responsive to the appropriate portions of the Quality Assurance Program described in Section 17.2.

Qualification and training of health physics and chemistry personnel will follow ANSI/ANS 3.1- 2014 guidance.

12.3.5 REFERENCES

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Table 12.3-1

PLANT RADIATION ZONE DESCRIPTION

DESIGNATION	MAXIMUM DESIGN DOSE RATE (mRem/hr)	DESCRIPTION
I	≤ 0.5	No radiation sources, no radiological control required
II	≤ 2.5	Low radiation sources, radiological control required
III	≤ 15	Low to moderate radiation sources, radiological control required
IV	< 100	Moderate radiation sources, radiological control required
V	≥ 100	High radiation sources, radiological control required

Table 12.3-2

LIST OF COMPUTER CODES USED IN SHIELDING DESIGN CALCULATIONS

GRACE 1	Multigroup, multiregion, gamma ray attenuation code used to compute gamma heating and gamma dose rates in slab geometry (Reference 12.3-6).
GRACE 2	Multigroup, multiregion, gamma ray attenuation code used to compute the dose rate or heat generation rate for a spherical or a cylindrical source with slab or concentric shields (Reference 12.3-7).
ANISN	Multigroup, multiregion code solving the Boltzmann transport equation for neutrons and gamma rays in one-dimensional slab, cylindrical, or spherical geometry (Reference 12.3-8).
SDC	Multigroup, multiregion, gamma ray attenuation code that calculates dose rates for 13 geometry options (Reference 12.3-9).
QAD	Multigroup, multiregion, three-dimensional, point kernel code that calculates fast neutron and gamma ray dose and heat generation rates (Reference 12.3-10).
NAP	Determines neutron activation and gamma emission source strengths as a function of neutron exposure and decay time (Reference 12.3-11).
MORSE-CG	Three-dimensional Monte Carlo neutron and gamma ray general transport code (Reference 12.3-12).
DOT 3	Two-dimensional neutron, gamma ray, discrete ordinate, transport code (Reference 12.3-13).
ORIGEN	Isotopic generation and depletion code that solves equations of radioactive growth and decay for isotopes of arbitrary coupling (Reference 12.3-14).
G-33	A general purpose gamma ray scattering code (Reference 12.3-15).

These programs are as used in original plant design. Updated versions or alternative programs applying the same basic industry standard analysis methodology may be used in evaluation of plant design changes.

Table 12.3-3

TURBINE ENCLOSURE VENTILATION SYSTEM DESIGN FEATURES

AREA	RADIOLOGICAL SAFETY FEATURES	SUPPLY/EXHAUST AIR FLOW RATE (cfm)
General Personnel Access Areas	Three 50% supply fans, three 50% exhaust fans	250,000/200,000
Equipment Areas	Two 100% exhaust fans, continuously filtered	0/63,000

Table 12.3-4

CONTROL STRUCTURE VENTILATION SYSTEM DESIGN FEATURES

OPERATION MODE	RADIOLOGICAL SAFETY FEATURES	AIR FLOW RATE (cfm)	EXPOSURE TO AIRBORNE CONCENTRATIONS
Normal	Two 100% supply and return fans	26,200	Background
Accident	Two 100% supply fans. Automatic/ manual switch to emergency intake and filtering and recirculation system on high activity signal; recirculation and filtering	3,000 maximum	Less than allowable limits set in 10CFR20

Table 12.3-5

REACTOR ENCLOSURE AND REFUELING AREA VENTILATION SYSTEMS
DESIGN FEATURES

AREA	RADIOLOGICAL SAFETY FEATURES	SUPPLY/EXHAUST AIR FLOW RATE (cfm)
Reactor Enclosure General Personnel Access Areas	Three 50% supply fans, three 50% exhaust fans. No or low activity exhaust is not filtered; enclosure isolation on high activity signal. Automatic switch to recirculation and SGTS.	180,000/140,000 Emergency: 60,000 recirculation 3,000 maximum SGTS
Reactor Enclosure Equipment Areas	Two 100% exhaust fans, two 100% filters. Automatic switch to recirculation and SGTS.	0/40,000(1)
Refueling Area General Personnel Access Areas	Three 50% supply fans, three 50% exhaust fans. No or low activity exhaust is not filtered; area isolation on high activity signal. Automatic switch to SGTS.	54,000/54,000 3,000 maximum SGTS

(1) Transfer air flow from personnel access areas

Table 12.3-6

RADWASTE CHEMISTRY LABORATORY AND OFFGAS
ENCLOSURES VENTILATION SYSTEM DESIGN FEATURES

AREA	RADIOLOGICAL SAFETY FEATURES	SUPPLY/EXHAUST AIR FLOW RATE (cfm)
Equipment Areas	Two 100% supply fan cabinets, two 100% supply fans, and two 100% exhaust fans; all exhaust are passed through HEPA filters.	0/53,000
Service and Control Areas	Same as equipment areas.	0/2,850
Fume Hoods	*Two 100% supply fan cabinets and two 100% exhaust fans; exhausts are passed through HEPA filters.	5510/11200
General Personnel Access Areas	Two 100% supply fan cabinets, two 100% supply fans, and two 100% exhaust fans.	73,500/16,490
Common Tank Vent	One 100% exhaust fan.	0/385

* Located in the Penthouse of the Chemistry Lab Building

Table 12.3-7

AREA RADIATION MONITORING SYSTEM EQUIPMENT

CHANNEL NUMBER[4]	SENSOR NUMBER	DESCRIPTION	ENCLOSURE[1]	LOCATION[2]	ELEVATION (feet)	RANGE (mRem/hr)
01	RE01-M1-1N001	RCIC pump compartment	RE	E-14	177	.01-10^4
01	RE01-M1-2N001	RCIC pump compartment	RE	E-31	177	.01-10^4
02	RE02-M1-1N001	HPCI pump compartment	RE	F-14	177	.01-10^4
02	RE02-M1-2N001	HPCI pump compartment	RE	F-31	177	.01-10^4
03	RE03-M1-1N001	Sump compartment	RE	H-22	177	.01-10^4
03	RE03-M1-2N001	Sump compartment	RE	H-23	177	.01-10^4
04	RE04-M1-1N001	CRD pumps area	TE	M-8	200	.01-10^4
04	RE04-M1-2N001	CRD pumps area	TE	M-38	200	.01-10^4
05	RE05-M1-1N001	Turbine auxiliary bay hallway	TE	M-12	200	.01-10^4
05	RE05-M1-2N001	Turbine auxiliary bay hallway	TE	M-34	200	.01-10^4
06	RE06-M1-1N001	Isolation valve compartment	RE	J-17	201	.01-10^4
06	RE06-M1-2N001	Isolation valve compartment	RE	J-26	201	.01-10^4
07	RE07-M1-1N001	Condensate pump compartment	TE	Q-19	189	.01-10^4
07	RE07-M1-2N001	Condensate pump compartment	TE	Q-27	189	.01-10^4
08	RE08-M1-1N001	RHR division I compartment	RE	D-17	201	.01-10^4
08	RE08-M1-2N001	RHR division I compartment	RE	D-25	201	.01-10^4
09	RE09-M1-1N001	RHR division II compartment	RE	D-20	201	.01-10^4
09	RE09-M1-2N001	RHR division II compartment	RE	D-30	201	.01-10^4
10	RE10-M1-1N001	Steam vent area stairwell	RE	E-21	217	.01-10^4
10	RE10-M1-2N001	Steam vent area stairwell	RE	E-25	217	.01-10^4
11	RE11-M1-1N001	Railroad access airlock	RA	F-23	217	.01-10^4
11	RE11-M1-2N001	Railroad access airlock	RA	F-23	217	.01-10^4
12	RE12-M1-1N001	Hallway, condensate filter/demineralizers	TE	J-13	217	.01-10^4
12	RE12-M1-2N001	Hallway, condensate filter/demineralizers	TE	J-33	217	.01-10^4
13	RE13-M1-1N002	Condenser area	TE	N-8	217	1.0-10^6
13	RE13-M1-2N002	Condenser area	TE	N-38	217	1.0-10^6
14	RE14-M1-1N002	Reactor drywell	RE	F-20	253	1.0-10^6
14	RE14-M1-2N002	Reactor drywell	RE	F-29	253	1.0-10^6
15	RE15-M1-1N001	CRD HCU area east	RE	G-23	253	.01-10^4
15	RE15-M1-2N001	CRD HCU area east	RE	G-32	253	.01-10^4
16	RE16-M1-1N001	CRD HCU area, west	RE	G-14	253	.01-10^4
16	RE16-M1-2N001	CRD HCU area, west	RE	G-23	253	.01-10^4
17	RE17-M1-1N001	Neutron monitoring system area	RE	J-21	253	.01-10^4
17	RE17-M1-2N001	Neutron monitoring system area	RE	J-30	253	.01-10^4
18	RE18-M1-1N001	Neutron monitoring drive mechanism	RE	H-22	253	.01-10^4
18	RE18-M1-2N001	Neutron monitoring drive mechanism	RE	J-31	253	.01-10^4
19	RE19-M1-1N002	Turbine auxiliary bay hallway east	TE	N-17	239	1.0-10^6
19	RE19-M1-2N002	Turbine auxiliary bay hallway east	TE	N-36	239	1.0-10^6

Table 12.3-7 (Cont'd)

CHANNEL NUMBER[4]	SENSOR NUMBER	DESCRIPTION	ENCLOSURE[1]	LOCATION[2]	ELEVATION (feet)	RANGE (mRem/hr)
20	RE20-M1-1N002	Turbine auxiliary bay hallway west	TE	N-10	239	$1.0\text{-}10^6$
20	RE20-M1-2N002	Turbine auxiliary bay hallway west	TE	N-30	239	$1.0\text{-}10^6$
21	RE21-M1-1N001	Reactor water cleanup pump area	RE	F-14	283	$.01\text{-}10^4$
21	RE21-M1-2N001	Reactor water cleanup pump area	RE	F-31	283	$.01\text{-}10^4$
22	RE22-M1-1N001	Reactor water cleanup heat exchanger area	RE	E-15	283	$.01\text{-}10^4$
22	RE22-M1-2N001	Reactor water cleanup heat exchanger area	RE	E-31	283	$.01\text{-}10^4$
23	RE23-M1-1N001	Standby liquid control system area	RE	F-21	283	$.01\text{-}10^4$
23	RE23-M1-2N001	Standby liquid control system area	RE	F-24	283	$.01\text{-}10^4$
24	RE24-M1-1N001	RWCU instrument rack area	RE	H-15	283	$.01\text{-}10^4$
24	RE24-M1-2N001	RWCU instrument rack area	RE	H-31	283	$.01\text{-}10^4$
25	RE25-M1-1N001	Turbine auxiliary bay	TE	M-12	269	$.01\text{-}10^4$
25	RE25-M1-2N001	Turbine auxiliary bay	TE	M-34	269	$.01\text{-}10^4$
26	RE26-M1-1N001	Washdown area	TE	Q-10	269	$.01\text{-}10^4$
26	RE26-M1-2N001	Washdown area	TE	Q-37	269	$.01\text{-}10^4$
27	RE27-M1-1N001	Reactor water cleanup filter area	RE	H-15	313	$.01\text{-}10^4$
27	RE27-M1-2N001	Reactor water cleanup filter area	RE	H-31	313	$.01\text{-}10^4$
28	RE28-M1-1N001	Equipment compartment exhaust filters area	TE	K-12	302	$.01\text{-}10^4$
28	RE28-M1-2N001	Equipment compartment exhaust filters area	TE	K-34	302	$.01\text{-}10^4$
29	RE29-M1-1N001	Drywell head lay-down area	RA	D-18	352	$.01\text{-}10^4$
29	RE29-M1-2N001	Drywell head lay-down area	RA	D-28	352	$.01\text{-}10^4$
30	RE30-M1-1N001	Dryer/separator area	RA	G-14	352	$.01\text{-}10^4$
30	RE30-M1-2N001	Dryer/separator area	RA	G-32	352	$.01\text{-}10^4$
31	RE31-M1-1N001	Spent fuel pool	RA	J-21	352	$.01\text{-}10^4$
31	RE31-M1-2N001	Spent fuel pool	RA	J-25	352	$.01\text{-}10^4$
32	RE32-M1-1N001	Fuel storage vault	RA	H-22	350	$.01\text{-}10^4$
32	RE32-M1-2N001	Fuel storage vault	RA	H-24	350	$.01\text{-}10^4$
33	RE33-M1-1N001	Pool plug lay-down area	RA	J-18	352	$.01\text{-}10^4$
33	RE33-M1-2N001	Pool plug lay-down area	RA	J-28	352	$.01\text{-}10^4$
34	RE34-M1-1N001	Hydrogen/oxygen analyzers area	CS	K-23	200	$.01\text{-}10^4$
34	RE34-M1-2N001	Hydrogen/oxygen analyzers area	CS	K-24	200	$.01\text{-}10^4$
35	RE35-M1-1N001	Gaseous radwaste recombiner hallway	CS	K-23	180	$.01\text{-}10^4$
35	RE35-M1-2N001	Gaseous radwaste recombiner hallway	CS	K-23	180	$.01\text{-}10^4$
36	RE36-M1-0N001	Unit 1 deep bed demin area	TE	N-9	217	$.01\text{-}10^4$
41	RE41-M1-0N001	RWCU Sludge discharge mixing pump-room	RWE	B-11	162	$.01\text{-}10^4$
42	RE42-M1-0N001	Radwaste enclosure hallway	RWE	D-12	162	$.01\text{-}10^4$
43	RE43-M1-0N001	Concentrate storage discharge pump-room	RWE	F-10	191	$.01\text{-}10^4$
44	RE44-M1-0N001	Laundry drain processing room	RWE	H-10	191	$.01\text{-}10^4$
45	RE45-M1-0N001	Floor drain filter holding pump-room	RWE	F-12	191	$.01\text{-}10^4$
46	RE46-M1-0N001	Fuel pool holding pump-room	RWE	G-12	191	$.01\text{-}10^4$
47	RE47-M1-0N001	Precoat tank & pump-room	RWE	H-14	191	$.01\text{-}10^4$
48	RE48-M1-0N001	Remote shutdown control area	CS	M-20	289	$.01\text{-}10^4$

Table 12.3-7 (Cont'd)

CHANNEL NUMBER[4]	SENSOR NUMBER	DESCRIPTION	ENCLOSURE[1]	LOCATION[2]	ELEVATION (feet)	RANGE (mRem/hr)
49	RE49-M1-0N001	Radwaste cask loading area	RWE	C-11	217	.01-10^4
50	RE50-M1-0N001	Railroad car airlock	RA	D-23	217	01-10^4
51	RE51-M1-0N001	Radwaste enclosure hallway	RWE	G-11	217	.01-10^4
52	RE52-M1-0N001	Hot maintenance shop	AB	J-34	217	.01-10^4
53	RE53-M1-0N001	Entrance, turbine enclosure railroad	TE	R-23	217	.01-10^4
54	RE54-M1-0N001	Radwaste building, el 239'	RWE	F-10	239	.01-10^4
55	RE55-M1-0N001	Radwaste exhaust fan area	RWE	G-10	257	.01-10^4
56	RE56-M1-0N001	Control room	CS	J-23	269	.01-10^4
57	RE57-M1-0N001	Turbine area operating floor/operational support center	TE	N-23	269	.01-10^4
58	RE58-M1-0N001	Standby gas treatment filter room	CS	M-25	332	.01-10^4
60	RE60-M1-0N001	North stack instrument room	RE	H-21	411	.01-10^4
-	RIAH-TA-025[3]	(Local) Source storage & calibration room	RWE	D-10	191	.1-10^4
-	RIAH-TA-001[3]	(Local) A turbine enclosure crane	TE	variable	310	.01-10^4
-	RIAH-TA-002[3]	(Local) B turbine enclosure crane	TE	variable	310	.01-10^4
-	RIAH-TA-003	(Local) C turbine enclosure crane	TE	Variable	310	.01-10^4
-	RIAH-TA-101[3]	(Local) refueling platform	RA	variable	352	.01-10^4
-	RIAH-TA-201[3]	(Local) refueling platform	RA	variable	352	.01-10^4
-	RIAH-TA-102[3]	(Local) turbine deep bed vsl area	TE	M-7	217	.01-10^2
-	RIAH-TA-103[3]	(Local) turbine deep bed vsl area	TE	M-11	217	.01-10^2
-	RIAH-TA-202[3]	(Local) turbine deep bed vsl area	TE	M-38	217	.01-10^2
-	RIAH-TA-203[3]	(Local) turbine deep bed vsl area	TE	M-35	217	.01-10^2

(1) RE Reactor enclosure
RA Refueling area
TE Turbine enclosure
RWE Radwaste enclosure
CS Control structure
AB Administration building

(2) Locations indicate east-west and north-south column lines (Drawings N-110, N-111, N-112, N-113, N-115, N-116, N-117, N-118, N-119, N-120, N-121, N-122, N-124, N-125, N-126, N-127, N-128, N-130, N-131, N-132, N-133, N-134, N-135, N-136, N-137, N-140, N-141, N-142, and N-143).

(3) Local monitor only - requires local power supply.

(4) When the same channel number is given twice, the sensor number ending in 1N001 refers to a Unit 1 sensor, and 2N001 refers to a Unit 2 sensor.

Table 12.3-8

AREA RADIATION MONITORING ENVIRONMENTAL PARAMETERS

ENVIRONMENTAL PARAMETER	DESIGN CENTER	MONITOR RANGE	DETECTOR, PREAMPLIFIER RANGE
Temperature	77°F	41°F-122°F	32°F-140°F
Relative Humidity	50%	20%-90%	20%-100%
Pressure	Atmospheric	Atmospheric	Atmospheric

Table 12.3-9

REMOTE EQUIPMENT PANEL LOCATIONS

EQUIPMENT	PANEL NOS.	
	Auxiliary Equipment Room	Control Room
Common equipment:		
Indicator and trip units	00C643	-
Recorders	-	00C624
Annunciators	-	00C824
Unitized equipment:		
Indicator and trip units	10C605, 20C605	
Recorders	-	10C600, 20C600
Annunciators	-	10C800, 20C800

12.4 DOSE ASSESSMENT

This section discusses the estimated radiation exposures both in-plant and at locations outside the plant structures. Sections 12.4.1 and 12.4.2 discuss direct radiation and airborne radiation exposures within the plant; Section 12.4.3 is concerned with exposures outside the plant structures; and Section 12.4.4 estimates the exposure to Unit 2 construction workers during the operation of Unit 1. The ISFSI radiation exposures are not considered here, as they are addressed in separate 10CFR72.212 document(s).

Not all the methods for occupational radiation dose assessment discussed in Regulatory Guide 8.19 are employed for LGS. Alternative methods are described in Section 12.4.1.

12.4.1 Direct Radiation Dose Estimates For Exposures Within The Plant

To estimate the total annual man-rem dose from direct radiation to personnel within the plant, seven broad categories or job functions were defined, and the annual man-rem dose for each category was evaluated. Where the functions and expected radiation levels are predictable or clearly defined, analytical methods were employed for the man-rem estimates. In other cases, the estimate basis is historical exposure data from operating BWR power plants. Section 12.4.1.1 provides the definitions and components of each of the seven broad categories, and Section 12.4.1.2 describes briefly the estimation techniques used.

The resultant dose estimates are contained in Section 12.4.1.3, along with further discussion of the factors involved and the methodology used for each category and its related components.

12.4.1.1 Definition of Categories Used in Exposure Estimates

Seven broad categories were used in estimating the total annual man-rem dose. These categories are:

Routine Operations: This category is composed of the following three components or subcategories:

a. Routine patrols and surveillances of the reactor enclosure, turbine enclosure, control structure, and radwaste and offgas enclosures.

b. Periodic tests and checks in the reactor enclosure, turbine enclosure, control structure, and radwaste and offgas enclosures.

c. Control room operations; specifically, the dose received by operators in the control room and radwaste control room.

Routine Maintenance: This includes all scheduled maintenance. This does not imply that a particular date has been established, but rather that the maintenance is planned and occurs at least annually. This category also includes the preventative maintenance performed in the radiation areas of the reactor, turbine, radwaste, and offgas enclosures.

Inservice Inspections: These are inspections normally performed by NDT personnel and outside contractors. Such inspections normally occur during outages on piping and systems that cannot be checked while at power.

Special Maintenance: All maintenance that is not scheduled. This maintenance is not planned in advance and normally cannot be predicted.

Radwaste Processing: This includes any work with solid or liquid radwaste: movement of casks and liners; radwaste, condensate system, or fuel pool filter changes; resin moving; baling of low level trash, etc. Maintenance of radwaste equipment is covered by the maintenance categories and is not included in this job function.

Refueling: This is all work with fuel or reactor components performed in the reactor and pool area.

Health Physics: This covers all health physics activities and includes chemistry operations and sample collection.

12.4.1.2 Exposure Estimate Methodology

Analytical Method: The analytical method used for man-rem estimation is based upon the product of estimated exposure time and estimated ambient dose rate. Estimates of the occupancy time requirements for operations associated with equipment in plant radiation areas (e.g., maintenance time or surveillance time) are first developed. An applicable frequency of occurrence is then factored in to determine the annual exposure time for each operation. Areas with no significant radiation sources are not included in the exposure estimate. Where radiation sources are present, the design maximum dose rate of 2.5 mRem/hr is assumed for some Zone II areas (radiation zones are defined in Table 12.3-1). Similarly, 15.0 mRem/hr is assumed for some Zone III areas. All other estimated dose rates are based on either calculations or actual radiation levels encountered at operating plants. Radiation levels encountered or estimated are adjusted in proportion to power. The analytical method was used in determining the exposure estimates for the routine maintenance and routine operations categories.

Historical Method: In the historical method, the annual man-rem is estimated from the exposures received at operating BWR power plants. This method was used for all the remaining categories (special maintenance, inservice inspection, radwaste processing, refueling, and health physics). The data sources are the annual and semiannual BWR operating reports and plant correspondence with regulatory agencies. Included are a total of 61 reactor years of operation for 16 nuclear units, which are listed in Table 12.4-1. The average licensed power level of these units is 747 MWe with the smallest rated at 514 Mwe. The data were
collected and assembled using the following guidelines:

a. No data before the first calendar year which contained at least nine months of commercial operation are used.

b. In multiple unit plants, each unit is assumed to contribute equally to the annual exposures.

c. If exposure contributions from two or more job functions cannot be separated, a conservative approach is taken by assigning all the exposure to one function and by making no entry in the data base for the other.

Table 12.4-2 contains the results of the historical data compilation and includes both the number of reactor years contributing to and the standard deviations associated with each job function. The large standard deviations, which range from about 60% to 160% of the mean values, are indicative of the wide spread of data that have been reported within each exposure category.

12.4.1.3 Results of Annual Direct Radiation Dose Estimates

The annual man-rem estimates for each category and subcategory are detailed below in Sections 12.4.1.3.1 through 12.4.1.3.7. The methods used in their determination are as described previously, with any additional assumptions or required information included below.

In each of the following sections, the annual exposure estimates are reported for two plant configurations: single-unit operational, and two units operational. In general, the "two-unit dose" is twice the "single-unit dose"; however, the exposures associated with certain job functions are assumed to be independent of the number of units in operation since the functions are performed regardless of whether one or two units are operational. These specific job functions are:

a. Control room operations

b. Radwaste control room operations

c. Radwaste and offgas enclosure routine surveillances

d. Radwaste and offgas enclosure periodic testing

e. Radwaste and offgas enclosure routine maintenance

For these estimates, the single-unit dose is assumed to be the same as the two-unit dose.

A summary of the direct radiation dose estimates is given in Section 12.4.1.3.8.

12.4.1.3.1 Routine Operations Dose Estimate

During normal operations, routine patrols and surveillances are performed by plant operators. The majority of items checked are rotating equipment (pumps, fans, etc), and each is viewed to verify the absence of leaks, excessive vibrations, or other abnormal conditions. For the surveillance man-rem exposure estimation, the following assumptions were made:

a. Dose rates are estimated as outlined in Section 12.4.1.2. Additionally, because of the high potential dose rates associated with certain equipment, routine surveillances of such equipment are performed from a remote location (such as the equipment cell doorway) and credit is taken for the lower ambient radiation level at that point.

b. Each patrol consists of only one person.

The results of the routine surveillance exposure estimate are contained in Tables 12.4-3 through 12.4-5.

Similarly, the details and results of the exposure estimate for the periodic testing subcategory are also contained in Tables 12.4-3 through 12.4-5. Since periodic testing is assumed to occur during equipment shutdown, the estimated shutdown dose rates are therefore used for determining the associated exposures.

The remaining subcategory is control room operations exposures. Exposures have been estimated from the anticipated control room radiation levels and the staffing requirements for the main and radwaste control rooms. It is assumed that the staffing levels of both control rooms are identical for either one or two units operational. Table 12.4-6 contains the details of the control room operations exposure estimate.

The total annual exposure estimate for the routine operations category is the sum of the three subcategory annual exposures as shown in Table 12.4-7 and summarized below:

Annual Exposure Estimate: Routine Operations

42.6 man-rem (single-unit operational)

68.9 man-rem (two units operational)

12.4.1.3.2 Routine Maintenance Dose Estimate

A detailed review of plant radiation areas was performed to produce a listing of the types and quantities of selected equipment present in each area. Next, total annual maintenance man-hours were estimated for each equipment type identified based on a combination of operating experience and engineering judgement. Total estimated man-hours are shown in Table 12.4-8 and are intended to include all expected routine activities for each equipment type such as valve repacking, valve relapping, pump seal replacement, fan overhaul, etc.

In any area, the total annual man-hours for routine maintenance is then the summation of the quantity-man-hour products for all equipment types found in the area. Multiplying the area's annual maintenance man-hours by the anticipated area dose rate produces the estimated man-rem by area. As with periodic testing, the estimated shutdown dose rate was used for estimating maintenance exposures.

A "total annual" maintenance approach was used for each component since currently available data generally does not contain sufficient information to provide a basis for man-hour breakdowns by maintenance activity. In addition, the area-by-area methodology employed makes estimate compilations by system unnecessary, since locations where high man-rem expenditures are expected are clearly indicated. Tables 12.4-3 through 12.4-5 contain the details of the routine maintenance exposure estimate for each enclosure. The sum from the three enclosures is presented below:

Annual Exposure Estimate: Routine Maintenance

232.5 man-rem (single-unit operational)

427.7 man-rem (two units operational)

12.4.1.3.3 Inservice Inspection Dose Estimate

The annual exposure estimate for inservice inspection is based upon the data from operating BWRs given in Table 12.4-2, and is:

Annual Exposure Estimate: Inservice Inspection

27.5 man-rem (single-unit operational)

55.0 man-rem (two units operational)

12.4.1.3.4 Special Maintenance Dose Estimate

The annual exposure estimate for special maintenance is based upon the data from operating BWRs given in Table 12.4-2, and is:

Annual Exposure Estimate: Special Maintenance

273.1 man-rem (single-unit operational)

546.2 man-rem (two units operational)

12.4.1.3.5 Radwaste Processing Dose Estimate

Most of the operations in the plant associated with the radwaste processing category are performed remotely and are therefore not suitable for evaluation by the analytical estimation technique. Consequently, the annual man-rem estimate for radwaste processing is more properly taken from the historical BWR operating data of Table 12.4-2, since this provides a conservative estimate of the anticipated exposure.

Annual Exposure Estimate: Radwaste Processing

37.0 man-rem (single-unit operational)

74.0 man-rem (two units operational)

12.4.1.3.6 Refueling Dose Estimate

The annual exposure estimate for refueling is based upon the data from operating BWRs given in Table 12.4-2, and is:

Annual Exposure Estimate: Refueling

19.2 man-rem (single-unit operational)

38.4 man-rem (two units operational)

12.4.1.3.7 Health Physics Dose Estimate

The annual exposure estimate for health physics monitoring is based upon the data from operating BWRs given in Table 12.4-2, and is:

Annual Exposure Estimate: Health Physics

29.3 man-rem (single-unit operational)

58.6 man-rem (two units operational)

12.4.1.3.8 Summary of Direct Radiation Dose Estimates

The annual dose estimates in the preceding seven sections are summarized and totaled in Table 12.4-9. As shown in this table, the estimate of total annual in-plant exposure from direct radiation is:

Annual Exposure Estimate: Total

661.2 man-rem (single-unit operational)

1,268.7 man-rem (two units operational)

Dose estimates for inservice inspection, special maintenance, radwaste processing, refueling, and health physics are based on historical data from operating facilities. Any further breakdown of the dose estimate (such as was made for routine operations and routine maintenance) for these types of activities would still rely primarily on the historical information available. The resultant dose estimate would therefore not be any more precise than an estimate based solely on reported radiation exposures.

In all five areas where historical data is used in the dose estimate, the LGS design includes design features which will reduce actual exposures received by plant personnel. However, due to the lack of sufficiently detailed information to allow the precise quantification of the dose reduction, the calculation of the reduction was not attempted.

As an example of design features which will result in dose reduction, the following design features have been incorporated to facilitate inservice inspection:

a. Quick removal insulation around the RPV nozzles

b. Access panels in the shield wall to the RPV bottom head welds

c. The use of a remote, trackless vehicle for RPV weld inspection

d. The use of remote automatic weld inspection of the RPV nozzle welds

12.4.2 AIRBORNE RADIOACTIVITY DOSE ESTIMATES FOR EXPOSURES WITHIN THE PLANT

The estimated exposures to plant personnel from airborne radioactivity are based upon the source distributions and radionuclide concentrations presented in Section 12.2.2 and Tables 12.2-93 through 12.2-101. Because of the limited geometry afforded by the finite compartment sizes within the plant, personnel exposures due to noble gas immersion are expected to be insignificant when compared to inhalation exposures and therefore have not been estimated.

In order to determine whether exposure contributions from airborne radioactive particulates are significant, an evaluation was made in each area of the ratio of total particulate maximum permissible concentration fractions to total radioiodine MPC fractions (which is equivalent to the ratio of particulate MPC-hours to iodine MPC-hours). For the turbine and reactor enclosure areas, the particulate-to-iodine ratios are approximately 0.02 and 0.05, respectively, indicating that the particulate inhalation exposures are not significant in those areas. In the radwaste enclosure areas, however, the particulate-to-iodine ratio is approximately 1.11. Since over 75% of the total particulate MPC fraction is attributable to Co-60, both the thyroid inhalation dose due to

radioiodines and the lung inhalation dose due to Co-60 were estimated for the radwaste enclosure (the thyroid and the lung are the critical organs for iodines and Co-60, respectively).

In addition to the inhalation exposures due to radioiodines (all enclosures) and to Co-60 (radwaste enclosure), whole body exposures due to airborne tritium were also estimated for those areas where tritium is assumed to be present (turbine and reactor enclosures).

Tables 12.4-10 through 12.4-12 contain the compilations of the estimated annual occupancy times and the estimated annual exposures for each of the areas identified in Section 12.2.2 as potential sources of airborne radioactivity. The occupancy times are based upon detailed reviews of each area and the determination of the operations which might occur in those areas. The exposures are based upon the estimated airborne concentrations in Tables 12.2-98 through 12.2-100, dose factors from table C-1 of Regulatory Guide 1.109, and an assumed breathing rate of 3.47×10^{-4} m^3/sec.

12.4.3 Exposures At Locations Outside Plant Structures

The radiation exposures at locations outside the plant structures were estimated for two areas: the site boundary and the visitor's center. Section 12.4.3.1 discusses direct radiation exposure at these locations, and Section 12.4.3.2 deals with airborne exposures.

12.4.3.1 Direct Radiation Dose Estimates Outside Plant Enclosures

At locations outside plant enclosures, the direct radiation exposure has two principal components:

a. Sources of activity stored outside the enclosures, specifically, the refueling water storage tanks and the CST.

b. Turbine shine due to the N-16 present in the reactor steam.

Based on the calculated surface dose rates for the refueling water storage tanks and CST given in Section 12.2.1.7, the dose contribution at locations outside the plant enclosures due to these tanks is considered negligible.

The N-16 present in the reactor steam in the primary steam lines, turbines, and moisture separators provides a dose contribution to locations outside the plant enclosure as a result of the high energy gamma rays that it emits as it decays. To reduce the turbine shine doses, radiation shielding is provided around each turbine train.

Hydrogen injection by the HWC system causes the reactor water chemistry to become less oxidizing which results in a re-distribution of the N-16 normally produced by radiolysis in the reactor core. Under HWC conditions, more of the N-16 is carried over into the steam and less remains in the reactor water. Thus, areas where steam piping exists will experience a greater level of radiation due to the increased N-16. The increased exposure is within the estimates provided in Chapter 11 and 12.

Exposure at locations outside plant structures will also increase due to direct radiation and turbine shine from the N-16, which is a high energy gamma emitter. In order to minimize these effects, additional radiation shielding has been installed around the high pressure turbine and combined intermediate valves.

The resultant annual exposure due to turbine shine was calculated with the SKYSHINE computer program (Reference 12.4-1). Point sources are used to represent the components on the turbine deck and the source strengths are given in Table 12.4-13.

With an assumed 100% occupancy factor and an 80% capacity factor, the maximum calculated dose rate occurs at the northeast site boundary (Figure 12.4-1 and Table 12.4-14) and is 5.5 mRem/year.

The dose rate in the visitor's center is calculated by the SKYSHINE program to be 1.53×10^{-3} mRem/hr with two units operational. Assuming a visitor stays at the visitor's center one day a year for eight hours, the estimated dose for the visitor is 1.2×10^{-2} mRem/year, as shown in Table 12.4-14.

12.4.3.2 Airborne Radioactivity Dose Estimates Outside Plant Enclosures

Doses at the site boundary due to released radioactivity are given in Section 11.3.

12.4.4 EXPOSURES TO CONSTRUCTION WORKERS

12.4.4.1 Direct Radiation Dose Estimates

The estimated dose rates from direct radiation and turbine shine received by construction workers on Unit 2 due to the operation of Unit 1 are well within the limits of 10CFR20 for exposure to individuals in unrestricted areas. Access to Unit 1 for Unit 2 workers is restricted by permanent concrete walls, security fences or chains, etc.

The estimated dose rates are the sums of the direct radiation from the Unit 1 reactor enclosure, turbine enclosure, radwaste enclosure, and offgas enclosure; and the turbine shine doses resulting from the decay of N-16 in the steam lines and turbine equipment of Unit 1. As discussed in Section 12.4.3.1, dose contributions from outside storage tanks are considered negligible and are not included in the exposure estimate.

The annual dose from Unit 1 operation has been estimated for various points in the Unit 2 construction area. The results of this estimate are listed in Table 12.4-15, and their corresponding points are shown on Figure 12.4-1.

The doses from turbine shine were calculated with the SKYSHINE computer program in the manner described in Section 12.4.3.1. The resultant dose includes the direct as well as air-scattered contribution. Credit is taken for the shielding which is afforded by the Unit 2 walls and floor slabs. The radioactive wastes are processed and stored in the radwaste enclosure, where shielding is provided to ensure that the dose outside the enclosure is less than 0.5 mRem/hr. With an allowance for distance between the radwaste enclosure and the Unit 2 construction area, the estimated direct shine dose is less than 0.01 mrem/hr under normal operating conditions.

The exposure for Unit 2 construction workers has been estimated based on the following assumptions:

a. The current construction schedule is met.

b. Personnel assigned to the control structure or Unit 2 turbine enclosure are assumed to work in the turbine enclosure only. Personnel assigned to the Unit 2 reactor enclosure or drywell are assumed to work in the reactor enclosure only.

c. The average dose rate in the yard areas is the average of the dose rates at points 1 through 5 of Figure 12.4-1, 0.0335 mRem/hr. The average dose rate in the field office is 0.0215 mRem/hr. Each of these dose rates includes 0.01 mRem/hr for the direct shine contribution and is for 100% plant capacity.

d. The capacity factor for Unit 1 in determining total estimated exposure is 80%.

e. 40 hours per week per person at the work site, 50 weeks per year.

Exposure to personnel in various categories and locations is summarized in Table 12.4-15, which gives the total estimated exposure to Unit 2 construction workers as 41.16 man-rem.

10CFR20.202 specifies that personnel monitoring equipment is required if the maximum expected dose per calendar quarter for workers in an area exceeds one-fourth of the 1250 mRem/quarter limit. It is determined that, even in areas with the highest radiation levels (the turbine deck), no construction worker would receive a dose greater than this, so personnel monitoring equipment is not necessary. However, periodic radiation surveys are to be made by the radiation protection staff.

12.4.4.2 Exposures Due to Airborne Radioactivity

Based on expected annual releases of gaseous effluents (Table 11.3-1), a worst location annual average atmospheric dispersion factor of 1.48×10^{-5} sec/m^3, and an annual occupancy of 2000 hr (40 hr/week for 50 weeks/year) the total body gamma, beta skin, and thyroid gamma dose rates from airborne radionuclides to a construction worker are estimated to be 2.47 mRem/year, 4.77 mRem/year and 0.57 mRem/year, respectively, during the construction stage. Dose rates at specific receptor points are presented in Table 12.4-16. A comparison of these values with those in Table 12.4-14 shows that doses to construction workers resulting from direct shine are dominant.

12.4.5 REFERENCES

12.4-1 M.G. Wells, D.G. Collins, R.B. Small and J.J. Newell, "SKYSHINE, A Computer Procedure For Evaluation Effect of the Structure Design on N-16 Gamma Ray Dose Rates", RRA-T7209, (November 1, 1972).

Table 12.4-1

SUMMARY OF HISTORICAL DATA USED IN COMPILATION OF
EXPOSURES RECEIVED AT OPERATING BOILING WATER REACTORS

					NUMBER OF OPERATING YEARS ACTUALLY CONTRIBUTING TO DATA BASE							
PLANT	UNIT	NET MWe[1]	DATE OF COMMERCIAL OPERATION[1]	TOTAL OPERATING YEARS[2]	ROUTINE OPERATIONS	ROUTINE MAINT	INSERVICE INSPECTION	SPECIAL MAINT	WASTE PROCESSING	REFUELING OPERATIONS	HEALTH PHYSICS	ANNUAL TOTAL
Brunswick	2	821	11/75	1	1	1	1	1	1	1	1	1
Cooper	-	778	7/74	2	2	2	2	2	2	2	2	2
Dresden	2	809	8/70	6	4	4	0	4	4	4	3	6
Dresden	3	809	10/71	5	4	4	0	4	4	4	3	5
Duane Arnold	1	538	1/75	2	1	1	1	1	1	1	1	2
Edwin I. Hatch	1	786	5/75	1	1	1	1	1	1	1	1	1
Millstone	1	690	3/71	6	3	3	1	3	1	1	2	6
Monticello	-	545	6/71	5	4	4	2	4	3	4	2	5
Nine Mile Point	1	610	12/69	7	5	5	1	5	1	5	5	6
Oyster Creek	1	650	12/69	7	7	7	3	4	3	2	6	7
PBAPS	2	1065	7/74	2	2	1	1	1	1	2	2	2
PBAPS	3	1065	12/74	2	2	1	1	1	1	2	2	2
Pilgrim	1	655	12/72	4	3	3	2	3	2	3	2	4
Quad-Cities	1	809	8/72	4	4	4	0	4	4	4	3	4
Quad-Cities	2	809	10/72	4	4	4	0	4	4	4	3	4
Vermont Yankee	-	514	11/72	4	2	2	2	2	2	2	2	4
			Totals:	62	49	47	18	44	35	42	40	61

(1) Source - "U.S. Central Station Nuclear Electric Generating Units: Significant Milestones", ERDA 77-30/1, (January 1, 1977).
(2) Total number of operating years available to the data base through the end of 1976 beginning with the first calendar year which includes at least nine months of commercial operation

Table 12.4-2

OCCUPATIONAL EXPOSURES BY JOB FUNCTION FOR
OPERATING BOILING WATER REACTORS

	NUMBER OF REACTOR YEARS AVERAGED	AVERAGE MAN-REM PER REACTOR YEAR	STANDARD DEVIATION (MAN-REM PER REACTOR YEAR)
Job Functions:			
Routine Operations	49	60.1	43.8
Routine Maintenance	47	110.8	103.4
Inservice Inspection	18	27.5	29.1
Special Maintenance	44	273.1	285.7
Waste Processing	35	37.0	38.0
Refueling	42	19.2	30.1
Health Physics	40	29.3	17.0
Total Reported[1] Annual Exposure:	61	511.4	454.8

(1) Total exposure by job function differs from the annual reported total exposure due to conservatisms employed in compilation of job function exposures.

Table 12.4-3

EXPOSURE ESTIMATES FOR THE TURBINE ENCLOSURE AND CONTROL STRUCTURE[1]

			ROUTINE SURVEILLANCE		PERIODIC TESTING		ROUTINE MAINTENANCE	
ELEVATION	ROOM NO.[4]	ESTIMATED DOSE RATE (mRem/hr)	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM
180'-0"	154	60	-	-	24	1.440	203	12.180
	161,162	2	-	-	0	0.000	282	0.564
	161,162	15[3]	30	0.450	-	-	-	-
	165	2.5	-	-	23	0.058	288	0.720
200'-0"	249	2.3	-	-	3	0.007	38	0.087
	252A	2.5	-	-	6	0.150	12	0.3
	252B	3.5	-	-	9	0.032	414	1.449
	252C	2.5	-	-	1.5	0.038	6	.15
	253	4	-	-	15	0.060	745	2.980
	254	4	-	-	0	0.000	450	1.800
	255	4	-	-	35	0.140	532	2.128
	255	50	30	1.500	-	-	-	-
	256	2	-	-	92	0.184	1,481	2.962
	256	60	91	5.460	-	-	-	-
	264	2.3	-	-	96	0.221	1,909	4.391
	264	15[3]	30	0.450	-	-	-	-
	270A	25.0	-	-	6	0.150	12	0.300
	270B	3.5	-	-	9	0.032	414	1.449
	270C	25.0	-	-	1.5	0.038	6	0.150
	299	2.5	-	-	11	0.028	0	0.000
217'-0"	332	4	-	-	158	0.632	804	3.216
	332	50	20	1.000	-	-	-	-
	333,334	6	-	-	0	0.000	1,286	7.716
	333,334	5[3]	46	0.230	-	-	-	-
	337	2.5	13	0.033	15	0.038	422	1.055
	340	1.6	-	-	21	0.034	927	1.483
	340	2.5[3]	20	0.050	-	-	-	-
	341-H	25	-	-	-	-	216	5.4
	342	2	-	-	3	0.006	47	0.094
	354 A-H	25	-	-	-	-	216	5.4
239'-0"	407	29	-	-	0	0.000	30	0.870
	438	4	-	-	78	0.312	67	0.268
	438	50	4	0.200	-	-	-	-
	439-441	3	-	-	36	0.108	1,041	3.123
	439-441	10[3]	13	0.130	-	-	-	-
	499	4	-	-	56	0.224	1,696	6.784
	499	50	7	0.350	-	-	-	-

Table 12.4-3 (Cont'd)

ELEVATION	ROOM NO.[4]	ESTIMATED DOSE RATE (mRem/hr)	ROUTINE SURVEILLANCE ESTIMATED ANNUAL MAN-HOURS	ROUTINE SURVEILLANCE ESTIMATED ANNUAL MAN-REM	PERIODIC TESTING ESTIMATED ANNUAL MAN-HOURS	PERIODIC TESTING ESTIMATED ANNUAL MAN-REM	ROUTINE MAINTENANCE ESTIMATED ANNUAL MAN-HOURS	ROUTINE MAINTENANCE ESTIMATED ANNUAL MAN-REM
269'-0"	518	29	-	-	0	0.000	88	2.552
	544	1.6	-	-	0	0.000	3,568	5.709
	544	15[3]	9	0.135	-	-	-	-
	545-547	3	-	-	9	0.027	426	1.278
	545-547	10[3]	13	0.130	-	-	-	-
	551	3	-	-	8	0.024	376	1.128
	551	10[3]	4	0.040	-	-	-	-
302'-0"	621	15	13	0.195	0	0.000	76	1.140
332'-0"	624	2.5	-	-	46	0.115	106	0.265
		TOTALS:	343	10.353	746	3.788	17,536	71.792

(1) All values are on a per unit basis.

(2) The estimated exposures assume all man-hours are expended in the area in which they appear. Portions of these man-hours may actually be spent at lower radiation levels within the area. Components may also be removed to a lower background area for maintenance.

(3) Estimated dose rate is based upon surveillance being performed from a remote location such as the equipment cell doorway. Estimated and measured dose rates will increase approximately in proportion to power.

(4) Room numbers are shown on drawings N-110, N-111, N-112, N-113, N-115, N-116, N-117, N-118, N-119, N-120, N-121, N-122, N-124, N-125, N-126, N-127, N-128, N-130, N-131, N-132, N-133, N-134, N-135, N-136, N-137, N-140, N-141, N-142, and N-143.

Table 12.4-4

EXPOSURE ESTIMATES FOR THE REACTOR ENCLOSURE[1]

			ROUTINE SURVEILLANCE		PERIODIC TESTING		ROUTINE MAINTENANCE	
ELEVATION	ROOM NO.:[5]	ESTIMATED DOSE RATE (mRem/hr)	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM
177'-0"	102	15	-	-	66	0.990	752	11.280
	102	2.5[3]	46	0.115	-	-	-	-
	103	15	-	-	66	0.990	752	11.280
	103	2.5[3]	46	0.115	-	-	-	-
	108	2.5	46	0.115	72	0.180	650	1.625
	109	2.5	46	0.115	83	0.208	917	2.293
	115	2.5	-	-	23	0.058	288	0.720
	115	15	46	0.690	-	-	-	-
201'-0"	203	15	-	-	11	0.165	422	6.330
	204	15	-	-	11	0.165	238	3.570
	209	20	-	-	0	0.000	98	1.960
	297	2.5	-	-	0	0.000	84	0.210
	298	2.5	-	-	0	0.000	26	0.065
217'-0"	309	15	-	-	5	0.075	683	10.245
253'-0"	402A	2.5	137	0.343	0	0.000	600	1.500
	403	13	-	-	222[4]	2.886	0	0.000
	406	15	-	-	0	0.000	126	1.890
	407A	29	-	-	0	0.000	114	3.306
283'-0"	501	2.5	-	-	39	0.098	44	0.110
	503-505	28	-	-	29	0.812	537	15.036
	503-505	5[3]	13	0.065	-	-	-	-
	507-509	28	-	-	33	0.924	360	10.080
	507-509	5[3]	20	0.100	-	-	-	-
	510	28	-	-	0	0.000	135	3.780
	511	16	-	-	66	1.056	570	9.120
	511	5[3]	30	0.150	-	-	-	-
	518A	29	-	-	0	0.000	74	2.146
	522	28	-	-	24	0.672	125	3.500
	523	15	-	-	0	0.000	95	1.425
	599	2.5	-	-	0	0.000	156	0.390

Table 12.4-4 (Cont'd)

			ROUTINE SURVEILLANCE		PERIODIC TESTING		ROUTINE MAINTENANCE	
ELEVATION	ROOM NO.[5]	ESTIMATED DOSE RATE (mRem/hr)	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM
313'-0"	600	2.3	-	-	6	0.014	519	1.194
	600	15[3]	13	0.195	-	-	-	-
	616,617	15	13	0.195	0	0.000	40	0.600
	618	15	13	0.195	3	0.045	40	0.600
352'-0"	700	1	-	-	119	0.119	2,068	2.068
	700	2.5	46	0.115	-	-	-	-
Drywell	400	10	-	-	0	0.000	191	1.910
	400A	11	-	-	0	0.000	442	4.862
	400B	10	-	-	0	0.000	532	5.320
	400C	10	-	-	15	0.150	184	1.840
	400D	10	-	-	0	0.000	303	3.030
	400E	10	-	-	0	0.000	11	0.110
		TOTALS:	515	2.508	893	9.607	12,176	123.395

(1) All values are on a per unit basis.

(2) The estimated exposures assume all man-hours are expended in the area in which they appear. Portions of these man-hours may actually be spent at lower radiation levels within the area. Components may also be removed to a lower background area for maintenance.

(3) Estimated dose rate is based upon surveillance being performed from a remote location such as the equipment cell doorway. Estimated and measured dose rates will increase approximately in proportion to power.

(4) Control rod drive rebuild, repair, and testing.

(5) Room numbers are shown on drawings N-110, N-111, N-112, N-113, N-115, N-116, N-117, N-118, N-119, N-120, N-121, N-122, N-124, N-125, N-126, N-127, N-128, N-130, N-131, N-132, N-133, N-134, N-135, N-136, N-137, N-140, N-141, N-142, and N-143.

Table 12.4-5

EXPOSURE ESTIMATES FOR THE RADWASTE AND OFFGAS ENCLOSURES[1]

			ROUTINE SURVEILLANCE		PERIODIC TESTING		ROUTINE MAINTENANCE	
ELEVATION	ROOM NO.[5]	ESTIMATED DOSE RATE (mRem/hr)	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM
162'-0"	124	10	-	-	6	0.060	212	2.120
	124	5[3]	6	0.030	-	-	-	-
	126,130	3	-	-	10	0.030	449	1.347
	126,130	15	12	0.180	-	-	-	-
	127,129	10	-	-	12	0.120	449	4.490
	127,129	5[3]	12	0.060	-	-	-	-
	132	3	-	-	5	0.015	165	0.495
	132	5[3]	6	0.030	-	-	-	-
	133	3	-	-	5	0.015	571	1.713
	133	5[3]	6	0.030	-	-	-	-
	137	2.5	-	-	2	0.005	168	0.420
	137	15	6	0.090	-	-	-	-
	138	10	-	-	3	0.030	146	1.460
	138	5[3]	6	0.030	-	-	-	-
	139	10	-	-	3	0.030	146	1.460
	139	5[3]	6	0.030	-	-	-	-
	142	3	-	-	17	0.051	109	0.327
	142	5[3]	6	0.030	-	-	-	-
	144	10	-	-	11	0.110	233	2.333
	144	5[3]	6	0.030	-	-	-	-
	146	3	-	-	21	0.063	288	0.864
	146	15	6	0.090	-	-	-	-
	147	2.5	-	-	3	0.008	287	0.718
	147	2.5	6	0.015	-	-	-	-
	148	2.5	-	-	6	0.015	0	0.000
	148	2.5	6	0.015	-	-	-	-
Offgas Areas		5	-	-	0	0.000	780	3.900
191'-0"	228	2.5	6	0.015	59	0.148	404	1.010
	231	2.5	-	-	6	0.015	203	0.508
	231	15	6	0.090	-	-	-	-
	232	2.5	-	-	5	0.013	117	0.293
	232	15	6	0.090	-	-	-	-
	233	2.6	-	-	3	0.008	3	0.008

Table 12.4-5 (Cont'd)

			ROUTINE SURVEILLANCE		PERIODIC TESTING		ROUTINE MAINTENANCE	
ELEVATION	ROOM NO.[5]	ESTIMATED DOSE RATE (mRem/hr)	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM	ESTIMATED ANNUAL MAN-HOURS	ESTIMATED ANNUAL MAN-REM
	234	2.6	-	-	2	0.005	122	0.317
	234	15	6	0.090	-	-	-	-
	236	2.3	-	-	72	0.166	549	1.263
	236	5[3]	6	0.030	-	-	-	-
	237	2.3	-	-	26	0.060	253	0.582
	237	5[3]	6	0.030	-	-	-	-
	238	2.3	-	-	17	0.039	300	0.690
	238	5[3]	6	0.030	-	-	-	-
	242,243	20	-	-	16	0.320	100	2.000
	242,243	5[3]	12	0.060	-	-	-	-
	245	42	-	-	0	0.000	78	3.276
	247	3	-	-	5	0.015	142	0.426
	247	5[3]	6	0.030	-	-	-	-
	248	3	-	-	5	0.015	142	0.426
	248	5[3]	6	0.030	-	-	-	-
217'-0"	422	2.5	-	-	0	0.000	60	0.150
	423	2.5	-	-	0	0.000	40	0.100
237'-0"	470,471	30	-	-	0	0.000	34	1.020
	470,471	5[3]	61	0.305	-	-	-	-
	485,486	15	-	-	0	0.000	40	0.600
257'-0"	515,516	30	-	-	0	0.000	100	3.000
	515,516	5[3]	30	0.150	-	-	-	-
		TOTAL:	247	1.610	320	1.356	6,690	37.316

(1) All values are on a per unit basis.

(2) The estimated exposures assume all man-hours are expended in the area in which they appear. Portions of these man-hours may actually be spent at lower radiation levels within the area. Components may also be removed to a lower background area for maintenance.

(3) Estimated dose rate is based upon surveillance being performed from a remote location such as the equipment cell doorway. Estimated and measured dose rates will increase approximately in proportion to power.

(4) Room numbers are shown on drawings N-110, N-111, N-112, N-113, N-115, N-116, N-117, N-118, N-119, N-120, N-121, N-122, N-124, N-125, N-126, N-127, N-128, N-130, N-131, N-132, N-133, N-134, N-135, N-136, N-137, N-140, N-141, N-142, and N-143.

Table 12.4-6

ESTIMATED EXPOSURE FOR OPERATORS
IN CONTROL ROOMS

	OPERATORS[1] PER SHIFT	SHIFTS MANNED[1] PER DAY	ANNUAL OPERATOR MAN-HOURS[2]	ESTIMATED DOSE RATE (mRem/hr)	ANNUAL OPERATOR MAN-REM[1]
Control Room	5	3	43,800	0.25	11.0
Radwaste Control Room	1	3	8,760	0.25	2.2
TOTAL	6		52,560		13.2

(1) Assumed to be independent of the number of units in operation
(2) Based on each operator spending 8 hours in the control room and the control rooms being manned 365 days per year

Table 12.4-7

SUMMARY OF ROUTINE OPERATIONS EXPOSURE ESTIMATE [3]

	ANNUAL ESTIMATED MAN-REM	
	SINGLE-UNIT	TWO UNITS
Routine Surveillances:		
Turbine enclosure[1]	10.4	20.7
Reactor enclosure	2.5	5.0
Radwaste enclosure[2]	1.6	1.6
	14.5	27.3
Periodic Tests:		
Turbine enclosure[1]	3.9	7.8
Reactor enclosure	9.6	19.2
Radwaste enclosure[2]	1.4	1.4
	14.9	28.4
Control Room Operations:		
Control room	11.0	11.0
Radwaste control room	2.2	2.2
	13.2	13.2
TOTAL	42.6	68.9

(1) Includes control structure exposures
(2) Includes offgas enclosure exposures
(3) Estimated and measured dose rates will increase approximately in proportion to power.

Table 12.4-8

ESTIMATE OF EXPECTED ROUTINE MAINTENANCE REQUIREMENTS

EQUIPMENT TYPE OR ACTIVITY	ESTIMATED MAN-HOURS PER YEAR
1. Valves	
a. Under 3 inches	3
b. 3 to 6 inches	9
c. 8 to 10 inches	12
d. 12 to 16 inches	17
e. Over 16 inches	23
2. Valve Operators	
a. Reach rod	1
b. Air operator	2
c. Motor operator	2
3. Pumps	
a. Reactor recirculation	150
b. RHR or condensate	100
c. Any other pump	50
4. Motors	
a. 200 hp or greater	20
b. Less than 200 hp	13
5. Motor-generator	35
6. Main generator	1000
7. Turbines	
a. Main turbine	2400
b. Any other turbine	240
8. Heat exchanger	30
9. Deleted	50
10. Chiller	5
11. Unit heater	5
12. Unit cooler	5
13. Compressor	24

Table 12.4-8 (Cont'd)

EQUIPMENT TYPE OR ACTIVITY	ESTIMATED MAN-HOURS PER YEAR
14. Fan or blower25	
15. Main condenser (per shell)	150
16. Hoist or crane	60
17. Instrument panel	150
18. Instrument rack	150
19. Motor control center	5
20. Switchgear	120
21. Centrifuge	37
22. Agitator	5
23. Transfer cart or conveyor	15
24. TIP drive	20
25. CRD hydraulic units (total per reactor)	600
26. HVAC filter unit (prefilter, HEPA filters, and charcoal filter)	20
27. Offgas system (holdup pipe to stack - total for station)	780

Table 12.4-9

SUMMARY OF IN-PLANT DIRECT RADIATION EXPOSURE ESTIMATES [1]

CATEGORY	ANNUAL ESTIMATED MAN-REM	
	SINGLE-UNIT	TWO UNITS
Routine Operations	42.6	68.9
Routine Maintenance	232.5	427.7
Inservice Inspection	27.5	55.0
Special Maintenance	273.1	546.2
Radwaste Processing	37.0	74.0
Refueling	19.2	38.4
Health Physics	29.3	58.6
Total	661.2	1,268.8

(1) Estimated and measured dose rates will increase approximately in proportion to power.

Table 12.4-10

ESTIMATED TURBINE ENCLOSURE AND CONTROL STRUCTURE INHALATION EXPOSURES DUE TO AIRBORNE RADIOACTIVITY[1]

ROOM[4]	ESTIMATED ANNUAL MAN-HOURS				ESTIMATED THYROID DOSE[2] (MAN-REM/YR)	ESTIMATED TRITIUM DOSE[3] (MAN-REM/YR)
	SURVEILLANCE	TESTING	MAINTENANCE	TOTAL		
Condenser Areas						
253	0	15	745	760	2.3	2.1×10^{-2}
254	0	0	450	450	1.4	1.3×10^{-2}
255	30	35	532	597	1.8	1.5×10^{-2}
256	91	92	1481	1664	5.0	4.7×10^{-2}
332	20	158	804	982	2.9	2.7×10^{-2}
342	0	3	47	50	1.5×10^{-1}	1.4×10^{-3}
499	7	56	1696	1759	5.3	4.9×10^{-2}
SJAE Areas						
154	0	24	203	227	5.7×10^{-2}	5.2×10^{-4}
333,334	46	0	1286	133	3.3×10^{-1}	3.1×10^{-3}
Mechanical Vacuum Pump Areas						
337	13	15	422	450	3.0	2.9×10^{-2}
Turbine Hall Areas						
544	9	0	3568	3577	6.4×10^{-1}	6.1×10^{-3}

Table 12.4-10 (Cont'd)

ROOM[4]	ESTIMATED ANNUAL MAN-HOURS SURVEILLANCE	TESTING	MAINTENANCE	TOTAL	ESTIMATED THYROID DOSE[2] (MAN-REM/YR)	ESTIMATED TRITIUM DOSE[3] (MAN-REM/YR)
Other Equipment Areas						
161,162	30	0	282	312	5.9×10^{-2}	5.6×10^{-4}
165	0	23	288	311	5.9×10^{-2}	5.6×10^{-4}
249	0	3	38	41	7.8×10^{-3}	7.4×10^{-5}
264	30	96	1909	2035	3.9×10^{-1}	3.7×10^{-3}
299	0	11	0	11	2.1×10^{-3}	2.0×10^{-5}
340	20	21	927	968	1.8×10^{-1}	1.7×10^{-3}
407	0	0	30	30	5.7×10^{-3}	5.4×10^{-5}
438	4	78	67	149	2.8×10^{-2}	2.7×10^{-4}
439,440,441	13	36	1041	1090	2.1×10^{-1}	2.0×10^{-3}
518	0	0	88	88	1.7×10^{-2}	1.6×10^{-4}
545,546,547	13	9	426	448	8.5×10^{-2}	8.1×10^{-4}
551	4	8	376	388	7.4×10^{-2}	7.0×10^{-4}
621	13	0	76	89	1.7×10^{-2}	1.6×10^{-4}
624	0	46	106	152	2.9×10^{-2}	2.7×10^{-4}
TOTALS	343	729	16,888	17,960	$2.4 \times 10^{+1}$	2.2×10^{-1}

(1) All values in the table are on a per unit basis.
(2) Thyroid dose attributable only to inhalation of radioiodines.
(3) Uniform dose to the total body from uptake of tritium.
(4) Room numbers are shown on drawings N-110, N-111, N-112, N-113, N-115, N-116, N-117, N-118, N-119, N-120, N-121, N-122, N-124, N-125, N-126, N-127, N-128, N-130, N-131, N-132, N-133, N-134, N-135, N-136, N-137, N-140, N-141, N-142, and N-143.

Table 12.4-11

ESTIMATED REACTOR ENCLOSURE INHALATION EXPOSURES DUE TO AIRBORNE RADIOACTIVITY[1]

ROOM[6]	ESTIMATED ANNUAL MAN-HOURS				ESTIMATED THYROID DOSE[4] (MAN-REM/YR)	ESTIMATED TRITIUM DOSE[5] (MAN-REM/YR)
	SURVEILLANCE	TESTING	MAINTENANCE	TOTAL		
RWCU Pump Areas						
503,504,505	13	29	537	579	9.8×10^{-1}	-
507,508,509	20	33	360	413	7.0×10^{-1}	-
510	0	0	135	135	2.3×10^{-1}	-
522	0	24	125	149	2.5×10^{-1}	-
RWCU Filter/ Demineralizer Areas						
600	13	6	519	538	1.7	-
Refueling Areas						
700	46	119	4,233[2]	4,398	6.6×10^{-1}	3.8×10^{-2}
ECCS Areas						
102	46	66	752	864	5.8×10^{-1}	-
103	46	66	752	864	5.8×10^{-1}	-
108	46	72	650	768	5.1×10^{-1}	-
109	46	83	917	1,046	7.0×10^{-1}	-
203	0	11	422	433	2.9×10^{-1}	-
204	0	11	238	249	1.7×10^{-1}	-
297	0	0	84	84	5.6×10^{-2}	-
298	0	0	26	26	1.7×10^{-2}	-
309	0	5	683	688	4.6×10^{-1}	-
400	0	0	191	191	5.5	-
400A	0	0	442	442	$1.3 \times 10^{+}$	-
400B	0	0	532	532	$1.5 \times 10^{+1}$	-
400C	0	15	184	199	5.8	-
400D	0	0	303	303	8.8	-
400E	0	0	11	11	3.2×10^{-1}	-

Table 12.4-11 (Cont'd)

ROOM[6]	ESTIMATED ANNUAL MAN-HOURS				ESTIMATED THYROID DOSE[4] (MAN-REM/YR)	ESTIMATED TRITIUM DOSE[5] (MAN-REM/YR)
	SURVEILLANCE	TESTING	MAINTENANCE	TOTAL		
Other Equipment Areas						
115	46	23	288	357	1.9×10^{-1}	-
209	0	0	98	98	5.1×10^{-2}	-
402A	137	0	600	737	3.8×10^{-1}	-
403	0	222	0	222	1.2×10^{-1}	-
406	0	0	126	126	6.6×10^{-2}	-
407A	0	0	114	114	5.9×10^{-2}	-
501	0	39	44	83	4.3×10^{-2}	-
511	30	66	570	666	3.5×10^{-1}	-
518A	0	0	74	74	3.8×10^{-2}	-
523	0	0	95	95	4.9×10^{-2}	-
599	0	0	156	156	8.1×10^{-2}	-
616,617	13	0	40	53	2.8×10^{-2}	-
618	13	3	40	56	2.9×10^{-2}	
TOTALS	515	893	14,341	15,749	$5.8 \times 10^{+1}$(3)	3.8×10^{-2}

(1) All values in the table are on a per unit basis.

(2) Maintenance man-hours include 2,165 man-hours for refueling operations.

(3) The total thyroid dose of 58 man-rem takes no credit for respiratory protection. If a protection factor as low as 5 is assumed in the drywell (which is estimated to produce over 80% of the reactor enclosure thyroid exposures), the total thyroid dose is reduced to below 20 man-rem per year.

(4) Thyroid dose attributable only to inhalation of radioiodines.

(5) Uniform dose to the total body from uptake of tritium.

(6) Room numbers are shown on drawings N-110, N-111, N-112, N-113, N-115, N-116, N-117, N-118, N-119, N-120, N-121, N-122, N-124, N-125, N-126, N-127, N-128, N-130, N-131, N-132, N-133, N-134, N-135, N-136, N-137, N-140, N-141, N-142, and N-143.

Table 12.4-12

ESTIMATED RADWASTE AND OFFGAS ENCLOSURES INHALATION EXPOSURES DUE TO AIRBORNE RADIOACTIVITY[1]

ROOM[3]	ESTIMATED ANNUAL MAN-HOURS				ESTIMATED THYROID DOSE	ESTIMATED LUNG DOSE
	SURVEILLANCE	TESTING	MAINTENANCE	TOTAL	(MAN-REM/YR)	(MAN-REM/YR)
Solid Radwaste Handling Areas						
124	6	6	212	224	3.6×10^{-2}	1.7×10^{-2}
126,130	12	10	449	471	7.5×10^{-2}	3.5×10^{-2}
127,129	12	12	449	473	7.6×10^{-2}	3.5×10^{-2}
138	6	3	146	155	2.5×10^{-2}	1.2×10^{-2}
139	6	3	146	155	2.5×10^{-2}	1.2×10^{-2}
142	6	17	109	132	2.1×10^{-2}	9.9×10^{-3}
144	6	11	233	250	4.0×10^{-2}	1.9×10^{-2}
233	0	3	3	6	9.6×10^{-4}	4.5×10^{-4}
234	6	2	122	130	2.1×10^{-2}	9.8×10^{-3}
422	0	0	60	60	9.6×10^{-3}	4.5×10^{-3}
423	0	0	40	40	6.4×10^{-3}	3.0×10^{-3}
470,471	61	0	34	95	1.5×10^{-2}	7.1×10^{-3}
515,516	30	0	100	130	2.1×10^{-2}	9.8×10^{-3}
[2]	0	0	4000	4000	6.4×10^{-1}	3.0×10^{-1}
Liquid Radwaste Handling Areas						
132	6	5	165	176	1.6×10^{-1}	7.6×10^{-2}
133	6	5	571	582	5.3×10^{-1}	2.5×10^{-1}
137	6	2	168	176	1.6×10^{-1}	7.6×10^{-2}
147	6	3	287	296	2.7×10^{-1}	1.3×10^{-1}
148	6	6	0	12	1.1×10^{-2}	5.2×10^{-3}
231	6	6	203	215	2.0×10^{-1}	9.2×10^{-2}
232	6	5	117	128	1.2×10^{-1}	5.5×10^{-2}

Table 12.4-12 (Cont'd)

ROOM[3]	ESTIMATED ANNUAL MAN-HOURS				ESTIMATED THYROID DOSE	ESTIMATED LUNG DOSE
	SURVEILLANCE	TESTING	MAINTENANCE	TOTAL	(MAN-REM/YR)	(MAN-REM/YR)
Liquid Radwaste Handling Areas (continued)						
237	6	26	253	285	2.6×10^{-1}	1.2×10^{-1}
238	6	17	300	323	2.9×10^{-1}	1.4×10^{-1}
242,243	12	16	100	128	1.2×10^{-1}	5.5×10^{-2}
245	0	0	78	78	7.1×10^{-2}	3.4×10^{-2}
247	6	5	142	153	1.4×10^{-1}	6.6×10^{-2}
248	6	5	142	153	1.4×10^{-1}	6.6×10^{-2}
Other Equipment Areas						
146	6	21	288	315	1.2×10^{-1}	5.7×10^{-2}
228	6	59	404	469	1.8×10^{-1}	8.4×10^{-2}
236	6	72	549	627	2.4×10^{-1}	1.1×10^{-1}
485,486	0	0	40	40	1.5×10^{-2}	7.2×10^{-3}
OFFGAS	0	0	780	780	3.0×10^{-1}	1.4×10^{-1}
TOTALS	247	320	10,690	11,257	4.3	2.0

(1) All values are on a per unit basis.
(2) Solid radwaste processing, container handling, and radwaste shipping.
(3) Room numbers are shown on drawings N-110, N-111, N-112, N-113, N-115, N-116, N-117, N-118, N-119, N-120, N-121, N-122, N-124, N-125, N-126, N-127, N-128, N-130, N-131, N-132, N-133, N-134, N-135, N-136, N-137, N-140, N-141, N-142, and N-143.

Table 12.4-13

SKYSHINE SOURCE TERMS FOR ONE-UNIT OPERATING[1]

SOURCE DESCRIPTION	γ (6.2 MeV)/sec
HP Turbine	4.209×10^{9}
LP Turbine A	3.525×10^{9}
LP Turbine B	3.405×10^{9}
LP Turbine C	4.038×10^{9}
28"ϕ HP Turbine Inlet Pipe (Two)	3.010×10^{10} (Each)
42"ϕ HP Turbine Exhaust Pipe (Two)	2.836×10^{10} (Each)
42"ϕ Cross-Around Pipe (Six)	1.866×10^{10} (Each)
Steam Seal Evaporator	1.239×10^{10}

(1) These are all the exposed sources above the turbine operating deck, el 269'-0".

Table 12.4-14

DIRECT RADIATION DOSE RATES[1]

YARD AREA[2]

RECEPTOR POINT	DOSE RATE[3] (mRem/hr)
1. Field Office	2.30×10^{-2}
2. Lay-down Area	1.47×10^{-2}
3. Circulating Water Pump Structure	5.67×10^{-2}
4. Sewage Treatment Plant	2.52×10^{-2}
5. Access Road	5.97×10^{-2}

SITE BOUNDARY AND VISITORS' CENTER[4]

RECEPTOR POINT	DISTANCE FROM ORIGIN (ft)	DOSE RATE (mRem/yr)
6. Visitor's Center	1724	1.18×10^{-2}[5]
7. N	2835	4.3
8. NNE	2550	5.4
9. NE	2560	5.5
10. ENE	2579	3.9
11. E	2581	3.6
12. ESE	2579	1.9
13. SE	2570	1.5
14. SSE	3247	0.6
15. S	2504	3.7
16. SSW	2549	2.9
17. SW	2942	0.7
18. WSW	2787	1.3
19. W	2825	1.8
20. WNW	2636	2.8
21. NW	2571	3.4
22. NNW	2818	4.3

(1) Locations of receptor points and origin are shown on Figure 12.4-1. For receptor points 7 through 22, the distances given are the closest location to the origin within each of the 16 sectors.

(2) For Unit 1 only, operation at a capacity of 100%

(3) Dose rates include 0.01 mRem/hr for direct radiation from the radwaste enclosure.

(4) For both units operating at full power at a capacity of 80%

(5) Based on continuous occupancy of 8 hours per year at 100% plant capacity.

Table 12.4-15

ESTIMATED EXPOSURE TO UNIT 2 CONSTRUCTION WORKERS

PERSONNEL	ASSUMED LOCATION	ESTIMATED OCCUPANCY[1] (MAN-HOURS)	AVERAGE DOSE RATE (mRem/hr)[4]	ESTIMATED EXPOSURE[2] (MAN-REM)
Manual	Yard Area[3]	89,000	0.0335[5]	2.39
Manual	Unit 2 Reactor Enclosure Below Refueling Floor and Containment	91,000	0.01	0.73
Manual	On and Above Refueling Floor	25,000	0.311	6.22
Manual	Unit 2 Turbine Enclosure Below Turbine Deck	150,000	0.01	1.20
Manual	On and Above Turbine Deck	62,000	0.546	27.08
Nonmanual	Field Office	62,000	0.0215	1.07
Nonmanual	Unit 2 Reactor Enclosure Below Refueling Floor and Containment	19,000	0.01	0.15
Nonmanual	On and Above Refueling Floor	5,300	0.311	1.32
Nonmanual	Unit 2 Turbine Enclosure Below Turbine Deck	32,000	0.01	0.26
Nonmanual	On and Above Turbine Deck	13,000	0.0711	0.74
	TOTAL	548,300		41.16

(1) For remainder of Unit 2 construction, after Unit 1 operation commences.
(2) Based on an assumed availability of 80% for Unit 1.
(3) Average of points 1 through 5 shown on Figure 12.4-1.
(4) Based on operation at 100% power.
(5) From Table 12.4-14.

Table 12.4-16

AIRBORNE RADIOACTIVITY DOSES TO CONSTRUCTION WORKERS IN YARD AREA

	DOSE RATES (mRem/yr)		
RECEPTOR POINT[1]	TOTAL BODY (GAMMA)	SKIN (BETA)	THYROID (GAMMA)
1. Field Office	2.47	4.77	0.57
2. Lay-down Area	1.14	2.21	0.27
3. Circulating Water Pump Structure	1.14	2.21	0.27
4. Sewage Treatment Plant	1.14	2.21	0.27
5. Access Road	2.47	4.77	0.57

(1) Locations of receptor points are shown on Figure 12.4-1.

12.5 HEALTH PHYSICS PROGRAM

12.5.1 ORGANIZATION

The organizational structure, including the responsibilities of those charged with performance of health physics duties, is described in Section 13.1. Health physics operations are made effective and ALARA goals are achieved through the cooperation and active participation of the various group represented in this structure.

The objectives of health physics operations are to:

a. Detect, identify and define radiation hazards.

b. Provide protection for personnel against radiation hazards.

c. Monitor and measure radioactive effluents from the plant.

d. Control plant-related radiation exposures (occupational and general public) to levels ALARA.

e. Control plant radioactive effluents to levels ALARA.

f. Conduct plant activities in conformance with authorized procedures and applicable regulations.

These objectives are accomplished or enhanced by the various training programs, by the use of prepared procedures, by performance of area surveys and monitoring of personnel, by record keeping, by applying good health physics practices, by periodic review and revision of procedures, by evaluation of activities for ALARA purposes, and by the control of plant operations to minimize occupational exposures and releases to the environment. Health physics operations include the posting, notification, and reporting provisions of 10CFR19 and General Employee Training (Section 13.2) provides the requisite instruction to workers.

Health physics operations conform with the guidelines of Regulatory Guide 8.2 (Rev 0) and of ANSI N13.2 (1969), Guide for Administrative Practices in Radiation Monitoring, with the clarification that controlled areas which are locked or otherwise prevent personnel access are not required to be surveyed at a specific periodicity. In addition to this section, Sections 13.1, 13.2, 13.5, and 12.1 describe the management commitment, organization, responsibilities, authority, training, procedures, and review techniques which implement Regulatory Guide 8.8 (Rev 3), as it applies to the operating phase and Regulatory Guide 1.8 (Rev 1-R). As described in Section 12.1, a formal ALARA review program, which is consistent with the guidelines given in Regulatory Guide 8.8, was implemented during the design and construction phase. The qualification requirements for the Radiation Protection Manager are described in Section 13.1.3. Chapter 17 addresses implementation of other applicable regulatory guides. Implementation of Regulatory Guide 1.16 is addressed in the Technical Specifications.

12.5.2 FACILITIES, EQUIPMENT, AND INSTRUMENTS

This section describes the basic facilities, equipment, and instruments directly related to the health physics operations.

12.5.2.1 Health Physics and Chemistry Facilities

12.5.2.1.1 Supervisory Offices and Field Offices

Health Physics and Chemistry supervisory offices are located outside the RCA. Field offices and work areas for technicians are located adjacent to the RCA.

12.5.2.1.2 Chemical Laboratories

Chemical laboratories are located in the Chemistry Laboratory Expansion including the Hot Lab, the Instrumentation Lab (within the bounds of the RCA) and the Cold Lab (beyond the bounds of the RCA). A conventional chemistry section and radiochemistry section are provided. These sections are segregated so that noncontaminated samples (such as river water) can be prepared and analyzed without having to work under radiologically controlled conditions. The laboratories are accessible to the counting room for convenience in transporting prepared samples for counting. Sample stations are located near their respective systems for sampling condensate, feedwater, reactor water, and radwaste. The laboratories are designed to support routine chemical analysis, as well as, developmental work for emergent issues and appropriate emergency response functions as described in the Emergency Plan.

12.5.2.1.3 Counting Room

The counting room is located in the Chemistry Laboratory Expansion in a low background area. The room is designed with thick shield walls to further reduce background radiation, thus improving instrumentation sensitivity.

12.5.2.1.4 Control Points

Control points and change areas are located throughout the plant near the various job sites. These facilities are for the most part temporary. They are set up during outages and special jobs. They are staffed and stocked to provide health physics monitoring and protective equipment on an as-needed basis.

12.5.2.1.5 Testing and Laboratory Facilities

Calibration and instrument repair facilities are provided. Licensed sources are stored in this facility under approval of the Manager Radiation Protection. Sources are used to calibrate portable radiation survey meters, direct reading dosimeters, certain process and effluent radiation instruments, and area monitors.

12.5.2.1.6 Medical Support

Arrangements with local physicians and hospitals provide offsite support for continued medical treatment of traumas involving radioactive contamination.

A contract is maintained with a primary health physics-medical consultant. The consultant retains a qualified staff that provides expertise in the long-term treatment of patients exposed to excessive external radiation or internal contamination.

12.5.2.1.7 Personnel Decontamination Facility

A personnel decontamination facility located in the radwaste enclosure at el 217' is provided with a sink, shower, change area, and contamination monitoring devices. Personnel decontamination is performed in accordance with Health Physics procedures. Control of personnel decontamination is provided by procedures that are responsive to the appropriate portions of the Quality Assurance Program.

No male/female discrimination has been made in the design for the decontamination facilities. Adequate showers and sinks are available for personnel decontamination. Procedures will be implemented to provide the appropriate privacy. Additional male and female facilities are provided in the administration building but are not intended for contamination removal.

12.5.2.1.8 Laundry and Respirator Facility

A laundry and respirator facility is located adjacent to the Unit 1 turbine enclosure at el 217'. The facility includes space for sorting anticontamination clothing, and for receiving clothing from an offsite laundry. The facility includes space for inspecting, surveying, bagging, and repairing respirators. Procedures are established for inspection, cleaning and maintenance of such protective equipment.

12.5.2.2 Instruments and Equipment

Instrumentation design and capabilities improve as the state of the art changes. Normally, the instrumentation listed in Table 12.5-1 or instruments of similar capabilities will be provided. Any instrumentation or equipment described in these sections may be replaced by items providing similar or improved capabilities.

Instrumentation for detecting and measuring radiation consists of counting room equipment, portable instrumentation, and air samplers. Capabilities for detecting alpha, beta, gamma, and neutron radiation are provided. Sufficient inventory is provided to accommodate use, repairs and calibration. The equipment is described later in this section and is listed in Table 12.5-1. Sufficient chemical equipment and analytical instruments are provided to perform the required sample preparations and analyses.

LGS will equip the counting room and provide the portable instruments, personnel monitoring instruments, and protective equipment with the capabilities as described in Regulatory Guide 8.8, section 4. Support facilities at LGS will also follow the guidance of Regulatory Guide 8.8.

LGS is in compliance with Regulatory Guide 1.97 (Rev 2) in regard to Health Physics and Chemistry Laboratory and survey equipment.

Control of instrument storage, calibration and maintenance is provided by procedures that are responsive to the appropriate portions of the Quality Assurance Program.

Operability of personnel monitors, radiation survey instruments, and laboratory equipment is verified periodically in accordance with plant procedures and work processes.

12.5.2.2.1 Chemical Laboratories

The chemical laboratories are segregated so that one section handles only low level or background samples and the remaining section handles contaminated samples.

Grab samples are transported to the appropriate section of the laboratories. The laboratories, are equipped with constant air flow fume hoods. The fume hoods permit safe preparation and processing of samples under controlled conditions. Effluent of fume hoods within the RCA are filtered through HEPA filters. The laboratories are stocked with chemical reagents and equipment to provide for sample preparation and analysis.

The laboratories contain conventional analytical instruments, equipment and chemicals. Samples intended for activity analysis and isotopic identification are prepared for transport to the counting room. A frisking station is located in the Chemistry Laboratory Expansion.

12.5.2.2.2 Counting Room

Samples processed in the chemical laboratories for activity analysis and isotopic identification, and samples direct from the plant (such as air samples and smears) are transported to the counting room located in the Chemistry Lab Expansion. Equipment is available for gross alpha, gross beta, and gross gamma activity measurements and for determination of the activity levels of specific isotopes. Proportional counters and gamma spectrometers are provided. The room itself has thick shield walls to reduce instrument background radiation. The room is temperature controlled and the voltage supply is regulated for instrument stability.

Major instrumentation includes a Gamma Spectrometer for specific isotopic identification; alpha and beta counters; a scintillation detector; and a liquid scintillation analyzer for low energy emitters such as tritium.

Background and efficiency checks are performed routinely. Alpha and beta plateaus are established to determine operating voltages for proportional counters. Calibrations are based on NIST related standards for the isotopes of interest. Conventional reference standards such as Sr, C, and Ra in equilibrium with daughter activity, Cs, and Co are used for calibration when gross counting is the objective.

12.5.2.2.3 Portable Survey Instruments and Equipment

Portable survey instruments and equipment are used primarily for conducting area surveys and for monitoring personnel throughout the plant. Some portable instruments and equipment are designated for emergency use and will be stored at the Technical Support Center, readily accessible to personnel responding to an emergency.

Portable instruments and equipment for routine plant use are provided to permit alpha, beta, gamma, and neutron radiation measurements, and for obtaining samples of surface and airborne contamination. The inventory includes ion chambers, GM probes, neutron rem counters or equivalent, alpha probes, alpha and beta counters, scintillation detectors, high and low volume air samplers, filters, charcoal cartridges, and smears. Portable instruments and equipment available for emergency use include air sampling equipment with particulate filters and silver zeolite cartridges, portable ion chambers, alpha scintillation probes, energy compensated beta/gamma GM probes (for low energy photons), and portable beta/gamma geiger counters.

At least some of the ion chambers and GM probes have movable beta shields to enable distinguishing between beta and gamma radiation. The ion chambers are the prime devices for dose rate determinations and have beta factors specified as appropriate for the type of meter and its use.

GM probes may be used for dose rate determinations. Their application for this purpose is of value when the ability of an ion chamber to respond reliably is impaired by high humidity, high or low temperature, or very low dose rates. Certain instrument designs with GM probes have extendable arms. This feature allows the user to remain in a relatively lower radiation area while measuring high dose rates at the point of interest. This application is a good example of an effective ALARA policy.

The ranges and numbers of instruments are adequate for their intended use whether routine or emergency.

12.5.2.2.4 Personnel Dosimeters

Personnel monitoring is provided by the use of such devices as optically stimulated luminescent, direct reading dosimeters (electronic dosimeters or pocket ion chambers), or calculations from area survey data and exposure times. Personnel monitoring is provided per 10CFR20. The form of personnel monitoring depends on the type of radiation and the expected radiation level. Types of dosimetry devices change as the state of the art improves.

Devices are available and used appropriately for determining whole body or equivalent exposure, extremities exposure and skin exposure. Health Physics practices include the use of multiple badges in addition to the whole body badge as required by procedures.

A direct reading dosimeter will be used by all personnel entering the RCA who are required to be monitored for exposure per 10CFR20. The DRD is used to provide real time indications of dose received by an individual and provides estimated exposure data. As required, these dosimeters are calibrated and/or drift checked on a routine basis per procedures.

Dosimetry devices used for determining the official exposure doses are subject to extensive quality control programs. This is true whether the processing is by a contractor or onsite. Currently, DLRs are used for penetrating (gamma, neutron) and nonpenetrating (beta) radiation. Whenever neutron exposure is of concern, the current technique is to use neutron survey instruments to determine a rem dose rate, then to multiply by the stay time or a monitoring device/DLR which has been accredited for neutron monitoring through NAVLAP N13.11 criteria.

The personnel dosimetry program is conducted by qualified personnel under the direction of the Radiation Protection Manager.

Control of personnel monitoring (e.g., whole body counter) and external (e.g., DLR system) is provided by procedures that are responsive to the appropriate portions of the Quality Assurance Program.

12.5.2.2.5 Miscellaneous Instruments and Equipment

Other monitoring devices are available and may be assigned to personnel or located in work areas for the purpose of alerting personnel to changes in radiation condition.

Radiation monitors that "chirp" at a rate proportional to gamma dose rate or contain an audible alarming feature are assigned to personnel as deemed necessary. These devices are of particular value when worn by individuals whose duties routinely involve entering various areas of the plant. Changing operating conditions or the progression of the individual into the area could cause sudden changes in radiation levels. These devices alarm at preset values to alert personnel of the changed conditions as the individual walks into the area.

Alarming rate meters may be positioned in a given work area. They serve the purpose of alerting individuals working in that area of increases in radiation level above a preset value.

Friskers, personnel contamination monitors, or portal monitors are positioned at or near various change areas and plant exit points. The purpose of these devices is to control the spread of radioactive contamination. Friskers are generally used within the plant for personnel to monitor themselves at any time, especially when leaving a controlled area. Personnel contamination monitors or friskers are generally used at all primary exits from the radiologically controlled area and at the access points to approved eating, drinking, and smoking areas within the radiological controlled area. The placement of these devices may vary in support of the station's contamination control program, and other devices with the required sensitivity may be considered for use if the situation warrants. Instrumentation, such as small article monitors or friskers, is used to monitor tools, equipment and personal items. The instruments are used to ensure that items exiting the RCA are within procedurally defined limits.

Continuous air monitors are used to monitor airborne concentration at specific work locations. These CAMs provide the means to observe trends or sudden changes in the airborne concentrations. They are not intended for quantitative analysis. The fixed filter-type can be used as a low volume grab air sample in that the filter medium can be removed and analyzed in more detail in the counting room.

Fixed area radiation monitors are mounted in selected locations. Each contains a gamma-sensitive detector, local indicator and local alarm, as well as indicators, alarms, and recorders in the control room. These monitors will alert personnel to unexpected or abnormally high radiation levels in these areas.

12.5.2.2.6 Bioassay

Internally deposited radioactive material is evaluated by use of whole body counting or in-vitro analysis. The whole body counter sensitivity for gamma emitting isotopes of interest will be equivalent to small fractions of isotopic organ burdens.

The bioassay program will incorporate features of Regulatory Guide 8.9 and Regulatory Guide 8.26. Conservative investigation levels are established. When investigation levels are exceeded, an investigation will be performed and, as necessary, will include consultation with independent experts for further evaluation of internal exposure consistent with Regulatory Guide 8.9 and International Commission on Radiological Protection criteria.

12.5.2.2.7 Personnel Protective Equipment

Special protective equipment such as coveralls, plastic suits, shoe covers, gloves, head covers, and respirators are available, and are stored in various plant locations and clothing change areas. This equipment is used to prevent deposition of radioactive material internally or on body surfaces. Most of the plant will be kept free of contamination so that no special protective equipment will be needed. Contaminated areas are identified with posted signs. Radiological postings, work orders or RWPs (or equivalent) are the primary mechanisms for defining the equipment required to enter these contaminated areas.

A variety of combinations of protective equipment may be prescribed depending on the nature and level of the contamination. The use of engineering controls will be considered to minimize the need for protective equipment and clothing as practical. Cotton clothes may be adequate normally; but in wet areas plastic rain suits or bubble suits may be prescribed. Respirators may be required if airborne hazards exist or if surface contamination could cause an airborne hazard as defined in the implementing procedures. Sufficient quantities of NIOSH approved respiratory equipment will be provided to adequately protect workers in general and emergency conditions. This will include SCBAs, respirators (general use or welding), and all the necessary supplementary equipment required (hoses, regulators, etc.).

The guidance of Regulatory Guide 8.15 will be followed to ensure the proper selection, care, fitting, and use of respiratory protective equipment. Regular sampling and survey programs will be provided to determine the need for the appropriate respiratory protective devices. Bioassays, record keeping, and medical evaluations will be incorporated into the LGS respiratory protection program. Written procedures will be developed with the help of the operating experience at PBAPS to provide an effective and acceptable respiratory protection program. Section 12.5.3.5.3 also addresses compliance with Regulatory Guide 8.15.

Control of respiratory protection, including testing, is provided by procedures that are responsive to the appropriate portions of the Quality Assurance Program.

12.5.3 PROCEDURES AND PRACTICES

Health physics procedures are classified according to specific concerns. Thus, there are operating procedures, analytical procedures, emergency procedures, and surveillance test procedures. Health physics is a consideration in other plant procedures as well. This section describes the fundamental procedures applicable to health physics operations. The procedures and methods of operation which, in combination with licensee policy and training, ensure that radiation exposures will be ALARA are those which implement the controls and prescribe the use of equipment described in this section and in Section 12.5.1.

12.5.3.1 Radiation Surveys (Area Surveys)

Area survey procedures describe the purpose and techniques of detecting the presence of and measuring the level of radiation and contamination. Contamination may be on surfaces or airborne. Area surveys are conducted throughout the plant. Such surveys may be routine or may be related to specific jobs upon request. An area survey may be performed before, during, and after various work activities. Area surveys are performed by health physics technicians or other trained and qualified personnel (i.e. Advanced Radiation Workers). Control of radioactivity sampling (air, surface, liquids) is provided by procedures that are responsive to the appropriate portions in the Quality Assurance Program.

12.5.3.1.1 Radiation Detection

The primary instrument for beta/gamma dose rate measurements is an ion chamber. Circumstances may require the use of other instruments to determine dose rates. GM probes may be used for low radiation levels or where environmental conditions (temperatures, humidity) cause erratic responses from ion chambers.

Surveys for neutrons are performed by instruments designed for that purpose. A rem counter or equivalent that has the ability to measure neutron dose rate in rem per hour is the preferred neutron measurement instrument. However, other instruments or devices for determining neutron energies may also be used. For example, moderated and unmoderated boron triflouride (BF_3) probes may be used to detect the presence of low and high energy neutrons. Some instruments are designed with extension arms. These types of instruments may be used in high dose rate areas to provide distance from the source to the technician, thus reducing personnel dose.

12.5.3.1.2 Surface Contamination Detection

A variety of techniques are necessary to detect and measure radioactive contamination. Procedures describe the use of smears (e.g., small paper discs) and swipes (e.g., large area survey) to wipe a surface to pick up removable contamination. Smears and swipes are analyzed using portable survey meters and/or counting room equipment. Fixed contamination is determined by scanning a surface with portable survey meters. Equipment is available for alpha and beta/gamma activity measurements.

12.5.3.1.3 Airborne Contamination

Airborne contamination is determined by using air samplers to draw a known volume of air through a filter paper or charcoal cartridge. A charcoal cartridge is used with the filter paper where iodine is of concern. The filter paper is analyzed by gross beta/gamma count and/or gamma spectrometry. Gamma spectroscopy is also performed on the charcoal cartridges. The gamma spectrometry identifies the particulate and iodine isotopic activity. DAC-hours shall be tracked in accordance with Heath Physics procedures. Gross beta/gamma count data is used to judge the need for filter paper gamma spectrometry. High volume air samplers and low volume air samplers having nominal sample rates of 25 scfm and 1 scfm, respectively, are available. The high volume air sampler is used primarily to obtain grab samples rapidly before, during, and after work activities. The low volume air sampler is used primarily to obtain the average air concentration for the work period.

12.5.3.1.4 Survey Frequency and Techniques

The frequency and extent (scope) of area surveys is a function of dose rate in the area, accessibility to the area, and nature of the area in plant operations. For example, contamination checks in control rooms and eating areas are performed nominally on a daily basis; seldom entered high radiation areas are surveyed as infrequently as monthly, or only as needed for entries. As part of the ALARA program, the performance of area surveys are coordinated so that, wherever feasible, routine area survey data is used to perform RWP work. This practice avoids duplication and reduces exposure to technicians.

Area survey data are usually obtained or known before work starts in an area. Resurveys may be performed in the area during the job if the work activity is prolonged. Other conditions for

resurveys would be if the work activity or other plant operation caused changed conditions. Surveys may also be performed at the completion of the work activity.

Depending on the survey results, the area surveyed is roped off and posted appropriately to alert personnel to the radiation conditions and requirements for entry.

Procedures for area surveys describe the use of instruments, effective survey techniques, and documentation of data. The specifications for clean, radiation and high radiation areas are defined. Various levels of surface and airborne contamination are established as guidelines for prescribing protective equipment such as clothing and respirators. Procedures include consideration for potential as well as actual radiation hazards.

12.5.3.2 Radiation Work Permits (or Equivalent)

Where radiation dose rates, airborne concentrations, or surface contamination levels exceed procedural limits, an RWP (or equivalent) is required for work. Health Physics will evaluate the radiological conditions associated with the work to be performed. Health Physics will specify the appropriate protective clothing, equipment, and monitoring required including dosimetry by use of radiological postings, work orders, or RWPs. Area survey frequency is established by Health Physics. All personnel performing work under a particular RWP (or equivalent) must be familiar with the permit conditions and must sign a RWP (or equivalent) compliance sheet. Information documented from RWP (or equivalent) entries include name, time in and out, and estimated exposure for entry. The RWP (or equivalent) computer may be used in lieu of a compliance sheet to document this information. Health Physics may terminate an RWP (or equivalent) if radiation conditions change.

Health Physics supervision selectively reviews RWPs and survey documentation which are then filed. RWPs (or equivalent) serve as a source of data for dose comparison on repeat jobs. They can be used to determine the effectiveness of ALARA efforts.

12.5.3.3 Handling and Storage of Radioactive Material

Health Physics personnel are notified of the receipt of radioactive material, and of intended shipment of radioactive material. This is done so that required surveys can be performed and to verify that correct labeling and placarding has been accomplished.

Calibration sources for radiation instrumentation and sources used to prepare secondary standards are stored in a source vault. This vault is capable of being locked. The lock is under the control of the Radiation Protection Manager.

Small quantities of sealed or unsealed sources may be stored for convenience in shielded cabinets, caves, or safes. Such sources are used locally in the chemical laboratories, counting room, or when response-checking instruments throughout the plant.

Spare instruments containing built-in sources and slightly contaminated equipment intended for reuse may be stored at times in the warehouse. Such items are clearly identified as containing radioactive material.

12.5.3.4 Controlling Access and Stay Time

The plant is surrounded by security fencing. Entrance must be via the guardhouse. Security procedures are applied by the guards at this point to identify each individual and to determine

their purpose for entry. Security and dosimetry badges are assigned. Escorts are provided to satisfy procedural requirements. Entrance to the RCA is via the Health Physics Access Point. Health Physics procedures are applied at this point to set exposure limits and ensure Health Physics Training of each individual prior to entry.

12.5.3.4.1 Access to Radiation and High Radiation Areas

Radiation areas are identified by posted radiation signs. Signs are used to define requirements for entry. Where appropriate, yellow and magenta or black rope or tape is used as a barrier to prevent access or to divert personnel to a specific control point for access. RWPs are used to define the exposure limits, document entry and exit, and record estimated exposure for each individual. Procedures describe the purpose and application of the RWPs. Administrative guides for personnel exposure are established by procedure. These guides are set at values less than the exposure dose limits in 10CFR20. Variations from these guides must be requested. Procedures describe the steps for approval of dose extensions. Additionally, positive control is exercised over each high radiation area by use of barricades, conspicuously posting the area, and requiring an RWP for entrance. Areas greater than 1000 mR/hr are controlled by using lock doors or gates. Exceptions to this practice are permitted per Technical Specification 6.12. Issuance of the keys are controlled by Health Physics. Each key used and the individual using the key are recorded. Certain work activities having high dose rates and short stay time may be monitored directly by Health Physics Technicians to prevent personnel from inadvertently exceeding the prescribed dose for the work. Personnel are advised to observe the reading on their direct reading dosimeter frequently.

12.5.3.4.2 Contamination Control

Contaminated areas are conspicuously identified to prevent inadvertent access. Floor coverings, called step off pads, typically are used to access these areas. Appropriate procedures give guidance for the selection and application of protective clothing and respirators under various specific conditions. Personnel requiring access to contaminated areas must determine the radiological controls and requirements via Health Physics briefings, radiological postings, work orders or RWPs.

As personnel leave the work area, they remove the protective clothing and respirators before stepping across the step-off-pad. Personnel must monitor themselves to assure that no contamination has been transferred to their bodies or clothing.

Tools or equipment to be removed from a contaminated area are surveyed or contained prior to removal from the area. Items suspected of or having loose surface contamination must be placed in a container (e.g., a plastic bag), surveyed, and tagged at the step-off-pad. The tools may be placed in storage, may be taken to another contaminated area for reuse, or they may be designated for appropriate storage, disposal, or decontamination. Tools, equipment and personal items are surveyed prior to removal from the RCA. Health Physics procedures describe the survey techniques and limits.

The presence of radioactive contamination, whether surface or airborne, inhibits mobility of personnel around the plant. Protective equipment that must be worn creates inconveniences and introduces other factors that affect performance. For these reasons, plus the obvious external and internal radiation hazards, decontamination is initiated judiciously to confine the contamination to as small an area as practicable and/or to reduce the contamination levels to minimize protective requirements. Special coatings that aid in decontamination are applied to walls and floors. The ventilation flow pattern is from clean areas to contaminated areas. Process equipment is isolated in various cavities or cells. These cells are vented in a controlled manner, usually through filters to

effluent stacks that monitor flow rate and radioactivity. Highly contaminated equipment drains are piped to sumps to avoid the use of floor drains and attendant spillage of fluids on the floor.

Control of radioactive contamination measurement and analysis and radioactive contamination control are provided by procedures that are responsive to the appropriate portions of the Quality Assurance Program.

12.5.3.5 Training

See Section 13.2.

12.5.3.5.1 Respiratory Fit Test

A functioning Respiratory Protection Program, which meets the requirements of 10CFR20. and Regulatory Guide 8.15 (October 1976), permits the application of protection factors to select the appropriate type of respirators. This can only be done for individuals who have received training in the use of the respirators, have been tested for the validity of fit for the type of respirators intended for their use, and who have been medically certified. Procedures are established that describe the technique, fit test frequency, and define acceptance criteria.

12.5.3.5.2 Compliance with Regulatory Guides

Regulatory Guide 8.2 - Section 12.1 describes the general ALARA program and policies. As specific procedures and the LGS ALARA plan are developed, Regulatory Guide 8.2 will be used for guidance.

Regulatory Guide 8.7 - Exposure records will be kept in accordance with 10CFR20 and maintained until the NRC authorizes their disposition. As the procedures are developed, the guidance of ANSI N13.6 (1969) as endorsed by Regulatory Guide 8.7 will be followed.

Regulatory Guide 8.8 - Sections 13.1, 13.2, 13.5, 12.1, and 12.5 address the management commitment, organization responsibilities, authority, training, procedures, and review techniques which implement Regulatory Guide 8.8 for LGS operation.

Regulatory Guide 8.9 - As stated in Section 12.5.2.2.6, the bioassay program will incorporate features of Regulatory Guide 8.9. When conservative investigative levels are exceeded, a consultant will assist in a more detailed evaluation of internal exposure. These procedures and practices will follow the guidance of International Committee of Radiation Protection publications and Regulatory Guide 8.9.

Regulatory Guide 8.10 - The development and implementation of a formal ALARA program will follow the guidance of Regulatory Guide 8.8 which is a nuclear power plant specific reference of Regulatory Guide 8.10.

Regulatory Guide 8.13 - Instruction to workers concerning prenatal radiation exposure will be given as part of the General Employee Training Program. This program will provide all employees with the information that is identified in Regulatory Guide 8.13.

Regulatory Guide 8.15 - The development and implementation of a respiratory protective equipment program will follow the guidance of Regulatory Guide 8.15.

Regulatory Guide 8.26 - The bioassay program will incorporate features of Regulatory Guide 8.26.

Regulatory Guide 1.8 - LGS is in compliance with this guide to the extent discussed in Sections 13.1 and 13.2. The licensee has implemented ANSI/ANS 3.1-2014, section 5, which is endorsed by Regulatory Guide 1.8.

Regulatory Guide 1.16 - LGS Technical Specifications were based on NUREG-0123, Revision 4, "Standard Technical Specifications for General Electric BWRs," as described in Chapter 16. Reporting of operating information will be in accordance with the Technical Specifications,

Regulatory Guide 1.33 - LGS will follow the guidance of Regulatory Guide 1.33 which endorses/modifies ANSI N18.7 (1976) with certain alternate approaches which are addressed in detail in Section 17.2.

Regulatory Guide 1.39 - LGS is in general conformance to the guidance of Regulatory Guide 1.39, which endorses/modifies ANSI N45.2.3 (1973). LGS will comply with Regulatory Guide 1.39 with certain alternate approaches which are outlined in detail in Section 17.2.

Regulatory Guide 1.97 - LGS is in compliance with Regulatory Guide 1.97 in regard to Health Physics and Chemistry Laboratory and Survey Equipment.

Table 12.5-1

HEALTH PHYSICS INSTRUMENTATION

INSTRUMENT	SENSITIVITY/RANGE	USE	NORMALLY REQUIRED QUANTITIES NOW
Gamma Spectrometer	10 minute count (μCi): [Co-60, Cs-134,] [Cs-137, I-131,] - $1x10^{-4}$ [Zn-65] Noble Gases - $1x10^{-3}$	Gamma scans	4
Alpha/Beta Counter	Beta Efficiency 10%-50% (E dependent)	Alpha/beta discrimination	2
Whole Body Counter System	<1/20 of the International Committee of Radiation Protection Publication 30 Annual Limit of Intake	Internal dosimetry	1

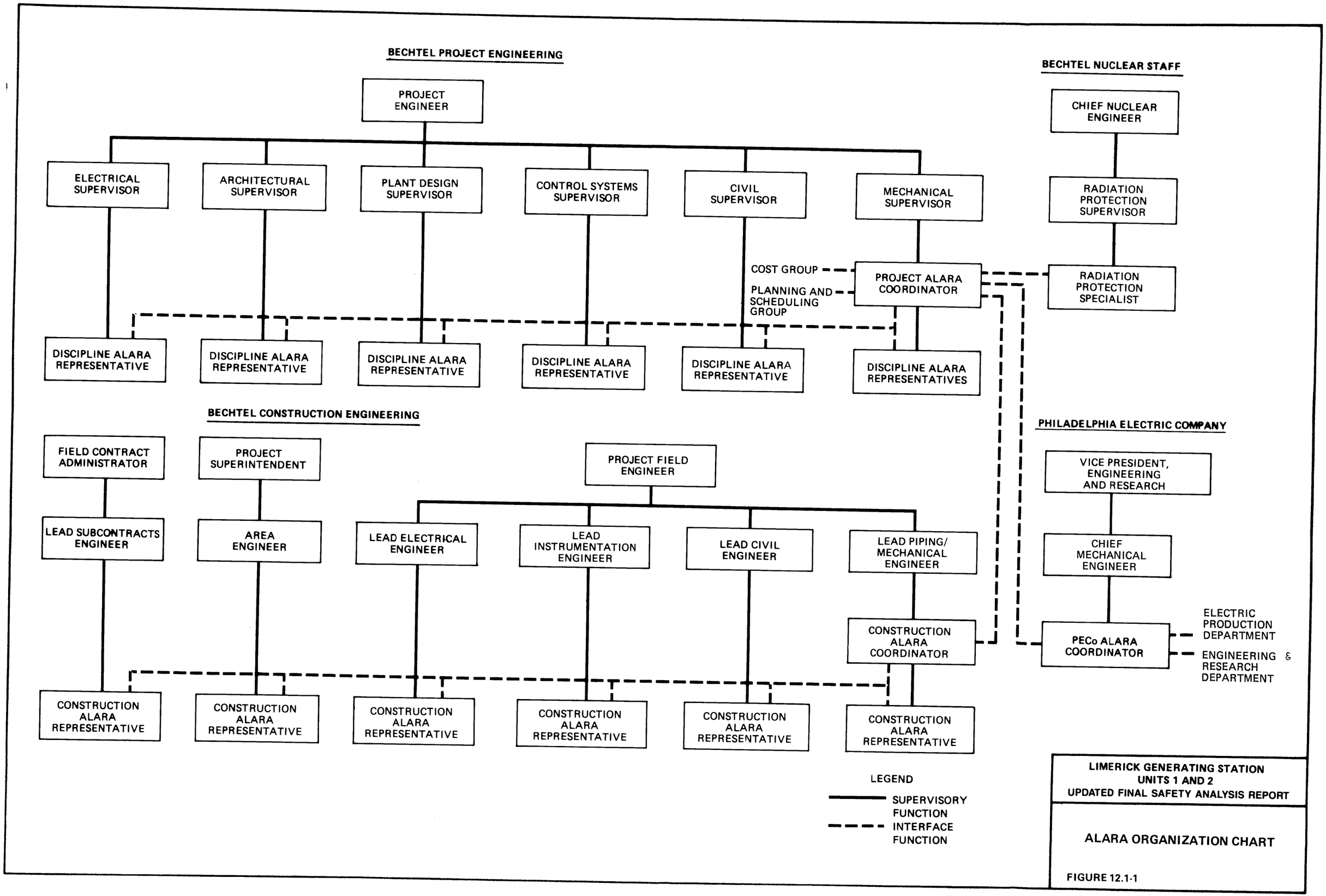
RADIOSURVEILLANCE INSTRUMENTS	SENSITIVITY/RANGE	USE	NORMALLY REQUIRED QUANTITIES NOW
RO-2	0-5000 mR/hr	Field survey	10
RO-2A	0-50 R/hr	Field survey	15
E-520	0.2-2000 mR/hr	Field survey	5

Table 12.5-1 (Cont'd)

RADIOSURVEILLANCE INSTRUMENTS	SENSITIVITY/RANGE	USE	NORMALLY REQUIRED QUANTITIES NOW
E-140N	0-50,000 cpm	Field survey	15
HP270 probe	0.1 mR/hr-10 R/hr	Field survey	15
HP210AL probe	-	Field survey	15
HP210T probe	-	Field survey	15
Teletector	0-1000 R/hr	Field survey	3
HP220A probe	-	Field Survey	1
HP260A probe	-	Field Survey	10
EC4-X (& cables)	0.01 mR/hr-10,000 R/hr	Portable area monitors	10
DA1-6 probe (for EC4-X)		Portable area monitors	10
PRM-6 with AC-3	0-500,000 cpm	Alpha surveys	0
PNR 4	0-5000 mR/hr	Neutron surveys	4
HP280 - 3 in. sphere		Neutron surveys	0
RO7 + BH midrange detector + BH high range detector, + RX5 - 5 ft extender, + 2 (15 ft) cables	0-200 R/hr; 0-20,000 R/hr	High range ion chamber	2
Underwater probe	0-5000 R/hr 5-5000 mR/hr	High range under water	2
Rm 20	0-500,000 cpm	Frisking stations	25
Alpha + Beta CAMs		Air monitoring	3
Low Volume air samplers	-	Air monitoring	25
SAC-4		Alpha Survey	3

Table 12.5-1 (Cont'd)

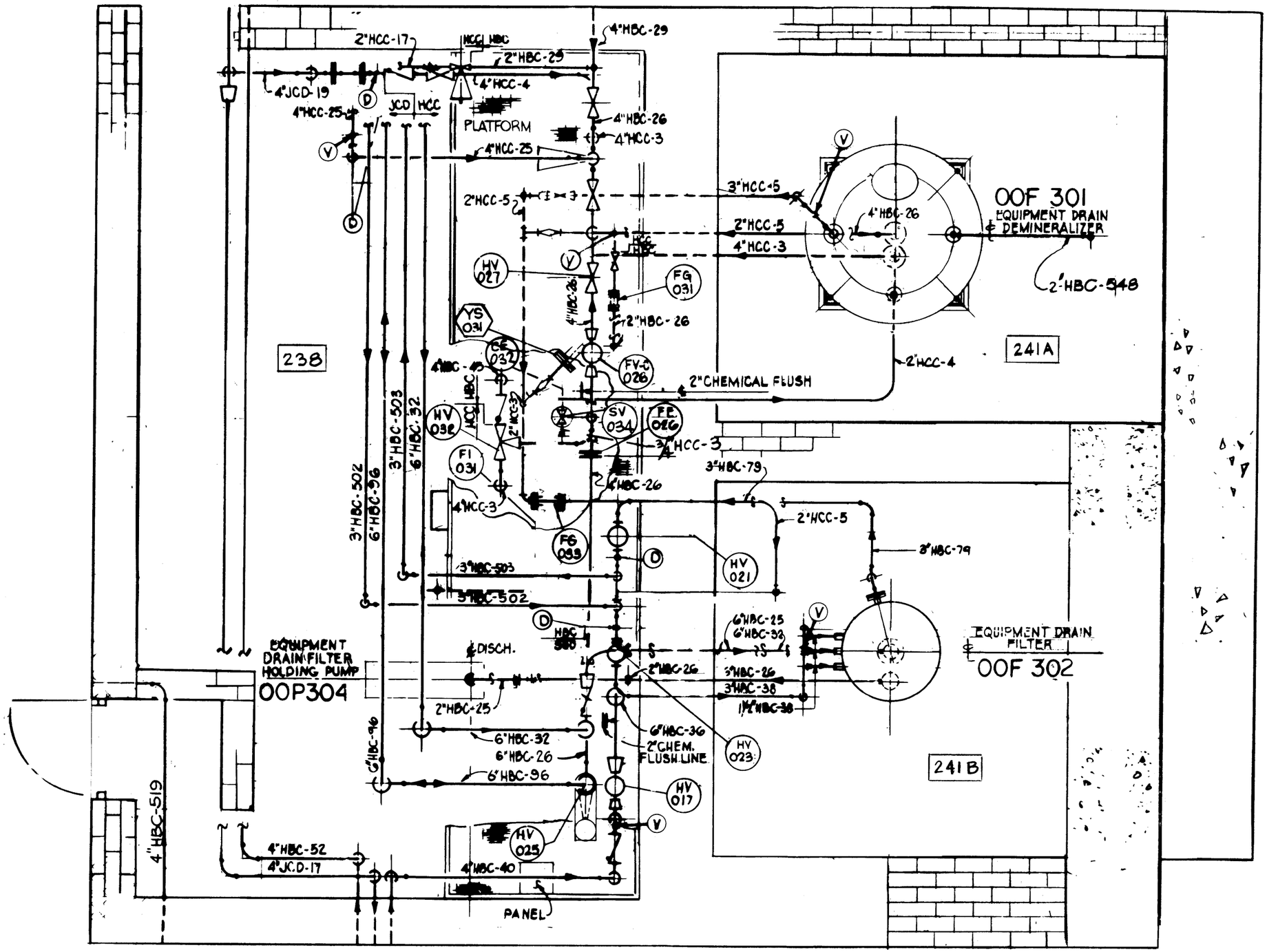
RADIOSURVEILLANCE INSTRUMENTS	SENSITIVITY/RANGE	USE	NORMAL REQUIRED QUANTITIES NOW
High Volume air samplers	-	Air monitoring	10
Portal Monitors	Approx. MDA 1 mR	Contamination control	5
Pocket Ion Chamber:			
Charging Units		Exposure control	as needed
0-200 mR	0-200 mR		
0-500 mR	0-500 mR		
0-1500 mR	0-1500 mR		
Electronic Dosimeter		Exposure Control	as needed
Portable MCA + HP Ge detector + 24 hr dewar			1
E-530N	0.02-20 R/hr	Field surveys	2
Shepherd 142-10 panoramic calibrator	0-1,600 mR/hr	Calibration	1
Shepherd 89 calibrator	0.01 mR/hr-1200 R/hr	Calibration	1
Condenser R meter	-	Calibration	1



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

ALARA ORGANIZATION CHART

FIGURE 12.1-1



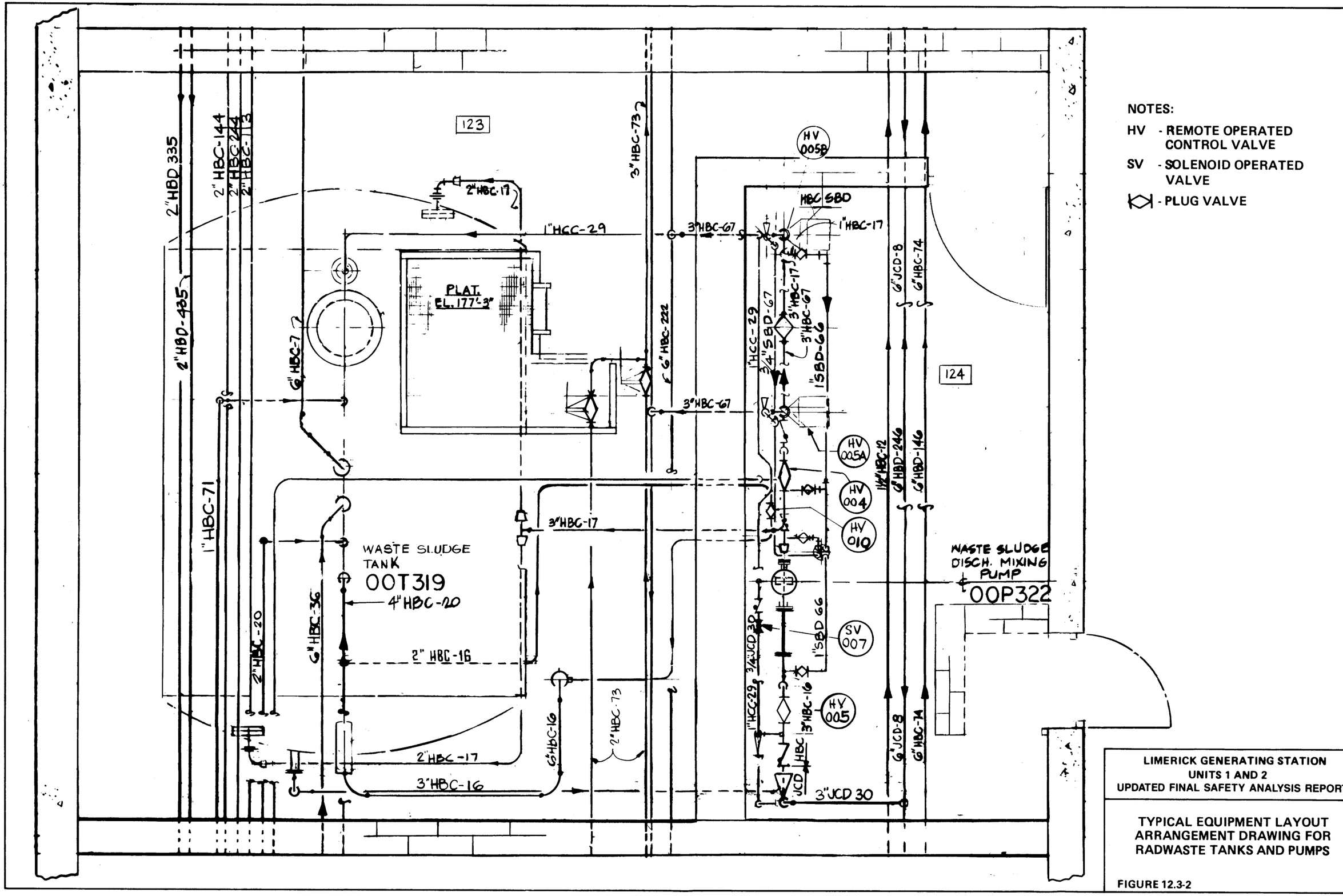
NOTES:

HV—REMOTE OPERATED CONTROL VALVE
FV—C-FLOW CONTROL VALVE
SV—SOLENOID OPERATED VALVE
LF—LINE FILTER
FE—FLOW ELEMENT
FG—FLOW GAUGE
FI—FLOW INDICATOR
YS—Y STRAINER

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TYPICAL EQUIPMENT LAYOUT ARRANGEMENT DRAWING FOR FILTERS, DEMINERALIZERS AND VALVES

FIGURE 12.3-1



NOTES:

HV - REMOTE OPERATED CONTROL VALVE

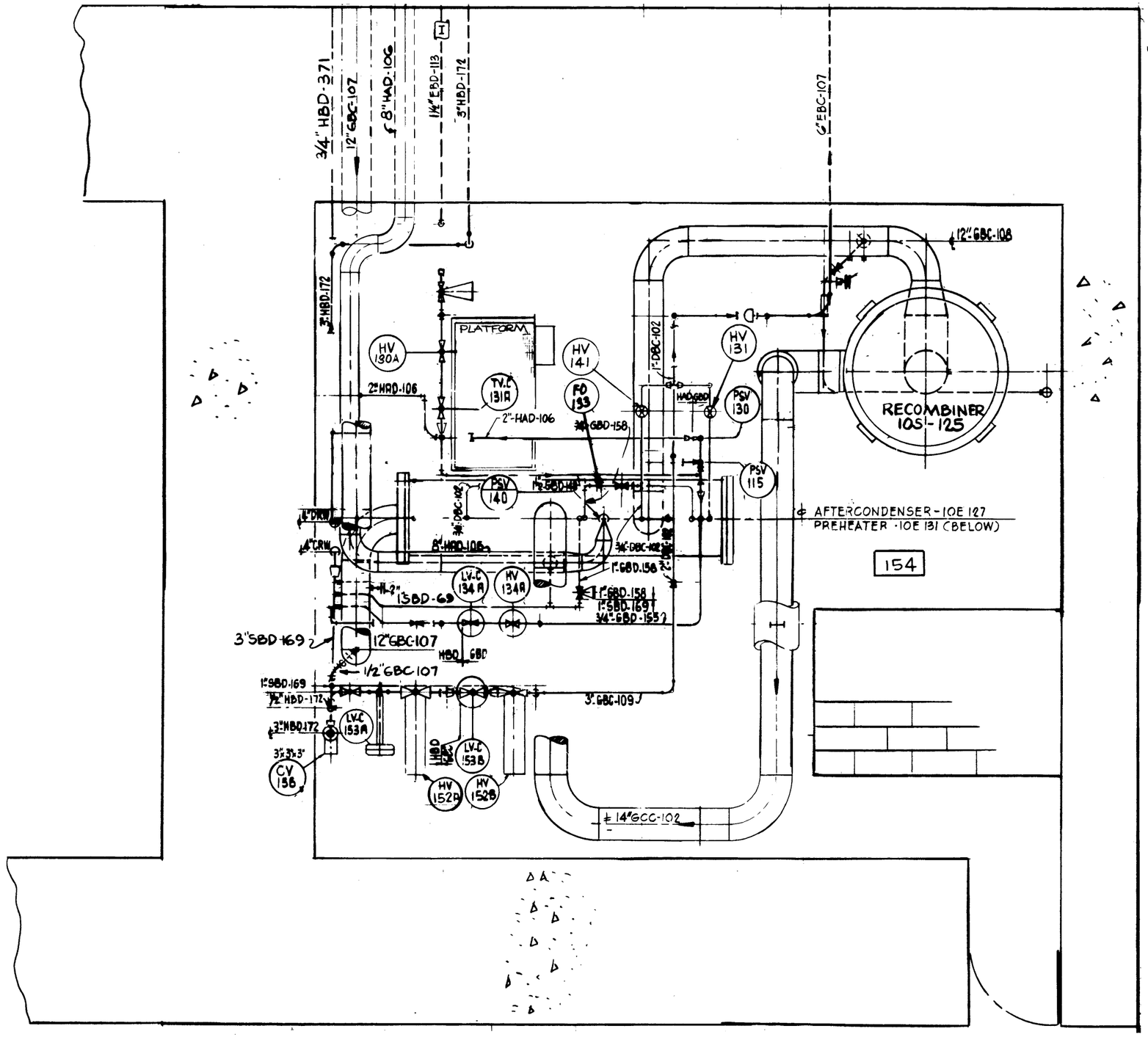
SV - SOLENOID OPERATED VALVE

⋈ - PLUG VALVE

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UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL EQUIPMENT LAYOUT ARRANGEMENT DRAWING FOR RADWASTE TANKS AND PUMPS

FIGURE 12.3-2



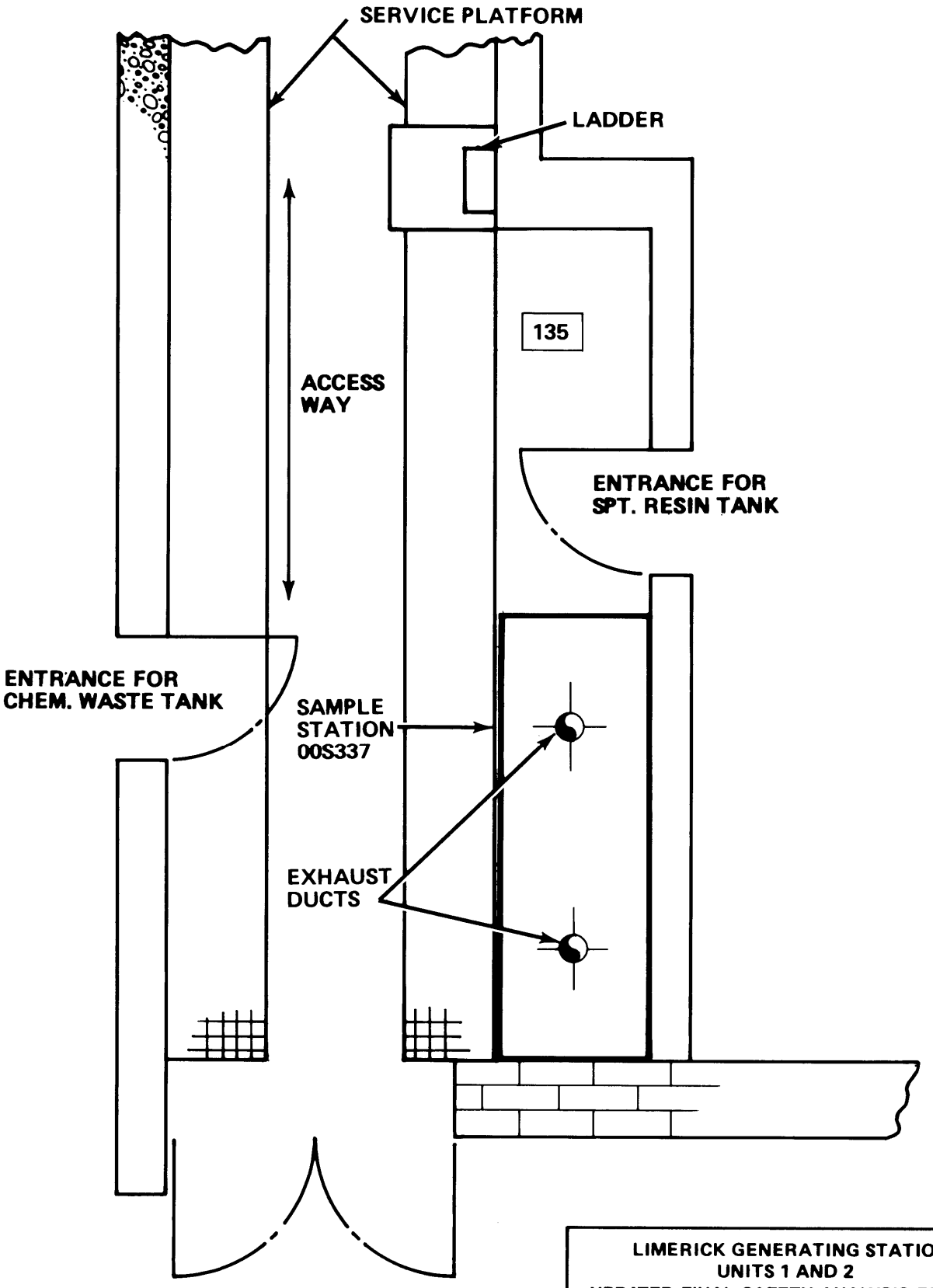
NOTES:

HV—REMOTE OPERATED CONTROL VALVE
LV-C—LEVEL CONTROL VALVE
TV-C—TEMPERATURE CONTROL VALVE
CV—CONDUCTIVITY CONTROL VALVE
PSV—PRESSURE SAFETY VALVE

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TYPICAL EQUIPMENT LAYOUT ARRANGEMENT DRAWING FOR OFFGAS RECOMBINERS

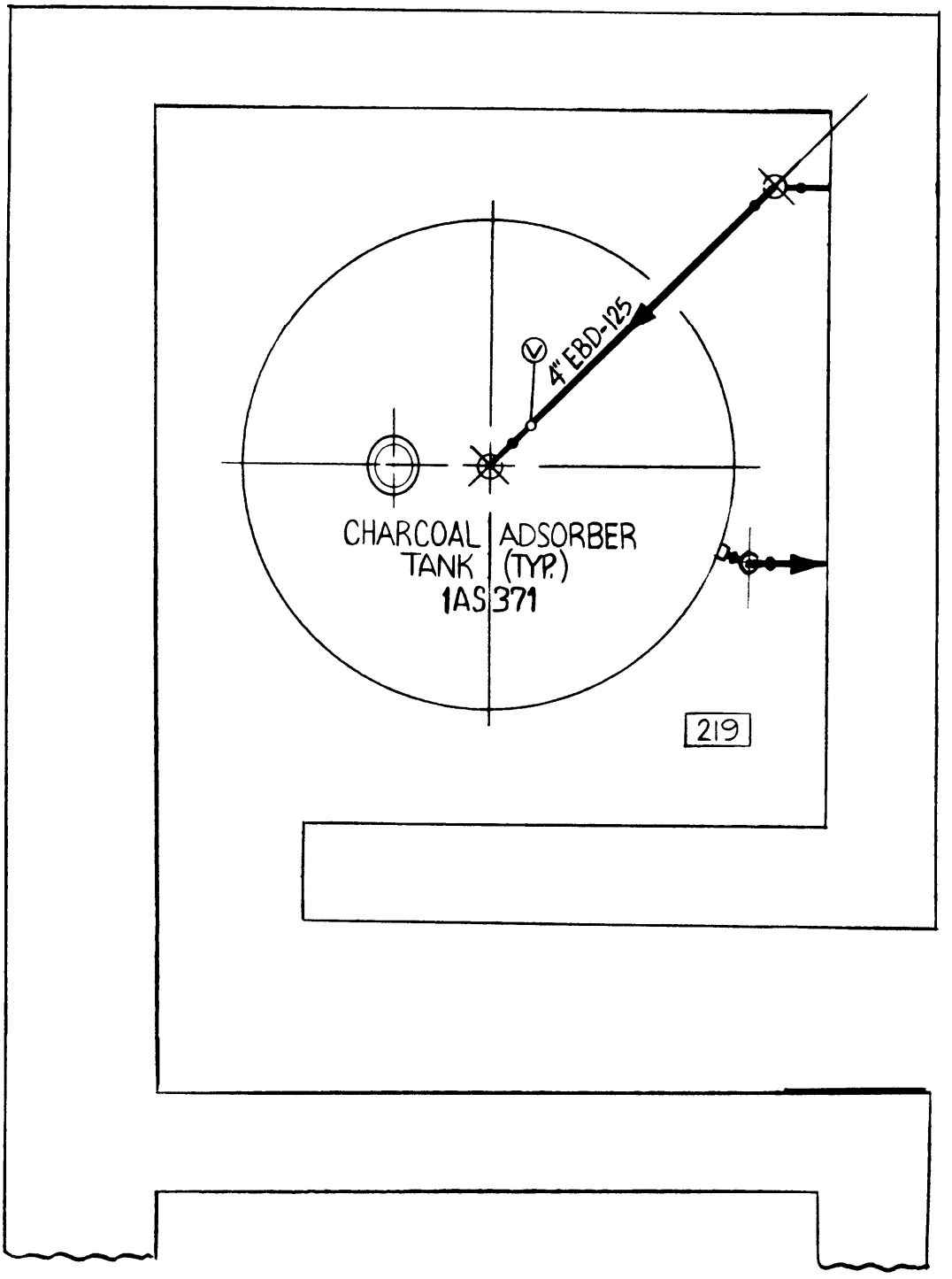
FIGURE 12.3-4



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TYPICAL EQUIPMENT LAYOUT ARRANGEMENT DRAWING FOR SAMPLE STATIONS

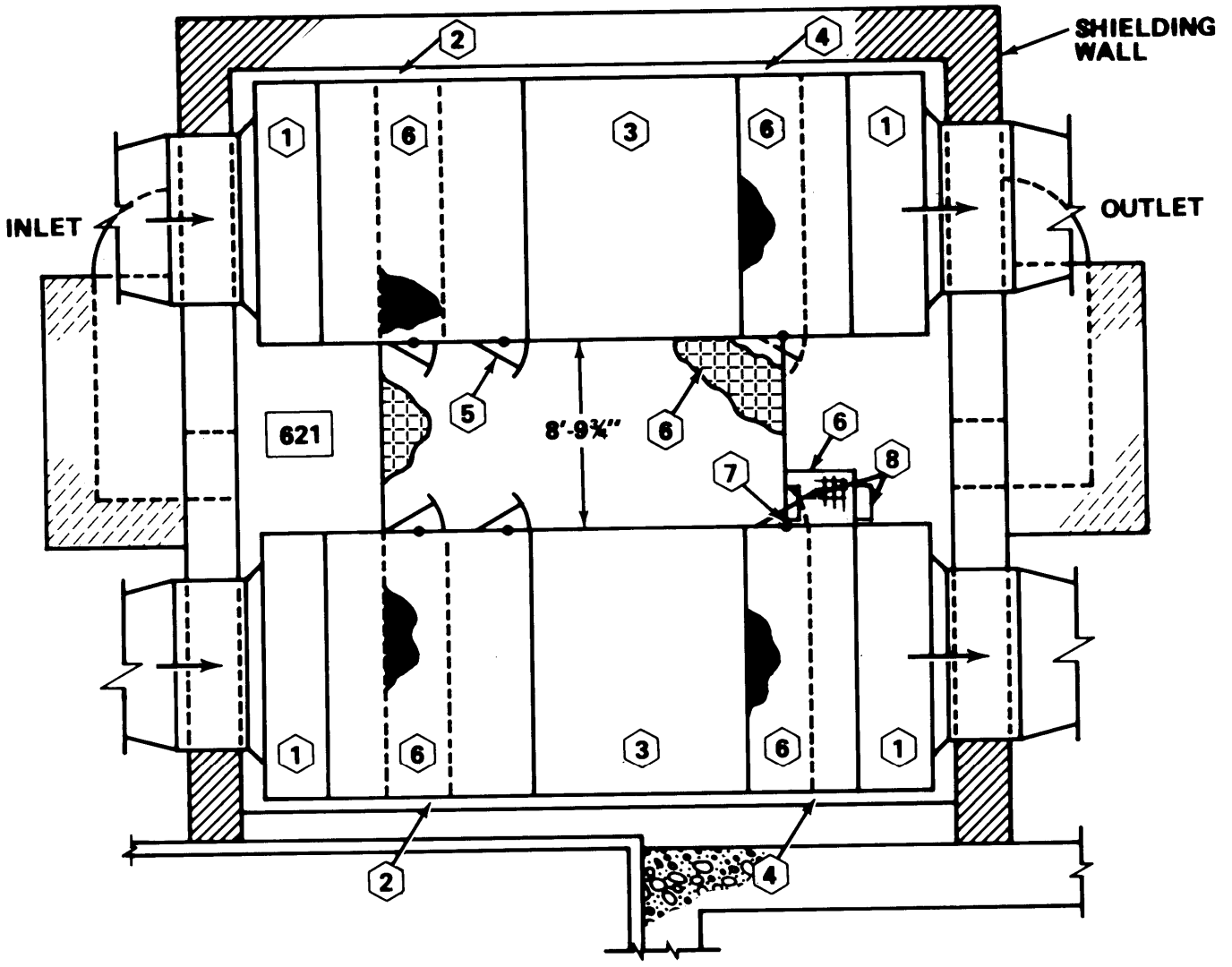
FIGURE 12.3-5



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UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL EQUIPMENT LAYOUT
ARRANGEMENT DRAWING FOR
CHARCOAL ADSORBER BEDS

FIGURE 12.3-6



1. PLENUM
2. PREFILTER AND HEPA FILTER BANK
3. RECHARGABLE CARBON FILTERS
4. HEPA FILTER BANK
5. ACCESS DOORS
6. PLATFORM
7. TESTING CONNECTIONS
8. LADDER

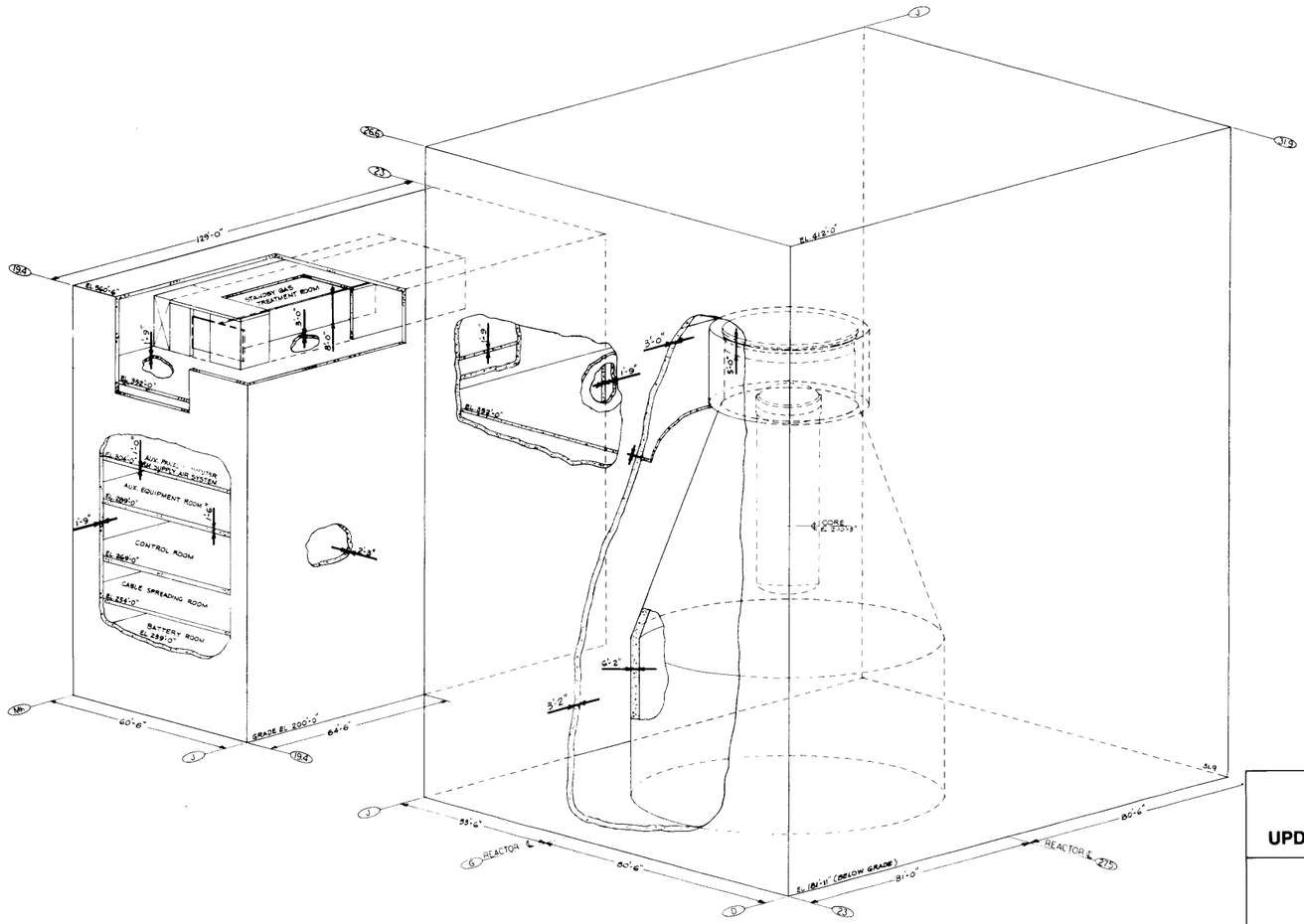
LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

TYPICAL SHIELDING ARRANGEMENT FOR CHARCOAL AND PARTICULATE FILTERS

FIGURE 12.3-7

Figures 12.3-8 thru 12.3-25

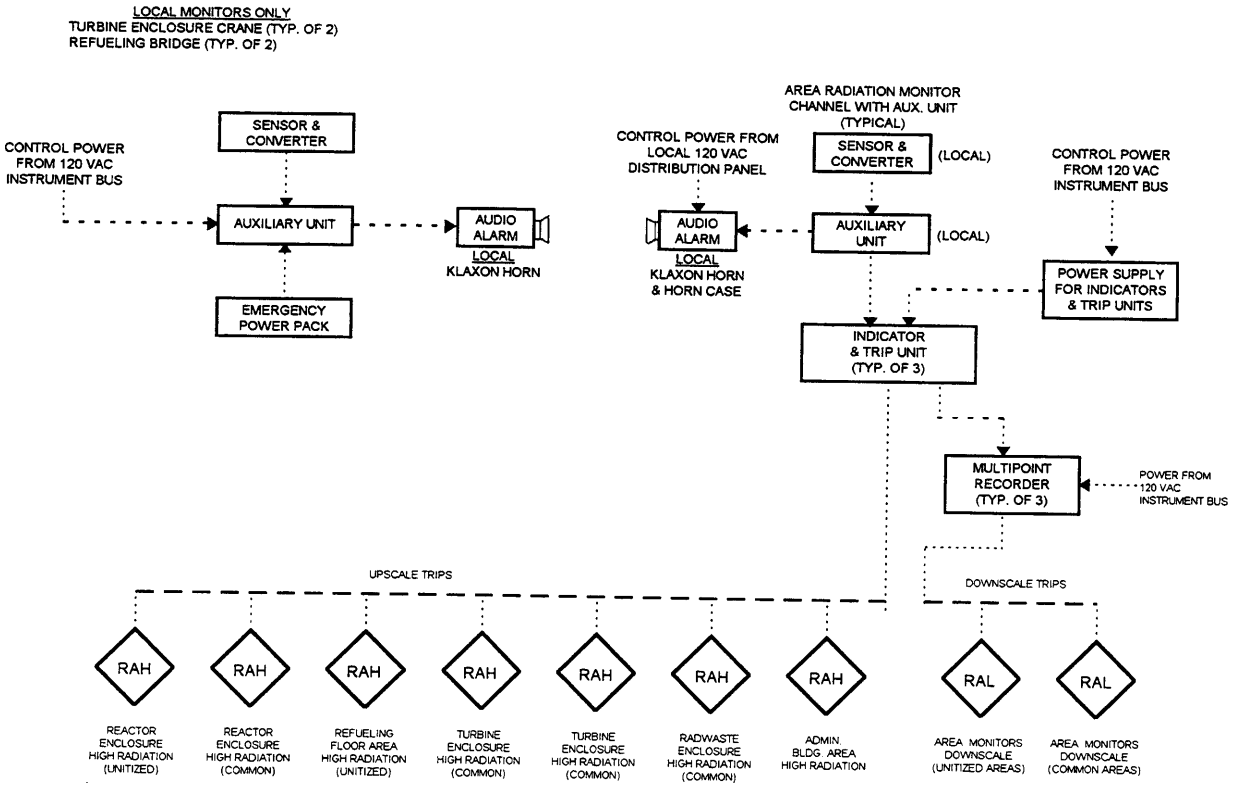
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SCALED ISOMETRIC OF CONTROL STRUCTURE WITH RELATION TO CONTAINMENT

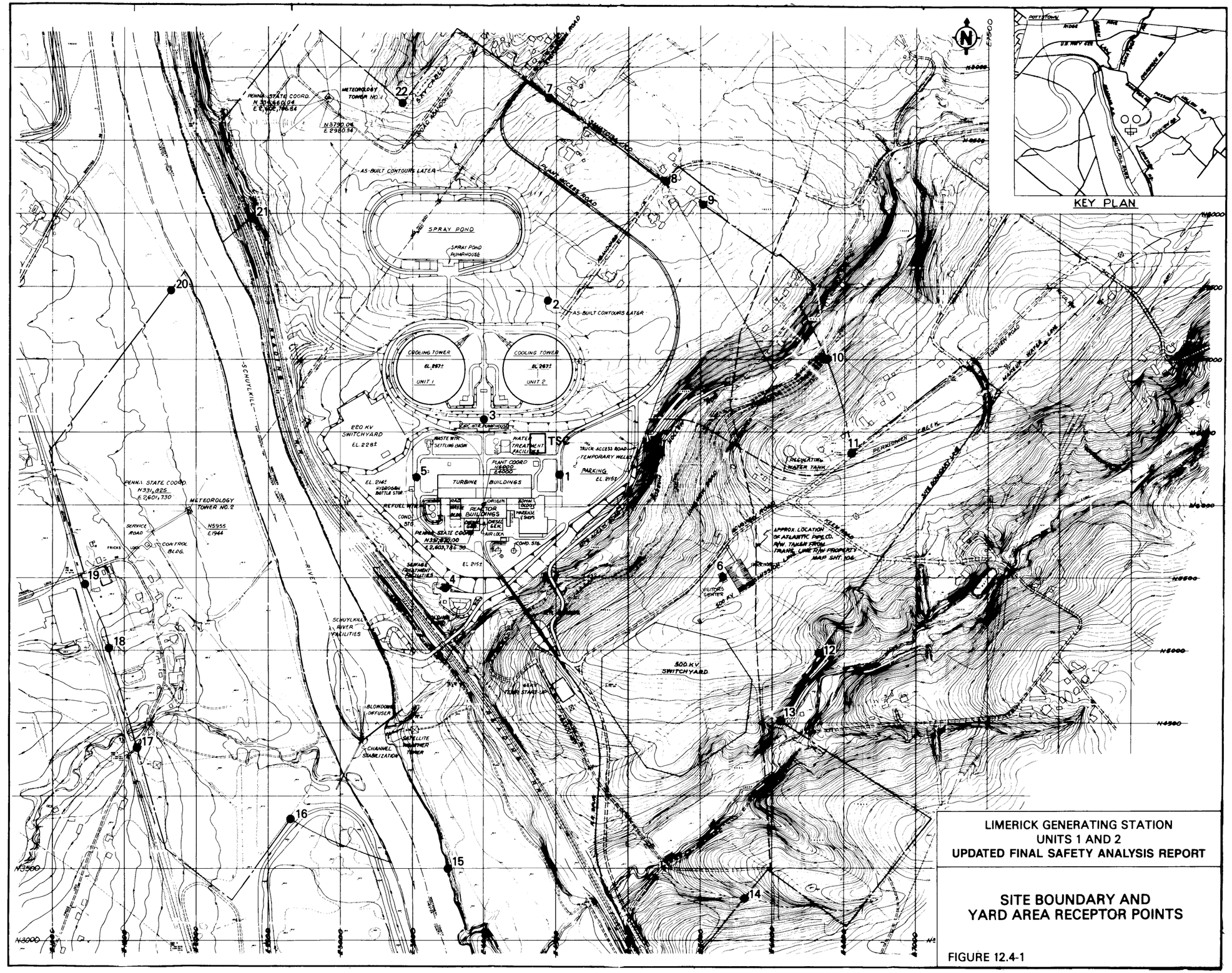
FIGURE 12.3-26



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AREA RADIATION MONITORING SYSTEM SCHEMATIC DIAGRAM

FIGURE 12.3-27 **Rev. 10 10/00**


KEY PLAN
SPRAY POND
SPRAY POND PUMPHOUSE
AS-BUILT CONTOURS LATER
COOLING TOWER
UNIT 1
UNIT 2
230 KV SWITCHYARD
500 KV SWITCHYARD
TURBINE BUILDINGS
REACTOR BUILDINGS
WASTE WTR. SETTLING BASIN
WATER TREATMENT FACILITIES
TSC
PLANT ACCESS ROAD
TEMPORARY WELL
PARKING
METEOROLOGY TOWER NO. 1
METEOROLOGY TOWER NO. 2
SCHUYLKILL RIVER
SCHUYLKILL RIVER FACILITIES
BLOWDOWN DIFFUSER
CHANNEL STABILIZATION
SATELLITE WATER TOWER
VISITORS CENTER
SERVICE ROAD
CONTROL BLDG.
REFUEL WTR.
COND. STG.
HYDROGEN BOTTLE STOR.
SEWAGE TREATMENT FACILITIES
PERKIOMEN CREEK
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT
SITE BOUNDARY AND YARD AREA RECEPTOR POINTS
FIGURE 12.4-1

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13.1.2.1.3 Deleted
13.1.2.1.4 Deleted
13.1.2.1.5 Deleted
13.1.2.2 Deleted
13.1.2.3 Deleted
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13.5.1.24 Procedure for Preparation of Off-Normal Procedures
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FIGURE	TITLE
13.1-1	Deleted
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13.5-1	Definition of "At the Controls"
13.5-2	SRO Control Room Boundaries

CHAPTER 13 - CONDUCT OF OPERATIONS

13.1 ORGANIZATIONAL STRUCTURE

The Exelon Generation Company, LLC (EGC) corporate organization and its functions and responsibilities are described in Chapter 1 of the Quality Assurance Topical Report (QATR) designated as NO-AA-10, as revised.

13.1.2 OPERATING ORGANIZATION

The organizational structure and reporting relationships are described in the Quality Assurance Topical Report, NO-AA-10 and Nuclear Organization charts, HR-AA-2009.

Table 13.1-2, shows the title of each position and the positions for which reactor operator and senior reactor operator licenses are required.

13.1.2.1 Deleted

13.1.2.1.1 Deleted

13.1.2.1.2 Deleted

13.1.2.1.3 Deleted

13.1.2.1.4 Deleted

13.1.2.1.5 Deleted

13.1.2.2 Deleted

13.1.2.3 Deleted

13.1.2.4 Deleted

13.1.2.5 Deleted

13.1.2.6 Deleted

13.1.2.7 Deleted

13.1.2.8 Deleted

13.1.3 Qualification of Nuclear Plant Personnel

The qualification requirements for the onsite plant staff personnel are described in the Quality Assurance Topical Report, NO-AA-10.

13.1.3.1 Deleted

13.1.3.2 Deleted

13.1.4 Special Projects

Executive Management for each Special Project is accountable to the President and Chief Nuclear Officer. Special Projects are responsible for the investigation and performance of ventures outside of the NG. Special Projects does not directly support the operation/maintenance of NG facilities.

Table 13.1-1 - Deleted

Table 13.1-2

SHIFT CREW COMPOSITION - MINIMUM REQUIREMENTS[1,2,3,4]

		ONE UNIT FUELED		TWO UNITS FUELED		
POSITION	LICENSE REQUIRED	Operating	Cold Shutdown	Two Units Operating	One-Unit Operating and One-Unit Shutdown	Two Units Cold Shutdown
Shift Manager	SRO	1	1	1 per 2 units	1 per 2 units	1 per 2 units
Shift supervisor	SRO	2	2	2 per 2 units	2 per 2 units	2 per 2 units
Plant Reactor operator	RO	1	The Plant Reactor operator position or the assistant position will be manned.	1 per 2 units	1 per 2 units	-
Reactor operator	RO	1	-	1 per unit	1 per unit	1 per unit
Equipment operator	-	2	The equipment operator position will be manned	3 per 2 units	3 per 2 units	3 per 2 units

.

(1) At least one licensed RO shall be present in the control room and assigned to each reactor that contains fuel.

(2) At least 2 licensed ROs, excluding the operator of the second unit, shall be present in the control room during reactor startup, scheduled reactor shutdown, and recovery from reactor trips.

(3) All core alterations shall be directly supervised by either a licensed SRO or SRO Limited to Fuel Handling, who has no other concurrent responsibility during this operation.

(4) A health physics technician shall be onsite at all times when fuel is in a reactor to ensure implementation of the radiation protection program.

13.2 TRAINING

13.2.1 PLANT PERSONNEL TRAINING PROGRAM

The Limerick Generating Station (LGS) training program incorporates the requirements specified in 10CFR55, 10CFR50 as promulgated in the NRC Final Rule 10CFR50.120 - "Training and Qualification of Nuclear Power Plant Personnel," which became effective May 26, 1993 and the applicable provisions of the Operating Licenses, including the Technical Specifications. The LGS training program is based on a Systems Approach to Training (SAT). The training program provides qualified personnel to operate and maintain the facility in a safe manner in all modes of operation. The training program will be periodically reviewed by management for effectiveness, and will be periodically evaluated and revised, as appropriate, to reflect industry experience as well as changes to the facility, procedures, regulations, and quality assurance requirements. Achievement of this goal is based on a philosophy of providing training developed from a systematic analysis of job requirements using job and task analysis where available. This philosophy is consistent with both Nuclear Regulatory Commission (NRC) requirements and Institute of Nuclear Power Operations (INPO) recommendations necessary for accreditation of training programs.

13.2.1.1 INPO Accredited Training Programs

The following training programs have been accredited by INPO and are continually maintained based on Systems Approach to Training (SAT).

	Program	Date Originally Accredited
1.	Non-Licensed Operator	10/30/86
2.	Reactor Operator	10/30/86
3.	Senior Reactor Operator	10/30/86
4.	Shift Manager (formerly Shift Supervisor)	10/30/86
5.	Shift Technical Advisor	10/30/86
6.	Engineering Support Personnel	10/30/86
7.	Licensed Operator Requalification	10/30/86
8.	Maintenance Technician - Mechanical and Supervisor	10/30/86
9.	Maintenance Technician - Electrical and Supervisor	10/30/86
10.	Instrument and Control Technician and Supervisor	10/30/86
11.	Chemistry Technician	10/30/86
12.	Health Physics Technician	10/30/86

Program/Course plans describing the content and details of these programs are maintained by the Nuclear Training Section.

13.2.1.2 Access Training

Persons employed at LGS, including temporary maintenance and service personnel, are required to successfully complete General Employee Training (GET) and Fitness for Duty Training (FFD) prior to being granted unescorted site protected area access. The frequency of retraining for GET and continuing training programs are determined by following the SAT-based training process. Retraining for FFD is required on a nominal annual basis. Training content is commensurate with job responsibilities, and complies with the requirements of:

10CFR19.12	(GET),
10CFR26	(FFD),

and the guidance specified in:

ANSI/ANS 3.1-2014	(GET),
Regulatory Guide 8.13	(GET),
Regulatory Guide 8.29	(GET).

General Respiratory Training (GRT) is required for personnel who may wear respiratory protective equipment as part of normal work requirements or as emergency response team members. Re-training in GRT is required on a nominal annual basis. The content and conduct of GRT complies with the recommendations specified in NUREG-0041, "Manual of Respiratory Protection Against Airborne Radio-Materials," and Regulatory Guide 1.78, Position C-13, and the criteria of ANSI Z88.2.

Program/Course Plans for GET, GRT, and FFD are maintained by the Nuclear Training Section. These plans provide a detailed description of the Program/Course, in accordance with the provisions of Regulatory Guide 1.70.

13.2.1.3 Emergency Preparedness Training

See the Emergency Plan (Ref: UFSAR 13.3)

13.2.1.4 Radwaste Shipping Training

Training of personnel involved in Radwaste packing, shipping, handling, or minimization receive training appropriate to the level of the task they perform. This training complies with the guidance in NRC I.E. Bulletin 79-19. A Program/Course Plan for Radwaste Shipping Training is maintained by the Nuclear Training Section. These plans provide a detailed description of the Program/Course, in accordance with the provisions of Regulatory Guide 1.70.

13.2.1.5 Fire Protection Training

The objective of fire protection training is to ensure that the shift and plant staff Fire and Damage Teams are prepared and capable of responding to fire emergencies. Leaders and members of the Fire Brigade receive initial training at the West Conshohocken Fire School. Site specific fire training is administered on a 2 year cycle. Each fire brigade member participates in at least two drills per year. Also see Section 9.5.1.5.

The fire brigade training program will consist of an initial classroom instruction program followed by periodic classroom instruction, fire fighting practice, and fire drills as follows:

a. Instruction

1. The initial classroom instruction will include:

(a) Indoctrination of the plant fire fighting plan with specific identification of each individual's responsibilities.

(b) Identification of the type and location of fire hazards and associated types of fires that could occur in the plant.

(c) Toxic and corrosive characteristics of expected products of combustion.

(d) Identification of the location of fire fighting equipment for each fire area and familiarization with the layout of the plant, including access and egress routes to each area.

(e) Proper use of available fire fighting equipment and the correct method of fighting each type of fire. The types of fires covered should include fires in energized electrical equipment, fires in cables and cable trays, hydrogen fires, fires involving flammable and combustible liquids or hazardous process chemicals, fires resulting from construction or modifications (welding), and record file fires.

(f) Proper use of communication, lighting, ventilation, and emergency breathing equipment.

(g) Proper method for fighting fires inside buildings and confined spaces.

(h) Direction and coordination of the fire fighting activities (fire brigade leaders only).

(i) Detailed review of fire fighting strategies and procedures.

(j) Review of the latest plant modifications that affect the fire fighting equipment or the fire fighting plans.

Items (i) and (j) may be deleted from training of no more than two of the non-operations personnel who may be assigned to the fire brigade

2. Instruction will be provided by qualified individuals who are knowledgeable, experienced, and suitably trained in fighting the types of fires that could occur in the plant and in using the types of equipment available in the plant.

3. Instruction will be provided to all fire brigade members and fire brigade leaders.

4. Regular planned meetings will be held at least every 3 months for all brigade members to review changes in the fire protection program and other subjects as necessary.

5. Periodic refresher training sessions will be held to repeat the classroom instruction program for all brigade members over a 2 year period. These sessions may be concurrent with the regular planned meetings.

b. Practice

Practice sessions will be held on the proper method of fighting the various types of fires that could occur in a nuclear power plant. These sessions will provide brigade members with experience in actual fire extinguishment and the use of emergency breathing apparatus under strenuous conditions encountered in fire fighting. These practice sessions will be provided at least once per year for each fire brigade member.

c. Drills

1. Fire brigade drills will be performed in the plant so that the fire brigade can practice as a team. In addition to in-plant drills, an offsite facility enables drills to include the use of the live fire conditions. These elements plus the use of breathing apparatus and full protective clothing create actual conditions that would be encountered during a real plant fire emergency. Additional drills, including backshift unannounced drills are conducted in plant areas throughout the year.

2. Drills will be performed at regular intervals not to exceed 3 months. Each fire brigade member should participate in each drill, but must participate in at least two drills per year.

   A sufficient number of these drills, but not less than one for each shift fire brigade per year, will be unannounced to determine the fire fighting readiness of the plant fire brigade, brigade leader, and fire protection systems and equipment. Persons planning and authorizing an unannounced drill will ensure that the responding shift fire brigade members are not aware that a drill is being planned until it is begun. Unannounced drills will not be scheduled closer than 4 weeks.

   At least one drill per year will be performed on a "back shift" for each shift fire brigade.

3. The drills will be preplanned to establish the training objectives of the drill and will be critiqued to determine how well the training objectives have been met.

   Unannounced drills will be planned and critiqued by members of the management staff responsible for plant safety and fire protection. Performance deficiencies of a fire brigade or of individual fire brigade members will be remedied by scheduling additional training for the brigade

or members. Unsatisfactory drill performance will be followed by a repeat drill within 30 days.

4. At 3 year intervals, a randomly selected unannounced drill will be critiqued by qualified individuals independent of the plant staff. A copy of the written report from such individuals will be available for NRC review.

5. Drills will, as a minimum, include the following:

   (a) Assessment of fire alarm effectiveness, time required to notify and assemble the fire brigade, and selection, placement, and use of equipment and fire fighting strategies.

   (b) Assessment of each brigade member's knowledge of their role in the fire fighting strategy for the area assumed to contain the fire. Assessment of the brigade member's conformance with established plant fire fighting procedures and use of fire fighting equipment, including self-contained emergency breathing apparatus, communication equipment, and ventilation equipment, to the extent practicable.

   (c) Simulated use of fire fighting equipment required to cope with the situation and type of fire selected for the drill. The area and type of fire chosen for the drill should differ from those used in the previous drill so that brigade members are trained in fighting fires in various plant areas. The situation selected should simulate the size and arrangement of a fire that could reasonably occur in the area selected, allowing for fire development due to the time required to respond, to obtain equipment, and organize for the fire, assuming the loss of automatic suppression capability.

   (d) Assessment of the brigade leader's direction of the fire fighting effort as to thoroughness, accuracy, and effectiveness.

d. Records

Individual records of training provided to each fire brigade member, including drill critiques, will be maintained for at least 3 years to ensure that each member receives training in all parts of the training program. These records of training will be available for NRC review. Retraining or broadened training for fire fighting within buildings will be scheduled for all those brigade members whose performance records show deficiencies.

13.2.1.6 Fire Protection Requalification Training

Leaders and members of the Fire Brigade receive annual refresher training at the West Conshohocken Fire School. Site specific fire training is administered on a 2 year cycle. Each fire brigade member participates in at least two drills per year.

All diesel operations and operational maintenance activities at LGS are performed by operations personnel as described in Section 13.1.2. The licensee includes diesel generator training in the

INPO accredited programs for operations personnel and supervision, tailored to the specific job classifications, based upon task analyses. This training, originally drawn from manufacturer's recommendations, is equivalent to vendor training. Operations personnel perform diesel generator activities in accordance with approved operating and test procedures.

Activities beyond the responsibilities assigned to operating personnel are referred to plant technical personnel and/or maintenance personnel. Maintenance personnel may be members of the onsite or offsite organization. The licensee provides a variety of INPO accredited maintenance training classes to ensure the availability of qualified maintenance technicians and supervisors. Maintenance activities are performed under supervision appropriately qualified and experienced on the type of diesel generators at Limerick. Maintenance supervision is responsible for the assignment of personnel properly qualified for the task. Qualified personnel, qualified and experienced Maintenance supervision, use of approved procedures, and technical expertise of manufacturer's service representatives provides competency equivalent to vendor training so that diesel generator reliability is maintained.

13.2.2 Records

The plant training organization is responsible for maintaining training records for the plant staff. Records for the plant staff shall be sufficient to show qualification for the position held. As applicable for the training course, records include copies of written examinations and answers, lecture attendance records, results of evaluations, and records of additional remedial training. All quality records indicating pertinent, formalized training of the plant staff shall be entered into the Nuclear Records Management System for proper maintenance and recall, by the plant nuclear training section.

13.2.3 Training Organization

13.2.3.1 See Figure 13.2-1

Table 13.2-1

Matrix of LGS Training Program Guidelines

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(See Section 13.2.1)

13.3 EMERGENCY PLANNING

The Exelon Standardized Radiological Emergency Plan (EP-AA-1000) for the LGS has been submitted as a separate document.

13.4 REVIEW AND AUDIT

13.4.1 GENERAL

The licensee shall establish and implement review and audit functions to ensure that activities important to safety are properly accomplished in accordance with company policies and rules, approved operating procedures, and operating license provisions during the operations phase. As fully described below, these functions are as provided in ANSI N18.7 (1976)/ANS 3.2, paragraphs 4.1 through 4.5, as modified by Regulatory Guide 1.33 (Rev 2), positions C.3, C.4, and C.5.a, and ensure implementation of 10CFR50.59 with regard to proposed changes, tests, and experiments. The review and audit functions will be implemented in accordance with the provisions of the Quality Assurance Topical Report (QATR) and are described in the QATR.

13.4.2 ONSITE REVIEW

The Plant Operations Review Committee (PORC) satisfies a portion of the independent review program requirement described in ANSI N187 (1976) / ANS 3.2, Section 4.3, "Independent Review Program". A comprehensive description of the PORC function is located in Exelon Procedure LS-AA-106, "Plant Operations Review Committee". Exelon process description NO-AA-10, "Standard Quality Assurance Topical Report (QATR)," also includes a description of PORC functions. PORC performs independent reviews of activities that have the potential to affect nuclear safety and advises the plant manager regarding approval or disapproval of these activities.

13.4.3 INDEPENDENT REVIEW

The information from this section has been relocated to the Quality Assurance Topical Report (QATR).

13.4.4 ASSESSMENT PROGRAM

The information from this section has been relocated to the Quality Assurance Topical Report (QATR).

The QATR describes how the Quality Assurance Program is to be functionally implemented with due regard to the safety and health of the public and the personnel on site. The LGS Quality Assurance Program as described by the QATR is incorporated herein by reference.

13.4.5 INDEPENDENT TECHNICAL REVIEW FUNCTION

The information from this section has been relocated to the Quality Assurance Topical Report (QATR).

13.5 PLANT PROCEDURES

Safety-related activities performed by the plant staff shall be governed by written and approved procedures of a type appropriate to the circumstances and activity, and shall be carried out in accordance with those procedures. Where appropriate for determining that important activities have been satisfactorily accomplished, quantitative or qualitative acceptance criteria shall be included. The licensee utilizes the operating experience gained at PBAPS Units 2 & 3 (BWR units similar to LGS) in the development of the procedures.

As fully described below, the licensee has implemented ANSI N18.7 (1976)/ ANS 3.2, Section 5 as modified by NRC Regulatory Guide 1.33 (Rev 2), paragraphs C.1 and C.5.b through C.5.j, as these documents apply to operating staff activities, in the preparation, content, and control of procedures. Programmatic controls are in place to assure that procedures are maintained current. These controls take the place of, and eliminate the need for, scheduled periodic reviews and revisions.

Sections 13.5.1.1 through 13.5.1.27 describe administrative procedures. Many of these sections describe how various procedure types (such as maintenance procedures or preventive maintenance procedures) are developed and controlled, whereas other sections describe an administrative process (such as purchasing).

It is planned that most administrative and operating procedures will be in effect at least six months prior to fuel loading of Unit 1. The procedures will be implemented with sufficient lead time to ensure that operating personnel can become familiar with them. The licensee recognizes the benefits of using the preoperational testing phase to demonstrate the adequacy of operating procedures and, where practicable, this will be accomplished.

The following paragraphs describe the types of procedures to be employed by station operating personnel in the conduct of safety-related activities. These procedures are normally prepared by the station operating staff. However, organizations providing technical support and consultants may assist in procedure development. The procedures and revisions thereto are reviewed by Station Qualified Reviewers (SQRs) who are approved and designated as such by the PORC Chairman to perform such reviews for specific classes of procedures. The SQRs determine in writing if a cross-disciplinary review is required by the appropriate personnel prior to approval. Procedures or revisions thereto are approved by responsible Superintendents who are designated as such for specific classes of procedures by administrative procedures. PORC reviews administrative procedures and those procedures or revisions thereto requiring a 10 CFR 50.59 evaluation be performed. The Plant Manager or his designated alternate approves administrative procedures, emergency plan implementing procedures, security plan implementing procedures, and any procedure or revision thereto requiring a 10 CFR 50.59 evaluation be performed.

13.5.1 ADMINISTRATIVE PROCEDURES

Administrative procedures generally include those that establish station management policy, those that control activities that involve interfaces among disciplines or groups supporting plant operations, and those that establish criteria for procedures and activities implemented by the plant staff and support organizations. Administrative procedures shall be prepared in sufficient detail so that tasks are performed in a consistent, efficient manner and to ensure that the necessary reviews and approvals are performed.

The following paragraphs describe the administrative procedures expected to be employed. The numbers of procedures and their specific content may be altered as the procedures are developed and experience is gained in their implementation.

13.5.1.1 Procedure for Preparation and Control of Administrative Procedures

This procedure shall provide the measures to control and coordinate the preparation, review, approval, and issuance of administrative procedures. This procedure shall require that administrative procedures be distributed to appropriate personnel in accordance with current distribution lists to ensure that outdated or inappropriate procedures are not used. The format and content of administrative procedures shall be defined as:

a. Descriptive title and revision number.

b. Statement of applicability or purpose.

c. References, including technical specifications or procedures as applicable.

d. Prerequisites when there are independent actions or procedures that must be completed prior to using the procedure.

e. Procedure section. The procedure shall provide the steps needed to perform the task in the degree of detail necessary to ensure correct, efficient performance without direct supervision or undue reliance on memory. This section may also provide criteria statements to be implemented by other procedures.

Administrative procedures are written to provide direction for the efficient administration of plant business and reflect the station management philosophy and to implement corporate policies regarding these functions.

13.5.1.2 Procedure for Plant Operations Review Committee

This procedure shall define the requirements of membership, meeting frequency, quorum, responsibilities, authority, and records for the PORC in implementation of technical specification provisions. The PORC shall review significant conditions adverse to plant safety to ensure that the cause of the condition is identified, that corrective action is taken and documented, and that appropriate subjects are referred to the Nuclear Review Board.

13.5.1.3 Procedure for Plant and Shift Operations

This procedure shall define the responsibilities and authority of plant operating personnel, including:

a. Prohibition against manipulation of the reactor controls by personnel who are not licensed reactor operators or senior reactor operators. Trainees may manipulate controls under the direct supervision of a licensed operator.

b. Requirement that apparatus and mechanisms that may affect the reactivity or power level of the reactor only be manipulated with the knowledge and consent of the licensed reactor operator or senior reactor operator present at the controls.

c. Requirement for a licensed reactor operator or senior reactor operator to be present at the controls at all times when fuel is in the reactor.

d. Reactor operator's responsibility and authority for shutting down the reactor when he determines that the safety of the reactor is in jeopardy, when operating parameters exceed reactor protection setpoints and automatic shutdown does not occur, or when there is doubt as to whether safe conditions exist.

e. Responsibility to determine the circumstances, analyze the cause, and determine that operations can proceed safely before the reactor is returned to power after a trip or unscheduled or unexplained power change.

f. Senior reactor operator's responsibility for directing the licensed activities of the reactor operator and to be present at the plant and to provide direction for returning the reactor to power following a trip or an unscheduled or unexplained power change.

g. Responsibility to respond conservatively to instrument indications including the case in which the credibility of the indication is in doubt.

h. Responsibility to adhere to the technical specifications and the provisions of the operating license.

i. Responsibility to review routine operating information to ensure safe operation.

j. Functional relationship of the STA to the operating shift.

This procedure shall also provide instructions to plant staff and operating personnel in areas of general and continuing applicability to plant management such as:

a. The necessity to adhere to plant procedures and to refer directly to procedures for complex or extensive jobs where reliance on memory cannot be trusted, such as reactor startup, tasks that are infrequently performed, and complex tasks that must be performed in a specific order.

b. The responsibility of plant personnel to take action, in the event of an emergency not covered by approved procedures, so as to minimize personnel injury and damage to the facility, and to protect public health and safety.

c. Personnel conduct.

d. Availability on call of plant staff and operating personnel.

e. Preparation of plant logs and records.

f. Requirements for shift turnover.

g. Definition of "at the controls" (Figure 13.5-1).

h. Recording data or completing documentation as tasks are performed when such data or documentation of tasks is required.

i. Definition of SRO control room boundaries (Figure 13.5-2).

13.5.1.4 Procedure for Release of Safety-Related Equipment

This procedure shall implement the licensee's standard requirements for blocking and tagging equipment and shall establish criteria for this function such as:

a. Designation of personnel authorized to release equipment or systems for maintenance and the method of documenting such authorization.

b. Aspects to be considered in releasing equipment such as: how long equipment may be out of service; potential for degradation of protection when one subsystem of a redundant safety system has been removed from service; equipment and personnel safety.

c. Aspects to be considered in returning equipment to service such as removal of jumpers and test signals and return of valves, breakers, or switches to proper positions.

This procedure shall provide for identification of released equipment and for controls, such as blocking/locking or tagging, to maintain personnel and reactor safety and to avoid unauthorized operation of the equipment. The procedure shall provide for independent verification, where appropriate, to ensure that the blocking and tagging methods have been implemented correctly. The functional acceptability of equipment shall be verified and documented as equipment is returned to service.

Operating personnel will ensure that when any part of a redundant safety system is removed from service, the portion remaining in service is operable and in surveillance as required in the Technical Specifications. An administrative procedure, which governs when equipment is returned to service, requires Shift Management to review all Work Orders and testing pertaining to the safety system being returned to service. Shift Management will ascertain if additional testing is required and consider the consequences of returning equipment to service.

13.5.1.5 Procedure for Temporary Modifications

This procedure shall provide controls for temporary modifications such as electrical jumpers, lifted electrical leads, and bypass lines. The requirements shall include independent verification of the intent/need for the installation, consideration of the need to revise applicable procedures, and a logging system to indicate current status of the temporary modification.

13.5.1.6 Procedure for Control of Plant Modifications

This procedure shall provide the controls for administration, design and design review, and preplanning of plant modifications so that modifications are performed in a manner to ensure quality as specified in the original or approved modification design. The procedure shall provide for consideration and specification of appropriate inspections and tests to develop a suitable level of confidence that the modification has been properly installed. Activities that ensure the quality of the modification shall be performed in accordance with documented drawings or instructions appropriate to the circumstances, that conform to the specified design requirements, and that provide for documentation of activities where appropriate. Skills normally possessed by trained

craft personnel may not require detailed step-by-step delineations in a written procedure. As part of the modification process, consideration shall be given to the need for revising applicable procedures.

The procedure for control of plant modifications shall require that the status of inspections and tests performed on items be indicated by use of stamps, tags, labels, routing cards, procedural sign-offs, or other suitable means that provide traceability between the record and the item(s). Also, where necessary to preclude inadvertent bypassing of inspections and tests, the procedure shall require that the item(s) that have satisfactorily passed required inspections and tests be identified. This procedure shall require that the following aspects of housekeeping and cleanliness control be considered in the development of instructions for the modification:

a. Housekeeping provisions shall recognize the special requirements involved with radiation zones and control areas.

b. Only proper materials, equipment, processes, and procedures may be used to ensure that the quality of plant equipment is not degraded.

c. Where necessary, special instructions for housekeeping and cleaning operations shall be provided and used.

d. Where needed to prevent contamination of safety systems with foreign materials, personnel and/or materials access control shall be established and a cleanliness inspection shall be performed immediately prior to closure. The inspection results shall be documented.

The procedure for control of plant modification shall require that appropriate inspections be established and implemented for modifications in accordance with the following criteria:

a. Inspections, examinations, measurements, or tests shall be specified and performed for each work activity where necessary to ensure quality.

b. Inspections shall be performed by qualified individuals other than those who performed or directly supervised the activity being inspected. Inspection of certain activities (such as work functions associated with normal plant operations, routine maintenance, and certain technical services routinely assigned to the onsite operating organization) may be conducted by shift or plant staff supervisory personnel or by other qualified personnel not assigned first-line supervisory responsibility for conduct of the work.

c. Modification work similar to construction phase work shall be subject to inspections similar to those performed in the construction phase.

d. Inspections shall be performed in accordance with approved written instructions or procedures that contain or reference the requirements, acceptance limits, and responsibilities for the inspection.

e. When specific hold points are required, they shall be indicated in appropriate documents.

f. When inspection techniques require specialized qualifications, inspection personnel shall meet the specified requirements for the technique involved.

g. If inspection is impossible or disadvantageous, indirect control by monitoring process methods, equipment, and personnel shall be provided. Both inspection and process monitoring shall be provided when control is inadequate without both.

h. Inspection instructions or procedures shall include or reference requirements for evaluation of inspection results when the nature of the results indicates that such an evaluation is needed to determine if the plant can be operated safely. Evaluation beyond that given by inspection-level personnel shall not normally be required for go/no-go and pass/fail type inspections.

i. Inspectors, data recorders, and those evaluating inspection results shall be identified and the records shall reflect implementation of the inspections and actions completed or planned to correct noted deficiencies.

The procedure for control of plant modifications shall require that special processes be identified and accomplished under controlled conditions in accordance with applicable codes, standards, specifications, criteria, or other special requirements. The procedure shall require that special processes be accomplished by qualified personnel using qualified procedures and equipment as provided in the specified requirements for the activity.

The procedure for control of plant modifications shall require that modifications be tested to demonstrate that they will perform satisfactorily in service and that such testing be performed in accordance with written test procedures or instructions that incorporate or reference the requirements and acceptance limits contained in the applicable design documents. Such testing shall confirm that modifications and associated procedure changes, if any, produce expected results.

13.5.1.7 Procedure for Control of In-plant Work

This procedure shall provide the controls needed to coordinate, approve, and implement in-plant work. The controls provided shall include:

a. Planning and coordination of maintenance and modification work so as not to compromise plant safety, including the consequences of concurrent or sequential maintenance and modification activities, the need to provide operable equipment to support the operating mode of the plant, and the need to remain within license limits. Such planning shall also include evaluation of use of special processes, equipment, and materials in regard to potential hazards to personnel and equipment.

b. A method to ensure that conditions adverse to plant safety (such as failures, malfunctions, deficiencies, deviations, defective plant equipment, abnormal occurrences and nonconformances related to plant equipment) shall be identified and corrected through corrective maintenance.

c. A method to maintain or coordinate maintenance of the identification and traceability of materials, parts, and components as it is established in the storeroom to provide insurance that only correct and accepted items are used and installed.

d. Obtaining the necessary permits, such as blocking and tagging of equipment and radiation work permits that specify radiation protection measures, monitoring, and protective clothing.

e. Review of repetitive malfunctions to determine the cause and corrective measures. This activity can include referral to Engineering for evaluation, determination of repair or replacement parts, and associated design, testing, and installation requirements.

13.5.1.8 Procedure for Administration of the Preventive Maintenance Program

This procedure shall establish the administrative requirements for the preventive maintenance program so that preventive maintenance is preplanned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Preventive maintenance shall include those routine actions needed to ensure that plant equipment (including special tools) continues to operate properly by detection or prevention of actual or impending failures or substandard performance. The aspects of preventive maintenance that shall be addressed in this procedure include:

a. Establishment of the frequency and schedule for preventive maintenance actions.

b. Records of completion of preventive maintenance actions.

c. Preparation, approval, and control of written procedures, documented instructions, or drawings that are appropriate to the circumstances for the performance of preventive maintenance actions. The written procedures, documented instructions or drawings shall conform to the design requirements, and provide for documentation of activities where appropriate. Skills normally possessed by trained craft personnel may not require detailed step-by-step delineations in a written procedure. Preventive maintenance procedures shall be distributed to appropriate personnel in accordance with current distribution lists to ensure that outdated or inappropriate procedures are not used.

This procedure shall establish the format and content of preventive maintenance procedures as follows:

a. Descriptive title and revision number.

b. Statement of applicability or purpose.

c. References, including technical specifications, vendor documents, and drawings as appropriate to ensure the required quality of the work.

d. Prerequisites, including those independent actions or procedures that must exist prior to use of the preventive maintenance procedure. Prerequisites applicable only to certain sections of the procedure shall be so identified.

e. Precautions to alert the individual performing the task to those important measures that should be used to protect equipment and personnel, including the public, or to avoid an abnormal or emergency situation. Routine precautions that a trained craftsman is expected to take, such as normal electrical safety methods, shall not be required to be stated.

f. Procedure section. The procedure shall provide the steps needed to perform the task in the degree of detail necessary to ensure safety and correct performance without undue reliance on memory or direct supervision and in consideration of the skills normally possessed by trained craft personnel. Precautions and reference documents important to specific steps in the procedure shall be identified or included at those steps. This section shall also provide instructions for performing and documenting the results of required inspections and tests and provides the necessary acceptance criteria. When appropriate, checkoff lists shall be included in or appended to preventive maintenance procedures.

g. Return-to-normal. This section shall contain instructions as to the mode or condition in which the equipment is to be placed after completion of the preventive maintenance action.

Maintenance and preventive maintenance procedures are proven to be correct through their use. Because they are written for specific equipment, they are not subject to intersystem changes that may affect other procedure types, such as general plant procedures.

Maintenance and preventive maintenance procedures are reviewed when equipment modifications are made through the controlled modification program at the station. In addition, when indicated by the review of NRC Bulletins, Circulars and Notices, INPO documents and industry documents, the procedures are revised if necessary on a case-by-case basis.

To ensure feedback, preventive maintenance procedures are reviewed in accordance with performance enhancement procedures following unusual incidents that reflect adversely on the adequacy of these procedures.

13.5.1.9 Procedure for Administration of the Surveillance Testing Program

This procedure shall establish the administrative requirements and responsibilities for the surveillance testing program so that such testing is preplanned and performed in accordance with written procedures and drawings appropriate to the circumstances, and in accordance with the technical specification requirements. Included in this program shall be the safety-related instruments and control devices and special equipment as defined in the technical specifications. The aspects of surveillance testing that shall be addressed in this procedure include:

a. Establishment of calibration intervals and methods for installed safety-related instruments and control devices as defined in the technical specifications.

b. Requirements for the calibration of measuring and test equipment at specified intervals or prior to use to ensure the necessary accuracy of equipment and requirements for use of measuring and test equipment of the proper type and range.

c. Requirements for performing a documented evaluation of the validity and acceptability of previous calibration activities when measuring and test equipment are found to be out of calibration. The evaluation shall cover the applicable surveillance tests from the time of the previous calibration.

d. Requirements for performing special calibrations of installed safety-related instruments and control devices when the accuracy of the equipment is questionable.

e. Requirements for recording calibration activities and suitably marking equipment to indicate calibration status.

f. Establishment of a master surveillance test schedule reflecting the status of all planned surveillance tests.

g. Responsibilities for timely performance of surveillance tests, evaluation of results, reporting completion, and maintenance of appropriate records.

h. Planning for performance of required tests so as not to compromise plant safety including the possible consequences of concurrent or sequential testing, the need to provide operable equipment to support the operating mode of the plant, and the need to remain within license limits.

i. Preparation, approval, and control of written procedures for the performance of individual surveillance tests. Surveillance test procedures shall be distributed to appropriate personnel in accordance with current distribution lists to ensure that outdated or inappropriate procedures are not used.

This procedure shall establish the format and content of surveillance test procedures as follows:

a. Descriptive title and revision number.

b. Statement of applicability and objectives(s) of the test.

c. References, including technical specifications, drawings, and vendor documents as appropriate to ensure the required quality of the work.

d. Prerequisites including those independent actions or procedures that must be completed and plant conditions that must exist prior to use of the surveillance test procedure, and including any special conditions to be used to simulate normal or abnormal operating conditions. Prerequisites applicable to only certain sections of the procedure shall be so identified. Special equipment or calibrations required to conduct the test shall be listed.

e. Precautions to alert the individual performing the task to those important measures that should be used to protect equipment and personnel, including the public; or to avoid an abnormal or emergency situation. Applicable limiting conditions shall be included.

   Routine precautions that trained craftsmen or test personnel are expected to take, such as normal electrical safety methods, need not be stated.

f. Procedure section. The procedure shall provide the steps needed to perform the test in the degree of detail necessary to ensure safety and correct performance without direct supervision and in consideration of the skills normally possessed by trained craft and testing personnel. Precautions and reference documents

important to specific steps in the procedure shall be identified or included at those steps. Where test steps are to be witnessed, the test sequence shall identify the hold points and shall require appropriate approval for the test to continue beyond the designated hold point. The procedure requires recording of test results, including data such as as-found and as-left information where appropriate. Acceptance criteria for the tests shall be specified. When appropriate, checkoff lists shall be included in or appended to the surveillance test procedures.

g. Return-to-normal. This section shall contain instructions as to the mode or condition in which the equipment is to be placed after completion of the surveillance test.

This procedure shall require recording the test date, corrective actions taken (if any), identification of those performing the test, and identification of those evaluating the test results to ensure that requirements have been met.

Surveillance tests and routine tests are performed on a periodic basis; this step-by-step use of the procedure demonstrates the adequacy of the procedures. In addition, when changes in the plant Technical Specifications are received, the appropriate procedures are identified and revised. Plant modifications, NRC Bulletins, and Information Notices also initiate procedure review and revision, if needed.

To ensure feedback, surveillance test procedures are reviewed in accordance with performance enhancement procedures following unusual incidents that reflect adversely on the adequacy of these procedures.

The surveillance test program shall include procedures for monitoring performance of plant systems to ensure that engineered safety features and emergency equipment are in the required state of readiness and that operating systems are performing properly.

The limits for significant parameters shall be identified as well as the nature and frequency of monitoring.

13.5.1.10 Procedure for Administration of Plant Records

This procedure shall establish the provisions and responsibilities for retention of plant records. Preparation of records is discussed in procedures that cover the specific activities. The responsibility for maintaining and storing records at specified location(s) shall be assigned. This procedure shall ensure that retention times are established so that applicable statutory requirements are satisfied. The significance of the event covered by the record-type and the contribution of the record to the ability to reconstruct significant events shall also be considered in establishing retention periods.

13.5.1.11 Procedure for Procurement

This procedure shall establish the controls for activities performed by the plant operating staff in regard to procurement of safety-related equipment. This procedure shall require that procurement of safety-related equipment (including spares and replacements) be purchased to specifications and codes equivalent to those specified for original equipment or to approved alternate requirements that have been evaluated to ensure that interfaces, interchangeability, safety, fit, and function are not adversely affected or contrary to applicable regulatory or code requirements. The

results of this evaluation shall be documented. The procedure shall define the requirements for preparation, review, and approval of procurement requirements and changes thereto to ensure that applicable regulatory requirements, design bases, and other requirements necessary to ensure adequate quality are included or referenced.

The procedure for procurement shall define the content of procurement documents as follows:

a. To the extent necessary, the procurement document shall require suppliers of Q-listed items to provide a quality assurance program consistent with original requirements, ANSI/ASME NQA-1-1994, 10CFR50, Appendix B, or approved alternate requirements as described above. When applicable, suppliers shall be required to extend applicable requirements of the procurement documents to their suppliers and subcontractors.

b. Basic technical requirements. Required drawings, specifications, and industrial codes and standards shall be identified by titles and dates of issue in such a way as to clearly set forth the applicable documents for fabrication. Where procedural requirements apply, they shall be identified clearly and in such a way as to avoid uncertainty as to source and need. Packaging and transportation shall be required to be accomplished in a manner that will ensure that quality is not degraded and that applicable regulatory requirements are met.

c. Source inspection and audit. Provisions for access to suppliers' facilities and records for source inspection and audit shall be specified when the need for such inspection or audit is determined.

d. Documentation requirements. Necessary records to show compliance with specifications, codes, standards, and fabrication requirements shall be specified as to preparation, retention, and submittal. In addition, applicable vendor documents such as drawings, specifications, procedures, qualification records, material analyses, and inspection and test records shall be specified as to preparation, retention, and submittal.

The procedure for procurement shall contain the provisions and responsibility for receipt inspection to determine the acceptability of purchased items in regard to the procurement documents and/or receipt inspection instructions. The procedure shall provide that, where required by contract requirements, codes, or regulations, documentary evidence that items conform to procurement requirements shall be available at the plant site prior to installation or use of such items, shall be retrievable, and shall be sufficient to identify the specific requirements such as codes, standards, or specifications met by the purchased item. The documentary evidence may be records as specified in the procurement documents, or results of tests and inspections such as material analyses, source inspection, performance data, in-depth sampling, and receipt.

This procedure provides that items not passing receipt inspection (including incomplete or incorrect documentation) shall not be considered acceptable. Affected items shall be considered inoperable and reliance shall not be placed on such items to fulfill their intended safety functions until such discrepancies are dispositioned by proper authority. The controls specified for such nonconforming items shall include:

a. Identification of nonconforming items by tagging and, where practicable, segregation.

b. Control of further processing or installation until the disposition is determined and approved.

c. Disposition of the nonconforming item as "use-as-is," repair, rework to complete or correct the item to the specified requirements, or reject (scrap). The responsibility and authority for the disposition shall be defined. Repaired and reworked items shall be reinspected in accordance with applicable procedures or instructions.

d. Documentation of the satisfactory completion of the disposition. This includes documentation verifying the acceptability of nonconforming items that are dispositioned "use-as-is" or repair, and describing the deviation and as-built condition.

e. Notification to appropriate organizations to ensure that effected drawings or records reflect as-built conditions.

The procedure for procurement shall establish requirements for identification and control of received materials, parts, and components (including partially fabricated subassemblies) to ensure that only correct and acceptable items are used and installed. The procedure shall provide for:

a. Use of physical identification (such as marking or tagging) to the maximum extent practicable. Physical separation, procedural control, or other appropriate means shall be used when physical identification is not used or not sufficient. Identification can be on the item or on records traceable to the item.

b. Identification marking shall be clear and unambiguous, and shall employ methods and materials that will remain legible considering the handling, storage, and installation conditions expected. The marking must not affect the function of the item.

c. Markings shall be transferred to subdivided parts and shall not be obliterated or hidden by surface treatment or coatings unless other identification means are instituted.

d. When applicable codes, standards, or specifications require traceability of materials, parts, or components to specific inspection or test records, such traceability shall be provided.

e. Identification shall relate the item to applicable drawings, specifications, procurement documents, or other pertinent technical documents.

13.5.1.12 Procedure for Administration of the Plant Security Program

This procedure shall establish the administrative requirements and responsibilities for the plant security program that is developed to implement the industrial security plan and to supplement features and physical barriers designed to control access to the plant and, as appropriate, to vital areas within the plant. This procedure shall require that security procedures be distributed to appropriate personnel in accordance with current distribution lists, which reflect the confidentiality of security provisions, to ensure that outdated or inappropriate procedures are not used.

This procedure shall define the format and content of security procedures as follows:

a. Descriptive title and revision number.

b. Statement of applicability or purpose of the procedure.

c. Prerequisites, when needed, including those independent actions or procedures that must be completed prior to use of the security procedure.

d. References, when needed.

e. Precautions to alert the individual performing the task to those important measures that should be used to protect equipment and personnel, including the public, or to avoid abnormal or emergency conditions.

f. Procedure section. The procedure shall provide the steps needed to perform the task in the degree of detail necessary to ensure safety and correct performance without undue reliance on memory or direct supervision. Precautions and reference documents important to specific steps in the procedure shall be identified or included at those steps. Acceptance criteria, where appropriate, shall be specified. When appropriate, checkoff lists shall be included in or appended to the procedure.

To ensure feedback, security procedures are reviewed in accordance with performance enhancement procedures following unusual incidents that reflect adversely on the adequacy of these procedures.

13.5.1.13 Procedure for Preparation of Maintenance Procedures

This procedure shall establish the administrative requirements and responsibilities for the preparation and control of maintenance procedures that are developed to maintain safety-related equipment. Actual coordination and planning for maintenance actions shall be accomplished through the procedure for controlling in-plant work. The following aspects of maintenance work shall be addressed in this procedure:

a. The need to perform maintenance activities in a manner to ensure quality as specified in the original or approved modification design.

b. Specification and performance of appropriate inspections and tests to attain a suitable level of confidence that the maintenance has been properly performed.

c. Activities that ensure the quality of maintenance shall be performed in accordance with documented drawings or instructions that are appropriate to the circumstances, that conform to the design requirements, and which provide for documentation of activities where appropriate. Skills normally possessed by trained craft personnel may not require detailed step-by-step delineations in a written procedure.

d. The status of inspections and tests performed on items shall be indicated by the use of stamps, tags, labels, routing cards, procedural sign-offs, or other methods that provide traceability between the record and the item(s). Also, where necessary to preclude inadvertent bypassing of inspections and tests, items that have satisfactorily passed required inspections and tests shall be identified.

e. Special control requirements for emergency maintenance that must proceed immediately to correct a degraded safety condition and for which a procedure does not exist.

This procedure shall require that the following aspects of housekeeping and cleanliness control be considered in development of maintenance procedures:

a. Housekeeping provisions must recognize the special requirements involved with radiation zones and control areas.

b. Only proper materials, equipment, processes, and procedures may be used to ensure that the quality of plant equipment is not degraded.

c. Where necessary, special instructions for housekeeping and cleaning operations shall be provided and used.

d. Where needed to prevent contamination of safety systems with foreign materials, personnel and/or materials access control shall be established and a cleanliness inspection shall be performed immediately before closure. The Inspection results shall be documented.

This procedure shall require that appropriate inspections be established and implemented for maintenance actions in accordance with the following criteria:

a. Inspections, examinations, measurements, or tests shall be specified and performed for each work activity where necessary to ensure quality.

b. Inspections shall be performed by qualified individuals other than those who performed or directly supervised the activity being inspected. Inspection of certain activities (such as work functions associated with normal plant operations, routine maintenance, and certain technical services routinely assigned to the onsite operating organization) may be conducted by shift or plant staff supervisory personnel or by other qualified personnel not assigned first-line supervisory responsibility for conduct of the work.

c. Inspections shall be performed in accordance with written approved instructions, drawings or procedures that contain or reference the requirements, acceptance limits, and responsibilities for the inspection.

d. When specific hold points are required, they shall be indicated in appropriate documents.

e. When inspection techniques require specialized qualifications, inspection personnel shall meet the specified requirements for the technique involved.

f. If inspection is impossible or disadvantageous, indirect control by monitoring process methods, equipment, and personnel shall be provided. Both inspection and process monitoring shall be provided when control is inadequate without both.

g. Inspection instructions or procedures shall include or reference requirements for evaluation of inspection results when the nature of the results indicates that such an evaluation is needed to determine if the plant can be operated safely. Evaluation beyond that given by inspection-level personnel is not normally required for go/no-go and pass/fail type inspections.

h. Inspectors, data recorders, and those evaluating inspection results shall be identified and the records shall reflect implementation of the inspections and actions completed or planned to correct noted deficiencies.

This procedure shall require that special processes be identified and accomplished under controlled conditions in accordance with applicable codes, standards, specifications, criteria, or other special requirements. The procedure shall require that special processes be accomplished by qualified personnel using qualified procedures and equipment as provided in the specified requirements for the activity.

This procedure shall require testing to be performed as necessary to demonstrate that the item performs satisfactorily in service.

The testing shall be performed in accordance with written approved procedures or instructions that include or reference requirements and acceptance criteria defined in appropriate design documents.

This procedure shall define the format and content of maintenance procedures as follows:

a. Descriptive title and revision number.

b. Statement of applicability or purpose.

c. References, including technical specifications, vendor documents, and drawings as appropriate to ensure the required quality of the work.

d. Prerequisites, including those independent actions or procedures that must be completed and plant conditions that must exist prior to use of the maintenance procedure. Prerequisites applicable to only certain sections of the procedure shall be so identified.

e. Precautions to alert the individual performing the task to those important measures that should be used to protect equipment and personnel, including the public, or to avoid an abnormal or emergency situation. Routine precautions that a trained craftsman is expected to take, such as normal electrical safety methods, do not need to be stated.

f. Procedure section. The procedure shall provide the steps needed to perform the task in the degree of detail necessary to ensure safety and correct performance without undue reliance on memory or direct supervision, and in consideration of the skills normally possessed by trained craft personnel. Precautions and reference documents important to specific steps in the procedure shall be identified or included at those steps. This section shall also provide instructions for performing and documenting the results of required inspections and tests and provides the

necessary acceptance criteria. When appropriate, checkoff lists shall be included in or appended to maintenance procedures.

g. Return-to-normal. This section shall contain instructions as to the mode or condition in which the equipment is placed after completion of the maintenance action.

Maintenance procedures will normally be prepared by members of the Nuclear Maintenance Division staff, knowledgeable in the areas which the procedures address; however, members of the station operating staff and organizations providing technical support, including consultants, may assist in procedure development.

Maintenance and preventive maintenance procedures are proven to be correct through their use. Because they are written for specific equipment, they are not subject to intersystem changes that may affect other procedure types, such as general plant procedures.

Maintenance and preventive maintenance procedures are reviewed when equipment modifications are made through the controlled modification program at the station. In addition, when indicated by the review of NRC IE Bulletins, Circulars and Notices, INPO documents and industry documents, the procedures are revised if necessary on a case-by-case basis.

To ensure feedback, maintenance procedures are reviewed in accordance with performance enhancement procedures following unusual incidents that reflect adversely on the adequacy of these procedures. Procedures shall also require that maintenance procedures be distributed to appropriate personnel in accordance with current distribution lists to ensure that outdated or inappropriate procedures are not used.

13.5.1.14 Procedure for Preparation of Transient Response Implementation Plan Procedures and Severe Accident Management Plan Procedures

This procedure shall establish the administrative requirements and responsibilities for the preparation of Transient Response Implementation Plan and the Severe Accident Management Plan procedures.

Transient Response Implementation Plan procedures are symptom oriented decision tree flow charts for operator actions based on recognition of critical symptoms and definition of actions to maintain key plant parameters within predetermined ranges. The Transient Response Implementation Plan and the Severe Accident Management Plan procedures have been developed from the BWROG EPG/SAGs.

To ensure feedback, TRIP and SAMP procedures are reviewed in accordance with performance enhancement procedures following unusual incidents that reflect adversely on the adequacy of these procedures.

Transient Response Implementation Plan and the Severe Accident Management Plan procedures shall be distributed to appropriate personnel in accordance with current distribution lists to ensure that outdated or inappropriate procedures are not used.

13.5.1.15 Procedure for Preparation of Emergency Plan Procedures

This procedure shall establish the administrative requirements and responsibilities for the preparation of emergency plan procedures that implement the emergency plan. This procedure shall establish the format and content of the emergency plan procedures.

Emergency plan procedures shall be distributed to appropriate personnel in accordance with current distribution lists to ensure that outdated or inappropriate procedures are not used.

13.5.1.16 Procedure for Preparation of General Plant Procedures

This procedure shall establish the administrative requirements and responsibilities for the preparation of general plant procedures that are written to provide integrated instructions for major plant evolutions such as plant startup or shutdown. This procedure shall establish the criteria for general plant procedures, such as:

a. Preparation of startup procedures including reactor startup from cold and hot conditions, generator synchronization, and recovery from reactor trips. These procedures shall implement the authority and responsibilities of reactor operators as defined in other administrative procedures.

b. Preparation of shutdown procedures including controlled shutdown and reactor trips to the establishment and maintenance of hot or cold shutdown conditions.

c. Preparation of procedures covering steady-state and load changing conditions and operations such as use of control rods, coolant flow control, and adjusting operating parameters.

This procedure shall establish the format and content of general plant procedures as follows:

a. Descriptive title and revision number.

b. Statement of applicability or purpose.

c. References, including technical specifications, drawings, or procedures as applicable.

d. Prerequisites, including those independent actions or procedures that must be completed and plant conditions that must exist prior to use of the procedure. Prerequisites applicable to only certain sections of the procedure shall be so identified. Startup procedures shall require documentation of completion of prerequisites such as confirmation that necessary instruments are operable and properly set; that necessary valves are properly aligned; that necessary procedures, tests, and calibrations have been completed; and that required approvals have been obtained. Checkoff lists can be used for the purpose of defining and documenting completion of prerequisites.

e. Precautions, where necessary to alert the individual performing the task to those important measures that should be used to protect equipment and personnel, including the public, or to avoid an abnormal or emergency situation.

f. Procedure section. The procedure shall provide the sequence and steps needed to perform the task in the degree of detail necessary to ensure safety and correct

performance without undue reliance on memory or direct supervision. Cautionary notes applicable to specific steps shall be identified and included. System procedures or other detailed instructions not contained in the general plant procedure shall be referenced at the applicable steps. Where appropriate, check off lists shall be included in or appended to the procedure for the purpose of assisting the operator and/or confirming completion of major steps in the proper sequence. Limitations on parameters being controlled and appropriate corrective measures to return the parameter to the proper value shall be specified where appropriate.

To ensure feedback, general plant procedures are reviewed in accordance with performance enhancement procedures following unusual incidents that reflect adversely on the adequacy of these procedures. When determined necessary by the PORC, tests shall be performed to confirm that significant changes to general plant procedures produce the expected results. General plant procedures shall be distributed to appropriate personnel in accordance with current distribution lists to ensure that outdated or inappropriate procedures are not used.

13.5.1.17 Procedure for Preparation of System Procedures

This procedure shall establish the administrative requirements and responsibilities for the preparation of system procedures for safety-related systems. The procedure shall require system procedures to address normally expected operations such as energizing, filling, venting, draining, starting up, shutting down, and changing modes of operation as applicable to the system. It is not the intent of these procedures to cover actions, operations, or system conditions that would be unique to a special operation, such as maintenance, and would be covered in a special procedure written at the time the operation is needed.

This procedure shall establish the format and content of system procedures as follows:

a. Descriptive title and revision number.

b. Statement of applicability or purpose.

c. References including technical specifications, drawings, procedures, equipment manuals, and vendor documents as applicable.

d. Prerequisites, including those independent actions or procedures that must be completed and plant conditions that must exist prior to use of the procedure. Prerequisites applicable to only certain sections of the procedure shall be so identified.

e. Procedure section. This section shall provide the steps to perform the various operations in the degree of detail necessary to ensure safety and correct performance without undue reliance on memory or direct supervision, and in consideration of the skills possessed by trained operators. Cautionary notes applicable to specific steps shall be identified or included. Limitations on parameters being controlled and appropriate corrective measures to return the parameter to the proper value shall be specified where appropriate. Where appropriate, check off lists shall be included in or appended to the procedure.

To ensure feedback, system procedures are reviewed in accordance with performance enhancement procedures following unusual incidents that reflect adversely on the adequacy of these procedures. When determined necessary by the PORC, tests shall be performed to confirm that significant changes to system procedures produce the expected results. System procedures shall be distributed to appropriate personnel in accordance with current distribution lists to ensure that outdated or inappropriate procedures shall be not used.

13.5.1.18 Procedure for Preparation of Operational Transient Procedures

This procedure shall establish the administrative requirements and responsibilities for the preparation of operational transient procedures for the restoration of normal operating conditions following a perturbation. This procedure shall establish the format and content of operational transient procedures as follows:

a. Descriptive title and revision number.

b. Entry conditions.

c. Immediate operator actions. This section shall specify immediate actions for operation of controls to restore normal operating conditions.

d. Follow-up actions.

e. Verification of automatic actions. The automatic actions that are expected to occur as a result of the condition shall be identified.

To ensure feedback, operational transient procedures are reviewed in accordance with performance enhancement procedures following unusual incidents that reflect adversely on the adequacy of these procedures. Operational transient procedures shall be distributed to appropriate personnel in accordance with current distribution lists to ensure that outdated or inappropriate procedures are not used.

13.5.1.19 Procedure for Preparation of Alarm Response Cards

This procedure shall establish the administrative requirements and responsibilities for the preparation of individual alarm response cards. The procedure shall provide for preparation of individual alarm response cards to which operators refer. Alarm response cards shall be maintained in the control room and shall contain the following information:

a. Identification of the alarm

b. Alarm setpoint

c. Identification of the signal source instrument

d. Automatic actions that are expected to occur

e. Operator response (immediate and long-term)

To ensure feedback, safety-related alarm response cards are reviewed in accordance with performance enhancement procedures following unusual incidents that reflect adversely on the adequacy of the alarm response card.

Unique numbers have been assigned to each control room alarm based on a sequential number for each annunciator window within a specific panel. Alarm response information is retrieved by identifying the alarm number and referring to the corresponding alarm card or procedure number.

13.5.1.20 Procedure for Preparation of Fuel Handling Procedures

This procedure shall establish the administrative requirements and responsibilities for the preparation of fuel handling procedures that shall specify actions for core alterations, accountability for fuel, partial or complete refueling operations, receipt and shipment of fuel, and such specific procedures for each refueling outage as necessary to accomplish the required actions in a safe, efficient manner. This procedure shall establish the format and content of fuel handling procedures as follows:

a. Descriptive title and revision number.

b. Statement of applicability or purpose.

c. References, including technical specifications, drawings, or procedures as applicable.

d. Prerequisites, including those independent actions or procedures that must be completed and plant conditions that must exist prior to use of the procedure. Prerequisites applicable to only certain sections of the procedure shall be so identified.

e. Precautions, where necessary, to alert the individual(s) performing the task to those important measures that should be used to protect equipment and personnel, including the public, or to avoid an abnormal or emergency situation.

f. Limitations and actions. Limitations on appropriate parameters and corrective action to return the parameter to the proper value or other appropriate action shall be specified.

g. Procedure section. The procedure shall provide the needed steps and requirements to perform the refueling task in the degree of detail necessary to ensure safety and correct performance without undue reliance on memory or direct supervision. Cautionary notes and references applicable to specific steps shall be identified and included. Where appropriate, check off lists shall be included in or appended to the procedure for the purpose of assisting the operator and/or confirming completion of appropriate steps.

This procedure shall require documentation of final fuel and component serial numbers and locations to be developed and maintained.

To ensure feedback, fuel handling procedures are reviewed in accordance with performance enhancement procedures following unusual incidents that reflect adversely on the adequacy of these procedures. Fuel handling procedures shall be distributed to appropriate personnel in

accordance with current distribution lists to ensure that outdated or inappropriate procedures are not used.

13.5.1.21 Procedure for Preparation of Health Physics Procedures

This procedure shall establish the administrative requirements and responsibilities for the preparation of health physics procedures that implement the radiation protection program. This procedure shall require preparation of health physics procedures in the following areas:

a. Monitoring external and internal exposures of appropriate employees utilizing accepted techniques.

b. Routine radiation surveys of work areas.

c. Environmental monitoring within the scope of the operating staff responsibility.

d. Radiation monitoring of maintenance and special work activities.

e. Maintenance of records demonstrating the adequacy of measures taken to control radiation exposures of employees and other appropriate personnel.

f. Control, receipt, and shipment of radioactive material.

This procedure shall establish the format and content of health physics procedures as follows:

a. Descriptive title and revision number.

b. Statement of applicability or purpose.

c. References, including technical specifications, drawings, procedures, and operating manuals as applicable.

d. Apparatus, such as instruments or special equipment, as applicable.

e. Precautions, where necessary, to alert the individual performing the task to those important measures that should be used to protect equipment and personnel, including the public, or to avoid an abnormal or emergency situation. Routine precautions that a trained technician is expected to take need not be listed.

f. Procedure section. The procedure shall provide the needed steps to perform the task in the degree of detail necessary to ensure safety and correct performance without undue reliance on memory or direct supervision. Precautions and references important to specific steps in the procedure shall be identified and included at those steps. When appropriate, check off lists shall be included in or appended to health physics procedures.

Health Physics procedures will normally be prepared by members of the LGS Services organization, knowledgeable in Health Physics; however, organizations providing technical support and consultants may assist in procedure development. These procedures will be developed in consultation with the Director of the Radiation Protection Section and his staff.

The Health Physics procedures are primarily administrative and analytic. They represent the most efficient way to administer the Health Physics program. Many are based on either the type of equipment in use in the plant or, in the case of shipping radioactive materials, they are based on regulations. When the regulations change, the Health Physics procedures would be revised if needed. If new equipment for analysis is obtained, new procedures would be written for that new equipment.

To ensure feedback, health physics procedures are reviewed in accordance with performance enhancement procedures following unusual incidents that reflect adversely on the adequacy of these procedures. Health physics procedures shall be distributed to appropriate personnel in accordance with current distribution lists to ensure that outdated or inappropriate procedures are not used.

13.5.1.22 Procedure for Preparation of Chemistry Procedures

This procedure shall establish the administrative requirements and responsibilities for the preparation of chemistry procedures that include chemical and radiochemical control activities. This procedure shall establish the format, content, and distribution requirements for chemistry procedures as described for health physics procedures.

13.5.1.23 Procedure for Temporary Changes to Approved Procedures

This procedure shall establish the administrative requirements and responsibilities for making temporary changes to approved procedures. The procedure shall provide that temporary changes, clearly not changing the intent of the approved procedure, shall be documented and approved by two members of the plant staff knowledgeable in the area(s) affected by the procedure. At least one of these individuals shall be a shift manager or a senior licensed operator on the unit affected. Temporary changes shall be incorporated in the next procedure revision if appropriate.

13.5.1.24 Procedure for Preparation of Off-Normal Procedures

This procedure shall establish the administrative requirements and responsibilities for the preparation of off-normal procedures that are written to specify operator actions following an operator observation of an off-normal (nontransient) condition which requires immediate action to prevent degeneration of the existing condition. This procedure shall establish the format and content of off-normal procedures as follows:

a. Descriptive title and revision number.

b. Symptoms. This section shall include symptoms to aid in identifying or confirming the off-normal condition. Alarm conditions, parameter changes, and other observations shall be considered.

c. Operator actions. This section shall specify actions to be taken to identify, confirm, or correct the cause of the off-normal condition.

To ensure feedback, off-normal procedures are reviewed in accordance with performance enhancement procedures following unusual incidents that reflect adversely on the adequacy of these procedures. Off-normal procedures shall be distributed to appropriate personnel in accordance with current distribution lists to ensure that outdated or inappropriate procedures are not used.

13.5.1.25 Procedure for Preparation of Event Procedures and Special Event Procedures

This procedure shall establish the administrative requirements and responsibilities for the preparation of event procedures and special event procedures that are written to specify operator actions following an operator observation of an event of an emergency or unusual nature.

13.5.1.25.1 Procedure for Preparation of Event Procedures

This Procedure establishes the format and content of event procedures as follows:

a. Confirming indications.
b. Initial actions.
c. Follow-up actions.

13.5.1.25.2 Procedure for Preparation of Special Event Procedures

This Procedure establishes the format and content of special event procedures as follows:

a. Purpose.
b. Symptoms. Symptoms shall be included to aid in the identification of the plant condition.
c. Immediate operator actions. This section shall specify action to be taken as a result of the identified condition.
d. Follow-up actions.

13.5.1.26 Procedure for Preparation of Radwaste Procedures

This procedure shall establish the administrative requirements and responsibilities for the preparation of radwaste procedures. This procedure shall require administration of the station radwaste program in the following areas:

a. Control handling, packaging, storage, and shipment of radioactive material.

b. Inspection, installation, and use of equipment used to process and package radwaste.

c. Processing and handling of radwaste using vendor equipment.

This procedure shall establish the format, content, and control of radwaste procedures.

13.5.1.27 Procedure for Fire Safe Shutdown Guides

This procedure shall establish the administrative requirements and responsibilities for the preparation of fire safe shutdown procedures that are written to identify available plant instrumentation and equipment which may be relied upon in the event of a fire in a specific fire area. This procedure shall establish the format and content of fire safe shutdown guides as follows:

a. Descriptive title and revision number.

b. Available Equipment. This section shall include a listing of protected equipment which is shown by analysis to be available following an exposure fire in a specific area.

c. Contingency Actions. This section shall specify operator actions to be taken to restore essential equipment and/or system functions which have the potential of being affected by a fire in a specific area.

13.5.2 OPERATING AND MAINTENANCE PROCEDURES

13.5.2.1 Control Room Operating Procedures

Operating procedures which are primarily performed by licensed operators in the control room include general plant procedures, system procedures, operational transient procedures, off-normal procedures, alarm response cards, Transient Response Implementation Plan procedures, event procedures, special event procedures, and fire safe shutdown guides. The format and content of these classes of procedures are described in Section 13.5.1. General plant procedures and system procedures will be developed to cover the activities listed in sections 2 and 4, respectively, of appendix A to Regulatory Guide 1.33 (Rev 2). Examples of the types of activities covered by operating procedures or the anticipated procedure titles are listed below:

General Plant Procedures: Reactor startup from cold conditions; reactor startup from hot conditions; turbine-generator startup; power operation and monitoring; plant shutdown to hot standby; shutdown from hot standby to cold conditions; preparation for refueling operations.

System Procedures: Recirculation system; reactor water cleanup system; residual heat removal system; high pressure coolant injection system; core spray system; reactor core isolation cooling system; standby liquid control system; fuel pool cooling system; containment; control rod drive systems; reactor protection system; main steam system; turbine-generator; condensate and feedwater systems; circulating water system; cooling towers; cooling water systems; main generator; plant electrical systems; dc systems; diesel generators; radwaste systems; solid radwaste processing; standby gas treatment system; heating, ventilation, and air conditioning systems; fire protection systems; nuclear instrumentation.

Operational Transient Procedures: Reactor low level; high drywell pressure; reactor high pressure; positive reactivity insertion; scram discharge volume high level; condenser low vacuum; reactor high level; recirculation pump trip; and inadvertent opening of a relief valve.

Off-Normal Procedures: Failure of a jet pump; loss of isolated phase bus cooling; air ejector discharge high radiation; offgas stack high radiation; control rod uncoupled; stuck control rod; loss of CRD regulating function; low scram air header pressure; total loss of the SRM, IRM, or APRM systems; loss of primary containment; loss of secondary containment; loss of stator cooling; main steam line high radiation; and loss of uninterruptible ac power.

Transient Response Implementation Plan Procedures: Reactor pressure vessel control; primary containment control; secondary containment control; radioactive release control; alternate level pressure control; emergency depressurization; reactor pressure vessel flooding; anticipated transient without scram pressure vessel control; reactor pressure vessel control OPCON 4; containment and radioactivity release control OPCON 4; reactor pressure vessel flooding OPCON 4; decay heat control OPCON 5; and containment and radioactivity release control OPCON 5.

Severe Accident Management Plan Procedures: Reactor pressure vessel control; containment and radioactive release control; reactor pressure vessel control OPCON 5; containment radioactive release control (OPCON 5).

Event procedures and Special Event Procedures: Earthquake; flood; shutdown from outside the control room; control room enclosure toxic gas; oil spills; and fire.

Licensed reactor operators and senior reactor operators are required to know the immediate operator actions in operational transient procedures, event procedures, special event procedures, and the entry condition of Transient Response Implementation Plan procedures. When entry conditions for Transient Response Implementation Plan procedures are met, operator actions are directed by the Transient Response Implementation Plan procedure as a priority over actions described in other procedures.

Fire Safe Shutdown Guides: Contingency steps to operate plant equipment.

13.5.2.2 Control of Unit 2 Construction Activities During Unit 1 Operation

Refer to Section 1.2.5

13.5.2.3 Additional Operating and Maintenance Procedures

In addition to operating procedures related primarily to control room operations, procedures shall be issued to control other plant activities. These procedures shall include emergency plan procedures, fuel handling procedures, chemistry procedures, health physics procedures, maintenance procedures, security procedures, surveillance test procedures, and preventive maintenance procedures. The types of activities covered by these procedures are listed below. The format and content of these procedures are described in Section 13.5.1.

Fuel Handling Procedures: New fuel inspection; irradiated fuel inspection; installation, removal, and transfer of fuel assemblies; installation and removal of control rods; core sipping; installation and removal of source holder; installation and removal of incore detectors.

Health Physics Procedures: Radiation exposure limits; dosimetry requirements; personnel exposure records; radiation work permit; radiation control area classification; radiation/contamination surveys; decontamination; shipment of radioactive material; control and accountability of radioactive material; operation and calibration of radiation monitoring equipment; airborne radioactivity monitoring; various analytical procedures; laboratory calibration procedures.

Security Procedures: Response to industrial security threats; civil disturbance; communications; security force duties and responsibilities; receipt control; key control; guard patrols; personnel identification; access control; vehicle traffic and parking; testing and maintenance of security systems; record keeping; visitor control.

Chemistry Procedures: Sampling reactor water; sampling reactor steam; gaseous samples; sampling condensate storage tank; various analytical procedures; control of radioactive calibration sources; laboratory calibration procedures.

Maintenance Procedures: Reactor recirculation pump seal overhaul; control rod drive repair; hydraulic control unit repair; control rod drive O-ring replacement; removal and replacement of drywell head; removal and replacement of reactor vessel head; removal and replacement of steam dryer; nuclear instrumentation removal and replacement; offgas filter maintenance; motor operator adjustment; standby liquid control explosive valve replacement.

Emergency Plan Procedures: Radiological surveys and monitoring; rescue operations; fire fighting; first aid; decontamination; personnel accountability; communications, repairs and damage control; record keeping; organization, duties.

13.5.3 OPERATIONS TECHNICAL REQUIREMENTS MANUAL (TRM)

The Technical Requirements Manual (TRM) contains the technical requirements and/or supporting information (e.g., tables and component lists) which were once contained in the LGS Technical Specifications (TS) (i.e., Appendix A of the LGS Facility Operating License). Removal of the TS and information was approved by the NRC through individual TS amendments. The TRM is intended to provide operational guidance and requirements for various plant conditions, actions, and testing similar to TS, however, these requirements are in accordance with licensing commitments. Future changes to the relocated requirements and supporting information are processed in accordance with Section 6.0 of the LGS TS, and are subject to a 10CFR50.59 Review.

The TRM is comprised of an index, the individual specification and bases. The manual is intended to provide a single location for the relocated TS items as a convenience for operations and other station personnel. The individual sections of the TRM contain the relocated licensing commitments which are subject to the provisions of 10CFR50.59 as described above.

In accordance with NEI 98-03, Revision 1 (Reference 13.5-1), as endorsed by NRC Regulatory Guide 1.181 (Reference 13.5-2), the TRM is treated in a manner consistent with procedures fully or partially described in the UFSAR, and therefore, is controlled as a procedure in accordance with the applicable established procedure process. For the purposes of 10 CFR 50.59, information presented in the TRM is considered to be information described in the UFSAR, and therefore, is to be treated at the same level as information presented in the UFSAR. (Reference 13.5-3)

13.5.4 SURVEILLANCE FREQUENCY CONTROL PROGRAM (SFCP)

The Surveillance Frequency Control Program (SFCP) was implemented as a result of NRC issuance of Amendment Nos. 186 and 147, dated September 28, 2006, to the Limerick Generating Station (LGS), Unit 1 and Unit 2, Technical Specifications (TS), respectively. Administrative controls for the SFCP were added to the Administrative Controls section of the LGS TS for both units, and are implemented through administrative procedures. The SFCP ensures that surveillance requirements specified in the TS are performed at intervals sufficient to assure the associated TS Limiting Conditions for Operation are met. The SFCP contains a list of frequencies of those surveillance requirements for which the frequency is controlled by the program and changes to the frequencies listed in the SFCP are made in accordance with NEI 04-01, "Risk-Informed Method for Control of Surveillance Frequencies," Revision 0.

13.5.5 RISK INFORMED CATEGORIZATION AND TREATMENT

13.5.5.1 Introduction

Limerick Generating Station has implemented 10 CFR 50.69 using the processes for categorization of Risk-Informed Safety Class (RISC)-1, RISC-2, RISC- 3, and RISC-4 structures, systems, and components (SSCs) using:

- Probabilistic Risk Assessment (PRA) models to evaluate risk associated with internal events, including internal flooding, and internal fire; the shutdown safety assessment process to assess shutdown risk;
- The Arkansas Nuclear One, Unit 2 (ANO-2) passive categorization method to assess passive component risk for Class 2 and Class 3 SSCs and their associated supports;

- The results of non-PRA evaluations that are based on the IPEEE Screening Assessment for External Hazards, i.e., seismic margin analysis (SMA) to evaluate seismic risk, and a screening of other external hazards updated using the external hazard screening significance process identified in ASME/ANS PRA Standard RA-Sa-2009.

13.5.5.2 SSC Categorization

As outlined in the Safety Evaluation Report (SER) for License Amendments 230 and 193 to Renewed Facility Operating License Nos. NPF-39 and NPF-85, respectively (Reference 13.5-4), Limerick will use the methodology described in 13.5.5.1.

10 CFR 50.69(f)(2) requires updating the UFSAR to reflect which systems have been categorized. Table 13.5-1 is revised as part of the periodic UFSAR update to reflect systems that have been categorized. 10 CFR 50.69 system boundaries are defined in the associated System Categorization Document (Reference 13.5-5).

13.5.5.3 SSC Treatment

13.5.5.3.1 Treatment of Component Categories

The programs or processes that implement the special treatment requirements are revised to recognize that the special treatments no longer apply to RISC-3 and RISC-4 SSCs. The programs or processes either allow continued application of the special treatments or acceptable alternative treatments, as applicable, to provide reasonable confidence that these SSCs would perform their safety-related function under design basis conditions.

For those components that are categorized as Low Safety Significant, 10 CFR 50.69(b)(1) allows compliance with alternative requirements in lieu of the following special treatment requirements.

(i) 10 CFR Part 21.

(ii) The portion of 10 CFR 50.46a(b) that imposes requirements to conform to Appendix B to 10 CFR Part 50.

(iii) 10 CFR 50.49.

(iv) 10 CFR 50.55(e).

(v) The in-service testing requirements in 10 CFR 50.55a(f): the in-service inspection and repair, and replacement (with the exception of fracture toughness), requirements for ASME Class 2 and Class 3 SSCs in 10 CFR 50.55a(g); and the electrical component quality and qualification requirements in Section 4.3 and 4.4 of IEEE 279, and Sections 5.3 and 5.4 of IEEE 603-1991, as incorporated by reference in 10 CFR 50.55a(h).

(vi) 10 CFR 50.65, except for paragraph (a)(4).

(vii) 10 CFR 50.72.

(viii) 10 CFR 50.73.

(ix) Appendix B to 10 CFR Part 50.

(x) The Type B and Type C leakage testing requirements in both Options A and B of Appendix J to 10 CFR Part 50, for penetrations and valves meeting the following criteria:

(A) Containment penetrations that are either 1-in. nominal size or less, or continuously pressurized.

(B) Containment isolation valves that meet one or more of the following criteria:

(1) The valve is required to be open under accident conditions to prevent or mitigate core damage events;

(2) The valve is normally closed and in a physically closed, water-filled system;

(3) The valve is in a physically closed system whose piping pressure rating exceeds the containment design pressure rating and is not connected to the reactor coolant pressure boundary; or

(4) The valve is 1-in. nominal size or less.

(xi) Appendix A to Part 100, Sections Vl(a)(1) and Vl(a)(2), to the extent that these regulations require qualification testing and specific engineering methods to demonstrate that SSCs are designed to withstand the Safe Shutdown Earthquake and Operating Basis Earthquake.

Performance monitoring is being performed on all RISC-1, RISC-2, RISC-3, and RISC-4 SSCs and the station adjusts, as necessary, to either the categorization or treatment process so that the categorization process and results are maintained valid.

13.5.5.3.2 Enhanced Treatment of RISC-2 SSCs

The 10 CFR 50.69 procedures and 10 CFR 50.69(d)(1) require that RISC-2 SSCs perform their functions consistent with the categorization process assumptions by evaluating treatment being applied to these SSCs to ensure that it supports the key assumptions in the categorization process that relate to their assumed performance.

13.5.6 REFERENCES

13.5-1 NEI 98-03, “Guidelines for Updating Final Safety Analysis Reports,” Revision 1, dated June 1999.

13.5-2 Regulatory Guide 1.181, “Content of the Updated Final Safety Analysis Report in Accordance with 10 CFR 50.71(e),” dated September 1999.

13.5-3 Letter from P. Bamford, U.S. Nuclear Regulatory Commission, to C. G. Pardee, Exelon Generating Company, LLC, “Limerick Generating Station, Units 1 and 2 – Issuance of Amendment RE: Changes to Accident Monitoring Instrumentation Technical Specifications (TAC Nos. MD5937 and MD5938),” dated May 29, 2008.

13.5-4 Safety Evaluation by the Office of Nuclear Reactor Regulation related to Amendment No. 230 and 193 to Renewed Facility Operating License Nos. NPF-39 and NPF-85 for the Limerick Generation Station, Units 1 and 2, respectively, Docket Nos. 50-352 and 50-353, ML18165A162.

13.5-5 10 CFR 50.69 Categorization Documents:
LG-5069-052-003, Core Spray System (052)
LG-5069-048-003, Standby Liquid Control System (048)
LG-5069-077-003, Drywell HVAC System (077)
LG-5069-026-003, Process Radiation Monitoring System (026)LG
LG-5069-057-058-003, Containment Atmosphere Control (057) and Containment Hydrogen Recombiner Systems (058)

LG-5069-059-003, Primary Containment Instrument Gas System (059)
LG-5069-020-081-092-003, Diesel Generator System (020, 081, 092)
LG-5069-051-003, Residual Heat Removal (051)
LG-5069-012-003, Residual Heat Removal Service Water System (012/RHRSW))
LG-5069-076-003, Reactor Enclosure HVAC System (076)
LG-5069-055-056-003, High Pressure Coolant Injection (055, 056)
LG-5069-078-090-003, Control Enclosure HVAC and Control Enclosure Chilled Water System (078, 090)
LG-5069-049-003, Reactor Core Isolation Cooling System (049)
LG-5069-001-003, Main Steam System (001)
LG-5069-011-003, Emergency Service Water System (011)
LG-5069-061-003, Liquid Radwaste System (061)
LG-5069-087-003, Drywell Chilled Water System (087)
LG-5069-025-003, Steam Detection System (025)
LG-5069-036E-003, Redundant Reactivity Control System (036E)
LG-5069-075-003, Turbine Enclosure HVAC System (075)
LG-5069-081-003, Spray Pond Pump House HVAC System (081B)
LG-5069-013-003, Reactor Enclosure Cooling Water System (013)
LG-5069-0044-045-003, Reactor Water Cleanup System (044-045)

Table 13.5-1

SYSTEMS CATEGORIZED IN THE 10 CFR 50.69 CATEGORIZATION PROCESS
(Reference 13.5-5)

System Name
Core Spray
Standby Liquid Control
Drywell HVAC
Process Radiation Monitoring
Containment Atmosphere Control
Containment Hydrogen Recombiner
Primary Containment Instrument Gas
Diesel Generator System
Residual Heat Removal
Residual Heat Removal Service Water
Reactor Enclosure HVAC
High Pressure Coolant Injection
Control Enclosure HVAC
Control Enclosure Chilled Water System
Reactor Core Isolation Cooling
Main Steam
Emergency Service Water
Liquid Radwaste
Drywell Chilled Water
Steam Leak Detection
Redundant Reactivity Control System
Turbine Enclosure HVAC
Spray Pond Pump House HVAC
Reactor Enclosure Cooling Water
Reactor Water Cleanup

13.6 INDUSTRIAL SECURITY

A physical security plan that describes a comprehensive program of physical protection for the facility has been submitted as a separate part of the license application. The physical security plan is withheld from public disclosure pursuant to 10CFR2.790(d), "Rules of Practice." Implementation of the plan provides protection with high assurance against successful industrial sabotage as described in 10CFR73.55(a) "General Performance Requirements."

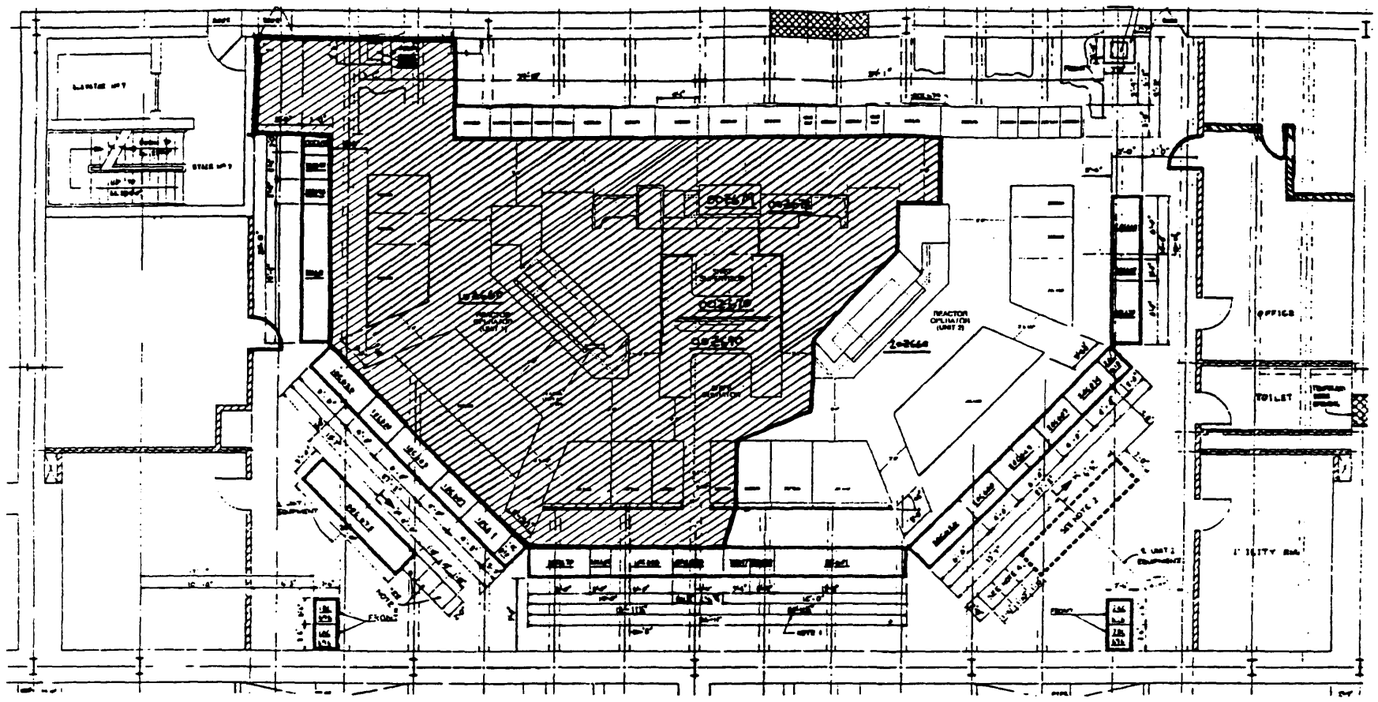
The plan addresses the following: physical security organization, physical barriers, access requirements, detection aids, communication requirements, testing and maintenance, and response requirements. Implementation of the plan becomes effective at the time of fuel loading.

Figures 13.1-1 through 13.1-4

Deleted

Figure 13.2-1

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UNIT 1

NOTES

(1) ONLY CONTROL PANELS ASSOCIATED WITH THE OPERATION OF THAT UNIT OR COMMON UNIT PANELS ARE INCLUDED INSIDE THE DEFINED BOUNDARY. IF, IN THE FUTURE, PANELS ARE ADDED TO THE CONTROL ROOM, THEY ARE NECESSARILY INCLUDED IN THE DEFINITION OF "AT THE CONTROLS" FOR THAT UNIT.

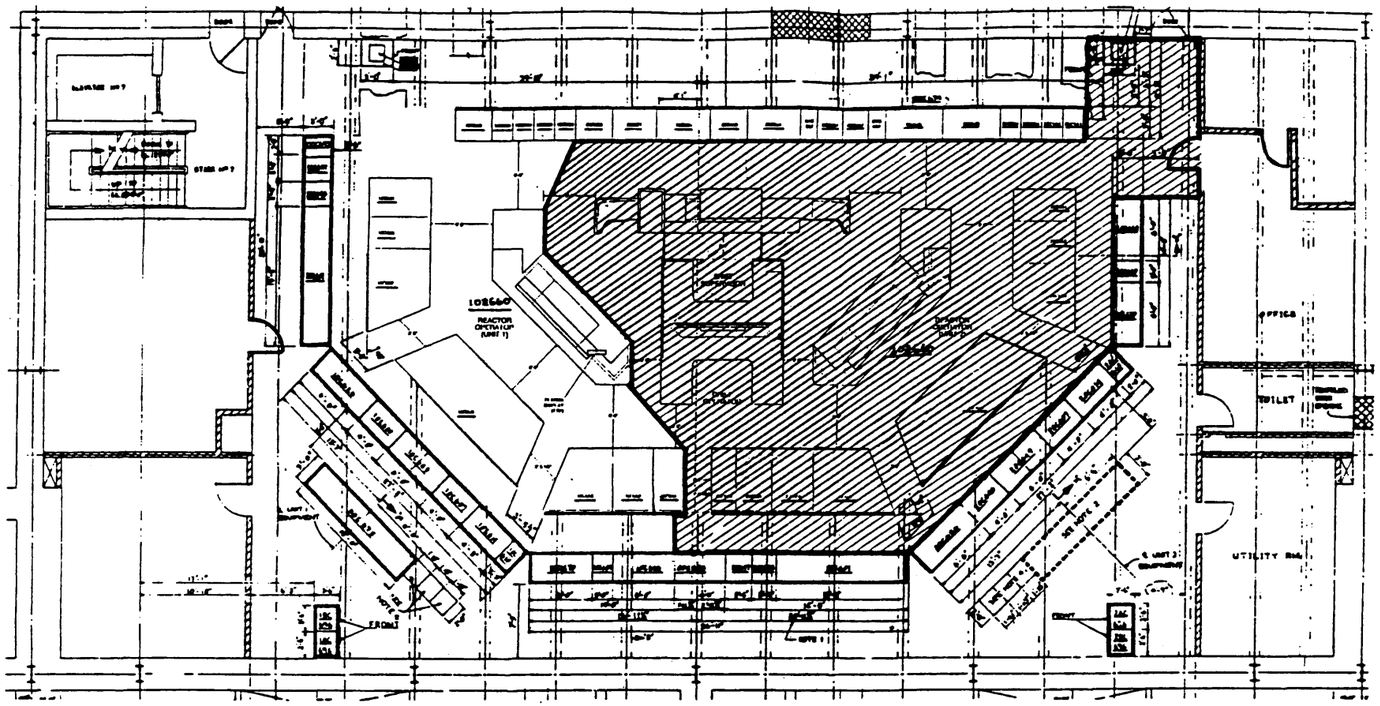
(2) NORMAL "AT THE CONTROLS" LOCATIONS DO NOT APPLY DURING ANY CONDITION DURING WHICH THE CONTROL ROOM IS NOT HABITABLE. IN THAT EVENT, THE "AT THE CONTROL" LOCATION IS THE EMERGENCY SHUTDOWN PANEL FOR THAT UNIT.

(3) IN THE EVENT OF AN EMERGENCY AFFECTING THE SAFETY OF OPERATIONS, THE OPERATOR MAY MOMENTARILY BE ABSENT FROM THE DESIGNATED AREA TO VERIFY THE RECEIPT OF AN ANNUNCIATOR ALARM OR INITIATE CORRECTIVE ACTION, PROVIDED THE OPERATOR REMAINS WITHIN THE CONFINES OF THE CONTROL ROOM AND OBTAINS THE PERMISSION OF THE CONTROL ROOM SRO AT THE TIME.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DEFINITION OF
"AT THE CONTROLS"
SHEET 1 OF 2

FIGURE 13.5-1 REV. 13 09/06



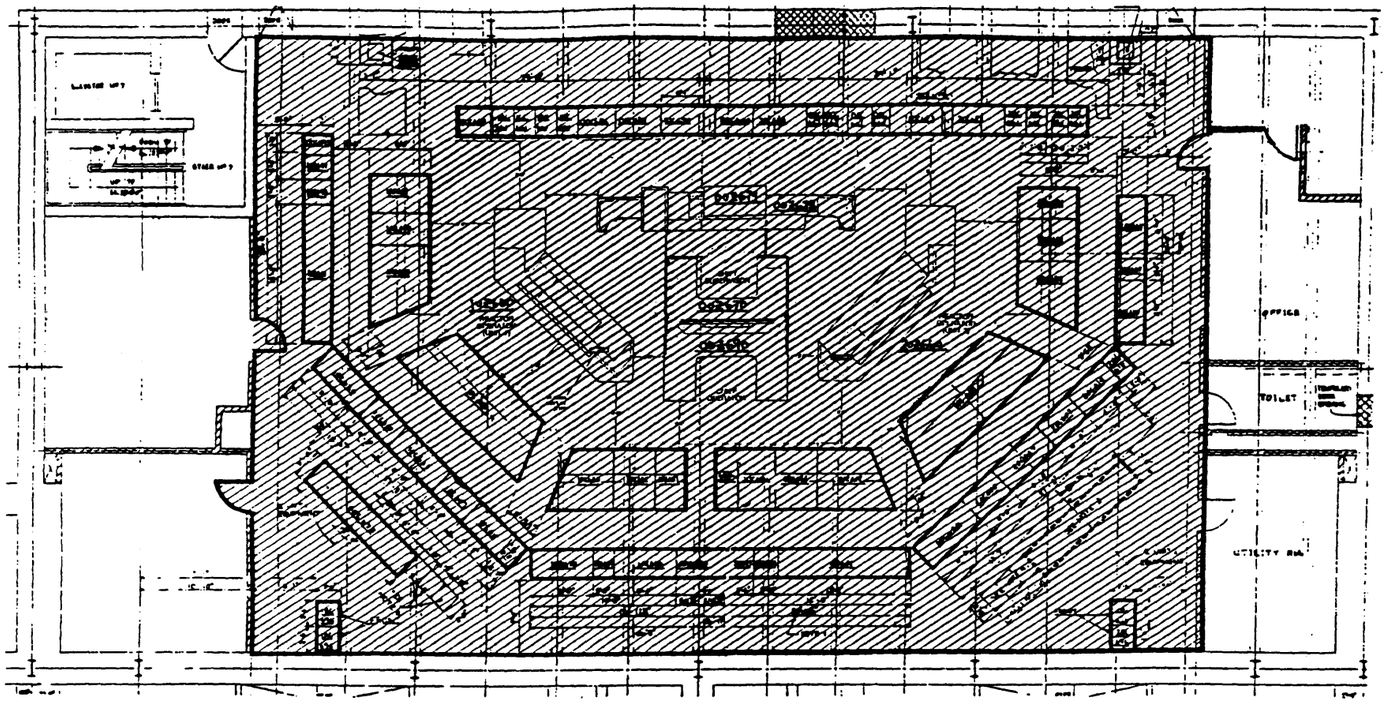
UNIT 2

NOTES

(1) ONLY CONTROL PANELS ASSOCIATED WITH THE OPERATION OF THAT UNIT OR COMMON UNIT PANELS ARE INCLUDED INSIDE THE DEFINED BOUNDARY. IF, IN THE FUTURE, PANELS ARE ADDED TO THE CONTROL ROOM, THEY ARE NECESSARILY INCLUDED IN THE DEFINITION OF "AT THE CONTROLS" FOR THAT UNIT. OFFICE, UTILITY, OR REST FACILITIES ARE NOT INCLUDED IN THE DEFINED BOUNDARY WITH THE FOLLOWING EXCEPTION: THE UNIT 2 OPERATOR MAY OPEN THE SHIFT SUPERINTENDENT OFFICE DOOR, FOR VERBAL COMMUNICATION AS LONG AS HE REMAINS IN THE AREA CIRCUMSCRIBED BY THE DOOR AND THE DOOR IS HELD OPEN.

(2) NORMAL "AT THE CONTROLS" LOCATIONS DO NOT APPLY DURING ANY CONDITION DURING WHICH THE CONTROL ROOM IS NOT HABITABLE. IN THAT EVENT, THE "AT THE CONTROL" LOCATION IS THE EMERGENCY SHUTDOWN PANEL FOR THAT UNIT.

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NOTES

(1) ONLY CONTROL PANELS ASSOCIATED WITH THE OPERATION OF THAT UNIT OR COMMON UNIT PANELS ARE INCLUDED INSIDE THE DEFINED BOUNDARY. IF, IN THE FUTURE, PANELS ARE ADDED TO THE CONTROL ROOM, THEY ARE NECESSARILY INCLUDED IN THE DEFINITION OF "AT THE CONTROLS" FOR THAT UNIT. OFFICE, UTILITY, OR REST FACILITIES ARE NOT INCLUDED IN THE DEFINED BOUNDARY WITH THE FOLLOWING EXCEPTION : THE SRO MAY OPEN THE SHIFT SUPERINTENDENT OR ADJACENT OFFICE INSTRUMENT LAB, AND SHOP DOORS FOR VERBAL COMMUNICATION AS LONG AS HE REMAINS IN THE AREA CIRCUMSCRIBED BY THE DOOR AND THE DOOR IS HELD OPEN.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SRO CONTROL
ROOM BOUNDARIES

FIGURE 13.5-2 REV. 13 09/06

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CHAPTER 14 - INITIAL TEST PROGRAM

14.1 SPECIFIC INFORMATION INCLUDED IN THE PSAR

This section is not applicable to Chapter 14 of the UFSAR.

14.2 SPECIFIC INFORMATION INCLUDED IN THE FSAR

14.2.1 SUMMARY OF TEST PROGRAM AND OBJECTIVES

As construction of the systems/components is completed, the construction organization relinquishes jurisdictional control of these systems/components through a formal turnover to the licensee. Eventually all plant systems/components are turned over to the licensee.

The initial test program for each unit encompasses the scope of events that commences with system/component turnover and terminates with the completion of power ascension testing. The initial test program is conducted in two separate and sequential subprograms: the preoperational test program and the startup test program. At the conclusion of these subprograms, each unit is ready for normal power operation. Testing during the preoperational and startup test programs is accomplished in four distinct and sequential major phases.

Major Test Phases - Initial Test Program

a. Phase I - Preoperational Testing

b. Phase II - Initial Fuel Loading and Zero Power Testing

c. Phase III - Low Power Testing

d. Phase IV - Power Ascension Testing

Preoperational testing is completed during the preoperational test program. Initial fuel loading and zero power testing, low power testing, and power ascension testing are completed during the startup test program. See Figure 14.2-1 for a pictorial representation of the Unit 1 and Unit 2 initial test programs.

14.2.1.1 Preoperational Test Program

The preoperational test program is defined as that part of the initial test program that commences with system/component turnover, and terminates with the beginning of unit fuel loading. Formal tests, denoted as preoperational tests (Table 14.2-1), are conducted during this program. These tests demonstrate, to the extent practicable, the capability of structures, systems, and components to meet performance requirements, and to satisfy design requirements.

To the extent practicable, the objectives of the preoperational test program are to:

a. Verify the adequacy of plant design.

b. Verify that plant construction is in accordance with design.

c. Demonstrate proper system/component response to postulated accidents and malfunctions.

d. Confirm the adequacy of plant operating and emergency procedures.

e. Familiarize the plant staff operating, technical, and maintenance personnel with the plant operation.

14.2.1.2 Startup Test Program

The startup test program is defined as that part of the initial test program that commences with the start of nuclear fuel loading, and terminates with the completion of power ascension testing. Formal tests, denoted as startup tests (Table 14.2-2), are conducted during this program. Main steam turbine trip test for Unit 2 (ref. Startup test STP-36) at 100% power level will be performed during commercial operation of that unit. These tests confirm the design bases and demonstrate, to the extent practicable, that the plant operates and responds to anticipated transients and to postulated accidents as designed. Startup testing is sequenced to ensure that the safety of the plant is not dependent upon the performance of untested structures, systems, or components.

The objectives of the startup test program are to:

a. Accomplish a controlled, orderly, and safe initial core loading.

b. Accomplish a controlled, orderly, and safe initial criticality.

c. Conduct low power testing sufficient to ensure that design parameters are satisfied, and that safety analysis assumptions are correct or conservative.

d. Perform a controlled, orderly, and safe power ascension with requisite testing, terminating at plant rated conditions.

14.2.2 ORGANIZATION AND STAFFING

The LGS Plant Manager has overall responsibility for the initial test program. Two basic organizational units, the plant staff and the startup group, jointly conduct the different phases of the test program. Test personnel for the preoperational and startup testing will be assigned to the site in a time frame in advance of the need determined by the latest revision of the startup schedule. Sufficient numbers of qualified people will be assigned to support the startup schedule from the licensee, Bechtel Power Corporation, or vendors. In addition to these basic organizational units, the LGS Plant Manager is assisted by two review organizations: the Plant Operations Review Committee, and the Test Review Board. The organization, authority, responsibility, and degree of participation of each of these organizational units during the initial test program are described in the following sections.

14.2.2.1 Plant Staff

The plant staff consists of the permanent onsite licensee personnel responsible for the safe operation and proper maintenance of the plant. Chapter 13 describes the plant staff organization as it exists during the initial test program. Chapter 13 also establishes responsibilities and reporting relationships for principal plant staff supervisory personnel.

The plant staff is utilized, to the fullest extent practicable, during the initial test program. Specific responsibilities of the plant staff during the initial test program include:

a. Performing selected preventive and corrective maintenance.

b. Operating plant equipment.

c. Calibrating instruments, meters, and relays.

d. Performing chemical and radiological inspections and tests.

e. Providing selected required replacement and spare parts.

f. Providing the operator, technician, and appropriate maintenance support to the startup group.

g. Ensuring that vendors, consultants, and other temporary personnel assisting the plant staff, work in accordance with established procedures.

h. Confirming the adequacy of plant operating and emergency procedures.

i. Authorizing and ensuring proper documentation, identification, and restoration of temporary modifications made during the startup test program (for selected systems/components, this function may be assumed by the plant staff during the preoperational test program).

j. Authorizing and monitoring rework, modification, and maintenance during the startup test program (for selected systems/components, this function may be assumed by the plant staff during the preoperational test program).

k. Authorizing and monitoring the performance of testing during the startup test program.

l. Coordinating preparation, review, and approval of startup test procedures.

m. Coordinating performance of startup testing.

n. Coordinating review and approval of startup test results.

o. Planning and scheduling startup test program activities.

14.2.2.2 Startup Group - Organization and Responsibilities

The startup group is a temporary organizational unit established to augment the plant staff during the initial test program; their primary role is during the preoperational test program. The startup group is comprised of individuals from various organizations (Bechtel Startup, GE, the licensee, and others). Figure 14.2-2 shows the organizational structure of the startup group during the preoperational test phase, and the reporting relationships of the major constituents of the startup group. The number and timing of personnel assigned to the startup group are field determined to allow the testing effort of the initial test program to meet projected fuel load and commercial operation dates. The responsibility of principal startup group supervisory personnel, the structure of the basic constituents comprising the group, and the responsibilities delegated to the group are described in the following sections.

14.2.2.2.1 LGS Unit 2 Startup Manager

The LGS Unit 2 Startup Manager has overall responsibility for implementation of the postconstruction electrical and instrument testing, the development and implementation of the

preoperational testing program (Phase I of the initial test program), and the development of the Unit 2 power ascension program (Phases II, III, and IV of the initial testing program). The Startup Manager reports to the Vice President - LGS and coordinates with the LGS Plant Manager to ensure that the safety and reliability of Unit 1 are not compromised by Unit 2 startup activities and that the adequacy and quality of the Unit 2 startup programs prove Unit 2 operability in accordance with design criteria.

The minimum qualifications for the LGS Unit 2 Startup Manager are one of the following:

a. Graduate of a 4 year accredited engineering or science college or university, plus 6 years of experience in design, testing, or operation of power plants, nuclear facilities, or similar industrial installations. At least 3 years of this experience should be associated with nuclear facilities or the individual must have training sufficient to acquaint him thoroughly with the safety aspects of a nuclear facility.

b. High school graduate, plus 15 years of experience in testing or operation (or both) of power plants, nuclear facilities, or similar industrial installations. At least 6 years of this experience should be associated with nuclear facilities or the individual must have training sufficient to acquaint him thoroughly with the safety aspects of nuclear facilities.

14.2.2.2.2 LGS Startup Superintendent - Support

The LGS Startup Superintendent - Support has overall responsibility for supervising the conduct of postconstruction electrical and instrument testing. The LGS Startup Superintendent - Support reports to the LGS Unit 2 Startup Manager on matters pertaining to postconstruction testing. The minimum qualifications for the LGS Unit 2 Startup Superintendent - Support are one of the following:

a. Graduate of a 4 year accredited engineering or science college or university, plus 5 years of experience in design, testing, or operation of power plants, nuclear facilities, or similar industrial installations. At least 2 years of this experience should be associated with nuclear facilities; or the individual must have training sufficient to acquaint him thoroughly with the safety aspects of a nuclear facility.

b. High school graduate, plus 10 years of experience in testing or operation (or both) of power plants, nuclear facilities, or similar industrial installations. At least 2 years of this experience should be associated with nuclear facilities or the individual must have training sufficient to acquaint him thoroughly with the safety aspects of nuclear facilities.

14.2.2.2.3 LGS Startup Superintendent - Operations

The LGS Startup Superintendent - Operations has overall responsibility for supervising the conduct of the startup group. The LGS Startup Superintendent - Operations reports to the LGS Unit 2 Startup Manager on matters pertaining to the initial test program.

The minimum qualifications for the LGS Startup Superintendent - Operations are one of the following:

a. Graduate of a 4 year accredited engineering or science college or university, plus 5 years of experience in design, testing, or operation of power plants, nuclear facilities,

or similar industrial installations. At least 2 years of this experience should be associated with nuclear facilities; or the individual must have training sufficient to acquaint him thoroughly with the safety aspects of a nuclear facility.

b. High school graduate, plus 10 years of experience in testing or operation (or both) of power plants, nuclear facilities, or similar industrial installations. At least 2 years of this experience should be associated with nuclear facilities; or the individual must have training sufficient to acquaint him thoroughly with the safety aspects of nuclear facilities.

14.2.2.2.4 Project Startup Engineer

The Project Startup Engineer performs a line function and reports to the LGS Startup Superintendent - Operations. He assists the LGS Startup Superintendent - Operations in supervising and directing startup personnel during the applicable part of the initial test program. In the absence of the LGS Startup Superintendent - Operations, the Project Startup Engineer assumes the responsibilities of the LGS Startup Superintendent - Operations.

Minimum qualifications for the Project Startup Engineer are the same as those for the LGS Startup Superintendent - Operations.

14.2.2.2.5 Assistant Project Startup Engineer

The Assistant Project Startup Engineer performs a line function, and reports directly to the Project Startup Engineer. The Assistant Project Startup Engineer is specifically responsible for supervision of systems group leaders. Minimum qualifications for the Assistant Project Startup Engineer are one of the following:

a. High school graduate or equivalent, and 4 years of power plant experience.

b. Graduate of 4 year accredited engineering or science college, and 2 years of power plant experience.

14.2.2.2.6 Technical Staff Specialists

Technical Staff Specialists perform a staff function and report to the Project Startup Engineer. Technical Staff Specialists function as advisors to those individuals who have direct system responsibility. Technical Staff Specialists may have a secondary function within the startup group.

Typical Technical Staff Specialists assigned to the startup group might include:

a. Discipline specialists (mechanical, electrical, instrument and control, nuclear, etc.)

b. NSSS specialist

c. Turbine-generator specialist

14.2.2.2.7 Administrative Staff Specialists

Administrative Staff Specialists perform a staff function, and report to the Project Startup Engineer. Administrative Staff Specialists may have a secondary function within the startup group.

Typical Administrative Staff Specialists assigned to the startup group might include:

a. Planning and scheduling specialist

b. Startup quality engineer

c. Startup/operations coordinator

d. Startup/construction coordinator

e. Startup test coordinator

f. Startup administrative (clerical) coordinator

14.2.2.2.8 Systems Group Leaders

Systems group leaders perform a line function, and report to the assistant project startup engineer. Group leaders are assigned a staff of system startup engineers, and leaders have overall responsibility for assigned systems.

Minimum qualifications for a systems group leader are one of the following:

a. Graduate of 4 year accredited engineering or science college, and 2 years of power plant experience.

b. High school graduate or equivalent, and 4 years of power plant experience.

14.2.2.2.9 Startup Responsibilities

Specific responsibilities delegated to the startup group during the initial test program include:

a. Coordinating system/component turnovers.

b. Coordinating initial instrument, relay, and meter calibration.

c. Coordinating initial digital and analog control loop checkout.

d. Coordinating equipment initial operation.

e. Coordinating system cleanliness verification after turnover.

f. Ensuring that assigned vendors and other consultants assisting the startup group work in accordance with approved procedures.

g. Authorizing and ensuring proper identification, documentation, and restoration of temporary modifications made during the preoperational test program (for selected systems/components this responsibility may be assumed by the plant staff prior to the conclusion of the preoperational test program).

h. Documenting and reporting design problems identified during the initial test program, until licensee permanent plant procedures are implemented to perform this function, at which time this becomes a plant staff responsibility.

i. Documenting and reporting construction problems identified during the initial test program, until licensee permanent plant procedures are implemented to perform this function, at which time this becomes a plant staff responsibility.

j. Authorizing and monitoring rework, modification, and maintenance during the preoperational test program (for selected systems/components this responsibility may be assumed by the plant staff prior to conclusion of the preoperational test program).

k. Coordinating preparation, review, and approval of preoperational test procedures.

l. Coordinating performance of preoperational testing.

m. Coordinating review and approval of preoperational test results.

n. Planning and scheduling preoperational test program activities.

14.2.2.3 Plant Operations Review Committee

The PORC consists of the individuals assigned independent review responsibility per the requirements of Chapter 13. The responsibilities and reporting relationships of PORC members are also described in Chapter 13. During the initial test program, additional PORC responsibilities include reviewing startup test procedures prior to testing and reviewing startup test results. Based upon their review findings, PORC recommends to the plant manager whether the procedure and/or procedure results are acceptable or not.

14.2.2.4 Test Review Board

The TRB is a temporary review organization established specifically for the initial test program. TRB members may consist of individuals of various organizations Bechtel Startup, the licensee, PECo, or others. Figure 14.2-3 shows the organization and structure of the TRB. The TRB is responsible for reviewing preoperational test procedures prior to testing, and for reviewing preoperational test results. Based upon its review findings, the TRB recommends to the plant manager whether the procedure and/or procedure results are acceptable or not.

The LGS Plant Manager is responsible for assigning individuals to the TRB. These assignments may be either permanent or temporary. The TRB chairman is responsible for the conduct of the TRB, and reports directly to the LGS Plant Manager.

Minimum qualifications for the TRB chairman are the same as those for the LGS Startup Superintendent, identified in Section 14.2.2.2.3.

Minimum qualifications for TRB members are the same as those for the Assistant Project Startup Engineer, identified in Section 14.2.2.2.5.

14.2.3 TEST PROCEDURES

The initial test program is conducted in accordance with detailed preoperational and startup test procedures. The licensee maintains overall responsibility for test procedure preparation, review, and approval. These activities are completed as described in the following sections.

14.2.3.1 Procedure Preparation

Test procedure drafts are initially prepared by designated organizations (Bechtel Startup, GE, the licensee, or others) in accordance with the standard format of Figure 14.2-4. Specific acceptance criteria are developed using reference material such as plant Technical Specifications, FSAR Chapter 15 accident analyses, other FSAR sections, vendor topical reports, vendor technical documents, Bechtel Power Corporation design diagrams, instrument and equipment indexes, and applicable regulatory guides and codes. These specific criteria are listed in each test procedure, followed by the reference documents from which they were obtained. The completed drafts are then reviewed by cognizant design organization representatives, to ensure that the test procedure objectives and acceptance criteria are consistent with current design document requirements. Review comments are resolved between the writing organization and the cognizant design organization representative. Upon satisfactory resolution of comments, subsequent changes to test procedure objectives or acceptance criteria are based on changes to approved design documents or design organization concurrence.

14.2.3.2 Procedure Review and Approval

Following initial preparation, test procedures are processed through a formal review and approval cycle. The LGS Unit 2 Startup Manager or his designee is responsible for coordinating this process and for resolving review comments.

Preoperational test procedures are reviewed by the TRB, and startup test procedures are reviewed by the PORC. Individuals who are designated review responsibility are responsible for reviewing test procedures for accuracy, technical content, conformance with FSAR requirements, and compatibility with approved design documents. Additional specific review responsibilities include the following:

a. Verifying that procedure references have been updated to latest revisions.

b. Verifying that the procedure has been revised to incorporate design changes.

c. Verifying procedure compatibility with field installation of equipment.

d. Verifying procedure conformance with FSAR amendments, environmental Technical Specifications, and plant operating Technical Specifications.

e. Verifying that procedures reflect reactor operating and testing experiences of similar power plants.

Upon completion of initial reviews and inclusion of required changes, test procedures are submitted to the LGS Plant Manager for final approval.

Test procedure revisions and procedure modifications are processed through the same review and approval cycle.

14.2.4 CONDUCT OF TEST PROGRAM

The administrative controls that govern conduct of the plant staff and of the startup group during the initial test program are specified by administrative procedures. These administrative procedures are licensee controlled and approved documents. Administrative procedures define tasks to be performed, prescribe methods, and assign responsibilities for performing them.

The administrative procedures governing conduct of the startup group are contained in the Startup Administrative Manual. These procedures do not establish the administrative controls of other project groups or organizations, except as they interface with the startup group. Each procedure of the Startup Administrative Manual is approved for use by the appropriate authorities prior to starting the initial test program.

Station administrative procedures govern the conduct of Phases II, III, and IV of the initial test program.

The administrative procedures governing conduct of the plant staff are described in Chapter 13. The preparation, review, and approval of these procedures are also described in Chapter 13. Sufficient time is provided for procedures to be available for use, prior to the time they are required to be implemented.

14.2.4.1 Test Performance

Testing performed during the initial test program is in accordance with approved test procedures. The method for preparing, reviewing, and approving test procedures is detailed in Section 14.2.3. Before testing, a test director is assigned to each procedure. The test director is the individual designated as being responsible for coordinating test performance. Test directors are assigned from the startup group or the vendor-augmented plant staff by the LGS Plant Manager or his designee.

Specific responsibilities of the test director include, but are not limited to:

a. Verifying test prerequisites are complete and properly documented, except as provided by Section 14.2.4.2.

b. Ensuring that required test apparatus and/or equipment is available.

c. Documenting test performance on the official test copy of the procedure.

d. Ensuring that proper precautions are observed during testing.

e. Adhering to the detailed instructions of the approved procedure, except as provided by Section 14.2.4.3.

f. Ensuring that test personnel have been properly briefed.

g. Documenting and reporting test exceptions.

Minimum qualifications for a test director performing preoperational tests are one of the following:

a. High school graduate or equivalent, and 1 year of power plant or industrial experience.

b. Graduate of a 4 year accredited engineering or science college.

Minimum qualifications for a test director performing startup tests are one of the following:

a. High school graduate or equivalent, and 4 years of power plant experience.

b. Graduate of a 4 year accredited engineering or science college, and 1 year of power plant experience.

The plant operating staff is responsible for the safe and proper operation of equipment during testing. Should an unsafe condition arise, the plant operating staff takes whatever action is necessary including, but not limited to, stopping the test in order to restore safe plant conditions. During startup testing, the plant operating staff is specifically responsible for compliance with operating technical specifications, compliance with the provisions of the operating license, and authorization of testing.

14.2.4.2 Test Prerequisites

Specific test prerequisites are identified in each preoperational and startup test procedure. Figure 14.2-8 depicts some of the typical prerequisites that are included in each preoperational test procedure as applicable to the system being tested. The test director verifies that each prerequisite is completed and properly documented prior to sign-off in the official test copy of the procedure. If a prerequisite cannot be satisfied, the test director may waive the prerequisite to expedite testing. Waiving of a prerequisite is permissible only if the prerequisite has a minimal and definable effect on the test.

Waiving of a prerequisite constitutes a procedure modification; the test director is responsible for complying with the requirements of Section 14.2.4.3.

14.2.4.3 Procedure Modifications

Tests are intended to be conducted in accordance with the approved procedure; but, if necessary, a procedure may be modified to complete testing. Such modifications are documented within the text of the procedure and on a special change form for major modifications. The test director marks up the official test copy of the procedure to clearly delineate the required change, and initials and dates the change. For modifications to startup test procedures, the change is also initialed and dated by a licensed senior operator. In addition for major modifications, the test director prepares and processes a change form. The change form becomes an attachment to the official test copy of the procedure. Review and approval requirements for change forms are the same as for the original procedure. Preparation, review, and approval activities are accomplished before or after the performance of associated testing based on one of the following criteria:

a. For minor modifications that obviously preserve the intent of the test, the change is documented within the text of the procedure prior to performance of that part of the test and is reviewed after the performance of associated testing with the test results.

b. For major modifications that alter the intent of the test, the change form is processed before performance of the associated testing.

14.2.4.4 Design Problems

In the process of checkout, preliminary operation, and testing, design problems may be encountered. All such design problems are formally documented and reported to appropriate design organization representatives for resolution. Typical design problems include:

a. Errors or discrepancies in approved project design documents.

b. Items that represent a potential hazard to personnel safety.

c. Proposed facility modifications.

d. Failure of a tested system or component to satisfy design requirements or acceptance criteria.

e. Operating problems where operation is in accordance with approved procedures.

Design response for all such reported items is mandatory. Should the response require a facility modification, the appropriate design documents are revised and issued to the field. Field implementation of the modification is subsequently controlled in accordance with Section 14.2.4.5.

14.2.4.5 Control of Rework, Modifications, and Repairs

A comprehensive listing of outstanding work items is maintained for each system during the initial test program. This listing is maintained to ensure that identified work is performed. Typical listed work items include:

a. Incomplete or incorrect equipment installation

b. Required equipment repairs (corrective maintenance)

c. Approved facility modifications

d. New or additional construction

This work is performed by the construction organization, the plant maintenance staff, or a contract organization in accordance with approved procedures. In any event, in order to maintain the required controls, formal authorization is required to perform the work. This authorization is obtained from the startup group, or from the plant staff through the implementation of appropriate administrative procedures. These administrative procedures, in addition to authorizing performance of the work, specifically identify any retesting required as a result of the work, and document completion of both the work and the retesting. Closure of the associated work list item also requires completion of both the specified work and the specified retesting.

14.2.4.6 Major Test Phase Prerequisites

Completion of each major phase of the initial test program is a prerequisite to starting the succeeding phase. Section 14.2.11 identifies the specific testing scheduled to be conducted during each of the phases. A phase is considered complete only after the results of required testing are evaluated, reviewed, and approved per the requirements of Section 14.2.5.

14.2.5 REVIEW, EVALUATION, AND APPROVAL OF TEST RESULTS

The licensee has overall responsibility for review, evaluation, and approval of test results. The following sections establish the requirements for review, evaluation, and approval of individual test results, major test phase test results, and power ascension test results.

14.2.5.1 Individual Test Results

Upon completion of testing, the test director assembles a test package that includes the official test copy of the procedure and related documentation. Preoperational test packages are submitted to the TRB chairman, who disseminates the information to TRB members responsible for performing an in-depth review and evaluation of test results. Startup test packages are submitted to the PORC chairman, who disseminates the information to PORC members responsible for performing an in-depth review and evaluation of test results.

Test discrepancies, deficiencies, and omissions identified during testing or during review of test results are documented as test exceptions. Test exceptions occurring because of design problems are reported to appropriate design organization representatives for resolution per Section 14.2.4.4. Following review and resolution of review comments, the responsible chairman (TRB or PORC) has three options:

a. Recommend that the entire test be repeated.

b. Recommend that test results are unacceptable until all or part of the outstanding exceptions are resolved.

c. Recommend acceptance of test results with or without exceptions.

Approval of preoperational and startup test results (with or without exceptions) is by the LGS Plant Manager.

14.2.5.2 Test Exceptions

Each exception and its disposition are evaluated and resolved by processing the information through the same review and approval cycle as the original procedure, until such time as the system has been turned over to the plant staff, at which time PORC will perform the review.

14.2.5.3 Major Test Phase - Test Results

Commencement of each major test phase of the startup test program requires that the following test procedure review and approval commitments be satisfied:

a. Commencement of initial fuel loading and zero power testing requires that the results of the preoperational tests of Figure 14.2-6 be reviewed and approved in accordance with Section 14.2.5.1.

b. Commencement of low power testing requires that the results of the initial fuel loading and zero power tests of Figure 14.2-5, be reviewed and approved per the requirements of Section 14.2.5.1.

c. Commencement of power ascension testing requires that the results of the low power tests of Figure 14.2-5 be reviewed and approved per the requirements of Section 14.2.5.1.

14.2.5.4 Power Ascension Testing - Test Results

Figure 14.2-5 prescribes the sequence of testing, during the power ascension testing phase, as a function of reactor power and flow. Commencement of testing specified for each level requires that the test results of the preceding level be reviewed and approved per the requirements of Section 14.2.5.1.

14.2.6 TEST RECORDS

A single copy of each approved procedure, denoted as the official test copy, is used as the official record of the test. The completed official test copy and associated test documents are assembled into a test package at the end of testing. Test packages are retained for the life of the plant, in accordance with licensee procedures for retention of historical records. Each test package contains, either as part of the procedure or as separate documentation, the following information:

a. A description of the test method and objectives

b. A comparison of test data with acceptance criteria

c. Deficiencies relating to design and construction identified during testing

d. Modifications and corrective actions required

e. Justification for acceptance of systems or components not in conformance with design predictions or performance requirements

f. Conclusions regarding system or component adequacy

This test package is intended to serve as the main report for each test because it contains all necessary information concerning the test. Additional individual test reports, summarizing test results, are not contemplated, except as required by plant operation technical specifications.

14.2.7 CONFORMANCE OF TEST PROGRAMS WITH REGULATORY GUIDES

The initial test program to be conducted at LGS is as defined in this chapter. This chapter establishes both the administrative and technical requirements of the test program. Implementation of the initial test program must be in accordance with these requirements.

This program was developed in accordance with the following positions, as related to regulatory guides.

14.2.7.1 General Position - Regulatory Guides

The purpose of the regulatory guides, as related to testing, is to describe the scope and depth (administratively and technically) of an initial test program, acceptable for light-water-cooled nuclear power plants. The basis for the regulatory guides is 10CFR50.34 and 10CFR50, Appendix B. These two items specifically apply to testing structures, systems, and components important to

safety; that is, there must be sufficient testing to provide reasonable assurance that the facility can be operated without undue risk to the health and safety of the public.

Structures, systems, and components important to safety are classified as safety-related and are identified in Section 3.2. The remaining structures, systems, and components are considered nonsafety-related, and the plant design is based upon the concept that failure of a nonsafety-related structure, system, or component cannot jeopardize the health or safety of the public. The regulatory guides, as related to testing, apply administratively and technically only to structures, systems, and components classified as safety-related; however, to comply with the positions in the guides, systems meeting the criteria of Regulatory Guide 1.68, position C.1, will also be tested.

14.2.7.2 Specific Position - Regulatory Guides

In accordance with the general position of Section 14.2.7.1 plant structures, systems, and components classified as safety-related will be tested in accordance with the testing criteria of the following regulatory guides with specific exceptions, if any, noted below.

Only those portions of the regulatory guides that apply to the initial test program are considered. Other portions of the regulatory guides are implemented as applicable in the plant technical specifications. In addition, testing as specified in these guides is in accordance with existing design.

Regulatory Guide 1.20 (Rev 2) - "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing" (May 1976).

Regulatory Guide 1.41 - "Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignments" (March 16, 1973).

Regulatory Guide 1.52 (Rev 2) - "Design, Testing, and Maintenance Criteria for Engineered Safety Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants" (March 1978).

Regulatory Guide 1.56 (Rev 1) - "Maintenance of Water Purity in Boiling Water Reactors" (July 1978).

Regulatory Guide 1.68 (Rev 2) - "Initial Test Programs for Water-Cooled Reactor Power Plants" (August 1978).

The Unit 2 preoperational test program may use some data and test results from testing conducted outside of and prior to the preoperational test. Where this alternate testing is used to satisfy acceptance criteria of the preoperational test, the associated documentation will be reviewed by Quality Assurance and the TRB during the preoperational test results review cycle.

Additionally, for systems or features provided on both Units 1 and 2 to ensure or support the operation of engineered safety features, an alternative to concurrent testing has been developed. These systems can demonstrate support through flow balancing, or for HVAC systems, as discussed below.

Assurance that the safety-related HVAC systems will maintain the safety-related components within their design temperature range, with the components operating in a manner that produces maximum heat load, is provided by the following:

a. The sizing of the safety-related HVAC equipment was based on the maximum heat loads that would occur for DBA conditions.

b. The safety-related fans were performance tested by the vendor to AMCA Standards.

c. The safety-related cooling coils carry coil ratings as follows:

1. Cooling coils that fall within the parameters of the ARI Certified Rating Program carry an ARI certified performance rating. The ARI ratings are based on qualification test data approved by ARI.

2. Cooling coils with parameters (entering air temperature, etc) that fall outside the ARI Certified Rating Program are performance rated in accordance with the American Air Filter Company Topical Report AAF-TR-7101, "Design and Testing of Fan Cooler-Filter Systems for Nuclear Applications." This topical report presents the interpolation procedure used to extend the ARI rating technique beyond its approved range. The validity of the procedure has been confirmed by performance tests, and it has been approved by ARI and accepted by the NRC.

d. The balancing of the HVAC systems (air and water sides) will be administered by a startup technical procedure. The monitoring of the HVAC balancing will ensure that the design air and water flows are attained.

e. The Control Enclosure Chilled Water Preoperational Test Procedure IP-30.2 will require verification at the 44°F design chilled water temperature is attained.

The combination of equipment selection of maximum DBA heat loads, equipment performance ratings to accepted standards, air and water balancing along with proper chilled water temperature to satisfy coil performance rating parameters, and air balancing to attain design duct air flow rates is verification that the safety-related HVAC systems will function as designed and will maintain design temperatures as required for DBA conditions.

Regulatory Guide 1.68.1 (Rev 1) - "Preoperational and Initial Startup Testing of Feedwater and Condensate Systems for Boiling Water Reactor Power Plants" (January 1977).

The Unit 2 preoperational test program may use some data and test results from testing conducted outside of and prior to the preoperational test. Where this alternate testing is used to satisfy acceptance criteria of the preoperational test, the associated documentation will be reviewed by Quality Assurance and the TRB during the preoperational test results review cycle.

Regulatory Guide 1.68.2 - "Initial Startup Test Program to Demonstrate Remote Shutdown Capability for Water-Cooled Nuclear Power Plants" (January 1977).

Regulatory Guide 1.68.3 - "Preoperational Testing of Instrument and Control Air Systems" (April 1982).

Compliance is demonstrated by preoperational test procedures P-18.1, P-25.1, P-83.1, and P-100.2.

The Unit 2 preoperational test program may use some data and test results from testing conducted outside of and prior to the preoperational test. Where this alternate testing is used to satisfy acceptance criteria of the preoperational test, the associate documentation will be reviewed by Quality Assurance and the TRB during the preoperational test results review cycle.

Regulatory Guide 1.70 (Rev 3) - "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants" (November 1978).

Regulatory Guide 1.104 - "Overhead Crane Handling Systems for Nuclear Power Plants" (February 1976).

Overhead crane testing exceptions are as outlined in Section 9.1.5.

Regulatory Guide 1.108 (Rev 1) - "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants" (August 1977).

Testing of the diesel generators is discussed in Section 8.1.6.1.20.

Regulatory Guide 1.140 (Rev 1) - "Design, Testing, and Maintenance Criteria for Normal Ventilation Exhaust System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants" (October 1979).

14.2.8 UTILIZATION OF REACTOR OPERATING AND TESTING EXPERIENCE IN THE DEVELOPMENT OF THE TEST PROGRAM

The TRB and the PORC are responsible for ensuring that reactor operating and testing experiences of similar power plants are utilized during the initial test program. The primary sources of experience feedback is the Independent Safety Engineering Group and the Operating Experience Assessment Committee who provide relevant information based upon their continuing review of the industry via such sources as INPO Significant Operating Experience

Reports and Significant Event Reports, GE Service Information Letters, and NRC Licensee Event Reports. This review includes at least a two year period prior to the commencement of the initial test program. The TRB chairman and the PORC chairman are each responsible for disseminating this feedback material to individuals who are designated test procedure review responsibility. During their review of assigned test procedures, TRB and PORC members are subsequently responsible for ensuring that pertinent feedback experiences are considered.

14.2.9 TRIAL USE OF PLANT OPERATING AND EMERGENCY PROCEDURES

The preparation, review, and approval of plant operating and emergency procedures are described in Chapter 13. Sufficient time is provided for confirming procedure adequacy by trial use during the initial test program. Those procedures that do not require nuclear fuel are confirmed as adequate during the preoperational test program. Those procedures that require nuclear fuel are confirmed as adequate during the startup test program.

The plant operating staff is responsible for confirming operating and emergency procedures. The LGS Plant Manager is responsible for ensuring that comments and/or changes identified during confirmation are incorporated into finalized procedures.

It is not intended that preoperational and startup test procedures explicitly incorporate or reference plant operating and emergency procedures, although they may do so where appropriate. These tests are intended to stand on their own, since they are not necessarily compatible with configurations and conditions required for confirmation of facility operating and emergency procedures.

14.2.10 INITIAL FUEL LOADING AND INITIAL CRITICALITY

Initial fuel loading is accomplished in accordance with startup test procedure, "Fuel Loading, STP-3." Initial criticality is accomplished in accordance with startup test procedure, "Full Core Shutdown Margin, STP-4." These procedures comply with the general guidelines and regulatory positions contained in Regulatory Guide 1.68 (Rev 2 - August 1978). Test abstracts establishing the objectives, prerequisites, test method, and acceptance criteria for these procedures are presented in Table 14.2-3.

14.2.11 TEST PROGRAM SCHEDULE

The schedule, relative to the initial fuel loading date, for conducting each major test phase of the initial test program is presented in Figure 14.2-1. This figure illustrates that the preoperational test program is scheduled for 15 months duration for Unit 1, 16 months duration for Unit 2, and that the subsequent startup test programs are scheduled at 3 months and 6 months duration for Units 1 and 2, respectively. Approved preoperational test procedures are intended to be available for NRC review at least 60 days prior to scheduled implementation. Copies of approved test procedures for fuel loading, initial startup testing (zero power testing), and supporting activities through Phase II of the initial test program are intended to be available for NRC examination not less than 60 days before the scheduled fuel load date. Copies of test procedures for Phase III (Low Power Testing) and Phase IV (Power Ascension Testing) of the initial test program are intended to be available for NRC examination not less than 60 days prior to the scheduled fuel load date. Every effort will be made to provide approved test procedures for Phases III and IV; however, if such procedures are not available, copies of draft procedures will be provided.

The sequential schedules for conducting individual preoperational tests for each unit are presented in Figures 14.2-6 and Figure 14.2-7. These sequential schedules offer one possible plan for an orderly and efficient progression of testing. While these sequences may be preferred, numerous acceptable alternatives exist because few preoperational tests are dependent on performance of other preoperational tests. The actual test sequences are determined daily at the job-site to reflect construction status, manpower availability, and test prerequisite status.

The sequential schedule for conducting Unit 1 and Unit 2 startup tests is presented in Figure 14.2-5. This schedule establishes the required order of startup testing as a function of test phase and power level. Even though this basic order of testing is required, there is still considerable flexibility in sequencing the startup testing specified to be conducted at each test phase or startup level. Detailed startup testing schedules, commensurate with the requirements of this schedule, are developed at the job-site to schedule startup testing when operationally expedient.

14.2.12 INDIVIDUAL TEST DESCRIPTIONS

Individual abstracts for each preoperational test conducted during the preoperational test program are given in Table 14.2-4. Individual abstracts for each startup test conducted during the subsequent startup test program are given in Table 14.2-3. These abstracts identify each test by title and number, describe the test objectives, identify the test prerequisites, provide a summary

description of the test method, and establish basic test acceptance criteria. Presently known documents that provide sources of acceptance criteria are identified in parentheses in the acceptance criteria section of the individual abstracts. Other documents or FSAR sections referenced within the identified document may also serve as sources of acceptance criteria. The test abstracts are not intended to be ongoing documents that are continuously changed as references are modified. The identification of documents may be modified as specific acceptance criteria are developed and test procedures are written.

Table 14.2-1

PREOPERATIONAL TEST PROCEDURES

TEST NUMBER	TEST TITLE
P-2.1	125 V (Div III, IV) Dc Safeguard Power System
P-2.2	125/250 V (Div I, II) Dc Safeguard Power System
P-3.1	13.2 kV Unit Auxiliary Power System
P-4.1	4 kV Safeguard Power System
P-5.1	Safeguard 440 V Load Centers
P-6.1	Safeguard 440 V Motor Control Centers
P-7.1	Standby Dc Lighting System
P-11.1	Service Water System
P-13.1	Fire Protection Water Systems
P-13.2	Fire Protection CO_2 System
P-13.3	Fire Protection Air Foam System
P-13.4	Smoke Detection System
P-13.5	Fire Protection Halon System
P-14.1	Reactor Enclosure Cooling Water System
P-15.1	Turbine Enclosure Cooling Water System
P-16.1	Residual Heat Removal Service Water System
P-17.1	Instrumentation Ac Power System
P-18.1	Instrument Air System
P-23.1	Diesel Generator Fuel Oil System
P-24.1	Standby Diesel Generator System
P-25.1	Primary Containment Instrument Gas System
P-28.1	Diesel Generator Enclosure HVAC System
P-28.2[(1)]	Spray Pond Pump Structure HVAC System

Table 14.2-1 (Cont'd)

TEST NUMBER	TEST TITLE
P-30.1[(1)]	Control Enclosure HVAC System
P-30.2[(1)]	Control Enclosure Chilled Water System
P-32.1[(1)]	Control Room HVAC System
P-32.2[(1)]	Control Room Isolation and Purge System
P-33.1	Turbine Enclosure HVAC System
P-34.1	Reactor Enclosure HVAC System
P-34.2	Refueling Area HVAC System
P-35.1	Fuel Pool Cooling and Cleanup System
P-37.1	Condensate and Refueling Water Transfer System
P-39.1	Condensate Demineralizer System
P-41.1	Cooling Tower System
P-42.1	Circulating Water System
P-43.1	Condenser and Air Removal System
P-44.1	Condensate System
P-45.1	Feedwater System
P-46.1	Extraction Steam and Feedwater Heater Systems
P-49.1	Residual Heat Removal System
P-50.1	Reactor Core Isolation Cooling System
P-51.1	Core Spray System
P-52.1	High Pressure Coolant Injection System
P-53.1	Standby Liquid Control System
P-54.1	Emergency Service Water System
P-55.1	Control Rod Drive Hydraulic System
P-56.1	Reactor Manual Control System

Table 14.2-1 (Cont'd)

TEST NUMBER	TEST TITLE
P-57.1	Uninterruptible Ac Power System
P-58.1	Reactor Protection System
P-58.2	Redundant Reactivity Control System for ATWS
P-59.1	Containment Isolation and Nuclear Steam Supply Shutoff System
P-59.2	Primary Containment Integrated Leak Rate Test
P-59.3	Suppression Pool, Pool Cleanup, and Vacuum Relief
P-60.1	Drywell HVAC System
P-61.1	Reactor Water Cleanup System
P-62.1	Reactor Vessel and Auxiliaries
P-64.1	Reactor Recirculation System
P-65.1(1)	Radwaste Enclosure HVAC System
P-66.1	Reactor Enclosure Unit Cooler System
P-66.2(1)	Control Enclosure Unit Coolers
P-68.1	Solid Radwaste System
P-69.1	Equipment Drain Collection and Storage System
P-69.3	Liquid Radwaste System
P-70.1(1)	Standby Gas Treatment System and Reactor Enclosure Air Recirculation, Secondary Containment Isolation
P-72.1	Gaseous Radwaste Recombiners and Filters
P-73.1	Containment Atmosphere Control System
P-76.1	Process Sampling System
P-76.2	Postaccident Sampling System
P-78.1	Startup Range Detector Drive Control and Neutron Monitoring System

Table 14.2-1 (Cont'd)

TEST NUMBER	TEST TITLE
P-78.2	Power Range Neutron Monitoring System
P-78.3	Traversing Incore Probes Calibration System
P-79.1	Area Radiation Monitoring System
P-79.2	Process Radiation Monitoring System
P-80.1	Reactor Vessel Instrumentation System
P-81.1	Fuel Handling System
P-83.1	Main Steam System
P-83.2	Automatic Depressurization System
P-83.3	Steam Leak Detection System
P-85.1	Cathodic Protection System
P-85.2	Freeze Protection and Heat Trace Systems
P-91.1	Plant Annunciator Systems
P-93.2	Main Turbine Control System
P-93.3	Main Turbine Supervisory System
P-99.1	Reactor Enclosure Crane
P-99.2	Seismographical Monitoring System
P-99.3	Public Address and Evacuation System
P-100.1	Loss of Offsite Power Test
P-100.2	Loss of Instrument Air
P-100.3	Mechanical Snubber Testing (Replaced by TT1.30)
P-100.4	Standby Diesel Generator Loading

(1) Common System - All common testing to be performed during Unit 1 initial test program only.

Table 14.2-2

STARTUP TEST PROCEDURES

TEST NUMBER	TEST TITLE
STP-1	Chemical and Radiochemical (Formerly SUT-1)
STP-2	Radiation Measurements (Formerly SUT-2)
STP-3	Fuel Loading (Formerly SUT-3)
STP-4	Full Core Shutdown Margin (Formerly SUT-4)
STP-5	Control Rod Drive System (Formerly SUT-5)
STP-6	Source Range Monitor Performance and Control Rod Sequence (Formerly SUT-6)
STP-9	Water Level Reference Leg Temperature (Formerly SUT-7)
STP-10	Intermediate Range Monitor Performance (Formerly SUT-8)
STP-11	Local Power Range Monitoring Calibration (Formerly SUT-9)
STP-12	Average Power Range Monitoring Calibration (Formerly SUT-10)
STP-13	Process Computer Performance Verification (Unit 1) (Formerly SUT-11)
STP-13	Plant Monitoring System Performance Verification (Unit 2)
STP-14	RCIC System Performance Verification (Formerly SUT-12)
STP-14.1	RCIC System Startup After Loss of Ac Power to the System (Formerly SUT-12.1)
STP-14.2	RCIC System Operation with a Sustained Loss of Ac Power to the System (Formerly SUT-12.2)
STP-15	HPCI System Performance Verification (Formerly SUT-13)
STP-16	Selected Process Temperatures Verification (Formerly SUT-14)
STP-17	System Expansion (Formerly SUT-15)

Table 14.2-2 (Cont'd)

TEST NUMBER	TEST TITLE
STP-18	TIP Uncertainty (Formerly SUT-16)
STP-19	Core Performance (Formerly SUT-17)
STP-20	Steam Production
STP-21	DELETED
STP-22	Pressure Regulator Response (Formerly SUT-19)
STP-23	Feedwater Control System Demonstration (Formerly SUT-20)
STP-24	Main Turbine Valves Surveillance Test (Formerly SUT-23)
STP-25	Main Steam Isolation Valves Performance Verification (Formerly SUT-21)
STP-26	Main Steam Relief Valves Performance (Formerly SUT-22)
STP-27	Turbine Trip and Generator Load Rejection Demonstration (Formerly SUT-25)
STP-28	Shutdown from Outside the Main Control Room Demonstration (Formerly SUT-24)
STP-29	Recirculation Flow Control Demonstration (Formerly SUT-26)
STP-30	Recirculation System (Formerly SUT-27)
STP-31	Loss of Turbine-Generator and Offsite Power (Formerly SUT-28)
STP-32	Essential HVAC System Operation and Containment Hot Penetration Temperature Verification (Formerly SUT-34)
STP-33	Piping Steady-State Vibration Measurements (Formerly SUT-29)
STP-34	Offgas System Performance Verification (Formerly SUT-33)

Table 14.2-2 (Cont'd)

TEST NUMBER	TEST TITLE
STP-35	Recirculation Flow Calibration (Formerly SUT-30)
STP-36	Piping Dynamic Transient (Formerly SUT-36)
STP-37	DELETED
STP-38	DELETED
STP-70	Reactor Water Cleanup System Performance Verification (Formerly SUT-31)
STP-71	Residual Heat Removal System Performance Verification (Formerly SUT-32)

Table 14.2-3

STARTUP TEST PROCEDURE ABSTRACTS

(STP-1) Chemical and Radiochemical

Test Objectives - The test objectives are to ensure that the systems provide adequate means to maintain control and knowledge of the quality of the plant systems chemistry and to ensure that the sampling equipment, procedures, and analytic techniques are adequate to supply the data required to demonstrate that the fluids meet quality specifications and process requirements. They must also monitor the integrity of the fuel, the operation of the demineralizers and filters, the condenser tube integrity, the operation of the offgas system, and the tuning of certain process instruments.

Prerequisites - Instrument calibration and preoperational testing of chemical, radiation, and radiochemical monitors are completed, and a set of chemical and radiochemical samples were taken to functionally check sample stations.

Test Method - Prior to fuel loading, a set of chemical and radiochemical samples is taken to determine initial concentrations for selected systems. Subsequent to fuel loading, during reactor heatup, and at each major power level change, samples are taken and measurements are made to determine the chemical and radiochemical quality of reactor water and reactor feedwater, the amount of radiolytic gas in the steam, gaseous activities after the air ejectors, decay times in the offgas lines, and the performance of filters and demineralizers. Monitors in the liquid waste system and liquid process lines are adjusted as required. The chemical and radiochemical monitors and the sample system operation verify that the system is capable of providing true samples at proper flow, temperature, and/or moisture content, as applicable, so that means are available for the reliable analysis of the process by instrumentation or plant personnel.

Acceptance Criteria - Water quality remains within applicable guidelines, and gaseous and liquid effluent activities conform with plant requirements.

(STP-2) Radiation Measurements

Test Objectives - The test objectives are: to determine the background gamma and neutron radiation levels in the plant environs prior to operation in order to provide base data on activity buildup and shielding adequacy; and to monitor radiation at selected power levels to ensure the protection of personnel, and continuous compliance with the guideline standards of 10CFR20 during plant operation.

Prerequisites - A survey of natural background radiation is made at selected locations throughout the plant site.

Test Method - Subsequent to fuel loading, during reactor heatup, and at various selected power levels, gamma radiation level measurements and, where appropriate, neutron dose rate measurements are made at significant locations throughout the plant site. Potentially high radiation areas are surveyed.

Acceptance Criteria - Plant radiation doses and personnel occupancy times are controlled within allowable limits as defined in 10CFR20.

Table 14.2-3 (Cont'd)

(STP-3) Fuel Loading

Test Objective - The test objective is to load fuel safely and efficiently to the full core size.

Prerequisites - The preoperational test program test results have been reviewed and approved, and an NRC license has been issued to PECo. A neutron source is installed near the center of the core. At least three neutron detectors, calibrated and connected in a noncoincident mode to high flux scram trips, are located to produce acceptable signals during loading. Final testing of this reactor protection system and final reactor coolant leak rate testing have been completed.

Test Method - The fuel loading procedure includes the loading sequence, pattern, and records for logging, a running inventory of fuel status, control rod checks, minimum shutdown checks, neutron monitoring, subcritical multiplication behavior, communication requirements, safety requirements, emergency procedures, and additional checks to be performed during fuel loading.

For Unit 1, fuel loading begins at the center of the core and proceeds radially to the fully loaded configuration. During the loading of each cell, two fuel assemblies will be loaded in the location not occupied by the blade guide. The blade guide will be removed, and loading of the cell will be completed. A functional check to verify the operability of the control rod and drive will be performed on each cell after the cell is loaded.

This functional check may also serve as a subcritical check to verify that the next cell may be safely loaded.

For Unit 2, fuel loading will begin off-center so that loading can begin between an SRM and the closest source, and will continue in a spiral pattern to the full loaded configuration. During the loading of each cell, two fuel assemblies will be loaded in the location not occupied by the blade guide. The blade guide will be removed, and loading of the cell will be completed. A functional check to verify the operability of the control rod and drive will be performed on each cell after the cell is loaded. This functional check may also serve as a subcritical check to verify that the next cell may be safely loaded. Subcritical checks are not required for the first 16 fuel bundles loaded since an analysis has been performed which indicates that the first 16 fuel bundles loaded cannot establish a critical geometry.

Acceptance Criteria - The core is fully loaded in accordance with established procedures, and the core is subcritical.

(STP-4) Full Core Shutdown Margin

Test Objective - The test objective is to demonstrate that the reactor is sufficiently subcritical throughout the first fuel cycle, with any single control rod fully withdrawn.

Prerequisites - The core is fully loaded; the subcritical checks are completed; and the SRMs and IRMs are installed in the vessel and connected in a noncoincident mode, to scram at a high neutron level. The rod worth minimizer system is operational.

Table 14.2-3 (Cont'd)

Test Method - The shutdown margin test is performed by fully withdrawing a series of previously selected rods until criticality is reached. The empirical data are analyzed and compared with calculated data to determine the test results.

Acceptance Criteria - The basic criterion for reactivity control is that the core, in its maximum reactivity state at any time in the cycle, be sufficiently subcritical, with the strongest rod withdrawn, and all other rods fully inserted. Satisfactory completion of the shutdown margin test ensures, at the time of fuel loading, that this criterion has been met.

(STP-5) Control Rod Drive System

Test Objectives - The test objectives are to demonstrate that the CRD system operates over the full range of primary coolant temperatures and pressures, from ambient to operating, and to determine the initial operating characteristics of the entire CRD system.

Prerequisites - The process computer, scram time recorder, or equivalent recording equipment is on-line and available to monitor events; the CRD electrical and hydraulic system preoperational testing is completed satisfactorily; and the vessel water level is always above the upper core grid during all CRD movements. The reactor protection system preoperational test is completed, and the scram pilot valves are ready for energization.

Test Method - For Unit 1, during fuel load, a visual check is made of the position indication of each control rod, and the four-rod displays are checked for missing numbers. Insert and withdrawal times are verified during fuel load, and again at rated pressure for selected rods. Scram testing will be performed following fuel loading and at rated pressure. Coupling checks are again verified by the operator. Friction testing is conducted by measuring the pressure differential between the insert and withdrawal lines during the continuous insertion of a control rod.

For Unit 2, during fuel load, a visual check is made of the position indication of each control rod, and the four-rod displays are checked for missing numbers. Insert and withdrawal times are verified during fuel load, and again at rated pressure for selected rods. Scram testing will be performed following fuel loading and at rated pressure. Coupling checks are again verified by the operator. Friction testing is conducted by measuring the pressure differential between the insert and withdrawal lines or between the drive water header pressure downstream of the CRD Friction Testing Station and reactor pressure during the continuous insertion of a control rod.

Acceptance Criteria - Scram times and friction test results fall within acceptance limits. Each CRD has normal insert and withdrawal times within the limits indicated.

(STP-6) SRM Performance and Control Rod Sequence

Test Objective - The test objective is to demonstrate that the sources and SRM system provide sufficient information for knowledgeable and controlled reactor startup at low neutron levels.

Prerequisites - Fuel loading is completed, neutron sources are in place, and the core is clean and cold with all control rods inserted.

Table 14.2-3 (Cont'd)

Test Method - All control rod movement or operation is in compliance with approved owner operating procedures. The SRMs are connected, and subcritical testing verifies SRM response to control rod withdrawal. With the SRMs operational, criticality is approached. Records are maintained of count rate, rod configuration, and times. Criticality is achieved by withdrawing rods in the designated sequence.

Acceptance Criteria - SRMs are operational and read on-scale within the designed range for a cold clean core.

(STP-9) Water Level Reference Leg Temperature

Test Objective - The test objective is to demonstrate the calibration and agreement of the installed reactor vessel water level instrumentation at normal operating pressure and temperature.

Prerequisites - The following are determined and recorded: elevations of instrument taps, condensing chambers, head chambers indicating zero water level, and instrument ranges. The reactor is in a steady-state condition during each stage of testing. Air temperature in the vicinity of the level columns is stabilized.

Test Method - The test will be done at rated temperature and pressure and under steady-state conditions; the reference leg temperature will be measured and compared to the value assumed during initial calibration. If the difference exceeds operating tolerances, the instruments will be recalibrated using the measured value.

Acceptance Criteria - The installed reactor water level indication and controls provide accurate information and sufficient operating tolerances under normal operating conditions.

(STP-10) IRM Performance

Test Objective - The test objective is to demonstrate IRM system response to neutron flux and IRM overlap with the SRM and APRM systems.

Prerequisites - Fuel loading is completed, and the reactor is just critical. IRM gains are set at maximum for conservatism on Unit 1. IRM gains are set conservatively on Unit 2.

Test Method - After criticality and when flux level is sufficient, IRM response to neutron flux and the IRM/SRM overlap is verified. The SRMs and IRMs may then be taken out of noncoincident scram. Following APRM calibration in accordance with another procedure, the IRM gains may be adjusted to optimize the IRM overlap with the SRMs and APRMs.

Acceptance Criteria - Resulting IRM overlap with the SRMs and APRMs is established within acceptable limits.

(STP-11) Local Power Range Monitoring Calibration

Test Objective - The test objective is to calibrate the LPRM system.

Prerequisites - Reactor power and LPRM gains are sufficient to observe chamber response to the adjacent control rod during calibration of any LPRMs. The ability of the APRM system to provide

Table 14.2-3 (Cont'd)

input to the reactor protection system is maintained during this test. The process computer or off-line computer is available.

Test Method - The core is operated in a specified test condition, for a period sufficient to obtain short-term equilibrium conditions. LPRMs are calibrated in accordance with the calibration procedure. The meter reading of each LPRM chamber is proportional to the average heat flux in the four adjacent fuel rods at the height of the chamber.

Acceptance Criteria - LPRM calibration, in accordance with the procedure, is satisfactorily completed.

(STP-12) APRM Calibration

Test Objective - The test objective is to calibrate the APRM system.

Prerequisites - The core is at steady-state condition at the desired power level and core flow rate. Control rod positions and core flow are not changed during the time data are taken for these calibrations.

Test Method - With the core in a steady-state condition, calculations are made of the percent of rated power by heat balance. The APRMs are calibrated to agree with the calculated power value.

Acceptance Criteria - The APRMs are calibrated to read equal to or greater than the calculated core thermal power.

(STP-13) Process Computer Performance Verification (Unit 1)

Test Objective - The test objective is to demonstrate the ability of the process computer to provide accurate information pertaining to plant process variables under operating conditions.

Prerequisites - Fuel loading is completed to the extent necessary to perform this test. Applicable field inputs are terminated, computer room HVAC is operational, and the computer is operational, with plant data available.

Test Method - Following fuel loading, and during plant heatup and ascension to rated power, plant process variables, sensed by the computer as digital or analog signals, are recorded. Performance calculation programs are run, and the results recorded.

Acceptance Criteria - Programs P-1, OD-1, and OD-6 are considered operational when:

a. The MFLCPR, calculated by an independent method, and calculated by process computer, either:

   1. Are in the same fuel assembly and do not differ in value by more than 2%.

   2. When the MFLCPR calculated by the process computer is in a different assembly than that calculated by the independent method, the MFLCPR calculated by the two methods agree within 2%, for each assembly.

Table 14.2-3 (Cont'd)

b. The MFLPD, calculated by the independent method, and by the proces computer, either:

   1. Are in the same fuel assembly and do not differ in value by more than 2%.

   2. When the MFLPD calculated by the process computer is in a different assembly than that calculated by the independent method, the MFLPD calculated by the two methods agree within 2%, for each assembly.

c. The MAPLHGR, calculated by the independent method, and the process computer, either:

   1. Are in the same fuel assembly and do not differ in value more than 2%.

   2. When the MAPLHGR calculated by the process computer is in a different assembly than that calculated by the independent method, the MAPLHGR calculated by the two methods agree within 2%, for each assembly.

d. The LPRM calibration factors calculated by the independent method and the process computer agree to within 2%.

e. The remaining programs are considered operational upon successful completion of the static and dynamic testing.

(STP-13) Plant Monitoring System Performance Verification (Unit 2)

Test Objective - The test objective is to demonstrate the ability the PMS to provide accurate information pertaining to plant process variables under operating conditions.

Prerequisites - Fuel loading is completed to the extent necessary to perform this test. Applicable field inputs are terminated, computer room HVAC is operational, and the computer is operational, with plant data available.

Test Method - Following fuel loading, and during plant heatup and ascension to rated power, plant process variables, sensed by the computer as digital or analog signals, are recorded. Performance calculation programs are run, and the results recorded.

Acceptance Criteria - Programs P-1, OD-1, and OD-6 are considered operational when:

a. The MFLCPR, calculated by an independent method, and calculated by the PMS, either:

   1. Are in the same fuel assembly and do not differ in value by more than 2%.

   2. When the MFLCPR calculated by the PMS is in a different assembly than that calculated by the independent method, the MFLCPR calculated by the two methods agree within 2%, for each assembly.

Table 14.2-3 (Cont'd)

b. The MFLPD, calculated by the independent method, and by the PMS, either:

   1. Are in the same fuel assembly and do not differ in value by more than 2%.

   2. When the MFLPD calculated by the PMS is in a different assembly than that calculated by the independent method, the MFLPD calculated by the two methods agree within 2%, for each assembly.

c. The MAPLHGR, calculated by the independent method, and the PMS, either:

   1. Are in the same fuel assembly and do not differ in value more than 2%.

   2. When the MAPLHGR calculated by the PMS is in a different assembly than that calculated by the independent method, the MAPLHGR calculated by the two methods agree within 2%, for each assembly.

d. The LPRM calibration factors calculated by the independent method and the PMS agree to within 2%.

e. The remaining programs are considered operational upon successful completion of the static and dynamic testing.

(STP-14) Reactor Core Isolation Cooling System Performance Verification

Test Objective - The test objective is to demonstrate operation of the RCIC system over its required operating pressure range.

Prerequisites - The preoperational test of the RCIC system is completed. Fuel loading is completed, and sufficient nuclear steam is available to operate the RCIC pump throughout its operating range.

Test Method - A controlled start of the RCIC system is done at a reactor pressure of nominal 150 psig, and an automatic actuation start is done at rated reactor pressure. Verify the proper operation of the RCIC system and determine the time to reach rated flow. These tests may first be performed with the system in the test mode, so that discharge flow is not routed to the reactor pressure vessel. The final demonstration is made so that discharge flow is routed to the reactor pressure vessel while the reactor is at partial power. A cold quick start is performed with the system on the full flow test loop.

Acceptance Criteria - The RCIC system must have the capability to deliver specified flow, in less than or equal to the rated actuation time, against nominal rated reactor pressure.

Table 14.2-3 (Cont'd)

(STP-14.1) RCIC System Startup After Loss of Ac Power to the System

Test Objective - The test objective is to demonstrate the ability of the system to start without the aid of ac power with the exception of the RCIC dc/ac inverters.

Prerequisites - The preoperational test of the RCIC system is completed. Fuel loading is completed, and sufficient nuclear steam is available to operate the RCIC pump throughout its operating range. Power to RCIC components fed by site ac power is secured, and the station batteries are fully charged.

Test Method - A manual initiation of the RCIC system is accomplished at rated reactor pressure to verify the proper operation of all components to reach rated flow.

Acceptance Criteria - The RCIC system must have the capability to deliver specified flow against nominal rated reactor pressure without the normal ac site power supply.

(STP-14.2) RCIC System Operation with a Sustained Loss of Ac Power to the System

Test Objective - The test objective is to verify the operation of the RCIC beyond its design basis to evaluate the limits of the system operation with extended loss of ac power to the RCIC system and support systems with the exception of the RCIC dc/ac inverters.

Prerequisites - The preoperational test of the RCIC system is completed. Fuel loading is completed, and sufficient nuclear steam is available to operate the RCIC pump throughout its operating range. The RCIC system valves are in a normal standby lineup with suction from the CST. Power to RCIC components fed by site ac power is secured including the RCIC area coolers and battery chargers supplying the station battery from which the RCIC dc loads are powered. The RCIC batteries are fully charged. Instrument air is available for operation and controls of the appropriate valves.

Test Method - Start and operate the RCIC system with return to the CST and run the system for two hours or until any system limiting parameter is approached (e.g.: high RCIC area temperature, low battery voltage or high suppression pool temperature).

Acceptance Criteria - No defined acceptance criteria. The purpose of the test is to verify the operation of RCIC beyond its design basis.

(STP-15) High Pressure Coolant Injection System Performance Verification

Test Objective - The test objective is to demonstrate proper operation of the HPCI system over its required operating pressure range.

Prerequisites - The preoperational test of the HPCI system is completed. Fuel loading is completed, and sufficient nuclear steam is available to operate the HPCI pump throughout its operating range.

Table 14.2-3 (Cont'd)

Test Method - Controlled starts of the HPCI system are done at reactor pressures near 150 and rated during the heatup phase, and an automatic start is initiated. Verify the proper operation of the HPCI System, determine the time to reach rated flow, and adjust the flow controller in the HPCI System for proper flow rate. These tests are performed with the system in the test mode, so that discharge flow is not routed to the reactor pressure vessel. The final demonstration is made so that discharge flow is routed to the reactor pressure vessel, while the reactor is at partial power.

Acceptance Criteria - The HPCI turbine must not trip off during startup. The HPCI system must have the capability to deliver specified flow, in less than or equal to rated actuation time, against nominal rated reactor pressure.

(STP-16) Selected Process Temperatures Verification (Unit 1)

Test Objectives - The test objectives are: to establish the proper setting for the low speed limiter for the recirculation pumps, to keep the bottom head water temperature from being too low; and to demonstrate that the bottom head drain temperature corresponds to bottom head coolant temperature, during normal operation.

Prerequisites - The reactor is in a low power condition.

Test Method - With recirculation pumps at approximately 28% of maximum speed, allow the reactor to attain a steady-state condition. Data are recorded; then the speed of the pumps is slowly lowered until 20% of maximum speed or the minimum stable speed is reached, whichever is greater. Data are again recorded. The empirical data are analyzed to determine the optimum low speed limiter setting.

Acceptance Criteria - The resultant low speed setting maintains upper and lower region coolant temperatures within the specified limits.

(STP-16) Selected Process Temperatures Verification (Unit 2)

Test Objectives - The test objective is: to demonstrate that the bottom head drain temperature corresponds to bottom head coolant temperature, during normal operation.

Prerequisites - The reactor core flow is ≥95% of rated.

Test Method - With core flow at ≥95% of rated compare bottom drain line temperature with recirculation loop coolant temperature.

Acceptance Criteria - The bottom head drain temperature corresponds to the bottom head coolant temperature within specified limits.

(STP-17) System Expansion

Test Objectives - The test objectives are: to demonstrate that major equipment and the piping systems throughout the plant are free and unrestrained, with regard to thermal expansion; and that suspension components are functioning in the specified manner. See Section 3.9.2.1a.2 for nuclear steam supply system (NSSS) piping, and Table 3.9-7 for non-NSSS piping.

Table 14.2-3 (Cont'd)

The test also provides data for calculating stress levels in various critical nozzles and weldments.

Prerequisites - Engineering review of the piping systems is completed. Fuel loading and preservice examination of snubbers is completed and cold plant data are recorded. Preservice examination will include the following (Section 3.9.3.5.2.4):

a. There are no visible signs of damage or impaired operability as a result of storage, handling, or installation.

b. Location, orientation, position setting, and configuration are according to design drawings and specifications.

c. Snubbers are not seized, frozen, or jammed.

d. Adequate swing clearance is provided to allow snubber movement.

e. Structural connections such as pins, fasteners, and other connecting hardware such as lock nuts, tabs, wire, cotter pins are installed correctly.

When the interval between performance of snubber preservice inspection and initial power operation exceeds 6 months, items (a) and (d) above shall be reperformed and documented.

Test Method - During equipment heatup, observations and/or recordings of the horizontal and vertical movements of major equipment and piping in the NSSS and BOP systems are made to ensure that components are free to move as designed. Adjustments are made as necessary for freedom of movement.

Acceptance Criteria - There is no evidence of blocking the displacement of any system component caused by thermal expansion of the system.

Inspected hangers are not bottomed out or fully extended.

The shock suppressor positions allow movement at operating temperature with adequate swing clearance.

All measured displacements of the piping are within the specified acceptable range.

(STP-18) TIP Uncertainty

Test Objectives - The test objectives are: to demonstrate the reproducibility of the TIP system readings.

Prerequisites - The core is at steady-state power level with equilibrium xenon. It remains in this condition with no control rod motion or change in core flow until completion of the TIP traces.

Test Method - The rod pattern and all APRM system and LPRM system readings are recorded. TIP reproducibility is checked with the plant at steady-state condition by producing several TIP traces in the same location, with each TIP machine. The traces are evaluated to determine the extent of deviations between traces from the same TIP machine.

Table 14.2-3 (Cont'd)

Acceptance Criteria - The TIP system error level is within the specified limits.

(STP-19) Core Performance

Test Objective - The test objective is to evaluate the principal thermal and hydraulic parameters associated with core behavior.

Prerequisites - The plant is operating in an essentially steady-state condition.

Test Method - With the core operating in a steady-state condition, the core performance evaluation is used to determine the principal thermal and hydraulic parameters associated with core behavior. These parameters are: core flow rate, core thermal power level, MAPLHGR, MLHGR, core MCPR, and MFLPD.

Acceptance Criteria - The principal thermal and hydraulic parameters associated with core behavior meet appropriately calculated limits (Vendor Test Specifications and plant Technical Specifications).

(STP-20) Steam Production

Test Objective - The objective of this test is to demonstrate that the NSSS is providing steam sufficient to satisfy all appropriate warranties.

Prerequisites - Required preoperational tests have been completed. All required instrumentation is installed and calibrated.

Test method - A NSSS steam output performance test of nominal 100 hours of continuous operation at the warranted steam output will be performed.

Acceptance Criteria - The NSSS shall be capable of supplying steam sufficient to satisfy all appropriate warranties.

(STP-21) DELETED

(STP-22) Pressure Regulator Response

Test Objectives - The test objectives are: to demonstrate the reactor pressure control system responses to pressure regulator setpoint changes, the stability of the reactivity void feedback loop to pressure perturbation, the control characteristics of the bypass and control valves, and the takeover capabilities of the backup pressure regulator; and to optimize the pressure regulator settings to give the best combination of fast response and small overshoot.

Prerequisites - Fuel loading is completed and nuclear steam is available.

Table 14.2-3 (Cont'd)

Test Method - The pressure setpoint is decreased rapidly and then increased rapidly by about 10 psi. The response of the system is measured in each case. The backup regulator is tested by

increasing the operating pressure regulator setpoint rapidly, until the backup regulator takes over control. The load reference setpoint is reduced, and the test is repeated with the bypass valve having control. The response of the system is measured and evaluated, and the regulator settings are optimized.

Acceptance Criteria - The decay ratio is acceptable for each process variable that exhibits oscillatory response to pressure regulator changes.

During the simulated failure of the primary controlling pressure regulator, the backup regulator is expected to control the transient so that the reactor does not scram.

Steady-state hunting or limit cycle characteristics due to control and valve dead band are acceptable at rated steam flow.

(STP-23) Feedwater Control System Demonstration

Test Objectives - The test objectives are: to evaluate and adjust feedwater controls; to demonstrate the capability of the automatic flow runback feature to prevent a low water level scram, following the trip of one feedwater pump; to demonstrate acceptable performance of feedwater pumps and turbine drivers within specifications; to demonstrate adequate response to feedwater heater loss (inlet subcooling change); and to demonstrate acceptable reactor water level control.

Prerequisites - The reactor is operating at a steady-state condition.

Test Method - At power levels of approximately 25%, 50%, 75%, and 100%, the reactor water level setpoint is changed approximately ±6 inches, to evaluate acceptability of the feedwater control systems at all modes of operation.

One of the three operating feedwater pumps is tripped at a power level such that the automatic flow runback circuit acts to drop power to within the capability of the remaining pumps.

The resulting transients from the loss of feedwater heating are evaluated at nominal 90% power.

Feedwater pumps and turbine driver variables are monitored throughout power ascension testing to demonstrate operability within specified limits.

Acceptance Criteria - The decay ratio is acceptable for each process variable that exhibits oscillatory response to feedwater control system setpoint changes, when the plant is operating above the lower limit of the master flow controller. The system has the capacity for automatic flow runback to prevent a low water level scram following the trip of one feedwater pump. The feedwater pumps and turbine drivers perform within specified limits (Vendor Test Specification).

Table 14.2-3 (Cont'd)

(STP-24) Main Turbine Valves Surveillance Test

Test Objective - The test objective is to demonstrate acceptable procedures for routine surveillance testing of the turbine stop, control, and bypass valves at a power level as high as possible, without producing a reactor scram.

Prerequisites - The main turbine is operational, and the power testing program is in progress.

Test Method - The individual turbine valves are closed at several points along the 100% power/flow control line, to establish the maximum possible power level for performance of this test, without producing a reactor scram.

Acceptance Criteria - With the plant at power and testing in progress, peak neutron flux is at a value below the scram setting. Peak reactor pressure is at a value below the high pressure scram setting. Peak steam flow in the main steam lines remains at values below the high flow isolation trip setting.

(STP-25) Main Steam Isolation Valves Performance Verification

Test Objectives - The test objectives are: to functionally check the MSIVs for proper operation at selected power levels; to determine reactor transient behavior during and following simultaneous full closure of all MSIVs, and following closure of one valve; and to determine isolation valve closure time.

Prerequisites - Fuel loading is completed, and nuclear steam is available.

Test Method - Functional checks (at least 10% closure) of each isolation valve are performed at selected reactor power levels. A test of simultaneous full closure of all MSIVs is performed at about 100% of rated thermal power. Operation of the RCIC and SRVs is monitored. Reactor process variables are monitored to determine the transient behavior of the system during and following full isolation. The MSIVs closure times are determined.

Acceptance Criteria - MSIV closure times are within applicable limits. Reactor pressure is maintained below specified values during the transient following full closure of all MSIVs.

(STP-26) Main Steam Relief Valves Performance

Test Objectives - The test objectives are: to demonstrate proper operation of the dual-purpose MSRVs and to demonstrate their leak-tightness following operation.

Prerequisites - Factory calibration data are verified, and setting adjustment mechanism factory seals, if applicable, are intact. The reactor is on pressure control with adequate bypass or main steam flow.

Test Method - The MSRVs are opened manually so that only one is opened at any time. Proper resetting of each MSRV is verified by observing temperatures in the MSRV discharge piping. The capacity of each MSRV is measured by opening the MSRV and observing the corresponding decrease in main steam line flow.

Table 14.2-3 (Cont'd)

Acceptance Criteria - Each MSRV flow compares favorably with the value assumed in the accident analysis at design reactor pressure. The leakage of each MSRV is low enough to allow the temperature measured by the thermocouples, in the discharge side of the valves, to fall within an acceptable margin of the temperature recorded, before the valve was opened.

(STP-27) Turbine Trip and Generator Load Rejection Demonstration

Test Objectives - The test objectives are: to determine the response of the reactor system to a turbine trip or generator load rejection; and to evaluate the response of the bypass, SRV, and the reactor protection systems.

Prerequisites - Logic testing of generator lockouts to produce a direct turbine trip are completed. Fuel loading is completed, and the power testing is completed to the extent necessary for performing this test.

Test Method - Dynamic transients are induced at selected reactor power levels by manual turbine trips. Neutron flux, feedwater flow and temperature, and vessel water level and pressure are monitored. Responses of selected control valves, stop valves, SRVs, and bypass valves are recorded. The peak values and the rate of change of both reactor power and reactor steam dome pressure are recorded. The capacity of the turbine bypass valves is checked.

Acceptance Criteria - The turbine control valves and the stop valves close during the stop valve fast closure test. Feedwater settings prevent flooding of the steam lines following these transients. The measurement of simulated heat flux is not significantly greater than preanalysis. The trip at less than 25% power does not cause a scram. The pressure regulator regains control before a low pressure reactor isolation occurs. Turbine bypass flow capacity compares favorably with the value assumed in the accident analysis (Vendor Test Specification). The flow coast-down characteristics of the recirculation pump are reconfirmed as part of the turbine trip demonstration at near rated power and flow.

(STP-28) Shutdown from Outside the Main Control Room Demonstration

Test Objective - The test objective is to demonstrate that the power plant can be safely shut down from outside the control room, to demonstrate that the power plant can be maintained in a hot standby condition from outside the control room, and to demonstrate that the power plant can be safely cooled from hot standby to cold shutdown conditions from outside the control room.

Prerequisites - Preoperational testing of plant instrumentation, controls, and systems to be used at the remote shutdown station have been completed. Fuel loading is completed, and the power ascension testing program is in progress.

Test Method - Using only the minimum number of personnel in a shift crew required to be onsite at any one time, the reactor is manually scrammed from outside the control room and placed in hot standby condition from the remote shutdown station. The plant is maintained in hot standby condition for at least 30 minutes. Using additional personnel who could be made available prior to the time cooldown would be initiated, initiate a plant cooldown from hot standby conditions from outside the control room. Initiate RHR system operation and demonstrate the ability to achieve cold shutdown conditions from outside the control room.

Table 14.2-3 (Cont'd)

Acceptance Criteria -

a. Shutdown to hot standby can be achieved.

b. Plant can be maintained at stable hot standby. Reactor water level and pressure can be controlled.

c. Reactor coolant temperature and pressure can be lowered sufficiently to place the RHR system in operation.

d. A heat transfer path to the spray pond can be established.

e. Cooldown with the RHR system can be controlled to a rate that would not exceed technical specification limits.

(STP-29) Recirculation Flow Control Demonstration

Test Objective - The test objective is to determine the plant response to a change in recirculation flow, to optimize the setting of the master flow controller, and to demonstrate the plant loading capability in master manual flow control mode.

Prerequisites - The reactor is in a steady-state condition and the feedwater system is operating in three-element control.

Test Method - Data are recorded during the step and ramp changes. The final controller settings for both the master flow controller and the individual loop speed controllers are determined.

Acceptance Criteria - The decay ratio for each process variable that exhibits oscillatory response to flow control changes is acceptable. The plant response to a change in recirculation flow is acceptable. The plant loading capability in the master manual flow control mode is acceptable (Vendor Test Specification).

(STP-30) Recirculation System (Unit 1)

Test Objectives - The test objectives are: to determine transient responses and steady-state conditions following recirculation pump trips at selected power levels; to obtain jet pump performance data; and to demonstrate that no recirculation system cavitation occurs in the operation region of the power/flow map.

Prerequisites - The recirculation system preoperational test is completed; the process computer is available; and power testing is in progress.

Table 14.2-3 (Cont'd)

Test Method - Single-pump and two-pump trips are performed from specified power levels. The single-pump trips are initiated by opening the generator field breaker on the applicable motor generator or by opening the MG set drive motor breaker. The two-pump trip is initiated by tripping the recirculation pump trip breakers. Reactor pressure, reactor level, steam and feedwater flow, and neutron flux are recorded during the transient and steady-state conditions. The data recorded during rated power operation verify the noncavitation performance of the recirculation pumps and the jet pumps.

Acceptance Criteria - All responses to the pump trip test transients are within limits. Pump performance testing under operating conditions verifies the noncavitation within the operating range. Plant stability is within specified limits.

(STP-30) Recirculation System (Unit 2)

Test Objectives - The test objectives are: to determine transient responses and steady-state conditions following recirculation pump trips at selected power levels; and to obtain jet pump performance data.

Prerequisites - The recirculation system preoperational test is completed; the process computer is available, and power testing is in progress.

Test Method - Single-pump and two-pump trips are performed from specified power levels. The single-pump trips are initiated by opening the generator field breaker on the applicable motor generator or by opening the MG set drive motor breaker. The two-pump trip is initiated by tripping the recirculation pump trip breakers. Reactor pressure, reactor level, steam and feedwater flow, and neutron flux are recorded during the transient and steady-state conditions.

Acceptance Criteria - All responses to the pump trip test transients are within limits. Plant stability is within specified limits.

(STP-31) Loss of Turbine-Generator and Offsite Power

Test Objective - The test objective is to demonstrate the performance of the reactor and plant electrical equipment and systems, during the loss of auxiliary power transient.

Prerequisites - The diesel generators are in the automatic start mode, and the plant is operating at power.

Test Method - The loss of auxiliary power test is performed at nominal 25% rated power. The proper response of reactor plant equipment, automatic switching equipment, and the proper sequencing of the diesel generator load are checked. Appropriate reactor parameters are recorded during the resultant transient.

Acceptance Criteria - All safety systems function as required, without manual assistance. Reactor steam dome pressure is maintained below acceptable limits. Normal reactor cooling systems are capable of maintaining adequate suppression pool water temperature, adequate drywell cooling, and of preventing actuation of the ADS.

Table 14.2-3 (Cont'd)

(STP-32) Essential HVAC System Operation and Containment Hot Penetration Temperature Verification

Test Objective - The test objective is to demonstrate, under actual operating conditions, satisfactory performance of the drywell, control enclosure, control room, reactor enclosure, and radwaste enclosure HVAC systems and to verify that concrete temperature surrounding hot penetrations remain within specified limits.

Prerequisites - Air flow balancing, cooling water balancing, and fuel loading are completed; power ascension testing is in progress.

Test Method - Air temperatures are monitored and recorded at nominal 50% and 100% power. Space temperatures are not allowed to exceed predetermined maximum temperatures. Adjustments to air and/or cooling water flows are made, if required, to maintain temperature within specified limits. Concrete temperatures surrounding hot penetrations are monitored and recorded.

Acceptance Criteria - The drywell, control enclosure, control room, reactor enclosure, and radwaste HVAC systems provide adequate cooling, and concrete temperatures surrounding hot penetrations remain within specified limits.

(STP-33) Piping Steady-State Vibration Measurements

Test Objective - The test objective is to obtain vibration measurements on selected safety-related NSSS piping and selected BOP piping (Table 3.9-7), located both inside and outside of the primary containment. The test results are used to demonstrate the mechanical integrity of the selected systems to flow-induced vibration, and to check the validity and accuracy of the analytical models.

Prerequisites - Engineering review of the piping system is complete. The required preoperational test has been completed. Instrumentation has been installed and calibrated.

Test Method - The systems to be tested are operated in their normal modes, and data are collected at specified power levels. The empirical data are analyzed to determine test results.

Acceptance Criteria - Analysis of the empirical data satisfies the requirements of applicable criteria and calculations. The steady-state vibration of the piping system is qualified as acceptable by visual inspection, if the level of vibration is too small to be detected by the naked eye, and, in the analyst's judgement, the possibility of damage is minimal; or the stresses in the piping based on the measured maximum displacement due to steady-state vibration are less than the endurance limit of the material as specified in Section 3.9.2.1b.2.

(STP-34) Offgas System Performance Verification

Test Objective - The test objective is to demonstrate proper operation of the offgas system under its expected operating conditions.

Prerequisites - Fuel loading is completed, and power ascension testing is in progress.

Table 14.2-3 (Cont'd)

Test Method - At startup flow and again at normal flow, the flows, temperatures, and pressures at selected locations are recorded and checked to see if they are within acceptable limits. The hydrogen concentration, drainage of condensate, dilution flow, and charcoal system operability are checked periodically throughout plant startup. The catalytic recombiner is operated, and its operating characteristics are recorded. Grab samples are taken periodically for radionuclide analysis.

Acceptance Criteria - The release of gaseous and airborne radioactive effluents does not exceed the limits specified in the Technical Specifications. The system measured variables are within acceptable limits of design. The catalytic recombiner, carbon beds, and filters perform properly.

(STP-35) Recirculation Flow Calibration

Test Objective - The test objective is to perform a complete calibration of the installed recirculation system flow instrumentation.

Prerequisites - The reactor is operating in a steady-state condition. Flow instrumentation static calibration is completed prior to the first flow calibration. The zero setting on transmitters is checked and adjusted prior to a flow calibration.

Test Method - With the reactor in a steady-state condition, recirculation flow data are recorded. The data are analyzed to determine the required adjustments on APRM and RBM flow units, and the jet pump loop flow proportional amplifiers. The resulting settings are documented on the instrument data sheets, for the owner's records.

Acceptance Criteria - Jet pump flow instruments are adjusted so that the jet pump total flow recorder provides a correct core flow indication at rated conditions. The APRM/RBM flow bias instrumentation is adjusted to function properly at rated conditions.

(STP-36) Piping Dynamic Transient

Test Objectives - The objective of this test is to verify the design adequacy of the piping systems for the transients indicated in Table 3.9-7.

Prerequisites - An engineering review of the piping system after construction is completed. The required preoperational tests have been completed. Instrumentation has been installed and calibrated.

Test Method - Response of the piping system (displacements or restraint loads) is measured during the transient event specified.

Acceptance Criteria - The measured response of the piping system and restraint loads shall be less than the acceptable response determined by analysis as specified in Section 3.9.2.1b.1.

(STP-37) DELETED

(STP-38) DELETED

Table 14.2-3 (Cont'd)

(STP-70) Reactor Water Cleanup System Performance Verification

Test Objective - The test objective is to demonstrate specific aspects of the mechanical operability of the RWCU system.

Prerequisites - The RWCU system preoperational test is completed satisfactorily. The reactor is operated at, or near, rated temperature and pressure, long enough to achieve a steady-state condition.

Test Method - The system is operated in blowdown, hot shutdown, and normal modes to provide data for analysis. The system is allowed to stabilize in each mode prior to recording of data. These data are analyzed to determine the test results.

Acceptance Criteria - The data indicates operation in the listed modes is satisfactory.

(STP-71) Residual Heat Removal System Performance Verification

Test Objectives - The test objectives are to demonstrate the ability of the RHR system to remove residual and decay heat from the nuclear system, so that refueling and nuclear system servicing can be performed.

Prerequisites - The RHR system preoperational test is completed satisfactorily.

Test Method - Two modes are tested to verify system capability under actual operating conditions. The modes to be tested are the shutdown cooling and the suppression pool cooling modes. During the operation, the heat transfer rate is controlled to maintain acceptable reactor pressure vessel RPV cooldown rates. Data are recorded before and during each portion of testing. The empirical data are analyzed to verify the satisfactory operation of the RHR system within the limits of acceptance criteria.

Acceptance Criteria - The RHR system is capable of operating at an acceptable flow rate and heat removal capability.

Table 14.2-4

PREOPERATIONAL TEST PROCEDURE ABSTRACTS

(P-2.1) 125 V (Div III, IV) Dc Safeguard Power System

Unit Scope -

a. 1P-2.1 (Unit 1 and portions of Unit 2 system components)

b. 2P-2.1 (Unit 2 remaining system components)

Test Objective - The test objective is to demonstrate the ability of the 125 V dc safeguard power system to provide an uninterruptible source of power to the 125 V dc distribution panels.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Batteries are filled with electrolyte to normal level, and 440 V ac power is available to provide power to the battery chargers. The load resistor bank is available to support the battery load capacity test. Battery room ventilation and emergency eyewash are available and operational.

Test Method - Battery charger capacity is verified by the application of its full load rating for 8 hours. Battery capacity is verified by the application of a constant test load at the battery manufacturer's 4 hour rate. System response to the design load profile is verified by the application of stepped test currents. Battery system recharge characteristics are determined by integrating amp-hours into the battery following the design load profile discharge test.

Acceptance Criteria -

a. The ac input voltage to the battery chargers is within specified limits. (Vendor Technical Manual)

b. The dc distribution equipment is connected to the proper safety division. (Section 8.3.2.1.1)

c. The battery capacity is equal to or greater than that specified. (Table 8.3-18)

d. The battery capacity is sufficient to supply the specific application requirements with respect to the calculated load discharge profile. (Table 8.3-18)

e. The battery will accept a charge equal to or greater than the number of amp-hours required to restore the energy dissipated during a design load discharge test within 8 hours while the charger maintains normal plant loads. (Section 8.3.2.1.1.3)

f. The battery chargers will supply rated load or greater for 8 hours without degradation. (Section 8.3.2.1.1.3 and Vendor Technical Manual)

g. The battery chargers will supply regulated and conditioned dc within specified limits. (Vendor Technical Manual)

Table 14.2-4 (Cont'd)

h. Battery system off-normal conditions are properly identified and annunciated. (Sections 8.3.2.1.1.2 and 8.3.2.1.1.3)

(P-2.2) 125/250 V (Div I, II) Dc Safeguard Power System

Unit Scope -

a. 1P-2.2 (Unit 1 and portions of Unit 2 system components)

b. 2P-2.2 (Unit 2 remaining system components)

Test Objective - The test objective is to demonstrate the ability of the 125/250 V dc safeguard power system to provide an uninterruptible source of power to the 125/250 V dc motor control centers and to various 125 V dc distribution panels.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Batteries are filled with electrolyte to normal level, and 440 V ac power is available to provide power to the battery chargers. The load resistor bank is available to support the battery load capacity test. Battery room ventilation and emergency eyewash are available and operational.

Test Method - Battery charger capacity is verified by the application of its full load rating for 8 hours. Battery capacity is verified by the application of a constant test load at the battery manufacturer's 4 hour rate. System response to the design load profile is verified by the application of stepped test currents. Battery system recharge characteristics are determined by integrating amp-hours into the battery following the design load profile test.

Acceptance Criteria -

a. The ac input voltage to the battery chargers is within specified limits. (Vendor Technical Manual)

b. The dc distribution equipment is connected to the proper safety division. (Section 8.3.2.1.1)

c. The battery capacity is equal to or greater than that specified. (Table 8.3-18)

d. The battery capacity is sufficient to supply the specific application requirements with respect to the calculated load discharge profile. (Table 8.3-18)

e. The battery will accept a charge equal to or greater than the number of amp-hours required to restore the energy dissipated during a design load discharge test within 8 hours while the charge maintains normal plant loads. (Section 8.3.2.1.1.3)

f. The battery chargers will supply rated load or greater for 8 hours without degradation. (Section 8.3.2.1.1.3 and Vendor Technical Manual)

Table 14.2-4 (Cont'd)

g. The battery chargers will supply regulated and conditioned dc within specified limits. (Vendor Technical Manual)

h. Battery system off-normal conditions are properly identified and annunciated. (Section 8.3.2.1.1.2 and 8.3.2.1.1.3)

(P-3.1) 13.2 kV Unit Auxiliary Power System

Unit Scope -

a. 1P-3.1 (Unit 1, common, and portions of Unit 2 system components)

b. 2P-3.1 (Unit 2 remaining system components)

Test Objective - The test objective is to demonstrate the capability of the 13.2 kV unit auxiliary power system to provide reliable electrical service to the 13.2 kV buses, which include feeder breakers for the 4 kV safeguard power system.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Offsite power is available from both the 220 kV and the 500 kV substations. 125 V dc control power is available and operational.

Test Method - The 13.2 kV unit auxiliary buses are energized from both offsite power sources, and alarms and control devices are actuated.

Acceptance Criteria -

a. System breakers operate properly. (Vendor Technical Manual)

b. System automatic transfer circuits operate properly. (Electrical Schematic Diagrams)

c. Feeder breaker interlocks operate properly. (Electrical Schematic Diagrams)

d. System alarms operate properly. (Electrical Schematic Diagrams)

(P-4.1) 4 kV Safeguard Power System

Unit Scope -

a. 1P-4.1 (Unit 1 and common system components)

b. 2P-4.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the capability of the 4 kV safeguard power system to provide reliable electrical service to the 4 kV buses.

Table 14.2-4 (Cont'd)

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The 13.2 kV power and 125 V dc control power are available and operational.

Test Method - The 4 kV buses are energized, and system alarms and control devices are actuated.

Acceptance Criteria -

a. System breakers operate properly. (Section 8.3.1.1.2)

b. System automatic transfer circuits operate properly. (Section 8.3.1.1.2)

c. Feeder breaker interlocks operate properly. (Section 8.3.1.1.2)

d. System alarms operate properly. (Section 8.3.1.1.2)

(P-5.1) Safeguard 440 V Load Centers

Unit scope -

a. 1P-5.1 (Unit 1 system components)

b. 2P-5.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the capability of the safeguard 440 V load centers to provide reliable power to connected 440 V loads and motor control centers.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The 4 kV buses are available for energization of the 440 V load centers. The 125 V dc control power is available for operation of the 4 kV switchgear breakers.

Test Method - Breakers are operated to energize the 440 V load centers and motor control centers. System alarms and controls, both manual and automatic, are actuated.

Acceptance Criteria -

a. System breakers operate properly. (Section 8.3.1.1.2)

b. System bus voltages meet acceptable voltages. (Section 8.3.1.1.2)

c. System alarms operate properly. (Section 8.3.1.1.2)

(P-6.1) Safeguard 440 V Motor Control Centers

Unit scope -

a. 1P-6.1 (Unit 1 system components)

Table 14.2-4 (Cont'd)

b. 2P-6.1 (Unit 2 system components)

Test Objectives - The test objective is to demonstrate the capability of the safeguard 440 V motor control centers to provide reliable power to the motor control centers panels and loads.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The 440 V Class 1E load centers are available for energization of the 440 V motor control centers. 125 V dc control power is available for operation of the switchgear breakers.

Test Method - Breakers are operated to energize the 440 V motor control centers. System alarms and controls, both manual and automatic, are actuated.

Acceptance Criteria -

a. System breakers operate properly. (Section 8.3.1.1.2)

b. System bus voltages are acceptable. (Section 8.3.1.1.2)

c. System alarms operate properly. (Section 8.3.1.1.2)

(P-7.1) Standby Dc Lighting System

Unit scope -

a. 1P-7.1 (Unit 1 system components)

b. 2P-7.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the ability of the standby dc lighting system to provide emergency lighting on loss of normal lighting power.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Offsite ac power and 125 V dc power are available.

Test Method - The standby dc lighting panels are energized from their normal ac supply. The normal power supply is interrupted, and 125 V dc power is verified as an emergency lighting power source. Adequate illumination exists for safe plant operation.

Acceptance Criteria -

a. System breakers operate properly. (Section 9.5.3.2.2)

b. System supply voltages are acceptable. (Section 9.5.3.2.2)

c. System automatic transfer devices operate properly. (Section 9.5.3.2.2)

Table 14.2-4 (Cont'd)

d. Adequate illumination exists for safe plant operation. (Section 9.5.3.2.2)

(P-11.1) Service Water System

Unit Scope -

a. 1P-11.1 (Unit 1, common, and portions of Unit 2 system components)

b. 2P-11.1 (Unit 2 remaining system components)

Test Objective - The test objective is to demonstrate the ability of the service water system to furnish cooling water to the heat exchangers, chillers, coolers, and condensers in the control structure, turbine, reactor, and radwaste buildings; to furnish dilution and injection water to the chlorination and acid systems; and to furnish seal water to miscellaneous components.

Prerequisites - To the extent necessary to perform this test, the construction is completed and instrumentation and controls are operable. The circulating pump structure and cooling tower basin are available and operable to support this test.

Test Method - Operate the service water pumps in single and dual pump modes, and verify adequate flow to the service water components.

Acceptance Criteria -

a. Service water pumps operate properly. (Section 9.2.1)

b. Service water system provides an adequate water supply to system loads in the normal mode of operation. (Section 9.2.1)

c. Service water system provides an adequate water supply to system loads in the winter bypass mode of operation. (Section 9.2.1)

d. System alarms operate properly. (Section 9.2.1)

(P-13.1) Fire Protection Water System

Unit Scope -

a. 1P-13.2 (Unit 1, common, and portions of Unit 2 system components)

b. 2P-13.2 (Unit 2 remaining system components)

Test Objectives - The test objective is to demonstrate that the fire protection water system operates as designed, to supply fire water to required areas.

Table 14.2-4 (Cont'd)

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Sufficient water is available in the cooling tower basin to conduct the test.

Test Method - The fire protection water system is placed in operation, and performance data are obtained for the diesel and electric fire pumps. System controls and alarms are actuated, including auto and manual initiation of system sprinklers. The transformer deluge is activated and the system hose reel and hydrants are operated.

Acceptance Criteria -

a. System pumps meet acceptable head and flow values. (Section 9.5.1)

b. System automatic and manual initiation operate properly. (Section 9.5.1)

c. System sprinklers operate properly. (Section 9.5.1)

d. System hydrants and hose reels operate properly. (Section 9.5.1)

e. System deluge patterns are acceptable. (Section 9.5.1)

(P-13.2) Fire Protection CO_2 System

Unit Scope -

a. 1P-13.2 (Unit 1, common, and portions of Unit 2 system components)

b. 2P-13.2 (Unit 2 remaining system components)

Test Objectives - The test objective is to demonstrate the capability of the fire protection carbon dioxide system to initiate CO_2 release to designated areas, as designed.

Prerequisites - To the extent necessary to perform this test, construction is completed and instrumentation and controls are operable and calibrated. Sufficient CO_2 is available for the required discharge tests.

Test Method - CO_2 discharge is initiated manually. Operation of dampers by CO_2 is verified.

Acceptance Criteria -

a. System manual initiation operates properly. (Section 9.5.1)

b. Damper operation is acceptable. (Section 9.5.1)

c. System alarms operate properly. (Section 9.5.1)

Table 14.2-4 (Cont'd)

(P-13.3) Fire Protection Air Foam System

Unit Scope -

a. 1P-13.3 (Unit 1 and common)

Test Objective - The test objective is to demonstrate that the fire protection air foam system delivers air foam to designated areas.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The fire protection water system is operable and capable of supplying sufficient water to the foam eductor.

Test Method - The air foam system is manually initiated, and foam is produced.

Acceptance Criteria -

a. System manual initiation operates properly. (Section 9.5.1.2.5)

b. System foam production is acceptable. (Section 9.5.1.2.5)

(P-13.4) Smoke Detection System

Unit scope -

a. 1P-13.4 (Unit 1 system components)

b. 2P-13.4 (Unit 2 system components)

Test Objectives - The test objective is to demonstrate the proper operation of the smoke detection system.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - Smoke, fire, and trouble conditions are simulated, and system local and remote alarms and indication are verified.

Acceptance Criteria -

a. System detectors operate properly. (Section 9.5.1.2.9 and Appendix 9A.2.12)

b. System alarms and indicators operate properly. (Section 9.5.1.2.9 and Appendix 9A.2.12)

Table 14.2-4 (Cont'd)

(P-13.5) Fire Protection Halon System

Unit scope -

a. 1P-13.5 (Unit 1 system components)

b. 2P-13.5 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the capability of the fire protection halon to all floor sections, as designed.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Sufficient Halon is available for the required discharge tests.

Test Method - Smoke and heat detectors are activated, and automatic initiation is simulated. System is manually initiated, and proper Halon distribution is verified. Trouble conditions are simulated, and proper alarm annunciation is verified.

Acceptance Criteria -

a. Smoke detectors actuate early warning alarms. (Section 9.5.1.2.7)

b. Heat detectors actuate predischarge alarms followed by automatic discharge after a time-delay. (Section 9.5.1.2.7)

c. System automatic and manual initiation is acceptable. (Section 9.5.1.2.7)

d. Halon distribution to all floor sections is acceptable. (Section 9.5.1.2.7)

e. System alarms operate properly. (Section 9.5.1.2.7)

(P-14.1) Reactor Enclosure Cooling Water System

Unit Scope -

a. 1P-14.1 (Unit 1 system components)

b. 2P-14.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the ability of the RECW system to provide sufficient cool water to designated equipment in the reactor enclosure.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The service water system is available to provide cooling water for the system.

Table 14.2-4 (Cont'd)

Test Method - The RECW system is placed in operation, and pump performance data are obtained. System controls and alarms are actuated.

Acceptance Criteria -

a. System pumps meet acceptable head and flow values. (Section 9.2.8.2)

b. System head tank level controls maintain tank level properly. (Section 9.2.8.2)

c. System pump automatic start features operate properly. (Section 9.2.8.2)

d. The reactor recirculation pump seal and motor oil cooler isolation valves and their logic circuits operate properly. (Section 9.2.8.2)

e. Flow is verified to each system component. (Section 9.2.8.2)

f. System alarms operate properly. (Section 9.2.8.5)

(P-15.1) Turbine Enclosure Cooling Water System

Unit Scope -

a. 1P-15.1 (Unit 1 system components)

b. 2P-15.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the ability of the TECW system to provide sufficient cooling water to designated equipment in the turbine enclosure.

Prerequisites - To the extent necessary to perform this test, construction is completed and instrumentation and controls are operable and calibrated. The service water system is available to provide cooling water for the system.

Test Method - The TECW system is placed in operation, and pump performance data is obtained. System controls and alarms are actuated.

Acceptance Criteria -

a. System pumps operate properly. (Section 9.2.9)

b. Standby pump automatic starting controls function properly. (Section 9.2.9)

c. System head tank level controls maintain proper tank level. (Section 9.2.9)

d. System provides cooling water to system components. (Section 9.2.9)

e. System alarms operate properly. (Section 9.2.9)

Table 14.2-4 (Cont'd)

(P-16.1) Residual Heat Removal Service Water System

Unit Scope -

a. 1P-16.1 (Unit 1, common, and portions of Unit 2 system components)

b. 2P-16.1 (Unit 2 remaining system components)

Test Objective - The test objective is to demonstrate that under normal and emergency conditions, the RHRSW system supplies cooling water as designed.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Required portions of the cooling tower are operable, and the spray pond has water to operate the RHRSW pumps. The RHR heat exchangers are installed to provide a flow path for the pumps. The ESW system is available to support the flow verification test, as applicable.

Test Method - The RHRSW pumps and their controls are operated, and flow is measured for normal system operation modes. System automatic valve alignment is initiated for high radiation and ESW pump start. The high radiation pump trip and the manual override operations are conducted. The spray networks are visually inspected for evenly distributed flow. System alarms are also actuated.

Acceptance Criteria -

a. System pumps meet acceptable head and flow values for different system modes of operation. (Section 9.2.3.2)

b. System logic circuits operate properly. (Section 9.2.3.2)

c. System is operable from both the control room and the remote shutdown panel. Remote shutdown panel instrumentation operates properly. (Section 9.2.3.2)

d. RHRSW cross-ties to the cooling towers and to the ESW system pump circuits operate properly. (Section 9.2.3.2)

e. System alarms operate properly. (Section 9.2.3.5)

f. All key-locks and automatic features operate properly. (Section 9.2.3.2)

(P-17.1) Instrumentation Ac Power System

Unit Scope -

a. 1P-17.1 (Unit 1 system components)

b. 2P-17.1 (Unit 2 system components)

Table 14.2-4 (Cont'd)

Test Objectives - The test objective is to demonstrate the capability of the instrumentation ac power system to supply electrical power to the 120 V ac instrument panels.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The 440 V ac power is available for energization of the instrumentation ac panels.

Test Method - Breakers are operated to energize the instrument ac panels, and system alarms and control devices are actuated.

Acceptance Criteria -

a. System 440 V ac breakers operate properly. (Vendor Technical Manual)

b. System bus voltages are acceptable. (Section 8.3.1.1.2)

c. System ac electrical power is available to all system distribution panels and instrument panels. (Electrical Single-Line Diagram)

(P-18.1) Instrument Air System

Unit Scope -

a. 1P-18.1 (Unit 1, common, and portions of Unit 2 system components)

b. 2P-18.1 (Unit 2 remaining system components)

Test Objective - The test objective is to demonstrate the capability of the instrument air system to provide dry compressed air at the rated capacity.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Air dryer chambers are filled with desiccant, and TECW is available.

Test Method - The system is placed in operation both automatically and manually, and performance data are obtained. Proper air distribution is verified. System control devices and alarms are actuated.

Acceptance Criteria -

a. System compressors discharge pressure, temperature, and capacity are within specified limits. (Section 9.3.1.1.2)

b. Compressor trips, interlocks, and automatic start logic operate properly. (Section 9.3.1.1.2)

c. Air dryer cycles are proper, and air moisture content is maintained within specified limits. (Section 9.3.1.1.2)

Table 14.2-4 (Cont'd)

d. System supplies air to each major distribution area. (Section 9.3.1.1.2)

e. System alarms operate properly. (Section 9.3.1.1.5)

(P-23.1) Diesel Generator Fuel Oil System

Unit Scope -

a. 1P-23.1 (Unit 1 and common system components)

b. 2P-23.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate that the diesel generator fuel oil system is capable of supplying fuel oil to the standby diesel generator day tanks.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are available and operational. Adequate fuel oil is present in the diesel oil storage tanks.

Test Method - The diesel oil transfer pumps are operated, and performance data are measured. System alarms and control devices are also actuated.

Acceptance Criteria -

a. System pumps meet acceptable delivery capability. (Section 9.5.4.2)

b. Automatic operation of the diesel oil transfer pumps is acceptable. (Section 9.5.4.2)

c. Each diesel oil transfer pump is capable of supplying any of the four diesel oil day tanks. (Section 9.5.4.2)

d. System alarms operate properly. (Section 9.5.4.5)

(P-24.1) Standby Diesel Generator System

Unit Scope -

a. 1P-24.1 (Unit 1 system components)

b. 2P-24.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the capability of the standby diesel generator system to provide reliable electric power to Class 1E buses.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Temporary cooling water, diesel

generator enclosure HVAC, 125 V dc power, fuel oil, and fire protection are available for diesel generator operation.

Test Method - The diesel generators are started both manually and automatically. Starting times and repetitive starting capability are determined. Diesel generator and auxiliary systems performance is measured and adequate reliability is demonstrated. System protection alarms and controls are also actuated. This test, in conjunction with Tests P-100.1 (Loss of Offsite Power) and P-100.4 (Standby Diesel Generator Loading), constitutes the individual diesel generator preoperational testing program.

Acceptance Criteria -

a. Each diesel generator is automatically started on simulated automatic actuation signals and reaches the required voltage and frequency within an acceptable time. (Section 8.3.1.1.3)

b. Electrical interlocks between the diesel generators and their associated 4 kV buses operate properly. (Section 8.3.1.1.3)

c. Each diesel generator is capable of being stopped and started manually from local and remote locations. (Section 8.3.1.1.3)

d. Each diesel generator air starting system, fuel oil system, oil lubrication system, and its air supply and exhaust systems operate properly. (Sections 9.5.4, 9.5.6, 9.5.7, and 9.5.8)

e. Each system breaker operates properly. (Vendor Technical Manual)

f. System alarms and logics operate properly. (Section 8.3.1.1.3)

g. Each diesel generator operates properly during the transient following a complete loss of load. (Section 8.3.1.1.3)

h. When operating in test (droop) mode parallel to the grid, each diesel generator breaker opens and governor converts to automatic (isochronous) mode upon receipt of a LOCA signal, and continues to operate.

i. Each diesel generator is capable of starting a minimum of 23 consecutive times with no failures.

(P-25.1) Primary Containment Instrument Gas System

Unit Scope -

a. 1P-25.1 (Unit 1 system components)

b. 2P-25.1 (Unit 2 system components)

Test Objective - The test objectives are to demonstrate the capability of the PCIG system to provide compressed gas at proper temperature and moisture content for containment services, and to demonstrate system isolation following a primary containment isolation signal.

Table 14.2-4 (Cont'd)

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The service water system is available to provide the cooling water requirements of the system, as applicable.

Test Method - The system is placed in operation automatically and manually, and performance data are obtained. System controls and alarms are actuated, including operation of the systems containment isolation valves upon a simulated primary containment isolation signal. System valves are realigned to utilize the backup containment instrument gas supply from the plant instrument air system.

Acceptance Criteria -

a. System compressors meet acceptable values of discharge pressure and capacity. (Section 9.3.1.3)

b. Compressor trips, interlocks, and start logic operate properly. (Section 9.3.1.3)

c. System isolation valves operate properly. (Section 6.2.4)

d. System alarms operate properly. (Section 9.3.1.3.5)

e. Gas temperature and moisture content are maintained within specified limits. (Section 9.3.1.3)

f. Both system components fail independently. (Section 9.3.1.3)

(P-28.1) Diesel Generator Enclosure HVAC System

Unit Scope -

a. 1P-28.1 (Unit 1 system components)

b. 2P-28.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the capability of the standby diesel generator enclosure HVAC system to provide air flow to respond to simulated room temperature variations.

Prerequisites - To the extent necessary to perform this test, construction is completed and instrumentation and controls are operable and calibrated.

Test Method - The fans are started automatically and manually. System alarms are also actuated.

Acceptance Criteria -

a. Each diesel generator cell's unit heaters operate properly. (Section 9.4.6)

b. Each cell's exhaust fans operate properly. (Section 9.4.6)

c. Enclosure cell exhaust fan and damper operating logic, including automatic start, automatic stop, and standby operation, operates properly. (Section 9.4.6)

d. System alarms operate properly. (Section 9.4.6.5)

(P-28.2) Spray Pond Pumphouse HVAC System

Unit Scope -

a. 1P-28.2 (Common system components)

Test Objective - The test objective is to demonstrate the capability of the spray pond pumphouse HVAC system to provide air flow and temperature control in the pumphouse.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - The spray pond pumphouse HVAC system is placed in service. Enclosure temperature variations are simulated and system response verified. System controls, logics, and alarms are actuated. System parameters are monitored and recorded.

Acceptance Criteria -

a. Each system unit heater operates properly. (Section 9.4.7)

b. Each system supply fan operates properly. (Section 9.4.7)

c. Supply fan and damper logic operates properly. (Section 9.4.7.5)

d. System alarms operate properly. (Section 9.4.7.5)

(P-30.1) Control Enclosure HVAC System

Unit Scope -

a. 1P-30.1 (Unit 1, Unit 2 and Common system components)

Test Objective - The test objective is to demonstrate the capability of the control enclosure HVAC system to provide air flow and temperature control in the structure by simulated room temperature variations.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. North vent stack and battery room exhaust fans are available for system operation.

Test Method - Control structure temperature variations are simulated and system response verified. The auxiliary equipment enclosure is purged, and system alarms and control devices are actuated. System parameters are monitored and recorded for systems cooling ESF components.

Table 14.2-4 (Cont'd)

Acceptance Criteria -

a. System fans operate properly. (Section 9.4.1)

b. System unit heaters operate properly. (Section 9.4.1)

c. System automatic start features and fan interlocks operate properly. (Section 9.4.1)

d. System fan and damper logic operates properly. (Section 9.4.1)

e. System alarms operate properly. (Section 9.4.1.9)

f. Results of in-place filter efficiency testing are acceptable.

(P-30.2) Control Enclosure Chilled Water System

Unit Scope -

a. 1P-30.2 (Common system components)

Test Objective - The test objective is to demonstrate the ability of the CECWS to provide chilled water flow for cooling the air supply to the control room, the auxiliary equipment compartment, the emergency auxiliary switchgear and battery compartments, and the SGTS area.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The demineralized water and ESW systems are available to provide the water requirement of the system.

Test Method - Chiller operation, chilled water circulation pump operation, and system alignment are initiated by automatic start and manual signals. Flow paths are verified. System alarms are also actuated.

Acceptance Criteria -

a. System circulation pumps meet acceptable head and discharge values. (Section 9.2.10.2)

b. System water chillers operate properly. (Section 9.2.10.2)

c. Flow is verified to each system component. (Section 9.2.10.2)

d. System alarms operate properly. (Section 9.2.10.2)

Table 14.2-4 (Cont'd)

(P-32.1) Control Room HVAC System

Unit Scope -

a. 1P-32.1 (Common system components)

Test Objective - The test objective is to demonstrate the capability of the control room HVAC system to provide air flow and temperature control in the control room by simulated room temperature variations.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - The fans are placed in operation. Control room temperature variations are simulated and system response is verified. Control devices are actuated to automatically align the system and to maintain positive pressure within the control room. Room air leakage is measured and system alarms are also actuated.

Acceptance Criteria -

a. System fans operate properly. (Sections 9.4.1 and 6.4)

b. System fan automatic start features and interlocks operate properly. (Sections 9.4.1 and 6.4)

c. System fan and damper logic operates properly. (Sections 9.4.1 and 6.4)

d. System alarms operate properly. (Sections 9.4.1 and 6.4)

e. Air leakage from control room does not exceed design. (Sections 9.4.1 and 6.4)

(P-32.2) Control Room Isolation and Purge System

Unit Scope -

a. 1P-32.2 (Common system components)

Test Objective - The test objective is to demonstrate the capability of the control room isolation and purge system to isolate the control room from radiation or chlorine entering through the control room ventilation system and to purge the control room of smoke.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The following systems are available for operation: the control room supply and return air system and the control room emergency fresh air supply system.

Test Method - High radiation and chlorine conditions are simulated to verify the automatic isolation of the control room. The control room purge system is actuated and system response verified. System alarms are actuated.

Table 14.2-4 (Cont'd)

Acceptance Criteria -

a. The control room is isolated and maintained at a positive pressure during a high radiation condition. (Sections 9.4.1 and 6.4)

b. The control room emergency fresh air supply system automatically starts during a high radiation condition. (Sections 9.4.1 and 6.4)

c. The control room is completely isolated during a high chlorine condition. (Sections 9.4.1 and 6.4)

d. System purge mode operates properly. (Sections 9.4.1 and 6.4)

e. System alarms operate properly. (Sections 9.4.1 and 6.4)

f. Results of in-place filter efficiency testing are acceptable.

(P-33.1) Turbine Enclosure HVAC System

Unit Scope -

a. 1P-33.1 (Unit 1 system components)

b. 2P-33.1 (Unit 2 system components)

Test Objectives - The test objective is to demonstrate the capability of the turbine enclosure HVAC system to provide air flow and temperature control in the structure by simulated room temperature variations.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - The turbine enclosure HVAC system is placed in operation. Enclosure temperature variations are simulated, and system response is verified. System controls, logics, and alarms are actuated.

Acceptance Criteria -

a. System fans operate properly. (Section 9.4.4)

b. System fan and damper logic operates properly. (Section 9.4.4)

c. System cooling coils and temperature control valves operate properly. (Section 9.4.4)

d. System heating coils and temperature control valves operate properly. (Section 9.4.4)

e. Results of in-place filter efficiency testing are acceptable.

Table 14.2-4 (Cont'd)

f. System alarms operate properly. (Section 9.4.4.5)

(P-34.1) Reactor Enclosure HVAC System

Unit Scope -

a. 1P-34.1 (Unit 1 system components)

b. 2P-34.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the capability of the reactor enclosure HVAC system to provide normal air flow and temperature control in the enclosure.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The turbine enclosure north and south vent stacks are available to support this test.

Test Method - The fans are placed in operation. Control devices are actuated. System alarms are also actuated.

Acceptance Criteria -

a. System fans operate properly. (Section 9.4.2)

b. System fan standby features, interlocks, permissives, and automatic start circuits operate properly. (Section 9.4.2)

c. System alarms operate properly. (Section 9.4.2.2.5)

d. Results of in-place filter efficiency testing are acceptable

(P-34.2) Refueling Area HVAC System

Unit Scope -

a. 1P-34.2 (Unit 1 system components)

b. 2P-34.2 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the capability of the refueling area HVAC system to provide normal air flow and fuel handling accident mode air flow and temperature control to the refueling area.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The turbine enclosure north and south vent stacks are available to support this test. The SGTS is operational.

Test Method - The fans are placed in operation. Control devices are actuated to isolate the refueling area, and the system is operated in its fuel handling accident mode. System alarms are also actuated.

Table 14.2-4 (Cont'd)

Acceptance Criteria -

a. System fans operate properly. (Section 9.4.2)

b. System fan standby features, interlocks, permissives, and automatic start circuits operate properly. (Section 9.4.2)

c. System unit heaters and cooling coil operate properly. (Section 9.4.2)

d. System alarms operate properly. (Section 9.4.2.2.5)

e. Refueling area isolation logic operates properly. (Section 9.4.2)

(P-35.1) Fuel Pool Cooling and Cleanup System

Unit Scope -

a. 1P-35.1 (Unit 1 system components)

b. 2P-35.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the operability of the FPCC system.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Makeup water from the demineralized water tank is available. The RHR system is capable of supplying water to system diffusers.

Test Method - System pumps are placed in operation and system flow paths are verified. System controls are verified. System filter cycles are verified.

Acceptance Criteria -

a. System pumps meet acceptable head and flow values. (Section 9.1.3)

b. System controls operate properly. (Section 9.1.3)

c. Filter hold, precoat, and backwash controls operate properly, (Section 9.1.3)

d. Siphon breaker holes in the system return lines operate properly. (Section 9.1.3)

e. Fuel transfer canal gates prevent excessive water loss from the spent fuel pool when adjacent cavities are empty. (Section 9.1.3)

f. System alarms operate properly. (Section 9.1.3.5)

Table 14.2-4 (Cont'd)

(P-37.1) Condensate and Refueling Water Transfer System

Unit Scope -

a. 1P-37.1 (Unit 1 and common system components)

b. 2P-37.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the ability of the condensate and refueling water transfer system to transfer water from the CSTs and refueling water tanks to various systems.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Demineralized water, plant heating steam, and instrument air systems are operable.

Test Method - System is operated, and power-operated valves are cycled both automatically and manually. Flow is directed through each flow path. Tank levels and temperatures are simulated, and control system operation is verified.

Acceptance Criteria -

a. System pump's head and capacity are within specified limits. (Section 9.2.7)

b. Pump trips and control logic operate properly. (Section 9.2.7)

c. Power-operated valves operate properly. (Section 9.2.7)

d. Condensate and refueling water temperature controls operate properly. (Section 9.2.7)

e. Flow is verified through each major flow path. (Section 9.2.7)

f. System alarms operate properly. (Section 9.2.7.5)

(P-39.1) Condensate Demineralizer System

Unit Scope -

a. 1P-39.1 (Unit 1 system components)

b. 2P-39.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the ability of the condensate demineralizer system to maintain condensate feedwater chemistry and the ability of the precoat and backwash systems to operate properly.

Prerequisites - To the extent necessary to support this test, construction is completed, and instrumentation and controls are operable. The condensate system is operable and lined up to recirculate water to the hotwells via the feed pump bypass and startup recirculation lines. The instrument air system and process sampling systems are operational. Refueling water pumps are operational, and sufficient water is available in the refueling water tank to support this test.

Table 14.2-4 (Cont'd)

For Unit 2, the refueling water pumps and refueling water will not be used prior to tie-in to common plant systems. Unit 2 testing will be performed utilizing temporary equipment in order to avoid contamination. Low pressure air blower is operational, and the backwash receiving tank is operational with sufficient volume to support this test.

Test Method - The filter/demineralizer units are placed in operation, and their controls are operated. Effluent water purity is verified. Flow rates, flow controls, and system flow balancing are verified. Automatic precoat cycle operation is verified for each vessel.

Acceptance Criteria -

a. Vessel cleaning and precoat cycles operate properly. (Vendor Technical Manual)

b. Each demineralizer produces effluent water of the proper quality. (Section 10.4.6)

c. The system flow balancing system operates properly. (Section 10.4.6)

d. The cation and anion feeders supply resin to the precoat tank. (Vendor Technical Manual)

e. The precoat pump and the system hold pumps operate properly. (Section 10.4.6)

f. System pneumatic valves operate properly. (Section 10.4.6)

g. System controls, interlocks, and alarms operate properly. (Section 10.4.6)

(P-41.1) Cooling Tower System

Unit Scope -

a. 1P-41.1 (Unit 1 system components)

b. 2P-41.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the operability of the cooling tower chlorination system, sulfuric acid injection system, icing control system, and makeup water flow control valves.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The service water system, circulating water system, Schuylkill river makeup water system, instrument air system, circulating water pumphouse domestic water supply, and the circulating water pump structure power roof ventilators are operational as required to support the test.

Test Method - The cooling tower chlorination system, sulfuric acid injection system, icing control system, and makeup water flow control valves are placed in operation. Each system response to simulated cooling tower conditions is verified. System controls logics, and alarms are operated.

Table 14.2-4 (Cont'd)

Acceptance Criteria -

a. The cooling tower chlorination system operates properly. (Section 10.4.5.1)

b. The cooling tower sulfuric acid injection system operates properly. (Section 10.4.5.1)

c. The cooling tower icing control system operates properly. (Vendor Technical Manual)

d. The cooling tower makeup water flow control valves operate properly. (Section 10.4.5.2)

e. System alarms operate properly. (Section 10.4.5.1.5)

(P-42.1) Circulating Water System

Unit Scope -

a. 1P-42.1 (Unit 1 system components)

b. 2P-42.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate that the circulating water system delivers cooling water to the main condenser as designed.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The cooling tower is operational, and the circulating water system is filled sufficiently to operate the circulating water pumps. The main condenser is available to receive cooling water.

Test Method - The circulating water pumps and their controls are operated. System flows and flow paths are measured and verified. The water box scavenging pumps and their controls are operated. The main condenser fill and drain system is operated.

Acceptance Criteria -

a. Circulating water pumps head and flow are acceptable. (Section 10.4.5.1)

b. System automatic valves operate properly. (Section 10.4.5.1)

c. System controls, interlocks, and permissives operate properly. (Section 10.4.5.1)

d. Water box scavenging pumps operate properly. (Section 10.4.5.1)

e. Main condenser drain and fill system operates properly. (Section 10.4.5.1)

f. Circulating water winter bypass flow is acceptable. (Section 10.4.5.1)

Table 14.2-4 (Cont'd)

g. System alarms operate properly. (Section 10.4.5.1.5)

(P-43.1) Condenser and Air Removal System

Unit Scope -

a. 1P-43.1 (Unit 1 system components)

b. 2P-43.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the ability of the main condenser air removal system to both pull and hold a vacuum in the main condenser.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are calibrated. The main turbine is on the turning gear with steam seals established.

Test Method - With the turbine on turning gear and necessary support systems operating, the mechanical vacuum pumps are operated to initially pull a vacuum on the main condenser. The SJAEs, using auxiliary steam, are then cut in to maintain an acceptable vacuum.

Acceptance Criteria -

a. The mechanical vacuum pump pulls an acceptable vacuum. (Section 10.4.2)

b. The SJAEs maintain an acceptable vacuum. (Section 10.4.2)

c. System logics and alarms operate properly. (Section 10.4.2.5)

d. System offgas isolation operates properly. (Section 10.4.2)

(P-44.1) Condensate System

Unit Scope -

a. 1P-44.1 (Unit 1 system components)

b. 2P-44.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the ability of the condensate system to supply water to the feedwater system, and the proper operation of system controls.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

The feedwater system is available to provide a flow path back to the main condenser. The condenser and the condensate storage system have sufficient water to operate the condensate pumps. TECW is available.

Table 14.2-4 (Cont'd)

Test Method - The condensate pumps and their controls are operated. System flows and flow paths are measured and verified. Automatic pump minimum flow control as well as the ability of the makeup and reject system to control hotwell level is demonstrated. Major valves are operated to demonstrate the ability to isolate sections of the system.

Acceptance Criteria -

a. Condensate pump head and flow meet acceptable values. (Section 10.4.7.2.1)

b. Pump controls, interlocks, and permissives operate properly. (Section 10.4.7.2.1)

c. System MOVs operate properly. (Section 10.4.7.2.1)

d. System makeup valves and logics operate properly. (Section 10.4.7.2.1)

e. Condensate pump recirculation flow meets acceptable values. (Section 10.4.7.2.1)

f. System alarms operate properly. (Section 10.4.7.5)

(P-45.1) Feedwater System

Unit Scope -

a. 1P-45.1 (Unit 1 system components)

b. 2P-45.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the operability of the reactor feedwater pumps, their turbine drivers, and the feedwater control system, and to verify that the feedwater system functions to the degree that is possible with the limited steam available. For Unit 2 (Test 2P-45.1), an additional objective is to demonstrate the ability of the turbine supervisory system to monitor the operation of the reactor feedwater pump-turbines. For Unit 1 this was tested by Test 1P-93.3.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The condensate system is available for supplying water to the feedwater pumps. The auxiliary steam system is able to supply steam to the feedwater pump-turbine drivers. The main condenser is available to receive the turbine exhaust. The service water system is available to satisfy the system's cooling water requirements.

Test Method - The feedwater pump-turbine drivers are first operated uncoupled from the pumps. After coupling and with the condensate system running, each feedwater pump is operated separately, recirculating water back to the condenser. System controls and alarms are actuated, including operation of the feedwater pump minimum flow valves and the feedwater pump-turbine lube oil system. Feedwater control system inputs are verified. Various inputs are simulated and output response to small and large signal changes is checked.

Table 14.2-4 (Cont'd)

Acceptance Criteria -

a. The reactor feed pumps and turbines operate properly using the auxiliary steam supply. (Section 10.4.7.2.2)

b. Reactor feed pump recirculation valves operate properly. (Section 10.4.7.2.2)

c. Reactor feed pump turbine lube oil systems operate properly. (Section 10.4.7.2.2)

d. Reactor feed pump seals operate properly. (Section 10.4.7.2.2)

e. Feedwater control system inputs operate properly. (Section 7.7.1.4)

f. Feedwater control system response is proper to simulated small and large signal changes. (Section 7.7.1.4)

g. System MOVs and AOVs operate properly. (Section 10.4.7.2.2)

h. System instruments and alarms operate properly. (Sections 10.4.7.3 and 10.2.5.a and Vendor Technical Manual)

i. Each feed pump and its associated feedwater heater can be isolated for maintenance with pressure in the system. (Section 10.4.7.2.2)

j. Feedwater control system outputs are proper during simulated operation. (Section 7.7.1.4)

(P-46.1) Extraction Steam and Feedwater Heater System

Unit Scope -

a. 1P-46.1 (Unit 1 system components)

b. 2P-46.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate operability of the extraction steam and feedwater heater level control and automatic isolation systems.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - Turbine trip and pressure signals are simulated, and automatic isolation valve and bleeder trip check valve operation are verified. Feedwater heater level signals are simulated to verify proper response of drain valves, dump valves, bleeder trip valves, and extraction line drain valves. System alarms are actuated.

Acceptance Criteria -

a. Bleeder trip check valve closing times and extraction steam line drain valve opening times are acceptable. (Section 10.2.2.4)

Table 14.2-4 (Cont'd)

b. Valve interlocks and logic operate properly. (Section 10.2.2.4)

c. System alarms operate properly. (Section 10.2.2.4)

(P-49.1) Residual Heat Removal System

Unit Scope -

a. 1P-49.1 (Unit 1 system components)

b. 2P-49.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate that the RHR system delivers cooling water for each of the following system modes of operation: shutdown cooling, LPCI, suppression pool cooling, and fuel pool cooling.

Prerequisites - To the extent necessary to perform this test, construction is completed, instrumentation and controls are operable and calibrated, and testing of relief and safety valves is completed. The RPV is available and filled with water above the minimum level required to provide suction to the RHR pumps. The recirculation loops are complete to the extent required for system operation in the shutdown cooling mode. The ESW system is available to provide cooling water to the RHR pumps. The suppression pool is available and filled above the low water level to provide suction to the RHR pumps. The fuel pool and fuel pool skimmer surge tanks are full of water and available for fuel pool cooling mode operation.

Test Method - The operating modes of the RHR system are initiated manually from the control room and remote shutdown panel and, where applicable, automatically. RHR pump performance is determined for each mode. System flow paths are verified. The containment spray flow path is demonstrated by an air flow test that overlaps with the pump water flow path. Adequate NPSH and absence of vortexing is verified by testing the pumps at the lowest suppression pool level allowed by the Technical Specifications (Unit 1), or by testing the pumps at approximately the lowest level that will be reached by the suppression pool during the course of a LOCA while the pumps are operating (Unit 2). System controls and alarms are actuated. Watertight door gaskets and dogs are inspected and operated. Room flood detectors are operated.

Acceptance Criteria -

a. RHR pumps meet acceptable values of head and flow for system operating modes. (Sections 6.3.2.2.4 and 5.4.7)

b. System valves are operable from the control room, and all key-locks operate properly. (Sections 6.3.2.2.4 and 5.4.7)

c. The system operates properly to provide supplemental fuel pool cooling. (Sections 6.3.2.2.4 and 5.4.7)

d. The system operates properly in the shutdown cooling mode. (Sections 6.3.2.2.4 and 5.4.7)

Table 14.2-4 (Cont'd)

e. The system operates properly in the suppression pool cooling mode. (Section 7.2.1.1.5)

f. The system operates properly in the LPCI mode. (Section 7.3.1.1.4)

g. Steam condensing valves and logic operate properly. (Sections 6.3.2.2.4 and 5.4.7)

h. Containment spray valves and logic operate properly. (Section 7.3.1.1.4)

i. The RHR room flood detector operates properly. (Sections 6.3.2.2.4 and 5.4.7)

j. System alarms operate properly. (Sections 6.3.2.2.4 and 5.4.7)

k. The condensate transfer system and the safeguard piping fill pumps are each capable of maintaining full RHR pump discharge lines. (Section 6.3.2.2.6)

l. Remote shutdown panel instrumentation and controls operate properly. (Sections 6.3.2.2.4 and 5.4.7)

m. System overpressure protection interlocks operate properly. (Sections 6.3.2.2.4 and 5.4.7)

n. NPSH is within specified limits, and no vortexing is present. (Section 6.3.2.2.5)

o. Watertight doors exhibit a full seal when dogged down. (Vendor Technical Specification)

(P-50.1) Reactor Core Isolation Cooling System

Unit Scope -

a. 1P-50.1 (Unit 1 system components)

b. 2P-50.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the operability of the RCIC system in delivering water to the reactor vessel and to verify proper separation of the RCIC dc components by observing the effect of disconnecting the RCIC dc bus on RCIC operation.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The CST and suppression pool are filled above the low water level to provide suction to the pump, and auxiliary steam is available to supply steam to the RCIC pump-turbine driver.

Test Method - RCIC system operation is initiated from the control room and remote shutdown panel by manual and automatic start signals. Pump and turbine performance is verified. System controls and alarms are actuated. During system testing, the RCIC dc bus will be disconnected to verify inoperability of the RCIC system. Adequate NPSH and absence of vortexing is verified by testing the pumps at the lowest suppression pool level allowed by the Technical Specifications (Unit 1), or

Table 14.2-4 (Cont'd)

by testing the pumps at approximately the lowest level that will be reached by the suppression pool during the course of a LOCA while the pumps are operating (Unit 2).

Watertight door gaskets and dogs are inspected and operated. Room flood detectors are operated.

Acceptance Criteria -

a. The RCIC turbine controls and logic operate properly. (Sections 5.4.6 and 7.4.1.1)

b. The RCIC pump and turbine operate properly using their auxiliary steam supply. (Sections 5.4.6 and 7.4.1.1)

c. System manual and automatic initiation logic operate properly. (Sections 5.4.6 and 7.4.1.1)

d. The RCIC room flood detector operates properly. (Sections 5.4.6 and 7.4.1.1)

e. System alarms operate properly. (Sections 5.4.6 and 7.4.1.1)

f. Securing of the RCIC dc bus results in inoperability of the RCIC system. (Sections 5.4.6 and 7.4.1.1)

g. Remote shutdown panel instrumentation and controls operate properly. (Sections 5.4.6 and 7.4.1.1)

h. NPSH is within specified limits, and no vortexing is present. (Sections 5.4.6 and 7.4.1.1)

i. Watertight doors exhibit a full seal when dogged down. (Vendor Technical Specification)

Full flow and minimum start time criteria are not demonstrated until nuclear steam is available during the power test program.

(P-51.1) Core Spray System

Unit Scope -

a. 1P-51.1 (Unit 1 system components)

b. 2P-51.1 (Unit 2 system components)

Test Objectives - The test objective is to demonstrate the ability of the core spray system to deliver water spray to the reactor core.

Table 14.2-4 (Cont'd)

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The CST and the suppression pool are filled above the low water level. The RPV head is off, and the vessel is available to receive water from the core spray system.

Test Method - Core spray system operation is initiated and pump flow rates are measured in the various design modes of operation. System performance is verified. System controls and alarms are actuated. The safeguard piping fill system is operated and safeguard piping leakage is monitored. Adequate NPSH and absence of vortexing is verified by testing the pumps at the lowest suppression pool level allowed by the Technical Specifications (Unit 1), or by testing the pumps at approximately the lowest level that will be reached by the suppression pool during the course of a LOCA while the pumps are operating (Unit 2).

Acceptance Criteria -

a. The core spray pumps meet acceptable head and flow values. (Sections 6.3.2.2.3 and 7.3.1.1.1)

b. System manual and automatic initiation is acceptable. (Sections 6.3.2.2.3 and 7.3.1.1.1)

c. System MOVs operate properly. (Sections 6.3.2.2.3 and 7.3.1.1.1)

d. The core spray room flood detector operates properly. (Sections 6.3.2.2.3 and 7.3.1.1.1)

e. Systems alarms operate properly. (Sections 6.3.2.2.3 and 7.3.1.1.1)

f. Safeguard piping fill pumps operate properly and keep core spray discharge piping full. (Sections 6.3.2.2.3 and 7.3.1.1.1)

g. The condensate transfer system is capable of maintaining full core spray discharge lines. (Sections 6.3.2.2.3 and 7.3.1.1.1.3)

h. Total leakage from all safeguard piping fed by the safeguard piping fill pumps does not exceed the capability of the fill pumps. (Sections 6.3.2.2.3 and 7.3.1.1.1.3)

i. Core spray flow rates from the suppression pool to the reactor vessel are set to meet acceptance criteria by adjusting the size of the spray line discharge orifice. (Sections 6.3.2.2.3 and 7.3.1.1.1.3)

Table 14.2-4 (Cont'd)

j. System overpressure protection interlocks operate properly. (Sections 6.3.2.2.3 and 7.3.1.1.1.3)

k. NPSH is within specified limits, and no vortexing is present. (Sections 6.3.2.2.3 and 7.3.1.1.1.3)

(P-52.1) High Pressure Coolant Injection System

Unit Scope -

a. 1P-52.1 (Unit 1 system components)

b. 2P-52.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate that the HPCI system delivers cooling water to the RPV as designed.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The CST and the suppression pool are filled above the low water level to provide suction to the pump. The auxiliary boiler is available to provide steam to the HPCI pump-turbine driver.

Test Method - With the HPCI pumps uncoupled, performance of the turbine driver is measured, including operation of the turbine control and trip system. Limited pump operation (coupled) is conducted for all modes of operation (to the extent possible using auxiliary steam). System performance is determined. System controls and alarms are actuated. Adequate NPSH and absence of vortexing is verified by testing the pumps at the lowest suppression pool level allowed by the Technical Specifications (Unit 1), or by testing the pumps at approximately the lowest level that will be reached by the suppression pool during the course of a LOCA while the pumps are operating (Unit 2). Watertight door gaskets and dogs are inspected and operated. Room flood detectors are operated.

Acceptance Criteria -

a. The HPCI turbine controls and logic operate properly. (Sections 6.3.1.2.1 and 7.3.1.1.1.1)

b. The HPCI pump and turbine operate properly using the auxiliary steam supply. (Sections 6.3.1.2.1 and 7.3.1.1.1.1)

c. System automatic start, shutdown, and restart occur properly. (Sections 6.3.1.2.1 and 7.3.1.1.1.1)

d. Manual operation of system components is acceptable. (Sections 6.3.1.2.1 and 7.3.1.1.1.1)

e. Controls affecting the transfer of HPCI pump suction water supplies operate properly. (Sections 6.3.1.2.1 and 7.3.1.1.1.1)

Table 14.2-4 (Cont'd)

f. The HPCI room flood detector operates properly. (Sections 6.3.1.2.1 and 7.3.1.1.1.1)

g. System alarms operate properly. (Sections 6.3.1.2.1 and 7.3.1.1.1.1)

h. The condensate transfer system and a safeguard piping fill pump are each capable of maintaining a full HPCI pump discharge line. (Sections 6.3.1.2.1 and 7.3.1.1.1.1)

i. NPSH is within specified limits, and no vortexing is present. (Sections 6.3.2.2.1.1 and 6.3.2.2.1.2)

j. Watertight doors exhibit a full seal when dogged down. (Vendor Technical Specification)

Full flow and minimum start time criteria are not demonstrated until nuclear steam is available during the startup test program.

(P-53.1) Standby Liquid Control System

Unit Scope -

a. 1P-53.1 (Unit 1 system components)

b. 2P-53.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the proper operation of the SLCS.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The RPV is available for demineralized water injection. The SLCS tank is filled with demineralized water.

Test Method - The SLCS is manually placed in operation to the reactor in conjunction with the test firing of each squib operated valve. System performance is determined, including pump flow rates and tank heater operation. System controls and alarms are actuated.

Acceptance Criteria -

a. The standby liquid pumps meet acceptable values of flow and discharge pressure. (Section 3.9.3.1.12)

b. The standby liquid control tank temperature is controlled properly. (Section 9.3.5)

c. System manual initiation operates properly. (Section 9.3.5)

d. System automatic initiation operates properly. (Sections 7.4.1.2.3.2 and 7.6.1.8.3.4)

e. System alarms operate properly. (Section 9.3.5)

f. For each train, the connected explosive valve opens. (Section 9.3.5)

Table 14.2-4 (Cont'd)

(P-54.1) Emergency Service Water System

Unit Scope -

a. 1P-54.1 (Unit 1 system components)

b. 2P-54.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate that the ESW system supplies cooling water to safeguard equipment as designed.

Prerequisites - To the extent necessary for performance of this test, construction is completed, and instrumentation and controls are operable and calibrated. The cooling tower basin is operable, and the spray pond is at its normal operating level to provide water for the ESW pumps. The heat exchangers served by this system are available to provide a flow path for the pumps. Applicable portions of the RHRSW system are operable to support the flow verification test.

Test Method - The ESW system pumps are started manually and automatically. System controls in the control room and the remote shutdown station are operated and pump flow rates are measured. System alarms are also actuated.

Acceptance Criteria -

a. System pumps meet acceptable head and flow values for the various design flow paths. (Sections 9.2.2 and 7.3.1.1.11)

b. System pump automatic start features operate properly. (Sections 9.2.2 and 7.3.1.1.11)

c. System valves, controls and instrumentation are operable from both the control room and the remote shutdown panel; all key-locks and valve automatic features operate properly. (Sections 9.2.2 and 7.3.1.1.11)

d. System alarms operate properly. (Sections 9.2.2 and 7.3.1.1.11)

(P-55.1) Control Rod Drive Hydraulic System

Unit Scope -

a. 1P-55.1 (Unit 1 system components)

b. 2P-55.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the proper operation of the CRD hydraulic system, including CRD mechanisms, HCUs, power supply, instrumentation, and controls.

Table 14.2-4 (Cont'd)

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The condensate transfer and storage system, and the RMCS are available and operational to support the system test. The TECW system is available and operational to provide the cooling water requirement of the drive water pumps. The compressed air system is available and operational to provide the instrument air requirements of the system.

Test Method - The CRD hydraulic system is placed in operation utilizing the flow and pressure control stations. Pump controls are operated and flow rates measured. CRDs are exercised to verify latching, position indication, and stroke speeds. Scram times are measured for each control rod.

Acceptance Criteria -

a. The CRD hydraulic supply and discharge sections supply water at acceptable flow and pressure to the HCUs. (Sections 4.6.1 and 4.6.3)

b. Each HCU operates properly to drive its control rod at proper speeds. (Sections 4.6.1 and 4.6.3)

c. Position indication and latching operate properly. (Sections 4.6.1 and 4.6.3)

d. System alarms operate properly. (Sections 4.6.1 and 4.6.3)

(P-56.1) Reactor Manual Control System

Unit Scope -

a. 1P-56.1 (Unit 1 system components)

b. 2P-56.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate proper operation of the RMCS, including relays, control circuitry, switches, rod blocks, indicating lights, and control valves; and proper operation of the RWM system.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - System integrated operation is initiated manually. Controls are operated, and simulated signals are applied to verify: rod blocks; alarms and interlocks and control functions of the reactor mode switch; operation of the rod position information system and rod drift alarm circuit; and directional control valve time sequence for insert and withdraw commands. Proper operation of the RWM system is verified.

Table 14.2-4 (Cont'd)

Acceptance Criteria -

a. The system operates properly during both insert and withdrawal cycles. (Section 7.7.1.2)

b. Rod block functions, interlocks, bypasses, and indications are acceptable. (Section 7.7.1.2)

c. Rod position indication operate properly. (Section 7.7.1.2)

d. System alarms operate properly. (Section 7.7.1.2)

(P-57.1) Uninterruptible Ac Power System

Unit Scope -

a. 1P-57.1 (Unit 1 system components)

b. 2P-57.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the proper operation of the uninterruptible ac power system.

Prerequisites - To the extent necessary to perform this test, construction is completed and instrumentation and controls are operable and calibrated. The 250 V dc and 440 V motor control center buses are available for energization of the 120 V or 120/240 V uninterruptible ac distribution panel.

Test Method - The 120 V or 120/240 V uninterruptible ac distribution panels are energized from the 250 V dc power system and transfer to the 440 V ac power system is initiated. Other system controls and alarms are also actuated.

Acceptance Criteria -

a. System static inverters operate properly while supplying a design value of load. (Vendor Technical Manual)

b. System static inverter transfer time between alternate and preferred sources is acceptable. (Section 7.2.1.1.3)

c. System 440 V ac and 125/250 V dc breakers operate properly. (Vendor Technical Manual)

d. System bus voltages are acceptable. (Vendor Technical Manual)

e. System ac electrical power is available to all system distribution panels. (Electrical Single-Line Diagram)

Table 14.2-4 (Cont'd)

(P-58.1) Reactor Protection System

Unit Scope -

a. 1P-58.1 (Unit 1 system components)

b. 2P-58.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate that the RPS operates properly during integrated system functions.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - The various RPS sensors, sensor relays and devices will be actuated and timed to designated points along the scram chain logic. RPS response measurements will be run twice for each channel. The plant operating technical specification trip setpoints will be demonstrated at least one time by actual application of an input to the sensor/device or stroking an associated valve to actuate position switches as appropriate.

Acceptance Criteria -

a. System input scram function signals cause trips within design values. (Section 7.2)

b. System actuated logics operate properly. (Section 7.2).

c. Scram modes and bypasses operate properly. (Section 7.2)

d. Response time of the scram chain from sensor actuation through initiating logic and 90% rod insertion is within design values. (Section 7.2)

e. System indicators and alarms operate properly. (Section 7.2)

(P-58.2) Redundant Reactivity Control System for ATWS

Unit Scope -

a. 1P-58.2 (Unit 1 system components)

b. 2P-58.2 (Unit 2 system components)

Test Objective - The test objective is to demonstrate proper operation of the RRCS logic and to verify proper response in those systems it affects.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are calibrated and operable. The following systems are available for operation: SLCS, RWCU, CRD, reactor recirculation, APRMs, and feedwater. The reactor vessel, CST, and suppression pool are filled with demineralized water.

Table 14.2-4 (Cont'd)

Test Method - The ATWS logic is operated manually and also automatically by using simulated reactor vessel water level and steam dome pressure signals. APRM power level will also be simulated. Where appropriate, signals from the RPS will be inhibited to allow independent demonstration and redundancy verification of ATWS logic and results. Resultant actions of recirculation pump trip, alternate rod insertion, RWCU isolation and standby liquid control start will be verified. Manual operation or operating limit reset of a system while under the influence of an ATWS logic signal will be demonstrated as appropriate.

Acceptance Criteria -

a. System sensing devices, trip systems, and actuator logics operate and trip within design limits. (Section 7.6.1.8)

b. System alarms and indications operate properly. (Section 7.6.1.8)

c. System logic and its action on other systems is independent and redundant. (Section 7.6.1.8)

(P-59.1) Containment Isolation and Nuclear Steam Supply Shutoff System

Unit Scope -

a. 1P-59.1 (Unit 1 system components)

b. 2P-59.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate that the primary containment isolation and NSSSS actuates the isolation valves following simulated primary containment isolation signals.

Prerequisites - To the extent necessary to perform this test, construction is completed and instrumentation and controls are operable and calibrated. Isolation valves actuator trip relays are placed in untripped condition. Primary containment isolation valves are operable.

Test Method - The actuator trip relay for each isolation valve is operated using simulated signals as necessary to create a trip condition. The actuator trip relay then operates the corresponding isolation valve. System alarms are also actuated.

Acceptance Criteria -

a. System sensing devices, trip systems, and actuator logics operate and trip within design limits. (Section 7.3.1.1.2)

b. Closing times for valves closed by this system are within acceptable values. (Section 6.2.4)

c. System alarms operate properly.

Table 14.2-4 (Cont'd)

(P-59.2) Primary Containment Integrated Leak Rate Test

Unit Scope -

a. 1P-59.2 (Unit 1 system components)

b. 2P-59.2 (Unit 2 system components)

Test Objective - The test objective is to determine the leakage rate in the primary containment at the peak calculated accident pressure and to determine the bypass leakage from the drywell to the wetwell at the peak drywell to wetwell differential pressure and reduced differential pressure corresponding to approximately the submergence of the vents. In addition, the test will verify the proper connection and tracking of the containment pressure instruments.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The Type B and C testing has been completed in accordance with Chapters 6 and 16. The integrated leakage rate measurement system is calibrated and operational. All containment pressure instruments have been calibrated and are valved into service.

Test Method - The containment is pressurized, and the absolute pressure, dry-bulb temperature, and dew point temperature (water vapor pressure) within the containment and the drywell are recorded to determine the leak rate. The containment is depressurized, the drywell is pressurized to reduced test pressure, and data are taken to determine the drywell bypass leakage rate. As containment pressure is increased during the containment ILRT, proper tracking of all containment pressure instruments is verified.

Acceptance Criteria -

The primary containment and drywell bypass leakage rates are within acceptable limits (Section 6.2.6). All containment instruments track properly, and all affected instrument lines are clear of obstructions.

(P-59.3) Suppression Pool, Pool Cleanup and Vacuum Relief

Unit Scope -

a. 1P-59.3 (Unit 1 system components)

b. 2P-59.3 (Unit 2 system components)

Test Objectives - The test objective is to demonstrate the operability of the suppression pool cleanup and vacuum relief system, the suppression pool level instruments, and system valves.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The suppression pool is sufficiently full of water and the condenser hotwell is available.

Table 14.2-4 (Cont'd)

Test Method - The suppression pool cleanup system is operated, and the pump flow rate measured. The suppression pool level is varied, and the operability of the pool level instruments is verified. Primary containment vacuum relief valves and pressure instruments are also operated.

Acceptance Criteria -

a. The suppression pool cleanup pump meets acceptable head and flow values. (Vendor Technical Specification)

b. Primary containment vacuum relief valves operate properly. (Section 7.3.2.6.1.1)

c. System MOVs operate properly. (Section 6.4.2)

d. Suppression pool level instruments operate properly. (Section 7.5.1.4.2.1)

e. System alarms operate properly. (Section 6.3.2.2.3)

f. Containment pressure indicators used to track accident conditions operate properly. (Section 7.5.1.4.2.1)

(P-60.1) Drywell HVAC System

Unit Scope -

a. 1P-60.1 (Unit 1 system components)

b. 2P-60.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the operability of the primary containment ventilation system.

Prerequisites - To the extent necessary to perform this test, construction is completed, instrumentation and controls are operable and calibrated, chilled water flow balancing and drywell air balancing are complete.

Test Method - The ventilation system fans and chillers are operated. Controls and alarms are actuated.

Acceptance Criteria -

a. Drywell unit coolers and fans operate properly. (Section 9.4.5.2)

b. Drywell chilled water circulation pumps operate properly. (Section 9.2.10.1)

c. Drywell water chillers operate properly. (Section 9.2.10.1)

Table 14.2-4 (Cont'd)

d. System isolation and control valves operate properly. (Sections 9.2.10.1 and 9.4.5.2)

e. System alarms operate properly. (Sections 9.2.10.1 and 9.4.5.2)

(P-61.1) Reactor Water Cleanup System

Unit Scope -

a. 1P-61.1 (Unit 1 system components)

b. 2P-61.1 (Unit 2 system components)

Test Objective - The test objectives is to demonstrate the operability of the RWCU system and to verify that the system functions properly.

Prerequisites - To the extent necessary for performance of this test, construction is completed, and instrumentation and controls are operable and calibrated. The demineralizers are precoated, as required, and ready to process system flow. The RECW system is available to satisfy the system's cooling requirements.

Test Method - The recirculation pumps are operated and their performance characteristics are determined. Data are obtained during demineralizer cleanup, backwash, and precoat operations. System controls and alarms are actuated, including operation of the system isolation valves. Simulated signals are used as required.

Acceptance Criteria -

a. System pumps meet acceptable values of head and flow. (Section 5.4.8)

b. Filter precoat and backwash cycles operate properly. (Vendor Technical Manual)

c. System isolation valves operate properly. (Section 5.4.8)

d. System flow circuits operate properly. (Section 5.4.8)

e. System alarms operate properly. (Section 5.4.8)

(P-62.1) Reactor Vessel and Auxiliaries

Unit Scope -

a. 1P-62.1 (Unit 1 system scope)

b. 2P-62.1 (Unit 2 system scope)

Table 14.2-4 (Cont'd)

Test Objective - The test objective is to detect damage, excessive wear, loose parts, or other evidence of unacceptable vibration which could result from assembly errors or undesirable deviations from the previously qualified prototype plant construction.

This test is a quality assurance measure which experimentally confirms the absence of excessive vibration of core support structures, jet pumps, lower plenum components, and other major internal structures. The test is conducted without fuel, and is not intended to be a test of fuel or incore instrument vibration. However, the specified test conditions, without fuel present, provide a level of vibration excitation of major internal structures which is at least as high as that measured in normal power operation.

Prerequisites: To the extent necessary to perform this test, all reactor internals components are installed, except:

a. The core matrix is empty; there are no fuel assemblies, incore instrumentation tubes, or neutron source rods. Control blades are withdrawn or not installed. Fuel support castings are installed.

b. The dryer assembly need not be installed.

c. One of the access hole covers on the shroud support plate must remain unwelded until after the test to provide access for inspection. A temporary closure must be provided.

The reactor vessel is closed, filled, and ready for pressurization. The recirculation pumps are operable. RHR system pumps are operable to provide necessary temperature rise. The CRD system is operable to control reactor vessel pressure. RWCU system heat exchangers are operable for temperature control.

Test Method - A visual inspection is made before and after the required 100% speed pump runs. These flow runs include 35 hours of two-loop operation and 14 hours each for loops A and B. The total run time is 63 hours. These hours may not be sequential, but they must be between the initial and final inspections.

Acceptance Criteria -

Initial and final inspection results are acceptable. (Section 3.9.2.4)

(P-64.1) Reactor Recirculation System

Unit Scope -

a. 1P-64.1 (Unit 1 system components)

b. 2P-64.1 (Unit 2 system components)

Test Objective - The test objectives are to demonstrate that the reactor recirculation system components function properly, and to demonstrate the flow performance of the system to the degree possible prior to fuel loading.

Table 14.2-4 (Cont'd)

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The RPV is available and filled with demineralized water above the minimum level required for reactor recirculation pumps operation. The RECW system and DCWS are available to provide the cooling water requirements of the pumps.

Test Method - The recirculation pumps are operated at various speeds while corresponding pump flow rate and head characteristics are determined. The system is tested by individual and group operation of the pumps, MG sets, valves and controls. System interlocks and alarms are actuated, using simulated signals as required.

Acceptance Criteria -

a. Recirculation pumps meet acceptable values of head and flow for various motor input frequencies. (Sections 5.4 and 7.7.1.3)

b. System flow instrumentation operates properly. (Sections 5.4 and 7.7.1.3)

c. Recirculation pump isolation valves operate properly. (Sections 5.4 and 7.7.1.3)

d. System alarms are operable. (Sections 5.4 and 7.7.1.3)

e. System control logic operates properly. (Sections 5.4 and 7.7.1.3)

f. MG sets operate properly. (Sections 5.4 and 7.7.1.3)

g. MG sets' lube oil system operates properly. (Sections 5.4 and 7.7.1.3)

(P-65.1) Radwaste Enclosure HVAC System

Unit Scope -

a. 1P-65.1 (Common system components)

Test Objective - The test objective is to demonstrate the ability the radwaste enclosure HVAC system to provide air flow and respond to simulated temperature variations in the radwaste enclosure, equipment compartment, service and control, and fume hood areas. Additional objectives are to demonstrate the ability of the charcoal vault cooling system to maintain temperature control in charcoal vaults 1, 2, and 3, and the ability of the radwaste enclosure HVAC system to maintain positive air flow from clean areas to areas of increasing potential contamination.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - System fans and filter units are placed in operation. System controls and interlocks are operated. The charcoal vault cooling system and controls are operated. System temperature control valves response to temperature controls are verified. System alarms are activated.

Table 14.2-4 (Cont'd)

Acceptance Criteria -

a. System supply and exhaust fans operate properly. (Section 9.4.3)

b. System temperature control valves respond to temperature controls. (Section 9.4.3)

c. Results of in-place filter efficiency testing are acceptable (Table 9.4-18).

d. Supply and exhaust fan controls and interlocks operate properly. (Section 9.4.3)

e. The charcoal vault cooling system operates properly. (Section 9.4.3)

f. Compartment differential pressures are maintained. (Section 9.4.3)

g. System alarms operate properly. (Section 9.4.3.5)

(P-66.1) Reactor Enclosure Unit Cooler System

Unit Scope -

a. 1P-66.1 (Unit 1 system components)

b. 2P-66.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the capability of the reactor enclosure unit coolers to provide air flow to the RCIC, core spray, RHR, and HPCI safeguard pump compartments.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - The unit coolers are placed in operation. Pump compartment temperature variations are simulated and system response is verified. Unit cooler component interlocks are verified. The ESW system valves are operated throughout the test. System alarms are verified under actual and simulated conditions as practicable. System parameters are monitored and recorded for systems cooling ECCS equipment.

Acceptance Criteria -

a. The unit coolers operate properly. (Section 9.4.2)

b. The unit coolers automatic start features and interlocks operate properly in both the automatic and standby modes. (Section 9.4.2)

c. The unit coolers respond properly to temperature variations within the respective pump compartments. (Section 9.4.2)

d. Cooling water central valves are operated whenever the applicable unit cooler is energized. (Section 9.4.2)

Table 14.2-4 (Cont'd)

e. System alarms operate properly. (Section 9.4.2)

(P-66.2) - Control Enclosure Unit Coolers

Unit Scope -

a. 1P-66.2 (Common system components)

Test Objective - The test objective is to demonstrate the capability of the control enclosure unit coolers to provide cooling air flow to the SGTS room and access.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Applicable portions of the HVAC air balancing test are completed.

Test Method - The unit coolers are placed in operation. SGTS room and access temperature variations are simulated and system response is verified. Unit cooler component interlocks are verified.

Acceptance Criteria -

a. The unit coolers operate properly in the RUN, AUTO, and STBY modes. (Section 9.4.1)

b. Chill water inlet valves open when their associated unit cooler fan starts. (Section 9.4.1)

c. Chill water pumps start whenever one of the unit are operable from both the control room and the remote shutdown panel; coolers they supply starts. (Section 9.4.1)

d. SGTS access dampers open when their associated unit cooler fan starts. (Section 9.4.1)

(P-68.1) Solid Radwaste System

Unit Scope -

a. 1P-68.1 (Common system components)

b. 2P-68.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the operability of the solid radwaste system including the radwaste solidification system.

Prerequisite - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Demineralized water is available.

Table 14.2-4 (Cont'd)

Test Method - The solid radwaste system is tested with actual, nonradioactive, representative waste streams, which include backwash resins from RWCU, fuel pool cleanup, and condensate cleanup. The system is tested to ensure that these representative waste streams can be processed from their respective collection tanks through the phase separators, centrifuges and drumming process. Major operations verified in the test include the ability to mix sludge/resins and water in the backwash and sludge tanks to produce transportable mixtures, use of the phase separator tanks to concentrate sludge and resins by the decanting process prior to discharging to the centrifuges and high integrity containers.

Acceptance Criteria -

a. System pumps operate properly and are able to agitate contents of tanks and to transport slurry mixtures. (Section 11.4)

b. System alarms and controls operate properly. (Section 11.4)

c. System components (e.g., centrifuges, tank agitators, transfer carts, radwaste crane, etc.) operate properly. (Section 11.4)

d. System discharge product meets free liquid content limit as identified in Chapter 11.

(P-69.1) Equipment Drain Collection and Storage System

Unit Scope -

a. 1P-69.1 (Unit 1 and common system components)

b. 2P-69.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the ability of the equipment drain system to collect, store, and transfer potentially contaminated low conductivity liquid wastes.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - System pumps are operated in both manual and automatic modes. Power-operated valves are cycled in both manual and automatic modes. System alarms are verified by using actual or simulated conditions, as practical. Containment isolation signals are initiated to verify valve interlocks. Sumps fitted with positive exhaust connections are smoke tested.

Acceptance Criteria -

a. System pumps operate satisfactorily. (Sections 9.3.3 and 11.2)

b. System pumps operate in both manual and automatic modes. (Sections 9.3.3 and 11.2)

c. System power-operated valves operate in both manual and automatic modes. (Sections 9.3.3 and 11.2)

Table 14.2-4 (Cont'd)

d. Containment isolation valve interlocks operate. (Sections 9.3.3 and 11.2)

e. Sump exhausts draw room air into sump. (Sections 9.3.3 and 11.2)

f. System alarms operate. (Sections 9.3.3 and 11.2)

(P-69.3) Liquid Radwaste System

Unit Scope -

a. 1P-69.3 (Unit 1 and common system components)

b. 2P-69.3 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the ability of the equipment drain subsystem to transfer and process potentially contaminated low conductivity liquid wastes; the flow drain subsystem to collect, transfer, and process potentially contaminated high conductivity liquid wastes; and the fuel pool filter precoat and backwash system to clean and precoat both the equipment drain and floor drain filters. In addition, the ability of the chemical waste subsystem to collect and transfer corrosive liquid wastes; and the laundry drain subsystem to collect, transfer, and process liquid detergent wastes shall be demonstrated.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. System filters have been precoated and system demineralizers have been loaded with resin.

Test Method - The liquid radwaste system is operated with representative nonradioactive waste influent. Equipment and subsystems to be tested include equipment and floor drain processing, chemical waste, and laundry drains. System pumps are operated in both manual and automatic modes. The fuel pool precoat and backwash system is operated to clean and precoat both the equipment drain and the floor drain filters. System alarms are verified by using actual or simulated conditions where practical. The effluent of each filter and demineralizer is sampled to ensure that it is of acceptable quality. Power-operated valves are cycled in both manual and automatic modes.

Acceptance Criteria -

a. System pumps operate properly. (Section 11.2)

b. System pumps operate in both manual and automatic modes. (Section 11.2)

c. Fuel pool filter precoat and backwash system cleans and precoats both the equipment drain and floor drain filters. (Section 11.2)

d. System power-operated valves operate in both manual automatic modes. (Section 11.2)

e. The equipment and floor drain subsystems produce condensate storage quality water. (Section 11.2)

Table 14.2-4 (Cont'd)

f. The laundry drain subsystem produces water of acceptable quality to discharge to the environment. (Section 11.2)

g. Contents of the chemical waste tank can be mixed and neutralized prior to discharge for processing. (Section 11.2)

h. System alarms operate properly. (Section 11.2)

(P-70.1) Standby Gas Treatment System and Reactor Enclosure Air Recirculation, Secondary Containment Isolation

Unit Scope -

a. 1P-70.1 (Unit 1 system components)

b. 2P-70.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the capability of the reactor enclosure secondary containment to isolate and of the air recirculation and standby gas treatment systems to function properly.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The reactor enclosure H&V system and the turbine enclosure vent north stack are available and operational to support the system test.

Test Method - The reactor enclosure secondary containment is isolated, the reactor enclosure air recirculation and the standby gas treatment start automatically by a simulated reactor enclosure isolation signal. The SGTS, RERS, and secondary containment isolation performance is determined by measuring secondary containment pressures, system pressures, and fan air flow rates. Systems controls and alarms are actuated.

Acceptance Criteria -

a. System fans, both singularly and in combinations, provide acceptable values of flow through the system filters. (Section 6.5.1)

b. Fan interlocks, automatic start and shutout features, and damper logic operate properly. (Sections 6.5.1, 7.3.1.1.7, and 7.3.1.1.8)

c. Results of in-place filter efficiency testing are acceptable. (Section 6.5.1)

d. System alarms operate properly. (Sections 6.5.1, 7.3.1.1.7, 7.3.1.1.8, and 7.3.1.1.9)

e. Reactor enclosure isolation logic operates properly. (Section 6.2.3)

f. The reactor enclosure ventilation system is shut down and isolated properly. (Section 6.2.3)

Table 14.2-4 (Cont'd)

g. System steam flooding damper operation is proper. (Section 9.4.2.1)

(P-72.1) Gaseous Radwaste Recombiners and Filters

Unit Scope -

a. 1P-72.1 (Unit 1 and common system components)

b. 2P-72.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the operability of the gaseous radwaste system.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Nitrogen and auxiliary steam are available as required. Service water and RECW are operable, and the turbine enclosure ventilation stack is available for discharges.

Test Method - System recombiner and charcoal treatment trains are operated and their performance is verified.

Acceptance Criteria -

a. System recombiner and charcoal treatment trains operate properly. (Section 11.3)

b. System controls and alarms operate properly. (Section 11.3)

(P-73.1) Containment Atmosphere Control System

Unit Scope -

a. 1P-73.1 (Unit 1 system components)

b. 2P-73.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the ability of the CAC system to provide accurate analysis of containment oxygen and hydrogen content and to demonstrate the operability of the hydrogen recombiner packages. The actual hydrogen/oxygen recombination process is not demonstrated at this time.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - The combustible gas analyzer packages are operated and system flow rates determined. Gas samples containing known concentrations of oxygen and hydrogen are introduced into the system to verify proper response of the gas concentration indicating and recording equipment. The hydrogen recombiner system is operated, and system flow rates determined. System controls and alarms are actuated.

Table 14.2-4 (Cont'd)

Acceptance Criteria -

a. System atmosphere control isolation valves operate properly. (Section 9.4.5.1)

b. Containment hydrogen recombiners meet acceptable values of flow and temperature. (Section 9.4.5.1)

c. System hydrogen/oxygen analyzers operate properly. (Section 9.4.5.1)

d. System alarms operate properly. (Section 9.4.5.1)

(P-76.1) Process Sampling System

Unit Scope -

a. 1P-76.1 (Unit 1 system components)

b. 2P-76.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the ability of the process sampling system to provide various process samples with adequate flow indication to installed analytical monitoring equipment and grab samples stations.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - Each sample station is operated and grab samples are drawn as available. Chemical fume hoods and the turbine enclosure sample station drain recovery tank pumps are operated. System alarms are actuated.

Acceptance Criteria -

a. Sample lines are unobstructed. (Section 9.3.2)

b. Grab sample valves operate properly. (Section 9.3.2)

c. The turbine enclosure sample station drain recovery tank pumps operate properly. (Section 9.3.2)

d. The chemical fume hoods operate properly. (Section 9.3.2)

e. System alarms operate properly. (Section 9.3.2)

(P-76.2) Postaccident Sampling System

Unit Scope -

a. 1P-76.2 (Unit 1 system components)

Table 14.2-4 (Cont'd)

b. 2P-76.2 (Unit 2 system components)

Test Objective - The objective is to demonstrate the operability of the postaccident sampling system.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The postaccident sampling system and support systems are complete and operational.

Test Method - Component control and status indication will be tested, and base line operating data will be obtained for major components. The system will be operationally checked by taking actual samples.

Acceptance Criteria -

a. System gas pumps, gas breakdown pump, and liquid chiller function properly. (Section 11.5.5)

b. Component control and status indication devices function properly. (Section 11.5.5)

c. The system is capable of obtaining process samples from all design sampling points. (Section 11.5.5)

(P-78.1) Startup Range Detector Drive Control and Neutron Monitoring System

Unit Scope -

a. 1P-78.1 (Unit 1 system components)

b. 2P-78.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the operability of the startup range neutron monitoring system which includes both source and intermediate range neutron monitoring equipment.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - Each source and intermediate range detector is positioned from its fully inserted position to its fully retracted position to demonstrate the operability of the insert/retract mechanisms. Using simulated input signals, each source and intermediate range detector loop is tested to demonstrate meter indication, trip circuit operation, retract and insert permissives, associated rod block signals, and alarm operation.

Acceptance Criteria -

a. The startup range drive system is capable of positioning each detector through its full length of travel. (Section 7.7.2.6)

Table 14.2-4 (Cont'd)

b. Startup range neutron flux level and rate circuits indicate properly. (Section 7.7.2.6)

c. Startup range trip signals operate properly. (Section 7.7.2.6)

d. Startup range selector switch logic and insert/retract permissives operate properly. (Section 7.7.2.6)

e. Startup range rod block signals are generated per design. (Section 7.7.2.6)

f. System alarms operate properly. (Section 7.7.2.6)

(P-78.2) Power Range Neutron Monitoring System [1]

Unit Scope -

a. 1P-78.2 (Unit 1 system components)

b. 2P-78.2 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the operability of LPRM and APRM systems.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - Each LPRM channel is tested using simulated signals to its tripping, alarm, or indicating function. Each APRM channel is tested for its tripping, alarm, or indicating function using simulated signals from the LPRM. Simulated recirculation flow signals are also utilized to provide the bias for varying the rod block and trip setpoints. Simulated signals are used to test the rod block monitor outputs.

[1] This information is for historical reference only.

Acceptance Criteria -

a. The local power range neutron flux circuits operate properly and are capable of providing signals to the APRM system, the RBM system, the process computer, and to LPRM system indicating meters and auxiliary devices. (Section 7.6.1.4)

b. LPRM and APRM system trip signals operate properly. (Section 7.6.1.4)

c. Average power range power level circuits operate properly. (Section 7.6.1.4)

d. System alarms operate properly. (Section 7.6.1.4)

e. Rod block monitor outputs operate. (Section 7.6.1.4)

Table 14.2-4 (Cont'd)

(P-78.3) Traversing Incore Probes Calibration System

Unit Scope -

a. 1P-78.3 (Unit 1 system components)

b. 2P-78.3 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the operability of the TIP calibration system and to verify the system functions properly.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The primary containment instrument gas is available, as required, for purging the system.

Test Method - Verification that the system operates in the manual, automatic, and hand crank modes. Indexer cross-calibration interlock, shear valve control monitor, TIP automatic detector withdrawal, containment secure and squib circuits verification, ball valve control, ball valve open interlock, and purging operations are conducted. System manual and automatic controls and alarms are actuated and the ability to override automatic functions is demonstrated.

Acceptance Criteria -

a. The automatic and manual modes function in the correct designed sequence. (Section 7.7.1.6.3)

b. System drive mechanisms, including position indication, and the drive interlocks and time delays operate properly. (Section 7.7.1.6.3)

c. System signal channels, indicators, recorders, and alarms operate properly. (Section 7.7.1.6.3)

d. The system indexing mechanism and its interlocks operate properly. (Section 7.7.1.6.3)

e. The system automatically withdraws the detectors on a containment isolation signal, after which the containment isolation valves close. (Section 7.7.1.6.3)

(P-79.1) Area Radiation Monitoring System

Unit Scope -

a. 1P-79.1 (Unit 1 system components)

b. 2P-79.1 (Unit 2 system components)

Test Objective - The test objectives are to demonstrate that the area radiation monitoring system is operable and has correct high and low and alarm settings.

Table 14.2-4 (Cont'd)

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - Verification of the area radiation monitoring system capability is demonstrated by the integrated operation of the channel trip units, local and remote alarm annunciators, lights, and recorders. The site environs radiation monitoring stations are tested for Unit 1 only, as this equipment is common to both Unit 1 and Unit 2.

Acceptance Criteria -

a. Each area radiation monitoring channel operates properly. (Section 7.7.1.10)

b. Each area radiation monitoring channel high and low trip setpoint is set properly. (Section 7.7.1.10)

c. Each monitor responds properly to its internal check source. (Section 7.7.1.10)

d. The indicator and trip units properly initiate their respective indicators, alarms, and horns. (Section 7.7.1.10)

e. Each trip circuit produces an alarm upon interruption or failure of the ac power supply. (Section 7.7.1.10)

(P-79.2) - Process Radiation Monitoring System

Unit Scope -

a. 1P-79.2 (Unit 1 system components)

b. 2P-79.2 (Unit 2 system components)

Test Objective - The test objectives are to demonstrate that the process radiation monitoring system is operable and has the capability to detect a gross release of fission products from the fuel.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - Verification of the process radiation monitoring system's capability is demonstrated by the integrated operation of the channel trip units, alarm annunciators, and lights and recorders. Test signals are fed into the monitors at the control modules.

Acceptance Criteria -

a. Each process radiation monitoring channel operates properly. (Sections 7.7.1.9 and 7.6.1.1)

b. The indicator and trip units properly operate their respective indicators and alarms. (Section 7.7.1.9)

Table 14.2-4 (Cont'd)

c. As applicable, each monitor responds properly to its secondary check source. (Section 7.7.1.9)

d. Provides trip signals to initiate a reactor shutdown and containment isolation on detection of a gross release of fission products from the fuel. (Section 7.7.1.9)

(P-80.1) Reactor Vessel Instrumentation System

Unit Scope -

a. 1P-80.1 (Unit 1 system components)

b. 2P-80.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate that the reactor non-nuclear instrumentation systems operate properly to provide trip, indication, and alarm information.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Relays that are initiated from the reactor vessel level and pressure sensors are placed in untripped condition.

Test Method - Simulated signals are introduced into the reactor non-nuclear instrument loops and proper trip, alarm, and indication outputs are verified.

Acceptance Criteria -

a. System indications and trips operate properly. (Section 7.7.1.1)

b. System alarms operate properly. (Section 7.7.1.1)

(P-81.1) Fuel Handling System

Unit Scope -

a. 1P-81.1 (Unit 1 system components)

b. 2P-81.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate that the refueling platform and the various servicing tools can be used for their intended operations.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The RMCS, fuel pool, and the reactor cavity and core structure are available for testing. Dynamic and static load tests of fuel handling equipment are completed.

Table 14.2-4 (Cont'd)

Test Method - The fuel servicing equipment, refueling equipment, and servicing aids are operated. Their associated controls and alarms are actuated.

Acceptance Criteria -

a. The fuel preparation machines operate properly. (Section 9.1.4)

b. The refueling platform operates properly. (Section 9.1.4)

c. Refueling interlocks and logic operate properly. (Section 7.7.1.15)

d. Fuel position indicators operate properly. (Section 9.1.4)

(P-83.1) Main Steam System[1]

Unit Scope -

a. 1P-83.1 (Unit 1 system components)

b. 2P-83.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the proper operation of the main steam system, including the MSIVs, the leakage control system, and the ADS.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Primary containment instrument gas and instrument air are available to operate the main steam line isolation valves and SRVs.

(1) This information is for historical reference only.

Test Method - The MSIV-LCS valves, blowers, heaters, and controls are operated. System logic, valve times, and flows are verified and measured. The MSIVs are stroked and timed in their various modes. The ADS is functionally checked without lifting pressure relief valves. Other main steam system controls and alarms are actuated.

Acceptance Criteria -

a. The MSIVs stroke properly in the manual mode (fast and slow). (Section 5.4.5)

b. The MSIVs automatic closure is within acceptable times. (Section 5.4.5)

c. MSIV control logic, indications, and alarms operate properly. (Section 7.3.1.1.2)

d. The MSIV-LCS operates properly, valve times are as specified and system flows are acceptable. (Sections 6.7 and 7.3.1.1.3)

e. Nuclear system pressure relief valves control circuits operate properly. (Section 5.2.2)

f. The main steam line flow monitors operate properly. (Section 7.3.1.1.2)

Table 14.2-4 (Cont'd)

(P-83.2) Automatic Depressurization System

Unit Scope -

a. 1P-83.2 (Unit 1 system components)

b. 2P-83.2 (Unit 2 system components)

Test Objective - The test objectives are to demonstrate the operability of the ADS and to verify system response to signals from the logic channels.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - High drywell pressure and low reactor water level signals are simulated and system response to the logic channels is verified.

Acceptance Criteria -

a. ADS channel A responds properly to signals from logic channels A and E. (Section 7.3.1.1.1.2)

b. ADS channel C responds properly to signals from logic channels C and G. (Section 7.3.1.1.1.2)

c. The core spray and RHR pump permissive interlocks function properly. (Section 7.3.1.1.1.2)

d. ADS valves operate properly. (Section 5.2.2)

e. System instruments and alarms operate properly. (Section 7.3.1.1.1.2)

(P-83.3) Steam Leak Detection System

Unit Scope -

a. 1P-83.3 (Unit 1 system components)

b. 2P-83.3 (Unit 2 system components)

Test Objective - The test objective is to demonstrate that the steam leak detection system is operable and that system instruments have the correct trip and alarm setpoints.

Prerequisites - To the extent necessary to complete this test, construction is completed, and instrumentation and controls are operable and calibrated.

Table 14.2-4 (Cont'd)

Test Method - System temperature changes are simulated at the system control sensors. Capability of system instrumentation to respond to temperature changes and alarm setpoints is verified. The generation of isolation signals to the channel trip units is verified.

Acceptance Criteria -

a. System temperature monitors operate properly. (Sections 5.2.5 and 7.6.1.3)

b. System temperature alarms and temperature indicators operate properly. (Sections 5.2.5 and 7.6.1.3)

c. Steam leak detection temperature isolation signals are generated by the applicable circuitry to the NSSSS, the HPCI system, and the RCIC system. (Sections 5.2.5 and 7.6.1.3)

(P-85.1) Cathodic Protection System

Unit Scope -

a. 1P-85.1 (Unit 1 & 2 and Common system components)

Test Objective - The test objective is to demonstrate the capability of the cathodic protection system to maintain buried steel piping and structures at the design electrical potential.

Prerequisite - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - The cathodic rectifiers are operated and voltage, current, and resistance measurements are made.

Acceptance Criteria -

a. The electrical potential of buried steel piping and structures is maintained within acceptable limits. (Vendor Technical Manual)

b. The cathodic rectifiers operate properly. (Vendor Technical Manual)

(P-85.2) Freeze Protection and Heat Trace Systems

Unit Scope -

a. 1P-85.2 (Unit 1, common, and portions of Unit 2 system components

b. 2P-85.2 (Unit 2 remaining system components)

Test Objective - The test objective is to demonstrate the operability of the freeze protection and heat trace systems.

Table 14.2-4 (Cont'd)

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - Each freeze protection and heat trace system is operated. Control setpoints are varied, and system response is verified. System alarms are actuated.

Acceptance Criteria -

a. The freeze protection and heat trace systems energize and de-energize in response to the thermostatic controls. (Electrical Schematic Diagram)

b. System alarms operate properly. (Electrical Schematic Diagram)

(P-91.1) Plant Annunciator Systems

Unit Scope -

a. 1P-91.1 (Unit 1, common, and portions of Unit 2 system components

b. 2P-91.1 (Unit 2 remaining system components)

Test Objective - The test objective is to demonstrate the ability of the plant annunciator systems to provide both audible and visual indications of an alarm condition.

Prerequisites - To the extent necessary to perform this test, construction is completed and plant annunciator panels are operable.

Test Method - Annunciator panel test devices are operated. Alarm contacts are jumpered to demonstrate annunciator operability.

Acceptance Criteria -

a. The main control room annunciators operate properly. (Electrical Schematic Diagram)

b. The radwaste control room annunciators operate properly. (Electrical Schematic Diagram)

(P-93.2) Main Turbine Control System

Unit Scope -

a. 1P-93.2 (Unit 1 system components)

b. 2P-93.2 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the ability of the EHC system to operate the turbine-generator.

Table 14.2-4 (Cont'd)

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. The hydraulic fluid reservoir is filled with EHC fluid.

Test Method - The hydraulic system is placed in operation and alarms, trips, and control devices are actuated.

Acceptance Criteria -

a. Hydraulic system pressure meets acceptable values. (Vendor Technical Manual)

b. Turbine stop and bypass valves operate properly. (Vendor Technical Manual)

c. System alarms operate properly. (Sections 7.7.1.5 and 10.2)

d. System trips operate properly. (Sections 7.7.1.5 and 10.2)

(P-93.3) Main Turbine Supervisory System

Unit Scope -

a. 1P-93.3 (Unit 1 system components)

b. 2P-93.3 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the ability of the turbine supervisory system to monitor the operation of the main turbine. For Unit 1, this test also demonstrates system ability to monitor operation of the reactor feed pump-turbines. This aspect is accomplished by Test P-45.1 (Feedwater System) for Unit 2.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation is operable and calibrated.

Test Method - Signal inputs are simulated in the turbine supervisory system, and recording equipment and alarms are actuated.

Acceptance Criteria -

a. Instrumentation operates properly. (Vendor Technical Manual)

b. System alarms operate properly. (Section 10.2.5, Items a, b, c, f, h, and p)

(P-99.1) Reactor Enclosure Crane

Unit Scope -

a. 1P-99.1 (Unit 1 and Unit 2 system components)

Test Objective - The test objective is to demonstrate the capability of the reactor enclosure crane to safely move expected loads within the reactor enclosure.

Table 14.2-4 (Cont'd)

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Construction proof testing as identified in Section 9.1.5 has been completed.

Test Method - The crane is used to maintain its nominal rated load in a static position. Test loads are lifted and travel limits, as well as hoist, trolley, and bridge travel speeds, are measured. System controls and alarms are actuated.

Acceptance Criteria -

a. The crane load capacity is acceptable (Section 9.1.5)

b. Crane controls, alarms, interlocks, and limits operate properly. (Section 9.1.5)

c. Crane protective devices and interlocks operate properly. (Section 9.1.5)

d. Equipment safety devices operate properly. (Section 9.1.5)

(P-99.2) Seismographical Monitoring System

Unit Scope -

a. 1P-99.2 (Common system components)

Test Objective - The test objective is to demonstrate the ability of the seismographical monitoring system to measure and record seismic data.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated.

Test Method - Earthquake conditions are simulated by applying a physical force to the seismic sensors. Automatic system operation is verified.

Acceptance Criteria -

a. Peak acceleration recorders operate properly. (Vendor Technical Manual)

b. Strong motion accelerographs operate properly. (Vendor Technical Manual)

c. Seismic triggers operate properly. (Section 3.7.4)

d. Magnetic tape playback system operates properly. (Section 3.7.4)

e. Response spectrum analyzer operates properly. (Section 3.7.4)

f. System alarms operate properly. (Section 3.7.4)

Table 14.2-4 (Cont'd)

(P-99.3) Public Address and Evacuation System

Unit Scope -

a. 1P-99.3 (Unit 1 and Common system components)

b. 2P-99.3 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the ability of the public address system to transmit voice communication and the plant evacuation alarm and river warning systems to broadcast various alarms and prerecorded messages to selected areas.

Prerequisites - To the extent necessary to perform this test, construction is completed, and equipment is operational.

Test Method - Each public address station is operated in both the page and party line modes. Evacuation alarm and river warning signals are simulated, and system operation is verified.

Acceptance Criteria -

a. The public address system is operable from all stations in the page and party line modes. (Section 9.5.2)

b. All public address speakers operate properly. (Section 9.5.2)

c. The evacuation alarm system operates properly. (Section 9.5.2.2.4)

d. The river warning system operates properly. (Section 9.5.2.2.4)

e. The evacuation alarm system automatic transfer power switch operates properly. (Section 9.5.2.2.4)

(P-100.1) Loss of Offsite Power Test

Unit Scope -

a. 1P-100.1 (Unit 1 system components)

b. 2P-100.1 (Unit 2 system components)

Test Objective - The test objective is to demonstrate that the plant emergency systems are capable of operating as expected on an integrated basis in normal and emergency modes, and thus are ready for fuel loading.

Prerequisites - Selected preoperational tests are performed prior to or concurrent with operation of equipment for the cold functional test.

Table 14.2-4 (Cont'd)

Test Method - Plant operating procedures are utilized, to the extent practicable, to place plant emergency systems in service on an integrated basis for normal and emergency modes. The standby diesel generators are operated in all possible combinations, in response to simulated LOOP, and LOCA conditions.

The first of these tests consists of a diesel generator automatic start from standby conditions on receipt of LOCA signal with coincident LOOP. The plant emergency loads are automatically applied, and proper system response to the loading sequence is verified. This test, in conjunction with Tests P-24.1 (Standby Diesel Generator System) and P-100.4 (Standby Diesel Generator Loading), constitute the entire diesel generator preoperational test program.

Equipment parameters are allowed to stabilize for each operational combination, and any abnormal conditions are investigated. Equipment not under test is monitored to verify the absence of voltage.

Testing during the LOOP test or prerequisite tests will be performed using maximum attainable loads (given equipment operating restrictions) during the test. If full accident load conditions are not attained, recorded currents and voltages will be extrapolated and compared with design conditions. Testing during the LOOP test will be conducted using only one source of power to each bus.

Acceptance Criteria -

a. Integrated system performance, to the extent possible during the test, is acceptable. (Vendor test specification)

b. System electrical and mechanical performance is acceptable (Vendor test specification)

c. Each diesel generator operates properly during automatic load shedding and the automatic design accident loading sequence from standby conditions. Voltage and frequency remain within acceptable limits during the transients following each incremental application of load. (Section 8.3.1.1.3)

(P-100.2) Loss of Instrument Air

Unit Scope -

a. 1P-100.2 (Unit 1 and common system components)

b. 2P-100.2 (Unit 2 system components)

Test Objective - The test objective is to demonstrate the design response to a loss of instrument air accident of safety-related components supplied by the system.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. Cooling water is available to meet the requirements of the system. There are no essential plant systems operating that will be affected by performance of this test.

Table 14.2-4 (Cont'd)

Test Method - The system is placed in operation, and components to be tested are placed in their normal operation position in so far as plant conditions allow. Instrument air is shut off in a manner that would simulate an instrument air pipe break. The test is repeated to simulate a loss of instrument air by moisture freezing and plugging the main supply line. Affected components are verified to respond properly.

Acceptance Criteria -

a. Proper movement of affected components is verified. (System P&IDs)

b. Feeders or branches sustain an adequate share of the decaying air supply as required by the operational mode. (System P&IDs)

(P-100.4) Standby Diesel Generator Loading

Unit Scope -

a. 1P-100.4 (Unit 1 system and components)

b. 2P-100.4 (Unit 2 system and components)

Test Objective - The objective of this test is to demonstrate the capability of the standby diesel generators to accept the design accident loading sequence with a coincident LOOP.

Prerequisites - To the extent necessary to perform this test, construction is completed, and instrumentation and controls are operable and calibrated. ESW or temporary cooling water for Unit 2, diesel generator enclosure HVAC, 125 V dc power, fuel oil, and fire protection are available for diesel generator operation. ESF systems are available for operation during accident response testing.

Test Method - Each diesel generator is verified to automatically start and accelerate to rated speed and voltage on receipt of a simulated LOCA signal with coincident LOOP. To the extent that they are available for this test, the plant emergency loads are automatically applied, and proper system response to the loading sequence is verified. The applied loads consist of the major ESF system loads as a minimum, plus as many of the ancillary 440 V loads that are available at the time of the test, and any temporary means so that the actual demand seen by the diesel is simulated as close as practical. This test is conducted on each engine individually, immediately after the engine has been operated at full load temperature conditions for a 24 hour period. In addition, diesel generator synchronization to offsite power and load transfer is verified.

An analogous test will be conducted on each engine from standby conditions as a part of preoperational Test 1P-100.1 (Loss of Offsite Power) except that this test is conducted concurrently on each engine using the actual plant emergency loads. Proper system response to the loading sequence is also verified at this time.

Proper diesel generator and auxiliary system performance is verified during the 24 hour run. From the data taken at this time, the fuel oil storage system, the lube oil system, and the jacket water system are analytically verified to contain enough inventory to sustain each diesel generator for a 7 day period of continuous full load operation.

Table 14.2-4 (Cont'd)

This test, in conjunction with Tests P-24.1 (Standby Diesel Generator System) and P100.1 (Loss of Offsite Power) constitutes the entire individual diesel generator preoperational testing program.

Acceptance Criteria -

a. Each diesel generator is automatically started on a simulated LOCA with coincident LOOP, and reaches the required voltage and frequency within an acceptable time. (Section 8.3.1.1.3)

b. Each diesel generator is capable of carrying its full load for 24 hour period, the first two hours of which are at a load equivalent to the peak rating of the diesel generator (3135 kW) and the remaining 22 hours are at a load equivalent to the continuous rating of the diesel generator (2850 kW). The engine is permitted to reach temperature equilibrium prior to the application of the peak load. (Section 8.3.1.1.3)

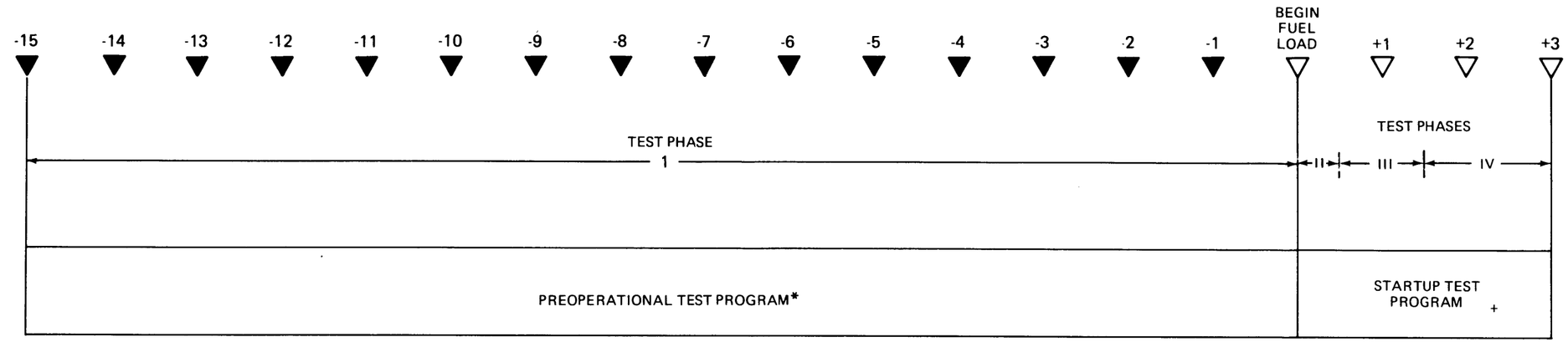
c. Each diesel generator accepts the automatic design accident loading sequence at full load temperature conditions (immediately following the 24 hour test, above), and voltage and frequency are maintained within the required limits. The applied loads consist of the major ESF system loads as a minimum, plus as many of the 440 V auxiliary loads that are available at the time of this test, and any temporary means by which the actual demand seen by the diesel is simulated as close as practical. (Section 8.3.1.1.3)

d. Each diesel generator operates properly during load shedding, including loss of the single largest emergency load (a RHR pump). (Section 8.3.1.1.3)

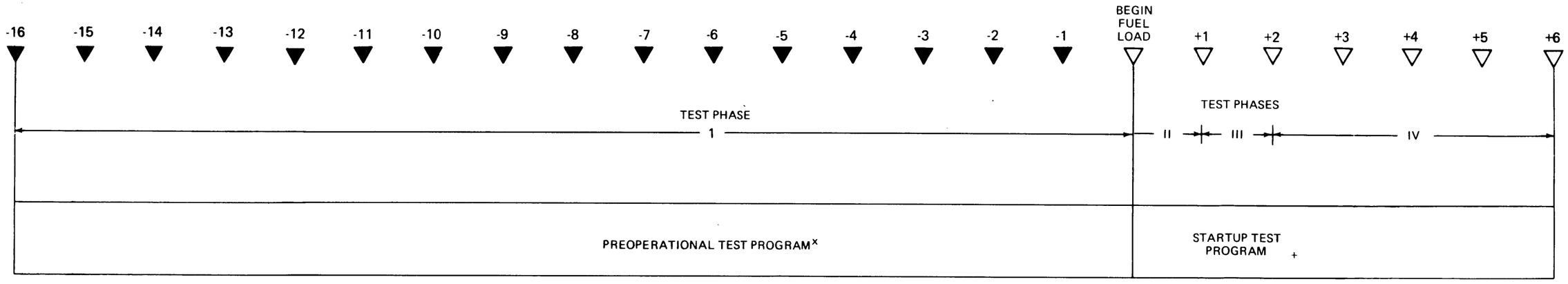
e. While carrying its emergency loads, each diesel generator is capable of: (1) synchronizing with the offsite power source, (2) transferring its loads to the offsite power source, and (3) returning to standby status. (Section 8.3.1.1.3)

f. Each diesel generator auxiliary system operates properly and the fuel oil, lube oil, and jacket water systems will contain enough inventory to sustain the diesel generator for a 7 day period of continuous full load operation. (Sections 8.3.1.1.3, 9.5.4, 9.5.5, and 9.5.7)

MONTHS RELATIVE TO INITIAL FUEL LOAD – UNIT 1



MONTHS RELATIVE TO INITIAL FUEL LOAD – UNIT 2



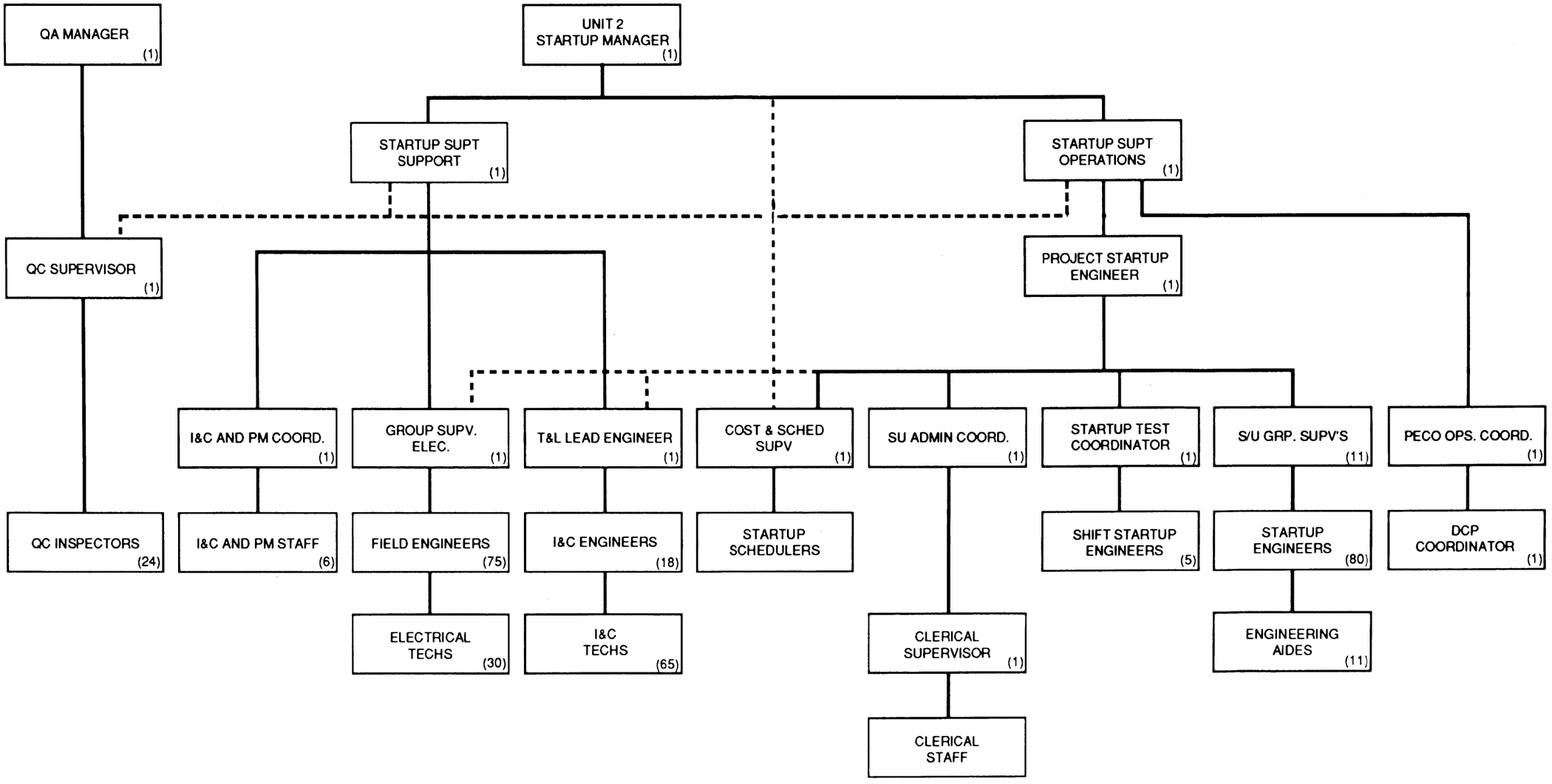
NOTES:

(*) REFERENCE FIGURE 14.2-6 FOR PREOPERATIONAL TEST SEQUENCE
(x) REFERENCE FIGURE 14.2-7 FOR PREOPERATIONAL TEST SEQUENCE
(+) REFERENCE FIGURE 14.2-5 FOR STARTUP TEST SEQUENCE

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INITIAL TEST PROGRAM SCHEDULES

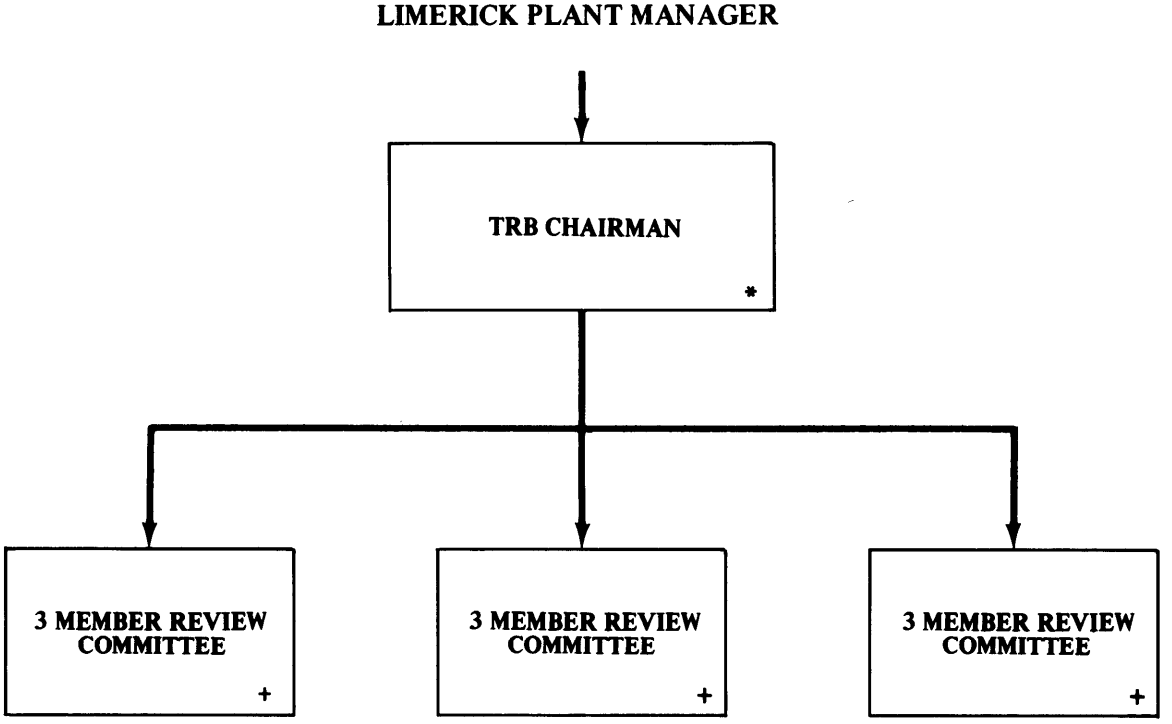
FIGURE 14.2-1



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STARTUP ORGANIZATION

FIGURE **14.2-2**



* PERMANENT MEMBER (MAY ALSO SERVE AS REVIEW COMMITTEE MEMBER)

+ REVIEW MEMBERS ASSIGNED AS REQUIRED (MINIMUM OF 3 PER COMMITTEE).

THE TRB CHAIRMAN MAY SERVE AS ONE MEMBER OF A REVIEW COMMITTEE.

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TEST REVIEW BOARD ORGANIZATION

FIGURE 14.2-3

1. OBJECTIVES

2. ACCEPTANCE CRITERIA

3. REFERENCES

4. PRECAUTIONS, NOTES, AND DEFINITIONS

5. TEST EQUIPMENT

6. SYSTEM TEST

   6.1 PREREQUISITES
   6.2 TEMPORARY INSTALLATIONS
   6.3 INITIAL STATUS
   6.4 TEST INSTRUCTIONS
   6.5 RESTORATION

7. APPENDICES, FIGURES, TABLES

LIMERICK GENERATING STATION
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TEST PROCEDURE STANDARD FORMAT
(SHEET 1 of 2)

FIGURE 14.2-4

STARTUP TEST PROCEDURE STANDARD FORMAT

STPXX.0	MAIN BODY
STPXX.0.1	OBJECTIVES
STPXX.0.2	DESCRIPTION
STPXX.0.3	ACCEPTANCE CRITERIA
STPXX.0.4	REFERENCES
STPXX.0.5	PROCEDURE
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STPXX.Y	SUBTEST
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STPXX.Y.2	PRECAUTIONS
STPXX.Y.3	TEST EQUIPMENT
STPXX.Y.4	PREREQUISITES
STPXX.Y.5	INITIAL STATUS
STPXX.Y.6	TEST INSTRUCTIONS
STPXX.Y.7	ANALYSIS
STPXX.Y-A	SPECIFIC APPENDICES

LEGEND XX – STARTUP TEST PROCEDURE NUMBER

Y – SUBTEST NUMBER

A – APPENDIX DESIGNATOR

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TEST PROCEDURE STANDARD FORMAT
(SHEET 2 of 2)

FIGURE 14.2-4

TEST NO.	PROCEDURE DESCRIPTION	OPEN VESSEL	HEAT UP	1	2	3	4	5	6	WAR-RANT
1	CHEMICAL AND RADIOCHEMICAL	X	X	X	X	X		X(6)	X	
2	RADIATION MEASUREMENTS	X	X		X	X			X	
3	FUEL LOADING	X								
4	FULL CORE SHUTDOWN MARGIN		X(4)							
5	CONTROL ROD DRIVE SYSTEM	X	X		X	X(11)			X	
6	SRM PERFORMANCE AND CONTROL ROD SEQUENCE		X(4)							
9	WATER LEVEL REFERENCE LEG TEMPERATURE		X	X	X	X	X	X	X	
10	IRM PERFORMANCE		X(4)	X						
11	LRPM CALIBRATION		X	X		X			X	
12	APRM CALIBRATION		X	X	X	X(10)		X	X	X
13	PROCESS COMPUTER PERFORMANCE VERIFICATION	X	X	X	X	X			(5)	
14	RCIC SYSTEM PERFORMANCE VERIFICATION		X	X	X(5,6)					
14.1	RCIC SYSTEM STARTUP AFTER LOSS OF AC POWER TO THE SYSTEM			X(6)						
14.2	RCIC SYSTEM OPERATION WITH A SUSTAINED LOSS OF AC POWER TO THE SYSTEM			X(6)						
15	HPCI SYSTEM PERFORMACE VERIFICATION		X			X				
16	SELECTED PROCESS TEMPERATURE VERIFICATION		X(10)			X	X(10)		X(10)	
17	SYSTEM EXPANSION	X	X		X(6)				X(6,8)	
18	TIP UNCERTAINITY					X			X	
19	CORE PERFORMANCE			X	X	X	X	X	X	X
20	STEAM PRODUCTION									X
21	DELETED									
22	PRESSURE REGULATOR RESPONSE			X	X	X	X(10)	X	X	
23	FEEDWATER CONTROL SYSTEM DEMONSTRATION			X	X	X	X	X	X(5)	
24	MAIN TURBINE VALVES SURVEILLANCE TEST					X			X(5,9)	
25	MAIN STEAM ISOLATION VALVES PERFORMANCE VERIFICATION		X	X		X(3)			X,SD(2,9,12)	
26	MAIN STEAM RELIEF VALVES PERFORMANCE		X		X					
27	TURBINE TRIP AND GENERATOR LOAD REJECTION DEMONSTRATION				X(7)	X,SD(2,11)			X,SD(2)	
28	SHUTDOWN FROM OUTSIDE THE MAIN CONTROL ROOM DEMONSTRATION				X,SD(2)					
29	RECIRCULATION FLOW CONTROL DEMONSTRATION					X(5)			X(5)	
30	RECIRCULATION SYSTEM				X	X	X		X	
31	LOSS OF TURBINE-GENERATOR AND OFFSITE POWER				X,SD					
32	ESSENTIAL HVAC SYSTEM OPERATION AND CONTAINMENT HOT PENETRATION TEMPERATURE VERIFICATION		X			X			X	
33	PIPING STEADY STATE VIBRATION		X		X	X(5)		X	X(5,6,8)	
34	OFFGAS SYSTEM PERFORMANCE VERIFICATION		X	X		X			X(5)	
35	RECIRCULATION FLOW CALIBRATION					X(5)	X	X(5,6,8)		
36	PIPING DYNAMIC TRANSIENT (13)		X		X	X			X	
37	DELETED									
38	DELETED									
70	REACTOR WATER CLEANUP SYSTEM PERFORMANCE VERIFICATION		X							
71	RESIDUAL HEAT REMOVAL SYSTEM PERFORMANCE VERIFICATION				X(6)				X(6,8)	

LEGEND

X TEST INDEPENDENT OF FLOW CONTROLLER MODE

SD SCRAM DEFINITE

NOTES

(1) SEE FIGURE 14.2-9 TEST CONDITION REGION MAP

(2) PERFORM TEST 5, TIMING OF 4 SLOWEST CONTROL RODS IN CONJUNCTION WITH THESE SCRAMS

(3) FULL CLOSURE ON ONE VALVE ONLY

(4) MAY BE DONE DURING TEST CONDITION OPEN VESSEL

(5) SOME TEST DONE DURING APPROACH TO TEST CONDITION

(6) MAY BE DONE DURING AND EARLIER TEST CONDITION IF CONDITIONS WARRANT

(7) DONE WITH STEAM BYPASS CAPACITY

(8) SOME TEST DONE AFTER PLANNED TRIPS FROM POWER

(9) DETERMINE MAXIMUM POWER LEVEL TEST CAN BE PERFORMED WITHOUT CAUSING REACTOR SCRAM

(10) TEST NOT REQUIRED FOR UNIT 2

(11) TEST NOT REQUIRED FOR UNIT 2. NO TC-3 SCRAM DURING STP-27. NO. STP-5 SCRAM TIMING TEST DUE TO NO. SCRAM

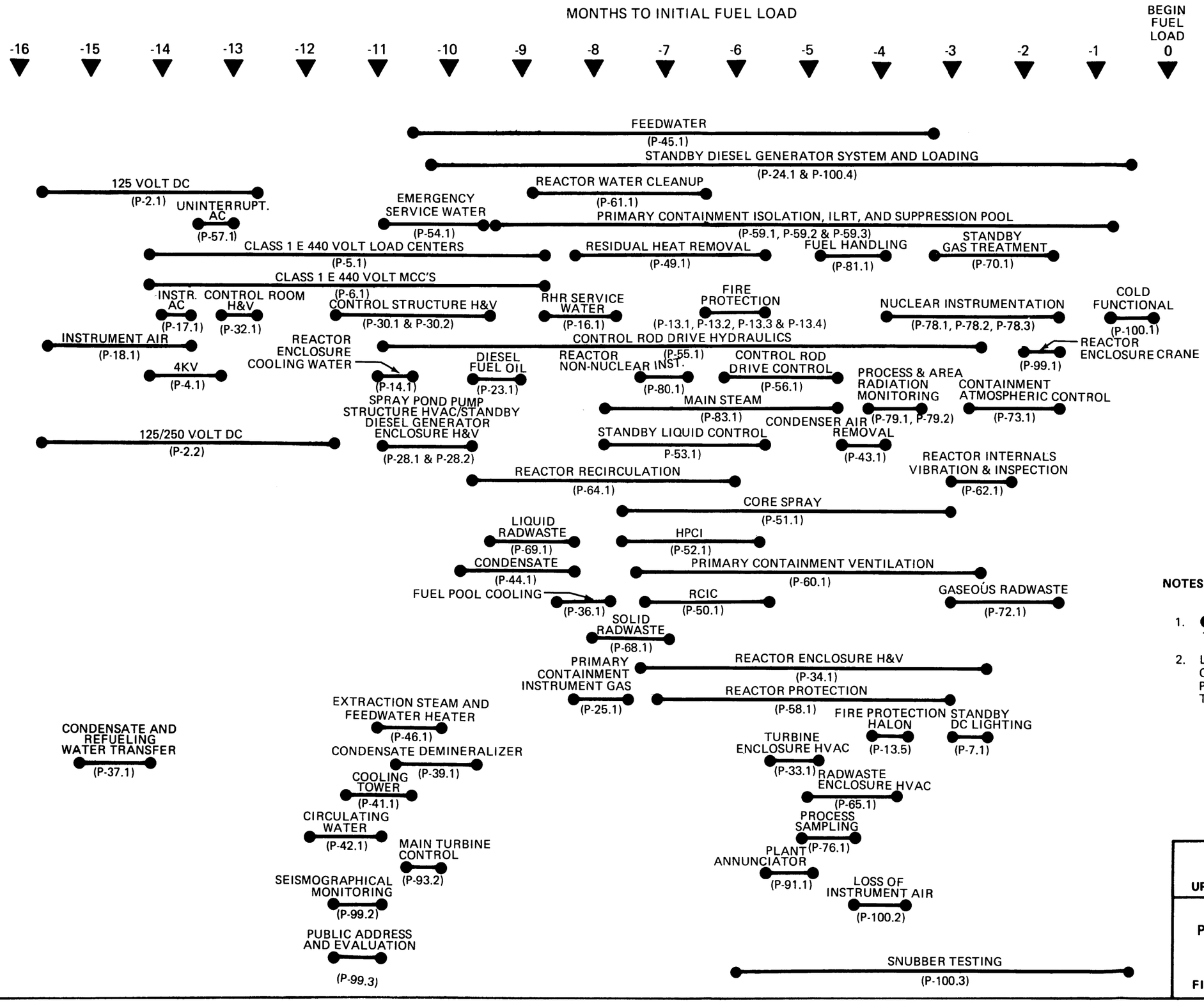
(12) FOR UNIT 2 ONLY, FULL CLOSURE OF ONE VALVE TO DETERMINE THE MAXIMUM POWER LEVEL WHICH WILL NOT CAUSE A REACTOR SCRAM WILL BE PERFORMANCE AT TEST CONDITIONS.

(13) MAIN STEAM TURBINE TRIP TEST FOR UNIT 2 (REF. STARTUP TEST STP-36) AT 100% LEVEL WILL BE PERFORMED DURING COMMERCIAL OPERATION OF THAT UNIT.

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STARTUP TEST SEQUENCE
(UNITS 1 & 2)

FIGURE 14.2-5 REV. 3 NOV./93



NOTES:

1. SYSTEM NAME — TEST NUMBER(S)
2. LINE DURATION INCLUDES COMPLETION OF SYSTEM TEST PREREQUISITES AND PERFORMANCE OF PREOPERATIONAL TESTING.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PREOPERATIONAL TEST SEQUENCE UNIT 1

FIGURE 14.2-6

Months to Fuel Load

Begin Fuel Load

−16 −15 −14 −13 −12 −11 −10 −9 −8 −7 −6 −5 −4 −3 −2 −1 0

Electrical systems energized (P3.1)

Plant annunciator (P91.1)

Uninterruptable AC power (P57.1)

Fire protection, water and smoke detection (P13.1, P13.4)

Instrument air P18.1

Primary containment instrument gas (P25.1)

Process sampling (P76.1)

Service water (P11.1)

Reactor encl. cooling water (P14.1)

Turbine encl cooling water (P15.1)

Diesel generator fuel oil (P23.1)

Standby diesel generators (P24.1)

D/G loading (P100.4)

Diesel generator encl HVAC (P28.1)

Fuel pool cooling (P35.1)

Residual heat removal (P49.1)

RCIC (P50.1)

Core spray (P51.1)

HPCI (P52.1)

Standby liquid control (P53.1)

Reactor water cleanup (P61.1)

Reactor internals, vibration, inspection (P62.1)

Reactor recirculation (P64.1)

Control rod drive hydraulic system (P55.1)

Control rod drive control (P56.1)

Reactor protection, redundant reactivity control system (P58.1, P58.2)

Nuclear instrumentation (P78.1, P78.2, P78.3)

Primary containment isolation, suppression pool and ILRT (P59.1, P59.2, P59.3)

Condenser and air removal (P43.1)

Feedwater (P45.1)

Condensate (P44.1)

Condensate filter demineralizers (P39.1)

Extraction steam and feedwater heaters (P46.1)

Main steam, automatic depressurization, steam leak detection (P83.1, P83.2, P83.3)

Main turbine control (EHC) (P93.2)

Turbine supervisory (P93.3)

Reactor encl unit cooler (P66.1)

Reactor encl and refuel floor HVAC (P34.1, P34.2)

Drywell HVAC (P60.1)

Turbine encl unit coolers (P66.2)

Turbine encl HVAC (P33.1)

Standby gas treatment (P70.1)

Cooling tower (P41.1)

Circulating water (P42.1)

Standby DC lighting (P7.1)

125 Volt DC (P2.1)

Public address and evacuation (P99.3)

125/250 Volt DC (P2.2)

Fire protection, CO2 and Halon (P13.2, P13.5)

Loss of instrument air (P100.2)

Post accident sampling (P76.2)

Cathodic and freeze protectiion (P85.1 and P85.2)

Emergency service water (P54.1)

RHR service water (P16.1)

Loss of offsite power (P100.1)

Fuel handling (P81.1)

Solid radwaste (P68.1)

Equipment drain collection and liquid radwaste (P69.1, P69.3)

Gaseous radwaste recombiners and filters (P72.1)

Containment atmospheric control (P73.1)

Area and process radiatiion monitoring (P79.1, P79.2)

Reactor vessel instrumentation (P80.1)

NOTES:

1. System Name — Test No.
2. Line durations include completion of system test prerequisites and performance of preoperational testing

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PREOPERATIONAL TEST SEQUENCE
UNIT 2

FIGURE 14.2-7

Verified by
Date _____

6. SYSTEM TEST

6.1 PREREQUISITES

6.1.1 SYSTEM LEVEL PREREQUISITES

6.1.1.1 SYSTEM TURNOVER

Turnover from Bechtel Construction to PECo Startup is complete. _____ _____

6.1.1.2 SYSTEM WALK THROUGH

The system has been walked through and verified complete to the extent required to conduct this test. _____ _____

6.1.1.3 HYDROSTATIC TESTING AND CLEANNESS VERIFICATIONS

Hydrostatic testing and cleanness verifications have been completed to the extent required to perform this test, and records are on file. _____ _____

6.1.1.4 STARTUP WORK LIST

The Startup Work List has been reviewed, and outstanding or closed items (if any) have been evaluated as to the effect on this test. A summary list of outstanding items is attached. _____ _____

6.1.1.5 STARTUP FIELD REPORTS

Startup Field Reports pertaining to this system have been reviewed, and outstanding or closed items (if any) have been evaluated as to their effect on this test. A summary list of outstanding items is attached. _____ _____

6.1.1.6 TEMPORARY MODIFICATIONS

The Log of Temporary Modifications has been reviewed, is current, and is satisfactory for testing. _____ _____

6.1.1.7 STARTUP WORK ORDERS AND MAINTENANCE REQUEST FORMS

Startup Work Orders and Maintenance Request Forms pertaining to this system have been reviewed, and outstanding items (if any) have been evaluated as to their effect on this test. _____ _____

TYPICAL TEST PREREQUISITES
(SHEET 1)

FIGURE 14.2-8

Verified by
Date

6.1.2 'COMPONENT LEVEL PREREQUISITES

6.1.2.1 COMPONENT TECHNICAL TESTS

The required inspections and tests, as indicated in the Component Technical Test Summary, Appendix A, have been completed and verified by the responsible group. _____ _____

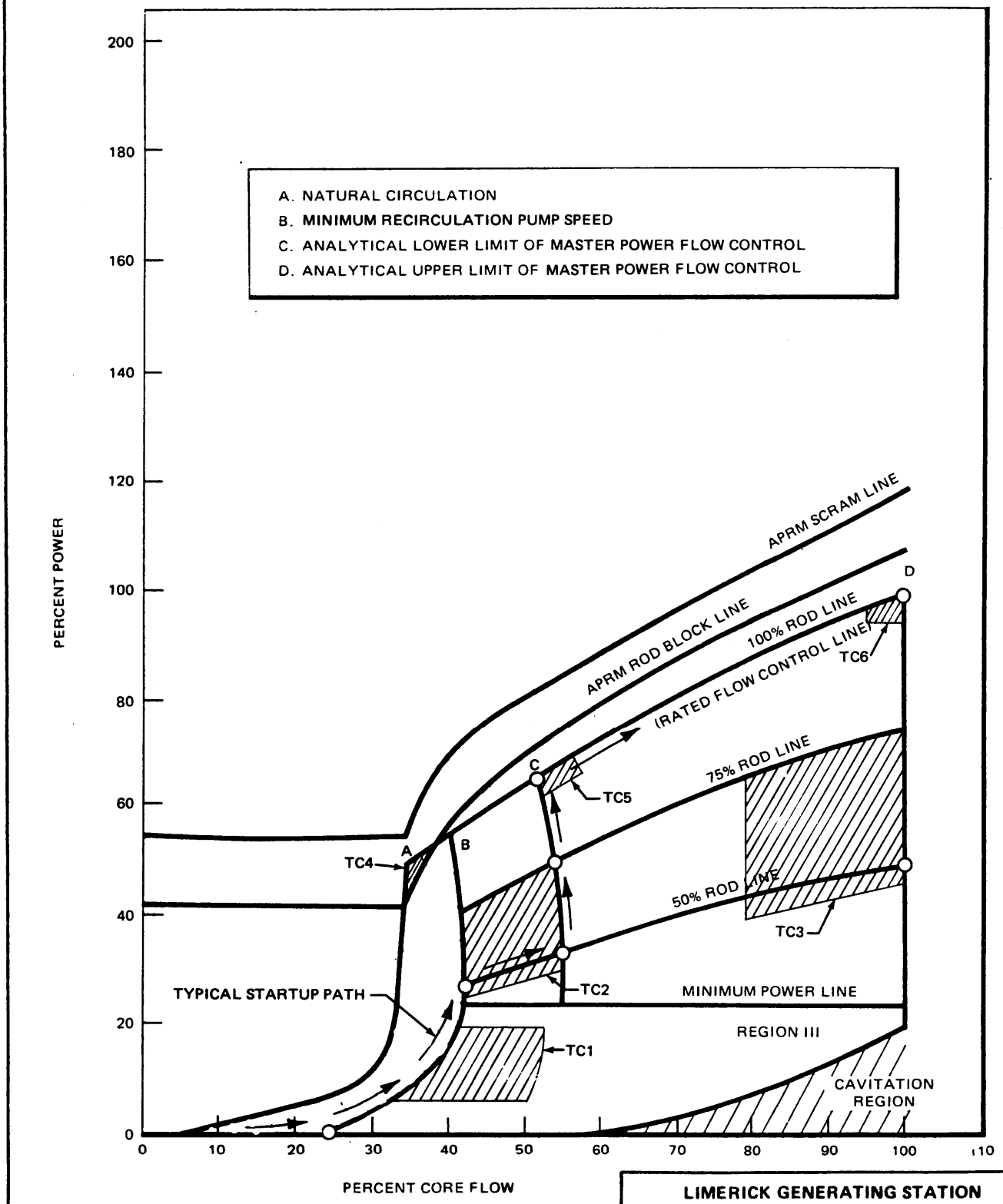
6.1.2.2 COMPONENT CALIBRATIONS

The required inspections and calibrations, as indicated in the Component Calibration Summary, Appendix B, have been completed and verified by the responsible group. _____ _____

LIMERICK GENERATING STATION
UNITS 1 AND 2
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TYPICAL TEST PREREQUISITES
(SHEET 2)

FIGURE 14.2-8



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

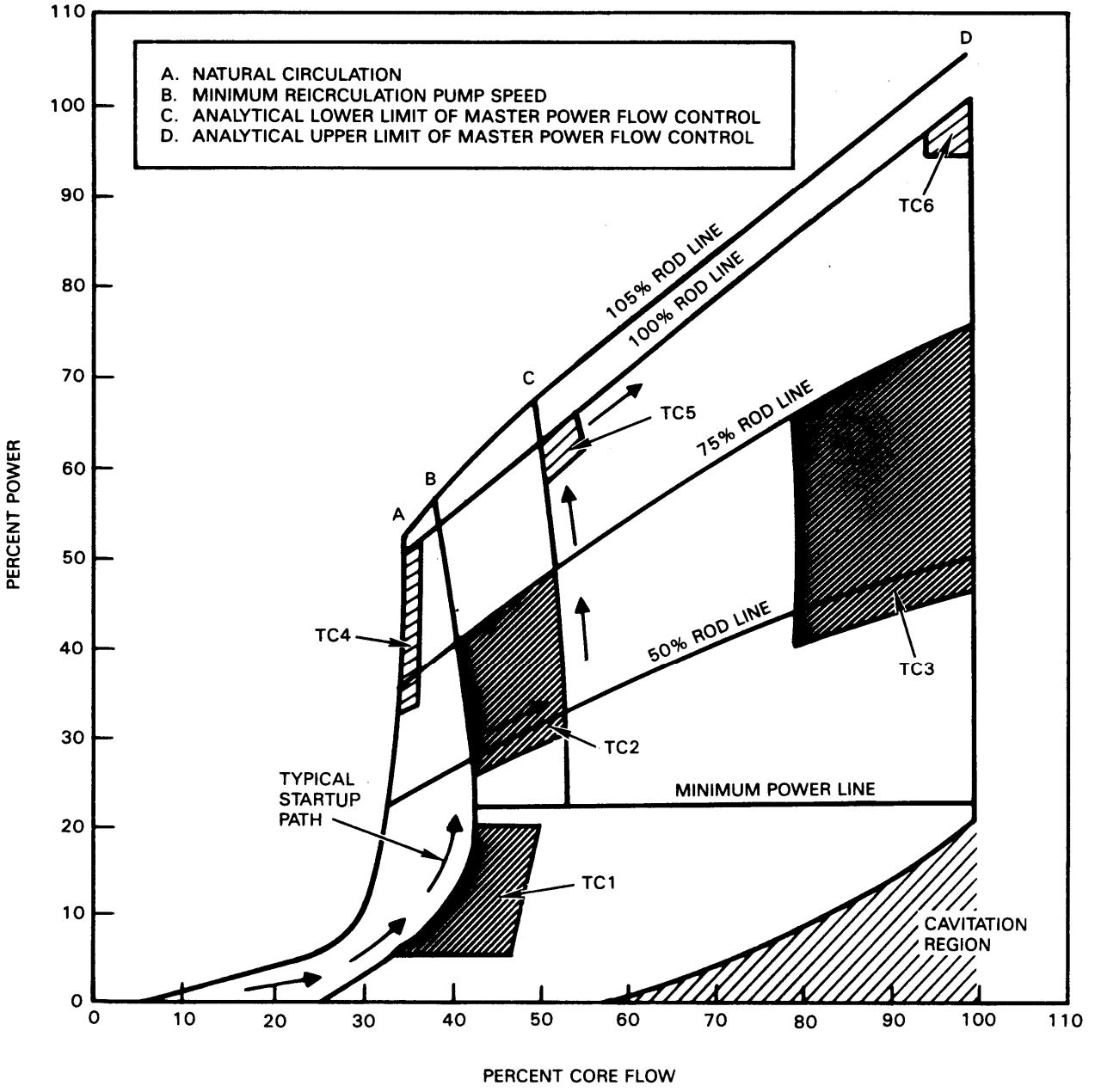
POWER–FLOW OPERATING MAP
(UNIT 1 - HISTORICAL)
(SHEET 1 OF 4)

FIGURE 14.2-9

Rev. 16 09/12

TEST CONDITION (TC) REGION DEFINITIONS

TEST CONDITION NO.	POWER–FLOW MAP REGION AND NOTES
1	BEFORE OR AFTER MAIN GENERATOR SYNCHRONIZATION BETWEEN 5 AND 20% THERMAL POWER-WITHIN +10, –0% OF M-G SET MINIMUM OPERATING SPEED LINE IN LOCAL MANUAL MODE.
2	AFTER MAIN GENERATOR SYNCHRONIZATION BETWEEN THE 45 AND 75% POWER ROD LINES BETWEEN M-G SET MINIMUM SPEEDS FOR LOCAL MANUAL AND MASTER MANUAL MODES.
3	FROM 45 TO 75% CONTROL ROD LINES–CORE FLOW BETWEEN 80 AND 100% OF ITS RATED VALUE.
4	ON THE NATURAL CIRCULATION CORE FLOW LINE–WITHIN +0, –5% OF THE INTERSECTION WITH THE 100% POWER ROD LINE.
5	WITHIN +0, –5% OF THE 100% CONTROL ROD LINE–WITHIN –0, +5% OF THE ANALYTICAL LOWER LIMIT OF MASTER FLOW CONTROL.
6	WITHIN +0, –5% OF RATED 100% POWER – WITHIN +0, –5% OF RATED 100% CORE FLOW RATE.



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

POWER–FLOW OPERATING MAP
(UNIT 2 - HISTORICAL)
(SHEET 3 OF 4)

FIGURE 14.2-9

Rev. 16 09/12

TEST CONDITION (TC) REGION DEFINITIONS

TEST CONDITION NO.	POWER–FLOW MAP REGION AND NOTES
1	BEFORE OR AFTER MAIN GENERATOR SYNCHRONIZATION BETWEEN 5 AND 20% THERMAL POWER-WITHIN +10, –0% OF M-G SET MINIMUM OPERATING SPEED LINE IN LOCAL MANUAL MODE.
2	AFTER MAIN GENERATOR SYNCHRONIZATION BETWEEN THE 45 AND 75% POWER ROD LINES BETWEEN M-G SET MINIMUM SPEEDS FOR LOCAL MANUAL AND MASTER MANUAL MODES.
3	FROM 45 TO 75% CONTROL ROD LINES–CORE FLOW BETWEEN 80 AND 100% OF ITS RATED VALUE.
4	ON THE NATURAL CIRCULATION CORE FLOW LINE–WITHIN +0, –20% OF THE INTERSECTION WITH THE 100% POWER ROD LINE.
5	WITHIN +0, –5% OF THE 100% CONTROL ROD LINE–WITHIN –0, +5% OF THE ANALYTICAL LOWER LIMIT OF MASTER FLOW CONTROL.
6	WITHIN +0, –5% OF RATED 100% POWER – WITHIN +0, –5% OF RATED 100% CORE FLOW RATE.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

POWER–FLOW OPERATING MAP
(UNIT 2 - HISTORICAL)
(SHEET 4 OF 4)

FIGURE 14.2-9 Rev. 16 09/12

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CHAPTER 15 - ACCIDENT ANALYSIS

15.0 GENERAL

This chapter describes the transient and accident analyses for LGS Units 1 and 2. The original analyses have been updated as part of the Power Rerate Project which increased the licensed rated thermal power to 3458 MWt (Reference 15.0-7). In addition, the original analyses have been supplemented to reflect changes to the licensed reactor operating domain (References 15.0-7, 15.0-10 and 15.0-11). As a result of improvements in plant feedwater flow measurement accuracy, a reduced reactor thermal power uncertainty can be applied. Due to the reduced uncertainty a MUR power uprate has been implemented that increases the licensed rated thermal power to 3515 MWt (1.65%) (See Section 1.1). Transient analyses to support MUR power uprate were performed for the first reload for MUR operation. Results are given in Cycle 14 reload documents. Radiological consequences evaluated for the Power Rerate Project are bounding for MUR because they were performed at a power level of 3527 MWt. The LGS operating domain is described in Appendix 15B. Limerick Units 1 and 2 contain GNF3 fuel only; however, references to GNF2 fuel for some accident analyses, such as CRDA, remain applicable.

The results of the analyses presented in the following sections provide the user with information regarding the general sequence of events, features, system behaviors, and trends and characteristics of each event. The information provided allows for an evaluation of the potential impact of changes to plant systems on the results of a particular analysis. The specific results presented (i.e. peak neutron flux and pressure, ΔCPR, etc.) are explicitly applicable to the LGS Unit 1 Cycle 5 core only, which was the basis of the analyses (unless specified otherwise). The results are, however, representative of the expected plant response for both units.

The limiting transients in each category of event are discussed in detail and have been revised to reflect power rerate conditions. In general, the non-limiting events have not been reanalyzed for power rerate. The results presented in Chapter 15 for the non-limiting events reflect the original plant operating conditions. However, these results continue to provide a reasonable representation of the trends and characteristics of the event.

For each core reload, a cycle specific safety analysis is performed utilizing the methods described in References 15.0-2 to 15.0-5, 15.0-13, 15.0-15, and 15.0-16. The limiting transient events are re-evaluated for each reload. The results of these analyses are documented in the cycle specific Supplemental Reload Licensing Report (SRLR). Information from the SRLR is used in the development of the cycle specific Core Operating Limit Report (COLR).

The scope of the situations analyzed includes anticipated (expected) operational occurrences (e.g., loss of electrical load); off design, abnormal (unexpected) transients that induce system operation disturbances; postulated accidents of low probability (e.g., the sudden loss of integrity of a major component); and hypothetical events of extremely low probability (e.g., an ATWS).

15.0.1 ANALYTICAL OBJECTIVE

The spectrum of postulated initiating events is divided into categories based upon the type of disturbance and the expected frequency of the initiating occurrence; the limiting events in each combination of category and frequency are quantitatively analyzed. The plant safety analysis evaluates the ability of the plant to operate within regulatory guidelines, without undue risk to the public health and safety.

15.0.2 ANALYTICAL CATEGORIES

Transient and accident events contained in this report are discussed in individual categories as required by Reference 15.0-1. The results of the events are summarized in Table 15.0-1, for the initial core, and in Table 15.0-1A for rerated conditions. Each event evaluated is assigned to one of the following applicable categories:

a. Decrease in Core Coolant Temperature - Reactor vessel water (moderator) temperature reduction results in an increase incore reactivity. This could lead to fuel cladding damage.

b. Increase in Reactor Pressure - Nuclear system pressure increases threaten to rupture the RCPB. Increasing pressure also collapses the voids in the core moderator, thereby increasing core reactivity and power level which threaten fuel cladding due to overheating.

c. Decrease in Reactor Core Coolant Flow Rate - A reduction in the core coolant flow rate threatens to overheat the cladding as the coolant becomes unable to adequately remove the heat generated by the fuel.

d. Reactivity and Power Distribution Anomalies - Transient events included in this category are those that cause rapid increases in power and are due to increased core flow disturbance events. Increased core flow reduces the void content of the moderator, increasing core reactivity and power level.

e. Increase in Reactor Coolant Inventory - Increasing coolant inventory could result in excessive moisture carryover to the main turbine, feedwater turbines, etc.

f. Decrease in Reactor Coolant Inventory - Reductions in coolant inventory could threaten the fuel as the coolant becomes less able to remove the heat generated in the core.

g. Radioactive Release from Subsystems and Components - Loss of integrity of a radioactive containment component is postulated.

h. Anticipated Transients Without Scram - In order to determine the capability of plant design to accommodate an extremely low probability event, a multisystem maloperation situation is postulated.

15.0.3 TRANSIENT OR ACCIDENT EVALUATION

15.0.3.1 Identification of Causes and Frequency Classification

Situations and causes that lead to the initiating event analyzed are described within the categories designated above. The frequency of occurrence of each transient or accident is summarized based upon currently available operating plant history for the transient, or accident. Transients, or accidents, for which inconclusive data exist are discussed separately within each section.

Each initiating event within the major groups is assigned to one of the following frequency groups:

a. Incidents of moderate frequency - These are accidents that may occur from once during a calendar year to once per 20 years for a particular plant. These events are referred to as "anticipated (expected) operational transients."

b. Infrequent incidents - These are accidents that may occur occasionally during the life of a particular plant, ranging in time from once in 20 years to once in 100 years. These events are referred to as "abnormal (unexpected) operational transients."

c. Limiting faults - These are accidents that are not expected to happen, but are postulated because they may result in the release of significant amounts of radioactive material. These events are referred to as "design basis (postulated) accidents."

d. Normal operation - Operations of high frequency are not discussed here, but are examined, along with (a), (b), and (c), in the nuclear systems operational analyses in Section 15.9.

15.0.3.1.1 Unacceptable Results for Incidents of Moderate Frequency - Anticipated (Expected) Operational Transients

The following are considered to be unacceptable safety results for incidents of moderate frequency (anticipated operational transients):

a. A release of radioactive material to the environs that exceeds the limits of 10CFR20.

b. Reactor operation induced fuel cladding failure.

c. Nuclear system stresses in excess of those allowed for the transient classification by applicable industry codes.

d. Containment stresses in excess of those allowed for the transient classification by applicable industry codes.

15.0.3.1.2 Unacceptable Results for Infrequent Incidents - Abnormal (Unexpected) Operational Transients

The following are considered to be unacceptable safety results for infrequent incidents (abnormal operational transients):

a. Release of radioactivity that results in dose consequences that exceed a small fraction of 10CFR50.67.

b. Failure of fuel cladding which could cause changes in core geometry such that core cooling would be inhibited.

c. Generation of a condition that results in consequential loss of function of the reactor coolant system.

d. Generation of a condition that results in a consequential loss of function of a necessary containment barrier.

e. Nuclear system stresses in excess of those allowed for the accident classification by applicable industry codes.

15.0.3.1.3 Unacceptable Results for Limiting Faults - Design Basis (Postulated) Accidents

The following are considered to be unacceptable safety results for limiting faults (DBAs):

a. Radioactive material release that results in dose consequences that exceed the guideline values of 10CFR50.67.

b. Failure of fuel cladding which could cause sufficient changes in core geometry such that core cooling would be inhibited.

c. Nuclear system stresses in excess of those allowed for the accident classification by applicable industry codes.

d. Containment stresses in excess of those allowed for the accident classification by applicable industry codes when containment is required.

e. Radiation exposure to plant operations personnel in the main control room in excess of 5 rem TEDE (total effective dose equivalent).

15.0.3.2 Sequence of Events and System Operation

Each transient, or accident, is discussed and evaluated in terms of the following:

a. A step-by-step sequence of events, from initiation to final stabilized condition.

b. The extent to which normally operating plant instrumentation and controls are assumed to function.

c. The extent to which plant and reactor protection systems are required to function.

d. The credit taken for the functioning of normally operating plant systems.

e. The operation of engineered safety systems that is required.

f. The effect of a single active failure, or of a single operator error.

g. The effects of plant equipment out-of-service.

15.0.3.2.1 Single Active Failures or Single Operator Errors

15.0.3.2.1.1 General

This paragraph discusses a very important concept pertaining to the application of single active failures and single operator errors in analyses of the postulated events. Single active failure criteria have been required, and successfully applied, in past NRC-approved docket applications to DBA categories only. Reference 15.0-1 infers that "single active failures and single operator errors" requirements should be applied to transient events (including high, moderate, and low probability occurrences) as well as to accident (very low probability) situations.

Transient evaluations have been judged against a criterion of one single active failure, or one single operator error, as the initiating event, with no additional single failure assumptions to the protective sequences, although a great majority of these protective sequences are utilized in safety systems that can accommodate single active failures aspects. Even under these postulated transients, or

accidents, the plant damage allowances, or limits, were very much the same as those for normal operation.

Reference 15.0-1 suggests that the transient and accident scenarios should now include multifailure event sequences. The format requested follows:

a.	For initiating occurrence	1 -	An equipment failure or an operator error, and
b.	For single active failure or operator error analysis	2 -	Another equipment failure or failures and/or another operator error or errors.

Most transients, or accidents, postulated for consideration are the result of a single active failure or a single operator error that have been postulated during any normal or planned mode of plant operations. The types of operational single active failures and single operator errors considered as initiating events, and subsequent protective sequence challenges, are identified in the paragraphs below.

15.0.3.2.1.2 Initiating Event Analysis

a. The undesired opening or closing of any single valve (a check valve is not assumed to close against normal flow), or

b. The undesired starting or stopping of any single component, or

c. The malfunction or maloperation of any single control device, or

d. Any single electrical component failure, or

e. Any single operator error.

Operator error is defined as "an active deviation from written operating procedures or nuclear plant standard operating practices." The result of a single operator error is the set of actions that follows a single erroneous decision. The set of actions is limited as follows:

a. Those actions that could be performed by one person.

b. Those actions that would have constituted a correct procedure had the initial decision been correct.

c. Those actions that are subsequent to the initial operator error and have an effect on the designed operation of the plant, but are not necessarily directly related to the operator error.

Examples of single operator errors are as follows:

a. An increase in power above the established flow control power limits from control rod withdrawal in the specified sequences.

b. The selection and complete withdrawal of a single control rod out-of-sequence.

c. The incorrect calibration of an APRM.

d. Manual isolation of the main steam lines as a result of operator misinterpretation of an alarm or indicator.

15.0.3.2.1.3 Single Active Failure or Single Operator Error Analysis

a. The undesired action or maloperation of a single active component, or

b. Any single operator error as defined in Section 15.0.3.2.1.2.

15.0.3.2.2 Analyzed Transients and Nonsafety-Grade Systems or Components

The thermal and pressure safety limits are not compromised by inclusion of the simulated response of nonsafety-grade systems when analyzing transients.

Referring to Table 15.0-6, the analysis for each of the transients is based on the single failure criterion associated with abnormal transients (i.e., abnormal transients are defined as events that occur as a result of equipment malfunctions as a result of a single active component failure or operator error). Following this single failure, the resulting transient is simulated in a conservative fashion to show the response of primary system variables and how the various plant systems would interact and function. In the transients, the consideration of any additional failures is not considered appropriate within the realm of the abnormal transient definition, but shifts them to infrequent events (infrequent events being those not expected in the 40 year plant lifetime).

Although certain transient events assume the operation of specific nonsafety-grade equipment to provide a realistic transient signature, failures of such equipment would not make these events more thermal or pressure limiting than the limiting accidents already addressed in Chapters 5 and 15. In fact, many of the events that have a Level 8 turbine trip (nonsafety-grade trip) would be less severe if the Level 8 trip was assumed not to function.

For example, failure of the Level 8 turbine trip or failure of the bypass to open when the Level 8 trip does occur was studied for a BWR similar to the LGS design. The increase in ΔCPR was about 0.02 for a delay in the turbine trip and 0.08 for failure of bypass. Although thermal margins are reduced, no significant (if any) fuel damage is expected. The offsite doses (if any) would be negligible and therefore would have no impact from a health and safety viewpoint. The loss of feedwater event is analytically about the same with or without the recirculation runback ahead of the Level 2 trip.

15.0.3.3 Core and System Performance

15.0.3.3.1 Introduction

Reactor core and system performance analysis must demonstrate that:

1. The margin of safety for Anticipated Operational Occurrences (AOOs) remain within all applicable criteria.

2. All fuel and thermal mechanical transient overpowers are within the applicable design bases.

3. The maximum reactor vessel pressure does not exceed the ASME code allowable peak pressure of 1375 psig.

4. Primary containment integrity is not comprised.

Section 4.4 describes the various fuel failure mechanisms. Avoidance of mechanisms (a) and (b) for incidents of moderate frequency is verified statistically with consideration given to data, calculating, manufacturing, and operating uncertainties. An acceptable criterion was determined to be that 99.9% of the fuel rods in the core would not be expected to experience boiling transition (References 15.0-2, 15.0-15, and 15.0-16). Limerick has adopted TSTF-564, which established a revised safety limit basis. The revised basis will ensure that there is a 95% probability at a 95% confidence level that no fuel rods will be susceptible to boiling transition using a safety limit based on the critical power ratio statistics. For TRACG applications, an operating limit MCPR (OLMCPR) is calculated for the transient initial condition that will result in no more than 0.1% of the fuel rods susceptible to boiling transition. For non-TRACG AOO analyses, this criterion is met by demonstrating that incidents of moderate frequency do not result in a MCPR less than the established Safety Limit $MCPR_{99.9\%}$. The reactor steady-state CPR operating limit is derived by determining the decrease in MCPR for the most limiting transient, or accident. All other transients, or accidents, result in smaller MCPR decreases and are not reviewed in depth in this chapter. The MCPR during significant abnormal transient, or accident, is calculated using a transient core heat transfer analysis computer program. The computer program for historical non-TRACG AOO analysis is based upon a multinode, single channel thermal-hydraulic model that requires simultaneous solution of the partial differential equations for the conservation of mass, energy, and momentum in the bundle, and that accounts for axial variation in power generation. The primary inputs to the model include a physical description of the bundle, channel inlet flow and enthalpy, and pressure and power generation as functions of time.

A detailed description of the analytical model may be found in Reference 15.0-2 or Reference 15.0-13 for TRACG reload AOO methodology. The initial condition assumed for all full power transient MCPR calculations is that the bundle is operating at or above the applicable Safety Limit $MCPR_{99.9\%}$ documented in the cycle-specific Core Operating Limits Report (COLR). Maintaining MCPR greater than the cycle-specific Safety Limit $MCPR_{99.9\%}$ is a sufficient, but not necessary, condition to assure that no fuel damage occurs.

For situations in which fuel damage is sustained, the extent of damage is determined by correlating fuel energy content, cladding temperature, fuel rod internal pressure, and cladding mechanical characteristics.

These correlations are substantiated by fuel rod failure tests, and are discussed in Section 4.4 and Section 6.3.

The closure of all MSIVs causes an abrupt pressure increase in the reactor vessel. System pressure increase is mitigated by the actuation of the SRVs within their design and operating limits. Operating limits are placed on all RCPB component to ensure compliance to ASME overpressure protection criteria. Limits are also placed on reactor dome operating pressure and on SRVs out-of-service. These limits assure that the ASME code allowable value for peak vessel pressure is not exceeded and RCPB integrity is maintained.

The Mark II primary containment is designed to accommodate pressures, temperatures, and dynamic loads resulting from pipe breaks within the drywell or reactor blowdown through the SRV discharge and thereby limit the release of radioactive material to the plant and its environs. Core and containment cooling systems assure a coolable fuel geometry and control drywell and wetwell pressure and temperature conditions within primary containment design limits. Limits placed on reactor and core operating conditions assure that containment integrity is maintained.

15.0.3.3.2 Input Parameters and Initial Conditions for Analyzed Events

In general, the transients, or accidents, analyzed within this section have values for input parameters and initial conditions as specified in Table 15.0-2, for the initial core, and in Table 15.0.2A for power rerate. Analyses that assume data inputs different from these values are designated accordingly in the appropriate event discussion.

The transient analyses herein includes an RPT actuated by either fast closure of the turbine control valves or closure of the turbine stop valve.

For the original Cycle 1 transient event evaluations, low water level MSIV closure was simulated at Level 2. Subsequent design modifications have lowered the closure setpoint to Level 1. However, HPCI and RCIC initiation at Level 2 will prevent the water level from dropping to Level 1, and no MSIV closure will occur. Because no safety limits are approached during events for which the level is predicted to reach Level 2, reanalysis for the setpoint change is not required for the Cycle 1 analyses. The power rerate analysis utilized the Level 1 MSIV closure setpoint.

The UFSAR evaluates a wide range of process disturbances and component failures of varying severity to demonstrate conformance to plant safety and licensing criteria (Reference 15.0-1).

Generic guidelines for uprating BWRs (Reference 15.0-8) and established LGS reload licensing practice identify transient and accident events that are limiting to BWRs or are otherwise sufficient to demonstrate that all NRC protection criteria are met for LGS power rerate operation. The evaluations, where appropriate, are based on the characteristics of the LGS Unit 1 Cycle 5 core configuration. Comparisons of the results of the baseline evaluations for power rerate conditions and originally licensed operating conditions using improved models and methods are provided.

Input parameters consist of heat balance information, core characteristics, and reactor protection specifications. The inputs include the initial power and flow conditions, core pressure drop, nuclear dynamic parameters (scram times, void fraction, Doppler coefficient) and system set points (SRVs,reactor scram, recirculation and feedwater pump trips, etc.). The analyses cover the full spectrum of core conditions from the beginning to the end of the fuel cycle, whichever is more limiting for the event in consideration.

The analyses are based on the core loading characteristic of LGS Unit 1 Cycle 5. The GEMINI methodology is applied as recommended in the generic power uprate guidelines (Reference 15.0-8), which is consistent with the LGS reload licensing practice.

The key system input parameters used in the power rerate transient analysis are shown in Table 15.0-2A; corresponding evaluation results are summarized in Table 15.0-1A.

15.0.3.3.3 Initial Power/Flow Operating Constraints

The analysis basis for most of the transient and accident analyses is the most limiting point on the power/flow operating map. Typically, this is at the maximum licensed core thermal power. Depending on the event being analyzed, the core thermal power is adjusted, either directly or indirectly, to account for the required licensing power uncertainty as described in GESTAR II (Reference 4.1-1) (See Section 15.0.4, Regulatory Guide 1.49). The limiting core flow rate is also dependent on the event being analyzed.

The operating power/flow map shown in Figure 15.0-1 includes the Maximum Extended Load Line Limit (MELLL) and Increased Core Flow (ICF) to 110% core flow operating domain.

The following performance improvement features are also included in the transient analyses: the FFWTR option used in conjunction with ICF at the end of the cycle, TBSOOS (formally documented as 'TBVOOS', which is now separate; see Sections 15B.4.1 and 15B.4.6), EOC-RPTOOS, TCVOOS and/or TSVOOS, PLUOOS, 1 MSIVOOS, 2 SRVOOS, 1 TBVOOS, FWHOOS, and PROOS. Additional details related to the combination of equipment OOS options with ARTS, MELLL, and ICF operation can be found in References 15.0-10 and 15.0-11.

The operating and performance improvement features described above are part of the LGS licensed operating domain. A detailed discussion of the LGS licensed operating domain is found in Appendix 15B.

Certain localized events are evaluated at other than the above mentioned conditions. These other conditions are discussed with the appropriate transient, or accident.

15.0.3.3.4 Results

The results of analytical evaluations are provided for each transient, or accident. In addition, critical parameters are shown in Table 15.0-1 for Cycle 1 conditions and in Table 15.0-1A for power rerate conditions. From the data in Table 15.0-1, an evaluation of the limiting event for that particular category and parameter can be made. In Table 15.0-3, a summary of applicable accidents is provided. This table compares the GE calculated amount of failed fuel to that used in worst case radiological calculations.

The results of each transient or accident for subsequent cycles can be found in the Supplemental Reload Licensing Report.

15.0.3.4 Barrier Performance

This section primarily evaluates the performance of both the RCPB and the containment system during transients and accidents.

During transients that occur with no release of coolant to the containment, only RCPB performance is considered. If release to the containment occurs, as in the case of limiting faults, then challenges to the containment are evaluated as well.

Containment integrity is maintained as long as internal pressures remain below the maximum allowable values. The design internal pressures are as follows:

Drywell (primary containment)	55 psig
Suppression Chamber (Primary Containment)	55 psig
Secondary Containment	7 in H2O

The LOCA radiological analyses account for the radiation released from the secondary containment during the time that the pressure exceeds minus 0.25 inch wg.

Damage to any of the radioactive material barriers as a result of accident-initiated fluid impingement, and jet forces, is considered in the other portions of the UFSAR where mechanical design features

of the systems and components are described. Design basis accidents are used in determining the size and strength requirements of the essential nuclear system components. A comparison of the accidents considered in this section with those used in the mechanical design of equipment reveals that either the applicable accidents are the same, or that the accident in this section results in less severe stresses than those assumed for mechanical design.

15.0.3.5 Radiological Consequences

In this chapter, the consequences of radioactivity release during the three types of events are considered:

a. Incidents of moderate frequency (anticipated operational transients)

b. Infrequent incidents (abnormal operational transients)

c. Limiting faults (DBA).

For all transients, or accidents, whose consequences are limiting, a detailed quantitative evaluation is presented. For nonlimiting transients, or accidents, a qualitative evaluation is presented, or results are referenced from a more limiting or enveloping case.

The original plant design basis included the analyses of radiological consequences based on the source terms of TID-14844 and Regulatory Guides 1.3, 1.5 and 1.25.

Regulation 10CFR50.67, "Accident Source Term," provides a mechanism to replace the traditional TID-14844 accident source term with an "Alternative Source Term" (AST). The methodology of approach to this replacement is provided in Regulatory Guide 1.183 and its associated Standard Review Plan 15.0.1.

In support of a full scope implementation of AST in accordance with Regulatory Guide 1.183, AST radiological consequence analyses were performed for the four Design Basis Accidents that result in offsite exposures. These include the Loss of Coolant Accident (LOCA), Main Steam Line Break (MSLB). Fuel Handling Accident (FHA) and Control Rod Drop Accident (CRDA). The dose consequences for these accidents are discussed elsewhere in Chapter 15 and result in doses that are within the guidelines of 10CFR50.67.

Although only the four major accidents have been evaluated using the AST methodology, the AST analytical methods described in Regulatory Guide 1.183 and dose limits defined in 10CFR50.67 comprise the design basis for Limerick for all design basis accidents.

Short-term, site specific X/Qs were calculated as described in Section 2.3 and are shown in Table 15.0-4.

15.0.4 REGULATORY GUIDE CONFORMANCE

The regulatory guides pertinent to accident analyses, and LGS conformance, are as follows:

Regulatory Guide 1.3 (Radiological Consequences of a LOCA)

The Limerick original LOCA dose consequences were determined in accordance with Regulatory Guide 1.3. With the implementation of Alternative Source Term in accordance with 10CFR50.67, the dose consequence analytical methodology of Regulatory Guide 1.183 applies

and supersedes the methodology of Regulatory Guide 1.3. LGS is in conformance with Regulatory Guide 1.183 requirements.

Regulatory Guide 1.5 (Radiological Consequences of a Steam Line Break)

The Limerick original main steam line break dose consequences were determined in accordance with Regulatory Guide 1.5. With the implementation of Alternative Source Term in accordance with 10CFR50.67, the dose consequence analytical methodology of Regulatory Guide 1.183 applies and supersedes the methodology of Regulatory Guide 1.5. LGS is in conformance with Regulatory Guide 1.183 requirements.

Regulatory Guide 1.25 (Radiological Consequences of a Fuel Handling Accident)

The Limerick original fuel handling accident dose consequences were determined in accordance with Regulatory Guide 1.25. With the implementation of Alternative Source Term in accordance with 10CFR50.67, the dose analytical methodology of Regulatory Guide 1.183 applies and supersedes the methodology of Regulatory Guide 1.25. LGS is in conformance with Regulatory Guide 1.183 requirements as noted in NRC Safety Evaluation Reports dated September 8, 2006, and March 15, 2017.

Regulatory Guide 1.49 (Power Levels of Nuclear Power Plants).

The power levels assumed in the analyses are in accordance with this guide.

NOTE: Transient analyses were performed at the licensed rated thermal power of 3515 MWt for the first reload for MUR operation. Radiological consequences evaluated for the Power Rerate Project are bounding because they were performed at a power level of 3527 MWt (102% of the Power Rerate Project thermal power of 3458 MWt).

Regulatory Guide 1.98 (radiological consequences of an offgas system failure).

LGS is in conformance with this guide, with the following clarifications:

a. In reference to Paragraph c.4.a of the guide, the LGS total whole body dose is calculated based upon the radiation at a depth of 5 cm, the average depth of the blood-forming organs. This is standard practice and is endorsed for use in Appendix E, Paragraph 3, of Regulatory Guide 1.109 (doses for routine releases).

b. Dose conversion factors are taken from the most recent data available, rather than the reference given in Paragraph c.4.b of the guide.

Regulatory Guide 1.183 (Alternative Source Terms for Evaluating Design Basis Accidents)

Regulation 10CFR50.67, "Accident Source Term, "provides a mechanism to replace the traditional TID-14844 accident source term with an "Alternative Source Term" (AST). The methodology of approach to this replacement is provided in Regulatory Guide 1.183 and its associated Standard Review Plan 15.0.1.

In support of a full scope implementation of AST in accordance with Regulatory Guide 1.183, AST radiological consequence analyses were performed for the four Design Basis Accidents that result in offsite exposures. These include the Loss of Coolant Accident (LOCA), Main Steam Line Break (MSLB), Fuel Handling Accident (FHA) and Control Rod Drop Accident

(CRDA). The dose consequences for these accidents are discussed elsewhere in Chapter 15 and result in doses that are within the guidelines of 10CFR50.67.

Although only the four major accidents have been evaluated using the AST methodology, the AST analytical methods described in Regulatory Guide 1.183 and dose limits defined in 10CFR50.67 comprise the design basis for Limerick for all design basis accidents.

LGS is in conformance with the requirements of Regulatory Guide 1.183 as noted in NRC Safety Evaluation Reports dated September 8, 2006, and March 15, 2017.

15.0.5 NUCLEAR SAFETY OPERATIONAL ANALYSIS RELATIONSHIP

Section 15.9 is a comprehensive, total plant, system level, qualitative FMEA, relative to all the Chapter 15 events considered, the protective sequences utilized to accommodate the transients, or accidents, and their effects, and the systems involved in the protective actions.

Interdependency of analysis, and cross-referral of protective actions, are an integral part of this chapter and the section.

A summary table that classifies events by frequency only (i.e., not just within a given category such as decrease in core coolant temperature) is in Section 15.9.

15.0.6 LICENSING BASIS VS. EMERGENCY PROCEDURE GUIDELINES

The NRC Staff review of the BWR Owners' Group Emergency Procedure Guidelines (EPGs), Revision 4 (NEDO-31331, March 1987) is documented in an NRC Safety Evaluation Report (SER) dated September 12, 1988. In this SER, the NRC Staff concluded that the guidelines are acceptable for implementation; however, the NRC stated that each BWR Licensee who wishes to incorporate Revision 4 of the EPGs should assure that the EPGs will not impact its licensing bases.

To ensure that implementation of EPGs, Rev. 4 did not conflict with the LGS licensing based analyses, a review of the Cycle 1 analyzed transients was conducted. This review (documented in reference 15.0-6) identified the Pressure Regulator Failure-Open Direction event as the only analyzed transient in which operator action, as instructed by the Transient Response Implementation Plan (TRIP) Procedures, could interfere with the analyzed transient response as discussed in Section 15. For the Pressure Regulator Failure-Open Direction transient, it was concluded that procedural actions are sufficient to make the end result for the transient the same as that analyzed in Section 15.

This review was performed based on the following position regarding Licensing Basis vs. EPGs:

> Implementation of the TRIP procedures for events within the design basis does not conflict with the licensing basis as long as the successful implementation of operator actions makes the end result for the transient response the same as or more conservative than that analyzed in the UFSAR.

The Revision 4 BWROG EPGs already included, to a considerable degree, operator actions required to prevent or mitigate what are termed severe accidents (considered to begin with the onset of core damage). Subsequent to the issue of the Revision 4 EPGs, the preparation of Individual Plant Examinations (IPE) for nuclear plants, in conjunction with industry research, have provided additional severe accident mitigation information that was not available during the development of the

Revision4 EPGs. To ensure that the EPG strategies reflect the most current severe accident mitigation information available, a review of the EPG strategies, to the additional available severe accident mitigation information, was conducted. As a result of this review, the BWROG developed the Emergency Procedure and Severe Accident Guidelines (EPG/SAG). The SAG, together with the modified EPGs, form an integrated set of symptomatic instructions that attempt to cover all possible mechanistic accident sequences. The EPGs contain strategies applicable prior to the transition to a severe accident, and the SAG contain strategies applicable after the transition. EPG/SAG has superseded EPG, Revision 4 as the basis for the Emergency Operating Procedures (EOPs) at LGS.

To ensure that the implementation of EPG/SAG did not conflict with the LGS licensing-based analysis, a review of the SAR analyzed accidents, transients, and special events was conducted. The conclusions of this review are contained in the 10CFR50.59 Reviews prepared for the Plant Specific Technical Guidelines (PSTGs) and Plant Specific Severe Accident Management Guidelines (PSSAMGs) which support the transition from EPG, Revision 4 to EPG/SAG. Plant-unique variations from the EPG/SAG guidance have been evaluated in the 10CFR50.59 Reviews, the Plant Specific Technical Guidelines (PSTGs), and the Plant Specific Severe Accident Management Guidelines (PSSAMGs).

15.0.7 REFERENCES

15.0-1 Regulatory Guide 1.70 (Rev 3), "Standard Format and Content of Safety Analysis Report for Nuclear Power Plants, Light-Water Reactor Edition," NRC, (November 1978).

15.0-2 "General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation and Design Application," NEDO-10958-A, GE, (January 1977).

15.0-3 R.B. Linford, "Analytical Methods of Plant Transient Evaluations for the General Electric Boiling Water Reactor", NEDO-10802, GE, (February 1973).

15.0-4 NEDO-24154, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors", GE, (October 1978).

15.0-5 F. Odar et al, "Safety Evaluation for the General Electric Topical Report: Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors", NEDO-24154 and NEDE-24154-P, Volumes I, II, III, GE, (1980).

15.0-6 Design Analysis dated May 14, 1990, for resolution of Justification for Continued Operation L-90-050-001, Mode Switch Position Vs. Accident Analysis.

15.0-7 "Power Rerate Safety Analysis Report for Limerick Generating Station Units 1 and 2, " NEDC-32225P, GE, (September 1993).

15.0-8 "Generic Guidelines for General Electric Boiling Water Reactor Power Uprate," NEDO-31897, GE, (February 1992), and NEDC-31897P-A, GE (May 1992).

15.0-9 "Generic Evaluations of General Electric Boiling Water Reactor Power Uprate," Volume I, NEDC-31984P, GE, (July 1991).

15.0-10 "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2", NEDC-32193P, Revision 2, GE, (October 1993).

15.0-11 GE Nuclear Energy, "Safety Review for Limerick Generating Station Units 1 and 2 110% Increased Core Flow Operation and Final Feedwater Temperature Reduction," NEDC-32224P (Revision 1), October 1994.

15.0-12 "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A-32, August 2024; and U.S. Supplement NEDE-24011-P-A-32-US, August 2024.

15.0-13 “Migration to TRACG04 / PANAC11 from TRACG02 / PANAC10 for TRACG AOO and ATWS Overpressure Transients,” NEDE-32906P Supplement 3-A, Revision 1, April 2010.

15.0-14 GE-Hitachi Nuclear Energy, 0000-0077-4603-R1, "BWR Owners Group Evaluation of Steam Flow Induced Error (SFIE) Impact on the L3 Setpoint Analytic Limit", October 2008.

15.0-15 "Methodology and Uncertainties for Safety Limit MCPR Evaluations," NEDC-32601P-A, August 1999.

15.0-16 "Power Distribution Uncertainties for Safety Limit MCPR Evaluations," NEDC-32694-P-A, August 1999.

15.0-17 Deleted

Table 15.0-1* (See Note)

SUMMARY OF INITIAL CORE TRANSIENTS

UFSAR SECTION	FIGURE NO.	DESCRIPTION	MAXIMUM NEUTRON FLUX % NBR	MAXIMUM DOME PRESSURE (psig)	MAXIMUM VESSEL PRESSURE (psig)	MAXIMUM STEAM LINE PRESSURE (psig)	MAXIMUM CORE AVERAGE SURFACE HEAT FLUX % OF INITIAL	ΔCPR[2]	FREQUENCY CATEGORY[1]	NO. OF VALVES 1ST BLOW-DOWN	DURATION OF BLOWDOWN (sec)
15.1		DECREASE IN CORE COOLANT TEMPERATURE									
15.1.1		Loss of Feedwater Heater, Manual Flow Control	127.7	1030.0	1069.0	1016.0	119.4	0.16	a	0	0.0
15.1.2	15.1-3	Feedwater Controller Failure, Maximum Demand, 135.4% Flow[3]	156.3	1168	1194	1165	105.0	0.06	a	14	6.0
15.1.2	15.1-1	Feedwater Controller Failure Maximum Demand, Bypass Off 135.4% Flow[3]	216.6	1204	1231	1200	110.2	0.11	b	14	
15.1.3	15.1-4	Pressure Regulator Failure - Open	104.3	1149.0	1165.0	1148.0	100.3	<0.06[4]	a	5	3.2
15.1.4	-	Inadvertent Opening of Safety or Relief Valve	See Section 15.1						b		
15.1.6	-	Inadvertent RHR Shutdown Cooling Operation	See Section 15.1						a		
15.2	-	INCREASE IN REACTOR PRESSURE									
15.2.1	-	Pressure Regulator Failure - Closed	See Sections 15.2.2 and 15.2.3 (Bypass on)						a		
15.2.2	15.2-1	Generator Load Rejection, Trip Scram, Bypass, and RPT - On[3]	178.5	1169	1193	1164	101.2	0.03	a	14	6.0

Table 15.0-1 (Cont'd)*

UFSAR SECTION	FIGURE NO.	DESCRIPTION	MAXIMUM NEUTRON FLUX % NBR	MAXIMUM DOME PRESSURE (psig)	MAXIMUM VESSEL PRESSURE (psig)	MAXIMUM STEAM LINE PRESSURE (psig)	MAXIMUM CORE AVERAGE SURFACE HEAT FLUX % OF INITIAL	ΔCPR(2)	FREQUENCY CATEGORY(1)	NO. OF VALVES 1ST BLOW-DOWN	DURATION OF BLOWDOWN (sec)
15.2.2	15.2-2	Generator Load Rejection, Trip Scram, Bypass - Off, RPT - On(3)	222.5	1200	1225.0	1196.0	106.2	0.08	a(6)	14	12.7
15.2.3	15.2-3	Turbine Trip, Trip Scram, and RPT - On	163.3	1174.0	1196.0	1169.0	102.0	<0.16(4)	a	14	5.8
15.2.3	15.2-4	Turbine Trip, Trip Scram, Bypass - Off, RTP - On(3)	198.4	1198	1223.0	1195.0	104.5	0.06	a(6)	14	12.6
15.2.4	15.2-5	MSIV Closure, Position Switch Scram	190.9	1187.0	1220.0	1185.0	100.0	<0.06(4)	a	14	11.5
15.2.5	15.2-6	Loss of Condenser Vacuum	160.9	1172.0	1194.0	1168.0	101.9	<0.06(4)	a	14	10.8
15.2.6	15.2-7	Loss of Auxiliary Power Transformer	See Loss of All Grid Connections								
15.2.6	15.2-8	Loss of All Grid Connections	178.5	1168.4	1175.4	1164.2	101.3	<0.06(4)	a	14	4.8
15.2.7	15.2-9	Loss of All Feedwater Flow	104.3	1144.0	1155.0	1144.0	100.0	<0.06(4)	a	5	2.2
15.2.8	-	Feedwater Line Break	See Table 15.0-3, event 15.6.6								
15.2.9	-	Failure of RHR Shutdown Cooling	See Section 15.2								
15.3	-	DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE									
15.3.1	15.3-1	Trip of One Recirculation Pump Motor	104.3	1021.0	1057.0	1011.0	100.0	<0.06(4)	a	0	0.0

Table 15.0-1 (Cont'd)*

UFSAR SECTION	FIGURE NO.	DESCRIPTION	MAXIMUM NEUTRON FLUX % NBR	MAXIMUM DOME PRESSURE (psig)	MAXIMUM VESSEL PRESSURE (psig)	MAXIMUM STEAM LINE PRESSURE (psig)	MAXIMUM CORE AVERAGE SURFACE HEAT FLUX % OF INITIAL	ΔCPR[2]	FREQUENCY CATEGORY[1]	NO. OF VALVES 1ST BLOW-DOWN	DURATION OF BLOWDOWN (sec)
15.3.1	15.3-2	Trip of Both Recirculation Pump Motors	104.3	1149.0	1160.0	1148.0	100.1	<0.06[4]	a	5	3.0
15.3.2	-	Recirculation Flow Control Failure - Decreasing Flow	See Section 15.3.1						a		
15.3.3	15.3-3	Seizure of One Recirculation Pump	104.3	1023.0	1057.0	1013.0	102.2	<0.16[4]	c	0	0.0
15.3.4	-	Recirculating Pump Shaft Break	See Section 15.3.3						c		
15.4	-	REACTIVITY AND POWER DISTRIBUTION ANOMALIES									
15.4.1.1	-	Rod Withdrawal Error - Refueling	See Section 15.4						b		
15.4.1.2	-	Rod Withdrawal Error - Startup	See Section 15.4						b		
15.4.2	-	Rod Withdrawal Error - At Power	See Section 15.4						b		
15.4.3	-	Control Rod Misoperation	See Sections 15.4.1 and 15.4.2						b		
15.4.4		Abnormal Startup of Idle Recirculation Loop	454.9	981.0	996.0	977.0	150.8	[5]	a	0	0.0
15.4.5	15.4-3	Recirculation Flow Control Failure - Increasing Flow	382.3	982.0	1001.0	978.0	145.1	[5]	a	0	0.0
15.4.7	-	Misplaced Bundle Accident	See Section 15.4						b		
15.4.9	-	Rod-Drop Accident	See Section 15.4						c		

Table 15.0-1 (Cont'd)*

UFSAR SECTION	FIGURE NO.	FLUX DESCRIPTION	MAXIMUM NEUTRON PRESSURE % NBR	MAXIMUM DOME (psig)	MAXIMUM VESSEL PRESSURE (psig)	MAXIMUM STEAM LINE PRESSURE (psig)	MAXIMUM CORE AVERAGE SURFACE HEAT FLUX % OF INITIAL	ΔCPR[2]	FREQUENCY CATEGORY[1]	NO. OF VALVES 1ST BLOW-DOWN	DURATION OF BLOWDOWN (sec)
15.5	-	INCREASE IN REACTOR COOLANT INVENTORY									
15.5.1	15.5-1[7]	Inadvertent HPCI Pump Start	118.8	1020.0	1059.0	1007.0	107.6	<0.16[4]	a	0	0.0
15.5.3	-	BWR Transients	See appropriate events in Sections 15.1 and 15.2								

(1) a = Incidents of moderate frequency
b = Infrequent incidents
c = Limiting faults

(2) ΔCPRs are based on initial CPR that would yield a MCPR of 1.06.

(3) Results do not include adjustment factors and utilize EOC parameters (Reference 15.0-4).

(4) Estimated value, based on comparison with the most severe transient in the pressurization or nonpressurization category.

(5) These events are postulated to occur at low power and low flow conditions; a larger thermal margin is maintained above the safety limit prior to the event occurrence. Therefore, the resulting MCPR is well above 1.06.

(6) These events are classified as moderate frequency events for analysis purposes, pending the final resolution of this generic issue, as discussed in Sections 15.2.2.1.2.2 and 15.2.3.1.2.2.

(7) Figure 15.5-1 shows inadvertent HPCI with scram on Level 8 based on GNF3 design conditions

***NOTE:** The information in this table is based on the original design conditions. The results of transient analyses performed rerated conditions are tabulated in Table 15.0-1A

Table 15.0-1A

TRANSIENT ANALYSIS RESULTS (Power Rerate Conditions)
Unit 1 Cycle 5 Characteristics

UFSAR SECTION	TRANSIENT(a)	INITIAL (b) POWER/FLOW	PEAK NEUTRON FLUX (%NBR)	HEAT FLUX (%NBR)	PEAK VESSEL PRESS (psig)	PEAK ΔCPR (c) GE8x8NB/GE11	SYSTEM RESPONSE CURVES
15.2.3	TTNBP	100RP/100F	446	119	1271	0.17/0.25	Fig. 15.2-4
	TTNBP(h)	100RP/110F	328	113	1265	0.21	
	TTNBP	100RP/110F	482	120	1272	0.17/0.24	
	TTNBP	100RP/81F	362	117	1269	0.12/0.25	
	TTNBP(d)	100RP/110F	638	126	1276	0.22/0.30	
	TTNBP(d)	100RP/81F	415	120	1270	0.14/0.27	
15.2.2	LRNBP	100RP/100F	429	118	1270	0.15/0.25	Fig. 15.2-2
	LRNBP(h)	100RP/110F	332	115	1266	0.22	
	LRNBP(d)	100RP/110F	631	128	1276	0.22/0.32	Fig. 15.2-14
15.1.2	FWCF(e)	100RP/100F	348	122	1218	0.15/0.22	Fig. 15.1-3
	FWCF(e)	100RP/100F	348	122	1218	0.15/0.22	
	FWCF(e)	100RP/81F	314	119	1217	0.11/0.22	
	FWCF(e,f)	100RP/110F	500	129	1259	0.21/0.28	Fig.15.1-1
	FCWF(e,f)	100RP/81F	450	127	1260	0.16/0.29	
	FWCF(d,e,f)	100RP/110F	647	136	1263	0.24/0.33	
	FWCF(d,e,f)	100RP/81F	509	131	1261	0.18/0.31	
15.5.1	HPCI,BOC	102RP/100F	112	109	1082	N/A	Fig. 15.5-1(i)
	HPCI,BOC	102RP/81F	112	110	1077	N/A	
15.0.1	LFWH,EOC	100RP/110F	N/A	N/A	N/A	0.08	
	LFWH,BOC	100RP/81F	N/A	N/A	N/A	0.09	
	LFWH,MOC	100RP/81F	N/A	N/A	N/A	0.09	
15.4.2	RWE	100RP/100F	N/A	N/A	N/A	0.13	
15.3.3	RPSE,EOC	102RP/100F	102	102	1085	N/A	Fig. 15.3-3
15.2.4	MSIVF	102RP/110F	536	131	1314	N/A	
	MSIVF(g)	102RP/110F	536	131	1342	N/A	Fig. 15.2-1

Table 15.0-1A (Cont'd)

TRANSIENT ANALYSIS RESULTS FOR POWER RERATE
(UNIT 1 CYCLE 5 CHARACTERISTICS)

Footnote

(a) TTNBP = turbine trip with no bypass
LRNBP = load rejection with no bypass
FWCF = feedwater controller failure to maximum demand
MSIVF = main steam isolation valve closure, flux scram
HPCI = inadvertent actuation of high pressure coolant injection system
LFWH = loss of 100F° feedwater heating
RWE = rod withdrawal error
BOC, MOC, EOC = beginning-of-cycle 5, mid-of-cycle 5, end-of-cycle 5
RPSE = recirculation pump seizure

(b) 100RP = rerate power of 3458 MWt
100F = rated core flow of 100.0 Mlb/hr

110F = ICF flow point (110M lb/hr) at rerate power

81F = MELLL flow point (81M lb/hr) at rerate power

(c) ΔCPR based on initial CPR which yields MCPR = 1.07, uncorrected for ODYN options A and B for TTNBP, LRNBP and FWCF events. GE8x8NB refers to the most limiting of all the 8x8 array fuel types in LGS Units 1 Cycle 5 core.

(d) EOC-RPT out-of-service (EOC-RPTOOS)

(e) Reduced feedwater temperature 320°F (105°F reduction at rerate conditions).

(f) Turbine bypass valves out-of service (TBVOOS)

(g) Three SRVs out-of-services (3SRVOOS)

(h) Unit 1, Cycle 8, TCV modified for full arc admission, GE 13 fuel.

(i) Representative for the Inadvertent HPCI with scram on Level 8 GNF3 design conditions.

Table 15.0-2

INPUT PARAMETERS AND INITIAL CONDITIONS
FOR INITIAL CORE TRANSIENTS*

1. Thermal power level, MWt	
Warranted value	$3.293 \times 10^{+3}$
Analysis value - radiological consequence	$3.458 \times 10^{+3}$
- transient analysis	$3.435 \times 10^{+3}$
2. Steam flow, lb/hr	
Warranted value	$1.416 \times 10^{+7}$
Analysis value	$1.486 \times 10^{+7}$
3. Core flow, lb/hr	$1.0 \times 10^{+8}$
4. Feedwater flow rate, lb/sec	
Warranted value	$3.958 \times 10^{+3}$
Analysis value	$4.129 \times 10^{+3}$
5. Feedwater temperature, °F	$4.25 \times 10^{+2}$
6. Vessel dome pressure, psig	$1.020 \times 10^{+3}$
7. Vessel core pressure, psig	$1.031 \times 10^{+3}$
8. Turbine bypass capacity, % NBR	$2.5 \times 10^{+1}$
9. Core coolant inlet enthalpy, Btu/lb	$5.266 \times 10^{+2}$
10. Turbine inlet pressure, psig	$9.6 \times 10^{+2}$
11. Fuel lattice	P8x8R
12. Core average gap conductance, Btu/sec-ft^2-°F	0.1744
13. Core leakage flow, %	12
14. Required MCPR operating limit	See Figure 15.0-3 and Table 15.0-5
15. MCPR safety limit	1.06

* Information for Cycle 1 analysis. The inputs and initial conditions for power rerate are tabulated in Table 15.0-2A.

Table 15.0-2 (Cont'd)*

16. Doppler coefficient, -¢/°F	
Nominal EOC-1	2.29×10^{-1}
Analysis data(3)	2.06×10^{-1}
17. Void coefficient, -¢/% Rated voids	
Nominal EOC-1	7.61
Analyses data for power increase events(3)	$1.271 \times 10^{+1}$
Analyses data for power decrease events	3.63
18. Core average rated void fraction, %	$4.345 \times 10^{+1}$
19. Scram reactivity, $\$\Delta k$	
Analysis data(3)	Figure 15.0-2
20. CRD speed, position versus time	Figure 15.0-2
21. Jet pump ratio, M	2.0
22. SRV capacity, % NBR	
At 1142.0 psig	$8.74 \times 10^{+1}$
Manufacturer	Target Rock
Quantity installed	14
23. Safety/relief function delay, seconds	4.0×10^{-1}
24. Safety/relief function response, seconds	1.5×10^{-1}
25. Setpoints for SRVs(2)	
Safety/relief function, psig	1142.0, 1152.0, 1162.0
26. Number of valve groups simulated	
Safety/relief function, Number	3
27. High flux trip, % NBR	
Analysis setpoint (121.0 x 1.043)	$1.262 \times 10^{+2}$
28. High pressure scram setpoint, psig	$1.071 \times 10^{+3}$

* Information for Cycle 1 analysis. The inputs and initial conditions for power rerate are tabulated in Table 15.0-2A.

Table 15.0-2 (Cont'd)*

29. Vessel level trips, feet above bottom of separator skirt (42.83 ft above vessel zero)	
Level 8 - (L8), feet	6.018
Level 4 - (L4), feet	3.625
Level 3 - (L3), feet (4)	1.750
Level 2 - (L2), feet	-3.708
30. Recirculation pump trip delay, seconds	1.75×10^{-1}
31. Recirculation pump trip inertia time constant for analysis, seconds (1)	4.5
32. Total steam line volume, ft^3	$6.015 \times 10^{+3}$

(1) The inertia time constant is defined by the expression:

$$t = \frac{2J_o n}{gT_o}$$

where t = inertia time constants (sec)
J_o = pump motor inertia ($lb\text{-}ft^2$)
n = pump speed (rps)
g = gravitational constant (ft/sec^2)
T_o = pump shaft torque (lb-ft)

(2) Safety analyses are conservatively based on these setpoints. Actual setpoints are 1130 psig, 1140 psig, and 1150 psig.

(3) Applicable to events analyzed using model described in Reference 15.0-3.

(4) **The L3 Analytical value in this table may be slightly different for various events due to a steam flow induced process measurement error. However, as described in Reference 15.0-13 the impact of the change is not significant and the event descriptions or conclusions need not be modified.**

* Information for Cycle 1 analysis. The inputs and initial conditions for power rerate are tabulated in Table 15.0-2A.

Table 15.0-2A

INPUT PARAMETERS AND INITIAL CONDITIONS
FOR TRANSIENTS (Unit 1, Cycle 5)[5]

1. Thermal power level, MWt	
Rated value	3458
Analysis value - radiological consequence	3527
- transient analysis	3458
2. Steam flow, lb/hr (rated)	15.0×10^6
3. Core flow, lb/hr (maximum core flow assumed)	1.1×10^8
4. Feedwater flow rate, lb/hr (rated)	15.0×10^6
5. Feedwater temperature, °F	425
6. Vessel dome pressure, psig	1045
7. Vessel core pressure, psig	1060
8. Turbine bypass capacity, % NBR[4]	20.1
9. Core coolant inlet enthalpy, Btu/lb (Corresponding to 110% core flow)	532.9
10. Turbine inlet pressure, psig	990
11. Fuel lattice	GE8x8NB, GE11
12. Core average gap conductance, Btu/sec-ft^2-°F	0.3568
13. Core leakage flow, %	12
14. Required MCPR operating limit	See Figure 15.0-3 and Table 15.0-5
15. MCPR safety limit	1.07

Table 15.0-2A (Cont'd)

16. Doppler coefficient, -¢/°F	
(at 100% rerated power, 100% rated core flow)	0.19
17. Void coefficient, -¢/% Rated voids	
(at 100% rerated power, 100% rate core flow)	10.18
18. Core average rated void fraction, %	4.061
19. Scram reactivity, $\$\Delta k$ Analysis data[3]	Figure 15.0-2
20. CRD speed, position versus time	Figure 15.0-2
21. Jet pump ratio, M	2.0
22. SRV capacity, % NBR	
At 1142.0 psig	$8.74 \times 10^{+1}$
Manufacturer	Target Rock
Quantity installed	14
23. Safety/relief function delay, seconds	4.0×10^{-1}
24. Safety/relief function response, seconds	1.5×10^{-1}
25. Setpoints for SRVs[2]	
Safety/relief function,	1182, 1192 1202
26. Number of valve groups simulated	
Safety/relief function, Number	3
27. High flux trip, % NBR	
Analysis setpoint (121.0 x 1.05)	1.27.05
28. High pressure scram setpoint, psig	1111

Table 15.0-2A (Cont'd)

29. Vessel level trips, inches above vessel zero	
Level 8 - (L8), inches	586.5
Level 4 - (L4), inches	556
Level 3 - (L3), inches (6)	535
Level 2 - (L2), inches	469.5
30. Recirculation pump trip delay, seconds	1.75×10^{-1}
31. Recirculation pump trip inertia time constant for analysis, seconds (1)	4.5
32. Total steam line volume, ft^3	$6.015 \times 10^{+3}$

(1) The inertia time constant is defined by the expression:

$$t = \frac{2J_o n}{gT_o}$$

where t = inertia time constants (sec)
J_o = pump motor inertia ($lb\text{-}ft^2$)
n = pump speed (rps)
g = gravitational constant (ft/sec^2)
T_o = pump shaft torque (lb-ft)

(2) Power Re-Rate safety analyses are conservatively based on these setpoints. Re-analysis for $\pm$3% setpoint tolerance used 1205, 1215, and 1226 psig (nominal +3% setpoint). Actual setpoints are 1170 psig, 1180 psig, and 1190 psig.

(3) Applicable to events analyzed using model described in Reference 15.0-3.

(4) Assuming 7 of 9 valves operable. Total capacity of bypass system is 25.8% NBR (9 valves)

(5) The data in this table is historical. For current Unit 1 and Unit 2 input parameters, see the cycle specific reload documents.

(6) **The L3 Analytical value in this table may be slightly different for various events due to a steam flow induced process measurement error. However, as described in Reference 15.0-13 the impact of the change is not significant and the event descriptions or conclusions need not be modified**.

Table 15.0-3

SUMMARY OF ACCIDENTS

UFSAR SECTION	TITLE	FAILED FUEL RODS GE CALCULATED VALUE	NRC WORST CASE ASSUMPTION
15.3.3	Seizure of One Recirculation Pump	None	-
15.3.4	Recirculation Pump Shaft Break	None	-
15.4.9	Control Rod-Drop Accident	<770(1)	770(1)
15.6.2	Instrument Line Break	None	None
15.6.4	Steam System Pipe Break Outside Containment	None	None
15.6.5	LOCA Within RCPB	None	100%
15.6.6	Feedwater Line Break	None	None
15.7.1.1	Main Condenser Offgas Treatment System Failure	N/A	N/A
15.7.3	Liquid Radwaste Tank Failure	N/A	N/A
15.7.4	Fuel Handling Accident	<212	212
15.7.5	Cask-Drop Accident	N/A	N/A

(1) Evaluation of the dose consequences of the control rod drop accident using the methodology of Regulatory Guide 1.183 utilized a failure of 1200 fuel rods.

Table 15.0-4

ATMOSPHERIC DISPERSION PARAMETERS

TIME PERIODS - X/Q VALUES[1]	0-2 hr	0-8 hr	8-24 hr	1-4 days	4-30 days
Exclusion Area Boundary (731 Meters)	3.18×10^{-4}	-	-	-	-
Low Population Zone (2043 Meters)	-	5.79×10^{-5}	4.10×10^{-5}	1.95×10^{-5}	6.68×10^{-6}

(1) Units for X/Q values are sec/m^3.

Table 15.0-5

REQUIRED OPERATING LIMIT CPR VALUES
FOR INITIAL CORE TRANSIENTS*

Pressurization Events:

	CPR (Option A)[1]	CPR (Option B)[1]
Load Rejection Without Bypass	1.19	1.11
Turbine Trip Without Bypass	1.17	1.10
Feedwater Controller Failure	1.17	1.14
Load Rejection	1.14	1.07
Feedwater Controller Failure Without Bypass	1.22	1.19
Feedwater Controller Failure Without Bypass and With EOC RPT Out-of-Service	1.30	1.23
Load Rejection Without Bypass and with EOC RPT Out-of-Service	1.28	1.17

Nonpressurization Events:

	CPR
Rod Withdrawal Error(3)	1.21
Loss of Feedwater Heater	1.22[2]

(1) Includes adjustment factors as specified in Reference 15.0-5.

(2) Required OLCPR using either Option A or Option B adjustment factor without bypass with operable EOC RPT.

(3) OLCPR value is obtained for the 107% rod block setpoint, control cell core analysis.

* Applies to Cycle 1 only. The updated rerate analysis information is contained in Table 15.0-1A.

Table 15.0-6

TRANSIENTS WHERE NONSAFETY-GRADE SYSTEMS/COMPONENTS ARE ACTUATED DURING THE COURSE OF THE EVENT

UFSAR SECTION	TRANSIENT	NONSAFETY-GRADE SYSTEM OR COMPONENT
15.1.2	Feedwater Controller Failure - Maximum Demand	Level 8 Turbine and Feedwater Trip, Turbine Bypass
15.1.3	Pressure Regulator Failure - Open	Level 8 Turbine and Feedwater Trip, Turbine Bypass
15.2.2	Generator Load Rejection	Turbine Bypass(1)
15.2.3	Turbine Trip	Turbine Bypass(1)
15.2.5	Loss of Condenser Vacuum	Turbine Bypass
15.2.6	Loss of Ac Power	Turbine Bypass
15.2.7	Loss of Feedwater Flow	Recirculation Runback(2)
15.3.1	Recirculation Pump Trip - Two Pumps	Level 8 Turbine Trip, Turbine Bypass
15.3.2	Recirculation Flow Control Failure - Decreasing Flow	Level 8 Turbine Trip, Turbine Bypass
15.4.1	Rod Withdrawal Error - Low Power	Rod Worth Minimizer System
15.4.2	Rod Withdrawal Error - At Power	Rod Block Monitor

(1) Level 8 (high water level) trip potentially activated following the initial part of these events, but it is not a significant factor in fuel or vessel protection evaluation.

(2) Neglected in the analysis.

15.1 DECREASE IN REACTOR COOLANT TEMPERATURE

15.1.1 LOSS OF FEEDWATER HEATING

15.1.1.1 Identification of Causes and Frequency Classification

15.1.1.1.1 Identification of Causes

Feedwater heating can be lost in at least two ways:

a. Steam extraction line valves to one heater string are closed.

b. Feedwater train is isolated automatically by high water level in either the first or second heaters.

The first case produces a gradual cooling of the feedwater. The second case produces a slight cooling of the feedwater. In both cases the reactor vessel receives cooler feedwater. The maximum number of feedwater heaters that can be isolated by a single event represents the most severe transient for analysis considerations. This transient has been conservatively estimated to incur a loss of up to 100°F of the feedwater heating capability of the plant and causes an increase in core inlet subcooling. This increases core power due to the negative void reactivity coefficient.

The design specification of the feedwater heater system requires that the maximum temperature decrease caused by a single failure should be less than or equal to 100°F. In the unlikely event that a drop in feedwater temperature in excess of 100°F occurs, and assuming no operator action, the decrease in the MCPR and increase in reactor power would still be bounded by the limiting event (i.e. generator load rejection trip with failure of bypass).

15.1.1.1.2 Frequency Classification

The feedwater heating system is designed to provide and maintain adequate heating such that under any single failure condition, the loss of feedwater heating is limited to less than 100°F. The loss of feedwater heating event is categorized as an incident of moderate frequency in the General Electric Standard Application for Reactor Fuel (Supplement for United States) (GESTAR II). This event is considered to be one of the limiting Anticipated Operational Occurrences (AOOs) events. Therefore, this transient is analyzed as an incident of moderate frequency; a 100°F drop of feedwater temperature at full power is postulated.

15.1.1.2 Sequence of Events and System Operation

15.1.1.2.1 Sequence of Events

Table 15.1-2 lists the sequence of events for this transient. An APRM Simulated Thermal Power Upscale alarm alerts the operator to insert control rods or to reduce recirculation flow. The operator should determine from existing tables the maximum allowable turbine-generator output with feedwater heaters out of service. If reactor scram occurs, the operator should monitor the reactor water level, pressure controls, and turbine-generator auxiliaries during coast-down.

15.1.1.2.2 System Operation

In establishing the expected sequence of events and simulating plant performance, it is assumed that normal functioning occurs in the plant instrumentation and controls, plant protection, and reactor protection systems.

Required operation of ESF is not expected in either case for this transient. The APRM Simulated Thermal Power - Upscale scram is the primary protection system trip in mitigating the consequences of this event.

15.1.1.2.3 The Effect of Single Failures and Operator Errors

This transient generally leads to an increase in reactor power level. Single failures are not expected to result in a more severe transient than analyzed. See Section 15.9 for a detailed discussion of this subject.

15.1.1.3 Core and System Performance

15.1.1.3.1 Mathematical Model

Due to its slow progression, this event is treated as a quasi-steady-state transient and is analyzed with a steady-state, three dimensional BWR core simulator. The core simulator is used to evaluate the differences, including thermal margins, between the initial conditions of the event and the final equilibrium state point after the loss of feedwater heating.

15.1.1.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions as tabulated in Table 15.0-2A. The events are analyzed for full cycle exposures at the BOC, MOC, and EOC conditions in order to bound the LGS operating domain described in Appendix 15B.

In addition to the inadvertent loss of feedwater heating event, consideration has also been given to planned operation with partial feedwater heating as follows.

There are two distinct periods of concern when operating with reduced feedwater temperature:

a. Before EOC - Reducing the feedwater temperature before EOC may occur during routine maintenance. The peak pressure will be lower because of the reduced steam production. The basis for the plant safety analysis covers this operating condition, and a cycle specific analysis is performed to confirm the plant safety.

b. After EOC - Operating with reduced feedwater temperature may occur as a result of an extended fuel cycle. The basis for the plant safety analysis covers this operating condition, and a cycle specific analysis is performed to confirm the plant safety.

The safety analyses for operation with reduced feedwater temperature evaluates: anticipated operational transients, including the LFWH event; Design Basis Accidents, including LOCA containment response; thermal-hydraulic instability; and reactor vessel internals, including feedwater nozzle and sparger fatigue. (Refer to Sections 15B.1.2 and 15B1.3 for more information.)

15.1.1.3.3 Results

The LFWH event is initiated from a closure of a steam extraction line to a feedwater heater or when feedwater is bypassed around one or more feedwater heaters. In either case, the feedwater temperature is reduced and core inlet subcooling is gradually increased. As a result, core power increases due to the negative void reactivity coefficient.

Vessel steam flow increases and the system pressure increase is slight so the RCPB is not threatened. The increased core inlet subcooling aids core thermal margins and the minimum MCPR is maintained above the Safety Limit $MCPR_{99.9\%}$. The ΔCPR for this event is 0.09 which is significantly less than the ΔCPR for the limiting event (generator load rejection with bypass failure). Therefore, the safety limit is satisfied.

Sensitivity studies have shown that the effect of initial power level on core thermal margin is negligible, with the event occurring at high power slightly more severe.

The results at the low core flow condition (MELLL case) are actually slightly more severe than for the high core flow condition (ICF case) because of increased inlet subcooling into the reactor core.

15.1.1.3.4 Considerations of Uncertainties

Important factors (such as reactivity coefficient, scram characteristics, magnitude of the feedwater temperature change) are assumed to be at the worst configuration so that any deviations seen in the actual plant operation reduce the severity of the transient.

15.1.1.4 Barrier Performance

As noted above consequences of this transient do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed; therefore, these barriers maintain their integrity and function as designed.

15.1.1.5 Radiological Consequences

Since this transient does not result in any additional fuel failures or any release of primary coolant to either the secondary containment or the environment, there are no radiological consequences associated with this transient.

15.1.2 FEEDWATER CONTROLLER FAILURE - MAXIMUM DEMAND

15.1.2.1 Identification of Causes and Frequency Classification

15.1.2.1.1 Identification of Causes

This transient is postulated on the basis of a single failure of a control device, specifically one which can directly cause an increase in coolant inventory by increasing the feedwater flow. The most severe applicable transient is a feedwater controller failure during maximum flow demand. The feedwater controller is forced to its upper limit at the beginning of the transient.

15.1.2.1.2 Frequency Classification

This transient is considered to be an incident of moderate frequency.

15.1.2.2 Sequence of Events and System Operation

15.1.2.2.1 Sequence of Events

With excess feedwater flow the water level rises to the high level reference point at which time the feedwater pumps and the main turbine are tripped and a scram is initiated. Table 15.1-3 lists the sequence of events for Figure 15.1-3. The figure shows the changes in important variables during this transient.

The operator should:

a. Observe that high feedwater pump trip has terminated the failure event.

b. Switch the feedwater controller from automatic to manual control in order to try to regain a correct output signal.

c. Identify causes of the failure and report all key plant parameters during the transient.

15.1.2.2.2 System Operation

To properly simulate the expected sequence of events, the analysis of this transient assumes normal functioning of plant instrumentation and controls, plant protection, and reactor protection systems. Important system operational actions for this transient are high level tripping of the main turbine, turbine stop valve scram trip initiation, RPT, and low water level initiation of the RCIC system and the HPCI system to maintain long-term water level control following tripping of feedwater pumps.

15.1.2.2.3 The Effect of Single Failures and Operator Errors

In Table 15.1-3 the first sensed event to initiate corrective action to the transient is the vessel high water level (Level 8) trip. Multiple level sensors are used to sense and detect when the water level reaches the Level 8 setpoint. At this point in the logic, a single failure will not initiate or prevent a turbine trip signal. Turbine trip signal transmission, however, is not built to single failure criterion. The result of a failure at this point would have the effect of delaying the pressurization "signature." High levels in the turbine's moisture separators will result in a trip of the unit before high moisture levels enter the low pressure turbine.

Scram trip signals from the turbine are designed such that a single failure neither initiates nor impedes a reactor scram trip initiation. See Section 15.9 for a discussion of this subject.

15.1.2.3 Core and System Performance

15.1.2.3.1 Mathematical Model

The predicted dynamic behavior has been determined using a computer simulated, analytical models of a generic direct-cycle BWR. The models are described in detail in Reference 15.0-4 (ODYN) and Reference 15.0-13 (TRACG). These computer models have been improved and verified through extensive comparison of their predicted results with BWR test data.

The nonlinear computer simulated analytical model is designed to predict associated transient behavior of this reactor. Some of the significant features of the ODYN model are:

a. An integrated one-dimensional core model is assumed which includes a detailed description of hydraulic feedback effects, axial power shape changes, and reactivity feedbacks.

b. The fuel is represented by an average cylindrical fuel and cladding node for each axial location in the core.

c. The steam lines are modeled by eight pressure nodes incorporating mass and momentum balances which will predict any wave phenomena present in the steam line during pressurization transient.

d. The core average axial water density and pressure distribution is calculated using a single channel to represent the heated active flow and a single channel to represent the bypass flow. A model, representing liquid and vapor mass and energy conservation, and mixture momentum conservation, is used to describe the thermal-hydraulic behavior. Changes in the flow split between the bypass and active channel flow are accounted for during transient events.

e. Principal controller functions such as feedwater flow, recirculation flow, reactor water level, and pressure and load demand, are represented together with their dominant nonlinear characteristics.

f. The ability to simulate necessary reactor protection system functions is provided.

g. The control systems and reactor protection system models are, for the most part, identical to those employed in the point reactor model, which is described in detail in Reference 15.0.4-2 and used in analysis for other transients.

The TRACG model has similar features except it is a three-dimensional model.

15.1.2.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with the plant conditions as tabulated in Table 15.0-2A.

This event is typically analyzed at the limiting EOC (all-rods-out) statepoint, and at the limiting conditions (i.e. core flow, feedwater temperature, etc.), which bound the allowable LGS operating domain (see Appendix 15B). The cycle-specific maximum feedwater system runout capability is specified, with 5% additional feedwater runout capability applied for conservatism. The results

presented (LGS Unit 1, Cycle 5) are based on a 149% runout capability (144% + 5%) (where 100% feedwater flow is defined as 15.0×10^6lb/hr).

15.1.2.3.3 Results

The simulated feedwater controller transient is shown in Figure 15.1-3. The high water level turbine trip and feedwater pump trip are initiated at approximately 8.6 seconds. Scram occurs simultaneously from stop valve closure and limits the neutron flux peak and fuel thermal transient so that no fuel damage occurs. MCPR remains considerably above the safety limit. The turbine bypass system opens to limit peak pressure at the bottom of the vessel to about 1218 psig.

Consequently, the nuclear system process barrier pressure limit is not endangered.

The bypass valves subsequently close to re-establish pressure control in the vessel during shutdown. The level would gradually drop to the low level isolation reference point, activating the RCIC/HPCI systems for long-term level control.

15.1.2.3.4 Consideration of Uncertainties

All systems utilized for protection in this transient were assumed to have the most conservative allowable response (e.g., relief setpoints, scram stroke time, and reactivity characteristics). Expected plant behavior is, therefore, expected to lead to a less severe transient.

15.1.2.4 Barrier Performance

As noted above, the consequences of this transient do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed; therefore, these barriers maintain their integrity and function as designed.

15.1.2.5 Radiological Consequences

While the consequence of this transient does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via MSRV operation. Because this activity is contained in the primary containment, there is no exposure to operating personnel. This transient does not result in an uncontrolled release to the environment, so the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release conditions. If purging of the containment is chosen, the release will be in accordance with established technical specifications and, at the worst, would only result in a small increase in yearly integrated exposure level.

15.1.2.6 Additional Transients Evaluated

Additional transients have been considered for LGS. Table 15.0-1A shows the peak transient responses for the various cases analyzed. For the ICF and the MELLL conditions, the FWCF event becomes more limiting due to the TBSOOS and the EOC-RPTOOS analysis assumptions. The fuel thermal margin results are within the acceptable limits for the fuel types analyzed. The sequence of events with an inoperative bypass system is shown on Table 15.1-3 and the transient parameters are on Figure 15.1-1. The MCPR values for these transients are also shown in Table 15.0-1A.

15.1.3 PRESSURE REGULATOR FAILURE - OPEN

15.1.3.1 Identification of Causes and Frequency Classification

15.1.3.1.1 Identification of Causes

The total steam flow rate to the main turbine resulting from a pressure regulator malfunction is limited by a maximum flow limiter imposed at the turbine controls. This limiter is set to limit maximum steam flow to approximately 115% NBR.

If the controlling regulator fails, the backup controller will take over control with a bumpless switchover. If both controllers fail to the open position, the turbine control valves can be fully opened and the turbine bypass valves can be partially or fully opened until the maximum steam flow is established.

15.1.3.1.2 Frequency Classification

This transient is categorized as an incident of moderate frequency.

15.1.3.2 Sequence of Events and System Operation

15.1.3.2.1 Sequence of Events

This is a non-limiting event that has not been reanalyzed for power rerate. The sequence of events presented in Table 15.1-4 are based on Cycle 1 conditions. An analysis of this event for rerate conditions is not expected to result in a change in the general trends and characteristics as shown.

Table 15.1-4 lists the sequence of events for Figure 15.1-4.

When a fault is detected with the controlling pressure regulator and preceded by spurious or erratic behavior of the controlling device, an automatic "bumpless" failover will occur to the back-up redundant pressure regulator controller. The operator does not have the ability to select the primary or backup controller. If both controllers fail to the open position, and if the reactor scrams as a result of the isolation caused by the low pressure at the turbine inlet in the run mode, the following is the sequence of operator actions expected during the course of the Once isolation occurs the pressure will increase to a point where the relief valves open. Operator actions for the case where high level (Level 8) trip occurs before the isolation are essentially identical. The operator should:

a. Monitor that all rods are in.

b. Monitor reactor water level and pressure.

c. Observe turbine coast-down and break vacuum before the loss of steam seals. Check turbine auxiliaries.

d. Observe that the reactor pressure relief valves open at their setpoint.

e. Observe that RCIC and HPCI initiate on low water level.

f. Secure both HPCI and RCIC when reactor pressure and level are under control.

g. Monitor reactor water level and continue cooldown per the normal procedure.

h. Complete the scram report and initiate a maintenance survey of pressure regulator before reactor restart.

15.1.3.2.2 System Operation

To simulate the expected sequence of events properly, the analysis of this transient assumes normal functioning of plant instrumentation and controls, plant protection, and reactor protection systems except as otherwise noted.

Initiation of HPCI and RCIC system functions will occur when the vessel water level reaches the Level 2 setpoint. Normal startup and actuation can take up to 30 seconds before full flow is realized. The 30 seconds is based on the cycle 1 conditions. This event was not reanalyzed for power rerate. If these events occur, they will follow sometime after the primary concerns of fuel thermal margin and overpressure effects have occurred, and are expected to be less severe than those already experienced by the system.

15.1.3.2.3 The Effect of Single Failures and Operator Errors

This transient leads to a loss of pressure control such that the increased steam flow demand causes a depressurization. Instrumentation for pressure sensing of the turbine inlet pressure is designed to be single failure proof for initiation of MSIV closure.

Reactor scram sensing, originating from limit switches on the turbine stop valves, is designed to be single failure proof. It is therefore concluded that the basic phenomenon of pressure decay is adequately terminated. See Section 15.9 for a detailed discussion of this subject.

15.1.3.3 Core and System Performance

15.1.3.3.1 Mathematical Model

The nonlinear dynamic model described in Reference 15.0-3 is used to simulate this transient.

15.1.3.3.2 Input Parameters and Initial Conditions

This transient is simulated by assuming both the primary and backup regulator outputs to a high value, which causes the turbine admission valves and the turbine bypass valves to open fully. Regulator failure with 135% steam flow was simulated as a worst case since 115% is the normal maximum flow limit.

A 5 second isolation valve closure instead of a 3 second closure is assumed when the turbine pressure decreases below the turbine inlet low pressure setpoint for main steam line isolation initiation. This is within the specification limits of the valve and represents a conservative assumption.

This analysis has been performed, unless otherwise noted, using Cycle 1 plant conditions as listed in Table 15.0-2.

15.1.3.3.3 Results

The results of this event are based on Cycle 1 conditions. An analysis of this event for current conditions is not expected to result in a change in the general trends and characteristics as shown.

A Pressure Regulator Failure-Open (PRFO), is non-limiting for fuel cladding integrity because the Critical Power Ratio (CPR) increases during the event, and they are not typically included in the scope of reload evaluations including uprate conditions and or raising the MSIV low pressure isolation setpoint. The following evaluation predicts that reactor vessel water level would swell during a PRFO transient; the depressurization would be terminated by a high level turbine trip.

Reactor vessel water level swell is difficult to predict and the reactor vessel water level swell portion of transient models have larger uncertainties than other portions of the transient models. Recent evaluations by GE with improved transient models have determined that the reactor vessel water level swell may not be sufficient to reach the high level trip, in which case the depressurization could be terminated by MSIV closure at the LPIS. The analysis of this scenario is provided In References 15.1-2, 15.1-3 and 15.1-4.

Figure 15.1-4 shows the response of important nuclear system variables for this transient. The water level rises to the high level trip setpoint and initiates trip of the main turbine and feedwater turbines. Closure of the turbine stop valves initiates scram and RPT. After the pressurization resulting from the turbine stop valve closure, pressure again drops and continues to drop until the turbine inlet pressure is below the low turbine pressure isolation setpoint when the main steam line isolation finally terminates the depressurization.

Reactor high level trip limits the duration and severity of the depressurization so that no significant thermal-stresses are imposed on the nuclear system process barrier. After the rapid portion of the transient is complete, the MSRVs operate intermittently to relieve the pressure rise that results from decay heat generation. No significant reductions in fuel thermal margins occur. Because the rapid portion of the transient results in only momentary depressurization of the nuclear system, the MSRVs need operate only to relieve the pressure increase caused by decay heat, the nuclear system process barrier is not threatened by high internal pressure for this pressure regulator malfunction.

15.1.3.3.4 Consideration of Uncertainties

If the maximum flow limiter were set higher or lower than normal, there would result a faster or slower loss in nuclear steam pressure. The rate of depressurization may be limited by the bypass capacity. For example, the turbine valves will open to the wide open state admitting slightly more than the rated steam flow, and with the limiter in this analysis set to fail at 135%, no more than 25% is expected to be bypassed. This is therefore not a limiting factor on this plant. If the rate of depressurization does change it will be terminated by the low turbine inlet pressure trip setpoint.

The depressurization rate has a proportional effect upon the voiding action of the core. If it is not large enough, the sensed vessel water level trip setpoint (Level 8) may not be reached and a turbine and feedwater pump trip will not occur in the transient. In this case, the turbine inlet pressure will drop below the low pressure isolation setpoint and the expected transient signature will conclude with an isolation of the main steam lines. The reactor will be shut down by the scram initiated from MSIV closure.

15.1.3.4 Barrier Performance

This is a non-limiting event that has not been reanalyzed for power rerate or for raising the MSIV low pressure isolation setpoint. The results presented are based on Cycle 1 conditions. An analysis of this event for rerate conditions is not expected to result in a change in the general trends and

characteristics as shown. Raising the MSIV low pressure isolation setpoint would terminate the event sooner and be less limiting.

Barrier performance analyses are not required since the consequences of this transient do not result in any temperature or pressure transient in excess of the criteria for which fuel, pressure vessel, or containment are designed. Peak pressure in the bottom of the vessel reaches 1165 psig which is below the ASME code limit of vessel dome pressure, 1375 psig for the RCPB. Vessel dome pressure reaches 1149 psig, just slightly below the setpoint of the second pressure relief group.

15.1.3.5 Radiological Consequences

While the consequence of this transient does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via MSRV operation. Because this activity is contained in the primary containment, there is no exposure to operating personnel. This transient does not result in an uncontrolled release to the environment, so the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release conditions. If purging of the containment is chosen, the release will be in accordance with established technical specifications and, at the worst, would only result in a small increase in the yearly integrated exposure level.

15.1.4 INADVERTENT MAIN STEAM RELIEF VALVE OPENING

15.1.4.1 Identification of Causes and Frequency Classification

15.1.4.1.1 Identification of Causes

Cause of inadvertent MSRV opening is attributed to malfunction of the valve or an operator initiated opening. Opening and closing circuitry at the individual valve level (as opposed to groups of valves) is subject to a single failure event. It is therefore simply postulated that a failure occurs and the transient is analyzed accordingly. Detailed discussion of the valve design is provided in Chapter 5.

15.1.4.1.2 Frequency Classification

This transient is categorized as an infrequent incident. However, it is analyzed as an incident of moderate frequency.

15.1.4.2 Sequence of Events and System Operation

15.1.4.2.1 Sequence of Events

This is a non-limiting event that has not been reanalyzed for the power rerate. The sequence of events is based on Cycle 1 conditions. An analysis of this event for rerate conditions is not expected to result in a change in the general trends and characteristics as shown.

Table 15.1-5 lists the sequence of events for this transient.

The plant operator must "reclose" the valve as soon as possible and check that reactor and turbine-generator output return-to-normal. If the valve cannot be closed, plant shutdown should be initiated.

The operator will have the time period between the valve first sticking full open and the bulk pool temperature reaching 110°F before he must scram the reactor to be in compliance with the Technical Specifications.

If it is assumed that the suppression pool is at its maximum operating temperature (95°F) and minimum operating volume with no pool cooling systems in operation when the valve first opens, the operator will have more than 6 minutes before the pool scram temperature of 110°F is reached. If the above worst case assumptions were relaxed, the time for operator action would increase.

Delaying the reactor scram to 10 minutes after the valve sticks full open would have no adverse effect on plant safety. Even though the suppression pool temperature would approach 120°F at the time of scram, the maximum allowable suppression pool temperature limits would not be exceeded.

15.1.4.2.2 System Operation

This transient assumes normal functioning of normal plant instrumentation and controls, specifically the operation of the pressure regulator and levels control systems.

15.1.4.2.3 The Effect of Single Failures and Operator Errors

Failure of additional components (e.g., pressure regulator, feedwater flow controller) is discussed elsewhere in this chapter.

15.1.4.3 Core and System Performance

15.1.4.3.1 Mathematical Model

The computer model used to simulate this transient is discussed in detail in Reference 15.1-1. It has been determined that this transient is not limiting from a core performance standpoint. Therefore, a qualitative presentation of results is described below.

15.1.4.3.2 Input Parameters and Initial Conditions

This event is based on Cycle 1 conditions (see Table 15.0-2).

For this event it is assumed that the reactor is operating at an initial power level of 3458 MWt when an MSRV is inadvertently opened. Flow through the valve at normal plant operating conditions stated above is approximately 7% of original rated steam flow.

15.1.4.3.3 Results

This is a non-limiting event that has not been reanalyzed for power rerate. The results presented are based on Cycle 1 conditions. An analysis of this event for current conditions is not expected to result in a change in the general trends and characteristics as shown.

The opening of an MSRV allows steam to be discharged into the suppression pool. The sudden increase in the rate of steam flow leaving the reactor vessel causes a mild depressurization transient.

The pressure regulator senses the nuclear system pressure decrease and within a few seconds closes the turbine control valve far enough to stabilize reactor vessel pressure at a slightly lower value, and reactor power settles at nearly the initial power level. Thermal margins decrease only slightly through the transient, and no fuel damage results from the transient. MCPR is essentially unchanged and therefore the safety limit margin is unaffected.

15.1.4.4 Barrier Performance

As discussed above, the transient resulting from an inadvertent MSRV opening is a mild depressurization which is within the range of normal load-following and therefore has no significant effect on RCPB and containment design pressure limits.

15.1.4.5 Radiological Consequences

While the consequence of this transient does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via MSRV operation. Because this activity is contained in the primary containment, there is no exposure to operating personnel. This transient does not result in an uncontrolled release to the environment, so the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release conditions. If purging of the containment is chosen, the release will be in accordance with the established Technical Specifications and, at the worst, would only result in a small increase in the yearly integrated exposure level.

15.1.5 SPECTRUM OF STEAM SYSTEM PIPING FAILURES INSIDE AND OUTSIDE OF CONTAINMENT IN A PWR

This event is not applicable to BWR plants.

15.1.6 INADVERTENT RHR SHUTDOWN COOLING OPERATION

15.1.6.1 Identification of Causes and Frequency Classification

15.1.6.1.1 Identification of Causes

At design power conditions no conceivable malfunction in the shutdown cooling system could cause temperature reduction.

If the reactor were critical or near critical in a startup or cooldown condition, a very slow increase in reactor power could result. A shutdown cooling malfunction leading to a moderator temperature decrease could result from misoperation of the cooling water controls for the RHR heat exchangers. The resulting temperature decrease would cause a slow insertion of positive reactivity into the core. If the operator did not act to control the power level, a high neutron flux reactor scram would terminate the transient without violating fuel thermal limits and without any measurable increase in nuclear system pressure.

15.1.6.1.2 Frequency Classification

Although no single failure could cause this transient, it is conservatively categorized as a transient of moderate frequency.

15.1.6.2 Sequence of Events and System Operation

15.1.6.2.1 Sequence of Events

A shutdown cooling malfunction leading to a moderator temperature decrease could result from misoperation of the cooling water controls for RHR heat exchangers. The resulting temperature decrease causes a slow insertion of positive reactivity into the core. Scram will occur before any thermal limits are reached if the operator does not take action. The sequence of events for this transient is shown in Table 15.1-1.

15.1.6.2.2 System Operation

A shutdown cooling malfunction causing a moderator temperature decrease must be considered in all operating states. However, this transient is not considered while at power operation since the nuclear system pressure is too high to permit operation of the RHR shutdown cooling mode.

No unique safety actions are required to avoid unacceptable safety results for transients as a result of a reactor coolant temperature decrease induced by misoperation of the shutdown cooling heat exchangers. In startup or cooldown operation, where the reactor is or nearly is critical, the slow power increase resulting from the cooler moderator temperature would be controlled by the operator in the same manner normally used to control power in the source or intermediate power ranges.

15.1.6.2.3 The Effect of Single Failures and Operator Errors

No single failures can cause this transient to be more severe. If the operator takes action, the slow power rise will be controlled in the normal manner. If no operator action is taken, scram will terminate the power increase before thermal limits are reached (Section 15.9).

15.1.6.3 Core and System Performance

The increased subcooling caused by misoperation of the RHR shutdown cooling mode could result in a slow power increase due to the reactivity insertion. This power rise would be terminated by a flux scram before fuel thermal limits are approached. Therefore, only a qualitative description is provided here.

15.1.6.4 Barrier Performance

As noted above, the consequences of this transient do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed, therefore, these barriers maintain their integrity and function as designed.

15.1.6.5 Radiological Consequences

Since this transient does not result in any fuel failures, no analysis of radiological consequences is required for this transient.

15.1.7 REFERENCES

15.1-1 R.B. Linford, "Analytical Methods of Plant Transient Evaluations for the General Electric Boiling Water Reactor," NEDO-10802, (February 1973).

15-1-2 General Electric "10 CFR 21 Reportable Condition Notification: Potential to Exceed Low Pressure Technical Specification Safety Limit," March 29, 2005.

15-1-3 NEDC-33743, Revision 0, "BWR Owner's Group Reload Analysis and Core Management Committee SC05-03 Analysis Report," GE Hitachi Energy, April 2012.

15-1-4 EC 400057, Revision 0, SC05-03 Assessment for Limerick, Units 1 and 2.

Table 15.1-1

SEQUENCE OF EVENTS FOR INADVERTENT RHR
SHUTDOWN COOLING OPERATION

TIME (min)	EVENT
0	Reactor at states B or D (Section 15.9) when RHR shutdown cooling inadvertently activated.
0-10	Slow rise in reactor power.
+10	Operator may take action to limit power rise. Flux scram will occur if no action is taken.

Table 15.1-2

SEQUENCE OF EVENTS FOR LOSS OF FEEDWATER HEATING

TIME (sec)	EVENT
0	Initiate a 100°F temperature reduction into the feedwater system.
25.0 (approx.)	Initial effect of unheated feedwater to raise core power level and steam flow.
65.0 (approx.)	Bypass valves open to accommodate the increasing steam flow.
120.0 (approx.)	New higher power, steady-state conditions reached

Table 15.1-3

SEQUENCE OF EVENTS FOR FEEDWATER CONTROLLER FAILURE

TIME (sec)	EVENT[1] (WITH TURBINE BYPASS)
0	Initiate simulated failure of feedwater controller to upper limit on feedwater flow.
8.4	Level 8 vessel level setpoint trips main turbine and feedwater pumps.
8.4	Reactor scram trip actuated from main turbine stop valve position switches.
8.4	RPT actuated by stop valve position switches.
8.6	Main turbine stop valves closed and turbine bypass valves start to open.
8.6	Recirculation pump motor circuit breakers open causing recirculation drive flow to start to coast down.
11.2	First group of SRVs open due to high pressure (May not occur at off-rated conditions).
TIME (sec)	**EVENT[2] (WITHOUT TURBINE BYPASS)**
0	Initiate simulated failure of feedwater controller to upper limit on feedwater flow.
8.3	Level 8 vessel level setpoint trips main turbine and feedwater pumps.
8.3(est)	Reactor scram trip actuated from main turbine stop valve position switches.
8.3	RPT actuated by stop valve position switches.
8.5	Turbine bypass valves fail to open.
8.5	Main turbine stop valves closed.
8.6	Recirculation pump motor circuit breakers open causing recirculation drive flow to coast-down.
10.5	First groups 1 to 3 actuated due to high pressure.

[1] See Figure 15.1-3.
[2] See Figure 15.1-1.

Table 15.1-4

SEQUENCE OF EVENTS FOR PRESSURE REGULATOR FAILURE[1]

TIME (sec)	EVENT
0	Simulate maximum limit flow to main turbine.
0.4	Main turbine bypass opens.
0.7(est)	Turbine control valves open wide.
4.7	Vessel water level (Level 8) trip initiates main turbine and feedwater turbine trips.
4.7	Main turbine stop valve position initiates reactor scram and RPT.
4.8	Turbine stop valves closed.
4.9	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
46.8	Main steam line isolation on low turbine inlet pressure.
51.8	MSIVs closed. Bypass valves remain open, exhausting steam in steam lines downstream of isolation valves.
52.0	RCIC AND HPCI systems initiation on low level (Level 2).
>100.0	Group 1 MSRVs actuate and cycle.

(1) See Figure 15.1-4.

NOTE: This is a non-limiting event that has not been re-analyzed for power rerate or for raising the MSIV low pressure isolation setpoint. The results of this event are based on Cycle 1 conditions. An analysis of this event for the rerate conditions is not expected to result in a change in the general trends and characteristics as shown. Raising the MSIV low pressure isolation setpoint would terminate the event sooner and be less limiting.

Table 15.1-5

SEQUENCE OF EVENTS FOR INADVERTENT MAIN STEAM RELIEF VALVE OPENING

TIME (sec)	EVENT
0	Initiate opening of one MSRV.
0.5(est)	MSRV flow reaches full flow.
15.0(est)	System establishes new steady-state operation.

NOTE: This is a non-limiting event that has not been re-analyzed for power rerate. The results of this event are based on Cycle 1 conditions. An analysis of this event for the rerate conditions is not expected to result in a change in the general trends and characteristics as shown.

15.2 INCREASE IN REACTOR PRESSURE

15.2.1 PRESSURE REGULATOR FAILURE - CLOSED

15.2.1.1 Identification of Causes and Frequency Classification

15.2.1.1.1 Identification of Causes

The Digital Electro-Hydraulic Control (DEHC) pressure regulator control function is performed via application software running on redundant controllers. The main steam pressure indications and pressure setpoint adjustments and indications are located on the HMI workstation of the turbine control panel. Each functional controller in the redundant pair executes the same application program, although only one controller at a time accesses the I/O and runs in the control mode. The partner processor runs in the backup mode. The transfer between the primary and the backup regulator controllers is automatic. The operator does not have the ability to select the primary or backup regulator controller. It is assumed, for the purposes of this transient analysis that a single failure occurs, erroneously causes the controlling regulator processor to close the main turbine control valves. Failure of the primary controlling regulator processor results in the automatic bumpless transfer between the primary and the backup regulator controllers, thereby preventing an increase in reactor pressure.

15.2.1.1.2 Frequency Classification

This transient is treated as a moderate frequency event.

15.2.1.2 Sequence of Events and System Operation

15.2.1.2.1 Sequence of Events

When a fault is detected with the controlling pressure regulator processor, as discussed in Section 15.2.1.1.1, an automatic "bumpless" failover will occur to the back-up redundant regulator controller. The pressure increase will be small, if any. Both regulators receive the same setpoint value from the operator input via the HMI, thus, pressure will be controlled at approximately the same value prior to the assumed failure.

15.2.1.2.2 Systems Operation

Normal plant instrumentation and control is assumed to function. This transient requires no protection system, or safeguard systems, operation.

15.2.1.2.3 The Effect of Single Failures and Operator Errors

The nature of the first assumed failure produces a slight pressure increase in the reactor until the backup processor gains control. The control system is designed to provide a bumpless transfer between control modes and various control functions throughout the reactor power range (0-100%), such as primary to backup pressure regulator controller, valve tests, and automatic cool down. Also, upon detection of a primary controller fault, the control of the I/O interface is automatically transferred to the backup controller. To minimize the effects from transferring control from the primary to backup regulator control processor (bumpless transfer), the algorithms track the output values, pass the information upstream, and apply the data during the first pass of execution. Each processor has its own network connection that is integrated

into the process module and provides complete redundancy. To ensure redundant communications, each processor in the redundant pair is attached to a different switch. This ensures that there is no single point of failure. The term "bumpless" is defined as not exceeding 2 psi as set forth for pressure control. This means that mode changes and switching of functions will not cause a step change in throttle pressure greater than 2 psi operating throttle pressure variations.

15.2.1.3 Core and System Performance

The disturbance is mild, similar to a pressure setpoint change, and no significant reductions in fuel thermal margins occur. This transient is much less severe than the generator and turbine trip transients described in Sections 15.2.2 and 15.2.3.

15.2.1.3.1 Mathematical Model

Qualitative evaluation provided only.

15.2.1.3.2 Input Parameters and Initial Conditions

Qualitative evaluation provided only.

15.2.1.3.3 Results

Response of the reactor during this primary pressure regulator control processor failure is such that the pressure change at the turbine inlet is small, and no pressure disturbance in the vessel. Thus, neutron flux and pressure trip margins will be maintained.

15.2.1.3.4 Consideration of Uncertainties

All systems utilized for protection in this transient were assumed to have the most conservative allowable response (e.g., relief setpoints, scram stroke time, and worth characteristics). Normal plant behavior is, therefore, expected to reduce the actual severity of the transient.

15.2.1.4 Barrier Performance

The consequences of this transient do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel or containment are designed. Therefore, these barriers maintain their integrity and function as designed.

15.2.1.5 Radiological Consequences

Because this transient does not result in any fuel failures, or any release of primary coolant to either the secondary containment or to the environment, there are no radiological consequences associated with this transient.

15.2.2 GENERATOR LOAD REJECTION

15.2.2.1 Identification of Causes and Frequency Classification

15.2.2.1.1 Identification of Causes

Fast closure of the turbine control valves is initiated whenever electrical grid disturbances occur that result in significant loss of electrical load on the generator. The turbine control valves are required to close as rapidly as possible to prevent excessive overspeed of the turbine-generator. Closure of the main turbine control valves will cause a sudden reduction in steam flow that results in an increase in system pressure and a reactor shutdown.

15.2.2.1.2 Frequency Classification

15.2.2.1.2.1 Generator Load Rejection

This transient is categorized as an incident of moderate frequency.

15.2.2.1.2.2 Generator Load Rejection with Bypass Failure

Frequency Basis: Thorough searches of domestic plant operating records have revealed three instances of bypass failure during 628 bypass system operations. This gives a probability of bypass failure of 0.0048. Combining the actual frequency of a generator load rejection with the failure rate of the bypass yields an event frequency of a generator load rejection with bypass failure of 0.0036/plant year.

15.2.2.2 Sequence of Events and System Operation

15.2.2.2.1 Sequence of Events

15.2.2.2.1.1 Generator Load Rejection - Turbine Control Valve Fast Closure

A loss of generator electrical load from high power conditions produces the sequence of events listed in Table 15.2-1.

15.2.2.2.1.2 Generator Load Rejection with Failure of Bypass

A loss of generator electrical load at high power with bypass failure produces the sequence of events listed in Table 15.2-2.

15.2.2.2.1.3 Identification of Operator Actions

The operator should:

a. Verify proper bypass valve operation.

b. Observe that the feedwater/level controls have maintained the reactor water level at a satisfactory value.

c. Observe that the pressure regulator is controlling reactor pressure at the desired value.

d. Record peak power and pressure.

e. Verify relief valve operation.

15.2.2.2.2 System Operation

15.2.2.2.2.1 Generator Load Rejection with Bypass

This is a non-limiting event that has not been reanalyzed for power rerate.

In order to properly simulate the expected sequence of events, the analysis of this transient assumes normal functioning of plant instrumentation and controls, plant protection, and reactor protection systems, unless stated otherwise.

Turbine control valve fast closure initiates a trip signal for power levels greater than 30% NBR. In addition, RPT is initiated. Both of these trip signals satisfy single failure criteria, and credit is taken for these protective features.

The nuclear pressure relief system, which operates the MSRVs independently when system pressure exceeds relief valve instrumentation setpoints, is assumed to function normally during the time period analyzed.

15.2.2.2.2.2 Generator Load Rejection with Failure of Bypass

This is the same as Section 15.2.2.2.2.1, except that failure of the main turbine bypass valves is assumed for the entire transient.

15.2.2.2.3 The Effect of Single Failures and Operator Errors

Mitigation of pressure increase, the basic nature of this transient, is accomplished by the RPS functions. Turbine control valves trip and RPT are designed to satisfy single failure criteria. An evaluation of the most limiting single failure (i.e., failure of the bypass system) was considered in this transient. Single failure analysis can be found in Section 15.9.

15.2.2.3 Core and System Performance

15.2.2.3.1 Mathematical Model

The computer models described in Section 15.1.2.3.1 are used to simulate this transient.

15.2.2.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with the plant conditions tabulated in Table 15.0-2A for rerate conditions.

The turbine EHC system detects load rejection before a measurable speed change takes place.

The closure characteristics of the turbine control valves are assumed to have a full stroke closure time, from fully open to fully closed, of 0.15 seconds.

Auxiliary power would normally be independent of any turbine- generator overspeed effects, and be continuously supplied at rated frequency as automatic fast transfer to auxiliary power supplies occurs. For the purposes of worse case analysis, the recirculation pumps are assumed to remain tied to the main generator, and thus increase in speed with the turbine-generator overspeed until tripped by the RPT system.

The reactor is operating in the manual flow control mode when load rejection occurs.

The bypass valve opening characteristics are simulated, using the specified delay together with the specified opening characteristic required for bypass system operation.

Actual closure of MSIVs as caused by low water level trip (Level 1), and actual flow from initiation of RCIC and HPCI core cooling system functions do not occur during the duration of the simulation. If these events occur, they will follow sometime after the primary concerns of fuel margin and overpressure effects have passed and are expected to result in effects less severe than those already experienced by the reactor system.

15.2.2.3.3 Results

15.2.2.3.3.1 Generator Load Rejection with Bypass

The results of this event are based on Cycle 1 conditions. An analysis of this event for current conditions is not expected to result in a change in the general trends and characteristics as shown.

Figure 15.2-1 shows the results of the generator trip from 104.3% rated power. Peak neutron flux rises to 178.5% of NBR conditions.

The average surface heat flux peaks at 101.2% of its initial value. The change in CPR for this event is only 0.03, and CPR does not significantly decrease below its initial value.

15.2.2.3.3.2 Generator Load Rejection with Failure of Bypass

Beginning with Cycle 8 of Unit 1, the turbine control valves (TCV) have been modified to operate in full arc admission. In this configuration the TCVs close sooner than the turbine stop valves to shut off steam flow. As a result, the Generator Load Rejection with Failure of Bypass event (LRNBP) is more limiting than the turbine trip with failure of bypass (TTNBP). Table 15.0-1A provides the results of the LRNBP analyses for several different conditions, including one for the TCVs in full arc admission configuration. Figure 15.2-2 depicts the transient response of various plant parameters following a LRNBP event. The LRNBP is also analyzed assuming the EOC-RPT function is inoperable to provide a basis for this possible mode of operation. A similar analysis has been performed to address power load unbalance (PLU) function failure. For cycle specific reload licensing analysis the LRNBP event is evaluated at the limiting operating domain condition (see Appendix 15B).

Additionally, an analysis of Generator Load Rejection and Turbine Trip events with simultaneous Failure of Bypass and End of Cycle Recirculation Pump Trip (EOC-RPT) was performed using the ODYN code. The Generator Load Rejection event bounds the turbine trip. Table 15.2-14 presents a summary of the initial conditions and significant results for the Generator Load Rejection with no bypass and no EOC-RPT event, while Figure 15.2-14 shows its time history.

15.2.2.3.4 Consideration of Uncertainties

The full stroke closure time of the turbine control valves of 0.15 seconds is conservative. Typically, actual closure time is more like 0.2 seconds. Thus, the shorter time chosen for closure results in a more severe pressurization effect.

All systems utilized for protection in this transient were assumed to have the poorest allowable response (e.g., relief setpoints, scram stroke time, and work characteristics). Anticipated plant behavior is, therefore, expected to reduce the actual severity of the transient.

15.2.2.4 Barrier Performance

15.2.2.4.1 Generator Load Rejection

Peak pressure remains within normal operating range and no threat to the barrier exists.

15.2.2.4.2 Generator Load Rejection with Failure of Bypass

As shown in Table 15.0-1A the peak nuclear system pressure at the bottom of the vessel remains well below the nuclear barrier transient pressure limit of 1375 psig.

15.2.2.5 Radiological Consequences

While the consequence of this transient does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via MSRV operation. Because this activity is restricted to the primary containment, there is no exposure to operating personnel. This transient does not result in an uncontrolled release to the environment, so the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release conditions. If purging of the containment is chosen, the release will be in accordance with established Technical Specifications and, at the worst, would only result in a small increase in the yearly integrated exposure level.

15.2.3 TURBINE TRIP

15.2.3.1 Identification of Causes and Frequency Classification

15.2.3.1.1 Identification of Causes

A variety of turbine or nuclear system malfunctions will initiate a turbine trip. Some examples are: moisture separator and heater drain tank high levels, operational lockout, loss of control fluid pressure, low condenser vacuum, and reactor high water level.

15.2.3.1.2 Frequency Classification

15.2.3.1.2.1 Turbine Trip with Bypass

This transient is categorized as an incident of moderate frequency. In defining the frequency of this transient, turbine trips that occur as a by-product of other transients, such as loss of condenser vacuum or reactor high level trip events, are not included. However, spurious low vacuum or high level trip signals, which cause an unnecessary turbine trip, are included in defining the frequency. In order to get an accurate event-by-event frequency breakdown, this division of initiating causes is required.

15.2.3.1.2.2 Turbine Trip with Failure of the Bypass

Frequency Basis: As discussed in Section 15.2.2.1.2.2, the failure rate of the bypass is 0.0048. Combining this with the turbine trip frequency of 1.33 events/plant year yields the frequency of 0.0064/plant year.

15.2.3.2 Sequence of Events and System Operation

15.2.3.2.1 Sequence of Events

15.2.3.2.1.1 Turbine Trip with Bypass

This event is non-limiting and was not reanalyzed at power rerate conditions. A turbine trip at high power with bypass produces the sequence of events listed in Table 15.2-3 for Cycle 1 conditions.

15.2.3.2.1.2 Turbine Trip with Failure of the Bypass

A turbine trip at high power with bypass failure produces the sequence of events listed in Table 15.2-4.

15.2.3.2.1.3 Identification of Operator Actions

The operator should:

a. Verify automatic transfer of buses supplied by generator to incoming power. If automatic transfer does not occur, manual transfer must be made.

b. Monitor and maintain reactor water level at required level.

c. Check turbine for proper operation of all auxiliaries during coast-down.

d. Depending upon conditions, initiate normal operating procedures for cooldown, or maintain pressure for restart purposes.

e. Put the mode switch in the shutdown position and verify all control rods are inserted.

f. Secure the RCIC operation if automatic initiation occurred due to low water level.

g. Monitor CRD positions and insert both the IRMs and SRMs.

h. Cool down the reactor per standard procedure if a restart is not intended.

15.2.3.2.2 System Operation

15.2.3.2.2.1 Turbine Trip with Bypass

All plant control systems maintain normal operation unless otherwise noted.

Turbine stop valve closure initiates a reactor trip via position signals to the protection system. Credit is taken for successful operation of the RPS.

Turbine stop valve closure initiates RPT, thereby terminating the jet pump drive flow.

The nuclear pressure relief system, which consists of the MSRVs that operate independently when system pressure exceeds relief valve setpoints, is assumed to function normally during the time period analyzed.

15.2.3.2.2.2 Turbine Trip with Failure of the Bypass

Same as Section 15.2.3.2.2.1 except that failure of the main turbine bypass system is assumed for the entire transient time period analyzed.

15.2.3.2.2.3 Turbine Trip at Low Power with Failure of the Bypass

Same as Section 15.2.3.2.2.1 except that failure of the main turbine bypass system is assumed.

It should be noted that, below 30% NBR power level a main stop valve trip inhibit signal is actuated by the first-stage pressure of the turbine. This is done to eliminate the stop valve trip signal from scramming the reactor, provided the bypass system functions properly. In other words, the bypass would be sufficient at this low power to accommodate a turbine trip without the necessity of shutting down the reactor. All other protection system functions remain operative as before, and credit is taken for those protection system trips.

15.2.3.2.3 The Effect of Single Failures and Operator Errors

15.2.3.2.3.1 Turbine Trips at Power Levels Greater Than 30% NBR

Mitigation of pressure increase, the basic nature of this transient, is accomplished by RPS functions. The main stop valve closure trip is designed to satisfy the single failure criterion.

15.2.3.2.3.2 Turbine Trips at Power Levels Less Than 30% NBR

This is the same as in Section 15.2.3.2.3.1, except RPT and stop valve closure trip is normally inoperative. Since protection is still provided by high flux, high pressure, etc., these factors will scram the reactor should a single failure occur.

15.2.3.3 Core and System Performance

15.2.3.3.1 Mathematical Model

The computer model described in Section 15.1.1.3.1 was used to simulate these transients with normal bypass operation. The infrequent event of turbine trip with bypass failure is simulated with the computer models in Section 15.1.2.3.1.

15.2.3.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions as tabulated in Table 15.0-2 for Cycle 1 and in Table 15.02A for rerate.

Turbine stop valves full stroke closure time is 0.1 second.

A reactor scram is initiated by position switches on the stop valves when the valves are not fully open. This stop valve trip signal is automatically bypassed when the reactor is below 30% NBR power level.

Reduction in core recirculation flow is initiated by position switches on the main stop valves that trip the recirculation pumps.

15.2.3.3.3 Results

15.2.3.3.3.1 Turbine Trip with Bypass

The results of this event are based on Cycle 1 conditions. An analysis of this event for current conditions is not expected to result in a change in the general trends and characteristics as shown.

A turbine trip with the bypass system operating normally is simulated at 104.3% NBR steam flow conditions in Figure 15.2-3.

Neutron flux increases rapidly because of the void reduction caused by the pressure increase. However, the flux increase is limited to 163.3% of rated value by the stop valve scram and the RPT system. Peak fuel surface heat flux does not exceed 102% of its initial value. The ΔCPR is less than that for turbine trip with assumed bypass failure (Section 15.2.3.3.3.2) and the MCPR remains well above the safety limit.

15.2.3.3.3.2 Turbine Trip with Failure of Bypass

The TTNBP event is caused by the rapid closure of the turbine stop valves. A reactor scram signal is immediately initiated from the position switches on the TSVs. The turbine bypass system is conservatively assumed to be inoperable.

With the TCVs configured for full arc admission, the TTNBP is bounded by the LRNBP event. The TTNBP event is also analyzed assuming the EOC-RPT function is inoperable to provide a basis for this possible mode of operation. The TTNBP transient results are summarized in Table 15.0-1A. The system response curves are shown in Figure 15.2-4. The fuel transient thermal and mechanical overpower results are below the design criteria.

15.2.3.3.3.3 Turbine Trip with Bypass Valve Failure, Low Power

This transient is less severe than a similar one at high power. Below 30% of rated power, the turbine stop valve and turbine control valve closure scrams are automatically bypassed. At these lower power levels, the turbine first-stage pressure is used to initiate the scram logic bypass. The scram which terminates the transient is initiated by high neutron flux or high vessel pressure. The bypass valves are assumed to fail; therefore, system pressure will increase until the pressure relief setpoints are reached. At this time, because of the relatively low power of this transient event, relatively few MSRVs will open to limit reactor pressure. Peak pressures are not expected to greatly exceed the MSRV setpoints, and will be significantly below the RCPB transient limit of 1375 psig. Peak surface heat flux and peak fuel center temperature remain at relatively low values, and MCPR remains well above the GETAB safety limit.

15.2.3.3.4 Consideration of Uncertainties

Uncertainties in these analyses involve protection system settings, system capacities, and system response characteristics. The most conservative values are used in all the analyses. For example:

a. Control rod scram speed based on conservative statistical aproach consistent with GEMINI methodology option A/B.

b. Scram worth shape for all rod-out conditions is assumed.

c. Minimum specified MSRV capacities are utilized for overpressure protection.

d. Setpoints of the MSRVs include errors (high) for all valves.

15.2.3.4 Barrier Performance

15.2.3.4.1 Turbine Trip with Bypass

NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

Peak pressure in the bottom of the vessel reaches 1196 psig, which is below the ASME code limit of 1375 psig for the RCPB. Vessel dome pressure does not exceed 1174 psig. The severity of turbine trips from low initial power levels decreases to the point where a scram can be avoided if auxiliary power is available and the power level is within bypass capability.

15.2.3.4.2 Turbine Trip with Failure of the Bypass

The MSRVs open and close sequentially as the stored energy is dissipated and the pressure falls below the setpoints of the valves. As shown in Table 15.0-1A, the peak nuclear system pressure at the vessel bottom remains below the RCPB transient pressure limit of 1375 psig.

15.2.3.4.2.1 Turbine Trip with Failure of Bypass at Low Power

Qualitative discussion is provided in Section 15.2.3.3.3.3.

15.2.3.5 Radiological Consequences

Although the consequence of this transient does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via MSRV operation. Because this activity is contained in the primary containment, there is no exposure to operating personnel. This transient does not result in an uncontrolled release to the environment, so the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release conditions. If purging of the containment is chosen, the release will be in accordance with established Technical Specifications and, at the worst, would only result in a small increase in the yearly integrated exposure level.

15.2.4 MSIV CLOSURES

15.2.4.1 Identification of Causes and Frequency Classification

15.2.4.1.1 Identification of Causes

Various steam line and nuclear system malfunctions, or operator actions, can initiate MSIV closure. Examples are: low steam line pressure, high steam line flow, low water level, or manual action.

15.2.4.1.2 Frequency Classification

15.2.4.1.2.1 Closure of All Main Steam Isolation Valves

This transient is categorized as an incident of moderate frequency. To define the frequency of this transient, as an initiating transient and not the byproduct of another transient, only the following contribute to the frequency: manual action (purposely or inadvertent), spurious signals such as low pressure, low reactor water level, low condenser vacuum, etc.; and, finally, equipment malfunctions such as faulty valves or operating mechanisms. A closure of one MSIV may cause an immediate closure of all the other MSIVs, depending upon reactor conditions. If this occurs, it is also included in this category. During the MSIV closure, position switches on the valves provide a reactor scram if the valves in three or more main steam lines are not fully open, except for interlocks which permit proper plant startup. Protection system logic, however, permits the test closure of one valve without initiating scram from the position switches.

15.2.4.1.2.2 Closure of One Main Steam Isolation Valve

This transient is categorized as an incident of moderate frequency. RPS logic allows for one MSIV at a time to be closed without generating a half scram signal. Operator error or equipment malfunction may cause a single MSIV to be closed inadvertently. If reactor power is greater than approximately 90% when this occurs, a high flux scram or high steam line flow scram may result. If all MSIVs close as a result of the single closure, the transient is considered as a closure of all MSIVs.

15.2.4.2 Sequence of Events and System Operation

15.2.4.2.1 Sequence of Events

This is a non-limiting event that has not been reanalyzed for power rerate. The sequence of events is Table 15.2-5 is based on Cycle 1 conditions. The general trend and characteristics shown here are not expected to change for current conditions.

Table 15.2-5 lists the sequence of events for Figure 15.2-5.

The following is the sequence of operator actions expected during the course of the transient, assuming no restart of the reactor. The operator should:

a. Observe that all rods have been inserted.

b. Observe that the relief valves have opened for reactor pressure control.

c. Check that RCIC/HPCI automatically starts on the impending low reactor water level condition.

d. Switch the feed pump controllers to the manual position.

e. When the reactor vessel level has recovered to a satisfactory level, secure RCIC/HPCI.

f. When the reactor pressure has decayed sufficiently, initiate shutdown cooling.

g. Before resetting the MSIV isolation, determine the cause of valve closure.

h. Observe turbine coast-down and break vacuum before the loss of sealing steam. Check turbine-generator auxiliaries for proper operation.

j. Reset and open MSIVs if conditions warrant and assure that the pressure regulator setpoint is above vessel pressure.

15.2.4.2.2 System Operation

15.2.4.2.2.1 Closure of All Main Steam Isolation Valves

MSIV closures initiate a reactor scram trip through position signals to the protection system. Credit is taken for successful operation of the protection system.

The nuclear pressure relief system, which opens the MSRVs when system pressure exceeds relief valve setpoints, is assumed to function normally during the time period analyzed.

All plant control systems maintain normal operation unless otherwise noted.

15.2.4.2.2.2 Closure of One Main Steam Isolation Valve

The closure of a single MSIV at any given time will not initiate a reactor scram. This is because the valve position scram trip logic is designed to accommodate single valve operation and testability during normal reactor operation at limited power levels. Credit is taken for the operation of the pressure and flux signals to initiate a reactor scram.

All plant control systems maintain normal operation unless otherwise noted.

15.2.4.2.3 The Effect of Single Failures and Operator Errors

Mitigation of pressure increase is accomplished by initiation of the reactor scram via MSIV position switches and the protection system. MSRVs also operate to limit system pressure. All of these functions are designed to single failure criteria, and additional single failures would not alter the results of this analysis.

Failure of a single MSRV to open is not expected to have any significant effect. Such a failure is expected to result in less than a 20 psi increase in the maximum vessel pressure rise. The peak pressure will still remain considerably below 1375 psig. The design basis and performance of the pressure relief system is discussed in Section 5.2.

15.2.4.3 Core and System Performance

15.2.4.3.1 Mathematical Model

The computer model described in Section 15.1.1.3.1 was used to simulate these transient events.

15.2.4.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with plant conditions tabulated in Table 15.0-2.

The MSIV closing time is adjustable between 3 and 10 seconds. The worst case, the 3 second closure time, is assumed in this analysis.

Position switches on the valves initiate a reactor scram when the valves are not fully open. Closure of these valves inhibits steam flow to the feedwater turbines, terminating feedwater flow.

Because of the loss of feedwater flow, water level within the vessel decreases sufficiently to initiate the HPCI and RCIC systems.

15.2.4.3.3 Results

15.2.4.3.3.1 Closure of All Main Steam Isolation Valves

This is a non-limiting event that has not been reanalyzed for power rerate. The results of this event are based on Cycle 1 conditions. An analysis of this event for current conditions is not expected to result in a change in the general trends and characteristics as shown.

Figure 15.2-5 shows the changes in important nuclear system variables for the simultaneous isolation of all main steam lines while the reactor is operating at 104.3% of NBR steam flow. Peak neutron flux reaches 190.9% of rated value in the first few seconds of the event. At the time of peak neutron flux, the nonlinear valve closure becomes a strong effect, and the conservative scram characteristic assumption has not yet allowed credit for the full shutdown of the reactor. As pressure increases, recirculation pumps trip on the high vessel pressure.

Water level decreases cause initiation of the HPCI and RCIC systems. Although there is a delay of up to 30 seconds before the water supply enters the vessel, there is no change in the thermal margins. The 30 seconds is based on cycle 1 conditions. This event was not reanalyzed for power rerate.

15.2.4.3.3.2 Closure of One Main Steam Isolation Valve

This is a non-limiting event that has not been reanalyzed for power rerate. The results of this event are based on Cycle 1 conditions. An analysis of this event for current conditions is not expected to result in a change in the general trends and characteristics as shown.

RPS logic is such that only one isolation valve at a time can be closed without generating a half scram signal. With a 3 second closure of one MSIV with reactor power greater than approximately 90%, the steam flow disturbance may raise vessel pressure and reactor power enough to initiate a high neutron flux scram. This transient is considerably milder than the closure of all MSIVs at power.

No quantitative analysis is furnished for this transient. However, no significant change in thermal margins is experienced, and no fuel damage occurs. Peak pressure remains below MSRV setpoints.

For testing purposes, one MSIV at a time is partially slow closed using a test push button to verify the RPS logic.

Inadvertent closure of one or all of the isolation valves while the reactor is shut down (such as operating state C, as defined in Section 15.9) will produce no significant transient. Closures during plant heatup (operating state D) will be less severe than the maximum power cases (maximum stored and decay heat) discussed in Section 15.2.4.3.3.1.

15.2.4.3.4 Consideration of Uncertainties

Uncertainties in these analyses involve protection system settings, system capacities, and system response characteristics. In all cases, the most conservative values are used in the analyses. For example:

a. Slowest allowable control rod scram motion is assumed.

b. Scram worth shape for all rod-out conditions is assumed.

c. Minimum specified MSRV capacities are utilized for overpressure protection.

d. MSRV setpoints are assumed to be 3% higher than the valves' nominal setpoints. Additionally, Unit 2, cycle 4 parameters were used for the performance of the 3% analysis (Reference 5.3-10).

15.2.4.4 Barrier Performance

15.2.4.4.1 Closure of All Main Steam Isolation Valves

The MSRVs begin to open within the first few seconds after the start of isolation. The valves close sequentially as the stored heat is dissipated, but continue to discharge the decay heat intermittently. Peak pressure at the vessel bottom reaches 1220 psig, clearly below the pressure limits of the RCPB. Peak pressure in the main steam line is 1185 psig.

15.2.4.4.2 Closure of One Main Steam Isolation Valve

No significant effect is imposed on the RCPB, since if closure of the valve occurs at an unacceptably high operating power level, a flux or pressure scram will result. The main turbine bypass system will continue to regulate system pressure through the other three "live" steam lines.

15.2.4.5 Radiological Consequences

While the consequence of this transient does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via MSRV operation. Because this activity is contained in the primary containment, there is no exposure to operating personnel. This transient does not result in an uncontrolled release to the environment, so the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release conditions. If purging of the containment is chosen, the release will be in accordance with

established Technical Specifications and, at the worst, would only result in a small increase in the yearly integrated exposure level.

15.2.5 LOSS OF CONDENSER VACUUM

15.2.5.1 Identification of Causes and Frequency Classification

15.2.5.1.1 Identification of Causes

Various system malfunctions that can cause a loss of condenser vacuum are designated in Table 15.2-6.

15.2.5.1.2 Frequency Classification

This transient is categorized as an incident of moderate frequency.

15.2.5.2 Sequence of Events and System Operation

15.2.5.2.1 Sequence of Events

This event was not reanalyzed for power rerate. The sequence of events in Table 15.2-7 is based on Cycle 1 conditions.

Table 15.2-7 lists the sequence of events for Figure 15.2-6.

The operator should:

a. Verify automatic transfer of buses supplied by generator to incoming power. If automatic transfer has not occurred, manual transfer must be made.

b. Monitor and maintain reactor water level at required level.

c. Check turbine for proper operation of all auxiliaries during coast-down.

d. Depending upon conditions, initiate normal operating procedures for cooldown, or maintain pressure for restart purposes.

e. Put the mode switch in the STARTUP position before the reactor pressure decays to the turbine inlet low pressure setpoint.

f. Secure RCIC operation if automatic initiation occurred due to low water level.

g. Monitor CRD positions and insert both the IRMs and SRMs.

h. Cool down the reactor following standard procedures if a restart is not intended.

15.2.5.2.2 System Operation

In establishing the expected sequence of events and simulating the plant performance, it was assumed that normal functioning occurred in the plant instrumentation and controls, and plant protection and reactor protection systems.

Tripping functions associated with a loss of main turbine condenser vacuum are listed in Table 15.2-8.

15.2.5.2.3 The Effect of Single Failures and Operator Errors

This transient does not lead to a general increase in reactor power level due to the protection system initiating a scram.

Failure of the integrity of the offgas treatment system is considered to be an accident situation and is described in Section 15.7.1.

Single failures will not affect the vacuum monitoring and turbine trip devices which are redundant. The protective sequences of the anticipated operational transient are shown to be single failure proof (Section 15.9).

15.2.5.3 Core and System Performance

15.2.5.3.1 Mathematical Model

The computer model described in Section 15.1.1.3.1 was used to simulate this transient event.

15.2.5.3.2 Input Parameters and Initial Conditions

This analysis was performed with plant conditions tabulated in Table 15.0-2 unless otherwise noted.

Turbine stop valves full stroke closure time is 0.1 second.

A reactor scram is initiated by position switches on the stop valves when the valves are not fully open. This stop valve closure trip signal is automatically bypassed when the reactor is below 30% NBR power level.

The analysis presented here is a hypothetical case with a conservative 2 in. Hg/sec vacuum decay rate. The bypass system was assumed to be available for several seconds by simulating bypass valve closure at a vacuum level of 10 inches Hg less than the stop valve closure vacuum level.

15.2.5.3.3 Results

This is a non-limiting event that has not been reanalyzed for power rerate. The results of this event are based on Cycle 1 conditions. An analysis of this event for current conditions is not expected to result in a change in the general trends and characteristics as shown.

Under this hypothetical 2 in. Hg/sec vacuum decay condition, the turbine bypass valve and MSIV closure would follow main turbine and feedwater turbine trips about 5 seconds after being initiated by the transient. This transient, therefore, is similar to a normal turbine trip with bypass. The effect of MSIV closure tends to be minimal, since the closure of main turbine stop valves, and subsequently the bypass valves, has already shut off the main steam line flow. Figure 15.2-6 shows the transient expected for this event. It is assumed that the plant is initially operating at 105% NBR steam flow conditions. Peak neutron flux reaches 160.9% of NBR power, while average fuel surface heat flux reaches 101.9% of rated value. MSRVs open to limit the pressure rise, then sequentially reclose as the stored energy is dissipated.

15.2.5.3.4 Consideration of Uncertainties

The reduction, or loss, of vacuum in the main condenser sequentially trip the main and feedwater turbines, and close the MSIVs and bypass valves. While these are the major events occurring, other resultant actions will include scram (from stop valve closure) and bypass opening with the main turbine trip. Because the protective actions are actuated at various levels of condenser vacuum, the severity of the resulting transient is directly dependent upon the rate at which the vacuum is lost. Normal loss of vacuum, due to loss of cooling water pumps or steam jet air ejector problems, produces a very slow rate of loss that is timed in minutes, not seconds (Table 15.2-6). If corrective actions by the reactor operators are not successful, then sequential trips of the main and feedwater turbines and, ultimately, complete isolation by closing the MSIVs and the bypass valves (opened with the main turbine trip), will occur.

A faster rate of loss of the condenser vacuum would shorten the time for the scram and reduce the overall effectiveness of the bypass valves since they would be closed more quickly.

Other uncertainties in these analyses involve protection system settings, system capacities, and system response characteristics.

In all cases, the most conservative values are used in the analyses. For example:

a. Slowest allowable control rod scram motion is assumed.

b. Scram worth shape for all rod-out conditions is assumed.

c. Minimum specified MSRV capacities are utilized for overpressure protection.

d. Setpoints of the MSRVs are assumed to be at the upper limit of Technical Specifications for all valves.

15.2.5.4 Barrier Performance

Peak nuclear system pressure is 1194 psig at the vessel bottom. The overpressure transient is below the RCPB transient pressure limit of 1375 psig. Vessel dome pressure does not exceed 1172 psig. A comparison of these values to those for turbine trip with bypass failure at high power shows the similarities between these two transients. The prime differences are the loss of feedwater and main steam line isolation, and the resulting low water level trips.

15.2.5.5 Radiological Consequences

While the consequence of this transient does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via MSRV operation. Because this activity is contained in the primary containment, there is no exposure to operating personnel. This transient does not result in an uncontrolled release to the environment, so the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release conditions. If purging of the containment is chosen, the release will be in accordance with established Technical Specifications and, at the worst, would only result in a small increase in the yearly integrated exposure level.

15.2.6 LOSS OF AC POWER

15.2.6.1 Identification of Causes and Frequency Classification

15.2.6.1.1 Identification of Causes

15.2.6.1.1.1 Loss of Auxiliary Power Transformers

The loss of all plant auxiliary buses due to transformer failure would require the simultaneous loss of three separate auxiliary transformers: the 1 Unit Auxiliary, the 10 Station Auxiliary, and the 20 Regulating transformers. The simultaneous loss of all three transformers is not considered credible without a common mode failure initiating event. Under this scenario, the plant sees a loss of all grid connections which is analyzed in the following sections.

15.2.6.1.1.2 Loss of All Grid Connections

Loss of all grid connections can result from major shifts in electrical loads, seismic events, loss of loads, lightning, storms, wind, etc., that contribute to electrical grid instabilities. These instabilities cause equipment damage if unchecked. Protective relay schemes automatically disconnect electrical sources and loads to mitigate damage and regain electrical grid stability.

15.2.6.1.2 Frequency Classification

15.2.6.1.2.1 Loss of All Grid Connections

This transient disturbance is categorized as an incident of moderate frequency.

15.2.6.2 Sequence of Events and System Operation

15.2.6.2.1 Sequence of Events

15.2.6.2.1.1 Loss of All Grid Connections

This is a non-limiting event that has not been reanalyzed for power rerate. The results of this event are based on Cycle 1 conditions. An analysis of this events for current conditions is not expected to result in a change in the general trends and characteristics as shown.

Table 15.2-10 lists the sequence of events for Figure 15.2-8.

15.2.6.2.1.2 Identification of Operator Actions

The operator should maintain the reactor water level by use of the RCIC or HPCI system, control reactor pressure by use of the relief valves, and verify that the turbine dc oil pump is operating satisfactorily to prevent turbine bearing damage. The operator should also verify proper switching and loading of the emergency diesel generators.

The following is the sequence of operator actions expected during the course of the events when no immediate restart is assumed. The operator should:

a. Following the scram, verify all rods-in.

b. Check that diesel generators start and carry the vital loads.

c. Check that both RCIC and HPCI start when reactor vessel level drops to the initiation point after the relief valve opens.

d. Break vacuum before the loss of sealing steam occurs.

e. Check turbine-generator auxiliaries during coast-down.

f. When both the reactor pressure and level are under control, secure both HPCI and RCIC as necessary.

g. Continue cooldown following normal procedures.

15.2.6.2.2 System Operation

15.2.6.2.2.1 Loss of All Grid Connections

This transient analysis, unless otherwise stated, assumes and takes credit for normal functioning of plant instrumentation and controls, and plant protection and reactor protection systems.

The loss of all grid connections causes the loss of all auxiliary power. This transient consists of a generator load rejection and recirculation pump trip at time t=0. The load rejection immediately closes the turbine control valves and causes a scram.

15.2.6.2.3 The Effect of Single Failures and Operator Errors

Loss of all connections to the grid leads to a turbine trip due to load rejection and an immediate scram due to turbine control valve fast closure. Additional failures of other systems designed to protect the reactor would not result in effects different from those reported. Failures of the protective systems have been considered and satisfy single failure criteria, so no change in analyzed consequences is expected. See Section 15.9 for details on single failure analysis.

15.2.6.3 Core and System Performance

15.2.6.3.1 Mathematical Model

The computer model described in Section 15.1.1.3.1 was used to simulate this transient.

Operation of the RCIC or HPCI systems is not included in the simulation of this transient, since startup of these pumps does not permit flow in the time period of this simulation.

15.2.6.3.2 Input Parameters and Initial Conditions

15.2.6.3.2.1 Loss of All Grid Connections

These analyses have been performed, unless otherwise noted, with the plant conditions tabulated in Table 15.0-2, and under the assumed systems constraints described in Section 15.2.6.2.2.

15.2.6.3.3 Results

15.2.6.3.3.1 Loss of All Grid Connections

This is a non-limiting event that has not been reanalyzed for power rerate. The results of this event are based on Cycle 1 conditions. An analysis of this event for current conditions is not expected to result in a change in the general trends and characteristics as shown.

Loss of all grid connections causes simultaneous generator load rejection and loss of all auxiliary power. It essentially takes on the characteristic response of the standard full load rejection discussed in Section 15.2.2. Figure 15.2-8 graphically shows the simulated transient. Peak neutron flux reaches 178.5% of NBR power while fuel surface heat flux peaks at 101.3% of initial value.

15.2.6.3.4 Consideration of Uncertainties

The most conservative characteristics of protection features are assumed. Any actual deviations in plant performance are expected to make the results of this transient less severe.

Operation of the RCIC or HPCI systems is not included in the simulation of the first 50 seconds of this transient. Startup of these pumps occurs in the latter part of this time period, but the systems have no significant effect on the results of this transient.

Following turbine control valve closure, the reactor pressure is expected to increase until the MSRV setpoints are reached. During this time the valves operate in a cyclic manner to discharge the decay heat to the suppression pool.

15.2.6.4 Barrier Performance

15.2.6.4.1 Loss of All Grid Connections

MSRVs open in the pressure relief mode of operation as the pressure increases beyond their setpoints. The vessel bottom peak pressure is well below the vessel pressure limit of 1375 psig.

15.2.6.5 Radiological Consequences

While the consequence of this transient does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via MSRV operation. Because this activity is contained in the primary containment, there is no exposure to operating personnel. This transient does not result in an uncontrolled release to the environment, so the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release conditions. If purging of the containment is chosen, the release will be in accordance with established Technical Specifications and, at the worst, would only result in a small increase in the yearly integrated exposure level.

15.2.7 LOSS OF FEEDWATER FLOW

The Loss of Feedwater Flow (LOFW) event represents the design basis for the performance of the reactor core isolation cooling (RCIC) system. The following criteria are applied to this event:

1) The RCIC system shall maintain sufficient water level inside the core shroud to assure that the top of active fuel remains covered throughout the event.

2) The RCIC system shall maintain wide range sensed reactor water level high enough that the very low level instrument trip setpoint (Level 1) for low pressure emergency core cooling system initiation and MSIV closure is not activated.

This transient event does not pose any direct challenge to the reactor vessel or core in terms of a power or pressure increase. All unacceptable safety results are avoided. However, it is included in the evaluation to provide assurance that sufficient makeup water capability is available to keep the core covered when all normal feedwater flow is lost.

15.2.7.1 Identification of Causes and Frequency Classification

15.2.7.1.1 Identification of Causes

A loss of feedwater flow could occur due to pump failures, feedwater controller failures, operator errors, or reactor system variables such as a high vessel water level (Level 8) trip signal.

15.2.7.1.2 Frequency Classification

This transient disturbance is categorized as an incident of moderate frequency.

15.2.7.2 Sequence of Events and System Operation

15.2.7.2.1 Sequence of Events

Table 15.2-11 lists the sequence of events for Figures 15.2-9A and 15.2-9B.

The operator should verify RCIC and HPCI actuation, so that water inventory is maintained in the reactor vessel. The operator should also monitor reactor water level, pressure control, and turbine-generator auxiliaries during shutdown.

The following is the sequence of operator actions expected during the course of the event when no immediate restart is assumed. The operator should:

a. Verify that all rods are in, following the scram.

b. Verify the initiation of HPCI and RCIC.

c. Verify that the recirculation pumps trip on reactor low level.

d. Secure HPCI when reactor level and pressure are under control.

e. Continue operation of the RCIC until decay heat diminishes to a point where the RHR system can be put into service.

f. Monitor the turbine coast-down, breaking vacuum as necessary.

15.2.7.2.2 System Operation

Loss of feedwater flow results in a proportional reduction of vessel inventory, causing the vessel water level to drop. The first corrective action is the low level (Level 3) trip actuation. RPS responds within 1.05 seconds after reaching this trip level to scram the reactor. The 1.05 second total response

time is equal to the level sensor response time (1.0 seconds) plus the RPS logic delay time (0.05 seconds). The low level (Level 3) trip function meets the single failure criterion.

Pressure control is maintained by the turbine bypass system, since the MSIVs remain open.

Because of an additional steam flow induced process measurement error in the Level 3 scram, the timing values in Table 15.2-11 following Low water level scram based on the L3 Analytical Limit are slightly different. However, as described in Reference 15.2-4, the impact of the change is not significant.

15.2.7.2.3 The Effect of Single Failures and Operator Errors

The nature of this transient, as explained above, results in a lowering of vessel water level. Key corrective actions to shut down the reactor are automatic, and designed to satisfy the single failure criterion.

15.2.7.3 Core and System Performance

15.2.7.3.1 Mathematical Model

The computer model described in Reference 6.3.7 was used to simulate this transient.

15.2.7.3.2 Input Parameters and Initial Conditions

This analysis has been performed, unless otherwise noted, with plant conditions as described in Section 6.3.3.

15.2.7.3.3 Results

Feedwater flow termination results in a decrease in subcooling, causing a reduction in core power level and pressure. As power level is lowered, the turbine steam flow starts to drop off because the pressure regulator is attempting to maintain pressure. Water level continues to drop until the vessel level (Level 3) scram trip setpoint is reached, whereupon the reactor is shut down. The trip of the recirc pumps occurs at approximately 13 seconds (after reactor scram) due to vessel water dropping to the Level 2 trip setpoint. Also at this time RCIC operation is initiated. For this analysis the HPCI system is assumed to be unavailable. MCPR remains considerably above the safety limit since increases in heat flux are not experienced.

The timing values in Table 15.2-11 following Low water level scram based on the L3 Analytical Limit are slightly different. However, as described in Reference 15.2-4, the impact of the change is not significant.

Water level in the annulus slowly decreases until the boil off from decay heat is matched by the RCIC makeup flow. The LOFW analysis (Reference 15.2.2) assumed 3622 MWt for an initial core thermal power. For these conditions the minimum water level in the annulus region is predicted to reach a minimum of 6.5 feet above the level 1 setpoint, occurring at approximately 800 seconds after the start of the event. Since natural recirculation flow continues through the core, the water level inside the shroud is maintained within the separator elevation.

15.2.7.3.4 Consideration of Uncertainties

EOC scram characteristics are assumed.

This transient is most severe from high power conditions, because the rate of level decrease is greatest, and the amounts of stored and decay heat to be dissipated are highest. As noted the LOFW analysis was conservatively performed at a power level of 3622 MWt. Furthermore, the HPCI systems was assumed to be unavailable. The RCIC system is assumed to inject at rated flow 55 seconds after the level 2 initiation signal.

An additional steam flow induced process measurement error in the Level 3 scram was accounted for in the Loss of Normal Feedwater event. A lowering in the Level 3 Analytical Limit (AL) setpoint was calculated in Reference 15.2-4. It was determined that adequate margin exists to Top of Active Fuel (TAF) uncovery while considering a bounding process measurement error applicable for this event. The consequences of lowering the AL is a bounding reduction in minimum water level in the upper plenum of 12 inches and a bounding reduction in minimum water level of 12 inches in the vessel downcomer region as discussed in Reference 15.2-4. The analysis also shows significant margin to the TAF. The results of the analysis are applicable for power levels up to extended (20%) Power Uprate (3952 MWt). The impact of the change is not significant, and no event descriptions or conclusions in the UFSAR need to be modified.

15.2.7.4 Barrier Performance

The consequences of this transient do not result in a temperature or pressure transient. Therefore, the RCPB is not threatened.

15.2.7.5 Radiological Consequences

Since this transient does not result in fuel failures or release of reactor coolant, there are no radiological consequences associated with the transient.

15.2.8 FEEDWATER LINE BREAK

Refer to Section 15.6.6

15.2.9 FAILURE OF RHR SHUTDOWN COOLING

Normally, in evaluating component failure considerations associated with the RHR shutdown cooling mode of operation, active pumps or instrumentation (all of which are redundant for safety system portions) would be assumed to be the likely failed equipment. For purposes of analysis, the single recirculation loop suction valve to the redundant RHR loops is assumed to fail. This failure would, of course, still leave four complete RHR loops for LPCI, or two RHR loops for LPCI and two loops for pool, and containment cooling minus the normal RHR shutdown cooling loop connection. Although the valve could be manually opened, it is assumed to be failed indefinitely. If it is now assumed that the single active failure criterion is applied, the plant operator has at least one complete RHR loop with a heat exchanger available.

Recent analytical evaluations of this transient have required additional worst case assumptions. These include:

a. Loss of all offsite ac power.

b. Utilization of safety shutdown equipment only.

c. Operator involvement only after 10 minutes after coincident assumptions.

Incorporation of these assumptions changes the initial incident (malfunction of RHR suction valve) from a moderate frequency incident to a classification in the design basis accident status. However, the transient is evaluated as a moderate frequency event with its subsequent limits.

During cold shutdown or refueling operation conditions, four subsystems of shutdown cooling exist, comprised of the A heat exchanger and A RHR pump, A heat exchanger and C RHR pump, B heat exchanger and B RHR pump, and B heat exchanger and D RHR pump. If two subsystems of shutdown cooling are required to be operable per Technical Specifications and both subsystems are associated with the same heat exchanger, a failure of the shutdown cooling discharge valve or discharge check valve associated with that heat exchanger may require use of the alternate vessel return flowpath, if manual repair of the valve can not be effected. This single failure is considered to be bounded by the single failure of the recirculation loop suction valve to the redundant RHR loops described above in that mitigating actions required to be taken in the event of a suction valve failure (ADS/relief valve with alternate shutdown cooling flowpath) exceed the required actions for a discharge valve failure. Further, a loss of electical power to the shutdown cooling discharge valve following the initial establishment of shutdown cooling would not require a change in cooling flowpath as the motor-operated valve fails in-place, and would be positioned for normal shutdown cooling return.

15.2.9.1 Identification of Causes and Frequency Classification

15.2.9.1.1 Identification of Causes

The plant is operating at 3528 MWt when a long-term LOOP occurs, causing multiple MSRV actuation (Section 15.2.6) and subsequent heatup of the suppression pool. Reactor vessel depressurization is initiated to bring the reactor pressure to approximately 75 psig. Concurrent with the LOOP, an additional single failure occurs which prevents the operator from establishing the normal shutdown cooling path through the RHR shutdown cooling lines. The operator then establishes a shutdown cooling path for the vessel through the ADS valves.

15.2.9.1.2 Frequency Classification

This transient is evaluated as a moderate frequency event. However, for the following reasons it could be considered an infrequent incident:

a. No RHR valves have failed in the shutdown cooling mode in BWR total operating experience.

b. The set of conditions evaluated is for multiple failure as described above and is only postulated (not expected) to occur.

15.2.9.2 Sequence of Events and System Operation

15.2.9.2.1 Sequence of Events

The sequence of events for this transient is shown in Table 15.2-12. Figures 15.2-10 and 15.2-11 show shutdown cooling paths.

For the early part of the transient, the operator actions are identical to those described in Section 15.2.6 (LOOP transient with isolation/scram).

The operator should do the following:

a. Within approximately 10 minutes of the isolation/scram, the operator should initiate RPV shutdown depressurization at 100°F/hr by manual actuation of the MSRVs.

b. At approximately 15 minutes into the transient, the operator should initiate suppression pool cooling (again for purposes of this analysis, it is assumed that only one RHR heat exchanger is available).

c. After the RPV is depressurized to approximately 75 psig, the operator should attempt to open the two RHR shutdown cooling suction valves. This attempt is assumed to be unsuccessful.

d. The operator then powers open the ADS relief valves to complete blowdown, and floods the RPV with LPCI or core spray to establish a closed cooling path as described in Figure 15.2-11.

15.2.9.2.2 System Operation

Plant instrumentation and control is assumed to be functioning normally except as noted. In this evaluation, credit is taken for the plant and reactor protection systems and/or the ESF is used.

15.2.9.2.3 The Effect of Single Failures and Operator Errors

The worst case single failure has already been analyzed in this transient. Therefore, no single failure or operator error can make the consequences of this event any worse. See Section 15.9 for a discussion of this subject.

15.2.9.3 Core and System Performance

15.2.9.3.1 Methods, Assumptions, and Conditions

A transient that can directly cause reactor vessel water temperature increase is one in which the energy removal rate is less than the decay heat rate. The applicable transient is loss of RHR shutdown cooling. This transient can occur only during the low pressure portion of a normal reactor shutdown and cooldown, when the RHR system is operating in the shutdown cooling mode. During this time, MCPR remains high and nucleate boiling heat transfer is not exceeded at any time. Therefore, the core thermal safety margin remains essentially unchanged. The 10 minute time period assumed for operator action is an estimate of how long it would take before the operator would initiate the necessary actions; it is not a time by which he must initiate action.

15.2.9.3.2 Mathematical Model

In evaluating this transient, the important parameters to consider are reactor depressurization rate and suppression pool temperature. Models used for this evaluation are described in Section 6.2.1.8.

15.2.9.3.3 Input Parameters and Initial Conditions

Table 15.2-13 shows the input parameters and initial conditions used in evaluation of this transient.

15.2.9.3.4 Results

For most single failures that could result in loss of shutdown cooling, no unique safety actions are required. In these cases, shutdown cooling is simply re-established using an alternate shutdown cooling flow path. In cases where either of the RHR shutdown cooling suction valves cannot be opened, alternate paths are available to accomplish the shutdown cooling function (Figure 15.2-10). An evaluation has been performed assuming the worst single failure that could disable the RHR shutdown cooling valves.

As a result of SIL 636, the failure of RHR cooling transient was re-evaluated to determine the impact of the increased decay heat and was performed at a reactor power of 3528 MWt and a revised K-factor for the RHR heat exchangers. This qualitative evaluation concludes that there no significant changes in the suppression pool temperature profile or shutdown cooling time, more information on the SIL 636 evaluation is provided in Section 6.2.1.8.

The analysis demonstrates the capability to safely transfer fission product decay heat, and other residual heat, from the reactor core so that specified acceptable fuel design limits and the design conditions of the RCPB are not exceeded. The evaluation assures that, for onsite electric power system operation (assuming offsite power is not available), and for offsite electric power system operation (assuming onsite power is not available), the safety function can be accomplished, assuming a worst case single failure.

The alternate cooldown path, chosen to accomplish the shutdown cooling function, utilizes the RHR pumps and heat exchangers, core spray pumps and ADS or normal relief valve systems (Reference 15.2-1 and Figure 15.2-11).

The alternate shutdown systems are capable of performing the function of transferring heat from the reactor to the environment using only safety-grade equipment. Even if it is additionally postulated that all of the ADS or relief valves discharge piping also fails, the shutdown cooling function would eventually be accomplished as the cooling water would run directly out of the ADS or MSRVs, flooding into the drywell and then to the suppression pool.

The systems have suitable redundancy in components so that, for onsite electrical power operation (assuming offsite power is not available), and for offsite electrical power operation (assuming onsite power is also not available), the systems' safety function can be accomplished, even assuming an additional single failure. The systems can be fully operated from the main control room.

The design evaluation is divided into two phases:

a. Full power operation to approximately 75 psig vessel pressure.

b. Approximately 75 psig vessel pressure to cold shutdown (200°F) conditions.

15.2.9.3.4.1 Full Power to Approximately 75 psig

Independent of the transient that initiated plant shutdown (whether it be a normal plant shutdown or a forced plant shutdown), the reactor is normally brought to approximately 75 psig using either the main condenser or, in the case where the main condenser is unavailable, the RCIC/HPCI systems, together with the nuclear boiler pressure relief system.

For evaluation purposes, however, it is assumed that plant shutdown is initiated by a transient event (LOOP) that results in reactor isolation/scram and subsequent relief valve actuation and suppression pool heatup. For this postulated condition, the reactor is shut down and the reactor vessel pressure and temperature are reduced to, and maintained at, saturated conditions at approximately 75 psig. The RPV is depressurized by manually opening selected MSRVs. Reactor vessel makeup water is automatically provided via the RCIC/HPCI systems. While in this condition, the RHR system (suppression pool cooling mode) is used to maintain the suppression pool temperature within design limits.

These systems are designed to routinely perform their functions for both normal and forced plant shutdown. Since the RCIC, HPCI, and RHR systems are divisionally separated, no single failure, together with the LOOP, can prevent reaching the 75 psig level.

For conservatism in the analysis of this event, it was assumed that the reactor vessel makeup water was provided by the feedwater system instead of the HPCI/RCIC system. While feedwater system is not a safety system, this assumption maximizes the energy addition to the vessel and containment due to the residual heat in the feedwater system. This results in a conservative calculation of the vessel depressurization and cooldown and conservative suppression pool temperature results.

15.2.9.3.4.2 Approximately 75 psig to Cold Shutdown

The following assumptions are used for the analyses of the procedures for attaining cold shutdown from a pressure of approximately 75 psig:

a. The vessel is at 75 psig and saturated conditions.

b. A worst case single failure is assumed to have occurred (i.e., loss of a division of emergency power).

c. There is no offsite power available.

In the event that the RHR shutdown suction line is not available because of single failure, the first action to be taken will be for personnel to gain access to the suction line and to attempt to effect repairs. For example, if a single electrical failure caused a suction valve to fail in the closed position, a hand wheel is provided on the valve to allow manual operation. If for some reason the normal shutdown cooling suction line cannot be repaired, the capabilities described below will satisfy the normal shutdown cooling requirements and comply with GDC 34.

The RHR shutdown cooling line valves are in two divisions (Division 1 = the outboard valve, and Division 2 = the inboard valve) to satisfy containment isolation criteria. For evaluation purposes, the worst case failure is assumed to be the loss of a division of emergency power, since this also prevents actuation of one shutdown cooling line valve. ESF equipment available for accomplishing the shutdown cooling function includes (for the selected path) the following:

a. ADS (dc Division 1 and dc Division 3)

b. RHR Loop A (Division 1)

c. RHR Loop B (Division 2)

d. HPCI (dc Division 2 and 4)

e. RCIC (dc Division 1 and 3)

f. Core Spray A (Division 1 and 3)

g. Core Spray B (Division 2 and 4).

For failures of Division 1 or 2, the following systems are assumed to be functional:

a. Division 1 fails, Divisions 2, 3, and 4 are functional:

Failed Systems	Functional Systems
RHR Pump A	HPCI
CS Loop A	ADS (one solenoid)
RCIC	RHR Loop B
	CS Loop B
	RHR Pumps B, C, and D

b. Division 2 fails, Divisions 1,3, and 4 are functional:

Failed Systems	Functional Systems
RHR Pump B	CS Loop A
CS Loop B	RCIC
HPCI	RHR Loop A
	ADS
	RHR Pumps A, C, and D

Assuming the single failure is the failure of Division 1, the safety function is accomplished by establishing one of the cooling loops described in Activity C1 of Figure 15.2-11. If the assumed single failure is Division 2, the safety function is accomplished by establishing one of the cooling loops described as Activity C2 of Figure 15.2-11.

Using the above assumptions, and following the depressurization transient shown in Figure 15.2-12A and 15.2-12B, the suppression pool temperature is shown in Figure 15.2-13.

The failure of RHR shutdown cooling event was evaluated for power rerate at an initial power level of 3694 MWt, ANS 5.1-1979 nominal decay heat values, and RHR heat exchanger K-value of 288.9 BTU/sec-F.

A qualitative evaluation was performed for this event considering the increased decay heat loads of SIL 636. Using an initial power level of 3528 MWt and an RHR heat exchanger K-value of 305

BTU/sec-F, the increase in decay values of SIL 636 with 2 sigma uncertainty is not expected to increase the shutdown cooling time beyond the 30 hours calculated for power rerate at 3694 MWt. (Ref. 15.2-3)

15.2.9.4 Barrier Performance

As noted above, the consequences of this transient do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment are designed. Release of coolant to the containment occurs via MSRV actuation. Release of radiation to the environment is described below.

15.2.9.5 Radiological Consequences

While this transient does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via MSRV operation. Because this activity is contained in the primary containment, there is no exposure to operating personnel. This transient does not result in an uncontrolled release to the environment, so the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release conditions. If purging of the containment is chosen, the release will be in accordance with established technical specifications and, at the worst, would only result in a small increase in the yearly integrated exposure level.

15.2.10 LOSS OF STATOR COOLING

15.2.10.1 Identification of Causes and Frequency Classification

15.2.10.1.1 Identification of Causes

A Loss of Stator Cooling (LOSC) event begins after a sustained Stator Coolant Trouble signal resulting from low coolant flow, low system discharge pressure, or high system return temperature.

15.2.10.1.2 Frequency Classification

A LOSC is a moderate frequency event and classified as an AOO.

15.2.10.2 Sequence of Events and System Operation

15.2.10.2.1 Sequence of Events

Table 15.2-15 lists the sequence of events for a LOSC event initiated at rated power. The sequence of events presented in Table 15.2-15 is for the analysis conditions. In the most recent analysis both recirculation pumps run back in tandem after a 10 second delay; however, in actuality the recirculation pump runbacks are separated by several seconds as discussed in the Table 15.2-15 footnotes.

15.2.10.2.2 System Operation

Once the LOSC signal is confirmed, both recirculation pumps will runback to 42% speed. Additionally a runback of the turbine-generator will initiate. The turbine-generator runback will cause the turbine control valves to close slowly. The turbine bypass valves will open in response to the closure of the turbine control valves. Once the available bypass capacity is exceeded, the system will begin to pressurize. The event is terminated when the reactor scrams on high pressure or high neutron flux. The analysis also considers the TBSOOS condition.

15.2.10.2.3 The Effect of Single Failures and Operator Errors

The single failure for the LOSC is the failure which initiates the event. No consideration for additional failures is required.

15.2.10.3 Core and System Performance

15.2.10.3.1 Mathematical Model

The computer models described in Section 15.1.2.3.1 are used to simulate this transient.

15.2.10.3.2 Input Parameters and Initial Conditions

The LOSC is assumed to occur at time zero, as shown in Table 15.2-15. At the same time, both recirculation pumps runback to 42% speed and the turbine-generator runback begins. The turbine-generator runback is assumed to reduce the load set from 105% to 20% over a period of 140 seconds which bounds actual plant response. The first LOSC analysis was done for Unit 1 Cycle 16 and is based on the rated power of 3,515 MWt (Reference 15.2-5).

15.2.10.3.3 Results

The LOSC event has the potential to be a limiting AOO and is therefore analyzed or confirmed to be bounded by other transients as part of each reload's safety analysis.

15.2.10.3.4 Consideration of Uncertainties

All systems utilized for protection in this transient were assumed to have the most conservative allowable response (e.g., pressure scram setpoint). Normal plant behavior is, therefore, expected to reduce the actual severity of the transient.

In actuality, the LOSC signal must be present for several seconds before any plant response is initiated. Additionally, the recirculation pump runbacks do not occur simultaneously but are separated by several seconds. This difference does not impact the results of the analysis because core flow reaches the reduced steady state flow well before the pressurization part of the event occurs. Finally, the actual turbine-generator runback times are greater than the assumed value. A shorter runback time results in a greater pressurization rate, increasing the severity of the event.

15.2.10.4 Barrier Performance

The consequences of this transient do not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel or containment are designed. Therefore, these barriers maintain their integrity and function as designed.

15.2.10.5 Radiological Consequences

Because this transient does not result in any fuel failures, or any release of primary coolant to either the secondary containment or to the environment, there are no radiological consequences associated with this transient.

15.2.11 REFERENCES

15.2-1 Letter R.S. Boyd to I.F. Stuart, "Requirements Delineated for RHRS - Shutdown Cooling System - Single Failure Analysis" (November 12, 1975).

15.2-2 "Emergency Core Cooling System Parameter Relaxations for Limerick Generating Station Units 1 & 2, GE-NE-L12-00822, February 1995.

15.2-3 "Limerick Generating Station 1 & 2 SIL 636 Evaluation," GE, GE-NE-0000-0003-3779, June 2003

15.2-4 GE-Hitachi Nuclear Energy, 0000-0077-4603-R1, "BWR Owners Group Evaluation of Steam Flow Induced Error (SFIE) Impact on the L3 Setpoint Analytic Limit," October 2008.

15.2-5 GE Hitachi Nuclear Energy document number 000N3759-R0, "Limerick Units 1 and 2 LOSC with Recirculation Runback Off-rated Limits," February 2014.

Table 15.2-1

SEQUENCE OF EVENTS FOR
TURBINE-GENERATOR LOAD REJECTION WITH BYPASS[1]

TIME (sec)	EVENT
-0.015 (approx.)	Turbine-generator detection of loss of electrical load
0.0	Turbine-generator power load unbalance devices trip to initiate turbine control valve fast closure.
0.0	Turbine-generator power load unbalance trip initiates main turbine bypass system operation.
0.03	Fast turbine control valve closure initiates scram trip.
0.05	Turbine control valve closure initiates an RPT.
0.07	Turbine control valve closed.
0.14	Turbine bypass valves start to open.
0.175	Recirculation pump motor circuit breakers open causing the recirculation drive flows to coast down.
2.0	Group 1 MSRVs actuated.
2.15	Group 2 MSRVs actuated.
2.40	Group 3 MSRVs actuated.
3.90	Group 1 MSRVs close.

(1) See Figure 15.2-1.

NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

Table 15.2-2

SEQUENCE OF EVENTS FOR
TURBINE-GENERATOR LOAD REJECTION WITHOUT BYPASS[1]

TIME (sec)	EVENT
-0.015 (approx.)	Turbine-generator detection of loss of electrical load.
0.0	Turbine-generator power load unbalance devices trip to initiate turbine control valve fast closure.
0.0	Turbine bypass valves fail to operate.
0.03	Fast control valve closure initiates scram trip.
0.05	Turbine control valve closure initiates a recirculation pump trip (RPT).
0.08 (approx.)	Turbine control valve closed.
0.175	Recirculation pump motor circuit breakers open causing the recirculation drive flow to begin to coast down.
1.9	MSRV actuation initiated.
> 6	MSRV closed.

(1) See Figure 15.2-2.

Table 15.2-3

SEQUENCE OF EVENTS FOR TURBINE TRIP WITH BYPASS[1]

TIME (sec)	EVENT
0.0	Turbine trip initiates closure of main stop valves.
0.0	Turbine trip initiates bypass operation.
0.01	Main turbine stop valves reach 90% open position and initiates reactor scram trip.
0.01	Main turbine stop valves reach 90% open position and initiates an RPT.
0.1	Turbine stop valves closed.
0.17	Turbine bypass valves start to open to regulate pressure.
2.5	Group 1 MSRVs actuated.
2.7	Group 2 MSRVs actuated.
2.9	Group 3 MSRVs actuated.
8.3	All MSRVs closed.

[1] See Figure 15.2-3.

NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

Table 15.2-4

SEQUENCE OF EVENTS FOR TURBINE TRIP WITHOUT BYPASS[1]

TIME (sec)	EVENT
0.0	Turbine trip initiates closure of main stop valves.
0.0	Turbine bypass valves fail to operate.
0.01	Main turbine stop valves reach 90% open position and initiate reactor scram trip.
0.01	Main turbine stop valves reach 90% open position and initiate an RPT.
0.1	Turbine stop valves closed.
0.175	Recirculation pump motor circuit breakers open causing the recirculation drive flows to coast down.
≈ 1.8	MSRV actuation initiated.
> 6	MSRVs closed.

(1) See Figure 15.2-4.

Table 15.2-5

SEQUENCE OF EVENTS FOR MSIV CLOSURE[2]

TIME (sec)	EVENT
0.0	Initiate closure of all MSIV
0.3	MSIV position trip scram initiated[1]
2.9	Recirculation pump drive motors are tripped
3.1	MSRVs open 3 groups due to pressure relief setpoint action
14.6	All MSRVs closed
26.0	Initiate HPCI and RCIC systems on low-low water level (Level 2)

(1) The event was simulated with an MSIV position trip at the 90% open position. Using an analytical value of 85% has no significant impact on the ΔCPR and peak system pressure results.

(2) See Figure 15.2-5.

NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

Table 15.2-6

TYPICAL RATES OF DECAY FOR CONDENSER VACUUM

CAUSE	ESTIMATED VACUUM DECAY RATE
a. Failure or isolation of steam jet air ejectors	<1 inch Hg/minute
b. Loss of sealing steam to shaft gland seals	1 to 2 inches Hg/minute (approx)
c. Opening of vacuum breaker valves	2 to 12 inches Hg/minute (approx)
d. Loss of one or more circulating water pumps	4 to 24 inches Hg/minute (approx)

Table 15.2-7

SEQUENCE OF EVENTS FOR LOSS OF CONDENSER VACUUM[1]

TIME (sec)	EVENT
-3.0	Initiate simulated loss of condenser vacuum at 2 inches of Hg per second.
0.0 (est)	Low condenser vacuum main turbine trip actuated.
0.0 (est)	Low condenser vacuum feedwater trip actuated.
0.01	Main turbine trip initiates reactor scram.
0.01	Main turbine trip initiates RPT.
0.1	Turbine stop valves closed.
0.1	Bypass valves begin to open.
2.5	Group 1 MSRV setpoints actuated.
2.7	Group 2 MSRV setpoints actuated.
2.9	Group 3 MSRV setpoints actuated.
5.0	Low condenser vacuum initiates MSIV closure.
5.0	Low condenser vacuum initiates bypass valve closure.
13.3	All MSRVs close.
16.9	MSRV cyclic actuation on pressure demand.
50.6	HPCI/RCIC system initiation on low level (Level 2) (not included in simulation)

(1) See Figure 15.2-6.

NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

Table 15.2-8

TRIP SIGNALS ASSOCIATED WITH LOSS OF CONDENSER VACUUM

	Condenser Vacuum (Inches of Hg) Transient Analysis (Table 15.2-7)
a. Normal Operating Range	-
b. Main Turbine Trip	20
c. Feedwater Trip	20
d. MSIV Closure Initiated	10
e. Bypass Valve Closure Initiated	10

(1) In the plant, the spread between the turbine trip (b) and bypass valve closure (e) conservatively exceeds the analyzed condition. The transient analysis ΔCPR and peak system pressure results remain bounding.

NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

Table 15.2-9

SEQUENCE OF EVENTS FOR LOSS OF AUXILIARY POWER TRANSFORMER[1]

REFER TO TABLE 15.2-10

[1] See Figure 15.2-7.

Table 15.2-10

SEQUENCE OF EVENTS FOR LOSS OF ALL GRID CONNECTIONS[1]

TIME (sec)	EVENT
-0.015 (approx.)	Loss of grid causes turbine-generator to detect a loss of electrical load.
0.0	Turbine control valve fast closure is initiated.
0.0	Turbine-generator power load unbalance trip initiates main turbine bypass system operation.
0.0	Recirculation system pump motors are tripped.
0.0	Turbine control valve fast closure initiates a reactor scram trip.
0.07	Turbine control valves closed.
0.10	Turbine bypass valves begin to open.
2.0	Feedwater pumps trip on low suction pressure.
2.4	MSRVs open and cycle.
7.2	Initial SRVs closure.
49	Low water Level 2 setpoint reached, HPCI/RCIC initiated (not simulated).

(1) See Figure 15.2-8.

NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

Table 15.2-11

SEQUENCE OF EVENTS FOR LOSS OF FEEDWATER FLOW

TIME (sec)[2]	EVENT
0.0	Trip of all feedwater pumps initiated.
~6	Vessel water level (Level 3)[1] trip initiates scram trip.
~19	Vessel water level (Level 2)* trip initiates RCIC (and HPCI) operation.
~19	Vessel water level (Level 2) trip initiates containment isolation.
~19	Vessel water level (Level 2) trip initiates recirculation pump trip.
~74	Rated RCIC flow is achieved. **
~800	Minimum Level is reached (444 inches above vessel zero), approx. 45.5 inches above Level 1 trip.***

Note:

(1) **Because of an additional steam flow induced process measurement error in the Level 3 scram, the timing values following Low water level scram based on the L3 Analytical Limit are slightly different. However, as described in Reference 15.2-4, the impact of the change is not significant.**

(2) Results presented above are taken from historical analyses but continue to be generally representative and applicable to modern fuel designs.

* Level 2 (Analytical Limit) is assumed to be at 457.5 inches above vessel zero.

** A system response time of 55 seconds is assumed.

*** Level 1 (NTSP) is 398.5 inches above vessel zero.

Table 15.2-12

SEQUENCE OF EVENTS FOR FAILURE OF RHR SHUTDOWN COOLING

TIME (min)	EVENT
0	Reactor is operating at 3528 MWt when LOOP occurs initiating plant shutdown.
0	Concurrently, loss of one division of power occurs.
10	Controlled depressurization initiated (100%) using selected MSRVs.
15	Suppression pool cooling initiated to prevent overheating from MSRV actuation(1).
157	Blowdown to approximately 75.0 psig completed.
157	Personnel are sent in to open RHR shutdown cooling suction valve; this fails.
187	Actuate core spray into vessel and reopen ADS valves to establish alternate cooling path.

(1) See Table 15.2-9 for detailed sequence of events for loss of ac power transient.

Table 15.2-13

INPUT PARAMETERS FOR EVALUATION OF FAILURE
OF RHR SHUTDOWN COOLING

Initial power level (MWt)	3528
Suppression pool mass (lb_m)	7.364×10^{6}
RHR (KHX value) (Btu/sec/°F)	305
Initial vessel condition	
Pressure (psia)	1068
Temperature (°F)	553
Initial primary fluid inventory (lb_m)	6.253×10^{5}
Initial pool temperature, (°F)	$9.500 \times 10^{+1}$
Service water temperature, (°F)	$9.500 \times 10^{+1}$
Vessel heat capacity (Btu/lb_m/°F)	1.230×10^{-1}
Core spray flow rate, (lb_m/sec)	$8.690 \times 10^{+2}$
RHR pool cooling flow rate (lb_m/sec)	$1.390 \times 10^{+3}$

TABLE 15.2-14

SIGNIFICANT INITIAL CONDITIONS AND RESULTS
FOR THE GENERATOR LOAD REJECTION WITHOUT BYPASS AND RPT

INITIAL CONDITIONS	
Initiating Event:	Generator Load Rejection
Failed Systems	Recirculation Pump Trip[1] Turbine Bypass Valves
First Functioning Scram Signal	Turbine Control Valve Fast Closure
RESULTS	
Maximum Vessel Pressure (psig)	1276
Time of Maximum Pressure (sec)	2.1
Delta Critical Power Ratio (ΔCPR)	0.22/0.32/0.32[2]
Time of MCPR (sec)	1.19/1.22/1.19[2]

(1) Initiated by Turbine Control Valve Fast Closure.

(2) GE8X8NB/GE11/GNF3

Table 15.2-15

SEQUENCE OF EVENTS FOR
LOSS OF STATOR COOLING

TIME (sec)	EVENT
0.0	Loss of Stator Cooling occurs.
0.0[a]	Dual Recirculation Pump to 42% Speed is initiated[b].
0.0	Turbine-Generator Load Set Runback begins from 105% going to 20% over 140 seconds.
45 (approx.)[a][c]	Turbine-Generator Load Set reaches Turbine Control Valve (TCV) position and starts causing the TCVs to close. Turbine Bypass Valves (TBV) begin to open in response to the TCV Closure.
75 (approx.)[a][c]	TBVs open to their available capacity. Pressurization begins due to mismatch between steam flow coming from the vessel and the available TCV/TBV capacity.
95 (approx.)[a][c]	Reactor scrams on high pressure or neutron flux.

(a) This timeline assumes the feedwater flow interlock does not inhibit recirculation runback.

(b) In the original LOSC analysis both recirculation pumps runback immediately at time 0. In subsequent cycle-specific analyses the pumps are conservatively modeled as running back together after an approximately 10 second delay. In reality, Recirculation Pump 'A' runback is initiated at 1 second and Recirculation Pump 'B' runback is initiated at 10 seconds after event start.

(c) If recirculation runback is inhibited, this time will increase by approximately 45 seconds.

15.3 DECREASE IN REACTOR COOLANT SYSTEM FLOW RATE

15.3.1 RECIRCULATION PUMP TRIP

15.3.1.1 Identification of Causes and Frequency Classification

15.3.1.1.1 Identification of Causes

Recirculation pump motor operation can be tripped off either by design for the reduction of other core and RCPB transient effects or by random unpredictable operational failures. Intentional tripping will occur in response to the following:

a. Reactor vessel water level Level 2 setpoint trip

b. Turbine control valve fast closure or stop valve closure

c. Reactor vessel high pressure setpoint trip

d. Motor branch circuit overcurrent protection

e. Motor overload protection

f. Suction block valve not fully open (Unit 2 only)

g. Discharge valve not fully open (Unit 2 only)

h. Deleted

i. Low lube oil pressure

j. Main unit lockout

k. Deleted

l. Deleted

m. Bus undervoltage

n. High oil temperature

o. Manual trip

Random tripping will occur in response to the following:

a. Operator error

b. Loss of electrical power source to the pumps

c. Equipment or sensor failures and malfunctions which initiate the above trips.

15.3.1.1.2 Frequency Classification

15.3.1.1.2.1 Trip of One Recirculation Pump

This transient is categorized as one of moderate frequency.

15.3.1.1.2.2 Trip of Two Recirculation Pumps

This transient is categorized as one of moderate frequency.

15.3.1.2 Sequence of Events and System Operation

15.3.1.2.1 Sequence of Events

15.3.1.2.1.1 Trip of One Recirculation Pump

Table 15.3-1 lists the sequence of events for Figure 15.3-1.

15.3.1.2.1.2 Trip of Two Recirculation Pumps

Table 15.3-2 lists the sequence of events for Figure 15.3-2.

15.3.1.2.1.3 Identification of Operator Actions

15.3.1.2.1.3.1 Trip of One Recirculation Pump

Since no scram occurs for trip of one recirculation pump, no immediate operator action is required. As soon as possible, the operator should first verify that no operating limits are being exceeded and then reduce the flow of the operating pump to conform to the single pump flow criteria. Also, the operator must determine the cause of failure before following the restart procedure and returning the system to normal.

15.3.1.2.1.3.2 Trip of Two Recirculation Pumps

Tripping of two recirculation pumps will cause a reactor water level swell that will trip the main turbine. This in turn will cause a reactor scram. The operator should ascertain that the reactor has been scrammed by the turbine trip resulting from reactor water level swell. The operator should regain control of reactor water level through RCIC operation, monitoring reactor water level and pressure control after shutdown. When both reactor pressure and level are under control, the operator may secure both HPCI and RCIC as necessary. The operator should also determine the cause of the trip before returning the system to normal.

15.3.1.2.2 System Operation

15.3.1.2.2.1 Trip of One Recirculation Pump

Tripping a single recirculation pump requires no protection system or safeguard system operation. This analysis assumes normal functioning of plant instrumentation and controls.

15.3.1.2.2.2 Trip of Two Recirculation Pumps

Analysis of this transient assumes normal functioning of plant instrumentation and controls as well as plant and reactor protection systems.

Specifically, this transient takes credit for vessel level (Level 8) instrumentation that closes the turbine stop valves. Reactor shutdown relies on scram trips from the turbine stop valves. High system pressure is limited by MSRV operation.

15.3.1.2.3 The Effect of Single Failures and Operator Errors

15.3.1.2.3.1 Trip of One Recirculation Pump

Since no corrective action is required, no additional effects of single failures need be discussed. If additional single active failure or single operator error are assumed (for envelope purposes the other pump is assumed tripped), then the following two-pump trip analysis is provided (Section 15.9.6.3.3.g, Table 15.9-2).

15.3.1.2.3.2 Trip of Two Recirculation Pumps

Table 15.3-2 lists the vessel level (Level 8) trip event as the first response to initiate corrective action in this transient. The level (Level 8) is intended to prohibit moisture carryover to the main turbine. Multiple level sensors are used to sense and detect when the water level reaches the Level 8 setpoint. At this point, a single failure will neither initiate nor impede a turbine trip signal. However, turbine trip signal transmission circuitry is not built to the single failure criterion. The result of a failure at this point would have the effect of delaying the pressurization "signature." However, high moisture levels entering the turbine can trip the turbine via turbine supervisory instrumentation.

Scram trip signals from the turbine are designed so that a single failure will neither initiate nor impede a reactor scram trip initiation (Section 15.9.6.3.3.g, Table 15.9-2).

15.3.1.3 Core and System Performance

15.3.1.3.1 Mathematical Model

The nonlinear dynamic model used to simulate this transient is discussed in Reference 15.1-1.

15.3.1.3.2 Input Parameters and Initial Conditions

Unless otherwise noted, these analyses have been performed using Cycle 1 plant conditions.

Pump motors and pump rotors are simulated with minimum specified rotating inertias.

15.3.1.3.3 Results

The results of these events are based on Cycle 1 conditions. However, with the development of new analysis methodologies and the introduction of new fuel types, a recirculation pump trip does not have as significant of a level response and the Level 8 setpoint is not expected to be reached. In this scenario, a two recirculation pump trip remains non-limiting. Additionally, other transient events which result in a two recirculation pump trip model the recirculation pump trip as part of the event, and the resulting level response may be different than the historic Cycle 1 response due to the introduction of new fuel types and the use of newer analysis methodologies.

15.3.1.3.3.1 Trip of One Recirculation Pump

Figure 15.3-l shows the results of losing one recirculation pump. The tripped loop diffuser flow reverses in approximately 2.7 seconds. However, the ratio of diffuser mass flow to pump mass flow in the active jet pumps increases considerably and produces approximately 154% of normal diffuser flow and 58% of rated core flow. MCPR remains well above the safety limit; thus, the fuel thermal limits are not violated. During this transient, level swell is not sufficient to cause turbine trip and scram.

15.3.1.3.3.2 Trip of Two Recirculation Pumps

Figure 15.3-2 shows this transient, with minimum specified rotating inertia, in graph form. MCPR remains unchanged. No scram is initiated directly by pump trip. The vessel water level swell due to rapid flow coast-down is expected to reach the high level trip, thereby shutting down the main turbine and feed pump turbines and scramming the reactor. Subsequent events, such as main steam line isolation and initiation of RCIC and HPCI systems occurring later in this transient, have no significant effect on the results.

15.3.1.3.4 Consideration of Uncertainties

Initial conditions chosen for these analyses are conservative and tend to force analytical results to be more severe than those expected under actual plant conditions.

Actual pump and pump motor driveline rotating inertias are expected to be somewhat greater than the minimum design values assumed in this simulation. Actual plant deviations regarding inertia are expected to lessen the severity of the results indicated by this analysis. Minimum design inertias were used as well as the least negative void coefficient, because the primary concern here is flow reduction.

15.3.1.4 Barrier Performance

15.3.1.4.1 Trip of One Recirculation Pump

Figure 15.3-1 results indicate a basic reduction in system pressures from the initial conditions. Therefore, the RCPB barrier is not threatened.

15.3.1.4.2 Trip of Two Recirculation Pumps

The results shown in Figure 15.3-2 indicate that peak pressures stay well below the 1375 psig limit allowed by the applicable code. Therefore, the barrier pressure boundary is not threatened.

15.3.1.5 Radiological Consequences

While the consequence of this transient does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via MSRV operation. Because this activity is contained in the primary containment, there is no exposure to operating personnel. This transient does not result in an uncontrolled release to the environment, so the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release conditions. If purging of the containment is chosen, the release will be in accordance with established technical specifications and, at the worst, would only result in a small increase in the yearly integrated exposure level.

15.3.2 RECIRCULATION FLOW CONTROL FAILURE - DECREASING FLOW

15.3.2.1 Identification of Causes and Frequency Classification

15.3.2.1.1 Identification of Causes

Some causes of recirculation flow control failure are malfunction of the active ASD controller (one of two redundant controllers), malfunction of the PLC supplying command signals to the controllers, or corruption to the communication between these devices (one of two redundant channels). These malfunctions can result in a rapid flow decrease in only one recirculation loop.

15.3.2.1.2 Frequency Classification

This transient is categorized as an incident of moderate frequency.

15.3.2.2 Sequence of Events and System Operation

15.3.2.2.1 Sequence of Events

15.3.2.2.1.1 Failure of One Controller - Closed

The sequence of events for this transient is similar to, and can never be more severe than, that listed in Table 15.3-1 for the trip of one recirculation pump.

15.3.2.2.1.2 Deleted

15.3.2.2.1.3 Identification of Operator Actions

As soon as possible, the operator should verify that no operating limits are being exceeded. If limits are exceeded, corrective action must be initiated. The operator must also determine the cause of the trip before returning the system to normal.

15.3.2.2.2 System Operation

Normal plant instrumentation and control is assumed to function. Credit is taken for scram in response to vessel high water level (Level 8) turbine trip if it occurs.

15.3.2.2.3 The Effect of Single Failures and Operator Errors

The single failure and operator error considerations for these events are the same as those discussed in Section 15.3.1.2.3 on the RPT. Failure of an ASD and thus an RPT, would be the envelope case for additional single action failure or single operator error (Section 15.9.6.3.3.f, Table 15.9-2).

15.3.2.3 Core and System Performance

15.3.2.3.1 Mathematical Model

The nonlinear dynamic model used to simulate these transients is discussed in Reference 15.1-1.

15.3.2.3.2 Input Parameters and Initial Conditions

These analyses have been performed, unless otherwise noted, with Cycle 1 plant conditions. The lowest negative void coefficient in Table 15.0-2 was used for these analyses.

15.3.2.3.3 Results

The results of these events are based on Cycle 1 conditions. An analysis of these events for current conditions is not expected to result in a change in the general trends and characteristics as shown.

In the case of zero demand to both controllers each individual ASD speed controller has internal limits established in its system operating program (SOP) that limits the maximum rate of change of speed in each loop. Thus, the results of these transients can never be more severe than those of the simultaneous trip of both recirculation pumps, as evaluated in Section 15.3.1.3.3.2.

The failure of one controller has two possible outcomes. A detectable failure of the active primary controller will cause swap-over to the back-up controller, resulting in maintaining pump speed at a lower fixed (speed-hold) value. An undetectable malfunction of the primary active controller or malfunction of an active back-up controller (with primary controller inactive) can result in a speed decrease at an uncontrolled rate (step change) to 0% speed. This case is similar to the trip of one recirculation pump, described in Section 15.3.1.3.3.1, and is less severe than the transient that results from the simultaneous trip of both recirculation pumps.

15.3.2.3.4 Consideration of Uncertainties

Initial conditions chosen for these analyses are conservative and tend to force the analytical results to be more severe than would otherwise be expected. These analyses, unlike the pump trip series, will be unaffected by deviations in pump/pump motor and driveline inertias because the flow controllers are what cause rapid recirculation decreases.

15.3.2.4 Barrier Performance

The barrier performance considerations for these events are the same as those discussed in Section 15.3.1.4.

15.3.2.5 Radiological Consequences

While the consequence of this transient does not result in fuel failure, it does result in the discharge of normal coolant activity to the suppression pool via MSRV operation. Because this activity is contained in the primary containment, there will be no exposure to operating personnel. This transient does not result in an uncontrolled release to the environment, so the plant operator can choose to leave the activity bottled up in the containment, or discharge it to the environment under controlled release conditions. If purging of the containment is chosen, the release will be in accordance with established Technical Specifications and, at the worst, would only result in a small increase in the yearly integrated exposure level.

15.3.3 RECIRCULATION PUMP SEIZURE

15.3.3.1 Identification of Causes and Frequency Classification

The seizure of a recirculation pump is considered as a DBA. It has been evaluated as being a very mild accident in relation to other DBAs such as the LOCA. The analysis has been conducted with

consideration to both single-loop and two-loop operations. A discussion is given in GESTAR II (Reference 4.1-1).

15.3.3.1.1 Identification of Causes

The case of recirculation pump seizure represents the extremely unlikely event of instantaneous stoppage of the pump motor shaft of one recirculation pump. This accident produces a very rapid decrease of core flow as the result of the large hydraulic resistance introduced by the stopped rotor.

15.3.3.1.2 Frequency Classification

This accident is considered a limiting fault but results in effects that are comparable to those of an accident of greater probability (i.e. infrequent incident classification).

15.3.3.2 Sequence of Events and System Operation

15.3.3.2.1 Sequence of Events

Table 15.3-3 lists the sequence of events for Figure 15.3-3. Appropriate operator actions must be taken for recovery after the recirculation pump seizure event.

15.3.3.2.2 System Operation

In order to properly simulate the expected sequence of events, the analysis of this accident assumes normal functioning of plant instrumentation and controls, plant protection, and reactor protection systems.

Operation of safe shutdown features, though not included in this simulation, is expected to be utilized in order to maintain adequate water level.

15.3.3.2.3 The Effect of Single Failures and Operator Errors

Corrective action by the level control is expected to establish a new stable operating state. The effect of a single failure in the level control system has rather straightforward consequences, including level rise or fall by improper control of the feedwater system. Increasing level will trip the main and feedwater turbines. This trip signal is described in Section 15.1.2.2.3. Decreasing level will automatically initiate scram at the low level (Level 3) trip which is designed to single failure criteria (Section 15.9.6.4.3.e, Table 15.9-2).

15.3.3.3 Core and System Performance

15.3.3.3.1 Mathematical Model

The nonlinear dynamic model used to simulate this accident is discussed in Reference 15.1-1.

15.3.3.3.2 Input Parameters and Initial Conditions

This analysis has been performed, unless otherwise noted, with the plant conditions tabulated in Table 15.0-2A.

For the purpose of evaluating consequences to the fuel thermal limits, this accident is assumed to occur as the result of an unspecified, instantaneous stoppage of one recirculation pump shaft while the reactor is operating at 102% rated power. The reactor is also assumed to be operating at thermally limited conditions.

15.3.3.3.3 Results

Figure 15.3-3 presents the results of the accident while operating in two-loop mode. Core coolant flow drops rapidly, reaching its minimum value in approximately 1.7 seconds. The vessel water level rises and feedwater flow reduces to compensate. The reactor stabilizes at a new steady-state operating condition. The peak neutron flux and average surface heat flux did not increase significantly above the initial conditions, therefore no impact on the fuel thermal margins is postulated to occur.

A specific analysis has been performed to model the recirculation pump seizure transient while in single-loop mode and is used to establish a MCPR requirement for single-loop operation. See Reference 15.3-1.

15.3.3.3.4 Consideration of Uncertainties

This transient is predicted to result in a reactor vessel water level increase to slightly below the high level (Level 8) turbine trip setpoint. Slightly different nuclear boiler system operational parameters might result in the level swell causing a turbine trip. Should the vessel water level reach the high water level setpoint (Level 8), main turbine trip, resulting from stop valve closure, and feedwater pump trip would be initiated. Subsequently, reactor scram and the remaining recirculation pump trip would be initiated due to the turbine trip. The vessel water level would eventually be controlled by HPCI and RCIC flow.

Further uncertainties are considered in the GETAB (Reference 15.0-2) analysis.

15.3.3.4 Barrier Performance

The bypass valves, and possible momentary opening of some of the MSRVs, limit the pressure well within the range allowed by the ASME vessel code. Therefore, the RCPB is not threatened by overpressure.

15.3.3.5 Radiological Consequences

While the consequence of this accident does not result in fuel failure, it could result in the discharge of normal coolant activity to the suppression pool via MSRV operation. Because this activity is contained in the primary containment, there would be no exposure to operating personnel. This accident does not result in an uncontrolled release to the environment, so the plant operator can choose to leave the activity bottled up in the containment or discharge it to the environment under controlled release conditions. If purging of the containment is chosen, the release will be in accordance with established Technical Specifications and, at the worst, would only result in a small increase in the yearly integrated exposure level.

15.3.4 RECIRCULATION PUMP SHAFT BREAK

15.3.4.1 Identification of Causes and Frequency Classification

The breaking of the shaft of a recirculation pump is considered an accident. It has been evaluated as a very mild accident in relation to other DBAs such as the LOCA. The analysis has been conducted with consideration to both single-loop and two-loop operation.

This postulated accident is bounded by the more limiting case of recirculation pump seizure. Quantitative results for this more limiting case are presented in Section 15.3.3.

15.3.4.1.1 Identification of Causes

Recirculation pump shaft breakage represents the extremely unlikely event of instantaneous stoppage of one recirculation pump motor. This accident produces a very rapid decrease of core flow as a result of the broken pump shaft.

15.3.4.1.2 Frequency Classification

This accident is considered a limiting fault, but results in effects that are comparable to those of an accident of greater probability (i.e., infrequent incident classification).

15.3.4.2 Sequence of Events and System Operation

15.3.4.2.1 Sequence of Events

A postulated instantaneous break of the motor shaft of one recirculation pump, as discussed in Section 15.3.4.1.1, will cause the core flow to decrease rapidly and result in water level swell in the reactor vessel but no scram. The core flow and power will stabilize at new equilibrium conditions. Appropriate operator actions must be taken for recovery after the recirculation pump shaft break event.

15.3.4.2.2 System Operation

Normal operation of plant instrumentation and control is assumed. Operation of HPCI and RCIC systems during shutdown is expected in order to maintain adequate water level control.

15.3.4.2.3 The Effect of Single Failures and Operator Errors

Effects of single failures are similar to those considered in Section 15.3.3.2.3 .

Refer to Section 15.9.6.4.3.f and Table 15.9-3 for more details.

15.3.4.3 Core and System Performance

The severity of this pump shaft break accident is bounded by the pump seizure accident as described in Section 15.3.3. This can be easily demonstrated by consideration of these two accidents as discussed in the section below. Since the shaft break accident is less limiting than the accident discussed in Section 15.3.3 only a qualitative evaluation is provided. Therefore, no discussion of mathematical model, input parameters, and consideration of uncertainties, etc., is necessary.

15.3.4.4 Qualitative Results

If this extremely unlikely accident occurs, core coolant flow will drop rapidly. The vessel level increases but remains below the trip level (Level 8) of the main and feedwater turbines. The flow in the recirculation loop with the failed pump decreases rapidly. The core flow and then the reactor power stabilize at lower values within less than a minute of the failure.

The severity of this pump shaft break accident is bounded by the pump seizure accident (Section 15.3.3). This can be demonstrated easily by consideration of the two types of accidents. In both accidents, the recirculation drive flow of the affected loop decreases rapidly. In the case of the pump seizure accident, the loop flow decreases faster than the normal flow coast-down as a result of the large hydraulic resistance introduced by the stopped rotor. In the case of the pump shaft break accident, the hydraulic resistance caused by the broken pump shaft is less than that of the stopped rotor for the pump seizure accident. Therefore, the core flow decrease following a pump shaft break effect is slower than the pump seizure accident. Thus, it can be concluded that the potential effects of the hypothetical pump shaft break accident are bounded by the effects of the pump seizure accident.

15.3.4.5 Barrier Performance

The bypass valves, and possible momentary opening of some of the MSRVs, limit the pressure well within the range allowed by the ASME vessel code. Therefore, the RCPB is not threatened by overpressure.

15.3.4.6 Radiological Consequences

While the consequence of this accident does not result in fuel failure, it could result in the discharge of normal coolant activity to the suppression pool via MSRV operation. Because this activity is contained in the primary containment, there would be no exposure to operating personnel. This accident does not result in an uncontrolled release to the environment, so the plant operator can choose to leave the activity bottled up in the containment, or discharge it to the environment under controlled conditions. If purging of the containment is chosen, the release will be in accordance with established Technical Specifications and, at the worst, would only result in a small increase in the yearly integrated exposure level.

15.3.5 REFERENCES

15.3-1 006N2787 Rev 2, "GNF3 Fuel Design Cycle-Independent Analyses for Limerick Generating Station Units 1 and 2," April 2021

Table 15.3-1

SEQUENCE OF EVENTS FOR TRIP OF ONE RECIRCULATION PUMP[1]

TIME (sec)	EVENT
0.0	Trip of one recirculation pump initiated.
2.7	Diffuser flow decreases significantly in the tripped loop.
20.0	Core flow stabilizes at new equilibrium conditions.
40.0	Power level stabilizes at new equilibrium conditions.

[1] See Figure 15.3-1.

NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

Table 15.3-2

SEQUENCE OF EVENTS FOR TRIP OF BOTH RECIRCULATION PUMPS[2]

TIME (sec)	EVENT[1]
0.0	Trip of both recirculation pumps initiated.
5.2	Vessel water level (Level 8) trip initiates turbine trip and feedwater pumps trip.
5.2	Turbine trip initiates bypass operation.
5.2	Turbine trip initiates reactor scram trip.
9.9	Group 1 MSRVs open.
12.9	Group 1 MSRVs close.
43.5	Level 2 vessel level setpoint initiates steam line isolation and HPCI/RCIC start.

(1) For these events, MSIV closure was simulated at Level 2. Subsequent design modifications have lowered the closure setpoint to Level 1. However, HPCI and RCIC initiation at Level 2 will prevent the water level from dropping to Level 1 and no MSIV closure will occur. Because no safety limits are approached during this event, reanalysis for the setpoint change is not required.

(2) See Figure 15.3-2.

NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

Table 15.3-3

SEQUENCE OF EVENTS FOR RECIRCULATION PUMP SEIZURE[1]

TIME (sec)	EVENT
0.0	Single pump seizure was initiated.
0.7	Jet pump diffuser flow reverses in seized loop.
4.0	Core flow stabilizes at new equilibrium conditions.
40.0	Power stabilizes at new equilibrium conditions.

(1) See Figure 15.3-3, Applicable for Dual Loop Operation.

15.4 REACTIVITY AND POWER DISTRIBUTION ANOMALIES

15.4.1 ROD WITHDRAWAL ERROR - LOW POWER

15.4.1.1 Control Rod Removal Error During Refueling

15.4.1.1.1 Identification of Causes and Frequency Classification

The transient considered here is inadvertent criticality due to the complete withdrawal or removal of the highest worth control rod during refueling. The probability of the initial causes alone is considered low enough to warrant its being categorized as an infrequent incident, since there is no postulated set of circumstances that results in an inadvertent rod withdrawal error while in the refueling mode.

15.4.1.1.2 Sequence of Events and System Operation

15.4.1.1.2.1 Initial Control Rod Removal or Withdrawal

During refueling operations system interlocks provide assurance that inadvertent criticality does not occur because two control rods have been removed or withdrawn together.

When fuel is being moved from the core to the spent fuel pool during refueling, the refueling interlocks may be disabled for core cells from which the four fuel assemblies have been removed if the conditions contained in technical specification 3.9.10.2 are met and compensating administrative controls are established.

15.4.1.1.2.2 Fuel Insertion With Control Rod Withdrawn

To minimize the possibility of loading fuel into a cell containing no control rod, all control rods must be fully inserted when fuel is being loaded into the core. This requirement is backed up by refueling interlocks on rod withdrawal and movement of the refueling platform. When the mode switch is in the REFUEL position, the interlocks prevent the platform from being moved over the core if a control rod is withdrawn and fuel is on the hoist. Likewise, if the refueling platform is over the core and fuel is on the hoist, control rod motion is blocked by the interlocks.

When fuel is being moved from the core to the spent fuel pool during refueling, the refueling interlocks may be disabled for core cells from which the four fuel assemblies have been removed if the conditions contained in technical specification 3.9.10.2 are met and compensating administrative controls are established.

15.4.1.1.2.3 Second Control Rod Removal or Withdrawal

When the platform is not over the core (or fuel is not on the hoist) and the mode switch is in the REFUEL position, only one control rod can be withdrawn. Any attempt to withdraw a second rod results in a rod block by the refueling interlocks. Since the core is designed to meet shutdown requirements with the highest worth rod withdrawn, the core remains subcritical even with one rod withdrawn.

15.4.1.1.2.4 Control Rod Removal Without Fuel Removal

Finally, the design of the control rod, incorporating the velocity limiter, does not physically permit the upward removal of the control rod without prior or simultaneous removal of the four adjacent fuel bundles. This precludes any hazardous condition.

15.4.1.1.2.5 Identification of Operator Actions

No operator actions are required to preclude this transient since the plant design, as discussed above, prevents its occurrence.

15.4.1.1.2.6 Effect of Single Failure and Operator Errors

If any one of the operations involved in initial failure or error is followed by any other single active failure or single operator error, the necessary safety actions (e.g., rod block or scram) are taken automatically prior to limit violation (Section 15.9).

15.4.1.1.3 Core and System Performances

Since the probability of inadvertent criticality during refueling is precluded, the core and system performances were not analyzed. The withdrawal of the highest worth control rod during refueling will not result in criticality. This is determined analytically during the core design process. Shutdown Margin is verified experimentally during the first startup following refueling operations. (See Section 4.3.2 for a description of the methods and results of the shutdown margin analysis.) Additional reactivity insertion is precluded by interlocks (Section 7.7). As a result, no radioactive material is ever released from the fuel making it unnecessary to assess any radiological consequences.

No mathematical models are involved in this transient. The need for input parameters or initial conditions is not required as there are no results to report. Consideration of uncertainties is not appropriate.

15.4.1.1.4 Barrier Performance

An evaluation of the barrier performance was not made for this transient, since there is not a postulated set of circumstances for which this transient could occur.

15.4.1.1.5 Radiological Consequences

An evaluation of the radiological consequences was not made for this transient, since no radioactive material is released from the fuel.

15.4.1.2 Continuous Rod Withdrawal During Reactor Startup

15.4.1.2.1 Identification of Causes and Frequency Classification

The probability of initial causes or errors of this transient alone is considered low enough to warrant its being categorized as an infrequent incident. The probability of further development of this transient is extremely low because it is contingent upon the failure of the RWM system, together with a high worth out-of-sequence rod selection contrary to procedures, and operator failure to acknowledge continuous alarm annunciations prior to safety system actuation.

15.4.1.2.2 Sequence of Events and System Operation

15.4.1.2.2.1 Sequence of Events

Control rod withdrawal errors are not considered credible in the startup and low power ranges. The RWM system prevents the operator from selecting and withdrawing an out-of-sequence control rod.

15.4.1.2.2.2 Identification of Operator Actions

No operator actions are required to preclude this transient since the plant design, as discussed above, prevents its occurrence.

15.4.1.2.2.3 The Effect of Single Failures and Operator Errors

If any one of the operations involved the initial failure or error is followed by another single active failure or single operator error, the necessary safety actions (e.g., rod blocks) are automatically taken prior to any limit violation (Section 15.9). Further development of this event is contingent upon simultaneous failure of two systems as described in Appendix 15A.

15.4.1.2.3 Core and System Performance

The performance of the RWM system prevents erroneous selection and withdrawal of an out-of-sequence rod. The core and system performance is not affected by such an operator error.

No mathematical models are involved in this transient. The need for input parameters, or initial conditions, is not required as there are no results to report. Consideration of uncertainties is not appropriate.

15.4.1.2.4 Barrier Performance

An evaluation of the barrier performance was not made for this transient, since there is no postulated set of circumstances for which this error could occur.

15.4.1.2.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this transient, since no radioactive material is released from the fuel.

15.4.2 ROD WITHDRAWAL ERROR - AT POWER

15.4.2.1 Identification of Causes and Frequency Classification

15.4.2.1.1 Identification of Causes

While operating in the power range in a normal mode of operation, the reactor operator makes a procedural error and continuously withdraws a high worth control rod until the RBM system inhibits further withdrawal.

15.4.2.1.2 Frequency Classification

This transient is classified as an incident of moderate frequency.

15.4.2.2 Sequence of Events and System Operation

15.4.2.2.1 Sequence of Events

The sequence of events for this transient, as calculated with conservative assumptions, is presented in Table 15.4-1. No operator actions are required during this transient. However, operator procedural actions expected to occur are shown in the above referenced table.

15.4.2.2.2 System Operation

The focal point of this transient is localized to a small portion of the core. Therefore, although reactor controls and instrumentation are assumed to function normally, credit is taken only for the RBM system. A discussion of the transient follows below.

While operating in the power range in a normal mode of operation, the reactor operator withdraws high worth control rod until the RBM system inhibits further withdrawal.

Under most normal operating conditions, no operator action is required since the transient which would occur would be very mild.

If the rod withdrawal error is severe enough, the RBM system would sound alarms, at which time the operator would acknowledge the alarm and take corrective action. Even assuming that the operator ignores all alarms and warnings and continues to withdraw the control rod, the RBM system will block further withdrawal of the control rod before the fuel reaches the point of boiling transition or the 1% strain limit imposed on the cladding.

15.4.2.2.3 The Effect of Single Failures and Operator Errors

The effect of operator errors has been discussed above. It was shown that operator errors (which initiated this transient) cannot impact the consequences of this transient due to the highly reliable RBM system (Section 15.9).

15.4.2.3 Core and System Performance

The Rod withdrawal Error (RWE) event has been analyzed generically to support the Rod Block Monitor (RBM) set points established by the ARTS program. The RWE analysis and the ARTS program for Limerick are discussed in Reference 15.0-10. The generic RWE analysis provides a relationship between ΔCPR and Rod Block Monitor set points.

Reference 15.4-21 concludes that the generic ARTS rated RWE ΔCPR can be eliminated for Limerick Generating Station for all RBM setpoints. Sufficient off-rated analyses are performed for the first cycle with GNF3 as fresh fuel for Limerick Unit 1 and Limerick Unit 2 to confirm that the conclusion is applicable to GNF3 reload cores. A cycle-specific generic ARTS RWE Kp validation is performed for all RBM high power trip setpoints (HTSPs) to ensure that the calculated rated RWE ΔCPR, combined with the generic ARTS RWE Kp limits, provide adequate RWE protection for the cycle. Limits are documented in the Supplemental Reload Licensing Report and incorporated in the Core Operating Limits Report for the cycle. If necessary, new RBM set points are established. The generic and

cycle specific RWE analyses also verify conformance to the fuel thermal-mechanic limit of 1 % strain.

15.4.2.4 Barrier Performance

An evaluation of the barrier performance was not made for this transient, since this is a localized transient with very little change in the gross core characteristics. Typically, the increase in total core power is less than 5% and the changes in pressure are negligible.

15.4.2.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this transient, since no radioactive material is released from the fuel.

15.4.3 CONTROL ROD MALOPERATION (SYSTEM MALFUNCTION OR OPERATOR ERROR)

This transient is covered by the evaluations cited in Sections 15.4.1 and 15.4.2.

15.4.4 ABNORMAL STARTUP OF IDLE RECIRCULATION PUMP

15.4.4.1 Identification of Causes and Frequency Classification

15.4.4.1.1 Identification of Causes

This action results directly from the operator's manual action to initiate pump operation. It assumes that the remaining loop is already operating.

15.4.4.1.1.1 Normal Restart of Recirculation Pump at Power

This transient is categorized as an incident of moderate frequency.

15.4.4.1.1.2 Abnormal Startup of Idle Recirculation Pump

This transient is categorized as an incident of moderate frequency.

15.4.4.2 Sequence of Events and System Operation

15.4.4.2.1 Sequence of Events

Table 15.4-3 lists the sequence of events.

The normal sequence of operator actions expected in starting the idle loop is as follows. The operator should:

a. Adjust rod pattern as necessary for new power level following idle loop start.

b. Determine that the idle recirculation pump suction valve is open, the discharge valve is closed, and the coupler in the idle loop is in the starting position. If they are not, the operator must place them in these configurations.

c. Readjust flow of the running loop downward to less than one-half of rated flow.

d. Determine that the temperature differential between the reactor pressure vessel steam space coolant and the bottom head drain line coolant is no more than 145°F.

e. Determine that the temperature difference between the two loops is no more than 50°F.

f. Start the idle loop pump and open the discharge valve by jogging manual circuitry.

g. Adjust flow to match the adjacent loop flow. Monitor reactor power.

h. Readjust power, as necessary, to satisfy plant requirements per standard procedure.

The time required to do the above work is approximately ½ hour.

15.4.4.2.2 System Operation

This transient assumes and takes credit for normal functioning of plant instrumentation and controls, plant protection, and RPS. In particular, credit is taken for high flux scram to terminate the transient. No ESF action occurs as a result of the transient.

15.4.4.2.3 The Effect of Single Failures and Operator Errors

This transient leads to a quick rise in reactor power level. Corrective action first occurs in the APRM neutron flux upscale trip and, being part of the RPS, it is designed to the single failure criterion. Therefore, shutdown is assured. Operator errors are not of concern here in view of the fact that automatic shutdown transients follow so quickly after the postulated failure (Section 15.9).

15.4.4.3 Core and System Performance

15.4.4.3.1 Mathematical Model

The nonlinear dynamic model described briefly in Section 15.1.1.3.1 is used to simulate this transient.

15.4.4.3.2 Input Parameters and Initial Conditions

This analysis has been performed, unless otherwise noted, with plant conditions as tabulated in Table 15.0-2.

One recirculation loop is idle and filled with cold water at 100°F. (Normal procedure when starting an idle loop with one pump already running requires heating the idle recirculation loop to within 50°F of core inlet temperature prior to loop startup.)

The active recirculation loop is operating with about 84% of normal rated diffuser flow going across the active jet pumps.

The core is receiving 38% of its normal rated flow. The remainder of the coolant flows in the reverse direction through the inactive jet pumps.

Reactor power is 55% of NBR power conditions. (Normal procedures require startup of an idle loop at a lower power.)

The idle recirculation pump suction valve is open, but the pump discharge valve is closed.

The idle pump fluid coupler is at a setting that approximates 50% generator speed demand.

15.4.4.3.3 Results

The results of this event are based on Cycle 1 conditions. An analysis of this event for current conditions is not expected to result in a change in the general trends and characteristics as shown.

Shortly after the pump begins to move, a surge in flow from the jet pump diffusers causes the core inlet flow to rise sharply.

When the neutron flux peak reaches the APRM neutron flux upscale scram setpoint, reactor scram is initiated. The neutron flux peaks at 454.9% of NBR. Surface heat flux follows the slower response of the fuel and peaks at 90% NBR. Nuclear system pressures do not increase significantly above the initial pressures. The water level does not reach either the high or low level setpoints.

15.4.4.3.4 Consideration of Uncertainties

This particular transient is analyzed for an initial power level that is much higher than that expected for the actual transient. The much slower thermal response of the fuel mitigates the effects of the rather sharp neutron flux spike and, even in this high range of power, no threat to thermal limits is possible.

15.4.4.4 Barrier Performance

No evaluation of barrier performance is required for this transient, since no significant pressure increases are incurred.

15.4.4.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this transient, since no radioactive material is released from the fuel.

15.4.5 RECIRCULATION FLOW CONTROL FAILURE WITH INCREASING FLOW

15.4.5.1 Identification of Causes and Frequency Classification

15.4.5.1.1 Identification of Causes

Failure of an individual flow controller can cause a speed increase for its associated recirculation pump. The failure of one ASD controller has two possible outcomes. A detectable failure of the active primary controller will cause swap-over to the back-up controller, resulting in maintaining pump speed at a lower fixed (speed-hold) value. An undetectable malfunction of the primary active controller or malfunction of the active back-up controller (with primary controller inactive) can result in a speed decrease at an uncontrolled rate (step change) to 0% speed.

15.4.5.1.2 Frequency Classification

This transient is classified as an incident of moderate frequency.

15.4.5.2 Sequence of Events and System Operation

15.4.5.2.1 Sequence of Events

Table 15.4-4 lists the sequence of transients for Figure 15.4-3.

Initial actions by the operator include:

a. Reducing recirculation flow to minimum

b. Identifying the cause of the failure.

Reactor pressure will be controlled as required, depending upon whether a restart or cooldown is planned. In general, the corrective action would be to hold reactor pressure and condenser vacuum for restart after the malfunctioning flow controller has been repaired. The following is the sequence of operator actions expected during the course of the transient. The operator should:

a. Observe that all rods are in.

b. Check the reactor water level and maintain it above low level (Level 1) trip to prevent MSIVs from isolating.

c. Switch the reactor mode switch to the STARTUP position.

d. Continue to maintain vacuum and turbine seals.

e. Reduce seep demand to 28% or less.

f. Monitor the turbine coast-down and auxiliary systems.

The time required from first alarm to restart would be approximately one hour.

15.4.5.2.2 System Operation

The analysis of this transient assumes and takes credit for normal functioning of plant instrumentation and controls, and the RPS. Operation of engineered safeguards is not expected.

15.4.5.2.3 The Effect of Single Failures and Operator Errors

This transient leads to a quick rise in reactor power level. Corrective action first occurs in the APRM neutron flux upscale trip and, being part of the RPS, it is designed to the single failure criterion. Therefore, shutdown is assured (Section 15.9). Operator errors are not of concern here in view of the fact that automatic shutdown transients follow so quickly after the postulated failure.

15.4.5.3 Core and System Performance

15.4.5.3.1 Mathematical Model

The nonlinear dynamic model described briefly in Section 15.1.1.3.1 is used to simulate this transient.

15.4.5.3.2 Input Parameters and Initial Conditions

This analysis has been performed, unless otherwise noted, with Cycle 1 plant conditions.

In each of these transients, the most severe transient results when initial conditions are established for operation at the low end of the rated flow control rod line. Specifically, at 57% NBR power and 39.6% core flow.

Maximum change in speed control occurs with a malfunction of one of the two redundant ASD controllers that results in an instantaneous step change to maximum output speed.

15.4.5.3.3 Results

The results of this event are based on Cycle 1 conditions. An analysis of this event for current conditions is not expected to result in a change in the general trends and characteristics as shown.

Figure 15.4-3 shows the results of the transient. The changes in nuclear system pressure are not significant with regard to overpressure. Pressure decreases over most of the transient. The rapid increase in core coolant flow causes an increase in neutron flux, which initiates a reactor APRM neutron flux upscale scram.

The peak neutron flux rise reaches 382.3% of NBR flux, and the accompanying transient fuel surface heat flux reaches 82.7% of rated. The MCPR remains above the safety limit, and fuel center temperature increases only 383°F. Therefore, the design basis is satisfied.

15.4.5.3.4 Consideration of Uncertainties

Some uncertainties in void reactivity characteristics, scram time, and worth are expected to be more optimistic and will therefore produce less severe consequences than those simulated here.

15.4.5.4 Barrier Performance

This transient results in a very slight increase in reactor vessel pressure, as shown in Figure 15.4-3, and therefore represents no threat to the RCPB.

15.4.5.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this transient, since no radioactive material is released from the fuel.

15.4.6 CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTIONS

These are not applicable to BWRs. This is a PWR transient.

15.4.7 MISPLACED BUNDLE ACCIDENT

15.4.7.1 Identification of Causes and Frequency Classification

15.4.7.1.1 Identification of Causes

The accident discussed in this section is the improper loading of a fuel bundle and subsequent operation of the core. Three errors must occur for this accident to take place in the initial core loading. First, a bundle must be loaded into a wrong location in the core. Second, the bundle which was supposed to be loaded where the mislocation occurred would have to be overlooked and also put in an incorrect location. Third, the misplaced bundles would have to be overlooked during the core verification performed following initial core loading.

15.4.7.1.2 Frequency Classification

This accident occurs when a fuel bundle is loaded into the wrong location in the core. It is assumed the bundle is misplaced in the worst possible location, and the plant is operated with the mislocated bundle. This accident is categorized as an infrequent incident based upon the following data:

Expected Frequency: 0.004 events/operating cycle

The above number is based upon past experience. The only misloading accidents that have occurred in the past were in reload cores where only two errors are necessary. Therefore, the frequency of occurrence for initial cores is even lower since three errors must occur concurrently.

15.4.7.2 Sequence of Events and System Operation

The postulated sequence of transients for the misplaced bundle accident is presented in Table 15.4-5.

Fuel loading errors, undetected by incore instrumentation following fueling operations, may result in undetected reductions in thermal margins during power operations. No detection is assumed and, therefore, no corrective operator action or automatic protection system functioning occurs.

15.4.7.2.1 The Effect of Single Failures and Operator Errors

This analysis already represents the worst case (i.e., operation of a misplaced bundle with three single active failures or single operator errors) and there are no further operator errors which can make the accident results any worse. It is felt that this section is not applicable to this accident (Section 15.9).

15.4.7.3 Core and System Performance

This event is discussed in the corresponding section of GESTAR II (Reference 4.1-1).

Results of analyzing the worst fuel bundle loading error are reported in Table 15.4-6. As can be seen, MCPR remains well above the point where boiling transition would be expected to occur, and the MLHGR does not exceed the 1% strain limit for the cladding. Therefore, no fuel damage occurs as a result of this accident.

15.4.7.4 Barrier Performance

An evaluation of the barrier performance was not made for this accident since it is very mild and highly localized. No perceptible change in the core pressure would be observed.

15.4.7.5 Radiological Consequences

An evaluation of the radiological consequences is not required for this accident since no radioactive material is released from the fuel.

15.4.8 SPECTRUM OF ROD EJECTION ACCIDENTS

This is not applicable to BWRs since the BWR has precluded this transient by incorporating into its design mechanical equipment which restricts any movement of the CRD system assemblies. The CRD housing support assemblies are described in Chapter 4.

15.4.9 CONTROL ROD-DROP ACCIDENT

15.4.9.1 Identification of Causes and Frequency Classification

Causes and frequency of the control rod-drop accident are described in the corresponding section of GESTAR II (Reference 4.1-1).

15.4.9.2 Sequence of Events and System Operation

A description of the sequence of events and the operation of the system during a control rod-drop accident is provided in the corresponding Section of GESTAR II (Reference 4.1-1).

15.4.9.3 Core and System Performance

15.4.9.3.1 Mathematical Model

The analytical methods, assumptions and conditions for evaluating the excursion aspects of the control rod-drop accident originally presented in the UFSAR are described in detail in GESTAR II (Reference 4.1-1). In support of the deletion of the MSLRM trip and valve closure functions, a new analysis was performed as described in NEDO-31400A, Reference 15.4-7.

15.4.9.3.2 Input Parameters and Initial Conditions

The input parameters and conditions for the control rod-drop accident originally presented in the UFSAR are described in GESTAR II (Reference 4.1-1). In support of the deletion of the MSLRM trip and valve closure functions, a new analysis was performed, with slightly different input parameters, as described in NEDO-31400A, Reference 15.4-7.

15.4.9.3.3 Results

The radiological consequences of the control rod drop accident are based on the methodology of Regulatory Guide 1.183 and the assumed failure of 1200 fuel rods of GNF2 and GNF3 10x10 fuel in an equivalent pin array of 85.6 and 88.3, respectively, and with a radial peaking factor of 2.0.

Two cases were evaluated. One with a release pathway through the main condenser where the condenser is assumed to leak radioactivity into the turbine enclosure and then released to the environment. The second pathway is through the Steam Jet Air Ejectors which discharge to the

off-gas system. In all cases, the dose for the main condenser leakage pathway bound the off-gas pathway dose.

The offsite dose limits established by Regulatory Guide 1.183 are 6.3 rem TEDE at the exclusion area boundary and 6.3 rem TEDE at the low population zone. The calculated dose at the exclusion area boundary is 0.054 rem TEDE and at the low population zone is 0.038 rem TEDE and are well within the prescribed limits.

The control room dose limit established by 10 CFR 50.67 is 5 rem TEDE. The calculated dose in the control room for the control rod drop accident is 1.85 rem TEDE and is within the prescribed limit.

15.4.9.4 Barrier Performance

An evaluation of the barrier performance was not made for this accident, since this is a highly localized accident with no significant change in the gross core temperature or pressure.

15.4.9.5 Radiological Consequences for the CRDA

Regulation 10 CFR 50.67, "Accident Source Term," provides a mechanism for power reactor licensees to voluntarily replace the traditional TID-14844 (Ref. 15.4-9) accident source term used in design-basis accident analyses with an "Alternative Source Term" (AST). The methodology of approach to this replacement is given in USNRC Regulatory Guide 1.183 (Ref. 15.4-10) and its associated Standard Review Plan 15.0.1 (Ref. 15.4-11).

Accordingly, Limerick Generating Station, Units 1 and 2, have applied the AST methodology for several areas of operational relief in the event of a Design Basis Accident (DBA), without fully crediting the use of previously assumed safety systems. Amongst these systems are the Control Room Emergency Fresh Air Supply System (CREFAS) and the Standby Gas Treatment System (SGTS).

In support of a full-scope implementation of AST as described in and in accordance with the guidance of Ref. 15.4-10, AST radiological consequence analyses are performed for the four DBAs that result in offsite exposure (i.e., Loss of Coolant Accident (LOCA), Main Steam Line Break (MSLB), Fuel Handling Accident (FHA), and Control Rod Drop Accident (CRDA)).

Implementation consisted of the following steps:

- Identification of the AST based on plant-specific analysis of core fission product inventory,
- Calculation of the release fractions for the four DBAs that could potentially result in control room and offsite doses (i.e., LOCA, MSLB, FHA, and CRDA),
- Analysis of the atmospheric dispersion for the radiological propagation pathways,
- Calculation of fission product deposition rates and removal mechanisms,
- Calculation of offsite and control room personnel Total Effective Dose Equivalent (TEDE) doses.

15.4.9.5.1 Regulatory Approach

The analyses are prepared in accordance with the guidance provided by Regulatory Guide 1.183 (Ref. 15.4-10).

15.4.9.5.2 Dose Acceptance Criteria

The AST acceptance criteria for Control Room dose for postulated major credible accident scenarios such as those resulting in substantial meltdown of the core with release of appreciable quantities of fission products is provided by 10 CFR 50.67, which requires:

> "Adequate radiation protection is provided to permit access to and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) total effective dose equivalent (TEDE) for the duration of the accident."

This limit is applied by Regulatory Guide 1.183 to all of the accidents considered with AST.

The AST acceptance criteria for an individual located at any point on the boundary of the exclusion area (the Exclusion Area Boundary or EAB) are provided by 10 CFR 50.67 as 25 rem TEDE for any 2-hour period following the onset of the postulated fission product release.

The AST acceptance criteria for an individual located at any point on the outer boundary of the low population zone (LPZ) are provided by 10 CFR 50.67 as 25 rem TEDE during the entire period of passage of the radioactive cloud resulting from the postulated fission product release.
These limits are applied by Regulatory Guide 1.183 to events with a higher probability of occurrence (including CRDA, MSLB, and FHA considered herein) to provide the following acceptance criteria:

- For the BWR MSLB for the case of an accident assuming fuel damage or a pre-incident Iodine spike, doses at the EAB and LPZ should not exceed 25 rem TEDE for the accident duration (2 hour dose for EAB and 30 day dose for LPZ). For MSLB accidents assuming normal equilibrium Iodine activity, doses should not exceed 2.5 rem TEDE for the accident duration.
- For the BWR CRDA, doses at the EAB and LPZ should not exceed 6.3 rem TEDE for the accident duration (2 hour dose for EAB and 24 hour dose for LPZ).
- For the FHA, doses at the EAB and LPZ should not exceed 6.3 rem TEDE for the accident duration (2 hour dose for EAB and 30 day dose for LPZ).

15.4.9.5.3 Computer Codes

New AST calculations for the CRDA were prepared to simulate the radionuclide release, transport, removal, and dose estimates associated with the postulated accident scenarios.

The RADTRAD computer code (Ref. 15.4-13) endorsed by the NRC for AST analyses was used in the calculations for the CRDA. The RADTRAD program is a radiological consequence analysis code used to estimate post-accident doses at plant offsite locations and in the control room. The

CRDA assessment takes no credit for control room isolation, emergency ventilation or filtration of intake air for the duration of the accident event.

Offsite X/Qs were calculated with the PAVAN computer code (Ref. 15.4-14), using the guidance of Regulatory Guide 1.145 (Ref. 15.4-15); control room X/Qs were calculated with the ARCON96 computer code (Ref. 15.4-16). The PAVAN and ARCON96 codes generally calculate relative concentrations in plumes from nuclear power plants at offsite locations and control room air intakes, respectively.

All of these computer codes have been used by the NRC staff in their safety reviews.

15.4.9.5.4 Source Terms

Core Inventory

The inventory of reactor core fission products used in RADTRAD for the AST CRDA analysis is based on maximum full power operation at a power level of 3527 MWth, which includes a 2% instrument error per Reg. Guide 1.49 (Ref. 15.4-17). The fission products used for the accidents are the 60 isotopes of the standard RADTRAD input library, determined by the code developer as significant in dose consequences. These were extracted from Attachment A of the LGS Design Analysis LM-0645 (Ref. 15.4-18), and correspond to 24 month cycle burnup parameters, conservatively calculated using the ORIGEN-ARP code.

Reactor Coolant Inventory

The reactor coolant fission product inventory for CRDA analysis is based on the Technical Specification concentration limits.

Release Fraction

Current design basis accident evaluations as modified by Regulatory Guide 1.183 (Ref. 15.4-10) were used to determine the specific releases of radioactive isotopes at the given stages of fuel pin failure and provide these releases as a percentage of the total release for each accident, as summarized below.

15.4.9.5.5 Methodology

Dose Calculations

As per Regulatory Guide 1.183 {Ref. 15.4-10), Total Effective Dose Equivalent (TEDE) doses are determined as the sum of the CEDE and the Effective Dose Equivalent (EDE) using dose conversion factors for inhalation CEDE from Federal Guidance Report No. 11 (Ref. 15.4-19) and for external exposure EDE from Federal Guidance Report No. 12 (Ref. 15.4-20).

Table 15.4-11 lists key assumptions and inputs used in the CRDA analysis. The design basis CRDA involves the rapid removal of a highest worth control rod resulting in a reactivity excursion that encompasses the consequences of any other postulated CRDA. The core performance analysis shows that the energy deposition that results from this event is inadequate to damage fuel pellets or cladding. However, for the dose consequence analysis, it was assumed that 1200 fuel pins in the full core were damaged, with melting occurring in 0.77 percent of the damaged

rods. This is applicable to the currently limiting assumption of a core loaded solely with 10x10 GNF2 or GNF3 fuel. A core average radial peaking factor of 2.0 was also assumed in the analysis, consistent with core operating limit report bases, as suggested in Regulatory Guide 1.183.

Releases to the environment are possible via two pathways. The first is through the Main Condenser. The main condenser is assumed to leak activity into the Turbine Building (TB) at a rate of 1% per day. This activity is then released, unfiltered, to the environment by way of the North Vent Stack, taking no credit for holdup in the TB. The north vent stack is the most conservative release point with respect to the Control Room intake, as the normal release pathway via the South Stack is further from the intake, with lower X/Q's.

The second pathway is through the Steam Jet Air Ejectors. When in operation, the Steam Jet Air Ejectors (SJAE) discharge to the augmented off-gas system. The augmented off-gas system charcoal delay beds in this scenario substantially delay noble gas release and essentially eliminate iodine release.

Both were evaluated in Ref. 15.4-12, and the first release scenario, through the main condenser, was found to clearly be the bounding DBA.

The analysis assumptions for the transport, reduction, and release of the radioactive material from the fuel and the reactor coolant are consistent with the guidance provided in Appendix C of Regulatory Guide 1.183, and are provided in the design analysis of Ref. 15.4-12.

15.4.9.5.6 Atmospheric Dispersion Factors (X/Qs)

Table 15.4-12 lists *X/Q* values used for the control room dose assessments, as derived in UFSAR Chapter 2 and applied for release points applicable to the CRDA.

Table 15.4-12 lists *X/Q* values for the EAB and LPZ boundaries, as also derived in UFSAR Chapter 2 and applied for release points applicable to the CRDA.

15.4.9.5.7 Summary and Conclusions

The radiological consequences of the postulated CRDA are given in Table 15.4-13. As indicated, the control room, EAB, and LPZ calculated doses are within regulatory limits after AST implementation.

15.4.10 REFERENCES

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15.4-8 Letter, A.C. Thadani, NRC, to George J. Beck, BWROG, May 15, 1991 - Subject: Acceptance for Referencing of Licensing Topical Report NEDO-31400.

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15.4-12 LGS Design Analysis LM-0643, Rev. 3, "Re-analysis of Control Rod Drop Accident (CRDA) Using Alternative Source Terms."

15.4-13 RADTRAD Code, "A Simplified Model for Radionuclide Transport and Removal and Dose Estimation," Version 3.03.

15.4-14 PAVAN Code, "An Atmospheric Dispersion Program for Evaluating Design Bases Accidental Releases of Radioactive Materials from Nuclear Power Stations."

15.4-15 U. S. Nuclear Regulatory Commission Regulatory Guide 1.145, "Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants," Revision 1, November 1982.

15.4-16 ARCON96 Code, "Atmospheric Relative Concentrations in Building Wakes."

15.4-17 U. S. Nuclear Regulatory Commission Regulatory Guide 1.49, "Power Levels of Nuclear Power Plants," Revision 1, December 1973.

15.4-18 LGS Design Analysis LM-0645, Rev. 5, "Re-analysis of Fuel Handling Accident (FHA) Using Alternative Source Terms."

15.4-19 Federal Guidance Report No. 11, "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion," 1988.

15.4-20 Federal Guidance Report No. 12, "External Exposure to Radionuclides in Air, Water, and Soil," 1993.

15.4-21 006N2787, "GNF3 Fuel Design Cycle-Independent Analyses for Limerick Generating Station Units 1 and 2", Revision 2, April 2021.

Table 15.4-1

SEQUENCE OF EVENTS FOR CONTROL ROD
WITHDRAWAL ERROR IN POWER RANGE

- Operator selects (the RBM is automatically normalized) and withdraws high worth control rod.

- The RBM system indicates excessive local peaking. Operator ignores the alarm and continues to withdraw control rod.

- The RBM system initiates a rod block, inhibiting further withdrawal.

- Operator verifies fuel thermal limits are satisfied before renormalizing RBM to further withdraw control rod.

Table 15.4-3

SEQUENCE OF EVENTS FOR ABNORMAL STARTUP OF
IDLE RECIRCULATION PUMP

TIME (sec)	EVENT
0	Start pump motor.
9.0	Startup loop flow starts to increase significantly.
10.4	APRM neutron flux upscale scram initiated.
>50.0	Vessel level returning to normal and will stabilize quickly.

NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

Table 15.4-4

SEQUENCE OF EVENTS FOR RECIRCULATION FLOW CONTROL FAILURE WITH INCREASING FLOW[1]

TIME (sec)	EVENT
0	Simulate failure of single-loop control.
1.7	APRM neutron flux upscale scram trip initiated.
5.5	Turbine control valves start to close upon falling turbine pressure.
20.2	Feedwater decreases upon rising water level.
>100.0	Reactor variables settle into new steady-state.

[1] See Figure 15.4-3.

NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

Table 15.4-5

SEQUENCE OF EVENTS FOR MISPLACED BUNDLE ACCIDENT

a. During core loading operation, bundle is placed in the wrong location.

b. Subsequently, the bundle intended for this location is placed in the location of the previous bundle.

c. During core verification procedure, error is not observed.

d. Plant is brought to full power operation without detecting misplaced bundle.

e. Plant continues to operate.

Table 15.4-6

INITIAL CONDITIONS AND RESULTS
OF FUEL BUNDLE LOADING ERROR[1]

Reactor Power, % rated	100
Core Flow, % rated	100
For Largest ΔCPR:	
Core Exposure, MWD/ST	7810
Location of Error	(29, 32)
Initial CPR without Fuel Loading Error	1.40
Minimum CPR with Fuel Loading Error	1.29
ΔCPR	0.11
For Largest ΔMLHGR:	
Core Exposure, MWD/ST	5000
Location of Error	(21, 54)
Initial LHGR (Assumed at Operating Limit), kW/ft	13.4
LHGR with Fuel Loading Error, kW/ft	16.97
Core Conditions	
Minimum CPR Operating Limit	1.22
Minimum CPR Safety Limit	1.06

(1) Core conditions are assumed to be normal for a hot, operating core.

NOTE: This is a non-limiting event that has not been reanalyzed for power rerate. The results of this event are based on Cycle 1 conditions. This event is analyzed for the initial core and for each reload to confirm the CPR is non-limiting. See current SRLR for cycle-specific values.

Tables 15.4-7 through 15.4-10

Tables 15.4-7 through 15.4-10
DELETED

Table 15.4-11

CRDA – RADIOLOGICAL CONSEQUENCES
KEY INPUTS AND ASSUMPTIONS

KEY CRDA ANALYSIS INPUTS AND ASSUMPTIONS

Input/Assumption	Value
Core Damage	1200 fuel rods failed*
Percent of Damaged Fuel with Melt	0.77%
Radial Peaking Factor	2.0
Condenser Leak Rate	1% per day
Release Period	24 hours
CREFAS System Initiation	Not utilized
Charcoal Delay Bed Noble Gas Delay for SJAE pathway	816 hours for Xe 35.5 hours for Kr

* A bounding value, per use of 10x10 GNF2 or GNF3 fuel and associated 2.0 radial peaking factor assumptions.

Table 15.4-12

X/Q VALUES FOR CRDA

Onsite Control Room **X/Q** Values for the CRDA Releases[1]

Time Period	X/Q **(sec/m^3)**
0 – 2 hrs	6.88E-03
2 – 8 hrs	5.17E-03
8 – 24 hrs	2.04E-03

Note
1. North Vent Stack release to Control Room X/Q values based on ARCON96.

Offsite X/Q (sec/m^3) Values for the CRDA Releases[1]

Time Period	**EAB** X/Q **(sec/m^3)**	**LPZ** X/Q **(sec/m^3)**
0 – 2 hrs	3.18E-04	---
0 – 8 hrs	---	5.79E-05
8 – 24 hrs	---	4.10E-05

Notes:
1. North Vent Stack release to offsite locations X/Q values based on Regulatory Guide 1.145 methodology.

Table 15.4-13

CRDA RADIOLOGICAL CONSEQUENCES ANALYSIS RESULTS

CRDA Radiological Consequence Analysis Scenario 1 (Main Condenser Leakage – DBA)			
Location	Duration	TEDE (rem)	Regulatory Limit TEDE (rem)
Control Room	30 days	1.85	5
EAB	Maximum, 2 hours	0.054	6.3
LPZ	30 days	0.038	6.3
Scenario 2 (SJAE Release)			
Location	Duration	TEDE (rem)	Regulatory Limit TEDE (rem)
Control Room	30 days	0.0268	5
EAB	Maximum, 2 hours	0.0274	6.3
LPZ	30 days	0.0099	6.3

15.5 INCREASE IN REACTOR COOLANT INVENTORY

15.5.1 INADVERTENT HPCI STARTUP

15.5.1.1 Identification of Causes and Frequency Classification

15.5.1.1.1 Identification of Causes

Manual startup of the HPCI system is postulated for this analysis, i.e., operator error.

15.5.1.1.2 Frequency Classification

This transient is categorized as an incident of moderate frequency.

15.5.1.2 Sequence of Events and System Operation

15.5.1.2.1 Sequence of Events

Table 15.5-1 lists the sequence of events for Figure 15.5-1.

15.5.1.2.1.1 Identification of Operator Actions

Relatively small changes would be experienced in plant conditions as a result of inadvertent HPCI start-up. The operator should, after hearing the alarm that the HPCI has commenced operation, check reactor water level and drywell pressure. If conditions are normal, the operator should shut down the system.

15.5.1.2.2 System Operation

In order to properly simulate the expected sequence of events, the analysis of this transient assumes normal functioning of plant instrumentation and controls; specifically, the pressure regulator and the vessel level control which respond directly to this event.

The Inadvertent HPCI injection results in a mild depressurization followed by increasing reactor water level. It is probable that feedwater control systems will appropriately adjust downscale to account for the rising water level; however, for conservatism the water level is modeled to rise until the high level (L8) trip setpoint is reached, resulting in a turbine trip. At this point the event largely proceeds as the Turbine Bypass transient.

Required operation of engineered safeguards other than what is described is not expected for this transient event.

The system is assumed to be in the manual flow control mode of operation.

15.5.1.2.3 The Effect of Single Failures and Operator Errors

The effect of a single failure in the pressure regulator will aggravate the transient depending upon the nature of the failure. Pressure regulator failures are discussed in Sections 15.1.3 and 15.2.1.

The effect of a single failure in the level control system has rather straightforward consequences including level rise or fall by improper control of the feedwater system. Increasing level will trip the

turbine and automatically trip the HPCI system off. This trip signature is already described in the failure of feedwater controller with increasing flow. Decreasing level will automatically initiate scram at the Level 3 level trip and will have a signature similar to loss of feedwater control - decreasing flow.

15.5.1.3 Core and System Performance

15.5.1.3.1 Mathematical Model

The detailed nonlinear dynamic models described briefly in Section 15.1.2.3.1 are used to simulate this transient.

15.5.1.3.2 Input Parameter and Initial Conditions

The original analysis was performed with the conditions in Table 15.0-2. Subsequent analyses utilize reload specific parameters shown in the reload transient analyses documents (e.g., FRED Form, OPL-3, WILMA).

The water temperature of the HPCI system was assumed to be 40°F with an enthalpy of 11.0 Btu/lb.

Inadvertent startup of the HPCI system was chosen for analysis since it provides the greatest auxiliary source of cold water for the vessel.

15.5.1.3.3 Results

Figure 15.5-1 shows the simulated transient. It begins with the introduction of cold water into the vessel through the core spray nozzles and the feedwater injection spargers. Within one second the full HPCI flow is established (2,000 gpm through the core spray and 3,600 gpm through the feedwater). The HPCI flow split event is conservative because it maximizes the decrease in the core inlet. No delays were considered because they are not relevant to the analysis.

Addition of cooler water through the feedwater sparger increases core inlet subcooling, causing power to go up. The effect of the cool water through the core sprays, however, is some small condensation of steam in the upper plenum, resulting in a mild depressurization. The loss of steam flow through the condensation process is small when compared to the gain in steam flow that is due to subcooling change. The combined effect is a decrease in reactor pressure, along with some increase in reactor power. The water level begins to rise until the high vessel water level (Level 8) setpoint trip initiates main turbine and feedwater turbine trips. The event is bounded by FWCF or LRNBP/TTNBP, and MCPR remains well above the safety limit.

15.5.1.3.4 Consideration of Uncertainties

Important analytical factors, including reactivity coefficient and feedwater temperature change, have been assumed to be at the worst conditions so that any deviations in the actual plant parameters will produce a less severe transient.

15.5.1.4 Barrier Performance

Figure 15.5-1 indicates a slight pressure reduction from initial conditions, therefore, no further evaluation is required as RCPB pressure margins are maintained.

15.5.1.5 Radiological Consequences

Since no activity is released during this transient, a detailed evaluation is not required.

15.5.2 CHEMICAL VOLUME CONTROL SYSTEM MALFUNCTION (OR OPERATOR ERROR)

Not applicable to BWR. This is a PWR transient.

15.5.3 OTHER BWR TRANSIENTS WHICH INCREASE REACTOR COOLANT INVENTORY

These transients are discussed and considered in Sections 15.1 and 15.2.

Table 15.5-1

SEQUENCE OF EVENTS: INADVERTENT HPCI STARTUP[1]

TIME (sec)	EVENT
0	Simulate HPCI cold water injection.
2.0	Full Flow for HPCI reached, reactor water level increasing for remainder of event
5.0	Feedwater Control System begins reducing coolant flow
8.0	Dome Pressure equalizes at slightly lower value
8.0	Steam Flow to turbine equalized at slightly lower value
34.0	Reactor water level reaches high trip value, turbine trip initiated[2]
34.01	Main Turbine stop valves reach 90% open and initiate RPS scram and RPT
34.17	Turbine Stop valves fully close, causing pressurization and cessation of steam flow
35	Turbine Bypass valves open. MSRVs are available for additional pressure relief (cycling as needed)

(1) See Figure 15.5-1.

(2) Assumes single failure of level control or FW control

Note: All timing values are approximate and generally representative; see current SRLR for cycle-specific values.

15.6 DECREASE IN REACTOR COOLANT INVENTORY

15.6.1 INADVERTENT MAIN STEAM RELIEF VALVE OPENING

This transient is discussed and analyzed in Section 15.1.4.

15.6.2 INSTRUMENT LINE PIPE BREAK

This accident involves the postulation of a small steam or liquid line pipe break inside or outside primary containment but within a controlled release structure. In order to bound the accident, it is assumed that a small instrument line, instantaneously and circumferentially, breaks at a location where it may not be able to be isolated and where immediate detection is not automatic or apparent.

Obviously, this accident is far less limiting than the postulated events in Sections 15.6.4, 15.6.5, and 15.6.6.

This postulated accident represents the envelope evaluation for small line failure inside and outside primary containment, relative to sensitivity to detection. It is summarized in Tables 15.6-1 through 15.6-7 and Figure 15.6-1.

15.6.2.1 Identification of Causes and Frequency Classification

15.6.2.1.1 Identification of Causes and Event Description

There is no specific event or circumstance identified that results in the failure of an instrument line. These lines are designed to high quality engineering codes and standards, and seismic and environmental requirements. However, for the purpose of evaluating the consequences of a small line rupture, the failure of an instrument line is assumed to occur.

A circumferential rupture of an instrument line connected to the primary coolant system is postulated to occur outside primary containment but inside secondary containment. This failure results in the release of primary system coolant to the secondary containment until the reactor is depressurized. This accident could conceivably occur also in the drywell. However, the associated effects would not be as significant as those from a failure in the secondary containment.

15.6.2.1.2 Frequency Classification

This accident is categorized as a limiting fault.

15.6.2.2 Sequence of Events and System Operation

15.6.2.2.1 Sequence of Events

The sequence of events for this accident is shown in Table 15.6-1.

The operator should isolate the affected instrument line. Depending on which line is broken, the operator should determine whether to continue plant operation until a scheduled shutdown can be made or to proceed with an immediate, orderly plant shutdown and initiate the SGTS or other ventilation effluent treatment systems.

As a result of increased radiation, temperature, humidity, fluid, and noise levels within the secondary containment, operator action can be initiated by any one or any combination of the following:

a. Operator comparing the readings of several instruments monitoring the same process variable, such as reactor level, jet pump flow, steam flow, and steam pressure.

b. By alarm, either high or low in the control room, from the instrument served by the failed line.

c. By a half-channel scram if rupture occurred on an RPS instrument line.

d. By a general increase in the area radiation monitor readings.

e. By an increase in the ventilation process radiation monitor readings.

f. By leak detection system actuation.

Upon receiving one or more of the above signals and having made an unsuccessful attempt to isolate the break, the operator should proceed to shutdown the plant in an orderly manner.

15.6.2.2.2 System Operation

Normal plant instrumentation and controls are assumed to be fully operational during the entire plant transient to ensure positive identification of the break and safe shutdown of the plant. Minimum reactor and plant protection system operations are assumed for the analysis, e.g., minimum ECCS flow, and pool cooling capability. As a consequence of the accident, the reactor is scrammed and the reactor vessel cooled and depressurized over a 5 hour period.

15.6.2.2.3 The Effect of Single Failures and Operator Errors

The initiating event is handled by a protection sequence that can accommodate additional single failures. See Section 15.9 for a more detailed discussion of this subject.

15.6.2.3 Core and System Performance

15.6.2.3.1 Qualitative Summary

Instrument line breaks, because of their small size, are substantially less limiting from a core and systems performance standpoint than the accidents examined in Sections 15.6.4, 15.6.5, and 15.6.6. Consequently, instrument line breaks are considered to be bounded specifically by the steam line break (Section 15.6.4). Details of this calculation, including those pertinent to core and system performance, are discussed in detail in Section 15.6.4.3.

Since instrument line breaks result in a slower rate of coolant loss and are bounded by the calculations referenced above, the results presented here are qualitative rather than quantitative. Since the rate of coolant loss is slow, an orderly reactor system depressurization follows reactor scram, and the primary system is cooled down and maintained without ECCS actuation. No fuel damage or core uncovering occurs as a result of this accident.

15.6.2.3.2 Quantitative Results

Instrument line breaks, because of their small size, are substantially less limiting from a core and system performance standpoint than the steam line break outside primary containment. Similarly, instrument line breaks are considered within the spectrum considered in ECCS performance calculations discussed in detail in Section 6.3.3.

Therefore, all information concerning ECCS models employed, input parameters, and detailed results for a more limiting (steam line break) event may be found in Section 6.3.

15.6.2.3.3 Consideration of Uncertainties

The approach toward conservatively analyzing this accident is discussed in detail for a more limiting case in Section 6.3.

15.6.2.4 Barrier Performance

15.6.2.4.1 General

The release of primary coolant through the orificed instrument line could result in an increase in secondary containment pressure and the potential for isolation of the normal ventilation system.

The following assumptions and conditions are the basis for the mass loss during the 5 hour reactor shutdown period of this accident:

a. Shutdown and depressurization initiated 10 minutes after break occurs.

b. Normal depressurization and cooldown of RPV.

c. Line contains a ¼ inch diameter flow restricting orifice inside the drywell.

d. Moody critical blowdown flow model (Reference 15.6-1) is applicable, and flow is critical at the orifice.

The total integrated mass of fluid released into the secondary containment via the break during the blowdown is 25,000 pounds. Of this total, 6000 pounds flash to steam. Release of this mass of coolant results in a secondary containment pressure that is well below the design pressure.

Using the assumptions and methods discussed above, analysis shows that following the break of an instrument line installed with a ¼ inch orifice, the vessel inventory mass loss during the first two hours is 14,500 pounds; of this total, 4200 pounds flash to steam.

Small lines connected to the primary reactor coolant system and penetrating the containment that do not have a ¼ inch orifice upstream of the primary containment are listed below:

System	Containment Penetration No.
Recirculation Loop Sample	X-28A-1
CRD Insert	X-37A-D
CRD Withdraw	X-38A-D
SLCS	X-42
Main Steam Sample	X-43B

As identified in Table 6.2-17, these lines have redundant containment isolation barriers, except for the CRD withdraw lines. An estimate of the primary coolant released from the CRD withdraw lines in the event of a break is provided in NUREG-0803, "Generic Safety Evaluation Report Regarding Integrity of BWR Scram System Piping." Analyses to determine the amount of primary coolant released from the other lines have not been performed because the offsite radiological consequences of breaks in these lines would be bounded by those of a large steam line break outside primary containment (Section 15.6.4).

15.6.2.5 Radiological Consequences

Two separate radiological analyses are provided for this accident:

a. The first is based on conservative assumptions considered to be acceptable to the NRC for the purpose of determining adequacy of the plant design to meet 10CFR100. This analysis is referred to as the "design basis analysis."

b. The second is based on assumptions considered to provide a realistic conservative estimate of the radiological consequences. This analysis is referred to as the "realistic analysis."

A schematic of the release path is shown in Figure 15.6-1.

15.6.2.5.1 Design Basis Analysis

The design basis analysis is based on SRP 15.6.2 and Regulatory Guide 1.5. The specific models, assumptions, and the program used for computer evaluation are described in Section 15.10. Specific values of parameters used in the evaluation are presented in Table 15.6-2.

The assumptions and calculation methodology used are as follows:

a. Spiking factor

The activity released from the fuel to the coolant as a consequence of reactor scram and vessel depression was based on measurements during plant shutdowns (Reference 15.6-2). It was shown that for a 95 percentile probability, a total of 7 Ci of I-131 is released to the coolant for every 1 μCi/sec of prespike I-131 release. This conservative ratio was applied for all the iodine isotopes for the dose analysis. The

prespike iodine releases were those that correspond to a 0.35 Ci/sec noble gases release, a DBA assumption.

b. Iodine concentration in coolant

The total iodine released from the fuel to the coolant was assumed to take place in a span of 5 hours, resulting in continued buildup of coolant activity during that period. The coolant activity during 0-2 hours was assumed to be constant and equal to that at the end of the first hour. The coolant activity during 2-5 hours was assumed to be equal to that at the end of 3½ hours. This is a conservative assumption, since the rate of increase in coolant activity decreases with time.

c. Partition factor

It was assumed that 100% of the activity in the coolant that flashed into steam remains airborne and that 10% of the activity carried by the coolant water into the secondary containment becomes airborne (corresponding to a conservative partition factor of 0.1).

d. Activity in secondary containment and released to the environment

The secondary containment volume was assumed to consist of one reactor enclosure, as discussed in Section 15.6.5.5.1.2. The activity airborne in the secondary containment was assumed to be uniformly mixed by the RERS with an air flow rate of 60,000 cfm and a 95% efficient filter. Secondary containment air is released to the environment via the SGTS at the rate of two secondary containment volumes change per day. The SGTS filter has an efficiency of 99%. The SGTS draws air from the RERS exhaust. The activity airborne in the secondary containment and the activity released to the environment are presented in Tables 15.6-3 and 15.6-4, respectively.

The calculated exposure at the EAB and LPZ are presented in Table 15.6-7.

15.6.2.5.2 Realistic Analysis

The realistic analysis was based on a realistic but still conservative assessment of this accident. The specific models, assumptions, and the program used for computer evaluation are described in Reference 15.6-3. Specific values of parameters used in the evaluation are presented in Table 15.6.2. The leakage path used in these calculations is shown in Figure 15.6-1.

Assumptions and calculations for the realistic analysis were identical to that of the design basis except for the following:

a. Total iodine released from the fuel to the coolant was assumed to be 2 Ci for every 1 μCi/sec prespike release. This is an estimated ratio for a 50 percentile probability spiking release during plant shutdowns (Reference 15.6-2).

b. The 50% X/Qs were used instead of the 5% X/Qs used for the design basis analysis.

The activity airborne in the secondary containment is presented in Table 15.6-5. The activity released to the environment is presented in Table 15.6-6. The calculated exposure at the EAB and the LPZ are presented in Table 15.6-7.

15.6.3 STEAM GENERATOR TUBE FAILURE

This section is not applicable to the direct cycle BWR; this is a PWR-related event.

15.6.4 STEAM SYSTEM PIPING BREAK OUTSIDE PRIMARY CONTAINMENT

This accident involves the postulation of a large steam line pipe break outside primary containment. It is assumed that the largest steam line instantaneously and circumferentially breaks at a location downstream of the outermost isolation valve. The plant is designed to immediately detect such an occurrence, initiate isolation of the broken line, and actuate the necessary protective features. This postulated accident represents the envelope evaluation of steam line failures outside primary containment.

This accident is summarized in Tables 15.6-8 through 15.6-11 and the leakage path used in these calculations is shown in Figure 15.6-2.

15.6.4.1 Identification of Causes and Frequency Classification

15.6.4.1.1 Identification of Causes

A main steam line break is postulated without the cause being identified. These lines are designed to high quality engineering codes and standards, and seismic and environmental requirements. However, for the purpose of evaluating the consequences of a postulated large steam line rupture, the failure of a main steam line is assumed to occur.

15.6.4.1.2 Frequency Classification

This accident is categorized as a limiting fault.

15.6.4.2 Sequence of Events and System Operation

15.6.4.2.1 Sequence of Events

Accidents that result in the release of radioactive materials directly outside primary containment are primary results of postulated breaches in the RCPB or the steam power conversion system boundary. A break spectrum analysis for the complete range of reactor conditions indicates that the limiting fault accident for breaks outside primary containment is a complete severance of one of the four main steam lines. The sequence of events and approximate time required to respond to the accident is given in Table 15.6-8.

Normally, the reactor operator will maintain reactor vessel water inventory and, therefore, core cooling with the RCIC system. Without operator action, the RCIC would initiate automatically on low water level following isolation of the main steam supply system (i.e., MSIV closure). The core would be covered throughout the accident and there would be no fuel damage. Without taking credit for the RCIC water makeup capability and assuming HPCI failure, the termination of the accident without fuel damage is assured because the ADS will actuate at low water level (Level 1). This will permit the low pressure ECCS to re-establish water level above the core.

15.6.4.2.2 System Operation

A postulated guillotine break of one of the four main steam lines outside primary containment results in mass loss from both ends of the break. The flow from the upstream side is initially limited by the flow restrictor upstream of the inboard isolation valve. Flow from the downstream side is initially limited by the total area of the flow restrictors in the three unbroken lines. Subsequent closure of the MSIVs further limits the flow when the valve area becomes less than the limiter area and finally terminates the mass loss when the full closure is reached.

A discussion of plant and reactor protection system action and ESF action is given in Sections 6.3, 7.3, and 7.6.

15.6.4.2.3 The Effect of Single Failures and Operator Errors

The effect of single failures has been considered in analyzing this accident. The ECCS aspects are covered in Section 6.3. The break detection and isolation considerations are defined in Sections 7.3 and 7.6. All of the protective sequences for this accident are capable of single failure accommodation and yet completion of the necessary safety action (Section 15.9).

15.6.4.3 Core and System Performance

Quantitative results (including mathematical models, input parameters, and consideration of uncertainties) for this accident are given in Section 6.3. The temperature and pressure transients resulting as a consequence of this accident are insufficient to cause fuel damage.

15.6.4.3.1 Input Parameters and Initial Conditions

Refer to Section 6.3 for initial conditions.

15.6.4.3.2 Results

There is no fuel damage as a consequence of this accident. Refer to Section 6.3 for ECCS analysis.

15.6.4.3.3 Consideration of Uncertainties

Sections 6.3 and 7.3 contain discussions of the uncertainties associated with the ECCS performance and the containment isolation systems, respectively.

15.6.4.4 Barrier Performance

Since this break occurs outside primary containment, barrier performance within the primary containment envelope is not applicable. Details of the results of this accident can be found in Section 6.2.3.

The following assumptions and conditions are used in determining the mass loss from the primary system from the inception of the break to full closure of the MSIVs:

a. The reactor is operating at the power level associated with maximum mass release (4% Reactor Power, 35% Core Flow).

b. Nuclear system pressure is initially 1060 psia.

c. An instantaneous circumferential break of the main steam line occurs.

d. Isolation valves start to close at 1.0 second on high flow signal and are fully closed at 6.0 seconds.

e. The Moody critical flow model (Reference 15.6-1) is applicable.

f. The SAFER Code (Ref. 15.6-10) is used to calculate the time varying two-phase flow and system pressure during the accident.

Initially, only steam will issue from the broken end of the steam line. The flow in each line is limited by critical flow at the limiter to a maximum of 200% of rated flow for each line. Rapid depressurization of the RPV causes the water level to rise, resulting in a steam/water mixture flowing from the break until the valves are closed. The total integrated mass leaving the RPV through the steam line break is 115,700 lbm of which 101,562 lbm is liquid and 14,138 lbm is steam (Ref. 15.6-26). For the radiological consequence evaluation, a total mass of 140,000 lbm is assumed.

15.6.4.5 Radiological Consequences for the MSLB

Regulation 10CFR50.67, "Accident Source Term," provides a mechanism for power reactor licensees to voluntarily replace the traditional TID-14844 (Ref. 15.6-11) accident source term used in design-basis accident analyses with an "Alternative Source Term" (AST). The methodology of approach to this replacement is given in USNRC Regulatory Guide 1.183 (Ref. 15.6-12) and its associated Standard Review Plan 15.0.1 (Ref. 15.6-13).

Accordingly, Limerick Generating Station, Units 1 and 2, have applied the AST methodology for several areas of operational relief in the event of a Design Basis Accident (DBA), without fully crediting the use of previously assumed safety systems. Amongst these systems are the Control Room Emergency Fresh Air Supply System (CREFAS) and the Standby Gas Treatment System (SGTS).

In support of a full-scope implementation of AST as described in and in accordance with the guidance of Ref. 15.6-12, AST radiological consequence analyses are performed for the four DBAs that result in offsite exposure (i.e., Loss of Coolant Accident (LOCA), Main Steam Line Break (MSLB), Fuel Handling Accident (FHA), and Control Rod Drop Accident (CRDA).

Implementation consisted of the following steps:

- Identification of the AST based on plant-specific analysis of core fission product inventory,
- Calculation of the release fractions for the four DBAs that could potentially result in control room and offsite doses (i.e., LOCA, MSLB, FHA, and CRDA),
- Analysis of the atmospheric dispersion for the radiological propagation pathways,
- Calculation of fission product deposition rates and removal mechanisms,

- Calculation of offsite and control room personnel Total Effective Dose Equivalent (TEDE) doses.

15.6.4.5.1 Regulatory Approach

The analyses are prepared in accordance with the guidance provided by Regulatory Guide 1.183 (Ref. 15.6-12).

15.6.4.5.2 Dose Acceptance Criteria

The AST acceptance criteria for Control Room dose for postulated major credible accident scenarios such as those resulting in substantial meltdown of the core with release of appreciable quantities of fission products is provided by 10CFR50.67, which requires:

> "Adequate radiation protection is provided to permit access to and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) total effective dose equivalent (TEDE) for the duration of the accident."

This limit is applied by Regulatory Guide 1.183 to all of the accidents considered with AST.

The AST acceptance criteria for an individual located at any point on the boundary of the exclusion area (the Exclusion Area Boundary or EAB) are provided by 10 CFR 50.67 as 25 rem TEDE for any 2-hour period following the onset of the postulated fission product release.

The AST acceptance criteria for an individual located at any point on the outer boundary of the low population zone (LPZ) are provided by 10CFR50.67 as 25 rem TEDE during the entire period of passage of the radioactive cloud resulting from the postulated fission product release.

These limits are applied by Regulatory Guide 1.183 to events with a higher probability of occurrence (including CRDA, MSLB, and FHA considered herein) to provide the following acceptance criteria:

- For the BWR MSLB for the case of an accident assuming fuel damage or a pre-incident Iodine spike, doses at the EAB and LPZ should not exceed *25* rem TEDE for the accident duration (2 hour dose for EAB and 30 day dose for LPZ). For MSLB accidents assuming normal equilibrium Iodine activity, doses should not exceed 2.5 rem TEDE for the accident duration.
- For the BWR CRDA, doses at the EAB and LPZ should not exceed 6.3 rem TEDE for the accident duration (2 hour dose for EAB and 24 hour dose for LPZ).
- For the FHA, doses at the EAB and LPZ should not exceed 6.3 rem TEDE for the accident duration (2 hour dose for EAB and 30 day dose for LPZ).

15.6.4.5.3 Computer Codes

New AST calculations for the MSLB were prepared to simulate the radionuclide release, transport, removal, and dose estimates associated with the postulated accidents.

While the RADTRAD computer code (Ref. 15.6-15) endorsed by the NRC for AST analyses was used in the calculations for the LOCA, CRDA and FHA, the MSLB was analyzed using the

Regulatory Guide 1.183 methodology. The MSLB assessment takes no credit for control room isolation, emergency ventilation or filtration of intake air for the duration of the accident event.

15.6.4.5.4 Source Terms

Reactor Coolant Inventory

The reactor coolant fission product inventory for MSLB analysis is based on the Technical Specification limits in terms of Dose Equivalent I-131 (the concentration of I-131 that alone would produce the same dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present), using inhalation Committed Effective Dose Equivalent (CEDE) dose conversion factors from Federal Guidance Report No. 11 (Ref. 15.6-20). Cesium, as Cesium Iodide, and Noble Gas releases are also considered, but the iodine isotopes are the only significant dose contributors.

15.6.4.5.5 Methodology

Dose Calculations

As per Regulatory Guide 1.183 (Ref. 15.6-12), Total Effective Dose Equivalent (TEDE) doses are determined as the sum of the CEDE and the Effective Dose Equivalent (EDE) using dose conversion factors for inhalation CEDE from Federal Guidance Report No. 11 (Ref. 15.6-20) and for external exposure EDE from Federal Guidance Report No. 12 (Ref. 15.6-21).

Main Steam Line Break (MSLB)

Table 15.6-9 lists the key assumptions and inputs used in the analysis. The postulated MSLB accident assumes a double-ended break of one main steam line outside the primary containment with displacement of the pipe ends that permits maximum blowdown rates. However, the break mass released is taken for the dose calculations as a bounding maximized value for all current Boiling Water reactor plants of 140,000 pounds of water, as provided in Standard Review Plan 15.6.4 for a GESSAR-251 plant. This value bounds for dose calculation purposes the historic UFSAR values, ensuring that the dose consequences are maximized and that the releases bound any other credible pipe break. Two activity release cases corresponding to the pre-accident spike and maximum equilibrium concentration allowed by Technical Specifications of 4.0 μCi/gm and 0.2 μCi/gm dose equivalent I-131 respectively were assumed, with inhalation CEDE dose conversion factors from Federal Guidance Report 11 conservatively used for normalized Dose Equivalent I-131 determination. The released activity assumptions are consistent with the guidance provided in Appendix D of Regulatory Guide 1.183.

The analysis assumes an instantaneous ground level release. For the control room dose calculations, the released reactor coolant and steam is assumed to expand to a hemispheric volume at atmospheric pressure and temperature (consistent with an assumption of no Turbine Building credit). This hemisphere is then assumed to move at a speed of 1 meter per second downwind past the control room intake. No credit is taken for buoyant rise of the steam cloud or for decay, and dispersion of the activity of the plume was conservatively ignored. For offsite locations, the buoyant rise of the steam cloud is similarly ignored, and the ground level dispersion is based on the conservative and simplified Regulatory Guide 1.5 (Ref. 5.6-22) methodology.

The radiological consequences following an MSLB accident were determined using a spreadsheet. The following significant assumptions were made and are detailed in the applicable MSLB design analysis (Ref. 15.6-14):

- Iodine activity distribution in the coolant as follows:

Iodine Isotope	Activity (μCi/cc)
I-131	0.039
I-132	0.360
I-133	0.267
I-134	0.720
I-135	0.390

- Release from the break to the environment is assumed instantaneous. No holdup in the Turbine Building or dilution by mixing with Turbine Building air volume is credited.

- The steam cloud is assumed to consist of the portion of the liquid reactor coolant release that flashed to steam.

- The activity of the cloud is based on the total mass of water released from the break. This assumption is conservative because it considers the maximum release of fission products.

- Flashing fraction of liquid water released was assumed as 40%. However, all activity in the water is assumed to be released.

15.6.4.5.6 Atmospheric Dispersion Factors (X/Qs)

For the control room dose calculations, the released reactor coolant and resultant flashed steam is assumed to expand to a hemispheric volume at atmospheric pressure and temperature (consistent with an assumption of no Turbine Building credit). This hemisphere is then assumed to move at a speed of 1 meter per second downwind past the control room intake. No credit is taken for buoyant rise of the steam cloud or for decay, and dispersion of the activity of the plume was conservatively ignored.

For offsite locations, the buoyant rise of the steam cloud is similarly ignored, and the ground level dispersion is based on the conservative and simplified Regulatory Guide 1.5 (Ref. 15.6-22) methodology. Table 15.6-10 lists X/Q values for the EAB and LPZ boundaries.

15.6.4.5.7 Summary and Conclusions

The radiological consequences of the postulated MSLB are given in Table 15.6-11. As indicated, the control room, EAB, and LPZ calculated doses are within regulatory limits after AST implementation.

15.6.5 LOSS-OF-COOLANT ACCIDENTS (RESULTING FROM SPECTRUM OF POSTULATED PIPING BREAKS WITHIN THE REACTOR COOLANT PRESSURE BOUNDARY) INSIDE PRIMARY CONTAINMENT

This accident involves the postulation of a spectrum of piping breaks inside containment varying in size, type, and location. The break type includes steam and/or liquid process system lines.

The accident is analyzed quantitatively in Sections 6.3, 6.2, 7.3, 7.6, and 8.3. Therefore, the following discussion provides only new information not presented in the subject sections. All other information is covered by cross-referencing.

The postulated accident represents the envelope evaluation for liquid or steam line failures inside primary containment. It is summarized in Tables 15.6-13 through 15.6-20 and the leakage path used in these calculations is shown in Figure 15.6-3.

15.6.5.1 Identification of Causes and Frequency Classification

15.6.5.1.1 Identification of Causes

There are no realistic, identifiable events that would result in a pipe break inside primary containment of the magnitude required to constitute a LOCA coincident with a single active failure. The subject piping is designed to high quality engineering codes and standards, and seismic and environmental requirements. However, for estimating the resultant effects of this category of pipe breaks, a LOCA plus single active failure are assumed to occur without the causes being identified.

15.6.5.1.2 Frequency Classification

This accident is categorized as a limiting fault.

15.6.5.2 Sequence of Events and System Operation

15.6.5.2.1 Sequence of Events

The sequence of events associated with this accident is shown in Table 6.3-2 for core system performance and Table 6.2-8 for barrier (containment) performance.

Following the pipe break and scram, the low-low water level (Level 2) trip or the high drywell pressure trip will start the HPCI system. The MSIVs will begin to close on the low-low-low water level (Level 1) trip. Either the Level 1 trip or the high drywell pressure coincident with low reactor pressure trip will start the CS and LPCI systems. From time zero, the CS system will start at less than or equal to 54 seconds, the HPCI system will start at approximately 60 seconds and the LPCI system will start at less than or equal to 70 seconds..

Since automatic actuation and operation of the ECCS is a system design basis, no credit for immediate operator actions are assumed in the evaluation of the accident. However, in accordance with procedural requirements, the operator should perform the following described actions.

The operator should, after ensuring that all rods have been inserted at time 0 plus approximately 10 seconds, determine plant condition by observing the annunciators. After observing that the ECCS flows are initiated, the operator should check that the diesel generators have started and are on standby condition, and that the ESW system has started. Based on plant conditions, the operator should initiate operation of the RHRSW system and the RHR system heat exchangers in the suppression pool cooling mode. After the RHR system and other auxiliary systems are in proper operation, the operator should monitor the hydrogen concentration in the drywell for proper activation of the post-LOCA recombiners, if necessary.

15.6.5.2.2 System Operation

Accidents that could result in the release of radioactive fission products directly into the containment are the result of postulated nuclear system RCPB pipe breaks. A spectrum of pipe break sizes and locations are examined in Sections 6.2 and 6.3, including the severance of small process system lines, the main steam lines upstream of the flow restrictors, and the recirculation loop pipelines. The most severe nuclear system effects and the greatest release of radioactive material to the containment result from a complete circumferential break of one of the two recirculation loops. The minimum required functions of any reactor and plant protection system are discussed in Sections 6.2, 6.3, 7.3, 7.6, 8.3, and 15.9.

15.6.5.2.3 The Effect of Single Failures and Operator Errors

Single failures and operator errors have been considered in the analysis of the entire spectrum of primary system breaks. The consequences of a LOCA with considerations for single failures are shown to be fully accommodated without the loss of any required safety function (Section 15.9).

15.6.5.3 Core and System Performance

15.6.5.3.1 Mathematical Model

The analytical methods and associated assumptions used in evaluating the consequences of this accident are considered to provide a conservative assessment of the expected consequences of this very improbable event.

The details of these calculations, their justification, and bases for the models are developed in Sections 6.3, 7.3, 7.6, 8.3, and 15.9.

15.6.5.3.2 Input Parameters and Initial Conditions

Input parameters and initial conditions used for the analysis of this event are given in Table 6.3-1.

15.6.5.3.3 Results

Results of this accident are given in detail in Section 6.3. Even though some swelling may have occurred, the temperature and pressure transients resulting as a consequence of this accident are insufficient to cause perforation of the fuel cladding. Postaccident tracking instrumentation and control are assured. Continued long-term core cooling is demonstrated. Radiological input is minimized and within limits. Continued operator control and surveillance are examined and guaranteed.

15.6.5.3.4 Consideration of Uncertainties

This event was conservatively analyzed (Sections 6.3, 7.3, 7.6, 8.3, and 15.9).

15.6.5.4 Barrier Performance

The primary containment is designed to maintain pressure integrity in the event of an instantaneous rupture of the largest single primary system piping within the structure while also accommodating the dynamic effects of the pipe break. Therefore, any postulated LOCA would not

exceed the containment design limit. For details and results of the analyses, see Sections 3.8, 3.9, and 6.2.

15.6.5.5 Radiological Consequences for the LOCA

Regulation 10CFR50.67, "Accident Source Term," provides a mechanism for power reactor licensees to voluntarily replace the traditional TID-14844 (Ref. 15.6-11) accident source term used in design-basis accident analyses with an "Alternative Source Term" (AST). The methodology of approach to this replacement is given in USNRC Regulatory Guide 1.183 (Ref. 15.6-12) and its associated Standard Review Plan 15.0.1 (Ref. 15.6-13).

The AST methodology has been applied to justify that a Design Basis Accident (DBA) can be accommodated without fully crediting the use of previously assumed safety systems. Amongst these systems are the Control Room Emergency Fresh Air Supply System (CREFAS) and the Standby Gas Treatment System (SGTS).

In support of a full-scope implementation of AST as described in and in accordance with the guidance of Ref. 15.6-12, AST radiological consequence analyses are performed for the four DBAs that result in offsite exposure (i.e., Loss of Coolant Accident (LOCA), Main Steam Line Break (MSLB), Fuel Handling Accident (FHA), and Control Rod Drop Accident (CRDA)).

Implementation consisted of the following steps:

- Identification of the AST based on plant-specific analysis of core fission product inventory,
- Calculation of the release fractions for the four DBAs that could potentially result in control room and offsite doses (i.e., LOCA, MSLB, FHA, and CRDA),
- Analysis of the atmospheric dispersion for the radiological propagation pathways,
- Calculation of fission product deposition rates and removal mechanisms,
- Calculation of offsite and control room personnel Total Effective Dose Equivalent (TEDE) doses,
- Evaluation of suppression pool pH to ensure that the particulate iodine deposited into the pool during a DBA LOCA does not re-evolve and become airborne as elemental iodine.

15.6.5.5.1 Regulatory Approach

The analyses are prepared in accordance with the guidance provided by Regulatory Guide 1.183 (Ref. 15.6-12).

15.6.5.5.2 Dose Acceptance Criteria

The AST acceptance criteria for Control Room dose for postulated major credible accident scenarios such as those resulting in substantial meltdown of the core with release of appreciable quantities of fission products is provided by 10 CFR 50.67, which requires:

> "Adequate radiation protection is provided to permit access to and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) total effective dose equivalent (TEDE) for the duration of the accident."

This limit is applied by Regulatory Guide 1.183 to all of the accidents considered with AST.

The AST acceptance criteria for an individual located at any point on the boundary of the exclusion area (the Exclusion Area Boundary or EAB) are provided by 10 CFR 50.67 as 25 rem TEDE for any 2-hour period following the onset of the postulated fission product release.

The AST acceptance criteria for an individual located at any point on the outer boundary of the low population zone (LPZ) are provided by 10 CFR 50.67 as 25 rem TEDE during the entire period of passage of the radioactive cloud resulting from the postulated fission product release.

These limits are applied by Regulatory Guide 1.183 to events with a higher probability of occurrence (including CRDA, MSLB, and FHA considered herein) to provide the following acceptance criteria:

- For the BWR MSLB for the case of an accident assuming fuel damage or a pre-incident Iodine spike, doses at the EAB and LPZ should not exceed 25 rem TEDE for the accident duration (2 hour dose for EAB and 30 day dose for LPZ). For MSLB accidents assuming normal equilibrium Iodine activity, doses should not exceed 2.5 rem TEDE for the accident duration.
- For the BWR CRDA, doses at the EAB and LPZ should not exceed 6.3 rem TEDE for the accident duration (2 hour dose for EAB and 24 hour dose for LPZ).
- For the FHA, doses at the EAB and LPZ should not exceed 6.3 rem TEDE for the accident duration (2 hour dose for EAB and 30 day dose for LPZ).

15.6.5.5.3 Computer Codes

New AST calculations for the LOCA were prepared to simulate the radionuclide release, transport, removal, and dose estimates associated with the postulated accident scenario.

The RADTRAD computer code (Ref. 15.6-15) endorsed by the NRC for AST analyses was used in the calculations for the LOCA. The RADTRAD program is a radiological consequence analysis code used to estimate post-accident doses at plant offsite locations and in the control room.

Offsite X/Qs were calculated using the guidance of Regulatory Guide 1.145 (Ref. 15.6-17); control room X/Qs were calculated with the ARCON96 computer code (Ref. 15.6-18).

All of these computer codes and methodologies have been used by the NRC staff in their safety reviews.

15.6.5.5.4 Source Terms

Core Inventory

The inventory of reactor core fission products used in RADTRAD for the AST LOCA analysis is based on maximum full power operation at a power level of 3527 MWth, which includes a 2%

instrument error per Reg. Guide 1.49 (Ref: 15.6-19) (See Section 15.0.4, Regulatory Guide 1.49). The fission products used for the accidents are the 60 isotopes of the standard RADTRAD input library, determined by the code developer as significant in dose consequences. These were extracted from Attachment A of the LGS Design Analysis LM-0645 (Ref: 15.6-24), and correspond to 24 month cycle burnup parameters, conservatively calculated using the ORIGEN-ARP code.

Release Fraction

Current design basis accident evaluations as modified by Regulatory Guide 1.183 (Ref: 15.6-12) were used to determine the specific releases of radioactive isotopes at the given stages of fuel pin failure and provide these releases as a percentage of the total release for the accident, as summarized below.

15.6.5.5.5 Methodology

Dose Calculations

As per Regulatory Guide 1.183 (Ref. 15.6-12), Total Effective Dose Equivalent (TEDE) doses are determined as the sum of the CEDE and the Effective Dose Equivalent (EDE) using dose conversion factors for inhalation CEDE from Federal Guidance Report No. 11 (Ref: 15.6-20) and for external exposure EDE from Federal Guidance Report No. 12 (Ref. 15.6-21). Breathing rates and occupancy factors are given in Table 15.6-13.

Loss of Coolant Accident (LOCA)

The LOCA radiological assessment was performed in accordance with the guidance of Regulatory Guide 1.183. The key inputs used in this analysis are included in Tables 15.6-14 through Table 15.6-17. These inputs and assumptions are grouped into three main categories (i.e., release, transport, and removal). The initial source term parameters are given in Table 15.6-14.

LOCA Release Inputs

Key parameters used in the release pathway modeling for the LOCA analysis are given in Table 15.6-15. The primary containment is assumed to leak at 0.5 v%/day for the first 24 hours, then at a reduced rate of 0.25 v%/day for the remaining 30-day duration of the accident. Separately, the MSIVs are assumed to leak at a combined total of 200 scfh for the first 24 hours, then at a reduced rate of 110.20 scfh for the remaining accident duration, due to reductions in containment pressure. No primary containment leakage, with the exception of MSIV leakage, has been identified to bypass the secondary containment to be released unfiltered to the atmosphere.

The analysis assumes that the leak rate through the MSIVs to the environment is 200 scfh at a test pressure of 22 psig for the first 24 hours of the accident. This rate is then assumed to be reduced to 110.20 scfh after 24 hours and for the duration of the accident, due to containment pressure reductions. The maximum allowable per line is 100 scfh(*).

(*) For Unit 1 Cycle 19 only. The 1B outboard main steam isolation valve (28B) exceeded the 100 scfh leakage by 4.88 scfh. TS Amendment 245 approved a one-time allowable leakage limit of 105 scfh for a single MSIV (UFSAR Reference 15.6-27).

The analysis assumes an emergency core cooling system (ECCS) liquid leakage rate outside of containment of 5 gpm (Table 15.6-15). Ten percent of the activity in the leakage is assumed to become airborne. This is consistent with Regulatory Guide 1.183. Although the ECCS leakage rate may realistically be assumed to begin approximately 15 minutes following the accident, with the actuation of the drywell sprays, the present analysis conservatively assumes leakage to begin at the onset of the accident and to continue throughout the 30-day duration of the postulated accident.

The Regulatory Guide 1.183 accident isotopic release specification allows deposition of iodine in the suppression pool. Essentially all of the iodine is assumed to remain in solution as long as the pool pH is maintained at or above a level of 7. Station procedures will direct operators, upon detection of symptoms indicating that core damage is occurring to manually initiate the SLC System. The calculation results demonstrate the buffering effect of the boron solution maintains the suppression pool pH above 7 for the 30-day duration of the postulated LOCA.

LOCA Transport Inputs

Prior to the LOCA, the reactor enclosure is mechanically maintained at a negative pressure. At the beginning of the LOCA event, the reactor enclosure exhaust fans are tripped and the reactor enclosure (i.e., secondary containment) is then exhausted by the SGTS continuing the building's negative pressure thus precluding unfiltered exfiltration.

In the analysis, the control room is assumed to be automatically isolated upon a high radiation signal, and therefore in Radiation Mode prior to activity infiltration. Flow rates are given in Table 15.6-16.

LOCA Removal Inputs

Key parameters identifying radionuclide removal processes are given in Table 15.6-17. The activity of elemental iodine and aerosols released from the core into the drywell is reduced by deposition (i.e., plate-out) and settling in the drywell utilizing the natural deposition values identified in the RADTRAD code. No credit is assumed for natural deposition of elemental or organic iodine, or for suppression pool scrubbing.

Containment leakage into the reactor building is collected by the SGTS, which exhausts the reactor building, via filters, and reduces releases. The deposition removal mechanisms are characteristics of the AST methodology and represent a change in the plant design and licensing basis.

Main steam line pipe and main steam condenser particulate and chemical iodine deposition was modeled using the RADTRAD code with removal coefficients based on gravitational settling and chemical plateout. Two-node treatment is used for each steam line in which flow occurs. The first node is from the reactor vessel to the inboard MSIV. The second node is from the inboard MSIV to the outboard MSIV. No credit is taken for holdup or plate-out in the main steam lines beyond the outboard MSIV. However, additional credit is taken for plate-out in the main condenser. Main steam line deposition was based on using the shortest line (i.e., most rapid transport) for the worst case line (i.e., the one with the assumed failed inboard isolation valve).

Removal efficiencies for the standby gas treatment system (SGTS), reactor enclosure recirculation system, and the control room emergency filtration system (CREFAS) filters are given in Table 15.6-17.

The analysis assumptions for the transport, reduction, and release of the radioactive material from the fuel and the reactor coolant are consistent with the guidance provided in Appendix C of Regulatory Guide 1.183, and are provided in the design analysis of Ref. 15.6-23.

15.6.5.5.6 Atmospheric Dispersion Factors (X/Qs)

The station release points and control room intake are shown in Figure 15.6-3. Table 15.6-19 lists X/Q values used for the control room dose assessments. For release points applicable to the LOCA, the zero velocity vent release X/Q values were calculated with the ARCON96 computer code, as derived in UFSAR Chapter 2.

Table 15.6-20 lists X/Q values for the EAB and LPZ boundaries. These X/Q values are calculated using Regulatory Guide 1.145 methodology, as derived in UFSAR Chapter 2.

15.6.5.5.7 Summary and Conclusions

The radiological consequences of the postulated LOCA are given in Table 15.6-18. As indicated, the control room, EAB, and LPZ calculated doses are within regulatory limits after AST implementation.

15.6.6 FEEDWATER LINE BREAK OUTSIDE PRIMARY CONTAINMENT

The postulated break of the feedwater line, representing the largest liquid line outside primary containment, provides the envelope evaluation relative to this type of occurrence. The break is assumed to be instantaneous, circumferential, and upstream of the outermost isolation valve.

A more limiting accident from a core performance evaluation standpoint (feedwater line break inside primary containment) has been quantitatively analyzed in Section 6.3. Therefore, the following discussion provides only new information not presented in Section 6.3. All other information is covered by cross- referencing.

15.6.6.1 Identification of Causes and Frequency Classification

15.6.6.1.1 Identification of Causes

A feedwater line break is assumed without the cause being identified. The subject piping is designed to high quality engineering codes and standards, and seismic and environmental requirements.

15.6.6.1.2 Frequency Classification

This accident is categorized as a limiting fault.

15.6.6.2 Sequence of Events and System Operation

15.6.6.2.1 Sequence of Events

The sequence of events is shown in Table 15.6-23.

Since automatic actuation and operation of the ECCS is a system design basis, no credit for immediate operator actions are assumed in the evaluation for this accident. However, in accordance with procedural requirements the operator should perform the following actions, which are shown below for informational purposes:

a. The operator should determine that a line break has occurred and evacuate the area of the turbine enclosure.

b. The operator is not required to take any action to prevent primary reactor system mass loss, but should ensure that the reactor is shut down and that RCIC and/or HPCI are operating normally.

c. The operator should implement appropriate radiation incident procedures.

d. If possible, the operator should shut down the feedwater system and de-energize any electrical equipment that may be damaged by water from the feedwater system in the turbine enclosure.

e. The operator should continue to monitor reactor water level and the performance of the ECCS while the radiation incident procedure is being implemented and should begin normal reactor cooldown measures.

f. When the reactor pressure has decreased below 75 psig, operator should initiate RHR in the shutdown cooling mode to continue cooling down the reactor.

The operator procedures above occur over an elapsed time of 3-4 hours.

15.6.6.2.2 System Operation

It is assumed that the normally operating plant instrumentation and controls are functioning. Credit is taken for the actuation of the reactor isolation system and ECCS. The RPS (MSRVs, ECCS, and CRD) and plant protection system (RHR heat exchangers) are assumed to function properly to assure a safe shutdown.

The ESF and RCIC/HPCI systems are assumed to operate normally.

15.6.6.2.3 The Effect of Single Failures and Operator Errors

The feedwater line break outside of primary containment is a high energy line break as described in paragraph 3.6.1.2.1.3. For purposes of plant transient analysis, it is considered as a special case of the general LOCA break spectrum considered in detail in Section 6.3. The general single failure analysis for LOCAs is discussed in detail in Section 6.3.3.3. For the feedwater line break outside primary containment, since the break can be isolated, either the RCIC or HPCI can provide adequate flow to the vessel to maintain core cooling and prevent fuel clad failure. A single failure of either the HPCI or the RCIC would still provide sufficient flow to keep the core covered with water. See Sections 6.3 and 15.9 for detailed description of the analysis.

15.6.6.3 Core and System Performance

15.6.6.3.1 Qualitative Summary

The accident evaluation qualitatively considered in this section is considered to be a conservative and envelope assessment of the consequences of the postulated failure (i.e., severance) of one of the feedwater piping lines outside primary containment. The accident is postulated to occur at the input parameters and initial conditions given in Table 6.3-1.

15.6.6.3.2 Qualitative Results

The feedwater line break outside the containment is less limiting than either of the steam line breaks outside primary containment (analysis presented in Section 6.3 and/or in Section 15.6.4) or the feedwater line break inside primary containment (analysis presented in Sections 6.3.3 and 15.6.5). It is far less limiting than the DBA (the recirculation line break analysis presented in Sections 6.3.3 and 15.6.5).

The RCIC and the HPCI initiate on low-low (Level 2) water level and together restore the reactor water level to the normal elevation. MSIV isolation will occur upon receipt of a low-low-low (Level 1) water level signal, but it is unlikely that this level will be reached during this event. The fuel is covered throughout the accident and there are no pressure or temperature transients sufficient to cause fuel damage.

15.6.6.3.3 Consideration of Uncertainties

This accident was conservatively analyzed, and uncertainties were adequately considered (Section 6.3).

15.6.6.4 Barrier Performance

Accidents that result in the release of radioactive materials outside primary containment are the results of postulated breaches in the RCPB or the steam power conversion system boundary. A break spectrum analysis for the complete range of reactor conditions indicates that the limiting fault event for breaks outside primary containment is a complete severance of one of the main steam lines as described in Section 15.6.4. The feedwater system piping break is less severe than the main steam line break. Results of analysis of this accident can be found in Sections 6.2.3 or 6.2.4.

15.6.6.5 Radiological Consequences

15.6.6.5.1 Design Basis Analysis

No design basis analysis is presented.

15.6.6.5.2 Realistic Analysis

The realistic analysis is based on a conservative assessment of this accident. The specific models and assumptions, and the program used for computer evaluation, are described in Reference 15.6-3. Specific values of parameters used in the evaluation are presented in Table 15.6-24. A schematic diagram of the leakage path for this accident is shown in Figure 15.6-4.

15.6.6.5.2.1 Fission Product Release

There is no fuel damage as a consequence of this accident. In addition, an insignificant quantity of activity (compared to that existing in the main condenser hotwell prior to occurrence of the break) is released from the contained piping system prior to isolation closure.

The iodine concentration in the main condenser hotwell is consistent with an offgas release rate of 0.10 Ci/sec at 30 minutes delay and is 0.02 (2% carryover) times the concentration in the reactor coolant. Noble gas activity in the condensate is negligible, since the air ejector removes practically all noble gas from the condenser.

15.6.6.5.2.2 Fission Product Transport to the Environment

Two breaks were postulated for release of liquid coolant: a break just outside primary containment, and a break on the 30 inch header manifolding the discharge of three condensate pumps.

If a break just outside primary containment is considered, reverse flow would release 650 gallons of feedwater before the check valve inside primary containment fully closes. During this time no reactor water would be discharged through the break. On the pump side, either the turbine drive protection equipment would sense overspeed, or the pump itself would see low suction pressure. Very rapid trip would result in either case, minimizing spillage.

For the break on the 30 inch header, the condensate from the hotwell would be released along with the makeup from the CST. Backflow from upstream of the condensate filter/demineralizer would again close the check valves, but condensate in the feedwater heaters would be spilled. Since more coolant would be discharged by this break than by the break just outside primary containment, it was used for the analysis.

The fission transport pathway consists of liquid release from the break, carryover to the turbine enclosure atmosphere due to flashing and partitioning, and unfiltered release to the environment through the turbine enclosure ventilation system.

From the hotwell, 967,000 lb of condensate is released, of which 64,800 lb flashes to steam. Also released is 150,000 lb of condensate that was in the pipes from the break to the filter/demineralizers. Of this condensate, 10,100 lb flashes to steam. Low level in the condenser will send a signal for makeup to the CST; thus, 542,000 lb will be released, of which 36,300 lb will flash to steam. Upstream of the filter/demineralizers, 584,000 lb of condensate will backflow, with 146,000 lb flashing into steam. The condensate is assumed to be at a reactor steam concentrations. Of the activity remaining in the unflashed liquid, 10% is assumed to become airborne. Liquid that was upstream of the filter/demineralizers has passed through the condensate cleanup system, which have a 90% iodine removal efficiency. The CST is assumed to be 99% free of iodine.

Taking no credit for holdup, decay, or plateout during transport through the turbine enclosure, the release of activity to the environment is presented in Table 15.6-25. The release is assumed to take place within two hours of the occurrence of the break.

15.6.6.5.2.3 Results

The calculated exposures for the realistic analysis are presented in Table 15.6-26 and are a small fraction of 10CFR100 limits.

15.6.7 LOSS OF FEEDWATER FLOW

Refer to Section 15.2.7

15.6.8 REFERENCES

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Table 15.6-1

SEQUENCE OF EVENTS FOR INSTRUMENT LINE BREAK

TIME	EVENT
0	Instrument line fails
0-10 min	Identification of break
10 min	Activate SBGTS and initiate orderly shutdown
5 hours	Reactor vessel depressurized and break flow terminated

Table 15.6-2

INSTRUMENT LINE BREAK ACCIDENT: PARAMETERS
TABULATED FOR POSTULATED ACCIDENT ANALYSES

	DESIGN BASIS ASSUMPTIONS	REALISTIC BASIS ASSUMPTIONS
I. Data and Assumptions used to Estimate Radioactive Source from Postulated Accidents		
A. Power Level	102%	102%
B. Burnup	NA	NA
C. Fission Product Release from Fuel (fuel damaged)	NA	None
D. Release of Activity by Nuclide to the environment	Table 15.6-4	Table 15.6-6
E. Iodine Fractions		
1. Organic	NA	0
2. Elemental	NA	1
3. Particulate	NA	0
F. Reactor Coolant Activity Before the Accident	Section 15.6.4.5.1	Section 15.6.4.5.2
II. Data and Assumptions Used to Estimate Activity Released		
A. Primary Containment Leak Rate (%/day)	NA	NA
B. Secondary Containment Release Rate (%/day)	100	100
C. Valve Movement Times	NA	NA
D. Adsorption and Filtration Efficiencies (SGTS)		
1. Organic iodine	99	99
2. Elemental iodine	99	99
3. Particulate iodine	99	99
4. Particulate fission products	99	99
E. Recirculation System Parameters		
1. Flow rate (cfm)	60,000	60,000
2. Mixing efficiency	50	50
3. Filter efficiency	95	95
F. Containment Spray Parameters (flow rate, drop size, etc.)	NA	NA

Table 15.6-2 (Cont'd)

	DESIGN BASIS ASSUMPTIONS	REALISTIC BASIS ASSUMPTIONS
G. Secondary Containment Volume (ft^3)		
Reactor enclosure, Unit 1	$1.8x10^6$	$1.8x10^6$
H. All Other Pertinent Data and Assumptions	NA	NA
III. Dispersion Data		
A. EAB/LPZ Distance (m)	731/2043	731/2043
B. X/Qs for Time Intervals of		
1. 0-2 hrs – EAB	$2.9x10^{-4}$	$1.2x10^{-4}$
2. 0-8 hrs – LPZ	$4.0x10^{-5}$	$2.0x10^{-5}$
3. 8-24 hrs – LPZ	$2.9x10^{-5}$	$1.6x10^{-5}$
4. 1-4 days – LPZ	$1.4x10^{-5}$	$9.0x10^{-6}$
5. 4-30 days – LPZ	$5.4x10^{-6}$	$4.2x10^{-6}$
IV. Dose Data		
A. Method of Dose Calculation	Section 15.10	Reference 15.6-3
B. Dose Conversion Assumptions	Section 15.10	Reference 15.6-3
C. Peak Activity in reactor enclosure	Table 15.6-3	Table 15.6-5
D. Doses	Table 15.6-7	Table 15.6-7

Table 15.6-3

INSTRUMENT LINE FAILURE:
ACTIVITY AIRBORNE IN REACTOR ENCLOSURE(1)

DESIGN BASIS ANALYSIS

ISOTOPE	2 HRS	5 HRS	8 HRS	1 DAY	4 DAYS	30 DAYS
I-131	6.76×10^{-1}	1.82	1.57×10^{-5}	1.53×10^{-32}	0.0	0.0
I-132	1.15×10^{1}	2.35×10^{1}	8.24×10^{-5}	6.67×10^{-34}	0.0	0.0
I-133	5.14	1.33×10^{1}	1.05×10^{-4}	6.40×10^{-32}	0.0	0.0
I-134	3.18×10^{1}	4.81×10^{1}	3.89×10^{-5}	0.0	0.0	0.0
I-135	9.03	2.18×10^{1}	1.39×10^{-4}	2.69×10^{-32}	0.0	0.0
TOTAL	5.81×10^{1}	1.08×10^{2}	3.81×10^{-4}	1.07×10^{-31}	0.0	0.0

(1) Units for activities are in curies.

Table 15.6-4

INSTRUMENT LINE FAILURE:
ACTIVITY RELEASED TO THE ENVIRONMENT[1]

DESIGN BASIS ANALYSIS

ISOTOPE	0-2 HRS	2-5 HRS	5-8 HRS	8-24 HRS	1-4 DAYS	4-30 DAYS
I-131	4.91×10^{-5}	2.15×10^{-4}	1.95×10^{-5}	1.68×10^{-10}	0.0	0.0
I-132	8.46×10^{-4}	2.81×10^{-3}	2.34×10^{-4}	8.20×10^{-10}	0.0	0.0
I-133	3.74×10^{-4}	1.58×10^{-3}	1.41×10^{-4}	1.12×10^{-9}	0.0	0.0
I-134	2.36×10^{-3}	5.86×10^{-3}	4.28×10^{-4}	3.47×10^{-10}	0.0	0.0
I-135	6.58×10^{-4}	2.59×10^{-3}	2.28×10^{-4}	1.45×10^{-9}	0.0	0.0
TOTAL	4.29×10^{-3}	1.31×10^{-2}	1.05×10^{-3}	3.90×10^{-9}	0.0	0.0

[1] Units for activities are in curies.

Table 15.6-5

INSTRUMENT LINE FAILURE:
ACTIVITY AIRBORNE IN REACTOR ENCLOSURE[1]

REALISTIC ANALYSIS

ISOTOPE	2 HRS	5 HRS	8 HRS	1 DAY	4 DAYS	30 DAYS
I-131	1.93×10^{-1}	5.20×10^{-1}	4.48×10^{-6}	4.39×10^{-33}	0.0	0.0
I-132	3.29	6.71	2.35×10^{-5}	1.91×10^{-34}	0.0	0.0
I-133	1.47	3.80	3.00×10^{-5}	1.83×10^{-32}	0.0	0.0
I-134	9.07	1.37×10^{1}	1.11×10^{-5}	0.0	0.0	0.0
I-135	2.58	6.23	3.97×10^{-5}	7.69×10^{-33}	0.0	0.0
TOTAL	1.66×10^{1}	3.10×10^{1}	1.09×10^{-4}	3.06×10^{-32}	0.0	0.0

[1] Units for activities are in curies.

Table 15.6-6

INSTRUMENT LINE BREAK:
ACTIVITY RELEASED TO THE ENVIRONMENT(1)

REALISTIC ANALYSIS

ISOTOPE	0-2 HRS	2-5 HRS	5-8 HRS	8-24 HRS	1-4 DAYS	4-30 DAYS
I-131	1.40×10^{-5}	6.15×10^{-5}	5.57×10^{-6}	4.81×10^{-11}	0.0	0.0
I-132	2.42×10^{-4}	8.04×10^{-4}	6.67×10^{-5}	2.34×10^{-10}	0.0	0.0
I-133	1.07×10^{-4}	4.50×10^{-4}	4.04×10^{-5}	3.19×10^{-10}	0.0	0.0
I-134	6.75×10^{-4}	1.68×10^{-3}	1.22×10^{-4}	9.92×10^{-11}	0.0	0.0
I-135	1.88×10^{-4}	7.41×10^{-4}	6.51×10^{-5}	4.15×10^{-10}	0.0	0.0
TOTAL	1.23×10^{-3}	3.73×10^{-3}	3.00×10^{-4}	1.12×10^{-9}	0.0	0.0

(1) Units for activities are in curies.

Table 15.6-7

INSTRUMENT LINE FAILURE: RADIOLOGICAL EFFECTS

DESIGN BASIS ANALYSIS

	WHOLE BODY DOSE (rem)	THYROID DOSE (rem)
Exclusion Area Boundary (731 meters - 2 hr dose)	5.89×10^{-7}	2.33×10^{-5}
Low Population Zone (2043 meters - 30 day dose)	3.37×10^{-7}	1.76×10^{-5}

REALISTIC ANALYSIS

	WHOLE BODY DOSE (rem)	THYROID DOSE (rem)
Exclusion Area Boundary (731 meters - 2 hr dose)	6.96×10^{-8}	2.75×10^{-6}
Low Population Zone (2043 meters - 30 day dose)	4.81×10^{-8}	2.51×10^{-6}

Table 15.6-8

SEQUENCE OF EVENTS FOR STEAM LINE BREAK
OUTSIDE PRIMARY CONTAINMENT

TIME (sec)	EVENT
0	Guillotine break of one main steam line outside primary containment.
1.0 (approx)	High steam line flow signal initiates closure of MSIV.
< 1.5	Reactor begins scram.
≤ 6.0	MSIVs fully closed.
60.0 (approx)	RCIC and HPCI initiate on low water level (Level 2) (RCIC considered unavailable, HPCI assumed single failure and therefore may not be available).
60.0 (approx)	SRVs open on high vessel pressure. The valves open and close to maintain vessel pressure at approximately 1170 psi.
1780 (approx)	Low water level (Level 1) reached. Low pressure ECCS receives signal to start. ADS logic is initiated.
1900 (approx)	High drywell pressure bypass timer and ADS timer "timed out". ADS starts. Vessel depressurizes.
2100 (approx)	Low pressure ECCS begin injection. Core partially uncovers.
2160 (approx)	Core effectively reflooded and clad temperature heatup terminated. No fuel rod failure.

Table 15.6-9

MSLB – RADIOLOGICAL CONSEQUENCES
KEY INPUTS AND ASSUMPTIONS

Key MSLB Accident Analysis Inputs and Assumptions

Input/Assumption	Value
Mass Release	140,000 lb_m of reactor coolant
Pre-Accident Spike Iodine Concentration	4 µCi/gm I-131 equivalent
Maximum Equilibrium Iodine Concentration	0.2 µCi/gm I-131 equivalent
Transport model for Control Room	Steam cloud moves past the Control Room intake at 1 m/sec
Control Room Filtration	No Credit Taken
Control Room Free Volume	126,000 ft^3

Table 15.6-10

MSLB X/Q VALUES

Offsite X/Q (sec/m^3) Values for the MSLB Releases

Time Period	EAB χ/Q (sec/m^3)	LPZ χ/Q (sec/m^3)
0 – 2 hrs	4.77E-04 [1]	1.89E-04 [1]

Notes:
1. Based on Regulatory Guide 1.5 methodology with Pasquill F atmospheric conditions and 1 meter/second wind speed.

Table 15.6-11

MSLB RADIOLOGICAL CONSEQUENCE RESULTS

MSLB Accident Radiological Consequence Analysis Results

		4 µCi/gm Dose Equivalent I-131 TEDE (rem)	**0.2 µCi/gm Dose Equivalent I-131 TEDE (rem)**	**Regulatory Limit TEDE (rem)**
Control Room	30 day integrated dose	3.97	0.198	5
EAB	Worst 2-hour integrated dose	2.22	0.111	25 (4.0 µCi/gm) 2.5 (0.2 µCi/gm)
LPZ	30 day integrated dose	0.877	0.044	25 (4.0 µCi/gm) 2.5 (0.2 µCi/gm)

Table 15.6-12

Table 15.6-12
Deleted

Table 15.6-13

LOSS OF COOLANT ACCIDENT: PERSONNEL DOSE INPUTS

Personnel Dose Inputs	
Input/Assumption	**Value**
Onsite Breathing Rate	3.5E-04 m^3/sec
Offsite Breathing Rate	0-8 hours: 3.5E-4 m^3/sec 8-24 hours: 1.8E-4 m^3/sec 1-30 days: 2.3E-4 m^3/sec
Control Room Occupancy Factors	0-1 day: 1.0 1-4 days: 0.6 4-30 days: 0.4

Table 15.6-14

LOSS OF COOLANT ACCIDENT: SOURCE TERM

Key Analysis Inputs and Assumptions	
Release Inputs - LOCA Radionuclide Source Term	
Input/Assumption	**Value**
Core Fission Product Inventory	ORIGEN-ARP Only the 60 nuclides considered by RADTRAD are utilized in the LOCA release analysis
Core Power Level	3,527 MWt
Fission Product Release Fractions for LOCA	**RG 1.183, Table 1** **BWR Core Inventory Fraction Released Into Containment** **Group** / **Gap Release Phase** / **Early In-vessel Phase** / **Total** Noble Gases 0.05 0.95 1.0 Halogens 0.05 0.25 0.3 Alkali Metals 0.05 0.20 0.25 Tellurium Metals 0.00 0.05 0.05 Ba, Sr 0.00 0.02 0.02 Noble Metals 0.00 0.0025 0.0025 Cerium Group 0.00 0.0005 0.0005 Lanthanides 0.00 0.0002 0.0002
Fission Product Release Timing (Per RG 1.183, the release phases are modeled sequentially)	**RG 1.183, Table 4** **LOCA Release Phases** **BWRs** **Phase** / **Onset** / **Duration** Gap Release 2 min 0.5 hr Early In-Vessel 0.5 hr 1.5 hr

Table 15.6-15

LOSS OF COOLANT ACCIDENT: CONTAINMENT PARAMETERS

Key LOCA Analysis Inputs and Assumptions	
Release Inputs - Primary and Secondary Containment Parameters	
Input/Assumption	**Value**
Containment Free Volume	3.79E+05 cubic feet
Suppression Pool Water Volume	118,655 cubic feet
Primary Containment Leak Rate	0.5% per day for 0 – 24 hours 0.25% per day for 24 – 720 hours
Total MSIV leak rate @ 22 psig test pressure	200 scfh total for 0 – 24 hours (100 scfh max per line)(*) 110.20 scfh for 24 – 720 hours
Secondary Containment Volume	1.8E+06 cubic feet
SGTS Flow Rate (maximum)	3,000 cfm (during drawdown) 2,500 cfm (post-drawdown)
RERS Flow Rate (minimum)	54,000 cfm
Secondary Containment Drawdown Time	15.5 minutes
ECCS Systems Leak Rate Outside of Primary Containment (includes factor of 2 margin)	5 gpm
ECCS Leakage Duration	0-30 days
Release Location ECCS/Containment Leakage MSIV Leakage	 North Vent Stack North Vent Stack
Release Duration ECCS/Containment Leakage MSIV Leakage	 0-30 days 0-30 days

(*) For Unit 1 Cycle 19 only. The 1B outboard main steam isolation valve (28B) exceeded the 100 scfh leakage by 4.88 scfh. TS Amendment 245 approved a one-time allowable leakage limit of 105 scfh for a single MSIV (UFSAR Reference 15.6-27).

Table 15.6-16

LOSS OF COOLANT ACCIDENT: CONTROL ROOM PARAMETERS

Key LOCA Analysis Inputs and Assumptions	
Transport Inputs - Control Room Parameters	
Input/Assumption	**Value**
Nuclide Release Locations	Figure 15.6-3
CREFAS System Initiation (Radiation Mode)	On High Radiation Signal
Control Room Free Volume	126,000 cubic feet
CREFAS Air Intake Flow Rate (Radiation Mode)	525 cfm
CREFAS Recirculation Flow Rate	2175 cfm
Total Filtered Intake	2700 cfm
Control Room Unfiltered Inleakage Rate	225 cfm

Table 15.6-17

LOSS OF COOLANT ACCIDENT: REMOVAL INPUTS

Key LOCA Analysis Inputs and Assumptions	
Removal Inputs	
Input/Assumption	**Value**
Aerosol Natural Deposition Coefficients Used in the Drywell	Credit is taken for natural deposition of aerosols based on equations for the Power's model in NUREG/CR 6189 and input directly into RADTRAD as natural deposition time dependent lambdas.
Main Steam Lines Deposition	Two-node treatment, each well-mixed, is used for each steam line in which flow occurs. The first node is from the reactor vessel to the inboard MSIV. The second node is from the inboard MSIV to the turbine stop valve. Gravitational settling applied to aerosols on horizontal pipe projected areas, based on a 20 group probability distribution as a function of particle velocities and characteristics. For Elemental Iodine, deposition velocities are calculated based on the pipe wall temperatures, and because elemental iodine deposition is not gravity dependant, all interior pipe surface is credited.
Main Steam Condenser Credit	Only the deposition area of the horizontal surface of the wetwell of the HP Condenser is credited. Aerosol and Elemental Iodine removal efficiencies are calculated in a manner similar to that used for the main steam lines, as discussed in the applicable design analysis.

Table 15.6-17 (Cont'd)

Key LOCA Analysis Inputs and Assumptions	
Removal Inputs	
Input/Assumption	**Value**
SGTS Filter Efficiency	HEPA: Particulate aerosol 99% Charcoal: Elemental and organic iodine 99%
RERS Filter Efficiency	HEPA: Particulate aerosol 99% Charcoal: Elemental and organic iodine 95%
CREFAS Filter Efficiency	HEPA: Particulate aerosol 99% Charcoal: Elemental and organic iodine 95%

Table 15.6-18

LOSS OF COOLANT ACCIDENT: RADIOLOGICAL DOSE SUMMARY

LOCA Radiological Doses			
Location	Duration	TEDE (rem)	Regulatory Limit TEDE (rem)
Control Room	30 days	4.783*	5
EAB	Maximum, 2 hours	0.931	25
LPZ	30 days	1.264	25

* The doses here include general external gamma shine and inhalation doses from radioactivity drawn into the control room.

Table 15.6-19

LOSS OF COOLANT ACCIDENT: CONTROL ROOM DISPERSION FACTORS

Onsite Control Room Dispersion Factors Values for Activity Release from the North Vent Stack to the Control Room Intake[1,2]	
Time Period	**Control Room χ/Q (sec/m^3)**
0 - 2 hrs	6.88E-03
2 - 8 hrs	5.17E-03
8 - 24 hrs	2.04E-03
1 - 4 d	1.29E-03
4 - 30 d	9.63E-04

Notes:

1. Elevated release χ/Q values are based on Regulatory Guide 1.145 methodology.
2. Control room intake χ/Q values are also applicable for control room inleakage.

Table 15.6-20

LOSS-OF-COOLANT ACCIDENT: OFFISTE DISPERSION FACTORS

Offsite Dispersion Factors Values for Activity Release from the North Vent Stack to the EAB and LPZ Using RG 1.145 Methodology		
Time Period	**EAB χ/Q (sec/m^3)**	**LPZ χ/Q (sec/m^3)**
0 - 2 hrs	3.18E-04	-
0 - 8 hrs	-	5.79E-05
8 - 24 hrs	-	4.10E-05
1 - 4 days	-	1.95E-05
4 - 30 days	-	6.68E-06

Table 15.6-21

Table 15.6-21
Deleted

Table 15.6-22

Table 15.6-22
Deleted

Table 15.6-23

SEQUENCE OF EVENTS FOR FEEDWATER LINE BREAK
OUTSIDE PRIMARY CONTAINMENT

TIME (min)[2]	EVENT
0	One feedwater line breaks.
0+	Feedwater line check valves isolate the reactor from the break.
<0.5	At low water level (Level 3), reactor scram would initiate. At low-low water (Level 2), HPCI would initiate, RCIC would initiate, and recirculation pumps would trip. If low-low-low water level (Level 1) is reached, MSIV closure begins, and CS and LPCI receive initiation signals but will not inject due to high reactor pressure.[1]
2 (approx)	The MSRVs would open and close and maintain the reactor vessel pressure at approximately 1170 psig.
60 - 120	Normal reactor cooldown procedure established.

Note:

(1) **Because of an additional steam flow induced process measurement error in the Level 3 scram, the timing values following Low water level scram based on the L3 Analytical Limit are slightly different. However, as described in Reference 15.6-25, the impact of the change is not significant.**

(2) The timetable for this case is representative of the general scenario. This case is bounded by the Steam Line Break Outside Containment scenario in Table 15.6-8.

Table 15.6-24

FEEDWATER LINE BREAK ACCIDENT: PARAMETERS
TABULATED FOR POSTULATED ACCIDENT ANALYSES

	DESIGN BASIS ASSUMPTIONS	REALISTIC BASIS ASSUMPTIONS
I. Data and Assumptions Used to Estimate Radioactive Source from Postulated Accidents		
A. Power Level	NA	NA
B. Burnup	NA	NA
C. Fission Products Released from Fuel (fuel damaged)	NA	None
D. Release of Activity by Nuclide	NA	Table 15.6-25
E. Iodine Fractions		
1. Organic	NA	0
2. Elemental	NA	1.0
3. Particulate	NA	0
F. Reactor Coolant Activity Before the Accident	NA	Section 15.6.6.5.2
II. Data and Assumptions Used to Estimate Activity Released		
A. Primary containment Leak Rate (%/day)	NA	NA
B. Secondary Containment Release Rate (%/day)	NA	NA
C. Isolation Valve Closures Time (sec)	NA	NA
D. Adsorption and Filtration Efficiencies		
1. Organic iodine	NA	NA
2. Elemental iodine	NA	NA
3. Particulate iodine	NA	NA
4. Particulate fission products	NA	NA
E. Recirculation System Parameters	NA	NA
1. Flow rate	NA	NA
2. Mixing efficiency	NA	NA
3. Filter efficiency	NA	NA
F. Containment Spray Parameters (flow rate, drop size, etc.)	NA	NA
G. Containment Volumes	NA	NA

Table 15.6-24 (Cont'd)

	DESIGN BASIS ASSUMPTIONS	REALISTIC BASIS ASSUMPTIONS
H. All Other Pertinent Data and Assumptions	NA	None
III. Dispersion Data		
A. EAB/LPZ Distance (m)	NA	731/2043
B. X/Qs for Total Dose	-	1.2×10^{-4}
EAB/LPZ (8 hr)	NA	2.0×10^{-5}
IV. Dose Data		
A. Method of Dose Calculation	NA	Reference 15.6-3
B. Dose Conversion Assumptions	NA	Reference 15.6-3
C. Peak Activity Concentrations in Containment	NA	NA
D. Doses	NA	Table 15.6-26

Table 15.6-25

FEEDWATER LINE BREAK:
ACTIVITY RELEASED TO THE ENVIRONMENT

REALISTIC ANALYSIS

ISOTOPE	ACTIVITY (Ci)
I-131	1.17
I-132	10.84
I-133	8.05
I-134	21.69
I-135	11.75
TOTAL	5.35×10^{1}

Table 15.6-26

FEEDWATER LINE BREAK: RADIOLOGICAL EFFECTS

REALISTIC ANALYSIS

	WHOLE BODY DOSE (rem)	THYROID DOSE (rem)
Exclusion Area Boundary (731 meters - 2 hr dose)	3.06×10^{-3}	3.14×10^{-1}
Low Population Zone (2043 meters - 2 hr[1] dose)	5.10×10^{-4}	5.23×10^{-2}

(1) Duration of accident is 2 hours

Table 15.6-27

LOSS OF COOLANT ACCIDENT: SEQUENCE OF EVENTS FOR RADIOLOGICAL CONSEQUENCE ANALYSIS

Time	Events and Assumptions
0	DBA LOCA is initiated. - Instantaneous Regulatory Guide 1.183 source term assumed. - Activity release from Reactor Enclosure taken at design basis SGTS flow of 3000 cfm per Reactor enclosure, to simulate exfiltration.
18 sec	SGTS is initiated. - No credit is taken for filtration during drawdown period. - Exfiltration of 3000 cfm per Reactor Enclosure continues to be assumed.
3 min	RERS is initiated. - No credit is taken for filtration during drawdown period.
15.5 min.	Reactor enclosure reaches -¼ inch wg. [Drawdown Period Ends(1).] - Unfiltered exfiltration ceases. - Reactor Enclosure exhausts at 2500 cfm [TS inleakage limit] throughout SGTS with 99% iodine removal eff. - RERS filtration of recirculation flow with iodine removal eff. of 95% for organic / elemental and 99% for particulate.

(1) Drawdown period determined based on a more conservative 2800 cfm SGTS flow, to allow for flow balancing margin.

15.7 RADIOACTIVE RELEASES FROM SUBSYSTEMS AND COMPONENTS

15.7.1 RADIOACTIVE GAS WASTE SYSTEM LEAK OR FAILURE

The following radioactive gas waste system components are examined under severe failure mode conditions for effects on plant safety:

a. Main condenser offgas treatment system failure

b. Malfunction of main turbine gland sealing system

c. Failure of SJAE lines.

15.7.1.1 Main Condenser Offgas Treatment System Failure

15.7.1.1.1 Identification of Causes and Frequency Classification

15.7.1.1.1.1 Identification of Causes

Those events which could cause a failure in the offgas treatment system are:

a. A seismic occurrence greater than the equipment can withstand.

b. A fire in the filter assemblies.

c. Failure of spacially related equipment.

The equipment and piping are designed to resist any hydrogen/oxygen detonation that has a reasonable probability of occurring. Consequently, a detonation is not considered as a possible failure mode.

The decay heat on the filters is handled inherently by the system and by the available air flows.

The system is reasonably isolated from other systems or components that could cause any serious interaction or failure. The only credible event that could result in the release of significant activity to the environment is an earthquake.

Even though the offgas system is designed to the requirements of Regulatory Guide 1.143 as discussed in Section 11.3, an event resulting in the failure of the offgas system is assumed to occur.

The design basis, description, and performance evaluation of the subject system is given in Section 11.3.

15.7.1.1.1.2 Frequency Classification

This accident is categorized as a limiting fault.

15.7.1.1.2 Sequence of Events and System Operation

15.7.1.1.2.1 Sequence of Events

The sequence of events following this failure is shown in Table 15.7-1.

15.7.1.1.2.2 Identification of Operator Actions

Gross failure of this system may require manual isolation of this system from the main condenser. This isolation results in high condenser pressure and a reactor scram. The operator should monitor the turbine-generator auxiliaries and break vacuum as soon as possible. The operator should notify personnel to evacuate the area immediately and notify radiation protection personnel to survey the area and determine requirements for re-entry. The time to perform these actions is estimated to be about two minutes.

15.7.1.1.2.3 System Operation

In analyzing the postulated offgas system failure, credit is taken for functioning of normally operating plant instrumentation and controls and other systems only in assuming the following:

a. Capability to detect the failure itself, indicated by an alarmed increase in radioactivity levels seen by the area radiation monitoring system, in a loss of flow in the offgas system, and in an alarmed increase in activity at the ventilation release.

b. Capability to isolate the system and shut down the reactor.

c. Operational indicators and annunciators in the control room.

15.7.1.1.2.4 The Effect of Single Failures and Operator Errors

After the initial system gross failure, the inability of the operator to actuate a system isolation could affect the analysis. However, a seismic event greater than design basis will cause the tripping of the turbine, or will lead to a load rejection. This will result in a scram and negate a need for the operator to initiate a reactor shutdown via system isolation.

See Section 15.9 for a further detailed discussion of this subject.

15.7.1.1.3 Core and System Performance

The postulated failure results in a system isolation necessitating reactor shutdown because of loss of vacuum in the main condenser. This transient is analyzed in Section 15.2.5.

15.7.1.1.4 Barrier Performance

The postulated failure is the rupture of the offgas treatment system pressure boundary. No credit is taken for performance of secondary barriers, except to the extent inherent in the assumed equipment release fractions discussed in Section 15.7.1.1.5, below.

15.7.1.1.5 Radiological Consequences

15.7.1.1.5.1 General

Two separate radiological analyses are provided for this accident:

a. The first is based upon conservative assumptions considered to be acceptable to the NRC for the purpose of determining adequacy of the plant design to meet 10CFR100. This analysis is referred to as the "design basis analysis."

b. The second is based upon assumptions considered to provide a realistic conservative estimate of radiological consequences. This analysis is referred to as the "realistic analysis."

15.7.1.1.5.2 Design Basis Analysis

Regulatory Guide 1.98 contains specific quantitative regulatory guidelines upon which a design basis analysis can be performed. The primary differences between this analysis and the realistic analysis are in the basic source terms and atmospheric dilution factors. The same analytical techniques used for the realistic analysis are used for this evaluation. Specific parametric values used in this evaluation are presented in Table 15.7-2.

15.7.1.1.5.2.1 Fission Product Release

15.7.1.1.5.2.1.1 Initial Conditions

The activity in the offgas system was based upon the following conditions:

a. 6 scfm air inleakage.

b. 0.35 Ci/sec noble gas after 30 minutes delay for a period of one month, preceding the accident and 0.1 Ci/sec (at 30 minutes delay) for a time earlier than 30 days.

c. The total mass of charcoal in the system is 321,790 lbs. The adsorption coefficients for Xe and Kr are 1000 cc/g and 65 cc/g, respectively.

d. The uncontrolled releases from the SJAE occur for a period of 1 hour following the accident. The delay time between the SJAE and the break is five minutes.

15.7.1.1.5.2.1.2 Assumptions

Depending upon assumptions as to radionuclide release fractions, various equipment pieces may be controlling with respect to dose consequences. The assumed release fractions are shown in Table 15.7-3. All other release sources are negligible. Iodine and activation gases are neglected per Regulatory Guide 1.98.

15.7.1.1.5.2.2 Fission Product Transport to the Environment

The transport pathway consists of direct release from the failed component to the environment through the radwaste enclosure ventilation system. The activity released to the environment is presented in Tables 15.7-4 and 15.7-8.

15.7.1.1.5.2.3 Results

The dose contributions due to releases from the charcoal tanks and SJAE are presented in Tables 15.7-6 and 15.7-9(a) respectively. The total offsite doses due to failure of the system are summarized in Table 15.7-9(b).

15.7.1.1.5.3 Realistic Analysis

The realistic analysis is based upon an engineered but still conservative assessment of this accident. Specific values of parameters used in the evaluation are presented in Table 15.7-2.

15.7.1.1.5.3.1 Fission Product Release

15.7.1.1.5.3.1.1 Initial Conditions

The activity in the offgas system is based upon the following conditions:

a. 20 scfm air inleakage.

b. 0.06 Ci/sec noble gas after 30 minutes delay.

c. The total mass of charcoal in the system is 321,790 lbs. The adsorption coefficients for Xe and Kr are 733 cc/g and 31.8 cc/g, respectively.

d. The uncontrolled releases from the SJAE occur for a period of 1 hour following the accident. The delay time between the SJAE and the break is five minutes.

15.7.1.1.5.3.2 Fission Product Transport to the Environment

The activity released to the environment is presented in Table 15.7-5 and 15.7-8.

15.7.1.1.5.3.3 Results

The dose contributions due to releases from the charcoal tanks and SJAE are presented in Tables 15.7-6 and 15.7-9(a) respectively. The total offsite doses due to failure of the system are summarized in Table 15.7-9(b).

15.7.1.2 Malfunction of Main Turbine Gland Sealing System

15.7.1.2.1 Identification of Causes and Frequency Classification

15.7.1.2.1.1 Identification of Causes

Those events that could cause a malfunction failure in the main turbine gland sealing system are:

a. Failure of the gland steam evaporator and its backup supply.

b. Failure of the gland steam condenser exhausters.

c. Excessive pressure in the steam seal header.

15.7.1.2.1.2 Frequency Classification

This accident is categorized as a limiting fault.

15.7.1.2.2 Sequence of Events and System Operation

It is assumed that the system fails near the condenser. This results in activity normally processed by the offgas treatment system being discharged directly to the turbine enclosure and subsequently through the ventilation system to the environment.

The operator initiates a normal shutdown of the reactor to reduce the gaseous activity being discharged. A loss of main condenser vacuum will result in a turbine trip and reactor shutdown.

Failure of the gland steam evaporator and its backup steam supply would result in the discharge of a small amount of contaminated steam from the high pressure and low pressure shaft seals to the gland steam condenser exhauster.

Failure of both of the gland steam condenser exhausters results in the escape of clean steam from the high pressure and low pressure shaft seals.

Excessive pressure in the steam seal header as a result of a malfunction of the gland steam evaporator or the backup steam supply valve is prevented by a relief valve, so that there is no detrimental effect on the operation of the seals.

15.7.1.2.3 Core and System Performance

The failure of this power conversion system does not directly affect the NSSS. It will, of course, lead to the decoupling of the NSSS from the power conversion system.

This failure has no applicable effect on the core or the NSSS safety performance.

15.7.1.2.4 Barrier Analysis

This release occurs outside primary containment; therefore, the primary containment barrier integrity is not involved.

15.7.1.2.5 Radiological Consequences

Each of the assumed malfunctions results in negligible releases of activity. Therefore, the doses that result from these failures are inconsequential.

15.7.1.3 Failure of Steam Jet Air Ejector Lines

15.7.1.3.1 Identification of Causes and Frequency Classification

15.7.1.3.1.1 Identification of Causes

An evaluation of events that could cause a failure of the SJAE line indicates that a seismic event or hydrogen detonation more serious than the system is able to withstand are the only events that could rupture the lines.

15.7.1.3.1.2 Frequency Classification

This accident is categorized as a limiting fault.

15.7.1.3.2 Sequence of Events and System Operation

It is assumed that the line leading from the SJAE to the offgas treatment system fails. This results in activity normally processed by the offgas treatment system being discharged directly to the turbine enclosure and subsequently through the ventilation system to the environment.

The operator will initiate a normal shutdown of the reactor to reduce the gaseous activity being discharged. The operator will isolate the main condenser, which results in high condenser pressure and a reactor scram. The operator will notify personnel to evacuate the area immediately and notify radiation protection personnel to survey the area and determine requirements for re-entry.

15.7.1.3.3 Core and System Performance

The failure of this power conversion system does not directly affect the NSSS. It will, of course, lead to the decoupling of the NSSS with power conversion system.

This failure has no applicable effect on the core or the NSSS safety performance.

15.7.1.3.4 Barrier Analysis

This release occurs outside primary containment; therefore, the primary containment barrier integrity is not involved.

15.7.1.3.5 Radiological Consequences

The offgas release rates at the SJAE are assumed for the design basis and the realistic case to be 0.35 Ci/Sec and 0.06 Ci/Sec at 30 minutes decay, respectively. The delay between the SJAE and the break is assumed to be five minutes. It is conservatively assumed that activities are released directly to the environment and that the uncontrolled release period is one hour before the plant operator initiates a plant shutdown. Iodines are neglected per Regulatory Guide 1.98. Specific parametric values in this evaluation are presented in Table 15.7-7.

The activity released to the environment and the calculated exposures are presented in Tables 15.7-8 and 15.7-9, respectively.

15.7.2 LIQUID RADIOACTIVE WASTE SYSTEM FAILURE

15.7.2.1 Identification of Causes and Frequency Classification

15.7.2.1.1 Identification of Causes

It was assumed that an unspecified event causes the complete release of the average radioactivity inventory in the tank containing the largest quantities of significant radionuclides in the liquid radwaste system. This is the RWCU phase separator in the radwaste enclosure. The airborne radioactivity released during this accident passes directly to the environment via the ventilation stack.

Postulated events that could cause release of the radioactive inventory of the RWCU phase separator are cracks in the vessel and operator error. The possibility of small cracks and consequent low-level release rates receives primary consideration in system and component design. The RWCU phase separator is designed to operate at atmospheric pressure and 212°F, so the possibility of failure is considered small. A liquid radwaste release caused by operator error

is also considered a remote possibility. Operating techniques and administrative procedures emphasize detailed system and equipment operating instruction. Should a release of liquid radioactive wastes occur, floor drain sump pumps in the floor of the radwaste enclosure will receive a high-water level signal, activate automatically, and remove the spilled liquid.

15.7.2.1.2 Frequency Classification

Much of the discussion concerning the remote likelihood of a leakage or malfunction accident of a RWCU phase separator applies equally to a complete release accident. The probability of a complete rupture or complete malfunction accident is, however, considered even lower.

Although not analyzed for the requirements of seismic Category I equipment, the liquid radwaste tanks are constructed in accordance with sound engineering principles. Therefore, simultaneous failure of all the tanks is not considered credible.

This accident is expected to occur with the frequency of a limiting fault.

15.7.2.2 Sequence of Events and System Operation

The sequence of events following this accident is shown in Table 15.7-10.

The rupture of a RWCU phase separator would leave little recourse to the operator. No method of recontaining the gaseous phase discharge is available.

15.7.2.3 Core and System Performance

Failure of a RWCU phase separator does not directly affect the NSSS. It will, of course, lead to the decoupling of the NSSS from the liquid radioactive waste system.

This failure is not expected to have any applicable effect on the core or NSSS safety performance.

15.7.2.4 Barrier Performance

This release occurs outside primary containment; therefore, barrier integrity is not involved.

15.7.2.5 Radiological Consequences

15.7.2.5.1 Design Basis Analysis

It is assumed that a RWCU phase separator contains the inventory of radioactive material as presented in Section 12.2. A RWCU phase separator, which contains the greatest amount of iodine inventory that could be released, is assumed to fail releasing the entire contents of this tank (equal to 80% of the tank capacity) to the radwaste enclosure. An iodine partitioning factor of 100 is assumed for the spilled liquid. The airborne iodine activity is exhausted through the radwaste ventilation system over a two-hour period. Specific parametric values used in this evaluation are presented in Table 15.7-11.

Table 15.7-12 lists the iodine activity released to the environment.

The offsite radiological doses for a RWCU phase separator rupture accident are given in Table 15.7-14.

15.7.2.5.2 Realistic Analysis

It is assumed that the inventory in a RWCU phase separator corresponds to 0.05 Ci/sec offgas release under normal operation. Other assumptions are the same as that of the design basis analysis. Activities released to the environment and offsite doses are presented in Tables 15.7-13 and 15.7-14, respectively.

15.7.3 POSTULATED RADIOACTIVE RELEASES DUE TO LIQUID RADWASTE TANK FAILURE

Refer to Section 2.4.12 for a discussion of tank failures.

15.7.4 FUEL HANDLING ACCIDENT

The material presented in Section 15.7.4 is historical and based on an 8x8 fuel design. However, the material presented in Section 15.7.4.5 is updated for Alternative Source Terms and represents the current licensing basis for the FHA. The analytical methodology and licensing bases for the Fuel Handling Accident are provided in GESTAR II (Reference 4.1-1). Compliance with these bases is verified in Amendment 22 of GESTAR II for each new fuel design. The analysis in this Section generally follows the methodology described in GESTAR II, however, it applies additional conservative assumptions. The GE RCWP jib cranes are permitted to extend into the boundary zone during fuel handling based on a determination in a GE analysis that a collision between a loaded fuel grapple and the GE RCWP would not result in dropping the fuel bundle or mast fuel grapple assembly onto the core; and therefore the original FHA remains bounding.

15.7.4.1 Identification of Causes and Frequency Classification

15.7.4.1.1 Identification of Causes

The fuel handling accident is assumed to occur as a consequence of a failure of the fuel assembly lifting mechanism resulting in the dropping of a raised fuel assembly onto other fuel bundles. A variety of events that qualify for the class of accidents termed "fuel handling accidents" has been investigated. The accident that produces the largest number of failed spent fuel rods is the drop of a spent fuel bundle and the fuel grapple assembly of the refueling platform into the reactor core when the reactor vessel head is off. The fuel grapple assembly consists of a telescopic mast and head assembly.

15.7.4.1.2 Frequency Classification

This accident is categorized as a limiting fault.

15.7.4.2 Sequence of Events and System Operation

15.7.4.2.1 Sequence of Events

The sequence of events following this failure is shown in Table 15.7-15.

15.7.4.2.2 Identification of Operator Actions

The operator actions are as follows:

a. Initiate the evacuation of the refueling area.

b. Notify Health Physics

c. The supervisor in charge of fuel handling will alert the control room operator to the accident.

d. Determine if the normal ventilation system has isolated and the SGTS is in operation.

e. Initiate action to determine the extent of potential radiation doses by measuring the radiation levels in the vicinity of or close to the refueling area.

f. Appropriate radiological control methods should be implemented at the entrance of the refueling area.

g. Before entering the refueling area, a careful study of conditions, radiation levels, etc., will be performed.

15.7.4.2.3 System Operation

Normally, operating plant instrumentation and controls are assumed to function, although credit is taken only for the isolation of the normal ventilation system and the operation of the SGTS. Operation of other plant or RPS or ESF systems is not expected.

15.7.4.2.4 The Effect of Single Failures and Operator Errors

The automatic ventilation isolation system includes the radiation monitoring detectors and isolation valves. The SGTS is designed to the single failure criterion and safety requirements. Refer to Sections 7.6, 9.4 and 15.10 for further details.

15.7.4.3 Core and System Performance

15.7.4.3.1 Mathematical Model

The analytical methods and associated assumptions used to evaluate the consequences of this accident are considered to provide a realistic yet conservative assessment of the consequences.

Calculations were performed to evaluate the consequences of a variety of drop scenarios. The worst-case scenario that produced the greatest number of failed fuel rods is represented by the fuel bundle and grapple assembly falling as two separate and independent units from their respective fully raised heights.

The consequences of a drop scenario consisting of a fuel bundle and grapple assembly falling as a single unit are bounded by the above worst-case scenario, mainly because twice as many fuel rods are struck (and consequently fail due to bending) by the drop of two independent units.

The calculated results of the worst case scenario are conservative because both of the following unlikely events would have to occur:

a. The fuel bundle becomes detached from the grapple by either a break of the bail handle or grapple.

b. The grapple assembly becomes detached from the refueling platform by either a break of the cables or a break of the cable support eye bracket.

To estimate the expected number of failed fuel rods in each impact, an energy approach is used.

The fuel assembly and grapple assembly are expected to impact on the reactor core at a small angle from the vertical, possibly inducing a bending mode of failure on the fuel rods of the dropped assembly. It is assumed that each fuel rod resists the imposed bending load by a couple consisting of two equal, opposite concentrated forces. Therefore, fuel rods are expected to absorb little energy prior to failure as a result of bending. Actual bending tests with concentrated point loads show that each fuel rod absorbs approximately 1 ft-lb prior to cladding failure. Each rod that fails as a result of gross compression distortion is expected to absorb approximately 250 ft-lb before cladding failure (based upon 1% uniform plastic deformation of the rods). The energy of the dropped assemblies is conservatively assumed to be absorbed by only the cladding and other core structures. Because a typical 8x8 fuel assembly consists of 72% fuel, 11% cladding, and 17% other structural material by weight, the assumption that no energy is absorbed by the fuel material results in considerable conservatism in the mass-energy calculations that follow.

It should be noted that the energy required to cause cladding failure due to compression and weight percentages of fuel, cladding, and other structural material are fuel type specific. The values given here are historical as discussed in Section 15.7.4.

The energy absorption on successive impacts is estimated by considering a plastic impact. Conservation of momentum under a plastic impact shows that the fractional kinetic energy absorbed during impact is:

$$1 - \frac{M_1}{M_1 + M_2}$$

where M_1 is the impacting mass and M_2 is the struck mass.

15.7.4.3.2 Input Parameters and Initial Conditions

The assumptions used in the analysis of this accident are listed below:

a. The fuel assembly and grapple assembly are dropped from the maximum height allowed by the refueling platform (32 feet and 47 feet, respectively, when handling fuel) as two separate and independent units.

b. The entire amount of potential energy, referenced to the top of the reactor core, is available for application to the fuel assemblies involved in the accident. This assumption neglects the dissipation of some of the mechanical energy of the falling fuel assembly and grapple assembly in the water above the core.

c. None of the energy associated with the dropped assemblies is absorbed by the fuel material (uranium dioxide).

d. The minimum water depth between the top of the fuel rods and the fuel pool surface is 22 feet.

e. Maximum fuel rod pressurization is 2072 psia.

f. The peak linear power density for the highest power assembly discharged is 13.4 kW/ft and the corresponding maximum centerline operating fuel temperature is 3412°F.

g. Because the weights of the fuel assembly and grapple assembly are similar, the fractional energy losses are assumed to be the same for both assemblies.

15.7.4.3.3 Results

15.7.4.3.3.1 Energy Available

Dropping a fuel assembly onto the reactor core from the maximum height allowed by the refueling platform (32 feet) results in an impact velocity of 45.4 fps. Dropping the fuel grapple assembly onto the reactor core from the maximum height allowed by the refueling platform (47 feet) results in an impact velocity of 55.0 fps.

The total kinetic energy acquired by the falling assemblies is approximately 45,900 ft-lb and is dissipated in one or more impacts. The total kinetic energy equals the sum of the kinetic energy of the dropped fuel assembly (32 ft x 700 lb = 22,400 ft-lb) and the dropped fuel grapple assembly (47 ft x 500 lb = 23,500 ft-lb).

A review has been made to determine whether there are any potential drops of loads lighter than a fuel bundle and full grapple assembly (i.e., 1200 lb) that could have a higher kinetic energy due to a higher carrying height. The following conclusions have been reached:

No load that weighs less than 540 lb can develop a higher kinetic energy than a fuel bundle and full grapple assembly if dropped over spent fuel. This value is based on a potential energy of 45,900 ft-lb with the load at the maximum lift height of the reactor enclosure crane and relative to the reactor core (worst case). The majority of light loads carried over spent fuel weigh less than 540 lb.

As listed in Table 15.7-22, the potential energy of the remaining few light loads which will be handled over spent fuel and which weigh more than 540 lb is less than 45,900 ft-lb because their maximum drop heights are less than the worst case. Infrequent or unexpected movement of light loads (i.e., weighing greater than 540 lb but less than 1200 lb) over spent fuel which are not identified in Table 15.7-22 are administratively controlled on a case-by-case basis. These infrequent or unexpected load handling situations use the load handling guidelines to ensure that the probability of a load drop is extremely small or that the consequences are acceptable.

Based on the above review, the maximum kinetic energy resulting from the drop of each object weighing less than a fuel bundle and grapple assembly that could be handled over spent fuel will not exceed the effects of the fuel handling accident described above.

15.7.4.3.3.2 Energy Loss Per Impact

Based on the fuel geometry in the reactor core and the long narrow shape of both dropped assemblies, four fuel assemblies are struck by each dropped assembly. The fractional energy loss on the first impact is approximately 80%.

The second impact is expected to be less direct. The broadside of each dropped assembly impacts approximately 24 more fuel assemblies, so that after the second impact less than 240 ft-lb (approximately 1% of the original kinetic energy) is available for a third impact. Because a single fuel rod is capable of absorbing 250 ft-lb in compression before cladding failure, it is unlikely that any fuel rod will fail on a third impact.

If each dropped assembly strikes only one or two fuel assemblies on its first impact, the energy absorption by the core support structure results in approximately the same energy dissipation on the first impact as in the case where four fuel assemblies are struck. The energy relations on the second and third impacts remain approximately the same as in the original case. Thus, the calculated energy dissipation is as follows:

First impact	80%
Second impact	19%
Third impact	1% (no cladding failures)

15.7.4.3.3.3 Fuel Rod Failures

15.7.4.3.3.3.1 First Impact Failures

The first impacts dissipate 0.80 x 45,900 or 36,720 ft-lb of energy. It is assumed that 50% of this energy is absorbed by the dropped fuel assembly and that the remaining 50% is absorbed by the struck fuel assemblies in the core. In addition, it is conservatively assumed that 0% of this energy is absorbed by the dropped grapple assembly and 100% is absorbed by the struck fuel assemblies. Because the fuel rods of the dropped fuel assembly are susceptible to the bending mode of failure and because 1 ft-lb of energy is sufficient to cause cladding failure as a result of bending, all 62 rods of the dropped fuel assembly are assumed to fail.

Each assembly, fuel and grapple, hits four fuel assemblies in the reactor core. This results in 64 tie rod failures as follows: 2 dropped assemblies (fuel and grapple) x 4 struck fuel assemblies per dropped assembly x 8 tie rods per struck fuel assembly.

Because the remaining fuel rods of the struck assemblies are held rigidly in place in the core, they are susceptible only to the compression mode of failure. To cause cladding failure of one fuel rod as a result of compression, 250 ft-lb of energy is required. To cause failure of all the remaining rods of each group of four struck assemblies, 250 x 54 x 4 or 54,000 ft-lb of energy would have to be absorbed in cladding alone. Thus, it is clear that not all the remaining fuel rods of the struck assemblies can fail on the first impact. The number of fuel rod failures caused by compression is computed as follows:

Dropped fuel assembly:

$$\frac{0.5 \times 0.8 \times 22{,}400 \times \frac{11}{11 + 17}}{250} = 14$$

Dropped fuel grapple assembly:

$$\frac{11}{}$$

$$\frac{1.0 \times 0.8 \times 23{,}500 \times 11 + 17}{250} = \frac{30}{44}$$

Thus, during the first impact, fuel rod failures are as follows:

Dropped fuel assembly	62 rods (bending)
Struck assemblies	64 tie rods (bending)
Struck assemblies	44 rods (compression)
	170 failed rods

15.7.4.3.3.3.2 Second Impact Failures

Because of the less severe nature of the second impact and the distorted shape of each dropped assembly, it is assumed that the tie rods in only two of the 24 struck assemblies are subjected to bending failure. Because each dropped assembly strikes 24 fuel assemblies, 2 x 2 x 8 = 32 tie rods are assumed to fail. The number of fuel rod failures caused by compression on the second impact is computed as follows:

Dropped fuel assembly:

$$\frac{0.19}{\frac{2 \times 22{,}400 \times \overline{11 + 17}}{250}} = 3$$

Dropped fuel grapple assembly:

$$\frac{1.0 \times 0.19 \times 23{,}500 \times \overline{11 + 17}}{250} = \frac{7}{10}$$

Thus, during the second impact, the fuel rod failures are as follows:

Struck assemblies	32 tie rods (bending)
Struck assemblies	10 rods (compression)
	42 failed rods

15.7.4.3.3.3.3 Total Failures

The total number of failed rods resulting from the accident is as follows:

First impact	170 rods
Second impact	42 rods
Third impact	0 rods
	212 total failed rods

15.7.4.4 Barrier Performance

The RCPB and primary containment are assumed to be open. The transport of fission products from the refueling area is discussed in Sections 15.7.4.5.2.1 and 15.7.4.5.2.2.

15.7.4.5 Radiological Consequences for the FHA

Regulation 10CFR50.67, "Accident Source Term," provides a mechanism for power reactor licensees to voluntarily replace the traditional TID-14844 (Ref. 15.7-4A) accident source term used in design-basis accident analyses with an "Alternative Source Term" (AST). The methodology of approach to this replacement is given in USNRC Regulatory Guide 1.183 (Ref. 15.7-5) and its associated Standard Review Plan 15.0.1 (Ref. 15.7-6).

Accordingly, Limerick Generating Station, Units 1 and 2, have applied the AST methodology for several areas of operational relief in the event of a Design Basis Accident (DBA), without fully crediting the use of previously assumed safety systems. Amongst these systems are the Control Room Emergency Fresh Air Supply System (CREFAS) and the Standby Gas Treatment System (SGTS).

In support of a full-scope implementation of AST as described in and in accordance with the guidance of Ref. 15.7-5, AST radiological consequence analyses are performed for the four DBAs that result in offsite exposure (i.e., Loss of Coolant Accident (LOCA), Main Steam Line Break (MSLB), Fuel Handling Accident (FHA), and Control Rod Drop Accident (CRDA)).

Implementation consisted of the following steps:

- Identification of the AST based on plant-specific analysis of core fission product inventory,
- Calculation of the release fractions for the four DBAs that could potentially result in control room and offsite doses (i.e., LOCA, MSLB, FHA, and CRDA),
- Analysis of the atmospheric dispersion for the radiological propagation pathways,
- Calculation of fission product deposition rates and removal mechanisms,
- Calculation of offsite and control room personnel Total Effective Dose Equivalent (TEDE) doses.

15.7.4.5.1 Regulatory Approach

The analyses are prepared in accordance with the guidance provided by Regulatory Guide 1.183 (Ref. 15.7-5).

15.7.4.5.2 Dose Acceptance Criteria

The AST acceptance criteria for Control Room dose for postulated major credible accident scenarios such as those resulting in substantial meltdown of the core with release of appreciable quantities of fission products is provided by 10CFR50.67, which requires:

> "Adequate radiation protection is provided to permit access to and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) total effective dose equivalent (TEDE) for the duration of the accident."

This limit is applied by Regulatory Guide 1.183 to all of the accidents considered with AST.

The AST acceptance criteria for an individual located at any point on the boundary of the exclusion area (the Exclusion Area Boundary or EAB) are provided by 10 CFR 50.67 as 25 rem TEDE for any 2-hour period following the onset of the postulated fission product release.

The AST acceptance criteria for an individual located at any point on the outer boundary of the low population zone (LPZ) are provided by 10CFR50.67 as 25 rem TEDE during the entire period of passage of the radioactive cloud resulting from the postulated fission product release.

These limits are applied by Regulatory Guide 1.183 to events with a higher probability of occurrence (including CRDA, MSLB, and FHA considered herein) to provide the following acceptance criteria:

- For the BWR MSLB for the case of an accident assuming fuel damage or a pre-incident Iodine spike, doses at the EAB and LPZ should not exceed 25 rem TEDE for the accident duration (2-hour dose for EAB and 30-day dose for LPZ). For MSLB accidents assuming normal equilibrium Iodine activity, doses should not exceed 2.5 rem TEDE for the accident duration.
- For the BWR CRDA, doses at the EAB and LPZ should not exceed 6.3 rem TEDE for the accident duration (2-hour dose for EAB and 24-hour dose for LPZ).
- For the FHA, doses at the EAB and LPZ should not exceed 6.3 rem TEDE for the accident duration (2-hour dose for EAB and 30-day dose for LPZ).

15.7.4.5.3 Computer Codes

New AST calculations were prepared for the FHA to simulate the radionuclide release, transport, removal, and dose estimates associated with the postulated accident.

The RADTRAD computer code (Ref. 15.7-9) endorsed by the NRC for AST analyses was used in the calculations for analyzing the FHA. The RADTRAD program is a radiological consequence analysis code used to estimate post-accident doses at plant offsite locations and in the control room. The FHA assessment takes no credit for SGTS operation, control room isolation, emergency ventilation or filtration of intake air for the duration of the accident event.

Offsite X/Qs were calculated with the PAVAN computer code (Ref. 15.7-10), using the guidance of Regulatory Guide 1.145 (Ref. 15.7-11). Control room X/Qs were calculated with the ARCON96 computer code (Ref. 15.7-12). The PAVAN and ARCON96 codes calculate relative concentrations in plumes from nuclear power plants at offsite locations and control room air intakes, respectively.

All of these computer codes have been used by the NRC staff in its safety reviews.

15.7.4.5.4 Source Terms

Core Inventory

As with the LOCA analysis, the inventory of reactor core fission products used as input to RADTRAD for the AST FHA analysis is based on maximum full power operation at a power level of 3527 MWth, which includes a 2% instrument error per Reg. Guide 1.49 (Ref. 15.7-13). The fission products used for the accidents are the 60 isotopes of the standard RADTRAD input library, determined by the code developer as significant in dose consequences. These were extracted from Attachment A of the LGS Design Analysis LM-0645 (Ref. 15.7-14), and

correspond to 24 month cycle burnup parameters, conservatively calculated using the ORIGEN-ARP code.

Release Fraction

Current design basis accident evaluations as modified by Regulatory Guide 1.183 (Ref. 15.7-5) were used to determine the specific releases of radioactive isotopes at the given stages of fuel pin failure and provide these releases as a percentage of the total release for each accident, as summarized below.

15.7.4.5.5 Methodology

Dose Calculations

As per Regulatory Guide 1.183 (Ref. 15.7-5), Total Effective Dose Equivalent (TEDE) doses are determined as the sum of the CEDE and the Effective Dose Equivalent (EDE) using dose conversion factors for inhalation CEDE from Federal Guidance Report No. 11 (Ref. 15.7-15) and for external exposure EDE from Federal Guidance Report No. 12 (Ref. 15.7-16).

Fuel Handling Accident (FHA)

Table 15.7-16 lists the key assumptions and inputs used in the analysis. The AST FHA dose assessments use historical fuel damage assumptions of a total of 212 failed rods based on an 8x8 fuel design containing 62 fuel rods, but with a conservatively higher radial peaking factor (PF) of 1.69 instead of 1.5, as suggested by Reg. Guide 1.183. As per Section 15.7.4, the analytical methodology and licensing bases for determination of fuel damage in an FHA are provided in GESTAR II, and compliance with these bases is verified for each new fuel design. The new radiological analysis applies additional conservative assumptions so as to continue to provide margin.

The assumed accident is an assembly and mast drop from the maximum height allowed by the refueling platform (a height of 32 feet for the fuel assembly, and 47 feet for the mast) over the reactor well onto fuel in the reactor. Based on fuel damage assessments in Ref. 15.7-17, this bounds the damage assessments for various 8x8 and 7x7 array fuel types with 60 and 49 fuel pins per bundle, respectively, and 111 failed pins and a 1.5 PF, as well as GE11 or GE13 9x9 array fuel types with 74 fuel pins per bundle, 140 failed pins and a 1.5 PF, GE14 or GNF2 10x10 array fuel types with 172 failed pins per bundle and a 2.0 PF, and GNF3 10x10 array fuel types with 169 failed pins per bundle and a 2.0 PF.

The analysis assumes that the activity from the damaged fuel is released from the reactor building through the South Vent Stack with no further credit for reactor building holdup or dilution. No credit is taken for the control room emergency ventilation system or standby gas treatment system operation.

The analysis assumptions for the transport, reduction, and release of the radioactive material from the fuel and the reactor coolant are consistent with the guidance provided in Appendix B of Regulatory Guide 1.183, and are provided in the design analysis of Ref. 15.7-14 and Ref 15.7-17.

15.7.4.5.6 Atmospheric Dispersion Factors (X/Qs)

Table 15.7-17 lists X/Q values used for the control room dose assessments, as derived in UFSAR Chapter 2 and applied for the release point (south vent stack) applicable to the FHA, for a zero velocity vent release.

Table 15.7-15 lists X/Q values for the EAB and LPZ boundaries, as also derived in UFSAR Chapter 2 and applied for the release point (south vent stack) applicable to the FHA, for a zero velocity vent release.

15.7.4.5.7 Summary and Conclusions

The radiological consequences of the postulated FHA are given in Table 15.7-18. As indicated, the control room, EAB, and LPZ calculated doses are within regulatory limits after AST implementation.

15.7.5 SPENT FUEL CASK-DROP ACCIDENT

The spent fuel, ISFSI cask, and/or HI-TRAC VW cask will be equipped with lifting lugs and yoke(s) which are single failure proof in accordance with NUREG-0612 compatible with the single failure proof reactor enclosure crane and main hook, thus precluding a cask-drop due to a single failure. Therefore, an analysis of the cask-drop is not required. Refer to Section 9.1.5 for a description of the reactor enclosure crane and the interlocks that prevent moving the cask over the fuel pool.

15.7.6 MOVEMENT OF LOADS WITHOUT SECONDARY CONTAINMENT

The methodology provided in the reference 15.7-3 calculation allows the movement of various loads over irradiated fuel, without refueling area secondary containment integrity in place. The calculation provides the methodology to determine the consequences of dropping a load onto irradiated fuel, without secondary containment integrity, to remain bounded by the Fuel Handling Accident Analysis. Using the methodology provided in reference 15.7-3 ensures that the offsite dose values for the UFSAR Fuel Handling Accident Analysis will not be exceeded if the load being carried over irradiated fuel is dropped.

15.7.7 REFERENCES

15.7-1 D. Nguyen, "Realistic Accident Analysis - The RELAC Code", NEDO-21142, (January 1978).

15.7-2 N.R. Horton, W.A. Williams, and J.W. Holtzclaw, "Analytical Methods for Evaluating the Radiological Aspects of the General Electric Boiling Water Reactor," APED 5756, (March 1969).

15.7-3 LGS Design Analysis LM-0033, Rev. 6, "Methodology to determine the acceptability of Moving Loads over Irradiated Fuel Without Secondary Containment Integrity"

15.7-4 Not Used

15.7-4A U. S. Atomic Energy Commission, Technical Information Document (TID) 14844, "Calculation of Distance Factors for Power and Test Reactor Sites," March 23, 1962.

15.7-5 U. S. Nuclear Regulatory Commission Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," July 2000.

15.7-6 U. S. Nuclear Regulatory Commission Standard Review Plan 15.0.1, "Radiological Consequence Analyses Using Alternative Source Terms," Revision 0, July 2000.

15.7-7 Not Used

15.7-8 Not Used

15.7-9 RADTRAD Code, "A Simplified Model for Radionuclide Transport and Removal and Dose Estimation," Version 3.03.

15.7-10 PAVAN Code, "An Atmospheric Dispersion Program for Evaluating Design Bases Accidental Releases of Radioactive Materials from Nuclear Power Stations."

15.7-11 U. S. Nuclear Regulatory Commission Regulatory Guide 1.145, "Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants," Revision 1, November 1982.

15.7-12 ARCON96 Code, "Atmospheric Relative Concentrations in Building Wakes."

15.7-13 U. S. Nuclear Regulatory Commission Regulatory Guide 1.49, "Power Levels of Nuclear Power Plants," Revision 1, December 1973.

15.7-14 LGS Design Analysis LM-0645, Rev. 5, "Re-analysis of Fuel Handling Accident (FHA) Using Alternative Source Terms."

15.7-15 Federal Guidance Report No. 11, "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion," 1988.

15.7-16 Federal Guidance Report No. 12, "External Exposure to Radionuclides in Air, Water, and Soil," 1993.

15.7-17 “GNF2 Fuel Design Cycle Independent Analyses for Limerick Generating Station Units 1 and 2,” Global Nuclear Fuels Document, NEDC-33627P, (latest approved revision).

Table 15.7-1

SEQUENCE OF EVENTS FOR
MAIN CONDENSER OFFGAS TREATMENT SYSTEM FAILURE

TIME (sec)	EVENTS
0	Event begins - system fails.
0	Noble gases are released.
<60	Area radiation alarms alert plant personnel.
<60	Operator actions begin with: a. Initiation of appropriate system isolations. b. Manual scram actuation. c. Assurance of reactor shutdown cooling.

Table 15.7-2

RADIOACTIVE GAS WASTE SYSTEM FAILURE: PARAMETERS TABULATED FOR POSTULATED ACCIDENT ANALYSES

	DESIGN BASIS ASSUMPTIONS	REALISTIC BASIS ASSUMPTIONS
I. Data and Assumptions Used to Estimate Radioactive Source from Postulated Accidents		
A. Power Level	3527	3527
B. Burnup	NA	NA
C. Fission Product Released from Fuel (fuel damaged)	None	None
D. Release of Activity by Nuclide	Table 15.7-4	Table 15.7-5
E. Iodine Fractions		
1. Organic	NA	NA
2. Elemental	NA	NA
3. Particulate	NA	NA
F. Reactor Coolant Activity before the Accident	NA	NA
II. Data and Assumptions Used to Estimate Activity Released		
A. Primary Containment Leak Rate (%/day)	NA	NA
B. Secondary Containment Release Rate (%/day)	NA	NA
C. Valve Movement Times	NA	NA
D. Adsorption and Filtration Efficiencies	NA	NA
1. Organic iodine	NA	NA
2. Elemental iodine	NA	NA
3. Particulate iodine	NA	NA
4. Particulate fission products	NA	NA
E. Recirculation System Parameters	NA	NA
1. Flow rate	NA	NA
2. Mixing efficiency	NA	NA
3. Filter efficiency	NA	NA
F. Containment Spray Parameters (flow rate, drop size, etc.)	NA	NA
G. Containment Volumes	NA	NA
H. All Other Pertinent Data and Assumptions	Section 15.7.1.1.5	Section 15.7.1.1.5

Table 15.7-2 (Cont'd)

	DESIGN BASIS ASSUMPTIONS	REALISTIC BASIS ASSUMPTIONS
III. Dispersion Data		
A. EAB/LPZ distances (m)	731/2043	731/2043
B. X/Qs for		
EAB(2 hr)	2.9×10^{-4}	1.2×10^{-4}
LPZ(8 hr)	4.0×10^{-5}	2.0×10^{-5}
IV. Dose Data		
A. Method of Dose Calculation	Section 15.7-1	Reference 15.7-1
B. Dose Conversion Assumptions	Section 15.10	Reference 15.7-1
C. Peak Activity Concentrations in Containment	NA	NA
D. Doses	Table 15.7-9(b)	Table 15.7-9(b)

Table 15.7-3

OFFGAS EQUIPMENT FAILURE RELEASE ASSUMPTIONS:
RELEASE FRACTIONS ASSUMED FOR
DESIGN BASIS AND REALISTIC ANALYSIS

EQUIPMENT	NOBLE GASES	SOLID DAUGHTERS	RADIOIODINE
Charcoal Guard Bed	1.0/1.0	NA	NA
Charcoal Adsorbers	1.0/1.0	NA	NA
Afterfilter	1.00/1.00	NA	NA

Table 15.7-4

MAIN CONDENSER OFFGAS TREATMENT SYSTEM FAILURE
(CHARCOAL ADSORBER VESSELS): ACTIVITY RELEASED TO THE ENVIRONMENT

DESIGN BASIS ANALYSIS

ISOTOPE	ACTIVITY (Ci)
Kr-83m	$9.54 \times 10^{+1}$
Kr-85m	$2.33 \times 10^{+2}$
Kr-85	$1.97 \times 10^{+2}$
Kr-87	$3.54 \times 10^{+2}$
Kr-88	$9.10 \times 10^{+2}$
Kr-89	1.81×10^{-1}
Xe-131m	$6.56 \times 10^{+1}$
Xe-133m	$2.77 \times 10^{+2}$
Xe-133	$1.86 \times 10^{+4}$
Xe-135m	$3.23 \times 10^{+1}$
Xe-135	$3.62 \times 10^{+3}$
Xe-137	8.79×10^{-1}
Xe-138	$1.44 \times 10^{+2}$

Table 15.7-5

MAIN CONDENSER OFFGAS TREATMENT SYSTEM FAILURE
(CHARCOAL ADSORBER VESSELS): ACTIVITY RELEASED TO THE ENVIRONMENT

REALISTIC ANALYSIS

ISOTOPE	ACTIVITY (Ci)
Kr-83m	$1.86 \times 10^{+1}$
Kr-85m	$4.30 \times 10^{+1}$
Kr-85	5.93
Kr-87	$7.55 \times 10^{+1}$
Kr-88	$1.74 \times 10^{+2}$
Kr-89	3.07
Xe-131m	$1.30 \times 10^{+1}$
Xe-133m	$4.78 \times 10^{+1}$
Xe-133	$3.24 \times 10^{+3}$
Xe-135m	$1.44 \times 10^{+2}$
Xe-135	$6.59 \times 10^{+2}$
Xe-137	6.26
Xe-138	$5.65 \times 10^{+1}$

Table 15.7-6

MAIN CONDENSER OFFGAS TREATMENT SYSTEM FAILURE
(CHARCOAL ADSORBER VESSELS): RADIOLOGICAL EFFECTS

DESIGN BASIS ANALYSIS

	WHOLE BODY DOSE (rem)
Exclusion Area Boundary (731 meters - 2 hr dose)	2.70×10^{-1}
Low Population Zone (2043 meters - 2 hr[1] dose)	3.70×10^{-2}

REALISTIC ANALYSIS

	WHOLE BODY DOSE (rem)
Exclusion Area Boundary (731 meters - 2 hr dose)	2.30×10^{-2}
Low Population Zone (2043 meters - 2 hr[1] dose)	3.70×10^{-3}

(1) Duration of accident is 2 hours

Table 15.7-7

FAILURE OF STEAM JET AIR EJECTOR LINES: PARAMETERS TABULATED FOR POSTULATED ACCIDENT ANALYSES

	DESIGN BASIS ASSUMPTIONS	REALISTIC BASIS ASSUMPTIONS
I. Data and Assumptions Used to Estimate Radioactive Source from Postulated Accidents		
A. Power Level	3527	3527
B. Burnup	NA	NA
C. Fission Product from Fuel (fuel damaged)	NA	NA
D. Release of Activity by Nuclide	NA	None
E. Iodine Fractions	NA	NA
1. Organic	NA	NA
2. Elemental	NA	NA
3. Particulate	NA	NA
F. Reactor Coolant Activity before the Accident	NA	NA
II. Data and Assumptions Used to Estimate Activity Released		
A. Primary Containment Leak Rate (%/day)	NA	NA
B. Secondary Containment Release Rate (%/day)	NA	NA
C. Valve Movement Times	NA	NA
D. Adsorption and Filtration Efficiencies	NA	NA
1. Organic iodine	NA	NA
2. Elemental iodine	NA	NA
3. Particulate iodine	NA	NA
4. Particulate fission products	NA	NA
E. Recirculation System Parameters	NA	NA
1. Flow rate	NA	NA
2. Mixing efficiency	NA	NA
3. Filter efficiency	NA	NA
F. Containment Spray Parameters (flow rate, drop size, etc.)	NA	NA
G. Containment Volumes	NA	NA

Table 15.7-7 (Cont'd)

	DESIGN BASIS ASSUMPTIONS	REALISTIC BASIS ASSUMPTIONS
H. All Other Pertinent Data and Assumptions	Section 15.7.1.3.5	Section 15.7.1.3.5
III. Dose Data		
A. Method of Dose Calculation	Section 15.10	Reference 15.7-1
B. Dose Conversion Assumptions	Section 15.10	Reference 15.7-1
C. Peak Activity Concentrations in Containment	NA	NA
D. Doses	Table 15.7-9(a)	Table 15.7-9(a)

Table 15.7-8

FAILURE OF STEAM JET AIR EJECTOR LINES:
ACTIVITY RELEASED TO THE ENVIRONMENT

DESIGN BASIS ANALYSIS

Isotope	Activity (Ci)
Kr-83m	$4.19 \times 10^{+1}$
Kr-85m	$3.91 \times 10^{+1}$
Kr-85	2.52×10^{-1}
Kr-87	$2.41 \times 10^{+2}$
Kr-88	$2.47 \times 10^{+2}$
Kr-89	$5.56 \times 10^{+2}$
Xe-131m	1.87×10^{-1}
Xe-133m	3.60
Xe-133	$1.04 \times 10^{+2}$
Xe-135m	$2.61 \times 10^{+2}$
Xe-135	$2.75 \times 10^{+2}$
Xe-137	$7.71 \times 10^{+2}$
Xe-138	$8.74 \times 10^{+2}$

REALISTIC ANALYSIS

Isotope	Activity (Ci)
Kr-83m	7.18
Kr-85m	6.70
Kr-85	4.32×10^{-2}
Kr-87	$4.13 \times 10^{+1}$
Kr-88	$4.23 \times 10^{+1}$
Kr-89	$9.53 \times 10^{+1}$
Xe-131m	3.21×10^{-2}
Xe-133m	6.16×10^{-1}
Xe-133	$1.79 \times 10^{+1}$
Xe-135m	$4.48 \times 10^{+1}$
Xe-135	$4.72 \times 10^{+1}$
Xe-137	$1.32 \times 10^{+2}$
Xe-138	1.50×10^{2}

Table 15.7-9(a)

FAILURE OF STEAM JET AIR EJECTOR LINES:
RADIOLOGICAL EFFECTS

DESIGN BASIS ANALYSIS

	TOTAL BODY DOSE (rem)
Exclusion Area Boundary (731 meters - 2 hr[1] dose)	2.3×10^{-1}
Low Population Zone (2043 meters - 2 hr[1] dose)	3.1×10^{-2}

REALISTIC ANALYSIS

	TOTAL BODY DOSE (rem)
Exclusion Area Boundary (731 meters - 2 hr[1] dose)	1.6×10^{-2}
Low Population Zone (2043 meters - 2 hr[1] dose)	2.7×10^{-3}

(1) Duration of accident is 2 hours

Table 15.7-9(b)

MAIN CONDENSER OFFGAS TREATMENT SYSTEM
FAILURE: RADIOLOGICAL EFFECTS

DESIGN BASIS ANALYSIS

	TOTAL BODY DOSE (rem)
Exclusion Area Boundary (731 meters - 2 hr dose)	4.96×10^{-1}
Low Population Zone (2043 meters - 2 hr[1] dose)	6.82×10^{-2}

REALISTIC ANALYSIS

	TOTAL BODY DOSE (rem)
Exclusion Area Boundary (731 meters - 2 hr dose)	3.90×10^{-2}
Low Population Zone (2043 meters - 2 hr[1] dose)	6.40×10^{-3}

(1) Duration of accident is 2 hours

Table 15.7-10

SEQUENCE OF EVENTS:
LIQUID RADWASTE TANK FAILURE

TIME (min)	SEQUENCE OF EVENTS
0.0	Event begins - failure occurs
1.0 (approx)	Area radiation alarms alert plant personnel
<10.0	Operator action begins

Table 15.7-11

LIQUID RADWASTE TANK FAILURE: PARAMETERS
TABULATED FOR POSTULATED ACCIDENT ANALYSES

	DESIGN BASIS ASSUMPTIONS	REALISTIC BASIS ASSUMPTIONS
I. Data and Assumptions Used to Estimate Radioactive Source from Postulated Accidents		
A. Power Level	NA	NA
B. Burnup	NA	NA
C. Fission Products Released from Fuel (fuel damaged)	NA	NA
D. Release of Activity by Nuclide	NA	None
E. Iodine Partition Factors	Table 15.7-12	Table 15.7-13
1. Organic	0.01	0.01
2. Elemental	0.01	0.01
3. Particulate	0.01	0.01
F. Reactor Coolant Activity before the Accident	NA	NA
II. Data and Assumptions Used to Estimate Activity Released		
A. Containment Leak Rate (%/day)	NA	NA
B. Secondary Containment Release Rate (%/day)	NA	NA
C. Valve Movement Times	NA	NA
D. Adsorption and Filtration Efficiencies	NA	NA
1. Organic iodine	NA	NA
2. Elemental iodine	NA	NA
3. Particulate iodine	NA	NA
4. Particulate fission products	NA	NA
E. Recirculation System Parameters	NA	NA
1. Flow rate	NA	NA
2. Mixing efficiency	NA	NA
3. Filter efficiency	NA	NA
F. Containment Spray Parameters (flow rate, drop size, etc.)	NA	NA
G. Containment Volumes	NA	NA
H. All Other Pertinent Data and Assumptions		
1. Dilution factor afforded by public waterway	NA	NA

Table 15.7-11 (Cont'd)

	DESIGN BASIS ASSUMPTIONS	REALISTIC BASIS ASSUMPTIONS
2. Dilution of liquid ingestion	NA	NA
3. Aquatic life consumed (qms)	NA	NA
III. Dose Data		
A. Method of Dose Calculation	Section 15.10	Reference 15.7-1
B. Dose Conversion Assumptions	Section 15.10	Reference 15.7-1
C. Peak Activity Concentrations in Containment	NA	NA
D. Doses	Table 15.7-14	Table 15.7-14

Table 15.7-12

LIQUID RADWASTE TANK FAILURE
(RWCU PHASE SEPARATOR): ACTIVITY RELEASED TO THE ENVIRONMENT

DESIGN BASIS ANALYSIS

ISOTOPE	ACTIVITY (Ci)
I-131	$1.52 \times 10^{+1}$
I-132	$2.49 \times 10^{+1}$
I-133	$1.10 \times 10^{+1}$
I-134	$1.23 \times 10^{+0}$
I-135	$5.27 \times 10^{+0}$
TOTAL	5.76×10^{1}

Table 15.7-13

LIQUID RADWASTE TANK FAILURE
(RWCU PHASE SEPARATOR): ACTIVITY RELEASED TO THE ENVIRONMENT

REALISTIC ANALYSIS

ISOTOPE	ACTIVITY (Ci)
I-131	2.17
I-132	3.55
I-133	1.58
I-134	0.174
I-135	0.754
TOTAL	8.23

Table 15.7-14

LIQUID RADWASTE TANK FAILURE
(RWCU PHASE SEPARATOR): RADIOLOGICAL EFFECTS

DESIGN BASIS ANALYSIS

	WHOLE BODY DOSE (rem)	THYROID DOSE (rem)
Exclusion Area Boundary (731 meters - 2 hr dose)	5.41×10^{-3}	2.91
Low Population Zone (2043 meters - 2 hr[1] dose)	7.47×10^{-4}	4.03×10^{-1}

REALISTIC ANALYSIS

	WHOLE BODY DOSE (rem)	THYROID DOSE (rem)
Exclusion Area Boundary (731 meters - 2 hr dose)	3.2×10^{-4}	1.72×10^{-1}
Low Population Zone (2043 meters - 2 hr[1] dose)	5.34×10^{-5}	2.87×10^{-2}

(1) Duration of accident is 2 hours

Table 15.7-15

SEQUENCE OF EVENTS FOR FUEL HANDLING ACCIDENT

TIME (min)	EVENT
0	Fuel assembly is being handled by refueling equipment. The fuel assembly and fuel grapple assembly drop onto the top of the core.
0	Some of the fuel rods in both the dropped assembly and reactor core are damaged, resulting in the release of gaseous fission products to the reactor coolant and eventually to the refueling area atmosphere.
<1	The refueling area ventilation radiation monitoring system alarms to alert plant personnel.
<5	Operator actions begin.

Table 15.7-16

FHA – RADIOLOGICAL CONSEQUENCES
KEY INPUTS AND ASSUMPTIONS

Key FHA Analysis Inputs and Assumptions

Input/Assumption	Value
Reactor Power	3527 MWth
Core Damage	212 fuel pins (8 x 8 rod array)*
Radial Peaking Factor	1.69
Damaged Fuel Effective Power	26.6774 MWth
Fuel Decay Period	24 hours
Fuel Pool Water Iodine Decontamination Factor	DF = 200 (23 feet depth)
Release Location	South Vent Stack Unfiltered, zero-velocity vent release
CREFAS System Initiation	No Credit Taken

* This combination bounds all configurations for fuels currently implemented at LGS.

Table 15.7-17

FHA X/Q VALUES

Onsite Control Room X/Q Values for the FHA Releases

Time Period	χ/Q (sec/m^3)[1]
0 – 2 hrs	1.26E-03

Notes:
1. X/Q values for south vent stack release to control room based on ARCON96.

Offsite X/Q (sec/m^3) Values for the FHA Releases

Time Period	EAB χ/Q (sec/m^3)	LPZ χ/Q (sec/m^3)
0 – 2 hrs	3.18E-04 [1]	1.15E-04 [1]

Notes:
1. X/Q values for south vent stack release to offsite dose locations based on Regulatory Guide 1.145 methodology.

Table 15.7-18

FHA RADIOLOGICAL CONSEQUENCES ANALYSIS RESULTS

Location	Duration	TEDE (rem)	Regulatory Limit TEDE (rem)
Control Room	30 days	4.502	5
EAB	Maximum, 2 hours	1.501	6.3
LPZ	30 days	0.543	6.3

Table 15.7-19

Table 15.7-19
Deleted

Table 15.7-20

Table 15.7-20
Deleted

Table 15.7-21
Deleted

Table 15.7-22

POTENTIAL ENERGY OF LIGHT LOADS TO BE HANDLED OVER SPENT FUEL

	Load	Approximate Combined Weight, Handling Tool Plus Load (lb)	Potential Energy, (ft-lb) Normal Height	Potential Energy, (ft-lb) Maximum Height
a.	New fuel bundle or dummy bundle (Reactor enclosure crane relative to spent fuel pool)	700	21,000	29,000
b.	In-Vessel storage rack (Refueling platform hoist relative to core)	600	21,000	33,000

15.8 ANTICIPATED TRANSIENTS WITHOUT SCRAM

15.8.1 REQUIREMENTS

The LGS plant incorporates many features and systems designed to mitigate ATWS events. These features were originally incorporated into LGS in response to NRC concerns. They were based on extensive assessments of ATWS mitigation and are consistent with Alternate 3A (Reference 15.8-1). These features and systems, which meet the current ATWS requirements of 10CFR50.62, are described briefly below.

15.8.2 PLANT CAPABILITIES

The LGS design uses diverse, redundant, and reliable scram systems. This includes the normal scram systems plus the electrically diverse alternate rod insertion system. Each of these systems is frequently tested and would insert the control rods even if multiple component failures should occur, thus making the probability of an ATWS event extremely remote.

The ATWS-RPT feature prevents reactor vessel overpressure and possible short-term fuel damage for the most limiting postulated ATWS event by reducing reactor power. Subsequent to an ATWS event for which the ARI system does not insert the control rods, the long-term shutdown of the reactor can be accomplished by either manual insertion of the control rods or injection of sodium pentaborate solution into the vessel by the SLCS.

15.8.3 EQUIPMENT DESCRIPTION

This section describes the equipment and control logic added or modified exclusively for ATWS prevention or mitigation. The description covers design and functional requirements and references that contain more detailed information. The dynamic and environmental qualifications are described in Sections 3.9, 3.10, and 3.11.

15.8.3.1 Redundant Reactivity Control System

The RRCS determines that a transient is under way that exceeds expected operating parameters. After deciding that ATWS mitigation is the appropriate action, the RRCS activates ATWS prevention equipment and then ATWS mitigation equipment. The RRCS uses transient detection sensors for high vessel dome pressure and low vessel water level and the actuation logic to initiate ARI, RPT, SLCS injection, and feedwater runback.

The RRCS consists of two completely redundant divisions. Each division is initiated automatically by the ATWS detection sensors, which are independent of the RPS sensors, or manually by switches that require the same type of operator actions as manual scram.

Additional information on the RRCS is contained in Sections 7.1 and 7.6.

15.8.3.2 Alternate Rod Insertion

The ARI is designed to provide a parallel path for actuation of the scram valves, which results in control rod insertion. ARI consists of the redundant valves on the scram valve pilot air headers that are actuated by the RRCS logic. The RRCS logic is designed so that successful ARI performance will avoid subsequent ATWS mitigation action (feedwater runback and SLCS initiation).

Additional information on the ARI system is contained in Sections 7.1 and 7.6.

15.8.3.3 Recirculation Pump Trip

The recirculation pump motors are tripped by the RRCS logic. The purpose of the RPT is to reduce core flow and create core voids to decrease power generation, thus limiting any power or pressure disturbance. The RPT function is single failure proof and is provided with in service test capability (except for the action of the final breakers).

Additional information on the RPT function of the RRCS is contained in Sections 7.1 and 7.6.

15.8.3.4 Feedwater Runback

Upon the receipt of a high pressure signal from the RRCS and after a specified time-delay, if core power is not reduced as evidenced by the APRMs reading downscale (not low water level), feedwater flow would be automatically limited by the RRCS, thereby reducing power and steam discharge to the suppression pool. The system provides for manual operation to be returned to the operator after a time-delay to allow an increase in feedwater flow if needed.

Additional information on the feedwater runback function of the RRCS is contained in Sections 7.1 and 7.6.

15.8.3.5 Standby Liquid Control System

The SLCS is automatically actuated by the RRCS or manually initiated by an operator in the main control room upon indication of a failure to scram and in accordance with plant operating procedures. The system is designed to inject sodium pentaborate solution through a core spray sparger. Simultaneous operation of at least two of the three pumps at full capacity allows adequate margin to control the power production. The system can be periodically tested without affecting its ability to respond to an actuation signal.

Additional information on the SLCS is provided in Sections 3.9, 7.1, 7.4, and 9.3.5.

15.8.3.6 Scram Discharge Volume

The SDV of the CRD system minimizes the potential for a common mode failure of the scram function. Redundant instrument volume water level sensors for the CRDs and instrument line piping ensure the availability of sufficient capacity to receive water from a full reactor scram. The design employs redundant Class 1E sensors and redundant vent and drain valves. Performance of the safety functions is assured in the event of a single active failure or the bypass of the sensors during plant operation.

Additional information on the SDV is contained in Section 4.6. Instrumentation is described in Chapter 7.

15.8.3.7 HPCI Flow Split Modification

LGS, although a BWR/4, shares some design characteristics in common with BWR/5 reactors. The HPCI system has been split into two components. About one-half of the flow goes into the core spray sparger, similar to the high pressure core spray system of a BWR/5. The remaining portion is routed to the feedwater sparger as is typical of BWR/4s. Also, as mentioned in Section

15.8.3.5, the SLCS flow is injected via the core spray sparger, which is also typical of BWR/5s. The flow split modification maintains proper HPCI flow mixing with the reactor coolant and avoids encountering localized fuel channel hydrodynamic effects that might cause local power peaking, if an adjacent control rod should fail to fully insert. Drawing E41-1020-G-002 shows flow rates at the ATWS condition.

The additional HPCI flow split equipment consist of cross-tie piping between the HPCI and feedwater injection lines, an MOV with associated control logic and equipment, and two flow balancing orifices as shown on drawings M-55 and M-56.

15.8.3.8 Steam Flow Induced Process Measurement Error

An additional steam flow induced process measurement error (SFIE) in the Level 3 (L3) scram was evaluated by GE in Reference 15.8-2 for the ATWS event and it was concluded that it is not affected by a change in the L3 analytical limit (AL) as there is no L3 function directly credited by the ATWS events. However since there is no scram there is bypass steam flow in the annular region outside the dryer, which causes an SFIE induced error in the L2 trip.

For the limiting A TWS events, the scenario involves pressurization due to the MSIV closure. The reactor isolation leads to a recirculation pump trip (ATWS APT) very early in the transient and the trip is usually reached at about the same time the MSIVs are full closed. The ATWS APT rapidly reduces power and steaming rate and is the key feature that reduces the steaming rate to be within the capacity of the Safety / Relief Valves. The post APT power level is on the order of 50 to 55% power and by the time the level is near the Level 2 AL, the power and steaming rate is below 50%.

With the reactor steaming rate reduced to 50%, the error will be significantly reduced, and the SFIE effect with be approximately 1/4 of the effect at rated conditions. This would reduce the SFIE of 6 inches, for example, at rated power to about 1.5 inches at these conditions. Since the RCIC / HPCI initiation at this water level for ATWS is not critical to the event mitigation, this error and delay to L2 is considered insignificant.
A small delay for the RCIC / HPCI initiation would be slightly beneficial as the water level would be lower during a portion of the transient and would result in a reduced reactor power and reduced steaming rate to the suppression pool.

The long-term mitigation of these events involves controlling water level to low levels in the vessel. Again the small error at these conditions (< 2 inches) is insignificant for water level control and power generation compared to the analysis.

Non-limiting ATWS events that may initiate the Level 2 ATWS-RPT or other L2 functions for ATWS would also be affected by L3 analytical limit error. An example would be the LOFW event. This event would result in recirculation runback associated with the loss of flow and low level (e.g., level 4). This would reduce the power and steaming rate. The power would also reduce due to the reduced subcooling associated with the loss of feedwater flow. The combined effect would reduce the error to approximately half of the condition at rated power (based on an estimated power and steaming rate reduced to 70% prior to level 2). As events that trip ATWS-RPT on low level are power and pressure reduction events, they do not challenge the ATWS acceptance criteria and therefore a low level ATWS APT delay due

to L3 scram error is not significant for compliance to the ATWS acceptance criteria. Therefore, the expected SFIE (approximately half of the error at rated conditions) will have no significant effect on the power and pressure events, and these events will remain far from limiting.

15.8.4 REFERENCES

15.8-1 Assessment of BWR Mitigation of ATWS (NUREG-0460 Alternate 3, Volume 4 [for comment]), NEDE-24222, GE, (1979).

15.8-2 **GE-Hitachi Nuclear Energy, 0000-0077-4603-R1, "BWR Owners Group Evaluation of Steam Flow Induced Error (SFIE) Impact on the L3 Setpoint Analytic Limit," October 2008.**

15.9 PLANT NUCLEAR SAFETY OPERATIONAL ANALYSIS (A SYSTEM LEVEL/QUALITATIVE-TYPE PLANT FMEA)

15.9.1 OBJECTIVES

The objectives of the nuclear safety operational analysis are listed below:

a. Essential Protective Sequences: Identify and demonstrate that the essential protection sequences needed to accommodate normal plant operations, anticipated and abnormal operational transients, and DBAs are available and adequate. Each event considered in Chapter 15 is further examined and analyzed. Specific essential protective sequences are identified. The appropriate sequence is discussed for all BWR operating modes.

b. Design Basis Adequacy: Identify and demonstrate that the safety design basis of the various structures, systems, or components needed to satisfy the plant essential protection sequences are appropriate, available, and adequate. Each protective sequence identifies the specific structures, systems, or components performing safety or power generation functions. Interrelationships between primary systems and secondary (or auxiliary equipment) in providing these functions are shown. The individual design bases (identified throughout the UFSAR for each structure, system, or component) are brought together by the analysis in this section. In addition to the individual equipment design bases, the plant-wide design bases are examined and presented here.

c. System Level/Qualitative-Type FMEA: Identify a system level/qualitative-type FMEA of essential protective sequences to show compliance with the single active component failure or single operator error criteria. Each protective sequence entry is evaluated relative to single active component failure or single operator error criteria. Safety classification aspects and interrelationships between systems are also considered.

d. NSOA Criteria Relative to Plant Safety Analysis: Identify the systems, equipment, or components' operational conditions and requirements which are essential to satisfy the nuclear safety operational criteria utilized in the Chapter 15 plant events.

e. Technical Specification Operational Basis: Establish limiting operating conditions, testing, and surveillance bases relative to plant Technical Specification operational requirements.

15.9.2 APPROACH TO OPERATIONAL NUCLEAR SAFETY

15.9.2.1 Classification of Plant Events

The specified measures of safety used in this analysis are referred to as "unacceptable consequences." They are analytically determinable limits on the consequences of different classifications of plant events. The NSOA is thus an evaluation oriented to "event consequence." Refer to Figure 15.9-1 for a description of the systematic process by which these unacceptable results are converted so as to conform to safety requirements.

15.9.2.2 NSOA Development

The following guidelines are used to develop the NSOA:

15.9.2.2.1 Scope and Classification Of Plant Events

The scope and classification of the situations analyzed include the following:

a. Normal Operations

Normal operations are those under planned conditions without significant abnormalities. Operations subsequent to an incident (transient, accident, or special event) are not considered planned operations until the procedures being followed or equipment being used are identical to those used during any one of the defined planned operations. Specific events are listed in Table 15.9-1.

b. Anticipated Operational Transients

Anticipated operational transients are deviations from normal conditions that are expected to occur with moderate frequency and, as such, the design should include capability to withstand the conditions without operational impairment. Included are incidents that result from a single operator error, a control malfunction. These and other incidents are listed in Table 15.9-2.

c. Abnormal Operational Transients

Abnormal operational transients are deviations from normal conditions that occur infrequently. The design should include a capability to withstand these conditions without operational impairment. Refer to Table 15.9-3 which lists events included within this classification.

d. Design Basis Accident

A DBA is an hypothesized accident, whose characteristics and consequences are utilized in the design of those systems and components pertinent to the preservation of radioactive material barriers and the restriction of radioactive material release from the barriers. The potential radiation exposures resulting from a DBA are greater than for any similar accident postulated from the same general accident assumptions. DBAs are listed in Table 15.9-4.

e. Special Events

Special events are postulated to demonstrate some special capability of the plant in accordance with NRC requirements. For analyzed events within this classification, see Table 15.9-5.

15.9.2.2.2 Safety and Power Generation

Safety functions include:

a. Accommodation of abnormal operational transients and postulated DBAs

b. Maintenance of containment integrity

c. Assurance of ECCS

d. Continuance of RCPB

Safety classified aspects are related to Regulatory Guide 1.183 and 10CFR50.67 dose limits, infrequent and low probability occurrences, single active component failure criteria, worst case operating conditions and initial assumptions, automatic (less than 10 minutes) corrective action, significant unacceptable dose and environmental effects, and the involvement of other coincident (mechanistic or nonmechanistic) plant and environmental situations.

Power generation classified considerations are related to continued plant power generation operation, equipment operational matters, component availability aspects, and long-term offsite public effects.

Power generation functions include:

a. Accommodation of planned operations and anticipated operational transients.

b. Minimization of radiological releases to appropriate levels.

c. Assurance of safe and orderly reactor shutdown and/or return to power generation operation.

d. Continuance of plant equipment design conditions to ensure long-term reliable operation.

Power generation is related to 10CFR20, 10CFR50, Appendix I, moderate and high probability occurrences, nominal operating conditions and initial assumptions, allowable immediate operator manual actions, and environmental effects.

15.9.2.2.3 Frequency of Events

Consideration of the frequency of the initial (or initiating) event is reasonably straightforward. Added considerations (e.g., further failures or operator errors) influence the classification grouping. The events in this Section are grouped according to initiating frequency occurrence. The imposition of additional failures necessitates further classification to a lower frequency category.

The introduction of single active component failure or single operator error into the examination of planned operation, anticipated operational transients, or abnormal operational transient evaluations has not been previously considered a design basis or evaluation prerequisite. It is included and provided here to demonstrate the plant's capability to accommodate this requirement.

15.9.2.2.4 Conservative Analysis Margins

The unacceptable consequences established in this section relative to public health and safety are in strict and conservative conformance to regulatory requirements.

15.9.2.2.5 Safety Function Definition

The essential protective sequences shown for an event in this section list the minimum structures and systems that are required to satisfy the single active component failure or single operator error evaluation of the event. Protective success paths other than those shown exist in some cases. Not all the events involve the same natural, environmental, or plant conditional assumptions. In Event 40, control rod-drop accident is not assumed to be associated with any SSE or OBE occurrence. Therefore, seismic safety function requirements are not considered for Event 40. Some of the safety function equipment associated with the Event 40 protective sequence are also capable of more limiting events, such as Event 42.

The primary containment may perform a safety function for some events (when uncontained radiological release would be unacceptable), but for other events, it may not be applicable (e.g., during refueling). The requirement to maintain the containment in postaccident recovery is needed to limit doses to less than 10CFR50.67 and Regulatory Guide 1.183 limits. After radiological sources are depleted with time, the further use of primary containment is unnecessary. Thus, the "time domain" and "need for" aspects of a function should be, and are, taken into account when evaluating events.

The operation of ESF equipment for normal operational events should not be misunderstood to mean that ESF equipment requirements apply to this event category. Also, the interpretation of the use of ESF single active component failure capable systems for anticipated operational transient protective sequences should not imply that these equipment requirements (seismic, redundancy, diversity, testable, IEEE, etc.) are appropriately required for anticipated operational transients.

15.9.2.2.6 Envelope and Actual Event Analyses

Study of the actual plant occurrences, their frequency, and their actual impact are reflected in their categorization in this section. This places the plant safety evaluations into a better perspective by focusing attention on the envelope analysis.

15.9.2.2.7 Analysis Consistency

Figure 15.9-2 illustrates three inconsistencies. Panel A shows the possible inconsistency resulting from operational requirements being placed on separated levels of protection for one event. If the second and sixth levels of protection are important enough to warrant operational requirements, then so are the third, fourth, and fifth levels. Panel B shows the possible inconsistency resulting from operational requirements being arbitrarily placed on some action thought to be important to safety. In the case shown, scram represents different protection levels for two similar events in one category; if the fourth level of protection for Event B is important enough to warrant an operational requirement, then so is the fourth level for Event A. Thus, to simply place operational requirements on all equipment needed for some action (scram, isolation, etc.) could be inconsistent and unreasonable if different protection levels are represented. Panel C shows the possible inconsistency resulting from operational requirements being placed on some arbitrary level of protection for any and all postulated events. Here, the

inconsistency is not recognizing and accounting for different event categories based upon cause or expected frequency of occurrence.

Inconsistencies of the types illustrated in Figure 15.9-2 are avoided in the NSOA by directing the analysis to event consequences oriented aspects. Analytical inconsistencies are avoided by treating all the events of a category under the same set of functional rules, by applying another set of functional rules to another category, and by having a consistent set of rules between categories. Thus, it is valid to compare the results of the analyses of the events in any one category and invalid to compare events of a different categories (with different rules). An example of this is the different rules (limits, assumptions, etc.) of accidents compared to anticipated transients.

15.9.2.3 Comprehensiveness of the Analysis

The method of analysis must be sufficiently comprehensive so that all plant hardware and the full range of plant operating conditions are considered. The tendency to be preoccupied with "worst cases" (those that appear to give the most severe consequences) is recognized; however, the protection sequences essential to lesser cases may be different (more or less restrictive) from the worst case sequence. To assure that operational and design basis requirements are defined and appropriate for all equipment essential to attaining acceptable consequences, all essential protection sequences must be identified for each of the plant safety events examined. Only in this way is a comprehensive level of safety attained. Thus, the NSOA is also protection sequence oriented.

15.9.2.4 Systematic Approach of the Analysis

In summary, the systematic method utilized in this analysis contributes to both the consistency and comprehensiveness of the analysis mentioned above. The desired characteristics representative of a systematic approach to selecting BWR operational requirements are as follows:

a. Specify measures of safety/unacceptable consequences.

b. Consider all normal operations.

c. Systematic event selection.

d. Common treatment analysis of all events of any one type.

e. Systematic identification of plant actions and systems essential to avoid unacceptable consequences.

f. Emergence of operational requirements and limits from system analysis.

Figure 15.9-1 illustrates the systematic process by which the operational and design basis nuclear safety requirements and technical specifications are derived. The process involves the evaluation of carefully selected plant events relative to the unacceptable consequences (specified measures of safety). Those limits, actions, systems, and components found to be essential to achieving acceptable consequences are the subjects of operational requirements.

15.9.2.5 Relationship of Nuclear Safety Operational Analysis to Safety Analyses of Chapter 15

One of the main objectives of the operational analysis is to identify all essential protection sequences and establish the detailed equipment conditions essential to satisfy the nuclear safety operational criteria. The spectrum of events examined in Chapter 15 represent a complete set of plant safety considerations. The main objective of the earlier analyses of Chapter 15 was to provide detailed worst case (limiting or envelope) analyses of plant events. The worst cases are correspondingly analyzed and treated in this section. However, here the frequency of occurrence, unacceptable consequences, assumption categories, etc are taken into account.

Tables 15.9-1 through 15.9-5 provide cross-correlation between the NSOA event, its protection sequence diagram, and its safety evaluation in Chapter 15.

15.9.2.6 Relationship Between NSOA and Operational Requirements, Technical Specifications, Design Bases, and Single Active Component Failure Aspects

By definition, an "operational requirement" is a requirement or restriction (limit) on either the value of a plant variable or the operability condition associated with a plant system. Such requirements must be observed during all modes of plant operation (not just at full power) to assure that the plant is operated safely to avoid unacceptable results. There are two kinds of operational requirements for plant hardware:

a. Limiting condition for operation: the required condition for a system while the reactor is operating in a specified state.

b. Surveillance requirements: the nature and frequency of tests required to ensure that the system is capable of performing its essential functions.

Operational requirements are systematically selected for one of two basic reasons:

a. To ensure that unacceptable consequences are mitigated following specified plant events by examining and challenging the system design.

b. To ensure the consequences of a transient or accident are acceptable with the existence of a single active component failure or single operator error.

The individual structures and systems that perform a safety function are required to do so under design basis conditions including environmental considerations and under single active component failure assumptions. The NSOA confirms the previous examination of the individual equipment (Section 15.0.3) requirement conformance analyses.

15.9.2.7 Unacceptable Consequences Criteria

Tables 15.9-6 through 15.9-10 identify the unacceptable consequences associated with different event categories. In order to prevent or mitigate them, they are recognized as the major bases for identifying system operational requirements as well as the bases for all other safety analysis criteria throughout the UFSAR.

15.9.2.8 General Nuclear Safety Operational Criteria

The following general nuclear safety operational criteria are used to select operational requirements:

Applicability	Nuclear Safety Operational Criteria
Planned operation anticipated, abnormal operational transients, DBAs, additional special plant capability events	The Plant shall be operated so as to avoid unacceptable consequences.
Anticipated and abnormal operational transients and DBA.	The plant shall be operated such that no single active component failure can prevent the safety actions essential to avoid the unacceptable consequences associated with anticipated or abnormal operational transients or DBAs. However, this requirement is not applicable during structure, system, or component repair if the availability of the safety action is maintained either by restricting the allowable repair time or by more frequent testing of a redundant structure, system, or component.

The unacceptable consequences associated with the different categories of plant operation and events are dictated by:

a. Probability of occurrence.

b. Allowable limits (per the probability) related to radiological, structural, environmental, etc., aspects.

c. Coincidence of other related or unrelated disturbances.

d. Time domain of event and consequences consideration.

15.9.3 METHOD OF ANALYSIS

15.9.3.1 General Approach

The NSOA is performed on the plant as designed. The end products of the analysis are the nuclear safety operational requirements and the restrictions on plant hardware and its operation that must be observed both to satisfy the nuclear safety operational criteria and to show compliance of the plant safety and power generation systems with plant wide requirements. Figure 15.9-1 shows the process used in the analysis. The following inputs are required for the analysis of specific plant events:

a. Unacceptable consequences criteria (Section 15.9.2.7).

b. General nuclear safety operational criteria (Section 15.9.2.8).

c. Definition of BWR operating states (Section 15.9.3.2).

d. Selection of events for analysis (Section 15.9.3.3).

e. Guidelines for event analysis (Section 15.9.3.5).

With the above information, each selected event can be evaluated systematically to determine the actions, systems, and limits essential to avoid unacceptable consequences. The essential plant components and limits so identified are then considered to be in agreement with, and subject to, nuclear operational design basis requirements and Technical Specification restrictions.

15.9.3.2 BWR Operating States

The four BWR operating states in which the reactor can exist are defined in Section 15.9.6.2.4 and summarized in Table 15.9-11.

The main objective in selecting operating states is to divide the BWR operating spectrum into sets of initial conditions to facilitate consideration of various events in each state.

Each operating state includes a wide spectrum of values for important plant parameters. Within each state, these parameters are considered over their entire range to determine the limits on their values necessary to satisfy the nuclear safety operational criteria. Such limitations are presented in the sections of the UFSAR that describe the systems associated with the parameter limit. The plant parameters to be considered in this manner include the following:

a. Reactor coolant temperature

b. Reactor vessel water level

c. Reactor vessel pressure

d. Reactor vessel water quality

e. Reactor coolant forced circulation flow rate

f. Reactor power level (thermal and neutron flux)

g. Core neutron flux distribution

h. Feedwater temperature

i. Primary containment temperature and pressure

j. Suppression pool water temperature and level

k. Control rod worth

15.9.3.3 Selection of Events for Analysis

15.9.3.3.1 Normal Operations

Operations subsequent to an incident (transient, accident, or additional plant capability event) are not considered planned operations until the actions taken or equipment used in the plant are identical to those that would be used had the incident not occurred. As defined, planned operations can be considered in the following chronological sequence: refueling outage, achieving criticality, heatup, power operation, achieving shutdown, cooldown, refueling outage.

For the analyses in Section 15.9, the normal operations events are defined as follows:

a. Refueling Outage: Includes all the planned operations associated with a normal refueling outage except those tests in which the reactor is taken critical and returned to the shutdown condition. The following planned operations are included in a refueling outage:

    1. Planned, physical movement of core components (fuel, control rods, etc.)

    2. Refueling test operations (except criticality and shutdown margin tests)

    3. Planned maintenance

    4. Required inspection

b. Achieving Criticality: Includes all plant actions normally accomplished in bringing the plant from a condition in which all control rods are fully inserted to a condition in which nuclear criticality is achieved and maintained.

c. Heatup: Begins when achieving criticality ends and includes all plant actions normally accomplished in approaching nuclear system rated temperature and pressure by using nuclear power (reactor critical). Heatup extends through warmup and synchronization of the main turbine-generator.

d. Power Operation: Begins when heatup ends and includes continued plant operation at power levels in excess of heatup power.

e. Achieving Shutdown: Begins when the main generator is unloaded and includes all plant actions normally accomplished in achieving nuclear shutdown (more than one rod subcritical) following power operation.

f. Cooldown: Begins when achieving nuclear shutdown ends and includes all plant actions normal to the continued removal of decay heat and the reduction of reactor temperature and pressure.

The exact point at which some of the planned operations end and others begin cannot be precisely determined. It will be shown later that such precision is not required, because the protection requirements are adequately defined in passing from one state to the next. Dependence of several planned operations on the one rod subcritical condition provides an exact point on either side of which protection (especially scram) requirements differ. Thus, where a precise boundary between planned operations is needed, the definitions provide the needed precision.

Together, BWR operating states and planned operations define the full spectrum of conditions from which transients, accidents, and special events are initiated. The BWR operating states define only the physical condition (pressure, temperature, etc.) of the reactor; the planned operations define the condition of the plant. The separation of physical conditions from the operation being performed is deliberate and facilitates careful consideration of all possible initial conditions from which incidents may occur.

15.9.3.3.2 Anticipated Operational Transients

To select anticipated operational transients, eight nuclear system parameter variations are considered as potential initiating causes of threats to the fuel and the RCPB. The parameter variations are as follows:

a. Reactor coolant pressure increase

b. Reactor coolant (moderator) temperature decrease

c. Control rod withdrawal

d. Reactor coolant inventory decrease

e. Reactor coolant flow decrease

f. Reactor coolant flow increase

g. Reactor coolant temperature increase

h. Reactor coolant inventory increase

These parameter variations, if uncontrolled, could result in damage to the reactor fuel or RCPB or both. A nuclear system pressure increase threatens to rupture the RCPB from internal pressure. A pressure increase also collapses voids in the moderator, causing an insertion of positive reactivity that threatens fuel damage as a result of overheating. A reactor coolant temperature decrease results in an insertion of positive reactivity as density increases. This could lead to fuel overheating. Positive reactivity insertions are possible from causes other than nuclear system pressure or moderator temperature changes; such reactivity insertions threaten fuel damage caused by overheating. Both reactor coolant inventory decrease and a reduction in coolant flow through the core threaten the integrity of the fuel. An increase in coolant flow through the core reduces the void content of the moderator and results in an insertion of positive reactivity. Core coolant temperature increase threatens the integrity of the fuel; such a variation could be the result of a heat exchanger malfunction during operation in the shutdown cooling mode. An excess of coolant inventory could be the result of malfunctioning water level control equipment; such a malfunction can result in a turbine trip, which causes an expected increase in nuclear system pressure and power.

Anticipated operational transients are defined as transients resulting from an single active component failure or single operator error that can be reasonably expected (moderate probability of occurrence, once per day to once in 20 years) during any mode of plant operation. Examples of single operational failures or operator errors in this range of probability are:

a. Opening or closing any single valve (a check valve is not assumed to close against normal flow).

b. Starting or stopping any single component.

c. Malfunction or maloperation of any single control device.

d. Any single electrical failure.

e. Any single operator error.

An operator error is defined as an active deviation from nuclear plant standard operating practices. A single operator error is the set of actions that is a direct consequence of a single reasonably expected erroneous decision. The set of actions is limited as follows:

a. Those that could be performed by only one person.

b. Those that would have constituted a correct procedure had the initial decision been correct.

c. Those that are subsequent to the initial operator error and that affect the designed operation of the plant, but are not necessarily directly related to the operator error.

Examples of single operator errors are as follows:

a. An increase in power above the established flow control power limits by control rod withdrawal in the specified sequences while observing all normal core power distribution related fuel thermal limits.

b. The selection and complete withdrawal of a single control rod out-of-sequence.

c. An incorrect calibration of an APRM.

d. Manual isolation of the main steam lines caused by operator misinterpretation of an alarm or indication.

The various types of single active component failure or single operator error are applied to various plant systems, with consideration for a variety of plant conditions, to discover events directly resulting in an undesired parameter variation. Once discovered, each event is evaluated for the threat it poses to the integrity of the radioactive material barriers.

15.9.3.3.3 Abnormal Operational Transients

To select abnormal operational transients, eight nuclear system parameter variations are considered as potential initiating causes of gross corewide fuel failures and threats to the RCPB. The parameter variations are as follows:

a. Reactor coolant pressure increase

b. Reactor coolant (moderator) temperature decrease

c. Control rod withdrawal

d. Reactor coolant inventory decrease

e. Reactor coolant flow decrease

f. Reactor coolant flow increase

g. Reactor coolant temperature increase

h. Reactor coolant inventory increase

The eight parameter variations listed above include all effects within the nuclear system caused by abnormal operational transients that threaten gross corewide reactor fuel integrity, or seriously affect the reactor coolant pressure boundary. Variation of any one parameter may cause a change in another listed parameter; however, for analysis purposes, threats to barrier integrity are evaluated by groups according to the parameter variation originating the threat.

Abnormal operational transients are defined as incidents resulting from single or multiple equipment failures and/or single or multiple operator errors that are not reasonably expected (less than one event in 20 years to one in 100 years) during any mode of plant operation. Examples of single or multiple operational failures and/or single or multiple operator errors are:

a. Failure of major power generation equipment components.

b. Multiple electrical failures.

c. Multiple operator errors.

d. Combinations of equipment failure and an operator error.

Operator error is defined as an active deviation from nuclear plant standard operating practices. A multiple operator error is the set of actions that is a direct consequence of several unexpected erroneous decisions.

An example of multiple operator errors is inadvertent loading of a fuel assembly in an improper position and operating with the fuel assembly in an improper position.

The various types of single errors and/or single malfunctions are applied to various plant systems, with consideration for a variety of plant conditions, to discover events directly resulting in an undesired parameter variation. Once discovered, each event is evaluated for the threat it poses to the integrity of the various radioactive material barriers.

15.9.3.3.4 Design Basis Accidents

Accidents are defined as hypothesized events that affect the radioactive material barriers and are not expected during plant operations. These are plant events, equipment failures, and combinations of initial conditions that are of extremely low probability (once in 100 years to once in 10,000 years). The postulated accident types considered are as follows:

a. Mechanical failure of a single component leading to the release of radioactive material from one or more barriers. The components referred to here are not those that act as radioactive material barriers. An example of mechanical failure is the breakage of the coupling between a CRD and the control rod.

b. Arbitrary rupture of any single pipe up to, and including, complete severance of the largest pipe in the RCPB. This kind of accident is considered only under conditions in which the nuclear system is pressurized.

For purposes of analysis, accidents are categorized as those events that result in releasing radioactive material (Tables 15.9-4 and 15.9-5):

a. From the fuel with the RCPB and reactor enclosure initially intact (Event 40).

b. Directly to the primary containment (Event 42).

c. Directly to the reactor, or turbine enclosures, with the primary containment initially intact (Events 40, 43, 44, 45, 50).

d. Directly to the reactor enclosure with the primary containment not intact (Events 41, 50).

e. Directly to the spent fuel-containing facilities (Events 41, 50).

f. Directly to the turbine enclosure (Events 46, 47).

g. Directly to the environs (Events 48, 49).

The effects of various accident types are investigated, with consideration for the full spectrum of plant conditions, to examine events that result in the release of radioactive material.

15.9.3.3.5 Special Events

A number of additional events are evaluated to demonstrate plant capabilities relative to special arbitrary nuclear safety criteria. These special events involve extremely low probability situations. As an example, the adequacy of the redundant reactivity control system is demonstrated by evaluating the special event: "reactor shutdown without control rods." Another similar example, the capability to perform a safe shutdown from outside the main control room, is demonstrated by evaluating the special event: "reactor shutdown from outside the main control room."

15.9.3.4 Applicability of Events to Operating States

The first step in performing an operational analysis for a given incident (transient, accident, or special event) is to determine in which operating states the incident can occur. An incident is considered applicable within an operating state if the incident can be initiated from the physical conditions that characterize the operating state. Applicability of the "normal operations" to the operating states follows from the definitions of planned operations. A planned operation is considered applicable within an operating state if the planned operation can be conducted when the reactor exists under the physical conditions defining the operating state.

15.9.3.5 Guidelines for Event Analysis

Functional guidelines followed in performing single active component failure, operational, and design basis analyses for the various plant events are listed below:

a. An action, system, or limit shall be considered essential only if it is essential to avoid an unacceptable result or satisfy the nuclear safety operational criteria.

b. The full range of initial conditions (as defined in (c) below) shall be considered for each event analyzed so that all essential protection sequences are identified. Consideration is not limited to worst cases, because lesser cases sometimes may require more restrictive actions or systems different from those of the worst cases.

c. The initial conditions for transients, accidents, and special events shall be limited to conditions that would exist during planned operations in the applicable operating state.

d. For normal operations, consideration shall be made only for actions, limits, and systems essential to avoid the unacceptable consequences during operation in that state (as opposed to transients, accidents, and special events that are followed through to completion). Normal operations are treated differently from other events, because the transfer from one state to another during planned operations is deliberate. For events other than normal operations, the transfer from one state to another may be unavoidable.

e. Limits shall be derived only for those essential parameters that are continuously available for monitoring. Parameter limits associated with the required performance of an essential system are considered to be included in the requirement for the operability of the system. Limits on frequently monitored process parameters are called "envelope limits," and limits on parameters associated with the operability of a safety system are called "operability limits." Systems associated with the control of the envelope parameters are considered nonessential if it is possible to place the plant in a safe condition without using the system in question.

f. For transients, accidents, and special events, consideration shall be made for the entire duration of the event and aftermath until some planned operation is resumed. Normal operation is considered resumed when the procedures being followed or equipment being used are identical to those used during any one of the defined planned operations. Where extended core cooling is an immediate integral part of the event, it will be included in the protection sequence. Where it may be an

eventual part of the event, it will not be directly added but can be implied to be available.

g. Credit for operator action shall be taken on a case-by- case basis depending on the conditions that would exist at the time operator action would be required. Because transients, accidents, and special events are considered through the entire duration of the event until normal operation is resumed, manual operation of certain systems is sometimes required following the more rapid or automatic portions of the event. Credit for operator action is taken only when the operator can reasonably be expected to accomplish the required action under the existing conditions.

h. For transients, accidents, and special events, only those actions, limits, and systems shall be considered essential for which there arises a unique requirement as a result of the event. For instance, if a system that was operating prior to the event (during planned operation) is to be employed in the same manner following the event, and if the event did not affect the operation of the system, then the system would not appear on the protection sequence diagram.

i. The operational analyses shall identify all the support or auxiliary systems essential to the functioning of the front-line safety systems. Safety system auxiliaries whose failure results in safe failure of the front line safety systems shall be considered nonessential.

j. A system or action that plays a unique role in the response to a transient, accident, or special event shall be considered essential unless (1) the effects of the system or action are not included in the detailed analysis of the event or (2) unless failure of the system or action results in an overall event probability less frequent than that within which the initiating event is categorized.

15.9.3.6 Steps in an Operational Analysis

All information needed to perform an operational analysis for each plant event has been presented (Figure 15.9-1). The procedure followed in performing an operational analysis for a given event (selected according to the event selection criteria) is as follows:

a. Determine the BWR operating states in which the event is applicable.

b. Identify all the essential protection sequences (safety actions and front-line safety systems) for the event in each applicable operating state.

c. Identify all the auxiliary systems essential to the functioning of the front-line safety systems.

The preceding three steps are performed in Section 15.9.6. To derive the operational requirements and Technical Specifications for the individual components of a system included in any essential protection sequence, the following steps are taken:

a. Identify all the essential actions within the system (intrasystem actions) necessary for the system to function to the degree necessary to avoid the unacceptable consequences.

b. Identify the minimum hardware conditions necessary for the system to accomplish the minimum intrasystem actions.

c. If the single failure criterion applies, identify the additional hardware conditions necessary to achieve the plant safety actions (scram, pressure relief, isolation, cooling, etc.) in spite of single failures. This step gives the nuclear safety operational requirements for the plant components so identified.

d. Identify surveillance requirements and allowable out-of- service times for the essential plant hardware (Section 15.9.5).

e. Simplify the operational requirements determined in steps (c) and (d), so that Technical Specifications may be obtained that encompass the true operational requirements and are easily used by plant operations and management personnel.

15.9.4 DISPLAY OF OPERATIONAL ANALYSIS RESULTS

15.9.4.1 General

To fully identify and establish the requirements, restrictions, and limitations that must be observed during plant operation, plant systems and components must be related to the needs for their actions in satisfying the nuclear safety operational criteria. This section displays these relationships in a series of block diagrams.

Tables 15.9-1 through 15.9-5 and Table 15.9-11 indicate in which operating states each event is applicable. For each event, a block diagram is presented showing the conditions and systems required to achieve each essential safety action. The block diagrams show only those systems necessary to provide the safety actions so that the nuclear safety operational and design basis criteria are satisfied. The total plant capability to provide a safety action generally is not shown; only the minimum capability essential to satisfy the operational criteria is shown. Only enough protective equipment is cited in the diagram to provide the necessary action. Many events can utilize many more paths to success than are shown. Operational analyses involve the minimum equipment needed to prevent or avert an unacceptable consequence. Thus, the diagrams depict all essential protection sequences for each event with the least amount of protective equipment needed. Once all of the these protection sequences are identified in block diagram form, system requirements are derived by considering all events in which the particular system is employed. The analysis considers the following conceptual aspects:

a. The BWR operating state.

b. Types of operations or events that are possible within the operating state.

c. Relationships of certain safety actions to the unacceptable consequences and to specific types of operations and events.

d. Relationships of certain systems to safety actions, and to specific types of operations and events.

e. Supporting or auxiliary systems essential to the operation of the front-line safety systems.

f. Functional redundancy. (The single failure criterion applied at the safety action level. This is, in effect, a qualitative system level, FMEA-type analysis.)

Each block in the sequence diagrams represents a finding of essentiality for the safety action, system, or limit under consideration. Essentiality in this context means that the safety action, system, or limit is needed to satisfy the nuclear safety operational criteria. Essentiality is determined through an analysis in which the safety action, system, or limit being considered is completely disregarded in the analyses of the applicable operations or events. If the nuclear safety operational criteria are satisfied without the safety action, system, or limit, then the safety action, system, or limit is not essential, and no operational nuclear safety requirement would be indicated. When disregarding a safety action, system, or limit results in violating one or more nuclear safety operational criteria, the safety action, system, or limit is considered essential, and the resulting operational nuclear safety requirements can be related to specific criteria and unacceptable consequences.

15.9.4.2 Protection Sequence and Safety System Auxiliary Diagrams

Block diagrams illustrate essential protection sequences for each event requiring unique safety actions. These protection sequence diagrams show only the required front-line safety systems. The format and conventions used for these diagrams are shown in Figure 15.9-4.

The auxiliary systems essential to the correct functioning of the front-line safety systems are shown on safety system auxiliary diagrams. The format used for these diagrams is shown in Figure 15.9-5. The diagram indicates that auxiliary systems A, B, and C are required for proper operation of front-line safety system X.

With these three types of diagrams, it is possible to determine for each system the detailed functional requirements and conditions to be observed regarding system hardware in each operating state. The detailed conditions to be observed regarding system hardware include such nuclear safety operational requirements as test frequencies and the number of components that must be operable.

15.9.5 BASES FOR TECHNICAL SPECIFICATIONS

15.9.5.1 Surveillance Test Requirements

After the nuclear safety systems and engineered safeguards have been identified by applying the nuclear safety operational criteria, surveillance requirements are established for the safety systems. The purpose of surveillance requirements is to assure, at appropriate intervals, that a failure or failures have not occurred in a safety system while that system is in the standby mode. The appropriate surveillance interval is determined by consideration of the effect of system unavailability on plant safety and the effect of testing on plant safety.

15.9.5.2 Limiting Condition for Operation

Required operating conditions for safety systems, including number of operable channels, minimum or maximum setpoints, and other performance factors are established. If a safety system is found to be in a Limiting Condition for Operation, specified corrective action must be taken.

15.9.5.3 Maximum Allowable Out-of-Service Time

When a safety system does not meet the specified Limiting Condition for Operation, the system should be repaired, retested, and returned to service as quickly as possible consistent with good maintenance practice. A maximum allowable out-of-service time is specified, after which time the specified corrective action must be taken to place the plant in a safer mode of operation. If the nature of the failed condition is such that it is apparent that repair will require longer than the allowable out-of-service time, the specified action should be taken immediately. The maximum allowable out-of-service time is determined by consideration of the effect of the out-of-service condition on plant safety and the effect of the specified corrective action on plant safety. As a general rule, the reactor should not be scrammed for an out-of-service condition, and the maximum allowable out-of-service time should be at least 12 hours if the specified corrective action is plant shutdown. Other considerations include the need for a reasonable time for repair based on experienced or projected mean time to repair and resources involved in taking the specified corrective action.

15.9.6 OPERATIONAL ANALYSES

Results of the operational analyses are discussed in the following paragraphs and displayed in Figures 15.9-7 through 15.9-12 and Tables 15.9-1 through 15.9-5.

15.9.6.1 Safety System Auxiliaries

Figures 15.9-7 and 15.9-8 show the safety system auxiliaries essential to the functioning of each front-line safety system.

15.9.6.2 Normal Operations

15.9.6.2.1 General

Requirements for the normal or planned operations normally involve limits (L) on certain key process variables and restrictions (R) on certain plant equipment. The control block diagrams for each operating state (Figures 15.9-9 through 15.9-12) show only those controls necessary to avoid unacceptable safety consequences 1-1 through 1-4 of Table 15.9-6.

Following is a description of the planned operations (Events 1 through 6) as they pertain to each of the four operating states. The description of each operating state contains a definition of that state, a list of the planned operations that apply to that state, and a list of the safety actions that are required to avoid the unacceptable safety consequences.

15.9.6.2.2 Event Definitions

a. Event 1 - Refueling Outage

Refueling outage includes all the planned operations associated with a normal refueling outage except those tests in which the reactor is made critical and returned to the shutdown condition. The following planned operations are included in refueling outage:

1. Planned, physical movement of core components (fuel, control rods, etc.)

2. Refueling test operations (except criticality and shutdown margin tests)

3. Planned maintenance

4. Required inspection

b. Event 2 - Achieving Criticality

Achieving criticality includes all the plant actions normally accomplished in bringing the plant from a condition in which all control rods are fully inserted to a condition in which nuclear criticality is achieved and maintained.

c. Event 3 - Heatup

Heatup begins where achieving criticality ends and includes all plant actions normally accomplished in approaching nuclear system-rated temperature and pressure by using nuclear power (reactor critical). Heatup extends through warmup and synchronization of the main turbine-generator.

d. Event 4 - Power Operation

Power operation begins where heatup ends and includes plant operation at power levels in excess of heatup power and at steady-state operation. It also includes plant maneuvers such as:

1. Electrical load reduction and recoveries

2. Electrical grid frequency control adjustment

3. Control rod movements

4. Power generation surveillance testing involving:

   (a) Turbine stop valve closing

   (b) Turbine control valve adjustments

   (c) MSIV exercising

e. Event 5 - Achieving Shutdown

Achieving shutdown begins where the main generator is unloaded and includes all plant actions normally accomplished in achieving nuclear shutdown (more than one rod subcritical) following power operation.

f. Event 6 - Reactor Cooldown

Cooldown begins where achieving shutdown ends and includes all plant actions normal to the continued removal of decay heat and the reduction of nuclear system temperature and pressure.

15.9.6.2.3 Required Safety Actions/Related Unacceptable Consequences

The following paragraphs describe the safety actions for planned operations. Each description includes a selection of the operating states that apply to the safety action, the plant system affected by limits or restrictions, and the unacceptable consequence that is avoided. The four operating states are defined in Table 15.9-11. The unacceptable consequences criteria are tabulated in Table 15.9-6.

15.9.6.2.3.1 Radioactive Material Release Control

Radioactive materials may be released to the environs in any operating state; therefore, radioactive material release control is required in all operating states. Because of the significance of preventing excessive release of radioactive materials to the environs, this is the only safety action for which monitoring systems are explicitly shown. Limits are expressed on the gaseous, liquid, and solid radwaste systems, so that the planned releases of radioactive materials comply with the limits given in 10CFR20, 10CFR50, and 10CFR71 (related unacceptable safety result 1-1).

15.9.6.2.3.2 Core Coolant Flow Rate Control

In State D, when above approximately 10% rated power, the core coolant flow rate must be maintained above certain minimums (i.e., limited) to maintain the integrity of the fuel cladding (1-2) and ensure the validity of the plant safety analysis (1-4).

15.9.6.2.3.3 Core Power Level Control

The plant safety analyses of accidental positive reactivity additions have assumed as an initial condition that the neutron source level is above a specified minimum. Because a significant positive reactivity addition can only occur when the reactor is less than one rod subcritical, the assumed minimum source level need be observed only in States B and D. The minimum source level assumed in the analyses has been related to the counts/sec readings on the SRMs; thus, this minimum power level limit on the fuel is expressed as a required SRM count level. Observing the limit ensures the validity of the plant safety analysis (1-4). The count rate limit is conservatively applied to the ALL RODS INSERTED condition prior to initial control rod withdrawal. Any expected ALL RODS INSERTED count rate within the SRM monitoring range will fully satisfy the safety analysis criteria for noncritical initiating conditions. Maximum core power limits are also expressed for operating States B and D to maintain fuel integrity (1-2) and remain below the maximum power levels assumed in the plant safety analysis (1-4).

15.9.6.2.3.4 Core Neutron Flux Distribution Control

Core neutron flux distribution must be limited in State D; otherwise, core power peaking could result in fuel failure (1-2). Additional limits are expressed in this state, because the core neutron flux distribution must be maintained within the envelope of conditions considered by plant safety analysis (1-4).

15.9.6.2.3.5 Reactor Vessel Water Level Control

In any operating state, the reactor vessel water level could, unless controlled, drop to a level that will not provide adequate core cooling; therefore, reactor vessel water level control applies to all operating states. Observation of the RPV water level limits protects against fuel failure (1-2) and ensures the validity of the plant safety analysis (1-4).

15.9.6.2.3.6 Nuclear System Pressure Control

System pressure control is not needed in States A and B, because vessel pressure cannot be increased above atmospheric pressure. In State C, a limit is expressed on the reactor vessel to ensure that it is not hydrostatically tested until the temperature is above the NDTT plus 60°F; this prevents excessive stress (1-3). Also, in States C and D a limit is expressed on the RHR system to ensure that it is not operated in the shutdown cooling mode when the RPV pressure is greater than the RHR shutdown cooling interlock pressure; this prevents excessive stress (1-3). In States C and D, a limit on the RPV pressure is necessitated by the plant safety analysis (1-4).

15.9.6.2.3.7 Nuclear System Temperature Control

In operating States C and D, a limit is expressed on the reactor vessel to prevent the reactor vessel head bolting studs from being in tension when the temperature is less than the minimum bolt-up temperature to avoid excessive stress (1-3) on the reactor vessel flange. This limit does not apply in States A and B, because the head will not be bolted in place during criticality tests or refueling. In all operating states, a limit is expressed on the reactor vessel to prevent an excessive rate of change of the reactor vessel temperature to avoid excessive stress (1-3). In States C and D, where it is planned operation to use the feedwater system, a limit is placed on the reactor fuel, so that the feedwater temperature is maintained within the envelope of conditions considered by the plant safety analysis (1-4). For State D, a limit is placed on the temperature difference between the recirculation system and the reactor vessel to prevent the starting of the recirculation pumps when a large differential temperature exists. This operating restriction and limit prevents excessive stress in the reactor vessel (1-3).

15.9.6.2.3.8 Nuclear System Water Quality Control

In all operating states, water of improper chemical quality could produce excessive stress as a result of chemical corrosion (1-3). Therefore, a limit is placed on reactor coolant chemical quality in all operating states. For all operating states where the nuclear system can be pressurized (States C and D), an additional limit on reactor coolant activity ensures the validity of the analysis of the main steam line break accident (1-4).

15.9.6.2.3.9 Nuclear System Leakage Control

Because excessive nuclear system leakage could occur only while the reactor vessel is pressurized, limits are applied only to the reactor vessel in States C and D. Observing these limits prevents vessel damage due to excessive stress (1-3) and ensures the validity of the plant safety analysis (1-4).

15.9.6.2.3.10 Core Reactivity Control

In State A, during refueling outages, a limit is imposed on core loading (fuel) to ensure that core reactivity is maintained within the envelope of conditions considered by the plant safety analysis (1-4). In all states, limits are imposed on the control rod drive system to ensure adequate control of core reactivity, so that core reactivity remains within the envelope of conditions considered by the plant safety analysis (1-4).

15.9.6.2.3.11 Control Rod Worth Control

Any time the reactor is not shut down and is generating less than the low power setpoint (State D), a limit is imposed on the control rod pattern to ensure that control rod worth is maintained within the envelope of conditions considered by the analysis of the control rod-drop accident (1-4).

15.9.6.2.3.12 Refueling Restriction

By definition, planned operation Event 1 (refueling outage) applies only to State A. Observing the restrictions on the reactor fuel and on the operation of the CRD system within the specified limit maintains plant conditions within the envelope considered by the plant safety analysis (1-4).

15.9.6.2.3.13 Primary Containment Pressure and Temperature Control

In States C and D, limits are imposed on the primary containment pressure and suppression pool temperature to maintain pressure and temperature within the envelope considered by plant safety analysis (1-4). These limits ensure an environment in which instruments and equipment can operate correctly within the drywell. Limits on the pressure-suppression pool apply to the water temperature and water level to ensure that it has the capability of absorbing the energy discharged during an SRV blowdown or a LOCA.

15.9.6.2.3.14 Stored Fuel Shielding, Cooling, and Reactivity Control

Because both new and spent fuel will be stored during all operating states, stored fuel shielding, cooling, and reactivity control apply to all operating states. Limits are imposed on the spent fuel pool storage positions, water level, fuel handling procedures, and water temperature. Observing the limits on fuel storage positions ensures that spent fuel reactivity remains within the envelope of conditions considered by the plant safety analysis (1-4). Observing the limits on water level ensures shielding in order to maintain conditions within the envelope of conditions considered by the plant safety analysis (1-4), and provides the fuel cooling necessary to avoid fuel damage (1-2). Observing the limit on water temperature avoids excessive fuel pool stress (1-3).

15.9.6.2.4 Operational Safety Evaluations

a. State A

In State A, the reactor is in a shutdown condition, the vessel head is off, and the vessel is at atmospheric pressure. The applicable events for planned operations are refueling outage, achieving criticality, and cooldown (Events 1, 2, and 6, respectively).

Figure 15.9-9 shows the necessary safety actions for planned operations, corresponding plant systems, and the event for which these actions are necessary. As indicated in the diagram, the required safety actions are as follows:

1. Radioactive material release control

2. Reactor vessel water level control

3. Nuclear system temperature control

4. Nuclear system water quality control

5. Core reactivity control

6. Refueling restrictions

7. Stored fuel shielding, cooling, and reactivity control

b. State B

In State B, the reactor vessel head is off, the reactor is not shutdown, and the vessel is at atmospheric pressure. Applicable planned operations are achieving criticality and shutdown (Events 2 and 5, respectively).

Figure 15.9-10 relates the necessary safety actions for planned operations, plant systems, and the event for which the safety actions are necessary. The required safety actions for planned operation in State B are as follows:

1. Radioactive material release control

2. Core power level control

3. Reactor vessel water level control

4. Nuclear system temperature control

5. Nuclear system water quality control

6. Core reactivity control

7. Rod worth control

8. Stored fuel shielding, cooling, and reactivity control

c. State C

In State C, the reactor vessel head is on and the reactor is shut down. Applicable planned operations are achieving criticality and cooldown (Events 2 and 6, respectively).

Sequence diagrams relating safety actions for planned operations, plant systems, and applicable events are shown in Figure 15.9-11. The required safety actions for planned operation in State C are as follows:

1. Radioactive material release control

2. Reactor vessel water level control

3. Nuclear system pressure control

4. Nuclear system temperature control

5. Nuclear system water quality control

6. Nuclear system leakage control

7. Core reactivity control

8. Primary containment pressure and temperature control

9. Stored fuel shielding, cooling, and reactivity control

d. State D

In State D, the reactor vessel head is on and the reactor is not shut down. Applicable planned operations are achieving criticality, heatup, power operation, and shutdown (Events 2, 3, 4, and 5, respectively).

Figure 15.9-12 relates safety actions for planned operations, corresponding plant systems, and events for which the safety actions are necessary. The required safety actions for planned operation in State D are as follows:

1. Radioactive material release control

2. Core coolant flow rate control

3. Core power level control

4. Core neutron flux distribution control

5. Reactor vessel water level control

6. Nuclear system pressure control

7. Nuclear system temperature control

8. Nuclear system water quality control

9. Nuclear system leakage control

10. Core reactivity control

11. Rod worth control

12. Primary containment pressure and temperature control

13. Stored fuel shielding, cooling, and reactivity control

15.9.6.3 Anticipated Operational Transients

15.9.6.3.1 General

The safety requirements and protection sequences for anticipated operational transients are described in the following paragraphs for Events 7 through 29. The protection sequence block diagrams show the sequence of front-line safety systems. (Figures 15.9-13 through 15.9-34 and 15.9-36). The auxiliaries for the front-line safety system are indicated in the auxiliary diagrams (Figures 15.9-7 and 15.9-8).

15.9.6.3.2 Required Safety Actions/Related Unacceptable Consequences

Safety actions for anticipated operational transients that mitigate or prevent the unacceptable safety consequences are listed below. Refer to Table 15.9-7 for the unacceptable consequences criteria.

Safety Action	Related Unacceptable Consequence Criteria	Reason Action Required
Scram and/or RPT	2-2 2-3	To prevent fuel damage and limit nuclear system pressure rise
Pressure relief	2-3	To prevent excessive nuclear system pressure rise
Core and primary containment cooling	2-1 2-2 2-4	To prevent fuel and primary containment damage in the event that normal cooling is interrupted
Reactor vessel isolation	2-2	To prevent fuel damage by reducing the outflow of steam and water from the reactor vessel, thereby limiting the decrease in reactor vessel water level
Restore ac power	2-2	To prevent fuel damage by restoring ac power to systems essential to other safety actions
Prohibit rod motion	2-2	To prevent exceeding fuel limits during transients
Primary containment isolation	2-1 2-4	To minimize radiological effects

15.9.6.3.3 Event Definitions and Operational Safety Evaluations

a. Event 7 - Manual and Inadvertent Scram

The deliberate manual or inadvertent automatic scram due to single operator error is an event that can occur under any operating condition. Although assumed to

occur here for examination purposes, multiple operator error or action is necessary to initiate such an event.

While all the safety criteria apply, no unique safety actions are required to control the planned operation-like event after effects of the subject initiation actions. In all operating states, therefore, the safety criteria are met through the basic design of the plant systems. Figure 15.9-13 identifies the protection sequences for this event.

b. Event 8 - Loss of Plant Instrument/Service Air System

Loss of the plant instrument and service air systems causes reactor shutdown and the closure of MSIVs. Although these actions occur, they are not a requirement to prevent unacceptable consequences in themselves. Multiple equipment failures would be necessary to cause the deterioration of the subject system to the point that the components supplied with instrument or service air would cease to operate normally and/or fail-safe. The resulting actions are identical to Event 14 described later.

Isolation of the main steam lines can result in a transient for which some degree of protection is required only in operating States C and D. In operating States A and B, the main steam lines are normally isolated.

The effect of isolation of all main steam lines is most severe in operating State D during power operation.

Figures 15.9-14 and 15.9-21 show how scram is accomplished by main steam line isolation through the actions of the RPS and CRD system. The MSRV system provides pressure relief. Pressure relief, combined with loss of feedwater flow, causes reactor vessel water level to fall. Either HPCI or RCIC supplies water to maintain water level and protect the core until normal steam flow (or other planned operation) is established.

Adequate reserve pneumatic supplies are maintained exclusively for the continual operation of the ADS SRVs until reactor shutdown is accomplished.

c. Event 9 - Inadvertent NSSS Pump Start (Moderator Temperature Decrease)

An inadvertent pump start (temperature decrease) is defined as an unintentional start of any NSSS pump that adds sufficient cold water to the reactor coolant inventory to cause a measurable decrease in moderator temperature. This event is considered in all operating states, because it can potentially occur under any operating condition. Since the HPCI pump operates over nearly the entire range of the operating states and delivers by far the greatest amount of cold water to the vessel, the following analysis will describe its inadvertent operation rather than other NSSS pumps (e.g., RCIC, RHR, core spray).

While all the safety criteria apply, no unique safety actions are required to control the adverse effects of such a pump start (i.e., pressure increase and temperature decrease in States A and C). In these operating states, the safety criteria are met through the basic design of the plant systems, and no safety action is specified. In States B and D, where the reactor is not shut down, the operator or the plant's

normal control system can control any power changes in the normal manner of power control.

Figure 15.9-15 illustrates the protection sequence for the subject event. Single failures to the plant's normal control system pressure regulator or the feedwater controller systems will result in further protection sequences. These are shown in Events 22 and 23. The single failure aspects of their protection sequences will, of course, not be required.

d. Event 10 - Startup of Idle Recirculation Pump

The cold loop startup of an idle recirculation pump can occur in any state. The attendant reactivity insertion effects are most severe and rapid for those operating states in which the reactor may be critical (States B and D). If the reactivity insertion is sufficient to require safety action, a high neutron flux signal (IRM or APRM) that exceeds the specified trip setpoint will occur.

As shown in Figure 15.9-16, the required safety action is accomplished through the combined actions of the NMS, RPS, and CRD system.

e. Event 11 - Recirculation Flow Control Failure (Increasing Flow)

A recirculation flow control failure causing increased flow is applicable in States C and D. In State D, the resulting increase in power level is limited by a reactor scram. As shown in Figure 15.9-17, the required safety action is accomplished through the combined actions of the NMS, RPS, and CRD system.

f. Event 12 - Recirculation Flow Control Failure (Decreasing Flow)

This recirculation flow control malfunction causes a decrease in core coolant flow. This event is not applicable to States A and B, because the reactor vessel head is off and the recirculation pumps normally would not be in use.

The number and type of flow controller failure modes determine the protection sequence for the event. ASD controller failures (for one or both ASD trains will result in a transient bounded by the previous transient associated with the original configuration for the MG set controller failures (a transient bounded by one or two RPT transients (Figure 15.9-18)).

g. Event 13 - Trip of One or Both Recirculation Pumps

The trip of one recirculation pump produces a milder transient than does the simultaneous trip of two recirculation pumps.

The transient resulting from this two-loop trip is not severe enough to require any unique safety action. The transient is compensated for by the inherent nuclear stability of the reactor. This event is not applicable in States A and B, because the reactor vessel head is off and the recirculation pumps normally would not be in use. Figure 15.9-19 provides the protection sequence for the event for one or both pump trip actuations for States C and D.

This event constitutes an acceptable operational technique to reduce or minimize the effects of other event conditions. To this end, an engineered recirculation pump trip capability is included in the plant design to reduce pressure and thermal-hydraulic transient effects.

A two-pump trip can result in a high water level trip of the main turbine, which further causes a stop valve closure and its subsequent scram actuation. Containment isolation occurs and RCIC/HPCI systems initiate on low water level. Relief valve actuation will follow.

h. Event 14 - Isolation of One or All Main Steam Lines

Isolation of the main steam lines can result in a transient for which some degree of protection is required only in operating States C and D. In operating States A and B, the main steam lines are normally isolated.

Isolation of all main steam lines is most severe and rapid in operating State D during power operation.

Figure 15.9-20 shows how a scram is initiated by main steam line isolation triggering the actions of the RPS and CRD systems. The MSRV system provides pressure relief. Pressure relief, combined with loss of feedwater flow, causes reactor vessel water level to fall and either HPCI or RCIC supply water to maintain water level and protect the core until adequate long-term cooling is established.

Isolation of one main steam line causes a significant transient only in State D during operation above approximately 90% power. If the feedwater system and main condenser remain in operation following the event, no unique requirement arises for core cooling.

As shown in Figure 15.9-21, the required safety action is accomplished.

i. Event 15 - Inadvertent Opening of an MSRV

The inadvertent opening of an MSRV is only possible in operating States C and D. In State C the water level cannot be lowered far enough to threaten fuel damage; therefore, no safety actions are required. The protection sequences in State D are shown in Figure 15.9-22.

In State D, there is a slight decrease in reactor pressure following the event. The pressure regulator closes the main turbine control valves enough to stabilize pressure at a level slightly below the initial value. There are no unique safety system requirements for this event.

j. Event 16 - Control Rod Withdrawal Error For Refueling and Startup Operations

Because a control rod withdrawal error resulting in an increase of positive reactivity can occur under any operating condition, it must be considered in all operating states. For this specific event situation, only States A and B apply.

1. Refueling

No unique safety action is required in operating State A for the withdrawal of one control rod, because the core is more than one control rod subcritical. Withdrawal of more than one control rod is precluded by the protection sequence shown in Figure 15.9-23. During core alterations, the mode switch is normally in the REFUEL position, which allows the refueling equipment to be positioned over the core and also inhibits control rod withdrawal. Therefore, this transient applies only to operating State A.

No safety action is required, because the total worth (positive reactivity) of one fuel assembly or control rod is not adequate to cause criticality. Moreover, mechanical design of the control rod assembly prevents physical removal without removing the adjacent fuel assemblies.

2. Startup

During low power operation, the NMS via the RPS will initiate scram if necessary (Figure 15.9-23).

k. Event 17 - Control Rod Withdrawal Error (During Power Operation)

Because a control rod withdrawal error resulting in an increase of positive reactivity can occur under any operating condition, it must be considered in all operating states. For this specific event situation, only States C and D apply.

During power operation (State D), a number of plant protective devices of various designs prohibit the control rod motion before critical levels are reached (Figure 15.9-24).

Below the low power setpoint, the selection of an out- of-sequence rod movement is prevented by the RWM which uses banked position withdrawal sequences. In addition, the movement of the rod is monitored and limited within acceptable intervals either by neutronic effects or actual rod motion. The RBM provides movement surveillance. Beyond these rod motion control limits are the fuel/core scram protection systems.

While in State C, no protection action is needed.

l. Event 18 - Loss of Shutdown Cooling

The loss of RHR system shutdown cooling can occur only during the low pressure portion of a normal reactor shutdown and cooldown.

As shown in Figure 15.9-25, for most single failures that could result in primary loss of shutdown cooling capabilities, no unique safety actions are required; in these cases, shutdown cooling is simply re-established using redundant shutdown cooling equipment. In the cases where the RHR shutdown cooling suction line becomes inoperative, a unique arrangement for cooling arises. In States A and B, in which the reactor vessel head is off, the LPCI and CS can be used to maintain RPV water level. In State C, in which the reactor vessel head is on and the system can be

pressurized, the ADS or manual operation of relief valves in conjunction with any of the ECCS and the RHR suppression pool cooling mode (both manually operated) can be used to maintain water level and remove decay heat. Suppression pool cooling is actuated to remove heat energy from the suppression pool system.

m. Event 19 - RHR Shutdown Cooling - Increased Cooling

An RHR shutdown cooling malfunction causing a moderator temperature decrease must be considered in all operating states. However, this event is not considered in States C and D if nuclear system pressure is too high to permit operation of the RHR shutdown cooling (Figure 15.9-26). No unique safety actions are required to avoid the unacceptable safety consequences for transients as a result of a reactor coolant temperature decrease induced by misoperation of the shutdown cooling heat exchangers.

In States B and D, where the reactor is at or near critical, the slow power increase resulting from the cooler moderator temperature would be controlled by the operator in the same manner normally used to control power in the source or intermediate power ranges.

n. Event 20 - Loss of All Feedwater Flow

A loss of feedwater flow results in a net decrease in the coolant inventory available for core cooling. A loss of feedwater flow can occur in States C and D. Appropriate responses to this transient include a reactor scram on low water level and restoration of reactor vessel water level by HPCI and RCIC.

As shown in Figure 15.9-27, the RPS and CRD systems effect a scram on low water level. The PCRVICS acts to isolate the containment. Either the RCIC or HPCI system can maintain adequate water level for initial core cooling and to restore and maintain water level.

The requirements for operating State C are the same as for State D, except that the scram initiation is not required in State C.

o. Event 21 - Loss of a Feedwater Heater

Loss of a feedwater heater must be considered with regard to the nuclear safety operational criteria only in operating State D, because significant feedwater heating does not occur in any other operating state.

A loss of feedwater heating transient causes a neutron flux increase that might reach the scram setpoint depending upon the degree of feedwater heating loss. As shown in Figure 15.9-28 required safety action is accomplished through actions of the NMS, RPS, and CRD system.

p. Event 22 - Feedwater Controller Failure (Maximum Demand)

A feedwater controller failure, causing an excess of coolant inventory in the reactor vessel, is possible in all operating states. Feedwater controller failures considered are those that would give failures of automatic or manual level controls. In

operating States A and B, no safety actions are required, since the vessel head is removed and the moderator temperature is low. In operating State D, any positive reactivity effects responses by the reactor caused by cooling of the moderator can be mitigated by a scram. As shown in Figure 15.9-29, scram is accomplished through the combined actions of the neutron monitoring, reactor protection, and CRD systems. Pressure relief is required in States C and D and is achieved through the operation of the MSRV system. Initial restoration of the core water level is by the RCIC and HPCI systems. Planned operations will proceed to achieve long-term cooling.

q. Event 23 - Pressure Regulator Failure (Open Direction)

A pressure regulator failure in the open direction, causing the opening of a turbine control or bypass valve, applies only in operating States C and D, because in other states the pressure regulator is not in operation. A pressure regulator failure is most severe and rapid in operating State D at low power.

The various protection sequences giving the safety actions are shown in Figure 15.9-30. Depending on plant conditions existing prior to the event, scram will be initiated either on main steam line isolation, main turbine trip or reactor vessel low water level. The sequence resulting in reactor vessel isolation also depends on initial conditions. With the mode switch in RUN, isolation is initiated when main steam line pressure drops below the low turbine inlet pressure setpoint. After isolation is completed, decay heat will cause nuclear system pressure to increase until limited by the operation of the relief valves. Core cooling following isolation can be provided by RCIC or HPCI. Shortly after reactor vessel isolation, normal core cooling can be re-established via the main condenser and feedwater systems or, if prolonged isolation is necessary, extended core and containment cooling will be manually actuated.

r. Event 24 - Pressure Regulator Failure (Closed Direction)

A pressure regulator failure in the closed direction, causing the closing of turbine control valves, applies only in operating States C and D, because in other states the pressure regulator is not in operation.

A single pressure regulator failure would result in little or no effect on the plant operation. The second pressure regulator would provide control. Failure of the second unit, which would result in the worst situation, is much less severe than Events 25, 27, 30, and 31. The dual pressure regulator failures are most severe and rapid in operating State D at high power.

The various protection sequences giving the safety actions are shown in Figure 15.9-31. Upon failure of one pressure regulator, normally a backup regulator will maintain the plant in the normal status. An additional failure of the backup regulator will result in a high flux or pressure scram, containment isolation, and subsequent HPCI/RCIC actuations. Closure of the turbine stop valve and bypass valves effectively isolates the reactor vessel.

s. Event 25 - Main Turbine Trips With Bypass System Operation

A main turbine trip can occur only in operating State D (during heatup or power operation). A turbine trip during heatup is not as severe as a trip at full power, because operation of the turbine bypass system minimizes the effects of the transient, enabling return to planned operations. For a turbine trip above the bypass capacity, a scram as well as RPT will occur via turbine stop valve closure. Subsequent relief valve actuation will occur. Eventual containment isolation and RCIC and HPCI system initiation will result from low water level. Figure 15.9-32 depicts the protection sequences required for main turbine trips. Main turbine trip and main generator trip are similar anticipated operational transients, and the required safety actions are the same.

t. Event 26 - Loss of Main Condenser Vacuum (Turbine Trip)

A loss of vacuum in the main turbine condenser can occur any time steam pressure is available and the condenser is in use; it is applicable to operating States C and D. This nuclear system pressure increase transient is the most severe of the pressure increase transients. However, scram protection in State C is not needed, since the reactor is not coupled to the turbine system.

For State D, above the turbine stop valve closure scram bypass setpoint, loss of condenser vacuum will initiate a turbine trip with its attendant stop valve closures (which lead to scram and an RPT). RCIC and HPCI are initiated on low water level. Below the turbine stop valve closure scram bypass setpoint (State D), scram is initiated by a high neutron flux signal. Figure 15.9-33 shows the protection sequences. Decay heat will necessitate extended core and suppression pool cooling. When the RPV depressurizes sufficiently, the low pressure core cooling systems provide core cooling until a planned operation via RHR shutdown cooling is achieved.

u. Event 27 - Main Generator Trip With Bypass System Operation

A main generator trip with bypass system operation can occur only in operating State D (during heatup or power operation). Fast closure of the main turbine control valves is initiated whenever an electrical grid disturbance occurs, which results in significant loss of electrical load on the generator. The turbine control valves are required to close as rapidly as possible to prevent excessive overspeed of the main turbine-generator rotor. Closure of the turbine control valves will cause a sudden reduction in steam flow, which results in an increase in system pressure. Above the turbine control valve closure scram bypass setpoint, scram and RPT will occur as a result of fast control valve closure. Subsequently, containment isolation will result, and pressure relief and initial core cooling by RCIC and HPCI will take place. Planned operation can be resumed to achieve shutdown. A generator trip during heatup is not severe when the turbine bypass system can accommodate decoupling the reactor and the turbine-generator unit. Figure 15.9-34 depicts the protection sequences required for a main generator trip. Main generator trip and main turbine trip are similar anticipated operational transients, and the required safety actions for both are the same sequence.

v. Event 28 - Loss of Auxiliary Power Transformers

There are a variety of possible plant electrical component failures that could affect the reactor system. The total loss of ac auxiliary power is the most severe. The loss of auxiliary power results in a sequence of events similar to that resulting from a loss of all connections to the grid. The most severe situation occurs in State D during power operation. This event requires the same protection sequences as shown for Event 29 in Figure 15.9-36.

w. Event 29 - Loss of Offsite Power - Grid Loss

There are a variety of plant grid electrical component failures that can affect reactor operation. The total loss of ac auxiliary power is the most severe. The loss of all auxiliary power sources results in a sequence of events similar to that resulting from a main generator trip with bypass (Event 27), with respect to response of reactor systems. The most severe case occurs in State D during power operation. Figure 15.9-36 shows the safety actions required for a total loss of offsite power in all States (A, B, C, and D).

Scram and RPT will be initiated by turbine control valve fast closure. Loss of condenser circulating water will reduce condenser vacuum, which will close the turbine bypass valves and MSIVs. After the MSIVs close, system pressure rises to the lowest relief valve setting. Pressure is relieved by the MSRV system. After the reactor is isolated and feedwater flow has been lost, decay heat continues to increase nuclear system pressure, periodically causing relief valves to lift and, therefore, causing reactor water level to decrease. The core and containment cooling sequence shown in Figure 15.9-36 shows the sequence for achieving adequate cooling.

15.9.6.4 Abnormal Operational Transients

15.9.6.4.1 General

The safety requirements and protection sequences for abnormal operational transients are described in the following paragraphs for Events 30 through 37. The protection sequence block diagrams show the sequence of front-line safety systems (Figures 15.9-37 through 15.9-39). The auxiliaries for the front-line safety systems are indicated in the auxiliary diagrams (Figures 15.9-7 and 15.9-8).

15.9.6.4.2 Required Safety Actions/Related Unacceptable Consequences

The following list relates the safety actions for abnormal operational transients to mitigate or prevent the unacceptable safety consequences cited in Table 15.9-8.

Safety Action	Related Unacceptable Consequence	Reason Action Required
Scram and/or RPT	3-2 3-3 3-5	To limit gross core-wide fuel damage and to limit nuclear system pressure rise

Pressure relief	3-3 3-5	To prevent excessive nuclear system pressure rise
Core, suppression pool, and primary containment cooling	3-2 3-4	To limit further fuel and containment damage if normal cooling is interrupted
Reactor vessel isolation	3-2	To limit further fuel damage by reducing the outflow of steam and water from the reactor vessel, thereby limiting the decrease in reactor vessel water level
Restore ac power	3-2	To limit initial fuel damage by restoring ac power to systems essential to other safety actions
Primary containment isolation	3-1	To limit radiological effects

15.9.6.4.3 Event Definition and Operational Safety Evaluation

a. Event 30 - Main Generator Trip Without Bypass System Operation

A main generator trip without bypass system operation can occur only in operating State D (during heatup or power operation). The thermal-hydraulic effects on the core are more severe than with the bypass operating (Event 27).

Figure 15.9-37 depicts the protection sequences required for a main generator trip with bypass failure. If the turbine control valve closure scram bypass setpoint is exceeded, a turbine control valve fast closure signal will initiate RPS and RPT. Containment isolation, relief valve actuation, and RCIC and HPCI operation will follow. Turbine control valve closure with bypass valve failure effectively isolates the reactor. Prolonged shutdown will necessitate extended core and containment/suppression pool cooling.

The load rejection and turbine trip are similar abnormal operational transients, and the required safety actions are the same.

b. Event 31 - Main Turbine Trip Without Bypass System Operation

A main turbine trip without bypass can occur only in operating State D (during heatup or power operation). Figure 15.9-38 depicts the protection sequences required for main turbine trips. Turbine stop valve closure with bypass valve failure effectively isolates the reactor.

Turbine trips without bypass system operations result in severe thermal-hydraulic effects on the reactor core.

c. Event 32 - Inadvertent Loading and Operation with Assembly in Improper Position

Operation with a fuel assembly in the improper position is shown in Figure 15.9-39 and can occur in all operating states. No protection sequences are necessary relative to this event. Calculated results of worst fuel bundle loading error will not cause fuel cladding integrity damage. It requires three independent equipment/operator errors to allow this situation to develop.

d. Events 33 through 37 - (Not Used)

15.9.6.5 Design Basis Accidents

15.9.6.5.1 General

The safety requirements and protection sequences for accidents are described in the follow paragraphs for Events 38 through 49. The protection sequence block diagrams show the safety actions and the sequence of front-line safety systems used for the accidents (refer to Figures 15.9-40 through 15.9-49). The auxiliaries for the front-line safety systems are indicated in the auxiliary diagrams (Figures 15.9-7 and 15.9-8).

15.9.6.5.2 Required Safety Actions/Unacceptable Consequences

The following list relates the safety actions for design basis accident to mitigate or prevent the unacceptable consequences cited in Table 15.9-9.

Safety Action	Related Unacceptable Consequence	Reason Action Required
Scram	4-2 4-3	To prevent fuel cladding failure(1) and prevent excessive nuclear system pressures
Pressure relief	4-3	To prevent excessive nuclear system pressure
Core cooling	4-2	To prevent fuel cladding failure
Reactor vessel isolation	4-1	To limit radiological effect to not exceed the values of 10CFR50.67 and Regulatory Guide 1.183
Establish primary containment	4-1	To limit radiological effects to not exceed the values of 10CFR50.67 and Regulatory Guide 1.183
Primary containment cooling	4-4	To prevent excessive pressure in the containment when containment is required.
Prevent control rod ejection	4-2	To prevent fuel cladding failure
Restrict loss of reactor coolant (passive)	4-2	To prevent fuel cladding failure
Main control room	4-5	To prevent overexposure to radiation of

environmental control		plant personnel in the control room
Limit reactivity insertion rate (passive)	4-2 4-3	To prevent fuel cladding failure and excessive nuclear system pressure

(1) Failure of fuel barrier includes fuel cladding fragmentation (LOCA) and excessive fuel enthalpy (control rod-drop accident).

15.9.6.5.3 Event Definition and Operational Safety Evaluations

a. Event 38 - Recirculation Pump Seizure

A recirculation pump seizure event considers the instantaneous stoppage of the pump motor shaft of one recirculation loop pump. The case involves operation at design power in State D. It assumed that a main turbine trip will occur as reactor vessel water level swell exceeds the turbine trip setpoint. This results in a scram and an RPT when the turbine stop valves close. Relief valve opening will occur to control pressure level and temperatures. RCIC or HPCI system will maintain vessel water level.

The protection sequence for this event is given in Figure 15.9-40. If reactor vessel swell does not exceed the turbine trip setpoint, then no safety actions are required.

b. Event 39 - Recirculation Pump Shaft Break

A recirculation pump shaft break event considers the degraded, delayed stoppage of the pump motor shaft of one recirculation loop pump. The case involves operation at design power in State D. It is assumed that a main turbine trip will occur as reactor vessel water level swell exceeds the turbine trip setpoint. This results in a scram and an RPT when the turbine stop valves close. Relief valve opening will occur to control pressure and temperature. RCIC or HPCI systems will maintain vessel water level.

The production sequence for this event is given in Figure 15.9-41. If reactor vessel swell does not exceed the turbine trip setpoint, then no safety actions arre required.

c. Event 40 - Control Rod-Drop Accident

The control rod-drop accident results from an assumed failure of the control rod-to-drive mechanism coupling after the control rod (very reactive rod) becomes stuck in its fully inserted position. It is assumed that the control rod drive is then fully withdrawn before the stuck rod falls out of the core. The control rod velocity limiter, an engineered safeguard, limits the control rod-drop velocity. The resultant radioactive material release is maintained far below the values of 10CFR50.67 and Regulatory Guide 1.183.

No safety actions are required in States A or C where the plant is in a shutdown state by more than the reactivity worth of one rod prior to the accident. The control rod-drop accident is applicable only in States B and D. In State B the low fission product inventory assures inconsequential radiological releases should a control rod-drop accident occur. Direct radiation dose to personnel on the refueling floor is maintained acceptable by the shielding provided by water above the core and by administrative procedures controlling personnel access. For State B, control rod worth is limited by the RWM system such that damage to the reactor coolant pressure boundary is prevented. Under most instances fuel failures are not expected. Therefore, the only safety response required in State B is scram.

Figure 15.9-42 presents the different protection sequences for the control rod-drop accident. As shown in Figure 15.9-42, the reactor is automatically scrammed and, in some cases, isolated. For all design basis cases, the NMS, RPS, and CRD system will provide a scram from high neutron flux. Because LGS utilizes the banked position withdrawal sequence which mitigates rod-drop consequences, no fuel failures are expected.

After the reactor has been scrammed and isolated, the pressure relief system allows the steam (produced by decay heat) to be directed to the suppression pool. Initial core cooling is accomplished by either the RCIC or HPCI or the normal feedwater system. With prolonged isolation, as indicated in Figure 15.9-42, the reactor operator initiates the RHR/suppression pool cooling mode and depressurizes the vessel with the manual mode of the ADS or via normal manual relief valve operation. The RHR/shutdown cooling mode accomplishes extended core cooling.

d. Event 41 - Fuel Handling Accident

Because a fuel handling accident can potentially occur any time when fuel assemblies are being manipulated, either over the reactor core or in a spent fuel pool, this accident is considered in all operating states. Considerations include mechanical fuel damage caused by drop impact and a subsequent release of fission products. The protection sequences pertinent to this accident are shown in Figure 15.9-43. Refueling area isolation and SGTS operation are automatically initiated by the ventilation radiation monitoring systems.

e. Event 42 - LOCAs Resulting from Postulated Piping Breaks Within RCPB Inside Containment (DBA LOCA)

Pipe breaks inside the containment are considered only when the nuclear system is significantly pressurized (States C and D). The result is a release of steam and water into the containment. Consistent with NSOA criteria, the protection requirements consider all size line breaks, from large liquid recirculation loop piping breaks down to small steam instrument line breaks. The most severe cases are the circumferential break of the largest (liquid) recirculation system pipe and the circumferential break of the largest main steam line.

As shown in Figure 15.9-44, in operating State C (reactor shutdown, but pressurized), a pipe break accident up to the DBA can be accommodated within the nuclear safety operational criteria through the various operations of the main steam

line isolation valves, emergency core cooling systems (HPCI, ADS, LPCI, and CS), PCRVICS, containment, reactor enclosure, SGTS, control room heating, cooling and ventilation system, ESW and RHRSW systems, hydrogen control system, equipment cooling systems, and the incident detection circuitry. For small pipe breaks inside the containment, pressure relief is effected by the MSRV system, which transfers decay heat to the suppression pool. For large breaks, depressurization takes place through the break itself. In State D (reactor not shut down, but pressurized), the same equipment is required as in State C but, in addition, the RPS and the CRD system must operate to scram the reactor. The limiting items, upon which the operation of the above equipment is based, are the allowable fuel cladding temperature and the containment pressure capability. The CRD housing supports are considered necessary whenever the system is pressurized to prevent excessive control rod movement through the RPV following the postulated rupture of one CRD housing (a lesser case of the design basis LOCA and a related preventive of a postulated rod ejection accident).

After completion of the automatic action of the above equipment, manual operation of the RHR system (suppression pool cooling mode) or relief valves and ADS (controlled depressurization) is required to maintain containment pressure and fuel cladding temperature within limits during extended core cooling.

f. Events 43, 44, 45 - Piping Breaks Outside Containment

Pipe break accidents outside the containment are assumed to occur any time the nuclear system is pressurized (States C and D). This accident is most severe during operation at high power (State D). In State C, this accident becomes a subset of the State D sequence.

The protection sequences for the various possible pipe breaks outside the containment are shown in Figure 15.9-45. For small breaks, the reactor operator can use a large number of process indications to identify and isolate the break.

In operating State D (reactor not shut down, but pressurized), scram is accomplished through operation of the RPS and the CRD system. Reactor vessel isolation is accomplished through operation of the MSIVs and the PCRVICS.

For a main steam line break, initial core cooling is accomplished by HPCI, RCIC, ADS, or manual relief valve operation in conjunction with CS and LPCI. These systems provide parallel paths to effect initial core cooling, thereby satisfying the single failure criterion. Extended core cooling is accomplished by the single failure proof, parallel combination of CS and LPCI. The ADS or relief valve system operation and the RHR suppression pool cooling mode (both manually operated) are required to maintain containment pressure and fuel cladding temperature within limits during extended core cooling.

g. Event 46 - Gaseous Radwaste System Leak or Failure

It is assumed that the line leading to the SJAE fails near the main condenser. This results in activity normally processed by the offgas treatment system being discharged directly to the turbine enclosure and subsequently through the ventilation system to the environment. This failure is indicated by a lack of flow in

the offgas discharge line. This event can be considered only under States C and D and is shown in Figure 15.9-46.

The reactor operator initiates shutdown of the SJAEs/offgas system to reduce the gaseous activity being discharged. A loss of main condenser vacuum will result (timing depending on main condenser air inleakage rate) in a main turbine trip and ultimately a reactor shutdown. Refer to Event 26 for reactor protection sequence (Figure 15.9-33).

h. Event 47 - Augmented Offgas Treatment System Failure

An evaluation of those events that could cause a gross failure in the offgas system has resulted in the identification of a postulated seismic event, more severe than the one for which the system is designed, as the only conceivable event that could cause significant damage.

The gross failure of this system requires a manual isolation of the system from the main condenser. The isolation results in a loss of main condenser vacuum (timing dependent on air inleakage rate). Protection sequences for this event are shown in Figure 15.9-47.

i. Event 48 - Liquid Radwaste System Leak or Failure

Releases that could occur inside and outside of the containment, not covered by Events 38 through 47, include small spills and equipment leaks of radioactive materials inside structures housing the subject process equipment. Conservative values for leakage have been assumed and evaluated in the plant under routine releases (Section 11.2). The offsite dose that results from any small spill that could occur outside containment will be negligible in comparison to the dose resulting from the accountable (expected) plant leakages.

The protective sequences for this event are provided in Figure 15.9-48.

j. Event 49 - Liquid Radwaste System - Storage Tank Failure

Refer to Section 2.4 for a discussion of liquid tank failures.

The protective sequences for this event are provided in Figure 15.9-49.

15.9.6.6 Special Events

15.9.6.6.1 General

Additional special events are postulated to demonstrate that the plant is capable of accommodating off-design occurrences. (refer to Events 50 through 53). As such, these events are beyond the safety requirements of the other event categories. The safety actions shown in the sequence diagrams (Figures 15.9-50 through 15.9-53) for the additional special events follow directly from the requirements cited in the demonstration of the plant's capability.

Auxiliary systems are shown in Figures 15.9-7 and 15.9-8.

15.9.6.6.2 Required Safety Action/Unacceptable Consequences

The following list relates the safety actions for special events to prevent the unacceptable consequences cited in Table 15.9-10.

Safety Action	Related Unacceptable Consequence	Reason For Action Available
Main Control Room Considerations		
Manually initiate all shutdown controls from remote shutdown panel or local panels	5-1 5-2	Local panel control has been provided and is available outside main control room
Manually initiate SLCS	-3	SLCS to control reactivity to cold shutdown available

15.9.6.6.3 Event Definitions and Operational Safety Evaluation

a. Event 50 - Shipping Cask-Drop

Due to the redundant nature of the plant crane, the cask-drop accident is not believed to be a credible accident. However, the accident is hypothetically assumed to occur as a consequence of an unspecified failure of the cask-lifting mechanism, thereby allowing the cask to fall.

It is assumed that an ISFSI transfer cask, HI-TRAC VW cask and/or spent fuel shipping cask containing irradiated fuel assemblies is in the process of being moved with the cask suspended from the crane above the rail car. The fuel assemblies have been out of the reactor for at least 90 days.

Through some unspecified failure, the cask is released from the crane and falls onto the rail car. Some of the coolant in the outer cask structure may leak from the cask.

The reactor operator will ascertain the degree of cask damage and, if possible, make the necessary repairs and refill the cask coolant to its normal level if coolant has been lost.

It is assumed that if the coolant is lost from the external cask shield, the operator will establish forced cooling of the cask by introducing water into the outer structure annulus or by spraying water on the cask exterior surface. Maintaining the cask in a cool condition will, therefore, ensure no fuel damage as a result of a temperature increase due to decay heat.

Because the cask is still within the refueling area volume, any activity postulated to be released can be accommodated by the SGTS.

The protective sequences for this event are provided in Figure 15.9-50.

b. Event 51 - Reactor Shutdown, Anticipated Transient Without Scram

Reactor shutdown from a plant transient occurrence without the use of control rods is applicable in State D only. The protection sequences for this extremely improbable class of events in shown in Figure 15.9-51.

On initiation of the plant transient situation by a turbine trip, for example, a scram is automatically initiated, but no control rods are assumed to move; the operator may attempt to insert control rods manually. The recirculation pumps are tripped as a consequence of the initial turbine trip. If the nuclear system becomes isolated from the main condenser, heat can be transferred from the reactor to the suppression pool via the relief valves; the HPCI and RCIC are initiated on low water level and then maintain reactor vessel water level. The RRCS, on detecting high pressure or low water level in the reactor, will also attempt to insert control rods by actuation of the ARI valves of the CRD system and will also initiate a recirculation pump trip (which has previously occurred for this transient). If the reactor power is still significant after appropriate time delays, the RRCS automatically initiates feedwater runback and SLCS operation. Operation of the SLCS results in a transition from low power neutron heat to decay heat. The RHR suppression pool cooling mode is used to remove the low power neutron and decay heat from the suppression pool as required. After attaining hot shutdown, further depressurization to the suppression pool and use of the RHR shutdown cooling mode results in achieving a cold shutdown condition.

c. Event 52 - Reactor Shutdown From Outside Control Room

Reactor shutdown from outside the control room is an event investigated to evaluate the capability of the plant to be safely shut down and cooled to the cold shutdown state from outside the control room.

Figure 15.9-52 shows the protection sequences for this event in operating States B, C and D. In State A, no sequence is shown, because the reactor is already in the condition finally required for the event. In State C, only cooldown is required, since the reactor is already shut down.

A scram from outside the control room can be achieved by opening the ac supply breakers for the RPS. Reactor pressure will be controlled and decay heat transferred to the suppression pool via the relief valves. Reactor water level will be maintained by the RCIC system, and the suppression pool will be cooled using the RHR suppression pool cooling mode. When system pressure is sufficiently reduced, the RHR shutdown cooling mode will be used for long-term cooling.

d. Event 53 - Reactor Shutdown Without Control Rods

Reactor shutdown without control rods is an event requiring an alternate method of reactivity control: the SLCS. By definition, this event can occur only when the reactor is not already shut down. Therefore, this event is considered only in operating States B and D.

The SLCS must operate to meet capability demonstration requirement 5-3. The design bases for the SLCS result from these operating criteria when applied under the most severe conditions (State D at rated power). As indicated in Figure 15.9-53, the SLCS is manually initiated and controlled in States B and D.

15.9.7 SUMMARY AND CONCLUSIONS

With the information presented in the protection sequence block diagrams and the auxiliary diagrams, it is possible to examine the functional and hardware requirements for each system. This is done by considering the events in which the systems are employed and deriving sets of operational requirements. This limiting set of operational requirements establishes the lowest acceptable level of performance for a system or component, or the minimum number of components or portions of a system that must be operable so that plant operation may continue, as indicated in Section 15.9.5.

Safety actions to maintain core cooling are, in general, automatically controlled by NSSS ESF systems. Required manual actions are limited to RHR system adjustment to control suppression pool temperatures.

For LOCA events, all short-term (t = 0 through 10 minutes) safety functions are automatically initiated and controlled. All safety actions to provide adequate core cooling over the long-term (t = 10 minutes to 30 days) are automatically provided by the necessary NSSS ESF systems. Control of LOCA suppression pool thermal response, however, may require the operator to place one loop of the containment cooling system (RHR) into operation, but no such action is required earlier than 10 minutes into the event. Extended long-term NSSS ESF manual actions would be centered around RHR shutdown cooling aspects.

For anticipated operational transient events, no operator action is required in less than 10 minutes to mitigate the consequences of the event or to achieve a steady reactor condition or a controlled shutdown mode. Most events involve automatic process control systems (e.g., feedwater or pressure controls that are usually in operation). Some events allow operator manual control adjustments (e.g., control rod insertion) prior to an automatic protection action, but in no case will the failure or error of the operator manual action negate any protective function or cause a radiological safety problem. Operator actions may improve the course of a transient, but no credit is taken (ahead of 10 minutes) in the current safety evaluation analyses.

When the initial stages of these events are completed and the operator has taken over manual control, the EOPs govern all actions taken.

The operational requirements derived using the above process may be complicated functions of operating states, parameter ranges, and hardware conditions. The final step is to translate these results into technical specifications that encompass the operational requirements and can be used by plant operations and management personnel.

It is concluded that the nuclear safety operational and plant design basis criteria are satisfied when the plant is operated in accordance with the nuclear safety operational requirements determined by the method presented in this section.

Table 15.9-1

NORMAL OPERATION

NSOA EVENT NO.	EVENT DESCRIPTION	NSOA EVENT FIGURE NO.	UFSAR SECTION NO.	BWR OPERATING STATE A	B	C	D
1	Refueling - Initial - Reload	15.9-9	-	X			
2	Achieving Criticality	15.9-9 through 15.9-12	-	X	X	X	X
3	Heatup	15.9-12					X
4	Power Operation – Generation - Steady state - Daily load reduction & recovery - Grid frequency control response - Control rod sequence exchanges - Power generation surveillance Testing # Turbine stop valve surveillance tests # Turbine control valve surveillance tests # MSIV surveillance tests	15.9-12	-				X
5	Achieving Shutdown	15.9-10 and 15.9-12	-		X		X
6	Cooldown	15.9-9 and 15.9-11		X		X	

Table 15.9-2

ANTICIPATED OPERATIONAL TRANSIENTS

NSOA EVENT NO.	EVENT DESCRIPTION	NSOA EVENT FIGURE NO.	UFSAR SECTION NO.	BWR OPERATING STATE A	B	C	D
7	Manual or inadvertent scram	15.9-13	7.2	X	X	X	X
8	Loss of plant instrument and service air systems	15.9-14	9.3.1	X	X	X	X
9	Inadvertent startup of NSSS pump	15.9-15	15.5.1	X	X	X	X
10	Inadvertent startup of idle recirculation loop pump	15.9-16	15.4.4	X	X	X	X
11	Recirculation loop flow control failure with increasing flow	15.9-17	15.4.5			X	X
12	Recirculation loop flow control failure with decreasing flow	15.9-18	15.3.2			X	X
13	Recirculation loop pump trip - With one pump - With two pumps	15.9-19	15.3.1			X	X
14	Inadvertent MSIV closure		15.2.4				
	- All main steam lines isolated	15.9-20				X	X
	- One main steam line isolated	15.9-21				X	X
15	Inadvertent opening of an MSRV	15.9-22	15.6.1			X	X
16	Control rod withdrawal error	15.9-23	15.4.1				
	- During startup				X		
	- During refueling			X			
17	Control rod withdrawal rod error at power	15.9-24	15.4.2			X	X
18	RHR shutdown cooling failure loss of cooling	15.9-25	15.2.9	X	X	X	

Table 15.9-2 (Cont'd)

NSOA EVENT NO.	EVENT DESCRIPTION	NSOA EVENT FIGURE NO.	UFSAR SECTION NO.	BWR OPERATING STATE A	B	C	D
19	RHR shutdown cooling failure increased cooling	15.9-26	15.1.6	X	X	X	X
20	Loss of all feedwater flow	15.9-27	15.2.7			X	X
21	Loss of feedwater heater	15.9-28	15.1.1				X
22	Feedwater controller failure maximum demand	15.9-29	15.1.2	X	X	X	X
23	Pressure regulator failure - open	15.9-30	15.1.3			X	X
24	Pressure regulator failure - closed	15.9-31	15.2.1			X	X
25	Main turbine trip with bypass system operation	15.9-32	15.2.3				X
26	Loss of main condenser vacuum	15.9-33	15.2.5			X	X
27	Main generator trip with bypass system operation	15.9-34	15.2.2				X
28	Loss of auxiliary transformers	15.9-36	15.2.6	X	X	X	X
29	Loss of plant normal offsite ac power - grid connection failure	15.9-36	15.2.6	X	X	X	X

Table 15.9-3

ABNORMAL OPERATIONAL TRANSIENTS

NSOA EVENT NO.	EVENT DESCRIPTION	NSOA EVENT FIGURE NO.	UFSAR SECTION NO.	BWR OPERATING STATE A	B	C	D
30	Main generator trip with bypass system failure	15.9-37	15.2.2				X
31	Main turbine trip with bypass system failure	15.9-38	15.2.3				X
32	Inadvertent loading and operation of a fuel assembly in an improper position	15.9-39	15.4.7	X	X	X	X
33	Not Used	-	-				
34	Not Used	-	-				
35	Not Used	-	-				
36	Not Used	-	-				
37	Not Used	-	-				

Table 15.9-4

DESIGN BASIS ACCIDENTS

NSOA EVENT NO.	EVENT DESCRIPTION	NSOA EVENT FIGURE NO.	UFSAR SECTION NO.	BWR OPERATING STATE A	B	C	D
38	Recirculation Pump Seizure	15.9-40	15.3.3				X
39	Recirculation Pump Shaft Break	15.9-41	15.3.4				X
40	Control rod-drop accident	15.9-42	15.4.9		X		X
41	Fuel handling accident	15.9-43	15.7.4	X	X	X	X
42	LOCA resulting from spectrum of postulated piping breaks within the RCPB inside containment	15.9-44	15.6.5			X	X
43	Piping breaks outside containment	15.9-45	15.6.4			X	X
44	Instrument line break outside drywell	15.9-45	15.6.2			X	X
45	Feedwater line break outside containment	15.9-45	15.6.6			X	X
46	Gaseous radwaste system leak or failure	15.9-46	15.7.1			X	X
47	Augmented offgas treatment system failure	15.9-47	15.7.1			X	X
48	Liquid radwaste system leak or failure	15.9-48	15.7.2	X	X	X	X
49	Liquid radwaste system storage tank failure	15.9-49	15.7.3	X	X	X	X

Table 15.9-5

SPECIAL EVENTS

NSOA EVENT NO.	EVENT DESCRIPTION	NSOA EVENT FIGURE NO.	UFSAR SECTION NO.	BWR OPERATING STATE A	B	C	D
50	ISFSI Transfer Cask, HI-TRAC VW cask and/or Shipping cask-drop - Solid radwaste - Spent fuel - New fuel	15.9-50	15.7.5	X	X	X	X
51	Reactor shutdown from ATWS	15.9-51	15.8				X
52	Reactor shutdown from outside control room	15.9-52	7.4.1.4		X	X	X
53	Reactor shutdown without control rods	15.9-53	9.3.5		X		X

Table 15.9-6

UNACCEPTABLE CONSEQUENCES CRITERIA
PLANT EVENT CATEGORY - NORMAL OPERATION

	Unacceptable Consequences
1-1	Release of radioactive material to the environs that exceeds the limits of either 10CFR20 or 10CFR50.
1-2	Fuel failure to such an extent that were the freed fission products released to the environs via the normal discharge paths for radioactive material, the limits of 10CFR20 would be exceeded.
1-3	Nuclear system stress in excess of that allowed for planned operation by applicable industry codes.
1-4	Existence of a plant condition not considered by plant safety analyses.

Table 15.9-7

UNACCEPTABLE CONSEQUENCES CRITERIA - PLANT EVENT
CATEGORY - ANTICIPATED OPERATIONAL TRANSIENTS

	Unacceptable Consequences
2-1	Release of radioactive material to the environs that exceeds the limits of 10CFR20.
2-2	Reactor operation induced cladding failure.
2-3	Nuclear system stress in excess of that allowed for the transient classification by applicable industry codes.
2-4	Containment stresses in excess of that allowed for the transient classification by applicable industry codes when containment is required.

Table 15.9-8

UNACCEPTABLE CONSEQUENCES CRITERIA
PLANT EVENT CATEGORY - ABNORMAL OPERATIONAL TRANSIENTS

	Unacceptable Consequences
3-1	Release of radioactivity which results in dose consequences that exceed a small fraction of 10CFR100;
3-2	Failure of fuel cladding which could cause changes in core geometry such that core cooling would be inhibited;
3-3	Generation of a condition that results in consequential loss of function of the reactor coolant system;
3-4	Generation of a condition that results in a consequential loss of function of a necessary containment barrier; and
3-5	Nuclear system stresses in excess of those allowed for the accident classification by applicable industry codes.

Table 15.9-9

UNACCEPTABLE CONSEQUENCES CRITERIA
PLANT EVENT CATEGORY - DESIGN BASIS ACCIDENTS

	Unacceptable Consequences
4-1	Radioactive dose consequence exceeding the values of 10CFR50.67 and Regulatory Guide 1.183;
4-2	Failure of fuel cladding which could cause sufficient changes in core geometry such that core cooling would be inhibited;
4-3	Nuclear system stresses in excess of those allowed for the accident classification by applicable industry codes;
4-4	Containment stresses in excess of those allowed for the accident classification by applicable industry codes when containment is required; and
4-5	Radiation exposure to plant operations personnel in the main control room in excess of 5 rem whole body, 30 rem inhalation, and 75 rem skin.

Table 15.9-10

UNACCEPTABLE CONSEQUENCES CONSIDERATIONS
PLANT EVENT CATEGORY - SPECIAL EVENTS

Special Events Considered

A. Reactor shutdown from outside control room.

B. Reactor shutdown without control rods.

C. Reactor shutdown with ATWS.

D. ISFSI Transfer Cask, HI-TRAC VW cask and/or Shipping Cask-Drop.

Capability Demonstration

5-1	Ability to shut down reactor by manipulating controls and equipment outside the main control room.
5-2	Ability to bring the reactor to the cold shutdown condition from outside the main control room.
5-3	Ability to shut down the reactor independent of control rods.
5-4	Ability to contain radiological contamination.
5-5	Ability to limit radiological exposure.

Table 15.9-11

BWR OPERATING STATES[1]

Conditions[2]	States A	B	C	D
Reactor vessel head	X	X		
Reactor vessel head on			X	X
Shut down		X		X
Not shut down		X		X

(1) Further discussion is provided in Section 15.9.6.2.4.

(2) Shutdown: K_{eff} sufficiently less than 1 that the full withdrawal of any one control rod could not produce criticality under the most restrictive potential conditions of temperature, pressure, core age, and fission product concentrations.

15.10 ACCIDENT DOSE MODEL DESCRIPTIONS

15.10.1 OFFSITE DOSE MODEL

This discussion identifies the models used to calculate offsite radiological doses that would result from releases of radioactivity due to various postulated accidents.

The following assumptions are basic to both the model for the whole body dose from immersion in a cloud of radioactivity and the model for the thyroid dose from inhalation of radioactivity:

a. Direct radiation from the source point is negligible compared with whole body radiation due to submersion in the radioactivity leakage cloud.

b. All radioactivity releases are treated as ground level releases regardless of the point of discharge.

c. The dose receptor is a standard man, as defined by the International Commission on Radiological Protection (Reference 15.10-1).

d. Isotopic data, such as decay constants, are taken from the Table of Isotopes (Reference 15.10-2). Table 15.10-1 lists those values.

e. Dose conversion factors are taken from TID-14844 (Reference 15.10-3), Federal Guidance Report 11 (Reference 15.10-16) and from Regulatory Guide 1.109. Gamma and beta dose conversion factors are found by using the method of Meteorology and Atomic Energy (Reference 15.10-4). Table 15.10-1 lists those values.

15.10.1.1 Whole Body Gamma Dose

Calculation of the gamma dose from an extended source, such as a cloud, starts with the consideration that the radiation received by the receptor from a differential area or volume is the same as if it came from a point source. If the dimensions of a homogeneous cloud of gamma-emitting material are large compared with the distance that the gamma rays travel, an equilibrium condition occurs, provided the receptor volume is small. A cloud with these dimensions acts as though the plume were an infinite source of gamma-emitting material. For a receptor at ground level, only half the passing cloud contributes to the gamma dose of the receptor.

The semi-infinite whole body gamma dose as described in Reference 15.10-4 is given by the following equation:

$$D_\gamma = X/Q \sum_{i=1}^{N} (DCF_i)\, Q_i \qquad \text{(EQ. 15.10-1)}$$

where:

D_γ = gamma dose from semi-infinite cloud, rem

DCF_i = gamma dose conversion factor for isotope (i), rem-m^3/Ci-sec

Q_i = source strength for isotope (i), Ci

X/Q = atmospheric dilution factor, sec/m^3

15.10.1.2 Thyroid Inhalation Dose

Assuming the atmospheric dilution factors given in Table 2.3.4-4, the thyroid dose for a given time is obtained from the following equation:

$$D_T = (X/Q)\, B \sum_{i=1}^{N} Q_i\, DCF_i \qquad \text{(EQ. 15.10-2)}$$

where:

D_T = thyroid inhalation dose, rem

X/Q = atmospheric dilution factor, sec/m^3

N = number of isotopes

B = breathing rate, m^3/sec

Q_i = total activity of iodine isotope (i) released, Ci

DCF_i = dose conversion factor for iodine isotope (i), rem/Ci

The isotopic data and breathing rates are given in Tables 15.10-1 and 15.10-3, respectively.

15.10.1.3 Beta Skin Dose

Assuming the atmospheric dilution factor given in Table 2.3.4-4, the dose in air for a semi-infinite cloud of beta radiation is given by:

$$D_\beta = (X/Q) \sum_{i=1}^{N} Q_i\, DCF_i \qquad \text{(EQ. 15.10-3)}$$

where:

D_β = beta dose from a semi-infinite cloud, rem
X/Q = atmospheric dilution factor, sec/m^3
N = number of isotopes
Q_ι = source strength for isotope (ι), Ci
DCF_1 = dose conversion factor, rem-m^3/Ci-sec

15.10.2 CONTROL ROOM DOSES

15.10.2.1 Calculation of Control Room X/Q

This section describes the governing atmospheric dispersion modeling equations and assumptions in accordance with Draft Regulatory Guide 1111 (Reference 15.10-6). Estimates of atmospheric diffusion (X/Q) are made at the control room intake for releases from the North and South Stacks for periods of 2, 8, and 16 hours and for 3 and 26 days. The NRC recommended model, ARCON96, in Reference 15.10-5 is utilized. Since the North and South Stacks are not 2.5 times the height of the adjacent structures, they do not qualify as an elevated release per DG-1111, therefore, ARCON96 is executed in vent release mode. With an assumed zero (0) vertical exit velocity, vent releases are treated as ground-level releases by ARCON96.

15.10.2.1.1 Diffusion Model (excerpted from NUREG/CR-6331 Rev. 1)

The ARCON96 code implements a straight-line Gaussian diffusion model. The basic model for a ground-level release is

$$\frac{X}{Q'} = \frac{1}{\pi\sigma_y\sigma_z U} \exp\left[-0.5\left(\frac{y}{\sigma_y}\right)^2\right] \qquad (15.10\text{-}4a)$$

X/Q' = relative concentration (concentration divided by release rate) [(ci/m^3)/(ci/s)]
σ_y, σ_z = diffusion coefficients (m)
U = wind speed *(m/s)*
Y = distance from the center of the plume (m)

This equation assumes that the release is continuous, constant, and of sufficient duration to establish a representative mean concentration. It also assumes that the material being released is reflected by the ground. Diffusion coefficients are typically determined from atmospheric stability and distance from the release point using empirical relationships. A diffusion coefficient parameterization from the NRC PAYAN (Reference 15.10-6) and XOQDOQ (Reference 15.10-7) codes is used for σ_y and σ_z.

The diffusion coefficients have the general form

$$\sigma = ax^b + c$$

were x is the distance from the release point, in meters, and a , b, and c are parameters that are functions of stability. The parameters are defined for 3 distance ranges – 0 to 100 m, 100 to 1000 m, and greater than 1000 m. The parameter values may be found in the listing of Subroutine NSIGMA1 in Appendix A of NUREG/CR-6331 Rev. 1.

Diffusion coefficient adjustments for wakes and low wind speeds are incorporated as follows:

To estimate diffusion in building wakes, composite wake diffusion coefficients, $\sum_y$ and $\sum_z$, replace σ_y and σ_z. The composite wake diffusion coefficients are defined by

$$\sum_y = \left[\sigma_y^2 + \Delta\sigma_{y1}^2 + \Delta\sigma_{y2}^2 \right]^{1/2} \qquad (15.10\text{-}4b)$$

$$\sum_z = \left[\sigma_z^2 + \Delta\sigma_{z1}^2 + \Delta\sigma_{z2}^2 \right]^{1/2} \qquad (15.10\text{-}4c)$$

Where σ_y and σ_z are the normal diffusion coefficients, $\Delta\sigma_{y1}$ and $\Delta\sigma_{z1}$ are the low wind speed corrections, and $\Delta\sigma_{y2}$ and $\Delta\sigma_{z2}$ are the building wake corrections. These corrections are described and evaluated in Ramsdall and Fosmire (Reference 15.10-8). The form of the low wind speed corrections is

$$\Delta\sigma_{y1}^2 = 9.13 \times 10^5 \left[1 - \left[1 + \frac{x}{1000U} \right] \exp\left[\frac{-x}{1000U} \right] \right] \qquad (15.10\text{-}4d)$$

$$\Delta\sigma_{z1}^2 = 6.67 \times 10^2 \left[1 - \left[1 + \frac{x}{100U} \right] \exp\left[\frac{-x}{100U} \right] \right] \qquad (15.10\text{-}4e)$$

Where x is the distance from the release point to the receptor, in meters, and U is the wind speed in meters per second. It is appropriate to use the slant range distance for x because these corrections are made only when the release is assumed to be at the ground level and the receptor is assumed to be on the axis of the plume. The diffusion coefficients corrections that account for enhanced diffusion in the wake have a similar form. These corrections are

$$\Delta\sigma_{y2}^2 = 5.24 \times 10^{-2} U^2 A \left[1 - \left[1 + \frac{x}{10\sqrt{A}} \right] \exp\left[\frac{-x}{10\sqrt{A}} \right] \right] \qquad (15.10\text{-}4f)$$

$$\Delta\sigma_{z2}^2 = 1.17 \times 10^{-2} U^2 A \left[1 - \left[1 + \frac{x}{10\sqrt{A}} \right] \exp\left[\frac{-x}{10\sqrt{A}} \right] \right] \qquad (15.10\text{-}4g)$$

Where A is the cross-sectional area of the building.

An upper limit is placed on $\sum_y$ as a conservative measure. This limit is the standard deviation associated with a concentration uniformly distributed across a sector with width equal to the circumference of a circle with radius to the distance between the source and receptor. This value is

$$\sum_{ymax} = \frac{2\pi x}{\sqrt{12}}$$

$\cong$ 1.81x (15.1-4h)

15.10.2.1.2 Meteorological Input

The 1996-2000 meteorological database utilized in ARCON96 consists of Tower 1 hourly meteorological data observations of 30 and 175 foot wind speed and direction, and 171-26 foot Delta Temperature Stability Class from Tower 2 data were used only for substitution of any missing Tower 1 data as follows:

Instrument Elevations (above tower grade)

	Tower 1 (primary) (Grade: 250 ft msl)	Tower 2 (backup) Grade: 121 ft msl)
Wind Speed:		
Elevation 1	30 ft	159 ft
Elevation 2	175 ft	304ft
Wind Direction:		
Elevation 1:	30 ft	159 ft
Elevation 2:	175ft	304 ft

Meteorological Evaluation Services Co., Inc. (MES) illustrated that the Tower 2 delta temperature data are sufficiently representative to be substituted for the Tower 1 delta temperature data; however, since the Tower 1 and Tower 2 delta temperature height intervals differ from each other somewhat, and also since for all years shown, the primary Tower 1 has data recovery rates well above the NRC's 90 percent requirements, it was deemed unnecessary to make such substitutions.

The designation of 'calm' is made to all wind speed observations 0.5 mph or less. The higher of the starting speeds of the Climatronics® wind vane and anemometer equipment on each of the towers (i.e., 0.5 mph) was used as the threshold for calm winds, per Regulatory Guide 1.145, Section 1.1 Reference 15.10-9.

15.10.2.1.3 Model Input Parameters

The parameters that were input into the ARCON96 model for use in calculating the Control Room X/Q are summarized below:

	North Stack	South Stack
Release Height (m)	61	61
Intake Height (m)	37.8	37.8
Horizontal Distance from Intake to Stack (m)	16.5	64.8
Elevation Difference between Stack Grade and Intake Grade (m)	0	0
Building Area (m^2)	5851	5851
Direction from Intake to Stack (°)	180	180

Vertical Velocity (m/s)	0	0
Stack Flow (m^3/s)	0	0
Stack Radius (m)	0	0

15.10.2.1.4 Control Room X/Q Results

A summary of the atmospheric diffusion estimates at the Control Room Intake for releases from the North and South Stacks is shown in Table 15.10-2.

15.10.2.2 Control Room Dose Model

The design basis for control room ventilation and shielding design is to limit exposures received by control room operating personnel to 5 rem total effective dose equivalent (TEDE) per 10CFR50.67. This basis is consistent with GDC 19.

The control room shielding is designed to reduce gamma radiation shine from normal and postaccident radiation sources to levels consistent with the requirements of 10CFR20 and GDC 19.

The postaccident ventilation system is designed to preclude entrance of unfiltered air to the control room, and to maintain outleakage of air from this zone with respect to other plant ventilation zones and the air outside the plant.

Details of control room postaccident ventilation system design and instrumentation are discussed in Sections 9.4.1 and 6.4.

During postaccident ventilation system operation, approximately 525 cfm of filtered outside air is supplied to the control room if airborne radioactivity is present outside the control room. If a high radiation accident occurs with the control room in the chlorine isolation mode for testing purposes or as required by the Action statement of an associated Technical Specifications Limiting Condition of Operation, automatic isolation of the control room for high radiation would not occur. Analysis of the event where the MCR HVAC is in a Chlorine Isolation has determined that the MCR HVAC can be in a chlorine isolation for the first seven hours, before it must be transferred into a Radiation Isolation Mode. This analysis assumes 0 scfm filtered air is supplied to the control room for the first seven hours.

In addition to the intake of air through the filter system, some air may enter the control room from inleakage through duct-work and other sources. An infiltration rate of 225 scfm (215 scfm unfiltered inleakage plus 10 scfm due to control room ingress/egress) has been assumed for these unfiltered sources. An assumed inleakage of 10 scfm through the control room doors has been justified by the use of a MCR door seal. The door seal is designed to be erected when thyroid dose in the Turbine Enclosure reaches 10 Rem/Hr. The design of the MCR door seal ensures a minimum cross sectional area through the door way during egress and ingress to ensure air velocity out of the MCR is sufficient to maintain a clean room environment.

Under accident conditions, radiation doses to control room personnel may come from several sources. While in the control room, personnel are exposed to beta and gamma radiation from gaseous fission products that enter after an accident through the ventilation system, or from unfiltered air entering the control room. In addition, personnel are subject to gamma shine dose

from fission products in the containment, and from fission products in the atmosphere outside the control room.

To evaluate the capability of the control room ventilation system and shielding to keep personnel doses within the specified criteria, an estimate of the average cloud activity concentration by time period prior to intake into the control room ventilation system was made. Since the plume is released as leakage from the containment, the released fission products were assumed to mix in the structure wake. The atmospheric dilution factors were determined using the assumptions and methods described in Reference 15.10-12.

The time-dependent concentration of activity outside the control structure is found by the following equation:

$$C_o = A\,(X/Q) \qquad \text{(EQ. 15.10-5)}$$

where:

A = activity release rate as a function of time, Ci/sec

X/Q = atmospheric dilution factor, sec/m^3

The activity in the control room is equal to the amount that enters during a given time, plus the amount present at the beginning of the period. The rate at which activity enters the control structure is given by:

$$Q = 1.7\,(F\,(1.0\text{-}E) + F_{01})C_o \qquad \text{(EQ. 15.10-6)}$$

where:

Q = activity intake rate, Ci/hr

F = ventilation flow rate of air into the control room (525 cfm) (0 cfm when control room HVAC system is in chlorine isolation mode)

E = efficiency of the intake filter (95% for iodine, 0% for the noble gases)

F_{01} = unfiltered air inleakage rate into the control room (225 scfm) (215 scfm unfiltered leakage plus 10 scfm for control room ingress/egress)

1.7 = conversion factor (cfm - 1.7 m^3/hr)

Activity buildup in the control room is given by:

$$\frac{dA}{dt} = Q - \left(\frac{60F}{V} + \frac{60F_{01}}{V} + \lambda_R + \lambda_O\right)A \qquad \text{(EQ. 15.10-7)}$$

where:

Q = activity intake rate, Ci/hr

A = activity present in control room, Ci

V = control room free volume, ft^3

λ_R = $\frac{\text{Recirculation rate}}{V} \cdot$ filter efficiency

= $\frac{(F_R)(E_R)}{V} \cdot 60$

λ_O = isotopic decay constant, hrs^{-1}

F_R = recirculation rate = 2475 cfm (3000 cfm when control room HVAC is in chlorine isolation mode)

E_R = recirculation filter efficiency (95% for iodine, 0% for noble gases)

Equation 15.10-7 can be solved analytically to obtain the activity as a function of time in the control room, A(t), and this integrated over a time period to obtain the time integrated activity inventory in the control room, (I). The time integrated concentration (c) for a given time period is calculated by dividing the inventory (I) by the control room volume. Dose rates in the control room can then be computed by time period.

The whole body dose model for operators inside the control room assumes that the operator is at the center of a finite hemispherical cloud of uniform concentration, whose volume is the same as that of the control room. For a point gamma source, the whole body dose is given by:

$$D_f = D_\infty / GF \qquad \text{(EQ. 15.10-8)}$$

where:

D_f = whole body gamma dose, rem/hr

D_∞ = gamma dose from semi-infinite cloud given by Equation 15.10-10

GF = geometry factor of control room

GF = $\frac{\text{Dose from an infinite cloud}}{\text{Dose from a cloud of volume (V)}}$ (EQ. 15.10-9)

= $\frac{1173}{V^{0.338}}$

(Reference 15.10-12)

V = volume of control room, ft^3

Whole body doses are given by the equation:

$$D_\infty = 3600 \sum_{}^{N} DCF_i \, C_i \qquad \text{(EQ. 15.10-10)}$$

$$\sum_{i=1}$$

where:

DCF_i = whole body gamma dose conversion factor, rem-m^3/Ci-sec

C_i = activity for isotope (i), Ci-hr/m^3

Skin doses from beta radiation are given by the equation:

$$D_s = 3600 \sum_{i=1}^{N} C_i DCF_i \qquad \text{(EQ. 15.10-11)}$$

where:

D_s = beta skin dose, rem

C_i = activity concentration, Ci-hr/m^3

DCF_i = beta dose conversion factor, rem-m^3/Ci-sec

3600 = conversion from hrs to seconds

The beta dose conversion factors are based on the work done by Berger (Reference 15.10-13), and include the effect of attenuation by the layer of dead skin. Values for these dose conversion factors are given in Table 15.10-1.

The thyroid dose for a given time period is given by the equation:

$$D_t = 3600\, B \sum_{i=1}^{N} C_i DCF_i \qquad \text{(EQ. 15.10-12)}$$

where:

D_t = thyroid inhalation dose, rem

B = breathing rate = 3.47×10^{-4} m^3/sec

DCF_i = thyroid dose conversion factors, rem/Ci

C_i = average iodine concentration, Ci-hr/m^3

3600 = conversion from hrs to seconds

15.10.3 REFERENCES

15.10-1 "Report of ICRP Committee II Permissible Dose for Internal Radiation (1959)," Health Physics, Vol 3, pp 30, 146-153, (1960).

15.10-2 C.M. Leadered, et al, "Table of Isotopes", 6th ed, (1968) (or other recognized references).

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15.10-4 D.H. Slade, ed, "Meteorology and Atomic Energy", TID-2419C, (1968).

15.10-5 "Atmospheric Relative Concentrations in Building Wakes"; NUREG/CR-6331, PNNL-10521, Rev. 1; prepared by J. V. Ramsdell, Jr., C. A. Simmons, Pacific Northwest National Laboratory; prepared for U.S. Nuclear Regulatory Commission; May 1997 (Errata, July 1997).

15.10-6 "Atmospheric Dispersion Code System for Evaluating Accidental Radioactivity Releases from Nuclear Power Stations", PAVAN, Version 2, Oak Ridge National Laboratory, U.S. Nuclear Regulatory Commission, December 1997.

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15.10-8 "Atmospheric Dispersion Estimates in the Vicinity of Buildings"; J. V. Ramsdell and C. J. Fosmire, Pacific Northwest Laboratory; 1995.

15.10-9 NRC, Regulatory Guide 1.145, "Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants (Revision 1)", November 1982.

15.10-10 No longer used.

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15.10-13 M.J. Berger, "Beta Ray Dose in Tissue-Equivalent Material Immersed in a Radioactive Cloud", Health Physics, pp 1-12, (January 1974).

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15.10-15 D.S. Duncan and A.B. Speir, "GRACE I - A Program Designed for Computing Gamma Ray Attenuation and Heating in Reactor Shields", Atomic International, (1959).

15.10-16 Federal Guidance Report Number 11, "Limiting Values of Radionuclides Intake and Air Concentration and Dose Conversion Factor for Inhalation, Submersion and Ingestion, "Office of Radiation Programs USEPA", 1989.

15.10-17 Federal Guidance Report Number 12, "External Exposure to Radionuclides in Air, Water, and Soil", 1993.

Table 15.10-1

PHYSICAL DATA FOR ISOTOPES

ISOTOPE	DECAY[1][4] CONSTANT (sec^{-1})	GAMMA WHOLE BODY[2] (Rem-m^3/Ci-sec)	THYROID[3] (Rem/Ci)	SKIN[2] (Rem-m^3/Ci-sec)
I-131	9.970E-07	6.734E-02	1.080E+06	1.103E-01
I-132	8.250E-05	4.144E-01	6.438E+03	5.846E-01
I-133	9.190E-06	1.088E-01	1.798E+05	2.157E-01
I-134	2.200E-04	4.810E-01	1.066E+03	6.919E-01
I-135	2.860E-05	2.953E-01	3.130E+04	4.107E-01
Kr-83m	1.040E-04	5.550E-06		1.317E-04
Kr-85m	4.140E-05	2.768E-02		8.288E-02
Kr-85	2.210E-09	4.403E-04		4.884E-02
Kr-87	1.480E-04	1.524E-01		5.069E-01
Kr-88	6.940E-05	3.774E-01		4.995E-01
Xe-133m	3.500E-06	5.069E-03		3.848E-02
Xe-133	1.520E-06	5.772E-03		1.839E-02
Xe-135m	7.560E-04	7.548E-02		1.099E-01
Xe-135	2.110E-05	4.403E-02		1.154E-01
Xe-138	6.580E-04	2.135E-01		3.959E-01

(1) From Reference 15.10-2.

(2) From Reference 15.10-17. Effective Dose Equivalents used for Whole Body Dose Conversion

(3) From Reference 15.10-16. Unweighted Thyroid Dose conversion factor used.

(4) These numbers may not match the quoted reference exactly. However, these values have been determined to be acceptable. .

Table 15.10-2

ACCIDENT ATMOSPHERIC DILUTION FACTORS - X/Q

TIME PERIOD (hrs)	NORTH STACK X/Q (sec/m^3)	SOUTH STACK X/Q (sec/m^3)
0-2	6.88×10^{-3}	1.26×10^{-3}
2-8	5.17×10^{-3}	9.64×10^{-4}
8-24	2.04×10^{-3}	3.80×10^{-4}
24-96	1.29×10^{-3}	2.39×10^{-4}
96-720	9.63×10^{-3}	1.80×10^{-4}

Table 15.10-3

BREATHING RATES
FOR OFFSITE DOSE CALCULATIONS

TIME PERIOD (hr)	BREATHING RATE (m^3/sec)
0-8	3.47×10^{-4}
8-24	1.75×10^{-4}
24-720	2.32×10^{-4}

15.11 PROBABILISTIC RISK ASSESSMENT

The LGS Probabilistic Risk Assessment was performed as requested by the NRC in its May 6, 1980 letter from D.G. Eisenhut (NRC) to E.G. Bauer, Jr. (PECo). The licensee submitted the PRA to the NRC in its March 17, 1981 letter from E.J. Bradley (PECo) to H.R. Denton (NRC).

15.12 STATION BLACKOUT

15.12.1 REQUIREMENTS AND LIMERICK RESPONSE

10 CFR 50.63 “Loss of All Alternating Current Power” defines the requirements for the Station Blackout and requires each light-water-cooled nuclear power plant licensed to operate to be able to withstand and recover from a station blackout as defined in 10 CFR 50.2. In 1988, the NRC issued Regulatory Guide 1.155, “Station Blackout” which describes a means acceptable to the NRC for meeting the requirements of 10 CFR 50.63. This regulatory guide endorses the document issued by the Nuclear Utility Management and Resources Council, NUMARC 87-00, “Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors.”

LGS Units 1 and 2 were evaluated in accordance with the requirements of the Station Blackout Rule using guidance from NUMARC 87-00, except where RG 1.155 takes precedence. The results of the Limerick analyses and assessments are documented in letters to the NRC (References 15.12-2, 15.12-3, 15.12-4, and 15.12-5). The NRC acceptance of the Limerick responses to the Station Blackout Rule is documented in Safety Evaluation Reports - (References 15.12-6, and 15.12-7).

15.12.2 DETERMINATION OF REQUIRED COPING DURATION

10CFR50.63 requires that the plant be capable of maintaining core cooling and appropriate containment integrity for the station blackout duration. Section 50.63 further requires the following Information:

- A proposed station blackout duration including a justification for the selection based on the redundancy and reliability of the onsite emergency AC power sources, the expected frequency of the loss of offsite power (LOOP), and the probable time needed to restore offsite power;

- A description of the procedures that will be implemented for station blackout events for the duration (as determined in the paragraph above) and for recovery there from; and a list and proposed schedule for any needed modifications to equipment and associated procedures necessary for the specified SBO duration.

The required coping duration category is based upon the following factors:

1. Offsite Power Design - NUMARC 87-00 distinguishes between sites having particular susceptibilities to losing off-site power to plant-centered, grid-related, and weather-related events. Three off-site power design groups are provided and are designed to be mutually exclusive. Of the three groups P2 includes those sites whose off-site power sources are less redundant or independent, or that are more susceptible to extended offsite power losses due to weather-initiated events or more frequent losses due to plant-centered events. Based upon NUMARC 87-00 guidance, Limerick Generating Station is determined to be in AC Power Design Characteristic Group, P2. This determination is based upon the following criteria of NUMARC 87-00.

    a) The expected frequency of grid-related loss of offsite power (LOOP) does not exceed once per twenty years. As discussed in Limerick Generating Station UFSAR Section 15.2.6, the loss of all grid connections is categorized as an incident of moderate frequency.

b) Sites are categorized in groups based upon the estimated frequency of LOOPs due to Extremely Severe Weather. The estimated frequency of loss of off-site power due to ESW is determined by the annual expectation of storms at the site with wind velocities greater than or equal to 125 mph. It has been determined that Limerick Generating Station falls within Extremely Severe Weather Group 3. This was determined utilizing Table 3-1, Extremely Severe Weather Groups Table and Table Extremely Severe Weather Data provided in NUMARC 87-00.

c) The estimated frequency of LOOPs due to severe weather places Limerick Generating Station in Severe Weather Group 2 based on site specific factors. This was determined utilizing Table 3-3, Severe Weather Data and Table 3-4, Severe Weather Group Table provided in NUMARC 87-00.

d) The potential for long duration loss of off-site power events can have a significant impact on station blackout risk and required coping duration. Long duration LOOP events are associated with grid failures due to severe weather conditions or unique transmission system features. Shorter duration LOOP events tend to be associated with specific switchyards features, in particular:

   1) The independence of the off-site power source constituting the preferred power supply to the shutdown buses on-site, and

   2) The power transfer schemes when the normal source of AC power is lost. Limerick Generating Station has two off-site power systems that provide the preferred AC electrical power to all Class 1E loads as discussed in UFSAR Chapter 8 (NUMARC 87-00 Group A).

   Limerick Generating Station also has two electrically-connected switchyards, and all safe shutdown busses are automatically transferred to the alternate power source on loss of the preferred source (NUMARC-87-00 Group 1 ½*).*

2. Onsite Emergency AC (EAC) Power Configuration - After the likelihood of losing off-site power, the redundancy of the emergency AC power system is the next most important contributor to station blackout risk. With greater EAC system redundancy, the potential for station blackout diminishes, as does the likelihood of core damage. Each Limerick unit is equipped with four emergency diesel generators (EDG). Anyone of the EDGs is necessary to operate safe-shutdown equipment at either unit following a loss of offsite power for an extended period.

It is noted that the total shutdown-load requirements for both units combined is greater than the continuous rating of one EDG in each unit and that a minimum of three EDGs are required to support simultaneous shutdown of the two units. Limerick credits excess capacity from the non-blacked out (NBO) unit as the alternate AC (AAC) power source for the blacked out (BO) unit. Limerick does not rely on a single EDG from the NBO unit as the AAC source for the BO unit. Also, a limited amount of operator actions are credited to initiate cross-ties between electrical power sources in order to justify the excess capacity from the NBO unit's EDGs. Shutdown-load requirements are such that the capacity of three EDGs is needed to shutdown the two units following a LOOP. For any Individual unit, the shutdown loads will require the capacity of more than one EDG. Thus, two are the minimum required number of EDGs per unit. Since two of the

four EDGs per unit are needed for shutdown, making the EAC classification of EAC Group B per NUMARC 87-00, Table 3-7.

a) Calculated EDG Reliability - The target emergency diesel generator reliability for Limerick Station is selected to be 0.95. The selection of this value is consistent with NUMARC 87-00 and is based upon having a nuclear unit average reliability for the last 100 demands greater than 0.95.

b) Allowed EDG Reliability - An EDG reliability program has been established to monitor and maintain the EDG target reliability of 0.95 utilizing guidance in RG 1.155, Regulatory Position C.1.2. If the EDG performance falls below the target reliability level of 0.95, action will be taken as required by the EDG reliability program to restore the affected EDG to the target reliability level.

In summary, using the above factors, LGS is a four hour coping duration plant per Table 3-8 in NUMARC 87-00 (Table 2 in RG 1.155).

15.12.3 USE OF ALTERNATE AC SOURCE

The LGS offsite power supplies, the station auxiliary power system, and the onsite 4 kV Safeguard Power System are shown in Drawings E-1, E-15 and E-16. At Limerick, Station Blackout is supported by the use of the diesel generators (excess capacity on non-blacked out unit) as an alternate ac (AAC) power source required to be available within one hour from the initiation of a station blackout event to support safe shutdown and decay heat removal from the blacked out unit for the required four hour coping duration. The potential for excess EAC power sources to be used as AAC is directly related to the existing level of EAC redundancy.

Each Limerick unit is equipped with four emergency diesel generators (EDGs). Any one of the EDGs is necessary to operate safe-shutdown equipment at either unit following a loss of offsite power for an extended period. It is noted that the total shutdown-load requirements for both units combined is greater than the continuous rating of one EDG in each unit and that minimum of three EDGs are required to support simultaneous shutdown of the two units. The AAC design at Limerick Generating Station uses a limited amount of operator actions to initiate electrical cross-ties between power sources in order for the blacked-out (BO) unit to utilize the excess capacity from the NBO EDGs.

There are a number of mechanical systems at LGS whose functions are normally shared between units (e.g., Residual Heat Removal Service Water (RHRSW), and Emergency Service Water (ESW)). Accordingly, the loads for certain of these systems were assumed to be powered by the adjacent unit's power source. Due to the assumed loss of one of the NBO diesels, there is some likelihood that the failed EDG will power an ESW pump and that only one ESW loop will be available in the initial few minutes of the SBO event. The ESW loop will be restored during the cross-tie of the NBO 4kV busses. After the busses are cross-tied, ESW will be restored and the third diesel on the NBO can be restarted to support the BO unit shutdown loads. This is intended to be performed during the first 60 minutes of the SBO event.

For LGS Units 1 and 2, the AAC power source satisfies the requirements for station blackout in conformance with Regulatory Guide 1.155.

15.12.4 ASSESSMENT OF ABILITY TO COPE WITH A STATION BLACKOUT

Coping with station blackout using the AAC approach entails a short period of time in an ac-independent state (up to one hour) while the operators initiate power from the AAC source. Once AAC power is available, the plant transitions to the AAC source which provides decay heat removal until offsite or EAC power becomes available. Therefore, the LGS coping assessments must address the four hour coping duration but certain safe shutdown equipment such as RHR pumps, air compressors, and battery chargers can be repowered after the first hour and used for the remainder of the coping duration. Coping assessments were performed in the following areas: condensate inventory, Class 1E battery capacity, compressed air, loss of ventilation, and containment isolation. In each case, capability to successfully cope with blackout for the four hour period was demonstrated.

15.12.4.1 Condensate Inventory for Decay Heat Removal

A supply of 92,100 gallons of water is required for decay-heat removal during a SBO 4-hour coping period. A calculation was performed to show that the Condensate Storage Tank (CST) provides 138,800 gallons of water, which exceeds the required quantity for coping with a four-hour station blackout. A leakage rate of 25 gpm per recirculation pump was assumed in the calculated analysis. Since the AAC power source will be available within one hour, the residual heat removal (RHR) system would be powered to provide suppression pool cooling. Therefore, the CST inventory will not be required at any time during the four-hour duration of the SBO event. The calculation demonstrates the acceptability of using only the suppression pool inventory for reactor pressure vessel (RPV) makeup and reactor heat removal. No credit for the water volume has been taken in the SBO analysis and the CST inventory is available as an additional heat removal source.

15.12.4.2 Class 1E Battery Capacity

The Class 1E battery bank has sufficient capacity to independently supply the required loads for a design basis accident for 4 hours. The SBO loads are a subset of the design basis accident loads, the station battery capacity is sufficient to meet SBO shutdown requirements for 4 hours. At 1 hour into the SBO event, with the AAC power source available, the ability to power selected battery chargers is available.

15.12.4.3 Compressed Gas

The AAC power source is capable of energizing an instrument air compressor and an instrument gas compressor within one hour of a station blackout. The only air-operated valves relied upon during a station blackout are the Automatic Depressurization System (ADS) valves. These valves have sufficient backup gas supplies to cope with a station blackout for the entire event and sufficient local gas supply is available such that reliance of the air compressor after an hour is not needed. Valves requiring manual operation or that need backup sources will be identified in station procedures.

15.12.4.4 Effects of Loss Of Ventilation

Reasonable assurance of operability is established if the following criteria are met:

1) The temperature in the Dominant Area of Concern (DAC) are calculated to be equal to or less than 120, or

2) The system in the DAC is assumed to operate no longer than 10 minutes after the onset of the blackout, or

3) The methodology outlined in Appendix F of NUMARC 87-00 indicates that no components in the DAC have operability limits below the calculated bulk room temperature.

At Limerick Generating Station, the AAC power supply does not power cooling loads to some plant areas that contain station blackout response equipment during the hour after the onset of the station blackout event. Evaluation of the following specific areas was performed Units 1 and 2 APRM Inverters (Aux Equip Rm), Unit 2 RPS computer and Inverter rooms, RCIC Pump Room, Drywell and Main Control Room. These areas have been evaluated to establish reasonable assurance of operability for station blackout event.

15.12.4.5 Containment Isolation

The station list of containment isolation valves has been reviewed to verify that the valves which must be capable of being closed or that must be operated (cycled) under station blackout conditions can be positioned (with indication) independent *at* the preferred and black-out unit's Class 1E power supplies.

No plant modifications were determined to be required to ensure that appropriate containment integrity can be provided under SSO conditions. Limerick Generating Station procedures include all actions necessary to assure containment integrity.

15.12.4.6 Reactor Coolant Inventory

Adequate reactor coolant system (RCS) inventory is maintained to ensure core cooling for 4-hour duration. HPCI and RCIC system are capable *at* supplying sufficient inventory to keep the core covered. RCS makeup is necessary to remove decay heat, to compensate for RCS cool down, and to replenish an assumed RCS inventory loss of 50 gpm due to the reactor coolant pump seal leakage (25 gpm per pump) and to provide for Technical Specification maximum allowable leakage (30 gpm). The RCIC pump, which is steam-driven, injects at a rate of 600 gpm, which exceeds the average water injection rate necessary for decay heat removal and the 80 gpm leak rate.

The AAC source powers the necessary make-up systems within 1 hour to maintain adequate RCS inventory to ensure that the core is cooled for the required coping duration. The expected rates of reactor coolant inventory loss under SBO conditions do not result in uncovering the core in an SBO of four hours.

15.12.5 PROCEDURES FOR SBO

Limerick Generating Station procedures comply with the guidelines of NUMARC 87-00, Section 4. SBO response guidelines provide for operator actions to be taken in a SBO event; guidance is provided to operations and load dispatcher personnel for actions to restore AC power in a station blackout; and guidance is given for operators to determine the proper actions due to the onset severe weather. During the SBO event, for the NBO unit, excess capacity is not attained by load shedding. This ensures that there is no degradation of the normally available shutdown capability for the LOOP condition. Additionally, there is no load switching or disablement of information readouts or alarms in the main control room that would degrade the normal

shutdown capability for a LOOP in the NBO unit. Limerick Generating Station procedures incorporate these guidelines and are described as follows:

Procedure E-1 – Loss of All AC Power (Station Blackout)

Procedure E-10/20 – Loss of Offsite Power
Verifies Containment Isolation Valves

Procedure SE-9 – Preparation for Severe Weather

15.12.6 REFERENCES

15.12-1 NUMARC 87-00, "Guidelines and Technical Bases for NUMACR initiatives Addressing Station Blackout at Light Water Reactors."

15.12-2 Letter to NRC Document Control Desk from G. A. Hunger dated April 17, 1989, Limerick Generating Station, Units 1 and 2, Response to 10CFR50.63, "Loss of All Alternating Current Power" (DCS Sequence # 2890013820).

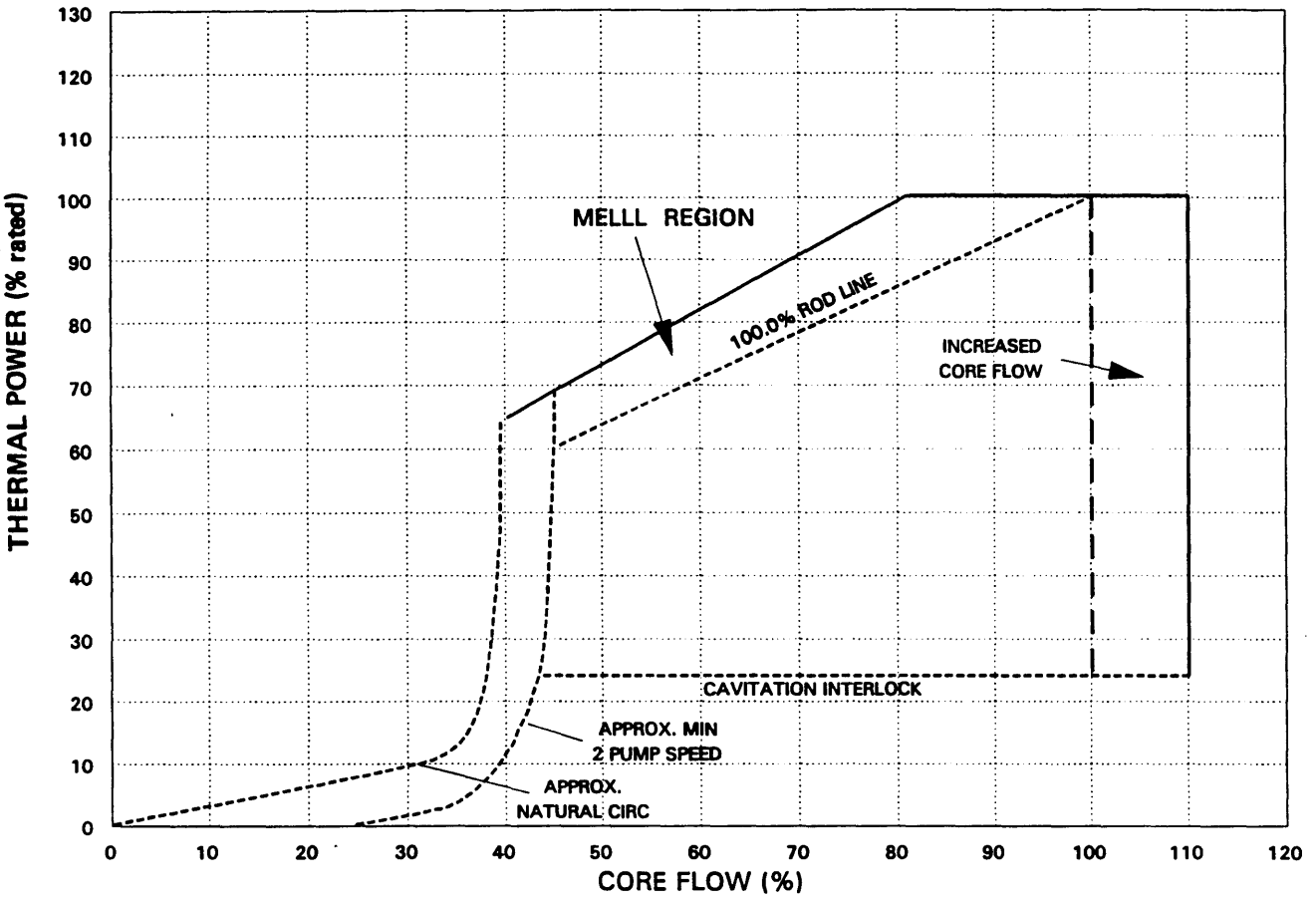
15.12-3 Letter to NRC Document Control Desk from G. A. Hunger dated April 9, 1990, Limerick Generating Station, Units 1 and 2, 10CFR50.63, "Loss of All Alternating Current Power" Supplemental Information (DCS Sequence # 2906110880).

15.12-4 Letter to NRC Document Control Desk from G.J. Beck dated September 4, 1991, Limerick Generating Station, Units 1 and 2, 10CFR50.63, "Loss of All Alternating Current", Response to NRC Safety Evaluation (DCS Sequence # 2916033730).

15.12-5 Letter to NRC Document Control Desk from G.J. Beck dated February 14, 1992, Limerick Generating Station, Units 1 and 2, 10CFR50.63, "Loss of All Alternating Current", Response to NRC Concerns (DCS Sequence # 2924001490).

15.12-6 Safety Evaluation by the Office of Nuclear Reactor Regulation, Station Blackout Safety Evaluation, Philadelphia Electric Company, Limerick Generating Station, Units 1 and 2, Docket Nos. 50-352/353, dated June 3, 1991 (DCS Sequence # 2916024860).

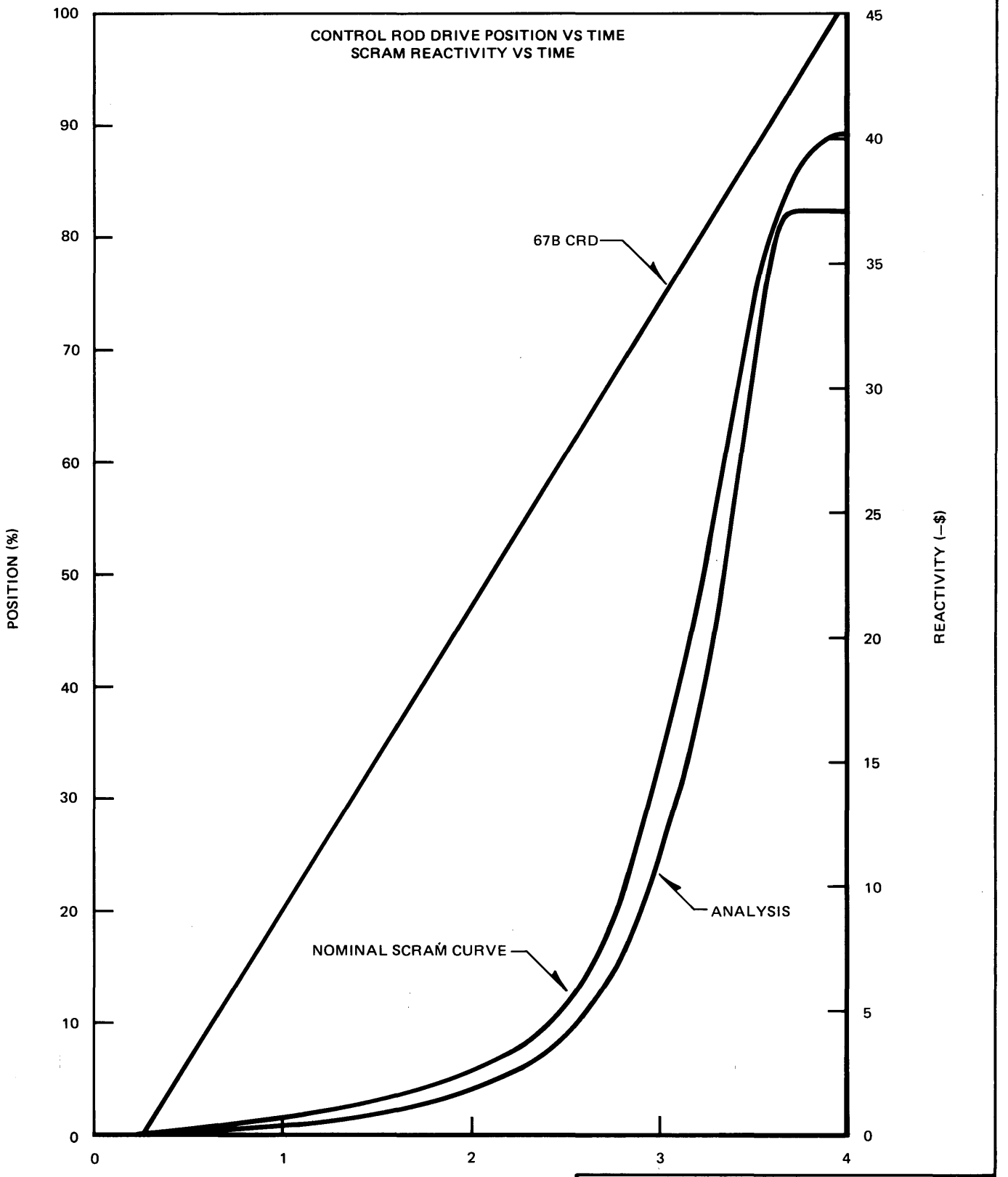
15.12-7 Supplemental Safety Evaluation by the Office of Nuclear Reactor Regulation, Station Blackout Rule (10CFR50.63), Philadelphia Electric Company, Limerick Generating Station, Units 1 and 2, Docket Nos. 50-352/353, dated June 10, 1992 (DCS Sequence # 2920013850).



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TYPICAL POWER/FLOW MAP

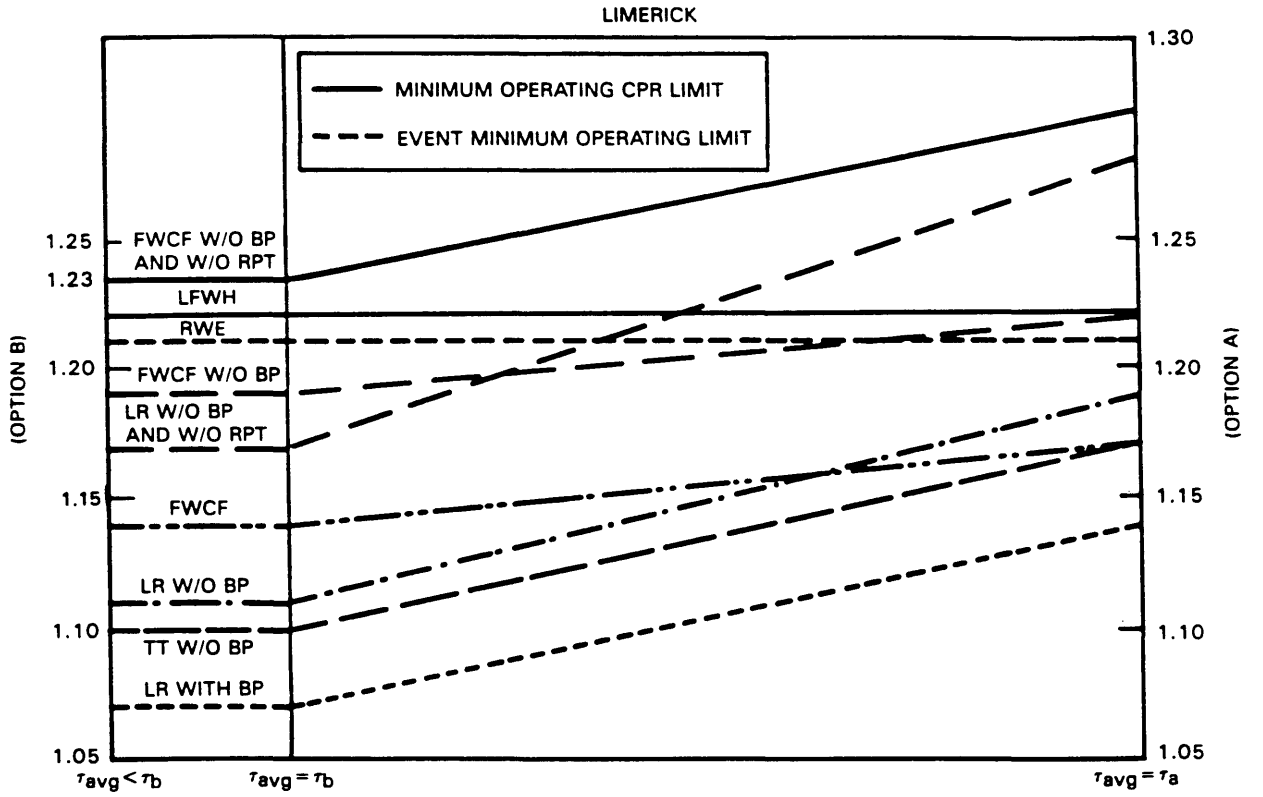
FIGURE 15.0-1 Rev. 5, 4/96



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SCRAM POSITION AND REACTIVITY CHARACTERISTICS

FIGURE 15.0-2

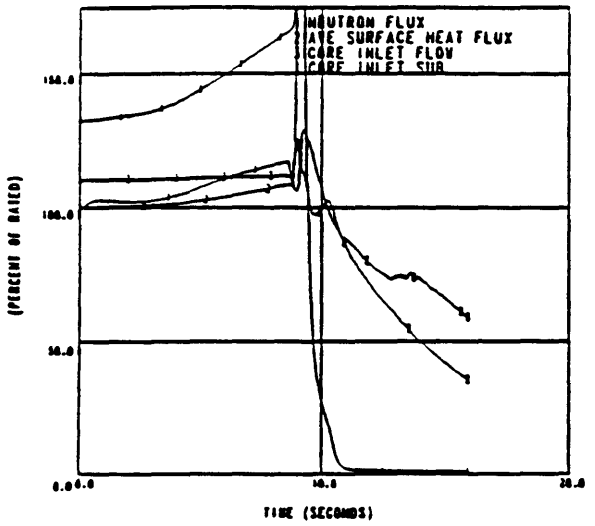


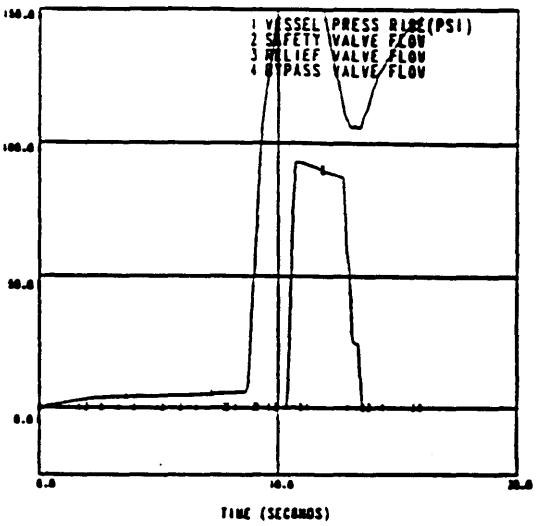
The results presented here are based on original plant condition. Operating limits are analyzed for each cycle.

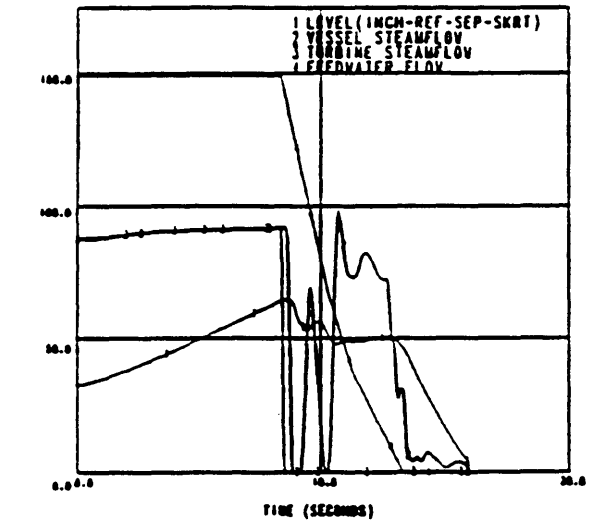
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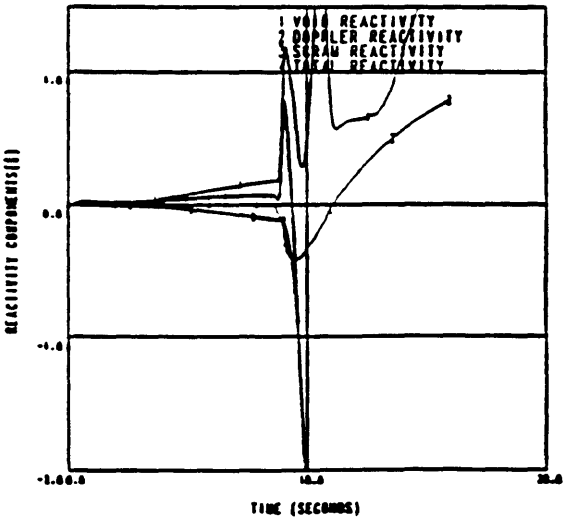
MINIMUM OPERATING CPR LIMITS
VS. SCRAM SPEED
INITIAL CORE

FIGURE 15.0-3 Rev. 5, 4/96





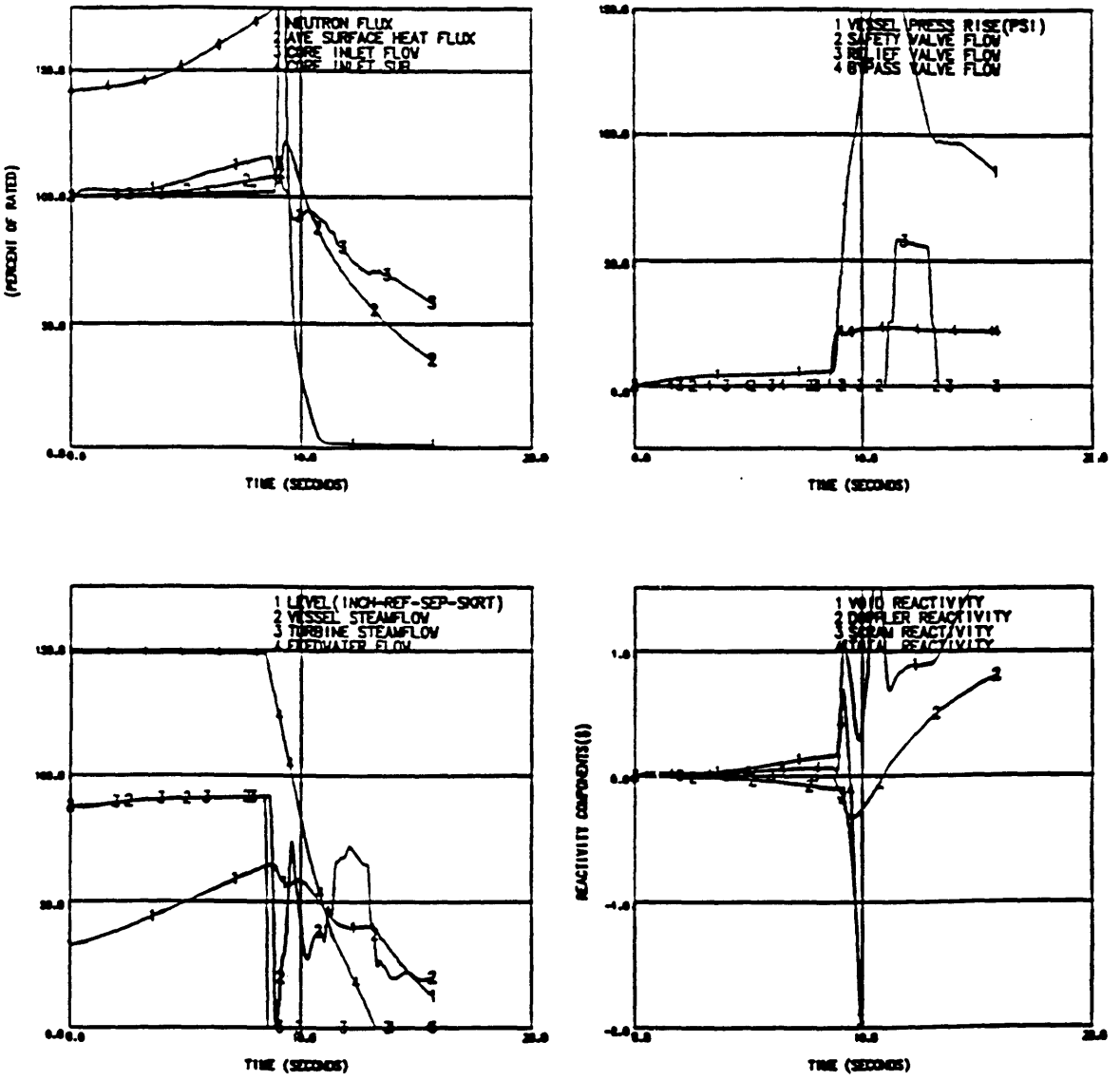




LIMERICK GENERATING STATION UNITS 1 AND 2 UPDATED FINAL SAFETY ANALYSIS REPORT
FEEDWATER CONTROLLER FAILURE WITHOUT TURBINE BYPASS
FIGURE 15.1-1 Rev. 5, 4/96

Figure 15.1-2

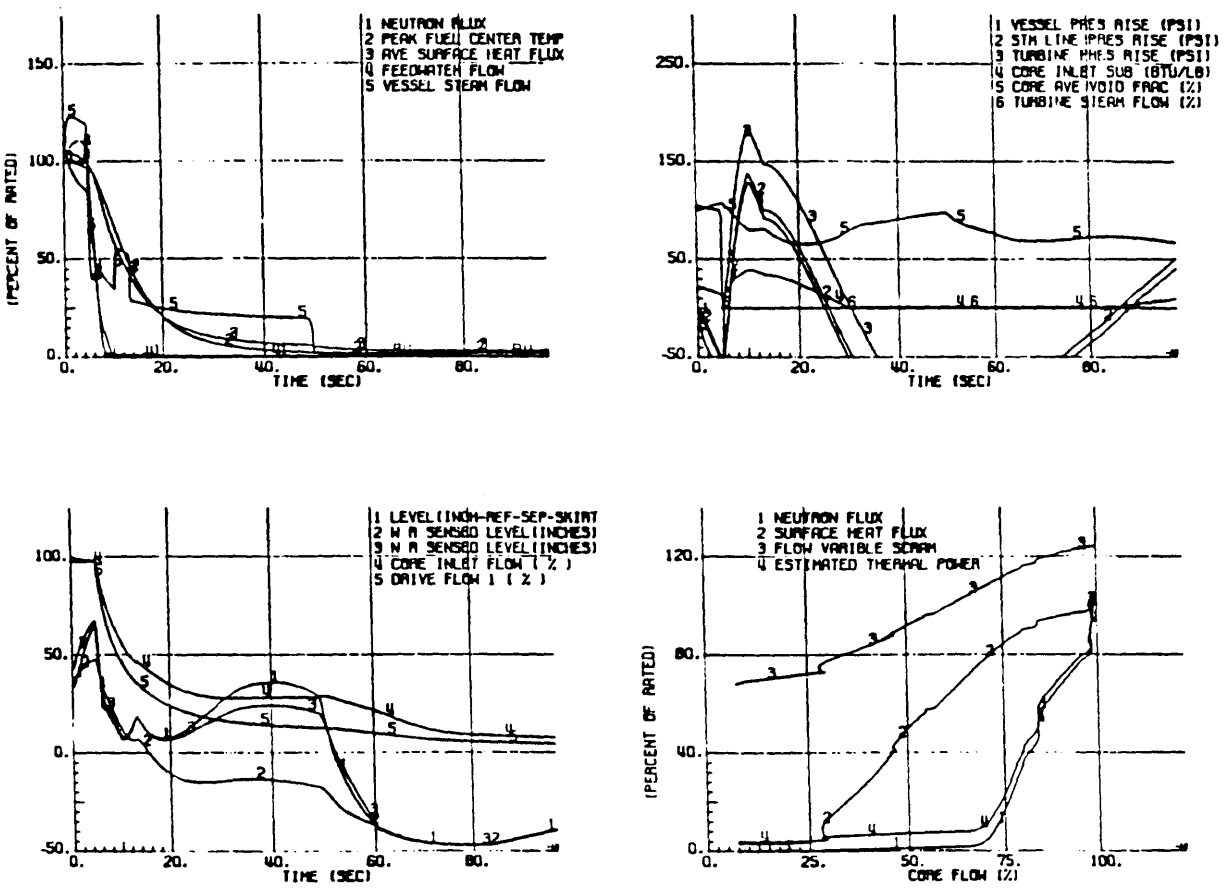
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FEEDWATER CONTROLLER
FAILURE, MAXIMUM DEMAND,
WITH HIGH LEVEL TURBINE TRIP

FIGURE 15.1-3 Rev. 5, 4/96



NOTE: The information presented here is based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions or for raising the MSIV low pressure isolation setpoint. However, the general trends and characteristics as shown here are not expected to change.

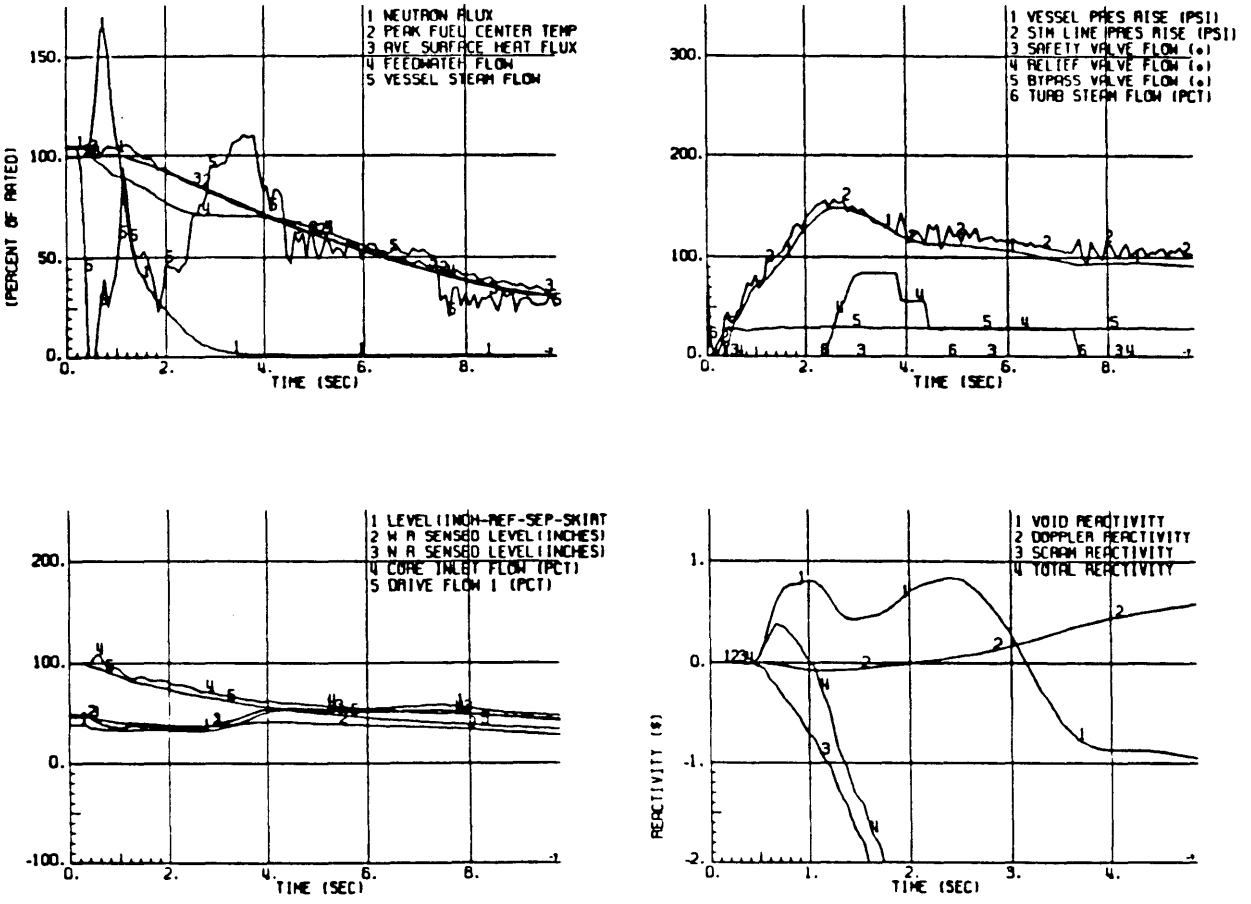
Raising the MSIV low pressure isolation setpoint would terminate the event sooner and be less limiting.

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PRESSURE REGULATOR FAILURE OPEN

Rev. 19, 09/18

FIGURE 15.1-4



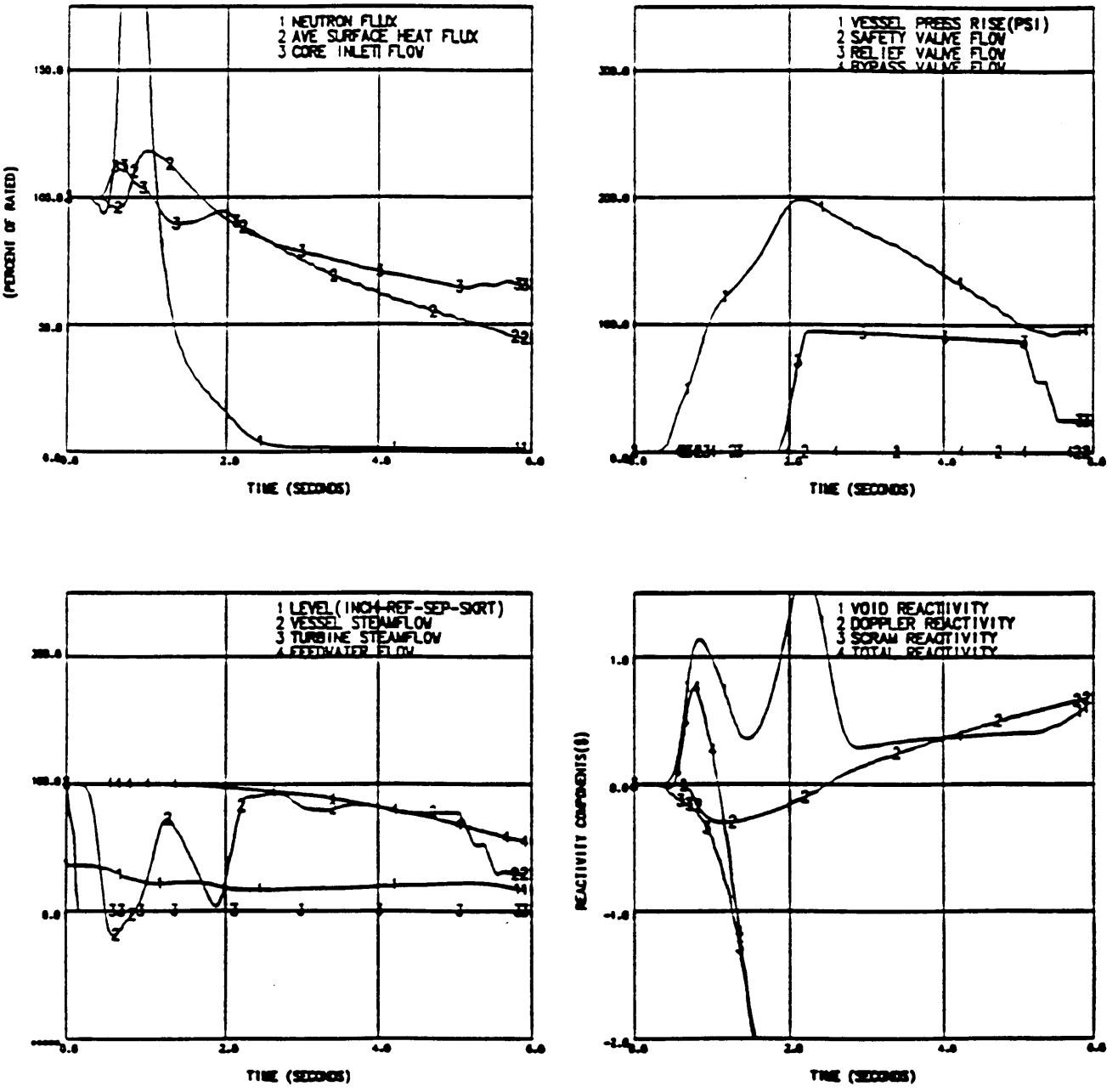
NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

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GENERATOR LOAD REJECTION, TRIP SCRAM, BYPASS – ON, RPT – ON

FIGURE **15.2-1**

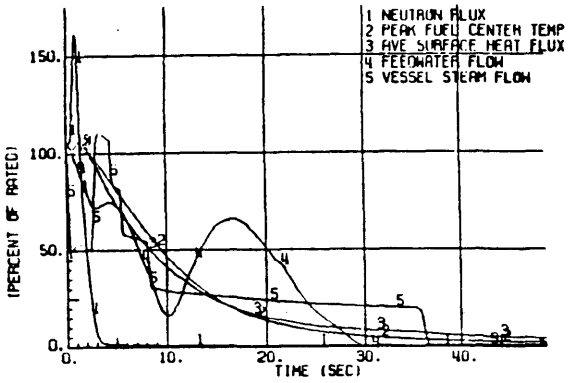
Rev. 5, 4/96

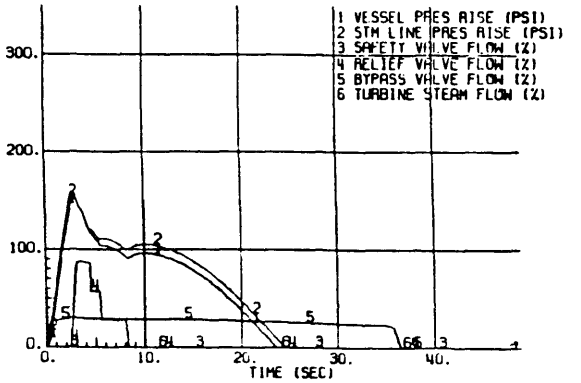


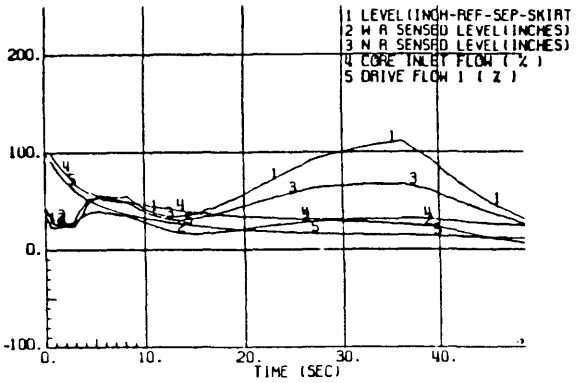
LIMERICK GENERATING STATION
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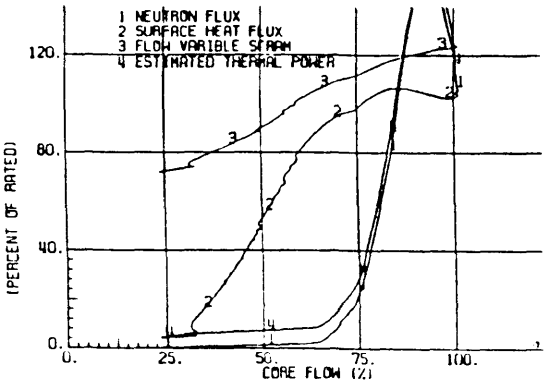
GENERATOR LOAD REJECTION, WITHOUT BYPASS

FIGURE 15.2-2 Rev. 5, 4/96

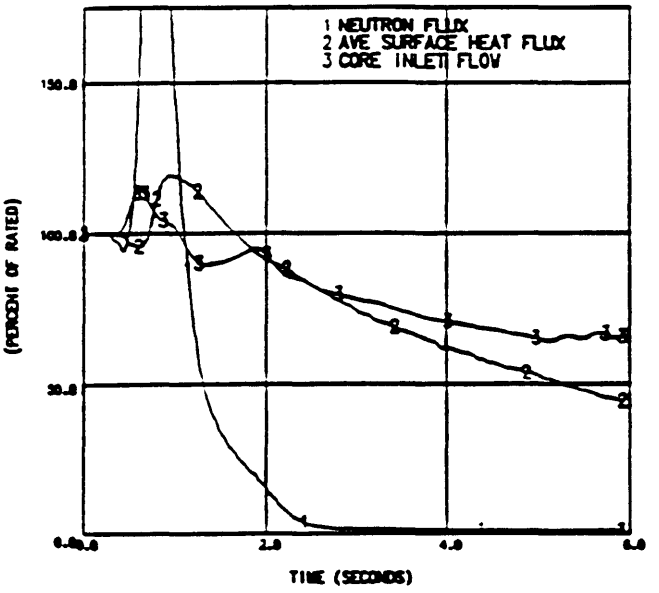


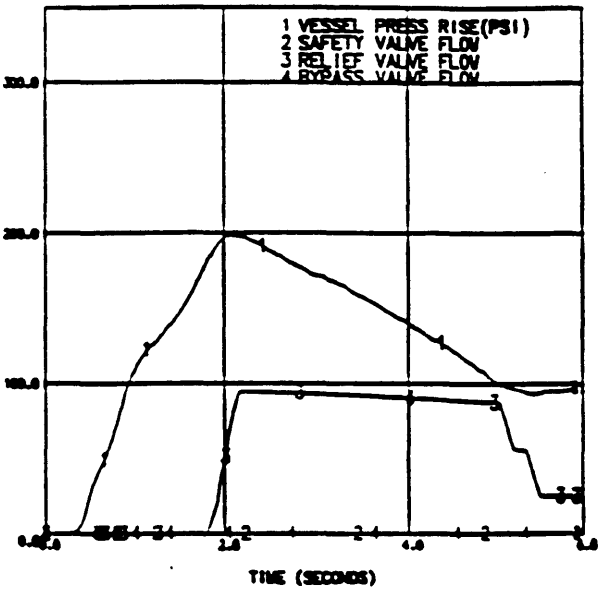


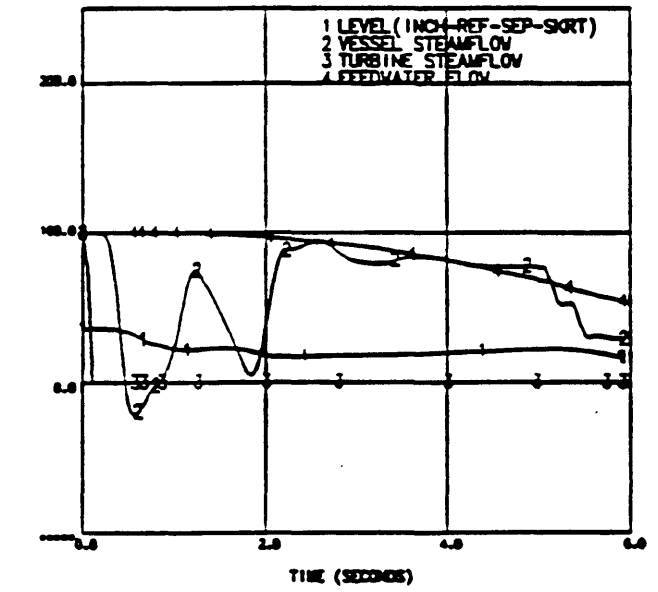


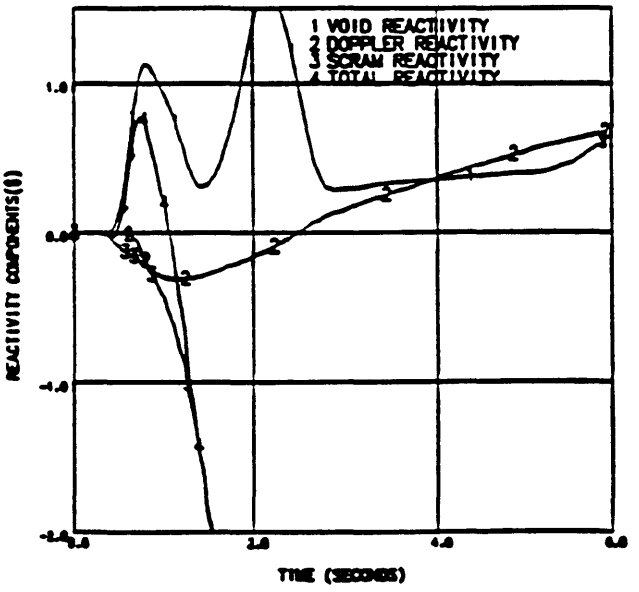


NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.





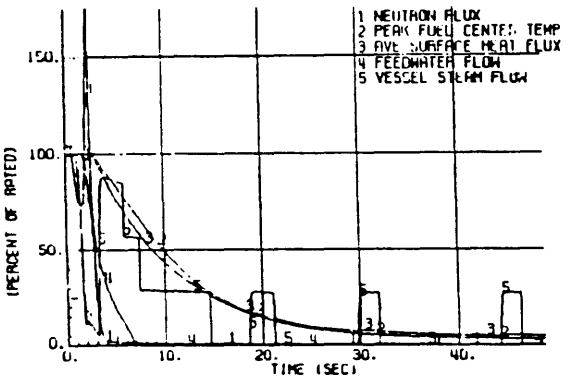


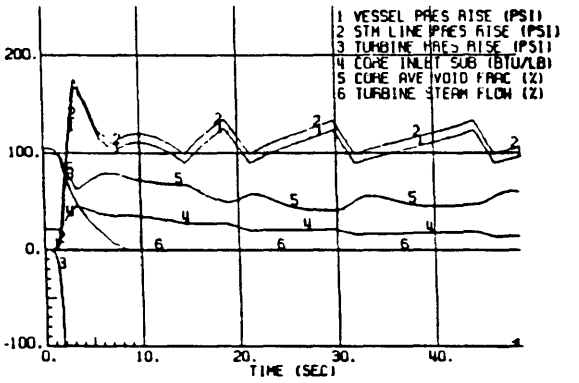


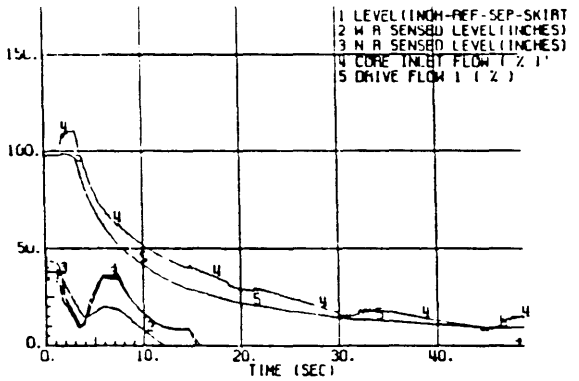
LIMERICK GENERATING STATION
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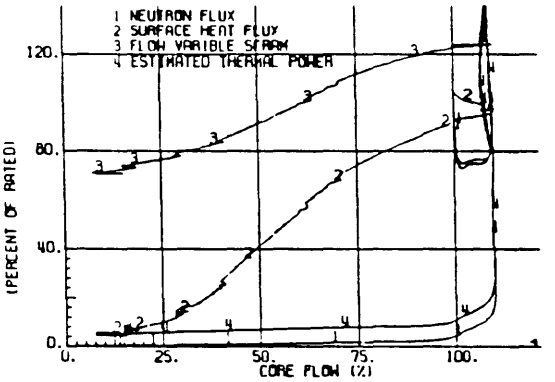
TURBINE TRIP WITHOUT BYPASS, TRIP SCRAM

FIGURE 15.2-4 Rev. 5, 4/96







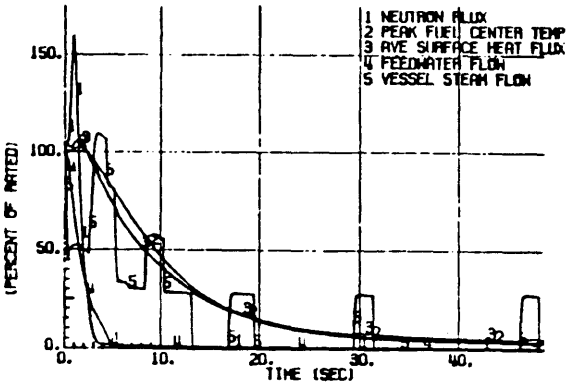


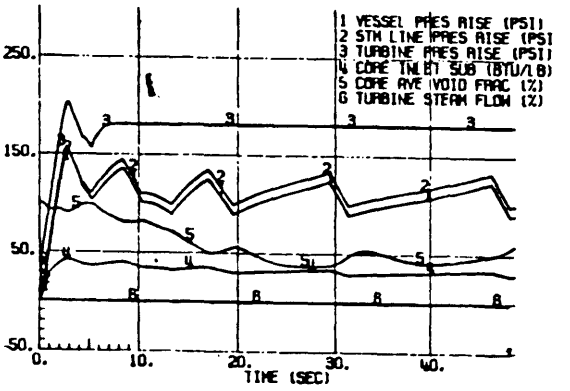
NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

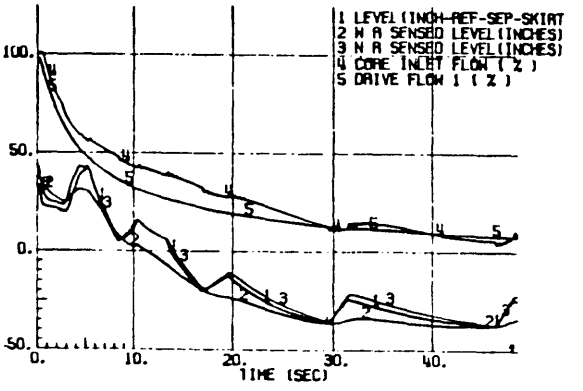
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UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

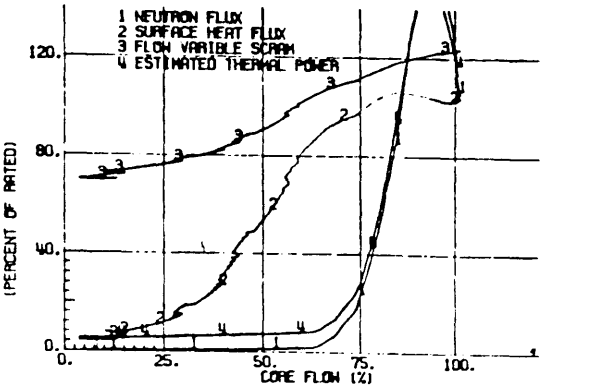
THREE-SECOND CLOSURE OF ALL MAIN STEAM LINE ISOLATION VALVES WITH POSITION SWITCH SCRAM

FIGURE 15.2-5 Rev. 5, 4/96









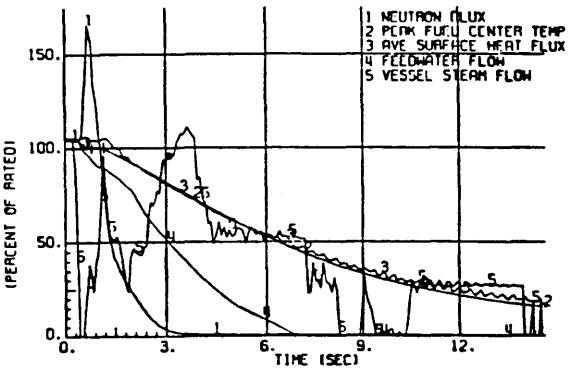
NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

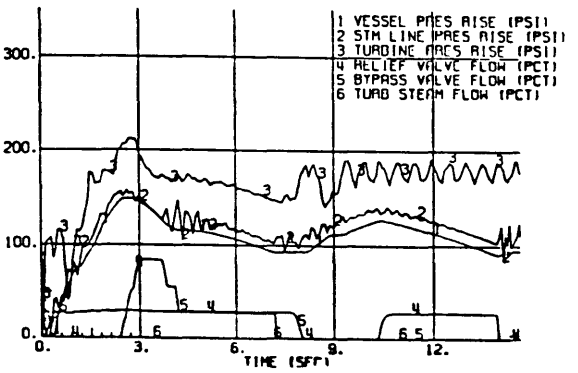
REFER TO FIGURE 15.2-8

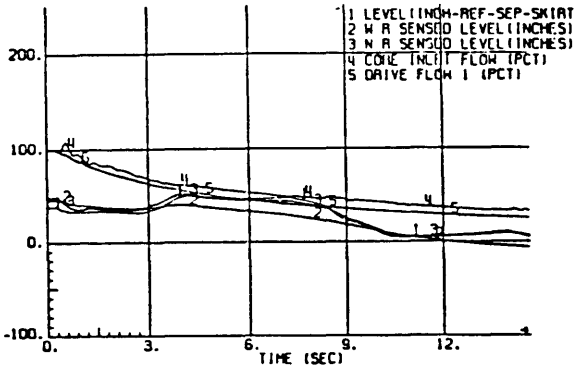
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

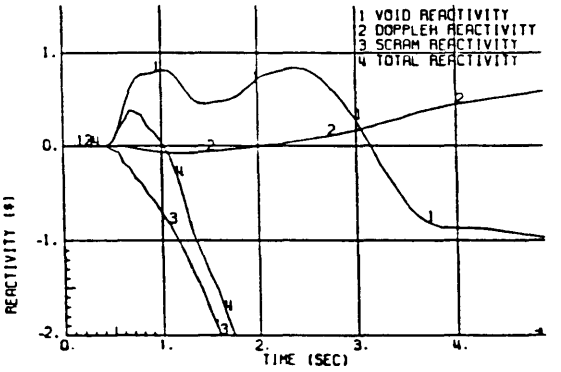
LOSS OF AUXILIARY POWER TRANSFORMER

FIGURE 15.2-7







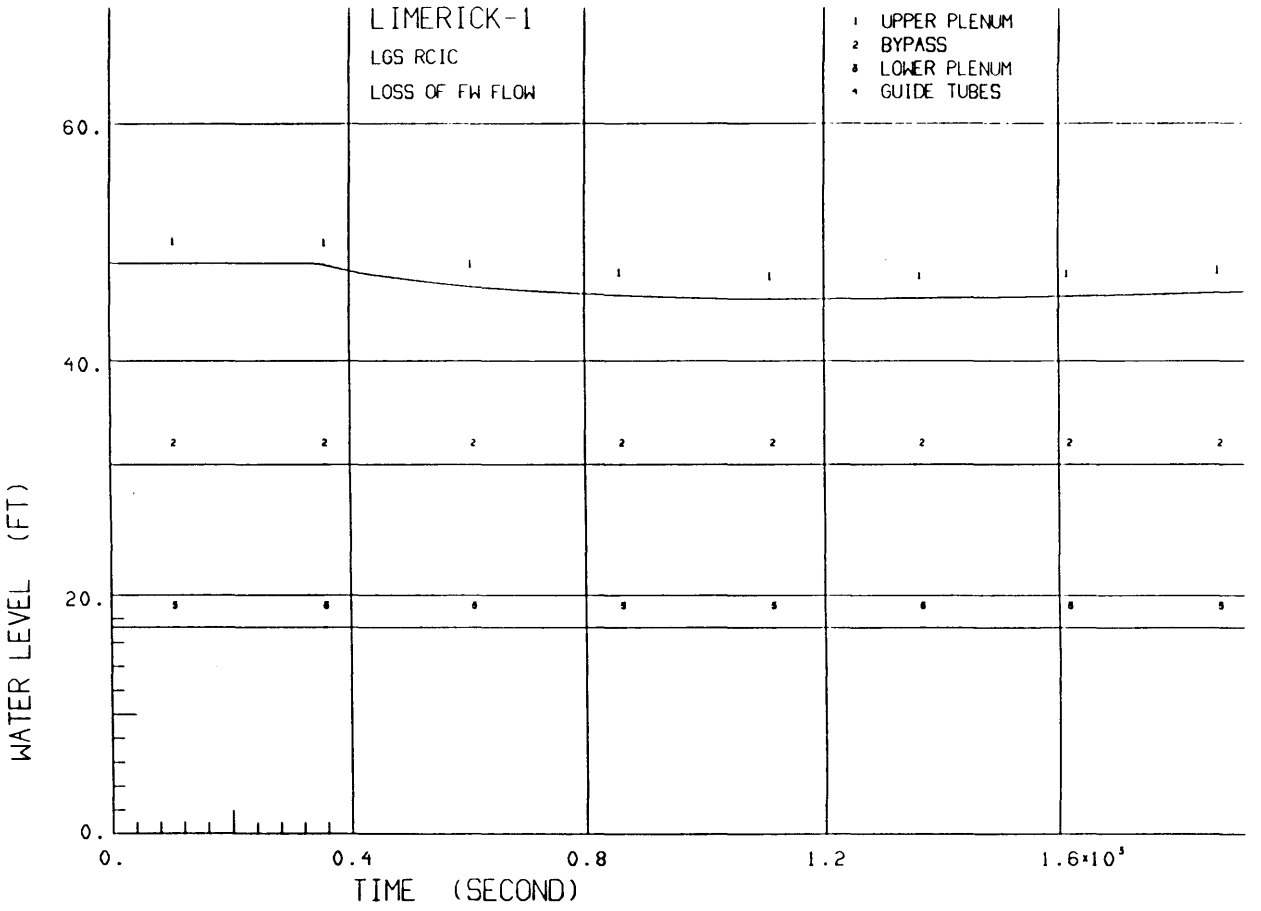


NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LOSS OF ALL GRID CONNECTIONS

FIGURE 15.2-8 Rev. 5, 4/96

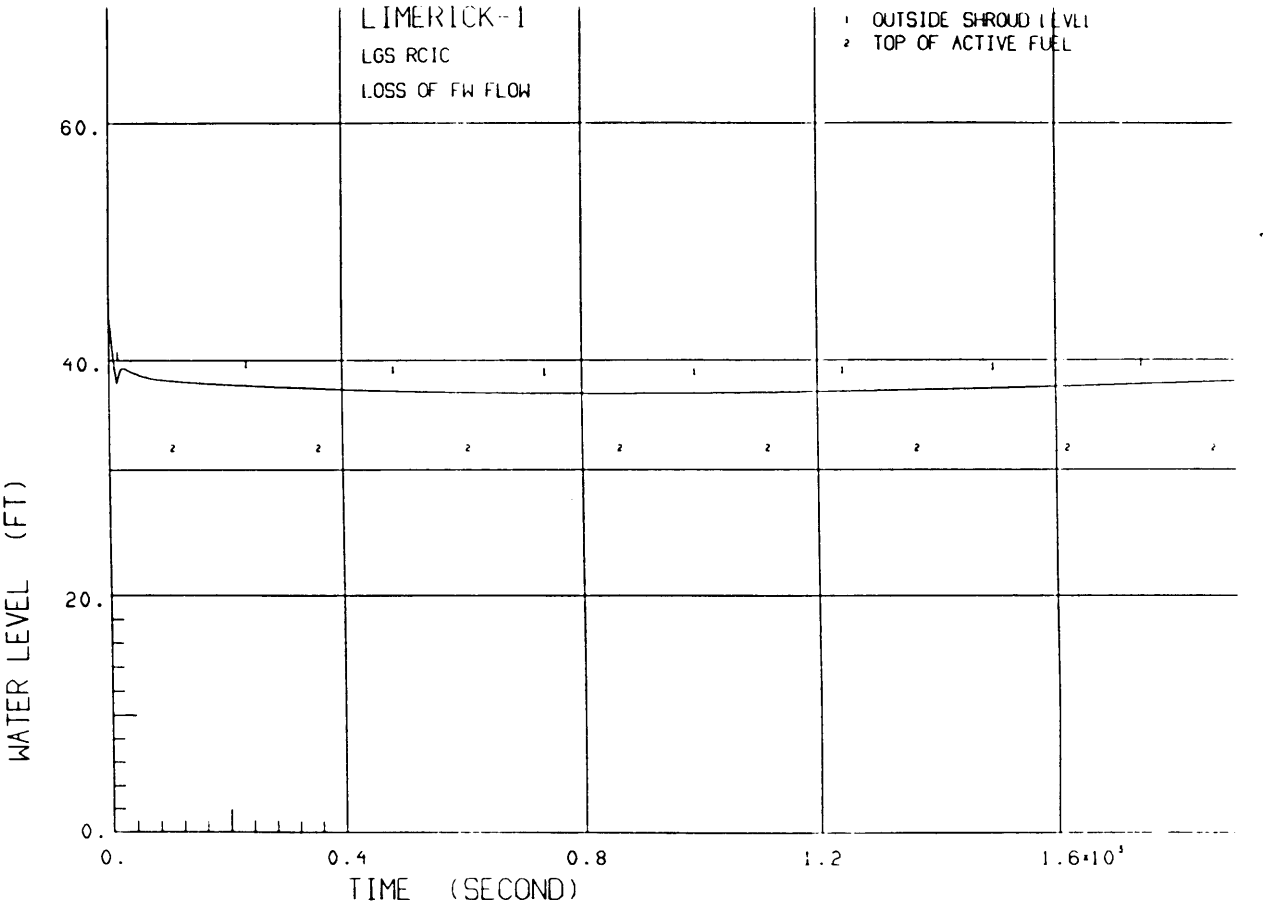


LIMERICK GENERATING STATION
UNITS 2 AND 3
UPDATED FINAL SAFETY ANALYSIS REPORT

LOSS OF ALL FEEDWATER FLOW

FIGURE 15.2-9A

REV. 5
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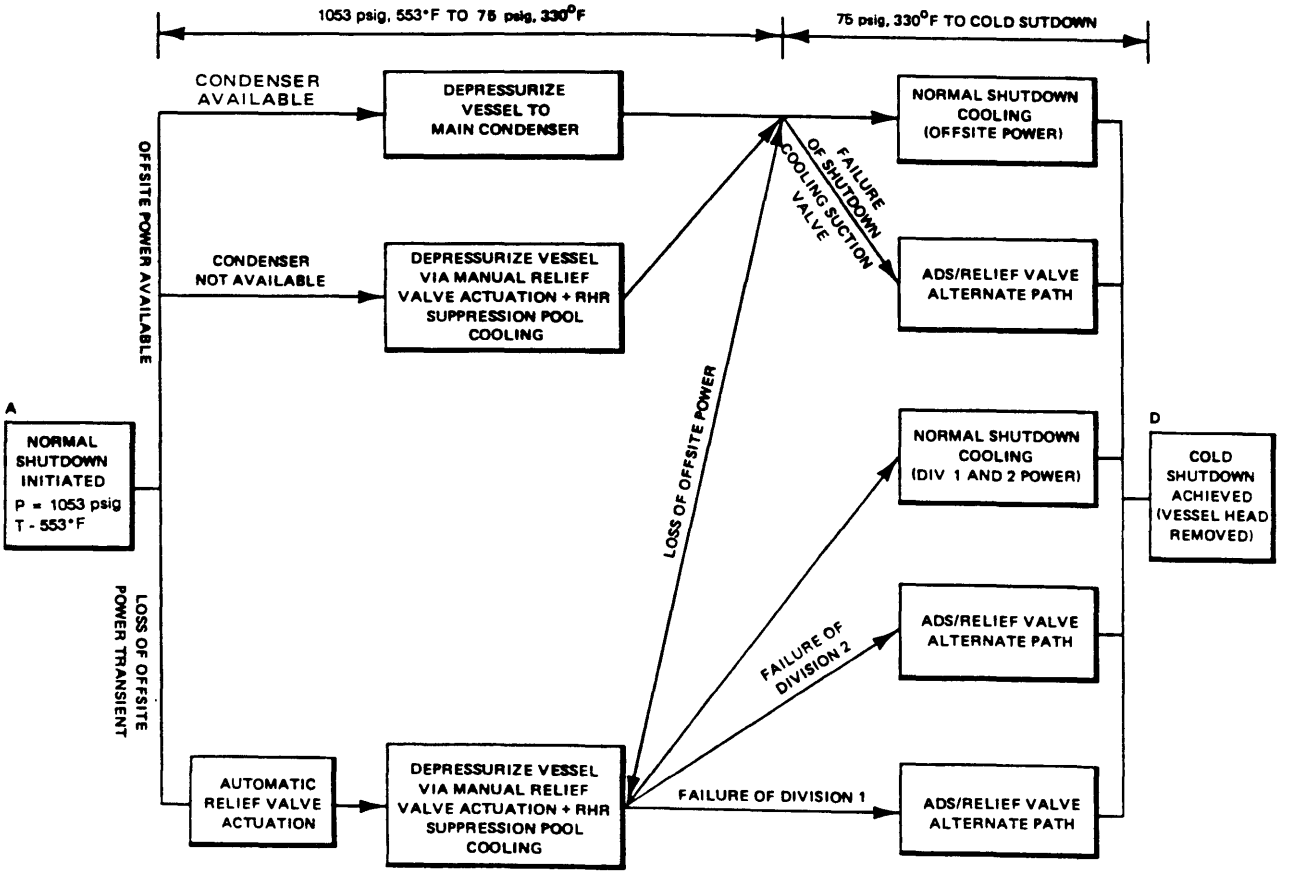


LIMERICK GENERATING STATION
UNITS 2 AND 3
UPDATED FINAL SAFETY ANALYSIS REPORT

LOSS OF ALL FEEDWATER FLOW

FIGURE 15.2-9B

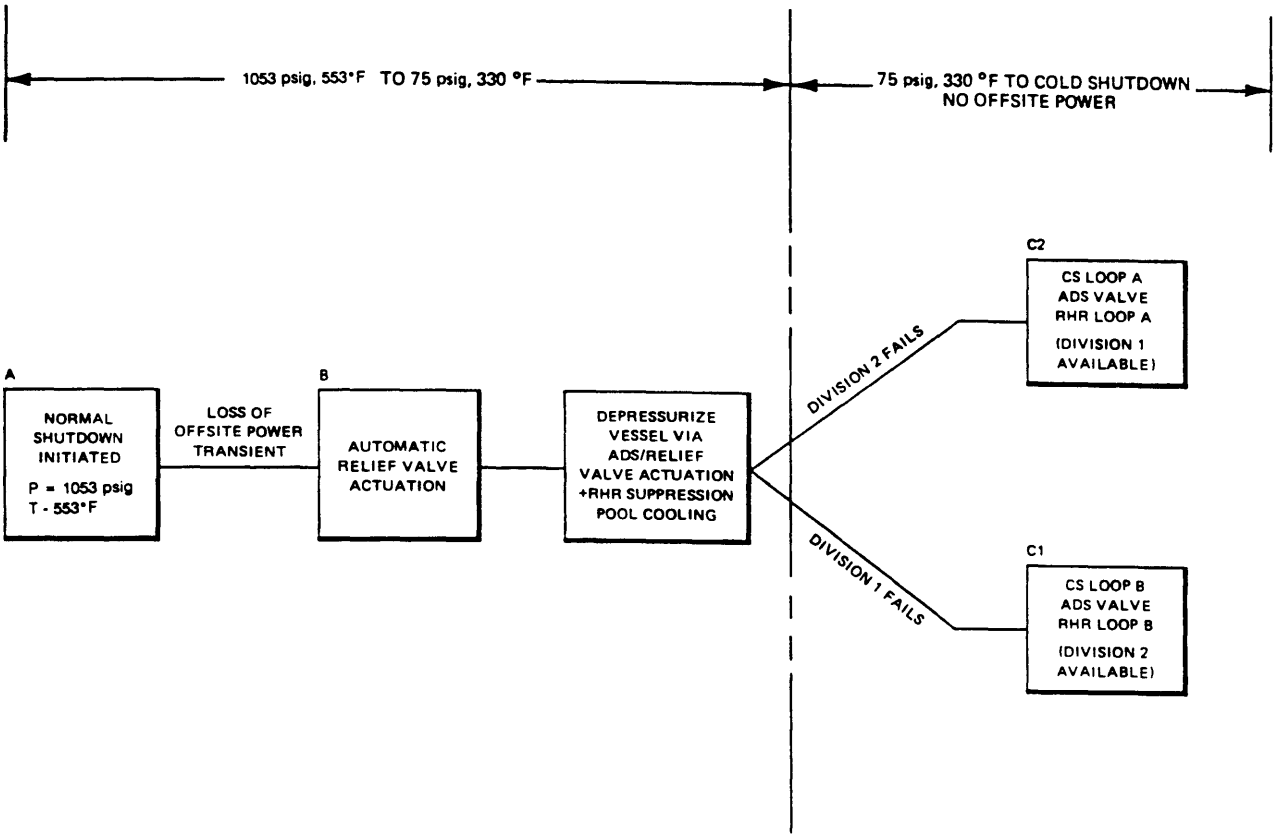
REV. 5
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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUMMARY OF PATHS AVAILABLE TO ACHIEVE COLD SHUTDOWN

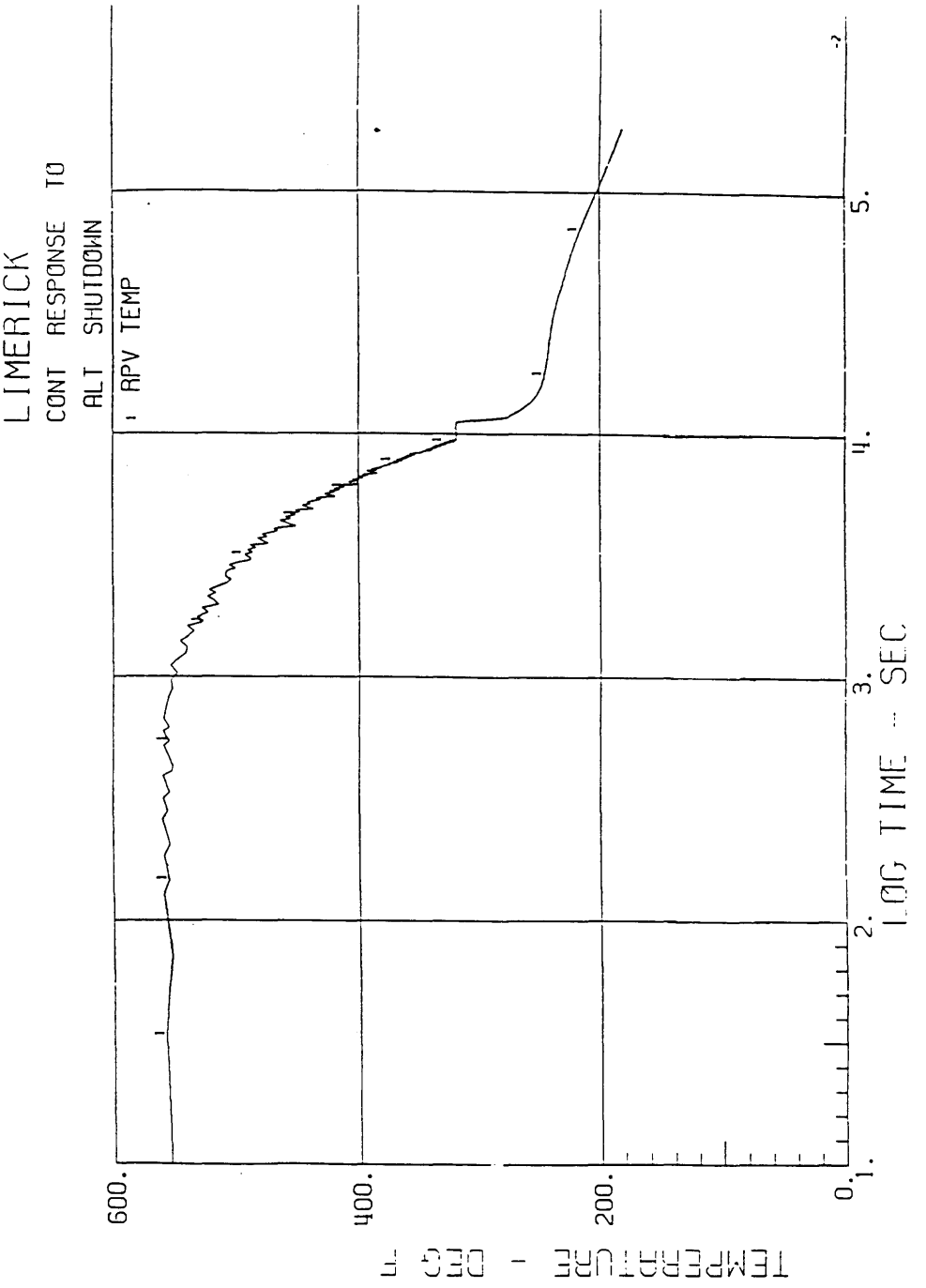
FIGURE 15.2-10 Rev. 5, 4/96



LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

USE OF ADS AND RHR SUPPRESSION POOL COOLING TO ACHIEVE COLD SHUTDOWN

FIGURE 15.2-11 Rev. 5, 4/96

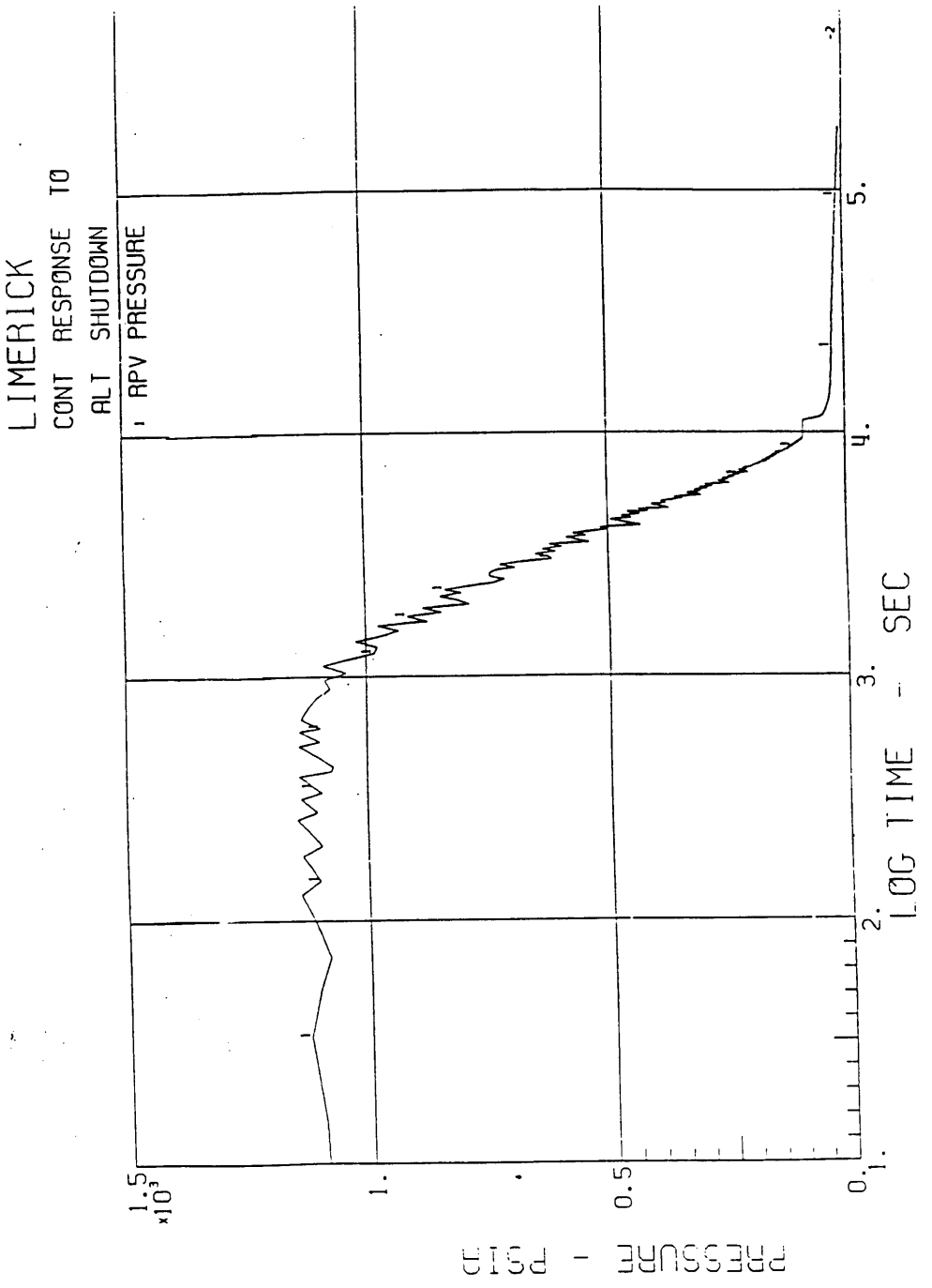


LIMERICK GENERATING STATION
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UPDATED FINAL SAFETY ANALYSIS REPORT

VESSEL TEMPERATURE VS TIME TO ACHIEVE COLD SHUTDOWN WITH ADS AND RHR SUPPRESSION POOL COOLING

FIGURE 15.2-12A

REV. 5
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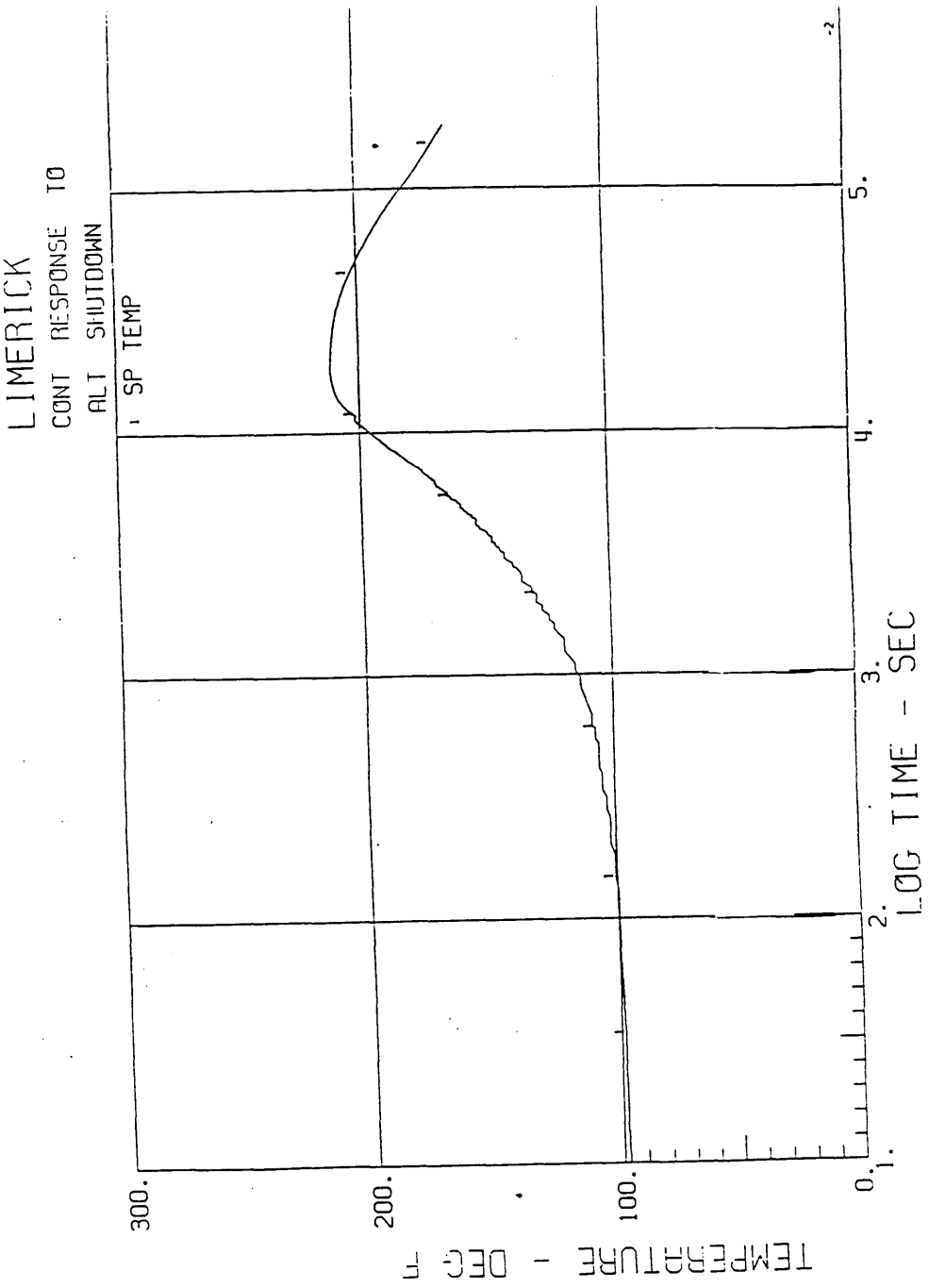


LIMERICK GENERATING STATION
UNITS 2 AND 3
UPDATED FINAL SAFETY ANALYSIS REPORT

VESSEL TEMPERATURE VS TIME TO ACHIEVE COLD SHUTDOWN WITH ADS AND RHR SUPPRESSION POOL COOLING

FIGURE 15.2-12B

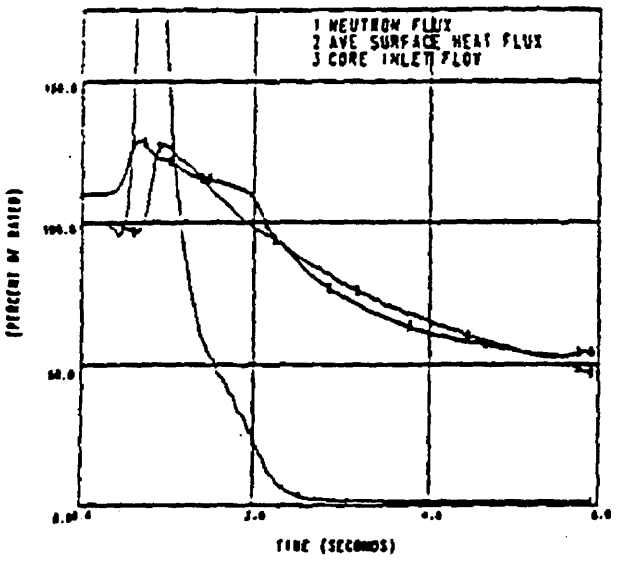
REV. 5
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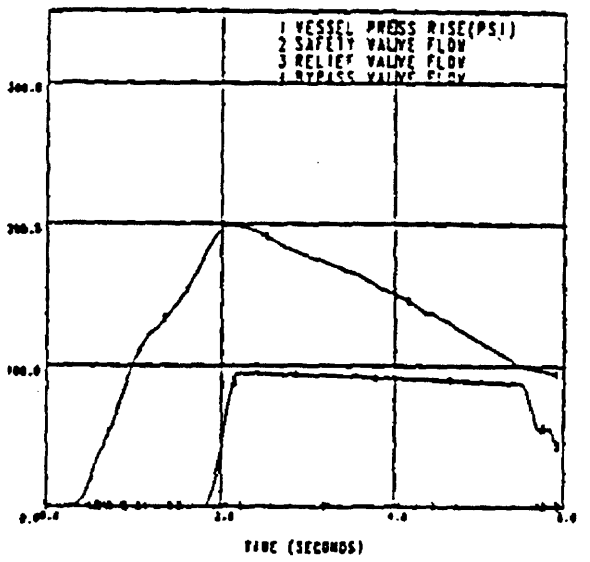


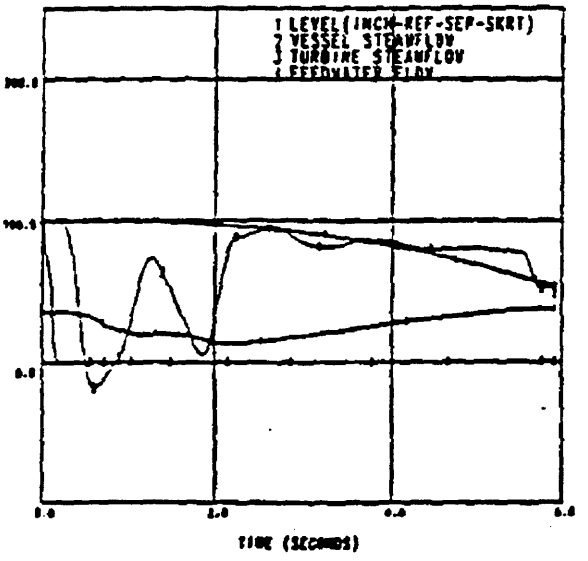
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

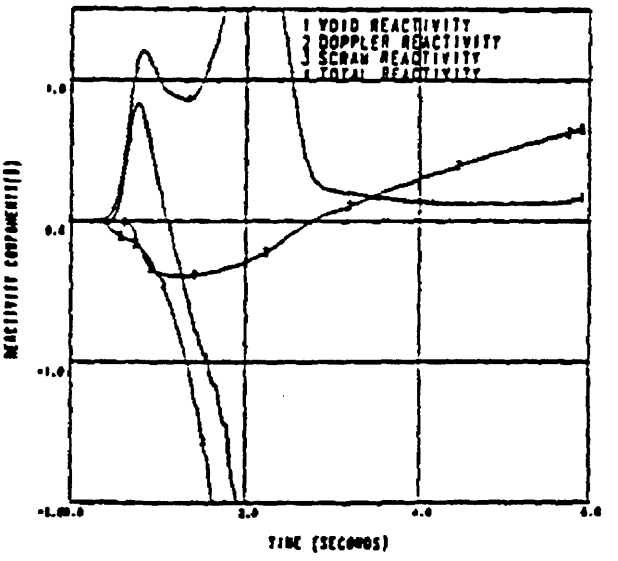
SUPPRESSION POOL TEMPERATURE VS TIME TO ACHIEVE COLD SHUTDOWN WITH ADS AND RHR SUPPRESSION POOL COOLING

FIGURE 15.2-13 Rev. 5, 4/96





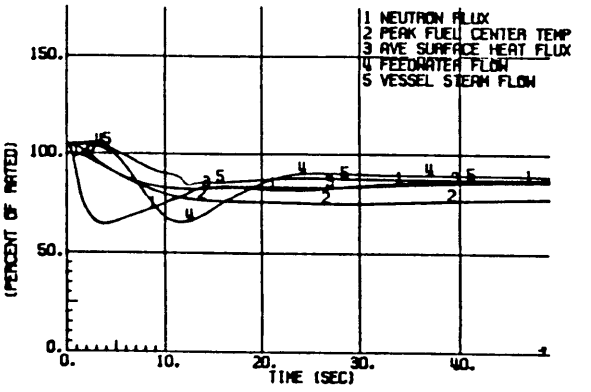


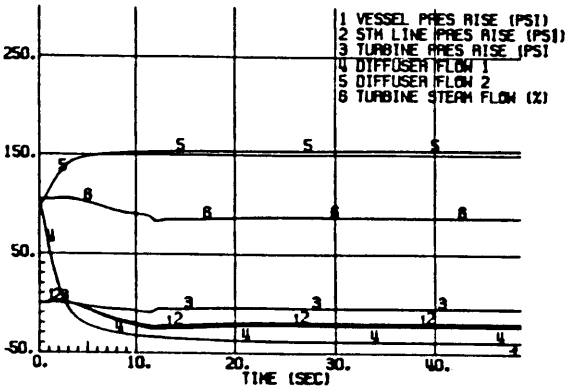


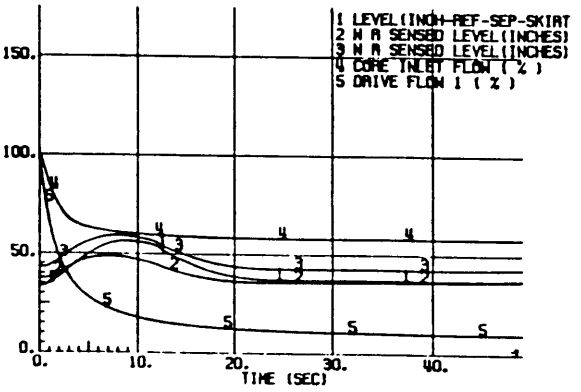
LIMERICK GENERATING STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

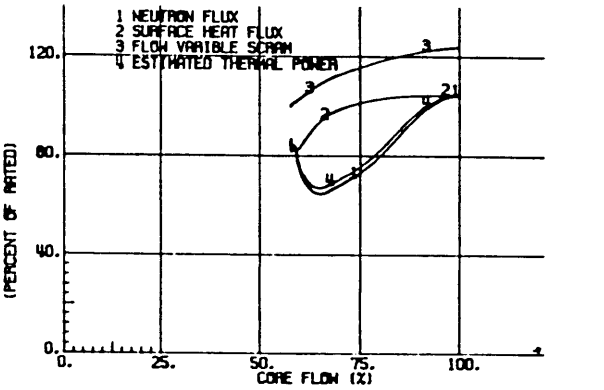
GENERATOR LOAD REJECTION
NO BYPASS,
NO EOC-RPT

FIGURE 15.2-14 Rev. 10 10/00

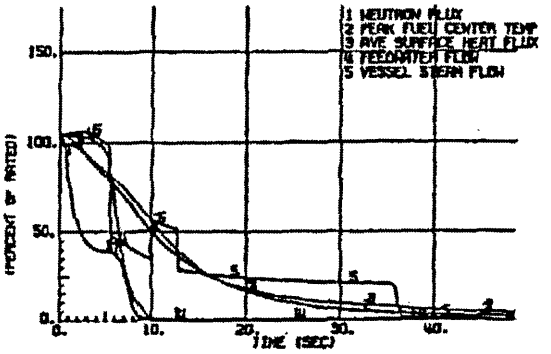


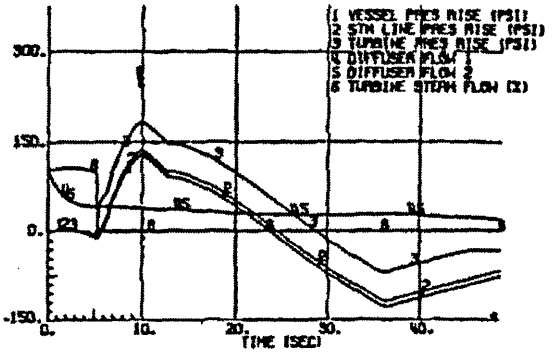


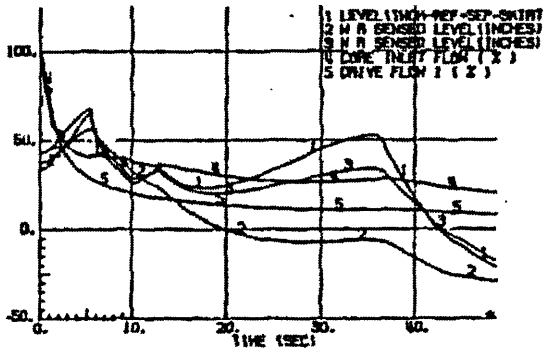


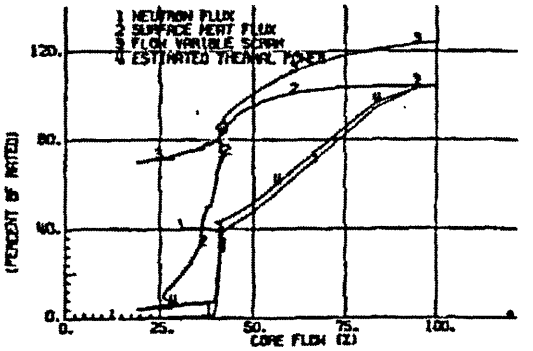


NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

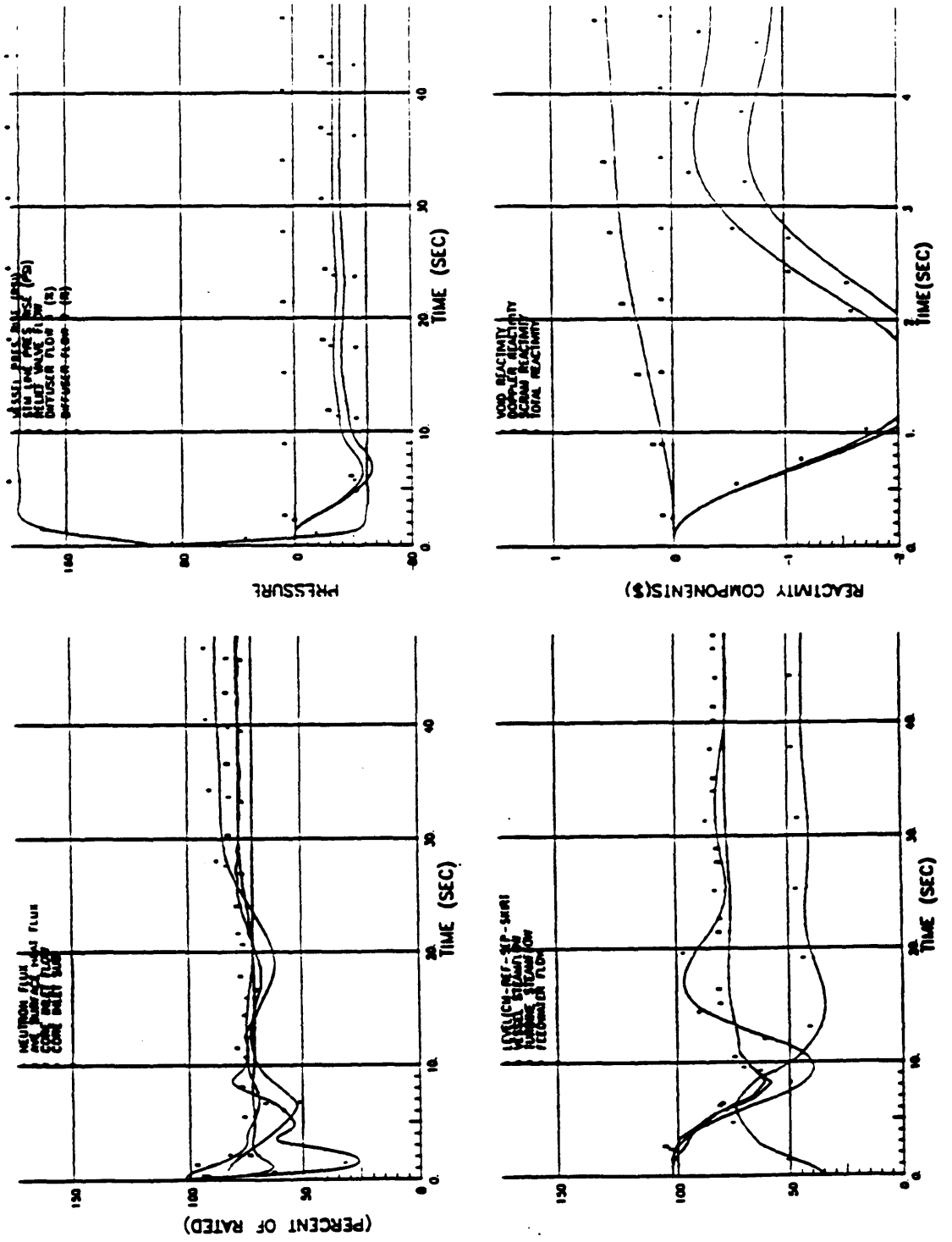








NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SEIZURE OF ONE RECIRCULATION PUMP

FIGURE 15.3-3

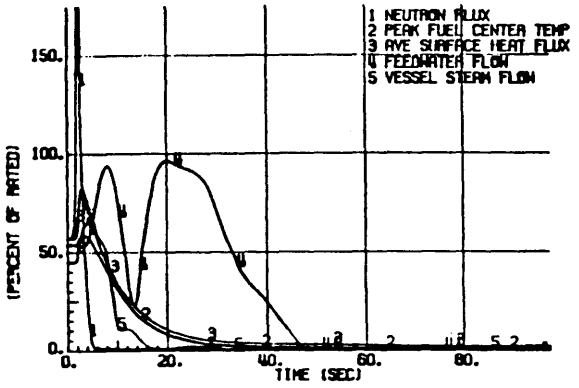
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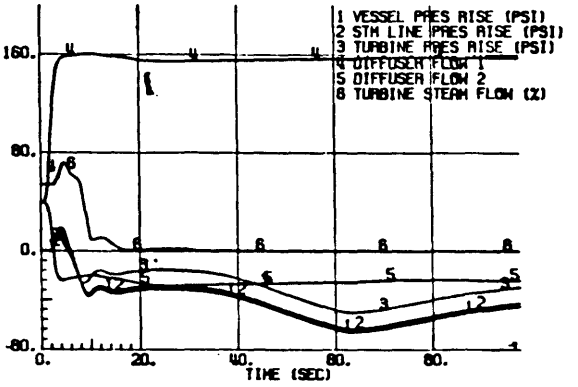
Figure 15.4-1

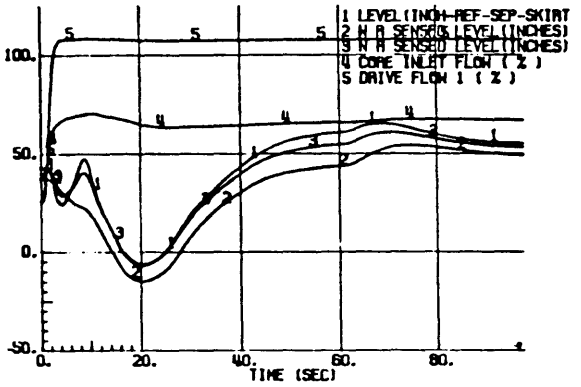
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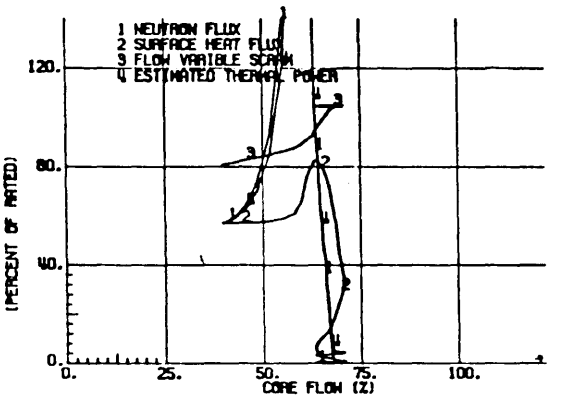
FIGURE 15.4-2

Figure 15.4-2 has been deleted









NOTE: The results presented here are based on original plant conditions. Because this is not a limiting transient, this event was not reanalyzed for rerated conditions. However, the general trends and characteristics as shown here are not expected to change.

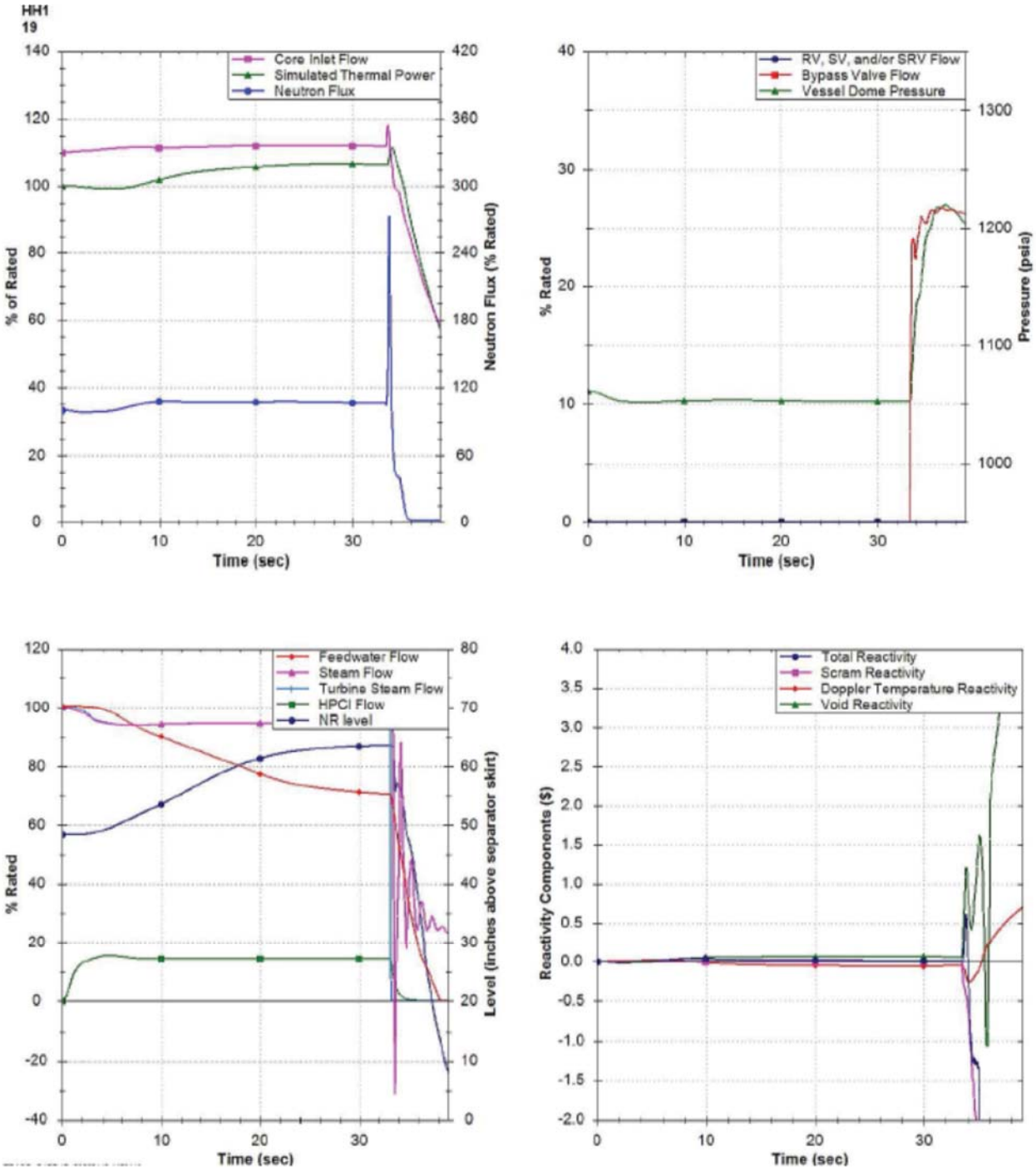
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RECIRCULATION FAILURE – INCREASING FLOW

FIGURE 15.4-3

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FIGURE 15.4-4 - Deleted

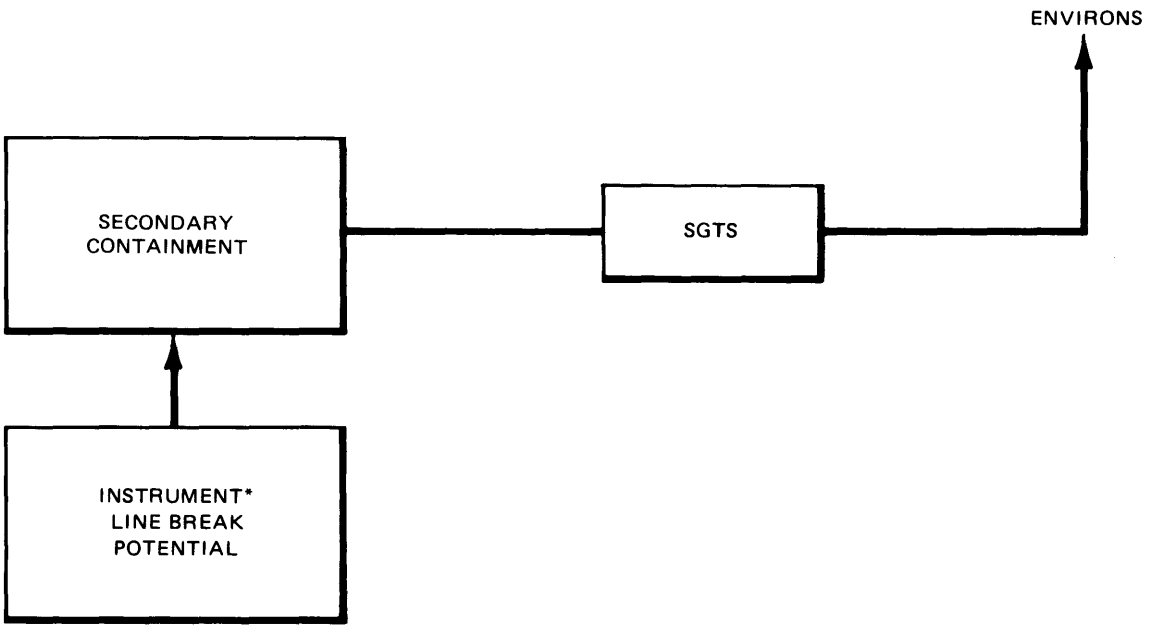


NOTE:
These results are based on GNF3 and are representative for this event. The general trends and characteristics as shown here are not expected to change.

LIMERICK GENERATING STATION
UNIT 1 AND 2
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INADVERTANT HPCI PUMP START
ICF

FIGURE 15.5-1 **Rev. 22, 09/24**

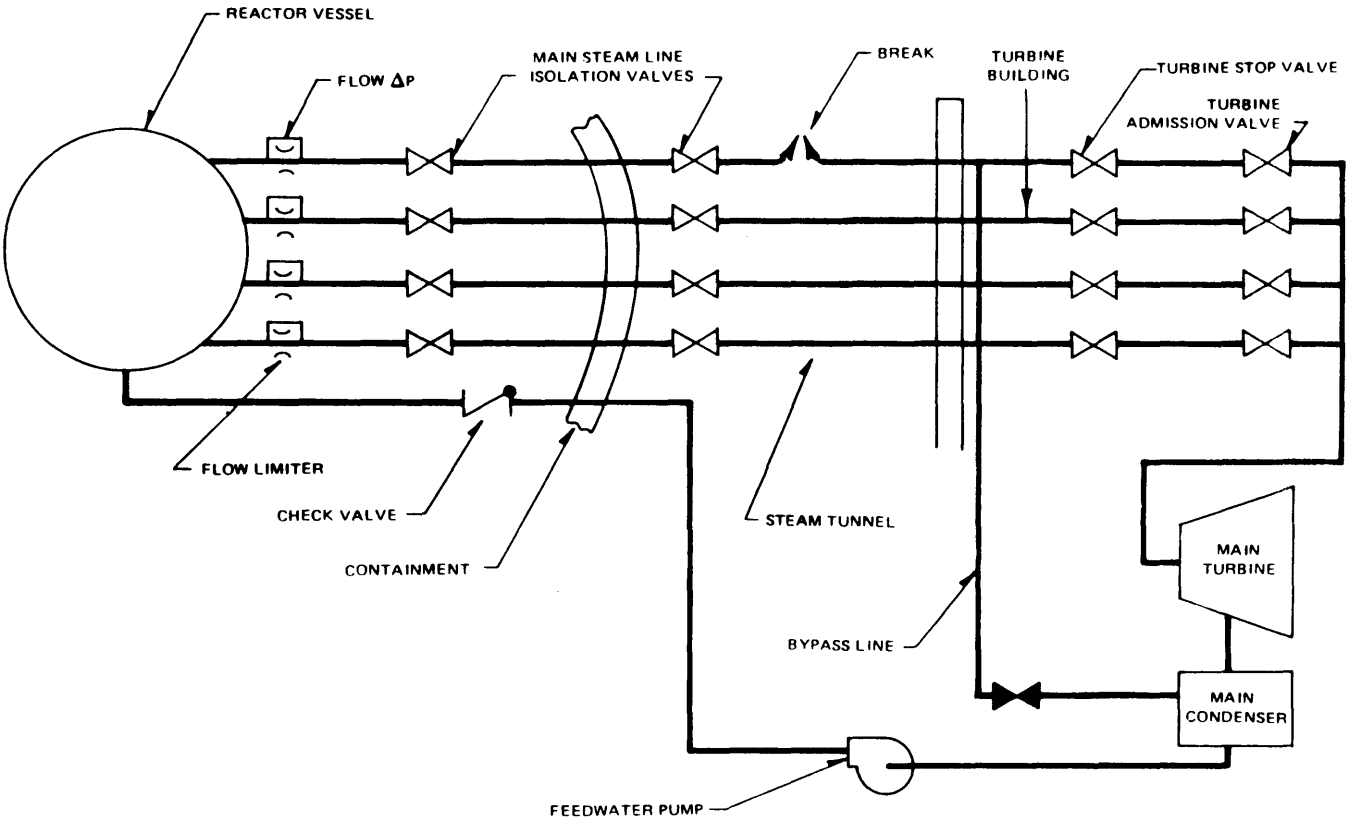


*LIMITING CASE RESULTS PRESENTED

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LEAKAGE PATH FOR INSTRUMENT LINE BREAK

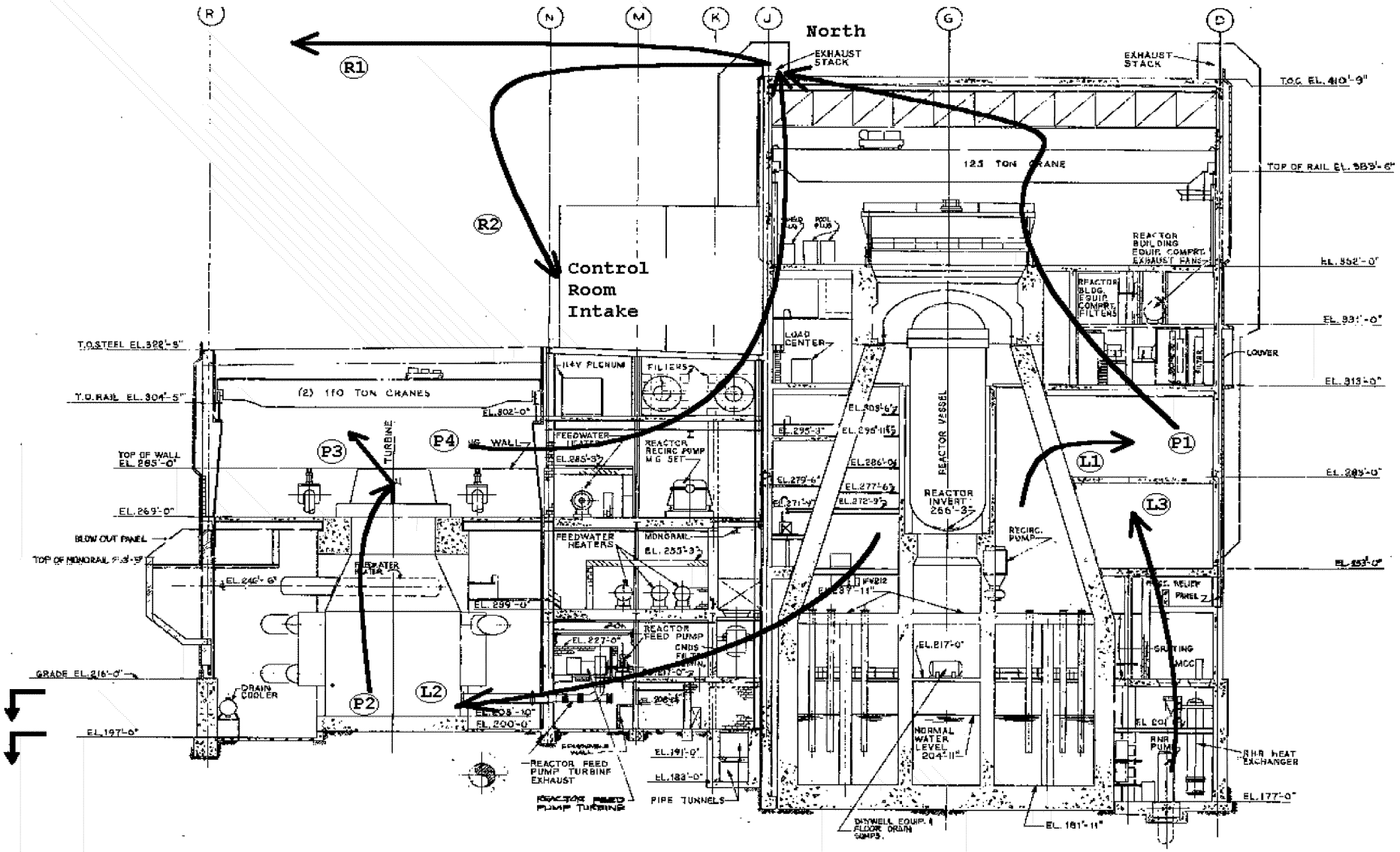
FIGURE 15.6-1



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

STEAM FLOW SCHEMATIC FOR STEAM BREAK OUTSIDE PRIMARY CONTAINMENT

FIGURE 15.6-2



LIMERICK GENERATING STATION
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LAYOUT OF INTAKES AND RELEASE POINTS

FIGURE 15.6-3 (Sheet 1 of 3) Rev. 14, 09/08

Figure 15.6-3 (Cont'd)

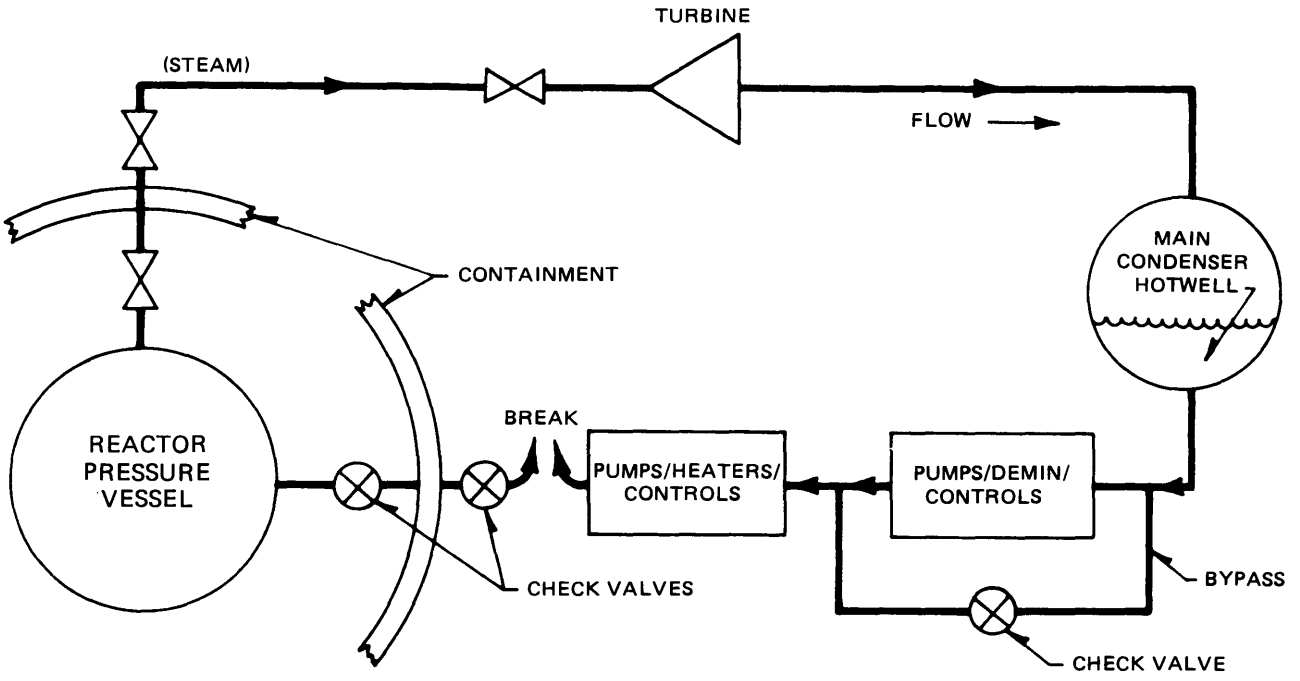
Layout of Intakes and Release Points
(Sheet 2 of 3)

Leakage Rates and Secondary Containment Mixing Parameters		
Path	**Description**	**Parameters & Values**
L_1	Primary Containment Leakage to Secondary Containment	Leak Rate: L_a = 0.50 %/day, 0 - 15.5 min after start of gap release. Release is unfiltered through the North Stack during drawdown period.
P_1	Release from Secondary Containment to Environment through SGTS Filter	L_a = 0.50 %/day, 15.5 min - 24hr Release is SGTS filtered through North Stack. 0.5 x L_a = 0.25 %/day, 1 - 30days Release is SGTS filtered through North Stack.
L_2	MSIV Leakage to Condenser Environment	Leak Rate: Based on LLRT acceptance criterion of 200 scfh for all main steam (MS) lines, 100 scfh maximum for any one MS line when measured at greater than or equal to 22 psig. Two steam lines are each treated as two-node well-mixed volumes each with 100 scfh flow, after various adjustments discussed below. Leak rate reduced to 55.1% after 24 hours. Release is from Turbine Building, unfiltered through North Stack. Analytically, flow is direct from the condenser to the North Stack.
P_2	Leakage Well Mixed in HP Turbine/Condenser Shell. No credit for transport to other shells through available opening. No credit for substantial plateout potential on Condenser Tubing.	
P_3	Leak from Turbine Shaft Seals to Turbine Building Atmosphere	
P_4	Flow from Turbine Building to North Stack. No credit for mixing or holdup or deposition in Turbine Building. No filtration is provided for this flow.	
L_3	**ECCS Leakage (Supp. Pool Water Source) to Secondary Containment**	Leak Rate: 5 gpm, 0 - 15.5 min {2x administrative limit} Release is unfiltered through North Stack during drawdown period.
P_1	Release from Secondary Containment to Environment through SGTS Filter	5 gpm, 15.5 min - 30days {2x administrative limit} Release is SGTS filtered through North Stack.

Figure 15.6-3 (Cont'd)

Layout of Intakes and Release Points
(Sheet 3 of 3)

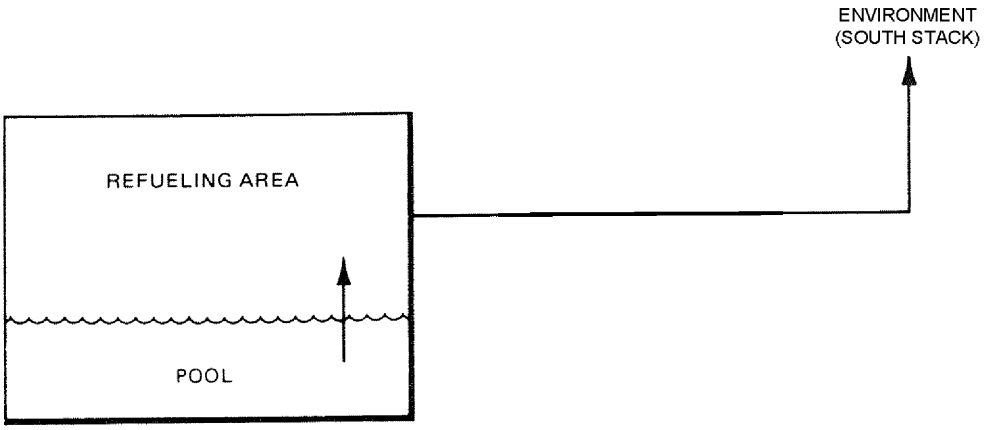
P_1	**Release of Secondary Containment Atmosphere to the Environment**	Secondary Containment mixing credit in 50% of the Reactor Enclosure Volume. RERS provides the mixing mechanism. Volume (for analysis) = 900,000 cubic feet Outflow (for analysis) = 3000 cfm during drawdown period and 2500 cfm thereafter. For the first 15.5 minutes, flow is directed through the North Stack without RERS or SGTS filter credit.
R_1	Control Room Intake from the Release to the Environment	525 cfm Maximum filtered intake, plus 225 cfm of unfiltered inleakage. Total CREFAS flow is 2700 cfm, with recirculation being the balance after intake is subtracted. CREFAS filters credited at 99% for aerosols (based on HEPA) and 95% for charcoal absorbers (for elemental and organic iodine.)
	Control Room Exhaust to Environment	750 cfm, to balance with intake and inleakage
R_2	Release to Environment for Offsite Dose Assessment Purposes	R_1 and R_2 include Primary Containment to Secondary Containment, ECCS Leakage, and MSIV Leakage related releases



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LEAKAGE PATH FOR FEEDWATER LINE BREAK OUTSIDE PRIMARY CONTAINMENT

FIGURE 15.6-4

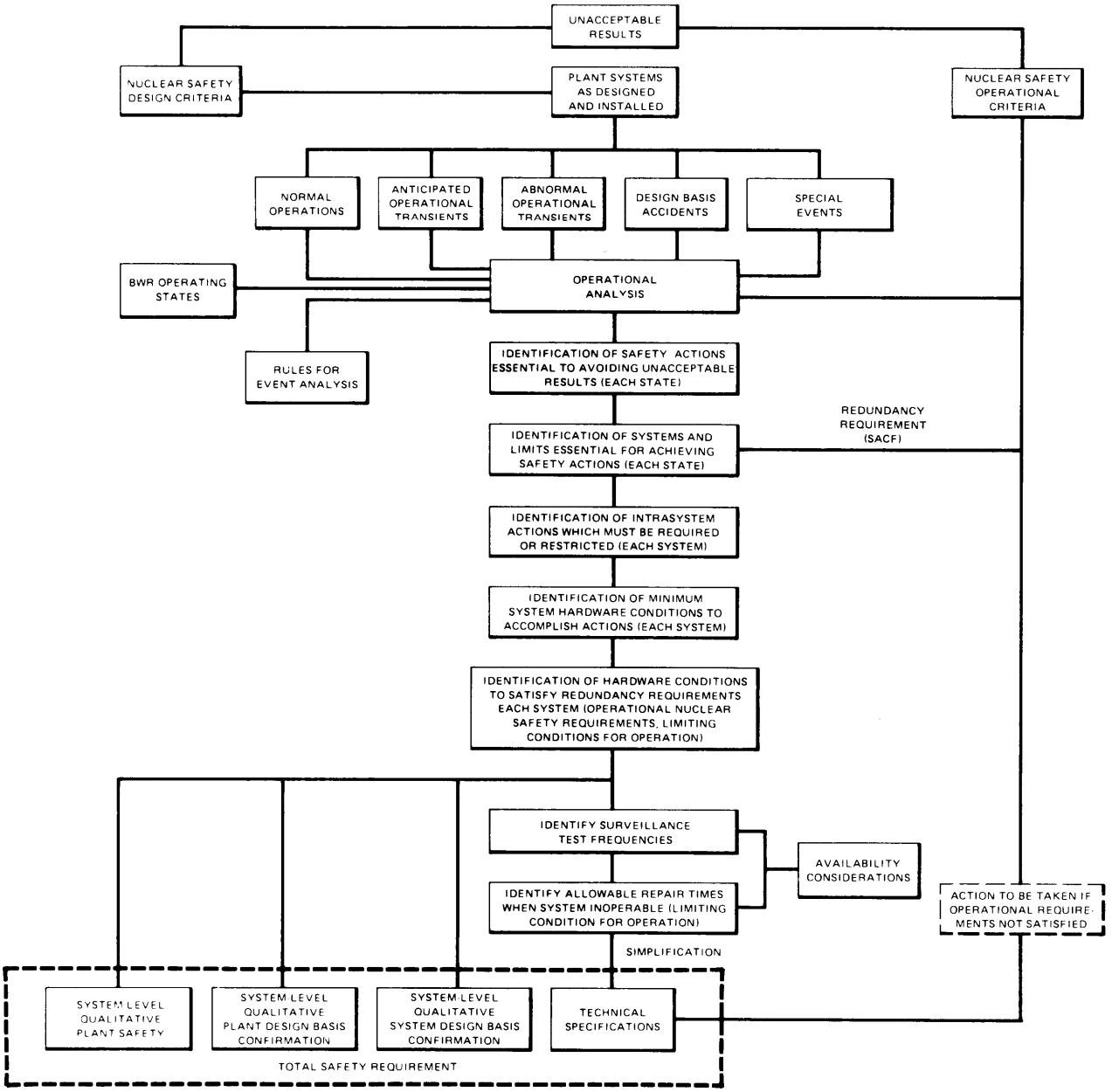


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LEAKAGE PATH FOR FUEL-HANDLING ACCIDENT

FIGURE 15.7-1

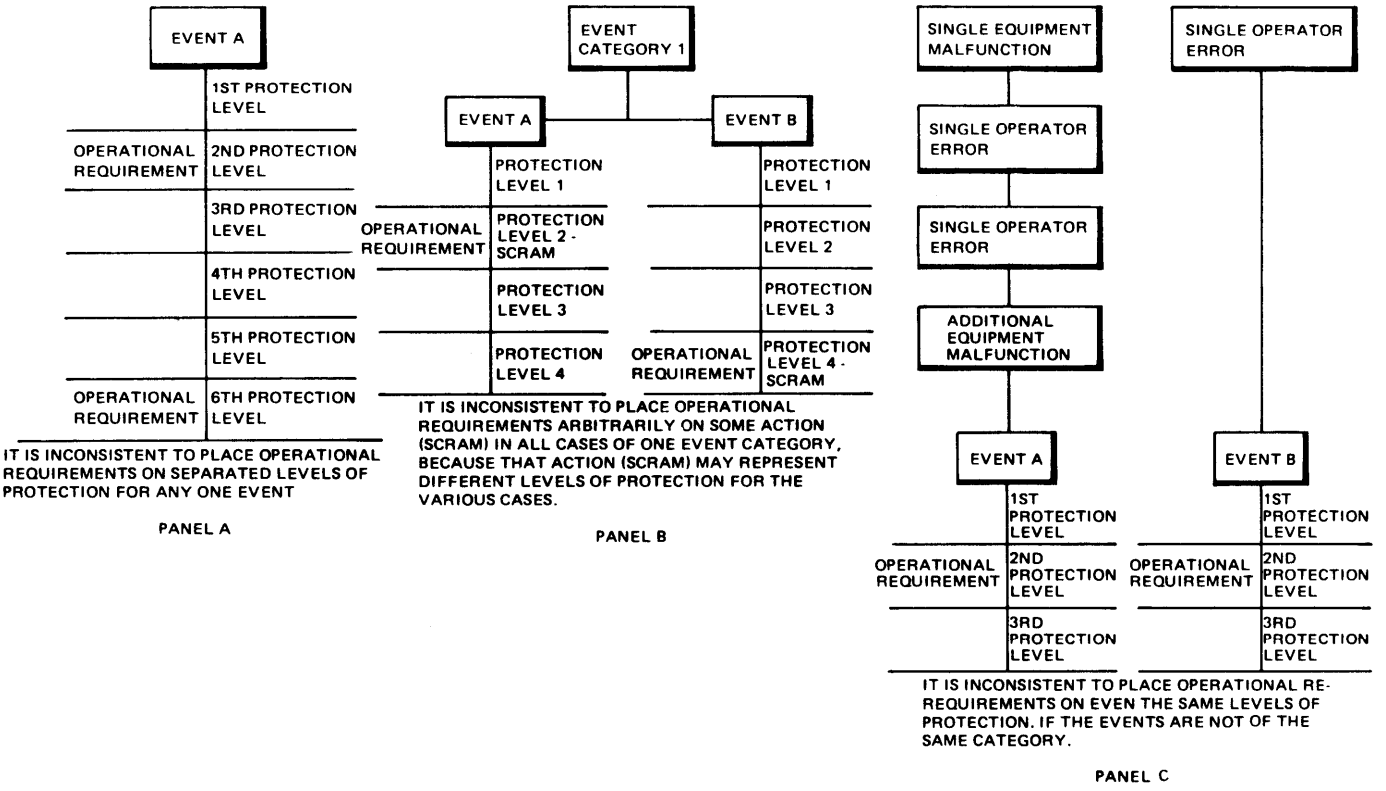
REV. 14, 09/08



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

BLOCK DIAGRAM OF METHOD USED TO DERIVE NUCLEAR SAFETY OPERATIONAL REQUIREMENTS SYSTEM, LEVEL QUALITATIVE FMEA, DESIGN BASIS CONFIRMATION AUDITS AND TECHNICAL SPECIFICATIONS

FIGURE 15.9-1

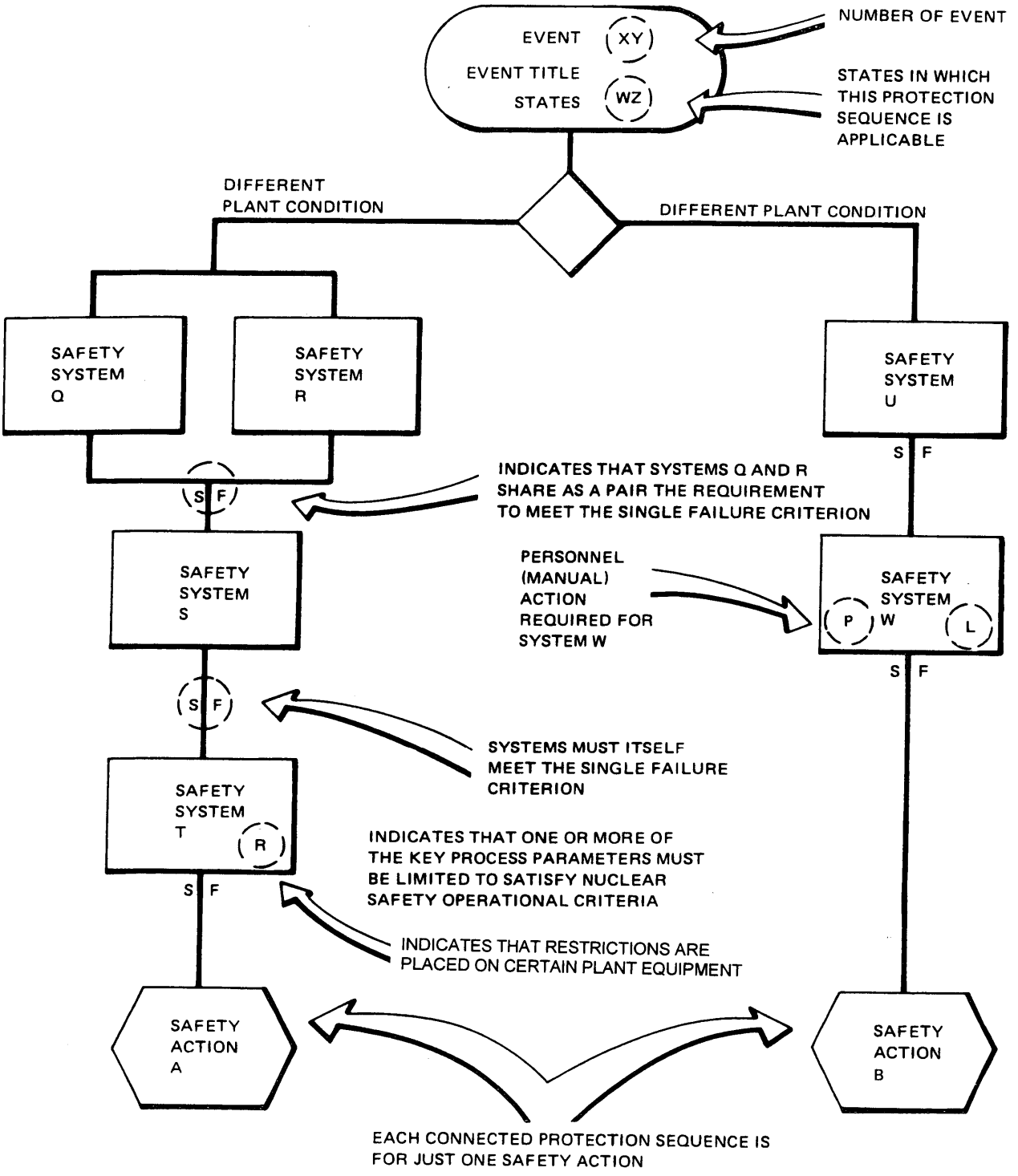


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

POSSIBLE INCONSISTENCIES IN THE SELECTION OF NUCLEAR SAFETY OPERATIONAL REQUIREMENTS

FIGURE 15.9-2

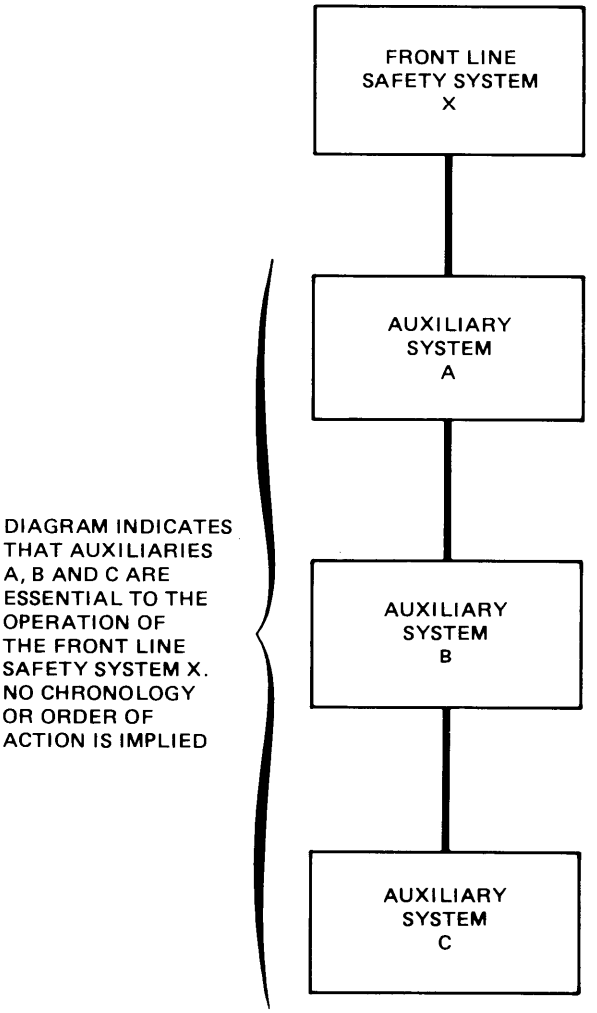
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LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FORMAT FOR PROTECTION SEQUENCE DIAGRAMS

FIGURE 15.9-4 Rev. 11 9/02

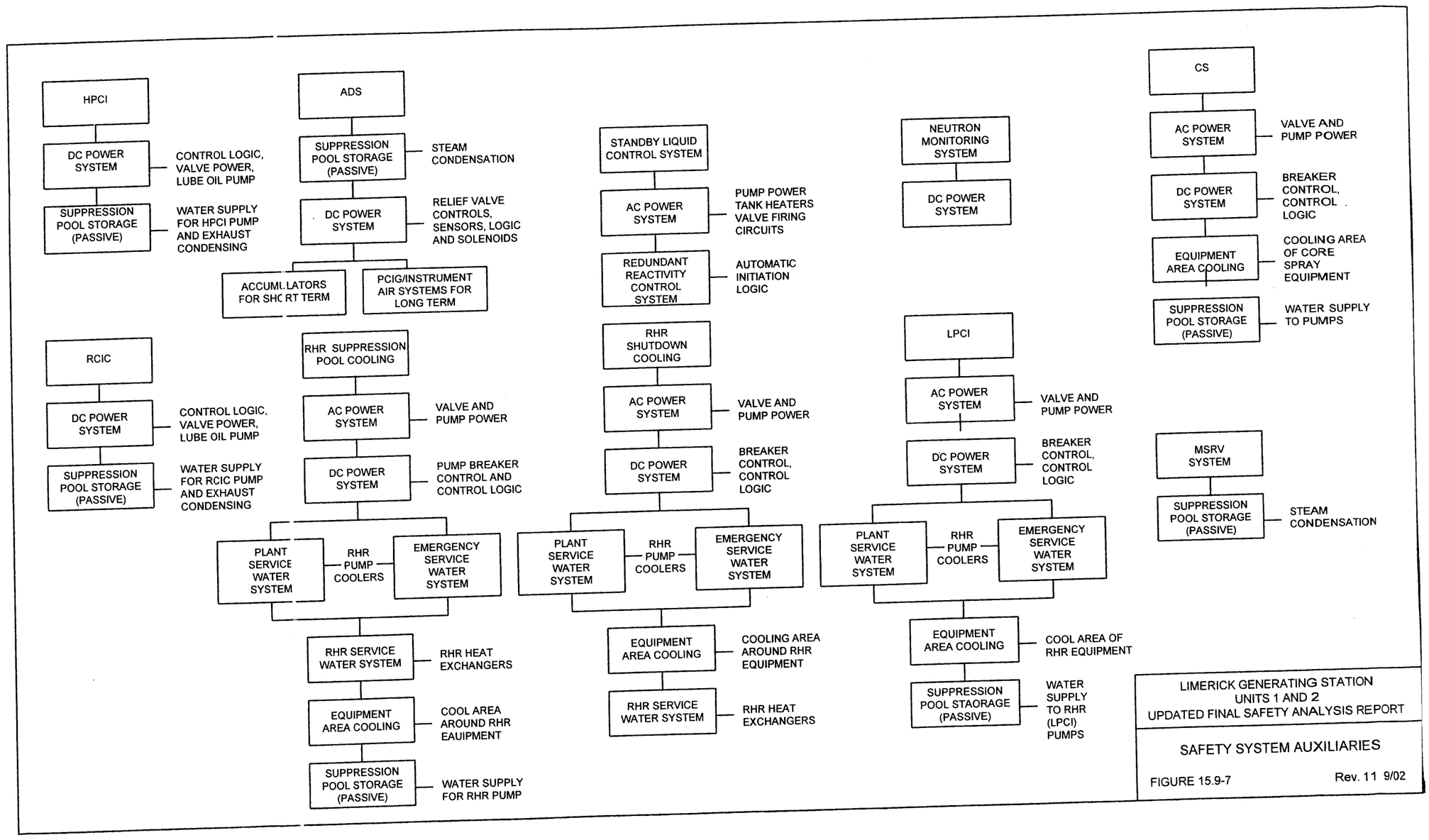


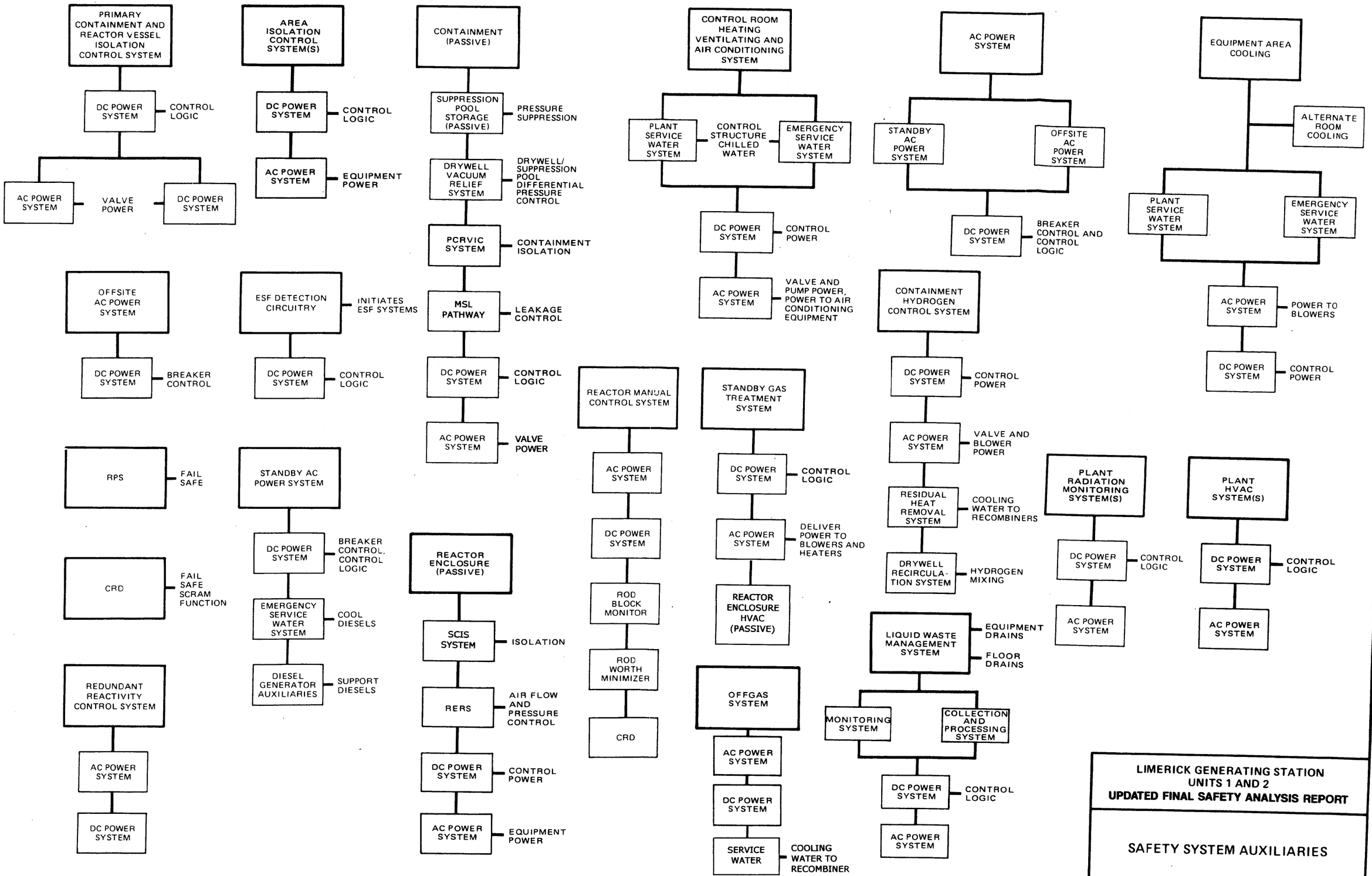
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FORMAT FOR
SAFETY SYSTEM
AUXILIARY DIAGRAMS

FIGURE 15.0-5

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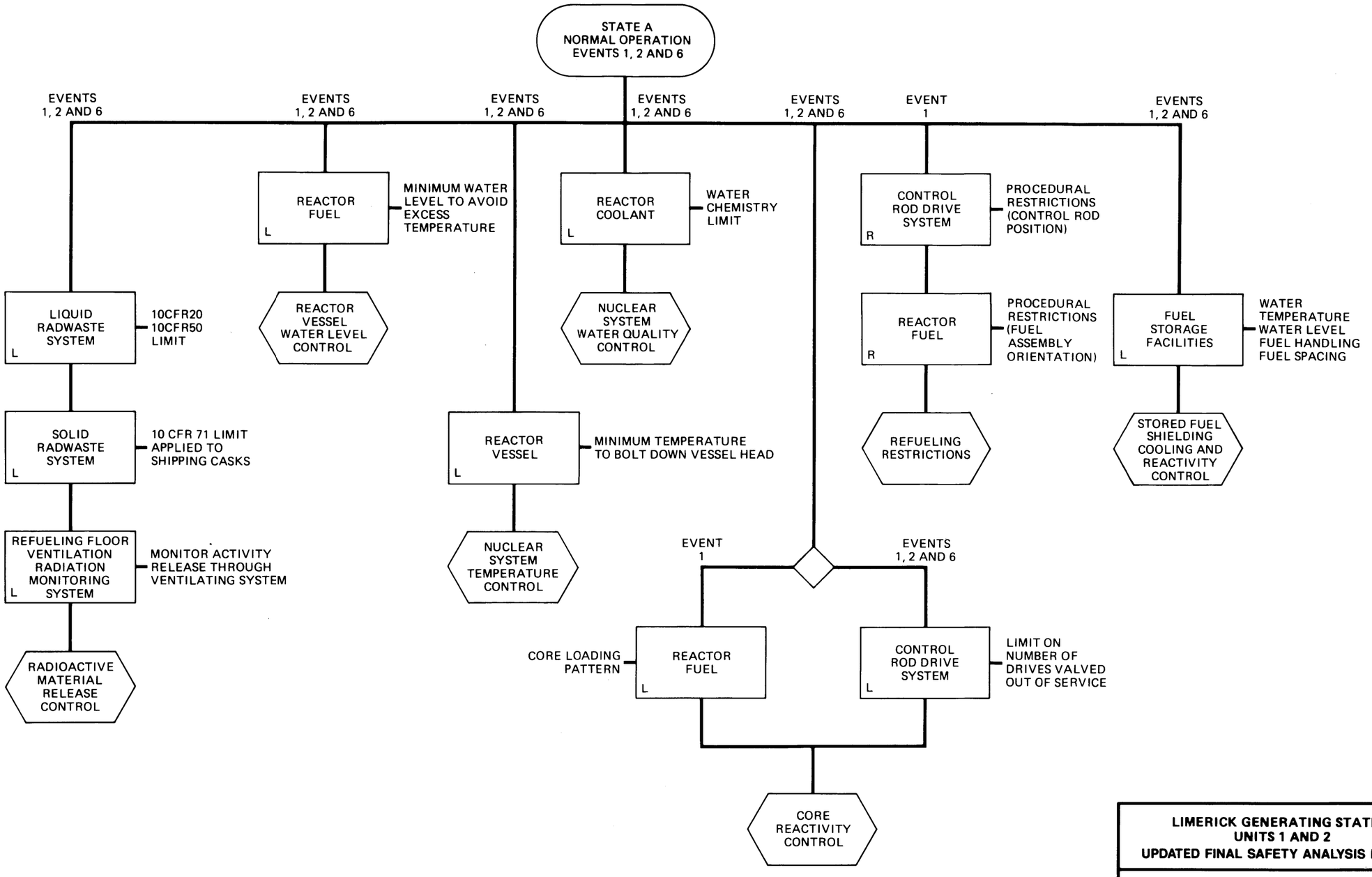

HPCI
DC POWER SYSTEM
CONTROL LOGIC, VALVE POWER, LUBE OIL PUMP
SUPPRESSION POOL STORAGE (PASSIVE)
WATER SUPPLY FOR HPCI PUMP AND EXHAUST CONDENSING
ADS
SUPPRESSION POOL STORAGE (PASSIVE)
STEAM CONDENSATION
DC POWER SYSTEM
RELIEF VALVE CONTROLS, SENSORS, LOGIC AND SOLENOIDS
ACCUMULATORS FOR SHORT TERM
PCIG/INSTRUMENT AIR SYSTEMS FOR LONG TERM
STANDBY LIQUID CONTROL SYSTEM
AC POWER SYSTEM
PUMP POWER TANK HEATERS VALVE FIRING CIRCUITS
REDUNDANT REACTIVITY CONTROL SYSTEM
AUTOMATIC INITIATION LOGIC
NEUTRON MONITORING SYSTEM
DC POWER SYSTEM
CS
AC POWER SYSTEM
VALVE AND PUMP POWER
DC POWER SYSTEM
BREAKER CONTROL, CONTROL LOGIC
EQUIPMENT AREA COOLING
COOLING AREA OF CORE SPRAY EQUIPMENT
SUPPRESSION POOL STORAGE (PASSIVE)
WATER SUPPLY TO PUMPS
RCIC
DC POWER SYSTEM
CONTROL LOGIC, VALVE POWER, LUBE OIL PUMP
SUPPRESSION POOL STORAGE (PASSIVE)
WATER SUPPLY FOR RCIC PUMP AND EXHAUST CONDENSING
RHR SUPPRESSION POOL COOLING
AC POWER SYSTEM
VALVE AND PUMP POWER
DC POWER SYSTEM
PUMP BREAKER CONTROL AND CONTROL LOGIC
PLANT SERVICE WATER SYSTEM
RHR PUMP COOLERS
EMERGENCY SERVICE WATER SYSTEM
RHR SERVICE WATER SYSTEM
RHR HEAT EXCHANGERS
EQUIPMENT AREA COOLING
COOL AREA AROUND RHR EAUIPMENT
SUPPRESSION POOL STORAGE (PASSIVE)
WATER SUPPLY FOR RHR PUMP
RHR SHUTDOWN COOLING
AC POWER SYSTEM
VALVE AND PUMP POWER
DC POWER SYSTEM
BREAKER CONTROL, CONTROL LOGIC
PLANT SERVICE WATER SYSTEM
RHR PUMP COOLERS
EMERGENCY SERVICE WATER SYSTEM
EQUIPMENT AREA COOLING
COOLING AREA AROUND RHR EQUIPMENT
RHR SERVICE WATER SYSTEM
RHR HEAT EXCHANGERS
LPCI
AC POWER SYSTEM
VALVE AND PUMP POWER
DC POWER SYSTEM
BREAKER CONTROL, CONTROL LOGIC
PLANT SERVICE WATER SYSTEM
RHR PUMP COOLERS
EMERGENCY SERVICE WATER SYSTEM
EQUIPMENT AREA COOLING
COOL AREA OF RHR EQUIPMENT
SUPPRESSION POOL STAORAGE (PASSIVE)
WATER SUPPLY TO RHR (LPCI) PUMPS
MSRV SYSTEM
SUPPRESSION POOL STORAGE (PASSIVE)
STEAM CONDENSATION
LIMERICK GENERATING STATION
UNITS 1 AND 2
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SAFETY SYSTEM AUXILIARIES
FIGURE 15.9-7
Rev. 11 9/02



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UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SAFETY SYSTEM AUXILIARIES

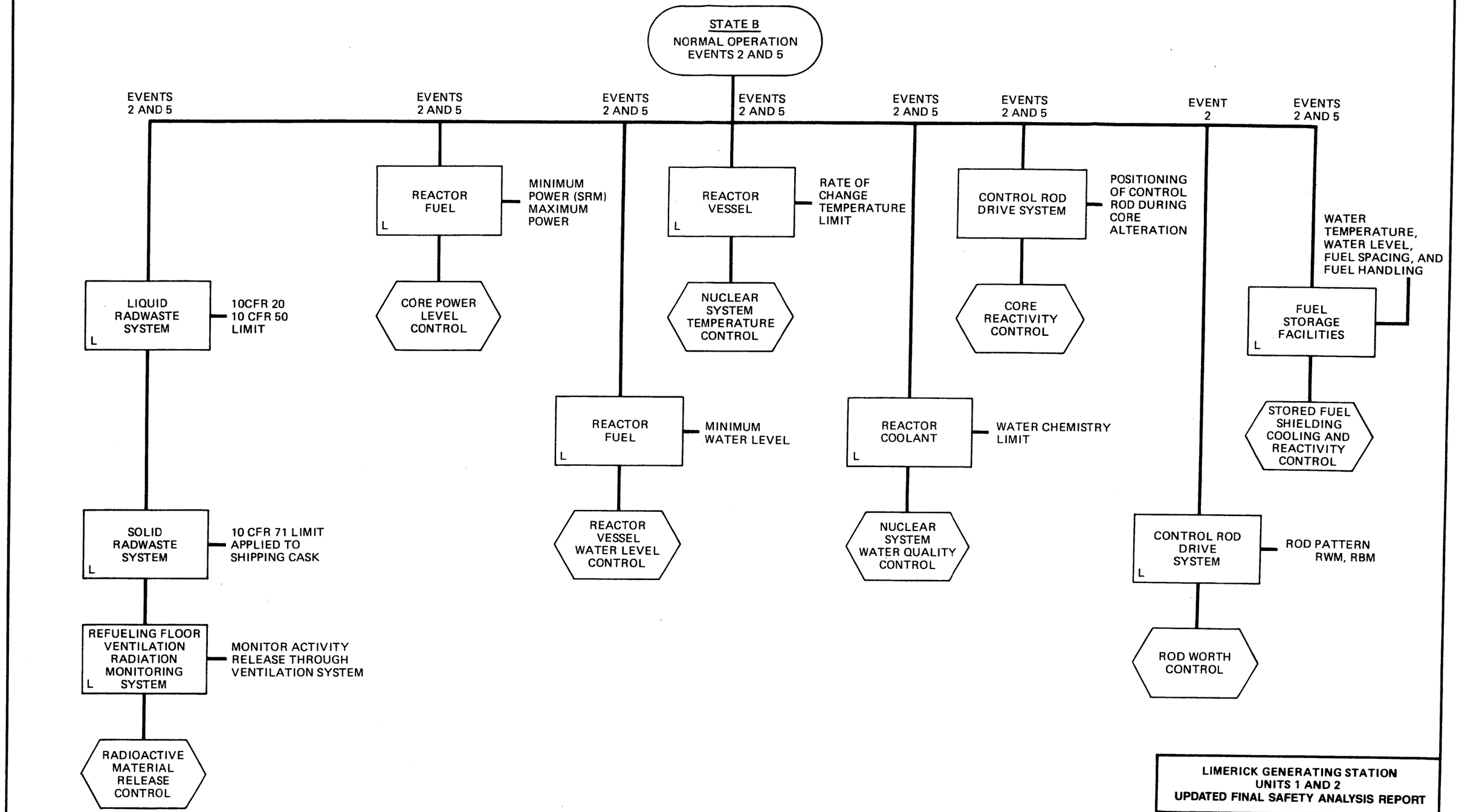
FIGURE 15.9-8 Rev. 11 9/02



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UNITS 1 AND 2
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SAFETY ACTION SEQUENCES FOR NORMAL OPERATION IN STATE A

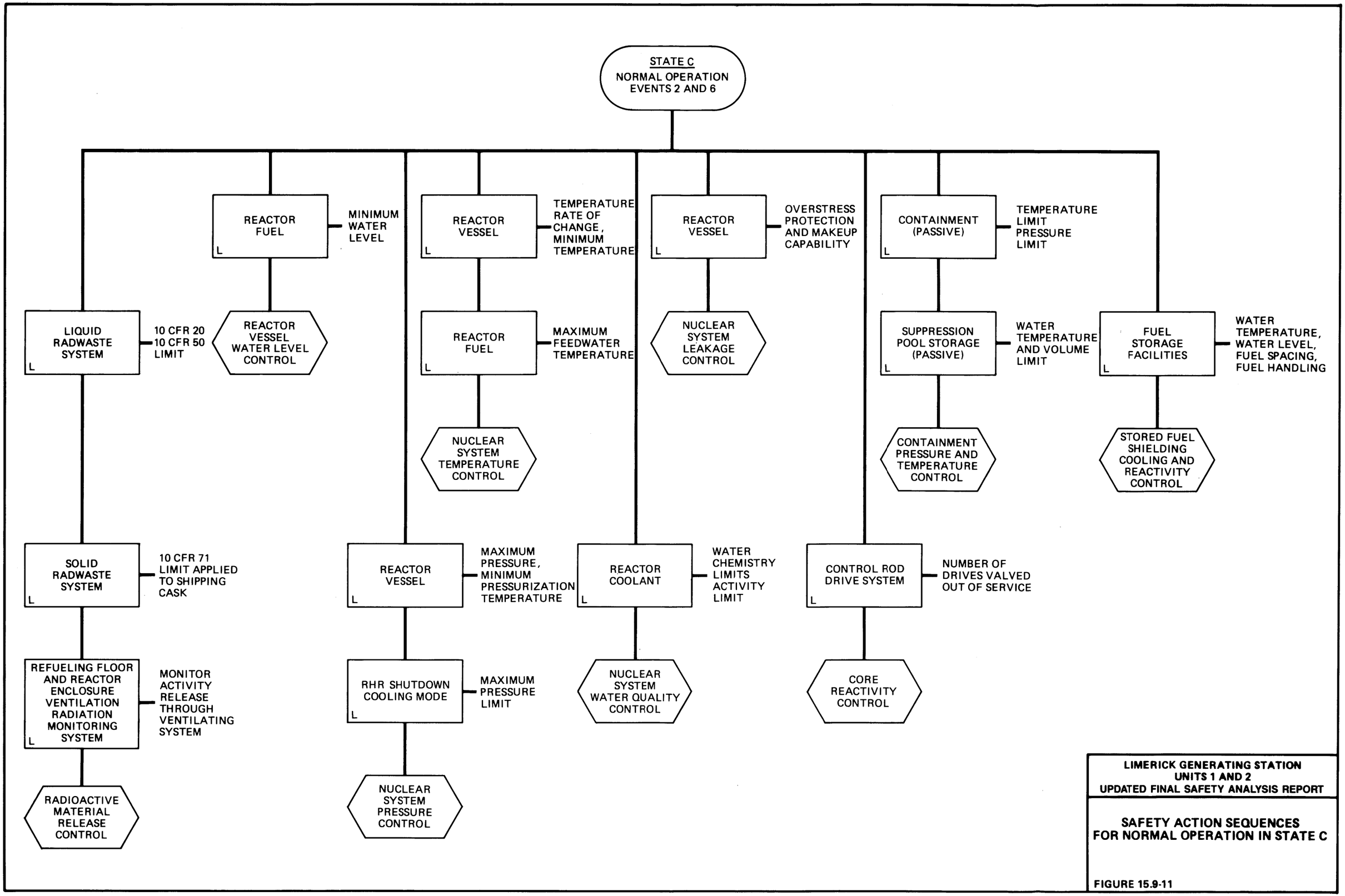
FIGURE 15.9-9



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SAFETY ACTION SEQUENCES
FOR NORMAL OPERATION IN STATE B

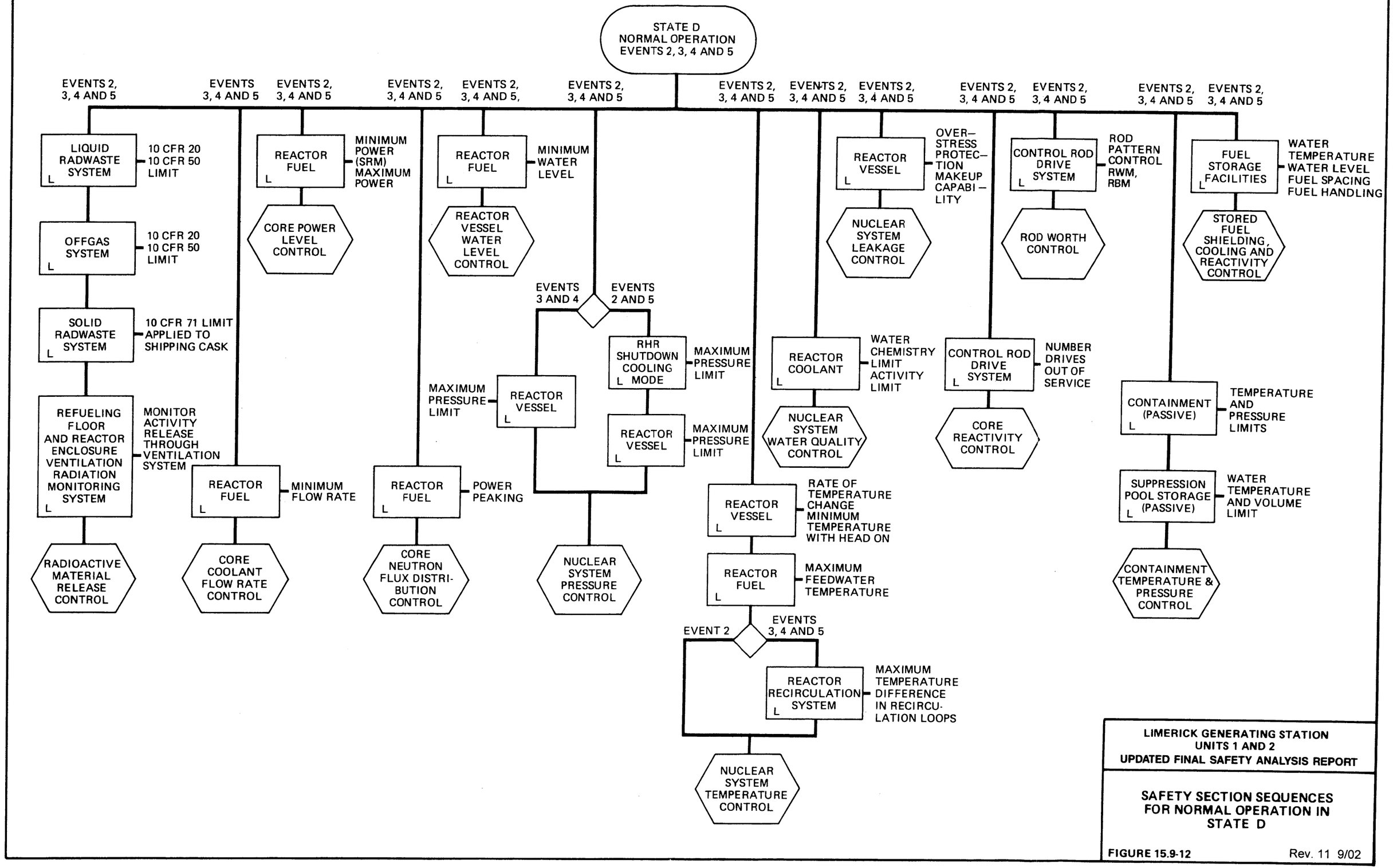
FIGURE 15.9-10 Rev. 11 9/02



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SAFETY ACTION SEQUENCES FOR NORMAL OPERATION IN STATE C

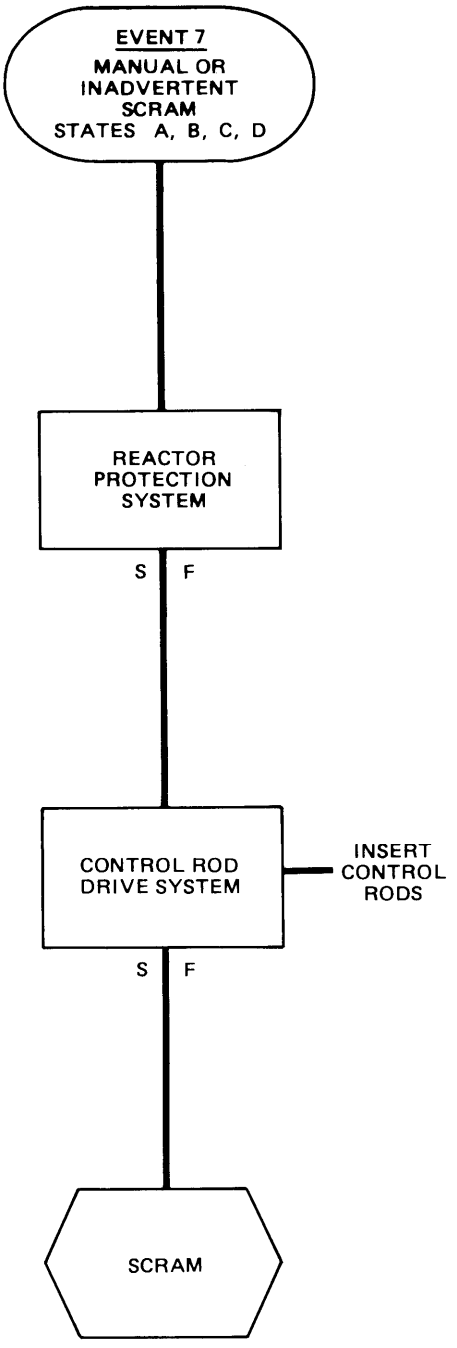
FIGURE 15.9-11



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SAFETY SECTION SEQUENCES FOR NORMAL OPERATION IN STATE D

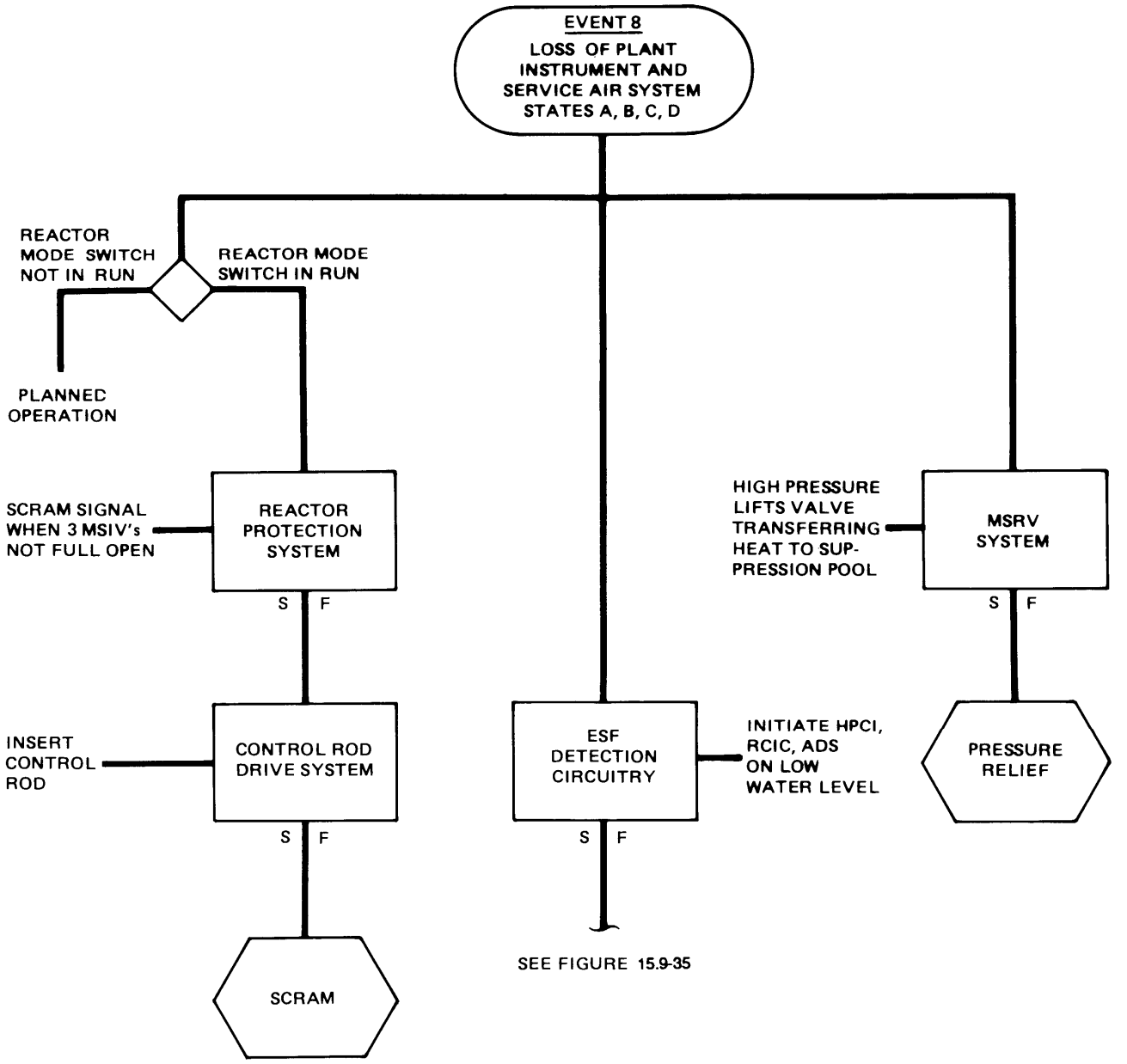
FIGURE 15.9-12 Rev. 11 9/02



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCE FOR
MANUAL OR INADVERTENT SCRAM

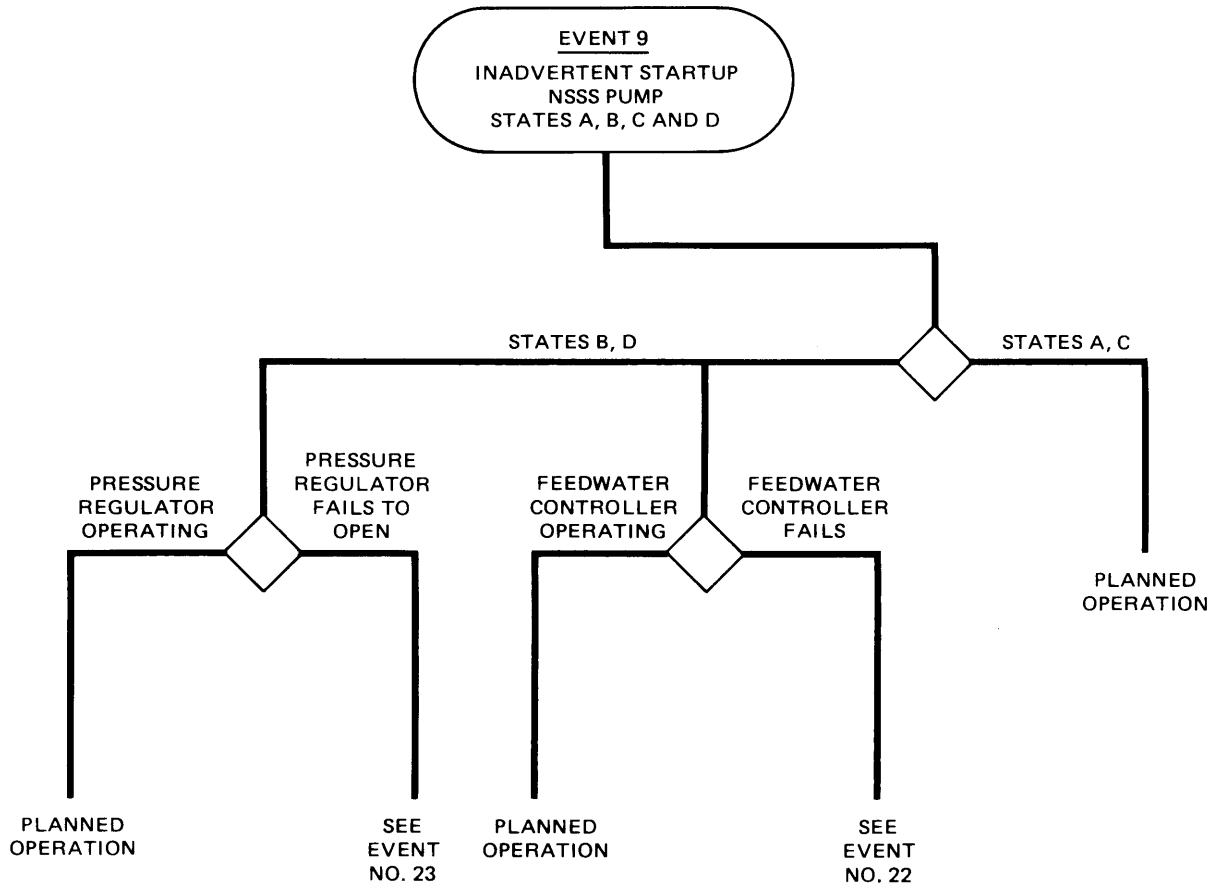
FIGURE 15.9-13



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR LOSS OF PLANT INSTRUMENT AND SERVICE AIR SYSTEM

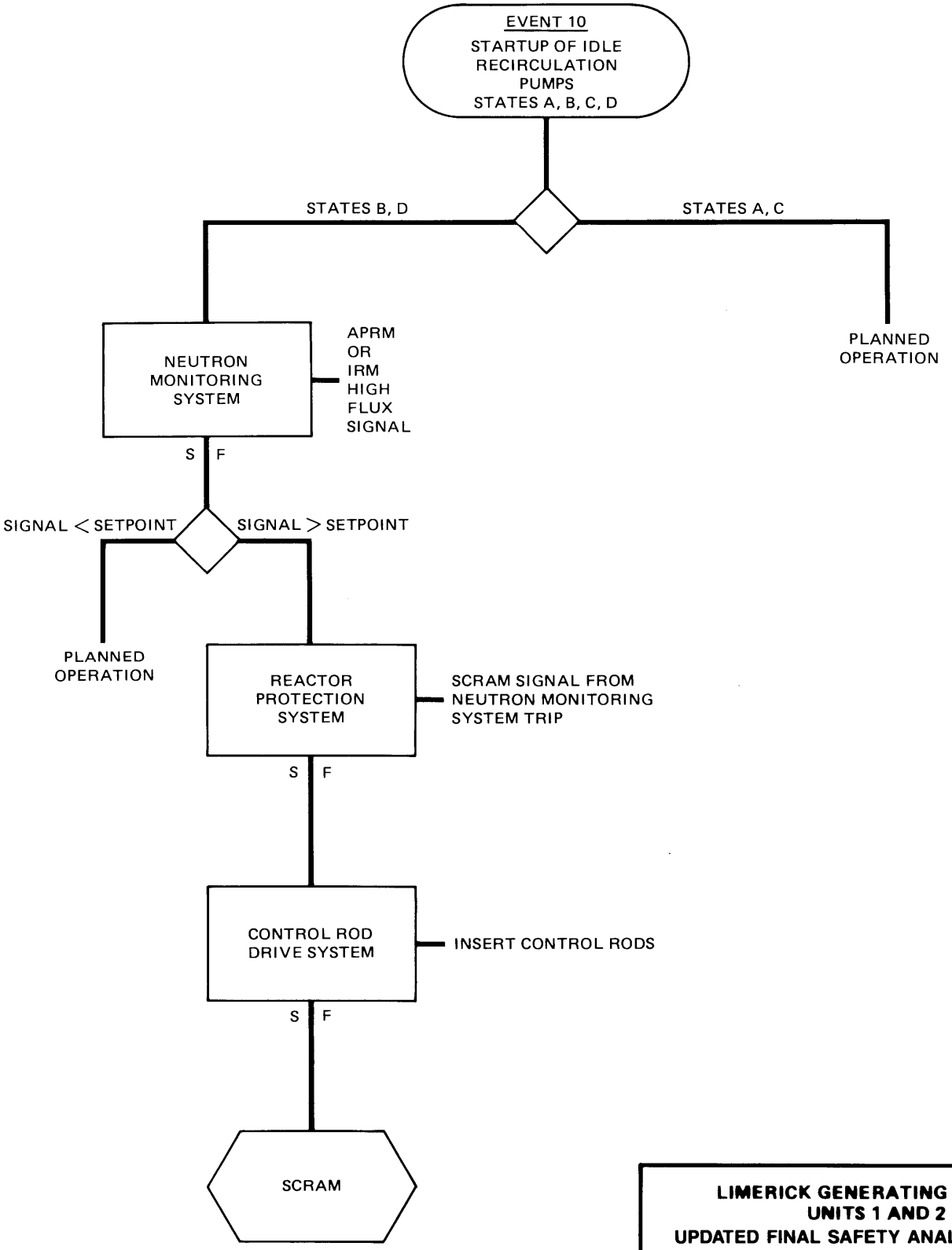
FIGURE 15.9-14



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCE FOR INADVERTENT STARTUP OF NSSS PUMP

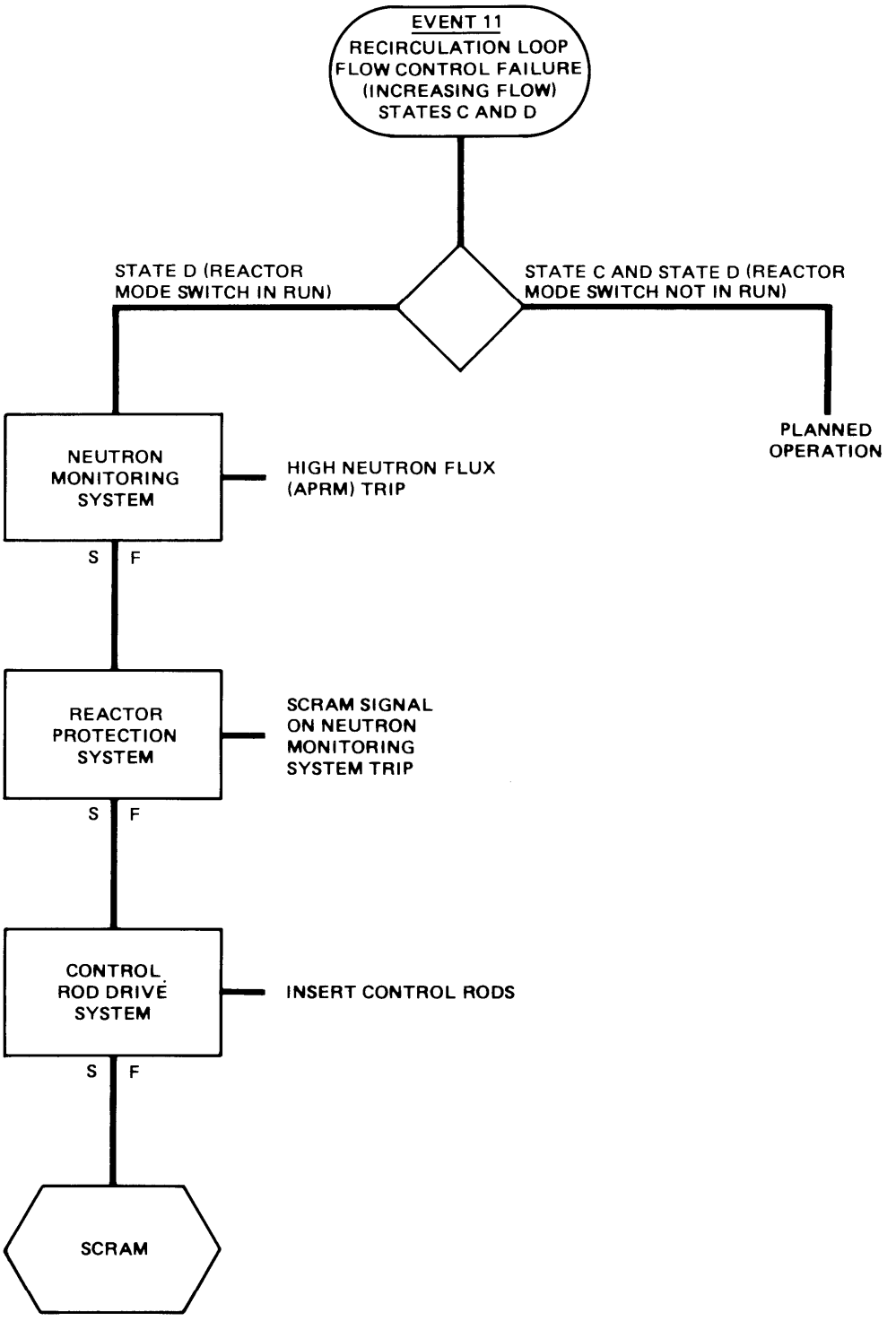
FIGURE 15.9-15



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCE FOR INADVERTENT STARTUP OF IDLE RECIRCULATION LOOP PUMP

FIGURE 15.9-16



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCE FOR RECIRCULATION LOOP FLOW CONTROL FAILURE (INCREASING FLOW)

FIGURE 15.0-17

EVENT 12
RECIRCULATION LOOP FLOW CONTROL FAILURE (DECREASING FLOW) STATES C AND D

HIGH WATER LEVEL TURBINE TRIP

STATE D ONLY

MSRV SYSTEM
S F
PRESSURE RELIEF

REACTOR PROTECTION SYSTEM
SCRAM FROM TURBINE STOP VALVE CLOSURE
S F
CONTROL ROD DRIVE SYSTEM
INSERT CONTROL RODS
S F
SCRAM

NO HIGH WATER LEVEL TURBINE TRIP

AFTER ISOLATION

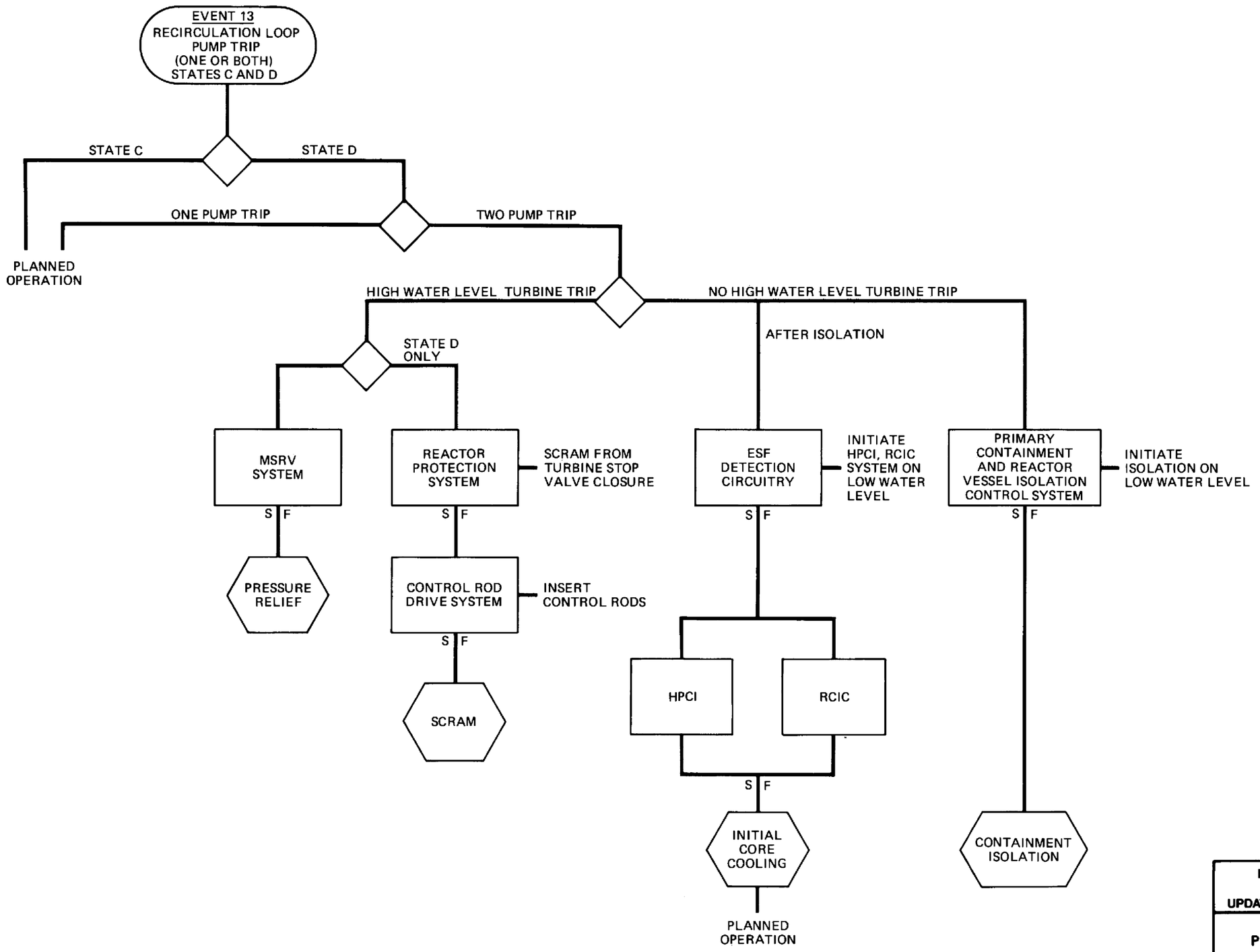
ESF DETECTION CIRCUITRY
INITIATE HPCI, RCIC SYSTEM ON LOW WATER LEVEL
S F
HPCI
RCIC
S F
INITIAL CORE COOLING
PLANNED OPERATION

PRIMARY CONTAINMENT AND REACTOR VESSEL ISOLATION CONTROL SYSTEM
INITIATE ISOLATION ON LOW WATER LEVEL
S F
CONTAINMENT ISOLATION

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCE FOR RECIRCULATION LOOP FLOW CONTROL FAILURE (DECREASING FLOW)

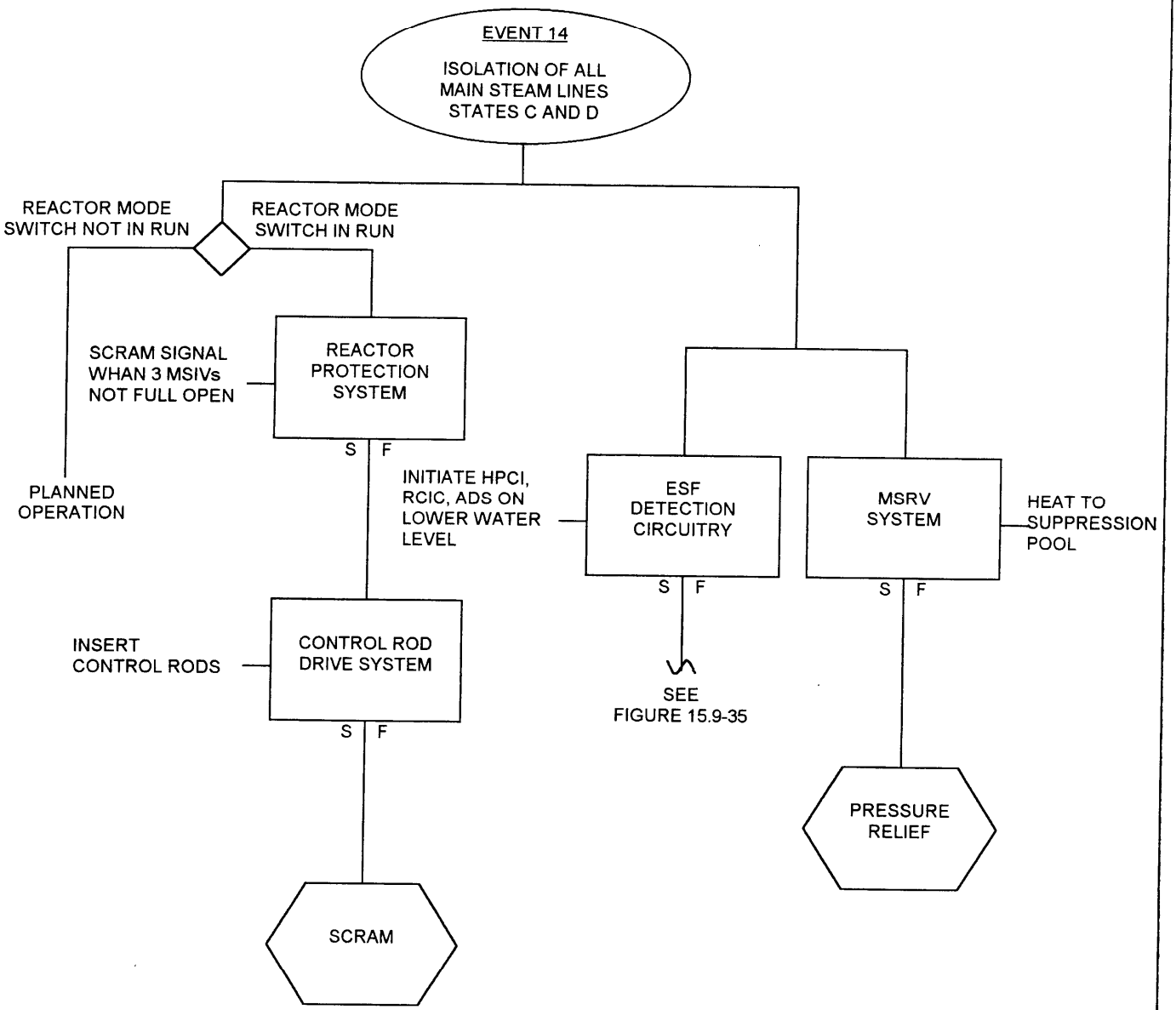
FIGURE 15.9-18



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR RECIRCULATION PUMP TRIP (ONE OR BOTH)

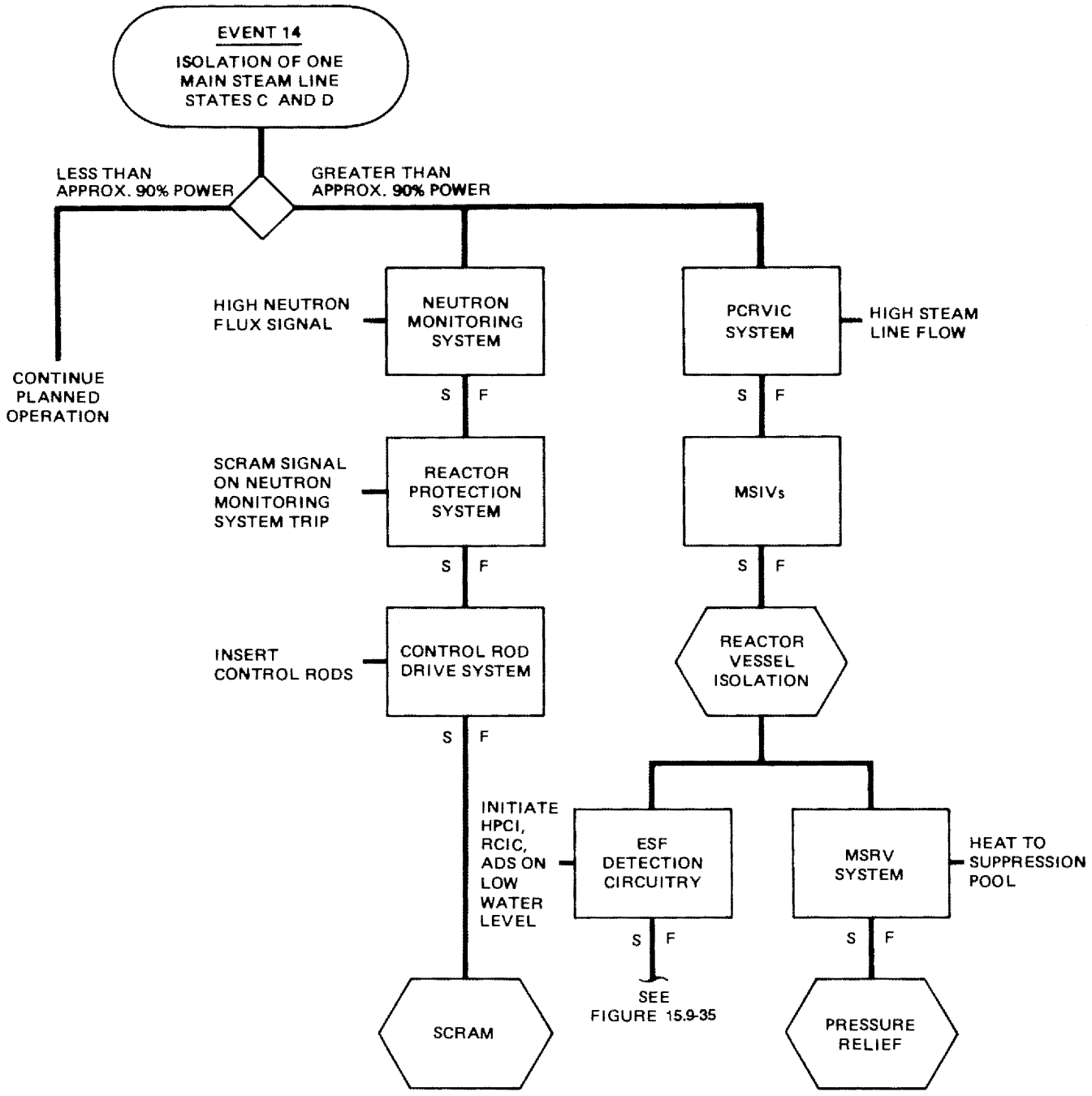
FIGURE 15.9-19



LIMERICK GENERATING STATION
UNITS 2 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR ISOLATION OF ALL MAIN STEAM LINES

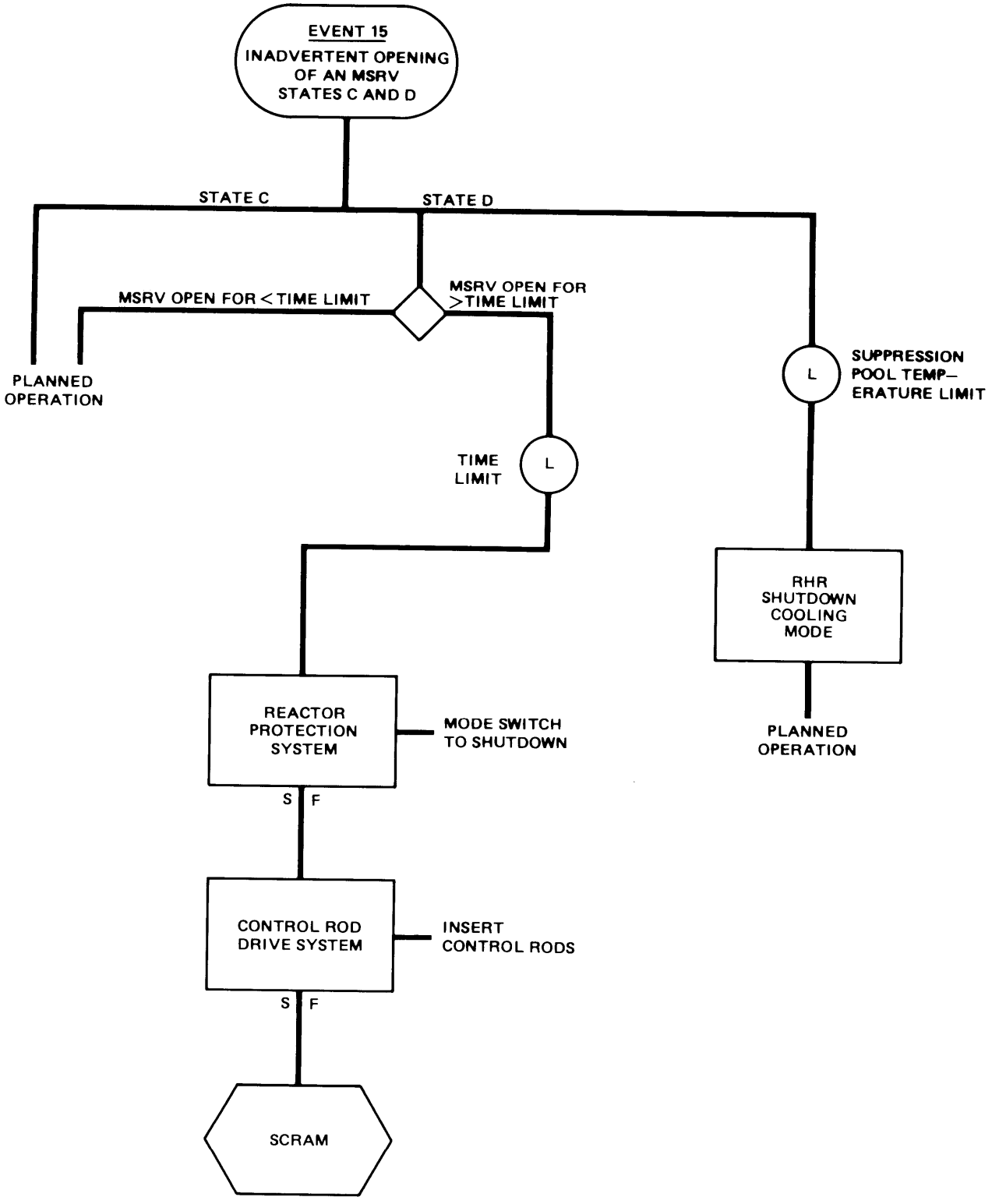
FIGURE 15.9-20 Rev. 11 9/02



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR ISOLATION OF ONE MAIN STEAM LINE

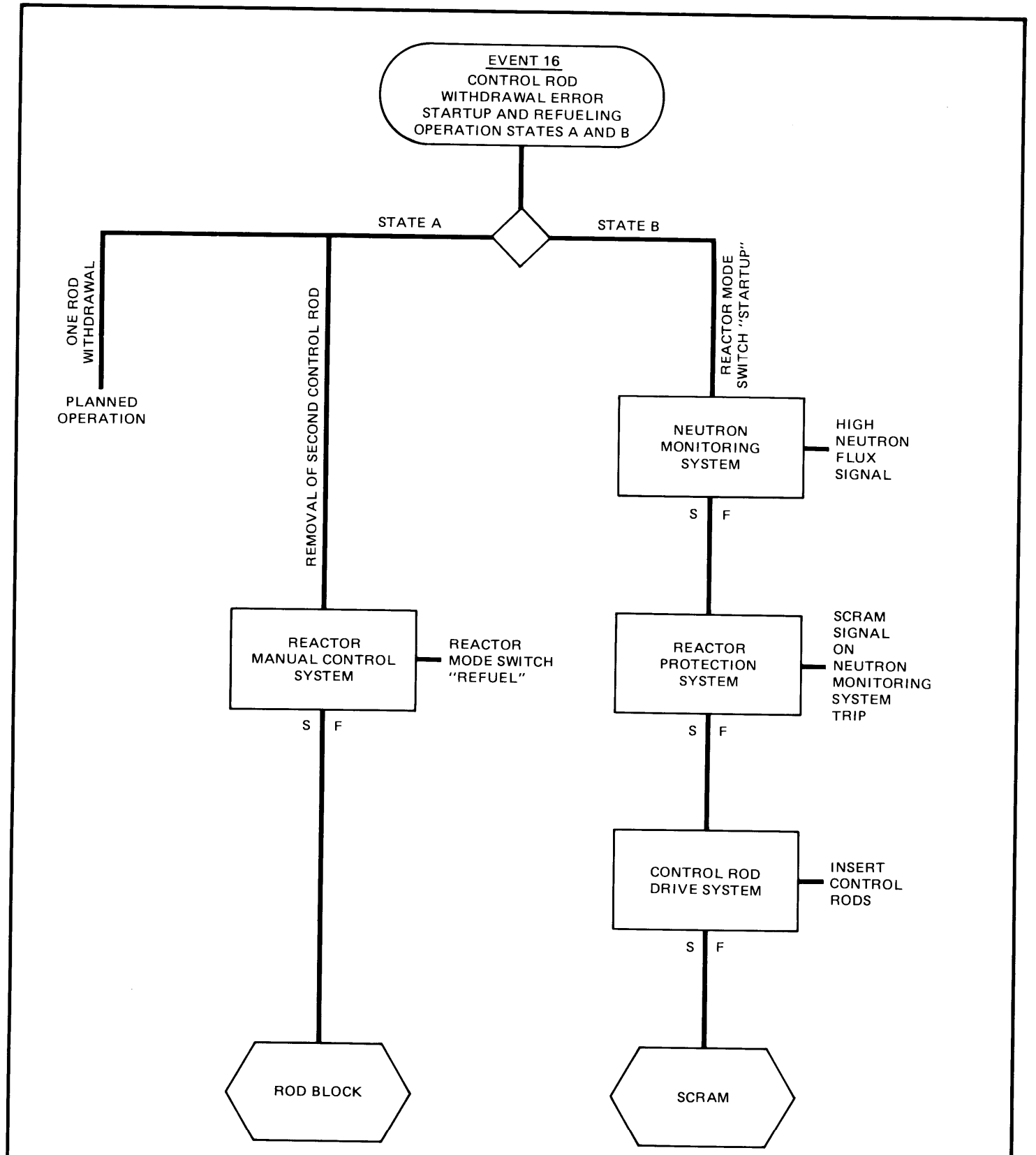
FIGURE 15.9-21



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR INADVERTENT OPENING OF AN MSRV

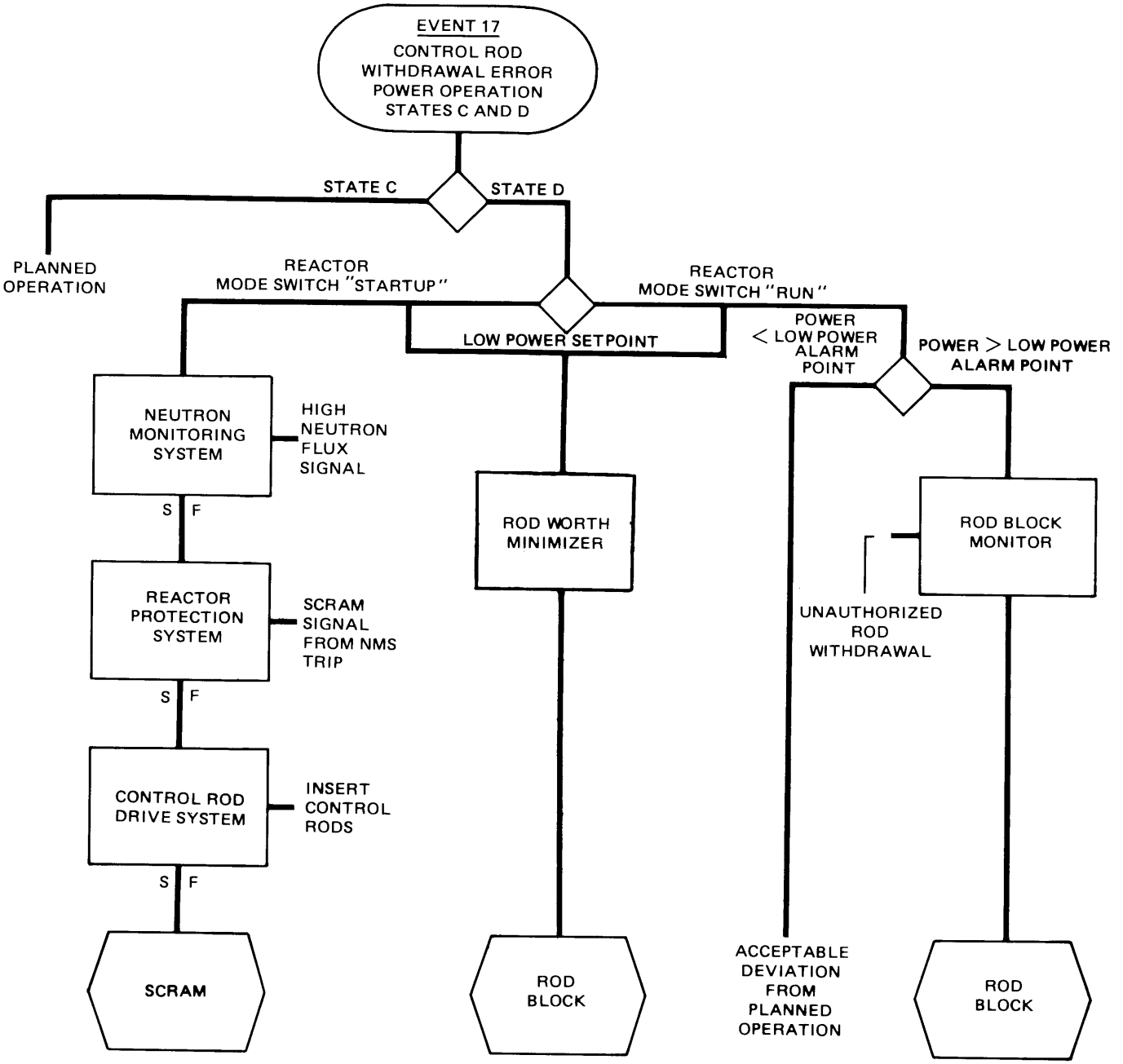
FIGURE 15.9-22



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCE FOR CONTROL ROD WITHDRAWAL ERROR FOR STARTUP AND REFUELING OPERATIONS

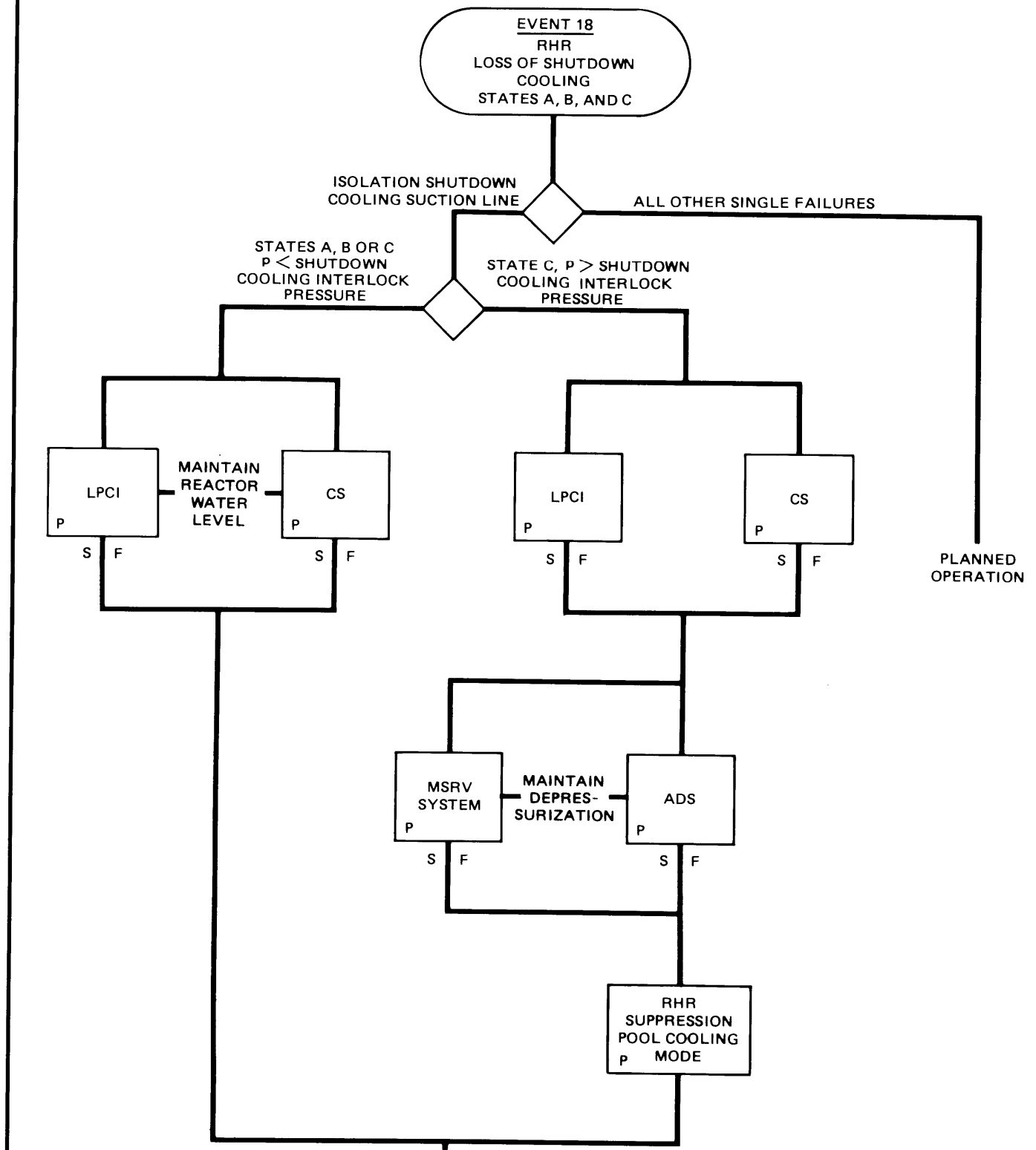
FIGURE 15.9-23



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCE FOR CONTROL ROD WITHDRAWAL ERROR– POWER OPERATION

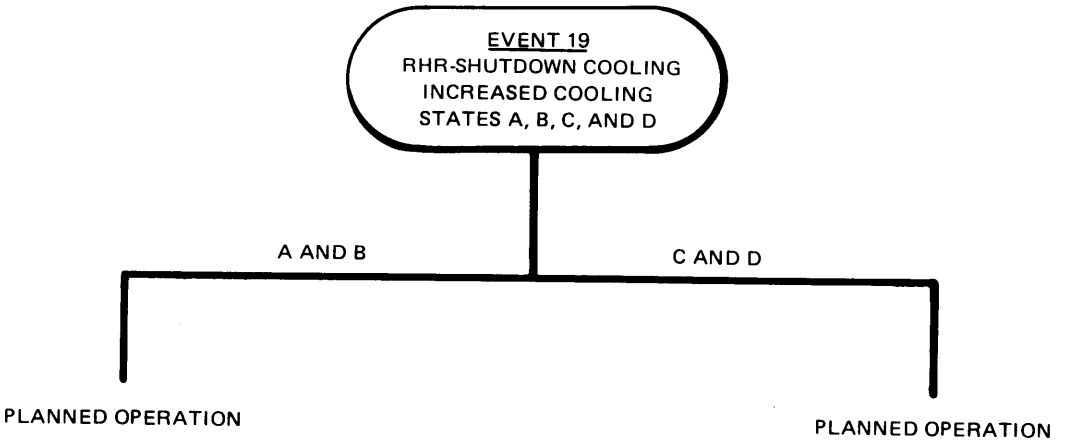
FIGURE 15.9-24



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR RHR–LOSS OF SHUTDOWN COOLING

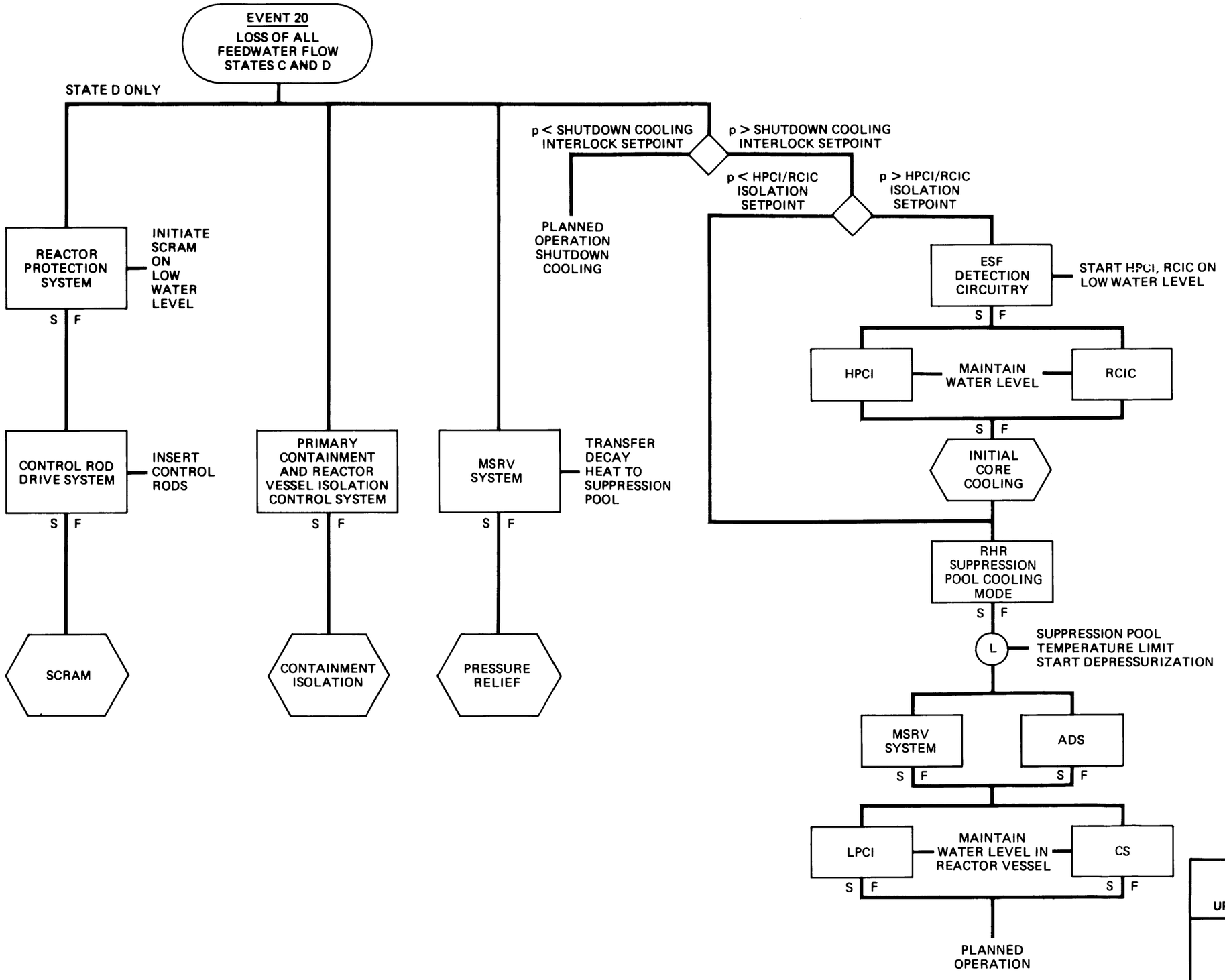
FIGURE 15.9-25



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR RHR (SHUTDOWN COOLING) INCREASED COOLING

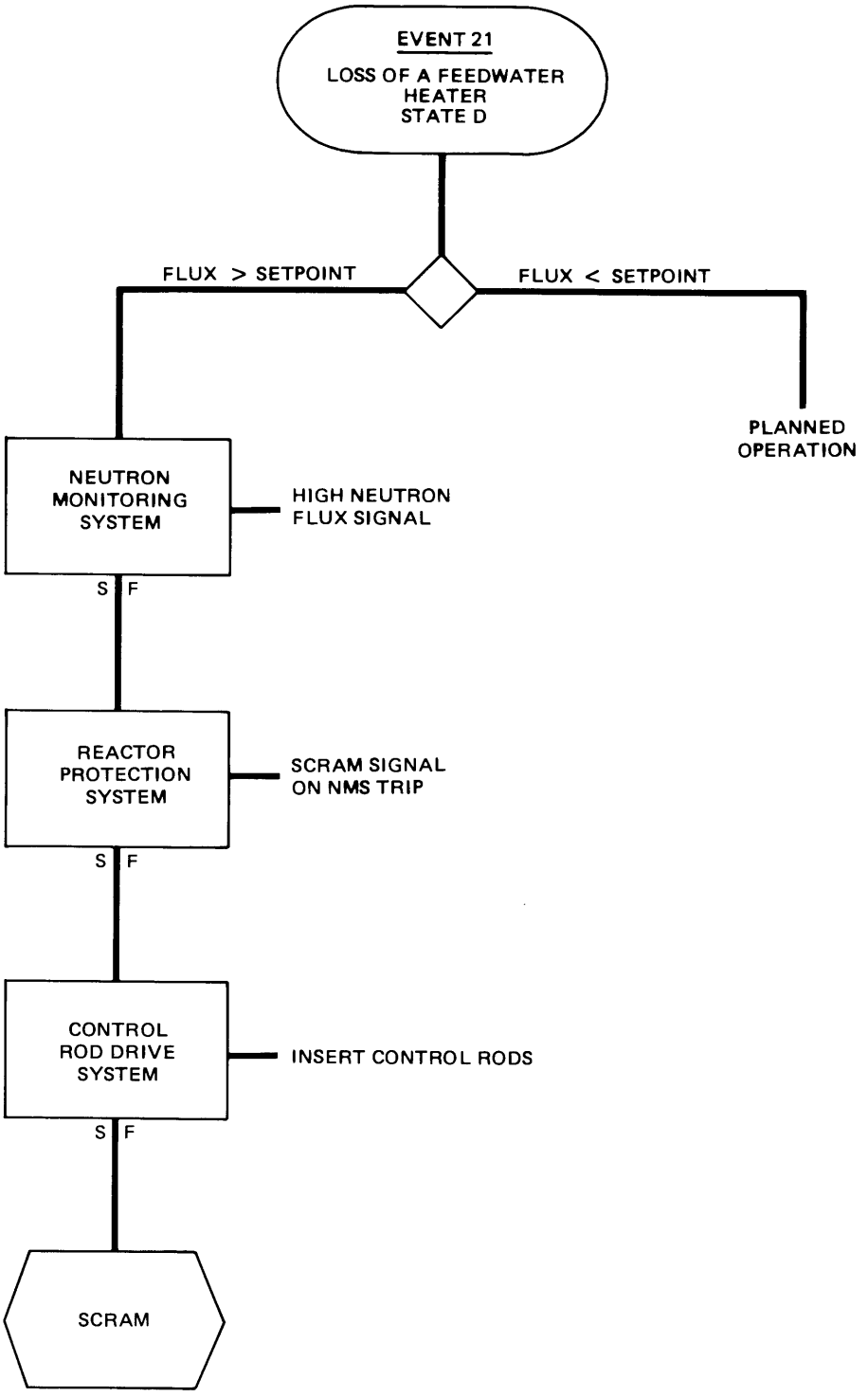
FIGURE 15.9-26



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR LOSS OF FEEDWATER FLOW

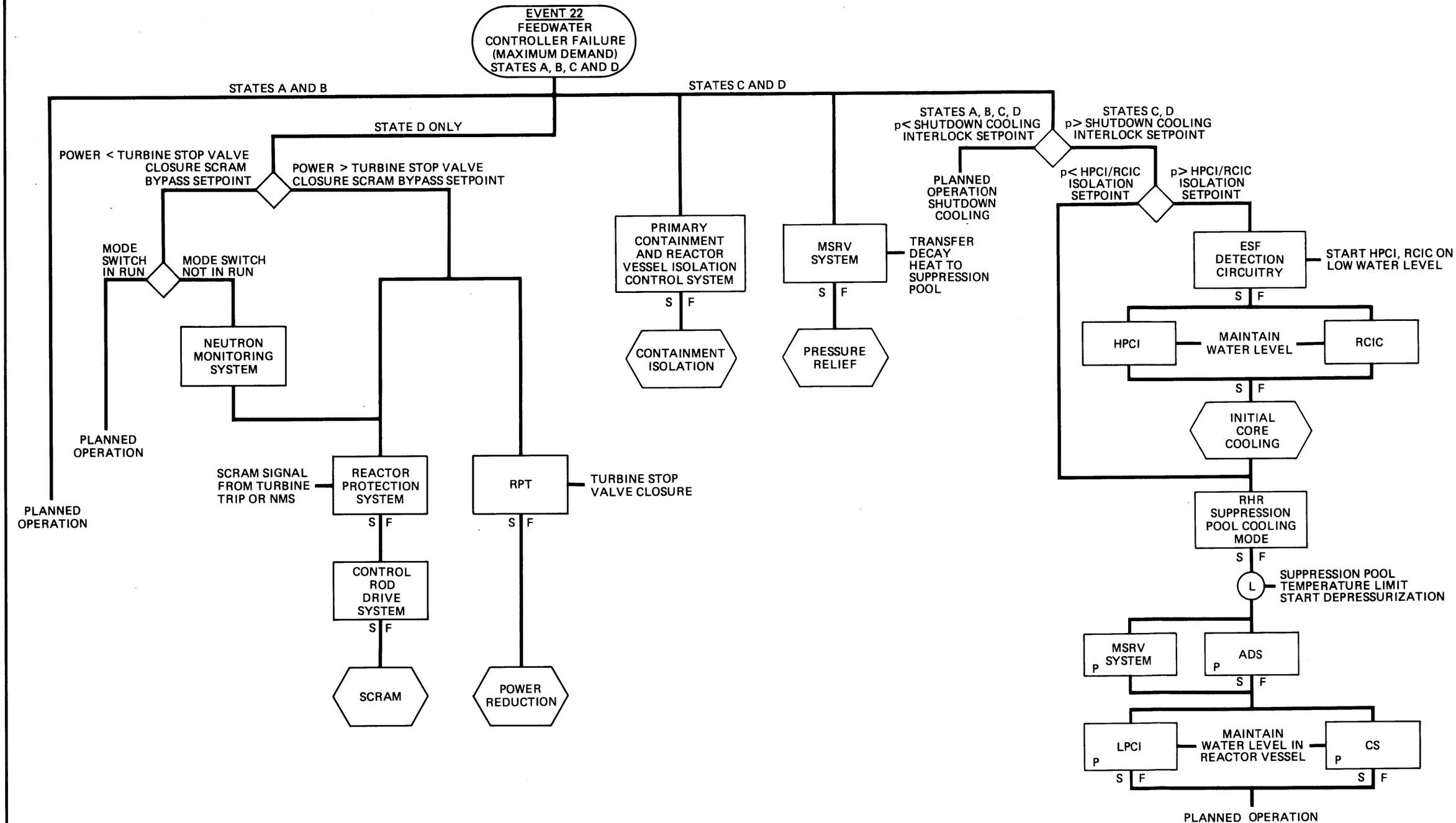
FIGURE 15.9-27



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCE FOR LOSS OF A FEEDWATER HEATER

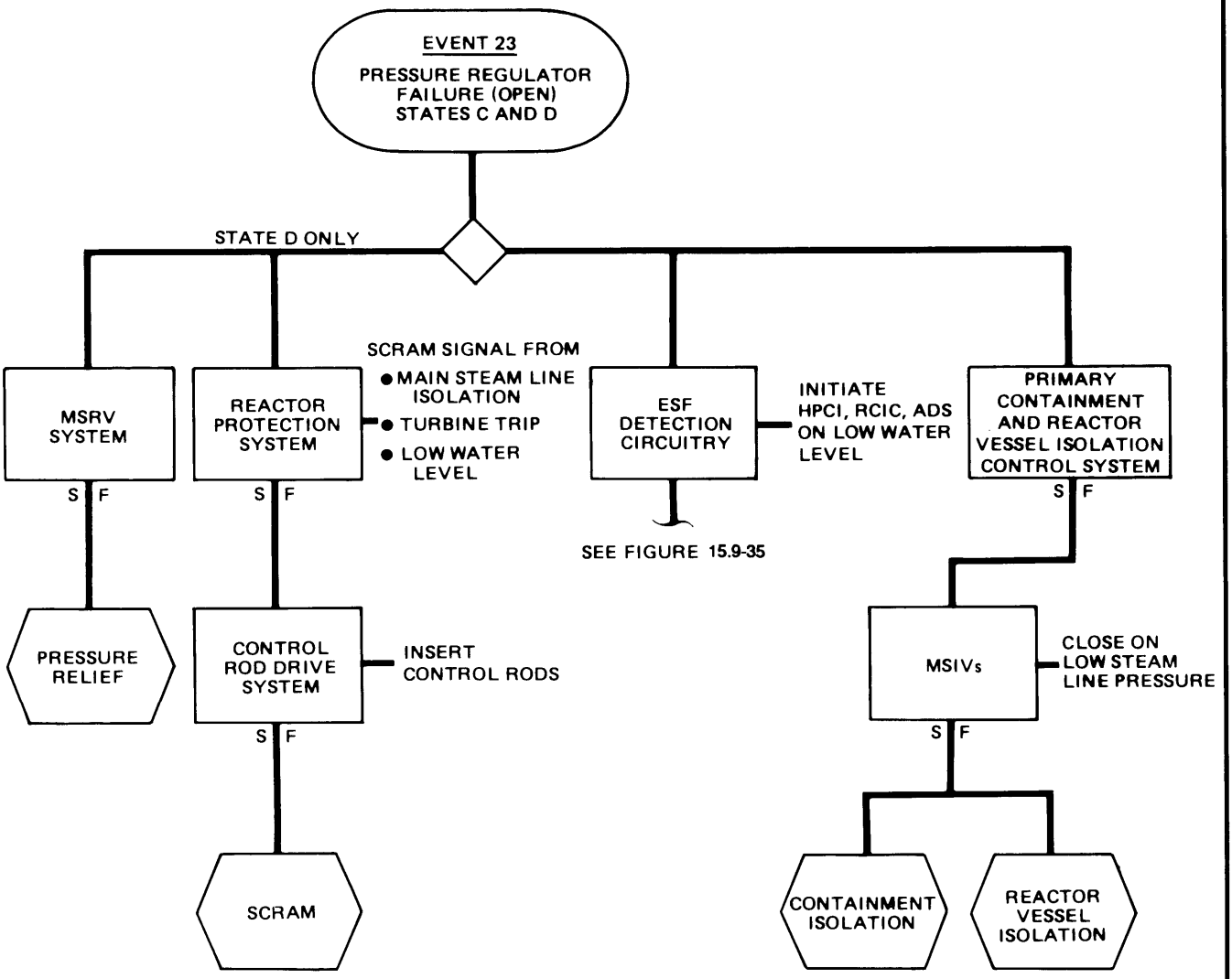
FIGURE 15.9-28



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR FEEDWATER CONTROLLER FAILURE (MAXIMUM DEMAND)

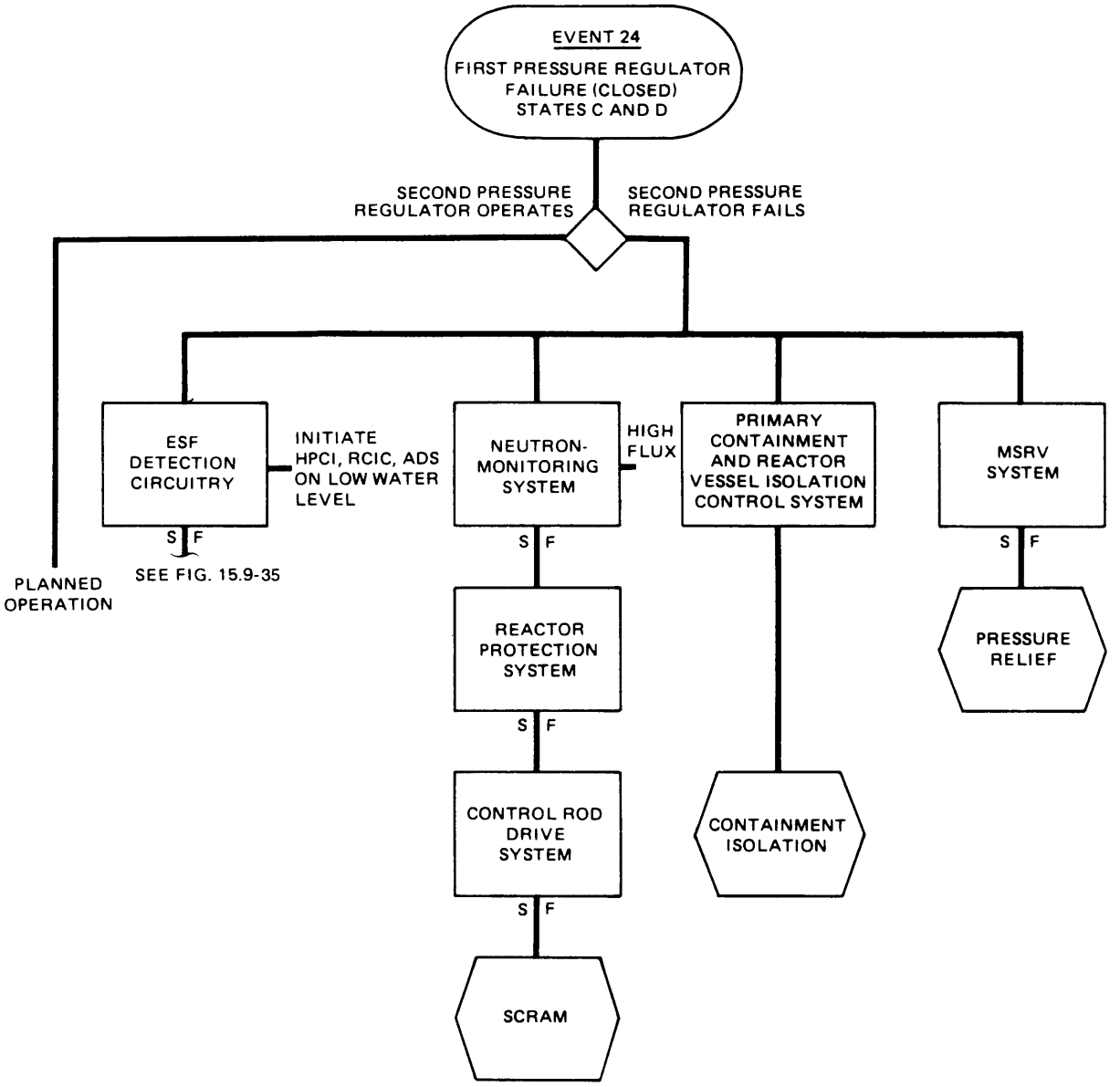
FIGURE 15.9-29



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR PRESSURE REGULATOR FAILURE (OPEN)

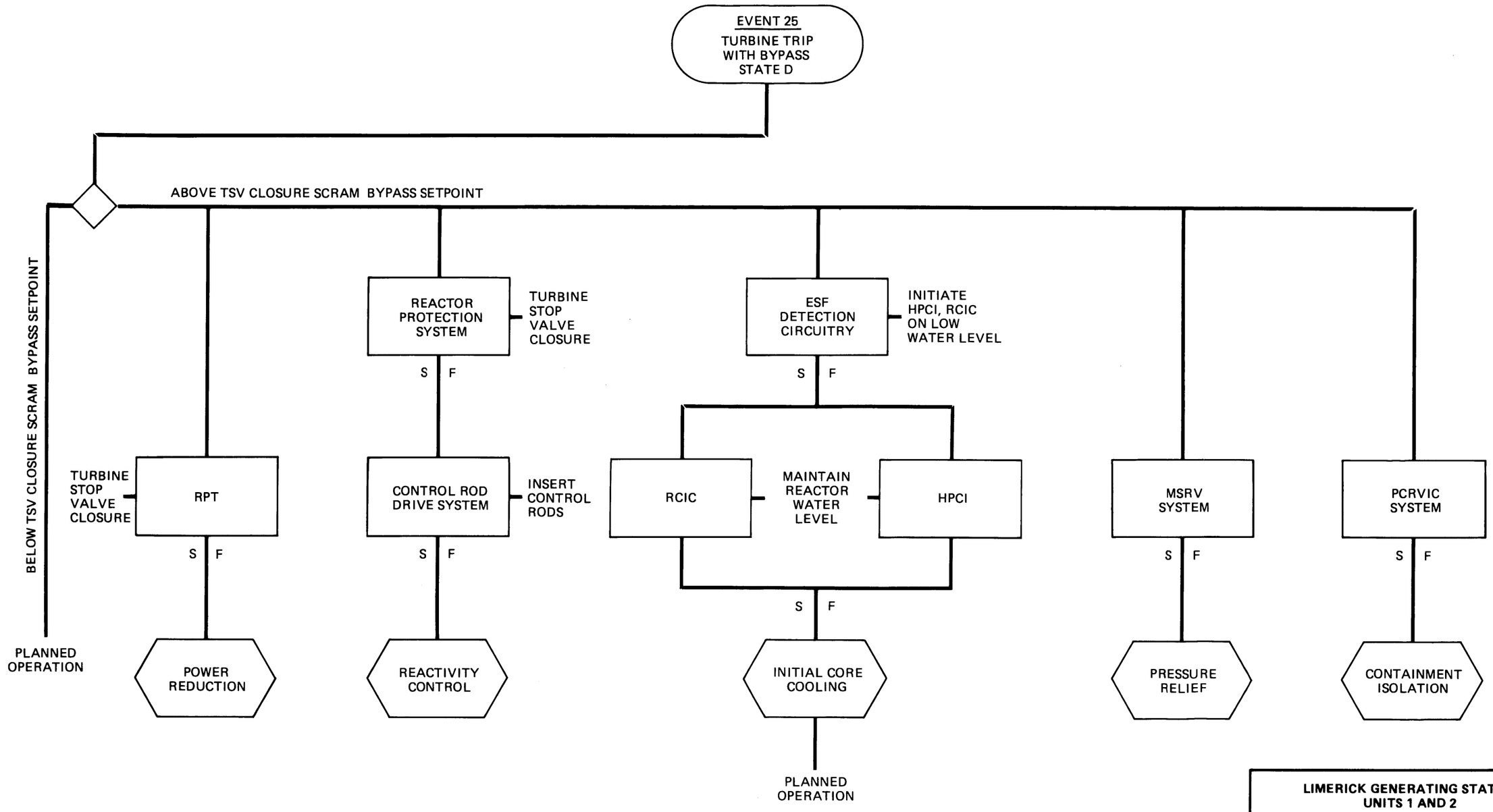
FIGURE 15.9-30



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR PRESSURE REGULATOR FAILURE (CLOSED)

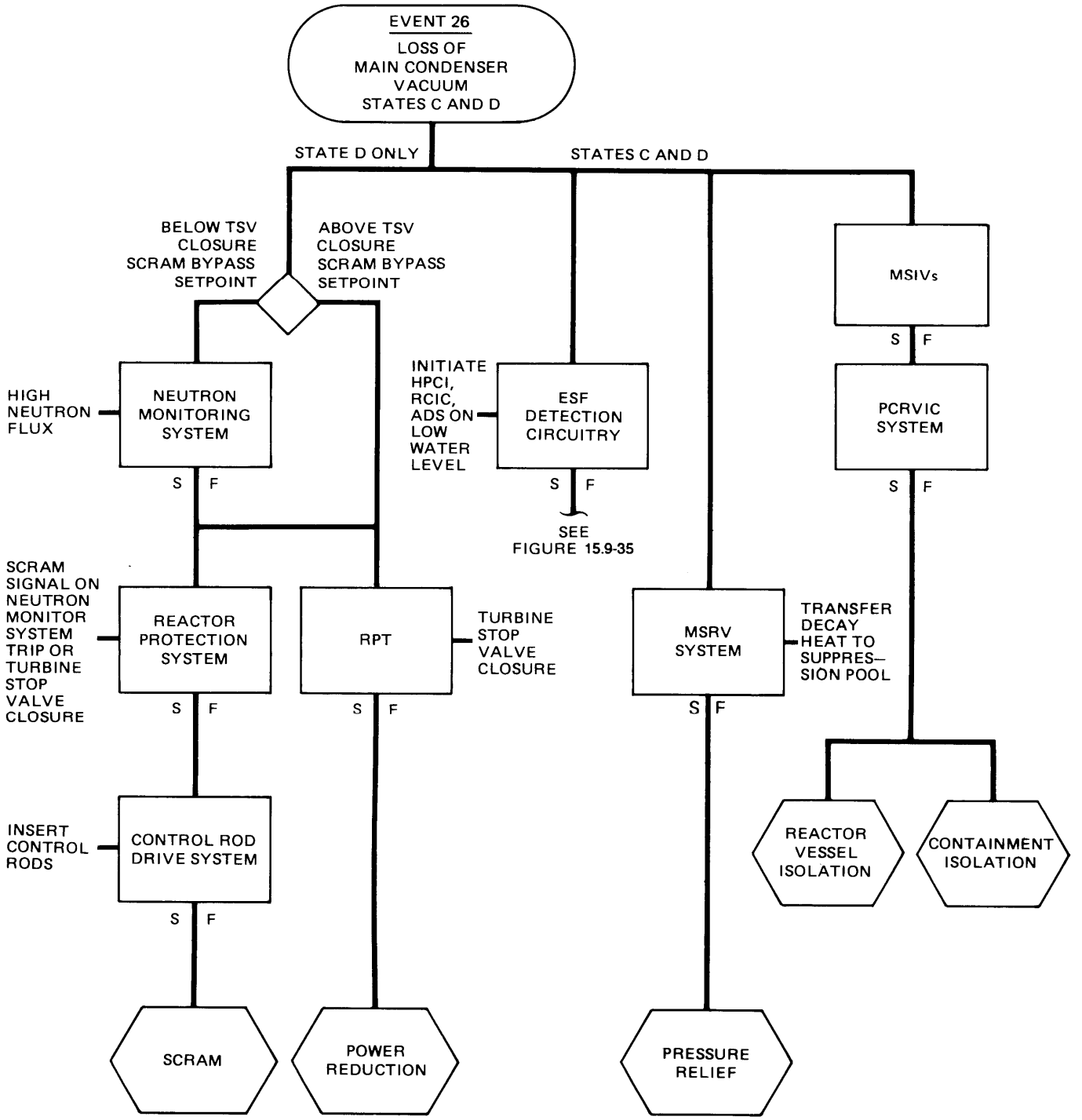
FIGURE 15.9-31



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR MAIN TURBINE TRIP WITH BYPASS SYSTEM OPERATION

FIGURE 15.9-32



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR LOSS OF MAIN CONDENSER VACUUM

FIGURE 15.9-33

EVENT 27
GENERATOR TRIP WITH BYPASS STATE D

ABOVE TCV CLOSURE SCRAM BYPASS SETPOINT

BELOW TCV CLOSURE SCRAM BYPASS SETPOINT

PLANNED OPERATION

TURBINE CONTROL VALVE FAST CLOSURE

RPT

S F

POWER REDUCTION

REACTOR PROTECTION SYSTEM

TURBINE CONTROL VALVE FAST CLOSURE

S F

CONTROL ROD DRIVE SYSTEM

INSERT CONTROL RODS

S F

SCRAM

ESF DETECTION CIRCUITRY

INITIATE HPCI, RCIC ON LOW WATER LEVEL

S F

RCIC

MAINTAIN REACTOR WATER LEVEL

HPCI

S F

INITIAL CORE COOLING

PLANNED OPERATION

MSRV SYSTEM

S F

PRESSURE RELIEF

PCRVIC SYSTEM

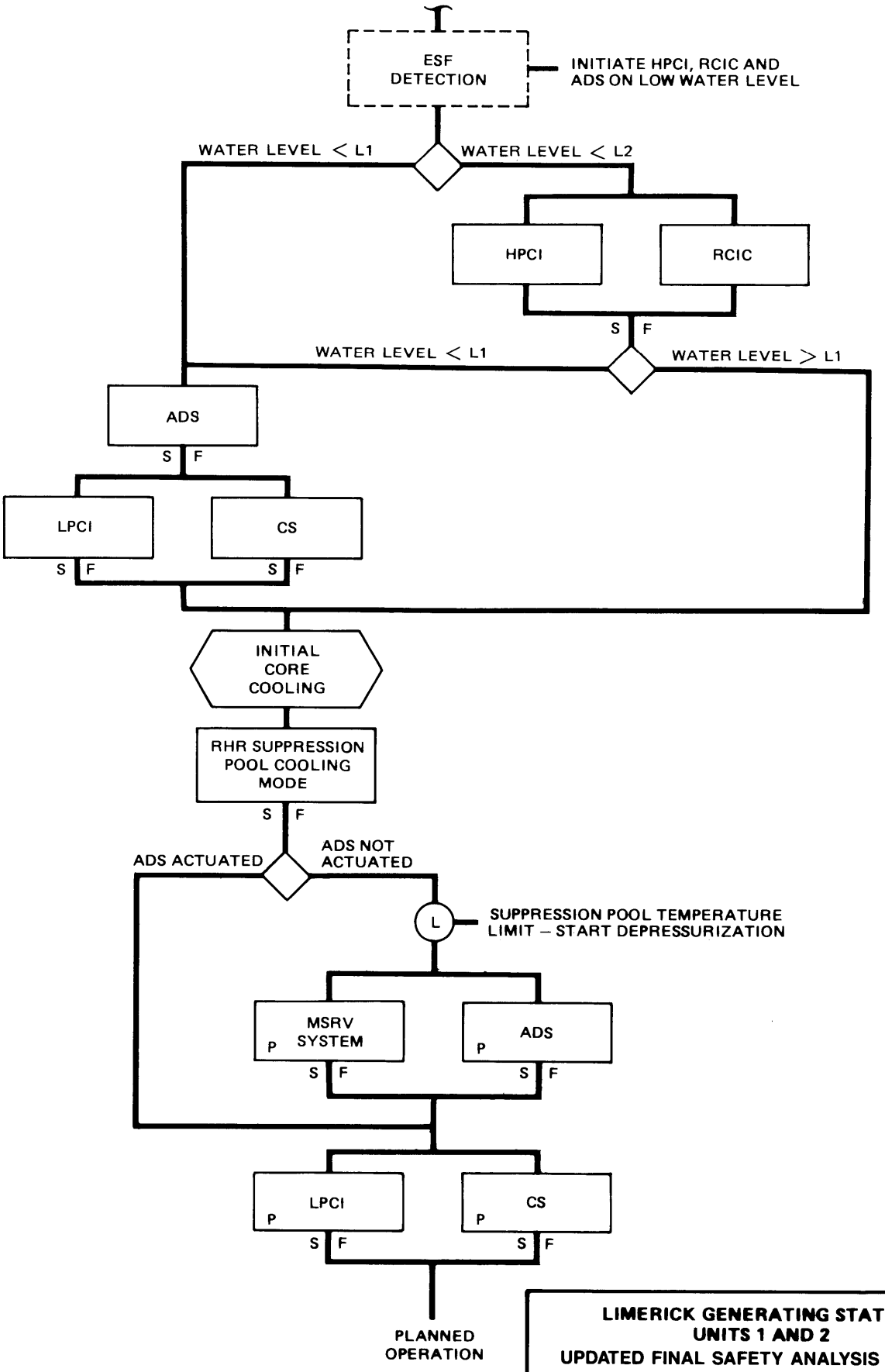
S F

CONTAINMENT ISOLATION

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR MAIN GENERATOR TRIP WITH BYPASS SYSTEM OPERATION

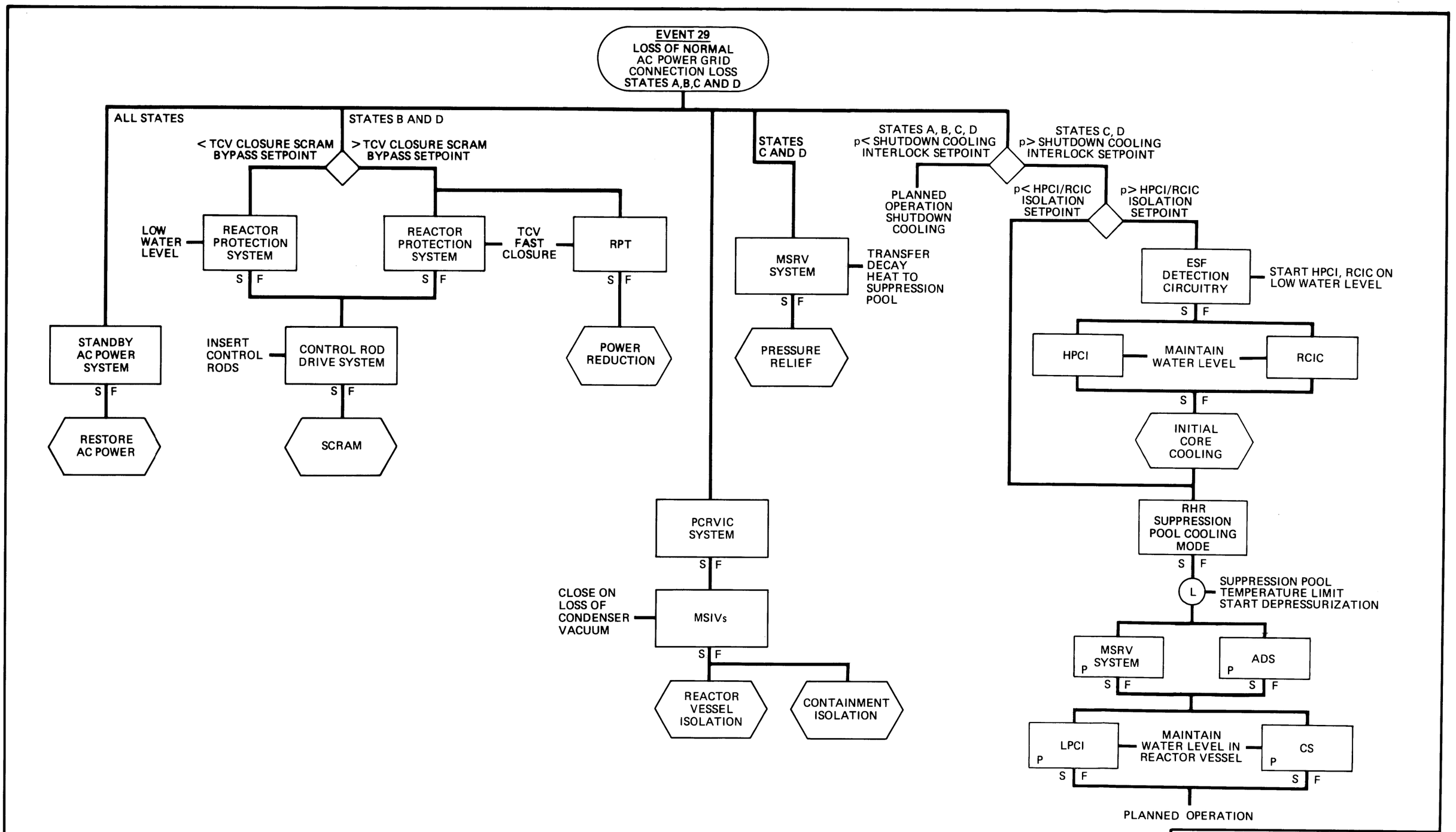
FIGURE 15.9-34



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR ACHIEVING SHUTDOWN COOLING WITH REACTOR VESSEL ISOLATED

FIGURE 15.9-35



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR LOSS OF NORMAL AC POWER (GRID CONNECTION LOSS)

FIGURE 15.9-36

EVENT 30
GENERATOR TRIP WITH BYPASS FAILURE STATE D

BELOW TCV CLOSURE SCRAM BYPASS SETPOINT

ABOVE TCV CLOSURE SCRAM BYPASS SETPOINT

REACTOR PROTECTION SYSTEM
- SCRAM SIGNALS:
  1. HIGH PRESSURE
  2. HIGH FLUX

S F

CONTROL ROD DRIVE SYSTEM

S F

SCRAM

RPT
- TURBINE CONTROL VALVE FAST CLOSURE

S F

POWER REDUCTION

SCRAM SIGNAL: TURBINE CONTROL VALVE FAST CLOSURE

REACTOR PROTECTION SYSTEM

S F

CONTROL ROD DRIVE SYSTEM
- INSERT CONTROL RODS

S F

SCRAM

ESF DETECTION CIRCUITRY
- INITIATE HPCI, RCIC, ADS ON LOW WATER LEVEL

S F

SEE FIGURE 15.9-35

MSRV SYSTEM

S F

PRESSURE RELIEF

PCRVIC SYSTEM

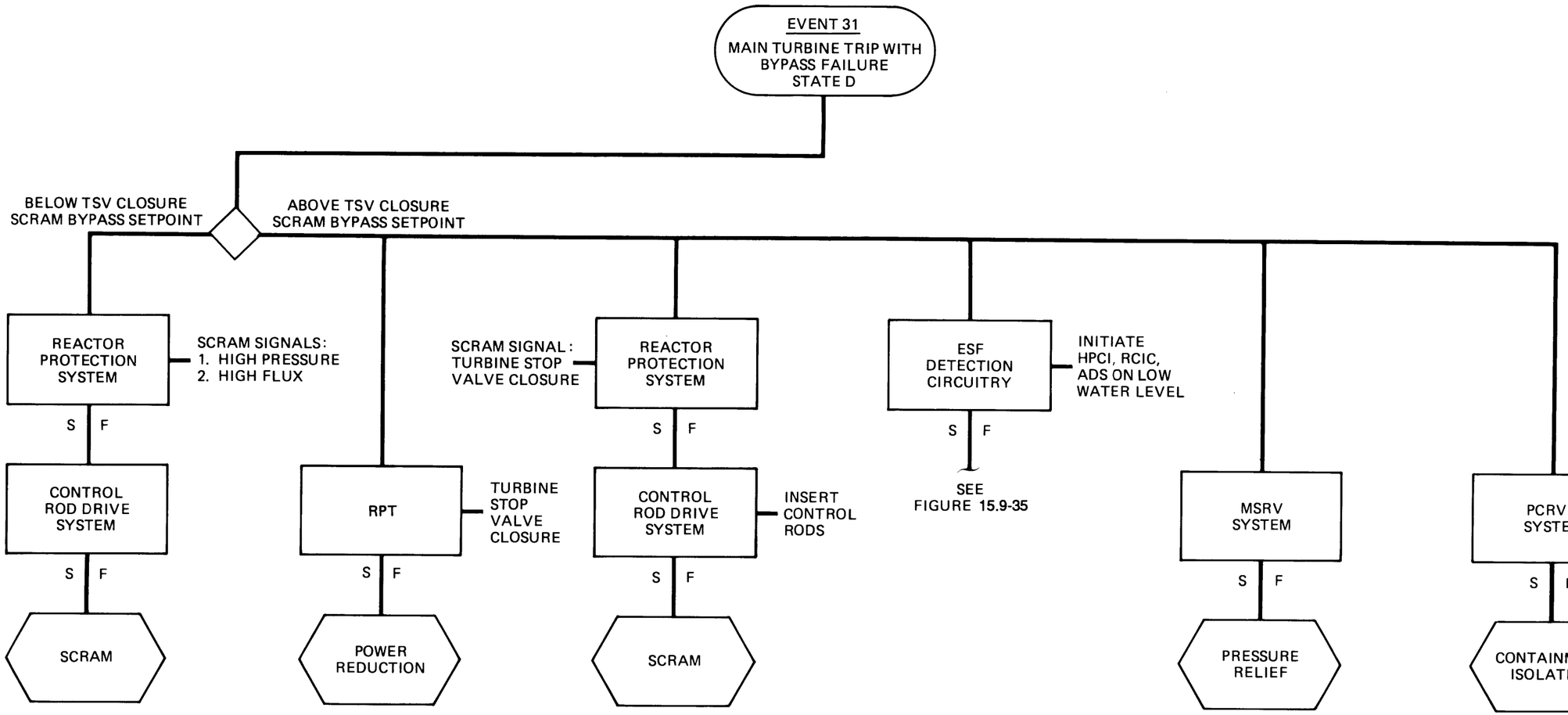
S F

CONTAINMENT ISOLATION

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR MAIN GENERATOR TRIP WITH BYPASS SYSTEM FAILURE

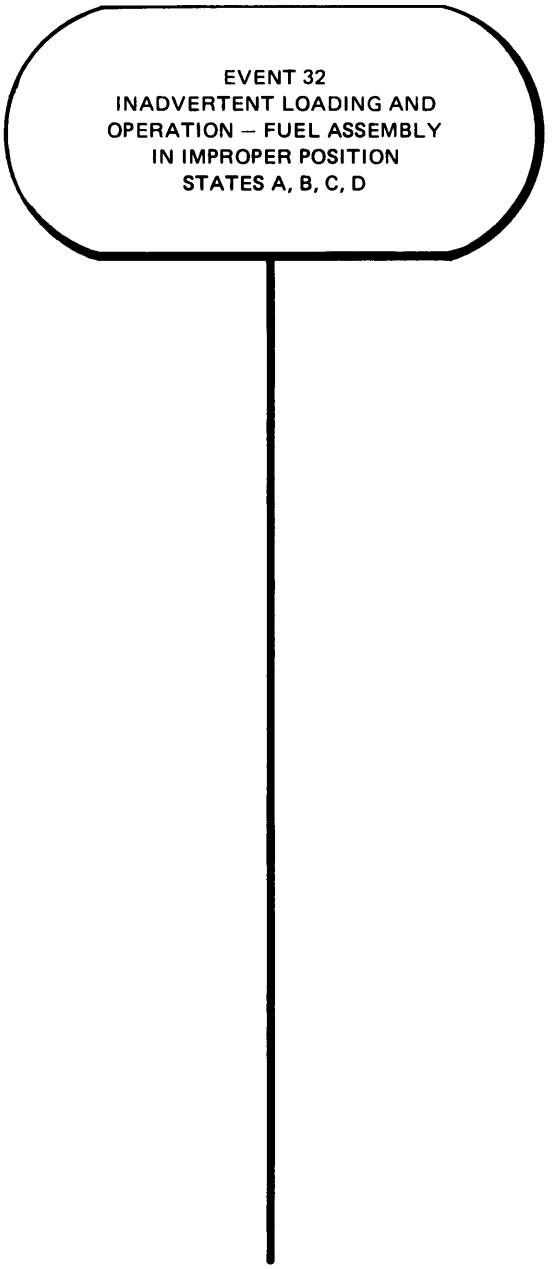
FIGURE 15.9-37



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR MAIN TURBINE TRIP WITH BYPASS SYSTEM FAILURE

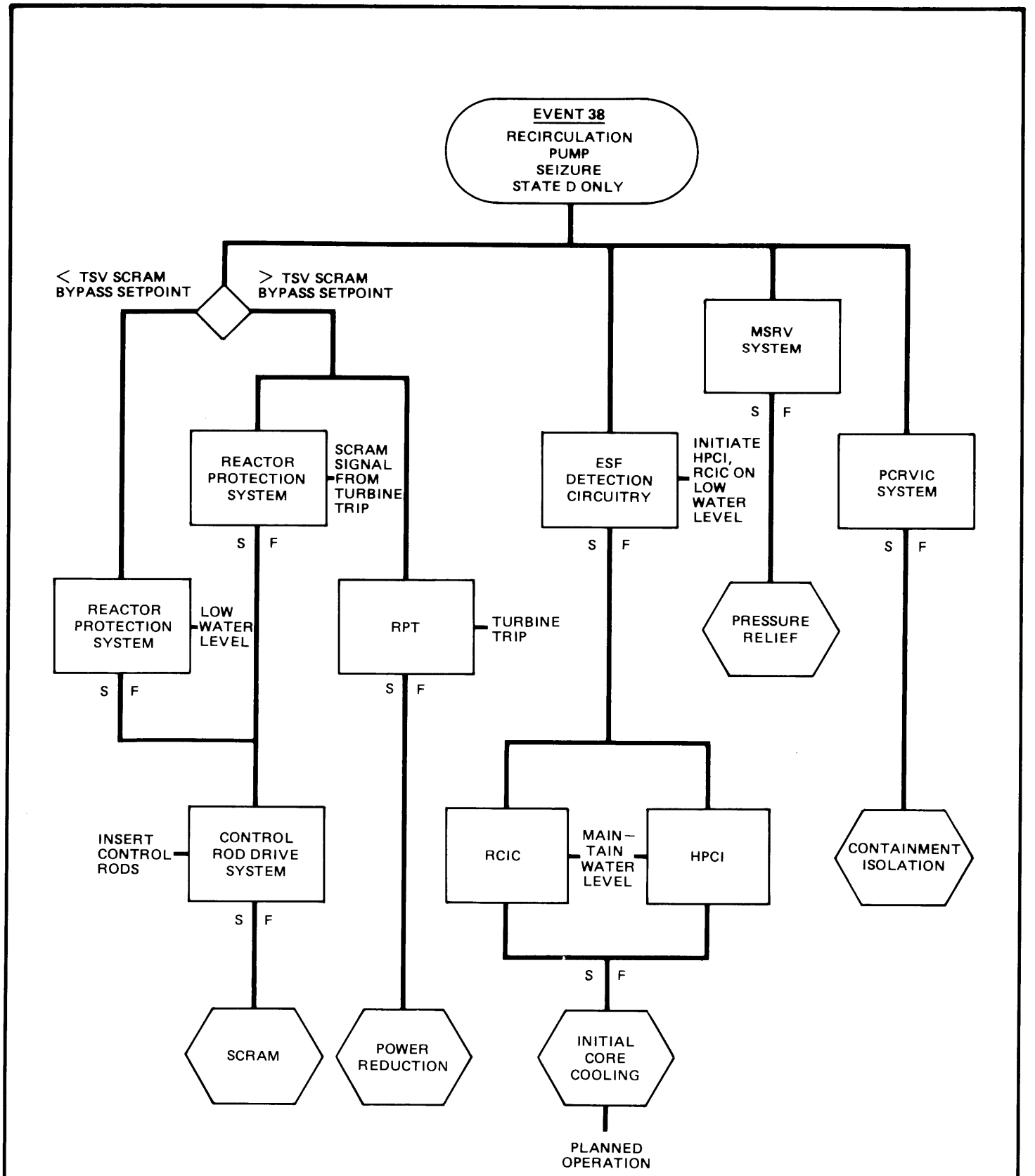
FIGURE 15.9-38



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCE FOR INADVERTENT LOADING AND OPERATION OF FUEL ASSEMBLY IN IMPROPER POSITION

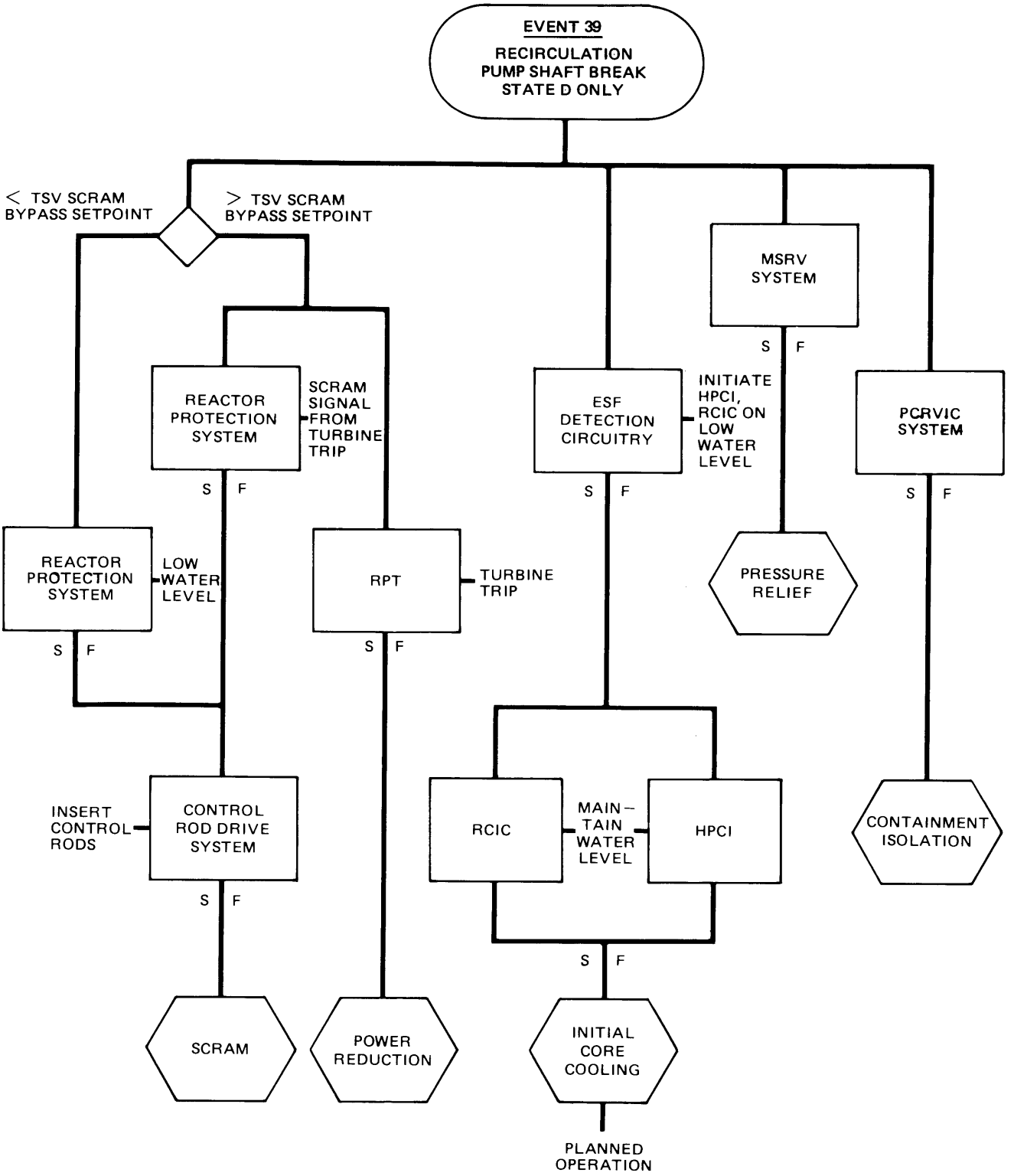
FIGURE 15.9-39



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR RECIRCULATION PUMP SEIZURE

FIGURE 15.9-40



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UNITS 1 AND 2
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PROTECTION SEQUENCES FOR RECIRCULATION PUMP SHAFT BREAK

FIGURE 15.9-41

EVENT 40
CONTROL ROD
DROP ACCIDENT
STATES B AND D

STATES B AND D

STATE D ONLY

NEUTRON
MONITORING
SYSTEM

HIGH
NEUTRON
FLUX
SIGNAL

S F

CONTROL
ROD
VELOCITY
LIMITER
(PASSIVE)

REACTOR
PROTECTION
SYSTEM

SCRAM
SIGNAL ON
NEUTRON
MONITORING
SYSTEM TRIP

S F

CONTROL ROD
DRIVE SYSTEM

INSERT
CONTROL
RODS

S F

LIMIT
REACTIVITY
INSERTION
RATE

SCRAM

PRIMARY
CONTAINMENT
AND REACTOR
VESSEL ISOLATION
CONTROL SYSTEM

S F

CONTAINMENT
ISOLATION

ESF DETECTION
CIRCUITRY

INITIATE
HPCI, RCIC,
ADS ON
LOW WATER
LEVEL

S F

SEE FIGURE 15.9-35

MSRV
SYSTEM

S F

PRESSURE
RELIEF

RADIATION
MONITOR
TRIP

CONTROL ROOM
HVAC SYSTEM

S F

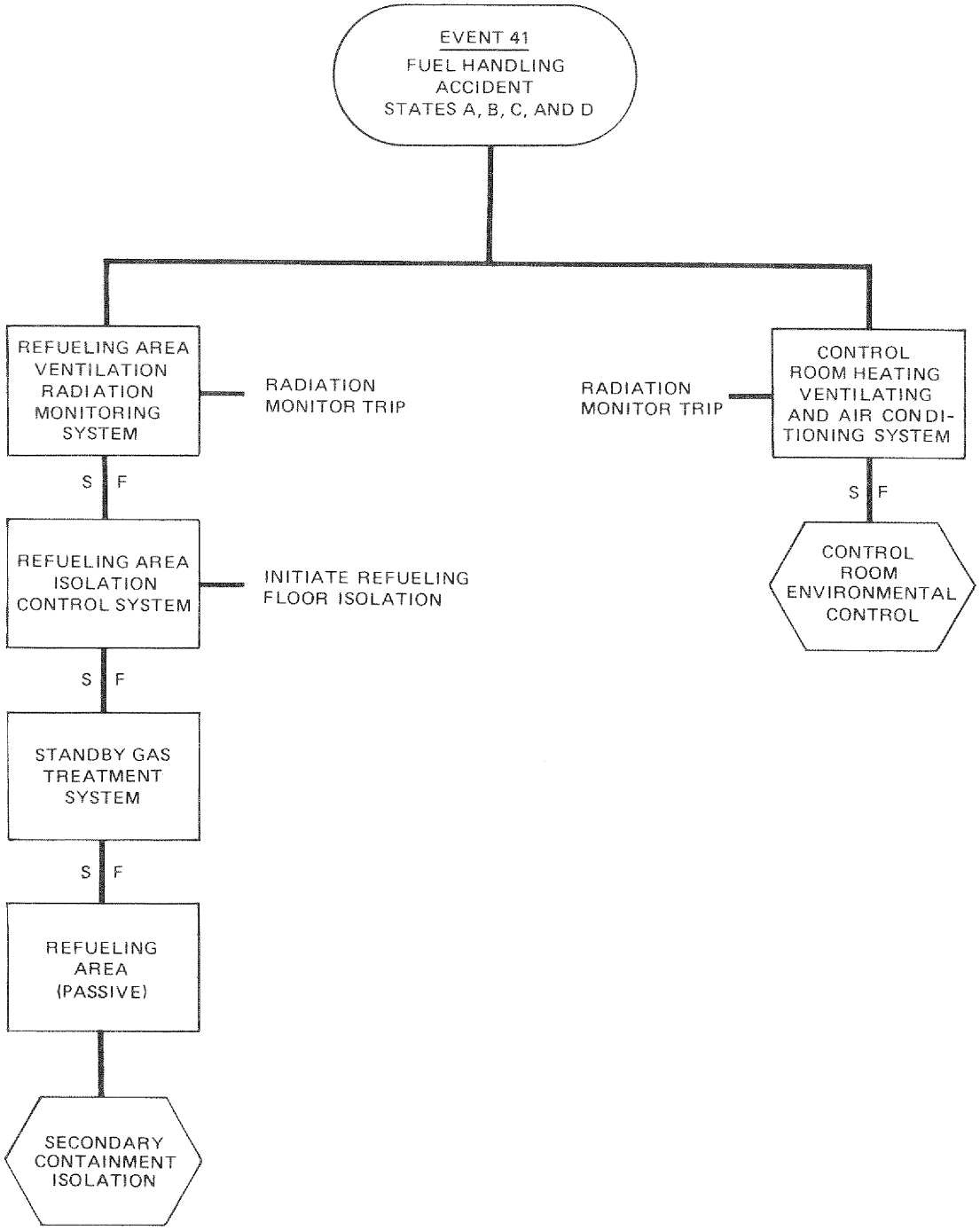
CONTROL
ROOM
ENVIRONMENTAL
CONTROL

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PROTECTION SEQUENCES FOR
CONTROL ROD DROP ACCIDENT

FIGURE 15.9-42

Rev. 15, 09/10



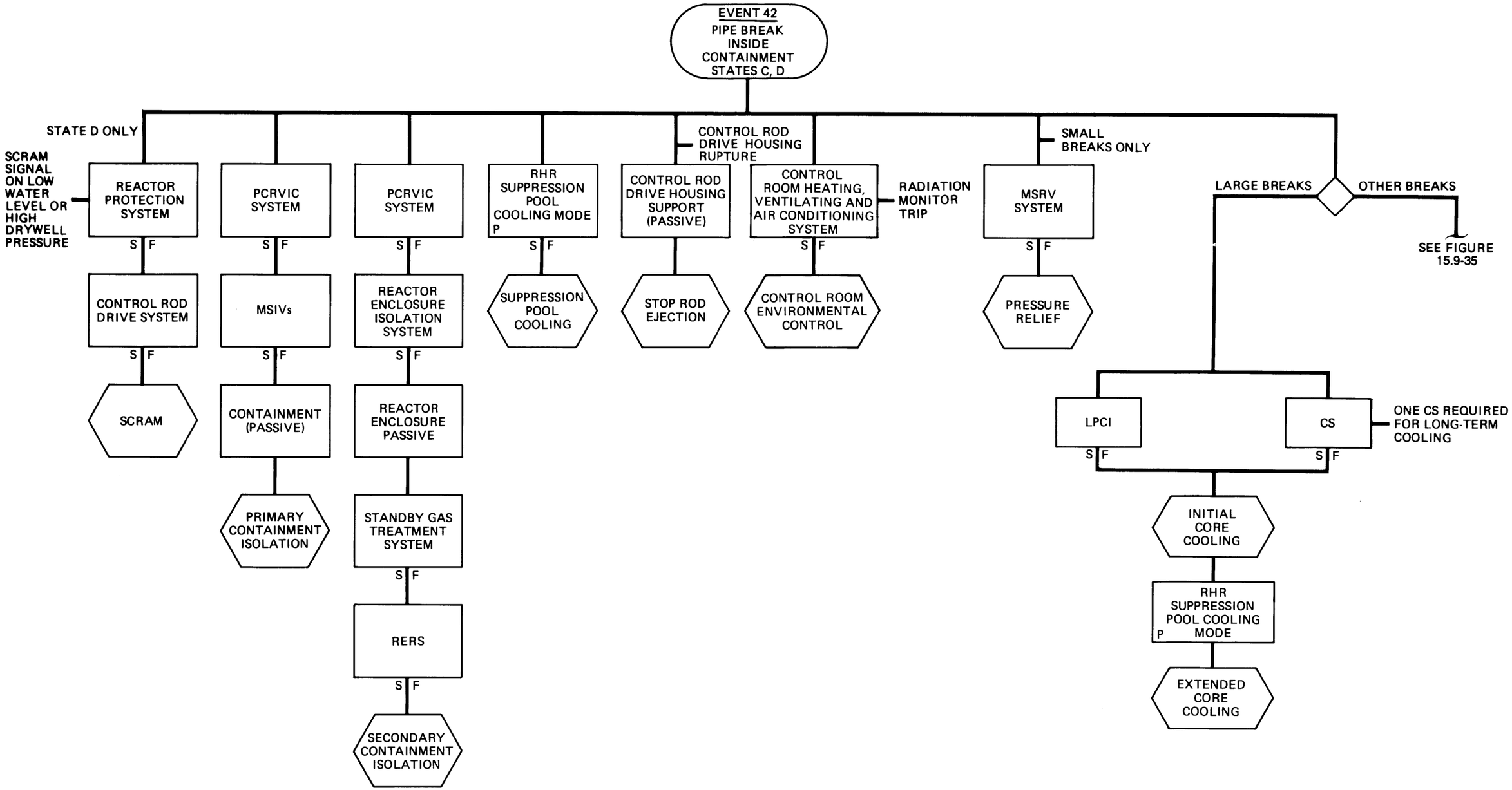
Note:
The application of Alternative Source Terms per Regulatory Guide 1.183 no longer requires refuel area isolation, or use of Standby Gas Treatment System for certain activities that could result in a fuel handling accident. See LGS Technical Specifications for SGTS and isolation requirements.

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PROTECTION SEQUENCES FOR FUEL HANDLING ACCIDENT

FIGURE 15.9-43

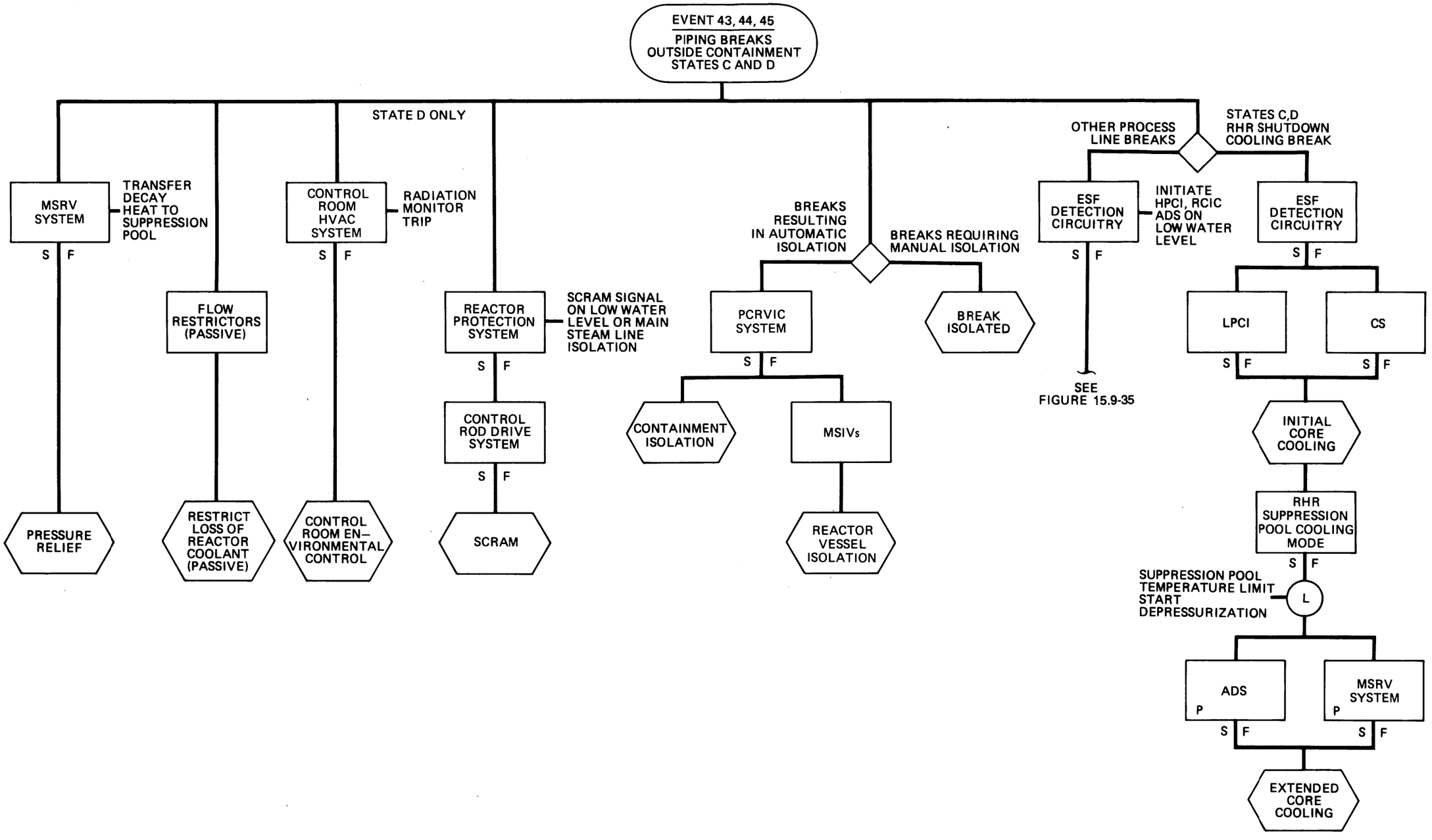
REV. 14, 09/08



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PROTECTION SEQUENCES FOR LOSS-OF-COOLANT PIPING BREAKS IN RCPB INSIDE CONTAINMENT

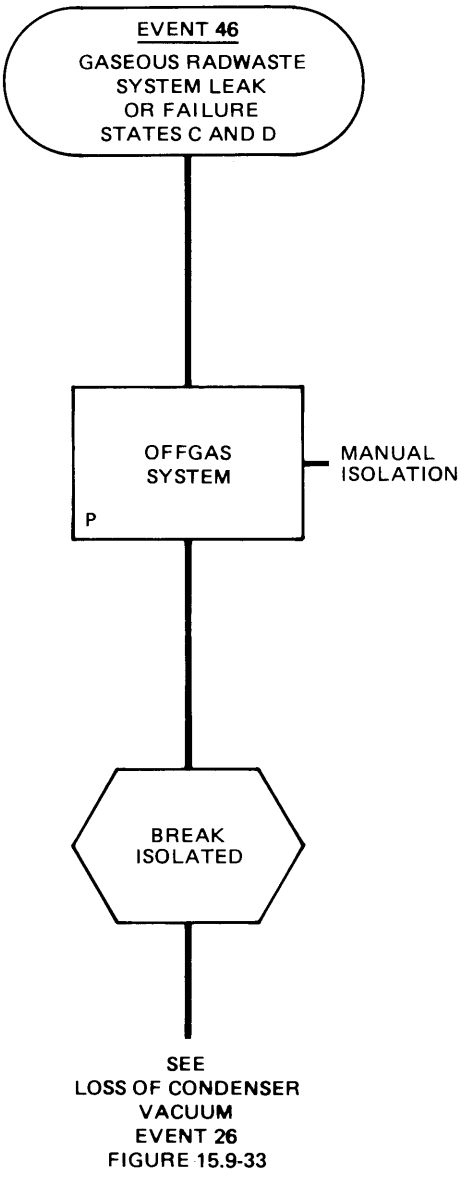
FIGURE 15.9-44



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PROTECTION SEQUENCES FOR PIPING BREAKS OUTSIDE CONTAINMENT

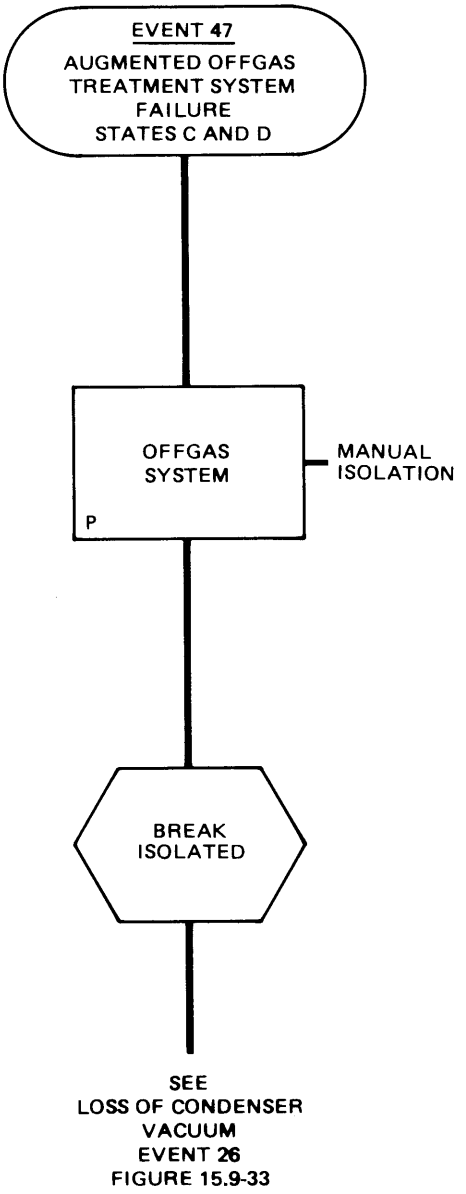
FIGURE 15.9-45



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PROTECTION SEQUENCES FOR GASEOUS RADWASTE SYSTEM LEAK OR FAILURE

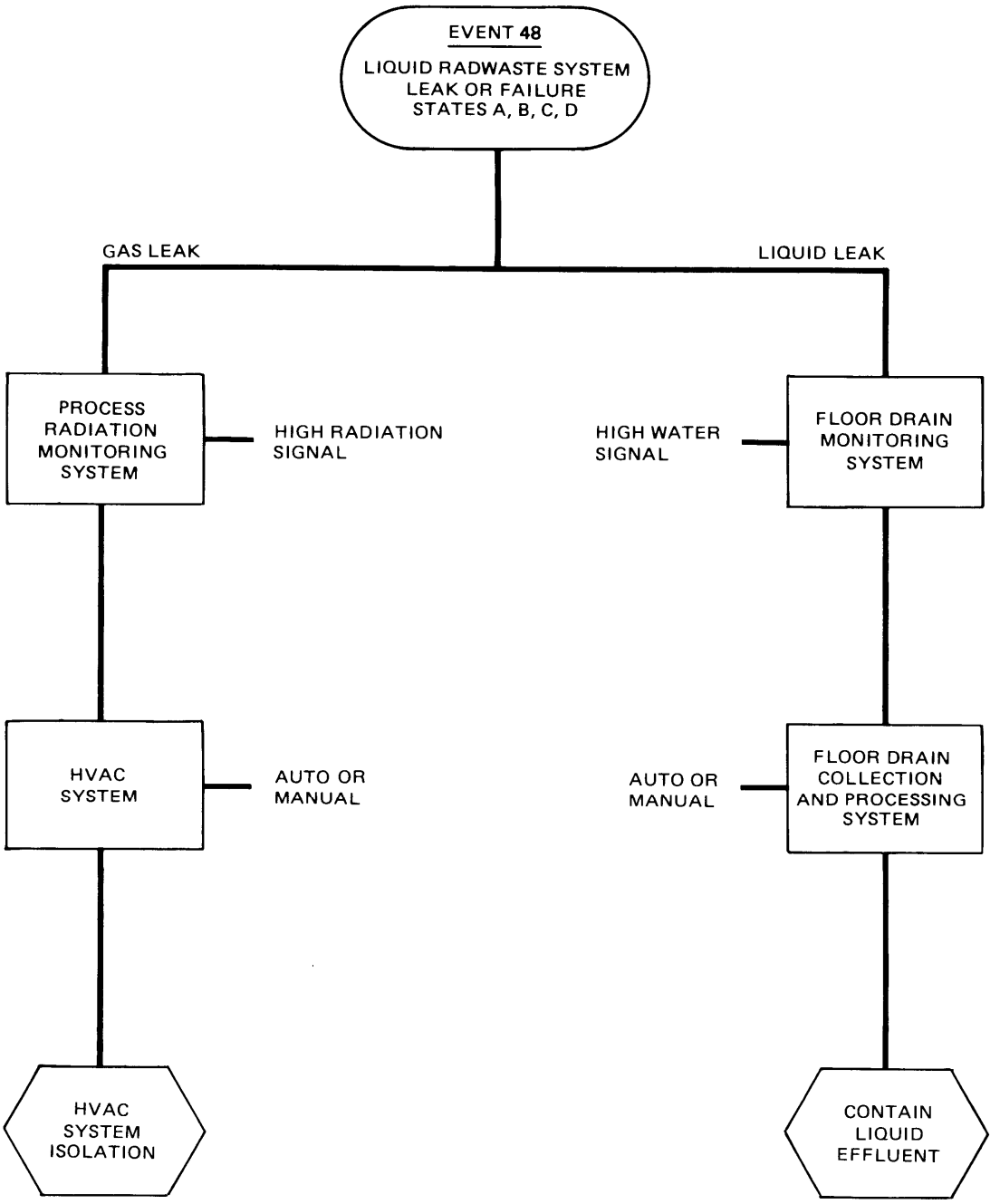
FIGURE 15.9-46



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PROTECTION SEQUENCES FOR AUGMENTED OFFGAS TREATMENT SYSTEM FAILURE

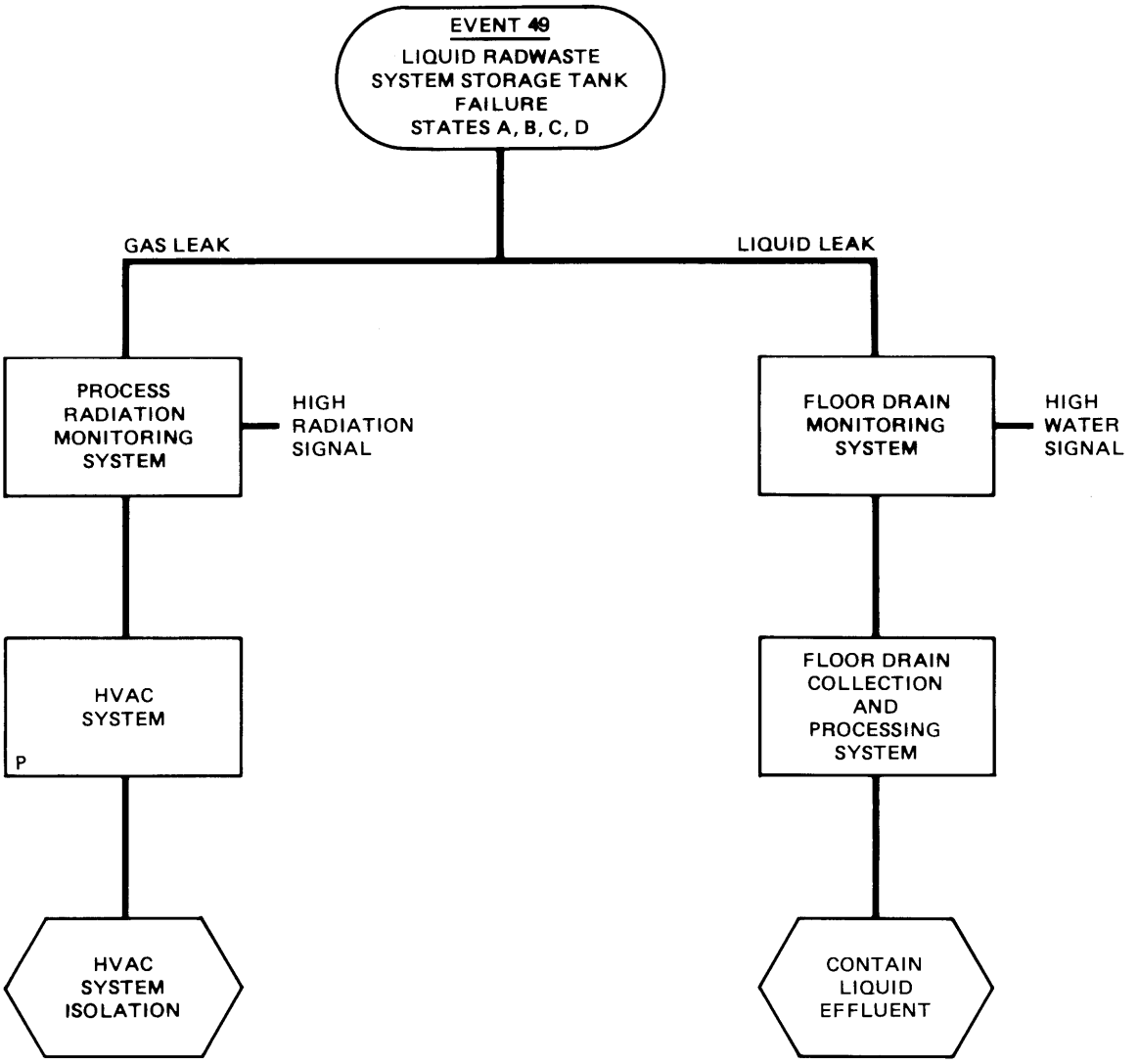
FIGURE 15.9-47



LIMERICK GENERATING STATION
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PROTECTION SEQUENCES FOR LIQUID RADWASTE SYSTEM LEAK OR FAILURE

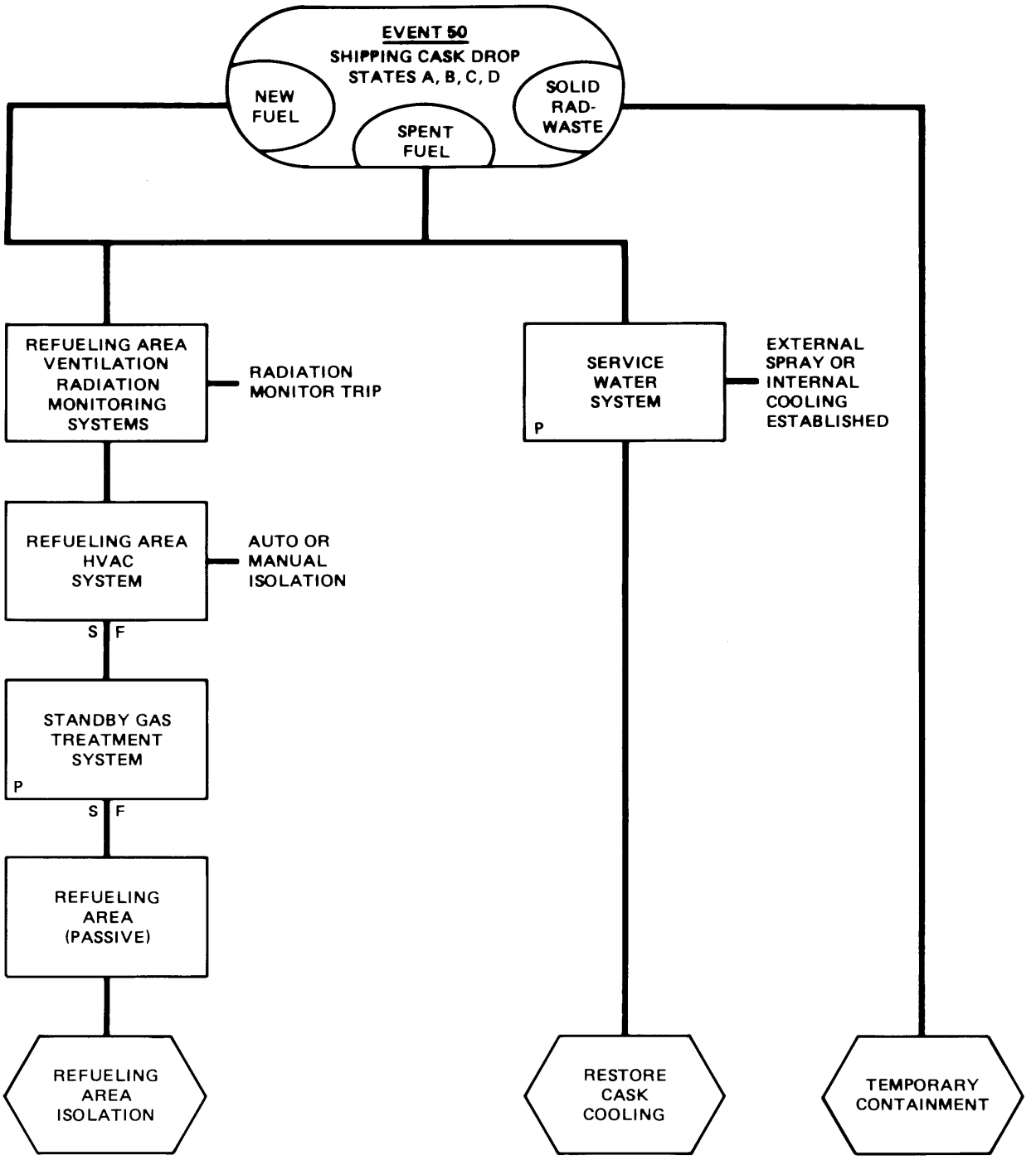
FIGURE 15.9-48



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PROTECTION SEQUENCES FOR LIQUID RADWASTE SYSTEM– STORAGE TANK FAILURE

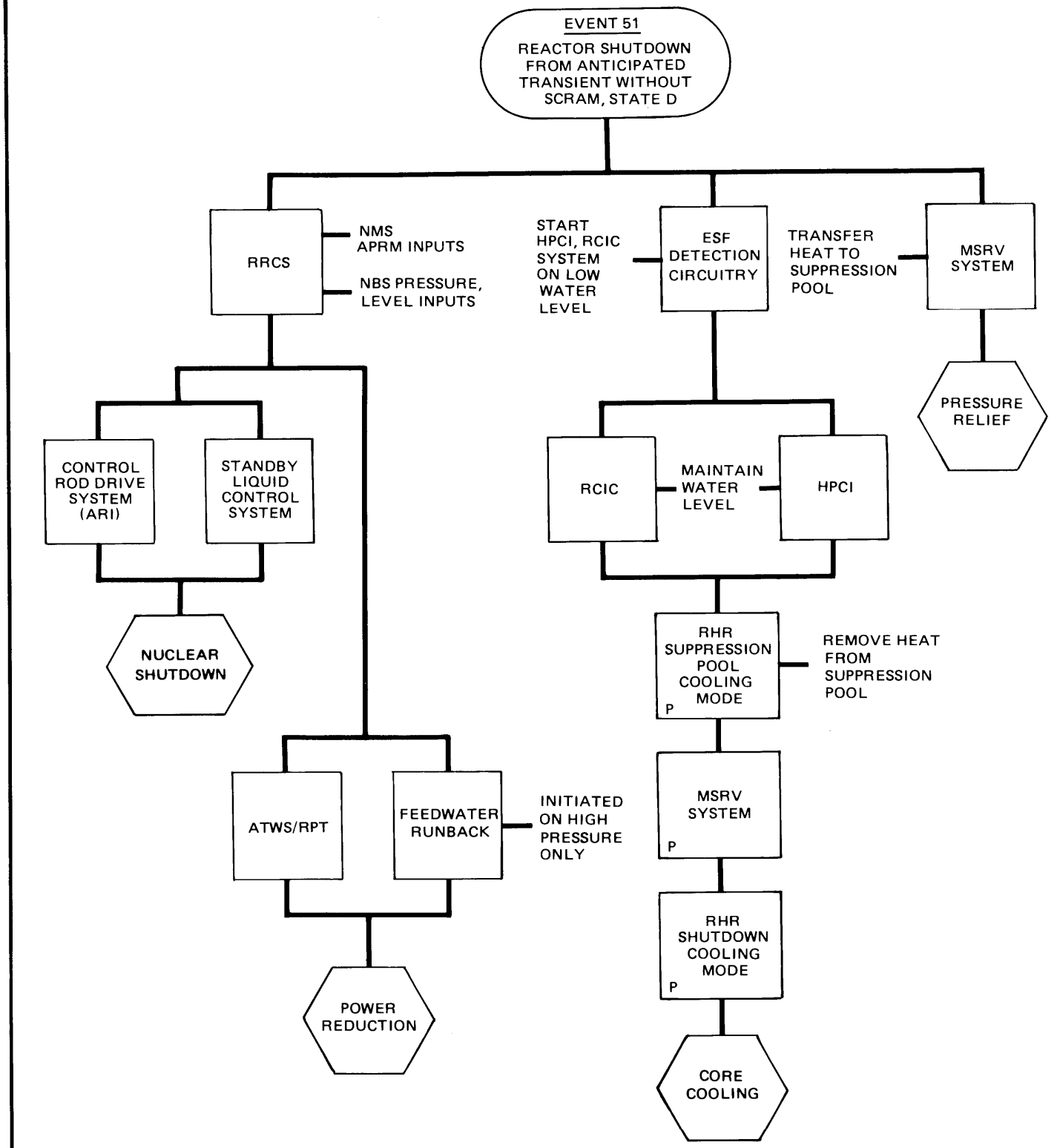
FIGURE 15.9-49



LIMERICK GENERATING STATION
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PROTECTION SEQUENCES FOR SHIPPING CASK DROP

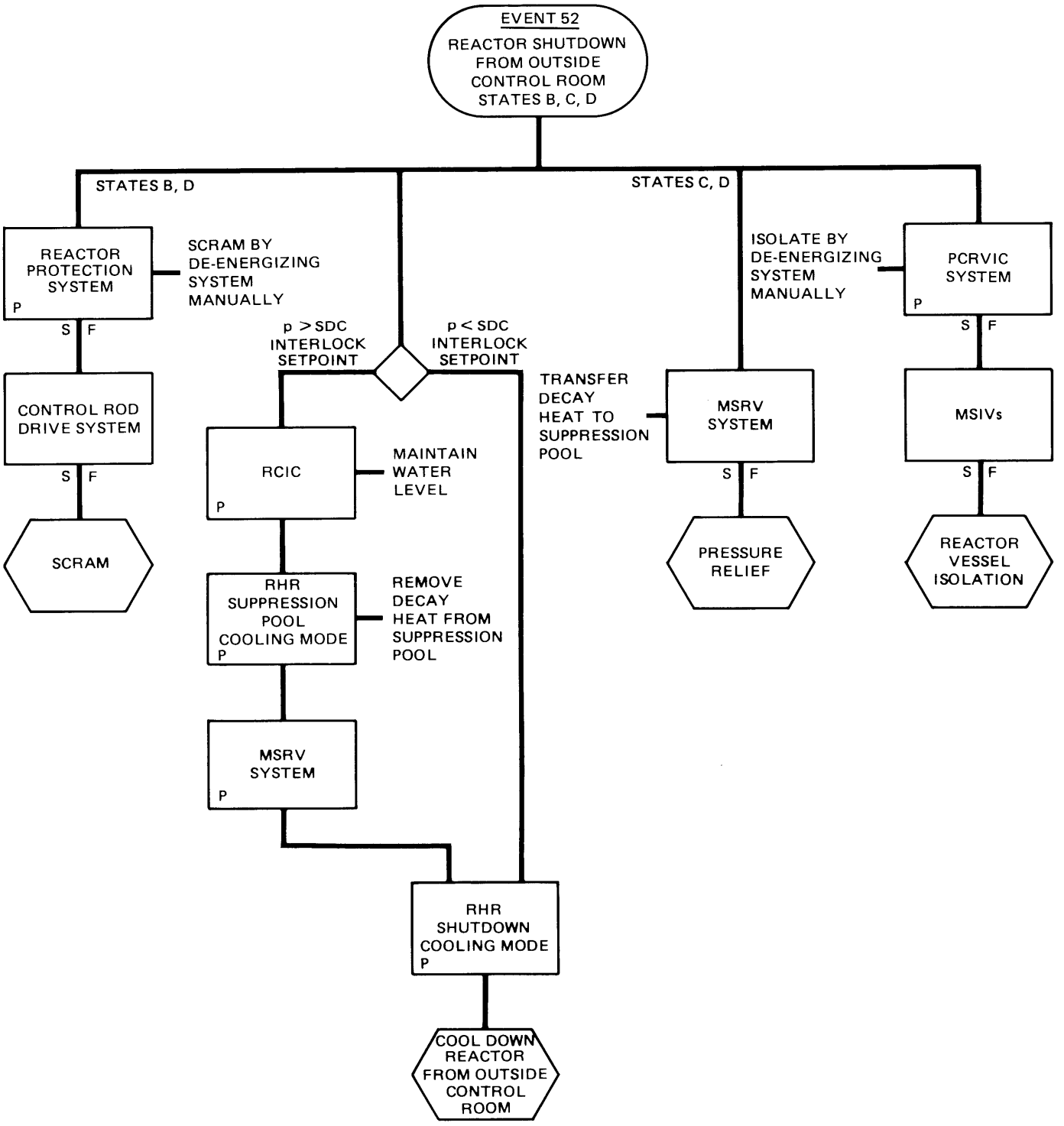
FIGURE 15.9-50



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UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR REACTOR SHUTDOWN/ATWS

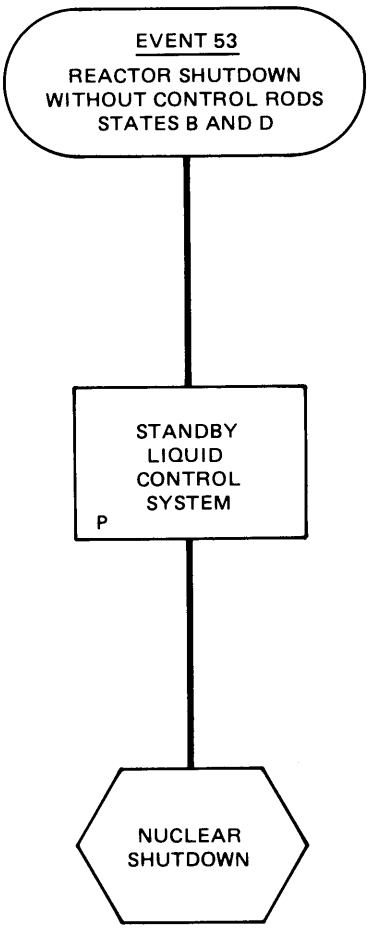
FIGURE 15. 9-51



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UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR REACTOR SHUTDOWN FROM OUTSIDE CONTROL ROOM

FIGURE 15.9-52



BOP IS CONTROLLED BY
NORMAL OPERATION

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UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PROTECTION SEQUENCES FOR REACTOR SHUTDOWN WITHOUT CONTROL RODS

FIGURE 15.9-53

APPENDIX 15A - CONTINUOUS CONTROL ROD WITHDRAWAL TRANSIENT ANALYSIS

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15A.2 METHODS OF ANALYSIS

15A.3 RESULTS

15A.4 CONCLUSIONS

15A.5 REFERENCES

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15A-2	Summary of Results for Detailed and Point Kinetics Evaluations of Continuous Rod Withdrawal in the Startup Range

APPENDIX 15A - CONTINUOUS CONTROL ROD WITHDRAWAL TRANSIENT ANALYSIS

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15A-1	Point Kinetics Control Rod Reactivity Insertion
15A-2	P/A versus Rod Worth NEDO-10527 Supplement 1 and Detailed Analysis
15A-3	Continuous RWE in the Startup Range, Core Average Power versus Time for 1.6%, 2.0%, and 2.5% Worth's (Point Model Kinetics)
15A-4	Continuous Control Rod Withdrawal from Hot Startup

APPENDIX 15A - CONTINUOUS CONTROL ROD WITHDRAWAL TRANSIENT ANALYSIS

15A.1 INTRODUCTION

The continuous control rod withdrawal transient analysis in the startup range (Section 15.4.1.2) was performed to demonstrate that the licensing basis criteria for fuel failure will not be exceeded when an out-of-sequence control rod is withdrawn at the maximum allowable normal drive speed. The sequence and timing assumed in this special analysis are shown in Table 15A-1.

The RWM constraints on rod sequences will prevent the continuous withdrawal of an out-of-sequence rod. This analysis was performed to demonstrate that, even for the unlikely event where the RWM fails to block the continuous withdrawal of an out-of-sequence rod, the licensing basis criterion for fuel failure is still satisfied.

The methods and design basis used for performing the detailed analysis for this event are similar to those previously approved for the control rod-drop accident (References 15A.1 through 15A.3). Additional simplified point model kinetics calculations were performed to evaluate the dependence of peak fuel enthalpy on the control blade worth. For the detailed calculation, the 50% control rod density pattern was selected as the initial starting condition, which is consistent with the approved design basis for the control rod-drop accident (References 15A.1 through 15A-3).

The licensing basis criterion for fuel failure is the contained energy of a fuel pellet located in the peak power region of the core which shall not exceed 170 cal/gm-UO_2.

15A.2 METHODS OF ANALYSIS

Because the rod worth calculations using the approved design basis methods (References 15A.1 through 15A-3) use three-dimensional geometry, it is not practical to do a detailed analysis of this event parameterizing control rod worths. Therefore, the methods of analysis employed were to perform a detailed evaluation of this event for a typical BWR and control rod worth (1.6% Δk) and to use a point model calculation to evaluate the results over the expected ranges of out-of-sequence control rod worths. The detailed calculations are performed to demonstrate (1) the consequences of this event over the expected power operating range and (2) the validity of the approximate point model calculation. The point model calculation will demonstrate that the licensing criterion for fuel failure is satisfied over the range of expected out-of-sequence control rod worths. These methods are described in detail below.

The methods used to perform the detailed calculation are identical to those used to perform the design basis control rod-drop accident with the following exceptions:

a. The rod withdrawal rate is 3.6 in/sec (0.3 fps) rather than the blade drop velocity of 3.11 fps.

b. Scram is initiated either by the IRM or 15% APRM scram in the startup range. The IRM system is assumed to be in the worst bypass condition allowed by Technical Specifications.

c. The blade being withdrawn inserts along with remaining drives at Technical Specification insertion rates upon initiation of scram signal.

Examination of a number of rod withdrawal transients in the low power startup range, using a two-dimensional R-Z model, has shown that higher fuel enthalpy addition would result from transients starting at the 1% power level rather than from lower power levels. The analysis further shows that for continuous rod withdrawal from these initial power levels (1% range) the APRM 15%

power level scram is likely to be reached as soon as the degraded (worst bypass condition) IRM scram. Consequently, credit is taken for either the IRM or APRM 15% scram in meeting the consequences of this event. The transients for this response were initiated at 1% of power and were performed using the 15% APRM scram.

An initial point kinetics calculation was run to determine the time to scram based on an APRM scram setpoint of 15% power and an initial power level of 1%. From this time and the maximum allowable rod withdrawal speed, it is possible to show the degree of rod withdrawal before reinsertion due to the scram. From this information, Figure 15A-1, showing the modified effective reactivity shape, was constructed.

The point model kinetics calculations use the same equations employed in the adiabatic approximation described on page 4-1 of Reference 15A.1. The rod reactivity characteristics and scram reactivity functions are input identically to the adiabatic calculations, and the Doppler reactivity is input as a function of core average fuel enthalpy. The Doppler reactivity feedback function input to the point model calculations was derived from the detailed analysis of the 1.6% rod worth case described above. This is a conservative assumption for higher rod worths because the power peaking and therefore spatial Doppler feedback will be larger for higher rod worths. As will be seen in Section 15A.3, maximum enthalpies resulted from cases initiated at 1% of rated power. In this power range, the APRM will initiate a scram at 15% of power; therefore, the APRM 15% power scram was used for these calculations, thereby eliminating the need to perform the spatial analysis required for the IRM scram. All other inputs are consistent with the detailed transient calculation.

The point model kinetics calculations result in core average enthalpies. The peak enthalpies were calculated using the following equation:

$$h = h_o + (P/A)_T (\bar{h}_f - h_o) \qquad \text{(EQ. 15A-1)}$$

where:

- h = Final peak fuel enthalpy
- h_o = Initial fuel enthalpy
- $\bar{h}_f$ = Final core average fuel enthalpy
- $(P/A)_T$ = Total peaking factor (radial peaking · axial peaking · local fuel pin peaking).

For these calculations, the (radial · axial) peaking factors as a function of rod worth were obtained from the calculations performed in section 3.6 of Reference 15A-2 and are shown in Figure 15A-2. It was conservatively assumed that no power flattening due to Doppler feedback occurred during the course of the transient.

15A.3 RESULTS

The reactivity insertion resulting from moving the control rod is shown in Figure 15A-1 for the point kinetics calculations. The core average power versus time and the global peaking factors from section 3.6 of Reference 15A-2 are shown in Figures 15A-3 and 15A-2, respectively. The results of the point kinetics calculation are summarized in Table 15A-2 along with the results of the detailed analysis.

From Figure 15A-3 and Table 15A-2, it is shown that the core average energy deposition is insensitive to control rod worth; therefore, the only change in peak enthalpy as a function of rod worth will result from differences in the global peaking which increases with rod worth. Comparison of the global peaking factors shown in Figure 15A-2 with the values used in the detailed calculations demonstrates that the Reference 15A-2 values are reasonable for their application in this study. For all cases, the peak fuel enthalpy is well below the licensing design criteria of 170 cal/gm.

Cases 4 and 5 of Table 15A-2 show that the point kinetics calculations give conservative results relative to the detailed evaluations. The primary difference is that the global peaking will flatten during the transient due to Doppler feedback. This is accounted for in the detailed calculation, but the point kinetics calculations conservatively assumed that the peaking remains constant at its initial value.

The differences in core average and peak enthalpy between cases 1 and 5 are due to the fact that for case 1 the scram was initiated by the 15% APRM scram setpoint, whereas in case 5 the scram was initiated by the IRMs. As seen by Figure 15A-4, this occurred at a core average power of 21%. Because the APRM trip point will be reached first, it is reasonable to take credit for the APRM scram.

15A.4 CONCLUSIONS

From this study, the following conclusions can be stated:

a. The resultant peak fuel enthalpies due to the continuous withdrawal of an out-of-sequence rod in the startup range results in peak fuel enthalpies that are significantly less than the licensing basis criteria of 170 cal/gm.

b. The point model calculations used to assess the sensitivity of peak enthalpy as a function of control rod worth are in good agreement with, and slightly conservative relative to the more detailed design basis model which is employed to evaluate the continuous rod withdrawal transient in the startup range.

15A.5 REFERENCES

15A-1 C.J. Paone et al, "Rod Drop Accident Analysis For Large Boiling Water Reactors", NEDO-10527, (March 1972).

15A-2 R.C. Stirn et al, "Rod Drop Accident Analysis For Large Boiling Water Reactors", NEDO-10527, Supplement 1, (July 1972).

15A-3 R.C. Stirn, "Rod Drop Accident Analysis For Large Boiling Water Reactors, Addendum 2, Exposed Cores", NEDO-10527, Supplement 2, (January 1973).

Table 15A-1

SEQUENCE OF EVENTS FOR CONTINUOUS ROD WITHDRAWAL DURING REACTOR STARTUP

TIME (sec)	EVENT
0	The reactor is critical and operating in the startup range.
>0	The operator selects and withdraws an out-of-sequence control rod at the maximum normal drive speed of 3.6 in/sec.
4 sec (Approx)	The RWM fails to block the selection (selection error) and continuous withdrawal (withdraw error) of the out-of-sequence rod.
4-8 sec	The reactor scram is initiated by the IRM system or the APRM system.
5-9 sec	The prompt power burst is terminated by a combination of Doppler and/or scram feedback.
10 sec	The transient is finally terminated by the scram of all rods, including the control rod being withdrawn. Scram insertion times are assumed to be technical specification insertion rates.

Table 15A-2

SUMMARY OF RESULTS FOR DETAILED AND POINT KINETICS EVALUATIONS OF CONTINUOUS ROD WITHDRAWAL IN THE STARTUP RANGE

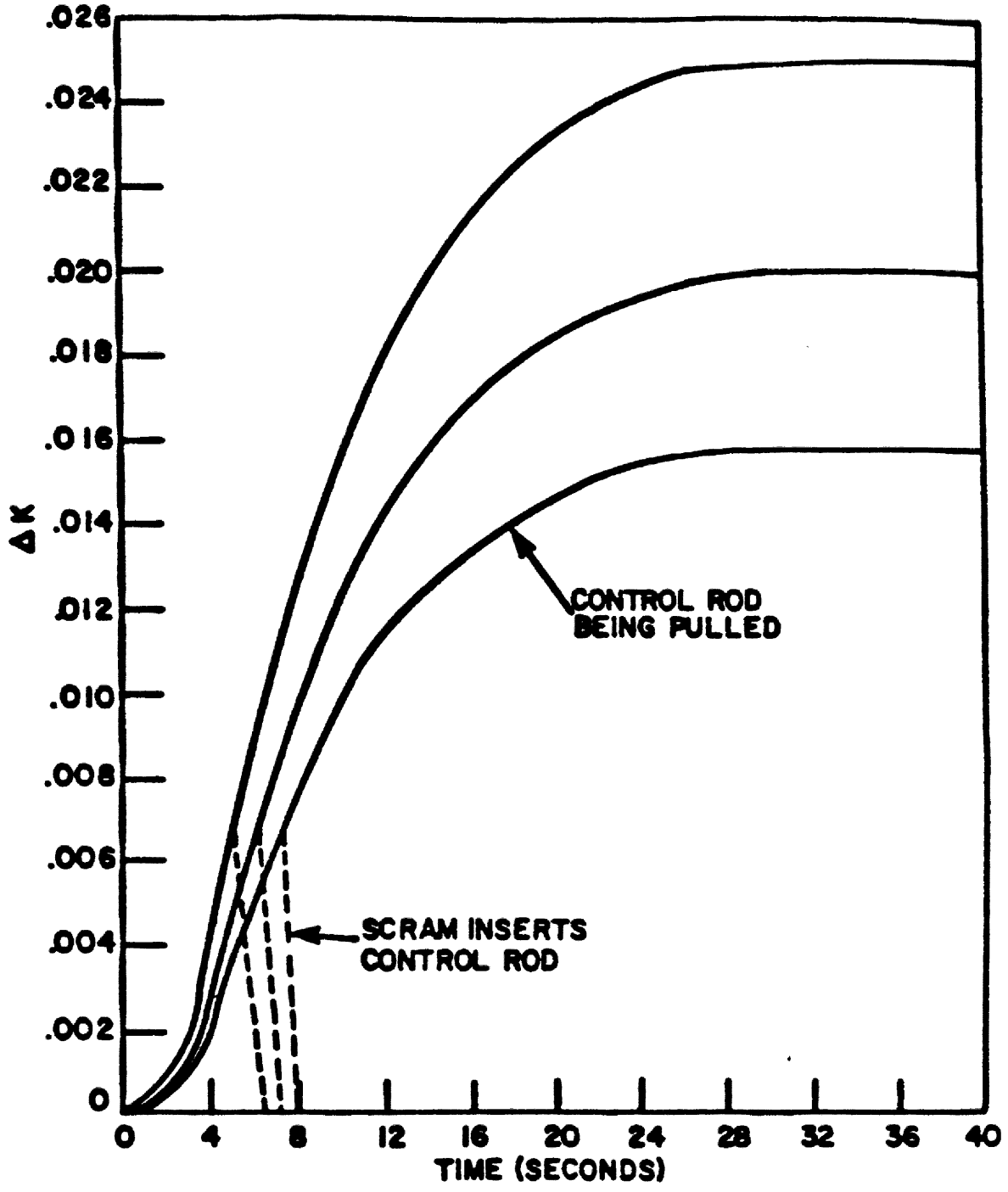
Case	Control Rod Worth (%Δk)	h_f(cal/gm)	P/A[1]	h(cal/gm)
1	1.6	17.3	24.2	42.7
2	2.0	17.3	30.9	50.0
3	2.5	17.2	46.0	58.5
4	1.6[2]	18.3	19.7[3]	56.2
5	1.6[4]	18.3	19.7	59.6

(1) P/A = global peaking factor (Radial · Axial).

(2) Detailed transient calculation. All other data reported are for point kinetics calculations.

(3) The P/A = 19.7 is the initial value. For the detailed analysis, this value will decrease during the course of the transient because the power shape will flatten due to Doppler feedback.

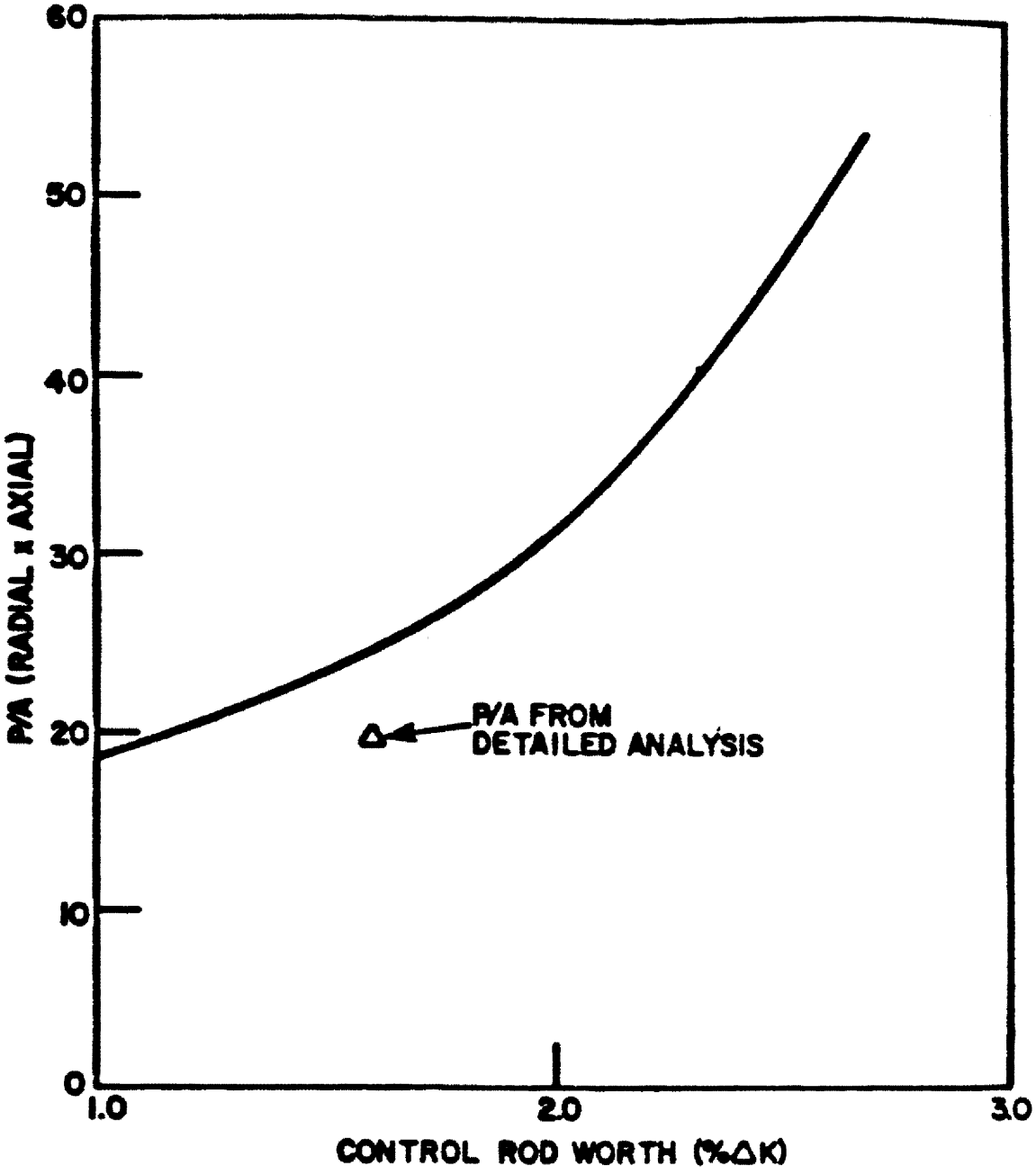
(4) Point kinetics calculation with IRM initiated scram and three-dimensional simulator global peaking.



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POINT KINETICS CONTROL ROD
REACTIVITY INSERTION

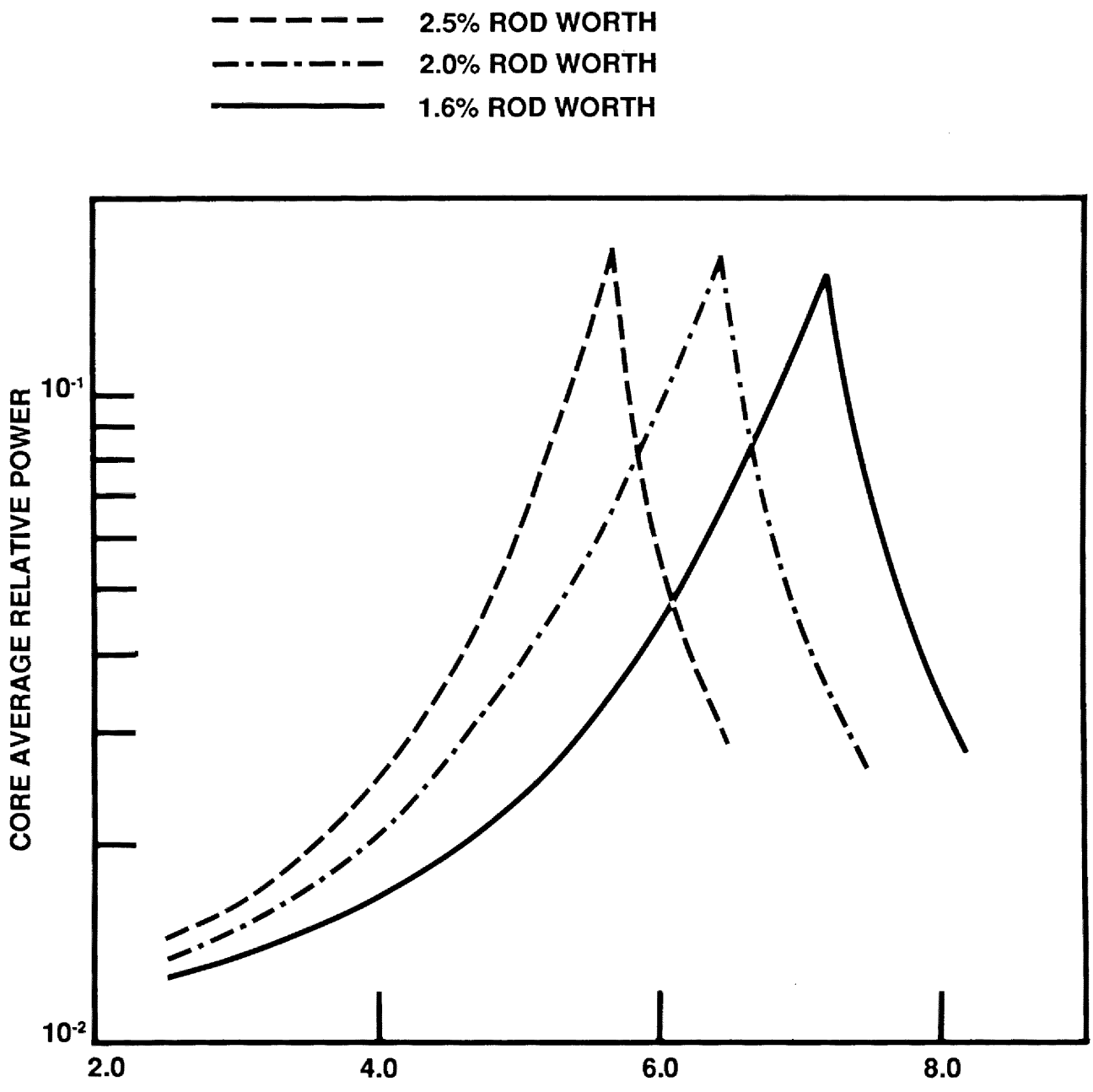
FIGURE 15A-1



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P/A VS. ROD WORTH NEDO-10527 SUPPLEMENT 1[2] AND DETAILED ANALYSIS

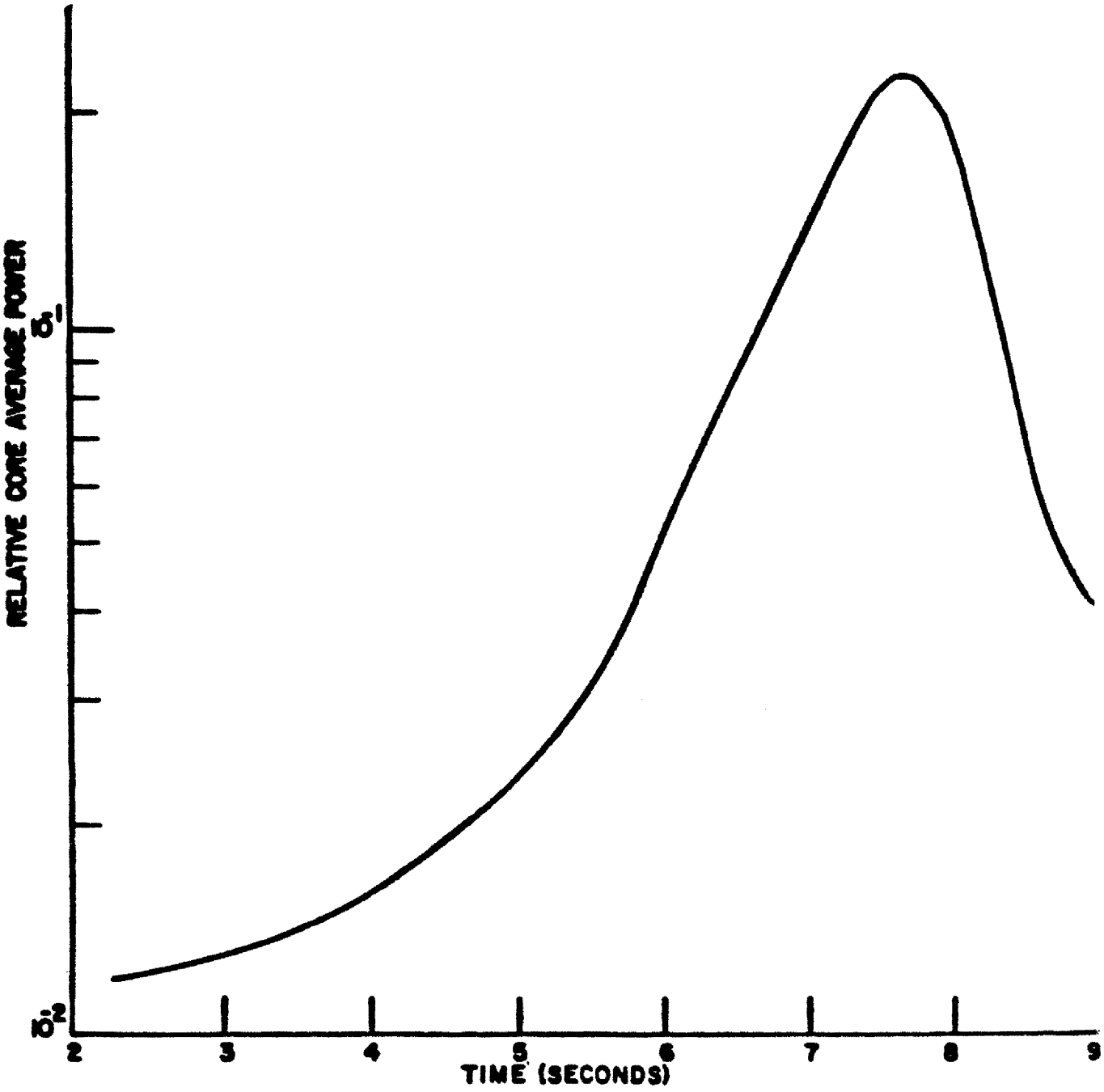
FIGURE 15A-2



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CONTINUOUS RWE IN THE STARTUP RANGE CORE AVERAGE POWER VS. TIME FOR 1.6%, 2.0% AND 2.5% WORTH'S (POINT MODEL KINETICS)

FIGURE 15A-3



ASSUMPTIONS:

1. 1.6% Δk ROD
2. 0.3 fps WITHDRAWAL VELOCITY
3. IRM SCRAM FOR WORST BYPASS CONDITION
4. $P_o = 10^{-2}$ OF RATED
5. 1967 PRODUCT LINE TECH SPEC SCRAM RATE
6. EXPOSURE = 0.0 GWD/T

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CONTINUOUS CONTROL ROD WITHDRAWAL FROM HOT STARTUP

FIGURE 15A-4

APPENDIX 15B – RELOAD EVALUATIONS

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15B.1.2	INCREASED CORE FLOW/FINAL FEEDWATER TEMPERATURE REDUCTION REGION
15B.1.3	PARTIAL FEEDWATER HEATING OR FEEDWATER HEATING OUT-OF-SERVICE
15B.2	ARTS PROGRAM
15B.3	SINGLE LOOP OPERATION
15B.4	OTHER EQUIPMENT OUT-OF-SERVICE
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15B.4.7	MAIN STEAM ISOLATION VALVE OUT-OF-SERVICE
15B.5	SUMMARY AND CONCLUSIONS
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APPENDIX 15B – RELOAD EVALUATIONS

LIST OF TABLES

Table	Title
15B-1	Deleted
15B-2	Deleted
15B-3	Deleted

APPENDIX 15B – RELOAD EVALUATIONS

LIST OF FIGURES

Figure	Title
15B-1	Deleted
15B-2	Deleted
15B-3	Deleted
15B-4	Deleted
15B-5	Deleted
15B-6	Deleted

APPENDIX 15B

Limerick Generating Station, (LGS) Units 1 and 2

15B.0 INTRODUCTION

This appendix summarizes the analyses performed in support of the LGS Units 1 and 2 operating power/flow map expansion and the contingency mode of operation with selected individual equipment out-of-service. The maximum extended operating domain consists of the maximum extended load line region and the increased core flow region. The equipment out-of-service analyses include turbine bypass system, feedwater heaters, end-of-cycle recirculation pump trip and single recirculation loop operation. The power/flow map expansion and equipment out-of-service analyses assume the rerate thermal power of 3458 MWt (References 1 through 6). TRACG implementation analyses results (References 7 and 8) are based on a thermal power of 3,515 MWt.

15B.1 MAXIMUM EXTENDED OPERATING DOMAIN AND PARTIAL FEEDWATER HEATING ANALYSIS

This analysis justifies the operation of LGS Units 1 and 2 in the maximum extended operating domain described in Figure 15.0-1. The safety impact evaluation of this extended region was performed with partial feedwater heating.

15B.1.1 MAXIMUM EXTENDED LOAD LINE LIMIT REGION

The maximum extended load line limit (MELLL) region is defined as a power/flow operating domain bounded by:

a. 100% rated power.

b. the load line which intercepts 100% power, and

c. 100% rated rod line.

MELLL improves operational flexibility during power ascension by providing additional operating room above the original rated load line. It also provides a lower core flow condition at a rated power to allow for flow control reactivity compensation due to fuel burnup during an operating cycle and for improved fuel cycle economics.

The extended power/flow region has been created to provide relief from the operating restrictions inherently imposed during ascension to power by the previous power/flow region. The MELLL boundary (% core flow at the 100% rerated core power) was determined generically, based on safety and evaluations performed to meet required thermal and reactivity margins for BWR plants. When compared to the initial power/flow operating domain, operating in the MELLL region results in plant operation at a higher load line, which allows for higher core power at a given core flow. This condition increases the fluid subcooling in the downcomer region of the reactor vessel which affects the power distribution in the core and potentially affects steady-state operating thermal limits and transient accident/performances. The impact of this operating mode was evaluated to ensure safe plant operation.

The evaluations to support this operational domain at the rerated condition of 3458 Mwt are documented in Reference 1 and 6. The MELLL analyses also considered the equipment out-of-service assumptions.

15B.1.2 INCREASED CORE FLOW/FINAL FEEDWATER TEMPERATURE REDUCTION REGION

The increased core flow (ICF) region (Figure 15.0-1) is defined as a power/flow operating domain bounded by:

a. 100% rated power.

b. 110% rated core flow, and

c. 100% rated core flow.

The ICF region is a feature that improves operational flexibility during power ascension by providing additional flow range at rated power to compensate for xenon variations during power changes. The ICF capability provides reactivity compensation due to fuel burnup during an operation cycle and additional reactivity to extend an operating cycle to improve fuel cycle economics.

The safety evaluation addresses ICF operation throughout the cycle, and ICF with Final Feedwater Temperature Reduction (FFWTR) during end-of-cycle extension and power coastdown. The amount of FFWTR considered in the analysis corresponds to a reduction of 105°F from the nominal feedwater temperature conditions.

Limiting transients events were performed at the bounding condition of 110% of rated core flow, and the results are documented in Reference 3. These ICF/FFWTR evaluations also included various equipment out-of-service such as the turbine bypass system, and the end-of-cycle recirculation pump trip.

15B.1.3 FEEDWATER HEATING OUT-OF-SERVICE

Feedwater heating out-of-service (FWHOOS) is defined as operation with feedwater heaters out-of-service, corresponding to operation with a reduction in feedwater temperature of up to 60°F from nominal.

The FWHOOS feature provides potential improved plant availability by allowing continued unrestricted plant operation with feedwater heaters out-of-service.

The FWHOOS analysis was performed for a core thermal power of 3458 MWt, using the LGS expanded operating domain. The results are described in References 4 and 5.

15B.2 ARTS PROGRAM

The ARTS program is a performance improvement feature which updates fuel thermal limits administration at partial power/flow conditions, improves instrumentation response and increases plant operating flexibility and efficiency.

ARTS provides limits for MCPR and MAPLHGR as a function of power and flow to better ensure fuel cladding integrity. It also modifies the basis of rod block monitor trips to terminate excessive reactivity insertions during rod withdrawal error events. The original flow-biased rod block monitor trips are replaced by local power biased trips.

The ARTS analyses (References 2 and 6) were performed at the rerated power level of 3458 MWt and a maximum core flow of 110% of rated. The analysis also assumes equipment out-of-service such as turbine bypass and end-of-cycle recirculation pump trip and single loop operation. The results are summarized in Reference 2 for all equipment in-service and in Reference 6 for the equipment out-of-service conditions.

15B.3 SINGLE LOOP OPERATION

Single Loop Operation (SLO) at a reduced power is a valuable feature from a plant availability/outage standpoint. The capability to operate with a single recirculation loop is highly desirable in the event that a recirculation pump or other component renders one loop inoperable. The analyses necessary to justify SLO operation are evaluated in Reference 2.

15B.4 OTHER EQUIPMENT OUT-OF-SERVICE

In addition to the FWHOOS feature, LGS also has the turbine bypass system out-of-service (TBSOOS) and the end-of-cycle recirculation pump trip out-of-service (EOC-RPTOOS) features. Subsequent to the analysis supporting power/flow map expansion, an additional equipment out-of-service feature, power load unbalance out-of-service (PLUOOS), was implemented.

15B.4.1 TURBINE BYPASS SYSTEM OUT-OF-SERVICE

Turbine bypass operation has a significant impact on the severity of fast pressurization events. Of these AOOs, the turbine trip no bypass (TTNBP) and load rejection no bypass (LRNBP) events already exclude the turbine bypass operation from their licensing event basis assumptions. The feedwater controller failure (FWCF) normally evaluated with an operable bypass system is therefore re-analyzed without the turbine bypass function.

The TBSOOS option was integrated in the power/flow map expansion and performance improvement programs (including power rerate) previously described. The results of the Anticipated Operating Occurrences (AOO) analysis with TBSOOS are described in Reference 1.

Turbine Bypass System OOS may be referred to as Turbine Bypass Valve (TBVOOS) in some documentation. Starting with Limerick 2 Cycle 14, references to "TBVOOS" that do not meet the definition in Section 15B.4.6 were changed to be referred to as "TBSOOS" to reflect that the bypass valves are assumed to be unable to provide pressure control, and so transients that rely on the bypass system for pressure control (e.g., rod withdrawal error), are analyzed accordingly for the TBSOOS condition.

15B.4.2 END-OF-CYCLE RECIRCULATION PUMP TRIP OUT-OF-SERVICE

The purpose of the end-of-cycle recirculation pump trip (EOC-RPT) is to protect the integrity of the fuel cladding during fast pressurization transients, especially turbine generator trips. It supplements the reactor scram function during these events. The trip of the reactor recirculation pumps early in these transient events decreases the magnitude of the power excursion by adding negative reactivity to the core, consequently resulting in lower thermal operating limits.

For the power/flow map expansion and equipment-out-of-service features previously described, both the limiting TTNBP and FWCF events are analyzed with the EOC-RPTOOS option. The results of these analyses are described in Reference 1.

15B.4.3 POWER LOAD UNBALANCE OUT-OF-SERVICE

The purpose of the power load unbalance (PLU) is to prevent turbine over-speed in the event of a load rejection. The PLU prompts the fast closure of the turbine control valves when an unbalance is detected while operating above 55% power. With the PLUOOS, a load rejection event will not cause fast closure of the TCVs. A backup trip from the generator protection system logic is credited and results in a turbine trip signal.

15B.4.4 PRESSURE REGULATOR OUT-OF-SERVICE

The purpose of the Pressure Regulator Out-of-Service (PROOS) is to support operation when one pressure regulator is out-of-service and the system is no longer single failure proof. Failure of a pressure regulator downscale, when there is no second pressure regulator operable will cause slow closure of the turbine control valves. This event can require more limiting thermal limits.

The results of these analyses are described in References 7 and 8 and/or included as part of the cycle-specific reload analysis.

15B.4.5 SAFETY RELIEF VALVE OUT-OF-SERVICE

The Safety/Relief Valves (S/RVs), as described in UFSAR Chapter 5, ensure that peak reactor pressure is maintained below ASME upset limits. This option provides support to operate the plant with two safety and/or relief valves declared out-of-service (OOS) and is included with the SRV setpoint tolerance increase (Reference 9). The transient analyses are confirmed on a reload-specific basis; other analyses (LOCA, structural, etc.) are performed generically or with fuel-type specific basis.

15B.4.6 TURBINE BYPASS VALVE OUT-OF-SERVICE

This option differs from TBSOOS discussed in 15B.4.1 in that a limited number of Turbine Bypass Valves (TBV) are out-of-service instead of the entire Turbine Bypass System. As permitted by station Technical Specifications, a certain number of TBVs are permitted to be OOS as specified in the Core Operating Limits Report (COLR). If this number is exceeded, the entire Turbine Bypass System is considered to be OOS.

15B.4.7 MAIN STEAM ISOLATION VALVE OUT-OF-SERVICE

This option provides justification for continuous operation with a main steam isolation valve (MSIV) OOS when there is not compliance with the requirements of the technical specifications for the main steam isolation valves closure characteristics (Reference 10). Limitations on the maximum permissible power level when operating with an MSIVOOS are provided in the cycle specific Supplemental Reload Licensing Report (SRLR).

15B.5 SUMMARY AND CONCLUSION

Specific analyses have been performed to determine the impact of LGS plant operation with the above specified reactor performance improvements. The results demonstrate that all licensing basis criteria for the required safety analyses are acceptable. These include the following analysis evaluations.

a. Anticipated Operational Occurrences (AOOs) Analysis

b. Loss-Of-Coolant Analysis

c. Containment Response

d. Reactor Vessel and Internals Mechanical Integrity

e. Miscellaneous Impact Verifications (e.g. Anticipated Transients Without Scram).

The AOOs analyses are cycle-specific and are reanalyzed during subsequent fuel cycles as part of the reload licensing scope of work. The LOCA analysis is fuel type specific and is evaluated or reanalyzed as required. The containment dynamic loads, reactor internal components structural integrity and the miscellaneous analyses are cycle-independent. These tasks are performed during the initial application of the performance improvement programs and remain valid for subsequent fuel reloads, unless the analyses boundaries and/or analytical assumptions are subsequently changed.

15B.6 REFERENCES

1. GE Nuclear Energy, "Power Rerate Safety Analysis Report" for Limerick Generating Station Units 1 and 2, Licensing Topical Report NEDC-32225P, Class III (Proprietary), September 1993.

2. GE Nuclear Energy, "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses" For Limerick Generating Station Units 1 and 2, NEDC-32193P (Revision 2), October 1993.

3. GE Nuclear Energy, "Safety Review for Limerick Generating Station Units 1 and 2 110% Increased Core Flow Operation and Final Feedwater Temperature Reduction" NEDC-32224P (Revision 1), October 1994.

4. GE Nuclear Energy, "Increased Core Flow and Partial Feedwater Heating Analysis For Limerick Generating Station Unit 1 Cycle 1," NEDC-31323, October 1986.

5. GE Nuclear Energy, "Impact of Power Rerate and Final Feedwater Temperature Reduction (FFWTR) or Limerick Feedwater Nozzle Fatigue," GE-Ne-523-102-0793, July 27, 1993.

6. GE-NE letter/Report transmittal to PECO, (G93-PEPR-327) Subject "Limerick ARTS Application with Equipment Out-of-service (EOOS)", December 10, 1993.

7. GE Hitachi Nuclear Energy, "Limerick Generating Station Units 1 and 2 TRACG Implementation for Reload Licensing Transient Analysis," 0000-0137-9500-R1, October 2017.

8. GE Hitachi Nuclear Energy, "Limerick Generating Station (LGS) Units 1 and 2 TRACG Cycle-Independent PROOS Analysis Report," 002N4397-R1, January 2016.

9. NEDC-32645P, Revision 2, Limerick Generating Station Units 1 and 2 SRV Setpoint Tolerance Relaxation Licensing Report, December 1998.

10. NEDE-24011-P-A-32-US, General Electric Standard Application for Reactor Fuel, August 2024.

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CHAPTER 16 - TECHNICAL SPECIFICATIONS

16.1 PRELIMINARY TECHNICAL SPECIFICATIONS

This section is not applicable to the LGS UFSAR.

16.2 PROPOSED FINAL TECHNICAL SPECIFICATIONS

The final Technical Specifications for Limerick Unit 1 are based on the NRC's Standard Technical Specifications for BWRs (NUREG-0123) and were issued as Appendix A to Facility Operating License NPF-39. The proposed final Technical Specifications for Unit 2 were based on Unit 1 Technical Specifications as a guide. The Unit 2 Technical Specifications were issued as Appendix A to Facility Operating License NPF-85.

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APPENDIX 17.2.II - Deleted.

CHAPTER 17 - QUALITY ASSURANCE

17.1 QUALITY ASSURANCE DURING DESIGN AND CONSTRUCTION

This section is not applicable to the LGS UFSAR.

17.2 QUALITY ASSURANCE DURING THE OPERATIONS PHASE

The licensee is responsible for the operation and maintenance of Limerick Generating Station (LGS). These activities are presently conducted in accordance with the NRC approved Quality Assurance Topical Report (QATR) which describes the formal and comprehensive control methods established to assure compliance with 10CFR50, Appendix B.

The QATR describes how the Quality Assurance Program is to be functionally implemented with due regard to the safety and health of the public and the personnel on site. The LGS Quality Assurance Program as described by the QATR is incorporated herein by reference.

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A.1 Introduction

The application for a renewed operating license is required by 10 CFR 54.21(d) to include a UFSAR Supplement. This appendix, which includes the following sections, comprises the UFSAR supplement:

- Section A.1.1 contains a listing of the aging management programs that correspond to NUREG-1801 Chapter XI programs.
- Section A.1.2 contains a listing of the plant-specific aging management programs.
- Section A.1.3 contains a listing of aging management programs that correspond to NUREG-1801 Chapter X programs associated with Time-Limited Aging Analyses.
- Section A.1.4 contains a listing of the Time-Limited Aging Analyses summaries (TLAAs).
- Section A.1.5 contains a discussion of the Quality Assurance Program and Administrative Controls.
- Section A.2.1 contains a summarized description of the NUREG-1801 Chapter XI programs for managing the effects of aging.
- Section A.2.2 contains a summarized description of the plant-specific programs for managing the effects of aging.
- Section A.3 contains a summarized description of the NUREG-1801 Chapter X programs that support the TLAAs.
- Section A.4 contains a summarized description of the TLAAs applicable to the period of extended operation.
- Section A.5 contains the License Renewal Commitment List.

The integrated plant assessment for license renewal identified new and existing aging management programs necessary to provide reasonable assurance that systems, structures, and components within the scope of license renewal will continue to perform their intended functions consistent with the Current Licensing Basis (CLB) for the period of extended operation. The period of extended operation is defined as 20 years from the unit's operating license expiration date that existed prior to License Renewal.

A.1.1 NUREG-1801 Chapter XI Aging Management Programs

The NUREG-1801 Chapter XI Aging Management Programs (AMPs) are described in the following sections. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-1801 or require enhancements.

The following list reflects the status of these programs at the time of the renewed licenses issuance. Commitments for program additions and enhancements are identified in the Appendix A.5 License Renewal Commitment List.

1. ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section A.2.1.1) [Existing]
2. Water Chemistry (Section A.2.1.2) [Existing]
3. Reactor Head Closure Stud Bolting (Section A.2.1.3) [Existing]
4. BWR Vessel ID Attachment Welds (Section A.2.1.4) [Existing]
5. BWR Feedwater Nozzle (Section A.2.1.5) [Existing]
6. BWR Control Rod Drive Return Line Nozzle (Section A.2.1.6) [Existing – Requires Enhancement]
7. BWR Stress Corrosion Cracking (Section A.2.1.7) [Existing]
8. BWR Penetrations (Section A.2.1.8) [Existing]
9. BWR Vessel Internals (Section A.2.1.9) [Existing – Requires Enhancement]
10. Flow-Accelerated Corrosion (Section A.2.1.10) [Existing]
11. Bolting Integrity (Section A.2.1.11) [Existing - Requires Enhancement]
12. Open-Cycle Cooling Water System (Section A.2.1.12) [Existing – Requires Enhancement]
13. Closed Treated Water Systems (Section A.2.1.13) [Existing – Requires Enhancement]
14. Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (Section A.2.1.14) [Existing – Requires Enhancement]
15. Compressed Air Monitoring (Section A.2.1.15) [Existing]
16. BWR Reactor Water Cleanup System (Section A.2.1.16) [Existing]
17. Fire Protection (Section A.2.1.17) [Existing – Requires Enhancement]
18. Fire Water System (Section A.2.1.18) [Existing – Requires Enhancement]
19. Aboveground Metallic Tanks (Section A.2.1.19) [Existing – Requires Enhancement]
20. Fuel Oil Chemistry (Section A.2.1.20) [Existing – Requires Enhancement]
21. Reactor Vessel Surveillance (A.2.1.21) [Existing]

22. One-Time Inspection (Section A.2.1.22) [New]

23. Selective Leaching (A.2.1.23) [New]

24. One-Time Inspection of ASME Code Class 1 Small-Bore Piping (Section A.2.1.24) [New]

25. External Surfaces Monitoring of Mechanical Components (Section A.2.1.25) [New]

26. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section A.2.1.26) [New]

27. Lubricating Oil Analysis (Section A.2.1.27) [Existing]

28. Monitoring of Neutron-Absorbing Materials Other than Boraflex (Section A.2.1.28) [Existing – Requires Enhancement]

29. Buried and Underground Piping and Tanks (Section A.2.1.29) [Existing – Requires Enhancement]

30. ASME Section XI, Subsection IWE (Section A.2.1.30) [Existing – Requires Enhancement]

31. ASME Section XI, Subsection IWL (Section A.2.1.31) [Existing – Requires Enhancement]

32. ASME Section XI, Subsection IWF (Section A.2.1.32) [Existing – Requires Enhancement]

33. 10 CFR Part 50, Appendix J (Section A.2.1.33) [Existing]

34. Masonry Walls (Section A.2.1.34) [Existing – Requires Enhancement]

35. Structures Monitoring (Section A.2.1.35) [Existing – Requires Enhancement]

36. RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section A.2.1.36) [Existing – Requires Enhancement]

37. Protective Coating Monitoring and Maintenance Program (Section A.2.1.37) [Existing – Requires Enhancement]

38. Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.38) [New]

39. Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (Section A.2.1.39) [New]

40. Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.40) [New]

41. Metal Enclosed Bus (Section A.2.1.41) [New]

42. Fuse Holders (Section A.2.1.42) [New]

43. Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.43) [New]

A.1.2 Plant-Specific Aging Management Programs

None. Limerick Generating Station, Units 1 and 2 do not have plant-specific aging management programs as a result of License Renewal.

A.1.3 NUREG-1801 Chapter X Aging Management Programs

The NUREG-1801 Chapter X Aging Management Programs (AMP) associated with Time-Limited Aging Analyses are described in the following sections. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-1801 Chapter X or require enhancements. The following list reflects the status of these programs at the time of the renewed licenses issuance. Commitments for program additions and enhancements are identified in Appendix A.5 License Renewal Commitment List.

1. Fatigue Monitoring (Section A.3.1.1) [Existing – Requires Enhancement]

2. Environmental Qualification (EQ) of Electric Components (Section A.3.1.2) [Existing]

A.1.4 Time-Limited Aging Analyses

Summaries of the Time-Limited Aging Analyses applicable to the period of extended operation are included in the following sections:

1. Reactor Pressure Vessel Neutron Embrittlement Analysis (Section A.4.2)

2. Metal Fatigue (Section A.4.3)

3. Environmental Qualification (EQ) of Electric Components (Section A.4.4)

4. Containment Liner and Penetrations Fatigue Analysis (Section A.4.5)

5. Other Plant-Specific Time-Limited Aging Analyses (Section A.4.6)

A.1.5 Quality Assurance Program and Administrative Controls

The Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2, “Quality

Assurance For Aging Management Programs (Branch Technical Position IQMB-1)" of NUREG-1800. The Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and nonsafety-related systems, structures, and components (SSCs) that are subject to Aging Management Review (AMR). In many cases, existing activities were found adequate for managing aging effects during the period of extended operation. As permitted by the License Amendment to implement 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors," Alternative Treatments may be applied in lieu of 10 CFR 50 Appendix B for components that have a Risk-Informed Safety Classification (RISC) RISC-3 or RISC-4.

A.1.6 OPERATING EXPERIENCE

The Operating Experience program is an existing program that has been enhanced to ensure, through the ongoing review of both internal and external operating experience, that the license renewal aging management programs are effective to manage the aging effects for which they are credited throughout the period of extended operation. The programs are either enhanced or new programs developed when the review of operating experience indicates that the effects of aging may not be adequately managed.

The Operating Experience program has been enhanced to:

1. Explicitly require the review of operating experience for aging-related degradation.

2. Establish criteria to define aging-related degradation.

3. Establish identification coding for use in identification, trending and communications of aging-related degradation.

4. Require communication of significant internal aging-related degradation, associated with SSCs in the scope of license renewal, to other Exelon plants and to the industry. Criteria will be established for determining when aging-related degradation is significant.

5. Require review of external operating experience for information related to aging management and evaluation of such information for potential improvements to LGS aging management activities.

6. Provide training to those responsible for screening, evaluating and communicating operating experience items related to aging management.

These enhancements were implemented prior to the date that the renewed operating licenses were issued and will be conducted on an ongoing basis throughout the terms of the renewed licenses.

A.2 Aging Management Programs

A.2.1 NUREG-1801 Chapter XI Aging Management Programs

This section provides summaries of the NUREG-1801 programs credited for managing the effects of aging.

A.2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program is an existing program that consists of periodic volumetric and visual examinations of components for assessment, identification of signs of degradation, and establishment of corrective actions. The program includes inspections performed to identify and manage cracking and loss of fracture toughness in Class 1, 2, and 3 piping and components exposed to reactor coolant and treated water environments. The inspections will be implemented in accordance with 10 CFR 50.55(a) and ASME Code, Section XI Subsections IWB, IWC, and IWD. These activities include inspections, and monitoring and trending of results to confirm that aging effects are managed. As permitted by the License Amendment to implement 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors," Alternative Treatments may be applied in lieu of 10 CFR 50.55(a) ASME Section XI Inservice Inspection requirements for ASME Class 2 and Class 3 components that have a Risk-Informed Safety Classification (RISC) RISC-3 or RISC-4.

A.2.1.2 Water Chemistry

The Water Chemistry aging management program is an existing program whose activities consist of monitoring and control of water chemistry to manage the aging of reactor vessel, reactor internals, piping, piping elements and piping components, heat exchangers and tanks that are exposed to treated water. The Water Chemistry aging management program keeps peak levels of various contaminants below system-specific limits based on the industry recognized guidelines of the Boiling Water Reactor Vessel and Internals Project (BWRVIP-190, Revision 1, Electric Power Research Institute - 3002002623) for the prevention or mitigation of loss of material, reduction of heat transfer and cracking aging effects. In addition, the water chemistry program is also credited for mitigating loss of material and cracking for components exposed to sodium pentaborate, steam and reactor coolant environments. To mitigate aging effects on component surfaces the chemistry program is used to control water chemistry for impurities that accelerate corrosion.

A.2.1.3 Reactor Head Closure Stud Bolting

The Reactor Head Closure Stud Bolting program is an existing program that provides for condition monitoring and preventive activities to manage reactor head closure studs and associated nuts, washers and flange threads for cracking and loss of material. The program is implemented through station

procedures based on the examination and inspection requirements specified in ASME Section XI, Table IWB-2500-1 and preventive measures described in NRC Regulatory Guide 1.65, “Materials and Inspection for Reactor Vessel Closure Studs”, with the exception that stud bolting material having a measured yield stress greater than 150 ksi is used.

A.2.1.4 BWR Vessel ID Attachment Welds

The BWR Vessel ID Attachment Welds aging management program is an existing aging management program that incorporates the inspection and evaluation recommendations of BWRVIP-48-A, and the recommendations described in the Water Chemistry (A.2.1.2) program. The program is implemented through station procedures that provide for mitigation of cracking through management of reactor water chemistry and monitoring for cracking through in-vessel examinations of the reactor vessel internal attachment welds. Examinations performed under this program are implemented via augmented inservice inspection requirements.

A.2.1.5 BWR Feedwater Nozzle

The BWR Feedwater Nozzle aging management program is an existing program that manages the effects of cracking in the feedwater nozzles by augmented in-service inspection (ISI) in accordance with the requirements of the ASME Code, Section XI, Subsection IWB, Table IWB-2500-1 and the recommendations provided within BWROG Licensing Topical Report, GE-NE-523-A71-0594-A, Revision 1. Inspections of the feedwater nozzles are performed in accordance with the ISI Program Plan.

A.2.1.6 BWR Control Rod Drive Return Line Nozzle

The BWR Control Rod Drive Return Line (CRDRL) Nozzle aging management program is an existing program that provides for condition monitoring of the CRDRL reactor pressure vessel nozzle for cracking. The CRDRL nozzle has been capped to mitigate thermal fatigue cracking on both units. The program performs In-service Inspection (ISI) examinations to monitor the effects of cracking on the intended function of the CRDRL nozzle. Volumetric ultrasonic inspection is performed on the CRDRL nozzle including the nozzle-to-vessel weld, nozzle blend radius and nozzle-to-cap welds. The CRDRL nozzle and nozzle-to-vessel weld examinations are performed at the frequency specified in ASME Code, Section XI, Table IWB-2500-1. The CRDRL nozzle-to-cap weld examinations are performed at a frequency specified by the BWR Stress Corrosion Cracking (A.2.1.7) program that implements commitments from NRC Generic Letter 88-01 and BWRVIP-75-A. The nozzle, cap and associated welds are included in the visual inspection (VT-2) during the reactor pressure test performed each refueling outage.

A.2.1.7 BWR Stress Corrosion Cracking

The BWR Stress Corrosion Cracking aging management program is an existing augmented Inservice Inspection program that manages intergranular stress corrosion cracking (IGSCC) in relevant piping and piping welds made of stainless steel and nickel based alloy, regardless of code classification, as delineated in NUREG-0313, Revision 2, and NRC Generic Letter 88-01 and its Supplement 1. The program includes preventive measures to mitigate IGSCC, and inspection and flaw evaluation to monitor IGSCC and its effects. The schedule and extent of the inspections are performed in accordance with the NRC staff-approved BWRVIP-75-A report.

A.2.1.8 BWR Penetrations

The BWR Penetrations aging management program is an existing program that manages the effects of cracking of reactor vessel instrumentation penetrations, and CRD housing and incore-monitoring housing penetrations exposed to reactor coolant through water chemistry and in-service inspections. The scope of the program includes beltline instrumentation nozzles and other instrumentation nozzles; except for the core plate differential pressure (dP) instrumentation nozzle and the jet pumps instrumentation nozzles, which are in the scope of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (A.2.1.1) program. The BWR Penetrations aging management program incorporates the inspection and evaluation recommendations of BWRVIP-49-A, "Instrument Penetration Inspection and Flaw Evaluation Guidelines," BWRVIP-47-A, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," and the water chemistry recommendations described in the Water Chemistry (A.2.1.2) program.

BWRVIP-27-A does not apply to LGS because Standby Liquid Control (SLC) injects through the Core Spray piping. Inspections of the instrument penetrations and CRD housing and incore-monitoring housing penetrations are implemented through station ISI procedures, which incorporate the requirements of ASME Section XI. The requirements of ASME Section XI are implemented in accordance with 10 CFR 50.55(a).

A.2.1.9 BWR Vessel Internals

The BWR Vessel Internals program is an existing program that manages the effects of cracking, loss of material and loss of fracture toughness of reactor pressure vessel internal components through condition monitoring activities that consist of examinations that are implemented through station procedures consistent with the recommendations of the BWRVIP guidelines and ASME Code, Section XI, Table IWB-2500-1. The program also mitigates these aging effects by managing water chemistry per the Water Chemistry (A.2.1.2) program.

The program will include aging management of reactor internal components fabricated from Cast Austenitic Stainless Steel (CASS) for loss of fracture toughness due to thermal aging and neutron embrittlement.

The BWR Vessel Internals aging management program will be enhanced to:

1. Perform an assessment of the susceptibility of reactor vessel internal components fabricated from Cast Austenitic Stainless Steel (CASS) to loss of fracture toughness due to thermal aging embrittlement. If material properties cannot be determined to perform the screening, they will be assumed susceptible to thermal aging for the purposes of determining program examination requirements.

2. Perform an assessment of the susceptibility of reactor vessel internal components fabricated from Cast Austenitic Stainless Steel (CASS) to loss of fracture toughness due to neutron irradiation embrittlement.

3. Specify the required periodic inspection of CASS components determined to be susceptible to loss of fracture toughness due to thermal aging and neutron irradiation embrittlement.

These enhancements will be implemented prior to the period of extended operation. The initial inspections will be performed either prior to or within 5 years after entering the period of extended operation.

A.2.1.10 Flow-Accelerated Corrosion

The Flow-Accelerated Corrosion (FAC) aging management program is an existing program based on EPRI guidelines in NSAC-202L, “Recommendations for an Effective Flow Accelerated Corrosion Program”. The program provides guidance for prediction, detection, and monitoring wall thinning in piping and fittings, valve bodies, and heat exchangers due to FAC. Analytical evaluations and periodic examinations of locations that are most susceptible to wall thinning due to FAC are used to predict the amount of wall thinning in pipes, fittings, and feedwater heater shells. Program activities include analyses to determine critical locations, baseline inspections to determine the extent of thinning at these critical locations, and follow-up inspections to confirm the predictions. Repairs and replacements are performed as necessary.

The Flow-Accelerated Corrosion aging management program also manages wall thinning caused by mechanisms other than FAC, such as cavitation, flashing, droplet impingement, and solid particle impingement, in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanism(s).

A.2.1.11 Bolting Integrity

The Bolting Integrity aging management program is an existing program that provides for aging management for loss of material, cracking, and loss of preload of pressure retaining bolted joints within the scope of license renewal. The Bolting Integrity program incorporates NRC and industry recommendations delineated in NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants,” EPRI TR-104213, “Bolted Joint Maintenance & Applications Guide,” and EPRI NP 5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” as part of the comprehensive component pressure retaining bolting program. The program provides for managing loss of material, cracking, and loss of preload by performing visual inspections of safety-related pressure retaining bolted joints at least once per refueling cycle for leakage, loss of material, cracking, and loss of preload. Bolting for other pressure retaining components is inspected for signs of leakage. Inspection activities for bolting in buried and underground applications is performed in conjunction with inspection activities for the Buried and Underground Piping and Tanks (A.2.1.29) aging management program due to the restricted accessibility to these locations.

The Bolting Integrity aging management program is supplemented by aging management activities included in several other programs including ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD (A.2.1.1), Reactor Head Closure Stud Bolting (A.2.1.3), Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (A.2.1.14), External Surfaces Monitoring of Mechanical Components (A.2.1.25), Buried and Underground Piping and Tanks (A.2.1.29), ASME Section XI, Subsection IWE (A.2.1.30), ASME Section XI, Subsection IWF (A.2.1.32), Structures Monitoring (A.2.1.35), and Reg. Guide 1.127 Inspection of Water Control Structures Associated With Nuclear Power Plants (A.2.1.36).

The Bolting Integrity aging management program will be enhanced to:

1. Provide guidance to ensure proper specification of bolting material, lubricant and sealants, storage, and installation torque or tension to prevent or mitigate degradation and failure of closure bolting for pressure retaining components.

2. Prohibit the use of lubricants containing molybdenum disulfide for pressure retaining components.

3. Minimize the use of high strength bolting (actual measured yield strength equal to or greater than 150 ksi) for closure bolting for pressure retaining components. High strength bolting, if used, will be monitored for cracking.

4. Perform visual inspection of bolting for the Residual Heat Removal System, Core Spray System, High Pressure Coolant Injection System, and Reactor Core Isolation Cooling System suppression pool suction strainers for loss of material and loss of preload during each ISI inspection interval.

The enhancements will be implemented prior to the period of extended operation.

A.2.1.12 Open-Cycle Cooling Water System

The Open-Cycle Cooling Water System (OCCWS) aging management program is an existing program that manages heat exchangers, piping, piping elements and piping components in safety-related and nonsafety-related raw water systems that are exposed to raw water and air/gas-wetted environments for loss of material, reduction of heat transfer, and hardening and loss of strength of elastomers. This is accomplished through tests and inspections per the guidelines of NRC Generic Letter 89-13. System and component testing, visual inspections, non-destructive examination (i. e. Radiographic Testing, Ultrasonic Testing and Eddy Current Testing), and chemical injection are conducted to ensure that aging effects are managed such that system and component intended functions and integrity are maintained.

The OCCWS includes those systems that transfer heat from safety-related structures, systems and components to the ultimate heat sink as defined in GL-89-13 as well as those raw water systems which are in scope for license renewal for spatial interaction but have no safety-related heat transfer function. Periodic heat transfer testing or inspection and cleaning of heat exchangers with a heat transfer intended function is performed in accordance with LGS commitments to GL 89-13 to verify heat transfer capabilities. Heat exchangers which have no safety-related heat transfer function are periodically inspected and cleaned.

Periodic volumetric inspections will be performed in the non-buried portions of the Safety Related Service Water System to provide a sufficient understanding of the buried service water piping conditions throughout the period of extended operation. The inspection locations are selected to ensure that conditions are similar (e. g. flow, temperature) to those in the buried portions of the Safety Related Service Water System piping.

The OCCWS aging management program also manages the loss of coating integrity in a raw water environment. Internal coatings in the service water side of the Main Control Room Chiller Condensers and Reactor Enclosure Cooling Water Heat Exchangers, and in circulating water system piping are visually inspected to ensure that loss of coating integrity is detected. The inspections of the Main Control Room Chiller Condensers and circulating water system piping will be performed by inspectors qualified to international standards endorsed in RG 1.54, including, ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II. The inspections of the Reactor Enclosure Cooling Water Heat Exchangers will be performed by inspectors with a demonstrated working knowledge of EPRI Report 1019157, “Guideline on Nuclear Safety-Related Coatings”. Inspections are performed for signs of coating failures and precursors to coating failures including peeling, delamination, blistering, cracking, flaking, chipping, rusting, and mechanical damage. When acceptance criteria are not met, visual inspection is supplemented by additional testing such as DFT (Dry Film Thickness), adhesion, continuity, or other inspection technique as determined by the qualified inspector to accurately assess coating condition. Adhesion testing will be performed using international standards endorsed in RG 1.54. A coatings specialist qualified to ASTM D-7108 will evaluate the results of the coating inspections. Evaluations are performed for inspection results that do not satisfy established acceptance criteria and the conditions are entered into the LGS 10 CFR 50 Appendix B

corrective action program. The corrective action program ensures that conditions adverse to quality are promptly corrected. Corrective actions may include coating repair or replacement prior to the component being returned to service.

The Open-Cycle Cooling Water System aging management program will be enhanced to:

1. Perform internal inspection of buried Safety Related Service Water Piping when it is accessible during maintenance and repair activities

2. Perform periodic inspections for loss of material in the Nonsafety-Related Service Water System at a minimum of five locations on each unit once every refueling cycle.

3. Replace the supply and return piping for the Core Spray pump compartment unit coolers.

4. Replace degraded RHRSW piping in the pipe tunnel.

5. Perform periodic inspections for loss of material in the Safety Related Service Water System at a minimum of ten locations every two years.

The enhancements will be implemented prior to the period of extended operation.

A.2.1.13 Closed Treated Water Systems

The Closed Treated Water Systems program is an existing mitigation program that includes (a) nitrite-based water treatment, including pH control and the use of corrosion inhibitors for carbon steel and copper alloys, to modify the chemical composition of the water such that the function of the equipment is maintained and such that the effects of corrosion are minimized; and (b) chemical testing of the water to ensure that the water treatment program maintains the water chemistry within acceptable guidelines. The Closed Treated Water Systems program manages the loss of material and the reduction of heat transfer in piping, piping components, piping elements, tanks, and heat exchangers exposed to a closed treated water environment.

The Closed Treated Water Systems aging management program will be enhanced to:

1. Perform condition monitoring and performance monitoring, including periodic testing and opportunistic and periodic NDE, to verify the effectiveness of water chemistry control to mitigate aging effects. A representative sample of piping and components will be selected based on likelihood of corrosion and inspected at an interval not to exceed once in 10 years during the period of extended operation.

2. Perform condition monitoring for the loss of material due to cavitation erosion in the reactor enclosure cooling water piping to the 2A Reactor Water Cleanup System (RWCU) non-regenerative heat exchanger. An

initial inspection frequency of 4 years has been established. The inspection frequency will be re-evaluated and adjusted as necessary based on trend data.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.14 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program is an existing condition monitoring program that manages the effects of loss of material on the bridge, bridge rails, bolting and trolley structural components for those cranes, hoists and rigging beams that are within the scope of license renewal. The program also manages loss of preload of associated bolted connections. Procedures and controls implement the guidance on the control of overhead heavy load cranes specified in NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants”. The program utilizes periodic inspections as described in the ASME B30 series of standards for inspection, monitoring and detection of aging effects.

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program will be enhanced to:

1. Perform annual periodic inspections as defined in the appropriate ASME B30 series standard for all cranes, hoists, and equipment handling systems within the scope of license renewal. For handling systems that are infrequently in service, such as those only used during refueling outages, annual periodic inspections may be deferred until just prior to use.

2. Perform inspections of structural components and bolting for loss of material due to corrosion, rails for loss of material due to wear and corrosion, and bolted connections for loss of preload.

3. Evaluate loss of material due to wear or corrosion and any loss of bolting preload on cranes, hoists, and equipment handling systems per the appropriate ASME B30 series standard.

4. Perform repairs to cranes, hoists, and equipment handling systems per the appropriate ASME B30 series standard.

Enhancements will be implemented prior to the period of extended operation.

A.2.1.15 Compressed Air Monitoring

The Compressed Air Monitoring aging management program is an existing program that manages piping, piping components, piping elements, and valve bodies for loss of material in the compressed air systems. The Compressed Air Monitoring aging management activities consist of air quality monitoring and trending, preventive maintenance, and condition monitoring measures to manage the aging effects.

The Compressed Air Monitoring program is based on the LGS response to NRC Generic letter 88-14, "Instrument Air Supply Problems" and utilizes guidance and standards provided in INPO SOER 88-01. The Compressed Air Monitoring program activities implement the moisture and contaminant criteria of ANSI MC11.1 (ISA S7.3, incorporated into ANSI/ISA-S7.0.01). Program activities include air quality checks at various locations to ensure that dew point, particulates, lubricant content and contaminants are maintained within the specified limits.

The Compressed Air Monitoring Program will be enhanced to:

1. Perform periodic analysis and trending of air quality monitoring results.

This enhancement will be implemented prior to the period of extended operation.

A.2.1.16 BWR Reactor Water Cleanup System

The BWR Reactor Water Cleanup System program is an existing condition monitoring and mitigation program that describes the requirements for augmented inservice inspection (ISI) for stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) on stainless steel Reactor Water Cleanup (RWCU) System piping welds outboard of the second (outboard) primary containment isolation valves. The program includes the measures delineated in NUREG-0313, Rev. 2, and in NRC Generic Letter (GL) 88-01 and its Supplement 1. The program is implemented in conjunction with the Water Chemistry (A.2.1.2) program to minimize the potential of cracking due to SCC or IGSCC in a treated water environment. The BWR Reactor Water Cleanup System program activities, and the control of reactor water chemistry, manage the aging effects in stainless steel RWCU System piping welds outboard of the second primary containment isolation valves thereby maintaining the intended function of this piping.

The BWR Reactor Water Cleanup System program includes acceptable inspection alternatives to staff positions delineated in GL 88-01 as described in GL 88-01, Supplement 1. In accordance with the staff's criteria regarding the acceptable inspection schedules for the portion of the RWCU System piping welds outboard of the second primary containment isolation valves, the NRC has approved the elimination of the requirements to perform examinations of the outboard portion of the RWCU System for both LGS Unit 1 and Unit 2. If one or more of the RWCU System welds inboard of the primary containment isolation valves inspected as part of the on-going GL 88-01 inspections under the BWR Stress Corrosion Cracking (A.2.1.7) program have confirmed IGSCC or SCC indications, then an additional sample of RWCU system welds outboard of the primary containment isolation valves is selected and examined based on the requirements of GL 88-01.

A.2.1.17 Fire Protection

The Fire Protection aging management program is an existing program that includes fire barrier visual inspections, and halon system visual inspections and functional tests. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, floors and other materials that perform a fire barrier function. Periodic visual inspection and functional testing of the fire rated doors and visual inspection of fire rated dampers is performed to ensure that their functionality is maintained. The program also includes visual inspections and periodic operability tests of halon fire suppression systems using the National Fire Protection Association Codes and Standards for guidance.

The Fire Protection aging management program will be enhanced to:

1. Provide additional inspection guidance to identify degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling and loss of material.

2. Provide additional inspection guidance for identification of excessive loss of material due to corrosion on the external surfaces of the halon system.

Enhancements will be implemented prior to the period of extended operation.

A.2.1.18 Fire Water System

The Fire Water System aging management program is an existing program that provides for system pressure monitoring, fire system header flushing and flow testing, pump performance testing, hydrant flushing, and visual inspection activities. System flow tests measure hydraulic resistance and compare results with previous testing as a means of evaluating the internal piping conditions. The program manages loss of material due to corrosion, including MIC, fouling, flow blockage because of fouling, and loss of coating integrity. Major component types include piping, piping components and piping elements, tanks, pump casings, and valve bodies. Monitoring system piping flow characteristics ensures that signs of loss of material will be detected in a timely manner. Monitoring system piping flow characteristics and opportunistic internal inspections of the cement lined fire main ensure that signs of loss of coating integrity will be detected in a timely manner. Within 10 years prior to the PEO, five inspections of the cement lined fire main will be performed. Pump performance tests, hydrant flushing and system inspections are based on guidance from the applicable National Fire Protection Association (NFPA) standards. The fire water system is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated. Fire system main header flow tests, sprinkler system inspections, visual yard hydrant inspections, hydrostatic tests, gasket inspections, volumetric inspections, and fire hydrant flow tests and pump capacity tests are performed periodically to assure that aging effects are managed such that the system intended functions are maintained.

The Fire Water System aging management program will be enhanced to:

1. Replace sprinkler heads or perform 50-year sprinkler head testing using the guidance of NFPA 25 “Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems” (2011 Edition), Section 5.3.1.1.1. This testing will be performed after the 50-year in-service date and every 10 years thereafter.

2. Inspect selected portions of the water based fire protection system piping located aboveground and exposed to the fire water internal environment by non-intrusive volumetric examinations. These inspections shall be performed prior to the period of extended operation and will be performed every 10 years thereafter.

3. Inspect and clean line strainers for deluge systems after each actuation. Strainers for deluge systems subject to periodic full flow testing will be inspected and cleaned on a frequency consistent with the deluge system test frequency.

4. Inspect and clean the foam system water supply strainer after each system actuation and no less than once per refueling interval.

5. Perform external visual inspection of deluge piping and nozzles for the HVAC charcoal filters for signs of leakage, corrosion, physical damage, and correct orientation each time the charcoal is removed for replacement.

6. Perform flow tests for the hydraulically most remote hose stations once every five years, scheduling the testing so that some of the tests are performed in each year of the five year interval.

7. Perform a main drain test annually for the fire water piping in each of the following locations: Unit 1 Reactor Enclosure, Unit 2 Reactor Enclosure, Unit 1 Turbine Enclosure, Unit 2 Turbine Enclosure, Control Enclosure, and Radwaste Enclosure. Flow blockage or abnormal discharge identified during flow testing or any change in pressure during the test greater than ten percent at a specific location is entered into the corrective action program for evaluation.

8. Perform charcoal filter deluge valve exercise testing and air flow testing each time the charcoal is removed for replacement interval and perform air flow testing for the deluge systems for the hydrogen seal oil units and lube oil reservoirs every two years.

9. Perform the following for Fire Water System sprinkler and deluge systems:

   - Perform visual internal inspections, consistent with NFPA 25, for corrosion and obstructions to flow on at least five wet pipe sprinkler systems every five years.

- Collect and evaluate solids discharged from wet pipe sprinkler system flow testing. Flow testing through the inspector's test valve will be performed on an interval no greater than 18 months for each wet pipe system.

- Perform visual internal inspections for corrosion and obstructions to flow for dry pipe preaction sprinkler systems of surfaces made accessible when preaction and water deluge valves are serviced on an interval no greater than a refueling interval.

- Perform visual internal inspections for corrosion and obstructions to flow for deluge systems of surfaces made accessible when deluge valves are serviced on at least ten deluge systems on an interval no greater than three years. To provide reasonable assurance of the presence of sufficient coating, two of the ten inspections will be associated with the galvanized transformer deluge system piping.

- Perform a visual internal inspection for corrosion and obstructions to flow for any wet pipe, dry pipe preaction, or deluge system after any system actuation prior to return to service.

- Perform an obstruction evaluation for conditions that indicate degraded flow.

- Perform follow-up volumetric inspections for pipe wall thickness if internal visual inspections detect surface irregularities that could be indicative of wall loss below nominal wall thickness.

- Sprinkler and deluge systems that are normally dry but may be wetted as the result of testing or actuations will have augmented tests and inspections on piping segments that cannot be drained or piping segments that allow water to collect. These augmented inspections will be performed in each five year interval beginning five years prior to the period of extended operation and consist of either a flow test or flush sufficient to detect potential flow blockage or a visual inspection of 100 percent of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect. In addition, in each five year interval of the period of extended operation, 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect is subject to volumetric wall thickness inspections.

10. Perform wall thickness measurements using UT or other suitable techniques at five selected locations every year to identify loss of material in the carbon steel backup fire water piping. When these examinations identify pipe degradation, additional examinations will be performed in accordance with the following criteria:

    - At least four additional locations will be examined if wall loss is greater than 50 percent of nominal wall thickness,

- Two additional locations will be examined if wall loss is 30 percent to 50 percent of nominal wall thickness and the calculated remaining life is less than two years,

- No additional examinations will be performed if wall loss is less than 30 percent of nominal wall thickness.

These inspections will be performed until the piping degradation no longer meets the criteria for recurring internal corrosion.

Enhancements will be implemented prior to the period of extended operation, with the testing and inspections performed in accordance with the schedule described above.

A.2.1.19 Aboveground Metallic Tanks

The Aboveground Metallic Tanks aging management program is an existing program that manages the loss of material aging effect of the Backup Water Storage Tank. Paint is a corrosion preventive measure, and periodic visual inspections will monitor degradation of the paint and any resulting metal degradation of metallic tanks.

The Aboveground Metallic Tanks aging management program will be enhanced to:

1. Include UT measurements of the bottom of the Backup Water Storage Tank. Tank bottom UT inspections will be performed within five years prior to entering the period of extended operation and every five years thereafter. If no tank bottom plate material loss is identified after the first two inspections, the remaining inspections will be performed whenever the tank is drained during the period of extended operation.

2. Provide visual inspections of the Backup Water Storage Tank external surfaces and include, on a sampling basis, removal of insulation to permit inspection of the tank surface. An inspection performed prior to entering the period of extended operation will include a minimum of 25 locations to demonstrate that the tank painted surface is not degraded under the insulation. Subsequent tank external surface visual inspection will be conducted on a two-year frequency and include a minimum of four locations. Annual visual inspections will be performed of the tank insulation surface for degradation. Rips, tears and gaps in the insulation skin will be repaired. Evidence of water intrusion beneath the insulation will be evaluated in accordance with the LGS corrective action program.

3. Perform visual inspections of the Backup Water Storage Tank wetted and nonwetted internal surfaces. Tank internal inspections will be performed within five years prior to entering the period of extended operation and every five years thereafter. The tank bottom will be inspected for evidence of voids beneath the floor in accordance with NFPA 25, Section 9.2.6.5. Where pitting and general corrosion to below the nominal wall thickness occurs or any coating failure occurs in which bare metal is exposed, additional inspections and tests shall be performed in accordance with NFPA 25, Section 9.2.7. These tests include adhesion testing of the coating in the vicinity of the coating failure, dry film thickness measurements, spot wet sponge testing, and nondestructive examination to determine remaining wall thickness where bare metal has been exposed. Tank bottom weld seams in the area of degraded coating will be leak tested in accordance with NFPA 25, Section 9.2.7, by vacuum-box testing or magnetic particle (MT) examination. In addition, adhesion testing shall be performed in the vicinity of blisters even though bare metal may not be exposed.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.20 Fuel Oil Chemistry

The Fuel Oil Chemistry aging management program is an existing mitigation and condition monitoring program that includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of license renewal. The Fuel Oil Chemistry program manages loss of material in piping, piping elements, piping components and tanks in a fuel oil environment. The fuel oil tanks within the scope of license renewal are maintained by monitoring and controlling fuel oil contaminants in accordance with the Technical Specifications, Technical Requirements Manual, and ASTM guidelines. Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel oil and stored fuel oil. Fuel oil tanks are periodically drained of accumulated water and sediment, cleaned, and internally inspected. These activities effectively manage the effects of aging by maintaining potentially harmful contaminants at low concentrations.

The Fuel Oil Chemistry program also manages the loss of coating integrity in a fuel oil environment. Fuel oil tank internal coatings are visually inspected to ensure that loss of coating integrity is detected. The inspections will be performed by inspectors qualified to international standards endorsed in RG 1.54, including, ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II. Inspections are performed for signs of coating failures and precursors to coating failures including peeling, delamination, blistering, cracking, flaking, chipping, rusting, and mechanical damage. When acceptance criteria are not met, visual inspection is supplemented by additional testing such as DFT (Dry Film Thickness), adhesion, continuity, or other inspection technique as determined by the qualified inspector to accurately assess coating condition. Adhesion testing will be performed using international standards endorsed in RG 1.54. A coatings specialist qualified to ASTM D-7108 will evaluate the

results of the coating inspections. Evaluations are performed for inspection results that do not satisfy established acceptance criteria and the conditions are entered into the LGS 10 CFR 50 Appendix B corrective action program. The corrective action program ensures that conditions adverse to quality are promptly corrected. Corrective actions may include coating repair or replacement prior to the component being returned to service.

The Fuel Oil Chemistry aging management program will be enhanced to:

1. Periodically drain water from the Fire Pump Engine Diesel Oil Day Tank and the Fire Pump Diesel Engine Fuel Tank.

2. Perform internal inspections of the Fire Pump Engine Diesel Oil Day Tank, the Fire Pump Diesel Engine Fuel Tank, and the Diesel Generator Day Tanks at least once during the 10-year period prior to the period of extended operation, and, at least once every 10 years during the period of extended operation. Each diesel fuel tank will be drained, cleaned and the internal surfaces either volumetrically or visually inspected. If evidence of degradation is observed during visual inspections, the diesel fuel tanks will require follow-up volumetric inspection.

3. Perform periodic analysis for total particulate concentration and microbiological organisms for the Fire Pump Engine Diesel Oil Day Tank and the Fire Pump Diesel Engine Fuel Tank.

4. Perform periodic analysis for water and sediment and microbiological organisms for the Diesel Generator Diesel Oil Storage Tanks.

5. Perform periodic analysis for water and sediment content, total particulate concentration, and the levels of microbiological organisms for the Diesel Generator Day Tanks.

6. Perform analysis of new fuel oil for water and sediment content, total particulate concentration and the levels of microbiological organisms for the Fire Pump Engine Diesel Oil Day Tank and the Fire Pump Diesel Engine Fuel Tank.

7. Perform analysis of new fuel oil for total particulate concentration and the levels of microbiological organisms for the Diesel Generator Diesel Oil Storage Tanks.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.21 Reactor Vessel Surveillance

The Reactor Vessel Surveillance aging management program is an existing program that manages the loss of fracture toughness due to neutron irradiation embrittlement of the reactor vessel beltline materials. The program meets the requirements of 10 CFR 50, Appendix H. The program evaluates neutron embrittlement by projecting Upper Shelf Energy (USE) for reactor materials and impact on Adjusted Reference Temperature for the development of pressure-temperature limit curves. Embrittlement evaluations are performed in accordance with Regulatory Guide 1.99, Rev. 2. The Reactor Vessel Surveillance program is part of the BWRVIP Integrated Surveillance Program (ISP) described in BWRVIP-86, Rev.1-A, and approved by the NRC staff. The schedule for removing surveillance capsules is in accordance the timetable specified in BWRVIP-86, Rev.1-A for both the current license term and the period of extended operation.

The program monitors plant operating conditions to ensure appropriate steps are taken if reactor vessel exposure conditions are altered; such as the review and updating of 60-year fluence projections to support upper shelf energy calculations and pressure-temperature limit curves. The program also includes condition monitoring by removal and analysis of surveillance capsules as part of the BWRVIP ISP. These measures are effective in detecting the extent of embrittlement to prevent significant degradation of the reactor pressure vessel during the period of extended operation.

A.2.1.22 One-Time Inspection

The One-Time Inspection program is a new condition monitoring program that will be used to verify the system-wide effectiveness of the Water Chemistry (A.2.1.2) program, Fuel Oil Chemistry (A.2.1.20) program, and Lubricating Oil Analysis (A.2.1.27) program which are designed to prevent or minimize aging to the extent that it will not cause a loss of intended function during the period of extended operation. The program manages loss of material, cracking and reduction of heat transfer in piping, piping components, piping elements, heat exchangers, and other components within the scope of license renewal. The program provides inspections focusing on locations that are isolated from the flow stream, that are stagnant, or that have low flow for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. The inspections will include a representative sample of the system population and will focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. The program either verifies that unacceptable degradation is not occurring or triggers additional actions that will assure the intended function of affected components will be maintained during the period of extended operation.

The One-Time Inspection program will be implemented prior to the period of extended operation. The one-time inspections will be performed within the 10 years prior to the period of extended operation.

A.2.1.23 Selective Leaching

The Selective Leaching aging management program is a new condition monitoring program that will include one-time inspections of a representative sample of susceptible components to manage loss of material due to selective leaching. Components include piping and fittings, valve bodies, pump casings, heat exchanger components, tanks, and fire hydrants. The materials of construction for these components are gray cast iron, and copper alloy with greater than 15 percent zinc. These components are exposed to raw water, treated water, closed cycle cooling water, waste water, and soil. These one-time inspections for selective leaching will include visual examinations, supplemented by hardness tests or other mechanical techniques as required. If selective leaching is found, the condition will be evaluated to determine the need to expand inspection scope.

The Selective Leaching program will be implemented prior to the period of extended operation. One-time inspections will be conducted within the five years prior to entering the period of extended operation.

Status of Selective Leaching Program: One-Time Inspections for Selective Leaching were conducted in the five years prior to the Period of Extended Operation. These efforts found instances of selective leaching in the following populations: Gray Cast Iron/Raw Water, Gray Cast Iron/Soil, and Copper Alloy/Raw Water. Based on these results, selective leaching has been determined to be present at Limerick. To expand inspection scope, periodic inspections of components in the above material/environment groupings will be performed during the period of extended operation in accordance with the Selective Leaching Aging Management Program.

A.2.1.24 One-Time Inspection of ASME Code Class 1 Small-Bore Piping

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping aging management program is a new condition monitoring program that will manage the aging effect of cracking in ASME Code Class 1 small-bore piping that is less than nominal pipe size (NPS) 4-inches, and greater than or equal to NPS 1-inch. The program implements one-time inspection of a sample of piping full penetration (butt) and partial penetration (socket) welds that are susceptible to cracking using volumetric examinations. The inspection sample size will include 3 percent or a maximum of 10 welds of each type (butt welds and socket welds), for each LGS unit. This sample size is based upon an OE review following 30 years of service which identified no instances of Code Class 1 small bore piping caused by IGSCC or fatigue at LGS 1 or 2 for components within the scope of the AMP. Inspection of socket welds will be performed by volumetric examination technique demonstrated to be capable of detecting cracking. If such a volumetric technique is not available by the time of the inspections, the examination method will be by destructive examination. Inspections required by the program will augment ASME Code, Section XI requirements.

Cracking of ASME Code Class 1 small-bore piping due to stress corrosion cracking, cyclical (including thermal, mechanical, and vibration fatigue) loading, thermal stratification or thermal turbulence has not been experienced at LGS Units 1 and 2. Therefore, this one-time inspection program is applicable and

adequate to manage this aging effect during the period of extended operation. A plant specific periodic inspection program will be implemented if evidence of cracking caused by IGSCC or fatigue is revealed in ASME Class 1 small-bore piping.

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping program will be implemented prior to the period of extended operation. One-time inspections will be performed within the six years prior to the period of extended operation.

A.2.1.25 External Surfaces Monitoring of Mechanical Components

The External Surfaces Monitoring of Mechanical Components aging management program is a new condition monitoring program that directs visual inspections of external surfaces of components be performed during system inspections and walkdowns. The program consists of periodic visual inspection of metallic and elastomeric components such as piping, piping components, ducting, and other components within the scope of license renewal. The program manages aging effects of metallic and elastomeric materials through visual inspection of external surfaces for evidence of loss of material and cracking. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers.

Inspections are performed at a frequency not to exceed one refueling cycle. This frequency accommodates inspections of components that may be in locations that are normally only accessible during outages. Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained.

A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point), are periodically inspected, under the insulation, every 10 years during the period of extended operation. Inspections subsequent to the initial inspection will consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation if the initial inspection verifies no loss of material beyond that which could have been present during initial construction and no evidence of cracking. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or if there is evidence of water intrusion through the insulation, then periodic inspections under insulation to detect corrosion under insulation will continue.

The external surfaces of components that are buried are inspected via the Buried and Underground Piping and Tanks (A.2.1.29) program. The external surface of the backup fire water storage tank is inspected via the Aboveground Metallic Tanks (A.2.1.19) program.

This new aging management program will be implemented prior to the period of extended operation.

A.2.1.26 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program is a new condition monitoring program that directs visual inspections of internal surfaces of components be performed when they are made accessible during maintenance activities. The program consists of visual inspections of metallic and elastomeric components such as piping, piping elements and piping components, ducting components, tanks, heat exchangers, elastomers and other components within the scope of license renewal. This program will manage the aging effects of loss of material, loss of fracture toughness, reduction of heat transfer, and cracking for metallic components, and loss of material and hardening and loss of strength for elastomers. The program includes provisions for visual inspections of the internal surfaces of components not managed under other aging management programs, augmented by physical manipulation of flexible elastomers where appropriate.

This opportunistic approach is supplemented to ensure a representative sample of components within the scope of this program are inspected. At a minimum, in each 10-year period during the period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections continue in each 10-year period despite meeting the sampling minimum requirement. For the waste water environment, a maximum of 25 components per population will be inspected. To provide reasonable assurance of the presence of sufficient coating, 10 of the 25 internal inspections will be of the normal waste, oily waste, sanitary waste and storm drain galvanized piping, and 15 of the internal inspections will be of the radioactive floor and equipment drain carbon steel piping.

This new aging management program will be implemented prior to the period of extended operation.

A.2.1.27 Lubricating Oil Analysis

The Lubricating Oil Analysis aging management program is an existing program that provides oil condition monitoring activities to manage the loss of material and the reduction of heat transfer in piping, piping components, piping elements, heat exchangers, and tanks within the scope of license renewal exposed to a lubricating oil environment. Sampling, analysis, and condition monitoring activities identify specific wear products and contamination and determine the physical properties of lubricating oil within operating machinery. These activities are used to verify that the wear product and contamination levels and the physical properties of lubricating oil are maintained within acceptable limits to ensure that intended functions are maintained.

The Lubricating Oil Analysis program also manages the loss of coating integrity in a lube oil environment. The RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir internal coatings are visually inspected to ensure that loss of coating integrity is detected. The inspections will be performed by inspectors qualified to international standards endorsed in RG 1.54, including, ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II. Inspections are performed for signs of coating failures and precursors to coating failures including peeling, delamination, blistering, cracking, flaking, chipping, rusting, and mechanical damage. When acceptance criteria are not met, visual inspection is supplemented by additional testing such as DFT (Dry Film Thickness), adhesion, continuity, or other inspection technique as determined by the qualified inspector to accurately assess coating condition. Adhesion testing will be performed using international standards endorsed in RG 1.54. A coatings specialist qualified to ASTM D-7108 will evaluate the results of the coating inspections. Evaluations are performed for inspection results that do not satisfy established acceptance criteria and the conditions are entered into the LGS 10 CFR 50 Appendix B corrective action program. The corrective action program ensures that conditions adverse to quality are promptly corrected.

A.2.1.28 Monitoring of Neutron-Absorbing Materials Other Than Boraflex

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex program is an existing condition monitoring program that periodically analyzes test coupons of the Boral material in the Unit 1 and Unit 2 spent fuel racks to determine if the neutron-absorbing capability of the material has degraded. This program ensures that a 5 percent sub-criticality margin is maintained in the spent fuel pool.

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex aging management program will be enhanced to:

1. Perform test coupon analysis on a ten-year frequency**,** beginning no earlier than 2020 for Unit 1 and 2021 for Unit 2.

2. Initiate corrective action if coupon test result data indicates that acceptance criteria will be exceeded prior to the next scheduled test coupon analysis.

3. Resume the accelerated exposure configuration for the Boral coupons (surrounded by freshly discharged fuel assemblies) at each of five additional refueling cycles, beginning with the next refueling for each unit (2013 for Unit 2, 2014 for Unit 1).

4. Maintain the coupon exposure such that it is bounding for the Boral material in all spent fuel racks, by relocating the coupon tree to a different spent fuel rack cell location each cycle and by surrounding the coupons with a greater number of freshly discharged fuel assemblies than that of any other cell location.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.29 Buried and Underground Piping and Tanks

The Buried and Underground Piping and Tanks aging management program is an existing program that manages the external surface aging effects of loss of material for piping and components in a buried or underground environment. The LGS program activities consist of preventive, mitigative, (i.e., coatings, backfill quality and cathodic protection) and inspection activities to manage, detect and monitor the loss of material due to external corrosion for piping and components within the scope of license renewal that are in a buried or underground environment.

External inspections of buried components will occur opportunistically when they are excavated for any reason.

The Buried and Underground Piping and Tanks aging management program will be enhanced to:

1. If adverse indications are detected during inspection of in-scope buried piping, inspection sample sizes within the affected piping categories are doubled. If adverse indications are found in the expanded sample, an analysis is conducted to determine the extent of condition and extent of cause. The size of the follow-on inspections will be determined based on the extent of condition and extent of cause.

2. Coat the underground Emergency Diesel Generator System fuel oil piping prior to the period of extended operation. The coating will be in accordance with Table 1 of NACE SP0169-2007 or Section 3.4 of NACE RP0285-2002.

3. Perform direct visual inspections and volumetric inspections of the underground Emergency Diesel Generator System fuel oil piping and components during each 10-year period beginning 10 years prior to the entry into the period of extended operation. Prior to the period of extended operation all in scope Emergency Diesel Generator System fuel oil piping and components located in underground vaults will undergo a 100 percent visual inspection. Volumetric inspections will also be performed. After entering the period of extended operation, 2 percent of the linear length of in scope Emergency Diesel Generator System fuel oil piping and components located in underground vaults will undergo direct visual inspections and volumetric inspections every 10 years. Inspection locations after entering the period of extended operation will be selected based on susceptibility to degradation and consequences of failure. Visual inspections will be performed by a NACE Coating Inspector Program Level 2 or 3 qualified inspector or an individual that has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course.

4. Perform two sets of volumetric inspections of the Safety Related Service Water System underground piping and components during each 10-year

period beginning 10 years prior to the entry into the period of extended operation. Each set of volumetric inspections will assess either the entire length of a run of in scope Safety Related Service Water piping and components in the underground vault or a minimum of 10 feet of the linear length of in scope Safety Related Service Water System piping and components in the underground vault. Inspection locations will be selected based on susceptibility to degradation and consequences of failure.

5. Specify that visual inspections of Safety Related Service Water System underground piping and components will be performed by a NACE Coating Inspector Program Level 2 or 3 qualified inspector or an individual that has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course.

6. Perform trending of the cathodic protection testing results to identify changes in the effectiveness of the system and to ensure that the rectifiers remain operational at least 85% of the time and cathodic protection effectiveness will be maintained greater than 80%. Cathodic protection operational and effectiveness requirements shall be met for the 10 years prior to the period of extended operation (PEO), and throughout the PEO.

7. Modify the yearly cathodic protection survey acceptance criterion to meet NACE SP0169-2007 standards and add a statement that if negative polarized potential exceeds -1100mV relative to copper/copper sulfate electrode an issue report will be entered into the corrective action program. In performing cathodic protection surveys, the polarized potential criterion of -850mV for copper/copper sulfate reference electrodes (CSEs) will be used to determine cathodic protection system effectiveness. Other standard reference electrodes may be substituted for the CSEs; however their voltage measurements must be converted to the CSE equivalents in accordance with NACE RP0285-2002.

8. Whenever pipe is excavated and damage to the coating is significant and the damage was caused by non-conforming backfill, an extent of condition evaluation should be conducted to ensure that the as-left condition of backfill in the vicinity of observed damage will not lead to further degradation. Visual inspection of coatings will be performed by a NACE Coating Inspector Program Level 2 or 3 qualified inspector or an individual that has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course.

These enhancements will be implemented prior to the period of extended operation, with the actions performed in accordance with the schedule described above.

A.2.1.30 ASME Section XI, Subsection IWE

The ASME Section XI, Subsection IWE aging management program is an existing program based on ASME Code and complies with the provisions of 10 CFR 50.55(a). The program consists of periodic inspection of the primary containment liner plate surfaces and components, including its integral attachments, diaphragm slab carbon steel liner, downcomers and bracing, penetration sleeves, pressure retaining bolting, personnel airlock and equipment hatches, drywell head, and other pressure retaining components for loss of material, loss of preload, loss of leak-tightness, and fretting or lockup.

Examination methods include visual and volumetric testing as required by ASME Section XI, Subsection IWE. Observed conditions that have the potential for impacting an intended function are evaluated for acceptability in accordance with ASME requirements or corrected in accordance with corrective action program.

The ASME Section XI, Subsection IWE aging management program will be enhanced to:

1. Manage the suppression pool liner and coating system to:

    a. Remove any accumulated sludge in the suppression pool every refueling outage. *De-sludging in 1R18 was not performed due to the COVID-19 pandemic.

    b. Perform an ASME IWE examination of the submerged portion of the suppression pool each ISI period. *The ASME IWE examination in 1R18 was not performed due to the COVID-19 pandemic. This is a one-time exception to the 4-year LR SER inspection interval.

    c. Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following prior to the period of extended operation (PEO):

        - Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 100 mils plate thickness loss will be recoated in the outage they are identified. This plate thickness loss criterion for local areas will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.

        - Areas of general corrosion greater than 65 mils average plate thickness loss will be recoated based on ranking of affected surface area, high to low. This plate thickness loss criterion for areas of general corrosion will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.

    d. Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following during the PEO:

- Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 100 mils plate thickness loss will be recoated in the outage they are identified. This plate thickness loss criterion for local areas will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.

- Areas of general corrosion greater than 65 mils average plate thickness loss will be recoated in the outage they are identified. This plate thickness loss criterion for areas of general corrosion will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.

The coating maintenance plan will be initiated in the 2012 refueling outage for Unit 1 and the 2013 refueling outage for Unit 2. The coating maintenance plan will continue through the period of extended operation to ensure the coating protects the liner to avoid significant material loss.

2. Use the results of the ASME IWE inspection of the submerged portions of the suppression pool downcomers to perform the following:

   - Local areas (less than or equal to 5.5 inches in any direction) that have 40 mils or more metal thickness loss will be recoated. This downcomer metal thickness loss criteria for local areas will also be used to determine when the submerged portions of the downcomers require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.

   - Areas of general corrosion (greater than 5.5 inches in any direction) that have 30 mils or more metal thickness loss will be recoated. This downcomer metal thickness loss criteria for areas of general corrosion will also be used to determine when the submerged portions of the downcomers require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.

   The downcomer recoat and augmented inspection criteria will be implemented prior to receipt of the renewed licenses.

3. When IWE examinations are conducted, perform ultrasonic thickness measurements on four areas of submerged suppression pool liner affected by general corrosion. The ultrasonic thickness measurement requirements will be implemented prior to receipt of the renewed licenses.

4. Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.31 ASME Section XI, Subsection IWL

The ASME Section XI, Subsection IWL aging management program is an existing program based on ASME Code and complies with the provisions of 10 CFR 50.55(a). The program requires periodic inspection of Containment Structure concrete surfaces to identify areas of deterioration and distress such as defined in ACI 201.1 and ACI 349.3R, including cracking, loss of bond, and loss of material.

Inspection methods, inspected parameters, and acceptance criteria are in accordance with ASME Section XI, Subsection IWL as approved by 10 CFR 50.55(a). Observed conditions that have the potential for impacting an intended function are evaluated for acceptability in accordance with ASME Section XI, Subsection IWL requirements or corrected in accordance with the corrective action program.

The ASME Section XI, Subsection IWL aging management program will be enhanced to:

1. Include second tier acceptance criteria of ACI 349.3R.

This enhancement will be implemented prior to the period of extended operation.

A.2.1.32 ASME Section XI, Subsection IWF

The ASME Section XI, Subsection IWF aging management program is an existing program that consists of periodic visual examinations of ASME Class 1, 2, 3, and MC piping and component supports for identification of signs of degradation such as loss of material, loss of mechanical function and loss of pre-load. The program is implemented through corporate and station procedures, which provide inspection and acceptance criteria consistent with the requirements of the ASME Code, Section XI, Subsection IWF as approved in 10 CFR 50.55(a). The monitoring methods are effective in detecting the applicable aging effects, and the frequency of monitoring is adequate to prevent significant degradation.

The ASME Section XI, Subsection IWF aging management program will be enhanced to:

1. Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.33 10 CFR Part 50, Appendix J

The 10 CFR Part 50, Appendix J aging management program is an existing program that monitors leakage rates through the containment pressure boundary, including penetrations and other access openings, in order to detect

age related degradation of the containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria. The Primary Containment Leakage Rate Testing Program (LRT) provides for aging management of pressure boundary degradation due to aging effects from the loss of material, loss of sealing, loss of leak tightness, or loss of preload in systems penetrating containment. The Appendix J program also detects degradation of gaskets and seals for the primary containment pressure boundary access points. Consistent with the current licensing basis, the containment leak rate tests are performed in accordance with the regulations and guidance provided in 10 CFR 50 Appendix J Option B, Regulatory Guide 1.163, “Performance-Based Containment Leak-Test Program,” NEI 94-01 “Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50 Appendix J,” and ANSI/ANS 56.8, “Containment System Leakage Testing Requirements.” As permitted by the License Amendment to implement 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors," Alternative Treatments may be applied in lieu of 10 CFR 50 Appendix J requirements for penetrations and valves classified as RISC-3 and RISC-4, meeting the criteria of 10 CFR 50.69(b)(1)(x).

A.2.1.34 Masonry Walls

The Masonry Walls program is an existing program implemented as part of the Structures Monitoring (A.2.1.35) program. Masonry wall condition monitoring is based on guidance provided in IE Bulletin 80-11, "Masonry Wall Design”, and NRC Information Notice 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11," and is implemented through station procedures.

The Masonry Walls aging management program addresses loss of material, and cracking due to age-related degradation of concrete for masonry walls and will inspect for shrinkage or separation, along with gaps between the supports and masonry walls. The program relies on periodic visual inspections to monitor and maintain the condition of masonry walls within the scope of license renewal. Masonry walls that are considered fire barriers are also managed by the Fire Protection (A.2.1.17) program.

The Masonry Walls aging management program will be enhanced to:

1. Add the following structures with masonry walls to the program scope:

    a. Administration Building Warehouse

    b. Fuel Oil Pumphouse

    c. Transformer foundation dike walls.

2. Provide additional guidance for inspection of masonry walls for shrinkage, separation, and for gaps between the supports and walls that could impact the wall’s intended function.

3. Require an inspection frequency of not greater than 5 years.

4. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.35 Structures Monitoring

The Structures Monitoring program is an existing program that was developed to implement the requirements of 10 CFR 50.65 and is based on NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” and Regulatory Guide 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” The program includes elements of the Masonry Walls (A.2.1.34) program. The program relies on periodic visual inspections to monitor the condition of structures and structural components, structural bolting, component supports, and masonry block walls. The inspections are conducted on a frequency not to exceed 5 years.

The Structures Monitoring aging management program will be enhanced to:

1. Add the following structures:

   a. Admin Building Warehouse

   b. Fuel Oil Pumphouse

   c. Service Water Pipe Tunnel

   d. Yard Structures

      - Aux Fire Water Storage Tank Foundation
      - Backup Fire Pump House and Foundation
      - Well Pump #3 Enclosure and Foundation
      - Railroad Bridge
      - Manholes 001 and 002
      - Fuel Oil Storage Tank Dike
      - Transformer foundations and dikes

2. Add the following components and commodities:

   a. Pipe, electrical, and equipment component support members

   b. Pipe whip restraints and jet impingement shields

   c. Panels, Racks, and other enclosures

   d. Sliding surfaces

   e. Sump and Pool liners

   f. Electrical cable trays and conduits

   g. Electrical duct banks

h. Tube tracks

i. Doors

j. Penetration seals

k. Blowout panels

l. Permanent drywell shielding

m. Roof scuppers

3. Monitor groundwater chemistry on a frequency not to exceed 5 years for pH, chlorides, and sulfates and verify that it remains non-aggressive, or evaluate results exceeding criteria to assess impact, if any, on below-grade concrete.

4. Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. Revise storage requirements for high strength bolts to include recommendations of Research Council on Structural Connections (RSCS) Specification for Structural Joints Using High Strength Bolts, Section 2.0.

5. Monitor concrete for areas of abrasion, erosion, and cavitation degradation, drummy areas that can exceed the cover concrete thickness in depth, popouts and voids, scaling, and passive settlements or deflections.

6. Perform inspections on a frequency not to exceed 5 years.

7. Perform inspections of sub-drainage sump pit internal concrete on a 5-year frequency as a leading indicator the condition of below grade concrete exposed to ground water.

8. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R.

9. Perform inspection of elastomeric vibration isolation elements and structural seals for cracking, loss of material and hardening. Visual inspections of elastomeric vibration isolation elements are to be supplemented by manipulation to detect hardening when vibration isolation function is suspect.

10. Monitor accessible sliding surfaces to detect significant loss of material due to wear, corrosion, debris, or dirt, that could result in lock-up or reduced movement.

11. Perform opportunistic inspection of below grade portions of in scope structures in the event of excavation which exposes normally inaccessible below grade concrete.

12. Include applicable acceptance criteria from ACI 349.3R.

13. Clarify that loose bolts and nuts and cracked high strength bolts are not acceptable unless accepted by engineering evaluations.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.36 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants

The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program is an existing program which will be enhanced to provide management of aging effects for water-control structures. The program monitors the condition of the Spray Pond and Pumphouse and the Yard Facilities dikes around the Condensate Storage Tanks (CST) storage tanks. The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program addresses age-related deterioration, degradation due to extreme environmental conditions, and the effects of natural phenomena that may affect the intended function of the water-control structures. The program is used to manage conditions such as, loss of material, loss of preload, cracking, loss of bond, loss of material (spalling, scaling) and cracking, increase in porosity and permeability, loss of strength, or loss of form. Elements of the program are designed to detect degradation and take corrective actions to prevent the loss of an intended function.

The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will be enhanced to:

1. Require inspection of structural bolting integrity (loss of material and loosening of the bolts).

2. Require monitoring of aging effects for increase of porosity and permeability of concrete structures and loss of material for steel components.

3. Require the proper functioning of dike drainage systems.

4. Require increased inspection frequency if the extent of the degradation is such that the structure or component may not meet its design basis if allowed to continue uncorrected until the next normally scheduled inspection.

5. Require (a) evaluation of the acceptability of inaccessible areas when conditions exist in the accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas, and (b) examination of the exposed portions of the below-grade concrete when excavated for any reason.

6. Monitor raw water chemistry at least once every 5 years for pH, chlorides, and sulfates and verify that it remains non-aggressive, or evaluate results exceeding criteria to assess impact, if any, on submerged concrete.

7. Require visual examinations of the Spray Pond and Pumphouse submerged wetwell concrete for signs of degradation during maintenance activities. If significant concrete degradation is identified, a plant specific aging management program should be implemented to manage the concrete aging during the period of extended operation.

8. Require that active cracks in structural concrete or extent of corrosion in steel are documented and trended, until the condition is no longer occurring or until a corrective action is implemented.

9. Require acceptance and evaluation of structural concrete using quantitative criteria based on Chapter 5 of ACI 349.3R.

10. Provide guidance to ensure proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. Revise storage requirements for high strength bolts to include recommendations of Research Council on Structural Connections (RSCS) Specification for Structural Joints Using High Strength Bolts, Section 2.0.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.37 Protective Coating Monitoring and Maintenance Program

The Protective Coating Monitoring and Maintenance Program is an existing condition monitoring program that provides for aging management of Service Level I coatings inside the LGS primary containment in air-indoor and treated water environments. The failure of the Service Level I coatings could adversely affect the operation of the Emergency Core Cooling Systems (ECCS) by clogging the ECCS suction strainers. Proper maintenance of the Service Level I coating ensures that coating degradation will not impact the operability of the ECCS systems. The Protective Coating Monitoring and Maintenance Program provides for coating system visual inspection, assessment, and repair for any condition that adversely affects the ability of Service Level I coatings to function as intended.

Service Level I coatings will prevent or minimize the loss of material due to corrosion but these coatings are not credited for managing the effects of corrosion for the carbon steel containment liners and components at LGS. This program ensures that the Service Level I coatings maintain adhesion so as to not effect the intended function of the ECCS suction strainers.

The program also provides controls over the amount of unqualified coating which is defined as coating inside the primary containment that has not passed the required laboratory testing, including irradiation and simulated Design Basis Accident (DBA) conditions. Unqualified coating may fail in a way to affect the intended function of the Emergency Core Cooling Systems (ECCS) suction strainers. Therefore, the quantity of unqualified coating is controlled to ensure that the amount of unqualified coating in the primary containment is kept within acceptable design limits.

The Protective Coating Monitoring and Maintenance Program will be enhanced to:

1. Create the position of Nuclear Coatings Specialist qualified to ASTM D 7108 standards.

This enhancement will be implemented prior to the period of extended operation.

A.2.1.38 Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new program that will be used to manage aging of the insulation material for non-EQ cables and connections during the period of extended operation. Accessible cables and connections located in adverse localized environments will be visually inspected at least once every 10 years for indications of reduced insulation resistance, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service environment for the cable or connection.

This new program will be implemented prior to the period of extended operation. In addition, the first inspections will be completed prior to the period of extended operation.

A.2.1.39 Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

The Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program is a new program that will be used to manage aging of non-EQ cable and connection insulation of the in scope portions of the Process Radiation Monitoring and Neutron Monitoring Systems.

The in scope process radiation monitoring and neutron monitoring circuits are sensitive instrumentation circuits with high voltage, low-level current signals and are located in areas where the cables and connections could be exposed to adverse localized environments caused by temperature, radiation, or moisture. These adverse localized environments can result in reduced insulation resistance causing increases in leakage currents.

Calibration testing will be performed for the in scope process radiation monitoring circuits. Direct cable testing will be performed for the in scope neutron monitoring circuits. These calibration and cable tests will be performed and results will be assessed for reduced insulation resistance prior to the period of extended operation and at least once every 10 years during the period of extended operation.

A.2.1.40 Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new program that will be used to manage the aging effects and mechanisms of non-EQ, in scope, inaccessible power cables. For this program, power is defined as greater than or equal to 400 V. These inaccessible power cables may at times be exposed to significant moisture. Power cable exposure to significant moisture may cause reduced insulation resistance that can potentially lead to failure of the cable's insulation system.

The cables in the scope of this aging management program will be tested using a proven test for detecting reduced insulation resistance of the cable's insulation system due to wetting or submergence, such as Dielectric Loss (Dissipation Factor or Power Factor), AC Voltage Withstand, Partial Discharge, Step Voltage, Time Domain Reflectometry, Insulation Resistance and Polarization Index, Line Resonance Analysis, or other testing that is state-of-the-art at the time the test is performed. The cables will be tested at least once every 6 years. More frequent testing may occur based on test results and operating experience. The first tests will be completed prior to the period of extended operation.

Periodic actions will be taken to prevent inaccessible cables from being exposed to significant moisture. Manholes associated with the cables included in this aging management program will be inspected for water collection with subsequent corrective actions (e.g., water removal), as necessary. Prior to the period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant specific operating experience with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding. Operation of dewatering devices will be verified prior to any known or predicted heavy rain or flooding event. The first inspections will be completed prior to the period of extended operation. During the period of extended operation, the inspections will occur at least annually.

A.2.1.41 Metal Enclosed Bus

The Metal Enclosed Bus aging management program is a new program that will be used to manage aging of in scope metal enclosed bus during the period of extended operation. The internal portions of the bus enclosure assemblies will be inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus insulation will be visually inspected for signs of reduced insulation resistance, such as embrittlement, cracking, chipping, melting, discoloration, swelling or surface contamination. The internal bus insulating supports will be visually inspected for structural integrity and signs of cracks. Enclosure assembly elastomers will be visually inspected for surface cracking, crazing, scuffing, dimensional change, shrinkage, discoloration, hardening, and loss of strength. A sample of accessible bolted connections will be inspected for increased resistance of connection using thermography. The sample will be 20 percent of the accessible metal enclosed bus bolted connection population with a maximum sample size of 25.

The inspections and thermography will be performed at least once every 10 years for indications of aging degradation. This new program will be implemented prior to the period of extended operation. In addition, the first tests and inspections will be completed prior to the period of extended operation.

A.2.1.42 Fuse Holders

The Fuse Holders aging management program is a new program that applies to fuse holders located outside of active devices that have been identified as susceptible to aging effects. Fuse holders located inside an active device are not within the scope of this program. This program will be used to manage aging of the metallic portions of fuse holders. Stressors managed by this aging management program include frequent manipulation, vibration, chemical contamination, corrosion, oxidation, ohmic heating, thermal cycling and electrical transients. Fuse holders subject to increased resistance of connection or fatigue, will be tested, by a proven test methodology, at least once every 10 years for indications of aging degradation. Visual inspection is not part of this program.

The new Fuse Holders program will be implemented prior to the period of extended operation. In addition, the first tests will be completed prior to the period of extended operation.

A.2.1.43 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program. The program will implement one-time testing of a representative sample of non-EQ electrical cable connections to ensure that either increased resistance of connection is not occurring or that the existing preventive maintenance program is effective such that a periodic inspection program is not required. A representative sample of non-EQ electrical cable connections will be selected for one-time testing considering application (medium and low voltage), circuit loading (high loading) and location (high temperature, high humidity and vibration). The sample tested will be 20 percent of the population with a maximum sample size of 25 connections. The technical basis for the sample selected is to be documented. The specific type of test performed will be a proven test for detecting increased resistance of connections, such as thermography, contact resistance measurement, or another appropriate test.

The new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be implemented prior to the period of extended operation. The one-time tests will be completed prior to the period of extended operation.

A.2.2 Plant-Specific Aging Management Programs

None. Limerick Generating Station, Units 1 and 2 do not have plant-specific aging management programs as a result of License Renewal.

A.3 NUREG-1801 Chapter X Aging Management Programs

A.3.1 Evaluation of Chapter X Aging Management Programs

Aging Management Programs evaluated in Chapter X of NUREG-1801 are associated with Time-Limited Aging Analysis for metal fatigue of the reactor coolant pressure boundary and environmental qualification (EQ) of electric components. These programs are evaluated in this section.

A.3.1.1 Fatigue Monitoring

The Fatigue Monitoring program is an existing program that manages fatigue damage of reactor coolant pressure boundary (RCPB) and other components subject to the reactor coolant, treated water, steam, and air-indoor uncontrolled environments.

The Fatigue Monitoring program is a preventive program that monitors and tracks the number of critical thermal, pressure, and seismic transients to ensure that the cumulative usage factor (CUF) for each analyzed component does not exceed the design limit of 1.0 through the period of extended operation. The program reviews the temperature and pressure profiles of the actual transients and counts them in the appropriate design transient category. The program compares the cumulative cycles for each design transient to the cycle limits specified in Technical Specification 5.6, UFSAR Table 3.9-2, "Design Events," and Table 5.2-9, “RCPB Operating Thermal Cycles.”

If a limit is approached, corrective actions are triggered to prevent exceeding the limit. The fatigue analyses may be revised to account for increased numbers of cycles or increased transient severity such that the cumulative usage factor (CUF) does not exceed the design limit of 1.0, including environmental effects where applicable.

The effect of the reactor coolant environment on RCPB component fatigue life has been determined by performing environmental fatigue analyses for locations selected using NUREG/CR-6260 guidance. Additional environmental fatigue analyses were performed for limiting locations within the RPV and for each RCPB system. Environmentally-adjusted cumulative usage factors (CUFen) were computed in accordance with the requirements specified in NUREG/CR-6909 for each material.

The Fatigue Monitoring aging management program will be enhanced to:

1. Monitor additional plant transients that are significant contributors to fatigue usage and to impose administrative transient cycle limits corresponding to the limiting numbers of cycles used in the environmental fatigue calculations.

This enhancement will be implemented prior to the period of extended operation.

A.3.1.2 Environmental Qualification (EQ) of Electric Components

The Environmental Qualification (EQ) of Electric Components is an existing program that manages the aging of electrical equipment within the scope of 10 CFR 50.49, “Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants.” The program establishes, demonstrates, and documents the level of qualification, qualified configurations, maintenance, surveillance and replacements necessary to meet 10 CFR 50.49. A qualified life is determined for equipment within the scope of the program and appropriate actions such as replacement or refurbishment are taken prior to or at the end of the qualified life of the equipment so that the aging limit is not exceeded. The various aging effects addressed by this program are adequately managed so that the intended functions of components within the scope of 10 CFR 50.49 are maintained consistent with the current licensing basis during the period of extended operation. As permitted by the License Amendment to implement 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors," Alternative Treatments may be applied in lieu of 10 CFR 50.49 requirements for components classified as RISC-3 and RISC-4.

A.4 Time-Limited Aging Analyses

A.4.1 Identification of Time-Limited Aging Analyses

As part of the application for a renewed license, 10 CFR 54.21(c) requires that an evaluation of Time-Limited Aging Analyses (TLAAs) for the period of extended operation be provided.

10 CFR 54.21(c)(2) requires that the application for a renewed license include a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based upon TLAAs as defined in 10 CFR 54.3. It also requires an evaluation that justifies the continuation of these exemptions for the period of extended operation. Only two exemptions were identified that are based upon a TLAA. These were associated with Pressure-Temperature (P-T) limits developed using exemptions to 10 CFR 50 Appendix G to permit use of ASME Code Cases N-588 and N-640. Continuation of these exemptions into the PEO is acceptable because the use of Code Cases N-588 and N-640 as a basis for the 32 EFPY P-T limits was approved by the NRC without a limitation with respect to plant operation beyond the original license term. In addition, this is justified because the provisions of Code Cases N-588 and N-640 utilized in developing the current P-T limit curves remain acceptable since they were incorporated into the ASME Code, Section XI, Appendix G, in the 1998 Edition through 2000 Addenda, as described in Regulatory Issue Summary (RIS) 2004-04, and this Code was approved for use as described in 10 CFR 50.55a (b)(2).

PT curves were developed for 57 EFPY in support of the Period of Extended Operation for License Renewal, the methods of ASME Section XI, Appendix G, 2007 Edition with addenda through 2008, has been used.

A.4.2 Reactor Pressure Vessel Neutron Embrittlement Analysis

10 CFR 50.60 requires that all light-water reactors meet the fracture toughness, P-T limits, and material surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR 50 Appendices G and H. The reactor pressure vessel embrittlement calculations for LGS that evaluated reduction of fracture toughness of the Unit 1 and Unit 2 reactor pressure vessel beltline materials for 40 years are based upon a predicted End of License fluence of 32 Effective Full Power Years (EFPY). These analyses are considered TLAAs as defined in 10 CFR 54.21(c) and they were evaluated for the increased neutron fluence associated with 57 EFPY of operation as described in the subsections below.

A.4.2.1 Neutron Fluence Projections

High energy (>1 MeV) neutron fluence was calculated for the RPV beltline welds and shells using the Radiation Analysis Model Application (RAMA) Fluence Methodology. Use of this model was performed in accordance with NRC Regulatory Guide 1.190. This RAMA methodology was used to develop 60-year, 57 EFPY fluence values for LGS. The 57 EFPY fluence projections are used in the evaluations of the neutron embrittlement TLAAs.

The 57 EFPY fluence projections have been determined for reactor vessel beltline materials, which include the reactor vessel plate materials, welds, and forgings that will be exposed to 1.0 E+17 neutrons/cm^2 (n/cm^2) or more during 60 years of operation. Fluence projections have also been determined for specific reactor vessel internals components, both to evaluate fluence-based TLAAs and to determine when specified fluence threshold values may be exceeded that are used to invoke specific aging management requirements for these components, such as inspections.

A.4.2.2 Upper-Shelf Energy

10 CFR 50 Appendix G, Paragraph IV.A.1.a, requires that the reactor vessel beltline materials must maintain Charpy upper-shelf energy (USE) throughout the life of the vessel of no less than 50 ft-lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Regulation, that lower values of Charpy upper-shelf energy will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

Upper Shelf Energy (USE) values were computed for all LGS beltline materials that will be exposed to over 1.0 E+17 n/cm^2 by the end of the period of extended operation (57 EFPY). The 57 EFPY USE values for the beltline materials were determined using methods consistent with Regulatory Guide 1.99, Revision 2.

The USE values for LGS beltline materials remain within the limits of 10 CFR 50 Appendix G requirements at 57 EFPY, either by having USE values of at least 50 ft-lb or through an equivalent margins analysis (EMA). Therefore, the analyses are projected for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.3 Adjusted Reference Temperature

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the beltline P-T limits to account for irradiation effects. The initial nil-ductility reference temperature, RT_{NDT}, is the temperature at which a non-irradiated metal (ferritic steel) changes in fracture characteristics from ductile to brittle behavior. RT_{NDT} is evaluated according to the procedures in the ASME Code, Section III. Neutron embrittlement increases the RT_{NDT} beyond its initial value.

10 CFR 50 Appendix G defines the fracture toughness requirements for the life of the vessel. The shift in the initial RT_{NDT} (ΔRT_{NDT}) is evaluated as the difference in the 30 ft-lb index temperatures from the average Charpy curves measured before and after irradiation. This increase (ΔRT_{NDT}) means that higher temperatures are required for the material to continue to act in a ductile manner. The ART is defined as Initial RT_{NDT} + ΔRT_{NDT} + Margin. The Margin term is defined in Regulatory Guide 1.99, Revision 2.

ART values were computed for LGS beltline materials in accordance with Regulatory Guide 1.99, Revision 2. The ART values of the limiting beltline materials at 57 EFPY for each unit remain below 200 degrees F, which is the RT_{NDT} limit.

The analysis for the adjusted reference temperature has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.4 Pressure – Temperature Limits

10 CFR 50 Appendix G requires that the reactor pressure vessel be maintained within established (P-T) limits, including heatup and cooldown operations. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the reactor pressure vessel is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated reactor vessel fluence.

The current P-T limits were updated based upon 57 EFPY fluence projections, consistent with the amount of power to be generated over 60 years of plant operation. The P-T limits satisfy the criteria of 10 CFR 54.3(a).

A.4.2.5 Axial Weld Inspection

The BWRVIP recommendations for inspection of reactor pressure vessel shell welds in BWRVIP-05 include examination of 100 percent of the axial welds and inspection of the circumferential welds only at the intersections of these welds with the axial welds. BWRVIP-05 contains generic analyses supporting a conclusion in the NRC Final Safety Evaluation Report (FSER) that the generic-plant axial weld failure rate is orders of magnitude greater than the 40-year end-of-life circumferential weld failure probability and used this analysis to justify relief from inspection of the circumferential welds. The failure frequency is dependent upon given assumptions of flaw density, distribution, and location. Since the axial weld failure probability assessment is based on 32 EFPY fluence values associated with 40 years of operation, it has been identified as a TLAA requiring evaluation for the period of extended operation.

The LGS axial weld failure probability has been projected for the period of extended operation. In order to evaluate the axial weld failure probability assessment for 60 years, 57 EFPY fluence values were derived for the limiting axial weld. Using the 57 EFPY fluence values, the LGS Mean RTNDT values were computed for each unit and compared to the NRC analytical results for 64 EFPY provided in the FSER to BWRVIP-05. Although a conditional failure probability has not been calculated for the LGS units, the fact that the LGS Mean RTNDT values for the period of extended operation are significantly less than the NRC value leads to the conclusion that the Unit 1 and 2 conditional failure probability is bounded by the NRC analysis, consistent with the requirements defined in GL 98-05. This analysis has been projected through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.6 Circumferential Weld Inspection

ASME Section XI governs the inspection of the reactor pressure vessel circumferential welds, as implemented by the LGS In-service Inspection Program. LGS has received inspection relief for circumferential welds for the remainder of the 40-year license period. The circumferential weld failure probability assessment is based on 32 EFPY fluence values associated with 40 years of operation and has been identified as a TLAA requiring evaluation for the period of extended operation.

In order to evaluate the LGS circumferential weld failure probability assessment for 60 years, 57 EFPY fluence values were derived for the limiting circumferential weld. Using the 57 EFPY fluence values, the LGS Mean RT_{NDT} values were computed for each unit and compared to the NRC analytical results for 64 EFPY provided in the FSER to BWRVIP-05. Although a conditional failure probability has not been calculated for the LGS units, the fact that the LGS Mean RT_{NDT} values for the period of extended operation are significantly less than the NRC value leads to the conclusion that the LGS conditional failure probability is bounded by the NRC analysis, consistent with the requirements defined in GL 98-05.

The effects of aging on the reactor pressure vessel intended functions will be managed in accordance with 10 CFR 54.21(c)(1)(iii) for the period of extended operation by reapplication for circumferential weld examination relief under 10 CFR 50.55a (a)(3). The plant-specific information described above

demonstrates that at the end of the renewal period, the circumferential welds meet the limiting conditional failure probability for circumferential welds specified in the FSER of BWRVIP-05. Operator training and procedures will continue to be utilized during the license renewal term to limit cold over-pressure events.

A.4.2.7 Reactor Pressure Vessel Reflood Thermal Shock

A generic fracture mechanics evaluation was performed in 1979 to evaluate the effects of a postulated Loss of Coolant Accident (LOCA) on the structural integrity of a BWR-6 reactor pressure vessel. The LOCA event considered was a rupture of a main steam line, which was determined to bound all other LOCA events with respect to this evaluation. Several emergency core cooling systems are activated at different times after the LOCA and the vessel is flooded with cooling water. The vessel blowdown and the subsequent injection of cold water produce low temperature and high thermal stresses in the vessel. This analysis concluded that the reactor pressure vessel has a considerable margin to failure by brittle fracture even in the presence of large postulated initial flaws. This generic analysis envelopes LGS and is based on BWR vessel material properties and cumulative fluence assumed for 40 years of operation. Therefore, this analysis has been identified as a TLAA requiring evaluation for the period of extended operation.

An updated 60-year fracture mechanics evaluation was performed for the reflood thermal shock event using plant-specific reactor pressure vessel data for LGS. The analysis determined that during the period of extended operation for both units, there is sufficient toughness margin to prevent fracture due to reflood thermal shock. An existing flaw in the reactor pressure vessel would not propagate due to brittle fracture during a LOCA.

The reactor pressure vessel reflood thermal shock analysis has been projected for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.3 Metal Fatigue

Metal fatigue was considered explicitly in the design process for pressure boundary components designed in accordance with ASME Section III, Class A or Class 1 requirements. Metal fatigue was evaluated implicitly for components designed in accordance with ASME Section III, Class 2 or 3 requirements or ANSI B31.1 requirements. These fatigue analyses and fatigue exemptions are considered to be Time-Limited Aging Analyses (TLAAs) requiring evaluation for the period of extended operation in accordance with 10 CFR 54.21(c).

A.4.3.1 ASME Section III, Class 1 Fatigue Analyses

The LGS reactor pressure vessel (RPV) and reactor coolant pressure boundary (RCPB) piping and components were designed in accordance with the ASME Code Section III, Class 1 requirements. Fatigue analyses were prepared for these components to determine the effects of cyclic loadings resulting from changes in system temperature and pressure and for seismic loading cycles. These Class 1 fatigue analyses are included in stress reports that evaluated an explicit number and type of transients to envelope the number of occurrences projected during the 40-year design life of the plant. These stress reports include fatigue analyses and fatigue exemptions, where applicable, that have been identified as TLAAs since they are based upon 40-year design transients. Each analysis was required to demonstrate that the Cumulative Usage Factor (CUF) for the component will not exceed the design limit of 1.0 when the component is exposed to all of the postulated transients. The Class 1 valve analyses were required to demonstrate that the valves can be operated for a minimum of 2,000 cycles and that the fatigue usage factor for step changes in fluid temperature It does not exceed a limit of 1.0.

The calculation of fatigue usage factors is part of the current licensing basis and is used to support safety determinations and since the number of occurrences of each transient type was based upon 40-year assumptions, these Class 1 fatigue analyses and fatigue exemptions have been identified as time-limited aging analyses.

Each of the Class 1 fatigue analyses and fatigue exemptions was evaluated for 60 years by determining that the numbers of cycles assumed in the 40-year analysis will remain bounding of the numbers of cycles projected for the component through the end of the period of extended operation. These 60-year projections were based upon cumulative cycles to-date plus future cycles predicted based upon the average rates of past occurrences. In order to ensure that these fatigue analyses and fatigue exemptions remain valid, the Fatigue Monitoring program will be used to ensure the cycle limits are not exceeded during the period of extended operation. The program includes requirements that trigger corrective action if a transient approaches a cycle limit. Corrective action may include reanalysis of affected Class 1 components to address increased numbers of cycles, repair, or replacement of the component.

The effects of aging on the intended functions of components analyzed in accordance with ASME Section III, Class 1 requirements will be adequately managed for the period of extended operation by the Fatigue Monitoring program in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.2 ASME Section III, Class 2 and 3 and ANSI B31.1 Allowable Stress Calculations

Piping designed in accordance with ASME Section III, Class 2 or 3 design rules or ANSI B31.1 Piping Code design rules is not required to have an explicit analysis of cumulative fatigue usage, but cyclic loading is considered in the design process. If the numbers of anticipated thermal cycles exceed specified limits, these codes require the application of a stress range reduction factor to the allowable stress to prevent damage from cyclic loading. This is considered to be an implicit fatigue analysis since it is based upon cycles anticipated for the life of the component.

These codes first require the overall number of thermal and pressure cycles expected during the 40-year lifetime of these components to be determined. A stress range reduction factor is then determined for that number of cycles using the applicable design code. If the total number of cycles is 7,000 or less, the stress range reduction factor of 1.0 is applied which would not reduce the allowable stress values. For higher numbers of cycles, the stress range reduction factor limits the allowable stresses that can be applied to the piping.

For the piping and components that are affected by the reactor vessel operational transients, including the Class 2 and 3 piping extending from Class 1 systems, the 60-year cycle projections demonstrate that the total number of thermal and pressure cycles will not exceed 7,000 cycles during the period of extended operation. The effects of aging on the intended function(s) of components will be adequately managed for the period of extended operation by the Fatigue Monitoring program in accordance with 10 CFR 54.21(c)(1)(iii).

For the remaining systems that are affected by different thermal and pressure cycles, an operational review was performed that also concluded that the total number of cycles, projected for the period of extended operation, will not exceed 7,000 cycles for these systems. This includes portions of the Fire Protection, Emergency Diesel Generator, and Auxiliary Steam systems. Systems with operating temperatures below specified thresholds were determined to have low numbers of equivalent full temperature cycles since the fluid temperature changes are small. For these systems, the maximum allowable stress range values for the existing fatigue analysis remain valid in accordance with 10 CFR 54.21(c)(1)(i) because the allowable limit for the number of full thermal range transient cycles will not be exceeded during the period of extended operation.

A.4.3.3 Environmental Fatigue Analyses for RPV and Class 1 Piping

NUREG-1800, Revision 2 provides a recommendation for evaluating the effects of the reactor water environment on the fatigue life of ASME Section III Class 1 components that contact reactor coolant. One method to satisfy this recommendation is to assess the impact of the reactor coolant environment on a sample of critical components as described in NUREG/CR-6260. Additional

component locations are evaluated if they are considered to be more limiting than those considered in NUREG/CR-6260.

Environmental fatigue calculations were performed for component locations listed in NUREG/CR-6260 for the newer-vintage BWR. In order to ensure that any other locations that may not be bounded by the NUREG/CR-6260 locations were evaluated, environmental fatigue calculations were performed for each RPV component location that has a reported cumulative usage factor (CUF) in the RPV stress report and for each ASME Class 1 RCPB piping system. These environmental fatigue calculations were performed for the limiting wetted location for each material within the component that contacts reactor coolant.

NUREG-1800, Revision 2, specifies options for evaluating environmental effects. The formulae specified in the option listed below for each material were used in evaluating the LGS components for environmental effects:

Carbon and Low Alloy Steels

- Those provided in Appendix A of NUREG/CR-6909, using either the applicable ASME Section III fatigue design curve or the fatigue design curve for carbon and low alloy steel provided in NUREG/CR-6909 (Figure A.1 and A.2, respectively, and Table A.1).

Austenitic Stainless Steels

- The formula provided in NUREG/CR-6909, using the fatigue design curve for austenitic stainless steel provided in NUREG/CR-6909 (Figure A.3 and Table A.2).

Nickel Alloys

- The formula provided in NUREG/CR-6909, using the fatigue design curve for austenitic stainless steel provided in NUREG/CR-6909 (Figure A.3 and Table A.2).

Additional refinements were performed as appropriate and several locations required a reduction in the numbers of postulated cycles. The resulting environmentally-adjusted CUF values (CUF_{en}) were demonstrated not to exceed the design Code limit of 1.0.

These environmental fatigue analyses will be managed by the Fatigue Monitoring program in the same manner as all other Class 1 fatigue analyses. The program ensures that the cumulative number of occurrences of each transient type is maintained below the number of cycles used in the most limiting fatigue analysis.

If a cycle limit is approached, corrective actions are triggered to prevent exceeding the limit. The fatigue analyses may be revised to account for increased numbers of cycles or transient severity such that the CUF value does not exceed the Code design limit of 1.0, including environmental effects where applicable.

Prior to the period of extended operation, the Fatigue Monitoring program will be enhanced to impose administrative transient cycle limits corresponding to the limiting numbers of cycles used in the environmental fatigue calculations.

The effects of aging on the intended functions will be adequately managed for the period of extended operation by the LGS Fatigue Monitoring program in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.4 Reactor Vessel Internals Fatigue Analyses

The RPV and RPV internal components were included in the NSSS New Loads Design Adequacy Evaluations performed for each unit to address the effects of plant-specific seismic loadings and suppression pool hydrodynamic structural loadings on NSSS equipment. These evaluations included fatigue analyses of components if the applied loadings exceed certain thresholds. These fatigue analyses and fatigue exemptions have been identified as TLAAs that require evaluation for the period of extended operation.

The fatigue analyses and fatigue exemptions performed for the reactor internals components are based upon the same set of design transients as those used in the fatigue analyses for the reactor pressure vessel. Transient cycle projections were prepared that demonstrate the design transient cycle limits will not be exceeded in 60 years. In order to ensure that these fatigue analyses and fatigue exemptions will remain valid, the Fatigue Monitoring program will be used to manage fatigue of these components through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.5 High-Energy Line Break (HELB) Analyses Based Upon Fatigue

High Energy Line Break (HELB) analyses for LGS used the CUF values from the ASME Class 1 fatigue analyses as input in determining intermediate break locations. Since the Class 1 fatigue analyses that provided the CUF values are based upon 40-year transient assumptions, these analyses have been identified as TLAAs.

Transient cycle projections were performed that determined the 40-year transient cycle limits will not be exceeded in 60 years. The Class 1 piping fatigue analyses were demonstrated to remain valid for the period of extended operation. Therefore, the HELB break determinations based upon these fatigue analyses will also remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.4 Environmental Qualification (EQ) of Electric Components

A.4.4.1 Environmental Qualification (EQ) of Electric Components

Thermal, radiation, and cyclical aging analyses of plant electrical and I&C components, developed to meet 10 CFR 50.49 requirements, have been identified as time-limited aging analyses (TLAAs) for LGS. The NRC has established nuclear station environmental qualification (EQ) requirements in 10 CFR 50.49 and 10 CFR 50, Appendix A, Criterion 4. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that

certain electrical components located in harsh plant environments are qualified to perform their safety function in those harsh environments after the effects of inservice aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a loss-of-coolant accident (LOCA), high energy line break (HELB), or post-LOCA radiation. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

The Environmental Qualification (EQ) of Electric Components (A.3.1.2) program will manage the effects of aging effects for the components associated with the environmental qualification TLAA. This program implements the requirements of 10 CFR 50.49 (as further defined and clarified by NUREG-0588, and RG 1.89, Rev. 1). Component aging evaluations are reanalyzed on a routine basis to extend the qualifications of components as part of the LGS EQ Program. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). The Environmental Qualification (EQ) of Electric Components (A.3.1.2) program methodology is further described in Appendix A, Section A.3.1.2. As permitted by the License Amendment to implement 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors," Alternative Treatments may be applied in lieu of 10 CFR 50.49 requirements for components classified as RISC-3 and RISC-4.

Under the LGS EQ Program, the reanalysis of an aging evaluation could extend the qualification of the component. If the qualification cannot be extended by reanalysis, the component must be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner such that sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful.

A.4.5 Containment Liner and Penetrations Fatigue Analysis

A.4.5.1 Containment Liner and Penetrations Fatigue Analysis

The LGS primary containment liner and penetrations were designed and analyzed for transient cycles predicted to occur in 40 years. The Class 1 flued-head penetrations were also analyzed for fatigue using cycles predicted to occur for 40 years. These analyses have been identified as TLAAs.

Transient cycle projections were performed that determined the 40-year transient cycle limits will not be exceeded in 60 years. This includes startup and shutdown cycles and Design Basis Accident events. An operational review was performed for the MSRV lift cycles that concluded the total number of cycles, projected for 60 years, will not exceed the number analyzed for 40 years. Therefore, the analyses remain valid for the period of extended operation in accordance with 10 CFR 54-21(c)(1)(i).

A.4.6 Other Plant–Specific Time-Limited Aging Analyses

A.4.6.1 Reactor Enclosure Crane Cyclic Loading Analysis

The LGS reactor enclosure crane is designed to meet the fatigue requirements of the Crane Manufacturers Association of America (CMAA) Specification 70 for a Class A, Standby or Infrequent Service Crane, as discussed in UFSAR Section 9.1.5.2, "Reactor Enclosure Crane, Equipment Design." This evaluation of cycles over the 40-year plant life is the basis of a safety determination and has been identified as a TLAA that requires evaluation for the period of extended operation.

The reactor enclosure crane was purchased as a Class A crane and can be considered a crane experiencing “irregular occasional use followed by long idle periods”. For this crane, the CMAA design considerations allow a minimum of 20,000 cycles.

The evaluation of the reactor enclosure crane cyclic load limit TLAA included (1) reviewing the existing 40-year design basis to determine the number of load cycles considered in the design of the crane, (2) developing a 60-year projection for load cycles for the crane, and (3) comparing the 60-year projected number of cycles to the minimum allowable design value of 20,000 cycles. The number of cycles projected for 60 years of operation is 3,468 cycles, which is less than 20 percent of the minimum allowable design value. Therefore, the reactor enclosure crane load cycle fatigue analysis remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.6.2 Emergency Diesel Generator Enclosure Cranes Cyclic Loading Analysis

LGS has eight emergency diesel generator enclosure cranes. These cranes were designed to meet or exceed the design fatigue requirements of the Crane Manufacturers Association of America (CMAA) Specification 70 for Class A, Standby or Infrequent Service Cranes. The evaluation of cycles expected over the 40-year life has been identified as a TLAA that requires evaluation for the period of extended operation.

The emergency diesel generator enclosure cranes were evaluated for the period of extended operation by developing 60-year projections for crane load cycles and comparing these projected cycles to the number of cycles evaluated for the design life of the cranes. The emergency diesel generator enclosure cranes were purchased as Class A cranes. They are considered to be cranes experiencing “irregular occasional use followed by long idle periods." For this category of crane, the CMAA design requirements permit a minimum of 20,000 load cycles.

The 60-year load cycle projection includes all load cycles and is based on an estimated 500 load cycles during original construction and 50 load cycles per year during diesel generator maintenance. The 3,500 load cycles are less than 20 percent of the allowable design value of 20,000 cycles. Therefore, the analysis of the emergency diesel generator enclosure cranes remains valid for the period of extended operation.

The analysis remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.6.3 RPV Core Plate Rim Hold-Down Bolt Loss of Preload

The RPV core plate is attached to the core support structure by stainless steel hold-down bolts that are preloaded during initial installation. These bolts are subject to stress relaxation (loss of preload) due to irradiation effects. An analysis was performed concluding that a reduction in preload as high as 19 percent over the 40-year life of the bolts is acceptable to meet design requirements. A subsequent re-evaluation determined that this maximum relaxation value of 19 percent is applicable to an average fluence level of 8.0 E+19 n/cm^2 over the entire length of the bolt located at the azimuthal location with peak fluence. These analyses were identified as TLAAs.

In order to determine if these analyses will remain valid for 60 years, RAMA fluence projections were prepared for LGS for 57 EFPY for the core plate rim bolt located at the azimuthal location with peak fluence. In order to determine the average fluence value along the length of the bolt, fluence projections were made at 75 discrete points along the length of the bolt on the bolt surface nearest the core. These results were integrated and divided by the length of the bolt, resulting in an average fluence value of 3.37 E+19 n/cm^2 along the length of the bolt. This is well below the average fluence of 8.0 E+19 n/cm^2 value previously evaluated. Therefore, the analysis remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.6.4 Main Steam Line Flow Restrictors Erosion Analysis

A main steam line flow restrictor is welded into each of the four main steam lines between the main steam relief valves and the inboard main steam isolation valve (MSIV). The restrictor assemblies consist of a stainless steel venture-type nozzle welded into the carbon steel main steam line piping. The restrictors are designed to limit steam flow prior to MSIV closure in the event of a main steam line break outside of primary containment.

There is no specific analysis of main steam line flow restrictor erosion other than that discussed in UFSAR Section 5.4.4. The UFSAR indicates that very slow erosion occurs with time and such slight enlargement has no safety significance. Since the erosion evaluation could have assumed 40 years of operation, erosion of the main steam line flow restrictor has been identified as a TLAA that requires evaluation for the period of extended operation.

Calculations indicate that even with erosion rates as high as 0.004 inch per year, the increase in choked flow rate would be no more than 5 percent after 40 years of operation, and no more than 10 percent after 60 years. The LGS Main Steam Line Break dose calculation determined that the mass of coolant leaving the reactor through the main steam line break is 108,785 lb, but uses 140,000 lb to determine the dose impact from this event. Therefore, sufficient margin exists in the dose calculation to accommodate the postulated erosion of the main steam line flow restrictor through the end of the period of extended operation.

The analysis remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.6.5 Jet Pump Auxiliary Spring Wedge Assembly

Auxiliary spring wedge assemblies have been designed and installed in LGS jet pumps to maintain lateral support for the jet pump inlet mixer. The design analysis considered potential aging effects based upon a design life of 40 years, including fatigue usage and loss of preload due to neutron fluence. These analyses have been identified as TLAAs.

The jet pump auxiliary spring wedge assembly is not an ASME Code component, but it was evaluated using stress and fatigue limits of the ASME Code as guidelines. The cumulative fatigue usage was determined to be 0.77 using the original design basis load cycles from the reactor vessel thermal cycle diagram. The 60-year transient projections for LGS demonstrate that these transient cycle limits will not be exceeded in 60 years of operation. Therefore, the fatigue TLAA remains valid for the period of extended operation.

The auxiliary spring wedge assembly design analysis also evaluated loss of preload due to integrated neutron fluence of 1.4 E+20 n/cm^2 for 40 years. In order to evaluate loss of bolt preload during the period of extended operation, the maximum service life was first determined. The first Unit 1 wedge assembly installed will have a service life of 41 years by the end of the period of extended operation, and the first Unit 2 wedge assembly will have a service life of 45 years.

The RAMA fluence projections were used to determine how long the auxiliary spring wedge assemblies could remain in service before the analyzed fluence value of 1.4 E+20 n/cm^2 would be reached. The fluence projections for the jet pump riser brace location were used since they are bounding for the locations of the auxiliary spring wedge assembly. The evaluation determined that the auxiliary spring wedge assemblies will not reach the previously evaluated fluence value of 1.4 E+20 n/cm^2. Therefore, the loss of preload TLAA also remains valid for the period of extended operation in accordance with 10CFR 54.21(c)(1)(i).

A.4.6.6 Jet Pump Restrainer Bracket Pad Repair Clamps

Visual inspections at LGS have found wear at the inlet-mixer wedge/restrainer bracket pad interface on several jet pumps. A repair clamp has been designed and installed that replaces the support function of the restrainer bracket pad. The repair clamp design analysis evaluated end-of-life preload relaxation for 40 years based upon a 5 percent decrease due to thermal and radiation effects. This analysis was identified as a TLAA.

The fluence value used to determine the loss of preload in the design analysis is five percent higher than the fluence value calculated for the repair location for a 40-year service life. Since the first clamps were installed in Unit 2 in 2009 and no clamps have been installed in Unit 1, these clamps will have a maximum service life of 40.25 years. Therefore, since the repair clamp design

analysis includes an allowance for loss of preload that is bounding for 42 years, the analysis remains valid in accordance with 10 CFR 54.21(c)(1)(i).

The repair clamp design analysis also evaluated fatigue for 40 years, which was identified as a TLAA. The clamping loads do not cycle except for the load changes associated with startup/shutdown temperature changes. The maximum calculated stress amplitude is 7,781 psi, which is within the American Society of Mechanical Engineers (ASME) Code stress limit for 304 stainless steel of 13,600 psi for 10^{11}cycles, and the General Electric Hitachi design limit of 10,000 psi for flow-induced vibration stress cycles. Since the calculated cyclic loads of 7,781 psi are less than these limits, fatigue usage will be insignificant for up to 10^{11} startup/shutdown cycles. Therefore the fatigue analysis remains valid through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.6.7 Refueling Bellows and Supports Cyclic Loading Analysis

The refueling bellows and supports were analyzed for cycles predicted to occur in 40 years. Therefore, these fatigue analyses have been identified as TLAAs that require evaluation for the period of extended operation.

Transient cycle projections were performed that determined the 40-year transient cycle limits will not be exceeded in 60 years based upon the average rate of occurrence to-date. The analyses remain valid for the period of extended operation in accordance with 10 CFR 54-21(c)(1)(i).

A.4.6.8 Downcomers and MSRV Discharge Piping Fatigue Analyses

The downcomers and bracing inside the suppression chamber and the MSRV discharge piping quenchers have been evaluated for transient cycles predicted to occur in 40 years. Therefore, these fatigue analyses have been identified as TLAAs.

The downcomers and bracing were analyzed for a minimum of 7,700 MSRV stress cycles that were considered to account for the pool dynamic loads, based on 1,100 actuations of all MSRVs times seven stress cycles per actuation. For the most frequently actuated MSRVs, the analysis was based on 4,700 actuations times three stress cycles per actuation (14,100 total cycles). They were also analyzed for 3,000 chugging cycles that could occur following a LOCA event, 50 OBE cycles (five events with ten cycles per event), and ten SSE cycles (one event with ten cycles). The quenchers were analyzed for 7,000 MSRV actuations (opening and closing cycles) and 1,000,000 irregular condensation load cycles.

An operational review was performed for MSRV actuations that concluded the total number of MSRV actuations, projected for 60 years, will not exceed the number analyzed for 40 years in either unit. The 60-year projection for Unit 1 is 211 actuations and for Unit 2 is 138 actuations, which are well below the 1100 actuations analyzed. No OBE or SSE event has occurred to-date and neither has a 60-year projection that exceeds the design limit of one event. The Fatigue Monitoring program is credited for managing fatigue of these components in accordance with 10 CFR 54.21 (c)(1)(iii) by ensuring that the

analyzed numbers of cycles are not exceeded during the period of extended operation.

The MSRV discharge lines were analyzed for significant thermal and pressure transients defined for the Main Steam system and for the same MSRV, chugging, OBE and SSE cycles described above for the downcomers. Each of these transients has been evaluated and shown to have 60-year projections that do not exceed the numbers of cycles analyzed. The Fatigue Monitoring program is credited for managing fatigue of these components in accordance with 10 CFR 54.21 (c)(1)(iii) by ensuring that the analyzed numbers of cycles are not exceeded during the period of extended operation.

A.4.6.9 Jet Pump Slip Joint Repair Clamps

Jet pump slip joint repair clamps have been designed and installed at LGS to minimize vibration and wear of the jet pump assemblies. The structural evaluation determined the loss of preload that would result from neutron fluence during the design life of the clamps. This analysis was identified as a TLAA. The maximum service life of the slip joint clamps from initial installation through the period of extended operation will be less than 40 years for the Unit 1 clamps and less than 45 years for the Unit 2 clamps. RAMA fluence projections for each unit have determined the maximum fluence the slip joint clamps can receive during their service life. These fluence values are less than the fluence value used to determine the loss of preload allowance applied in the structural evaluation of the clamps. Therefore, the jet pump slip joint clamp design analysis for loss of preload due to neutron fluence remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.6.10 Fuel Pool Girder Loss of Prestress

The design analysis of the LGS Fuel Pool Girders has been identified as a plant-specific TLAA because it includes a time-limited evaluation of loss of prestress of the fuel pool girders. The girder analysis used a 4% stress relaxation value that is based upon stress relaxation test data, projected for 1,000,000 hours (114 years), which is a time-limited assumption. The TLAA remains valid in accordance with 10 CFR 54.21(c)(1)(i) because the loss of prestress values used in the analysis were demonstrated to remain valid through the period of extended operation.

A.4.6.11 RHR and Core Spray Suction Strainer Fatigue Analyses

The design analyses for the RHR and Core Spray suction strainers have been identified as TLAAs because they include a time-limited fatigue analysis of the stainless steel bolting and stainless steel strainer assembly. These analyses were based upon 34,200 MSRV stress cycles (11,400 actuations), 10 SSE stress cycles (1 event), 50 OBE cycles (5 events), and condensation oscillation and chugging cycles that would result from LOCA events. These are the same types of transients analyzed for the downcomers described in LRA Section 4.6.8.

The Fatigue Monitoring program is credited for managing fatigue of the RHR and Core Spray strainer assemblies and bolting, in accordance with 10 CFR 54.21(c)(1)(iii).

Note: This table contains commitments related to the renewed LGS operating licenses. Because these commitments are contained within the UFSAR, any potential changes to these commitments require evaluation in accordance with 10 CFR 50.59 as defined per the Exelon commitment management process. In addition, that process must be followed to ensure that the commitment tracking database is updated with the latest commitment implementation information. Refer to PIMS AR A1813863 and Passport AR 1232104 for LGS license renewal commitment tracking data.

A.5 License Renewal Commitment List

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Existing program is credited.	Ongoing	Section A.2.1.1
2	Water Chemistry	Existing program is credited.	Ongoing	Section A.2.1.2
3	Reactor Head Closure Stud Bolting	Existing program is credited.	Ongoing	Section A.2.1.3
4	BWR Vessel ID Attachment Welds	Existing program is credited.	Ongoing	Section A.2.1.4
5	BWR Feedwater Nozzle	Existing program is credited.	Ongoing	Section A.2.1.5
6	BWR Control Rod Drive Return Line Nozzle	Existing program is credited.	Ongoing	Section A.2.1.6
7	BWR Stress Corrosion Cracking	Existing program is credited.	Ongoing	Section A.2.1.7
8	BWR Penetrations	Existing program is credited.	Ongoing	Section A.2.1.8

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
9	BWR Vessel Internals	BWR Vessel Internals is an existing program that will be enhanced to: 1. Perform an assessment of the susceptibility of reactor vessel internal components fabricated from Cast Austenitic Stainless Steel (CASS) to loss of fracture toughness due to thermal aging embrittlement. If material properties cannot be determined to perform the screening, they will be assumed susceptible to thermal aging for the purposes of determining program examination requirements. 2. Perform an assessment of the susceptibility of reactor vessel internal components fabricated from Cast Austenitic Stainless Steel (CASS) to loss of fracture toughness due to neutron irradiation embrittlement. 3. Specify the required periodic inspection of CASS components determined to be susceptible to loss of fracture toughness due to thermal aging and neutron irradiation embrittlement.	Program to be enhanced prior to the period of extended operation. The initial inspections will be performed either prior to or within 5 years after entering the period of extended operation.	Section A.2.1.9
10	Flow-Accelerated Corrosion	Existing program is credited.	Ongoing	Section A.2.1.10

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
11	Bolting Integrity	Bolting Integrity is an existing program that will be enhanced to: 1. Provide guidance to ensure proper specification of bolting material, lubricant and sealants, storage, and installation torque or tension to prevent or mitigate degradation and failure of closure bolting for pressure retaining components. 2. Prohibit the use of lubricants containing molybdenum disulfide for closure bolting for pressure retaining components. 3. Minimize the use of high strength bolting (actual measured yield strength equal to or greater than 150 ksi) for closure bolting for pressure retaining components. High strength bolting, if used, will be monitored for cracking. 4. Perform visual inspection of bolting for the Residual Heat Removal System, Core Spray System, High Pressure Coolant Injection System and Reactor Core Isolation Cooling System suppression pool suction strainers for loss of material and loss of preload during each ISI inspection interval.	Program to be enhanced prior to the period of extended operation.	Section A.2.1.11 LGS letter dated 3/12/2012 RAI 3.2.2.1.1-1
12	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System is an existing program that will be enhanced to:	Program to be enhanced prior to the	Section A.2.1.12

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		1. Perform internal inspection of buried Safety Related Service Water Piping when it is accessible during maintenance and repair activities. 2. Perform periodic inspections for loss of material in the Nonsafety-Related Service Water System at a minimum of five locations on each unit once every refueling cycle. 3. Replace the supply and return piping for the Core Spray pump compartment unit coolers. 4. Replace degraded RHRSW piping in the pipe tunnel. 5. Perform periodic inspections for loss of material in the Safety Related Service Water System at a minimum of ten locations every two years. The Open-Cycle Cooling Water System aging management program also manages the loss of coating integrity in the service water side of the Main Control Room Chiller Condensers and Reactor Enclosure Cooling Water Heat Exchangers, and, in circulating water system piping. • As described below, baseline inspections will occur in the 10-year period prior to the period of extended operation. The maximum interval of subsequent	period of extended operation. Inspection schedule identified in commitment.	LGS Letter dated 2/15/12 RAI B.2.1.12-1 RAI B.2.1.12-2 LGS letter dated 6/22/12 RAI B.2.1.12-3 LGS Letter dated 3/14/14 RAI 3.0.3-1 LGS letter dated 05/21/14 RAI 3.0.3.4-1

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		coating inspections will comply with Table 4a of GALL Report AMP XI.M42 in draft LR-ISG-2013-01 dated January 6, 2014 (ADAMS Accession No. ML13262A442). • The inspection of the Main Control Room Chiller Condensers will be performed by inspectors qualified to ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II. • The inspection of the Reactor Enclosure Cooling Water Heat Exchangers will be performed by inspectors with a demonstrated working knowledge of EPRI Report 1019157, “Guideline on Nuclear Safety-Related Coatings”. • The inspection of 73 one-foot axial length circumferential segments of coated circulating water system piping will be performed by inspectors qualified to ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II. • The acceptance criteria for coating degradation and the requirements for physical inspections when degradation is identified will be in accordance with Element 6 of GALL Report AMP XI.M42 in draft LR-ISG-2013-01 dated January 6, 2014.		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
13	Closed Treated Water Systems	Closed Treated Water Systems is an existing program that will be enhanced to: 1. Perform condition monitoring and performance monitoring, including periodic testing and opportunistic and periodic NDE, to verify the effectiveness of water chemistry control to mitigate aging effects. A representative sample of piping and components will be selected based on likelihood of corrosion and inspected at an interval not to exceed once in 10 years during the period of extended operation. 2. Perform condition monitoring for the loss of material due to cavitation erosion in the reactor enclosure cooling water piping to the 2A Reactor Water Cleanup System (RWCU) non-regenerative heat exchanger. An initial inspection frequency of 4 years has been established. The inspection frequency will be re-evaluated and adjusted as necessary based on trend data.	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.13 LGS Letter dated 4/13/12 RAI B.2.1.13-2.1
14	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems is an existing program that will be enhanced to: 1. Perform annual periodic inspections as defined in the appropriate ASME B30 series standard for all cranes, hoists, and equipment handling systems within the scope of license renewal. For handling systems that	Program to be enhanced prior to the period of extended operation.	Section A.2.1.14

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		are infrequently in service, such as those only used during refueling outages, annual periodic inspections may be deferred until just prior to use. 2. Perform inspections of structural components and bolting for loss of material due to corrosion, rails for loss of material due to wear and corrosion, and bolted connections for loss of preload. 3. Evaluate loss of material due to wear or corrosion and any loss of bolting preload on cranes, hoists, and equipment handling systems per the appropriate ASME B30 series standard. 4. Perform repairs to cranes, hoists, and equipment handling systems per the appropriate ASME B30 series standard.		
15	Compressed Air Monitoring	Compressed Air Monitoring is an existing program that will be enhanced to: 1. Perform periodic analysis and trending of air quality monitoring results.	Program to be enhanced prior to the period of extended operation.	Section A.2.1.15 LGS letter dated 2/15/12 RAI B.2.1.15-1
16	BWR Reactor Water Cleanup System	Existing program is credited.	Ongoing	Section A.2.1.16
17	Fire Protection	Fire Protection is an existing program that will be enhanced to:	Program to be enhanced prior to the	Section A.2.1.17

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		1. Provide additional inspection guidance to identify degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling and loss of material. 2. Provide additional inspection guidance for identification of excessive loss of material due to corrosion on the external surfaces of the halon system.	period of extended operation.	
18	Fire Water System	Fire Water System is an existing program that will be enhanced to: 1. Replace sprinkler heads or perform 50-year sprinkler head testing using the guidance of NFPA 25 “Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems” (2011 Edition), Section 5.3.1.1.1. This testing will be performed prior to the 50-year in-service date and every 10 years thereafter. 2. Inspect selected portions of the water based fire protection system piping located aboveground and exposed to the fire water internal environment by non-intrusive volumetric examinations. These inspections shall be performed prior to the period of extended operation and will be performed every 10 years thereafter.	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.18 LR-ISG-2012-02 review 03/12/2014 LGS Letter dated 3/14/14 RAI 3.0.3-1 LGS Letter dated 5/21/14 RAI 3.0.3.3.1-1 RAI 3.0.3.4-1

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		3. Inspect and clean line strainers for deluge systems after each actuation. Strainers for deluge systems subject to full flow testing will be inspected and cleaned on a frequency consistent with the deluge test frequency. 4. Inspect and clean the foam system water supply strainer after each system actuation and no less than once per refueling interval. 5. Perform external visual inspection of deluge piping and nozzles for the HVAC charcoal filters for signs of leakage, corrosion, physical damage, and correct orientation each time the charcoal is removed for replacement. 6. Perform flow tests for the hydraulically most remote hose stations once every five years, scheduling the testing so that some of the tests are performed in each year of the five year interval. 7. Perform a main drain test annually for the fire water piping in each of the following locations: Unit 1 Reactor Enclosure, Unit 2 Reactor Enclosure, Unit 1 Turbine Enclosure, Unit 2 Turbine Enclosure, Control Enclosure, and Radwaste Enclosure. Flow blockage or abnormal discharge identified during flow testing or any change in pressure during the		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		test greater than ten percent at a specific location is entered into the corrective action program for evaluation. 8. Perform charcoal filter deluge valve exercise testing and air flow testing each time the charcoal is removed for replacement and perform air flow testing for the deluge systems for the hydrogen seal oil units and lube oil reservoirs every two years. 9. Perform the following for Fire Water System sprinkler and deluge systems: • Perform visual internal inspections, consistent with NFPA 25, for corrosion and obstructions to flow on at least five wet pipe sprinkler systems every five years. • Collect and evaluate solids discharged from wet pipe sprinkler system flow testing. Flow testing through the inspector's test valve will be performed on an interval no greater than 18 months for each wet pipe system. • Perform visual internal inspections for corrosion and obstructions to flow for dry pipe preaction sprinkler systems of surfaces made accessible when preaction and water		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		deluge valves are serviced on an interval no greater than a refueling interval. • Perform visual internal inspections for corrosion and obstructions to flow for deluge systems of surfaces made accessible when deluge valves are serviced on at least ten deluge systems on an interval no greater than three years. To provide reasonable assurance of the presence of sufficient coating, two of the ten inspections will be associated with the galvanized transformer deluge system piping. • Perform a visual internal inspection for corrosion and obstructions to flow for any wet pipe, dry pipe preaction, or deluge system after any system actuation prior to return to service. • Perform an obstruction evaluation for conditions that indicate degraded flow. • Perform followup volumetric inspections for pipe wall thickness if internal visual inspections detect surface irregularities that could be indicative of wall loss below nominal wall thickness.		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		• Sprinkler and deluge systems that are normally dry but may be wetted as the result of testing or actuations will have augmented tests and inspections on piping segments that cannot be drained or piping segments that allow water to collect. These augmented inspections will be performed in each five year interval beginning five years prior to the period of extended operation and consist of either a flow test or flush sufficient to detect potential flow blockage or a visual inspection of 100 percent of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect. In addition, in each five year interval of the period of extended operation, 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect is subject to volumetric wall thickness inspections. 10. Perform wall thickness measurements using UT or other suitable techniques at five selected locations every year to identify loss of material in the carbon steel backup fire water piping. When these examinations identify pipe degradation, additional examinations will be performed in accordance with the following criteria:		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		• At least four additional locations will be examined if wall loss is greater than 50 percent of nominal wall thickness, • Two additional locations will be examined if wall loss is 30 percent to 50 percent of nominal wall thickness and the calculated remaining life is less than two years, • No additional examinations will be performed if wall loss is less than 30 percent of nominal wall thickness. The Fire Water System aging management program also manages the loss of coating integrity in the buried cement lined fire main header. • System flow testing activities measure system hydraulic resistance as a means of evaluating the internal piping condition. • Opportunistic internal inspections evaluate the condition of the cement lined fire main header. • Within 10 years prior to the PEO, five internal visual inspections of the cement lining in the fire main header will be performed.		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
19	Aboveground Metallic Tanks	Aboveground Metallic Tanks is an existing program that will be enhanced to: 1. Include UT measurements of the bottom of the Backup Water Storage Tank. Tank bottom UT inspections will be performed – within five years prior to entering the period of extended operation and every five years thereafter. If no tank bottom plate material loss is identified after the first two inspections, the remaining inspections will be performed whenever the tank is drained during the period of extended operation. 2. Provide visual inspections of the Backup Water Storage Tank external surfaces and include, on a sampling basis, removal of insulation to permit inspection of the tank surface. An inspection performed prior to entering the period of extended operation will include a minimum of 25 locations to demonstrate that the tank painted surface is not degraded under the insulation. Subsequent tank external surface visual inspection will be conducted on a two year frequency and include a minimum of four locations. Annual visual inspections will be performed of the tank insulation surface for degradation. Rips, tears, and gaps in the insulation skin will be repaired. Evidence of water intrusion beneath the insulation will be evaluated in accordance with the LGS corrective action program.	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.19 LGS Letter dated 2/15/12 RAI B.2.1.19-1 RAI B.2.1.19-2 LR-ISG-2012-02 review 03/12/2014 LGS Letter dated 5/21/14 RAI 3.0.3.3.3-1 RAI 3.0.3.3.3-2

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		3. Perform visual inspections of the Backup Water Storage Tank wetted and nonwetted internal surfaces. Tank internal inspections will be performed within five years prior to entering the period of extended operation and every five years thereafter. The tank bottom will be inspected for evidence of voids beneath the floor in accordance with NFPA 25, Section 9.2.6.5. Where pitting and general corrosion to below the nominal wall thickness occurs or any coating failure occurs in which bare metal is exposed, additional inspections and tests shall be performed in accordance with NFPA 25, Section 9.2.7. These tests include adhesion testing of the coating in the vicinity of the coating failure, dry film thickness measurements, spot wet sponge testing, and nondestructive examination to determine remaining wall thickness where bare metal has been exposed. Tank bottom weld seams in the area of degraded coating will be leak tested in accordance with NFPA 25, Section 9.2.7, by vacuum-box testing or magnetic particle (MT) examination. In addition, adhesion testing shall be performed in the vicinity of blisters even though bare metal may not be exposed.		
20	Fuel Oil Chemistry	Fuel Oil Chemistry is an existing program that will be enhanced to:	Program to be enhanced prior to the period of extended operation.	Section A.2.1.20

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		1. Periodically drain water from the Fire Pump Engine Diesel Oil Day Tank and the Fire Pump Diesel Engine Fuel Tank. 2. Perform internal inspections of the Fire Pump Engine Diesel Oil Day Tank, the Fire Pump Diesel Engine Fuel Tank, and the Diesel Generator Day Tanks, at least once during the 10-year period prior to the period of extended operation and at least once every 10 years during the period of extended operation. Each diesel fuel tank will be drained, cleaned and the internal surfaces either volumetrically or visually inspected. If evidence of degradation is observed during visual inspections, the diesel fuel tanks will require follow-up volumetric inspection. 3. Perform periodic analysis for total particulate concentration and microbiological organisms for the Fire Pump Engine Diesel Oil Day Tank and the Fire Pump Diesel Engine Fuel Tank. 4. Perform periodic analysis for water and sediment and microbiological organisms for the Diesel Generator Diesel Oil Storage Tanks. 5. Perform periodic analysis for water and sediment content, total particulate concentration, and the	Inspection schedule identified in commitment.	LGS Letter dated 3/14/14 RAI 3.0.3-1 LGS letter dated 05/21/14 RAI 3.0.3.4-1

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		levels of microbiological organisms for the Diesel Generator Day Tanks. 6. Perform analysis of new fuel oil for water and sediment content, total particulate concentration and the levels of microbiological organisms for the Fire Pump Engine Diesel Oil Day Tank and the Fire Pump Diesel Engine Fuel Tank. 7. Perform analysis of new fuel oil for total particulate concentration and the levels of microbiological organisms for the Diesel Generator Diesel Oil Storage Tanks. The Fuel Oil Chemistry aging management program also manages the loss of coating integrity in the eight main fuel oil storage tanks. • Each fuel oil tank will be internally inspected at least once during the 10-year period prior to the period of extended operation and at least once every 10 years during the period of extended operation • The inspection of the eight main fuel oil storage tanks will be performed by inspectors qualified to ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		• The acceptance criteria for coating degradation and the requirements for physical inspections when degradation is identified will be in accordance with Element 6 of GALL Report AMP XI.M42 in draft LR-ISG-2013-01 dated January 6, 2014.		
21	Reactor Vessel Surveillance	Existing program is credited.	Ongoing	Section A.2.1.21
22	One-Time Inspection	One-Time Inspection is a new program that will be used to verify the system-wide effectiveness of the Water Chemistry, Fuel Oil Chemistry and Lubricating Oil Analysis programs.	Program to be implemented prior to the period of extended operation. One-time inspections will be performed within the 10 years prior to the period of extended operation.	Section A.2.1.22
23	Selective Leaching	Selective Leaching is a new program that will include one-time inspections of a representative sample of susceptible components to determine if loss of material due to selective leaching is occurring.	Program to be implemented prior to the period of extended operation. One-time inspections will be performed within the five years prior to the period of extended operation.	Section A.2.1.23

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
			Periodic inspections will be performed during the period of extended operations (PEO).	
24	One-Time Inspection of ASME Code Class 1 Small-Bore Piping	One-Time Inspection of ASME Code Class 1 Small-Bore Piping is a new program that will manage the aging effect of cracking in stainless steel and carbon steel Class 1 small-bore piping that is less than nominal pipe size (NPS) 4-inches, and greater than or equal to NPS 1-inch.	Program to be implemented prior to the period of extended operation. One-time Inspections will be performed within the six years prior to the period of extended operation.	Section A.2.1.24
25	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components is a new program that manages aging effects of metallic and elastomeric materials through periodic visual inspection of external surfaces for evidence of loss of material. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers. A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components	Program to be implemented prior to the period of extended operation.	Section A.2.1.25 LR-ISG-2012-02 review 03/12/2014

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		exposed to condensation (due to the in-scope component being operated below the dew point), are periodically inspected, under the insulation, every 10 years during the period of extended operation. Inspections subsequent to the initial inspection will consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation if the initial inspection verifies no loss of material beyond that which could have been present during initial construction. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or if there is evidence of water intrusion through the insulation, then periodic inspections under insulation to detect corrosion under insulation will continue.		
26	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is a new program that manages aging effects of metallic and elastomeric materials through visual inspections of internal surfaces for evidence of loss of material. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers. This opportunistic approach is supplemented to ensure a representative sample of components within the scope of this program are inspected. At a minimum, in each 10-year period during the period of extended operation, a representative sample of 20 percent of the population	Program to be implemented prior to the period of extended operation.	Section A.2.1.26 LR-ISG-2012-02 review 03/12/2014 LGS letter dated 05/21/14 RAI 3.0.3.4-1

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		(defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections continue in each 10-year period despite meeting the sampling minimum requirement. For the waste water environment, a maximum of 25 components per population will be inspected. To provide reasonable assurance of the presence of sufficient coating, 10 of the 25 internal inspections will be of the normal waste, oily waste, sanitary waste and storm drain galvanized piping, and 15 of the internal inspections will be of the radioactive floor and equipment drain carbon steel piping.		
27	Lubricating Oil Analysis	Existing program is credited. The Lube Oil Analysis aging management program also manages the loss of coating integrity in the RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir. • As described below, baseline inspections will occur in the 10-year period prior to the period of extended operation. The maximum interval of subsequent coating inspections will comply with Table 4a of GALL Report AMP XI.M42 in draft LR-ISG-2013-01	Ongoing	Section A.2.1.27 LGS Letter dated 3/14/14 RAI 3.0.3-1 LGS letter dated 05/21/14 RAI 3.0.3.4-1

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		dated January 6, 2014 (ADAMS Accession No. ML13262A442). • The inspection of the RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir will be performed by inspectors qualified to ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II. • The acceptance criteria for coating degradation and the requirements for physical inspections when degradation is identified will be in accordance with Element 6 of GALL Report AMP XI.M42 in draft LR-ISG-2013-01 dated January 6, 2014.		
28	Monitoring of Neutron-Absorbing Materials Other than Boraflex	Monitoring of Neutron-Absorbing Materials Other than Boraflex is an existing program that will be enhanced to: 1. Perform test coupon analysis on a ten-year frequency, beginning no earlier than 2020 for Unit 1 and 2021 for Unit 2. 2. Initiate corrective action if coupon test result data indicates that acceptance criteria will be exceeded prior to the next scheduled test coupon analysis. 3. Resume the accelerated exposure configuration for the Boral coupons (surrounded by freshly	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.28 LGS Letter dated 2/28/12 RAI B.2.1.28-1 LGS Letter dated 4/27/12 RAI B.2.1.28-2

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		discharged fuel assemblies) at each of five additional refueling cycles, beginning with the next refueling for each unit (2013 for Unit 2, 2014 for Unit 1). 4. Maintain the coupon exposure such that it is bounding for the Boral material in all spent fuel racks, , by relocating the coupon tree to a different spent fuel rack cell location each cycle and by surrounding the coupons with a greater number of freshly discharged fuel assemblies than that of any other cell location.		
29	Buried and Underground Piping and Tanks	Buried and Underground Piping and Tanks is an existing program that will be enhanced to: 1. If adverse indications are detected during inspection of in-scope buried piping, inspection sample sizes within the affected piping categories are doubled. If adverse indications are found in the expanded sample, an analysis is conducted to determine the extent of condition and extent of cause. The size of the follow-on inspections will be determined based on the extent of condition and extent of cause. 2. Coat the underground Emergency Diesel Generator System fuel oil piping prior to the period of extended operation. The coating will be in accordance with	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.29 LGS Letter dated 2/15/12 RAI B.2.1.29-2 RAI B.2.1.29-3 LGS Letter dated 3/30/12 RAI B.2.1.29-2.1 LGS Letter dated 6/17/2013 ISG-2011-03 LGS Letter dated

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		Table 1 of NACE SP0169-2007 or Section 3.4 of NACE RP0285-2002. 3. Perform direct visual inspections and volumetric inspections of the underground Emergency Diesel Generator System fuel oil piping and components during each 10-year period beginning 10 years prior to the entry into the period of extended operation. Prior to the period of extended operation all in scope Emergency Diesel Generator System fuel oil piping and components located in underground vaults will undergo a 100 percent visual inspection. Volumetric inspections will also be performed. After entering the period of extended operation, 2 percent of the linear length of in scope Emergency Diesel Generator System fuel oil piping and components located in underground vaults will undergo direct visual inspections and volumetric inspections every 10 years. Inspection locations after entering the period of extended operation will be selected based on susceptibility to degradation and consequences of failure. Visual inspections will be performed by a NACE Coating Inspector Program Level 2 or 3 qualified inspector or an individual that has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course.		8/6/13 RAI B.2.1.29-4

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		4. Perform two sets of volumetric inspections of the Safety Related Service Water System underground piping and components during each 10-year period beginning 10 years prior to the entry into the period of extended operation. Each set of volumetric inspections will assess either the entire length of a run of in scope Safety Related Service Water System piping and components in the underground vault or a minimum of 10 feet of the linear length of in scope Safety Related Service Water System piping and components in the underground vault. Inspection locations will be selected based on susceptibility to degradation and consequences of failure. 5. Specify that visual inspections of Safety Related Service Water System underground piping and components will be performed by a NACE Coating Inspector Program Level 2 or 3 qualified inspector or an individual that has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course. 6. Perform trending of the cathodic protection testing results to identify changes in the effectiveness of the system and to ensure that the rectifiers remain operational at least 85% of the time, and cathodic protection effectiveness will be maintained greater		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		than 80%. Cathodic Protection operational and effectiveness requirements shall be met for the 10 years prior to the period of extended operation (PEO), and throughout the PEO. 7. Modify the yearly cathodic protection survey acceptance criterion to meet NACE SP0169-2007 standards and add a statement that if negative polarized potential exceeds -1100mV relative to copper/copper sulfate electrode an issue report will be entered into the corrective action program. In performing cathodic protection surveys, the polarized potential criterion of -850mV for copper/copper sulfate reference electrodes (CSEs) will be used to determine cathodic protection system effectiveness. Other standard reference electrodes may be substituted for the CSEs; however their voltage measurements must be converted to the CSE equivalents in accordance with NACE RP0285-2002. 8. Whenever pipe is excavated and damage to the coating is significant and the damage was caused by non-conforming backfill, an extent of condition evaluation should be conducted to ensure that the as-left condition of backfill in the vicinity of observed damage will not lead to further degradation. Visual inspection of coatings will be performed by a NACE Coating Inspector Program Level 2 or 3 qualified		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		inspector or an individual that has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course.		
30	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE is an existing program that will be enhanced to: Manage the suppression pool liner and coating system to: a. Remove any accumulated sludge in the suppression pool every refueling outage. *De-sludging in 1R18 was not performed due to the COVID-19 pandemic. b. Perform an ASME IWE examination of the submerged portion of the suppression pool each ISI period. *The ASME IWE examination in 1R18 was not performed due to the COVID-19 pandemic. This is a one-time exception to the 4-year LR SR inspection interval. c. Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following prior to the period of extended operation (PEO): • Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 100 mils plate thickness loss	Program to be enhanced prior to the period of extended operation. The coating maintenance plan will be initiated in the 2012 refueling outage for Unit 1 and the 2013 refueling outage for Unit 2. The downcomer recoat and augmented inspection criteria will be implemented prior to receipt of the renewed licenses.	Section A.2.1.30 LGS Letter dated 9/12/2012 OI 3.0.3.2.13-1 LGS Letter dated 10/25/12 RAI B.2.1.30-7 LGS letter dated 10/25/12 RAI B.2.1.30-2.2 LGS letter dated 10/25/12 RAI B.2.1.30-6

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		will be recoated in the outage they are identified. This plate thickness loss criterion for local areas will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C. • Areas of general corrosion greater than 65 mils average plate thickness loss will be recoated based on ranking of affected surface area, high to low. This plate thickness loss criterion for areas of general corrosion will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C. d. Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following during the PEO: • Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 100 mils plate thickness loss will be recoated in the outage they are	The ultrasonic thickness measurement requirements will be implemented prior to receipt of the renewed licenses.	

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		identified. This plate thickness loss criterion for local areas will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C. • Areas of general corrosion greater than 65 mils average plate thickness loss will be recoated in the outage they are identified. This plate thickness loss criterion for areas of general corrosion will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C. The coating maintenance plan will continue through the period of extended operation to ensure the coating protects the liner to avoid significant material loss. 2. Use the results of the ASME IWE inspection of the submerged portions of the suppression pool downcomers to perform the following:		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		a. Local areas (less than or equal to 5.5 inches in any direction) that have 40 mils or more metal thickness loss will be recoated. This downcomer metal thickness loss criteria for local areas will also be used to determine when the submerged portions of the downcomers require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C. b. Areas of general corrosion (greater than 5.5 inches in any direction) that have 30 mils or more metal thickness loss will be recoated. This downcomer metal thickness loss criteria for areas of general corrosion will also be used to determine when the submerged portions of the downcomers require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C. 3. When IWE examinations are conducted, perform ultrasonic thickness measurements on four areas of submerged suppression pool liner affected by general corrosion. 4. Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting.		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
31	ASME Section XI, Subsection IWL	ASME Section XI, Subsection IWL is an existing program that will be enhanced to: 1. Include second tier acceptance criteria of ACI 349.3R.	Program to be enhanced prior to the period of extended operation.	Section A.2.1.31
32	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF is an existing program that will be enhanced to: 1. Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting.	Program to be enhanced prior to the period of extended operation.	Section A.2.1.32
33	10 CFR Part 50, Appendix J	Existing program is credited.	Ongoing	Section A.2.1.33
34	Masonry Walls	Masonry Walls is an existing program that will be enhanced to: 1. Add the following structures with masonry walls to the program scope: a. Administration Building Warehouse b. Fuel Oil Pumphouse c. Transformer foundation dike walls 2. Provide additional guidance for inspection of masonry walls for shrinkage, separation, and for gaps between the supports and walls that could impact the wall's intended function.	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.34

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		3. Require an inspection frequency of not greater than 5 years. 4. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R.		
35	Structures Monitoring	Structures Monitoring is an existing program that will be enhanced to: 1. Add the following structures: a. Admin Building Warehouse b. Fuel Oil Pumphouse c. Service Water Pipe Tunnel d. Yard Structures • Aux Fire Water Storage Tank Foundation • Backup Fire Pump House and Foundation • Well Pump #3 Enclosure and Foundation • Railroad Bridge • Manholes 001 and 002 • Fuel Oil Storage Tank Dike • Transformer foundations and dikes 2. Add the following components and commodities; a. Pipe, electrical, and equipment component support members b. Pipe whip restraints and jet impingement shields c. Panels, Racks, and other enclosures	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.35 LGS Letter dated 4/13/12 RAI 3.5.2.3.2-1.1

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		d. Sliding surfaces e. Sump and Pool liners f. Electrical cable trays and conduits g. Electrical duct banks h. Tube tracks i. Doors j. Penetration seals k. Blowout panels l. Permanent drywell shielding m. Roof scuppers 3. Monitor groundwater chemistry on a frequency not to exceed 5 years for pH, chlorides, and sulfates and verify that it remains non-aggressive, or evaluate results exceeding criteria to assess impact, if any, on below-grade concrete. 4. Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. Revise storage requirements for high strength bolts to include recommendations of Research Council on Structural Connections (RSCS) Specification for Structural Joints Using High Strength Bolts, Section 2.0. 5. Monitor concrete for areas of abrasion, erosion, and cavitation degradation, drummy areas that can exceed the cover concrete thickness in depth,		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		popouts and voids, scaling, and passive settlements or deflections. 6. Perform inspections on a frequency not to exceed 5 years. 7. Perform inspections of sub-drainage sump pit internal concrete on a 5-year frequency as a leading indicator the condition of below grade concrete exposed to ground water. 8. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R. 9. Perform inspection of elastomeric vibration isolation elements and structural seals for cracking, loss of material and hardening. Visual inspections of elastomeric vibration isolation elements are to be supplemented by manipulation to detect hardening when vibration isolation function is suspect. 10. Monitor accessible sliding surfaces to detect significant loss of material due to wear, corrosion, debris, or dirt, that could result in lock-up or reduced movement. 11. Perform opportunistic inspection of below grade portions of in-scope structures in the event of		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		excavation which exposes normally inaccessible below grade concrete. 12. Include applicable acceptance criteria from ACI 349.3R. 13. Clarify that loose bolts and nuts and cracked high strength bolts are not acceptable unless accepted by engineering evaluations.		
36	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants is an existing program that will be enhanced to: 1. Require inspection of structural bolting integrity (loss of material and loosening of the bolts). 2. Require monitoring of aging effects for increase of porosity and permeability of concrete structures and loss of material for steel components. 3. Require the proper functioning of dike drainage systems. 4. Require increased inspection frequency if the extent of the degradation is such that the structure or component may not meet its design basis if allowed to continue uncorrected until the next normally scheduled inspection.	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.36

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		5. Require (a) evaluation of the acceptability of inaccessible areas when conditions exist in the accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas, and (b) examination of the exposed portions of the below-grade concrete when excavated for any reason. 6. Monitor raw water chemistry at least once every 5 years for pH, chlorides, and sulfates and verify that it remains non-aggressive, or evaluate results exceeding criteria to assess impact, if any, on submerged concrete. 7. Require visual examinations of the Spray Pond and Pumphouse submerged wetwell concrete for signs of degradation during maintenance activities. If significant concrete degradation is identified, a plant specific aging management program should be implemented to manage the concrete aging during the period of extended operation. 8. Require that active cracks in structural concrete or extent of corrosion in steel are documented and trended, until the condition is no longer occurring or until a corrective action is implemented.		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		9. Require acceptance and evaluation of structural concrete using quantitative criteria based on Chapter 5 of ACI 349.3R. 10. Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. Revise storage requirements for high strength bolts to include recommendations of Research Council on Structural Connections (RSCS) Specification for Structural Joints Using High Strength Bolts, Section 2.0.		
37	Protective Coating Monitoring and Maintenance Program	Protective Coating Monitoring and Maintenance Program is an existing program that will be enhanced to: 1. Create the position of Nuclear Coatings Specialist qualified to ASTM D 7108 standards.	Program to be enhanced prior to the period of extended operation.	Section A.2.1.37
38	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that will be used to manage aging of the insulation material for non-EQ cables and connections. Accessible cables and connections located in adverse localized environments will be visually inspected at least once every 10 years for indications of reduced insulation resistance, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination.	Program and initial inspections to be implemented prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.38

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
39	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits is a new program that will be used to manage aging of non-EQ cable and connection insulation of the in scope portions of the Process Radiation Monitoring and Neutron Monitoring Systems. Calibration and cable tests will be performed and results will be assessed for reduced insulation resistance prior to the period of extended operation and at least once every 10 years during the period of extended operation.	Program and initial assessment of calibration and test results to be implemented prior to the period of extended operation. Assessment schedule identified in commitment.	Section A.2.1.39
40	Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that will be used to manage the aging effects and mechanisms of non-EQ, in scope, inaccessible power cables. Cables will be tested using a proven test for detecting reduced insulation resistance of the cable's insulation system. The cables will be tested at least once every 6 years. More frequent testing may occur based on test results and operating experience. Periodic actions will be taken to prevent inaccessible cables from being exposed to significant moisture. Manholes associated with the cables included in this aging management program will be inspected for water	Program and initial tests and inspections to be implemented prior to the period of extended operation. Test and Inspection schedule identified in commitment.	Section A.2.1.40 LGS Letter dated 2/28/12 RAI B.2.1.40-1 RAI B.2.1.40-3 RAI B.2.1.40-4

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		collection with subsequent corrective actions (e.g., water removal), as necessary. Prior to the period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant specific operating experience with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding. Operation of dewatering devices will be verified prior to any known or predicted heavy rain or flooding event. During the period of extended operation, the inspections will occur at least annually.		
41	Metal Enclosed Bus	Metal Enclosed Bus is a new program that will be used to manage aging of in scope metal enclosed bus. The internal portions of bus enclosure assemblies, bus insulation, bus insulating supports and elastomers will be visually inspected. A sample (20 percent with a maximum sample size of 25) of the accessible metal enclosed bus bolted connection population will be tested using thermography. The inspections and thermography will be performed at least once every 10 years for indications of aging degradation.	Program and initial tests and inspections to be implemented prior to the period of extended operation. Test and inspection schedule identified in commitment.	Section A.2.1.41
42	Fuse Holders	Fuse Holders aging management program is a new program that applies to fuse holders located outside of active devices that have been identified as susceptible to aging effects.	Program and initial tests to be implemented prior to	Section A.2.1.42

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		Fuse holders subject to increased resistance of connection or fatigue, will be tested, by a proven test methodology, at least once every 10 years for indications of aging degradation. Visual inspection is not part of this program.	the period of extended operation. Test schedule identified in commitment.	
43	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will implement one-time testing of a representative sample (20 percent with a maximum sample size of 25) of non-EQ electrical cable connections to ensure that either aging of metallic cable connections is not occurring or that the existing preventive maintenance program is effective such that a periodic inspection program is not required.	Program and one-time tests to be implemented prior to the period of extended operation.	Section A.2.1.43
44	Fatigue Monitoring	Fatigue Monitoring is an existing program that will be enhanced to: 1. Monitor additional plant transients that are significant contributors to fatigue usage and to impose administrative transient cycle limits corresponding to the limiting numbers of cycles used in the environmental fatigue calculations.	Program to be enhanced prior to the period of extended operation.	Section A.3.1.1
45	Environmental Qualification (EQ) of Electric Components	Existing program is credited.	Ongoing	Section A.3.1.2

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
46	Operating Experience	The Operating Experience Program is an existing program that will be enhanced to: 1. Explicitly require the review of operating experience for aging-related degradation. 2. Establish criteria to define aging-related degradation. 3. Establish identification coding for use in identification, trending and communications of aging-related degradation. 4. Require communication of significant internal aging-related degradation, associated with SSCs in the scope of license renewal, to other Exelon plants and to the industry. Criteria will be established for determining when aging-related degradation is significant. 5. Require review of external operating experience for information related to aging management, and evaluation of such information for potential improvements to LGS aging management activities. 6. Provide training to those responsible for screening, evaluating and communicating operating experience items related to aging management.	Complete Program was enhanced prior to the date that the renewed operating licenses were issued.	Section A.1.6 LGS Letter dated 3/13/ 2012 RAI B.1.4-1 RAI A.1-1 LGS Letter dated 7/11/2012 RAI B.1.4-3 LGS Letter dated 9/12/2012 OI 3.0.5-1 LGS Letter dated 10/12/2012 RAI B.1.4-4

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
47	BWRVIP-74-A Report License Renewal Action Item 14	Re-evaluate the flaw in the Unit 1 RPV nozzle to safe-end weld VRR-1RD-1A-N2H in accordance with ASME Code Section XI, sub-section IWB-3600 for the 60-year service period corresponding to the LR term.	Prior to the period of extended operation	LGS Letter, dated 2/15/12 RAI BWRVIP-1

ATTACHMENT 3

LGS Unit 1 and 2, Technical Specification Bases

Limerick Generating Station Unit 1 Technical Specification Bases

BASES

FOR

SECTION 2.0

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

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NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Section 2.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

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2.0 INTRODUCTION

The fuel cladding, reactor pressure vessel and primary system piping are the principal barriers to the release of radioactive materials to the environs. Safety Limits are established to protect the integrity of these barriers during normal plant operations and anticipated transients. The Technical Specification Safety Limit is set generically on a fuel product Minimum Critical Power Ration (MCPR) correlation basis as the MCPR which corresponds to a 95% probability at a 95% confidence level that transition boiling will not occur, referred to as SLMCPR(95/95). The fuel cladding integrity Safety Limit is set such that no significant fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a step-back approach is used to establish a Safety Limit such that the MCPR is not less than the limit specified in Specification 2.1.2. MCPR greater than the specified limit represents a conservative margin relative to the conditions required to maintain fuel cladding integrity. The fuel cladding is one of the physical barriers which separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses which occur from reactor operation significantly above design conditions and the Limiting Safety System Settings. While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross rather than incremental cladding deterioration. Therefore, the fuel cladding Safety Limit is defined with a margin to the conditions which would produce onset of transition boiling, MCPR of 1.0. These conditions represent a significant departure from the condition intended by design for planned operation. This is accomplished by having a Safety Limit Minimum Critical Power Ratio (SLMCPR) design basis, referred to as SLMCPR(95/95), which corresponds to a 95% probability at a 95% confidences level (the 95/95 MCPR criterion) that transition boiling will not occur.

2.1.1 THERMAL POWER, Low Pressure or Low Flow

GNF critical power correlation for GNF3 is applicable for all critical power calculations at pressures ≥ 700 psia and core flows ≥ 10% of rated flow (Ref. 3). For operation at low pressures or low flows, another basis is used. This is done by establishing a limiting condition on core THERMAL POWER with the following basis. Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be greater than 4.5 psi. Analyses show that with a bundle flow of 28×10^3 lb/hr, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be greater than 28×10^3 lb/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER of more than 50% of RATED THERMAL POWER. Thus, a THERMAL POWER limit of 25% of RATED THERMAL POWER for reactor pressure below 700 psia is conservative.

2.1.2 THERMAL POWER, High Pressure and High Flow

The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Since the parameters which result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions resulting in a departure from nucleate boiling have been used to mark the beginning of the region where fuel damage could occur. Although it is recognized that a departure from nucleate boiling would not necessarily result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit. The Technical Specification Safety Limit value is dependent on the fuel product line and the corresponding MCPR correlation, which is cycle independent. The value is based on the Critical Power Ratio (CPR) data statistics and a 95% probability with 95% confidence that rods are not susceptible to boiling transition, referred to as MCPR(95/95).

The Safety Limit is based on GNF3 fuel. For cores with a single fuel product line, the SLMCPR(95/95) is the MCPR(95/95) for the fuel type. For cores loaded with a mix of applicable fuel types, the SLMCPR(95/95) is based on the largest (i.e., most limiting) of the MCPR values for the fuel product lines that are fresh or once-burnt at the start of the cycle.

Reference:

1. "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A (latest approved revision).
2. Deleted
3. “GEXL21 Correlation for GNF3 Fuel,” NEDC-33880P Rev. 1, November 2017

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2.1.3 REACTOR COOLANT SYSTEM PRESSURE

The Safety Limit for the reactor coolant system pressure has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to Section III of the ASME Boiler and Pressure Vessel Code 1968 Edition, including Addenda through Summer 1969, which permits a maximum pressure transient of 110%, 1375 psig, of design pressure 1250 psig. The Safety Limit of 1325 psig, as measured by the reactor vessel steam dome pressure indicator, is equivalent to 1375 psig at the lowest elevation of the reactor coolant system. The reactor coolant system is designed to the ASME Boiler and Pressure Vessel Code, 1977 Edition, including Addenda through Summer 1977 for the reactor recirculation piping, which permits a maximum pressure transient of 110%, 1375 psig of design pressure, 1250 psig for suction piping and 1500 psig for discharge piping. The pressure Safety Limit is selected to be the lowest transient overpressure allowed by the ASME Boiler and Pressure Vessel Code Section III, Class I.

2.1.4 REACTOR VESSEL WATER LEVEL

With fuel in the reactor vessel during periods when the reactor is shutdown, consideration must be given to water level requirements due to the effect of decay heat. If the water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the water level became less than two-thirds of the core height. The Safety Limit has been established at the top of the active irradiated fuel to provide a point which can be monitored and also provide adequate margin for effective action.

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Protection System instrumentation setpoints specified in Table 2.2.1-1 are the values at which the reactor trips are set for each parameter. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist in mitigating the consequences of accidents. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or less than the drift allowance assumed for each trip in the safety analyses.

1. Intermediate Range Monitor, Neutron Flux - High

The IRM system consists of 8 chambers, 4 in each of the reactor trip systems. The IRM is a 5 decade 10 range instrument. The trip setpoint of 120 divisions of scale is active in each of the 10 ranges. Thus as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during the power increase is due to control rod withdrawal. In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

2. Average Power Range Monitor

The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. All four voters will trip (full scram) when any two unbypassed APRM channels exceed their trip setpoints.

APRM trip Functions 2.a, 2.b, 2.c, and 2.d are voted independently from OPRM Upscale Function 2.f. Therefore, any Function 2.a, 2.b, 2.c, or 2.d trip from any two unbypassed APRM channels will result in a full trip in each of the four voter channels. Similarly, a Function 2.f trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels.

For operation at low pressure and low flow during STARTUP, the APRM Neutron Flux-Upscale (Setdown) scram setting of 15% of RATED THERMAL POWER provides adequate thermal margin between the setpoint and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Temperature coefficients are small and control rod patterns are constrained by the RWM. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant amount, the rate of power rise is very slow. Generally the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit. The 15% Neutron Flux - Upscale (Setdown) trip remains active until the mode switch is placed in the Run position.

The APRM trip system is calibrated using heat balance data taken during steady state conditions. Fission chambers provide the basic input to the system and therefore the monitors respond directly and quickly to changes due to transient operation for the case of the Neutron Flux - Upscale setpoint; i.e., for a power increase, the THERMAL POWER of the fuel will be less than that indicated by the neutron flux due to the time constants of the heat transfer associated with the fuel. For the Simulated Thermal Power - Upscale setpoint, a time constant of 6 ± 0.6 seconds is introduced into the flow-biased APRM in order to simulate the fuel thermal transient characteristics. A more conservative maximum value is used for the flow-biased setpoint as shown in Table 2.2.1-1.

A reduced Trip Setpoint and Allowable Value is provided for the Simulated Thermal Power - Upscale Function, applicable when the plant is operating in Single Loop Operation (SLO) per LCO 3.4.1.1. In SLO, the drive flow values (W) used in the Trip Setpoint and Allowable Value equations is reduced by 7.6%. The 7.6% value is established to conservatively bound the inaccuracy created in the core flow/drive flow correlation due to back flow in the jet pumps associated with the inactive recirculation loop. The Trip Setpoint and Allowable Value thus maintain thermal margins essentially unchanged from those for two-loop operation. The Trip Setpoint and Allowable Value equations for single loop operation are only valid for flows down to W = 7.6%. The Trip Setpoint and Allowable Value do not go below 61.5% and 62.0% RATED THERMAL POWER, respectively. This is acceptable because back flow in the inactive recirculation loop is only an issue with drive flows of approximately 40% or greater (Reference 1).

The APRM setpoints were selected to provide adequate margin for the Safety Limits and yet allow operating margin that reduces the possibility of unnecessary shutdown.

The APRM channels also include an Oscillation Power Range Monitor (OPRM) Upscale Function. The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR Safety Limit due to anticipated thermal-hydraulic power oscillations. The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into “cells” for evaluation by the OPRM algorithms.

References 2, 3 and 4 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60% as indicated by APRM measured recirculation drive flow. (NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. Refer to TS Bases 3/4.3.1 for further discussion concerning the recirculation drive flow/core flow relationship.) This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. See Reference 5 for additional discussion of OPRM Upscale trip enable region limits. These setpoints, which are sometimes referred to as the "auto-bypass" setpoints, establish the boundaries of the OPRM Upscale trip enabled region. The APRM Simulated Thermal Power auto-enable setpoint has 1% deadband while the drive flow setpoint has a 2% deadband. The deadband for these setpoints is established so that it increases the enabled region.

An OPRM Upscale trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in a cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the growth rate or amplitude based algorithms detect oscillatory changes in the neutron flux for one or more cells in that channel.

There are four "sets" of OPRM related setpoints or adjustment parameters: a) OPRM trip auto-enable setpoints for APRM Simulated Thermal Power (29.5%) and recirculation drive flow (60%); b) period based detection algorithm (PBDA) confirmation count and amplitude setpoints; c) period based detection algorithm tuning parameters; and d) growth rate algorithm (GRA) and amplitude based algorithm (ABA) setpoints.

The first set, the OPRM auto-enable region setpoints, are treated as nominal setpoints with no additional margins added as discussed in Reference 5. The settings, 29.5% APRM Simulated Thermal Power and 60% recirculation drive flow, are defined (limit values) in a note to Table 2.2.1-1. The second set, the OPRM PBDA trip setpoints, are established in accordance with methodologies defined in Reference 4, and are documented in the COLR. There are no allowable values for these setpoints. The third set, the OPRM PBDA "tuning" parameters, are established or adjusted in accordance with and controlled by station procedures. The fourth set, the GRA and ABA setpoints, in accordance with References 2 and 3, are established as nominal values only, and controlled by station procedures.

3. Reactor Vessel Steam Dome Pressure-High

High pressure in the nuclear system could cause a rupture to the nuclear system process barrier resulting in the release of fission products. A pressure increase while operating will also tend to increase the power of the reactor by compressing voids thus adding reactivity. The trip will quickly reduce the neutron flux, counteracting the pressure increase. The trip setting is slightly higher than the operating pressure to permit normal operation without spurious trips. The setting provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This trip setpoint is effective at low power/flow conditions when the turbine stop valve and control fast closure trips are bypassed. For a turbine trip or load rejection under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

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REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

4. Reactor Vessel Water Level-Low

The reactor vessel water level trip setpoint has been used in transient analyses dealing with coolant inventory decrease. The scram setting was chosen far enough below the normal operating level to avoid spurious trips but high enough above the fuel to assure that there is adequate protection for the fuel and pressure limits.

5. Main Steam Line Isolation Valve-Closure

The main steam line isolation valve closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIVs are closed automatically from measured parameters such as high steam flow, low reactor water level, high steam tunnel temperature, and low steam line pressure. The MSIVs closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

6. DELETED

7 Drywell Pressure-High

High pressure in the drywell could indicate a break in the primary pressure boundary systems or a loss of drywell cooling. The reactor is tripped in order to minimize the possibility of fuel damage and reduce the amount of energy being added to the coolant and to the primary containment. The trip setting was selected as low as possible without causing spurious trips.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

8. Scram Discharge Volume Water Level-High

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water at pressures below 65 psig, control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is indeed filling up, but the volume is still great enough to accommodate the water from the movement of the rods at pressures below 65 psig when they are tripped. The trip setpoint for each scram discharge volume is equivalent to a contained volume of 25.45 gallons of water.

9. Turbine Stop Valve-Closure

The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of 5% of valve closure from full open, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst design basis transient.

10. Turbine Control Valve Fast Closure, Trip Oil Pressure-Low

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection with or without coincident failure of the turbine bypass valves. The Reactor Protection System initiates a trip when fast closure of the control valves is initiated by the fast acting solenoid valves and in less than 30 milliseconds after the start of control valve fast closure. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic trip oil pressure at the main turbine control valve actuator disc dump valves. This loss of pressure is sensed by pressure switches whose contacts form the one-out-of-two-twice logic input to the Reactor Protection System. This trip setting, a faster closure time, and a different valve characteristic from that of the turbine stop valve, combine to produce transients which are very similar to that for the stop valve. Relevant transient analyses are discussed in Section 15.2.2 of the Final Safety Analysis Report.

11. Reactor Mode Switch Shutdown Position

The reactor mode switch Shutdown position is a redundant channel to the automatic protective instrumentation channels and provides additional manual reactor trip capability.

12. Manual Scram

The Manual Scram is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

REFERENCES:

1. NEDC-31300, “Single-Loop Operation Analysis for Limerick Generating Station, Unit 1,” August 1986.

2. NEDO-31960-A, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.

3. NEDO-31960-A, Supplement 1, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.

4. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications,” August 1996.

5. BWROG Letter 96113, K. P. Donovan (BWROG) to L. E. Phillips (NRC), “Guidelines for Stability Option III ‘Enable Region’ (TAC M92882),” September 17, 1996.

BASES FOR

SECTIONS 3.0 AND 4.0

LIMITING CONDITIONS FOR OPERATION

AND

SURVEILLANCE REQUIREMENTS

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NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Sections 3.0 and 4.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

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BASES

Specifications 3.0.1 through 3.0.9 establish the general requirements applicable to Limiting Conditions for Operation. These requirements are based on the requirements for Limiting Conditions for Operation stated in the Code of Federal Regulations, 10 CFR 50.36(c)(2):

> "Limiting Conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specification until the condition can be met."

Specification 3.0.1 establishes the Applicability statement within each individual specification as the requirement for when (i.e., in which OPERATIONAL CONDITIONS or other specified conditions) conformance to the Limiting Conditions for Operation is required for safe operation of the facility. The ACTION requirements establish those remedial measures that must be taken within specified time limits when the requirements of a Limiting Condition for Operation are not met. The ACTIONS for not meeting a single LCO adequately manage any increase in plant risk, provided any unusual external conditions (e.g., severe weather, offsite power instability) are considered. In addition, the increased risk associated with simultaneous removal of multiple structures, systems, trains or components from service is assessed and managed in accordance with 10 CFR 50.65(a)(4).

There are two basic types of ACTION requirements. The first specifies the remedial measures that permit continued operation of the facility which is not further restricted by the time limits of the ACTION requirements. In this case, conformance to the ACTION requirements provides an acceptable level of safety for unlimited continued operation as long as the ACTION requirements continue to be met. The second type of ACTION requirement specifies a time limit in which conformance to the conditions of the Limiting Condition for Operation must be met. This time limit is the allowable outage time to restore an inoperable system or component to OPERABLE status or for restoring parameters within specified limits. If these actions are not completed within the allowable outage time limits, a shutdown is required to place the facility in an OPERATIONAL CONDITION or other specified condition in which the specification no longer applies.

The specified time limits of the ACTION requirements are applicable from the point of time it is identified that a Limiting Condition for Operation is not met. The time limits of the ACTION requirements are also applicable when a system or component is removed from service for surveillance testing or investigation of operational problems. Individual specifications may include a specified time limit for the completion of a Surveillance Requirement when equipment is removed from service. In this case, the allowable outage time limits of the ACTION requirements are applicable when this limit expires if the surveillance has not been completed. When a shutdown is required to comply with ACTION requirements, the plant may have entered an OPERATIONAL CONDITION in which a new specification becomes applicable. In this case, the time limits of the ACTION requirements would apply from the point in time that the new specification becomes applicable if the requirements of the Limiting Condition for Operation are not met.

Specification 3.0.2 establishes that noncompliance with a specification exists when the requirements of the Limiting Condition for Operation are not met and the associated ACTION requirements have not been implemented within the specified time interval, unless otherwise specified. The purpose of this specification is to clarify that (1) implementation of the ACTION requirements within the specified time interval constitutes compliance with a specification and (2) completion of the remedial measures of the ACTION requirements is not required when compliance with a Limiting Condition of Operation is restored within the time interval specified in the associated ACTION requirements.

Specification 3.0.3 establishes the shutdown ACTION requirements that must be implemented when a Limiting Condition for Operation is not met and the condition is not specifically addressed by the associated ACTION requirements or the required ACTION is not met. The purpose of this specification is to delineate the time limits for placing the unit in a safe shutdown CONDITION when plant operation cannot be maintained within the limits defined by the Limiting Conditions for Operation and its ACTION requirements. Planned entry into LCO 3.0.3 should be avoided. If it is not practicable to avoid planned entry into LCO 3.0.3, plant risk should be assessed and managed in accordance with 10 CFR 50.65(a)(4), and the planned entry into LCO 3.0.3 should have less effect on plant safety than other practicable alternatives.

Upon entering LCO 3.0.3, a risk assessment addressing inoperable systems and components must be completed and appropriate risk management actions must be implemented within 6 hours. The risk assessment must consider all inoperable equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Regulatory Guide 1.160 endorses the guidance in Section 11 of NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” All relevant elements of the risk assessment description in Section 11 will be included. These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures). A formal cause or apparent cause evaluation is not required because of the limited time available, but the likely cause of the conditions that resulted in LCO 3.0.3 entry are considered. If the extent of condition is unknown, the risk assessment will consider the possibility of common cause failure either numerically or through risk management actions.

Continuing operation for a limited time is acceptable if the risk assessment determines that for the current plant configuration, the Incremental Core Damage Probability (ICDP) is less than 1E-5, and the Incremental Large Early Release Probability (ILERP) is less than 1E-6. Non-quantifiable factors will also be assessed. In addition, the configuration-specific Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) will be evaluated to identify high-risk situations. A configuration-specific CDF in excess of 1E-3/year or LERF in excess of 1E-4/year does not support continuing operation. The impact on plant risk is evaluated from the baseline, zero-maintenance, condition.

Whenever practicable, a quantitative value for risk will be determined. If determination of a quantitative value for risk is not practicable, a qualitative assessment of risk may be used with appropriate consideration of the plant conditions and uncertainties to determine whether continued operation for a limited time is acceptable.

If during the 24-hour period the plant configuration changes such that plant risk may be increased, the risk must be reassessed. If the configuration no longer supports continuing plant operation, action must be initiated to shut down the unit in accordance with the LCO 3.0.3 requirements.

Appropriate risk management actions are implemented in accordance with the Maintenance Rule procedures that are appropriate for the current plant condition and the inoperable equipment. Risk management actions are used to address non-quantifiable factors, increase risk awareness, and reduce the risk magnitude and duration.

If the risk assessment determines that continuing operation is acceptable, that the appropriate risk management actions are implemented, and that entry into LCO 3.0.3 was unplanned, action to shut down the unit must be initiated within 24 hours of entry into LCO 3.0.3. It is not necessary for the planned restoration of compliance with the LCO or ACTIONS to be within 24 hours as other actions are available, such as regulatory relief or an orderly shutdown. The 24-hour provision may not be used if the LCO 3.0.3 entry is planned, such as intentionally removing a train from service when the redundant train is inoperable. However, it may be used for emergent conditions that occur in parallel with other planned or unplanned inoperabilities.

The determination that continuing operation is acceptable will be documented in sufficient detail to allow a knowledgeable individual to understand the basis for the determination.

If the risk assessment determines that continuing operation is not acceptable, if the risk assessment was not completed, the appropriate risk management actions were not implemented, or if entry into LCO 3.0.3 was planned, action to shut down the unit must be initiated following the 6 hour time period provided to perform the risk assessment and implement risk management actions.

All times for completing actions and entering OPERATIONAL CONDITIONS are determined from entry into LCO 3.0.3.

The time limits specified to enter lower CONDITIONS of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the cooldown capabilities of the facility assuming only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the primary coolant system and the potential for a plant upset that could challenge safety systems under conditions for which this specification applies.

If remedial measures permitting limited continued operation of the facility under the provisions of the ACTION requirements are completed, the shutdown may be terminated. The time limits of the ACTION requirements are applicable from the point in time there was a failure to meet a Limiting Condition for Operation. Therefore, the shutdown may be terminated if the ACTION requirements have been met, the ACTION is no longer applicable, or time limits of the ACTION requirements have not expired, thus providing an allowance for the completion of the required actions.

The time limits of Specification 3.0.3 allow 36 hours for the plant to be in COLD SHUTDOWN after a shutdown is initiated during POWER operation. If the plant is in a lower CONDITION of operation when a shutdown is initiated, the time limit for entering the next lower CONDITION of operation applies. However, if a lower CONDITION of operation is entered in less time than allowed, the total allowable time to enter COLD SHUTDOWN, or other OPERATIONAL CONDITION, is not reduced. For example, if HOT SHUTDOWN is entered 10 hours after a shutdown is initiated, the time allowed to enter COLD SHUTDOWN is the next 26 hours because the total time to enter COLD SHUTDOWN is not reduced from the allowable limit of 36 hours after a shutdown is initiated. Therefore, if remedial measures are completed that would permit a return to POWER operation, a penalty is not incurred by having to enter a lower CONDITION of operation in less than the total time allowed.

The same principle applies with regard to the allowable outage time limits of the ACTION requirements, if compliance with the ACTION requirements for one specification results in entry into an OPERATIONAL CONDITION or condition of operation for another specification in which the requirements of the Limiting Condition for Operation are not met. If the new specification becomes applicable in less time than specified, the difference may be added to the allowable outage time limits of the second specification. However, the allowable outage time limits of ACTION requirements for a higher CONDITION of operation may not be used to extend the allowable outage time that is applicable when a Limiting Condition for Operation is not met in a lower CONDITION of operation.

The shutdown requirements of Specification 3.0.3 do not apply in CONDITIONS 4 and 5, because the ACTION requirements of individual specifications define the remedial measures to be taken.

Specification 3.0.4 establishes limitations on changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability when a Limiting Condition for Operation is not met. It allows placing the unit in an OPERATIONAL CONDITION or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the Limiting Condition for Operation would not be met, in accordance with either Specification 3.0.4.a, Specification 3.0.4.b, or Specification 3.0.4.c.

Specification 3.0.4.a allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met when the associated ACTION requirements to be entered following entry into the OPERATIONAL CONDITION or other specified condition in the Applicability will permit continued operation within the MODE or other specified condition for an unlimited period of time. Compliance with ACTIONS that permit continued operation of the unit for an unlimited period of time in an OPERATIONAL CONDITION or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the OPERATIONAL CONDITION change. Therefore, in such cases, entry into an OPERATIONAL CONDITION or other specified condition in the Applicability may be made and the Required Actions followed after entry into the Applicability.

For example, LCO 3.0.4.a may be used when the Required Action to be entered states that an inoperable instrument channel must be placed in the trip condition within the Completion Time. Transition into a MODE or other specified condition in the Applicability may be made in accordance with LCO 3.0.4 and the channel is subsequently placed in the tripped condition within the Completion Time, which begins when the Applicability is entered. If the instrument channel cannot be placed in the tripped condition and the subsequent default ACTION ("Required Action and associated Completion Time not met") allows the OPERABLE train to be placed in operation, use of LCO 3.0.4.a is acceptable because the subsequent ACTIONS to be entered following entry into the MODE include ACTIONS (place the OPERABLE train in operation) that permit safe plant operation for an unlimited period of time in the MODE or other specified condition to be entered.

Specification 3.0.4.b allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities be assessed and managed. The risk assessment, for the purposes of Specification 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed OPERATIONAL CONDITION change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the Limiting Condition for Operation would be met prior to the expiration of the ACTION requirement's specified time interval that would require exiting the Applicability.

Specification 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and any corresponding risk management actions. The Specification 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in OPERATIONAL CONDITION 1 for the duration of the specified time interval. Since this is allowable, and since in general the risk impact in that particular OPERATIONAL CONDITION bounds the risk of transitioning into and through the applicable OPERATIONAL CONDITIONS or other specified conditions in the Applicability of the Limiting Condition for Operation, the use of the Specification 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the Specification 3.0.4.b allowance is prohibited. The Limiting Condition for Operations governing these system and components contain Notes prohibiting the use of Specification 3.0.4.b by stating that Specification 3.0.4.b is not applicable.

Specification 3.0.4.c allows entry into a OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met based on a Note in the Specification which states Specification 3.0.4.c is applicable. These specific allowances permit entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability when the associated ACTION requirements to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTION requirements or to a specific ACTION requirement of a Specification. The risk assessments performed to justify the use of Specification 3.0.4.b usually only consider systems and components. For this

reason, Specification 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., Reactor Coolant Specific Activity), and may be applied to other Specifications based on NRC plant-specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated OPERATIONAL CONDITION or other specified condition in the Applicability.

The provisions of Specification 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements. In addition, the provisions of Specification 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified

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conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, and OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4.

Upon entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met, Specification 3.0.1 and Specification 3.0.2 require entry into the applicable Conditions and ACTION requirements until the Condition is resolved, until the Limiting Condition for Operation is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by Specification 4.0.1. Therefore, utilizing Specification 3.0.4 is not a violation of Specification 4.0.1 or Specification 4.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected Limiting Condition for Operation.

Specification 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONs. The sole purpose of this Specification is to provide an exception to Specifications 3.0.1 and 3.0.2 (e.g., to not comply with the applicable ACTION(s)) to allow the performance of required testing to demonstrate:

a. The OPERABILITY of the equipment being returned to service, or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONs is limited to the time necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance. LCO 3.0.5 should not be used in lieu of other practicable alternatives that comply with Required Actions and that do not require changing the MODE or other specified conditions in the Applicability in order to demonstrate equipment is OPERABLE. LCO 3.0.5 is not intended to be used repeatedly.

An example of demonstrating equipment is OPERABLE with the Required Actions not met is opening a manual valve that was closed to comply with Required Actions to isolate a flowpath with excessive Reactor Coolant System (RCS) Pressure Isolation Valve (PIV) leakage in order to perform testing to demonstrate that RCS PIV leakage is now within limit.

Examples of demonstrating equipment OPERABILITY include instances in which it is necessary to take an inoperable channel or trip system out of a tripped condition that was directed by a Required Action, if there is no Required Action Note for this purpose. An example of verifying OPERABILITY of equipment removed from service is taking a tripped channel out of the tripped condition to permit the logic to function and indicate the appropriate response during performance of required testing on the inoperable channel.

Examples of demonstrating the OPERABILITY of other equipment are taking an inoperable channel or trip system out of the tripped condition 1) to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system, or 2) to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

The administrative controls in LCO 3.0.5 apply in all cases to systems or components in Chapter 3 of the Technical Specifications, as long as the testing could not be conducted while complying with the Required Actions. This includes the realignment or repositioning of redundant or alternate equipment or trains previously manipulated to comply with ACTIONS, as well as equipment removed from service or declared inoperable to comply with ACTIONS.

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Specification 3.0.6 establishes an exception to Specifications 3.0.1 and 3.0.2 for supported systems that have a support system Limiting Condition for Operation specified in the Technical Specifications (TS). The exception to Specification 3.0.1 is provided because Specification 3.0.1 would require that the ACTIONs of the associated inoperable supported system Limiting Condition for Operation be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified in the support system Limiting Condition for Operation's ACTIONs. These ACTIONs may include entering the supported system's ACTIONs or may specify other ACTIONs. The exception to Specification 3.0.2 is provided because Specification 3.0.2 would consider not entering into the ACTIONs for the supported system within the specified time intervals as a TS noncompliance.

When a support system is inoperable and there is a Limiting Condition for Operation specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' ACTIONs unless directed to do so by the support system's ACTIONs. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' Limiting Condition for Operations' ACTIONs are eliminated by providing all the actions that are necessary to ensure the plant is maintained in a safe condition in the support system's ACTIONs.

However, there are instances where a support system's ACTION may either direct a supported system to be declared inoperable or direct entry into ACTIONS for the supported system. This may occur immediately or after some specified delay to perform some other ACTION. Regardless of whether it is immediate or after some delay, when a support system's ACTION directs a supported system to be declared inoperable or directs entry into ACTIONs for a supported system, the applicable ACTIONs shall be entered in accordance with Specification 3.0.1.

Specification 6.17, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into Specification 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system ACTIONs. The SFDP implements the requirements of Specification 3.0.6.

The following examples use Figure B 3.0-1 to illustrate loss of safety function conditions that may result when a TS support system is inoperable. In this figure, the fifteen systems that comprise Train A are independent and redundant to the fifteen systems that comprise Train B. To correctly use the figure to illustrate the SFDP provisions for a cross train check, the figure establishes a relationship between support and supported systems as follows: the figure shows System 1 as a support system for System 2 and System 3; System 2 as a support system for System 4 and System 5; and System 4 as a support system for System 8 and System 9. Specifically, a loss of safety function may exist when a support system is inoperable and:

a. A system redundant to system(s) supported by the inoperable support system is also inoperable (EXAMPLE B 3.0.6-1),

b. A system redundant to system(s) in turn supported by the inoperable supported system is also inoperable (EXAMPLE B 3.0.6-2), or

c. A system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable (EXAMPLE B 3.0.6-3).

For the following examples, refer to Figure B 3.0-1.

EXAMPLE B 3.0.6-1
If System 2 of Train A is inoperable and System 5 of Train B is inoperable, a loss of safety function exists in Systems 5, 10, and 11.

EXAMPLE B 3.0.6-2

If System 2 of Train A is inoperable, and System 11 of Train B is inoperable, a loss of safety function exists in System 11.

EXAMPLE B 3.0.6-3

If System 2 of Train A is inoperable, and System 1 of Train B is inoperable, a loss of safety function exists in Systems 2, 4, 5, 8, 9, 10 and 11.

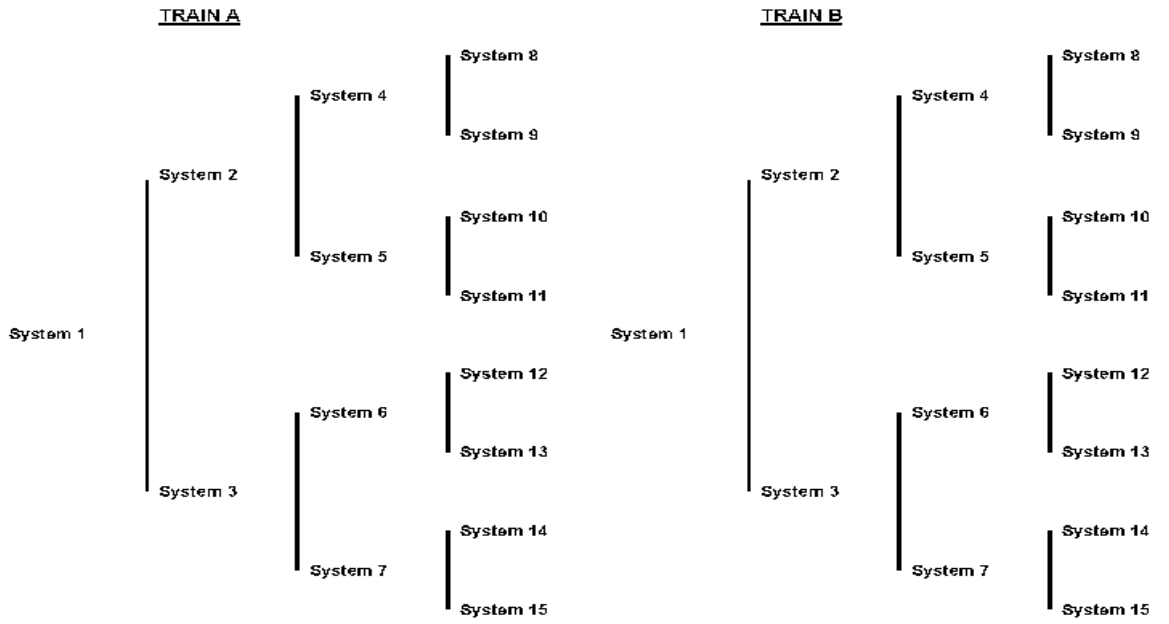


Figure B 3.0-1
Configuration of Trains and Systems

If an evaluation determines that a loss of safety function exists, the appropriate ACTIONs of the Limiting Condition for Operation in which the loss of safety function exists are required to be entered. This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operations are being restricted in accordance with the ACTIONs of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account.

When loss of safety function is determined to exist, and the SFDP requires entry into the appropriate ACTIONs of the Limiting Condition for Operation in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level), the appropriate Limiting Condition for Operation is the Limiting Condition for Operation for the support system. The ACTIONs for a support system Limiting Condition for Operation adequately address the inoperabilities of that system without reliance on entering its supported system Limiting Condition for Operation. When the loss of function is the result of multiple support systems, the appropriate Limiting Condition for Operation is the Limiting Condition for Operation for the supported system.

Specification 3.0.7 - Not Used

Specification 3.0.8 establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s). This Specification states that the supported system is not considered to be inoperable solely due to one or more snubbers not capable of performing their associated support function(s). This is appropriate because a limited length of time is allowed for maintenance, testing, or repair of one or more snubbers not capable of performing their associated support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the Technical Specifications (TS) under licensee control. The snubber requirements do not meet the criteria in 10 CFR 50.36(c)(2)(ii), and, as such, are appropriate for control by the licensee.

If the allowed time expires and the snubber(s) are unable to perform their associated support function(s), the affected supported system's Limiting Condition for Operation must be declared not met and the associated ACTION requirements shall be met in accordance with Specification 3.0.1.

Specification 3.0.8.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single train or subsystem of a multiple train or subsystem supported system or to a single train or subsystem supported system. Specification 3.0.8.a allows 72 hours to restore the snubber(s) before declaring the supported system inoperable. The 72-hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function and due to the availability of the redundant train of the supported system.

Specification 3.0.8.b applies when one or more snubbers are not capable of providing their associated support function(s) to more than one train or subsystem of a multiple train or subsystem supported system. Specification 3.0.8.b allows 12 hours to restore the snubber(s) before declaring the supported system inoperable. The 12-hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function.

The following configuration restrictions shall be applied to the use of Specification 3.0.8:

(1) Specification 3.0.8.a can only be used if one of the following two means of heat removal is available:

a. At least one high pressure makeup path (e.g., using High Pressure Coolant Injection (HPCI) or Reactor Core Isolation Cooling (RCIC) or its equivalent) and heat removal capability (e.g., suppression pool cooling), including a minimum set of supporting equipment required for success, not associated with the inoperable snubber(s), or

b. At least one low pressure makeup path (e.g., Low Pressure Coolant Injection (LPCI) or Core Spray (CS)) and heat removal capability (e.g., suppression pool cooling or shutdown cooling), including a minimum set of supporting equipment required for success, not associated with the inoperable snubber(s).

(2) Specification 3.0.8.b can only be used following verification that at least one success path exists, using equipment not associated with the inoperable snubber(s), to provide makeup and core cooling needed to mitigate Loss of Offsite Power (LOOP) accident sequences (i.e., initiated by a seismically-induced LOOP event with concurrent loss of all safety system trains supported by the out-of-service snubbers).

Specification 3.0.8 only applies to the seismic function of snubbers; it does not apply to the non-seismic functions of snubbers. Therefore, each use of Specification 3.0.8 for seismic snubbers that also have non-seismic functions requires confirmation that at least one train (or subsystem) of systems supported by the inoperable snubbers would remain capable of performing their required safety or support functions for postulated design loads other than seismic loads. In addition, a record of the design function of the inoperable snubber (i.e., seismic vs. non-seismic), implementation and compliance with the configuration restrictions defined above, and the associated plant configuration shall be available on a recoverable basis for NRC inspection.

Specification 3.0.8 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (i.e., the Maintenance Rule) does not address seismic risk. However, use of Specification 3.0.8 should be considered with respect to other plant maintenance activities, and integrated into the existing Maintenance Rule process to the extent possible so that maintenance on any unaffected train or subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified, but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

Specification 3.0.9 establishes conditions under which systems described in the Technical Specifications are considered to remain OPERABLE when required barriers are not capable of providing their related support function(s).

Barriers are doors, walls, floor plugs, curbs, hatches, installed structures or components, or other devices, not explicitly described in Technical Specifications, that support the performance of the safety function of systems described in the Technical Specifications. This Limiting Condition for Operation states that the supported system is not considered to be inoperable

solely due to required barriers not capable of performing their related support function(s) under the described conditions. Limiting Condition for Operation 3.0.9 allows 30 days before declaring the supported system(s) inoperable and the Limiting Conditions for Operation associated with the supported system(s) not met. A maximum time is placed on each use of this allowance to ensure that as required barriers are found or are otherwise made unavailable, they are restored. However, the allowable duration may be less than the specified maximum time based on the risk assessment.

If the allowed time expires and the barriers are unable to perform their related support function(s), the supported system's Limiting Conditions for Operation must be declared not met and the Conditions and Required Actions entered in accordance with Limiting Condition for Operation 3.0.2.

This provision does not apply to barriers which support ventilation systems or to fire barriers. The Technical Specifications for ventilation systems provide specific Conditions for inoperable barriers. Fire barriers are addressed by other regulatory requirements and associated plant programs. This provision does not apply to barriers which are not required to support system OPERABILITY (see NRC Regulatory Issue Summary 2001-09, "Control of Hazard Barriers," dated April 2, 2001).

The provisions of Limiting Condition for Operation 3.0.9 are justified because of the low risk associated with required barriers not being capable of performing their related support function. This provision is based on consideration of the following initiating event categories:

- Loss of coolant accidents;
- High energy line breaks;
- Feedwater line breaks;
- Internal flooding;
- External flooding;
- Turbine missile ejection; and
- Tornado or high wind.

The risk impact of the barriers which cannot perform their related support function(s) must be addressed pursuant to the risk assessment and management provision of the Maintenance Rule, 10 CFR 50.65 (a)(4), and the associated implementation guidance, Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Regulatory Guide 1.160 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions, and other aspects pertinent to plant operation with the barriers unable to perform their related support function(s). These considerations may result in risk management and other compensatory actions being required during the period that barriers are unable to perform their related support function(s).

Limiting Condition for Operation 3.0.9 may be applied to one or more trains or subsystems of a system supported by barriers that cannot provide their related support function(s), provided that risk is assessed and managed (including consideration of the effects on Large Early Release and from external events). If applied concurrently to more than one train or subsystem of a multiple train or subsystem supported system, the barriers supporting each of these trains or subsystems must provide their related support function(s) for different categories of initiating events. For example, Limiting Condition for Operation 3.0.9 may be applied for up to 30 days for more than one train of a multiple train supported system if the affected barrier for one train protects against internal flooding and the affected barrier for the other train protects against tornado missiles. In this example, the affected barrier may be the same physical barrier but serve different protection functions for each train.

The HPCI and RCIC systems are single train systems for injecting makeup water into the reactor during an accident or transient event. For the purposes of Limiting Condition for Operation 3.0.9, the HPCI system, the RCIC system, and the ADS are considered independent subsystems of a single system and Limiting Condition for Operation 3.0.9 can be used on these single train systems in a manner similar to multiple train or subsystem systems.

If during the time that Limiting Condition for Operation 3.0.9 is being used, the required OPERABLE train or subsystem becomes inoperable, it must be restored to OPERABLE status within 24 hours. Otherwise, the train(s) or subsystem(s) supported by barriers that cannot perform their related support function(s) must be declared inoperable and the associated Limiting Conditions for Operation declared not met. This 24 hour period provides time to respond to emergent conditions that would otherwise likely lead to entry into Limiting Condition for Operation 3.0.3 and a rapid plant shutdown, which is not justified given the low probability of an initiating event which would require the barrier(s) not capable of performing their related support function(s). During this 24 hour period, the plant risk associated with the existing conditions is assessed and managed in accordance with 10 CFR 50.65(a)(4).

Specification 4.0.1 through 4.0.5 establish the general requirements applicable to Surveillance Requirements. SR 4.0.2 and SR 4.0.3 apply in Section 6, Administrative Controls, only when invoked by a Section 6 Specification. These requirements are based on the Surveillance Requirements stated in the Code of Federal Regulations 10 CFR 50.36(c)(3):

"Surveillance requirements are requirements relating to test, calibration, or inspection to ensure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions of operation will be met."

Specification 4.0.1 establishes the requirement that SRs must be met during the OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which the requirements of the Limiting Condition for Operation apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Surveillance time interval and allowed extension, in accordance with Specification 4.0.2, constitutes a failure to meet the Limiting Condition for Operation.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in an OPERATIONAL CONDITION or other specified condition for which the requirements of the associated Limiting Condition for Operation are not applicable, unless otherwise specified. The SRs associated with a Special Test Exception Limiting Condition for Operation are only applicable when the Special Test Exception Limiting Condition for Operation is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given OPERATIONAL CONDITION or other specified condition.

Surveillances, including Surveillances invoked by ACTION requirements, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with Specification 4.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with Specification 4.0.2. Post maintenance testing may not be possible in the current OPERATIONAL CONDITION or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to an OPERATIONAL CONDITION or other specified condition where other necessary post maintenance tests can be completed.

Some examples of this process are:

a. Control Rod Drive maintenance during refueling that requires scram testing at > 950 psi. However, if other appropriate testing is satisfactorily completed and the scram time testing of Specification 4.1.3.2 is satisfied, the control rod can be considered OPERABLE. This allows startup to proceed to reach 950 psi to perform other necessary testing.

b. High pressure coolant injection (HPCI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPCI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

Specification 4.0.2 establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 24-month surveillance interval. It is not intended that this provision be used repeatedly to extend the surveillance intervals beyond that specified for surveillances that are not performed during refueling outages. Likewise, it is not the intent that REFUELING INTERVAL surveillances be performed during power operation unless it is consistent with safe plant operation. The limitation of Specification 4.0.2 is based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

Specification 4.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been performed within the specified Surveillance time interval and allowed extension. A delay period of up to 24 hours or up to the limit of the specified Surveillance time interval, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with Specification 4.0.2, and not at the time that the specified Surveillance time interval and allowed extension was not met.

When a Section 6.8, ‘Procedures and Programs,” specification states that the provisions of SR 4.0.3 are applicable, it permits the flexibility to defer declaring the testing requirement not met in accordance with SR 4.0.3 when the testing has not been completed within the testing interval (including the allowance of SR 4.0.2 if invoked by the Section 6.8 specification).

This delay period provides adequate time to perform Surveillances that have been missed. This delay period permits the performance of a Surveillance before complying with ACTION requirements or other remedial measures that might preclude performance of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. When a Surveillance with a Surveillance time interval based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering OPERATIONAL CONDITION 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to have not been performed when specified, Specification 4.0.3 allows for the full delay period of up to the specified Surveillance time interval to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

Specification 4.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of OPERATIONAL CONDITION changes imposed by ACTION requirements.

BASES

Specification 4.0.3 (Continued)
SR 4.0.3 is only applicable if there is a reasonable expectation the associated equipment is OPERABLE or that variables are within limits, and it is expected that the Surveillance will be met when performed. Many factors should be considered, such as the period of time since the Surveillance was last performed, or whether the Surveillance, or a portion thereof, has ever been performed, and any other indications, tests, or activities that might support the expectation that the Surveillance will be met when performed. An example of the use of SR 4.0.3 would be a relay contact that was not tested as required in accordance with a particular SR, but previous successful performances of the SR included the relay contact; the adjacent, physically connected relay contacts were tested during the SR performance; the subject relay contact has been tested by another SR; or historical operation of the subject relay contact has been successful. It is not sufficient to infer the behavior of the associated equipment from the performance of similar equipment. The rigor of determining whether there is a reasonable expectation a Surveillance will be met when performed should increase based on the length of time since the last performance of the Surveillance. If the Surveillance has been performed recently, a review of the Surveillance history and equipment performance may be sufficient to support a reasonable expectation that the Surveillance will be met when performed. For Surveillances that have not been performed for a long period or that have never been performed, a rigorous evaluation based on objective evidence should provide a high degree of confidence that the equipment is OPERABLE. The evaluation should be documented in sufficient detail to allow a knowledgeable individual to understand the basis for the determination.

Failure to comply with specified Surveillance time intervals and allowed extensions for SRs is expected to be an infrequent occurrence. Use of the delay period established by Specification 4.0.3 is a flexibility which is not intended to be used repeatedly to extend Surveillance intervals.

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While up to 24 hours or the limit of the specified Surveillance time interval is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, 'Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.' This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the ACTION requirements for the applicable Limiting Condition for Operation begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period or the variable is outside the specified limits, then the equipment is inoperable and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the allowed times specified in the ACTION requirements, restores compliance with Specification 4.0.1.

Specification 4.0.4 establishes the requirement that all applicable SRs must be met before entry into an OPERATIONAL CONDITION or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated OPERATIONAL CONDITION or other specified condition in the Applicability.

A provision is included to allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability when a Limiting Condition for Operation is not met due to a Surveillance not being met in accordance with Specification 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in Specification 4.0.4 restricting an OPERATIONAL CONDITION change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated

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SR(s) are not required to be performed, per Specification 4.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, Specification 4.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Surveillance time interval does not result in a Specification 4.0.4 restriction to changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability. However, since the Limiting Condition for Operation is not met in this instance, Specification 3.0.4 will govern any restrictions that may (or may not) apply to OPERATIONAL CONDITION or other specified condition changes. Specification 4.0.4 does not restrict changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Surveillance time interval, provided the requirement to declare the Limiting Condition for Operation not met has been delayed in accordance with Specification 4.0.3.

The provisions of Specification 4.0.4 shall not prevent entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements. In addition, the provisions of Specification 4.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, and OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4.

Specification 4.0.5 establishes the requirement that inservice inspection of ASME Code Class 1, 2 and 3 components and inservice testing of ASME Code Class 1, 2 and 3 pumps and valves shall be performed in accordance with a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda, and the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda as required by 10 CFR 50.55a. The provisions of SR 4.0.2 and SR 4.0.3 do not apply to the INSERVICE TESTING PROGRAM unless there is a specific SR referencing usage of the program.

Limerick Generating Station has received a license amendment to implement 10 CFR 50.69, “Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors,” and may voluntarily comply with the requirements of 10 CFR 50.69 as an alternative to compliance with the following requirements for structures, systems, and components (SSCs) that have a Risk-Informed Safety Class (RISC) of RISC-3:

(1) The INSERVICE TESTING PROGRAM requirements of 10 CFR 50.55a(f), and
(2) The inservice inspection, and repair and replacement (with the exception of fracture toughness), requirements for ASME Class 2 and Class 3 SSCs in 10 CFR 50.55a(g).

Therefore, SSCs that have been categorized as RISC-3 in accordance with 10 CFR 50.69 may be removed from the INSERVICE TESTING [IST] PROGRAM and the Inservice Inspection (ISI) Program in accordance with 10 CFR 50.69(b)(1)(v).

RISC-3 SSCs with technical specification surveillance requirements referencing Technical Specification 4.0.5, which have been removed from the IST/ISI programs, are subject to the alternative treatment requirements of 10 CFR 50.69(d)(2). The SSCs must continue to meet the acceptance criteria specified in associated technical specification surveillance requirements, as applicable; however, the surveillance frequency is determined as part of the alternative treatment.

3/4.1.1 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that (1) the reactor can be made subcritical from all operating conditions, (2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and (3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

Since core reactivity values will vary through core life as a function of fuel depletion and poison burnup, the demonstration of SHUTDOWN MARGIN will be performed in the cold, xenon-free condition and shall show the core to be subcritical by at least R + 0.38% Δ k/k or R + 0.28% Δ k/k, as appropriate. The 0.38% Δ k/k includes uncertainties and calculation biases. The value of R in units of % Δ k/k is the difference between the calculated value of minimum shutdown margin during the operating cycle and the calculated shutdown margin at the time of the shutdown margin test at the beginning of cycle. The value of R must be positive or zero and must be determined for each fuel loading cycle.

Two different values are supplied in the Limiting Condition for Operation to provide for the different methods of demonstration of the SHUTDOWN MARGIN. The highest worth rod may be determined analytically or by test. The SHUTDOWN MARGIN is demonstrated by (an insequence) control rod withdrawal at the beginning of life fuel cycle conditions, and, if necessary, at any future time in the cycle if the first demonstration indicates that the required margin could be reduced as a function of exposure. Observation of subcriticality in this condition assures subcriticality with the most reactive control rod fully withdrawn.

This reactivity characteristic has been a basic assumption in the analysis of plant performance and can be best demonstrated at the time of fuel loading, but the margin must also be determined anytime a control rod is incapable of insertion.

3/4.1.2 REACTIVITY ANOMALIES

Since the SHUTDOWN MARGIN requirement for the reactor is small, a careful check on actual conditions to the predicted conditions is necessary, and the changes in reactivity can be inferred from these comparisons of core $k_{effective}$ (k_{eff}). Since the comparisons are easily done, frequent checks are not an imposition on normal operations. A 1% change is larger than is expected for normal operation so a change of this magnitude should be thoroughly evaluated. A change as large as 1% would not exceed the design conditions of the reactor and is on the safe side of the postulated transients.

3/4.1.3 CONTROL RODS

The specification of this section ensure that (1) the minimum SHUTDOWN MARGIN is maintained, (2) the control rod insertion times are consistent with those used in the accident analysis, and (3) the potential effects of the rod drop accident are limited. The ACTION statements permit variations from the basic requirements but at the same time impose more restrictive criteria for continued operation. A limitation on inoperable rods is set such that the resultant effect on total rod worth and scram shape will be kept to a minimum. The requirements for the various scram time measurements ensure that any indication of systematic problems with rod drives will be investigated on a timely basis.

Damage within the control rod drive mechanism could be a generic problem, therefore with a control rod immovable because of excessive friction or mechanical interference, operation of the reactor is limited to a time period which is reasonable to determine the cause of the inoperability and at the same time prevent operation with a large number of inoperable control rods.

Control rods that are inoperable for other reasons are permitted to be taken out of service provided that those in the nonfully-inserted position are consistent with the SHUTDOWN MARGIN requirements.

With two or more withdrawn control rods immovable, the reactor must be brought to HOT SHUTDOWN. The occurrence of more than one control rod immovable at a withdrawn position increases the probability that the reactor cannot be shut down if required. Insertion of all insertable control rods eliminates the possibility of an additional failure of a control rod to insert.

The number of control rods permitted to be inoperable could be more than the eight allowed by the specification, but the occurrence of eight inoperable rods could be indicative of a generic problem and the reactor must be shutdown for investigation and resolution of the problem.

The control rod system is designed to bring the reactor subcritical at a rate fast enough to prevent the MCPR from becoming less than the fuel cladding safety limit during the limiting power transient analyzed in Section 15.2 of the FSAR. This analysis shows that the negative reactivity rates resulting from the scram with the average response of all the drives as given in the specifications, provided the required protection and MCPR remains greater than the fuel cladding safety limit. The occurrence of scram times longer then those specified should be viewed as an indication of a systemic problem with the rod drives and therefore the surveillance interval is reduced in order to prevent operation of the reactor for long periods of time with a potentially serious problem.

Scram time testing at zero psig reactor coolant pressure is adequate to ensure that the control rod will perform its intended scram function during startup of the plant until scram time testing at 950 psig reactor coolant pressure is performed prior to exceeding 40% rated core thermal power.

The scram discharge volume is required to be OPERABLE so that it will be available when needed to accept discharge water from the control rods during a reactor scram and will isolate the reactor coolant system from the containment when required.

CONTROL RODS (Continued)

The OPERABILITY of all SDV vent and drain valves ensures that the SDV vent and drain valves will close during a scram to contain reactor water discharged to the SDV piping. The SDV has one common drain line and one common vent line. Since the vent and drain lines are provided with two valves in series, the single failure of one valve in the open position will not impair the isolation function of the system. Additionally, the valves are required to open on scram reset to ensure that a path is available for the SDV piping to drain freely at other times.

When one SDV vent or drain valve is inoperable in one or more lines, the valves must be restored to OPERABLE status within 7 days. The allowable outage time is reasonable, given the level of redundancy in the lines and the low probability of a scram occurring while the valve(s) are inoperable. The SDV is still isolable since the redundant valve in the affected line is OPERABLE. During these periods, the single failure criterion may not be preserved, and a higher risk exists to allow reactor water out of the primary system during a scram.

If both valves in a line are inoperable, the line must be isolated to contain the reactor coolant during a scram. When a line is isolated, the potential for an inadvertent scram due to high SDV level is increased. The associated ACTION is modified by a note ("****") that allows periodic draining and venting of the SDV when a line is isolated. During these periods, the line may be unisolated under administrative control. This allows any accumulated water in the line to be drained, to preclude a reactor scram on SDV high level. This is acceptable since the administrative controls ensure the valve can be closed quickly, by a dedicated operator, if a scram occurs with the valve open. The 8 hour allowable outage time to isolate the line is based on the low probability of a scram occurring while the line is not isolated and the unlikelihood of significant CRD seal leakage.

Control rods with inoperable accumulators are declared inoperable and Specification 3.1.3.1 then applies. This prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed even though control rods with inoperable accumulators may still be inserted with normal drive water pressure. The drive water pressure normal operating range is specified in system operating procedures which provide ranges for system alignment and control rod motion (exercising). Operability of the accumulator ensures that there is a means available to insert the control rods even under the most unfavorable depressurization of the reactor. A control rod is considered trippable if it is capable of fully inserting as a result of a scram signal.

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CONTROL RODS (Continued)

Control rod coupling integrity is required to ensure compliance with the analysis of the rod drop accident in the FSAR. The overtravel position feature provides the only positive means of determining that a rod is properly coupled and therefore this check must be performed prior to achieving criticality after completing CORE ALTERATIONS that could have affected the control rod coupling integrity. The subsequent check is performed as a backup to the initial demonstration.

In order to ensure that the control rod patterns can be followed and therefore that other parameters are within their limits, the control rod position indication system must be OPERABLE.

The control rod housing support restricts the outward movement of a control rod to less than 3 inches in the event of a housing failure. The amount of rod reactivity which could be added by this small amount of rod withdrawal is less than a normal withdrawal increment and will not contribute to any damage to the primary coolant system. The support is not required when there is no pressure to act as a driving force to rapidly eject a drive housing.

The required surveillances are adequate to determine that the rods are OPERABLE and not so frequent as to cause excessive wear on the system components.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

Control rod withdrawal and insertion sequences are established to assure that the maximum insequence individual control rod or control rod segments which are withdrawn at any time during the fuel cycle could not be worth enough to result in a peak fuel enthalpy greater than 280 cal/gm in the event of a control rod drop accident. The specified sequences are characterized by homogeneous, scattered patterns of control rod withdrawal. When THERMAL POWER is greater than 10% of RATED THERMAL POWER, there is no possible rod worth which, if dropped at the design rate of the velocity limiter, could result in a peak enthalpy of 280 cal/gm. Thus requiring the RWM to be OPERABLE when THERMAL POWER is less than or equal to 10% of RATED THERMAL POWER provides adequate control.

The RWM provides automatic supervision to assure that out-of-sequence rods will not be withdrawn or inserted.

The analysis of the rod drop accident is presented in Section 15.4.9 of the FSAR and the techniques of the analysis are presented in a topical report, Reference 1, and two supplements, References 2 and 3. Additional pertinent analysis is also contained in Amendment 17 to the Reference 4 topical report.

The RBM is designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density over the range of power operation. Two channels are provided. Tripping one of the channels will block erroneous rod withdrawal to prevent fuel damage. This system backs up the written sequence used by the operator for withdrawal of control rods. RBM OPERABILITY is required when the limiting condition described in Specification 3.1.4.3 exists.

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

The standby liquid control system provides a backup capability for bringing the reactor from full power to a cold, Xenon-free shutdown, assuming that the withdrawn control rods remain fixed in the rated power pattern. To meet this objective it is necessary to inject a quantity of boron which produces a concentration of 660 ppm in the reactor core and other piping systems connected to the reactor vessel. To allow for potential leakage and improper mixing, this concentration is increased by 25%. The required concentration is achieved by having available a minimum quantity of 3,160 gallons of sodium pentaborate solution containng a minimum of 3,754 lbs of sodium pentaborate having the requisite Boron-10 atom % enrichment of 29% as determined from Reference 5. This quantity of solution is a net amount which is above the pump suction shutoff level setpoint thus allowing for the portion which cannot be injected.

The above quantities calculated at 29% Boron-10 enrichment have been demonstrated by analysis to provide a Boron-10 weight equivalent of 185 lbs in the sodium pentaborate solution. Maintaining this Boron-10 weight in the net tank contents ensures a sufficient quantity of boron to bring the reactor to a cold, Xenon-free shutdown.

The pumping rate of 37.0 gpm provides a negative reactivity insertion rate over the permissible solution volume range, which adequately compensates for the positive reactivity effects due to elimination of steam voids, increased water density from hot to cold, reduced doppler effect in uranium, reduced neutron leakage from boiling to cold, decreased control rod worth as the moderator cools, and xenon decay. The temperature requirement ensures that the sodium pentaborate always remains in solution.

With redundant pumps and explosive injection valves and with a highly reliable control rod scram system, operation of the reactor is permitted to continue for short periods of time with the system inoperable or for longer periods of time with one of the redundant components inoperable.

The SLCS system consists of three separate and independent pumps and explosive valves. Two of the separate and independent pumps and explosive valves are required to meet the minimum requirements of this technical specification and, where applicable, satisfy the single failure criterion. To ensure that SLCS pump discharge pressure does not exceed the SLCS relief valve setpoint during operation following an anticipated transient without scram (ATWS) event, no more than two pumps shall be aligned for automatic operation in OPERATIONAL CONDITIONS 1, 2, and 3. This maintains the equivalent control capacity to satisfy 10 CFR 50.62 (Requirements for reduction of risk from anticipated transients without scram (ATWS). With three pumps aligned for automatic operation, the system is inoperable and ACTION statement (b) applies.

The SLCS must have an equivalent control capacity of 86 gpm of 13% weight sodium pentaborate in order to satisfy 10 CFR 50.62. As part of the ARTS/MELLL program the ATWS analysis was updated to reflect the new rod line. As a result of this it was determined that the Boron 10 enrichment was required to be increased to 29% to prevent exceeding a suppression pool temperature of 190°F. This equivalency requirement is fulfilled by having a system which satisfies the equation given in 4.1.5.b.2.

The upper limit concentration of 13.8% has been established as a reasonable limit to prevent precipitation of sodium pentaborate in the event of a loss of tank heating, which allow the solution to cool. A SLCS Pump flowrate of 37.0 gpm (minimum) and a Sodium Pentaborate Solution concentration of 9% by weight (minimum) will require a Boron-10 enrichment of 49 atom % to be added to the tank. The decreased pump flowrate and increased solution enrichment are acceptable because the results of the ATWS Rule Equation will remain > 1.0.

STANDBY LIQUID CONTROL SYSTEM (Continued)

Surveillance requirements are established on a frequency that assures a high reliability of the system. Once the solution is established, boron concentration will not vary unless more boron or water is added, thus a check on the temperature and volume assures that the solution is available for use.

Replacement of the explosive charges in the valves will assure that these valves will not fail because of deterioration of the charges.

The Standby Liquid Control System also has a post-DBA LOCA safety function to buffer Suppression Pool pH in order to maintain bulk pH above 7.0. The buffering of Suppression Pool pH is necessary to prevent iodine re-evolution to satisfy the methodology for Alternative Source Term. Manual initiation is used, and the minimum amount of total boron required for Suppression Pool pH buffering is 256 lbs. Given that at least 185 lbs of Boron-10 is maintained in the tank, the total boron in the tank will be greater than 256 lbs for the range of enrichments from 29% to 62%.

ACTION Statement (a) applies only to OPERATIONAL CONDITIONS 1 and 2 because a single pump can satisfy both the reactor control function and the post-DBA LOCA function to control Suppression Pool pH since boron injection is not required until 13 hours post-LOCA. ACTION Statement (b) applies to OPERATIONAL CONDITIONS 1, 2 and 3 to address the post-LOCA safety function of the SLC system.

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1. C. J. Paone, R. C. Stirn and J. A. Woolley, "Rod Drop Accident Analysis for Large BWR's," G. E. Topical Report NEDO-10527, March 1972.

2. C. J. Paone, R. C. Stirn, and R. M. Young, Supplement 1 to NEDO-10527, July 1972.

3. J. M. Haun, C. J. Paone, and R. C. Stirn, Addendum 2, "Exposed Cores," Supplement 2 to NEDO-10527, January 1973.

4. Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel."

5. "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," NEDC-32193P, Revision 2, October 1993.

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3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

This specification assures that the peak cladding temperature (PCT) following the postulated design basis Loss-of-Coolant Accident (LOCA) will not exceed the limits specified in 10 CFR 50.46 and that the fuel design analysis limits specified in NEDE-24011-P-A (Reference 2) will not be exceeded.

Mechanical Design Analysis: NRC approved methods (specified in Refer-ence 2) are used to demonstrate that all fuel rods in a lattice operating at the bounding power history, meet the fuel design limits specified in Reference 2. No single fuel rod follows, or is capable of following, this bounding power history. This bounding power history is used as the basis for the fuel design analysis MAPLHGR limit.

LOCA Analysis: A LOCA analysis is performed in accordance with 10 CFR 50 Appendix K to demonstrate that the permissible planar power (MAPLHGR) limits comply with the ECCS limits specified in 10 CFR 50.46. The analysis is performed for the most limiting break size, break location, and single failure combination for the plant, using the evaluation model described in Reference 9.

The MAPLHGR limit as show in the CORE OPERATING LIMITS REPORT is the most limiting composite of the fuel mechanical design anaylsis MAPLHGR and the ECCS MAPLHGR limit.

Only the most limiting MAPLHGR values are shown in the CORE OPERATING LIMITS REPORT for multiple lattice fuel. Compliance with the specific lattice MAPLHGR operating limits, which are available in Reference 3, is ensured by use of the process computer.

As a result of no longer utilizing an APRM trip setdown requirement, additional constraints are placed on the MAPLHGR limits to assure adherence to the fuel-mechanical design bases. These constraints are introduced through the MAPFAC(P) and MAPFAC(F) factors as defined in the COLR.

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3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady-state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity MCPR(99.9%), and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady-state operating limit, it is required that less than 0.1% of fuel rods in the core are susceptible to transition boiling or that the resulting MCPR does not decrease below the operating limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease.

The evaluation of a given transient begins with the system initial parameters shown in FSAR Table 15.0-2 that are input to a BWR system dynamic behavior transient computer program. The codes used to evaluate transients are discussed in Reference 2.

MCPR(99.9%) is determined to ensure more than 99.9% of the fuel rods in the core are not susceptible to boiling transition using a statistical model that combines all the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the approved Critical Power correlations. Details of the MCPR(99.9%) calculation are given in Reference 2. Reference 2 also includes a tabulation of the uncertainties and the nominal values $MCPR_{99.9\%}$ statistical analysis.

The MCPR operating limits are derived from the MCPR(99.9%) value and the transient analysis and are dependent on the operating core flow and power state (MCPR(F), and MCPR(P), respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency (Ref. 6). Flow dependent MCPR limits (MCPR(F)) are determined by steady state thermal hydraulic methods with key physics response inputs benchmarked using the three dimensional BWR simulator code (Ref. 7) to analyze slow flow runout transients.

Power dependent MCPR limits (MCPR(P)) are determined by approved transient analysis (Reference 2). Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scrams are bypassed, high and low flow MCPR(P), operating limits are provided for operating between 25% RTP and 30% RTP.

The MCPR operating limits specified in the COLR (MCPR(99.9%) value, MCPR(F), and MCPR(P) values) are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is determined by the larger of the MCPR(F), and MCPR(P) limits, which are based on the MCPR(99.9%) limit specified in the COLR.

MINIMUM CRITICAL POWER RATIO (Continued)

At THERMAL POWER levels less than or equal to 25% of RATED THERMAL POWER, the reactor will be operating at minimum recirculation pump speed and the moderator void content will be very small. For all designated control rod patterns which may be employed at this point, operating plant experience indicates that the resulting MCPR value is in excess of requirements by a considerable margin. During initial start-up testing of the plant, a MCPR evaluation will be made at 25% of RATED THERMAL POWER level with minimum recirculation pump speed. The MCPR margin will thus be demonstrated such that future MCPR evaluation below this power level will be shown to be unnecessary. The daily requirement for calculating MCPR when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement for calculating MCPR when a limiting control rod pattern is approached ensures that MCPR will be known following a change in THERMAL POWER or power shape, regardless of magnitude, that could place operation at a thermal limit.

3/4.2.4 LINEAR HEAT GENERATION RATE

This specification assures that the Linear Heat Generation Rate (LHGR) in any rod is less than the design linear heat generation even if fuel pellet densification is postulated.

Reference:

1. Deleted.

2. "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A (latest approved revision).

3. "Basis of MAPLHGR Technical Specifications for Limerick Unit 1," NEDO-31401, February 1987 (as amended).

4. Deleted

5. Increased Core Flow and Partial Feedwater Heating Analysis for Limerick Generating Station Unit 1 Cycle 1, NEDC-31323, October 1986 including Errata and Addenda Sheet No. 1 dated November 6, 1986.

6. NEDC-32193P, "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," Revision 2, October 1993.

7. NEDO-30130-A, "Steady State Nuclear Methods," May 1985.

8. NEDO-24154, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors, "October 1978.

9. NEDC-32170P, "Limerick Generating Station Units 1 and 2 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," June 1993.

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3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and

d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its intended function even during periods when instrument channels may be out of service because of maintenance. When necessary, one channel may be made inoperable for brief intervals to conduct required surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed.

The system meets the intent of IEEE-279 for nuclear power plant protection systems. Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System" and NEDC-32410P-A, “Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function.” The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

The APRM Functions include five Functions accomplished by the four APRM channels (Functions 2.a, 2.b, 2.c, 2.d, and 2.f) and one accomplished by the four 2-Out-Of-4 Voter channels (Function 2.e). Two of the five Functions accomplished by the APRM channels are based on neutron flux only (Functions 2.a and 2.c), one Function is based on neutron flux and recirculation drive flow (Function 2.b) and one is based on equipment status (Function 2.d). The fifth Function accomplished by the APRM channels is the Oscillation Power Range Monitor (OPRM) Upscale trip Function 2.f, which is based on detecting oscillatory characteristics in the neutron flux. The OPRM Upscale Function is also dependent on average neutron flux (Simulated Thermal Power) and recirculation drive flow, which are used to automatically enable the output trip.

The Two-Out-Of-Four Logic Module includes 2-Out-Of-4 Voter hardware and the APRM Interface hardware. The 2-Out-Of-4 Voter Function 2.e votes APRM Functions 2.a, 2.b, 2.c, and 2.d independently of Function 2.f. This voting is accomplished by the 2-Out-Of-4 Voter hardware in the Two-Out-Of-Four Logic Module. The voter includes separate outputs to RPS for the two independently voted sets of Functions, each of which is redundant (four total outputs). The analysis in Reference 2 took credit for this redundancy in the justification of the 12-hour allowed out-of-service time for

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

Action b, so the voter Function 2.e must be declared inoperable if any of its functionality is inoperable. The voter Function 2.e does not need to be declared inoperable due to any failure affecting only the APRM Interface hardware portion of the Two-Out-Of-Four Logic Module.

Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. To provide adequate coverage of the entire core, consistent with the design bases for the APRM Functions 2.a, 2.b, and 2.c, at least 20 LPRM inputs, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM channel. In addition, no more than 9 LPRMs may be bypassed between APRM calibrations (weekly gain adjustments). For the OPRM Upscale Function 2.f, LPRMs are assigned to "cells" of 3 or 4 detectors. A minimum of 23 cells (Reference 9), each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for each APRM channel for the OPRM Upscale Function 2.f to be OPERABLE in that channel. LPRM gain settings are determined from the local flux profiles measured by the TIP system. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 2000 EFPH frequency is based on operating experience with LPRM sensitivity changes.

References 4, 5 and 6 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

An OPRM Upscale trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in any cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the growth rate or amplitude based algorithms detect growing oscillatory changes in the neutron flux for one or more cells in that channel.

The OPRM Upscale Function is required to be OPERABLE when the plant is at $\geq$ 25% RATED THERMAL POWER. The 25% RATED THERMAL POWER level is selected to provide margin in the unlikely event that a reactor power increase transient occurring while the plant is operating below 29.5% RATED THERMAL POWER causes a power increase to or beyond the 29.5% RATED THERMAL POWER OPRM Upscale trip auto-enable point without operator action. This OPERABILITY requirement assures that the OPRM Upscale trip automatic-enable function will be OPERABLE when required.

Actions a, b and c define the Action(s) required when RPS channels are discovered to be inoperable. For those Actions, separate entry condition is allowed for each inoperable RPS channel. Separate entry means that the allowable time clock(s) for Actions a, b or c start upon discovery of inoperability for that specific channel. Restoration of an inoperable RPS channel satisfies only the action statements for that particular channel. Action statement(s) for remaining inoperable channel(s) must be met according to their original entry time.

A Note has been provided to modify the Actions when Functional Unit 2.b and 2.c channels are inoperable due to failure of SR 4.3.1.1 and gain adjustments are necessary. The Note allows entry into associated Actions to be delayed for up to 2 hours if the APRM is indicating a lower power value than the calculated power (i.e., the gain adjustment factor (GAF) is high (non-conservative)). The GAF for any channel is defined as the power value determined by the heat balance divided by the APRM reading for that channel. Upon completion of the gain adjustment, or

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

expiration of the allowed time, the channel must be returned to OPERABLE status or the applicable Actions taken. This Note is based on the time required to perform gain adjustments on multiple channels.

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (NEDC-30851P-A and NEDC-32410P-A) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided that the associated Function's (identified as a "Functional Unit" in Table 3.3.1-1) inoperable channel is in one trip system and the Function still maintains RPS trip capability. Alternatively, an allowable out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

The requirements of Action a are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic, including the IRM Functions and APRM Function 2.e (trip capability associated with APRM Functions 2.a, 2.b, 2.c, 2.d, and 2.f are discussed below), this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip).

For Function 5 (Main Steam Isolation Valve--Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 9 (Turbine Stop Valve-Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The completion time to satisfy the requirements of Action a is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels. Alternatively, the completion time can be determined in accordance with the Risk Informed Completion Time Program.

With trip capability maintained, i.e., Action a satisfied, Actions b and c as applicable must still be satisfied. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Action b requires that the channel or the associated trip system must be placed in the tripped condition. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue.

As noted, placing the trip system in trip is not applicable to satisfy Action b for APRM functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of one required APRM channel affects both trip systems. For that condition, the Action b requirements can only be satisfied by placing the inoperable APRM channel in trip. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and the requirement to satisfy Action a.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

The requirements of Action c must be satisfied when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, normally the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system (see additional bases discussion above related to loss of trip capability and the requirements of Action a, and special cases for Functions 2.a, 2.b, 2.c, 2.d, 2.f, 5 and 9).

The requirements of Action c limit the time the RPS scram logic, for any Function, would not accommodate single failure in both tip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in NEDC-3Ø851P-A for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function must have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing the actions required by Action c restores RPS to a reliability level equivalent to that evaluated in NEDC-3Ø851P-A, which justified a 12 hour allowable out of service time as allowed by Action b. To satisfy the requirements of Action c, the trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what OPERATIONAL CONDITION the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour allowable out of service time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

As noted, Action c is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of an APRM channel affects both trip systems and is not associated with a specific trip system as are the APRM 2-Out-Of-4 voter and other non-APRM channels for which Action c applies. For an inoperable APRM channel, the requirements of Action b can only be satisfied by tripping the inoperable APRM channel. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure.

If it is not desired to place the channel (or trip system) in trip to satisfy the requirements of Action a, Action b or Action c (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Action d requires that the Action defined by Table 3.3.1-1 for the applicable Function be initiated immediately upon expiration of the allowable out of service time.

Table 3.3.1-1, Function 2.f, references Action 1Ø, which defines the action required if OPRM Upscale trip capability is not maintained. Action 1Øb is required to address identified equipment failures. Action 1Øa is to address common mode vendor/industry identified issues that render all four OPRM channels inoperable at once. For this condition, References 2 and 3 justified use of alternate methods to

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

detect and suppress oscillations for a limited period of time, up to 120 days. The alternate methods are procedurally established consistent with the guidelines identified in Reference 7 requiring manual operator action to scram the plant if certain predefined events occur. The 12-hour allowed completion time to implement the alternate methods is based on engineering judgment to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and suppress trip capability is formally in place. The 120-day period during which use of alternate methods is allowed is intended to be an outside limit to allow for the case where design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. The evaluation of the use of alternate methods concluded, based on engineering judgment, that the likelihood of an instability event that could not be adequately handled by the alternate methods during the 120-day period was negligibly small. Plant startup may continue while operating within the allowed completion time of Action 10a. The primary purpose of this is to allow an orderly completion, without undue impact on plant operation, of design and verification activities in the event of a required design change to the OPRM Upscale function. This exception is not intended as an alternative to restoring inoperable equipment to OPERABLE status in a timely manner.

Action 10a is not intended and was not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to be accomplished within the completion times allowed for LCO 3.3.1 Action a or Action b, as applicable. Action 10b applies when routine equipment OPERABILITY cannot be restored within the allowed completion times of LCO 3.3.1 Actions a or b, or if a common mode OPRM deficiency cannot be corrected and OPERABILITY of the OPRM Upscale Function restored within the 120-day allowed completion time of Action 10a.

The OPRM Upscale trip output shall be automatically enabled (not-bypassed) when APRM Simulated Thermal Power is $\geq$ 29.5% and recirculation drive flow is $<$ 60% as indicated by APRM measured recirculation drive flow. NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. As noted in Table 4.3.1.1-1, Note c, CHANNEL CALIBRATION for the OPRM Upscale trip Function 2.f includes confirming that the auto-enable (not-bypassed) setpoints are correct. Other surveillances ensure that the APRM Simulated Thermal Power properly correlates with THERMAL POWER (Table 4.3.1.1-1, Note d) and that recirculation drive flow properly correlates with core flow (Table 4.3.1.1-1, Note g).

If any OPRM Upscale trip auto-enable setpoint is exceeded and the OPRM Upscale trip is not enabled, i.e., the OPRM Upscale trip is bypassed when APRM Simulated Thermal Power is $\geq$ 29.5% and recirculation drive flow is $<$ 60%, then the affected channel is considered inoperable for the OPRM Upscale Function. Alternatively, the OPRM Upscale trip auto-enable setpoint(s) may be adjusted to place the channel in the enabled condition (not-bypassed). If the OPRM Upscale trip is placed in the enabled condition, the surveillance requirement is met and the channel is considered OPERABLE.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

As noted in Table 4.3.1.1-1, Note g, CHANNEL CALIBRATION for the APRM Simulated Thermal Power - Upscale Function 2.b and the OPRM Upscale Function 2.f, includes the recirculation drive flow input function. The APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function both require a valid drive flow signal. The APRM Simulated Thermal Power - Upscale Function uses drive flow to vary the trip setpoint. The OPRM Upscale Function uses drive flow to automatically enable or bypass the OPRM Upscale trip output to RPS. A CHANNEL CALIBRATION of the APRM recirculation drive flow input function requires both calibrating the drive flow transmitters and establishing a valid drive flow / core flow relationship. The drive flow / core flow relationship is established once per refuel cycle, while operating within 10% of rated core flow and within 10% of RATED THERMAL POWER. Plant operational experience has shown that this flow correlation methodology is consistent with the guidance and intent in Reference 8. Changes throughout the cycle in the drive flow / core flow relationship due to the changing thermal hydraulic operating conditions of the core are accounted for in the margins included in the bases or analyses used to establish the setpoints for the APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function.

For the Simulated Thermal Power - Upscale Function (Function 2.b), the CHANNEL CALIBRATION surveillance requirement is modified by two Notes. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be within the as-left tolerance of the Trip Setpoint. The as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the Trip Setpoint, then the channel shall be declared inoperable. The as-left tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy and the measurement and test equipment error (including readability). The as-found tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy, instrument drift, and the measurement and test equipment error (including readability).

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are adjusted to the reactor power calculated from a heat balance if the heat balance calculated reactor power exceeds the APRM channel output by more than 2% RTP.

This Surveillance does not preclude making APRM channel adjustments, if desired, when the heat balance calculated reactor power is less than the APRM channel output. To provide close agreement between the APRM indicated power and to preserve operating margin, the APRM channels are normally adjusted to within +/- 2% of the heat balance calculated reactor power. However, this agreement is not required for OPERABILITY when APRM output indicates a higher reactor power than the heat balance calculated reactor power.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

As noted in Table 3.3.1-2, Note "*", the redundant outputs from the 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8 to determine the interval between tests for application of Specification 4.3.1.3 (REACTOR PROTECTION SYSTEM RESPONSE TIME). The note further requires that testing of OPRM and APRM outputs shall be alternated.

Each test of an OPRM or APRM output tests each of the redundant outputs from the 2-Out-Of-4 Voter channel for that function, and each of the corresponding relays in the RPS. Consequently, each of the RPS relays is tested every fourth cycle. This testing frequency is twice the frequency justified by References 2 and 3.

Automatic reactor trip upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

The measurement of response time at the frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable except for the APRM Simulated Thermal Power - Upscale and Neutron Flux - Upscale trip functions and the OPRM Upscale trip function (Table 3.3.1-2, Items 2.b, 2.c, and 2.f). Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times. Response time testing for the sensors as noted in Table 3.3.1-2 is not required based on the analysis in NEDO-32291-A. Response time testing for the remaining channel components is required as noted. For the digital electronic portions of the APRM functions, performance characteristics that determine response time are checked by a combination of automatic self-test, calibration activities, and response time tests of the 2-Out-Of-4 Voter (Table 3.3.1-2, Item 2.e).

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensures the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 2, "Technical Specification Improvement Analysis for BWR Instrumentation Common to RPS and ECCS Instrumentation" as approved by the NRC and documented in the NRC Safety Evaluation Report (SER) (letter to D.N. Grace from C.E. Rossi dated January 6, 1989) and NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," as approved by the NRC and documented in the NRC SER (letter to S.D. Floyd from C.E. Rossi dated June 18, 1990).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Automatic closure of the MSIVs upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 10-second diesel startup and the 3 second load center loading delay. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13-second delay. It follows that checking the valve speeds and the 13-second time for emergency power establishment will establish the response time for the isolation functions.

Response time testing for sensors are not required based on the analysis in NEDO 32291-A. Response time testing of the remaining channel components is required as noted in Table 3.3.2-3.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses. Primary containment isolation valves that are actuated by the isolation signals specified in Technical Specification Table 3.3.2-1 are identified in Technical Requirements Manual Table 3.6.3-1.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.3.2 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

3/4.3.3 EMERGENCY CORE COOLING ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11X00X relay, the grid voltage is monitored to 230kV (for the 101 Safeguard Bus Source) or 525kV (for the 201 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11X00X relay.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.3.A REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

Technical Specifications are required by 10 CFR 50.36 to include limiting safety system settings (LSSS) for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The actual settings for the automatic isolation channels are the same as those established for the same functions in OPERATIONAL CONDITIONS 1, 2, and 3 in Table 3.3.2-2, "ISOLATION ACTUATION INSTRUMENTATION SETPOINTS."

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation if they will be isolated by valves that will close

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation.

The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, "Reactor Pressure Vessel (RPV) Water Inventory Control (WIC)," and the definition of DRAIN TIME. There are functions that support automatic isolation of Residual Heat Removal (RHR) subsystem and Reactor Water Cleanup (RWCU) system penetration flow path(s) on low RPV water level.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in OPERATIONAL CONDITIONS 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered in which an initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure. It is assumed, based on engineering judgment, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can be manually initiated to maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Permissive and interlock setpoints are generally considered as nominal values without regard to measurement accuracy.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function-by-Function basis.

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

RHR System Isolation - Reactor Vessel Water Level Low - Level 3

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level Low - Level 3 Function associated with RHR System isolation may be credited for automatic isolation of penetration flow paths associated with the RHR System.

Reactor Vessel Water Level Low - Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level Low - Level 3 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level Low - Level 3 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level Low - Level 3 Allowable Value (Table 3.3.2-2), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level Low - Level 3 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 2 valves.

Reactor Water Cleanup (RWCU) System Isolation - Reactor Vessel Water Level - Low, Low - Level 2

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

Vessel Water Level - Low, Low - Level 2 Function associated with RWCU System isolation may be credited for automatic isolation of penetration flow paths associated with the RWCU System. Reactor Vessel Water Level - Low, Low - Level 2 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level - Low, Low - Level 2 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level - Low, Low - Level 2 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level - Low, Low Level 2 Allowable Value (Table 3.3.2-2), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level - Low, Low Level 2 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 3 valves.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Actions

A note has been provided to modify the ACTIONs related to RPV Water Inventory Control instrumentation channels. The ACTIONs for inoperable RPV Water Inventory Control instrumentation channels provide appropriate compensatory measures for each inoperable RPV Water Inventory Control instrumentation channel.

ACTION a. directs taking the appropriate ACTION referenced in Table 3.3.3.A-1. The applicable ACTION referenced in the table is Function dependent.

RHR System Shutdown Cooling Mode Isolation, Reactor Vessel Water Level Low - Level 3, and Reactor Water Cleanup System Isolation, Reactor Vessel Water Level - Low, Low - Level 2 functions are applicable when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. If the instrumentation is inoperable, ACTION 38 directs immediate action to place the channel in trip. With the inoperable channel in the tripped condition, the remaining channel will isolate the penetration flow path on low water level. If both channels are inoperable and placed in trip, the penetration flow path will be isolated. Alternatively, ACTION 38 requires the associated penetration flow path(s) to be immediately declared incapable of automatic isolation and directs initiating action to calculate of DRAIN TIME. The calculation cannot credit automatic isolation of the affected penetration flow paths.

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

REFERENCES

1. Information Notice 84-81, "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3. Generic Letter 92-Ø4, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 1Ø CFR 5Ø.54(f)," August 1992.

4. NRC Bulletin 93-Ø3, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

3/4.3.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-1Ø349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 29.5% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, i.e., 175 ms. Included in this time are: the response time of the sensor, the time allotted for breaker arc suppression, and the response time of the system logic.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel. This instrumentation does not provide actuation of any of the emergency core cooling equipment.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been specified in accordance with recommendations made by GE in their letter to the BWR Owner's Group dated August 7, 1989, SUBJECT: "Clarification of Technical Specification changes given in ECCS Actuation Instrumentation Analysis."

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," as approved by the NRC and documented in the SER (letter to D. N. Grace from C. E. Rossi dated September 22, 1988).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

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3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring instrumentation ensures that: (1) the radiation levels are continually measured in the areas served by the individual channels, and (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded, and (3) sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with 10 CFR Part 50, Appendix A, General Design Criteria 19, 41, 60, 61, 63, and 64.

The surveillance interval for the Main Control Room Normal Fresh Air Supply Radiation Monitor is determined in accordance with the Surveillance Frequency Control Program.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

3/4.3.7.2 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

3/4.3.7.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.4 REMOTE SHUTDOWN SYSTEM

The OPERABILITY of the remote shutdown system ensures that sufficient capability is available to permit shutdown and maintenance of HOT SHUTDOWN of the unit from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criterion 19 of 10 CFR Part 50, Appendix A.

The systems/functions for which the RSP provides remote instrumentation and controls to accomplish this purpose are as follows:

- Reactor Core Isolation Cooling (RCIC) system to maintain reactor vessel water level.
- Main steam line safety/relief valves (manual actuation) to reduce reactor vessel pressure.
- Nuclear boiler instrumentation to monitor reactor vessel pressure and level.
- Residual Heat Removal (RHR) system for suppression pool cooling and shutdown cooling.
- RHR Service Water system to supply cooling water to the RHR heat exchanger.
- Emergency Service Water (ESW) system to supply cooling water to RCIC and RHR room coolers, RHR motor oil and seal coolers, and the emergency diesel generator.
- Containment and suppression pool system monitoring instrumentation.
- Standby AC power that supplies power to the above systems.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess important variables following an accident. This capability is consistent with the recommendations of Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," December 1975 and NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

Table 3.3.7.5-1, Accident Monitoring Instrumentation, Item 2, requires two OPERABLE channels of Reactor Vessel Water Level monitoring from each of two overlapping instrumentation loops to ensure monitoring of Reactor Vessel Water Level over the range of -350 inches to +60 inches. Each channel is comprised of one OPERABLE Wide Range Level instrument loop (-150 inches to +60 inches) and one OPERABLE Fuel Zone Range instrument loop (-350 inches to -100 inches). Both instrument loops, Wide Range and Fuel Zone Range, are required by Tech. Spec. 3.3.7.5 to provide sufficient overlap to bound the required range as described in UFSAR Section 7.5. Action 80 is applicable if the required number of instrument loops per channel (Wide Range and Fuel Zone Range) is not maintained.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION (continued)

Table 3.3.7.5-1, Accident Monitoring Instrumentation, Item 13, requires two OPERABLE channels of Neutron Flux monitoring from each of three overlapping instrumentation loops to ensure monitoring of Neutron Flux over the range of 10^{-6}% to 100% full power. Each channel is comprised of one OPERABLE SRM (10^{-9}% to 10^{-3}% power), one OPERABLE IRM (10^{-4}% to 40% power) and one OPERABLE APRM (0% to 125% power). All three instrument loops, SRM, IRM and APRM, are required by Tech. Spec. 3.3.7.5 to provide sufficient overlap to bound the required range as described in UFSAR Section 7.5. Action 80 is applicable if the required number of instrument loops per channel (SRM, IRM, and APRM) is not maintained.

3/4.3.7.6 SOURCE RANGE MONITORS

The source range monitors provide the operator with information of the status of the neutron level in the core at very low power levels during startup and shutdown. At these power levels, reactivity additions shall not be made without this flux level information available to the operator. When the intermediate range monitors are on scale, adequate information is available without the SRMs and they can be retracted.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

3/4.3.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.8 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.9 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

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3/4.3.7.10 (Deleted)

3/4.3.7.11 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.12 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM AND THE TRM.

3/4.3.8 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

The feedwater/main turbine trip system actuation instrumentation is provided to initiate action of the feedwater system/main turbine trip system in the event of failure of feedwater controller under maximum demand.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

REFERENCES:

1. NEDC-30851P-A, “Technical Specification Improvement Analyses for BWR Reactor Protection System,” March 1988.

2. NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," October 1995.

3. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," November 1997.

4. NEDO-31960-A, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.

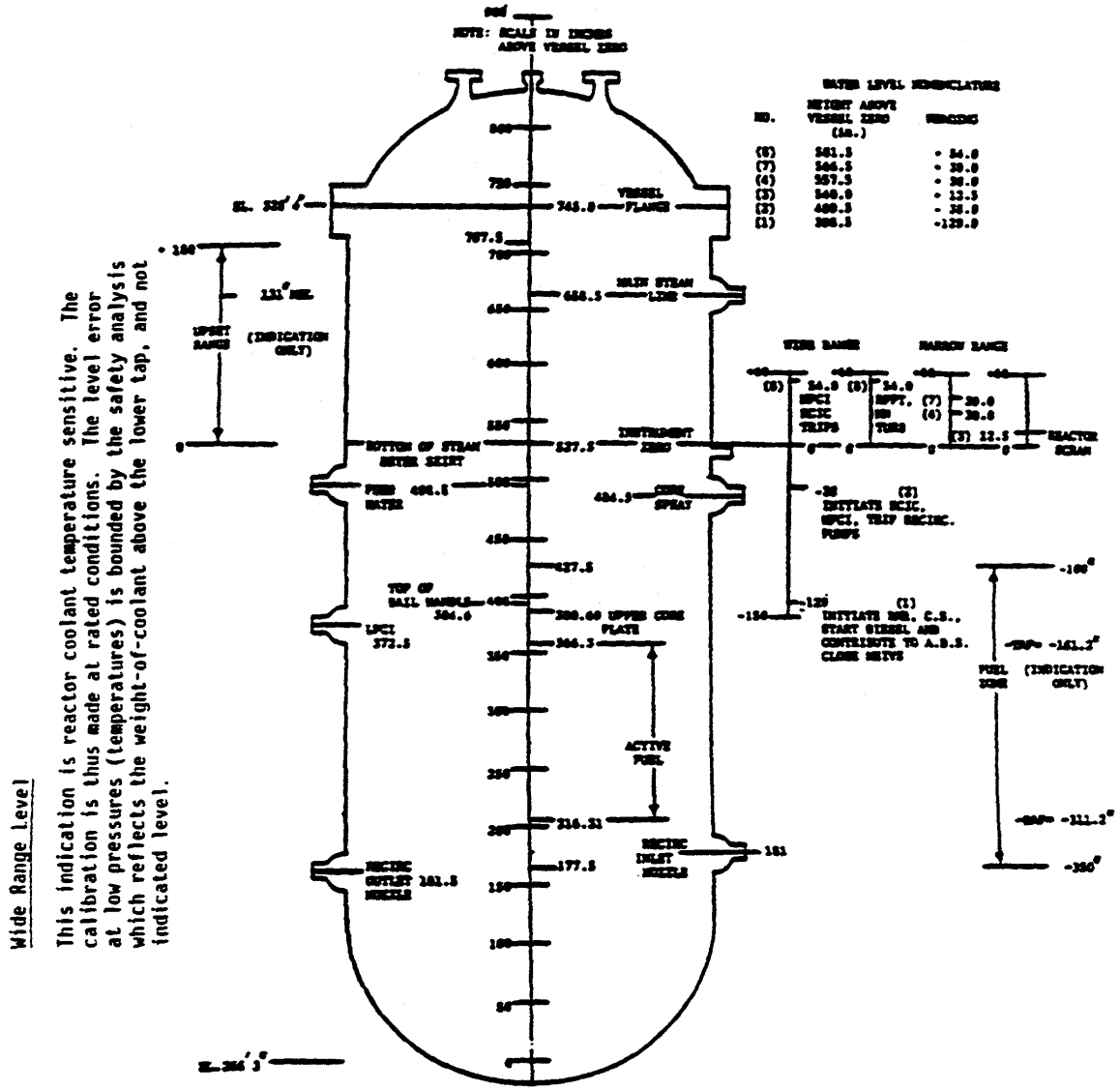
5. NEDO-31960-A, Supplement 1, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.

6. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications,” August 1996.

7. Letter, L. A. England (BWROG) to M. J. Virgilio, “BWR Owners’ Group Guidelines for Stability Interim Corrective Action,” June 6, 1994.

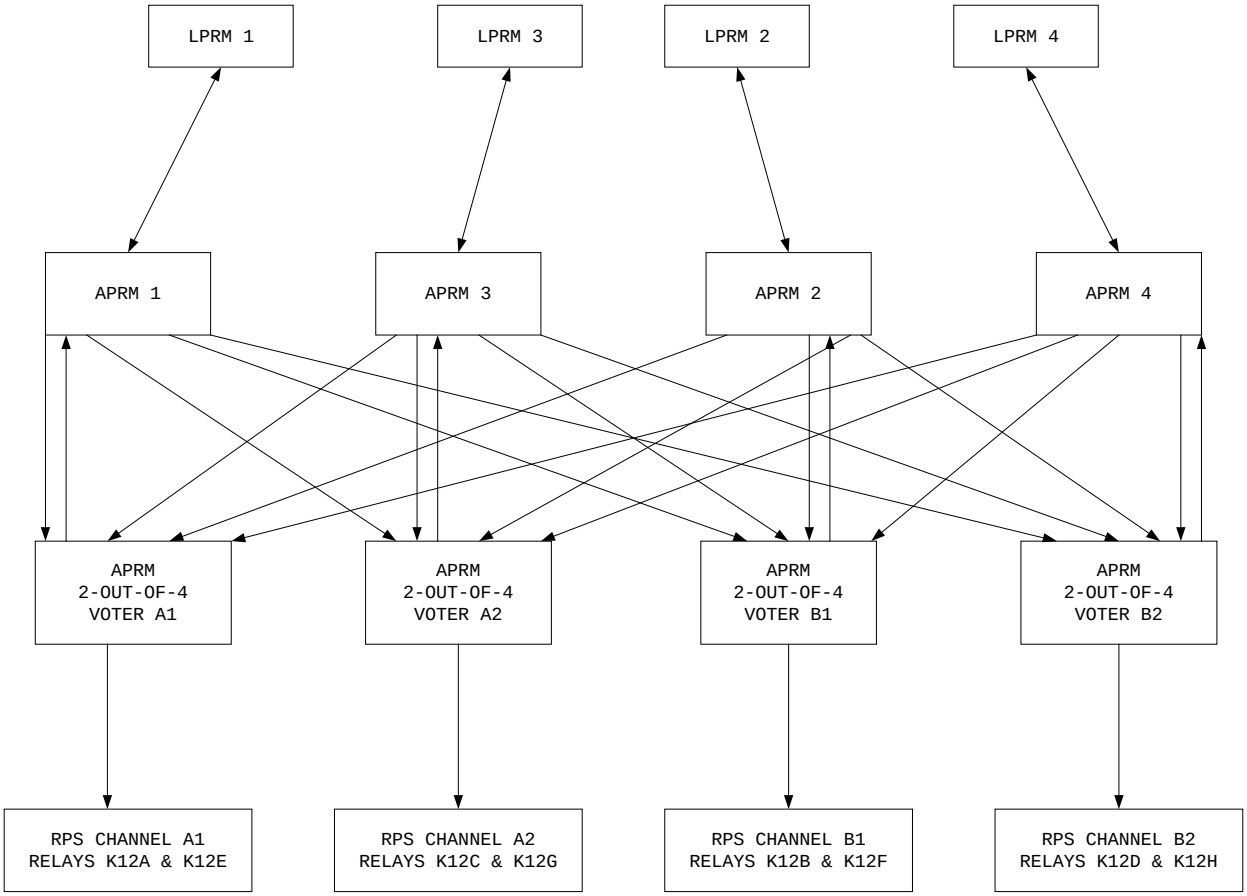
8. GE Service Information Letter No. 516, “Core Flow Measurement - GE BWR/3, 4, 5 and 6 Plants,” July 26, 1990.

9. GE Letter NSA 00-433, Alan Chung (GE) to Sujit Chakraborty (GE), “Minimum Number of Operable OPRM Cells for Option III Stability at Limerick 1 & 2,” May 02, 2001.



BASES FIGURE B 3/4.3-1

REACTOR VESSEL WATER LEVEL



BASES FIGURE B 3/4 3-2

APRM CONFIGURATION

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3/4.4.1 RECIRCULATION SYSTEM

The impact of single recirculation loop operation upon plant safety is assessed and shows that single-loop operation is permitted if the MCPR(99.9%) is increased as noted in the COLR, APRM scram and control rod block setpoints are adjusted as noted in Tables 2.2.1-1 and 3.3.6-2, respectively.

An inoperable jet pump is not, in itself, a sufficient reason to declare a recirculation loop inoperable, but it does, in case of a design-basis-accident, increase the blowdown area and reduce the capability of reflooding the core; thus, the requirement for shutdown of the facility with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed schedule for significant degradation.

Additionally, surveillance on the pump speed of the operating recirculation loop is imposed to exclude the possibility of excessive internals vibration. The surveillance on differential temperatures below 30% RATED THERMAL POWER or 50% rated recirculation loop flow is to mitigate the undue thermal stress on vessel nozzles, recirculation pump and vessel bottom head during the extended operation of the single recirculation loop mode.

Surveillance of recirculation loop flow, total core flow, and diffuser-to-lower plenum differential pressure is designed to detect significant degradation in jet pump performance that precedes jet pump failure. This surveillance is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while base-lining new "established patterns," engineering judgment of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation pump speed operating characteristics (pump flow and loop flow versus pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow and loop flow versus pump speed relationship must be verified.

3/4.4.1 RECIRCULATION SYSTEM (continued)

Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system. Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data.

Recirculation pump speed mismatch limits are in compliance with the ECCS LOCA analysis design criteria for two recirculation loop operation. The limits will ensure an adequate core flow coastdown from either recirculation loop following a LOCA. In the case where the mismatch limits cannot be maintained during two loop operation, continued operation is permitted in a single recirculation loop mode.

In order to prevent undue stress on the vessel nozzles and bottom head region, the recirculation loop temperatures shall be within 50°F of each other prior to startup of an idle loop. The loop temperature must also be within 50°F of the reactor pressure vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles. Sudden equalization of a temperature difference > 145°F between the reactor vessel bottom head coolant and the coolant in the upper region of the reactor vessel by increasing core flow rate would cause undue stress in the reactor vessel bottom head.

3/4.4.2 SAFETY/RELIEF VALVES

The safety valve function of the safety/relief valves operates to prevent the reactor coolant system from being pressurized above the Safety Limit of 1325 psig in accordance with the ASME Code. A total of 12 OPERABLE safety/relief valves is required to limit reactor pressure to within ASME III allowable values for the worst case upset transient.

Demonstration of the safety/relief valve lift settings will occur only during shutdown. The safety/relief valves will be removed and either set pressure tested or replaced with spares which have been previously set pressure tested and stored in accordance with manufacturers recommendations at the frequency specified in the Surveillance Frequency Control Program.

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.3.1 LEAKAGE DETECTION SYSTEMS

BACKGROUND

UFSAR Safety Design Basis (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of Reactor Coolant System (RCS) PRESSURE BOUNDARY LEAKAGE. Regulatory Guide 1.45, Revision 0, (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Limits on leakage from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of leakage rates. In addition to meeting the OPERABILITY requirements, the monitors are typically set to provide the most sensitive response without causing an excessive number of spurious alarms.

Systems for quantifying the leakage are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action. Leakage from the RCPB inside the drywell is detected by at least one of four (4) independently monitored variables which include drywell sump flow monitoring equipment with the required RCS leakage detection instrumentation (i.e., the drywell floor drain sump flow monitoring system, or, the drywell equipment drain sump monitoring system with the drywell floor drain sump overflowing to the drywell equipment drain sump), drywell gaseous radioactivity, drywell unit cooler condensate flow rate and drywell pressure/temperature levels. The primary means of quantifying leakage in the drywell is the drywell sump monitoring system for UNIDENTIFIED LEAKAGE and the drywell equipment drain tank flow monitoring system for IDENTIFIED LEAKAGE. IDENTIFIED leakage is not germane to this Tech Spec and the associated drywell equipment drain tank flow monitoring system is not included.

The drywell floor drain sump flow monitoring system monitors UNIDENTIFIED LEAKAGE collected in the floor drain sump. UNIDENTIFIED LEAKAGE consists of leakage from RCPB components inside the drywell which are not normally subject to leakage and otherwise routed to the drywell equipment drain sump. The primary containment floor drain sump has transmitters that supply level indication to the main control room via the plant monitoring system. The floor drain sump level transmitters are associated with High/Low level switches that open/close the sump tank drain valves automatically. The level instrument processing unit calculates an average leak rate (gpm) for a given measurement period which resets whenever the sump drain valve closes. The level processing unit provides an alarm to the main control room each time the average leak rate changes by a predetermined value since the last time the alarm was reset. For the drywell floor drain sump flow monitoring system, the setpoint basis is a 1 gpm change in UNIDENTIFIED LEAKAGE.

An alternate to the drywell floor drain sump flow monitoring system for quantifying UNIDENTIFIED LEAKAGE is the drywell equipment drain sump monitoring system, if the drywell floor drain sump is overflowing to the drywell equipment drain sump. In this configuration, the drywell equipment drain sump collects all leakage into the drywell equipment drain sump and the overflow from the drywell floor drain sump. Therefore, if the drywell floor drain sump is overflowing to the drywell equipment drain sump, the drywell equipment drain sump monitoring system can be used to quantify UNIDENTIFIED LEAKAGE. In this condition, all leakage measured by the drywell equipment drain sump monitoring system is assumed to be UNIDENTIFIED LEAKAGE. The leakage determination process, including the transition to and use of the alternate method is described in station procedures. The alternate method would only be used when the drywell floor drain sump flow monitoring system is unavailable.

In addition to the drywell sump monitoring system described above, the discharge of each sump is monitored by an independent flow element. The measured flow rate from the flow element is integrated and recorded. A main control room alarm is also provided to indicate an excessive sump discharge rate measured via the flow element. This system, referred to as the “drywell floor drain flow totalizer”, is not credited for drywell floor drain sump flow monitoring system operability.

BACKGROUND (Continued)

The primary containment atmospheric gaseous radioactivity monitoring system continuously monitors the primary containment atmosphere for gaseous radioactivity levels. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water leakage, is annunciated in the main control room.

Condensate from the eight drywell air coolers is routed to the drywell floor drain sump and is monitored by a series of flow transmitters that provide indication and alarms in the main control room. The outputs from the flow transmitters are added together by summing units to provide a total continuous condensate drain flow rate. The high flow alarm setpoint is based on condensate drain flow rate in excess of 1 gpm over the currently identified preset leak rate. The drywell air cooler condensate flow rate monitoring system serves as an added indicator, but not quantifier, of RCS UNIDENTIFIED LEAKAGE (Ref. 4).

The drywell temperature and pressure monitoring systems provide an indirect method for detecting RCPB leakage. A temperature and/or pressure rise in the drywell above normal levels may be indicative of a reactor coolant or steam leakage (Ref. 5).

APPLICABLE SAFETY ANALYSES

A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. Leakage rate limits are set low enough to detect the leakage emitted from a single crack in the RCPB (Refs. 6 and 7).

A control room alarm allows the operators to evaluate the significance of the indicated leakage and, if necessary, shut down the reactor for further investigation and corrective action. The allowed leakage rates are well below the rates predicted for critical crack sizes (Ref. 7). Therefore, these actions provide adequate responses before a significant break in the RCPB can occur.

RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement.

LIMITING CONDITION FOR OPERATION (LCO)

This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide confidence that small amounts of UNIDENTIFIED LEAKAGE are detected in time to allow actions to place the plant in a safe condition, when RCS leakage indicates possible RCPB degradation.

The LCO requires four instruments to be OPERABLE.

The required instrumentation to quantify UNIDENTIFIED LEAKAGE from the RCS consists of either the drywell floor drain sump flow monitoring system, or, the drywell equipment drain sump monitoring system with the drywell floor drain sump overflowing to the drywell equipment drain sump. For either system to be considered operable, the flow monitoring portion of the system must be operable. The identification of an increase in UNIDENTIFIED LEAKAGE will be delayed by the time required for the UNIDENTIFIED LEAKAGE to travel to the drywell floor drain sump and it may take longer than one hour to detect a 1 gpm increase in UNIDENTIFIED LEAKAGE, depending on the origin and magnitude of the leakage. This sensitivity is acceptable for containment sump monitor OPERABILITY.

The reactor coolant contains radioactivity that, when released to the primary containment, can be detected by the gaseous primary containment atmospheric radioactivity monitor. A radioactivity detection system is included for monitoring gaseous activities because of its sensitivity and rapid response to RCS leakage, but it has recognized limitations. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. If there are few fuel element cladding defects and low levels of activation products, it may not be possible for the gaseous primary

LIMITING CONDITION FOR OPERATION (LCO) (Continued)

containment atmospheric radioactivity monitor to detect a 1 gpm increase within 1 hour during normal operation. However, the gaseous primary containment atmospheric radioactivity monitor is OPERABLE when it is capable of detecting a 1 gpm increase in UNIDENTIFIED LEAKAGE within 1 hour given an RCS activity equivalent to that assumed in the design calculations for the monitors (Reference 9).

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the drywell floor drain sump monitoring system in combination with a gaseous primary containment atmospheric radioactivity monitor, a primary containment air cooler condensate flow rate monitoring system, and a primary containment pressure and temperature monitoring system provides an acceptable minimum.

APPLICABILITY

In OPERATIONAL CONDITIONS 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.3.2. This applicability is consistent with that for LCO 3.4.3.2.

ACTIONS

A. With the primary containment atmosphere gaseous monitoring system inoperable, grab samples of the primary containment atmosphere must be taken and analyzed to provide periodic leakage information. [Provided a sample is obtained and analyzed once every 12 hours, the plant may be operated for up to 30 days to allow restoration of the radioactivity monitoring system. The plant may continue operation since other forms of drywell leakage detection are available.]

   The 12 hour interval provides periodic information that is adequate to detect leakage. The 30 day Completion Time for Restoration recognizes other forms of leakage detection are available.

B. With required drywell sump monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage at the required 1 gpm/hour sensitivity. However, the primary containment atmospheric gaseous monitor [and the primary containment air cooler condensate flow rate monitor] will provide indication of changes in leakage.

   With required drywell sump monitoring system inoperable, drywell condensate flow rate monitoring frequency increased from 12 to every 8 hours, and UNIDENTIFIED LEAKAGE and total leakage being determined every 8 hours (Ref. SR 4.4.3.2.1.b) operation may continue for 30 days. To the extent practical, the surveillance frequency change associated with the drywell condensate flow rate monitoring system, makes up for the loss of the drywell floor drain monitoring system which had a normal surveillance requirement to monitor leakage every 8 hours. Also note that in this instance, the drywell floor drain tank flow totalizer will be used to comply with SR 4.4.3.2.1.b. The 30 day Completion Time of the required ACTION is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available.

C. With the required primary containment air cooler condensate flow rate monitoring system inoperable, SR 4.4.3.1.a must be performed every 8 hours to provide periodic information of activity in the primary containment of more frequent interval than the routine frequency of every 12 hours. The 8 hour interval provides periodic information that is adequate to detect leakage and recognizes that other forms of leakage detection are available. The required ACTION has been clarified to state

ACTIONS (Continued)

that the additional surveillance requirement is not applicable if the required primary containment atmosphere gaseous radioactivity monitoring system is also inoperable. Consistent with SR 4.0.3, surveillances are not required to be performed on inoperable equipment. In this case, ACTION Statement A. and E. requirements apply.

D. With the primary containment pressure and temperature monitoring system inoperable, operation may continue for up to 30 days given the system's indirect capability to detect RCS leakage. However, other more limiting Tech Spec requirements associated with the primary containment pressure/temperature monitoring system will still apply.

E. With both the primary containment atmosphere gaseous radioactivity monitor and the primary containment air cooler condensate flow rate monitor inoperable, the only means of detecting leakage is the drywell floor drain sump monitor and the drywell pressure/temperature instrumentation. This condition does not provide the required diverse means of leakage detection. The required ACTION is to restore either of the inoperable monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period. While the primary containment atmosphere gaseous radioactivity monitor is INOPERABLE, primary containment atmospheric grab samples will be taken and analyzed every 12 hours since ACTION Statement A. requirements also apply.

F. With the drywell floor drain sump monitoring system inoperable and the drywell unit coolers condensate flow rate monitoring system inoperable, one of the two remaining means of detecting leakage is the primary containment atmospheric gaseous radiation monitor. The primary containment atmospheric gaseous radiation monitor typically cannot detect a 1 gpm leak within one hour when RCS activity is low. Indirect methods of monitoring RCS leakage must be implemented. Grab samples of the primary containment atmosphere must be taken and analyzed and monitoring of RCS leakage by administrative means must be performed every 12 hours to provide alternate periodic information.

Administrative means of monitoring RCS leakage include monitoring and trending parameters that may indicate an increase in RCS leakage. There are diverse alternative mechanisms from which appropriate indicators may be selected based on plant conditions. It is not necessary to utilize all of these methods, but a method or methods should be selected considering the current plant conditions and historical or expected sources of UNIDENTIFIED LEAKAGE. The administrative methods are the drywell cooling fan inlet/outlet temperatures, drywell equipment drain sump temperature indicator, drywell equipment drain tank hi temperature indicator, and drywell equipment drain tank flow indicator. These indications, coupled with the atmospheric grab samples, are sufficient to alert the operating staff to an unexpected increase in UNIDENTIFIED LEAKAGE.

In addition to the primary containment atmospheric gaseous radiation monitor and indirect methods of monitoring RCS leakage, the primary containment pressure and temperature monitoring system is also available to alert the operating staff to an unexpected increase in UNIDENTIFIED LEAKAGE.

ACTIONS (Continued)

The 12 hour interval is sufficient to detect increasing RCS leakage. The Required Action provides 7 days to restore another RCS leakage monitor to OPERABLE status to regain the intended leakage detection diversity. The 7-day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

G. If any required ACTION of Conditions A, B, C, D, E or F cannot be met within the associated Completion Time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least HOT SHUTDOWN within 12 hours and COLD SHUTDOWN within the next 24 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the ACTIONS in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 4.4.3.1.a
This SR is for the performance of a CHANNEL CHECK of the required primary containment atmospheric monitoring system. The check gives reasonable confidence that the channel is operating properly.

SR 4.4.3.1.b
This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

SR 4.4.3.1.c
The SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment.

SR 4.4.3.1.d
This SR provides a routine check of primary containment pressure and temperature for indirect evidence of RCS leakage.

REFERENCES

1. LGS UFSAR, Section 5.2.5.1.
2. Regulatory Guide 1.45, Revision 0, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.
3. LGS UFSAR, Section 5.2.5.2.1.3.
4. LGS UFSAR, Section 5.2.5.2.1.4.
5. LGS UFSAR, Section 5.2.5.2.1.1(2).
6. GEAP-5620, April 1968
7. NUREG-75/067, October 1975.
8. LGS UFSAR, Section 5.2.5.6.
9. LGS UFSAR, Section 5.2.5.2.1.5

3/4.4.3.2 OPERATIONAL LEAKAGE

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The normally expected background leakage due to equipment design and the detection capability of the instrumentation for determining system leakage was also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for UNIDENTIFIED LEAKAGE the probability is small that the imperfection or crack associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the values specified, the reactor will be shutdown to allow further investigation and corrective action. The limit of 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period and the monitoring of drywell floor drain sump and drywell equipment drain tank flow rate at least once every eight (8) hours conforms with NRC staff positions specified in NRC Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," as revised by NRC Safety Evaluation dated March 6, 1990. The ACTION requirement for the 2 gpm increase in UNIDENTIFIED LEAKAGE limit ensures that such leakage is identified or a plant shutdown is initiated to allow further investigation and corrective action. Separating the sources of LEAKAGE (i.e., LEAKAGE from an identified source versus LEAKAGE from an unidentified source) is necessary for prompt identification of potentially adverse conditions, assessment of the safety significance, and corrective action. Once identified, reactor operation may continue dependent upon the impact on total leakage.

PRESSURE BOUNDARY LEAKAGE is prohibited as the leak itself could cause further reactor coolant pressure boundary deterioration, resulting in higher leakage. If PRESSURE BOUNDARY LEAKAGE exists, the affected component, pipe, or vessel must be isolated from the reactor coolant system by a closed manual valve, closed and de-activated automatic valve, blind flange, or check valve within 4 hours. While in this condition, structural integrity of the system should be considered because the structural integrity of the part of the system within the isolation boundary must be maintained under all licensing basis conditions, including consideration of the potential for further degradation of the isolated location. Normal leakage past the isolation device is acceptable as it will limit reactor coolant system leakage and is included in IDENTIFIED LEAKAGE or UNIDENTIFIED LEAKAGE. This ACTION is necessary to prevent further deterioration of the reactor coolant pressure boundary. If the ACTION cannot be completed in the required time, then the reactor will be shutdown to allow further investigation and corrective action.

The function of Reactor Coolant System Pressure Isolation Valves (PIVs) is to separate the high pressure Reactor Coolant System from an attached low pressure system. The ACTION requirements for pressure isolation valves are used in conjunction with the system specifications for which PIVs are listed in the Technical Requirements Manual and with primary containment isolation valve requirements to ensure that plant operation is appropriately limited.

The Surveillance Requirements for the RCS pressure isolation valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS pressure isolation valves is not included in any other allowable operational leakage specified in Section 3.4.3.2.

3/4.4.4 (Deleted) INFORMATION FROM THIS SECTION RELOCATED TO THE TRM

3/4.4.4 (Deleted) INFORMATION FROM THIS SECTION RELOCATED TO THE TRM

3/4.4.5 SPECIFIC ACTIVITY

The limitations on the specific activity of the primary coolant ensure that the 2 hour thyroid and whole body doses resulting from a main steam line failure outside the containment during steady state operation will not exceed small fractions of the dose guidelines of 10 CFR Part 100. The values for the limits on specific activity represent interim limits based upon a parametric evaluation by the NRC of typical site locations. These values are conservative in that specific site parameters, such as SITE BOUNDARY location and meteorological conditions, were not considered in this evaluation.

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the primary coolant's specific activity greater than 0.2 microcurie per gram DOSE EQUIVALENT I-131, but less than or equal to 4 microcuries per gram DOSE EQUIVALENT I-131, accommodates possible iodine spiking phenomenon which may occur following changes in the THERMAL POWER. This action is modified by a Note that permits the use of the provisions of Specification 3.0.4.c. This allowance permits entry into the applicable OPERATIONAL CONDITION (S) while relying on the ACTION requirements. Operation with specific activity levels exceeding 0.2 microcurie per gram DOSE EQUIVALENT I-131 but less than or equal to 4 microcuries per gram DOSE EQUIVALENT I-131 must be restricted since these activity levels increase the 2-hour thyroid dose at the SITE BOUNDARY following a postulated steam line rupture.

Closing the main steam line isolation valves prevents the release of activity to the environs should a steam line rupture occur outside containment. The surveillance requirements provide adequate assurance that excessive specific activity levels in the reactor coolant will be detected in sufficient time to take corrective action.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

All components in the reactor coolant system are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are introduced by normal load transients, reactor trips, and startup and shutdown operations. The various categories of load cycles used for design purposes are provided in Section 3.9 of the FSAR. During startup and shutdown, the rates of temperature and pressure changes are limited so that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation.

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PRESSURE/TEMPERATURE LIMITS (Continued)

The operating limit curves specified in the PTLR are derived from the fracture toughness requirements of 10 CFR 50 Appendix G and ASME Code Section XI, Appendix G. The curves are based on the RT_{NDT} and stress intensity factor information for the reactor vessel components. Fracture toughness limits and the basis for compliance are more fully discussed in FSAR Chapter 5, Paragraph 5.3.1.5, "Fracture Toughness."

The reactor vessel materials have been tested to determine their initial RT_{NDT}. The results of these tests are specified in the PTLR. Reactor operation and resultant fast neutron, E greater than 1 MeV, irradiation will cause an increase in the RT_{NDT}. Therefore, an adjusted reference temperature, based upon the fluence, nickel content and copper content of the material in question, can be predicted using the PTLR and the recommendations of Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials." The pressure/temperature limit curves specified in the PTLR include an assumed shift in RT_{NDT} for the conditions at 57 EFPY.

The pressure-temperature limit lines specified in the PTLR for reactor criticality and for inservice leak and hydrostatic testing have been provided to assure compliance with the minimum temperature requirements of Appendix G to 10 CFR Part 50 for reactor criticality and for inservice leak and hydrostatic testing.

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

Double isolation valves are provided on each of the main steam lines to minimize the potential leakage paths from the containment in case of a line break. Only one valve in each line is required to maintain the integrity of the containment, however, single failure considerations require that two valves be OPERABLE. The surveillance requirements are based on the operating history of this type valve. The maximum closure time has been selected to contain fission products and to ensure the core is not uncovered following line breaks. The minimum closure time is consistent with the assumptions in the safety analyses to prevent pressure surges.

3/4.4.8 (DELETED)

3/4.4.9 RESIDUAL HEAT REMOVAL

The RHR system is required to remove decay heat and sensible heat in order to maintain the temperature of the reactor coolant. RHR shutdown cooling is comprised of four (4) subsystems which make two (2) loops. Each loop consists of two (2) motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Two (2) redundant, manually controlled shutdown cooling subsystems of the RHR System can provide the required decay heat removal capability. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via the associated recirculation loop or to the reactor via the low pressure coolant injection pathway. The RHR heat exchangers transfer heat to the RHR Service Water System. The RHR shutdown cooling mode is manually controlled.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. In HOT SHUTDOWN condition, the requirement to maintain OPERABLE two (2) independent RHR shutdown cooling subsystems means that each subsystem considered OPERABLE must be associated with a different heat exhanger loop, i.e., the "A" RHR heat exchanger with the "A" RHR pump or the "C" RHR pump, and the "B" RHR heat exchanger with the "B" RHR pump or the "D" RHR pump are two (2) independent RHR shutdown cooling subsystems. Only one (1) of the two (2) RHR pumps associated with each RHR heat exchanger loop is

3/4.4.9 RESIDUAL HEAT REMOVAL (Continued)

required to be OPERABLE for that independent subsystem to be OPERABLE. During COLD SHUTDOWN and REFUELING conditions, however, the subsystems not only have a common suction source, but are allowed to have a common heat exchanger and common discharge piping. To meet the LCO of two (2) OPERABLE subsystems, both pumps in one (1) loop or one (1) pump in each of the two (2) loops must be OPERABLE. Since the piping and heat exchangers are passive components, that are assumed not to fail, they are allowed to be common to both subsystems. Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one (1) subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. Management of gas voids is important to RHR Shutdown Cooling System OPERABILITY.

Alternate decay heat removal methods are available to operators. These alternate methods of decay heat removal can be verified available either by calculation (which includes a review of component and system availability to verify that an alternate decay heat removal method is available) or by demonstration, and that a method of coolant mixing be operational. Decay heat removal capability by ambient losses can be considered in evaluating alternate decay heat removal capability.

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of non-condensable gas into the reactor vessel. This surveillance verifies that the RHR Shutdown Cooling System piping is sufficiently filled with water prior to initially placing the system in operation during reactor shutdown. The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water to ensure that it can reliably perform its intended function.

The RHR Shutdown Cooling System is a manually initiated mode of the RHR System whose use is typically preceded by system piping flushes that disturb both the RHR pump suction and discharge piping. RHR Shutdown Cooling System is flushed and manually aligned for service using system operating procedures that ensure the RHR shutdown cooling suction and discharge flow paths are sufficiently filled with water. In the event that RHR Shutdown Cooling is required for emergency service, the system operating procedures that align and start the RHR System in shutdown cooling mode include the flexibility to eliminate piping flushes while maintaining minimum requirements to ensure that the suction and discharge flow paths are sufficiently filled with water. The RHR Shutdown Cooling System surveillance is met through the performance of the operating procedures that initially place the RHR shutdown cooling sub-system in service.

This surveillance requirement is modified by a Note allowing sufficient time (12 hours) to align the RHR System for Shutdown Cooling operation after reactor dome pressure is less than the RHR cut-in permissive set point.

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3/4.5.1 ECCS - OPERATING

The core spray system (CSS), together with the LPCI mode of the RHR system, is provided to assure that the core is adequately cooled following a loss-of-coolant accident and provides adequate core cooling capacity for all break sizes up to and including the double-ended reactor recirculation line break, and for smaller breaks following depressurization by the ADS. Management of gas voids is important to ECCS injection/spray subsystem OPERABILITY.

The CSS is a primary source of emergency core cooling after the reactor vessel is depressurized and a source for flooding of the core in case of accidental draining.

The surveillance requirements provide adequate assurance that the CSS will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown.

The low pressure coolant injection (LPCI) mode of the RHR system is provided to assure that the core is adequately cooled following a loss-of-coolant accident. Four subsystems, each with one pump, provide adequate core flooding for all break sizes up to and including the double-ended reactor recirculation line break, and for small breaks following depressurization by the ADS.

The surveillance requirements provide adequate assurance that the LPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown.

The CCS pump flow of 3,175 gpm and the LPCI pump flow of 10,000 gpm are flow values at nominal grid frequency of 60 Hz. The 10 CFR 50.46 LOCA Analysis of Record (AOR) uses 80% of the prescribed TS SR flow values (2,500 and 8,000 respectively). The calculated TS SR flow rates at the reduced Emergency Diesel Generator minimum steady-state voltage of 4,160 V and 59.8 Hz, when off site power is not available, demonstrate that the ECCS flow rates used in the LOCA analysis are bounding and satisfy SRs 4.5.1.b.1 and 4.5.1.b.2.

The high pressure coolant injection (HPCI) system is provided to assure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the reactor coolant system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCI system permits the reactor to be shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. The HCPI system continues to operate until reactor vessel pressure is below the pressure at which CSS operation or LPCI mode of the RHR system operation maintains core cooling.

The capacity of the system is selected to provide the required core cooling. The HPCI pump is designed to deliver greater than or equal to 5600 gpm at reactor pressures between 1182 and 200 psig and is capable of delivering at least 5000 gpm between 1182 and 1205 psig. In the system's normal alignment, water from the condensate storage tank is used instead of injecting water from the suppression pool into the reactor, but no credit is taken in the safety analyses for the condensate storage tank water.

ECCS - OPERATING (Continued)

With the HPCI system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the CS and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor low water level condition. The HPCI out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems and the RCIC system. The HPCI system, and one LPCI subsystem, and/or one CSS subsystem out-of-service period of 8 hours ensures that sufficient ECCS, comprised of a minimum of one CSS subsystem, three LPCI subsystems, and all of the ADS will be available to 1) provide for safe shutdown of the facility, and 2) mitigate and control accident conditions within the facility. Alternatively, the out-of-service times described above can be determined in accordance with the Risk Informed Completion Time Program. A Note prohibits the application of Specification 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that the HPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor shutdown.

During plant startup, when HPCI surveillance tests are being performed, the HPCI System is required to be tested within 12 hours after reactor pressure is adequate to perform each surveillance test. For the low reactor pressure surveillance requirement, the intent is to verify HPCI System operability prior to increasing reactor pressure above 215 psig. If operability of the HPCI System is not demonstrated within the 12-hour period, reactor steam dome pressure must be reduced to less than 200 psig within the following 72 hours. For the high reactor pressure surveillance test, the intent is to verify HPCI System operability as soon as possible once plant conditions support the testing. Power ascension can continue during the testing; however, if HPCI is found inoperable or the 12-hour period has elapsed power ascension must be stopped, and reactor steam dome pressure must be reduced to less than 200 psig within the following 72 hours.

The ECCS injection/spray subsystem flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the ECCS injection/spray subsystems and may also prevent a water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of ECCS injection/spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The ECCS injection/spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits. ECCS injection/spray

ECCS - OPERATING (Continued)

subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

Surveillance 4.5.1.a.1.b is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

Upon failure of the HPCI system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety/relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 100 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring ADS.

SR 4.5.1.c.1 excludes automatic dampers and valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to dampers or valves that are locked, sealed, or otherwise secured in the actuated position since the affected dampers or valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve or damper in a locked, sealed, or otherwise secured position requires an assessment of the operability of the system or any supported systems, including whether it is necessary for the valve or damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve or damper to the non-actuated position requires verification that the SR has been met within its required Frequency.

ADS automatically controls five selected safety-relief valves. The safety analysis assumes all five are operable. The allowed out-of-service time for one valve for up to fourteen days is determined in a similar manner to other ECCS subsystem out-of-service time allowances. Alternatively, the allowed out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

Verification that ADS accumulator gas supply header pressure is ≥90 psig ensures adequate gas pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator at least two valve actuations can occur with the drywell at 70% of design pressure. The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of ≥90 psig is provided by the PCIG supply.

3/4.5.2 - REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC)

Background:

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

Applicable Safety Analysis:

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material to the environment should an unexpected draining event occur.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in OPERATIONAL CONDITIONS 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered in which an initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure (an event that creates a drain path through multiple vessel penetrations located below top of active fuel, such as loss of normal power, or a single human error). It is assumed, based on engineering judgement, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Limiting Condition for Operation:

The RPV water level must be controlled in OPERATIONAL CONDITIONS 4 and 5 to ensure that if an unexpected draining event should occur, the reactor coolant water level remains above the top of the active irradiated fuel as required by Safety Limit 2.1.4.

The Limiting Condition for Operation (LCO) requires the DRAIN TIME of RPV water inventory to the TAF to be $\geq$ 36 hours. A DRAIN TIME of 36 hours is considered reasonable to identify and initiate action to mitigate unexpected draining of reactor coolant. An event that could cause loss of RPV water inventory and result in the RPV water level reaching the TAF in greater than 36 hours does not represent a significant challenge to Safety Limit 2.1.4 and can be managed as part of normal plant operation.

One low pressure ECCS injection/spray subsystem is required to be OPERABLE and capable of being manually aligned and started from the control room to provide defense-in-depth should an unexpected draining event occur. OPERABILITY of the ECCS injection/spray subsystem includes any necessary valves, instrumentation, or controls needed to manually align and start the subsystem from the control room. A low pressure ECCS injection/spray subsystem consists of either one Core Spray System (CSS) subsystem or one Low Pressure Coolant Injection (LPCI) subsystem. Each CSS subsystem consists of two motor driven pumps, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the RPV. Each LPCI subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV.

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The LCO is modified by a note which allows a required LPCI subsystem to be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. This allowance is necessary since the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Because of the restrictions on DRAIN TIME, sufficient time will be available following an unexpected draining event to manually align and initiate LPCI subsystem operation to maintain RPV water inventory prior to the RPV water level reaching the TAF.

Applicability:

RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5. Requirements on water inventory control are contained in LCO 3.3.3.A, REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION, and LCO 3.5.2, REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC). RPV water inventory control is required to protect Safety Limit 2.1.4 which is applicable whenever irradiated fuel is in the reactor vessel.

Actions:

Action a. - If none of the required low pressure ECCS injection/spray subsystems are OPERABLE, one subsystem must be restored to OPERABLE status within 4 hours. In this condition, the LCO controls on DRAIN TIME minimize the possibility that an unexpected draining event could necessitate the use of the ECCS injection/spray subsystem; however, the defense-in-depth provided by the ECCS injection/spray subsystem is lost. The 4-hour allowed outage time for restoring the required low pressure ECCS injection/spray subsystem to OPERABLE status is based on engineering judgment that considers the LCO controls on DRAIN TIME and the low probability of an unexpected draining event that would result in loss of RPV water inventory.

If the inoperable ECCS injection/spray subsystem is not restored to OPERABLE status within 4 hours, action must be initiated immediately to establish a method of water injection capable of operating without offsite electrical power. The method of water injection includes the necessary instrumentation and controls, water sources, and pumps and valves needed to add water to the RPV or refueling cavity should an unexpected draining event occur. The method of water injection may be manually initiated and may consist of one or more systems or subsystems, and must be able to access water inventory capable of maintaining the RPV water level above the TAF for $\geq$ 36 hours. If recirculation of injected water would occur, it may be credited in determining the necessary water volume.

Action b. - Deleted

Action c. - With the DRAIN TIME less than 36 hours but greater than or equal to 8 hours, compensatory measures should be taken to ensure the ability to implement mitigating actions should an unexpected draining event occur. Should a draining event lower the reactor coolant level to below the TAF, there is potential for damage to the reactor fuel cladding and release of radioactive material. Additional actions are taken to ensure that radioactive material will be contained, diluted, and processed prior to being released to the environment.

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The secondary containment provides a controlled volume in which fission products can be contained, diluted, and processed prior to release to the environment. Verification of the capability to establish SECONDARY CONTAINMENT INTEGRITY in less than the DRAIN TIME is required. The required verification confirms actions to establish SECONDARY CONTAINMENT INTEGRITY are preplanned and necessary materials are available. SECONDARY CONTAINMENT INTEGRITY is considered established when one Standby Gas Treatment (SGT) subsystem is capable of maintaining a negative pressure in the secondary containment with respect to the environment. Verification that SECONDARY CONTAINMENT INTEGRITY can be established must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

Secondary containment penetration flow paths form a part of SECONDARY CONTAINMENT INTEGRITY. Verification of the capability to isolate each secondary containment penetration flow path in less than the DRAIN TIME is required. The required verification confirms actions to isolate secondary containment penetration flow paths are preplanned and necessary materials are available. Power operated valves are not required to receive automatic isolation signals if they can be closed manually within the required time. Verification that secondary containment penetration flow paths can be isolated must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

One SGT subsystem is capable of maintaining the secondary containment at a negative pressure with respect to the environment and filter gaseous releases. Verification of the capability to place one SGT subsystem in operation in less than the DRAIN TIME is required. The required verification confirms actions to place a SGT subsystem in operation are preplanned and necessary materials are available. Verification that a SGT subsystem can be placed in operation must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

Action d. - With the DRAIN TIME less than 8 hours, mitigating actions are implemented in case an unexpected draining event should occur. Note that if the DRAIN TIME is less than 1 hour, the required Action e. to restore DRAIN TIME to 36 hours or greater is also applicable.

Immediate action to establish an additional method of water injection augmenting the ECCS injection/spray subsystem required by the LCO is required. The additional method of water injection includes the necessary instrumentation and controls, water sources, and pumps and valves needed to add water to the RPV or refueling cavity should an unexpected draining event occur. The note states that either the ECCS injection/spray subsystem or the additional method of water injection must be capable of operating without offsite electrical power. The additional method of water injection may be manually initiated and may consist of one or more systems or subsystems. The additional method of water injection must be able to access water inventory capable of being injected to maintain the RPV water level above the TAF for $\geq$ 36 hours. The additional method of water injection and the ECCS injection/spray subsystem may share all or part of the same water sources. If recirculation of injected water would occur, it may be credited in determining the required water volume.

Should a draining event lower the reactor coolant level to below the TAF, there is potential for damage to the reactor fuel cladding and release of radioactive material. Additional actions are taken to ensure that radioactive material will be contained, diluted, and processed prior to being released to the environment.

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The secondary containment provides a control volume into which fission products can be contained, diluted, and processed prior to release to the environment. Actions to immediately establish SECONDARY CONTAINMENT INTEGRITY are required. With SECONDARY CONTAINMENT INTEGRITY established, one SGT subsystem is capable of maintaining a negative pressure in the secondary containment with respect to the environment.

The secondary containment penetrations form a part of SECONDARY CONTAINMENT INTEGRITY. Actions to immediately verify that each secondary containment penetration flow path is isolated or to verify that it can be automatically or manually isolated from the control room are required.

One SGT subsystem is capable of maintaining the secondary containment at a negative pressure with respect to the environment and filter gaseous releases. Actions to immediately verify that at least one SGT subsystem is capable of being placed in operation are required. The required verification is an administrative activity and does not require manipulation or testing of equipment.

Action e. - If the ACTIONs and associated allowed outage times are not met or if the DRAIN TIME is less than 1 hour, actions must be initiated immediately to restore the DRAIN TIME to ≥ 36 hours. In this condition, there may be insufficient time to respond to an unexpected draining event to prevent the RPV water inventory from reaching the TAF. Note that ACTIONs are also applicable when DRAIN TIME is less than 1 hour.

Surveillance Requirements:

Surveillance Requirement (SR) 4.5.2.1 verifies that the DRAIN TIME of RPV water inventory to the TAF is ≥ 36 hours. The period of 36 hours is considered reasonable to identify and initiate action to mitigate draining of reactor coolant. Loss of RPV water inventory that would result in the RPV water level reaching the TAF in greater than 36 hours does not represent a significant challenge to Safety Limit 2.1.4 and can be managed as part of normal plant operation.

The definition of DRAIN TIME states that realistic cross-sectional areas and drain rates are used in the calculation. A realistic drain rate may be determined using a single, step-wise, or integrated calculation considering the changing RPV water level during a draining event. For a control rod RPV penetration flow path with the control rod drive mechanism removed and not replaced with a blank flange, the realistic cross-sectional area is based on the control rod blade seated in the control rod guide tube. If the control rod blade will be raised from the penetration to adjust or verify seating of the blade, the exposed cross-sectional area of the RPV penetration flow path is used.

The definition of DRAIN TIME excludes from the calculation those penetration flow paths connected to an intact closed system, or isolated by manual or automatic valves that are closed and administratively controlled, blank flanges, or other devices that prevent flow of reactor coolant through the penetration flow paths. A blank flange or other bolted device must be connected with a sufficient number of bolts to prevent draining. Normal or expected leakage from closed systems or past isolation devices is permitted. Determination that a system is intact and closed or isolated must consider the status of branch lines.

The Residual Heat Removal (RHR) Shutdown Cooling System is only considered an intact closed system when misalignment issues (Reference 6) have been precluded by functional valve interlocks or by isolation devices, such that redirection of RPV water out of an RHR subsystem is precluded. Further, the RHR Shutdown Cooling System is only considered an intact closed system if its controls have not been transferred to Remote Shutdown, which disables the interlocks and isolation signals.

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The exclusion of a single penetration flow path, or multiple penetration flow paths susceptible to a common mode failure, from the determination of DRAIN TIME should consider the effects of temporary alterations in support of maintenance (rigging, scaffolding, temporary shielding, piping plugs, freeze seals, etc.). If reasonable controls are implemented to prevent such temporary alterations from causing a draining event from a closed system or between the RPV and the isolation device, the effect of the temporary alterations on DRAIN TIME need not be considered. Reasonable controls include, but are not limited to, controls consistent with the guidance in NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 4, NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," or commitments to NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants."

TS 4.0.1 requires SRs to be met between performances. Therefore, any changes in plant conditions that would change the DRAIN TIME requires that a new DRAIN TIME be determined.

SRs 4.5.2.2 and 4.5.2.3 - The minimum water level of 16 feet required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the CSS subsystem or LPCI subsystem pumps, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, the required ECCS injection/spray subsystem is inoperable unless aligned to an OPERABLE CST.

The required CSS subsystem is OPERABLE if it can take suction from the CST, and the CST water level is sufficient to provide the required NPSH for the CSS pumps. Therefore, a verification that either the suppression pool water level is greater than or equal to 16 feet 0 inches or that a CSS subsystem is aligned to take suction from the CST and the CST contains greater than or equal to 135,000 available gallons of water, equivalent to a level of 29 feet 0 inches, ensures that the CSS subsystem can supply the required makeup water to the RPV.

SR 4.5.2.4 - The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the required ECCS injection/spray subsystems full of water ensures that the ECCS subsystem will perform properly. This may also prevent a water hammer following an ECCS actuation. One acceptable method of ensuring that the lines are full is to vent at the high points.

SR 4.5.2.5 - DELETED

SR 4.5.2.6 - Verifying that the required ECCS injection/spray subsystem can be manually aligned, and the pump started and operate for at least 10 minutes demonstrates that the subsystem is available to mitigate a draining event. This surveillance requirement is modified by two footnotes. The first states that testing the ECCS injection/spray subsystem may be done through the test return line to avoid overfilling the refueling cavity. The second states that credit for meeting the surveillance requirement may be taken for normal system operation that satisfies the surveillance requirement, such as using the RHR mode of LPCI for greater than or equal to 10 minutes. The minimum operating time of 10 minutes was based on engineering judgement.

SR 4.5.2.7 and 4.5.2.8 exclude automatic dampers and valves that are locked, sealed, or otherwise secured in the actuated position. The SRs do not apply to dampers or valves that are locked, sealed, or otherwise secured in the actuated position since the affected dampers or valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve or damper in a locked, sealed, or otherwise secured position requires an assessment of the operability of the system or any supported systems, including whether it is necessary for the valve or damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve or damper to the non-actuated position requires verification that the applicable SR has been met within its required Frequency.

SR 4.5.2.7 - Verifying that each valve credited for automatically isolating a penetration flow path actuates to the isolation position on an actual or simulated RPV water level isolation signal is required to prevent RPV water inventory from dropping below the TAF should an unexpected draining event occur.

RPV WATER INVENTORY CONTROL (WIC) (Continued)

SR 4.5.2.8 - This surveillance verifies that a required CSS subsystem or LPCI subsystem can be manually aligned and started from the control room, including any necessary valve alignment, instrumentation, or controls, to transfer water from the suppression pool or CST to the RPV.

The Surveillance Frequencies in the above SRs are controlled under the Surveillance Frequency Controlled Program.

REFERENCES

1. Information Notice 84-81, "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.

4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

6. General Electric Service Information Letter No. 388, "RHR Valve Misalignment During Shutdown Cooling Operation for BWR 3/4/5/6," February 1983.

3/4.5.3 SUPPRESSION CHAMBER

The suppression chamber is required to be OPERABLE as part of the ECCS to ensure that a sufficient supply of water is available to the HPCI, CS and LPCI systems in the event of a LOCA. This limit on suppression chamber minimum water volume ensures that sufficient water is available to permit recirculation cooling flow to the core. The OPERABILITY of the suppression chamber in OPERATIONAL CONDITION 1, 2, or 3 is also required by Specification 3.6.2.1.

BASES

3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 PRIMARY CONTAINMENT INTEGRITY

PRIMARY CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the SITE BOUNDARY radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

3/4.6.1.2 PRIMARY CONTAINMENT LEAKAGE

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value calculated in the safety analyses at the design basis LOCA maximum peak containment pressure of 44 psig, Pa. As an added conservatism, the measured overall integrated leakage rate (Type A Test) is further limited to less than or equal to 0.75 La during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

Operating experience with the main steam line isolation valves has indicated that degradation has occasionally occurred in the leak tightness of the valves; therefore the special requirement for testing these valves.

The surveillance testing for measuring leakage rates is consistent with the Primary Containment Leakage Rate Testing Program.

Limerick has an approved license amendment to implement 10 CFR 50.69, “Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors”, and may voluntarily comply with the treatment requirements of 10 CFR 50.69 as an alternative to compliance with the Type B and Type C leakage testing requirements of 10 CFR 50, Appendix J for Risk-Informed Safety Classification (RISC) RISC-3 or RISC-4 penetrations and valves meeting the following criteria:

A. Containment penetrations that are either 1-inch nominal size or less, or continuously pressurized.
B. Containment isolation valves that meet one or more of the following criteria.
   1. The valve is required to be open under accident conditions to prevent or mitigate core damage events;
   2. The valve is normally closed and in a physically closed, water-filled system;
   3. The valve is in a physically closed system whose piping pressure rating exceeds the containment design pressure rating and is not connected to the reactor coolant pressure boundary; or
   4. The valve is 1-inch nominal size or less.

RISC-3 penetrations and valves that meet the criteria above may be removed from the scope of the Primary Containment Leakage Rate Testing Program, as implemented by Technical Specifications 3.6.1, 4.6.1 and 6.8.4.g. Alternative Treatment will be implemented in accordance with the requirements of 10 CFR 50.69(d).

3/4.6.1.3 PRIMARY CONTAINMENT AIR LOCK

The limitations on closure and leak rate for the primary containment air lock are required to meet the restrictions on PRIMARY CONTAINMENT INTEGRITY and the Primary Containment Leakage Rate Testing Program. Only one closed door in the air lock is required to maintain the integrity of the containment.

3/4.6.1.4 MSIV LEAKAGE ALTERNATE DRAIN PATHWAY

Calculated doses resulting from the maximum leakage allowances for the main steamline isolation valves in the postulated LOCA situations will not exceed the criteria of 10 CFR Part 100 guidelines, provided the main steam line system from the isolation valves up to and including the turbine condenser remains intact. Operating experience has indicated that degradation has occasionally occurred in the leak tightness of the MSIVs such that the specified leakage requirements have not always been continuously maintained. The requirement for the MSIV Leakage Alternate Drain Pathway serves to reduce the offsite dose.

3/4.6.1.5 PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the maximum calculated pressure in the event of a LOCA. A visual inspection in accordance with the Primary Containment Leakage Rate Testing Program is sufficient to demonstrate this capability.

3/4.6.1.6 DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

The limitations on drywell and suppression chamber internal pressure ensure that the calculated containment peak pressure does not exceed the design pressure of 55 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 5.0 psid. The limit of - 1.0 to + 2.0 psig for initial containment pressure will limit the total pressure to ≤ 44 psig which is less than the design pressure and is consistent with the safety analysis.

3/4.6.1.7 DRYWELL AVERAGE AIR TEMPERATURE

The limitation on drywell average air temperature ensures that the containment peak air temperature does not exceed the design temperature of 340°F during steam line break conditions and is consistent with the safety analysis.

3/4.6.1.8 DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

The drywell and suppression chamber purge supply and exhaust isolation valves are required to be closed during plant operation except as required for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. Limiting the use of the drywell and suppression chamber purge system to specific criteria is imposed to protect the integrity of the SGTS filters. Analysis indicates that should a LOCA occur while this pathway is being utilized, the associated pressure surge through the (18 or 24") purge lines will adversely affect the integrity of SGTS. This condition is not imposed on the 1 and 2 inch valves used for pressure control since a surge through these lines does not threaten the operability of SGTS.

Surveillance requirement 4.6.1.8 ensures that the primary containment purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. The SR is modified by a Note stating that primary containment purge valves are only required to be closed in OPERATIONAL CONDITIONS 1, 2 and 3. The SR is also modified by a Note stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The 18 or 24 inch purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time.

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3/4.6.2 DEPRESSURIZATION SYSTEMS

The specifications of this section ensure that the primary containment pressure will not exceed the design pressure of 55 psig during primary system blowdown from full operating pressure. Management of gas voids is important to Suppression Pool Cooling/Spray Subsystem OPERABILITY.

The suppression chamber water provides the heat sink for the reactor coolant system energy release following a postulated rupture of the system. The suppression chamber water volume must absorb the associated decay and structural sensible heat released during reactor coolant system blowdown from rated conditions. Since all of the gases in the drywell are purged into the suppression chamber air space during a loss-of-coolant accident, the pressure of the suppression chamber air space must not exceed 55 psig. The design volume of the suppression chamber, water and air, was obtained by considering that the total volume of reactor coolant is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water volumes given in this specification, suppression pool pressure during the design basis accident is below the design pressure. Maximum water volume of 134,600 ft^3 results in a downcomer submergence of 12'3" and the minimum volume of 122,120 ft^3 results in a submergence approximately 2'3" less. The majority of the Bodega tests were run with a submerged length of 4 feet and with complete condensation. Thus, with respect to the downcomer submergence, this specification is adequate. The maximum temperature at the end of the blowdown tested during the Humboldt Bay and Bodega Bay tests was 170°F and this is conservatively taken to be the limit for complete condensation of the reactor coolant, although condensation would occur for temperature above 170°F.

Should it be necessary to make the suppression chamber inoperable, this shall only be done as specified in Specification 3.5.3.

Under full power operating conditions, blowdown through safety/relief valves assuming an initial suppression chamber water temperature of 95°F results in a bulk water temperature of approximately 140°F immediately following blowdown which is below the 190°F bulk temperature limit used for complete condensation via T-quencher devices. At this temperature and atmospheric pressure, the available NPSH exceeds that required by both the RHR and core spray pumps, thus there is no dependency on containment overpressure during the accident injection phase. If both RHR loops are used for containment cooling, there is no dependency on containment overpressure for post-LOCA operations.

3/4.6.2 DEPRESSURIZATION SYSTEMS (Continued)

RHR Suppression Pool Cooling/Spray subsystem piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR suppression pool subsystems and may also prevent water hammer and pump cavitation.

Selection of RHR Suppression Pool Cooling/Spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR Suppression Pool Cooling/Spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR Suppression Pool Cooling/Spray subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

One of the surveillance requirements for the suppression pool cooling (SPC) mode of the RHR system is to demonstrate that each RHR pump develops a flow rate $\geq$10,000 gpm while operating in the SPC mode with flow through the heat exchanger and its associated closed bypass valve, ensuring that pump performance has not degraded during the cycle and that the flow path is operable. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component operability, trend performance and detect incipient failures by indicating abnormal performance. The RHR heat exchanger bypass valve is used for adjusting flow through the heat exchanger and is not designed to be a tight shut-off valve. With the bypass valve closed, a portion of the total flow still travels through the bypass, which

3/4.6.2 DEPRESSURIZATION SYSTEMS (Continued)

can affect overall heat transfer. However, no heat transfer performance requirement of the heat exchanger is intended by the current Technical Specification surveillance requirement. This is confirmed by the lack of any flow requirement for the RHRSW system in Technical Specifications Section 3/4.7.1. Verifying an RHR flowrate through the heat exchanger does not demonstrate heat removal capability in the absence of a requirement for RHRSW flow. LGS does perform heat transfer testing of the RHR heat exchangers as part of its response to Generic Letter 89-13, which verified the commitment to meet the requirements of GDC 46.

Experimental data indicate that excessive steam condensing loads can be avoided if the peak local temperature of the suppression pool is maintained below 200°F during any period of relief valve operation for T-quencher devices. Specifications have been placed on the envelope of reactor operating conditions so that the reactor can be depressurized in a timely manner to avoid the regime of potentially high suppression chamber loadings.

Because of the large volume and thermal capacity of the suppression pool, the volume and temperature normally changes very slowly and monitoring these parameters daily is sufficient to establish any temperature trends. By requiring the suppression pool temperature to be frequently recorded during periods of significant heat addition, the temperature trends will be closely followed so that appropriate action can be taken.

In addition to the limits on temperature of the suppression chamber pool water, operating procedures define the action to be taken in the event a safety-relief valve inadvertently opens or sticks open. As a minimum this action shall include: (1) use of all available means to close the valve, (2) initiate suppression pool water cooling, (3) initiate reactor shutdown, and (4) if other safety-relief valves are used to depressurize the reactor, their discharge shall be separated from that of the stuck-open safety/relief valve to assure mixing and uniformity of energy insertion to the pool.

During a LOCA, potential leak paths between the drywell and suppression chamber airspace could result in excessive containment pressures, since the steam flow into the airspace would bypass the heat sink capabilities of the chamber. Potential sources of bypass leakage are the suppression chamber-to-drywell vacuum breakers (VBs), penetrations in the diaphragm floor, and cracks in the diaphragm floor and/or liner plate and downcomers located in the suppression chamber airspace. The containment pressure response to the postulated bypass leakage can be mitigated by manually actuating the suppression chamber sprays. An analysis was performed for a design bypass leakage area of $A/\sqrt{k}$ equal to 0.0500 ft^2 to verify that the operator has sufficient time to initiate the sprays prior to exceeding the containment design pressure of 55 psig. The limit of 10% of the design value of 0.0500 ft^2 ensures that the design basis for the steam bypass analysis is met.

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DEPRESSURIZATION SYSTEMS (Continued)

The drywell-to-suppression chamber bypass test at a differential pressure of at least 4.0 psi verifies the overall bypass leakage area for simulated LOCA conditions is less than the specified limit. For those outages where the drywell-to-suppression chamber bypass leakage test in not conducted, the VB leakage test verifies that the VB leakage area is less than the bypass limit, with a 76% margin to the bypass limit to accommodate the remaining potential leakage area through the passive structural components. Previous drywell-to-suppression chamber bypass test data indicates that the bypass leakage through the passive structural components will be much less than the 76% margin. The VB leakage limit, combined with the negligible passive structural leakage area, ensures that the drywell-to-suppression chamber bypass leakage limit is met for those outages for which the drywell-to-suppression chamber bypass test is not scheduled.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

The OPERABILITY of the primary containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 through 57 of Appendix A of 10 CFR Part 50. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

The scram discharge volume vent and drain valves serve a dual function, one of which is primary containment isolation. Since the other safety functions of the scram discharge volume vent and drain valves would not be available if the normal PCIV actions were taken, actions are provided to direct the user to the scram discharge volume vent and drain operability requirements contained in Specification 3.1.3.1. However, since the scram discharge volume vent and drain valves are PCIVs, the Surveillance Requirements of Specification 4.6.3 still apply to these valves.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.6.3 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

Primary containment isolation valves governed by this Technical Specification are identified in Table 3.6.3-1 of the TRM.

This Surveillance Requirement requires a demonstration that a representative sample of reactor instrument line excess flow check valves (EFCVs) is OPERABLE by verifying that the valve actuates to the isolation position on a simulated instrument line break signal. The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested in accordance with the Surveillance Frequency Control Program. In addition, the EFCVs in the sample are representative of the various plant configurations, models, sizes, and operating environments. This ensures that any potentially common problem with a specific type or application of EFCV is detected at the earliest possible time. This Surveillance Requirement provides assurance that the instrumentation line EFCVs will perform so that predicted radiological consequences will not be exceeded during a postulated instrument line break event. Furthermore, any EFCV failures will be evaluated to determine if additional testing in the test interval is warranted to ensure overall reliability is maintained. Operating experience has demonstrated that these components are highly reliable and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint. For some EFCVs, this Surveillance can be performed with the reactor at power.

3/4.6.4 VACUUM RELIEF

Vacuum relief valves are provided to equalize the pressure between the suppression chamber and drywell. This system will maintain the structural integrity of the primary containment under conditions of large differential pressures.

The vacuum breakers between the suppression chamber and the drywell must not be inoperable in the open position since this would allow bypassing of the suppression pool in case of an accident. Two pairs of valves are required to protect containment structural integrity. There are four pairs of valves (three to provide minimum redundancy) so that operation may continue for up to 72 hours or in accordance with the Risk Informed Completion Time Program with no more than two pairs of vacuum breakers inoperable in the closed position.

Each vacuum breaker valve's position indication system is of great enough sensitivity to ensure that the maximum steam bypass leakage coefficient of

$$\frac{A}{\sqrt{k}} = 0.05 \text{ ft}^2$$

for the vacuum relief system (assuming one valve fully open) will not be exceeded.

3/4.6.5 SECONDARY CONTAINMENT

Secondary containment is designed to minimize any ground level release of radioactive material which may result from an accident. The Reactor Enclosure and associated structures provide secondary containment during normal operation when the drywell is sealed and in service. At other times the drywell may be open and, when required, secondary containment integrity is specified.

Establishing and maintaining a vacuum in the reactor enclosure secondary containment with the standby gas treatment system in accordance with the Surveillance Frequency Control Program, along with the surveillance of the doors, hatches, dampers and valves, is adequate to ensure that there are no violations of the integrity of the secondary containment.

The OPERABILITY of the reactor enclosure recirculation system and the standby gas treatment systems ensures that sufficient iodine removal capability will be available in the event of a LOCA. The reduction in containment iodine inventory reduces the resulting SITE BOUNDARY and Control Room radiation doses associated with containment leakage. The operation of these systems and resultant iodine removal capacity are consistent with the assumptions used in the LOCA analysis. Provisions have been made to continuously purge the filter plenums with instrument air when the filters are not in use to prevent buildup of moisture on the adsorbers and the HEPA filters.

As a result of the Alternative Source Term (AST) project, secondary containment integrity of the refueling area is not required during certain conditions when handling irradiated fuel or during CORE ALTERATIONS and alignment of the Standby Gas Treatment System to the refueling area is not required. The control room dose analysis for the Fuel Handling Accident (FHA) is based on unfiltered releases from the South Stack and therefore, does not require the Standby Gas Treatment System to be aligned to the refueling area.

However, when handling RECENTLY IRRADIATED FUEL, secondary containment integrity of the refueling area is required and alignment of the Standby Gas Treatment System to the refueling area is required. The AST fuel handling analysis does not include an accident involving RECENTLY IRRADIATED FUEL or an accident involving draining the reactor vessel.

The Standby Gas Treatment System is required to be OPERABLE when handling irradiated fuel, handling RECENTLY IRRADIATED FUEL and during CORE ALTERATIONS. Fuel Handling Accident releases from the North Stack must be filtered through the Standby Gas Treatment System to maintain control room doses within regulatory limits. The OPERABILITY of the Standby Gas Treatment System assures that releases, if made through the North Stack, are filtered prior to release.

SECONDARY CONTAINMENT (Continued)

Surveillances 4.6.5.1.1.a and 4.6.5.1.2.a are each modified by a footnote (*) which states the surveillance is not required to be met for up to 4 hours if an analysis demonstrates that one standby gas treatment subsystem remains capable of establishing the required secondary containment vacuum. Use of the footnote is expected to be infrequent but may be necessitated by situations in which secondary containment vacuum may be less than the required containment vacuum, such as, but not limited to, wind gusts or failure or change of operating normal ventilation subsystems. These conditions do not indicate any change in the leak tightness of the secondary containment boundary. The analysis should consider the actual conditions (equipment configuration, temperature, atmospheric pressure, wind conditions, measured secondary containment vacuum, etc.) to determine whether, if an accident requiring secondary containment to be OPERABLE were to occur, one train of standby gas treatment could establish the assumed secondary containment vacuum within the time assumed in the accident analysis. If so, the surveillance may be considered met for a period up to 4 hours. The 4-hour limit is based on the expected short duration of the situations when the footnote would be applied.

Surveillances 4.6.5.1.1.b.2 and 4.6.5.1.2.b.2 require verifying that one secondary containment personnel access door in each access opening is closed which provides adequate assurance that exfiltration from the secondary containment will not occur. An access opening contains at least one inner and one outer door. The intent is to not breach the secondary containment, which is achieved by maintaining the inner or outer personnel access door closed. Surveillances 4.6.5.1.1.b.2 and 4.6.5.1.2.b.2 provide an allowance for brief, inadvertent, simultaneous openings of redundant secondary containment personnel access doors for normal entry and exit conditions.

SR 4.6.5.3.d.2 excludes automatic dampers and valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to dampers or valves that are locked, sealed, or otherwise secured in the actuated position since the affected dampers or valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve or damper in a locked, sealed, or otherwise secured position requires an assessment of the operability of the system or any supported systems, including whether it is necessary for the valve or damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve or damper to the non-actuated position requires verification that the SR has been met within its required Frequency.

Although the safety analyses assumes that the reactor enclosure secondary containment draw down time will take 930 seconds, these surveillance requirements specify a draw down time of 916 seconds. This 14 second difference is due to the diesel generator starting and sequence loading delays which is not part of this surveillance requirement.

The reactor enclosure secondary containment draw down time analyses assumes a starting point of 0.25 inch of vacuum water gauge and worst case SGTS dirty filter flow rate of 2800 cfm. The surveillance requirements satisfy this assumption by starting the drawdown from ambient conditions and connecting the adjacent reactor enclosure and refueling area to the SGTS to split the exhaust flow between the three zones and verifying a minimum flow rate of 2800 cfm from the test zone. This simulates the worst case flow alignment and verifies adequate flow is available to drawdown the test zone within the required time. The Technical Specification Surveillance Requirement 4.6.5.3.b.3 is intended to be a multi-zone air balance verification without isolating any test zone.

SECONDARY CONTAINMENT (Continued)

The SGTS fans are sized for three zones and therefore, when aligned to a single zone or two zones, will have excess capacity to more quickly drawdown the affected zones. There is no maximum flow limit to individual zones or pairs of zones and the air balance and drawdown time are verified when all three zones are connected to the SGTS.

The three zone air balance verification and drawdown test will be done after any major system alteration, which is any modification which will have an effect on the SGTS flowrate such that the ability of the SGTS to drawdown the reactor enclosure to greater than or equal to 0.25 inch of vacuum water gage in less than or equal to 916 seconds could be affected.

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3/4.6.5 SECONDARY CONTAINMENT (Continued)

The field tests for bypass leakage across the SGTS charcoal adsorber and HEPA filter banks are performed at a flow rate of 5764 ± 10% cfm. The laboratory analysis performed on the SGTS carbon samples will be tested at a velocity of 66 fpm based on the system residence time.

The SGTS filter train pressure drop is a function of air flow rate and filter conditions. Surveillance testing is performed using either the SGTS or drywell purge fans to provide operating convenience.

Each reactor enclosure secondary containment zone and refueling area secondary containment zone is tested independently to verify the design leak tightness. A design leak tightness of 2500 cfm or less for each reactor enclosure and 764 cfm or less for the refueling area at a 0.25 inch of vacuum water gage will ensure that containment integrity is maintained at an acceptable level if all zones are connected to the SGTS at the same time.

The Reactor Enclosure Secondary Containment Automatic Isolation Valves and Refueling Area Secondary Containment Automatic Isolation Valves can be found in the UFSAR.

SR 4.6.5.4.d.2 excludes automatic dampers and valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to dampers or valves that are locked, sealed, or otherwise secured in the actuated position since the affected dampers or valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve or damper in a locked, sealed, or otherwise secured position requires an assessment of the operability of the system or any supported systems, including whether it is necessary for the valve or damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve or damper to the non-actuated position requires verification that the SR has been met within its required Frequency.

The post-LOCA offsite dose analysis assumes a reactor enclosure secondary containment post-draw down leakage rate of 2500 cfm and certain post-accident X/Q values. While the post-accident X/Q values represent a statistical interpretation of historical meteorological data, the highest ground level wind speed which can be associated with these values is 7 mph (Pasquill-Gifford stability Class G for a ground level release). Therefore, the surveillance requirement assures that the reactor enclosure secondary containment is verified under meteorological conditions consistent with the assumptions utilized in the design basis analysis. Reactor Enclosure Secondary Containment leakage tests that are successfully performed at wind speeds in excess of 7 mph would also satisfy the leak rate surveillance requirements, since it shows compliance with more conservative test conditions.

3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL

The primary containment atmospheric mixing system is provided to ensure adequate mixing of the containment atmosphere to prevent localized accumulations of hydrogen and oxygen from exceeding the lower flammability limit during post-LOCA conditions.

All nuclear reactors must be designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment. With the primary containment inert, that is, oxygen concentration <4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. The capability to inert the primary containment and maintain oxygen <4.0 v/o works together with Drywell Hydrogen Mixing System to provide redundant and diverse methods to mitigate events that produce hydrogen.

3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL (Continued)

If oxygen concentration is ≥ 4.0 v/o at any time while operating in OPERATIONAL CONDITION 1 or 2, oxygen concentration must be restored to < 4.0 v/o within 72 hours. The 72 hour Completion Time is allowed when oxygen concentration is ≥ 4.0 v/o because of the low probability and long duration of an event that would generate significant amounts of hydrogen occurring during this period.

The provision of Specification 3.0.4.c is applicable. This allowance permits entry into the applicable OPERATIONAL CONDITION(S) while relying on the Actions. This allowance is acceptable because inerting the primary containment prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup, after entering OPERATIONAL CONDITIONS 1 and 2, and deinerted as soon as possible in the plant shutdown. It is acceptable to intentionally enter the Action prior to a shutdown in order to begin deinerting the primary containment prior to exiting the Applicability.

If oxygen concentration cannot be restored to within the limit within the required Completion Time, the plant must be brought to a OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, power must be reduced to HOT SHUTDOWN within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

3/4.7.1 SERVICE WATER SYSTEMS - COMMON SYSTEMS

The OPERABILITY of the service water systems ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

The RHRSW and ESW systems are common to Units 1 and 2 and consist of two independent subsystems each with two pumps. One pump per subsystem (loop) is powered from a Unit 1 safeguard bus and the other pump is powered from a Unit 2 safeguard bus. In order to ensure adequate onsite power sources to the systems during a loss of offsite power event, the inoperability of these supplies are restricted in system ACTION statements.

RHRSW is a manually operated system used for core and containment heat removal. Each of two RHRSW subsystems has one heat exchanger per unit. Each RHRSW pump provides adequate cooling for one RHR heat exchanger. By limiting operation with less than three OPERABLE RHRSW pumps with OPERABLE Diesel Generators, each unit is ensured adequate heat removal capability for the design scenario of LOCA/LOOP on one unit and simultaneous safe shutdown of the other unit.

Each ESW pump provides adequate flow to the cooling loads in its associated loop. With only two divisions of power required for LOCA mitigation of one unit and one division of power required for safe shutdown of the other unit, one ESW pump provides sufficient capacity to fulfill design requirements. ESW pumps are automatically started upon start of the associated Diesel Generators. Therefore, the allowable out of service times for OPERABLE ESW pumps and their associated Diesel Generators is limited to ensure adequate cooling during a loss of offsite power event. Alternatively, the allowable out-of-service times can be determined in accordance with the Risk Informed Completion Time Program.

SR 4.7.1.2.b.1 excludes automatic dampers and valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to dampers or valves that are locked, sealed, or otherwise secured in the actuated position since the affected dampers or valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve or damper in a locked, sealed, or otherwise secured position requires an assessment of the operability of the system or any supported systems, including whether it is necessary for the valve or damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve or damper to the non-actuated position requires verification that the SR has been met within its required Frequency.

3/4.7.2.1 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM

The OPERABILITY of the control room emergency fresh air supply system ensures that the control room will remain habitable for occupants during and following an uncontrolled release of radioactivity, hazardous chemicals, or smoke. Constant purge of the system at 1 cfm is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less Total Effective Dose Equivalent. This limitation is consistent with the requirements of 10 CFR Part 50.67, Accident Source Term.

Each CREFAS subsystem is considered OPERABLE when the individual components necessary to limit Control Room Envelope occupant exposure are OPERABLE. A subsystem is considered OPERABLE when its associated:

a. CREFAS fan is OPERABLE, and

b. HEPA filter and charcoal adsorbers are capable of performing their filtration function, and

c. Heater, ductwork, dampers, controls, and power are OPERABLE, and air circulation to the occupied areas can be maintained. Air circulation is a support system function provided by one control room AC supply fan and one control room AC return air fan, and

d. CRE boundary is OPERABLE.

Since the Control Room Emergency Fresh Air Supply System is not credited for filtration in OPERATIONAL CONDITIONS 4 and 5, applicability to 4 and 5 is only required to support the Chlorine and Toxic Gas design basis isolation requirements.

The Control Room Envelope (CRE) is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and other noncritical areas including adjacent support offices, toilet and utility rooms. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, ceiling, ducting, valves, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

In addition, The CREFAS System provides protection from smoke and hazardous chemicals to the CRE occupants. The analysis of hazardous chemical releases demonstrates that the toxicity limits are not exceeded in the CRE following a hazardous chemical release (Ref. 1). The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown panels (Ref. 2).

In order for the CREFAS subsystems to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that CRE occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated.

3/4.7.2.1 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM
(Continued)

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem TEDE), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

During the period that the CRE boundary is considered inoperable, action must be initiated immediately to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

SR 4.7.2.2 verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem Total Effective Dose Equivalent and the CRE occupants are protected from hazardous chemicals and smoke. SR 4.7.2.2 verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Required Action 3.7.2.a.2 must be entered. Required Action 3.7.2.a.2.c allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 3) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 4). These compensatory measures may also be used as mitigating actions as required by Required Action 3.7.2.a.2.b. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 5). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

3/4.7.2.1 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

REFERENCES

1. UFSAR Section 6.4
2. UFSAR Section 9.5
3. Regulatory Guide 1.196
4. NEI 99-03, "Control Room Habitability Assessment Guidance," June 2001.
5. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML040300694).

3/4.7.2.2 CONTROL ROOM AIR CONDITIONING (AC) SYSTEM COMMON SYSTEM

Each MCR AC subsystem is considered operable when the individual components necessary to maintain the control room temperature are functional. Each subsystem includes a supply fan, a return air fan, associated ductwork, dampers, centrifugal water chiller, a chilled water circulating pump, MCR cooling coil, controls, power, piping, and valves. One control room supply fan and one control room return air fan and their associated ductwork, dampers and controls are also required for air circulation to support the CREFAS subsystem function by providing a flow path to and from the control room whenever CREFAS is operating.

If both chillers or subsystems become inoperative and main control room temperature remains less than 90°F WBGT, 72-hours is permitted to restore one chiller/subsystem provided control room temperature is monitored once per 4 hours to ensure that temperature is being maintained low enough that occupants and equipment in the control room are not adversely affected. This repair time duration is reasonable considering that the control room temperature is being maintained within allowable limits and the low probability of an event occurring requiring control room isolation.

The main control room purge mode of operation, and any other viable supplemental cooling options (portable cooling, fans, opening doors, etc.) can be utilized if both chillers or subsystems are inoperative. A concurrent design basis event is not postulated while in the complete loss of cooling LCO to support supplemental cooling, as required, in order to maintain main control room temperature less than 90°F WBGT. This is based upon the low probability of a concurrent event occurring while in the 72-hour LCO that requires MCR isolation.

Temporary DWCW to CECW crosstie jumpers can also be utilized as a viable supplemental cooling option, but it requires a HELB door between the Turbine Enclosure and Control Enclosure to be breached (blocked open) while only in the 72-hour complete loss of cooling LCO. It is permitted to breach the subject HELB door for supplemental cooling jumper use although it impacts several multi-train TS systems and creates a loss of function situation which is not permitted under TS 3.0.9 if a HELB occurred. CREFAS SGT, and EDGs (required for DBA accident mitigation) all constitute loss of function situations.

The safety related SSCs protected by the breached HELB door to solely facilitate utilizing the CECW to DWCW crosstie cooling jumpers are not required to be declared inoperable while in the complete loss of CECW cooling 72-hour LCO.

The justification for this request was (1) the low probability of HELB occurring while in the LCO and (2) the ability to realistic detect a turbine enclosure high energy line leak far prior to a break occurring. The caveat for breaching the HELB door for this supplemental cooling provision is to confirm that a main steam line or feedwater high energy line leak is nonexistent. With this basis, safety related equipment in Control Enclosure room 619 would not be exposed to any HELB environmental conditions that could compromise equipment functionality while only in the 72-hour complete loss of cooling dual unit LCO. Notwithstanding the above justification, if a postulated HELB occurred with the HELB door breached, while in the LCO, the ability to mitigate the consequences of a HELB are still maintained and plant safe shutdown can be achieved by using a preexisting fire safe shutdown strategy.

A list of impacted Tech. Spec. SSCs protected by the breached HELB door are provided below:

- Unit 1 and 2 SGT TS 3.6.5.3, 3.0.3 dual unit shutdown
- Unit 1 and 2 CREFAS TS 3.7.2.1, 3.0.3 dual unit shutdown
- Unit 1 RERS TS 3.6.5.4, 12-hour shutdown
- Unit 1 EDG Power TS 3.8.1.1 (3 inoperable EDGs), 2-hour action
- Unit 2 2B RERS, TS 3.6.5.4. 7 day LCO
- Unit 2 EDG Power TS 3.8.1.1 (2 inoperable EDGs), 72-hour LCO

3/4.7.2.2 CONTROL ROOM AIR CONDITIONING (AC) SYSTEM - COMMON SYSTEM (Continued)

The MCR AC periodic surveillance requirement verifies that the system is capable of removing the control room design basis heat loads.

When handling RECENTLY IRRADIATED FUEL, a fuel handling accident is postulated and therefore it is appropriate to suspend movement of RECENTLY IRRADIATED FUEL.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

The reactor core isolation cooling (RCIC) system is provided to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without requiring actuation of any of the emergency core cooling system equipment. The RCIC system is conservatively required to be OPERABLE whenever reactor pressure ex-ceeds 150 psig. This pressure is substantially below that for which low pressure core cooling systems can provide adequate core cooling. Management of gas voids is important to RCIC System OPERABILITY.

The RCIC system specifications are applicable during OPERATIONAL CONDITIONS 1, 2, and 3 when reactor vessel pressure exceeds 150 psig because RCIC is the primary non-ECCS source of emergency core cooling when the reactor is pressurized.

With the RCIC system inoperable, adequate core cooling is assured by the OPERABILITY of the HPCI system and justifies the specified 14 day out-of-service period. Alternatively, out-of-service time can be determined in accordance with the Risk Informed Completion Time Program. A Note prohibits the application of Specification 3.0.4.b to an inoperable RCIC system. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable RCIC subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that RCIC will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation during reactor operation, a complete functional test requires reactor shutdown.

During plant startup, when RCIC surveillance tests are being performed, the RCIC System is required to be tested within 12 hours after reactor pressure is adequate to perform each surveillance test. For the low reactor pressure surveillance requirement, the intent is to verify RCIC System operability prior to increasing reactor pressure above 165 psig. If operability of the RCIC System is not demonstrated within the 12-hour period, reactor steam dome pressure must be reduced to less than 150 psig within the following 72 hours. For the high reactor pressure surveillance test, the intent is to verify RCIC System operability as soon as possible once plant conditions support the testing. Power ascension can continue during the testing; however, if RCIC is found inoperable or the 12-hour period has elapsed power ascension must be stopped, and reactor steam dome pressure must be reduced to less than 150 psig within the following 72 hours.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM (Continued)

The RCIC System flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RCIC System and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RCIC System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RCIC System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RCIC System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

Surveillance 4.7.3.a.2 is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

SR 4.7.3.c.1 excludes automatic dampers and valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to dampers or valves that are locked, sealed, or otherwise secured in the actuated position since the affected dampers or valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve or damper in a locked, sealed, or otherwise secured position requires an assessment of the operability of the system or any supported systems, including whether it is necessary for the valve or damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve or damper to the non-actuated position requires verification that the SR has been met within its required Frequency.

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3/4.7.5 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. This limitation will ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values. Sealed sources are classified into three groups according to their use, with surveillance requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism, i.e,, sealed sources within radiation monitoring devices, are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

3/4 7.6 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4 7.8 MAIN TURBINE BYPASS SYSTEM

The required OPERABILITY of the main turbine bypass system is consistent with the assumptions of the feedwater controller failure analysis in the cycle specific transient analysis.

The main turbine bypass system is required to be OPERABLE to limit peak pressure in the main steam lines and to maintain reactor pressure within acceptable limits during events that cause rapid pressurization such that the Safety Limit MCPR is not exceeded. With the main turbine bypass system inoperable, continued operation is based on the cycle specific transient analysis which has been performed for the feedwater controller failure, maximum demand with bypass failure.

3/4 7.9 TURBINE ENCLOSURE MAIN STEAM LINE TUNNEL TEMPERATURE

Should a temperature greater than the limit be detected, operators will determine if there is a leak from the Main Steam Line pressure boundary. Evidence of a Main Steam Line leak includes, but is not limited to:

- An unexpected sudden rise in tunnel temperature,
- An unexpected increase in radiation monitor readings,
- An unexpected rise in TE sump levels,
- An unexpected decrease in plant electrical output, or
- Visual and sound indications.

If a Main Steam Line pressure boundary leak is detected, a plant shutdown is required. Pressure boundary leakage includes ASME SSC(s). Leakage past gaskets, packing, and seals is not pressure boundary leakage.

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety-related equipment required for (1) the safe shutdown of the facility and (2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criterion 17 of Appendix A to 10 CFR Part 50.

An offsite power source consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E emergency bus or buses. The determination of the OPERABILITY of an offsite source of power is dependent upon grid and plant factors that, when taken together, describe the design basis calculation requirements for voltage regulation. The combination of these factors ensures that the offsite source(s), which provide power to the plant emergency buses, will be fully capable of supporting the equipment required to achieve and maintain safe shutdown during postulated accidents and transients.

The plant factors consist of the status of the Startup Transformer (#10 and #20) load tap changers (LTCs), the status of the Safeguard Transformer (#101 and #201) load tap changers (LTCs), and the alignment of emergency buses on the Safeguard Buses (101-Bus and 201-Bus). For an offsite source to be considered operable, both of its respective LTCs (#10 AND #101 for the source to the 101-Bus, #20 AND #201 for the source to the 201-Bus) must be in service, and in automatic. For the third offsite source (from 66 kV System) to be considered operable, the connected Safeguard Transformer (#101 or #201) LTC must be in service and in automatic. There is a dependency between the alignment of the emergency buses and the allowable post contingency voltage drop percentage.

The grid factors consist of actual grid voltage levels (real time) and the post trip contingency voltage drop percentage value.

The minimum offsite source voltage levels are established by the voltage regulation calculation. The transmission system operator (TSO) will notify LGS when an agreed upon limit is approached.

The post trip contingency percentage voltage drop is a calculated value determined by the TSO that would occur as a result of the tripping of one of the Limerick generators. The TSO will notify LGS when an agreed upon limit is exceeded. The voltage regulation calculation establishes the acceptable percentage voltage drop based upon plant configuration; the acceptable value is dependent upon plant configuration.

Due to the 20 Source being derived from the tertiary of the 4A and 4B transformer, its operability is influenced by both the 230 kV system and the 500 kV system. The 10 Source operability is only influenced by the 230 kV system.

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS

The anticipated post trip contingency voltage drop for the 66 kV Source (Transformer 80) is calculated to be less than the 230 kV and 500 kV systems. This is attributed to the electrical distance between the output of the Limerick generators and the input to the 80 transformer. Additionally, the Unit Auxiliary Buses do not transfer to the 80 transformer; this provides margin to the calculated post trip contingency voltage drop limit.

There are various means of hardening the 10 and 20 Sources to obtain additional margin to the post trip contingency voltage drop limits. These means include, but are not limited to, source alignment of the 4 kV buses, preventing transfer of 13 kV buses, limiting transfer of selected 13 kV loads, and operation with 13 kV buses on the offsite sources. The specific post trip contingency voltage drop percentage limits for these alignments are identified in the voltage regulation calculation, and controlled via plant procedures. There are also additional restrictions that can be applied to these limits in the event that an LTC is taken to manual, or if the bus alignment is outside the Two Source rule set.

LGS unit post trip contingency voltage drop percentage calculations are performed by the PJM Energy Management System (EMS). The PJM EMS consists of a primary and backup system. LGS will be notified if the real time contingency analysis capability of PJM is lost. Upon receipt of this notification, LGS is to request PJM to provide an assessment of the current condition of the grid based on the tools that PJM has available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and whether the current condition of the grid is bounded by the grid studies previously performed for LGS.

Based on specific design analysis, variations to any of these parameters can be determined, usually at the sacrifice of another parameter, based on plant conditions. Specifics regarding these variations must be controlled by plant procedures or by operability determinations, backed by specific design calculations.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the safety analyses and are based upon maintaining at least two of the onsite A.C. and the corresponding D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss-of-offsite power and single failure of the other onsite A.C. or D.C. source. At least two onsite A.C. and their corresponding D.C. power sources and distribution systems providing power for at least two ECCS divisions (1 Core Spray loop, 1 LPCI pump and 1 RHR pump in suppression pool cooling) are required for design basis accident mitigation as discussed in UFSAR Table 6.3-3.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Onsite A.C. operability requirements for common systems such as RHRSW and ESW are addressed in the appropriate system specification action statements.

A.C. Sources

As required by Specification 3.8.1.1, Action e, when one or more diesel generators are inoperable, there is an additional ACTION requirement to verify that all required systems, subsystems, trains, components, and devices, that depend on the remaining OPERABLE diesel generators as a source of emergency power, are also OPERABLE. The LPCI mode of the RHR system is considered a four train system, of which only two trains are required. The verification for LPCI is not required until two diesel generators are inoperable. This requirement is intended to provide assurance that a loss-of-offsite power event will not result in a complete loss of safety function of critical systems during the period when one or more of the diesel generators is inoperable. The term verify as used in this context means to administratively check by examining logs or other information to determine if certain components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

Specification 3.8.1.1, Action j, prohibits the application of Specification 3.0.4.b to an inoperable diesel generator. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable diesel generator subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

If it can be determined that the cause of the inoperable EDG does not exist on the remaining operable EDG(s), based on a common-mode evaluation, then the EDG start test (SR 4.8.1.1.2.a.4) does not have to be performed. If it cannot otherwise be determined that the cause of the initial inoperable EDG does not exist on the remaining EDG(s), then satisfactory performance of the start test suffices to provide assurance of continued operability of the remaining EDG(s). If the cause of the initial inoperability exists on the remaining operable EDG(s), the EDG(s) shall be declared inoperable upon discovery and the appropriate action statement for multiple inoperable EDGs shall be entered. In the event the inoperable EDG is restored to operable status prior to completing the EDG start test (SR 4.8.1.1.2.a.4) or common-mode failure evaluation as required in Specification 3.8.1.1, the plant corrective action program shall continue to evaluate the common-mode failure possibility. However, this continued evaluation is not subject to the time constraint imposed by the action statement. The provisions contained in the inoperable EDG action requirements that avoid unnecessary EDG testing are based on Generic Letter 93-05, “Line-Item Technical Specifications Improvement to Reduce Surveillance Requirements for Testing During Power Operation,” dated September 27, 1993.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

The time, voltage, and frequency acceptance criteria specified for the EDG single largest post-accident load rejection test (SR 4.8.1.1.2.e.2) are derived from Regulatory Guide 1.9, Rev. 2, December 1979, recommendations. The test is acceptable if the EDG speed does not exceed the nominal (synchronous) speed plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 115% of nominal, whichever is lower. This computes to be 66.5 Hz for the LGS EDGs. The RHR pump motor represents the single largest post-accident load. The 1.8 seconds specified is equal to 60% of the 3-second load sequence interval associated with sequencing the next load following the RHR pumps in response to an undervoltage on the electrical bus concurrent with a LOCA. This provides assurance that EDG frequency does not exceed predetermined limits and that frequency stability is sufficient to support proper load sequencing following a rejection of the largest single load.

D.C. Sources

With one division with one or two battery chargers inoperable (e.g., the voltage limit of 4.8.2.1.a.2 is not maintained), the ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Action a.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 18 hours, the battery will be restored to its fully charged condition (Action a.2) from any discharge that might have occurred due to the charger inoperability.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 18 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 18 hours (Action a.2).

Action a.2 requires that the battery float current be verified for Divisions 1 and 2 as $\leq$ 2 amps, and for Divisions 3 and 4 as $\leq$ 1 amp. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 18 hour period the battery float current is not within limits this indicates there may be additional battery problems.

Action a.3 limits the restoration time for the inoperable battery charger to 7 days or in accordance with the Risk Informed Completion Time Program. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 days reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status. Alternatively, the allowable out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

With one or more cells in one or more batteries in one division < 2.07 V, the battery cell is degraded. Per Action b.1, within 2 hours, verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (4.8.2.1.a.2) and of the overall battery state of charge by monitoring the battery float charge current (4.8.2.1.a.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, with one or more cells in one or more batteries < 2.07 V, continued operation is permitted for a limited period up to 24 hours.

Division 1 or 2 with float current > 2 amps, or Division 3 or 4 with float current > 1 amp, indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Per Action b.2, within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage.

Since Actions b.1 and b.2 only specify "perform," a failure of 4.8.2.1.a.1 or 4.8.2.1.a.2 acceptance criteria does not result in this Action not being met. However, if one of the Surveillance Requirements is failed the appropriate Action(s), depending on the cause of the failures, is also entered.

If the Action b.2 condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 18 hours is a reasonable time prior to declaring the battery inoperable.

With one or more batteries in one division with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits (i.e., greater than minimum level indication mark), the battery still retains sufficient capacity to perform the intended function. Per Action b.3, within 31 days the minimum established design limits for electrolyte level must be re-established.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Action b.3 addresses this potential (as well as provisions in Specification 6.8.4.h, "Battery Monitoring and Maintenance Program"). Within 8 hours level is required to be restored to above the top of the plates. The Action requirement to verify that there is no leakage by visual inspection and the Specification 6.8.4.h item to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE Standard 450-1995. They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the battery may have to be declared inoperable and the affected cell(s) replaced.

Per Action b.4, with one or more batteries in one division with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

Per Action b.5, with one or more batteries in more than one division with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that multiple divisions are involved. With multiple divisions involved, this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer restoration times specified for battery parameters on one division not within limits are therefore not appropriate, and the parameters must be restored to within limits on all but one division within 2 hours.

When any battery parameter is outside the allowances of Actions b.1, b.2, b.3, b.4, or b.5, sufficient capacity to supply the maximum expected load requirement is not ensured and a 2 hour restoration time is appropriate. Additionally, discovering one or more batteries in one division with one or more battery cells float voltage less than 2.07 V and float current greater than limits indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be restored within 2 hours.

When any batteries and/or battery chargers in two divisions of the required D.C. electrical sources are inoperable, or when two or more of the required A.C. and/or D.C. distribution system divisions are not energized resulting in a loss of function, the unit must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least HOT SHUTDOWN within 12 hours and to COLD SHUTDOWN within 36 hours. The allowed times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that (1) the facility can be maintained in the shutdown or refueling condition for extended time periods and (2) sufficient instrumentation and control capability is available for monitoring and maintaining the unit status.

The surveillance requirements for demonstrating the OPERABILITY of the diesel generators are in accordance with the recommendations of Regulatory Guide 1.9,

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

"Selection of Diesel Generator Set Capacity for Standby Power Supplies," March 10, 1971, Regulatory Guide 1.137 "Fuel-Oil Systems for Standby Diesel Generators," Revision 1, October 1979 and Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977 except for paragraphs C.2.a(3), C.2.b, C.2.c(1), C.2.c(2), C.2.d(3) and C.2.d(4), and the periodic testing will be performed in accordance with the Surveillance Frequency Control Program. The exceptions to Regulatory Guide 1.108 allow for gradual loading of diesel generators during testing and decreased surveillance test frequencies (in response to Generic Letter 84-15). The single largest post-accident load on each diesel generator is the RHR pump.

The Surveillance Requirement for removal of accumulated water from the fuel oil storage tanks is for preventive maintenance. The presence of water does not necessarily represent failure of the Surveillance Requirement, provided the accumulated water is removed during performance of the Surveillance. Accumulated water in the fuel oil storage tanks constitutes a collection of water at a level that can be consistently and reliably measured. The minimum level at which accumulated water can be consistently and reliably measured in the fuel oil storage tank sump is 0.25 inches. Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of accumulated water from the fuel storage tanks once every (31) days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137.

The surveillance requirements for demonstrating the OPERABILITY of the units batteries are in accordance with the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications."

Verifying battery float current while on float charge (4.8.2.1.a.1) is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE Standard 450-1995.

This Surveillance Requirement (4.8.2.1.a.1) states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of 4.8.2.1.a.2. When this float voltage is not maintained, the Actions of 3.8.2.1 Action a., provides the necessary and appropriate verifications of the battery condition. Furthermore, the float current limits are established based on the float voltage range and is not directly applicable when this voltage is not maintained.

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A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Verifying, per 4.8.2.1.a.2, battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the minimum float voltage established by the battery manufacturer (2.20 Vpc, average, or 132 V at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years).

Surveillance Requirements 4.8.2.1.b.1 and 4.8.2.1.c require verification that the cell float voltages are equal to or greater than 2.07 V.

The limit specified in 4.8.2.1.b.2 for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability.

Surveillance Requirement 4.8.2.1.b.3 verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60 degrees Fahrenheit). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity.

Surveillance Requirement 4.8.2.1.d.1 verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32, the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

Surveillance Requirement 4.8.2.1.d.1 requires that each battery charger be capable of supplying the amps listed for the specified charger at the minimum established float voltage for 4 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. This time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

A battery service test, per 4.8.2.1.d.2, is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements as specified in the UFSAR.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

A battery performance discharge test (4.8.2.1.e and f) is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage. Degradation (as used in 4.8.2.1.f) is indicated when the battery capacity drops more than 10% from its capacity on the previous performance test, or is below 90% of the manufacturer's rating.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying 4.8.2.1.e and 4.8.2.1.f; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of 4.8.2.1.d.2.

3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

The RPS Electric Power Monitoring System is provided to isolate the RPS bus from the RPS/UPS inverter or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus from unacceptable voltage and frequency conditions. The essential equipment powered from the RPS buses includes the RPS logic, scram solenoids, and valve isolation logic.

The Allowable Values are derived from equipment design limits, corrected for calibration and instrument errors. The trip setpoints are then determined, accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection and include allowances for instrumentation uncertainties, calibration tolerances, and instrument drift.

The Allowable Values for the instrument settings are based on the RPS providing power within the design ratings of the associated RPS components (e.g., RPS logic, scram solenoids). The most limiting voltage requirement and associated line losses determine the settings of the electric power monitoring instrument channels.

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3/4.9.1 REACTOR MODE SWITCH

Locking the OPERABLE reactor mode switch in the Refuel position, as specified, ensures that the restrictions on control rod withdrawal and refueling platform movement during the refueling operations are properly activated. These conditions reinforce the refueling procedures and reduce the probability of inadvertent criticality, damage to reactor internals or fuel assemblies, and exposure of personnel to excessive radioactivity.

The effect of these requirements is to lock the Reactor Mode Switch in the Refuel position during refueling operations, which is defined at Limerick by our refueling procedures and only occurs during OPCON 5. Additionally, in OPCON 3 and 4 when the one rod out interlock is required to be OPERABLE to withdraw a single control rod with the Mode Switch in the Refuel Position.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of at least two source range monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core. The minimum count rate is not required when sixteen or fewer fuel assemblies are in the core. During a typical core reloading, two, three or four irradiated fuel assemblies will be loaded adjacent to each SRM to produce greater than the minimum required count rate. Loading sequences are selected to provide for a continuous multiplying medium to be established between the required operable SRMs and the location of the core alteration. This enhances the ability of the SRMs to respond to the loading of each fuel assembly. During a core un-loading, the last fuel to be removed is that fuel adjacent to the SRMs.

3/4.9.3 CONTROL ROD POSITION

The requirement that all control rods be inserted during other CORE ALTERATIONS ensures that fuel will not be loaded into a cell without a control rod.

3/4.9.4 DECAY TIME

The minimum requirement for reactor subcriticality prior to fuel movement ensures that sufficient time has elapsed to allow the radioactive decay of the short lived fission products. This decay time is consistent with the assumptions used in the accident analyses.

3/4.9.5 COMMUNICATIONS

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity condition during movement of fuel within the reactor pressure vessel.

3/4.9.6 REFUELING PLATFORM

The OPERABILITY requirements ensure that (1) the refueling platform will be used for handling control rods and fuel assemblies within the reactor pressure vessel, (2) each hoist has sufficient load capacity for handling fuel assemblies and control rods, (3) the core internals and pressure vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations, and (4) inadvertent criticality will not occur due to fuel being loaded into a unrodded cell.

Inadvertent criticality is prevented by the refueling interlocks that block unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn or withdrawal of a rod from the core while the grapple is over the core and loaded with fuel). The hoist loaded values identified in Sections 4.9.6.1b and 4.9.6.1c support the refueling interlock logic by ensuring that the hoist fuel loaded switches function with a load lighter than the weight of a single fuel assembly in water. Load values represent fuel (load) on the grapple. The values of 485 +/- 50 pounds and 550 + 0, - 115 pounds are both less than the weight of a single fuel assembly in water attached to the grapple. These load values ensure that as soon as a fuel assembly is grappled and lifted, the refueling interlocks (control rod block and bridge motion interlock) are enforced as required. The hoist load weighing system is compensated for mast weight to ensure that lifting of components other than fuel assemblies (e.g., blade guides) do not cause inadvertent control rod blocks or bridge motion stops.

3/4.9.7 CRANE TRAVEL - SPENT FUEL STORAGE POOL

The restriction on movement of loads in excess of the nominal weight of a fuel assembly and associated lifting device over other fuel assemblies in the storage pool ensures that in the event this load is dropped 1) the activity release will be limited to that contained in a single fuel assembly, and 2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the safety analyses.

3/4.9.8 and 3/4.9.9 WATER LEVEL - REACTOR VESSEL and WATER LEVEL - SPENT FUEL STORAGE POOL

The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. This minimum water depth is consistent with the assumptions of the accident analysis.

3/4.9.10 CONTROL ROD REMOVAL

These specifications ensure that maintenance or repair of control rods or control rod drives will be performed under conditions that limit the probability of inadvertent criticality. The requirements for simultaneous removal of more than one control rod are more stringent since the SHUTDOWN MARGIN specification provides for the core to remain subcritical with only one control rod fully withdrawn.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed by the RHR system to maintain adequate reactor coolant temperature.

RHR shutdown cooling is comprised of four (4) subsystems which make two (2) loops. Each loop consists of two (2) motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Two (2) redundant, manually controlled shutdown cooling subsystems of the RHR system provide decay heat removal. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System.

An OPERABLE RHR shutdown cooling subsystem consists of one (1) OPERABLE RHR pump, one (1) heat exchanger, and the associated piping and valves. The requirement for having one (1) RHR shutdown cooling subsystem OPERABLE ensures that 1) sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor pressure vessel below 140°F, and 2) sufficient coolant circulation would be available through the reactor core to assure accurate temperature indication. Management of gas voids is important to RHR Shutdown Cooling Subsystem OPERABILITY.

The requirement to have two (2) RHR shutdown cooling subsystems OPERABLE when there is less than 22 feet of water above the reactor vessel flange ensures that a single failure of the operating loop will not result in a complete loss of residual heat removal capability. With the reactor vessel head removed and 22 feet of water above the reactor vessel flange, a large heat sink is available for core cooling. Thus, in the event of a failure of the operating RHR subsystem, adequate time is provided to initiate alternate methods capable of decay heat removal or emergency procedures to cool the core.

To meet the LCO of the two (2) subsystems OPERABLE when there is less than 22 feet of water above the reactor vessel flange, both pumps in one (1) loop or one (1) pump in each of the two (2) loops must be OPERABLE. The two (2) subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Additionally, each shutdown cooling subsystem can provide the required decay heat removal capability; however, ensuring operability of the other shutdown cooling subsystem provides redundancy.

The required cooling capacity of an alternate method of decay heat removal should be ensured by verifying its capability to maintain or reduce reactor coolant temperature either by calculation (which includes a review of component and system availability to verify that an alternate decay heat removal method is available) or by demonstration. Decay heat removal capability by ambient losses can be considered in evaluating alternate decay heat removal capability.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION (Continued)

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of non-condensible gas into the reactor vessel. This surveillance verifies that the RHR Shutdown Cooling System piping is sufficiently filled with water prior to placing the system in operation when in OPCON 5. The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water to ensure that it can reliably perform its intended function.

The RHR Shutdown Cooling System is a manually initiated mode of the RHR System that is aligned for service using system operating procedures that ensure the RHR shutdown cooling suction and discharge flow paths are sufficiently filled with water. An RHR Shutdown Cooling sub-system that is already in operation at the time of entry into the APPLICABILITY is OPERABLE. For an idle RHR Shutdown Cooling subsystem, the surveillance is met through the performance of the operating procedures that place the RHR Shutdown Cooling subsystem in service.

With the required decay heat removal subsystem(s) inoperable and the required alternate method(s) of decay heat removal not available in accordance with Action "a", additional actions are required to minimize any potential fission product release to the environment. This includes ensuring Refueling Floor Secondary Containment is OPERABLE; one (1) Standby Gas Treatment subsystem is OPERABLE; and Secondary Containment isolation capability (i.e., one (1) Secondary Containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated penetration not isolated that is assumed to be isolated to mitigate radioactive releases. This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

If no RHR subsystem is in operation, an alternate method of coolant circulation is required to be established within one (1) hour. The Completion Time is modified such that one (1) hour is applicable separately for each occurrence involving a loss of coolant circulation.

3.4.10.1 PRIMARY CONTAINMENT INTEGRITY

The requirement for PRIMARY CONTAINMENT INTEGRITY is not applicable during the period when open vessel tests are being performed during the low power PHYSICS TESTS.

3/4.10.2 ROD WORTH MINIMIZER

In order to perform the tests required in the technical specifications it is necessary to bypass the sequence restraints on control rod movement. The additional surveillance requirements ensure that the specifications on heat generation rates and shutdown margin requirements are not exceeded during the period when these tests are being performed and that individual rod worths do not exceed the values assumed in the safety analysis.

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

Performance of shutdown margin demonstrations with the vessel head removed requires additional restrictions in order to ensure that criticality does not occur. These additional restrictions are specified in this LCO.

3/4.10.4 RECIRCULATION LOOPS

This special test exception permits reactor criticality under no flow conditions and is required to perform certain startup and PHYSICS TESTS while at low THERMAL POWER levels.

3/4.10.5 OXYGEN CONCENTRATION

Relief from the oxygen concentration specifications is necessary in order to provide access to the primary containment during the initial startup and testing phase of operation. Without this access the startup and test program could be restricted and delayed.

3/4.10.6 TRAINING STARTUPS

This special test exception permits training startups to be performed with the reactor vessel depressurized at low THERMAL POWER and temperature while controlling RCS temperature with one RHR subsystem aligned in the shutdown cooling mode in order to minimize contaminated water discharge to the radioactive waste disposal system.

3/4.10.7 RESERVED - CURRENTLY NOT USED

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

This special test exception permits certain reactor coolant pressure tests to be performed in OPERATIONAL CONDITION 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) or plant temperature control capabilities during these tests require the pressure testing at temperatures greater than 200°F (normally corresponding to OPERATIONAL CONDITION 3). The additionally imposed OPERATIONAL CONDITION 3 requirements for SECONDARY CONTAINMENT INTEGRITY provide conservatism in response to an operational event.

Invoking the requirement for Refueling Area Secondary Containment Integrity along with the requirement for Reactor Enclosure Secondary Containment Integrity applies the requirements for Reactor Enclosure Secondary Containment Integrity to an extended area encompassing Zones 1 and 3. Core alterations and fuel handling are prohibited in this secondary containment configuration. Drawdown and inleakage testing performed for the combined zone system alignment shall be considered adequate to demonstrate integrity of the combined zones.

Inservice hydrostatic testing and inservice leak pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code are performed prior to the reactor going critical after a refueling outage. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.6, Reactor Coolant System Pressure/Temperature Limits. These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence. With increased reactor fluence over time, the minimum allowable vessel temperature increases at a given pressure.

3/4.11.1.1 and 3/4.11.1.2 (Deleted)

THE INFORMATION FROM THESE SECTIONS
HAS BEEN RELOCATED TO THE ODCM.

3/4.11.1.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.11.1.4 LIQUID HOLDUP TANKS

The tanks listed in this specification include all those outdoor radwaste tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

Restricting the quantity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tanks' contents, the resulting concentrations would be less than 10 times the limits of 10 CFR Part 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an UNRESTRICTED AREA.

3/4.11.2.1 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.11.2.2 through 3/4.11.2.4 (Deleted)

THE INFORMATION FROM THESE SECTIONS
HAS BEEN RELOCATED TO THE ODCM.

3/4.11.2.5 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.11.2.6 MAIN CONDENSER

Restricting the gross radioactivity rate of noble gases from the main condenser provides reasonable assurance that the total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR Part 100 in the event this effluent is inadvertently discharged directly to the environment without treatment. This specification implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR Part 50.

3/4 11.2.7, 3/4 11.3, and 3/4 11.4 (Deleted) - INFORMATION FROM THESE SECTIONS RELOCATED TO THE ODCM OR PCP.

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Section 3/4.12 (Deleted)

THE INFORMATION FROM THIS SECTION HAS BEEN RELOCATED TO THE ODCM. BASES PAGE B 3/4 12-2 HAS BEEN INTENTIONALLY OMITTED.

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Limerick Generating Station Unit 2 Technical Specification Bases

BASES

FOR

SECTION 2.0

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Section 2.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

2.0 INTRODUCTION

The fuel cladding, reactor pressure vessel and primary system piping are the principle barriers to the release of radioactive materials to the environs. Safety Limits are established to protect the integrity of these barriers during normal plant operations and anticipated transients. The Tech Spec Safety Limit is set generically on a fuel product Minimum Critical Power Ratio (MCPR) correlation basis as the MCPR which corresponds to a 95% probability at a 95% confidence level that transition boiling will not occur, referred to as SLMCPR(95/95). The fuel cladding integrity Safety Limit is set such that no significant fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a step-back approach is used to establish a Safety Limit such that the MCPR is not less than the limit specified in Specification 2.1.2 MCPR greater than the specified limit represents a conservative margin relative to the conditions required to maintain fuel cladding integrity. The fuel cladding is one of the physical barriers which separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses which occur from reactor operation significantly above design conditions and the Limiting Safety System Settings. While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross rather than incremental cladding deterioration. Therefore, the fuel cladding Safety Limit is defined with a margin to the conditions which would produce onset of transition boiling, MCPR of 1.0. These conditions represent a significant departure from the condition intended by design for planned operation. This is accomplished by having a Safety Limit Minimum Critical Power Ratio (SLMCPR) design basis, referred to as SLMCPR(95/95), which corresponds to a 95% probability at a 95% confidences level (the 95/95 MCPR criterion) that transition boiling will not occur.

2.1.1 THERMAL POWER, Low Pressure or Low Flow

GNF critical power correlation for GNF3 is applicable for all critical power calculations at pressures ≥ 700 psia and core flows ≥ 10% of rated flow (Ref. 3). For operation at low pressures or low flows, another basis is used. This is done by establishing a limiting condition on core THERMAL POWER with the following basis. Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be greater than 4.5 psi. Analyses show that with a bundle flow of 28×10^3 lb/hr, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be greater than 28×10^3 lb/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER of more than 50% of RATED THERMAL POWER. Thus, a THERMAL POWER limit of 25% of RATED THERMAL POWER for reactor pressure below 700 psia is conservative.

2.1.2 THERMAL POWER, High Pressure and High Flow

The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Since the parameters which result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions resulting in a departure from nucleate boiling have been used to mark the beginning of the region where fuel damage could occur. Although it is recognized that a departure from nucleate boiling would not necessarily result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit. The Technical Specification Safety Limit value is dependent on the fuel product line and the corresponding MCPR correlation, which is cycle independent. The value is based on the Critical Power Ratio (CPR) data statistics and a 95% probability with 95% confidence that rods are not susceptible to boiling transition, referred to as MCPR(95/95).

The Safety Limit is based on GNF3 fuel. For cores with a single fuel product line, the SLMCPR(95/95) is the MCPR(95/95) for the fuel type. For cores loaded with a mix of applicable fuel types, the SLMCPR(95/95) is based on the largest (i.e., most limiting) of the MCPR values for the fuel product lines that are fresh or once-burnt at the start of the cycle.

Reference:

1. "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A (latest approved revision).
2. Deleted
3. “GEXL21 Correlation for GNF3 Fuel,” NEDC-33880P Rev. 1, November 2017

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Associated with Amendment ~~199~~
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2.1.3 REACTOR COOLANT SYSTEM PRESSURE

The Safety Limit for the reactor coolant system pressure has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to Section III of the ASME Boiler and Pressure Vessel Code 1968 Edition, including Addenda through Summer 1969, which permits a maximum pressure transient of 110%, 1375 psig, of design pressure 1250 psig. The Safety Limit of 1325 psig, as measured by the reactor vessel steam dome pressure indicator, is equivalent to 1375 psig at the lowest elevation of the reactor coolant system. The reactor coolant system is designed to the ASME Boiler and Pressure Vessel Code, 1977 Edition, including Addenda through Summer 1977 for the reactor recirculation piping, which permits a maximum pressure transient of 110%, 1375 psig of design pressure, 1250 psig for suction piping and 1500 psig for discharge piping. The pressure Safety Limit is selected to be the lowest transient overpressure allowed by the ASME Boiler and Pressure Vessel Code Section III, Class I.

2.1.4 REACTOR VESSEL WATER LEVEL

With fuel in the reactor vessel during periods when the reactor is shutdown, consideration must be given to water level requirements due to the effect of decay heat. If the water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the water level became less than two-thirds of the core height. The Safety Limit has been established at the top of the active irradiated fuel to provide a point which can be monitored and also provide adequate margin for effective action.

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Protection System instrumentation setpoints specified in Table 2.2.1-1 are the values at which the reactor trips are set for each para-meter. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist in mitigating the consequences of accidents. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or less than the drift allowance assumed for each trip in the safety analyses.

1. Intermediate Range Monitor, Neutron Flux - High

The IRM system consists of 8 chambers, 4 in each of the reactor trip systems. The IRM is a 5 decade 10 range instrument. The trip setpoint of 120 divisions of scale is active in each of the 10 ranges. Thus as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during the power increase is due to control rod withdrawal. In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

2. Average Power Range Monitor

The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. All four voters will trip (full scram) when any two unbypassed APRM channels exceed their trip setpoints.

APRM trip Functions 2.a, 2.b, 2.c, and 2.d are voted independently from OPRM Upscale Function 2.f. Therefore, any Function 2.a, 2.b, 2.c, or 2.d trip from any two unbypassed APRM channels will result in a full trip in each of the four voter channels. Similarly, a Function 2.f trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels.

For operation at low pressure and low flow during STARTUP, the APRM Neutron Flux-Upscale (Setdown) scram setting of 15% of RATED THERMAL POWER provides adequate hermal margin between the setpoint and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Tempera-ture coefficients are small and control rod patterns are constrained by the RWM. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant amount, the rate of power rise is very slow. Generally the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit. The 15% Neutron Flux - Upscale (Setdown) trip remains active until the mode switch is placed in the Run position.

The APRM trip system is calibrated using heat balance data taken during steady state conditions. Fission chambers provide the basic input to the system and therefore the monitors respond directly and quickly to changes due to transient operation for the case of the Neutron Flux - Upscale setpoint; i.e., for a power increase, the THERMAL POWER of the fuel will be less than that indicated by the neutron flux due to the time constants of the heat transfer associated with the fuel. For the Simulated Thermal Power - Upscale setpoint, a time constant of 6 ± 0.6 seconds is introduced into the flow-biased APRM in order to simulate the fuel thermal transient characteristics. A more conservative maximum value is used for the flow-biased setpoint as shown in Table 2.2.1-1.

A reduced Trip Setpoint and Allowable Value is provided for the Simulated Thermal Power - Upscale Function, applicable when the plant is operating in Single Loop Operation (SLO) per LCO 3.4.1.1. In SLO, the drive flow values (W) used in the Trip Setpoint and Allowable Value equations is reduced by 7.6%. The 7.6% value is established to conservatively bound the inaccuracy created in the core flow/drive flow correlation due to back flow in the jet pumps associated with the inactive recirculation loop. The Trip Setpoint and Allowable Value thus maintain thermal margins essentially unchanged from those for two-loop operation. The Trip Setpoint and Allowable Value equations for single loop operation are only valid for flows down to W = 7.6%. The Trip Setpoint and Allowable Value do not go below 61.5% and 62.0% RATED THERMAL POWER, respectively. This is acceptable because back flow in the inactive recirculation loop is only an issue with drive flows of approximately 40% or greater (Reference 1).

The APRM setpoints were selected to provide adequate margin for the Safety Limits and yet allow operating margin that reduces the possibility of unneces-sary shutdown.

The APRM channels also include an Oscillation Power Range Monitor (OPRM) Upscale Function. The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR Safety Limit due to anticipated thermal-hydraulic power oscillations. The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into “cells” for evaluation by the OPRM algorithms.

References 2, 3 and 4 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

The OPRM Upscale trip output shall be automatically enabled (not bypassed) when APRM Simulated Thermal Power is ≥ 29.5% and recirculation drive flow is < 60% as indicated by APRM measured recirculation drive flow. (NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. Refer to TS Bases 3/4.3.1 for further discussion concerning the recirculation drive flow/core flow relationship.) This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. See Reference 5 for additional discussion of OPRM Upscale trip enable region limits. These setpoints, which are sometimes referred to as the "auto-bypass" setpoints, establish the boundaries of the OPRM Upscale rip enabled region. The APRM Simulated Thermal Power auto-enable setpoint has 1% deadband while the drive flow setpoint has a 2% deadband. The deadband for these setpoints is established so that it increases the enabled region.

An OPRM Upscale trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in a cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the growth rate or amplitude based algorithms detect oscillatory changes in the neutron flux for one or more cells in that channel.

There are four "sets" of OPRM related setpoints or adjustment parameters: a) OPRM trip auto-enable setpoints for APRM Simulated Thermal Power (29.5%) and recirculation drive flow (60%); b) period based detection algorithm (PBDA) confirmation count and amplitude setpoints; c) period based detection algorithm tuning parameters; and d) growth rate algorithm (GRA) and amplitude based algorithm (ABA) setpoints.

The first set, the OPRM auto-enable region setpoints, are treated as nominal setpoints with no additional margins added as discussed in Reference 5. The settings, 29.5% APRM Simulated Thermal Power and 60% recirculation drive flow, are defined (limit values) in a note to Table 2.2.1-1. The second set, the OPRM PBDA trip setpoints, are established in accordance with methodologies defined in Reference 4, and are documented in the COLR. There are no allowable values for these setpoints. The third set, the OPRM PBDA "tuning" parameters, are established or adjusted in accordance with and controlled by station procedures. The fourth set, the GRA and ABA setpoints, in accordance with References 2 and 3, are established as nominal values only, and controlled by station procedures.

3. Reactor Vessel Steam Dome Pressure-High

High pressure in the nuclear system could cause a rupture to the nuclear system process barrier resulting in the release of fission products. A pressure increase while operating will also tend to increase the power of the reactor by compressing voids thus adding reactivity. The trip will quickly reduce the neutron flux, counteracting the pressure increase. The trip setting is slightly higher than the operating pressure to permit normal operation without spurious trips. The setting provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This trip setpoint is effective at low power/flow conditions when the turbine stop valve and control fast closure trips are bypassed. For a turbine trip or load rejection under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

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REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

4. Reactor Vessel Water Level-Low

The reactor vessel water level trip setpoint has been used in transient analyses dealing with coolant inventory decrease. The scram setting was chosen far enough below the normal operating level to avoid spurious trips but high enough above the fuel to assure that there is adequate protection for the fuel and pressure limits.

5. Main Steam Line Isolation Valve-Closure

The main steam line isolation valve closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIVs are closed automatically from measured parameters such as high steam flow, low reactor water level, high steam tunnel temperature, and low steam line pressure. The MSIVs closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

6. DELETED

7. Drywell Pressure-High

High pressure in the drywell could indicate a break in the primary pressure boundary systems or a loss of drywell cooling. The reactor is tripped in order to minimize the possibility of fuel damage and reduce the amount of energy being added to the coolant and to the primary containment. The trip setting was selected as low as possible without causing spurious trips.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

8. Scram Discharge Volume Water Level-High

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water at pressures below 65 psig, control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is indeed filling up, but the volume is still great enough to accommodate the water from the movement of the rods at pressures below 65 psig when they are tripped. The trip setpoint for each scram discharge volume is equivalent to a contained volume of 25.58 gallons of water.

9. Turbine Stop Valve-Closure

The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of 5% of valve closure from full open, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst design basis transient.

10. Turbine Control Valve Fast Closure, Trip Oil Pressure-Low

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection with or without coincident failure of the turbine bypass valves. The Reactor Protection System initiates a trip when fast closure of the control valves is initiated by the fast acting solenoid valves and in less than 30 milliseconds after the start of control valve fast closure. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic trip oil pressure at the main turbine control valve actuator disc dump valves. This loss of pressure is sensed by pressure switches whose contacts form the one-out-of-two-twice logic input to the Reactor Protection System. This trip setting, a faster closure time, and a different valve characteristic from that of the turbine stop valve, combine to produce transients which are very similar to that for the stop valve. Relevant transient analyses are discussed in Section 15.2.2 of the Final Safety Analysis Report.

11. Reactor Mode Switch Shutdown Position

The reactor mode switch Shutdown position is a redundant channel to the automatic protective instrumentation channels and provides additional manual reactor trip capability.

12. Manual Scram

The Manual Scram is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

REFERENCES:

1. NEDC-31300, “Single-Loop Operation Analysis for Limerick Generating Station, Unit 1,” August 1986.

2. NEDO-31960-A, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.

3. NEDO-31960-A, Supplement 1, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.

4. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications,” August 1996.

5. BWROG Letter 96113, K. P. Donovan (BWROG) to L. E. Phillips (NRC), “Guidelines for Stability Option III ‘Enable Region’ (TAC M92882),” September 17, 1996.

BASES FOR

SECTIONS 3.0 AND 4.0

LIMITING CONDITIONS FOR OPERATION

AND

SURVEILLANCE REQUIREMENTS

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NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Sections 3.0 and 4.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

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Specifications 3.0.1 through 3.0.9 establish the general requirements applicable to Limiting Conditions for Operation. These requirements are based on the requirements for Limiting Conditions for Operation stated in the Code of Federal Regulations, 10 CFR 50.36(c)(2):

> "Limiting Conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specification until the condition can be met."

Specification 3.0.1 establishes the Applicability statement within each individual specification as the requirement for when (i.e., in which OPERATIONAL CONDITIONS or other specified conditions) conformance to the Limiting Conditions for Operation is required for safe operation of the facility. The ACTION requirements establish those remedial measures that must be taken within specified time limits when the requirements of a Limiting Condition for Operation are not met. The ACTIONS for not meeting a single LCO adequately manage any increase in plant risk, provided any unusual external conditions (e.g., severe weather, offsite power instability) are considered. In addition, the increased risk associated with simultaneous removal of multiple structures, systems, trains or components from service is assessed and managed in accordance with 10 CFR 50.65(a)(4).

There are two basic types of ACTION requirements. The first specifies the remedial measures that permit continued operation of the facility which is not further restricted by the time limits of the ACTION requirements. In this case, conformance to the ACTION requirements provides an acceptable level of safety for unlimited continued operation as long as the ACTION requirements continue to be met. The second type of ACTION requirement specifies a time limit in which conformance to the conditions of the Limiting Condition for Operation must be met. This time limit is the allowable outage time to restore an inoperable system or component to OPERABLE status or for restoring parameters within specified limits. If these actions are not completed within the allowable outage time limits, a shutdown is required to place the facility in an OPERATIONAL CONDITION or other specified condition in which the specification no longer applies.

The specified time limits of the ACTION requirements are applicable from the point of time it is identified that a Limiting Condition for Operation is not met. The time limits of the ACTION requirements are also applicable when a system or component is removed from service for surveillance testing or investigation of operational problems. Individual specifications may include a specified time limit for the completion of a Surveillance Requirement when equipment is removed from service. In this case, the allowable outage time limits of the ACTION requirements are applicable when this limit expires if the surveillance has not been completed. When a shutdown is required to comply with ACTION requirements, the plant may have entered an OPERATIONAL CONDITION in which a new specification becomes applicable. In this case, the time limits of the ACTION requirements would apply from the point in time that the new specification becomes applicable if the requirements of the Limiting Condition for Operation are not met.

Specification 3.0.2 establishes that noncompliance with a specification exists when the requirements of the Limiting Condition for Operation are not met and the associated ACTION requirements have not been implemented within the specified time interval, unless otherwise specified. The purpose of this specification is to clarify that (1) implementation of the ACTION requirements within the specified time interval constitutes compliance with a specification and (2) completion of the remedial measures of the ACTION requirements is not required when compliance with a Limiting Condition of Operation is restored within the time interval specified in the associated ACTION requirements.

Specification 3.0.3 establishes the shutdown ACTION requirements that must be implemented when a Limiting Condition for Operation is not met and the condition is not specifically addressed by the associated ACTION requirements or the required ACTION is not met. The purpose of this specification is to delineate the time limits for placing the unit in a safe shutdown CONDITION when plant operation cannot be maintained within the limits defined by the Limiting Conditions for Operation and its ACTION requirements. Planned entry into LCO 3.0.3 should be avoided. If it is not practicable to avoid planned entry into LCO 3.0.3, plant risk should be assessed and managed in accordance with 10 CFR 50.65(a)(4), and the planned entry into LCO 3.0.3 should have less effect on plant safety than other practicable alternatives.

Upon entering LCO 3.0.3, a risk assessment addressing inoperable systems and components must be completed and appropriate risk management actions must be implemented within 6 hours. The risk assessment must consider all inoperable equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Regulatory Guide 1.160 endorses the guidance in Section 11 of NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” All relevant elements of the risk assessment description in Section 11 will be included. These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures). A formal cause or apparent cause evaluation is not required because of the limited time available, but the likely cause of the conditions that resulted in LCO 3.0.3 entry are considered. If the extent of condition is unknown, the risk assessment will consider the possibility of common cause failure either numerically or through risk management actions.

Continuing operation for a limited time is acceptable if the risk assessment determines that for the current plant configuration, the Incremental Core Damage Probability (ICDP) is less than 1E-5, and the Incremental Large Early Release Probability (ILERP) is less than 1E-6. Non-quantifiable factors will also be assessed. In addition, the configuration-specific Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) will be evaluated to identify high-risk situations. A configuration-specific CDF in excess of 1E-3/year or LERF in excess of 1E-4/year does not support continuing operation. The impact on plant risk is evaluated from the baseline, zero-maintenance, condition.

Whenever practicable, a quantitative value for risk will be determined. If determination of a quantitative value for risk is not practicable, a qualitative assessment of risk may be used with appropriate consideration of the plant conditions and uncertainties to determine whether continued operation for a limited time is acceptable.

If during the 24-hour period the plant configuration changes such that plant risk may be increased, the risk must be reassessed. If the configuration no longer supports continuing plant operation, action must be initiated to shut down the unit in accordance with the LCO 3.0.3 requirements.

Appropriate risk management actions are implemented in accordance with the Maintenance Rule procedures that are appropriate for the current plant condition and the inoperable equipment. Risk management actions are used to address non-quantifiable factors, increase risk awareness, and reduce the risk magnitude and duration.

If the risk assessment determines that continuing operation is acceptable, that the appropriate risk management actions are implemented, and that entry into LCO 3.0.3 was unplanned, action to shut down the unit must be initiated within 24 hours of entry into LCO 3.0.3. It is not necessary for the planned restoration of compliance with the LCO or ACTIONS to be within 24 hours as other actions are available, such as regulatory relief or an orderly shutdown. The 24-hour provision may not be used if the LCO 3.0.3 entry is planned, such as intentionally removing a train from service when the redundant train is inoperable. However, it may be used for emergent conditions that occur in parallel with other planned or unplanned inoperabilities.

The determination that continuing operation is acceptable will be documented in sufficient detail to allow a knowledgeable individual to understand the basis for the determination.

If the risk assessment determines that continuing operation is not acceptable, if the risk assessment was not completed, the appropriate risk management actions were not implemented, or if entry into LCO 3.0.3 was planned, action to shut down the unit must be initiated following the 6 hour time period provided to perform the risk assessment and implement risk management actions.

All times for completing actions and entering OPERATIONAL CONDITIONS are determined from entry into LCO 3.0.3.

The time limits specified to enter lower CONDITIONS of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the cooldown capabilities of the facility assuming only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the primary coolant system and the potential for a plant upset that could challenge safety systems under conditions for which this specification applies.

If remedial measures permitting limited continued operation of the facility under the provisions of the ACTION requirements are completed, the shutdown may be terminated. The time limits of the ACTION requirements are applicable from the point in time there was a failure to meet a Limiting Condition for Operation. Therefore, the shutdown may be terminated if the ACTION requirements have been met, the ACTION is no longer applicable, or time limits of the ACTION requirements have not expired, thus providing an allowance for the completion of the required actions.

The time limits of Specification 3.0.3 allow 36 hours for the plant to be in COLD SHUTDOWN after a shutdown is initiated during POWER operation. If the plant is in a lower CONDITION of operation when a shutdown is initiated, the time limit for entering the next lower CONDITION of operation applies. However, if a lower CONDITION of operation is entered in less time than allowed, the total allowable time to enter COLD SHUTDOWN, or other OPERATIONAL CONDITION, is not reduced. For example, if HOT SHUTDOWN is entered 10 hours after a shutdown is initiated, the time allowed to enter COLD SHUTDOWN is the next 26 hours because the total time to enter COLD SHUTDOWN is not reduced from the allowable limit of 36 hours after a shutdown is initiated. Therefore, if remedial measures are completed that would permit a return to POWER operation, a penalty is not incurred by having to enter a lower CONDITION of operation in less than the total time allowed.

The same principle applies with regard to the allowable outage time limits of the ACTION requirements, if compliance with the ACTION requirements for one specification results in entry into an OPERATIONAL CONDITION or condition of operation for another specification in which the requirements of the Limiting Condition for Operation are not met. If the new specification becomes applicable in less time than specified, the difference may be added to the allowable outage time limits of the second specification. However, the allowable outage time of ACTION requirements for a higher CONDITION of operation may not be used to extend the allowable outage time that is applicable when a Limiting Condition for Operation is not met in a lower CONDITION of operation.

The shutdown requirements of Specification 3.0.3 do not apply in CONDITIONS 4 and 5, because the ACTION requirements of individual specifications define the remedial measures to be taken.

Specification 3.0.4 establishes limitations on changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability when a Limiting Condition for Operation is not met. It allows placing the unit in an OPERATIONAL CONDITION or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the Limiting Condition for Operation would not be met, in accordance with either Specification 3.0.4.a, Specification 3.0.4.b, or Specification 3.0.4.c.

Specification 3.0.4.a allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met when the associated ACTION requirements to be entered following entry into the OPERATIONAL CONDITION or other specified condition in the Applicability will permit continued operation within the MODE or other specified condition for an unlimited period of time. Compliance with ACTIONS requirements that permit continued operation of the unit for an unlimited period of time in an OPERATIONAL CONDITION or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the OPERATIONAL CONDITION change. Therefore, in such cases, entry into an OPERATIONAL CONDITION or other specified condition in the Applicability may be made and the Required Actions followed after entry into the Applicability.

For example, LCO 3.0.4.a may be used when the Required Action to be entered states that an inoperable instrument channel must be placed in the trip condition within the Completion Time. Transition into a MODE or other specified condition in the Applicability may be made in accordance with LCO 3.0.4 and the channel is subsequently placed in the tripped condition within the Completion Time, which begins when the Applicability is entered. If the instrument channel cannot be placed in the tripped condition and the subsequent default ACTION ("Required Action and associated Completion Time not met") allows the OPERABLE train to be placed in operation, use of LCO 3.0.4.a is acceptable because the subsequent ACTIONS to be entered following entry into the MODE include ACTIONS (place the OPERABLE train in operation) that permit safe plant operation for an unlimited period of time in the MODE or other specified condition to be entered.

Specification 3.0.4.b allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities be assessed and managed. The risk assessment, for the purposes of Specification 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed OPERATIONAL CONDITION change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the Limiting Condition for Operation would be met prior to the expiration of the ACTION requirement's specified time interval that would require exiting the Applicability.

Specification 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the OPERATIONAL CONDITION or other specified condition in the Applicability, and any corresponding risk management actions. The Specification 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in OPERATIONAL CONDITION 1 for the duration of the specified time interval. Since this is allowable, and since in general the risk impact in that particular OPERATIONAL CONDITION bounds the risk of transitioning into and through the applicable OPERATIONAL CONDITIONS or other specified conditions in the Applicability of the Limiting Condition for Operation, the use of the Specification 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the Specification 3.0.4.b allowance is prohibited. The Limiting Condition for Operations governing these system and components contain Notes prohibiting the use of Specification 3.0.4.b by stating that Specification 3.0.4.b is not applicable.

Specification 3.0.4.c allows entry into a OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met based on a Note in the Specification which states Specification 3.0.4.c is applicable. These specific allowances permit entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability when the associated ACTION requirements to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTION requirements or to a specific ACTION requirement of a Specification. The risk assessments

performed to justify the use of Specification 3.0.4.b usually only consider systems and components. For this reason, Specification 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., Reactor Coolant Specific Activity), and may be applied to other Specifications based on NRC plant-specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated OPERATIONAL CONDITION or other specified condition in the Applicability.

The provisions of Specification 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements. In addition, the provisions of Specification 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that result from any unit shutdown. In this

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context, a unit shutdown is defined as a change in OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, and OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4.

Upon entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met, Specification 3.0.1 and Specification 3.0.2 require entry into the applicable Conditions and ACTION requirements until the Condition is resolved, until the Limiting Condition for Operation is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by Specification 4.0.1. Therefore, utilizing Specification 3.0.4 is not a violation of Specification 4.0.1 or Specification 4.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected Limiting Condition for Operation.

Specification 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONs. The sole purpose of this Specification is to provide an exception to Specifications 3.0.1 and 3.0.2 (e.g., to not comply with the applicable ACTION(s)) to allow the performance of required testing to demonstrate:

a. The OPERABILITY of the equipment being returned to service, or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONs is limited to the time necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance. LCO 3.0.5 should not be used in lieu of other practicable alternatives that comply with Required Actions and that do not require changing the MODE or other specified conditions in the Applicability in order to demonstrate equipment is OPERABLE. LCO 3.0.5 is not intended to be used repeatedly.

An example of demonstrating equipment is OPERABLE with the Required Actions not met is opening a manual valve that was closed to comply with Required Actions to isolate a flowpath with excessive Reactor Coolant System (RCS) Pressure Isolation Valve (PIV) leakage in order to perform testing to demonstrate that RCS PIV leakage is now within limit.

Examples of demonstrating equipment OPERABILITY include instances in which it is necessary to take an inoperable channel or trip system out of a tripped condition that was directed by a Required Action, if there is no Required Action Note for this purpose. An example of verifying OPERABILITY of equipment removed from service is taking a tripped channel out of the tripped condition to permit the logic to function and indicate the appropriate response during performance of required testing on the inoperable channel.

Examples of demonstrating the OPERABILITY of other equipment are taking an inoperable channel or trip system out of the tripped condition to 1) prevent the trip function from occurring during the performance of required testing on another channel in the other trip system, or 2) to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

The administrative controls in LCO 3.0.5 apply in all cases to systems or components in Chapter 3 of the Technical Specifications, as long as the testing could not be conducted while complying with the Required Actions. This includes the realignment or repositioning of redundant or alternate equipment or trains previously manipulated to comply with ACTIONS, as well as equipment removed from service or declared inoperable to comply with ACTIONS.

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Specification 3.0.6 establishes an exception to Specifications 3.0.1 and 3.0.2 for supported systems that have a support system Limiting Condition for Operation specified in the Technical Specifications (TS). The exception to Specification 3.0.1 is provided because Specification 3.0.1 would require that the ACTIONs of the associated inoperable supported system Limiting Condition for Operation be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified in the support system Limiting Condition for Operation's ACTIONs. These ACTIONs may include entering the supported system's ACTIONs or may specify other ACTIONs. The exception to Specification 3.0.2 is provided because Specification 3.0.2 would consider not entering into the ACTIONs for the supported system within the specified time intervals as a TS noncompliance.

When a support system is inoperable and there is a Limiting Condition for Operation specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' ACTIONs unless directed to do so by the support system's ACTIONs. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' Limiting Condition for Operations' ACTIONs are eliminated by providing all the actions that are necessary to ensure the plant is maintained in a safe condition in the support system's ACTIONs.

However, there are instances where a support system's ACTION may either direct a supported system to be declared inoperable or direct entry into ACTIONS for the supported system. This may occur immediately or after some specified delay to perform some other ACTION. Regardless of whether it is immediate or after some delay, when a support system's ACTION directs a supported system to be declared inoperable or directs entry into ACTIONs for a supported system, the applicable ACTIONs shall be entered in accordance with Specification 3.0.1.

Specification 6.17, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into Specification 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system ACTIONs. The SFDP implements the requirements of Specification 3.0.6.

The following examples use Figure B 3.0-1 to illustrate loss of safety function conditions that may result when a TS support system is inoperable. In this figure, the fifteen systems that comprise Train A are independent and redundant to the fifteen systems that comprise Train B. To correctly use the figure to illustrate the SFDP provisions for a cross train check, the figure establishes a relationship between support and supported systems as follows: the figure shows System 1 as a support system for System 2 and System 3; System 2 as a support system for System 4 and System 5; and System 4 as a support system for System 8 and System 9. Specifically, a loss of safety function may exist when a support system is inoperable and:

a. A system redundant to system(s) supported by the inoperable support system is also inoperable (EXAMPLE B 3.0.6-1),

b. A system redundant to system(s) in turn supported by the inoperable supported system is also inoperable (EXAMPLE B 3.0.6-2), or

c. A system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable (EXAMPLE B 3.0.6-3).

For the following examples, refer to Figure B 3.0-1.

EXAMPLE B 3.0.6-1
If System 2 of Train A is inoperable and System 5 of Train B is inoperable, a loss of safety function exists in Systems 5, 10, and 11.

EXAMPLE B 3.0.6-2

If System 2 of Train A is inoperable, and System 11 of Train B is inoperable, a loss of safety function exists in System 11.

EXAMPLE B 3.0.6-3

If System 2 of Train A is inoperable, and System 1 of Train B is inoperable, a loss of safety function exists in Systems 2, 4, 5, 8, 9, 10 and 11.

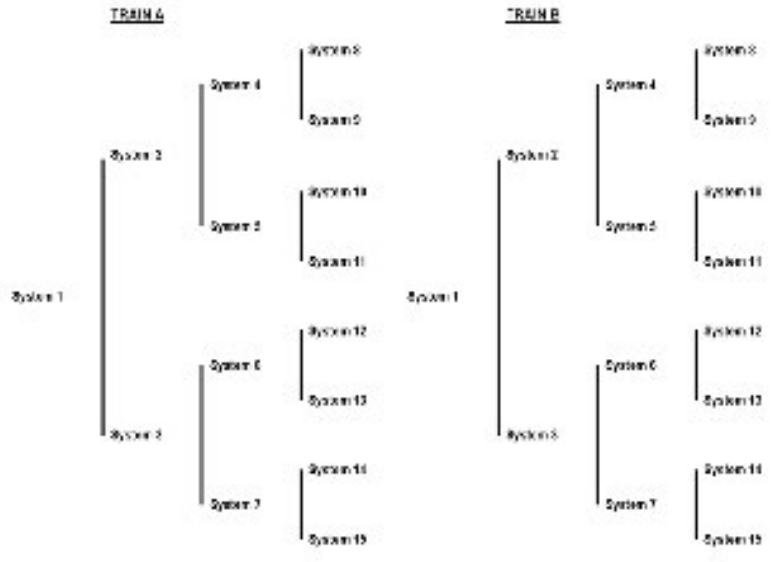


Figure B 3.0-1
Configuration of Trains and Systems

If an evaluation determines that a loss of safety function exists, the appropriate ACTIONs of the Limiting Condition for Operation in which the loss of safety function exists are required to be entered. This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operations are being restricted in accordance with the ACTIONs of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account.

When loss of safety function is determined to exist, and the SFDP requires entry into the appropriate ACTIONs of the Limiting Condition for Operation in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction source due to low tank level), the appropriate Limiting Condition for Operation is the Limiting Condition for Operation for the support system. The ACTIONs for a support system Limiting Condition for Operation adequately address the inoperabilities of that system without reliance on entering its supported system Limiting Condition for Operation. When the loss of function is the result of multiple support systems, the appropriate Limiting Condition for Operation is the Limiting Condition for Operation for the supported system.

Specification 3.0.7 - Not Used

Specification 3.0.8 establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s). This Specification states that the supported system is not considered to be inoperable solely due to one or more snubbers not capable of performing their associated support function(s). This is appropriate because a limited length of time is allowed for maintenance, testing, or repair of one or more snubbers not capable of performing their associated support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the Technical Specifications (TS) under licensee control. The snubber requirements do not meet the criteria in 10 CFR 50.36(c)(2)(ii), and, as such, are appropriate for control by the licensee.

If the allowed time expires and the snubber(s) are unable to perform their associated support function(s), the affected supported system's Limiting Condition for Operation must be declared not met and the associated ACTION requirements shall be met in accordance with Specification 3.0.1.

Specification 3.0.8.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single train or subsystem of a multiple train or subsystem supported system or to a single train or subsystem supported system. Specification 3.0.8.a allows 72 hours to restore the snubber(s) before declaring the supported system inoperable. The 72-hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function and due to the availability of the redundant train of the supported system.

Specification 3.0.8.b applies when one or more snubbers are not capable of providing their associated support function(s) to more than one train or subsystem of a multiple train or subsystem supported system. Specification 3.0.8.b allows 12 hours to restore the snubber(s) before declaring the supported system inoperable. The 12-hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function.

The following configuration restrictions shall be applied to the use of Specification 3.0.8:

(1) Specification 3.0.8.a can only be used if one of the following two means of heat removal is available:

a. At least one high pressure makeup path (e.g., using High Pressure Coolant Injection (HPCI) or Reactor Core Isolation Cooling (RCIC) or its equivalent) and heat removal capability (e.g., suppression pool cooling), including a minimum set of supporting equipment required for success, not associated with the inoperable snubber(s), or

b. At least one low pressure makeup path (e.g., Low Pressure Coolant Injection (LPCI) or Core Spray (CS)) and heat removal capability (e.g., suppression pool cooling or shutdown cooling), including a minimum set of supporting equipment required for success, not associated with the inoperable snubber(s).

(2) Specification 3.0.8.b can only be used following verification that at least one success path exists, using equipment not associated with the inoperable snubber(s), to provide makeup and core cooling needed to mitigate Loss of Offsite Power (LOOP) accident sequences (i.e., initiated by a seismically-induced LOOP event with concurrent loss of all safety system trains supported by the out-of-service snubbers).

Specification 3.0.8 only applies to the seismic function of snubbers; it does not apply to the non-seismic functions of snubbers. Therefore, each use of Specification 3.0.8 for seismic snubbers that also have non-seismic functions requires confirmation that at least one train (or subsystem) of systems supported by the inoperable snubbers would remain capable of performing their required safety or support functions for postulated design loads other than seismic loads. In addition, a record of the design function of the inoperable snubber (i.e., seismic vs. non-seismic), implementation and compliance with the configuration restrictions defined above, and the associated plant configuration shall be available on a recoverable basis for NRC inspection.

Specification 3.0.8 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (i.e., the Maintenance Rule) does not address seismic risk. However, use of Specification 3.0.8 should be considered with respect to other plant maintenance activities, and integrated into the existing Maintenance Rule process to the extent possible so that maintenance on any unaffected train or subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified, but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

Specification 3.0.9 establishes conditions under which systems described in the Technical Specifications are considered to remain OPERABLE when required barriers are not capable of providing their related support function(s).

Barriers are doors, walls, floor plugs, curbs, hatches, installed structures or components, or other devices, not explicitly described in Technical Specifications, that support the performance of the safety function of systems described in the Technical Specifications. This Limiting Condition for Operation states that the supported system is not considered to be inoperable

solely due to required barriers not capable of performing their related support function(s) under the described conditions. Limiting Condition for Operation 3.0.9 allows 30 days before declaring the supported system(s) inoperable and the Limiting Conditions for Operation associated with the supported system(s) not met. A maximum time is placed on each use of this allowance to ensure that as required barriers are found or are otherwise made unavailable, they are restored. However, the allowable duration may be less than the specified maximum time based on the risk assessment.

If the allowed time expires and the barriers are unable to perform their related support function(s), the supported system's Limiting Conditions for Operation must be declared not met and the Conditions and Required Actions entered in accordance with Limiting Condition for Operation 3.0.2.

This provision does not apply to barriers which support ventilation systems or to fire barriers. The Technical Specifications for ventilation systems provide specific Conditions for inoperable barriers. Fire barriers are addressed by other regulatory requirements and associated plant programs. This provision does not apply to barriers which are not required to support system OPERABILITY (see NRC Regulatory Issue Summary 2001-09, "Control of Hazard Barriers," dated April 2, 2001).

The provisions of Limiting Condition for Operation 3.0.9 are justified because of the low risk associated with required barriers not being capable of performing their related support function. This provision is based on consideration of the following initiating event categories:

- Loss of coolant accidents;
- High energy line breaks;
- Feedwater line breaks;
- Internal flooding;
- External flooding;
- Turbine missile ejection; and
- Tornado or high wind.

The risk impact of the barriers which cannot perform their related support function(s) must be addressed pursuant to the risk assessment and management provision of the Maintenance Rule, 10 CFR 50.65 (a)(4), and the associated implementation guidance, Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Regulatory Guide 1.160 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions, and other aspects pertinent to plant operation with the barriers unable to perform their related support function(s). These considerations may result in risk management and other compensatory actions being required during the period that barriers are unable to perform their related support function(s).

Limiting Condition for Operation 3.0.9 may be applied to one or more trains or subsystems of a system supported by barriers that cannot provide their related support function(s), provided that risk is assessed and managed (including consideration of the effects on Large Early Release and from external events). If applied concurrently to more than one train or subsystem of a multiple train or subsystem supported system, the barriers supporting each of these trains or subsystems must provide their related support function(s) for different categories of initiating events. For example, Limiting Condition for Operation 3.0.9 may be applied for up to 30 days for more than one train of a multiple train supported system if the affected barrier for one train protects against internal flooding and the affected barrier for the other train protects against tornado missiles. In this example, the affected barrier may be the same physical barrier but serve different protection functions for each train.

The HPCI and RCIC systems are single train systems for injecting makeup water into the reactor during an accident or transient event. For the purposes of Limiting Condition for Operation 3.0.9, the HPCI system, the RCIC system, and the ADS are considered independent subsystems of a single system and Limiting Condition for Operation 3.0.9 can be used on these single train systems in a manner similar to multiple train or subsystem systems.

If during the time that Limiting Condition for Operation 3.0.9 is being used, the required OPERABLE train or subsystem becomes inoperable, it must be restored to OPERABLE status within 24 hours. Otherwise, the train(s) or subsystem(s) supported by barriers that cannot perform their related support function(s) must be declared inoperable and the associated Limiting Conditions for Operation declared not met. This 24 hour period provides time to respond to emergent conditions that would otherwise likely lead to entry into Limiting Condition for Operation 3.0.3 and a rapid plant shutdown, which is not justified given the low probability of an initiating event which would require the barrier(s) not capable of performing their related support function(s). During this 24 hour period, the plant risk associated with the existing conditions is assessed and managed in accordance with 10 CFR 50.65(a)(4).

BASES

Specification 4.0.1 through 4.0.5 establish the general requirements applicable to Surveillance Requirements. SR 4.0.2 and SR 4.0.3 apply in Section 6, Administrative Controls, only when invoked by a Section 6 Specification. These requirements are based on the Surveillance Requirements stated in the Code of Federal Regulations 10 CFR 50.36(c)(3):

"Surveillance requirements are requirements relating to test, calibration, or inspection to ensure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions of operation will be met."

Specification 4.0.1 establishes the requirement that SRs must be met during the OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which the requirements of the Limiting Condition for Operation apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Surveillance time interval and allowed extension, in accordance with Specification 4.0.2, constitutes a failure to meet the Limiting Condition for Operation.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in an OPERATIONAL CONDITION or other specified condition for which the requirements of the associated Limiting Condition for Operation are not applicable, unless otherwise specified. The SRs associated with a Special Test Exception Limiting Condition for Operation are only applicable when the Special Test Exception Limiting Condition for Operation is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given OPERATIONAL CONDITION or other specified condition.

Surveillances, including Surveillances invoked by ACTION requirements, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with Specification 4.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with Specification 4.0.2. Post maintenance testing may not be possible in the current OPERATIONAL CONDITION or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to an OPERATIONAL CONDITION or other specified condition where other necessary post maintenance tests can be completed.

Some examples of this process are:

a. Control Rod Drive maintenance during refueling that requires scram testing at > 950 psi. However, if other appropriate testing is satisfactorily completed and the scram time testing of Specification 4.1.3.2 is satisfied, the control rod can be considered OPERABLE. This allows startup to proceed to reach 950 psi to perform other necessary testing.

b. High pressure coolant injection (HPCI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPCI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

Specification 4.0.2 establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 24-month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend the surveillance intervals beyond that specified for surveillances that are not performed during refueling outages. Likewise, it is not the intent that REFUELING INTERVAL surveillances be performed during power operation unless it is consistent with safe plant operation. The limitation of Specification 4.0.2 is based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

Specification 4.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been performed within the specified Surveillance time interval and allowed extension. A delay period of up to 24 hours or up to the limit of the specified Surveillance time interval, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with Specification 4.0.2, and not at the time that the specified Surveillance time interval and allowed extension was not met.

When a Section 6.8, “Procedures and Programs,” specification states that the provisions of SR 4.0.3 are applicable, it permits the flexibility to defer declaring the testing requirement not met in accordance with SR 4.0.3 when the testing has not been completed within the testing interval (including the allowance of SR 4.0.2 if invoked by the Section 6.8 specification).

This delay period provides adequate time to perform Surveillances that have been missed. This delay period permits the performance of a Surveillance before complying with ACTION requirements or other remedial measures that might preclude performance of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. When a Surveillance with a Surveillance time interval based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering OPERATIONAL CONDITION 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to have not been performed when specified, Specification 4.0.3 allows for the full delay period of up to the specified Surveillance time interval to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

Specification 4.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of OPERATIONAL CONDITION changes imposed by ACTION requirements.

Specification 4.0.3 (Continued)

SR 4.0.3 is only applicable if there is a reasonable expectation the associated equipment is OPERABLE or that variables are within limits, and it is expected that the Surveillance will be met when performed. Many factors should be considered, such as the period of time since the Surveillance was last performed, or whether the Surveillance, or a portion thereof, has ever been performed, and any other indications, tests, or activities that might support the expectation that the Surveillance will be met when performed. An example of the use of SR 4.0.3 would be a relay contact that was not tested as required in accordance with a particular SR, but previous successful performances of the SR included the relay contact; the adjacent, physically connected relay contacts were tested during the SR performance; the subject relay contact has been tested by another SR; or historical operation of the subject relay contact has been successful. It is not sufficient to infer the behavior of the associated equipment from the performance of similar equipment. The rigor of determining whether there is a reasonable expectation a Surveillance will be met when performed should increase based on the length of time since the last performance of the Surveillance. If the Surveillance has been performed recently, a review of the Surveillance history and equipment performance may be sufficient to support a reasonable expectation that the Surveillance will be met when performed. For Surveillances that have not been performed for a long period or that have never been performed, a rigorous evaluation based on objective evidence should provide a high degree of confidence that the equipment is OPERABLE. The evaluation should be documented in sufficient detail to allow a knowledgeable individual to understand the basis for the determination.

Failure to comply with specified Surveillance time intervals and allowed extensions for SRs is expected to be an infrequent occurrence. Use of the delay period established by Specification 4.0.3 is a flexibility which is not intended to be used repeatedly to extend Surveillance intervals.

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While up to 24 hours or the limit of the specified Surveillance time interval is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, 'Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.' This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the ACTION requirements for the applicable Limiting Condition for Operation begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period or the variable is outside the specified limits, then the equipment is inoperable and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the allowed times specified in the ACTION requirements, restores compliance with Specification 4.0.1.

Specification 4.0.4 establishes the requirement that all applicable SRs must be met before entry into an OPERATIONAL CONDITION or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated OPERATIONAL CONDITION or other specified condition in the Applicability.

A provision is included to allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability when a Limiting Condition for Operation is not met due to a Surveillance not being met in accordance with Specification 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in Specification 4.0.4 restricting an OPERATIONAL CONDITION change or other specified

condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per Specification 4.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, Specification 4.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Surveillance time interval does not result in a Specification 4.0.4 restriction to changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability. However, since the Limiting Condition for Operation is not met in this instance, Specification 3.0.4 will govern any restrictions that may (or may not) apply to OPERATIONAL CONDITION or other specified condition changes. Specification 4.0.4 does not restrict changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Surveillance time interval, provided the requirement to declare the Limiting Condition for Operation not met has been delayed in accordance with Specification 4.0.3.

The provisions of Specification 4.0.4 shall not prevent entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTION requirements. In addition, the provisions of Specification 4.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, and OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4.

Specification 4.0.5 establishes the requirement that inservice inspection of ASME Code Class 1, 2 and 3 components and inservice testing of ASME Code Class 1, 2 and 3 pumps and valves shall be performed in accordance with a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda, and the ASME Code for Operation and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda as required by 10 CFR 50.55a. The provisions of SR 4.0.2 and SR 4.0.3 do not apply to the INSERVICE TESTING PROGRAM unless there is a specific SR referencing usage of the program.

Limerick Generating Station has received a license amendment to implement 10 CFR 50.69, “Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors,” and may voluntarily comply with the requirements of 10 CFR 50.69 as an alternative to compliance with the following requirements for structures, systems, and components (SSCs) that have a Risk-Informed Safety Class (RISC) of RISC-3:

(1) The INSERVICE TESTING PROGRAM requirements of 10 CFR 50.55a(f), and
(2) The inservice inspection, and repair and replacement (with the exception of fracture toughness), requirements for ASME Class 2 and Class 3 SSCs in 10 CFR 50.55a(g).

Therefore, SSCs that have been categorized as RISC-3 in accordance with 10 CFR 50.69 may be removed from the INSERVICE TESTING [IST] PROGRAM and the Inservice Inspection (ISI) Program in accordance with 10 CFR 50.69(b)(1)(v).

RISC-3 SSCs with technical specification surveillance requirements referencing Technical Specification 4.0.5, which have been removed from the IST/ISI programs, are subject to the alternative treatment requirements of 10 CFR 50.69(d)(2). The SSCs must continue to meet the acceptance criteria specified in associated technical specification surveillance requirements, as applicable; however, the surveillance frequency is determined as part of the alternative treatment.

BASES

3/4.1.1 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that (1) the reactor can be made subcritical from all operating conditions, (2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and (3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

Since core reactivity values will vary through core life as a function of fuel depletion and poison burnup, the demonstration of SHUTDOWN MARGIN will be performed in the cold, xenon-free condition and shall show the core to be subcritical by at least R + 0.38% Δ k/k or R + 0.28% Δ k/k, as appropriate. The 0.38% Δ k/k includes uncertainties and calculation biases. The value of R in units of % Δ k/k is the difference between the calculated value of minimum shutdown margin during the operating cycle and the calculated shutdown margin at the time of the shutdown margin test at the beginning of cycle. The value of R must be positive or zero and must be determined for each fuel loading cycle.

Two different values are supplied in the Limiting Condition for Operation to provide for the different methods of demonstration of the SHUTDOWN MARGIN. The highest worth rod may be determined analytically or by test. The SHUTDOWN MARGIN is demonstrated by (an insequence) control rod withdrawal at the beginning of life fuel cycle conditions, and, if necessary, at any future time in the cycle if the first demonstration indicates that the required margin could be reduced as a function of exposure. Observation of subcriticality in this condition assures subcriticality with the most reactive control rod fully withdrawn.

This reactivity characteristic has been a basic assumption in the analysis of plant performance and can be best demonstrated at the time of fuel loading, but the margin must also be determined anytime a control rod is incapable of insertion.

3/4.1.2 REACTIVITY ANOMALIES

Since the SHUTDOWN MARGIN requirement for the reactor is small, a careful check on actual conditions to the predicted conditions is necessary, and the changes in reactivity can be inferred from these comparisons of core $k_{effective}$ (k_{eff}). Since the comparisons are easily done, frequent checks are not an imposition on normal operations. A 1% change is larger than is expected for normal operation so a change of this magnitude should be thoroughly evaluated. A change as large as 1% would not exceed the design conditions of the reactor and is on the safe side of the postulated transients.

3/4.1.3 CONTROL RODS

The specification of this section ensure that (1) the minimum SHUTDOWN MARGIN is maintained, (2) the control rod insertion times are consistent with those used in the accident analysis, and (3) the potential effects of the rod drop accident are limited. The ACTION statements permit variations from the basic requirements but at the same time impose more restrictive criteria for continued operation. A limitation on inoperable rods is set such that the resultant effect on total rod worth and scram shape will be kept to a minimum. The requirements for the various scram time measurements ensure that any indication of systematic problems with rod drives will be investigated on a timely basis.

Damage within the control rod drive mechanism could be a generic problem, therefore with a control rod immovable because of excessive friction or mechanical interference, operation of the reactor is limited to a time period which is reasonable to determine the cause of the inoperability and at the same time prevent operation with a large number of inoperable control rods.

Control rods that are inoperable for other reasons are permitted to be taken out of service provided that those in the nonfully-inserted position are consistent with the SHUTDOWN MARGIN requirements.

With two or more withdrawn control rods immovable, the reactor must be brought to HOT SHUTDOWN. The occurrence of more than one control rod immovable at a withdrawn position increases the probability that the reactor cannot be shut down if required. Insertion of all insertable control rods eliminates the possibility of an additional failure of a control rod to insert.

The number of control rods permitted to be inoperable could be more than the eight allowed by the specification, but the occurrence of eight inoperable rods could be indicative of a generic problem and the reactor must be shutdown for investigation and resolution of the problem.

The control rod system is designed to bring the reactor subcritical at a rate fast enough to prevent the MCPR from becoming less than the fuel cladding safety limit during the limiting power transient analyzed in Section 15.2 of the FSAR. This analysis shows that the negative reactivity rates resulting from the scram with the average response of all the drives as given in the specifications, provided the required protection and MCPR remains greater than the fuel cladding safety limit. The occurrence of scram times longer then those specified should be viewed as an indication of a systemic problem with the rod drives and therefore the surveillance interval is reduced in order to prevent operation of the reactor for long periods of time with a potentially serious problem.

Scram time testing at zero psig reactor coolant pressure is adequate to ensure that the control rod will perform its intended scram function during startup of the plant until scram time testing at 950 psig reactor coolant pressure is performed prior to exceeding 40% rated core thermal power.

The scram discharge volume is required to be OPERABLE so that it will be available when needed to accept discharge water from the control rods during a reactor scram and will isolate the reactor coolant system from the containment when required.

CONTROL RODS (Continued)

The OPERABILITY of all SDV vent and drain valves ensures that the SDV vent and drain valves will close during a scram to contain reactor water discharged to the SDV piping. The SDV has one common drain line and one common vent line. Since the vent and drain lines are provided with two valves in series, the single failure of one valve in the open position will not impair the isolation function of the system. Additionally, the valves are required to open on scram reset to ensure that a path is available for the SDV piping to drain freely at other times.

When one SDV vent or drain valve is inoperable in one or more lines, the valves must be restored to OPERABLE status within 7 days. The allowable outage time is reasonable, given the level of redundancy in the lines and the low probability of a scram occurring while the valve(s) are inoperable. The SDV is still isolable since the redundant valve in the affected line is OPERABLE. During these periods, the single failure criterion may not be preserved, and a higher risk exists to allow reactor water out of the primary system during a scram.

If both valves in a line are inoperable, the line must be isolated to contain the reactor coolant during a scram. When a line is isolated, the potential for an inadvertent scram due to high SDV level is increased. The associated ACTION is modified by a note ("****") that allows periodic draining and venting of the SDV when a line is isolated. During these periods, the line may be unisolated under administrative control. This allows any accumulated water in the line to be drained, to preclude a reactor scram on SDV high level. This is acceptable since the administrative controls ensure the valve can be closed quickly, by a dedicated operator, if a scram occurs with the valve open. The 8 hour allowable outage time to isolate the line is based on the low probability of a scram occurring while the line is not isolated and the unlikelihood of significant CRD seal leakage.

Control rods with inoperable accumulators are declared inoperable and Specification 3.1.3.1 then applies. This prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed even though control rods with inoperable accumulators may still be inserted with normal drive water pressure. The drive water pressure normal operating range is specified in system operating procedures which provide ranges for system alignment and control rod motion (exercising). Operability of the accumulator ensures that there is a means available to insert the control rods even under the most unfavorable depressurization of the reactor. A control rod is considered trippable if it is capable of fully inserting as a result of a scram signal.

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CONTROL RODS (Continued)

Control rod coupling integrity is required to ensure compliance with the analysis of the rod drop accident in the FSAR. The overtravel position feature provides the only positive means of determining that a rod is properly coupled and therefore this check must be performed prior to achieving criticality after completing CORE ALTERATIONS that could have affected the control rod coupling integrity. The subsequent check is performed as a backup to the initial demonstration.

In order to ensure that the control rod patterns can be followed and therefore that other parameters are within their limits, the control rod position indication system must be OPERABLE.

The control rod housing support restricts the outward movement of a control rod to less than 3 inches in the event of a housing failure. The amount of rod reactivity which could be added by this small amount of rod withdrawal is less than a normal withdrawal increment and will not contribute to any damage to the primary coolant system. The support is not required when there is no pressure to act as a driving force to rapidly eject a drive housing.

The required surveillances are adequate to determine that the rods are OPERABLE and not so frequent as to cause excessive wear on the system components.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

Control rod withdrawal and insertion sequences are established to assure that the maximum insequence individual control rod or control rod segments which are withdrawn at any time during the fuel cycle could not be worth enough to result in a peak fuel enthalpy greater than 280 cal/gm in the event of a control rod drop accident. The specified sequences are characterized by homogeneous, scattered patterns of control rod withdrawal. When THERMAL POWER is greater than 10% of RATED THERMAL POWER, there is no possible rod worth which, if dropped at the design rate of the velocity limiter, could result in a peak enthalpy of 280 cal/gm. Thus requiring the RWM to be OPERABLE when THERMAL POWER is less than or equal to 10% of RATED THERMAL POWER provides adequate control.

The RWM provides automatic supervision to assure that out-of-sequence rods will not be withdrawn or inserted.

The analysis of the rod drop accident is presented in Section 15.4.9 of the FSAR and the techniques of the analysis are presented in a topical report, Reference 1, and two supplements, References 2 and 3. Additional pertinent analysis is also contained in Amendment 17 to the Reference 4 Topical Report.

The RBM is designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density over the range of power operation. Two channels are provided. Tripping one of the channels will block erroneous rod withdrawal to prevent fuel damage. This system backs up the written sequence used by the operator for withdrawal of control rods. RBM OPERABILITY is required when the limiting condition described in Specification 3.1.4.3 exists.

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

The standby liquid control system provides a backup capability for bringing the reactor from full power to a cold, Xenon-free shutdown, assuming that the withdrawn control rods remain fixed in the rated power pattern. To meet this objective it is necessary to inject a quantity of boron which produces a concen-tration of 660 ppm in the reactor core and other piping systems connected to the reactor vessel. To allow for potential leakage and improper mixing, this con-centration is increased by 25%. The required concentration is achieved by having available a minimum quantity of 3,160 gallons of sodium pentaborate solution containng a minimum of 3,754 lbs of sodium pentaborate having the requisite Boron-10 atom % enrichment of 29% as determined from Reference 5. This quantity of solution is a net amount which is above the pump suction shutoff level setpoint thus allowing for the portion which cannot be injected.

The above quantities calculated at 29% Boron-10 enrichment have been demonstrated by analysis to provide a Boron-10 weight equivalent of 185 lbs in the sodium pentaborate solution. Maintaining this Boron-10 weight in the net tank contents ensures a sufficient quantity of boron to bring the reactor to a cold, Xenon-free shutdown.

The pumping rate of 37.0 gpm provides a negative reactivity insertion rate over the permissible solution volume range, which adequately compensates for the positive reactivity effects due to elimination of steam voids, increased water density from hot to cold, reduced doppler effect in uranium, reduced neutron leakage from boiling to cold, decreased control rod worth as the moderator cools, and xenon decay. The temperature requirement ensures that the sodium pentaborate always remains in solution.

With redundant pumps and explosive injection valves and with a highly reliable control rod scram system, operation of the reactor is permitted to continue for short periods of time with the system inoperable or for longer periods of time with one of the redundant components inoperable.

The SLCS system consists of three separate and independent pumps and explosive valves. Two of the separate and independent pumps and explosive valves are required to meet the minimum requirements of this technical specification and, where applicable, satisfy the single failure criterion. To ensure that SLCS pump discharge pressure does not exceed the SLCS relief valve setpoint during operation following an anticipated transient without scram (ATWS) event, no more than two pumps shall be aligned for automatic operation in OPERATIONAL CONDITIONS 1, 2, and 3. This maintains the equivalent control capacity to satisfy 10 CFR 50.62 (Requirements for reduction of risk from anticipated transients without scram (ATWS). With three pumps aligned for automatic operation, the system is inoperable and ACTION statement (b) applies.

The SLCS must have an equivalent control capacity of 86 gpm of 13% weight sodium pentaborate in order to satisfy 10 CFR 50.62. As part of the ARTS/MELLL program the ATWS analysis was updated to reflect the new rod line. As a result of this it was determined that the Boron 10 enrichment was required to be increased to 29% to prevent exceeding a suppression pool temperature of 190°F. This equivalency requirement is fulfilled by having a system which satisfies the equation given in 4.1.5.b.2.

The upper limit concentration of 13.8% has been established as a reasonable limit to prevent precipitation of sodium pentaborate in the event of a loss of tank heating, which allow the solution to cool. A SLCS Pump flowrate of 37.0 gpm (minimum) and a Sodium Pentaborate Solution concentration of 9% by weight (minimum) will require a Boron-10 enrichment of 49 atom % to be added to the tank. The decreased pump flowrate and increased solution enrichment are acceptable because the results of the ATWS Rule Equation will remain > 1.0.

STANDBY LIQUID CONTROL SYSTEM (Continued)

Surveillance requirements are established on a frequency that assures a high reliability of the system. Once the solution is established, boron concentration will not vary unless more boron or water is added, thus a check on the temperature and volume assures that the solution is available for use.

Replacement of the explosive charges in the valves will assure that these valves will not fail because of deterioration of the charges.

The Standby Liquid Control System also has a post-DBA LOCA safety function to buffer Suppression Pool pH in order to maintain bulk pH above 7.0. The buffering of Suppression Pool pH is necessary to prevent iodine re-evolution to satisfy the methodology for Alternative Source Term. Manual initiation is used, and the minimum amount of total boron required for Suppression Pool pH buffering is 256 lbs. Given that at least 185 lbs of Boron-10 is maintained in the tank, the total boron in the tank will be greater than 256 lbs for the range of enrichments from 29% to 62%.

ACTION Statement (a) applies only to OPERATIONAL CONDITIONS 1 and 2 because a single pump can satisfy both the reactor control function and the post-DBA LOCA function to control Suppression Pool pH since boron injection is not required until 13 hours post-LOCA. ACTION Statement (b) applies to OPERATIONAL CONDITIONS 1, 2 and 3 to address the post-LOCA safety function of the SLC system.

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1. C. J. Paone, R. C. Stirn and J. A. Woolley, "Rod Drop Accident Analysis for Large BWR's," G. E. Topical Report NEDO-10527, March 1972.

2. C. J. Paone, R. C. Stirn, and R. M. Young, Supplement 1 to NEDO-10527, July 1972.

3. J. M. Haun, C. J. Paone, and R. C. Stirn, Addendum 2, "Exposed Cores," Supplement 2 to NEDO-10527, January 1973.

4. Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel".

5. "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," NEDC-32193P, Revision 2, October 1993.

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3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

This specification assures that the peak cladding temperature (PCT) following the postulated design basis Loss-of-Coolant Accident (LOCA) will not exceed the limits specified in 10 CFR 50.46 and that the fuel design analysis limits specified in NEDE-24011-P-A (Reference 2) will not be exceeded.

Mechanical Design Analysis: NRC approved methods (specified in Reference 2) are used to demonstrate that all fuel rods in a lattice operating at the bounding power history, meet the fuel design limits specified in Reference 2. No single fuel rod follows, or is capable of following, this bounding power history. This bounding power history is used as the basis for the fuel design analysis MAPLHGR limit.

LOCA Analysis: A LOCA analysis is performed in accordance with 10CFR50 Appendix K to demonstrate that the permissible planar power (MAPLHGR) limits comply with the ECCS limits specified in 10 CFR 50.46. The analysis is performed for the most limiting break size, break location, and single failure combination for the plant, using the evaluation model described in Reference 9.

The MAPLHGR limit as showm in the CORE OPERATING LIMITS REPORT is the most limiting composite of the fuel mechanical design anaylsis MAPLHGR and the ECCS MAPLHGR limit.

Only the most limiting MAPLHGR values are shown in the CORE OPERATING LIMITS REPORT for multiple lattice fuel. Compliance with the specific lattice MAPLHGR operating limits, which are available in Reference 3, is ensured by use of the process computer.

As a result of no longer utilizing an APRM trip setdown requirement, additional constraints are placed on the MAPLHGR limits to assure adherence to the fuel-mechanical design bases. These constraints are introduced through the MAPFAC(P) and MAPFAC(F) factors as defined in the COLR.

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3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady-state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity MCPR(99.9%), and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady-state operating limit, it is required that less than Ø.1% of fuel rods in the core are susceptible to transition boiling of that the resulting MCPR does not decrease below the operating limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease.

The evaluation of a given transient begins with the system initial parameters shown in FSAR Table 15.Ø-2 that are input to a BWR system dynamic behavior transient computer program. The codes used to evaluate transients are discussed in Reference 2.

MCPR(99.9%) is determined to ensure more than 99.9% of the fuel rods in the core are not susceptible to boiling transition using a statistical model that combines all the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the approved Critical Power correlations. Details of the MCPR(99.9%) calculation are given in Reference 2. Reference 2 also includes a tabulation of the uncertainties and the nominal values of the parameters used in the MCPR99.9% statistical analysis.

The MCPR operating limits are derived from the MCPR(99.9%) value and the transient analysis, and are dependent on the operating core flow and power state (MCPR(F), and MCPR(P), respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency (Ref. 6). Flow dependent MCPR limits (MCPR(F)) are determined by steady state thermal hydraulic methods with key physics response inputs benchmarked using the three dimensional BWR simulator code (Ref. 7) to analyze slow flow runout transients.

Power dependent MCPR limits (MCPR(P)) are determined by approved transient analysis (Reference 2). Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scrams are bypassed, high and low flow MCPR(P), operating limits are provided for operating between 25% RTP and 3Ø% RTP.

The MCPR operating limits specified in the COLR (MCPR(99.9%) value MCPR(F), and MCPR(P) values are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is determined by the larger of the MCPR(F), and MCPR(P) limits which are based on the MCPR(99.9%) limit specified in the COLR.

MINIMUM CRITICAL POWER RATIO (Continued)

At THERMAL POWER levels less than or equal to 25% of RATED THERMAL POWER, the reactor will be operating at minimum recirculation pump speed and the moderator void content will be very small. For all designated control rod patterns which may be employed at this point, operating plant experience indicates that the resulting MCPR value is in excess of requirements by a considerable margin. During initial startup testing of the plant, a MCPR evaluation will be made at 25% of RATED THERMAL POWER level with minimum recirculation pump speed. The MCPR margin will thus be demonstrated such that future MCPR evaluation below this power level will be shown to be unnecessary. The daily requirement for calculating MCPR when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement for calculating MCPR when a limiting control rod pattern is approached ensures that MCPR will be known following a change in THERMAL POWER or power shape, regardless of magnitude, that could place operation at a thermal limit.

3/4.2.4 LINEAR HEAT GENERATION RATE

This specification assures that the Linear Heat Generation Rate (LHGR) in any rod is less than the design linear heat generation even if fuel pellet densification is postulated.

Reference:

1. Deleted.

2. "General Electric Standard Application for Reactor Fuel," NEDE-24011-P-A (latest approved revision).

3. "Basis of MAPLHGR Technical Specifications for Limerick Unit 2," NEDC-31930P (as amended).

4. Deleted

5. Increased Core Flow and Partial Feedwater Heating Analysis for Limerick Generating Station Unit 2 Cycle 1, NEDC-31578P, MARCH 1989 including Errata and Addenda Sheet No. 1 dated MAY 31, 1989.

6. NEDC-32193P, "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Limerick Generating Station Units 1 and 2," Revision 2, October 1993.

7. NEDO-30130-A, "Steady State Nuclear Methods," May 1985.

8. NEDO-24154, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," October 1978.

9. NEDC-32170P, "Limerick Generating Station Units 1 and 2 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," June 1993.

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3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and

d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its intended function even during periods when instrument channels may be out of service because of maintenance. When necessary, one channel may be made inoperable for brief intervals to conduct required surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. The APRM system is divided into four APRM channels and four 2-Out-Of-4 Voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed.

The system meets the intent of IEEE-279 for nuclear power plant protection systems. Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System" and NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function." The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

The APRM Functions include five Functions accomplished by the four APRM channels (Functions 2.a, 2.b, 2.c, 2.d, and 2.f) and one accomplished by the four 2-Out-Of-4 Voter channels (Function 2.e). Two of the five Functions accomplished by the APRM channels are based on neutron flux only (Functions 2.a and 2.c), one Function is based on neutron flux and recirculation drive flow (Function 2.b) and one is based on equipment status (Function 2.d). The fifth Function accomplished by the APRM channels is the Oscillation Power Range Monitor (OPRM) Upscale trip Function 2.f, which is based on detecting oscillatory characteristics in the neutron flux. The OPRM Upscale Function is also dependent on average neutron flux (Simulated Thermal Power) and recirculation drive flow, which are used to automatically enable the output trip.

The Two-Out-Of-Four Logic Module includes 2-Out-Of-4 Voter hardware and the APRM Interface hardware. The 2-Out-Of-4 Voter Function 2.e votes APRM Functions 2.a, 2.b, 2.c, and 2.d independently of Function 2.f. This voting is accomplished by the 2-Out-Of-4 Voter hardware in the Two-Out-Of-Four Logic Module. The voter includes separate outputs to RPS for the two independently voted sets of Functions, each of which is redundant (four total outputs). The analysis in Reference 2 took credit for this redundancy in the justification of the 12-hour allowed out-of-service time for

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

Action b, so the voter Function 2.e must be declared inoperable if any of its functionality is inoperable. The voter Function 2.e does not need to be declared inoperable due to any failure affecting only the APRM Interface hardware portion of the Two-Out-Of-Four Logic Module.

Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. To provide adequate coverage of the entire core, consistent with the design bases for the APRM Functions 2.a, 2.b, and 2.c, at least 20 LPRM inputs, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM channel. In addition, no more than 9 LPRMs may be bypassed between APRM calibrations (weekly gain adjustments). For the OPRM Upscale Function 2.f, LPRMs are assigned to "cells" of 3 or 4 detectors. A minimum of 23 cells (Reference 9), each with a minimum of 2 OPERABLE LPRMs, must be OPERABLE for each APRM channel for the OPRM Upscale Function 2.f to be OPERABLE in that channel. LPRM gain settings are determined from the local flux profiles measured by the TIP system. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 2000 EFPH frequency is based on operating experience with LPRM sensitivity changes.

References 4, 5 and 6 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

An OPRM Upscale trip is issued from an APRM channel when the period based detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in any cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the growth rate or amplitude based algorithms detect growing oscillatory changes in the neutron flux for one or more cells in that channel.

The OPRM Upscale Function is required to be OPERABLE when the plant is at $\geq$ 25% RATED THERMAL POWER. The 25% RATED THERMAL POWER level is selected to provide margin in the unlikely event that a reactor power increase transient occurring while the plant is operating below 29.5% RATED THERMAL POWER causes a power increase to or beyond the 29.5% RATED THERMAL POWER OPRM Upscale trip auto-enable point without operator action. This OPERABILITY requirement assures that the OPRM Upscale trip automatic-enable function will be OPERABLE when required.

Actions a, b and c define the Action(s) required when RPS channels are discovered to be inoperable. For those Actions, separate entry condition is allowed for each inoperable RPS channel. Separate entry means that the allowable time clock(s) for Actions a, b or c start upon discovery of inoperability for that specific channel. Restoration of an inoperable RPS channel satisfies only the action statements for that particular channel. Action statement(s) for remaining inoperable channel(s) must be met according to their original entry time.

A Note has been provided to modify the Actions when Functional Unit 2.b and 2.c channels are inoperable due to failure of SR 4.3.1.1 and gain adjustments are necessary. The Note allows entry into associated Actions to be delayed for up to 2 hours if the APRM is indicating a lower power value than the calculated power (i.e., the gain adjustment factor (GAF) is high (non-conservative)). The GAF for any channel is defined as the power value determined by the heat balance divided by the APRM reading for that channel. Upon completion of the gain adjustment, or

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

expiration of the allowed time, the channel must be returned to OPERABLE status or the applicable Actions taken. This Note is based on the time required to perform gain adjustments on multiple channels.

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (NEDC-30851P-A and NEDC-32410P-A) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided that the associated Function's (identified as a "Functional Unit" in Table 3.3.1-1) inoperable channel is in one trip system and the Function still maintains RPS trip capability. Alternatively, an allowable out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

The requirements of Action a are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic, including the IRM Functions and APRM Function 2.e (trip capability associated with APRM Functions 2.a, 2.b, 2.c, 2.d, and 2.f are discussed below), this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip).

For Function 5 (Main Steam Isolation Valve--Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 9 (Turbine Stop Valve-Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The completion time to satisfy the requirements of Action a is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels. Alternatively, the completion time can be determined in accordance with the Risk Informed Completion Time Program.

With trip capability maintained, i.e., Action a satisfied, Actions b and c as applicable must still be satisfied. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Action b requires that the channel or the associated trip system must be placed in the tripped condition. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue.

As noted, placing the trip system in trip is not applicable to satisfy Action b for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of one required APRM channel affects both trip systems. For that condition, the Action b requirements can only be satisfied by placing the inoperable APRM channel in trip. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and the requirement to satisfy Action a.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

The requirements of Action c must be satisfied when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, normally the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system (see additional bases discussion above related to loss of trip capability and the requirements of Action a, and special cases for Functions 2.a, 2.b, 2.c, 2.d, 2.f, 5 and 9).

The requirements of Action c limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in NEDC-30851P-A for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function must have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing the actions required by Action c restores RPS to a reliability level equivalent to that evaluated in NEDC-30851P-A, which justified a 12 hour allowable out of service time as allowed by Action b. To satisfy the requirements of Action c, the trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what OPERATIONAL CONDITION the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour allowable out of service time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

As noted, Action c is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of an APRM channel affects both trip systems and is not associated with a specific trip system as are the APRM 2-Out-Of-4 voter and other non-APRM channels for which Action c applies. For an inoperable APRM channel, the requirements of Action b can only be satisfied by tripping the inoperable APRM channel. Restoring OPERABILITY or placing the inoperable APRM channel in trip are the only actions that will restore capability to accommodate a single APRM channel failure.

If it is not desired to place the channel (or trip system) in trip to satisfy the requirements of Action a, Action b or Action c (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Action d requires that the Action defined by Table 3.3.1-1 for the applicable Function be initiated immediately upon expiration of the allowable out of service time.

Table 3.3.1-1, Function 2.f, references Action 10, which defines the action required if OPRM Upscale trip capability is not maintained. Action 10b is required to address identified equipment failures. Action 10a is to address common mode vendor/industry identified issues that render all four OPRM channels inoperable at once. For this condition, References 2 and 3 justified use of alternate methods to detect and suppress oscillations for a limited period of

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

time, up to 120 days. The alternate methods are procedurally established consistent with the guidelines identified in Reference 7 requiring manual operator action to scram the plant if certain predefined events occur. The 12-hour allowed completion time to implement the alternate methods is based on engineering judgment to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and suppress trip capability is formally in place. The 120-day period during which use of alternate methods is allowed is intended to be an outside limit to allow for the case where design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. The evaluation of the use of alternate methods concluded, based on engineering judgment, that the likelihood of an instability event that could not be adequately handled by the alternate methods during the 120-day period was negligibly small. Plant startup may continue while operating within the allowed completion time of Action 10a. The primary purpose of this is to allow an orderly completion, without undue impact on plant operation, of design and verification activities in the event of a required design change to the OPRM Upscale function. This exception is not intended as an alternative to restoring inoperable equipment to OPERABLE status in a timely manner.

Action 10a is not intended and was not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to be accomplished within the completion times allowed for LCO 3.3.1 Action a or Action b, as applicable. Action 10b applies when routine equipment OPERABILITY cannot be restored within the allowed completion times of LCO 3.3.1 Actions a or b, or if a common mode OPRM deficiency cannot be corrected and OPERABILITY of the OPRM Upscale Function restored within the 120-day allowed completion time of Action 10a.

The OPRM Upscale trip output shall be automatically enabled (not-bypassed) when APRM Simulated Thermal Power is $\geq$ 29.5% and recirculation drive flow is $<$ 60% as indicated by APRM measured recirculation drive flow. NOTE: 60% recirculation drive flow is the recirculation drive flow that corresponds to 60% of rated core flow. This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations may occur. As noted in Table 4.3.1.1-1, Note c, CHANNEL CALIBRATION for the OPRM Upscale trip Function 2.f includes confirming that the auto-enable (not-bypassed) setpoints are correct. Other surveillances ensure that the APRM Simulated Thermal Power properly correlates with THERMAL POWER (Table 4.3.1.1-1, Note d) and that recirculation drive flow properly correlates with core flow (Table 4.3.1.1-1, Note g).

If any OPRM Upscale trip auto-enable setpoint is exceeded and the OPRM Upscale trip is not enabled, i.e., the OPRM Upscale trip is bypassed when APRM Simulated Thermal Power is $\geq$ 29.5% and recirculation drive flow is $<$ 60%, then the affected channel is considered inoperable for the OPRM Upscale Function. Alternatively, the OPRM Upscale trip auto-enable setpoint(s) may be adjusted to place the channel in the enabled condition (not-bypassed). If the OPRM Upscale trip is placed in the enabled condition, the surveillance requirement is met and the channel is considered OPERABLE.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

As noted in Table 4.3.1.1-1, Note g, CHANNEL CALIBRATION for the APRM Simulated Thermal Power - Upscale Function 2.b and the OPRM Upscale Function 2.f, includes the recirculation drive flow input function. The APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function both require a valid drive flow signal. The APRM Simulated Thermal Power - Upscale Function uses drive flow to vary the trip setpoint. The OPRM Upscale Function uses drive flow to automatically enable or bypass the OPRM Upscale trip output to RPS. A CHANNEL CALIBRATION of the APRM recirculation drive flow input function requires both calibrating the drive flow transmitters and establishing a valid drive flow / core flow relationship. The drive flow / core flow relationship is established once per refuel cycle, while operating within 10% of rated core flow and within 10% of RATED THERMAL POWER. Plant operational experience has shown that this flow correlation methodology is consistent with the guidance and intent in Reference 8. Changes throughout the cycle in the drive flow / core flow relationship due to the changing thermal hydraulic operating conditions of the core are accounted for in the margins included in the bases or analyses used to establish the setpoints for the APRM Simulated Thermal Power - Upscale Function and the OPRM Upscale Function.

For the Simulated Thermal Power - Upscale Function (Function 2.b), the CHANNEL CALIBRATION surveillance requirement is modified by two Notes. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be within the as-left tolerance of the Trip Setpoint. The as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the Trip Setpoint, then the channel shall be declared inoperable. The as-left tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy and the measurement and test equipment error (including readability). The as-found tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy, instrument drift, and the measurement and test equipment error (including readability).

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are adjusted to the reactor power calculated from a heat balance if the heat balance calculated reactor power exceeds the APRM channel output by more than 2% RTP.

This Surveillance does not preclude making APRM channel adjustments, if desired, when the heat balance calculated reactor power is less than the APRM channel output. To provide close agreement between the APRM indicated power and to preserve operating margin, the APRM channels are normally adjusted to within +/- 2% of the heat balance calculated reactor power. However, this agreement is not required for OPERABILITY when APRM output indicates a higher reactor power than the heat balance calculated reactor power.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION (continued)

As noted in Table 3.3.1-2, Note "*", the redundant outputs from the 2-Out-Of-4 Voter channel are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels, so N = 8 to determine the interval between tests for application of Specification 4.3.1.3 (REACTOR PROTECTION SYSTEM RESPONSE TIME). The note further requires that testing of OPRM and APRM outputs shall be alternated.

Each test of an OPRM or APRM output tests each of the redundant outputs from the 2-Out-Of-4 Voter channel for that function, and each of the corresponding relays in the RPS. Consequently, each of the RPS relays is tested every fourth cycle. This testing frequency is twice the frequency justified by References 2 and 3.

Automatic reactor trip upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

The measurement of response time at the frequencies specified in the Surveillance Frequency Control Program provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable except for the APRM Simulated Thermal Power - Upscale and Neutron Flux - Upscale trip functions and the OPRM Upscale trip function (Table 3.3.1-2, Items 2.b, 2.c, and 2.f). Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times. Response time testing for the sensors as noted in Table 3.3.1-2 is not required based on the analysis in NEDO-32291-A. Response time testing for the remaining channel components is required as noted. For the digital electronic portions of the APRM functions, performance characteristics that determine response time are checked by a combination of automatic self-test, calibration activities, and response time tests of the 2-Out-Of-4 Voter (Table 3.3.1-2, Item 2.e).

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensures the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30851P, Supplement 2, "Technical Specification Improvement Analysis for BWR Instrumentation Common to RPS and ECCS Instrumentation" as approved by the NRC and documented in the NRC Safety Evaluation Report (SER) (letter to D.N. Grace from C.E. Rossi dated January 6, 1989) and NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," as approved by the NRC and documented in the NRC SER (letter to S.D. Floyd from C.E. Rossi dated June 18, 1990).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Automatic closure of the MSIVs upon receipt of a high-high radiation signal from the Main Steam Line Radiation Monitoring System was removed as the result of an analysis performed by General Electric in NEDO-31400A. The NRC approved the results of this analysis as documented in the SER (letter to George J. Beck, BWR Owner's Group from A.C. Thadani, NRC, dated May 15, 1991).

Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 10-second diesel startup and the 3 second load center loading delay. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13-second delay. It follows that checking the valve speeds and the 13-second time for emergency power establishment will establish the response time for the isolation functions.

Response time testing for sensors are not required based on the analysis in NEDO-32291-A. Response time testing of the remaining channel components is required as noted in Table 3.3.2-3.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses. Primary containment isolation valves that are actuated by the isolation signals specified in Technical Specification Table 3.3.2-1 are identified in Technical Requirements Manual Table 3.6.3-1.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.3.2 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION (Continued)

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with NEDC-30936P, Parts 1 and 2, "Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," as approved by the NRC and documented in the SER (letter to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1) and letter to D. N. Grace from C. E. Rossi dated December 9, 1988 (Part 2)).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power for energizing various components such as pump motors, motor operated valves, and the associated control components. If the loss of power instrumentation detects that voltage levels are too low, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The loss of power relays in each channel have sufficient overlapping detection characteristics and functionality to permit operation subject to the conditions in Action Statement 37. Bases 3/4.8.1, 3/4.8.2, and 3/4.8.3 provide discussion regarding parametric bounds for determining operability of the offsite sources. Those Bases assume that the loss of power relays are operable. With an inoperable 127Z-11XØX relay, the grid voltage is monitored to 230kV (for the 1Ø1 Safeguard Bus Source) or 525kV (for the 2Ø1 Safeguard Bus Source) to increase the margin for the operation of the 127Z-11XØX relay.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.3.A REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

Technical Specifications are required by 1Ø CFR 5Ø.36 to include limiting safety system settings (LSSS) for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a safety action is initiated to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur. The actual settings for the automatic isolation channels are the same as those established for the same functions in OPERATIONAL CONDITIONS 1, 2, and 3 in Table 3.3.2-2, "ISOLATION ACTUATION INSTRUMENTATION SETPOINTS."

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

if they will be isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation.

The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, "Reactor Pressure Vessel (RPV) Water Inventory Control (WIC)," and the definition of DRAIN TIME. There are functions that support automatic isolation of Residual Heat Removal (RHR) subsystem and Reactor Water Cleanup (RWCU) system penetration flow path(s) on low RPV water level.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in OPERATIONAL CONDITIONS 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered postulated in which an initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure. It is assumed, based on engineering judgment, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can be manually initiated to maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Permissive and interlock setpoints are generally considered as nominal values without regard to measurement accuracy.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function-by-Function basis.

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

RHR System Isolation - Reactor Vessel Water Level Low - Level 3

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level Low - Level 3 Function associated with RHR System isolation may be credited for automatic isolation of penetration flow paths associated with the RHR System.

Reactor Vessel Water Level Low - Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level Low - Level 3 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level Low - Level 3 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level Low - Level 3 Allowable Value (Table 3.3.2-2), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level Low - Level 3 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 2 valves.

Reactor Water Cleanup (RWCU) System Isolation - Reactor Vessel Water Level - Low, Low - Level 2

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. The Reactor Vessel Water Level - Low, Low - Level 2 Function associated with RWCU System isolation may be credited for automatic isolation of penetration flow paths associated with the RWCU System.

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

Reactor Vessel Water Level - Low, Low - Level 2 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level - Low, Low - Level 2 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level - Low, Low - Level 2 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level - Low, Low Level 2 Allowable Value (Table 3.3.2-2), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level - Low, Low - Level 2 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. This Function isolates the Group 3 valves.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Actions

A note has been provided to modify the ACTIONs related to RPV Water Inventory Control instrumentation channels. The ACTIONs for inoperable RPV Water Inventory Control instrumentation channels provide appropriate compensatory measures for each inoperable RPV Water Inventory Control instrumentation channel.

ACTION a. directs taking the appropriate ACTION referenced in Table 3.3.3.A-1. The applicable ACTION referenced in the table is Function dependent.

RHR System Shutdown Cooling Mode Isolation, Reactor Vessel Water Level Low - Level 3, and Reactor Water Cleanup System Isolation, Reactor Vessel Water Level - Low, Low - Level 2 functions are applicable when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. If the instrumentation is inoperable, ACTION 38 directs immediate action to place the channel in trip. With the inoperable channel in the tripped condition, the remaining channel will isolate the penetration flow path on low water level. If both channels are inoperable and placed in trip, the penetration flow path will be isolated. Alternatively, ACTION 38 requires the associated penetration flow path(s) are incapable of automatic isolation and calculation of DRAIN TIME. The calculation cannot credit automatic isolation of the affected penetration flow paths.

3/4.3.3.A RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

REFERENCES

1. Information Notice 84-81 "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3. Generic Letter 92-Ø4, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 1Ø CFR 5Ø.54(f)," August 1992.

4. NRC Bulletin 93-Ø3, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-1Ø349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a supplement to the reactor trip. During turbine trip and generator load rejection events, the EOC-RPT will reduce the likelihood of reactor vessel level decreasing to level 2. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 29.5% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, i.e., 175 ms. Included in this time are: the response time of the sensor, the time allotted for breaker arc suppression, and the response time of the system logic.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R.D. Binz, IV, from C.E. Rossi dated July 21, 1992).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel. This instrumentation does not provide actuation of any of the emergency core cooling equipment.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage times have been specified in accordance with recommendations made by GE in their letter to the BWR Owner's Group dated August 7, 1989, SUBJECT: "Clarification of Technical Specification changes given in ECCS Actuation Instrumentation Analysis."

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

Surveillance intervals are determined in accordance with the Surveillance Frequency Control Program and maintenance outage time have been determined in accordance with NEDC-30851P, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," as approved by the NRC and documented in the SER (letter to D. N. Grace from C. E. Rossi dated September 22, 1988).

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

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3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring instrumentation ensures that: (1) the radiation levels are continually measured in the areas served by the individual channels, and (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded, and (3) sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with 10 CFR Part 50, Appendix A, General Design Criteria 19, 41, 60, 61, 63, and 64.

The surveillance interval for the Main Control Room Normal Fresh Air Supply Radiation Monitor is determined in accordance with the Surveillance Frequency Control Program.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

3/4.3.7.2 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

3/4.3.7.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.4 REMOTE SHUTDOWN SYSTEM

The OPERABILITY of the remote shutdown system ensures that sufficient capability is available to permit shutdown and maintenance of HOT SHUTDOWN of the unit from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criterion 19 of 10 CFR Part 50, Appendix A. The Unit 1 RHR transfer switches are included only due to their potential impact on the RHRSW system, which is common to both units.

The systems/functions for which the RSP provides remote instrumentation and controls to accomplish this purpose are as follows:

- Reactor Core Isolation Cooling (RCIC) system to maintain reactor vessel water level.
- Main steam line safety/relief valves (manual actuation) to reduce reactor vessel pressure.
- Nuclear boiler instrumentation to monitor reactor vessel pressure and level.
- Residual Heat Removal (RHR) system for suppression pool cooling and shutdown cooling.
- RHR Service Water system to supply cooling water to the RHR heat exchanger.
- Emergency Service Water (ESW) system to supply cooling water to RCIC and RHR room coolers, RHR motor oil and seal coolers, and the emergency diesel generator.
- Containment and suppression pool system monitoring instrumentation.
- Standby AC power that supplies power to the above systems.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess important variables following an accident. This capability is consistent with the recommendations of Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," December 1975 and NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

Table 3.3.7.5-1, Accident Monitoring Instrumentation, Item 2, requires two OPERABLE channels of Reactor Vessel Water Level monitoring from each of two overlapping instrumentation loops to ensure monitoring of Reactor Vessel Water Level over the range of -350 inches to +60 inches. Each channel is comprised of one OPERABLE Wide Range Level instrument loop (-150 inches to +60 inches) and one OPERABLE Fuel Zone Range instrument loop (-350 inches to -100 inches). Both instrument loops, Wide Range and Fuel Zone Range, are required by Tech. Spec. 3.3.7.5 to provide sufficient overlap to bound the required range as described in UFSAR Section 7.5. Action 80 is applicable if the required number of instrument loops per channel (Wide Range and Fuel Zone Range) is not maintained.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION (continued)

Table 3.3.7.5-1, Accident Monitoring Instrumentation, Item 13, requires two OPERABLE channels of Neutron Flux monitoring from each of three overlapping instrumentation loops to ensure monitoring of Neutron Flux over the range of 10^{-6}% to 100% full power. Each channel is comprised of one OPERABLE SRM (10^{-9}% to 10^{-3}% power), one OPERABLE IRM (10^{-4}% to 40% power) and one OPERABLE APRM (0% to 125% power). All three instrument loops, SRM, IRM and APRM, are required by Tech. Spec. 3.3.7.5 to provide sufficient overlap to bound the required range as described in UFSAR Section 7.5. Action 80 is applicable if the required number of instrument loops per channel (SRM, IRM, and APRM) is not maintained.

3/4.3.7.6 SOURCE RANGE MONITORS

The source range monitors provide the operator with information of the status of the neutron level in the core at very low power levels during startup and shutdown. At these power levels, reactivity additions shall not be made without this flux level information available to the operator. When the intermediate range monitors are on scale, adequate information is available without the SRMs and they can be retracted.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

3/4.3.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.8 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.3.7.9 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

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3/4.3.7.10 (Deleted)

3/4.3.7.11 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.3.7.12 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM AND THE TRM.

3/4.3.8 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE UFSAR.

3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

The feedwater/main turbine trip system actuation instrumentation is provided to initiate action of the feedwater system/main turbine trip system in the event of failure of feedwater controller under maximum demand.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

REFERENCES:

1. NEDC-30851P-A, “Technical Specification Improvement Analyses for BWR Reactor Protection System,” March 1988.

2. NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," October 1995.

3. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," November 1997.

4. NEDO-31960-A, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.

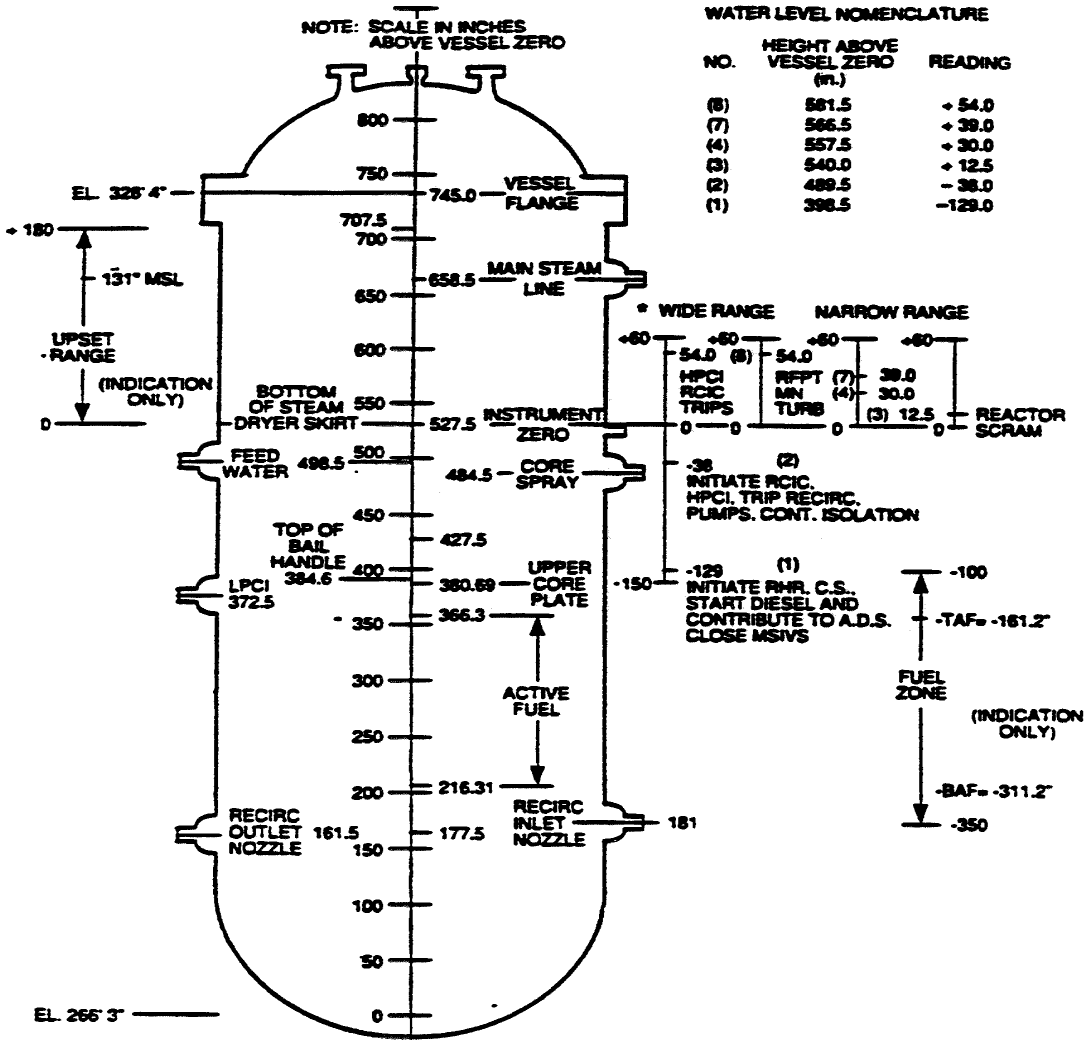
5. NEDO-31960-A, Supplement 1, "BWR Owners’ Group Long-Term Stability Solutions Licensing Methodology,” November 1995.

6. NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications,” August 1996.

7. Letter, L. A. England (BWROG) to M. J. Virgilio, “BWR Owners’ Group Guidelines for Stability Interim Corrective Action,” June 6, 1994.

8. GE Service Information Letter No. 516, “Core Flow Measurement - GE BWR/3, 4, 5 and 6 Plants,” July 26, 1990.

9. GE Letter NSA 00-433, Alan Chung (GE) to Sujit Chakraborty (GE), “Minimum Number of Operable OPRM Cells for Option III Stability at Limerick 1 & 2,” May 02, 2001.

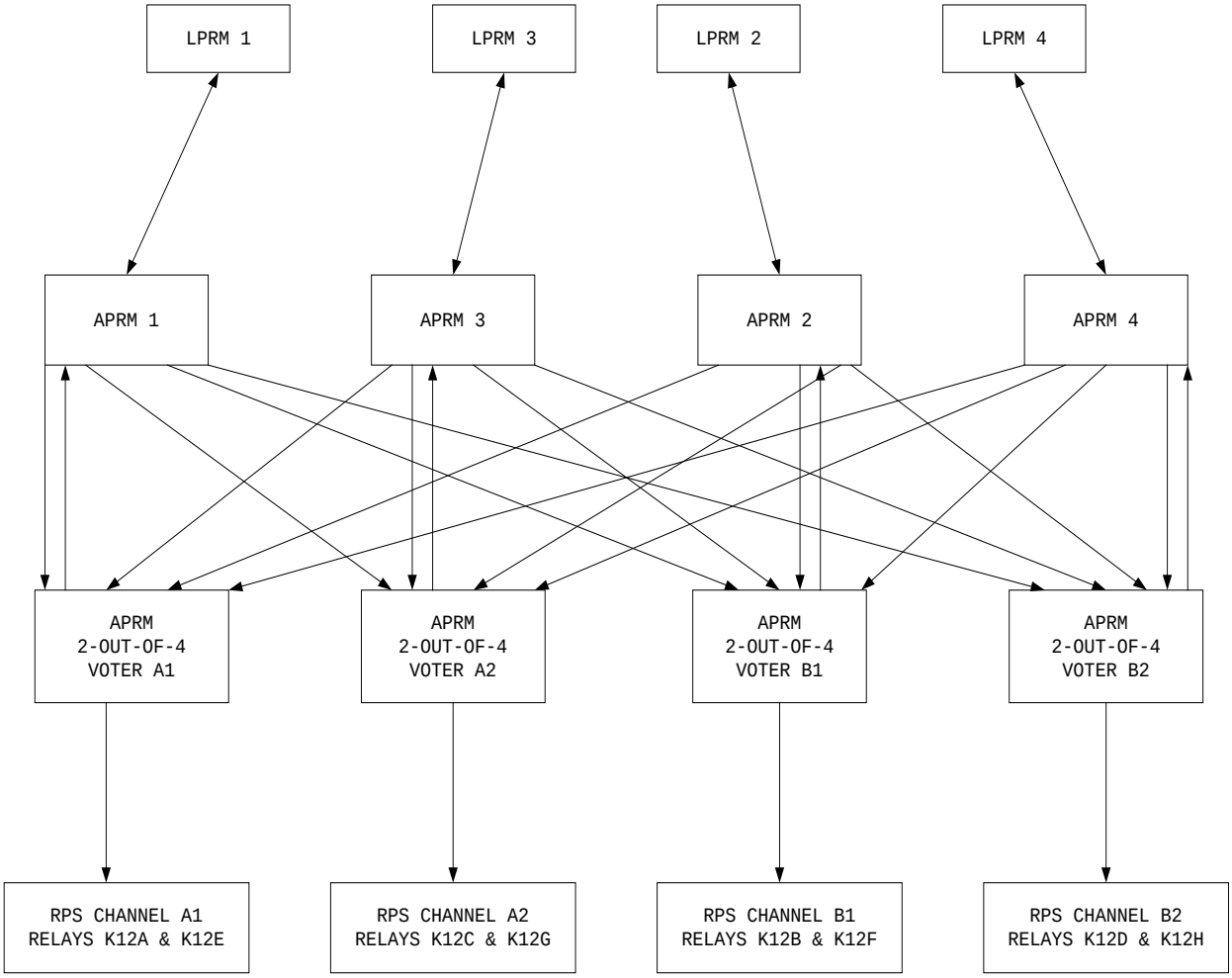


* Wide Range Level

This indication is reactor coolant temperature sensitive. The calibration is thus made at rated conditions. The level error at low pressures (temperatures) is bounded by the safety analysis which reflects the weight-of-coolant above the lower tap, and not indicated level.

BASES FIGURE B 3/4.3-1

REACTOR VESSEL WATER LEVEL



BASES FIGURE B 3/4 3-2

APRM CONFIGURATION

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3/4.4.1 RECIRCULATION SYSTEM

The impact of single recirculation loop operation upon plant safety is assessed and shows that single-loop operation is permitted if the MCPR(99.9%) is increased as noted in the COLR, APRM scram and control rod block setpoints are adjusted as noted in Tables 2.2.1-1 and 3.3.6-2, respectively.

An inoperable jet pump is not, in itself, a sufficient reason to declare a recirculation loop inoperable, but it does, in case of a design-basis-accident, increase the blowdown area and reduce the capability of reflooding the core; thus, the requirement for shutdown of the facility with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed schedule for significant degradation.

Additionally, surveillance on the pump speed of the operating recirculation loop is imposed to exclude the possibility of excessive internals vibration. The surveillance on differential temperatures below 30% RATED THERMAL POWER or 50% rated recirculation loop flow is to mitigate the undue thermal stress on vessel nozzles, recirculation pump and vessel bottom head during the extended operation of the single recirculation loop mode.

Surveillance of recirculation loop flow, total core flow, and diffuser-to-lower plenum differential pressure is designed to detect significant degradation in jet pump performance that precedes jet pump failure. This surveillance is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while base-lining new "established patterns," engineering judgment of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation pump speed operating characteristics (pump flow and loop flow versus pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow and loop flow versus pump speed relationship must be verified.

3/4.4.1 RECIRCULATION SYSTEM (continued)

Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system. Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data.

Recirculation pump speed mismatch limits are in compliance with the ECCS LOCA analysis design criteria for two recirculation loop operation. The limits will ensure an adequate core flow coastdown from either recirculation loop following a LOCA. In the case where the mismatch limits cannot be maintained during two loop operation, continued operation is permitted in a single recirculation loop mode.

In order to prevent undue stress on the vessel nozzles and bottom head region, the recirculation loop temperatures shall be within 50°F of each other prior to startup of an idle loop. The loop temperature must also be within 50°F of the reactor pressure vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles. Sudden equalization of a temperature difference > 145°F between the reactor vessel bottom head coolant and the coolant in the upper region of the reactor vessel by increasing core flow rate would cause undue stress in the reactor vessel bottom head.

3/4.4.2 SAFETY/RELIEF VALVES

The safety valve function of the safety/relief valves operates to prevent the reactor coolant system from being pressurized above the Safety Limit of 1325 psig in accordance with the ASME Code. A total of 12 OPERABLE safety/relief valves is required to limit reactor pressure to within ASME III allowable values for the worst case upset transient.

Demonstration of the safety/relief valve lift settings will occur only during shutdown. The safety/relief valves will be removed and either set pressure tested or replaced with spares which have been previously set pressure tested and stored in accordance with manufacturers recommendations at the frequency specified in the Surveillance Frequency Control Program.

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.3.1 LEAKAGE DETECTION SYSTEMS

BACKGROUND

UFSAR Safety Design Basis (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of Reactor Coolant System (RCS) PRESSURE BOUNDARY LEAKAGE. Regulatory Guide 1.45, Revision 0, (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Limits on leakage from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of leakage rates. In addition to meeting the OPERABILITY requirements, the monitors are typically set to provide the most sensitive response without causing an excessive number of spurious alarms.

Systems for quantifying the leakage are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action. Leakage from the RCPB inside the drywell is detected by at least one of four (4) independently monitored variables which include drywell sump flow monitoring equipment with the required RCS leakage detection instrumentation (i.e., the drywell floor drain sump flow monitoring system, or, the drywell equipment drain sump monitoring system with the drywell floor drain sump overflowing to the drywell equipment drain sump), drywell gaseous radioactivity, drywell unit cooler condensate flow rate and drywell pressure/temperature levels. The primary means of quantifying leakage in the drywell is the drywell sump monitoring system for UNIDENTIFIED LEAKAGE and the drywell equipment drain tank flow monitoring system for IDENTIFIED LEAKAGE. IDENTIFIED leakage is not germane to this Tech Spec and the associated drywell equipment drain tank flow monitoring system is not included.

The drywell floor drain sump flow monitoring system monitors UNIDENTIFIED LEAKAGE collected in the floor drain sump. UNIDENTIFIED LEAKAGE consists of leakage from RCPB components inside the drywell which are not normally subject to leakage and otherwise routed to the drywell equipment drain sump. The primary containment floor drain sump has transmitters that supply level indication to the main control room via the plant monitoring system. The floor drain sump level transmitters are associated with High/Low level switches that open/close the sump tank drain valves automatically. The level instrument processing unit calculates an average leak rate (gpm) for a given measurement period which resets whenever the sump drain valve closes. The level processing unit provides an alarm to the main control room each time the average leak rate changes by a predetermined value since the last time the alarm was reset. For the drywell floor drain sump flow monitoring system, the setpoint basis is a 1 gpm change in UNIDENTIFIED LEAKAGE.

An alternate to the drywell floor drain sump flow monitoring system for quantifying UNIDENTIFIED LEAKAGE is the drywell equipment drain sump monitoring system, if the drywell floor drain sump is overflowing to the drywell equipment drain sump. In this configuration, the drywell equipment drain sump collects all leakage into the drywell equipment drain sump and the overflow from the drywell floor drain sump. Therefore, if the drywell floor drain sump is overflowing to the drywell equipment drain sump, the drywell equipment drain sump monitoring system can be used to quantify UNIDENTIFIED LEAKAGE. In this condition, all leakage measured by the drywell equipment drain sump monitoring system is assumed to be UNIDENTIFIED LEAKAGE. The leakage determination process, including the transition to and use of the alternate method is described in station procedures. The alternate method would only be used when the drywell floor drain sump flow monitoring system is unavailable.

In addition to the drywell sump monitoring system described above, the discharge of each sump is monitored by an independent flow element. The measured flow rate from the flow element is integrated and recorded. A main control room alarm is also provided to indicate an excessive sump discharge rate measured via the flow element. This system, referred to as the “drywell floor drain flow totalizer”, is not credited for drywell floor drain sump flow monitoring system operability.

BACKGROUND (Continued)

The primary containment atmospheric gaseous radioactivity monitoring system continuously monitors the primary containment atmosphere for gaseous radioactivity levels. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water leakage, is annunciated in the main control room.

Condensate from the eight drywell air coolers is routed to the drywell floor drain sump and is monitored by a series of flow transmitters that provide indication and alarms in the main control room. The outputs from the flow transmitters are added together by summing units to provide a total continuous condensate drain flow rate. The high flow alarm setpoint is based on condensate drain flow rate in excess of 1 gpm over the currently identified preset leak rate. The drywell air cooler condensate flow rate monitoring system serves as an added indicator, but not quantifier, of RCS UNIDENTIFIED LEAKAGE (Ref. 4).

The drywell temperature and pressure monitoring systems provide an indirect method for detecting RCPB leakage. A temperature and/or pressure rise in the drywell above normal levels may be indicative of a reactor coolant or steam leakage (Ref. 5).

APPLICABLE SAFETY ANALYSES

A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. Leakage rate limits are set low enough to detect the leakage emitted from a single crack in the RCPB (Refs. 6 and 7).

A control room alarm allow the operators to evaluate the significance of the indicated leakage and, if necessary, shut down the reactor for further investigation and corrective action. The allowed leakage rates are well below the rates predicted for critical crack sizes (Ref. 7). Therefore, these actions provide adequate response before a significant break in the RCPB can occur.

RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement.

LIMITING CONDITION FOR OPERATION (LCO)

This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide confidence that small amounts of UNIDENTIFIED LEAKAGE are detected in time to allow actions to place the plant in a safe condition, when RCS leakage indicates possible RCPB degradation.

The LCO requires four instruments to be OPERABLE.

The required instrumentation to quantify UNIDENTIFIED LEAKAGE from the RCS consists of either the drywell floor drain sump flow monitoring system, or, the drywell equipment drain sump monitoring system with the drywell floor drain sump overflowing to the drywell equipment drain sump. For either system to be considered operable, the flow monitoring portion of the system must be operable. The identification of an increase in UNIDENTIFIED LEAKAGE will be delayed by the time required for the UNIDENTIFIED LEAKAGE to travel to the drywell floor drain sump and it may take longer than one hour to detect a 1 gpm increase in UNIDENTIFIED LEAKAGE, depending on the origin and magnitude of the leakage. This sensitivity is acceptable for containment sump monitor OPERABILITY.

The reactor coolant contains radioactivity that, when released to the primary containment, can be detected by the gaseous primary containment atmospheric radioactivity monitor. A radioactivity detection system is included for monitoring gaseous activities because of its sensitivity and rapid response to RCS leakage, but it has recognized limitations. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. If there are few fuel element cladding defects and low levels of activation products, it may not be possible for the gaseous primary

LIMITING CONDITION FOR OPERATION (LCO) (Continued)

containment atmospheric radioactivity monitor to detect a 1 gpm increase within 1 hour during normal operation. However, the gaseous primary containment atmospheric radioactivity monitor is OPERABLE when it is capable of detecting a 1 gpm increase in UNIDENTIFIED LEAKAGE within 1 hour given an RCS activity equivalent to that assumed in the design calculations for the monitors (Reference 9).

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the drywell floor drain sump monitoring system in combination with a gaseous primary containment atmospheric radioactivity monitor, a primary containment air cooler condensate flow rate monitoring system, and a primary containment pressure and temperature monitoring system provides an acceptable minimum.

APPLICABILITY

In OPERATIONAL CONDITIONS 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.3.2. This applicability is consistent with that for LCO 3.4.3.2.

ACTIONS

A. With the primary containment atmosphere gaseous monitoring system inoperable, grab samples of the primary containment atmosphere must be taken and analyzed to provide periodic leakage information. [Provided a sample is obtained and analyzed once every 12 hours, the plant may be operated for up to 30 days to allow restoration of the radioactivity monitoring system. The plant may continue operation since other forms of drywell leakage detection are available.]

   The 12 hours interval provides periodic information that is adequate to detect leakage. The 30 day Completion Time for Restoration recognizes other forms of leakage detection are available.

B. With required drywell sump monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage at the required 1 gpm/hour sensitivity. However, the primary containment atmospheric gaseous monitor [and the primary containment air cooler condensate flow rate monitor] will provide indication of changes in leakage.

   With required drywell sump monitoring system inoperable, drywell condensate flow rate monitoring frequency increased from 12 to every 8 hours, and UNIDENTIFIED LEAKAGE and total leakage being determined every 8 hours (Ref: SR 4.4.3.2.1.b) operation may continue for 30 days. To the extent practical, the surveillance frequency change associated with the drywell condensate flow rate monitoring system, makes up for the loss of the drywell floor drain sump monitoring system which had a normal surveillance requirement to monitor leakage every 8 hours. Also note that in this instance, the drywell floor drain tank flow totalizer will be used to comply with SR 4.4.3.2.1.b. The 30 day Completion Time of the required ACTION is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available.

C. With the required primary containment air cooler condensate flow rate monitoring system inoperable, SR 4.4.3.1.a must be performed every 8 hours to provide periodic information of activity in the primary containment at a more frequent interval than the routine frequency of every 12 hours. The 8 hour interval provides periodic information that is adequate to detect leakage and recognizes that other forms of leakage detection are available. The required ACTION has been clarified to state

ACTIONS (Continued)

that the additional surveillance requirement is not applicable if the required primary containment atmosphere gaseous radioactivity monitoring system is also inoperable. Consistent with SR 4.0.3, surveillances are not required to be performed on inoperable equipment. In this case, ACTION Statement A. and E. requirements apply.

D. With the primary containment pressure and temperature monitoring system inoperable, operation may continue for up to 30 days given the system's indirect capability to detect RCS leakage. However, other more limiting Tech Spec requirements associated with the primary containment pressure/temperature monitoring system will still apply.

E. With both the primary containment atmosphere gaseous radioactivity monitor and the primary containment air cooler condensate flow rate monitor inoperable, the only means of detecting leakage is the drywell floor drain sump monitor and the drywell pressure/temperature instrumentation. This condition does not provide the required diverse means of leakage detection. The required ACTION is to restore either of the inoperable monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period. While the primary containment atmosphere gaseous radioactivity monitor is INOPERABLE, primary containment atmospheric grab samples will be taken and analyzed every 12 hours since ACTION Statement A. requirements also apply.

F. With the drywell floor drain sump monitoring system inoperable and the drywell unit coolers condensate flow rate monitoring system inoperable, one of the two remaining means of detecting leakage is the primary containment atmospheric gaseous radiation monitor. The primary containment atmospheric gaseous radiation monitor typically cannot detect a 1 gpm leak within one hour when RCS activity is low. Indirect methods of monitoring RCS leakage must be implemented. Grab samples of the primary containment atmosphere must be taken and analyzed and monitoring of RCS leakage by administrative means must be performed every 12 hours to provide alternate periodic information.

Administrative means of monitoring RCS leakage include monitoring and trending parameters that may indicate an increase in RCS leakage. There are diverse alternative mechanisms from which appropriate indicators may be selected based on plant conditions. It is not necessary to utilize all of these methods, but a method or methods should be selected considering the current plant conditions and historical or expected sources of UNIDENTIFIED LEAKAGE. The administrative methods are the drywell cooling fan inlet/outlet temperatures, drywell equipment drain sump temperature indicator, drywell equipment drain tank hi temperature indicator, and drywell equipment drain tank flow indicator. These indications, coupled with the atmospheric grab samples, are sufficient to alert the operating staff to an unexpected increase in UNIDENTIFIED LEAKAGE.

In addition to the primary containment atmospheric gaseous radiation monitor and indirect methods of monitoring RCS leakage, the primary containment pressure and temperature monitoring system is also available to alert the operating staff to an unexpected increase in UNIDENTIFIED LEAKAGE.

ACTIONS (Continued)

The 12 hour interval is sufficient to detect increasing RCS leakage. The Required Action provides 7 days to restore another RCS leakage monitor to OPERABLE status to regain the intended leakage detection diversity. The 7-day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

G. If any required ACTION of Conditions A, B, C, D, E or F cannot be met within the associated Completion Time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least HOT SHUTDOWN within 12 hours and COLD SHUTDOWN within the next 24 hours. The allowed Completion Times are reasonable, based on operating experience, to perform the ACTIONS in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 4.4.3.1.a
This SR is for the performance of a CHANNEL CHECK of the required primary containment atmospheric monitoring system. The check gives reasonable confidence that the channel is operating properly.

SR 4.4.3.1.b
This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the alarm setpoint and relative accuracy of the instrument string. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

SR 4.4.3.1.c
This SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment.

SR 4.4.3.1.d
This SR provides a routine check of primary containment pressure and temperature for indirect evidence of RCS leakage.

REFERENCES

1. LGS UFSAR, Section 5.2.5.1.
2. Regulatory Guide 1.45, Revision 0, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.
3. LGS UFSAR, Section 5.2.5.2.1.3
4. LGS UFSAR, Section 5.2.5.2.1.4
5. LGS UFSAR, Section 5.2.5.2.1.1(2)
6. GEAP-5620, April 1968.
7. NUREG-75/067, October 1975.
8. LGS UFSAR, Section 5.2.5.6.
9. LGS UFSAR, Section 5.2.5.2.1.5

3/4.4.3.2 OPERATIONAL LEAKAGE

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The normally expected background leakage due to equipment design and the detection capability of the instrumentation for determining system leakage was also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for UNIDENTIFIED LEAKAGE the probability is small that the imperfection or crack associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the values specified, the reactor will be shutdown to allow further investigation and corrective action. The limit of 2 gpm increase in UNIDENTIFIED LEAKAGE over a 24-hour period and the monitoring of drywell floor drain sump and drywell equipment drain tank flow rate at least once every eight (8) hours conforms with NRC staff positions specified in NRC Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," as revised by NRC Safety Evaluation dated March 6, 1990. The ACTION requirement for the 2 gpm increase in UNIDENTIFIED LEAKAGE limit ensures that such leakage is identified or a plant shutdown is initiated to allow further investigation and corrective action. Separating the sources of LEAKAGE (i.e., LEAKAGE from an identified source versus LEAKAGE from an unidentified source) is necessary for prompt identification of potentially adverse conditions, assessment of the safety significance, and corrective action. Once identified, reactor operation may continue dependent upon the impact on total leakage.

PPRESSURE BOUNDARY LEAKAGE is prohibited as the leak itself could cause further reactor coolant pressure boundary deterioration, resulting in higher leakage. If PRESSURE BOUNDARY LEAKAGE exists, the affected component, pipe, or vessel must be isolated from the reactor coolant system by a closed manual valve, closed and de-activated automatic valve, blind flange, or check valve within 4 hours. While in this condition, structural integrity of the system should be considered because the structural integrity of the part of the system within the isolation boundary must be maintained under all licensing basis conditions, including consideration of the potential for further degradation of the isolated location. Normal leakage past the isolation device is acceptable as it will limit reactor coolant system leakage and is included in the IDENTIFIED LEAKAGE or UNIDENTIFIED LEAKAGE. This ACTION is necessary to prevent further deterioration of the reactor coolant pressure boundary. If the ACTION cannot be completed in the required time, then the reactor will be shutdown to allow further investigation and corrective action.

The function of Reactor Coolant System Pressure Isolation Valves (PIVs) is to separate the high pressure Reactor Coolant System from an attached low pressure system. The ACTION requirements for pressure isolation valves are used in conjunction with the system specifications for which PIVs are listed in The Technical Requirements Manual and with primary containment isolation valve requirements to ensure that plant operation is appropriately limited.

The Surveillance Requirements for the RCS pressure isolation valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS pressure isolation valves is not included in any other allowable operational leakage specified in Section 3.4.3.2.

3/4.4.4 (Deleted) INFORMATION FROM THIS SECTION RELOCATED TO THE TRM

3/4.4.5 SPECIFIC ACTIVITY

The limitations on the specific activity of the primary coolant ensure that the 2-hour thyroid and whole body doses resulting from a main steam line failure outside the containment during steady state operation will not exceed small fractions of the dose guidelines of 10 CFR Part 100. The values for the limits on specific activity represent interim limits based upon a parametric evaluation by the NRC of typical site locations. These values are conservative in that specific site parameters, such as SITE BOUNDARY location and meteorological conditions, were not considered in this evaluation.

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the primary coolant's specific activity greater than 0.2 microcurie per gram DOSE EQUIVALENT I-131, but less than or equal to 4 microcuries per gram DOSE EQUIVALENT I-131, accommodates possible iodine spiking phenomenon which may occur following changes in THERMAL POWER. This action is modified by a Note that permits the use of the provisions of Specification 3.0.4.c. This allowance permits entry into the applicable OPERATIONAL CONDITION (S) while relying on the ACTION requirements. Operation with specific activity levels exceeding 0.2 microcurie per gram DOSE EQUIVALENT I-131 but less than or equal to 4 microcuries per gram DOSE EQUIVALENT I-131 must be restricted since these activity levels increase the 2-hour thyroid dose at the SITE BOUNDARY following a postulated steam line rupture.

Closing the main steam line isolation valves prevents the release of activity to the environs should a steam line rupture occur outside containment. The surveillance requirements provide adequate assurance that excessive specific activity levels in the reactor coolant will be detected in sufficient time to take corrective action.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

All components in the reactor coolant system are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are introduced by normal load transients, reactor trips, and startup and shutdown operations. The various categories of load cycles used for design purposes are provided in Section 3.9 of the FSAR. During startup and shutdown, the rates of temperature and pressure changes are limited so that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation.

PRESSURE/TEMPERATURE LIMITS (Continued)

The operating limit curves specified in the PTLR are derived from the fracture toughness requirements of 10 CFR 50 Appendix G and ASME Code Section XI, Appendix G. The curves are based on the RT_{NDT} and stress intensity factor information for the reactor vessel components. Fracture toughness limits and the basis for compliance are more fully discussed in FSAR Chapter 5, Paragraph 5.3.1.5, "Fracture Toughness."

The reactor vessel materials have been tested to determine their initial RT_{NDT}. The results of these tests are specified in the PTLR. Reactor operation and resultant fast neutron, E greater than 1 MeV, irradiation will cause an increase in the RT_{NDT}. Therefore, an adjusted reference temperature, based upon the fluence, nickel content and copper content of the material in question, can be predicted using the PTLR and the recommendations of Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials." The pressure/temperature limit curves specified in the PTLR include an assumed shift in the RT_{NDT} for the conditions at 57 EFPY.

The pressure-temperature limit lines specified in the PTLR for reactor criticality and for inservice leak and hydrostatic testing have been provided to assure compliance with the minimum temperature requirements of Appendix G to 10 CFR Part 50 for reactor criticality and for inservice leak and hydrostatic testing.

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

Double isolation valves are provided on each of the main steam lines to minimize the potential leakage paths from the containment in case of a line break. Only one valve in each line is required to maintain the integrity of the containment, however, single failure considerations require that two valves be OPERABLE. The surveillance requirements are based on the operating history of this type valve. The maximum closure time has been selected to contain fission products and to ensure the core is not uncovered following line breaks. The minimum closure time is consistent with the assumptions in the safety analyses to prevent pressure surges.

3/4.4.8 (DELETED)

3/4.4.9 RESIDUAL HEAT REMOVAL

The RHR system is required to remove decay heat and sensible heat in order to maintain the temperature of the reactor coolant. RHR shutdown cooling is comprised of four (4) subsystems which make two (2) loops. Each loop consists of two (2) motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Two (2) redundant, manually controlled shutdown cooling subsystems of the RHR System can provide the required decay heat removal capability. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via the associated recirculation loop or to the reactor via the low pressure coolant injection pathway. The RHR heat exchangers transfer heat to the RHR Service Water System. The RHR shutdown cooling mode is manually controlled.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. In HOT SHUTDOWN condition, the requirement to maintain OPERABLE two (2) independent RHR shutdown cooling subsystems means that each subsystem considered OPERABLE must be associated with a different heat exhanger loop, i.e., the "A" RHR heat exchanger with the "A" RHR pump or the "C" RHR pump, and the "B" RHR heat exchanger with the "B" RHR pump or the "D" RHR pump are two (2) independent RHR shutdown cooling subsystems. Only one (1) of the two (2) RHR pumps associated with each RHR heat exchanger loop is

3/4.4.9 RESIDUAL HEAT REMOVAL (Continued)

required to be OPERABLE for that independent subsystem to be OPERABLE. During COLD SHUTDOWN and REFUELING conditions, however, the subsystems not only have a common suction source, but are allowed to have a common heat exchanger and common discharge piping. To meet the LCO of two (2) OPERABLE subsystems, both pumps in one (1) loop or one (1) pump in each of the two (2) loops must be OPERABLE. Since the piping and heat exchangers are passive components, that are assumed not to fail, they are allowed to be common to both subsystems. Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one (1) subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. Management of gas voids is important to RHR Shutdown Cooling System OPERABILITY.

Alternate decay heat removal methods are available to operators. These alternate methods of decay heat removal can be verified available either by calculation (which includes a review of component and system availability to verify that an alternate decay heat removal method is available) or by demonstration, and that a method of coolant mixing be operational. Decay heat removal capability by ambient losses can be considered in evaluating alternate decay heat removal capability.

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of non-condensable gas into the reactor vessel. This surveillance verifies that the RHR Shutdown Cooling System piping is sufficiently filled with water prior to initially placing the system in operation during reactor shutdown. The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water to ensure that it can reliably perform its intended function.

The RHR Shutdown Cooling System is a manually initiated mode of the RHR System whose use is typically preceded by system piping flushes that disturb both the RHR pump suction and discharge piping. RHR Shutdown Cooling System is flushed and manually aligned for service using system operating procedures that ensure the RHR shutdown cooling suction and discharge flow paths are sufficiently filled with water. In the event that RHR Shutdown Cooling is required for emergency service, the system operating procedures that align and start the RHR System in shutdown cooling mode include the flexibility to eliminate piping flushes while maintaining minimum requirements to ensure that the suction and discharge flow paths are sufficiently filled with water. The RHR Shutdown Cooling System surveillance is met through the performance of the operating procedures that initially place the RHR shutdown cooling sub-system in service.

This surveillance requirement is modified by a Note allowing sufficient time (12 hours) to align the RHR System for Shutdown Cooling operation after reactor dome pressure is less than the RHR cut-in permissive set point.

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3/4.5.1 ECCS - OPERATING

The core spray system (CSS), together with the LPCI mode of the RHR system, is provided to assure that the core is adequately cooled following a loss-of-coolant accident and provides adequate core cooling capacity for all break sizes up to and including the double-ended reactor recirculation line break, and for smaller breaks following depressurization by the ADS. Management of gas voids is important to ECCS injection/spray subsystem OPERABILITY.

The CSS is a primary source of emergency core cooling after the reactor vessel is depressurized and a source for flooding of the core in case of accidental draining.

The surveillance requirements provide adequate assurance that the CSS will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown.

The low pressure coolant injection (LPCI) mode of the RHR system is provided to assure that the core is adequately cooled following a loss-of-coolant accident. Four subsystems, each with one pump, provide adequate core flooding for all break sizes up to and including the double-ended reactor recirculation line break, and for small breaks following depressurization by the ADS.

The surveillance requirements provide adequate assurance that the LPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown.

The CCS pump flow of 3,175 gpm and the LPCI pump flow of 10,000 gpm are flow values at nominal grid frequency of 60 Hz. The 10 CFR 50.46 LOCA Analysis of Record (AOR) uses 80 % of the prescribed TS SR flow values (2,500 and 8,000 respectively). The calculated TS SR flow rates at the reduced Emergency Diesel Generator minimum steady-state voltage of 4,160 V and 59.8 Hz, when off site power is not available, demonstrate that the ECCS flow rates used in the LOCA analysis are bounding and satisfy SRs 4.5.1.b.1 and 4.5.1.b.2.

The high pressure coolant injection (HPCI) system is provided to assure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the reactor coolant system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCI system permits the reactor to be shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. The HCPI system continues to operate until reactor vessel pressure is below the pressure at which CSS operation or LPCI mode of the RHR system operation maintains core cooling.

The capacity of the system is selected to provide the required core cooling. The HPCI pump is designed to deliver greater than or equal to 5600 gpm at reactor pressures between 1182 and 200 psig and is capable of delivering at least 5000 gpm between 1182 and 1205 psig. In the system's normal alignment, water from the condensate storage tank is used instead of injecting water from the suppression pool into the reactor, but no credit is taken in the safety analyses for the condensate storage tank water.

ECCS - OPERATING (Continued)

With the HPCI system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the CS and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor low water level condition. The HPCI out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems and the RCIC system. The HPCI system, and one LPCI subsystem, and/or one CSS subsystem out-of-service period of 8 hours ensures that sufficient ECCS, comprised of a minimum of one CSS subsystem, three LPCI subsystems, and all of the ADS will be available to 1) provide for safe shutdown of the facility, and 2) mitigate and control accident conditions within the facility. Alternatively, the out-of-service times described above can be determined in accordance with the Risk Informed Completion Time Program. A Note prohibits the application of Specification 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that the HPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor shutdown.

During plant startup, when HPCI surveillance tests are being performed, the HPCI System is required to be tested within 12 hours after reactor pressure is adequate to perform each surveillance test. For the low reactor pressure surveillance requirement, the intent is to verify HPCI System operability prior to increasing reactor pressure above 215 psig. If operability of the HPCI System is not demonstrated within the 12-hour period, reactor steam dome pressure must be reduced to less than 200 psig within the following 72 hours. For the high reactor pressure surveillance test, the intent is to verify HPCI System operability as soon as possible once plant conditions support the testing. Power ascension can continue during the testing; however, if HPCI is found inoperable or the 12-hour period has elapsed power ascension must be stopped, and reactor steam dome pressure must be reduced to less than 200 psig within the following 72 hours.

The ECCS injection/spray subsystem flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the ECCS injection/spray subsystems and may also prevent a water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of ECCS injection/spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The ECCS injection/spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

ECCS - OPERATING (Continued)

ECCS injection/spray subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

Surveillance 4.5.1.a.1.b is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

Upon failure of the HPCI system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety/relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 100 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring ADS.

SR 4.5.1.c.1 excludes automatic dampers and valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to dampers or valves that are locked, sealed, or otherwise secured in the actuated position since the affected dampers or valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve or damper in a locked, sealed, or otherwise secured position requires an assessment of the operability of the system or any supported systems, including whether it is necessary for the valve or damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve or damper to the non-actuated position requires verification that the SR has been met within its required Frequency.

ADS automatically controls five selected safety-relief valves. The safety analysis assumes all five are operable. The allowed out-of-service time for one valve for up to fourteen days is determined in a similar manner to other ECCS subsystem out-of-service time allowances. Alternatively, the allowed out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

Verification that ADS accumulator gas supply header pressure is ≥90 psig ensures adequate gas pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator at least two valve actuations can occur with the drywell at 70% of design pressure. The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of ≥90 psig is provided by the PCIG supply.

3/4.5.2 - REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC)

Background:

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.4 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

Applicable Safety Analysis:

With the unit in OPERATIONAL CONDITION 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 and the fuel cladding barrier to prevent the release of radioactive material to the environment should an unexpected draining event occur.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in OPERATIONAL CONDITIONS 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered in which an initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure (an event that creates a drain path through multiple vessel penetrations located below top of active fuel, such as loss of normal power or a single human error). It is assumed, based on engineering judgement, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can maintain adequate reactor vessel water level.

As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

Limiting Condition for Operation:

The RPV water level must be controlled in OPERATIONAL CONDITIONS 4 and 5 to ensure that if an unexpected draining event should occur, the reactor coolant water level remains above the top of the active irradiated fuel as required by Safety Limit 2.1.4.

The Limiting Condition for Operation (LCO) requires the DRAIN TIME of RPV water inventory to the TAF to be ≥ 36 hours. A DRAIN TIME of 36 hours is considered reasonable to identify and initiate action to mitigate unexpected draining of reactor coolant. An event that could cause loss of RPV water inventory and result in the RPV water level reaching the TAF in greater than 36 hours does not represent a significant challenge to Safety Limit 2.1.4 and can be managed as part of normal plant operation.

One low pressure ECCS injection/spray subsystem is required to be OPERABLE and capable of being manually aligned and started from the control room to provide defense-in-depth should an unexpected draining event occur. OPERABILITY of the ECCS injection/spray subsystem includes any necessary valves, instrumentation, or controls needed to manually align and start the subsystem from the control room. A low pressure ECCS injection/spray subsystem consists of either one Core Spray System (CSS) subsystem or one Low Pressure Coolant Injection (LPCI) subsystem. Each CSS subsystem consists of two motor driven pumps, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the RPV. Each LPCI subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV.

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The LCO is modified by a note which allows a required LPCI subsystem to be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. This allowance is necessary since the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Because of the restrictions on DRAIN TIME, sufficient time will be available following an unexpected draining event to manually align and initiate LPCI subsystem operation to maintain RPV water inventory prior to the RPV water level reaching the TAF.

Applicability:

RPV water inventory control is required in OPERATIONAL CONDITIONS 4 and 5. Requirements on water inventory control are contained in LCO 3.3.3.A, REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC) INSTRUMENTATION, and LCO 3.5.2, REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL (WIC). RPV water inventory control is required to protect Safety Limit 2.1.4 which is applicable whenever irradiated fuel is in the reactor vessel.

Actions:

Action a. - If none of the required low pressure ECCS injection/spray subsystems are OPERABLE, one subsystem must be restored to OPERABLE status within 4 hours. In this condition, the LCO controls on DRAIN TIME minimize the possibility that an unexpected draining event could necessitate the use of the ECCS injection/spray subsystem; however, the defense-in-depth provided by the ECCS injection/spray subsystem is lost. The 4-hour allowed outage time for restoring the required low pressure ECCS injection/spray subsystem to OPERABLE status is based on engineering judgment that considers the LCO controls on DRAIN TIME and the low probability of an unexpected draining event that would result in loss of RPV water inventory.

If the inoperable ECCS injection/spray subsystem is not restored to OPERABLE status within 4 hours, action must be initiated immediately to establish a method of water injection capable of operating without offsite electrical power. The method of water injection includes the necessary instrumentation and controls, water sources, and pumps and valves needed to add water to the RPV or refueling cavity should an unexpected draining event occur. The method of water injection may be manually initiated and may consist of one or more systems or subsystems, and must be able to access water inventory capable of maintaining the RPV water level above the TAF for $\geq$ 36 hours. If recirculation of injected water would occur, it may be credited in determining the necessary water volume.

Action b. - Deleted

Action c. - With the DRAIN TIME less than 36 hours but greater than or equal to 8 hours, compensatory measures should be taken to ensure the ability to implement mitigating actions should an unexpected draining event occur. Should a draining event lower the reactor coolant level to below the TAF, there is potential for damage to the reactor fuel cladding and release of radioactive material. Additional actions are taken to ensure that radioactive material will be contained, diluted, and processed prior to being released to the environment.

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The secondary containment provides a controlled volume in which fission products can be contained, diluted, and processed prior to release to the environment. Verification of the capability to establish SECONDARY CONTAINMENT INTEGRITY in less than the DRAIN TIME is required. The required verification confirms actions to establish SECONDARY CONTAINMENT INTEGRITY are preplanned and necessary materials are available. SECONDARY CONTAINMENT INTEGRITY is considered established when one Standby Gas Treatment (SGT) subsystem is capable of maintaining a negative pressure in the secondary containment with respect to the environment. Verification that SECONDARY CONTAINMENT INTEGRITY can be established must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

Secondary containment penetration flow paths form a part of SECONDARY CONTAINMENT INTEGRITY. Verification of the capability to isolate each secondary containment penetration flow path in less than the DRAIN TIME is required. The required verification confirms actions to isolate secondary containment penetration flow paths are preplanned and necessary materials are available. Power operated valves are not required to receive automatic isolation signals if they can be closed manually within the required time. Verification that secondary containment penetration flow paths can be isolated must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

One SGT subsystem is capable of maintaining the secondary containment at a negative pressure with respect to the environment and filter gaseous releases. Verification of the capability to place one SGT subsystem in operation in less than the DRAIN TIME is required. The required verification confirms actions to place a SGT subsystem in operation are preplanned and necessary materials are available. Verification that a SGT subsystem can be placed in operation must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

Action d. - With the DRAIN TIME less than 8 hours, mitigating actions are implemented in case an unexpected draining event should occur. Note that if the DRAIN TIME is less than 1 hour, the required Action e. to restore DRAIN TIME to 36 hours or greater is also applicable.

Immediate action to establish an additional method of water injection augmenting the ECCS injection/spray subsystem required by the LCO is required. The additional method of water injection includes the necessary instrumentation and controls, water sources, and pumps and valves needed to add water to the RPV or refueling cavity should an unexpected draining event occur. The note states that either the ECCS injection/spray subsystem or the additional method of water injection must be capable of operating without offsite electrical power. The additional method of water injection may be manually initiated and may consist of one or more systems or subsystems. The additional method of water injection must be able to access water inventory capable of being injected to maintain the RPV water level above the TAF for $\geq$ 36 hours. The additional method of water injection and the ECCS injection/spray subsystem may share all or part of the same water sources. If recirculation of injected water would occur, it may be credited in determining the required water volume.

Should a draining event lower the reactor coolant level to below the TAF, there is potential for damage to the reactor fuel cladding and release of radioactive material. Additional actions are taken to ensure that radioactive material will be contained, diluted, and processed prior to being released to the environment.

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The secondary containment provides a control volume into which fission products can be contained, diluted, and processed prior to release to the environment. Actions to immediately establish SECONDARY CONTAINMENT INTEGRITY are required. With SECONDARY CONTAINMENT INTEGRITY established, one SGT subsystem is capable of maintaining a negative pressure in the secondary containment with respect to the environment.

The secondary containment penetrations form a part of SECONDARY CONTAINMENT INTEGRITY. Actions to immediately verify that each secondary containment penetration flow path is isolated or to verify that it can be automatically or manually isolated from the control room are required.

One SGT subsystem is capable of maintaining the secondary containment at a negative pressure with respect to the environment and filter gaseous releases. Actions to immediately verify that at least one SGT subsystem is capable of being placed in operation are required. The required verification is an administrative activity and does not require manipulation or testing of equipment.

Action e. - If the ACTIONs and associated allowed outage times are not met or if the DRAIN TIME is less than 1 hour, actions must be initiated immediately to restore the DRAIN TIME to ≥ 36 hours. In this condition, there may be insufficient time to respond to an unexpected draining event to prevent the RPV water inventory from reaching the TAF. Note that ACTIONs are also applicable when DRAIN TIME is less than 1 hour.

Surveillance Requirements:

Surveillance Requirement (SR) 4.5.2.1 verifies that the DRAIN TIME of RPV water inventory to the TAF is ≥ 36 hours. The period of 36 hours is considered reasonable to identify and initiate action to mitigate draining of reactor coolant. Loss of RPV water inventory that would result in the RPV water level reaching the TAF in greater than 36 hours does not represent a significant challenge to Safety Limit 2.1.4 and can be managed as part of normal plant operation.

The definition of DRAIN TIME states that realistic cross-sectional areas and drain rates are used in the calculation. A realistic drain rate may be determined using a single, step-wise, or integrated calculation considering the changing RPV water level during a draining event. For a control rod RPV penetration flow path with the control rod drive mechanism removed and not replaced with a blank flange, the realistic cross-sectional area is based on the control rod blade seated in the control rod guide tube. If the control rod blade will be raised from the penetration to adjust or verify seating of the blade, the exposed cross-sectional area of the RPV penetration flow path is used.

The definition of DRAIN TIME excludes from the calculation those penetration flow paths connected to an intact closed system, or isolated by manual or automatic valves that are closed and administratively controlled, blank flanges, or other devices that prevent flow of reactor coolant through the penetration flow paths. A blank flange or other bolted device must be connected with a sufficient number of bolts to prevent draining. Normal or expected leakage from closed systems or past isolation devices is permitted. Determination that a system is intact and closed or isolated must consider the status of branch lines.

The Residual Heat Removal (RHR) Shutdown Cooling System is only considered an intact closed system when misalignment issues (Reference 6) have been precluded by functional valve interlocks or by isolation devices, such that redirection of RPV water out of an RHR subsystem is precluded. Further, the RHR Shutdown Cooling System is only considered an intact closed system if its controls have not been transferred to Remote Shutdown, which disables the interlocks and isolation signals.

RPV WATER INVENTORY CONTROL (WIC) (Continued)

The exclusion of a single penetration flow path, or multiple penetration flow paths susceptible to a common mode failure, from the determination of DRAIN TIME should consider the effects of temporary alterations in support of maintenance (rigging, scaffolding, temporary shielding, piping plugs, freeze seals, etc.). If reasonable controls are implemented to prevent such temporary alterations from causing a draining event from a closed system or between the RPV and the isolation device, the effect of the temporary alterations on DRAIN TIME need not be considered. Reasonable controls include, but are not limited to, controls consistent with the guidance in NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 4, NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," or commitments to NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants."

TS 4.0.1 requires SRs to be met between performances. Therefore, any changes in plant conditions that would change the DRAIN TIME requires that a new DRAIN TIME be determined.

SRs 4.5.2.2 and 4.5.2.3 - The minimum water level of 16 feet required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the CSS subsystem or LPCI subsystem pumps, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, the required ECCS injection/spray subsystem is inoperable unless aligned to an OPERABLE CST.

The required CSS subsystem is OPERABLE if it can take suction from the CST, and the CST water level is sufficient to provide the required NPSH for the CSS pumps. Therefore, a verification that either the suppression pool water level is greater than or equal to 16 feet 0 inches or that a CSS subsystem is aligned to take suction from the CST and the CST contains greater than or equal to 135,000 available gallons of water, equivalent to a level of 29 feet 0 inches, ensures that the CSS subsystem can supply the required makeup water to the RPV.

SR 4.5.2.4 - The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the required ECCS injection/spray subsystems full of water ensures that the ECCS subsystem will perform properly. This may also prevent a water hammer following an ECCS actuation. One acceptable method of ensuring that the lines are full is to vent at the high points.

SR 4.5.2.5 - DELETED

SR 4.5.2.6 - Verifying that the required ECCS injection/spray subsystem can be manually aligned, and the pump started and operated for at least 10 minutes demonstrates that the subsystem is available to mitigate a draining event. This surveillance requirement is modified by two footnotes. The first states that testing the ECCS injection/spray subsystem may be done through the test return line to avoid overfilling the refueling cavity. The second states that credit for meeting the surveillance requirement may be taken for normal system operation that satisfies the surveillance requirement, such as using the RHR mode of LPCI for greater than or equal to 10 minutes. The minimum operating time of 10 minutes was based on engineering judgement.

SR 4.5.2.7 and 4.5.2.8 exclude automatic dampers and valves that are locked, sealed, or otherwise secured in the actuated position. The SRs do not apply to dampers or valves that are locked, sealed, or otherwise secured in the actuated position since the affected dampers or valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve or damper in a locked, sealed, or otherwise secured position requires an assessment of the operability of the system or any supported systems, including whether it is necessary for the valve or damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve or damper to the non-actuated position requires verification that the applicable SR has been met within its required Frequency.

SR 4.5.2.7 - Verifying that each valve credited for automatically isolating a penetration flow path actuates to the isolation position on an actual or simulated RPV water level isolation signal is required to prevent RPV water inventory from dropping below the TAF should an unexpected draining event occur.

RPV WATER INVENTORY CONTROL (WIC) (Continued)

SR 4.5.2.8 - This surveillance verifies that a required CSS subsystem or LPCI subsystem can be manually aligned and started from the control room, including any necessary valve alignment, instrumentation, or controls, to transfer water from the suppression pool or CST to the RPV.

The Surveillance Frequencies in the above SRs are controlled under the Surveillance Frequency Controlled Program.

REFERENCES

1. Information Notice 84-81, "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.

4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

6. General Electric Service Information Letter No. 388, "RHR Valve Misalignment During Shutdown Cooling Operation for BWR 3/4/5/6," February 1983.

3/4.5.3 SUPPRESSION CHAMBER

The suppression chamber is required to be OPERABLE as part of the ECCS to ensure that a sufficient supply of water is available to the HPCI, CS and LPCI systems in the event of a LOCA. This limit on suppression chamber minimum water volume ensures that sufficient water is available to permit recirculation cooling flow to the core. The OPERABILITY of the suppression chamber in OPERATIONAL CONDITION 1, 2, or 3 is also required by Specification 3.6.2.1.

3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 PRIMARY CONTAINMENT INTEGRITY

PRIMARY CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the SITE BOUNDARY radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

3/4.6.1.2 PRIMARY CONTAINMENT LEAKAGE

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value calculated in the safety analyses at the design basis LOCA maximum peak containment pressure of 44 psig, Pa. As an added conservatism, the measured overall integrated leakage rate (Type A Test) is further limited to less than or equal to 0.75 La during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

Operating experience with the main steam line isolation valves has indicated that degradation has occasionally occurred in the leak tightness of the valves; therefore the special requirement for testing these valves.

The surveillance testing for measuring leakage rates is consistent with the Primary Containment Leakage Rate Testing Program.

Limerick has an approved license amendment to implement 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors", and may voluntarily comply with the treatment requirements of 10 CFR 50.69 as an alternative to compliance with the Type B and Type C leakage testing requirements of 10 CFR 50, Appendix J for Risk-Informed Safety Classification (RISC) RISC-3 or RISC-4 penetrations and valves meeting the following criteria:

A. Containment penetrations that are either 1-inch nominal size or less, or continuously pressurized.
B. Containment isolation valves that meet one or more of the following criteria.
   1. The valve is required to be open under accident conditions to prevent or mitigate core damage events;
   2. The valve is normally closed and in a physically closed, water-filled system;
   3. The valve is in a physically closed system whose piping pressure rating exceeds the containment design pressure rating and is not connected to the reactor coolant pressure boundary; or
   4. The valve is 1-inch nominal size or less.

RISC-3 penetrations and valves that meet the criteria above may be removed from the scope of the Primary Containment Leakage Rate Testing Program, as implemented by Technical Specifications 3.6.1, 4.6.1 and 6.8.4.g. Alternative Treatment will be implemented in accordance with the requirements of 10 CFR 50.69(d).

3/4.6.1.3 PRIMARY CONTAINMENT AIR LOCK

The limitations on closure and leak rate for the primary containment air lock are required to meet the restrictions on PRIMARY CONTAINMENT INTEGRITY and the Primary Containment Leakage Rate Testing Program. Only one closed door in the air lock is required to maintain the integrity of the containment.

3/4.6.1.4 MSIV LEAKAGE ALTERNATE DRAIN PATHWAY

Calculated doses resulting from the maximum leakage allowances for the main steamline isolation valves in the postulated LOCA situations will not exceed the criteria of 10 CFR Part 100 guidelines, provided the main steam line system from the isolation valves up to and including the turbine condenser remains intact. Operating experience has indicated that degradation has occasionally occurred in the leak tightness of the MSIVs such that the specified leakage requirements have not always been continuously maintained. The requirement for the MSIV Leakage Alternate Drain Pathway serves to reduce the offsite dose.

3/4.6.1.5 PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the maximum calculated pressure in the event of a LOCA. A visual inspection in accordance with the Primary Containment Leakage Rate Testing Program is sufficient to demonstrate this capability.

3/4.6.1.6 DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

The limitations on drywell and suppression chamber internal pressure ensure that the calculated containment peak pressure does not exceed the design pressure of 55 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 5.0 psid. The limit of - 1.0 to + 2.0 psig for initial containment pressure will limit the total pressure to $\leq$ 44 psig which is less than the design pressure and is consistent with the safety analysis.

3/4.6.1.7 DRYWELL AVERAGE AIR TEMPERATURE

The limitation on drywell average air temperature ensures that the containment peak air temperature does not exceed the design temperature of 340°F during steam line break conditions and is consistent with the safety analysis.

3/4.6.1.8 DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

The drywell and suppression chamber purge supply and exhaust isolation valves are required to be closed during plant operation except as required for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. Limiting the use of the drywell and suppression chamber purge system to specific criteria is imposed to protect the integrity of the SGTS filters. Analysis indicates that should a LOCA occur while this pathway is being utilized, the associated pressure surge through the (18 or 24") purge lines will adversely affect the integrity of SGTS. This condition is not imposed on the 1 and 2 inch valves used for pressure control since a surge through these lines does not threaten the operability of SGTS.

Surveillance requirement 4.6.1.8 ensures that the primary containment purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. The SR is modified by a Note stating that primary containment purge valves are only required to be closed in OPERATIONAL CONDITIONS 1, 2 and 3. The SR is also modified by a Note stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, deinerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The 18 or 24 inch purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time.

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3/4.6.2 DEPRESSURIZATION SYSTEMS

The specifications of this section ensure that the primary containment pressure will not exceed the design pressure of 55 psig during primary system blowdown from full operating pressure. Management of gas voids is important to Suppression Pool Cooling/Spray Subsystem OPERABILITY.

The suppression chamber water provides the heat sink for the reactor coolant system energy release following a postulated rupture of the system. The suppression chamber water volume must absorb the associated decay and structural sensible heat released during reactor coolant system blowdown from rated conditions. Since all of the gases in the drywell are purged into the suppression chamber air space during a loss-of-coolant accident, the pressure of the suppression chamber air space must not exceed 55 psig. The design volume of the suppression chamber, water and air, was obtained by considering that the total volume of reactor coolant is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water volumes given in this specification, suppression pool pressure during the design basis accident is below the design pressure. Maximum water volume of 134,600 ft^3 results in a downcomer submergence of 12'3" and the minimum volume of 122,120 ft^3 results in a submergence approximately 2'3" less. The majority of the Bodega tests were run with a submerged length of 4 feet and with complete condensation. Thus, with respect to the downcomer submergence, this specification is adequate. The maximum temperature at the end of the blowdown tested during the Humboldt Bay and Bodega Bay tests was 170°F and this is conservatively taken to be the limit for complete condensation of the reactor coolant, although condensation would occur for temperature above 170°F.

Should it be necessary to make the suppression chamber inoperable, this shall only be done as specified in Specification 3.5.3.

Under full power operating conditions, blowdown through safety/relief valves assuming an initial suppression chamber water temperature of 95°F results in a bulk water temperature of approximately 140°F immediately following blowdown which is below the 190°F bulk temperature limit used for complete condensation via T-quencher devices. At this temperature and atmospheric pressure, the available NPSH exceeds that required by both the RHR and core spray pumps, thus there is no dependency on containment overpressure during the accident injection phase. If both RHR loops are used for containment cooling, there is no dependency on containment overpressure for post-LOCA operations.

3/4.6.2 DEPRESSURIZATION SYSTEMS (Continued)

RHR Suppression Pool Cooling/Spray subsystem piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR suppression pool subsystems and may also prevent water hammer and pump cavitation.

Selection of RHR Suppression Pool Cooling/Spray subsystem locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR Suppression Pool Cooling/Spray subsystem is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR Suppression Pool Cooling/Spray subsystem locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

One of the surveillance requirements for the suppression pool cooling (SPC) mode of the RHR system is to demonstrate that each RHR pump develops a flow rate ^{3}10,000 gpm while operating in the SPC mode with flow through the heat exchanger and its associated closed bypass valve, ensuring that pump performance has not degraded during the cycle and that the flow path is operable. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component operability, trend performance and detect incipient failures by indicating abnormal performance. The RHR heat exchanger bypass valve is used for adjusting flow through the heat exchanger, and is not designed to be a tight shut-off valve. With the bypass valve closed, a portion of the total flow still travels through the bypass, which

3/4.6.2 DEPRESSURIZATION SYSTEMS (Continued)

can affect overall heat transfer. However, no heat transfer performance requirement of the heat exchanger is intended by the current Technical Specification surveillance requirement. This is confirmed by the lack of any flow requirement for the RHRSW system in Technical Specifications Section 3/4.7.1. Verifying an RHR flowrate through the heat exchanger does not demonstrate heat removal capability in the absence of a requirement for RHRSW flow. LGS does perform heat transfer testing of the RHR heat exchangers as part of its response to Generic Letter 89-13, which verified the commitment to meet the requirements of GDC 46.

Experimental data indicate that excessive steam condensing loads can be avoided if the peak local temperature of the suppression pool is maintained below 200°F during any period of relief valve operation for T-quencher devices. Specifications have been placed on the envelope of reactor operating conditions so that the reactor can be depressurized in a timely manner to avoid the regime of potentially high suppression chamber loadings.

Because of the large volume and thermal capacity of the suppression pool, the volume and temperature normally changes very slowly and monitoring these parameters daily is sufficient to establish any temperature trends. By requiring the suppression pool temperature to be frequently recorded during periods of significant heat addition, the temperature trends will be closely followed so that appropriate action can be taken.

In addition to the limits on temperature of the suppression chamber pool water, operating procedures define the action to be taken in the event a safety-relief valve inadvertently opens or sticks open. As a minimum this action shall include: (1) use of all available means to close the valve, (2) initiate suppression pool water cooling, (3) initiate reactor shutdown, and (4) if other safety-relief valves are used to depressurize the reactor, their discharge shall be separated from that of the stuck-open safety/relief valve to assure mixing and uniformity of energy insertion to the pool.

During a LOCA, potential leak paths between the drywell and suppression chamber airspace could result in excessive containment pressures, since the steam flow into the airspace would bypass the heat sink capabilities of the chamber. Potential sources of bypass leakage are the suppression chamber-to-drywell vacuum breakers (VBs), penetrations in the diaphragm floor, and cracks in the diaphragm floor and/or liner plate and downcomers located in the suppression chamber airspace. The containment pressure response to the postulated bypass leakage can be mitigated by manually actuating the suppression chamber sprays. An analysis was performed for a design bypass leakage area of $A/\sqrt{k}$ equal to 0.0500 ft^2 to verify that the operator has sufficient time to initiate the sprays prior to exceeding the containment design pressure of 55 psig. The limit of 10% of the design value of 0.0500 ft^2 ensures that the design basis for the steam bypass analysis is met

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DEPRESSURIZATION SYSTEMS (Continued)

The drywell-to-suppression chamber bypass test at a differential pressure of at least 4.0 psi verifies the overall bypass leakage area for simulated LOCA conditions is less than the specified limit. For those outages where the drywell-to-suppression chamber bypass leakage test in not conducted, the VB leakage test verifies that the VB leakage area is less than the bypass limit, with a 76% margin to the bypass limit to accommodate the remaining potential leakage area through the passive structural components. Previous drywell-to-suppression chamber bypass test data indicates that the bypass leakage through the passive structural components will be much less than the 76% margin. The VB leakage limit, combined with the negligible passive structural leakage area, ensures that the drywell-to-suppression chamber bypass leakage limit is met for those outages for which the drywell-to-suppression chamber bypass test is not scheduled.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

The OPERABILITY of the primary containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 through 57 of Appendix A of 10 CFR Part 50. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

The scram discharge volume vent and drain valves serve a dual function, one of which is primary containment isolation. Since the other safety functions of the scram discharge volume vent and drain valves would not be available if the normal PCIV actions were taken, actions are provided to direct the user to the scram discharge volume vent and drain operability requirements contained in Specification 3.1.3.1. However, since the scram discharge volume vent and drain valves are PCIVs, the Surveillance Requirements of Specification 4.6.3 still apply to these valves.

The opening of a containment isolation valve that was locked or sealed closed to satisfy Technical Specification 3.6.3 Action statements, may be reopened on an intermittent basis under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

Primary containment isolation valves governed by this Technical Specification are identified in Table 3.6.3-1 of the TRM.

This Surveillance Requirement requires a demonstration that a representative sample of reactor instrument line excess flow check valves (EFCVs) is OPERABLE by verifying that the valve actuates to the isolation position on a simulated instrument line break signal. The representative sample consists of an approximately equal number of EFCVs, such that each EFCV is tested in accordance with the Surveillance Frequency Control Program. In addition, the EFCVs in the sample are representative of the various plant configurations, models, sizes, and operating environments. This ensures that any potentially common problem with a specific type or application of EFCV is detected at the earliest possible time. This Surveillance Requirement provides assurance that the instrumentation line EFCVs will perform so that predicted radiological consequences will not be exceeded during a postulated instrument line break event. Furthermore, any EFCV failures will be evaluated to determine if additional testing in the test interval is warranted to ensure overall reliability is maintained. Operating experience has demonstrated that these components are highly reliable and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint. For some EFCVs, this Surveillance can be performed with the reactor at power.

3/4.6.4 VACUUM RELIEF

Vacuum relief valves are provided to equalize the pressure between the suppression chamber and drywell. This system will maintain the structural integrity of the primary containment under conditions of large differential pressures.

The vacuum breakers between the suppression chamber and the drywell must not be inoperable in the open position since this would allow bypassing of the suppression pool in case of an accident. Two pairs of valves are required to protect containment structural integrity. There are four pairs of valves (three to provide minimum redundancy) so that operation may continue for up to 72 hours or in accordance with the Risk Informed Completion Time Program with no more than two pairs of vacuum breakers inoperable in the closed position.

Each vacuum breaker valve's position indication system is of great enough sensitivity to ensure that the maximum steam bypass leakage coefficient of

$$\frac{A}{\sqrt{k}} = 0.05 \text{ ft}^2$$

for the vacuum relief system (assuming one valve fully open) will not be exceeded.

3/4.6.5 SECONDARY CONTAINMENT

Secondary containment is designed to minimize any ground level release of radioactive material which may result from an accident. The Reactor Enclosure and associated structures provide secondary containment during normal operation when the drywell is sealed and in service. At other times the drywell may be open and, when required, secondary containment integrity is specified.

Establishing and maintaining a vacuum in the reactor enclosure secondary containment with the standby gas treatment system in accordance with the Surveillance Frequency Control Program, along with the surveillance of the doors, hatches, dampers and valves, is adequate to ensure that there are no violations of the integrity of the secondary containment.

The OPERABILITY of the reactor enclosure recirculation system and the standby gas treatment systems ensures that sufficient iodine removal capability will be available in the event of a LOCA. The reduction in containment iodine inventory reduces the resulting SITE BOUNDARY and Control Room radiation doses associated with containment leakage. The operation of these systems and resultant iodine removal capacity are consistent with the assumptions used in the LOCA analysis. Provisions have been made to continuously purge the filter plenums with instrument air when the filters are not in use to prevent buildup of moisture on the adsorbers and the HEPA filters.

As a result of the Alternative Source Term (AST) project, secondary containment integrity of the refueling area is not required during certain conditions when handling irradiated fuel or during CORE ALTERATIONS and alignment of the Standby Gas Treatment System to the refueling area is not required. The control room dose analysis for the Fuel Handling Accident (FHA) is based on unfiltered releases from the South Stack and therefore, does not require the Standby Gas Treatment System to be aligned to the refueling area.

However, when handling RECENTLY IRRADIATED FUEL, secondary containment integrity of the refueling area is required and alignment of the Standby Gas Treatment System to the refueling area is required. The AST fuel handling analysis does not include an accident involving RECENTLY IRRADIATED FUEL or an accident involving draining the reactor vessel.

The Standby Gas Treatment System is required to be OPERABLE when handling irradiated fuel, handling RECENTLY IRRADIATED FUEL and during CORE ALTERATIONS. Fuel Handling Accident releases from the North Stack must be filtered through the Standby Gas Treatment System to maintain control room doses within regulatory limits. The OPERABILITY of the Standby Gas Treatment System assures that releases, if made through the North Stack, are filtered prior to release.

SECONDARY CONTAINMENT (Continued)

Surveillances 4.6.5.1.1.a and 4.6.5.1.2.a are each modified by a footnote (*) which states the surveillance is not required to be met for up to 4 hours if an analysis demonstrates that one standby gas treatment subsystem remains capable of establishing the required secondary containment vacuum. Use of the footnote is expected to be infrequent but may be necessitated by situations in which secondary containment vacuum may be less than the required containment vacuum, such as, but not limited to, wind gusts or failure or change of operating normal ventilation subsystems. These conditions do not indicate any change in the leak tightness of the secondary containment boundary. The analysis should consider the actual conditions (equipment configuration, temperature, atmospheric pressure, wind conditions, measured secondary containment vacuum, etc.) to determine whether, if an accident requiring secondary containment to be OPERABLE were to occur, one train of standby gas treatment could establish the assumed secondary containment vacuum within the time assumed in the accident analysis. If so, the surveillance may be considered met for a period up to 4 hours. The 4-hour limit is based on the expected short duration of the situations when the footnote would be applied.

Surveillances 4.6.5.1.1.b.2 and 4.6.5.1.2.b.2 require verifying that one secondary containment personnel access door in each access opening is closed which provides adequate assurance that exfiltration from the secondary containment will not occur. An access opening contains at least one inner and one outer door. The intent is to not breach the secondary containment, which is achieved by maintaining the inner or outer personnel access door closed. Surveillances 4.6.5.1.1.b.2 and 4.6.5.1.2.b.2 provide an allowance for brief, inadvertent, simultaneous openings of redundant secondary containment personnel access doors for normal entry and exit conditions.

SR 4.6.5.3.d.2 excludes automatic dampers and valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to dampers or valves that are locked, sealed, or otherwise secured in the actuated position since the affected dampers or valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve or damper in a locked, sealed, or otherwise secured position requires an assessment of the operability of the system or any supported systems, including whether it is necessary for the valve or damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve or damper to the non-actuated position requires verification that the SR has been met within its required Frequency.

Although the safety analyses assumes that the reactor enclosure secondary containment draw down time will take 930 seconds, these surveillance requirements specify a draw down time of 916 seconds. This 14 second difference is due to the diesel generator starting and sequence loading delays which is not part of this surveillance requirement.

The reactor enclosure secondary containment draw down time analyses assumes a starting point of 0.25 inch of vacuum water gauge and worst case SGTS dirty filter flow rate of 2800 cfm. The surveillance requirements satisfy this assumption by starting the drawdown from ambient conditions and connecting the adjacent reactor enclosure and refueling area to the SGTS to split the exhaust flow between the three zones and verifying a minimum flow rate of 2800 cfm from the test zone. This simulates the worst case flow alignment and verifies adequate flow is available to drawdown the test zone within the required time. The Technical Specification Surveillance Requirement 4.6.5.3.b.3 is intended to be a multi-zone air balance verification without isolating any test zone.

The SGTS is common to Unit 1 and 2 and consists of two independent subsystems. The power supplies for the common portions of the subsystems are from Unit 1 safeguard busses, therefore the inoperability of these Unit 1 supplies are addressed in the SGTS ACTION statements in order to ensure adequate onsite power sources to SGTS for its Unit 2 function during a loss of offsite power event. The allowable out of service times are consistent with those in the Unit 1 Technical Specifications for SGTS and AC electrical power supply out of service condition combinations.

SECONDARY CONTAINMENT (Continued)

The SGTS fans are sized for three zones and therefore, when aligned to a single zone or two zones, will have excess capacity to more quickly drawdown the affected zones. There is no maximum flow limit to individual zones or pairs of zones and the air balance and drawdown time are verified when all three zones are connected to the SGTS.

The three zone air balance verification and drawdown test will be done after any major system alteration, which is any modification which will have an effect on the SGTS flowrate such that the ability of the SGTS to drawdown the reactor enclosure to greater than or equal to 0.25 inch of vacuum water gage in less than or equal to 916 seconds could be affected.

The field tests for bypass leakage across the SGTS charcoal adsorber and HEPA filter banks are performed at a flow rate of 5764 ± 10% cfm. The laboratory analysis performed on the SGTS carbon samples will be tested at a velocity of 66 fpm based on the system residence time.

The SGTS filter train pressure drop is a function of air flow rate and filter conditions. Surveillance testing is performed using either the SGTS or drywell purge fans to provide operating convenience.

Each reactor enclosure secondary containment zone and refueling area secondary containment zone is tested independently to verify the design leak tightness. A design leak tightness of 2500 cfm or less for each reactor enclosure and 764 cfm or less for the refueling area at a 0.25 inch of vacuum water gage will ensure that containment integrity is maintained at an acceptable level if all zones are connected to the SGTS at the same time.

SR 4.6.5.4.d.2 excludes automatic dampers and valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to dampers or valves that are locked, sealed, or otherwise secured in the actuated position since the affected dampers or valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve or damper in a locked, sealed, or otherwise secured position requires an assessment of the operability of the system or any supported systems, including whether it is necessary for the valve or damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve or damper to the non-actuated position requires verification that the SR has been met within its required Frequency.

The Reactor Enclosure Secondary Containment Automatic Isolation Valves and Refueling Area Secondary Containment Automatic Isolation Valves can be found in the UFSAR.

The post-LOCA offsite dose analysis assumes a reactor enclosure secondary containment post-draw down leakage rate of 2500 cfm and certain post-accident X/Q values. While the post-accident X/Q values represent a statistical interpretation of historical meteorological data, the highest ground level wind speed which can be associated with these values is 7 mph (Pasquill-Gifford stability Class G for a ground level release). Therefore, the surveillance requirement assures that the reactor enclosure secondary containment is verified under meteorological conditions consistent with the assumptions utilized in the design basis analysis. Reactor Enclosure Secondary Containment leakage tests that are successfully performed at wind speeds in excess of 7 mph would also satisfy the leak rate surveillance requirements, since it shows compliance with more conservative test conditions.

3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL

The primary containment atmospheric mixing system is provided to ensure adequate mixing of the containment atmosphere to prevent localized accumulations of hydrogen and oxygen from exceeding the lower flammability limit during post-LOCA conditions.

All nuclear reactors must be designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment. With the primary containment inert, that is, oxygen concentration <4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. The capability to inert the primary containment and maintain oxygen <4.0 v/o works together with Drywell Hydrogen Mixing System to provide redundant and diverse methods to mitigate events that produce hydrogen.

If oxygen concentration is ≥ 4.0 v/o at any time while operating in OPERATIONAL CONDITION 1 or 2, oxygen concentration must be restored to < 4.0 v/o within 72 hours. The 72 hour Completion Time is allowed when oxygen concentration is ≥ 4.0 v/o because of the low probability and long duration of an event that would generate significant amounts of hydrogen occurring during this period.

The provision of Specification 3.0.4.c is applicable. This allowance permits entry into the applicable OPERATIONAL CONDITION(S) while relying on the Actions. This allowance is acceptable because inerting the primary containment prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup, after entering OPERATIONAL CONDITIONS 1 and 2, and deinerted as soon as possible in the plant shutdown. It is acceptable to intentionally enter the Action prior to a shutdown in order to begin deinerting the primary containment prior to exiting the Applicability.

If oxygen concentration cannot be restored to within the limit within the required Completion Time, the plant must be brought to a OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, power must be reduced to HOT SHUTDOWN within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

3/4.7.1 SERVICE WATER SYSTEMS - COMMON SYSTEMS

The OPERABILITY of the service water systems ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

The RHRSW and ESW systems are common to Units 1 and 2 and consist of two independent subsystems each with two pumps. One pump per subsystem (loop) is powered from a Unit 1 safeguard bus and the other pump is powered from a Unit 2 safeguard bus. In order to ensure adequate onsite power sources to the systems during a loss of offsite power event, the inoperability of these supplies are restricted in system ACTION statements.

RHRSW is a manually operated system used for core and containment heat removal. Each of two RHRSW subsystems has one heat exchanger per unit. Each RHRSW pump provides adequate cooling for one RHR heat exchanger. By limiting operation with less than three OPERABLE RHRSW pumps with OPERABLE Diesel Generators, each unit is ensured adequate heat removal capability for the design scenario of LOCA/LOOP on one unit and simultaneous safe shutdown of the other unit.

Each ESW pump provides adequate flow to the cooling loads in its associated loop. With only two divisions of power required for LOCA mitigation of one unit and one division of power required for safe shutdown of the other unit, one ESW pump provides sufficient capacity to fulfill design requirements. ESW pumps are automatically started upon start of the associated Diesel Generators. Therefore, the allowable out of service times for OPERABLE ESW pumps and their associated Diesel Generators is limited to ensure adequate cooling during a loss of offsite power event. Alternatively, the allowable out-of-service times can be determined in accordance with the Risk Informed Completion Time Program.

SR 4.7.1.2.b.1 excludes automatic dampers and valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to dampers or valves that are locked, sealed, or otherwise secured in the actuated position since the affected dampers or valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve or damper in a locked, sealed, or otherwise secured position requires an assessment of the operability of the system or any supported systems, including whether it is necessary for the valve or damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve or damper to the non-actuated position requires verification that the SR has been met within its required Frequency.

3/4.7.2.1 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM

The OPERABILITY of the control room emergency fresh air supply system ensures that the control room will remain habitable for occupants during and following an uncontrolled release of radioactivity, hazardous chemicals, or smoke. Constant purge of the system at 1 cfm is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less Total Effective Dose Equivalent. This limitation is consistent with the requirements of 10 CFR Part 50.67, Accident Source Term.

Each CREFAS subsystem is considered OPERABLE when the individual components necessary to limit Control Room Envelope occupant exposure are OPERABLE. A subsystem is considered OPERABLE when its associated:

a. CREFAS fan is OPERABLE, and

b. HEPA filter and charcoal adsorbers are capable of performing their filtration functions, and

c. Heater, ductwork, dampers, controls, and power are OPERABLE, and air circulation to the occupied areas can be maintained. Air circulation is a support system function provided by one control room AC supply fan and one control room AC return air fan, and

d. CRE boundary is OPERABLE.

Since the Control Room Emergency Fresh Air Supply System is not credited for filtration in OPERATIONAL CONDITIONS 4 and 5, applicability to 4 and 5 is only required to support the Chlorine and Toxic Gas design basis isolation requirements.

The CREFAS is common to Units 1 and 2 and consists of two independent subsystems. The power supplies for the system are from Unit 1 Safeguard busses, therefore, the inoperability of these Unit 1 supplies are addressed in the CREFAS ACTION statements in order to ensure adequate onsite power sources to CREFAS during a loss of offsite power event. The allowable out of service

3/4.7.2.1 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

times are consistent with those in the Unit 1 Technical Specifications for CREFAS and AC electrical power supply out of service condition combinations.

The Control Room Envelope (CRE) is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and other noncritical areas including adjacent support offices, toilet and utility rooms. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, ceiling, ducting, valves, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

In addition, the CREFAS System provides protection from radiation, smoke and hazardous chemicals to the CRE occupants. The analysis of hazardous chemical releases demonstrates that the toxicity limits are not exceeded in the CRE following a hazardous chemical release (Ref. 1). The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown panels (Ref. 2).

In order for the CREFAS subsystems to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that CRE occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated.

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem TEDE), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

3/4.7.2.1 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

During the period that the CRE boundary is considered inoperable, action must be initiated immediately to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

SR 4.7.2.2 verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem Total Effective Dose Equivalent and the CRE occupants are protected from hazardous chemicals and smoke. SR 4.7.2.2 verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Required Action 3.7.2.a.2 must be entered. Required Action 3.7.2.a.2.c allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 3) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 4). These compensatory measures may also be used as mitigating actions as required by Required Action 3.7.2.a.2.b. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 5). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

3/4.7.2.1 CONTROL ROOM EMERGENCY FRESH AIR SUPPLY SYSTEM - COMMON SYSTEM (Continued)

REFERENCES

1. UFSAR Section 6.4
2. UFSAR Section 9.5
3. Regulatory Guide 1.196
4. NEI 99-03, "Control Room Habitability Assessment Guidance," June 2001.
5. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML040300694).

3/4.7.2.2 CONTROL ROOM AIR CONDITIONING (AC) SYSTEM - COMMON SYSTEM

Each MCR AC subsystem is considered operable when the individual components necessary to maintain the control room temperature are functional. Each subsystem includes a supply fan, a return air fan, associated ductwork, dampers, centrifugal water chiller, a chilled water circulating pump, MCR cooling coil, controls, power, piping, and valves. One control room supply fan and one control room return air fan and their associated ductwork, CREFAS subsystem function by providing a flow path to and from the control room whenever CREFAS is operating.

If both chillers or subsystems become inoperative and main control room temperature remains less than 90°F WBGT, 72-hours is permitted to restore one chiller/subsystem provided control room temperature is monitored once per 4 hours to ensure that temperature is monitored that occupants and equipment in the control room are not adversely affected. This repair time duration is reasonable considering that the control room temperature is being maintained within allowable limits and the low probability of an event occurring requiring control room isolation.

The main control room purge mod of operation, and any other viable supplemental cooling options (portable cooling, fans, opening doors, etc.) can be utilized if both chillers or subsystems are inoperative. A concurrent design basis event is not postulated while in the complete loss of cooling LCO to support supplemental cooling, as required, in order to maintain main control room temperature less than 90°F WBGT. This is based upon the low probability of a concurrent event occurring while in the 72-hour LCO that requires MCR isolation.

Temporary DWCW to CECW crosstie jumpers can also be utilized as a viable supplemental cooling option, but it requires a HELB door between the Turbine Enclosure and Control Enclosure to be breached (blocked open) while only in the 72-hour complete loss of cooling LCO. It is permitted to breach the subject HELB door for supplemental cooling jumper use although it impacts several multi-train TS systems and creates a loss of function situation which is not permitted under TS 3.0.9 if a HELB occurred. CREFAS, SGT, and EDGs (required for DBA accident mitigation) all constitute loss of function situations.

The safety related SSCs protected by the breached HELB door to solely facilitate utilizing the CECW to DWCW- crosstie cooling jumpers are not required to be declared inoperable while in the complete loss of CECW cooling 72-hour LCO.

The justification for this request was (1) the low probability of HELB occurring while in the LCO and (2) the ability to realistic detect a turbine enclosure high energy line leak far prior to a break occurring. The caveat for breaching the HELB door for this supplemental cooling provision is to confirm that a main steam line or feedwater high energy line leak is nonexistent. With this basis, safety related equipment in Control Enclosure room 619 would not be exposed to any post HELB environmental conditions that could compromise equipment functionality while only in the 72-hour complete loss of cooling dual unit LCO. Notwithstanding the above justification, if a postulated HELB occurred with the HELB door breached, while in the LCO, the ability to mitigate the consequences of a HELB are still maintained and plant safe shutdown can be achieved by using a preexisting fire safe shutdown strategy.

A list of impacted Tech. Spec. SSCs protected by the breached HELB door are provided below:

- Unit 1 and 2 SGT TS 3.6.5.3, 3.0.3 dual unit shutdown
- Unit 1 and 2 CREFAS TS 3.7.2.1, 3.0.3 dual unit shutdown
- Unit 1 RERS TS 3.6.5.4, 12-hour shutdown
- Unit 1 EDG Power TS 3.8.1.1 (3 inoperable EDGs), 2-hour action
- Unit 2 2B RERS, TS 3.6.5.4 7 day LCO
- Unit 2 EDG Power TS 3.8.1.1 (2 inoperable EDGs), 72-hour LCO

3/4.7.2.2 CONTROL ROOM AIR CONDITIONING (AC) SYSTEM - COMMON SYSTEM (Continued)

The MCR AC periodic surveillance requirement verifies that the system is Capable of removing the control room design basis heat loads.

- When handling RECENTLY IRRADIATED FUEL, a fuel handling accident is postulated and therefore it is appropriate to suspend movement of RECENTLY IRRADIATED FUEL.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

The reactor core isolation cooling (RCIC) system is provided to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without requiring actuation of any of the emergency core cooling system equipment. The RCIC system is conservatively required to be OPERABLE whenever reactor pressure ex-ceeds 150 psig. This pressure is substantially below that for which low pressure core cooling systems can provide adequate core cooling. Management of gas voids is important to RCIC System OPERABILITY.

The RCIC system specifications are applicable during OPERATIONAL CONDITIONS 1, 2, and 3 when reactor vessel pressure exceeds 150 psig because RCIC is the primary non-ECCS source of emergency core cooling when the reactor is pressurized.

With the RCIC system inoperable, adequate core cooling is assured by the OPERABILITY of the HPCI system and justifies the specified 14 day out-of-service period. Alternatively, out-of-service time can be determined in accordance with the Risk Informed Completion Time Program. A Note prohibits the application of Specification 3.0.4.b to an inoperable RCIC system. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable RCIC subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

The surveillance requirements provide adequate assurance that RCIC will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation during reactor operation, a complete functional test requires reactor shutdown.

During plant startup, when RCIC surveillance tests are being performed, the RCIC System is required to be tested within 12 hours after reactor pressure is adequate to perform each surveillance test. For the low reactor pressure surveillance requirement, the intent is to verify RCIC System operability prior to increasing reactor pressure above 165 psig. If operability of the RCIC System is not demonstrated within the 12-hour period, reactor steam dome pressure must be reduced to less than 150 psig within the following 72 hours. For the high reactor pressure surveillance test, the intent is to verify RCIC System operability as soon as possible once plant conditions support the testing. Power ascension can continue during the testing; however, if RCIC is found inoperable or the 12-hour period has elapsed power ascension must be stopped, and reactor steam dome pressure must be reduced to less than 150 psig within the following 72 hours.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM (Continued)

The RCIC System flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RCIC System and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RCIC System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RCIC System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RCIC System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative subset of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

Surveillance 4.7.3.a.2 is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

SR 4.7.3.c.1 excludes automatic dampers and valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to dampers or valves that are locked, sealed, or otherwise secured in the actuated position since the affected dampers or valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve or damper in a locked, sealed, or otherwise secured position requires an assessment of the operability of the system or any supported systems, including whether it is necessary for the valve or damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve or damper to the non-actuated position requires verification that the SR has been met within its required Frequency.

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3/4.7.5 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. This limitation will ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values. Sealed sources are classified into three groups according to their use, with surveillance requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism, i.e,, sealed sources within radiation monitoring devices, are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

SEALED SOURCE CONTAMINATION (Continued)

The testing frequency for start-up sources and fission detectors is based upon physical limitations in leak testing. For example, the Californium 252 start-up neutron source must be leak tested by the manufacturer remotely in a hot cell facility. Due to the physical design of this source, a six month frequency for contamination testing provides reasonable assurance that the radioactive material is properly contained.

3/4.7.6 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.7.7 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4 7.8 MAIN TURBINE BYPASS SYSTEM

The required OPERABILITY of the main turbine bypass system is consistent with the assumptions of the feedwater controller failure analysis in the cycle specific
transient analysis.

The main turbine bypass system is required to be OPERABLE to limit peak pressure in the main steam lines and to maintain reactor pressure within acceptable limits during events that cause rapid pressurization such that the Safety Limit MCPR is not exceeded. With the main turbine bypass system inoperable, continued operation is based on the cycle specific transient analysis which has been performed for the feedwater controller failure, maximum demand with bypass failure.

3/4 7.9 TURBINE ENLCOSURE MAIN STEAM LINE TUNNEL TEMPERATURE

Should a temperature greater than the limit be detected, operators will determine if there is a leak from the Main Steam Line pressure boundary. Evidence of a Main Steam leak includes, but is not limited to:

- An unexpected sudden rise in tunnel temperature,
- An unexpected increase in radiation monitor readings,
- An unexpected rise in TE sump levels,
- An unexpected decrease in plant electrical output, or
- Visual and sound indications.

If a Main Steam Line pressure boundary leak is detected, a plant shutdown is required. Pressure boundary leakage includes ASME SSC(s). Leakage past gaskets, packing, and seals is not pressure boundary leakage.

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety-related equipment required for (1) the safe shutdown of the facility and (2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criterion 17 of Appendix A to 10 CFR Part 50.

An offsite power source consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E emergency bus or buses. The determination of the OPERABILITY of an offsite source of power is dependent upon grid and plant factors that, when taken together, describe the design basis calculation requirements for voltage regulation. The combination of these factors ensures that the offsite source(s), which provide power to the plant emergency buses, will be fully capable of supporting the equipment required to achieve and maintain safe shutdown during postulated accidents and transients.

The plant factors consist of the status of the Startup Transformer (#10 and #20) load tap changers (LTCs), the status of the Safeguard Transformer (#101 and #201) load tap changers (LTCs), and the alignment of emergency buses on the Safeguard Buses (101-Bus and 201-Bus). For an offsite source to be considered operable, both of its respective LTCs (#10 AND #101 for the source to the 101-Bus, #20 AND #201 for the source to the 201-Bus) must be in service, and in automatic. For the third offsite source (from 66 kV System) to be considered operable, the connected Safeguard Transformer (#101 or #201) LTC must be in service and in automatic. There is a dependency between the alignment of the emergency buses and the allowable post contingency voltage drop percentage.

The grid factors consist of actual grid voltage levels (real time) and the post trip contingency voltage drop percentage value.

The minimum offsite source voltage levels are established by the voltage regulation calculation. The transmission system operator (TSO) will notify LGS when an agreed upon limit is approached.

The post trip contingency percentage voltage drop is a calculated value determined by the TSO that would occur as a result of the tripping of one of the Limerick generators. The TSO will notify LGS when an agreed upon limit is exceeded. The voltage regulation calculation establishes the acceptable percentage voltage drop based upon plant configuration; the acceptable value is dependent upon plant configuration.

Due to the 20 Source being derived from the tertiary of the 4A and 4B transformer, its operability is influenced by both the 230 kV system and the 500 kV system. The 10 Source operability is only influenced by the 230 kV system.

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS

The anticipated post trip contingency voltage drop for the 66 kV Source (Transformer 80) is calculated to be less than the 230 kV and 500 kV systems. This is attributed to the electrical distance between the output of the Limerick generators and the input to the 80 transformer. Additionally, the Unit Auxiliary Buses do not transfer to the 80 transformer; this provides margin to the calculated post trip contingency voltage drop limit.

There are various means of hardening the 10 and 20 Sources to obtain additional margin to the post trip contingency voltage drop limits. These means include, but are not limited to, source alignment of the 4 kV buses, preventing transfer of 13 kV buses, limiting transfer of selected 13 kV loads, and operation with 13 kV buses on the offsite sources. The specific post trip contingency voltage drop percentage limits for these alignments are identified in the voltage regulation calculation, and controlled via plant procedures. There are also additional restrictions that can be applied to these limits in the event that an LTC is taken to manual, or if the bus alignment is outside the Two Source rule set.

LGS unit post trip contingency voltage drop percentage calculations are performed by the PJM Energy Management System (EMS). The PJM EMS consists of a primary and backup system. LGS will be notified if the real time contingency analysis capability of PJM is lost. Upon receipt of this notification, LGS is to request PJM to provide an assessment of the current condition of the grid based on the tools that PJM has available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and whether the current condition of the grid is bounded by the grid studies previously performed for LGS.

Based on specific design analysis, variations to any of these parameters can be determined, usually at the sacrifice of another parameter, based on plant conditions. Specifics regarding these variations must be controlled by plant procedures or by operability determinations, backed by specific design calculations.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the safety analyses and are based upon maintaining at least two of the onsite A.C. and the corresponding D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss-of-offsite power and single failure of the other onsite A.C. or D.C. source. At least two onsite A.C. and their corresponding D.C. power sources and distribution systems providing power for at least two ECCS divisions (1 Core Spray loop, 1 LPCI pump and 1 RHR pump in suppression pool cooling) are required for design basis accident mitigation as discussed in UFSAR Table 6.3-3.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Onsite A.C. operability requirements for common systems such as CREFAS, SGTS, RHRSW and ESW are addressed in the appropriate system specification action statements.

A.C. Sources

As required by Specification 3.8.1.1, Action e, when one or more diesel generators are inoperable, there is an additional ACTION requirement to verify that all remaining required systems, subsystems, trains, components, and devices, that depend on the OPERABLE diesel generators as a source of emergency power, are also OPERABLE. The LPCI mode of the RHR system is considered a four train system, of which only two trains are required. The verification for LPCI is not required until two diesel generators are inoperable. This requirement is intended to provide assurance that a loss-of-offsite power event will not result in a complete loss of safety function of critical systems during the period when one or more of the diesel generators are inoperable. The term verify as used in this context means to administratively check by examining logs or other information to determine if certain components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

Specification 3.8.1.1, Action j, prohibits the application of Specification 3.0.4.b to an inoperable diesel generator. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable diesel generator subsystem and the provisions of Specification 3.0.4.b, which allow entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the Limiting Condition for Operation not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

If it can be determined that the cause of the inoperable EDG does not exist on the remaining operable EDG(s), based on a common-mode evaluation, then the EDG start test (SR 4.8.1.1.2.a.4) does not have to be performed. If it cannot otherwise be determined that the cause of the initial inoperable EDG does not exist on the remaining EDG(s), then satisfactory performance of the start test suffices to provide assurance of continued operability of the remaining EDG(s). If the cause of the initial inoperability exists on the remaining operable EDG(s), the EDG(s) shall be declared inoperable upon discovery and the appropriate action statement for multiple inoperable EDGs shall be entered. In the event the inoperable EDG is restored to operable status prior to completing the EDG start test (SR 4.8.1.1.2.a.4) or common-mode failure evaluation as required in Specification 3.8.1.1, the plant corrective action program shall continue to evaluate the common-mode failure possibility. However, this continued evaluation is not subject to the time constraint imposed by the action statement. The provisions contained in the inoperable EDG action requirements that avoid unnecessary EDG testing are based on Generic Letter 93-05, “Line-Item Technical Specifications Improvement to Reduce Surveillance Requirements for Testing During Power Operation,” dated September 27, 1993.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

The time, voltage, and frequency acceptance criteria specified for the EDG single largest post-accident load rejection test (SR 4.8.1.1.2.e.2) are derived from Regulatory Guide 1.9, Rev. 2, December 1979, recommendations. The test is acceptable if the EDG speed does not exceed the nominal (synchronous) speed plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 115% of nominal, whichever is lower. This computes to be 66.5 Hz for the LGS EDGs. The RHR pump motor represents the single largest post-accident load. The 1.8 seconds specified is equal to 60% of the 3-second load sequence interval associated with sequencing the next load following the RHR pumps in response to an undervoltage on the electrical bus concurrent with a LOCA. This provides assurance that EDG frequency does not exceed predetermined limits and that frequency stability is sufficient to support proper load sequencing following a rejection of the largest single load.

D.C. Sources

With one division with one or two battery chargers inoperable (e.g., the voltage limit of 4.8.2.1.a.2 is not maintained), the ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Action a.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 18 hours, the battery will be restored to its fully charged condition (Action a.2) from any discharge that might have occurred due to the charger inoperability.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 18 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 18 hours (Action a.2).

Action a.2 requires that the battery float current be verified for Divisions 1 and 2 as $\leq$ 2 amps, and for Divisions 3 and 4 as $\leq$ 1 amp. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 18 hour period the battery float current is not within limits this indicates there may be additional battery problems.

Action a.3 limits the restoration time for the inoperable battery charger to 7 days or in accordance with the Risk Informed Completion Time Program. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 days reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status. Alternatively, the allowable out-of-service time can be determined in accordance with the Risk Informed Completion Time Program.

With one or more cells in one or more batteries in one division < 2.07 V, the battery cell is degraded. Per Action b.1, within 2 hours, verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (4.8.2.1.a.2) and of the overall battery state of charge by monitoring the battery float charge current (4.8.2.1.a.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, with one or more cells in one or more batteries < 2.07 V, continued operation is permitted for a limited period up to 24 hours.

Division 1 or 2 with float current > 2 amps, or Division 3 or 4 with float current > 1 amp, indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Per Action b.2, within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage.

Since Actions b.1 and b.2 only specify "perform," a failure of 4.8.2.1.a.1 or 4.8.2.1.a.2 acceptance criteria does not result in this Action not being met. However, if one of the Surveillance Requirements is failed the appropriate Action(s), depending on the cause of the failures, is also entered.

If the Action b.2 condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 18 hours is a reasonable time prior to declaring the battery inoperable.

With one or more batteries in one division with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, (i.e., greater than the minimum level indication mark), the battery still retains sufficient capacity to perform the intended function. Per Action b.3, within 31 days the minimum established design limits for electrolyte level must be re-established.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Action b.3 addresses this potential (as well as provisions in Specification 6.8.4.h, "Battery Monitoring and Maintenance Program"). Within 8 hours level is required to be restored to above the top of the plates. The Action requirement to verify that there is no leakage by visual inspection and the Specification 6.8.4.h item to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE Standard 450-1995. They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the battery may have to be declared inoperable and the affected cell(s) replaced.

Per Action b.4, with one or more batteries in one division with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

Per Action b.5, with one or more batteries in more than one division with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that multiple divisions are involved. With multiple divisions involved, this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer restoration times specified for battery parameters on one division not within limits are therefore not appropriate, and the parameters must be restored to within limits on all but one division within 2 hours.

When any battery parameter is outside the allowances of Actions b.1, b.2, b.3, b.4, or b.5, sufficient capacity to supply the maximum expected load requirement is not ensured and a 2 hour restoration time is appropriate. Additionally, discovering one or more batteries in one division with one or more battery cells float voltage less than 2.07 V and float current greater than limits indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be restored within 2 hours.

When any batteries and/or battery chargers in two divisions of the required D.C. electrical sources are inoperable, or when two or more of the required A.C. and/or D.C. distribution system divisions are not energized resulting in a loss of function, the unit must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least HOT SHUTDOWN within 12 hours and to COLD SHUTDOWN within 36 hours. The allowed times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that (1) the facility can be maintained in the shutdown or refueling condition for extended time periods and (2) sufficient instrumentation and control capability is available for monitoring and maintaining the unit status.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

The surveillance requirements for demonstrating the OPERABILITY of the diesel generators are in accordance with the recommendations of Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies, March 10, 1971, Regulatory Guide 1.137 "Fuel-Oil Systems for Standby Diesel Generators," Revision 1, October 1979 and Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977 except for paragraphs C.2.a(3), C.2.b, C.2.c(1), C.2.c(2), C.2.d(3) and C.2.d(4), and the periodic testing will be performed in accordance with the Surveillance Frequency Control Program. The exceptions to Regulatory Guide 1.108 allow for gradual loading of diesel generators during testing and decreased surveillance test frequencies (in response to Generic Letter 84-15). The single largest post-accident load on each diesel generator is the RHR pump.

The Surveillance Requirement for removal of accumulated water from the fuel oil storage tanks is for preventive maintenance. The presence of water does not necessarily represent failure of the Surveillance Requirement, provided the accumulated water is removed during performance of the Surveillance. Accumulated water in the fuel oil storage tanks constitutes a collection of water at a level that can be consistently and reliably measured. The minimum level at which accumulated water can be consistently and reliably measured in the fuel oil storage tank sump is 0.25 inches. Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of accumulated water from the fuel storage tanks once every (31) days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137.

The surveillance requirements for demonstrating the OPERABILITY of the units batteries are in accordance with the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications."

Verifying battery float current while on float charge (4.8.2.1.a.1) is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450-1995.

This Surveillance Requirement states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of 4.8.2.1.a.2. When this float voltage is not maintained the Actions of LCO 3.8.2.1, Action b., are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limits are established based on the float voltage range and is not directly applicable when this voltage is not maintained.

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A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Verifying, per 4.8.2.1.a.2, battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the minimum float voltage established by the battery manufacturer (2.20 Vpc, average, or 132 V at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years).

Surveillance Requirements 4.8.2.1.b.1 and 4.8.2.1.c require verification that the cell float voltages are equal to or greater than 2.07 V.

The limit specified in 4.8.2.1.b.2 for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability.

Surveillance Requirement 4.8.2.1.b.3 verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60 degrees Fahrenheit). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity.

Surveillance Requirement 4.8.2.1.d.1 verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32, the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

Surveillance Requirement 4.8.2.1.d.1 requires that each battery charger be capable of supplying the amps listed for the specified charger at the minimum established float voltage for 4 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. This time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

A battery service test, per 4.8.2.1.d.2, is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements as specified in the UFSAR.

A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

A battery performance discharge test (4.8.2.1.e and f) is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage. Degradation (as used in 4.8.2.1.f) is indicated when the battery capacity drops more than 10% from its capacity on the previous performance test, or is below 90% of the manufacturer's rating.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying 4.8.2.1.e and 4.8.2.1.f; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of 4.8.2.1.d.2.

3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

The RPS Electric Power Monitoring System is provided to isolate the RPS bus from the RPS/UPS inverter or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus from unacceptable voltage and frequency conditions. The essential equipment powered from the RPS buses includes the RPS logic, scram solenoids, and valve isolation logic.

The Allowable Values are derived from equipment design limits, corrected for calibration and instrument errors. The trip setpoints are then determined, accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection and include allowances for instrumentation uncertainties, calibration tolerances, and instrument drift.

The Allowable Values for the instrument settings are based on the RPS providing power within the design ratings of the associated RPS components (e.g., RPS logic, scram solenoids). The most limiting voltage requirement and associated line losses determine the settings of the electric power monitoring instrument channels.

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3/4.9 REFUELING OPERATIONS

BASES

3/4.9.1 REACTOR MODE SWITCH

Locking the OPERABLE reactor mode switch in the Refuel position, as specified, ensures that the restrictions on control rod withdrawal and refueling platform movement during the refueling operations are properly activated. These conditions reinforce the refueling procedures and reduce the probability of inadvertent criticality, damage to reactor internals or fuel assemblies, and exposure of personnel to excessive radioactivity.

The effect of these requirements is to lock the Reactor Mode Switch in the Refuel position during refueling operations, which is defined at Limerick by our refueling procedures and only occurs during OPCON 5. Additionally, in OPCON 3 and 4 when the one rod out interlock is required to be OPERABLE to withdraw a single control rod with the Mode Switch in the Refuel Position.

A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specifications tests as determined by the Surveillance Frequency Control Program.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of at least two source range monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core. The minimum count rate is not required when sixteen or fewer fuel assemblies are in the core. During a typical core reloading, two, three or four irradiated fuel assemblies will be loaded adjacent to each SRM to produce greater than the minimum required count rate. Loading sequences are selected to provide for a continuous multiplying medium to be established between the required operable SRMs and the location of the core alteration. This enhances the ability of the SRMs to respond to the loading of each fuel assembly. During a core un-loading, the last fuel to be removed is that fuel adjacent to the SRMs.

3/4.9.3 CONTROL ROD POSITION

The requirement that all control rods be inserted during other CORE ALTERATIONS ensures that fuel will not be loaded into a cell without a control rod.

3/4.9.4 DECAY TIME

The minimum requirement for reactor subcriticality prior to fuel movement ensures that sufficient time has elapsed to allow the radioactive decay of the short lived fission products. This decay time is consistent with the assumptions used in the accident analyses.

3/4.9.5 COMMUNICATIONS

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity condition during movement of fuel within the reactor pressure vessel.

3/4.9.6 REFUELING PLATFORM

The OPERABILITY requirements ensure that (1) the refueling platform will be used for handling control rods and fuel assemblies within the reactor pressure vessel, (2) each hoist has sufficient load capacity for handling fuel assemblies and control rods, (3) the core internals and pressure vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations, and (4) inadvertent criticality will not occur due to fuel being loaded into a unrodded cell.

Inadvertent criticality is prevented by the refueling interlocks that block unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn or withdrawal of a rod from the core while the grapple is over the core and loaded with fuel). The hoist loaded values identified in Sections 4.9.6.1b and 4.9.6.1c support the refueling interlock logic by ensuring that the hoist fuel loaded switches function with a load lighter than the weight of a single fuel assembly in water. Load values represent fuel (load) on the grapple. The values of 485 +/- 50 pounds and 550 + 0, -115 pounds are both less than the weight of a single fuel assembly in water attached to the grapple. These load values ensure that as soon as a fuel assembly is grappled and lifted, the refueling interlocks (control rod block and bridge motion interlock) are enforced as required. The hoist load weighing system is compensated for mast weight to ensure that lifting of components other than fuel assemblies (e.g., blade guides) do not cause inadvertent control rod blocks or bridge motion stops.

3/4.9.7 CRANE TRAVEL - SPENT FUEL STORAGE POOL

The restriction on movement of loads in excess of the nominal weight of a fuel assembly and associated lifting device over other fuel assemblies in the storage pool ensures that in the event this load is dropped 1) the activity release will be limited to that contained in a single fuel assembly, and 2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the safety analyses.

3/4.9.8 and 3/4.9.9 WATER LEVEL - REACTOR VESSEL and WATER LEVEL - SPENT FUEL STORAGE POOL

The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. This minimum water depth is consistent with the assumptions of the accident analysis.

3/4.9.10 CONTROL ROD REMOVAL

These specifications ensure that maintenance or repair of control rods or control rod drives will be performed under conditions that limit the probability of inadvertent criticality. The requirements for simultaneous removal of more than one control rod are more stringent since the SHUTDOWN MARGIN specification provides for the core to remain subcritical with only one control rod fully withdrawn.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed by the RHR system to maintain adequate reactor coolant temperature.

RHR shutdown cooling is comprised of four (4) subsystems which make two (2) loops. Each loop consists of two (2) motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Two (2) redundant, manually controlled shutdown cooling subsystems of the RHR system provide decay heat removal. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via the associated recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System.

An OPERABLE RHR shutdown cooling subsystem consists of one (1) OPERABLE RHR pump, one (1) heat exchanger, and the associated piping and valves. The requirement for having one (1) RHR shutdown cooling subsystem OPERABLE ensures that 1) sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor pressure vessel below 140°F, and 2) sufficient coolant circulation would be available through the reactor core to assure accurate temperature indication. Management of gas voids is important to RHR Shutdown Cooling Subsystem OPERABILITY.

The requirement to have two (2) RHR shutdown cooling subsystems OPERABLE when there is less than 22 feet of water above the reactor vessel flange ensures that a single failure of the operating loop will not result in a complete loss of residual heat removal capability. With the reactor vessel head removed and 22 feet of water above the reactor vessel flange, a large heat sink is available for core cooling. Thus, in the event of a failure of the operating RHR subsystem, adequate time is provided to initiate alternate methods capable of decay heat removal or emergency procedures to cool the core.

To meet the LCO of the two (2) subsystems OPERABLE when there is less than 22 feet of water above the reactor vessel flange, both pumps in one (1) loop or one (1) pump in each of the two (2) loops must be OPERABLE. The two (2) subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Additionally, each shutdown cooling subsystem can provide the required decay heat removal capability; however, ensuring operability of the other shutdown cooling subsystem provides redundancy.

The required cooling capacity of an alternate method of decay heat removal should be ensured by verifying its capability to maintain or reduce reactor coolant temperature either by calculation (which includes a review of component and system availability to verify that an alternate decay heat removal method is available) or by demonstration. Decay heat removal capability by ambient losses can be considered in evaluating alternate decay heat removal capability.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION (Continued)

RHR Shutdown Cooling System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR shutdown cooling subsystems and may also prevent water hammer, pump cavitation, and pumping of non-condensible gas into the reactor vessel. This surveillance verifies that the RHR Shutdown Cooling System piping is sufficiently filled with water prior to placing the system in operation when in OPCON 5. The RHR Shutdown Cooling System is OPERABLE when it is sufficiently filled with water to ensure that it can reliably perform its intended function.

The RHR Shutdown Cooling System is a manually initiated mode of the RHR System that is aligned for service using system operating procedures that ensure the RHR shutdown cooling suction and discharge flow paths are sufficiently filled with water. An RHR Shutdown Cooling sub-system that is already in operation at the time of entry into the APPLICABILITY is OPERABLE. For an idle RHR Shutdown Cooling subsystem, the surveillance is met through the performance of the operating procedures that place the RHR Shutdown Cooling subsystem in service.

With the required decay heat removal subsystem(s) inoperable and the required alternate method(s) of decay heat removal not available in accordance with Action "a", additional actions are required to minimize any potential fission product release to the environment. This includes ensuring Refueling Floor Secondary Containment is OPERABLE; one (1) Standby Gas Treatment subsystem is OPERABLE; and Secondary Containment isolation capability (i.e., one (1) Secondary Containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated penetration not isolated that is assumed to be isolated to mitigate radioactive releases. This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

If no RHR subsystem is in operation, an alternate method of coolant circulation is required to be established within one (1) hour. The Completion Time is modified such that one (1) hour is applicable separately for each occurrence involving a loss of coolant circulation.

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

The requirement for PRIMARY CONTAINMENT INTEGRITY is not applicable during the period when open vessel tests are being performed during the low power PHYSICS TESTS.

3/4.10.2 ROD WORTH MINIMIZER

In order to perform the tests required in the technical specifications it is necessary to bypass the sequence restraints on control rod movement. The additional surveillance requirements ensure that the specifications on heat generation rates and shutdown margin requirements are not exceeded during the period when these tests are being performed and that individual rod worths do not exceed the values assumed in the safety analysis.

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

Performance of shutdown margin demonstrations with the vessel head removed requires additional restrictions in order to ensure that criticality does not occur. These additional restrictions are specified in this LCO.

3/4.10.4 RECIRCULATION LOOPS

This special test exception permits reactor criticality under no flow conditions and is required to perform certain startup and PHYSICS TESTS while at low THERMAL POWER levels.

3/4.10.5 OXYGEN CONCENTRATION

Relief from the oxygen concentration specifications is necessary in order to provide access to the primary containment during the initial startup and testing phase of operation. Without this access the startup and test program could be restricted and delayed.

3/4.10.6 TRAINING STARTUPS

This special test exception permits training startups to be performed with the reactor vessel depressurized at low THERMAL POWER and temperature while controlling RCS temperature with one RHR subsystem aligned in the shutdown cooling mode in order to minimize contaminated water discharge to the radioactive waste disposal system.

3/4.10.7 SPECIAL INSTRUMENTATION - INITIAL CORE LOADING

This special test exception permits relief from the requirements for a minimum count rate while loading the first 16 fuel bundles to allow sufficient source-to-detector coupling such that minimum count rate can be achieved on an SRM. This is acceptable because of the significant margin to criticality while loading the initial 16 fuel bundles.

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

This special test exception permits certain reactor coolant pressure tests to be performed in OPERATIONAL CONDITION 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) or plant temperature control capabilities during these tests require the pressure testing at temperatures greater than 200°F (normally corresponding to OPERATIONAL CONDITION 3). The additionally imposed OPERATIONAL CONDITION 3 requirements for SECONDARY CONTAINMENT INTEGRITY provide conservatism in response to an operational event.

Invoking the requirement for Refueling Area Secondary Containment Integrity along with the requirement for Reactor Enclosure Secondary Containment Integrity applies the requirements for Reactor Enclosure Secondary Containment Integrity to an extended area encompassing Zones 2 and 3. Core alterations and fuel handling are prohibited in this secondary containment configuration. Drawdown and inleakage testing performed for the combined zone system alignment shall be considered adequate to demonstrate integrity of the combined zones.

Inservice hydrostatic testing and inservice leak pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code are performed prior to the reactor going critical after a refueling outage. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.6, Reactor Coolant System Pressure/Temperature Limits. These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence. With increased reactor fluence over time, the minimum allowable vessel temperature increases at a given pressure.

3/4.11.1.1 and 3/4.11.1.2 (Deleted)

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3/4.11.1.3 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.11.1.4 LIQUID HOLDUP TANKS

The tanks listed in this specification include all those outdoor radwaste tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

Restricting the quantity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tanks' contents, the resulting concentrations would be less than 10 times the limits of 10 CFR Part 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an UNRESTRICTED AREA.

3/4.11.2.1 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE ODCM.

3/4.11.2.2 through 3/4 11.2.4 (Deleted)

THE INFORMATION FROM THESE SECTIONS
HAS BEEN RELOCATED TO THE ODCM.

3/4.11.2.5 (Deleted) - INFORMATION FROM THIS SECTION RELOCATED TO THE TRM.

3/4.11.2.6 MAIN CONDENSER

Restricting the gross radioactivity rate of noble gases from the main condenser provides reasonable assurance that the total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR Part 100 in the event this effluent is inadvertently discharged directly to the environment without treatment. This specification implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR Part 50.

3/4.11.2.7, 3/4.11.3, and 3/4.11.4 (Deleted) - INFORMATION FROM THESE SECTIONS RELOCATED TO THE ODCM OR PCP.

Section 3/4.12 (Deleted)

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HAS BEEN RELOCATED TO THE ODCM.
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